

SUPPORT OF EOR  
TO  
INDEPENDENT PRODUCERS  
IN TEXAS

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Prairie View, Texas

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**MASTER**

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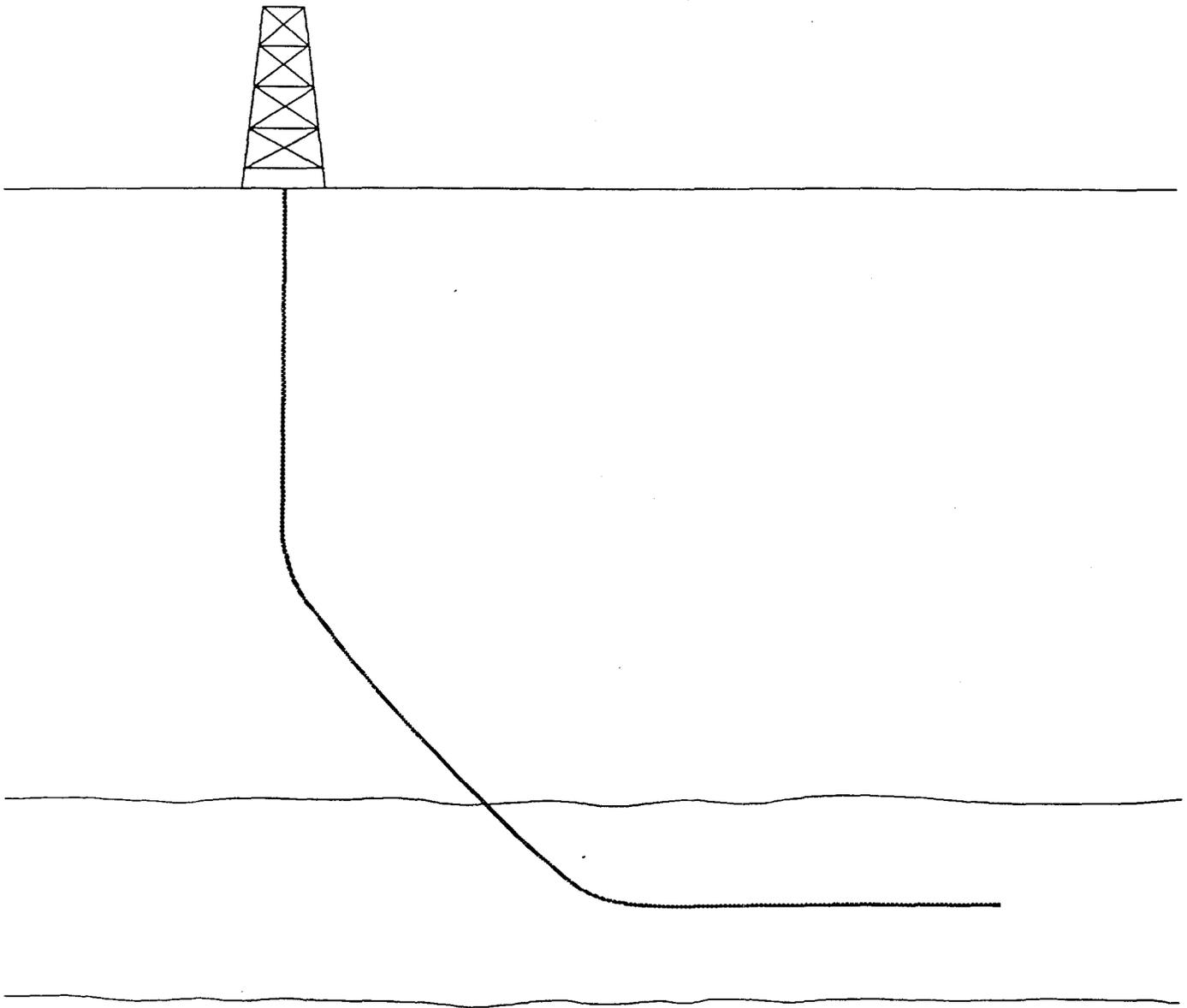
Extensive research has been conducted nationwide since the early 1970's to increase our domestic oil production via Enhanced Oil Recovery (EOR) technology. Less effort has been made to assure that state-of-the-art EOR technology reaches all producers, especially independents, so they can understand and use it to their benefit. Further, very little effort has been made to make EOR research results useful to the broadest possible base of producers.

The vision and scope of the proposed project by Prairie View A&M University and the associated project staff, is to lay the foundation for the first Multi-disciplinary Technology Transfer Center (MDTTC) in Texas to benefit oil producers, and independents in particular. To lay this foundation, we must explore with independents, EOR applications that will benefit them technically and financially.

The plan will maximize all appropriate talents and technologies in the oil industry from government departments, national research laboratories, academic institutions, major oil companies, and independent oil companies, and encourage independents to seriously consider EOR applications and financial rewards.

Prairie View A&M University is part of the Texas A&M University System. Because of the close proximity of the campus to Houston and our interest in becoming a more active education institution, the University leased a continuing education facility at COMPAQ Computer Corporation in Northwest Houston which might ultimately serve as a convenient base for a MDTTC.

# Horizontal Drilling



**Horizontal Drilling and Completions**  
**Sponsored Through Prairie View A&M University**  
**May 5, 1995**

Morning

Introduction

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Completion Considerations

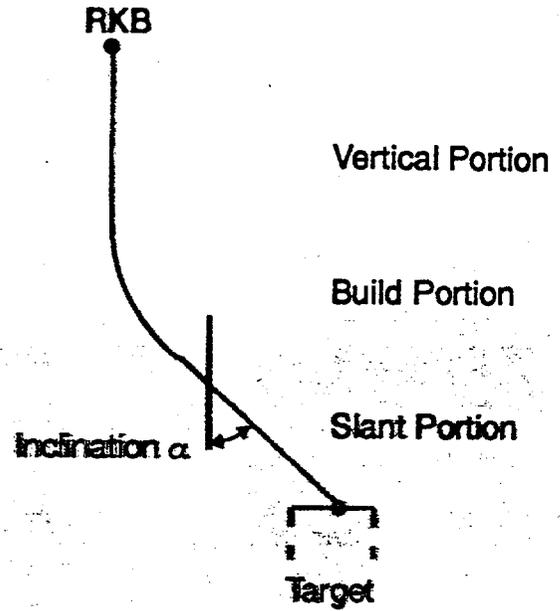
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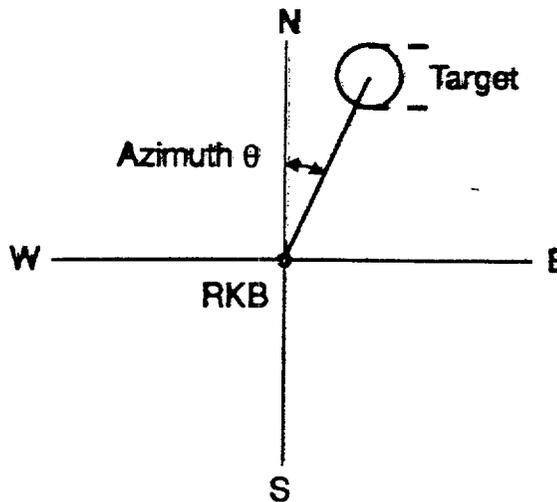
Downhole Equipment  
Artificial Lift

# Basic Terminology

## Vertical Section



## Plan View



## Glossary of Horizontal Drilling Terms

**AFE** - Authorization for expenditure.

**Alignment Angle of Stabilizer** - The angle between the center line of the stabilizer and the center line of the hole.

**Angle Build Motor** - A specially designed positive displacement motor with one or more bends included within the motor transmission or bearing area that cause the motor to deflect the hole at curvature range that are generally in the range from 6 to 20 degrees per 100'. The angle build motors are designed to provide nearly constant hole curvature rates. Angle build motors can utilize either high speed or high torque low speed positive displacement speed motors.

**Angle of Attack of the Bit** - The angle between the center line of the borehole at the bit and the center line of the bit. The sign convention of the angle is positive when the bit points in a direction above the hole and negative when it points below.

**API** - American Petroleum Institute.

**API Dogleg Severity Limits** - The calculated hole curvatures versus tensile load on the pipe that produces bending stresses on the pipe that just equal the API's estimate of the fatigue endurance limit for the pipe body.

**API Freewater** - The result of a standard laboratory test of a cement slurry that indicates how much free water will separate from a static slurry.

**Available Axial Weight** - The axial load available for supplying weight on the bit or other compressive axial loads from a section of the drillstring.

**Azimuth of Horizontal Well** - The direction of a horizontal well in terms of the azimuth angle measured clockwise from true north.

**Balanced Turn in a Complex Build** - The selection of a complex second build in which the hole is turned equal amounts to the right and left such that the final direction equals the initial direction.

**Bending Stress on Drillpipe** - The maximum axial stress on the outer surface of the pipe due to bending the pipe in a dogleg or due to the curvature caused by helically buckling the pipe.

**Build Rate, Vertical** - The rate of change of inclination angle expressed in degrees per 100 feet of measured length along the borehole. Positive indicates increasing angle; negative indicates dropping angle.

**Build and Turn Plan** - A well course produced by orienting the tool face of an angle build or other directional drilling tool to an angle other than zero or 180 degrees from vertical.

**Buoyant Weight** - The effective weight of a member submerged in fluid and is equal to the weight of the member in air minus the weight of the fluid it displaces.

**Casing Standoff** - The ratio of the minimum radial clearance of the casing in the hole divided by the displacement of the center line of the casing from the center of the hole. Also often expressed as a percentage.

**Combined Stress** - The effective stress calculated after the failure concepts of Von Mises. It considers the stresses in each of the principal directions as well as the shear stress induced by torque.

**Complex Tangent Build Curve** - The complex tangent utilizes two build intervals separated by an adjustable straight tangent interval. The complex tangent build curve differs from the simple tangent by utilizing a tool face orientation in the second build that produces a combination build and turn in this interval. The complex build curve allows the wellsite supervisor to adjust the vertical build rate by changing the tool face angle to more precisely hit a target.

**Critical Buckling Force** - The axial compressive force required to initiate buckling. In a straight vertical borehole a tubular member will helically buckle under negligible axial compressive loads; however, when the hole is inclined or curved, the force required to initiate buckling of the tubular is significantly increased.

**Critical Velocity for Turbulent Flow** - The average annular flow velocity at which a power law fluid ceases transition flow and begins turbulent flow.

**Displacement at EOC** - The lateral displacement of the end of curve position from a vertical projection of the surface location. It is equivalent to the closure distance for the end of curve depth computed in a directional survey.

Height of Build Curve - The true vertical depth difference between the end of curve position and the kickoff point. Heviwate Drillpipe - Drillco's proprietary tool jointed heavy-wall pipe. One unique feature of heviwate drillpipe is that the center of the joint has a support pad that is a little bit smaller than the tool joint. The pipe is ideally suited for use in directional wells and horizontal holes.

High Speed PDM - Positive displacement motors that utilize a 1/2 ratio between the numbers of lobes on the rotor versus cavities in the stator. These motors produce the highest possible speeds ranging from 200 RPM on 9" motors, 450 RPM on 6 1/2" OD motors to over 1500 RPM for motors smaller than 2 7/8" OD.

High Torque Low Speed PDM - These are positive displacement motors with from 3/4 to 5/6 ratios between the number of lobes on the rotor to the cavities in the stator. These motors produce less than 1/2 of the rotary speeds of the high speed motors. Typical rated RPM's for 6 1/2 motor are up to 180 RPM's.

Horizontal Hole - A well with a portion of the hole drilled at an angle that laterally intersects a pay zone. For a nondipping formation this would require a truly 90 degree horizontal hole. It could also be at any angle that tracks the dip or structure of the zone.

Horizontal Length - The length of a horizontal hole is defined as the measured length of horizontal hole that fits within the horizontal target.

Horizontal Target - The horizontal target represents the definition of the three-dimensional envelope that the horizontal well path must stay within. The target defines a vertical depth and tolerance limit that is frequently quite small, an areal tolerance position for the end of curve and a tolerance position and orientation for the length of the horizontal hole.

Horizontal Well - A well in which the lower part has been deflected laterally thru the producing zone in order to improve its performance. A "Horizontal" well can be at any angle depending on the dip of the formation.

Ideal Build Curve - The ideal build curve utilizes two build intervals with the first build obtained with the tool face pointed straight up and second build utilizing a build turn approach that provides an adjustable vertical build rate and improved accuracy in hitting small vertical targets.

**MWD, Negative Pulse** - A measurement while drilling tool that generates pressure pulses in the mud stream by venting fluid to the annulus to induce sudden drops in the pressure in the mud column.

**MWD, Positive Pulse** - A measurement while drilling tool that induces pressure pulses that are higher than the steady state mud column pressure by momentarily restricting the flow path of mud through the tool.

**Neutral Weight of the Drillstring** - The surface measured weight of the drillstring if there were no axial drag present. The neutral weight for zero weight on the bit is equal to the measured hook load while rotating with the bit above the bottom of the hole.

**No Load Pressure Loss of a PDM** - This is the pressure loss required to flow mud through a positive displacement motor with the bit off bottom or no torque on the bit.

**Nominal Weight of Drillpipe** - The calculated average weight of the now obsolete original API design for upset threaded and coupled drillpipe. It is typically five to ten percent less than the actual weight of the present day flash welded drillpipe.

**Nonmag Collar** - Drill collar composed of nonmagnetic stainless steels. Nonmag collars are required to isolate the magnetic effects of the drillstring from directional survey equipment. The required lengths are a function of the strength of the earth's magnetic field at the well site and the direction and inclination of the well.

**NSF** - National Science Foundation.

**Overall Radius of the Build Curve** - An approximate representation of the simple tangent or complex tangent build curve as an equivalent single build radius; it is usually set equal to the overall height or overall displacement of the curve.

**Overpull Design** - A common method for designing a drillstring composed of sections of pipe of differing strengths is to select lengths such that the weakest points in the drillstring reach their limits through application of a uniform axial overpull pull at the surface.

**PDC** - Polycrystalline diamond compact bit.

**Sidetracking** - The operations required to deflect the trajectory of the hole away from the original path of the bore hole generally off of a cement plug.

**Simple Tangent Build Curve** - This is a build curve composed of two build intervals, separated by a straight tangent interval. It is generally envisioned that the first and second builds are to be drilled with the same angle build motor and will produce the same curvature rates.

**Single Radius Build Curve** - A build curve composed of a single continuous build interval, beginning at the kickoff point and ending at the EOC (end of curve). It is generally envisioned that a single build curve will be drilled utilizing a single angle build motor.

**Slant Hole** - A "Horizontal" hole in which the hole intersects the full height of the target formation, generally at a high angle.

**Slick Motor** - A bent housing motor with or without a bent sub that is run without stabilizers.

**Slotted Liner** - Oilwell casing joint in which narrow slots have been milled to act as a screen to keep formation solids from flowing into the wellbore.

**Stabilizer, Undergauge** - A drilling stabilizer with an outside diameter smaller than the diameter of the bit.

**Stabilizer Jamming Angle** - The angle between the center line of the stabilizer and the center line of the hole when the stabilizer has been tilted enough to cause the ends of the stabilizer blades to contact both the top and bottom sides of the hole.

**Steerable Motor** - A positive displacement single or multibend motor that is used both in the oriented mode to deflect the hole or in the rotary mode to cause the tool to drill straight ahead. Steerable systems have replaced conventional directional drilling techniques in many areas, especially those with high daily operating costs. Steerable motors generally produce curvature rates in the range of 2 to 4 degrees per 100'.

**Steering** - Drilling with an oriented motor without rotating the drillstring.

**Structural Position Horizontal Target** - Refers to a horizontal hole where the planned path parallels a structural position within the reservoir.

**Total Curvature** - The true three-dimensional curvature of the borehole. Is also referred to as dogleg or dogleg angle on directional survey calculations. Units are typically degrees per 100'.

**Total Turn in a Complex Build** - Refers to the total change in direction in the second build of a complex build curve if all of the build and turn is oriented in the same direction.

**TSP** - Thermally stable polycrystalline.

**Tubing Conveyed Perforating** --- Nonwireline electrically operated, self contained perforating gun that is run on a tubing string and is either fired mechanically by dropping a bar or by using surface applied pressure to hydraulically fire the gun.

**TVD** - True vertical depth.

**TVD<sub>EOC</sub>** - The true vertical depth at the end of the build curve.

**TVD<sub>TP</sub>** - The true vertical depth of a point in the target plane that is directly under the surface location.

**Type 1 Motor** - A bent housing motor with stabilization or contact points located at the apex of the bend and at the top of the motor.

**Type 2 Motor** - A stabilized bent housing motor in which the first stabilizer is placed between the bit and the apex of the bent housing.

**Type 3 Motor** - A bent housing motor with the first stabilizer placed between the bit and the apex of the bent housing and a bent sub placed between the upper stabilizer and the motor.

**Type 4 Motor** - A type three motor with an additional bend located between the bit and first stabilizer.

**Vertical Depth Target** - Horizontal hole where the well path is intended to be truly horizontal, i.e., 90 degrees from vertical.

**Weight of Pipe in Mud** - The buoyant weight of the pipe.

**Well Azimuth** - The directional orientation of a point in the well measured clockwise from true north.

**WOB** - Weight on the bit.

**WOC** - Waiting on cement.

# Horizontal Drilling: Where We've Been And Where We're Going

by Frank J. Schuh, Drilling Technology Inc., Plano, Tex.

**T**his year we celebrate the tenth anniversary of ARCO's first highly successful Empire Abo minimum-radius horizontal well completion and the fourth anniversary of the birth of the medium-curvature horizontal drilling technique. Although a large number of relatively short horizontal holes have been drilled, it is the medium-curvature technique that has generated the boom.

The length of the horizontal well-

bore offers the key to the economics of this exciting development and experimental effort. A recent survey of horizontal holes with lengths over 1000 ft showed an impressive growth trend, essentially beginning with the birth of the medium-curvature method and continuing through the forecast of holes to be drilled this year. This data suggests a growth rate of 230 percent per year for horizontal completions of 1000 ft or longer.

Horizontal drilling is one of the most complex multidiscipline problems posed to the industry since hydraulic fracturing was launched in the late 1940s. Success in horizontal drilling requires selecting a suitable reservoir, selecting the correct direction, elevation, and length. In addition, the operator must design the well program, develop a suitable build curve design that hits the target, and complete the well within budget.

(Continued)

## Schuh's 20 Tips for Failure

1. Select a depleted, watered-out zone: Even with a perfectly designed and executed drilling program, you can't make a silk purse out of a sow's ear.
2. Drill as small a horizontal hole as possible: This solves many completion and production problems because most worthwhile equipment won't fit.
3. Precisely define the target TVD, end-of-curve and horizontal azimuth: Everyone then concentrates on hitting a tiny spot in space instead of saving money.
4. Keep target tolerances secret: The only thing worse than a small target is a large target no one knows about, with the result that everyone aims at the elusive small one.
5. Do not allow a tangent interval: The worst possible scenario in horizontal drilling is needing a higher curvature rate to hit the target than the tools on location can provide. When this happens in aviation, the airplane lands half a mile short of the runway.
6. Avoid written plans: While this may keep the guilty anonymous, it generally ensures that everyone will be guilty.
7. Avoid contingency planning: This is the perfect strategy to limit options to the equipment that probably just failed.
8. Select the smallest rig in the area: This will help focus on the magnitudes of torque and drag in the most meaningful way, because when the neutral weight plus the drag exceeds the maximum allowable hookload, you're stuck.
9. Use the minimum possible costs on the AFE: This will hugely cheer all partners—until the first problem occurs.
10. Shop for the lowest cost per day: This is great if you can spec your purchases. But if you can't define all requirements and intangibles, you probably won't get them all.
11. Discourage renting backup equipment: This affords a splendid opportunity to personally experience and appreciate the word "mean," as in "mean time to failure."
12. Start the well immediately after AFE approval: This solves all equipment-delivery problems, because you will only get what's readily available.
13. Spud the well in January: After all, everyone works better when they're freezing cold.
14. Keep subcontractors from contacting one another: This will prevent anybody from noticing that the tools don't fit together.
15. Select a wellsite supervisor without directional or horizontal experience two days before spud: Unfortunately, experience is the best teacher, and we usually learn by doing things wrong before we do them right.
16. Order service companies with one day's notice: This is your chance to learn if they're truly as busy as they've been telling you.
17. Assume no crossover subs will be needed: After all, some of those threads are interchangeable.
18. Freely substitute equipment if delivery is a problem: This has got to be the most expensive way to solve a scheduling problem.
19. Replace MWD with single shots after the first tool failure: Horizontal holes absolutely need close-spaced directional surveys. Even with difficulties, MWD will outperform single shots.
20. Delay developing completion plans until reaching TD: This will surely save the planning costs if the drilling turns out to be a disaster.

# Trajectory Control Objectives

- *Construct Usable Hole at Minimum Risk*
- *Meet Requirements*
  - *Legal*
  - *Contractual*
  - *Geological*
  - *Formation Evaluation*
  - *Completion*
  - *Production*
- *Remain Cost-Effective*

# Planning Considerations

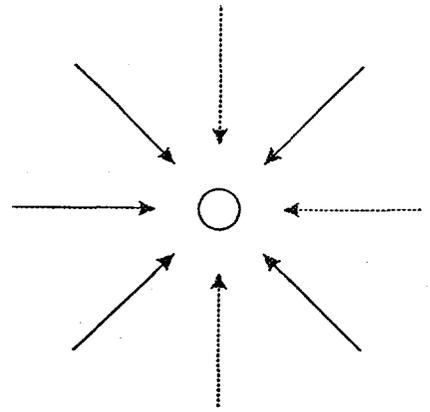
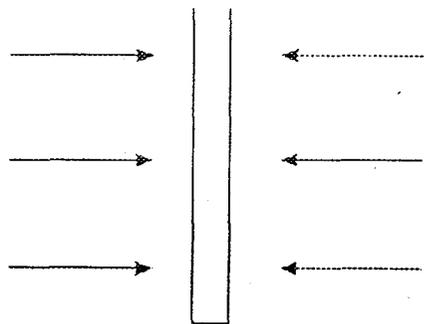
- *Controlling Vertical Position of Lateral*
- *Small Vertical Window = High Cost and Difficulty*
- *Adequate Planning (Months not Weeks)*
- *Total Team Effort*
- *Carry Through to Rig site*

# Horizontal Well Applications

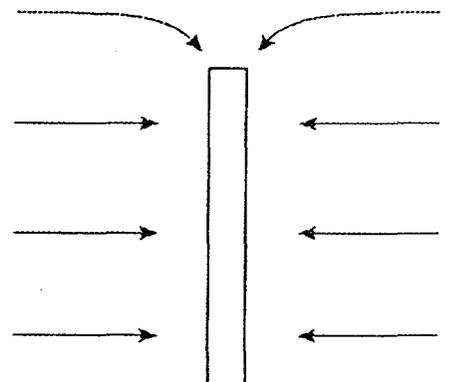
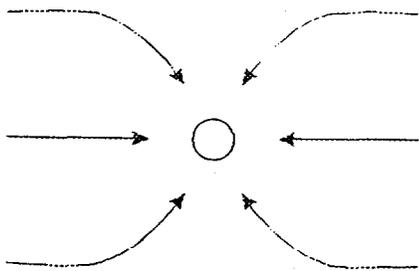
- *Connecting Vertical Fractures*
- *Thin Reservoirs*
- *Heterogeneous Reservoirs*
- *Avoiding Water and Gas Coning*
- *Increasing Drainage Area*
- *Controlling Sand Production*
- *Heavy Oil Recovery*
- *Increasing Injectivity*
- *Improving Sweep Efficiency*
- *Enhanced Oil Recovery*
- *Heat Exchanger Conduits*
- *Reaching Isolated Productive Areas*
- *Reducing Platform Well Slots*

# Production Flow Streams

## *Vertical Holes*



## *Horizontal Holes*



# Technology Breakthroughs

- *MWD Development*
- *Steerable Motor Systems*
- *Customized Drilling Fluids*
- *Cuttings Removal Understanding*
- *Torque and Drag Simulators*
- *BHA Prediction Models*
- *Completion Systems*

# Key Factors for Success

- *Comprehensive Pre-Spud Planning*
- *Multi-Disiplined Planning Team*
- *Contigency Plans*
- *Proper Tool and Equipment Selection*
- *Proper Equipment Selection*
- *Lease Considerations*
- *Post Mortem Analysis*

## Major Disadvantages to Horizontal Drilling

- *Limit to One Pay Zone*
- *Technical Difficulty*
- *High Cost*

# Horizontal Well Planning Essentials

- *Teamwork: Multi-Discipline Approach*
- *Evaluating the Application*
- *Geological Quality Control*
- *Realistic Geologic Target*
- *Adequate Horizontal Extension*
- *Vertical Continuity in Reservoir*
- *Quality Completion*
- *Favorable Economics*

# Horizontal Drilling BHA Tools

- **Mud Motor**

- *PDM*
- *Turbine*

- **Deflection Devices**

- *Bent Subs*
- *Bent Housing Motors*
- *DTU Housing*
- *Conventional Stabilizers*
- *Offset Stabilizer Pads*
- *Knuckle Joints*

- **Surveying Devices**

- *MWD*
- *Steering Tool*
- *Single Shots and Multi-Shots*
- *Gyro Survey*

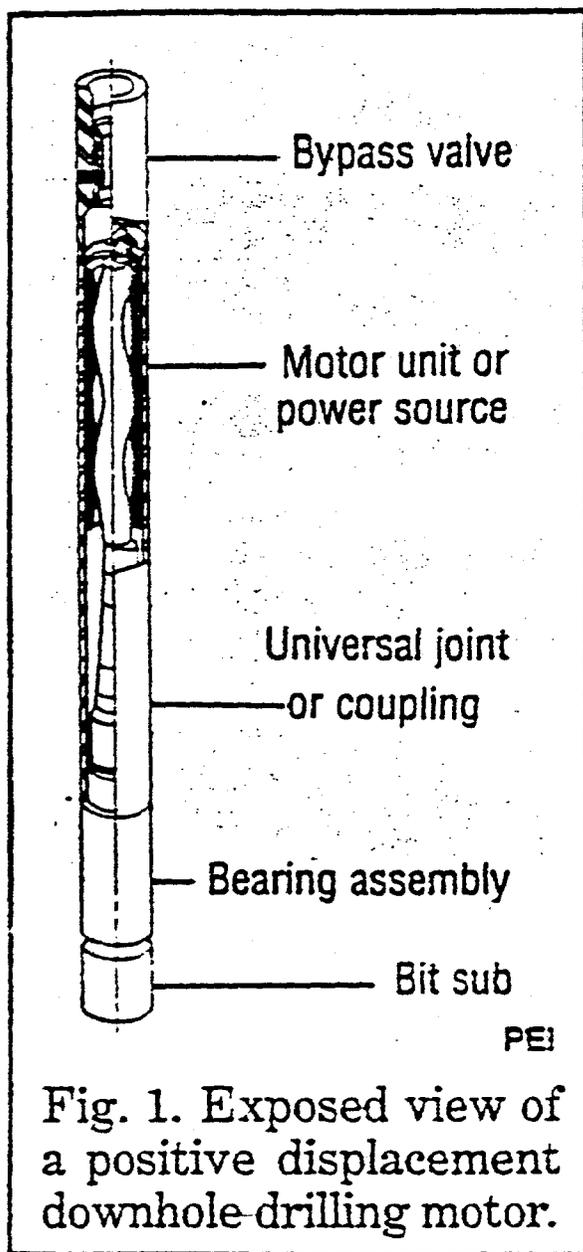


Fig. 1. Exposed view of a positive displacement downhole-drilling motor.

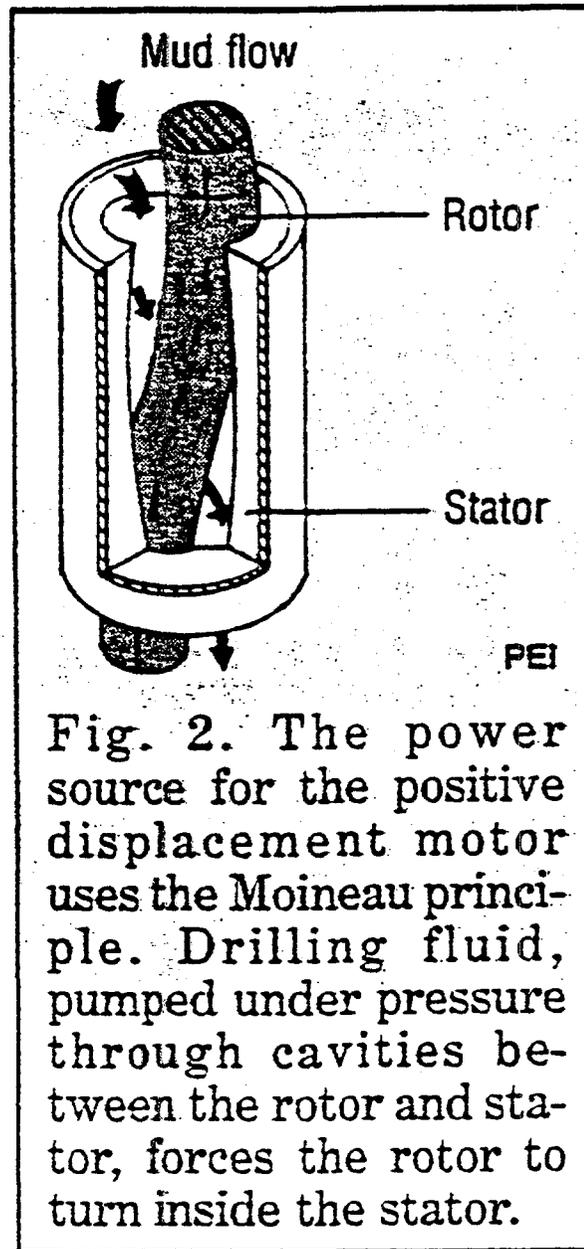
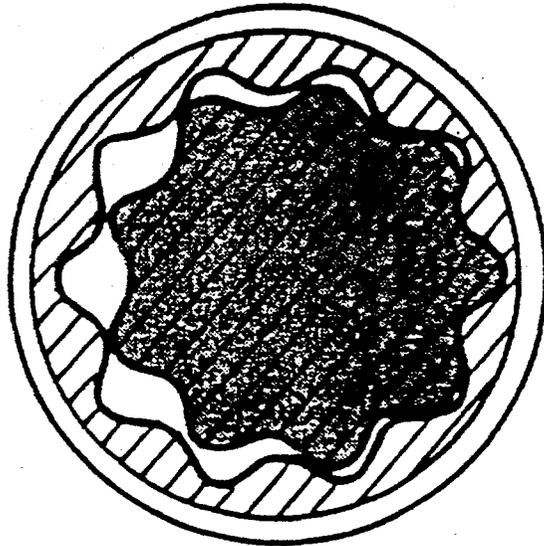
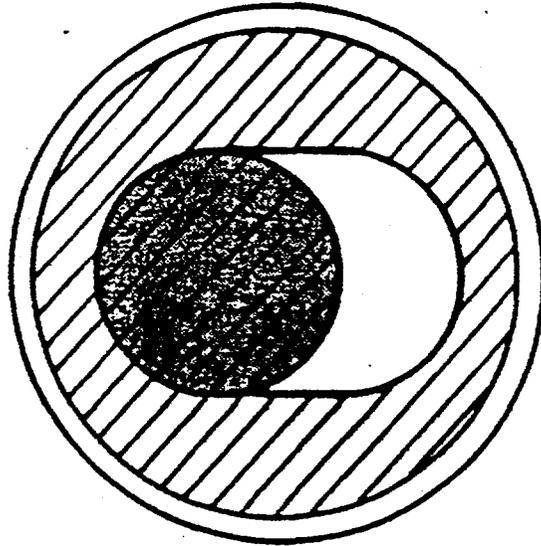


Fig. 2. The power source for the positive displacement motor uses the Moineau principle. Drilling fluid, pumped under pressure through cavities between the rotor and stator, forces the rotor to turn inside the stator.

Multilobe positive  
displacement motor



Conventional positive  
displacement motor



PEI

Fig. 3. Cross-sectional views of a multilobe and conventional positive displacement downhole drilling motor's power source. The increased number of lobes allows the motor to deliver higher power at low speeds and high torque.

## Navi-Drill® Mach 1

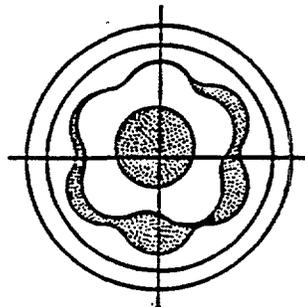
The Navi-Drill Mach 1 is a positive-displacement motor that develops high torque at the bit at a relatively low speed range (80-340 rpm). This makes it ideal for directional applications, drilling with high weight-on-bit. Navigation Drilling with roller cone or King Cutter PDC bits, and coring operations.

The Mach 1 motor has a multi-lobe (5/6) rotor/stator configuration, which generates more torque than other EC motors, permitting more weight-on-bit and increasing ROP. The Mach 1 is specifically recommended for use with roller cone bits. Because the motor develops its power at low speeds, it can improve the performance of these

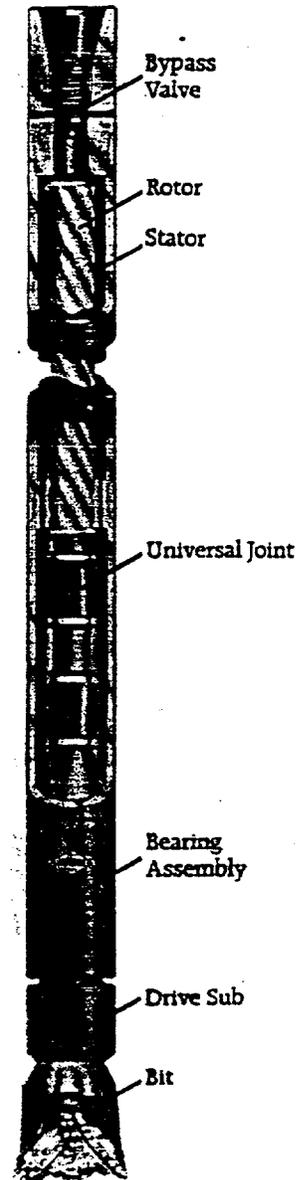
bits without accelerating wear on bit bearings or cones.

A unique bearing assembly and improved elastomer compounds in the stator have increased the Mach 1's hydraulic horsepower and extended operating life. The Mach 1 also has a new rotor nozzling system that allows the motor to be run at 50-100% over its maximum flow rate without exceeding maximum recommended motor speed. The additional mud passes through the motor's rotor, and flow rate can be adjusted with interchangeable nozzles. The higher rates offer improved hole cleaning and bit hydraulics.

Although primarily a directional performance drilling motor, the Mach 1 can also be used for straight-hole drilling and for coring operations.



5/6 Rotor/Stator Relationship



SPECIFICATIONS (U.S. Std.)													
Tool Size O.D.	Recommended Hole Size	Pump Rate GPM		Bit Speed Range rpm	Operating DiL Pressure psi	Operating Torque** ft.-lbs.	Max. Torque ft.-lbs.	Horsepower Range hp	Efficiency max. %	Thread Connection		Length ft.	Weight lbs.
		min.	max.							By-Pass Valve Box up	Bit Sub Box down		
3 3/4	4 1/4 - 5 1/4	65	185	120-340	800	890	1420	20-58	67	2 1/2" Reg	2 1/2" Reg	16.1	440
4 1/4	6 - 7 1/4	80	240	100-300	725	1180	1890	22-67	68	3 1/2" Reg	3 1/2" Reg	17.4	710
6 1/4	8 3/4 - 9 1/4	185	475	100-260	725	2800	4480	53-139	70	4 1/2" Reg	4 1/2" Reg	19.8	1720
8	9 1/2 - 12 1/4	315	685	85-190	580	4500	7200	73-163	70	6 3/4" Reg	6 3/4" Reg	22.9	2430
9 1/2	12 1/4 - 17 1/2	395	740	100-190	800	6870	10970	131-249	72	7 3/4" Reg	6 3/4" Reg	24.6	4080
11 1/4	17 1/2 - 26	525	1135	80-170	655	9770	15570	149-316	73	7 3/4" Reg	7 3/4" Reg	26.5	6070

SPECIFICATIONS (Metric)													
Tool Size O.D.	Recommended Hole Size	Pump Rate l/m		Bit Speed Range rpm	Operating DiL Pressure bar	Operating Torque** Nm	Max. Torque Nm	Horsepower Range kW	Efficiency max. %	Thread Connection		Length m	Weight kg
		min.	max.							By-Pass Valve Box up	Bit Sub Box down		
3 3/4	4 1/4 - 5 1/4	250	700	120-340	55	1200	1920	15-43	67	2 1/2" Reg	2 1/2" Reg	5.1	200
4 1/4	6 - 7 1/4	300	900	100-300	50	1600	2560	17-50	68	3 1/2" Reg	3 1/2" Reg	5.3	320
6 1/4	8 3/4 - 9 1/4	700	1800	100-260	50	3800	6080	40-103	70	4 1/2" Reg	4 1/2" Reg	6.1	781
8	9 1/2 - 12 1/4	1200	2600	85-190	40	6100	9760	54-121	70	6 3/4" Reg	6 3/4" Reg	7.0	1100
9 1/2	12 1/4 - 17 1/2	1500	2800	100-190	55	9300	14880	97-185	72	7 3/4" Reg	6 3/4" Reg	7.5	1850
11 1/4	17 1/2 - 26	2000	4300	80-170	45	13200	21120	109-235	73	7 3/4" Reg	7 3/4" Reg	8.1	2750

\*Available with 5 1/2" Reg in US only \*\*Operating above this level can shorten tool life.

# 4<sup>3</sup>/<sub>4</sub>" 5/6 LOBE E2000S

## DYNA-DRILL® MOTORS

- Diamond thrust bearings increase service life and perform in a wide weight-on-bit range, from very high to very low.
- Operates with bit pressure drops of up to 2,000 psi.
- Available in Slo-Speed or medium-speed models.
- Available in straight or steerable configurations.

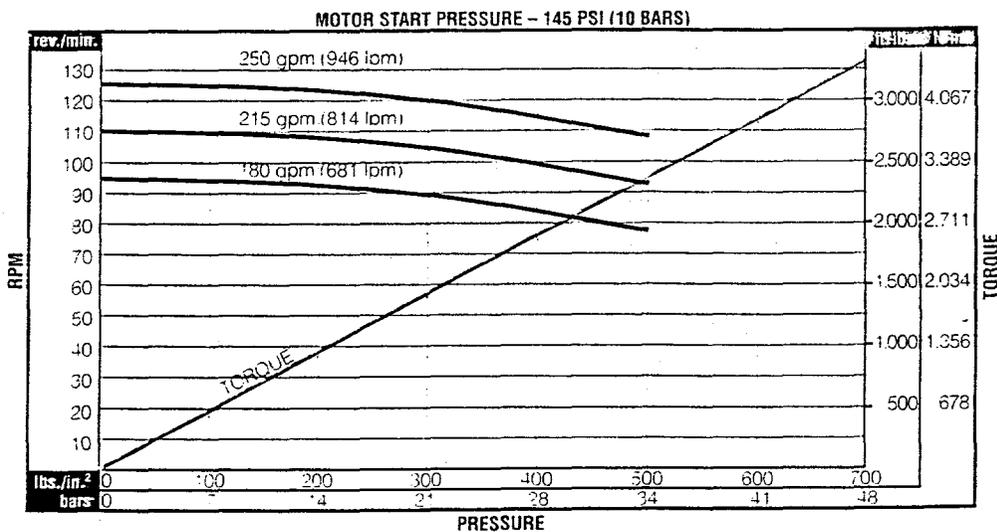
### DIMENSIONAL SPECIFICATIONS

Thread Connections		
Box-Up (API-Reg.)	3 1/2"	3 1/2"
Box-Down (API-Reg.)	3 1/2"	3 1/2"
Overall Length		
Without Saver Sub	21.3'	6.5 m
Tool Weight	1,025 lbs.	465 kg

### OPERATIONAL DATA

Hole Size Range	5 7/8"-7 7/8"	149-200 mm
Motor Flow Rate Range	180-215-250 gpm	681-814-946 lpm
Bit Speed Range	95-110-125 rpm	95-110-125 rpm
Motor Differential Pressure	300 psi	21 bars
Operating Torque	1,400 ft.-lbs.	1,898 N-m
Stall Torque	2,800 ft.-lbs.	3,796 N-m
Horsepower	25-29-33 hp	19-22-25 kW
Bit Differential Pressure	200-2,000 psi	14-138 bars

### PERFORMANCE CURVES



## D-89 Directional Turbodrill

The D-89 Directional Turbodrill is a turbine-type downhole motor powered by the rig's drilling fluid. Used with a bent sub for directional drilling applications, its power and high rotational speeds make it ideal for moderately hard to hard formations. Under optimum conditions the Turbodrill can generate over 100 horsepower and rotate up to 1000 rpm. The D-89 Turbodrill has proved to be a reliable tool in hot hole applications, including geothermal wells.

The Directional Turbodrill has the capability to drill a wide range of hole sizes, with bits up to 17½" OD. Its high flow rates help clear out cuttings from bottom hole. This is especially helpful when drilling larger holes. The Turbodrill is tolerant to abrasive drilling muds and can operate with mud temperatures up to 300° F.

Available for rental on a contract basis. These items sold for export only; use or resale for use in the United States is prohibited.

The D-89 Directional Turbodrill makes full-gauge hole at kick-off points and can be reoriented in-hole, allowing multiple corrections during the same tool run.

With rotary action only at the bit, wear on the drill string, casing, and draw works is eased and key seats caused by rotating pipe are avoided.

A safety locking device prevents the turbine shaft from dropping downhole in case of internal tool failure, avoiding expensive fishing delays.

## Drill Pipe Mud Screens

Drill Pipe Mud Screens, used to filter rocks and other debris out of the drilling mud, are available in two models.

The cone type mud screen operates in the kelly. (It is not designed for downhole use.) The rod plunger mud screen may be used in either the kelly or downhole, and is retrievable with an overshot.

### D-89 TURBODRILL

Outside Diameter	6 7/8"	7 1/2"	7 1/2"
Length (less IR, sub)	22.5'	22.5'	22.5'
Weight (lbs.)	1800	2200	2375
No. of Stages	75	75	75
IR Connection Box	4 1/2" API Reg. or 6 1/4" API Reg.	6 1/4" API Reg.	6 1/4" API Reg.
Top Connection Box	4 1/2" API Reg.	5 1/2" API Reg.	5 1/2" API Reg. or 6 1/4" API Reg.

\*Other sizes optional; float bore available.

### D-89 TURBODRILL PERFORMANCE DATA 75 Stage

Mud: 10 lb/gal 10 Plastic Viscosity  
Operated at Balanced Weight

Flow Rate (GPM)	Speed (RPM)	Pressure Drop (PSI)	Horsepower	Torque (ft-lb)	Balanced Weight (lbs.)
300	328	172	28.5	239	5992
325	375	233	31.5	246	6230
350	420	303	35.7	251	6665
375	468	329	41.9	285	7220
400	513	364	49.2	318	8011
425	560	409	59.0	350	8988
450	603	461	71.0	411	10139
475	653	517	84.7	467	11376
500	1000	573	100.0	525	12614

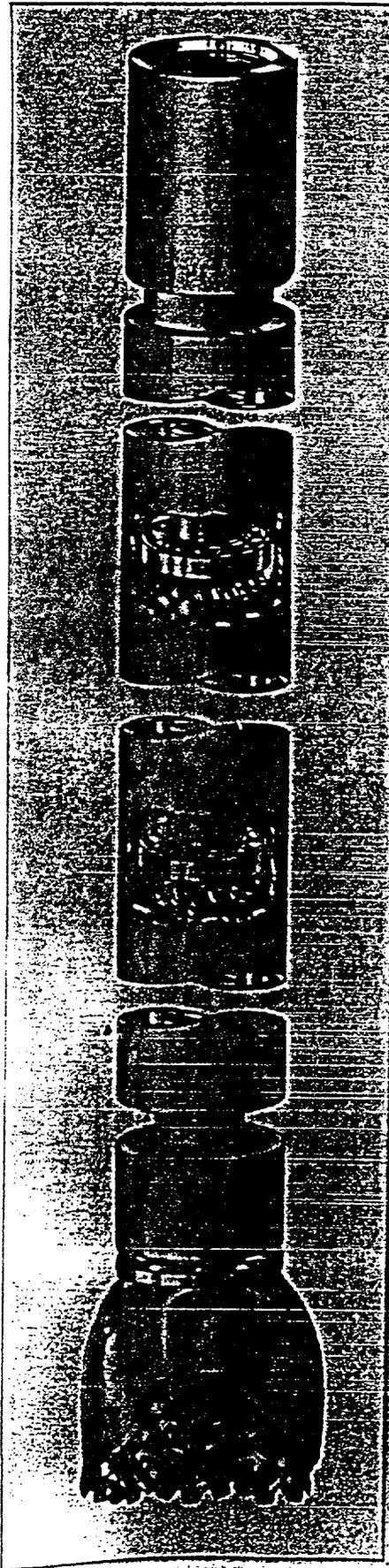
### DRILL PIPE MUD SCREENS

#### PLUNGER ROD TYPE

Part No.	Size	Weight (lbs.)	Length
D81-0221	4" API FH Box	18	60"
D81-0222	4 1/2" API FH Box	18	60"
D81-0224	5 1/2" API FH Box	20	60"
D81-0225	4 1/2" API FH Box (1 1/2" X-Hole)	18	60"
D81-0112	4" API IF (4 1/2" X-Hole)	18	50"

#### CONE TYPE

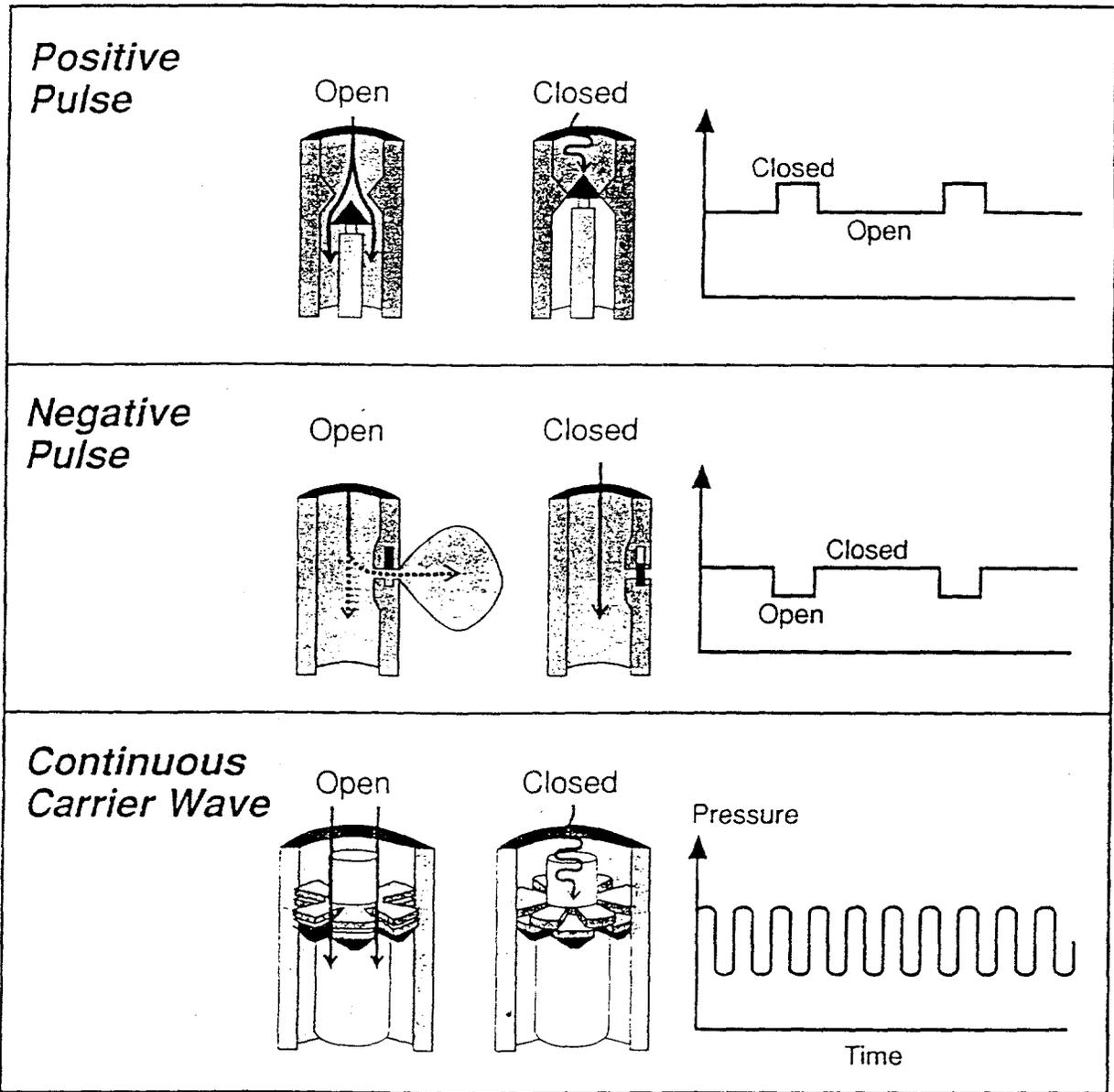
Part No.	Size	Weight (lbs.)	Length
D81-010	3 1/2" API X-Hole	1	12"
D81-011	4" API X-Hole	1.5	12"
D81-012	4 1/2" API X-Hole	1.5	12"
D81-013	5 1/2" API X-Hole	2	12"
D81-022	4 1/2" API FH	1.5	12"
D81-000	3 1/2" API F	1	12"
D81-032	4 1/2" API F	1.5	12"
D81-006	2 1/2" API IF	1	12"



# Surveying Methods

- *Physical Principles*
  - *Gravity*
  - *Direction Relative to Some Direction*
- *Types*
  - *Magnetic Single Shot*
  - *Magnetic Multi-Shot*
  - *Steering Tool*
  - *MWD*
  - *Gyro Instruments*

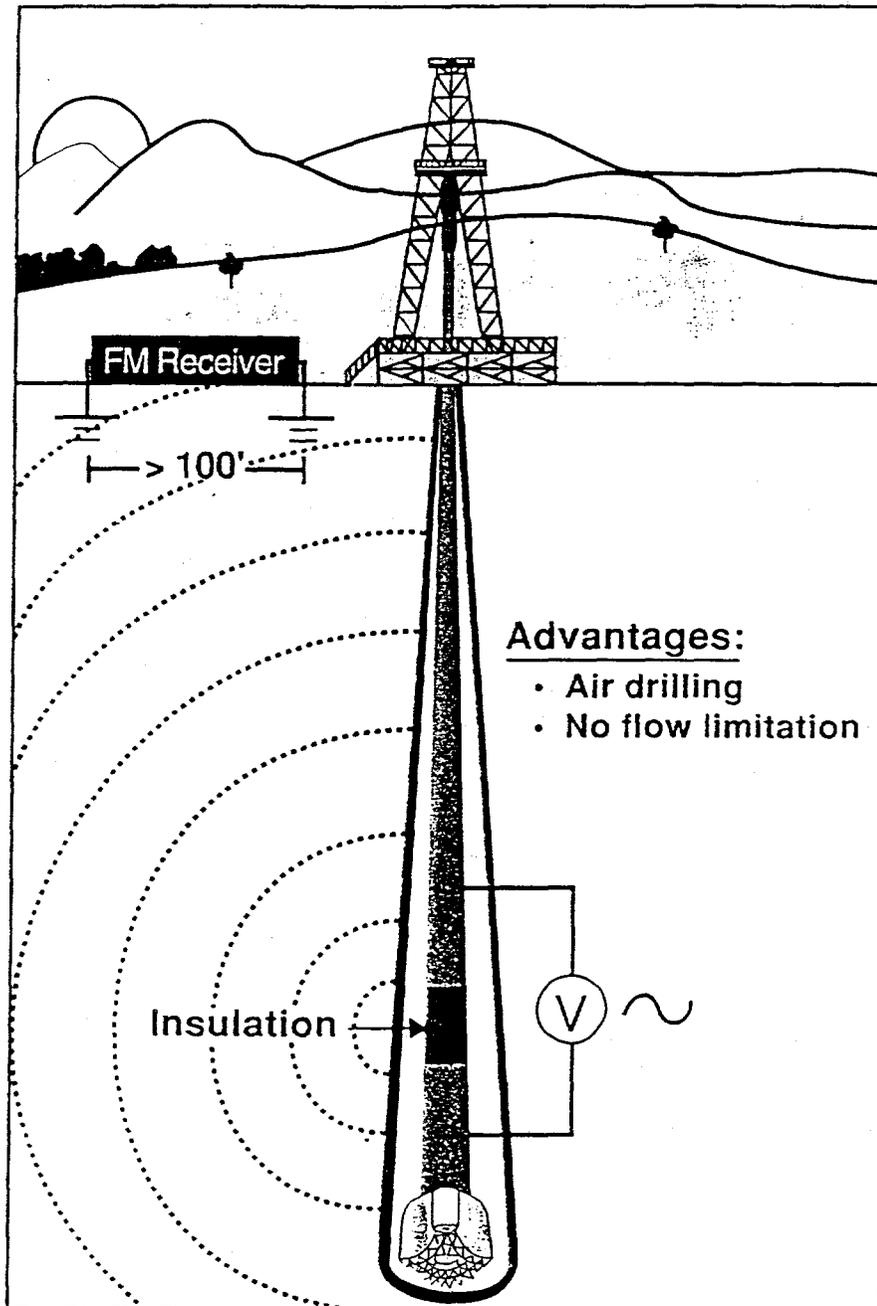
# Mud Pulse Telemetry



## Downhole Memory

Some tools augment real-time telemetry with a downhole memory for higher frequency data, and for recording data while not circulating. These data are usually read from memory when the tool is at the surface or transmitted from downhole when convenient.

