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THE DRILLING OF A HORIZONTAL WELL IN A MATURE OIL FIELD

Final Report

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EXECUTIVE SUMMARY

This report documents the drilling of a medium radius horizontal well in the Bartlesville Sand of the Flatrock Field, Osage County, Oklahoma by Rougeot Oil and Gas Corporation (Rougeot) of Sperry, Oklahoma. The report includes the rationale for selecting the particular site, the details of drilling the well, the production response, conclusions reached, and recommendations made for the future drilling of horizontal wells.

Horizontal drilling is being employed around the world to maximize the profitability of developing oil fields. Most horizontal drilling currently occurring involves high cost drilling for large quantities of oil reserves. However, in this project Rougeot was testing horizontal drilling on a low cost basis to recover the remaining reserves in a mature Mid-Continent oil field.

Rougeot has been active in drilling oil wells and related oil and gas production in the Flatrock Field for approximately 23 years. The Flatrock Field was discovered in 1904 and was considered fully developed by 1925 after over 1,000 development wells had been drilled to develop the field. The field has produced in excess of 30 million barrels of oil to date. It is estimated that millions of barrels of oil remain in the field, but because of various factors, it is not producible in economic quantities with currently available oil well drilling and completion technology. Horizontal drilling has the potential to access these resources and allow for the economic production of the oil remaining in the Flatrock Field as well as in potentially hundreds of other Mid-Continent oil fields.

The producing horizon for this project, the Bartlesville Sand, lies at a relatively shallow depth (about 1,400 feet), has low permeability, and is underlain by a sand aquifer. The Bartlesville Sand is classed as a fluvial dominated deltaic sandstone reservoir, a class ranked by the Department of Energy among the most important on the basis of potential recoverable oil. Reservoirs of this type will be targeted under the Department of Energy's new Oil Research Program Implementation Plan for research projects that will demonstrate successful technologies for recovering the oil remaining after primary and secondary production.

In the absence of private funding for an infill medium radius horizontal well, Rougeot submitted an unsolicited proposal to the U.S. Department of Energy to cost share the project. In July 1989 the

Department of Energy awarded Rougeot a grant providing funds for the drilling costs, under which Rougeot would fund all other capital items and expenses, and provide a report for use in the Department of Energy's technology transfer program.

Planning the well was difficult as there is very little publicly available data that provides details of horizontal drilling. The principal source of data was directional drilling vendors. The vendors projected job requirements were drastically different and somewhat contradictory. Vendor job cost estimates varied up to 300%.

The well plan called for the placement of a 1,000' horizontal wellbore at a vertical depth of 1400'. The drill target was 10' thick and 200' wide. The spacing of the two rows of producing wells between which the horizontal wellbore is centered is 510'.

In June of 1990, Rougeot drilled the horizontal well (Wilson 25) attaining 1,050' of horizontal wellbore at a total cost of \$150,532. The drilling problems that occurred were minor and are readily avoidable in the future.

The well's productivity was tested with a rod pumping system before any wellbore clean-up or stimulation. After three months' production, the well's stabilized production rate was 6 barrels of oil per day and 0.84 barrels of water per day, providing a very low water cut for this field. This level of oil production is 200% to 600% greater than a typical unstimulated vertical well. The production data for the well indicates that with wellbore clean-up/stimulation and increased wellbore length, future horizontal drilling in the Flatrock Field could be economically viable.

The data from the Wilson 25 well provides Rougeot and other independent oil companies a basis for estimating costs and planning the functional drilling of a medium radius horizontal well. Additional work and testing is needed in the areas of horizontal wellbore clean-up/stimulation and the effects of selecting a wellbore direction in non-fractured reservoirs before the full potential of horizontal drilling in the Mid-Continent area can be fairly evaluated.

BACKGROUND

U.S. Department of Energy's Objective.

In January 1989, Rougeot Oil and Gas Corporation (Rougeot) submitted to the U.S. Department of Energy (DOE) an unsolicited proposal (USP) to cost-share the drilling of a horizontal well in the Bartlesville Sand of the Flatrock Field in Osage County, Oklahoma. The Bartlesville Sand lies at relatively shallow depth (1,400 feet), has low permeability, and is underlain by a sand aquifer. The unit belongs to the high priority reservoir class termed "Fluvial-Dominated Delta" with billions of barrels of unrecovered oil, a major target of the DOE's Oil Research Implementation Plan. This sand is exploited mainly by the independent oil operators.

The production potential of a horizontal well in such a reservoir in a mature oil field needed to be evaluated and the technology transferred to the oil industry in the near term (one to five years). If economically successful, horizontal drilling in the Mid-Continent by the thousands of independent oil operators could increase the domestic oil supply as well as to provide an economic spark to the depressed oil industry. If not economically successful, the project would provide detailed technical information to the independent oil operators so they could assess the applicability of "horizontal drilling" on their leases.

In July 1989, Rougeot was awarded a grant from the DOE for cost-sharing the drilling of a medium radius horizontal well.

Rougeot's Objective.

Rougeot's objective was to drill an infill medium radius horizontal well in the Bartlesville Sand of the North Flatrock field, Osage County, Oklahoma, and obtain production data as a means of determining the profitability of a horizontal well versus a vertical well in a mature oil field.

Rougeot has found that private funding for an infill medium radius horizontal well was not available and approached the DOE to fund the project on a cost share basis as part of its program of technology transfer to independents.

In July 1989 the DOE awarded Rougeot a grant providing funds for the drilling costs; Rougeot contributed all other capital items (oil lease, production facilities, and salt water disposal facilities) and all other expenses (geological, engineering and production). Rougeot's comprehensive report on the drilling of the well will be disseminated to the public as part of the DOE's technology transfer program.

SITE SELECTION

History of the Flatrock Field.

The Flatrock Field is principally a Bartlesville Sand field that was discovered in 1904 and is located in southeast Osage County, Oklahoma (See Figure 1). There were in excess of 1000 wells drilled into this Bartlesville Sand field found at approximately 1400' between 1904 and 1925. Most wells were drilled on 6 acre spacing. The field covers approximately 7,000 acres and has produced in excess of 30,000,000 barrels of oil to date, principally from the Bartlesville Sand. The Bartlesville Sand in this field is generally 150' thick and is comprised of four sections that are described as follows:

- (a) The top 10 to 15 feet is a tight shaley sand commonly called the "gas sand". The name "gas sand" is relative to the oil sand as the drilling samples from this section contain no free oil and only a gas "show". The productive capability of this sand is not significant.
- (b) Below the "gas sand" is a section 20' to 40' thick that is less shaley than the "gas sand" and is commonly referred to as the "oil sand". In the drilling samples, the oil sand commences upon the first occurrence of free oil. This section contains the majority of the Bartlesville Sand oil reserves.
- (c) Below the "oil sand" is a transitional section that contains economical oil reserves with water. This sand is cleaner than the "oil sand" and is typically 20' to 40' thick.
- (d) Below the transitional section is the water sand which is a very clean sand that is capable of yielding water at rates greater than 1,000 barrels per day.

There are several shaley sand "breaks" within the "oil sand" and the transitional section. The average porosity of the "oil sand" is between 15% and 18% and water saturations between 25% and 40%. The total oil bearing sand (oil and transitional) section thickness is generally 60' to 80' with an average porosity of 12% to 13% and a water saturation of 42% to 48%. While the permeability of the entire transitional and water zones is not known, the "oil sand" permeability averages approximately 45 md. A fairly active water drive exists since the reservoir pressure has been naturally maintained between 200

and 250 PSI. All historic data suggests original bottom hole pressure was less than 400 PSI. The completion methods available to the early 1900s drillers were ideally suited for producing oil out of the upper part of the reservoir without incurring initial significant water production. The field was drilled using cable tools with 7" casing set on top of the Bartlesville gas sand. Generally, drilling continued until 20 feet of good Bartlesville "oil sand" was identified. This was the amount of sand deemed necessary to obtain an economic well, yet eliminated the risk of drilling into the water sand. The unstimulated production rate from this sand was usually less than 5 barrels of oil per day. The only known method of clean-up/stimulation, a nitroglycerin shot of 4½ quarts per foot, was necessary to bring the oil production up to acceptable economic volumes of the time. Although this stimulation technique is primitive compared to the modern day method of hydraulic fracturing, it was consistently effective in that it kept the stimulation out of the underlying water sand and resulted in wells that initially produced an average of 20 to 50 barrels of oil per day with very little water and on average attained cumulative production of 25,000 barrels of oil per well over a period of approximately 60 years. It should be noted that while initial water production rates were insignificant, the percentage of water to oil would become greater than 50% in less than a year.

Drilling in the North Flatrock Field - Rougeot's Experience

Detailed analysis of production records in the mid 1970s by Rougeot Oil and Gas Corporation (Rougeot) for the northern sector of the Flatrock Field revealed evidence that questioned the generally accepted belief that existing spacing had depleted the Bartlesville Sand. In these records Rougeot found two Bartlesville Sand wells drilled over two miles apart, each inside four 6 acre spaced wells ("five spotting"), recovered as much oil as was produced from each of the old original four surrounding wells. These two wells drilled in 1947 and 1954 respectively, are the Ryder 24 (SW/4 Sec. 28-21N-12E) and the Norris Bratton 15 (SW/4 Sec. 15-21N-12E). Based on oil production history of these two wells, it appeared that the old nitroglycerin shot wells drained a much smaller area than previously believed.

