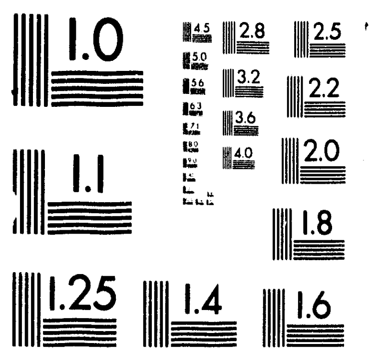

1.0
4.5
2.8
2.5
5.0
5.6
3.2
2.2
6.3
7.1
3.6
8.0
4.0
2.0
9.0
1.1
1.8
1.25
1.4
1.6

1 of 1

DOE/MC/26024-3528
(DE94000053)
Distribution Category UC-132

Slant Hole Completion Test

Final Report

R. L. Mann

Work Performed Under Contract No.: DE-AC21-90MC26024

For
U.S. Department of Energy
Office of Fossil Energy
Morgantown Energy Technology Center
P.O. Box 880
Morgantown, West Virginia 26507-0880

By
CER Corporation
950 Grier Drive
Las Vegas, Nevada 89119

July 1993

Contents

Figures

Tables

1.0 Executive Summary - SHCT-1

One of the Department of Energy's (DOE) Strategies and Objectives in the Natural Gas Program is to conduct activities to transfer technology from R&D programs to potential users. The Slant Hole Completion Test has achieved exactly this objective.

Quoting directly from the June 1993 issue of ***The Western Oil and Gas World*** *"Success on a U.S. Department of Energy (DOE) contract sparked action by other operators and gave DOE and CER Corp. of Las Vegas, Nev., the **Best Well Award** in our Best of the Rockies competition."*

The real significance of this award is that it recognizes the efforts of the DOE in helping industry unlock the vast resources in the low permeability sands in the Western United States through new and developing technology.

The Slant Hole site is essentially the same as the Multiwell site and is located in the southeastern portion of the Piceance Basin near Rifle, Colorado. The Piceance Basin is typical of the Western low permeability basins that contain thick sequences of sands, silts and coals deposited during the Cretaceous period. These sequences contain vast amounts of natural gas but have proven to be resistant to commercial production because of the low permeability of the host rocks.

Using the knowledge gained from the DOE's earlier Multiwell experiment, the SHCT-1 was drilled to demonstrate that by intersecting the natural fractures found in these "tight rocks." commercial gas production can be obtained.

From the data collected on the Multiwell Experiment, it was determined that the direction of the natural fracture system and the maximum principle stress was north 80° west. The initial well, SHCT-1, was drilled in essentially a north direction to intercept the maximum number of natural fractures. The well was drilled at a 60° angle (from vertical) through the Paludal section of the Mesaverde and then turned to enter the Cozzette interval horizontally.

The well was spudded in April 1990 and reached a total depth of 9,466 ft (7,981 ft TVD) on August 5, 1990. The well had penetrated 476 ft of Cozzette sandstone in the horizontal section of the hole. Mechanical problems that occurred while cementing the liner through this portion of the hole resulted in sticking the drill pipe and eventually losing the lower portion of the hole. Approximately 30 days were spent washing over and recovering the stuck drill pipe down to 5,335 ft. At that point, the rig was released and the well was temporarily abandoned.

The decision was made to re-enter the SHCT well and recover as much of the 7-in. casing as possible; then, the hole would be sidetracked and a second well would be drilled essentially parallel to the first well but 1,000 ft to the east.

The sidetrack operations were initiated on April 26, 1991, and the well was drilled to a total depth of 9,407 ft (7,948 ft TVD). Seven-inch casing was set through the 60° portion of the hole to a depth of 8,588 ft. The horizontal portion of the hole penetrated approximately 300 ft of pay in the Cozzette interval. The 819 ft of hole below the 7-in. casing was completed open hole. The Cozzette was briefly flow tested at rates up to 15.0 MMCFD during a 3-hour test prior to setting a temporary plug and releasing the rig. The rig was released August 24, 1991.

The SHCT-1 Sidetrack was completed into the Cozzette Formation during December 1991, and the Cozzette cleaned up, tested and put on production on January 16, 1992. The zone was tested at various flow rates until June 3, 1992. The well began making water in February and the water rates increased through the testing period. The well produced a little over 200 MMCF of gas during this period. The produced water during this same period was 12,646 bbl. The gas flow rate demonstrated during this 5-month test was significantly higher than from any vertical completion in this same interval.

The source of the water is unknown; the MWX-1 well has been producing from the Cozzette interval since December 1990 with very little associated water production. Because there was some belief that the water might be coming from the Rollins Formation behind the 7-in. casing, after the Cozzette was shut in, logs were run to attempt to pinpoint the source of the water. The logs indicated that there was water movement behind the casing, so the casing was perforated below the Rollins Formation and squeeze cemented. This was an attempt to shut off any water flow down into the Cozzette, if the Rollins indeed was the source.

The next phase of this experiment was to stimulate the Paludal section of the Mesaverde in the 60° portion of the hole. A retrievable bridge plug was set above the Rollins in the 7-in. casing, and the Paludal 2 sands and surrounding coals in the 60° hole were hydraulic-fracture stimulated through 16 perforations between 7,732 and 7,734 ft using 5,000-lb 100 mesh sand, 76,500-lb 20/40 sand, and 30,000 lb of resin-coated 20/40 sand carried in 1,036 bbl of crosslinked gel. The average treating rate was 30 BPM at a surface treating pressure of 8,200 psi. The well was fractured on June 23, 1992, and then cleaned up by flowing to the pit through July 8, 1992.

The Paludal 2 interval was produced into the gas sales line from July 1992 until January 1993. Production rates during this period ranged from 35 to 50 MCFD.

On January 13, 1993, the Paludal 2 zone was temporarily abandoned and work was initiated to fracture stimulate the Paludal 3 and 4 zones and the surrounding coals. The well was perforated from 7,386 to 7,388 ft with 16 jet shots oriented top and bottom.

The fracture treatment consisted of pumping 5,000-lb 100 mesh sand, 160,000 lb of 20/40 Ottawa sand and 30,000 lb of resin-coated sand (tail-in) in 1,790 bbl of crosslinked gel at a rate of 30 BPM and a maximum proppant concentration of 5.0 parts per gallon (ppg).

The well was flowed to clean up from January 22 to January 30, 1993, and then produced into the gas sales line until March 25. Gas flow rates of 145 MCFD were measured in February and gradually dropped off to approximately 100 MCFD before the well was shut in for recompletion in March.

The well was recompleted back into the Cozzette interval. It is configured such that the Cozzette could be produced up the tubing and the two Paludal intervals could be commingled and flowed up the casing-tubing annulus.

The previous water shut-off work did not appear to reduce the produced water when flowing the Cozzette. In fact, the water/gas ratio has increased since the initial Cozzette testing. There is still a lot of conjecture as to the source of the water. Meridian Oil Company has drilled a horizontal well directly offsetting the SHCT well in Section 33. They also experienced high water production from the Cozzette. However, they believe the horizontal borehole crossed a fault in the last 300 ft of their horizontal leg.

CONCLUSIONS AND RECOMMENDATIONS

- The Slant Hole Completion Test has been successful in providing good technology transfer to the oil and gas industry. A number of industry people made frequent visits to the site while the well was being drilled and tested In addition, frequent phone conversations and meetings were held to provide information on the progress of the project. Technical papers have been presented on the subject. Probably the greatest measure of successful technology transfer is the horizontal drilling programs that have been initiated in the general area by Barrett Energy, Meridian Oil Company, Mobil Oil Company and Oryx Energy Co.

- Another indication of the excellent technology transfer of this project is that the well was selected as the **"Best Well of 1992"** by a panel of six industry judges as part of "Best of the Rockies" competition sponsored by Western Oil and Gas World, an industry journal. This award was given primarily because of the industrial interest as seen in plans for at least five high-angle/horizontal wells being planned in the immediate area of the SHCT-1.

- The SHCT-1 has a significantly improved initial production potential when compared to vertical wells completed in the Cozzette Sand of the Mesaverde Group in the Rulison Field. This improvement is due to intersection of natural fractures which trend in a general east-west direction at the SHCT-1 site. The initial potential of the SHCT-1 is a minimum of two to three times higher than initial potentials of surrounding vertical wells.

- The presence of euhedral quartz and calcite crystals in the natural fractures in the cored Mesaverde and Cozzette intervals are good indications of open apertures in the subsurface. Therefore, drilling a well perpendicular to these open fractures should insure contacting the maximum number of fracture systems and consequently provide the greatest production potential for the well.

- Drilling the naturally-fractured intervals underbalanced (i.e., pore pressure greater than the hydrostatic column pressure) has the advantage of providing better indication of gas shows, more specific location of the fractures and also reduces the chance of damaging the natural fracture systems due to drilling mud invasion.

- The well can be safely drilled in an underbalanced condition, but care must be taken to have adequate surface facilities such as BOPs, gas busters, mud volume sensors, etc. It is also important that care is taken to insure that gas is not swabbed-in during tripping of the drill pipe.

- Stimulation in a high-angle, cemented wellbore, such as the Paludal interval in the SHCT-1, is more difficult because of high near-wellbore stresses resulting in higher treating pressures.

- Comparing the results of the two very similar hydraulic fracture treatments in the SHCT-1 and the MWX-1 wells indicate that there is no advantage in treatment in a slant wellbore as compared to a vertical wellbore. In fact, because of the higher treating pressures in a slant wellbore, the fracture treatments are very likely to be more expensive.

- It is believed that a high-angle well drilled perpendicular to the natural fracture system <u>and completing open hole or with an uncemented liner</u> may exhibit excellent production characteristics. During the drilling of the 60° portion of the hole, good gas kicks were noted. Sloughing coals and shales may preclude completing this interval open hole. However, in areas where the coals are not present, the high-angle open hole may provide good natural completions.

- The SHCT-1 produces water from the Cozzette Sand at rates significantly greater than surrounding vertical wells. The source of this water production is not presently understood. A diagnosis of this water production mechanism is vital to the economic exploitation of gas from the Cozzette Sand via horizontal drilling.

- Future work should focus on diagnosing the water production mechanism in the Cozzette Sand. This work could entail:

  - Open-hole logging of the horizontal lateral to assess possible intervals of water incursion.

  - A geologic study to determine the distribution of water in the Cozzette Sand within the Rulison Field and the effects of potential faulting on water distribution.

  - Core analysis of the Cozzette Sand to verify the relationship between existing and irreducible water saturations. The core analysis work should include capillary pressure determinations at various confining pressures.

  - Detailed reservoir modeling using a multi-phase model to determine the viability of water production from the rock matrix of the Cozzette sandstone.

- Similar demonstrations of the horizontal well technology need to be performed in other low-permeability basins where natural fracturing may exist. It is essential that good geological data be obtained prior to drilling a horizontal well in order to drill the horizontal leg in the direction to maximize the penetration of the natural fracture system.

2.0 Introduction and Background

The basins in the Rocky Mountains contain a vast amount of natural gas in the low permeability formations. The recognition of the great potential in these low permeability formations led the federal government into research in techniques to improve the recovery of natural gas from these tight intervals.

Three of the early industry-government plowshare experiments were performed to unlock these vast resources. The three nuclear explosive experiments were Project "Gas Buggy" in 1966, Project "Rulison" in 1969, and Project "Rio Blanco" in 1972. Two of the three plowshare experiments were conducted in the Piceance Basin. In fact, Project "Rulison" was detonated about 7 miles to the southwest of the current site of the Multiwell and Slant Hole projects. Figure 2-1 shows the location of the present SHCT and MWX site in Section 34, T6S, R94W, Garfield County, Colorado.

When it became clear that the use of nuclear explosives was not a viable or acceptable technique for stimulating these low permeability gas sands, the federal government joined with a number of industry partners to find other techniques for improving gas recovery. Efforts then focused upon massive hydraulic fracturing and a number of government-industry projects were conducted. The results were disappointing and did not result in either improved technology or proven commercial production. The basic shortcoming was that these past field tests did not provide sufficient data to define the critical factors affecting gas production from this low-permeability resource.

The DOE's Multiwell Experiment (MWX) was conceived as a field laboratory to obtain sufficient information on the geologic and technical aspects to unlock this valuable resource. A key feature of the MWX was three wells drilled on close spacing (between 110 and 215 ft apart) to allow determination of data not available from a single well. Detailed core, log and well test data from such close spacings provided a detailed characterization of the reservoir and production mechanisms. A broad spectrum of activities were carried out in the MWX field experiment such as: geophysical surveys, sedimentological studies, core and log analysis, in-situ stress determinations, various stimulation techniques, fracture diagnostics, and well testing using unique down-hole and surface instrumentation. This work was performed as part of the DOE's Western Gas Sands Program. The MWX work was initiated in 1980 and completed in 1988. Section 12.0 is a bibliography of reports and papers published on the Multiwell and Slant Hole Experiments.

One of the results of the MWX work was a better understanding of the geology and natural-fracture network found in these low-permeability sands and coals of the Mesaverde Group in the Piceance Basin of Colorado. As an alternate development strategy, the DOE funded the drilling of a directional/horizontal well at the MWX site to intersect the natural fracture system in the Paludal and Marine portions of the Mesaverde Group. This project was called the Slant Hole Completion Test (SHCT).

The first well was drilled to depth of 9,466 ft measured depth (MD) with the last 410 ft being close to horizontal in the upper Cozzette interval. The well was spudded on April 10, 1990, and reached total depth on August 4, 1990. Mechanical problems following the cementing of the production liner resulted in loss of the completion interval and the drill pipe being stuck in the hole from 7,822 ft.

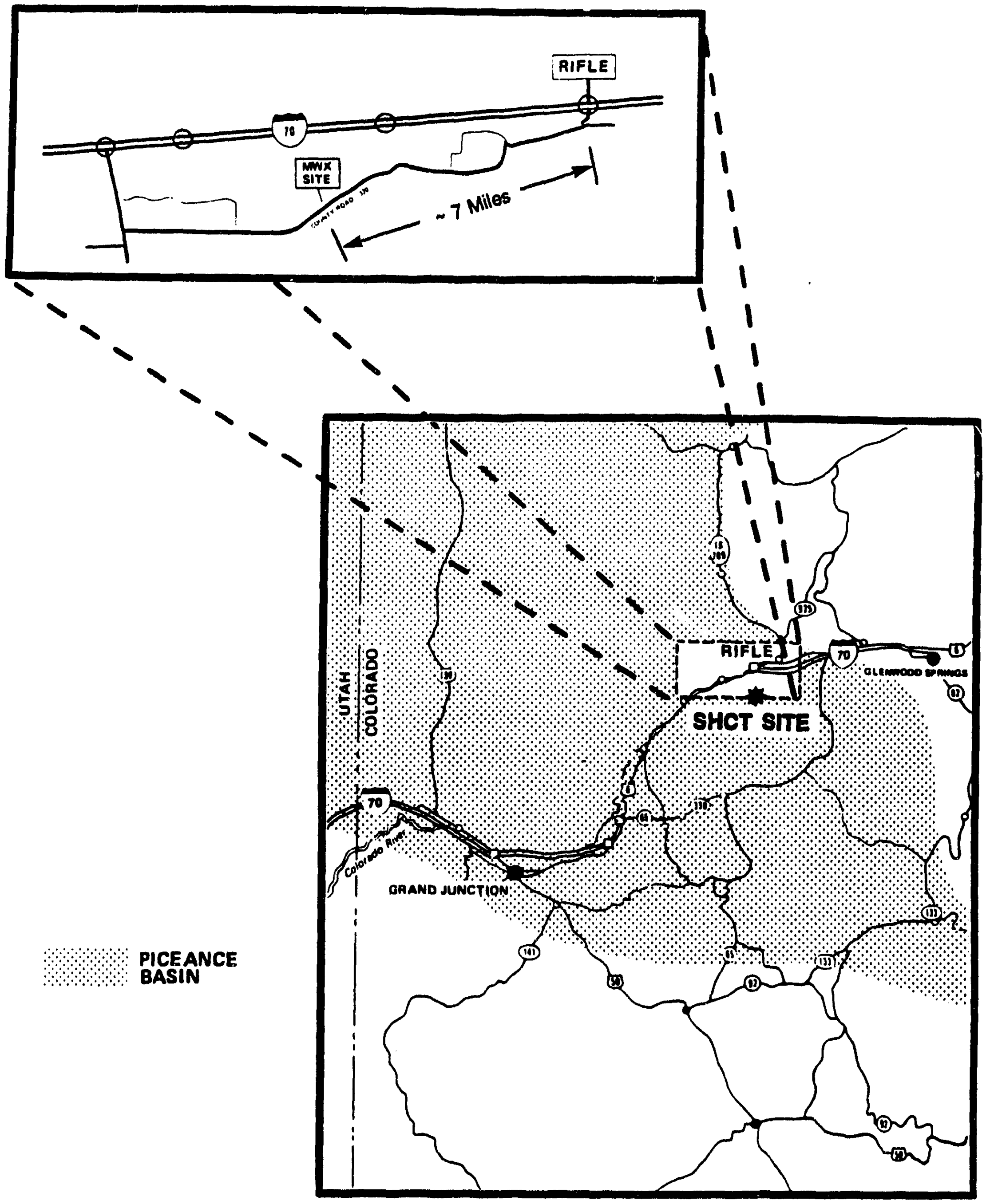


Figure 2-1 Location of SHCT Within the Piceance Basin

Wash-over operations were conducted from August 9 until operations were suspended on September 5, 1990. At this point, the drill pipe had been washed over and recovered to a depth of 5,335 ft.

In early 1991, DOE decided to sidetrack the hole to permit production testing of the lost interval. The sidetrack was designed to parallel the original wellbore, but to be drilled 1,000 ft to the east to minimize the chances of encountering formation damage from the original hole. The sidetrack, like the original hole, was to intersect the Paludal lenticular sands and coals at 60° and to penetrate the underlying Cozzette sand horizontally. The sidetrack was spudded May 12, 1991, and reached 9,407 ft MD on August 19, 1991. Three hundred feet of horizontal highly fractured Cozzette interval had been penetrated when drilling was shut down at 9,407 ft MD. The well was completed "open hole" from 8,588 to a TD of 9,407 ft. The bottomhole packer assembly was run and set in the 7-in. casing at 8,453 ft with the "R" plug installed, and the rig was released on August 24, 1991. Details of the drilling operations will be found in the "As Built" Reports[1,2].

On December 10, 1991, work was initiated to install tubing and begin testing of the Cozzette interval. The Cozzette Interval was tested for approximately six months, and then the zone was temporarily plugged while the Paludal sands and coals were stimulated and tested. Two Paludal intervals were separately fractured and tested. The testing details are found in the Topical Report[3].

3.0 Geological Summary

The Piceance Basin is a Laramide structural and sedimentary basin covering about 3,000 square miles in northwestern Colorado. The basin is bounded on the north by the Uinta and White River Uplifts, and on the south by the Sawatch Mountains Uplift, the San Juan volcanic field and the Uncompahgre Uplift. The Piceance Basin is separated from the Uinta Basin to the west by the Douglas Creek Arch and is highly asymmetric, being very steep on the west and gently inclined on the east. Most of the gas production is from low-permeability sediments that were deposited along the Western Interior seaway that persisted throughout the Cretaceous period.

Regional overpressuring is present in the deeper parts of the Piceance Basin. The present-day active gas generation is interpreted to be the cause of the abnormally high pressure found in these tight gas sequences of the lower Mesaverde. The organic-rich dark shales and coals of the Cretaceous and Tertiary ages are the source of the gas[4]. Figure 3-1 shows the paleoenvironmental depositional units at the MWX site as well as the regional stratigraphic nomenclature.

At the MWX and SHCT site the pressure gradient starts increasing from normal (0.43 psi/ft) at about 5,600 ft and increases with depth to about 0.78 psi/ft in the Cozzette interval at approximately 8,000 ft TVD. Figure 3-2 illustrates the pressure gradients determined at the MWX site[5].

The principal objective of the project is the upper Cozzette Sandstone which is approximately 65 ft thick at the MWX site. The upper 22 to 24 ft of this unit contain pyrobitumen, resulting in poor reservoir quality. Accordingly, the final build of the horizontal section was designed to penetrate the upper Cozzette below the pyrobitumen.

Secondary targets include the Mesaverde sandstones and coals within the Paludal depositional interval. The sidetrack wellbore slants through the Paludal Mesaverde interval at approximately 60° and then builds to nearly horizontal through the upper half of upper Cozzette Sandstone. Regional structural studies using surrounding well control in adjacent sections show that the local strike and dip in the north-central portion of Section 34 is N75°W, 1.8°NNE.

Although the sidetrack wellbore trajectory through the Cozzette interval is approximately 1,000 ft east of the original SHCT-1 wellbore, regional correlation studies and mud log descriptions suggest that the character of Cozzette in the sidetrack well is similar to the Cozzette in the MWX and SHCT-1 wells.

Natural fracture permeability is known to be an important gas production mechanism for Mesaverde wells in the area. For example, in the MWX-1 well in Section 34, T6S, R94W, formation permeability is at least an order of magnitude higher than core or log calculated permeability. Many natural fractures were noted in the core taken in the original wellbore[6], and it may be inferred from mud log gas shows that the Cozzette in the sidetrack wellbore is also naturally fractured. In the SHCT-1 well nearly 400 ft were cored, which included 276 ft in the Paludal interval and 118 ft in the upper Cozzette. Numerous natural fractures were noted in both core intervals. Most natural fractures were cut at about 90°.

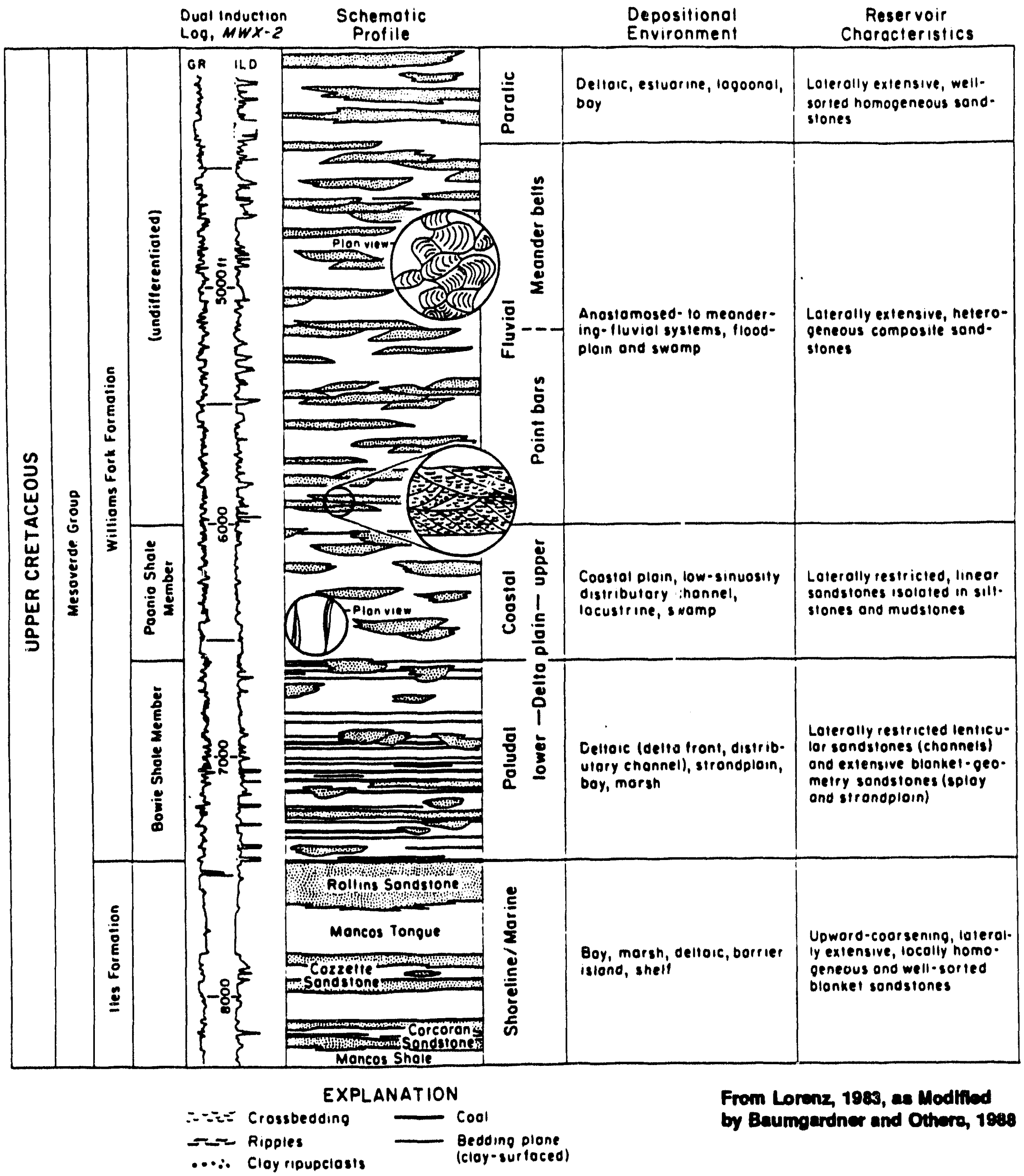
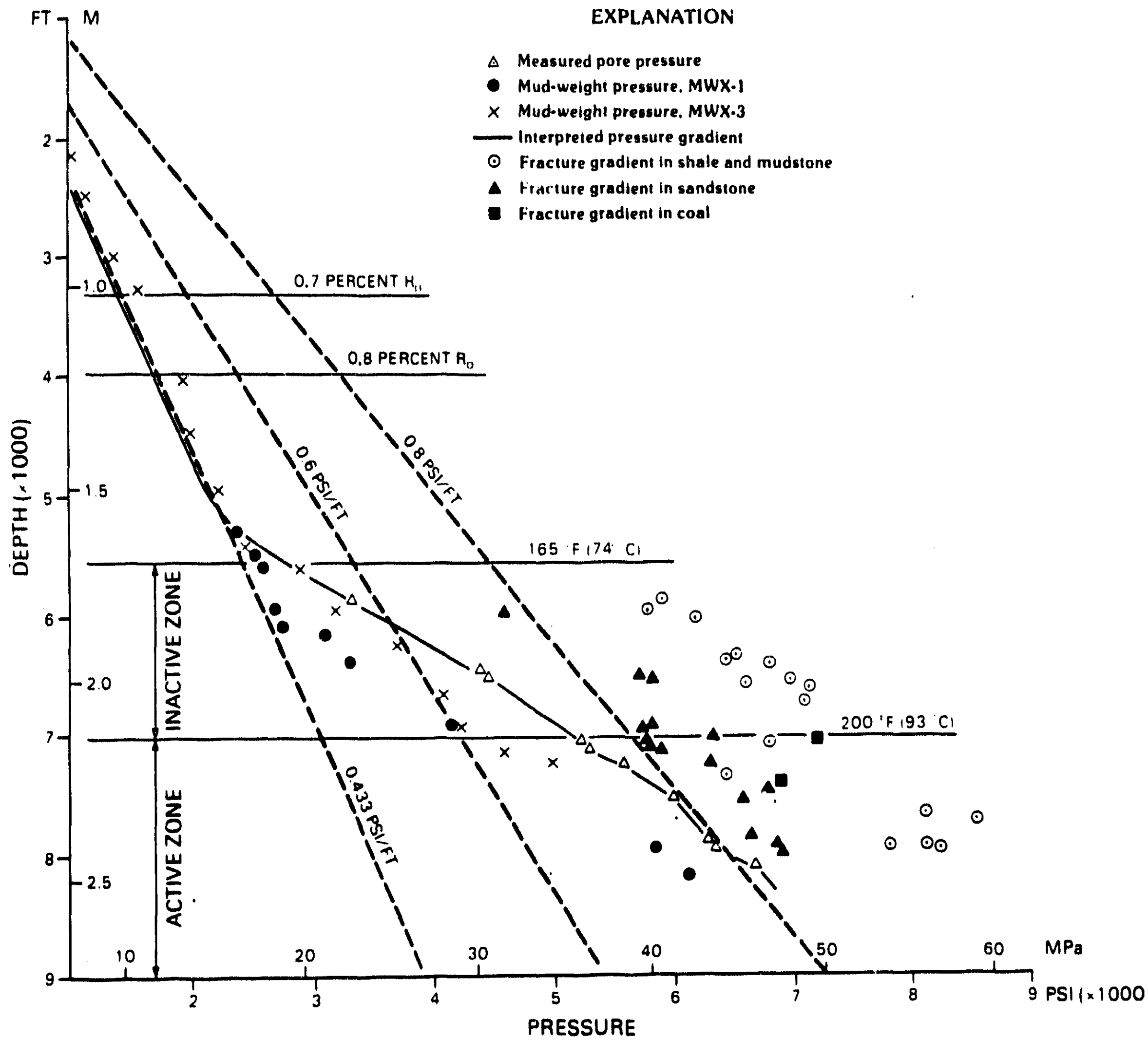


Figure 3-1 Correlation of Paleoenvironmental Depositional Units at the MWX Site with Regional Stratigraphic Nomenclature



From Law and Spencer, 1989

Figure 3-2 Interpreted Pressure Profile for MWX Site Wells, Piceance Basin with Fracture Gradient Data for Various Lithologies

The natural fractures are mineralized with euhedral quartz and calcite crystals indicating the fractures have open apertures in the subsurface. The fractures are oriented N80°W; this direction is also the direction of maximum horizontal stress as determined from hydraulic fracture orientations, borehole breakouts, drilling-induced fractures, and anelastic strain recovery of cores performed during the MWX project. These data were the primary reasons for drilling the SHCT well in a northerly direction. The sidetrack wellbore was not cored; however, the presence of natural fractures could be inferred by the numerous strong gas kicks encountered while drilling the well.

Regional geologic work in the vicinity of SHCT-1 showed that a correlatable marker exists approximately 100 ft above the Cozzette. This marker is apparently a volcanic ash fall bentonite. The marker is characterized by a higher gamma ray and a higher neutron porosity than is otherwise exhibited by the Mancos Tongue. This marker was used as the key correlation point during the drilling of the SHCT-1 sidetrack well. A gamma ray/neutron log was run through drill pipe to facilitate this correlation. The shale marker provided excellent control to determine the precise depth for initiating the second build.

The Paludal Mesaverde interval was successfully logged in the sidetrack well using drill pipe-conveyed logging. The log analysis results are detailed in a CER log analysis report[7].

4.0 SHCT-1

4.1 DRILLING OPERATIONS SUMMARY

4.1.1 Drilling Rig

The drilling rig chosen to drill the Slant Hole was Adcor Rig No. 44 with a depth capacity of 11,500 ft with 5-in. drill pipe. This diesel electric rig was equipped with a 131-ft mast having a 357,000-lb hook-load capacity using 10 lines. The rig was equipped with an 18-ft substructure and had a 300,000-lb set back capacity to efficiently rack 9,600 ft of 5-in. drill pipe and 5-in. heavy-weight drill pipe.

4.1.2 Surface Hole (17-1/2-in.)

A 17-1/2-in. hole was drilled with a small service unit to 115 ft and 13-3/8-in., 54.5-lb/ft, K55 casing was run to total depth and cemented to surface with 470 sacks of cement. [All depths are Measured Depths (MD) unless specified as True Vertical Depth (TVD)].

4.1.3 Intermediate Hole (12-1/4-in.)

The drilling rig was moved in, and a 12-1/4-in. hole was drilled through the Wasatch and 200 ft into the Mesaverde. A 9-5/8-in., 36-lb/ft, K55 casing string was run to 4,130 ft and cemented back to surface with 835 sacks of cement to isolate major caving and lost circulation zones in the Wasatch.