# Electromagnetic Telemetry



### Advantages:

- Air drilling
- No flow limitation

### Limited to:

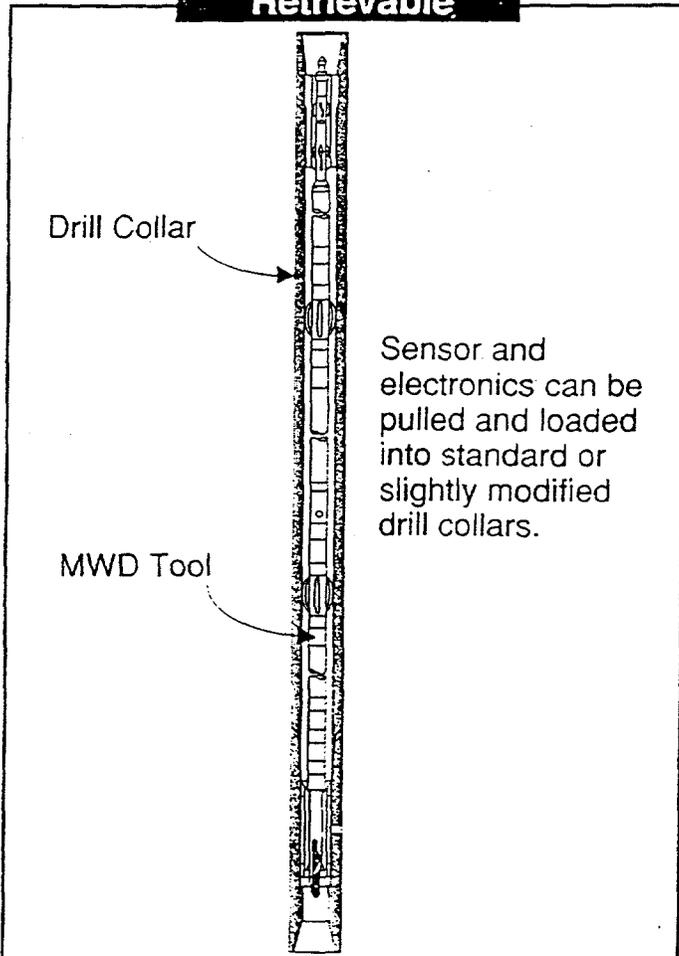
- Moderate to high formation resistivities
- Mostly onshore use

### Data Rate:

- About same as mud pulse  
- potential to go higher

# Retrievable vs Non-Retrievable

## Retrievable



Sensor and electronics can be pulled and loaded into standard or slightly modified drill collars.

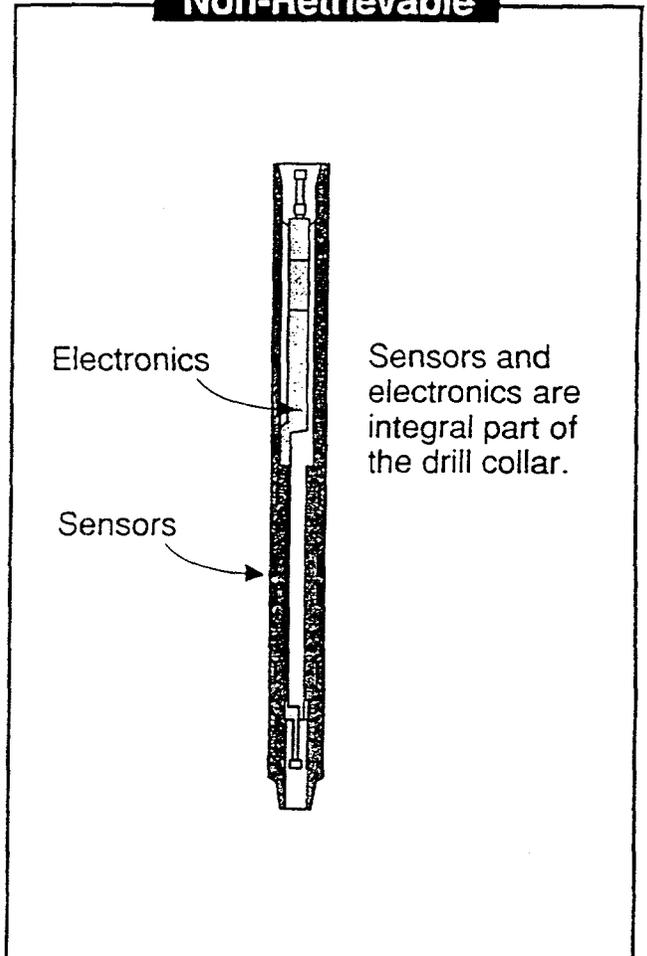
+

- Zero or limited lost-in-hole charges
- Light, easily transported
- Lower cost
- Run or replace on slick line when needed

-

- Limited sensors
- Typically lower reliability

## Non-Retrievable



Sensors and electronics are integral part of the drill collar.

+

- Typically multi-sensor
- Higher reliability

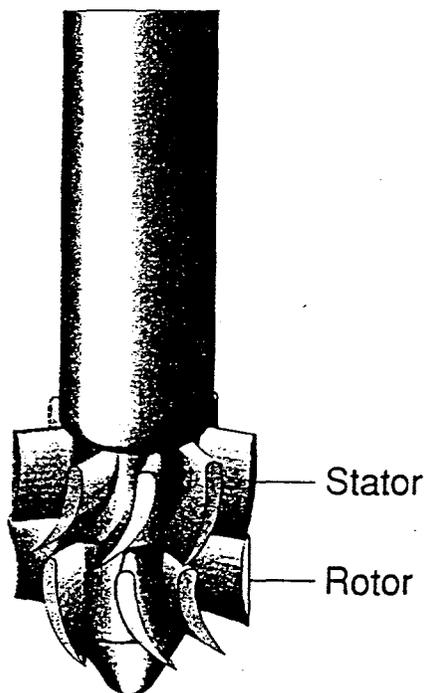
-

- High lost-in-hole charges
- Trip to replace



# MWD Power Sources

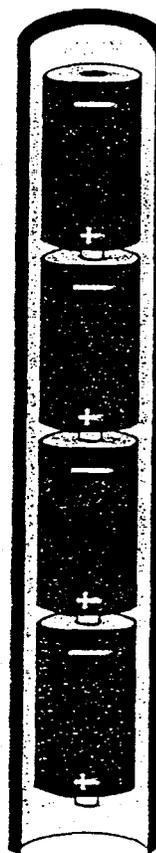
## Mud Turbines



- +
- More power
  - Longer life

- 
- Only works when circulating
  - Erosion in abrasive muds

## Batteries



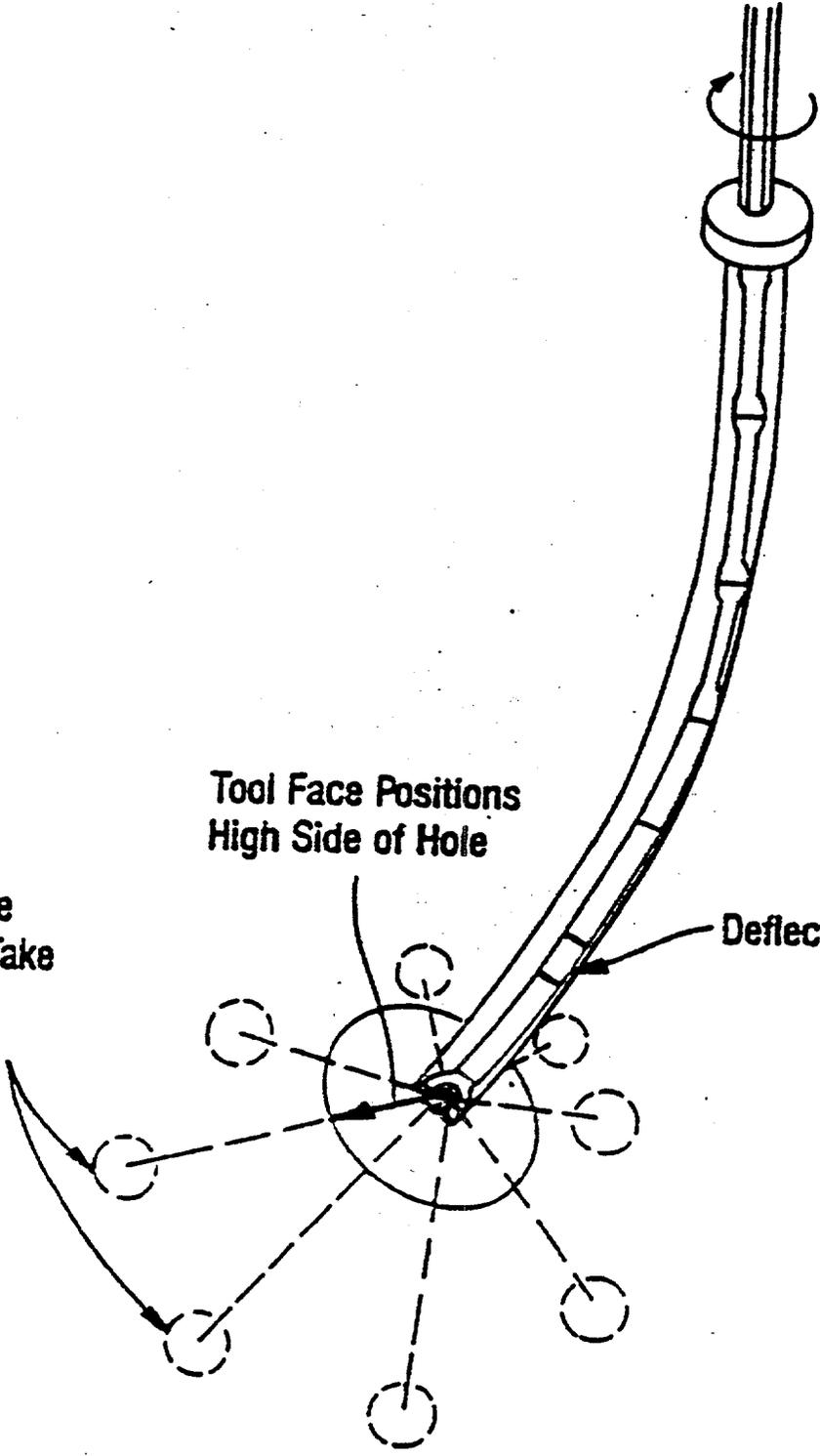
- +
- Measurements all the time

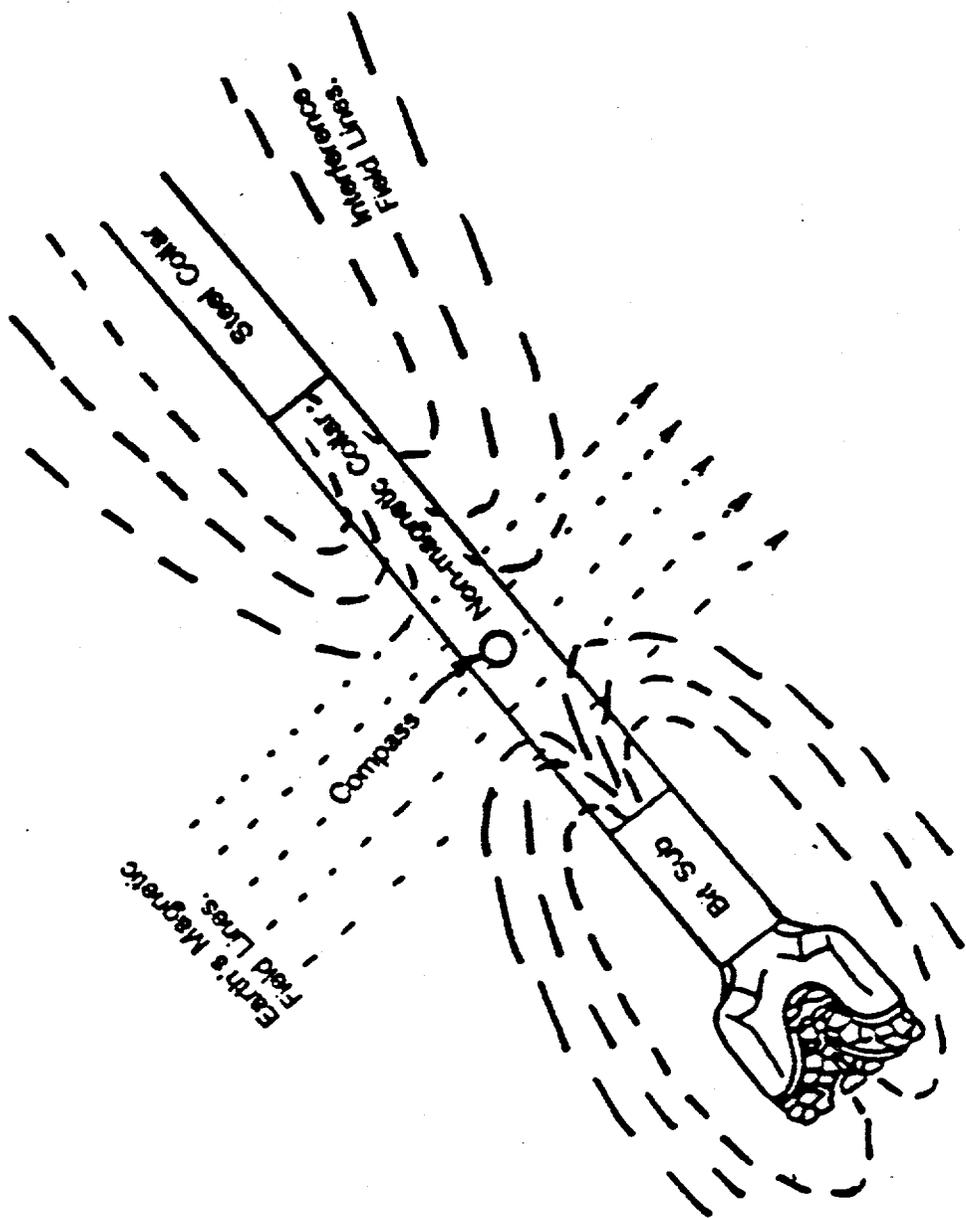
- 
- Shorter life
  - Temperature limited
  - Less power
  - Handling of lithium batteries

**Courses That The Wellbore Could Take By Rotating the Drill String and Deflecting Sub**

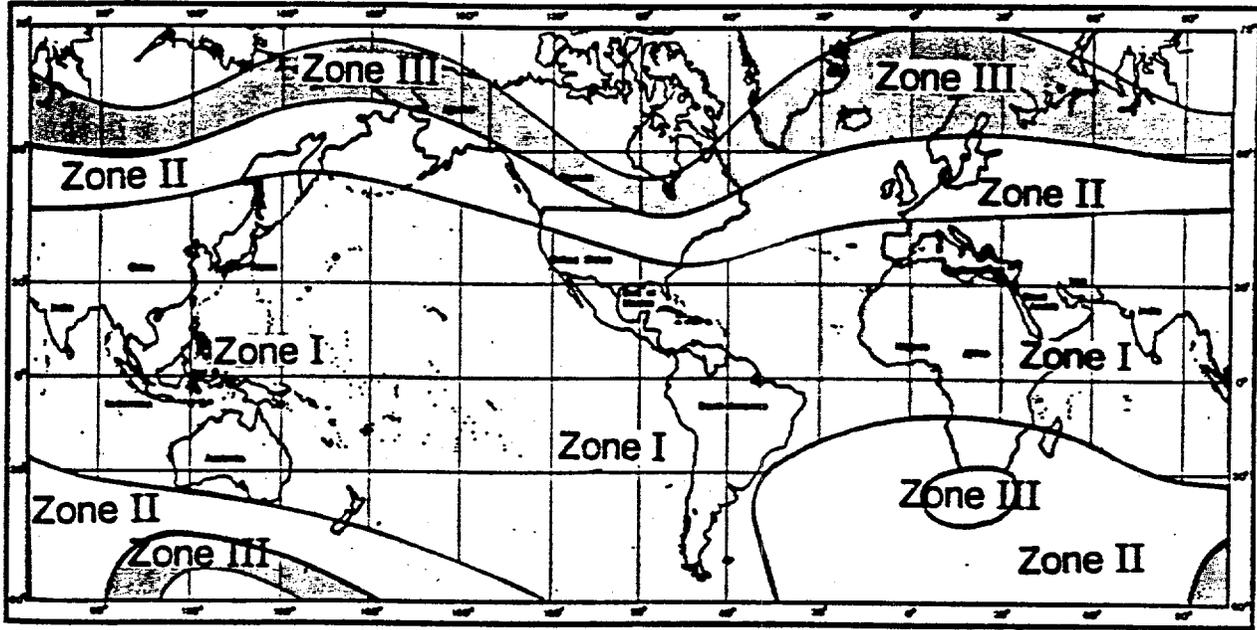
**Tool Face Positions High Side of Hole**

**Deflecting Sub**

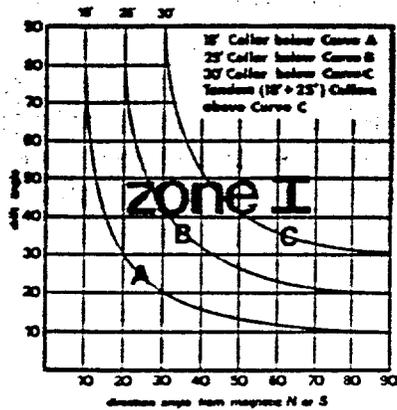




The Earth's horizontal magnetic intensity varies geographically, and the length of nonmagnetic drill collars used in a bottom hole assembly should fit the requirements of the particular area. This map is used to determine which set of empirical data should be used for a given area.

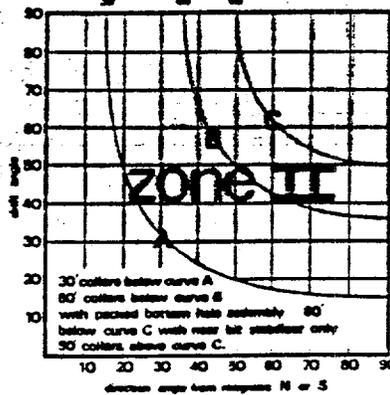


**Empirical Data Charts**



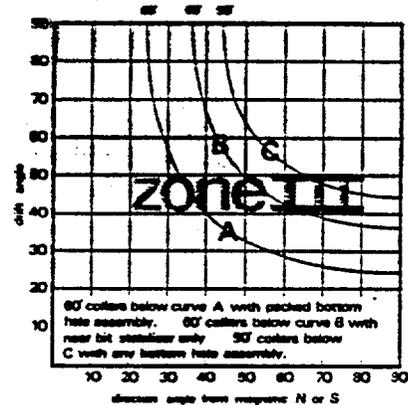
**Compass Spacing**

- 18' collar: 1' to 2' below center
- 25' collar: 2' to 3' below center
- 30' collar: 3' to 4' below center
- tandem 18' + 25': center of bottom collar



**Compass Spacing**

- 30' collar: 3' to 4' below center
- 60' collars: at center (curve B)
- 60' collars: 8' to 10' below center (curve C)
- 90' collars: at center



**Compass Spacing**

- 60' collars: at center (curve A)
- 60' collars: 8' to 10' below center (curve B)
- 90' collars: at center

Fig. 8.56—Zone-selection map and charts to determine how many nonmagnetic drill collars are required (courtesy Smith Intl. Inc.).

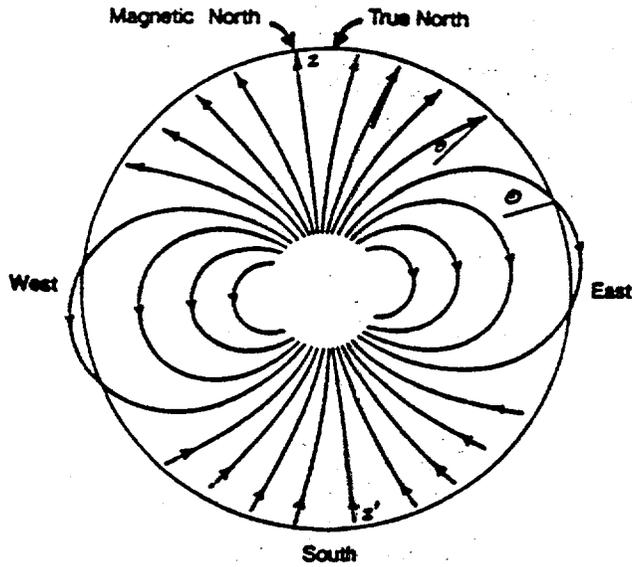


Fig. 8.62—Earth's magnetic field.

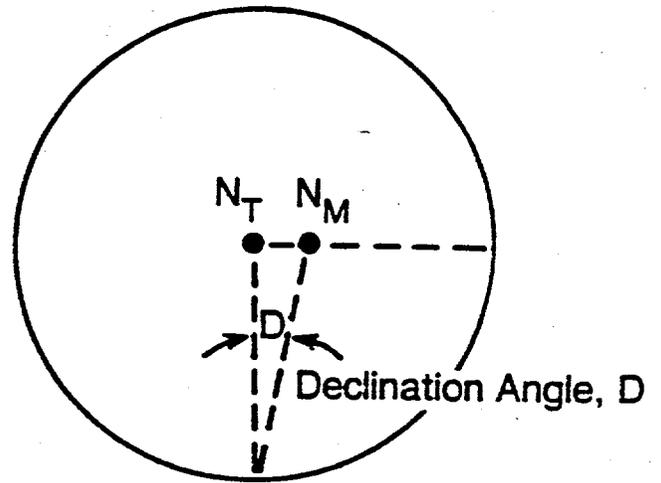


Fig. 8.63—Declination.

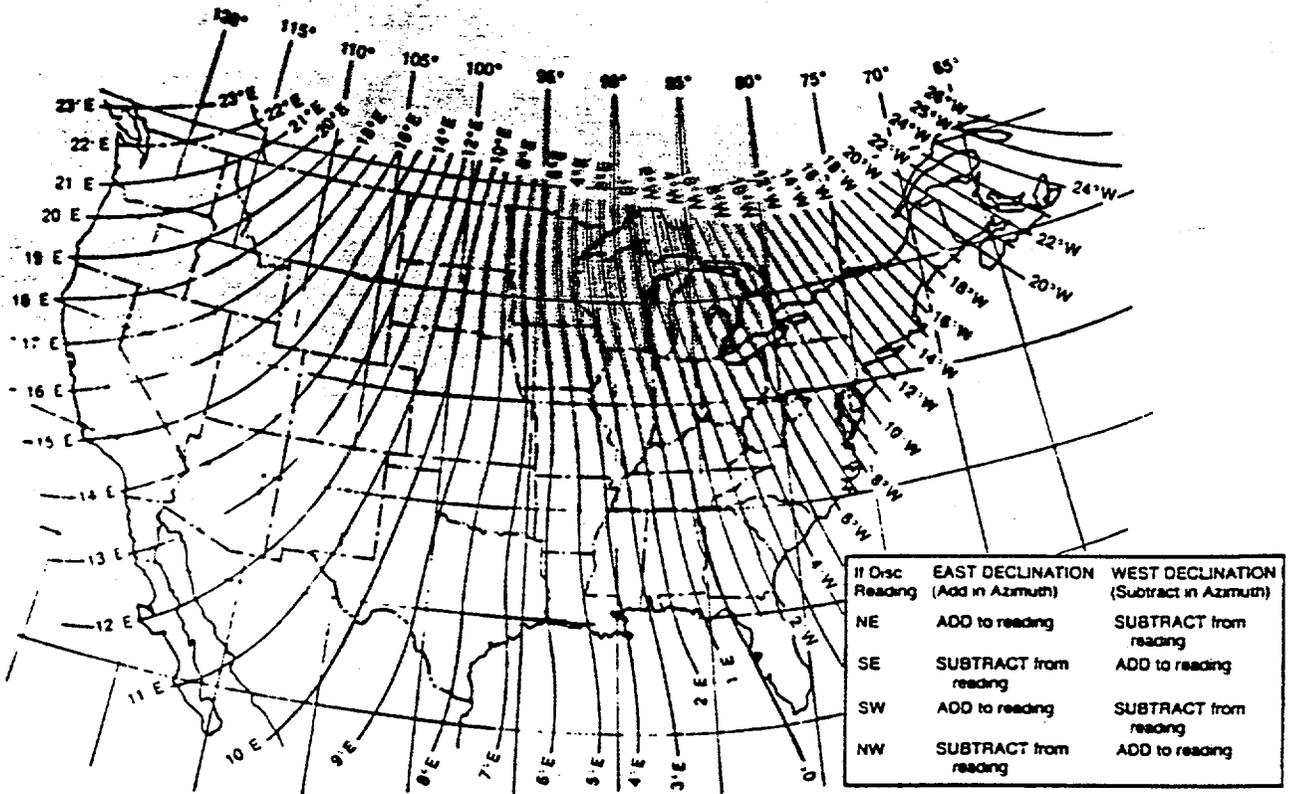
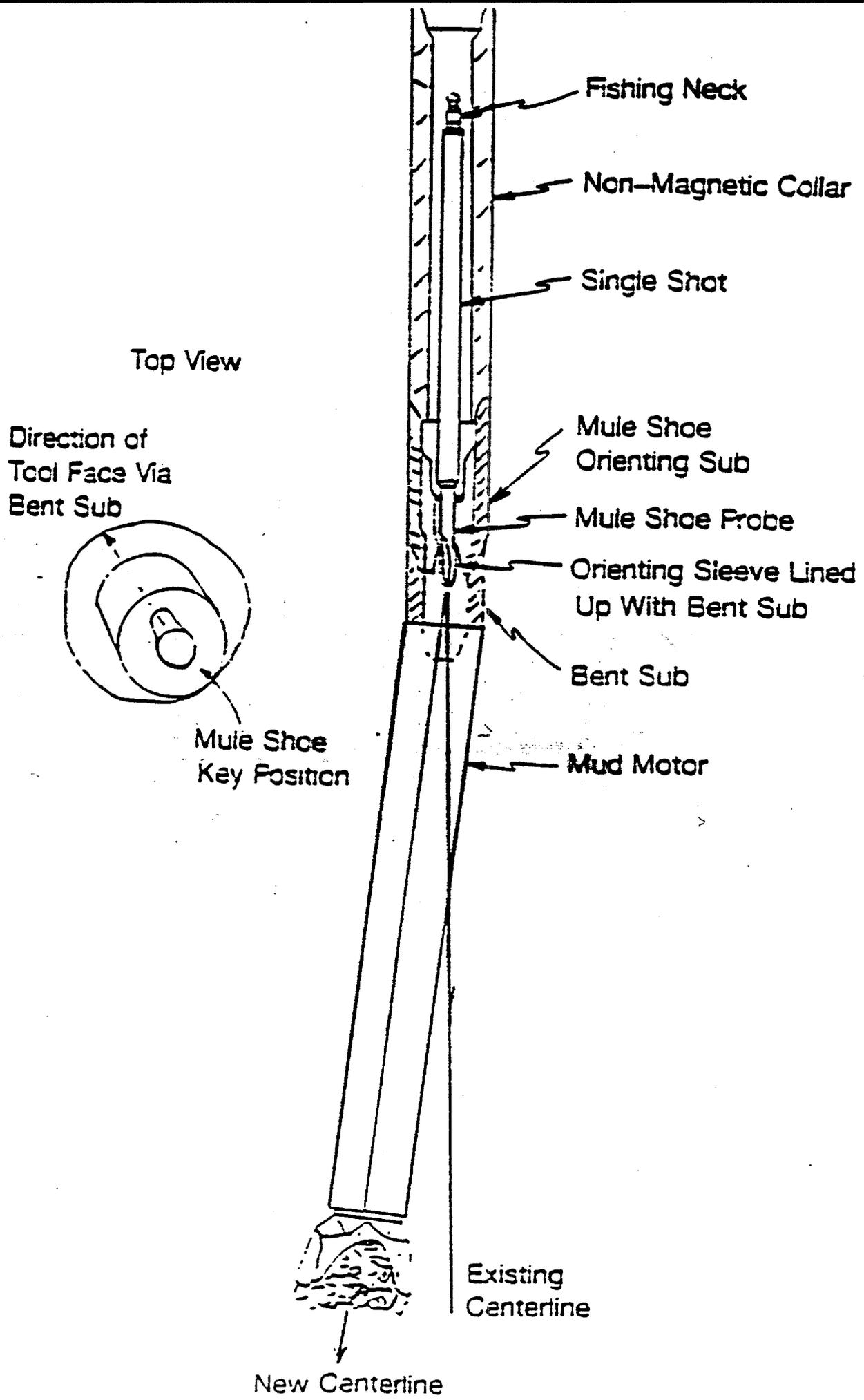
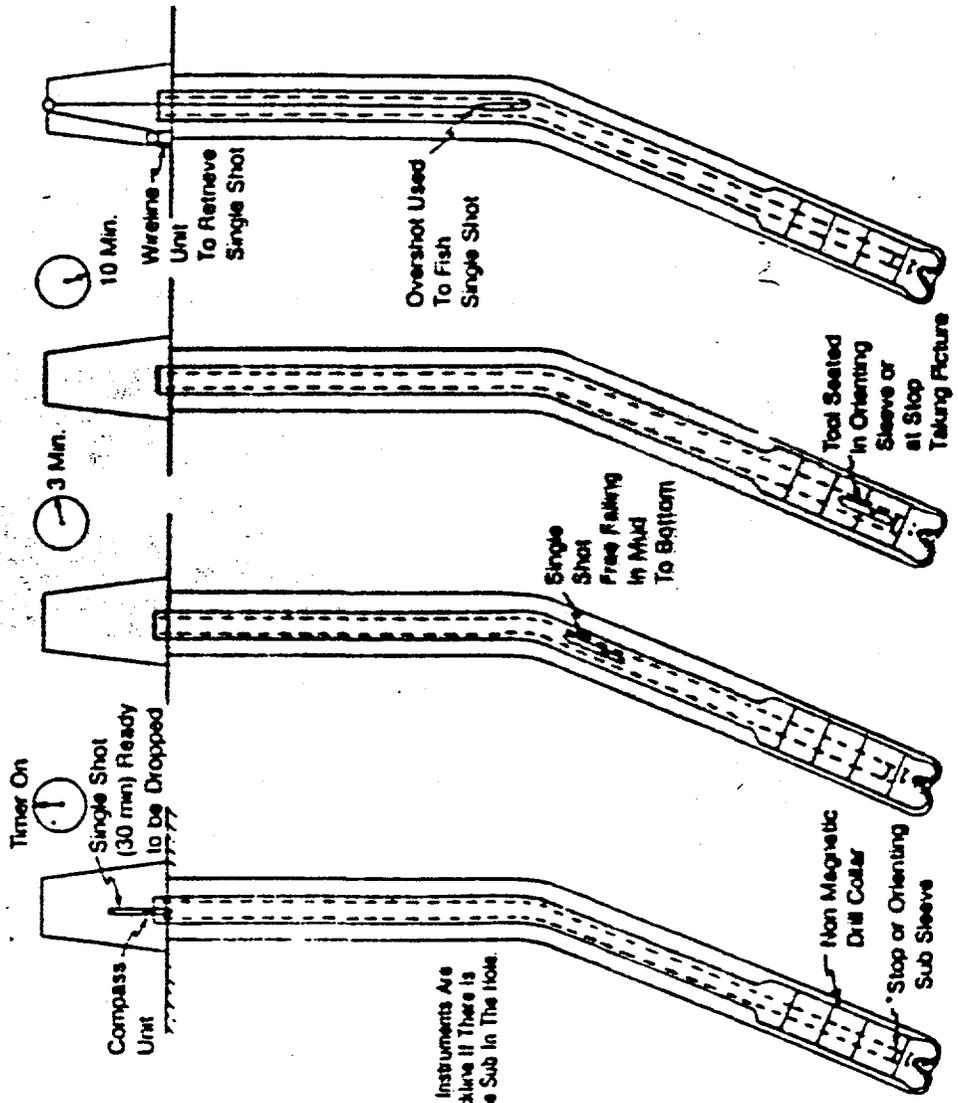
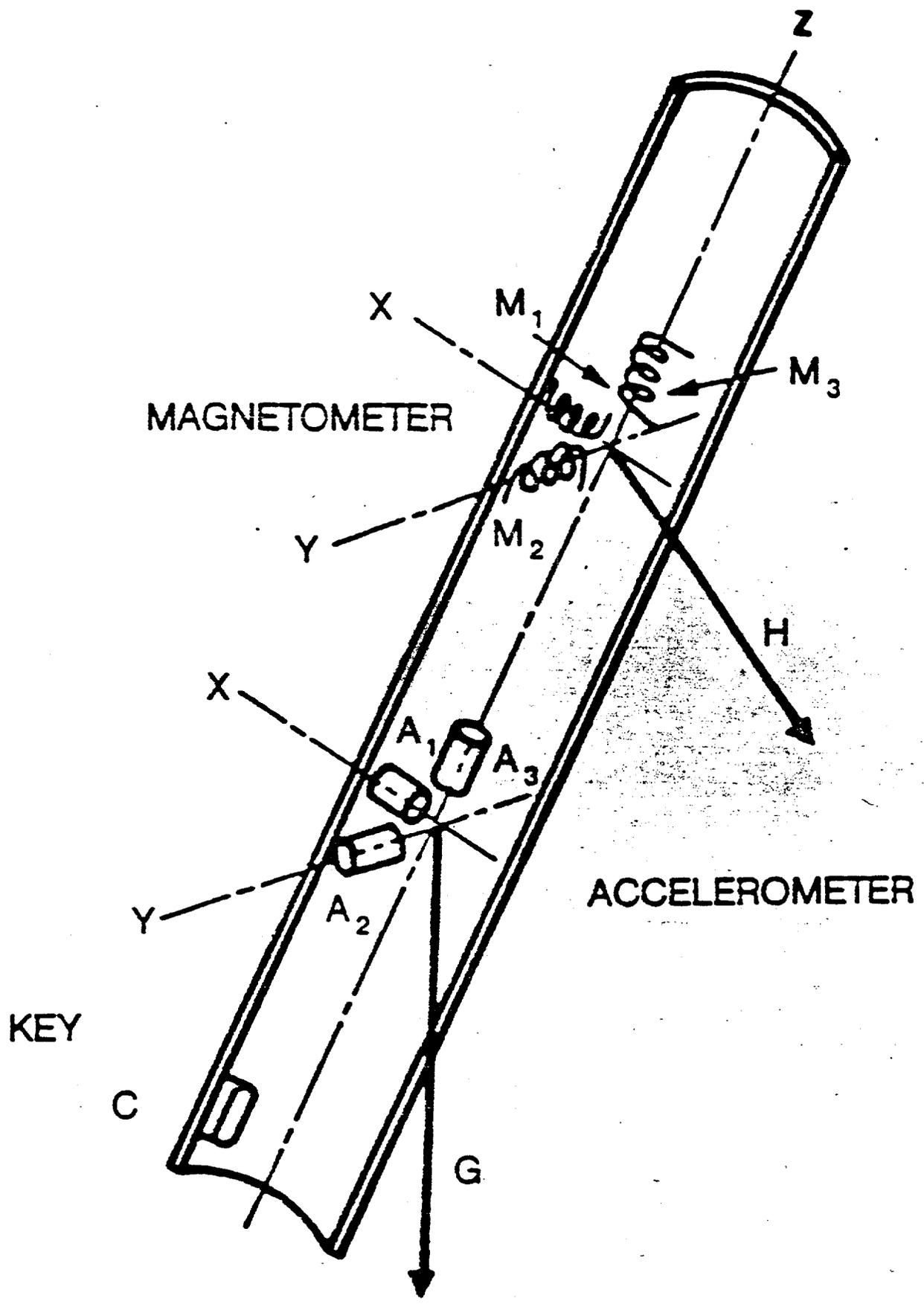


Fig. 8.64—Isogonic chart for the U.S.





\*Note:  
 Single Shot Instruments Are  
 Run On Slickline If There is  
 A Mule Shoe Sub In The Hole.



## Directional Orientation Tool (DOT)<sup>™</sup>

The Directional Orientation Tool (DOT) provides continuous real-time measurements of hole inclination, direction, and toolface orientation during drilling with a downhole motor. The DOT system comprises a solid-state electronic probe, a surface computer, a hard copy printer, and a driller's read out.

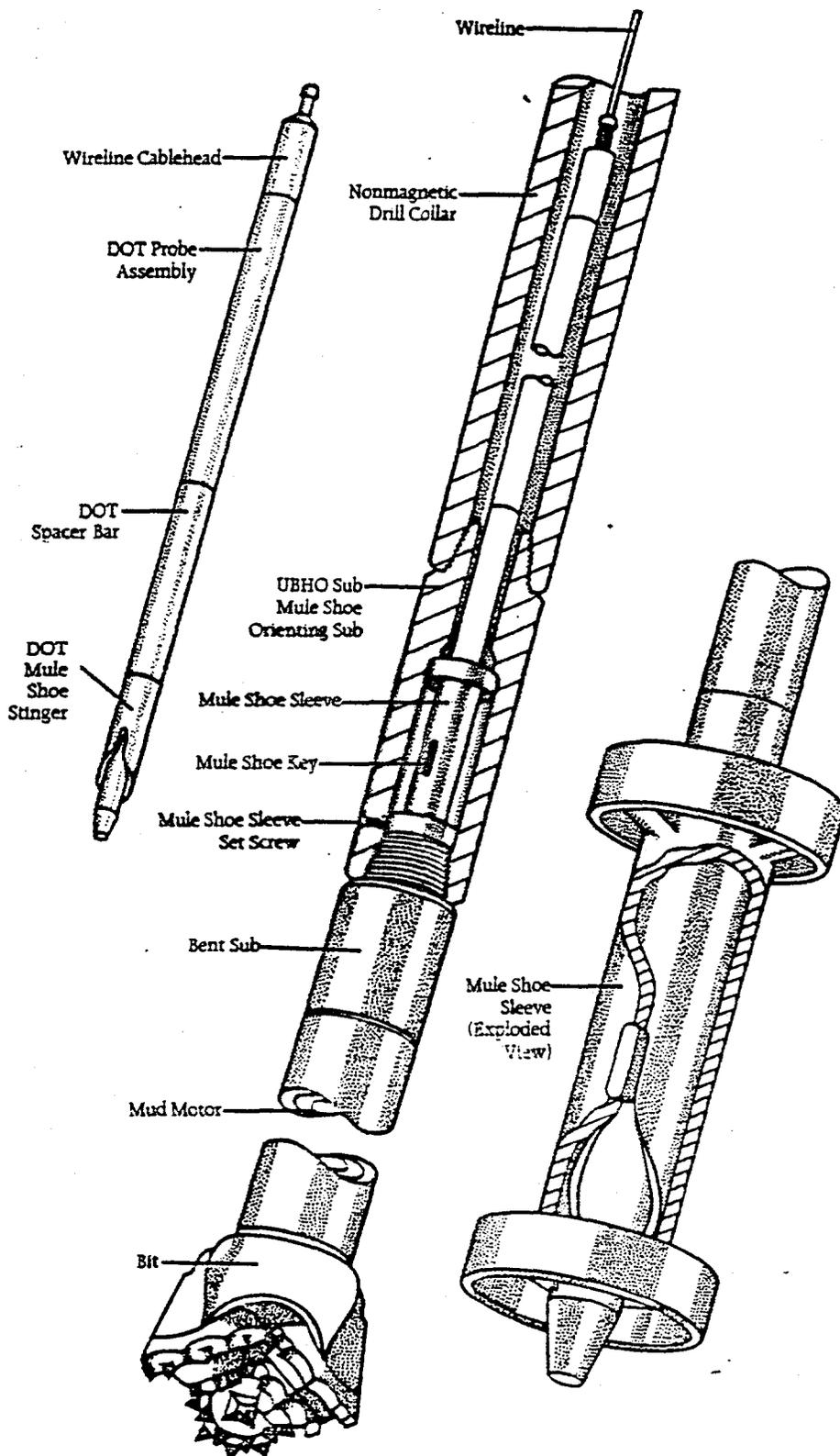
The probe is run downhole on a single-conductor wireline and seats in a mule shoe assembly in a UBHO sub immediately below a nonmagnetic collar. The probe is a 1 3/4" in diameter and the mule shoe stinger has a diameter of 1 1/4", allowing the tool to be used in drill string IDs as small as 2 1/8".

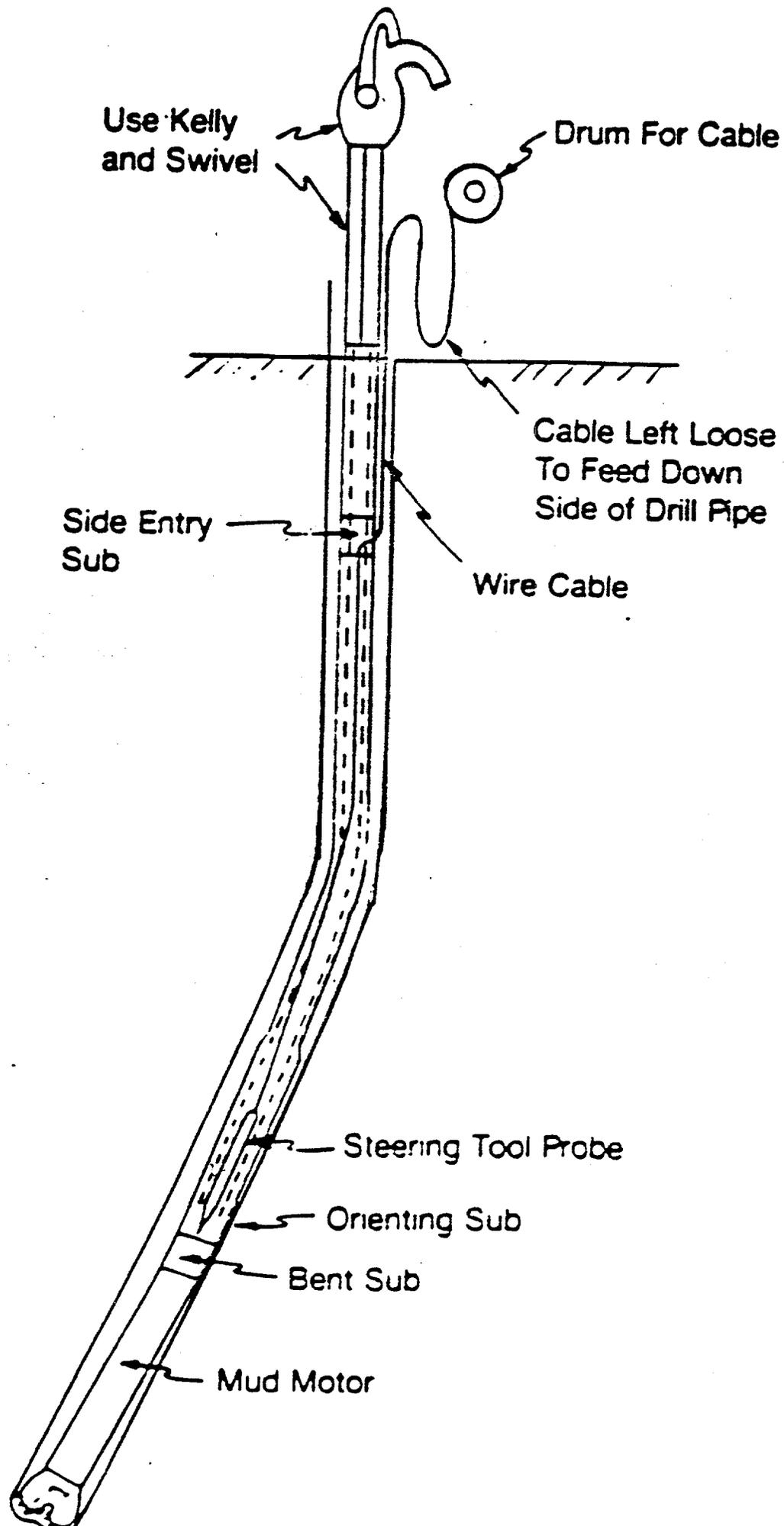
Optional electronics and calibration procedures for the DOT system are available to increase its accuracy and stability, especially in higher angle holes (over 45°).

The system computer provides continuous digital readouts, revised every three seconds, and changes from magnetic to high side mode at the flip of a switch—without changing probes. The computer monitors tool circuitry and wireline conditions and localizes any problems, allowing instant analysis of probe integrity.

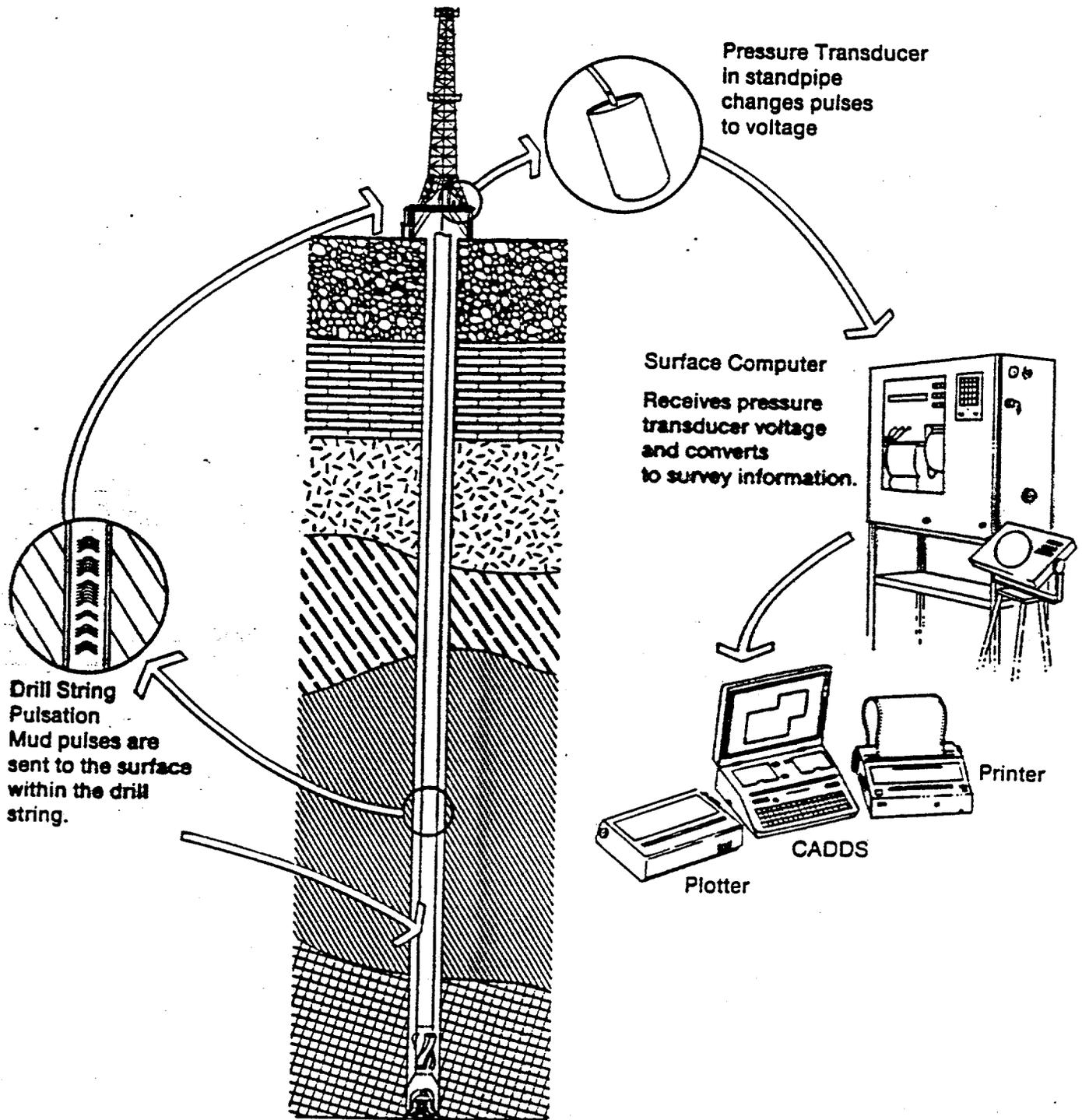
The system computer relays information to the driller's read out where hole direction and toolface orientation are registered on a compass and hole inclination is displayed digitally.

The Eastman Christensen wireline side entry sub permits drill pipe to be added as required without tripping the probe. (The use of a split kelly bushing is essential for safe operation of the wireline entry system.)