Rougeot subsequently drilled ten Bartlesville Sand "five spot" wells and wells spotted at less densely spaced locations on its acreage in the northern half of the Flatrock Field (North Flatrock Field). Instead of nitroglycerin shooting to complete these wells, Rougeot used hydraulic fracturing as a means of stimulation. In a reservoir like the Bartlesville Sand with a fairly active water sand below and in contact with the oil sand, it was very difficult for Rougeot to confine these fractures primarily to the oil sand and out of the underlying water sand. Rougeot's "five spot" infill drilling was successful in two cases in confining the hydraulic fracturing primarily to the oil sand, namely the Norris Bratton 1-A (SW/4 Sec. 15) and the Wheeler 1-A (SE/4 Sec. 15) drilled in 1978 and 1980 respectively.

Generally, "five spot" infill wells and wells drilled at less dense spacing than six acres into the Bartlesville Sand by Rougeot would make 1 to 3 barrels of oil per day naturally with little or no water. However, after fracture treatment, a typical well would yield minimal amounts of oil and hundreds of barrels of water per day. It is significant to note that each of the wells drilled verified the existence of an oil-water contact point close to the field's original and actual production volumes from the successfully completed wells confirmed that very little, if any, drainage of oil and gas reserves had occurred from these new wells due to the surrounding old original wells.

In an effort to develop a successful method to consistently complete in the Bartlesville Sand, Rougeot drilled the Childress 2-A (SW/4 Sec. 17-21N-12E) in 1986. A nitroglycerin shot of 4½ qts./ft. was detonated over a 20' Bartlesville oil sand section yielding initial production of 20 BOPD and 20 BWPD.

The decline curve of the Childress 2-A is comparable to the decline curve of the original wells in the field and its ultimate reserves should be in excess of 25,000 barrels. However, it will take 60 years to recover the 25,000 barrels. A nitroglycerin shot completion is relatively expensive and an oil price of over \$25.00/barrel is required to provide a reasonable return on investment.

Recent depressed world oil prices have caused both independent and major oil companies to search for technologies to improve the efficiency and economics of oil production. One such method known for years, but until recently has not been frequently employed, is medium radius horizontal drilling. Medium radius horizontal drilling appears to be a possible solution for completing in a reservoir with low permeability and bottom water such as the Bartlesville Sand reservoir. Where hydraulic fracturing creates the artificial permeability necessary for a tight oil sand like the Bartlesville Sand to drain efficiently, the azimuth or path of a hydraulic fracture cannot be controlled. As numerous completion attempts by Rougeot have been confirmed, hydraulic fracturing in the Bartlesville Sand has a high probability of resulting in fractures that extend into the underlying water sand yielding a non-commercial well. In medium radius horizontal drilling a horizontal well bore can be placed into the oil bearing portion of the Bartlesville Sand at a maximum vertical distance from the underlying water sand. Rougeot believes:

- (a) A much larger area of drainage can be accessed.
- (b) A more efficient drainage of the sand can be achieved (increase sweep efficiency).
- (c) Premature water production (coning) can be delayed or drastically reduced.

Achieving these results should significantly increase historic initial stimulated production rates and hopefully increase ultimate historical recoverable reserves.

Drill Site - Lease History and Reservoir Properties

The drill site (Wilson 25) is located on the Wilson lease (SE/4 Sec. 20-21N-12E) within the Flatrock Field, Osage County, Oklahoma. The lease covers 160 acres and produces from the Bartlesville Sand. While the Bartlesville Sand is structurally fairly flat sand (-635' +/- 10') due to surface topography, the Bartlesville is found between 1300' and 1450' on the Wilson lease. The lease was originally drilled between 1919 and 1921 with twenty-two (22) producing wells and one (1) dry hole drilled into the Bartlesville Sand. An unsuccessful Arbuckle Dolomite test was drilled in 1946. In 1975, an unsuccessful infill Bartlesville Sand well was drilled (third party). This well was unsuccessful because the well was "fraced into the water". Twenty (20) of the original twenty-two (22) were temporarily abandoned in the 1940s and were plugged by 1951. The two (2) unplugged wells are currently producing at a combined rate of 2 barrels of oil per day and 15 barrels of water per day (See Figure 2).

The eastern 1/3 of the Wilson lease is 5' - 15' structurally higher than western 2/3 of the Wilson lease. The structurally higher wells had higher initial production rates and cumulative production (See Figure 3 for estimated cumulative oil production per well). These cumulative oil production amounts were estimated based on relative initial production rates, abandonment/plugging dates, and offsetting leases' cumulative production amounts.

The estimated cumulative oil production for the wells offsetting the location of the proposed horizontal well bore is 20,000 to 25,000 barrels. The casinghead gas production was vented to the atmosphere and was not measured. The average cumulative production of the offsetting wells would be considered average for the entire North Flatrock Field.

Due to the fact that the horizontal well is being drilled within 300' of both an east and west line of wells, the lithology of the Bartlesville Sand at the horizontal well location can be fairly accurately projected. To summarize; the gas sand is expected to be 15' to 20' thick, the oil sand is expected to be 25' to 30' thick, and the transition zone is expected to be approximately 30' thick (See Figure 4).

It is Rougeot's belief that the recoverable oil reserves will be 7,500 to 10,000 barrels per acre and 7 to 10 acres could be drained by placing the horizontal well bore in a north-south direction. Rougeot

believes that these reserves are in place and are best accessed by a horizontal well bore based on two reservoir conditions. The following is a description of these two conditions:

- (1) Water Coning - The original vertical wells' oil-water ratio production history indicates bottom water encroachment almost from inception of the wells' life. The wells tended to have initial production rates of 20-50 barrels of oil per day at an oil cut of 75% or better. By the end of the well's first year of production, oil production would be less than 10 BOPD and the oil cut would be less than 25%. This precipitous decline in oil cut would occur while the decline in total fluid produced would be minimal. Generally, the decline in oil cut would continue until the oil cut would reach less than 10% in years 3-5 of the well's life and would remain constant at less than 10% for the remainder of the well's life. The net result of the water coning is that the original wells drained less than 3 net acres but due to the bottom water "sweep" the recovery factor over those 3 acres drained was 25% - 35% (over 60+ years).

There are several wells in the Flatrock Field which have been producing more than fifty years that have retained relatively high oil cuts (10% - 50%) throughout their life. These wells' total produced fluid is less than 5 BFPD which is unusually low for the field. These well's production history indicates that bottom water encroachment did not occur in all wells. However, these wells represent less than 5% of the total field wells and as a result it is not believed that these wells are a significant factor in estimating/characterizing remaining reserves for the field. It should be noted that based on the fact that these wells produce as much as 1.5 BOPD each today. The cumulative production is probably much greater than the 25,000 barrel field average. These high oil cut wells indirectly support the overall characterization of the remaining reserves of the field.

- (2) North-South Permeability Trend - The common understanding of the depositional pattern of the Bartlesville Sand in the North Flatrock Field suggests that a north-south permeability trend exists. This condition has probably caused the drainage

pattern of the original wells to approximate a north-south elliptical pattern versus a more uniform radial pattern. This causes the projected area of the "five spot" reserves to be wider east-west and have better north-south contiguousness than could be projected if the original wells had a more uniform radial drainage pattern.

It is believed that the two conditions described above cause the projected target oil reserves to be in an area that is rectangularly shaped and elongated in a north-south direction (See Figure 5). The projected average width (east-west) is estimated to be 300' to 400'. The projected length (north-south) is estimated to be 1300' to 1500'.

Ideally, two test wells (one east-west, one north-south) would be required to fully test the Flatrock Field as a horizontal drilling prospect. Due to the fact that capital was available for only one well, a choice needed to be made. It is believed that the rate of fluid recovery would be maximized by drilling perpendicular to the north-south permeability trend. However, there was concern about the portions of the horizontal hole that would be in areas that were partially depleted and the ability of an east-west horizontal to drain a significant area in a north-south direction. As a result of these concerns, it was decided a horizontal well drilled in a north-south direction would best access reserves in the "target" area.

DRILLING THE WELL

Drilling Plans:

The planning of Wilson 25 encompassed the following primary planning areas;

- 1.) Wellbore Design
- 2.) Equipment Personnel Requirements
- 3.) Transportation of Drilling Cuttings
- 4.) Drilling Location Layout

1.) Wellbore Design

The drilling target is defined as 1,000' long, 200' wide, and 10' thick. The true vertical depth of the target is 1418' to 1428' (See Figures 2, 6 A-D, and 8). The start point of the 1,000' horizontal is anywhere within a 300' north-south range.

