Baker Hughes INTEQ

Coring Handbook

503-001 Rev. C November 1999

INTEQ

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Introduction to Coring

Through coring, Engineers, Geologists and Petrophysicists gain access to reservoir information that can be gathered in no other way. Data on the formation's lithology, flow characteristics, storage capacity and production potential are just a few of the valuable types of information that can be obtained by a successful coring program. This chapter discusses what coring is and the benefits associated with the process. It also describes how to plan a successful coring project and the BHI coring services that are available.

Coring Definition

Coring is the removal of sample formation material from a wellbore. To the extent possible, core samples are taken in an undamaged, physically unaltered state. The formation material may be solid rock, friable rock, conglomerates, unconsolidated sands, coal, shales, gumbos, or clays. Coring can be conducted by various methods with a variety of tools. But in the oilfield, coring is generally accomplished by two methods:

- **Full Hole Coring:** Core material ranging in diameter from 1¾" to 5¼" is recovered inside of a core barrel in vertical, deviated, horizontal, or sidetracked wells. Depending upon the coring system employed, the core can be recovered in preserved or unpreserved states, and can be used for a wide range of analytical applications. Baker Hughes INTEQ offers a complete range of full-hole coring services.
- **Sidewall Coring:** Cylindrical plug-shaped samples, generally 1" in diameter, are recovered from the walls of the wellbore by percussion or rotary coring techniques. This sampling takes place in the first few inches of the wellbore wall in regions that generally are invaded by drilling fluid filtrates. The resulting samples are unpreserved and frequently are damaged by the recovery procedure. Sidewall core plugs are of limited use from an analytical standpoint. *Baker Hughes INTEQ does not offer sidewall coring services.*

The Purpose of Coring

Laboratory measurements performed on core samples recovered from hydrocarbon reservoirs furnish reservoir descriptive data available from no other source. Well logs, including the new generation NMR tools, play a very important role in reservoir identification and characterization. However, the reservoir core material itself will provide the most accurate information available to geologists, engineers, and petrophysicists. In addition, core material is needed to calibrate well logs.

Depending upon the people who are driving the project, the goals of the coring program differ. It should be understood that the coring goals of drilling engineers, reservoir engineers, geologists, petrophysicists, and core analysts may not be the same.

Evaluation data gained from core samples fall into three general categories: geological, completion, and engineering. Following is an outline of the types of information provided by each type of evaluation.

Geological Evaluations

- Lithology
- Depositional Environment
- Mineralology
- Formation Age and Geological Sequence
- Fracture Analysis
- Diagnosis
- Geochemistry
- Paleomagnetism
- Fluorescence

Completion Evaluations

- Acidization of the Wellbore
- Fracture Treatment Design
- Horizontal Permeability
- Vertical Permeability
- Formation Damage Potential
- Grain Size Distribution
- Residual Oil Saturation and Distribution
- Porosity Distribution
- Clay Type, Quantity, and Distribution
- Mineralology

Engineering Evaluations

- Porosity Distribution
- Permeability Distribution
- Permeability vs. Porosity Relationship
- Hydraulic Flow Unit Distribution
- Formation Heterogeneity
- Oil/Water Contacts
- Reservoir Fluid Saturations and Distribution
- Data for Calibration of Downhole Logs
  - Grain Density
  - Acoustic Velocity
  - Mineralology
  - Electrical Properties
  - Gamma Ray Response

- Special Core Analysis
    - Wettability
    - Relative Permeability
    - Capillary Pressure
    - Pore Volume Compressibility
    - Rock/Fluid Compatibility
- Performance Characteristics
    - Primary Production
    - Secondary Production (e.g., waterflood)
    - Tertiary Production (e.g., enhanced oil recovery)
- Rock Properties
    - Compressive Strength
    - Young's Modulus
    - Poisson's Ratio
    - Hardness

Whatever the goals of coring a well, *coring adds value* to any hydrocarbon exploration or development project.

"Coring and core analysis are essential to the exploration, development, and production phases of the oil and gas industry. This information provides engineers with clues to improve their understanding of the reservoir and prediction of its performance. If stored properly, core samples may assist in the development of the reservoir many years after the well is drilled."

– F. R. Bradburn and C. A. Cheatam, Shell Offshore Inc.

Planning the Successful Coring Program

The two most important factors leading to a successful coring operation are proper planning and communications. It is imperative that a planning or pre-spud meeting be held with representatives of the following:

- Drilling Department
- Geological Department
- Reservoir Engineering
- Baker Hughes INTEQ Coring Systems
- Drilling Fluids Department
- Rig Supervisor
- Core Analysis Company
- Logistics Department.

A complete understanding of the coring program goals by all parties involved is essential to promote synergism in the pre-spud meeting.

Coring Services

The need for proper communication and planning of any coring project can be reinforced by a review of the available coring services listed in Table 1-1. Every effort must be made to select the right service, tools, and procedures needed to meet the objectives of the coring program.

Conversion Factors and Physical Constants

Appendix A, Conversion Factors & Physical Constants, presents a comprehensive list of conversion factors and physical constants. These are often used in planning coring operations and in evaluating core samples.

Table 1-1 Coring Services

Service	Why Required or Used
HT Series Core Barrels for Conventional Coring	4¾" to 8" high torque barrels for conventional, long core, motor coring, and deviated well applications
Coremaster Core Barrels for Conventional Coring	4¾" and 6¾" heavy duty barrels for all standard, high torque, long footage, and deviated coring applications
Containerized Coring (for all core barrels)	Coring with disposable aluminum or fiberglass inner tubes to containerize the core; optimizes coring performance, reduces rig time, and protects the core
Hydrolift™ Full Closure Catcher (6¾" × 4" and 8" × 4¾" barrels)	Coring soft or unconsolidated formations with a full closure catcher; slick, unobstructed entry of core into the barrel to prevent jamming in the shoe
CoreDrill® Coring-While-Drilling (6¼" × 2" barrel – Model 1a; 6½" × 2" barrel w/MWD – Model 2)	Coring and drilling with the same bit and bottom hole assembly to reduce rig costs; rapid wireline retrieval of the core barrel useful in coal bed methane projects
Motor Coring	Coring with a downhole mud motor for deviated and horizontal wells and to reduce the weight on bit required
Modular Coring System (3¾" × 2" and 4¾" × 2⅝" barrels)	Coring in deviated wells with severe doglegs; uses a downhole mud motor to ease torque peaks and prevent damage to the core
Oriented Coring (4¾", 5¾", 6¼", 6¾" & 8" barrels)	Orients the core downhole to determine formation structural dip and inclination to evaluate fractures
Low Invasion Coring	Specially designed coring bits, extended pilot shoes and drilling fluids to limit filtrate invasion in the core
Gel Coring℠	An extension of low invasion coring using downhole encapsulation of the core with gels to protect and preserve the core and enhance core quality and performance

Table 1-1 Coring Services (continued)

Service	Why Required or Used
In Situ Data Gathering -Pressure Coring (5¾" × 2½" and 7" × 3¾" barrels)	In situ data gathering system recovers and retains cores at reservoir pressure with native fluids intact; excellent for true saturation analyses
High Pressure High Temperature (HPHT) Coring	Special coring procedures - including the use of pressure-relieving check valves - to core reservoirs at high formation pressure and temperature
So Coring (6¾" × 3½" core barrel) Reservoir Characterization Coring Service	Downhole encapsulation of core with an oil-absorptive foam to capture oil expelled during recovery; high quality saturation and analytical data thus can be obtained from the preserved core
Underbalanced (Air/Mist) Coring	Coring to reduce formation damage and increase penetration rates in underbalanced reservoirs
Slimhole Coring (3½" × 1¾" barrel)	Coring in small wellbores (3¾" - 5") where standard tools cannot be used
Coiled Tubing	Slimhole coring through existing tubing; re-entry applications
Core Jam Indicator	Coring in jamming-prone formations; fixed to the top of the inner core barrel, the CJI alerts the driller that a jam has occurred
JamBuster Telescoping Inner Core Barrels	For use in jam-prone formations; the telescoping system accommodates 3 jams before system must be pulled from hole
Anti-Whirl Core Bits	Specially designed coring bits eliminate downhole vibrations that damage core
Wellsite Preservation Services	Epoxy, gypsum, and foam stabilize core material in the container sleeves and protect the core during shipment
Wellsite Sampling Services	Plugging and preservation at the wellsite stabilize plug samples before alteration of the core can occur

Chapter 2

Coring Systems

The benefits of coring can be maximized by deploying the correct coring system for a given application. This chapter discusses the various types of BHI coring systems and tool features, application parameters, and the benefits of coring.

High Torque HT Series Core Barrels

Baker Hughes INTEQ HT Series™ and Coremaster™ high torque core barrels are designed for standard coring operations and high torque applications. HT Series barrels are used worldwide. Coremaster barrels are employed principally in the North Sea and Far East regions.

HT Series™

Baker Hughes INTEQ's HT Series core barrels are designed with high strength, double-shouldered connections. The HT barrels are fit-for-purpose for all standard coring operations, long core barrel runs (to 360 feet), motor coring, and coring in highly-deviated wells. HT series core barrels can operate at high ROPs and WOB, reducing the risk for torsional damage to the connections.

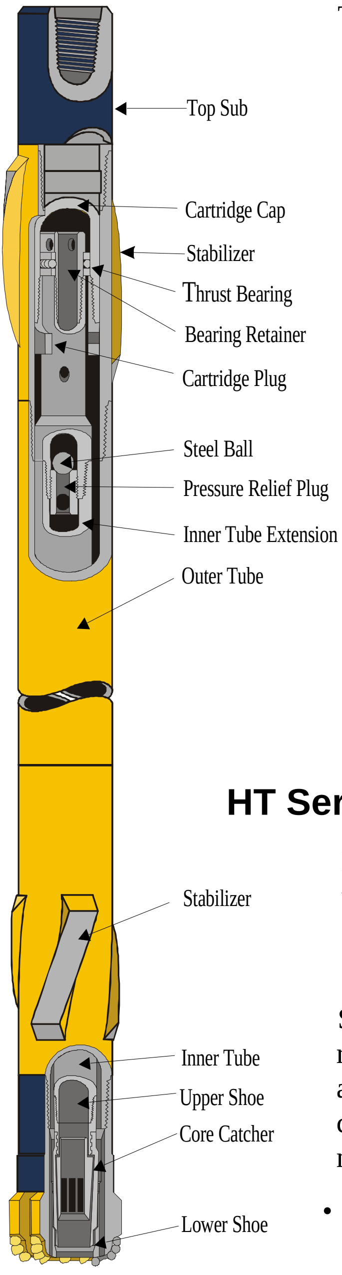


Figure 2-1 HT Series Core Barrel

The HT system offers additional options:

- The LDA (Long Distance Adjustment) for accurate positioning of the inner tube in relation to the core head
- A core jam indicator
- Inner barrel stabilization.

When so configured, these barrels offer the optimal coring system for enhanced coring performance and quality core recovery. Aluminum and fiberglass disposable inner barrels are used to containerize the core and to optimize coring efficiency.

HT Series specifications are listed in Table 2-4. Mechanical properties and dogleg severity limitations of these barrels are listed in Appendix B, Table 1.

HT Series Features

High-strength steel, rugged wall outer tube with double shouldered connections, and optimized thread design increases torsional strength.

Swivel assembly maintains penetration rates and smooth core recovery and allows optimized mud flow through the core barrel to enhance bit hydraulics and maintain circulation.

- Mud-lubricated thrust bearings with specially tempered ball bearings eliminate the need for surface lubricating devices. They enable hot hole or high-pressure applications.

- Pressure relief plug permits circulation through the core barrel, ensuring a clean inner tube and hole before coring begins. This minimizes core contamination and maintains circulation to the core head for proper cleaning and adequate cutter cooling.
- Long Distance Adjustment system (LDA) provides increased spacing for the inner assembly and enables correct positioning of the inner tube above the bit. It saves rig time over previous shim and sub methods and offers greatest strength and wear resistance.
- Precisely milled and hard faced integral blade stabilizers offer greatest strength and wear resistance of the core barrel.
- Disposable aluminum or fiberglass inner tubes maximize coring efficiency. Steel inner barrels are available. Inner tubes containerize the core, protecting the core from fluid contamination and erosion.
- Threaded upper inner tube shoe sub reduces thread damage between inner tube and inner tube shoe, enabling longer thread life and component use.
- Pilot-type inner tube shoe stabilizes the lower end of the inner tube against the core bit, and serves as a pilot to guide core into catcher and inner tube. Secures the core as soon as it is cut.
- Standard spring core catcher with tungsten carbide grit I.D. grips and breaks the core at the bottom. Core loss is prevented during retrieval of the core barrel to surface.
- Core jam indicator promotes immediate detection of jamming by increasing standpipe pressure at the surface. Ensures that cores are not lost due to milling.

- Inner tube stabilization centralizes inner assemblies, preventing flexing of inner tubes in deviated and vertical wells. This reduces the potential for jamming and mechanical damage of the core while coring.

Coremaster™ Series Core Barrels

Coremaster heavy-duty 4¾" and 6¾" core barrels were developed for high torque, long footage coring in highly deviated holes. They cut $2^{1}/_{8}$" and 4" diameter cores, respectively. See Figure 2-2.

Solidly constructed of 4142H steel tubing, the 6¾" barrels feature a 7¼" tool joint upset. Coremaster barrels incorporate double standard outer tube thread connections to enhance the strength of the tool.

Coremaster coring barrels are available in standard 30 foot lengths. The 4¾"outer tubes can be joined to form lengths to 270 ft (82 m), and the 6¾"outer tubes can be joined to form lengths to 360 feet (110 m). These coring systems are fully stabilized by integral SC-1 stabilizers.

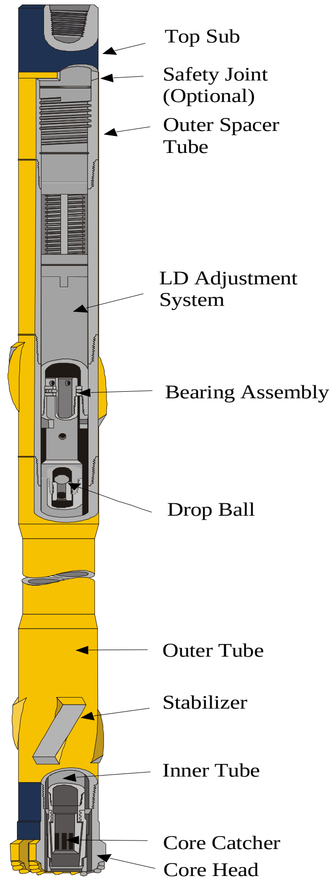


Figure 2-2 Coremaster 3/4" Core Barrel

The system uses INTEQ’s patented inner tube Long Distance Adjustment (LDA) system. A wide LDA adjustment range facilitates accurate spacing of the inner tube in relation to the core bit, compensating for thermal expansion of the inner tubes. Coremaster specifications appear in Table 2-4. Mechanical properties and dog leg severity limitations are listed in Appendix B, Table 2.

Table 2-4 Coremaster Specifications

Coremaster Series Core Barrel Specifications		
System Type	4¾"	6¾"
Outer Tube	4¾" × 3¼"	6¾" × 5⅜" with 7¼" × 5⅜" Upsets
Inner Tube	2⅞" × 2⅜"	4¾" × 4¼"
Core Diameter	2⅛"	4"
Top Connection	NC38 Box	7¼" O.D. with NC50 Box Connection
Core Bit Shank	4¾"	7¼" O.D.
Recommended Makeup Torque	13,200 ft-lbs / 18,000 N-m	19,600 ft-lbs / 26,500 N-m
Maximum Torque	17,400 ft-lbs / 23,600 N-m	24,500 ft-lbs / 33,200 N-m
Dogleg Severities	5.0 Deg./10 Metre Non-Rotating 1.7 Deg./10 Metre Rotating	10.7 Deg./10 Metre Non-Rotating 2.0 Deg./10 Metre Rotating
Standard Stabilizer Placement	2, 32, 62, 92, ….ft	2, 32, 62, 92, …. ft
Optional Stabilizer Placement	NA	15 ft intervals
Weight per Section	30 ft = 1,170 lbs/530 kg	30 ft = 1,750 lbs/800 kg

Coremaster Features & Benefits

- Optional safety joint assembly provides a durable threaded connection that can be broken easily on the rig floor to expedite core retrieval. Standard Coremaster barrels have a top sub.
- Swivel assembly permits maximum free rotation for maintaining penetration rates and smooth core recovery. Mud flow through the core barrel is optimized to control coring hydraulics and maintain circulation.
- Mud lubricated thrust bearing with tempered ball bearings eliminates the need for surface lubricating devices. Ball bearings, unaffected by bottomhole temperature or pressure, enable hot hole or high pressure applications.
- A pressure relief plug permits the operator to circulate a prescribed volume through the core barrel prior to coring, ensuring a clean inner tube and hole before coring begins.
- When seated in the relief plug, the steel drop ball diverts drilling fluids through ports above the inner tube, causing mud flow between inner and outer tubes. This minimizes core contamination and maintains circulation to the bit for proper cleaning and cooling.
- Long Distance Adjustment system enables correct positioning of the inner tube above the core head. A wide range of adjustment easily compensates for differential thermal expansion when using aluminum or fiberglass inner tubes.
- Inner tube stabilizers provide optimum stabilization and improved stiffness of the inner barrels when long core barrels are configured.
- Outer tube stabilizers provide a ribbed sub to reduce core barrel/outer tube contact against the

wellbore wall, reducing the risk of differential sticking and preventing premature core barrel wear to extend tool life.

- Optional core jam indicator allows immediate detection of jamming core by causing an increase in standpipe pressure at the surface, ensuring that cores are not lost due to milling.
- Pilot-type inner tube shoe stabilizes the lower end of the inner tube against the core bit or bit end bearing and serves as a pilot to guide the core into the catcher. Reduction of core jamming is anticipated.
- Standard spring core catcher with tungsten carbide grit I.D. provides gripping on consolidated cores. When pulling the string off bottom, the spring catcher will break the core and prevent its loss while retrieving the barrel to the surface.
- The Coremaster barrel is designed to be used in motor coring applications in hole inclinations exceeding 90 degrees.

Conventional 250P Core Barrels

Baker Hughes INTEQ has begun to phase older style conventional core barrels out of service in favor of the high torque HT Series and Coremaster alternatives. However, lower torque barrels are widely used and will continue to remain in service in certain locations.

250P Series Core Barrels

Baker Hughes INTEQ's 250P Core Barrels are double-tube, swivel type tools designed to provide maximum core recovery in all types of formations.

The 250P Core Barrel consists of an inner and outer tube. The outer tube protects the inner tube's components. Reinforced with either wear rib subs or core barrel stabilizers, the outer barrel reduces core bending, core blockage and bit wobble, permitting more weight-on-bit for improved penetration rates.

The inner tube provides a container where the recovered core is stored. Steel, fiberglass, and aluminum inner tubes are available. The inner and outer tubes are connected by a precision built swivel system that prevents inner tube rotation for better core recovery.

The 250P barrel also features a drop ball that permits bottom hole cleaning before coring, a positive safety joint that allows the inner tube to be removed with the core if the barrel becomes stuck, and a long distance adjusting (LDA) assembly to compensate for thermal expansion of the inner tubes.

Specifications for 250P series core barrels are detailed in Table 2-5. Mechanical properties and dogleg severity limitations of these barrels are listed in Table 3, and Table 4, in Appendix B.

Table 2-5 250P/350P Series Core Barrel Specifications

Item	**(350P) 3½" × 1¾"**	**$4^1/_8$" × $2^1/_8$"**	**4¾" × $2^5/_8$"**	**5¾" × 3½"**	**6¼" × 4"**	**6¾" × 4"**	**8" × 5¼"**
Length	**30 ft (9 m)**	**30 ft (9 m)**	**30 ft (9 m)**	**30 ft (9 m)**	**30 ft (9 m)**	**30 ft (9 m)**	**30 ft (9 m)**
Outer Tube	$3^1/_2$" × $2^3/_4$"	$4^1/_8$" × $3^1/_4$"	$4^3/_4$" × $3^3/_4$"	$5^3/_4$" × $4^5/_8$"	$6^1/_4$" × $5^1/_8$"	$6^3/_4$" × $5^3/_8$"	8" × $6^5/_8$"
Inner Tube	$2^3/_8$" × $1^7/_8$"	$2^7/_8$" × $2^3/_8$"	$3^7/_8$" × $2^7/_8$"	$4^1/_4$" × $3^3/_4$"	$4^3/_4$" × $4^1/_4$"	$4^3/_4$" × $4^1/_4$"	$6^1/_4$" × $5^1/_2$"
* Top Connection	$2^3/_8$" API Reg	$2^7/_8$" API Reg	$3^1/_2$" API FH	$4^1/_2$" API FH	$4^1/_2$" API FH	$4^1/_2$" API FH	$6^5/_8$" API Reg
Bore	1"	$1^1/_2$"	$2^7/_{16}$"	$3^5/_{32}$"	$3^5/_{32}$"	$3^5/_{32}$"	$3^5/_{32}$"
Steel Ball Size	0.625"	1.000"	1.000"	1.250"	1.250"	1.250"	1.250"
Core Size OD	$1^3/_4$"	$2^1/_8$"	$2^5/_8$"	$3^1/_2$"	4"	4"	$5^1/_4$"
Recommended Hole Sizes	$3^3/_4$" - 5"	5" - 6"	6" - 7"	7" - 8"	$7^7/_8$" - $8^1/_2$"	8" - 9"	9"-$12^1/_4$"
Weight (Gross) lbs	1,208	1,894	2,676	3,163	3,833	4,240	5,441
Recommended Max. Pull	166,367	172,000	232,000	328,000	350,000	407,000	602,000
Maximum Torque (ft-lbs)	2,904	4,400	5,800	10,800	11,800	13,900	27,300
Makeup Torque (ft-lbs)	2,323	3,500	4,700	8,600	9,400	11,100	21,900
*May differ in Eastern Hemisphere							

250P Core Barrel Features

- The safety joint assembly provides a durable threaded connection that can be broken easily on the rig floor to expedite the core retrieval process. If the core barrel sticks downhole, the safety joint assembly enables backing off of the core barrel, which permits the inner tube and core to be removed. It eliminates rig delays and maintenance expense and ensures core retrieval.
- Swivel assembly permits maximum free rotation for maintaining penetration rates and smooth core recovery. It allows optimized mud flow through the core barrel to enhance bit hydraulics and maintain circulation.
- Mud-lubricated thrust bearing with specially tempered ball bearings - same drilling fluid or air used to clean the hole is used for bearing lubrication, eliminating the need for surface lubricating devices. Ball bearings, unaffected by bottomhole temperature or pressure, enable hot hole or high pressure applications.
- Pressure relief plug permits operator to circulate prescribed volume through the core barrel, ensuring a clean inner tube and hole before coring begins. When seated in the relief plug, the steel ball diverts drilling fluids through ports above the inner tube, causing mud flow between the inner and outer tube which minimizes core contamination and maintains circulation to the bit for proper cleaning and cooling.
- Long Distance Adjustment assembly enables correct positioning of the inner tube above the bit, saves rig time over previous shim and sub method, enables precise long barrel coring, and enables 5 times greater travel than shim method.

- Outer tube sub with wear ribs provides a ribbed sub to reduce core barrel outer tube contact against the wellbore wall. It reduces risk of differential sticking, prevents premature core barrel wear and extends tool life.
- High strength, thick-walled steel outer tube with internal/external flush joints provides high tensile strength for increased tool durability in a wide range of coring situations.
- High strength, steel inner tube with internal/external flush joints. Use of optional aluminum or fiberglass inner tubes provides a holding compartment for the core and protects the core from fluid contamination and erosion.
- Upper inner tube shoe provides a threaded sub that reduces thread damage between the inner tube and the inner tube shoe, enables longer thread life and component use.
- Pilot type inner tube shoe stabilizes the lower end of the inner tube against the core bit, which serves as a pilot to guide core into the catcher and the inner tube. It enables quick and efficient core entry and reduces core erosion.
- Standard spring core catcher with tungsten carbide grit I.D. and 5° locking grip taper grips core to prevent core loss, ensuring core retrieval when pulling the string.
- Core barrel length can be varied in 30-foot increments. This eliminates need for additional core runs and reduces overall coring costs.

350P Slimhole Core Barrel

The slimhole 350P Core Barrel is a double-tube, swivel-type special application tool which is very similar to the 250P series, except it does not have a safety joint. This small diameter system is designed for use in wellbores of $4^1/_8$" to $4^3/_4$", which are too small for the smallest high torque or 250P series barrels.

When run in these smaller holes, the series 350 slimhole core barrel consistently recovers a maximum amount of core with a minimum of maintenance expense. The barrel can be run with rotary drillstrings, motors, or coiled tubing.

350P Operation

Like the high torque and 250P series barrels, the 350P core barrel is a straightforward, conventional core recovery tool. Slimhole core barrel operations follow those of the larger counterparts. Specifications for this tool are in Table 2-5.

350P Features

- Swivel assembly with double thrust bearings permits maximum free rotation for maintaining penetration rates and smooth core recovery. Also allows optimum mud flow through the core barrel to enhance bit hydraulics and maintain circulation.
- Mud-lubricated thrust bearing with specially-tempered ball bearings eliminates the need for surface lubricating devices. Ball bearings are unaffected by bottom hole temperature or pressure, enabling hot hole or high pressure applications.
- Pressure relief plug – dropped inside the drillstring – stops the flow of fluids through the center of the core barrel, permitting circulation of fluids through the barrel to thoroughly clean the inner tube and hole before coring. This also minimizes core

contamination and helps maintain circulation to the bit for proper cleaning and cooling.

- Outer tube sub with wear ribs reduces core barrel outer tube contact against the wellbore wall to help prevent differential sticking and premature core barrel wear, thus extending tool life.
- High quality, alloy steel outer tube with internal/ external flush joints provides high tensile strength for increased tool durability in a wide range of working loads.
- Quality steel inner tube with internal/external flush joints provides a temporary holding container for the core, protecting it from fluid contamination.
- Upper inner tube shoe provides a threaded sub that reduces thread damage between the inner tube and the inner tube shoe for longer thread life.
- Inner tube shoe (pilot type) stabilizes the lower end of the inner tube against the core bit, serving as a pilot to guide the core into the catcher and inner tube. This reduces core erosion and core jamming.
- Optional core barrel subs with stabilizer ribs are available in straight, right- or left-handed spiral ribs that serve to reinforce and stabilize the core barrel, reducing core barrel bending, core bit wobble and core blockage.
- Optional chrome-plated inner tube to replace standard steel inner tube is available in 30 foot lengths. It provides a harder surface for minimizing core jamming possibility and ensures smooth core recovery in hard, fractured formations.

Hydro-Lift™ Full Closure Catcher

By closing off the inner tube after coring is completed, the Baker Hughes INTEQ Hydro-Lift™ Full Closure Catcher (FCC) can efficiently recover core samples from soft, loose or unconsolidated formations. The Hydro-Lift design provides smooth, unobstructed core entry, eliminating the potential for damaging or jamming the core in the spring catcher. The 6¾" system's secondary spring-type, hard-faced core catcher, which is hidden behind the FCC sleeve while coring, also grips hard, consolidated cores securely, preventing core loss while tripping out of the hole. The FCC for the 8" barrel does not contain a hard-faced core catcher. See Figure 2-3.

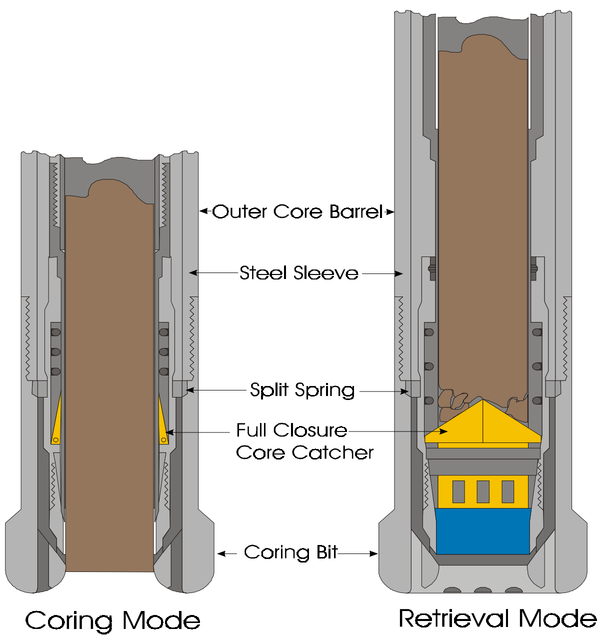


Figure 2-3 Hydro-Lift Full Closure Catcher

Tool Operation

Coring with the Hydro-Lift system proceeds much like conventional coring operations. Drilling fluid is initially circulated through the inner tube, ensuring that the coring assembly and hole are free from any fill before coring commences. A ball then is dropped, diverting the mud flow through the inner/outer barrel annulus to provide cooling and remove cuttings from the core bit. Coring proceeds as per established Hydro-Lift coring procedures in Chapter 5.

When coring is complete, a second ball is dropped, activating the Hydro-Lift system. Pressure from the drilling fluid forces the inner barrel to lift several inches. This action pulls the smooth, core-protecting sleeve out of the catcher assembly, allowing a heavy spring and cam to forcefully close the two full-closure shells. The spring-type catcher is also exposed. The dual catcher configuration will contain either soft or hard formation cores.

This system can be used with a variety of core bits and core shoes. However, CoreGard Low Invasion components are recommended to provide the most effective protection against core washing and drilling fluid contamination.

Specifications for the Hydro-Lift tool are listed in Table 2-6.

Table 2-6 Hydro-Lift Specifications

	6¾" × 4"		**8" × 4¾"**	
	Metric	U.S.	Metric	U.S.
Core Barrel Length	9, 18, 27 m	30, 60, 90 ft	9.1 m	30 ft
Outer Tube	6¾" × 5⅜"		8" × 6⅝"	
Inner Tube	4¾" × 4¼"		6¼" × 5½"	
Top Connection	4½ API FH		6⅝" API Reg.	
Bore	80.2 mm	3⁵⁄₃₂"	80.2 mm	3⁵⁄₃₂"
Steel Ball Sizes (2)	25.4 - 31.75 mm	1" to 1¼"	25.4 - 31.75 mm	1" to 1¼"
Recommended Bit Sizes	8" -8¾"		9" - 12¼"	

Table 2-6 Hydro-Lift Specifications (continued)

	6¾" × 4"		**8" × 4¾"**	
	Metric	U.S.	Metric	U.S.
Core Size OD	4"		4¾"	
Weight (gross)(30 ft Bbl)	1,100 kg	2,500 lbs	1,590 kg	3,500 lbs
Recommended Max. Pull	185,000 to 407,000 lbs		270,000 to 407,000 lbs	
Maximum Torque	18,850 N-m	13,900 ft-lbs	37,020 N-m	27,300 ft-lbs
Make Up Torque	8,200 N-m	11,100 ft-lbs	16,150 N-m	21,900 ft-lbs
Core Catcher	Full closure and hard faced spring type		Full closure	

Hydro-Lift Features & Benefits

- Clam shell closure by heavy-duty springs completely seals the inner tube, making core loss unlikely.
- Permits smooth entry of the core, eliminating damage at the catcher and preserving core quality.
- Secondary spring-type core catcher provides backup to the clam shell closure system in competent formations (6¾" × 4" system only).
- PVC liners and aluminum and fiberglass inner tubes provide easier handling and protection of core samples.
- A pressure relief plug permits the operator to circulate any required volume through the core barrel to ensure a clean hole and inner tube before coring begins.

The Hydro-Lift system offers significant advantages over other full closure catchers available in the industry.

Table 2-1 Mechanical Properties HT Outer Tubes

Core Barrel	Outer Tube Part Number	Make Up Torque (API)	Yield Torque (tested)	Tensile Yield	Buckling Load (Max Push)[1]	Collapse Pressure	Burst Pressure	Max. Dogleg Severity[2]
4¾" × 2⅝" HT 10	903-001-520	13,558 N-m 10,000 ft-lbs	30,000 N-m 22,100 ft-lbs	1,300 kN 292,000 lbs	297 kN (30 ft) 66,800 lbs 74 kN (60 ft) 16,700 lbs	1,420 bar 20,200 psi	1,582 bar 22,500 psi	4.7°/10 m (non-rotating) 2.1°/10 m (rotating)
6¾" × 4" HT 30	903-001-374	40,675 N-m 30,000 ft-lbs	75,000 N-m 55,300 ft-lbs	2,540 kN 571,000 lbs	1,190 kN (30 ft) 267,500 lbs 297 kN (60 ft) 66,800 lbs	1,380 bar 19,600	1,530 bar 21,800 psi	4.2°/10 m (non-rotating) 1.7°/10 m (rotating)
8" × 5¼" HT 40	903-001-418	54,223 N-m 40,000 ft-lbs	88,000 N-m 64,900 ft-lbs	2,950 kN 663,000 lbs	2,064 kN (30 ft) 463,900 lbs 516 kN (60 ft) 115,900 lbs	1,181 bar 16,800 psi	1,287 bar 18,300 psi	4.0°/10 m (non-rotating) 1.4°/10 m (rotating)

Table 2-2 Mechanical Properties 250P/ 350P Outer Tube

Core Barrel	Outer Tube Part Number	Make Up Torque (API)	Yield Torque	Tensile Yield (Max Pull)	Buckling Load (Max Push)[1]	Collapse Pressure	Burst Pressure	Max. Dogleg Severity[2]
3½" × 1¾" 350 P	015-164-154	3,150 N-m 2,323 ft-lbs	5,553 N-m 4,095 ft-lbs	740 kN 166,367 lbs	92 kN (30 ft) 20,683 lbs 23 kN (60 ft) 5,170 lbs	1,441 bar 20,895 psi	2,000 bar 29,000 psi	3.2°/10 m (non-rotating) 1.6°/10 m (rotating)
4¾" × 2⅝" 250 P	015-060-031	6,400 N-m 4,700 ft-lbs	11,870 N-m 8,752 ft-lbs	1,031 kN 232,000 lbs	297 kN (30 ft) 66,800 lbs 74 kN (60 ft) 16,700 lbs	1,420 bar 20,200 psi	1,582 bar 22,500 psi	4.4°/10 m (non-rotating) 1.9°/10 m (rotating)
6¾" × 4" 250 P	015-060-072	15,000 N-m 11,100 ft-lbs	28,000 N-m 20,632 ft-lbs	1,811 kN 407,000 lbs	1,190 kN (30 ft) 267,500 lbs 297 kN (60 ft) 66,800 lbs	1,380 bar 19,600	1,530 bar 21,800 psi	4.8°/10 m (non-rotating) 1.4°/10 m (rotating)
8" × 5¼" 250 P	015-061-021	29,700 N-m 21,900 ft-lbs	55,000 N-m 40,600 ft-lbs	2,678 kN 602,000 lbs	2,064 kN (30 ft) 463,900 lbs 516 kN (60 ft) 115,900 lbs	1,181 bar 16,800 psi	1,287 bar 18,300 psi	2.4°/10 m (non-rotating) 1.2°/10 m (rotating)

[1] Maximum push force at 30 respectively 60 ft unstabilized length. Actual push force also limited by bit strength!

[2] Only valid with recommended make-up torque.

Table 2-3 Mechanical Properties Inner Tubes

Core Barrel	Inner Tube Part Number	Make Up Torque (API)	Yield Torque	Tensile Yield (Max Pull)	Buckling Load (Max Push)[1]	Collapse Pressure	Burst Pressure
3½" × 1¾" 350 P	015-065-154 Steel	1,029 N-m 760 ft-lbs	1,815 N-m 1,340 ft-lbs	339 kN 76,214 lbs	19.4 kN (30 ft) 4,364 lbs 4.8 kN (60 ft) 1,091 lbs	1,430 bar 20,735 psi	1,597 bar 23,157 psi
	903-001-405 Al: 160 N/mm² 23,000 psi	230 N-m 197 ft-lbs	382 N-m 282 ft-lbs	71.5 kN 16,746 lbs	6.47 kN (30 ft) 1,455 lbs 1.62 kN (60 ft) 364 lbs	299 bar 4,336 psi	333 bar 4,829 psi
	Al: 275 N/mm² 40,000 psi	394 N-m 291 ft-lbs	657 N-m 485 ft-lbs	123 kN 27,653 lbs		519 bar 7,526 psi	580 bar 8,410 psi

Table 2-2 Mechanical Properties Inner Tubes (continued)

Core Barrel	Inner Tube Part Number	Make Up Torque (API)	Yield Torque	Tensile Yield (Max Pull)	Buckling Load (Max Push)[1]	Collapse Pressure	Burst Pressure
4¾" × 2⅝" 250P/HT 10	015-065-030 Steel	1,500 N-m 1,100 ft-lbs	2,856 N-m 2,107 ft-lbs	440 kN 99,000 lbs	59 kN (30 ft) 13,200 lbs 15 kN (60 ft) 3,300 lbs	1,000 bar 14,700 psi	1,100 bar 15,800 psi
	015-065-031 Al: 275 N/mm^2 40,000 psi	540 N-m 400 ft-lbs	1,026 N-m 757 ft-lbs	160 kN 36,000 lbs	19.5 kN (30 ft) 4,400 lbs 4.9 kN (60 ft) 1,100 lbs	370 bar 5,300 psi	400 bar 5,700 psi
	Al: 160 N/mm^2 23,000 psi	390 N-m 288 ft-lbs	650 N-m 480 ft-lbs	112 kN 25,180 lbs		235 bar 3,408 psi	278 bar 4,034 psi
	903-000-765 Fibreglass Steel couplers: 350 N/mm^2	789 N-m 582 ft-lbs	1,315 N-m 970 ft-lbs	65 kN (20°C) 14,613 lbs 59 kN (60°C) 13,264 lbs	2.2 kN (30 ft) 495 lbs 0.54 kN (60 ft) 121 lbs	50 bar (20°C) 725 psi 43 bar (60°C) 624 psi	

Table 2-2 Mechanical Properties Inner Tubes (continued)

Core Barrel	Inner Tube Part Number	Make Up Torque (API)	Yield Torque	Tensile Yield (Max Pull)	Buckling Load (Max Push)[1]	Collapse Pressure	Burst Pressure
6¾" × 4" 250 P/ HT 30	015-065-063 Steel	3,100 N-m 2,300 ft-lbs	5,900 N-m 4,350 ft-lbs	623 kN 140,000 lbs	175 kN (30 ft) 39,400 lbs 43 kN (60 ft) 9,800 lbs	745 bar 10,600 psi	790 bar 11,200 psi
	015-065-140 Al: 275 N/mm² 40,000 psi	1,100 Nm 800 ft-lbs	2,150 Nm 1,590 ft-lbs	227 kN 51,000 lbs	60 kN (30 ft) 13,400 lbs 14.6 kN (60 ft) 3,300 lbs	275 bar 3,900 psi	290 bar 4,100 psi
	Al: 160 N/mm² 23,000 psi	800 N-m 590 ft-lbs	1,330 N-m 981 ft-lbs	159 KN 35,746 lbs		167 bar 2,422 psi	188 bar 2,730 psi
	903-000-766 Fibreglass Steel couplers: 350 N/mm²	1,630 N-m 1,202 ft-lbs	2,717 N-m 2,404 ft-lbs	120 kN (20°C) 26,978 lbs 110 kN (60°C) 24,730 lbs	8.6 kN (30 ft) 1,933 lbs 2.2 kN (60 ft) 495 lbs	40 bar (20°C) 580 psi 34.4 bar (60°C) 499 psi	

Table 2-2 Mechanical Properties Inner Tubes (continued)

Core Barrel	Inner Tube Part Number	Make Up Torque (API)	Yield Torque	Tensile Yield (Max Pull)	Buckling Load (Max Push)[1]	Collapse Pressure	Burst Pressure
8" × 5¼" 250 P/ HT 40	015-065-071 Steel	8,400 N-m 6,200 ft-lbs	15,750 N-m 11,615 ft-lbs	1,230 kN 276,000 lbs	590 kN (30 ft) 131,800 lbs 146 kN (60 ft) 32,900 lbs	844 bar 12,000 psi	900 bar 12,800 psi
	015-065-075 Al: 275 N/mm² 40,000 psi	2,980 N-m 2,200 ft-lbs	5,764 N-m 4,251 ft-lbs	476 kN 107,000 lbs	195 kN (30 ft) 43,900 lbs 48.5 kN (60 ft) 10,900 lbs	302 bar 4,300 psi	323 bar 4,600 psi
	Al: 160 N/mm² 23,000 psi	2,135 N-m 1,575 ft-lbs	3,559 N-m 2,625 ft-lbs	314 kN 70,594 lbs		190 bar 2,755 psi	218 bar 3,164 psi
	015-388-133 Fibreglass 6.2 mm thick St. cpl : 350 N/mm²	4,352 N-m 3,209 ft-lbs	7,253 N-m 5,349 ft-lbs		17.6 kN (30 ft) 3,957 lbs 4.4 kN (60 ft) 989 lbs	21 bar (20°C) 305 psi 18 bar (60°C) 262 psi	
	903-000-768 Fibreglass 8 mm thick St. cpl : 350 N/mm²	4,352 N-m 3,209 ft-lbs	7,253 N-m 5,349 ft-lbs	200 kN (20°C) 44,964 lbs 180 kN (60°C) 40,468 lbs	24.5 kN (30 ft) 5,508 lbs 6.1 kN (60 ft) 1,371 lbs	45 bar (20°C) 653 psi 38.7 bar (60°C) 561 psi	

CoreDrill™ Coring-While-Drilling

Most of the expense associated with conventional coring operations is the rig time needed to trip the coring assembly in and out of the well. This applies particularly in exploration wells where core point determination is difficult or where reservoir sections are separated by long intervals.

Baker Hughes INTEQ addresses this problem by offering a drilling tool that incorporates the ability to drill ahead and core with the same bit without tripping the bottom hole assembly. This allows the operator to obtain cores in wells where coring has been traditionally excluded because of cost. CoreDrill is a good alternative to sidewall coring.

The CoreDrill bit, Figure 2-4, is used both to drill ahead and to core. The drill plug is wirelined in and out of the BHA, converting the bit from the coring mode to the drilling mode.

Figure 2-4 CoreDrill Core Bit with Insert

Specifications for CoreDrill Model 1a and Model 2 are listed in Table 2-7.

Table 2-7 CoreDrill Specifications

CoreDrill Specifications	Model 1	Navi-Gamma
Sizes	$6^1/_4$" × 2"	$6^1/_2$" × 2"
Core Barrel Length	15 - 120 ft	30 ft
Top SubConnection	NC50 ($4^1/_2$ IF)	NC50 ($4^1/_2$ IF)
Recommended Hole Sizes	$7^7/_8$" - $8^3/_4$"	$7^7/_8$" - $8^3/_4$"
Core Diameter	2"	2"
Weight: Inner Assembly Coring Inner Assembly Drilling	 180 lbs 750 lbs	 180 lbs 750 lbs
Outer Assembly: Make Up Torque Yield Torque Tensile Yield	 15,800 ft-lbs 21,250 ft-lbs 732.6 k-lbs	 33,000 ft-lbs 60,000 ft-lbs 685 k-lbs
Inner Assembly - Coring Steel/Aluminum Make Up Torque Yield Torque Tensile Yield	 440 ft-lbs 737 ft-lbs 38 k-lbs	 440 ft-lbs 740 ft-lbs 39 k-lbs
Inner Assembly - Drilling Make Up Torque Yield Torque Tensile Yield	 730 ft-lbs 1,106 ft-lbs 67.4 k-lbs	 1,000 ft-lbs 1,650 ft-lbs 96 k-lbs
Operating Parameters: Coring WOB RPM Flow Rate	 2,000 - 20,000 lbs 40 - 120 150 - 300 gal/min.	 2,000 - 30,000 lbs 40 - 150 150 - 300 gal/min.
Operating Parameters: Drilling WOB RPM Flow Rate	 2,000 - 20,000 lbs 60 - 120 150 - 400 gal/min.	 2,000 - 30,000 lbs 60 - 120 150 - 550 gal/ min.
Wireline Trip Speed	200 - 400 ft/min.	200 - 400 ft/min.
Minimum Drift Diameter	2.688"	2.688"

CoreDrill Model 1a

The CoreDrill™ system provides the operator with the flexibility to core or drill ahead as desired. Inner tube assemblies for coring and drilling are conveyed in and out of the hole through conventional drillstrings via wireline. The CoreDrill system provides the largest drilling diameter core that can be retrieved through conventional tubulars, and is recognized as the first petroleum industry coring system to offer the drilling feature.

CoreDrill Features/Benefits

- High torque connections on the outer barrel
- Two-inch diameter core can be retrieved through conventional oilfield tubulars
- Anti-whirl core bits improve core quality and coring efficiency
- Provides a cost-effective alternative to sidewall coring
- Can core long sections without multiple trips
- Can core highly-pressured formations where trips present safety concern
- Cores formations with multiple zones of interest and where sidewall cores are not practical
- Eliminates need to change BHA to drill rat hole after coring
- Minimizes impact of coring program on drilling days
- Cores highly fractured formations where jamming is common
- Cores in areas where fixed cutter drill bits are commonly used and zones of interest at core point are difficult to determine
- Retrieves coal bed methane core to surface in the shortest amount of time
- Circulates and reciprocates while retrieving core

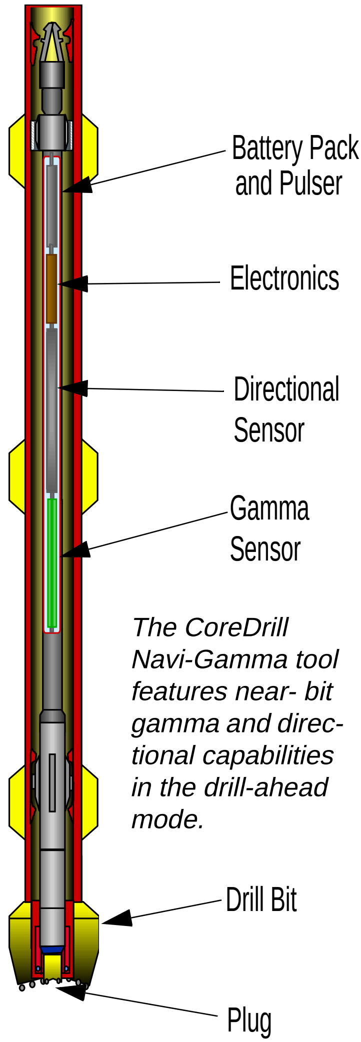
CoreDrill Navi-Gamma Tool (Model 2)

The new CoreDrill Navi-Gamma tool incorporates all of the above features with the addition of the logging-while-drilling capabilities:

- Near-bit gamma tool
- Inclination and directional sensors.