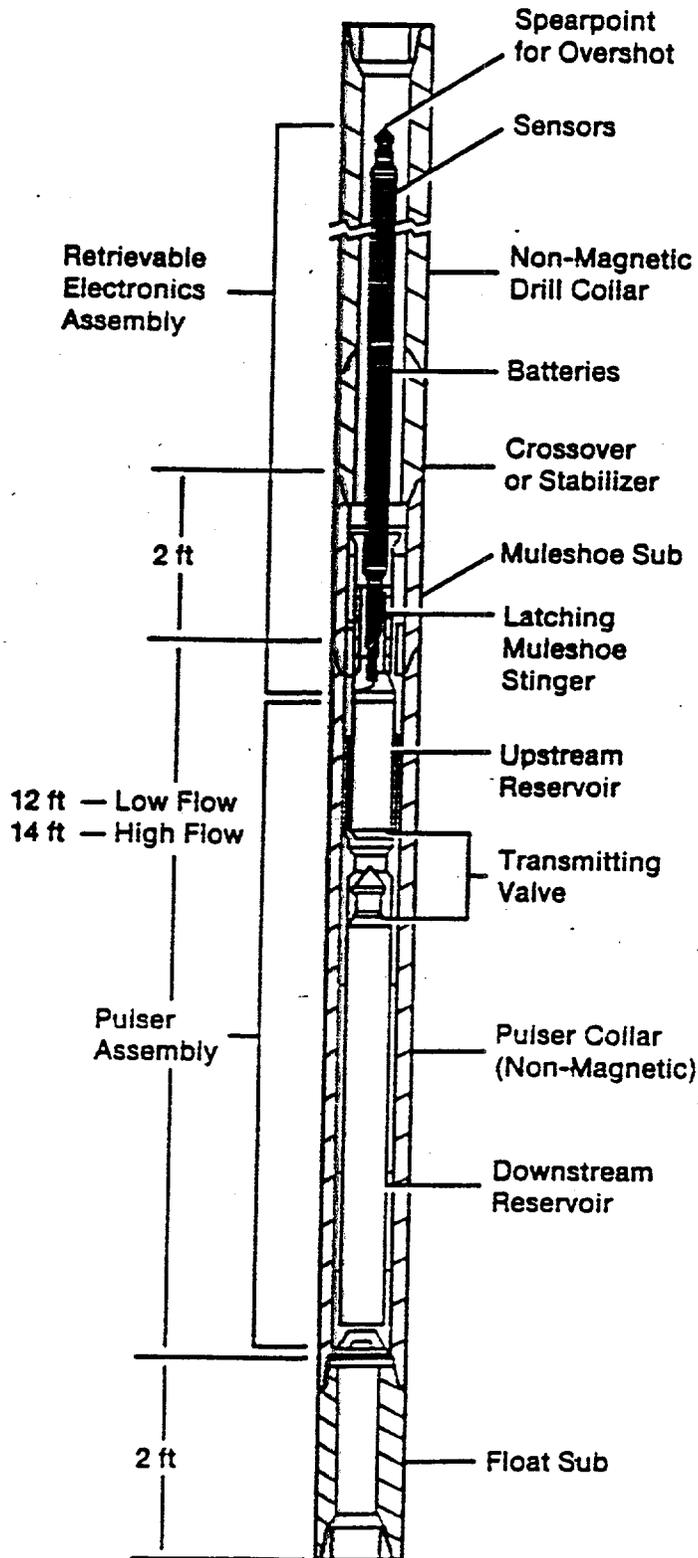


MWD System Schematic  
Figure 1

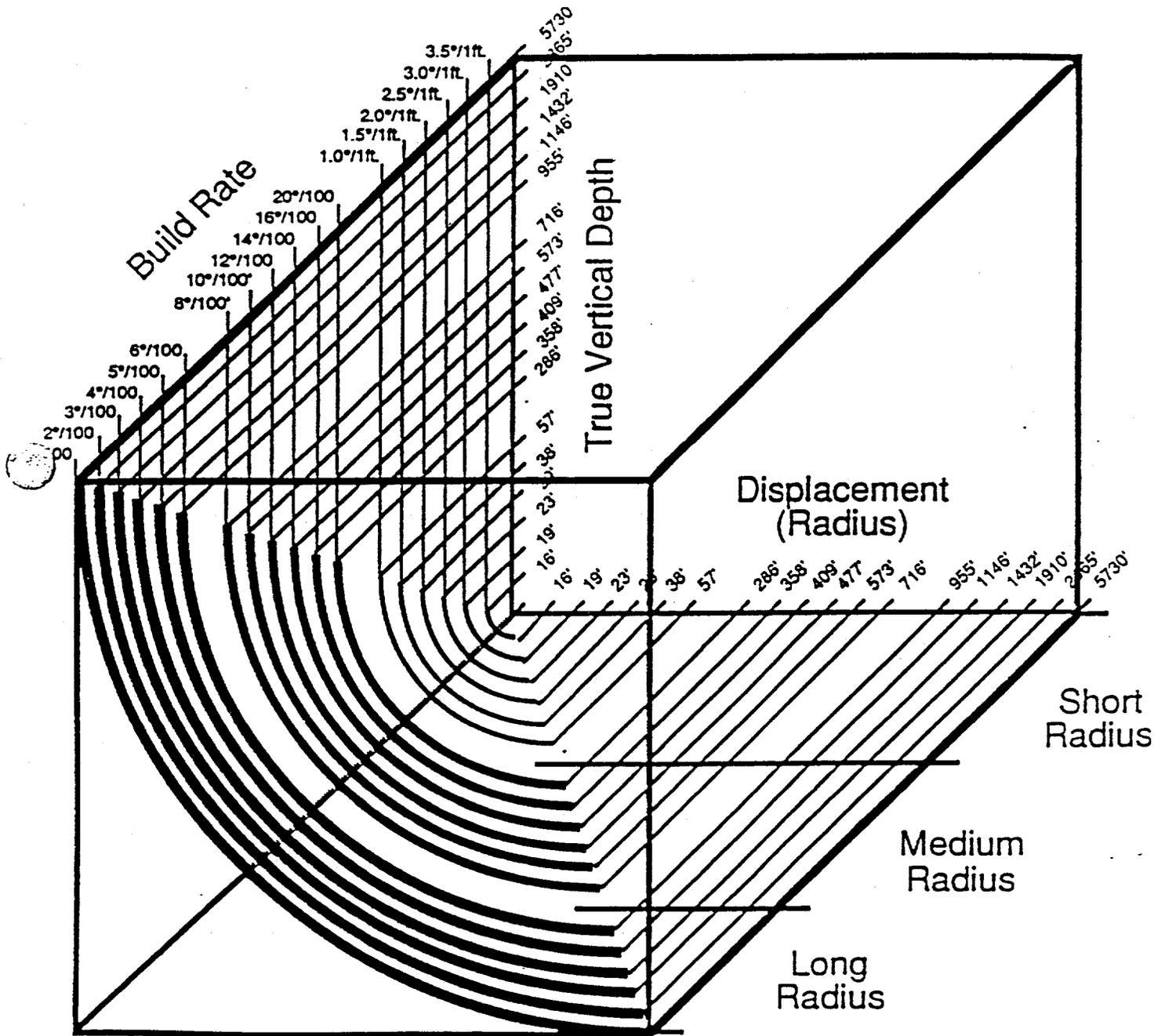


Downhole System  
Figure 3

Smith's Tool



$$\text{Radius of Curvature} = \frac{180}{\pi} \left( \frac{1}{\text{Build Rate } \%/\text{ft}} \right)$$



Build-Up Curves



**TARGETING**

**TARGET TYPES**

There are three general target types that have been used in horizontal drilling operations. These are:

1. Horizontal with wellbore inclined at 90°.
2. Drilled in the reservoir at a structural position so that the borehole parallels bedding of the formation.
3. Slant holes that cut across bedding in the formation at a high angle.

The principal candidate for truly horizontal targets are formations with both gas/oil and water/oil contacts. For these wells, a true horizontal well will keep the distances from the gas cap and water column constant along the wellbore length.

The most common target is the structural position target. For coning applications where only one unwanted fluid is present, the optimum position for the wellbore is to place it at the top of the formation to avoid water coning or at the base of the formation to avoid gas coning. In a sloping formation this will place one end of the horizontal hole closer to the unwanted fluid than the other, but this elevation will provide the maximum possible recovery of oil. In gently dipping formations, where the well can be drilled in either direction, one should consider placing the end most likely to cone at the bottom of the horizontal hole to simplify future remedial operations.

The slant hole has been widely used in horizontal wells. The slant hole design was originated by horizontal well planners concerned over the possibility that the subject reservoir had numerous sealing shale barriers throughout the height of the productive zone. It is reasoned that, if such a condition exists, a horizontal hole paralleling one of the beds might actually be completed in only a 1- or 2-ft high (thick) reservoir. By angling the well across the height of the entire zone, one can be assured of connection with each of the layers in the reservoir. If, in fact, a reservoir is composed of numerous isolated layers, neither a horizontal nor a slant well will likely be economical. The slant well will suffer nearly as much as the horizontal because it will only achieve limited lateral exposure in each of the layers. In order for a horizontal hole to be

successful, the reservoir must provide adequate vertical communication throughout its height, or its completion must connect the vertical height of the reservoir using stimulation treatments. For reservoirs with natural vertical conductivity or for reservoirs where vertical conductivity will be artificially induced, there is an optimum elevation for the horizontal hole. In the case of coning applications, a slant well places most of the hole at a point much closer to the unwanted fluid than a well drilled at the optimum elevation, and it therefore will certainly shorten its life and reduce its ultimate recovery. In the case of a formation with adequate natural vertical permeability, there is a optimum structural position in the reservoir from which the productivity and ultimate recovery will be the highest. For wells that will be stimulated, there is an optimum elevation from which to fracture vertically the desired productive interval. Portions of a slant wellbore that are either above or below the optimum elevation will require larger treatment in order to expose the zone and may, in fact, risk fracturing into other formations or not fully opening the productive interval.

#### DIRECTION

The selected direction for the horizontal holes is most important for naturally fractured reservoirs or for reservoirs that will be hydraulically fractured after completion. In these reservoirs the wellbore should be directed in a path that is perpendicular to the natural and/or induced vertical fractures in the formation. There are a number of methods available to the planner for identifying the direction of natural and induced fractures, in a given formation.

These include:

1. Oriented core.
2. Micro resistivity log.
3. Core stress relaxation tests on an oriented core.
4. Stress reapplication test on a oriented core.
5. Borehole televiewer.
6. Minifrac followed by a borehole televiewer.
7. Minifrac followed by an oriented core.
8. Study of the regional stresses in the area.
9. Orientation of vertical wells that were accidentally connected with hydraulic fractures.

Most of the inhole tests can be performed in vertical wells in the area prior to the drilling of the horizontal well. The most economical of these

methods appears to be the oriented core. The core should be taken at the target depth. The presence and orientation of natural fractures can be determined by standard core evaluation techniques. It is also possible to take a portion of the oriented core and determine the probable direction of the maximum and minimum horizontal stresses using core stress relaxation techniques. The testing must be performed immediately after core recovery.

The micro resistivity log can locate fractures that intersect the wellbore and allow measurement of their orientation.

The borehole televiewer can only detect fractures that cause a significant disturbance. The borehole televiewer can also be used to detect the orientation of elliptical hole enlargement or breakout that is used to identify the directions of the maximum and minimum horizontal stresses.

Using regional stresses is the riskiest of all of the techniques suggested. In an area where there are numerous parallel normal growth faults, the stress and fracture orientation should be similarly aligned. However, in more complex basins, the stress orientations can change over relatively short distances and induce significant errors in picking the right direction.

The cheapest and most reliable passive data is the orientation of wells that were accidentally connected with hydraulically induced fractures. If these incidents are close to, or even preferentially surround, the well site the orientation data should be quite accurate.

In formations without natural fractures scheduled to be completed without hydraulic fracturing, there is still an advantage in orienting the wellbore parallel to the minimum horizontal stress. Horizontal wells oriented in this direction should offer greater hole stability than holes oriented  $90^\circ$  from this direction. Although hole stability has not been a significant problem in most horizontal drilling, there is insufficient data to determine if the lack of field problems are due to the orientation of the horizontal wellbores or to a general exaggeration of the magnitude of this potential problem in the past.

## GEOLOGIC INPUT

Once the path, position and orientation of the horizontal hole have been selected, the most useful information for the well planner is a cross-section of the target formation and the identifiable gamma-ray markers in the 1000-ft-high (thick) interval above the horizontal target. The cross-section should extend along the planned path of the horizontal hole and include at least 1000 ft on each end of the planned horizontal borehole. The elevations of the marker beds between the surface location and the beginning of the horizontal portion of the hole are most important. The driller actually needs a log from the area that best represents the thickness and spacing of the marker beds relative to the horizontal well target. The most useful geologic input is an interpretation of whether the beds are expected to remain uniform in thickness throughout this build interval or if thinning or thickening is expected in the stratigraphic interval along the path of the horizontal borehole. The presence of faults in the target interval or along the horizontal well path will also have a major impact on the well design. In addition to the cross-section, the well planner will need a structural map on a suitable marker that is expected to parallel the targeted reservoir. Figure 10.5 is a typical structural cross-section of the targeted reservoir to be intersected by a horizontal well. In this case the well was planned to be drilled across the crest of a gently dipping anticlinal structure. The cross-section extends from the location of the vertical leg of the well, where the elevation of the target is 8825 ft, for a distance of 3000 ft. A horizontal well would need to achieve a  $90.25^\circ$  inclination angle at the elevation of the target vertically below its location in order to parallel this target at the end of the build interval. The well path needs to drop to  $89.75^\circ$  to continue to parallel the structure after crossing the crest of the anticline.

## WELLBORE TARGETING

The targeting for truly horizontal holes actually provides the simplest method of planning and adjusting in the field. If the target is a  $90^\circ$  inclination angle at a specified true vertical depth, the depth of the target is unaffected by variations in the displacement at the end of the curve as well as

the exact orientation of the wellbore. However, if the target is to lace the wellbore parallel to a given structural position in a dipping target, both the planning and the field monitoring become more complicated.

The simplest way to target a horizontal hole into a structurally dipping target is to approximate the position of the structural target with a flat plane that parallels the structural target at the point where the build curve ends and the horizontal hole interval begins. In order to fix the position of a dipping (sloping) plane in space, we must identify the vertical depth at one point in the plane, the dip angle of the plane, and the direction of dip. In order to guide a directionally drilled horizontal hole to intersect a dipping target plane, the most useful position with which to fix the elevation of the target plane is the true vertical depth of the target plane at a point that is directly below the surface location. This depth can be determined graphically from a cross-sectional plot of the target formation by constructing a straight line that is tangent to the target formation at the approximate end of curve position and extending that straight line to where it intercepts a vertical line projected through the surface location. The azimuth and the dip of the target lane can be best determined from the structural map of the formation in approximate area of the end of curve position.

If we generally drilled along strike or directly up or down dip, the calculations of target angle would be quite simple. However, because we generally drill at some other direction than those, the target angle must be calculated. Figures 10.6-7 show the relationships for determining the "horizontal" wellbore angle required to parallel a dipping structural target as well as the true vertical depth of that structural target.

In conventional directional drilling operations, one usually has a large enough target for the driller that any variations in the vertical depths of the target are not of any consequence. However, in many horizontal applications, the target is actually a thin narrow slice in the reservoir. The vertical tolerance on this type of target may be smaller than the variation in height of the target in the area where the horizontal well will likely intersect the target. Because the horizontal driller must both hit the target elevation and the wellbore at the

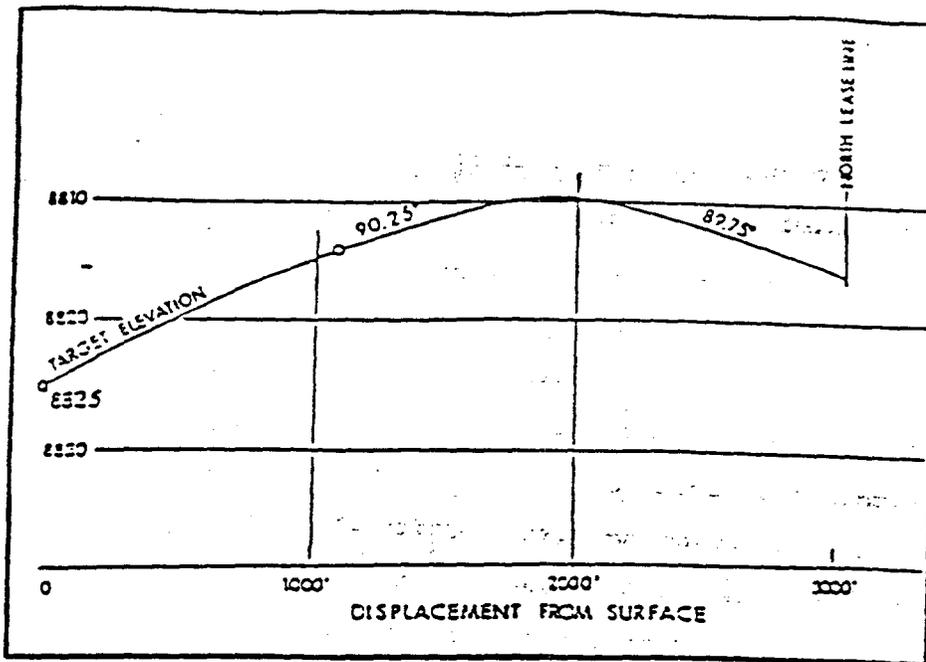


Figure 10.5 -- Cross-section of targeted reservoir, showing elevation of target along path of horizontal well.

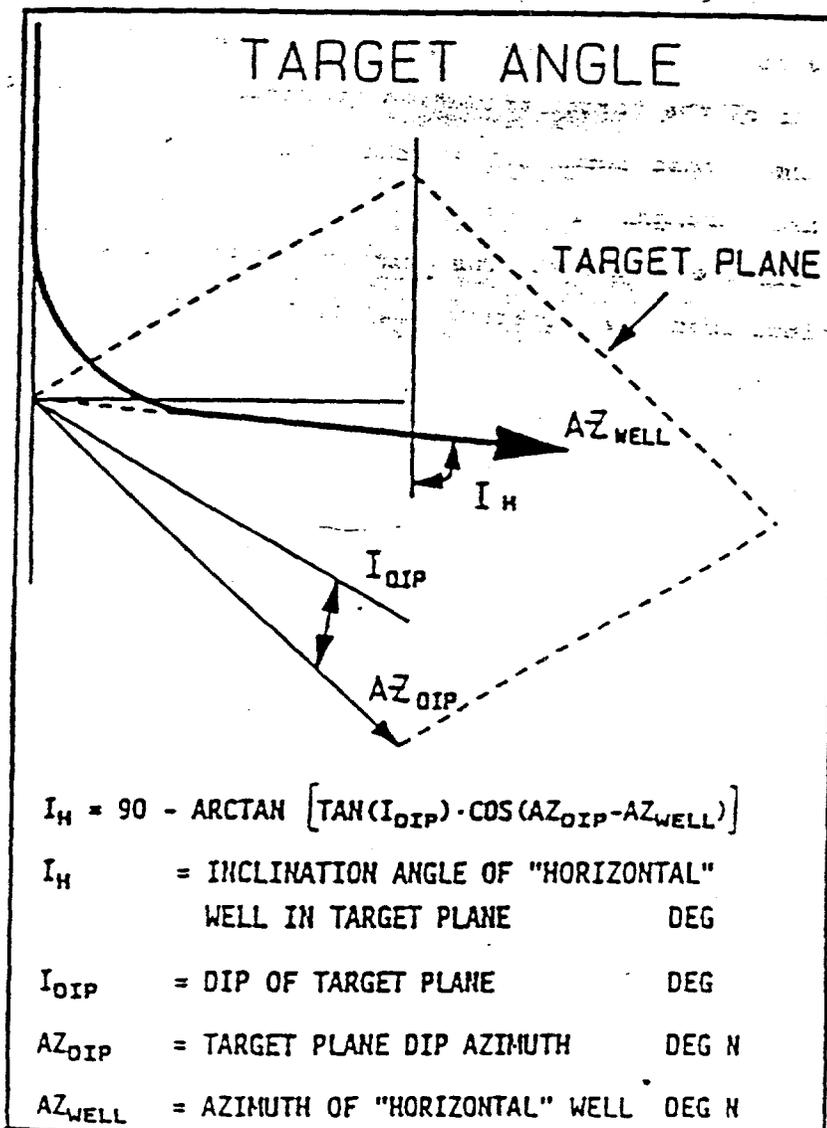


Figure 10.6 -- Relation of "horizontal" wellbore angle and structurally dipping target (reservoir).

$TVD_{EOC}$	=	$TVD_{TP} + DISPL \left[ \tan(I_{DIP}) \cdot \cos(AZ_{DIP} - AZ_{EOC}) \right]$	
$TVD_{EOC}$	=	TVD OF END OF CURVE IN TARGET PLANE	FT
$TVD_{TP}$	=	TVD OF TARGET PLANE UNDER SURFACE LOCATION	FT
DISPL	=	DISPLACEMENT LENGTH FROM SURFACE LOCATION TO EOC	FT
$I_{DIP}$	=	TARGET PLANE DIP ANGLE	DEG
$AZ_{DIP}$	=	TARGET PLANE DIP AZIMUTH	DEG N
$AZ_{EOC}$	=	AZIMUTH OF EOC FROM SURFACE LOCATION	DEG N
	=	$ARCTAN \left[ \frac{EAST}{NORTH} \right]$	DEG N
EAST	=	EAST COORDINATE OF EOC POSITION	FT
NORTH	=	NORTH COORDINATE OF EOC POSITION	FT

Figure 10.7 -- Depth of target (reservoir) in relation to horizontal wellbore angle and structural dip of target.

correct angle, he needs to have a reasonable sized area in which to "land" the hole and in a reasonable tolerance in the direction of the hole. The combination of these factors requires that the directional driller's target be described as a plane rather than a point in space.

# FRANK J. SCHUEH DRILLING TECHNOLOGY

## BUILD-CURVE DESIGN

The build-curve design represents a well designer's plan for deflecting the well from vertical and hitting the horizontal target within the required vertical height tolerance. The designer must make a number of significant decisions that will both impact the cost as well as the precision of hitting the target. The key decisions include the type of the build curve, the build rate, the target tolerance, the depths and variability of marker formations above the target, the presence of troublesome formations in or near the build curve, and the depths required for casing.

Because a horizontal target defines the elevation, inclination angle and direction of the borehole, it is much more difficult to hit a horizontal target than to hit a typical directional driller's aerial target. A directional driller can succeed in hitting his target by drilling the well above the planned path and then dropping it into the target, or conversely, drilling below the path and then passing through the target at a higher than planned inclination angle, or even come in from either side of the target and pass through the target area at a direction significantly different from the planned course. In a horizontal hole, we have lost one complete degree of freedom and lessened the magnitude of a second. The effect of having to hit the target at specific inclination angle requires that the curvature rate of the hole remain constant and predictable. There is, in fact, only one curvature rate that will allow one to hit a horizontal target from a given depth and inclination angle above the target.

The targeting of horizontal holes is also affected by the typical positioning of the measurement-while-drilling sensor packages in the bottom-hole assembly. With the typical motor systems used to drill the build curves and horizontal intervals, the directional sensor package must be generally located 50 to 75 ft above the bit with the most common positioning being about 60 ft

above the bit. With build rates of  $10^{\circ}/100$  ft, for example, the angle of the bit will be  $6^{\circ}$  greater than the angle measured at the MWD sensor. Predicting the angle of the hole at the bit requires a precise knowledge of the build rate of the assembly between the last survey and the bit.

The key tool utilized in hitting horizontal targets is the multibend motor, which provides highly consistent build rates on a given well as well as rates that are sufficiently close to that of the tool designer to allow us to routinely succeed in hitting small targets. Figures 10.8-9 are plots of typical build curves that show the consistency of the build rate that can be achieved with well stabilized multi-bend, angle-build motors. Figure 10.8 is a plot of the build curve on industry's first test of an angle-build motor. The key portion of the plot is the plot of inclination angle versus measured depth. A straight line on this type plot indicates a uniform build rate. The fact that the build rate remained constant throughout the interval demonstrates that the equipment is not sensitive to changes in inclination angle or gravity forces and is also not affected by the intersection of beds of differing hardness at angles of incidence--from  $0$  to  $90^{\circ}$ . This hardness test utilized a  $4\ 3/4$ -in. motor that was designed to build at  $20^{\circ}/100$  ft. The motor actually built at a rate of  $19.6^{\circ}/100$  ft, or only 2% less than the design.

Figure 10.9 is a plot of a well drilled with a  $6\ 3/4$ -in. multi-bend stabilized motor that was designed to build at  $8.7^{\circ}/100$  ft. The motor actually built at a rate of  $9.8^{\circ}/100$  ft and was exceedingly consistent in its curvature rate all the way from  $0$  to  $90^{\circ}$ . The consistency of curvature on this hole is especially remarkable because of the significant variability of the formations encountered in the build interval. This well encountered layers of limestone, salt, shale, and anhydrite throughout the build interval. In fact, there were thick salt sections crossed at  $30^{\circ}$  and  $65^{\circ}$ . The consistency of the build rate on this hole clearly shows the insensitivity of formation effects on the performance of the well stabilized angle-build tools.

The consistency of performance of an angle-build motor in a given hole is the key quality that makes it possible to hit small horizontal targets. The variability between the actual build rate and the tool designer's build rate

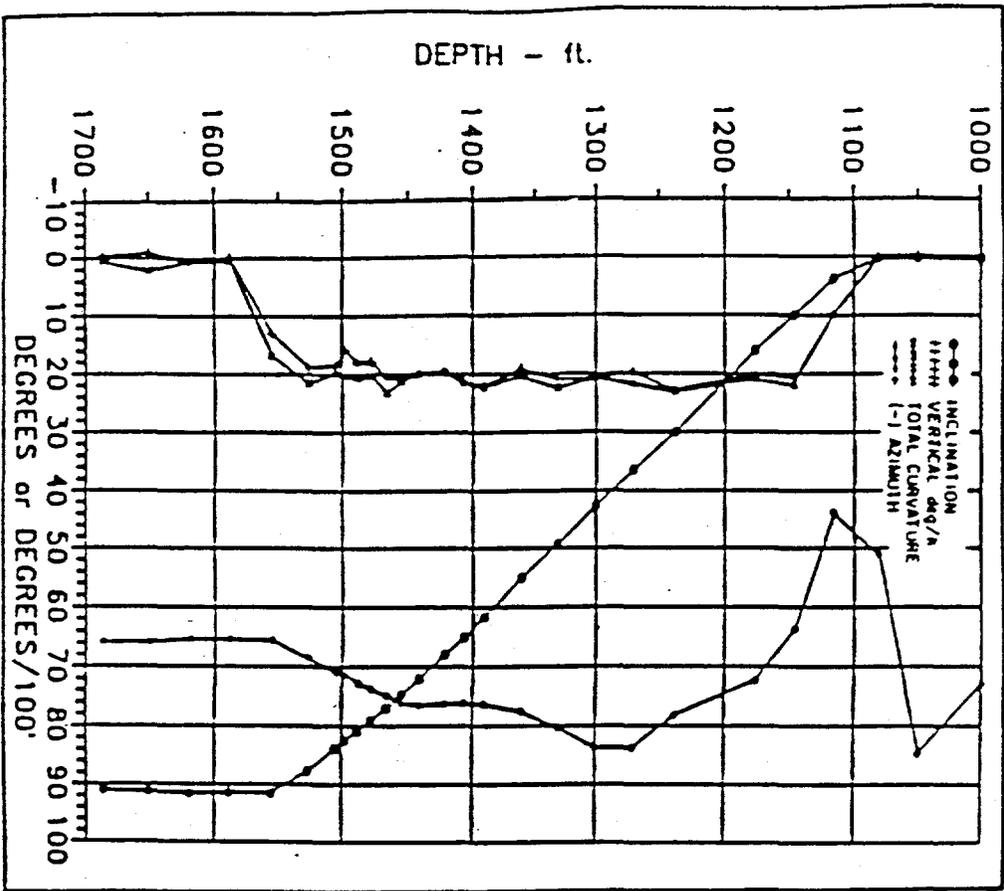


Figure 10.8 -- Arco medium-curvature test, Christensen angle build, Austin Chalk, Rockwall, Texas, showing uniform build rate in Industry's first test of an angle-build motor.

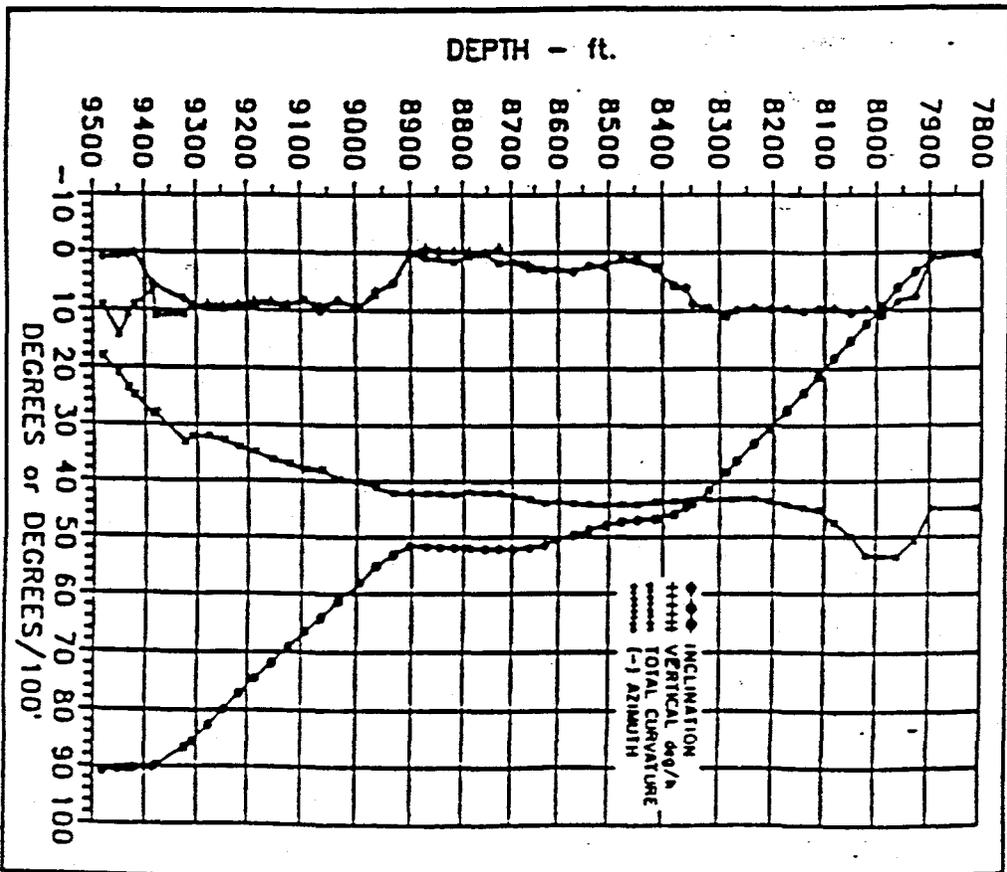


Figure 10.9 -- Plot of North Dakota well drilled to build an angle at 8.7°/100ft, in the Mississippian Bakken Formation.

requires the use of build-curve designs that will work with a range of performance of the angle-build tool.

#### FIELD CURVE DESIGN METHODS

There are two build-curve design methods. The first of these is based on utilizing the consistency of performance of the angle-build motors as the basis for designing the build curve to hit the target. The second method that is growing with the development of additional tools is to utilize steerable motor systems for the build curve and to use combinations of steering and rotation to achieve the desired average build rate. The original steerable motor systems were limited to curvature rates of only  $3^{\circ}$  to  $4^{\circ}/100$  ft. The latest additions to this style of equipment include motors with build rates of up to  $10^{\circ}/100$  ft that can also be rotated in order to reduce the average build rate.

Use of the nonrotatable angle-build motors provides the most economical method for hitting large targets as well as exceedingly small targets. The steerable motor technique is most probably suitable for medium-sized targets in the 5 to 20 ft range.

There are four types of build curves that can be utilized with the nonrotatable angle-build motors. The build-curve types arranged in order of increasing accuracy in hitting the target are:

1. The single build curve.
2. The simple tangent build curve.
3. The complex tangent build curve.
4. The ideal build curve (same accuracy as the complex tangent build curve).

#### SINGLE BUILD CURVE

The single build curve is the simplest and lowest cost method for drilling a build curve. In order to design a single build curve it is necessary to obtain performance data on the proposed motor to establish the probable range of performance of the tool. The closer the locations of experience data are to the proposed horizontal well location, the more reliable will be the design. One of the most common tools utilized in drilling single build curves is the  $20^{\circ}/100$  ft, 4 3/4-in. build tool for 6-in. holes. The performance of an angle-build tool is

affected by the stiffness of the assembly placed above the motor, the bit type and bit weight used in drilling. Because the type of nonmagnetic collar placed above the 4 3/4-in. motor is seldom varied, the variability in this size is limited to the affect of bit type and bit weight. Typical field-performance build rates for this tool have been in the range of 19'/100 ft + or - 5%.

To evaluate the potential use of a single build curve for an application requires that one compare the expected variation in the final elevation of the horizontal hole with the target tolerance required by the reservoir. The expected variability of performance is determined by calculating the range and height of the end of the build curve for build rates ranging from the maximum to the minimum expected for the proposed motor. In general, if the expected variation in height is less than half the target tolerance required for the reservoir, the single build curve should be used. Figure 10.10 is an example of an appropriate single build-curve application.

The plot shows the expected wellbore path that would be produced if the motor drilled at its most likely build rate as well as the effect on hitting the target if the build rate were either the maximum or minimum expected. If this range of height is smaller than the target tolerance, the technique can be used. Because the penalty for missing the target is usually quite costly, we do not recommend using a single build-curve design unless the allowable target tolerance is at least twice as high as the probable range of target error.

For an expected build rate of 19'/100 ft and a horizontal 90° target, the expected height of the build curve is 301.5 ft (see Appendix 10.1, for equations [Figs. 10.A1-4] required to design build curves). A variability of 5% + or - in this build rate would produce a reservoir-target-error range of about 30 ft. Therefore, if the target had an allowable tolerance of 60 ft or more, a single build curve would be the most effective build curve design.

#### SIMPLE TANGENT BUILD CURVE

Simple tangent build curve is the next logical step in improving the target accuracy of a build curve. Simple tangent-build-curve design is the most common method for drilling 8 1/2-in. diameter horizontal wells. In this size hole we

generally use 6 3/4-in. multibend motors with design build rates that range from 8° to 16°/100 ft. In this hole size there is a broad range of nonmagnetic equipment that can be placed immediately above the motor. It is possible to utilize equipment above the motor that is significantly stiffer than the motor or equipment that is significantly more flexible than the motor. Perhaps because of this additional variability, the typical angle-build motor in this size has produced a range of build rates that range from 10% less than the expected design rate to as much as 15% more than the expected design rate. If one attempted to use equipment with this much range for a single build curve, the error band would be quite large. For an angle-build motor with expected build rate of 10°/100 ft, the expected height of a single build curve would be 573 ft, but the error range would extend from 75 ft above the expected depth to 64 ft below the expected position.

With the simple-tangent-build-curve method, it is possible to greatly reduce the target error, even using tools with this much variability, or more. Figure 10.11 is a sketch that shows the simple tangent build curve. In this design the build interval is broken into two build intervals that are separated by a straight "tangent" adjustment interval. To design a simple tangent build curve the designer must know the minimum possible build rate for the angle-build motor that will be used in the interval. The build curve is then designed using the minimum expected build rate which produces the greatest height of the build interval. A short tangent interval is placed within the build curve to provide a means for adjusting the depth of the second kickoff point based on the observed performance of the angle-build motor in the first build interval. If the minimum possible build rate is utilized in the design, the actual build rate in the field will likely be greater than the design build rate. As long as the actual build rate is greater than the planned rate, the well plan can be adjusted to position the second kickoff point at a depth that will allow one to precisely hit the target if the second build rate is identical to that experienced in the first build (dashed build curve in Figure 10.12).

The target error with the simple tangent build curve is generally limited to the variability of the angle-build motor in the second build versus that in

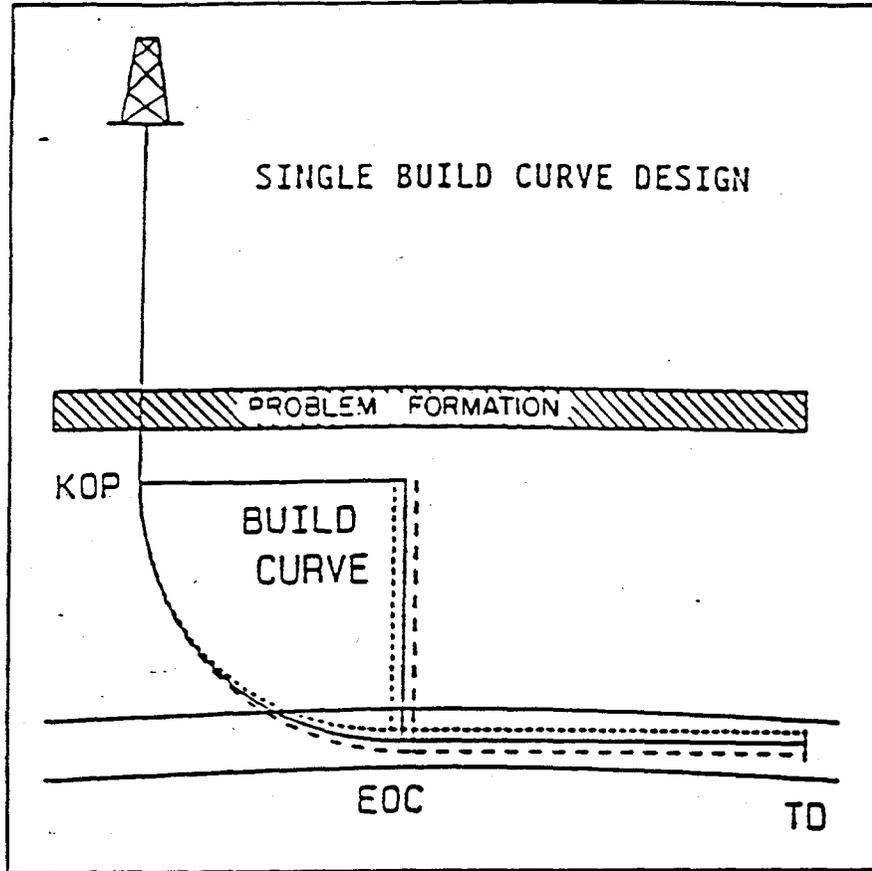


Figure 10.10 -- Single build curve design.

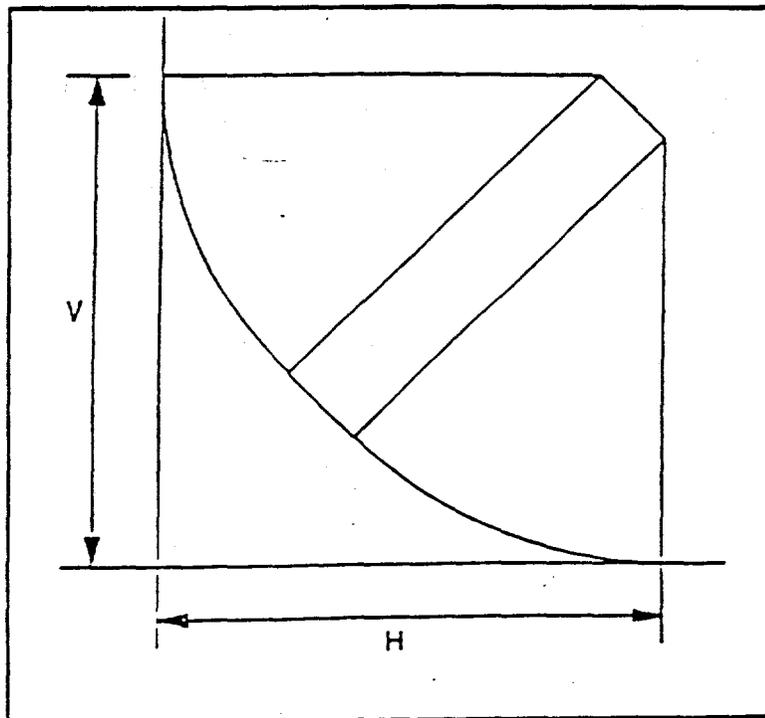


Figure 10.11 -- Simple tangent build curve.

the first build. Even if we experience a considerable variability in build rates, the error only affects the height of the second build curve. For example, with a 10./100 ft build rate and a 45° tangent angle and a 90° target, a 5% change in the performance of the angle-build motor between the first build and the second would only produce a target error of about 17 ft.

Changing the tangent angle, which reduces the height of the second build curve, directly reduces the target error. For the 10°/100 ft example, using a 60° tangent would reduce the error band to less than 8 ft.

When the target is a dipping structural target, part of the potential error in hitting the target is due to the error or imprecision in defining the exact depth of the structural target. These potential errors can be minimized by utilizing the observed depth of marker horizons in the build curve above the target. If the marker beds demonstrate a consistent thickness (or interval) between the marker and the target in the vicinity of the horizontal hole, the observed depth of these marker beds can be utilized to redefine the target depth while drilling the build curve. With the simple tangent build curve, the depth of the second kickoff point is the only field control point in the build curve. Thus, to utilize a marker to redirect the target on a well, the marker must be encountered at a depth that is well above the second kickoff point. If the marker bed is to be identified using a MWD gamma ray log, the marker must be located at a point in the borehole that is about 100 linear feet above the second kickoff point. For our 10°/100 ft example with a 45° tangent angle and a 90° target, the deepest useful marker would be 238 ft above the target formation. With a 60° tangent angle the deepest useful target marker is 127 ft above the target zone.

#### COMPLEX TANGENT BUILD CURVE

If the target tolerance is less than the expected variability of a simple tangent build curve, or if the critical target marker beds are closer to the target formation than can be utilized in adjusting the second kickoff point, the complex tangent build curve offers the most economical method for hitting the target.

The complex build curve is an extension of the simple tangent build curve method. In the complex tangent method we split the build curve into two intervals separated by a straight tangent adjustment interval, just as in the simple tangent build curve. We also utilize the minimum expected build rate in designing build curve for this method. However, for the complex build curve, we design the build curve for the second build utilizing a build rate that is less than was experienced on the first build. A typical complex design used a build rate difference of  $1\ 1/2^{\circ}/100$  ft. For example, with a tool that generated a  $10^{\circ}/100$  ft build rate in drilling the first build, one would select the second kickoff point based on a build rate in the second build equal to  $[10 - 1.5] = 8\ 1/2^{\circ}/100$  ft. This lower planned vertical build rate is accomplished by orienting the toolface (the plane of the multibends in the angle-build motor) to the right or left of vertical. The vertical build rate of an angle-build motor is numerically equal to the total curvature of the tool times the cosine of the toolface angle. For example, a  $10^{\circ}/100$  ft build tool will build vertical angle at the rate of  $8\ 1/2^{\circ}/100$  ft when the toolface is oriented  $32^{\circ}$  from vertical. Rotating the toolface to  $46^{\circ}$  would reduce the vertical build rate to  $7^{\circ}/100$  ft. Using a  $10^{\circ}/100$  ft build tool and a complex-tangent-build-curve-vertical build rate of  $8\ 1/2^{\circ}/100$  ft, the directional driller has the ability to change the vertical build rate at any time in the second build from  $7^{\circ}$  to  $10^{\circ}/100$  ft by simply adjusting the toolface angle between 0 and  $46^{\circ}$ . This capability provides the driller with the ability to adjust the final horizontal elevation by as much as  $15\%$  + or - of the remaining height.

Unfortunately, using a toolface angle other than zero also causes the well to change directions, either to the right if the toolface is turned to the right, or to the left if the toolface angle is to the left of vertical. Because we normally want the build curve to reach the target in a specific direction, the change in direction in the complex build curve must be neutralized by drilling about half of the hole with the toolface turned to the right and the remaining half with the toolface turned to the left. The change-over depth can be selected to exactly balance the right hand and left hand turns, thereby leaving the final direction of the end of curve parallel with the direction at the end of the

tangent interval. In actual practice one can easily get within 2 to 3° of the desired direction and the final adjustment can be made with a steerable motor system at the beginning of the horizontal interval. Figure 10.13 is a plot of a typical complex tangent build curve that shows the vertical section and plan view of the build-curve path. This build curve was based on a 10°/100 ft build tool, a 45° tangent angle, and an 8 1/2°/100 ft vertical build rate for the second build. The toolface angle was set at 32° to the right for the interval from 45° to 65.5° and to the left from 65.5° to 90°. Note that this produces a horizontal well path that parallels the first portion of the build curve but is offset about 65 ft to the right of the starting path.

Complex tangent build curves have successfully utilized toolface angles up to 65° which reduce the vertical build rate to only 42% of the capability of the motor. For normal design purposes we would like to keep the toolface angles in the range of 0 to 45°.

The complex tangent build curve allows one to utilize marker encountered in the second build curve to adjust the final depth target of the horizontal hole. With adequate quality markers, it is possible to hit 1-ft targets with the complex build curve design.

To utilize the complex tangent build curve requires increasing the length of the second build curve as compared with the simple tangent design. This also increases the total curvature required in the build curve. In typical designs, however, the additional length and additional dogleg are insignificant compared with the enhanced capability for hitting small targets. For a typical complex build curve, the total length of the build curve and total dogleg required for each horizontal are increased by about 10%.

#### IDEAL BUILD CURVE

A tangent interval is required whenever the expected performance range of the motor is similar to the minus 10%, plus 15% range considered applicable to the first time use of the motor in a new area. However, after a motor and BHA package have been utilized in several wells in an area, the expected variance in performance should drop to only a few percent. Whenever the expected range

The advantage of reducing the length of the build curve by increasing the

3. Control the bending stresses generated by the build curve.

build curve.

drilled length, something which should also reduce the time and cost to drill the shorter will be the height of the build curve, and the shorter will be the With all other factors equal, the higher the build rate selected, the

2. To minimize the cost of the build curve.

a shorter build curve than would otherwise be desirable. Avoiding problem zones may require utilizing higher build rates to obtain

point in the build curve.

within the straight tangent interval will cause fewer problems than at any other of the troublesome zone. If a problem zone cannot be avoided, placing the zone generally wash out is to design a build curve that begins below the deepest point the build interval. One of the most direct methods for avoiding formations that tubulars. The designer should, therefore, work to avoid any hole enlargement in section of the hole would significantly increase the bending stresses on the of a horizontal hole. Significant enlargement in a portion of the high-curvature Hole enlargement represents the worst possible problem in the build curve

1. To avoid problem formations.

rate for a horizontal hole. These are:

There are generally three factors considered in selecting the optimum build

### SELECTING THE BUILD RATES

multi-well project.

should be considered when designing and costing the typical well for a large, Although the ideal build curve has yet to be utilized in the field, it top of the target formation.

capability of hitting very small targets by keying off of markers close to the This eliminates two rather lengthy trips and yet would still provide the cost savings in areas where the whole build curve can be drilled with one bit. tangent build curve without a tangent interval. This can offer a significant becomes less than about + or - 5%, it will be possible to utilize a complex

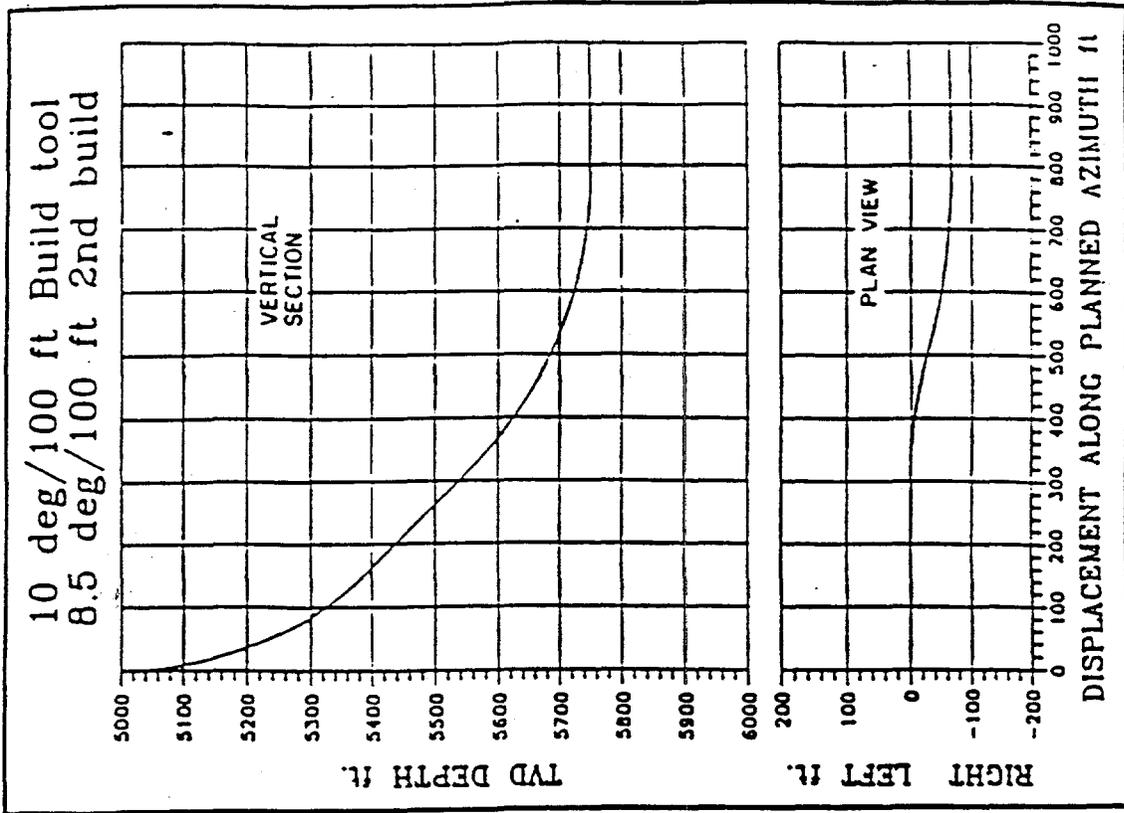


Figure 10.13 -- Complex tangent build curve, in vertical section and plan view.

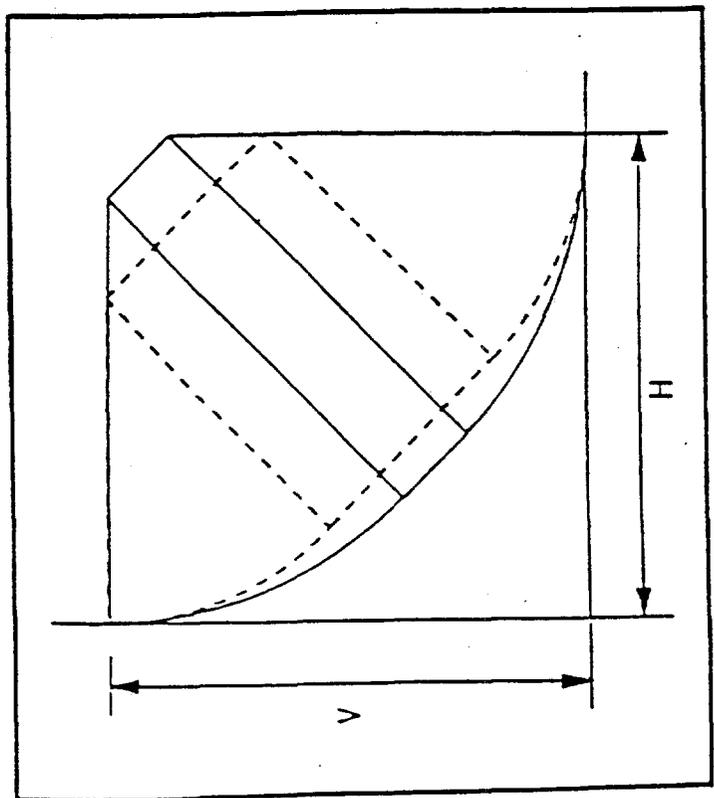


Figure 10.12 -- Tangent adjustment, 45° tangent

curvature rate must eventually be balanced by the effect of curvature on performance of the drilling and completion equipment needed in the horizontal hole. In 6-in. hole size, the fatigue endurance limit of 3 1/2-in. compressive service drillpipe exceeds 20°/100 ft. In the 8-1/2 in. hole size, one of the most important limits is the fatigue endurance for Heviwate drillpipe. The limits for 4 1/2-in. and 5-in. Heviwate are roughly 15°/100 ft.

The most significant bending limit for completions is the effect on the casing connections. While the connection stresses should be evaluated, they are generally not as important as the drillstring limitations.

#### DEPTH CORRELATION

One of the more important considerations in targeting a horizontal hole is the potential error between the MWD measurements and the electric-log-based target depths. Even for horizontal holes that are to be drilled at a 90° target angle, the critical formation depths are based on log measured depths. In a horizontal hole all of the measurements are based on driller's drillstring measurements and the MWD survey angles and azimuths. In a conventional vertical or directional well, differences between the driller's depths and the log measured depths do not affect the precision of the completion operations. For conventional completion operations, the use of collar-locator-correlation logs allows one to complete precisely at the depths relative to the electric-log measurements.

In horizontal wells, the well plan must include a means for correlating the MWD driller's depths in the horizontal hole with the log-based target depths. To be effective, the depths must be correlated and the target depth adjusted before the well reaches horizontal. There are three general methods for achieving the depth correlation. These are: (1) use of a mud logger, (2) a special correlation electric log run in the build interval, and (3) use of a MWD tool that includes a MWD gamma-ray or resistivity log in the build interval.

#### MUD LOGGER

The mud logger's formation tops based on cuttings depths are generally not

accurate enough to offer much help in depth correlation between the MWD and the electric-log depths. The greatest potential for using this relatively inexpensive correlation device is to coordinate a log top with a distinctive penetration rate response in the build curve. The mud logger will, therefore, precisely pick the depth of this soft streak or hard streak in the drilled hole and it can be correlated accurately back to the base logging data. If the correlation point is above the second kickoff point or if the complex type build curve is used for the second build, the correlation point can be used to correct the TVD target depth.

#### SPECIAL CORRELATION ELECTRIC LOG

The next lowest cost method for correlating the MWD depths with the planned electric-log target depths is to run a specialized correlation log in the build curve. The logging tool needs to combine the appropriate correlation logging sonde with the survey sonde of a dipmeter. This package can be used to prepare a TVD correlation log of the build interval. When using this type of log-run, one generally runs the tool on a wireline unit and logs from the deepest free-fall point obtained back to the casing shoe.

The TVD log can now be correlated with the base log used to pick the target. Any depth adjustments between the correlation log and the base log will be apparent. The correlation log depths can be correlated with the MWD depths by comparing the correlation log TVD depths with the MWD survey TVD depths at points where the MWD angle and the correlation log angles are equal. The most important correlation points are the last few surveys. The correlation depth differences should not deviate greatly between surveys. Large changes between groups of surveys above and below some depths suggest that was a drillstring measurement error at that depth. If the correlation logging tool reaches to a 55° or 60° inclination angle, the correlation can be quite accurate. At this angle the build curve is generally within 100 to 200 ft of the target zone. From this point to the end of the curve the only measurement errors that can affect the target are those that occur between the last correlation point and the end of the curve. Furthermore, length measurement errors in this interval only

affect the TVD accuracy by the length error times the cosine of the hole angle. In the high angle portion of the hole, the magnitude of additional depth errors becomes quite small. Furthermore, after reaching the horizontal, additional measurement errors have very little impact on the position of the hole.

