

## API Ballot # 6534

TG DSE  
Page 1 of 1

<b>Work Item Number</b>	7001
<b>Title of Work Item</b>	API RP 7G, Edition 16, Addendum 3
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<b>Impacted Documents</b>	API RP 7G, Edition 16
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### Work Item Charge

**Create RP7G-1 to update Performance Properties of Drill Stem Elements**

**Ballot Rationale:** This ballot removes from RP 7G the items that are replaced by RP7G-1

### Ballot Text

Ballot text attached

**Date of Issue:** [DATE] 2024

**Affected Publication:** API Recommended Practice 7G, Recommended Practice for Drill Stem Design and Operating Limits, Sixteenth Edition, August 1998

## **Addendum 3**

*Section 4 Properties of Drill Pipe and Tool Joints: This section shall be deleted*

*Table 1—New Drill Pipe Dimensional Data: This table shall be deleted*

*Table 2—New Drill Pipe Torsional and Tensile Data: This table shall be deleted*

*Table 3—New Drill Pipe Collapse and Internal Pressure Data: This table shall be deleted*

*Table 4—Used Drill Pipe Torsional and Tensile Data API Premium Class: This table shall be deleted*

*Table 5—Used Drill Pipe Collapse and Internal Pressure Data API Premium Class: This table shall be deleted*

*Table 6—Used Drill Pipe Torsional and Tensile Data API Class 2: This table shall be deleted*

*Table 7—Used Drill Pipe Collapse and Internal Pressure Data API Class 2: This table shall be deleted*

*Table 8—Mechanical Properties of New Tool Joints and New Grade E75 Drill Pipe: This table shall be deleted*

*Table 9—Mechanical Properties of New Tool Joints and New High Strength Drill Pipe: This table shall be deleted*

*Table 10—Recommended Minimum OD\* and Make-up Torque of Weld-on Type Tool Joints Based on Torsional Strength of Box and Drill Pipe: This table shall be deleted*

*Table 12—Rotary Shouldered Connection Interchange List: This table shall be deleted*

*Figure 1—NC26 Torsional Yield and Make-up: This figure shall be deleted*

*Figure 2— $2\frac{3}{8}$  Open Hole Torsional Yield and Make-up: This figure shall be deleted*

*Figure 3— $2\frac{3}{8}$  Wide Open Torsional Yield and Make-up: This figure shall be deleted*

*Figure 4— $2\frac{3}{8}$  SLH90 Torsional Yield and Make-up: This figure shall be deleted*

*Figure 5— $2\frac{3}{8}$  PAC Torsional Yield and Make-up: This figure shall be deleted*

*Figure 6—NC31 Torsional Yield and Make-up: This figure shall be deleted*

*Figure 7—2<sup>7</sup>/<sub>8</sub> SLH90 Torsional Yield and Make-up: This figure shall be deleted*

*Figure 8—2<sup>7</sup>/<sub>8</sub> Wide Open Torsional Yield and Make-up: This figure shall be deleted*

*Figure 9—2<sup>7</sup>/<sub>8</sub> Open Hole Torsional Yield and Make-up: This figure shall be deleted*

*Figure 10—2<sup>7</sup>/<sub>8</sub> PAC Torsional Yield and Make-up: This figure shall be deleted*

*Figure 11—NC38 Torsional Yield and Make-up: This figure shall be deleted*

*Figure 12—3<sup>1</sup>/<sub>2</sub> SLH90 Torsional Yield and Make-up: This figure shall be deleted*

*Figure 13—3<sup>1</sup>/<sub>2</sub> FH Torsional Yield and Make-up: This figure shall be deleted*

*Figure 14—3<sup>1</sup>/<sub>2</sub> Open Hole Torsional Yield and Make-up: This figure shall be deleted*

*Figure 15—3<sup>1</sup>/<sub>2</sub> PAC Torsional Yield and Make-up: This figure shall be deleted*

*Figure 16—3<sup>1</sup>/<sub>2</sub> XH Torsional Yield and Make-up: This figure shall be deleted*

*Figure 17—NC40 Torsional Yield and Make-up: This figure shall be deleted*

*Figure 18—4-Inch H90 Torsional Yield and Make-up: This figure shall be deleted*

*Figure 19—4-Inch Open Hole Torsional Yield and Make-up: This figure shall be deleted*

*Figure 20—NC46 Torsional Yield and Make-up: This figure shall be deleted*

*Figure 21—4<sup>1</sup>/<sub>2</sub> FH Torsional Yield and Make-up: This figure shall be deleted*

*Figure 22—4<sup>1</sup>/<sub>2</sub> H90 Torsional Yield and Make-up: This figure shall be deleted*

*Figure 23—4<sup>1</sup>/<sub>2</sub> Open Hole (Standard Weight) Torsional Yield and Make-up: This figure shall be deleted*

*Figure 24—NC50 Torsional Yield and Make-up: This figure shall be deleted*

*Figure 25—5<sup>1</sup>/<sub>2</sub> FH Torsional Yield and Make-up: This figure shall be deleted*

*Section 5 Properties of Drill Collars: This section shall be deleted*

*Section 6 Properties of Kellys: This section shall be deleted*

*Table 13—Drill Collar Weight (Steel) (pounds per foot): This table shall be deleted*

*Table 14—Recommended Make-up Torque<sup>1</sup> for Rotary Shouldered Drill Collar Connections: This table shall be deleted*

*Figure 26—Drill Collar Bending Strength Ratios, 1<sup>1</sup>/<sub>2</sub>- and 1<sup>3</sup>/<sub>4</sub>-Inch ID: This figure shall be deleted*

*Figure 27—Drill Collar Bending Strength Ratios, 2- and 2<sup>1</sup>/<sub>4</sub>-Inch ID: This figure shall be deleted*

*Figure 28—Drill Collar Bending Strength Ratios, 2<sup>1</sup>/<sub>2</sub>-Inch ID: This figure shall be deleted*

*Figure 29—Drill Collar Bending Strength Ratios, 2<sup>13</sup>/<sub>16</sub>-Inch ID: This figure shall be deleted*

*Figure 30—Drill Collar Bending Strength Ratios, 3-Inch ID: This figure shall be deleted*

*Figure 31—Drill Collar Bending Strength Ratios, 3<sup>1</sup>/<sub>4</sub>-Inch ID: This figure shall be deleted*

*Figure 32—Drill Collar Bending Strength Ratios, 3<sup>1</sup>/<sub>2</sub>-Inch ID: This figure shall be deleted*

*Table 15—Strength of Kellys: This table shall be deleted*

*Figure 33—New Kelly-New Drive Assembly: This figure shall be deleted*

*Figure 34—New Kelly-New Drive Assembly: This figure shall be deleted*

*Table 16—Contact Angle Between Kelly and Bushing for Development of Maximum Width Wear Pattern: This table shall be deleted*

*Table 17—Strength of Remachined Kellys: This table shall be deleted*

*Section 14 Special Processes: This section shall be deleted*

*Section 16 Classification Size and Make-Up Torque for Rock Bits: This section shall be deleted*

*Table 30—IADC Roller Bit Classification Chart: This table shall be deleted*

*Table 31—IADC Bit Classification Codes Fourth Position: This table shall be deleted*

*Table 32—Recommended Make-up Torque Ranges for Roller Cone Drill Bits: This table shall be deleted*

*Table 33—Recommended Minimum Make-up Torques for Diamond Drill Bits: This table shall be deleted*

*Table 34—Common Roller Bit Sizes: This table shall be deleted*

*Table 35—Common Fixed Cutter Bit Sizes: This table shall be deleted*

*Section A.2 Safety Factors: This section shall be deleted*

*Section A.3 Collapse Pressure for Drill Pipe: This section shall be deleted*

*Section A.5 Internal Pressure: This section shall be deleted*

*Section A.7 Tensile Strength of Drill Pipe Body: This section shall be deleted*

*Section A.8 Torsional Yield Strength of Drill Pipe Body: This section shall be deleted*

*Section A.9 Torque Calculations for Rotary Shouldered Connections (see Table A-1 and Figure A-2): This section shall be deleted*

*Section A.10 Combined Torsion and Tension to Yield Rotary Shouldered Connection and Drill Pipe Body: This section shall be deleted*

*Section A.11 Drill Collar Bending Strength Ratio: This section shall be deleted*

*Section A.12 Torsional Yield Strength of Kelly Drive Section: This section shall be deleted*

*Section A.13 Bending Strength, Kelly Drive Section: This section shall be deleted*

*Section A.14 Approximate Weight of Tool Joint Plus Drill Pipe: This section shall be deleted*

# Recommended Practice for Drill Stem Design and Operating Limits

API RECOMMENDED PRACTICE 7G  
SIXTEENTH EDITION, AUGUST 1998

EFFECTIVE DATE: DECEMBER 1, 1998

ERRATA: MAY 2000

ADDENDUM 1: NOVEMBER 2003

ADDENDUM 2: SEPTEMBER 2009

[ADDENDUM 3: XXX 2024](#)



*Committee Review Only*

# Recommended Practice for Drill Stem Design and Operating Limits

## Upstream Segment

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## FOREWORD

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The purpose of this recommended practice is to standardize techniques for the procedure of drill stem design and to define the operating limits of the drill stem.

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**NOTE TO EDITOR:** Remaining sections, tables, and figures will be renumbered.

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# CONTENTS

	Page
1 SCOPE.....	1
1.1 Coverage .....	1
1.2 Section Coverage.....	1
2 REFERENCES .....	1
3 DEFINITIONS.....	1
4 <del>PROPERTIES OF DRILL PIPE AND TOOL JOINTS.....</del>	<del>3</del>
5 <del>PROPERTIES OF DRILL COLLARS .....</del>	<del>33</del>
6 <del>PROPERTIES OF KELLYS .....</del>	<del>33</del>
7 DESIGN CALCULATIONS.....	46
7.1 Design Parameters .....	46
7.2 Special Design Parameters.....	46
7.3 Supplemental Drill Stem Members.....	46
7.4 Tension Loading .....	46
7.5 Collapse Due to External Fluid Pressure .....	50
7.6 Internal Pressure .....	51
7.7 Torsional Strength.....	51
7.8 Example Calculation of a Typical Drill String Design—Based on Margin of Overpull.....	51
7.9 Drill Pipe Bending Resulting From Tonging Operations .....	52
8 LIMITATIONS RELATED TO HOLE DEVIATION.....	53
8.1 Fatigue Damage.....	53
8.2 Remedial Action to Reduce Fatigue .....	54
8.3 Estimation of Cumulative Fatigue Damage .....	58
8.4 Identification of Fatigued Joints .....	58
8.5 Wear of Tool Joints and Drill Pipe.....	58
8.6 Heat Checking of Tool Joints .....	59
9 LIMITATIONS RELATED TO FLOATING VESSELS.....	59
10 DRILL STEM CORROSION AND SULFIDE STRESS CRACKING.....	61
10.1 Corrosion.....	61
10.2 Sulfide Stress Cracking.....	64
10.3 Drilling Fluids Containing Oil.....	65
11 COMPRESSIVE SERVICE LIMITS FOR DRILL PIPE.....	67
11.1 Compressive Service Applications .....	67
11.2 Drill Pipe Buckling in Straight, Inclined Well Bores.....	67
11.3 Critical Buckling Force for Curved Boreholes.....	78
11.4 Bending Stresses on Compressively Loaded Drill Pipe in Curved Boreholes ..	79
11.5 Fatigue Limits for API Drill Pipe .....	96
11.6 Estimating Cumulative Fatigue Damage.....	98
11.7 Bending Stresses on Buckled Drill Pipe.....	101
12 SPECIAL SERVICE PROBLEMS.....	101
12.1 Severe Downhole Vibration.....	101
12.2 Transition from Drill Pipe to Drill Collars .....	108

		Page		
12.3	Pulling on Stuck Pipe . . . . .	108	09	
12.4	Jarring . . . . .	109		
12.5	Torque in Washover Operations . . . . .	109		
12.6	Allowable Hookload and Torque Combinations . . . . .	109		
12.7	Biaxial Loading of Drill Pipe . . . . .	110		
12.8	Formulas and Physical Constants . . . . .	110		
12.9	Transition from Elastic to Plastic Collapse . . . . .	110		
12.10	Effect of Tensile Load on Collapse Resistance . . . . .	110		
12.11	Example Calculation of Biaxial Loading . . . . .	110		
13	IDENTIFICATION, INSPECTION AND CLASSIFICATION OF DRILL STEM COMPONENTS . . . . .	112		09
13.1	Drill String Marking and Identification . . . . .	112		
13.2	Inspection Standards—Drill Pipe and Tubing Work Strings . . . . .	112		
13.3	Tool Joints . . . . .	122		
13.4	Drill Collar Inspection Procedure . . . . .	124		
13.5	Drill Collar Handling Systems . . . . .	124		
13.6	Kellys . . . . .	125		
13.7	Recut Connections . . . . .	126		
13.8	Pin Stress Relief Grooves for Rental Tools and Other Short Term Usage Tools . . . . .	126		
14	SPECIAL PROCESSES . . . . .	127	03	
14.1	Drill Stem Special Processes . . . . .	127		
14.2	Connection Break In . . . . .	127		
15	DYNAMIC LOADING OF DRILL PIPE . . . . .	127		
16	CLASSIFICATION SIZE AND MAKE UP TORQUE FOR ROCK BITS . . . . .	128		
APPENDIX A	STRENGTH AND DESIGN FORMULAS . . . . .	133	03	
APPENDIX B	ARTICLES AND TECHNICAL PAPERS . . . . .	151		
Figures				
1-25	Torsional Strength and Recommended Make-up Torque Curves . . . . .	20-32		
26	Drill Collar Bending Strength Ratios, 1½- and 1¾-Inch ID . . . . .	39		
27	Drill Collar Bending Strength Ratios, 2 and 2¼-Inch ID . . . . .	40		
28	Drill Collar Bending Strength Ratios, 2½-Inch ID . . . . .	41		
29	Drill Collar Bending Strength Ratios, 2⅜-Inch ID . . . . .	42		
30	Drill Collar Bending Strength Ratios, 3-Inch ID . . . . .	44		
31	Drill Collar Bending Strength Ratios, 3¼-Inch ID . . . . .	45		
32	Drill Collar Bending Strength Ratios, 3½-Inch ID . . . . .	46		
33	New Kelly New Drive Assembly . . . . .	48		
34	New Kelly New Drive Assembly . . . . .	48		
35	Maximum Height of Tool Joint Above Slips to Prevent Bending During Tonging . . . . .	53		
36	Dogleg Severity Limits for Fatigue of Grade E75 Drill Pipe . . . . .	55		
37	Dogleg Severity Limits for Fatigue of S-135 Drill Pipe . . . . .	56		
38	Lateral Force on Tool Joint . . . . .	57		
39	Fatigue Damage in Gradual Doglegs (Noncorrosive Environment) . . . . .	58		
40	Fatigue Damage in Gradual Doglegs (In Extremely Corrosive Environment) . . . . .	58		

41	Lateral Forces on Tool Joints and Range 2 Drill Pipe 3½ Inch, 13.3 Pounds per Foot, Range 2 Drill Pipe, 4¾ Inch Tool Joints .....	60
42	Lateral Forces on Tool Joints and Range 2 Drill Pipe 4½ Inch, 16.6 Pounds per Foot, Range 2 Drill Pipe, 6¼ Inch Tool Joints .....	60
43	Lateral Forces on Tool Joints and Range 2 Drill Pipe 5 Inch, 19.5 Pounds per Foot, Range 2 Drill Pipe, 6¾ Inch Tool Joints .....	62
44	Lateral Forces on Tool Joints and Range 3 Drill Pipe 5 Inch, 19.5 Pounds per Foot, Range 3 Drill Pipe, 6¾ Inch Tool Joints .....	62
45	Delayed-Failure Characteristics of Unnotched Specimens of an SAE 4340 Steel During Cathodic Charging with Hydrogen Under Standardized Conditions .....	66
46–66	Approximate Axial Compressive Loads at which Sinusoidal Buckling is Expected to Occur .....	68–78
67a–74a	Bending Stress and Fatigue Limits .....	80–94
67b–74b	Lateral Contact Forces and Length .....	81–95
75	Hole Curvature Adjustment Factor To Allow for Differences in Tooljoint OD's .....	97
76	Median Failure Limits for API Drillpipe Noncorrosive Service .....	99
77	Minimum Failure Limits for API Drillpipe Noncorrosive Service .....	100
78a	Bending Stress for High Curvatures .....	102
78b	Lateral Contact Forces and Length .....	103
79a	Bending Stress for High Curvatures .....	104
79b	Lateral Contact Forces and Length .....	105
80a	Bending Stress for High Curvatures .....	106
80b	Lateral Contact Forces and Length .....	107
81	Ellipse of Biaxial Yield Stress or Maximum Shear-Strain Energy Diagram After Holmquist and Nadai, Collapse of Deep Well Casing, API Drilling and Production Practice (1939) .....	111
82	Marking on Tool Joints for Identification of Drill String Components .....	113
83	Recommended Practice for Mill Slot and Groove Method of Drill String Identification .....	114
84	Identification of Lengths Covered by Inspection Standards .....	116
85	Drill Pipe and Tool Joint Color Code Identification .....	122
86	Tong Space and Bench Mark Position .....	123
87	Drill Collar Elevator .....	124
88	Drill Collar Grooves for Elevators and Slips .....	125
89	Drill Collar Wear .....	125
90	Modified Pin Stress-Relief Groove .....	126
A-1	Eccentric Hollow Section of Drill Pipe .....	133
A-2	Rotary Shouldered Connection .....	135
A-3a	Make-up Torque Then Tension .....	137
A-3b	Tension Then Torque .....	137
A-3c	Make-up Torque Then Tension .....	139
A-3d	Tension Then Torque .....	139
A-4	Rotary Shouldered Connection Location of Dimensions for Bending Strength Ratio Calculations .....	141
A-5	Buckling Force vs Hole Curvature .....	143
A-6	Buckling Force vs Hole Curvature .....	144
A-7	Buckling Force vs Hole Curvature .....	145

09

03

## Tables

1	New Drill Pipe Dimensional Data .....	4
2	New Drill Pipe Torsional and Tensile Data .....	5
3	New Drill Pipe Collapse and Internal Pressure Data .....	6

03

4	<del>Used Drill Pipe Torsional and Tensile Data API Premium Class.....</del>	7	
5	<del>Used Drill Pipe Collapse and Internal Pressure Data API Premium Class.....</del>	8	
6	<del>Used Drill Pipe Torsional and Tensile Data API Class 2.....</del>	9	
7	<del>Used Drill Pipe Collapse and Internal Pressure Data API Class 2.....</del>	10	
8	<del>Mechanical Properties of New Tool Joints and New Grade E75 Drill Pipe.....</del>	11	
9	<del>Mechanical Properties of New Tool Joints and New High Strength Drill Pipe.....</del>	13	
10	<del>Recommended Minimum OD and Make-up Torque of Weld-on Type Tool Joints Based on Torsional Strength of Box and Drill Pipe.....</del>	15	03
11	Buoyancy Factors.....	18	
12	<del>Rotary Shouldered Connection Interchange List.....</del>	19	
13	<del>Drill Collar Weight (Steel) (pounds per foot).....</del>	34	
14	<del>Recommended Make-up Torque for Rotary Shouldered Drill Collar Connections.....</del>	35	03
15	<del>Strength of Kellys.....</del>	47	
16	<del>Contact Angle Between Kelly and Bushing for Development of Maximum Width Wear Pattern.....</del>	48	
17	<del>Strength of Remachined Kellys.....</del>	49	
18	Section Modulus Values.....	53	
19	Effect of Drilling Fluid Type on Coefficient of Friction.....	67	
20	Hole Curvatures that Prevent Buckling.....	79	
21	Youngstown Steel Test Results.....	96	
22	Fatigue Endurance Limits Compressively Loaded Drill Pipe.....	98	
23	Values Used in Preparing Figure 77.....	98	
24	<del>Classification of Used Drill Pipe.....</del>	115	
25	<del>Classification of Used Tubing Work Strings.....</del>	117	09
26	<del>Hook Load at Minimum Yield Strength for New, Premium Class (Used), and Class 2 (Used) Drill Pipe.....</del>	118	
27	Hook-Load at Minimum Yield Strength for New, Premium Class (Used), and Class 2 (Used) Tubing Work Strings.....	120	
28	Drill Collar Groove and Elevator Bore Dimensions.....	125	09
29	Maximum Stress at Root of Last Engaged Thread for the Pin of an NC50 Axisymmetric Model.....	126	
30	<del>IADC Roller Bit Classification Chart.....</del>	129	
31	<del>IADC Bit Classification Codes Fourth Position.....</del>	130	
32	<del>Recommended Make-up Torque Ranges for Roller Cone Drill Bits.....</del>	130	
33	<del>Recommended Minimum Make-up Torques for Diamond Drill Bits.....</del>	131	03
34	<del>Common Roller Bit Sizes.....</del>	131	
35	<del>Common Fixed Cutter Bit Sizes.....</del>	131	
A-1	Rotary Shouldered Connection Thread Element Information.....	148	03

[NOTE: Items highlighted blue were intended to be removed during Addendum 2 and shall be deleted]

# Recommended Practice for Drill Stem Design and Operating Limits

## 1 Scope

### 1.1 COVERAGE

This recommended practice involves not only the selection of drill string members, but also the consideration of hole angle control, drilling fluids, weight and rotary speed, and other operational procedures.

### 1.2 SECTION COVERAGE

Sections 4, 5, 6, and 7 provide procedures for use in the selection of drill string members. Sections 8, 9, 10, 11, 12, and 15 are related to operating limitations which may reduce the normal capability of the drill string. Section 13 contains a classification system for used drill pipe and used tubing work strings, and identification and inspection procedures for other drill string members. Section 14 contains statements regarding welding on down hole tools. Section 16 contains a classification system for rock bits.

## 2 References

(See also Appendix B.)

API

- RP 5C1 *Care and Use of Casing and Tubing*  
Bull 5C3 *Bulletin on Formulas and Calculations for Casing, Tubing, Drill Pipe, and Line Pipe Properties*  
Spec 7 *Specification for Rotary Drill Stem Elements*  
RP 7A1 *Recommended Practice for Testing of Thread Compounds for Rotary Shouldered Connections*  
RP 13B-1 *Recommended Practice Standard Procedure for Field Testing Water-Based Drilling Fluids*  
RP 13B-2 *Recommended Practice Standard Procedure for Field Testing Oil-Based Drilling Fluids*

ASTM<sup>1</sup>

- D3370 *Standard Practices for Sampling Water*

NACE<sup>2</sup>

- MR-01-75 *Sulfide Stress Cracking Resistant Metallic Material for Oil Field Equipment*

<sup>1</sup>American Society for Testing Materials, 100 Barr Harbor Drive, West Conshocken, Pennsylvania 19428.

<sup>2</sup>NACE International, P.O. Box 218340, Houston, Texas 77218-8340.

## 3 Definitions

**3.1 bending strength ratio:** The ratio of the section modulus of a rotary shouldered box at the point in the box where the pin ends when made up divided by the section modulus of the rotary shouldered pin at the last engaged thread.

**3.2 bevel diameter:** The outer diameter of the contact face of the rotary shouldered connection.

**3.3 bit sub:** A sub, usually with 2 box connections, that is used to connect the bit to the drill string.

**3.4 box connection:** A threaded connection on Oil Country Tubular Goods (OCTG) that has internal (female) threads.

**3.5 calibration system:** A documented system of gauge calibration and control.

**3.6 Class 2:** An API service classification for used drill pipe and tubing work strings.

**3.7 cold working:** Plastic deformation of metal at a temperature low enough to insure or cause permanent strain.

**3.8 corrosion:** The alteration and degradation of material by its environment.

**3.9 critical rotary speed:** A rotary speed at which harmonic vibrations occur. These vibrations may cause fatigue failures, excessive wear, or bending.

**3.10 decarburization:** The loss of carbon from the surface of a ferrous alloy as a result of heating in a medium that reacts with the carbon at the surface.

**3.11 dedendum:** The distance between the pitch line and root of thread.

**3.12 dogleg:** A term applied to a sharp change of direction in a wellbore or ditch. Applied also to the permanent bending of wire rope or pipe.

**3.13 dogleg severity:** A measure of the amount of change in the inclination and/or direction of a borehole, usually expressed in degrees per 100 feet of course length.

**3.14 drift:** A drift is a gauge used to check minimum ID of loops, flowlines, nipples, tubing, casing, drill pipe, and drill collars.

**3.15 drill collar:** Thick-walled pipe or tube designed to provide stiffness and concentration of weight at the bit.

**3.16 drill pipe:** A length of tube, usually steel, to which special threaded connections called tool joints are attached.



**98 | 3.17 drill string element:** Drill pipe with tool joints attached.

**3.18 failure:** Improper performance of a device or equipment that prevents completion of its design function.

**3.19 fatigue:** The process of progressive localized permanent structural change occurring in a material subjected to conditions that produce fluctuating stresses and strains at some point or points and that may culminate in cracks or complete fracture after a sufficient number of fluctuations.

**3.20 fatigue failure:** A failure which originates as a result of repeated or fluctuating stresses having maximum values less than the tensile strength of the material.

**3.21 fatigue crack:** A crack resulting from fatigue. See fatigue.

**3.22 forging:** (1) Plastically deforming metal, usually hot, into desired shapes with compressive force, with or without dies. (2) A shaped metal part formed by the forging method.

**3.23 kelly:** The square or hexagonal shaped steel pipe connecting the swivel to the drill string. The kelly moves through the rotary table and transmits torque to the drill string.

**98 | 3.24 kelly saver sub:** A short substitute that is made up onto the bottom of the kelly to protect the pin end of the kelly from wear during make-up and break-out operations.

**3.25 last engaged thread:** The last thread on the pin engaged with the box or the box engaged with the pin.

**98 | 3.26 lower kelly valve:** An essentially full-opening valve installed immediately below the kelly, with outside diameter equal to the tool joint outside diameter. Valve can be closed to remove the kelly under pressure and can be stripped in the hole for snubbing operations.

**3.27 make-up shoulder:** The sealing shoulder on a rotary shouldered connection.

**98 | 3.28 minimum make-up torque:** The minimum make-up torque is the minimum amount of torque necessary to develop an arbitrarily derived tensile stress in the pin or compressive stress in the box. This arbitrarily derived stress level is perceived as being sufficient in most drilling conditions to prevent downhole make-up and to prevent shoulder separation from bending loads.

**3.29 minimum OD:** For tool joints on drill pipe with rotary shouldered connections, the minimum OD is the minimum box OD that will allow the connection to remain as strong as a specified percentage of the drill pipe tube in torsion.

**3.30 oil muds:** The term "oil-base drilling fluid" is applied to a special type drilling fluid where oil is the continuous phase and water the dispersed phase. Such fluids contain blown asphalt and usually 1 to 5 percent water emulsified into

the system with caustic soda or quick lime and an organic acid. Silicate, salt, and phosphate may also be present. Oil-base drilling fluids are differentiated from invert-emulsion drilling fluids (both water-in-oil emulsions) by the amounts of water used, method of controlling viscosity and thixotropic properties, wall-building materials, and fluid loss.

**3.31 pin end:** A threaded connection on Oil Country Tubular Goods (OCTG) that has external (male) threads.

**3.32 plain end:** Drill pipe, tubing, or casing without threads. The pipe ends may or may not be upset. **98**

**3.33 premium class:** An API service classification for used drill pipe and tubing work strings.

**3.34 quenched and tempered:** Quench hardening—Hardening a ferrous alloy by austenitizing and then cooling rapidly enough so that some or all of the austenite transforms to martensite. Tempering—Reheating a quenched-hardened or normalized ferrous alloy to a temperature below the transformation range and then cooling at any rate desired.

**3.35 range:** A length classification for API Oil Country Tubular Goods.

**3.36 rotary shouldered connection:** A connection used on drill string elements which has coarse, tapered threads and sealing shoulders. **00**

**3.37 shear strength:** The stress required to produce fracture in the plane of cross section, the conditions of loading being such that the directions of force and of resistance are parallel and opposite although their paths are offset a specified minimum amount. The maximum load divided by the original cross-sectional area of a section separated by shear.

**3.38 slip area:** The slip area is contained within a distance of 48 inches along the pipe body from the juncture of the tool joint OD and the elevator shoulder.

**3.39 stress-relief feature:** A modification performed on rotary shouldered connections which removes the unengaged threads of the pin or box. This process makes the joint more flexible and reduces the likelihood of fatigue cracking in this highly stressed area.

**3.40 swivel:** Device at the top of the drill stem which permits simultaneous circulation and rotation. **98**

**3.41 tensile strength:** The maximum tensile stress which a material is capable of sustaining. Tensile strength is calculated from the maximum load during a tension test carried to rupture and the original cross-sectional area of the specimen.

**3.42 test pressure:** A pressure above working pressure used to demonstrate structural integrity of a pressure vessel.

**98 3.43 thread form:** The form of thread is the thread profile in an axial plane for a length of one pitch.

**3.44 tolerance:** The amount of variation permitted.

**3.45 tool joint:** A heavy coupling element for drill pipe having coarse, tapered threads and sealing shoulders designed to sustain the weight of the drill stem, withstand the strain of repeated make-up and break-out, resist fatigue, resist additional make-up during drilling, and provide a leak-proof seal. The male section (pin) is attached to one end of a length of drill pipe and the female section (box) is attached to the other end. Tool joints may be welded to the drill pipe, screwed onto the pipe, or a combination of screwed on and welded.

**3.46 upper kelly cock:** A valve immediately above the kelly that can be closed to confine pressures inside the drill string.

**3.47 upset:** A pipe end with increased wall thickness. The outside diameter may be increased, or the inside diameter may be reduced, or both. Upsets are usually formed by hot forging the pipe end.

**98 3.48 working gauges:** Gauges used for gauging product threads.

**3.49 working pressure:** The pressure to which a particular piece of equipment is subjected during normal operations.

**3.50 working temperature:** The temperature to which a particular piece of equipment is subjected during normal operations.

## 4 Properties of Drill Pipe and Tool Joints

~~4.1—This section contains a series of tables (Tables 1 through 11) designed to present the dimensional, mechanical, and performance properties of new and used drill pipe. Tables are also included listing these properties for tool joints used with new and used drill pipe.~~

~~4.2—All drill pipe and tool joint properties tables are included in Section 4.~~

~~4.3—Values listed in drill pipe tables are based on accepted standards of the industry and calculated from formulas in Appendix A.~~

~~4.4—Recommended drift diameters for new drill string assemblies are shown in column 8 of Tables 8 and 9. Drift bars must be a minimum of four inches long. The drift bar must pass through the upset area but need not penetrate more than twelve inches beyond the base of the elevator shoulder.~~

~~4.5—The torsional strength of a tool joint is a function of several variables. These include the strength of the steel, connection size, thread form, lead, taper and coefficient of friction on mating surfaces, threads, or shoulders. The coefficient of friction~~

~~for the purposes of this recommended practice is assumed a constant; it has been demonstrated, however, that new tool joints and service temperature often affect the coefficient of friction of the tool joint system. While new tool joints typically exhibit a low coefficient of friction, service temperatures greater than 300°F can dramatically increase or decrease the coefficient of friction depending primarily on thread compound. The torque required to yield a rotary shouldered connection may be obtained from the equation in Section A.9.~~

~~4.6—The pin or box area, whichever controls, is the largest factor and is subject to the widest variation. The tool joint outside diameter (OD) and inside diameter (ID) largely determine the strength of the joint in torsion. The OD affects the box area and the ID affects the pin area. Choice of OD and ID determines the areas of the pin and box and establishes the theoretical torsional strength, assuming all other factors are constant.~~

~~4.7—The greatest reduction in theoretical torsional strength of a tool joint during its service life occurs with OD wear. At whatever point the tool joint box area becomes the smaller or controlling area, any further reduction in OD causes a direct reduction in torsional strength. If the box area controls when the tool joint is new, initial OD wear reduces torsional strength. If the pin controls when new, some OD wear may occur before the torsional strength is affected. Conversely, it is possible to increase torsional strength by making joints with oversize OD and reduced ID.~~

~~4.8—Minimum OD, box shoulder, and make-up torque values listed in Table 10 were determined using the following criteria:~~

~~4.8.1—Calculations for recommended tool joint make-up torque are based on the use of a thread compound containing 40 to 60 percent by weight of finely powdered metallic zinc applied to all threads and shoulders, and containing not more than 0.3 percent total active sulfur (reference the caution regarding the use of hazardous materials in Specification 7, Appendix G). Calculations are also based on a tensile stress of 60 percent of the minimum tensile yield for tool joints.~~

~~4.8.2—In calculation of torsional strengths of tool joints, both new and worn, the bevels of the tool joint shoulders are disregarded.~~

~~4.8.3—Premium Class Drill String is based on drill pipe having a minimum wall thickness of 80 percent.~~

~~4.8.4—Class 2 drill string allows drill pipe with a minimum wall thickness of 70 percent.~~

~~4.8.5—The tool joint to pipe torsional ratios that are used here (.:0.80) are recommendations only and it should be realized that other combinations of dimensions may be used. A given assembly that is suitable for certain service may be inadequate for some areas and overdesigned for others.~~

Table 1—New Drill Pipe Dimensional Data

(1)	(2)	(3)	(4)	(5)	(6)	(7)
Size OD in. <i>D</i>	Nominal Weight Threads and Couplings, lb/ft	Plain-End Weight <sup>1</sup> lb/ft	Wall Thickness in.	ID in. <i>d</i>	Section Area Body of Pipe <sup>2</sup> sq. in. <i>A</i>	Polar Sectional Modulus <sup>3</sup> cu. in. <i>Z</i>
2 <sup>3</sup> / <sub>8</sub>	4.85	4.43	.190	1.995	1.3042	1.321
	6.65	6.26	.280	1.815	1.8429	1.733
2 <sup>7</sup> / <sub>8</sub>	6.85	6.16	.217	2.441	1.8120	2.241
	10.40	9.72	.362	2.151	2.8579	3.204
3 <sup>1</sup> / <sub>2</sub>	9.50	8.81	.254	2.992	2.5902	3.923
	13.30	12.31	.368	2.764	3.6209	5.144
	15.50	14.63	.449	2.602	4.3037	5.847
4	11.85	10.46	.262	3.476	3.0767	5.400
	14.00	12.93	.330	3.340	3.8048	6.458
	15.70	14.69	.380	3.240	4.3216	7.157
4 <sup>1</sup> / <sub>2</sub>	13.75	12.24	.271	3.958	3.6004	7.184
	16.60	14.98	.337	3.826	4.4074	8.543
	20.00	18.69	.430	3.640	5.4981	10.232
	22.82	21.36	.500	3.500	6.2832	11.345
5	16.25	14.87	.296	4.408	4.3743	9.718
	19.50	17.93	.362	4.276	5.2746	11.415
	25.60	24.03	.500	4.000	7.0686	14.491
5 <sup>1</sup> / <sub>2</sub>	19.20	16.87	.304	4.892	4.9624	12.221
	21.90	19.81	.361	4.778	5.8282	14.062
	24.70	22.54	.415	4.670	6.6296	15.688
6 <sup>5</sup> / <sub>8</sub>	25.20	22.19	.330	5.965	6.5262	19.572
	27.70	24.22	.362	5.901	7.1227	21.156

<sup>1</sup>lb/ft = 3.3996 × *A* (col. 6)

<sup>2</sup>*A* = 0.7854 (*D*<sup>2</sup> − *d*<sup>2</sup>)

<sup>3</sup>*Z* = 0.19635 ( $\frac{D^4 - d^4}{D - d}$ )

**4.9** Many sizes and styles of connections are interchangeable with certain other sizes and styles of connections. These conditions differ only in name and in some cases thread form. If the thread forms are interchangeable, the connections are interchangeable.

These interchangeable connections are listed in Table 12.

**4.10** The curves of Figures 1 through 25 depict the theoretical torsional yield strength of a number of commonly used tool joint connections over a wide range of inside and outside diameters. The coefficient of friction on mating surfaces, threads and shoulders, is assumed to be 0.08 (See Section 3 of API RP 7A1, *Recommended Practice for Testing of Thread Compound for Rotary Shouldered Connections*). The make-up torque should be based on a tensile stress level of 60 percent of the minimum yield for tool joints.

**4.11** The curves may be used by taking the following steps:

**4.11.1** Select the appropriately titled curve for the size and type tool joint connection being studied.

**4.11.2** Extend a horizontal line from the OD under consideration to the curve and read the torsional strength representing the box.

**4.11.3** Extend a vertical line from the ID to the curve and read the torsional strength representing the pin.

**4.11.4** The smaller of the two torsional strengths thus obtained is the theoretical torsional strength of the tool joint.

**4.11.5** It is emphasized that the values obtained from the curves are theoretical values of torsional strength. Tool joints in the field, subject to many factors not included in determination of points for the curves, may vary from these values.

**4.11.6** The curves are most useful to show the relative torsional strengths of joints for variations in OD and ID, both new and after wear. In each case, the smaller value should be used.

(Text continued on page 33.)

Committee Review Only

Table 2—New Drill Pipe Torsional and Tensile Data

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Size OD in.	Threads and Couplings lb/ft	<sup>1</sup> Torsional Data				<sup>2</sup> Tensile Data Based on Minimum Values			
		Torsional Yield Strength, ft-lb				Load at the Minimum Yield Strength, lb			
		E75	X95	G105	S135	E75	X95	G105	S135
2 <sup>3</sup> / <sub>8</sub>	4.85	4763.	6033.	6668.	8574.	97817.	123902.	136944.	176071.
	6.65	6250.	7917.	8751.	11251.	138214.	175072.	193500.	248786.
2 <sup>7</sup> / <sub>8</sub>	6.85	8083.	10238.	11316.	14549.	135902.	172143.	190263.	244624.
	10.40	11554.	14635.	16176.	20798.	214344.	271503.	300082.	385820.
3 <sup>1</sup> / <sub>2</sub>	9.50	14146.	17918.	19805.	25463.	194264.	246068.	271970.	349676.
	13.30	18551.	23498.	25972.	33392.	271569.	343988.	380197.	488825.
	15.50	21086.	26708.	29520.	37954.	322775.	408848.	451885.	580995.
4	11.85	19474.	24668.	27264.	35054.	230755.	292290.	323057.	415360.
	14.00	23288.	29498.	32603.	41918.	285359.	361454.	399502.	513646.
	15.70	25810.	32692.	36134.	46458.	324118.	410550.	453765.	583413.
4 <sup>1</sup> / <sub>2</sub>	13.75	25907.	32816.	36270.	46633.	270034.	342043.	378047.	486061.
	16.60	30807.	39022.	43130.	55453.	330558.	418707.	462781.	595004.
	20.00	36901.	46741.	51661.	66421.	412358.	522320.	577301.	742244.
	22.82	40912.	51821.	57276.	73641.	471239.	596903.	659734.	848230.
5	16.25	35044.	44389.	49062.	63079.	328073.	415559.	459302.	590531.
	19.50	41167.	52144.	57633.	74100.	395595.	501087.	553833.	712070.
	25.60	52257.	66192.	73159.	94062.	530144.	671515.	742201.	954259.
5 <sup>1</sup> / <sub>2</sub>	19.20	44074.	55826.	61703.	79332.	372181.	471429.	521053.	669925.
	21.90	50710.	64233.	70994.	91278.	437116.	553681.	611963.	786809.
	24.70	56574.	71660.	79204.	101833.	497222.	629814.	696111.	894999.
6 <sup>3</sup> / <sub>8</sub>	25.20	70580.	89402.	98812.	127044.	489464.	619988.	685250.	881035.
	27.70	76295.	96640.	106813.	137330.	534199.	676651.	747877.	961556.