These features allow the operator to select coring points without having to rely upon drill break indications at the surface.

The CoreDrill Navi-Gamma tool, Figure 2-5, combines proven gamma formation evaluation and near-bit directional technology with the drill-ahead and coring capabilities of the CoreDrill bit.



The CoreDrill Navi-Gamma tool features near- bit gamma and direc-tional capabilities in the drill-ahead mode.

Figure 2-5 CoreDrill Navi-Gamma Tool

Motor Coring

Motor coring can maximize performance in horizontal or deviated wells, or when coring in hard, fracture-prone formations. In motor coring, the core barrel is run below a Positive Displacement Motor (PDM). A PDM is powered by the flow of drilling fluid through the motor. A wide range of motor options can satisfy coring requirements in many situations.

A downhole motor combined with a natural or an impregnated diamond core bit can:

- Torsionally decouple the BHA from the drillstring
- Operate at high RPMs without causing the drillstring to whirl asymmetrically
- Minimize lateral vibration of the BHA.

A PDM used in combination with polycrystalline diamond compact (PDC) core bits can:

- Deliver smooth torque to the core bit, reducing torque spikes during rotary coring
- Reduce WOB and the likelihood of bit or WOB induced fracturing
- Increase RPM and torque at the bit to offset the lower WOB
- Maintain ROP.

Certain coring situations require that a thruster be placed on top of the PDM to deliver downward force to the BHA. A thruster can:

- Generate and maintain constant downhole WOB
- Maintain smooth WOB
- Alleviate bit bounce and maintain BHA stability
- Deliver the needed RPM and constant WOB to the bit.

The motor thruster combination often increases coring performance and reduces the potential for jamming.

Drop Ball Sub and Downhole Activated Flow Diverter

When using a positive displacement motor, diversion of fluid flow to flush the inner tube can be achieved only by running a drop ball sub or downhole activated flow diverter (DAFD) fitted between the motor and the core barrel. Either device allows flushing of the inner barrel to remove fill prior to coring.

With either device, increased flow rate after flushing drops a ball into its seat and diverts flow between the inner and outer barrels so that coring can commence. Both devices are discussed in more detail in Chapter 5.

Integral Coring Motor System

The 6¾" × 4" × 30/60 ft Integral Coring Motor 1 (ICM 1) coring system shown in Figure 2-6 is a positive displacement motor combined with an integral 6¾" × 4" core barrel. The motor transmits rotary power to the drill bit independently of drillstring rotation. This offers a significant advantage in horizontal coring operations as the constant torque and controllable RPM achieves higher penetration rates than rotary drilling operations. The ICM 1 features a non-rotating inner tube, minimizing the potential for core jamming and increasing core recovery and quality, especially in unconsolidated formations. The system also features an integral drop ball sub that facilitates flushing of the inner barrel when circulating off-bottom. Specifications for the ICM 1 are provided in Table 2-8.

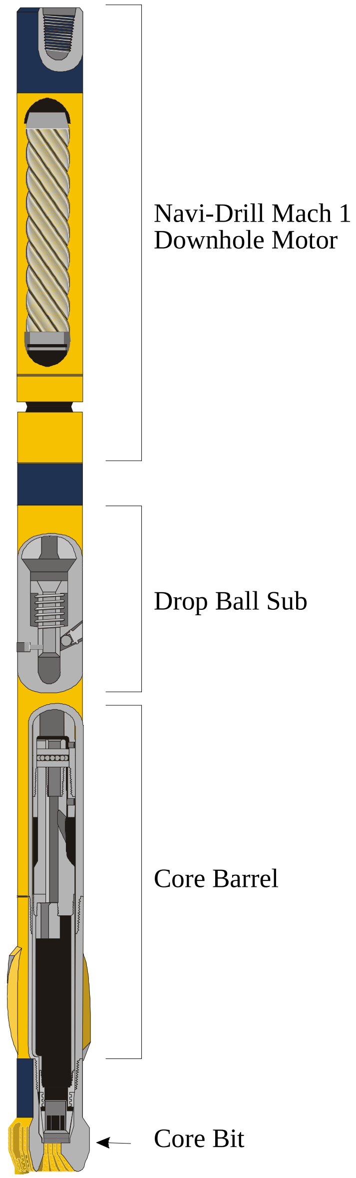


Figure 2-6 Navi-Drill w/ Core Barrel & Drop-Ball Sub

Table 2-8 ICM Technical Specifications

Specifications for the Integral Coring Motor 1 System	
Outer Tube	$6^3/_4$"
Core Diameter	4"
Core Length	30/60 ft
Top Connection	$4^1/_2$" reg.
Pump Rate	700-1,400 L/min (85-370 gpm)
Maximum Motor Pressure	40 bar/580 psi
Bit Speed Range	90 to 180 rpm
Maximum Torque	3,500 N-m/2,630 ft-lbs
Horse Power Range	33-66 kW/44-90 hp
Maximum Operating Temperature	140°C/ 88°F
Circulation Rate Flushing the Inner Tube	800 L/min / 211 gpm
Circulation Rate to Activate the Drop Ball	1,400 L/min / 370 gpm
Inner Tube	Steel, Fiberglass, or Aluminum

With its non-rotating inner tube, the ICM 1 motor is suitable to meet all requirements for core orientation:

- Continuous scribe line
- No spiraling scribe lines
- No interruption of coring for surveys
- One wireline single shot survey required – alternative continuous hole data by MWD equipment possible
- No loss in data due to damage of the survey tool during coring operation
- Ability to flush the inner tube before coring
- Inner tube shoe with alternative tungsten carbide and diamond scribe knifes available.

Modular Coring Systems

Deviated and long reach wells in fracture-prone formations present a challenge to coring operations. Often, the core quality suffers due to:

- Torsional vibration from the rotating drillstring
- Uneven torque on bit
- Uneven weight on bit (WOB)
- Rotation of the inner tube.

Baker Hughes INTEQ offers a Modular Coring System (MCS) to reduce the risks of coring in fractured formations by employing a variety of design features. The MCS incorporates:

- Integrated Coring Motor – the motor stator drives the outer barrel and rotates the core bit
- An inner tube that is directly connected to the drillstring via the motor's stator – the inner tube cannot rotate as on standard barrels
- Standard inner tube stabilization
- A sealed, oil lubricated double thrust, double radial bearing swivel assembly
- An integrated Core Jam Indicator
- An inner tube adjustment system – no shims are necessary.

Due to these features, the MCS offers the following advantages:

- Improved core quality since the core is not affected by rotating inner tubes
- Smooth and constant torque from the coring motor to minimize torque peaks
- Easy handling on rig floor due to the inner tube adjustment system

- A high level of tool safety due to an improved thread design and inner tube stabilization
- A constant WOB when used in combination with the optional thruster.

Specifications for the MCS are listed in Table 2-9.

Table 2-9 Modular Coring System Specifications

Item	$3^{3}/_{4}$" × 2"		$4^{3}/_{4}$" × $2^{5}/_{8}$"	
	Metric	U.S.	Metric	U.S.
Hole Size	104.78 - 120.65 mm	$4^{1}/_{8}$"- $4^{3}/_{4}$"	149.22 - 158.75 mm	$5^{7}/_{8}$"- $6^{1}/_{4}$"
Core Barrel Section Length	4.57 m	15 ft	4.57 m	15 ft
Max. Core Barrel Length	27.44 m	90 ft	36.59 m	120 ft
Outer Tube O.D.	96 mm	3.78"	120 mm	4.72"
Outer Tube I.D.	75 mm	2.95"	100 mm	3.93"
Outer Tube Wall Thickness	10.5 mm	0.41"	10 mm	0.39"
Inner Tube O.D.	65 mm	2.56"	82 mm	3.22"
Inner Tube I.D.	55 mm	2.17"	72 mm	2.83"
Inner Tube Wall Thickness	5 mm	0.20"	5 mm	0.20"
Core Diameter	50.8 mm	2"	66.6 mm	$2^{5}/_{8}$"
Top Connection	NC 26 $2^{3}/_{8}$" IF $2^{3}/_{8}$" reg	Rotary Rotary Motor	NC 35 $3^{3}/_{4}$" Reg	Rotary Motor
Maximum Pull	800 kN	180,000 lbs	1,400 kN	314,000 lbs
Make Up Torque	6,500 N-m	4,800 ft-lbs	13,600 N-m	10,000 ft-lbs
Max. Temperature Rating of Aluminum Inner Tube	200°C	400°F	200°C	400°F

Table 2-9 Modular Coring System Specifications (continued)

Item	$3^3/_4$" × 2"		$4^3/_4$" × $2^5/_8$"	
	Metric	U.S.	Metric	U.S.
Flow Rate	250 - 500 L/min	70 - 130 gpm	300 - 680 L/min	80 - 180 gpm
Bit Speed	120 - 240 rpm	12 0- 240 rpm	100 - 230 rpm	100 - 230 rpm
Weight On Bit	14 -50 kN	1.5 - 5 tons	30 - 80 kN	3 - 8 tons
Pressure Drop (Annulus between outer and inner tube)	1 bar/m	4.0 psi/ft	1.5 bar/m	6.4 psi/ft
Motor Type	Mach 1C		Mach 1C	
Operating Torque	1,200 N-m	890 ft-lbs	1,600 N-m	1,180 ft-lbs
Power Output	43 kW	58 hp	50 kW	67 hp
Flow Rate	250 - 500 L/min	70 - 130 gpm	300 - 900 L/min	80 - 240 gpm

Horizontal Coring Systems

Baker Hughes INTEQ offers various coring systems to meet the demands of coring in horizontal wells. These include systems for long and medium range applications and motor coring options.

Long Radius Coring System

The long radius coring systems employ conventional high torque barrels associated with vertical coring operations. Long radius is considered to be applications in which the wellbore coring radius is greater than 715 feet (218 m).

Medium Radius Coring System

The medium radius system is designed for coring in 286 to 715 foot (87 to 218 m) wellbore radius applications, using modified HT or Coremaster series high torque core barrels in 30 or 60 foot (9 or 18 m) configurations. The barrels are fully stabilized with specially designed, straight blade stabilizers. Core barrel options are listed in Table 2-10.

Table 2-10 Medium Radius Core Barrel Options

Barrel Size	HT Series	Coremaster Series	P250
$4^{1}/_{8}$" × $2^{1}/_{8}$"			X
$4^{3}/_{4}$" × $2^{5}/_{8}$"	X		X
$4^{3}/_{4}$" × $2^{1}/_{8}$"		X	
$5^{3}/_{4}$" × $3^{1}/_{2}$"			X
$6^{1}/_{4}$" × 4"			X
$6^{3}/_{4}$" × 4"	X	X	X
8" × $5^{1}/_{4}$"	X		X

The core barrel incorporates a bit end bearing to centralize the inner tube in the core bit throat.

Oriented Coring

Orientation services maintain a record of the core's original orientation relative to its native formation. See Figure 2-7. Oriented core samples gather reliable information on:

- Fracture direction
- Formation dip and strike
- Formation anisotropy
- Stress orientation
- Direction of maximum permeability.

Changing a core barrel assembly from standard to oriented coring is simple and can be done in the field with the addition of a few parts. Additional drillstring equipment includes a non-magnetic drill collar, a survey instrument, and non-magnetic extension equipment.

Two complete service systems and survey equipment lines are offered: the Electronic Magnetic Survey (EMS) and Modular Magnetic Tool (MMT).

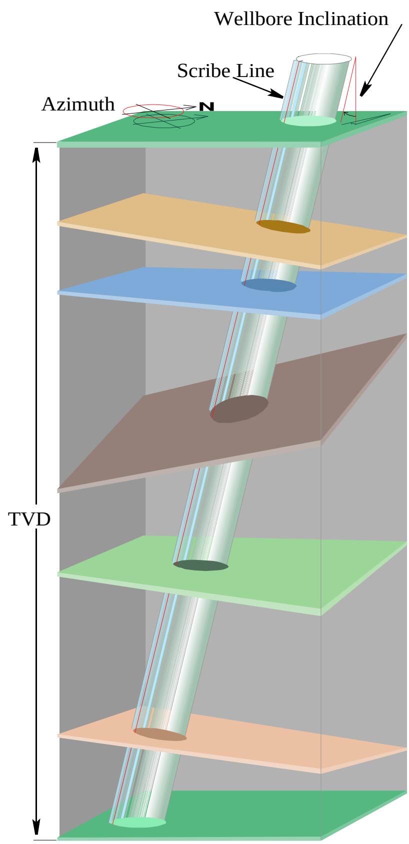


Figure 2-7 Oriented Coring

Application

When a core is oriented, the hole inclination and azimuth are recorded in addition to the directional orientation of a reference mark on the core itself. Three knives continuously scribe the core to provide maximum reliability in identifying the reference marks (see Figure 2-8). A telescopic alignment instrument is also used to accurately align the reference knife and the survey instrument.

The following information is needed to aid in the selection of the appropriate survey tool:

- Core barrel diameter
- Hole diameter, depth, and angle
- Smallest drillstring I.D.
- Bottomhole temperature
- Type and weight of drilling fluid
- Rock and formation characteristics.

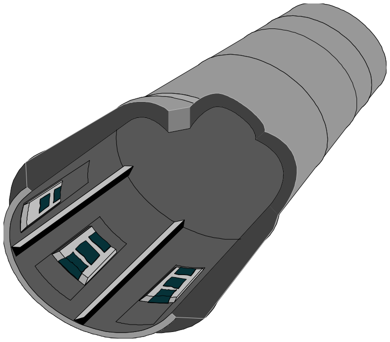


Figure 2-8 Oriented Core Catcher with Scribing Knives

Survey Tools

Electronic Magnetic Survey Tool

The Electronic Magnetic Surveyor (EMS) tool is uniquely suited to oriented coring. Data acquisition time can be programmed by the operator prior to the survey to compensate for anticipated drilling conditions. The probe setup allows tool face data and, by mechanical connection to the inner barrel, core knife scribe mark data to be taken continuously during the coring process.

EMS coring does not have to be stopped to take survey data. This minimizes core breakage and scribe mark spiraling, reduces core jamming, and improves overall coring and orientation efficiency. It also reduces the chances of getting stuck in hole.

Downhole data are downloaded from the EMS tool after coring is completed. The information is edited by the operator, saving only those shots which satisfy stringent editing criteria. A final tool face report is prepared, identifying the well, core, tool, and all other pertinent data. The report lists tool face orientation vs. depth, usually at every foot, as well as full survey information at the start and end of the coring interval. The tool must be checked prior to resumption of coring.

The EMS tool, Figure 2-9, is compatible with standard coring tools. It uses precise, non-magnetic rotating centralizers to fully isolate the surveying assembly from the effects of rotating drill collars. These centralizers protect the EMS tool and improve the integrity of downhole data as well.

Orientation equipment may be attached to the instrument and run with the core barrel. It may also be fitted with a wireline attachment and mule shoe assembly so it can be run with the core barrel and retrieved before the barrel is pulled. The mule shoe assembly is recommended for use in "hot" holes. EMS equipment exposure is limited to 4 hours at 500°F with the EMS tool fitted with a heat shield.

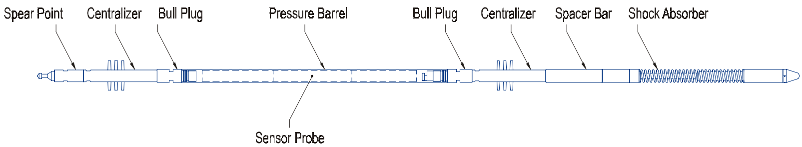


Figure 2-9 The Electronic Magnetic Survey Tool

Features of the EMS coring system include:

- Continuous scribe line
- No interruption of coring for surveys
- One wire line single shot survey required
- No loss in data due to damage of the survey tool during coring operation
- Ability to flush the inner tube before coring
- Inner tube shoe with alternative tungsten carbide or optional diamond scribe knives available.

Specifications for EMS are listed in Table 2-11.

Table 2-11 EMS Tool Specifications

Item	Specification
Nominal Diameter	1.75" (2.00" with heat shield)
Temperature Rating	125°C/ 257°F (260°C/ 500°F with heat shield)
Cycles Per Second	64
Tool Capacity	1,023 shots
Delay Mechanism	1 - 553 minutes
Standard Battery Type	alkali
Standard Application	single or tandem mode tripping with tool in place
Accelerometers (3)	measurement inclination
Magnetometers (3)	measure direction of true north

Positive Latch

The positive latch is a modified male/female mule shoe assembly used to positively anchor the survey probe to the inner core barrel. This mechanism, an alternative to the standard oriented coring mechanism, fixes the orientation probe into the positive latch on the top of the inner barrel.

Positive latch operational characteristics are:

- The probe remains fixed to the inner barrel and cannot unseat in high angle or horizontal wells. Consequently, it is recommended for horizontal-well oriented-coring applications
- In rough coring conditions – where vibrations are common – the positive latch keeps the male mule shoe fixed to the female mule shoe, negating the chances of disorientation
- The inner barrel can vent through a pressure relief valve type mechanism in the positive latch. This relieves pressure build-up from fluids trapped in the inner barrel during core entry. Inner barrel venting

is not available in the standard oriented coring system.

The tool cannot be run in hole when fitted with a positive latch. Positive latch inability to load the survey tool by wireline must be weighed against the ability to retrieve it by wireline once an aluminum pin in the latch is sheared.

Modular Magnetic Tool

The Modular Magnetic Tool (MMT) is a magnetic directional tool that can be used as a wireline steering tool, an electronic memory single shot, or multi-shot survey tool for oriented coring. See Figure 2-10.

The MMT uses a triaxial silicon-oil-filled force balance accelerometer (TRAX™). The TRAX accelerometer is a robust sensor that has high temperature, vibration, and shock resistance. The MMT is run inside of a non-magnetic drill collar. Data are transmitted real-time to the surface via wireline. In short radius operations, the MMT can accommodate a radius of 35 feet.

The surface system consists of a laptop computer capable of running Windows™, an interface power supply, and an intrinsically safe Remote Drillers Dial (RDD). The downhole package features a programmable instrument that can store 3,500 to 4,500 shots, depending on the mode of operation.

MMT Features

The general operating characteristics of MMT are summarized in the following:

- Can be used for steering and single-shot and multi-shot surveys
- Has robust triaxial silicon-oil-filled force balance accelerometer (TRAX™), high temperature rating (150°C/302°F) and is tolerant of vibration and shock
- Can be used in under-balanced and air drilling operations
- Can be used in geothermal applications
- Produces real time data transfer via wireline
- Small O.D. ($1^3/_8$")
- Ideal for short radius applications
- Powerful user friendly software package

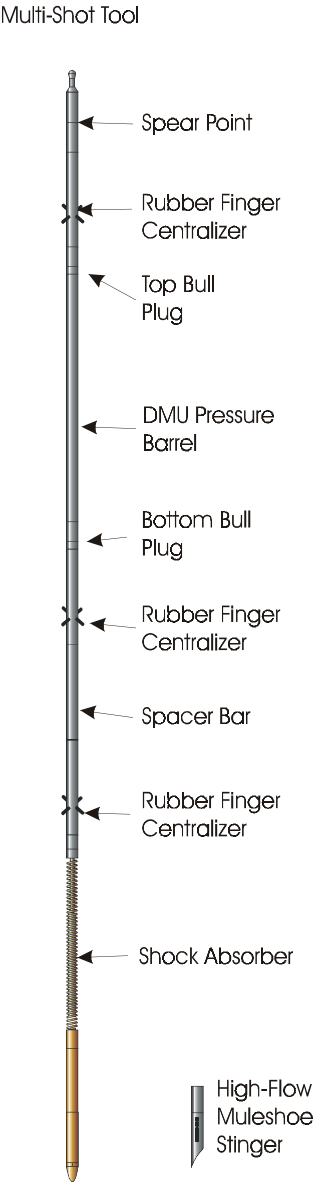


Figure 2-10 Modular Magnetic Tool

- Intrinsically safe Remote Driller Display (RDD)
- 4,800 shot memory capacity

Specifications for the MMT, Figure 2-10, are listed in Table 2-12.

Table 2-12 MMT Specifications

General Tool Specifications for the Modular Magnetics Tool	
Tool OD	$1^3/_8$" rated to 150°C (302°C) $1^3/_4$" heat shield rated to 285°C (545°C) to 8 hrs
Instrument Barrel Length	Steering Applications - 35" Memory Applications - 46"
Operating Mode	User defined - Steering Tool, Multi-Shot, Single-Shot, Core Orientation
Sensors	TRAX silicon oil-damped accelerometer High accuracy triaxial magnetometers
Parameters Sampled	Gx, Gy, Gz, Bx, By, Bz, temperature
Data Outputs	Sensor outputs (raw or processed) hole azimuth, inclination, magnetic toolface, gravity toolface, magnetic field strength, magnetic dip angle, total gravity, downhole temperature
Measurement	**Resolution**
Inclination Aximuth Toolface	0.01° 0.10° 0.01°
Power Source	6 AAA alkaline or 2 AA lithium battery cells
Battery Life	Up to 300 hours (lithium) Up to 150 hours (alkaline)
Surface Equipment	IBM portable PC
Minimum Shot Interval	10 seconds
Maximum Delay Time	200 hours

CoreGard™ Low Invasion Coring System

Filtrate Invasion

Filtrate invasion of the core by drilling fluid can make analyses of water saturation, effective permeability, and residual oil saturation highly speculative and unreliable. As major reservoir production decisions are dependent upon information gained from these analyses, the need for unflushed and uninvaded core samples becomes of paramount importance.

Experience has shown that filtrate invasion occurs in three ways:

- Dynamic invasion ahead of the bit

  This can be significant at low coring rates when the vertical flow velocity of the filtrate in the core exceeds the bit velocity.

- Dynamic invasion at the bit face and in the bit throat

  This occurs in all coring operations, but will be more severe with low coring rates and/or high filtrate loss fluids.

- Static invasion inside the inner core barrel

  Along with counter-current distribution, static invasion can affect core material while in the inner barrel.

Baker Hughes INTEQ’s CoreGard low invasion coring system is designed to minimize filtrate invasion by employing specially designed core bits, extended pilot shoes, and custom-formulated drilling fluids.

Bit Design

Low invasion CoreGard core bits with polycrystalline diamond compact (PDC) cutters (see Figure 2-11) are designed with the following features:

- Aggressive cutter design
- Parabolic crown profile
- No throat gage diamonds
- Core gage set with PDC cutters mounted on the bit nose
- Reduced I.D. gage length
- Face discharge ports.

These bits cut deeply into the formation ahead of the dynamic filtration zone, and direct most of the circulating fluid flow away from the forming column of core. The designs also maintain the integrity of the protective filter cake on the core.

Figure 2-11 Low Invasion CoreGard Core Bit

Inner Tube Pilot Shoe

An extended pilot on the lower shoe positions the inner core barrel closer to the bit face. This reduces the area in the bit throat in which dynamic filtrate invasion can affect the core.

CoreGard Features

- The parabolic crown profile of the core bit reduces the area where invasion ahead of the bit can invade the formation.
- Large-diameter PDC cutters provide faster penetration rates to get core into the inner tube and away from areas of dynamic fluid movement.
- Reduced cutter density provides greater cutter penetration at the same bit weight, producing higher penetration rates.
- Elimination of I.D. gage diamonds prevents the cutting and wiping action that can remove or damage the protecting filter cake on the core.
- Face discharge ports direct 80-90% of fluid flow out the face of the core bit away from the forming column of core.
- Extended pilot shoe increases the physical length of the lower shoe, further reducing the contact of drilling fluid with the core.
- Custom-designed drilling fluid rapidly forms an impermeable filtercake protecting the core from further filtrate invasion.

CoreGard techniques and equipment are adaptable to all of Baker Hughes INTEQ's fleet of coring equipment, and are highly recommended for Hydro-Lift™, Gel Coring℠ and the In Situ Data Gathering System (see Hydro-Lift™ Full Closure Catcher on page 2-15, Gel Coring℠ on page 2-57 and In Situ Data Gathering Pressure Coring on page 2-62).

Drilling Fluids Additives

Drilling Fluids Bridging Solids

Custom-formulated drilling fluids employ sized calcium carbonate with controlled particle size distribution to provide bridging solids. The particles range from colloidal to 192 microns in size and quickly form a protective, impermeable filter cake on the column of core. This protects the core from filtrate invasion, both in the throat of the bit and in the inner barrel.

Tracers

Even though the best low invasion coring system may be employed for a coring project, some fluid filtrate invasion into the core is inevitable. As this results in some flushing of the native pore fluids, special procedures must be employed to differentiate between these fluids and those that the coring process might have introduced into the core.

The most effective way to differentiate between native and introduced fluids is to add a tracer to the drilling fluid before coring is undertaken. Tracers can be detected in the extracted core in subsequent laboratory analyses.

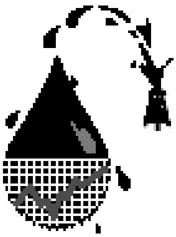
The successful application of a tracer depends upon three things:

1. The tracer must be added – generally at the rigsite – to the drilling fluid system in such a way as to become uniformly dispersed throughout the entire fluid system.
2. Samples of the fluid must be taken before, during, and after the core is cut to generate a baseline tracer concentration for later comparison.
3. Samples of the core must be taken, isolated, and properly preserved for extraction and analysis.

Laboratory procedures are readily available for tracer analysis and the subsequent determination of filtrate concentration. These include traditional extraction techniques and sophisticated analytical procedures involving various types of chromatographs and mass spectrophotometers.

ISOTAG

The Isotag Marking System® can determine with a high degree of accuracy and precession if dilution has occurred in any liquids. The system is ideally suited to determine what percentage of downhole formation samples is due to mud filtrate versus formation crude. Whether analyzing cores or wireline formation samples, a better estimate of water and oil saturation is critically important. The Isotag system is used to tag the mud in the parts per million range with environmentally friendly hydrocarbon compounds that do not affect the mud in any way. For example:



- Oil Based Mud Systems - We can determine with a very high degree of accuracy (+/- 2%) what the percentage of the oil in the sample is due to oil based mud filtrate.
- Water Based Mud Systems - we can also determine with the same degree of accuracy what percentage of the water in the sample is from water based mud filtrate.

This will allow the Manager the ability to calculate a more precise oil and water saturation for the hydrocarbon resources derived from more precise data can allow for better economic decisions to be made on large capital projects.

DFE-1503 Water-Base Mud

Product Description

DFE-1503 is a molecular taggant used to tag (or mark) water-base drilling fluids for quantification purposes. This technology was developed by ISOTAG LLP and is exclusively licensed by Baker Hughes INTEQ.

Features and Benefits

DFE-1503 is a molecular taggant dissolved in a water carrier. It can be added directly to an agitated mud pit.

DFE-1503 possesses the same non-toxic and biodegradable characteristics of water.

DFE-1503 does not affect the fluid properties in any manner.

Drilling fluids formulated with DFE-1503 deliver the same physical characteristics as those of non-tagged muds, with the added benefit of molecular quantification.

DFE-1503 allows the accurate determination of filtrate invasion for more precise calculations of oil and water saturation.

Application

DFE-1503 precisely quantifies the amount of filtrate invasion into reservoir core samples with an accuracy of ±5%.

DFE-1503 can be used in any organic-based drilling fluid application to allow the precise quantification of the mud filtrate in any substance which may subsequently contain it.

Recommended Treatment

DFE-1503 has a predetermined treatment concentration dependent on the total amount of base water in the active system.

Table 2-13 Typical Physical Properties

Typical Physical Properties	
Appearance	clear to pale yellow liquid
Viscosity, cSt @ 40°C	1
Specific gravity	1.0
Flash point (ASTM D56)	>60°C (>140°F)
Boiling point @ 1 atm	>100°C (>212°F)

Environmental Information

DFE-1503 has identical environmental data as that of water. For additional information concerning environmental regulations applicable to Baker Hughes

INTEQ products, contact the Health, Safety, and Environmental Department.

Shipping

Transportation of DFE-1503 is not restricted by either international or USA regulatory agencies.

Safe Handling Recommendations

A minimum of precautions are needed for handling DFE-1503. Normal precautions should be taken by employees when handling chemical products. Use of appropriate respirator, gloves, goggles, and apron is recommended for employees comfort and protection. Refer to the Material Safety Data Sheet (MSDS) prior to use.

Packaging

DFE-1503 is a liquid packaged in one gallon containers.

DFE-432 Oil-Based Mud

Product Description

DFE-432 is a molecular taggant used to tag (or mark) synthetic-, oil-, diesel-, ester- or any other organic-base drilling fluid for quantification purposes. This technology was developed by ISOTAG LLP and is exclusively licensed by Baker Hughes INTEQ.

Features and Benefits

DFE-432 is a molecular taggant solvated in an ISO-TEQ carrier and can be added directly to an agitated mud pit. In drilling fluids provided by Baker Hughes INTEQ, DFE-432 will be added at the mud plant.

DFE-432 possesses the same non-toxic and biodegradable characteristics of ISO-TEQ.

DFE-432 does not affect the fluid properties in any manner.

Drilling fluids formulated with DFE-432 deliver the same physical characteristics as those of non-tagged muds, with the added benefit of molecular quantification.

DFE-432 allows the accurate determination of filtrate invasion for more precise calculations of oil and water saturation.

Application

DFE-432 precisely quantifies the amount of filtrate invasion into reservoir core samples with an accuracy of ±5%.

DFE-432 can be used in any organic-based drilling fluid application to allow the precise quantification of the mud filtrate in any substance which may subsequently contain it.

Recommended Treatment

DFE-432 has a predetermined treatment concentration dependent on the total amount of base organic in the active system.

Table 2-14 Typical Physical Properties

Typical Physical Properties	
Appearance	clear to pale yellow liquid
Viscosity, cSt @ 40°F	3.5 - 3.6
Specific gravity	0.792
Flash point (ASTM D56)	>134°C (>273°F)
Boiling point @ 1 atm	>270°C (>518°F)

Environmental Information

DFE-432 has identical environmental data as that of ISO-TEQ. ISO-TEQ has been tested for biodegradability using the OECD 301 F Respirometry protocol. A normal BOD curve shows that ISO-TEQ is biodegradable. A BOD28/

COD ratio of 73% was obtained in 28 days, with a maximum of 59% within a 10-day period. Bioassays of ISO-TEQ-base drilling fluids, using the standard United States Environmental Protection Agency (US EPA) mysid shrimp test, has resulted in toxicity values greater than 500,000 ppm for the suspended particulate phase (SPP). For additional information concerning environmental regulations applicable to Baker Hughes INTEQ products, contact the Health, Safety, and Environmental Department.

Shipping

Transportation of DFE-432 is not restricted by either international or USA regulatory agencies.

Safe Handling Recommendations

A minimum of precautions are needed for handling DFE-432 because of its high flash point, low vapor pressure and absence of aromatic content. However, normal precautions should be taken by employees when handling chemical products. Use of appropriate respirator, gloves, goggles, and apron is recommended for employees comfort and protection. Refer to the Material Safety Data Sheet (MSDS) prior to use.

Packaging

DFE-432 is a powder packaged in one kilo containers.

Tracers for Water-Base Fluids

The tracers used in water based-fluids are:

- Chemical salts such as potassium iodide (KI)
- Stable isotopes such as deuterium oxide (D_2O)
- Radioactive isotopes, for use in water-base fluid, such as tritiated water.

Chemical Salts

Chemical salts that easily dissolve in the water phase of a water-base fluid have been used as tracers for many years. Such chemicals include: sodium bromide (NaBr), sodium or potassium iodide (NaI or KI), sodium nitrate ($NaNO_3$), and sodium thiocyanate (NaSCN). Sodium chloride (NaCl) can be used in applications where the formation brine approaches fresh water in salinity. An anion not normally present in sea or formation waters or present only in slight concentrations is employed. The ion chromatograph is the most commonly used analytical method of detection.

Stable Isotopes

Deuterium oxide, D_2O (heavy water), a stable isotope, has been used in recent years. D_2O is not radioactive. It is, however, used in the manufacture of certain nuclear devices and is subject to some regulation. As deuterium oxide is present in all water, it must be used in concentrations significantly higher than background levels. Deuteriated organics also are available for use in tracing water-base drilling fluids. These proprietary compounds, Isotags™, can be used in very minute quantities. The mass spectrometer is the instrument used for analytical detection for heavy water or deuteriated organics.

Radioactive Isotopes

Tritium, a radioactive isotope with a half life of 12.3 years, is ideal for use in fluid tracing. It lends itself to both water and oil-based fluids. While tritiated materials are subject to all the restrictions of the Atomic Energy Commission (AEC) and have been severely regulated in the past, there are analytical companies that are licensed to prepare and handle them. About 350 millicuries of tritium are needed to trace the fluid in a 1,600 bbl fluid system. Only a service company licensed by the AEC can bring on location, dilute, and mix this material into a drilling fluid system.

After dispersion in the fluid, the low concentration of radioactivity renders the fluid harmless. All other things being equal, tritium can be the most straightforward and cost-effective tracer available. The scintillation counting spectrometer is the instrument used for analytical detection.

Tracers for Oil-Base Fluids

Oil-based fluids can be tagged with a tracer whether the fluid base is crude oil, diesel oil, or synthetic oil. Emulsion fluids also can be traced in either the water or oil phase or both. Specially selected hydrocarbons such as iodonaphthalene also are used in oil-based fluids.

- A straight chain hydrocarbon, such as $C_{25}H_{52}$ can be added to the oil-based fluids if this material is not found to any great extent in either the drilling fluid formulation or the native hydrocarbon. Analysis of this material is carried out with a gas chromatograph (GC) equipped with a flame ionization detector (FID).
- Tritiated hexadecane ($C_{16}H_{33}T$), a radioactive material, is a very effective tracer for OBF. The properties which contribute significantly to the successful use of tritiated hexadecane as a tracer for oil systems are complete solubility in oil, low volatility (550°F/128°C boiling point), low melting point (64°F/18°C), linear paraffinic structure, and a half life of 12.3 years. Depending upon the size of the fluid system, radioactive quantities of the order of 350 to 400 millicuries are all that need be added. After it is mixed into the fluid system, it is present in concentrations well below those that might create a health hazard. There are no restrictions on environmentally proper disposal of the fluid. After the core has been extracted, the presence of any radioactivity is analyzed using a scintillation counting spectrometer. Tritiated hexadecane can be

mixed only into the fluid system by a service contractor which holds a license from the AEC.

- 1-Iodonapthalene has been used as a tracer for OBF filtrates, and fluid systems can be tagged with only 30 ppm of this material. 1-Iodonapthalene ends up in the organic solvent during the extraction process of core cleaning. It is analyzed using a gas chromatograph equipped with an electron capture detector (ECD).
- Isotag tracers containing deuteriated synthetic oils are being used in minute quantities to trace oil-based fluids. These tracers are quite effective in evaluations of formation damage, reservoir fluid contamination and core sample filtrate invasion. GC/MS analytical techniques are used to detect these deuteriated oils.

Baker Hughes INTEQ is experienced in the application and use of these tracer materials in coring operations. The selection of the proper tracer will depend upon the objectives of the coring program, reservoir fluids properties, and location.

Gel Coring℠

An issue confronting the coring and core analysis industry has been damage to the core during acquisition and handling. The act of coring as a means of sampling the formation while minimizing physical and chemical alteration of the rock does not preserve in situ reservoir properties because no provisions are made for core preservation prior to surfacing. Low invasion coring systems help minimize drilling fluids invasion, but rock wettability and saturation still can be altered by static drilling- fluid invasion in the inner barrel and during core storage before core analysis begins.

Gel Coring is a new technology using high-viscosity, zero spurt loss gels to encapsulate and preserve cores downhole while cutting. The standard viscous core gel is a high-molecular- weight polypropylene glycol-based material that is insoluble in water and environmentally safe. Polyethylene and vegetable- oil-based gels also are available. The gels are compatible with most water and oil-based drilling fluids. Because the gel encapsulates the core immediately after it is cut, exposure of the core to drilling fluid filtrate is minimized. See Figure 2-12.

Another benefit of Gel Coring is that the gels improve lubricity between the core and inner core barrel, reducing the potential for jamming in the inner tube. The high viscosity gels also stabilize poorly consolidated rocks with moderate compressive strengths and enhance the mechanical integrity of the core. Surface handling of the core is less intensive and core damage is reduced during transport to the laboratory.

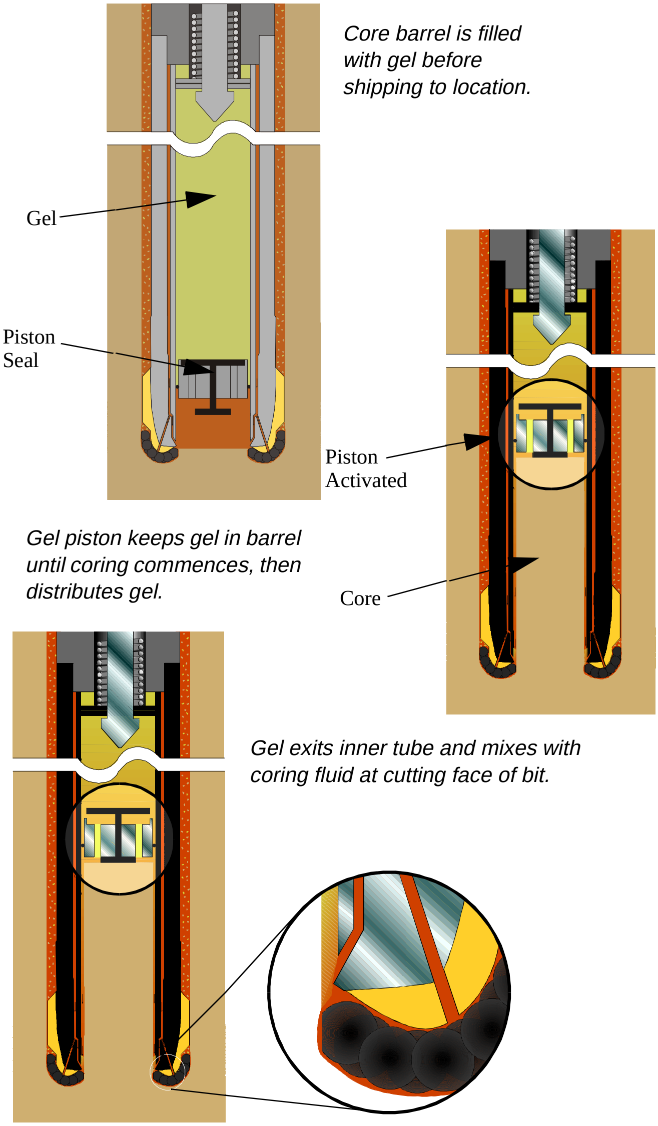


Figure 2-12 Gel Coring Technology

Gel Coring Benefits

The benefits of Gel Coring[SM] must be substantiated on a case-by-case basis. However, as an extension of Low Invasion Coring and a method to improve core recovery and quality, Gel Coring can:

- enhance core mechanical integrity for rock mechanics studies
- increase confidence in special core analysis programs by ensuring core quality
- improve coring performances by yielding higher core recovery
- increase lubricity, reducing the potential of a core jam
- reduce drilling fluid filtrate invasion, particularly when coring with poor fluid systems
- provide an alternative to sponge and pressure coring
- encapsulate the core downhole as a potential substitute for surface stabilization
- protect the core against oxidization and dehydration
- prevent core damage during wellsite handling and shipping to the laboratory.

The use of Core Gels has been particularly effective in improving recovery of high quality, preserved core material for saturation and special core analyses. In addition, the application of gels has led to higher core recoveries and barrel utilizations in long coring runs. The gels have been shown to protect core samples during the entire coring process: cutting, recovery, surface handling, transportation to lab, and short-term storage. The downhole encapsulating properties of the gels serve to protect the core, not only from filtrate invasion into the core, but from loss of pore fluids out of the core as well. Thus, Gel Coring may in some cases be used as a cost-effective substitute for sponge and pressure coring.

Filtration (spurt loss) specifications appear in Table 2-15. Product specifications for the gels are listed in Table 2-16.

Table 2-15 Gel Filtration Characteristics

Gel	Gels 3 and 4		Lubricore 400 (see note)	
Filtration Disk	Fluid Loss*	Δ Pressure	Fluid Loss*	Δ Pressure
0.5 darcy	0.0	500	no control	no control
5 darcy	0.0	500	no control	no control
10 darcy	0.0	500	no control	no control
** milliliters/30 minutes*				

Table 2-16 Coring Gel Specifications

Gel	Core Gel 3	Core Gel 4	Lubricore 400
Composition Base	Polypropylene Glycol	Polypropylene Glycol	Vegetable Oil
Color	White	White	Yellow
Solubility in Water	Nil	Nil	Nil
Fluorescence	Weak Orange (Mineral)	Weak Orange (Mineral)	Weak Blue-White
Rheological Characteristics	Pseudo Plastic	Pseudo Plastic	Pseudo Plastic
	24,200 to 8,929 cp at shear rates of 6.8 to 17 sec^{-1}	Less viscous than Core Gel 3	Less viscous than Core Gel 3
Specific Gravity	10.2 lbs/gal	10.1 lbs/gal	8.6 lbs/gal
Maximum Circulating Temperature	250°F/120°C	250°F/120°C	450°F/232°C

Table 2-16 Coring Gel Specifications (continued)

Gel	Core Gel 3	Core Gel 4	Lubricore 400
Applications	Hard to medium formation strengths	Medium formation strengths / low temperature applications	High temperature applications. Soft formations of low unconfined compressive strength

Note: *Lubricore 400 is included for comparison only. It is not a filtration control agent and is not intended as an extension of low invasion coring.*

Filtration tests were performed with the same equipment used to measure the filtration rate of drilling fluids at high temperatures and high pressures (HTHP).

In Situ Data Gathering Pressure Coring

The In situ Data Gathering System (IDGS) is an extension of Pressure Coring in which preserved core material is recovered under reservoir pressure in near native-state condition. IDGS incorporates Low Invasion Coring, Anti-Whirl core bits, Gel Coring (optional), and other high technology features to improve upon the original pressure poring service.

The ability to analyze a core sample that has been retained at nearly in situ conditions is a powerful reservoir engineering tool. In comparison with other methods, pressure-retained core analysis provides potentially the most reliable measurement of oil saturations and petrophysical properties. Pressure-retained core analysis is especially useful when the feasibility of a secondary or tertiary recovery method is being evaluated.

Pressure retained core analysis provides four primary types of information:

- **Fluid Saturation Data** – important for determining oil/water and gas/water contacts and for making reserve estimates
- **Wettability and Relative Permeability Measurements** – critical for determining recoverable hydrocarbons over the life of the reservoir and the most effective reservoir flooding process
- **Mechanical Properties Data** – pressurized core yields data on compressibility, shear strength, structure and porosity not obtainable from cores depressured by standard recovery processes
- **Gas Content and Deliverability from Coal** – coal bed methane evaluations.

The reliability and dependability of this technique for obtaining reservoir information is very high. Although the application of IDGS may be viewed as an expensive coring procedure, the information obtained by pressure coring often is worth many times the cost of obtaining it. Any project in which success is dependent upon accurate calculation of reserves in place or the reaction of reservoir rock to alternative recovery techniques is a candidate for the In Situ Data Gathering System.

IDGS Features

- Pressure cores are recovered in a sealed core barrel.
- Bottomhole pressure is retained in the core as the barrel is lifted to the surface.
- In situ fluid saturations - oil, gas, and water - are retained in the core and preserved.
- The recovered core remains as close to native state as possible.
- A sample of reservoir fluid is obtained and preserved in the core.
- Mechanical properties of the core are preserved.
- Reservoir/formation properties such as wettability are unaltered.
- IDGS is an alternative to sponge coring.
- There is a high level of safety with IDGS compared to RFT (Reservoir Fluid Testing) or DST (Drill Stem Testing).

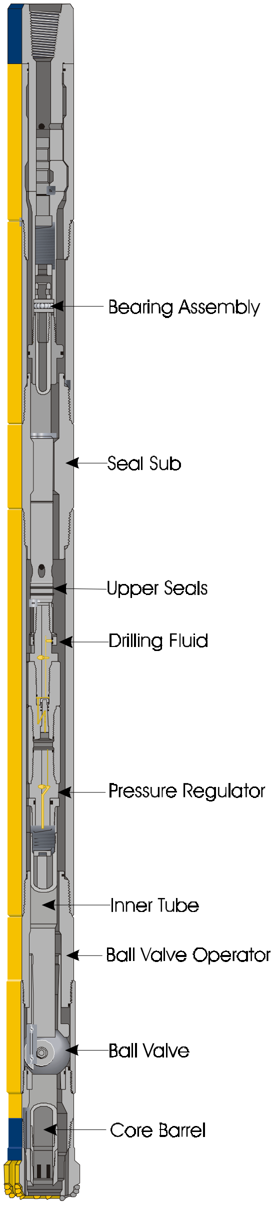


Figure 2-13 In Situ Data Gathering System Tool

IDGS Equipment Description

The IDGS tool is a double tube, pressure core barrel supplied in two sizes:

- $5^3/_4$" × $2^1/_2$" × 10' (6” ball valve) and
- 7" × $3^3/_4$" × 10' (8” ball valve).