4.1.4 Production Hole (8-3/4-in.)

An 8-3/4-in. hole was then drilled to the first kickoff point at 6,365 ft. Hole angle was built in the 8-3/4-in. hole using a 6-3/4-in. diameter angle-build motor having a design build rate of 8.7°/100 ft. The hole angle was built from 0° at 6,365 ft to 55.2° at 7,010 ft for an effective build rate of 8.6°/100 ft. Conventional rotary coring operations were undertaken in the Paludal Mesaverde between 7,324 and 7,581 ft. A pressure core, co-funded by the Gas Research Institute, was taken in a coal between 7,371 and 7,380 ft to directly determine the methane content and to compare it with conventional coal coring and desorption in the same interval. Drilling then proceeded in the tangent interval at a hole inclination of 59.1° using both steerable motors and conventional rotary methods to 8,667 ft in the Mancos shale, below the base of the Rollins sand. Mud weight was raised gradually from 13.3 to 15.0 PPG while drilling the tangent in an effort to stabilize caving in the over-pressured coals. The high mud weight required to stabilize the coals, in turn, aggravated lost circulation problems in the Rollins sand. Subsequent caving in of the overpressured coals and siltstones between 7,350 and 7,400 ft and lost circulation in the Rollins at 8,200 ft necessitated running the 7-in. casing early to isolate these intervals. The 7-in., 29-lb/ft N80 casing was run to 8,489 ft, where it became stuck, and was cemented in place with 770 sacks cement. At this time, the 5-in. drill pipe and handling equipment was changed out to 3-1/2-in. equipment.

4.1.5 Cozzette 85.1° Lateral (6-in.)

A 6-in. hole was then rotary drill to the second kickoff point at 8,834 ft. The second build was drilled from 8,834 to 8,949 ft with 4-3/4-in. diameter, 19.4°/100 ft angle-build motors. Inclination was built from 62.5° to 81.5° for an effective build rate of 15.3°/100 ft. Extreme difficulty was experienced uniformly sliding the 4-3/4-in. bottomhole assembly while drilling the second angle-build portion of the hole. It is strongly suspected that the lead stabilizer on the 19.4°/100 ft fixed angle-build motor dragged, not allowing the bottomhole assembly to continuously slide in the high-angle hole. This inability to continuously slide the fixed angle motor and bottomhole assembly in the high-angle hole resulted in sudden downward movement of the bottomhole assembly which would instantaneously increase the weight on the bit, bury the bit face and cause the mud motor to stall. At 8,994 ft, it was not possible to slide the fixed angle-build motor in the 80.9° hole to continue motor drilling the second angle build to 87° as planned. The last 40 ft of the second build, to 8,990 ft, was drilled with a conventional rotary angle-build assembly and the hole angle was built to 83.4°. At the end of the second build, the wellbore azimuth was due north, with the Cozzette dipping 1.7° to the north northeast. The effective hole angle in the Cozzette at the end of the second build was 85.1° at 8,990 ft.

The well was conventionally rotary cored from 8,990 to 9,108 ft. The hole was then rotary drilled to 9,466 ft TD, and the open-hole section was successfully logged using drill pipe-conveyed logging techniques. A number of gas kicks were recorded while drilling and coring this final section of the hole, indicating that the wellbore had traversed a number of gas-filled natural fractures.

A 4-1/2-in., 13.5-lb/ft, N80 liner was run to 9,466 ft (top liner tieback at 8,200 ft) and cemented with 300 sacks of cement. Mechanical problems that developed following liner cementing operations resulted in a major washover operation. Figure 4-1 illustrates the "As Built" wellbore configuration while Figures 4-2 and 4-3 present the wellbore profile and plan views.

4.2 DIRECTIONAL DRILLING SUMMARY

4.2.1 First Build

An 8-3/4-in. diameter hole was drilled out from under the 9-5/8-in., 36-lb/ft intermediate casing at 4,130 ft to the first kickoff point at 6,365 ft. A gyroscopic survey run at 6,365 ft indicated the hole angle to be 0.57° and determined the bottomhole location to be 65.83 ft east and 26.30 ft north of the surface location on an azimuth of N68°E. The eastward drift of the hole is attributable to intersecting and tracking a minor fault scarp initially encountered at 2,622 ft.

The entire first build interval was drilled with one 8.7°/100 ft angle-build motor assembly. The first build interval was completed at 7,010 ft with an inclination of 55.2° on an azimuth of N4.3°W for an effective build rate of 8.6°/100 ft.

An 8-3/4-in. Christensen Z437 mosaic bit was used to initiate the build and drilled from 6,365 to 6,423 ft, but was pulled, severely worn, when penetration rates did not exceed 3.9 ft/hr. One 8-3/4-in., Smith F3HL bit with heel buttons and stabilizer lugs drilled the remainder of the first build interval to 7,010 ft at an average penetration rate of 10.3 ft/hr.

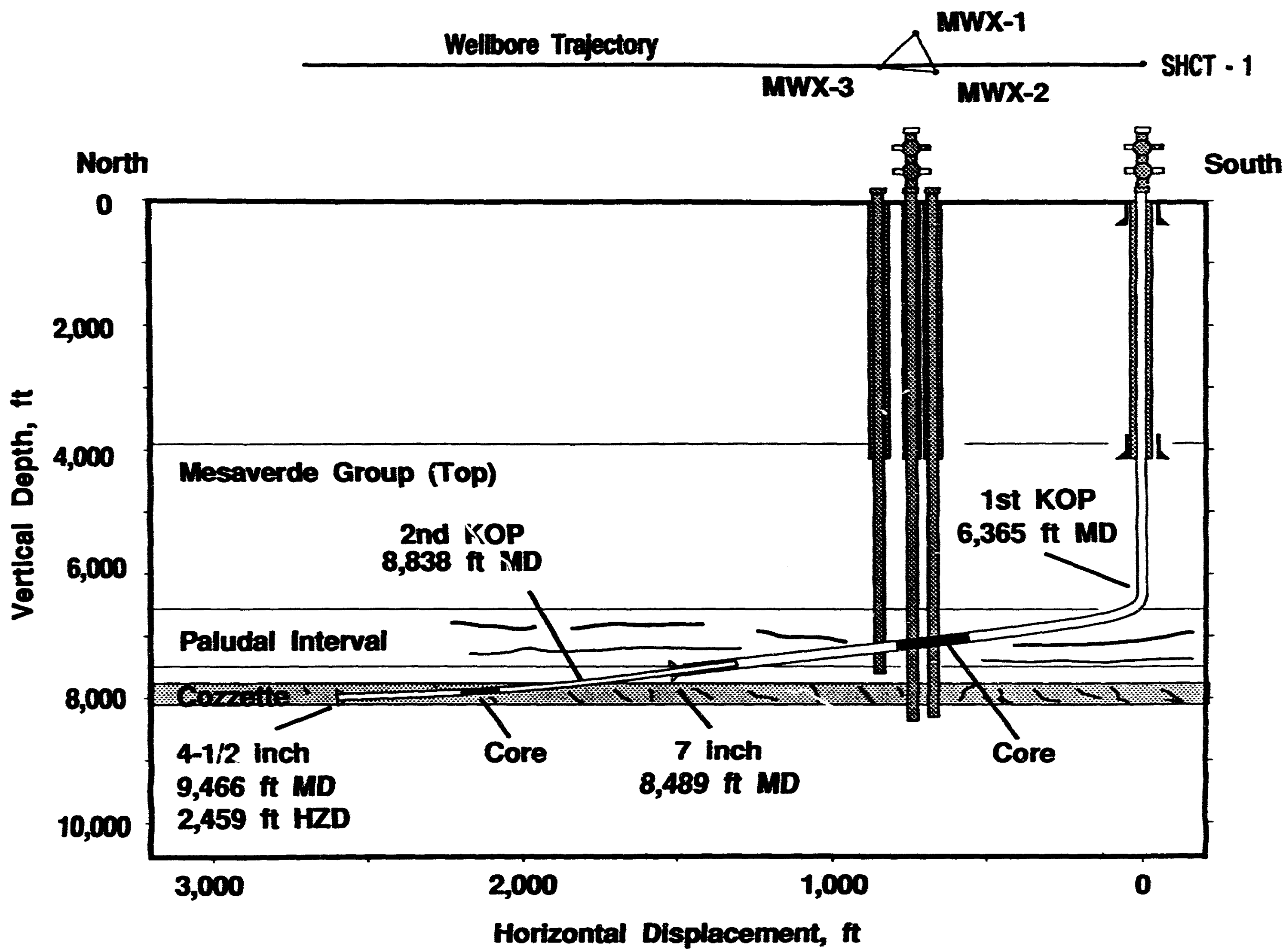


Figure 4-1 Slant Hole "As Built" Profile

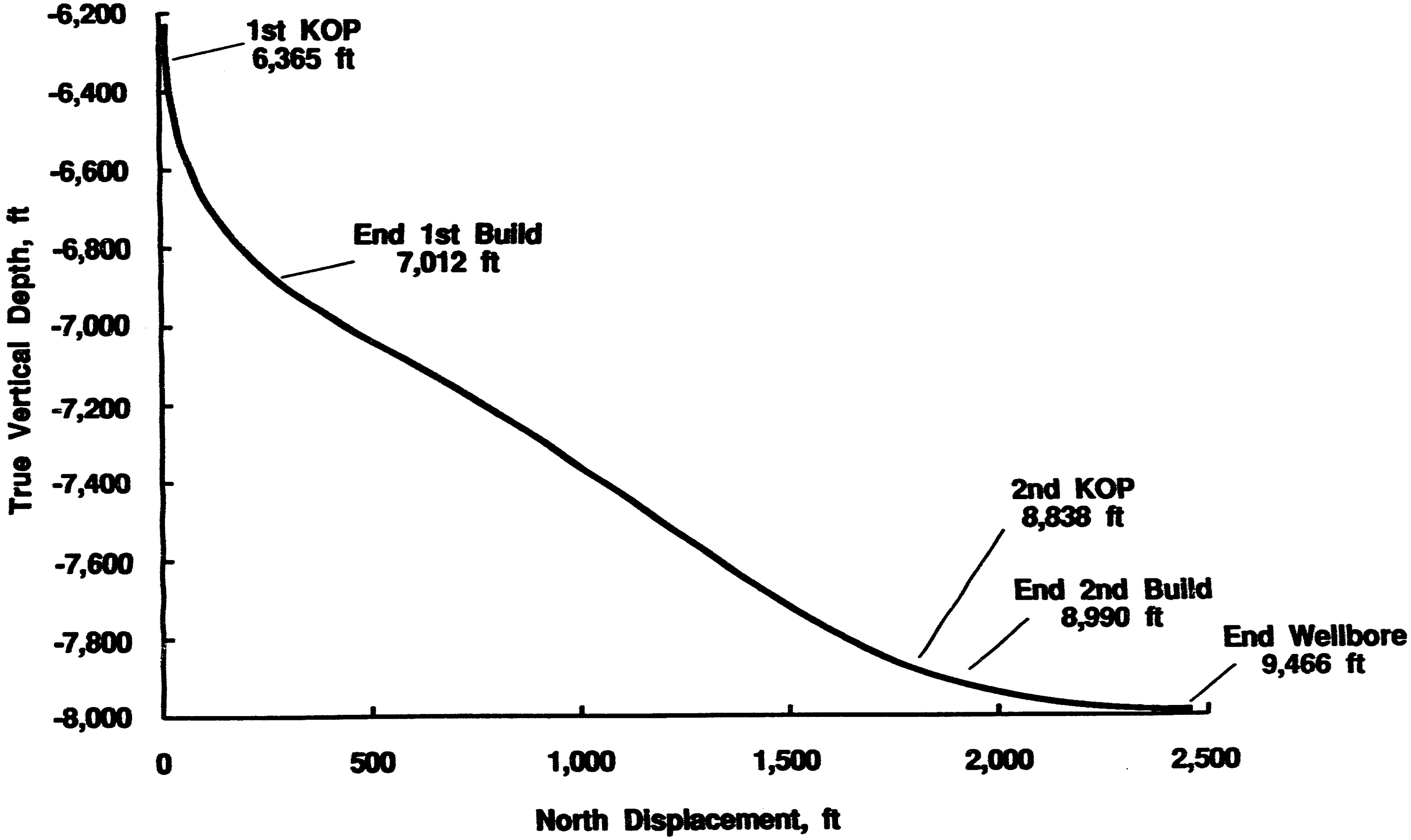


Figure 4-2 Slant Hole Wellbore, Profile View

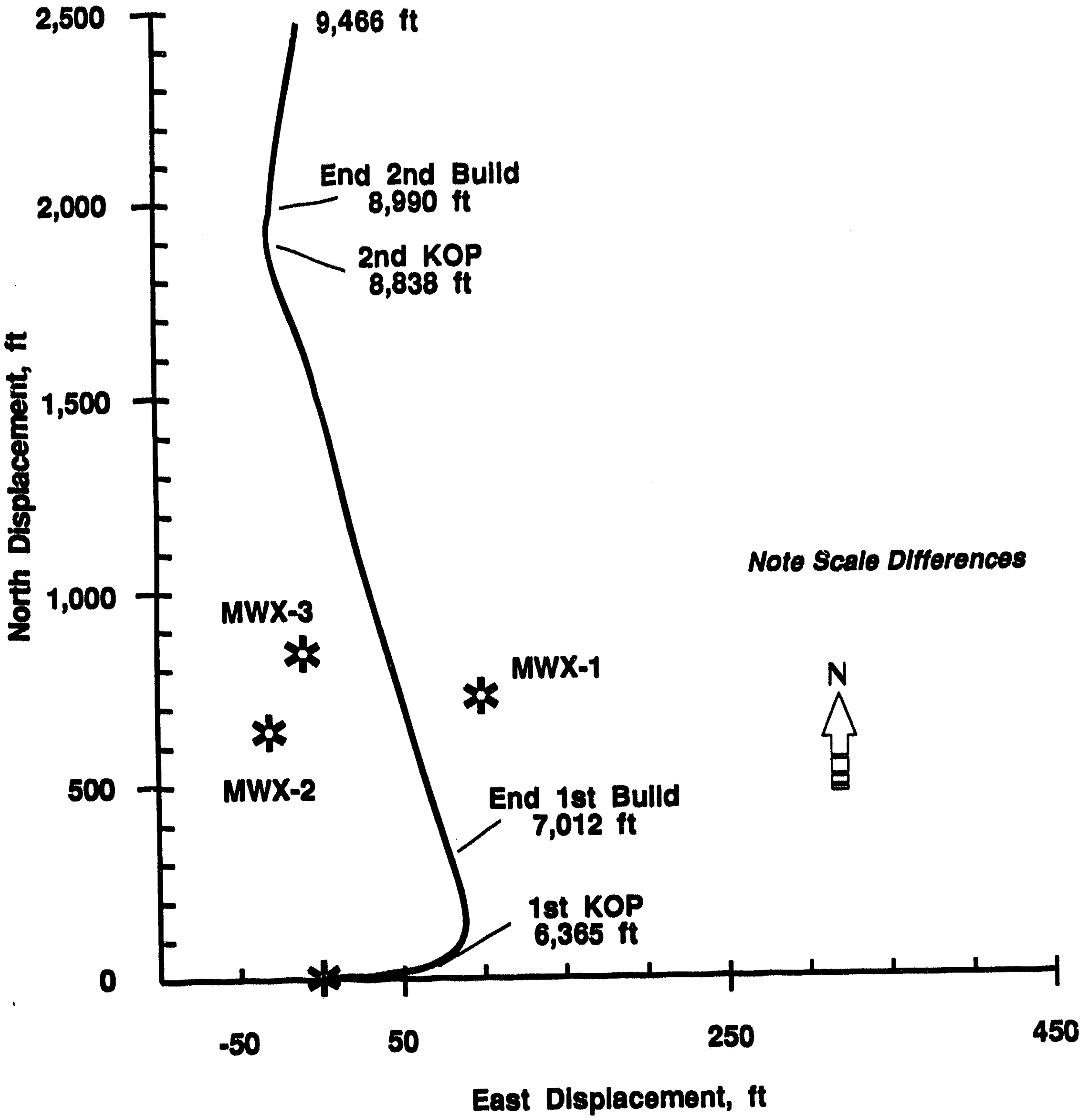


Figure 4-3 Slant Hole Wellbore, Plan View

4.2.2 Tangent

8-3/4-in. Tangent Section to 8,667 ft

The first tangent section was started with a steerable motor assembly. This assembly drilled 295 ft to the first core point at 7,305 ft while increasing the hole angle to 59.3°. A Smith F3HL bit with heel buttons and stabilizer lugs drilled this interval at an average penetration rate of 8.1 ft/hr. At this point, a wiper run was made with an 8-3/4-in. hole opener prior to initiating coring operations.

After completing coring operations at 7,581 ft, drilling of the 8-3/4-in. hole in the tangent section resumed, with the hole being drilled to 8,667 ft. Nine bottomhole assemblies were employed in this interval including both rotary and steerable motor assemblies. Nine bits, one re-run Christensen Z437 mosaic bit and eight Smith F3HL bits with heel buttons and stabilizer lugs were used to drill this interval. Penetration rates for the various bits ranged from 3.2 ft/hr to 7.7 ft/hr and averaged about 4.8 ft/hr. The mosaic bit averaged 3.6 ft/hr for 86 ft, prior to being pulled. The eight Smith F3HL bits averaged 5.0 ft/hr over a distance of 995 ft.

Fishing Operations

Two separate fishing operations occurred while drilling in the tangent section. The first at 7,829 ft resulted from losing two cones from a Smith F3HL bit while drilling with a steerable motor to raise hole angle. The second fishing operation occurred at 8,270 ft with the loss of one cone, two nose cones and bearings from a second Smith F3HL bit; again, the cones were lost while drilling with a steerable downhole motor and MWD.

Hole Caving and Lost Circulation

After building mud weight to 15 PPG in an attempt to stabilize the caving coals and after drilling the Rollins sandstone topped at 8,199 ft, lost circulation caused the drill pipe to become differentially stuck while drilling at 8,270 ft. The overpressured coals and fractured siltstones above the Rollins then kicked, unloading gas into the wellbore and causing the hole to cave. The drill pipe was worked loose, and the Rollins was successfully treated with lost circulation material to mitigate lost circulation. Drilling operations in the tangent continued with frequent tight spots to 8,667 ft. On a short trip to clean the hole, the drill pipe became stuck at 7,414 ft. Circulation with full returns was maintained even though the drill pipe could not be rotated or reciprocated. The drill pipe was backed off in the tangent section at 7,196 ft. A fishing assembly consisting of a cut lip screw-in sub, bumper jars and oil jars was run to the top of the fish and screwed into the fish. Following 1-1/2 hours jarring and circulating, the fish came free. Large, angular pieces of coal and siltstone were then circulated from the well while conditioning the hole. With the frequency of hole caving in the Paludal coals and occurrence of stuck drill pipe steadily increasing, it was decided to run and cement the 7-in. casing at 8,667 ft. Due to the threat of further caving, no open-hole logs were run in the 8-3/4-in. wellbore. It was felt that a lot of the hole problems may have been the result of frequent trips required for the coring operations and not the result of drilling in the high-angle hole.

7-in. Casing Set Through the Rollins

One-hundred-ninety-eight joints of 7-in., 29-lb/ft, N80 LT&C casing were run in the hole to 8,489 ft, 290 ft below the Rollins and into the Mancos shale. One-hundred-twelve centralizers were placed on 20-ft centers through the tangent and build sections of the hole. Difficulty was experienced running the casing between 7,287 and 8,489 ft. The casing was worked and washed down through this interval. Full returns were experienced while washing the casing down to 8,489 ft. The casing became stuck completely at that point, 178 ft off bottom. The casing was then cemented in one stage with 340 sacks of premium cement containing light weight additives and retarder followed by 430 sacks of premium cement containing silica flour and retarder, plus additives to control cement weight and water loss. Full returns were experienced throughout the job. A cement bond log run 5 days after completion of cementing operations indicated the cement top at 6,405 ft, approximately 40 ft below the top of the first build and 2,900 ft below the designed cement top at 3,500 ft. This was probably due to loss of cement into the Rollins and the enlarged hole through the coaly interval.

6-in. Tangent Section to 8,834 ft

The 5-in. drill pipe, heavy-weight drill pipe, and the associated handling equipment were replaced with 3-1/2-in. drill pipe and 3-1/2-in. heavy-weight drill pipe and handling equipment prior to drilling out from under the 7-in. casing. The shoe joint, 178 ft of 8-3/4-in. open hole, and 16 ft of new hole were drilled out with a conventional rotary drilling assembly to a depth of 8,683 ft. A 6-in. Christensen R433S PDC bit was then run on a rotary angle-hold assembly and drilled to the second kickoff point at 8,834 ft, a distance of 151 ft, at an average penetration rate of 9.7 ft/hr.

4.2.3 Second Build

The second kickoff point was determined using detailed structural mapping in conjunction with well-to-well correlation to stratigraphic markers as the well was being drilled. These stratigraphic markers include the major Paludal coals, Rollins sandstone, Mancos Tongue, a thin geologic marker 84 ft into the Mancos Tongue characterized by a high gamma ray and a high neutron porosity, and the top of the upper Cozzette interval. A gamma ray log was run through drill pipe to fine tune this correlation prior to reaching the second kickoff point. This was combined with MWD survey information to successfully project the expected depths of the markers. This procedure resulted in an accurate determination of the second kickoff point at 8,834 ft.

The 6-in. diameter hole in the second build interval was drilled with 19.4°/100 ft angle-build motors using one Christensen R433S PDC bit and one Christensen D331 natural diamond bit. Nine fixed angle-build assemblies were run between 8,834 and 8,949 ft.

The penetration rates were very low in the second build interval due to difficulty in sliding the 4-3/4-in. fixed angle-build motor and the 4-3/4-in. MWD in the high-angle hole. It is strongly suspected that the integral lead stabilizer on the 19.4°/100 ft fixed angle-build motor dragged, not allowing the bottomhole assembly to continuously slide in the high-angle hole. This inability to continuously slide the fixed angle-build motor and bottomhole assembly in the high-angle hole resulted in sudden downward movement of the bottomhole assembly, which, in turn, would instantaneously increase weight on bit, bury the bit face and cause the mud motor to stall. At 8,949 ft, it became impossible to further slide the 4-3/4-in. angle-build motor and MWD. The penetration rates through this interval ranged from 0.3 ft/hr to 4.3 ft/hr while using the fixed angle-build motor assembly, and averaged slightly less than 1.0 ft/hr. At this time, it was decided to run a rotating angle-build assembly to increase penetration rate and to complete drilling the second build. A rotating angle-build assembly was run at 8,949 ft and drilled to the end of the second build in the upper Cozzette at 8,990 ft. Inclination was built from 62.5° at 8,834 ft to 83.4° at 8,990 ft for an effective build rate of 13.4°/100 ft.

4.2.4 Horizontal Section

Detailed structural mapping has determined that the Cozzette sandstone dips to the north northeast at 1.7° in the area immediate to the Slant Hole Completion Test. Further, the wellbore azimuth at the top of the 40-ft (vertical thickness) upper Cozzette target interval is essentially due north. Consequently, the effective angle of penetration of the upper Cozzette is 85.1°.

After completing coring operation in the upper Cozzette between 8,990 and 9,108 ft, a rotary angle-building assembly was run in the hole with a Christensen D331 natural diamond bit. The entire horizontal section of the hole was drilled using surface rotation. Numerous natural fractures were encountered drilling from 9,108 to 9,398 ft, the base of the upper Cozzette interval. Progressive penetration of fractures was indicated by loss of 16.6 PPG drilling fluid and recurring, sporadic increases of gas on the chromatograph while drilling. The hole was bottomed at 9,466 ft, approximately 68 ft into the siltstone below the base of the upper Cozzette.

Drilling the 476 ft of 85.1° lateral between 8,990 and 9,466 ft in the upper Cozzette required one Christensen D331 and one Diamant Boart TB603 natural diamond bit. The penetration rates varied from 4.8 ft/hr to 5.7 ft/hr and averaged slightly less than 5.5 ft/hr.

4.3 DRILLING TIME SUMMARY

Figure 4-4 presents the drilling time versus depth versus cost information. Table 4-1 shows the cumulative time distribution in hours for drilling the SHCT-1.

4.4 FORMATION TOPS, CASING DEPTHS AND TOTAL DEPTH

Table 4-2 presents the formation tops, casing depths and total depths for the SHCT-1.

4.5 MUD SYSTEM

A low solids, non-dispersed (LSND) mud system was chosen to drill the Mesaverde sandstone, siltstone, shale and coal sequence. This highly shear-thinning system was chosen because it has a minimum of solids for improved penetration rate along with minimum viscosity at the bit, and provided for maximum annular velocity for hole cleaning. This LSND mud system had the following properties:

- pH at 9.0 to 9.5,
- 30-minute filtrates at 5 cc to 6 cc,
- mud weights maintained with barite to 16.6 PPG, and
- 8 percent diesel and a non-hydrocarbon lubricant used to increase lubricity.

The rig was equipped with a fine-screen shale shaker, desander, desilter, mud degasser, and a gas buster. This mud system was chosen over an oil-base mud due to the excellent results with a LSND mud at MWX-3 and for environmental reasons.

4.6 CORING PROGRAM

4.6.1 Pressure Core in Paludal Coal

The objective of the pressure core of a Paludal coal seam, cooperatively funded by the Gas Research Institute as an add-on activity, was to accurately measure the original gas content and coal mechanical

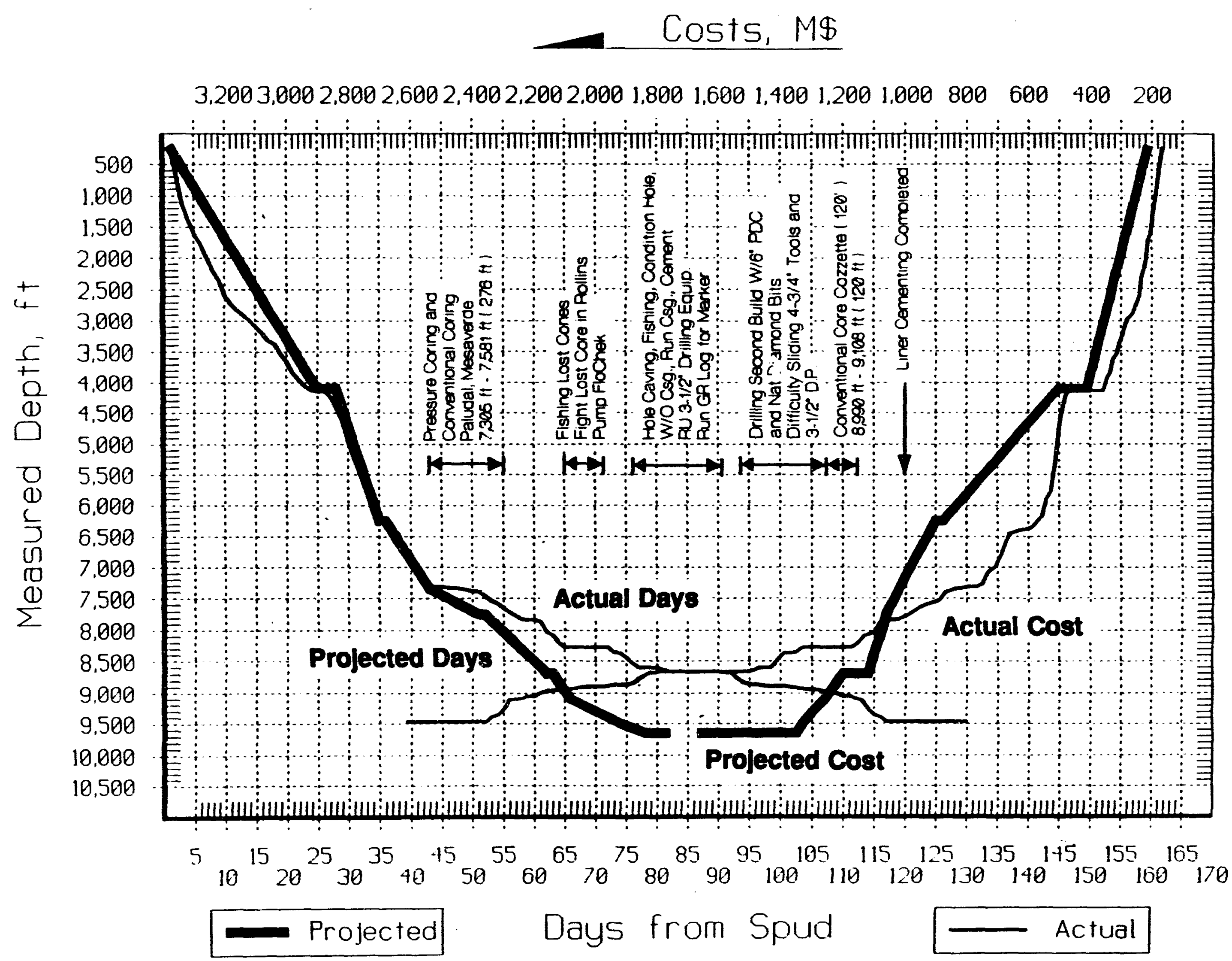


Figure 4-4 Drilling Time Vs. Depth Vs. Cost, SHCT

Table 4-1 Drilling Time Summary, SHCT-1

Cumulative Time Distribution	Hours
Drilling	1,206.75
Deviation Surveys	26.25
Trips	566.00
Reaming	122.00
Circulate & Condition Mud	211.25
RU & Run Casing & Liner	26.00
Install & Test BOP's, Casing, Remove, etc.	37.75
Control Pressure	46.25
Lost Circulation	76.00
Rig Maintenance	49.75
Rig Repair	107.50
Wireline Logging & Coring	109.25
Fishing	25.00
Washover Operations	457.50
PU, Lay Down Drill Collars, Pipe, Change BHAs	188.00
Wait On Orders, Equipment	34.00
Other	142.75
TOTAL	**3,432.00**

Table 4-2 Formation Tops, Casing Depths and Total Depths, SHCT-1

	Measured Depth, ft	TVD Depth, ft	MSL Elevation, ft
FORMATION TOPS			
Mesaverde	3,946	3,946	1,480
Rollins	8,199	7,553	-2,127
Cozzette	8,858	7,907	-2,481
CASING DEPTHS			
13-3/8-in. Surface	115	115	5,292
9-5/8-in. Intermediate	4,130	4,130	1,296
7-in. Production	8,489	7,720	-2,294
4-1/2-in. Liner	9,466	7,981	-2,555
TOTAL DEPTHS			
Drillers' TD	9,466	7,981	-2,555
Loggers' TD	9,468	7,981	-2,555

Note: SHCT No. 1 Elevation: 5,407 ft GL, 5,426 ft KB properties. Based on geologic projections, two 10-ft pressure cores were cut in siltstone and coal stringers between 7,305 and 7,324 ft, some 30 ft (vertically) above where the coal was ultimately encountered. Following a reaming run to open the hole from 6-1/2 to 8-3/4 in., 47 ft of conventional core was then cut (in three runs) and the 10-ft coal seam at the top of the Paludal 4 sand was finally located at 7,366 ft. Five feet of coal was cut with the conventional core barrel and was immediately loaded in canisters for low pressure gas desorption measurements. A successful pressure core was then taken in the 60° inclined wellbore from 7,371 to 7,380 ft with 9 ft of coal recovered under full pressure at the surface. Subsequent desorption of the pressure core indicated a methane content of 765 SCF/ton (not corrected for ash content).

4.6.2 Conventional Core in the Paludal Mesaverde

Conventional 4-in. diameter core was cut from 7,324 to 7,371 ft and from 7,380 to 7,581 ft in the 60° inclined wellbore. A 6-3/4-in. by 4-in. by 60-ft core barrel with a brass studded (centralized) inner barrel, and an 8-3/4-in. by 4-in. Christensen ZC476 PDC core bit was used to obtain core in the Paludal interval.