<sup>1</sup>Based on the shear strength equal to 57.7 percent of minimum yield strength and nominal wall thickness.—  
Minimum torsional yield strength calculated from Equation A.14.

<sup>2</sup>Minimum tensile strength calculated from Equation A.13.

Table 3—New Drill Pipe Collapse and Internal Pressure Data

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Nominal Weight		Collapse Pressure Based on				Internal Pressure at			
Size	Threads and	Minimum Values, psi				Minimum Yield Strength, psi			
OD	Couplings								
in.	lb/ft	E75	X95	G105	S135	E75	X95	G105	S135
2 <sup>3</sup> / <sub>8</sub>	4.85	11040.	13984.	15456.	19035.	10500.	13300.	14700.	18900.
	6.65	15599.	19759.	21839.	28079.	15474.	19600.	21663.	27853.
2 <sup>7</sup> / <sub>8</sub>	6.85	10467.	12940.	14020.	17034.	9907.	12548.	13869.	17832.
	10.40	16509.	20911.	23112.	29716.	16526.	20933.	23137.	29747.
3 <sup>1</sup> / <sub>2</sub>	9.50	10001.	12077.	13055.	15748.	9525.	12065.	13335.	17145.
	13.30	14113.	17877.	19758.	25404.	13800.	17480.	19320.	24840.
	15.50	16774.	21247.	23484.	30194.	16838.	21328.	23573.	30308.
4	11.85	8381.	9978.	10708.	12618.	8597.	10889.	12036.	15474.
	14.00	11354.	14382.	15896.	20141.	10828.	13716.	15159.	19491.
	15.70	12896.	16335.	18055.	23213.	12469.	15794.	17456.	22444.
4 <sup>1</sup> / <sub>2</sub>	13.75	7173.	8412.	8956.	10283.	7904.	10012.	11066.	14228.
	16.60	10392.	12765.	13825.	16773.	9829.	12450.	13761.	17693.
	20.00	12964.	16421.	18149.	23335.	12542.	15886.	17558.	22575.
	22.82	14815.	18765.	20741.	26667.	14583.	18472.	20417.	26250.
5	16.25	6938.	8108.	8616.	9831.	7770.	9842.	10878.	13986.
	19.50	9962.	12026.	12999.	15672.	9503.	12037.	13304.	17105.
	25.60	13500.	17100.	18900.	24300.	13125.	16625.	18375.	23625.
5 <sup>1</sup> / <sub>2</sub>	19.20	6039.	6942.	7313.	8093.	7255.	9189.	10156.	13058.
	21.90	8413.	10019.	10753.	12679.	8615.	10912.	12061.	15507.
	24.70	10464.	12933.	14013.	17023.	9903.	12544.	13865.	17826.
6 <sup>3</sup> / <sub>8</sub>	25.20	4788.	5321.	5500.	6036.	6538.	8281.	9153.	11768.
	27.70	5894.	6755.	7103.	7813.	7172.	9084.	10040.	12909.

Note: Calculations are based on formulas in API Bulletin 5C3.

Table 4—Used Drill Pipe Torsional and Tensile Data API Premium Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Size OD in.	New Weight Nominal W/ Threads and Couplings lb/ft	<sup>1,2</sup> Torsional Yield Strength— Based on Uniform Wear, ft-lb				<sup>2</sup> Tensile Data Based on Uniform Wear Load at Minimum Yield Strength, lb			
		E75	X95	G105	S135	E75	X95	G105	S135
2 <sup>7</sup> / <sub>8</sub>	4.85	3725.	4719.	5215.	6705.	76893.	97398.	107650.	138407.
	6.65	4811.	6093.	6735.	8659.	107616.	136313.	150662.	193709.
2 <sup>7</sup> / <sub>8</sub>	6.85	6332.	8020.	8865.	11397.	106946.	135465.	149725.	192503.
	10.40	8858.	11220.	12401.	15945.	166535.	210945.	233149.	299764.
3 <sup>1</sup> / <sub>2</sub>	9.50	11094.	14052.	15531.	19968.	152979.	193774.	214171.	275363.
	13.30	14361.	18191.	20106.	25850.	212150.	268723.	297010.	381870.
	15.50	16146.	20452.	22605.	29063.	250620.	317452.	350868.	451115.
4	11.85	15310.	19392.	21433.	27557.	182016.	230554.	254823.	327630.
	14.00	18196.	23048.	25474.	32752.	224182.	283963.	313854.	403527.
	15.70	20067.	25418.	28094.	36120.	253851.	321544.	355391.	456931.
4 <sup>1</sup> / <sub>2</sub>	13.75	20403.	25844.	28564.	36725.	213258.	270127.	298561.	383864.
	16.60	24139.	30576.	33795.	43450.	260165.	329542.	364231.	468297.
	20.00	28683.	36332.	40157.	51630.	322916.	409026.	452082.	581248.
	22.82	31587.	40010.	44222.	56856.	367566.	465584.	514593.	661620.
5	16.25	27607.	34969.	38650.	49693.	259155.	328263.	362817.	466479.
	19.50	32285.	40895.	45199.	58113.	311535.	394612.	436150.	560764.
	25.60	40544.	51356.	56762.	72979.	414690.	525274.	580566.	746443.
5 <sup>1</sup> / <sub>2</sub>	19.20	34764.	44035.	48670.	62575.	294260.	372730.	411965.	529669.
	21.90	39863.	50494.	55809.	71754.	344780.	436721.	482692.	620604.
	24.70	44320.	56139.	62048.	79776.	391285.	495627.	547799.	704313.
6 <sup>5</sup> / <sub>8</sub>	25.20	55766.	71522.	79050.	101635.	387466.	490790.	542452.	697438.
	27.70	60192.	77312.	85450.	109864.	422419.	535064.	591387.	760354.

<sup>1</sup>Based on the shear strength equal to 57.7 percent of minimum yield strength.<sup>2</sup>Torsional data based on 20 percent uniform wear on outside diameter and tensile data based on 20 percent uniform wear on outside diameter.

Table 5—Used Drill Pipe Collapse and Internal Pressure Data API Premium Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Size	Nominal Weight Threads and Couplings	<sup>1</sup> Collapse Pressure Based on Minimum Values, psi				<sup>2</sup> Minimum Internal Yield Pressure at Minimum Yield Strength, psi			
OD in.	lb/ft	E75	X95	G105	S135	E75	X95	G105	S135
2 <sup>3</sup> / <sub>8</sub>	4.85	8522.	10161.	10912.	12891.	9600.	12160.	13440.	17280.
	6.65	13378.	16945.	18729.	24080.	14147.	17920.	19806.	25465.
2 <sup>7</sup> / <sub>8</sub>	6.85	7640.	9017.	9633.	11186.	9057.	11473.	12680.	16303.
	10.40	14223.	18016.	19912.	25602.	15110.	19139.	21153.	27197.
3 <sup>1</sup> / <sub>2</sub>	9.50	7074.	8284.	8813.	10093.	8709.	11031.	12192.	15675.
	13.30	12015.	15218.	16820.	21626.	12617.	15982.	17664.	22711.
	15.50	14472.	18331.	20260.	26049.	15394.	19499.	21552.	27710.
4	11.85	5704.	6508.	6827.	7445.	7860.	9956.	11004.	14148.
	14.00	9012.	10795.	11622.	13836.	9900.	12540.	13860.	17820.
	15.70	10914.	13825.	15190.	18593.	11400.	14440.	15960.	20520.
4 <sup>1</sup> / <sub>2</sub>	13.75	4686.	5190.	5352.	5908.	7227.	9154.	10117.	13008.
	16.60	7525.	8868.	9467.	10964.	8987.	11383.	12581.	16176.
	20.00	10975.	13901.	15350.	18806.	11467.	14524.	16053.	20640.
	22.82	12655.	16030.	17718.	22780.	13333.	16889.	18667.	24000.
5	16.25	4490.	4935.	5067.	5661.	7104.	8998.	9946.	12787.
	19.50	7041.	8241.	8765.	10029.	8688.	11005.	12163.	15638.
	25.60	11458.	14514.	16042.	20510.	12000.	15200.	16800.	21600.
5 <sup>1</sup> / <sub>2</sub>	19.20	3736.	4130.	4336.	4714.	6633.	8401.	9286.	11939.
	21.90	5730.	6542.	6865.	7496.	7876.	9977.	11027.	14177.
	24.70	7635.	9011.	9626.	11177.	9055.	11469.	12676.	16298.
6 <sup>3</sup> / <sub>8</sub>	25.20	2931.	3252.	3353.	3429.	5977.	7571.	8368.	10759.
	27.70	3615.	4029.	4222.	4562.	6557.	8306.	9180.	11803.

Note: Calculations for Premium Class drill pipe are based on formulas in API Bulletin 5C3.

<sup>1</sup>Data are based on minimum wall of 80 percent nominal wall. Collapse pressures are based on uniform OD wear. Internal pressures are based on uniform wear and nominal OD.



Table 6—Used Drill Pipe Torsional and Tensile Data API Class 2

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Size OD in.	New Weight Nominal W/ Threads and Couplings lb/ft	<sup>1,2</sup> Torsional Yield Strength— Based on Uniform Wear, ft-lb				<sup>2</sup> Tensile Data Based on Uniform Wear Load at Minimum Yield Strength, lb			
		E75	X95	G105	S135	E75	X95	G105	S135
2 <sup>7</sup> / <sub>8</sub>	4.85	3224.	4083.	4513.	5802.	66686.	84469.	93360.	120035.
	6.65	4130.	5232.	5782.	7434.	92871.	117636.	130019.	167167.
2 <sup>7</sup> / <sub>8</sub>	6.85	5484.	6946.	7677.	9871.	92801.	117549.	129922.	167043.
	10.40	7591.	9615.	10627.	13663.	143557.	181839.	200980.	258403.
3 <sup>1</sup> / <sub>2</sub>	9.50	9612.	12176.	13457.	17302.	132793.	168204.	185910.	239027.
	13.30	12365.	15663.	17312.	22258.	183398.	232304.	256757.	330116.
	15.50	13828.	17515.	19359.	24890.	215967.	273558.	302354.	388741.
4	11.85	13281.	16823.	18594.	23907.	158132.	200301.	221385.	284638.
	14.00	15738.	19935.	22034.	28329.	194363.	246193.	272108.	349852.
	15.70	17315.	21932.	24241.	31166.	219738.	278335.	307633.	395528.
4 <sup>1</sup> / <sub>2</sub>	13.75	17715.	22439.	24801.	31887.	185389.	234827.	259545.	333701.
	16.60	20908.	26483.	29271.	37634.	225771.	285977.	316080.	406388.
	20.00	24747.	31346.	34645.	44544.	279502.	354035.	391302.	503103.
	22.82	27161.	34404.	38026.	48890.	317497.	402163.	444496.	571495.
5	16.25	23974.	30368.	33564.	43154.	225316.	285400.	315442.	405568.
	19.50	27976.	35436.	39166.	50356.	270432.	342548.	378605.	486778.
	25.60	34947.	44267.	48926.	62905.	358731.	454392.	502223.	645715.
5 <sup>1</sup> / <sub>2</sub>	19.20	30208.	38263.	42291.	54374.	255954.	324208.	358335.	460717.
	21.90	34582.	43804.	48414.	62247.	299533.	379409.	419346.	539160.
	24.70	38383.	48619.	53737.	69090.	339533.	430076.	475347.	611160.
6 <sup>5</sup> / <sub>8</sub>	25.20	48497.	61430.	67896.	87295.	337236.	427166.	472131.	607026.
	27.70	52308.	66257.	73231.	94155.	367455.	465443.	514437.	661419.

<sup>1</sup>Based on the shear strength equal to 57.7 percent of minimum yield strength.<sup>2</sup>Torsional data based on 30 percent uniform wear on outside diameter and tensile data based on 30 percent uniform wear on outside diameter.

Table 7—Used Drill Pipe Collapse and Internal Pressure Data API Class 2

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Size OD in.	Nominal Weight Threads and Couplings lb/ft	<sup>1</sup> Collapse Pressure Based on Minimum Values, psi				<sup>2</sup> Minimum Internal Yield Pressure at Minimum Yield Strength, psi			
		E75	X95	G105	S135	E75	X95	G105	S135
2 <sup>3</sup> / <sub>8</sub>	4.85	6852.	7996.	8491.	9664.	8400.	10640.	11760.	15120.
	6.65	12138.	15375.	16993.	21849.	12379.	15680.	17331.	22282.
2 <sup>7</sup> / <sub>8</sub>	6.85	6055.	6963.	7335.	8123.	7925.	10039.	11095.	14265.
	10.40	12938.	16388.	18113.	23288.	13221.	16746.	18509.	23798.
3 <sup>1</sup> / <sub>2</sub>	9.50	5544.	6301.	6596.	7137.	7620.	9652.	10668.	13716.
	13.30	10858.	13753.	15042.	18396.	11040.	13984.	15456.	19872.
	15.50	13174.	16686.	18443.	23712.	13470.	17062.	18858.	24246.
4	11.85	4311.	4702.	4876.	5436.	6878.	8712.	9629.	12380.
	14.00	7295.	8570.	9134.	10520.	8663.	10973.	12128.	15593.
	15.70	9531.	11468.	12374.	14840.	9975.	12635.	13965.	17955.
4 <sup>1</sup> / <sub>2</sub>	13.75	3397.	3845.	4016.	4287.	6323.	8010.	8853.	11382.
	16.60	5951.	6828.	7185.	7923.	7863.	9960.	11009.	14154.
	20.00	9631.	11598.	12520.	15033.	10033.	12709.	14047.	18060.
	22.82	11458.	14514.	16042.	20510.	11667.	14779.	16333.	21000.
5	16.25	3275.	3696.	3850.	4065.	6216.	7874.	8702.	11189.
	19.50	5514.	6262.	6552.	7079.	7602.	9629.	10643.	13684.
	25.60	10338.	12640.	13685.	16587.	10500.	13300.	14700.	18900.
5 <sup>1</sup> / <sub>2</sub>	19.20	2835.	3128.	3215.	3265.	5804.	7351.	8125.	10447.
	21.90	4334.	4733.	4899.	5465.	6892.	8730.	9649.	12405.
	24.70	6050.	6957.	7329.	8115.	7923.	10035.	11092.	14261.
6 <sup>3</sup> / <sub>8</sub>	25.20	2227.	2343.	2346.	2346.	5230.	6625.	7322.	9414.
	27.70	2765.	3037.	3113.	3148.	5737.	7267.	8032.	10327.

Note: Calculations for Class 2 drill pipe are based on formulas in API Bulletin 5C3.

<sup>1</sup>Data are based on minimum wall of 70 percent nominal wall. Collapse pressures are based on uniform OD wear. Internal pressures are based on uniform wear and nominal OD.

**Table 8—Mechanical Properties of New Tool Joints and New Grade E75 Drill Pipe**

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	
Drill Pipe Data								Mechanical Properties				
Nominal Size in.	Nominal Weight lb/ft	Approx. Weight <sup>†</sup> lb/ft	Type Upset	Tool Joint Data				Tensile Yield, lb		Torsional Yield, ft-lb		
				Conn.	OD in.	ID in.	Drift Diameter <sup>2</sup> in.	Pipe <sup>3</sup>	Tool Joint <sup>4</sup>	Pipe <sup>5</sup>	Tool Joint <sup>6</sup>	
2 <sup>7</sup> / <sub>8</sub>	4.85	5.26	EU	NC26(IF)	3 <sup>3</sup> / <sub>8</sub>	1 <sup>3</sup> / <sub>4</sub>	1.625	97817.	313681.	4763.	6875.b	98
		4.95	EU	OH	3 <sup>3</sup> / <sub>8</sub>	2	1.807	97817.	206416.	4763.	4526.p	
		5.05	EU	SLH90	3 <sup>3</sup> / <sub>4</sub>	2	1.850	97817.	202670.	4763.	5075.p	00
		5.15	EU	WO	3 <sup>3</sup> / <sub>8</sub>	2	1.807	97817.	195677.	4763.	4235.p	
	6.65	6.99	EU	NC26(IF)	3 <sup>3</sup> / <sub>8</sub>	1 <sup>3</sup> / <sub>4</sub>	1.625	138214.	313681.	6250.	6875.b	98
		6.89	EU	OH	3 <sup>3</sup> / <sub>4</sub>	1 <sup>3</sup> / <sub>4</sub>	1.625	138214.	294620.	6250.	6305.b	
		6.71	IU	PAC	2 <sup>7</sup> / <sub>8</sub>	1 <sup>3</sup> / <sub>8</sub>	1.250	138214.	238504.	6250.	4672.P	
		6.78	EU	SLH90	3 <sup>3</sup> / <sub>4</sub>	2	1.670	138214.	202850.	6250.	5075.p	
	6.85	7.50	EU	NC31(IF)	4 <sup>1</sup> / <sub>8</sub>	2 <sup>1</sup> / <sub>8</sub>	2.000	135902.	447130.	8083.	11790.p	
		6.93	EU	OH	3 <sup>3</sup> / <sub>4</sub>	2 <sup>7</sup> / <sub>16</sub>	2.253	135902.	223937.	8083.	5464.P	
		7.05	EU	SLH90	3 <sup>3</sup> / <sub>8</sub>	2 <sup>7</sup> / <sub>16</sub>	2.296	135902.	260783.	8083.	7513.p	00
		7.31	EU	WO	4 <sup>1</sup> / <sub>8</sub>	2 <sup>7</sup> / <sub>16</sub>	2.253	135902.	277553.	8083.	7015.p	
		10.40	EU	NC31(IF)	4 <sup>1</sup> / <sub>8</sub>	2 <sup>1</sup> / <sub>8</sub>	1.963	214344.	447130.	11554.	11790.p	
		10.59	EU	OH	3 <sup>3</sup> / <sub>8</sub>	2 <sup>5</sup> / <sub>32</sub>	1.963	214344.	345566.	11554.	8659.P	
		10.27	IU	PAC	3 <sup>3</sup> / <sub>8</sub>	1 <sup>1</sup> / <sub>2</sub>	1.375	214344.	272938.	11554.	5706.P	
		10.59	EU	SLH90	3 <sup>3</sup> / <sub>8</sub>	2 <sup>5</sup> / <sub>32</sub>	2.006	214344.	382765.	11554.	11227.p	
		11.19	IU	XH	4 <sup>1</sup> / <sub>4</sub>	1 <sup>7</sup> / <sub>8</sub>	1.750	214344.	505054.	11554.	13088.p	
		10.35	IU	NC26(SH)	3 <sup>3</sup> / <sub>8</sub>	1 <sup>3</sup> / <sub>4</sub>	1.625	214344.	313681.	11554.	6875.B	98
3 <sup>1</sup> / <sub>2</sub>	9.50	10.58	EU	NC38(IF)	4 <sup>3</sup> / <sub>4</sub>	2 <sup>11</sup> / <sub>16</sub>	2.563	194264.	587308.	14146.	18071.p	
		9.84	EU	OH	4 <sup>1</sup> / <sub>2</sub>	3	2.804	194264.	392071.	14146.	11803.p	
		9.99	EU	SLH90	4 <sup>5</sup> / <sub>8</sub>	3	2.847	194264.	366705.	14146.	12458.p	
		10.14	EU	WO	4 <sup>3</sup> / <sub>4</sub>	3	2.804	194264.	419797.	14146.	12723.p	
3 <sup>1</sup> / <sub>2</sub>	13.30	14.37	EU	H90	5 <sup>1</sup> / <sub>4</sub>	2 <sup>3</sup> / <sub>4</sub>	2.619	271569.	664050.	18551.	23443.p	
		13.93	EU	NC38(IF)	4 <sup>3</sup> / <sub>4</sub>	2 <sup>11</sup> / <sub>16</sub>	2.457	271569.	587308.	18551.	18071.p	
		13.75	EU	OH	4 <sup>3</sup> / <sub>4</sub>	2 <sup>11</sup> / <sub>16</sub>	2.414	271569.	559582.	18551.	17167.p	
		13.40	IU	NC31(SH)	4 <sup>1</sup> / <sub>8</sub>	2 <sup>1</sup> / <sub>8</sub>	2.000	271569.	447130.	18551.	11790.P	00
		13.91	EU	XH	4 <sup>3</sup> / <sub>4</sub>	2 <sup>7</sup> / <sub>16</sub>	2.313	271569.	570939.	18551.	16867.p	
		15.50	EU	NC38(IF)	5	2 <sup>9</sup> / <sub>16</sub>	2.414	322775.	649158.	21086.	20095.p	
		11.85	IU	H90	5 <sup>1</sup> / <sub>2</sub>	2 <sup>11</sup> / <sub>16</sub>	2.688	230755.	913708.	19474.	35308.p	
		13.52	EU	NC46(IF)	6	3 <sup>1</sup> / <sub>4</sub>	3.125	230755.	901164.	19474.	33228.p	
4	12.10	12.10	EU	OH	5 <sup>1</sup> / <sub>4</sub>	3 <sup>15</sup> / <sub>32</sub>	3.287	230755.	621357.	19474.	21903.p	
		12.91	EU	WO	5 <sup>3</sup> / <sub>4</sub>	3 <sup>7</sup> / <sub>16</sub>	3.313	230755.	782987.	19474.	28643.p	
		14.00	IU	NC40(FH)	5 <sup>1</sup> / <sub>4</sub>	2 <sup>11</sup> / <sub>16</sub>	2.688	285359.	711611.	23288.	23279.p	
		15.43	IU	H90	5 <sup>1</sup> / <sub>2</sub>	2 <sup>11</sup> / <sub>16</sub>	2.688	285359.	913708.	23288.	35308.p	
		15.85	EU	NC46(IF)	6	3 <sup>1</sup> / <sub>4</sub>	3.125	285359.	901164.	23288.	33228.p	

(Table continued on next page.)

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**Table 8—Mechanical Properties of New Tool Joints and New Grade E75 Drill Pipe (Continued)**

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Drill Pipe Data								Mechanical Properties			
								Tensile Yield, lb		Torsional Yield, ft-lb	
Nominal- Size in.	Nominal- Weight lb/ft	Approx- Weight <sup>†</sup> lb/ft	Type Upset	Conn.	OD in.	ID in.	Drift- Diameter <sup>‡</sup> in.	Pipe <sup>‡</sup>	Tool Joint <sup>‡</sup>	Pipe <sup>§</sup>	Tool Joint <sup>§</sup>
4	14.00	15.02	EU	OH	5 <sup>1</sup> / <sub>2</sub>	3 <sup>3</sup> / <sub>4</sub>	3.125	285359.	759875.	23288.	27060.p
		14.35	IU	SH	4 <sup>5</sup> / <sub>8</sub>	2 <sup>9</sup> / <sub>16</sub>	2.438	285359.	512035.	23288.	15026.P
	15.70	16.80	IU	NC40(FH)	5 <sup>1</sup> / <sub>4</sub>	2 <sup>11</sup> / <sub>16</sub>	2.563	324118.	776406.	25810.	25531.p
		17.09	IU	H90	5 <sup>1</sup> / <sub>2</sub>	2 <sup>13</sup> / <sub>16</sub>	2.688	324118.	913708.	25810.	35308.p
		17.54	EU	NC46(IF)	6	3 <sup>1</sup> / <sub>4</sub>	3.095	324118.	901164.	25810.	33228.p
4 <sup>1</sup> / <sub>2</sub>	13.75	15.23	IU	H90	6	3 <sup>1</sup> / <sub>4</sub>	3.125	270034.	938403.	25907.	38544.p
		15.36	EU	NC50(IF)	6 <sup>5</sup> / <sub>8</sub>	3 <sup>3</sup> / <sub>4</sub>	3.625	270034.	939096.	25907.	37269.p
		14.04	EU	OH	5 <sup>3</sup> / <sub>4</sub>	3 <sup>31</sup> / <sub>32</sub>	3.770	270034.	554844.	25907.	20678.p
		14.77	EU	WO	6 <sup>1</sup> / <sub>8</sub>	3 <sup>7</sup> / <sub>8</sub>	3.750	270034.	848619.	25907.	33492.p
	16.60	18.14	IEU	FH	6	3	2.875	330558.	976156.	30807.	34367.p
		17.92	IEU	H90	6	3 <sup>1</sup> / <sub>4</sub>	3.125	330558.	938403.	30807.	38544.p
		17.95	EU	NC50(IF)	6 <sup>5</sup> / <sub>8</sub>	3 <sup>3</sup> / <sub>4</sub>	3.625	330558.	939096.	30807.	37269.p
	17.07	17.07	EU	OH	5 <sup>7</sup> / <sub>8</sub>	3 <sup>3</sup> / <sub>4</sub>	3.625	330558.	713979.	30807.	26936.p
		16.79	IEU	NC38(SH)	5	2 <sup>11</sup> / <sub>16</sub>	2.563	330558.	587308.	30807.	18071.P
		18.37	IEU	NC46(XH)	6 <sup>1</sup> / <sub>4</sub>	3 <sup>1</sup> / <sub>4</sub>	3.125	330558.	901164.	30807.	33228.p
	20.00	21.64	IEU	FH	6	3	2.875	412358.	976156.	36901.	34367.p
		21.64	IEU	H90	6	3	2.875	412358.	1085665.	36901.	44948.p
		21.59	EU	NC50(IF)	6 <sup>5</sup> / <sub>8</sub>	3 <sup>5</sup> / <sub>8</sub>	3.452	412358.	1025980.	36901.	40915.p
		22.09	IEU	NC46(XH)	6 <sup>1</sup> / <sub>4</sub>	3	2.875	412358.	1048426.	36901.	38998.p
	22.82	24.11	EU	NC50(IF)	6 <sup>5</sup> / <sub>8</sub>	3 <sup>5</sup> / <sub>8</sub>	3.452	471239.	1025980.	40912.	40915.p
		24.56	IEU	NC46(XH)	6 <sup>1</sup> / <sub>4</sub>	3	2.875	471239.	1048426.	40912.	38998.p
5	19.50	22.28	IEU	5 <sup>1</sup> / <sub>2</sub> -FH	7	3 <sup>3</sup> / <sub>4</sub>	3.625	395595.	1448407.	41167.	62903.b
		20.85	IEU	NC50(XH)	6 <sup>5</sup> / <sub>8</sub>	3 <sup>3</sup> / <sub>4</sub>	3.625	395595.	939095.	41167.	37269.p
	25.60	28.27	IEU	5 <sup>1</sup> / <sub>2</sub> -FH	7	3 <sup>1</sup> / <sub>2</sub>	3.375	530144.	1619231.	52257.	62903.b
		26.85	IEU	NC50(XH)	6 <sup>5</sup> / <sub>8</sub>	3 <sup>1</sup> / <sub>2</sub>	3.375	530144.	1109920.	52257.	44456.p
5 <sup>1</sup> / <sub>2</sub>	21.90	23.78	IEU	FH	7	4	3.875	437116.	1265802.	50710.	55687.p
	24.70	26.30	IEU	FH	7	4	3.875	497222.	1265802.	56574.	55687.p
6 <sup>5</sup> / <sub>8</sub>	25.20	27.28	IEU	FH	8	5	4.875	489464.	1447697.	70580.	73224.p
6 <sup>5</sup> / <sub>8</sub>	27.70	29.06	IEU	FH	8	5	4.875	534198.	1447697.	76295.	73224.p

<sup>1</sup>Tool Joint plus drill pipe, for Range 2 steel pipe (See Appendix A for method of calculation).

<sup>2</sup>See Section 4.4.

<sup>3</sup>The tensile yield strength of Grade E drill pipe is based on 75,000 psi minimum yield strength.

**03** <sup>4</sup>The tensile strength of the tool joint pin is based on 120,000 psi minimum yield and the cross sectional area at the root of the thread <sup>3</sup>/<sub>4</sub> inch from the shoulder.

<sup>5</sup>The torsional yield strength is based on a shear strength of 57.7 percent of the minimum yield strength.

**98** <sup>6</sup>p = pin limited yield; b = box limited yield; P or B indicates that tool joint could not meet 80 percent of tube torsion yield.

Table 9—Mechanical Properties of New Tool Joints and New High Strength Drill Pipe

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Drill Pipe Data			Tool Joint Data			Mechanical Properties					
Nominal Size in.	Nominal Weight lb/ft	Approx. Weight <sup>1</sup> lb/ft	Type-Upset	Conn.	OD in.	ID in.	Drift Diameter <sup>2</sup> in.	Tensile Yield, lb		Torsional Yield, ft-lb	
								Pipe <sup>3</sup>	Tool Joint <sup>4</sup>	Pipe <sup>3</sup>	Tool Joint <sup>5</sup>
2 <sup>3</sup> / <sub>8</sub>	6.65	7.11	EU-X95	NC26(IF)	3 <sup>3</sup> / <sub>8</sub>	1 <sup>3</sup> / <sub>4</sub>	1.625	175072.	313681.	7917.	6875.b
		6.99	EU-X95	SLH90	3 <sup>1</sup> / <sub>4</sub>	1 <sup>13</sup> / <sub>16</sub>	1.670	175072.	270223.	7917.	6862.p
	6.65	7.11	EU-G105	NC26(IF)	3 <sup>3</sup> / <sub>8</sub>	1 <sup>3</sup> / <sub>4</sub>	1.625	193500.	313681.	8751.	6875.b
		6.99	EU-G105	SLH90	3 <sup>1</sup> / <sub>4</sub>	1 <sup>13</sup> / <sub>16</sub>	1.670	193500.	270223.	8751.	6862.P
2 <sup>7</sup> / <sub>8</sub>	10.40	11.09	EU-X95	NC31(IF)	4 <sup>1</sup> / <sub>8</sub>	2	1.875	271503.	495726.	14635.	13158.p
		10.95	EU-X95	SLH90	4	2	1.875	271503.	443971.	14635.	13119.p
	10.40	11.09	EU-G105	NC31(IF)	4 <sup>1</sup> / <sub>8</sub>	2	1.875	300082.	495726.	16176.	13158.p
		10.95	EU-G105	SLH90	4	2	1.875	300082.	443971.	16176.	13119.p
	10.40	11.55	EU-S135	NC31(IF)	4 <sup>3</sup> / <sub>8</sub>	1 <sup>5</sup> / <sub>8</sub>	1.500	385820.	623844.	20798.	16809.p
		11.26	EU-S135	SLH90	4 <sup>1</sup> / <sub>8</sub>	1 <sup>5</sup> / <sub>8</sub>	1.500	385820.	572089.	20798.	17130.p
3 <sup>1</sup> / <sub>2</sub>	13.30	14.60	EU-X95	H90	5 <sup>1</sup> / <sub>4</sub>	2 <sup>3</sup> / <sub>4</sub>	2.619	343988.	664050.	23498.	23443.p
		14.62	EU-X95	NC38(IF)	5	2 <sup>9</sup> / <sub>16</sub>	2.438	343988.	649158.	23498.	20095.p
		14.06	EU-X95	SLH90	4 <sup>3</sup> / <sub>4</sub>	2 <sup>9</sup> / <sub>16</sub>	2.438	343988.	596066.	23498.	20709.p
	13.30	14.71	EU-G105	NC38(IF)	5	2 <sup>7</sup> / <sub>16</sub>	2.313	380197.	708063.	25972.	22035.p
		14.06	EU-G105	SLH90	4 <sup>3</sup> / <sub>4</sub>	2 <sup>9</sup> / <sub>16</sub>	2.438	380197.	596066.	25972.	20709.p
	13.30	14.92	EU-S135	NC38(IF)	5	2 <sup>1</sup> / <sub>8</sub>	2.000	488825.	842440.	33392.	26503.P
		14.65	EU-S135	SLH90	5	2 <sup>1</sup> / <sub>8</sub>	2.000	488825.	789348.	33392.	27809.p
		15.13	EU-S135	NC40(4FH)	5 <sup>3</sup> / <sub>8</sub>	2 <sup>7</sup> / <sub>16</sub>	2.313	488825.	897161.	33392.	29764.p
	15.50	16.82	EU-X95	NC38(IF)	5	2 <sup>7</sup> / <sub>16</sub>	2.313	408848.	708063.	26708.	22035.p
		17.03	EU-G105	NC38(IF)	5	2 <sup>1</sup> / <sub>8</sub>	2.000	451885.	842440.	29520.	26503.p
	15.50	16.97	EU-G105	NC40(4FH)	5 <sup>1</sup> / <sub>4</sub>	2 <sup>9</sup> / <sub>16</sub>	2.438	451885.	838257.	29520.	27693.p
		17.57	EU-S135	NC40(4FH)	5 <sup>1</sup> / <sub>2</sub>	2 <sup>1</sup> / <sub>4</sub>	2.125	580995.	979996.	37954.	32693.p
4	14.00	15.34	IU-X95	NC40(FH)	5 <sup>1</sup> / <sub>4</sub>	2 <sup>11</sup> / <sub>16</sub>	2.563	361454.	776406.	29498.	25531.p
		15.63	IU-X95	H90	5 <sup>1</sup> / <sub>2</sub>	2 <sup>13</sup> / <sub>16</sub>	2.688	361454.	913708.	29498.	35308.p
		16.19	EU-X95	NC46(IF)	6	3 <sup>1</sup> / <sub>4</sub>	3.125	361454.	901164.	29498.	33228.p
	14.00	15.91	IU-G105	NC40(FH)	5 <sup>1</sup> / <sub>2</sub>	2 <sup>7</sup> / <sub>16</sub>	2.313	399502.	897161.	32603.	29764.p
		15.63	IU-G105	H90	5 <sup>1</sup> / <sub>2</sub>	2 <sup>11</sup> / <sub>16</sub>	2.688	399502.	913708.	32603.	35308.p
		16.19	EU-G105	NC46(IF)	6	3 <sup>1</sup> / <sub>4</sub>	3.125	399502.	901164.	32603.	33228.p
	14.00	16.19	IU-S135	NC40(FH)	5 <sup>1</sup> / <sub>2</sub>	2	1.875	513646.	1080135.	41918.	36262.p
		15.63	IU-S135	H90	5 <sup>1</sup> / <sub>2</sub>	2 <sup>11</sup> / <sub>16</sub>	2.688	513646.	913708.	41918.	35308.p
		16.42	EU-S135	NC46(IF)	6	3	2.875	513646.	1048426.	41918.	38998.p
	15.70	17.52	IU-X95	NC40(FH)	5 <sup>1</sup> / <sub>2</sub>	2 <sup>7</sup> / <sub>16</sub>	2.313	410550.	897161.	32692.	29764.p
		17.23	IU-X95	H90	5 <sup>1</sup> / <sub>2</sub>	2 <sup>11</sup> / <sub>16</sub>	2.688	410550.	913708.	32692.	35308.p
		17.80	EU-X95	NC46(IF)	6	3 <sup>1</sup> / <sub>4</sub>	3.125	410550.	901164.	32692.	33228.p
	15.70	17.52	IU-G105	NC40(FH)	5 <sup>1</sup> / <sub>2</sub>	2 <sup>7</sup> / <sub>16</sub>	2.313	453765.	897161.	36134.	29764.p
		17.23	IU-G105	H90	5 <sup>1</sup> / <sub>2</sub>	2 <sup>11</sup> / <sub>16</sub>	2.688	453765.	913708.	36134.	35308.p
		17.80	EU-G105	NC46(IF)	6	3 <sup>1</sup> / <sub>4</sub>	3.125	453765.	901164.	36134.	33228.p
	15.70	18.02	EU-S135	NC46(IF)	6	3	2.875	583413.	1048426.	46458.	38998.p
4 <sup>1</sup> / <sub>2</sub>	16.60	18.33	IEU-X95	FH	6	3	2.875	418707.	976156.	39022.	34367.p
		18.11	IEU-X95	H90	6	3 <sup>1</sup> / <sub>4</sub>	3.125	418707.	938403.	39022.	38544.p
		18.36	EU-X95	NC50(IF)	6 <sup>5</sup> / <sub>8</sub>	3 <sup>3</sup> / <sub>4</sub>	3.625	418707.	939095.	39022.	37269.p
		18.79	IEU-X95	NC46(XH)	6 <sup>1</sup> / <sub>4</sub>	3	2.875	418707.	1048426.	39022.	38998.p
4 <sup>7</sup> / <sub>2</sub>	16.60	18.33	IEU-G105	FH	6	3	2.625	462781.	976156.	43130.	34367.p
		18.33	IEU-G105	H90	6	3	3.125	462781.	1085665.	43130.	44948.p
		18.36	EU-G105	NC50(IF)	6 <sup>5</sup> / <sub>8</sub>	3 <sup>3</sup> / <sub>4</sub>	3.625	462781.	939095.	43130.	37269.p
		18.79	IEU-G105	NC46(XH)	6 <sup>1</sup> / <sub>4</sub>	3	2.875	462781.	1048426.	43130.	38998.p
		16.60	IEU-S135	FH	6 <sup>1</sup> / <sub>4</sub>	2 <sup>1</sup> / <sub>2</sub>	2.375	595004.	1235337.	55453.	44214.p

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(Table continued on next page.)