The planned wellbore design is as follows;

- A.) Drill a 9 1/2" hole to the kick-off point of 899'.
- B.) Drill a 8 3/4 " medium radius curve with an average build rate of 11 degrees/100' and a projected length of 818 feet. The curve will be drilled with mud motors. Scientific Drilling International (S.D.I.) will provide directional drilling supervisors, surveying services, and the mudmotors. Surveying will be performed using S.D.I.'s "Champ Steering Tool" which is an extremely accurate survey tool which operates on an electric wireline. The mudmotor will be S.D.I.'s (Deepco) double adjustable motor.
- C.) Run 7" casing to 1717 feet and cement to surface with 330 sacks regular cement with 3% calcium chloride (CC) and 5% salt.
- D.) Drill out cement and 1000' of 6 1/4" horizontal hole to a final measured depth of 2617'. The horizontal section will be drilled with air-mist and a rotary drilling assembly. Mudmotors will be employed if a "correction" is needed. Surveying in the horizontal section will be performed by pumping down a single shot survey tool.

2.) Equipment/Personnel Requirements

The critical equipment/personnel requirements are outlined below;

- A.) The requirements of the drilling rig were as follows:
 - 1.) The mud pump should be able to pump at a minimum rate of 345 gpm in order to attain the desired drill rates and hole cleaning.
 - 2.) The rig crews will need to be experienced/competent. Numerous trips of the drill pipe will be required in directional drilling. The

efficiency of the drillstring trips is a significant component of overall project cost control.

- 3.) The drilling rig hook load capacity will need to be in the 250,000# to 300,000# range to allow for pulling up to the maximum drill pipe tensile strength if the drill pipe becomes stuck in the well.
 - 4.) Other considerations are the rig floor size, move-in move-out cost, overall rig condition, and solids separation equipment. A rig that normally drills in 3,500' - 7,000' range is best suited for this job considering both cost and operational capability.
- B.) Maximum air requirements are estimated to be 2200 cfm at 350 p.s.i.g. The air compression package will be three (3) - 850 cfm at 200 PSI Quincy screw type compressors with a 7x5x5 air compressor booster to 1500 PSI to be provided by Air Drilling Company. Due to the nature of the drilling, twenty-four (24) hour supervision of the air equipment will be required.
- C.) A twenty-four (24) hour Company drilling engineer will be required to coordinate, advise, and make the final drilling decisions. Roustabouts will be on 24 hour call to move drill strings, weld, and fabricate as necessary. A geologist will be on 24 hour call to confirm surveys and planned target depth based on drill cuttings.
- D.) With the twenty-four (24) hour continual drilling supervision, onsite office and sleeping accommodations will be required.
- 3.) Transportation of drilling cuttings
- A.) The mud system will be steadily improved from top of the hole to the bottom. The vertical portion of the hole will be drilled with a basic 30 seconds/quart mud viscosity system which will be improved to the following as the directional portion of the hole progresses;
1. Funnel Viscosity - 36-40 seconds/quart
 2. API Filtrate of less than 25 ml/30 minutes.
 3. Plastic Viscosity - 12 centipoise
 4. Yield Point - 5 lb./100 sq. ft.
 5. Mud Weight - 8.5-8.8 pounds per gallon
- Annular velocity will be maintained at 150 feet per minute around 4.5 inch drill pipe.
- B.) The air rate will be maintained at 2200 cfm. Water, foamer, and corrosion inhibitor will be injected at the following rates;
1. Water - 3-7 gallons per minute
 2. Foamer - 1 gallon per 10 barrels of water
 3. Inhibitor - 2 gallons per 20 barrels of water

4.) Drilling Equipment Layout (See Figure 7)

The principal consideration in the planning of the drilling equipment layout is to allow for easy access for trucking-in/trucking-out of drillstrings while minimizing the area of the location that needs to be graveled. This will help keep down location construction costs and related bulldozer pull in-out costs. A forklift will be essential for moving pipe from pipe rack to pipe rack.

The principal planning is in the location and utilization of the pipe racks. Three pipe racks will be employed. The normally expected drilling rig pipe rack will be used for the drill string currently in use. A second pipe rack will be used to store the next drill string to be used. The third pipe rack will be used to store the 7" casing and drill pipe awaiting truck-out. The three pipe racks allows for maximum utilization of truck capacities (fully loaded roundtrips) which will greatly reduce trucking costs.

Once the drilling rig, pit and pipe racks are sited, the air equipment will be sited to be out of the traffic flow but close to the main road to minimize location construction and pull in-out costs.

Drilling Problems

Problems occurring during the drilling of the well were minimal and were well within the planned range. The principal vendors; Brown and Cruzen Drilling of Cleveland, Oklahoma (drilling rig), Scientific Drilling International of Oklahoma City, Oklahoma (directional drilling services), Air Drilling Company of Fort Smith, Arkansas, (Air Compressors), and William Sneed of Cleveland, Oklahoma (specialized tool fabrication) provided very high quality equipment and personnel. The drilling target was hit, the desired horizontal hole length was attained, and the well was completed within an acceptable budget range. The problems encountered are described in the following:

- 1.) At 582' in the vertical portion of the hole problems with pipe sticking occurred. The drilling mud was contaminated by calcium left in the rig mud tanks from the previous well and the mud was not yielding. Double the normal amount of gel was added and normal circulation was attained. Total drill time lost was 6 hours.
- 2.) The total length of the drilled curve was 917' long with a radius of 634' compared to the planned 818' long curve with a 521' radius. This difference was somewhat planned as the directional drillers extended the length of the curve to insure that the drill target is hit. The incremental drilling time was 5 hours which would be considered minimal since the drilling target was readily attained. The plan was to drill the entire curve with mudmotors and have no tangent section. Because of an excessive curve build rate through the first 538' of drilled curve (12-15 deg./100'), a 265' tangent section was drilled with a rotary drilling assembly. The rotary drilled tangent section saved 13-14 hours of planned mudmotor hours.
- 3.) The air compressor booster went down after 1 hour of drilling. Air Drilling Company had a new air compressor booster on-site and operating in 5 hours.
- 4.) The rotary drilling assembly that was utilized to drill out the cement and start the horizontal hole was intended to "climb". The concern was that if the rotary drilling assembly "dropped" it would be difficult to reverse without mudmotors. While correcting with mudmotors was possible, Rougeot's instructions to the

directional drillers was to avoid a mudmotor correction run at almost any cost. The 7" casing was set to a point that was 2 1/3 feet inside [1420.3 true vertical depth (T.V.D.)] the 10' thick target. Upon drilling out of the pipe, the "climbing" assembly was utilized for 104' [at 1920' measured depth (M.D.)] prior to being pulled for a "dropping" assembly. At the 1920' M.D. survey point the "climbing" assembly had climbed 2' in the 104' it was used. The "dropping" assembly climbed an additional 2 1/2' feet prior to developing its planned drop. The result was that 210' of the horizontal was 0-2' above the "target" (See Figure 8). This problem was an economic decision as this amount of hole outside the target by 2' or less was considered to be preferable to the cost of a mudmotor correction run.

- 5.) William Sneed (an oil field tool fabricator) designed a tool to allow for the pumping down of a single shot survey tool on a wireline. The tool served as a survey tool carrier which could be circulated through. Problems were encountered and solved as to the placement of cups on the tool, the cup wear, and the operation of the wireline unit. Seven surveys took 27 hours. The initial "air surveys" took five hours and the final surveys took less than 2 hours.
- 6.) At 2483' M.D. (at 666' of horizontal hole) we were unable to get the survey tool carrier down to the desired survey point because we ran out of the cups for the survey tool carrier. It was anticipated minimal cup wear however actual cup wear was excessive. The cups are a special fabricated item and a new supply of cups was not readily available. Rather than shutdown, the remainder of the well was drilled based on projected surveys.
- 7.) At approximately 2170' a significant amount of metal shavings began appearing in the drilling samples. This was the result of the hard banding on the 3 1/2" weight pipe wearing on the casing.
- 8.) At approximately 2300' M.D. the drilling returns changed from a cream to white foam to a brown viscous fluid which visually resembled drilling mud. The first reaction was that a hole had worn in the casing. The soap and inhibitor supplier

(Chemlink Petroleum Company) advised that additional foamer was needed. The rate of foam injection was increased from 1 gallon per 10 barrels of water to 1 gallon per 2 1/2 barrels of water and in the drilling returns appearance reverted to a white foam.

Results

A 9 1/2" hole was drilled to kick-off point (399'). An 8 3/4" hole was drilled to 1816' M.D.(1420.33 T.V.D.). The curve length was 918', with 652' drilled with mudmotors and 266' was rotary drilled (See Figure 9). 1816' of 7" casing was run and cemented to the surface per plan. The horizontal was placed within the target (1418' to 1428' T.V.D.) except as noted above (See Figure 8). The well T.D. was 2866' M.D. or 1050' of horizontal wellbore was rotary air-mist drilled.