The first two core runs, taken to locate the pressure core target coal, from 7,324 to 7,341 ft and from 7,341 to 7,358 ft, were prematurely terminated by core barrels jamming due to the highly-fractured nature of the coal stringers, siltstones and shales encountered. The third core from 7,358 to 7,371 ft was terminated 5 ft into the target coal to initiate pressure coring operations. The fourth conventional core taken from 7,380 to 7,418 ft encountered 5 natural fractures and was terminated when the core barrel jammed in a minor coal. The fifth core taken between 7,418 and 7,478 ft encountered 9 natural fractures in 39 ft of fine- to medium-grained sandstone. The sixth core taken from 7,478 to 7,538 ft encountered 24 fractures in 29 ft of fine-grained sandstone. A swarm of 21 of these fractures within a 3-ft interval were not mineralized and contained residual guar gels assumed to be from a hydraulic fracture stimulation conducted in the Paludal 3 sand in MWX-1 during 1984. The seventh core taken from 7,538 to 7,581 ft encountered 5 natural fractures in 24 ft of fine-grained sandstone, 10 ft of mudstone and 7 ft of coal. The coal recovered between 7,571 and 7,579 ft was loaded into canisters for low pressure gas desorption. Core recovery included the coal above the Paludal 4 sand, the Paludal 3 and 4 sands, and the coal below the Paludal 3 sand. Mud weight during coring operations was maintained at 13.3 PPG.

A total of 43 fractures were observed in the Paludal Mesaverde core, of which 22 were mineralized and open, while a swarm of 21 non-mineralized fractures over a 3-ft interval represented the hydraulic stimulation of the Paludal 3 sand in MWX-1.

4.6.3 Cozzette Core

Conventional 2-5/8-in. diameter core was cut from 8,990 to 9,108 ft in the 85.1° Cozzette lateral. A 4-3/4-in. by 2-5/8-in. by 30-ft conventional core barrel with brass wear pads at the midpoint position on the inner barrel for stabilization was used with a 6-in. by 2-5/8-in. Christensen C201 natural diamond core bit to cut 118 ft of Cozzette core.

The eighth core taken from 8,990 to 9,020 ft recovered 30 ft of sandstone containing 5 natural fractures. The ninth core taken from 9,020 to 9,050 ft recovered 30 ft of sandstone with 12 natural fractures.

The tenth core taken from 9,050 to 9,080 ft recovered 26 ft of sandstone containing 11 natural fractures. The eleventh core taken from 9,080 to 9,108 ft recovered 26-1/2 ft of sandstone containing 7 natural fractures. Gas entry during coring operations caused the drilling fluid weight to drop from 16.6 to 16.4 PPG while cutting the last core.

A total of 35 mineralized, mostly open natural fractures were observed in 118 ft of core taken in the Cozzette. Table 4-3 is a summary of the coring operation. Figure 4-5 illustrates the location of the natural fractures encountered in the cored intervals.

4.7 LOGGING PROGRAM

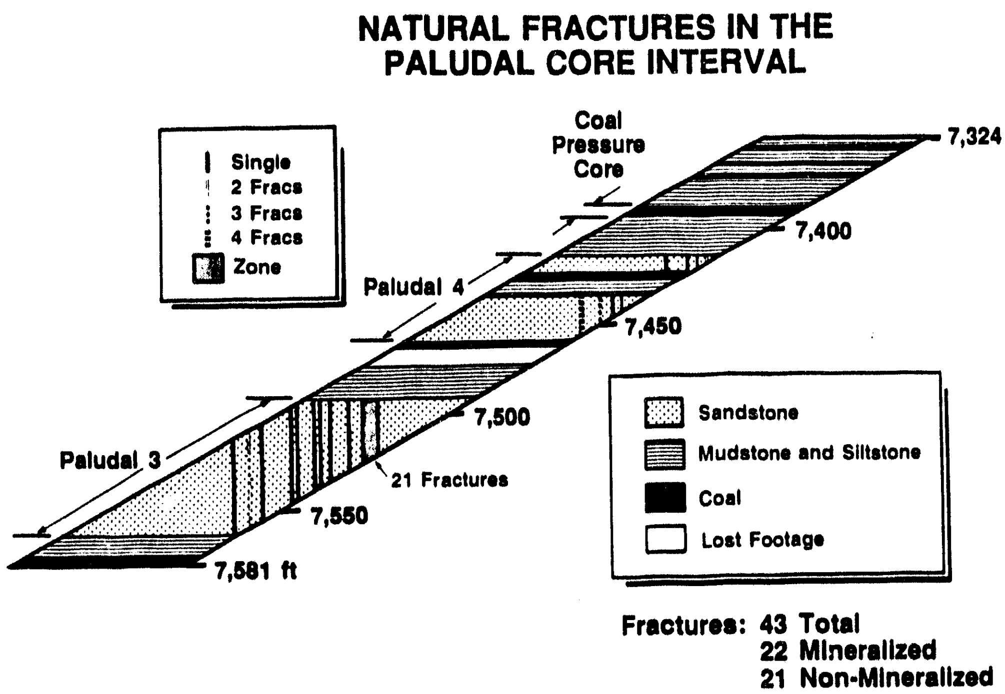
Two logging suites were run in the SHCT-1. The first suite was wireline conveyed from 4,130 ft back to surface, while the second log suite covered the 6-in. open hole from 9,466 to 8,489 ft.

4.7.1 Wireline-Conveyed Logging (115 to 4,130 ft)

A Formation Compensated Density Log with Gamma Ray Log was run in the 12-1/4-in. hole from 4,130 ft back to the 13-3/8-in. surface casing prior to running the 9-5/8-in. intermediate casing.

Table 4-3 Coring Summary, SHCT-1

Core Number	Depth Cut, ft	Depth Recovered, ft	Percent Recovered	Mineralized Natural Fractures
Pressure Core 1	7,305.0 - 7,314.0	7,305.0 - 7,313.5	94	Not Examined
Pressure Core 2	7,314.0 - 7,324.0	7,314.0 - 7,323.8	98	Not Examined
Core 1	7,324.0 - 7,341.6	7,324.0 - 7,341.6	100	2
Core 2	7,341.5 - 7,358.0	7,341.5 - 7,357.8	98	1
Core 3	7,358.0 - 7,371.0	7,358.0 - 7,370.9	99	2
Pressure Core 3	7,371.0 - 7,380.0	7,371.0 - 7,380.0	100	Not Examined
Core 4	7,380.0 - 7,418.0	7,380.0 - 7,415.4	93	5
Core 5	7,418.0 - 7,478.0	7,418.0 - 7,4467.9	83	6
Core 6	7,478.0 - 7,538.0	7,478.0 - 7,528.0	100	7
Core 7	7,538.0 - 7,581.0	7,538.0 - 7,579.0	95	5
Core 8	8,990.0 - 89,020.0	8,990.0 - 9,020.3	101	5
Core 9	9,020.3 - 8,050.3	9,020.3 - 9,050.1	99	12
Core 10	9,050.01 - 9,080.1	9,050.1 - 9,076.6	88	11
Core 11	9,090.1 - 9,108.4	9,080.1 - 9,106.5	93	7



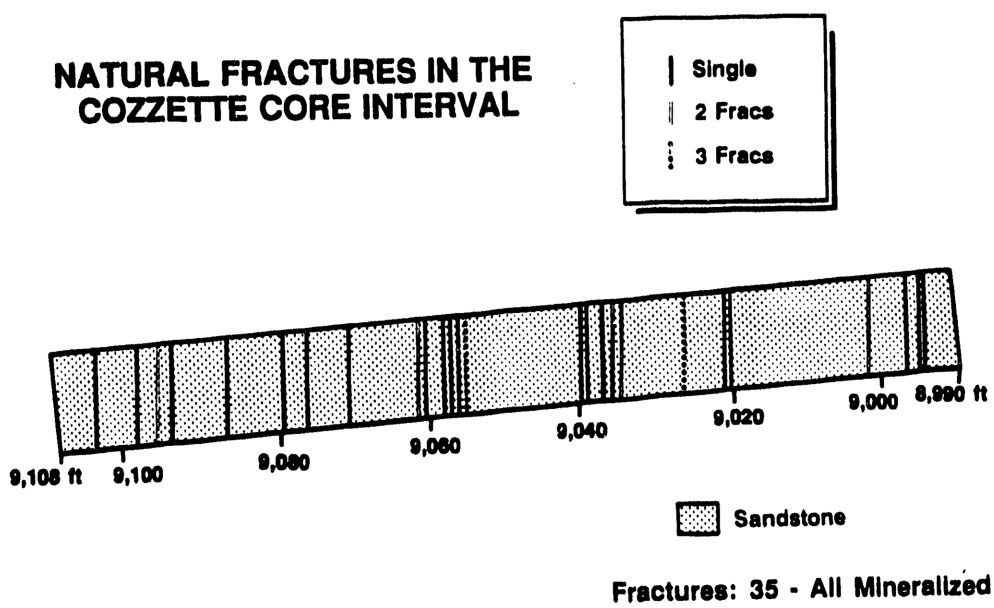


Figure 4-5 SHCT Cored Intervals

4.7.2 Drill Pipe-Conveyed Logging (8,489 to 9,466 ft)

The log suite for the Cozzette consisted of the Dual Induction Spherically Focused Log, the Lithodensity, Compensated Neutron, Gamma Ray, and Caliper. The open-hole section was logged from 9,461 ft, below the upper Cozzette, to the 7-in. casing seat in the Mancos Tongue at 8,489 ft. The Compensated Neutron Log was run through casing to the cement top at 6,405 ft. The logs were run in triple combination using drill pipe-conveyed logging techniques. The side-door entry sub was attached after running 6,400 ft of 3-1/2-in. drill pipe. The logging operation went smoothly, and log quality was good.

The operation required a careful coordination of drilling and logging crews since logging was performed while tripping drill pipe into and out of the hole. Tripping into the hole took approximately 14 hours and required some working of the drill pipe to get through the second build and to total depth at 9,466 ft. As well as providing logs on measured depth, the MWD survey was input to provide logs on true vertical depth for correlation with offset wells. A detailed report on the well log analysis was published January 13, 1992.[7]

4.7.3 Deviation Survey and Directional Survey

An Eastman Christensen Seeker Survey instrument (gyroscopic) was used to survey the vertical portion of the SHCT No. 1 wellbore from the surface to 6,360 ft.

Wellbore inclination and azimuth information in the 8-3/4-in. hole between 6,300 and 8,667 ft was obtained using the Eastman Christensen 6-3/4-in. Accu-Trak Directional MWD System. Wellbore inclination and azimuth information in the 6-in. wellbore between 8,667 and 8,990 ft was obtained using the Sperry Sun 4-3/4-in. Slimhole MWD System. Detailed survey data can be found in the "As Built" Report.[1]

4.8 DRILL BIT AND COREHEAD SUMMARY

Conventional coring in the 60° slant portion of the 8-3/4-in. wellbore in the Paludal Mesaverde was undertaken using the Christensen ZC476 PDC core bit. Conventional coring in the 85° portion of the 6-in. hole in the upper Cozzette sandstone utilized the Christensen C201 natural diamond core bit.

The 12-1/4-in. intermediate hole was drilled to 4,130 ft using 5 mill tooth and 2 insert bits. The 8-3/4-in. hole from 4,130 to 8,667 ft was drilled with 13 Smith journal bearing insert type bits and one Christensen Z437 PDC bit with mosaic cutters. The insert bits in the angle build and tangent sections were equipped with heel buttons and stabilizer lugs for gauge protection.

The 6-in. hole from 8,667 to 9,466 ft was drilled with one Christensen D331 natural diamond bit, one Christensen R433S PDC bit, and one 5-7/8-in. Diamant Boart TB603 natural diamond bit. The 5-7/8-in. Diamant Boart bit was used to drill the last 66 ft of the wellbore to avoid making a reaming run as the previous bit was pulled 1/8 in. undergauge.

4.9 MECHANICAL PROBLEMS RESULTING IN LOSS OF WELL

Twenty-nine joints of 4-1/2-in., 13.5-lb/ft, N80 LT&C liner were run on drill pipe to 9,466 ft. The top of the liner tieback sleeve was landed at 8,200 ft, and the liner was centralized at 20-ft intervals throughout its length. At the recommendation of the Mountain States Oil Tool representative the liner packoff was not run in conjunction with the rest of the liner assembly, as originally planned, because (1) of the possibility of high pressure during cement displacement prematurely setting the hydraulic set liner packoff, and (2) had the plugs not landed properly, it would have been impossible to set the liner packoff. A mechanically set liner top packoff was not used due to a pressure rating of 5,000 psi, which was deemed insufficient. The liner was then cemented with 300 sacks of premium cement containing silica flour and a cement retarder, plus additives to control cement weight, water loss and lost circulation. The cement slurry weight was 16.8 PPG.

Following 12 hours waiting on cement, a rerun 6-in. bit and a casing scraper were run in the well to 7,822 ft, approximately 400 ft above the liner tieback, to clean out the expected 200 to 300 ft of fill and polish the liner tieback sleeve prior to running an external liner packoff.

Circulation was established and continued until heavy mud cut cement and practically straight unset cement was circulated from the hole. The drill pipe was worked until returns were too thick to pump.

Attempts to pull out of the hole, to reverse circulate down the casing-drill pipe annulus, and to pump straight water down the drill pipe to move the mud, all proved unsuccessful. Recovery operations with wash over pipe were initiated at 346 ft on August 9, 1990. Initially, washover operations recovered 300 to 400 ft of fish per day. Then, even though this part of the well is very straight and vertical, the fish began laying against one side of the casing. Pipe recovery became slower and slower, since every tool joint had to be milled with washover shoes. Finally, after recovering a total of 5,335 ft of fish, progress essentially stopped. At that point, pipe recovery operations were halted due to budget considerations and the lack of progress. Figure 4-6 illustrates the position of the fish in the 7-in. casing at the time operations were suspended. On September 5, 1990, when operations were stopped, 2,487 ft of fish remained in the well.

Mechanical problems following liner cementing were probably the result of a combination of factors. These included not running a liner top packer and subsequent gas influx resulting in mud contaminated cement, as well as poor sweep during cement displacement and an optimistic hole volume from a caliper survey that resulted in overstating cement requirements.

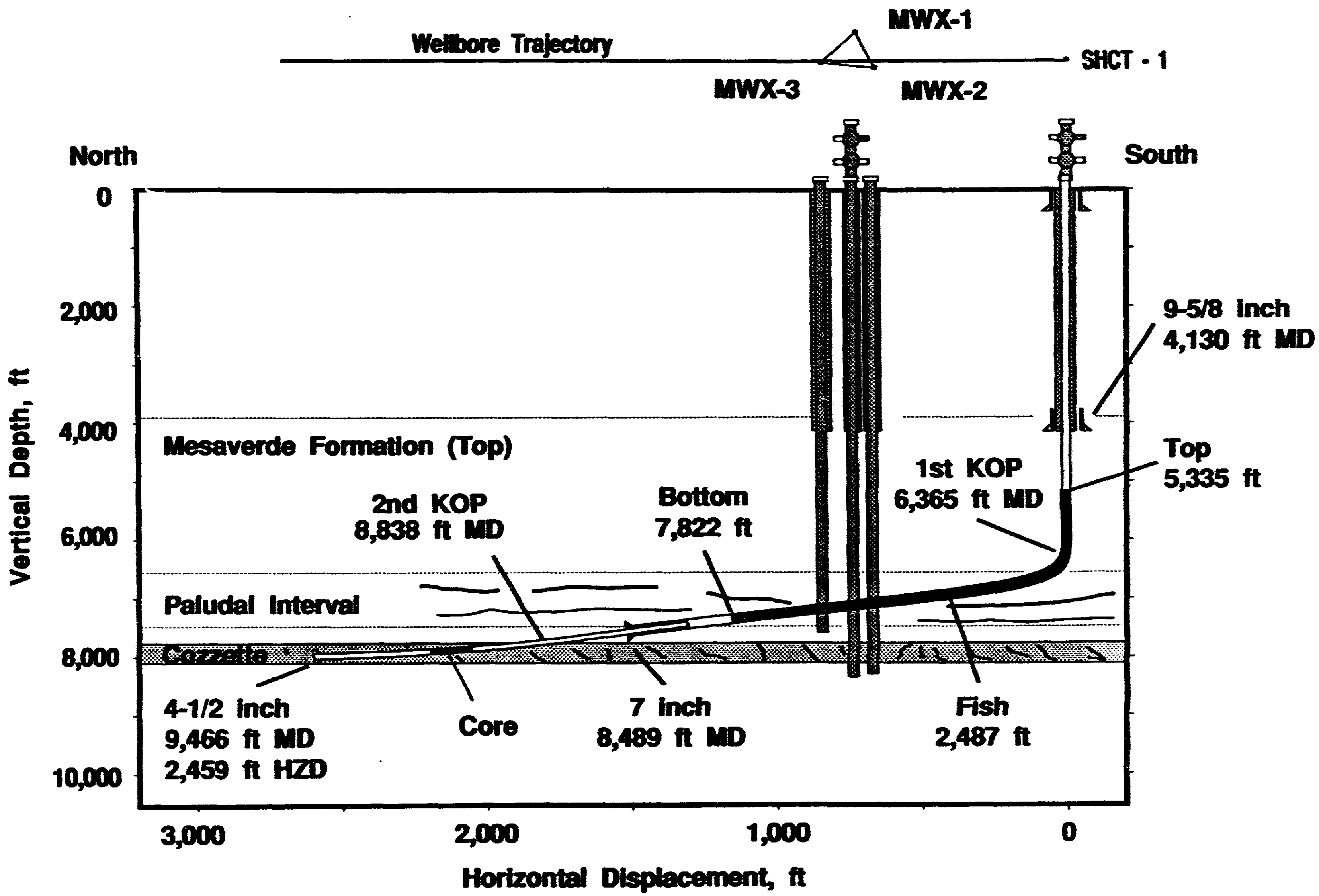


Figure 4-6 Position of the Fish in the 7-inch Casing September 5, 1990

5.0 SHCT-1 Sidetrack

5.1 KICK-OFF OPERATIONS FROM SHCT-1 WELLBORE

5.1.1 Drilling Rig

Veco Rig 10, the drilling rig chosen to drill the sidetrack, had a depth capacity of 15,000 ft with 5-in. drill pipe. This diesel electric rig was equipped with a 142-ft mast having a 960,000 lb hook load capacity with 10 lines. The rig was equipped with a 30-ft substructure rated at 1,200,000-lb capacity sufficient to rack 10,000 ft of 5-in. drill pipe and heavy-weight drill pipe.

5.1.2 Opening a Window

The sidetracking plan originally called for pulling of about 5,300 ft of the 7-in. casing from the old well, so that the lower hole could be redrilled with 8-3/4-in. bits. Pipe recovery operations were initiated on April 26, 1991, using a well service unit and casing jacks. Operations came to a halt 10 days later at 4,100 ft when no more joints came free. A stuck pipe log was run at this time which indicated that the 7-in. casing was tight from 4,180 to 4,215 ft. It became evident that approximately 140 ft of tightly held 7-in. casing would have to be washed over to provide a 100-ft open-hole window below the 9-5/8-in. intermediate casing shoe.

The well directional plan was adjusted to the shallower than expected kickoff point from which to sidetrack the hole. It was believed that washover operations could be performed more efficiently with the drilling rig. Consequently, the service unit was moved off and the drilling rig was moved on the hole on May 12, 1991. A pilot mill was run, and 2 ft of the casing stub was milled to 4,102 ft to smooth the top of the cut. An 8-5/8-in. washover shoe and 5 joints of 8-5/8-in. wash pipe were then used to wash-over the 7-in. casing stub from 4,100 to 4,239 ft. The casing was chemically cut at 4,237 ft; 136 ft of casing was recovered from the well. A Class G cement plug was set in the 7-in. casing stub from the cut-off at 4,237 ft to 5,087 ft to seal off the lower portion of the old hole. An additional Class G plug containing 2 percent $CaCl_2$ was set from 4,237 to 4,019 ft to serve as the actual kickoff plug.

5.1.3 Kicking Off at 4,160 ft

The kickoff plug was dressed off to 4,160 ft. A bottomhole assembly, consisting of an 8-3/4-in. IADC Code D8X5 sidetrack bit, a steerable mud motor with a 2° bent sub, and eleven 6-1/4-in. drill collars were used to kick off the sidetrack. At 4,254 ft, the kickoff bottomhole assembly (BHA) was pulled after drilling a distance of 92 ft. The hole inclination had been built to 6°, while the hole azimuth was S88°E. The sidetrack bit was replaced with an 8-3/4-in. IADC Code 537 insert bit, and a 1.5° bent sub was run with the steerable motor. Drilling continued to 4,504 ft at which time the motor and the sidetrack drilling assembly were laid down. At 4,504 ft (4,499 ft TVD), the hole inclination was 12° and the azimuth was S78°E.

5.2 DRILLING THE SIDETRACK

5.2.1 First Build

The upper part of the new hole was rotary drilled using conventional surface rotation, single-shot surveys for position control, and an 8-3/4-in. IADC Code 517 insert bit on a packed hole assembly. The well was drilled away from the old hole on a more or less straight tangent, at an inclination of 12° to 15° and a southeasterly azimuth. Over this section, from 4,504 ft to the first kickoff point at 6,550 ft, the average penetration rate was 6.81 ft/hr, while rotary drilling 2,046 ft of hole.

The kickoff point was reached at 6,550 ft at a hole inclination of 15.8°, on an azimuth of S67.7°E. Drilling of the first build proceeded satisfactorily, completing the compound turn at 7,309 ft with a hole inclination of 56° on an azimuth of N13.3°E. A 10.4 PPG mud weight was carried throughout the first build to 7,309 ft.

5.2.2 Redrill at 6,475 ft

At 7,309 ft, a packed hole rotary assembly was run in the hole to begin drilling the tangent section. The assembly became stuck at 6,708 ft in a portion of the build having a 15°/100 ft dogleg. On jarring loose, the bit and a near-bit stabilizer were left in the hole but were subsequently recovered. Efforts to ream out a second 15°/100 ft dogleg between 6,803 and 6,833 ft in a coaly section ultimately resulted in the hole being sidetracked at 6,833 ft. It was then decided to plug back to 6,450 ft and attempt a second kickoff. The first cement plug failed to set and was circulated from the hole. The second plug was satisfactory and a second kickoff was undertaken at 6,475 ft.

Redrilling of the first build proceeded slowly to 7,358 ft. The mud weight ultimately was raised to 12.5 PPG to stabilize sloughing shales and coal stringers. Extreme care was taken to hold dogleg severity below 8°/100 ft while drilling through the fractured interval where the 15°/100 ft doglegs occurred in the original hole. At the end of the build at 7,358 ft, the wellbore inclination was 57.1° and the hole azimuth was N14.6°E. The average penetration rate while drilling the 823 ft of the first build was 6.11 ft/hr.

5.2.3 Tangent

The first 208 ft of the tangent to 7,566 ft were drilled with both motor and surface rotation. An 8-3/4-in. insert bit was utilized with the steerable and rotatable motor to hold the hole inclination at 57.3° while turning the azimuth to N9.7°E. The remainder of the 1,230 ft tangent section to 8,588 ft was rotary drilled using an insert rock bit beefed up with heel buttons and stabilizer lugs. At 8,588 ft, the hole inclination was 60.4° and the hole azimuth was N9.7°E. While drilling the tangent section, it was necessary to steadily increase the mud weight to 14.3 PPG at 8,588 ft in the Mancos Shale to maintain wellbore stability. The lost circulation zone in the Rollins sand, where over 1,000 bbl of mud had been lost in the original slant hole, was drilled without incident.

5.2.4 Fishing Operations

Two separate fishing operations had to be conducted while drilling the tangent section. The first problem began while tripping out for a bit change after drilling to 8,422 ft, when the pipe got stuck part way out of the hole. Circulation with full returns was maintained even though the drill pipe could not be rotated or reciprocated. Apparently, hole caving occurred at a major coal encountered at 7,280 ft. The drill pipe was backed off at 7,283 ft and pulled, and a fishing assembly consisting of a cut lip screw-in sub and bumper and oil jars was run to the top of the fish. After screwing into the fish, it came free following several minutes of down-jarring. The fish was then washed and reamed through the caving rough hole area around 7,280 ft and pulled from the hole.

After drilling to 8,588 ft, the second fishing operation also occurred on a trip out of the hole. The top stabilizer in the drilling assembly became key seated at 7,645 ft in a shale above a coal seam. The drill pipe was backed off at 7,602 ft, and the hole was circulated clean. The previous fishing assembly was run in the well to the top of the fish and screwed in. The fish was jarred up the hole just 10 ft when it stuck again. A second backoff was performed at 7,622 ft. The fishing assembly was rerun and screwed into the fish, which was finally jarred free and pulled from the well.

With the increased frequency of hole instability, particularly caving in the Paludal coals, it was decided to run drill pipe-conveyed logs across the Paludal Mesaverde completion target, and then to run and cement the 7-in. casing at the present TD of 8,588 ft to stabilize the wellbore.

5.2.5 Setting the 7-in. Casing

Two-hundred-one joints of 7-in., 29-lb/ft N80 LT&C casing were run in the hole to 8,588 ft, 459 ft below the Rollins, and into the Mancos Shale. Fifty-one centralizers were placed with one centralizer above every collar through the tangent and build sections of the hole to the stage tool at 6,364 ft. Ten additional centralizers were placed above every second collar above that point. Some difficulty was experienced running the casing below 8,083 ft, but it was worked and washed down to bottom at 8,588 ft (7,780 ft TVD). Full returns were experienced throughout the washdown operation. The string weight was 165,000 lb, and the casing was landed in tension with 205,000 lb setting on the slips.

The casing was cemented in two stages. The first stage consisted of 385 sacks of Class G cement containing silica flour and additives to control cement weight and water loss. The well was circulated through the stage collar for ten hours prior to cementing the second stage. The second stage consisted of 285 sacks of Class G cement containing additives to control weight and water loss. Full returns were experienced while cementing both stages.

5.2.6 Second Build

The second kickoff point was determined as the well was being drilled, using detailed structural mapping of the Cozzette sand target in conjunction with well-to-well correlation of geologic markers. These markers include the major Paludal coals, Rollins Sandstone, Mancos Tongue, a thin geologic marker in the Mancos Tongue characterized by high gamma ray and neutron porosity signatures, and the top of the Upper Cozzette Sandstone. A gamma ray log was run through drill pipe to fine tune the geologic correlation points and to accurately select the second kickoff point.

A 6-in. diameter hole was drilled out from under the 7-in. casing shoe at 8,588 ft to the second kickoff point at 8,660 ft, using surface rotation and an angle building BHA with an insert bit.

The first part of the second build interval, from 8,660 to 8,812 ft, was drilled with 5°/100 ft steerable motors and 2 insert bits. The average penetration rate was poor at 3.61 ft/hr. Three different fixed angle-build assemblies were run over this 152-ft interval attempting to build angle. These BHAs seriously underperformed and only built 7° of hole angle over the distance. The remainder of the second build, from 8,812 to 9,020 ft, was drilled with an 11.6°/100 ft fixed angle-build motor and 3 insert bits. The average penetration rate was 4.17 ft/hr, and the build rate improved. The overall build rate through the second build interval averaged 6.9°/100 ft. At this point, the wellbore inclination was 85.9°, and the Cozzette was reached.

5.2.7 Cozzette Horizontal Section

The top of the upper Cozzette target interval was encountered at a depth of approximately 9,006 ft (7,928 ft TVD), where the hole azimuth was N10.9°E. Detailed structural mapping indicated that the Cozzette dips to the north northeast at about 1.7°. The intent was to gradually drop through the 60-ft thick Cozzette sand over a planned course length of 500 ft. Consequently, the required average angle of penetration of the Cozzette was 87.6°.

The Cozzette lateral from 9,006 to 9,289 ft was drilled using an IADC Code D2R2 natural diamond bit on a rotary angle hold assembly. Surveys from 9,050 to 9,112 ft indicated that the hole inclination was locked on 87.7°; unexpectedly, the bit tended to remain parallel to bedding, and the borehole was not cutting across the sand's thickness as planned. This problem did not occur in the original slant hole; in fact, the hole had dropped out of the sand a little ahead of schedule. An attempt was made with a steerable motor to increase the drop angle, but with marginal results. The diamond bit run averaged a penetration rate of 4.04 ft/hr. The lateral to 9,308 ft was rotary drilled ahead with an insert bit at an average penetration rate of 2.5 ft/hr.

The mud weight was held at 14 PPG to drill the naturally-fractured Cozzette pay. By design, this weight underbalanced reservoir pressure to minimize the loss of drilling fluid to the fracture system, as experienced in the original slant hole, as well as to minimize suppression of gas shows. The mud log indicated at least 10 major gas shows with chromatograph readings ranging from 190 to 800 units between 9,138 and 9,308 ft. The produced gas was successfully handled through the rig's gas buster.

5.2.8 Explosion and Fire

While tripping out of the hole for a bit change and with the bit at 5,200 ft, a very heavy gas kick threatened to blow out the well. The BOP was closed with 2,100 psi on the kelly, and an attempt was made to check the annular pressure. At that point, the 4-in. return line from the BOP stack ruptured just upstream of the choke manifold house. The released gas pressure pulled loose some electrical wiring and ignited. The resulting flash fire was quickly extinguished by closing the lower pipe rams on the BOP stack. Two rig site employees were injured. Only minor damage was done to the choke manifold house, but the 4-in. line to the choke manifold house had to be replaced.

As a result of the gas kick, the retrievable MWD tool was blown up the inside of the drill pipe approximately 1,000 ft, before it wedged in a tool joint and plugged the drill string. Since it was not possible to circulate during subsequent well control efforts, a hole volume (250 bbl) of 16 ppg mud was bull-headed down the drill pipe-casing annulus to kill the well. After a short quiet period, the well resumed flowing gas. Finally, 250 bbl of 18.7 ppg mud were pumped down the annulus to control the well. The pipe trip out was completed, and the MWD tool was located and recovered. A cleanout trip was made to 9,234 ft to circulate out the 18.7 ppg kill mud and replace it with 16.3 ppg mud prior to drilling the remainder of the Cozzette lateral.

5.2.9 Drilling the Cozzette to 9,407 ft

An IADC Code D2R2 natural diamond bit was selected to drill the remainder of the hole to TMD, projected at 9,500 ft, using an angle drop BHA and surface rotation. Seventy-five barrels of mud were lost while drilling from 9,308 to 9,358 ft. The presence of natural fractures was indicated by calcite and quartz crystals in cuttings samples. The mud weight was sufficiently overbalanced to suppress most of the gas shows. An additional 60 bbl of mud were lost as more fractured intervals were intersected between 9,376 and 9,407 ft. Three hundred feet of horizontal, highly-fractured Cozzette pay had been cut. At that point, it was decided to stop drilling operations at 9,407 ft TMD, 7,948 ft TVD, to minimize further mud loss to the fracture system. Approximately 400 bbl of drilling mud were lost into the Cozzette natural fracture system as a result of drilling and the post-fire well control operations. Figure 5-1 presents a diagram of the slant hole sidetrack wellbore at the end of drilling. Figure 5-2 presents a profile and plan view of the sidetrack wellbore. Figure 5-3, the wellsite plat, illustrates the relationship between the well path and lease boundaries.

5.3 COZZETTE FLOWBACK TESTING

The initial Cozzette bottomhole completion assembly is illustrated in Figure 5-4. A permanent production packer with one 6-ft joint of 2-7/8-in. tubing and an "R" nipple was run on drill pipe and set at 8,453 ft. The mud in the drill pipe was displaced with 2 percent KCL water, and the seal assembly was stung into the packer. The Cozzette was allowed to flow back to the burn pit through a choke manifold. Gas began arriving at the flare after 40 minutes while KCL load water slowly flowed from the well. Gas, water, mud and clouds of steam continued to flow at rapidly increasing rates, until approximately 200 bbl of water and drilling mud were recovered. After recovery of liquids stopped, up to 15.8 MMCFD of gas production were tested over a 3-hour period.

Following the brief flow test, a plug was set in the packer's "R" nipple to isolate the Cozzette open hole, a retrievable bridge plug was set in at 8,372 ft as a safety precaution, and the hole was displaced with 2 percent KCl water. The drilling rig was released on August 24, 1991.

5.4 DRILLING TIME SUMMARY

Figure 5-5 presents the drilling time versus depth versus cost information for drilling the SHCT No. 1 sidetrack. Table 5-1 shows the cumulative time distribution in hours.

