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LATERAL DRILLING AND COMPLETION TECHNOLOGIES FOR SHALLOW-SHELF CARBONATES OF THE RED RIVER AND RATCLIFFE FORMATIONS, WILLISTON BASIN

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Performed Under Contract No. DE-FC22-94BC14984

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Denver, Colorado

National Petroleum Technology Office
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Executive Summary

Luff Exploration Company (LEC) focused on involvement in technologies being developed utilizing horizontal drilling concepts to enhance oil- well productivity starting in 1992. Initial efforts were directed toward high-pressure lateral jetting techniques to be applied in existing vertical wells. After involvement in several failed field attempts with jetting technologies, emphasis shifted to application of emerging technologies for drilling short-radius laterals in existing wellbores and medium-radius technologies in new wells. These lateral drilling technologies were applied in the Mississippi Ratcliffe and Ordovician Red River formations at depths of 2590 to 2890 m (8500 to 9500 ft) in Richland Co., MT; Bowman Co., ND; and Harding Co., SD.

Background

In an effort to improve well completions and ultimate oil recovery, LEC decided to investigate application of various types of technologies for horizontal drilling. LEC concentrated initially on technologies that would conceivably be economically feasible to apply in marginal oil wells. This focus led initially to investigation of various lateral jetting technologies. The major emphasis was ultimately concentrated on conventional technologies.

Initial efforts were directed toward technology described in United States Patent No. 5,183,111 "Extended Reach Penetrating Tool and Method of Forming a Radial Hole in a Well Casing." It was determined that the ownership of the technology was being disputed with lawsuits therefore making involvement with field applications inadvisable. This tool is called the Excalibur Tool by its inventor.

Attention shifted to a simplistic technology called Landers Horizontal Drill being developed primarily for shallow well applications in the Illinois Basin Area. Two unsuccessful field application tests were witnessed. It was concluded that this technology could not be successful without significant design changes in the equipment being utilized. United States Patent No. 5,413,184 "Method of and Apparatus for Horizontal Well Drilling" was issued for this technology subsequent to LEC's association with the inventor. It is not known if design changes have been made that resulted in successful performance in field applications.

LEC then became involved in development of a type of jetting lance technology distinctly different from the two types previously investigated. This effort began in September 1993. The first attempt at field application of this technology was in the project area in Harding Co., SD and was unsuccessful mechanically. Based upon problems encountered in the field test, design changes were made. Several mechanically successful applications of this technology were later accomplished in wells in other than the project areas (Colorado, Texas and Wyoming) to depths exceeding 2440 m (8000 ft). Several lateral extensions up to 15 m (50 ft) were drilled and a few successful attempts with lateral lengths up to 122 m (400 ft) were completed. Although mechanical success was achieved with this technology, persistent mechanical problems were not eliminated and costs incurred significantly exceeded expectations.

After determining that the more experimental lateral jetting technologies discussed above were not viable options for the project area, a commercially available jetting technique was tried in the Red River B zone in Bowman Co., ND. This technology was marketed by Penetrators, Inc. Testing after its field application demonstrated that the tools did not perform in this case as represented.

LEC elected then to apply more conventional horizontal drilling technology in the project areas. An attempt was made to use tools developed by Amoco's Research and Development group. Lack of success with the Amoco technology led to application of slim-tool mud motor re-entry drilling. One successful attempt was made with a total lateral extension of 813 m (2667 ft). A medium radius horizontal well was also drilled in a partially depleted Red River B zone reservoir in Harding Co., SD. Lateral extension of 528 m (1733 ft) from the vertical section of this well was completed prior to the horizontal drilling tools becoming stuck following loss of circulation.

Jetting Lance Technologies

Excalibur Tool. The Excalibur tool is the downhole portion of the equipment necessary for application of this lateral jetting technology. Tools and equipment utilized on surface and downhole are as follows:

1) Conventional oil field servicing rig,
2) High pressure pumping unit with fluid filtration equipment capable of pumping approximately 76 l/min (20 gpm) up to 137,900 kPa (20,000 psi) discharge pressure,
3) High pressure hose,
4) High pressure swivel,
5) Power swivel to rotate tubing (conventional tubing power tongs can be used but are less desirable),
6) Tubing work-string capable of withstanding internal working pressures up to 137,900 kPa (20,000 psi),
7) Downhole Excalibur tool (see patent for description of tool components).

The Excalibur tool described in U.S. Patent No. 5,183,111 is designed for application in both open-hole and cased-hole completions. It must be run on a tubing workstring capable of withstanding internal working pressures up to 137,900 kPa (20,000 psi). All operations of the tool require use of pressure and/or rotation of the workstring.

Preparation of a well for application of the technology first requires removal of production equipment utilizing a conventional oil field servicing unit. The downhole tool is then run in the well on a high-pressure workstring. The tool may be positioned to directionally orient penetration of the well casing and rock formation. After the tool has been anchored at the desired depth in the well, a hole is cut in the well casing. This is accomplished by engaging a built-in milling device with pressure and turning the mill by rotating the workstring. A hole of approximately 2.5-cm (1.0-inch) diameter is cut in the well casing.

Following cutting a hole in the casing, the tool is shifted to retract the milling device and lower it below the hole it cut in the casing. This action places a jetting lance in position to exit the well casing through the hole previously cut. The tubing or workstring is then rotated to extend a small diameter tube (lance) with a jetting nozzle with a small orifice hole(s). Filtered fluid is pumped simultaneously at a high pressure level to cut a hole in the formation as the lance is extended. The lance is retracted by rotating the tubing the opposite direction. The tool can then be repositioned to cut additional laterals.

The diameter of the hole cut in the formation probably varies depending upon rock type but may be up to 5.1 cm (2 in.). The tool is designed to extend the lance up to 15 m (50 ft) from the well casing leaving the well casing at a 90° angle. There is no steering capability or any means available to record the actual path of the lance after it is retracted. A detailed description of the tool is provided in the patent.

LEC did not use the Excalibur tool technology on any wells. As a result, there is no actual cost information.

Landers Horizontal Drill. The tool and process described in U.S. Patent No. 5,413,184 encompass use of equipment as follows for its application:

1) Conventional oil field servicing rig,
2) High pressure pumping unit with filtration equipment and small diameter coiled tubing spool. Pumping is conducted at 7.5 to 15 l/m (2 to 4 gpm) and pressures up to 41,370 kPa (6000 psi) (design of unit was witnessed in field),
3) Well tubing workstring,
4) Specially designed guide elbow,
5) Miniature fluid driven motor with flexible output shaft,
6) Mills to cut through casing,
7) High pressure hose, and
8) Jet nozzles.

Detailed description of the various components of this lateral jet drilling system is provided in the patent.

These tools and process are the simplest design explored. The production tubing from the well or a work string must be used. This tubing is not subjected to pressure or movement during the operations of cutting through the well casing or formation.

Production equipment must be pulled from the well with an oil field servicing rig. The first step in application of the tool is to then run a guide elbow on the bottom of the well tubing or workstring. The guide elbow has a small diameter hole inside that changes direction 90° from pointing upward into the well tubing to pointing horizontally normal to the well casing.

After the guide elbow is set at the desired well depth, a small diameter mill on a flexible shaft connected to a miniature fluid driven motor is run down the tubing or workstring on small diameter, 1.6 cm (⅝ in.), stainless steel coiled tubing . As the coiled tubing is run in the well, weights are installed above the motor to provide downward force to assist milling through the well casing. Fluid is pumped down the coiled tubing to turn the motor and mill for cutting through the casing. After cutting through the casing the coiled tubing is pulled from the well and the motor and mill are removed.

The next step consists of running back in the well with the coiled tubing with a high pressure flexible hose connected to the coiled tubing and a jetting nozzle on the end of the hose. Fluid is then pumped at high pressure 34,470 to 41,370 kPa (5000 to 6000 psi) through the coiled tubing, hose and jetting nozzle to cut formation rock. Typical pumping rate is 11 to 15 l/min (3 to 4 gpm). The coiled tubing is progressively spooled down the tubing or workstring as the hole is cut in the formation and the hose and jet nozzle are extended into the horizontal lateral. The length of the lateral cut into the rock formation is limited to slightly less than the length of the hose.

There is no steering capability with this technology. Likewise, there is no device or technique incorporated with the tools to record the path of the lateral after it has been cut.

LEC did not apply these tools in any field tests. Two tests on shallow wells in Kentucky were witnessed by LEC personnel. Both tests were failures. Subsequent testing in a machine shop with the mill being applied to cut through casing utilizing a drill press was also unsuccessful. Based upon these observations, it was concluded that this technology did not merit consideration for testing in this joint DOE project. Since there was no field test, no cost information was obtained.

Long Reach Tool. Starting in September, 1993, LEC supported development of a type of jetting lance technology that incorporated some components of all types of jet drilling and conventional horizontal drilling. Unlike the other jetting technologies explored, this procedure does not deploy the jetting lance at an angle of 90° from the casing. The major components necessary for its application are as follows:

1) Conventional well servicing rig,
2) Power swivel,
3) Surface pumping unit with fluid filtration equipment capable of pumping approximately 76 l/min (20 gpm) at up to 137,900 kPa (20,000 psi) discharge pressure,
4) High pressure discharge hose,
5) High pressure power swivel isolation device,
6) Tubing workstring capable of withstanding internal working pressures up to 137,900 kPa (20,000 psi),
7) In-line filter at bottom of tubing workstring,
8) Downhole tool assembly consisting of
    a) Tool body (conventional well tubing),
    b) On-off tool,
    c) Fabricated whipstock,
    d) Anchoring tool,
    e) Lance (high pressure small diameter tubing), and
    f) Mill with jetting nozzle.

There is no pictorial presentation of equipment utilized in this process because this technology continues to be in a developmental state.

Production equipment must first be removed from the well with an oil field servicing unit. The downhole tool assembly is then run in the well on the tubing or workstring. After the tools are run in the hole, an anchoring device is set such that exit from the casing occurs approximately 9 cm (30 ft) above the depth where it is desired to penetrate horizontally. A jetting lance and casing mill are then released from the tool body. The lance and mill are lowered within the tool body until the mill contacts the casing off the face of a retrievable whipstock which is anchored in place as a part of the tool body. A window is then cut in the casing with dimensions approximately 5.1 cm (2 in.) wide and 76 cm (30 in.) long. This is accomplished by rotating the tubing or workstring at surface with the jetting lance and mill below the work string. The mill is cooled and cuttings are removed by circulating through the work string, jetting lance and mill while rotating to cut through the casing.

After the window is cut in the casing the pressure is increased to a level adequate to jet cut through the rock formations. This typically requires surface pressures ranging from 68,950 to 137,900 kPa (10,000 to 20,000 psi). Jetting action and back pressure at the mill occurs as a result of use of a jetting nozzle with an orifice size of 0.05 to 0.08 mm near the end of the mill. The lance is extended to the planned length by lowering the tubing work string at surface as the hole is jet-cut in the rock formation.

Based upon limited information obtained after jet-cutting of holes with these tools it is thought that the radius of curvature of the jetting lance is approximately 9 m (30 ft). After a penetration has been completed the lance is pulled back into and re-engaged with the tool body. The anchor is then released and the tool is ready to be set again for another penetration or removed from the well. Three casing windows are the maximum number that has been cut before wearing out the mill.

The tool is constructed such that the length of the jetting lance and tool body are determined by the desired length of penetration outside the well casing. This does not pose a problem of any consequence since both the tool body and jetting lance are made up of sections of conventional tubing used in oil and gas operations.