The total cost of the well was \$150,532 (See Appendix D). The cost of a cased vertical Bartlesville Sand well is \$35,000 unstimulated and \$55,000 if stimulated by nitroglycerin shooting. The subject well cost 4.30 times an unstimulated Bartlesville Sand well and 2.74 times a stimulated Bartlesville Sand well. Reservoir studies indicated that reserve recovery (over 25 years) for a 1,000' unstimulated wellbore would be 4-6 times a vertical well shot with nitroglycerin. Because an uncompleted vertical well is not economic there are no vertical wells that have been produced unstimulated for comparison. The cost of completing a horizontal well with nitroglycerin shot is estimated to be \$40,000 which will result in a horizontal/vertical well cost ratio of 3.46 times. Included in the following conclusions and recommendations are several recommendations which will significantly improve the horizontal/vertical well cost ratios described above.

Conclusions and Recommendations

The principal conclusions and recommendation for the drilling of the well are as follows:

- 1.) The most important area of planning for Rougeot's purposes was a pre-spud meeting occurring 15 days prior to spud date. The meeting was attended by Scientific Drilling International management and drillers, drilling consultants,

drilling rig management, and Company personnel. A quality drilling plan could not have resulted without this meeting and Rougeot believes costly misunderstandings were avoided. Critical communication occurred during that meeting that would not have occurred in any other format.

- 2.) The drilling rate over the last 300' of hole was 61'/hour. The daily incremental drilling cost was less than \$10,000 per day while drilling at 90 degrees. The drilling at T.D. was problem free. For \$30,000 (a 20% increase in cost), a 3,000' lateral could have been drilled. The expensive component of horizontal drilling is the curve and once 90 degrees is attained incremental footage is relatively inexpensive. The relationship between horizontal/vertical well cost and horizontal/vertical reserves is significantly enhanced as incremental horizontal footage is attained. While the marginal utility in terms of reserves per each incremental horizontal foot diminishes as more horizontal hole is cut, through at least 3,000', each incremental foot does improve the economics of horizontal drilling in this application.
- 3.) The majority of the time in horizontal drilling operations is spent making connections, surveying, and tripping bottomhole assemblies. The rig floor operations need to be analyzed to minimize non-drilling time. Rougeot believes that they did a good job in this area. Nonetheless of the 194.5 hours of directional drilling operations only 69 hours (35%) of that time was spent drilling (including connection time). Connection time was 10-20 minutes per connection.
- 4.) Excluding problems with pumping down the survey tool, the air drilling of the horizontal section was virtually problem free. Rougeot estimated the additional cost of air drilling versus mud drilling to be approximately \$17,000. With the experience gained with the survey tool carrier during the drilling of this well, the additional cost of air drilling over mud drilling for a well of this nature could be reduced to \$10,000.

- 5.) Two (2) - 6 1/4" rerun button bits were used to air drill the horizontal hole. The first bit ran for 18.5 hours and the second bit ran 7.75 hours. The second bit was worn to the point a cone was almost left in the hole. Re-run bits were found to be acceptable in the air-drilled horizontal section when a bottomhole assembly is being run to make a direction adjustment (short run). In the future, when it is hoped that a bottomhole assembly will cut a significant amount of hole, new bits will be used. In the mud drilled curve significant savings were attained with rerun bits and rerun bits will probably be used by Rougeot in the future when mud drilling.
- 6.) Most weight pipe is hard banded and the hard banding will cause excessive wear on casing. Operators need to take this into consideration when directional drilling out of cased holes is being undertaken.
- 7.) In the well planning it was projected that torque problems would be experienced in the horizontal portion of the hole and roller reamers would be needed to replace the stabilizers in the bottomhole assembly. The roller reamers were not used as no torque problems were experienced.

PRODUCING THE WELL

Equipment Used

The well was equipped for rod pumping with an insert pump (See Figure 10). Two key modifications to a normally expected rod pumping configuration are an oversized pumping unit and a oversized rod string. Tubing was run to the bottom of the casing (1816') and the well is being pumped from that point.

The surface production equipment layout is shown in Figure 11 and is typical for this area of Oklahoma. The well was equipped with an 80,000" # pumping unit with a 64" stroke. The 80,000" # pumping unit was set for the sole purpose of taking advantage of the 64" stroke length. The 64" stroke length and a 2" plunger pump will allow for up to 75 BFPD to be lifted while running the unit at 3 spm. The low spm is to allow plenty of time for rod fall and possible reduce rod and tubing wear. In the best case scenario, it was not expected that the well would produce more than 65 BFPD.

Normally a 5/8" or 3/4" rod string would be used at this depth. The well rod string includes 234' of 1-1/2" sinker bars and 875' of 7/8" rods with the remainder of the string 3/4" rods. The 7/8" rods and sinker bars provide the weight necessary for the rods to efficiently fall.

The bottomhole pump is laying inside the horizontal hole at 90 degrees. The balls are spring loaded to aid proper ball seating. The pump will pump at 100% efficiency when the fluid level is more than 200 vertical feet above the pump. The pump efficiency falls to 65-70% when the fluid level is 10 vertical feet above the pump.

Production Response

The well was placed on production on June 30, 1990. The production response was disappointing as the well averaged 9.41 BOPD and 1.26 BWPD in July 1990 and stabilized production as of September 30, 1990 was 6 BOPD and 0.84 BWPD (See Table 2 for complete production history). A fluid production range of 20 to 40 BOPD had been hoped for. The positive aspects of the well's production response are as follows:

- 1.) A vertical well before stimulation will typically produce between 1 and 3 BFPD.

This production rate is extrapolated from less than two days of fluid production data typically available prior to stimulation. Based on this vertical well data, a

productivity increase, horizontal versus vertical, in the range of 200% to 600% was attained.

- 2.) The vertical wells within 1/4 mile of the subject well and in the North Flatrock Field produced fluid oil cut averages less than 20% in all wells. The oil cut for the produced fluid from the subject well is 86%. This oil cut has been fairly consistent throughout the well's life to date.
- 3.) A complete static fluid build-up test was not performed, however the fluid level that built between 6-23-90 (drilling completion date) and 6-29-90 (well start-up) indicated the wells bottomhole pressure was at least 200 psig. Based on fluid build-up tests performed throughout the North Flatrock Field, a bottomhole pressure of between 200 psig - 250 psig was anticipated in the Wilson 25 well.

Conclusions and Recommendations

The principal conclusions and recommendations for producing the well are as follows:

- 1.) All of the fluid entering the wellbore is being pumped and the producing fluid level is being maintained twenty to thirty vertical feet above the pump. The pumping unit is running 3.4 strokes per minute and is timeclocked to run 15 minutes every hour. The projected horsepower requirement if this well were a vertical well would be approximately four horsepower. The actual horsepower use is six horsepower. This two horsepower differential appears to be the result of the friction caused by the rod string movement in the tubing string through the curve section of the hole.
- 2.) The rod pump configuration will have a relatively low operating cost and is very cost-effective for producing small volumes of fluid from a horizontal wellbore. While it is anticipated that rod and tubing wear in the Wilson 25 will be higher than in a vertical well, this incremental cost is not expected to be significant. The Wilson 25 equipment configuration will be utilized in for future horizontal wells.

PROJECT CONCLUSIONS

The following conclusions can be made from the drilling of a medium radius horizontal well in a shallow reservoir.

- 1.) The drilling plan, the drilling of the well, and the contractors used were adequate. The drilling target was hit, the desired horizontal hole length was attained, and the well was completed within an acceptable budget range.

The methods of applying "air-mist" drilling to the drilling of a medium radius horizontal well in a shallow reservoir (1,400 feet) were successful and the costs required have been documented.

- 2.) The unstimulated well production is 200% - 600% greater than the typical unstimulated vertical well production rate. This ratio should remain constant after stimulation. A typical vertical well stimulated with a nitroglycerin shot would have an average first year production rate of 8-10 barrels of oil per day.

The horizontal wellbore results in an enormous surface area compared to a typical vertical well. This increased surface area is generally thought to be equivalent to a hydraulic frac. However, the horizontal wellbore does not access and connect permeability vertically as does a hydraulic or explosive fracturing treatment.

- 3.) The oil producing response was disappointing while the water producing rate was better than anticipated.

The three month production record of the subject well indicates that the well is producing little water (averaging an 86% oil cut) and low oil rates (averaging 6 to 9 barrels of oil per day). A successful vertical well completed with nitroglycerin shot would have an initial oil cut of 75% and be down to a 25% oil cut within 90 days. The higher sustained oil cut in the subject well indicates that water coning will have less of a negative impact on the wells ultimate reserves in terms of both rate of recovery and total volume. These oil rates will not provide

an attractive return on the \$150,000 investment required for a horizontal well at projected stabilized oil prices of \$20.00 per barrel.

- 4.) Air drilling the horizontal hole was effective in reducing skin damage which is a critical concern in horizontal drilling. (Most horizontal wells are drilled with mud.)

While skin damage associated with air drilling is normally minimal, the occasional occurrence of viscous returns (resembling drilling mud) combined with a rotary action of the drill pipe caused some skin damage.

PROJECT RECOMMENDATIONS

The following recommendations are made based on the information contained in this report for the drilling of medium radius horizontal well (Wilson 25) in the Bartlesville Sand of the North Flatrock Field.