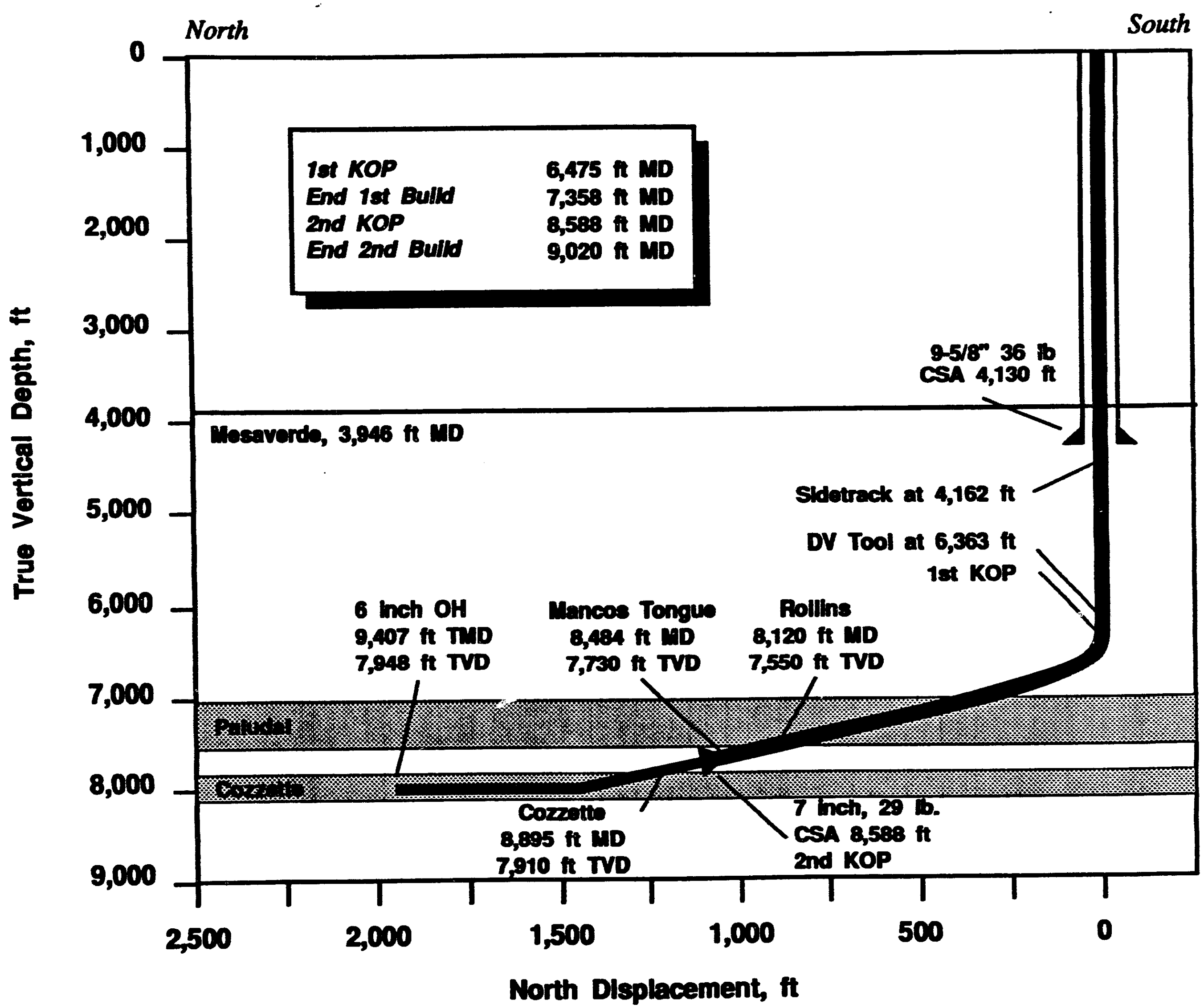


Figure 5-1 Slant Hole Sidetrack "As Built" Profile

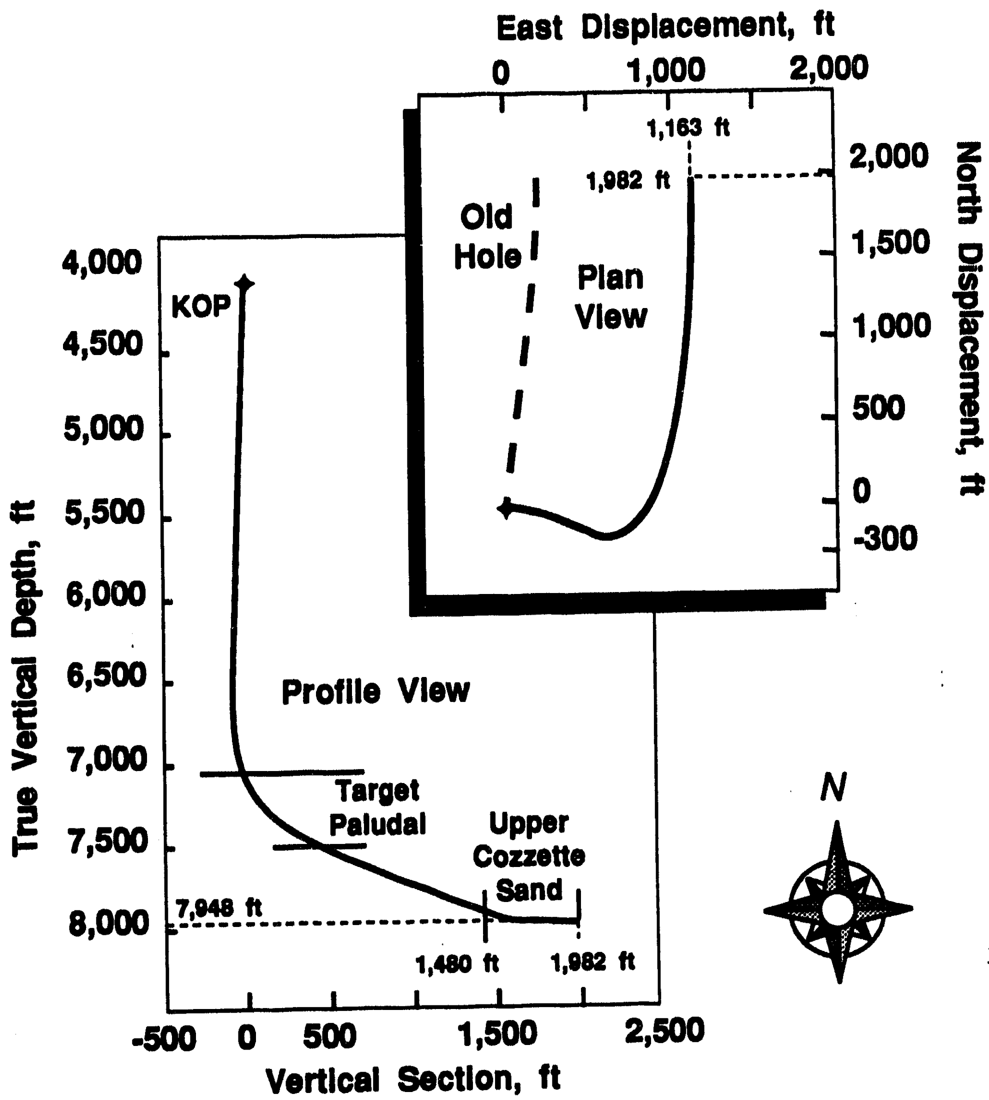
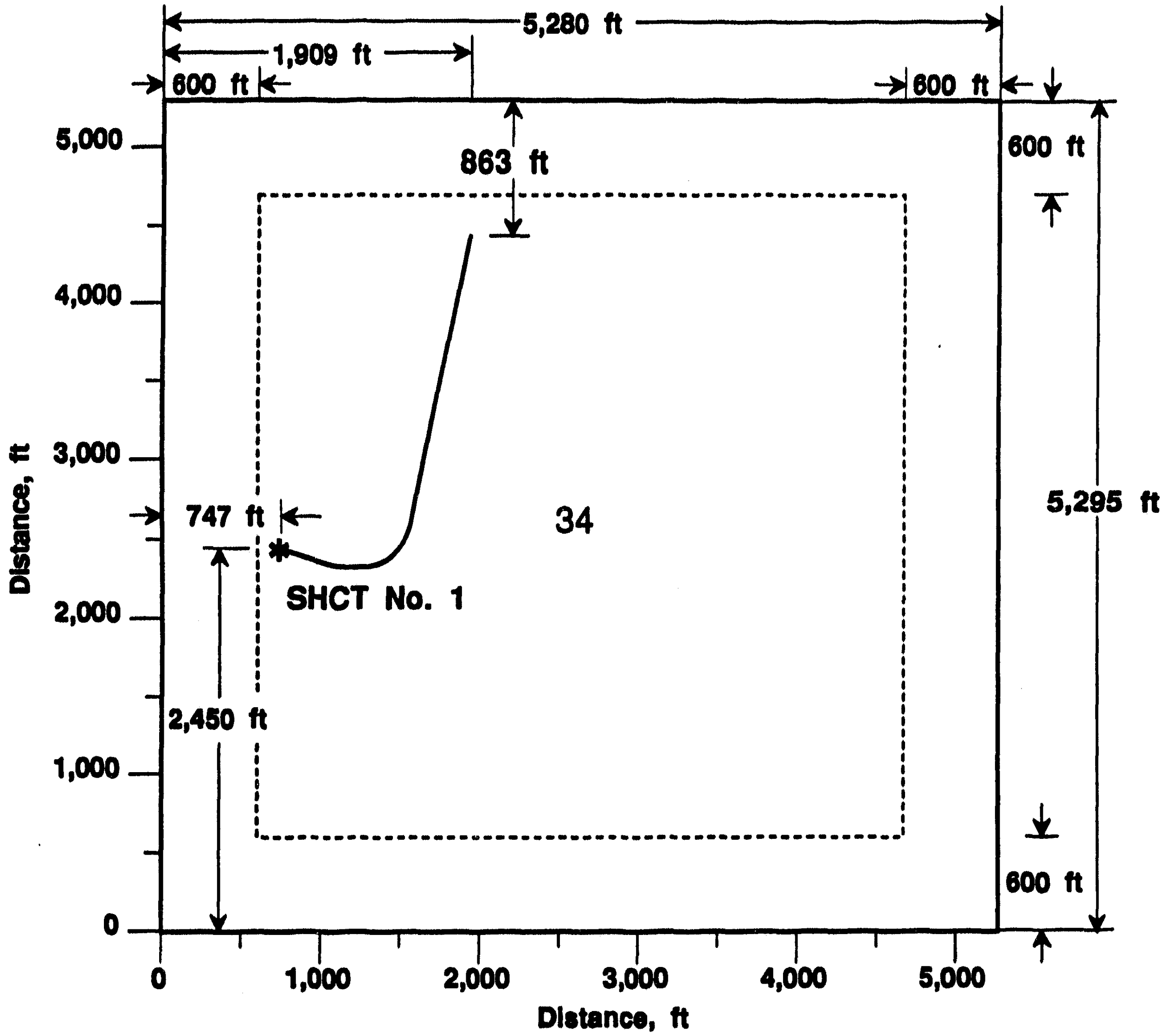


Figure 5-2 SHCT-1 Sidetrack Wellbore Profile and Plan Views



Surface Location: 747 FWL, 2,450 FSL, Sec 34, T6S, R94W
Bottomhole Location: 1,909 FWL, 863 FNL, Sec 34, T6S, R94W
Borehole Length: 9,407 ft MD
Azimuth: N 10.2° E (Cozzette Open-Hole)

Figure 5-3 Slant Hole Sidetrack Wellsite Plat

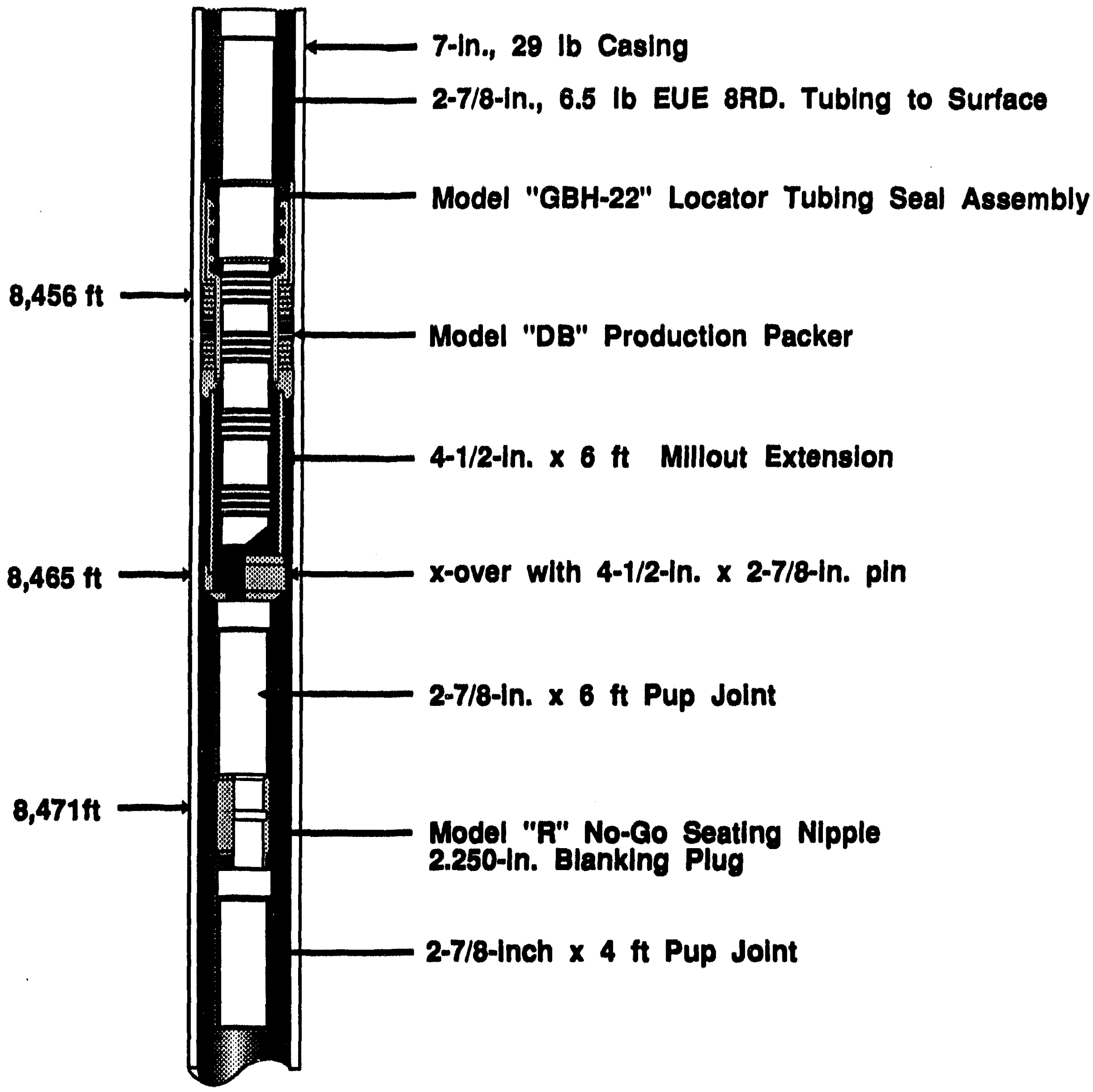


Figure 5-4 Original Cozzette Completion Assembly

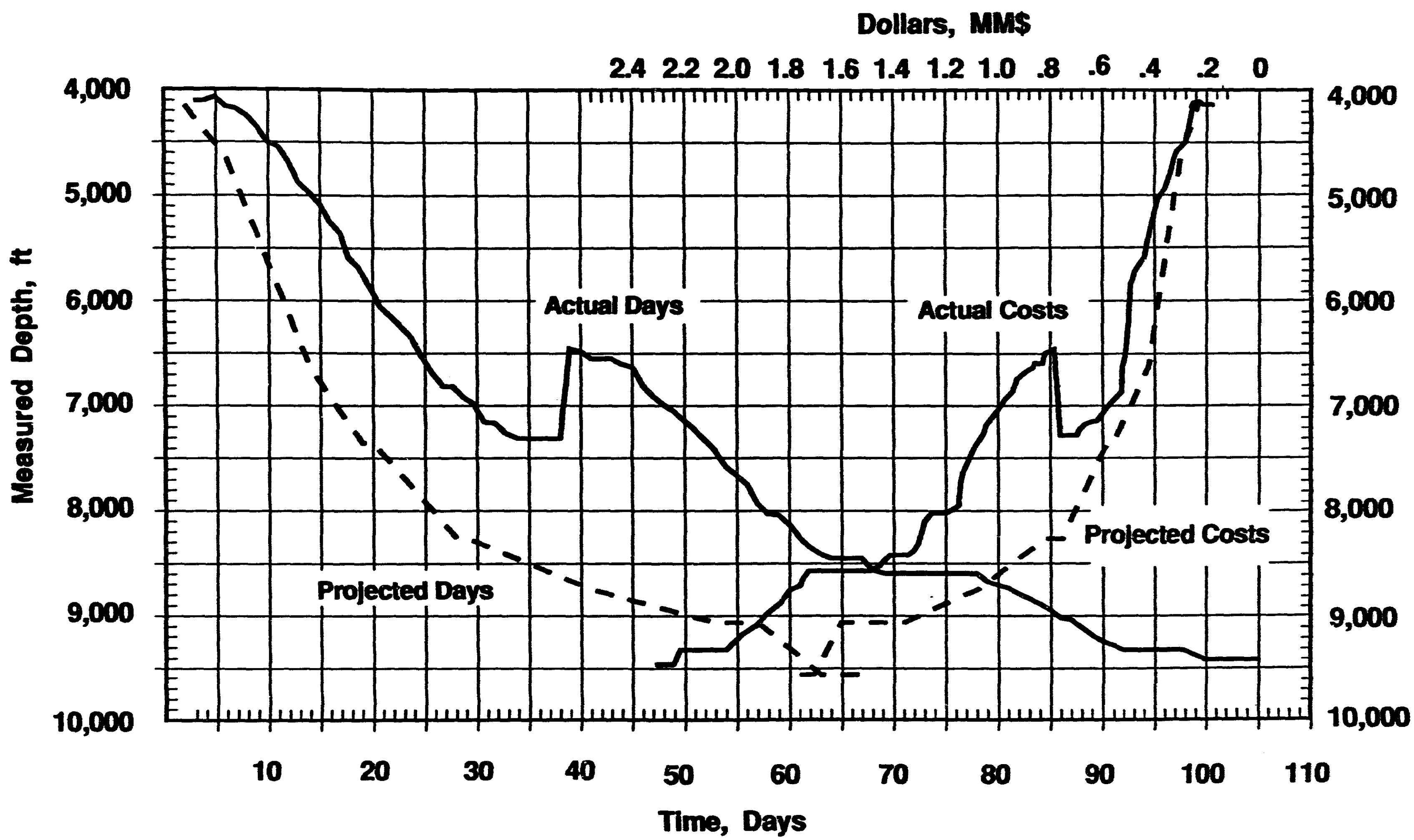


Figure 5-5 SHCT-1 Sidetrack, Depth Vs. Drilling Time Vs. Cost

Table 5-1 Drilling Time Summary, SHCT-1 Sidetrack

Cumulative Time Distribution	Hours
Drilling	1,041.25
Deviation Surveys	75.25
Trips	519.25
Reaming	160.00
Circulate & Condition Mud	147.25
RU and Run Casing and Liner	18.25
Install and Test BOP's, Casing, Remove, etc.	61.00
Control Pressure	79.25
Lost Circulation	0.00
Rig Maintenance	8.00
Rig Repair	3.75
Wireline Logging	40.50
Fishing	29.75
Washover Operations	10.75
PU, Lay Down Drill Collars, Pipe, Change BHAs	146.50
Wait On Orders, Equipment	0.00
Other	155.25
TOTAL	2,496.00

5.5 FORMATION TOPS, CASING DEPTHS AND TOTAL DEPTH

Table 5-2 presents the formation tops, casing depths and total depth of the SHCT-1 sidetrack.

Table 5-2 Formation Tops, Casing Depths and Total Depths, SHCT-1 Sidetrack

	Measured Depth, ft	TVD Depth, ft	MSL Elevation, ft
FORMATION TOPS			
Mesaverde	3,946	3,946	1,480
Rollins	8,120	7,550	-2,111
Cozzette	8,863	7,901	-2,462
CASING DEPTHS			
13-3/8-in. Surface	115	115	5,292
9-5/8-in. Intermediate	4,130	4,130	1,296
7-in. Production	8,588	7,780	-2,341
TOTAL DEPTHS			
Drillers' TD	9,407	7,948	-2,509

Note: SHCT No. 1 Elevation - 5,407 ft GL, 5,439 ft KB

5.6 MUD SYSTEM

A low solids, non-dispersed (LSND) mud system was chosen to drill the sidetrack hole. This system was chosen over an oil-base mud based on the excellent results with that mud while drilling the original slant hole. This highly-shear thinning system contained a minimum of solids for improved penetration rate along with minimum viscosity at the bit, resulting in maximum annular velocity for hole cleaning. The mud system had the following properties:

- pH at 9.0 to 9.5;
- 30-minute filtrates at 5 cc to 6 cc;
- mud weights maintained with barite to 16.4 PPG; and
- 8 percent diesel and a non-hydrocarbon lubricant to increase lubricity.

The rig was equipped with a fine-screened shale shaker, desander, desilter, mud cleaner, vacuum degasser, and a high capacity mud/gas separator (gas buster).

Figure 5-6 presents a plot of mud weight versus true vertical depth for the sidetrack and for the original slant hole.

5.7 DRILL PIPE-CONVEYED LOGGING PROGRAM

The log suite for the Paludal Mesaverde interval consisted of phasor induction spherically focused log, lithodensity, compensated neutron, gamma ray, and caliper tools. The first logging run for the SHCT-1 was attempted July 9, 1991, using wireline conveyed logging techniques. Problems with the logging tool malfunction and thickening of drilling fluid due to calcium contamination and heat precluded completion of wireline logging operations.

The second logging run was performed July 23, 1991, using drill pipe-conveyed logging techniques. The following services were provided by Schlumberger:

Service	Interval, ft
LithoDensity/Compensated Neutron Log with Gamma Ray and Caliper Logs	6,582 to 8,230
Phasor Dual Induction/Spherically Focused Log	6,582 to 8,230

The entire pipe-conveyed logging operation took approximately 18 hours; no major problems were encountered during either logging run, and log quality was excellent for the hole conditions. This operation required careful coordination between the rig and logging crews, since logging was performed while tripping drill pipe into and out of the hole.

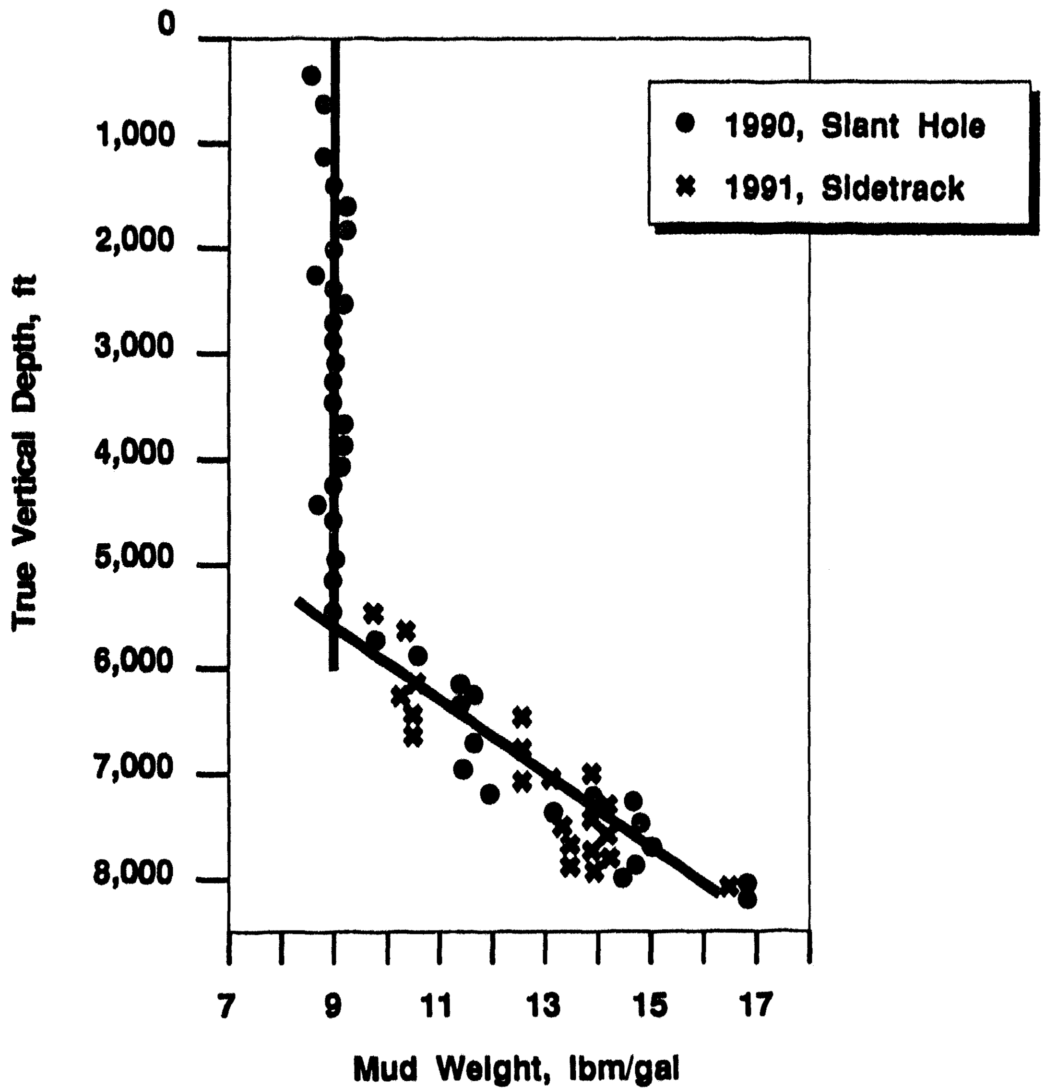


Figure 5-6 Mud Weight Vs. True Vertical Depth

MWD survey information was input to generate logs on true vertical depth for correlation purposes with offset wells; logs were also printed in measured depth format.

5.8 DIRECTIONAL SURVEY

Wellbore inclination and azimuth information in the build sections of the 8-3/4-in. hole between 6,450 and 8,588 ft was obtained using the Eastman Christensen 6-3/4-in. Accu-Trak Directional MWD System. Wellbore inclination and azimuth information in the 6-in. wellbore between 8,588 and 9,407 ft was obtained using the Eastman Christensen fully-retrievable 4-3/4-in. DMWD System.

5.9 DRILL BIT SUMMARY

The 8-3/4-in. hole from 4,160 to 8,588 ft was drilled with 20 insert bits and 1 natural diamond sidetracking bit. The insert type bits in the angle build and tangent section of the 8-3/4-in. hole were equipped with heel buttons and stabilizer lugs for gauge protection.

The 6-in. hole from 8,588 to 9,407 ft, through the second build and in the Cozzette horizontal section, was drilled with 7 insert type bits and 2 natural diamond bits.

6.0 SHCT-1 Sidetrack Completion Operations

6.1 INITIAL COZZETTE COMPLETION

At the completion of the brief flow test of the horizontal portion of the hole in the Cozzette Formation, a plug was set in the "R" nipple located below the model "DB" packer. A retrievable bridge plug was also set in the 7-in. casing at 8,372 ft as a safety precaution. The drilling rig was then released on August 24, 1991.

Operations to prepare the slant hole for testing and production operations were initiated December 10, 1991. A Halliburton acoustic cement bond log was run December 12 from 8,210 to 5,600 ft. The CBL/VDL generally showed 60 to 80 percent bond between 7,200 and 8,210 ft without any pressure on the wellbore. The addition of 1,500 psi pressure only marginally improved the quality of the cement bond log.

On December 12, 1991 partially dehydrated drilling mud was circulated out down to the retrievable bridge plug at 8,372 ft. The plug was retrieved without incident. Mud was then circulated from the hole from 8,372 ft to the top of the model "DB" packer at 8,456 ft. A 2-in. flush joint stinger assembly was picked up and run in the hole on 2-7/8-in. tubing to circulate mud from the 6.1-ft pup joint below the Model "DB" packer down to the top of the "R" plug.

A seal assembly was run on 2-7/8-in. tubing and stung into the model "DB" packer. The seal assembly was run in 6,500 lb compression, the tree was installed and successfully pressure tested, and the flare line was connected in preparation for flow testing the well.

Following an unsuccessful attempt on December 20, 1991, to wireline retrieve the "R" plug, a coiled tubing unit was moved on the well the following day; 160°F water was used to circulate out the last 6.1 ft of mud in the 2-7/8-in. tubing tail below the model "DB" packer. The equalizing pin was retrieved without incident using wireline-conveyed tools. This allowed the capability of flowing gas to surface through two 3/16-in. diameter equalizing ports in the "R" plug. Attempts to recover the "R" plug itself, with wireline-conveyed tools, were unsuccessful.

The remainder of December 1991 was occupied with construction of the 3-in. Schedule 40 lateral to the existing gas collection system and to install the 2-in. produced liquids dump line from the separator pad to the 400-bbl tank.

On January 2, 1992, a second attempt was made to retrieve the "R" plug using a coiled tubing unit. A 1-1/4-in. continuous coiled tubing was used to wash down to the top of the "R" plug at 8,472 ft. During this period, the well was flowed to the pit on an adjustable choke to allow easier access to the well with the coiled tubing. After pulling out of the hole in preparation for running the fishing tool on coiled tubing to retrieve the "R" plug, the choke seat and stem on the tree were checked for wear. A piece of the fishing neck from the "R" plug was found inside the choke receiver. At that time, it was decided to release the coiled tubing unit and flow test the well to see if the "R" plug had eroded away and, if present, how much its presence restricted flow from the Cozzette open hole.

On January 3, the well was flow tested on various size positive chokes, and an isochronal flow test was conducted in the Cozzette. The well was flowed from January 3 to January 9. Pipeline installation was also underway during this time. The results from this testing were inconclusive, primarily because the well had not sufficiently cleaned up at that time. The flow tests were hampered with line freeze-off and other problems. The decision was then made to cut off the tubing pup just above the "R" nipple to eliminate any conjecture about downhole restriction and the validity of future isochronal test information.

On January 9, 1992, Pomrenke Wireline Services rigged up under a 10,000 psi wp lubricator and ran a 2-1/4-in. diameter jet cutter, a casing collar locator, and 33 ft of sinker bars on wireline to the top of the "R" plug at 8,472 ft. The operator picked up 1 ft off the "R" plug, and cut off the 2-7/8-in. tubing just above the top of the "R" nipple. The operator picked up immediately, but the cutterhead, CCL, and sinker bars were stuck. The wireline was worked, came free, and moved up the hole about 40 ft where it again became stuck. After working the wireline several times, the wireline pulled out of the rope socket. On the way out of the hole, the wireline became hung up in the grease injector, jammed and parted, leaving approximately 3,000 ft of 7/32-in. diameter line hanging from the top of the lubricator, through the master valves, and into the well. The wireline BOPs would not sufficiently hold to allow removing the lubricator to replace the grease head and restring the wireline so that it could be pulled from the well.

It was decided to do a wellhead freeze to isolate wellbore pressure below the lower master valve; remove the lubricator; replace the grease injector; and restring the wireline preparatory to its recovery from the wellbore. The placement of the bentonite gel plug and actual wellhead freezing operations were undertaken January 11, 1992. The wireline was successfully recovered the next day.

The SHCT-1 was turned into the pipeline at 4 p.m. January 16, 1992, at 3,048 MCFD, 0 BOPD, 0 BWPD at 4,750 psi FTP. Production from the Cozzette zone in the SHCT-1 for January 1992 was 17,030 MCF (14.73 psia) and 100 BW.