This tool has been directionally oriented on several occasions. There has been no attempt thus far to incorporate steering capability or directional monitoring while jetting.

The prototype of this tool was first applied in a well in Harding Co., SD in the fall of 1993. Work at that time was unsuccessful but it served to provide the basis for necessary design changes that subsequently led to success. The next attempt with this technology was on a Niobrara Formation well in Moffat Co., CO. In this test, six windows were cut in the casing. Laterals were cut from these windows with lengths ranging from 11 to 26 m (37 to 87 ft). Fluid productivity increased substantially but unfortunately nearly all of the production was water. Several other mechanically successful jobs have been completed with this technology on wells in the Austin Chalk Formation in Texas. One lateral drilled from one of these wells extended in excess of 122 m (400 ft).

In April 1996, LEC applied this technology in a 1160-m (3800-ft) Almond Formation oil well in Sweetwater Co., WY. Numerous mechanical problems were experienced but success was achieved in drilling two laterals, each 15 meters (50 feet) long, from 14.0-cm (5½-in.) diameter casing. Prior to being shut-in for this work the well was producing 0.2 m^3 oil per day (1 bopd) and 284 m^3 gas per day (10 mcfd) prior to being shut-in. Following drilling of the two laterals it produced 0.6 m^3 oil per day (4 bopd) and 425 m^3 gas per day (15 mcfd). Total cost was approximately $134,000. Applications of this tool in other areas apparently had gross costs approaching or in excess of $100,000 per well. If the problems typically encountered with the tools and equipment used in this technology could be eliminated, costs per well could easily be reduced to $60,000 or less.

An attempt was made in June 1995 to use this technology in this DOE project. Mechanical problems experienced with the equipment and well conditions limiting applicability of the equipment caused LEC to abort these work attempts.

Penetrator, Inc. Tool. The Penetrator Tool is marketed commercially and most of the equipment unique to their application comes as a package in their service rates. The equipment used is as follows:

1) Conventional oil field service unit,
2) High pressure pumping unit with filtration equipment. Its design provides for pumping 76 to 106 l/min (20 to 28 gpm) at up to 68,950 kPa (10,000 psi),
3) High pressure hose,
4) Tubing workstring capable of withstanding internal working pressure up to 68,950 kPa (10,000 psi) and
5) Downhole tool as depicted in figure 1.

The Penetrator tool was invented and patented by the same individual as the Excalibur tool. It was invented first and is designed to penetrate up to 3 m (10 ft) horizontally away from the well casing. Detailed discussion of this tool and its application is provided in the literature (Peters and Hansen 1993).

This tool must be run on well tubing or workstring capable of withstanding internal pressures up to 68,950 kPa (10,000 psi). It is then anchored in the well casing at the depth of the desired horizontal lateral penetration. The tool may be set so the horizontal lateral is directionally oriented.

The original tool design incorporates a punch to penetrate the casing. Filtered fluid is pumped at high pressure to extend a punch from the tool to pierce the casing. An internal jetting lance then passes through the hole in the casing and is extended into the rock formation up to 3 m (10 ft) from the casing. The jetting lance extends into the rock formation by pressure imposed on the tool. The lance departs the well casing horizontally at 90° from the casing. There is no means of measuring the actual course of the lateral penetration. After the lance and punch are retracted, the tool can then be repositioned for additional penetrations.

A later tool design replaced the punch with a rotating mill to penetrate the casing. Like the original tool design, penetrating the casing and extending the lance are controlled by the surface operating pressure level.

The Penetrator tool technology was applied at the No.1-32 Swanson well in the study area (e/2sw, Sec.32, T.23N., R.6E., Harding Co., SD) in April 1995. Procedures were conducted to make nine casing penetrations and jet cut a 3-m (10-ft) lateral through each penetration. Total job cost for all services required was $62,426. Fees paid to Penetrators, Inc. for their services were $25,159.

After work was completed the No. 1-32 Swanson well was returned to production. Pumping for seven months after this work proved that no increase in production was achieved. Isolation testing in December 1995 showed that the Penetrator tool did not cut through the casing in some instances. In some cases it did cut through the casing but likely did not cut the laterals into the producing formation as contemplated.

After evaluating the downhole results of the Penetrator tool, additional work was done on the No. 1-32 Swanson. The same zones where the Penetrator tool was applied were conventionally re-perforated and acidized. A production increase was realized as demonstrated on figure 2. Based on these results, it was concluded that the Penetrator tool and technology cannot be beneficially applied in the Red River B zone dolomite at a depth of 2896 m (9500 ft).

Amoco Ultra-Short Radius Technology. Amoco's Research and Development group designed a set of downhole tools that constitutes a system for drilling short-radius laterals with a radius of 30 m (100 ft) and ultra-short radius laterals with a radius of less than 15 m 50 ft) from existing vertical wellbores (Warren et al 1993). Amoco tested this system with actual drilling operations at its field testing facility in Catoosa, Oklahoma. It then licenced the technology to several drilling service companies and a few oil and gas operators.

While Amoco refers to the system as *rotary steerable*, a more accurate description is *rotary point-able*, as the tool cannot be steered while drilling. The key components of Amoco's bottom-hole assembly are shown in figures 3 and 4 and described as follows:

1) A muleshoe to seat gyro survey wireline tools,
2) A knuckle joint for transmitting drillstring rotation and loads to the bit while maintaining flexibility, and
3) An eccentric, non-rotating sleeve assembly, designed in order to keep one side of the assembly constantly on the low side of the hole, while allowing the drillstring rotation to pass though the inside of the sleeve (via a mandrel) and rotate the drill bit (unique components of the eccentric sleeve are a latch assembly and a port, which will be discussed below),
4) A sub between the eccentric sleeve and the bit, which can be sized for different drilling radiuses, and
5) A specially designed bi-center, anti-whirl, PDC drill bit.

Amoco's Research and Development group designed the tools to address two key concepts: 1) the bit needs to drill exactly in the direction it is pointed and 2) the eccentricity at the upper end of the eccentric sleeve mandrel has to be held constant and pointed toward the outside of the curve.

If the tools can accomplish these requirements in actual downhole drilling conditions, then the geometry presented in figure 5 will be valid, and the assembly will self-correct to drill a curved section of hole exactly to the planned radius.

Amoco also designed the eccentric sleeve assembly to provide an indication at the surface of the downhole orientation of the sleeve, using a pressure signal. When the drillstring is rotated clockwise, the sleeve does not rotate, but the mandrel inside the sleeve transmits rotation to the drill bit. When the drillstring is slowly rotated counterclockwise, the mandrel latches in a latch pocket, and the eccentric sleeve rotates, changing the orientation of the bottom hole assembly. When the rotation of the sleeve occurs, approximately half of the circulating drilling fluid is diverted through a port, which corresponds to a reduction in pump pressure at the surface. When this pressure signal is observed, the drill string can be slowly rotated at the surface (using a compass around the drillstring) the desired number of degrees to adjust the orientation of the eccentric sleeve. When the drillstring is rotated clockwise, the latch disengages, and normal drilling can be accomplished while the orientation of the sleeve remains constant.

Operators usually rent drillpipe workstrings. Drillpipe previously used with the Amoco system for the curved and lateral sections of the hole include:

1) 7.3-cm (2⅞-in.) P110 and P105 grade pipe with Hydril PH-6 connections (for short radius applications),
2) American Open Hole drillpipe (for short radius applications),
3) Composite pipe bonded to Hydril PH-6 connections for ultra-short radius applications down to 9-m (30-ft) radius sections (When this pipe is used, a casing section must be removed for the casing exit, since the composite pipe cannot rotate past a whipstock and through a casing window without damage to the pipe. The durability of the pipe in downhole oil field conditions is still being tested),
4) 5.2-cm (2.063-in.) Q-125 pipe with IWSV connections (This pipe is typically not used in the petroleum industry. Amoco borrowed the pipe specifications from companies that drill bore holes beneath buildings and rivers for fiber-optic cable and telephone lines. Its ability to withstand downhole oilfield conditions is still questionable.)

Drillpipe for the vertical section of the hole can be 7.3 cm (2⅞ in.) with Hydril PH-6 connections or American Open Hole. It is important to use pipe in the vertical section that has a shoulder connection (unlike EUE tubing) to prevent orientation problems caused by connection make-up shifts.

The Amoco system relies on the azimuthal orientation of the drillstring at the surface reflecting the azimuthal orientation of the bottom-hole assembly. When the bottom-hole assembly is run, the orientation of the eccentric sleeve is measured compared with the muleshoe (where the orientation gyro seats) and relative orientation of the drill string is measured and marked joint-by-joint as the bottom hole assembly is run into the hole. A protractor plate is placed on the rig floor around the drill pipe string so that azimuthal orientation of the measured marks on the drill pipe string can be established. This approach makes the Amoco system susceptible to the following problems:

1) Shifting or creeping of connection make-up in the drillstring. For this reason, EUE tubing should not be used in the vertical portion of the drillstring and the makeup of shouldered connections (such as Hydril PH-6) needs to be carefully monitored.
2) Drillpipe wrap from energy stored in the drillstring during drilling rotation. This can be addressed to a certain extent, but it is still problematic.
3) Errors in measuring and marking the relative orientation of the eccentric sleeve, the mule shoe and the drill pipe string joints.

The Amoco system can be used with completion rigs, rather than drilling rigs, working during daylight hours. For the system to work properly downhole, the following equipment is required (or strongly recommended) at the surface:

1) A power swivel (rather than a rotary table) capable of providing a specified level of torque and rotations per minute (rpm) and with hydraulic controls (which provide sensitivity in slow rotation for orienting the bottom hole assembly).
2) A mud pump capable of suppling 341 to 492 l/min (90 to 130 gpm) at the likely pressure levels (which vary by depth). A needle-type pressure gauge on the end of a high pressure extension hose are useful for observing the pressure signal from the rig floor during counter-clockwise rotation.

3) Solids control equipment. Amoco claims that solids control with its system is not as critical as when steered mud motors are used. However, solids control (beyond a shale shaker) may still be prudent, using either using a centrifuge or using additional holding tank capacity, augmented with chemical flocculation to remove solids in colloidal suspension. Ditch magnets are required during the removal of a casing section (or milling of a casing window) to remove metal shavings.
4) A protractor plate on the rig floor, around the drill pipe string, for measuring azimuthal orientation.

As previously noted, the Amoco system can be used with completion rigs, typically during daylight hours. Well preparation includes pulling the existing tubing and artificial lift equipment and cleaning the inside of the casing using a bit and casing scraper. Casing departure can be accomplished by either removing a section of casing and setting a cement plug, or by setting a whipstock inside the casing and milling a window out the side of the casing. If a whipstock is used, the face of the whipstock needs to be oriented by gyro to the desired direction for the horizontal lateral. Figures 6 and 7 are schematics for the two approaches for casing departure.

After an effective casing exit has been created, a special pilot hole is drilled, using a bit similar to the bi-center, anti-whirl, PDC bit. At this point, the Amoco-designed bottom-hole assembly to drill the curved portion of the hole (as described above) is made up and run in the hole on a (typically rented) drillstring. Selectively sized drill collars may or may not be added for weight, and to minimize effects from wrapping of the drill string.

The drilling fluid is typically fresh water, treated water, or brine (depending on weather and sensitivity of the target producing zone), with occasional gel sweeps to clean the drilled hole.