- 1.) The well should be stimulated with explosives to remove any skin damage imposed by the drilling of the well and to connect by short vertical fractures the permeability adjacent to the wellbore.
- 2.) A second medium radius horizontal well should be drilled in an east-west direction that is perpendicular to the directional permeability of the field.

ACKNOWLEDGEMENTS

To write this report Rougeot has only referenced proprietary data. Rougeot has been active in the Flatrock Field for 23 years and during this period has commissioned numerous geological and engineering studies of the field.

Rougeot would like to acknowledge the several professionals who provided services that were critical to the project. The following is an alphabetical listing of these professionals:

Stephen Cochran
William Gardner	- The Directional Drillers provided Scientific Drilling International.
Sada Joshi	- Provided informal consulting regarding general horizontal drilling applications and experiences.
Morgan Kershner	- Provided informal consulting regarding Flatrock Field reservoir engineering.
Thomas F. Popp	- Provided informal consulting regarding directional air drilling.
Kenneth E. Proctor	- Provided informal geological consulting.
D.L. Reid	- Served as the Company drilling engineer. Was in charge of all drilling operations including selection of bottom hole assemblies.
J.J. Renfro	- Provided informal consulting regarding tangible equipment configuration.
William Sneed	- Provided consulting as to specialized tool fabrication for air drilling and general drilling knowledge.
J.W. Wisniewski	- Prepared the drilling plan including, but not limited to, determining mud and air requirements, drill string configuration, drilling rig requirements, and prepared torque and drag models.

TABLE 1

Cost Sharing of the Wilson 25

Department of Energy - Rougeot Oil and Gas Corporation

	<u>Total Cost</u>	<u>Contribution</u>	
		<u>Rougeot</u>	<u>DOE</u>
Leasehold (Wilson - 160 Acres) (Cost - \$27,000)	\$ 10,000	\$ 10,000	\$
Drill and Equip One Well	150,532	5,530	145,002
Complete Tank Battery	15,000	15,000	
Salt Water Disposal	35,000	35,000	
Project Reporting	<u>3,329</u>		<u>8,329</u>
	\$218,861	\$ 65,530	\$153,331
		30%	70%

TABLE 2**Wilson 25 - Production History**
6/29/90 - 9/30/90

<u>Date</u>	<u>Production</u>		<u>Fluid Level</u>		<u>Comments</u>
	<u>Oil</u>	<u>Water</u>	<u>MD</u>	<u>TVD</u>	
6/29			883'	883'	Starting pump at 11:30 a.m. Fluid level shot at 11:30 a.m.
6/30	49.45	0.00	1643'	1395'	Pumping Fluid Level (PFL) at 9:45 a.m. Well shut down for remainder of day to install time clock
7/1	1.1	0.0			Well turned on at 9:00 a.m. On time clock at 15 min. on - 45 min. off
7/2	16.90	1.35	1410'	1315'	PFL at 8:00 a.m.
			1410'	1315'	Static Fluid Level (SFL) at 3:00 p.m., well had been down 20 min.
			1441'	1330'	PFL at 3:45 p.m., after well had been pumping 15 min.
7/3	11.60	1.74	1380'	1301'	SFL at 8:00 a.m. Well went down during night, belts broke
7/4	16.90	2.20			Ran full time 6 hours, put back on clock, 15 min. on - 45 min. off
7/5	8.5	1.28			
7/6	11.65	1.28	1550'	1368'	SFL at 8:30 a.m. as pump cycle started
7/7	10.60	1.48			
7/8	10.60	1.27			
7/9	9.55	1.53	1565'	1372'	SFL at 1:30 p.m. Well had been down 20 minutes
7/10	11.65	1.51			
7/11	9.55	1.15			
7/12	7.45	0.82	1612'	1386'	PFL at 3:15 p.m. Had been running for 7 minutes
7/13	9.55	1.24			
7/14	8.50	1.11			
7/15	8.50	1.19			

<u>Date</u>	<u>Production</u>		<u>Fluid Level</u>		<u>Comments</u>
	<u>Oil</u>	<u>Water</u>	<u>MD</u>	<u>TVD</u>	
7/16	9.55	1.34			
7/17	8.40	1.68	1643'	1395'	SFL at 3:00 p.m., well had been down 15 min. Well is time clocked, 15 min. on - 45 min. off
7/18	8.40	0.84	1689'	1406'	SFL at 6:00 p.m., well had been running 5 hours.
7/19	9.55	1.72			
7/20	7.45	0.50			
7/21	8.50	1.50			
7/22	7.45	2.00			
7/23	9.55	1.25	1503'	1352'	SFL at 1:00 p.m., well had been down 15 mins. Well is time clocked, 15 min. on - 30 min. off
7/24	12.30	1.85			
7/25	8.40	1.24	1658'	1399'	SFL at 2:30 p.m., well had been down 15min. Well is time clocked, 15 min. on - 30 min off
7/26	8.40	0.76			
7/27	7.35	0.74			
7/28	7.35	0.96			
7/29	9.15	1.19			
7/30	10.20	1.02			
7/31	<u>7.05</u>	<u>1.13</u>			
Total July, 1990	291.65	38.95			Avg. July, 1990 9.41 BOPD 1.26 BWPD
August, 1990	210.15	31.10			Avg. August, 1990 6.78 BOPD 1.00 BWPD
8/8			1666'	1401'	SFL Well had been down 30 min. Time clock, 15 min. on - 30 min off
8/23			1651'	1397'	SFL Well had just ended pump cycle. Time clock, 15 min. on - 30 min off
September, 1990	181.30	25.88			Avg. Sept., 1990 6.01 BOPD 0.84 BWPD
9/24			1674'	1403'	Well had been down 15 min. Time clock, 15 min. on - 30 min off

Figure 1
Location of Flatrock Field in Oklahoma

SURFACE LOCATIONS WITH WELL NUMBERS

- PRODUCING VERTICAL WELL
- ⦿ PLUGGED VERTICAL WELL
- ⊙ PRODUCING HORIZONTAL WELL
- ✦ DRY HOLE
- UNCASSED HORIZONTAL WELL BORE

SCALE: 1" = 400'

20

Figure 2
Well Plat of SE/4 Sec. 20 T21N R12E

Figure 3
Average Cumulatives per Well of Leases in Area

Tidal Water Assoc. Oil Co.
 Wilson #24
 SE 1/4 SE
 20-21N-12E

Horizontal Well
 Roughcut Oil & Gas Corp.
 Wilson #25
 Well Surface Location
 C E/2 NE SE
 20-21N-12E

Tidal Oil Co.
 Wilson #9
 E/2 SE SE
 20-21N-12E

Roughcut Oil & Gas Corp.
 Wilson #8 #9
 C W/2 SW SW
 21-21N-12E

0.170 1810
 0.170 1810
 Squares Per Acre
 Complete in Zone
 other than Bartlesville Sand

Figure 4
 Cross Section of
 Bartlesville Sand at Site

Wells at 510' Spacing

ROUGEOT OIL & GAS CORP.

Figure 5
Projected Area of Target Reserves
Not to Scale

Figure 6A
Structure Contours: Top Bartlesville Sand
C.I. = 5'

Figure 6B
Structure Contours: Top Bartlesville Oil Sand
C.I. = 5'

Figure 6C
Contours: Estimated Feet of Bartlesville Oil Sand
C.I. = 5'

- 1) Brown & Cruzen Drilling Co., Inc.
Rig #3 -
Cooper LTD 650 Series with 112' Derrick
300,000# Hook Load
- 2) Substructure - 20'-5" long, 16'-9" wide, 12' high
Rotary Table - 17 1/2" Gardner - Denver
- 3) Mud Pump - Wilson 600" 5 1/2" x 14"
- 4) Steel Mud Pit - 420 Bbls. - 50' long, 12' wide, 5' high
with Brandt Single-Single Shale Shaker and Demco
De-Sander - (2) 12" Cones
- 5) Pre-Mix Tank - 100 Bbls. w/(2) 5" x 6" Pumps
- 6) Doghouse - 10' x 30' & Water Tank - 512 Bbls.
45' long, 10' wide, 8' depth ((2) level)
- 7) Generator Set & Fuel Trailer
(2) 155 Kw CatSR4
- 8) Cat Walk 8' x 45'
- 9) Drill Pipe Tubs (2) 8' x 35'
- 10) Pipe Racks (3) Sets
- 11) Quincy Model QSS Air Compressors
850 Cfm @ 200 Psi (3) Units
- 12) Gardner Denver Model MDY-HV
7 x 5 x 5 Air Compressor Booster to 1500 Psi
- 13) Kerr Model 3250 Mist Pump (4 - 31 Gpm)
- 14) Fuel Tank (1500 Gal)
- 15) Office Trailer (8' x 16')
- 16) Bunk House Trailer (8' x 26')
- 17) Earthen Reserve Pit (Approx. 1000 Bbl.)