#### MWD WITH GAMMA RAY OR RESISTIVITY LOGS

The best possible technique for correlating the MWD depths with the log-based target is through the use of a MWD gamma-ray tool in the build interval. This tool can be used to provide a continuous true-vertical-depth-based-gamma-ray correlation log while drilling the build interval. By identifying the TVD depths of the markers on the MWD gamma-ray log, it is possible to calculate a MWD target depth that will correlate with the relative position of the target formation below the marker depths.

Figure 10.14 shows a typical selection of gamma-ray marker points for the build curve of a horizontal hole. The ideal markers are single spikes that can be easily identified by a single depth. This log includes each of the markers identified (by a letter). The target TVD depth for the well is a function of the MWD TVD depth identified for the marker, the vertical build rate between that point and the target zone, and the required target angle. Figure 10.15 shows a graphic solution that relates the TVD target depth with the observed MWD/gamma-ray depth of the marker for several of the gamma-ray markers, assuming a range of build rates between 8 and 12°/100 ft. It should be noted that the correlation curves are relatively insensitive to this large range of build rates. All curves can be represented by a single line even though the more distant markers are represented by a relatively thick single line. The build rate required to hit the MWD target at the target inclination angle is a function of the remaining height and the angle of the hole at that point. This too can be solved graphically, as shown on Figures 10.16-18. The easiest way to use these graphical solutions is to plot the difference between the latest TVD target and the TVD depth of each MWD survey at the MWD survey inclination angle. The plot will then show the build rate (°/100 ft) required to hit the target TVD at the target angle. Note that a build-rate variation of only 0.2°/100 ft build rate

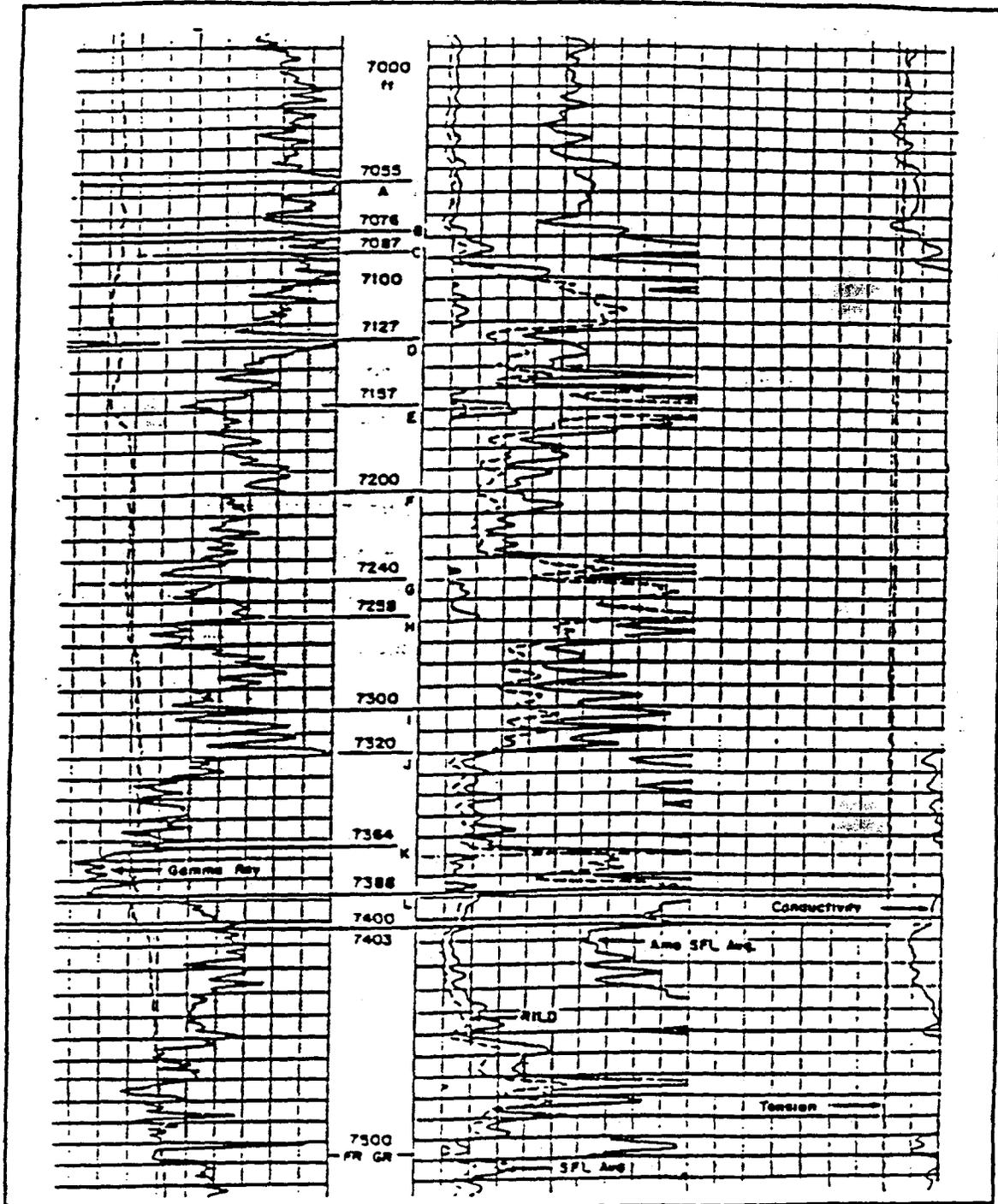


Figure 10.14 -- Typical gamma-ray markers utilized for the build curve of a horizontal hole.

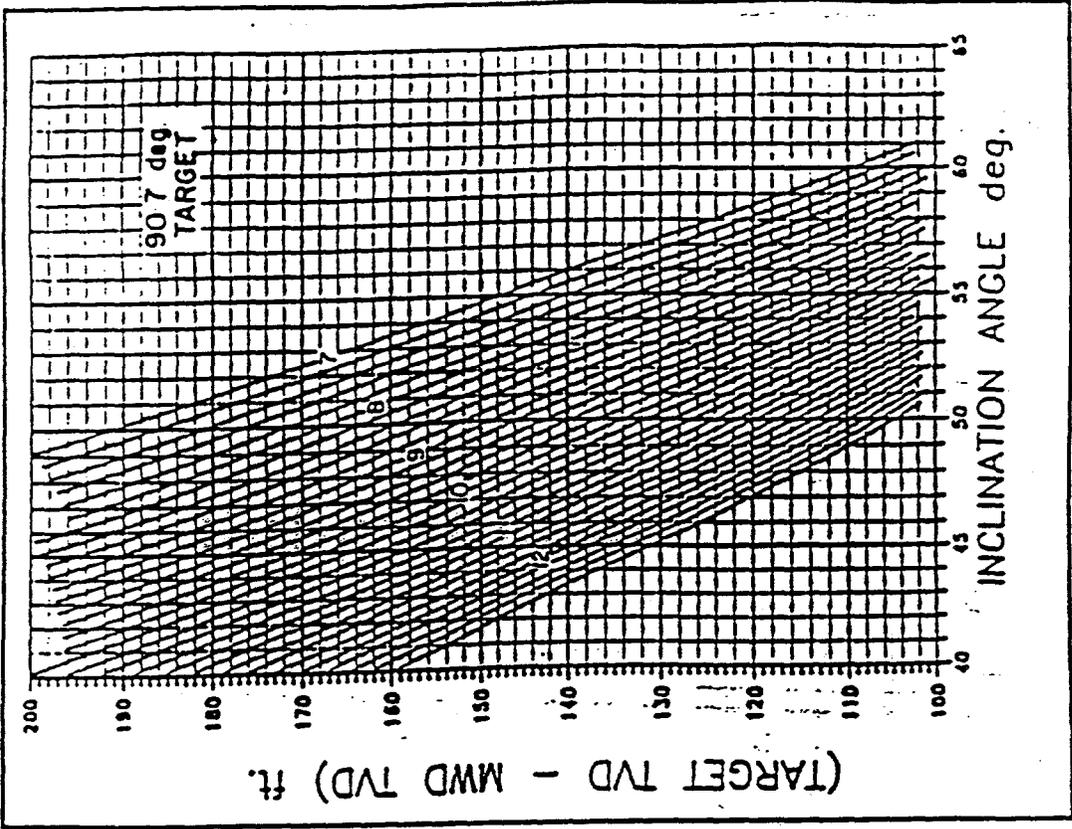


Figure 10.16 -- Required build rate to hit 90.7° target, with a difference between target and TVD of MWD survey of 100-200 ft, inclination angle of 40-62° and build rate of 7 to more than 12°/100ft.

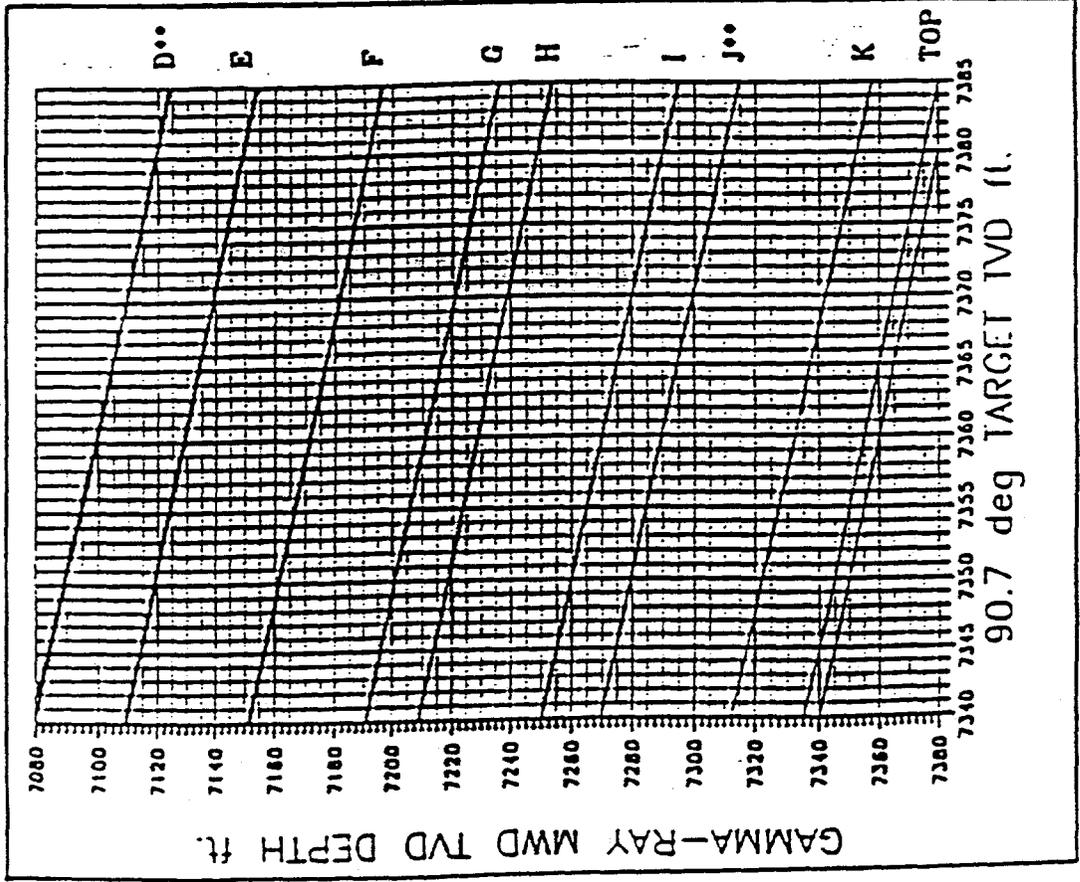


Figure 10.15 -- TVD of 90.7° target versus observed MWD gamma-ray depth for several markers in Fig. 10.14.

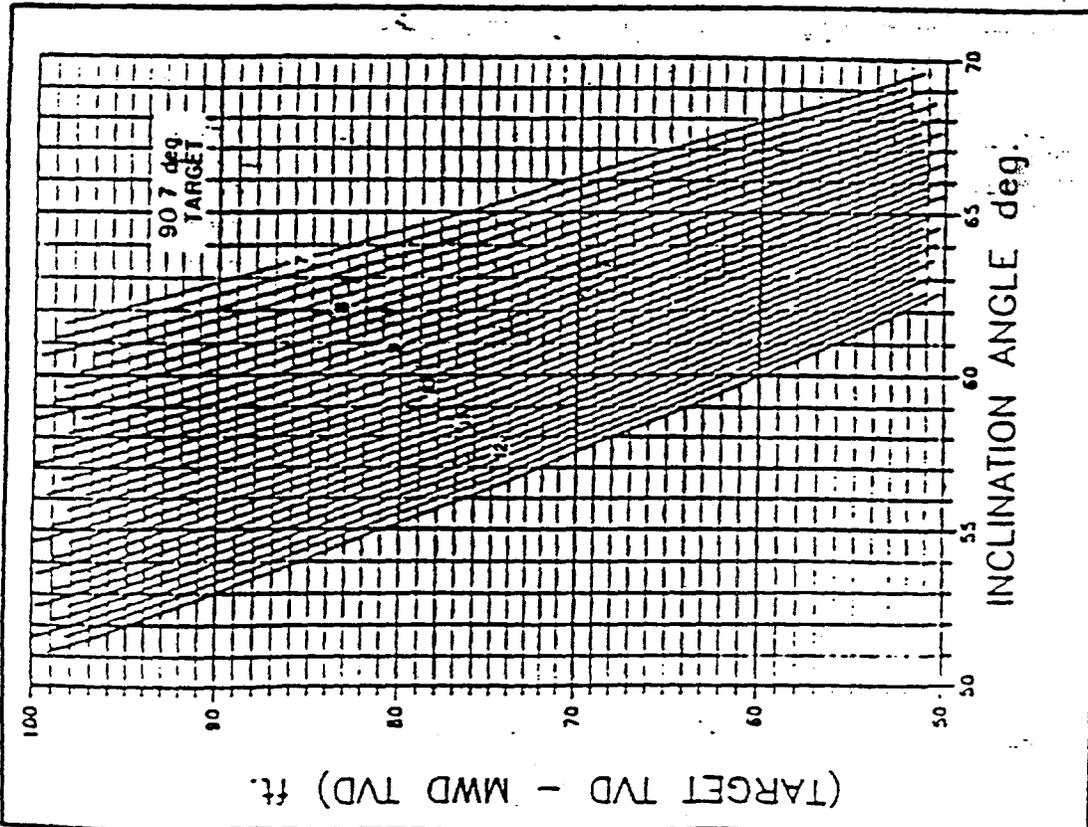


Figure 10.17 -- Required build rate to hit 90.7° target, with a difference between TVD target and TVD of HWD survey of 50-100ft, inclination angle of 50-70° and build rate of 7 to more than 12°/100ft.

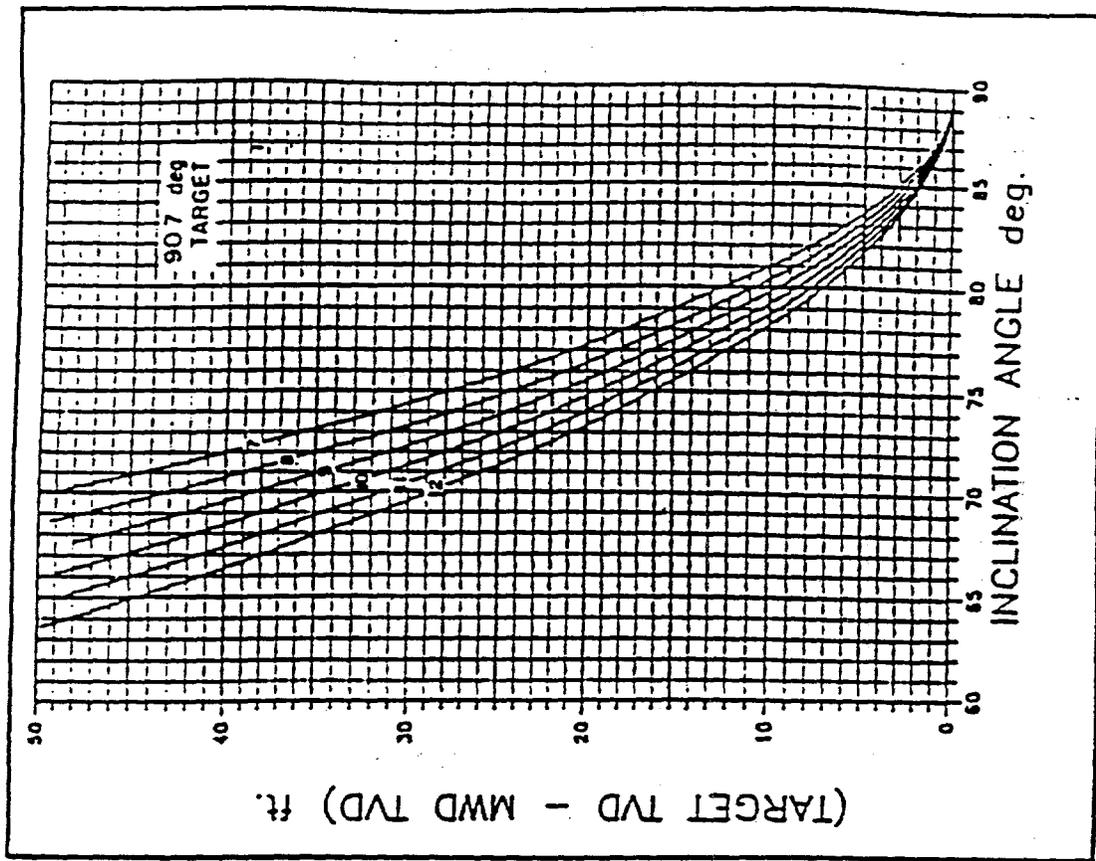


Figure 10.18 -- Required build rate to hit 90.7° target, with a difference between TVD target and TVD of HWD survey of 0-50 ft, inclination angle of 60-90° and build rate of 7-12°/100 ft.

Modular Tool Configuration



Directional Tool



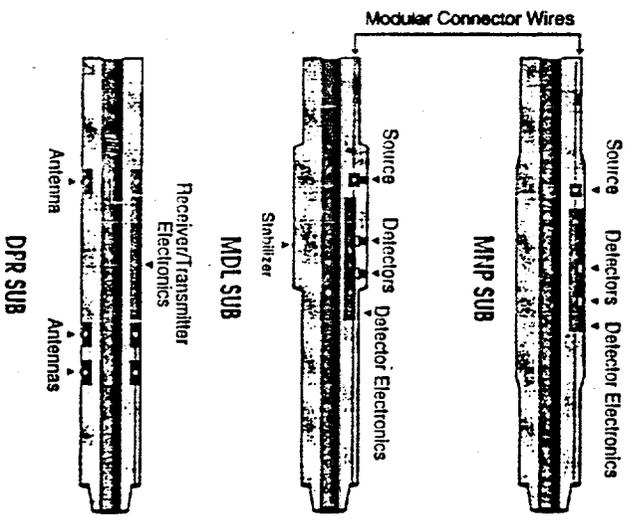
Neutron Porosity (MNP) Sub



Density/Lithology (MDL) Sub



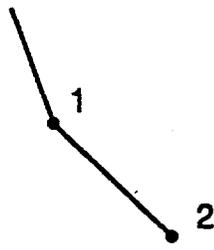
Dual Propagation Resistivity (DPR) Sub



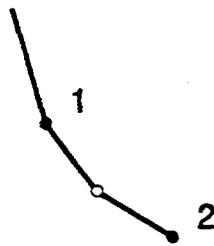
# Calculation Methods

## Straight Line

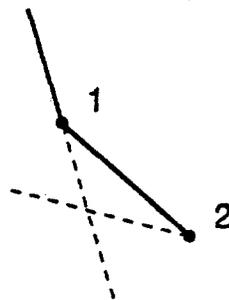
- *Tangential*



- *Balanced Tangential*



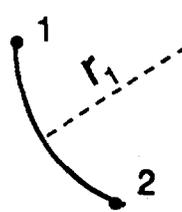
- *Average Angle*



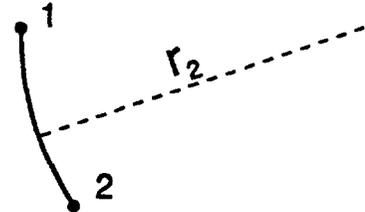
- *Mercury Method*

## Curved Segments

- *Radius of Curvature*

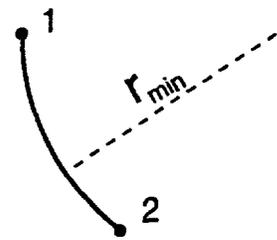


Horizontal Plane



Vertical Plane

- *Minimum Curvature*



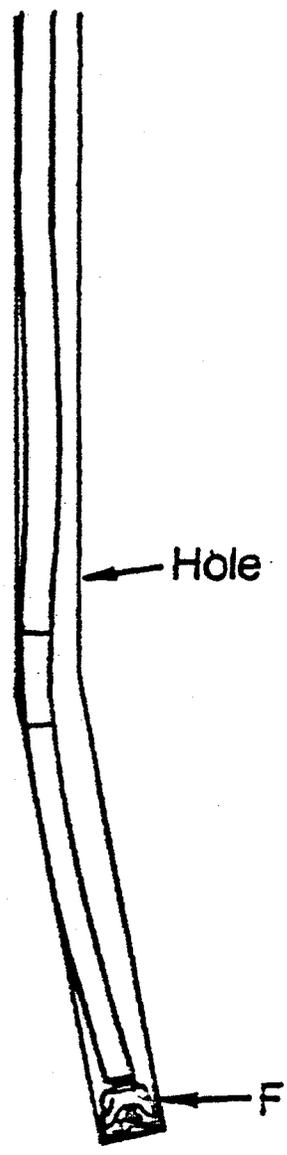
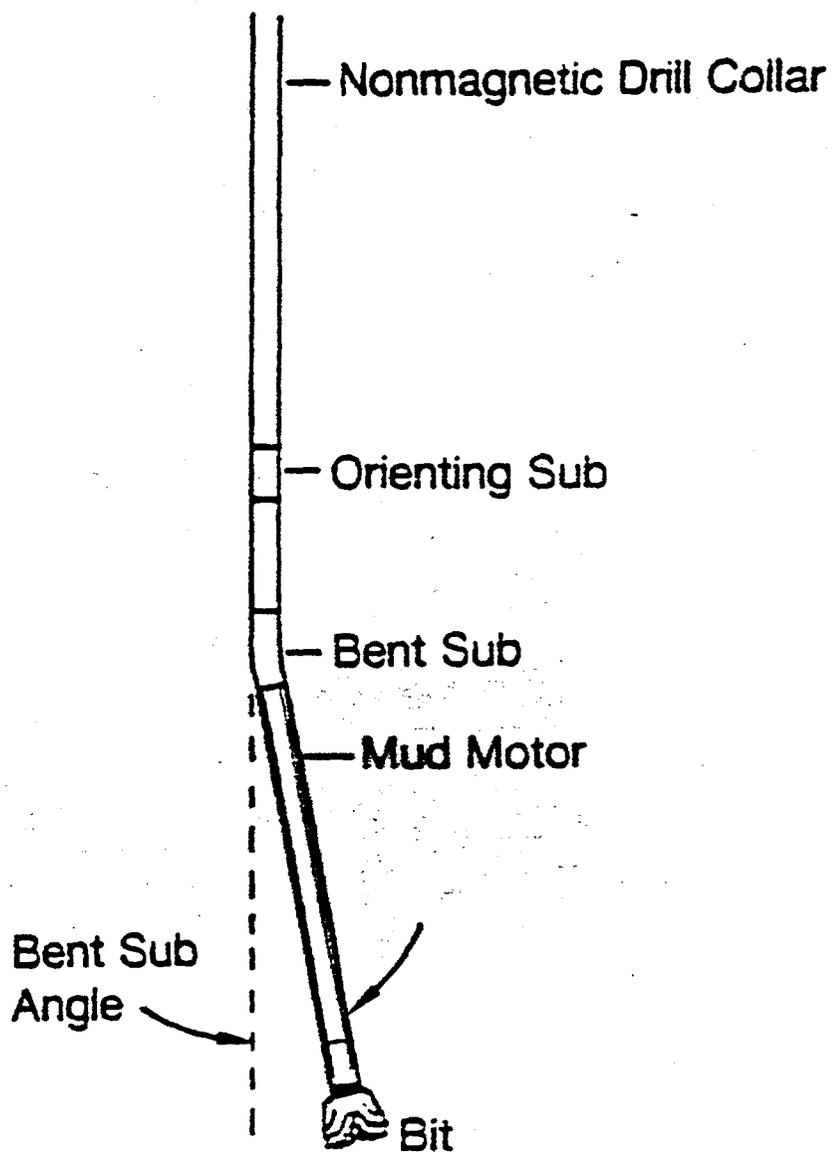
Oblique Plane

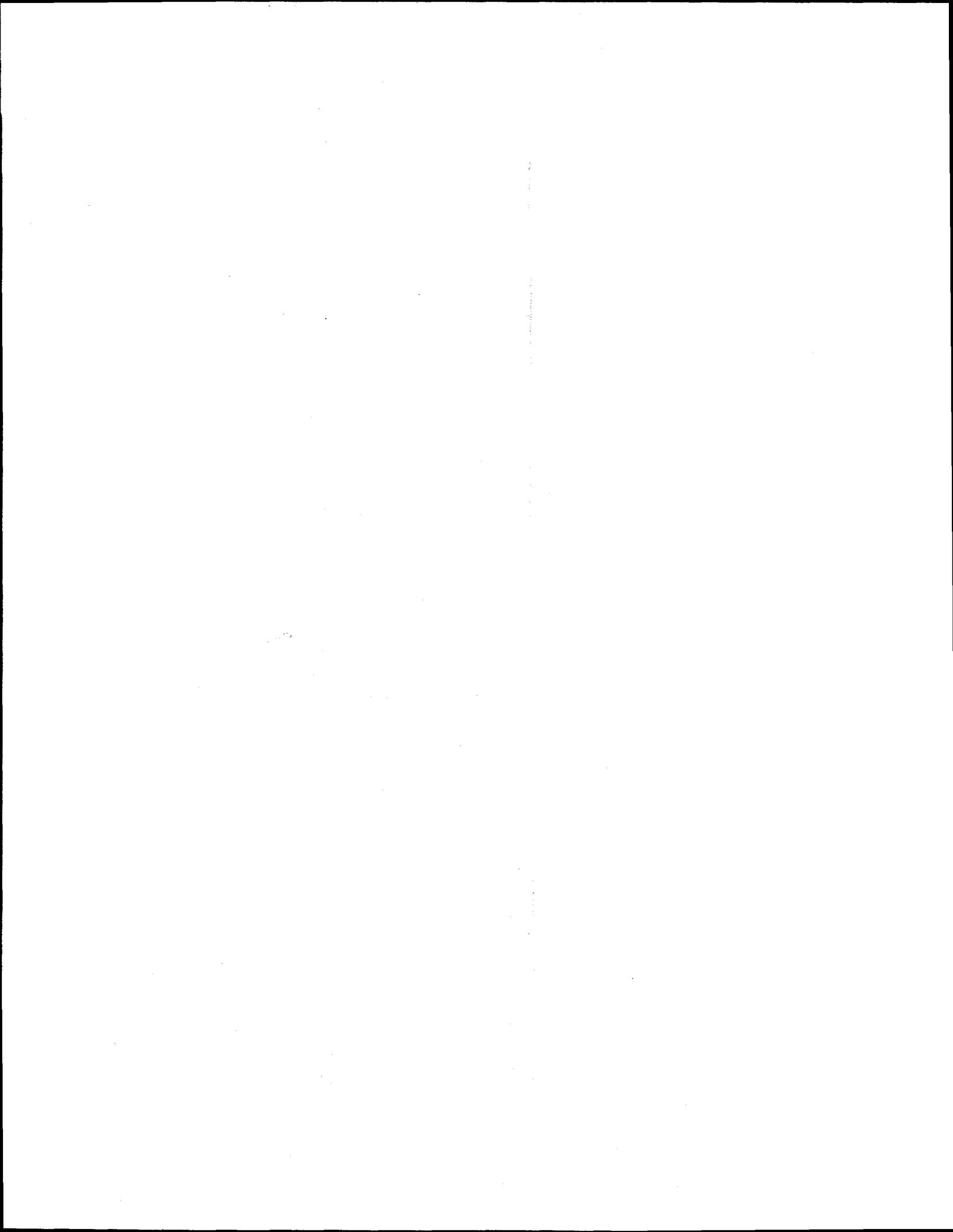
# Sources of Error

- *Human Factor*
- *Magnetic Declination*
- *Magnetic Shielding*
- *Tool Misalignment*
- *Survey Location*
- *Gyro Errors*
- *Mechanical and Calibration Errors*
- *Calculation Method*

# Deflection Techniques

- *Jetting*
- *Whipstock*
- *Curved Conductor Pipe*
- *BHA Deflection*
- *Motor Deflection*
  - *Bent Sub*
  - *Bent Housing Motor*
  - *Offset Stabilizer*
  - *Double Tilted U-Joint*





represents a vertical height of 2 ft when the angle is at 50°. At 70° a build rate variation of 1"/100 ft only represents about 3-ft change in target height. At 80° a variation of 1"/100 ft represents less than 1 ft of vertical height at the target. Because it requires decreasing levels of precision to control the vertical build height as the angle increases, it becomes extremely easy to hit the precise target once the complex build curve is properly aligned with the target.

#### IMPACT OF MARKER QUALITY ON BUILD CURVE DESIGN AND TARGET ACCURACY

The quality of a marker is defined as the expected variability in the distance between the marker and the target formation. In most areas the quality of the markers improves with the proximity to the target zone. This allows the accuracy of the target to be gradually improved as each marker is intersected. If the variability of the markers is less than 5% of the remaining "height", we should be able to "hit" even a 1-ft target with a complex build curve.

In areas where there are no markers in the build curve or the variability of the markers exceeds the target tolerance, a very special design may be required to hit the target. One such method requires drilling a deep high-angle tangent interval at whatever angle is needed in order to hit the target from the last possible marker. To use this technique the well must be drilled to reach the tangent angle depth before reaching the shallowest possible depth for the marker and then to continue at that angle until the marker is encountered.

#### DETERMINING THE OPTIMUM COMPLETION METHOD

Although most of the horizontal wells to date have been completed open hole or with uncemented liners, we believe that the majority of the future horizontal wells will be completed with cemented casing, selected perforated intervals, and some form of stimulation. The critical parameters that control the optimum completion method are:

1. The magnitude of damage caused by the drilling mechanics and drilling fluids.
2. The natural vertical permeability provided by the formation.
3. The likelihood of producing unwanted fluids from a portion of the wellbore before depleting the zone.

Slotted liners or open hole completions provide the optimum completion method for formations where the formation damage is minimal, where the formation has adequate natural vertical permeability, and where there is little likelihood that water or gas will break through the wellbore before depleting the zone.

If any of these factors is reversed, the well should probably be cased, cemented and selectively perforated. If the formation damage caused by the drilling fluids cannot be overcome by perforating alone, or if the natural vertical permeability does not open the entire reservoir, some form of well stimulation will be required."

\* After Joshi

# **Architectural Styles**

- *Ultrashort Radius*
- *Short Radius*
- *Medium Radius*
- *Long Radius*

## Ultra-Short Radius Laterals

- *Up to 90°/ft Curvature*
- *Water Jet Tools*
- *Hole Diameter 1-1/2 to 2-1/2 in.*
- *Typical Lateral Length 100 to 200 ft*
- *Openhole or Special Liner Completion*

# ULTRASHORT RADIUS RADIAL SYSTEM

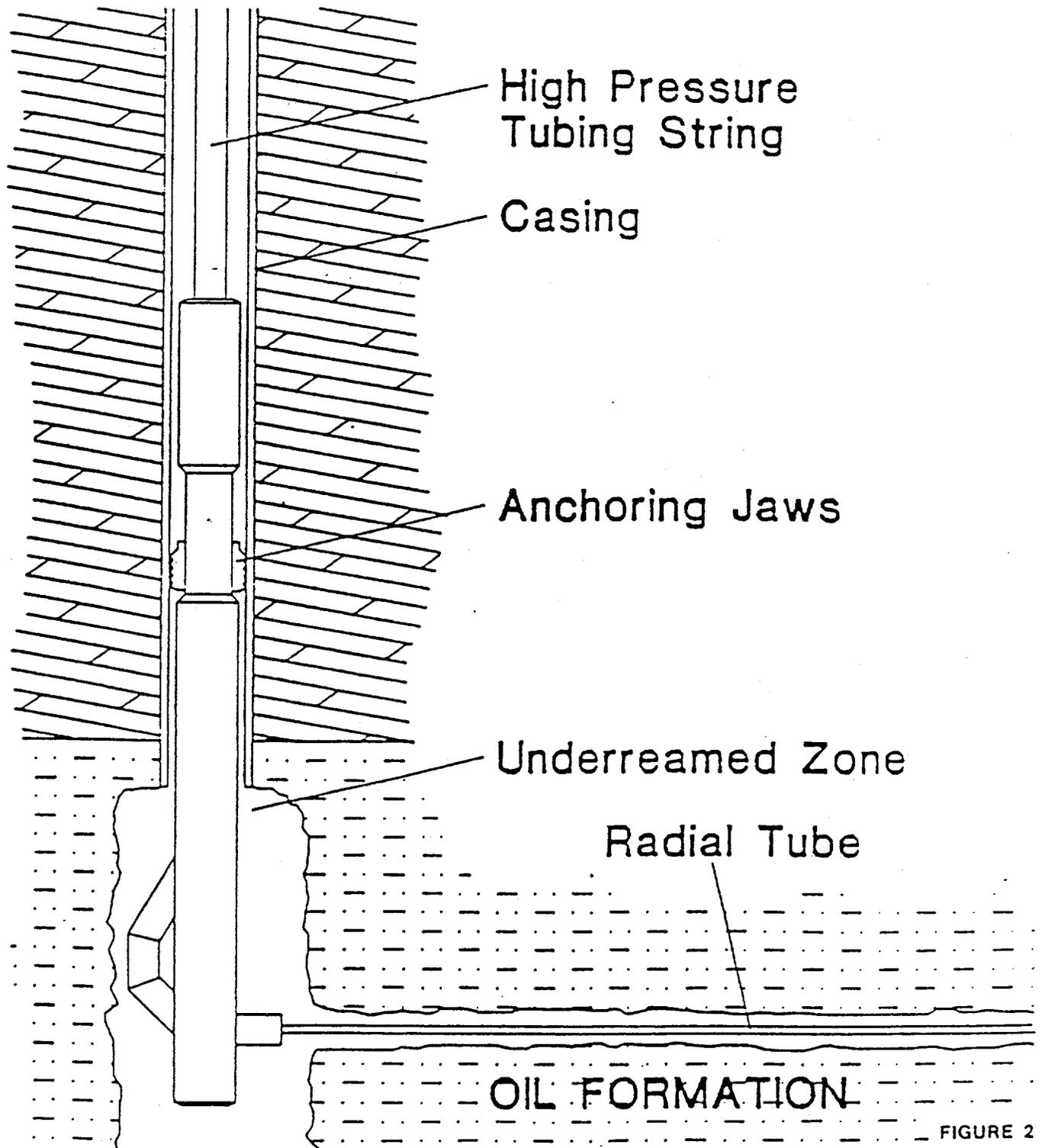


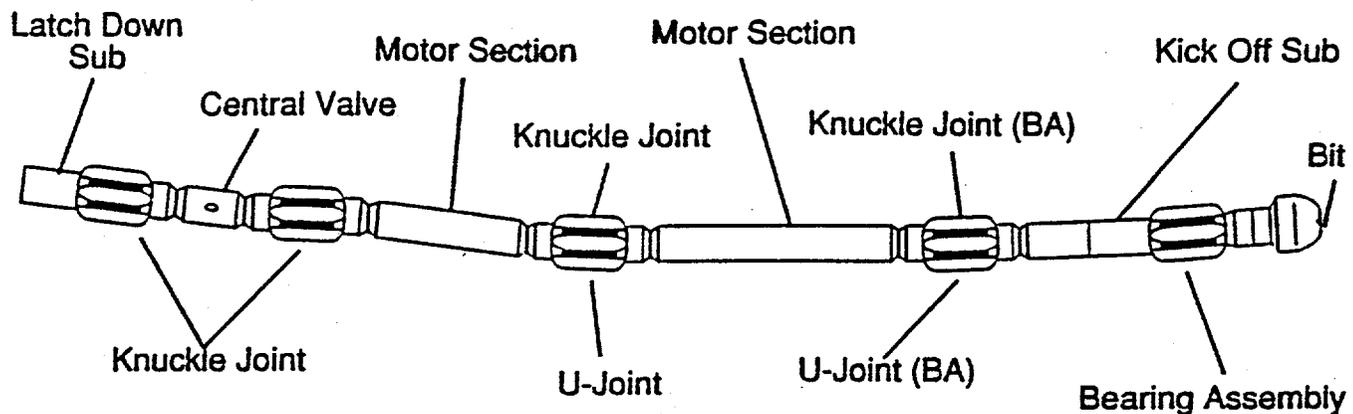
FIGURE 2

# Short Radius Architecture

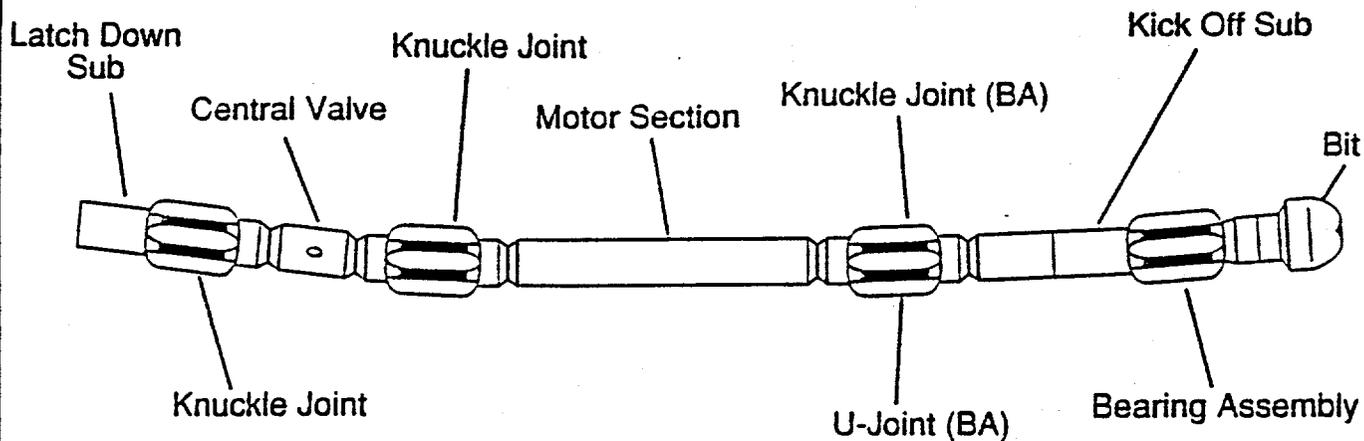
- *Build Rates 1-3.5 degrees/ft  
(57-16 ft Radius)*
- *Flexible Curved BHA*
- *Most Common Application -  
Drainhole Laterals*
- *Maximum 6" Hole Diameter*
- *Typical Lateral Length = 200-700 ft*

# Short-Radius Motor System

## Tool Size 3<sup>3</sup>/<sub>4</sub>"



## Tool Size 4<sup>3</sup>/<sub>4</sub>"



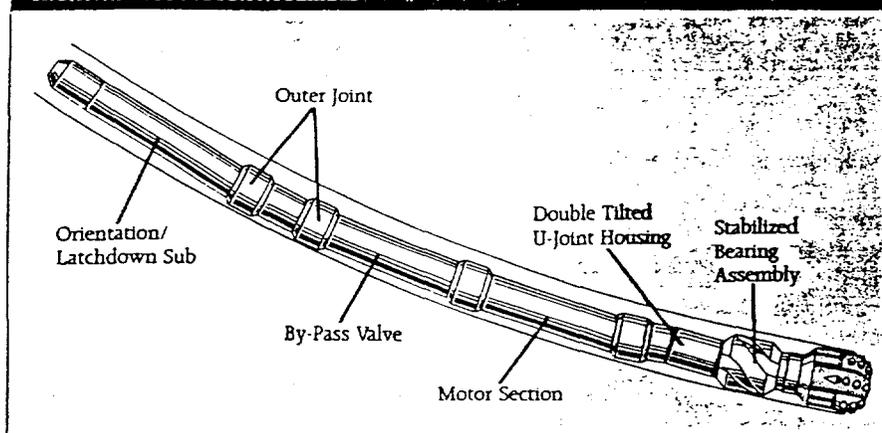
BA = Bearing Assembly

## **Short Radius Advantages**

- *Limited TVD Across Build (Artificial Lift)*
- *Accurate Lateral Placement*
- *Small Lease*
- *Troublesome Formations Above Pay*

## **Short Radius Disadvantages**

- *Relatively Short Laterals*
- *Slow Penetration Rate*
- *Limited Hard Rock Applicability*
- *Limited Directional Control*
- *Limited Log Capabilities*

**SHORT-RADIUS MOTOR ASSEMBLY**

**TUBULAR SPECIFICATIONS**

ARTICULATED DRIVE PIPE (ROTATED THROUGH CURVE)	3 3/4" System	4 1/2" System
OD (in.)	3 3/4"	4 1/2"
ID (in.)	1 1/2"	1 7/8"
Maximum Temperature (° F./°C)	260/127	260/127
Maximum Liner Pressure (psi/Bar)	1500/103	1500/103
Length (ft./m.)	20/6	20/6
Approximate Weight (lb.-ft./Kg./m.)	29.3/44.4	37.3/56.5
<b>CONNECTIONS:</b>		
Box Up	2 1/2" Reg. mod.	3 1/2" FH mod.
<b>CONNECTIONS:</b>		
Pin Down	2 1/2" Reg. mod.	3 1/2" FH mod.
Recommended Make Up Torque (ft.-lb./Nm)	3500/4745	4500/6100
<b>TUBING (ORIENTED THROUGH CURVE)</b>		
Type	P-105	P-105
OD (in.)	2 1/2"	2 1/2"
ID (in.)	2.259	2.259
Drift (in.)	2.165	2.165
Length (ft./m.)	30/9	30/9
Approximate Weight (lb.-ft./Kg./m.)	8.7/13.2	8.7/13.2
<b>CONNECTIONS:</b>		
Box Up	2 1/2" PH6	2 1/2" PH6
<b>CONNECTIONS:</b>		
Pin Down	2 1/2" PH6	2 1/2" PH6
<b>CONNECTIONS:</b>		
OD (in.)	3 1/2"	3 1/2"
Recommended Make Up Torque (ft.-lb./Nm)	3500/4745	3500/4745

**SPECIFICATIONS**

	3 3/4" System	4 1/2" System
Motor OD (in.)	3 3/4"	4 1/2"
Design Radius (ft./m.)	40/12.2	40 or 60/12.2 or 18.3
Hole Sizes Drilled (in.)	4 1/2" or 4 3/4"	6
Minimum Hole Size Above KOP (in.)	4 1/2"	6 1/4"
Minimum Casing Size Above KOP	5 1/2" 17#	7" 26#
Maximum Bottom Hole Temperature (° F./°C)	260/127	260/127

**MOTOR DATA**

	3 3/4" System	4 1/2" System
Speed (rpm)	225-550	150-260
Length (ft./m.)	12-17/3.7-5.2	12-17/3.7-5.2
Weight (lbs./Kgs.)	420/191	650/295
Flow Rate (gpm/lpm)	90-120/341-455	185-230/701-871
Drilling Differential Pressure (psi/Bar)	75-500/5-34	75-720/5-50
Maximum Differential Pressure (psi/Bar)	1000/69	1200/83
Operating Torque (ft.-lb./Nm)	500-700/678-949	350-700/474-949
<b>CONNECTIONS:</b>		
Box Up	2 1/2" PH6	2 1/2" PH6
Recommended Make Up Torque (ft.-lb./Nm)	3500/4745	3500/4745
<b>CONNECTIONS:</b>		
Box Down	2 1/2", 2 1/2" Reg.	3 1/2" Reg.
Recommended Make Up Torque (ft.-lb./Nm)	3500-5700/4745-7726	9400/12.742

**Relief Well Team**

Eastman Christensen's experience with relief wells dates back to 1934, when John Eastman successfully drilled the first relief well in history. Today our company still honors John Eastman's commitment, maintaining leadership in drilling-related services, technology and products.

Our Relief Well Team was created to focus exclusively on the engineering and execution of this most highly specialized and demanding directional drilling service work. Team members are selected based on experience, service and individual expertise.

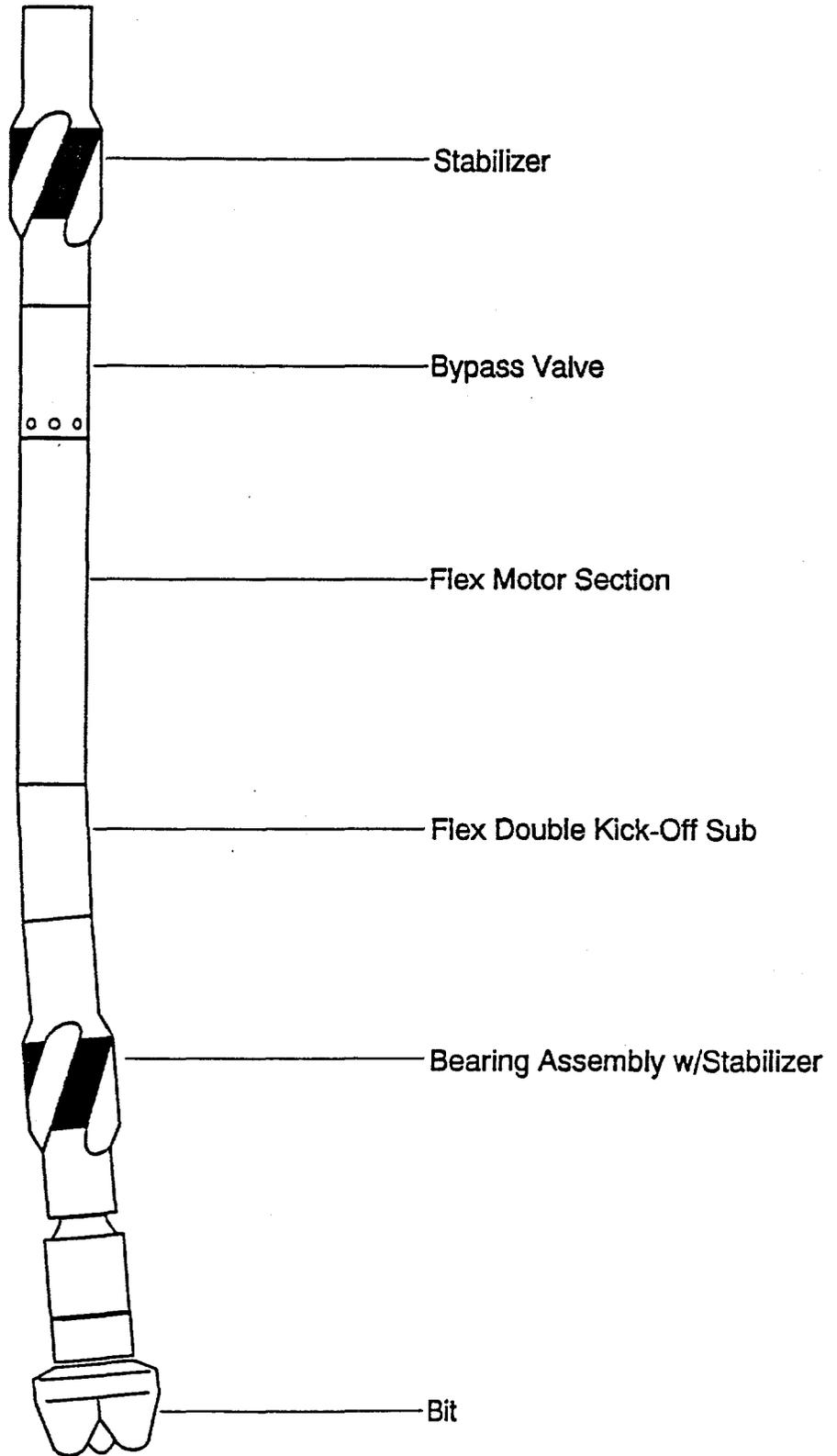
Our Relief Well Team includes: A **Relief Well Manager** who advises initial relief well strategy and is primary liaison between the operator and the Eastman Christensen team. Equipped with a computer, plotter and complete wellplanning and drilling software, he is located in the operator's office, providing operating engineers fulltime input and access to data through all phases of the operation.

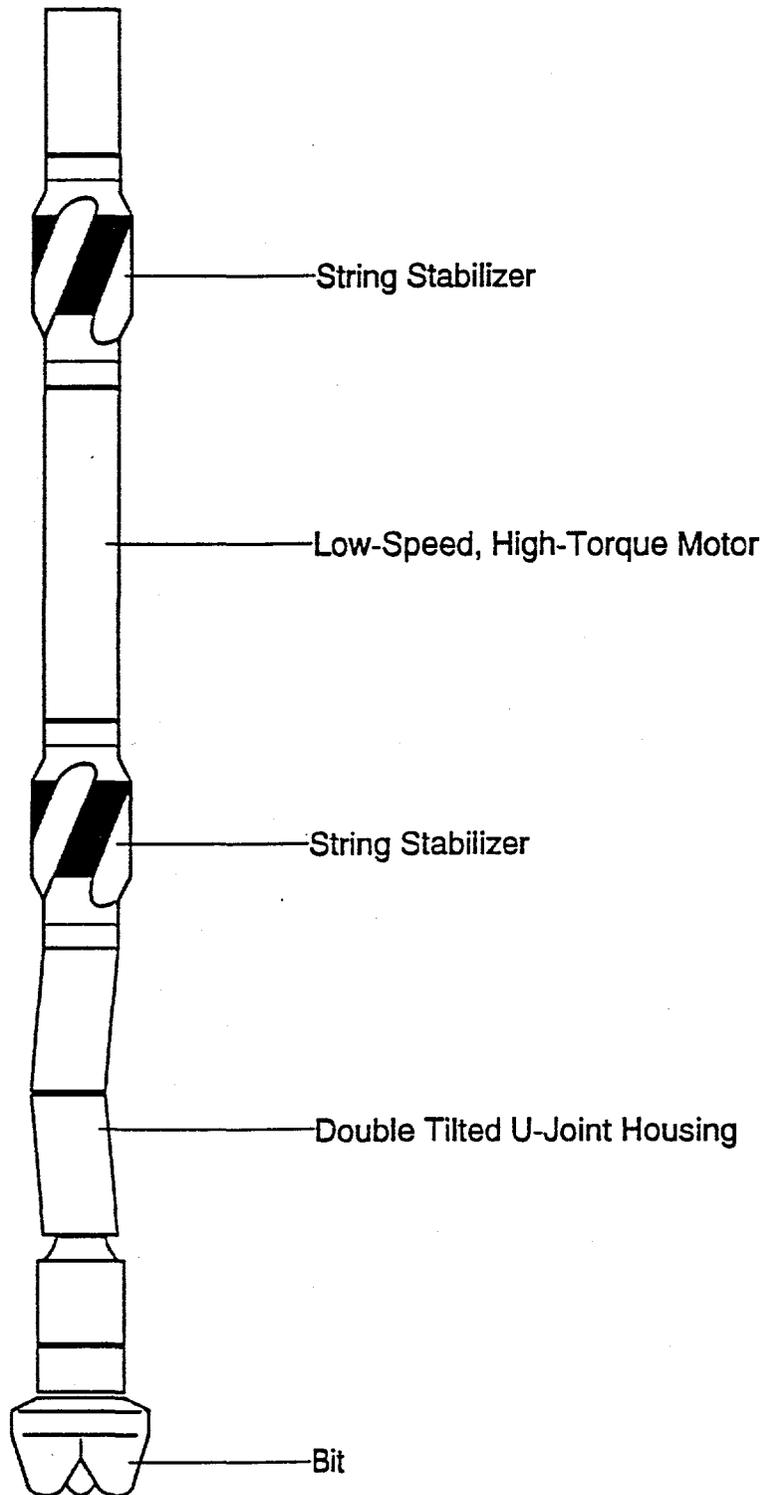
A **Relief Well Drilling Engineer** who acts as the communications link between personnel at the rigsite and the Relief Well Manager in the operator's office.