If a whipstock is used, another gyro shot is taken when the assembly is down at the whipstock and casing window, in order to verify the orientation of the whipstock face. The bottom-hole assembly is then lowered into the pilot hole, and the curved section of the hole is drilled. The orientation of the eccentric sleeve is checked every 0.3 m (1ft) for the first 1.5 m (5 ft) of curved section using counter-clockwise rotation and the port pressure signal at the surface, as described above. The relative orientation of the drillstring at surface and the eccentric sleeve downhole is measured and marked on the drillstring each time the bottom hole assembly is run in the hole.

After approximately half to two-thirds of the curved section has been drilled, the bottom-hole assembly is pulled out of the hole and a multi-shot directional survey is run using special tools run on fiberglass sucker rods as shown in figure 8.

The bottom-hole assembly is re-run to bottom and remaining portion of the curved-hole section is drilled with multi-shot surveys (orientation and inclination) and inclination-only surveys run as necessary. The bottom-hole assembly is adjusted as necessary after multi-shot surveys in order to land the curved section of hole in the target zone.

After the curved section has been drilled, the bottom hole assembly is modified and the horizontal lateral section of the hole is drilled and surveyed with multi-shot equipment.

After the drilling operations are completed, tubing and artificial lift equipment is re-run and the well is returned to production. Short-term fluid recovery can also be accomplished by swabbing after the tubing is run and before the artificial lift equipment (sucker rods and downhole pump) is run.

Literature and sales brochures from vendors (with licences from Amoco) suggest total job costs ranging from $75,000 to $150,000 depending on depth and desired lateral departure.

Luff Exploration Company attempted to use the Amoco short-radius rotary system to drill a horizontal lateral from an existing wellbore into the Ratcliffe formation. The well had been completed conventionally in the Ratcliffe.

Well:	M-17 Trudell
Location:	swsw, Sec.17, T.26N., R.58E.
Field:	North Sioux Pass
Casing size:	14.0 cm (5½ in.)
Top of Ratcliffe:	2646 m (8680 ft)
Ratcliffe perforations:	2652 - 2670 m (8701- 8759 ft)
Planned kick-off point:	2646 m (8680 ft) in anhydrite
Planned radius:	24 m (80 ft)
Planned departure:	152 to 183 m (500 to 600 ft)
Planned azimuth:	45 to 60° (northeast)

The planned azimuth was chosen so that the horizontal drilling trajectory would be perpendicular to the suspected orientation of natural fractures (subsequent oriented logs and cores taken from a nearby well confirmed the natural fracture orientation to be southwest-northeast). The trajectory was also planned to stay within the regulatory set-back distances for the M-17 Trudell spacing unit shown in figure 9.

Figure 10 presents a porosity log from the well showing the base of the last salt, the anhydrite section above the Ratcliffe, the top of the Ratcliffe, and the various porosity benches within the Ratcliffe interval.

Figure 11 presents a conceptual cross-sectional view of the existing conventional completion and the planned horizontal completion. The kick-off point was chosen to allow the 24-m (80-ft) radius to encounter each of porosity benches during the curve section of the hole and again as the planned trajectory climbed back to uppermost porosity bench at the end of the horizontal lateral (depending on the horizontal departure distance achieved).

By drilling perpendicular to the orientation of natural fractures in the Ratcliffe, and by designing the curve of the lateral to encounter each porosity bench once and possibly twice, it was hoped that the horizontal well trajectory would provide maximum exposure to the fracture-enhanced portions of the Ratcliffe interval.

The directional drilling services were provided by Wilson Downhole, one of several service companies licenced to use the Amoco technology. A specialized drilling/well-servicing rig with personnel experienced in horizontal drilling from existing wellbores was selected. Every care was taken to follow Amoco's recommendations for the following:

1) Power swivel,
2) Drilling fluid pump and pressure gauge,
3) Drilling fluid circulation / clarification system,
4) Drilling fluid,
5) Drillpipe for curved and horizontal section, and
6) Drillpipe for vertical section.

Additionally, Wilson Downhole reviewed drilling plan for the M-17 Trudell with Amoco's experts at the Catoosa Research facility in Oklahoma. Although the M-17 Trudell attempt was deeper than most of the previous applications of the Amoco system, the Amoco experts and the Houston representatives of Wilson Downhole were confident that the system would perform successfully.

The well work was conducted in January 1996 and progress was impeded by unseasonably cold weather. The tubing, rods, and downhole pump were pulled and the inside of the casing was conditioned with a bit and casing scraper. A whipstock was successfully set near the planned kick-off point in the anhydrite section (below the base of the last salt and above the Ratcliffe formation. Although difficulties were experienced orienting the whipstock, the azimuth of the whipstock face later measured 58° which was within the desired range. A window was then successfully milled through the side of the casing.

After the casing window was dressed off, Wilson Downhole directed the drilling of a pilot hole to a measured depth of 2640 m (8660 ft), or 4 m (14 ft) from the bottom of the casing window. The hole was circulated for 1.5 hours, which included a polymer sweep to remove drilling fines. Wilson Downhole then ran into the hole with Amoco's specialized bit and bottom-hole assembly (BHA) for drilling the curved section of the planned hole. The Amoco downhole tools passed though the casing window and through the pilot hole without incident. A single-shot gyro run was made to orient the tool, and then approximately 0.3 m (1 ft) was drilled to a measured depth of 2640 m (8661 ft). The drillstring was picked up to check orientation when the BHA became stuck. The Amoco tools in the BHA supposedly would withstand forces in excess of 13,608 kg (30,000 lb) so a force of 4536 kg (10,000 lb) over the drillstring weight was pulled three times in an attempt to free the BHA. On the third attempt, the BHA parted and the full string.was pulled out of the hole. The Amoco BHA parted near the knuckle joint, in an area with reduced cross-sectional area and likely stress concentrations.

Attempts to fish the bit and portions of the BHA were unsuccessful and field operations were suspended. During the fishing operations, a mill run reached a depth equal to the depth of 2460 m (8661 ft). This depth and the torquing experienced with the mill suggest that the mill was along the side of the bit and BHA. However, continued drilling operations past (but very near) the bit and BHA were considered risky. Luff Exploration Company considers investigations by Wilson Downhole into the failure of the Amoco tool to be inconclusive.

Slim-tool Mudmotor Short-radius Technology. After failure with tools developed by Amoco in the M-17 Trudell well, it was decided to make an attempt using conventional re-entry mudmotor short-radius technology. As with the Amoco tools, short radius was required because of the short distance between the base of the Charles Formation salt zone and the upper porosity bench of the Ratcliffe.

Two wells were chosen for application of re-entry slim-tool mudmotor short-radius technology. The No. 2-16 State well (nwse of Sec. 16, T.26N., R.58E.) was chosen as one candidate and the M-17 Trudell well, discussed previously, was the other candidate. Baker Hughes-Inteq was chosen as the directional drilling company. The horizontal lateral on the No. 2-16 State well was successfully completed with a lateral section length of 812 m (2667 ft) and 604 m (1982 ft) in the Ratcliffe interval. The M-17 Trudell horizontal attempt was abandoned after attempts to build the angle to depart from the casing were unsuccessful.

The tools used for re-entry work on the two Ratcliffe wells were as follows:

1) Workover rig rated at 113,398 kg (250,000 lb) capacity equipped with normal tools plus generator, pumps, mud tanks, sub-structure, rotary table with winterization components for conduction 24 hour operations,
2) Drillstring consisting of 7.3 cm (2⅞-in.) drillpipe and 7.3 cm (2⅞-in.) heavy weight drillpipe,
3) Baker Model "D" packer,
4) Packer anchored casing whipstock system,
5) Casing window milling systems,
5) Articulated and fixed-angle build 7.9 cm (3⅛-in.) motors,
6) Short radius measurements while drilling (MWD) system, and
7) Wireline surface-readout gyro equipment.

No. 2-16 State. The No. 2-16 State well was originally completed in the Ratcliffe in 1982 after depletion of the deeper Red River. The original Ratcliffe completion was by perforation and acidizing with 38,000 liters (10,000 gal). Production from the Ratcliffe completion had declined to 1.9 m^3 oil and 1.6 m^3 water per day (12 bopd and 10 bwpd) by 1994 and was shutin after a cumulative of 17,200 m^3 (108,193 bbl) oil. A pressure-transient test was performed by injecting water for 10 days prior to drilling the re-entry lateral to quantify bottomhole pressure and transmissibility. The bottomhole pressure was measured to be 21,800 kPa (3160 psi) which is 6200 kPa (900 psi) less than the original pressure. Permeability to water was calculated to be 5.9E-4 μm^2 (0.6 md) for the 21 ft of reservoir. An oriented core from a well one mile west indicated natural fractures orienting northwest-southeast in the Ratcliffe. It was concluded that the presence of natural fractures and high bottomhole pressure made the No. 2-16 State well a good candidate for a lateral drain hole.

Work on the No. 2-16 State well commenced in November 1996. After cleaning the wellbore, a Baker Model "D" packer was set at a depth of 2606 m (8879 ft). The casing whipstock was then oriented and set on the packer. Several orientation measurements were taken prior to setting the whipstock. The casing window was then cut and a 1-m (3-ft) pilot hole was drilled outside of the casing. Time required for these operations was 3.5 days.

A fixed-angle build (3.8°) motor was first attempted for starting the curve build section of the lateral. The bit and motor assembly could not be pushed through the BOP stack and the 14.0-cm (5½-in.) casing so those tools were removed from the drillstring. An articulated motor system was then run to start drilling the curved section. A total of 14 m (47 ft) was drilled with this assembly but it was determined that it was not building angle as required so it was pulled from the well. The hole drilled was plugged back into the casing with cement so another attempt could be made to drill the curved section.

After drilling out cement for the second attempt, the curve section was successfully drilled with a fixed-angle build assembly with heavy-weight drillpipe. Solids introduced into the drilling fluid system during the cement clean-out operation contributed to causing an MWD and motor failure while building the curve. However, after the solids were removed from the system, completion of drilling the curved section and landing in the target interval was completed. The total time to successfully finish drilling the curved section was 12 days.

Of the 12 days spent drilling the curved section, 9.5 days were spent attempting to drill the section, plugging back, waiting on cement to harden, drilling out cement and trying to get tools to operate properly. The successful attempt was slower than it should have been due to downhole equipment failures and tripping for bits. Six equipment failures and four bit replacements resulted in trip time in excess of 50 percent of the actual time spent drilling the curve portion of the hole.

Following drilling of the curve section, the horizontal section was successfully drilled using a 1.2° fixed-build motor assembly. Conventional MWD equipment was used to monitor inclination and azimuth while drilling. Total time required to drill the horizontal section was 11 days. Significantly more time was required for drilling this section than anticipated due to trips for bits and equipment failures. Six bits required to drill this section and two equipment failures resulted in trip time of approximately 30 percent of the actual time spent drilling the horizontal section .

Total costs estimated to drill the horizontal lateral from the No. 2-16 State wellbore were $360,000. The actual costs to successfully drill the lateral ($616,800) exceeded the original cost estimate by 71 percent. Numerous factors contributed to the cost over-run. The most significant components of the excessive costs were as follows

1) Extra time required due to downhole equipment and bit failures,
2) Multiple whipstock and tool orientation surveys, and
3) Unsuccessful first attempt to drill curve section and associated plugging back operations.

The time required for all of these events led to excessive costs for numerous rental items as well as for personnel whose time could not be effectively used while waiting for problems to be corrected. Additionally, costs were increased as a result of severe weather conditions experienced while conducting operations during November and December 1996. Table 1 summarizes costs incurred on the No. 2-16 State well.