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Table 9—Mechanical Properties of New Tool Joints and New High-Strength Drill Pipe (Continued)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Drill Pipe Data			Tool Joint Data			Mechanical Properties					
Nominal Size in.	Nominal Weight lb/ft	Approx. Weight <sup>1</sup> lb/ft	Type-Upset	Conn.	OD in.	ID in.	Drift Diameter <sup>2</sup> in.	Tensile Yield, lb		Torsional Yield, ft-lb	
								Pipe <sup>3</sup>	Tool Joint <sup>4</sup>	Pipe <sup>3</sup>	Tool Joint <sup>5</sup>
4½	16.60	18.33	IEU-S135	H90	6	3	2.875	595004.	1085665.	55453.	44948.p
		18.62	EU-S135	NC50(IF)	6⅝	3½	3.375	595004.	1109920.	55453.	44456.p
		19.00	IEU-S135	NC46(XH)	6¾	2¾	2.625	595004.	1183908.	55453.	44359.p
	20.00	22.39	IEU-X95	FH	6	2½	2.375	522320.	1235337.	46741.	44214.p
		21.78	IEU-X95	H90	6	3¼	3.125	522320.	938403.	46741.	38544.p
		22.08	EU-X95	NC50(IF)	6⅝	3½	3.375	522320.	1109920.	46741.	44456.p
		22.67	IEU-X95	NC46(XH)	6¾	2¾	2.625	522320.	1183908.	46741.	44359.p
	20.00	22.39	IEU-G105	FH	6	2½	2.375	577301.	1235337.	51661.	44214.p
		22.00	IEU-G105	H90	6	3	2.875	577301.	1085665.	51661.	44948.p
		22.08	EU-G105	NC50(IF)	6⅝	3½	3.375	577301.	1109920.	51661.	44456.p
		22.86	IEU-G105	NC46(XH)	6¾	2¾	2.375	577301.	1307608.	51661.	49297.p
	20.00	23.03	EU-S135	NC50(IF)	6⅝	3	2.875	742244.	1416225.	66421.	57534.p
		23.03	IEU-S135	NC46(XH)	6¾	2¾	2.125	742244.	1419527.	66421.	53800.p
	22.82	25.13	IEU-X95	FH	6¾	2¾	2.125	596903.	1347256.	51821.	48522.p
		24.24	EU-X95	NC50(IF)	6⅝	3½	3.375	596903.	1109920.	51821.	44456.p
		24.77	IEU-X95	NC46(XH)	6¾	2¾	2.625	596903.	1183908.	51821.	44359.p
	22.82	24.72	EU-G105	NC50(IF)	6⅝	3¼	3.125	659735.	1268963.	57276.	51217.p
		24.96	IEU-G105	NC46(XH)	6¾	2½	2.375	659735.	1307608.	57276.	49297.p
	22.82	25.41	EU-S135	NC50(IF)	6⅝	2¾	2.625	848230.	1551706.	73641.	63393.p
5	19.50	22.62	IEU-X95	5½-FH	7	3¾	3.625	501087.	1448407.	52144.	62903.b
		21.93	IEU-X95	H90	6½	3¼	3.125	501087.	1176265.	52144.	51220.p
		21.45	IEU-X95	NC50(XH)	6⅝	3½	3.375	501087.	1109920.	52144.	44456.p
	19.50	22.62	IEU-G105	5½-FH	7	3¾	3.625	553833.	1448407.	57633.	62903.b
		22.15	IEU-G105	H90	6½	3	2.875	553833.	1323527.	57633.	58008.p
		21.93	IEU-G105	NC50(XH)	6⅝	3¼	3.125	553833.	1268963.	57633.	51217.p
	19.50	23.48	IEU-S135	5½-FH	7¾	3½	3.375	712070.	1619231.	74100.	72213.p
		22.61	IEU-S135	NC50(XH)	6⅝	2¾	2.625	712070.	1551706.	74100.	63393.p
	25.60	28.59	IEU-X95	5½-FH	7	3½	3.375	671515.	1619231.	66192.	62903.b
		27.87	IEU-X95	NC50(XH)	6⅝	3	2.875	671515.	1416225.	66192.	57534.b
	25.60	29.16	IEU-G105	5½-FH	7¾	3½	3.375	742201.	1619231.	73159.	72213.p
		28.32	IEU-G105	NC50(XH)	6⅝	2¾	2.625	742201.	1551706.	73159.	63393.b
	25.60	29.43	IEU-S135	5½-FH	7¾	3¼	3.125	954259.	1778274.	94062.	78716.b
5½	21.90	24.53	IEU-X95	FH	7	3¾	3.625	553681.	1448407.	64233.	62903.b
		24.80	IEU-X95	H90	7	3½	3.125	553681.	1268877.	64233.	58033.p
	21.90	25.38	IEU-G105	FH	7¾	3½	3.375	611963.	1619231.	70994.	72213.p
	21.90	26.50	IEU-S135	FH	7½	3	2.875	786809.	1925536.	91278.	86765.p
	24.70	27.85	IEU-X95	FH	7¾	3½	3.375	629814.	1619231.	71660.	72213.p
5¾	24.70	27.85	IEU-G105	FH	7¾	3½	3.375	696111.	1619231.	79204.	72213.p
	24.70	27.77	IEU-S135	FH	7½	3	2.875	894999.	1925536.	101833.	86765.p
6⅝	25.20	27.15	IEU-X95	FH	8	5	4.875	619988.	1448416.	89402.	73224.p
		28.20	IEU-G105	FH	8¾	4¾	4.625	685250.	1678145.	98812.	85467.p
		29.63	IEU-S135	FH	8½	4¼	4.125	881035.	2102260.	127044.	108353.p
	27.70	30.11	IEU-X95	FH	8¾	4¾	4.625	676651.	1678145.	96640.	85467.p
	27.70	30.11	IEU-G105	FH	8¾	4¾	4.625	747250.	1678145.	106813.	85467.p
	27.70	31.54	IEU-S135	FH	8½	4¼	4.125	961556.	2102260.	137330.	108353.p

<sup>1</sup>Tool Joint plus drill pipe, for Range 2 steel pipe (See Appendix A for method of calculation).<sup>2</sup>See Section 4.4.



- 03 — <sup>3</sup>The torsional yield strength is based on a shear strength of 57.7 percent of the minimum yield strength.
- <sup>4</sup>The tensile strength of the tool joint pin is based on 120,000 psi yield and the cross sectional area at the root of the thread <sup>3</sup>/<sub>4</sub> inch from the shoulder.
- <sup>6</sup>p = pin limited yield; b = box limited yield; P or B indicates that tool joint could not meet 80 percent of tube torsion yield.

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**Table 10—Recommended Minimum OD\* and Make-up Torque of Weld-on Type Tool Joints—  
Based on Torsional Strength of Box and Drill Pipe**

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Drill Pipe							Premium Class			Class 2		
New Tool-Joint Data			New Tool-Joint Data				Min. OD	Min. Box Shoulder	Make-up Torque for	Min. OD	Min. Box Shoulder	Make-up Torque for
Nominal Size	Nom Weight	Type Upset and Grade	Conn.	New OD	New ID	Make-up Torque <sup>b</sup>	Tool Joint	with Eccentric Wear	Min. OD Tool Joint	Tool Joint	with Eccentric Wear	Min. OD Tool Joint
in.	lb/ft			in.	in.	ft-lb	in.	in.	ft-lb	in.	in.	ft-lb
2 <sup>3</sup> / <sub>8</sub>	4.85	EU-E75	NC26	3 <sup>3</sup> / <sub>8</sub>	1 <sup>3</sup> / <sub>4</sub>	4,125-B	3 <sup>1</sup> / <sub>8</sub>	3 <sup>1</sup> / <sub>64</sub>	1,945	3 <sup>1</sup> / <sub>32</sub>	1 <sup>1</sup> / <sub>32</sub>	1,689
	4.85	EU-E75	W.O.	3 <sup>3</sup> / <sub>8</sub>	2	2,541-P	3 <sup>1</sup> / <sub>16</sub>	1 <sup>1</sup> / <sub>16</sub>	1,994	3 <sup>1</sup> / <sub>32</sub>	3 <sup>1</sup> / <sub>64</sub>	1,746
	4.85	EU-E75	2 <sup>3</sup> / <sub>8</sub> -OHLW	3 <sup>1</sup> / <sub>8</sub>	2	2,716-P	3	1 <sup>1</sup> / <sub>16</sub>	1,723	2 <sup>11</sup> / <sub>32</sub>	3 <sup>1</sup> / <sub>64</sub>	1,481
	4.85	EU-E75	2 <sup>3</sup> / <sub>8</sub> -SL-H90	3 <sup>1</sup> / <sub>4</sub>	2	3,042-P	2 <sup>11</sup> / <sub>32</sub>	1 <sup>1</sup> / <sub>16</sub>	1,996	2 <sup>15</sup> / <sub>16</sub>	3 <sup>1</sup> / <sub>64</sub>	1,726
2 <sup>7</sup> / <sub>8</sub>	6.65	IU-E75	2 <sup>3</sup> / <sub>8</sub> -PAC <sup>2</sup>	2 <sup>7</sup> / <sub>8</sub>	1 <sup>3</sup> / <sub>8</sub>	2,803-P	2 <sup>25</sup> / <sub>32</sub>	9 <sup>1</sup> / <sub>64</sub>	2,455	2 <sup>21</sup> / <sub>32</sub>	7 <sup>1</sup> / <sub>64</sub>	2,055
	6.65	EU-E75	NC26	3 <sup>3</sup> / <sub>8</sub>	1 <sup>3</sup> / <sub>4</sub>	4,125-B	3 <sup>1</sup> / <sub>16</sub>	5 <sup>1</sup> / <sub>64</sub>	2,467	3 <sup>5</sup> / <sub>32</sub>	1 <sup>1</sup> / <sub>16</sub>	2,204
	6.65	EU-E75	2 <sup>3</sup> / <sub>8</sub> -SL-H90	3 <sup>1</sup> / <sub>4</sub>	2	3,042-P	3 <sup>1</sup> / <sub>32</sub>	3 <sup>1</sup> / <sub>32</sub>	2,549	2 <sup>21</sup> / <sub>32</sub>	1 <sup>1</sup> / <sub>16</sub>	1,996
	6.65	EU-E75	2 <sup>3</sup> / <sub>8</sub> -OHSW	3 <sup>1</sup> / <sub>4</sub>	1 <sup>3</sup> / <sub>4</sub>	3,783-B	3 <sup>1</sup> / <sub>16</sub>	3 <sup>1</sup> / <sub>32</sub>	2,216	3 <sup>1</sup> / <sub>32</sub>	5 <sup>1</sup> / <sub>64</sub>	1,967
2 <sup>3</sup> / <sub>8</sub>	6.65	EU-X95	NC26	3 <sup>3</sup> / <sub>8</sub>	1 <sup>3</sup> / <sub>4</sub>	4,125-B	3 <sup>1</sup> / <sub>4</sub>	7 <sup>1</sup> / <sub>64</sub>	3,005	3 <sup>1</sup> / <sub>32</sub>	3 <sup>1</sup> / <sub>32</sub>	2,734
2 <sup>7</sup> / <sub>8</sub>	6.65	EU-G105	NC26 <sup>3</sup>	3 <sup>3</sup> / <sub>8</sub>	1 <sup>3</sup> / <sub>4</sub>	4,125-B	3 <sup>9</sup> / <sub>32</sub>	1 <sup>1</sup> / <sub>8</sub>	3,279	3 <sup>1</sup> / <sub>4</sub>	7 <sup>1</sup> / <sub>64</sub>	3,005
2 <sup>7</sup> / <sub>8</sub>	6.85	EU-E75	NC31	4 <sup>1</sup> / <sub>8</sub>	2 <sup>1</sup> / <sub>8</sub>	7,074-P	3 <sup>11</sup> / <sub>16</sub>	5 <sup>1</sup> / <sub>64</sub>	3,154	3 <sup>11</sup> / <sub>32</sub>	1 <sup>1</sup> / <sub>16</sub>	2,804
	6.85	EU-E75	2 <sup>7</sup> / <sub>8</sub> -WO	4 <sup>1</sup> / <sub>8</sub>	2 <sup>7</sup> / <sub>16</sub>	4,209-P	3 <sup>5</sup> / <sub>8</sub>	5 <sup>1</sup> / <sub>64</sub>	3,216	3 <sup>10</sup> / <sub>32</sub>	1 <sup>1</sup> / <sub>16</sub>	2,876
	6.85	EU-E75	2 <sup>7</sup> / <sub>8</sub> -OHLW <sup>2</sup>	3 <sup>3</sup> / <sub>4</sub>	2 <sup>7</sup> / <sub>16</sub>	3,290-P	3 <sup>1</sup> / <sub>2</sub>	7 <sup>1</sup> / <sub>64</sub>	3,290	3 <sup>7</sup> / <sub>16</sub>	5 <sup>1</sup> / <sub>64</sub>	2,804
	6.85	EU-E75	2 <sup>7</sup> / <sub>8</sub> -SL-H90	3 <sup>7</sup> / <sub>8</sub>	2 <sup>7</sup> / <sub>16</sub>	4,504-P	3 <sup>1</sup> / <sub>2</sub>	3 <sup>1</sup> / <sub>32</sub>	3,397	3 <sup>7</sup> / <sub>16</sub>	1 <sup>1</sup> / <sub>16</sub>	2,666
2 <sup>7</sup> / <sub>8</sub>	10.40	EU-E75	NC31	4 <sup>1</sup> / <sub>8</sub>	2 <sup>1</sup> / <sub>8</sub>	7,074-P	3 <sup>10</sup> / <sub>16</sub>	9 <sup>1</sup> / <sub>64</sub>	4,597	3 <sup>1</sup> / <sub>4</sub>	7 <sup>1</sup> / <sub>64</sub>	3,867
	10.40	IU-E75	2 <sup>7</sup> / <sub>8</sub> -XH	4 <sup>1</sup> / <sub>4</sub>	1 <sup>7</sup> / <sub>8</sub>	7,853-P	3 <sup>21</sup> / <sub>32</sub>	9 <sup>1</sup> / <sub>64</sub>	4,357	3 <sup>21</sup> / <sub>32</sub>	7 <sup>1</sup> / <sub>64</sub>	3,664
	10.40	IU-E75	NC26 <sup>3</sup>	3 <sup>3</sup> / <sub>8</sub>	1 <sup>3</sup> / <sub>4</sub>	4,125-B	3 <sup>3</sup> / <sub>8</sub>	11 <sup>1</sup> / <sub>64</sub>	4,125	3 <sup>11</sup> / <sub>32</sub>	5 <sup>1</sup> / <sub>32</sub>	3,839
	10.40	EU-E75	2 <sup>7</sup> / <sub>8</sub> -OHSW <sup>2</sup>	3 <sup>7</sup> / <sub>8</sub>	2 <sup>5</sup> / <sub>32</sub>	5,194-P	3 <sup>10</sup> / <sub>32</sub>	5 <sup>1</sup> / <sub>32</sub>	4,411	3 <sup>9</sup> / <sub>16</sub>	7 <sup>1</sup> / <sub>64</sub>	4,079
2 <sup>7</sup> / <sub>8</sub>	10.40	EU-E75	2 <sup>7</sup> / <sub>8</sub> -SL-H90	3 <sup>7</sup> / <sub>8</sub>	2 <sup>5</sup> / <sub>32</sub>	6,732-P	3 <sup>10</sup> / <sub>32</sub>	9 <sup>1</sup> / <sub>64</sub>	4,529	3 <sup>17</sup> / <sub>32</sub>	7 <sup>1</sup> / <sub>64</sub>	3,770
	10.40	IU-E75	2 <sup>7</sup> / <sub>8</sub> -PAC <sup>2</sup>	3 <sup>1</sup> / <sub>8</sub>	1 <sup>1</sup> / <sub>2</sub>	3,424-P	3 <sup>1</sup> / <sub>8</sub>	15 <sup>1</sup> / <sub>64</sub>	3,424	3 <sup>1</sup> / <sub>8</sub>	15 <sup>1</sup> / <sub>64</sub>	3,424
	10.40	EU-X95	NC31	4 <sup>1</sup> / <sub>8</sub>	2	7,895-P	3 <sup>20</sup> / <sub>32</sub>	3 <sup>1</sup> / <sub>16</sub>	5,726	3 <sup>27</sup> / <sub>32</sub>	5 <sup>1</sup> / <sub>32</sub>	4,969
	10.40	EU-X95	2 <sup>7</sup> / <sub>8</sub> -SL-H90 <sup>2</sup>	3 <sup>7</sup> / <sub>8</sub>	2 <sup>5</sup> / <sub>32</sub>	6,732-P	3 <sup>1</sup> / <sub>16</sub>	3 <sup>1</sup> / <sub>16</sub>	5,702	3 <sup>5</sup> / <sub>8</sub>	5 <sup>1</sup> / <sub>32</sub>	4,915
2 <sup>7</sup> / <sub>8</sub>	10.40	EU-G105	NC31	4 <sup>1</sup> / <sub>8</sub>	2	7,895-P	3 <sup>15</sup> / <sub>16</sub>	11 <sup>1</sup> / <sub>64</sub>	6,110	3 <sup>7</sup> / <sub>8</sub>	11 <sup>1</sup> / <sub>64</sub>	5,345
2 <sup>7</sup> / <sub>8</sub>	10.40	EU-S135	NC31	4 <sup>3</sup> / <sub>8</sub>	1 <sup>5</sup> / <sub>8</sub>	10,086-P	4 <sup>1</sup> / <sub>16</sub>	17 <sup>1</sup> / <sub>64</sub>	7,694	4	15 <sup>1</sup> / <sub>64</sub>	6,893
3 <sup>1</sup> / <sub>2</sub>	9.50	EU-E75	NC38	4 <sup>3</sup> / <sub>4</sub>	3	7,595-P	4 <sup>11</sup> / <sub>32</sub>	1 <sup>1</sup> / <sub>8</sub>	5,773	4 <sup>11</sup> / <sub>32</sub>	3 <sup>1</sup> / <sub>32</sub>	4,797
	9.50	EU-E75	NC38	4 <sup>3</sup> / <sub>4</sub>	2 <sup>11</sup> / <sub>16</sub>	10,843-P	4 <sup>11</sup> / <sub>32</sub>	1 <sup>1</sup> / <sub>8</sub>	5,773	4 <sup>11</sup> / <sub>32</sub>	3 <sup>1</sup> / <sub>32</sub>	4,797
	9.50	EU-E75	3 <sup>1</sup> / <sub>2</sub> -OHLW	4 <sup>3</sup> / <sub>4</sub>	3	7,082-P	4 <sup>9</sup> / <sub>32</sub>	1 <sup>1</sup> / <sub>8</sub>	5,340	4 <sup>1</sup> / <sub>4</sub>	7 <sup>1</sup> / <sub>64</sub>	4,868
	9.50	EU-E75	3 <sup>1</sup> / <sub>2</sub> -SL-H90	4 <sup>5</sup> / <sub>8</sub>	3	7,469-P	4 <sup>3</sup> / <sub>16</sub>	7 <sup>1</sup> / <sub>64</sub>	5,521	4 <sup>5</sup> / <sub>32</sub>	3 <sup>1</sup> / <sub>32</sub>	5,003
3 <sup>1</sup> / <sub>2</sub>	13.30	EU-E75	NC38	4 <sup>3</sup> / <sub>4</sub>	2 <sup>11</sup> / <sub>16</sub>	10,843-P	4 <sup>1</sup> / <sub>2</sub>	11 <sup>1</sup> / <sub>64</sub>	7,274	4 <sup>7</sup> / <sub>16</sub>	9 <sup>1</sup> / <sub>64</sub>	6,268
	13.30	IU-E75	NC31 <sup>3</sup>	4 <sup>1</sup> / <sub>8</sub>	2 <sup>1</sup> / <sub>8</sub>	7,074-P	4	15 <sup>1</sup> / <sub>64</sub>	6,893	3 <sup>15</sup> / <sub>16</sub>	11 <sup>1</sup> / <sub>64</sub>	6,110
	13.30	EU-E75	3 <sup>1</sup> / <sub>2</sub> -OHSW	4 <sup>3</sup> / <sub>4</sub>	2 <sup>11</sup> / <sub>16</sub>	10,300-P	4 <sup>11</sup> / <sub>32</sub>	3 <sup>1</sup> / <sub>16</sub>	7,278	4 <sup>11</sup> / <sub>32</sub>	5 <sup>1</sup> / <sub>32</sub>	6,299
	13.30	EU-E75	3 <sup>1</sup> / <sub>2</sub> -H90	5 <sup>1</sup> / <sub>4</sub>	2 <sup>3</sup> / <sub>4</sub>	14,043-P	4 <sup>17</sup> / <sub>32</sub>	1 <sup>1</sup> / <sub>8</sub>	7,064	4 <sup>1</sup> / <sub>2</sub>	7 <sup>1</sup> / <sub>64</sub>	6,487
3 <sup>1</sup> / <sub>2</sub>	13.30	EU-X95	NC38	5	2 <sup>9</sup> / <sub>16</sub>	12,057-P	4 <sup>10</sup> / <sub>32</sub>	7 <sup>1</sup> / <sub>32</sub>	8,822	4 <sup>17</sup> / <sub>32</sub>	3 <sup>1</sup> / <sub>16</sub>	7,785
	13.30	EU-X95	3 <sup>1</sup> / <sub>2</sub> -SL-H90 <sup>2</sup>	4 <sup>5</sup> / <sub>8</sub>	2 <sup>11</sup> / <sub>16</sub>	11,073-P	4 <sup>5</sup> / <sub>8</sub>	11 <sup>1</sup> / <sub>64</sub>	8,742	4 <sup>5</sup> / <sub>16</sub>	11 <sup>1</sup> / <sub>64</sub>	7,647
	13.30	EU-X95	3 <sup>1</sup> / <sub>2</sub> -H90	5 <sup>1</sup> / <sub>4</sub>	2 <sup>3</sup> / <sub>4</sub>	14,043-P	4 <sup>5</sup> / <sub>8</sub>	11 <sup>1</sup> / <sub>64</sub>	8,826	4 <sup>9</sup> / <sub>16</sub>	9 <sup>1</sup> / <sub>64</sub>	7,646
	13.30	EU-G105	NC38	5	2 <sup>7</sup> / <sub>16</sub>	13,221-P	4 <sup>21</sup> / <sub>32</sub>	1 <sup>1</sup> / <sub>4</sub>	9,879	4 <sup>10</sup> / <sub>32</sub>	7 <sup>1</sup> / <sub>32</sub>	8,822
3 <sup>1</sup> / <sub>2</sub>	13.30	EU-S135	NC40	5 <sup>3</sup> / <sub>8</sub>	2 <sup>7</sup> / <sub>16</sub>	17,858-P	5	9 <sup>1</sup> / <sub>32</sub>	12,569	4 <sup>20</sup> / <sub>32</sub>	15 <sup>1</sup> / <sub>64</sub>	10,768
	13.30	EU-S135	NC38	5	2 <sup>1</sup> / <sub>8</sub>	15,902-P	4 <sup>11</sup> / <sub>16</sub>	21 <sup>1</sup> / <sub>64</sub>	12,614	4 <sup>21</sup> / <sub>32</sub>	9 <sup>1</sup> / <sub>32</sub>	10,957
3 <sup>1</sup> / <sub>2</sub>	15.50	EU-E75	NC38	5	2 <sup>9</sup> / <sub>16</sub>	12,057-P	4 <sup>17</sup> / <sub>32</sub>	3 <sup>1</sup> / <sub>16</sub>	7,785	4 <sup>15</sup> / <sub>32</sub>	5 <sup>1</sup> / <sub>32</sub>	6,769
3 <sup>1</sup> / <sub>2</sub>	15.50	EU-X95	NC38	5	2 <sup>7</sup> / <sub>16</sub>	13,221-P	4 <sup>21</sup> / <sub>32</sub>	1 <sup>1</sup> / <sub>4</sub>	9,879	4 <sup>10</sup> / <sub>32</sub>	7 <sup>1</sup> / <sub>32</sub>	8,822
3 <sup>1</sup> / <sub>2</sub>	15.50	EU-G105	NC38	5	2 <sup>1</sup> / <sub>8</sub>	15,902-P	4 <sup>21</sup> / <sub>32</sub>	9 <sup>1</sup> / <sub>32</sub>	10,957	4 <sup>5</sup> / <sub>8</sub>	15 <sup>1</sup> / <sub>64</sub>	9,348
	15.50	EU-G105	NC40	5 <sup>1</sup> / <sub>4</sub>	2 <sup>9</sup> / <sub>16</sub>	16,616-P	4 <sup>15</sup> / <sub>16</sub>	1 <sup>1</sup> / <sub>4</sub>	11,363	4 <sup>27</sup> / <sub>32</sub>	11 <sup>1</sup> / <sub>64</sub>	9,595
3 <sup>1</sup> / <sub>2</sub>	15.50	EU-S135	NC40	5 <sup>1</sup> / <sub>2</sub>	2 <sup>1</sup> / <sub>4</sub>	19,616-P	5 <sup>3</sup> / <sub>32</sub>	21 <sup>1</sup> / <sub>64</sub>	14,419	4 <sup>11</sup> / <sub>32</sub>	17 <sup>1</sup> / <sub>64</sub>	11,963
4	11.85	EU-E75	NC46	6	3 <sup>1</sup> / <sub>4</sub>	19,937-P	5 <sup>7</sup> / <sub>32</sub>	7 <sup>1</sup> / <sub>64</sub>	7,843	5 <sup>5</sup> / <sub>32</sub>	5 <sup>1</sup> / <sub>64</sub>	6,476
	11.85	EU-E75	4-WO	5 <sup>3</sup> / <sub>4</sub>	3 <sup>1</sup> / <sub>16</sub>	17,186-P	5 <sup>7</sup> / <sub>32</sub>	7 <sup>1</sup> / <sub>64</sub>	7,843	5 <sup>5</sup> / <sub>32</sub>	5 <sup>1</sup> / <sub>64</sub>	6,476

(Table continued on next page.)

Committee Review Only

**Table 10—Recommended Minimum OD\* and Make-up Torque of Weld-on Type Tool Joints—  
Based on Torsional Strength of Box and Drill Pipe (Continued)**

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Drill Pipe		New Tool-Joint Data					Premium Class			Class 2		
Nominal Size in.	Nom Weight lb/ft	Type and Grade	Conn.	New OD in.	New ID in.	Make-up Torque <sup>6</sup> ft-lb	Min. OD Tool Joint in.	Min. Box Shoulder with Eccen- tric Wear in.	Make-up Torque for Min. OD Tool Joint ft-lb	Min. OD Tool Joint in.	Min. Box Shoulder with Eccen- tric Wear in.	Make-up Torque for Min. OD Tool Joint ft-lb
4	11.85	EU-E75	4 OHLW	5 <sup>1</sup> / <sub>4</sub>	3 <sup>15</sup> / <sub>32</sub>	13,186 P	5	9 <sup>9</sup> / <sub>64</sub>	7,866	4 <sup>15</sup> / <sub>16</sub>	7 <sup>7</sup> / <sub>64</sub>	6,593
	11.85	IU-E75	4 H90	5 <sup>1</sup> / <sub>2</sub>	2 <sup>13</sup> / <sub>16</sub>	21,185 P	4 <sup>7</sup> / <sub>8</sub>	7 <sup>7</sup> / <sub>64</sub>	7,630	4 <sup>22</sup> / <sub>32</sub>	3 <sup>7</sup> / <sub>32</sub>	6,962
	14.00	IU-E75	NC40	5 <sup>1</sup> / <sub>4</sub>	2 <sup>13</sup> / <sub>16</sub>	13,968 P	4 <sup>13</sup> / <sub>16</sub>	3 <sup>7</sup> / <sub>32</sub>	9,017	4 <sup>3</sup> / <sub>4</sub>	5 <sup>5</sup> / <sub>32</sub>	7,877
	14.00	EU-E75	NC46	6	3 <sup>7</sup> / <sub>4</sub>	19,937 P	5 <sup>9</sup> / <sub>32</sub>	9 <sup>9</sup> / <sub>64</sub>	9,233	5 <sup>7</sup> / <sub>32</sub>	7 <sup>7</sup> / <sub>64</sub>	7,843
	14.00	IU-E75	4 SH <sup>2</sup>	4 <sup>5</sup> / <sub>8</sub>	2 <sup>9</sup> / <sub>16</sub>	9,016 P	4 <sup>7</sup> / <sub>16</sub>	15 <sup>15</sup> / <sub>64</sub>	8,782	4 <sup>3</sup> / <sub>8</sub>	13 <sup>7</sup> / <sub>64</sub>	7,817
	14.00	EU-E75	4 OHSW	5 <sup>1</sup> / <sub>2</sub>	3 <sup>7</sup> / <sub>4</sub>	16,236 P	5 <sup>1</sup> / <sub>16</sub>	11 <sup>1</sup> / <sub>64</sub>	9,131	5	9 <sup>9</sup> / <sub>64</sub>	7,839
	14.00	IU-E75	4 H90	5 <sup>1</sup> / <sub>2</sub>	2 <sup>13</sup> / <sub>16</sub>	21,185 P	4 <sup>15</sup> / <sub>16</sub>	9 <sup>9</sup> / <sub>64</sub>	8,986	4 <sup>7</sup> / <sub>8</sub>	7 <sup>7</sup> / <sub>64</sub>	7,630
	14.00	IU-X95	NC40	5 <sup>1</sup> / <sub>4</sub>	2 <sup>11</sup> / <sub>16</sub>	15,319 P	4 <sup>15</sup> / <sub>16</sub>	1 <sup>1</sup> / <sub>4</sub>	11,363	4 <sup>27</sup> / <sub>32</sub>	13 <sup>7</sup> / <sub>64</sub>	9,595
	14.00	EU-X95	NC46	6	3 <sup>7</sup> / <sub>4</sub>	19,937 P	5 <sup>7</sup> / <sub>8</sub>	3 <sup>7</sup> / <sub>16</sub>	11,363	5 <sup>5</sup> / <sub>16</sub>	5 <sup>5</sup> / <sub>32</sub>	9,937
	14.00	IU-X95	4 H90	5 <sup>1</sup> / <sub>2</sub>	2 <sup>13</sup> / <sub>16</sub>	21,185 P	5 <sup>1</sup> / <sub>32</sub>	3 <sup>7</sup> / <sub>16</sub>	11,065	4 <sup>21</sup> / <sub>32</sub>	5 <sup>5</sup> / <sub>32</sub>	9,673
	14.00	IU-G105	NC40	5 <sup>1</sup> / <sub>2</sub>	2 <sup>7</sup> / <sub>16</sub>	17,858 P	5	9 <sup>9</sup> / <sub>32</sub>	12,569	4 <sup>29</sup> / <sub>32</sub>	15 <sup>15</sup> / <sub>64</sub>	10,768
	14.00	EU-G105	NC46	6	3 <sup>7</sup> / <sub>4</sub>	19,937 P	5 <sup>7</sup> / <sub>16</sub>	7 <sup>7</sup> / <sub>32</sub>	12,813	5 <sup>11</sup> / <sub>32</sub>	11 <sup>7</sup> / <sub>64</sub>	10,647
4	14.00	IU-G105	4 H90	5 <sup>1</sup> / <sub>2</sub>	2 <sup>13</sup> / <sub>16</sub>	21,185 P	5 <sup>3</sup> / <sub>32</sub>	7 <sup>7</sup> / <sub>32</sub>	12,481	5 <sup>1</sup> / <sub>32</sub>	3 <sup>7</sup> / <sub>16</sub>	11,065
	14.00	EU-S135	NC46	6	3	23,399 P	5 <sup>9</sup> / <sub>16</sub>	9 <sup>9</sup> / <sub>32</sub>	15,787	5 <sup>1</sup> / <sub>2</sub>	1 <sup>1</sup> / <sub>4</sub>	14,288
	15.70	IU-E75	NC40	5 <sup>1</sup> / <sub>4</sub>	2 <sup>11</sup> / <sub>16</sub>	15,319 P	4 <sup>7</sup> / <sub>8</sub>	7 <sup>7</sup> / <sub>32</sub>	10,179	4 <sup>25</sup> / <sub>32</sub>	11 <sup>7</sup> / <sub>64</sub>	8,444
	15.70	EU-E75	NC46	6	3 <sup>7</sup> / <sub>4</sub>	19,937 P	5 <sup>5</sup> / <sub>16</sub>	5 <sup>5</sup> / <sub>32</sub>	9,937	5 <sup>1</sup> / <sub>4</sub>	1 <sup>1</sup> / <sub>8</sub>	8,535
	15.70	IU-E75	4 H90	5 <sup>1</sup> / <sub>2</sub>	2 <sup>13</sup> / <sub>16</sub>	21,185 P	4 <sup>21</sup> / <sub>32</sub>	5 <sup>5</sup> / <sub>32</sub>	9,673	4 <sup>29</sup> / <sub>32</sub>	1 <sup>7</sup> / <sub>8</sub>	8,305
	15.70	IU-X95	NC40	5 <sup>1</sup> / <sub>2</sub>	2 <sup>7</sup> / <sub>16</sub>	17,858 P	5	9 <sup>9</sup> / <sub>32</sub>	12,569	4 <sup>29</sup> / <sub>32</sub>	15 <sup>15</sup> / <sub>64</sub>	10,768
	15.70	EU-X95	NC46	6	3	23,399 P	5 <sup>7</sup> / <sub>16</sub>	7 <sup>7</sup> / <sub>32</sub>	12,813	5 <sup>11</sup> / <sub>32</sub>	11 <sup>7</sup> / <sub>64</sub>	10,647
	15.70	IU-X95	4 H90	5 <sup>1</sup> / <sub>2</sub>	2 <sup>13</sup> / <sub>16</sub>	21,185 P	5 <sup>3</sup> / <sub>32</sub>	7 <sup>7</sup> / <sub>32</sub>	12,481	5 <sup>1</sup> / <sub>32</sub>	3 <sup>7</sup> / <sub>16</sub>	11,065
	15.70	EU-G105	NC46	6	3	23,399 P	5 <sup>15</sup> / <sub>32</sub>	15 <sup>15</sup> / <sub>64</sub>	13,547	5 <sup>13</sup> / <sub>32</sub>	13 <sup>7</sup> / <sub>64</sub>	12,085
	15.70	IU-G105	4 H90	5 <sup>1</sup> / <sub>2</sub>	2 <sup>13</sup> / <sub>16</sub>	21,185 P	5 <sup>5</sup> / <sub>32</sub>	1 <sup>1</sup> / <sub>4</sub>	13,922	5 <sup>1</sup> / <sub>16</sub>	13 <sup>7</sup> / <sub>64</sub>	11,770
	15.70	IU-S135	NC46	6	2 <sup>5</sup> / <sub>8</sub>	26,982 B	5 <sup>21</sup> / <sub>32</sub>	21 <sup>7</sup> / <sub>64</sub>	18,083	5 <sup>17</sup> / <sub>32</sub>	17 <sup>7</sup> / <sub>64</sub>	15,035
	15.70	EU-S135	NC46	6	2 <sup>7</sup> / <sub>8</sub>	25,038 P	5 <sup>21</sup> / <sub>32</sub>	21 <sup>7</sup> / <sub>64</sub>	18,083	5 <sup>17</sup> / <sub>32</sub>	17 <sup>7</sup> / <sub>64</sub>	15,035
4 <sup>1</sup> / <sub>2</sub>	16.60	IEU-E75	4 <sup>1</sup> / <sub>2</sub> FH	6	3	20,620 P	5 <sup>3</sup> / <sub>8</sub>	13 <sup>13</sup> / <sub>64</sub>	12,125	5 <sup>9</sup> / <sub>32</sub>	5 <sup>5</sup> / <sub>32</sub>	10,072
	16.60	IEU-E75	NC46	6 <sup>1</sup> / <sub>4</sub>	3 <sup>7</sup> / <sub>4</sub>	19,937 P	5 <sup>13</sup> / <sub>32</sub>	13 <sup>13</sup> / <sub>64</sub>	12,085	5 <sup>11</sup> / <sub>32</sub>	11 <sup>7</sup> / <sub>64</sub>	10,647
	16.60	IEU-E75	4 <sup>1</sup> / <sub>2</sub> OHSW	5 <sup>7</sup> / <sub>8</sub>	3 <sup>7</sup> / <sub>4</sub>	16,162 P	5 <sup>7</sup> / <sub>16</sub>	13 <sup>13</sup> / <sub>64</sub>	11,862	5 <sup>3</sup> / <sub>8</sub>	11 <sup>7</sup> / <sub>64</sub>	10,375
	16.60	EU-E75	NC50	6 <sup>5</sup> / <sub>8</sub>	3 <sup>7</sup> / <sub>4</sub>	22,361 P	5 <sup>23</sup> / <sub>32</sub>	5 <sup>11</sup> / <sub>32</sub>	11,590	5 <sup>11</sup> / <sub>16</sub>	9 <sup>9</sup> / <sub>64</sub>	10,773
	16.60	IEU-E75	4 <sup>1</sup> / <sub>2</sub> H-90	6	3 <sup>7</sup> / <sub>4</sub>	23,126 P	5 <sup>11</sup> / <sub>32</sub>	3 <sup>7</sup> / <sub>16</sub>	12,215	5 <sup>9</sup> / <sub>32</sub>	5 <sup>5</sup> / <sub>32</sub>	10,642
	16.60	IEU-X95	4 <sup>1</sup> / <sub>2</sub> FH	6	2 <sup>3</sup> / <sub>4</sub>	23,695 P	5 <sup>1</sup> / <sub>2</sub>	17 <sup>17</sup> / <sub>64</sub>	14,945	5 <sup>13</sup> / <sub>32</sub>	7 <sup>7</sup> / <sub>32</sub>	12,821
	16.60	IEU-X95	NC46	6 <sup>1</sup> / <sub>4</sub>	3	19,937 P	5 <sup>7</sup> / <sub>32</sub>	17 <sup>17</sup> / <sub>64</sub>	15,035	5 <sup>7</sup> / <sub>16</sub>	7 <sup>7</sup> / <sub>32</sub>	12,813
	16.60	EU-X95	NC50	6 <sup>5</sup> / <sub>8</sub>	3 <sup>7</sup> / <sub>4</sub>	22,361 P	5 <sup>27</sup> / <sub>32</sub>	7 <sup>7</sup> / <sub>32</sub>	14,926	5 <sup>25</sup> / <sub>32</sub>	3 <sup>7</sup> / <sub>16</sub>	13,245
	16.60	IEU-X95	4 <sup>1</sup> / <sub>2</sub> H-90	6	3	26,969 P	5 <sup>15</sup> / <sub>32</sub>	1 <sup>1</sup> / <sub>4</sub>	15,441	5 <sup>3</sup> / <sub>8</sub>	13 <sup>13</sup> / <sub>64</sub>	13,013
	16.60	IEU-G105	4 <sup>1</sup> / <sub>2</sub> FH	6	2 <sup>3</sup> / <sub>4</sub>	23,695 P	5 <sup>9</sup> / <sub>16</sub>	19 <sup>19</sup> / <sub>64</sub>	16,391	5 <sup>15</sup> / <sub>32</sub>	1 <sup>1</sup> / <sub>4</sub>	14,231
	16.60	IEU-G105	NC46	6 <sup>1</sup> / <sub>4</sub>	3	23,399 P	5 <sup>19</sup> / <sub>32</sub>	19 <sup>19</sup> / <sub>64</sub>	16,546	5 <sup>1</sup> / <sub>2</sub>	1 <sup>1</sup> / <sub>4</sub>	14,288
	16.60	EU-G105	NC50	6 <sup>5</sup> / <sub>8</sub>	3 <sup>7</sup> / <sub>4</sub>	22,361 P	5 <sup>29</sup> / <sub>32</sub>	1 <sup>1</sup> / <sub>4</sub>	16,633	5 <sup>13</sup> / <sub>16</sub>	13 <sup>13</sup> / <sub>64</sub>	14,082
4 <sup>1</sup> / <sub>2</sub>	16.60	IEU-G105	4 <sup>1</sup> / <sub>2</sub> H-90	6	3	26,969 P	5 <sup>1</sup> / <sub>2</sub>	17 <sup>17</sup> / <sub>64</sub>	16,264	5 <sup>7</sup> / <sub>16</sub>	15 <sup>15</sup> / <sub>64</sub>	14,625
	16.60	IEU-S135	NC46	6 <sup>1</sup> / <sub>4</sub>	2 <sup>3</sup> / <sub>4</sub>	26,615 P	5 <sup>25</sup> / <sub>32</sub>	25 <sup>25</sup> / <sub>64</sub>	21,230	5 <sup>21</sup> / <sub>32</sub>	21 <sup>7</sup> / <sub>64</sub>	18,083
	16.60	EU-S135	NC50	6 <sup>5</sup> / <sub>8</sub>	3 <sup>7</sup> / <sub>2</sub>	26,674 P	6 <sup>1</sup> / <sub>16</sub>	21 <sup>21</sup> / <sub>64</sub>	21,017	5 <sup>21</sup> / <sub>32</sub>	9 <sup>9</sup> / <sub>32</sub>	18,367
	20.00	IEU-E75	4 <sup>1</sup> / <sub>2</sub> FH	6	3	20,620 P	5 <sup>15</sup> / <sub>32</sub>	1 <sup>1</sup> / <sub>4</sub>	14,231	5 <sup>3</sup> / <sub>8</sub>	13 <sup>13</sup> / <sub>64</sub>	12,125
	20.00	IEU-E75	NC46	6 <sup>1</sup> / <sub>4</sub>	3	23,399 P	5 <sup>1</sup> / <sub>2</sub>	1 <sup>1</sup> / <sub>4</sub>	14,288	5 <sup>13</sup> / <sub>32</sub>	13 <sup>13</sup> / <sub>64</sub>	12,085
	20.00	EU-E75	NC50	6 <sup>5</sup> / <sub>8</sub>	3 <sup>5</sup> / <sub>8</sub>	24,549 P	5 <sup>13</sup> / <sub>16</sub>	13 <sup>13</sup> / <sub>64</sub>	14,082	5 <sup>3</sup> / <sub>4</sub>	12 <sup>12</sup> / <sub>64</sub>	12,415
	20.00	IEU-E75	4 <sup>1</sup> / <sub>2</sub> H-90	6	3	26,969 P	5 <sup>13</sup> / <sub>32</sub>	7 <sup>7</sup> / <sub>32</sub>	13,815	5 <sup>11</sup> / <sub>32</sub>	3 <sup>7</sup> / <sub>16</sub>	12,215
	20.00	IEU-X95	4 <sup>1</sup> / <sub>2</sub> FH	6	2 <sup>1</sup> / <sub>2</sub>	26,528 P	5 <sup>3</sup> / <sub>8</sub>	21 <sup>21</sup> / <sub>64</sub>	17,861	5 <sup>17</sup> / <sub>32</sub>	9 <sup>9</sup> / <sub>32</sub>	15,665
	20.00	IEU-X95	NC46	6 <sup>1</sup> / <sub>4</sub>	2 <sup>3</sup> / <sub>4</sub>	26,615 P	5 <sup>21</sup> / <sub>32</sub>	21 <sup>21</sup> / <sub>64</sub>	18,083	5 <sup>9</sup> / <sub>16</sub>	9 <sup>9</sup> / <sub>32</sub>	15,787
	20.00	EU-X95	NC50	6 <sup>5</sup> / <sub>8</sub>	3 <sup>7</sup> / <sub>2</sub>	26,674 P	5 <sup>15</sup> / <sub>16</sub>	17 <sup>17</sup> / <sub>64</sub>	17,497	5 <sup>7</sup> / <sub>8</sub>	15 <sup>15</sup> / <sub>64</sub>	15,776
	20.00	IEU-X95	4 <sup>1</sup> / <sub>2</sub> H-90	6	3	26,969 P	5 <sup>9</sup> / <sub>16</sub>	19 <sup>19</sup> / <sub>64</sub>	17,929	5 <sup>15</sup> / <sub>32</sub>	1 <sup>1</sup> / <sub>4</sub>	15,441

(Table continued on next page.)