Typically, the IDGS tool cuts cores 10 feet in length. The barrels are oilfield-tough, exceptionally strong and rigid, and suitable for use in all open-hole operations. All connections are heavy, tapered threads using heavy wall tubing of heat-treated alloy steel. See Figure 2-13.

The outer barrel serves as the mechanical connection to the core bit, transmitting both bit weight and torque. It also serves as the pressure vessel for the recovered pressures.

The upper section of the IDGS core barrel is a telescoping, splined, slip joint containing a locking and releasing mechanism. This section allows the axial movement of the inner and outer barrels necessary to seal the pressure within the tool. The full travel spline transmits torque to the bit in any axial position. This can aid in freeing the barrel if it becomes stuck in the hole. The heavy-duty locking mechanism locks the barrel in the coring position and also in the “tripped” or sealed position for retrieval. In the sealed position, the locking mechanism has adequate strength to allow weight to be applied to the tool without tripping the barrel.

Between the slip jointed spline assembly and the outer tube is the seal sub. This portion contains a polished bore to receive the upper seals which form the main pressure containment above the core. This sub also contains a porting arrangement to allow measurement of contained pressure.

Below the outer tube is a ball valve assembly and a ball valve operator assembly. This portion of the barrel is required to form the main pressure seal below the core. The operator assembly serves the purpose of closing the ball valve.

Pressure is maintained in the barrel by a pressure regulator section during retrieval against the effects of temperature and differential-pressure-induced volume changes. This assembly consists of a high pressure inert gas reservoir, a regulator with adjustable settings, and associated valving which supplies gas at a predetermined pressure. The assembly compensates for the aforementioned effects.

The inner tube serves as a receiver for the core. As an option, it can be pre-filled with a core gel which encapsulates the core as it enters the inner barrel to help protect the core from static filtrate invasion. The inner tube also serves as a package in which the core is sent to the lab for analysis.

Service Unit

Due to the intricacies of the IDGS pressure core barrel and its servicing operations (i.e., flushing, freezing, etc.), a Pressure Coring Service Unit is required. This is a portable service shop which is capable of handling all required operations while on location. This unit is built into a forty-foot long, ocean-going freight container. All equipment required to service and maintain the pressure core barrel is contained within the unit. Adequate work space is maintained to allow all functions to be performed within the confines of the unit. This eliminates the need for external work areas, which are subject to environmental conditions.

A 12" deep sub-floor is built over the existing floor of the container. The sub-floor is divided into compartments for equipment storage and troughs for core barrel storage, transportation, and freezing.

All equipment necessary to “flush” the core barrel is contained within the unit in two skid-mounted systems. Rated to 10,000 psi (for the 5¾" barrel) and 5,000 psi (for the 7" barrel), these skids have self-contained hydraulic systems to maximize reliability.

With the exception of expendables (i.e., water, diesel fuel, etc.), the unit needs no support while in the field. Location requirements are minimal in that only a relatively level 50 × 15 foot space is required for placement of the unit. The only additional requirement is a means of transporting the core barrel between the rig and the unit. Specifications for the Service Unit are listed in Table 2-17.

Table 2-17 Service Unit Specifications

Length for Transport	40 feet (12 m)
Length – Operational on Location	50 feet (15 m)
Width	8 feet (2.5 m)
Height	8.3 feet (2.53 m)
Weight (Fully Equipped and Outfitted)	Approx. 45,000 lbs
Power Plant (220 VAC & 120 VAC)	15,000 Watts
Compressor	125 SCFM @ 125 psi
Hoist Capacity	4,200 lbs
Propane Heater Output (each)	19,500 BTU

HTHP (High Temperature High Pressure) Coring

Historically, the safe and successful retrieval of core samples from high pressure formations limited barrel lengths to 30 feet. This was due to the potential for trapped gas incidents:

- Pressure trapped across a connection can lead to a sudden, violent escape of gas during breaking of the inner barrel (tube). This may cause the suspended inner tube to be forcibly expelled from the barrel with possible injury to personnel.
- Trapped high pressure gases within the inner tube present a potentially explosive situation. This condition can arise if a high pressure sand is trapped between two low permeability shale bands.

Simply relieving the high pressure by pre-drilling the inner tubes with suitably spaced holes is not considered satisfactory due to the potential for wash-out caused by mud turbulence, ineffective cleaning during a run-in-hole operation, and possible weakening of the tube.

Gas expansion from pore fluids during tripping out of the hole also can cause severe core damage if the inner tubes are not adequately vented. In a situation where interbedded sandstones and shales have been cored, there is potential for the shales to expand, filling the annulus and preventing trapped gas from venting through the core bit or ball seat. The core is liable to fracture under the pressure of these fluids during tripping out of hole due to gas expansion unless the walls of the inner barrels are vented properly.

Baker Hughes INTEQ has devised a technique of constantly venting trapped gas by controlled means, allowing successful, long barrel coring of high pressure wells. The technique uses Pressure Relief Check Valves that are seated in aluminum (or steel) inner tubes and special pulling-out-of-hole procedures.

Each check valve consists of a small trapped ball and seat arrangement fitted to the inner barrel. The valves, installed prior to shipment, can be spring loaded.

Check valves:

- vent the hydrostatic head within the inner barrel during coring
- prevent circulating drilling fluid from entering through the inner tube wall
- allow safe venting of trapped gases (including H_2S) while pulling out of hole.

The valves generally are spaced every two feet along the inner tube, offset at 24° angles. However, they also may be offset at 0° or 90° angles, depending upon reservoir conditions and coring objectives. Detailed information on check valve placement is listed in Chapter 5.

Tests were conducted at temperatures up to 400°F (204°C), both on the tensile strength of aluminum and the differential expansion of steel/aluminum connections in the inner barrel assembly. These tests indicate that disposable aluminum inner tubes should be selected for hot hole environments. Pressure relieving check valves must be incorporated into the inner tubes prior to coring. Procedures for pulling-out-of-hole in HTHP (or H_2S) wells are described in Chapter 5.

S_o Coring – Reservoir Characterization Coring

Baker Hughes INTEQ has introduced a Reservoir Characterization Coring service. This service uses a porous, oil-absorptive foam to encapsulate core material downhole, capturing oil expelled from the core by pressure depletion during recovery to surface. Reservoir Characterization Coring provides enhanced formation data for engineers, geologists, and petrophysicists.

S_o Coring Features

- Oil-absorptive material is contained within disposable aluminum liners.
- Liners fit inside of a standard steel inner core barrel.
- Outer assembly is a standard high torque core barrel.
- 3.25-inch diameter × 30-foot (9 m) length core is cut.
- Ten 3-foot lined aluminum sleeves are contained within each 30-foot (9 m) inner barrel.

S_o Coring Benefits

- The core is encapsulated downhole, acting to preserve and protect the core.
- The oil expelled from the adjacent core is trapped.
- Highly accurate oil saturations can be obtained from analysis of the whole core.
- Water-oil and gas-oil transition zones can be easily identified.
- Static drilling fluid filtrate invasion is prevented by the encapsulation process.
- The preservation of the core leads to enhanced reservoir description evaluations.

Special rigsite tools and procedures are required for S_o coring. Contact Baker Hughes INTEQ for more information.

Underbalanced Coring

Underbalanced Coring (UBC) is employed in situations where formation damage of the reservoir is highly likely with conventional coring techniques and drilling fluids. If properly designed, an underbalanced coring program can eliminate:

- Filtrate or particulate invasion of the reservoir and core material
- Clay swelling
- Phase trapping
- Precipitation of asphaltenes or emulsification of hydrocarbons.

UBC drilling fluids can be nitrogen, air, gaseous hydrocarbons, flue gases, mists, or foams. The hydrostatic circulating pressure of such a system is less than the pressure of the formations being cored. The gas, mist, or foam must be circulated at a rate sufficient to cool the bit and disperse and lift the cuttings. As a general rule, the volume of air per minute recommended for air coring is ten cubic feet per minute times the GPM required for coring the same size hole with liquids. Where gas is used as the drilling medium while coring, the volume is usually higher, approximately 1,000 to 1,400 cubic feet (28.3 to 39.6 cubic meters) per minute more than that used in air coring.

If properly designed and implemented, UBC can:

- Prevent or reduce formation damage to the reservoir and recovered core
- Increase ROP and decrease coring time.

Underbalanced coring can be conducted with a wide range of conventional Baker Hughes INTEQ coring assemblies and bits. The technique is not applicable to Gel Coring, S_o Coring, or Hydro-Lift applications.

Some advance knowledge of reservoir properties is essential when considering a UBC program. Normally pressured homogeneous formations having low potential for formation damage may not be suitable candidates for underbalanced coring.

Safety concerns must be addressed when planning any underbalanced coring project. Special attention must be paid to blowout preventors and surface control equipment when considering UBC.

Coiled Tubing Coring

Coiled tubing coring operations, using oilfield coring equipment, are carried out in wellbores of $4^3/4$" to $4^1/_8$" diameter. Baker Hughes INTEQ offers two core barrel systems which can be run in combination with motors:

- 350P slimhole core barrel - $3^1/_2$" × $1^3/_4$"
- Modular Coring System - $3^3/_4$" × 2".

Baker Hughes INTEQ's Galileo coiled tubing rig is ideally suited for coring operations using these systems.

Figure 2-14 Galileo Coiled Tubing Drilling Unit

•Notes•

Inner Barrel Components

Inner barrel components can have a lasting impact upon the quality of the extracted core, as core quality is closely tied to the means of extraction and containerization. Charateristics of inner barrel components, their effect upon core quality, and criteria for component selection are discussed in this chapter.

Bottomhole Assembly

The bottomhole assembly (BHA) used in coring consists in general of two components - the outer barrel and the inner barrel assembly. Core material is recovered in the inner barrel, which is non-rotating and serves to containerize the core for recovery to the surface.

Inner barrels are made of steel, aluminum, fiberglass, and PVC. Steel inner barrels are considered to be non-disposable components. They can be used repeatedly. Inner barrrels made of the other materials listed above are disposable, single application components.

Other inner barrel components (such as telescoping inner sleeves, long distance adjustment assemblies, pressure relief valves, and flow diverters) can be included in the BHA to ensure optimal performance and control the coring process. Recommended pairing of inner barrels and outer barrels is indicated in Table 3-1 below.

Table 3-1 Inner/Outer Coring Barrel Pairing

Recommended Pairing of Inner Barrels with Coring Barrels				
Outer Barrels/ Coring Method	**Inner Barrels**			
	Steel	**Aluminum**	**Fiberglass**	**PVC Liner**
Conventional	*	*	*	*
Long Coring/High Torque	*	*	*	
Hydro-Lift		*	*	*
Oriented Coring	*	*	*	*
HTHP Coring	*	*		
Motor Coring	*	*	*	*
Gel Coring	*	*	*	*
CoreDrill	*	*		
Low Invasion	*	*	*	*
Pressure (IDGS)	*			
S_O		*		
Slimhole Coring	*	*		
Horizontal Coring	*	*	*	
Air Coring	*	*		*

Inner Coring Barrels and Liners

Steel Inner Barrels

Steel inner barrels (inner tubes) are the standard for most coring operations. They are available for all core barrel sizes. Steel inner barrels are non-disposable since they can be used repeatedly. They can be used at very high temperatures and provide the maximum support for core material.

Core material that is containerized in steel must be pumped or pushed out of the inner barrels on the rig floor. This may disturb or damage the core material. Cores handled in this fashion are exposed to the air and must be placed in cardboard or wooden boxes for transportation to the laboratory. Steel, opaque to gamma rays, prevents core logging on the rig floor.

Specifications for steel inner barrels are listed in Appendix B, Table B-4.

Disposable inner barrels (inner tubes) are recommended for coring operations where containerized coring and the preservation of core material is desired. They are available for most coring systems, can be used in all formations, and offer significant advantages over steel inner barrels. Since disposable inner tubes and their core sample generally are cut into 3 foot (1 m) sections on the rig floor, the core material inside of these sections remains undisturbed. The sections are stabilized if necessary, then immediately capped and sealed. The core remains protected and supported in the containerizing material during shipment off site.

A significant advantage of the disposable inner tube materials is that aluminum, fiberglass, and plastic produces less friction to the core than steel.

Reduced friction on core entry results in:

- Improved core quality and recovery
- Reduced potential for core jamming
- Improved rig time efficiency.

Disposable inner tubes have become an industry standard for most coring operations. In addition to supporting and protecting the core, these materials are transparent to gamma rays, allowing wellsite gamma logging of the core when required.

Aluminum Inner Tubes

Aluminum offers the best support for core material and the highest operating temperature and pressure range of the disposable inner tubes. Aluminum inner barrels can be connected to achieve coring runs of 30 to 270 feet (9 to 82 m) (possibly longer). Connections are made at the box and pin connectors that are machined into the aluminum itself. These tubes are excellent for maintaining core integrity during handling and transportation. The core-filled aluminum inner tubes can be cut easily, capped, and sealed for transport to the laboratory using a full range of wellsite handling equipment. See Table 3-2.

The significant difference in the thermal expansion of aluminum compared to that of steel must be taken into consideration when making up the BHA. The inner barrel must be properly spaced-out when making up the coring assembly - especially in higher temperature wells. Thermal expansion figures are listed in Appendix B, Table B-9.

Detailed specifications for aluminum inner barrels are listed in Table B-5. Mechanical properties are shown in Table B-6. Laydown procedures for aluminum inner tubes are reviewed in Chapter 5.

Table 3-2 General Specifications for Aluminum Inner Tubes

Aluminum Inner Tubes	
Maximum Operating Temperature	400°F/205°C
Thermal Expansion	1.6 x 10^{-4} in/ft °F / 2.4 x 10^{-2} mm/m °C
Available Lengths	30 foot (9 m) joints (15 foot/4.5 m available for CoreDrill)
Available Diameters	1.75" - 5.25"
Used with Check Valves	Yes

Fiberglass Inner Tubes

Fiberglass is an excellent inner tube material and is particularly useful when coring soft or unconsolidated formations. Fiberglass is available in 30 foot sections that can be connected for longer coring runs of up to 270 feet. Sections are made up at the steel box and pin connectors bonded to the ends of the fiberglass sections. The material is very easily cut on the rig floor or in the laboratory.

Fiberglass is resistant to the corrosive action of acids, chemicals, and salts found in drilling fluids. However, material constraints limit the use of fiberglass inner tubes to bottomhole temperatures of less than 250°F (121°C), and due to the flexibility of the material it is necessary to have a steel basket for securing the inner tubes on the rig floor. The thermal expansion of fiberglass compared to that of steel must be taken into consideration when making up the BHA. The inner barrel must be properly spaced when making up the coring assembly, especially in higher temperature wells. Thermal expansion charts for fiberglass are listed in Appendix B, Table B-9 (also see Chapter 5).

Fiberglass inner tube general specificatons are listed in Table 3-3 of this section, while mechanical properties appear in Appendix B, Table B-10.

Table 3-3 General Specifications for Fiberglass Inner Tubes

Fiberglass Inner Tubes	
Maximum Operating Temperature	250°F/121°C
Thermal Expansion	1.33 x 10^{-4} in/ft °F/2 × 10^{-2} mm/m °C
Available Lengths	30 foot (9 m) joints
Available Diameters	2.625" - 5.25"
Used with Check Valves	No
Maximum Coring Depth	14,000 ft/4200 m (assuming normal gradient)

Plastic Liners

For more detailed information, refer to Procedures for Plastic Liners or Inner Tubes on page 5-17.

Disposable Liners

Thin-walled aluminum, fiberglass, or PVC plastic liners in 30 to 60 foot (9 to 18 m) lengths can be placed inside of standard steel inner barrels for special core recovery operations such as coring unconsolidated sands. PVC liners are required for the large diameter (4½" core size) Hydro-Lift operations.

Lliners are more flexible than the standard aluminum or fiberglass inner tubes and require on-site support to prevent bending or flexing of the contained core. Liners are available in the following sizes:

- **Aluminum:** 6¾" × 4" core barrel to cut a 3½" diameter core (larger sizes may be available).

- **Fiberglass:** 6¾" × 4" core barrel to cut a 3½" diameter core, and 8" × 5¼" Hydro-Lift core barrel to cut a 4¾" diameter core.

- **PVC Plastic:** 5¾" × 3½" core barrel to cut a 3" core, 6¼" or 6¾" × 4" core barrel to cut a 3½" diameter core, and 8" × 5¼" Hydro-Lift core barrel to cut a 4¾" diameter core.

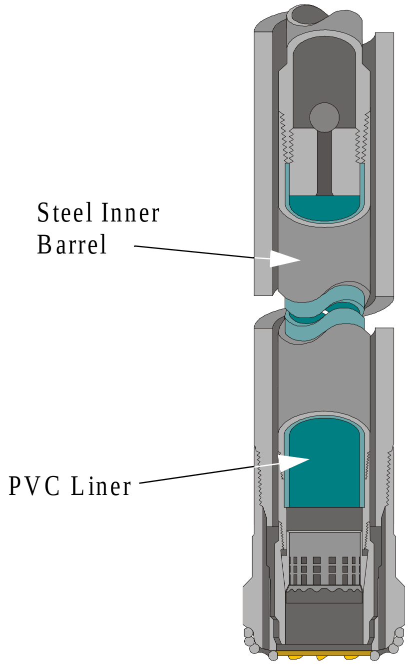


Figure 3-1 PVC Plastic Liner in Core Barrel

Inner Tube-to-Rock Friction

Laboratory tests have measured the coefficients of friction between rock and inner barrel materials in the presence of various fluids. Berea sandstone was used as the rock media. Various drilling fluid formulations along with air and water were evaluated as the liquid phase. The resulting coefficients of friction are listed in Table 3-4.

The data indicate that aluminum generally is the best inner tube material as it offers the lowest coefficient of friction to the core. Compared to fiberglass and PVC, aluminum is less affected by wear as the core enters the inner tube.

Field experience has demonstrated that PVC and fiberglass are quickly scratched – especially in the first few feet of the tube closest to the bit. Friction between the PVC or fiberglass and the core increases substantially after a short period of coring, increasing the potential for jamming. New steel offers low coefficient of friction values, but becomes much less effective with repeated use.

Table 3-4 Coefficients of Friction

Coefficient of Friction - Sandstone to Inner Barrel Material						
Material	Air	Water	Water-Based Drilling Fluid	Oil-Based Drilling Fluid	Gelled* Drilling Fluid	Bio-Drill**
Used Steel	0.62	0.60	0.62	0.55	0.60	0.65
New Steel		0.30	0.32	0.40	0.35	0.34
Aluminum	0.52	0.42	0.23	0.34	0.38	0.33
Fiberglass	0.48	0.35	0.34	0.44	0.45	0.36
PVC		0.35	0.35	0.44	0.42	0.35

** Bentonite water-base drilling fluid*

*** Bio-Drill is a water-based ROP enhancement/shale control formulation.*

JamBuster™ Anti-Jamming Coring System

Core jamming occurs in the core catcher or in the inner tube. It is a common reason for terminating coring operations and pulling out of hole. Jamming can be caused by several factors:

- Formation
  - *Formation Fault Slant* causes a classic wedging jam action
  - *Collapse of Unconsolidated Core Material* increases friction against the inner barrel
  - *Clay Expansion* leads to friction and adhesion against the inner barrel
- Core bit design and dynamics
- Bottomhole assembly configuration
- Inner sleeve and core catcher configuration.

The Baker Hughes INTEQ JamBuster anti-jamming system reduces the impact of jamming. Its telescoping inner barrel sleeves allow continued coring after jamming has occurred. See Figure 3-2. With JamBuster, coring can continue until three jams have been detected or the barrel is filled. The system is fitted into a high torque 6¾" × 3½" core barrel and incorporates the following features:

- Two telescoping aluminum sleeves within one fixed aluminum inner tube
- Shear pins that lock the sleeves together until jamming occurs - shear strength point is set to match formation properties
- An internal Core Jam Indicator
- JamBuster can be used in conjunction with Anti-Whirl Core Bits, Low Invasion Coring technology, and the Gel Coring^{sm} system.

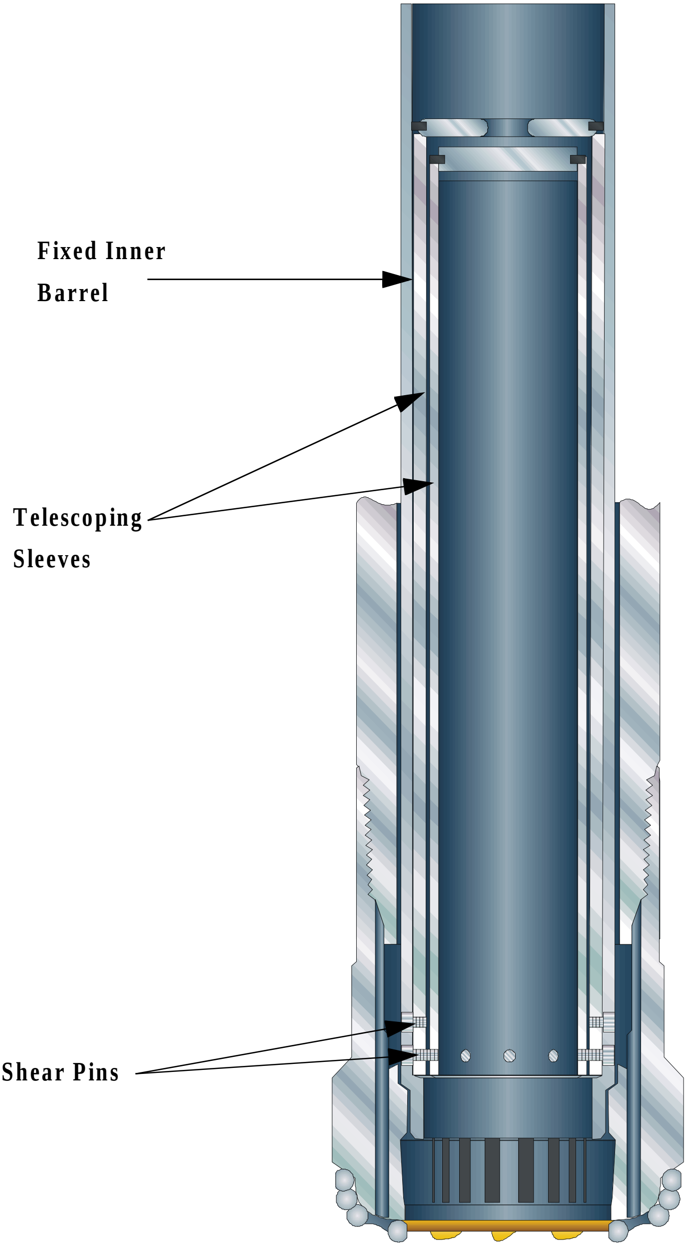


Figure 3-2 JamBuster Anti-Jamming System

Benefits of using the JamBuster system are:

- Coring can continue until three jams have occurred in the inner sleeves/barrel or the barrel fills.
- Field data indicate that improved coring efficiencies of 30-50% are achievable in jam-prone formations.

Specifications for the telescoping inner sleeve system are listed in Table 3-5.

Table 3-5 JamBuster Specifications

Core Barrel	Size	Length	Inner Barrel	Shear Pins	Hole Size
HT 30	6.75" O.D.	60 ft/18 m (min)	Aluminum	8 inner 12 middle	8.375" - 8.75"
Coremaster	6.75" O.D. with 7.25" upsets	60 ft/18 m (min)	Aluminum	8 inner 12 middle	8.375" - 8.75"

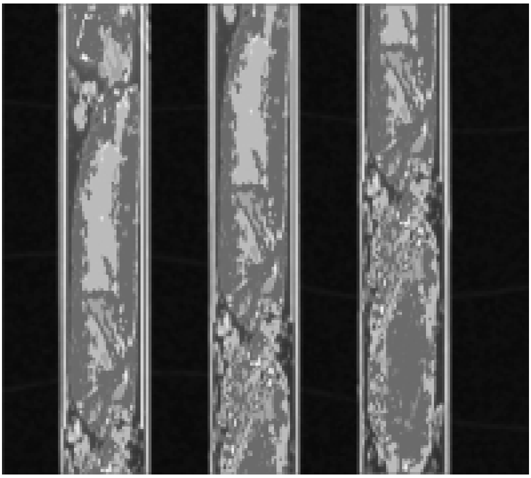


Figure 3-3 JamBuster Telescoping Inner Sleeves

JamBuster Benefits

- Requires 5 minutes to space the system.
- Accommodates 23 inches (584 mm) of adjustment.
- Enables long barrel coring that is difficult to space using shims.

Long Distance Adjustment

The Long Distance Adjustment (LDA) assembly has been developed to space-out aluminum or fiberglass inner tubes in high torque and conventional core barrels when coring in lengths of 90 feet (27.5 m) or greater. LDA directly replaces the shims on a standard safety joint or top sub. The LDA adjusts for the differences in thermal expansion of the outer steel barrel and disposable inner tube materials that occur with higher downhole temperatures. The LDA can be used to adjust for this difference in core barrel lengths to 270 feet (82 m).

Long Distance Adjustment assemblies are standard for all high torque core barrels. Conversion kits are available to fit the LDA into the conventional 250P series core barrels.

Core Jam Indicator

Frequently, jamming is not detected on the rig floor when coring with conventional tools. This results in the formation being drilled away instead of cored, leading to poor or no core recovery. The Core Jam Indicator assists the coring specialist in immediately identifying a jammed barrel.

Principle of Operation

The Core Jam Indicator is placed between the inner tube plug and upper connection on the top section of the inner tube. It consists of an inner rod which has a pressure relief plug at the top end and an inner tube connection at the bottom end. This rod is held in an extended position by Belleville springs housed in an outer mandrel.

Prior to the start of coring, the ball is dropped to divert flow from flushing through the inner tube to the annulus between the inner tube and outer barrel. This is achieved in the normal manner by the ball seating in the pressure relief plug, causing the flow to divert through ports in the inner tube plug. If a jam occurs, an upward force is immediately transmitted to the inner tube. This force causes the inner tube to lift slightly, pushing the rod of the Core Jam Indicator upwards. Since the pressure relief plug with the seated ball is attached to the top of the rod, the rod also is lifted to partially block the ports in the inner tube plug. This restriction is seen as an increase in standpipe pressure at the surface and an immediate indication of a jamming core. This increase in standpipe pressure will also occur when the barrel is full.

No special procedures are required for using the Core Jam Indicator. However, a two foot outer barrel extension sub must be fitted to the barrel due to the length of the indicator. In order to prevent the standpipe pressure rise from being excessive when using high mud weights or flow rates, the tool is easily adjusted to keep the pressure increase to approximately 200 psi.

Drop Ball Subs

Drop Ball Sub is available for dropping a ball to divert flow to the annulus space to the core barrel during coring operations with a motor or MWD tools. This sub is placed between the motor/MWD tool and the inner barrel.

Side Entry Drop Ball Sub

A spring-loaded ball is activated by a pressure surge in the circulation system. The use of the Drop Ball Sub is recommended to ensure that circulation through the inner tube will remove fill in the inner barrel before coring commences. A schematic of the sub is shown in Figure 3-4.

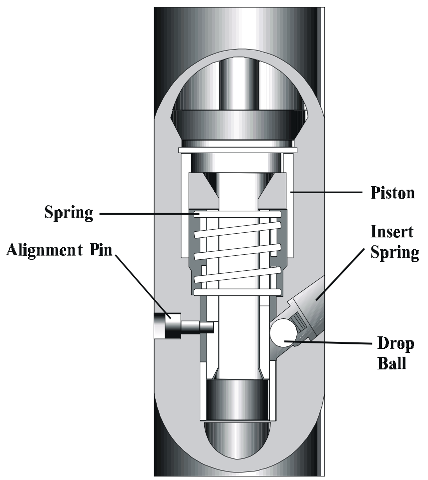


Figure 3-4 Drop Ball Sub

Downhole Activated Flow Diverter

Baker Hughes INTEQ has developed a pattented Downhole Activated Flow Diverter (DAFD). This simple device is run in place of the standard pressure relief plug and is activated at a known flow rate, depending upon mud weight. The tool response is very predictable, with the ball seating within 5 gpm of the calculated flow rate.

Application

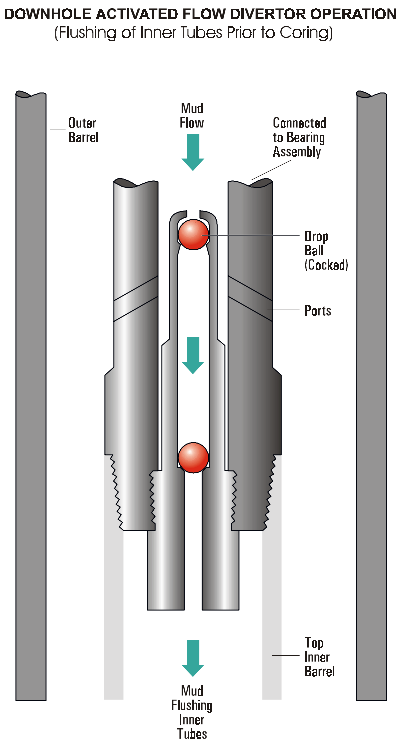


Figure 3-5 DAFD Sub

The Downhole Activated Flow Diverter (DAFD) tool allows flushing of the inner barrel and provides a positive seat for drop balls in high angle / horizontal coring applications. The tool is used when a ball cannot be dropped from surface and is run in place of a standard pressure relief plug.

This simple device consists of a drop ball held in a cocked position by four Colette fingers. The ball is released by the hydrodynamic force of the drilling fluid flow. The rate necessary to activate the ball is dependent upon the density of the drilling fluid as illustrated in the chart below. Tool response is very predictable, with the ball seating within 5 GPM of the calculated flow rate.

Downhole Activated Flow Diverters may be used in all 4.75", 6.75", and 8" core barrels for high angle / horizontal coring applications, motor coring, extended reach / long step-out coring, and coring with MWD. The benefits derived from the use of this coring tool include:

- a positive seat for the drop ball in high angle or horizontal wells;
- reduced rig time as the ball is not dropped from surface;
- flushing of the inner tube in situations where the ball would normally be run in place.

Pressure Venting Check Valves

Standard Pressure Check Valve

Check valves are used as a technique of venting trapped gas from aluminum or steel inner barrels by controlled means. Pressure-relieving check valves seated in the inner tubes relieve the gas in special pulling-out-of-hole procedures.

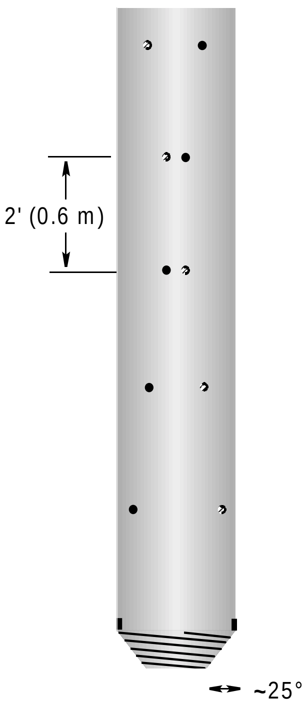


Figure 3-6 Check Valve Placement

The check valves consist of a small trapped ball and seat arrangement that is fitted into the inner barrel prior to shipment to the rigsite. Check valves:

- Vent the hydrostatic head within the inner barrel during coring
- Prevent circulating drilling fluid from entering through the inner tube wall
- Allow safe venting of trapped gases while pulling-out-of-hole.

The valves are generally spaced every 2 feet (0.6 m) along the inner tube, offset at 24° angles.

They also may be offset at 0° or 90° angles and spaced closer together or farther apart depending upon reservoir conditions and coring objectives.

Placement of the check valves is illustrated in Figure 3-6. Pulling-out-of-hole procedures for inner barrels fitted with check valves are listed in Chapter 5.

Spring-Loaded Pressure Check Valve

Spring-loaded pressure-relieving check valves with “cracking” pressures of 150-200 psi are available. These valves are identical in operation and placement to those described above, but offer better protection against drilling fluid leakage into the inner barrel. In addition, the spring-loaded valves can be used to contain the lower viscosity core gels in the inner barrels during the run-in-hole stage of operations in warm weather environments.

Inner Tube Stabilization

The outer barrel is designed to rotate about the inner tube during coring operations. In horizontal or deviated wells, an unsupported inner tube will tend to sag to the low side of the BHA, coming into contact with the outer barrel. This contact can force the inner tube to rotate or vibrate. Both situations will cause damage to the core. This in turn can lead to jamming of the core and cause premature tripping and/or poor recovery of damaged core. In vertical holes, vibration of the inner tube from bit or BHA dynamics also can cause contact between the inner tube and outer barrel.

To reduce such incidents of core jamming and damage, Baker Hughes INTEQ has developed Inner Tube Stabilizers and Bit End Bearings. These stabilize and fix in place the inner barrel. Inner tube stabilizers are one-foot long subs consisting of a mandrel with a trapped rotating sleeve that fits between the regular inner tube connections. The stabilizers have proven to be very effective in reducing incidents of core jamming and breaking in situations where sagging or vibration have previously been a problem. The rotating sleeve is a scalloped design which reduces fluid flow restriction to a minimum and provides lubrication. The faces on the ring also are case-hardened to HRC 58 (extreme) and ground for adequate wear resistance.

Inner tube stabilizers normally are run above the first and second 30 foot (9 m) sections of the inner tube. In very high angle/horizontal wells, it is recommended that stabilizers be placed at 15, 30, and 60 feet (4.5, 9 and 18 m) above the bit. This requires two 15 foot (4.5 m) sections of inner tube to be run in place of the first 30 foot (9 m) length.

Baker Hughes INTEQ recommends the use of bit end bearings to be run in conjunction with inner tube stabilizers. The bearings consist of five roller-type bearings set on a ring, and are placed between the upper shoe and pilot shoe. The bearing assembly sits in the specially machined core bit shank and effectively centralizes the pilot shoe in the core bit, reducing vibration and allowing easier entrance of the core into the inner tube. The use of the inner tube stabilizers and bit end bearings also reduces torque on the bit and outer barrel.

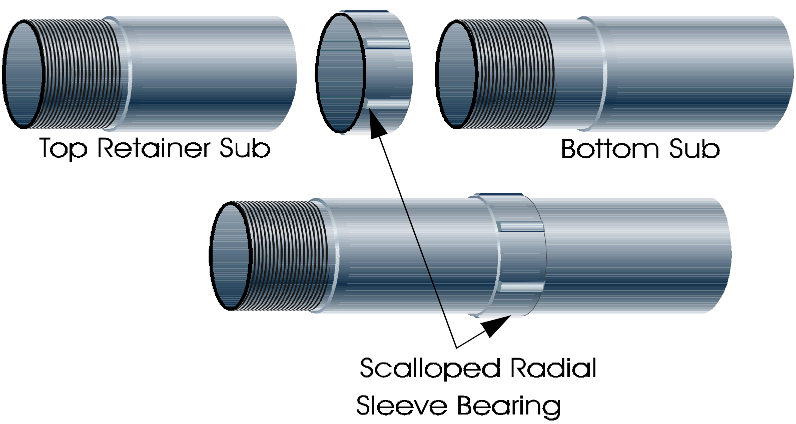


Figure 3-7 Inner Tube Stabilizers

Chapter 4

Coring Bits

Choosing the proper coring bit is critical to the success of any coring operation. This chapter discusses the Baker Hughes INTEQ coring bit selection, recommended applications, and the benefits of each bit type.

Introduction

Baker Hughes INTEQ's coring bits are manufactured by Hughes Christensen. The INTEQ/Hughes Christensen team provides the industry's widest selection of coring bits for every coring application.

Coring bit styles are listed in Table 4-1.

Table 4-1 Coring Bit Styles

Style	Description
RC	Synthetic Polycrystalline Diamond Compact (PDC)
ARC	Anti-Whirl™ PDC
C	Natural Diamonds
SC	Ballaset® thermally-stable synthetic diamond and sintered diamonds

PDC (Polycrystalline Diamond Compact) Bits

Polycrystalline diamond compact (PDC) cutters serve as the cutters in all diamond compact coring bits (Figure 4-1). These large-diameter synthetic diamond cutters achieve effective cutting action in a variety of soft-to-hard formations, providing deep cutting action, improved penetration rates, and increased core recovery.

Figure 4-1 PDC Coring Bits

Conventional PDC bits use natural diamond gage protection to assure full hole gage throughout the coring operation. Gage diamonds are not used in CoreGard low invasion coring bits where special PDC cutters are imbedded on the nose of the bit. Low invasion PDC bits are designed with face discharge fluid ports to reduce the effect of drilling fluid invasion on the forming core column.

Custom designed coring bits are available to suit unique applications and hole sizes.

PDC cutters are self sharpening and can be used in both rotary and downhole motor applications. The standard R-Series designs are available with light, medium, or heavy cutter densities to match the formation (soft formations typically require fewer cutters).

Various crown profiles are available:

- Round
- Short to medium parabolic (for low invasion bits)
- Anti-Whirl.

Standard profile variations match the formation being drilled. Cutter side and back rake angles can be modified to address specific applications.

Anti-Whirl™ PDC Bits

Bit whirl leads to cutter damage and poor core quality. Cutter damage leads to poor bit performance and shortens the life of the bit. Spiral-cut, broken, undergage, and non-uniform diameter cores can be caused by bit whirl. Fractured and disked cores may also result.

Anti-Whirl ARC series coring bits, Dogleg, reduce or eliminate bit whirl that results from lateral vibration of the bottom hole assembly and O.D. cutter hang-up on the wellbore. Anti-Whirl coring bits are engineered to balance vector forces and keep the bit rotating smoothly. They are designed with low friction gage pads and optimal profiles, and with cutter placement that keeps the bit rotating about its geometric center. These features maintain BHA stability, reducing vibrations and producing excellent core quality. Low invasion features such as face discharge ports also are incorporated into most ARC bits. Anti-Whirl PDC bits and drilling plugs are recommended for the CoreDrill tool.

The improved cores produced by Anti-Whirl coring bits are compared in Dogleg with the broken and spiral-cut cores produced by the bit-whirl of conventional coring bits.

Figure 4-2 ARC 435 (CoreDrill Bit with Drilling Plug)

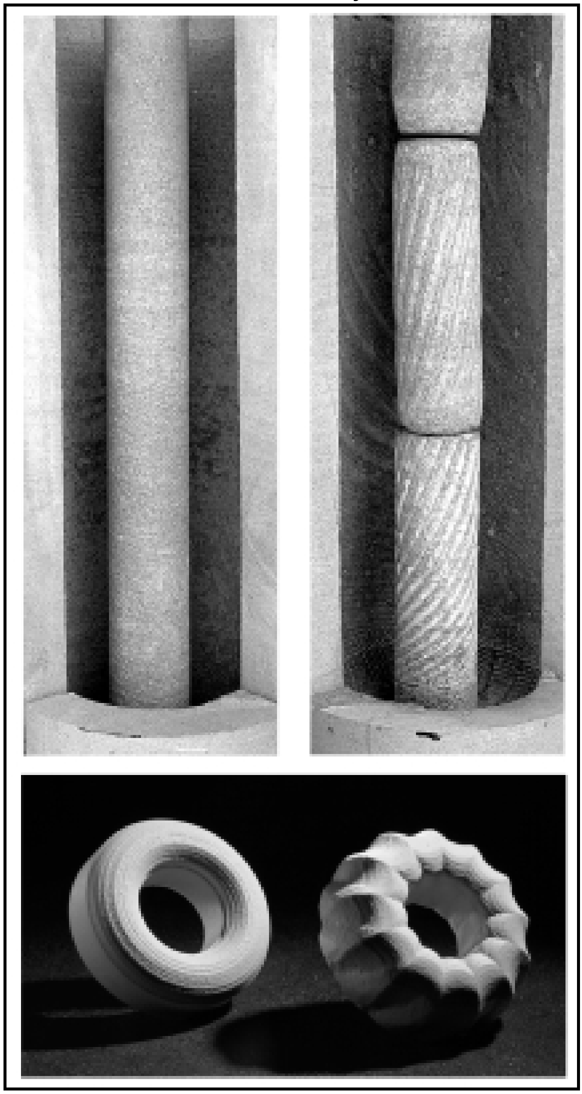


Figure 4-3 Effects of Bit Whirl on Extracted Core

PDC Cutter Options

Baker Hughes offers a wide range of proprietary PDC cutter designs to improve bit performance and life. Bits fitted with these premium cutters will be designed as “URC”.

Gold Series Cutters

- **Stress Engineered Cutter (SEC)** – SEC employs a thicker diamond table for added reinforcement against bending loads. The cutter is more wear-resistant to abrasive formations, which reduces fracturing and improves reliability, bit life, and ROP. SEC is also available with a radial interface design that pulls stress away from the cutter’s edge.
  See Figure 4-4.

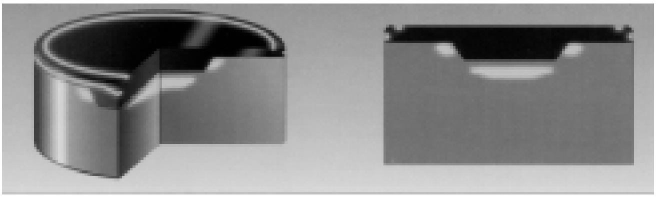
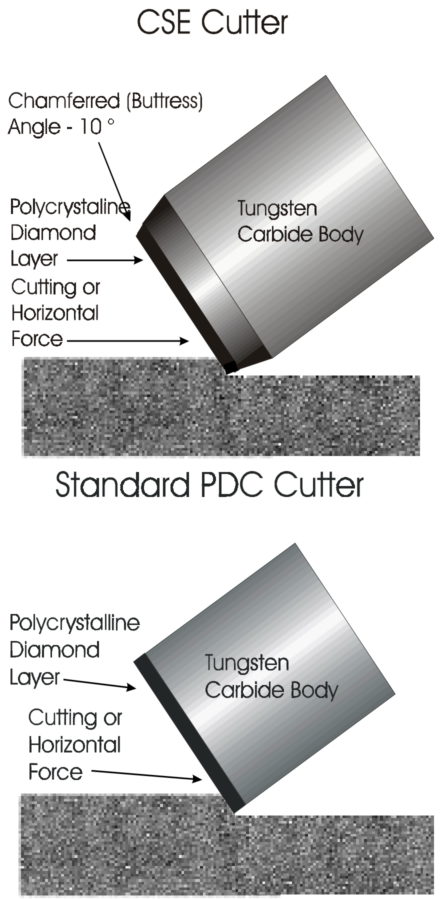


Figure 4-4 SEC Cutter Cross Section

The thick cutter section of SEC bits modifies stress distribution, provides extra stiffness, and improves wear resistance in abrasive formations.

- **Carbide Supported Edge (CSE)** – CSE cutters feature an extended chamfer edge to reinforce the diamond table against blows experienced during drilling. These cutters have half the tensile stress of a standard PDC cutter, which results in improved bit life at high ROP.
  See Figure 4-5.



CSE “Buttressed Edge” geometry dramatically strengthens the diamond edge against the cutting force.

Figure 4-5 CSE Buttressed Edge Cutters

- **Black Ice™ Polished Cutters –** Black Ice cutters are polished to reduce the frictional forces that allow cuttings to adhere to PDC surfaces. This allows for greatly improved cuttings removal and leads to improved drilling efficiency and ROP.
- **Engineered Cutter Placement (ECP)** – ECP places high tangential load cutters on the flank and

shoulder, and high axial load cutters on the center and nose of the bit surface. This gives the bit better resistance to wear and improves bit life and performance.

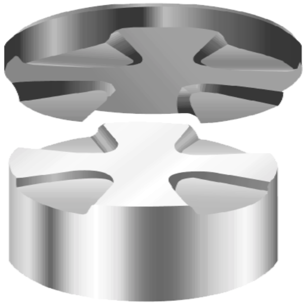
Black Diamond™ Cutters

Black Diamond cutters are available in various configurations. All incorporate Black Ice polished diamonds. See Figure 4-6.

- **RADXC** – Using a CSE chamfer and special interface, these cutters are designed for use in interbedded formations where impact damage is an issue.
- **RADXS** – RADXS cutters use a special interface and sharp edges to more effectively cut into reactive shales.
- **AXSYM** – A special interface is employed to provide resistance to impact and abrasion in firm to harder formations. These cutters are used primarily on the nose and shoulder areas of the bit.

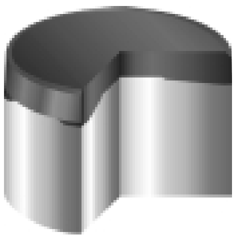
Engineering Cutter Layout

- Specific cutter layout designs obtain optimum performance in given drilling environments. Cutter position on the bit improves impact and abrasion performance. See Figure 4-7.



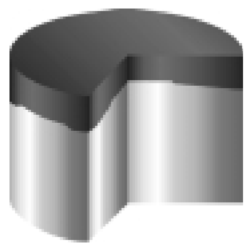
RAD Interface

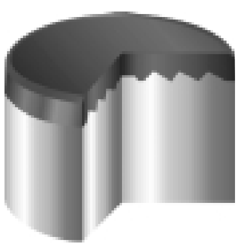
AXSYM Interface



RADXC *is designed for use in interbedded formations where impact is an issue. It uses the CSE chamfer.*

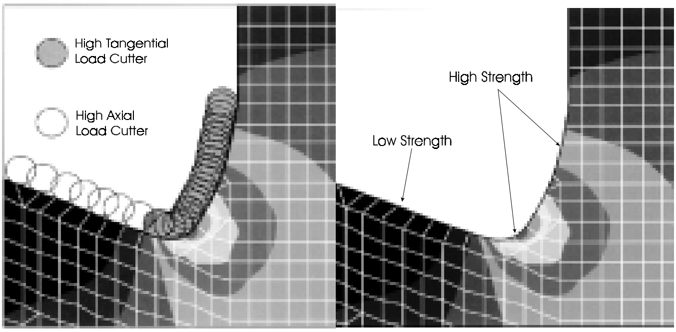
RADXS *is a sharp-edged cutter designed for drilling reactive shales by maximizing cutting efficiency.*





AXSYM *cutters provide resistance to impact and abrasion in firm to harder applications and are used primarily in the nose and shoulder of hard abrasive designs.*

Figure 4-6 Black Diamond Cutter Configurations



Cutters designed for specific loads are statically positioned on the bit body to match borehole rock strengths.