Although costs exceeded original estimates and considerably more time was required than planned, a re-entry horizontal lateral was successfully drilled from 14.0 cm (5½ in.) casing in the No. 2-16 State well. As discussed above, numerous problems were experienced in the process of completing this work. The total length of hole drilled outside the casing was 812 m (2667 ft) with 604 m (1982 ft) being in the Ratcliffe porous interval. Figure 12 illustrates time to drill the lateral and drilling bit history.

After drilling operations were completed, the well was put on pump. The well was produced for 108 days and averaged about 0.5 m^3 oil and 16.7 m^3 water per day (3 bopd and 105 bwpd). Although the well was producing significantly more fluid than from the conventional vertical completion, it was an economic failure.

M-17 Trudell. The attempt to drill a horizontal lateral from the M-17 Trudell well was unsuccessful. A whipstock had previously been set and a casing window had been cut when use of the tools developed by Amoco was attempted. The hole drilled along side the casing with the Amoco tool was plugged back with cement. After drilling out cement to outside of the casing window, the same procedure that was successful in the No. 2-16 State well was attempted. A fixed-angle build motor was used to initiate the curve section, but the bit appeared to follow the hole previously drilled during the attempt with the Amoco tool. As a result of this problem, work on the M-17 Trudell well was terminated. Costs incurred on the M-17 Trudell well, before the attempt to drill a horizontal lateral was terminated, amounted to a total of $135,090.

New Well Medium-Radius Technology. There has recently been a significant exploitation effort by application of horizontal drilling from new wells in the Red River B zone within and near to the study area of this project. Typical wells are drilled with lateral extensions up to 1524 m (5000 ft). Operators frequently drill vertically through the Red River, evaluate prospective zones, plug back and then drill the curve section. Casing is run and cemented in the vertical hole and through the curve section such that it is landed with the bottom of the casing being nearly horizontal, immediately above or barely into the top of the Red River B zone. The horizontal section is then drilled and left open for production or injection operations. Drilling a horizontal well in the study area in the Red River B zone averages approximately 30 days.

Two horizontal wells in the study area were included in this project, the M-20H Stearns well drilled by Luff Exploration Company (swsw, Sec. 20, T.22N., R.4E., Harding Co., SD) and the 1-26H Greni (w/2 Sec. 26, T.129N., R.103W., Bowman Co., ND) drilled by UMC as operator with Luff Exploration Company as a joint interest owner.

Conventional drilling rigs with all typical ancillary equipment were used for these drilling operations. Rigs capable of drilling to a vertical depth of 4267 m (14,000 ft) were required since the depth of the Red River B zone was nearly 2743 m (9000 ft) from surface and the lateral extension could be drilled up to a length of 1524 m (5000 ft).

After the vertical portion of the holes were drilled with conventional rotary drilling equipment, the curve sections were drilled using conventional downhole motor/steering/MWD systems. Likewise, following setting casing, the horizontal sections were drilled with downhole motor/steering/MWD systems. A 11.4-cm (4½-in.) drillstring was used for drilling the horizontal section down through 17.8-cm (7-in.) casing.

Horizontal wells in the study area typically have a 31.1-cm (12¼-in.) surface hole drilled to about 610 m (2000 ft). The surface hole is drilled using fresh water to protect shallow aquifers. Next, 24.4-cm (9⅝ -in.) casing is run and cemented up to ground surface. The vertical portion of the hole is then drilled with 22.2-cm (8¾-in.) bits to either the kick-off point for the curve section or through the Red River.

The 1-26H Greni well was drilled vertically to a kick-off depth of 2594 m (8510 ft) without drilling through and evaluating the Red River B zone before drilling horizontally. Conversely, the M-20H Stearns well was drilled through the Red River and evaluated by logs and drillstem tests before drilling the curve and horizontal section. The other significant difference in procedures used in drilling the M-20H Stearns and 1-26H Greni wells was the drilling fluid systems. An oil-based, reverse-emulsion system was used on the M-20H Stearns and a saturated saltwater gel-chemical system was used on the 1-26H Greni. The oil-based system is typically more expensive. It has advantages over the saturated-salt system as it provides better lubricity and it typically results in gauge hole through salt sections. Gauge hole through the salt sections is generally accepted by industry to be beneficial in reducing risk or subsequent dynamic movement that can displace or collapse the well casing.

M-20H Stearns. The M-20H Stearns was drilled between two existing Red River B zone completions to evaluate both oil productivity and water injectivity with the aim of using the technology for waterflooding the partially depleted field (a porosity log of the Red River B zone is shown in figure 13). The Red River B and D zones were both drill stem tested prior to drilling to total vertical depth in the M-20H Stearns well. After drilling the vertical hole, open-hole logs were then run to aid with evaluation of both intervals.

Following evaluation of the Red River Formation in the M-20H Stearns well, a cement plug was set in the hole from bottom from 2448 to 2755 m (8033 to 9044 ft. After allowing time for the cement to harden, the cement plug was drilled out down to a depth of 2536 m (8321 ft). A down-hole assembly designed to drill off the cement plug in a pre-determined and controlled direction was then run in the hole. Initiation of the curve was achieved by carefully time drilling off of the cement plug. The curve section was then drilled with a radius of approximately 128 m (420 ft) to a total drilled depth of 3066 m (10,059 ft) and true vertical depth of 2664 m (8743 ft). The end of the curve section was immediately on top of the Red River B zone at an angle of 89° from vertical. Downhole motors with 1.5 to 3.0° angle-build assemblies, using mud-pulse MWD systems were used to drill the curve portion of the hole.

After drilling the curve section was completed, 17.8-cm (7-in.) casing was run and cemented in place from surface to the end of the curve section. The horizontal section was then drilled with a 15.6-cm (6⅛-in.) bit using down-hole motors with 1.3° angle-build assemblies and MWD equipment. Unfortunately, circulation was lost after drilling horizontally 314 m (1029 ft) into the Red River B zone and as a result, the directional drilling tools and some of the drillstring became stuck in the hole. The main cause of loss of circulation was low bottomhole pressure of 7600 kPa (1100 psi) in the partially depleted Red River B zone.

A total of 30 days had been spent drilling the M-20H Stearns well when the directional drilling assembly became stuck in the hole. An additional 13 days were spent attempting to fish the stuck tools from the well. The only significant problem experienced prior to sticking tools in the horizontal section was initiation and drilling of the curve section. Initiating and drilling the curve section required 13 days time whereas without problems it should have taken approximately 3 days.

Estimated costs to drill and equip the M-20H Stearns well as an injection well were $914,000. Actual costs incurred up to the point in time when the directional drilling tools became stuck in the hole were approximately $810,000. Total costs incurred after attempting to fish stuck tools from the well were $1,434,000 (includes payment of $136,569 for tools stuck in well) . The cost over-run was attributable mainly to fishing operations; however, other factors such as severe winter weather conditions and relatively inexperienced drilling rig crews also contributed to over-expenditures.

Luff Exploration Company successfully used conventional steered motor horizontal technology to drill the M-20H Stearns well up to the point where directional drilling tools were stuck in the hole. The low bottom-hole pressure conditions were a known risk prior to drilling the well. Although the horizontal section of the wellbore was concluded at a shorter distance than planned, the well was pump tested as a producing oil well for 42 days followed by a 30-day water-injectivity test. The well produced at an average rate of 11.1 m^3 oil and 11.3 m^3 water per day (70 bopd and 71 bwpd) during the last 10 days. The average production from the two offset wells was 3.0 m^3 oil and 4.0 m^3 water per day (19 bopd and 25 bwpd) per well during that time. This indicates an improvement of productivity by a factor of 3.1 with a relatively short lateral with junk in the hole. Immediately after the short production test, a water injection test was performed. Water was injected at 800 bwpd for 9 days then reduced to 550 bwpd for the remainder of a 30-day test. The final pressure at reservoir depth of 2670 m (8760 ft) was 27,920 kPa (4050 psi)..

No. 1-26H Greni. The No. 1-26 Greni was drilled as an offset to existing production in the Red River B zone in State Line Field, Bowman Co., ND. The well is located on the west flank of a relatively large Red River structure. The existing well was producing water-free oil and with indications of a large reservoir which could not be efficiently drained with the existing vertical well. The No. 1-26H Greni well is the fourth well on a small Red River feature that has produced over 143,090 m^3 (900,000 bbl) of oil from B and D zones of the Red River since 1973.

The 1-26H Greni well was drilled to a vertical depth of 2594 m (8510 ft) at which point the curve section was initiated. A medium-radius curve section with a 150-m (493-ft) radius was drilled in a time period of 3 days. Procedures and equipment used were identical to those used on the M-20H Stearns well. Total length of the lateral drilled from the vertical wellbore was 1129 m (3705 ft) and the total drilled depth was 3723 m (12,215 ft). Drilling operations for the 1-26H Greni well took a total of 34 days. As operator of the 1-26H Greni well, UMC estimated gross costs to drill and equip it as a producing well to be $936,861. Actual gross costs incurred were $1,172,493. The 1-26H Greni was drilled and completed as a horizontal well as planned. The horizontal section of the well was successfully drilled with a lateral of 902 m (2959 ft) in the Red River B zone.

The well encountered the Red River B at a subsea datum which was 20 m (67 ft) low to the most updip well. The well was produced from the open-hole lateral section in the Red River B zone from October 1996 through April 1997. Production from the well was about 1.6 m^3 oil and 54.2 m^3 water per day (10 bopd and 341 bwpd) after 60 days. At that point it was decided to produce from the far portion of the lateral by isolating the near portion with inflatable packers and tubing. Production after placement of the isolation equipment was 0.6 m^3 oil and 24.2 m^3 water per day (4 bopd and 152 bwpd). The drilling of the No. 1-26H Greni appears to have resulted in a mechanical success but a failure with regard to reservoir development. The low structural position relative to offset production and poor oilcut indicate completion of the lateral below an oil-water contact.

Conclusions

In theory, all of the horizontal drilling techniques explored in this project have merit for application fitting specific criteria. From a realistic point of view, the only relatively trouble-free, adequately-proven technology employed was the medium-radius steered motor/MWD technology. The slim-tool steered motor/MWD re-entry technology has been used extensively but appears to still be significantly in developmental stages. This technology will probably always be more troublesome than the technology used to drill new wells because the smaller diameter required for the tools contributes to both design and operational complexities.

Although limited mechanical success has been achieved with some of the lateral jetting technologies and the Amoco tools, their predictability and reliability is unproven. Additionally, they appear to be limited to shallow depths and certain rock types. The Amoco technology probably has the most potential to be successfully developed for routinely reliable, field applications. A comparison of the various horizontal drilling technologies investigated is presented in Table 2.