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**Table 10—Recommended Minimum OD\* and Make-up Torque of Weld-on Type Tool Joints Based on Torsional Strength of Box and Drill Pipe (Continued)**

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Drill Pipe			New Tool-Joint Data				Premium Class			Class 2		
Nominal Size in.	Nom Weight lb/ft	Type Upset and Grade	Conn.	New OD in.	New ID in.	Make-up Torque <sup>6</sup> ft-lb	Min. Tool Joint in.	Min. Box Shoulder with Eccentric Wear in.	Make-up Torque for Min. OD Tool Joint ft-lb	Min. Tool Joint in.	Min. Box Shoulder with Eccentric Wear in.	Make-up Torque for Min. OD Tool Joint ft-lb
4 <sup>1</sup> / <sub>2</sub>	20.00	IEU-G105	NC46	6 <sup>1</sup> / <sub>4</sub>	2 <sup>1</sup> / <sub>2</sub>	29,578 P	5 <sup>23</sup> / <sub>32</sub>	2 <sup>3</sup> / <sub>64</sub>	19,644	5 <sup>5</sup> / <sub>8</sub>	5 <sup>1</sup> / <sub>16</sub>	17,311
	20.00	IEU-G105	NC50	6 <sup>5</sup> / <sub>8</sub>	3 <sup>1</sup> / <sub>2</sub>	26,674 P	6 <sup>1</sup> / <sub>32</sub>	5 <sup>1</sup> / <sub>16</sub>	20,127	5 <sup>20</sup> / <sub>32</sub>	1 <sup>1</sup> / <sub>4</sub>	16,633
4 <sup>1</sup> / <sub>2</sub>	20.00	IEU-S135	NC50	6 <sup>5</sup> / <sub>8</sub>	3	34,520 P	6 <sup>7</sup> / <sub>32</sub>	1 <sup>3</sup> / <sub>32</sub>	25,569	6 <sup>3</sup> / <sub>32</sub>	1 <sup>1</sup> / <sub>32</sub>	21,914
5	19.50	IEU-E75	NC50	6 <sup>5</sup> / <sub>8</sub>	3 <sup>1</sup> / <sub>4</sub>	22,361 P	5 <sup>2</sup> / <sub>8</sub>	1 <sup>5</sup> / <sub>64</sub>	15,776	5 <sup>13</sup> / <sub>16</sub>	1 <sup>3</sup> / <sub>64</sub>	14,082
5	19.50	IEU-X95	NC50	6 <sup>5</sup> / <sub>8</sub>	3 <sup>1</sup> / <sub>2</sub>	26,674 P	6 <sup>1</sup> / <sub>32</sub>	5 <sup>1</sup> / <sub>16</sub>	20,127	5 <sup>15</sup> / <sub>16</sub>	1 <sup>7</sup> / <sub>64</sub>	17,497
	19.50	IEU-X95	5 H-90	6 <sup>1</sup> / <sub>2</sub>	3 <sup>1</sup> / <sub>4</sub>	30,732 P	5 <sup>27</sup> / <sub>32</sub>	1 <sup>9</sup> / <sub>64</sub>	19,862	5 <sup>3</sup> / <sub>4</sub>	1 <sup>1</sup> / <sub>4</sub>	17,116
5	19.50	IEU-G105	NC50	6 <sup>5</sup> / <sub>8</sub>	3 <sup>1</sup> / <sub>4</sub>	30,730 P	6 <sup>3</sup> / <sub>32</sub>	1 <sup>1</sup> / <sub>32</sub>	21,914	6	1 <sup>9</sup> / <sub>64</sub>	19,244
	19.50	IEU-G105	5 H-90	6 <sup>1</sup> / <sub>2</sub>	3	34,805 P	5 <sup>20</sup> / <sub>32</sub>	2 <sup>1</sup> / <sub>64</sub>	21,727	5 <sup>13</sup> / <sub>16</sub>	9 <sup>1</sup> / <sub>32</sub>	18,940
5	19.50	IEU-S135	NC50	6 <sup>5</sup> / <sub>8</sub>	2 <sup>3</sup> / <sub>4</sub>	38,036 P	6 <sup>5</sup> / <sub>16</sub>	2 <sup>9</sup> / <sub>64</sub>	28,381	6 <sup>3</sup> / <sub>16</sub>	3 <sup>5</sup> / <sub>64</sub>	24,645
	19.50	IEU-S135	5 <sup>1</sup> / <sub>2</sub> FH	7 <sup>1</sup> / <sub>4</sub>	3 <sup>1</sup> / <sub>2</sub>	43,328 P	6 <sup>3</sup> / <sub>4</sub>	3 <sup>1</sup> / <sub>8</sub>	28,737	6 <sup>5</sup> / <sub>8</sub>	5 <sup>1</sup> / <sub>16</sub>	24,412
5	25.60	IEU-E75	NC50	6 <sup>5</sup> / <sub>8</sub>	3 <sup>1</sup> / <sub>2</sub>	26,674 P	6 <sup>1</sup> / <sub>32</sub>	5 <sup>1</sup> / <sub>16</sub>	20,127	5 <sup>15</sup> / <sub>16</sub>	1 <sup>7</sup> / <sub>64</sub>	17,497
	25.60	IEU-E75	5 <sup>1</sup> / <sub>2</sub> FH	7	3 <sup>1</sup> / <sub>2</sub>	37,742 B	6 <sup>1</sup> / <sub>2</sub>	1 <sup>1</sup> / <sub>4</sub>	20,205	6 <sup>13</sup> / <sub>32</sub>	1 <sup>3</sup> / <sub>64</sub>	17,127
5	25.60	IEU-X95	NC50	6 <sup>5</sup> / <sub>8</sub>	3	34,520 P	6 <sup>7</sup> / <sub>32</sub>	1 <sup>3</sup> / <sub>32</sub>	25,569	6 <sup>3</sup> / <sub>32</sub>	1 <sup>1</sup> / <sub>32</sub>	21,914
	25.60	IEU-X95	5 <sup>1</sup> / <sub>2</sub> FH	7	3 <sup>1</sup> / <sub>2</sub>	37,742 B	6 <sup>21</sup> / <sub>32</sub>	2 <sup>1</sup> / <sub>64</sub>	25,483	6 <sup>9</sup> / <sub>16</sub>	9 <sup>1</sup> / <sub>32</sub>	22,294
5	25.60	IEU-G105	NC50	6 <sup>5</sup> / <sub>8</sub>	2 <sup>3</sup> / <sub>4</sub>	38,036 P	6 <sup>9</sup> / <sub>32</sub>	7 <sup>1</sup> / <sub>16</sub>	27,437	6 <sup>5</sup> / <sub>32</sub>	3 <sup>1</sup> / <sub>8</sub>	23,728
	25.60	IEU-G105	5 <sup>1</sup> / <sub>2</sub> FH	7 <sup>1</sup> / <sub>4</sub>	3 <sup>1</sup> / <sub>2</sub>	43,328 P	6 <sup>23</sup> / <sub>32</sub>	2 <sup>3</sup> / <sub>64</sub>	27,645	6 <sup>5</sup> / <sub>8</sub>	5 <sup>1</sup> / <sub>16</sub>	24,412
5	25.60	IEU-S135	5 <sup>1</sup> / <sub>2</sub> FH	7 <sup>1</sup> / <sub>4</sub>	3 <sup>1</sup> / <sub>4</sub>	47,230 B	6 <sup>15</sup> / <sub>16</sub>	1 <sup>5</sup> / <sub>32</sub>	35,446	6 <sup>13</sup> / <sub>16</sub>	1 <sup>3</sup> / <sub>32</sub>	30,943
5 <sup>1</sup> / <sub>2</sub>	21.90	IEU-E75	5 <sup>1</sup> / <sub>2</sub> FH	7	4	33,412 P	6 <sup>15</sup> / <sub>32</sub>	1 <sup>5</sup> / <sub>64</sub>	19,172	6 <sup>13</sup> / <sub>32</sub>	1 <sup>3</sup> / <sub>64</sub>	17,127
5 <sup>1</sup> / <sub>2</sub>	21.90	IEU-X95	5 <sup>1</sup> / <sub>2</sub> FH	7	3 <sup>3</sup> / <sub>4</sub>	37,742 B	6 <sup>5</sup> / <sub>8</sub>	5 <sup>1</sup> / <sub>16</sub>	24,412	6 <sup>17</sup> / <sub>32</sub>	1 <sup>7</sup> / <sub>64</sub>	21,246
	21.90	IEU-X95	5 <sup>1</sup> / <sub>2</sub> H-90	7	3 <sup>1</sup> / <sub>2</sub>	34,820 P	6 <sup>3</sup> / <sub>16</sub>	2 <sup>1</sup> / <sub>64</sub>	24,414	6 <sup>3</sup> / <sub>32</sub>	9 <sup>1</sup> / <sub>32</sub>	21,349
5 <sup>1</sup> / <sub>2</sub>	21.90	IEU-G105	5 <sup>1</sup> / <sub>2</sub> FH	7 <sup>1</sup> / <sub>4</sub>	3 <sup>1</sup> / <sub>2</sub>	43,328 P	6 <sup>23</sup> / <sub>32</sub>	2 <sup>3</sup> / <sub>64</sub>	27,645	6 <sup>19</sup> / <sub>32</sub>	1 <sup>9</sup> / <sub>64</sub>	23,350
5 <sup>1</sup> / <sub>2</sub>	21.90	IEU-S135	5 <sup>1</sup> / <sub>2</sub> FH	7 <sup>1</sup> / <sub>2</sub>	3	52,059 P	6 <sup>15</sup> / <sub>16</sub>	1 <sup>5</sup> / <sub>32</sub>	35,446	6 <sup>13</sup> / <sub>16</sub>	1 <sup>3</sup> / <sub>32</sub>	30,943
5 <sup>1</sup> / <sub>2</sub>	24.70	IEU-E75	5 <sup>1</sup> / <sub>2</sub> FH	7	4	33,412 P	6 <sup>9</sup> / <sub>16</sub>	9 <sup>1</sup> / <sub>32</sub>	22,294	6 <sup>15</sup> / <sub>32</sub>	1 <sup>5</sup> / <sub>64</sub>	19,172
5 <sup>1</sup> / <sub>2</sub>	24.70	IEU-X95	5 <sup>1</sup> / <sub>2</sub> FH	7 <sup>1</sup> / <sub>4</sub>	3 <sup>1</sup> / <sub>2</sub>	43,328 P	6 <sup>25</sup> / <sub>32</sub>	2 <sup>3</sup> / <sub>64</sub>	27,645	6 <sup>19</sup> / <sub>32</sub>	1 <sup>9</sup> / <sub>64</sub>	23,350
5 <sup>1</sup> / <sub>2</sub>	24.70	IEU-G105	5 <sup>1</sup> / <sub>2</sub> FH	7 <sup>1</sup> / <sub>4</sub>	3 <sup>1</sup> / <sub>2</sub>	43,328 P	6 <sup>25</sup> / <sub>32</sub>	2 <sup>5</sup> / <sub>64</sub>	29,836	6 <sup>11</sup> / <sub>16</sub>	1 <sup>1</sup> / <sub>32</sub>	26,560
5 <sup>1</sup> / <sub>2</sub>	24.70	IEU-S135	5 <sup>1</sup> / <sub>2</sub> FH	7 <sup>1</sup> / <sub>2</sub>	3	52,059 P	7 <sup>1</sup> / <sub>32</sub>	3 <sup>3</sup> / <sub>64</sub>	38,901	6 <sup>7</sup> / <sub>8</sub>	7 <sup>1</sup> / <sub>16</sub>	33,180
6 <sup>5</sup> / <sub>8</sub>	25.20	IEU-E75	6 <sup>5</sup> / <sub>8</sub> FH	8	5	43,934 P	7 <sup>7</sup> / <sub>16</sub>	1 <sup>1</sup> / <sub>4</sub>	26,810	7 <sup>3</sup> / <sub>8</sub>	7 <sup>1</sup> / <sub>32</sub>	24,100
		IEU-X95	6 <sup>5</sup> / <sub>8</sub> FH	8	5	43,934 P	7 <sup>5</sup> / <sub>8</sub>	1 <sup>1</sup> / <sub>32</sub>	35,139	7 <sup>1</sup> / <sub>2</sub>	9 <sup>1</sup> / <sub>32</sub>	29,552
		IEU-G105	6 <sup>5</sup> / <sub>8</sub> FH	8 <sup>1</sup> / <sub>4</sub>	4 <sup>3</sup> / <sub>4</sub>	51,280 P	7 <sup>11</sup> / <sub>16</sub>	5 <sup>1</sup> / <sub>8</sub>	37,983	7 <sup>19</sup> / <sub>32</sub>	2 <sup>1</sup> / <sub>64</sub>	33,730
		IEU-S135	6 <sup>5</sup> / <sub>8</sub> FH	8 <sup>1</sup> / <sub>2</sub>	4 <sup>1</sup> / <sub>4</sub>	65,012 P	7 <sup>20</sup> / <sub>32</sub>	2 <sup>1</sup> / <sub>64</sub>	48,204	7 <sup>25</sup> / <sub>32</sub>	2 <sup>1</sup> / <sub>64</sub>	42,312
6 <sup>5</sup> / <sub>8</sub>	27.70	IEU-E75	6 <sup>5</sup> / <sub>8</sub> FH	8	5	43,934 P	7 <sup>1</sup> / <sub>2</sub>	9 <sup>1</sup> / <sub>32</sub>	29,552	7 <sup>13</sup> / <sub>32</sub>	1 <sup>5</sup> / <sub>64</sub>	25,451
		IEU-X95	6 <sup>5</sup> / <sub>8</sub> FH	8 <sup>1</sup> / <sub>4</sub>	4 <sup>3</sup> / <sub>4</sub>	51,280 P	7 <sup>11</sup> / <sub>16</sub>	3 <sup>1</sup> / <sub>8</sub>	37,983	7 <sup>9</sup> / <sub>16</sub>	5 <sup>1</sup> / <sub>16</sub>	32,329
		IEU-G105	6 <sup>5</sup> / <sub>8</sub> FH	8 <sup>1</sup> / <sub>4</sub>	4 <sup>3</sup> / <sub>4</sub>	51,280 P	7 <sup>3</sup> / <sub>4</sub>	1 <sup>3</sup> / <sub>32</sub>	40,860	7 <sup>21</sup> / <sub>32</sub>	2 <sup>3</sup> / <sub>64</sub>	36,556
		IEU-S135	6 <sup>5</sup> / <sub>8</sub> FH	8 <sup>1</sup> / <sub>2</sub>	4 <sup>1</sup> / <sub>4</sub>	65,012 P	8	1 <sup>27</sup> / <sub>32</sub>	52,714	7 <sup>27</sup> / <sub>32</sub>	2 <sup>9</sup> / <sub>64</sub>	45,241

<sup>1</sup>The use of outside diameters (OD) smaller than those listed in the table may be acceptable due to special service requirements.

<sup>2</sup>Tool joint with dimensions shown has lower torsional yield ratio than the 0.80 which is generally used.

<sup>3</sup>Recommended make-up torque is based on 72,000 psi stress.

<sup>4</sup>In calculation of torsional strengths of tool joints, both new and worn, the bevels of the tool joint shoulders are disregarded. This thickness measurement should be made in the plane of the face from the I.D. of the counter bore to the outside diameter of the box, disregarding the bevels.

<sup>5</sup>Any tool joint with an outside diameter less than API bevel diameter should be provided with a minimum <sup>1</sup>/<sub>32</sub> inch depth × 45 degree bevel on the outside and inside diameter of the box shoulder and outside diameter of the pin shoulder.

<sup>6</sup>P = Pin limit; B = Box limit.

\*Tool joint diameters specified are required to retain torsional strength in the tool joint comparable to the torsional strength of the attached drill pipe. These should be adequate for all service. Tool joints with torsional strengths considerably below that of the drill pipe may be adequate for much drilling service.

Table 11—Buoyancy Factors

(1)	(2)	(3)
Mud Density lb/gal	Mud Density lb/cu ft	Buoyancy Factor, Kb
8.4	62.84	.872
8.6	64.33	.869
8.8	65.83	.866
9.0	67.32	.862
9.2	68.82	.859
9.4	70.32	.856
9.6	71.81	.853
9.8	73.31	.850
10.0	74.80	.847
10.2	76.30	.844
10.4	77.80	.841
10.6	79.29	.838
10.8	80.79	.835
11.0	82.29	.832
11.2	83.78	.829
11.4	85.28	.826
11.6	86.77	.823
11.8	88.27	.820
12.0	89.77	.817
12.2	91.26	.814
12.4	92.76	.811
12.6	94.25	.807
12.8	95.75	.804
13.0	97.25	.801
13.2	98.74	.798
13.4	100.24	.795
13.6	101.74	.792
13.8	103.23	.789
14.0	104.73	.786
14.2	106.22	.783
14.4	107.72	.780
14.6	109.22	.777
14.8	110.71	.774
15.0	112.21	.771
15.2	113.70	.768
15.4	115.20	.765
15.6	116.70	.762
15.8	118.19	.759
16.0	119.69	.756
16.2	121.18	.752
16.4	122.68	.749
16.6	124.18	.746
16.8	125.67	.743
17.0	127.17	.740
17.2	128.66	.737
17.4	130.16	.734
17.6	131.66	.731
17.8	133.15	.728
18.0	134.65	.725
18.5	138.39	.717
19.0	142.13	.710
19.5	145.87	.702

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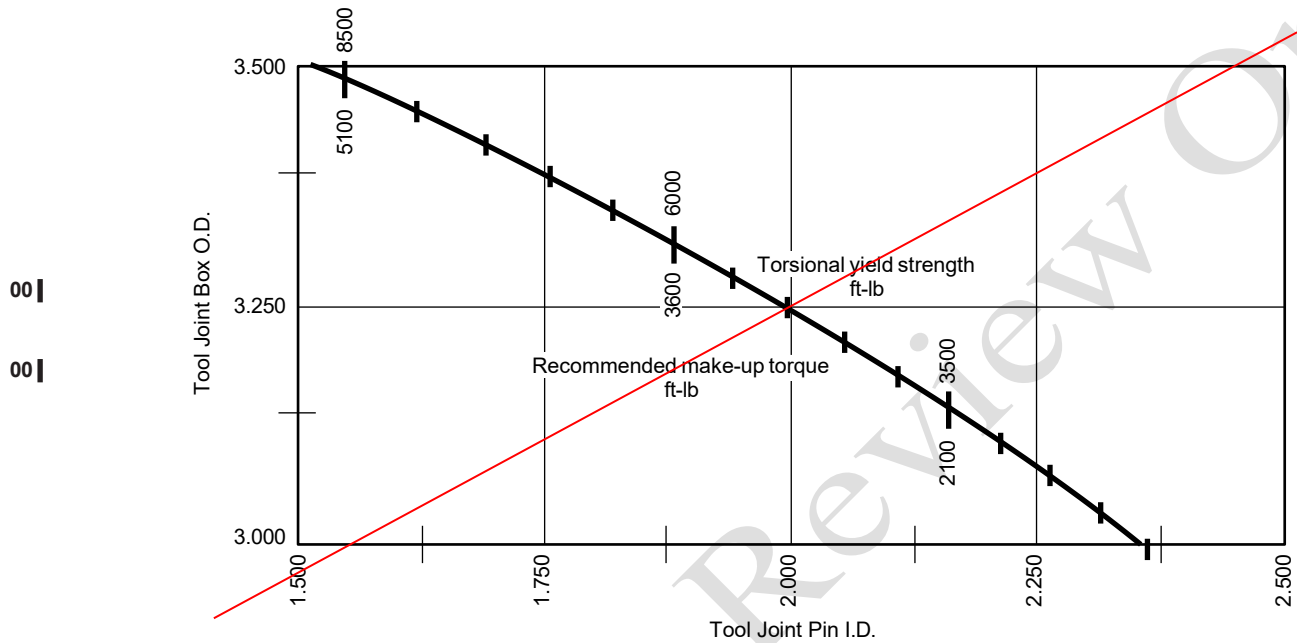


Table 12—Rotary Shouldered Connection Interchange List

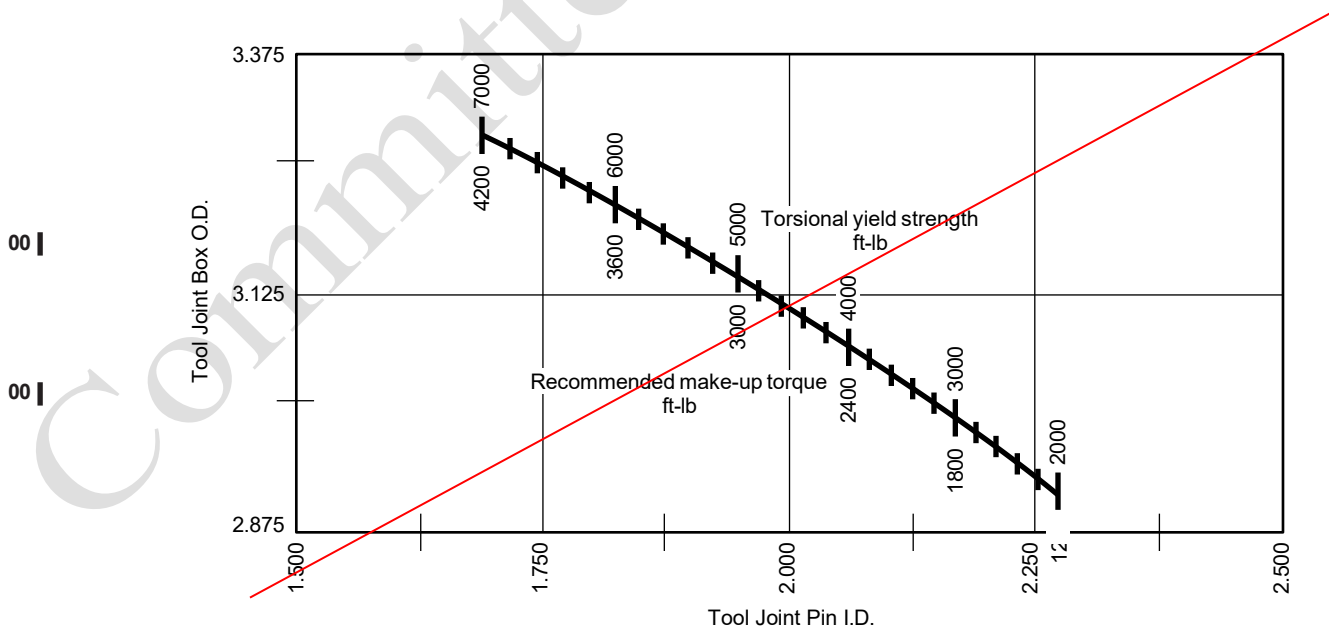
Common Name		Pin Base Diameter (Tapered)	Threads Per in.	Taper in/ft	Thread Form <sup>1</sup>	Same as or Interchanges With
Style	Size					
Internal Flush (I.F.)	2 <sup>7</sup> / <sub>8</sub>	2.876	4	2	V-0.065 (V-0.038R)	2 <sup>7</sup> / <sub>8</sub> Slim Hole N.C. 26 <sup>2</sup>
	2 <sup>7</sup> / <sub>8</sub>	3.391	4	2	V-0.065 (V-0.038R)	3 <sup>1</sup> / <sub>2</sub> Slim Hole N.C. 31 <sup>2</sup>
	3 <sup>1</sup> / <sub>2</sub>	4.016	4	2	V-0.065 (V-0.038R)	4 <sup>1</sup> / <sub>2</sub> Slim Hole N.C. 38 <sup>2</sup>
	4"	4.834	4	2	V-0.065 (V-0.038R)	4 <sup>1</sup> / <sub>2</sub> Extra Hole N.C. 46 <sup>2</sup>
	4 <sup>1</sup> / <sub>2</sub>	5.250	4	2	V-0.065 (V-0.038R)	5 Extra Hole N.C. 50 <sup>2</sup>
						5 <sup>1</sup> / <sub>2</sub> Double Streamline
Full Hole (F.H.)	4	4.280	4	2	V-0.065 (V-0.038R)	4 <sup>1</sup> / <sub>2</sub> Double Streamline N.C. 40 <sup>2</sup>
Extra Hole (X.H.) (E.H.)	2 <sup>7</sup> / <sub>8</sub>	3.327	4	2	V-0.065 (V-0.038R)	3 <sup>1</sup> / <sub>2</sub> Double Streamline
	3 <sup>1</sup> / <sub>2</sub>	3.812	4	2	V-0.065 (V-0.038R)	4 Slim Hole
	4 <sup>1</sup> / <sub>2</sub>	4.834	4	2	V-0.065 (V-0.038R)	4 <sup>1</sup> / <sub>2</sub> External Flush 4 Internal Flush N.C. 46 <sup>2</sup>
	5	5.250	4	2	V-0.065 (V-0.038R)	4 <sup>1</sup> / <sub>2</sub> Internal Flush N.C. 50 <sup>2</sup>
						5 <sup>1</sup> / <sub>2</sub> Double Streamline
Slim Hole (S.H.)	2 <sup>7</sup> / <sub>8</sub>	2.876	4	2	V-0.065 (V-0.038R)	2 <sup>7</sup> / <sub>8</sub> Internal Flush N.C. 26 <sup>2</sup>
	3 <sup>1</sup> / <sub>2</sub>	3.391	4	2	V-0.065 (V-0.038R)	2 <sup>7</sup> / <sub>8</sub> Internal Flush N.C. 31 <sup>2</sup>
	4	3.812	4	2	V-0.065 (V-0.038R)	3 <sup>1</sup> / <sub>2</sub> Extra Hole 4 <sup>1</sup> / <sub>2</sub> External Flush
	4 <sup>1</sup> / <sub>2</sub>	4.016	4	2	V-0.065 (V-0.038R)	3 <sup>1</sup> / <sub>2</sub> Internal Flush N.C. 38 <sup>2</sup>
Double-Streamline (DSL)	3 <sup>1</sup> / <sub>2</sub>	3.327	4	2	V-0.065 (V-0.038R)	2 <sup>7</sup> / <sub>8</sub> Extra Hole
	4 <sup>1</sup> / <sub>2</sub>	4.280	4	2	V-0.065 (V-0.038R)	4 Full Hole N.C. 40 <sup>2</sup>
	5 <sup>1</sup> / <sub>2</sub>	5.250	4	2	V-0.065 (V-0.038R)	4 <sup>1</sup> / <sub>2</sub> Internal Flush 5 Extra Hole N.C. 50 <sup>2</sup>
Numbered Connection (N.C.)	26	2.876	4	2	V-0.038R	2 <sup>7</sup> / <sub>8</sub> Internal Flush 2 <sup>7</sup> / <sub>8</sub> Slim Hole
	31	3.391	4	2	V-0.038R	2 <sup>7</sup> / <sub>8</sub> Internal Flush 3 <sup>1</sup> / <sub>2</sub> Slim Hole
	38	4.016	4	2	V-0.038R	3 <sup>1</sup> / <sub>2</sub> Internal Flush 4 <sup>1</sup> / <sub>2</sub> Slim Hole
	40	4.280	4	2	V-0.038R	4 Full Hole 4 <sup>1</sup> / <sub>2</sub> Double Streamline
	46	4.834	4	2	V-0.038R	4 Internal Flush 4 <sup>1</sup> / <sub>2</sub> Extra Hole
	50	5.250	4	2	V-0.038R	4 <sup>1</sup> / <sub>2</sub> Internal Flush 5 Extra Hole
External Flush (E.F.)	4 <sup>1</sup> / <sub>2</sub>	3.812	4	2	V-0.065 (V-0.038R)	4 Slim Hole 3 <sup>1</sup> / <sub>2</sub> Extra Hole

<sup>1</sup>Connections with two thread forms shown may be machined with either thread form without affecting gauging or interchangeability.<sup>2</sup>Numbered connections (N.C.) may be machined only with the V-0.038 radius thread form.

**Figures 1-25—Torsional Strength and Recommended Make-up Torque Curves—**  
**(All curves based on 120,000 psi minimum yield strength and 60 percent**  
**of minimum yield strength for recommended make-up torque.)**