Figure 7
Drilling Equipment Layout

Wilson #25
SE/20-21N-12E
Osage County, Oklahoma

Figure 8
Cross Section of Completed Well
Showing Horizontal Section in Bartlesville Sand

Wilson #25
SE/20-21N-12E
Osage County, Oklahoma

Figure 9
Complete Cross Section (Profiles)
of Completed Well

Figure 10
Sub-Surface Production Equipment Layout
Not To Scale

Figure II
Surface Production Equipment Layout
Not To Scale

FLATROCK FIELD**GEOLOGY**

The Bartlesville Sand Delta prograded south from southeast Kansas into northeastern Oklahoma during a regional regression of the Cherokee Sea in lower Desmoinesian time. The Delta was fluvial dominated with a shape intermediate between elongate and lobate. In later geologic time, as the "lower Desmoinesian Sea" invaded to the north-northwest, it deposited the blanket Inola limestone on top of the Deltaic complex marking the close of the Bartlesville sequence.

The Bartlesville Sand Delta in the area of the Flatrock Field can be subdivided into three intervals:

- (1) The "clean" Bartlesville sandstone,
- (2) The "muddy" interval,
- (3) The "upper Bartlesville interval".

The lowest subdivision, the "clean" zone, has an abrupt base, is lithologically homogenous and is the thickest of the three intervals representing over 100' of an approximately 150' thick total Bartlesville Sand interval. This zone persists laterally across the Flatrock Field and suggests lateral migration during distributary channel development. This section contains little clay and medium to fine-grained sandstone. Characteristic of all channel sands, the "clean" interval contains the coarsest sand at its base and graduates upwards to a finer grain size.

The top of the "clean" Bartlesville sandstone grades upward into an interval rich in mud and depleted in sand known as the "muddy" interval. This section reflects a diminished channel flow and abandonment of the distributary as the channel migrates from the area and the subsequent infilling of silt and clay occurs. This interval is the thinnest of the three intervals and although only 2'-10' thick persists laterally across the field. The lithology ranges from sandy siltstone to shale.

The section on top of the "muddy" interval is referred to as the "upper Bartlesville Interval". Following channel abandonment, this interdistributary sequence consists of lithologies that have localized longitude continuity but considerable lateral variations. These lithologies range from fine grained sand to shaley fine grained sand. Thickness of this interval generally ranges from 30' to 50'. These interdistributary areas are frequently interrupted during flood periods creating a complex of interfingering

channels and introducing cleaner channel sand sediments. These reoccurring cycles result in the "upper Bartlesville interval" as being characterized as a section of repeating sand, shaley sand, and sand sequences.

The Bartlesville Sandstone is a mineralogically submature lithadrenite. The principal clays include chlorite, kaozinite, mica, and illite. Consolidation depends on calcite cementation and pressure solution.

Porosity of the Bartlesville Sand in the Flatrock Field area is affected by the same depositional scheme that affects grain size, generally decreasing upward throughout the entire section. Permeability which relates to pore size distribution is principally dependent on the depositional energy of the channel complex. Due to the southward progration of the Bartlesville Sand Delta, a strong north-south directional permeability persists throughout the Bartlesville Sand section in the Flatrock Field area. Although the permeability fluctuates greatly, it also generally decreases upward.

Rapid rates of sedimentation related to deltas such at the Bartlesville Sand Delta provide for rapid burial of organic materials which may then generate oil. Oil that is generated will be trapped by the overlying impermeable Inola limestone. The reversal of paleoslopes and later tilting of the lower Absaroka Strata (east to west) no doubt allowed this oil to remigrate into porous and permeable sandstone beds along the eastern flanks of the distributary channel forming the Flatrock Field.

WILSON 25
Daily Drilling Summary

6/13/90

6:00 p.m. - 12:00 a.m. Spudded well with BHA #1, drilled to 312'

6/14/90

12:00 a.m. - 4:00 p.m. Drilled from 312' to 899' (KOP) (22 Hours)

4:00 p.m. - 12:00 a.m. POOH, rigging-up BHA #2

6/15/90

12:00 a.m. - 6:00 a.m. Rigging-up BHA #2

6:00 a.m. - 8:00 a.m. GIH, started drilling

8:00 a.m. - 11:45 a.m. Drilled from 963' to 963'. Survey indicated motor disorientation. POOH to check assembly.

11:45 a.m. - 8:15 p.m. Corrected motor orientation, pick-up BHA #3, GIH

8:15 p.m. - 12:00 a.m. Drilled from 899' to 1055'

Daily Summary

Directional Drilling Hours	7.5 Hours
Directional Footage	156'
Average Directional Ft./Hr.	20.8/Hr.
Bit #1 Hours	7.5 Hours
Mud	
Weight	9.1 - 9.3 ppg
Viscosity	34-35 Seconds
Total Hours from KOP	32 Hours

6/16/90

12:00 a.m. - 11:00 a.m. Drilled from 1055' to 1324'. BHA #3 was building at 14 degrees/100'. 7 degrees/100' required to reach target.

11:00 a.m. - 4:00 p.m. POOH, changed variable bent housing from 2 degrees to 1 degree. Projected build rate of assembly 6-8 degrees/100'. Pick-up BHA #4, GIH

4:00 p.m. - 9:00 p.m. Drilled from 1324' to 1437'. BHA #4 building at 11.25 degrees/100'

9:00 p.m. - 12:00 a.m. POOH, GIH to ream

	<u>DAY</u>	<u>CUMULATIVE</u>
Directional Drilling Hours	16 Hours	23.5 Hours
Directional Footage	382'	538'
Average Directional Ft./Hr.	23.88'/Hr.	22.89/Hr.
Bit #1 Hours	16 Hours	23.5 Hours
Mud		
Weight	9.1 - 9.5 ppg	
Viscosity	31-33 Seconds	
Total Hours From KOP	24 Hours	56 Hours

6/17/90

12:00 a.m. - 5:30 a.m. Finished Reaming - POOH. Pick-up BHA #5, GIH. Rotary drilling assembly to cut tangent section.

5:30 a.m. - 6:30 p.m. Drilled from 1437' to 1703'. POOH to run final mudmotor.

6:30 p.m. - 12:00 a.m. Pick-up BHA #6, GIH

	<u>DAY</u>	<u>CUMULATIVE</u>
Directional Drilling Hours	13 Hours	36.5 Hours
Directional Footage	266'	804'
Average Directional Ft./Hr.	20.46'/Hr.	22.03/Hr.
Bit #1 Hours		23.5 Hours
Bit #2 Hours	13 Hours	
Mud		
Weight	9.2 - 9.3 ppg	
Viscosity	38-42 Seconds	
Total Hours From KOP	24 Hours	80 Hours

6/18/90

12:00 a.m. - 7:30 a.m. Drilled from 1703' to 1816'.
90 degrees attained. POOH to run casing

7:30 a.m. - 6:15 p.m. Laid down mudmotor assembly, run 7" casing. Tacked first five joints of casing. Run 1816' of 7" casing.

6:15 p.m. - 7:00 p.m. Cemented -330 sack regular cement with 3% CC and 5% salt.

7:00 p.m. - 12:00 a.m. WOC, nipping up rotating head

	<u>DAY</u>	<u>CUMULATIVE</u>
Directional Drilling Hours	7.5 Hours	44 Hours
Directional Footage	113'	917'
Average Directional Ft./Hr.	15.20'/Hr.	20.86/Hr.
Bit #1 Hours		23.5 Hours
Bit #2 Hours	7.5 Hours	20.5 Hours
Mud		
Weight	9.3 ppg	
Viscosity	43 Seconds	
Total Hours From KOP	24 Hours	104 Hours

6/19/90

12:00 a.m. - 1:30 p.m.	WOC, nipping up rotating head. Pick up BHA #7, GIH. Tagged cement at 1756'
1:30 p.m. - 2:30 p.m.	Drilled from 1816' to 1850' Air booster failed, shutdown, wait on new booster
2:30 p.m. - 7:30 p.m.	Wait on new booster
7:30 p.m. - 7:45 p.m.	Drilled from 1850' to 1858'
7:45 p.m. - 12:00 a.m.	Shutdown to survey, problems with getting survey down

	<u>DAY</u>	<u>CUMULATIVE</u>
Directional Drilling Hours	1.25 Hours	45.25 Hours
Directional Footage	42'	960'
Average Directional Ft./Hr.	32.8'/Hr.	21.19/Hr.
Bit #1 Hours		23.5 Hours
Bit #2 Hours	7.5 Hours	20.5 Hours
Bit #3 Hours	1.25 Hours	1.25 Hours
Air Volume	2000 cfm	
Total Hours From KOP	24 Hours	128 Hours

6/20/90

12:00 a.m. - 1:00 a.m.	Shutdown to survey, problems with getting survey down.
1:00 a.m. - 3:00 a.m.	Drilled from 1858' to 1888'
3:00 a.m. - 8:15 a.m.	Shutdown to survey, problems with getting survey down.
8:15 a.m. - 9:15 a.m.	Drilled from 1888' to 1920'
9:15 a.m. - 2:30 p.m.	Survey, building angle POOH to pick up angle drop assembly, GIH BHA #8
2:30 p.m. - 4:00 p.m.	Drilled from 1920' to 1969'
4:00 p.m. - 5:45 p.m.	Shutdown, weld on rotating head, vibrating loose
5:45 p.m. - 6:45 p.m.	Drilled from 1969' to 1991'
6:45 p.m. - 9:15 p.m.	Survey
9:15 p.m. - 12:00 a.m.	Drilled from 1991' to 2028'