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Table 1
Wells Cost of Short-Radius Horizontal

Description	Total
Location, Roads & Damages	$ 7,800
Directional Drilling Services	$ 163,700
Completion & Servicing Unit	$ 167,500
Log, Perforate & Wireline	$ 3,700
Water Source & Hauling	$ 4,800
Bits, Coreheads & Reamers	$ 41,500
Cement & Cementing Services	$ 3,900
Drilling Fluids and Chemical	$ 6,200
Equipment Rental	$ 91,800
Trucking	$ 14,800
Company Labor	$ 700
Contract Labor	$ 39,200
Company Supervision	$ 1,300
Contract Supervision	$ 31,300
Administrative Overhead	$ 3,200
Other Costs	$ 35,400
Total Intangible Costs	$ 616,800

Table 2
Summary of Drilling Technologies for Lateral Drain Holes

	Hydraulic Jetting	Amoco Re-entry	Re-entry Steered-Motor Short Radius	New Well Steered-Motor Medium Radius
Lateral Reach	3 m (10 ft)	229 m (750 ft)	762 m (2500 ft)	1524 m (5000 ft)
Radius	less than .3 m (1 ft)	9 - 27 m (30 - 90 ft)	24- 46 m (80 - 150 ft)	107 - 152 m (350 - 500 ft)
Casing Departure	Milled hole	15 to 30-m (50 to 100-ft) casing section with cement plug, also side-cut window with whipstock	15 to 30-m (50 to 100-ft) casing section with cement plug, also side-cut window with whipstock	Drill out from bottom of long string
Casing Limitation	11.4 cm (4½ in.) possible 14.0 cm (5½ in.) recommended	11.4 cm (4½ in.) possible 14.0 cm (5½ in.) recommended	11.4 cm (4½ in.) possible 14.0 cm (5½ in.) recommended	17.8 cm (7 in.)
Orientation and Telemetry	None	Surface orientation Post-drilling telemetry	Downhole orientation Electric wireline or mud-pulse MWD telemetry	Downhole orientation Mud-pulse MWD telemetry
Drillpipe and BHA Equipment	No rotation High-pressure tubing BHA is proprietary	Carbon fiber or steel for curve section BHA is proprietary	Proprietary motor/steering/ MWD BHA	Proprietary motor/steering/ MWD BHA
Surface Equipment	Conventional well service unit with special high-pressure pumps	Conventional well service unit with power swivel and fluid circulating equipment	Special 24-hr operation well service unit with rotating and fluid circulating equipment	Conventional drilling rig
Maturity of Technology	Delicate BHA, Successful at depths less than 1524 m (5000 ft), No surface indication of penetration	Successful at depths less than 1524 m (5000 ft)	Rapidly improving in bit and MWD systems	Very mature, large casing diameter provide better options for bits, MWD and BHA
Typical Cost	10 holes $60,000 at 2743 m (9000 ft)	305-m (1000-ft) lateral $200,000 at 2743 m (9000 ft)	762-m (2500-ft) lateral $450,000 at 2743 m (9000 ft)	1372-m (4500-ft) lateral $1,200,000 at 2743 m (9000 ft)
Vendors	Limited	Small number of licensees	Several, well-established	Several, well-established

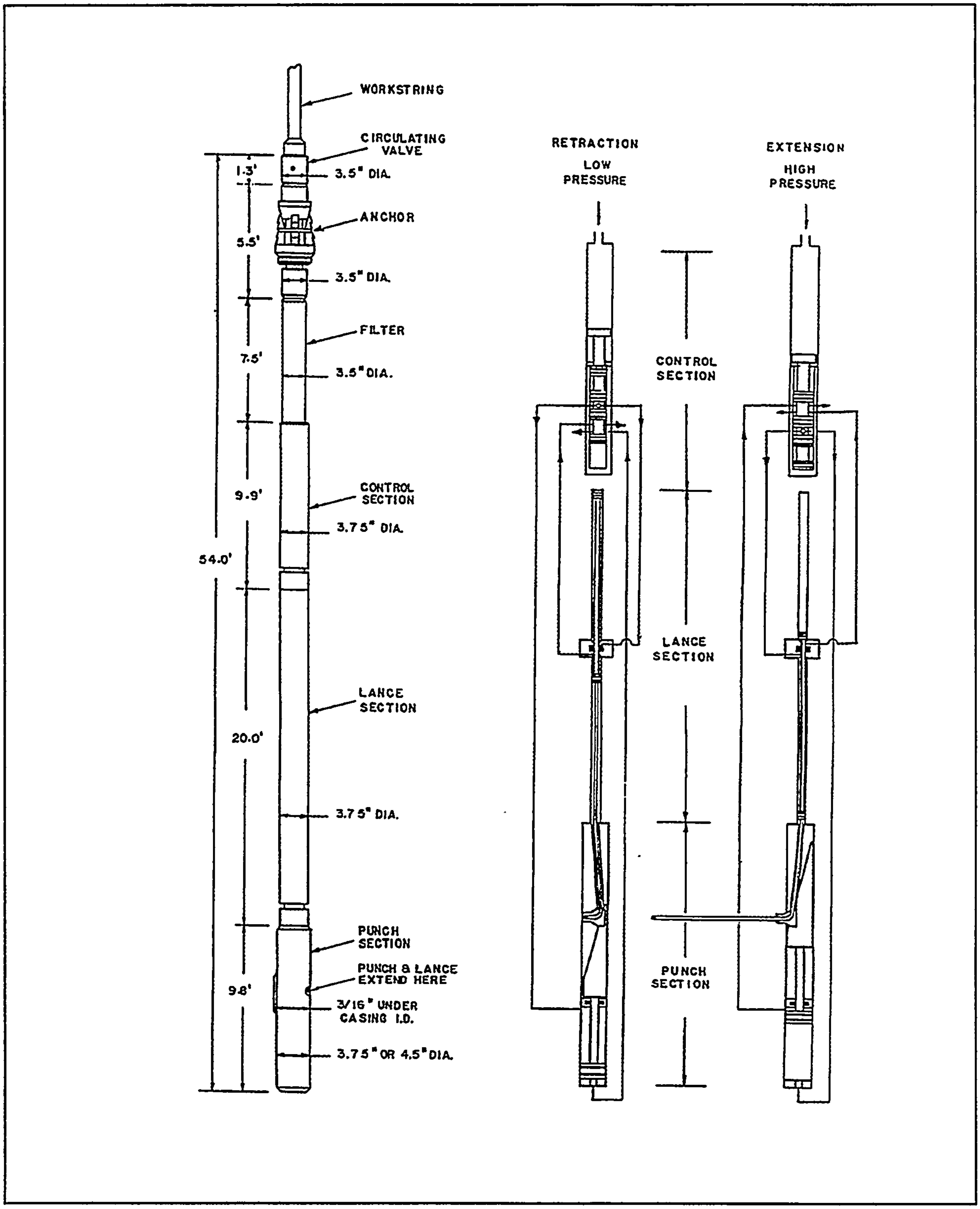


Figure 1: Schematic of 10-ft jetting lance tool, Penetrator, Inc.

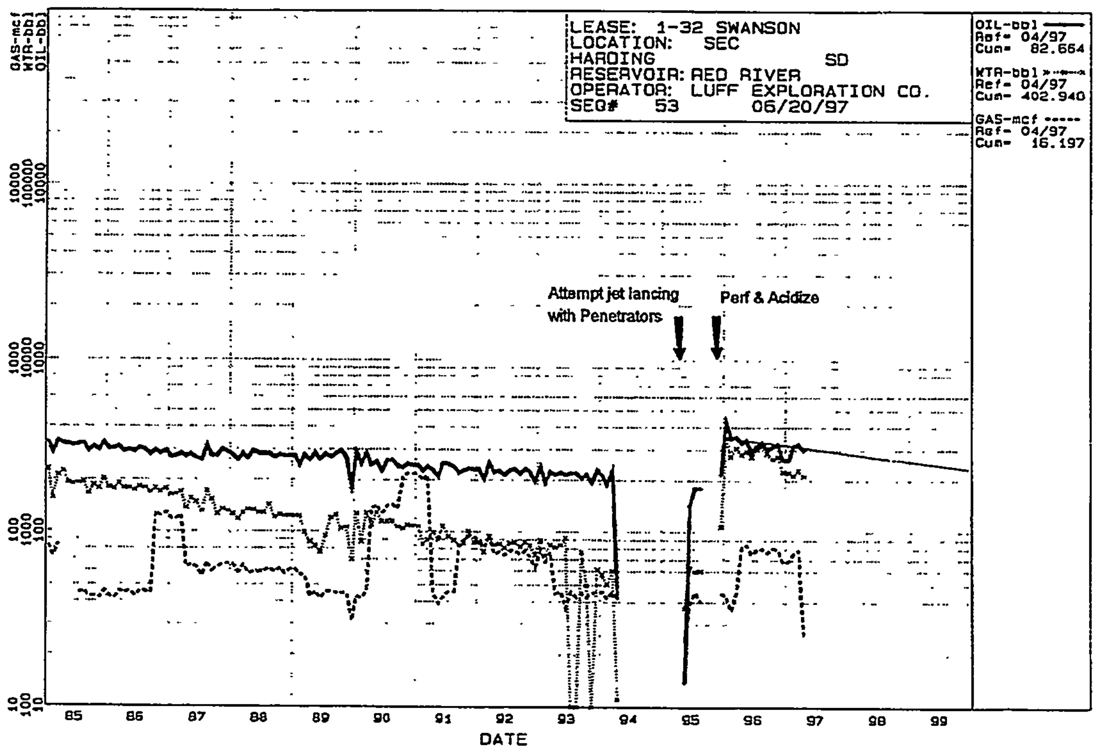


Figure 2: Production curve before and after application of 10-ft jetting lance tool at the No. 1-32 Swanson well. The jetting lance tool did not improve production while conventional re-perforating and acidizing did improve production.

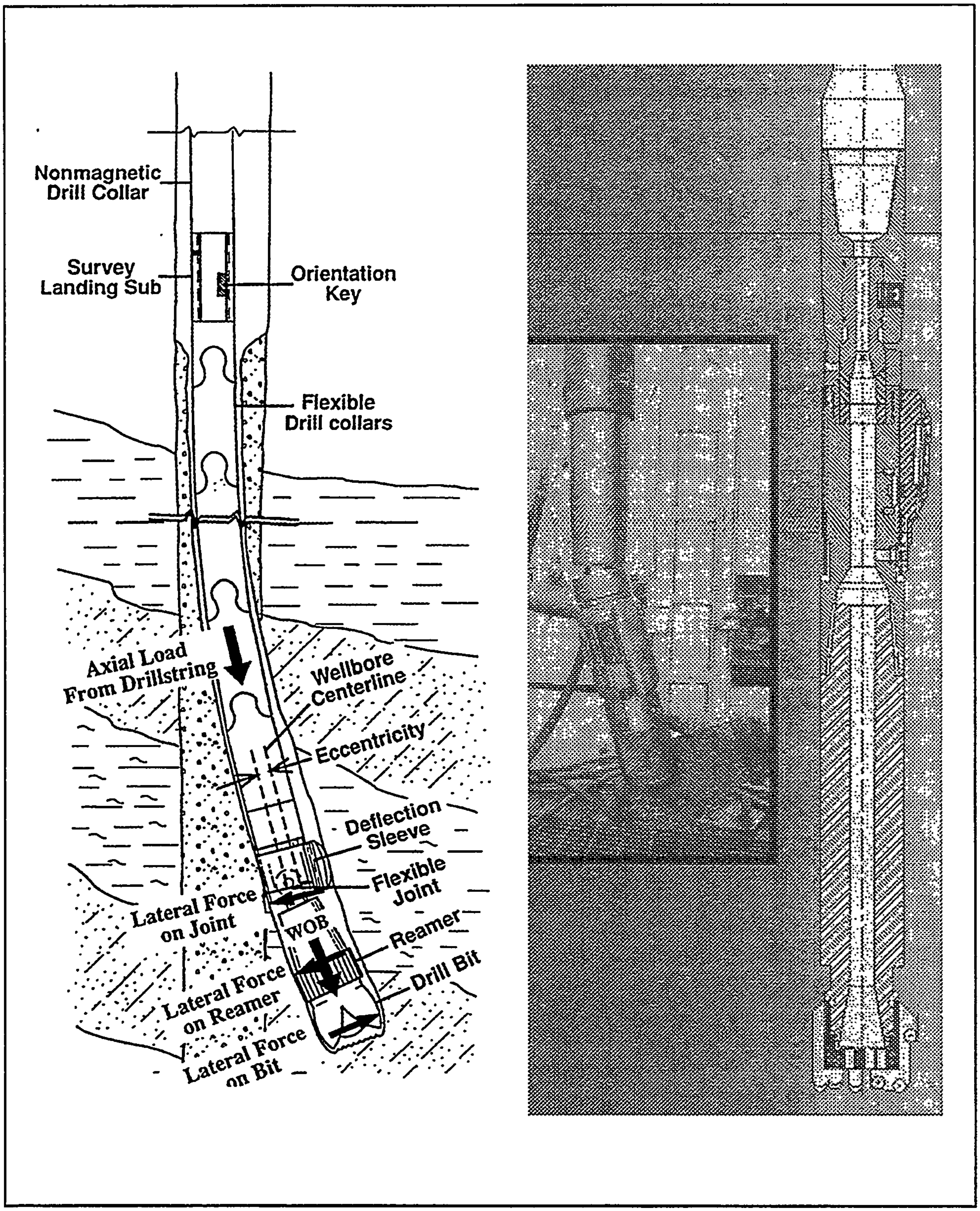


Figure 3: Amoco-design ultra-short radius horizontal drilling assembly.