**Figure 1—NC26 Torsional Yield and Make-up**



**Figure 2—2 3/8 Open Hole Torsional Yield and Make-up**

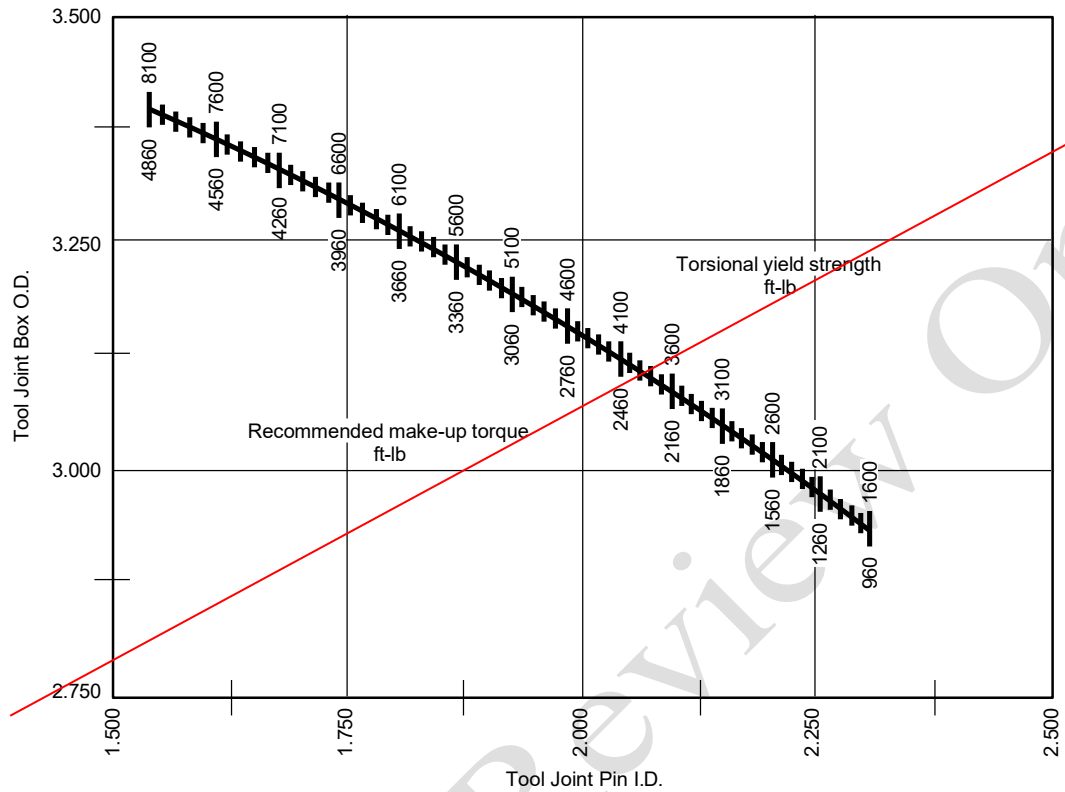


Figure 3—2 3/8 Wide Open Torsional Yield and Make-up

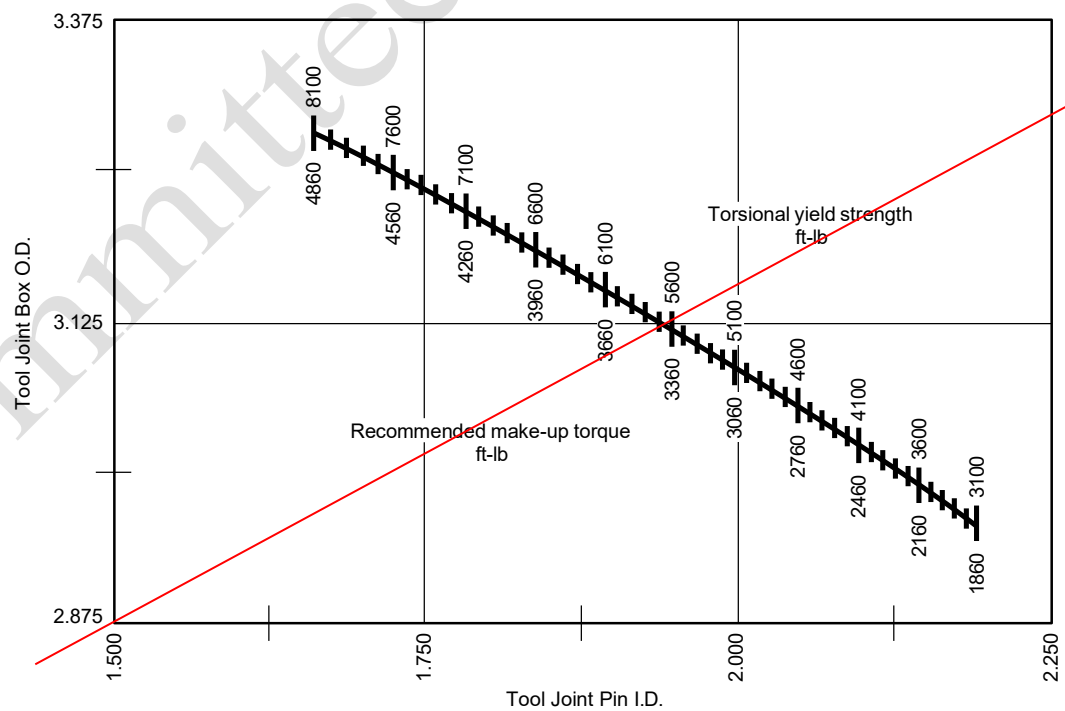


Figure 4—2 3/8 SLH90 Torsional Yield and Make-up

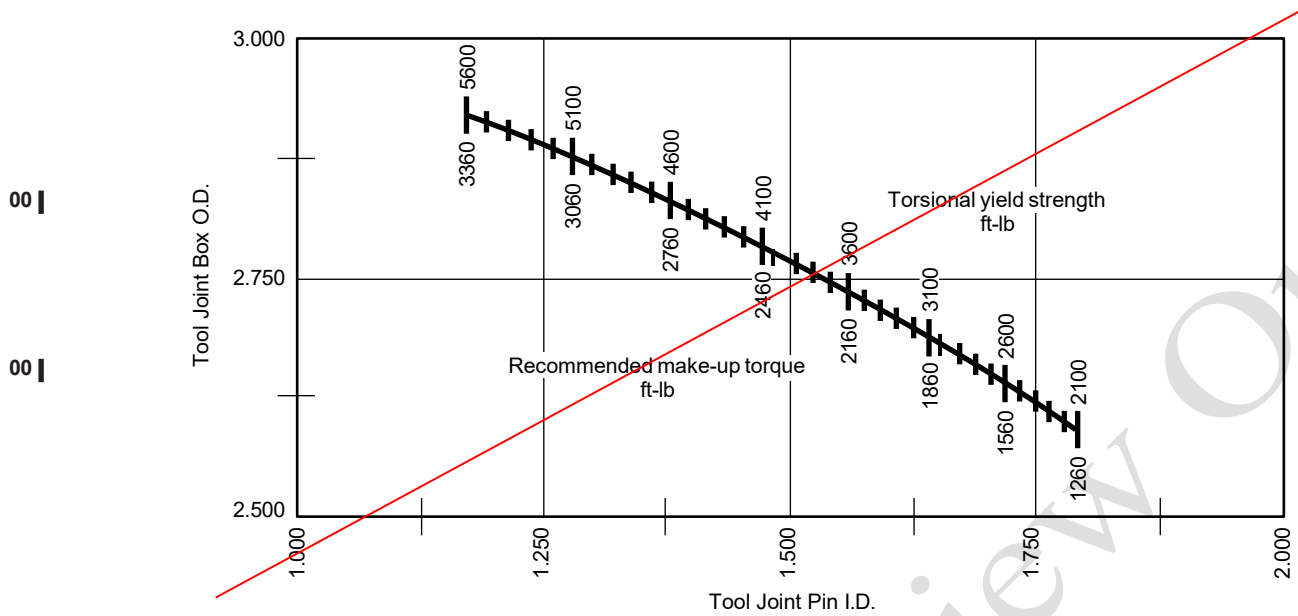


Figure 5—2 3/8 PAC Torsional Yield and Make-up

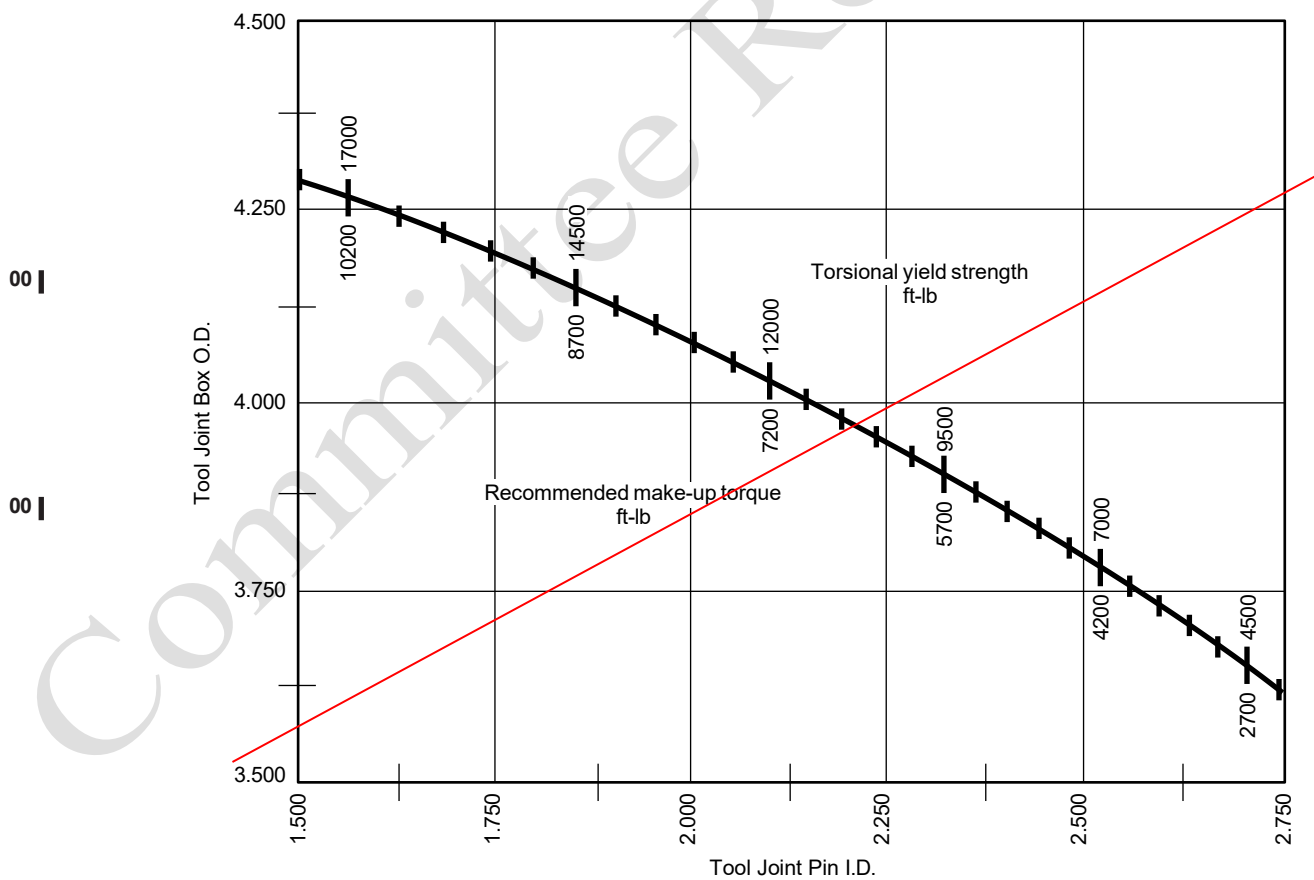


Figure 6—NC31 Torsional Yield and Make-up

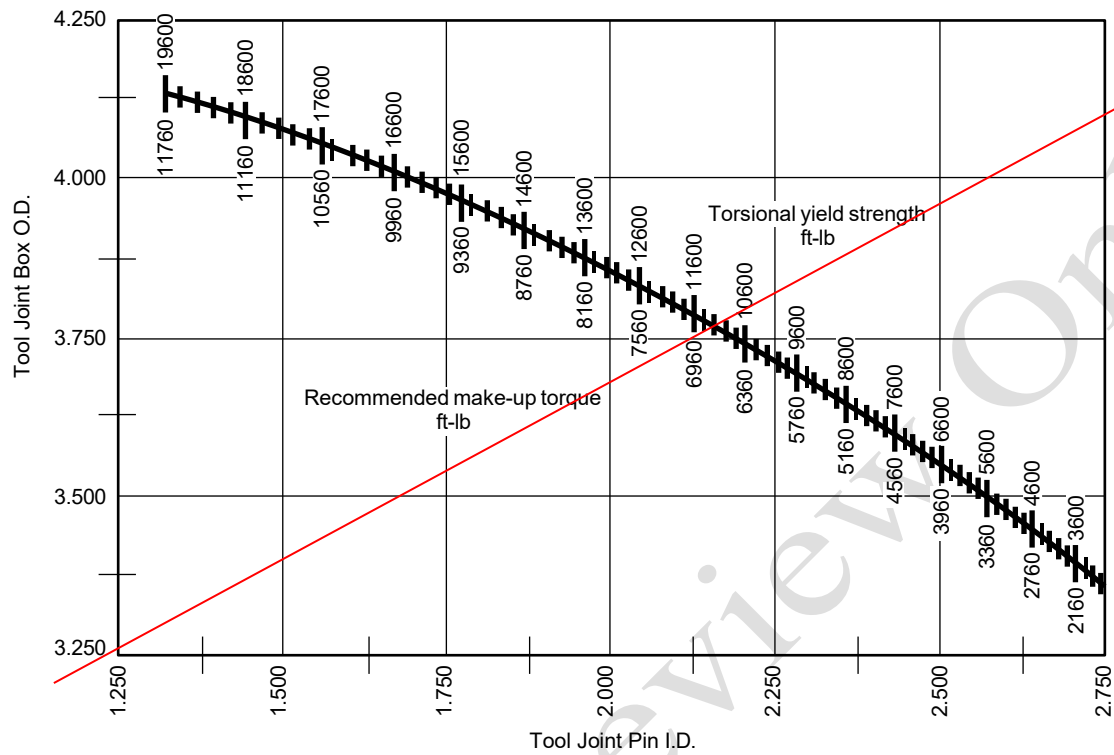


Figure 7—2 7/8 SLH90 Torsional Yield and Make-up

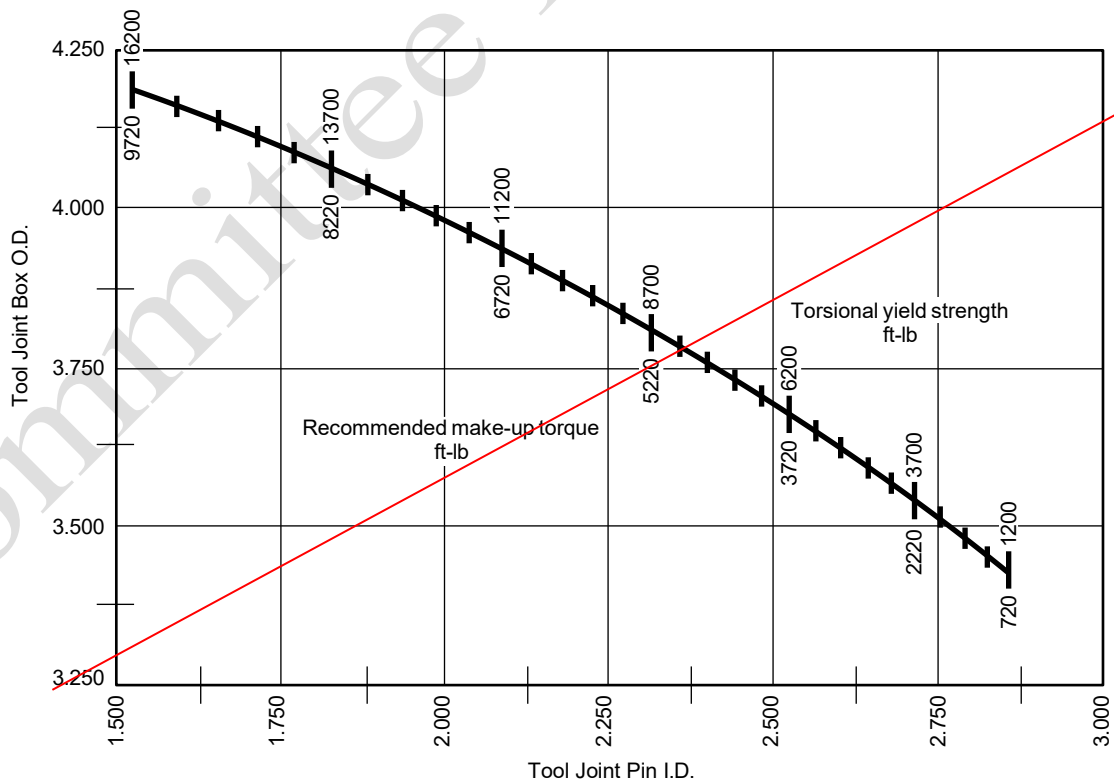


Figure 8—2 7/8 Wide Open Torsional Yield and Make-up

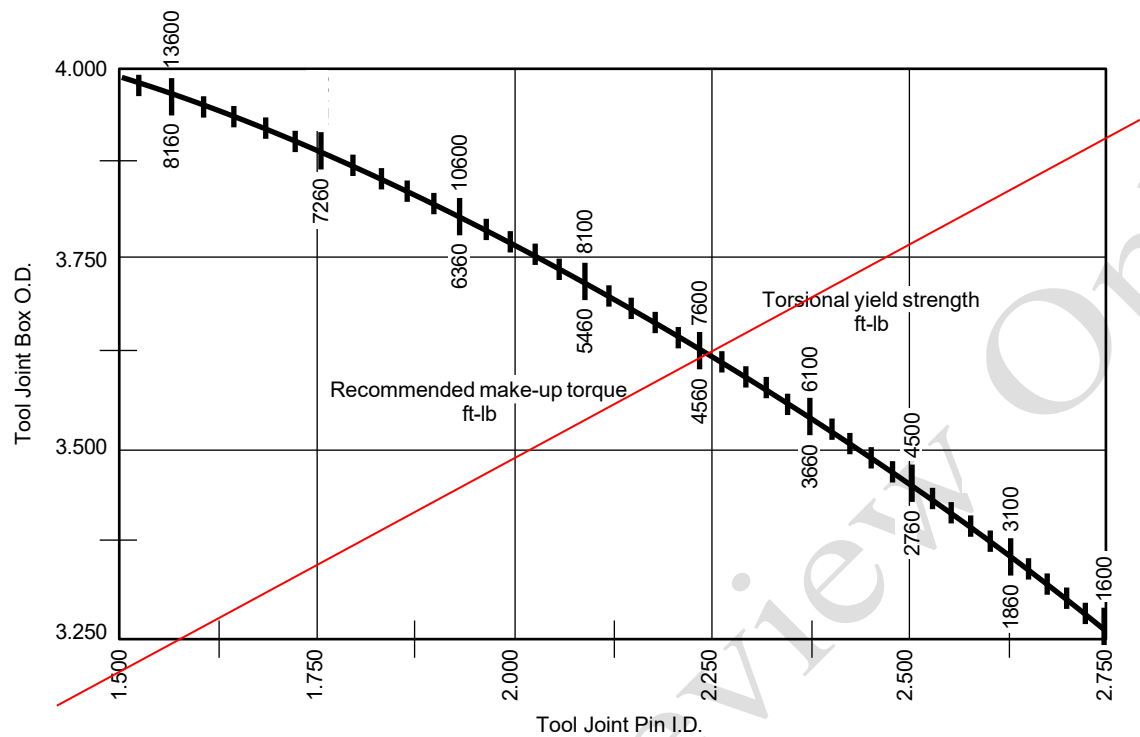


Figure 9—2 7/8 Open Hole Torsional Yield and Make-up

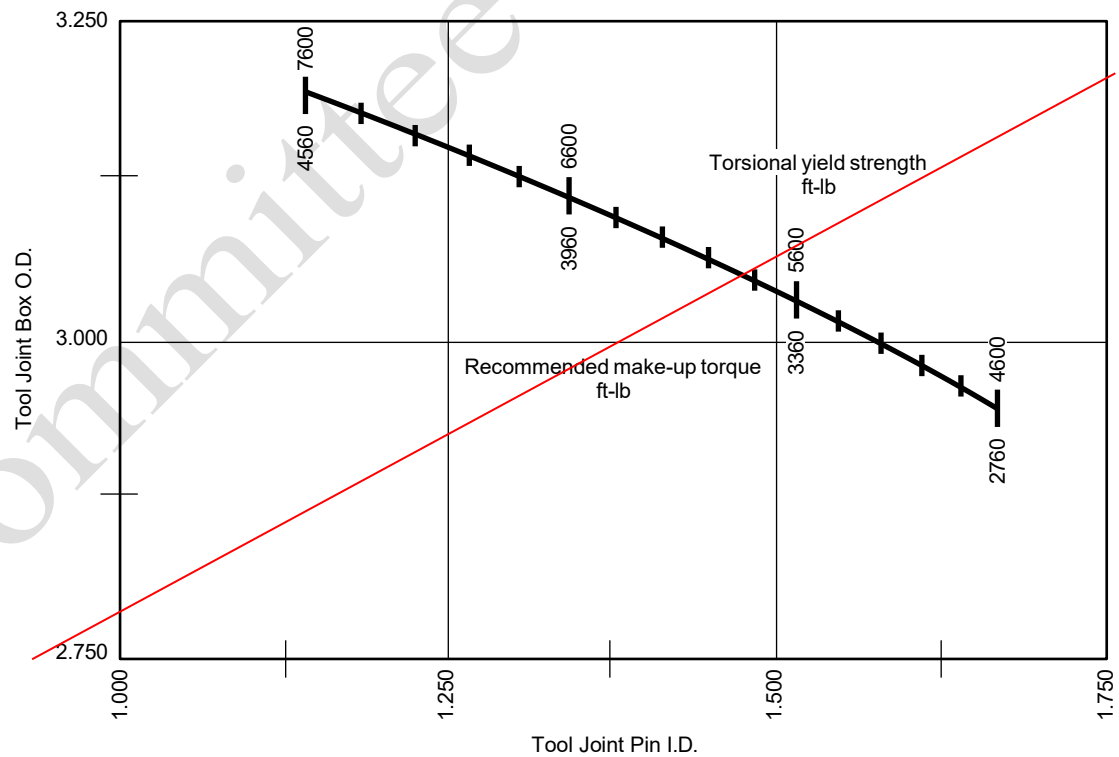


Figure 10—2 7/8 PAC Torsional Yield and Make-up

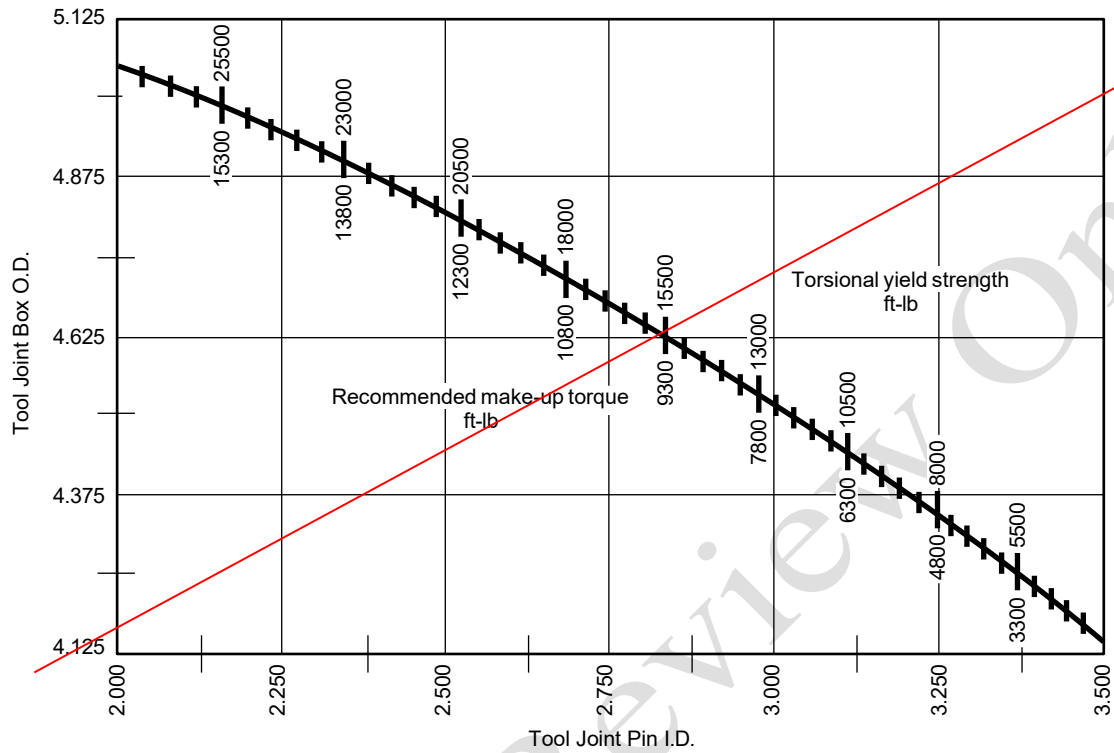


Figure 11—NC38 Torsional Yield and Make-up

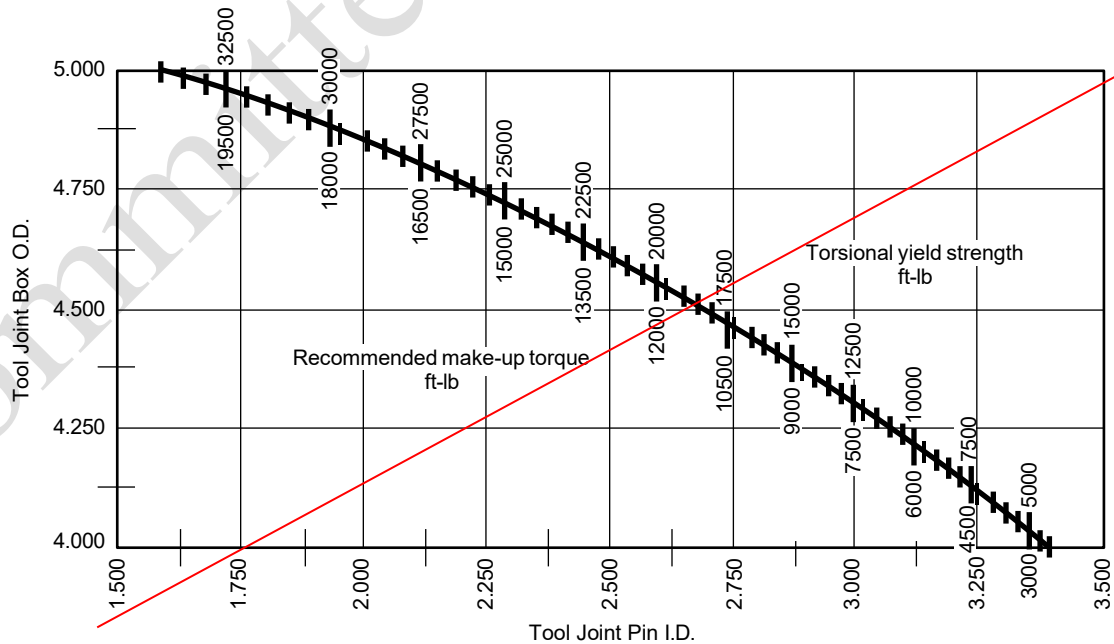


Figure 12—3 1/2 SLH90 Torsional Yield and Make-up

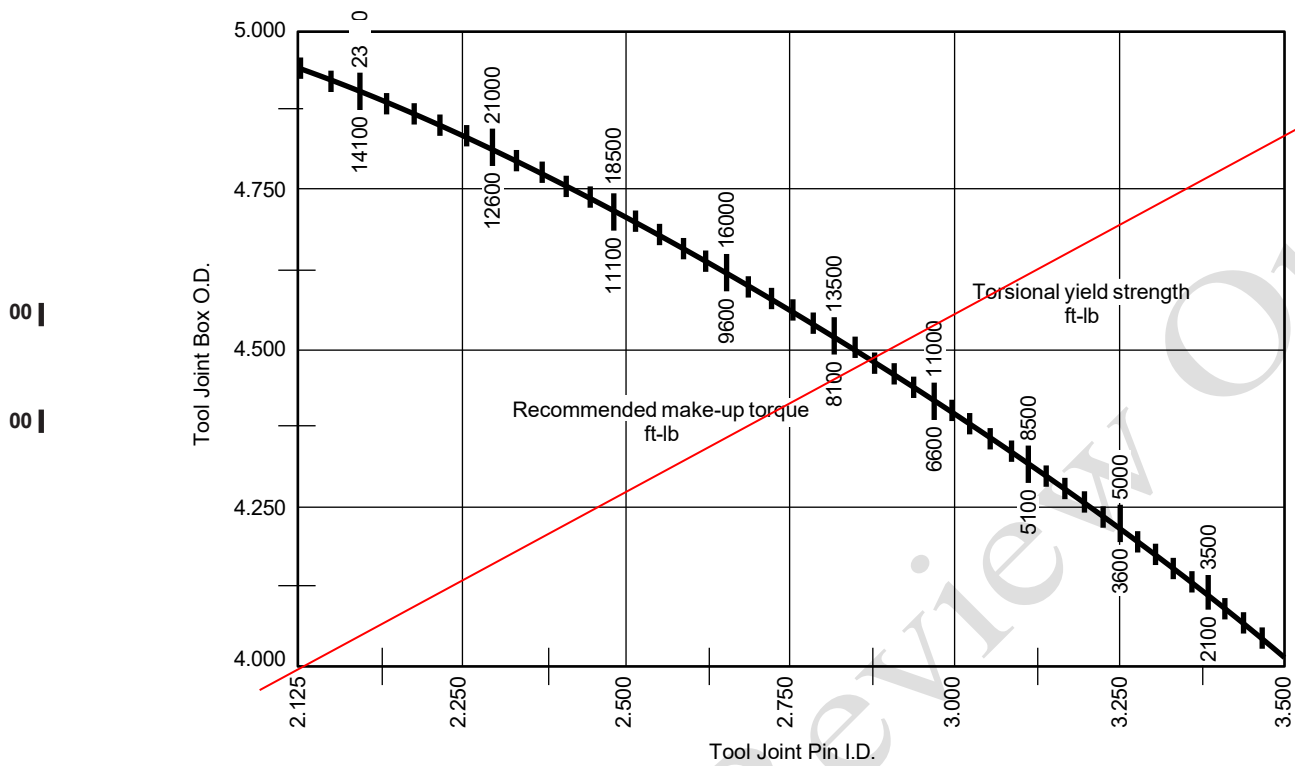


Figure 13—3 1/2 FH Torsional Yield and Make-up

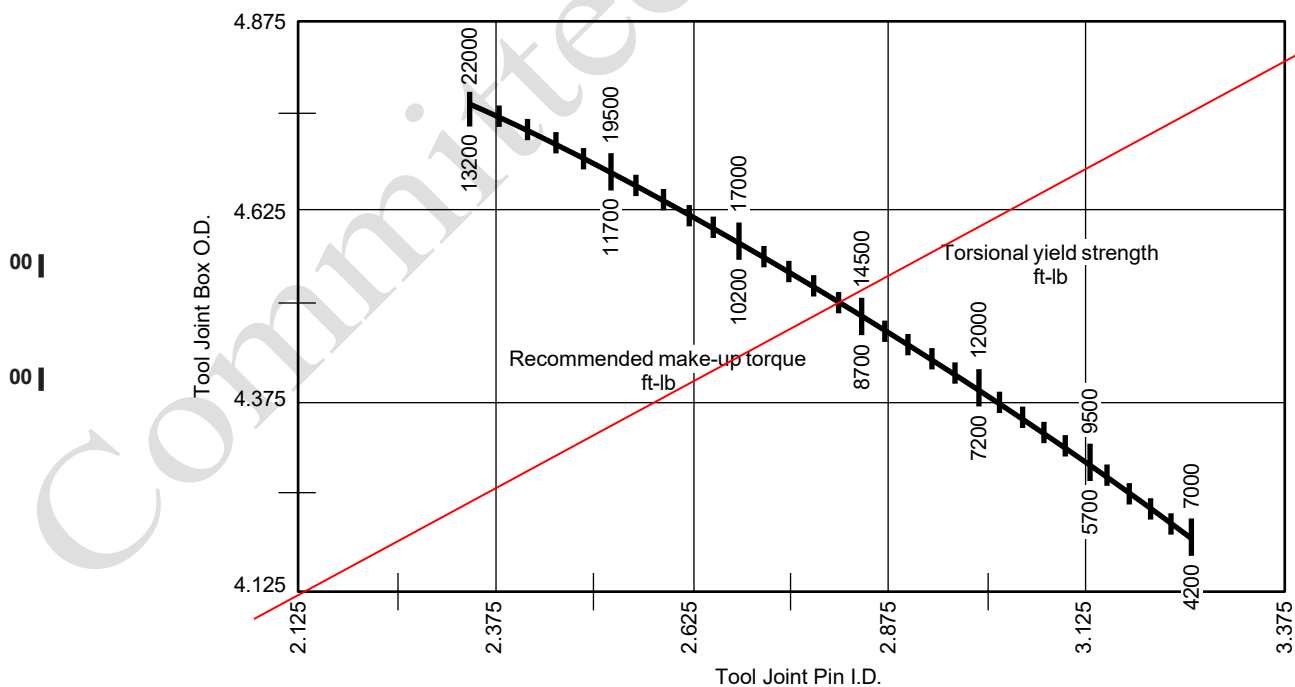


Figure 14—3 1/2 Open Hole Torsional Yield and Make-up



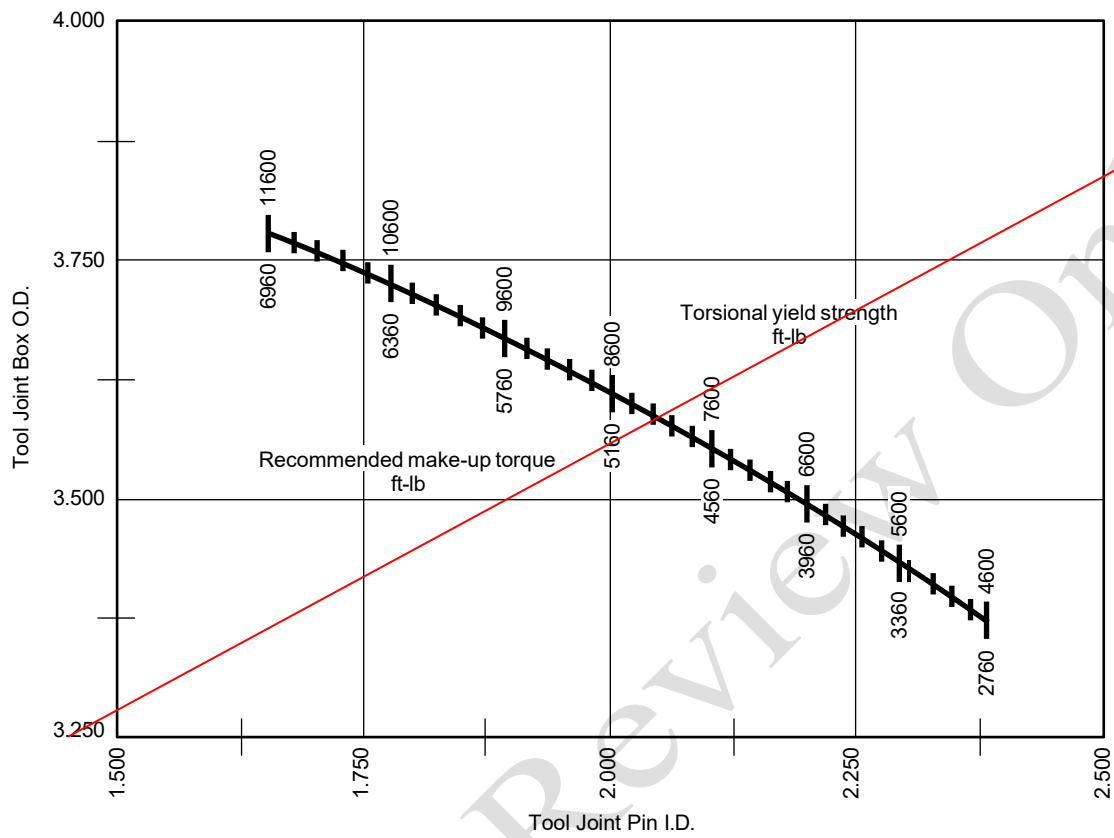


Figure 15—3 1/2 PAC Torsional Yield and Make-up

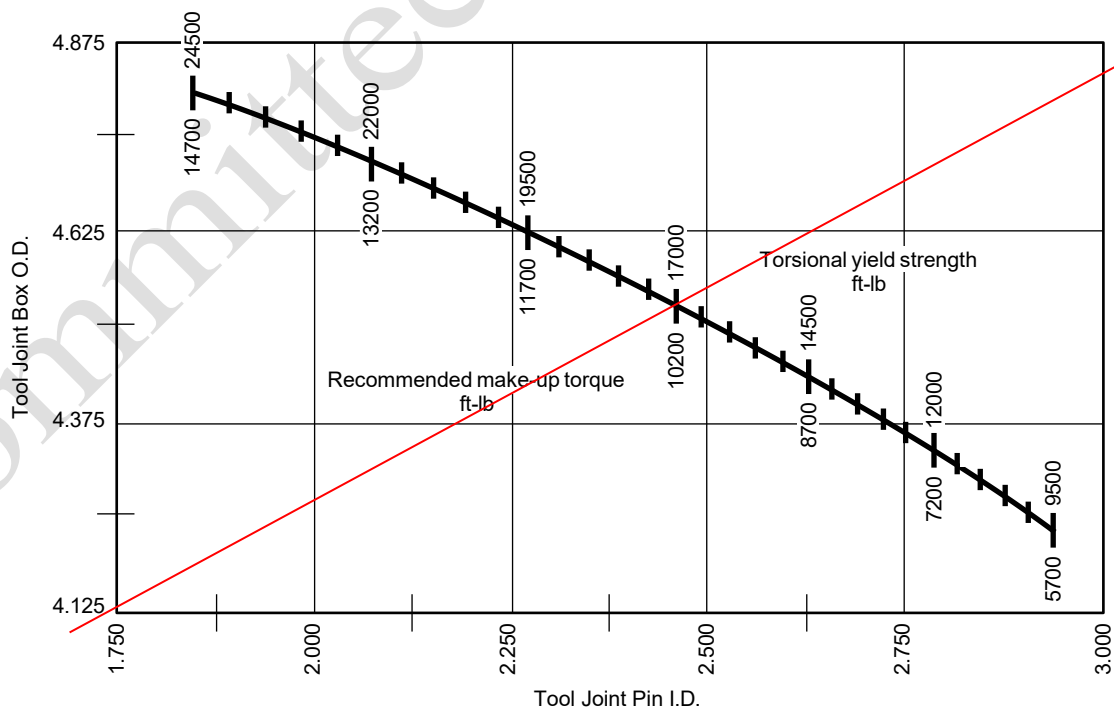


Figure 16—3 1/2 XH Torsional Yield and Make-up

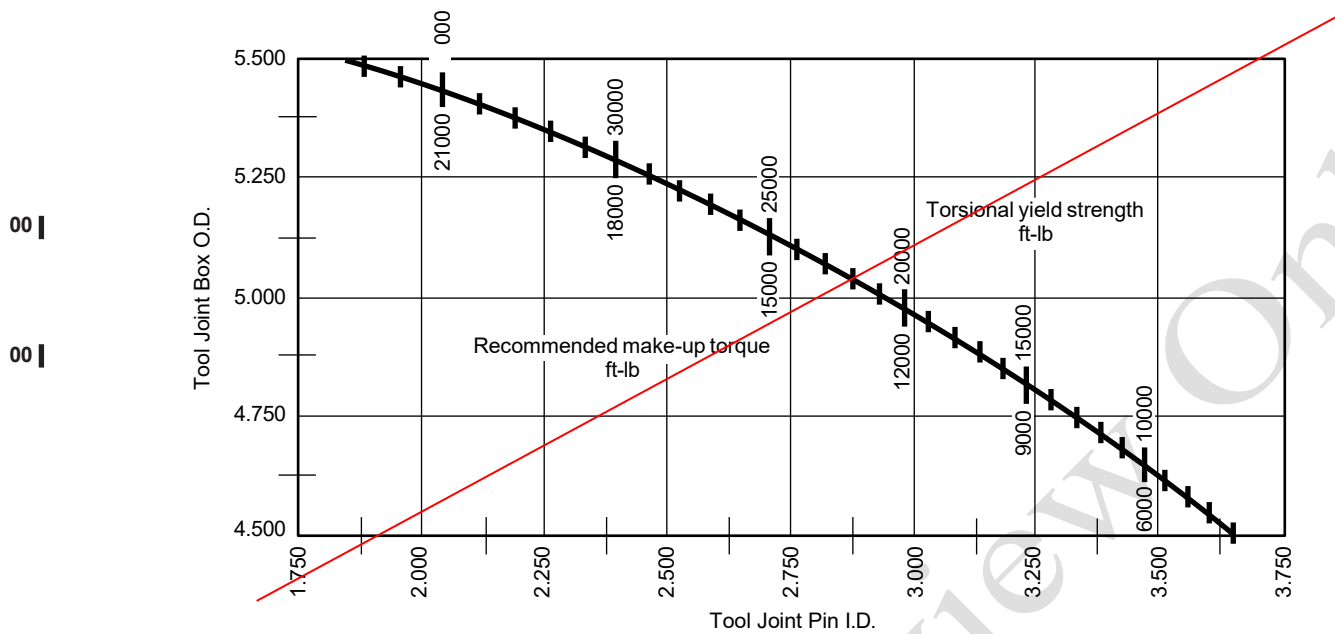


Figure 17—NC40 Torsional Yield and Make-up

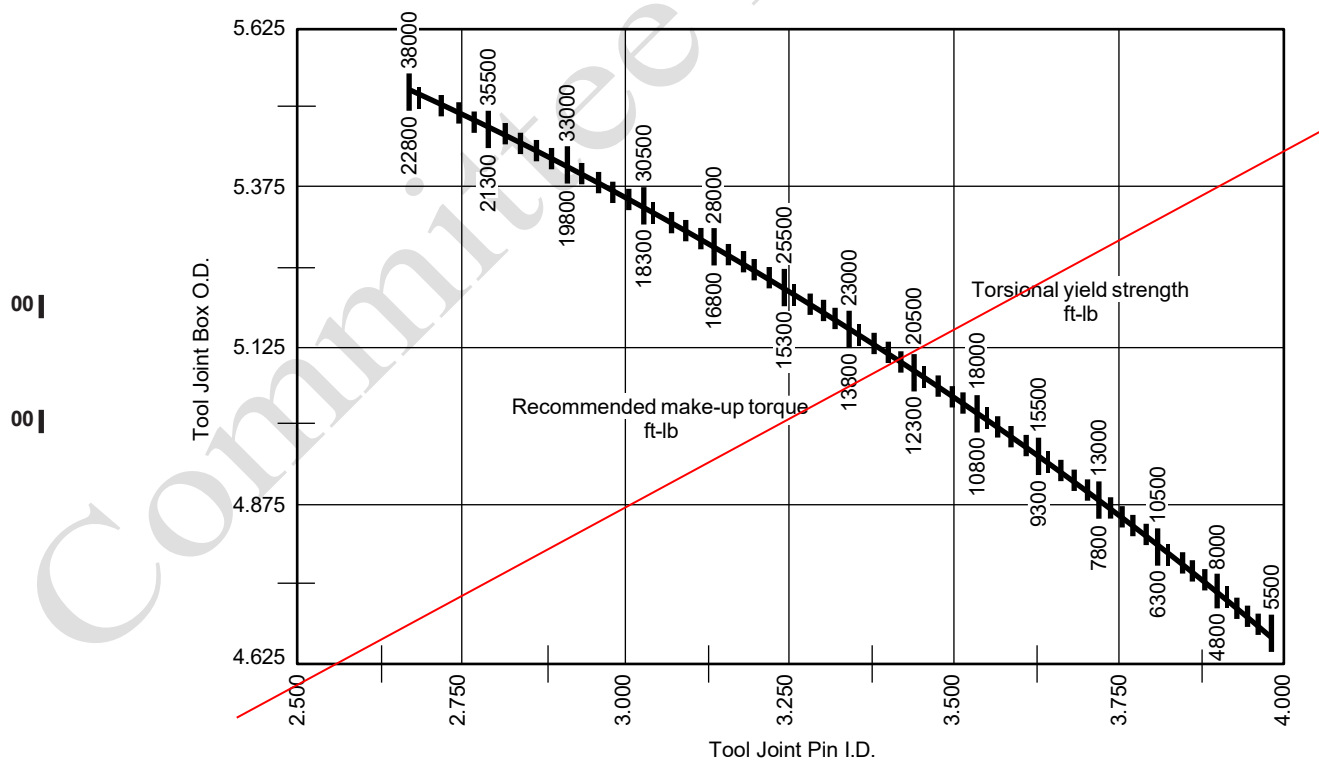


Figure 18—4-Inch H90 Torsional Yield and Make-up

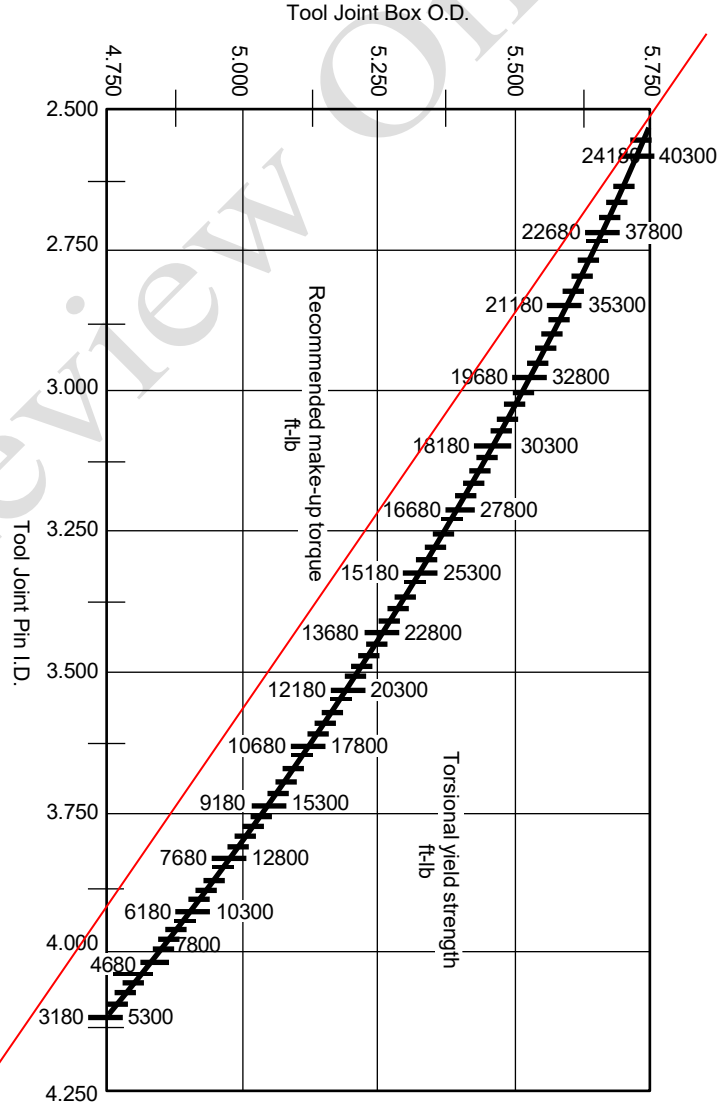


Figure 19 — 4-inch Open Hole Torsional Yield and Make-up

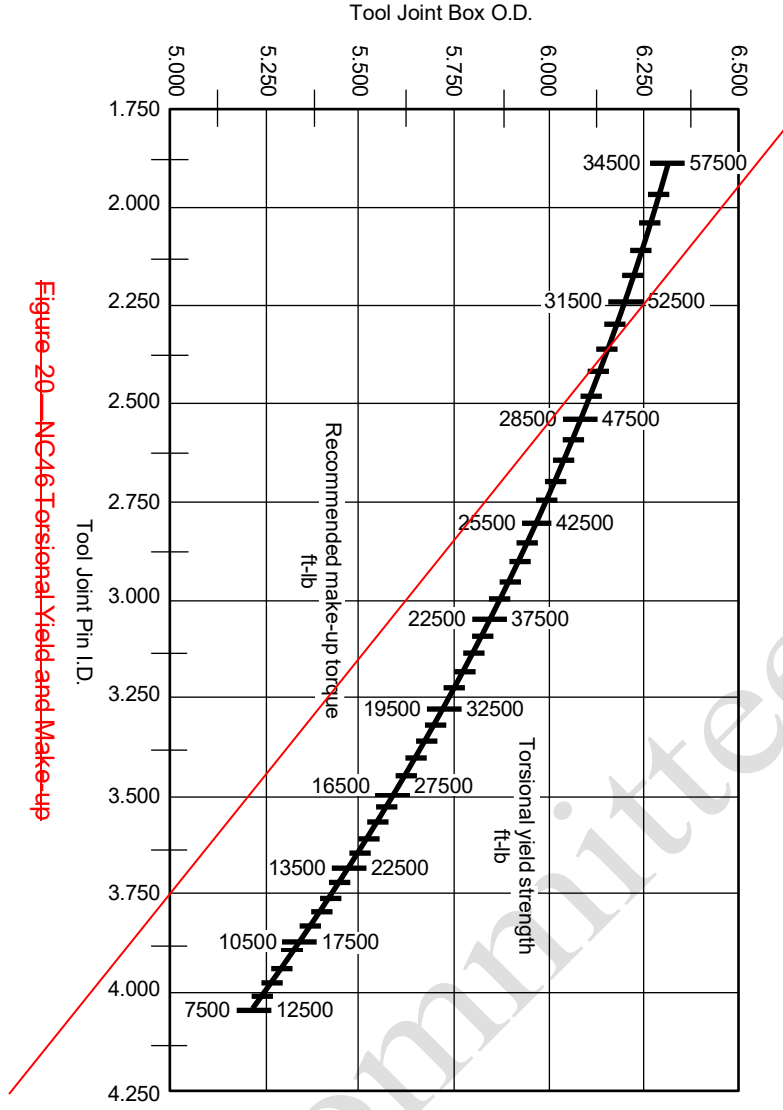


Figure 20 — NC416 Torsional Yield and Make-up

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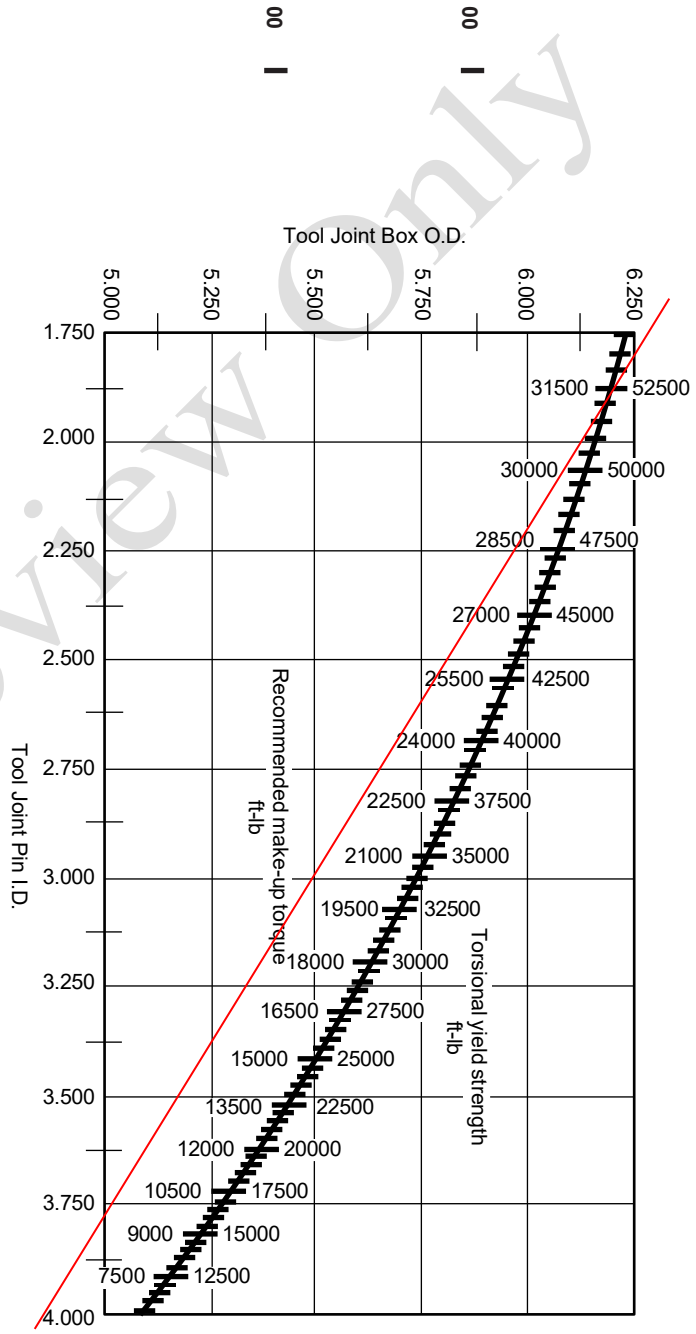


Figure 21 4 1/2 FH Torsional Yield and Make-up

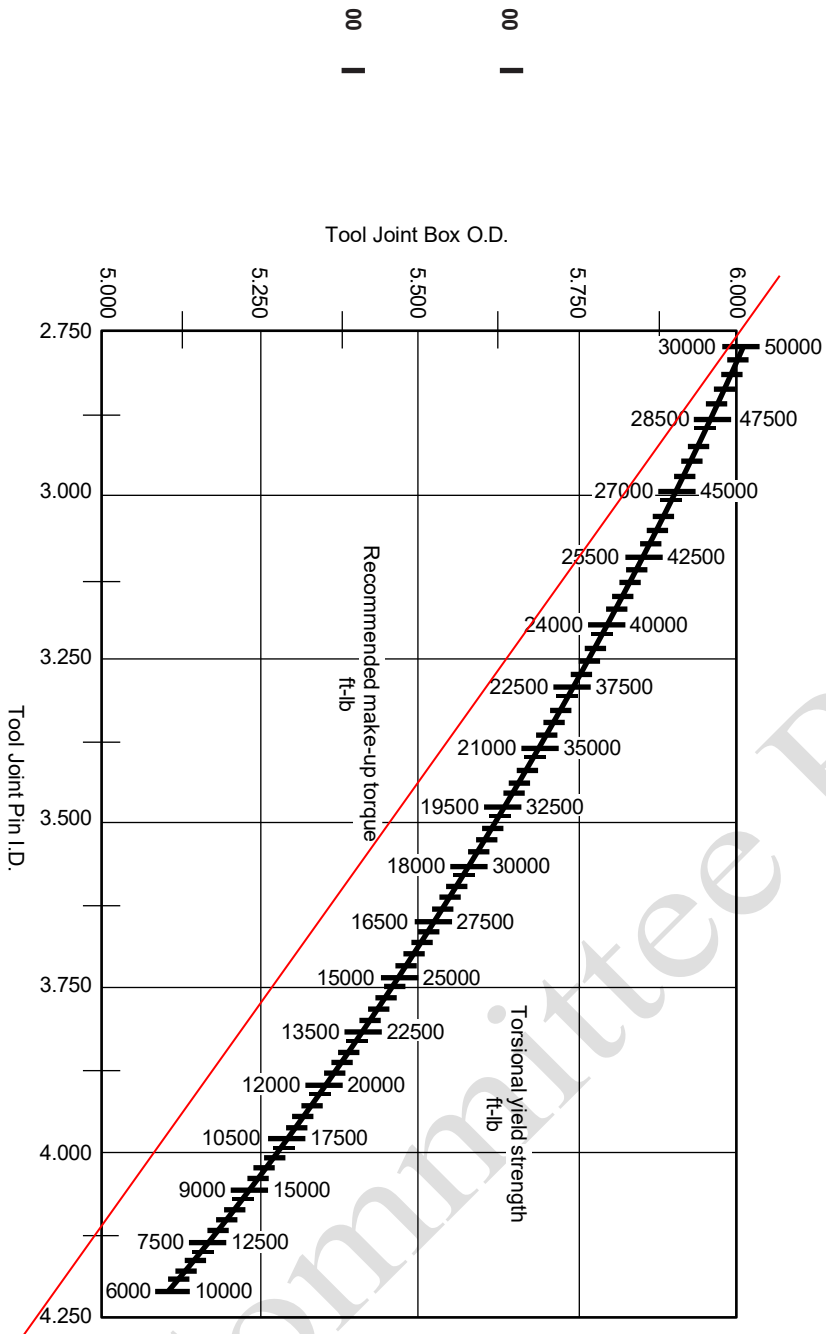


Figure 22 4 1/2 H90 Torsional Yield and Make-up

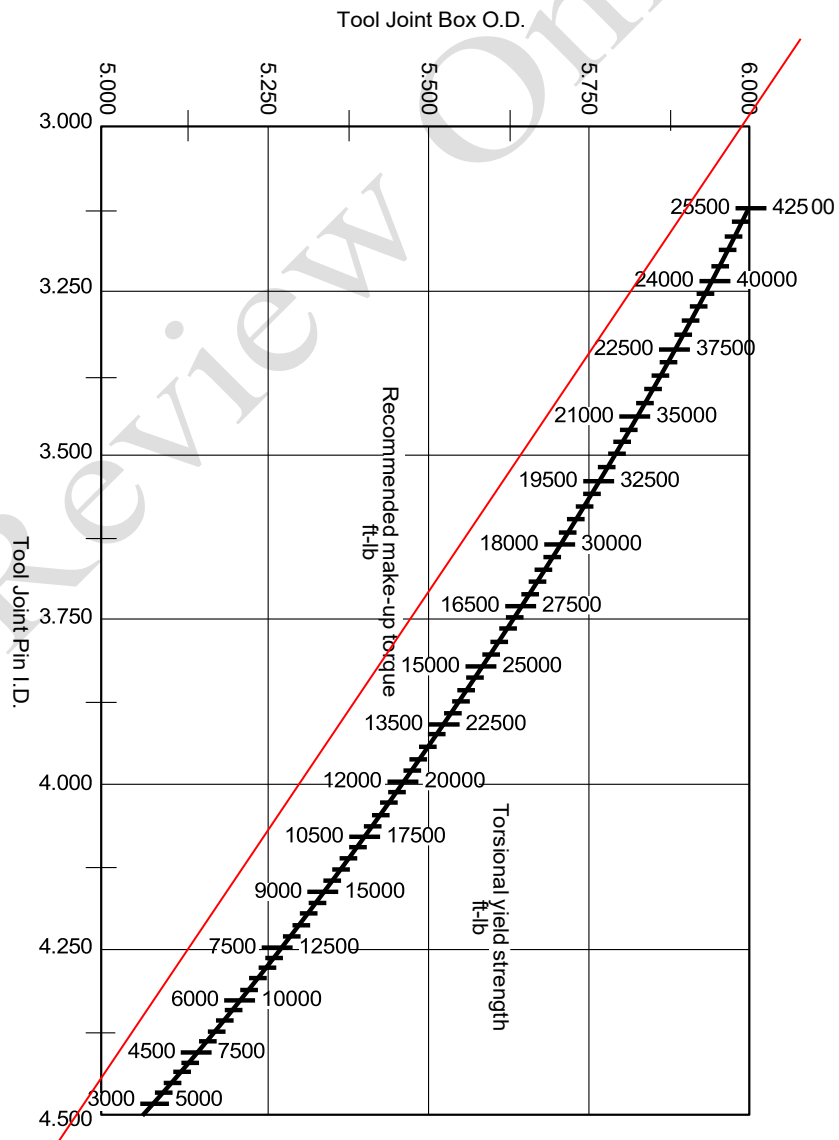


Figure 23 4 1/2" Open Hole (Standard Weight) Torsional Yield and Make-up

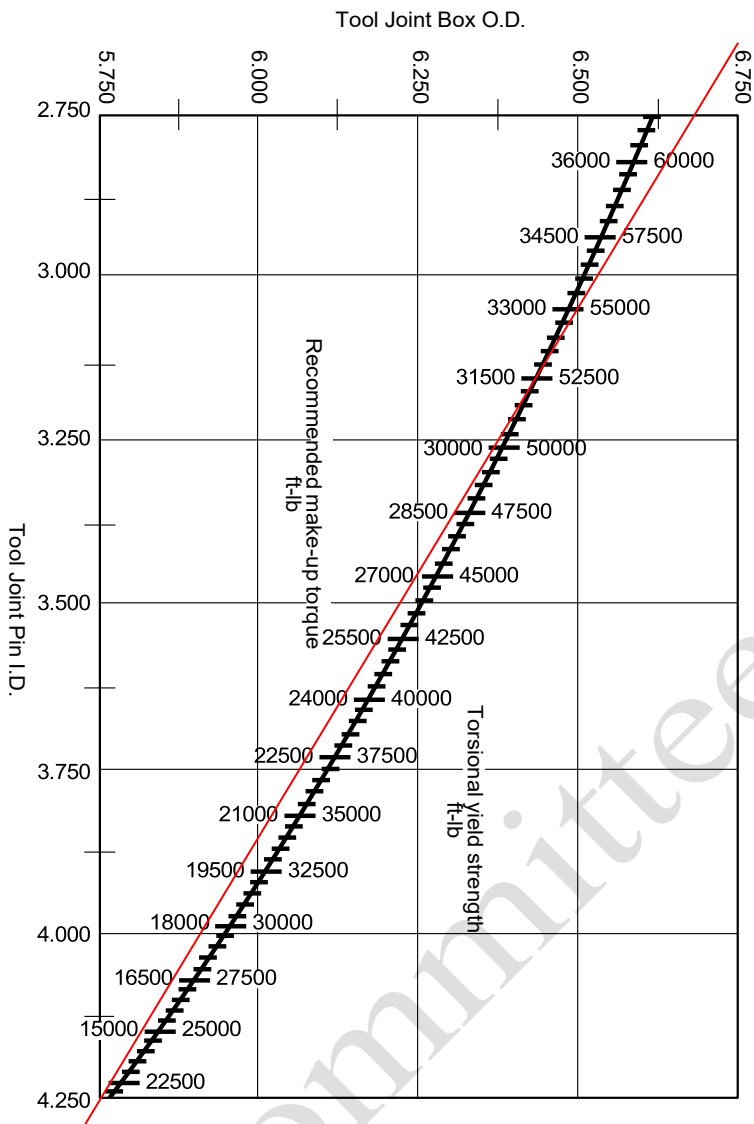


Figure 24 NC50 Torsional Yield and Make-up

- - - -

Committee Review Only

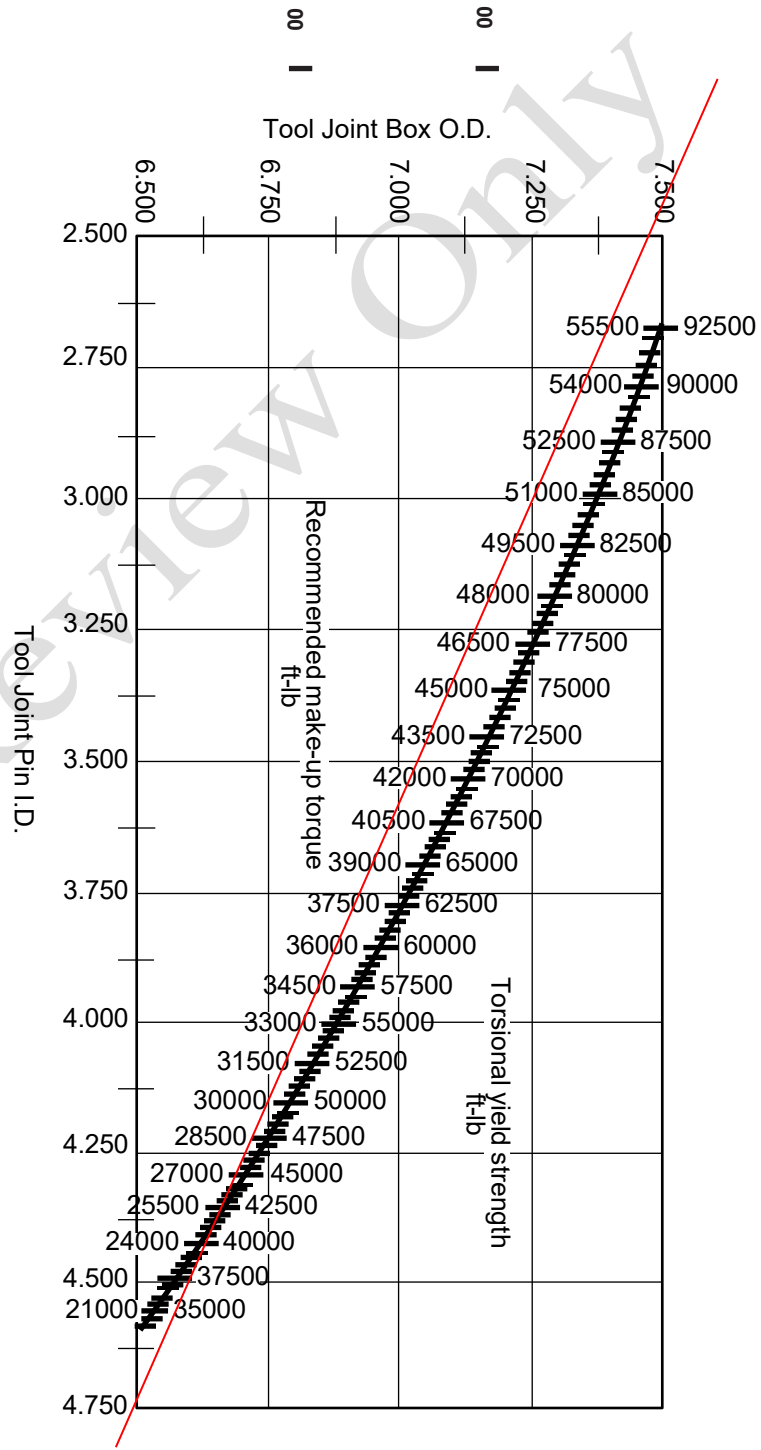


Figure 25 — 5 1/2 FH Torsional Yield and Make-up



**4.12**—The recommended make-up torque for a used tool joint is determined by taking the following steps:

**4.12.1**—Select the appropriately titled curve for the size and type tool joint connection being studied.

**4.12.2**—Extend a horizontal line from the OD under consideration to the curve and read the recommended make up torque representing the box.

**4.12.3**—Extend a vertical line from the ID under consideration to the curve and read the recommended make up torque representing the pin.

**4.12.4**—The smaller of the two recommended make up torques thus obtained is the recommended make up torque for the tool joint.

**4.12.5**—A make-up torque higher than recommended may be required under extreme conditions.

## 5 Properties Of Drill Collars

**5.1**—Table 13 contains steel drill collar weights for a wide range of OD and ID combinations, in both API and non-API sizes. Values in the table may be used to provide the basic information required to calculate the weights of drill collar strings that are not made up of collars having uniform and standard weights.

**5.2**—Recommended make up torque values for rotary shouldered drill collar connections are listed in Table 14. These values are listed for various connection styles and for commonly used drill collar OD and ID sizes. The table also includes a designation of the weak member (pin or box) for each connection size and style.

**5.3**—Many drill collar connection failures are a result of bending stresses rather than torsional stresses. Figures 26 through 32 may be used for determining the most suitable connection to be used on new drill collars or for selecting the new connection to be used on collars which have been worn down on the outside diameter.

**5.4**—A connection that has a bending strength ratio of 2.50:1 is generally accepted as an average balanced connection. However, the acceptable range may vary from 3.20:1 to 1.90:1 depending upon the drilling conditions.

**5.5**—As the outside diameter of the box will wear more rapidly than the pin inside diameter, the resulting bending strength ratio will be reduced accordingly. When the bending strength ratio falls below 2.00:1, connection troubles may begin. These troubles may consist of swollen boxes, split boxes, or fatigue cracks in the boxes at the last engaged thread.

**5.6**—The minimum bending strength ratio acceptable in one operating area may not be acceptable in another. Local operating practices experience based on recent predominance of failures and other conditions should be considered when

determining the minimum acceptable bending strength ratio for a particular area and type of operation.

**5.7**—Certain other precautions should be observed in using these charts. It is imperative that adequate shoulder width and area at the end of the pin be maintained. The calculations involving bending strength ratios are based on standard dimensions for all connections.

**5.8**—Minor differences between measured inside diameter and inside diameters in Figures 26 through 32 are of little significance; therefore select the figure with the inside diameter closest to measured inside diameter.

**5.9**—The curves in Figures 26 through 32 were determined from bending strength ratios calculated by using the Section Modulus (Z) as the measure of the capacity of a section to resist any bending moment to which it may be subjected. The effect of stress relief features is disregarded. The equation, its derivation, and an example of its use are included in A.11.

## 6 Properties of Kellys

**6.1**—Kellys are manufactured with one of two drive configurations, square or hexagonal. Dimensions are listed in Tables 2 and 3 entitled "Square Kellys" and "Hexagon Kellys" of API Specification 7.

**6.2**—Square kellys are furnished as forged or machined in the drive section. On forged kellys, the drive sections are normalized and tempered and the ends are quenched and tempered.

**6.3**—Hexagonal or fully machined square kellys are machined from round bars. Heat treatment may be either:

**6.3.1**—Full length quenched and tempered before machining; or

**6.3.2**—The drive section normalized and tempered and the ends quenched and tempered.

It should be noted that fully quenched drive sections have higher minimum tensile yield strength than normalized drive sections when tempered to the same hardness level. For the same hardness level, the ultimate tensile strength may be considered as the same in both cases.

**6.4**—The following criteria should be considered in selecting square or hexagonal kellys.

**6.4.1**—It may be noted from Table 15 that the drive section of the hexagonal kelly is stronger than the drive section of the square kelly when the appropriate kelly is selected for a given casing size.

Example: A 4<sup>1</sup>/<sub>4</sub>-inch square kelly or a 5<sup>1</sup>/<sub>4</sub>-inch hexagonal kelly would be selected for use in 8<sup>5</sup>/<sub>8</sub>-inch casing.

It should be noted, however, that the connections on these two kellys are generally the same and unless the bores (inside diameters) are the same, the kelly with the smaller bore could be interpreted to have the greater pin tensile and torsional strength.

(Text continued on page 46.)

Committee Review Only

**Table 13—Drill Collar Weight (Steel)  
(pounds per foot)**

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
Drill Collar OD, inches	Drill Collar ID, inches												
	1	1 <sup>1</sup> / <sub>4</sub>	1 <sup>1</sup> / <sub>2</sub>	1 <sup>3</sup> / <sub>4</sub>	2	2 <sup>1</sup> / <sub>4</sub>	2 <sup>1</sup> / <sub>2</sub>	2 <sup>13</sup> / <sub>16</sub>	3	3 <sup>1</sup> / <sub>4</sub>	3 <sup>1</sup> / <sub>2</sub>	3 <sup>3</sup> / <sub>4</sub>	4
2 <sup>7</sup> / <sub>8</sub>	19	18	16										
3	21	20	18										
3 <sup>1</sup> / <sub>8</sub>	22	22	20										
3 <sup>1</sup> / <sub>4</sub>	26	24	22										
3 <sup>1</sup> / <sub>2</sub>	30	29	27										
3 <sup>3</sup> / <sub>4</sub>	35	33	32										
4	40	39	37	35	32	29							
4 <sup>1</sup> / <sub>8</sub>	43	41	39	37	35	32							
4 <sup>1</sup> / <sub>4</sub>	46	44	42	40	38	35							
4 <sup>1</sup> / <sub>2</sub>	51	50	48	46	43	41							
4 <sup>3</sup> / <sub>4</sub>			54	52	50	47	44						
5			61	59	56	53	50						
5 <sup>1</sup> / <sub>4</sub>			68	65	63	60	57						
5 <sup>1</sup> / <sub>2</sub>			75	73	70	67	64	60					
5 <sup>3</sup> / <sub>4</sub>			82	80	78	75	72	67	64	60			
6			90	88	85	83	79	75	72	68			
6 <sup>1</sup> / <sub>4</sub>			98	96	94	91	88	83	80	76	72		
6 <sup>1</sup> / <sub>2</sub>			107	105	102	99	96	91	89	85	80		
6 <sup>3</sup> / <sub>4</sub>			116	114	111	108	105	100	98	93	89		
7			125	123	120	117	114	110	107	103	98	93	84
7 <sup>1</sup> / <sub>4</sub>			134	132	130	127	124	119	116	112	108	103	93
7 <sup>1</sup> / <sub>2</sub>			144	142	139	137	133	129	126	122	117	113	102
7 <sup>3</sup> / <sub>4</sub>			154	152	150	147	144	139	136	132	128	123	112
8			165	163	160	157	154	150	147	143	138	133	122
8 <sup>1</sup> / <sub>4</sub>			176	174	171	168	165	160	158	154	149	144	133