Figure 4-7 Core Bit Cutter Design

Natural Diamond Bits

Natural diamond bits employ comparatively large natural diamonds that are cast directly into a tungsten carbide matrix crown. The diamonds provide smooth cutting surfaces for improved wear during coring in medium-to-hard formations. Each C-Series coring bit is manufactured to match specific applications. Various grades, sizes, and concentrations of natural diamonds in these bits match specified criteria. The stones are surface-set in custom-designed bit bodies for high performance and long bit life.

Natural diamond bits are offered in a variety of styles for both rotary coring and motor coring applications. A C201 bit and drill plug also are available for CoreDrill bits.

Impregnated (Synthetic Diamond) Bits

SC-Series impregnated diamond bits use small thermally-stable, self-sharpening PDC cutters for fast penetration and long bit life in medium-to-hard, abrasive formations. These Ballaset™ synthetic cutters are cast into the tungsten carbide bit matrix. The bits can operate in situations where high frictional heat is generated (2,192°F/1,200°C).

Sintered diamond bits (within the SC-Series) contain sharp, grit-size synthetic diamonds sintered directly into the bit matrix in a high pressure, high temperature process. These bits are designed to drill the hardest, most abrasive formations at high-rpm without premature bit wear.

Core Bit Selection Guide

Core bits are selected partly by formation characteristics. The Core Bit Selection Guide, Table 4-2, matches the targeted formation with a recommended bit type.

Table 4-2 Core Bit Selection Guide

Formation	Rock Type	Recommended Core Bits
Soft formation with sticky layers and low compressive strength	Gumbo, Clay, Marl	ARC422
Soft formation with low compressive strength and high drillability	Marl, Salt, Anhydrite, Shale	ARC422, ARC412, ARC425
Soft to medium formation with low compressive strength interbedded with hard layers	Sand, Shale, Chalk	ARC425, RC476
Medium to hard formation with high compressive strength and small abrasive layers	Shale, Mudstone, Limestone	C18, SC226, SC777, ARC325, ARC427, RC478GN, ARC427
Hard and dense formation with very high compressive strength but non-abrasive	Limestone, Dolomite	C23, SC226, SC278, C201, SC777, ARC427, SC277, RC478GN
Hard and dense formation with very high compressive strength and some abrasive formation layers	Siltstone, Sandstone	C23, SC278, SC277, SC279, SC281
Extremely hard and abrasive formation	Quartzite, Volcanic	SC281

For a complete listing of all Baker Hughes INTEQ/Hughes Christensen core bits, refer to the BHI Bit Selection Guide brochure or contact your local BHI or HCC representative.

PDC Coring Bits

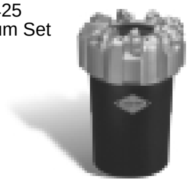
ARC412
Light Set
PDC
Anti-Whirl

For ultra soft-to-medium-hard formations where fast rates of penetration are required for low invasion.

ARC422
Light Set
PDC
Anti-Whirl

For ultra soft-to-medium-hard formations where fast rates of penetration are required for low invasion.

ARC425
Medium Set
PDC



For soft-to-medium-hard formations. Designed to produce uninvaded core at optimum penetration rates.

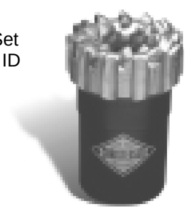
AWC425
Medium Set
PDC
Anti-Whirl
CoreDrill

Used with CoreDrill core barrel. Designed to drill and core a wide variety of formations at optimum penetration rates.

ARC325
Small Cutter
PDC Anti-Whirl

For medium-hard formations. Designed for applications where even cutter loading, small diameter coring bits, and enhanced performance in motor drilling are required.

RC476
Medium Set
PDC with ID



Fluid
Courses

Designed for general applications in soft-to-medium-hard formations.

ARC427
Heavy Set
PDC

For medium-to-hard formations where traditional PDC coring bits have not been able to core.

RC478GN
Heavy Set
PDC with ID

Designed for general application in medium-hard-to-hard formations.

Figure 4-8 PDC Coring Bits

Ballaset® Core Bits

SC226
Triangular Ballaset

For general purpose coring in medium-to-medium- hard formations: limestone, dolomites and siltstones.

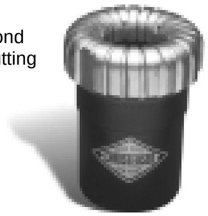
SC777
Heavy Set Cylindrical Ballaset

Used for medium-hard-to-hard formations with abrasive layers.

SC278
Ridge Set Ballaset

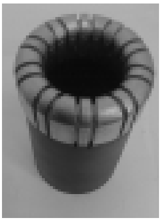
Designed to core formations generally considered too abrasive, fractured, or hard for standard Ballaset coring bits.

SC279
Synthetic Diamond Impregnated Cutting Elements



Used for coring hard, abrasive formations such as sandstones and conglomerates.

SC281

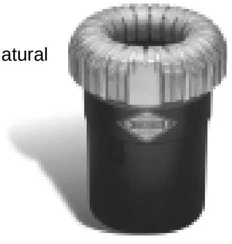


For extremely hard and abrasive formations.

Figure 4-9 Ballaset Core Bits

Natural Diamond Core Bits

C201
General Purpose Natural Diamond



Set with diamonds of 6 to 8 stones per caret. For medium-to-medium-hard formations.

C23
Ridge Set Natural Diamond

For coring in hard, dense, moderately abrasive formations with high compressive strength.

Figure 4-10 Natural Diamond Core Bits

Coring Procedures

This chapter reviews basic coring procedures using either a high torque or conventional core barrel with disposable inner tubes. Hydro-Lift, motor coring, high pressure coring, and wellsite handling procedures are also covered. Specialized procedures for Pressure Coring and for S_{or} Coring are not covered in this handbook.

Nomenclature

Major Core Barrel Components

- ***Outer Barrel*****:** outer, thick-walled barrel which attaches to core bit on one end and drillstring on the other. The outer barrel encloses inner core barrel components. The O.D. of the outer barrel is always less than the hole size to allow for fishing operations.
- ***Inner Barrel*****:** receiver for core column being cut by core bit. Inner barrels are generally made of thin-walled steel. Aluminum and Fiberglass inner barrels are now commonly used as the standard and preferred method to containerize the core. Both aluminum and fiberglass are disposable.

- ***Inner Tubes*****:** PVC, aluminum and fiberglass inserts for the steel inner barrel. Inner tubes containerize core samples and generally are disposable.
- ***Core Bit*****:** hollow drill bit at end of core barrel designed to cut the rock. The center part of the bit forms a column of rock to become a core. Core bits are application-specific with a cutting structure of choice, i.e., natural diamond, synthetic diamond, or polycrystalline diamond compact cutters.
- ***Outer Barrel Stabilizers:*** segments of outer barrel, generally 3 feet in length and constructed with hardened ribs, keep core barrel centered in well bore. OD of stabilizer ribs is larger than that of outer barrel and equal to hole size.
- ***Safety Joint:*** segment of bottomhole assembly that connects drillstring to core barrel. Safety joint threads are larger than any other found on the barrel, and are designed to allow inner barrel assembly to be backed-out and recovered in case of a stuck barrel.
- ***Top Sub:*** top part of the HT core barrel that connects to the drillstring. High torque core barrels (HT series & Core Master) have been designed and standardized with a top sub, leaving the safety joint as an option only.
- ***Swivel Assembly:*** a section of inner barrel that connects inner barrel to safety joint or top sub. Bearings allow outer barrel to rotate about inner barrel without turning the inner barrel.
- ***Drop Ball:*** a steel ball dropped from the surface through the drillstring or from a downhole sub assembly that seats in an inner tube, plugging and blocking flow of drilling fluid through the inner core barrel. The ball is dropped to initiate coring, which is conducted without drilling fluid flow through inner barrel. Seating action of the ball forces fluid flow through the annulus space between outer and inner core barrels.

- ***Core Catcher:*** a device configured inside a shoe assembly located at the bottom end of the inner barrel assembly. Its function is to grab and break the core at the bottom prior to retrieving the core. The sprint type catcher is the most commonly catcher type in use. The internal face (I.D. of catcher) is surfaced with tungsten carbide grit and opens to the size of the core cut.

  Various other catcher types are in use and application specific (basket, flapper, slip & dog, slip & knife, etc...).
- ***Lower Shoe:*** lower end of inner core barrel; holds core catcher and seats into throat of bit.
- ***Upper Shoe:*** extension connecting the pilot or extended pilot (Low Invasion) lower shoe to the inner barrel.

Other Components

- ***Inner Barrel Stabilizer:*** a device that centers inner barrel within outer barrel, keeping inner barrel straight and preventing contact between the outside diameter of the inner barrel and inside diameter of the outer barrel.
- ***Drop Ball Sub:*** a downhole device connected to the outer barrel and used to release a ball in any application where the ball cannot be dropped from the surface. The device is activated by a pressure surge in the circulating system.
- ***Downhole Activated Flow Diverter:*** a ball launcher holding the drop ball a few inches above the seat and located inside of the outer barrel. This is a replacement of the pressure relief plug (standard ball seat). DAFD is activated by an increase in flow rate inside of the core barrel.
- ***Long Distance Adjustment:*** a device and procedure for spacing aluminum or fiberglass inner tubes to compensate for differences in thermal expansion between steel outer barrel and disposable inner tubes.

Coring System Preparations

Outer Barrel Makeup

Core Barrels Shorter than Derrick Height

Makeup and handling of conventional 250P Series, Coremaster high torque and HT Series core barrels are similar. The following procedures are based on barrels shorter than the derrick in length.

1. Prior to makeup of outer barrel assembly, check the following items:
    - Check shoulder on safety joint or top sub for damage or washing
    - If running a safety joint assembly, examine friction ring for wear
    - Check all stabilizer diameter dimensions. Record the blade length, width and gauge length of blade
    - Measure outer barrel and document components, spacers and assembly lengths (O.D./I.D.)
    - Evaluate condition of bit and check the threads
    - Place the shoe assembly inside the core bits and verify that the shoe properly seats
    - Check the flow path inside the bit throat
    - Check the condition and seating of the core catcher inside the shoe assembly
    - Determine and check the X-overs, float and circulating sub requirements for the core barrel to make up the BHA.

2. Determine if drop ball will be run in place or dropped from surface.

   - Report completeness and status of the coring equipment requirements for the job to the company representative
   - Review and discuss with the company representative and rig crew the BHA design for the core barrel run.

Note: *When hole conditions dictate circulating extensively to reach bottom, leave drop ball out of barrel.*

3. Make up outer barrel as follows:

   a. Check lower thread protector and elevator lifting sub to ensure they are chain-tong tight prior to picking up.

Note: *Using a marker, draw a vertical line on the elevator sub and on the body of the top safety joint or top sub. This will allow for spot checks to make sure the elevator sub is not backing off.*

Note: *When possible, place the core barrel in the mouse hole and tighten lift elevator sub to specifications.*

   b. Pick up bottom section of core barrel

   c. With outer core barrel hanging in derrick, check the thread protector and make sure protector sub is tight.

   d. Torque top connection of near-bit stabilizer to required limits.

   e. Lower the barrel to the next stabilizer and set slips and drill collar clamp.

Note: *The drill collar clamp should never be higher than 2" above the drill collar slips and can not be set on/or above the core barrel connection.*

f. Torque pin of stabilizer to box of outer barrel.

g. Break-out the elevator lift sub.

Note: *See Appendix B for torque limits as applicable:*

- Table B-1, “HT Series Outer Barrel Mechanical Properties,” on page B-1
- Table B-2, “Coremaster Series Outer Barrel Mech. Properties,” on page B-1
- Table B-3, “250P Series Outer Barrel Mechanical Properties,” on page B-2
- Table B-4, “250P/350P/HT Series Inner Tube Mech. Properties,” on page B-3.

Note: *Avoid placing rig tongs over box section of core barrel thread, as this could give a false make-up torque reading.*

8. Pick up next outer barrel section.
9. Make up to next section of core barrel.
10. Torque outer tube connection.
11. Remove collar clamp and lower barrel to next connection.
12. Repeat Steps 4 to 7 for each section of core barrel required.
13. Make up final connection (bottom of top stabilizer).
14. Lower barrel and set slips as closely as possible to section body.

Note: *Leave enough room for a drill collar clamp.*

15. Back out top sub or safety joint and set aside until inner barrel is loaded.
16. Load inner barrels (refer to Loading Inner Barrels/ Tubes, page 5-12).
17. Make-up safety joint or top sub.
18. Pull outer assembly out of the rotary.
19. Break-off bottom protector.
20. With core gauge, measure shoe spacing with respect to outer barrel pin.
21. Adjust inner assembly with respect of specific expansion needed.
22. Pick-up core bit.
23. Install bit on core barrel.
    a. Using a bit breaker, place bit on a stripper on rotary table.
    b. Thread bit onto barrel until hand tight.
    c. Place bit with breaker into rotary table and lock table.
    d. Place rig tongs above blades of near bit stabilizer and torque to required limits.

Core Barrels Longer than Derrick Height

Makeup and handling of conventional 250P Series, Coremaster high torque and HT Series core barrels are similar. The following procedures are relevant for core barrels equipped with Long Distance Adjustment (LDA) and for barrel runs longer than the derrick can accommodate. Core barrels are to be fitted with an LDA for space out of the inner barrel assemblies without having to pull the outer assembly from the hole.

Considerations

Longer barrel runs reduce the number of core runs needed to complete the coring program and hence the rig time, which is of prime importance in drilling a well economically. The coring specialist shall attend and contribute to the pre-job meeting when required. Assemblies, hole angle, geology, rig capabilities, customer procedures, crew and operation safety have to be discussed with the Operator representatives.

- Core compaction can occur in certain formations as a result of filling excessive core length inside a long barrel. Consultation should be made with geology or petrophysics or the appropriate responsible person prior to any long barrel coring program to ascertain expected formation strengths.
- Longer barrels may resonate at a greater degree than shorter, stiffer barrels. To minimize vibrations, which can lead to disruptions of core with subsequent jamming, use of inner barrel stabilization and bit end bearings is recommendable for added stability.
- Spacing of the inner barrel to match the outer barrel to account for differential rates of thermal expansion becomes critical with long barrel coring.

Baker Hughes INTEQ employs a unique patented spacing system, the Long Distance Adjustment system or “LDA.” for short. This allows rapid adjustment of up to 23" on making-up the assembly, saving rig time.

Standard Barrel Application

When arriving on site, perform the following as early as possible.

- Check shoulder on safety joint or top sub for damage or washing
- If running a safety joint assembly, examine friction ring for wear

- Check all stabilizer diameter dimensions. Record the blade length, width and gauge length of blade
- Measure outer barrel and document components, spacers and assembly lengths (O.D./I.D.)
- Evaluate condition of bit and check the threads
- Place the shoe assembly inside the core bits and verify that the shoe properly seats
- Check the flow path inside the bit throat
- Check the condition and seating of the core catcher inside the shoe assembly
- Determine and check the X-overs, float and circulating sub requirements for the core barrel to make up the BHA.

Note: *When hole conditions dictate circulating extensively to reach bottom, leave drop ball out of barrel.*

1. Make up outer barrel as follows:

   a. Check lower thread protector and elevator lifting sub to ensure they are chain-tong tight prior to picking up.

Note: *Using a marker, draw a vertical line on the elevator sub and on the body of the top safety joint or top sub. This will allow for spot checks to make sure the elevator sub is not backing off.*

Note: *When possible, place the core barrel in the mouse hole and tighten lift elevator sub to specifications.*

   b. Pick up bottom section of core barrel.

c. With the outer barrel hanging in the derrick, remove the thread protector.

d. Dope the threads with an API-rated thread dope.

e. Make up the bit onto the core barrel until hand tight.

f. Place the bit breaker into rotary table and lock table.

g. Mount the bit breaker onto the bit shank.

h. Place rig tongs above blades, near bit stabilizer.

i. Torque the core bit to the required limit.

2. Pick-up the core barrel and remove the bit breaker.
3. Lower the barrel through the rotary to the next stabilizer and set slips and drill collar clamp.

Note: *Leave enough room for the drill collar clamp. The drill collar clamp should never be higher than 2" above the drill collar slips and can not be set on/or above the core barrel connection.*

4. Torque pin of stabilizer to box of outer barrel.
5. Break out the elevator lift sub.

Note: *See Appendix B for torque limits as applicable:*

- Table B-1, "HT Series Outer Barrel Mechanical Properties," on page B-1
- Table B-2, "Coremaster Series Outer Barrel Mech. Properties," on page B-1
- Table B-3, "250P Series Outer Barrel Mechanical Properties," on page B-2
- Table B-4, "250P/350P/HT Series Inner Tube Mech. Properties," on page B-3.

Note: *Avoid placing rig tongs over box section of core barrel thread as this could give a false make-up torque reading.*

6. Pick up next outer barrel section and remove protector.
7. Dope the connection with an API-rated thread dope.
8. Make up the core barrel section with chain tongs to the outer barrel. Torque the connection into the stabilizer box to the required limits.

Note: *Never use the rotary table to back into the outer core barrel connection.*

9. Remove the collar clamp and lower the barrel to the next connection.
10. Make up and torque the stabilizer to the required limit.

Note: *Repeat step 2 to 6 for each section of core barrel required.*

11. Make up the final top section of the core barrel.
12. Set slips 2 to 3 feet (0.5 to 0.75 m) from connection.
13. Place break-out tong on outer tube using caution not to damage or compress the box connection.
14. Torque connection to the required limits.
15. Back out the top sub and set aside until the inner barrels are loaded.
16. Once the inner barrels are loaded, connect LDA/top sub to the inner barrel assembly.
17. Perform spacer adjustment as shown in Long Distance Adjustment, page 5-16.

Loading Inner Barrels/Tubes

Procedures for Fiberglass & Aluminum Barrels

1. Pick up inner tubes using tugger and swivel with lifting cap or inner tube clamp.
2. Inspect and verify core catcher I.D. dimensions. Make up shoe assembly.
3. Thread shoe assembly with catcher to inner barrel, either on catwalk or with barrel hanging on tugger line.
4. With both connections tightened, run inner barrel into outer barrel.
5. Clamp inner barrel, leaving sufficient room for chain or pipe wrenches below box connection.

Note: *Leave thread protector lifting sub on until next joint of inner barrel has been picked up.*

Note: *If next section is to be picked up by a sling, string sling through elevators and lift with blocks. If possible, attach a swivel.*

6. Steady top inner tube from stabbing board.
7. With second inner tube hanging above core barrel, loosen bottom thread protector almost to removal.
8. Position inner tube close to box of installed inner tube.
9. Connect and tighten inner tube sections.

Note: *See Appendix B for torque limits as applicable:*

- Table B-5, “Aluminum Inner Tube (IT) Specifications,” on page B-5

- Table B-6, Aluminum Inner Tube Properties (6061-T6).

10. Remove clamp from first section.
11. Run tubes into outer barrel.
12. Clamp next barrel, ready to accept another section.
13. Repeat inner tube installations (steps 1 through 11) as required.
14. Make up inner tube plug to top section of inner barrel.
15. Torque top section connection to required limits using pipe wrenches.
16. Torque top sub and check inner barrel assembly for spacing.
17. Perform Inner Tube Adjustment procedure, following, to adjust spacing as required.

Inner Tube Adjustment

The length of the inner tube assembly must be adjusted either with shims or the Long Distance Adjustment (LDA) assembly. LDA is standard for every core barrel size. This requires adjusting the inner barrel spacing when the core head is to be made up first because of core barrel length exceeding the derrick length. The standoff between the bottom of the pilot shoe and the top of the core bit is determined by the coring engineer.

Note: *Refer to* Appendix B, Table B-14, “L.D. Adjustment System Calculation,” on page B-11.

Note: *Allow for thermal expansion of inner tubes. See* Appendix B *as applicable.*

- Table B-7, "Spacing of Aluminum Inner Tubes Based on Thermal Expansion Coefficients," on page B-6
- Table B-8, "Spacing of Fiberglass Inner Tubes Based on Thermal Expansion Coefficients," on page B-7
- Table B-9, "Inner Tube Relative Thermal Expansion," on page B-8.

Note: *Additional inner tube dimensions and specifications are provided for reference as needed. See the following tables:*

- Table B-10, "Fiberglass Inner Tube Dimensions," on page B-9
- Table B-11, "Fiberglass Inner Tube Specifications," on page B-9
- Table B-12, "Fiberglass Inner Tube Critical Buckling Pressure," on page B-10
- Table B-13, "Fiberglass Inner Tube Axial Tensile Strength," on page B-10.

Shims

1. Break core barrel at safety joint or top sub.
2. With rig block and elevators, lift safety joint or top sub until reaching the top of the swivel assembly (approximately 2 feet [0.6 m]).
3. Attach inner tube clamp at top of inner barrel and slack off until the inner tube rests on top of the outer barrel.

Note: *When installing split shims, skip steps 4 to 6.*

4. Break out joint between swivel assembly and top sub/safety joint.

5. Lift safety joint.
6. Take out or put in required number of adjusting shims.

Note: *4¾" core barrels can be shimmed between swivel assembly and top sub/safety joint. Break on inner tube plug to place shims.*

7. Two shim sizes are available; one set fits the inner barrel break and the other fits the cartridge cap.
8. Make up safety joint/top sub onto bearing assembly.

Note: *Extra precaution is required when making up or breaking fine thread connections.*

9. Tighten with chain tongs.
10. Remove inner barrel clamp and make up core barrel.

Long Distance Adjustment

Long Distance Adjustment (LDA) uses a locking screw with 23 inches (584 mm) of travel, replacing the shim and sub methods for thermal compensation. It is the best method for thermal compensation when long core barrels are being run.

1. Calculate standoff between bottom of pilot shoe and top of core bit.

Note: *See* Appendix B, Table B-14, "L.D. Adjustment System Calculation," on page B-11.

2. Make up inner barrel assembly, leaving out the cartridge cap.
3. Back off locknut approximately 8" (20 cm) and slide spline bushing up shaft.
4. Set cartridge bowl to NEUTRAL position at mark in shaft groove.
5. Gently screw in the top sub or safety joint pin until catcher shoe sits in bit.
6. Measure gap left in top sub or safety joint, then back out the pin.
7. Screw cartridge bowl up shaft a distance equal to measured gap plus 0.16 inches (4 mm) for standard clearance, plus clearance calculated for thermal expansion (if applicable).

Note: *If hot hole conditions exist, perform* Inner Tube Adjustment on page 5-13.

8. Slide spline bushing into position and secure with locknut.
9. Make-up safety joint or top sub and run in hole.

Procedures for Plastic Liners or Inner Tubes

Plastic liners are still used, primarily for containerization of the core, as an alternative to fiberglass and aluminum disposable inner barrels. It is important to realize two limitations when using plastic liners:

- Smaller diameter core is recovered
- Temperature limitations.

For higher temperature applications, aluminum tubes are recommended.

Plastic Liners

Plastic liners can be used in 250P series and 8" × 4$^{3}/_{4}$" Hydro-Lift core barrel to containerize the core. There are three types of plastic liners available.

- **PVC** (Polyvinyl chloride): Temperature limitations are 150°F for Type I and 140°F for Type II (High Impact).
- **ABS** (Acrylonitrile Butadiene Styrene): Temperature limitation is 180°F, but has lower chemical resistance and design strength than PVC. ABS is suited for low temperatures of 32°F or below.
- **BUTYRATE** (Tenide 525): Clear plastic liner. Temperature limitation is 140°F. Core can be viewed through the liner.

Running Plastic Liners w/ 250P Series Core Barrel

Care should always be taken in handling and loading the sleeve into the inner barrels. The sleeve to be used should be inspected inside and out. If there are any bubbles in the inside diameter, or if the plastic is distorted in any way, it should not be used. It is a good policy to load the inner barrels in the shop or yard if the plastic liner is to be used.

If the barrel is ready to pick up and assemble when it reaches the location, this saves rig time.

Loading 30-ft Core Barrel

If a 30-ft. core barrel is run, the loading and unloading procedures are as follows:

1. With the top section of the barrel laying horizontal on the pipe racks, remove the lower 2-ft. stabilizer and the outer tube bottom plug.
2. Remove the inner tube shoe assembly from the inner barrel, including the core maker.
3. Insert a 30-ft. joint of plastic sleeve into the inner barrel. Make sure the top of the plastic sleeve goes all the way in over the drop ball seat and is pushed up tight to the inner tube plug. The upper shoe is specially built for the use of plastic liners.
4. Measure the depth of the shoulder or seat in the inside diameter of the upper shoe (approximately 1 inch). Measure so the overall length of the plastic will seat in the upper half.
5. Holding the plastic sleeve tightly against the top of the inner barrel, saw off the excessive length of plastic exposed out of the inner barrel. Use a half moon file and smooth the sharp edge of the inner diameter of the plastic sleeve.
6. Clean and dope the threads, then tighten the inner tube shoe assembly. The plastic should be seated firmly into the upper half seat.

Care should be taken in measuring and cutting the plastic sleeve. After the inner tube shoe assembly is tight, there should not be any slack, or, if the sleeve was cut too long, it should not be squeezed into the inner barrel. It needs to be a good snug fit with no movement.

7. By looking into the end of the plastic sleeve, make sure there are no sharp edges sticking out into the

inner diameter of the upper half. Also make sure to taper or bevel the inner diameter of the plastic sleeve before installing the inner tube shoe.

8. Replace the outer tube 2-foot stabilizer and the outer tube bottom plug.

Note: *The barrel is now ready to be picked up and the core bit installed for the trip in the hole.*

Unloading 30-ft Core Barrel

1. After the core is cut (30 ft.) and pulled back to surface, remove the bit and make-up the thread protector.
2. Set the slips and safety clamp on the core barrel and break the safety joint in the normal way.
3. Pull the inner barrel out and lay it out on the walk.

Note: *If the safety joint pin and swivel assembly are all laid down together, care should be taken and safety should prevail. The safety joint pin can be broken off at the inner tube plug with the inner barrel clamped off. Then the inner barrel can be laid down with a lift plug or an elevator sub. See* Breaking Out of Outer and Inner Barrels, page 5-37.

4. After the inner barrel is on the walk, break the inner tube shoe top end off the inner barrel.
5. Take a pair of vise grips and clamp onto the plastic sleeve.

Note: *With a short piece of rope, the sleeve can be pulled out and cut off at any desired length.*

6. Reload the inner barrel with a new joint of plastic using the same procedures.

Note: *The inner barrel is ready to be picked up and put back together for another trip in the hole. If there is no more coring to be done, do not load the plastic.*

7. Install the inner tube shoe assembly, pick up the inner barrel and get the complete barrel broken down and ready to lay down for transportation back to the shop.

Loading 60-ft Core Barrel

Running a 60-foot core barrel, rather than a 30-foot barrel is slightly more complicated (and may adversely affect recovery levels.) With both barrels on the rack and made to go together as a 60-foot barrel, follow these procedures:

1. On the top section, remove the outer tube bottom plug (long).
2. Insert the plastic sleeve into the inner barrel.
3. Make sure the top of the plastic goes over the drop ball seat and against the inner tube plug.
4. Hold the plastic snug and saw off the excessive length even or flush with the pin threads on the inner barrel.
5. Taper the end of the plastic sleeve with a half moon file. Care should be taken not to file off too much, making the shoulder of the plastic too thin. Take just enough off to remove the sharp edges of the inside diameter.
6. Install the inner barrel protector; then install the outer tube bottom plug (long).

Note: *The top section is now ready to be picked up.*

7. On the bottom section of the 60-foot barrel, make sure the elevator sub is shouldered and tight into the inner barrel and also into the outer tube.

8. Remove the bottom 2-foot stabilizer and the outer tube bottom plug (short).
9. Remove the inner tube shoe assembly from the inner barrel.
10. Insert a joint of plastic into the inner barrel.
11. Measure the depth of the seat or shoulder in the upper shoe or half (approximately 1 inch), and cut the plastic, leaving that amount exposed out of the inner barrel. Taper the inside diameter of the plastic with a half moon file.
12. Clean and dope threads.
13. Tighten inner tube shoe assembly on the inner barrel.
14. Inspect the inside diameter of the upper shoe for sharp edges and for a snug fit into the seat of the upper shoe.
15. Replace the 2-foot stabilizer and the outer tube bottom plug (short).

Note: *The barrels are now loaded and ready to be picked up.*

16. Pick up the bottom section and place it in the rotary table with slips and safety clamp set.
17. Back out inner barrel and clamp off.
18. Remove the elevator sub from the inner barrel.

Note: *Notice the top of the plastic is now even with the bottom of the box on the inner barrel.*

19. Pick up top section of the core barrel.
20. Remove the outer tube bottom plug (long), and then remove the inner barrel protector with care. The plastic sleeve will be sitting in the protector.
21. Thread the protector off close to the rotary table.

22. With the plastic sleeve resting on the rotary table, pick up the core barrel above the top of the inner barrel so that it is in the rotary table.
23. Lift the plastic sleeve by hand and set it in the top of the bottom inner barrel. The plastic will go all the way down in the box and rest on top of the bottom plastic sleeve.
24. Make up the inner barrels together and tighten with chain tongs and/or pipe wrenches.

Note: *Remember that the bottom section of plastic was cut to fit at the bottom of the inner barrel box and that the top section of plastic was cut flush with the pin threads on the inner barrel.*

Note: *After the inner barrels are tightened together, the plastic then has to have a snug fit with no up and down movement.*

25. Make up and tighten the outer barrels with rig tongs.
26. Pull barrel out of the rotary table and remove outer tube bottom plug (short).
27. Inspect inner tube shoe assembly for spacing and look into the inside diameter of the inner tube shoe assembly for any distorted plastic. If it looks normal, install core bit and go into the hole.

Unloading 60-ft Core Barrel

With the core cut (60 feet) and back out of the hole, follow these procedures:

1. Remove bit and install a thread protector.
2. Set slips and install safety clamp.
3. Break safety joint and pull the top 30 feet out of outer barrel.

4. Clamp off bottom section of inner barrel.
5. Break and unscrew inner barrels.
6. Pick up top section of inner barrel approximately six inches. The plastic will be seated in the box of the bottom inner barrel. Care should be taken when you pick up the inner barrel. If the plastic is wedged, it will pick up with the inner barrel, leaving the core exposed.
7. If everything is normal, the inner barrel will raise, leaving the plastic sleeve seated in the bottom inner barrel.
8. Install the special inner barrel and plastic sleeve clamp.
9. Pick up inner barrel, plastic sleeve and core.
10. Set core on the pin with the special inner barrel protector.
11. Loosen clamp and tighten protector on the inner barrel. The top section is now ready to lay down.
12. Screw a pump-out bean with swivel and chain into the bottom inner barrel and tighten until shouldered. It is important that it be shouldered tightly. If it is not threaded in all the way, plastic will be cut too long when reloaded.
13. After the bottom section is tightened, lay it down.

Note: *Care should be taken while sliding the inner barrel out on the walk. If the shoe is a lip type, the lip can be damaged by sliding it on the steel walk.*

14. Break off the inner tube shoe assembly and pull the plastic out with vise grips and a short rope.

Note: *The top section will have about 8 inches of plastic to hold on to.*

15. Reload both inner barrels following the same procedures.
16. Pick up bottom inner barrel and clamp off.
17. Pick up top inner barrel and safety joint pin.
18. Screw inner barrels together and tighten with chain tongs and/or pipe wrenches.
19. Make-up outer barrels and get ready to go back into the hole.

Coring with Plastic Liners

Conventional coring with plastic will have a long, or standard, upper shoe. An orienting shoe will have a short upper shoe.

The only tools needed for using the plastic sleeve are a specially made clamp for handling the upper section of core, an 8 inch pin welded on a steel plate, a specially-made protector to hold the plastic and core in the upper section while laying it down, a pump-out bean with a swivel, and an endless chain to handle the bottom 30 feet of the inner plastic and core. (*These are the only five pieces of handling equipment required to lay down a plastic sleeve core*.)

It is advisable to omit the pressure relief ball so the mist and foam can lubricate the inside diameter of the plastic. If the ball is in place, the dry plastic gets hot, preventing the core from entering the plastic sleeve.

With this procedure, you can take any 250P series core barrel and use it with the plastic sleeve.

Anytime you use plastic, however, it cuts down the core O.D. by ½". (For example, a 6¼" × 4" barrel will cut a 3½" core and a 5¾" × 3½" barrel will cut a 3" core.) Also keep in mind that using plastic requires a special plastic sleeve core bit.

Using the plastic sleeve will give a less disturbed core compared to a used steel inner barrel, especially in a highly fractured formation. Better recoveries are anticipated. The core can then be packaged and readied for transportation to the core analysis lab.

Plastic sleeves can be run in some high temperature holes if circulation is broken quite often while going in the hole. Keep circulation and rotation at all times while on bottom. Do not let the barrel sit without circulation or rotation for any length of time. Break circulation coming out of the hole, depending on hole temperatures.

General Coring Procedure

Check Points Before Coring

Outer barrel make-up procedures include determination of whether the drop ball is to be run in place or dropped from the surface after bottom is reached. If drop ball is to be run in place, skip Dropping Ball to Start Coring on page 5-27.

Running in Hole

In full hole coring, enter into hole methodically. Exercise caution at all tight places to avert sticking of bit. Tight places must be reamed out. Do not ream long intervals with core bit, as bit life can be adversely affected.

1. Check for use of a float, type of float, and condition.
2. Check bore of jars to ensure passage of ball (usually 1¼" (32 mm) diameter).
3. Establish that the drilling assembly is free of debris.

Conditioning Hole

1. Establish circulation 2 or 3 stands off bottom.
2. Ensure that all measurements are correct to determine bottom.
3. Circulate without rotating if possible.

Note: *Should rotation be required, avoid coring on fill. Begin to rotate when nearing bottom.*

4. While circulating on bottom, raise barrel off bottom to ensure clean inner barrel.

Note: *It is necessary to raise BHA only a few inches until surface indicators show a loss of torque and WOB.*

Note: *If ball is to be dropped, skip steps 5 through 7 and perform* Dropping Ball to Start Coring *procedure below.*

5. Return to bottom.
6. Once on bottom, start slow rotation (30 to 40 rpm).
7. Set flow rate to coring flow rates required.
8. Add weight on bit in increments of 2,000 lbs, gradually increasing rpm until optimum coring conditions are stabilized, and then adjust WOB until desired ROP is reached.

Dropping Ball to Start Coring

1. Raise Kelly or top drive to first joint of drillpipe after hole has been circulated.
2. Remove Kelly or top drive and drop ball into drillpipe.
3. Once ball has been dropped, engage pumps and pump the ball down at a reduced circulation rate.

Note: *Allow one minute per 1,000 feet (305 m) for ball to drop.*

4. Record pump rate and stand pipe pressure while ball is falling. As ball nears bottom, slow pumps to allow ball to properly seat.

Note: *Ensure that pumps are cut back before ball lands on pressure relief plug.*

5. As soon as ball is seated, start the pumps and record increase in stand-pipe pressure and return to bottom.
6. Once on bottom, start slow rotation (30 to 40 rpm).

7. Add weight on bit in increments of 2,000 lbs, gradually increasing WOB, rpm, and fluid volume until optimum coring conditions are stabilized.

Rotary Rig Connection Procedure

Note: *Follow this procedure when using a rotary rig.*

After pulling off bottom to make a connection or to remove core barrel, make new connection as follows:

1. Stop rotation and shut off or idle pump.
2. Raise core barrel until weight indicator shows core spring has gripped core and core breaks, or until strain exceeds pulls listed in Table 5-5-1.

Table 5-1 Recommended Pull When Breaking Core

$2^1/_8$" Core	5,000 lbs.
$2^5/_8$" Core	10,000 lbs.
3" Core	12,000 lbs.
$3^1/_2$" Core	15,000 lbs.
4" Core	20,000 lbs.
$5^1/_4$" Core	35,000 lbs.

3. If core does not break with maximum strain, start pump and hold strain on core until it breaks.

Note: *It may be necessary to hold strain for 10 minutes or more for core to break.*

4. After core has broken, raise bit 10 feet (3 m).
5. Slowly lower to within one foot of bottom.

Note: *Maintain constant check of weight indicator to see that weight readings drop gradually without any obstruction caused by core left in hole.*

6. If core appears to be properly caught in barrel, pick up and make a connection. If not, pull out of hole.
7. Lock rotary table and back Kelly out with tongs when making connection.
8. After making connection, run coring assembly on bottom.
9. To resume after making a connection, return to bottom without rotating. With pump on, apply normal weight to help release core catcher so that core can enter inner barrel.
10. Pick up to starting weight.
11. Start slow rotation, gradually returning to normal coring conditions.

Note: *In those instances where there is a possibility of loose junk or pieces of core on bottom, use lighter WOB for first 6" (15 cm). Pump can dispose of small pieces of junk or formation material before normal coring weight is applied.*

Top Drive Connection Procedure

When coring with a top drive rig, perform the following procedure to make connection without pulling off bottom:

1. Once top drive reaches rig floor, allow core bit to drill off, then:
    a. Turn off depth recorder.
    b. Shut down rotary table.
    c. Shut down circulation pump.
2. Set slips; do not allow additional weight to be placed on bottom.
3. Back out top drive. Keep drillstring stationary.
4. Pick up drillpipe.

Note: *In most cases this will be a 90-foot (27 m) section.*

5. Make up new section to drillstring; keep drillstring stationary during make-up.
6. Start pumps and set to desired gpm.
7. Start rotating at desired rpm.
8. Add WOB until desired weight is obtained.
9. Turn on depth recorder and begin coring.

Note: *Most inner barrel jamming occurs after making a connection. Be alert to rig floor indicators of jamming.*

Operating Parameters

Circulation

Sand content of drilling fluid should be maintained at less than 1% to minimize fluid damage to core barrel, bit shank, and bit crown.

Volume of liquid to be circulated is determined by:

- Condition of well
- Size and design of bit
- Type of drilling fluid
- Depth of hole
- Drillpipe, core barrel, and pump capacity
- Formation characteristics.

Annular Velocities

Annular velocities as low as 90 feet (27 m) per minute have been used without creating problems when coring with a good drilling fluid. Sufficiently high velocities prevent settling of cuttings.

Coring bits of same size are designed for same circulation rate, even if different in configuration. Special requirements, however, for high fluid weights or plastic viscosities may affect these circulation rates.

Average circulation rate should be used with varying bit weights and rpm to obtain optimum penetration rate. Circulation rates can also be varied to provide efficient cleaning and cooling, thus maximizing bit life. A low circulating volume may not properly clean entire face of bit, resulting in regrinding of cuttings or burning of the bit. This will reduce penetration rate.

Circulation Volumes

High circulation volumes may be detrimental to bit at start of coring. A high volume may cause bit to lift off bottom and bounce, resulting in cutter damage, reduced penetration rate, and shorter bit life. High velocities also can cause inner barrel to rotate, creating jamming.

Washouts are a consequence of core fluid wash in soft formations. This results in poor core recovery. Face discharge bits and extended pilot type (CoreGard) core catchers are recommended for coring in soft or unconsolidated formations. Used together, these low invasion components will provide cleaning of bit face with a minimum of washing. Circulation rates can be reduced as a remedy for washouts, but care should be exercised to prevent burning of the bit.

Consideration should be given to cutting of short cores (30 foot/9 m length) when coring soft formations. Soft, unconsolidated formations can support very little weight. If weight of core above throat of bit exceeds formation strength, any further attempts to cut more core will result in grinding and washing away the core.

Coring with Lost Circulation Material

Baker Hughes INTEQ core barrels have operated effectively using muds with large quantities of lost circulation material (LCM). Close attention should be given to thorough mixing of mud to prohibit any concentration of LCM into masses or lumps. Concentrated LCM may subsequently block various parts of core barrel or plug fluid channels of the bit. LCM could also get on top of the core and prevent it from entering the inner barrel. LCM should not be mixed while coring operations are in progress unless absolutely necessary.

When coring with LCM, the core barrel is usually run in hole without a drop ball to prevent clogging the bearing assembly. A drop ball is used while coring to deter LCM accumulation between the core and inner barrel, which would result in a jammed core.

It may be necessary to break circulation several times while running in hole to prevent plugging of the barrel and accumulation of lost circulation material. Circulation should begin 60 feet (18 m) off bottom when LCM is used in the fluid system. The core barrel should be washed slowly to bottom. Fluid circulation may become necessary if a thief or lost circulation zone is very close to the bottom of the hole. Work pipe and circulate.

Rotary Speed

The best rotational speed for coring usually is established by well parameters and drilling equipment capabilities. Depth and size of hole, size and condition of drillpipe, size and number of drill collars and formation being cored – all must be considered when establishing rotational speed.

Concern should also be given to drillstring harmonics. For more information, consult API RP 7-G *API Recommended Practice for Drill Stem Design and Operating Limits*.

Experience in the field indicates that rotational speeds while coring are usually consistent with standard oilfield practices. PDC core bits generally are run with lower rotary speeds than PDC drilling bits. However, excellent results have been obtained at speeds other than those recommended.

Slow rotary speeds have been proven more effective when coring fractured and rubbelized formations. Speeds as low as 30 to 40 rpm may be required to minimize disturbance of the core and delay core jamming. As long as sufficient hydraulics are used to keep the bit clean, best rotational rate can be found by varying rotational speed while keeping weight on bit constant.

Certain formations, such as sticky shales or anhydrites, will create excessive torques. A smooth coring operation can be obtained in these formations by using a different combination of weight and rpm.

Weight on Bit (WOB)

WOB should never exceed available WOB of BHA and consistent with drilling practice. However, excessive BHA mass could be a hindrance, leading to coring disfunctions when running coring BHAs.

Feeding Weight

The proper weight on bit for each core run can be determined by increasing bit weight in steps of 1,000 to 2,000 lbs with a constant rpm. Coring should be continued at each interval while carefully observing penetration rate.

Optimum weight on bit has been reached when additional weight does not provide any further increase in penetration rate or requires excessive torque to rotate the bit.

After the desired drilling rate has been established, every effort should be made to keep WOB constant. The brake should be attended at all times. Do not apply weight and then let it drill off, only to apply more weight again.

Using too much WOB can cause natural diamond bits to penetrate too deeply into a soft formation if an insufficient amount of fluid passes between diamond cutters and the formation. High WOB could result in poor removal of cuttings. The core bit could clog or even burn, reducing penetration rate and bit life. In harder formations, excessive weight will cause burning on tips of cutters or shearing, with a resulting loss of bit life.

Automatic drillers are an acceptable means for maintaining a uniform and constant weight. Tests conducted with automatic drillers have shown an increase in bit life and a substantial gain in performance.

Standpipe Pressure Fluctuations

Changes or fluctuations in standpipe pressure may be observed during coring. These may be the result of problems with the drilling fluid circulation system or bottomhole conditions listed in Appendix B, Table B-15, “Possible Causes for Standpipe Pressure Changes,” on page B-12. If changes or fluctuations in standpipe pressure are observed, the circulation system (pump, mixers, pit, etc.) should be checked immediately and repaired if necessary. Refer to capacity tables:

- Table B-19, “Duplex Pump Capacities* (gallons/ stroke),” on page B-15
- Table B-20, “Triplex Pump Capacities* (gallons/ stroke),” on page B-16.

If no problems with this system are found, abort coring operations, pull-out-of-hole, and address bottomhole conditions.

Breaking Core

The procedure for breaking core prior to pulling out of hole is similar to breaking core to make a connection.

1. Stop rotation and shut off or idle pump.
2. Raise core barrel until weight indicator shows core spring has gripped core and core breaks, or until strain begins to exceed pulls listed in Table 5-1 on page 5-28.
3. If core does not break with maximum strain, start pump and hold strain on core until it breaks.

Note: *It may be necessary to hold strain for 10 minutes or longer for core to break.*

4. After core has broken, raise bit 10 feet (3 m).
5. Slowly lower string to within one foot of bottom.

Note: *Maintain a constant check of weight indicator, observing that weight readings drop gradually without any obstruction caused by core left in hole.*

6. Trip out of hole.

Jamming

Jamming an inner barrel is a common problem while coring. It is usually caused by formation conditions - fractures, unconsolidated material, or swelling shales. If the barrel jams in soft, unconsolidated formation, penetration rate may remain normal, but most likely will decrease. The standpipe pressure will increase initially and then decrease as the core bit drills off. A change in torque or pump strokes, or a decrease in pump pressure will also indicate a jammed core barrel.

An abrupt increase in standpipe pressure may be caused by plugging of the core barrel from an accumulation of foreign particles in the fluid system.

Pulling-Out-Of-Hole

Conventional

Gas expansion during POOH (pulling-out-of-hole) can damage core material. This is especially likely with friable or unconsolidated sandstones. It is recommended that the core barrel be retrieved at a rate to be determined by the operator. In the absence of any provided guide lines, POOH until the bubble point is reached in the well, then POOH at 2 to 3 minutes per stand. At 2,000 ft from surface, POOH at 3 to 4 minutes per stand. At 1,000 ft, POOH at 6 minutes per stand.

Note: *Operator should always dictate the POOH procedure.*

Vented Inner Barrels

In the event of high gas content or interbedded shale coring sequences, vented inner barrels are recommended for safety reasons. Pulling out of hole procedures similar to those described for high pressure high temperature wells should be followed.

See High Pressure Coring on page 5-61.

Breaking Out of Outer and Inner Barrels

When the core barrel reaches the surface, set the safety collar 2 to 3 feet from the safety joint box connection.

Break down all crossover subs on top of core barrel and lay aside.

Retrieving Drop Ball

1. Using a flashlight, check for debris inside the top of the core barrel.
2. Insert the ball retrieving tool into the top sub of the core barrel and retrieve the drop ball.
3. Check the ball for washouts.