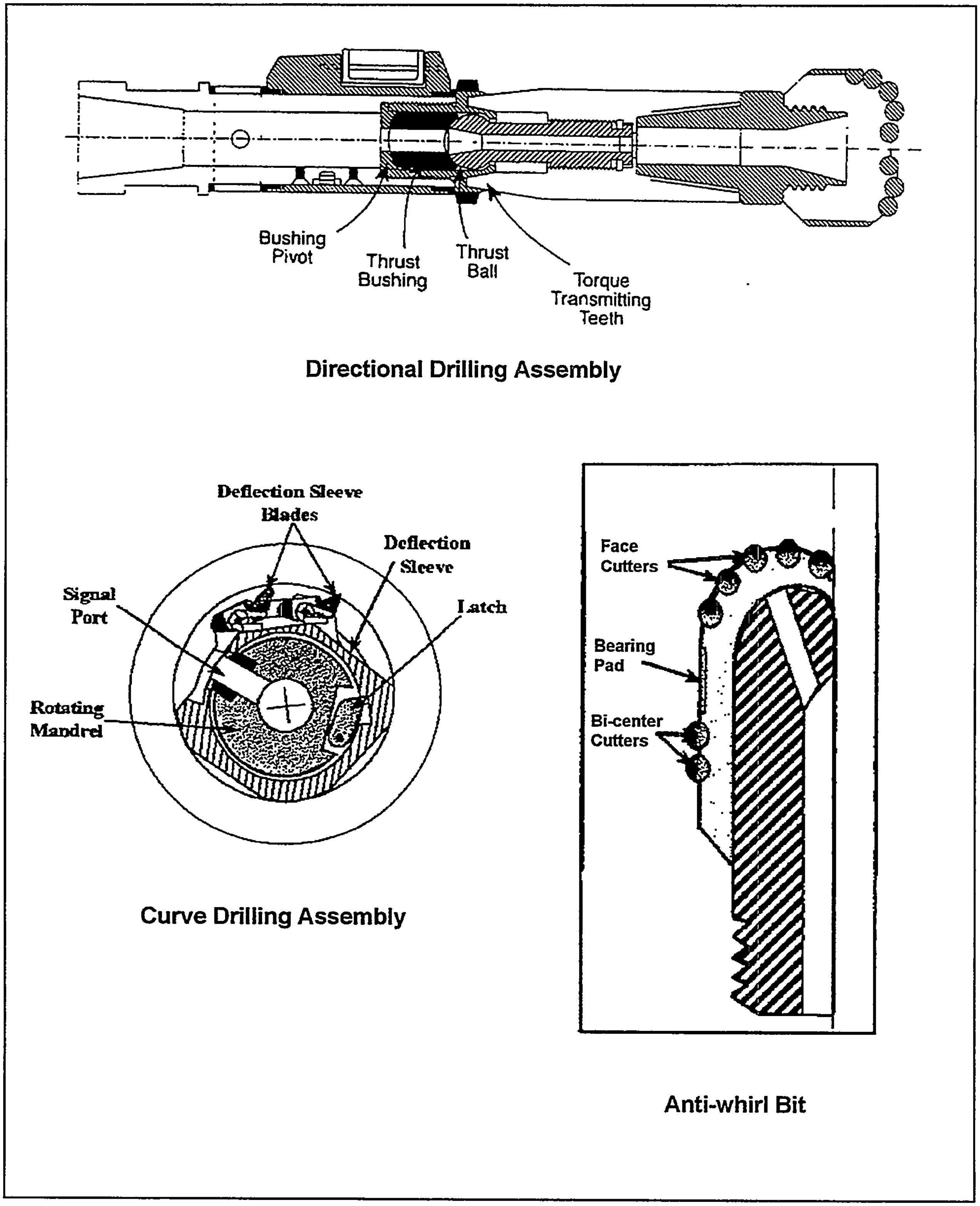
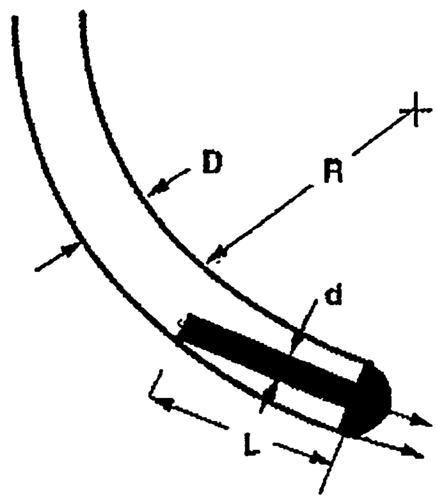


Figure 4: Detail of Amoco-system bit and downhole assembly.



$$R = \frac{L^2}{D - d}$$

Figure 5: Geometry of Amoco-system for drilling curve of horizontal departure.

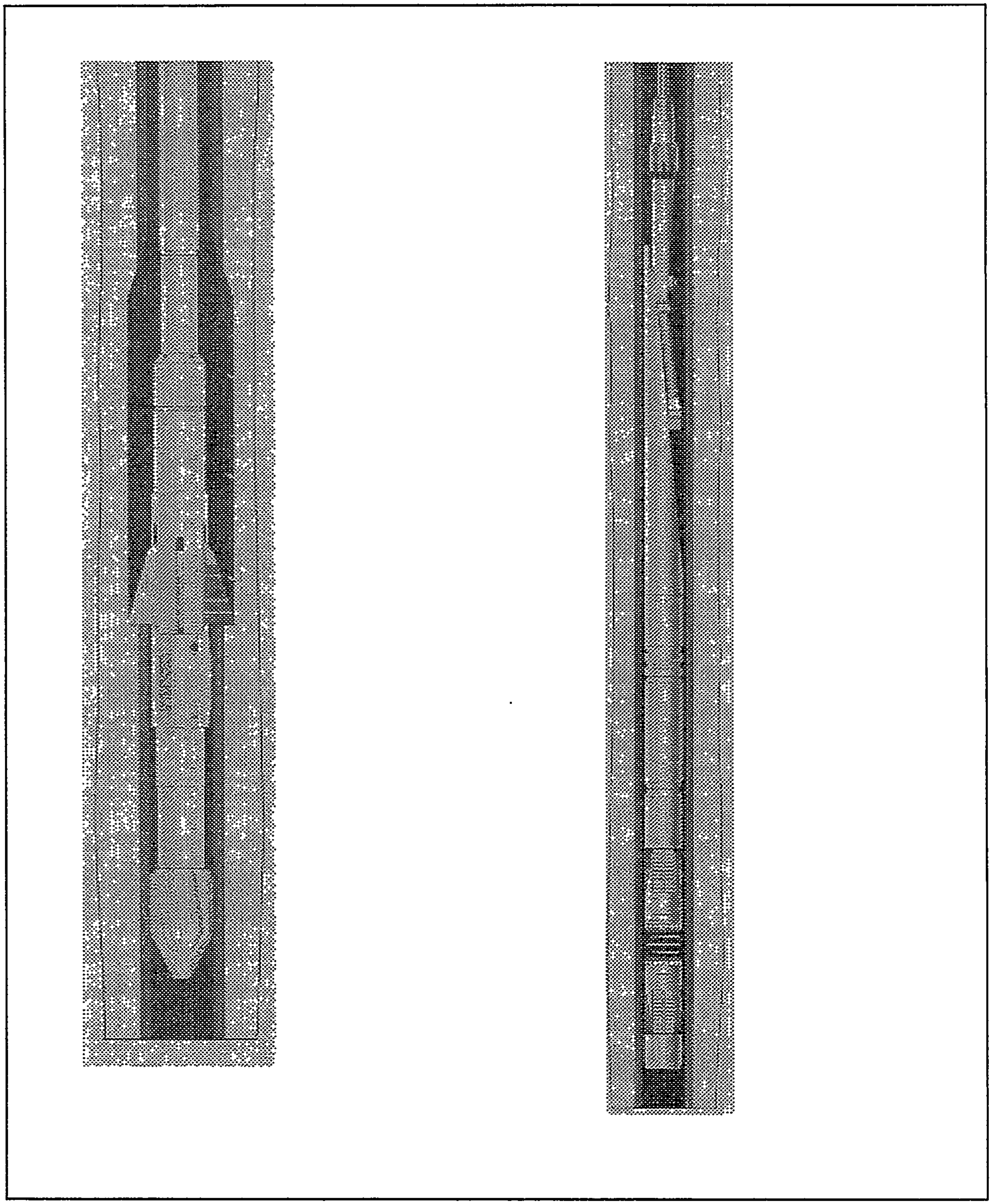


Figure 6: Two methods for casing exit. The left figure shows the milling of a full casing section while the right figure shows a whipstock and milled-window approach.