About February 10, the well started producing water while producing at the rate of 3 MCFD. The initial water rate was around 80 BPD but gradually increased during the month until it was producing over 300 BPD at the 3.0 MMCFD rate. When the rate was dropped back to 2.0 MMCFD, the water production rate decreased to about 140 BPD.

The water analysis run on the samples collected during the month appear to be consistent. At this time, it was not sure if the water was from the Cozzette Formation or possibly from the Rollins Formation and channeling behind the casing.

Production from the Cozzette zone in SHCT-1 for February 1992 was 66,537 MCF (14.73 psia) and 3,154 BW.

The well was produced at rates between 2.5 and 3.0 MMCFD and 350 to 380 BWPD until 9 a.m. March 16, 1992, at which time the well was shut in for pressure buildup. The well was returned to production at 1 p.m. March 27, 1992, at a rate of 1.0 MMCFD and 38 BWPD.

Production from the Cozzette zone in SHCT-1 for March 1992 was 40,385 MCF gas (14.73 psia) and 5,264 BW.

The SHCT-1 was shut in at 8 a.m. April 13, 1992, for a pressure buildup prior to conducting an isochronal test to determine open flow potential. The four point test was initiated at 8 a.m. April 17, 1992, and was completed at 2 a.m. April 22, 1992.

Production from the Cozzette zone in SHCT-1 for April 1992 was 25,055 MCF gas (14.73 psia) and 325 BW.

Production from the Cozzette zone in SHCT-1 for May 1992 was 47,750 MCF gas (14.73 psia) and 3,597 BW.

The test data and deliverability plots are presented in Section 7.0 of this report.

6.2 WATER SHUT-OFF OPERATIONS

During the early part of June 1992, a tubing plug was run and set in the 2-7/8-in. tubing stub below the model "DB" packer. This isolated the Cozzette Formation below the packer. The tubing string was stung out of the packer and pulled. A retrievable bridge plug was set at 8,420 ft.

Because it was hypothesized that the produced water might be migrating into the Cozzette from formations above, it was decided to run several logs to determine if there was channeling and water movement behind the 7-in. pipe. The Cement Evaluation Tool (CET), TDT and Oxygen Activation Logs were run from 8,420 to 6,400 ft. The CET log indicated severe channeling behind pipe throughout the logged interval. The ACT log also indicated water movement behind pipe.

The lower Rollins interval was perforated from 8,274 to 8,276 ft and squeeze cemented in an attempt to shut off any water flow behind the 7-in. casing into the Cozzette from above. Two squeeze jobs were required before a satisfactory squeeze pressure was attained.

6.3 PALUDAL 2 STIMULATION OPERATIONS

After the squeeze cementing work to attempt to shut off the water above the Cozzette interval, work was initiated to stimulate production from the Paludal 2 interval. Because of the poor cement behind the 7-in. casing, it was necessary to block squeeze above and below the Paludal 2 interval before it could be hydraulically fractured.

The Paludal 2 interval was block squeezed through perforations at 7,761 to 7,762 ft and at 7,730 to 7,731 ft. Through each set of perforations, 8 to 9 bbl of class G cement slurry were successfully squeezed. A satisfactory squeeze pressure was achieved on both squeeze jobs.

On June 23, 1992, a hydraulic fracture treatment was performed in the Lower Cameo Coal section of the SHCT-1 Sidetrack well through perforations in the Paludal 2 sand between Coals 7 and 8. Schlumberger perforated at 7,732 to 7,734 ft (7,340 ft TVD) with 8 SPF for a total of 16 holes. The

37-gram charges produced an average hole size of 0.47 in. and a total penetration depth of 6 to 9 in. The gun was oriented to shoot top and bottom only.

Following perforating, the 7-in. casing was pressured up to 4,000 psi with the rig pump in an attempt to break down the perforations. No breakdown was achieved, and minimal leakoff was observed indicating that the perforations were surrounded by good cement.

The decision was made to run in with a 3-1/2-in. frac workstring and a treating packer to isolate the majority of the 7-in. casing from the anticipated high treating pressures. The treating packer was set with the bottom at 7,701 ft and 40,000 lb of slack off. Calculated displacement to the top perf was 68 bbl. The annulus was pressured up to 3,500 psi prior to pumping the injection tests and fracture treatment.

Extensive quality control measures were performed on the frac fluids on the day preceding the fracture treatment. Western Company utilized its mobile lab van to test the rheology and break times of its crosslinked gel using chemicals and water on location. An aggressive breaker schedule was designed to break the crosslinked gel in 1 hour following shut in.

A mini-frac was performed prior to pumping the main frac. The well was pressured up to 5,500 psi without breaking down the perforations and the pumps were shut down to observe leakoff. The pumps were then engaged, and the pressure increased to approximately 6,400 psi where the perforations began taking fluid. No traditional "breakdown" was observed. It appeared more like a fracture that was re-opening. Injection rates with 2 percent KCl water were increased to 20 BPM at 7,500 psi. The decision was made not to pump the 7-1/2-percent HCl since the perforations were taking fluid at reasonable rates and pressures. Prior to starting the delayed crosslinked gel, 20 bbl of 2-percent KCl water was pumped. Once crosslinked gel hit the perforations, the injection rate was increased to 25 BPM (@ 7,900 psi). The pumps were shut down after approximately 25 bbl of gel had passed the perforations. A 3,000 psi friction pressure drop was observed at 25 BPM. About 1,900 psi is attributed to pipe friction while the friction at the perforations (and near-wellbore) is estimated at 1,100 psi. Another 25 bbl of crosslinked gel was pumped at 30 BPM (@ 8,400 psi) followed by a second shutdown. A friction pressure drop of about 3,600 psi was observed at 30 BPM (2,350 psi pipe friction and 1,250 psi at the perforations).

The ISIP following each shut-in was approximately 5,000 psi which corresponds to a fracture gradient of 1.12 psi/ft. The anticipated minimum stress gradient around the 60° deviated wellbore was 1.14 psi/ft based on an in-situ stress gradient of 0.85 psi/ft. Since the stresses observed were similar to those which were estimated and the near wellbore friction was not extremely high, the decision was made to pump the fracture treatment as designed.

The job was pumped according to the design. The total load water to recover including the 67 bbl flush and the mini-frac was 1,192 bbl.

The Paludal 2 sand and surrounding coals in the 60° hole was hydraulic-fracture stimulated through 16 perforations between 7,732 and 7,734 ft using 5,000-lb 100 mesh sand, 76,500-lb 20/40 sand, and 30,000 lb of resin-coated 20/40 sand carried in 43,512 gal of crosslinked gel. The average treating rate was 30 BPM at a surface treating pressure of 8,200 psi. The well was fractured on June 23, 1992, and then cleaned up by flowing to the pit through July 8, 1992.

On July 8, 1992, a Stop Work Order was issued by DOE to conserve remaining funds until it could be determined if FY 1993 funds would be available to complete the upper Cameo (Paludal 3 and 4 sands and surrounding coals) stimulation and testing activities. At this time, all field activities ceased. The wellhead was installed, the service unit and all rental equipment was released, and the well was reconnected to the pipeline for flow testing.

The test data and analysis are presented in Section 8.0 of this report.

6.4 PALUDAL 3 AND 4 STIMULATION OPERATIONS

Work was initiated on January 13, 1993, to complete the stimulation of the Paludal 3 and 4 intervals. A bridge plug was set above the Paludal 2 perforations at 7,520 ft, and the Paludal 3 and 4 interval was block squeezed. The squeeze intervals were 7,510 to 7,511 ft and 7,385 to 7,386 ft. Each interval was squeezed with 8 bbl of class G cement with a satisfactory squeeze pressure obtained on each set of perforations.

A hydraulic fracture treatment was performed in the Paludal 3 and 4 zones of the SHCT-1 Sidetrack on January 22, 1993. The well was perforated across the Paludal 4 sand at 7,386 to 7,388 ft (7,154 ft TVD) with 8 SPF for a total of 16 holes (34 gram, 0.5-in. diameter). The perforations were phased at 180° and oriented to the high and low side of the wellbore (0° and 180°) using spring decentralizers.

A 3-1/2-in. frac workstring and a 7-in. treating packer were utilized during the fracture treatment to isolate the 7-in. casing from the expected high treating pressures. The packer was set at 7,345 ft, and 2,800 psi was applied to the annulus using the rig pump.

Western Company utilized its mobile lab van to test the crosslink times and break times of its gel using chemicals and water on location. An aggressive breaker schedule was designed to break the cross-link gel in 1 hour following shut-in.

A breakdown and injection test (mini-frac test) using 25 bbl of 2 percent KCl water was pumped ahead of the main fracture treatment. The perforations broke down at 5,700 psi and the remainder of the KCl water was pumped at 15 BPM at about 7,100 psi surface pressure. The instantaneous shut-in pressure (ISIP) following the breakdown was 3,600 psi (0.94 psi/ft). Based on the pressures observed, the decision was made to pump the main fracture treatment as designed.

The fracture treatment consisted of pumping 5,000 lb 100 mesh, 160,000 lb of 20/40 Ottawa sand and 30,000 lb of resin-coated sand (tail-in) in 1,790 bbl of crosslinked gel at a rate of 30 BPM and a maximum proppant concentration of 5.0 ppg.

A radioactive tracer (Iridium 192 beads) was included during the sand stages to help evaluate the effectiveness of the fracturing treatment (i.e., the placement of the proppant).

There was a total of 1,964 bbl of fluid to recover; at the end of January, 1,158 bbl had been recovered. The well was flowed and swabbed to cleanup until January 30, 1993.

The SHCT-1 was produced 4.03 MMCF of gas into the sales line during February. As of the end of February, 1,158 of the 1,964 bbl of frac fluid had been recovered. The Paludal 3 and 4 interval produced at a rate of 100 to 150 MCFD. On March 3, 1993, a service rig was moved in and the tubing was pulled. A gamma ray log was run over the interval from 7,375 ft to 7,200 ft. The only indication of radioactive tracer was at the perforations and about 10 ft above. The hole was run in with a perforating gun and was perforated from 7,442 to 7,462 ft with 4 JSPF. Tubing was rerun with a packer, and the packer was set at 7,364 ft. The well was put back on production March 4, 1993. No significant increase in production was noted from the additional perforations.

The Paludal 3 and 4 zone was produced to the gas sales line until March 17 at which time it was shut in for a pressure buildup test. The shut-in tool was unable to reach bottom, so the well was flowed until 7 a.m. the next day and shut in again. The bottomhole pressure gauge was landed at 7,235 ft because the seating nipple was unreachable at 7333 ft. The well was shut-in until March 24 at which time it was blown down to start work to re-enter the Cozzette interval.

The test data and analysis are presented in Section 8.0 of this report.

6.5 RECOMPLETION TO THE COZZETTE

A workover rig was moved on March 25, 1993. The wellhead was nippled down, BOPs were installed and work began on drilling out cement retainers, cement and bridge plugs. There are three sets of retainers, cement and bridge plugs to be drilled up before getting to the retrievable bridge plug above the Cozzette.

The plugs were drilled up, the retrievable bridge plug was recovered and a new bottomhole assembly was run. The bottomhole assembly consisted of the model "D" seal assembly to sting into the existing model "DB" packer at 8,456 ft, an "R" nipple, hydraulic set packer, an "EF" nipple, "On/Off" tool, and a sliding sleeve. Figure 6-1 is a diagram of the new bottomhole assembly. This assembly was run on 2-7/8-in. tubing. The seal assembly was stabbed into the model "DB" packer and the hydraulic set packer was set. The tubing was then unlatched from the On/Off tool and the well was blown dry using nitrogen. The tubing was then reset in the On/Off tool and the tubing landed in tension in the wellhead. The tubing stub was perforated over a two-foot interval just above the plug in the bottom of the tubing below the model "DB" packer. The tubing was perforated under 2,300 psi surface pressure. After perforating, the pressure dropped to approximately 2,150 psi. On April 10, 1993, the Cozzette was put on production at approximately 2.0 MMCFD. The remainder of the month was spent testing the Cozzette for water and gas production.

Work has been completed on the well. The well has been configured to allow production of both the Paludal intervals up the tubing/casing annulus and the Cozzette up the tubing. The Cozzette interval continues to produce large volumes of water along with the gas. Figure 6-2 is a drawing of the present wellbore configuration.

The test and production data analysis are presented in Section 7.0 of this report.

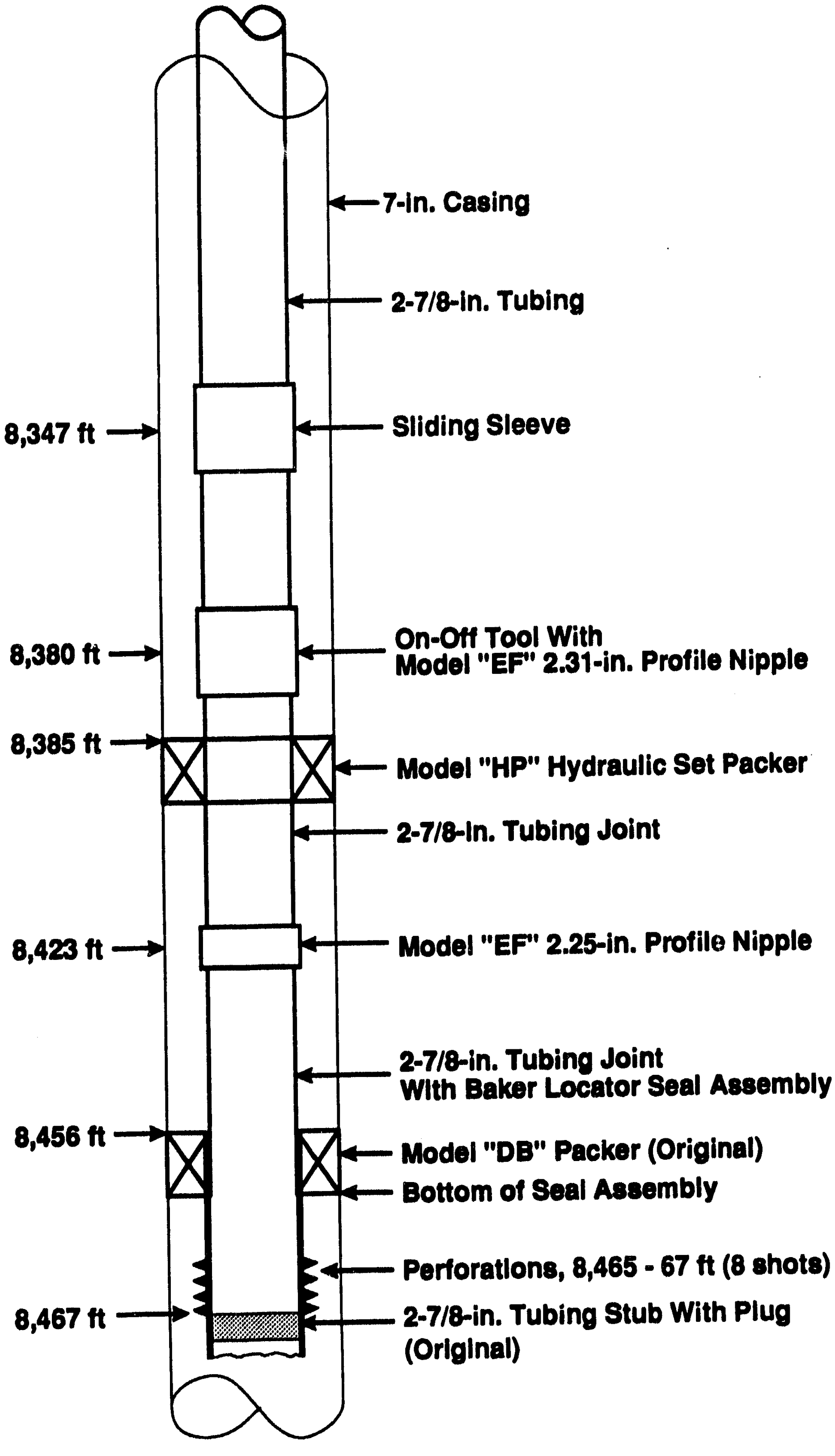


Figure 6-1 Present SHCT-1 Bottomhole Assembly

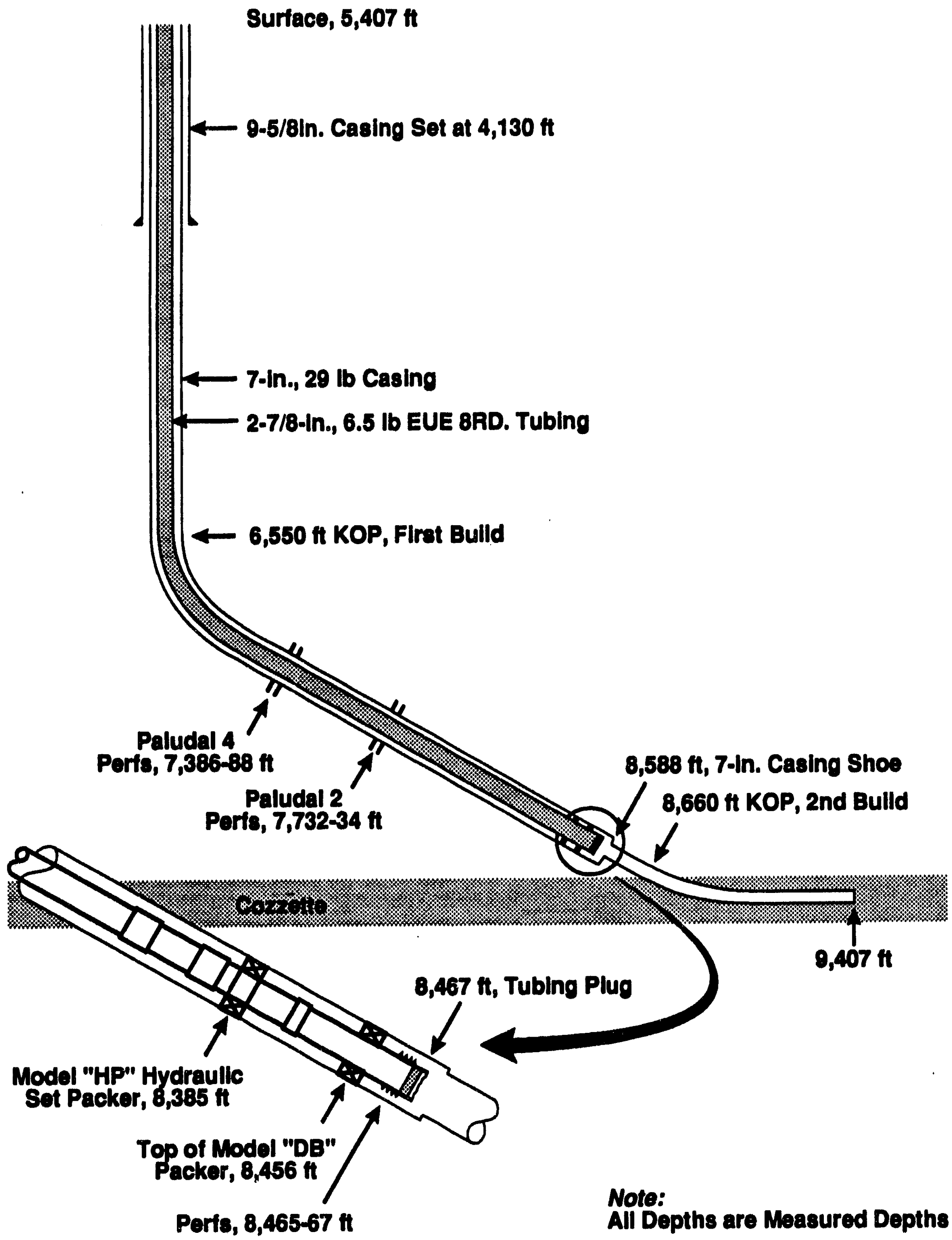


Figure 6-2 Present SHCT-1 Completion Profile

7.0 Cozzette Testing and Analysis

7.1 COZZETTE INITIAL FLOW TESTING

The SHCT-1 Sidetrack was completed into the Cozzette in December 1991 and testing was initiated in January 1992. The first test was a modified flow test was performed on January 3, 1992. Initial shut-in tubing pressure was 4,800 psi. Since the produced gases were to be flared, rates in excess of the proposed pipeline production rates were possible. Figure 7-1 is a deliverability plot of this production test data and includes the measured surface tubing pressure and calculated surface gas rates through a series of fixed chokes. It is felt that the calculated Absolute Open Flow (AOF) value of 15.3 MMCFD is too high, primarily because the flow was not stabilized; also there is reason to believe the initial bottomhole pressure that was used may also have been too high.

The presence of liquids during testing precludes extensive analysis of this data. It is clear, however, that the production potential was substantially higher than that experienced with vertical Cozzette completions in the Rulison Field.

An initial Cozzette bottomhole pressure of 6,250 psi had been measured during extensive well testing operations involving the adjacent MWX wells[8]. The 5,350 psi wellhead pressure measured at SHCT-1 on December 31, 1991, converts to 6,189 psi at Cozzette depth (7,925 ft TVD) using a static dry gas gradient. This calculated pressure is in good agreement with the MWX measurement for original Cozzette pressure. The validity of the December 31, 1991, wellhead pressure measurement is questionable; however, since all subsequent maximum static wellhead pressure measurements were in the range of 4,800 to 4,850 psi. These pressures are consistent with the estimated reservoir pressure measured in the April 1992 Cozzette buildup.

A second flow test was conducted on January 13, 1992, following the tubing cutoff operation. Initial shut-in tubing pressure was 4,800 psi. Figure 7-2 is a deliverability plot of this production test data and includes the measured surface tubing pressure and calculated surface gas rates through a series of fixed chokes. Again it is felt that the AOF value of 12.3 MMCFD is too optimistic, again for the same reasons sighted above. This test does confirm that SHCT-1 is highly productive and capable of producing at gas rates in excess of 5 MMCFD. It should also be noted that both the initial and supplementary flow tests began to show water production at wellhead pressures below 4,000 psi.

The SHCT-1 was turned into the pipeline at 4 p.m. January 16, 1992, at 3,048 MCFD, 0 BOPD, 0 BWPD at 4,750 psi FTP. Production from the Cozzette zone for the month of January 1992 was 17,030 MCF (14.73 psia) and 100 BW. The well was shut-in on January 31, 1992, for an upgrade to separation equipment.

The Cozzette was put back on production on February 2, 1992. Flow was maintained at approximately 2.0 MMCFD at a wellhead pressure of 4,450 to 4,500 psi until February 5, 1992. Flow rates were increased and ranged from 3.0 to 4.2 MMCFD. Wellhead pressures ranged from 3,800 to 4,300 psi during flows. Water production was first measured in significant quantity during this flow period. On February 5, 1992, 24 BW was metered during 14 hours of flow at rates between 3.0 and 3.5 MMCFD. Water production subsequently increased to 80 BPD on February 10, 1992. Gas rates on

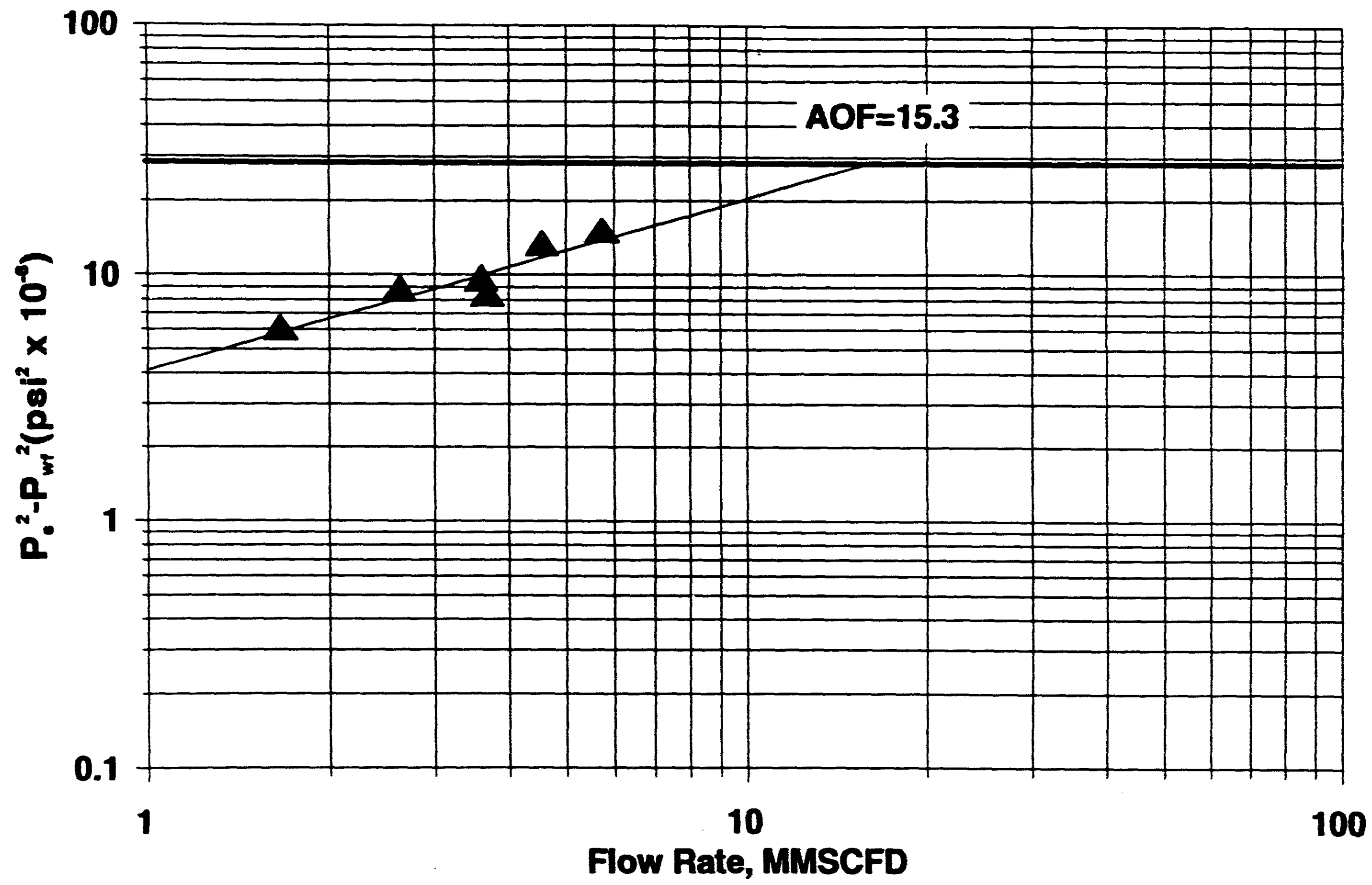


Figure 7-1 SHCT-1 Deliverability Plot, January 3, 1992

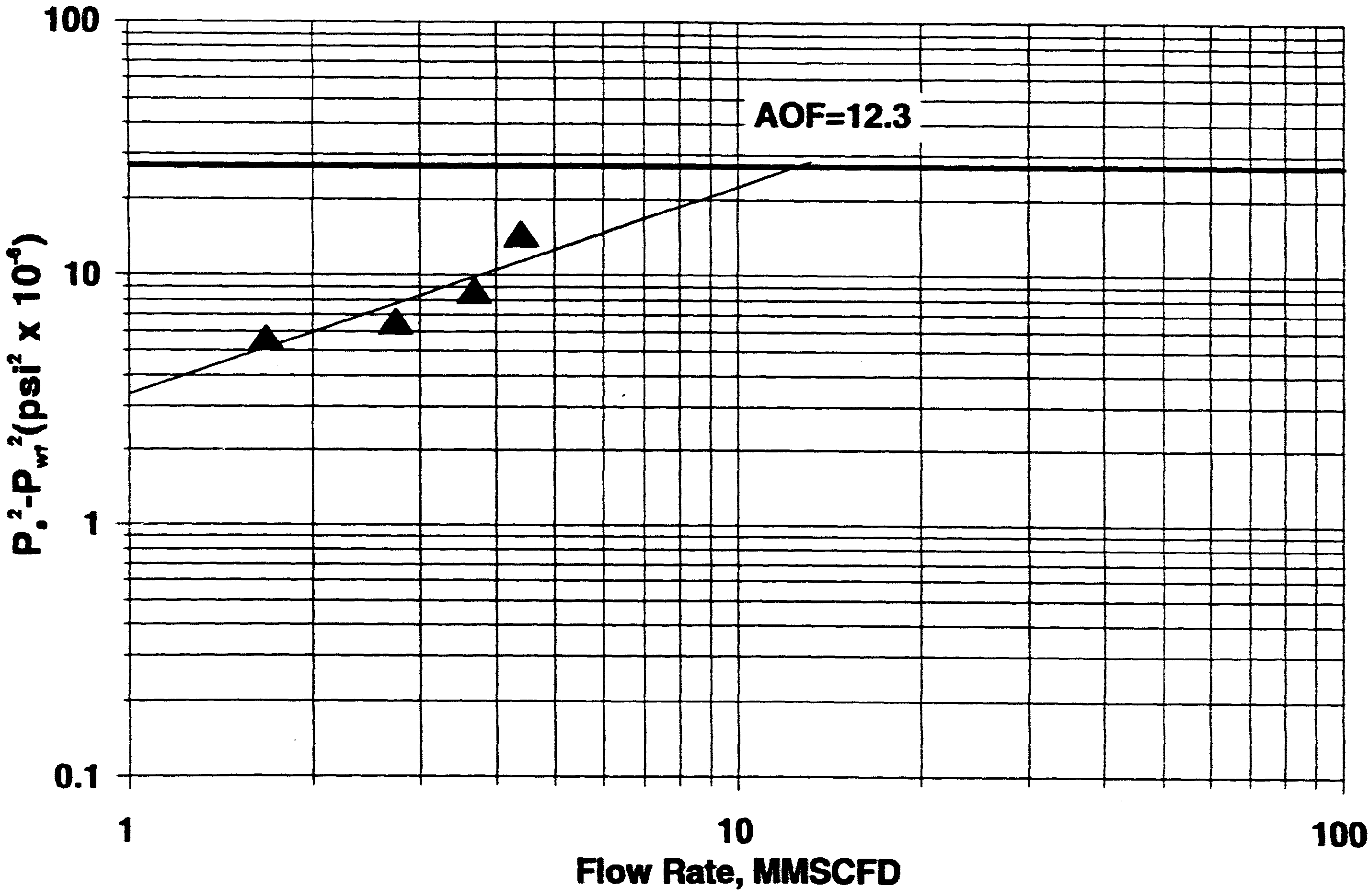


Figure 7-2 SHCT-1 Deliverability Plot, January 13, 1992

this date fluctuated between 2.8 and 4.2 MMCFD, and wellhead pressures fluctuated between 3,800 and 4,200 psi. Gas flow rates were then maintained at 3.0 MMCFD. Wellhead pressures declined steadily to 3,350 psi, and water rates increased steadily to 258 BPD on February 22, 1992. Gas flow rate was then decreased to 2.0 MMCFD. Wellhead pressures rose to 3,700 psi, and water rates declined steadily to 134 BPD on February 27, 1992.

Production from the Cozzette zone in SHCT-1 for the month of February 1992 was 66,537 MCF (14.73 psia) and 3,154 BW.

During early March 1992, flow rate was increased to between 2.5 and 3.0 MMCFD. Wellhead pressures dropped to 3,100 psi by March 15, and water rates increased steadily to 406 BPD on the same date.

On March 15, the well was shut-in and allowed to build up. Surface shut-in pressure on March 26 was 4,680 psi. A gradient survey was attempted on March 26; however, the pressure bomb could not be lowered past 7,590 ft. An analysis of the gradient survey data did not indicate the presence of a liquid column in the wellbore above 7,590 ft. Maximum bottomhole pressure measured was 5,366 psi at 7,590 ft.

From March 27 through April 13, 1992, gas flow rate was maintained at approximately 1.0 MMCFD. Flowing tubing pressure stabilized at 4,140 psi. Water rates were stable at 10 to 20 BPD at the end of the test period.

Production from the Cozzette zone in SHCT-1 for March 1992 was 40,385 MCF gas (14.73 psia) and 5,264 BW.