8 <sup>1</sup> / <sub>2</sub>			187	185	182	179	176	172	169	165	160	155	150
9			210	208	206	203	200	195	192	188	184	179	174
9 <sup>1</sup> / <sub>2</sub>			234	232	230	227	224	220	216	212	209	206	198
9 <sup>3</sup> / <sub>4</sub>			248	245	243	240	237	232	229	225	221	216	211
10			261	259	257	254	251	246	243	239	235	230	225
11			317	315	313	310	307	302	299	295	291	286	281
12			379	377	374	371	368	364	361	357	352	347	342

Notes:

- 98** | 1. See API Specification 7, Table 13 for API standard drill collar dimensions.  
2. For special configurations of drill collars, consult manufacturer for reduction in weight.

**Table 14—Recommended Make-up Torque<sup>1</sup> for Rotary Shouldered Drill Collar Connections—  
(See footnotes for use of this table.)**

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Connection			Minimum Make-up Torque ft-lb <sup>2</sup>											
Size	Type	OD, in.	Bore of Drill Collar, inches											
			1	1 <sup>1</sup> / <sub>4</sub>	1 <sup>1</sup> / <sub>2</sub>	1 <sup>3</sup> / <sub>4</sub>	2	2 <sup>1</sup> / <sub>4</sub>	2 <sup>1</sup> / <sub>2</sub>	2 <sup>3</sup> / <sub>4</sub>	3	3 <sup>1</sup> / <sub>4</sub>	3 <sup>1</sup> / <sub>2</sub>	3 <sup>3</sup> / <sub>4</sub>
API	NC-23	3	*2,508	*2,508	*2,508									
		3 <sup>1</sup> / <sub>8</sub>	*3,330	*3,330	2,647									
		3 <sup>1</sup> / <sub>4</sub>	4,000	3,387	2,647									
2 <sup>7</sup> / <sub>8</sub>	Regular	3		*2,241	*2,241	1,749								
		3 <sup>1</sup> / <sub>8</sub>		*3,028	2,574	1,749								
		3 <sup>1</sup> / <sub>4</sub>		3,285	2,574	1,749								
2 <sup>7</sup> / <sub>8</sub>	PAC <sup>3</sup>	3		*3,797	*3,797	2,926								
		3 <sup>1</sup> / <sub>8</sub>		*4,966	4,151	2,926								
		3 <sup>1</sup> / <sub>4</sub>		5,206	4,151	2,926								
2 <sup>3</sup> / <sub>8</sub>	API HF	3 <sup>1</sup> / <sub>2</sub>		*4,606	*4,606	3,697								
API	NC-26	3 <sup>1</sup> / <sub>4</sub>		5,501	4,668	3,697								
2 <sup>7</sup> / <sub>8</sub>	Regular	3 <sup>1</sup> / <sub>2</sub>		*3,838	*3,838	*3,838								
		3 <sup>3</sup> / <sub>4</sub>		5,766	4,951	4,002								
		3 <sup>7</sup> / <sub>8</sub>		5,766	4,951	4,002								
2 <sup>7</sup> / <sub>8</sub>	Slim Hole													
2 <sup>7</sup> / <sub>8</sub>	Extra Hole	3 <sup>3</sup> / <sub>4</sub>		*4,089	*4,089	*4,089								
3 <sup>1</sup> / <sub>2</sub>	Double-Streamline	3 <sup>7</sup> / <sub>8</sub>		*5,352	*5,352	*5,352								
2 <sup>7</sup> / <sub>8</sub>	Mod.-Open	4 <sup>1</sup> / <sub>8</sub>		*8,059	*8,059	7,433								
2 <sup>7</sup> / <sub>8</sub>	API HF	3 <sup>7</sup> / <sub>8</sub>		*4,640	*4,640	*4,640	*4,640							
API	NC-31	4 <sup>1</sup> / <sub>8</sub>		*7,390	*7,390	*7,390	6,853							
3 <sup>1</sup> / <sub>2</sub>	Regular	4 <sup>1</sup> / <sub>8</sub>		*6,466	*6,466	*6,466	*6,466	5,685						
		4 <sup>1</sup> / <sub>4</sub>		*7,886	*7,886	*7,886	7,115	5,685						
		4 <sup>1</sup> / <sub>2</sub>		10,471	9,514	8,394	7,115	5,685						
3 <sup>1</sup> / <sub>2</sub>	Slim Hole	4 <sup>1</sup> / <sub>4</sub>		*8,858	*8,858	8,161	6,853	5,391						
		4 <sup>1</sup> / <sub>2</sub>		10,286	9,307	8,161	6,853	5,391						
API	NC-35	4 <sup>1</sup> / <sub>2</sub>				*9,038	*9,038	*9,038	7,411					
		4 <sup>3</sup> / <sub>4</sub>				12,273	10,826	9,202	7,411					
		5				12,273	10,826	9,202	7,411					
3 <sup>1</sup> / <sub>2</sub>	Extra Hole	4 <sup>1</sup> / <sub>4</sub>				*5,161	*5,161	*5,161	*5,161					
4	Slim Hole	4 <sup>1</sup> / <sub>2</sub>				*8,479	*8,479	*8,479	8,311					
3 <sup>1</sup> / <sub>2</sub>	Mod.-Open	4 <sup>3</sup> / <sub>4</sub>				*12,074	11,803	10,144	8,311					
		5				13,283	11,803	10,144	8,311					
		5 <sup>1</sup> / <sub>4</sub>				13,283	11,803	10,144	8,311					
3 <sup>1</sup> / <sub>2</sub>	API HF	4 <sup>3</sup> / <sub>4</sub>				*9,986	*9,986	*9,986	*9,986	8,315				
API	NC-38	5				*13,949	*13,949	12,907	10,977	8,315				
4 <sup>1</sup> / <sub>2</sub>	Slim Hole	5 <sup>1</sup> / <sub>4</sub>				16,207	14,643	12,907	10,977	8,315				
		5 <sup>1</sup> / <sub>2</sub>				16,207	14,643	12,907	10,977	8,315				
3 <sup>1</sup> / <sub>2</sub>	H-90 <sup>4</sup>	4 <sup>3</sup> / <sub>4</sub>				*8,786	*8,786	*8,786	*8,786	*8,786				
		5				*12,794	*12,794	*12,794	*12,794	10,408				
		5 <sup>1</sup> / <sub>4</sub>				*17,094	16,929	15,137	13,151	10,408				
		5 <sup>1</sup> / <sub>2</sub>				18,522	16,929	15,137	13,151	10,408				
4	Full Hole	5				*10,910	*10,910	*10,910	*10,910	*10,910				
API	NC-40	5 <sup>1</sup> / <sub>4</sub>				*15,290	*15,290	*15,290	14,969	12,125				
4	Mod.-Open	5 <sup>1</sup> / <sub>2</sub>				*19,985	18,886	17,028	14,969	12,125				
4 <sup>1</sup> / <sub>2</sub>	Double-Streamline	5 <sup>3</sup> / <sub>4</sub>				20,539	18,886	17,028	14,969	12,125				
		6				20,539	18,886	17,028	14,969	12,125				
4	H-90 <sup>4</sup>	5 <sup>1</sup> / <sub>4</sub>				*12,590	*12,590	*12,590	*12,590	*12,590				
		5 <sup>1</sup> / <sub>2</sub>				*17,401	*17,401	*17,401	*17,401	16,536				
		5 <sup>3</sup> / <sub>4</sub>				*22,531	*22,531	21,714	19,543	16,536				
		6				25,408	23,671	21,714	19,543	16,536				
		6 <sup>1</sup> / <sub>4</sub>				25,408	23,671	21,714	19,543	16,536				

(Table continued on next page.)

Committee Review Only

**Table 14—Recommended Make-up Torque<sup>1</sup> for Rotary Shouldered Drill Collar Connections (Continued)**  
(See footnotes for use of this table.)

(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Connection		Minimum Make-up Torque ft-lb <sup>2</sup>													
		OD, in.	Bore of Drill Collar, inches												
00	Size	Type	1	1 <sup>1</sup> / <sub>4</sub>	1 <sup>1</sup> / <sub>2</sub>	1 <sup>3</sup> / <sub>4</sub>	2	2 <sup>1</sup> / <sub>4</sub>	2 <sup>1</sup> / <sub>2</sub>	2 <sup>13</sup> / <sub>16</sub>	3	3 <sup>1</sup> / <sub>4</sub>	3 <sup>1</sup> / <sub>2</sub>	3 <sup>3</sup> / <sub>4</sub>	
	4 <sup>1</sup> / <sub>2</sub>	API Regular	5 <sup>1</sup> / <sub>2</sub>			*15,576	*15,576	*15,576	*15,576	*15,576					
			5 <sup>3</sup> / <sub>4</sub>			*20,609	*20,609	*20,609	19,601	16,629					
			6			25,407	23,686	21,749	19,601	16,629					
			6 <sup>1</sup> / <sub>4</sub>			25,407	23,686	21,749	19,601	16,629					
	API	NC 44	5 <sup>3</sup> / <sub>4</sub>			*20,895	*20,895	*20,895	*20,895	18,161					
			6			*26,453	25,510	23,493	21,257	18,161					
			6 <sup>1</sup> / <sub>4</sub>			27,300	25,510	23,493	21,257	18,161					
			6 <sup>1</sup> / <sub>2</sub>			27,300	25,510	23,493	21,257	18,161					
	4 <sup>1</sup> / <sub>2</sub>	API Full Hole	5 <sup>1</sup> / <sub>2</sub>				*12,973	*12,973	*12,973	*12,973					
			5 <sup>3</sup> / <sub>4</sub>				*18,119	*18,119	*18,119	*18,119	17,900				
			6				*23,605	*23,605	23,028	19,921	17,900				
			6 <sup>1</sup> / <sub>4</sub>				27,294	25,272	23,028	19,921	17,900				
			6 <sup>1</sup> / <sub>2</sub>				27,294	25,272	23,028	19,921	17,900				
	4 <sup>1</sup> / <sub>2</sub>	Extra Hole	5 <sup>3</sup> / <sub>4</sub>				*17,738	*17,738	*17,738	*17,738					
	API	NC 46	6				*23,422	*23,422	22,426	20,311					
	4	API IF	6 <sup>1</sup> / <sub>4</sub>				28,021	25,676	22,426	20,311					
	4 <sup>1</sup> / <sub>2</sub>	Semi IF	6 <sup>1</sup> / <sub>2</sub>				28,021	25,676	22,426	20,311					
	5	Double Streamline	6 <sup>1</sup> / <sub>4</sub>				28,021	25,676	22,426	20,311					
	4 <sup>1</sup> / <sub>2</sub>	Mod. Open													
	4 <sup>1</sup> / <sub>2</sub>	H-90 <sup>4</sup>	5 <sup>3</sup> / <sub>4</sub>				*18,019	*18,019	*18,019	*18,019					
			6				*23,681	*23,681	23,159	21,051					
			6 <sup>1</sup> / <sub>4</sub>				28,732	26,397	23,159	21,051					
			6 <sup>1</sup> / <sub>2</sub>				28,732	26,397	23,159	21,051					
			6 <sup>3</sup> / <sub>4</sub>				28,732	26,397	23,159	21,051					
	5	H-90 <sup>4</sup>	6 <sup>1</sup> / <sub>4</sub>				*25,360	*25,360	*25,360	*25,360	23,988				
			6 <sup>1</sup> / <sub>2</sub>				*31,895	*31,895	29,400	27,167	23,988				
			6 <sup>3</sup> / <sub>4</sub>				35,292	32,825	29,400	27,167	23,988				
			7				35,292	32,825	29,400	27,167	23,988				
	4 <sup>1</sup> / <sub>2</sub>	API IF	6 <sup>1</sup> / <sub>4</sub>				*23,004	*23,004	*23,004	*23,004	*23,004				
	API	NC 50	6 <sup>1</sup> / <sub>2</sub>				*29,679	*29,679	*29,679	*29,679	26,675				
	5	Extra Hole	6 <sup>1</sup> / <sub>4</sub>				*36,742	35,824	32,277	29,966	26,675				
	5	Mod. Open	7				38,379	35,824	32,277	29,966	26,675				
	5 <sup>1</sup> / <sub>2</sub>	Double Streamline	7 <sup>1</sup> / <sub>4</sub>				38,379	35,824	32,277	29,966	26,675				
	5	Semi-IF	7 <sup>1</sup> / <sub>2</sub>				38,379	35,824	32,277	29,966	26,675				
	5 <sup>1</sup> / <sub>2</sub>	H-90 <sup>4</sup>	6 <sup>3</sup> / <sub>4</sub>				*34,508	*34,508	*34,508	34,142	30,781				
			7				*41,993	40,117	36,501	34,142	30,781				
			7 <sup>1</sup> / <sub>4</sub>				42,719	40,117	36,501	34,142	30,781				
			7 <sup>1</sup> / <sub>2</sub>				42,719	40,117	36,501	34,142	30,781				
	5 <sup>1</sup> / <sub>2</sub>	API Regular	6 <sup>3</sup> / <sub>4</sub>				*31,941	*31,941	*31,941	*31,941	30,495				
			7				*39,419	*39,419	36,235	33,868	30,495				
			7 <sup>1</sup> / <sub>4</sub>				42,481	39,866	36,235	33,868	30,495				
			7 <sup>1</sup> / <sub>2</sub>				42,481	39,866	36,235	33,868	30,495				
	5 <sup>1</sup> / <sub>2</sub>	API Full Hole	7				*32,762	*32,762	*32,762	*32,762	*32,762				
			7 <sup>1</sup> / <sub>4</sub>				*40,998	*40,998	*40,998	*40,998	*40,998				
			7 <sup>1</sup> / <sub>2</sub>				*49,661	*49,661	47,756	45,190	41,533				

(Table continued on next page.)