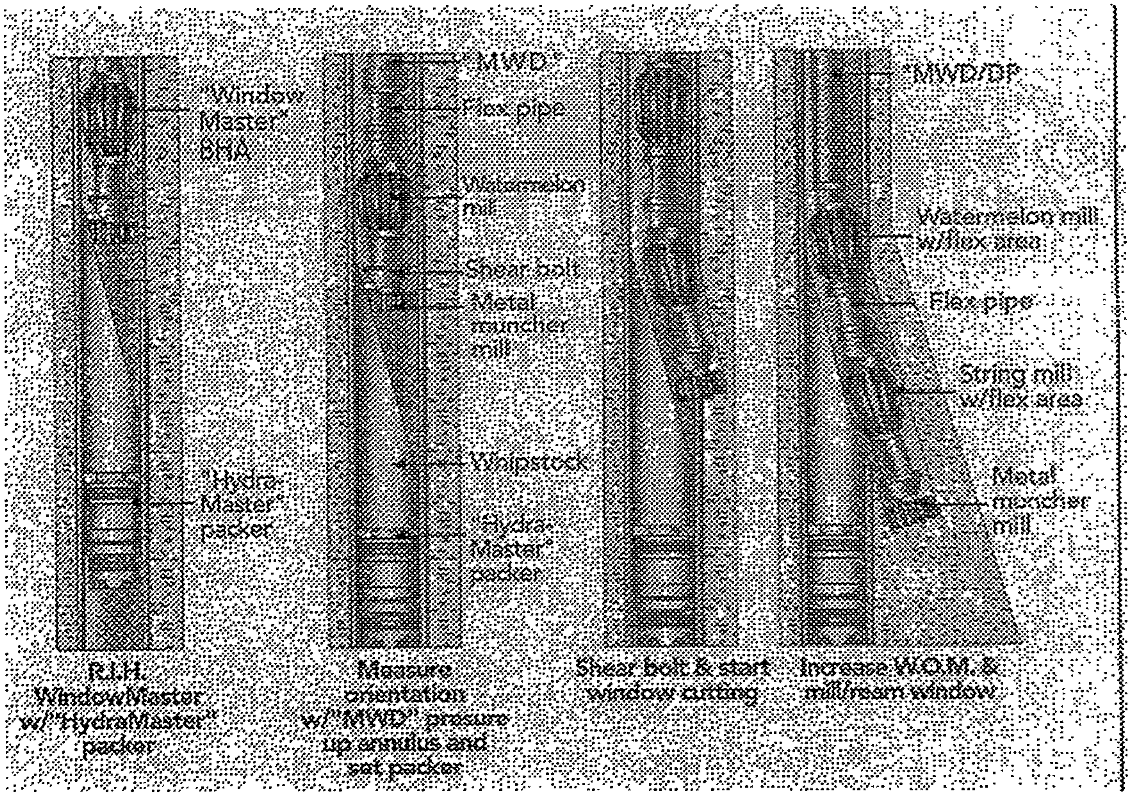


Figure 7: Steps for setting a whipstock and milling a casing window.

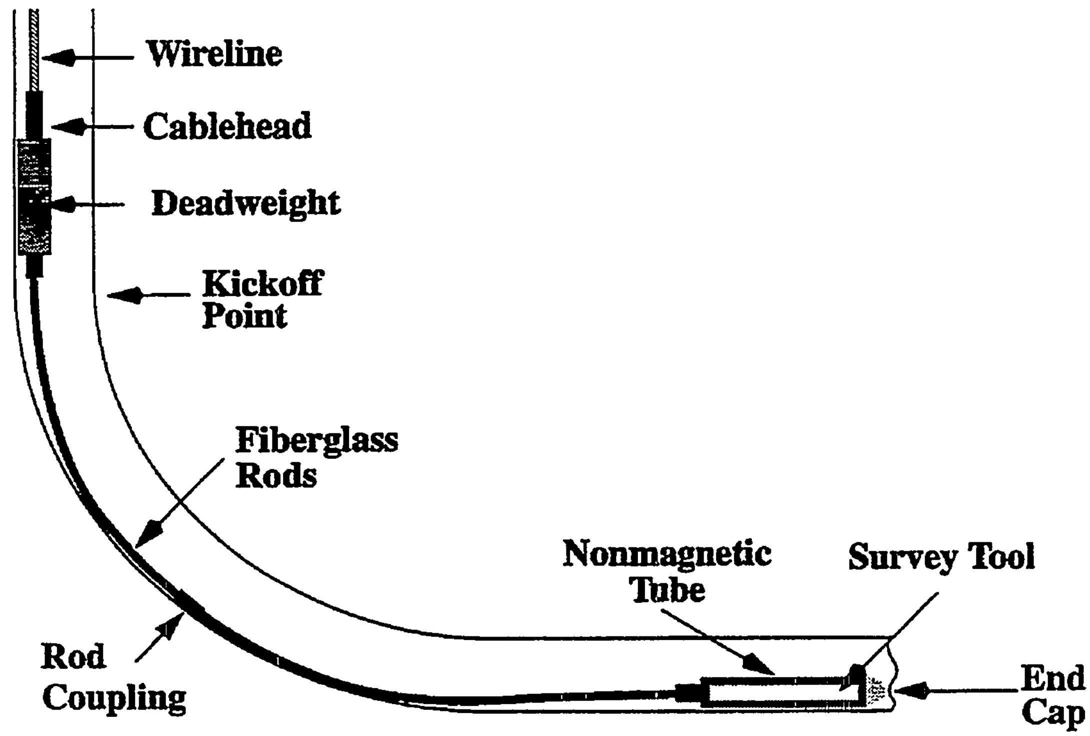


Figure 8: Tools and method for obtaining a direction survey in a hole drilled with the Amoco-system.

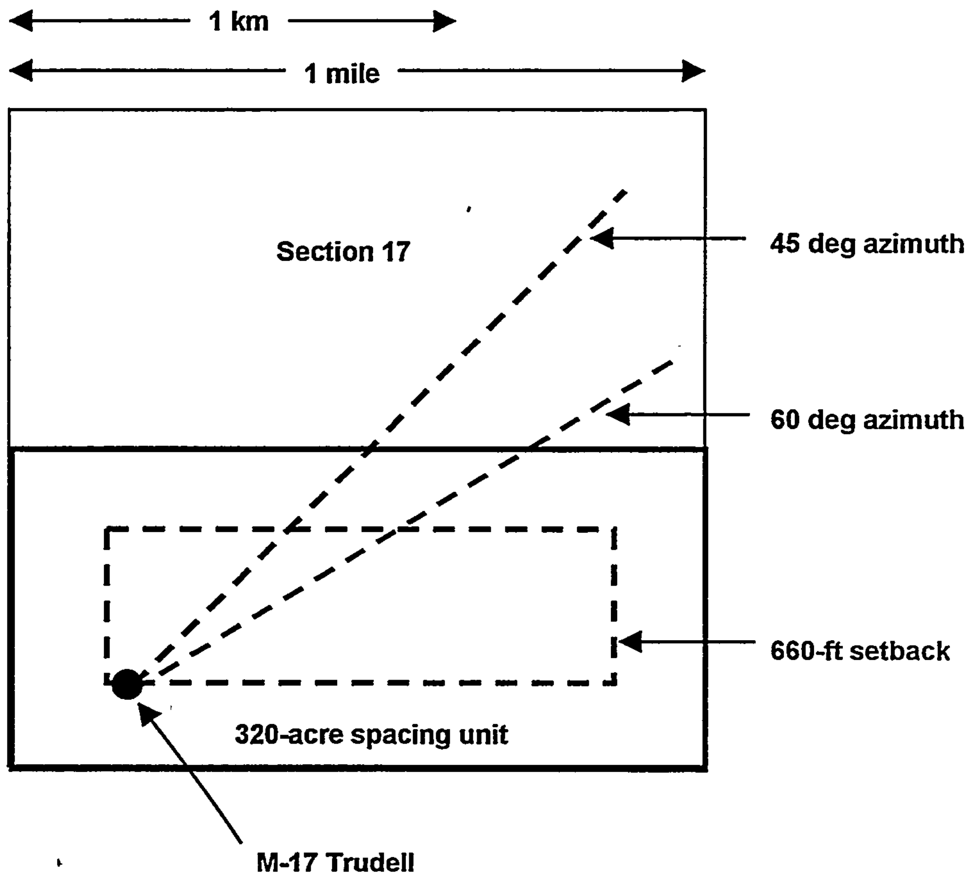


Figure 9: Spacing unit and planned azimuth window for M-17 Trudell well.

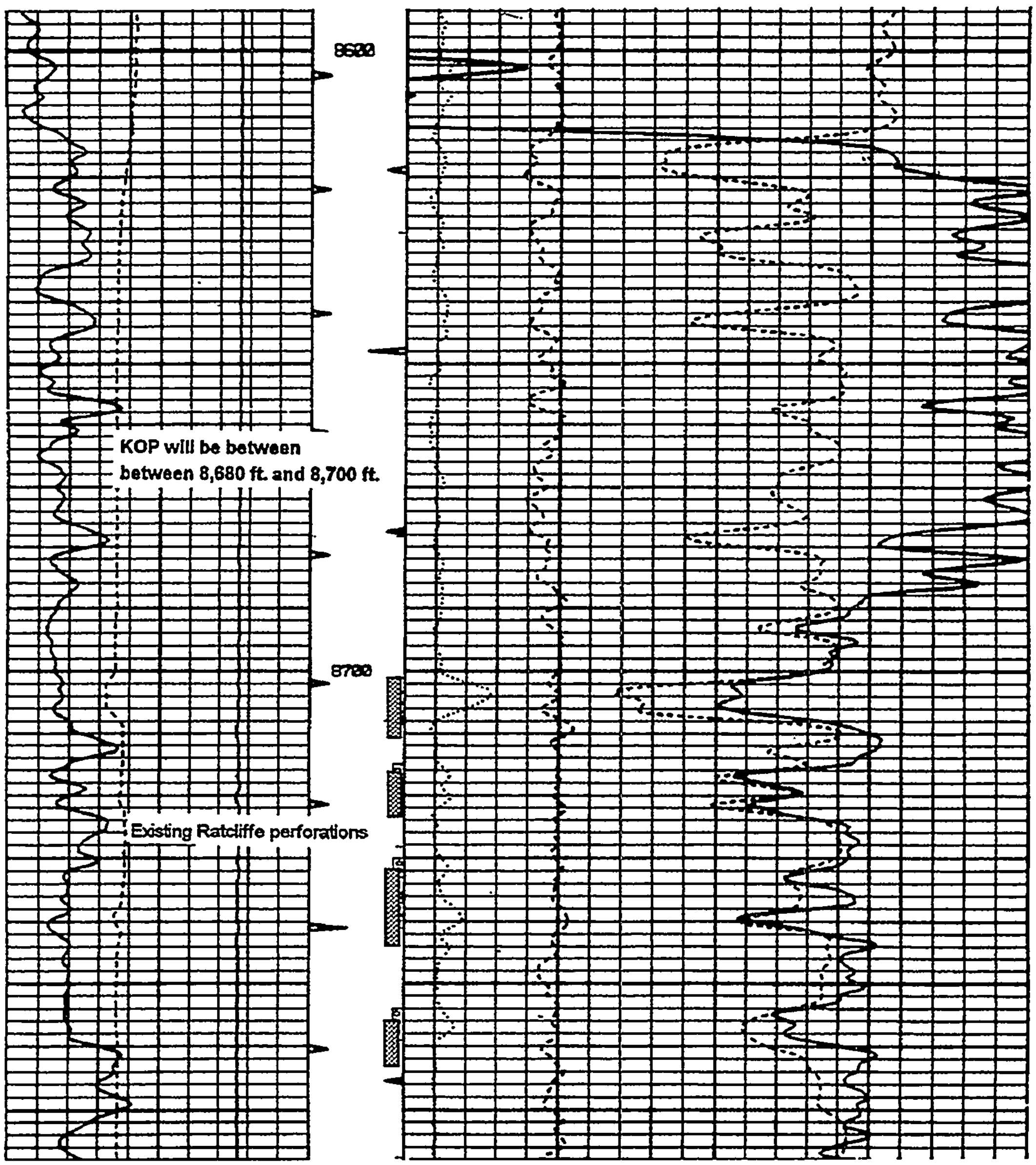


Figure 10: Porosity log of Ratcliffe section in M-17 Trudell well.