	<u>DAY</u>	<u>CUMULATIVE</u>
Directional Drilling Hours	8.25 Hours	53.5 Hours
Directional Footage	171'	1130'
Average Directional Ft./Hr.	10.72'/Hr.	21.12/Hr.
Bit #1 Hours		23.5 Hours
Bit #2 Hours	7.5 Hours	20.5 Hours
Bit #3 Hours	8.25 Hours	9.5 Hours
Air Volume	2400 cfm	
 Total Hours From KOP	 24 Hours	 152 Hours

6/21/90

12:00 a.m. - 12:45 a.m.	Drilled from 2028' to 2052'
12:45 a.m. - 4:30 a.m.	Survey
4:30 a.m. - 7:00 a.m.	Drilled from 2052' to 2144'
7:00 a.m. - 9:00 a.m.	Survey
9:00 a.m. - 1:15 p.m.	Drilled from 2144' to 2361'
1:15 p.m. - 7:00 p.m.	Survey POOH to pick up BHA #9, GIH
7:00 p.m. - 8:00 p.m.	Drilled from 2361' to 2451'
8:00 p.m. - 9:15 p.m.	Shutdown, severe thunderstorm
9:15 p.m. - 9:45 p.m.	Drilled from 2451' to 2483'
9:45 p.m. - 12:00 a.m.	Survey, could not get survey tool down

	<u>DAY</u>	<u>CUMULATIVE</u>
Directional Drilling Hours	9.0 Hours	62.5 Hours
Directional Footage	455'	1585'
Average Directional Ft./Hr.	50.55'/Hr.	25.36/Hr.
Bit #1 Hours		23.5 Hours
Bit #2 Hours		20.5 Hours
Bit #3 Hours	7.5 Hours	17.0 Hours
Bit #4 Hours	1.5 Hours	1.5 Hours
Air Volume	2400 cfm	
 Total Hours From KOP	 24 Hours	 176 Hours

6/22/90

12:00 a.m. - 12:15 a.m.	Drilled from 2483' to 2498'
12:15 a.m. - 7:00 a.m.	POOH, pick-up BHA #10, GIH
7:00 a.m. - 1:00 p.m.	Drilled from 2498' to 2866' Total depth

1:00 p.m. - 2:00 p.m.

Circulated Hole

2:00 p.m. - 6:30 p.m.

Laid down drill string

	<u>DAY</u>	<u>CUMULATIVE</u>
Directional Drilling Hours	6.25 Hours	69 Hours
Directional Footage	386'	1868'
Average Directional Ft./Hr.	61.76'/Hr.	27.07/Hr.
Bit #1 Hours		23.5 Hours
Bit #2 Hours		20.5 Hours
Bit #3 Hours		18.5 Hours
Bit #4 Hours	6.25 Hours	7.75 Hours
Air Volume	2400 cfm	
Total Hours from KOP	18.5 Hours	194.5 Hours

Abbreviations Used:

BHA - Bottom Hole Assembly
POOH - Pull Out of Hole
KOP - Kick Off Point
GIH - Go in Hole
WOC - Wait on Cement
CC - Calcium Chloride

WILSON 25Bottomhole AssembliesBHA #1

9½" Re-Run Bit - (ATJ-22) bit sub, X-O, 6 - 6½" drill collars, X-O, 19 jts. - 4½" HWDP.

Drilled from 0-899'.

BHA #2

8¾" Re-Run Bit - (S84F - Bit #1), 6½" motor with 1½ degree housing with 1" kick pad and top alignment sub, 1½ degree sub with orienting key, 2 - 6¼" monels, 19 jts. - 4½" HWDP, X-O, 6 - 6½" drill collars, X-O, 2 Jars, Side Entry sub.

Total length 864.18'. Drilled from 899' to 969'.

BHA #3

8¾" Re-Run Bit - (S84F - Bit #1), 6½" motor with 2 degree bent housing with 1" kick pad and top alignment sub, 1½ degree sub with orienting key, 2 - 6¼" monels, 22 jts. - 4½" HWDP, X-O, 6 - 6½" drill collars, X-O, 2 - 6¼" Jars, side entry sub.

Total length 953.23'. Drilled from 969' to 1326'.

BHA #4

8¾" Re-Run Bit - (S84F - Bit #1), 6½" motor with 1 degree bent housing with 1" kick pad and top alignment sub, 1½ degree sub with orienting key, 2 - 6¼" monels, 22 jts. - 4½" HWDP, X-O, 6 - 6½" drill collars, X-O, 2 - 6¼" Jars, side entry sub.

Total length 953.23'. Drilled from 1326' to 1437'.

BHA #5

8¾" Re-Run Bit - (M44NG - Bit #2), 8¾" roller reamer, 2 - 6¼" monels, 34 jts. - 4½" HWDP, X-O, 2 - 6¼" Jars

Total length 1290.70'. Drilled from 1437' to 1703'.

BHA #6

8¾" Re-Run Bit - (M44NG - Bit #2), 6½" motor with 1 degree bent housing with 1" kick pad and top alignment sub, 1½ degree sub with orienting key, 2 - 6¼" monels, 32 jts. - 4½" HWDP, X-O, 6 - 6½" drill collars, X-O, 2 - 6¼" Jars, side entry sub.

Total length 1309.36'. Drilled from 1703' to 1816'.

BHA #7

6¼" Re-Run Bit - (F2 - Bit #3), 4¾" float sub, - 6¼" IBS, 6¼" non-mag stabilizer, 4¾" monel collar, 6¼" non-mag stabilizer, 4¾" monel, inverter sub, 18 - 4½" jts. - 3½" drill pipe, 25 jts., - 3½" HWDP, 2 - 6¼" Jars, 12 - 4¾" drill collars.

Total length 1786.42'. Drilled from 1816' to 1920'.

BHA #8

6 $\frac{1}{4}$ " Re-Run Bit - (F2 - Bit #3), 4 $\frac{3}{4}$ " float sub, 6 $\frac{1}{4}$ " IBS, 4 $\frac{3}{4}$ " collar, 6 $\frac{1}{4}$ " IBS, 4 $\frac{3}{4}$ " monel, 6 $\frac{1}{4}$ " non-mag stabilizer, 4 $\frac{3}{4}$ " monel, inverter sub, 18 - 4 $\frac{1}{2}$ " jts. - 3 $\frac{1}{2}$ " drill pipe, 25 jts. - 3 $\frac{1}{2}$ " HWDP, 2 - 4 $\frac{3}{4}$ " Jars, 12 - 4 $\frac{3}{4}$ " drill collars, 2 jts. - 3 $\frac{1}{2}$ " HWDP.

Total length 1855.42'. Drilled from 1920' to 2361'.

BHA #9

6 $\frac{1}{4}$ " Re-Run Bit - (F2 - Bit #4), 4 $\frac{3}{4}$ " float sub, 6 $\frac{1}{4}$ " IBS, 4 $\frac{3}{4}$ " collar, 6 $\frac{1}{4}$ " IBS, 4 $\frac{3}{4}$ " monel, 6 $\frac{1}{4}$ " non-mag stabilizer, 4 $\frac{3}{4}$ " monel, inverter sub, 32 jts. - 3 $\frac{1}{2}$ " drill pipe, 27 - 3 $\frac{1}{2}$ " jts. - 3 $\frac{1}{2}$ " HWDP, - 2 - 4 $\frac{3}{4}$ " Jars, 12 - 4 $\frac{3}{4}$ " drill collars, 2 jts. - 3 $\frac{1}{2}$ " HWDP.

Total length 2285.07'. Drilled from 2361' to 2498'.

BHA #10

6 $\frac{1}{4}$ " Re-Run Bit - (F2 - Bit #5), 4 $\frac{3}{4}$ " float sub, 6 $\frac{1}{4}$ " IBS, 4 $\frac{3}{4}$ " collar, 6 $\frac{1}{4}$ " non-mag stabilizer, 4 $\frac{3}{4}$ " monel, 6 $\frac{1}{4}$ " non-mag stabilizer, 4 $\frac{3}{4}$ " monel, inverter sub, 32 jts. - 3 $\frac{1}{2}$ " drill pipe, 27 jts. - 3 $\frac{1}{2}$ " HWDP, 2 - 4 $\frac{3}{4}$ " Jars, 12 - 4 $\frac{3}{4}$ " drill collars, 5 jts. - 3 $\frac{1}{2}$ " HWDP.

Total length 2408.65'. Drilled from 2498' to 2866'.