Normal Operations

1. Make up the lift sub to the core barrel.
2. Remove the bit and install the thread protector.
3. Break out safety joint or top sub of the core barrel.
4. Thread sub into top of outer core barrel and tighten with chain tongs.
5. Break safety joint connection and remove using rig tongs.
6. Lift top section of core barrel with elevators until inner barrel is exposed.

7. With inner barrel exposed, install inner tube clamp or dog collar.

Note: *Leave sufficient room to place pipe wrenches on inner tube without compressing box connection. Ensure that clamp grips core barrel properly.*

8. Run tugger line through elevators and blocks 30 to 40 feet (9 to 12 m) up into derrick.
9. Lift the lifting sub to next inner barrel connection.

Note: *Use lifting sub with wireline and swivel (fed through elevators) of a double pin sub to lift inner barrel to next brake.*

10. Using two pipe wrenches and a slip, back out connection 2 to 3 turns.
11. Install guillotine clamp.

Note: *Place guillotine clamp close enough to pin connection so that sufficient core is exposed. Ensure that guillotine clears inner barrel top section pin connection.*

12. Back out inner barrels completely.
13. Raise the inner barrel carefully.

Note: *Close guillotine as soon as pin has cleared box connection of lower inner tube and core is exposed.*

14. Carefully back off inner barrel to expose core.
15. Place guillotine knife into guillotine and hammer in until core is broken.
16. Insert knife fully and install safety pins to secure knife.

Note: *With guillotine closed, core is held securely in top section of inner tube.*

Lay Down/Cutting of Inner Barrel

1. Pick up core handling frame (cradle) by air tugger line and position alongside each inner barrel as it is removed from the outer assembly.
2. Hoist a drill crew member on the man rider to clamp the inner barrel to the core handling frame.
3. Lay the cradle down on the catwalk.

Note: *Lay out bottom section of inner barrel without guillotine clamp, as core catcher secures core at bottom of this section.*

Note: *Reload outer barrel with inner barrels; if the core barrel is to be run again, refer to* Loading Inner Barrels/Tubes on page 5-12. *Break down barrel sections if coring is completed. See* Outer Barrel Breakdown Procedure on page 5-42.

4. Place the air saw at one end of the cradle.

Note: *Preferred systems allow inner barrels to be rolled directly from the cradle into the saw without bending or flexing core.*

5. Wipe any mud off the inner barrel.
6. Remove guillotine and clamp.
7. Start with the top section of the inner barrel, locate core top and measure core length.

Note: *Make measurements up-hole from known depth of core at start of coring.*

8. Mark depth and orientation on inner tube and mark where cuts will be made (generally every 3 feet or one meter).
9. Number measured inner barrel segments from top to bottom in depth sequence.
10. Unclamp the inner barrel from the handling frame.

Note: *Proper blade for cutting either aluminum or fiberglass should be in place on saw, i.e., diamond impregnated for fiberglass and tungsten carbide saw tooth for aluminum.*

Note: *It is recommended to use a fluid coolant on the diamond saw blade to effectively cut the aluminum tubing.*

11. Feed the inner barrel into saw along “V” channeling guide of tube cutter.

Note: *Most handling frames have rollers to facilitate travel of inner barrel.*

12. Start saw motor and blade coolant.
13. Cut core on the marks in one smooth pass every 3 feet (1 m) from top to bottom.
14. Place rubber caps on both ends of each section as it is cut.

Note: *It may be necessary to soften end caps in hot water to facilitate fitting.*

15. Secure caps with hose clamps.
16. Lay each section out on deck until entire 30 foot (9 m) section has been cut.
17. Continue this process until all but lower and last inner barrel section are reached.

18. Place lower inner barrel section on feed stand.
19. Mark depths and mark where cuts will be made.
20. Break out catcher shoe, measure length, and push core out of shoe into PVC pipe cut to appropriate length.
21. Mark depth and orientation on the PVC in the same manner as described above.
22. Cut inner barrel at pre-selected depths using saw.
23. Place rubber caps on both ends of each section as it is cut.
24. Secure caps with hose clamps.
25. Place each section into a cardboard or wooden box or a metal tray for shipment and storage.

Note: *If core stabilization or preservation is required, refer to* Stabilized Core Recovery on page 5-69.

Outer Barrel Breakdown Procedure

There should be no inner barrels left in the outer barrel assembly when outer barrel is laid down.

1. Connect the safety joint or top sub to the outer barrel (set in slips).
2. Pick up the core barrel and break all connections down to bottom of top section.

Note: *Make-up core barrel connections chain tight and secure connections for transportation back to the workshop.*

3. Set slips and collar clamp below stabilizer of next section.
4. With the connection broken between top section and the next section, back off top/outer barrel completely from bottom section.
5. Place pin protector on connection of top barrel.
6. Lay down top barrel.
7. Thread double pin lifting sub onto next section.
8. Repeat Steps 2 through 7, breaking out each intermediate section.
9. Continue bottom section breakout as described in Step 2, break out the bit and continue with Step 3.

Note: *If barrel is longer than 90 feet, the bit will be last item to break out.*

10. Lay down bottom section of core barrel.

Back-off of Safety Joint

Before performing a manual back-off, consult company personnel and the company man. They may want to run a free point, spot oil, jar or some other method of breaking loose before a back-off.

Following is the recommended procedure for a manual back-off of a safety joint on all 250P series core barrel, except the $3^{1}/_{2}$" × $1^{3}/_{4}$" barrel. If the core barrel becomes stuck, it is recommended to first try all possible ways of getting loose before manually backing off.

The first thing to do in a manual back-off is to establish the correct amount of weight of the drillstring. Pick up approximately 1,000 to 2,000 lbs. over the drillstring weight. If the Kelly is on the string and the rig has a reverse on it, it is best to put the rotary in reverse and put 8 rounds of torque on the rotary table. Be sure before doing this to check on the drillpipe to see if it will take that amount of torque. If the break does not occur, increase the torque to a total of 12 turns. If the break still has not occurred, hold the torque and drop to 2,000 lbs. pull on the core barrel. A sudden jar may help break the safety joint. If the rig has no reverse on the rotary table, torque-up the rotary clutch suddenly. Warn all personnel to stay clear of the rig floor before doing this.

If the core barrel becomes stuck with the Kelly not on the drillstring, all you have to work with is the drillpipe, and break the safety joint with rig tongs. Disassemble the make-up tongs. Turn the body over and reassemble the tongs. This makes two sets of break-out tongs.

Note: *If the break-out tongs cannot be turned over, acquire an extra set of break-out tongs. Get the required amount of weight (1,000 to 2,000 lb. pull).*

With all personnel (except the tong operators) off the rig floor, pull with the break-out tongs and hold backups with the bottom set of tongs. Ratchet the tongs until the desired amount of torque is required and the break occurs. If these procedures do not work, it may take a shot to help get loose and out of the hole. If the free point shows the string stuck above the core barrel, do not attempt the backoff. Always consult the company man in charge.

To backoff a core barrel with a safety joint, the following chart shows the number of turns necessary to unscrew the safety joint.

Core Barrel Size	Number of Turns
$3^1/_2$" × $1^3/_4$"	7
$3^1/_2$" × $2^1/_8$"	No Safety Joint
$4^1/_8$" × $2^1/_8$"	7
$4^3/_4$" × $2^5/_8$"	13
$5^3/_4$" × $3^1/_3$"	6
$6^1/_4$" × 4"	6
$6^3/_4$" × 4"	6
$8^1/_8$" × $5^1/_4$"	8

The following chart is the recommended maximum pull of Baker Hughes INTEQ core barrels above weight of drillstring:

Core Barrel Size	Maximum Pull
$3^1/_2$" × $1^3/_4$"	74,600 lbs.
$4^1/_8$" × $2^1/_8$"	101,400 lbs.
$4^3/_4$" × $2^5/_8$"	137,400 lbs.

Core Barrel Size	Maximum Pull
$5^3/_4$" × $3^1/_2$"	183,000 lbs.
$6^1/_4$" × 3"	290,000 lbs.
$6^1/_4$" × 4"	193,500 lbs.
$6^3/_4$" × 4"	227,000 lbs.
$6^7/_8$" × 4"	156,500 lbs.
$7^5/_8$" × $5^1/_4$"	239,000 lbs.
8" × $5^1/_4$"	322,000 lbs.

Procedure Summary

1. Pick up the drillstring to the neutral point.
2. Put left hand torque in the drillstring. (The amount of torque will vary with depth and drillpipe size.) Lock the rotary or snub the pipe with the rig tongs.
3. If using rig tongs, place them on the drillpipe high enough to allow at least 3 feet of slack.
4. Slack off about 20,000 lbs. hard (all at once).
5. The safety joint should break if all of the weight reaches bottom. When the safety joint breaks, you will loose all torque.
6. If the safety joint does not break on the first try, repeat until it does.
7. After the joint breaks, pick up until there is about 2,000 lbs. above the neutral weight. Finish unscrewing the safety joint.
8. To fish, break off the bearing assembly and go back in hole with jars on top of the safety joint. Screw back into the core barrel and try to jar it loose.

Another method that has been used to back the safety joint off when stuck is as follows:

1. Locate the free point where there is no weight on the safety joint and mark the drillpipe or Kelly.
2. Pull 10,000 to 20,000 lbs. over the string weight.
3. Very cautiously, put 12 revolutions left torque into the drillstring.
4. Keep the tongs high and work from a low position to remain safe.
5. Drop the drillstring and catch it with the brake at the free point that was marked.

Retrieval of Inner Barrel when Core Barrel Safety Joint has Backed Off and Outer Barrel is Left in Hole

This procedure is for retrieving and laying down inner tubes when the safety joint has backed off from outer barrel downhole.

Conduct a safety meeting with company representative, rig supervisor, and rig crew before attempting this procedure.

1. Observe following general guidelines to ensure safe operations:
    - Set slips and safety clamp a minimum of 18" (46 cm) from inner tube connections
    - Use chalk marks on elevator subs and lifting assemblies made up with chain tongs or pipe wrenches. This allows driller to monitor connection for a possible back-off of elevator sub
    - Once the safety joint and inner tubes have reached the surface, evaluate the lay-down options

- Set drillpipe slips carefully on inner barrel in the rotary table and apply as little downward motion as possible.

Note: *If only safety joint pin and inner barrel come out of hole, continue with following procedure.*

2. Set rotary slips around safety joint and body.
3. Attach safety clamp to safety joint pin above slips as pin is pulled through.
4. Pick up elevator sub and make up to safety joint with chain tongs or a pipe wrench and hammer.
5. Pick up first connection below inner tube plug using travel blocks.
6. Set slips.
7. Set inner tube clamp to secure inner tube in slips.
8. Verify that inner tubes are secure in slips; back out connection between inner tube plug and inner tube.
9. Lay down safety joint assembly on top sub.
10. Thread a lifting sub into inner tube.
11. Begin laying down inner tubes.

Check/Change-Out Core Bit on Multi-Section Barrels

Checking of bit on longer core barrels is similar to the breakdown process. However, complete break-out should be made only on every three sections of outer barrel, i.e., every 90 feet (27 m).

1. Rack back first 90 foot (27 m) section in derrick.
2. Raise, back out, and rack next 90 foot (27 m) section on derrick.
3. Repeat until bit can be viewed.

Makeup of Barrel After Bit Check/Replacement

Follow make-up procedure, using 90 foot (27 m) sections that are racked back in derrick.

Motor Coring

The 6¾" Mach 1 and Mach 2 Motor series supply desired torque and power output to drive any coring assembly. Core barrel lengths in excess of 90 ft are advised to be run in combination with the XL Series Motor. Use pin/pin crossover sub to connect core barrel to motor. Recommended parameters for motor coring with this configuration are as follows:

- **rpm**: 30 to 40 (effective rotary speed 180-250 rpm) - Adequate rpms prevent potential sidewall sticking due to differential pressure. Rpm of the motor will depend upon motor characteristics and fluid circulating rate.
- **Circulating Rate**: 275 to 450 gpm in 8½" holes. Minimum circulating rates required to effectively operate the downhole motor. A by-pass sub between the motor and the core barrel can be configured to divert a fraction of the flow out of the motor and reduce the flow through the core barrel.
- **WOB**: Apply constant weight in range of 6 to 10 k-lbs or else as required by the application.

Other motor assemblies are available for longer core runs. Refer to Motor Operations, Baker Hughes INTEQ *Navi-Drill® Motor Handbook* (P/N 503-002).

JamBuster Coring

The JamBuster assembly is configured inside a disposable inner barrel and is run as a conventional core barrel with aluminum inner tubes. A core jam indicator may be considered as an aid. Core gels can be used in conjunction with this system. The innermost telescoping sleeve will release once filled or jammed. The second (middle) sleeve will release when the second jam occurs and telescope upward inside the inner barrel. Additional outer barrel lengths are needed to accommodate the Jambuster.

Shear Pins

Prior to commencing set-up procedures, it is essential that the coring coordinator advises workshop staff of required shear settings for telescoping sleeves. This is determined by strength of formation to be cored and is adjusted by the number of aluminum shear pins set in each sleeve. Each shear pin has a failure strength equivalent to 200 kg applied force.

If no information regarding strength of formation is available, set default settings of shear pins as follows:

- Innermost sleeve: 600 Kg – 3 pins
- Middle sleeve: 800 Kg – 4 pins
- Top Flange: 1000 Kg – 5 pins

Set-Up Procedure

1. Using pipe cutters, square off both ends of each telescopic inner sleeve.

Note: *Before initiating assembly of inner barrel system, remove approximately $^{3}/_{16}$" (5 mm) from each end.*

2. Insert one end of middle ($4^1/_8$"/105 mm O.D.) inner sleeve into upper half shoe and seat firmly against upper internal stop.
3. Drill a $^9/_{16}$" (4.1 mm) hole through fixed aluminum inner tube using pre-drilled holes in upper half shoe as a guide.
4. Fix inner sleeve in place using a $^5/_{32}$" (4 mm) pop-rivet (shear pin) to attach sleeve to upper half shoe.
5. Insert shear pin from inside of sleeve.
6. Fix remaining pins required for securing middle sleeve as detailed above.

Note: *Ensure that pins are equally spaced around circumference of sleeve. Remove any burrs/ rivet stubs from inside surface of sleeve using a file or screwdriver.*

7. Insert one end of innermost $3^{11}/_{32}$" (98 mm) O.D. inner sleeve into middle sleeve. Push in until firmly seated against lower internal stop within upper half shoe.

Note: *In this position, innermost sleeve should protrude ≈1.5" (38 mm) beyond middle sleeve at box end. Check and adjust with pipe cutters as necessary.*

8. Fix innermost sleeve in place using a $^5/_{32}$" (4 mm) pop-rivet (shear pin), attaching it to upper half shoe.

Note: *Shear pin must be inserted from inside of inner sleeve.*

Note: *Fix remaining pins required for securing middle sleeve as detailed above, ensuring that they are equally spaced around circumference of sleeve. Number of pins connecting innermost sleeve to upper half shoe must be less than those connecting middle sleeve to upper half shoe.*

9. Insert top flange into innermost sleeve at box end and secure using shear pins as described above.

Note: *These pins must be inserted from outside of tube. The number of pins required must exceed the number used to fix middle sleeve into upper half shoe.*

10. Slip fixed aluminum inner tube over assembled telescoping system from box end.
11. Thread pin end of tube into box end of upper half shoe.

Note: *Telescoping system is approximately 18" (57 mm) shorter than fixed inner barrel.*

12. Fill all unused shear pin holes on upper half shoe with diver's cement or epoxy. Also, fill in any recesses left above shear pins which do not completely fill holes in upper half shoe.
13. Paint upper half shoe and mark shear pin settings.

Table 5-2 Jambuster Release Pin Settings

Formation	Soft	Medium	Hard
Inner sleeve	4	6	8
Outer sleeve	6	9	12
Plate	6	9	12

Jam Indicator Operations

Surface indicators must be monitored for evidence of a jam - with or without a core jam indicator in the JamBuster system. Typical indicators of a jam are:

- Without core jam indicator – approximately 200 psi decrease in standpipe pressure
- With core jam indicator – approximately 600 psi increase in standpipe pressure. Standpipe pressure increase is a function of the setting of the Core Jam Indicator.

Fishing Tools

Baker Hughes INTEQ can supply overshot retrieval tools for any core barrel. Overshots include a 30-inch extension sub, grapples and pack-off to allow circulation through any fish. Overshots will have IF connections to make up to any size drillstring. If overshots are not applicable due to restrictions caused by barrel and hole size, INTEQ can provide spears for internal latching to fish.

For more detailed information on fishing tools, refer to Chapter 6.

Hydro-Lift Procedures

Hydro-Lift operating procedures cover coring unconsolidated sand with a 30-foot core barrel and disposable inner tubes. Procedures may vary to accommodate more competent, hard, fractured formations.

Hydro-Lift Make Up

Install the slotted valve in top of the Kelly. Ensure that the valve is closed. Place 1¼" ball in sub, make up Kelly and set it back.

1. Pick up core barrel with elevators and lift sub.
2. Remove long thread protector and confirm that split ring has not been installed. Remove split ring if it has been installed. Re-install long thread protector.
3. Carefully lower core barrel into hole.

Note: *Tighten each joint to proper torque as barrel is lowered.*

4. When safety joint is reached, set slips and install a drill collar clamp on stabilizer sub.
5. Break out safety joint pin and pick up inner barrel.
6. Pull inner barrel from outer barrel.
7. Check that spring housing is seated solidly against sliding inner tube shoe. Push spring housing up until it seats solidly against sliding inner tube shoe.
8. Lower inner barrel back into outer barrel, checking that full closure catcher, inner barrel and Hydro-Lift connections are made up.
9. Install inner tube clamp.
10. Check that Hydro-Lift is extended and locked in “down” position.

11. Check for movement between inner mandrel and outer piston.
12. Place Hydro-Lift assembly in compression by resting inner clamp on outer barrel.
13. Verify that tool will not close.
14. Check that sliding valve is in the lower position, closing the ports on the mandrel.
15. Remove inner tube clamp.
16. Make up safety joint to recommended torque.
17. Raise core barrel out of hole and replace hole cover.
18. Remove long thread protector from bottom of outer tube sub.
19. Install split ring onto groove in spring housing.
20. Measure distance from end of outer tube sub pin thread to end of split ring with split ring solidly against bottom of groove.

Note: *Measurement must be between $^{1}/_{32}$" (1 mm) and $^{9}/_{32}$" (7 mm). If measurement is out of tolerance, adjust the shims.*

21. Thread split ring housing onto bit and install bit breaker onto bit.
22. Slide split ring housing over core shoe and split ring, and make-up thread.
23. Make up both split ring housing and bit to recommended torque (both connections can be made up at same time).

Note: *If core barrel has been run previously, place bit breaker on split ring housing and thread it onto outer tube sub. Make up to recommended torque.*

24. Remove bit breaker.
25. Pick up core barrel, reach inside bit, and ensure that inner barrel assembly rotates freely.
26. Adjust shim stack as necessary.
27. Lower core barrel into hole.
28. Set slips at top of outer tube just below collar clamp.
29. Remove lift sub and install a cross-over sub to match drill collar connection.
30. Make up core barrel to recommended torque.

Note: *See Appendix B for torque limits as applicable:*

- Table B-1, "HT Series Outer Barrel Mechanical Properties," on page B-1
- Table B-3, "250P Series Outer Barrel Mechanical Properties," on page B-2
- Table B-4, "250P/350P/HT Series Inner Tube Mech. Properties," on page B-3.

31. Lift string out of slips and remove collar clamp.

Hydro-Lift Coring Operations

1. Pick up Hydro-Lift core barrel complete with aluminum inner tubes and core bit.
2. Install drop ball sub with ball in place in Kelly stand or Top drive.
3. Trip into hole.
4. On reaching bottom, break circulation and work pipe a full stand to clean bottomhole of fill and to prevent hole enlargement.
5. While moving gradually, run to bottom. Once bottom is tagged, determine if top drive is spaced enough for core barrel length. If spacing is not satisfactory, add a 5, 10, 15 or 30 foot pup joint. If BHA is correctly spaced, return to bottom.

Note: *When having to use pup joints to space out on bottom, always space pup joints out one joint below rotary. This will allow 30 ft of movement during closed Hydril operations.*

6. Record pressure at normal coring rate.
7. Stop circulating, break-off top drive, then drop 1" drop ball.
8. Pump to bottom slowly until ball seats.
9. Bring pumps up to full coring flow rate and monitor pump pressure.
10. Adjust flow rate as low as possible to prevent core fluidization while providing cuttings removal. Set rotary speed at 50-60 rpm to break in core bit.
11. Maintain for 3 feet or until near-bit stabilizer is bedded in.
12. Increase rotary speed to 90 rpm once barrel is stable.

Note: *Core recovery, in unconsolidated formation, can be reduced if ROP > 90 ft/hr with insufficient hydrostatic overbalance.*

13. If tracers are used in drilling fluid, collect a one quart sample at start and end of coring interval for tracer analysis.

14. Launch the 1¼" ball from ball launcher once the core barrel has been filled.

Note: *Do not lift core barrel off bottom until catcher has been activated.*

Ball activates full closure catcher and allows tool to be picked up off bottom. Catcher is not activated prior to dropping second ball. Observe increase in pressure, followed by a decrease. This is an indication that tool has been activated.

Note: *Circulation through the core barrel will not be re-established after dropping the second ball and failure of the full closure catcher to activate.*

15. If a circulation sub is configured above the core barrel, circulation through the core barrel can be re-established by activating the circulating sub:

    a. Remove top drive and drop relevant ball.

    b. Reconnect top drive and start circulation.

Note: *To trip out of hole, follow the procedures in* Pulling Out Of Hole, page 5-61.

    c. Once the core barrel is near the surface, check for possible gas pressure or trapped gas inside of the barrel.

16. When the barrel reaches the surface, break out the core bit and split ring housing sub. Remove the split ring to permit inner barrel removal.

16. Install thread protector.

17. With the outer barrel standing in the slips, break the safety joint at top of barrel.

    a. Break threads at locations indicated by the INTEQ representative. Lay 30-foot (9 m) inner tubes down with cradle or sling. Follow the specified or recommended lay down procedure.

    b. For barrels longer than 30 feet (9 m), lift inner assembly to expose thread of inner tubes at center of a 60-foot (18 m) barrel.

3. Place clamp on lower barrel section and break thread.

4. Attach support clamp for core guillotine to upper barrel section.

5. Lift upper barrel section to expose ¼" to ½" (6.3 to 12.7 mm) of core.

6. Connect clamps on upper and lower barrel sections with chains to prevent offset and core loss when driving guillotine through core.

7. Drive guillotine into its slot to cut core, then bolt in place.

Note: *Lower 30 foot (9 m) section of aluminum inner barrel. Core is ready to be laid down.*

8. Place loops of sling 8 feet (2.4 m) from each end of inner barrel or use a lay-down cradle to secure the section.

Note: *An alternative is to attach a lift eye on the lower section of the inner barrel.*

9. With the upper section hanging in the elevator, lift the inner barrel with a tugger or cat line and place it in the V-door. Use a crane and lay down the section on a pipe rack.

10. Lay down upper section.

    a. Using a pedestal and guillotine blade, insert disc to lift core and remove guillotine blade.

    b. Remove clamp and guillotine housing. Place a thread protector on the pin of the upper inner barrel section.

29. Attach a lift eye and lay down the upper section first.

Note: The *upper section can be placed directly on* the *inner barrel clamp. Prepare for marking depth and orientation.*

30. Break the thread at the top of the full closure catcher so that it may be removed with a pipe wrench after the inner tubes have been laid down on pipe rack.

31. Cut the inner tube into 3-foot (1 meter) sections as described in Lay Down/Cutting of Inner Barrel, page 5-39.

32. Redress the Hydrolift assembly and run back into hole for next the core run as applicable.

33. Reset the ball launcher with a 1¼" ball.

High Pressure Coring

Coring in high pressure formations is conducted in a manner similar to that previously described. Care must be taken in tripping out of hole. Pressure relieving check valves will facilitate safe recovery and surface handling of core.

Pressure Relief Check Valves

Pressure relief check valves generally are spaced every 2 feet (61 cm) along the inner tube, offset at 24° angles. However, they also may be offset at 0° or 90° angles depending upon reservoir conditions and coring objectives. A schematic diagram of check valve placement is illustrated in Figure 5-1.

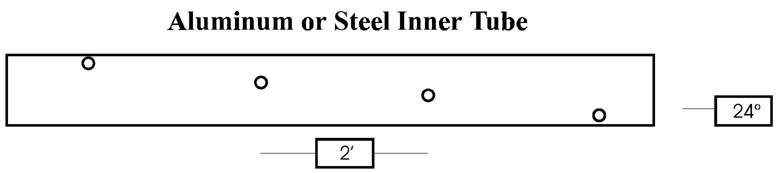


Figure 5-1 Check Valve Placement in Inner Tubes

Pulling Out Of Hole

Safe pulling of core barrels in high pressure or toxic gas wells requires special tripping-out-of-hole procedures. Although the procedure will vary depending upon reservoir conditions, the basic process involves a sequence of pulling-out-of-hole, then running-in-hole in stages. A circulating sub is recommended to be configured directly above the core barrel. This allows circulation and removal of trapped gas in the mud. Operator Trip Procedures and Well Control Procedures take precedence at all times.

Procedure 1

1. Pull out of hole to 1,500 feet (460 m).
2. Run in hole to 3,000 feet (920 m).
3. Close Blowout Preventer (BOP), then circulate up over choke.
4. Monitor for gas.
5. Open BOP, then pull out of hole to 850 feet (260 m).
6. Run in hole to 1,500 feet (460 m).
7. Close BOP, then circulate up over choke.
8. Monitor for gas.
9. Open BOP, then pull out of hole to BOP.
10. Run in hole to 850 feet (260 m). Close BOP, then circulate up over choke. Monitor for gas.
11. Pull out of hole to above BOP, then close blind rams.
12. Pull out of hole to surface.
13. Conduct standard break-out and lay-down procedures.

This process will add approximately 3 hours to trip time. However, safety benefits of this procedure offset extra rig time.

Procedure 2

1. Trip out of hole to 2,000 feet (610 m).
2. At 2,000 feet, reduce trip rate to 3 minutes/stand.
3. At 1,000 feet (305 m), reduce trip rate to 6 minutes/stand.

Core Barrel Maintenance (On-Site)

The bearing pack on the core barrel should be inspected and changed if required after each coring run. Where H_2S has been encountered, additional inspection is required to verify the integrity of the core barrel and its main components, e.g., the core catcher should be examined for damage or corrosion and replaced if necessary. These preventive maintenance actions are required to avoid or prevent failures caused by H_2S embrittlement of these metal components in subsequent coring runs.

Safety – H_2S Wells

1. Use H_2S monitors on the rig floor to measure H_2S levels at the top of the core barrel prior to breaking out top connection.
2. Perform H_2S monitoring when the ball has been removed from the ball seat.

Wellsite Core Handling

Although the American Petroleum Institute recommends that recovered core samples be preserved at the wellsite, there is often a need for examination of the material at the wellsite. For example, the ability to quickly identify pay zones and perforation zones from the core can be a requirement which supplies valuable information. In addition, it could be critical to rapidly sample and preserve sections of the recovered core material to prevent any oxidation or chemical changes to the core (wettability alterations) that would affect the accuracy of laboratory studies.

The Baker Hughes INTEQ portable GammaTrak logger and the Wellsite Core Evaluation Unit can provide on-site surface gamma logging, core plug sample collection, and laboratory services to address these issues.

GammaTrak Surface Logging

Disposable inner tubes generally are cut into 3 foot (one meter) sections after core-filled tubes have been recovered to the surface and laid down. Prior to cutting into sections, a surface gamma log of the core can be obtained to evaluate lithology, select sections for sampling (e.g., plugs), or generate logs for comparison to wireline data.

GammaTrak (G2) is a self-contained natural gamma, data acquisition system used to produce gamma logs of cores at the wellsite. The instruments consist of a CPU, NaI detector, high voltage power supply, digital counter board, LCD display, 3.5" floppy drive, numerical keypad, 12-volt battery, and depth encoder wheel.

The computer controls all digital input and output functions associated with the tool. These include processing of digital counts from the analog section and digital counts from the encoder wheel. Counts from the analog section correspond to gamma counts from the detector. Counts from the encoder wheel determine the distance traveled along the core sleeve.

The input/output consists of an LCD display, a portable printer and a keypad. The LCD allows for menu-driven options and graphical displays associated with gamma core analysis. The keypad allows for user input during the logging operation.

GammaTrak generates a log which enables wellsite personnel to:

- Match core depth with wireline log data
- Identify shale and non-shale zones
- Select segments for sampling.

GammaTrak creates data files that can be translated through various software programs to generate logs of gamma counts-per-second versus depth.

Wellsite Core Evaluation Unit

The Wellsite Core Evaluation Unit (WCEU) provides sampling and limited analytical capabilities that allow an operator to:

- Make quick, on-site completion/perforation determinations without having to wait for laboratory testing at distant locations
- Collect, isolate, and preserve test samples to prevent wettability alterations that could occur during shipment of recovered core to off-site laboratory facilities.

INTEQ’s Wellsite Core Evaluation Unit (WECU) is capable of providing the following:

- Cutting, trimming, and limited slabbing of full-diameter core samples
- Core plug preparation – plugging 1½" (38 mm) diameter samples from full-diameter cores

- Preservation of full-diameter and core plug samples with non-reactive wraps or ProtecCore® system
- Visual microscopic examination for lithology
- Determination of fluorescence with UV light
- Collection of first emerging pore fluids during flushing of core plugs
- Effective permeability to liquid (k_o at S_{wc} or k_w at S_{or}) at reservoir confining stress.

Since a gamma log would be important for sample selection procedures, the GammaTrak logging service is recommended for use with the wellsite unit.

Gamma scanning and visual examinations are used to identify target zones where sampling will be conducted. If gamma scan services are not used, well log data from off-set wells can be used to aid in identifying target zones. Core plug samples then are obtained from target zones for permeability to liquid determinations. The client's on-site representative can use a microscope and UV light for additional examination of core material and preliminary geological evaluations.

The self-contained WECU unit requires connection to rig electricity, water and air. It has self contained bottled gases. Dimensions of the unit are listed in Table 5-3 on page 5-68. A tool basket is provided to contain rig-up equipment too bulky to be stored within the unit. The basket contains all of utility power cables, air and water hoses, and communications cables.

The WECU does not offer full scale core analysis services, and it has no solvent extraction or drying equipment. Permeability to air and porosity measurements are not available without special considerations and additional planning.

Table 5-3 Wellsite Core Evaluation Unit

General Specifications		
Physical Dimensions	Wellsite Unit	Tool Basket
Weight, lbs.	18,000	3000 gross weight limit
Length	16' 3" (59.5 m)	8' (2.4 m)
Width	8' (2.4 m)	3' (1 m)
Height	9' 7" (35 m)	3' (1 m)

The unit is equipped with a lifting bridle certified for 25,000 lbs. It has a steel shell, and has fire-resistant materials in its interior. The WCEU can be trucked on U.S. highways without an oversize permit, and can be bobtailed into place on location.

Core Stabilization/Preservation

There are three types of recovered core material:

- Conventional Core Samples
- Sidewall Core Samples
- Preserved Core Material.

Stabilization and preservation techniques for conventional and preserved core material are discussed below. Handling of sidewall core samples is not discussed.

Conventional Core Recovery

Conventional core recovery techniques do not attempt to preserve core material downhole. Disposable inner tubes often are not used, and the core is pumped out of the inner barrel onto racks at the wellsite. At this point, the following handling procedures are employed:

1. The wellsite geologist will examine, then mark and label the core.
2. Cut the core into 3-foot (1 meter) sections as described in Lay Down/Cutting of Inner Barrel on page 5-39.

Conventionally recovered core material will generally be exposed to weathering and will most likely not be used for saturation analyses or special core analysis studies.

Stabilized Core Recovery

Stabilized core may be required to protect the integrity of the core and to preserve its chemical and physical properties. Low invasion coring procedures, possibly in combination with Gel Coring, are generally employed.

Preserved core material is subjected to special handling upon recovery to surface. Three techniques can be employed to stabilize and preserve the core for shipment to laboratory facilities:

- Basic preservation
- Freezing
- Stabilization.

The relative merits of the four techniques are listed in Table 5-4.

Table 5-4 Core Stabilization Techniques

Wellsite Core Stabilization and Preservation		
Technique	**Advantages**	**Disadvantages**
Freezing with Dry Ice	• Not chemically reactive with core • Immobilizes pore fluids • Prevents evaporation of pore fluids • Stabilizes unconsolidated core	• Dry ice is not available in many locations worldwide • Requires special insulated containers • Expansion of pore fluids on freezing may induce fractures • Expansion of pore water may displace tracers from core or concentrate tracers in zones
Foam Stabilization	• Easy to set up from kits • Components are mixed in injector nozzle	• Oil-wetting and porosity- may absorb oil from core • Expands upon hardening

Table 5-4 Core Stabilization Techniques (continued)

Wellsite Core Stabilization and Preservation		
Technique	**Advantages**	**Disadvantages**
Foam Stabilization (Continued)	• Easy to pump from pressurized containers • Less toxic than epoxy • No heat build-up during hardening	• U.V. fluorescence • May penetrate pore spaces • Expands upon contact with solvents (can damage test samples during extraction processes) • May alter core wettability
Epoxy Stabilization	• Components are mixed in injector nozzle • Easy to pump from pressurized containers • Quick set-up time • Hard-no give • Does not affect wettability of core • Does not expand upon hardening • Low viscosity-can be mixed in buckets and poured into annulus	• Heats up to 130°F during hardening • Set-up time is a function of ambient temperature • Toxic until hardened • Can harden in injector nozzle-requires frequent cleaning • Chemicals are expensive

Table 5-4 Core Stabilization Techniques (continued)

Wellsite Core Stabilization and Preservation		
Technique	**Advantages**	**Disadvantages**
Plaster of Paris (Gypsum) Stabilization	• Non-toxic • Non-reactive with core or pore fluids • Does not affect wettability • Raw materials are relatively inexpensive	• Slow set-up time (25+ minutes) • Requires retarders and accelerators to adjust set-up time • Absorbs water and oil from core • Brittle and fragile • Slurry is thick and may displace unconsolidated core from sleeves upon injection

Basic Preservation

Basic preservation of core samples entails cutting core-filled inner tubes into 3 foot (1 m) sections, covering ends of segments with rubber caps, and securing caps with hose clamps and (optional) duct tape.

Note: *In some cases the annulus between the O.D. of the core and the I.D. of inner tube can be filled with brine or oil, and the tubes sealed with rubber caps.*

Refer to Lay Down/Cutting of Inner Barrel on page 5-39.

Freezing

Where dry ice is available, freeze unconsolidated core samples that are recovered in a fiberglass inner tube using dry ice as follows:

1. Cut inner tube into 3 feet (1 m) segments or leave intact in 30 foot (9 m) stands.

Note: *The 30 foot (9 m) stands must be carefully supported to prevent bending or flexing throughout the freezing process.*

2. Seal ends of each segment using rubber caps and hose clamps.
3. Place segments or stands onto racks in an insulated box. Distribute dry ice in snow or pellet form evenly around core to freeze rapidly.

Note: *Do not use dry ice in block form as it will not freeze core uniformly. Uneven freezing may lead to re-distribution of pore fluids and tracers. If blocks of dry ice are used, break them into small pieces before use.*

4. Keep core frozen under dry ice until it is sampled in the laboratory.

Note: *Where a supply of liquid nitrogen is available, core may be exposed to liquid nitrogen to rapidly lower temperature, and then frozen in dry ice.*

Stabilization

Wellsite core stabilization consists of injecting polyurethane foam, polyurethane epoxy, or plaster of paris into annulus space between O.D. of core and I.D. of inner tube. This secures core in inner tube material, preventing damage during shipment and preserving fluid saturations and core properties from the effects of weathering.

1. Cut core-filled inner tubes into 3 foot (1 m) segments.

Note: *Refer to* Lay Down/Cutting of Inner Barrel on page 5-39.

2. Place each segment onto an inclined rack to allow drilling fluid in annulus to drain.
3. Small samples or chips may be taken from ends of exposed core material at this time.
4. Place a rubber cap on each end of each segment as temporary core protection.

Note: *There must be a hole in each cap to allow drainage of fluid. Orient each segment with hole down to allow drainage.*

5. Examine segments to determine that there is sufficient annulus space to accommodate injection of stabilizing agent.
6. If there is sufficient annulus space, stabilize each segment as follows:
   a. Cap and clamp lower end of segment.
   b. Store each segment on rack or lower it to a near vertical orientation.
   c. Pump stabilization agent into lower end of segment through a hole that is either punched

into rubber sleeve or drilled through inner tube sleeve.

Note: *Stabilization agent will flow around and up annulus space to top of segment. In some cases it may prove necessary to drill additional holes through mid-point of sleeve to facilitate injection and distribution of agent.*

Epoxy can be poured in through top.

Care must be taken during the injection process to prevent damage to the core. Injection at a high rate may induce fractures or widen existing fractures in the core. Rapid injection can also dislodge unconsolidated core and push material out of the sleeve.

d. Allow agent to harden in filled segment.

e. Cap top end of segment and seal.

f. Seal injection holes with duct tape.

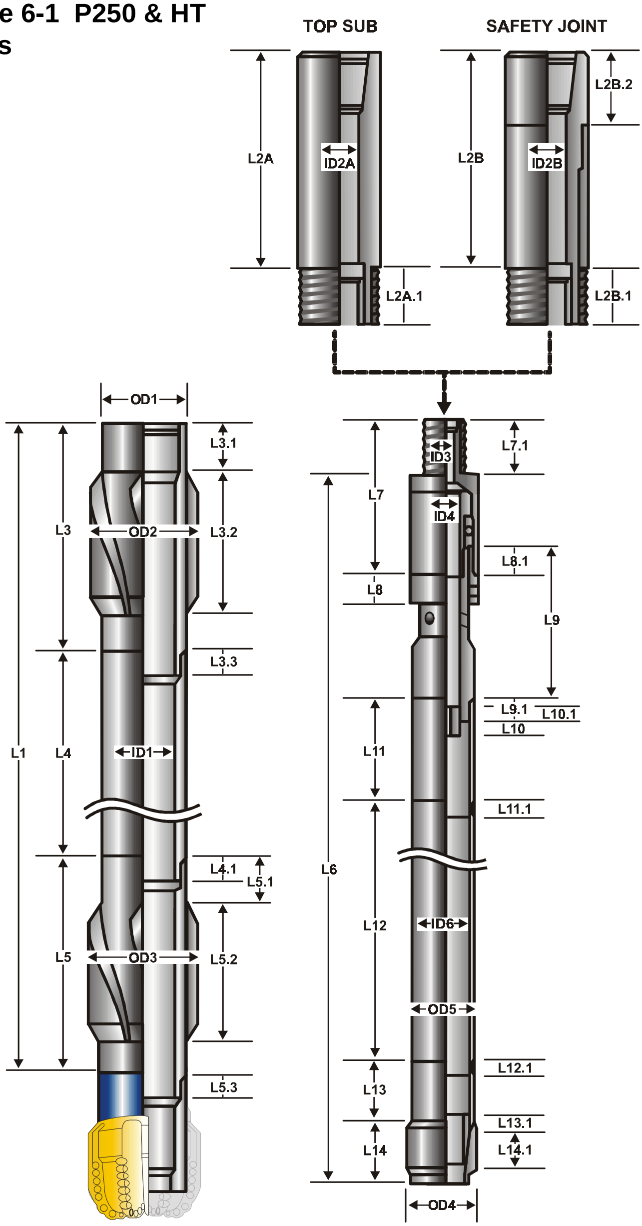
Note: *Sealing of injection holes is especially important when using foam or gypsum as stabilization agents.*

g. Place each segment into a separate wooden box.