Committee Review Only

**Table 14—Recommended Make-up Torque<sup>1</sup> for Rotary Shouldered Drill Collar Connections (Continued)**  
**(See footnotes for use of this table.)**

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Connection		Minimum Make-up Torque ft-lb <sup>2</sup>												
Size	Type	OD, in.	Bore of Drill Collar, inches											
			1	1 <sup>1</sup> / <sub>4</sub>	1 <sup>1</sup> / <sub>2</sub>	1 <sup>3</sup> / <sub>4</sub>	2	2 <sup>1</sup> / <sub>4</sub>	2 <sup>1</sup> / <sub>2</sub>	2 <sup>13</sup> / <sub>16</sub>	3	3 <sup>1</sup> / <sub>4</sub>	3 <sup>1</sup> / <sub>2</sub>	3 <sup>3</sup> / <sub>4</sub>
API	NC 56	7 <sup>3</sup> / <sub>4</sub>						54,515	51,687	47,756	45,190	41,533		
		7 <sup>1</sup> / <sub>4</sub>								*40,498	*40,498	*40,498	*40,498	
		7 <sup>1</sup> / <sub>2</sub>								*49,060	48,221	45,680	42,058	
		7 <sup>3</sup> / <sub>4</sub>								52,115	48,221	45,680	42,058	
6 <sup>5</sup> / <sub>8</sub>	API Regular	8								52,115	48,221	45,680	42,058	
		7 <sup>1</sup> / <sub>2</sub>								*46,399	*46,399	*46,399	*46,399	
		7 <sup>3</sup> / <sub>4</sub>								*55,627	53,346	50,704	46,936	
		8								57,393	53,346	50,704	46,936	
6 <sup>5</sup> / <sub>8</sub>	H-90 <sup>4</sup>	8 <sup>1</sup> / <sub>4</sub>								57,393	53,346	50,704	46,936	
		7 <sup>1</sup> / <sub>2</sub>								*46,509	*46,509	*46,509	*46,509	
		7 <sup>3</sup> / <sub>4</sub>								*55,708	*55,708	53,629	49,855	
		8								60,321	56,273	53,629	49,855	
API	NC 61	8 <sup>1</sup> / <sub>4</sub>								60,321	56,273	53,629	49,855	
		8								*55,131	*55,131	*55,131	*55,131	
		8 <sup>1</sup> / <sub>2</sub>								*65,438	*65,438	*65,438	61,624	
		8 <sup>3</sup> / <sub>4</sub>								72,670	68,398	65,607	61,624	
5 <sup>1</sup> / <sub>2</sub>	API IF	9								72,670	68,398	65,607	61,624	
		8								*56,641	*56,641	*56,641	*56,641	
		8 <sup>1</sup> / <sub>4</sub>								*67,133	*67,133	63,381	59,027	
		8 <sup>1</sup> / <sub>2</sub>								74,626	70,277	67,436	63,381	59,027
6 <sup>5</sup> / <sub>8</sub>	API Full Hole	8 <sup>3</sup> / <sub>4</sub>								74,626	70,277	67,436	63,381	59,027
		9								74,626	70,277	67,436	63,381	59,027
		9 <sup>1</sup> / <sub>4</sub>								74,626	70,277	67,436	63,381	59,027
		9 <sup>1</sup> / <sub>2</sub>								88,582	83,992	80,991	76,706	72,102
API	NC70	10								88,582	83,992	80,991	76,706	72,102
		9								*75,781	*75,781	*75,781	*75,781	*75,781
		9 <sup>1</sup> / <sub>4</sub>								*88,802	*88,802	*88,802	*88,802	*88,802
		9 <sup>1</sup> / <sub>2</sub>								*102,354	*102,354	*102,354	101,107	96,214
API	NC77	10 <sup>1</sup> / <sub>4</sub>								113,710	108,841	105,657	101,107	96,214
		10 <sup>1</sup> / <sub>2</sub>								113,710	108,841	105,657	101,107	96,214
		10 <sup>3</sup> / <sub>4</sub>								113,710	108,841	105,657	101,107	96,214
		11								154,297	148,965	145,476	140,488	135,119
7	H-90 <sup>4</sup>	8								*53,454	*53,454	*53,454	*53,454	*53,454
		8 <sup>1</sup> / <sub>4</sub>								*63,738	*63,738	*63,738	60,971	56,382
		8 <sup>1</sup> / <sub>2</sub>								*74,478	72,066	69,265	65,267	60,971
		8 <sup>3</sup> / <sub>4</sub>								*60,402	*60,402	*60,402	*60,402	*60,402
7 <sup>5</sup> / <sub>8</sub>	API Regular	9								*72,169	*72,169	*72,169	*72,169	*72,169
		9 <sup>1</sup> / <sub>4</sub>								*84,442	*84,442	84,221	79,536	74,529
		9 <sup>1</sup> / <sub>2</sub>								96,301	91,633	88,580	84,221	79,536
		9 <sup>3</sup> / <sub>4</sub>								96,301	91,633	88,580	84,221	79,536
7 <sup>5</sup> / <sub>8</sub>	H-90 <sup>4</sup>	10								*73,017	*73,017	*73,017	*73,017	*73,017
		9 <sup>1</sup> / <sub>4</sub>								*86,006	*86,006	*86,006	*86,006	*86,006
		9 <sup>1</sup> / <sub>2</sub>								*99,508	*99,508	*99,508	*99,508	*99,508
		10								*109,345	*109,345	*109,345	*109,345	*109,345



(Table continued on next page.)

Committee Review Only

**Table 14—Recommended Make-up Torque<sup>1</sup> for Rotary Shouldered Drill Collar Connections (Continued)**  
(See footnotes for use of this table.)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
Connection			Minimum Make-up Torque ft-lb <sup>2</sup>											
Size	Type	OD, in.	Bore of Drill Collar, inches											
			1	1 <sup>1</sup> / <sub>4</sub>	1 <sup>1</sup> / <sub>2</sub>	1 <sup>3</sup> / <sub>4</sub>	2	2 <sup>1</sup> / <sub>4</sub>	2 <sup>1</sup> / <sub>2</sub>	2 <sup>13</sup> / <sub>16</sub>	3	3 <sup>1</sup> / <sub>4</sub>	3 <sup>1</sup> / <sub>2</sub>	3 <sup>3</sup> / <sub>4</sub>
		10 <sup>7</sup> / <sub>8</sub>												
		10 <sup>1</sup> / <sub>2</sub>												
8 <sup>5</sup> / <sub>8</sub>	H-90 <sup>4</sup>	10 <sup>7</sup> / <sub>8</sub>												
		10 <sup>1</sup> / <sub>2</sub>												
7	H-90 <sup>4</sup>	8 <sup>3</sup> / <sub>4</sub>												
	(with low-torque face)	9												
7 <sup>5</sup> / <sub>8</sub>	API-Regular	9 <sup>1</sup> / <sub>4</sub>												
	(with low-torque face)	9 <sup>1</sup> / <sub>2</sub>												
		9 <sup>3</sup> / <sub>4</sub>												
		10												
7 <sup>5</sup> / <sub>8</sub>	H-90 <sup>4</sup>	9 <sup>3</sup> / <sub>4</sub>												
	(with low-torque face)	10												
		10 <sup>1</sup> / <sub>4</sub>												
		10 <sup>1</sup> / <sub>2</sub>												
8 <sup>5</sup> / <sub>8</sub>	API-Regular	10 <sup>3</sup> / <sub>4</sub>												
	(with low-torque face)	11												
		11 <sup>1</sup> / <sub>4</sub>												
8 <sup>5</sup> / <sub>8</sub>	H-90 <sup>4</sup>	10 <sup>3</sup> / <sub>4</sub>												
	(with low-torque face)	11												
		11 <sup>1</sup> / <sub>4</sub>												

\*Notes:

1. Torque figures preceded by an asterisk (\*) indicate that the weaker member for the corresponding outside diameter (OD) and bore is the BOX; for all other torque values, the weaker member is the PIN.

2. In each connection size and type group, torque values apply to all connection types in the group, when used with the same drill collar outside diameter and bore, i.e., 2<sup>7</sup>/<sub>8</sub> API IF, API NC 26, and 2<sup>7</sup>/<sub>8</sub> Slim Hole connections used with 3<sup>1</sup>/<sub>2</sub> x 1<sup>1</sup>/<sub>4</sub> drill collars all have the same minimum make-up torque of 4600 ft. lb., and the BOX is the weaker member.

3. Stress-relief features are disregarded for make-up torque.

<sup>1</sup>Basis of calculations for recommended make-up torque assumed the use of a thread compound containing 40–60 percent by weight of finely powdered metallic zinc or 60 percent by weight of finely powdered metallic lead, with not more than 0.3 percent total active sulfur (reference the caution regarding the use of hazardous materials in Appendix G of Specification 7) applied thoroughly to all threads and shoulders and using the modified Screw Jack formula in A.9, and a unit stress of 62,500 psi in the box or pin, whichever is weaker.

<sup>2</sup>Normal torque range is tabulated value plus 10 percent. Higher torque values may be used under extreme conditions.

<sup>3</sup>Make-up torque for 2<sup>7</sup>/<sub>8</sub> PAC connection is based on 87,500 psi stress and other factors listed in footnote 1.

<sup>4</sup>Make-up torque for H-90 connection is based on 56,200 psi stress and other factors listed in footnote 1.



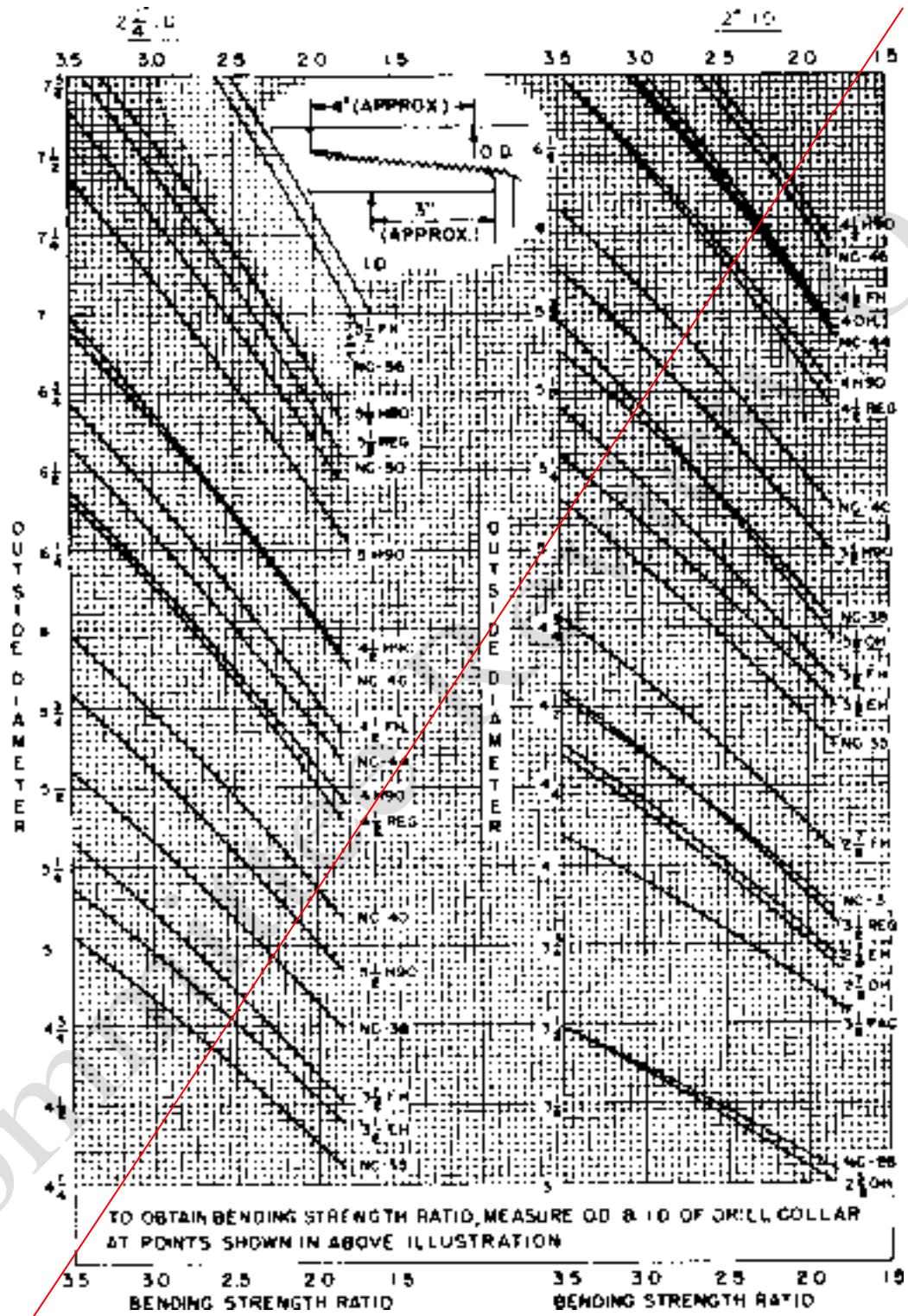


Figure 27—Drill Collar Bending Strength Ratios, 2- and 2 1/4-Inch ID





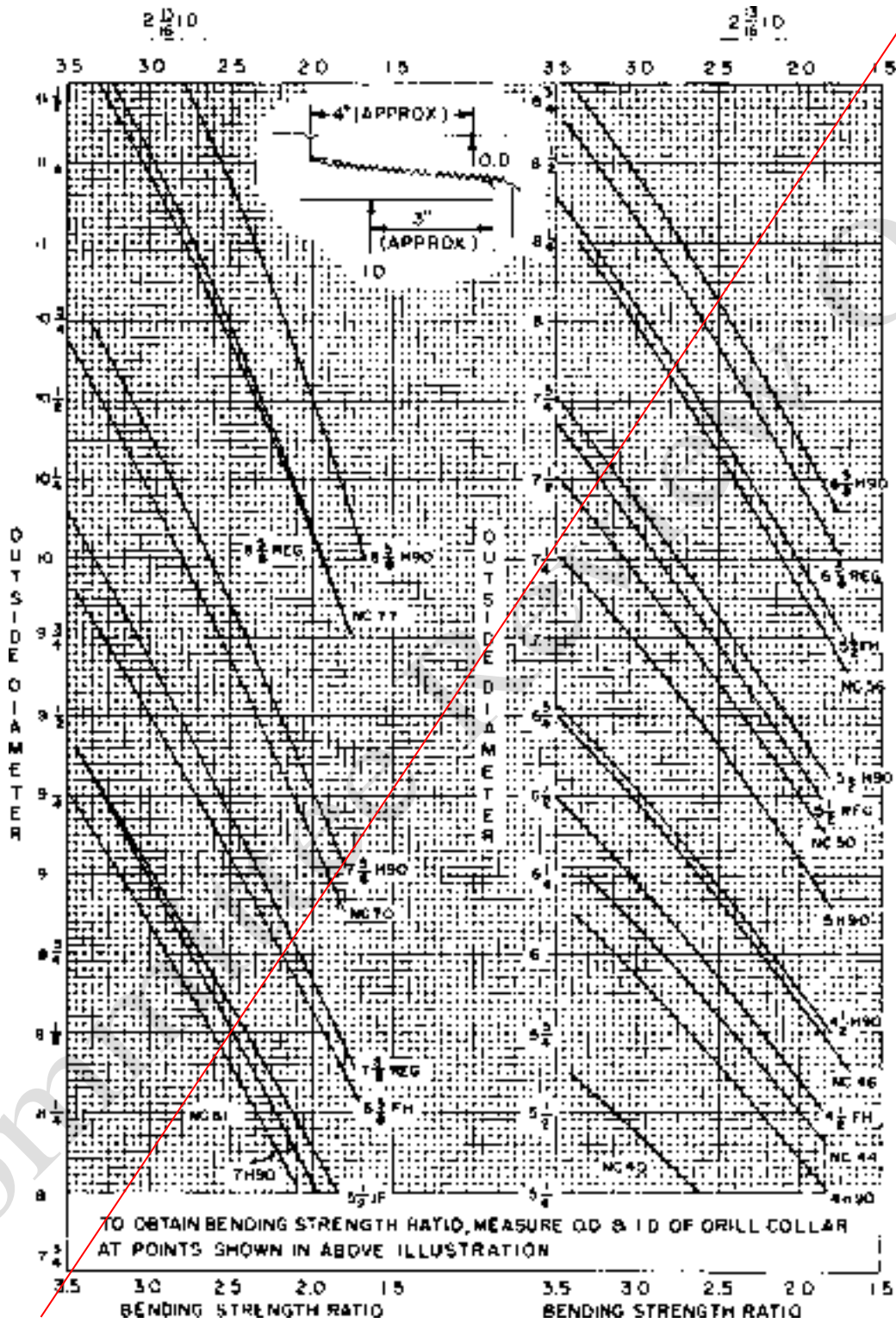


Figure 29—Drill Collar Bending Strength Ratios, 2<sup>13</sup>/<sub>16</sub>-Inch ID

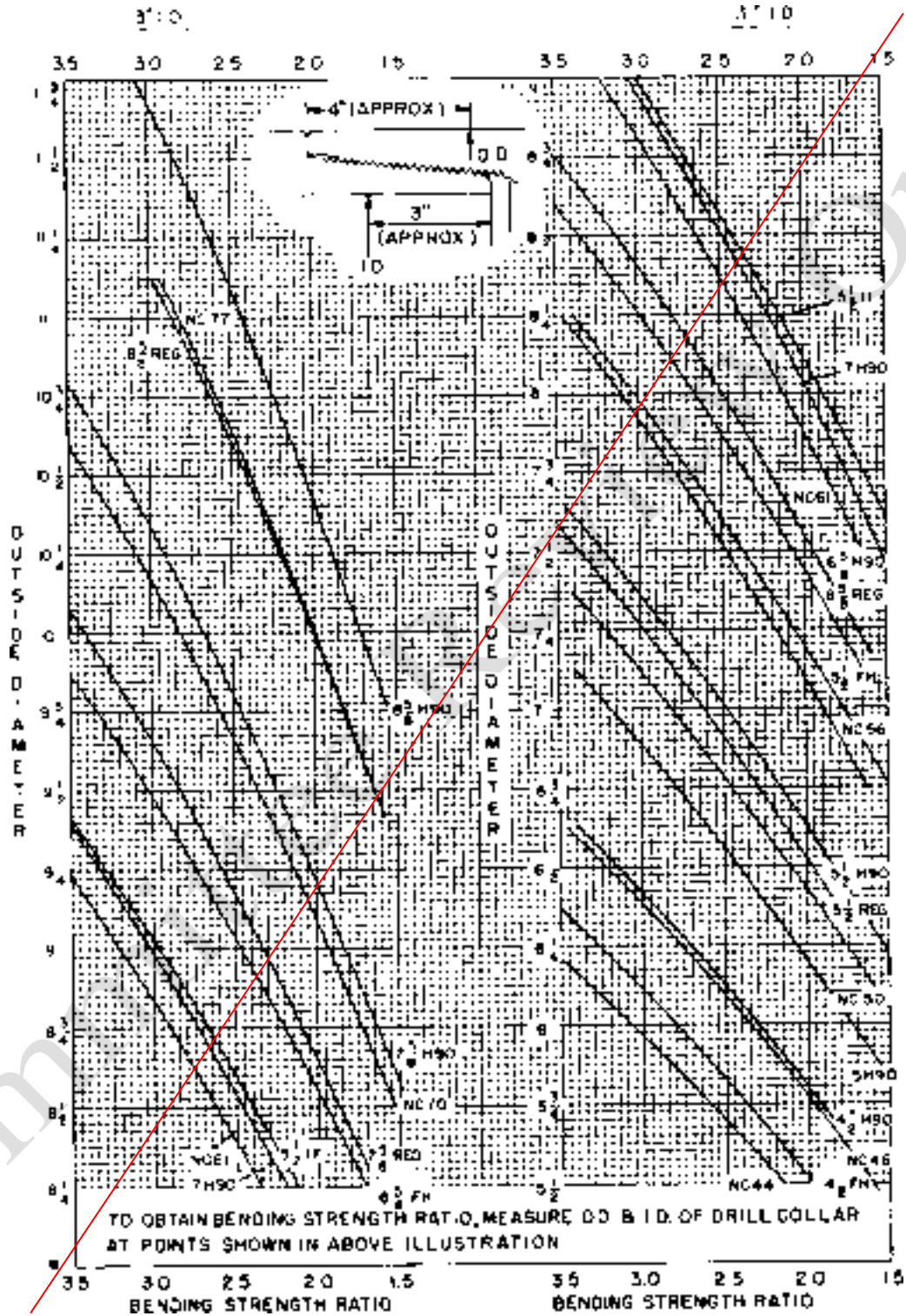


Figure 30—Drill Collar Bending Strength Ratios, 3-Inch ID



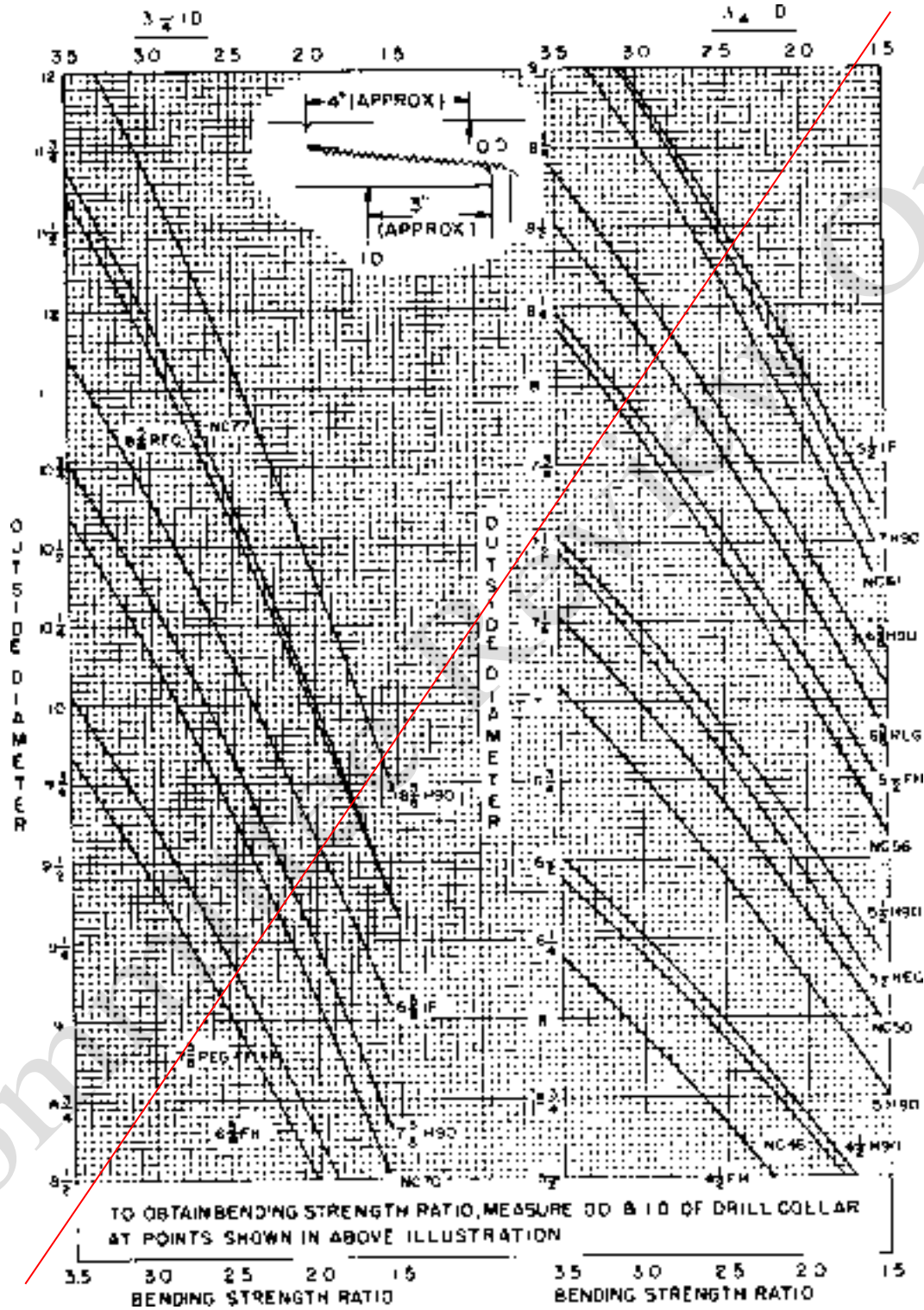


Figure 31—Drill Collar Bending Strength Ratios, 3 $\frac{1}{4}$ -Inch ID



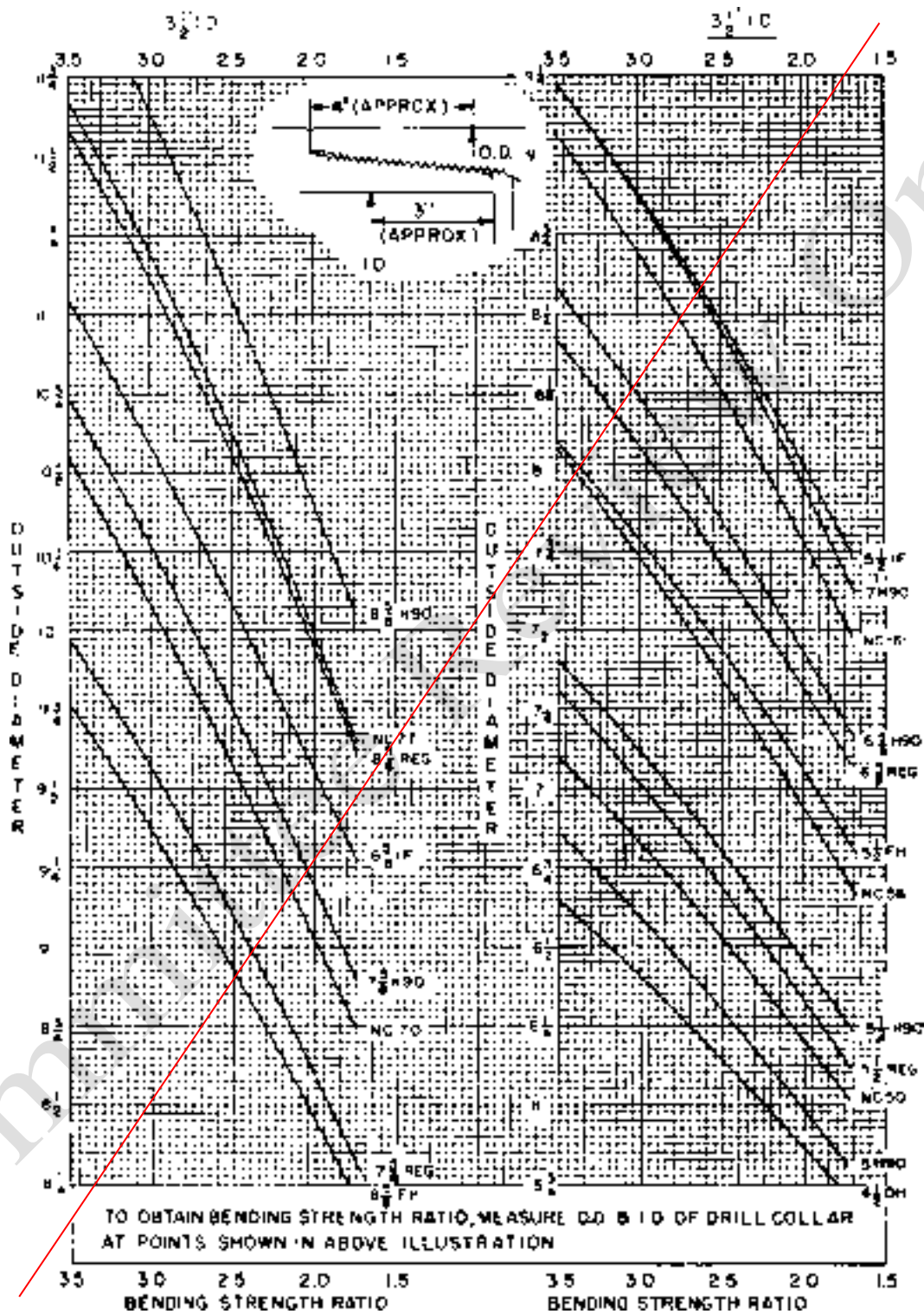


Figure 32—Drill Collar Bending Strength Ratios, 3½-Inch ID

**6.4.2** For a given tensile load, the stress level is less in the hexagonal section.

**6.4.3** Due to the lower stress level, the endurance limit of the hexagonal drive section is greater in terms of cycles to failure for a given bending load.

**6.4.4** Surface decarburization (decarb) is inherent in the *as forged* square kelly which further reduces the endurance limit in terms of cycles to failure for a given bending load. Hexagonal kellys and fully machined squares have machined surfaces and are generally free of decarb in the drive section.

**6.4.5** It is impractical to remove the decarb from the complete drive section of the forged square kelly; however, the decarb should be removed from the corners in the fillet between the drive section and the upset to aid in the prevention of fatigue cracks in this area. Machining of square kellys from round bars could eliminate this undesirable condition.

**6.4.6** The life of the drive section is directly related to the kelly fit with the kelly drive. A square drive section normally will tolerate a greater clearance with acceptable life than will a hexagonal section. A diligent effort by the rig personnel to maintain minimum clearance between the kelly drive section and the bushing will minimize this consideration in kelly selection. New roller bushing assemblies working on new kellys will develop wear patterns that are essentially flat in shape on the driving edge of the kelly. Wear patterns begin as point contacts of zero width near the corner. The pattern widens as the kelly and bushing begin to wear until a maximum wear pattern is achieved. The wear rate will be the least when the maximum wear pattern width is achieved. Figure 33 illustrates the maximum width flat wear pattern that could be expected on the kelly drive flats if the new assembly has clearances as shown in Table 16. The information in Table 16 and Figures 33 and 34 may be used to evaluate the clearances between kelly and bushing. This evaluation should be made as soon as a wear pattern becomes apparent after a new assembly is put into service.

**98** Example: At the time of evaluation, the wear pattern width for a  $5\frac{3}{4}$ -inch hexagonal kelly is 1.00 inch.

This could mean one of the following two conditions exist:

- a. If the contact angle is less than 8 degrees 37 minutes, the original clearances were acceptable. The wear pattern is not fully developed.
- b. If the contact angle is greater than 8 degrees 37 minutes, the wear pattern is fully developed. The clearance is greater than is recommended and should be corrected.

**6.5** Techniques for extending life of kellys include remachining drive sections to a smaller size and reversing ends.

## 6.5.1 Remachining

Before attempting to remachine a kelly, it should be fully inspected for fatigue cracks and also dimensionally checked to assure that it is suitable for remilling. The strength of a remachined kelly should be compared with the strength of the drill pipe with which the kelly is to be used. (See Table 17 for drive section dimensions and strengths.)

## 6.5.2 Reversing Ends

Usually both ends of the kelly must be butt welded (stubbed) for this to be possible as the original top is too short and the old lower end is too small in diameter for the connections to be reversed. The welds should be made in the upset portions on each end to insure the tensile integrity and fatigue resistance capabilities of the sections. Proper heating and welding procedures must be used to prevent cracking and to recondition the sections where welding has been performed.

**6.6** The internal pressure at minimum yield for the drive section may be calculated from Equation A.9:

# 7 Design Calculations

## 7.1 DESIGN PARAMETERS

It is intended to outline a step-by-step procedure to ensure complete consideration of factors, and to simplify calculations. Derivation of formulas may be reviewed in Appendix A. The following design criteria must be established:

- a. Anticipated total depth with this string.
- b. Hole size.
- c. Expected mud weight.
- d. Desired Factor of Safety in tension and/or Margin of Over Pull.
- e. Desired Factor of Safety in collapse.
- f. Length of drill collars, OD, ID, and weight per foot.
- g. Desired drill pipe sizes, and inspection class.

## 7.2 SPECIAL DESIGN PARAMETERS

If the actual wall thickness has been determined by inspection to exceed that in API tables, higher tensile, collapse, and internal pressure values may be used for drill stem design.

## 7.3 SUPPLEMENTAL DRILL STEM MEMBERS

Machining of the connections to API specifications and the proper heat treatment of the material shall be done on all supplemental drill stem members, such as subs, stabilizers, tools, etc.

## 7.4 TENSION LOADING

The design of the drill string for static tension loads requires sufficient strength in the topmost joint of each size, weight, grade, and classification of drill pipe to support the submerged weight of all the drill pipe plus the submerged

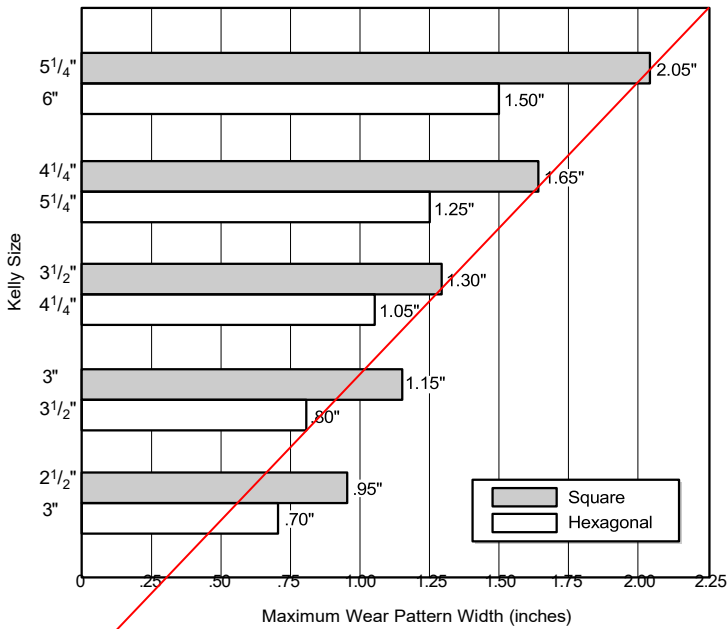
Table 15—Strength of Kellys<sup>1</sup>

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Kelly Size and Type in.	Kelly Bore in.	Lower Pin Connection		Minimum <sup>2</sup>	Tensile Yield		Torsional Yield		Yield in Bending	Internal Pressure at Minimum Yield
		Size and Style	OD in.	Recommended Casing OD in.	Lower Pin Connection <sup>3</sup> lb	Drive Section lb	Lower Pin Connection ft-lb	Drive Section ft-lb	Through Drive Section ft-lb	Drive Section psi
2 <sup>1</sup> / <sub>2</sub> Square	1 <sup>1</sup> / <sub>4</sub>	NC26	3 <sup>3</sup> / <sub>8</sub>	4 <sup>1</sup> / <sub>2</sub>	416,000	444,400	9,650	12,300	13,000	29,800
		(2 <sup>3</sup> / <sub>8</sub> IF)								
3 Square	1 <sup>3</sup> / <sub>4</sub>	NC31	4 <sup>1</sup> / <sub>8</sub>	5 <sup>1</sup> / <sub>2</sub>	535,000	582,500	14,450	19,500	22,300	25,500
		(2 <sup>7</sup> / <sub>8</sub> IF)								
3 <sup>1</sup> / <sub>2</sub> Square	2 <sup>1</sup> / <sub>4</sub>	NC38	4 <sup>3</sup> / <sub>4</sub>	6 <sup>5</sup> / <sub>8</sub>	724,000	725,200	22,700	28,300	34,200	22,200
		(3 <sup>1</sup> / <sub>2</sub> IF)								
4 <sup>1</sup> / <sub>4</sub> Square	2 <sup>13</sup> / <sub>16</sub>	NC46	6 <sup>1</sup> / <sub>4</sub>	8 <sup>5</sup> / <sub>8</sub>	1,054,000	1,047,000	39,350	49,100	60,300	19,500
		(4 IF)								
4 <sup>1</sup> / <sub>4</sub> Square	2 <sup>13</sup> / <sub>16</sub>	NC50	6 <sup>3</sup> / <sub>8</sub>	8 <sup>5</sup> / <sub>8</sub>	1,375,200	1,047,000	55,810	49,100	60,300	19,500
		(4 <sup>1</sup> / <sub>2</sub> IF)								
5 <sup>1</sup> / <sub>4</sub> Square	3 <sup>1</sup> / <sub>4</sub>	51/2 FH	7	9 <sup>5</sup> / <sub>8</sub>	1,609,000	1,703,400	72,950	99,400	117,000	20,600
3 Hex	1 <sup>1</sup> / <sub>2</sub>	NC26	3 <sup>3</sup> / <sub>8</sub>	4 <sup>1</sup> / <sub>2</sub>	356,000	540,500	8,300	20,400	20,000	26,700
		(2 <sup>3</sup> / <sub>8</sub> IF)								
3 <sup>1</sup> / <sub>2</sub> Hex	1 <sup>7</sup> / <sub>8</sub>	NC31	4 <sup>1</sup> / <sub>8</sub>	5 <sup>1</sup> / <sub>2</sub>	495,000	710,000	13,400	31,400	31,200	25,500
		(2 <sup>7</sup> / <sub>8</sub> IF)								
4 <sup>1</sup> / <sub>4</sub> Hex	2 <sup>1</sup> / <sub>4</sub>	NC38	4 <sup>3</sup> / <sub>4</sub>	6 <sup>5</sup> / <sub>8</sub>	724,000	1,046,600	22,700	56,600	56,000	25,000
		(3 <sup>1</sup> / <sub>2</sub> IF)								
5 <sup>1</sup> / <sub>4</sub> Hex	3	NC46	6 <sup>1</sup> / <sub>4</sub>	8 <sup>5</sup> / <sub>8</sub>	960,000	1,507,600	35,450	101,900	103,000	20,600
		(4 IF)								
5 <sup>1</sup> / <sub>4</sub> Hex	3 <sup>1</sup> / <sub>4</sub>	NC50	6 <sup>3</sup> / <sub>8</sub>	8 <sup>5</sup> / <sub>8</sub>	1,162,000	1,397,100	46,750	95,500	99,300	20,600
		(4 <sup>1</sup> / <sub>2</sub> IF)								
6 Hex	3 <sup>1</sup> / <sub>2</sub>	5 <sup>1</sup> / <sub>2</sub> FH	7	9 <sup>5</sup> / <sub>8</sub>	1,463,000	1,935,500	66,350	149,800	152,500	18,200

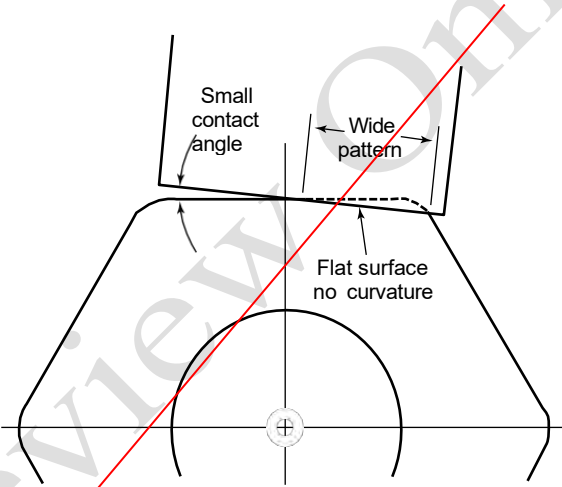
<sup>1</sup>All values have a safety factor of 1.0 and are based on 110,000 psi minimum tensile yield (quenched and tempered) for connections and 90,000 psi minimum tensile yield (normalized and tempered) for the drive section. Fully quenched and tempered drive sections will have higher values than those shown. Shear strength is based on 57.7 percent of the minimum tensile yield strength.