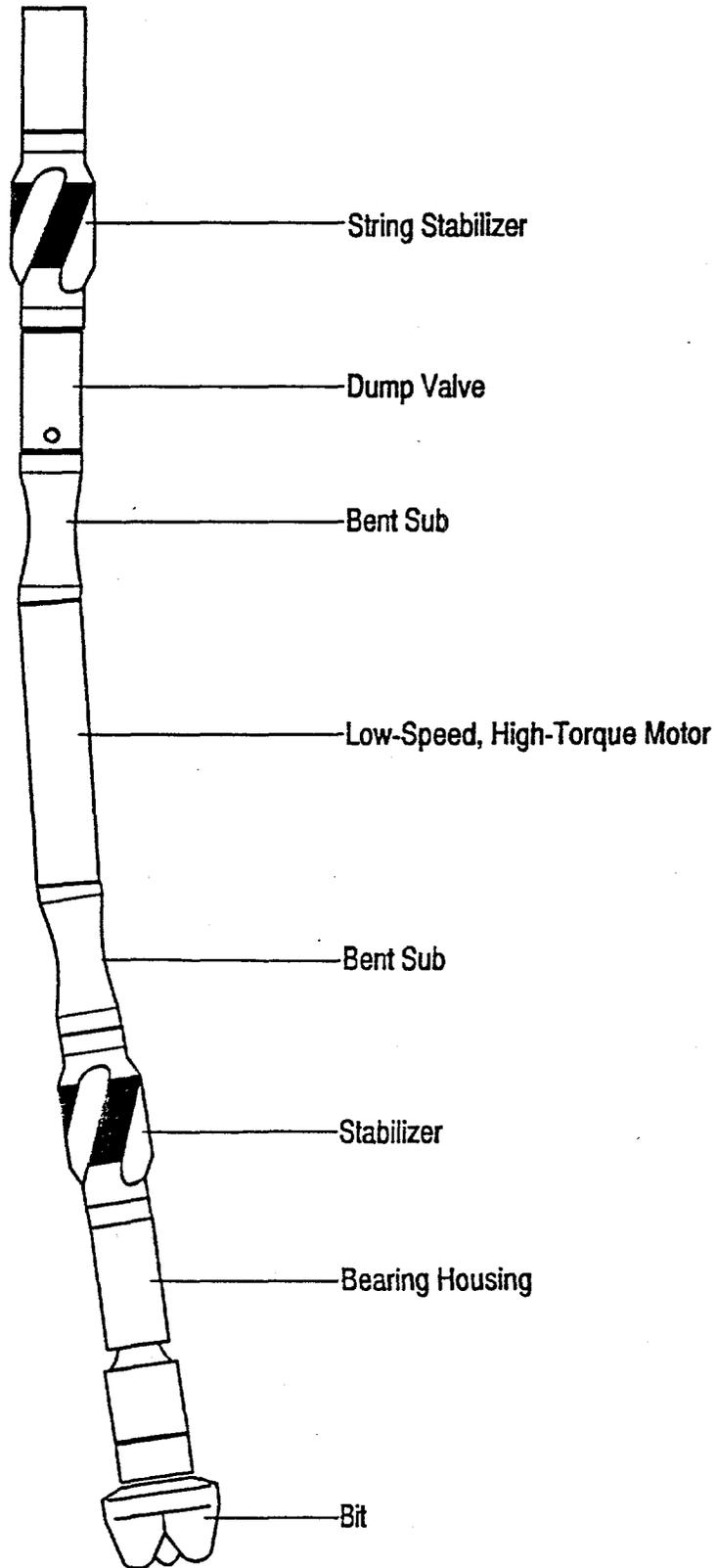
A local **Drilling Engineer** who analyzes geology and offset records to advise on bit selection, hydraulics, steerable systems, drilling tools, and drilling optimization.

**Local Drilling, Survey and MWD Coordinators** to provide logistical support for personnel and equipment.

Eastman Christensen's innovative, computerized approach affords instant data transfer from rig to office, or from office to headquarters, ensuring a vital line of communications is maintained throughout the relief well effort.







## **Medium Radius Advantages**

- *Longer Laterals Available (Short Radius)*
- *Case Troublesome Formation in Curve*
- *Shorter Curve Section (Long Radius)*
- *Deeper KOP = Higher Accuracy (Long Radius)*

## **Medium Radius Disadvantages**

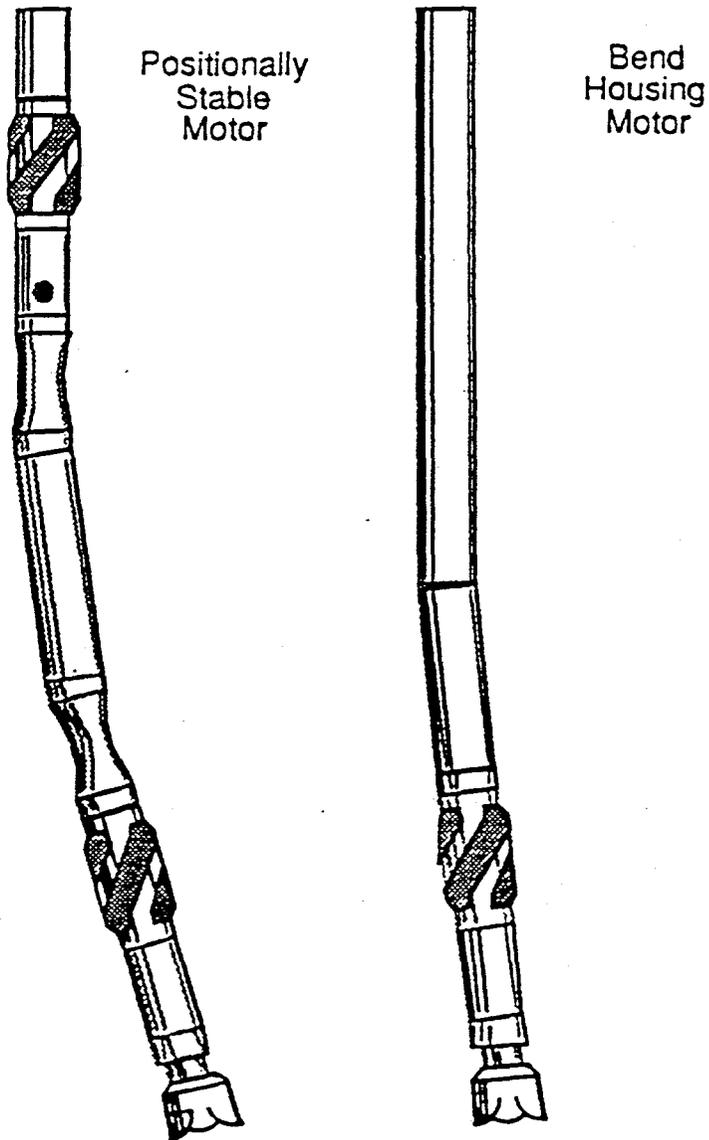
- *High Drillstring Stress*
- *High Casing Stress*
- *Less Conventional Tools (Long Radius)*

## **A STEERABLE SYSTEM WHAT IS IT?**

**AN OPTIMIZED BOTTOM HOLE ASSEMBLY INCLUDING A PDM WHICH CAN EFFECT CHANGES IN HOLE INCLINATION OR DIRECTION WHILE IN THE ORIENTED MODE OR MAINTAIN HOLE INCLINATION AND DIRECTION IN THE ROTARY MODE**

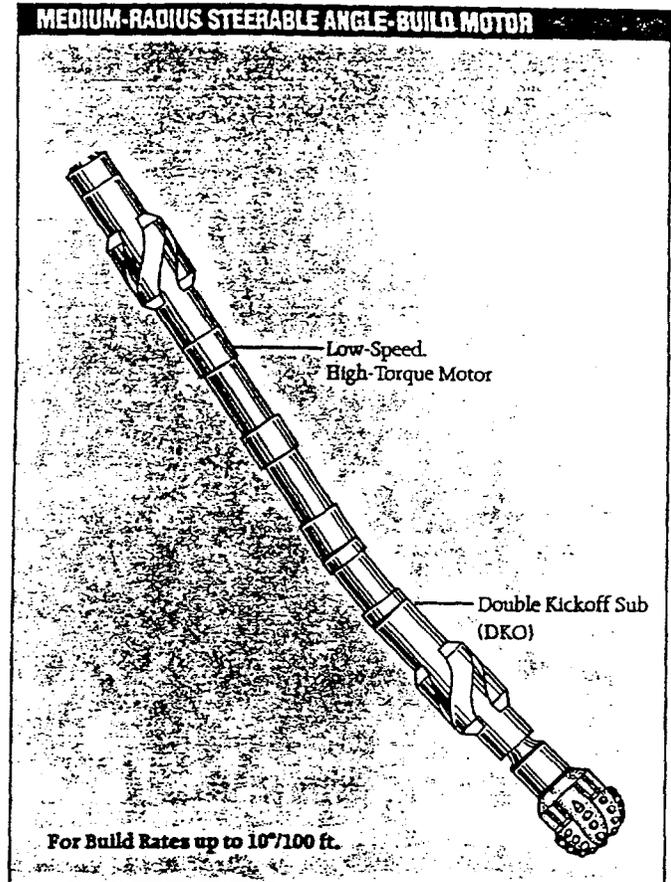
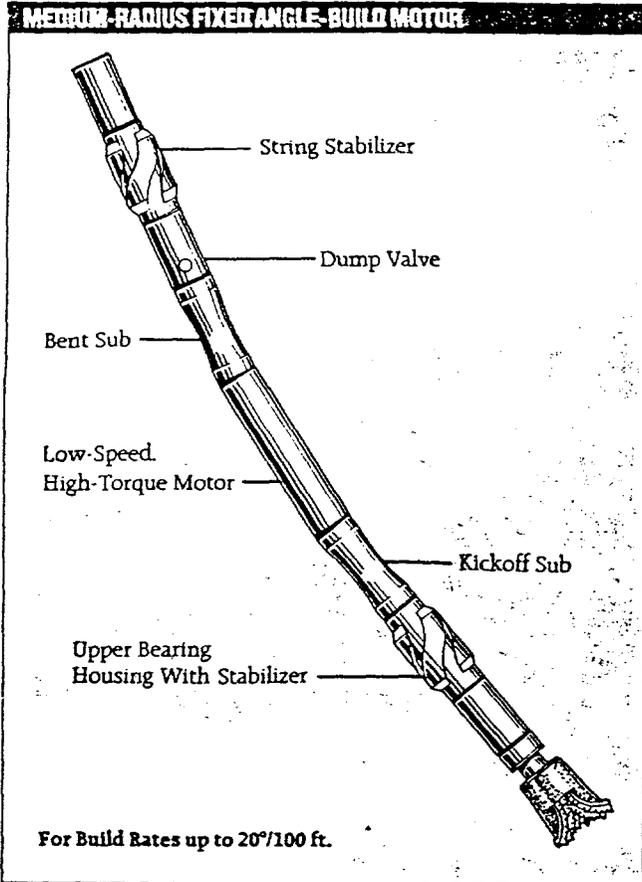
### ECONOMIC CONSIDERATIONS:

Both build and lateral sections of a medium-radius well are typically drilled with modified tooling which is configured to mate with standard oil field hardware, creating a "package" which can be mobilized to any rig with minimal additional modification.



### Medium-Radius Angle-Build Methods

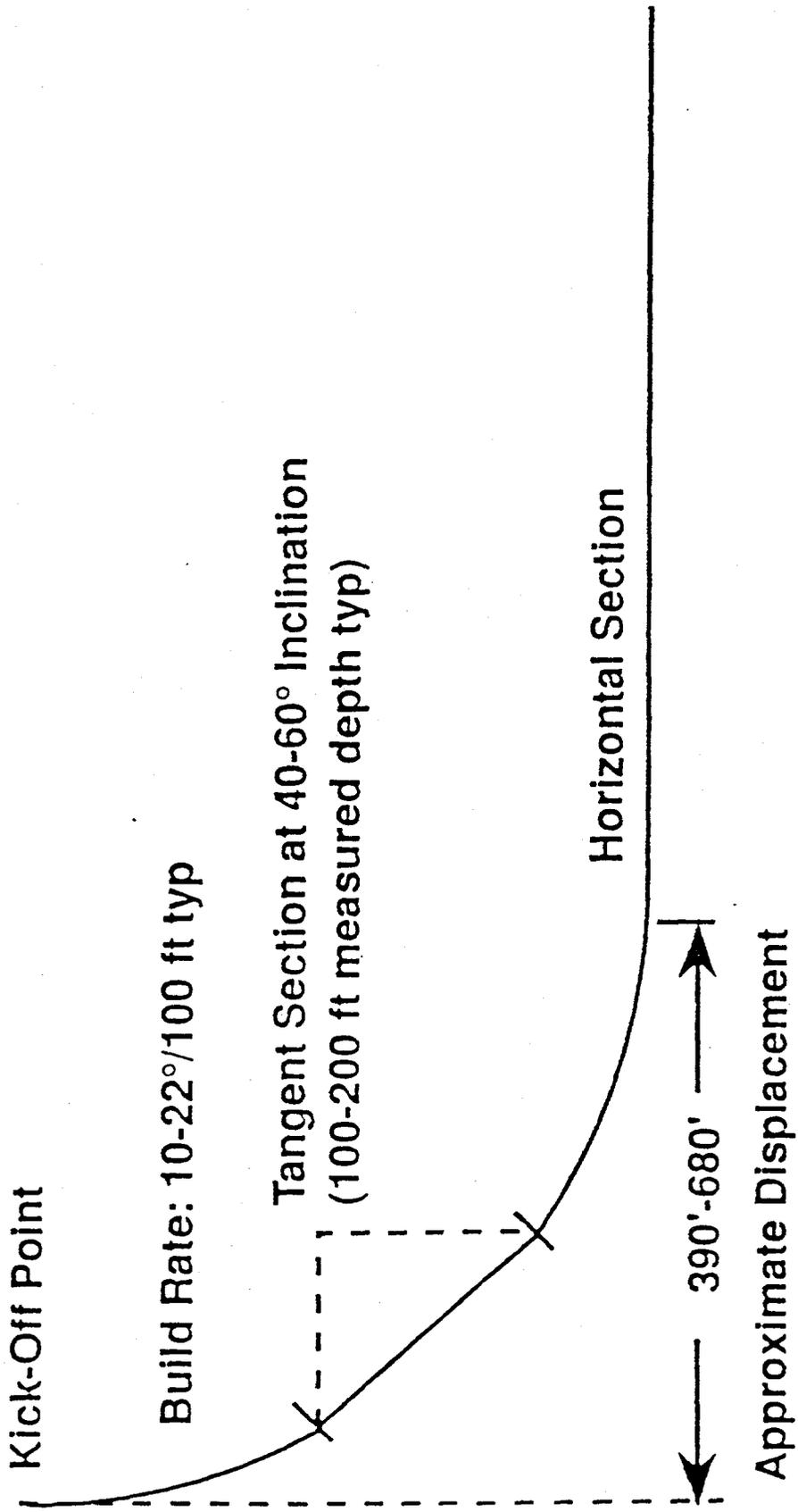
By combining several conventional hardware systems, the incremental cost of medium-radius drilling systems may be minimized. Unlike long-radius wells which require only one or two service contractors, medium-radius wells may involve as many as five service companies on a single project.



**MEDIUM-RADIUS SYSTEM SPECIFICATIONS**

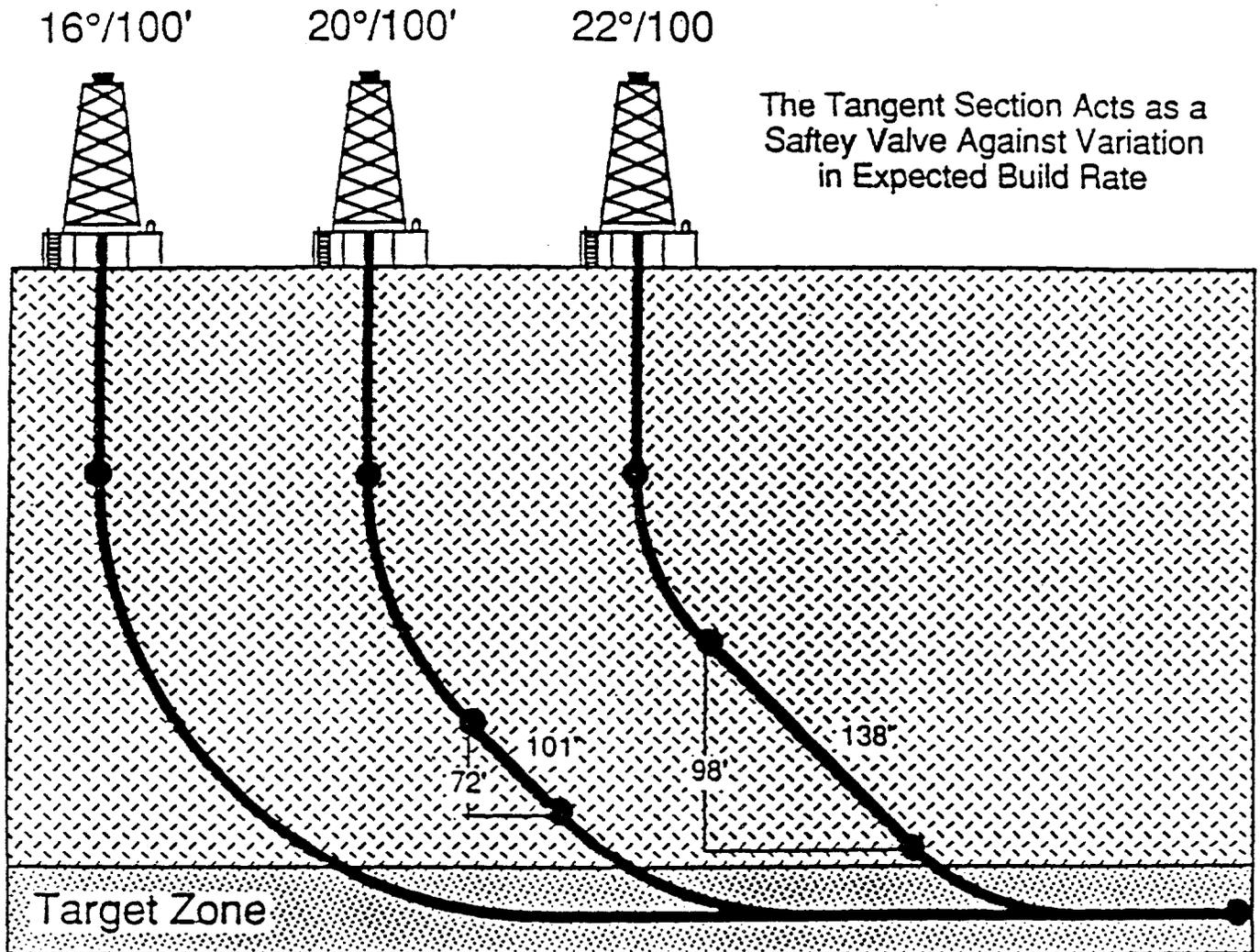
	Motor OD*	8"	6 1/4"	4 3/4"	3 3/4"
General Data	Design radius. (ft./m.)	715-410/218-125	715-410/218-125	286-300/87-91	286/87
	Min. vertical casing above K.O.P.	13 1/4"	9 1/4"	7"	5 1/2"
	Initiation: Off bottom-plug	Yes	Yes	Yes	Yes
	Off whipstock	Yes	Yes	Yes	Yes
	Min. vertical open hole OD	12 1/4"	8 3/4"	6"	4 1/4"
	Max. temperature. (°F/°C)	260/127	260/127	260/127	260/127
Angle-Build Assembly	Motor type	Mach 1	Mach 1	Mach 1	Mach 1
	Speed range. (rpm)	85-190	100-260	100-300	120-340
	Overall length. (ft./m.)	26.0/8.0	29.0/8.8	26.0/8.0	20.0/6.0
	Weight. (lbs./Kgs.) (approx.)	3500/1585	2500/1130	1100/500	700/320
	Connections: Upper box	6 1/2 Reg.	4 1/2 IF	3 1/2 IF	2 1/4 IF
	Lower bit box	6 1/2 Reg.	4 1/2 Reg.	3 1/2 Reg.	2 1/4 Reg.
	Max. flow rate (without bypass). (gpm/ lpm)	685/2600	475/1800	240/900	185/700
	Max. allow. diff. pressure. (psi/bar)	580/40	725/50	725/50	800/55
Operating torque. (ft.-lbs./Nm)	4500/6100	2800/3800	1180/1600	890/1200	
Angle-Hole Assembly	As above. except:				
	Overall length. (ft./m.)	26.0/8.0	26.5/8.1	23.5/7.1	21.1/6.4
	Weight. (lbs./Kgs.)	2800/1270	1900/860	950/430	600/270
Angle change rate. steering mode	2-5°/100 ft	2-6°/100 ft	2-6°/100 ft	2-6°/100 ft	
Orientation Techniques	Single Shot	Yes	Yes	Yes	Yes
	Steering tool	Yes	Yes	Yes	Yes
	MWD	Unrestricted	Unrestricted	Some limitations†	N/A
Drill Pipe	Conventional. (in.)	5 HWDP	4-5 HWDP	N/A	N/A
	3 1/2 S-135. w/wear knots	Yes	Yes	Yes	N/A
	2 1/4 S-135. w/wear knots	No	Yes	Yes	Yes

\*Other sizes available upon request. †Contact your Eastman Christensen representative for further details.



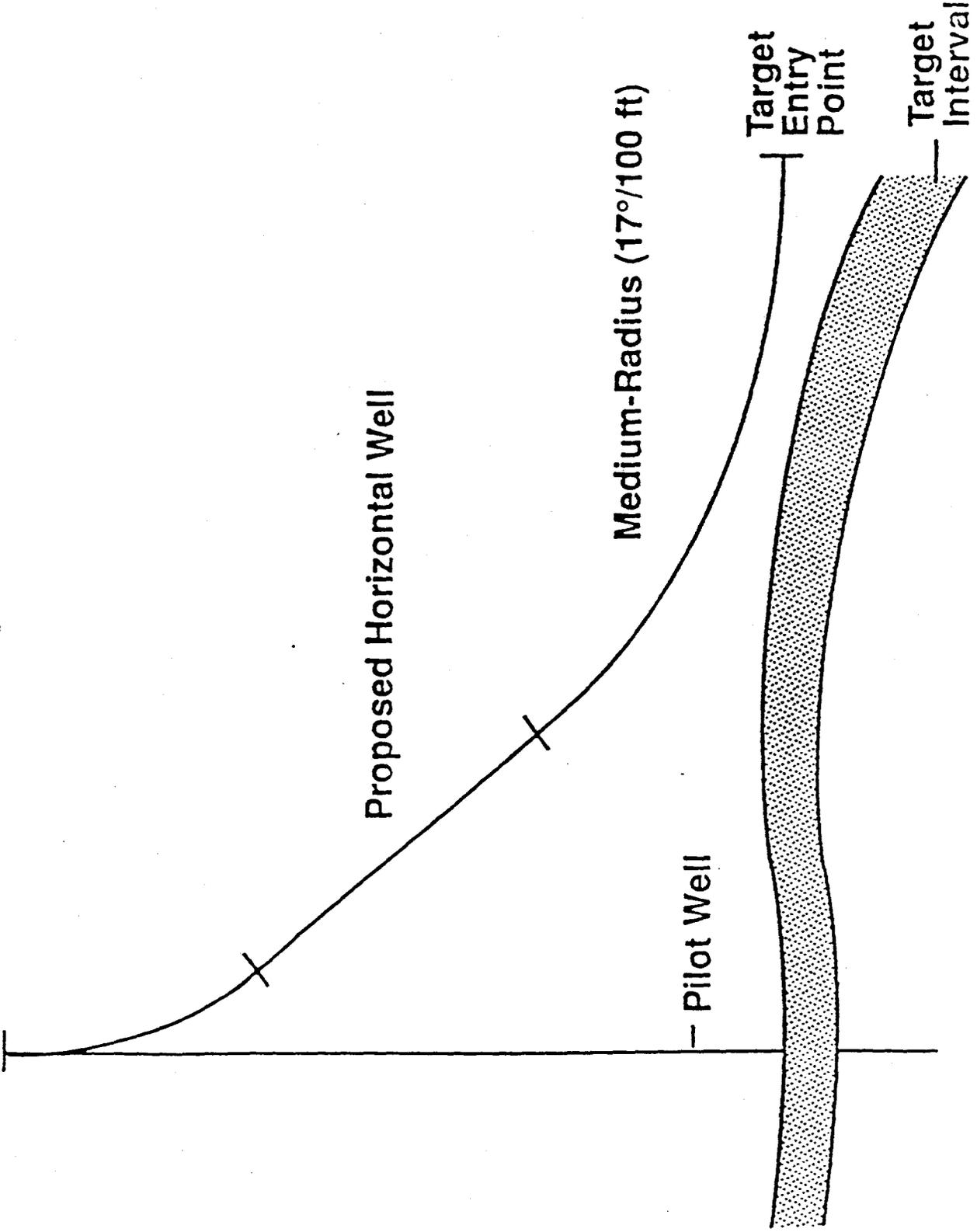
**Standard medium-radius well profile**

In addition, placing the KOP nearer the target in most cases will reduce the uncertainty of depth to the true target. At least one service company capitalizes on this attribute by including a "depth adjustment section" in the medium-radius well plan. Referred to as a "tangent," this section is typically placed at 45 to 75 degrees of inclination after 70 to 85 percent of target depth has been reached. This facilitates any change in planned target depth should formation, reservoir, or other factors require.

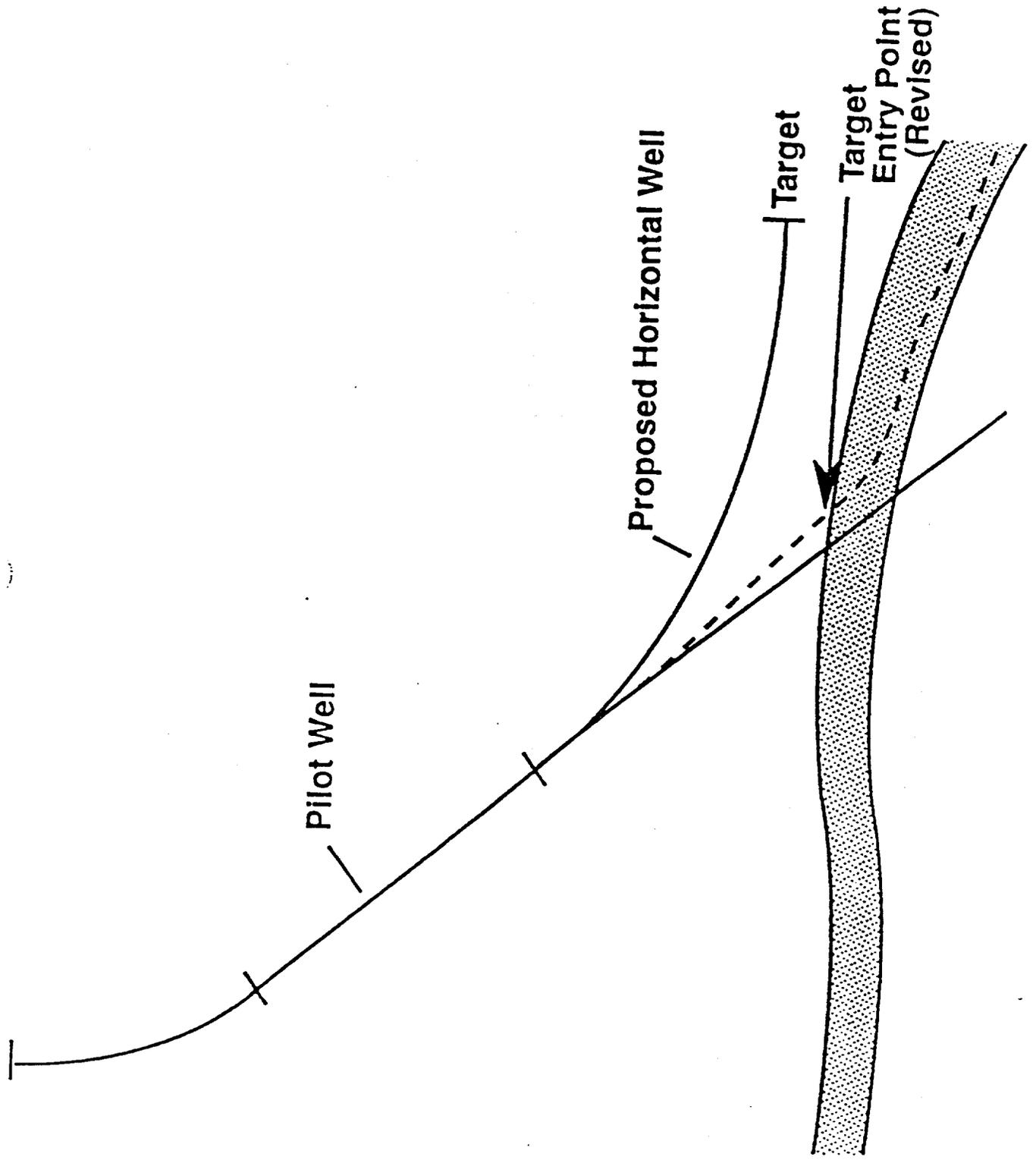


### Tangent Section

The disadvantages of medium-radius drilling are relatively few. At higher BURs, bending moment across tool joints, and material stress in the tube body may require engineering attention. And in snow bank drilling, bit side wall force caused by high curvature in a medium-radius hole can cause borehole wall gouges and possible sidetracking.



Vertical pilot well



**Angled pilot well**

# Long Radius Architecture

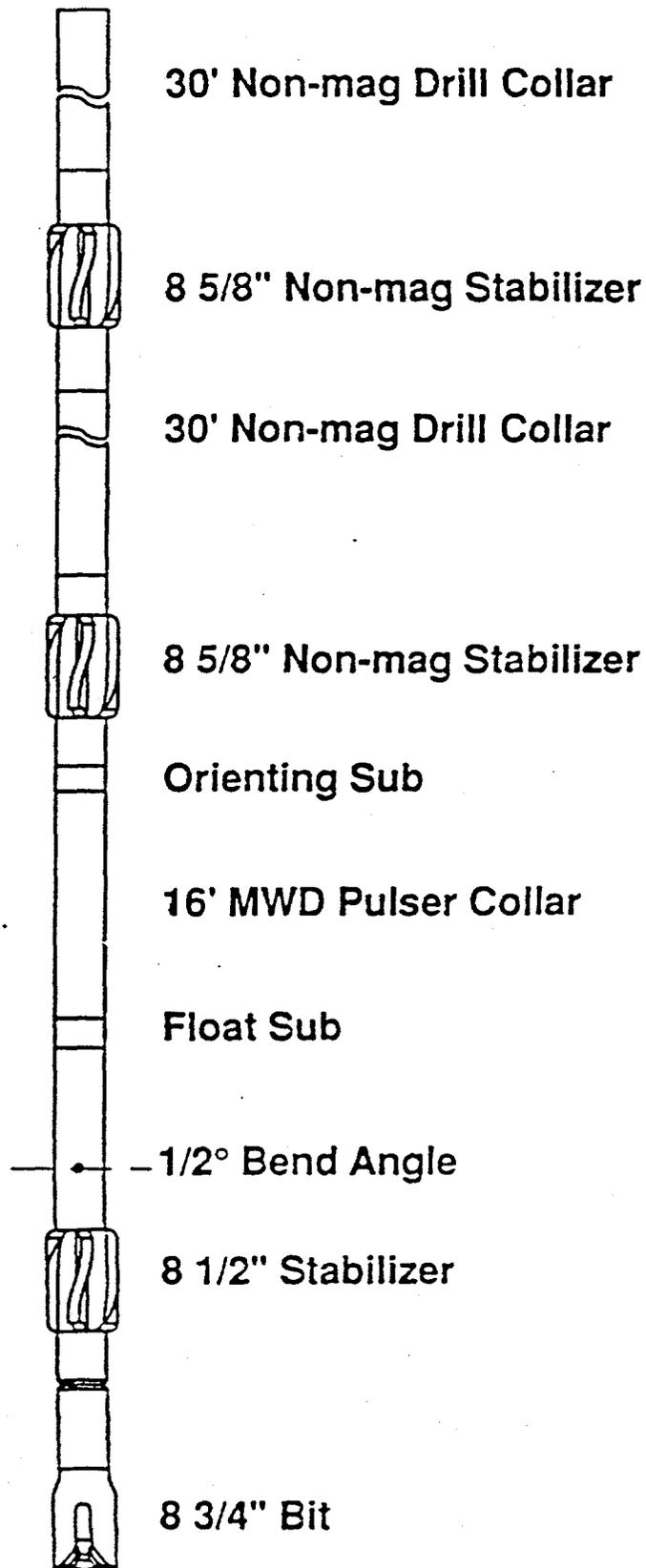
- *Build Rates 1-6 degrees /100 ft  
(5,730-955 ft Radius)*
- *Conventional BHA and Hole Diameters*
- *Typical Lateral Length = 3,000 - 10,000 ft*
- *Typical Hole Diameter = 8-1/2" - 12-1/4"*

## **Long Radius Advantages**

- *Longer Laterals (Medium and Short Radius)*
- *Conventional BHA*
- *Larger Drillstring and Casing Sizes Through Curve*
- *Ability to Rod Pump in Curve*

## **Long Radius Disadvantages**

- *"Roller Coaster" Wellbore*
- *Increased Torque and Drag*
- *Increased Drilling Time*
- *Increased Cost*
- *Difficult to Hit Small Targets*
- *Lease Considerations*



**Typical long-radius steerable assembly**

# 6-3/4" OR LARGER FIXED ANGLE-BUILD (FAB) HORIZONTAL DRILLING ASSEMBLY



Drill Pipe to Surface

Drill Collars for Added  
Weight in Vertical Hole  
(Optional but Preferred)

Heavy Weight Drill Pipe  
for Flexibility in Curve

Heavy Weight Drill Pipe  
for Flexibility in Curve



Compressive Service  
Drill Pipe (Non Mag)  
For MWD Isolation

MWD Survey System  
For Directional Control

Pup-Joint (10' Non-Mag)  
For Flexibility and  
MWD Isolation

Baker Hughes INTEQ  
Fixed Angle Build (FAB)  
PDM Drilling Motor

# 6-3/4" OR LARGER DOUBLE ADJUSTABLE BUILD (DAM) HORIZONTAL DRILLING ASSEMBLY



Drill Pipe to Surface

Drill Collars for Added Weight in Vertical Hole (Optional but Preferred)

Heavy Weight Drill Pipe for Flexibility in Curve

Heavy Weight Drill Pipe for Flexibility in Curve



Compressive Service Drill Pipe (Non Mag) For MWD Isolation

MWD Survey System For Directional Control

Pup-Joint (10' Non-Mag) For Flexibility and MWD Isolation

Baker Hughes INTEQ Double Adjustable Motor (DAM)

# 6-3/4" OR LARGER DOUBLE-ANGLE ADJUSTABLE BUILD (DAAB) HORIZONTAL DRILLING ASSEMBLY



Drill Pipe to Surface



Drill Collars for Added Weight in Vertical Hole (Optional but Preferred)



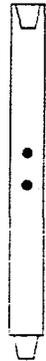
Heavy Weight Drill Pipe for Flexibility in Curve



Heavy Weight Drill Pipe for Flexibility in Curve



Compressive Service Drill Pipe (Non Mag) For MWD Isolation



MWD Survey System For Directional Control



Pup-Joint (10' Non-Mag) For Flexibility and MWD Isolation



drilling Stabilizer

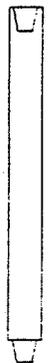


Baker Hughes INTEQ Double-Angle Adjustable Motor (DAAB)

# 6-3/4" OR LARGER DOUBLE-ANGLE ADJUSTABLE (DAAB) STEERABLE HORIZONTAL DRILLING ASSEMBLY



Drill Pipe to Surface



Drill Collars for Added Weight in Vertical Hole (Optional but Preferred)



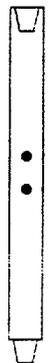
Heavy Weight Drill Pipe for Flexibility in Curve



Heavy Weight Drill Pipe for Flexibility in Curve



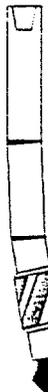
Compressive Service Drill Pipe (Non Mag) For MWD Isolation



MWD Survey System For Directional Control



Pup-Joint (10' Non-Mag) For Flexibility and MWD Isolation

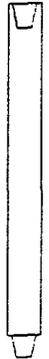


Baker Hughes INTEQ Double-Angle Adjustable Motor (DAAB)

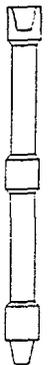
# 6-3/4" OR LARGER DOUBLE TILTED U-JOINT (DTU) STEERABLE HORIZONTAL DRILLING ASSEMBLY



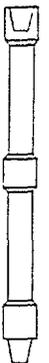
Drill Pipe to Surface



Drill Collars for Added Weight in Vertical Hole (Optional but Preferred)



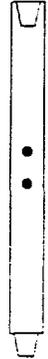
Heavy Weight Drill Pipe for Flexibility in Curve



Heavy Weight Drill Pipe for Flexibility in Curve



Compressive Service Drill Pipe (Non Mag) For MWD Isolation



MWD Survey System For Directional Control



Pup-Joint (10' Non-Mag) For Flexibility and MWD Isolation



Baker Hughes INTEQ Double Tilted U-Joint Steerable Motor (DTU)

# 6-3/4" OR LARGER ADJUSTABLE KICK-OFF SUB (AKO) STEERABLE HORIZONTAL DRILLING ASSEMBLY



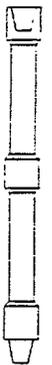
Drill Pipe to Surface



Drill Collars for Added Weight in Vertical Hole (Optional but Preferred)



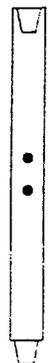
Heavy Weight Drill Pipe for Flexibility in Curve



Heavy Weight Drill Pipe for Flexibility in Curve



Compressive Service Drill Pipe (Non Mag) For MWD Isolation



MWD Survey System For Directional Control



Pup-Joint (10' Non-Mag) For Flexibility and MWD Isolation



Baker Hughes INTEQ Adjustable Kick-Off Sub (AKO) Motor

# 6-3/4" OR LARGER DOUBLE-ANGLE ADJUSTABLE (DAAB) STEERABLE HORIZONTAL DRILLING ASSEMBLY



Drill Pipe to Surface

Drill Collars for Added Weight in Vertical Hole (Optional but Preferred)

Heavy Weight Drill Pipe for Flexibility in Curve

Heavy Weight Drill Pipe for Flexibility in Curve

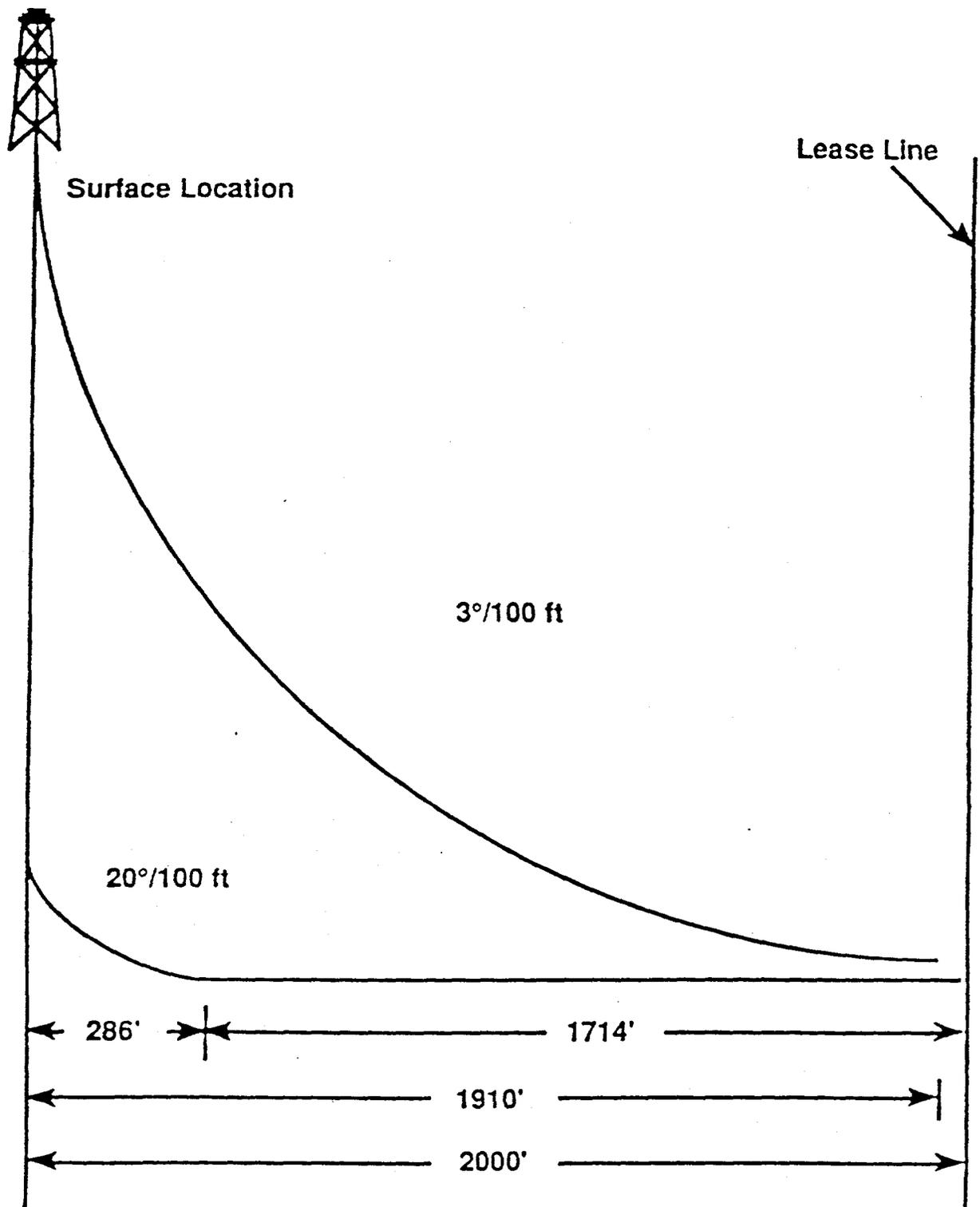


Compressive Service Drill Pipe (Non Mag) For MWD Isolation

MWD Survey System For Directional Control

Pup-Joint (10' Non-Mag) For Flexibility and MWD Isolation

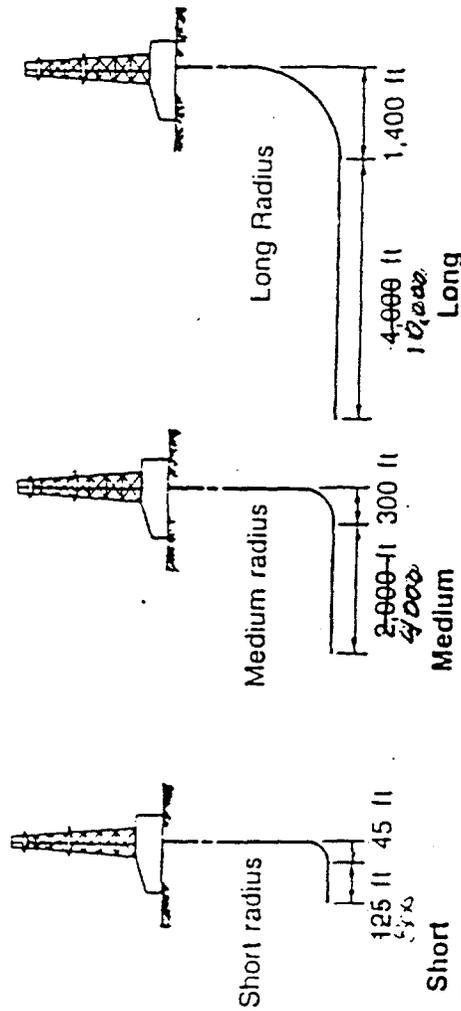
Baker Hughes INTEQ Double-Angle Adjustable Motor (DAAB)



**Medium vs. long-radius profiles to maximize horizontal displacement**

HORIZONTAL DRILLING SEMINAR

**HORIZONTAL WELL CLASSIFICATION**



Feature	Short	Medium	Long
Radius of curvature	30' - 45'	300' - 500'	1,200' - 3,000'
Typical build rate	191° - 126°/100'	18.8° - 11.5°/100'	4.8° - 3.8°/100'
Feet drilled to horizontal	47' - 71'	471' - 785'	1,885' - 4,712'
Feet of horizontal hole	75' - 125'	500' - 2,000'	1,000' - 4,000'
Drilling assemblies	Whipstock, articulated tools, knuckle joints, Compressive service	Conventional rotary Inverted drill string MWD, motor assemblies	Near-conventional Rotary, MWD and motor assemblies
Drilling operations	Very specialized	Conventional	Near-conventional
Surveying	Single-shot/multi-shot	MWD	MWD
Directional control	Initial aim only, off whipstock	Steerable	Steerable
Logging	None	MWD	MWD
Use in existing wells	Yes	Yes	Not likely
Cased horizontally	No	Yes	Yes

# Well Control Considerations

- *SIDPP = SICP*
- *Gas Migration Rates*
- *Use of Wait and Weight Technique*
- *Equivalent Circulating Densities*

# Bit Selection in Horizontal Wells

- *Formation Type*
- *Gauge Protection*
- *Motor Applications*
- *Roller Cone Shirrtail Pads*
  - *Gauge Protection*
  - *Reduced Steerability*
- *PDC Gauge Length*
  - *Shorter = Increased Steerability*
  - *Longer = Increased Holding Stability*
- *Motor Stall*

# Drilling Fluid Considerations

- *Hole Stability (Tensile and Compressive)*
- *Lubricity*
- *Filtration Control*
- *Hole Cleaning*
- *Barite Suspension*

# Particle Slip Velocity

- **Definition**

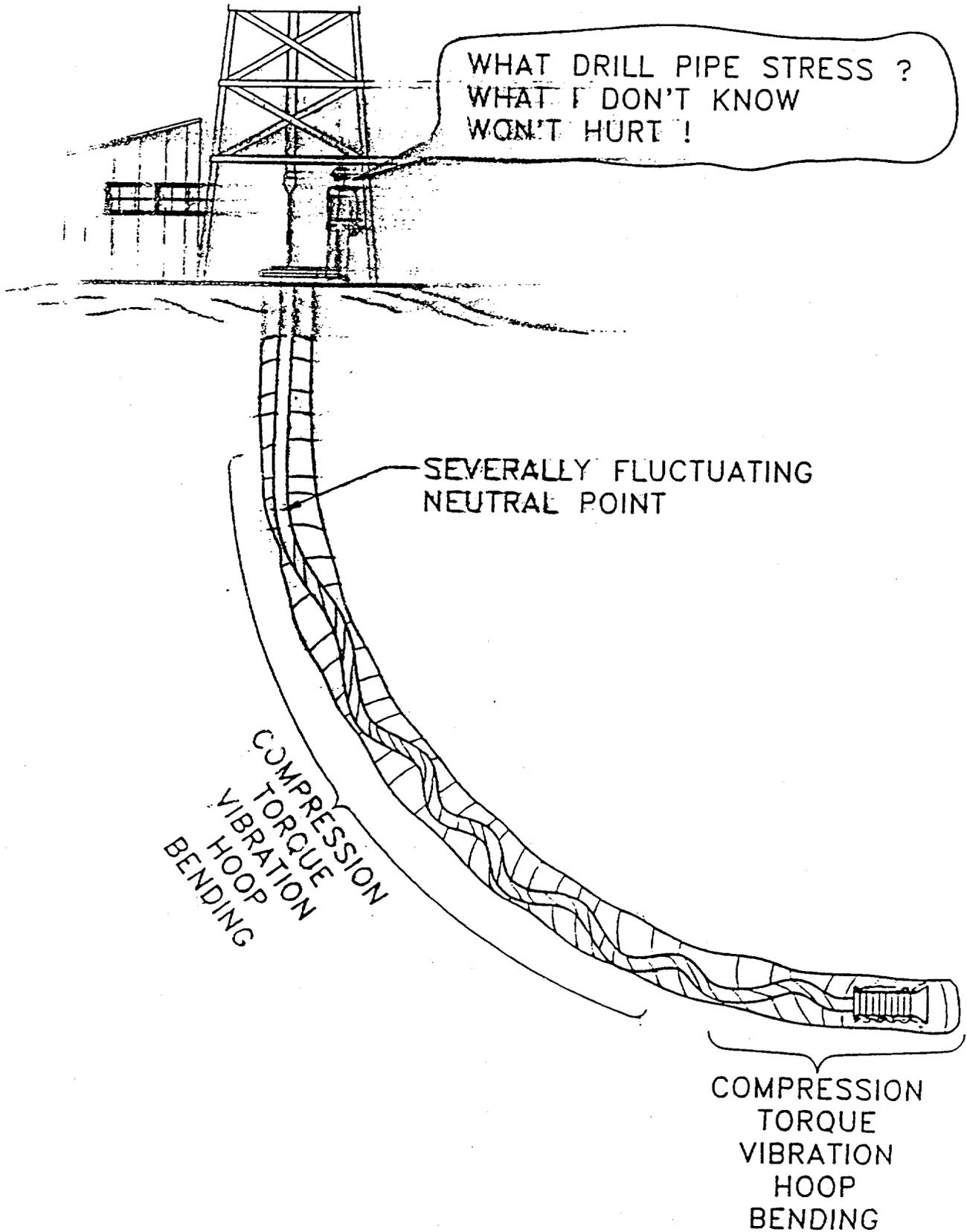
- *How Fast Particle Falls Relative to Liquid Medium*

- **Equation**

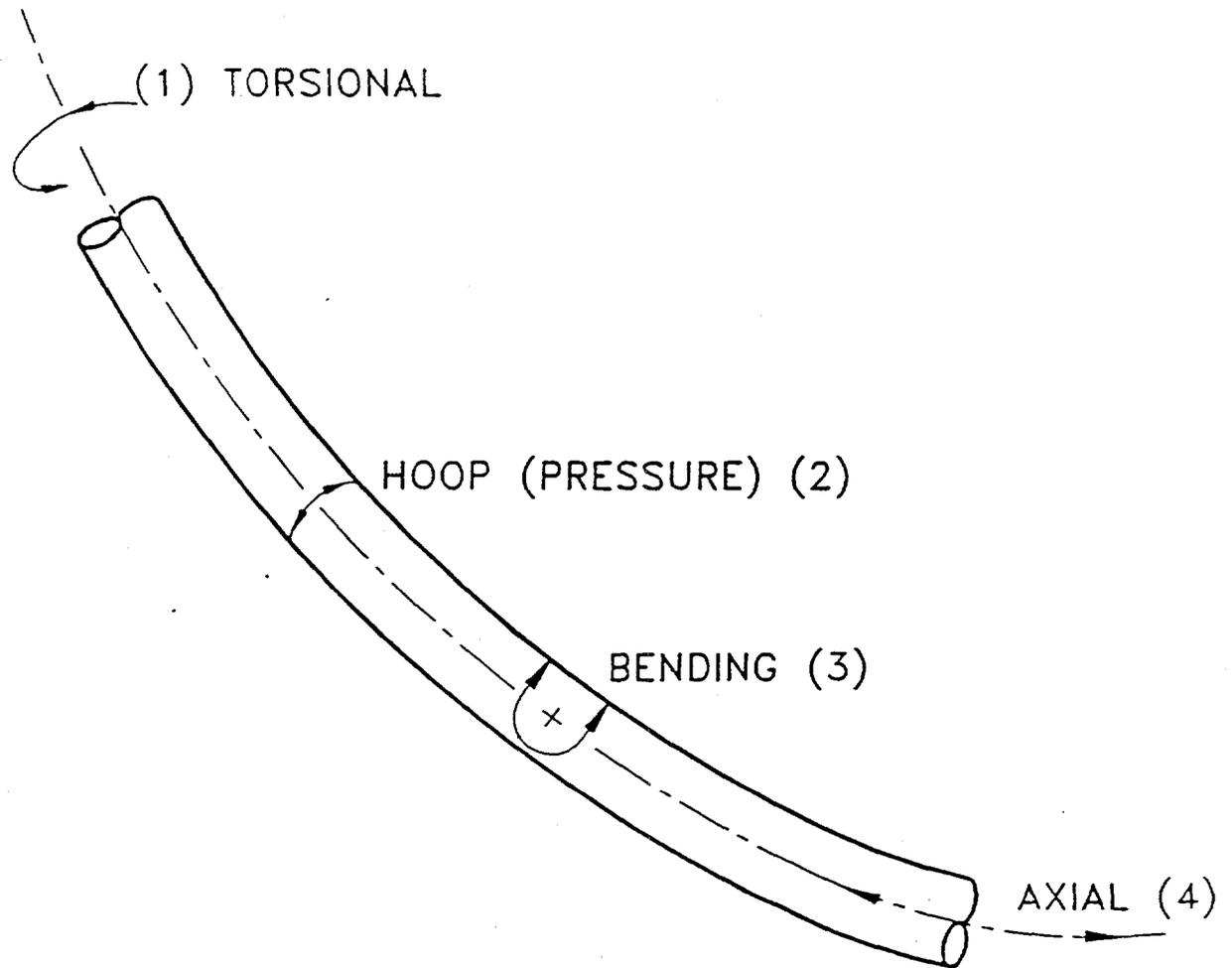
$$V_s = \frac{175 d_{\text{part}} (\rho_{\text{part}} - \rho)^{0.667}}{\rho^{0.333} \mu^{0.333}}$$