Note: *Foam may be sprayed into box to secure and cushion segment. Cover segment or place in a plastic bag prior to placing into box.*

Coring Fishing Diagrams

Figure 6-1 P250 & HT Series



250P Series

Tool Fishing Dimensions		**4-3/4" x 2-5/8" 250P**	
Dim#	Description	Metric [mm]	English [in]
L1	**Outer Assembly Total MUL 1**	**9753.60**	**384.000**
L2A	Top Sub	n/a	n/a
L2A.1	Top Sub Pin	n/a	n/a
L2B	Safety Joint	698.10	27.484
L2B.1	Safety Joint Upper Body	12.00	0.472
L3	Upper Stabilizer	609.60	24.000
L3.1	Stabilizer Upper Body	273.05	10.750
L3.2	Stabilizer Blade	279.40	11.000
L3.3	Stabilizer Pin	87.38	3.440
L4	Outer Tube	8534.40	336.000
L4.1	Outer Tube Pin	87.38	3.440
L5	Lower Stabilizer	609.60	24.000
L5.1	Stabilizer Upper Body	273.05	10.750
L5.2	Stabilizer Blade	279.40	11.000
L5.3	Stabilizer Pin	87.38	3.440

L6	**Inner Assembly Total MUL 2**	**9828.23**	**386.938**
L7	Cartrigde Cap	177.80	7.000
L7.1	Cartridge Cap Pin incl. 5/8" shims	63.50	2.500
L8	Cartrigde Plug	50.92	2.005
L8.1	Cartridge Plug Pin	57.08	2.247
L9	Inner Tube Plug1	355.75	14.006
L9.1	Inner Tube Plug Pin	50.80	2.000
L10	Pressure Relief Plug	50.30	1.980
L10.1	Pressure Relief Plug Pin	36.60	1.441
L11	Inner Tube Extension	304.80	-
L11.1	Inner Tube Extension Pin	50.80	-
L12	Inner Tube	9144.00	360.000
L12.1	Inner Tube Pin	50.80	2.000
L13	Upper Shoe	208.00	8.189
L13.1	Upper Shoe Pin	34.75	1.368
L14	Lower Shoe	113.56	4.471
L14.1	Lower Shoe to Bit Upset	84.96	3.345

Outer Diameters			
OD1	Outer Assembly	120.65	4.750
OD2	Upper Stabilizer Blade	As Ordered	
OD3	Lower Stabilizer Blade	As Ordered	
OD4	Lower Shoe	90.48	3.562
OD5	Inner Tube	85.73	3.375

Inner Diameters			
ID1	Outer Tube	95.25	3.750
ID2A	Top Sub	-	-
ID2B	Safety Joint	75.20	2.961
ID3	Cartridge Cap	44.45	1.750
ID4	Cartridge Plug	36.58	1.440
ID5	Inner Tube Plug	36.58	1.440
ID6	Pressure Relief Plug	19.34	0.761
ID7	Inner Tube	73.00	2.875

Fishing 250P (continued)

Tool Fishing Dimensions		**5-3/4" x 3-1/2" 250P**	
Dim#	Description	Metric [mm]	English [in]
L1	**Outer Assembly Total MUL 1**	**9753.60**	**384.000**
L2A	Top Sub	371.30	14.618
L2A.1	Top Sub Pin	88.90	3.500
L2B	Safety Joint	803.10	31.618
L2B.1	Safety Joint Upper Body	317.50	12.500
L3	Upper Stabilizer	614.10	24.177
L3.1	Stabilizer Upper Body	288.50	11.358
L3.2	Stabilizer Blade	274.50	10.807
L3.3	Stabilizer Pin	88.90	3.500
L4	Outer Tube	8534.40	336.000
L4.1	Outer Tube Pin	88.90	3.500
L5	Lower Stabilizer	614.10	24.177
L5.1	Stabilizer Upper Body	288.50	11.358
L5.2	Stabilizer Blade	274.50	10.807
L5.3	Stabilizer Pin	88.90	3.500
L6	**Inner Assembly Total MUL 2**	**9828.23**	**386.938**
L7	Cartrigde Cap	171.50	6.752
L7.1	Cartridge Cap Pin incl. 5/8" shims	76.20	3.000
L8	Cartrigde Plug	54.10	2.130
L8.1	Cartridge Plug Pin	57.90	2.280
L9	Inner Tube Plug1	257.30	10.130
L9.1	Inner Tube Plug Pin	44.50	1.752
L10	Pressure Relief Plug	50.80	2.000
L10.1	Pressure Relief Plug Pin	44.45	1.750
L11	Inner Tube Extension	-	-
L11.1	Inner Tube Extension Pin	-	-
L12	Inner Tube	9143.50	359.980
L12.1	Inner Tube Pin	44.50	1.752
L13	Upper Shoe	204.00	8.031
L13.1	Upper Shoe Pin	42.90	1.689
L14	Lower Shoe	122.20	4.811
L14.1	Lower Shoe to Bit Upset	93.78	3.692
Outer Diameters			
OD1	Outer Assembly	146.05	5.750
OD2	Upper Stabilizer Blade	As Ordered	
OD3	Lower Stabilizer Blade	As Ordered	
OD4	Lower Shoe	114.30	4.500
OD5	Inner Tube	108.00	4.252
Inner Diameters			
ID1	Outer Tube	117.48	4.625
ID2A	Top Sub	-	-
ID2B	Safety Joint	76.20	3.000
ID3	Cartridge Cap	63.50	2.500
ID4	Cartridge Plug	47.80	1.882
ID5	Inner Tube Plug	50.80	2.000
ID6	Pressure Relief Plug	25.40	1.000
ID7	Inner Tube	95.30	3.752

Fishing 250P (continued)

Tool Fishing Dimensions		6-1/4" x 4" 250P	
Dim#	Description	Metric [mm]	English [in]
L1	**Outer Assembly Total MUL 1**	**9753.60**	**384.000**
L2A	Top Sub	371.30	14.618
L2A.1	Top Sub Pin	101.60	4.000
L2B	Safety Joint	815.80	32.118
L2B.1	Safety Joint Upper Body	307.80	12.118
L3	Upper Stabilizer	919.40	36.197
L3.1	Stabilizer Upper Body	567.50	22.343
L3.2	Stabilizer Blade	295.50	11.634
L3.3	Stabilizer Pin	101.60	4.000
L4	Outer Tube	8229.60	324.000
L4.1	Outer Tube Pin	101.60	4.000
L5	Lower Stabilizer	919.40	36.197
L5.1	Stabilizer Upper Body	567.50	22.343
L5.2	Stabilizer Blade	295.50	11.634
L5.3	Stabilizer Pin	101.60	4.000

L6	**Inner Assembly Total MUL 2**	**9848.06**	**387.719**
L7	Cartrigde Cap	177.80	7.000
L7.1	Cartridge Cap Pin incl. 5/8" shims	82.60	3.252
L8	Cartrigde Plug	57.00	2.244
L8.1	Cartridge Plug Pin	57.30	2.256
L9	Inner Tube Plug1	383.50	15.098
L9.1	Inner Tube Plug Pin	50.80	2.000
L10	Pressure Relief Plug	50.80	2.000
L10.1	Pressure Relief Plug Pin	44.45	1.750
L11	Inner Tube Extension	-	-
L11.1	Inner Tube Extension Pin	-	-
L12	Inner Tube	9143.20	359.969
L12.1	Inner Tube Pin	50.80	2.000
L13	Upper Shoe	395.20	15.559
L13.1	Upper Shoe Pin	38.10	1.500
L14	Lower Shoe	115.80	4.559
L14.1	Lower Shoe to Bit Upset		

Outer Diameters			
OD1	Outer Assembly	158.75	6.250
OD2	Upper Stabilizer Blade	As Ordered	
OD3	Lower Stabilizer Blade	As Ordered	
OD4	Lower Shoe	101.60	4.000
OD5	Inner Tube	95.30	3.752

Inner Diameters			
ID1	Outer Tube	107.95	4.250
ID2A	Top Sub	-	-
ID2B	Safety Joint	69.90	2.752
ID3	Cartridge Cap	44.50	1.752
ID4	Cartridge Plug	36.60	1.441
ID5	Inner Tube Plug	36.60	1.441
ID6	Pressure Relief Plug	25.40	1.000
ID7	Inner Tube	82.60	3.252

Fishing 250P (continued)

Tool Fishing Dimensions		**6-3/4" x 4" 250P**	
Dim#	Description	Metric [mm]	English [in]
L1	**Outer Assembly Total MUL 1**	**9753.60**	**384.000**
L2A	Top Sub	368.40	14.504
L2A.1	Top Sub Pin	101.60	4.000
L2B	Safety Joint	812.80	32.000
L2B.1	Safety Joint Upper Body	317.50	12.500
L3	Upper Stabilizer	614.60	24.197
L3.1	Stabilizer Upper Body	279.70	11.012
L3.2	Stabilizer Blade	278.50	10.965
L3.3	Stabilizer Pin	101.60	4.000
L4	Outer Tube	8534.40	336.000
L4.1	Outer Tube Pin	101.60	4.000
L5	Lower Stabilizer	614.60	24.197
L5.1	Stabilizer Upper Body	279.70	11.012
L5.2	Stabilizer Blade	278.50	10.965
L5.3	Stabilizer Pin	101.60	4.000
L6	**Inner Assembly Total MUL 2**	**9649.05**	**379.884**
L7	Cartrigde Cap	209.30	8.240
L7.1	Cartridge Cap Pin incl. 5/8" shims	85.90	3.382
L8	Cartrigde Plug	57.20	2.252
L8.1	Cartridge Plug Pin	63.50	2.500
L9	Inner Tube Plug1	314.20	12.370
L9.1	Inner Tube Plug Pin	50.80	2.000
L10	Pressure Relief Plug	50.80	2.000
L10.1	Pressure Relief Plug Pin	44.45	1.750
L11	Inner Tube Extension	-	-
L11.1	Inner Tube Extension Pin	-	-
L12	Inner Tube	9143.20	359.969
L12.1	Inner Tube Pin	50.80	2.000
L13	Upper Shoe	127.00	5.000
L13.1	Upper Shoe Pin	49.30	1.941
L14	Lower Shoe	137.80	5.425
L14.1	Lower Shoe to Bit Upset	101.50	3.996
Outer Diameters			
OD1	Outer Assembly	171.45	6.750
OD2	Upper Stabilizer Blade	As Ordered	
OD3	Lower Stabilizer Blade	As Ordered	
OD4	Lower Shoe	130.20	5.126
OD5	Inner Tube	120.70	4.752
Inner Diameters			
ID1	Outer Tube	136.53	5.375
ID2A	Top Sub	-	-
ID2B	Safety Joint	82.60	3.252
ID3	Cartridge Cap	79.30	3.122
ID4	Cartridge Plug	60.50	2.382
ID5	Inner Tube Plug	60.50	2.382
ID6	Pressure Relief Plug	25.40	1.000
ID7	Inner Tube	108.00	4.252

Fishing 250P (continued)

Tool Fishing Dimensions		**8" x 5-1/4" 250P**	
Dim#	Description	Metric [mm]	English [in]
L1	**Outer Assembly Total MUL 1**	**10058.40**	**396.000**
L2A	Top Sub	369.80	14.559
L2A.1	Top Sub Pin	87.40	3.441
L2B	Safety Joint	819.20	32.252
L2B.1	Safety Joint Upper Body	336.60	13.252
L3	Upper Stabilizer	920.90	36.256
L3.1	Stabilizer Upper Body	601.00	23.661
L3.2	Stabilizer Blade	240.00	9.449
L3.3	Stabilizer Pin	87.40	3.441
L4	Outer Tube	8229.60	324.000
L4.1	Outer Tube Pin	87.40	3.441
L5	Lower Stabilizer	920.90	36.256
L5.1	Stabilizer Upper Body	601.00	23.661
L5.2	Stabilizer Blade	240.00	9.449
L5.3	Stabilizer Pin	87.40	3.441

L6	**Inner Assembly Total MUL 2**	**10143.34**	**399.344**
L7	Cartrigde Cap	222.30	8.752
L7.1	Cartridge Cap Pin incl. 5/8" shims	76.20	3.000
L8	Cartrigde Plug	72.00	2.835
L8.1	Cartridge Plug Pin	75.60	2.976
L9	Inner Tube Plug1	435.60	17.150
L9.1	Inner Tube Plug Pin	69.90	2.752
L10	Pressure Relief Plug	50.80	2.000
L10.1	Pressure Relief Plug Pin	44.45	1.750
L11	Inner Tube Extension	-	-
L11.1	Inner Tube Extension Pin	-	-
L12	Inner Tube	9143.10	359.965
L12.1	Inner Tube Pin	69.90	2.752
L13	Upper Shoe	270.00	10.630
L13.1	Upper Shoe Pin	70.60	2.780
L14	Lower Shoe	162.10	6.382
L14.1	Lower Shoe to Bit Upset	131.78	5.188

Outer Diameters			
OD1	Outer Assembly	203.20	8.000
OD2	Upper Stabilizer Blade	As Ordered	
OD3	Lower Stabilizer Blade	As Ordered	
OD4	Lower Shoe	165.10	6.500
OD5	Inner Tube	158.80	6.252

Inner Diameters			
ID1	Outer Tube	168.28	6.625
ID2A	Top Sub	-	-
ID2B	Safety Joint	82.60	3.252
ID3	Cartridge Cap	79.20	3.118
ID4	Cartridge Plug	76.20	3.000
ID5	Inner Tube Plug	60.50	2.382
ID6	Pressure Relief Plug	25.40	1.000
ID7	Inner Tube	139.70	5.500

HT Series

Tool Fishing Dimensions		**4-3/4" x 2-5/8" HT10**	
Dim#	Description	Metric [mm]	English [in]
L1	**Outer Assembly Total MUL 1**	**10363.20**	**408.000**
L2A	Top Sub	720.37	28.361
L2A.1	Top Sub Pin	89.65	3.530
L2B	Safety Joint	n/a	n/a
L2B.1	Safety Joint Upper Body	n/a	n/a
L3	Upper Stabilizer	1219.20	48.000
L3.1	Stabilizer Upper Body	689.61	27.150
L3.2	Stabilizer Blade	319.50	12.579
L3.3	Stabilizer Pin	89.90	3.540
L4	Outer Tube	7924.80	312.000
L4.1	Outer Tube Pin	89.90	3.540
L5	Lower Stabilizer	1219.20	48.000
L5.1	Stabilizer Upper Body	689.61	27.150
L5.2	Stabilizer Blade	319.50	12.579
L5.3	Stabilizer Pin	89.90	3.540

L6	**Inner Assembly Total MUL 2**	**10480.33**	**412.611**
L7	Cartrigde Cap	177.80	7.000
L7.1	Cartridge Cap Pin	63.50	2.500
L8	Cartrigde Plug	18.33	0.721
L8.1	Cartridge Plug Pin	52.26	2.058
L9	Inner Tube Plug	355.75	14.006
L9.1	Inner Tube Plug Pin	50.80	2.000
L10	Pressure Relief Plug	50.30	1.980
L10.1	Pressure Relief Plug Pin	36.60	1.441
L11	Inner Tube Extension	304.80	12.000
L11.1	Inner Tube Extension Pin	50.80	2.000
L12	Inner Tube	9144.00	360.000
L12.2	Inner Tube Pin	50.80	2.000
L13	Upper Shoe	208.00	8.189
L13.1	Upper Shoe Pin	34.75	1.368
L14	Lower Shoe	113.56	4.471
L14.1	Lower Shoe to Bit Upset	84.96	3.345

Outer Diameters			
OD1	Outer Assembly	120.65	4.750
OD2	Upper Stabilizer Blade	As Ordered	
OD3	Lower Stabilizer Blade	As Ordered	
OD4	Lower Shoe	90.48	3.562
OD5	Inner Tube	85.73	3.375

Inner Diameters			
ID1	Outer Tube	95.25	3.750
ID2A	Top Sub	64.30	2.531
ID2B	Safety Joint	n/a	n/a
ID3	Cartridge Cap	44.45	1.750
ID4	Bearing Retainer	36.58	1.440
ID5	Inner Tube Plug	36.58	1.440
ID6	Pressure Relief Plug	19.34	0.761
ID7	Inner Tube	73.00	2.875

HT Series (continued)

Tool Fishing Dimensions		**6-3/4" x 4" HT30**	
Dim#	Description	Metric [mm]	English [in]
L1	**Outer Assembly Total MUL 1**	**10363.20**	**408.000**
L2A	Top Sub	707.90	27.870
L2A.1	Top Sub Pin	105.13	4.139
L2B	Safety Joint	n/a	n/a
L2B.1	Safety Joint Upper Body	n/a	n/a
L3	Upper Stabilizer	1219.20	48.000
L3.1	Stabilizer Upper Body	726.13	28.588
L3.2	Stabilizer Blade	299.90	11.807
L3.3	Stabilizer Pin	104.90	4.130
L4	Outer Tube	7924.80	312.000
L4.1	Outer Tube Pin	104.90	4.130
L5	Lower Stabilizer	1219.20	48.000
L5.1	Stabilizer Upper Body	726.13	28.588
L5.2	Stabilizer Blade	299.90	11.807
L5.3	Stabilizer Pin	104.90	4.130

L6	**Inner Assembly Total MUL 2**	**10494.63**	**413.174**
L7	Cartrigde Cap	209.16	8.235
L7.1	Cartridge Cap Pin	85.85	3.380
L8	Cartrigde Plug	56.96	2.243
L8.1	Cartridge Plug Pin	63.56	2.502
L9	Inner Tube Plug	314.20	12.370
L9.1	Inner Tube Plug Pin	50.95	2.006
L10	Pressure Relief Plug	50.80	2.000
L10.1	Pressure Relief Plug Pin	44.45	1.750
L11	Inner Tube Extension	304.80	12.000
L11.1	Inner Tube Extension Pin	50.95	2.006
L12	Inner Tube	9144.00	360.000
L12.2	Inner Tube Pin	50.95	2.006
L13	Upper Shoe	163.09	6.421
L13.1	Upper Shoe Pin	49.37	1.944
L14	Lower Shoe	137.44	5.411
L14.1	Lower Shoe to Bit Upset	101.14	3.982

Outer Diameters			
OD1	Outer Assembly	171.45	6.750
OD2	Upper Stabilizer Blade	As Ordered	
OD3	Lower Stabilizer Blade	As Ordered	
OD4	Lower Shoe	130.18	5.125
OD5	Inner Tube	120.65	4.750

Inner Diameters			
ID1	Outer Tube	136.53	5.375
ID2A	Top Sub	82.6	3.250
ID2B	Safety Joint	n/a	n/a
ID3	Cartridge Cap	79.25	3.120
ID4	Bearing Retainer	60.33	2.375
ID5	Inner Tube Plug	60.33	2.375
ID6	Pressure Relief Plug	25.40	1.000
ID7	Inner Tube	107.95	4.250

HT Series (continued)

Tool Fishing Dimensions		**8" x 5-1/4" HT40**	
Dim#	Description	Metric [mm]	English [in]
L1	**Outer Assembly Total MUL 1**	**10820.40**	**426.000**
L2A	Top Sub	762.00	30.000
L2A.1	Top Sub Pin	76.20	3.000
L2B	Safety Joint	n/a	n/a
L2B.1	Safety Joint Upper Body	n/a	n/a
L3	Upper Stabilizer	1219.20	48.000
L3.1	Stabilizer Upper Body	576.65	22.703
L3.2	Stabilizer Blade	429.53	16.911
L3.3	Stabilizer Pin	109.95	4.329
L4	Outer Tube	7924.80	312.000
L4.1	Outer Tube Pin	109.95	4.329
L5	Lower Stabilizer	1219.20	48.000
L5.1	Stabilizer Upper Body	576.65	22.703
L5.2	Stabilizer Blade	429.53	16.911
L5.3	Stabilizer Pin	109.95	4.329

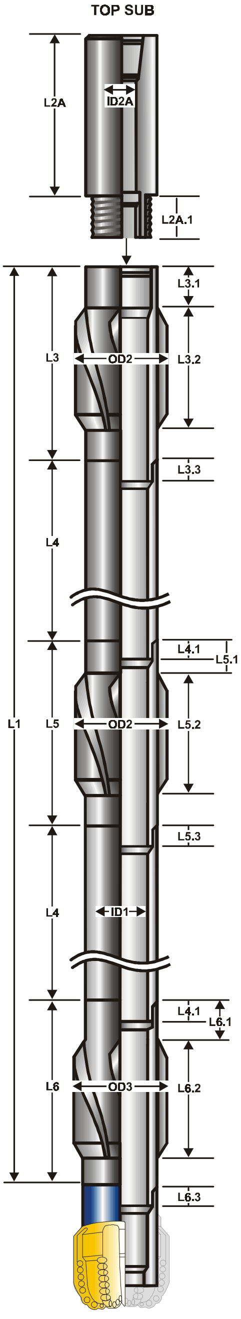
L6	**Inner Assembly Total MUL 2**	**10967.33**	**431.784**
L7	Cartrigde Cap	225.25	8.868
L7.1	Cartridge Cap Pin	76.20	3.000
L8	Cartrigde Plug	72.00	2.835
L8.1	Cartridge Plug Pin	75.58	2.976
L9	Inner Tube Plug	435.60	17.150
L9.1	Inner Tube Plug Pin	69.85	2.750
L10	Pressure Relief Plug	50.80	2.000
L10.1	Pressure Relief Plug Pin	44.45	1.750
L11	Inner Tube Extension	304.80	12.000
L11.1	Inner Tube Extension Pin	70.00	2.756
L12	Inner Tube	9144.00	360.000
L12.2	Inner Tube Pin	69.90	2.752
L13	Upper Shoe	270.00	10.630
L13.1	Upper Shoe Pin	70.60	2.780
L14	Lower Shoe	162.10	6.382
L14.1	Lower Shoe to Bit Upset	131.78	5.188

Outer Diameters			
OD1	Outer Assembly	203.20	8.000
OD2	Upper Stabilizer Blade	As Ordered	
OD3	Lower Stabilizer Blade	As Ordered	
OD4	Lower Shoe	165.10	6.500
OD5	Inner Tube	158.75	6.250

Inner Diameters			
ID1	Outer Tube	168.28	6.625
ID2A	Top Sub	82.55	3.250
ID2B	Safety Joint	n/a	n/a
ID3	Cartridge Cap	79.25	3.120
ID4	Bearing Retainer	76.20	3.000
ID5	Inner Tube Plug	60.45	2.380
ID6	Pressure Relief Plug	25.40	1.000
ID7	Inner Tube	139.70	5.500

CoreDrill Series

Figure 6-2 CoreDrill Series



CoreDrill Series

Tool Fishing Dimensions		**CDS Ia - 6.25" x 2"**	
Dim#	Description	Metric [mm]	English [in]
L1	**Outer Assembly Total MUL** [1]	**10058.40**	**396.000**
L2A	Top Sub	609.60	24.000
L2A.1	Top Sub Pin	117.00	4.606
L3	Upper Stabilizer	914.40	36.000
L3.1	Stabilizer Upper Body	458.50	18.051
L3.2	Stabilizer Blade	306.90	12.083
L3.3	Stabilizer Pin	117.00	4.606
L4	Outer Tube	3657.60	144.000
L4.1	Outer Tube Pin	117.00	4.606
L5	Middle Stabilizer	914.40	36.000
L5.1	Stabilizer Upper Body	458.50	18.051
L5.2	Stabilizer Blade	306.90	12.083
L5.3	Stabilizer Pin	117.00	4.606
L6	Lower Stabilizer	914.40	36.000
L6.1	Stabilizer Upper Body	458.50	18.051
L6.2	Stabilizer Blade	306.90	12.083
L6.3	Stabilizer Pin	117.00	4.606

Outer Diameters			
OD1	Outer Assembly	158.75	6.250
OD2	Upper Stabilizer Blade	As Ordered	
OD3	Lower Stabilizer Blade	As Ordered	

Inner Diameters			
ID1	Outer Tube	107.95	4.250
ID2A	Top Sub	68.25	2.687

[1]Measured from Shank shoulder to Top Sub pin shoulder.

[2]Measured from Lower Shoe seat in Shank to top of Latch fingers.

CoreDrill Series (continued)

Tool Fishing Dimensions		**CDS II - 6.50" x 2"**	
Dim#	Description	Metric [mm]	English [in]
L1	**Outer Assembly Total MUL [1]**	**10207.00**	**401.850**
L2A	Top Sub	679.83	26.765
L2A.1	Top Sub Pin	132.98	5.235
L3	Upper Stabilizer	914.40	36.000
L3.1	Stabilizer Upper Body	459.02	18.072
L3.2	Stabilizer Blade	293.40	11.551
L3.3	Stabilizer Pin	132.98	5.235
L4	Outer Tube	3731.90	146.925
L4.1	Outer Tube Pin	132.98	5.235
L5	Middle Stabilizer	914.40	36.000
L5.1	Stabilizer Upper Body	459.02	18.072
L5.2	Stabilizer Blade	293.40	11.551
L5.3	Stabilizer Pin	132.98	5.235
L6	Lower Stabilizer	914.40	36.000
L6.1	Stabilizer Upper Body	459.02	18.072
L6.2	Stabilizer Blade	293.40	11.551
L6.3	Stabilizer Pin	132.98	5.235

Outer Diameters			
OD1	Outer Assembly	165.10	6.500
OD2	Upper Stabilizer Blade	As Ordered	
OD3	Lower Stabilizer Blade	As Ordered	

Inner Diameters			
ID1	Outer Tube	107.95	4.250
ID2A	Top Sub	68.25	2.687

[1]Measured from Shank shoulder to Top Sub pin shoulder.

[2]Measured from Lower Shoe seat in Shank to top of Latch fingers.

CoreDrill Series (continued)

Tool Fishing Dimensions		**SH CDS - 4.75" x 1.625"**	
Dim#	Description	Metric [mm]	English [in]
L1	**Outer Assembly Total MUL** [1]	**10363.20**	**408.000**
L2A	Top Sub	720.37	28.361
L2A.1	Top Sub Pin	89.65	3.530
L3	Upper Stabilizer	1219.20	48.000
L3.1	Stabilizer Upper Body	689.61	27.150
L3.2	Stabilizer Blade	319.50	12.579
L3.3	Stabilizer Pin	89.90	3.540
L4	Outer Tube	7924.80	312.000
L4.1	Outer Tube Pin	89.90	3.540
L5	Middle Stabilizer	1219.20	48.000
L5.1	Stabilizer Upper Body	689.61	27.150
L5.2	Stabilizer Blade	319.50	12.579
L5.3	Stabilizer Pin	89.90	3.540
L6	Lower Stabilizer	1219.20	48.000
L6.1	Stabilizer Upper Body	689.61	27.150
L6.2	Stabilizer Blade	319.50	12.579
L6.3	Stabilizer Pin	89.90	3.540

Outer Diameters			
OD1	Outer Assembly	120.65	4.750
OD2	Upper Stabilizer Blade	As Ordered	
OD3	Lower Stabilizer Blade	As Ordered	

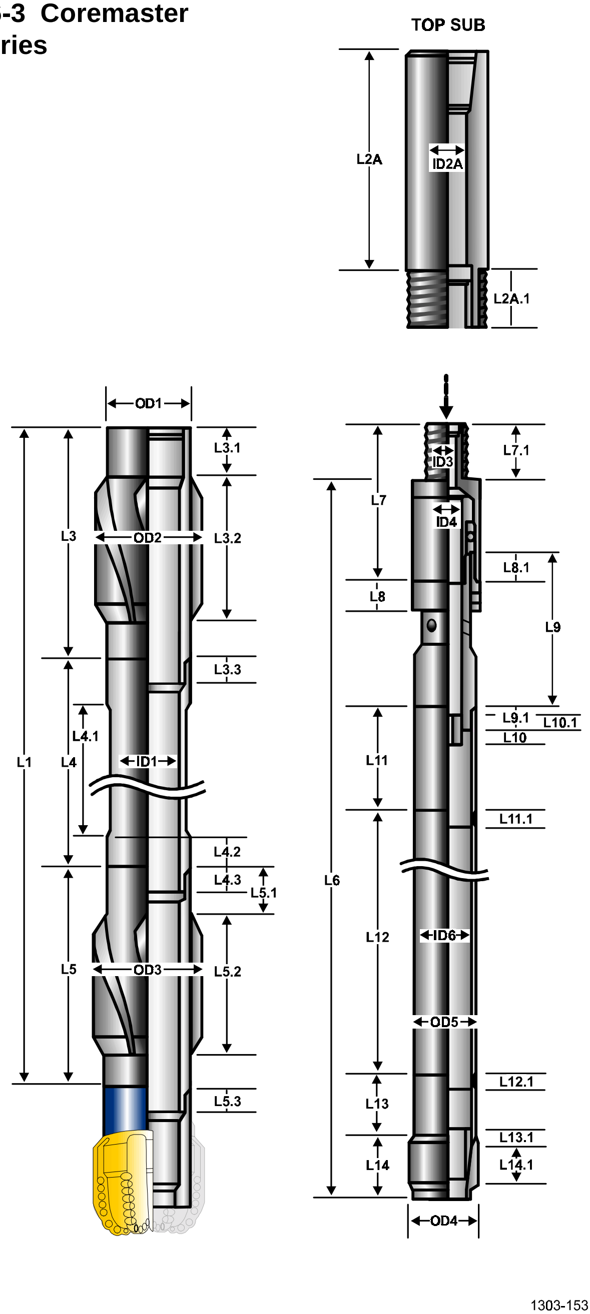
Inner Diameters			
ID1	Outer Tube	95.25	3.750
ID2A	Top Sub	64.30	2.531

[1]Measured from Shank shoulder to Top Sub pin shoulder.

[2]Measured from Lower Shoe seat in Shank to top of Latch fingers.

Coremaster Series

Figure 6-3 Coremaster & HT Series



Coremaster Series

Tool Fishing Dimensions		**4 3/4" X 2 1/8"**	
Dim#	**Description**	**Metric (mm)**	**English (in)**
L1	Outer Assembly Total MUL 1	11568.18	455.44
L2A	Top Sub	654.05	25.75
L2A.1	Top Sub Pin	146.05	5.25
L2B	Safety Joint	n/a	n/a
L2B.1	Safety Joint Upper Body	n/a	n/a
L3	Upper Stabilizer	615.95	24.25
L3.1	Stabilizer Upper Body	215.50	8.50
L3.2	Stabilizer Blade	203.20	8.00
L3.3	Stabilizer Pin	69.85	2.75
L4	Outer Tube	326.69	12.86
L4.1	Outer Tube Inset Length	69.85	2.75
L4.2	Outer Tube Pin Upset Length	n/a	n/a
L4.3	Outer Tube Pin	n/a	n/a
L5	Lower Stabilizer	615.95	24.25
L5.1	Stabilizer Upper Body	215.90	8.5
L5.2	Stabilizer Blade	203.20	8.00
L5.3	Stabilizer Pin	69.85	2.75
L6	Inner Assembly Total MUL 2	9828.23	386.938
L7	Cartridge Cap	177.80	7.000
L7.1	Cartridge Cap Pin incl. 5/8" shims	63.50	2.500
L8	Cartridge Plug	50.92	2.005
L8.1	Cartridge Plug Pin	57.08	2.247
L9	Inner Tube Plug 1	355.75	14.006
L9.1	Inner Tube Plug Pin	50.80	2.000
L10	Pressure Relief Plug	50.30	1.980
L10.1	Pressure Relief Plug Pin	36.60	1.441
L11	Inner Tube Extension	304.80	12.00
L11.1	Inner Tube Extension Pin	50.80	2.00
L12	Inner Tube	9144.00	360.00
L12.1	Inner Tube Pin	50.80	2.000
L13	Upper Shoe	208.00	8.189
L13.1	Upper Shoe	34.75	1.368
L14	Lower Shoe	113.56	4.471
L14.1	Lower Shoe	84.96	3.345

Outer Diameter			
OD1	Outer Assembly	120.65	4.75
OD2	Upper Stabilizer Blade		As Ordered
OD3	Outer Tube Inset		As Ordered
OD4	Lower Shoe	53.54	2.108
OD5	Inner Tube	73.03	2.875

Inner Diameters			
ID1	Outer Tube	82.55	3.25
ID2A	Top Sub	38.10	1.50
ID3	Cartridge Cap	38.10	1.50
ID4	Cartridge Plug	31.75	1.25
ID6	Pressure Relief Plug	19.05	0.76
ID7	Inner Tube	60.33	2.375

Coremaster Series

Tool Fishing Dimensions		(7 1/4") X 6 3/4" X 4"	
Dim#	**Description**	**Metric (mm)**	**English (in)**
L1	Outer Assembly Total MUL 1	11,322.91	445.78
L2A	Top Sub	460.00	18.11
L2A.1	Top Sub Pin	119.99	4.724
L2B	Safety Joint	n/a	n/a
L2B.1	Safety Joint Upper Body	n/a	n/a
L3	Upper Stabilizer	786.00	30.94
L3.1	Stabilizer Upper Body	460.00	18.11
L3.2	Stabilizer Blade	285.37	11.235
L3.3	Stabilizer Pin	119.99	4.724
L4	Outer Tube	8359.00	329.09
L4.1	Outer Tube Inset Length	7838.95	308.62
L4.2	Outer Tube Pin Upset Length	200.00	7.874
L4.3	Outer Tube Pin	119.09	4.724
L5	Lower Stabilizer	786.00	30.94
L5.1	Stabilizer Upper Body	460.00	18.11
L5.2	Stabilizer Blade	285.37	11.235
L5.3	Stabilizer Pin	119.99	4.724
L6	Inner Assembly Total MUL 2	9828.23	386.938
L7	Cartridge Cap	177.80	7.000
L7.1	Cartridge Cap Pin incl. 5/8" shims	63.50	2.500
L8	Cartridge Plug	50.92	2.005
L8.1	Cartridge Plug Pin	57.08	2.247
L9	Inner Tube Plug 1	355.75	14.006
L9.1	Inner Tube Plug Pin	50.80	2.000
L10	Pressure Relief Plug	50.30	1.980
L10.1	Pressure Relief Plug Pin	36.60	1.441
L11	Inner Tube Extension	304.80	12.00
L11.1	Inner Tube Extension Pin	50.80	2.00
L12	Inner Tube	9144.00	360.00
L12.1	Inner Tube Pin	50.80	2.000
L13	Upper Shoe	208.00	8.189
L13.1	Upper Shoe	34.75	1.368
L14	Lower Shoe	113.56	4.471
L14.1	Lower Shoe	84.96	3.345
Outer Diameter			
OD1	Outer Assembly	184.76	7.274
OD2	Upper Stabilizer Blade	As Ordered	
OD3	Outer Tube Inset	172.75	6.801
OD4	Lower Shoe	130.18	5.125
OD5	Inner Tube	122.12	4.808
Inner Diameters			
ID1	Outer Tube	95.25	3.750
ID2A	Top Sub	38.10	1.50
ID2B	Safety Joint	75.20	2.961
ID3	Cartridge Cap	44.45	1.750
ID4	Cartridge Plug	36.58	1.440
ID5	Inner Tube Plug	36.58	1.440
ID6	Pressure Relief Plug	19.34	0.761
ID7	Inner Tube	73.00	2.875

Conversion Factors & Physical Constants

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
A		
abamperes	1.0×10^{1}	amperes
abcoulombs	2.998×10^{10}	statcoulombs
abfarads	1.0×10^{9}	farads
abfarads	1.0×10^{15}	microfarads
abhenries	1.0×10^{-9}	henries
abhenries	1.0×10^{-6}	millihenries
abohms	1.0×10^{-9}	ohms
abohms	1.0×10^{15}	megohms
abvolts	1.0×10^{-8}	volts
acres	1.0×10^{1}	sq. chains (gunters)
acres	1.60×10^{2}	rods
acres	1.0×10^{5}	sq. links
acres	4.047×10^{1}	hectares or sq. hectometers
acres	4.35×10^{4}	sq. ft.
acres	4.047×10^{3}	sq. meters
acres	1.562×10^{-3}	sq. miles
acres	4.840×10^{3}	sq. yards
acre-feet	4.356×10^{4}	cu. feet
acre-feet	3.259×10^{5}	gallons
amperes/sq. cm.	6.452	amps/sq. in.

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
amperes/sq. cm.	1.0×10^{4}	amps/sq. meter
amperes/sq. in.	1.550×10^{-1}	amps/sq. cm.
amperes/sq. in.	1.550×10^{3}	amps/sq. meter
amperes/sq. meter	1.0×10^{-4}	amps/sq. cm.
amperes/sq. meter	6.452×10^{-4}	amps/sq. in.
ampere-hours	3.600×10^{3}	coulombs
ampere-hours	3.731×10^{-2}	faradays
ampere-turns	1.257	gilberts
ampere-turns/cm.	2.540	amp-turns/in.
ampere-turns/cm.	1.0×10^{2}	amp-turns/meter
ampere-turns/in.	3.937×10^{-1}	amp-turns/cm.
ampere-turns/in.	3.937×10^{1}	amp-turns/meter
ampere-turns/in.	4.950×10^{-1}	gilberts/cm.
ampere-turns/meter	1.0×10^{-2}	amp-turns/cm.
ampere-turns/meter	2.54×10^{-2}	amp-turns/in.
ampere-turns/meter	1.257×10^{-2}	gilberts/cm.
angstrom unit	3.937×10^{-9}	inches
angstrom unit	1.0×10^{-10}	meters
angstrom unit	1.0×10^{-4}	microns or (mu)
ares	2.471×10^{-2}	acres (U.S.)
ares	1.196×10^{2}	sq. yards
ares	1.0×10^{2}	sq. meters
astronomical unit	1.495×10^{8}	kilometers
atmospheres	7.348×10^{-3}	tons/sq. i n.
atmospheres	1.058	tons/sq. foot

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
atmospheres	7.6×10^{1}	cms. of mercury (at 0°C)
atmospheres	3.39×10^{1}	ft. of water (at 4°C)
atmospheres	2.992×10^{1}	in. of mercury (at 0°C)
atmospheres	7.6×10^{-1}	meters of mercury (at 0°C)
atmospheres	7.6×10^{2}	millimeters of mercury (at 0°C)
atmospheres	1.0333	kgs./sq. cm.
atmospheres	1.0333×10^{4}	kgs./sq. meter
atmospheres	1.47×10^{1}	pounds/sq. in.
B		
barrels (U.S., dry)	3.281	bushels
barrels (U.S., dry)	7.056×10^{3}	cu. inches
barrels (U.S., dry)	1.05×10^{2}	quarts (dry)
barrels (U.S. liquid)	3.15×10^{1}	gallons
barrels (oil)	4.2×10^{1}	gallons (oil)
bars	9.869×10^{-1}	atmospheres
bars	1.0×10^{6}	dynes/sq. cm.
bars	1.020×10^{4}	kgs./sq. meter
bars	2.089×10^{3}	pounds/sq. ft.
bars	1.45×10^{1}	pounds/sq. in.
barye	1.00	dynes/sq. cm.
bolt (U.S., cloth)	3.6576×10^{1}	meters
btu	1.0409×10^{1}	liter-atmospheres
btu	1.0550×10^{10}	ergs
btu	7.7816×10^{2}	foot-pounds

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
btu	2.52×10^{2}	gram-calories
btu	3.927×10^{-4}	horsepower-hours
btu	1.055×10^{3}	joules
btu	2.52×10^{-1}	kilogram-calories
btu	1.0758×10^{2}	kilogrammeters
btu	2.928×10^{-4}	kilowatt-hours
btu/hr.	2.162×10^{-1}	ft.-pounds/sec.
btu/hr.	7.0×10^{-2}	gram-cal./sec.
btu/hr.	3.929×10^{-4}	horsepower
btu/hr.	2.931×10^{-1}	watts
btu/min.	1.296×10^{1}	ft.-pounds/sec.
btu/min.	2.356×10^{-2}	horsepower
btu/min.	1.757×10^{-2}	kilowatts
btu/min.	1.757×10^{1}	watts
btu/sq. ft./min.	1.22×10^{-1}	watts/sq. in.
bucket (br. dry)	1.8184×10^{4}	cubic cm.
bushels	1.2445	cubic ft.
bushels	2.1504×10^{3}	cubic in.
bushels	3.524×10^{-2}	cubic meters
bushels	3.524×10^{1}	liters
bushels	4.0	pecks
bushels	6.4×10^{1}	pints (dry)
bushels	3.2×10^{1}	quarts (dry)

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
	C	
calories, gram (mean)	3.9685×10^{-3}	btu (mean)
candle/sq. cm.	3.146	lamberts
candle/sq. in.	4.870×10^{-1}	lamberts
centares	1.0	sq. meters
centigrade (degrees)	(°C x 9/5)+32	fahrenheit (degrees)
centigrade (degrees)	°C + 273.18	kelvin (degrees)
centigrams	1.0×10^{-2}	grams
centiliters	3.382×10^{-1}	ounce (fluid) U.S.
centiliters	6.103×10^{-1}	cubic in.
centiliters	2.705	drams
centiliters	1.0×10^{-2}	liters
centimeters	3.281×10^{-2}	feet
centimeters	3.937×10^{-1}	inches
centimeters	1.0×10^{-5}	kilometers
centimeters	1.0×10^{-2}	meters
centimeters	6.214×10^{-6}	miles
centimeters	1.0×10^{1}	millimeters
centimeters	3.937×10^{2}	mils
centimeters	1.094×10^{-2}	yards
centimeters	1.0×10^{4}	microns
centimeters	1.0×10^{8}	angstrom units
centimeter-dynes	1.020×10^{-3}	cn-grams
centimeter-dynes	1.020×10^{-8}	meter-kgs.

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
centimeter-dynes	7.376×10^{-8}	pound-ft.
centimeter-grams	9.807×10^{2}	cm.-dynes
centimeter-grams	1.0×10^{-5}	meter-kgs.
centimeter-grams	7.233×10^{-5}	pound-ft.
centimeters of mercury	1.316×10^{-2}	atmospheres
centimeters of mercury	4.461×10^{-1}	ft. of water
centimeters of mercury	1.36×10^{2}	kgs./sq. meter
centimeters of mercury	2.785×10^{1}	pounds/sq. ft.
centimeters of mercury	1.934×10^{-1}	pounds/sq. in.
centimeters/sec.	1.969	feet/min
centimeters/sec.	3.281×10^{-2}	feet/sec.
centimeters/sec.	3.6×10^{-2}	kilometers/hr.
centimeters/sec.	1.943×10^{-2}	knots
centimeters/sec.	6.0×10^{-1}	meters/min.
centimeters/sec.	2.237×10^{-2}	miles/hr.
centimeters/sec.	3.728×10^{-4}	miles/min.
centimeters/sec./sec.	3.281×10^{-2}	ft./sec./sec.
centimeters/sec./sec.	3.6×10^{-2}	kms./hr./sec.
centimeters/sec./sec.	1.0×10^{-2}	meters/sec./sec.
centimeters/sec./sec.	2.237×10^{-2}	miles/hr./sec.
centipoise	1.0×10^{-2}	gr./cm.-sec
centipoise	6.72×10^{-4}	pound/ft.-sec.
centipoise	2.4	pound/ft.-hr.
chains (gunters)	7.92×10^{2}	inches
chains (gunters)	2.012×10^{1}	meters

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
chains (gunters)	2.2×10^{1}	yards
circular mils	5.067×10^{-6}	sq cm.
circular mils	7.854×10^{-1}	sq. mils
circular mils	7.854×10^{-7}	sq. inches
circumference	6.283	radians
cords	8.0	cord ft.
cord K.	1.6×10^{1}	cubic ft.
coulombs	2.998×10^{9}	statcoulombs
coulombs	1.036×10^{-5}	faradays
coulombs/sq. cm.	6.452	coulombs/sq. in.
coulombs/sq. cm.	1.0×10^{4}	coulombs/sq. meter
coulombs/sq. in.	1.550×10^{-1}	coulombs/sq. cm.
coulombs/sq. in.	1.550×10^{3}	coulombs/sq.meter
coulombs/sq. meter	1.0×10^{-4}	coulombs/sq. cm.
coulombs/sq. meter	6.452×10^{-4}	coulombs/sq. in.
cubic centimeters	3.531×10^{-5}	cubic ft.
cubic centimeters	6.102×10^{-2}	cubic in.
cubic centimeters	1.0×10^{-6}	cubic meters
cubic centimeters	1.308×10^{-6}	cubic yards
cubic centimeters	2.642×10^{-4}	gallons (U.S. liquid)
cubic centimeters	1.0×10^{-3}	liters
cubic centimeters	2.113×10^{-3}	pints (U.S. liquid)
cubic centimeters	1.057×10^{-3}	quarts (U.S. liquid)
cubic feet	8.036×10^{-1}	bushels (dry)
cubic feet	2.8320×10^{4}	cu. cms.

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
cubic feet	1.728×10^{3}	cu. inches
cubic feet	2.832×10^{-2}	cu. meters
cubic feet gas (ft^3) (at 60°F, 1 atm)	2.68×10^{-2}	cu. meters gas (m^3) (at 0°C, 1 atm)
cubic feet	3.704×10^{-2}	cu. yards
cubic feet	7.48052	gallons (U.S. liquid)
cubic feet	2.832×10^{1}	liters
cubic feet	5.984×10^{1}	pints (U.S. liquid)
cubic feet	2.992×10^{1}	quarts (U.S. liquid)
cubic feet/min.	4.72×10^{2}	cu. cms./sec.
cubic feet/min.	1.247×10^{-1}	gallons/sec.
cubic feet/min.	4.720×10^{-1}	liters/sec.
cubic feet/min.	6.243×10^{1}	pounds water/min.
cubic feet/sec.	6.46317×10^{-1}	million gals./day
cubic feet/sec.	4.48831×10^{2}	gallons/min.
cubic inches	1.639×10^{1}	cu. cms.
cubic inches	5.787×10^{-4}	cu. ft.
cubic inches	1.639×10^{-5}	cu. meters
cubic inches	2.143×10^{-5}	cu. yards
cubic inches	4.329×10^{-3}	gallons
cubic inches	1.639×10^{-2}	liters
cubic inches	3.463×10^{-2}	pints (U.S. liquid)
cubic inches	1.732×10^{-2}	quarts (U.S. liquid)
cubic meters	2.838×10^{1}	bushels (dry)
cubic meters	1.0×10^{6}	cu. cms.

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
cubic meters	3.531×10^{1}	cu. ft.
cubic meters gas (m^3) (at 0°C, 1 atm)	3.725×10^{1}	cu. ft. gas (ft^3) (at 60°F, 1 atm)
cubic meters	6.1023×10^{4}	cu. inches
cubic meters	1.308	cu. yards
cubic meters	2.642×10^{2}	gallons (U.S. liquid)
cubic meters	1.0×10^{3}	liters
cubic meters	2.113×10^{3}	pints (U.S. liquid)
cubic meters	1.057×10^{3}	quarts (U.S. liquid)
cubic yards	7.646×10^{5}	cu. cms.
cubic yards	2.7×10^{1}	cu. ft.
cubic yards	4.6656×10^{4}	cu. inches
cubic yards	7.646×10^{-1}	cu. meters
cubic yards	2.02×10^{2}	gallons (U.S. liquid)
cubic yards	7.646×10^{2}	liters
cubic yards	1.6159×10^{3}	pints (U.S. liquid)
cubic yards	8.079×10^{2}	quarts (U.S. liquid)
cubic yards/min.	4.5×10^{-1}	cubic ft./sec.
cubic yards/min.	3.367	gallons/sec.
cubic yards/min.	1.274×10^{1}	liters/sec.
D		
daltons	1.650×10^{-24}	grams

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
days	8.64×10^{4}	seconds
days	1.44×10^{3}	minutes
days	2.4×10^{1}	hours
decigrams	1.0×10^{-1}	grams
deciliters	1.0×10^{-1}	liters
decimeters	1.0×10^{-1}	meters
degrees (angle)	1.111×10^{-2}	quadrants
degrees (angle)	1.745×10^{-2}	radians
degrees (angle)	3.6×10^{3}	seconds
degrees/sec.	1.745×10^{-2}	radians/sec.
degrees/sec.	1.667×10^{-1}	revolutions/min.
degrees/sec.	2.778×10^{-3}	revolutions/sec.
decagrams	1.0×10^{1}	grams
dekaliters	1.0×10^{1}	liters
dekameters	$10. \times 10^{1}$	meters
drams(apoth.ortroy)	1.3714×10^{-1}	ounces (avdp.)
drams(apoth.ortroy)	1.25×10^{-1}	ounces (troy)
drams (U.S. fluid or apoth.)	3.6967	cubic cm.
drams	1.7718	grams
drams	2.7344×10^{1}	grains
drams	6.25×10^{-2}	ounces
dynes/sq. cm.	1.0×10^{-2}	ergs/sq. millimeter
dynes/sq. cm.	9.869×10^{-7}	atmospheres
dynes/sq. cm.	2.953×10^{-5}	in. of mercury (at 0°C)

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
dynes/sq. cm.	4.015×10^{-4}	in. of water (at 4°C)
dynes	1.020×10^{-3}	grams
dynes	1.0×10^{-7}	joules/cm.
dynes	1.0×10^{-5}	joules/meter (newtons)
dynes	1.020×10^{-6}	kilograms
dynes	7.233×10^{-5}	poundals
dynes	2.248×10^{-6}	pounds
dynes/sq. cm.	1.0×10^{-6}	bars
	E	
ell	1.1430×10^{2}	cm.
ell	4.5×10^{1}	inches
em, pica	1.67×10^{-1}	inch
em, pica	4.233 x 10-	cm.
erg/sec.	1.0	dyne-cm./sec.
ergs	$9.486 \times 10^{-}$	btu
ergs	1.0	dyne-centimeters
ergs	7.376×10^{-8}	foot-pounds
ergs	2.389×10^{-8}	gram-calories
ergs	1.020×10^{-3}	gram-cms.
ergs	3.7250×10^{-14}	horsepower-hrs.
ergs	1.0×10^{-7}	joules
ergs	2.389×10^{-11}	kg.-calories
ergs	1.020×10^{-8}	kg.-meters
ergs	2.773×10^{-14}	kilowatt-hrs.

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
ergs	2.773×10^{-11}	watt-hrs.
ergs/sec.	5.668×10^{-9}	btu/min.
ergs/sec.	4.426×10^{-6}	ft.-lbs./min.
ergs/sec.	7.3756×10^{-8}	ft.-lbs./sec.
ergs/sec.	1.341×10^{-10}	horsepower
ergs/sec.	1.433×10^{-9}	kg-calories/min.
ergs/sec.	1.0×10^{-10}	kilowatts
	F	
farads	1.0×10^{6}	microfarads
faraday/sec.	9.65×10^{4}	ampere (absolute)
faradays	2.68×10^{1}	ampere-hours
faradays	9.649×10^{4}	coulombs
fathoms	1.8288	meters
fathoms	6.0	feet
feet	3.048×10^{1}	centimeters
feet	3.048×10^{-4}	kilometers
feet	3.048×10^{-1}	meters
feet	1.645×10^{-4}	miles (naut.)
feet	1.894×10^{-4}	miles (stat.)
feet	3.048×10^{2}	millimeters
feet	1.2×10^{4}	mils
feet of water	2.95×10^{-2}	atmospheres
feet of water	8.826×10^{-1}	in. of mercury
feet of water	3.048×10^{-2}	kgs./sq. cm.