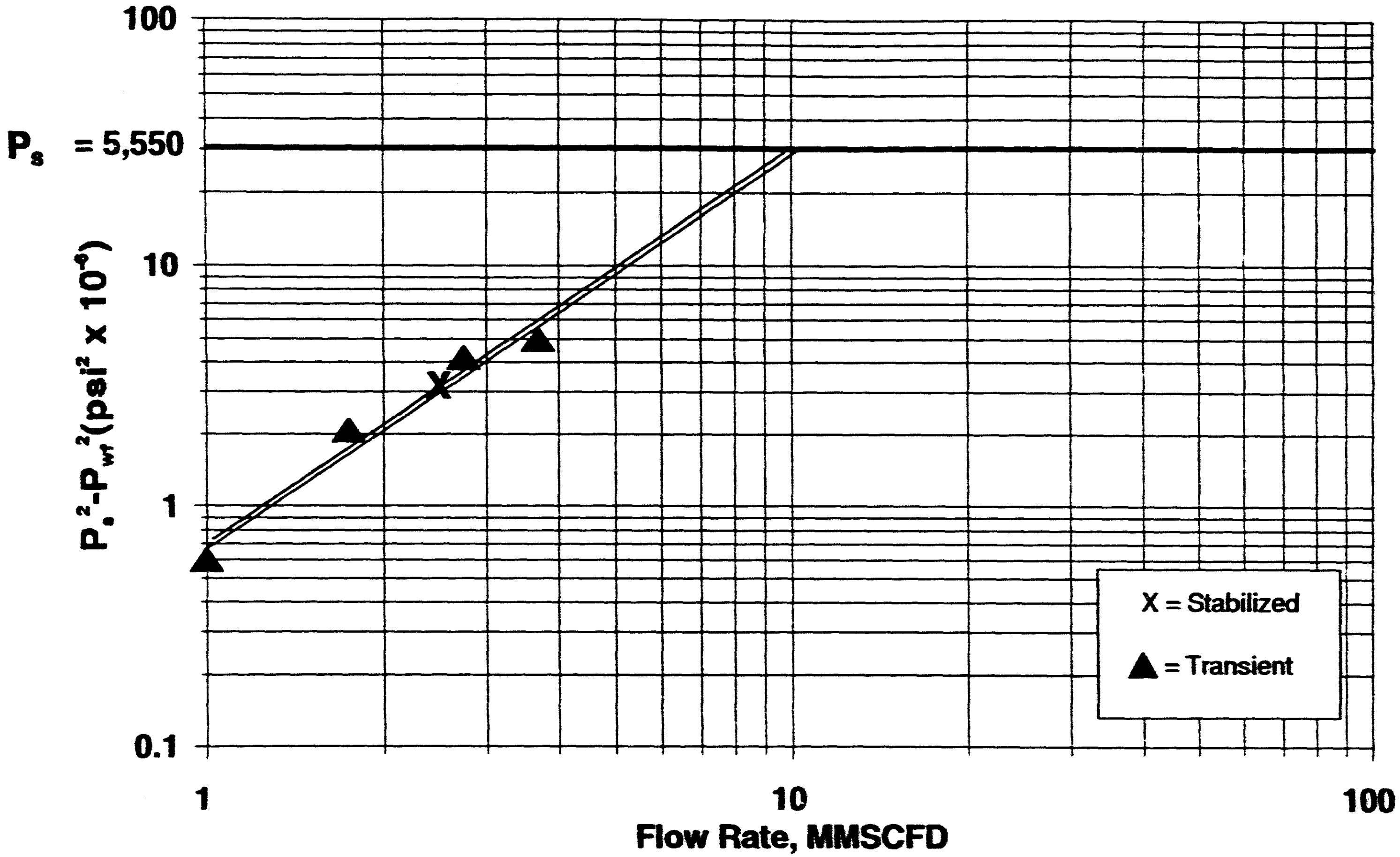
7.2 MODIFIED ISOCHRONAL TEST (April 14 through April 20, 1992)

A modified isochronal test was performed on April 17 to 18, 1992. The data was taken with Kuster gauges located at 7,250 ft. Prior to the flow tests, the well was shut-in for 4 days from April 14 through April 17. Initial shut-in bottomhole pressure was 5,415 psi. Flow and shut-in periods during the test were six hours in length. Figure 7-3 is a deliverability plot graph of the test data. All pressures were measured at 7,250 ft. Based on the modified isochronal test, the absolute open flow potential of SHCT-1 was estimated to be 10.0 MMCFD.

7.3 COZZETTE BUILDUP (April 21 through April 28, 1992)

A shut-in buildup test was recorded with Kuster gauges located at 7,250 ft. Maximum bottomhole buildup pressure at 7,250 ft was 5,500 psi after 177 hours. Figure 7-4 is a plot of the buildup in Horner time. Although the data quality is poor, some observations can be made.

Qualitatively, the pressure derivative appears to behave in a manner consistent with dual porosity reservoirs. If it is assumed that combined radial flow is effective at the end of the buildup, the extrapolated Horner buildup pressure would be 5,550 psi. Assuming a dry gas gradient, this is equivalent to a wellhead pressure of 4,830 psi. Analysis of this data is complicated by the fact that the depletion pattern in the Cozzette at SHCT-1 is probably not uniform due to the anisotropy of the



Calculated AOF = 9.636 MMSCFD
n = 0.6039

Figure 7-3 SHCT-1 Modified Isochronal Test, April 17-18, 1992

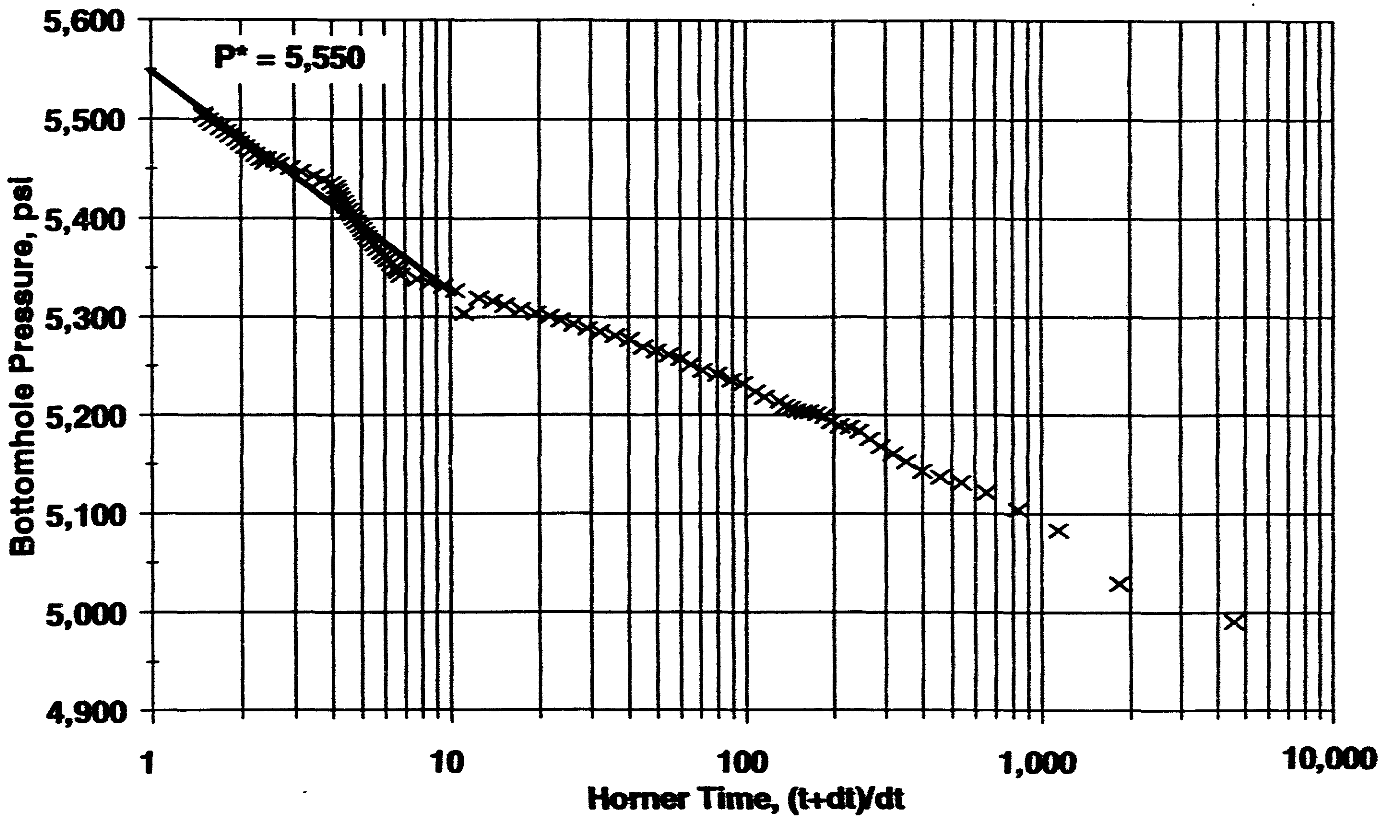


Figure 7-4 SHCT-1 Cozzette Buildup in Horner Time, April 21-28, 1992

natural fracture system[8]. Analysis is further complicated by an unknown source of water production and the mechanics of multiphase flow.

Wellbore pressure gradients measured after the buildup do not indicate a liquid column in the wellbore above the pressure bomb at the end of the test.

7.4 COZZETTE PRODUCTION TESTING (April 28 through June 2, 1992)

After the buildup test, gas production was maintained at a rate of 2.0 MMCFD. Wellhead pressures during this test period declined slowly to 3,899 psi. Water production rates stabilized at 62 to 67 BPD by May 7.

Production from the Cozzette zone in SHCT-1 for April 1992 was 25,055 MCF gas (14.73 psia) and 325 BW.

Gas production rates were increased to 3.0 MMCFD. Water production rates immediately increased to 187 BPD and continued to rise during the test period. Water production rate on May 11 was 397 BPD. Wellhead pressures had decreased to 2,948 psi over the same period.

Gas production rates were reduced to approximately 2.0 MMCFD. Water rates ranged between 348 and 355 BPD. Wellhead pressure stabilized at 3,180 psi.

On May 13, gas production rates were reduced to approximately 1.0 MMCFD. Water production ranged from 27 to 62 BPD. Wellhead pressures increased to approximately 3,800 psi by the end of the flow period. Production from the Cozzette zone in SHCT-1 for May 1992 was 47,750 MCF gas (14.73 psia) and 3,597 BW. Figure 7-5 is a plot of daily Cozzette gas and water production for 1992, and Figure 7-6 is a plot of average daily wellhead pressures for that period.

On June 3, 1992, a tubing plug was run and set in the 2-7/8-in. tubing stub below the model "DB" packer. This isolated the Cozzette Formation below the packer. The Cozzette zone would not be re-entered until after the completion of the stimulated and testing of the two Paludal intervals. The Cozzette was put back on production on April 12, 1993.

7.5 COZZETTE TESTING (April 12, 1993 through June 3, 1993)

On April 12, 1993, the Cozzette was put on production at approximately 2.0 MMCFD. Rates between April and June generally ranged from 1.0 to 1.7 MMCFD. Water production rates increased to 140 to 180 BPD by April 26 with corresponding wellhead pressures of 3,200 to 3,300 psi. Water/gas ratios deteriorated during May despite attempts to keep gas rates below 1.0 MMCFD. On June 6, 1993, gas flow rates were 350 to 425 MCFD at a wellhead pressure of 2,650 psi. The corresponding water rate was 251 BPD. Figure 7-7 is a plot of daily Cozzette gas and water production for 1993, and Figure 7-8 is a plot of average daily wellhead pressures covering the same period.

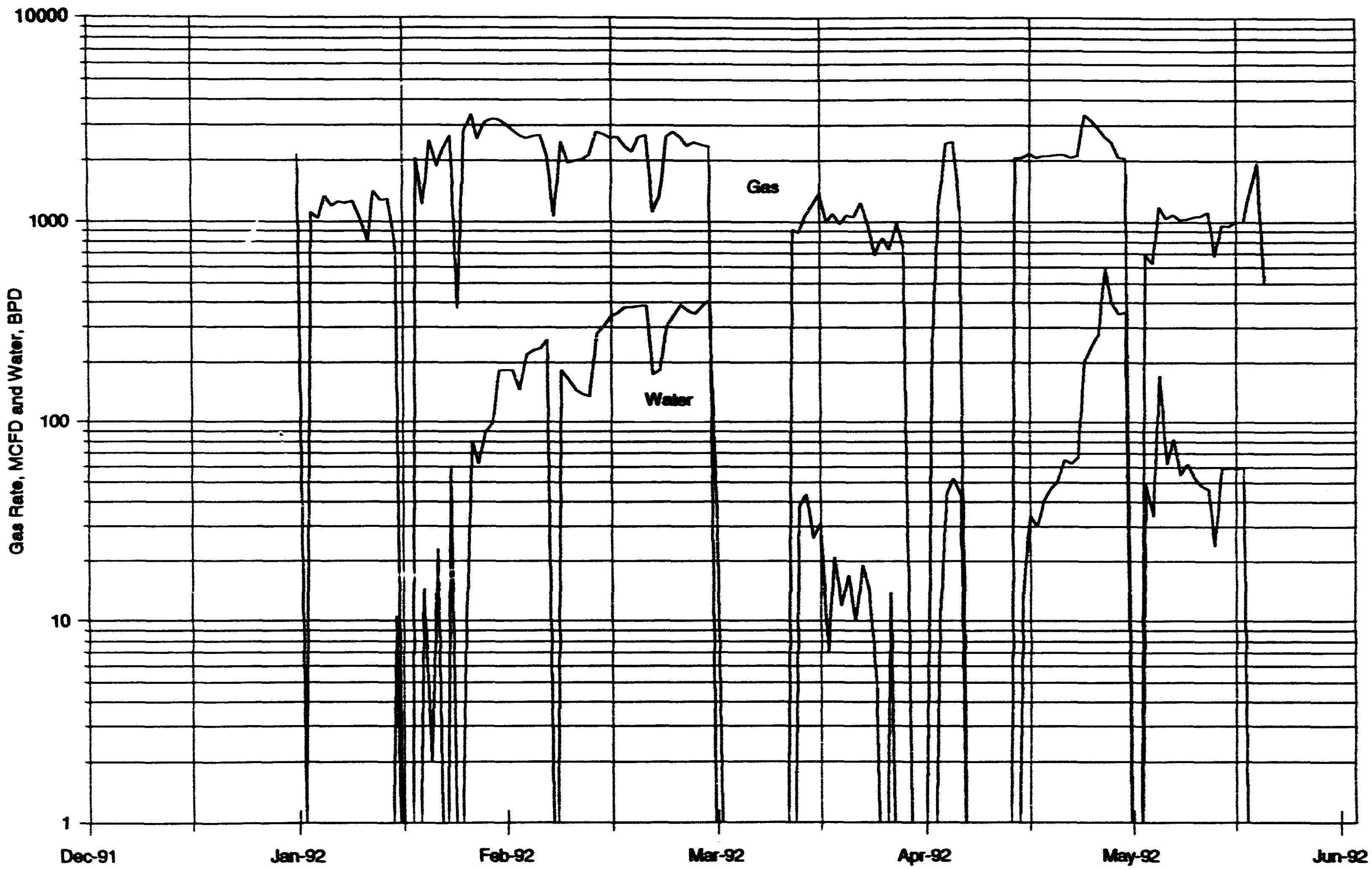


Figure 7-5 SHCT-1 Cozzette Gas and Water Production, January 1, 1992 - June 1, 1992

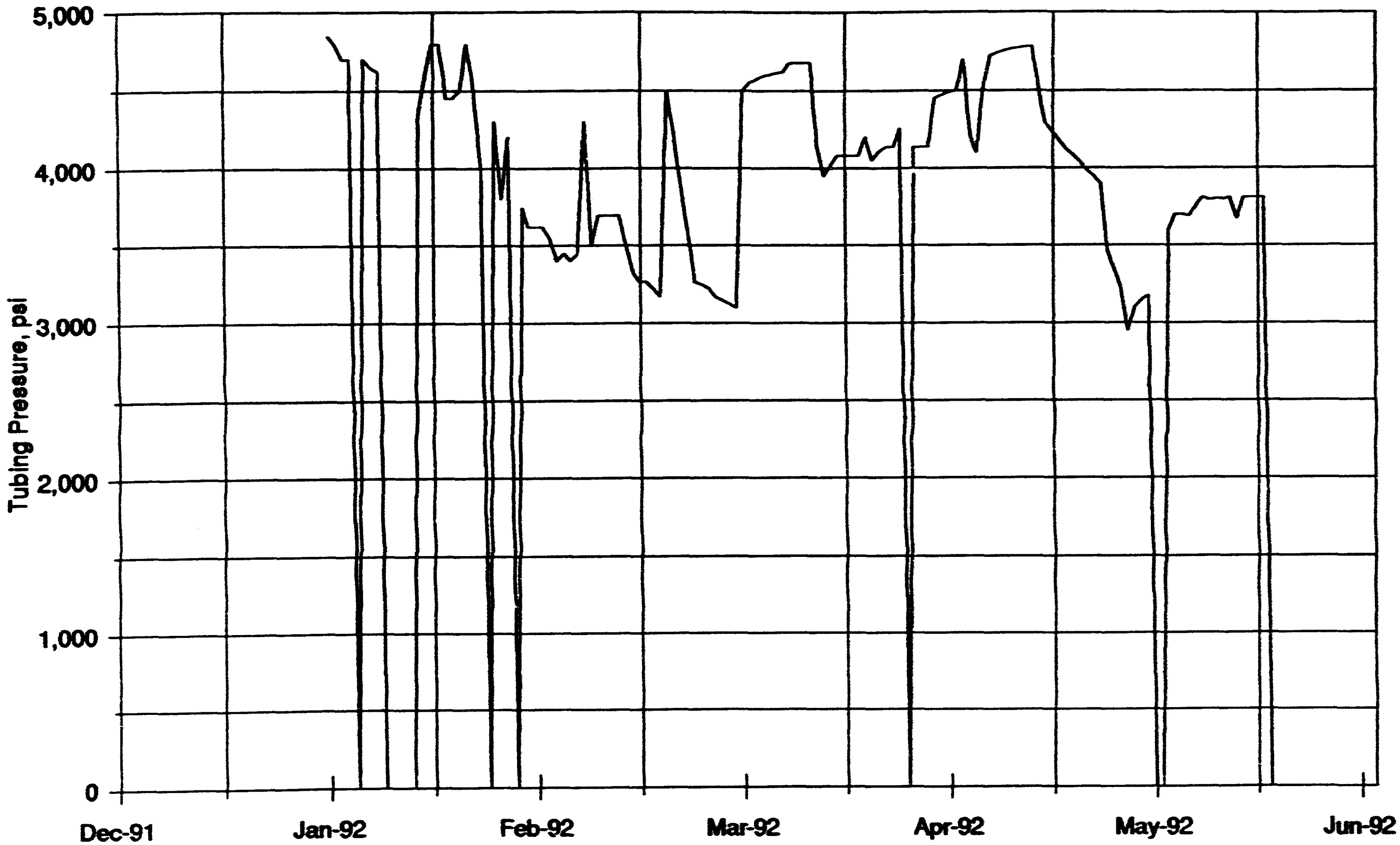


Figure 7-6 SHCT-1 Cozzette Wellhead Pressures, January 1, 1992 - June 1, 1992

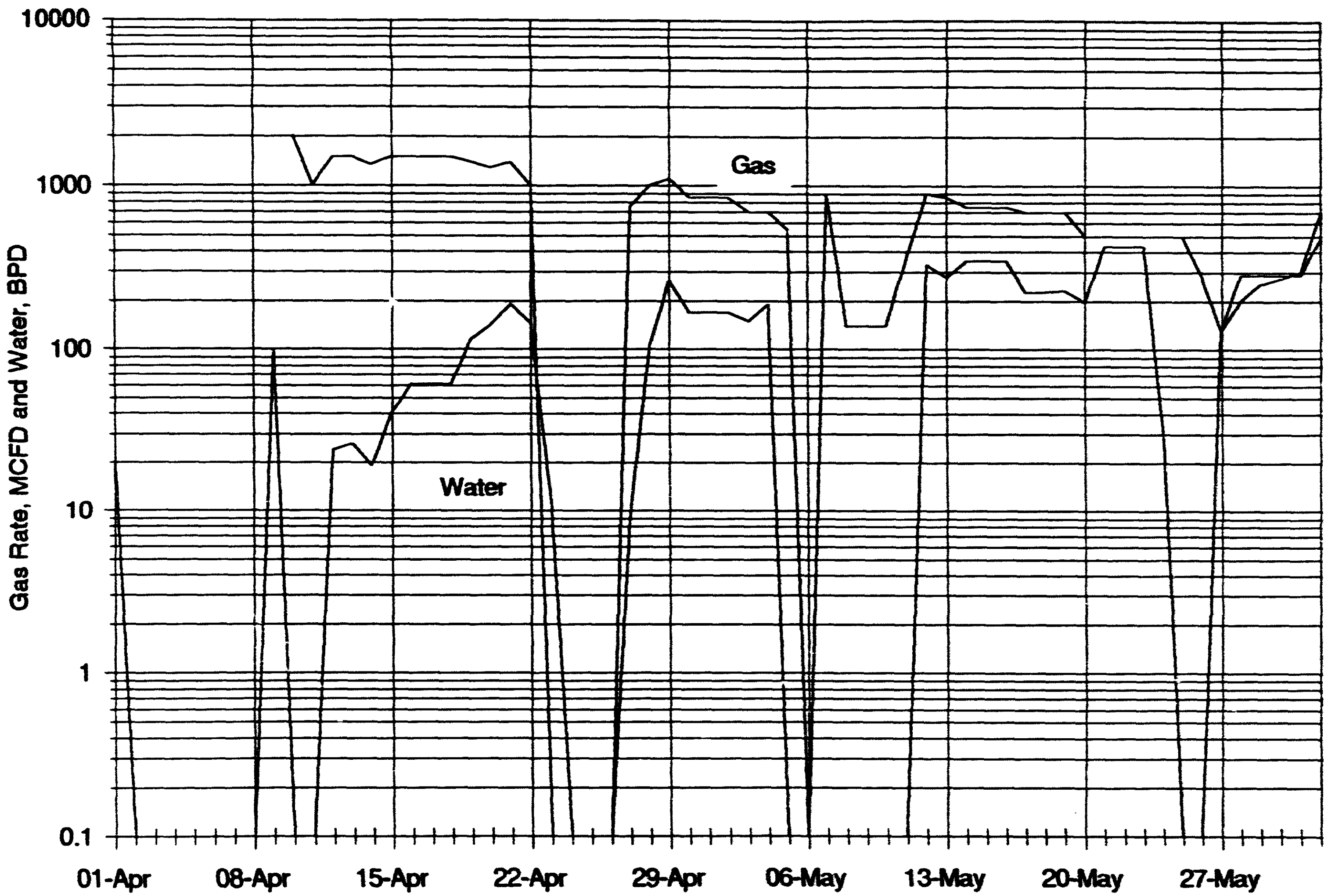


Figure 7-7 SHCT-1 Cozzette Gas and Water Production, April 1, 1993 - June 1, 1993

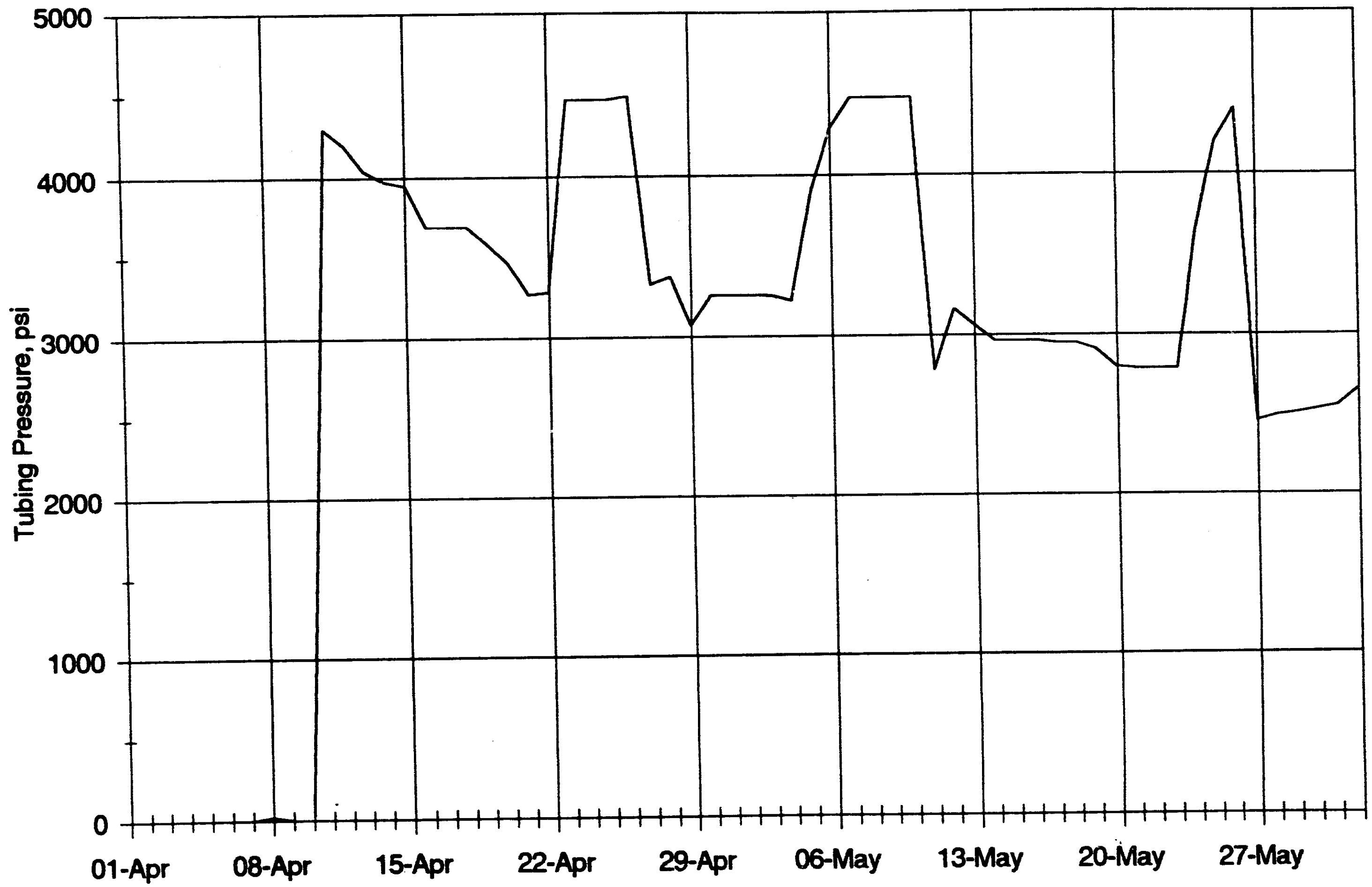


Figure 7-8 SHCT-1 Cozzette Wellhead Pressures, April 1, 1993 - June 1, 1993

7.6 COZZETTE WATER PRODUCTION

Recent horizontal wells drilled in the Rulison Field have experienced significant water production as well as significant gas production. The CER SHCT-1 Sidetrack in Section 34, T6S, R94W produced as much as 600 BWPD. The Meridian 43-33 Quarter Circle well in Section 33, T6S, R94W produced as much as 1,800 BWPD. This water production is a very serious problem and threatens the viability of horizontal drilling as a mechanism for enhancing gas production from low-permeability reservoirs in the Rulison Field.

It is not known for certain whether the water produced from the Rulison Field horizontal wells is being sourced from the Cozzette. Another possibility is that water is being sourced via mechanical communication with water reservoirs which overlie the Cozzette. The nature of the water production mechanism is not clearly understood, particularly in view of the fact that nearby vertical Cozzette completions have produced for many years without significant water production.

Relationship of Gas and Water Trapping to Structure

It is well known that the Piceance Basin traps gas downdip of water. This style of gas trapping has analogy to the San Juan Basin in New Mexico, the Deep Basin in Alberta, Canada, and the majority of Rocky Mountain basins. Trapping gas downdip of water is a specialized type of stratigraphic trapping mechanism and in general requires low-permeability so the buoyancy effect is minimized. In the Piceance Basin, gas is presently being generated in downdip areas of the basin.

In the Rulison Field, the Cozzette and Corcoran Sandstones and adjacent strata are actively generating gas. Gas trapping is fairly efficient and results in significant overpressuring, with pressure gradients up to 0.78 psi/ft. The Rollins Sandstone and underlying Mancos Tongue are also actively generating gas; however, the depositional character of this sand is relatively more homogeneous and much of the gas that is being generated moves laterally through the Rollins, escaping updip. Consequently, reservoir pore pressures within the Rollins, while still overpressured, are significantly lower than in the Corcoran and Cozzette.

Vertical gas wells completed in Corcoran and Cozzette reservoirs in the Rulison Field have not experienced significant water production. The MWX-1 well in Section 34, T6S, R94W has significant overpressuring in the Corcoran and Cozzette and did not produce significant water from the Cozzette. Because of this overpressured condition and the failure to produce water, until the last few years, it was commonly believed that the water saturation of these reservoirs is at or is near irreducible. Occasional water production problems, such as from the Clough 21 well in Section 20, T6S, R94W were thought to be related to mechanical communication with other reservoirs. In any case, there was no clear relationship of water production to structure.

Possible sources of water production from the SHCT-1 include:

- Water migration via one or more faults penetrated by the horizontal wellbore.
- Water migration behind pipe from zones above the Cozzette.
- Water production into the Cozzette fracture system from the rock matrix.

8.0 Paludal Testing and Analysis

8.1 PALUDAL 2 STIMULATION

The Paludal 2 sand and surrounding coals in the 60° hole was hydraulic fracture stimulated through 16 perforations between 7,732 and 7,734 ft using 5,000 lb 100 mesh sand, 76,500 lb 20/40 sand, and 30,000 lb resin-coated 20/40 sand carried in 1,036 bbl of crosslinked gel. The average treating rate was 30 BPM at a surface treating pressure of 8,200 psi. The well was fractured on June 23, 1992, and then cleaned up by flowing to the pit through July 8, 1992.

On July 8, 1992, a Stop Work Order was issued by DOE to conserve remaining funds until it could be determined if FY 1993 funds would be made available to complete the upper Cameo (Paludal 3 and 4 sands and surrounding coals) stimulation and testing activities. At that time all field activities ceased. The wellhead was installed, the service unit and all rental equipment was released, and the well was reconnected to the pipeline for flow testing.

8.2 PALUDAL 2 TESTING (July 9, 1992 through January 13, 1993)

Initial flow rates ranged from 20 to 80 MCFD. Initial flowing wellhead pressure was 500 psi. Wellhead pressures averaged 250 to 450 psi during this flow period. By January 13, 1993, 1,305 bbl of the initial 1,570 bbl fluid load had been recovered.

Figure 8-1 is a plot of daily Paludal 2 gas and water production from June 1992 through January 1993, and Figure 8-2 includes average daily wellhead pressures.

Because of the poor production performance from this interval, (averaging approximately 40 MCFD during the entire flow period), the decision was made to discontinue testing and move up to the Paludal 3 and 4 interval. No analysis of fracture length or conductivity was possible. However, based on the performance data, it is apparent that the fracture treatment was ineffective. No data is available to compare this interval in the Slant Hole to that in a nearby vertical well.

8.3 PALUDAL 3 AND 4 STIMULATION

Work was initiated on January 13, 1993, to complete the stimulation of the Paludal 3 and 4 intervals. A bridge plug was set above the Paludal 2 perforations at 7,520 ft, and the Paludal 3 and 4 interval block was squeezed. The squeeze intervals were 7,510 to 7,511 ft and 7,385 to 7,386 ft. Each interval was squeezed with 8 bbl of class G cement with a satisfactory squeeze pressure obtained on each set of perforations.