Abbreviations Used:

HWDP - Heavy Weight Drill Pipe

X-O - Cross-Over Sub

Jts. - Joints

Wilson 25
Drilling Cost
Estimated to Actual Analysis

<u>Cost to Casing Point</u>	<u>Estimated Cost</u>	<u>Actual Cost</u>
Surveyor	\$ 130	\$ 130
Land Damages	\$ 2,225	\$ 2,240
Road, Location, Pull In-Out		
Bulldozer (\$55/hr.)	\$ 1,807	\$ 1,390
Rock	\$ 750	\$ 714
Drilling Rig		
Move-in/Move-out (fixed bid)	\$ 7,000	\$ 7,000
Day work (\$125/hr.)	\$ 16,625	\$ 14,938
Surface/Mousehold Casing & Cement		
Drilling Rig (Turnkey)	\$ 1,200	\$ 1,200
Pipe and Cement	\$ 525	\$ 551
Drilling Supervision (Consultant)	\$ 2,000	\$ 4,000
Other		
Trailer Rental (Office/Bunkhouse)	\$ 670	\$ 627
Welding	\$ 315	\$ 1,340
Forklift Rental	\$ 670	\$ 737
Wireline Unit	\$ 0	\$ 750
Other	\$ 1,465	\$ 2,044
Total Costs to Casing Point	\$ 35,382	\$ 37,661
<u>Intangible Drilling Costs</u>		
Drilling Rig (\$125/hr.)	\$ 12,750	\$ 13,813
Power Tongs - Casing Crew	\$ 1,000	\$ 1,000
Completion Rig		
Run Tubing and Rods (\$55/hr.)	\$ 330	\$ 330
Equipment Rental - Downhole		
4 1/2" W.P. incl. insp. & repair	\$ 1,600	\$ 1,837
3 1/2" D.P. and W.P. incl. insp. & repair	\$ 2,820	\$ 3,251
Mudmotors (\$165/hr.)	\$ 7,500	\$ 4,868
6 1/2" stabilizers	\$ 3,110	\$ 3,110
Drilling Jars - 6 1/2" & 4 1/2"	\$ 1,827	\$ 1,720
8 1/2" Reamers	\$ 750	\$ 750
Non-Mag Collars - 6 1/2" & 4 1/2"	\$ 810	\$ 800
Other (Subs, X-O, screens, insp., etc.)	\$ 2,550	\$ 2,338
Trucking	\$ 4,899	\$ 4,185
Equipment Rental - Air Drilling		
Compressors		
(\$900/day + \$525/day standby)	\$ 4,125	\$ 4,125
Fuel	\$ 1,276	\$ 1,332
Chemical (soap & inhibitor)	\$ 1,000	\$ 1,263
Supervision (\$400/day)	\$ 2,000	\$ 2,000
Air Meter	\$ 250	\$ 225
Trucking - Compressors	\$ 2,064	\$ 2,103
Rotating Head and Rubber	\$ 1,067	\$ 1,115
Drilling Mud	\$ 750	\$ 1,691
Fluid Hauling - Haul-in/Haul-out	\$ 2,378	\$ 3,340
Pumping Service and Materials		
Cement longstring	\$ 2,630	\$ 2,630
Drill Bits		
(1) 9 1/2" Re-run Buttons	\$ 1,097	\$ 1,097
(2) 8 1/2" New Buttons	\$ 0	\$ 0
(2) 8 1/2" Re-run Buttons	\$ 1,600	\$ 1,600
(2) 6 1/2" New Buttons	\$ 0	\$ 0
(2) 6 1/2" Re-run Buttons	\$ 1,724	\$ 1,724
Directional Drilling Services		
Drillers (\$450/day)	\$ 9,000	\$ 9,000
Surveying	\$ 8,700	\$ 8,895
Fill Pits, Level Location, Pull in-out	\$ 1,440	\$ 1,805
Geological Service	\$ 1,200	\$ 1,125
Total Intangible Drilling Costs	\$ 82,247	\$ 83,072
<u>Tangible Completion Costs</u>		
Casing - (1900' - 7" 23#)	\$ 7,200	\$ 11,048
Tubing - (1900' - 2 3/4")	\$ 2,160	\$ 2,250
Rods - New (1800' mixed - 3/4", 1", sinker bars)	\$ 2,200	\$ 2,430
Bottomhole Pump and Filter - 2" Plunger	\$ 800	\$ 1,256
Pumping T, Wellhead, Polish Rod, etc.	\$ 2,023	\$ 2,298
Electric Line (1,000')	\$ 841	\$ 841
Oil and Gas Production Line (3,500')		
Material	\$ 2,500	\$ 2,500
Ditch and Backfill	\$ 1,436	\$ 1,484
Electric Motor (7 1/2 HP)	\$ 430	\$ 464
Panel Box and Misc. Electric Fittings	\$ 779	\$ 619
Pumping Unit (80,000#)	\$ 5,000	\$ 3,500
Gear Reduction Unit	\$ 0	\$ 781
Trucking	\$ 0	\$ 224
Other	\$ 301	\$ 104
Total Tangible Drilling Costs	\$ 25,670	\$ 29,799
Total Cost	\$ 143,299	\$ 150,532

WILSON 25 SURVEYS

MD ft	TVD ft	VS ft	C/L ft	INC dm	DIR dm	LAT ft	DEP ft	D'LEG °/100
0	0.00	0.00	0	0° 0' N 0° 0'E		0.00	0.00	0.00
892	891.98	5.13	0	0°42' S19°42'W		-5.13	-1.84	0.08
923	922.97	5.69	31	1°42' S33°42'E		-5.69	-1.65	4.52
954	953.91	6.73	31	5°24' S63°24'E		-6.73	-0.09	12.94
980	979.74	8.45	26	7°42' S47°48'E		-8.45	2.30	11.11
1010	1009.34	12.25	30	11° 0' S31° 0'E		-12.25	5.26	14.17
1039	1037.63	18.05	29	14°24' S18° 0'E		-18.05	7.80	15.25
1070	1067.35	26.54	31	18°36' S12°54'E		-26.54	10.10	14.32
1100	1095.39	36.96	30	23° 0' S11°12'E		-36.96	12.31	14.80
1130	1122.56	49.45	30	27° 6' S 9°54'E		-49.45	14.62	13.79
1160	1148.77	63.87	30	31° 6' S 7°24'E		-63.87	16.80	13.93
1190	1173.91	80.11	30	35° 0' S 6°30'E		-80.11	18.77	13.10
1220	1197.85	98.08	30	39° 6' S 5°30'E		-98.08	20.65	13.81
1250	1220.42	117.76	30	43°18' S 4°24'E		-117.76	22.35	14.21
1280	1241.52	139.05	30	47°18' S 1°30'E		-139.05	23.43	15.00
1309	1260.45	161.01	29	51°12' S 1° 0'W		-161.01	23.51	14.95
1341	1279.70	186.56	32	54°48' S 0°42'W		-186.56	23.13	11.27
1372	1296.76	212.43	31	58°24' S 1°18'W		-212.43	22.67	11.72
1403	1312.14	239.33	31	62° 6' S 1°42'W		-239.33	21.97	11.99
1451	1332.92	282.58	48	66°36' S 0°36'W		-282.58	21.11	9.60
1481	1344.45	310.28	30	68°12' S 0°36'W		-310.28	20.82	5.33
1512	1355.63	339.19	31	69°30' S 0°36'W		-339.19	20.52	4.19
1544	1366.52	369.27	32	70°42' S 0° 0'E		-369.27	20.36	4.14
1574	1376.02	397.73	30	72°24' S 0° 0'E		-397.73	20.36	5.67
1605	1385.00	427.40	31	73°54' S 0° 0'E		-427.40	20.36	4.84
1626	1390.74	447.60	21	74°24' S 0°18'W		-447.60	20.31	2.75
1656	1398.48	476.58	30	75°42' S 0°18'W		-476.58	20.15	4.33
1687	1405.90	506.68	31	76°36' S 0°18'W		-506.68	20.00	2.90
1711	1411.07	530.12	24	78°30' S 0° 6'W		-530.12	19.91	7.96
1742	1416.27	560.67	31	82°12' S 1°12'E		-560.67	20.21	12.63
1772	1419.35	590.49	30	86° 0' S 2°24'E		-590.49	21.15	13.28
1858	1421.23	676.41	86	91°30' S 0° 0'E		-676.41	22.95	6.98
1889	1420.28	707.37	31	92° 0' S 4° 0'E		-707.37	24.03	13.00
1946	1418.29	764.12	57	92° 0' S 6° 0'E		-764.12	28.99	3.51
2007	1416.69	824.82	61	91° 0' S 5° 0'E		-824.82	34.84	2.32
2099	1415.89	916.39	92	90° 0' S 6° 0'E		-916.39	43.65	1.54
2316	1421.57	1132.10	217	87° 0' S 6° 0'E		-1132.10	66.33	1.38
2411	1425.71	1226.49	95	88° 0' S 6° 0'E		-1226.49	76.25	1.05

Abbreviations Used:

MD - Measured Depth

TVD - True Vertical Depth

VS - Vertical Section

DIR - Hole Direction

DEP - Departure/East-West Distance

C/L - Course Length Measured From Previous Survey

INC - Degrees of Inclination

LAT - Latitude - North-South Distance

D'Log - Rate of Build for that Segment

END

DATE FILMED

02 / 22 / 91