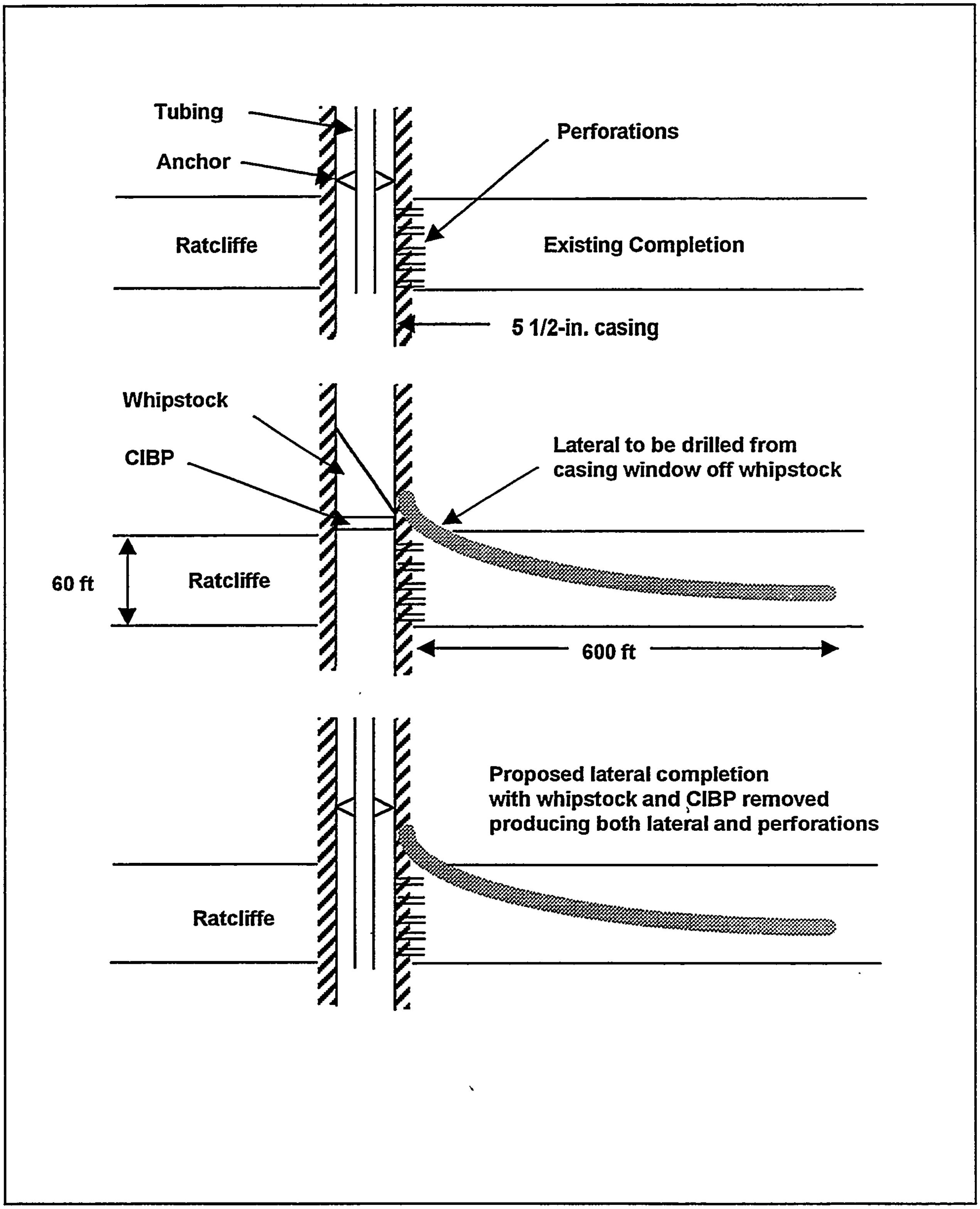


Figure 11: Cross section view of planned horizontal trajectory for M-17 Trudell well.

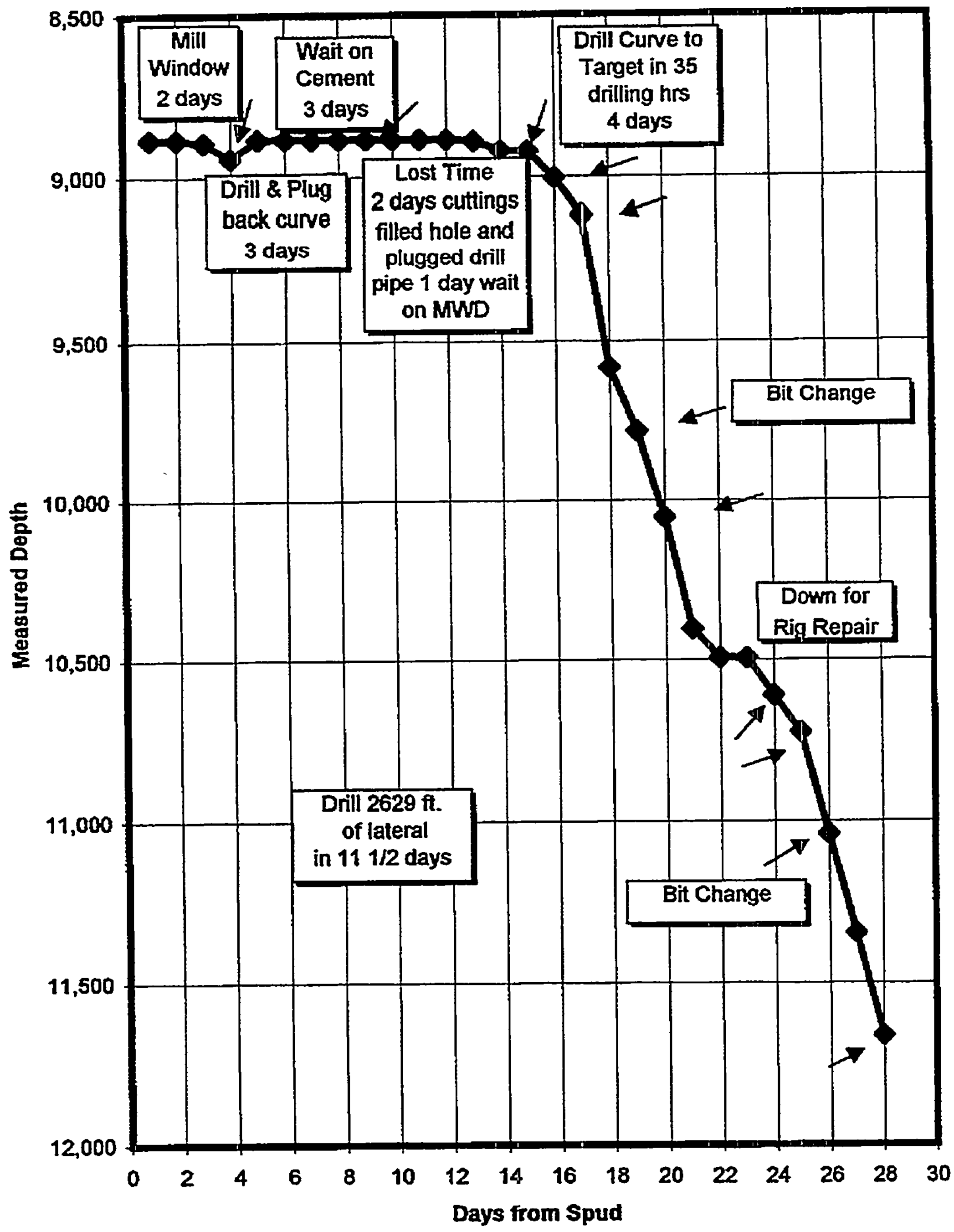


Figure 12: Drill-time curve for State 2-16 Ratcliffe re-entry with drill bit history.

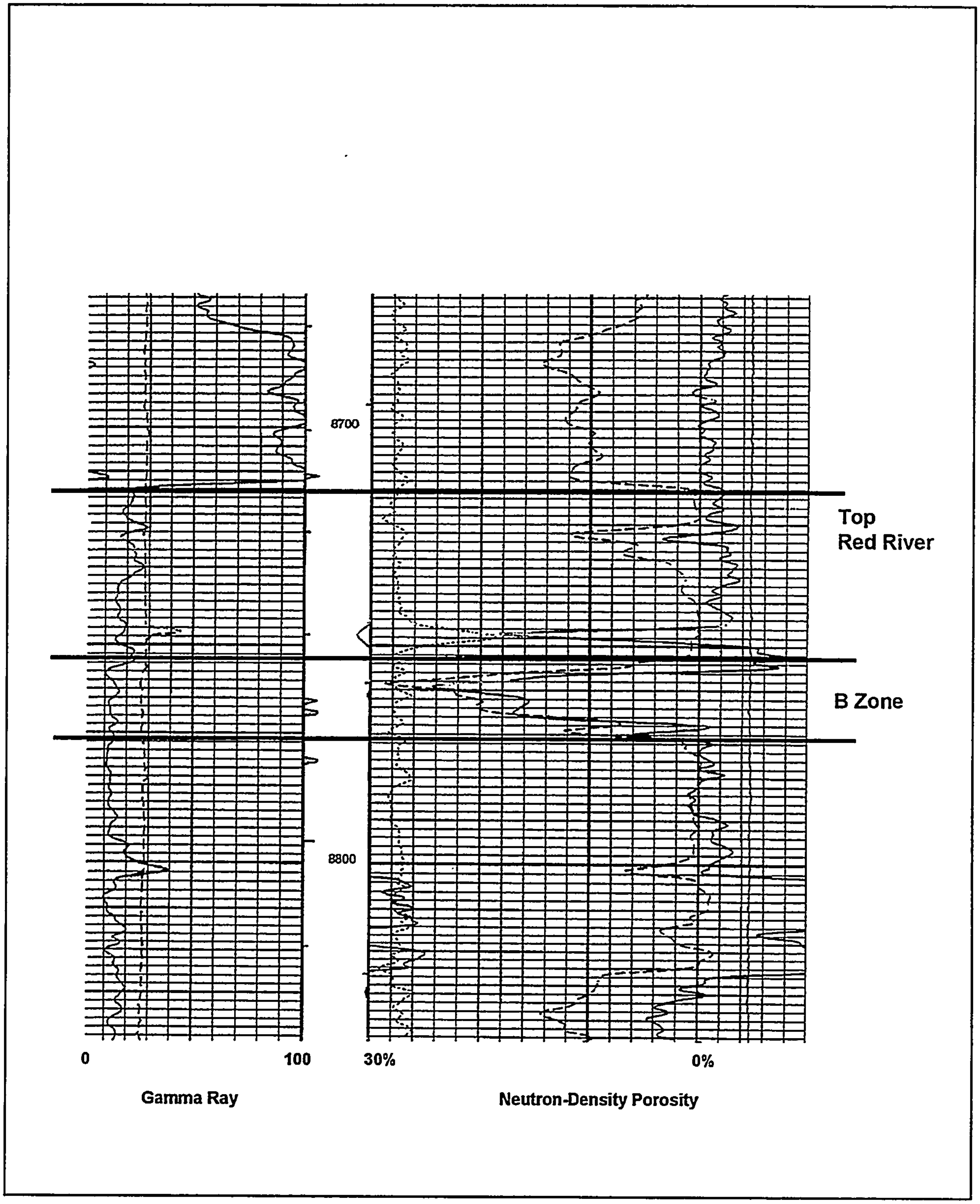


Figure 13: Porosity log from the M-20H Stearns (Buffalo Field, Harding Co., SD) showing Red River B zone target for horizontal drilling