A hydraulic fracture treatment was performed in the Paludal 3 and 4 zones of the SHCT Sidetrack No. 1 on January 22, 1993. The well was perforated across the Paludal 4 sand at 7,386 to 7,388 ft (7,154 ft TVD) with 8 SPF for a total of 16 holes (34 gram, 0.5-in. diameter). The perforations were phased at 180° and were oriented to the high and low side of the wellbore (0° and 180°) using spring decentralizers.

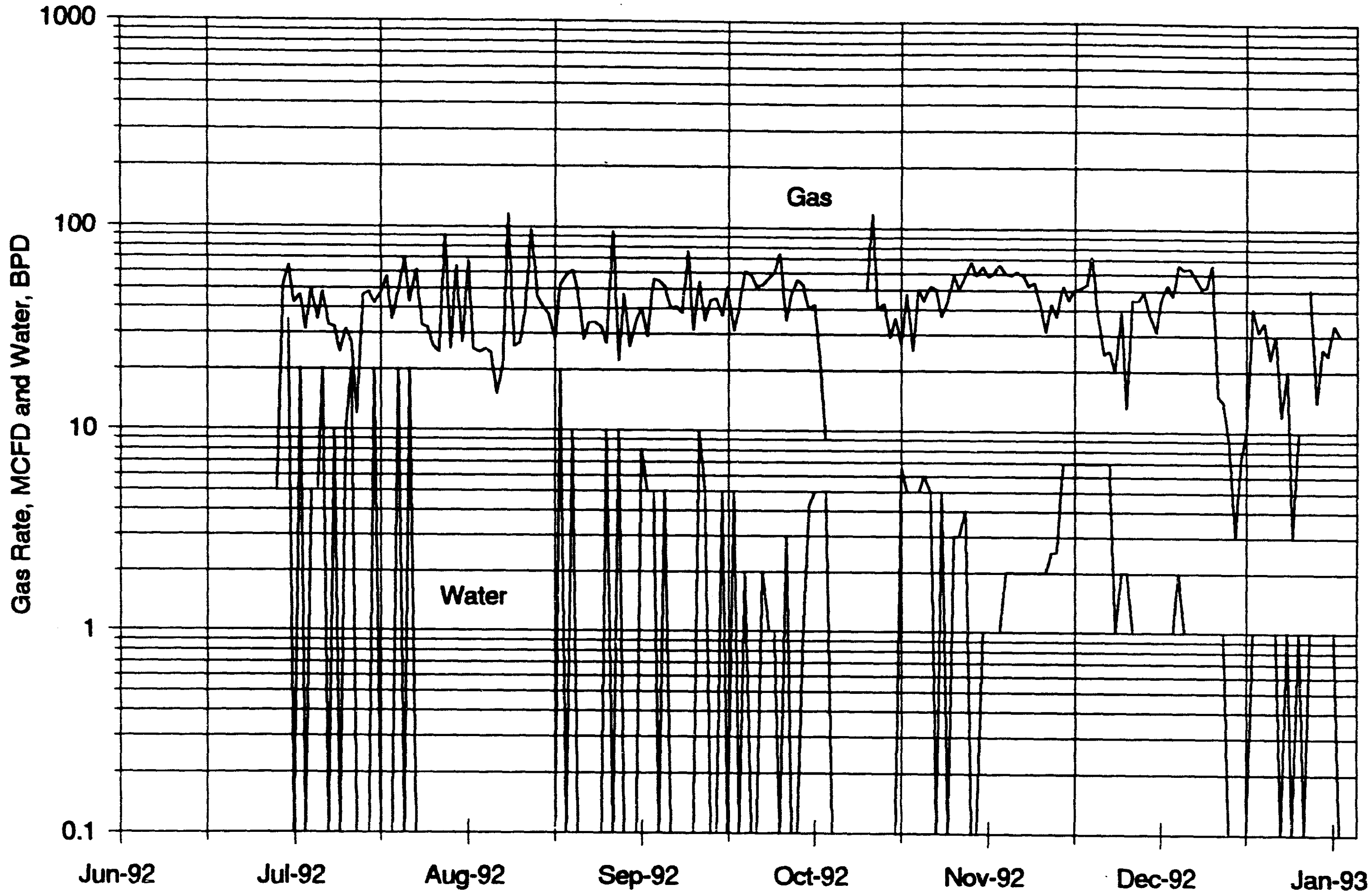


Figure 8-1 SHCT-1 Paludal 2 Gas and Water Production, June 15, 1992 - January 12, 1993

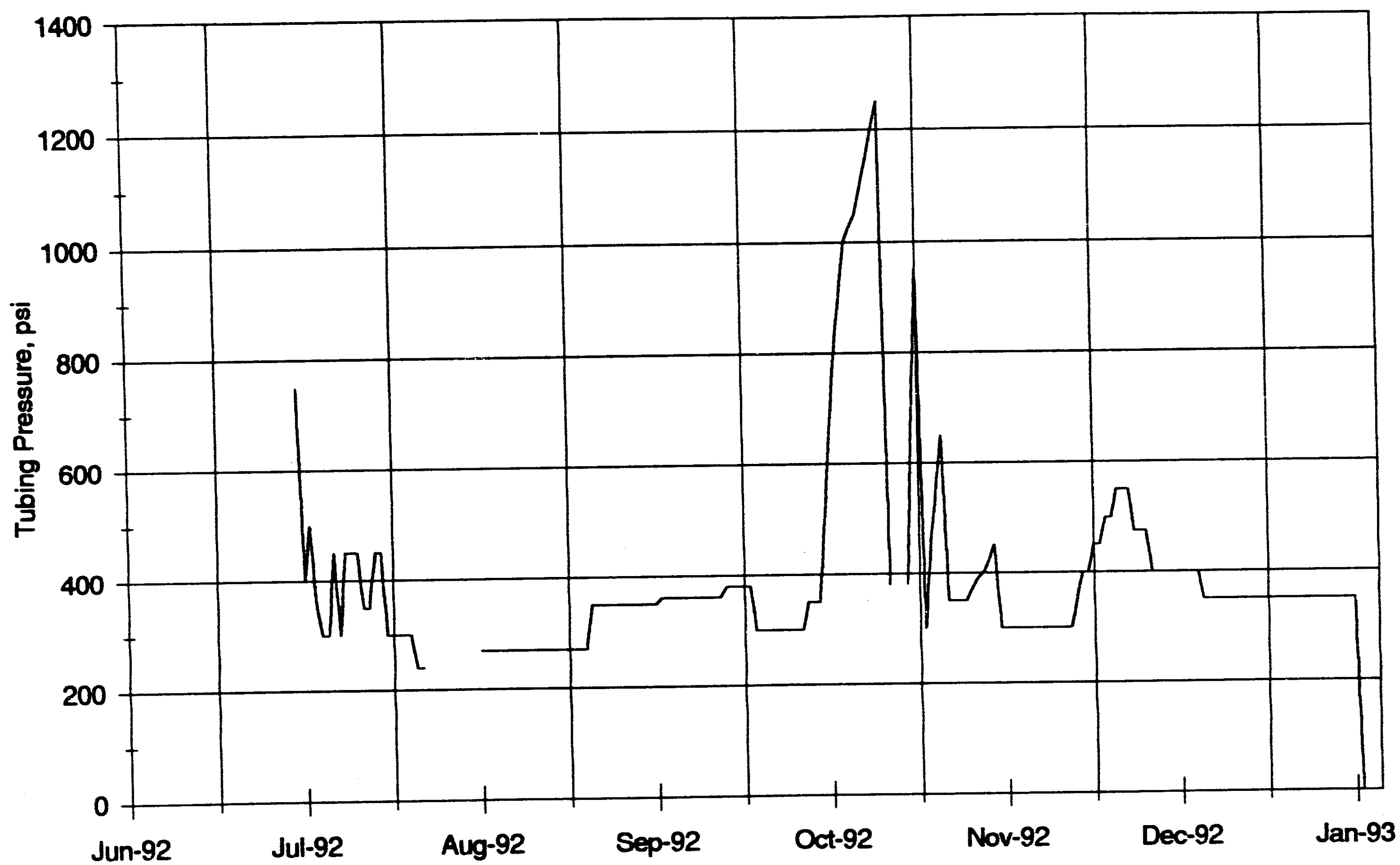


Figure 8-2 SHCT-1 Paludal 2 Wellhead Pressures, June 15, 1992 - January 12, 1993

The fracture treatment consisted of pumping 5,000 lb of 100 mesh sand, 160,000 lb of 20/40 Ottawa sand and 30,000 lb of resin-coated sand (tail-in) in 1,790 bbl of crosslinked gel at a rate of 30 BPM and a maximum proppant concentration of 5.0 ppg. A radioactive tracer (Iridium 192 beads) was included during the sand stages to help evaluate the effectiveness of the fracturing treatment (i.e., the placement of the proppant).

Flowback was initiated through the 3-1/2-in. frac workstring approximately 2-1/2 hours after the fracture treatment was completed on January 22, 1993. The well flowed on various chokes recovering 1,000 bbl of frac fluid until it died on January 26. The 3-1/2-in. tubing and packer were pulled, and 2-7/8-in. production tubing was run in the well (open-ended). After cleaning out sand from 7,370 to 7,500 ft, the tubing was landed at 7,389 ft (1 ft below the perfs at 7,386 to 7,388 ft). The well was swabbed intermittently for two days before it began flowing continuously.

There was a total of 1,964 bbl of fluid to recover. At the end of January, 1,158 bbl had been recovered. The well was flowed and swabbed to cleanup until January 30, 1993.

8.4 PALUDAL 3 AND 4 TESTING

The SHCT-1 produced 4.03 MMCF of gas into the sales line during February. As of the end of February, 1,405 of the 1,964 bbl of frac fluid had been recovered. The Paludal 3 and 4 interval produced at a rate of 100 to 150 MCFD. Approximately 75 percent of the load water (1,562/2,096 bbl) was recovered before the 2-7/8-in. tubing was pulled on March 3, 1993. Figures 8-3 and 8-4 are the gas, water and flowing tubing pressure for the test period.

On March 3, 1993, a service rig was moved in and the tubing pulled. A post-frac gamma ray log was run in the 7-in. casing (40 days after the frac) to observe the location of the radioactive tracer (Iridium-192 beads) that was pumped with the sand. The gamma ray survey was run from 7,200 to 7,475 ft at 20 ft per minute. The majority of the tracer was found across the perforations in the Paludal 4 sand at 7,386 to 7,388 ft. However, significant amounts of tracer were observed at 7,372 to 7,374 ft and 7,380 to 7,382 ft. Small traces of Ir-192 were found as high as 7,328 ft (58 ft above the perfs) while no tracer was observed below the perforations.

Although there was no indication from the gamma ray survey that the hydraulic fracture created in the Paludal 4 sand was in contact with the Paludal 3 at the wellbore, the Paludal 3 was perforated from 7,442 to 7,462 ft with 4 SPF (19 gram, 120° phasing) in an attempt to increase gas production rates. Following perforating, a packer and 2-7/8-in. tubing (with CER bottomhole shut-in nipple) were run in preparation for a buildup test. No significant increase in production was noted from the additional perforations. The well averaged 50 to 120 MCFD during the 10-day flow period prior to the buildup.

8.5 PALUDAL 3 AND 4 BUILDUP TEST AND ANALYSIS

The well was shut-in at the surface on March 17, 1993, to begin a pressure buildup test. A bottomhole shut-in could not be achieved for various reasons. Therefore, the bottomhole pressure gauge was left hanging at 7,230 ft (92 ft TVD above the perforations). A gradient survey taken while going in the well indicated scattered fluid at 4,500 ft and an approximate fluid level at 5,300 ft (±11 bbl in the tubing).

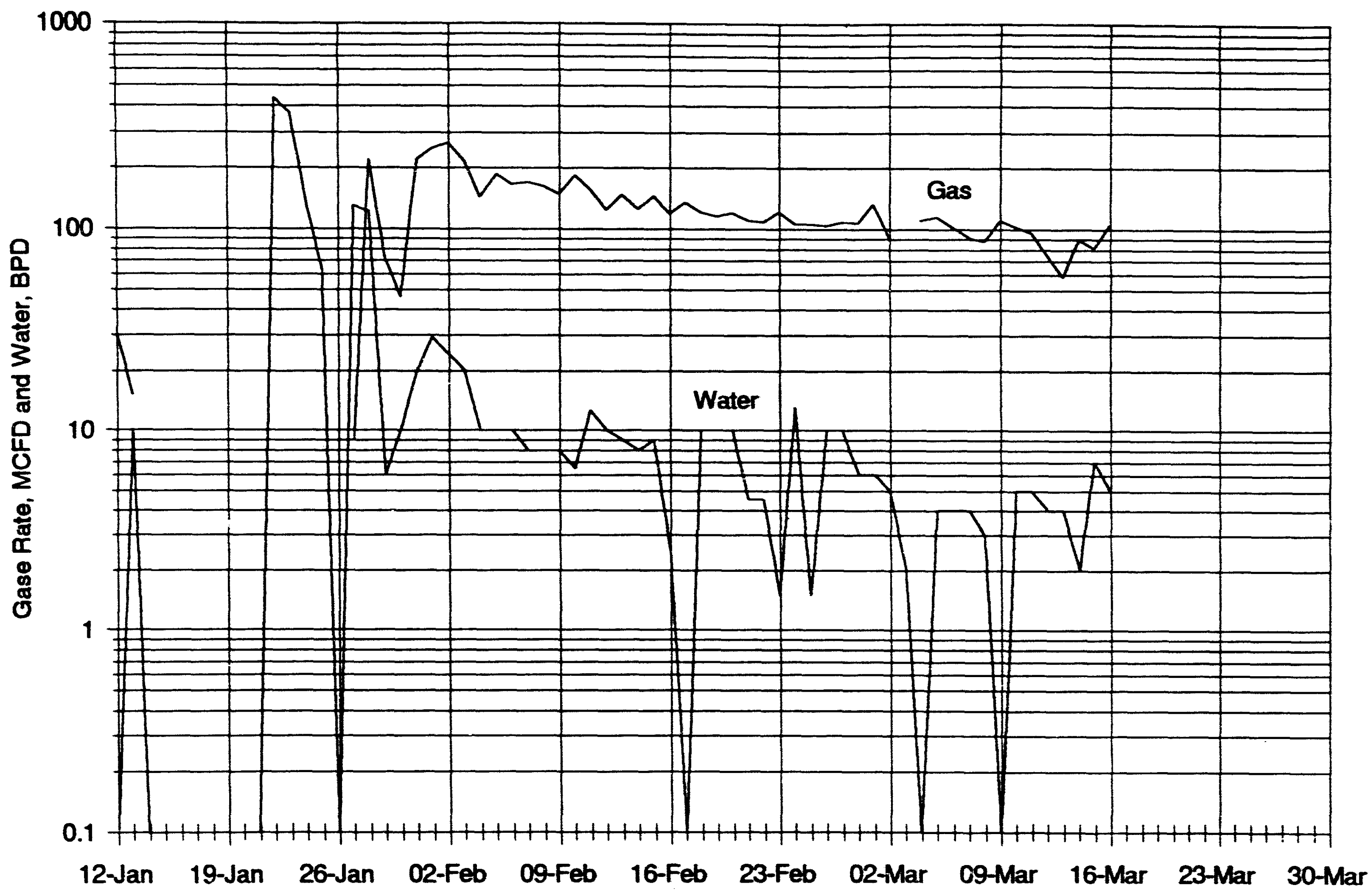


Figure 8-3 SHCT-1 Paludal 3 and 4 Gas and Water Production, January 12, 1993 - March 24, 1993

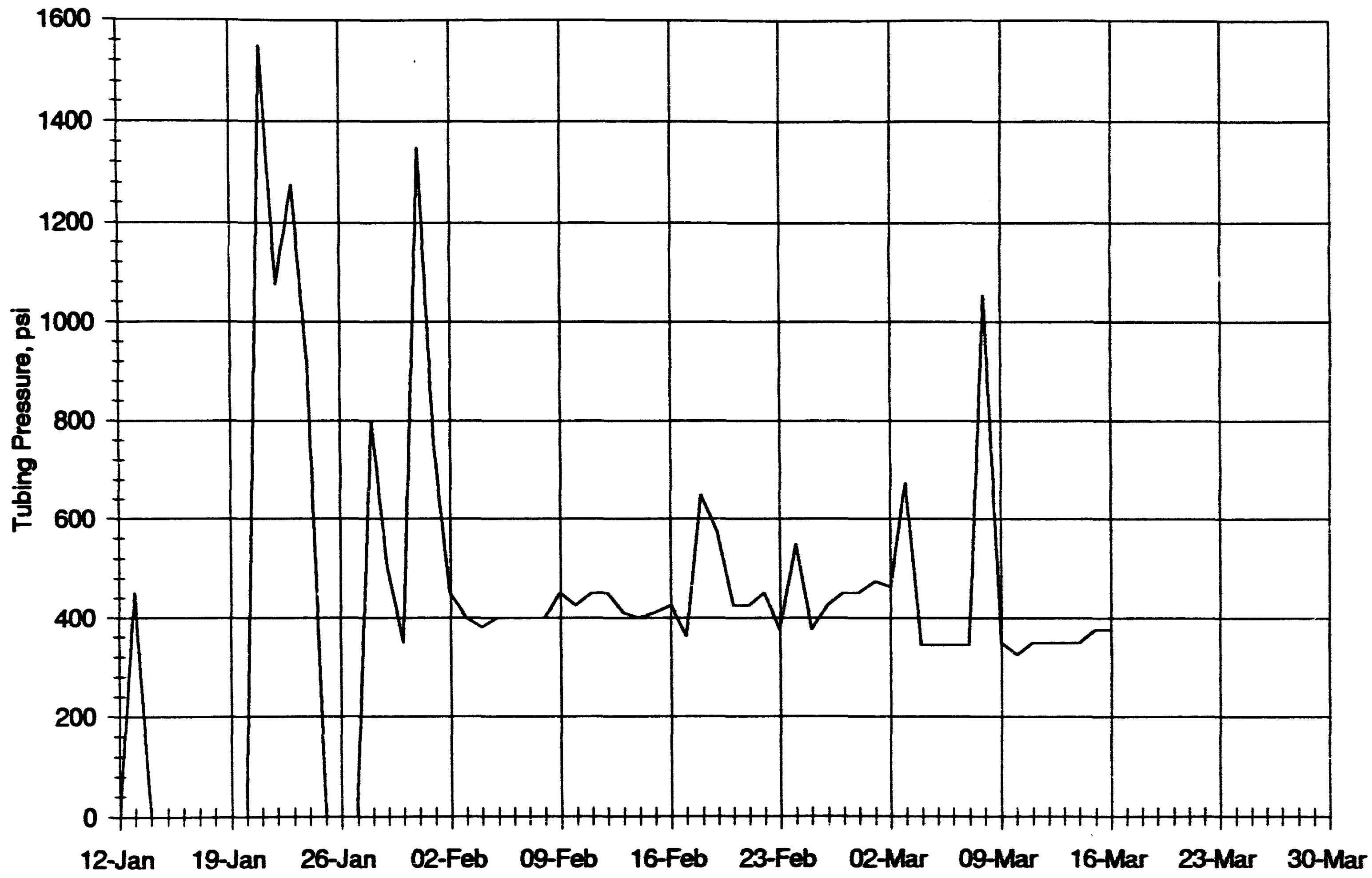


Figure 8-4 SHCT-1 Paludal 3 and 4 Wellhead Pressures, January 12, 1993 - March 24, 1993

The objective of the buildup test was to evaluate the effectiveness of the hydraulic fracture treatment and determine the characteristics of the created hydraulic fracture. History matching of the buildup data was performed using a single-layer, single-phase, single-porosity reservoir simulator. The following reservoir characteristics were input in the simulator:

Avg. Permeability	=	0.01 md
Matrix Porosity	=	10%
Water Saturation	=	46%
Reservoir Temp.	=	210°F
Reservoir Press.	=	5,300 psi
Gas Gravity	=	0.626
Net Height	=	60 ft
Depth	=	7,175 ft
Reservoir Size	=	350 ft X 4,000 ft (32 acres)

These reservoir properties were obtained from previous DOE work done in this same interval during the MWX Experiments[7]. The 20-ft thick Paludal 4 and the 40-ft thick Paludal 3 were modeled in this study as a single 60-ft layer. An average permeability of 0.01 md (10 times the matrix permeability) was used to simulate the presence of natural fractures. The reservoir simulator was produced at a constant bottomhole pressure of 1,150 psi for 46 days to simulate the production period following the hydraulic fracture treatment. The actual production rates ranged from 250 to 50 MCFD and 10 BWPD for the 46 days following fracture cleanup. These rates were similar to the post-frac production rates observed in the MWX-1 well.

The length and conductivity of the hydraulic fracture were varied in the simulator until a reasonable match of the pressure buildup data was achieved. Figure 8-5 is a plot showing the bottomhole pressure versus shut-in time of the actual buildup data along with the reservoir model results. A log-log diagnostic plot of the change in pressure versus the shut-in time and the derivative is given in Figure 8-6. Notice that a reasonably good match of the data is made after the first ±24 hours of shut-in time.

The hydraulic fracture parameters used in the simulator to obtain the pressure match are as follows:

Fracture Half-Length	=	100 ft
Fracture Width	=	0.6 in.
Fracture Permeability	=	2,000 md

This fracture half-length compares with that of 340 ft which was predicted from a post-frac analysis of the net fracturing pressure data using a 3-D hydraulic fracture simulator. An analysis of the log-log diagnostic plot shows that the well transitioned fairly quickly into formation linear flow (1/2 slope) and remained in that flow regime for the duration of the test. This quick transition into linear flow is characteristic of fractures which have a high dimensionless fracture conductivity (100 in this case). The high dimensionless fracture conductivity in this case is a result of the short fracture length.

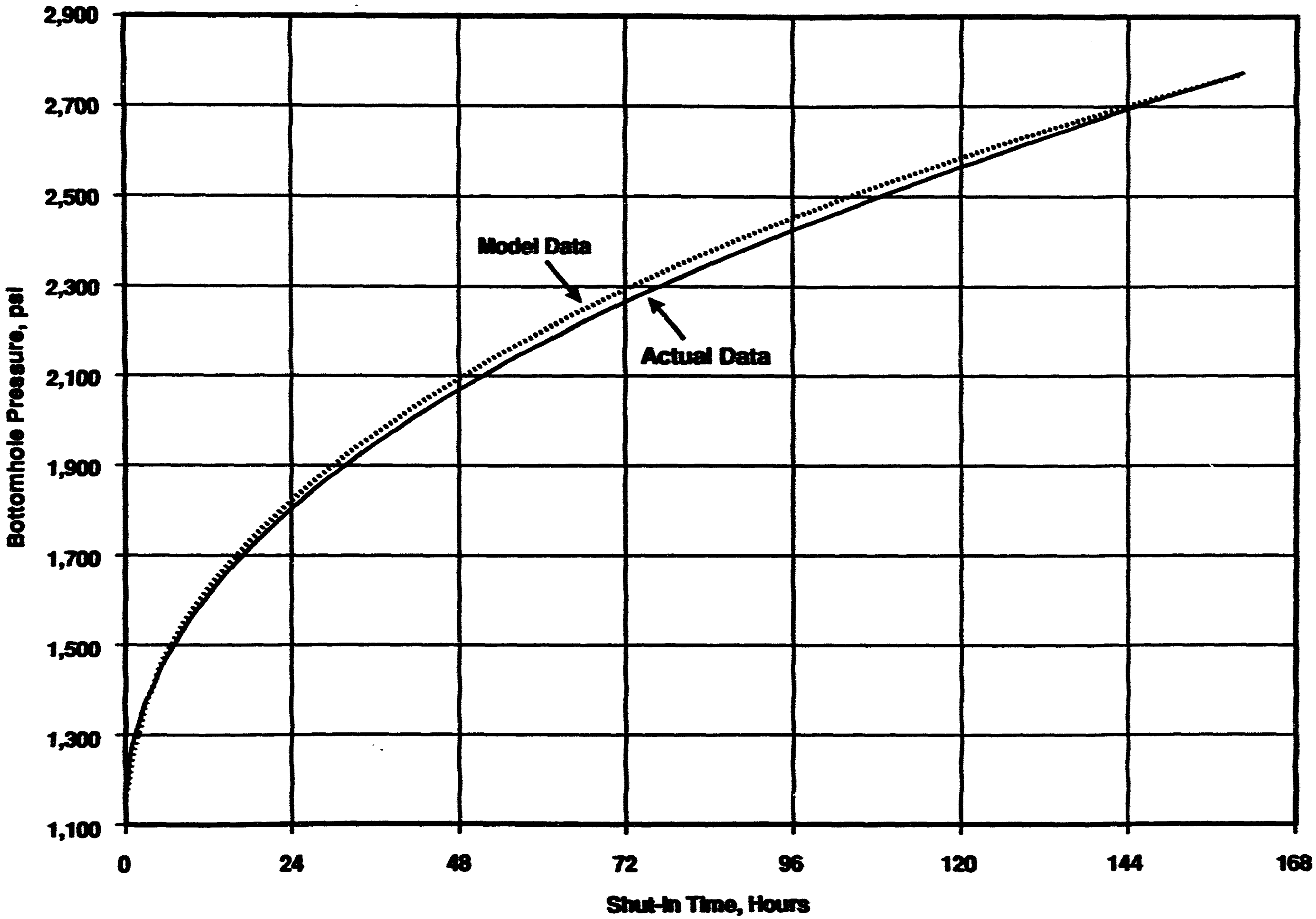


Figure 8-5 Bottomhole Pressure Vs. Shut-In Time Plot of the Actual and Simulated Buildup Data from the Paludal 3 and 4 Interval

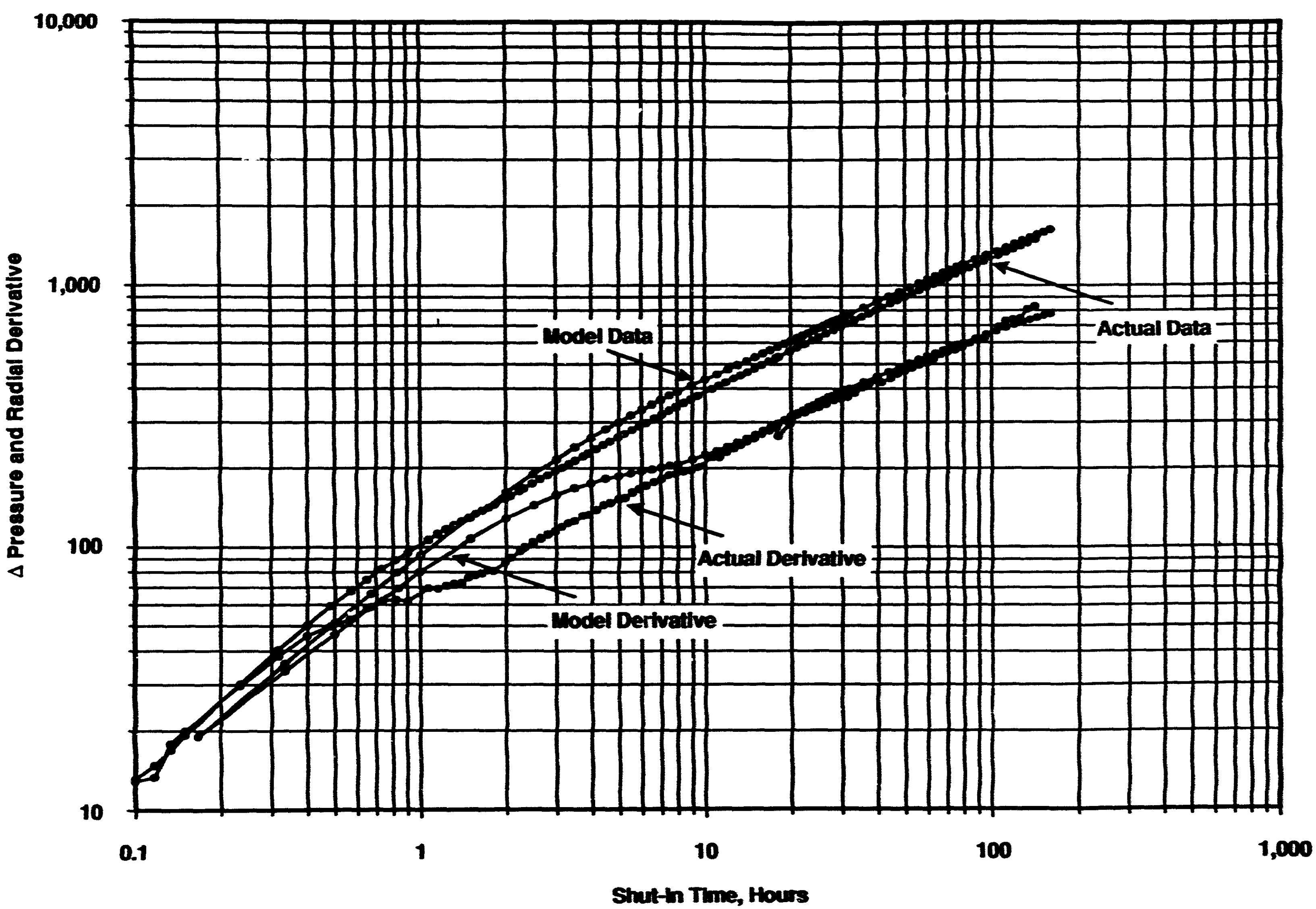


Figure 8-6 Log-Log Diagnostic Plot of the Actual and Simulated Buildup Data from the Paludal 3 and 4 Interval

A Horner plot of the buildup data is presented in Figure 8-7. This plot is characteristic of a typical Horner Plot of a hydraulically fractured vertical well. Since the well did not reach pseudoradial flow during the buildup, the Horner plot only serves to provide a qualitative assessment of the extrapolated reservoir pressure.

It should be noted that the size of the fracturing treatment in SHCT-1 was similar to that in MWX-1[7] as evidenced by the following parameters:

	SHCT-1	MWX-1
Fluid Volume, gals	83,286	81,464
Total Sand, lb	200,780	193,000
Maximum Prop. Con., ppg	5.0	5.5
Pump Rate, BPM	30	20

The Paludal 3 and 4 hydraulic fracture in MWX-1 had a modeled half length of 100 ft and a conductivity of 104 md-ft. The similarity of these parameters to the Paludal 3 and 4 modeled fracture parameters in SHCT-1 would indicate that the induced fracture geometry was unaffected by treatment in a deviated wellbore as opposed to a vertical wellbore.

As evidenced by Figure 8-3, the post-fracture production performance in SHCT-1 was also similar to the 150 MCFD average post-fracture production performance in MWX-1 prior to shut-in and re-entry[7]. This observation also supports the conclusion that hydraulic fracturing results do not improve based on stimulation from a deviated cemented wellbore when compared to the vertical wellbore in MWX-1.