- **Important Variables**

- *Particle Diameter*
  - *Density Difference*
  - *Mud Density*
  - *Mud Viscosity*



# TYPES OF DRILLSTRING STRESS



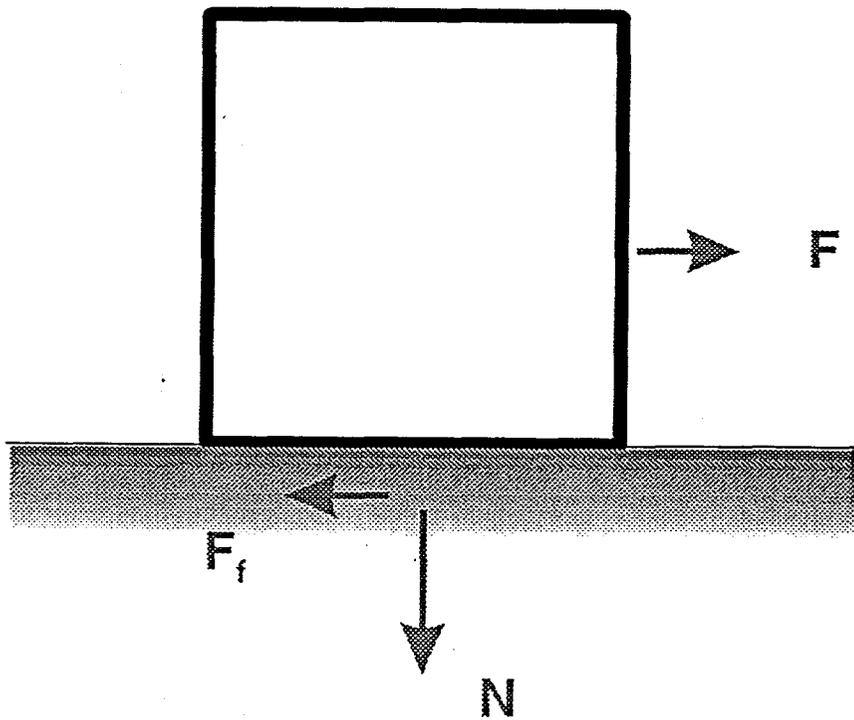
5) CYCLICAL ( VARYING AMPLITUDES OF 1 - 4 ABOVE )

6) VIBRATION ( HARMONICS IN TORSION OR AXIAL )

TORQUE AND DRAG = DRILLSTRING STRESS

THIS IS THE MOST SIGNIFICANT VARIABLE IN THE DRILLING  
LIMITATIONS OF MOST HORIZONTAL WELLS  
(ESPECIALLY EXTENDED REACH)

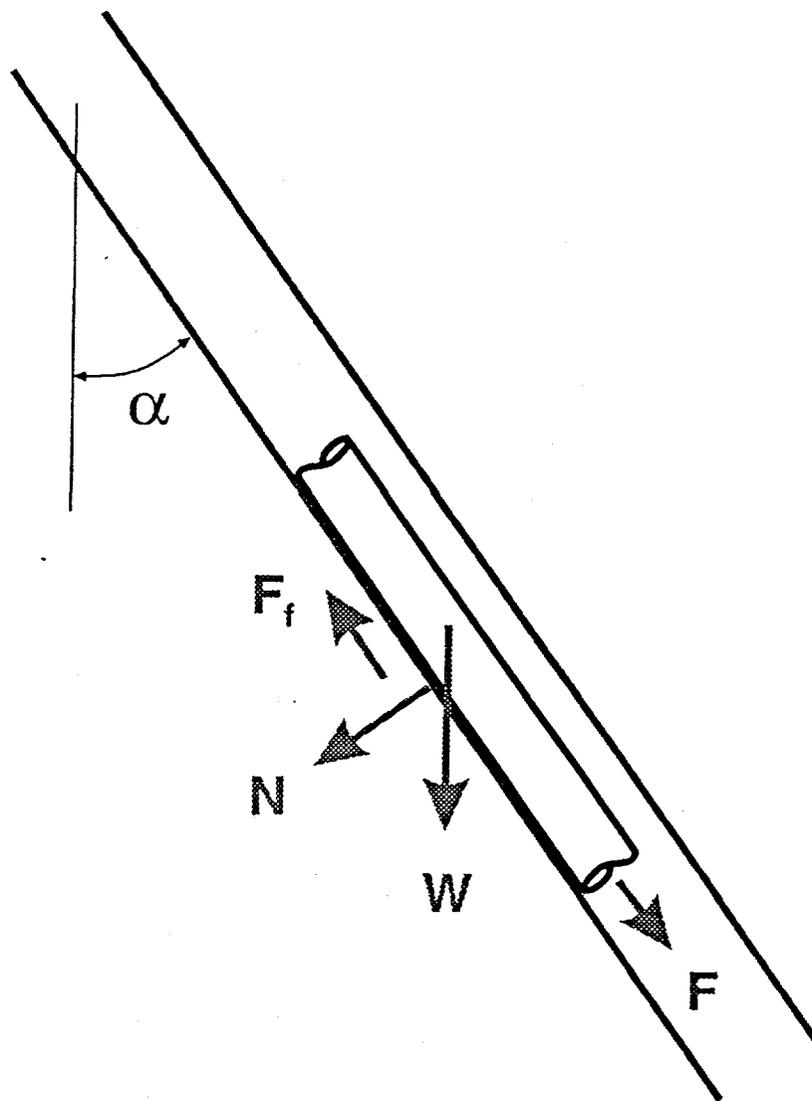
# FRICTION



$F$  required to initiate movement =  $\mu$  (static)  $N$

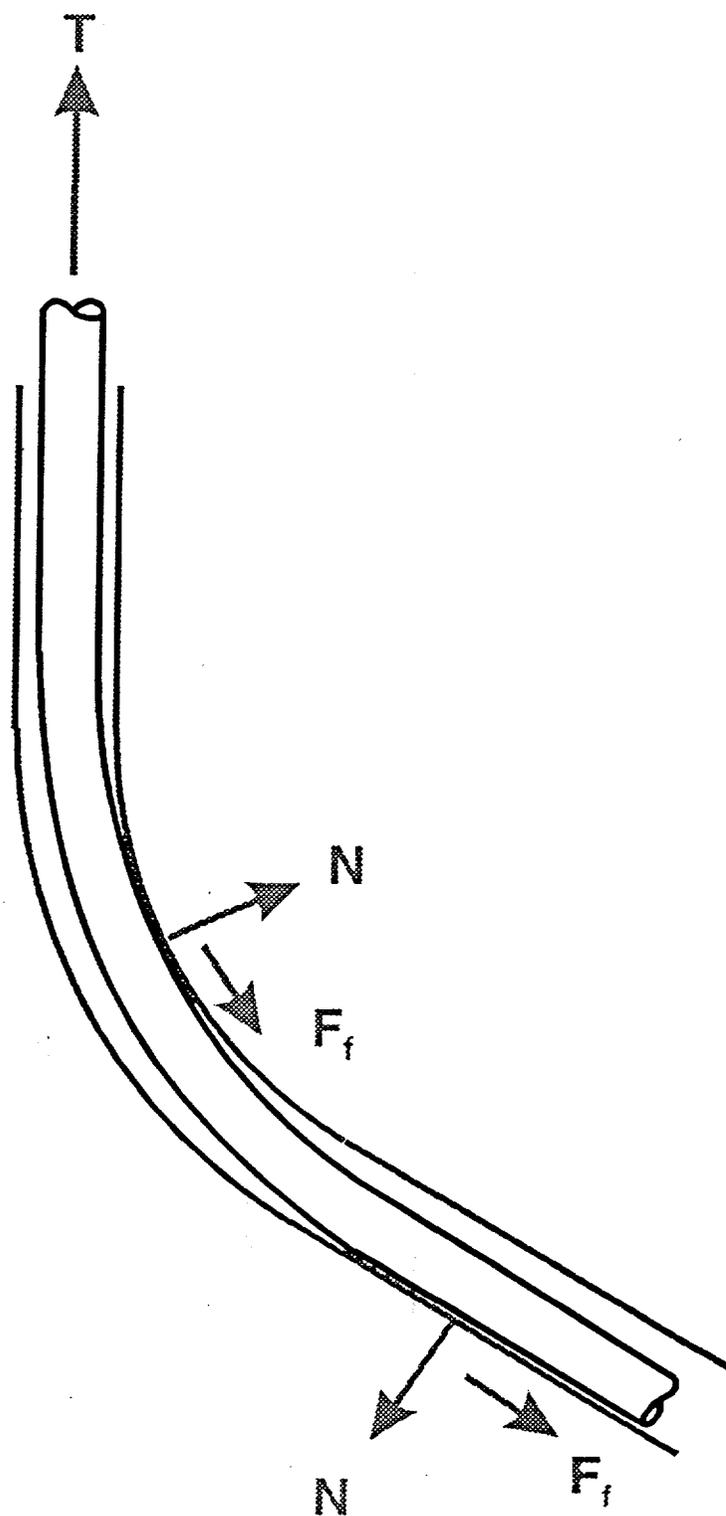
$F$  required to sustain movement =  $\mu$  (dynamic)  $N$

# Pipe Friction in Inclined Boreholes



$$\begin{aligned} F_f &= \mu N \\ &= \mu N \sin \alpha \end{aligned}$$

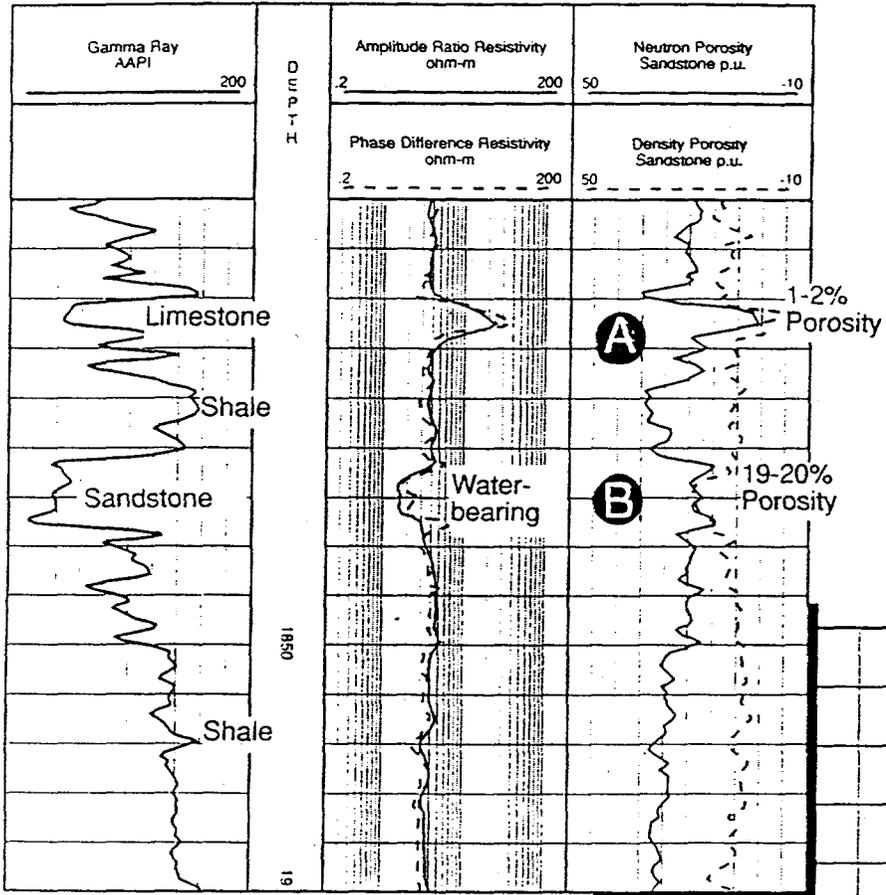
# Effect of Dogleg on Wellbore Friction



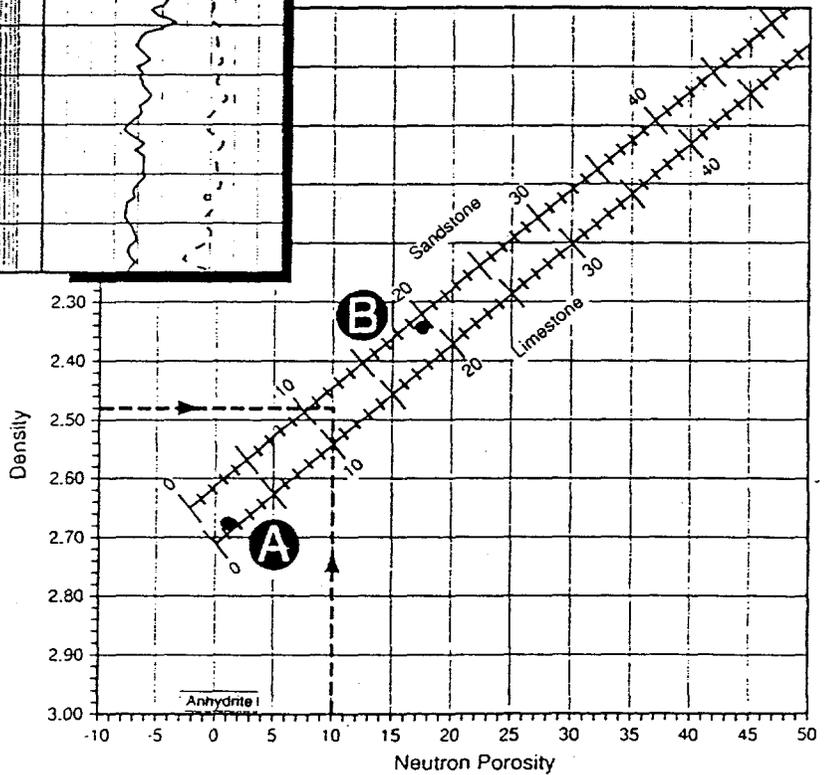
# Formation Evaluation

Using MWD Gamma, Resistivity, Density and Neutron

Field Presentation of MWD Data



Density - Neutron Crossplot

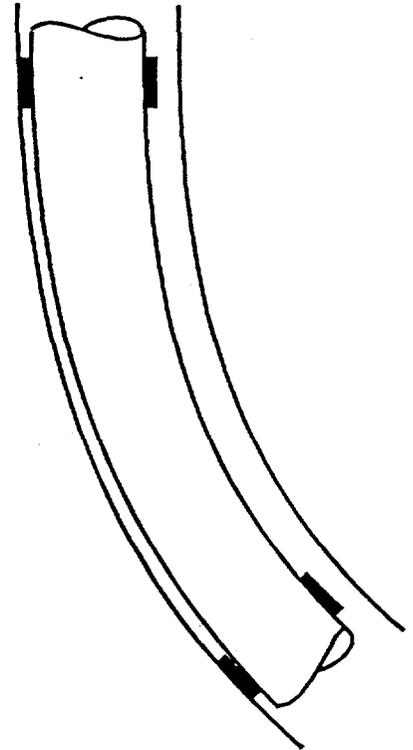


# Logging Horizontal Wells

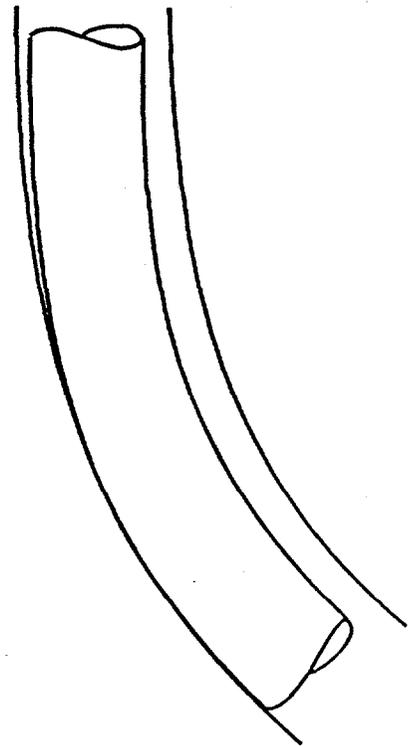
- Standard Electric Line Tools
- Coil Tubing Conveyed Tools
- Drillpipe Conveyed Tools
- LWD

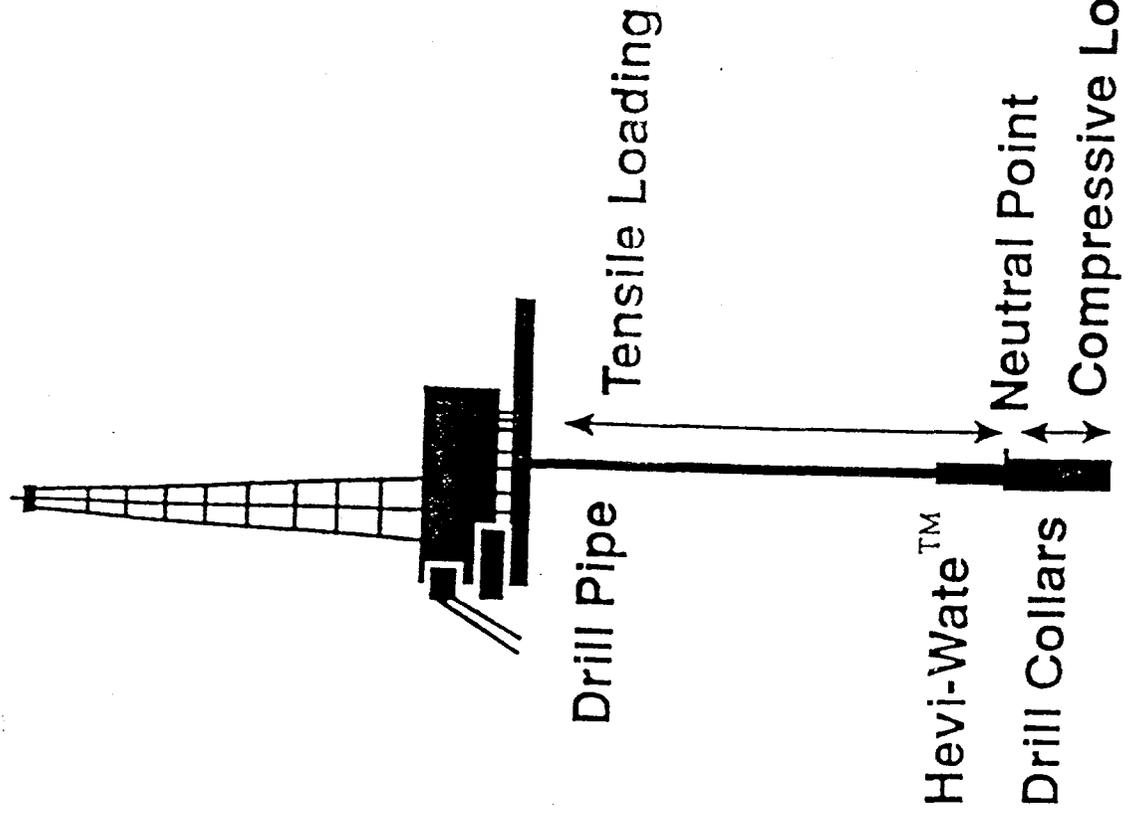
# Dogleg Bending Stress

*Lubinski's Equation  
Applicable for Collared Pipe*

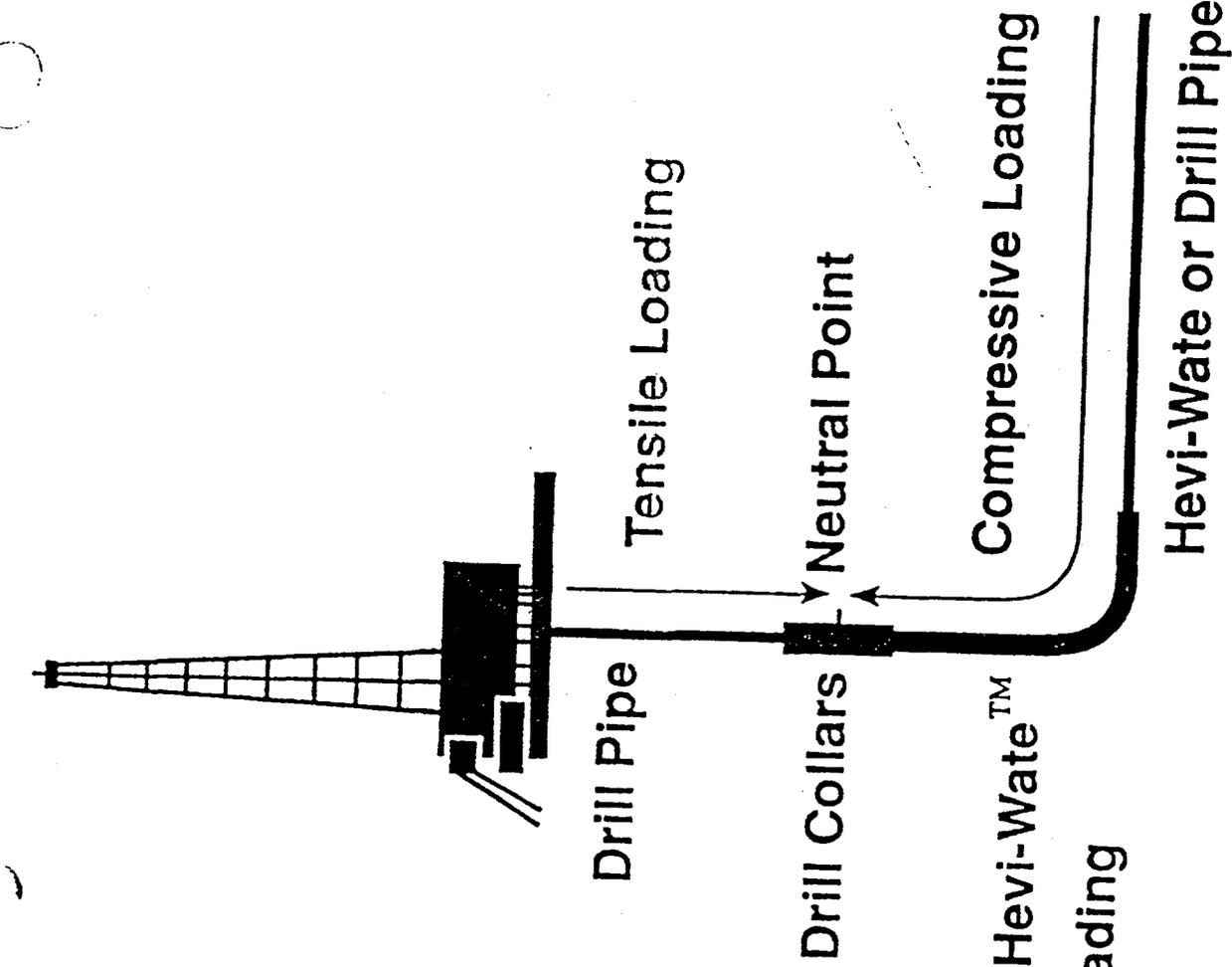


*Beam Deflection Equation  
Applicable for Flush Pipe*





**VERTICAL WELL**

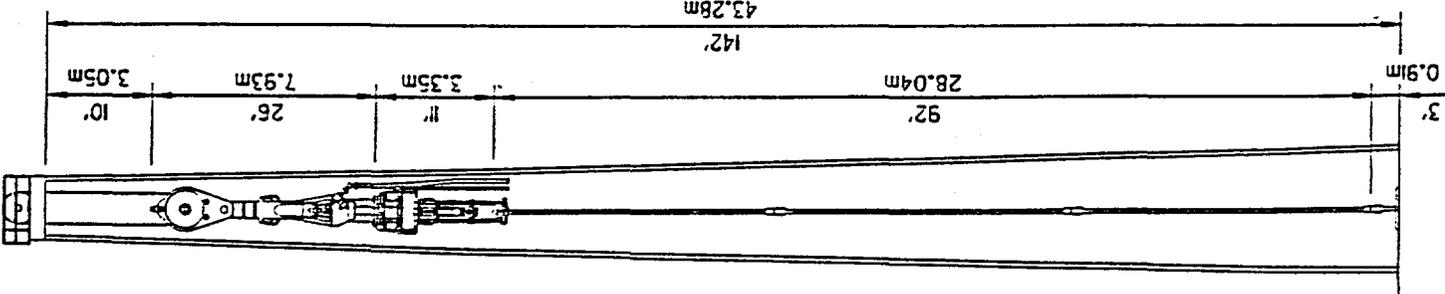
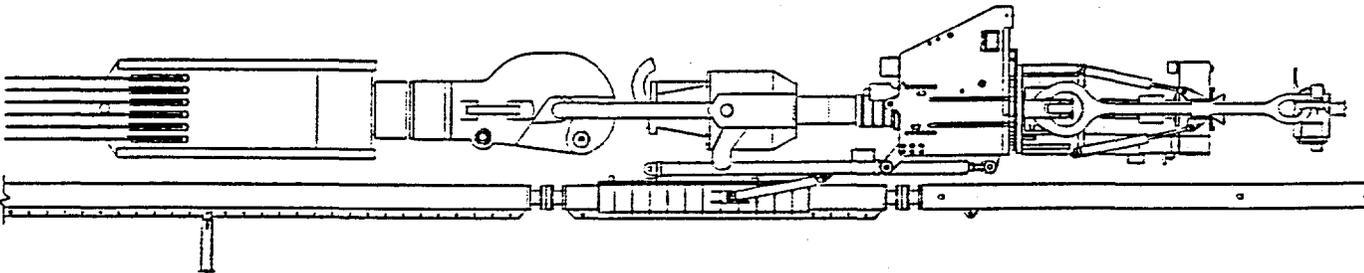
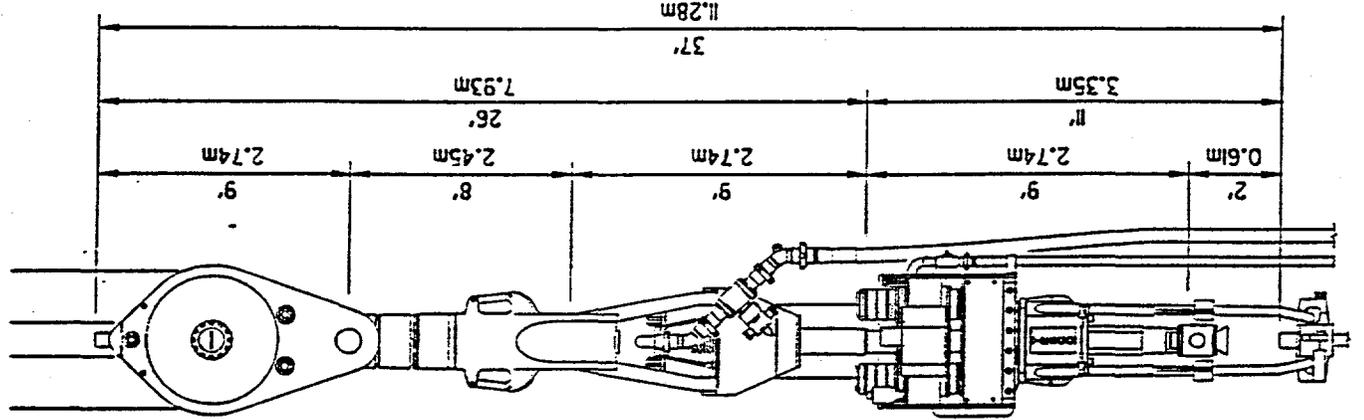


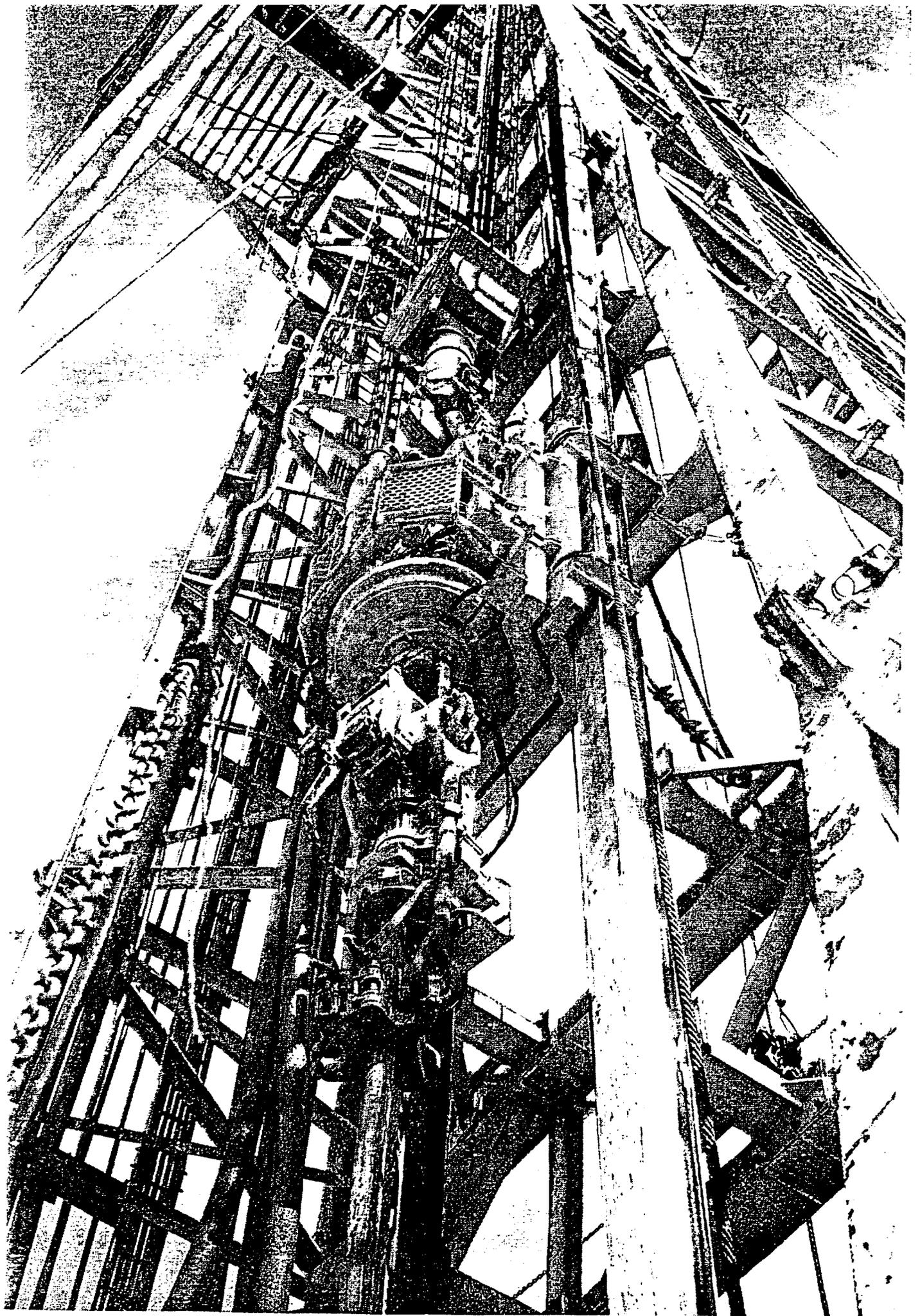
**HORIZONTAL WELL**

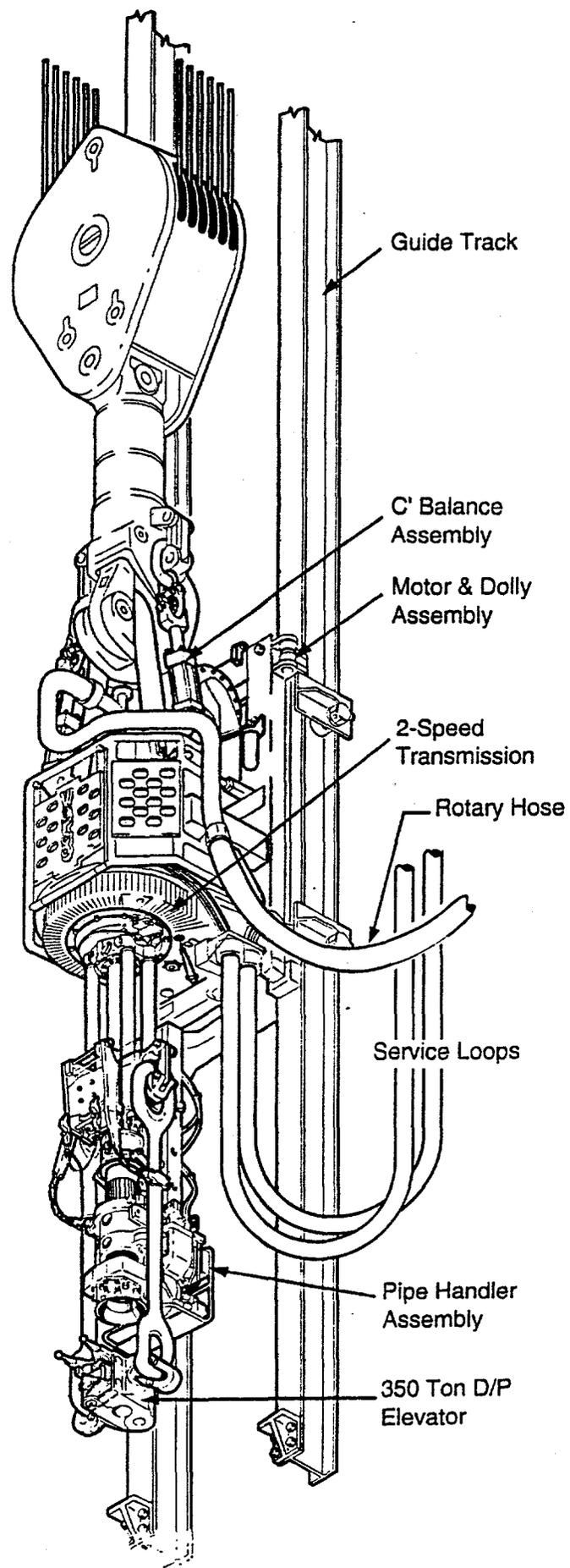
**Providing weight-on-bit in the horizontal section**

COMPANY	RIG	TYPICAL 500 TON SYSTEM		YOUR SYSTEM
		Ft.	M	
CLEAR WORKING HEIGHT		142	43.28	
BLOCKS		9	2.74	
HOOK		8	2.45	
SWIVEL		9	2.74	
500 TON TESCO TOP DRIVE		11	3.35	
92 FOOT TRIPLE STAND		92	28.04	
STUMP		3	0.91	
NET DERRICK CLEARANCE		10	3.05	

NOTE: THE HOOK CAN BE REMOVED FOR ADDITIONAL CLEARANCE







# **OPERATIONAL CONSIDERATIONS**

**MINIMIZE BUCKLING IF ECONOMICAL**

**INSPECT PIPE USING FULL EMI AND CRITICAL END AREA**

**USE HIGH STRENGTH PIPE**

**USE PIPE WITH HIGH DUCTILITY  
( CHARPIES GREATER THAN 40 FT-LBS )**

**ROTATE STRING ( TOP TO BOTTOM )**

**MINIMIZE CORROSIVE ATMOSPHERE**

**MINIMIZE STRESS RISERS**

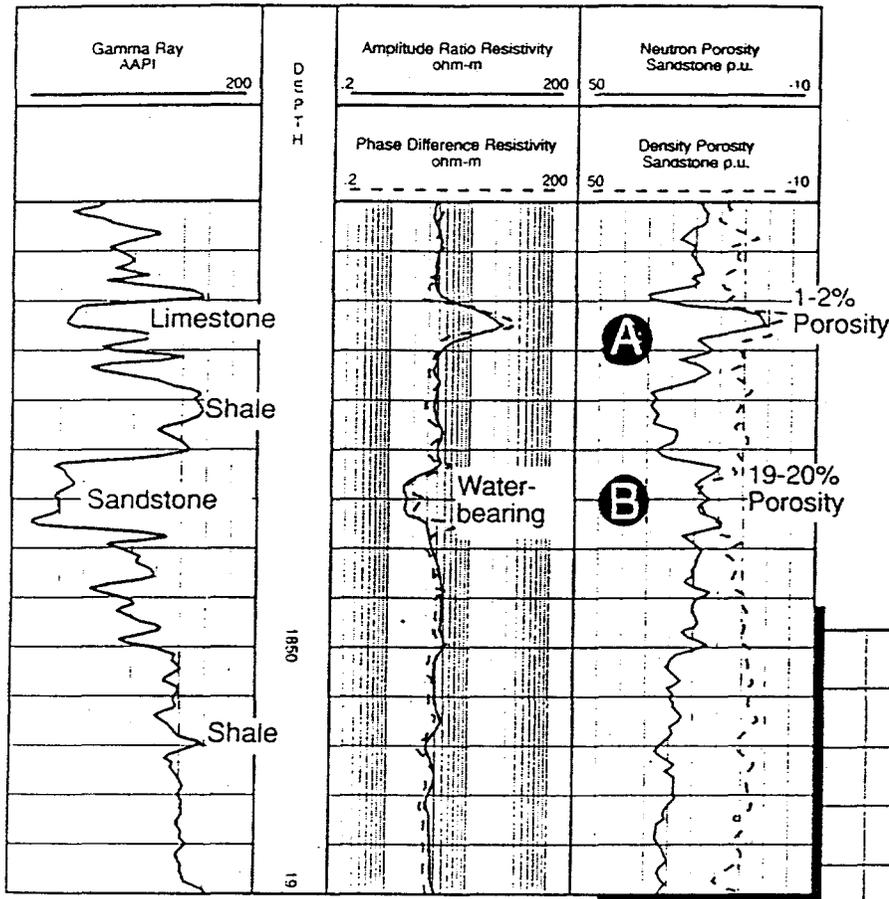
**MONITOR PRESSURE/RATE FOR WASHOUTS**

**DO NOT OPERATE AT CRITICAL SPEEDS**

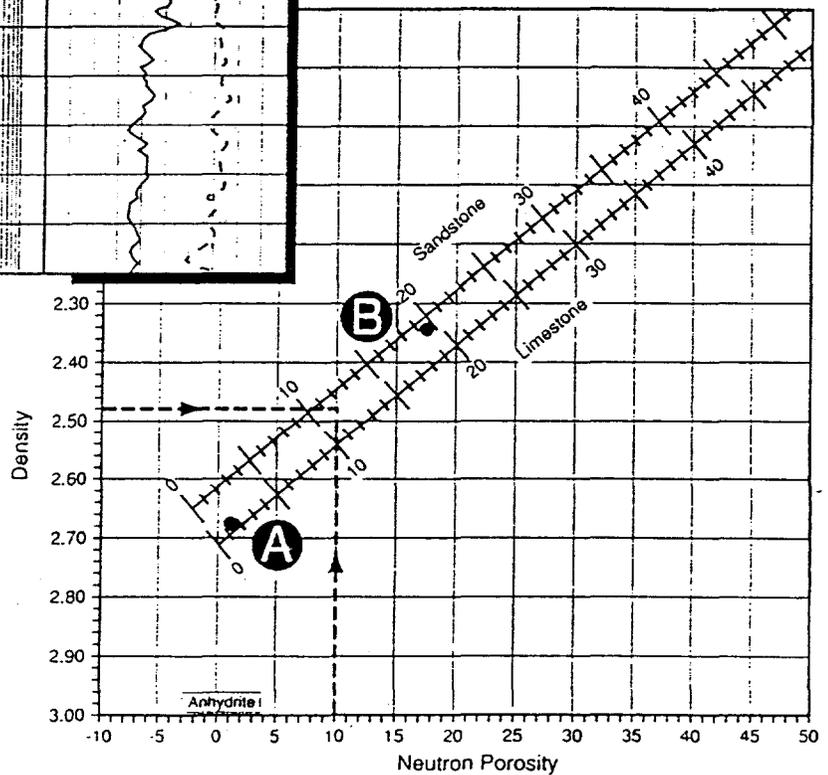
# Formation Evaluation

Using MWD Gamma, Resistivity, Density and Neutron

Field Presentation of MWD Data



Density - Neutron Crossplot



## CHAPTER 10

## HORIZONTAL WELL COMPLETION AND STIMULATION

## HORIZONTAL WELL COMPLETIONS

## Introductory Remarks

"In the last few years, significant advances have been made in drilling horizontal wells. For a successful horizontal well project, interdisciplinary interaction between geologists and reservoir, production and drilling engineers is necessary. The first step is to choose the appropriate reservoir to drill a horizontal well. The second step is to choose an appropriate drilling technique to drill the well. The last step is to select an appropriate completion technique for an economically successful project. This section describes various completion options and criteria for selecting the appropriate completion technique. Before completion details are discussed, a few terms are defined:

1. Horizontal well: A horizontal well is a new well drilled from the surface with length varying generally from 100 to 3000 ft.
2. Drainhole: Drainholes, or laterals, are normally drilled from an existing well. The length usually varies from 100 to 700 ft.

The drilling techniques to drill these wells are classified into four categories, depending upon their turning radius. Turning radius is the radius that is required to turn from the vertical to the horizontal direction. The four drilling categories are:

1. Ultra short: turning radius is 1-2 ft; build angle is  $45^{\circ}$  to  $60^{\circ}$ /ft.
2. Short: turning radius is 20 to 40 ft; build angle is  $2^{\circ}$  to  $5^{\circ}$ /ft.
3. Medium: turning radius is 300 to 1000 ft; build angle is  $6^{\circ}$  to  $20^{\circ}$ /ft.
4. Long: turning radius is 1000 to 3000 ft; build angle is  $2^{\circ}$  to  $6^{\circ}$ /100 ft.

The type of completion depends upon the drilling technique. For example, ultra short radius wells can be completed using only slotted pipe or gravel pack. Short radius wells can only be completed either as open hole or with a slotted

liner. It is not possible to cement these wells because of their sharp turning radius (less than 40 ft), which limits the use of various conventional oil field tools. By contrast, in the medium and long radius wells, many conventional tools can be used. This provides great flexibility in selecting a completion method.

#### COMPLETION OPTIONS (Figures 5.1 - 5.5)

1. Open Hole: Open hole completion is inexpensive but is limited to competent rock formations. Additionally, it is difficult to stimulate open hole wells, and there is no control over either injection or production along the well length. A few early horizontal wells have been completed open hole, but the trend is away from using open hole completions.

2. Slotted Liner Completion: The main purpose of inserting a slotted liner in a horizontal well is to guard against hole collapse. Additionally, a liner provides a convenient path to insert various tools such as coiled tubing in a horizontal well. Three types of liners have been used: (a) perforated liners, where holes are drilled in the liner; (b) slotted liners where slots of various width and depth are milled along the liner length; and (c) prepacked liners. Slotted liners provide limited sand control by selecting hole sizes and slot-width sizes. However, these liners are susceptible to plugging. In unconsolidated formations, wire wrapped slotted liners have been used effectively to control sand production. Recent literature indicates the use of gravel packing for effective sand control in a horizontal well. Examples (from Indonesia and Prudhoe Bay, Alaska) are shown schematically in Figures 5.2-5.3.

The main disadvantage of a slotted liner is the effective well stimulation can be difficult, due to the open annular space between the liner and the well. Similarly, selective production and injection is difficult.

3. Liner with Partial Isolations: Recently, external casing packers (ECPS) have been installed outside the slotted liner to divide a long horizontal wellbore into several small sections (Fig. 5.2). This method provides limited zone isolation, which can be used for stimulation or production control along the well length.

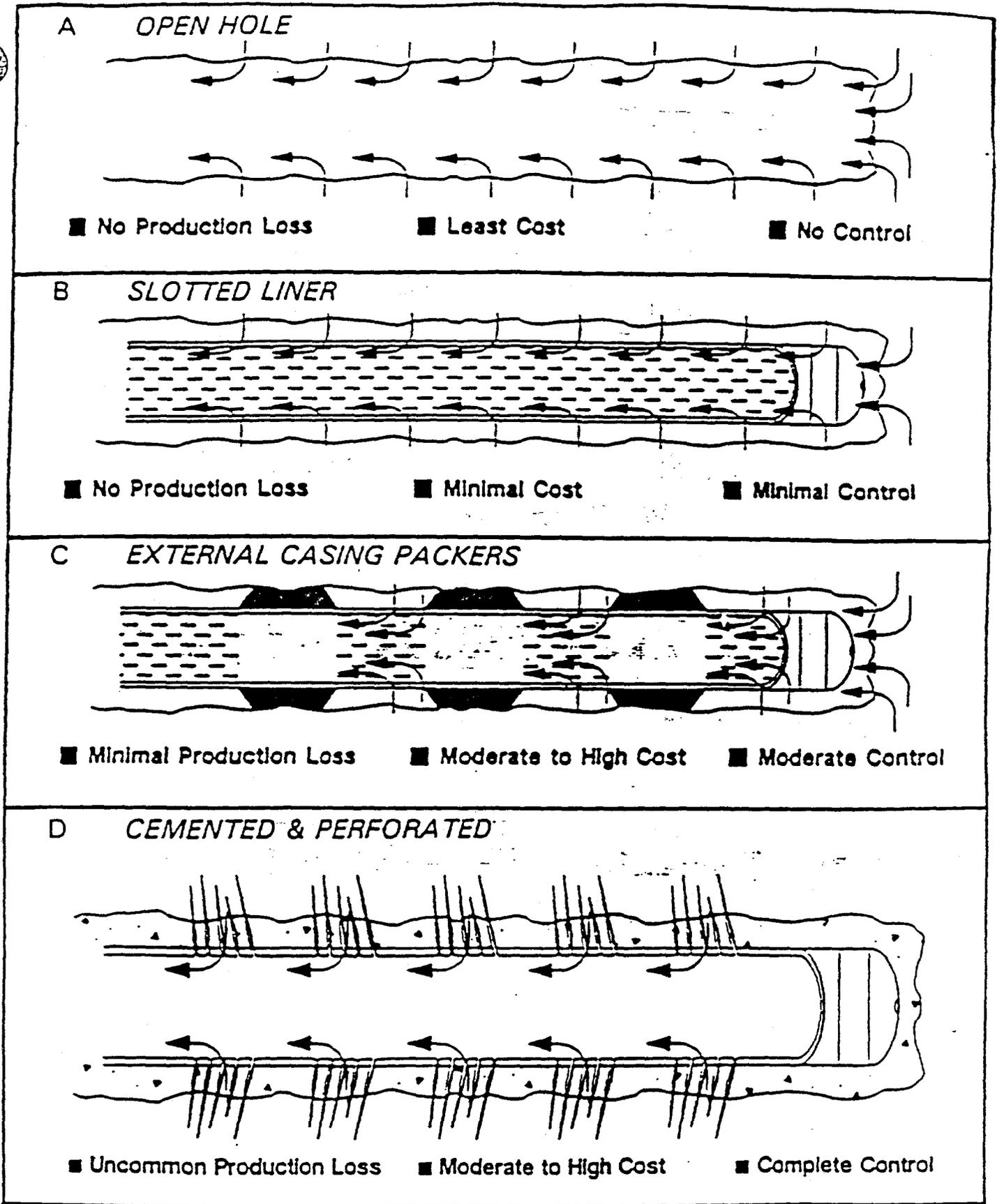


Figure 5.1 -- Horizontal well completion options. A. Open hole. B. Slotted liner. C. External casing packers (ECPS). D. Cemented and perforated.

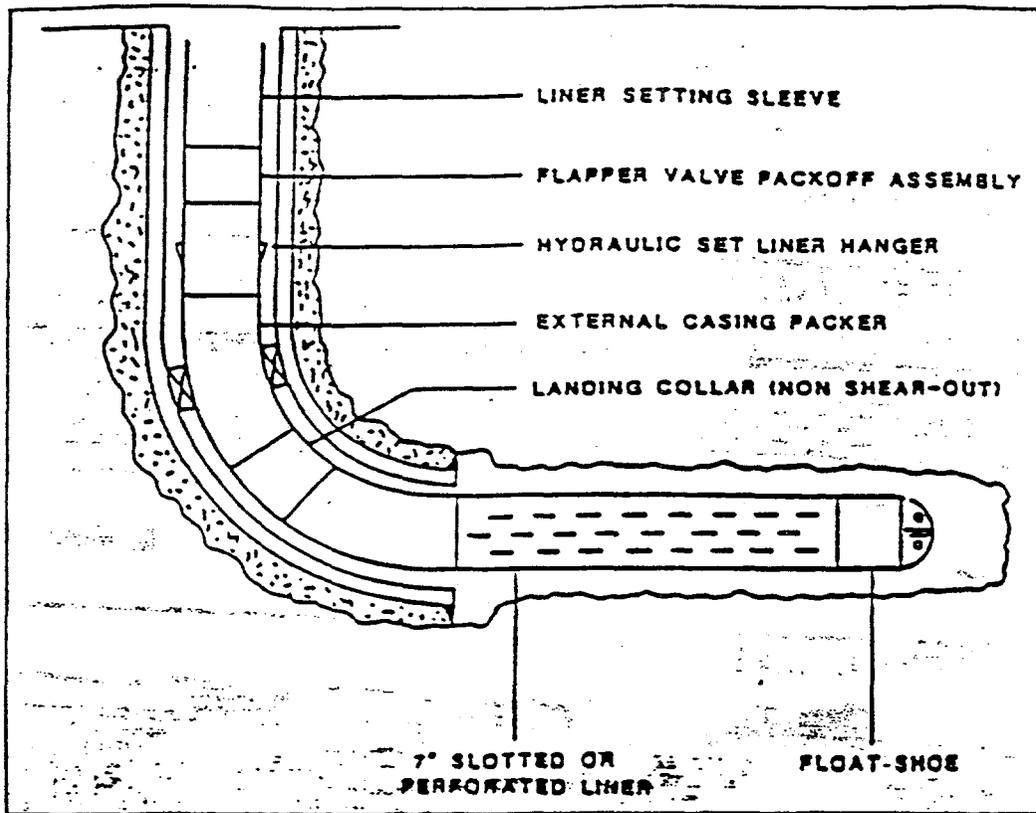


Figure 5.2 -- Slotted liner completion with external casing packer in Indonesia.

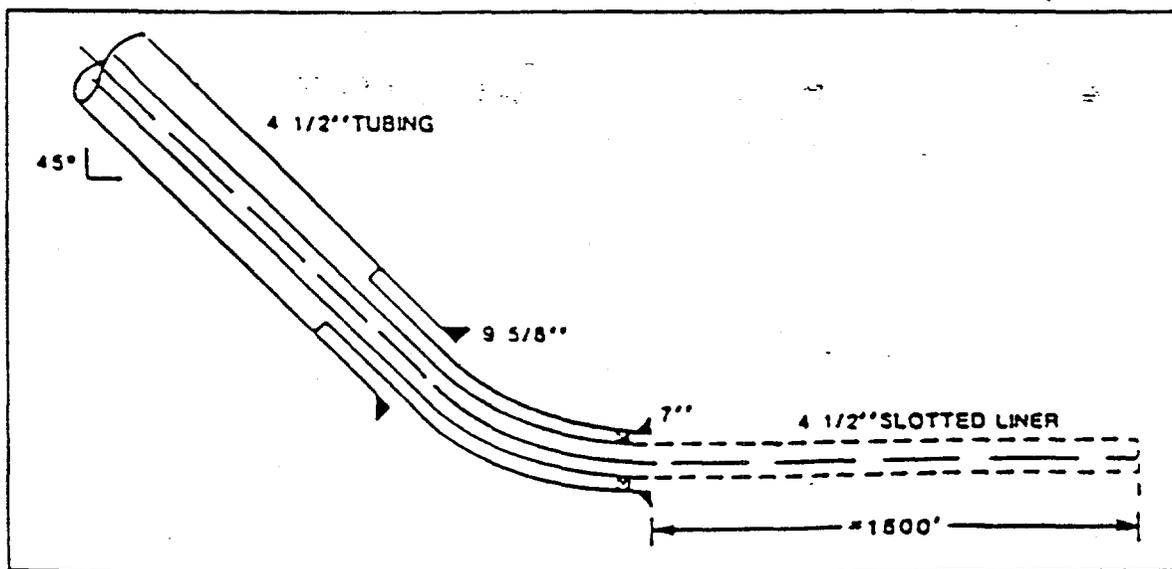


Figure 5.3 -- Typical horizontal well completion in Prudhoe Bay field, Alaska.