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
feet of water	3.048×10^{2}	kgs./sq. meter
feet of water	6.243×10^{1}	pounds/sq. ft.
feet of water	4.335×10^{-1}	pounds/sq. in.
feet/min.	5.080×10^{-1}	cms./sec.
feet/min.	1.667×10^{-2}	feet/sec.
feet/min.	1.829×10^{-2}	kms./hr.
feet/min.	3.048×10^{-1}	meters/min.
feet/min.	1.136×10^{-2}	miles/hr.
feet/sec.	3.048×10^{1}	cms./sec.
feet/sec.	1.097	kms./hr.
feet/sec.	5.921×10^{-1}	knots
feet/sec.	1.829×10^{1}	meters/min.
feet/sec.	6.818×10^{-1}	miles/hr.
feet/sec.	1.136×10^{-2}	miles/min.
feet/sec./sec.	3.048×10^{1}	cms./sec./sec.
feet/sec./sec.	1.097	kms./hr./sec.
feet/sec./sec.	3.048×10^{-1}	meters/sec./sec.
feet/sec./sec.	6.818×10^{-1}	miles/hr./sec.
feet/100 feet	1.0	per cent grade
foot-candle	1.0764×10^{1}	lumen/sq. meter
foot-candle	1.0764×10^{1}	lux
foot-pounds	1.286×10^{-3}	btu
foot-pounds	1.356×10^{7}	ergs
foot-pounds	3.241×10^{-1}	gram-calories
foot-pounds	5.050×10^{-7}	horsepower-hrs.

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
foot-pounds	1.356	joules
foot-pounds	3.241×10^{-4}	kg.-calories
foot-pounds	1.383×10^{-1}	kg.-meters
foot-pounds	3.766×10^{-7}	kilowatt-hrs.
foot-pounds/min.	1.286×10^{-3}	btu/min.
foot-pounds/min.	1.667×10^{-2}	foot-pounds/sec.
foot-pounds/min.	3.030×10^{-5}	horsepower
foot-pounds/min.	3.241×10^{-4}	kg.-calories/min.
foot-pounds/min.	2.260×10^{-5}	kilowatts
foot-pounds/sec.	4.6263	btu/hr.
foot-pounds/sec.	7.717×10^{-2}	btu/min.
foot-pounds/sec.	1.818×10^{-3}	horsepower
foot-pounds/sec.	1.945×10^{-2}	kg.-calories/min.
foot-pounds/sec.	1.356×10^{-3}	kilowatts
furlongs	1.25×10^{-1}	miles (U.S.)
furlongs	4.0×10^{1}	rods
furlongs	6.6×10^{2}	feet
furlongs	2.0117×10^{2}	meters
	G	
gallons	3.785×10^{3}	cu. cms.
gallons	1.337×10^{-1}	cu. feet
gallons	2.31×10^{2}	cu. inches

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
gallons	3.785×10^{-3}	cu. meters
gallons	4.951×10^{-3}	cu. yards
gallons	3.785	liters
gallons (liq. br. imp.)	1.20095	gallons (U.S. liquid)
gallons (U.S.)	8.3267×10^{-1}	gallons (imp.)
gallons of water	8.337	pounds of water
gallons/min.	2.228×10^{-3}	cu. feet/sec.
gallons/min.	6.308×10^{-2}	liters/sec.
gallons/min.	8.0208	cu. feet/hr.
gausses	6.452	lines/sq. in.
gausses	1.0×10^{-8}	webers/sq. cm.
gausses	6.452×10^{-8}	webers/sq. in.
gausses	1.0×10^{-4}	webers/sq. meter
gausses	7.958×10^{-1}	amp.-turn/cm.
gausses	1.0	gilbert/cm.
gilberts	7.958×10^{-1}	ampere-turns
gilberts/cm.	7.958×10^{-1}	ampere-turns/cm.
gilberts/cm.	2.021	ampere-turns/in.
gilberts/cm.	7.958×10^{1}	ampere-turns/meter
gills (british)	1.4207×10^{2}	cubic cm.
gills (U.S.)	1.18295×10^{2}	cubic cm.
gills (U.S.)	1.183×10^{-1}	liters
gills (U.S.)	2.5×10^{-1}	pints (liq.)
grade	1.571×10^{-2}	radian
grains	3.657×10^{-2}	drams (avdp.)

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
grains (troy)	1.0	grains (avdp.)
grains (troy)	6.48×10^{-2}	grams
grains (troy)	2.0833×10^{-3}	ounces (avdp.)
grains (troy)	4.167×10^{-2}	pennyweight (troy)
grains/U.S. gallon	1.7118×10^{-1}	parts/million
grains/U.S. gallon	1.4286×10^{2}	pounds/million gallons
grains/imp. gallon	1.4286×10^{1}	parts/million
grams	9.807×10^{2}	dynes
grams	1.543×10^{1}	grains (troy)
grams	9.807×10^{-5}	joules/cm.
grams	9.807×10^{-3}	joules/meter (newtons)
grams	1.0×10^{-3}	kilograms
grams	1.0×10^{3}	milligrams
grams	3.527×10^{-2}	ounces (avdp.)
grams	3.215×10^{-2}	ounces (troy)
grams	7.093×10^{-2}	poundals
grams	2.205×10^{-3}	pounds
grams/cm.	5.6×10^{-3}	pounds/in.
grams/cu. cm.	6.243×10^{1}	pounds/cu. ft.
grams/cu. cm.	3.613×10^{-2}	pounds/cu. in.
grams/cu. cm.	3.405×10^{-7}	pounds/mil-foot
grams/liter	5.8417×10^{1}	grains/gal.
grams/liter	8.345	pounds/1,000 gal.
grams/liter	6.2427×10^{-2}	pounds/cu. ft.
grams/sq. cm.	2.0481	pounds/sq. ft.

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
gram-calories	3.9683×10^{-3}	btu
gram-calories	4.184×10^{7}	ergs
gram-calories	3.086	foot-pounds
gram-calories	1.5596×10^{-6}	horsepower-hrs.
gram-calories	1.162×10^{-6}	kilowatt-hrs.
gram-calories	1.162×10^{-3}	watt-hrs.
gram-calories/sec.	1.4286×10^{1}	btu/hr.
gram-centimeters	9.297×10^{-8}	btu
gram-centimeters	9.807×10^{2}	ergs
gram-centimeters	9.807×10^{-5}	joules
gram-centimeters	2.343×10^{-8}	kg.-calories
gram-cent) meters	1.0×10^{-5}	kg.-meters
H		
hand	1.016×10^{1}	cm.
hectares	2.471	acres
hectares	1.076×10^{5}	sq. feet
hectograms	1.0×10^{2}	grams
hectoliters	1.0×10^{2}	liters
hectometers	1.0×10^{2}	meters
hectowatts	1.0×10^{2}	watts
henries	1.0×10^{3}	millihenries
hogsheads (british)	1.0114×10^{1}	cubic ft.
hogsheads (U.S.)	8.42184	cubic ft.
hogsheads (U.S.)	6.3×10^{1}	gallons (U.S.)

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
horsepower	4.244×10^{1}	btu/min.
horsepower	3.3×10^{4}	foot-lbs./min.
horsepower	5.50×10^{2}	foot-lbs./sec.
horsepower (metric)	9.863×10^{-1}	horsepower
horsepower	1.014	horsepower (metric)
horsepower	1.068×10^{1}	kg -calories/min.
horsepower	7.457×10^{-1}	kilowatts
horsepower	7.457×10^{2}	watts
horsepower (boiler)	3.352×10^{4}	btu/hr.
horsepower (boiler)	9.803	kilowatts
horsepower-hours	2.547×10^{3}	btu
horsepower-hours	2.6845×10^{13}	ergs
horsepower-hours	1.98×10^{6}	foot-lbs.
horsepower-hours	6.4119×10^{5}	gram-calories
horsepower-hours	2.684×10^{6}	joules
horsepower-hours	6.417×10^{2}	kg.-calories
horsepower-hours	2.737×10^{5}	kg.-meters
horsepower-hours	7.457×10^{-1}	kilowatt-hrs.
hours	4.167×10^{-2}	days
hours	5.952×10^{-3}	weeks
hours	3.6×10^{3}	seconds
hundredwgts (long)	1.12×10^{2}	pounds
hundredwgts (long)	5.0×10^{-2}	tons (long)
hundredwgts (long)	5.08023×10^{1}	kilograms
hundredwgts (short)	4.53592×10^{-2}	tons (metric)

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
hundredwgts (short)	4.46429×10^{-2}	tons (long)
hundredwgts (short)	4.53592×10^{1}	kilograms
	I	
inches	2.540	centimeters
inches	2.540×10^{-2}	meters
inches	1.578×10^{-5}	miles
inches	2.54×10^{1}	millimeters
inches	1.0×10^{3}	mils
inches	2.778×10^{-2}	yards
inches	2.54×10^{8}	angstrom units
inches	5.0505×10^{-3}	rods
inches of mercury	3.342×10^{-2}	atmospheres
inches of mercury	1.133	feet of water
inches of mercury	$3\ 453 \times 10^{-2}$	kgs./sq. cm.
inches of mercury	3.453×10^{2}	kgs./sq. meter
inches of mercury	7.073×10^{1}	pounds/sq. ft.
inches of mercury	4.912×10^{-1}	pounds/sq. in.
in. of water (at 4° C)	2.458×10^{-3}	atmospheres
in. of water (at 4° C)	7.355×10^{-2}	inches of mercury
in. of water (at 4° C)	2.54×10^{-3}	kgs./ sq. cm.
in.of water (at 4° C)	5.781×10^{-1}	ounces/sq. in.
in. of water (at 4° C)	5.204	pounds/ sq. ft.
in. of water (at 4° C)	3.613×10^{-2}	pounds/sq. in.
international ampere	9.998×10^{-1}	absolute amp. (U.S.)

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
international volt	1.00033	absolute volt (U.S.)
international coulomb	9.99835×10^{-1}	absolute coulomb
J		
joules	9.486×10^{-4}	btu
joules	1.0×10^{7}	ergs
joules	7.736×10^{-1}	foot-pounds
joules	2.389×10^{-4}	kg.-calories
joules	1.020×10^{-1}	kg.-meters
joules	2.778×10^{-4}	watt-hrs.
joules/cm.	1.020×10^{4}	grams
joules/cm.	1.0×10^{7}	dynes
joules/cm.	1.0×10^{2}	joules/meter (newtons)
joules/cm.	7.233×10^{2}	poundals
joules/cm.	2.248×10^{1}	pounds
K		
kilograms	9.80665×10^{5}	dynes
kilograms	1.0×10^{3}	grams
kilograms	9.807×10^{-2}	joules/cm.
kilograms	9.807	joules/meter (newtons)
kilograms	7.093×10^{1}	poundals
kilograms	2.2046	pounds
kilograms	9.842×10^{-4}	tons (long)

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
kilograms	1.102×10^{-3}	tons (short)
kilograms	3.5274×10^{1}	ounces (avdp.)
kilograms/cu. meter	1.0×10^{-3}	grams/cu. cm.
kilograms/cu. meter	6.243×10^{-2}	pounds/cu. ft.
kilograms/cu. meter	3.613×10^{-5}	pounds/cu. in.
kilograms/cu. meter	3.405×10^{-10}	pounds/mil-foot
kilograms/meter	6.72×10^{-1}	pounds/ft.
kilograms/sq. cm.	9.80665×10^{5}	dynes/sq. cm.
kilograms/sq. cm.	9.678×10^{-1}	atmospheres
kilograms/sq. cm.	3.281×10^{1}	feet of water
kilograms/sq. cm.	2.896×10^{1}	inches of mercury
kilograms/sq. cm.	2.048×10^{3}	pounds/sq. ft.
kilograms/sq. cm.	1.422×10^{1}	pounds/sq. in.
kilograms/sq. meter	9.678×10^{-5}	atmospheres
kilograms/sq. meter	9.807×10^{-5}	bars
kilograms/sq. meter	3.281×10^{-3}	feet of water
kilograms/sq. meter	2.896×10^{-3}	inches of mercury
kilograms/sq. meter	2.048×10^{-1}	pounds/sq. ft.
kilograms/sq. meter	1.422×10^{-3}	pounds/sq. in.
kilograms/sq. meter	9.80665×10^{1}	dynes/sq. cm.
kilograms/sq. mm.	1.0×10^{6}	kgs./sq. meter
kilogram-calories	3.968	btu
kilogram-calories	3.086×10^{3}	foot-pounds
kilogram-calories	1.558×10^{-3}	horsepower-hrs.
kilogram-calories	4183×10^{3}	joules

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
kilogram-calories	4.269×10^{2}	kg.-meters
kilogram-calories	4.186	kilojoules
kilogram-calories	1.163×10^{-3}	kilowatt-hrs.
kilogram-calories/min.	5.143×10^{1}	ft.-lbs./sec.
kilogram-calories/min.	9.351×10^{-2}	horsepower
kilogram-calories/min.	6.972×10^{-2}	kilowatts
kilogram-meters	9.296×10^{-3}	btu
kilogram-meters	9.807×10^{7}	ergs
kilogram-meters	7.233	foot-pounds
kilogram-meters	9.807	joules
kilogram-meters	2.342×10^{-3}	kg.-calories
kilogram-meters	2.723×10^{-6}	kilowatt-hrs.
kilolines	1.0×10^{3}	maxwells
kiloliters	1.0×10^{3}	liters
kiloliters	1.308	cubic yards
kiloliters	3.5316×10^{1}	cubic feet
kiloliters	2.6418×10^{2}	gallons (U.S. liquid)
kilometers	1.0×10^{5}	centimeters
kilometers	3.281×10^{3}	feet
kilometers	3.937×10^{4}	inches
kilometers	1.0×10^{3}	meters
kilometers	6.214×10^{-1}	miles (statute)
kilometers	5.396×10^{-1}	miles (nautical)
kilometers	1.0×10^{6}	millimeters

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
kilometers	1.0936×10^{3}	yards
kilometers/hr.	2.778×10^{1}	cms./sec.
kilometers/hr.	5.468×10^{1}	feet/min.
kilometers/hr.	9.113×10^{-1}	feet/sec.
kilometers/hr.	5.396×10^{-1}	knots
kilometers/hr.	1.667×10^{1}	meters/mm.
kilometers/hr.	6.214×10^{-1}	miles/hr.
kilometers/hr./sec.	2.778×10^{1}	cms./sec./sec.
kilometers/hr./sec.	9.113×10^{-1}	ft./sec./sec.
kilometers/hr./sec.	2.778×10^{-1}	meters/sec./sec.
kilometers/hr./sec.	6.214×10^{-1}	miles/hr./sec.
kilowatts	5.692×10^{1}	btu/min.
kilowatts	4.426×10^{4}	foot-lbs./min.
kilowatts	7.376×10^{2}	foot-lbs./sec.
kilowatts	1.341	horsepower
kilowatts	1.434×10^{1}	kg.-calories/min.
kilowatts	1.0×10^{3}	watts
kilowatt-hrs.	3.413×10^{3}	btu
kilowatt-hrs.	3.6×10^{13}	ergs
kilowatt-hrs.	2.655×10^{6}	foot-lbs.
kilowatt-hrs.	8.5985×10^{5}	gram calories
kilowatt-hrs.	1.341	horsepower-hours
kilowatt-hrs.	3.6×10^{6}	joules
kilowatt-hrs.	8.605×10^{2}	kg.-calories
kilowatt-hrs.	3.671×10^{5}	kg.-meters

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
kilowatt-hrs.	3.53	pounds of water evaporated from and at 212°F
kilowatt-hrs.	2.275×10^{1}	pounds of water raised from 62°F to 212°F
knots	6.076×10^{3}	feet/hr.
knots	1.852	kilometers/hr.
knots	1.0	nautical miles/hr.
knots	1.151	statute miles/hr.
knots	2.027×10^{3}	yards/hr.
knots	1.688	feet/sec.
knots	5.144×10^{1}	cm./sec.
	L	
lambert	3.183×10^{-1}	candle/sq. cm.
lambert	2.054	candle/sq. in.
league	3.0	miles (approx.)
light year	5.9×10^{12}	miles
light year	9.46091×10^{12}	kilometers
lines/sq. cm.	1.0	gausses
lines/sq. in.	1.55×10^{-1}	gausses
lines/sq. in.	1.55×10^{-9}	webers/sq. cm.
lines/sq. in.	1.0×10^{-8}	webers/sq. in.

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
lines/sq. in.	1.55×10^{-5}	webers/sq. meter
links (engineers)	1.2×10^{1}	inches
links (surveyors)	7.92	inches
liters	2.838×10^{-2}	bushels (U.S. dry)
liters	1.0×10^{3}	cu. cm.
liters	3.531×10^{-2}	cu. ft.
liters	6.102×10^{1}	cu. inches
liters	1.0×10^{-3}	cu. meters
liters	1.308×10^{-3}	cu. yards
liters	2.642×10^{-1}	gallons (U.S. liquid)
liters	2.113	pints (U.S. liquid)
liters	1.057	quarts (U.S. liquid)
liters/min.	5.886×10^{-4}	cu. ft./sec.
liters/min.	4.403×10^{-3}	gals./sec.
$\log_{10} n$	2.303	In n
In n	4.343×10^{-1}	$\log_{10} n$
lumen	7.958×10^{-2}	spherical candle power
lumen/sq. ft.	1.0	foot-candles
lumen/sq. ft.	1.076×10^{1}	lumen-sq. meter
lux	9.29×10^{-2}	foot-candles
M		
maxwells	1.0×10^{-3}	kilolines
maxwells	1.0×10^{-8}	webers
megalines	1.0×10^{6}	maxwells

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
mega-pascals	1.45×10^{2}	pounds/sq. in.
megohms	1.0×10^{12}	microhms
megohms	1.0×10^{6}	ohms
megmhos/cubic cm.	1.0×10^{-3}	abmhos/cubic cm.
megmhos/cubic cm.	2.54	megmhos/cubic in.
megmhos/cubic cm.	1.662×10^{-1}	mhos/mil. ft.
megmhos/in. cube	$3\ 937 \times 10^{-1}$	megmhos/cubic cm.
meters	1.0×10^{10}	angstrom units
meters	1.0×10^{2}	centimeters
meters	5.4681×10^{-1}	fathoms
meters	3.281	feet
meters	3.937×10^{1}	inches
meters	1.0×10^{-3}	kilometers
meters	5400×10^{-4}	miles (nautical)
meters	6.214×10^{-4}	miles (statute)
meters	1.0×10^{3}	millimeters
meters	1.094	yards
meters/min.	1.667	cms./sec.
meters/min.	3.281	feet/min.
meters/min.	5.468×10^{-2}	feet/sec.
meters/min.	6.0×10^{-2}	kms./hr.
meters/min.	3.240×10^{-2}	knots
meters/min.	3.728×10^{-2}	miles/hr.
meters/sec.	1.968×10^{2}	feet/min.
meters/sec.	3.281	feet/sec.

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
meters/sec.	3.6	kilometers/hr.
meters/sec.	6.0×10^{-2}	kilometers/min.
meters/sec.	2.237	miles/hr.
meters/sec.	3.728×10^{-2}	miles/min.
meters/sec./sec.	1.0×10^{2}	cms./sec./sec.
meters/sec./sec.	3.281	ft./sec./sec.
meters/sec./sec.	3.6	kms./hr./sec.
meters/sec./sec.	2.237	miles/hr./sec.
meter-kilograms	9.807×10^{7}	cm.-dynes
meter-kilograms	1.0×10^{5}	cm.-grams
meter-kilograms	7.233	pound-feet
microfarads	1.0×10^{-15}	abfarads
microfarads	1.0×10^{-6}	farads
microfarads	9.0×10^{5}	statfarads
micrograms	1.0×10^{-6}	grams
microhms	1.0×10^{3}	abohms
microhms	1.0×10^{12}	megohms
microhms	1.0×10^{-6}	ohms
microliters	1.0×10^{-6}	liters
micromicrons	1.0×10^{-12}	meters
microns	1.0×10^{-6}	meters
miles (nautical)	6.076×10^{3}	feet
miles (nautical)	1.852	kilometers
miles (nautical)	1.852×10^{3}	meters
miles (nautical)	1.1516	miles (statute)

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
miles (nautical)	2.0254×10^{3}	yards
miles (statute)	1.609×10^{5}	centimeters
miles (statute)	5.280×10^{3}	feet
miles (statute)	6.336×10^{4}	inches
miles (statute)	1.609	kilometers
miles (statute)	1.609×10^{3}	meters
miles (statute)	8.684×10^{-1}	miles (nautical)
miles (statute)	1.760×10^{3}	yards
miles (statute)	1.69×10^{-13}	light years
miles/hr.	4.470×10^{1}	cms./sec.
miles/hr.	8.8×10^{1}	ft./min.
miles/hr.	1.467	ft./sec.
miles/hr.	1.6093	kms./hr.
miles/hr.	2.682×10^{-2}	kms./min.
miles/hr.	8.684×10^{-3}	knots
miles/hr.	2.682×10^{1}	meters/min.
miles/hr.	1.667×10^{-2}	miles/min.
miles/hr./sec.	447×10^{1}	cms./sec./sec.
miles/hr./sec.	1.467	ft./sec./sec.
miles/hr./sec.	1.6093	kms./hr./sec.
miles/hr./sec.	4.47×10^{-1}	meters/sec./sec.
miles/min.	2.682×10^{3}	cms./sec.
miles/min.	8.8×10^{1}	feet/sec.
miles/min	1.6093	kms./min.
miles/min.	8.684×10^{-1}	knots/min.

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
miles/min.	6.0×10^{1}	miles/hr.
milliers	1.0×10^{3}	kilograms
millimicrons	1.0×10^{-9}	meters
milligrams	1.5432×10^{-2}	grains
milligrams	1.0×10^{-3}	grams
milligrams/liter	1.0	parts/million
millihenries	1.0×10^{-3}	henries
milliliters	1.0×10^{-3}	liters
millimeters	1.0×10^{-1}	centimeters
millimeters	3.281×10^{-3}	feet
millimeters	3.937×10^{-2}	inches
millimeters	1.0×10^{-6}	kilometers
millimeters	1.0×10^{-3}	meters
millimeters	6.214×10^{-7}	miles
millimeters	3.937×10^{1}	mils
millimeters	1.094×10^{-3}	yards
million gals./day	1.54723	cu. ft./sec.
mils	2.54×10^{-3}	centimeters
mils	8.333×10^{-5}	feet
mils	1.0×10^{-3}	inches
mils	2.54×10^{-8}	kilometers
mils	2.778×10^{-5}	yards
miner's inches	1.5	cu. ft./min.
minims (british)	5.9192×10^{-2}	cubic cm.
minims (U.S. fluid)	6.1612×10^{-2}	cubic cm.

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
minutes (angles)	1.667×10^{-2}	degrees
minutes (angles)	1.852×10^{-4}	quadrants
minutes (angles)	2.909×10^{-4}	radians
minutes (angles)	6.0×10^{1}	seconds
minutes (time)	9.9206×10^{-5}	weeks
minutes (time)	6.944×10^{-4}	days
minutes (time)	1.667×10^{-2}	hours
minutes (time)	6.0×10^{1}	seconds
myriagrams	1.0×10^{1}	kilograms
myriameters	1.0×10^{1}	kilometers
myriawatts	1.0×10^{1}	kilowatts
	N	
nails	2.25	inches
newtons	1.0×10^{5}	dynes
newtons	2.248×10^{-1}	pounds force
	O	
ohm (international)	1.0005	ohm (absolute)
ohms	1.0×10^{-6}	megohms
ohms	1.0×10^{6}	microhms
ounces	8.0	drams
ounces	4.375×10^{2}	grains
ounces	2.8349×10^{1}	grams
ounces	6.25×10^{-2}	pounds

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
ounces	9.115×10^{-1}	ounces (troy)
ounces	2.790×10^{-5}	tons (long)
ounces	3.125×10^{-5}	tons (short)
ounces (fluid)	1.805	cu. inches
ounces (fluid)	2.957×10^{-2}	liters
ounces (troy)	4.80×10^{2}	grains
ounces (troy)	3.1103×10^{1}	grams
ounces (troy)	1.097	ounces (avdp.)
ounces (troy)	2.0×10^{1}	pennyweights (troy)
ounces (troy)	8.333×10^{-2}	pounds (troy)
ounce/sq. in.	4.309×10^{3}	dynes/sq. cm.
ounce/sq. in.	6.25×10^{-2}	pounds/sq. in.
	P	
pace	3.0×10^{1}	inches
parsec	1.9×10^{13}	miles
parsec	3.084×10^{13}	kilometers
parts/million	5.84×10^{-2}	grains/U.S. gal.
parts/million	7.016×10^{-2}	grains/imp. gal.
parts/million	8.345	pounds/million gal.
pascals	1.450×10^{-4}	pounds/sq. in.
pecks (british)	5.546×10^{2}	cubic inches
pecks (british)	9.0919	liters
pecks (U.S.)	2.5×10^{-1}	bushels
pecks (U.S.)	5.376×10^{2}	cubic inches

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
pecks (U.S.)	8.8096	liters
pecks (U.S.)	8	quarts (dry)
pennyweights (troy)	2.4×10^{1}	grains
pennyweights (troy)	5.0×10^{-2}	ounces (troy)
pennyweights (troy)	1.555	grams
pennyweights (troy)	4.1667×10^{-3}	pounds (troy)
pints (dry)	3.36×10^{1}	cubic inches
pints (dry)	1.5625×10^{-2}	bushels
pints (dry)	5.0×10^{-1}	quarts
pints (dry)	5.5059×10^{-1}	liters
pints (liquid)	4.732×10^{2}	cubic cms.
pints (liquid)	1.671×10^{-2}	cubic ft.
pints (liquid)	2.887×10^{1}	cubic inches
pints (liquid)	4.732×10^{-4}	cubic meters
pints (liquid)	6.189×10^{-4}	cubic yards
pints (liquid)	1.25×10^{-1}	gallons
pints (liquid)	4.732×10^{-1}	liters
pints (liquid)	5.0×10^{-1}	quarts (liquid)
planck's quantum	6.624×10^{-27}	erg-seconds
poise	1.0	gram/cm.-sec.
pounds (avdp.)	1.4583×10^{1}	ounces (troy)
poundals	1.3826×10^{4}	dynes
poundals	1.41×10^{1}	grams
poundals	1.383×10^{-3}	joules/cm.
poundals	1.383×10^{-1}	joules/meter (newtons)

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
poundals	1.41×10^{-2}	kilograms
poundals	3.108×10^{-2}	pounds
pounds	2.56×10^{2}	drams
pounds	4.448×10^{5}	dynes
pounds	7.0×10^{3}	grains
pounds	4.5359×10^{2}	grams
pounds	4.448×10^{-2}	joules/cm.
pounds	4.448	joules/meter (newtons)
pounds	4.536×10^{-1}	kilograms
pounds	1.6×10^{1}	ounces
pounds	1.458×10^{1}	ounces (troy)
pounds	3.217×10^{1}	poundals
pounds	1.21528	pounds (troy)
pounds	5.0×10^{-4}	tons (short)
pounds (troy)	5.760×10^{3}	grains
pounds (troy)	$3\ 7324 \times 10^{2}$	grams
pounds (troy)	1.3166×10^{1}	ounces (avdp.)
pounds (troy)	1.2×10^{1}	ounces (troy)
pounds (troy)	2.4×10^{2}	pennyweights (troy)
pounds (troy)	8.2286×10^{-1}	pounds (avdp.)
pounds (troy)	3.6735×10^{-4}	tons (long)
pounds (troy)	3.7324×10^{-4}	tons (metric)
pounds (troy)	4.1143×10^{-4}	tons (short)
pounds of water	1.602×10^{-2}	cu. ft.

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
pounds of water	2.768×10^{1}	cu. inches
pounds of water	1.198×10^{-1}	gallons
pounds of water/min.	2.670×10^{-4}	cu.ft./sec.
pound-feet	1.356×10^{7}	cm.-dynes
pound-feet	1.3825×10^{4}	cm.-grams
pound-feet	1.383×10^{-1}	meter-kegs.
pounds/cu. ft.	1.602×10^{-2}	grams/cu. cm.
pounds/cu. ft.	1.602×10^{1}	kgs./cu. meter
pounds/cu. ft.	5.787×10^{-4}	pounds/cu. inches
pounds/cu. ft.	5.456×10^{-9}	pounds/mil-foot
pounds/cu. in.	2.768×10^{1}	grams/cu.cm.
pounds/cu. in.	2.768×10^{4}	kgs./cu. meter
pounds/cu. in.	1.728×10^{3}	pounds/cu. ft.
pounds/cu. in.	9.425×10^{-6}	pounds/mil-foot
pounds/ft.	1.488	kgs./meter
pounds/in.	1.786×10^{2}	grams/cm.
pounds/mil-foot	2.306×10^{6}	grams/cu. cm.
pounds/sq. ft.	4.725×10^{-4}	atmospheres
pounds/sq. ft.	1.602×10^{-2}	feet of water
pounds/sq. ft.	1.414×10^{-2}	inches of mercury
pounds/sq. ft.	4.882	kgs./sq. meter
pounds/sq. ft.	6.944×10^{-3}	pounds/sq. inch
pounds/sq. in.	6.804×10^{-2}	atmospheres
pounds/sq. in.	2.307	feet of water
pounds/sq. in.	2.036	inches of mercury

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
pounds/sq. in.	7.031×10^{2}	kgs./sq. meter
pounds/sq. in.	6.89×10^{-3}	mega-pascals
pounds/sq. in.	6.89×10^{3}	pascals
pounds/sq. in.	1.44×10^{2}	pounds/sq. ft.
pounds/sq. in.	7.2×10^{-2}	short tons/sq. ft.
pounds/sq. in.	7.03×10^{-2}	kgs./sq. cm.
	Q	
quadrants (angle)	9.0×10^{1}	degrees
quadrants (angle)	5.4×10^{3}	minutes
quadrants (angle)	1.571	radians
quadrants (angle)	3.24×10^{5}	seconds
quarts (dry)	6.72×10^{1}	cu. inches
quarts (liquid)	9.464×10^{2}	cu. cms.
quarts (liquid)	3.342×10^{-2}	cu. ft.
quarts (liquid)	5.775×10^{1}	cu. inches
quarts (liquid)	9.464×10^{-4}	cu. meters
quarts (liquid)	1.238×10^{-3}	cu. yards
quarts (liquid)	2.5×10^{-1}	gallons
quarts (liquid)	9.463×10^{-1}	liters
	R	
radians	5.7296×10^{1}	degrees
radians	3.438×10^{3}	minutes

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
radians	6.366×10^{-1}	quadrants
radians	2.063×10^{5}	seconds
radians/sec.	5.7296×10^{1}	degrees/sec.
radians/sec.	9.549	revolutions/min.
radians/sec.	1.592×10^{-1}	revolution/sec.
radians/sec./sec.	5.7296×10^{2}	revs./min./min.
radians/sec./sec.	9.549	revs./min./sec.
radians/sec./sec.	1.592×10^{-1}	revs./sec./sec.
reams	5.0×10^{2}	sheets
revolutions	3.60×10^{2}	degrees
revolutions	4.0	quadrants
revolutions	6.283	radians
revolutions/min.	6.0	degrees/sec.
revolutions/min.	1.047×10^{-1}	radians/sec.
revolutions/min.	1.667×10^{-2}	revs./sec.
revs./min./min.	1.745×10^{-3}	radians/sec./sec.
revs./min./min.	1.667×10^{-2}	revs./min./sec.
revs./min./min.	2.778×10^{-4}	revs./sec./sec.
revolutions/sec.	3.6×10^{2}	degrees/sec.
revolutions/sec.	6.283	radians/sec.
revolutions/sec.	6.0×10^{1}	revs./min.
revs./sec./sec.	6.283	radians/sec./sec.
revs./sec./sec.	3.6×10^{3}	revs./min./min.
revs./sec./sec.	6.0×10^{1}	revs./min./sec.
rods	2.5×10^{-1}	chains (gunters)

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
rods	5.029	meters
rods (surveyors' meas.)	5.5	yards
rods	1.65×10^{1}	feet
rods	1.98×10^{2}	inches
rods	3.125×10^{-3}	miles
rope	2.0×10^{1}	feet
	S	
scruples	2.0×10^{1}	grains
seconds (angle)	2.778×10^{-4}	degrees
seconds (angle)	1.667×10^{-2}	minutes
seconds (angle)	3.087×10^{-6}	quadrants
seconds (angle)	4.848×10^{-6}	radians
slugs	1.459×10^{1}	kilograms
slugs	3.217×10^{1}	pounds
sphere (solid angle)	1.257×10^{1}	steradians
square centimeters	1.973×10^{5}	circular mils
square centimeters	1.076×10^{-3}	sq. feet
square centimeters	1.550×10^{-1}	sq. inches
square centimeters	1.0×10^{-4}	sq. meters
square centimeters	3.861×10^{-11}	sq. miles
square centimeters	1.0×10^{2}	sq. millimeters
square centimeters	1.196×10^{-4}	sq. yards
square degrees	3.0462×10^{-4}	steradians
square feet	2.296×10^{-5}	acres

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
square feet	1.833×10^{8}	circular mils
square feet	9.29×10^{2}	sq. cms.
square feet	1.44×10^{2}	sq. inches
square feet	9.29×10^{-2}	sq. meters
square feet	3.587×10^{-8}	sq. miles
square feet	9.29×10^{4}	sq. millimeters
square feet	1.111×10^{-1}	sq. yards
square inches	1.273×10^{6}	circular mils
square inches	6.452	sq. cms.
square inches	6.944×10^{-3}	sq. ft.
square inches	6.452×10^{2}	sq. millimeters
square inches	1.0×10^{6}	sq. mils
square inches	7.716×10^{-4}	sq. yards
square kilometers	2.471×10^{2}	acres
square kilometers	1.0×10^{10}	sq. cms.
square kilometers	1.076×10^{7}	sq. ft.
square kilometers	1.550×10^{9}	sq. inches
square kilometers	1.0×10^{6}	sq. meters
square kilometers	3.861×10^{-1}	sq. miles
square kilometers	1.196×10^{6}	sq. yards
square meters	2.471×10^{-4}	acres
square meters	1.0×10^{4}	sq. cms.
square meters	1.076×10^{1}	sq. ft.
square meters	1.55×10^{3}	sq. inches
square meters	3.861×10^{-7}	sq. miles

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
square meters	1.0×10^{6}	sq. millimeters
square meters	1.196	sq. yards
square miles	6.40×10^{2}	acres
square miles	2.788×10^{7}	sq. ft.
square miles	2.590	sq. kms.
square miles	2.590×10^{6}	sq. meters
square miles	3.098×10^{6}	sq. yards
square millimeters	1.973×10^{3}	circular mils
square millimeters	1.0×10^{-2}	sq. cms.
square millimeters	1.076×10^{-5}	sq. ft.
square millimeters	1.55×10^{-3}	sq. inches
square mils	1.273	circular mils
square mils	6.452×10^{-6}	sq. cms.
square mils	1.0×10^{-6}	sq. inches
square yards	2.066×10^{-4}	acres
square yards	8.361×10^{3}	sq. cms.
square yards	9.0	sq. ft.
square yards	1.296×10^{3}	sq. inches
square yards	8.361×10^{-1}	sq. meters
square yards	3.228×10^{-7}	sq. miles
square yards	8.361×10^{5}	sq. millimeters
steradians	7.958×10^{-2}	spheres
steradians	1.592×10^{-1}	hemispheres
steradians	6.366×10^{-1}	spherical right angles

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
steradians	3.283×10^{3}	square degrees
steres	9.99973×10^{2}	liters
T		
temp (°C) +273	1.0	absolute temp (°K)
temp (°C) + 17.78	1.8	temp (°F)
temp (°F) +460	1.0	absolute temp (°R)
temp (°F) -32	5/9	temp (°C)
tons (long)	1.016×10^{3}	kilograms
tons (long)	2.24×10^{3}	pounds
tons (long)	1.12	tons (short)
tons (metric)	1.0×10^{3}	kilograms
tons (metric)	2.205×10^{3}	pounds
tons (short)	9.0718×10^{2}	kilograms
tons (short)	3.2×10^{4}	ounces
tons (short)	2.9166×10^{4}	ounces (troy)
tons (short)	2.0×10^{3}	pounds
tons (short)	2.43×10^{3}	pounds (troy)
tons (short)	8.9287×10^{-1}	tons (long)
tons (short)	9.078×10^{-1}	tons (metric)
tons (short)/sq. ft.	9.765×10^{3}	kgs./sq. meter
tons (short)/sq. ft.	1.389×10^{1}	pounds/sq. in.
tons (short)/sq. in.	1.406×10^{6}	kgs./sq. meter

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
tons (short)/sq. in.	2.0×10^{3}	pounds/sq. in.
tons of water/24 hrs.	8.333×10^{1}	pounds of water/hr.
tons of water/24 hrs.	1.6643×10^{-1}	gallons/min.
tons of water/24 hrs.	1.3349	cu. ft./hr.
	V	
volt/inch	3.937×10^{7}	abvolts/cm.
volt/inch	3.937×10^{-1}	volt/cm.
volt (absolute)	3.336×10^{-3}	stavolts
volts	1.0×10^{8}	abvolts
	W	
watts	3.4129	btu/hr.
watts	5.688×10^{-2}	btu/min.
watts	1.0×10^{7}	ergs/sec.
watts	4.427×10^{1}	ft.-lbs./min.
watts	7.378×10^{-1}	ft.-lbs./sec.
watts	1.341×10^{-3}	horsepower
watts	1.36×10^{-3}	horsepower (metric)
watts	1.433×10^{-2}	kg.-calories/min.
watts	1.0×10^{-3}	kilowatts
watts (abs.)	1.0	joules/sec.
watt-hours	3.413	btu
watt-hours	3.6×10^{10}	ergs
watt-hours	2.656×10^{3}	foot-lbs.
watt-hours	8.605×10^{2}	gram-calories

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
watt-hours	1.341×10^{-3}	horsepower-hours
watt-hours	8.605×10^{-1}	kilogram-calories
watt-hours	3.672×10^{2}	kilogram-meters
watt-hours	1.0×10^{-3}	kilowatt-hours
watt (international)	1.000165	watt (absolute)
webers	1.0×10^{8}	maxwells
webers	1.0×10^{5}	kilolines
webers/sq. in.	1.55×10^{7}	gausses
webers/sq. in.	1.0×10^{8}	lines/sq. in.
webers/sq. in.	1.55×10^{-1}	webers/sq. cm.
webers/sq. in.	1.55×10^{3}	webers/sq. meter
webers/sq. meter	1.0×10^{4}	gausses
webers/sq. meter	6.452×10^{4}	lines/sq. in.
webers/sq. meter	1.0×10^{-4}	webers/sq. cm.
webers/sq. meter	6.452×10^{-4}	webers/sq. in.
weeks	1.68×10^{2}	hours
weeks	1.008×10^{4}	minutes
weeks	6.048×10^{5}	seconds
	Y	
yards	9.144×10^{1}	centimeters
yards	9.144×10^{-4}	kilometers
yards	9.144×10^{-1}	meters
yards	4.934×10^{-4}	miles (nautical)
yards	5.682×10^{-4}	miles (statute)

Table A-1 Conversion Factors (in alphabetical order)

To Convert	Multiply By	To Obtain
yards	9.144×10^{2}	millimeters
years	3.65256×10^{2}	days (mean solar)
years	8.7661×10^{3}	hours (mean solar)

Physical Constants

Gas Constants (R)

R = 0.0821 (atm.) (liter)/(g.-mole) (°K)

R = 1.987 g.-cal./(g.-mole) (°K)

R = 1.987 B.t.u./(lb.-mole) (°R)

R = 1.987 c.h.u./lb.-mole) (°K)

R = 8.314 joules/(gm-mole) (°K)

R= 1,546 (ft.)(lb.force)/(lb.-mole) (°R)

R = 10.73 (lb.-force/sq.in.)(cu.ft.)/(lb.-mole) (°R)

R = 18510 (lb.-force/sq.in.)(cu.in.)/(lb.-mole) (°R)

R = 0.7302 (atm.) (cu.ft.)/(lb.-mole) (°R)

R = 8.48 x 10 (Kg./m^2) (cu.cm.)/(lb.-mole) (°K)

Acceleration of Gravity (Standard)

g = 32.17 ft./$sec.^2$ = 980.6 cm./$sec.^2$

Velocity of Sound in Dry Air @ 0°C and 1 ATM

33,136 cm./sec.= 1,089 ft./sec

Heat of Fusion of Water

79.7 cal./gm = 144 Btu/lb

Heat of Vaporization of Water 1.0 ATM

540 cal./gm = 970 Btu/lb

Specific Heat of Air

Cp = 0.238 cal./(gm) (°C)

Density of Dry Air @ 0°C and 760 mm

0.001293 gm/cu.cm.