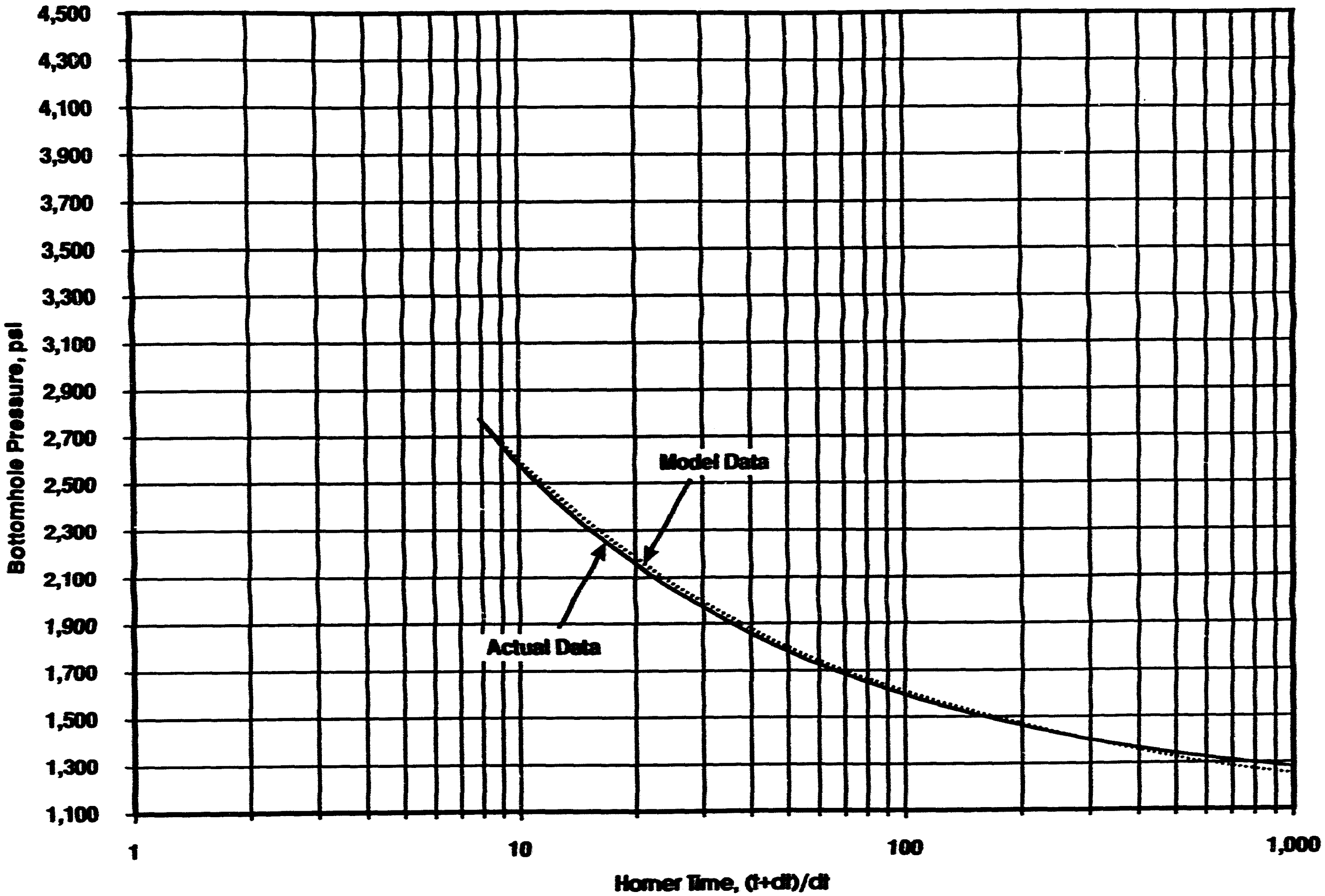


Figure 8-7 Horner Plot for the Paludal 3 and 4 Buildup Test

9.0 Conclusions and Recommendations

- The Slant Hole Completion Test has been successful in providing good technology transfer to the oil and gas industry. A number of industry people made frequent visits to the site while the well was being drilled and tested. In addition, frequent phone conversations and meetings were held to provide information on the progress of the project. Technical papers have been presented on the subject. Probably the greatest measure of successful technology transfer is the horizontal drilling programs that have been initiated in the general area by Barrett Energy, Meridian Oil Company, Mobil Oil Company and Oryx Energy Co.

- Another indication of the excellent technology transfer of this project is that the well was selected as the "**Best Well of 1992**" by a panel of six industry judges as part of "Best of the Rockies" competition sponsored by Western Oil and Gas World, an industry journal. This award was given primarily because of the industrial interest as seen in plans for at least five high-angle/horizontal wells being planned in the immediate area of the SHCT-1.

- The SHCT-1 has a significantly improved initial production potential when compared to vertical wells completed in the Cozzette Sand of the Mesaverde Group in the Rulison Field. This improvement is due to intersection of natural fractures which trend in a general east-west direction at the SHCT-1 site. The initial potential of the SHCT-1 is a minimum of two to three times higher than initial potentials of surrounding vertical wells.

- The presence of euhedral quartz and calcite crystals in the natural fractures in the cored Mesaverde and Cozzette intervals are good indications of open apertures in the subsurface. Therefore, drilling a well perpendicular to these open fractures should insure contacting the maximum number of fracture systems and consequently provide the greatest production potential for the well.

- Drilling the naturally-fractured intervals underbalanced (i.e., pore pressure greater than the hydrostatic column pressure) has the advantage of providing better indication of gas shows, more specific location of the fractures and also reduces the chance of damaging the natural fracture systems due to drilling mud invasion.

- The well can be safely drilled in an underbalanced condition, but care must be taken to have adequate surface facilities such as BOPs, gas busters, mud volume sensors, etc. It is also important that care is taken to insure that gas is not swabbed-in during tripping of the drill pipe.

- Stimulation in a high-angle, cemented wellbore, such as the Paludal interval in the SHCT-1, is more difficult because of high near-wellbore stresses resulting in higher treating pressures.

- Comparing the results of the two very similar hydraulic fracture treatments in the SHCT-1 and the MWX-1 wells indicate that there is no advantage in treatment in a slant wellbore as compared to a vertical wellbore. In fact, because of the higher treating pressures in a slant wellbore, the fracture treatments are very likely to be more expensive.

- It is believed that a high-angle well drilled perpendicular to the natural fracture system <u>and completing open hole or with an uncemented liner</u> may exhibit excellent production characteristics. During the drilling of the 60° portion of the hole, good gas kicks were noted. Sloughing coals and shales may preclude completing this interval open hole. However, in areas where the coals are not present, the high-angle open hole may provide good natural completions.

- The SHCT-1 produces water from the Cozzette Sand at rates significantly greater than surrounding vertical wells. The source of this water production is not presently understood. A diagnosis of this water production mechanism is vital to the economic exploitation of gas from the Cozzette Sand via horizontal drilling.

- Future work should focus on diagnosing the water production mechanism in the Cozzette Sand. This work could entail:

  - Open-hole logging of the horizontal lateral to assess possible intervals of water incursion.

  - A geologic study to determine the distribution of water in the Cozzette Sand within the Rulison Field and the effects of potential faulting on water distribution.

  - Core analysis of the Cozzette Sand to verify the relationship between existing and irreducible water saturations. The core analysis work should include capillary pressure determinations at various confining pressures.

  - Detailed reservoir modeling using a multi-phase model to determine the viability of water production from the rock matrix of the Cozzette sandstone.

- Similar demonstrations of the horizontal well technology need to be performed in other low-permeability basins where natural fracturing may occur. It is essential that good geological data be obtained prior to drilling a horizontal well in order to drill the horizontal leg in the direction to maximize the penetration of the natural fracture system.

10.0 Nomenclature

ACT	Oxygen Activation Log
BBL	42 Gallon Barrel
BHA	Bottomhole Assembly
BOP	Blow Out Preventors
BOPD	Barrels of Oil Per Day
BPD	Barrels per Day
BW	Barrels of Water
BWPD	Barrels of Water Per Day
CBL	Cement Bond Log
CCL	Casing Collar Locator
CET	Cement Evaluation Tool
DMWD	Directional Measurement While Drilling
FCP	Flowing Casing Pressure
FTP	Flowing Tubing Pressure
IADC	International Association of Drilling Contractors
ISIP	Instantaneous Shut-In Pressure
JSPF	Jet Shots Per Foot
KOP	Kick Off Point
LSND	Low Solids Non Dispersed (Drilling Mud)
MCFD	Thousand Cubic Feet per Day
MD	Measured Depth
MMCF	Million Standard Cubic Feet
MMCFD	Million Standard Cubic Feet per Day
MWD	Measurement While Drilling
PPG	Pounds Per Gallon
PSI	Pounds per Square Inch (pressure)
PSIA	Pounds per Square Inch Absolute
PSIG	Pounds per Square Inch Gauge
PU	Pick Up
RU	Rig Up
SCF	Standard Cubic Feet (measured at 14.73 psia and 60° F)
SICP	Shut-In Casing Pressure
SITP	Shut-In Tubing Pressure
SPF	Shots Per Foot
TD	Total Depth
TDT	Thermal Decay Time Log
TVD	True Vertical Depth
VDL	Variable Density Log
WP	Working Pressure

11.0 References

1. Slant Hole Completion Test (1990) "As Built" Report, Contract No. DE-AC21-90MC26024, prepared for Morgantown Energy Technology Center by CER Corporation, June 18, 1991

2. Slant Hole Completion Test (1991) Sidetrack "As Built" Report, Contract No. DE-AC21-90MC26024, prepared for Morgantown Energy Technology Center by CER Corporation, May 12, 1992.

3. Slant Hole Completion Test Cozzette and Paludal Production Testing Topical Report, Contract No. DE-AC21-90MC26024, prepared for Morgantown Energy Technology Center by CER Corporation, June 30, 1993.

4. Myal, F.R., E.H. Price, R.E. Hill, G.C. Kukal, P.A. Abadie and C.C. Riecken, "Geologic and Production Characteristics of the Tight Mesaverde Group, Piceance Basin, Colorado," U.S. Department of Energy, Morgantown Energy Technology Center, Pub. No. DOE/MC/24120-2769, 126 pages, July 1989.

5. Spencer, Charles W., "Hydrocarbon Generation as a Mechanism for Overpressuring in Rocky Mountain Region," The American Association of Petroleum Geologists Bulletin, Vol. 71, No. 4, April 1987.

6. Well Log Analysis of the Slant Hole Completion Test, Piceance Basin, Colorado, prepared by CER Corporation under Contract No. DE-AC21-90MC26024, for the U.S. Department of Energy Morgantown Energy Technology Center, January 13, 1992.

7. Multiwell Experiment Final Report: No. I, The Marine Interval of the Mesaverde Formation, SAND87-0327 - UC-92a, April 1987; No. II, The Paludal Interval of the Mesaverde Formation, SAND88-1008 - UC-92, May 1988; No. III, The Coastal Interval of the Mesaverde Formation, SAND88-3284 - UC-92, March 1989; No. IV, The Fluvial Interval of the Mesaverde Formation, SAND89-2612/B - UC-132, January 1990; compiled by the Multiwell Experiment Project Groups, Sandia National Laboratories and CER Corporation for the U.S. Department of Energy under Contract No. DE-AC04-76DP900789.

8. Multiwell Experiment MWX-1 As-Built Report, prepared by CER Corporation for Sandia National Laboratories, Contract No. SAND82-7201, Unlimited Release UC-92a, for the U.S. Department of Energy under Contract No. DE-AC04-76DP00789, July 1982.

12.0 Bibliography

1. Branagan, P., C. Cipolla and S.J. Lee: "Comprehensive Well Testing and Modeling of Pre and Post Fracture Well Performance of the MWX Lenticular Tight Gas Sands," SPE/DOE 13867, presented at the SPE/DOE 1985 Low Permeability Gas Reservoirs Meeting in Denver, CO, May 19-22, 1985.

2. Branagan, P., G. Cotner, S.J. Lee and R. Wilmer: "Interference Testing of the Naturally Fractured Cozzette: A Case Study at the DOE MWX Site," SPE 12869, presented at the Unconventional Gas Recovery Symposium in Pittsburgh, PA, May 13-15, 1984.

3. Branagan, P., S.J. Lee and R. Wilmer: "Well Testing and Reservoir Evaluation (2.16)," Technical Proceedings of the Western Gas Sands Subprogram Review, DOE/METC 843, Morgantown, WV, October 18-19, 1983.

4. Brower, K.R. and N.R. Morrow: "Fluid Flow in Cracks as Related to Low Permeability Gas Sands," SPE/DOE 11623, presented at the 1983 SPE/DOE Symposium on Low Permeability Reservoirs held in Denver, Colorado, March 14-16.

5. CER Corporation: "Multiwell Experiment, Fluvial C Fracturing Quality Control and Monitoring Results," June 12, 1987.

6. CER Corporation: "Multiwell Experiment, Altered Stress Experimental Field Data: Fluvial C Mini Frac," May 25, 1987.

7. CER Corporation: "Well Testing and Analysis of the Marine Blanket Sandstones at the DOE Multiwell Experiment Site," prepared under Sandia Contract No. 25-3097, April 1986.

8. CER Corporation: "Multiwell Experiment MWX-3 As-Built Report," prepared for Sandia National Laboratories, Contract No. SAND84-7132, Unlimited Release UC-92a, for the U.S. Department of Energy under Contract No. DE-AC04-76DP00789, May 1984.

9. CER Corporation: "Multiwell Experiment MWX-2 As-Built Report," prepared for Sandia National Laboratories, Contract No. SAND82 Unlimited Release UC-92a, for the U. S. Department of Energy under Contract No. DE-AC04-76DP00789, August 1982.

10. CER Corporation: "MWX Fluvial "B" Pre Stimulation Fracturing/Flowback Field Test Data," September 13, 1986.

11. CER Corporation for Sandia National Laboratories: "Multi-Well Experiment Activities, July 1, 1982 to December 31, 1982," Contractor Report SAND83-7465, Unlimited Release UC-92a, printed December 1983.

12. Eatough, M.O.: "Mineralogic and Petrologic Overview of Core Samples from the Department of Energy's Western Gas Sands Project Multiwell Experiment, Piceance Basin, Colorado," SPE/DOE 11764, presented at the 1983 SPE/DOE Symposium on Low Permeability held in Denver, Colorado, March 14-16.

13. Finley, S.J. and J.C. Lorenz: "Characterization and Significance of Natural Fractures in Mesaverde Reservoirs at the Multiwell Experiment Site," SPE 19007, presented at 1989 SPE Joint Rocky Mountain Regional Meeting and Low Permeability Reservoir Symposium, Denver, Colorado, March 6-8.

14. Fleming, R.P.and H.E. Morris: "Fracture Diagnostics Results for the Multiwell Experiment's Paludal Zone Stimulation," SPE/DOE/GRI 12852, presented at the 1984 SPE/DOE/GRI Unconventional Gas Recovery Symposium held in Pittsburgh, PA, May 13-15.

15. Gall, B.L. and C.J. Raible: "Molecular Size Studies of Degraded Fracturing Fluid Polymers," presented at the International Symposium on Oilfield and Geothermal Chemistry, SPE 13566, held in Phoenix, Arizona, April 9-11, 1985.

16. Johnson, P.A. and J.N. Albright: "In Situ Physical Properties Measurements Using Crosswell Acoustic Data," SPE 13811, presented at 1985 SPE/DOE Symposium on Low Permeability Gas Reservoirs, Denver, Colorado, May 19-20.

17. Johnson, R.C.: "Geologic History and Hydrocarbon Potential of Late Cretaceous-Age, Low Permeability Reservoir, Piceance Basin, Colorado," report prepared for U.S. Department of Energy, Morgantown Energy Technology Center, No. DOE/MC/20422-2337, 97 p, 1987.

18. Johnson, R.C. and V.F. Nuccio: "Late Cretaceous through Early Tertiary General Stratigraphy and Structural Geology of the Piceance Creek Basin, Colorado," in Spencer, C.W., and Keighin, C.W. (eds.), Geologic Studies in Support of the U.S. Department of Energy Multiwell Experiment: U.S. Geological Survey Open File Report 84-757, pp. 14-20, 1984.

19. Kilmer, N.H., N.R. Morrow and J.K. Pitman: "Pressure Sensitivity of Low Permeability Sandstones," Journal of Petroleum Science and Engineering, v.1, pp. 65-81, 1987.

20. Kukal, G.C. and R.E. Hill: "Log Analysis of Clay Volume: An Evaluation of Techniques and Assumptions Used in an Upper Cretaceous Sand-Shale Sequence," Paper RR, Transactions of the SPWLA 27th Annual Logging Symposium, June 1986.

21. Kukal, G.C. and R.E. Hill: "Improved Shaly Sand Analysis in Heavy Drilling Muds: A Simple Technique for Using the Photoelectric Measurement," Paper U, Transactions of the SPWLA 26th Annual Logging Symposium, June 1985.

22. Kukal, G.C. and K.E. Simons: "Log Analysis Techniques for Quantifying the Permeability of Submillidarcy Sandstone Reservoirs," SPE/DOE 13880, presented at the 1985 SPE/DOE Low Permeability Gas Reservoir Symposium, Denver, CO, May 19-22.

23. Kukal, G.C.: "A Systematic Approach for the Effective Log Analysis of Tight Gas Sands," SPE/DOE 12851, presented at the 1984 SPE/DOE/GRI Unconventional Gas Recovery Symposium, Pittsburgh, PA, May 13-15.

24. Kukal, G.C.: "Log Analysis in Low-Permeability Gas Sand Sequences - Correcting for Variable Unflushed Gas Saturation," Paper F, Transactions of the SPWLA 24th Annual Logging Symposium, June 1983.

25. Law, B.E.: "Relationships of Source-Rock, Thermal Maturity, and Overpressuring to Gas Generation and Occurrence in Low-Permeability Upper Cretaceous and Lower Tertiary Rocks, Greater Green River Basin, Wyoming, Colorado, and Utah," Rocky Mountain Association of Geologists, pp. 469-490.

26. Lee, M.W. and J.J. Miller: "Acquisition and Processing of Azimuthal Vertical Seismic Profiles at Multiwell Experiment Site, Garfield County, Colorado," USGS Open File Report 85-427, April 1985.

27. Lee, M.W.: "Vertical Seismic Profiles at Multi-Well Experiment Site, Garfield County, Colorado," USGS Open File Report 84-168, November 1983.

28. Lorenz, J.C.: 1987, "Reservoir Sedimentology of Mesaverde Rocks at the Multiwell Experiment Site and East-Central Piceance Creek Basin," Sandia National Laboratories Report SAND87-0040, 40 pp. (Also in U.S. Geological Survey Bulletin: Law, B.F., and C.W. Spencer (Eds.), Geology of Tight Gas Reservoirs in the Pinedale Anticline Area, Wyoming, and the Multiwell Experiment Site, Colorado, 1989).

29. Lorenz, J.C.: "Predictions of Size and Orientations of Lenticular Reservoirs in the Mesaverde Group, Northwestern Colorado," SPE/DOE 13851, May 19, 1985.

30. Lorenz, J.C.: "Reservoir Sedimentology of Mesaverde Rocks at the MWX Site," in Spencer, C.W., and Keighin, C.W. (Eds.), Geologic Studies in Support of the U.S. Department of Energy Multiwell Experiment, U.S. Geological Survey Open File Report 84-757, pp. 21-32, 1984.

31. Lorenz, J.C.: "Reservoir Sedimentology in Mesaverde Rocks at the Multi-Well Experiment Site," SAND83-1078, June 1983.

32. Lorenz, J.C.: "Lateral Variability in the Corcoran and Cozzette Blanket Sandstones and Associated Mesaverde Rocks, Piceance Creek Basin, Northwestern Colorado," SPE/DOE 11608, presented at the 1983 SPE/DOE Symposium on Low Permeability, Denver, Colorado, March 14-16.

33. Lorenz, J.C. and R.E. Hill: "Subsurface Fracture Spacing: Comparison of Inferences from Slant/Horizontal Core and Vertical Core in Mesaverde Reservoirs," SPE 21877, Proceedings of the 1991 SPE Rocky Mountain Regional Meeting and Low-Permeability Reservoirs Symposium, Denver, Colorado, April, pp. 705-716.

34. Lorenz, J.C. and S.J. Finley: "Differences in Fracture Characteristics and Related Production of Natural Gas in Different Zones of the Mesaverde Formation, Northwestern, Colorado," SPE 16809, presented at the Annual SPE Conference in Dallas, Texas, September 27-30, 1987; SPE Formation Evaluation, V. 4, No. 1, pp 11-16, 1989.

35. Lorenz, John C., Allan R. Sattler and Carol L. Stein: "Differences in Reservoir Characteristics of Marine and Nonmarine Sandstones of the Mesaverde Group, Northwestern Colorado," SAND88-1963.UC-92, Unlimited Release, printed February 1989.

36. Lorenz, J.C., N.R. Warpinski, L.W. Teufel, P.T. Branagan, A.R. Sattler and D.A. Northrop: "Results of the Multiwell Experiment, In Situ Stresses, Natural Fractures, and other Geological Controls on Reservoirs," EOS Vol. 69 No. 35, pp. 817, 825-26, August 30, 1988.

37. Lorenz, J.C., S.J. Finley and D.I. Norman: "Tectonism, Subsidence, and Fracturing Mesaverde Reservoirs in the Piceance Basin, Colorado," [abstract], AAPG Bull., v. 72, p. 215, 1988.

38. Lorenz, J.C., P. Branagan, N.R. Warpinski and A.R. Sattler: "Fracture Characteristics and Reservoir Behavior of Stress-Sensitive Fracture Systems in Flay-Lying Lenticular Formations," SPE 15244, May 18, 1986.

39. Lorenz, J.C., D.M. Heinze, J.A. Clark and C.A. Searls: "Determination of Widths of Meander-Belt Sandstone Reservoirs from Vertical Downhole Data, Mesaverde Group, Piceance Creek Basin, Colorado," AAPG Bull., v. 69, pp. 710-721, 1985.

40. Morrow, N.R., J. Ward and K.R. Brower: "Rock Matrix and Fracture Analysis of Flow in Tight Gas Sands," 1985 Annual Report, DOE/MC21179-2032, February 1986.

41. Morrow, N.R., K. R. Brower and N.H. Kilmer: "Relationship of Pore Structure to Fluid Behavior in Low Permeability Gas Sands," 1984 Final Report, DOE/BC10216-13, September 1984.

42. Myal, F.R., CER Corporation and K-H. Frohne, Morgantown Energy Technology Center: "Drilling and Early Testing of a Sidetrack from the Slant Hole Completion Test Well - A Case Study of Gas Recovery Research in Colorado's Piceance Basin," SPE 24382, presented at the Rocky Mountain Regional Meeting and Exhibition, Casper, Wyoming, May 18-21, 1992.

43. Myal, F.R., CER Corporation and K-H. Frohne, Morgantown Energy Technology Center, "Drilling the Slant Hole Completion Test Well in the Piceance Basin, Colorado," SPE 21866, presented at the Rocky Mountain Regional Meeting and Low Permeability Reservoirs Symposium, Denver, Colorado, April 15-17, 1991.

44. Northrop, D.A.: "Insights into Natural Gas Production from Low-Permeability Reservoirs," Society of Petroleum Engineers No. 17706, in Proceedings of Society of Petroleum Engineers Gas Technology Symposium, June 1988, Dallas, Texas, pp. 25-34.

45. Northrop, D.A., A.R. Sattler, R.L. Mann and K-H. Frohne: "Current Status of the Multiwell Experiment," SPE/DOE/GRI 12868, presented at the 1984 SPE/DOE/GRI Unconventional Gas Recovery Symposium held in Pittsburgh, PA, May 13-15.

46. Northrop, D.A.: "MWX Stimulation Experiments (2.19)," DOE/METC843, October 18, 1983.

47. Peterson, R.E.: "Geological and Production Characteristics of the Non-Marine Part of the Mesaverde Group, Rulison Field Area, Piceance Basin, Colorado," SPE 12835, May 14, 1984.

48. Peterson, R.E. and J. Kohout: "Approximating the Dimensions of Lenticular Mesaverde Group Sandstone Lenses Utilizing Close Well Corrections (2.2)," DOE/METC843, presented at WGSS Program Review, October 18-19, 1983, Morgantown, WV.

49. Peterson, R.E. and J. Kohout: "An Approximation of Continuity of Lenticular Mesaverde Sandstone Lenses Utilizing Close-Well Correlations, Piceance Basin, Northwestern Colorado," SPE/DOE 11610, presented at the 1983 SPE/DOE Symposium on Low Permeability, Denver, Colorado, March 14-16.

50. Peterson, R.E.: "Western Gas Sands Project: An Approximation of Continuity of Lenticular Mesaverde Sandstone Lenses, Utilizing Close Well Correlations, Piceance Basin, Northwest Colorado," DOE/NV102493, November 1982.

51. Pitman, J.K. and C.W. Spencer: "Petrology of Selected Sandstones in the MWX Wells (Northwest Colorado) and its Relationship to Borehole Geophysical-Log Analysis and Reservoir Quality," in Spencer, C.W., and Keighin, C.W. (eds.), Geologic Studies in Support of the U.S. Department of Energy Multiwell Experiment: U.S. Geological Survey Open File Report 84-757, pp. 33-66, 1984.

52. Pollastro, R.M.: "Mineralogy of Selected Sandstone/Shale Pairs and Sandstones from the Multiwell Experiment - Interpretations from X-ray Diffraction and Scanning Electron Microscopy Analysis," in, Spencer, C.W., and Keighin, C.W. (eds.), Geologic Studies in Support of the U.S. Department of Energy Multiwell Experiment: U.S. Geological Survey Open File Report 84-757, pp. 67-74, 1984.

53. Randolph, P.L., D.J. Soeder and P. Chowdiah: "Effects of Water and Stress Upon Permeability to Gas of Paludal and Coastal Sands; U.S. DOE Multiwell Experiment," DOE/MC/20342-7, April 1985.

54. Randolph, P.L., D.J. Soeder and P. Chowdiah: "Porosity and Permeability of Tight Sands," SPE/DOE/GRI 12836, presented at the 1984 SPE/DOE/GRI Unconventional Gas Recovery Symposium, Pittsburgh, PA, May 13-15.

55. Randolph, P.L.: "Porosity and Permeability of Mesaverde Sandstone Core from the U.S. DOE Multiwell Experiment, Garfield County, Colorado," SPE/DOE 11765, presented at the 1983 SPE/DOE Symposium on Low Permeability, Denver, Colorado, March 14-16.

56. Sattler, A.R., P.J. Hudson, C.J. Raible, B.L. Gall and D. Maloney: "Laboratory Studies for the Design and Analysis of Hydraulic Fractured Stimulations in Lenticular, Tight Gas Reservoirs," SPE 15245, presented at the Unconventional Gas Technology Symposium of the Society of Petroleum Engineers, Louisville, Kentucky, May 1, 1986.

57. Sattler, A.R., P. Branagan, J.C. Lorenz, D.A. Northrop, R.L. Mann and K-H. Frohne: "Fracturing and Testing Case Study of Paludal, Tight, Lenticular Gas Sands," SPE/DOE 13876, May 19, 1985.

58. Sattler, A.R., C.J. Raible and B.L. Gall: "Integration of Laboratory and Field Data for Insight of the Multiwell Experiment Paludal Stimulation," SPE/DOE 13891, May 19, 1985.

59. Sattler, A.R., A.A. Heckes and J.A. Clark: "Pressure Core Measurements in Tight Sandstone Lenses During the Multiwell Experiment," SPE 12853, presented at the 1984 SPE/DOE/GRI Unconventional Gas Recovery Symposium, Pittsburgh, PA, May 13-15.

60. Searls, C.A.: "The Multiwell Experiment Geophysics Program Final Report," SAND 85-1013, September 1985.

61. Searls, C.A., M.W. Lee, J.J. Miller, J.N. Albright, J. Fried and J.K. Applegate: "A Coordinated Seismic Study of the Multi-Well Experiment Site," SPE/DOE 11613, presented at the 1983 SPE/DOE Symposium on Low Permeability, Denver, Colorado, March 14-16.

62. Senseny, P.E.: "Laboratory Measurements of Mechanical Properties of Sandstones and Shales," SPE/DOE 11762, presented at the 1983 SPE/DOE Symposium on Low Permeability, Denver Colorado, March 14-16.

63. Soeder, D.J. and P.L. Randolph: "Porosity, Permeability and Pore Structure of the Tight Mesaverde Sandstone, Piceance Basin, Colorado," SPE 13134, presented at the 59th Annual Technical Conference and Exhibition, Houston, Texas, September 16-19, 1984.

64. Spencer, Charles W.: "Geologic Aspects of Tight Gas Reservoirs in the Rocky Mountain Region," Journal of Petroleum Technology, July 1985, pp. 1308-1314.

65. Spencer, C.W. and C.W. Keighin: "Geologic Studies in Support of the U.S. DOE's Multi-Well Experiment, Garfield County, Colorado," OFR 84757, November 1984.

66. Spencer, Charles W.: "Overpressuring in the Piceance Basin and the MWX Site," U.S. Geological Survey.

67. Teufel, L.W., C.M. Hart, A.R. Sattler and J.A. Clark: "Determination of Hydraulic Fracture Azimuth by Geophysical, Geological, and Oriented Core Methods at the Multi-Well Experiment Site, Rifle, Colorado," SPE 13226, presented at the 59th annual SPE Meeting, Houston, Texas, September 1984.

68. Teufel, L.W. and N.R. Warpinski: "Determination of In Situ Stress from Anelastic Strain Recovery Measurements of Oriented Core: Comparison to Hydraulic Fracture Stress Measurements in the Rollins Sandstone, Piceance Basin, Colorado," SAND840512C, in Proceedings of the 25th U.S. Symposium on Rock Mechanics, pp. 176-185, 1984.

69. Thorne, B.J. and Morris, H.E.: "Passive Seismic Monitoring of Hydraulic Fracture Experiments at the Multiwell Experiment Site," SAND88-1284, August 1988.

70. Thome, B.J. and H.E. Morris: "Advances in Borehole Seismic Fracture Diagnostics, SPE/DOE 16405, presented at the 1987 SPE/DOE Joint Symposium on Low Permeability Reservoir, Denver, Colorado, May 18-19.

71. Verbeek, E.R. and M.A. Grout: "Fracture Studies in Cretaceous and Paleocene Strata In and Around the Piceance Basin, Colorado," Preliminary Results and Their Bearing on a Fracture Controlled Natural Gas Reservoir at the MWX Site, U.S. Geological Survey Open-File Report, 84-156, 30p, 1984.

72. Ward, J. and N.R. Morrow: "Capillary Pressures and Gas Relative Permeabilities of Low Permeability Sandstone, SPE/DOE 13882, presented at the SPE/DOE 1985 Low Permeability Reservoirs Meeting, Denver, Colorado, May 19-22.

73. Warpinski, N.R., P. Branagan, A.R. Sattler, C. Cipolla, J.C. Lorenz and B.J. Thorne: "A Case Study of a Stimulation Experiment in A Fluvial, Tight, Sandstone Gas Reservoir," DOE 18258, October 2, 1988.

74. Warpinski, N.R.: "Dual Leakoff Behavior in Hydraulic Fracturing Tight Lenticular Gas Sands, SPE 18259, presented at the 63rd Annual Technical Conference and Exhibition of the Society of Petroleum Engineers, Houston, Texas, October 2-5, 1988.

75. Warpinski, N.R. and L.W. Teufel: "In Situ Stresses in Low Permeability, Nonmarine Rocks," SPE/DOE 16402, presented at the 1987 SPE/DOE Joint Symposium on Low Permeability Reservoirs, Denver, Colorado, May 18-19.

76. Warpinski, N.R.: "Elastic and Viscoelastic Calculations of Stresses in Sedimentary Basins," SPE 15243, presented at the Unconventional Gas Technology Symposium of the Society of Petroleum Engineers, Louisville, KY, May 18-21, 1986.

77. Warpinski, N.R., P. Branagan and R. Wilmer: "In-Situ Stress Measurements at DOE's Multiwell Experiment," Western Gas Sands Subprogram Review Technical Proceedings DOE/METC/84-3, January 1984.

78. Warpinski, N.R., P. Branagan and R. Wilmer: "In-Situ Stress Measurements at DOE's Multiwell Experiment Site, Mesaverde Group, Rifle, Colorado," SPE 12142, presented at the 58th Annual Technical Conference and Exhibition, San Francisco, California, October 5-8, 1983.

79. Wei, K.K., N.R. Morrow and K.R. Brower: "The Effect of Fluid, Confining Pressure, and Temperature on Absolute Permeabilities of Low Permeability Sandstones," SPE 13093, presented at the 59th Annual Technical Conference and Exhibition, Houston, Texas, September 16-19, 1984.

80. Yost, A.B. II, U.S. DOE Morgantown Energy Technology Center; W.K. Overby, BDM Corporation; and R.S. Carden, Grace, Shursen, Moore & Associates: "Drilling a 2,000-ft Horizontal Well in the Devonian Shale," SPE 16681, presented at the 62nd Annual Technical Conference and Exhibition of the Society of Petroleum Engineers, Dallas, Texas, September 27-30, 1987.

DATE

FILMED

2/7/94

END