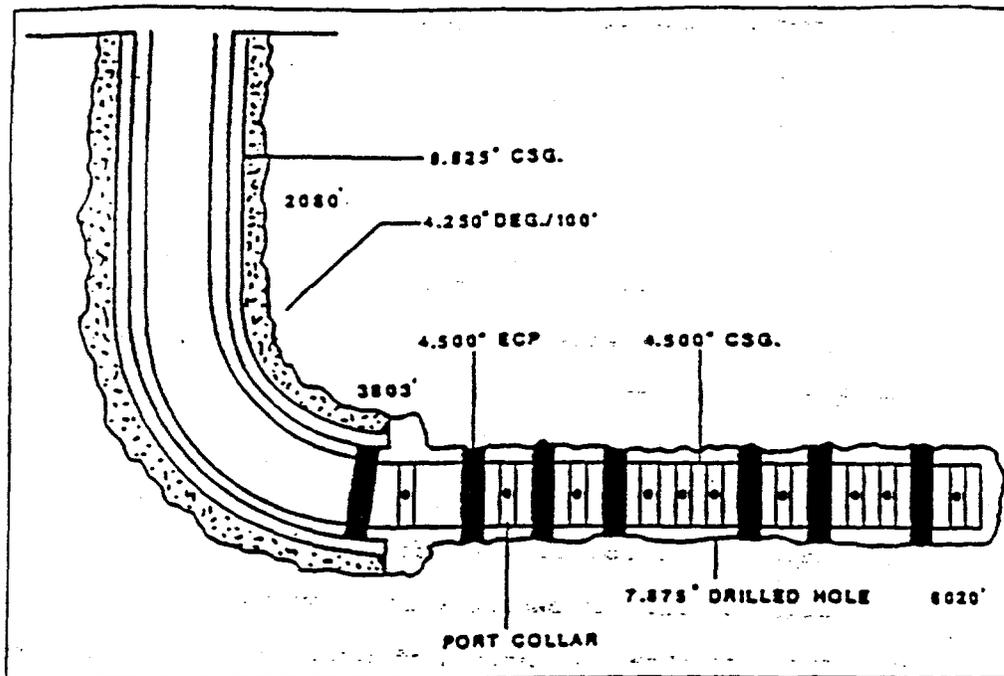


Figure 5.4 -- Completion of horizontal well in Devonian Shale, Appalachian Basin, Wayne County, West Virginia.

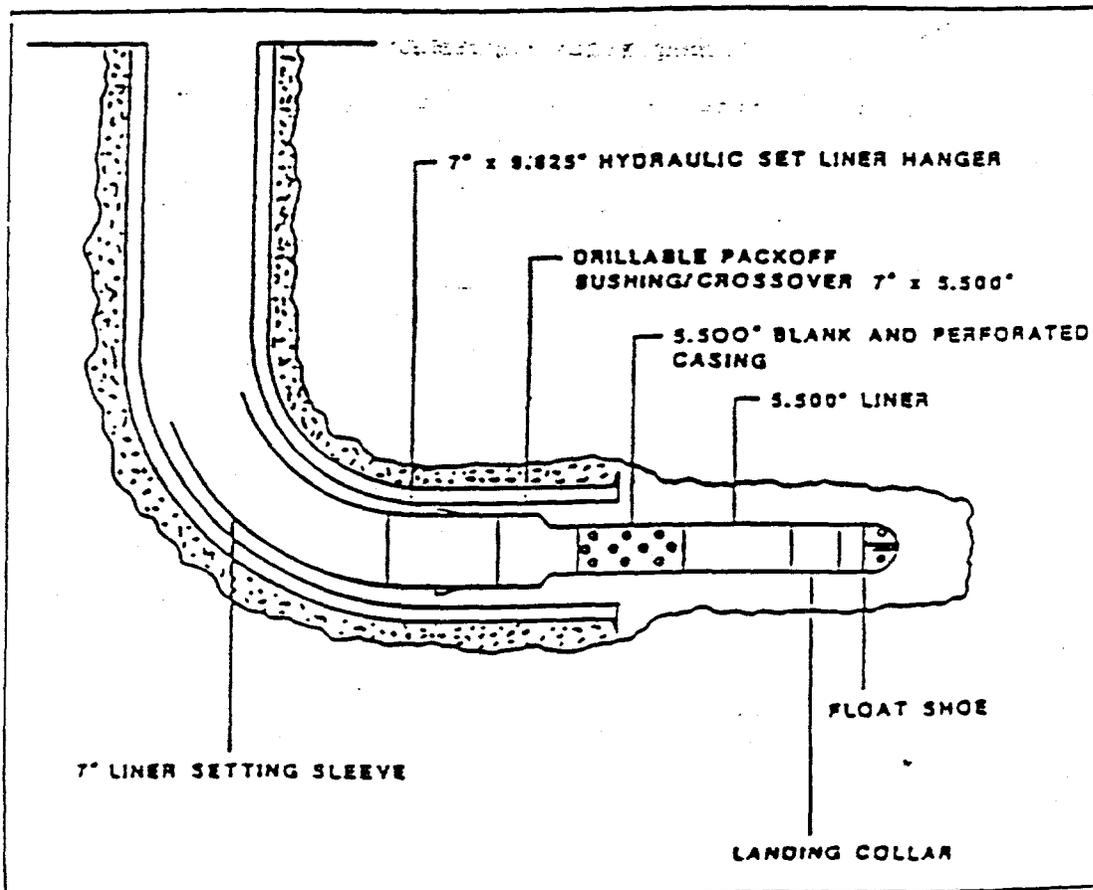


Figure 5.5 -- Perforated liner completion in North Sea horizontal well.

A recent DOE (Department of Energy) well in the Devonian shale formation in West Virginia, used a solid liner with port collars (Fig. 5.4). Additionally, external casing packers were also used to divide a long horizontal well into several sections. The well was stimulated successfully in several of the selected zones.

Normally, horizontal wells are not horizontal; rather, they have many bends and curves. In a hole with several bends it may be difficult to insert a liner with several external casing packers.

4. Cemented and Perforated Liners: It is possible to cement and perforate medium and long radius wells. As noted earlier, at the present time, it is not possible to cement short radius wells. Cement used in horizontal well completion should have significantly less free water content than that used for vertical well cementing. This is because, in a horizontal well, due to gravity, free water segregates near the top portion of the well and heavier cement settles to the bottom, resulting in a poor cement job. To avoid this it is important to conduct a free water test for cement at 45° instead of the conventional API free water test. An example (from the North Sea) is shown in Figure 5.5.

#### COMPLETION CONSIDERATIONS

Discussion of features that need to be considered before selecting an appropriate completion scheme is given below:

1. Rock and Formation Type: If an open hole completion is considered, then it is important to ensure that the rock is competent and the drilled hole will be stable. Several early horizontal wells drilled in competent limestone formations have been completed as open holes. However, recent trends are going away from open hole completion.

2. Drilling Method: As noted before, with short radius, only an open hole or a slotted liner completion is possible. With a medium and long radius well, one can complete them either as open hole, open hole with slotted liner, or cemented and perforated.

3. Drilling Fluid/Mud Clean-up: Formation damage during horizontal drilling is a serious problem in many wells, especially for wells drilled in low-

production-rate areas. Horizontal drilling takes significantly longer time than drilling a vertical well, and the producing formation is exposed to drilling fluid for a longer time period than in a vertical well. Thus, the possibility of mud invasion and related formation damage in a horizontal well is higher than that in a vertical well. Therefore, a method must be devised for well clean-up. Although not impossible, it is difficult to clean-up a horizontal well completed as an open hole or with slotted liners. If the well has a large turning radius, swab tools can reach at least to the end of the curve. For sharp turning radius wells, swab tools cannot reach beyond the vertical well portion.

To minimize damage, one can use polymer mud with either minimum or no solids to drill horizontal wells. However, these types of muds may have problems with shale caving and sloughing. Moreover, the mud may have a limited capacity to carry solid cuttings, resulting in accumulation of cuttings in the horizontal well portion. The cleanest horizontal hole observed by us was drilled partially with air-foam.

Another alternative to deal with formation damage is to cement and perforate the horizontal well, as vertical wells are completed. Perforations may extend beyond the drilling damage. Either the formation in a horizontal well is broken down or subjected to a limited fracture job in order to regain the lost productivity due to drilling and cementing. The objective of stimulating here is to achieve well productivity comparable to that for an undamaged open hole horizontal well.

It is important to note that many horizontal wells, especially in offshore Europe and Asia, have been successfully completed using slotted liners. In these high permeability wells, flow rates exceed a few hundred to thousands of barrels per day. At a high flow rate the well has a better chance of self clean-up than at low flow rates.

4. Stimulation Requirements: A cemented horizontal well is preferred, if the well is to be fractured. The well can be isolated in several zones along its length by using bridge plugs and each zone can be fractured independently. Recently, several wells have been completed by inducing multiple fractures along

the well length. From a mechanical standpoint, it is preferable to fracture various zones along the well length in stages. It is prudent to use reservoir engineering criteria to design the number of fractures required along the well length to maximize recovery and minimize fracturing cost.

It is difficult to fracture wells completed as an open hole or with a slotted liner because of large leak-off occurring along the well length. Similarly, uniform acidization along the length of a well completed as open hole or with slotted liner is also difficult. The difficulty in uniform acidization along the well length can be reduced by using coiled tubing. To ensure uniform acid distribution along the well length, the coiled tubing may have to be moved up and down the hole while spraying the acid.

5. Production Mechanism Requirements: In some wells, especially those drilled in a fractured reservoir with a bottom water drive, water may break through in a certain portion of the long horizontal well. Similarly, in an enhanced oil recovery application, the injected fluid, such as water, may show a premature break-through along a small portion of a long producing horizontal well. In such cases, one may have to plug-off a certain portion of a long well.

The effective way to plug-off well length is to isolate the zone where undesirable fluids are entering the well and squeeze that zone off using cement. A completion plan should include design considerations for such contingencies.

In reservoirs with gas caps, it is important to obtain effective well isolation from the gas cap. One can either use packers or cemented liners to isolate production tubing from the gas cap. Literature indicates that some horizontal wells were not able to meet their expectations due to premature gas break-through in the well portion located in the proximity of the gas cap.

Horizontal wells are rarely horizontal; rather, they wander up and down in the vertical plane. In low rate wells, well shapes can have significant impact on well productivity, especially when multi-phase flow is involved. For example, water may accumulate in a low portion of the wellbore, and it may be difficult to displace it. Similarly, there is a possibility of gas lock occurring near (hook) shaped well portions. In such situations, gas anchors can be used to

mitigate the problem. However, the best way to handle this completion problem is to design the well path after consideration of the reservoir mechanism to facilitate fluid segregation along the well length and reduce problems due to gas blocking in oil wells and liquid loading in gas wells.

6. Workover Requirements: Before selecting a completion option, workover requirements must be considered, but they are also difficult to anticipate. For example, consider completing a horizontal well in a competent but fractured limestone reservoir with a bottom water drive. One can anticipate a possibility of water break-through along a small portion of a medium radius long horizontal well, sometime during the well life. The following three completion scenarios are possible: (a) One can insert a slotted liner and pull it out later when water breaks-through or water cut becomes high. After pulling the liner, one can insert casing and cement it. This will stop water production. However, how risky is it to pull a slotted liner out of a horizontal hole? (b) One can cement the well and perforate it. Once the water breaks through, production logging can be used to locate the high water production zone. Later, one can squeeze the zone off using cement. (c) One can complete the well as an open hole and wait until water break-through occurs to design a course of action. Each of these options has costs and risks associated with it. The completion choice should be based on local operating experience and the operator's willingness to assume a degree of risk.

Presently, in the ultra-short radius technique, tubing is severed once the hole is drilled. Therefore, it is not possible to reenter the horizontal section of the wellbore. In a short radius well it is possible to reenter by using coiled tubing. With coiled tubing, it is probably safer to reenter a hole completed with a slotted liner than to reenter an open hole. In medium and long radius wells, reentry is not very difficult. In these wells either coiled tubing or drillpipe-conveyed tools can be used.

7. Abandonment Requirements: At the present time no special regulations are in effect for abandoning a horizontal well. However, an operator should

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anticipate these needs and design well completion so that the well can be abandoned safely.

# Completion Options

- **Open Hole**
  - *No Production Loss*
  - *Least Cost*
  - *No Control*
  
- **Slotted or Gravel Packed Liner**
  - *No Production Loss*
  - *Minimal Cost*
  - *Minimal Control*
  
- **External Casing Packers**
  - *Minimal Production Loss*
  - *Moderate - High Cost*
  - *Moderate Control*
  
- **Cemented and Perforated**
  - *Some Production Loss*
  - *Moderate - High Cost*
  - *Complete Control*

# **Cementing Complications**

- **Inadequate Centralization**
- **Cuttings Bed**
- **Slurry Free Water**

# Cementing Considerations

- **Preflush**

- *Thin*
- *Turbulent Flow Regime*
- *Intermediate Density*
- *Minimum Contact Time 10 minutes*

- **Liner Rotation**

- **1 or 2 Rigid Body Centralizers per Joint**

- **Drilling Fluid Conditioning**

- **Conditioning Time (3 Circulations)**

- **Turbulent Flow Regime**

- **Slurry Design**

- *Zero Solids Settling*
- *Zero Free Water*
- *Expansive Properties*

FRACTURING HORIZONTAL WELLS  
FRACTURED HORIZONTAL WELLS**FRANK J. SCHUH  
DRILLING TECHNOLOGY**

Fracturing horizontal wells in low-permeability reservoirs and in reservoirs to connect non-communicating layers is the subject of discussion in this section.

Mukherjee and Economides (1988) calculated the number of vertical fractures required to get the same productivity of a fractured horizontal well as that expected from an open-hole uncased horizontal well. Naturally, the purpose of the horizontal well is to increase the reservoir contact area. Because part of the flow is lost when a horizontal well is cemented, fractures are required as a stimulation in order to regain the reservoir contact.

A schematic of a long horizontal well with multiple fractures along the length is shown in Figure 5.7. Equations for such configurations are given by Giger (1985), Karcher et al. (1986) and others. Their steady-state productivity increase is shown in Figure 5.8. As the number of fractures is increased along the length of a horizontal well, productivity becomes higher and higher. In actual well practice, several operators have successfully completed multiple fracture jobs along the length of a horizontal well.

The question which still remains to be addressed: What is the optimum number of fractures along the length of a horizontal well?

It will be shown that at least 3 or 4 fractures are needed to match uncased hole productivity. What should be the preferred orientation of the fracture? Obviously, the horizontal well should be drilled in the direction of the minimum principal stress affecting the formation because the fracture will propagate along the plane defined by the maximum and intermediate principal stresses. Thus the induced fractures will propagate perpendicular to the wellbore. Essentially, the well itself will serve as a conduit. To address this problem very simply, it is easier to visualize each horizontal well as a fractured vertical well--but with some additional pressure drop. The additional pressure drop is caused by the fracture, which is perpendicular to the well. This is different from a vertical well, where the fracture is along the well length. An additional

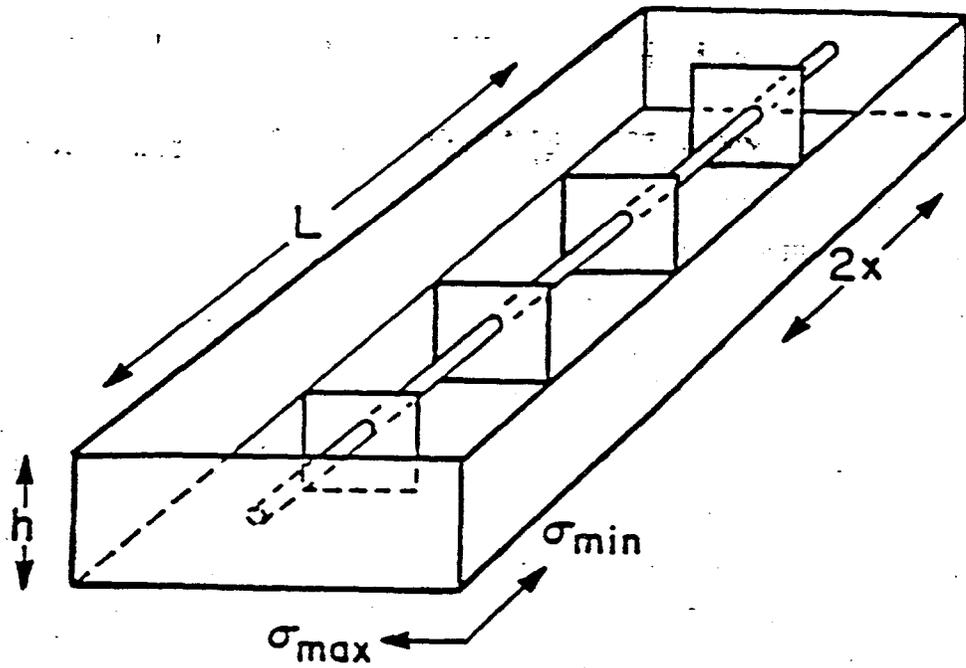


Figure 5.7 -- Horizontal well with multiple fractures.

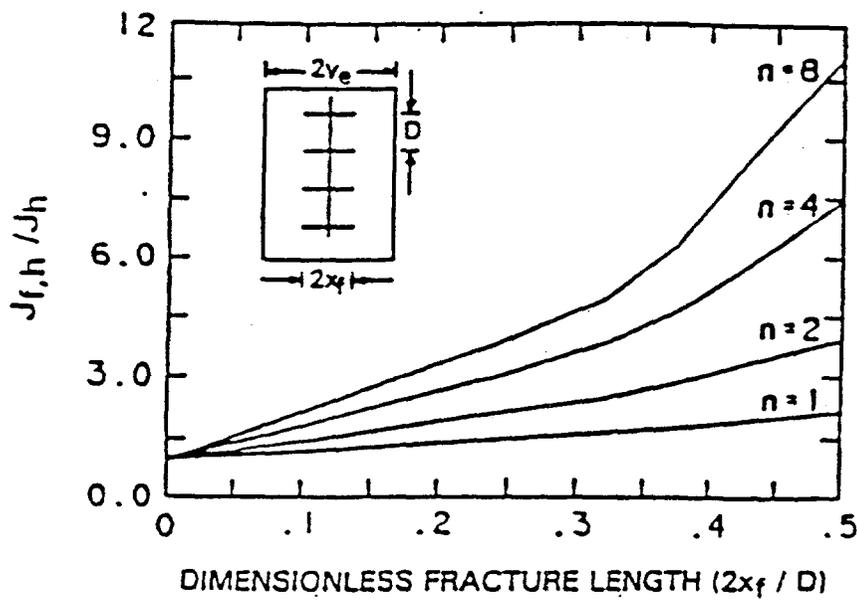


Figure 5.8 -- Performance comparison of stimulated and unstimulated horizontal wells (Karcher et al., 1986).

pressure drop due to the fracture perpendicular to the well is accounted for as an additional skin effect as shown below.

$$\Delta P_{skin} = (q\mu/2\pi kh) (kh/k_f b_f) [\ln(h/2r_w) - (\pi/2)] \quad (5.1)$$

$$(s_{ch})_c = (kh/k_f b_f) [\ln(h/2r_w) - \pi/2] \quad (5.2)$$

As noted earlier, fractured horizontal wells can be considered as a fractured vertical well with an additional pressure drop. The factors which determine the optimum number of fractures along the well lengths are economics and the time it will take to interfere with each other. When one fracture "sees" the other fracture, essentially they will be producing from the same zone and rendering them ineffective. Simulation studies available in the literature indicate the advantages of fractured horizontal wells. The number of infinite-conductivity fractures,  $n$ , which are required to give the same productivity as an uncased hole are given by the following equations.

$$n = \frac{1 + \sqrt{1 + 4D}}{2} \quad (5.3)$$

$$n(n-1) = \frac{L\pi}{4Cx_f} = D \quad (5.4)$$

$$C = \ln \left[ \frac{a + \sqrt{a^2 - (L/2)^2}}{L/2} \right] + (\beta h/L) \ln(\beta h/2r_w) \quad (5.5)$$

where  $a$  is calculated as:

$$a = L/2 [0.5 + [0.25 + (2r_{wh}/L)^4]^{0.5}]^{0.5} \quad (5.6)$$

and

$$\beta = \sqrt{k_h/k_v} \quad (7)$$

## EXAMPLE PROBLEM

Calculate the number of fractures needed to return the productivity of a cased, cemented, and perforated horizontal well to the productivity of an open hole completion, given the following data.

$$\begin{array}{ll} L = 2000 \text{ ft} & h = 100 \text{ ft} \\ k_v/k_h = 0.5 & r_w = 0.365 \text{ ft} \\ 160 \text{ acres spacing} & x_f = 100 \text{ ft} \end{array}$$

## SOLUTION

For 160 acres,  $r_{eh} = 1489 \text{ ft}$

$$\beta = \sqrt{K_h/K_v} = \sqrt{2} = 1.414 \quad (8)$$

$$a = L/2 [0.5 + [0.25 + (0.5r_{eh}/L)^4]^{0.5}]^{0.5} \quad (9)$$

$$a = 1000 [0.5 + [0.25 + (1.49)^4]^{0.5}]^{0.5} \quad (10)$$

$$a = 1.665.6 = 1666 \quad (11)$$

$$C = \ln \left[ \frac{1666 + \sqrt{(1666)^2 - (1000)^2}}{1000} \right] + \left( \frac{1.414 \times 100}{2000} \right) \ln \frac{1.414 \times 100}{2 \times 0.365} \quad (12)$$

$$C = 6.15$$

$$D = L\pi/4(Cx_f)$$

$$D = 2.55$$

"n" can now be calculated as

$$n = \frac{1 + \sqrt{1 + 4(2.55)}}{2} \quad (13)$$

$$n = 2.17.$$

Therefore, approximately two fractures are needed to return the well to open hole productivity.

## COMMENTS

For vertical wells, only one fracture can be created, whereas for horizontal wells several fractures can be induced along its length. Productivity of a stimulated horizontal well is about six to eight times greater than that of an unstimulated horizontal well and a stimulated vertical well.

Recently, a few horizontal wells have been fractured successfully, although only limited information has been published. The operators, after initial failures, have been able to induce multiple fractures along the length of a horizontal well.

For example, the DOE in cooperation with a contractor, the BDM Corporation, successfully developed multiple fractures from a horizontal wellbore drilled in the Devonian Shale, Wayne County, West Virginia (Appalachian basin). This technique was used not only to decrease the formation damage that would have resulted if the liner were cemented but also to eliminate the need for perforating (Fig. 5.9) with wellbore completion configurations).

Multiple fractures along a horizontal wellbore were also successfully initiated by Maersk Oil and Gas in the Dan field in the Danish Sector of the North Sea (Figs. 5.10-12 with wellbore profile, completion scheme used and productivity improvement due to multiple fractures).

In a naturally fractured reservoir, if a horizontal well is drilled perpendicular to the fractures, it will be able to intersect several fractures and, hence, drain the reservoir effectively. Horizontal wells have done exceedingly well in some naturally fractured reservoirs. However, if natural or induced fractures are in direct communication with the top gas or bottom water, a horizontal well with selective completion ability is highly desirable."

\* After Joshi

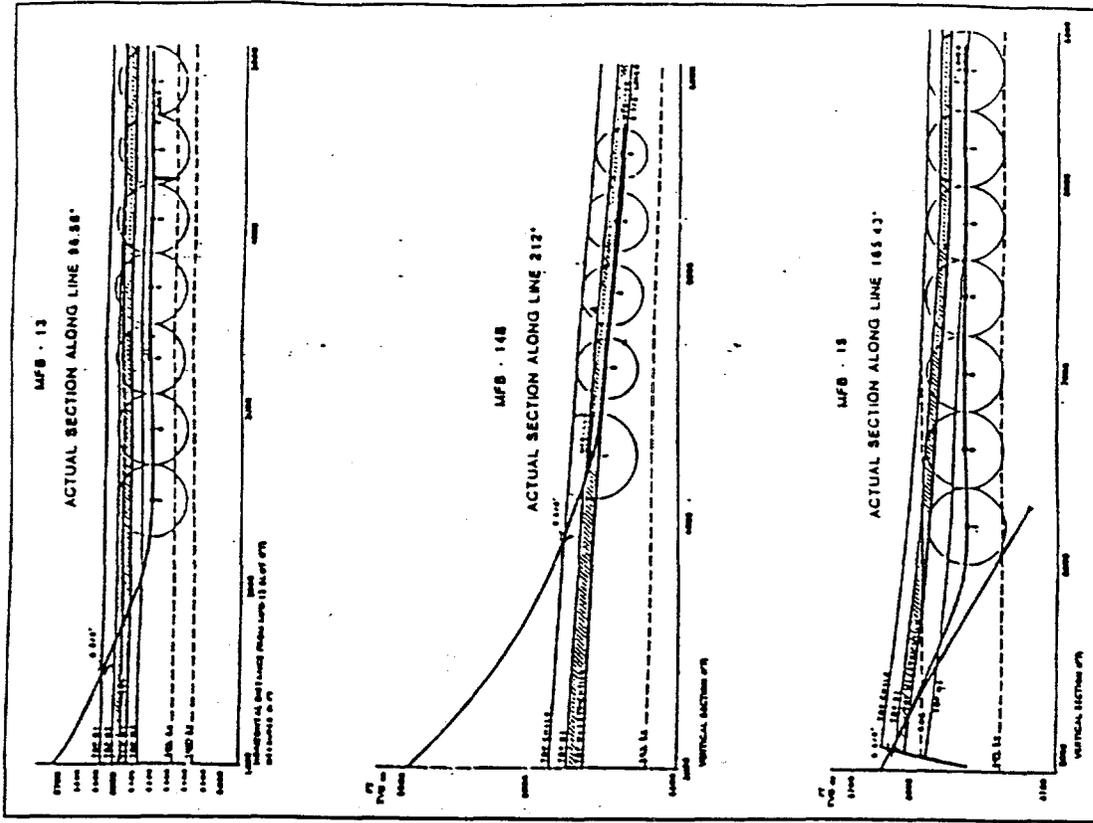


Figure 5.10 -- Wellbore schematics of multiple induced fractures (shown as circles) in three horizontal wellbores, Dan field, Danish Sector, North Sea (Anderson et al., 1988).

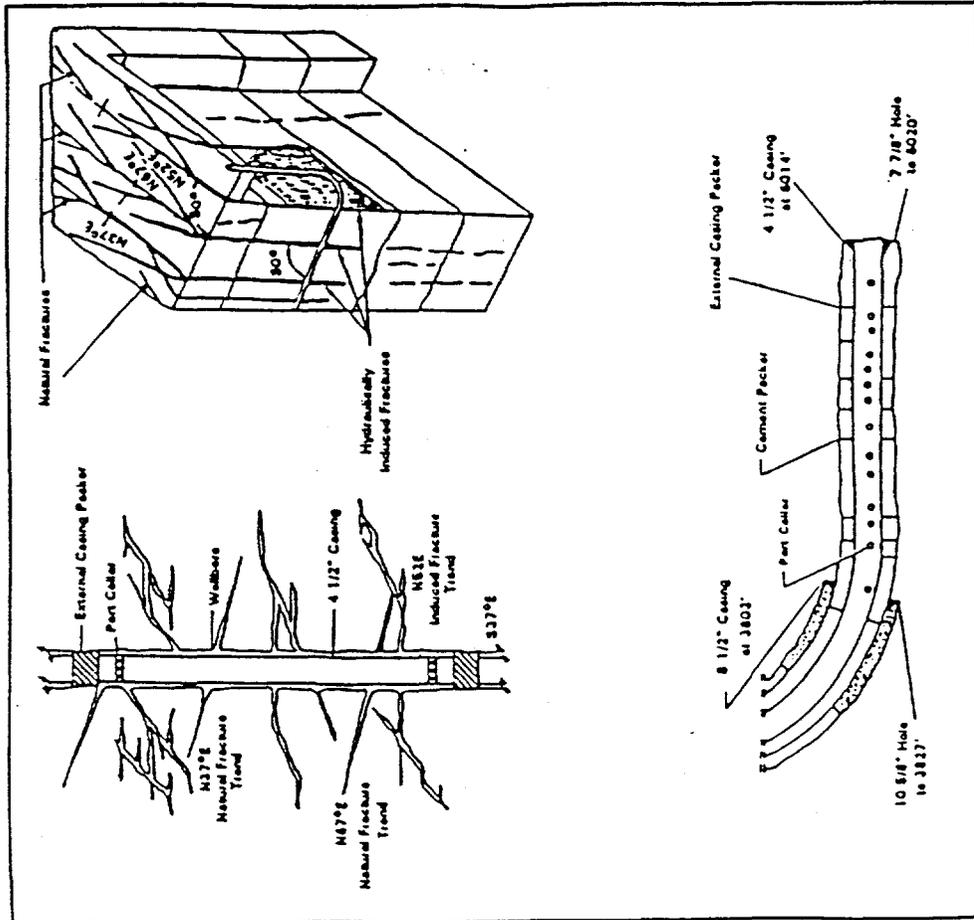


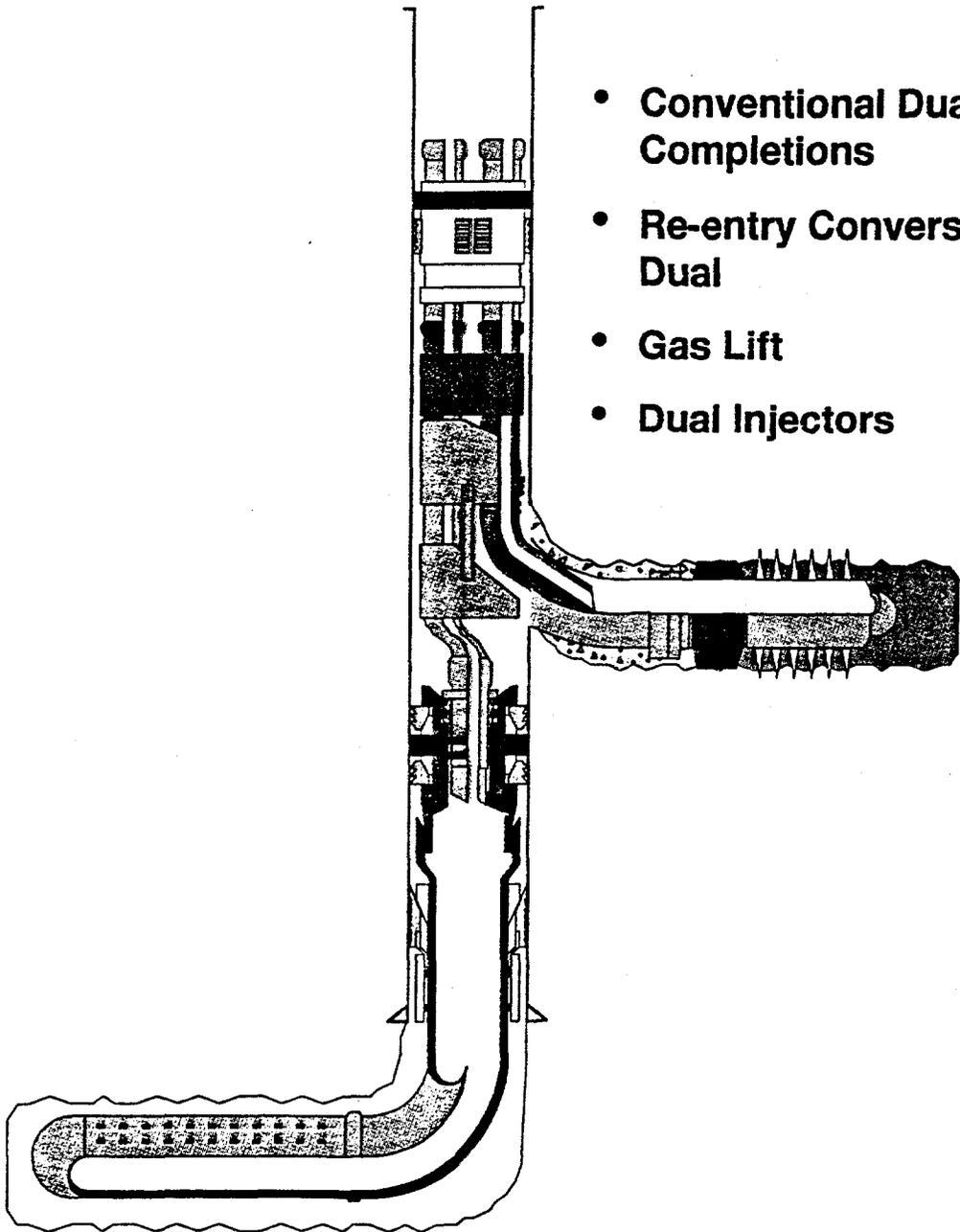
Figure 5.9 -- Fracture systems (natural and induced) in Devonian shale, Wayne County, West Virginia, Appalachian Basin, along with wellbore schematic (Yost et al., 1987).



# Dual Horizontal Goal



## Desired Final Completion

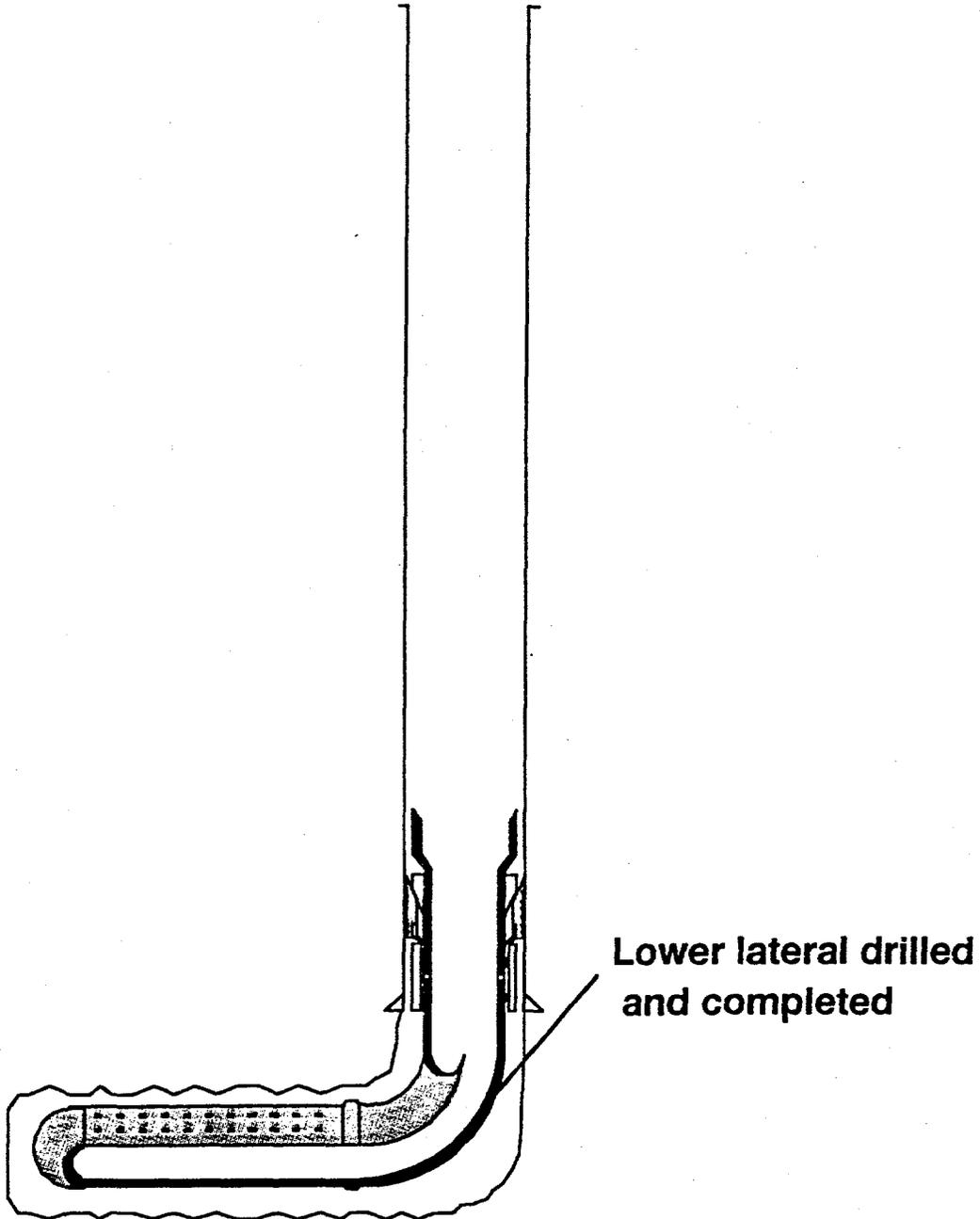


- Conventional Dual Completions
- Re-entry Conversion to Dual
- Gas Lift
- Dual Injectors

# Dual Horizontal Completion



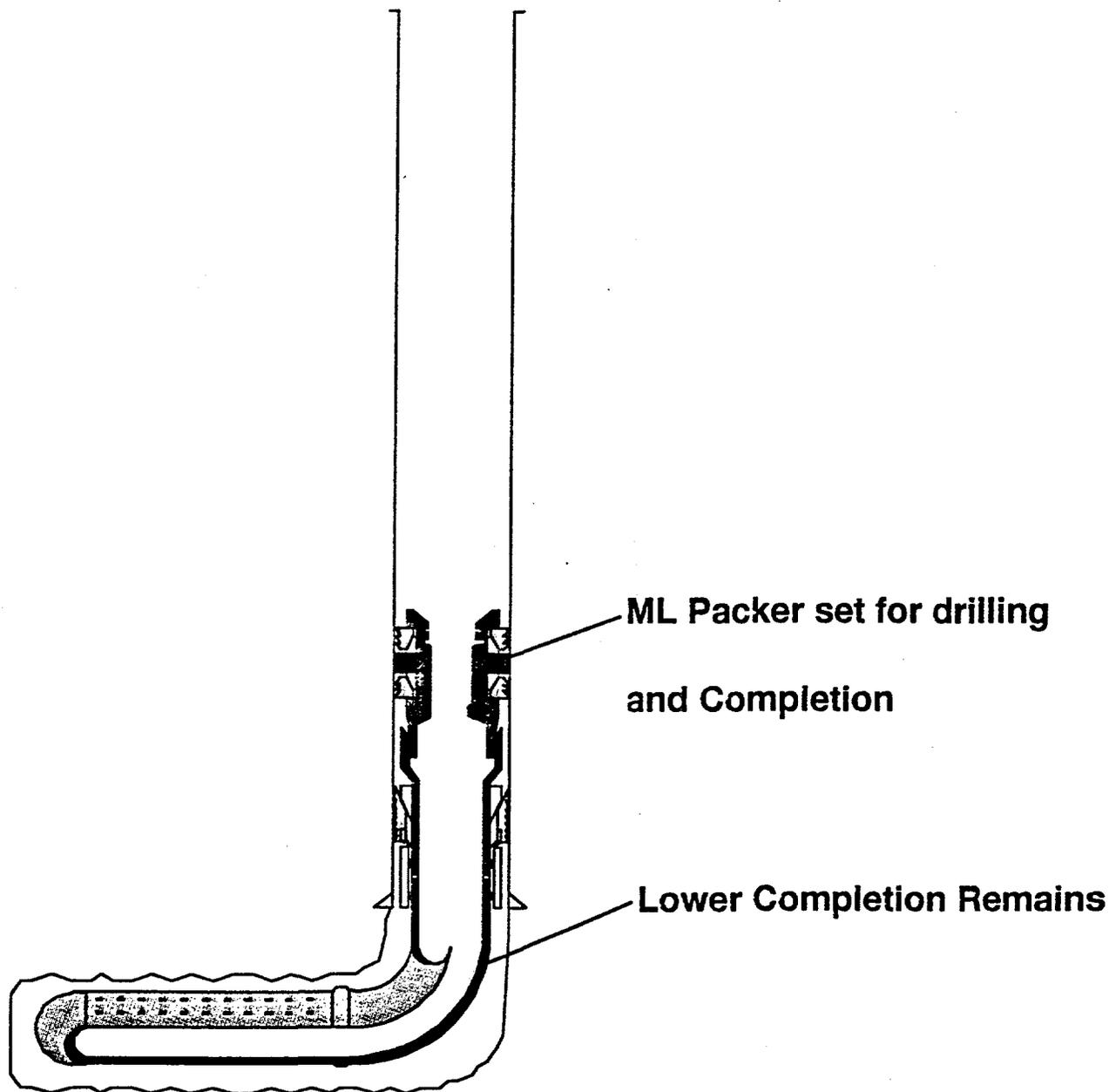
## FIRST LATERAL DRILLED AND LINER COMPLETION SET



# Dual Horizontal



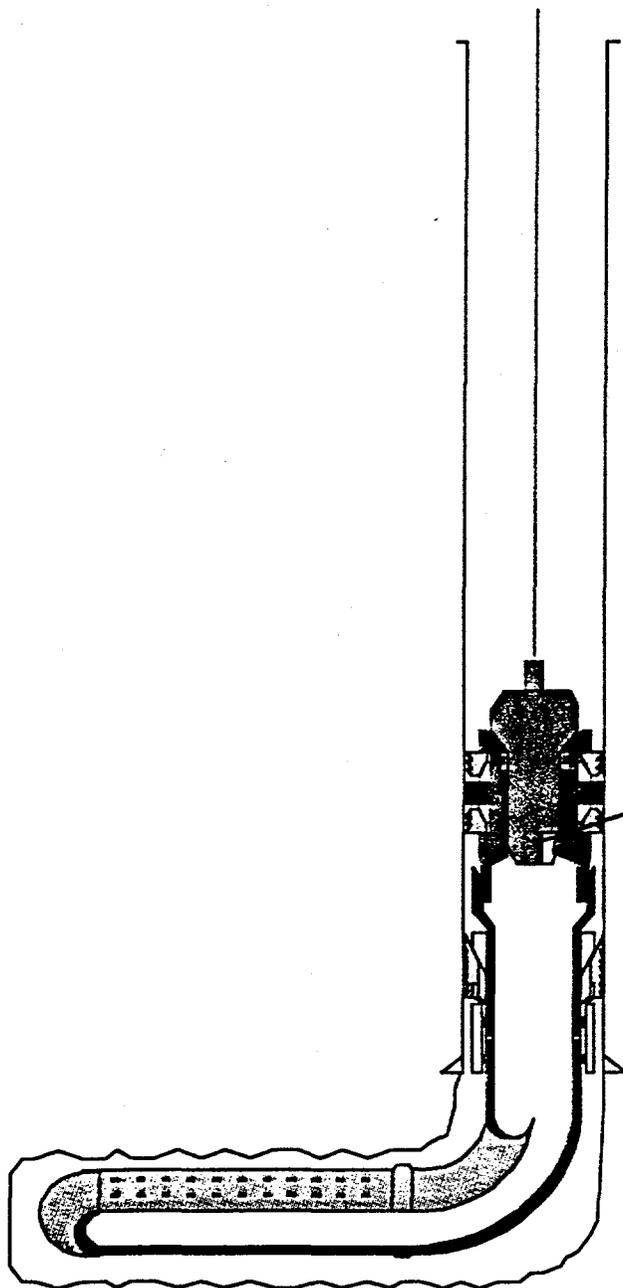
## 'ML' PACKER TIED BACK INTO LOWER COMPLETION AND SET



# Dual Horizontal



## SURVEY RUN REQUIRED TO DETERMINE ORIENTATION

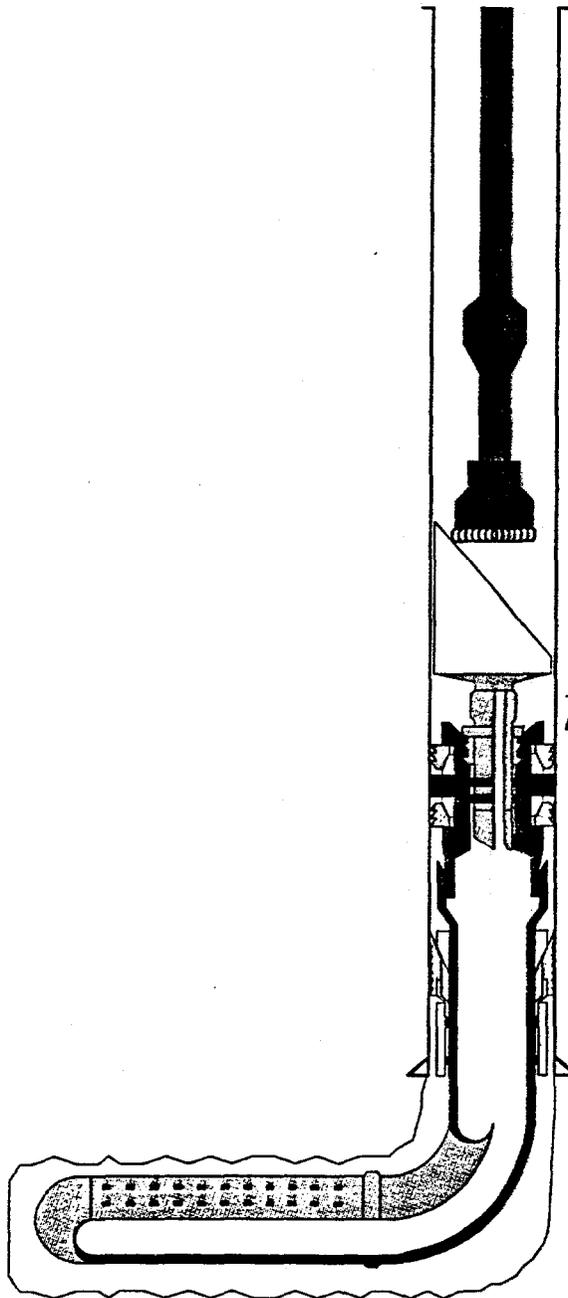


Survey system engaged  
in packer to determine  
orientation

# Dual Horizontal



## RETRIEVABLE WHIPSTOCK AND 'ML' ORIENTATION ANCHOR RUN ON DRILLPIPE WITH WINDOW MILL

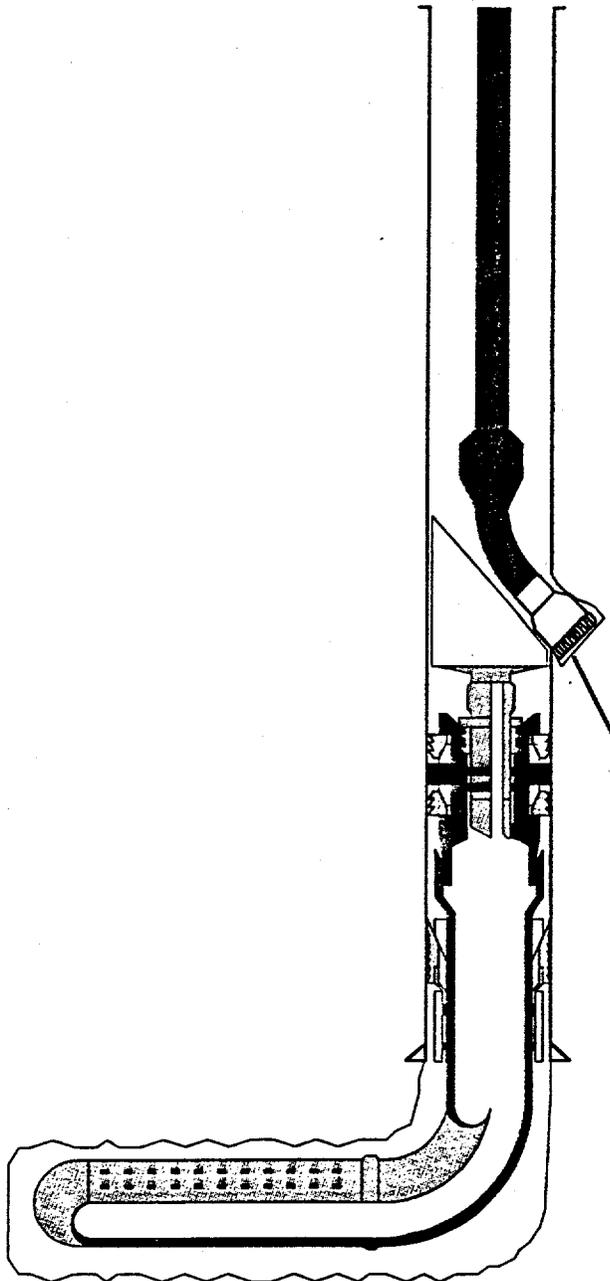


Retrieval Whipstock  
and Orientation Anchor  
Assembly engaged in  
ML Packer

# Dual Horizontal



## Milling Window

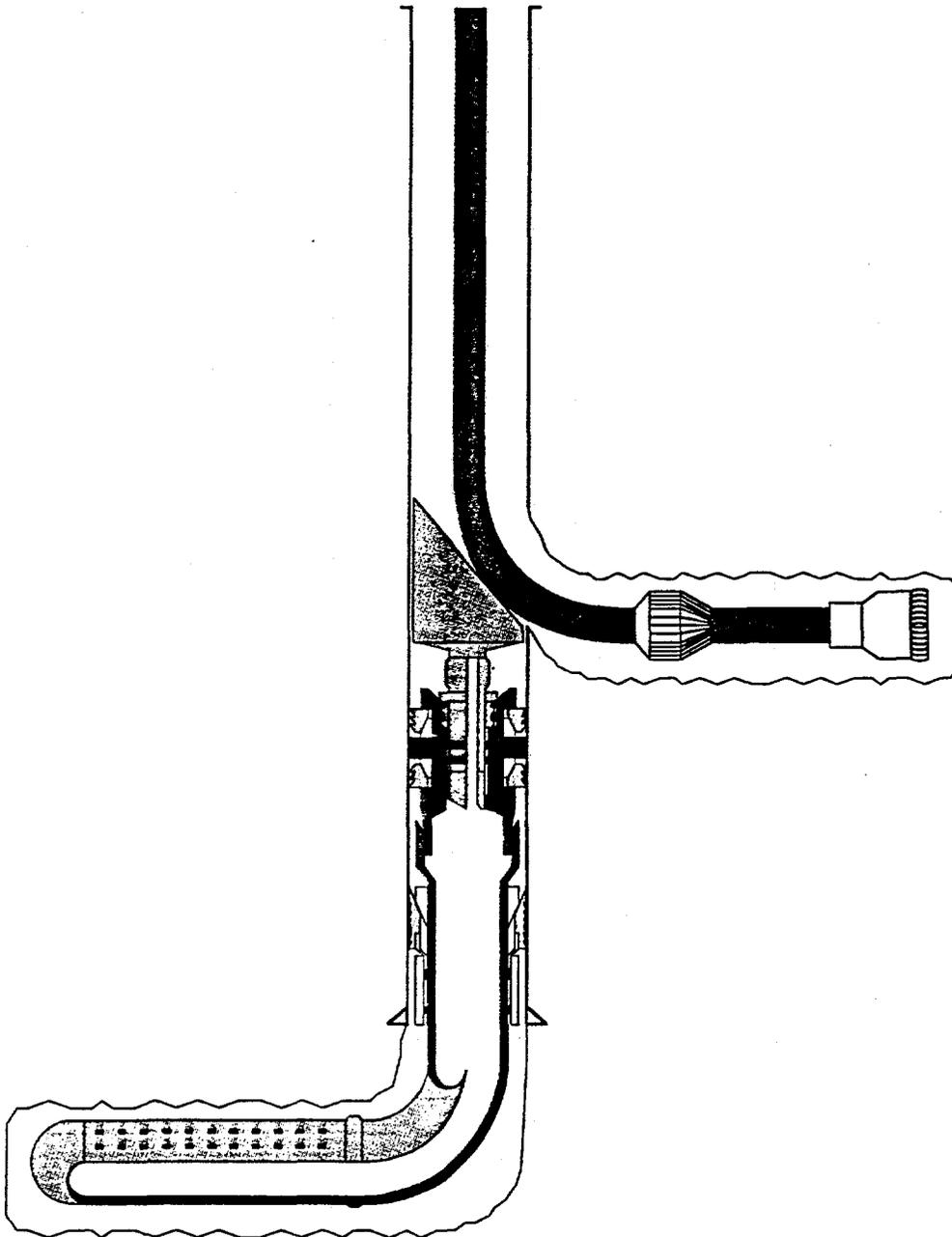


Mill assembly released  
and initial casing  
window cut

# Dual Horizontal



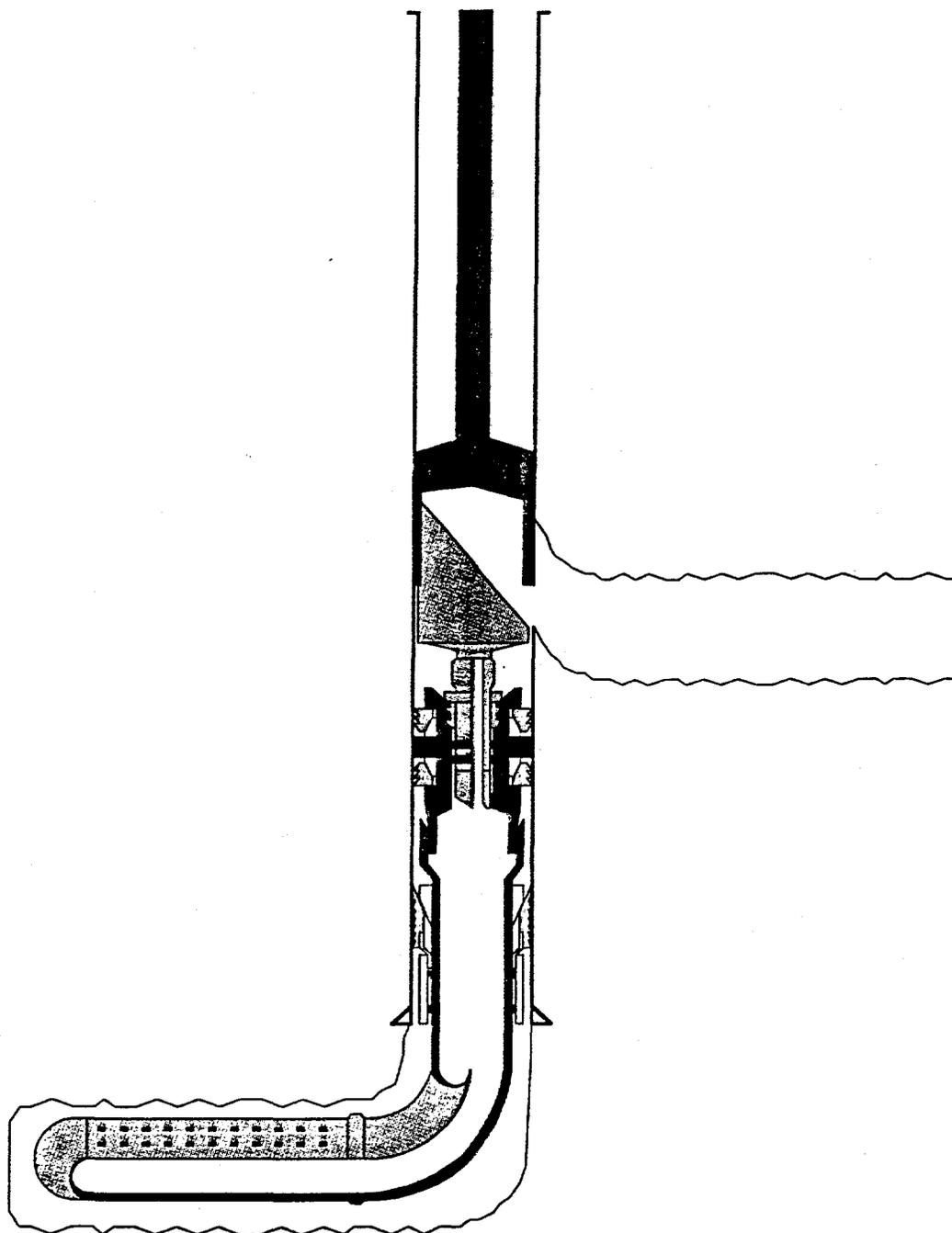
## WINDOW CUT AND 2nd BRANCH BEING DRILLED