Tables and Charts

Table B-1 HT Series Outer Barrel Mechanical Properties

Core Barrel	Make Up Torque (API)	Yield Torque (tested)	Tensile Yield	Buckling Load (Max Push)	Maximum Dogleg Severity
$4^{3}/_{4}$" x $2^{5}/_{8}$" HT10	13,558 Nm 10,000 ft-lbs	30,000 Nm 22,100 ft lb	1,300 kN 292,252 lbf	297 kN 66,800 lbf	4.7°/10 m (33 ft) (non-rotating) 2.1°/10 m (33 ft) (rotating)
$6^{1}/_{4}$" x 4" HT20	27,117 Nm 20,000 ft-lbs	Under development			
$6^{3}/_{4}$" x 4" HT30	40,675 Nm 30,000 ft-lbs	75,000 Nm 55,300 ft-lbs	2,540 kN 571,014 lbf	1,190 kN 267,500 lbf	4.2°/10 m (33 ft) (non-rotating) 1.7°/10 m (33 ft) (rotating)
8" x $5^{1}/_{4}$" HT40	54,223 Nm 40,000 ft-lbs	88,000 Nm 64,900 ft-lbs	2,950 kN 663,186 lbf	2,064 kN 464,000 lbf	4.0°/10 m (33 ft) (non-rotating) 1.4°/10 m (33 ft) (rotating)

Table B-2 Coremaster Series Outer Barrel Mech. Properties

Core Barrel	Make Up Torque (API)	Yield Torque (tested)	Tensile Yield	Buckling Load (Max Push)	Maximum Dogleg Severity
$4^{3}/_{4}$" x $2^{1}/_{8}$"	17,630 Nm 13,000 ft-lbs	31,000 Nm 22,800 ft-lbs	1,710 kN 384,400 lbf	397 kN 89,200 lbf	10.7°/10 m (33 ft) (Non-rotating) 2.0°/10 m (33 ft) (Rotating)
$6^{3}/_{4}$" x 4" ($7^{1}/_{4}$" upsets)	33,200 Nm 24,500 ft-lbs	50,000 Nm 36,900 ft-lbs	3,300 kN 742,000 lbf	1,200 kN 270,000 lbf	5°/10 m (33 ft) (Non-rotating) 1.7°/10 m (33 ft) (Rotating)

Table B-3 250P Series Outer Barrel Mechanical Properties

Core Barrel	Make Up Torque (API)	Yield Torque	Tensile Yield (Max Pull)	Buckling Load (Max Push)	Collapse Pressure	Burst Pressure	Max Dogleg Severity
$3^1/_2$" x $1^3/_4$" 350P	3,150 Nm 2,323 ft-lbs	5,553 Nm 4,095 ft-lbs	740 kN 166,400 lbf	92 kN (30 ft) 20,682 lbf 23 kN (60 ft) 5,170 lbf	1,441 bar 20,895 psi	2,000 bar 29,000 psi	3.2°/10m (33 ft) (non-rotating) 1.6°/10m (33 ft) (rotating)
$4^3/_4$" x $2^5/_8$" 250P	6,370 Nm 4,700 ft-lbs	11,870 Nm 8,752 ft-lbs	1,031 kN 231,800 lbf	297 kN (30 ft) 66,800 lbf 74 kN (60 ft) 16,600 lbf	1,420 bar 20,200 psi	1,582 bar 22,500 psi	4.4°/10 m (33 ft) (non-rotating) 1.9°/10 m (33 ft) (rotating)
$6^3/_4$" x 4" 250P	15,050 Nm 11,100 ft-lbs	28,000 Nm 20,632 ft-lbs	1,811 kN 407,000 lbf	1,190 kN (30 ft) 267,500 lbf 297 kN (60 ft) 66,800 lbf	1,380 bar 19,600 psi	1,530 bar 21,800 psi	4.8°/10 m (33 ft) (non-rotating) 1.4°/10 m (33 ft) (rotating)
8" x $5^1/_4$" 250P	29,700 Nm 21,900 ft-lbs	55,000 Nm 40,600 ft-lbs	2,678 kN 602,000 lbf	2,064 kN (30 ft) 464,000 lbf 516 kN (60 ft) 116,000 lbf	1,181 bar 16,800 psi	1,287 bar 18,300 psi	2.4°/10 m (33 ft) (non-rotating) 1.2°/10 m (33 ft) (rotating)

Table B-4 250P/350P/HT Series Inner Tube Mech. Properties

Core Barrel	Inner Tube	Make Up Torque (API)	Yield Torque	Tensile Yield (Max Pull)	Buckling Load (Max Push)	Collapse Pressure	Burst Pressure
$3^{1}/_{2}$" x $1^{3}/_{4}$" 350P	Steel	1,029 Nm 760 ft-lbs	1,815 Nm 1,340 ft-lbs	339 kN 76,210 lbf	19.4 kN (30 ft) 4,361 lbf 4.8 kN (60 ft) 1,079 lbf	1,430 bar 20,735 psi	1,597 bar 23,157 psi
	Aluminum 160 N/mm^2 23,000 psi	230 Nm 197 ft-lbs	382 Nm 282 ft-lbs	71.5 kN 16,746 lbf	6.47 kN (30 ft) 1,455 lbf 1.62 kN (60 ft) 364 ft lbf	299 bar 4,336 psi	333 bar 4,829 psi
	Aluminum 275 N/mm^2 40,000 psi	394 Nm 291 ft-lbs	657 Nm 485 ft-lbs	123 kN 27,653 lbf		519 bar 7,526 psi	580 bar 8,410 psi
$4^{3}/_{4}$" x $2^{5}/_{8}$" 250P/HT10	Steel	1,500 Nm 1,100 ft-lbs	2,856 Nm 2,107 ft-lbs	440 kN 99,000 lbf	59 kN (30 ft) 13,264 lbf 150 kN (60 ft) 3,300 lbf	1,100 bar 14,700 psi	1,100 bar 15,800 psi
	Aluminum 160 N/mm^2 23,000 psi	390 Nm 288 ft-lbs	650 Nm 450 ft-lbs	112 kN 25,180 lbf	19.5 kN (30 ft) 4,384 lbf 4.9 kN (60 ft) 1,100 lbf	235 bar 3,408 psi	278 bar 4,034 psi
	Aluminum 275 N/mm^2 40,000 psi	540 Nm 400 ft-lbs	1,026 Nm 757 ft-lbs	160 kN 36,000 lbf		370 bar 5,300 psi	400 bar 5,700 psi
	Fiberglass with steel couplers 350 N/mm^2	789 Nm 582 ft-lbs	1,315 Nm 970 ft-lbs	65 kN (20 C) 14,613 lbs 59 kN (60°C) 13,264 lbf	2.2 kN (30 ft) 495 lbf 0.54 kN (60 ft) 121 lbf	50 bar (20°C/ 68°F) 725 psi 43 bar (60°C/ 140°F) 624 psi	

Table B-4 250P/350P/HT Series Inner Tube Mech. Properties (continued)

Core Barrel	Inner Tube	Make Up Torque (API)	Yield Torque	Tensile Yield (Max Pull)	Buckling Load (Max Push)	Collapse Pressure	Burst Pressure
6¾" x 4" 250P/HT30	Steel	3,100 Nm 2,300 ft-lbs	5.900 Nm 4,350 ft-lbs	623 kN 140,000 lbs	175 kN (30 ft) 39,341 lbs 43 kN (60 ft) 9,700 lbs	745 bar 10,600 psi	790 bar 11,200 psi
	Aluminum 160 N/mm^2 23,000 psi	800 Nm 590 ft-lbs	1,330 Nm 981 ft-lbs	159 kN 35,744 lbs	60 kN (30 ft) 13,500 lbs 14.6 kN (60 ft) 3,300 lbs	167 bar 2,422 psi	188 bar 2,730 psi
	Aluminum 275 N/mm^2 40,000 psi	1,100 Nm 800 ft-lbs	2,150 Nm 1,590 ft-lbs	227 kN 51,000 lbs		275 bar 3,900 psi	290 bar 4,100 psi
	Fiberglass with steel couplers 350 N/mm^2	1,630 Nm 1,202 ft-lbs	2,717 Nm 2,404 ft-lbs	120 kN (20°C) 26,977 lbs 110 kN (60°C) 24,730 lbs	8.6 kN (30 ft) 1,933 lbs 2.2 kN (60 ft) 495 lbs	40 bar (20°C) 580 psi 34.4 bar (60°C) 499 psi	
8" x 5¼" 250P/HT40	Steel	8,400 Nm 6,200 ft-lbs	15,750 Nm 11,615 ft-lbs	1,230 kN 276,500 lbs	590 kN (30 ft) 132,600 lbs 146 kN (60 ft) 32,800 lbs	844 bar 12,000 psi	900 bar 12,800 psi
	Aluminum 160 N/mm^2 23,000 psi	2,135 Nm 1,575 ft-lbs	3,559 Nm 2,625 ft-lbs	314 kN 70,590 lbs	195 kN (30 ft) 43,800 lbs 48.5 kN (60 ft) 10,900 lbs	190 bar 2,755 psi	218 bar 3,164 psi
	Aluminum 275 N/mm^2 40,000 psi	2,980 Nm 2,200 ft-lbs	5,764 Nm 4,251 ft-lbs	476 kN 107,000 lbs		302 bar 4,300 psi	323 bar 4,600 psi
	Fiberglass 6.2 mm thick with steel couplers 350 N/mm^2	4,352 Nm 3,209 ft-lbs	7,253 Nm 5,349 ft-lbs		17.6 kN (30 ft) 3,957 lbs 4.4 kN (60 ft) 989 lbs	21 bar (20°C) 305 psi 18 bar (60°C) 262 psi	
	Fiberglass 8 mm thick with steel couplers 350 N/mm^2	4,352 Nm 3,209 ft-lbs	7,253 Nm 5,349 ft-lbs	200 kN (20°C) 44,961 lbs 180 kN (60°C) 40,465 lbs	24.5 kN (30 ft) 5,508 lbs 6.1 kN (60 ft) 1,371 lbs	45 bar (20°C) 653 psi 38.7 bar (60°C) 561 psi	63 Bar 913 psi

Table B-5 Aluminum Inner Tube (IT) Specifications

Material 6061-T6 (U.S.)	(U.S. Standard)	(Metric)
Yield Strength Tensile Strength Coefficient of Thermal Expansion* Modulus	40,000 psi 45,000 psi 1.54 x 10^{-4} in/ft deg. F 10 x 10^{6} psi	275 N/mm^2 310 N/mm^2 2.3 x 10^{-2} mm/m deg. C 69 x 10^{4} N/mm^2
Core Barrel Size	Makeup Torque	
4.75" x 2.62" 5.75" x 3.50" 6.25"/6.75" x 4.00" 8.00" x 5.25"	400 ft-lbs 700 ft-lbs 800 ft-lbs 2,200 ft-lbs	542 Nm 949 Nm 1,100 Nm 2,983 Nm
*use same calculation as on fiberglass		

Table B-6 Aluminum Inner Tube Properties (6061-T6)

Temperature		Axial Tensil Strength		Yield Strength	
Deg. F	Deg. C	KSI	(N/mm^2)	KSI	(N/mm^2)
-112	-80	49	340	42	290
-18	-30	47	325	41	285
75	25	45	310	40	275
212	100	42	290	38	260
300	150	34	235	31	215
400	205	19	130	15	105

Table B-7 Spacing of Aluminum Inner Tubes Based on Thermal Expansion Coefficients

Bottomhole° Minus Surface°	30 Foot Core Barrel Extra Length Spacing	60 Foot Core Barrel Extra Length Spacing	90 Foot Core Barrel Extra Length Spacing	Coremaster 180 Foot Core Barrel Extra Length Spacing	Coremaster 270 Foot Core Barrel Extra Length Spacing
°F	**Inches**	**Inches**	**Inches**	**Inches**	**Inches**
50	0.117	0.234	0.351	0.702	1.053
75	0.176	0.351	0.527	1.053	1.580
100	0.234	0.468	0.702	1.404	2.106
125	0.293	0.585	0.877	1.755	2.633
150	0.351	0.702	1.053	2.106	3.159
175	0.410	0.819	1.229	2.457	3.686
200	0.468	0.936	1.404	2.808	4.212
225	0.527	1.053	1.580	3.159	4.739
250	0.585	1.170	1.755	3.510	5.265
275	0.643	1.287	1.931	3.861	5.792
300	0.702	1.404	2.106	4.212	6.318
325	0.761	1.521	2.282	4.563	6.845
350	0.819	1.638	2.457	4.914	7.371
375	0.877	1.755	2.633	5.265	7.898
400	0.936	1.872	2.808	5.616	8.424
425	0.995	1.989	2.984	5.967	8.950
°C	**mm**	**mm**	**mm**	**mm**	**mm**
20	2.14	4.28	6.42	12.84	19.26
40	4.28	8.56	12.84	25.68	38.51
60	6.42	12.84	19.26	38.51	57.77
80	8.56	17.12	25.68	51.35	77.03
100	10.70	21.40	32.10	64.19	96.29
120	12.84	25.68	38.51	77.03	115.54

Table B-7 Spacing of Aluminum Inner Tubes Based on Thermal Expansion Coefficients (continued)

Bottomhole° Minus Surface°	30 Foot Core Barrel Extra Length Spacing	60 Foot Core Barrel Extra Length Spacing	90 Foot Core Barrel Extra Length Spacing	Coremaster 180 Foot Core Barrel Extra Length Spacing	Coremaster 270 Foot Core Barrel Extra Length Spacing
140	14.98	29.96	44.93	89.87	134.80
160	17.12	34.24	51.35	102.71	154.06
180	19.26	38.51	57.77	115.54	173.32
200	21.40	42.79	64.19	128.38	192.57
220	23.54	47.07	70.61	141.22	211.83

Table B-8 Spacing of Fiberglass Inner Tubes Based on Thermal Expansion Coefficients

Bottomhole° Minus Surface°	30 Foot Core Barrel Extra Length Spacing	60 Foot Core Barrel Extra Length Spacing	90 Foot Core Barrel Extra Length Spacing	Coremaster 180 Foot Core Barrel Extra Length Spacing	Coremaster 270 Foot Core Barrel Extra Length Spacing
°F	**Inches**	**Inches**	**Inches**	**Inches**	**Inches**
50	0.074	0.148	0.221	0.443	0.664
75	0.111	0.221	0.332	0.664	0.996
100	148	0.295	0.443	0.886	1.328
125	0.185	0.369	0.554	1.107	1.661
150	0.221	0.443	0.664	1.328	1.993
175	0.258	0.517	0.775	1.550	2.325
200	0.295	0.590	0.886	1.771	2.657
225	0.332	0.664	0.996	1.993	2.989
250	0.369	0.738	1.107	2.214	3.321
275	0.406	0.812	1.218	2.435	3.653
300	0.443	0.886	1.328	2.657	3.985
325	0.480	0.959	1.439	2.878	4.317

Table B-8 Spacing of Fiberglass Inner Tubes Based on Thermal Expansion Coefficients (continued)

Bottomhole° Minus Surface°	30 Foot Core Barrel Extra Length Spacing	60 Foot Core Barrel Extra Length Spacing	90 Foot Core Barrel Extra Length Spacing	Coremaster 180 Foot Core Barrel Extra Length Spacing	Coremaster 270 Foot Core Barrel Extra Length Spacing
350	0.517	1.033	1.550	3.100	4.649
°C	**mm**	**mm**	**mm**	**mm**	**mm**
20	1.35	2.70	4.05	8.10	12.15
40	2.70	5.40	8.10	16.20	24.29
60	4.05	8.10	12.15	24.29	36.44
80	5.40	10.80	16.20	32.39	48.59
100	6.75	13.50	20.24	40.49	60.73
120	8.10	16.20	24.29	48.59	72.88
140	9.45	18.90	28.34	56.69	85.03
160	10.80	21.59	32.39	64.78	97.18
180	12.15	24.29	36.44	72.88	109.32

Table B-9 Inner Tube Relative Thermal Expansion

Fiberglass		Temperature Difference (downhole - surface)		Aluminum	
30 ft.	**60 ft.**			**30 ft.**	**60 ft.**
in (mm)	**in (mm)**	**Deg. F**	**Deg. C**	**in (mm)**	**in (mm)**
0.07 (1)	0.15 (2)	50	28	0.12 (1.5)	0.23 (3)
0.15 (2)	0.30 (4)	100	56	0.23 (3)	0.47 (6)
0.22 (3)	0.44 (6)	150	83	0.35 (4.5)	0.70 (9)
0.30 (4)	0.59 (8)	200	111	0.47 (5.5)	0.94 (11)
0.37 (5)	0.74 (10)	250	139	0.59 (7)	1.17 (14)
0.44 (6)	0.89 (12)	300	167	0.70 (8.5)	1.40 (17)
0.52 (6.5)	1.03 (13)	350	194	0.82 (10)	1.64 (20)
Expansion of disposable inner tubes is greater than the steel outer tube expansion. Aluminum and fiberglass inner tubes must be properly spaced to account for the greater thermal expansion of these materials. This will allow the disposable inner tubes to properly seat in the bit throat at bottom hole temperatures.					

Adjusting for Thermal Expansion-Aluminum or Fiberglass Inner Tubes
Formula: **S = A × L × T** Example (for Fiberglass): **L** = Length of inner tube = 60 ft. **T** = Difference between downhole and surface temperature = 100°F **A** = Coefficient of Thermal Expansion of Fiberglass minus Steel = 4.92 × 10^{-5} in/ft deg. F **S** = Expansion of Fiberglass Inner Tube relative to Outer Tube (inches) **S = A × L × T** **S** = (4.92 × 10^{-5}) × 60 × 100 = 0.3 inches See Table B-9 for approximate additional spacing required for Inner Tube Relative Thermal Expansion

Table B-10 Fiberglass Inner Tube Dimensions

Core Barrel Size	4.75 x 2.625	5.75 x 3.5	6.25 x 3	6.75 x 4	8 x 5.25
Fiberglass Inner Tube O.D.	3.27 in 83 mm	4.24 in 107.7 mm	3.54 in 90 mm	4.75 in 120.7 mm	6.16 in 156.4 mm
Fiberglass Inner Tube I.D.	2.87 in 73 mm	3.75 in 95.3 mm	3.15 in 80 mm	4.25 in 108 mm	5.51 in 140 mm
Fiber Tube Length	360 in 9144 m	360 in 9144 m	360 in 9144 m	360 in 9144 m	360 in 9144 m
Wall Thickness	0.19 in 4.9 mm	0.24 in 6.2 mm	0.20 in 5 mm	0.24 in 6.2 mm	0.31 in 8 mm
Weight (30' section)	64 lbs 29 kgs	97 lbs 44 kgs	73 lbs 33 kgs	117 lbs 53 kgs	152 lbs 69 kgs

Table B-11 Fiberglass Inner Tube Specifications

Mechanical Specification	**U.S. Standard**	**Metric**
Axial Tensile Strength @ 68°F	8,000 psi	55 N/mm^2
Axial Tensile Modulus	1.42 x 10^6 psi	9.8 kN/mm^2
Axial Bending Strength	8,700 psi	60 N/mm^2
Axial Bending Modulus	1.42 x 10^6 psi	9.8 kN/mm^2
Coefficient of Linear Thermal Expansion	13.2 x 10^{-5} in/ft deg. F	2 x 10^{-2} mm/m deg. C
Inner Surface Roughness	2 x 10^{-4} in	5 x 10^{-3} mm
Maximum Coring Temperature	250°F	120°C
Maximum Static Bottom Hole Temperature	285°F	140°C
Makeup Torque: Same as steel inner tubes due to steel box and pins.		

Table B-12 Fiberglass Inner Tube Critical Buckling Pressure

Core Barrel I.D.		Outside Pressure at 68°F (20°C)	
in	**mm**	**psi**	**Bar**
2.875	73	725	50
3.75	95.3	725	50
4.25	108	580	40
5.5	140 (8 mm wall)	653	45
Above 68 deg. F, the above figures must be multiplied by the following correction factors:			

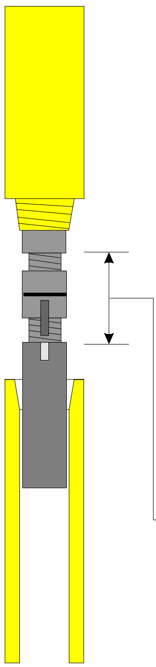
Fiberglass Critical Buckling Pressure Correction		
Temperature		
Deg. F	**Deg. C**	**Factor**
68	20	1
140	60	0.86
212	100	0.73
248	120	0.63

Table B-13 Fiberglass Inner Tube Axial Tensile Strength

Temperature		Barrel Size, inches/Tube Inner Diameter, mm			
Deg. F	**Deg. C**	**4.75 x 2.625 73 mm**	**5.75 x 3.5 95.3 mm**	**6.75 x 4 108 mm**	**8 x 5.25 140 mm**
68	20	6.5 tons	10.8 tons	12 tons	20 tons
140	60	5.9 tons	9.8 tons	11 tons	18 tons
212	100	4.4 tons	7.4 tons	8.3 tons	13.8 tons
248	120	3.5 tons	5.9 tons	6.6 tons	11 tons

Table B-14 L.D. Adjustment System Calculation

Dimensions are in mm



Outer Assembly Length	
LD Spacer Tube	
Stab. #1	
O.T. #1	
Stab #2	
O.T. #2	
Stab. #3	
O.T. #3	
Stab. #4	
O.T. #4	
Stab. #5	
O.T. #5	
Stab. #6	
Bit shank	
Total	

Inner Assembly Length	
Top Sub Pin	
C.J. Indicator w/ Swivel	
I.T. #1	
I.T. Stabilizer	
I.T. #2	
I.T. Stabilizer	
I.T. #3	
I.T. Stabilizer	
I.T. #4	
I.T. Stabilizer	
I.T. #5	
I.T. Stabilizer	
Top End	
Lower Shoe	
Lead	
Aluminum Expansion	X below
Total	Sum of above

LD Adj. System Total Length = Outer Assembly - Inner Assembly
LD Adj. System Total Length = Sum outer - Sum inner

Length of Exposed Cartridge Shaft = Total - 875 mm

Length of Exposed Cartridge Shaft	
mm:	**(Sum outer - Sum inner) - 875**
inches:	**above / 25.4**

Aluminum Expansion (X)		
Temp Difference °C	Length of Aluminum (m)	Expansion (mm)
calculated (bottom hole - surface)	(Sum inner) / 1000	see below

1 m = 1000 mm
1 inch = 25.4 mm

Expansion = (Temp. Diff in °C) x (Length of Aluminum in mm) x (0.0000117)

Notes:
1. **All values should be measured off equipment.**
2. **All values should be double checked to ensure accuracy.**
3. **If using steel inner tubes, there will be no expansion.**

Table B-15 Possible Causes for Standpipe Pressure Changes

Changes in Standpipe Pressure	Possible Causes due to Bottomhole Conditions
Sudden Pressure Increase	1. Circular groove cut into bit face due to damage or wear to the diamond cutters. 2. Foreign material plugging core barrel. 3. Inner barrel backed off and dropped into bit.
Gradual Pressure Increase	Core bit damaged. Pressure caused by circular groove starting on face of bit and gradually deepening, cutting off the fluid courses. Torque will also increase as waterways plug off.
Pressure Fluctuation	Indication of jammed inner barrel. Pressure fluctuation due to the jammed core taking weight causing the bit to drill off and drill up the core. Torque will also be erratic.
Pressure Decrease	Indication of jammed core barrel. Core cannot enter inner barrel causing the bit to drill off and stop penetration.
Gradual Pressure Decrease	Hole in drill pipe or washout in pin and box connection of pipe or core barrel.

Note: *When any of these symptoms are observed, first check the circulating system (pump, mixers, pit, etc.) and repair as necessary. If no problems are found with the circulation system, pull-out-of-hole* ***immediately*** *to prevent further damage to the bit and barrel.*

Additional Information: Check pump strokes hourly or if pressure changes to determine if the pump is a problem or washout has occurred. When drilling up, core pressure will fluctuate approximately 200 lbs. over and 200 lbs. under normal conditions.

Table B-16 Drillstring Connection Conversion

Rotary Shouldered Connection Interchange List			
Common Name		Pin Base Diameter (Tapered)	Same as or Interchanges with
Style	Size		
Internal Flush (I.F.)	$2^3/_8$"	2.876	$2^7/_8$" Slim Hole N.C. 26"
	$2^7/_8$"	3.391	$3^1/_2$" Slim Hole N.C. 31"
	$3^1/_2$"	4.016	$4^1/_2$" Slim Hole N.C. 38"
	4"	4.834	$4^1/_2$" Extra Hole N.C. 46"
	$4^1/_2$"	5.250	$5^1/_2$" Extra Hole N.C. 50" $5^1/_2$" Double Streamline
Full Hole (F.H.)	4"	4.280	$4^1/_2$" Double Streamline N.C. 40"
Extra Hole (X.H.)(E.H.)	$2^7/_8$"	3.327	$3^1/_2$" Double Streamline
	$3^1/_2$"	3.812	4" Slim Hole $4^1/_2$" External Flush
	$4^1/_2$"	4.834	4" Internal Flush N.C. 46"
	5"	5.250	$4^1/_2$" Internal Flush N.C. 50" $5^1/_2$" Double Streamline
Slim Hole (S.H.)	$2^7/_8$"	2.876	$2^3/_8$" Internal Flush N.C. 26"
	$3^1/_2$"	3.391	$2^7/_8$" Internal Flush N.C. 31"
	4"	3.812	$3^1/_2$" Extra Hole $4^1/_2$" External Flush
	$4^1/_2$"	4.016	$3^1/_2$" Internal Flush N.C. 38"

Table B-17 API Reg. Pin Connections by Bit Size

Bit Size	API Reg. Pin Connection
$3^{11}/_{16}$ to $4^{1}/_{2}$", inclusive	$2^{3}/_{8}$"
$4^{17}/_{32}$ to 5", inclusive	$2^{7}/_{8}$"
$5^{1}/_{32}$ to $7^{3}/_{8}$", inclusive	$3^{1}/_{2}$"
$7^{13}/_{32}$ to $9^{3}/_{8}$", inclusive	$4^{1}/_{2}$"
$9^{19}/_{32}$ to $14^{1}/_{2}$", inclusive	$6^{5}/_{8}$"
$14^{17}/_{32}$ to $18^{1}/_{2}$", inclusive	$7^{5}/_{8}$"
$18^{17}/_{32}$" and larger	$8^{5}/_{8}$"

Table B-18 Drill Collar Weights (lbs/ft)

O.D. Drill Collar	Bore of Collar										
	$1^{1}/_{2}$"	$1^{3}/_{4}$"	2"	$2^{1}/_{4}$"	$2^{1}/_{2}$"	$2^{3}/_{4}$"	3"	$3^{1}/_{4}$"	$3^{1}/_{2}$"	$3^{3}/_{4}$"	4"
$4^{1}/_{4}$"	42	40	37								
$4^{1}/_{2}$"	48	46	43								
$4^{3}/_{4}$"	54	52	50	47	44						
5"	61	59	56	53	50						
$5^{1}/_{4}$"	68	65	63	60	57						
$5^{1}/_{2}$"	75	73	70	67	64	61					
$5^{3}/_{4}$"	82	80	78	75	72	68	64	60			
6"	90	88	85	83	79	76	72	68			
$6^{1}/_{4}$"	98	96	94	91	88	84	80	76	72		
$6^{1}/_{2}$"	107	105	102	99	96	92	89	85	80		
$6^{3}/_{4}$"	116	114	111	108	105	101	98	93	89		
7"	125	123	120	117	114	111	107	103	98	93	84
$7^{1}/_{4}$"	134	132	130	127	124	120	116	112	108	103	93
$7^{1}/_{2}$"	144	142	139	137	133	130	126	122	117	113	102
$7^{3}/_{4}$"	154	152	150	147	144	140	136	132	128	123	112
8"	165	163	160	157	154	151	147	143	138	133	122
$8^{1}/_{4}$"	176	174	171	168	165	161	158	154	149	144	133

Table B-19 Duplex Pump Capacities* (gallons/stroke)

Linear Diameter	Area (sq.in.)	Stroke Length								
		5"	8"	10"	12"	14"	15"	16"	18"	20"
$2^1/_2$"	4.9	0.32	0.51							
3"	7.0	0.51	0.81							
$3^1/_2$"	9.6	0.72	1.17							
4"	12.5		1.58	2.06	2.46	2.87				
$4^1/_2$"	14.1		1.80	2.27	2.72	3.18				
$4^3/_4$"	17.7		2.03	2.81	3.37	3.93	4.20	4.49	5.06	5.61
5"	19.6		2.29	2.99	3.60	4.20	4.49	4.80	4.84	4.88
$5^1/_4$"	21.6		2.82	3.47	4.16	4.86	5.19	5.53	6.23	6.91
$5^1/_2$"	23.7		3.12	3.63	4.37	5.09	5.46	5.82	6.54	7.28
$5^3/_4$"	25.9		3.42	4.01	4.82	5.62	6.02	6.42	7.22	8.02
6"	28.2		3.74	4.23	5.20	6.04	6.51	5.94	7.82	8.68
$6^1/_4$"	30.6		4.08	4.74	5.69	6.64	7.12	7.60	8.56	9.50
$6^1/_2$"	33.1		4.42	5.20	6.23	7.24	7.80	8.33	9.37	10.42
$6^3/_4$"	35.7		4.79	5.57	6.76	7.84	8.44	9.01	10.13	11.28
7"	38.4		5.16	6.11	7.33	8.56	9.17	9.78	11.00	12.22
$7^1/_4$"	41.2		5.54	6.56	7.87	9.18	9.84	10.50	11.80	13.11
$7^1/_2$"	44.1				8.52	9.94	10.64	11.36	12.72	14.20
$7^3/_4$"	47.1					10.57	11.33	12.06	13.58	15.11
8"	50.2						12.22	12.91	14.67	16.28

*100% Volumetric efficiency and average rod diameters

Table B-20 Triplex Pump Capacities* (gallons/stroke)

Linear Diameter	Stroke Length								
	7"	7 1/2"	8"	8 1/2"	9"	9 1/4"	10"	11"	12"
4"	1.14	1.22	1.30	1.39	1.47				
4 1/4"	1.29	1.39	1.47	1.44	1.66				
4 1/2"	1.45	1.55	1.65	1.53	1.86	1.71	2.07		
4 3/4"	1.61	1.73	1.84	1.80	2.08	1.89	2.30		
5"	1.78	1.91	2.04	1.98	2.29	2.16	2.55	2.80	3.06
5 1/4"	1.97	2.11	2.25	2.16	2.54	2.34	2.81	3.10	3.38
5 1/2"	2.16	2.31	2.47	2.34	2.78	2.52	3.09	3.39	3.70
5 3/4"	2.36	2.53	2.70	2.61	3.04	2.79	3.37	3.72	4.05
6"	2.57	2.75	2.93	2.79	3.30	3.06	3.67	4.04	4.41
6 1/4"		2.99	3.19	3.06	3.59	3.69	3.98	4.39	4.78
6 1/2"		3.23	3.45	3.66	3.88	3.99	4.31	4.74	5.16
6 3/4"		3.48	3.72	3.96	4.18	4.31	4.65	5.12	5.57
7"			4.00	4.25	4.50	4.62	5.00	5.50	5.99
7 1/4"							5.36	5.91	6.43
7 1/2"							5.74	6.31	6.88
7 3/4"							6.13	6.75	7.36

*100% Volumetric Efficiency

Table B-21 Drill Collar Weights

Weight of 30' 0" Drill Collars (pounds)											
Drill Collar O.D. (in)	**Bore of Collar**										
	1 1/2"	1 3/4"	2"	2 1/4"	2 1/2"	2 3/4"	3"	3 1/4"	3 1/2"	3 3/4"	4"
4 1/4"	1,260	1,200	1,110								
4 1/2"	1,440	1,380	1,290								
4 3/4"	1,620	1,560	1,500	1,410	1,320						
5"	1,830	1,770	1,680	1,590	1,500						
5 1/4"	2,040	1,950	1,890	1,800	1,710						
5 1/2"	2,250	2,190	2,100	2,010	1,920	1,830					
5 3/4"	2,460	2,400	2,340	2,250	2,160	2,040	1,920	1,800			
6"	2,700	2,640	2,550	2,490	2,370	2,280	2,160	2,040			
6 1/4"	2,940	2,880	2,820	2,730	2,640	2,520	2,400	2,280	2,160		
6 1/2"	3,210	3,150	3,060	2,970	2,880	2,760	2,670	2,550	2,400		
6 3/4"	3,480	3,420	3,330	3,240	3,150	3,030	2,940	2,790	2,670		
7"	3,750	3,690	3,600	3,510	3,420	3,330	3,210	3,090	2,940	2,790	2,520
7 1/4"	4,020	3,960	3,900	3,810	3,720	3,600	3,480	3,360	3,240	3,090	2,790
7 1/2"	4,320	4,260	4,170	4,110	3,990	3,900	3,780	3,660	3,510	3,390	3,060
7 3/4"	4,620	4,560	4,500	4,410	4,320	4,200	4,080	3,960	3,840	3,690	3,360
8"	4,950	4,890	4,800	4,710	4,620	4,530	4,410	4,290	4,140	3,991	3,660
8 1/4"	5,280	5,220	5,130	5,040	4,950	4,830	4,740	4,620	4,470	4,320	3,990

Table B-22 Casing Drift Sizes

O.D.	Weight	Nominal I.D.	Drift Diameter	O.D.	Weight	Nominal I.D.	Drift Diameter
4"	11.60	3.428	3.303	9"	34.00	8.290	8.165
$4^{1}/_{2}$"	9.50	4.090	3.965		38.00	8.196	8.071
	11.60	4.000	3.875		40.00	8.150	8.025
	13.50	3.920	3.795		45.00	8.032	7.907
$4^{3}/_{4}$"	16.00	4.082	3.957		55.00	7.812	7.687
5"	11.50	4.560	4.435	$9^{5}/_{8}$"	29.30	9.063	8.907
	13.00	4.494	4.369		32.30	9.001	8.845
	15.00	4.408	4.283		36.00	8.921	8.765
	17.70	4.300	4.175		40.00	8.835	8.679
	18.00	4.276	4.151		43.50	8.755	8.599
	21.00	4.154	4.029		47.00	8.681	8.525
$5^{1}/_{2}$"	13.00	5.044	4.919		53.50	8.535	8.379
	14.00	5.012	4.887	10"	33.00	9.384	9.228
	15.00	4.974	4.849	$10^{3}/_{4}$"	32.75	10.192	10.036
	15.50	4.950	4.825		40.00	10.054	9.898
	17.00	4.892	4.767		40.50	10.050	9.894
	20.00	4.778	4.653		45.00	9.960	9.804
	23.00	4.670	4.545		45.50	9.950	9.794
$5^{3}/_{4}$"	14.00	5.290	5.165		48.00	9.902	9.746
	17.00	5.190	4.065		51.00	9.850	9.694
	19.50	5.090	4.965		54.00	9.784	9.628
	22.50	4.990	4.865		55.50	9.760	9.604
6"	15.00	5.524	5.399	$11^{3}/_{4}$"	38.00	11.150	10.994
	16.00	5.500	5.375		42.00	11.084	10.928
	18.00	5.424	5.299		47.00	11.000	10.844
	20.00	5.352	5.227		54.00	10.880	10.724
	23.00	5.240	5.115		60.00	10.772	10.616

Table B-22 Casing Drift Sizes (continued)

O.D.	Weight	Nominal I.D.	Drift Diameter	O.D.	Weight	Nominal I.D.	Drift Diameter
$6^5/_8$"	17.00	6.135	6.010	12"	40.00	11.384	11.228
	20.00	6.049	5.924	13"	40.00	12.438	12.282
	22.00	5.989	5.864		45.00	12.360	12.204
	24.00	5.921	5.796		50.00	12.282	12.126
	26.00	5.855	5.730		54.00	12.220	12.064
	26.80	5.837	5.712	$13^3/_8$"	48.00	12.715	12.559
	28.00	5.791	5.666		54.50	12.615	12.459
	29.00	5.761	5.636		61.00	12.515	12.359
	32.00	5.675	5.550		68.00	12.415	12.259
7"	17.00	6.538	6.413	$13^3/_8$"	72.00	12.347	12.191
	20.00	6.456	6.331		83.00	12.175	12.019
	22.00	6.398	6.273		85.00	12.159	12.003
	23.00	6.366	6.241	16"	55.00	15.375	15.187
	24.00	6.336	6.211		65.00	15.250	15.062
	26.00	6.276	6.151		75.00	15.125	14.937
	28.00	6.214	6.089		84.00	15.010	12.003
	29.00	6.184	6.059	$18^5/_8$"	78.00	17.855	17.667
	30.00	6.154	6.029		87.50	17.755	17.567
	32.00	6.094	5.969		96.50	17.655	17.467
	35.00	6.004	5.879	20"	90.00	19.190	19.002
	38.00	5.920	5.795		94.00	19.124	18.936
	40.00	5.836	5.711	$21^1/_2$"	92.50	20.710	20.522
$7^5/_8$"	20.00	7.125	7.000		103.00	20.610	20.422
	24.00	7.025	6.900		114.00	20.510	20.322
	26.40	6.969	6.844	$24^1/_2$"	100.50	23.750	23.562
	29.70	6.875	6.750		113.00	23.650	23.462

Table B-22 Casing Drift Sizes (continued)

O.D.	Weight	Nominal I.D.	Drift Diameter	O.D.	Weight	Nominal I.D.	Drift Diameter
$7^5/_8$"	33.70	6.765	6.640				
	39.00	6.625	6.500				
$8^5/_8$"	24.00	8.097	7.972				
	28.00	8.017	7.892				
	32.00	7.921	7.796				
	36.00	7.825	7.700				
	38.00	7.775	7.650				
	40.00	7.725	7.600				
	43.00	7.651	7.526				
	44.00	7.625	7.500				
	49.00	7.511	7.386				

Table B-23 Tubing Drift Sizes

Nominal (inches)	O.D. (inches)	Weight (pounds)	Nominal I.D. (inches)	Drift Diameter (inches)
$^{3}/_{4}$"	1.050	1.20	0.824	0.730
1"	1.315	1.80	1.049	0.955
1"	1.315	2.25	0.957	0.848
$1^{1}/_{4}$"	1.660	2.40	1.380	1.280
$1^{1}/_{2}$"	1.900	2.90	1.610	1.516
$2^{1}/_{16}$"	2.0625	3.25	1.751	1.657
$2^{3}/_{8}$"	2.375	4.70	1.995	1.901
$2^{3}/_{8}$"	2.375	5.30	1.939	1.845
$2^{7}/_{8}$"	2.875	6.50	2.441	2.347
$3^{1}/_{2}$"	3.500	9.30	2.992	2.867
$3^{1}/_{2}$"	3.500	10.30	2.922	2.797
4"	4.000	11.00	3.476	3.351
$4^{1}/_{2}$"	4.500	12.75	3.958	3.833

Table B-24 Fluid Density and Pressure Gradients

lbs/gal	lbs/ft^3	Density (g/mL)	Pressure Gradient (psi/ft)
8.00	59.8	0.96	0.416
8.34	62.4	1.00	0.433
9.00	67.3	1.08	0.468
10.00	74.8	1.20	0.520
11.00	82.3	1.32	0.571
12.00	89.9	1.44	0.624
13.00	97.2	1.56	0.675
14.00	104.7	1.68	0.727
15.00	112.2	1.80	0.779
16.00	119.7	1.92	0.831
17.00	127.2	2.04	0.883
18.00	134.6	2.16	0.935
19.00	142.1	2.28	0.987
20.00	149.6	2.40	1.039
21.00	157.1	2.52	1.091
22.00	164.1	2.64	1.143

Table B-25 Inch to Metric Conversion

Millimeter Equivalents																
Inches	0"	1/16"	1/8"	3/16"	1/4"	5/16"	3/8"	7/16"	1/2"	9/16"	5/8"	11/16"	3/4"	13/16"	7/8"	15/16"
0	0	1.6	3.2	4.8	6.3	7.9	9.5	11.1	12.7	14.3	15.9	17.5	19.0	20.6	22.2	23.8
1	25.4	27.0	28.6	30.2	31.7	33.3	34.9	36.5	38.1	39.7	41.3	42.9	44.4	46.0	47.6	49.2
2	50.8	52.4	54.0	55.6	57.1	58.7	60.3	61.9	63.5	65.1	66.7	68.3	69.8	71.4	73.0	74.6
3	76.2	77.8	79.4	81.0	82.5	84.1	85.7	87.3	88.9	90.5	92.1	93.7	95.2	96.8	98.4	100.0
4	101.6	103.2	104.8	106.4	107.9	109.5	111.1	112.7	114.3	115.9	117.5	119.1	120.5	122.2	123.8	125.4
5	127.0	128.6	130.2	131.8	133.3	134.9	136.5	138.1	139.7	141.3	142.9	144.5	146.0	147.6	149.2	160.8
6	152.4	154.0	155.6	157.2	158.7	160.3	161.9	163.5	165.1	166.7	168.3	169.9	171.4	173.0	174.6	176.2
7	177.8	179.4	181.0	182.6	184.1	185.7	187.3	188.9	190.5	192.1	193.7	195.3	196.8	198.4	200.0	201.6
8	203.2	204.8	206.4	208.0	209.5	211.1	212.7	214.3	215.9	217.5	219.1	220.7	222.2	223.8	225.4	227.0
9	228.6	230.2	231.8	233.4	234.9	236.5	238.1	239.7	241.3	242.9	244.5	246.1	247.6	249.2	250.8	252.4
10	254.0	255.6	257.2	258.8	260.3	261.0	263.5	265.1	266.7	268.3	269.9	271.5	273.0	274.6	276.2	277.8
11	279.4	281.0	282.6	284.2	285.7	287.3	288.9	290.5	292.1	293.7	295.3	296.9	298.4	300.0	301.6	303.2
12	304.8	306.4	308.0	309.6	311.1	312.7	314.3	315.9	317.5	319.1	320.7	322.3	323.8	325.4	327.0	328.6
13	330.2	331.8	333.4	335.0	336.5	338.1	339.7	341.3	342.9	344.5	346.1	347.7	349.2	350.8	352.4	354.0
14	355.6	357.2	358.8	360.4	361.9	363.5	365.1	366.7	368.3	369.9	371.5	373.1	374.6	376.2	377.8	379.4
15	381.0	382.6	384.2	385.8	387.3	388.9	390.5	392.1	393.7	395.3	396.9	398.5	400.0	401.6	403.2	404.8
16	406.4	408.0	409.6	411.2	412.7	414.3	415.9	417.5	419.1	420.7	422.3	423.9	425.4	427.0	428.6	430.2
17	431.8	433.4	435.0	436.6	438.1	439.7	441.3	442.9	444.6	446.1	447.7	449.3	450.8	452.4	454.0	455.6
18	457.2	458.8	460.4	462.0	463.5	465.1	466.7	468.3	469.9	471.5	473.1	474.7	476.2	477.8	479.4	481.0
19	482.6	484.2	485.8	487.4	488.9	490.5	492.1	493.7	495.3	496.9	498.5	500.1	501.6	503.2	504.8	506.4
20	508.0	509.6	511.2	512.8	514.3	515.9	517.5	519.1	520.7	522.3	523.9	525.5	527.0	528.6	530.2	531.8
21	533.4	535.0	536.6	538.2	539.7	541.3	542.9	544.5	546.1	547.7	549.3	550.9	552.4	554.0	555.6	557.2
22	558.8	560.4	562.0	563.6	565.1	566.7	568.3	569.9	571.5	573.1	574.7	576.3	577.8	579.4	581.0	582.6
23	584.2	585.8	587.4	589.0	590.5	592.1	593.7	595.3	596.9	598.5	600.1	601.7	603.2	604.8	606.4	608.0
24	609.6	611.2	612.8	614.4	615.9	617.5	619.1	620.7	622.3	623.9	625.5	627.1	628.6	630.2	631.8	633.4

Table B-26 Fraction Conversion Chart

fraction	mm	decimal		fraction	mm	decimal
$^{1}/_{64}$	0.4	0.015625		$^{33}/_{64}$	13.0	0.515625
$^{1}/_{32}$	0.8	0.031250		$^{17}/_{32}$	13.5	0.531250
$^{3}/_{64}$	1.2	0.046875		$^{35}/_{64}$	14.0	0.546875
$^{1}/_{16}$	1.6	0.062500		$^{9}/_{16}$	14.3	0.562500
$^{5}/_{64}$	2.0	0.078125		$^{37}/_{64}$	14.7	0.578125
$^{3}/_{32}$	2.4	0.093750		$^{19}/_{32}$	15.0	0.593750
$^{7}/_{64}$	2.8	0.109375		$^{39}/_{64}$	15.5	0.609375
$^{1}/_{8}$	3.2	0.125000		$^{5}/_{8}$	16.0	0.625000
$^{9}/_{64}$	3.6	0.140625		$^{41}/_{64}$	16.3	0.640625
$^{5}/_{32}$	4.0	0.156250		$^{21}/_{32}$	16.7	0.656250
$^{11}/_{64}$	4.4	0.171875		$^{43}/_{64}$	17.0	0.671875
$^{3}/_{16}$	4.8	0.187500		$^{11}/_{16}$	17.5	0.687500
$^{13}/_{64}$	5.2	0.203125		$^{45}/_{64}$	18.0	0.703125
$^{7}/_{32}$	5.6	0.218750		$^{23}/_{32}$	18.3	0.718750
$^{15}/_{64}$	6.0	0.234375		$^{47}/_{64}$	18.7	0.734375
$^{1}/_{4}$	6.4	0.250000		$^{3}/_{4}$	19.0	0.750000
$^{17}/_{64}$	6.8	0.265625		$^{49}/_{64}$	19.5	0.765625
$^{9}/_{32}$	7.2	0.281250		$^{25}/_{32}$	20.0	0.781250
$^{19}/_{64}$	7.6	0.296875		$^{51}/_{64}$	20.3	0.796875
$^{5}/_{16}$	8.0	0.312500		$^{13}/_{16}$	20.7	0.812500
$^{21}/_{64}$	8.4	0.328125		$^{53}/_{64}$	21.0	0.828125
$^{11}/_{32}$	8.8	0.343750		$^{27}/_{32}$	21.5	0.843750
$^{23}/_{64}$	9.2	0.359375		$^{55}/_{64}$	22.0	0.859375
$^{3}/_{8}$	9.6	0.375000		$^{7}/_{8}$	22.3	0.875000
$^{25}/_{64}$	10.0	0.390625		$^{57}/_{64}$	22.7	0.890625
$^{13}/_{32}$	10.4	0.406250		$^{29}/_{32}$	23.0	0.906250
$^{27}/_{64}$	10.8	0.421875		$^{59}/_{64}$	23.5	0.921875
$^{7}/_{16}$	11.2	0.437500		$^{15}/_{16}$	24.0	0.937500
$^{29}/_{64}$	11.5	0.453125		$^{61}/_{64}$	24.2	0.953125
$^{15}/_{32}$	12.0	0.468750		$^{31}/_{32}$	24.6	0.968750
$^{31}/_{64}$	12.3	0.484375		$^{63}/_{64}$	25.0	0.984375
$^{1}/_{2}$	12.7	0.500000		1	25.4	1.000000

Table B-27 Core Barrel Pressure Drop Calculations

The pressure drop through the annular space between the outer tube and the inner tube may become important when coring with fiberglass inner tubes of more than 90 ft. in length.
Besides core barrel geometry, pressure drop depends on mud weight, flow rate, and viscosity of mud. A fairly good approximation can be made with the following equation:

$$p/ft = (7.59) \times (a) \times (d) \times (Q/b)^2 \times [1 - (PV - 12) \div 200]$$

Where:

a, b = geometric constants of the core barrels
d = lb/gal (mud density)
Q = gpm (flow rate)
PV = centipoise (mud viscosity)
p/ft = psi

The table below was based upon 10 lb/gal mud and plastic viscosity of 15.

Core Barrel	a	b	gpm	p/ft.
4.75 x 2.62	229	10,335	90 120 164	1.30 2.31 4.30
6.75 x 4.00	164	18,808	180 250 340	1.12 2.17 4.00
8.00 x 5.25	245	17,322	210 250 295	2.69 3.82 5.31

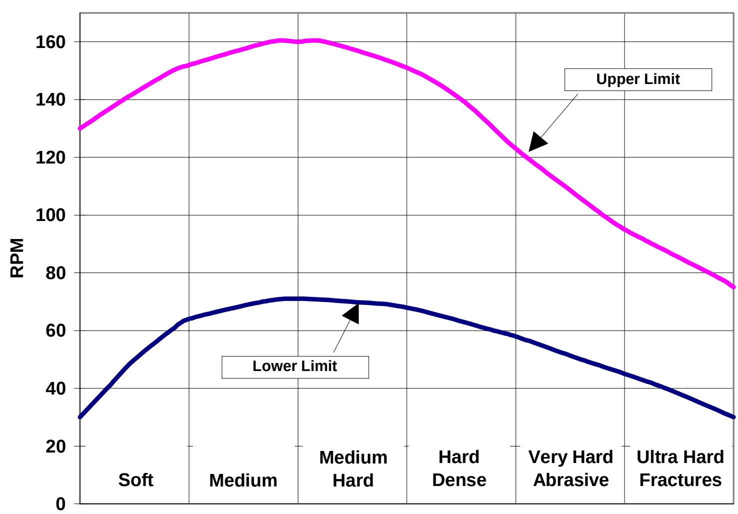


Figure B-1 Recommended Rotary Speed for Core Bits

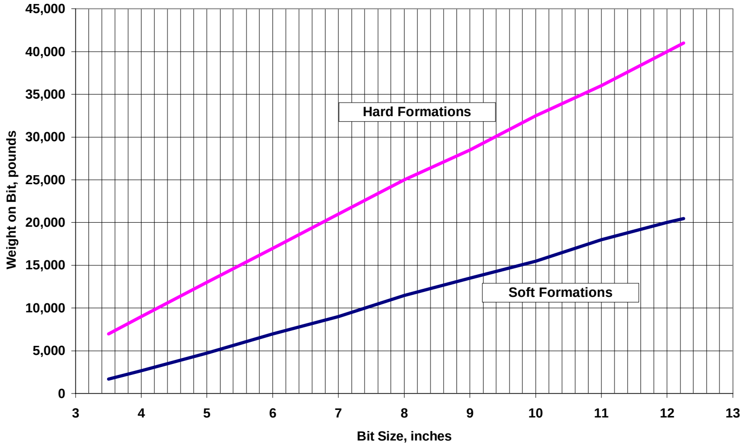


Figure B-2 Drilling Weight On Bit for Core Bits

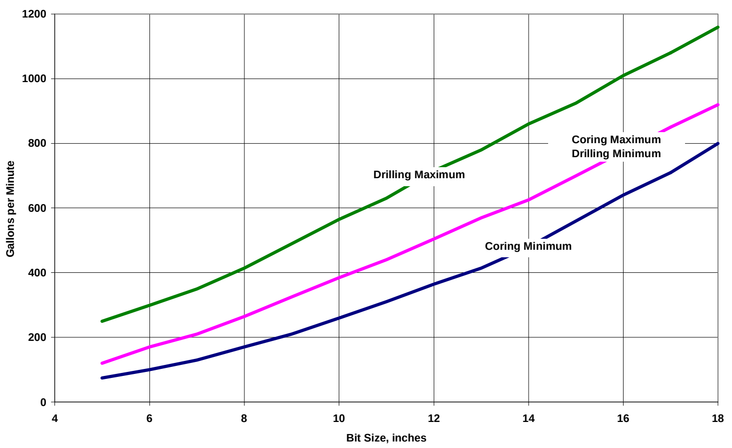


Figure B-3 Pump Discharge per Bit Size