# Dual Horizontal



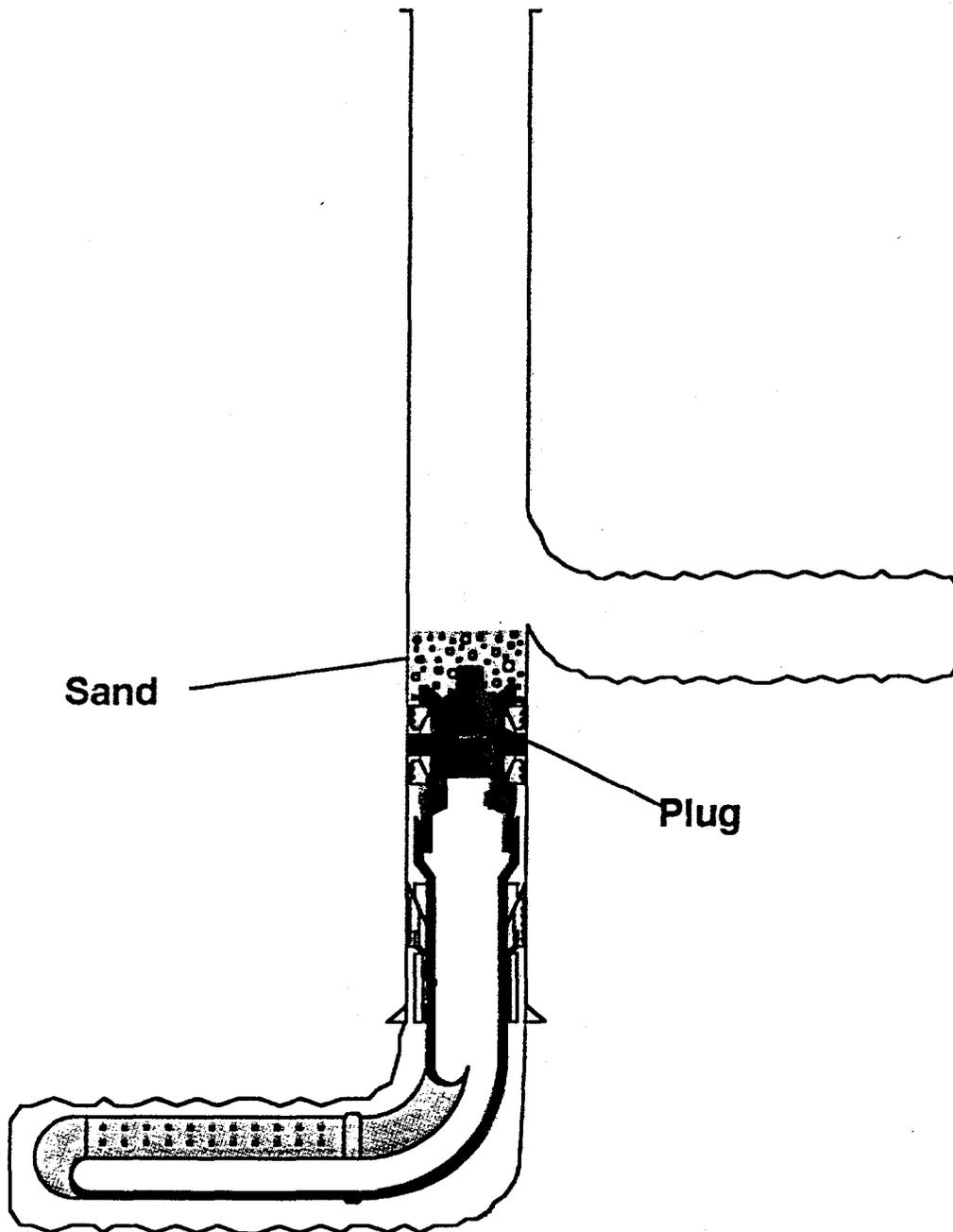
## UPPER Branch DRILLED RETRIEVING WHIPSTOCK



# Dual Horizontal



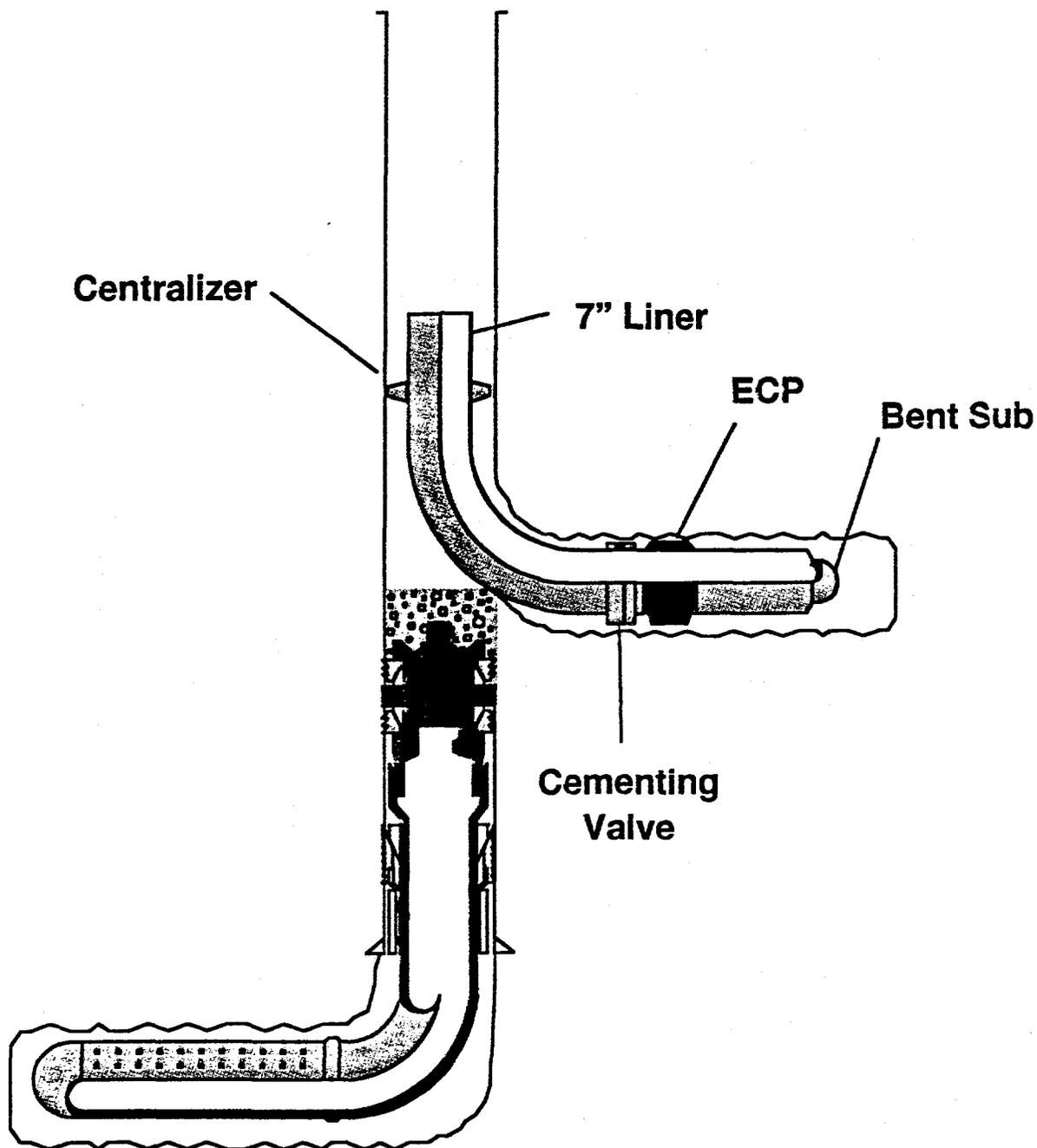
SET PLUG IN ML PAKER AND DUMP SAND



# Dual Horizontal



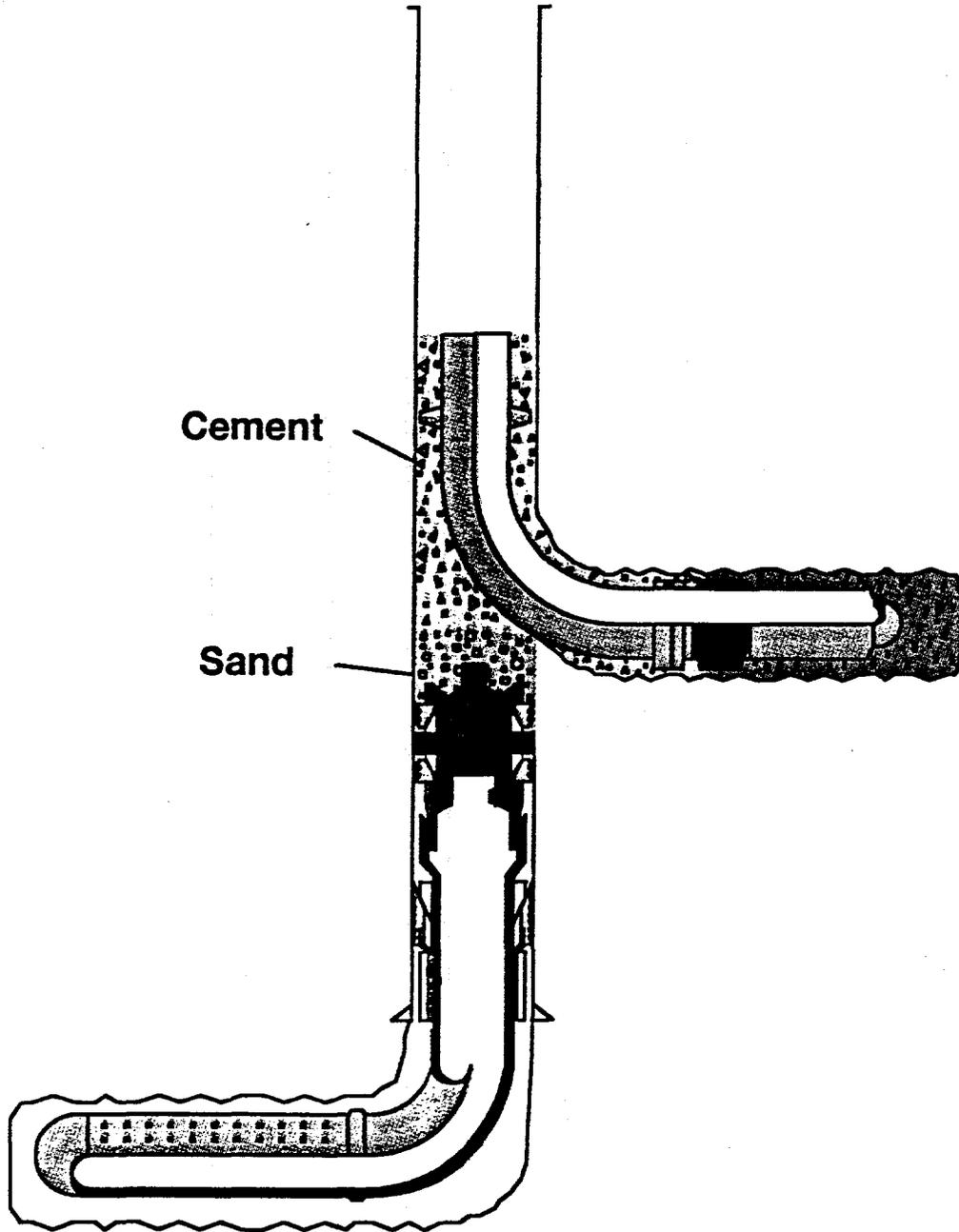
## LINER RUN TO DEPTH



# Dual Horizontal



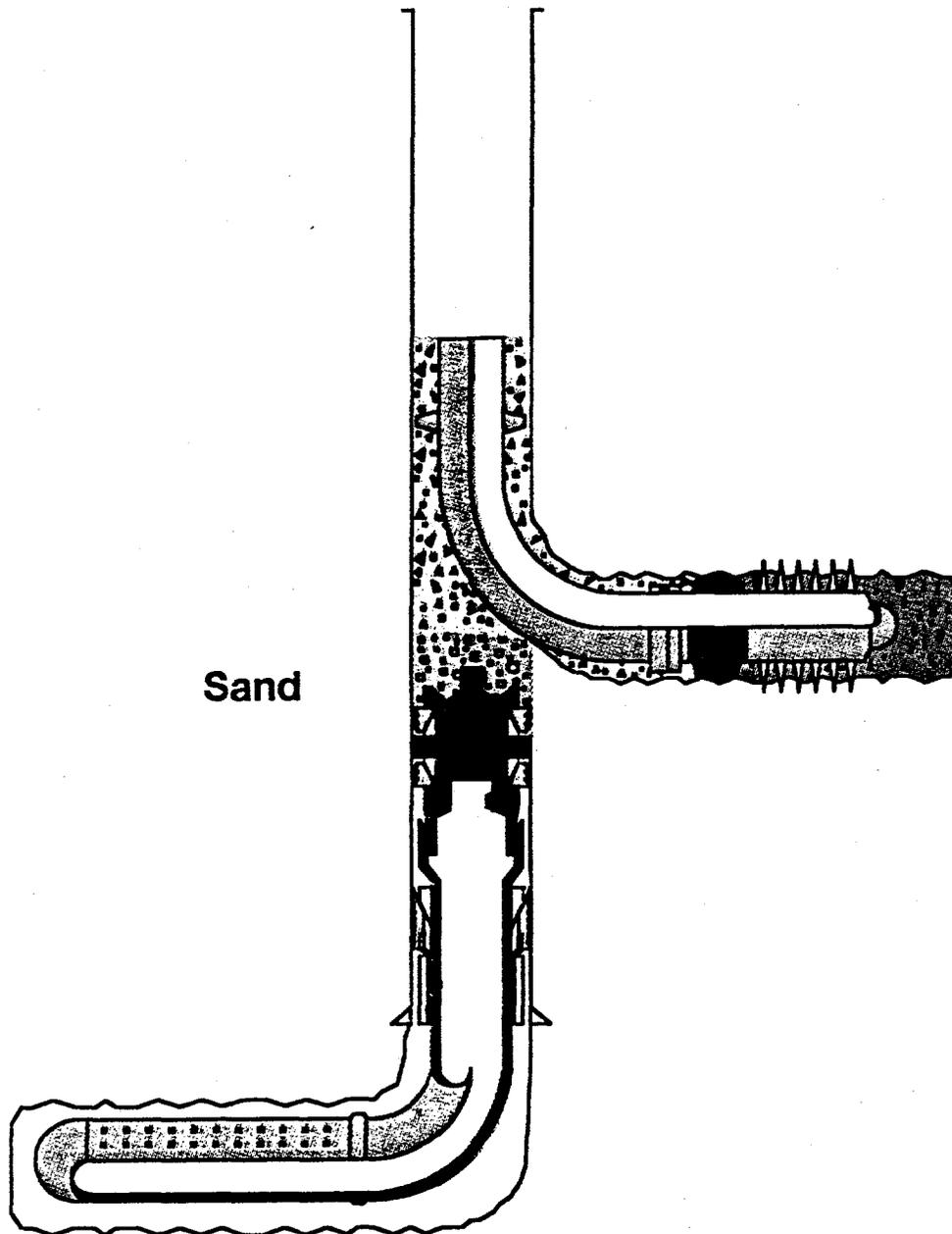
## CEMENT LINER 2 STAGE CEMENT JOB



# Dual Horizontal



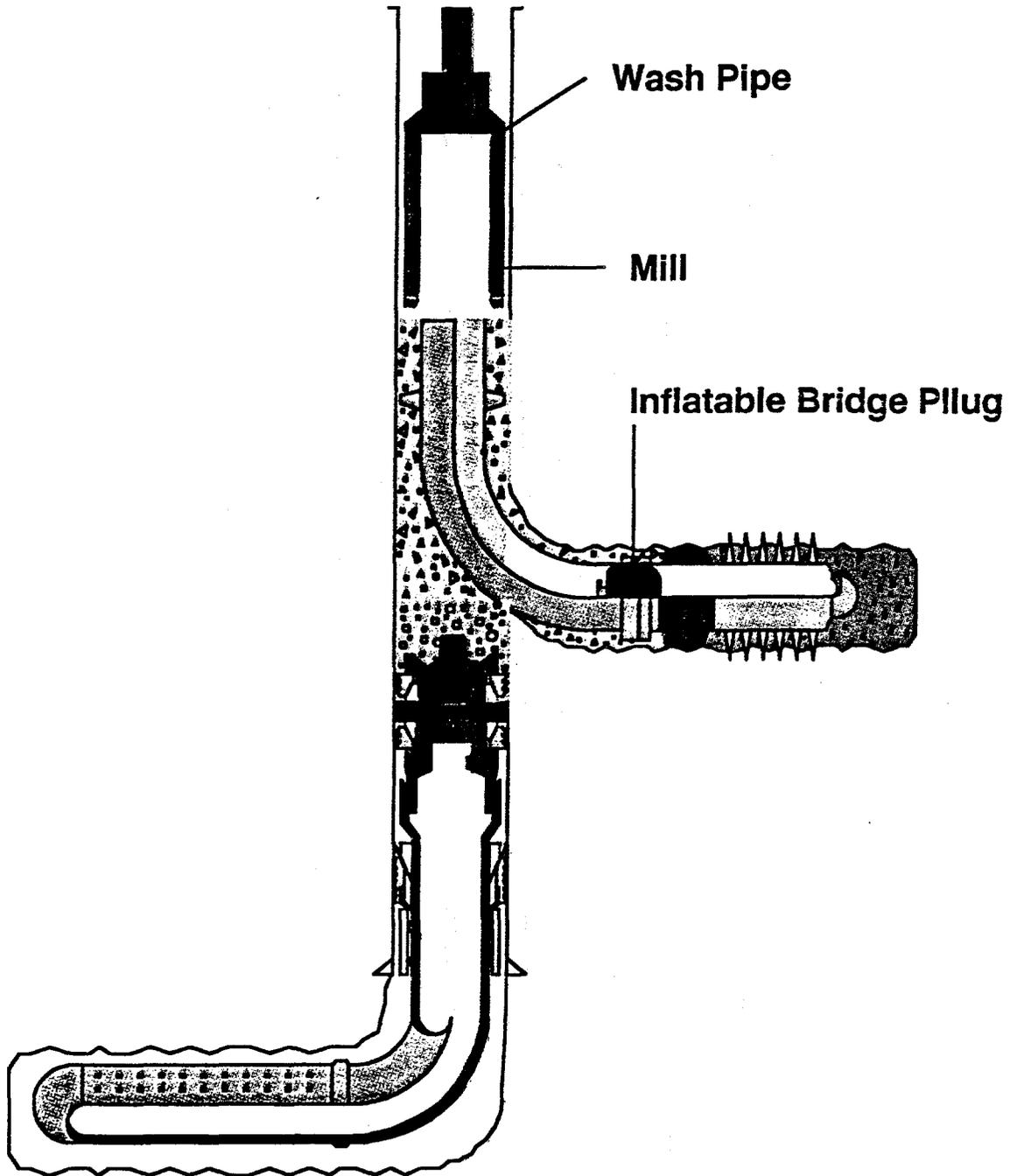
## PERFORATE & FRAC PAC



# Dual Horizontal



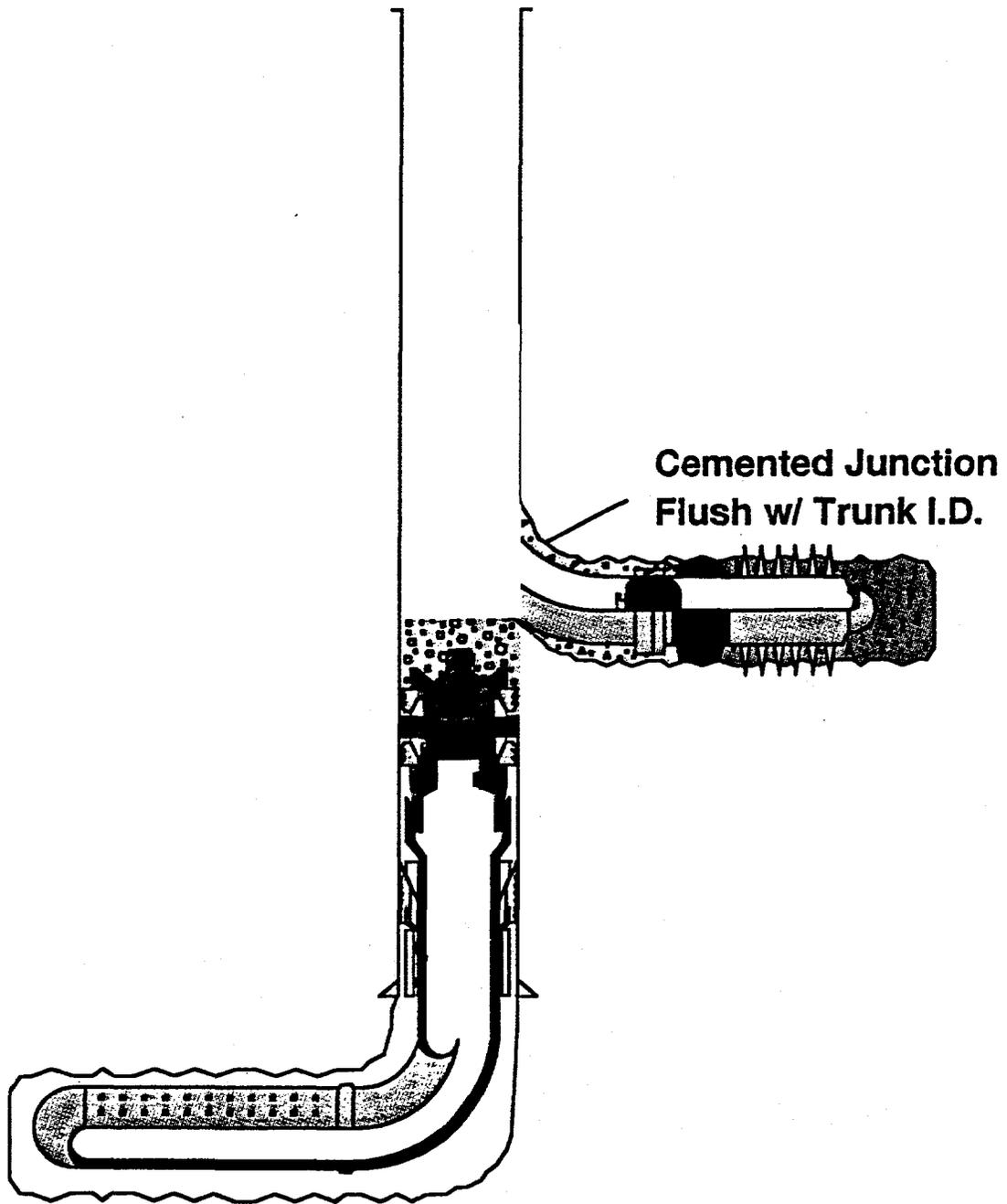
## WASH OVER LINER



# Dual Horizontal



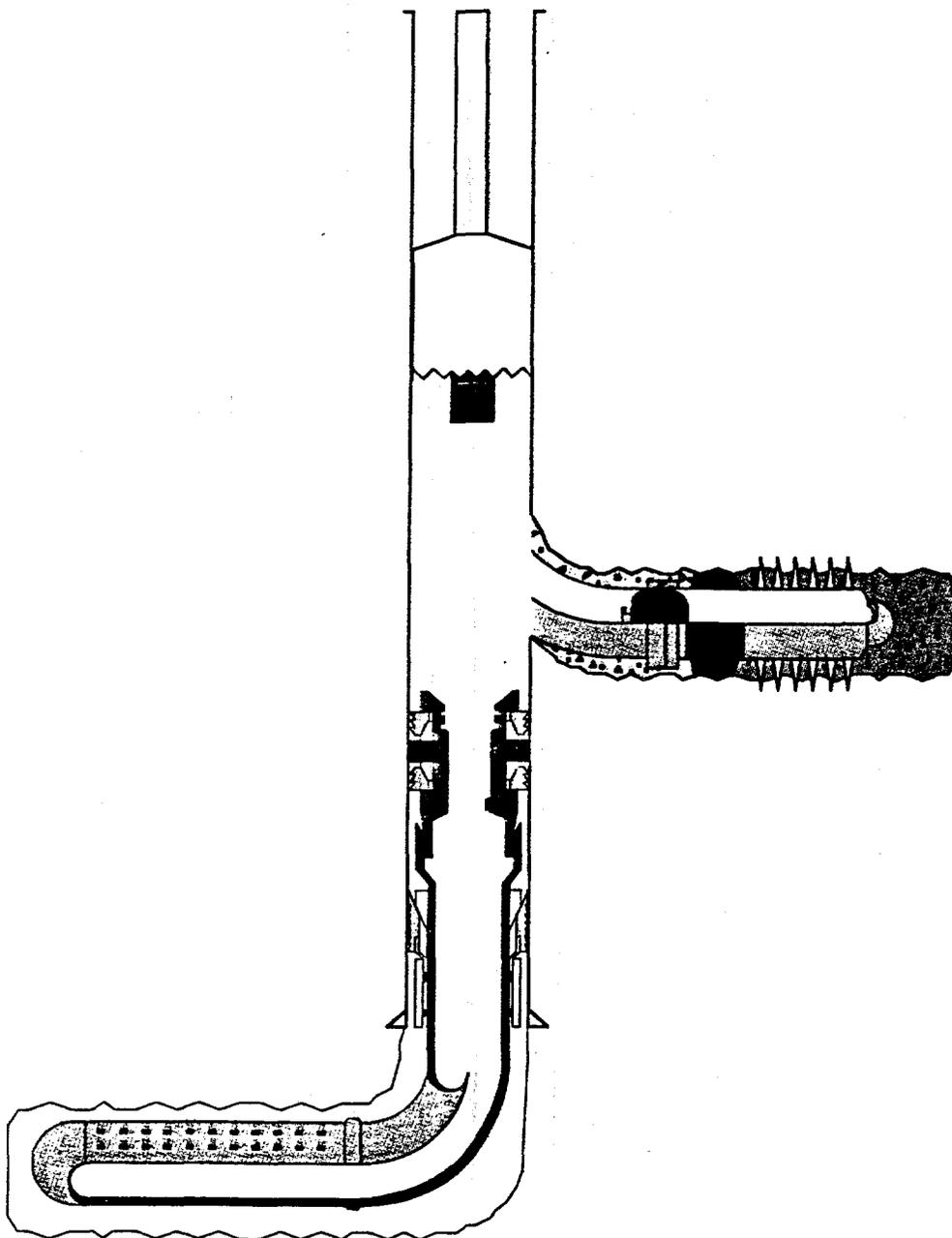
## LINER MILLED



# Dual Horizontal



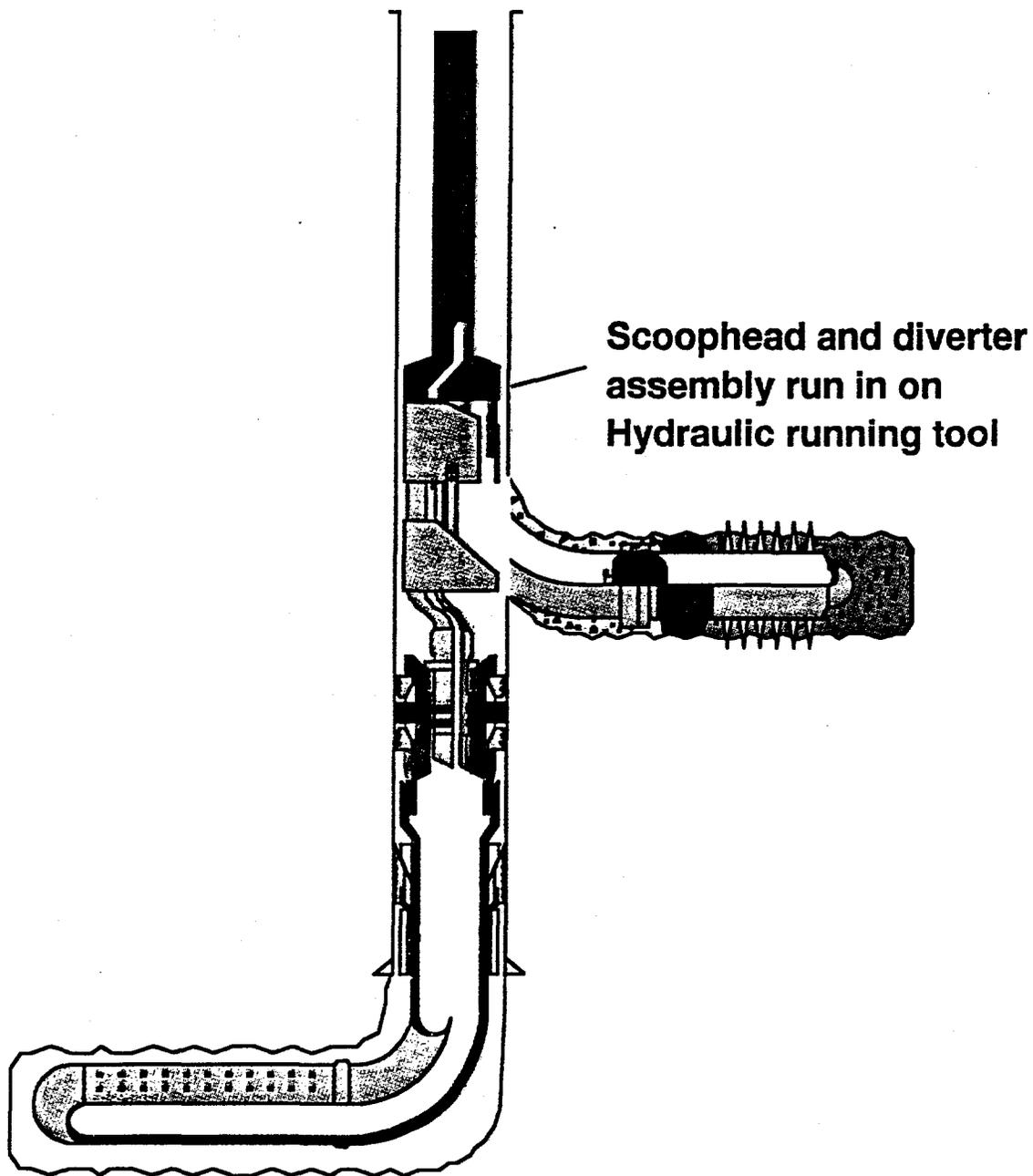
## WASH SAND RETRIEVE PLUG



# Dual Horizontal



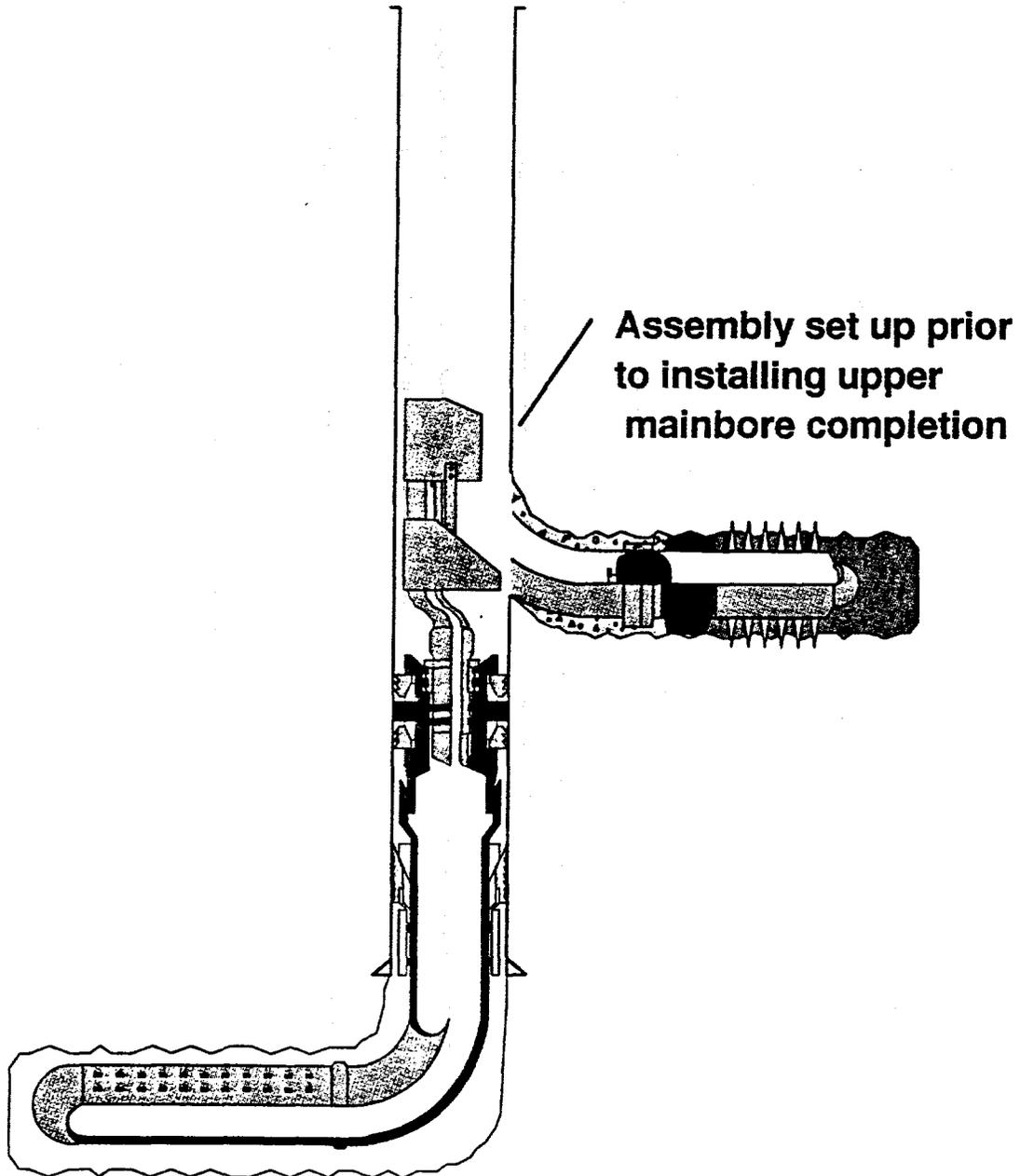
## INSTALL SCOOPHEAD



# Dual Horizontal



## DIVERTER INSTALLED

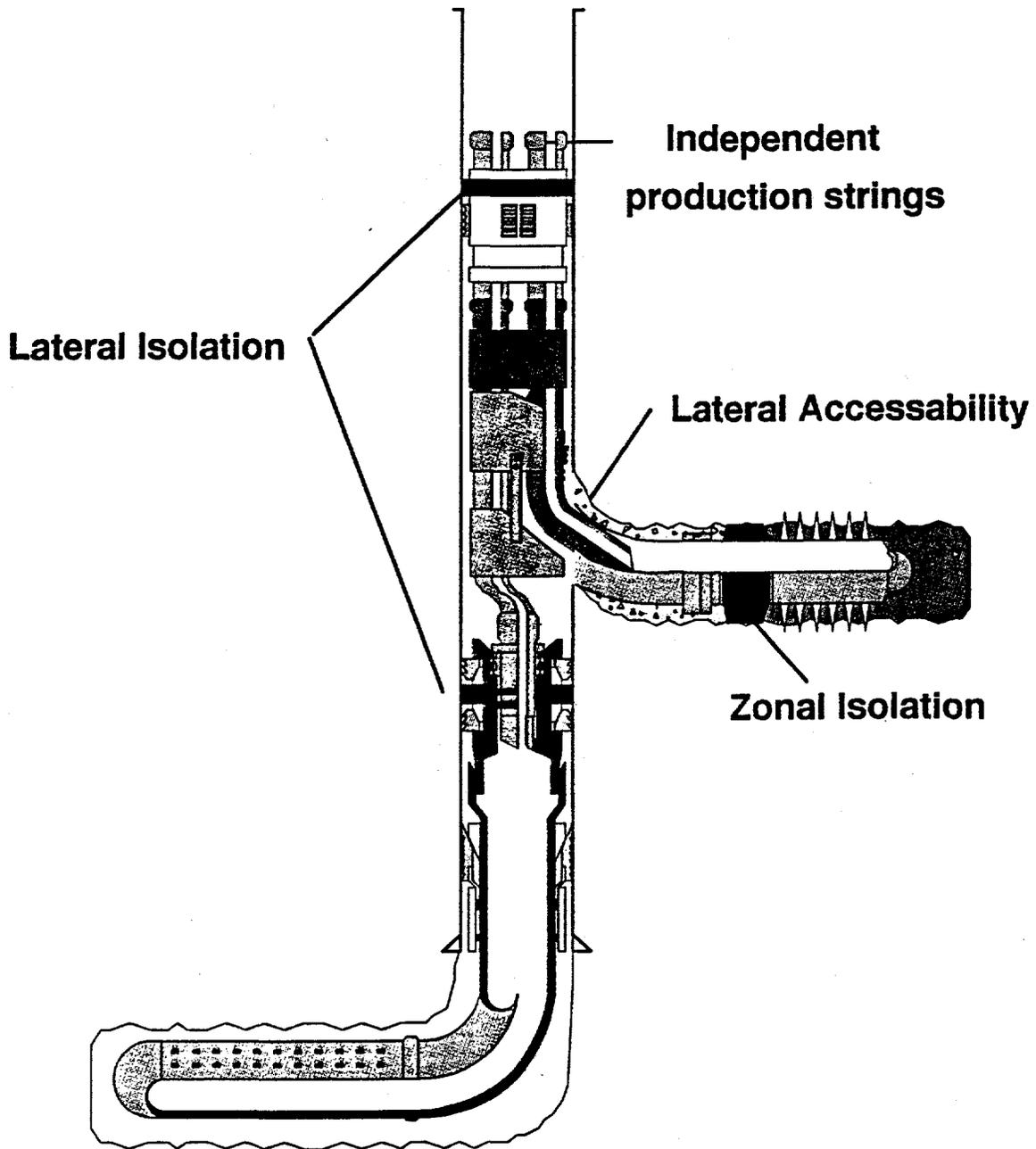


Assembly set up prior to installing upper mainbore completion

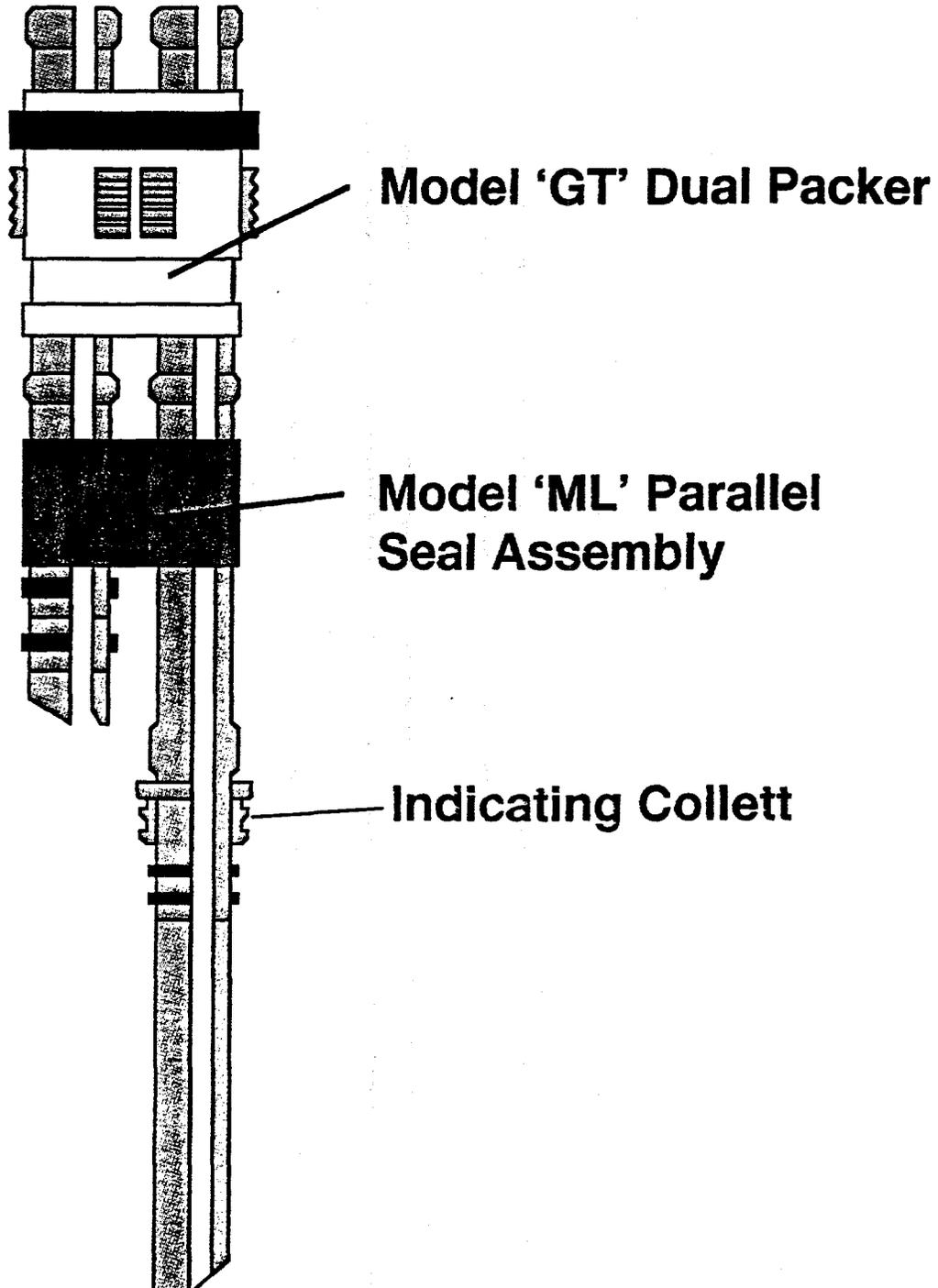
# Dual Horizontal



## DUAL HORIZONTAL COMPLETION INSTALLED



# Dual Horizontal



# Dual Horizontal



## FEATURES AND BENEFITS

- New or existing well application
- Zonal pressure integrity
- Branch May be conventionally treated
- Cemented and supported junction
- Full gage liner potential

# Dual Horizontal



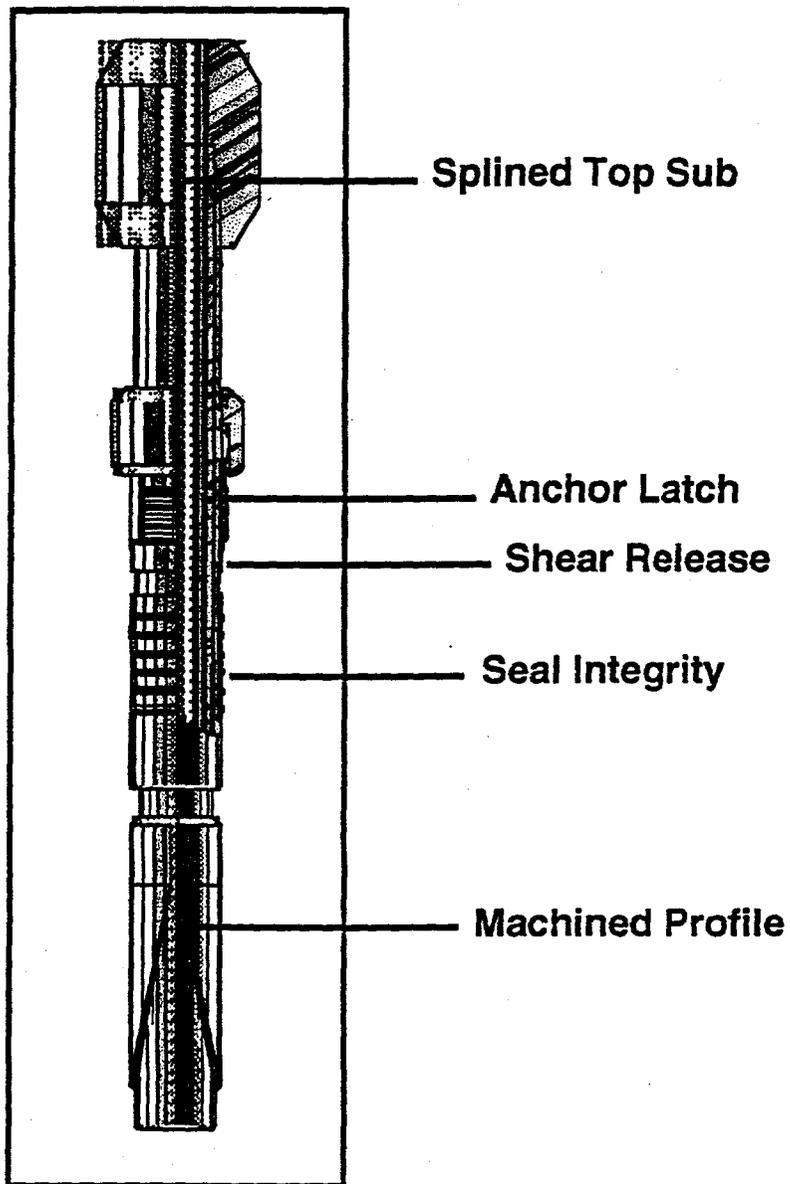
## Specifications/size available

- 9-5/8" by 3-1/2" x 3-1/2" strings.
- 8-5/8" by 3-1/2" x 2-3/8" strings.
- 7" by 2-3/8" x 2-3/8" strings.

# Dual Horizontal Completion



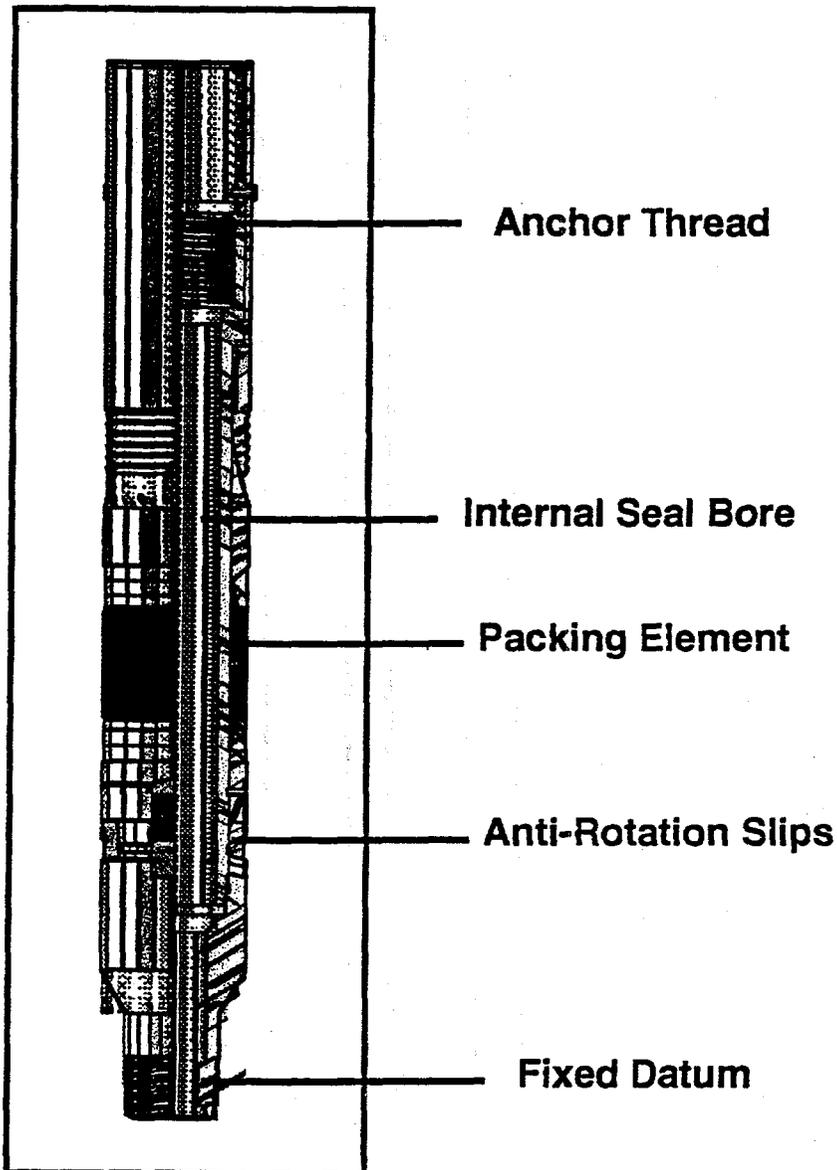
## Baker "ML" Orientation Anchor



# Dual Horizontal Completion



## Baker "ML" Whipstock Packer



# Dual Horizontal Completion