<sup>2</sup>Clearance between protector rubber on Kelly saver sub and casing inside diameter should also be checked.

<sup>3</sup>Tensile area calculated at root of thread <sup>3</sup>/<sub>4</sub> inch from pin shoulder.



Note: The maximum Wear Pattern Width is the average of the Wear Pattern Widths based on calculations using minimum and maximum clearances and contact angles in Table 16 and is accurate within 5 percent.



Note: Drive Edge will have a wide flat pattern with small contact angle.

Figure 33—New Kelly-New Drive Assembly

Figure 34—New Kelly-New Drive Assembly

Table 16—Contact Angle Between Kelly and Bushing for Development of Maximum Width Wear Pattern

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Hexagon				Square				
Kelly Size in.	For Minimum Clearance in.	Contact Angle Deg.-Min.	For Maximum Clearance in.	Contact Angle Deg.-Min.	For Minimum Clearance in.	Contact Angle Deg.-Min.	For Maximum Clearance in.	Contact Angle Deg.-Min.
2 1/2	—	—	—	—	.015	6°10'	.107	16°29'
3	.015	5°41'	.060	11°22'	.015	5°39'	.107	15°5'
3 1/2	.015	5°16'	.060	10°32'	.015	5°14'	.107	14°2'
4 1/4	.015	4°48'	.060	9°34'	.015	4°45'	.123	13°36'
5 1/4	.015	4°19'	.060	8°37'	.015	4°17'	.123	12°16'
6	.015	4°2'	.060	8°4'	—	—	—	—

Table 17—Strength of Remachined Kellys<sup>†</sup>

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Original Kelly-Size and-Type in.	Remachined Kelly-Size and-Type in.	Lower Pin-Connection			Tensile Yield		Torsional Yield		Yield in Bending Through Drive Section ft-lb
		Kelly Bore in.	Size and Style	OD in.	Lower-Pin Connection <sup>‡</sup> lb.	Drive Section lb.	Lower-Pin Connection ft-lb	Drive Section ft-lb	
4 <sup>1</sup> / <sub>4</sub> -Square	4-Square	2 <sup>7</sup> / <sub>8</sub>	NC50 (4 <sup>1</sup> / <sub>2</sub> -IF)	6 <sup>3</sup> / <sub>8</sub>	1,344,200	834,400	55,500	36,200	47,800
4 <sup>1</sup> / <sub>4</sub> -Square	4-Square	2 <sup>7</sup> / <sub>8</sub>	NC46 (4-IF)	6 <sup>1</sup> / <sub>4</sub>	1,011,600	834,400	38,300	36,200	47,800
5 <sup>1</sup> / <sub>4</sub> -Square	5-Square	3 <sup>3</sup> / <sub>4</sub>	5 <sup>1</sup> / <sub>2</sub> -IF	7 <sup>3</sup> / <sub>8</sub>	1,924,300	1,217,600	92,700	65,000	90,200
5 <sup>1</sup> / <sub>4</sub> -Square	5-Square	3 <sup>3</sup> / <sub>4</sub>	5 <sup>1</sup> / <sub>2</sub> -FH	7	1,356,800	1,217,600	58,900	65,000	90,200
5 <sup>1</sup> / <sub>4</sub> -Hex	4 <sup>27</sup> / <sub>32</sub> -Hex	3 <sup>1</sup> / <sub>4</sub>	NC46 (4-IF)	6 <sup>1</sup> / <sub>4</sub>	809,800	1,077,100	30,600	68,600	74,000
5 <sup>1</sup> / <sub>4</sub> -Hex	5-Hex	3 <sup>1</sup> / <sub>4</sub>	NC46 (4-IF)	6 <sup>1</sup> / <sub>4</sub>	809,800	1,196,800	30,600	78,500	83,300
5 <sup>1</sup> / <sub>4</sub> -Hex	5-Hex	3 <sup>1</sup> / <sub>2</sub>	NC50 (4 <sup>1</sup> / <sub>2</sub> -IF)	6 <sup>3</sup> / <sub>8</sub>	999,900	1,077,600	40,800	71,100	78,400
6-Hex	5 <sup>3</sup> / <sub>4</sub> -Hex	4	5 <sup>1</sup> / <sub>2</sub> -FH	7	1,189,500	1,443,400	51,300	109,100	119,900
6-Hex	5 <sup>3</sup> / <sub>4</sub> -Hex	4 <sup>1</sup> / <sub>8</sub>	5 <sup>1</sup> / <sub>2</sub> -IF	7 <sup>3</sup> / <sub>8</sub>	1,669,200	1,371,500	80,400	103,800	116,200

<sup>†</sup>All values have a safety factor of 1.0 and are based on 110,000-psi minimum tensile yield (quenched and tempered) for connections and 90,000-psi minimum tensile yield (normalized and tempered) for the drive section. Fully quenched and tempered drive sections will have higher values than those shown. Shear strength is based on 57.7 percent of the minimum tensile yield strength.

<sup>‡</sup>Tensile area calculated at root of thread <sup>3</sup>/<sub>4</sub>-inch from pin shoulder.

Note: Kelly bushings are normally available for Kellys in above table.

weight of the collars, stabilizer, and bit. This load may be calculated as shown in Equation 1. The bit and stabilizer weights are either neglected or included with the drill collar weight.

$$P = r(L_{dp} \times W_{dp}) + (L_c \times W_c)1 K_b \quad (1)$$

where

$P$  = submerged load hanging below this section of drill pipe, lb.,

$L_{dp}$  = length of drill pipe, ft.,

$L_c$  = length of drill collars, ft.,

$W_{dp}$  = weight per foot of drill pipe assembly in air,

$W_c$  = weight per foot of drill collars in air,

$K_b$  = buoyancy factor—see Table 11.

Any body floating or immersed in a liquid is acted on by a buoyant force equal to the weight of the liquid displaced. This force tends to reduce the effective weight of the drill string and can become of appreciable magnitude in the case of the heavier muds. For example, from Table 11, a one-pound weight submerged in a 14 lb./gal. mud would have an apparent weight of 0.786 lb.

Tension load data is given in Tables 2, 4, 6, and 8 for the various sizes, grades and inspection classes of drill pipe.

It is important to note that the tension strength values shown in the tables are theoretical values based on minimum

areas, wall thickness and yield strengths. The yield strength as defined in API specifications is not the specific point at which permanent deformation of the material begins, but the stress at which a certain total deformation has occurred. This deformation includes all of the elastic deformation as well as some plastic (permanent) deformation. If the pipe is loaded to the extent shown in the tables it is likely that some permanent stretch will occur and difficulty may be experienced in keeping the pipe straight. To prevent this condition a design factor of approximately 90 percent of the tabulated tension value from the table is sometimes used; however, a better practice is to request a specific factor for the particular grade of pipe involved from the drill pipe supplier.

$$P_a = P_t \times 0.9 \quad (2)$$

where

$P_a$  = maximum allowable design load in tension, lb.,

$P_t$  = theoretical tension load from table, lb.,

0.9 = a constant relating proportional limit to yield strength.

The difference between the calculated load  $P$  and the maximum allowable tension load represents the Margin of Over Pull (MOP).

$$MOP = P_a - P \quad (3)$$

The same values expressed as a ratio may be called the Safety Factor (SF).

$$SF = \frac{P_a}{P} \quad (4)$$

The selection of the proper safety factor and/or margin of over pull is of critical importance and should be approached with caution. Failure to provide an adequate safety factor can result in loss or damage to the drill pipe while an overly conservative choice will result in an unnecessarily heavy and more expensive drill string. The designer should consider the overall drilling conditions in the area, particularly hole drag and the likelihood of becoming stuck. The designer must also consider the degree of risk which is acceptable for the particular well for which the drill string is being designed. Frequently, the safety factor also includes an allowance for slip crushing and for the dynamic loading, which results from accelerations and decelerations during hoisting.

Slip crushing is not a problem if slips and master bushings are maintained. Inspection class also grades the pipe with regard to slip crushing.

Normally the designer will desire to determine the maximum length of a specific size, grade and inspection class of drill pipe which can be used to drill a certain well. By combining Equation 1 and either Equation 2 or 3, the following equations result:

$$\frac{P_t \xi 0.9}{SF \xi W_{dp} \xi K_b} - \frac{W_c L_c}{W_{dp}} = L_{\phi} \quad (5)$$

and/or

$$\frac{P_t \xi 0.9 - MOP}{W_{dp} \xi K_b} - \frac{W_c L_c}{W_{dp}} = L_{\phi} \quad (6)$$

If the string is to be a tapered string, i.e., to consist of more than one size, grade or inspection class of drill pipe, the pipe having the lowest load capacity should be placed just above the drill collars and the maximum length is calculated as shown previously. The next stronger pipe is placed next in the string and the  $WL$  term in Equation 5 or 6 is replaced by a term representing the weight in air of the drill collars plus the drill pipe assembly in the lower string. The maximum length of the next stronger pipe may then be calculated. An example calculation using the above formulas is included in 7.8.

## 7.5 COLLAPSE DUE TO EXTERNAL FLUID PRESSURE

The drill pipe may at certain times be subjected to an external pressure which is higher than the internal pressure. This

condition usually occurs during the drill stem testing and may result in collapse of the drill pipe. The differential pressure required to produce collapse has been calculated for various sizes, grades, and inspection classes of drill pipe and appears in Tables 3, 5, 7, and 9. The tabulated values should be divided by a suitable factor of safety to establish the allowable collapse pressure.

$$\frac{P_p}{SF} = P_{ac} \quad (7)$$

where

$P_p$  = theoretical collapse pressure from tables, psi,

$SF$  = safety factor,

$P_{ac}$  = allowable collapse pressure, psi.

When the fluid levels inside and outside the drill pipe are equal and provided the density of the drilling fluid is constant, the collapse pressure is zero at any depth, i.e., there is no differential pressure. If, however, there should be no fluid inside the pipe the actual collapse pressure may be calculated by the following equation:

$$P_c = \frac{L W_g}{19.251} \quad (8)$$

or

$$P_c = \frac{L W_f}{144} \quad (9)$$

where

$P_c$  = net collapse pressure, psi,

$L$  = the depth at which  $P_c$  acts, ft.,

$W_g$  = weight of drilling fluid, lb/gal,

$W_f$  = weight of drilling fluid, lb/cu. ft.

If there is fluid inside the drill pipe but the fluid level is not as high inside as outside or if the fluid inside is not the same weight as the fluid outside, the following equation may be used:

$$P_c = \frac{L W_g - (L - Y) W_g'}{19.251} \quad (10)$$

or

$$P_c = \frac{L W_f - (L - Y) W_f'}{144} \quad (11)$$

where

$Y$  = depth to fluid inside drill pipe, ft.,

$W_g'$  = weight of drilling fluid inside pipe, lb/gal,

$W_f'$  = weight of drilling fluid inside pipe, lb/cu ft.



## 7.6 INTERNAL PRESSURE

Occasionally the drill pipe may also be subjected to a net internal pressure. Tables 3, 5, 7, and 9 contain calculated values of the differential internal pressure required to yield the drill pipe. Division by an appropriate safety factor will result in an allowable net internal pressure.

## 7.7 TORSIONAL STRENGTH

The torsional strength of drill pipe becomes critical when drilling deviated holes, deep holes, reaming, or when the pipe is stuck. This is discussed under Sections 8 and 12. Calculated values of torsional strength for various sizes, grades, and inspection classes of drill pipe are provided in Tables 2, 4, 6, and 8. The basis for these calculations is shown in Appendix A. The actual torque applied to the pipe during drilling is difficult to measure, but may be approximated by the following equation:

$$T = \frac{HP \times 5,250}{RPM} \quad (12)$$

where

$T$  = torque delivered to drill pipe, ft-lbs,

$\frac{HP}{RPM}$  = horse power used to produce rotation of pipe, revolutions per minute.

Note: The torque applied to the drill string should not exceed the actual tool joint make-up torque. The recommended tool joint make-up torque is shown in Table 10.

## 7.8 EXAMPLE CALCULATION OF A TYPICAL DRILL STRING DESIGN—BASED ON MARGIN OF OVERPULL

Design parameters are as follows:

- Depth-12,700 feet.
- Hole size-7<sup>7</sup>/<sub>8</sub> inches.
- Mud weight-10 lb/gal.
- Margin of overpull (MOP)-50,000 lb. (assumed for this calculation).
- Desired safety factor in collapse-1<sup>1</sup>/<sub>8</sub> (assumed for this calculation).
- Drill collar data:
  - Length-630 feet.
  - OD-6<sup>1</sup>/<sub>4</sub> inches.
  - ID-2<sup>1</sup>/<sub>4</sub> inches.
  - Weight per foot-90 lb.

If the length of drill collars is not known, the following formula may be used:

$$L_c = \frac{Bit_{wm}}{\cos \alpha \times NP \times k_b \times W_c}$$

where

$L_c$  = length of drill collars, feet,

$Bit_{wm}$  = maximum weight on bit, lb,

$\alpha$  = hole angle from vertical, 3 degrees,

$NP$  = neutral point design factor determines neutral point position e.g., .85 means the neutral point will be 85 percent of the drill collar string length measured from the bottom (.85 assumed for this calculation),

$K_b$  = buoyancy factor, see Table 11,

$W_c$  = weight per foot of drill collars in air, lb,  
40,000

$$L_c = \frac{.998 \times .85 \times .847 \times 90}{.998 \times .85 \times .847 \times 90} = 618 \text{ feet, closest length based on 30 foot collars,} \\ = 630 \text{ feet or 21 drill collars.}$$

g. Drill string size: weight and grade-4<sup>1</sup>/<sub>2</sub> in. x 16.60 lb/ft x Grade E75, with 4<sup>1</sup>/<sub>2</sub> in., NC46 tool joints, 6<sup>1</sup>/<sub>4</sub> in. OD x 3<sup>1</sup>/<sub>4</sub> in. ID, Inspection Class 2.

From Equation 5:

$$L_{dp1} = \frac{(P_o \times .9) - MOP}{W_{dp1} \times K_b} - \frac{W_c \times L_c}{W_{dp1}} \\ = \frac{(225,771 \times .9) - 50,000}{18.37 \times .847} - \frac{90 \times 630}{18.37} \\ = 9846 - 3087 = 6759 \text{ feet}$$

It is apparent that drill pipe of a higher strength will be required to reach 12,700 feet. Add 4<sup>1</sup>/<sub>2</sub> in. x 16.60 lb/ft Grade X-95, with 4<sup>1</sup>/<sub>2</sub> in. X.H. tool joints, 6<sup>1</sup>/<sub>4</sub> in. OD x 3 in. ID (18.88 lb/ft) Inspection Class Premium.

Air weight of Number 1 drill pipe and drill collars:

$$\text{Total weight} = (L_{dp1} \times W_{dp1}) + (L_c \times W_c) \\ = (6759 \times 18.37) + (630 \times 90) \\ = 124,163 + 56,700 = 180,863 \text{ lb.}$$

From Equation 5:

$$L_{dp2} = \frac{(P_o \times .9) - MOP}{W_{dp2} \times K_b} - \frac{(L_{dp1} \times W_{dp1}) + (L_c \times W_c)}{W_{dp2}} \\ = \frac{(329,542 \times .9) - 50,000}{18.88 \times .847} - \frac{180,863}{18.88} \\ = 15,420 - 9580 = 5840 \text{ feet}$$

This is more drill pipe than required to reach 12,700 feet, so final drill string will consist of the following:

Item	Length (feet)	Weight in Air (pounds)	Weight in 10 lb/gal Mud (pounds)
Drill Collars 6 1/4" O.D. x 2 1/4" I.D.	630	56,700	48,025
No. 1 Drill Pipe 4 1/2" x 16.60 lb, Grade E75, Class 2	6759	124,163	105,166
No. 2 Drill Pipe 4 1/2" x 16.60 lb, Grade X-95, Premium Class	5311	100,272	84,930
	12,700	281,135	238,121

Torsional Yield of 4 1/2" x 16.60 lb x Grade E75 x Inspection Class 2 = 20,902 ft-lb.

Collapse Pressure of 4 1/2" x 16.60 lb x Grade E75 x Inspection Class 2 = 5951 psi.

Collapse pressure of 4 1/2" x 16.60 lb x Grade X-95 x Premium Inspection Class = 8868 psi.

From Equation 8:

$$\text{Pressure at bottom of drill pipe: } P_c = \frac{LW_g}{19.251},$$

$$L = 12,070 \text{ feet, } W_g = 10 \text{ lb/gal,}$$

$$P_c = \frac{12,070 \times 10}{19.251} = 6270 \text{ psi}$$

Therefore, this drill pipe has a lower collapse pressure than may be encountered in drilling to 12,700 feet. Precautions should be taken to prevent damage to the drill pipe when running the string dry below 10,183 feet. This is determined by solving Equation 8 for maximum length of drill pipe, and dividing by the safety factor in collapse of 1 1/8:

$$\begin{aligned} L_{max} &= \frac{P_c \times 19.251}{W_g} : 1.125 \\ &= \frac{5951 \times 19.251}{10} : 1.125 \\ &= 11,456 : 1.125 = 10,183 \text{ feet} \end{aligned}$$

## 7.9 DRILL PIPE BENDING RESULTING FROM TONGING OPERATIONS

It is generally known that the tool joint on a length of drill pipe should be kept as close to the rotary slips as possible dur-

ing make-up and break-out operations to prevent bending of the pipe.

There is a maximum height that the tool joint may be positioned above the rotary slips and the pipe to resist bending, while the maximum recommended make-up or break-out torque is applied to the tool joint.

Many factors govern this height limitation. Several of these which should be taken into most serious consideration are:

- The angle of separation between the make-up and break-out tongs, illustrated by Case I and Case II, Figure 35. Case I indicates tongs at 90 degrees and Case II indicates tongs at 180 degrees.
- The minimum yield strength of the pipe.
- The length of the tong handle.
- The maximum recommended make-up torque.

$$H_{max} = \frac{.053 Y_m L_T (I/C)}{T} \quad (\text{Case I}) \quad (13)$$

$$H_{max} = \frac{.038 Y_m L_T (I/C)}{T} \quad (\text{Case II}) \quad (14)$$

where

$H_{max}$  = height of tool joint shoulder above slips, ft.,

$Y_m$  = minimum tensile yield stress of pipe, psi,

$L_T$  = tong arm length, ft.,

$P$  = line pull (load), lbs,

$T$  = make-up torque applied to tool joint ( $P_x L_T$ ), ft-lb,

$I/C$  = section modulus of pipe-in<sup>3</sup>. (see Table 18).

Constants 0.053 and 0.038 include a factor of 0.9 to reduce  $Y_m$  to proportional limit (see 7.3).

Sample calculation:

Assume: 4 1/2-in., 16.60 lb/ft, Grade E drill pipe, with 4 1/2-in. X.H. 6 1/4-in. OD, 3 1/4-in. ID tool joints.

Tong arm 3 1/2-ft.

Tongs at 90 (Case I).

Using Equation 13:

$$H_{max} = \frac{.053 (Y_m) (I/C) (L_T)}{T}$$

$$Y_m = 75,000 \text{ psi (for Grade E),}$$

$$I/C = 4.27 \text{ in}^3 \text{ (Table 18),}$$

$$L_T = 3.5 \text{ ft.,}$$

$$T = 16,997 \text{ ft-lb (from Table 10),}$$

$$H_{max} = \frac{.053(75,000)(4.27)(3.5)}{16,997} = 3.4 \text{ ft.}$$



Table 18—Section Modulus Values

(1)	(2)	(3)
Pipe OD in.	Pipe Weight Nominal lbs/ft	I/C cu. in.
2 <sup>3</sup> / <sub>8</sub>	4.85	0.66
	6.65	0.87
2 <sup>7</sup> / <sub>8</sub>	6.85	1.12
	10.40	1.60
3 <sup>1</sup> / <sub>2</sub>	9.50	1.96
	13.30	2.57
	15.50	2.92
4	11.85	2.70
	14.00	3.22
	15.70	3.58
4 <sup>1</sup> / <sub>2</sub>	13.75	3.59
	16.60	4.27
	20.00	5.17
	22.82	5.68
	24.66	6.03
5	25.50	6.19
	16.25	4.86
	19.50	5.71
	25.60	7.25
5 <sup>1</sup> / <sub>2</sub>	19.20	6.11
	21.90	7.03
	24.70	7.84
6 <sup>5</sup> / <sub>8</sub>	25.20	9.79

## 8 Limitations Related to Hole Deviation

### 8.1 FATIGUE DAMAGE

Most drill pipe failures are a result of fatigue. Drill pipe will suffer fatigue when it is rotated in a section of hole in which there is a change of hole angle and/or direction, commonly called a dogleg. The amount of fatigue damage which results depends on the following:

#### 8.1.1 Tensile Load in the Pipe at the Dogleg

Following is an example calculation:

##### a. Data:

- 4<sup>1</sup>/<sub>2</sub>-inch, 16.60 lb/ft, Grade E, Range 2 drill pipe (actual weight in air including tool joints, 17.8 lb/ft) 7<sup>3</sup>/<sub>4</sub>-inch OD, 2<sup>1</sup>/<sub>4</sub>-inch ID drill collars (actual weight in air 147 lb/ft).
- 15 lb/gal (112.21 lb/cu. ft) mud.
- (buoyancy factor = 0.771)
- Dogleg depth: 3,000 ft.
- Anticipated total depth: 11,600 ft.
- Drill collar length: 600 ft.
- Drill pipe length at total depth: 11,000 ft.
- Length of drill collar string, whose buoyant weight is in excess of the weight on bit: 100 ft.

##### b. Solution:

Tensile load in the pipe at the dogleg:

$$r(11,000 - 3,000) 17.8 + 100 \times 147 \times 0.771 = 121,124 \text{ lb}$$

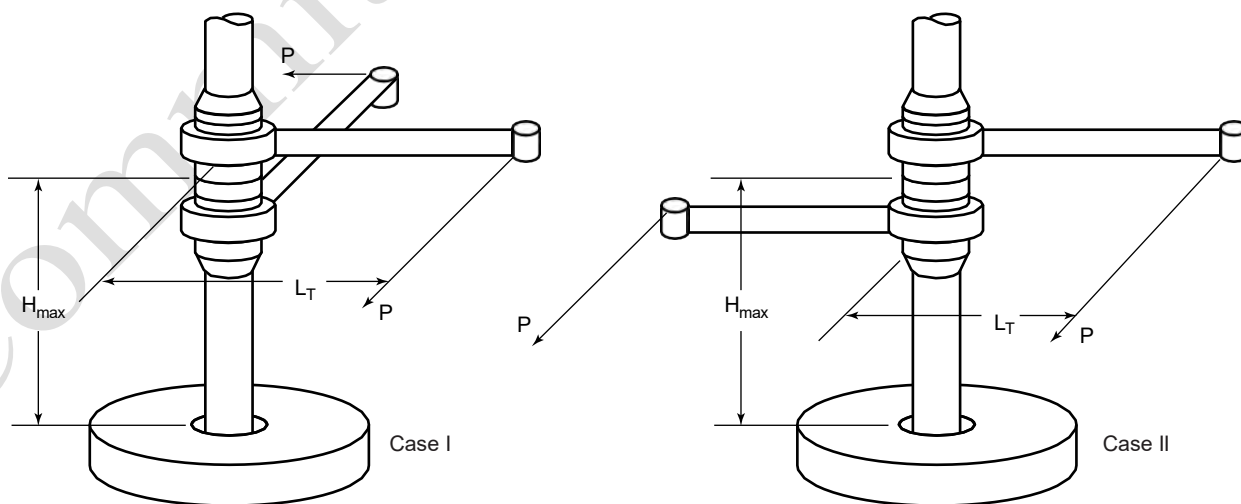


Figure 35—Maximum Height of Tool Joint Above Slips to Prevent Bending During Tonging

### 8.1.2 The Severity of the Dogleg

The number of cycles experienced in the dogleg, as well as the mechanical dimensions and properties of the pipe itself.

Because tension in the pipe is critical, a shallow dogleg in a deep hole often becomes a source of difficulty. Rotating off bottom is not a good practice since additional tensile load results from the suspended drill collars. Lubinski<sup>1</sup> and Nicholson<sup>2</sup> have published methods of calculating forces on tool joints and conditions necessary for fatigue damage to occur. Referring to Figures 36 and 37, note that it is necessary to remain to the left of fatigue curves to reduce fatigue damage. Programs to plan and drill wells to minimize fatigue have been reported by Schenck<sup>3</sup> and Wilson<sup>4</sup>. Such programs are necessary to reduce fatigue damage.

The curves on Figures 36, 37, and 38 (also Figures 41, 42, and 43) are for Range 2 drill pipe, i.e. for joint lengths of 30 feet. This length has an effect on the curves. Information is available on fatigue of Range 3 (45 feet) drill pipe.<sup>14</sup> The curves on Figures 36, 37, and 38 are independent of tool joint OD; however, the portion of the curve for which there is pipe-to-hole contact between tool joints (dashed lines on Figures 36 and 38) becomes longer when tool joint OD becomes smaller, and conversely.

The advent of electronic pocket calculators makes it easy to use the following equations instead of the curves in Figures 36 and 37.<sup>1,4</sup>

$$c = \frac{432,000}{v} \frac{6_b}{ED} \frac{\tanh KL}{KL} \quad (15)$$

$$K = \sqrt{\frac{T}{EI}} \quad (16)$$

where

- $c$  = maximum permissible dogleg severity (hole curvature), degrees per 100 feet,
- $E$  = Young's modulus, psi,  
= 30 x 10<sup>6</sup> psi, for steel,  
= 10.5 x 10<sup>6</sup> psi, for aluminum,
- $D$  = drill pipe OD, inches,
- $L$  = half the distance between tool joints, inches,  
= 180 inches, for Range 2.

Note: Equation 15 does not hold true for Range 3.<sup>14</sup>

- $T$  = buoyant weight (including tool joints) suspended below the dogleg, pounds,
- $6_b$  = maximum permissible bending stress, psi,
- $I$  = drill pipe moment of inertia with respect to its diameter, in.<sup>4</sup>, calculated by Equation 17.

$$I = \frac{v}{64} (D^4 - d^4), \quad (17)$$

where

- $D$  = drill pipe OD, inches,
- $d$  = drill pipe ID, inches.

The maximum permissible bending stress,  $6_b$ , is calculated from the buoyant tensile stress,  $6_t$  (psi), in the dogleg with Equations 19 and 20 below.  $6_t$  is calculated with Equation 18:

$$6_t = \frac{T}{A} \quad (18)$$

where

$A$  = cross sectional area of drill pipe body, square inches.

For Grade E:<sup>14</sup>

$$6_b = 19,500 - \frac{10}{67} 6_t - \frac{0.6}{(670)^2} (6_t - 33,500)^2 \quad (19)$$

Equation 19 holds true for values of  $6_t$  up to 67,000 psi.

For Grade S-135:<sup>2</sup>

$$\alpha_b = 20,000 \left( 1 - \frac{\alpha_t}{145,000} \right) \quad (20)$$

Equation 20 holds true for values of up to 133,400 psi.

The following equation may be used instead of Figure 38:

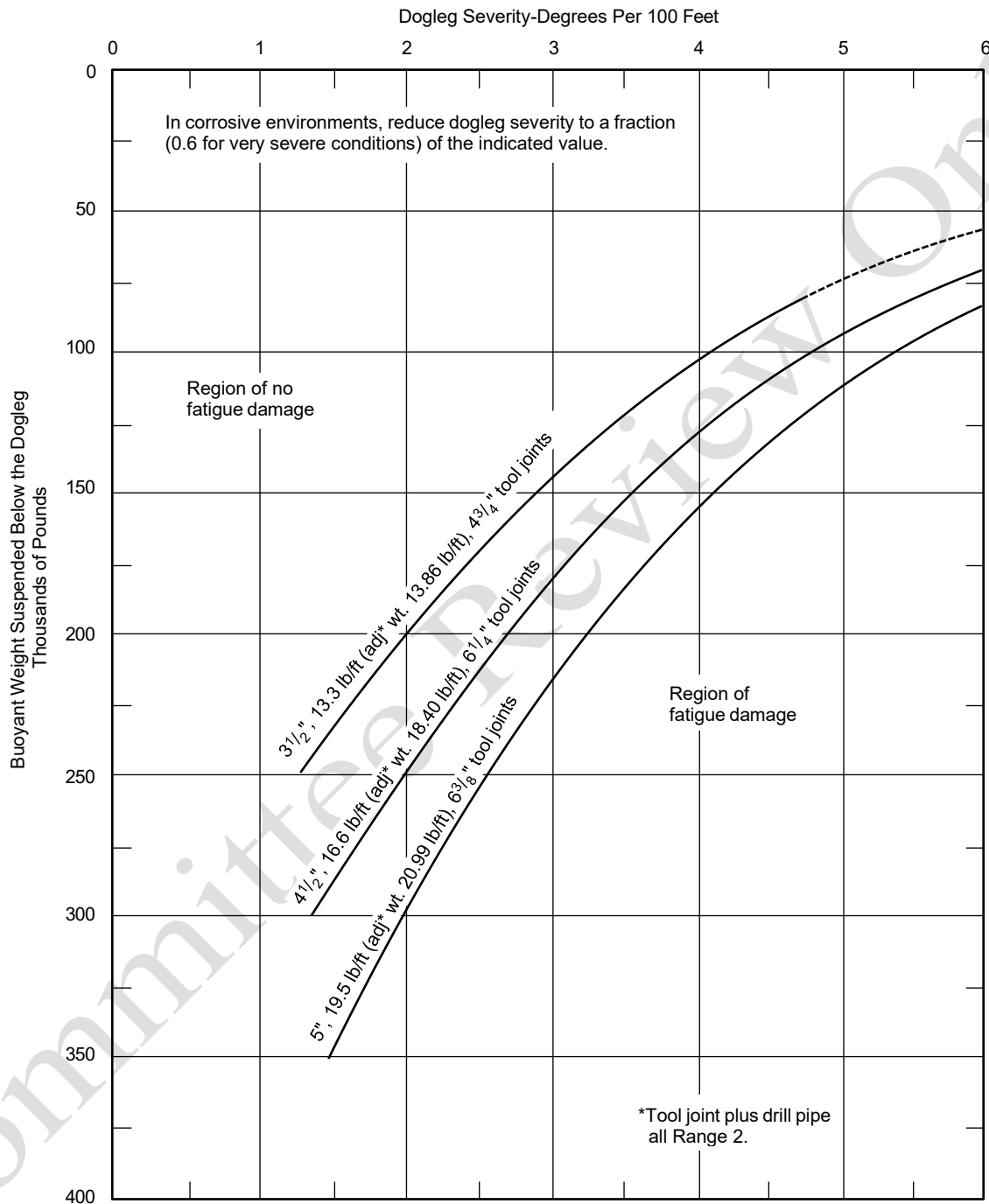
$$c = \frac{108,000}{vL} \frac{F}{T} \quad (21)$$

in which  $F$  is the lateral force on tool joint (1000, 2000, or 3000 pounds in Figure 38), and the meaning of the other symbols is the same as previously.

## 8.2 REMEDIAL ACTION TO REDUCE FATIGUE

If doglegs of sufficient magnitude are present or suspected, it is good practice to string ream the dogleg area. This reduces the severity of the hole angle change. With reference to Figure 40, the fatigue life of drill pipe will be decreased considerably when it is used in a corrosive drilling fluid. For many water-base drilling fluids, the fatigue life of steel drill stems may be increased by maintaining a pH of 9.5 or higher. Refer to 10.1.4 for description of a corrosion monitoring system.

Several methods are available for monitoring and controlling the corrosivity of drilling fluids. The most commonly used monitoring technique is the use of a corrosion ring inserted in the drill stem. For a description of this technique see API Recommended Practice 13B-1, *Recommended Practice Standard Procedure for Field Testing Water-Based Drilling Fluids*.



Note:  
Dashed curve corresponds to condition when drill pipe contacts the hole between tool joints, and then the permissible dogleg severity is greater than indicated.

Figure 36—Dogleg Severity Limits for Fatigue of Grade E75 Drill Pipe

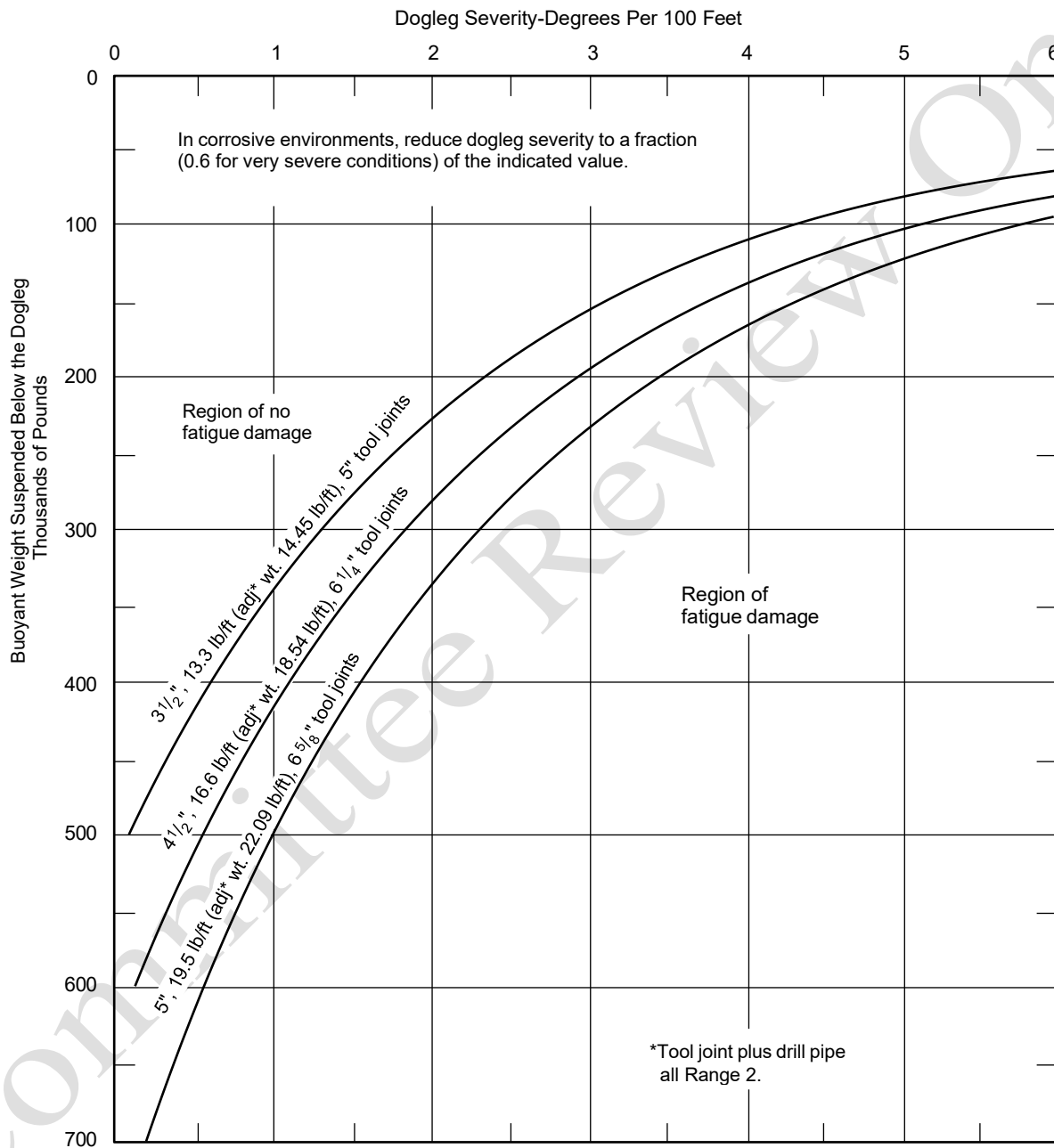
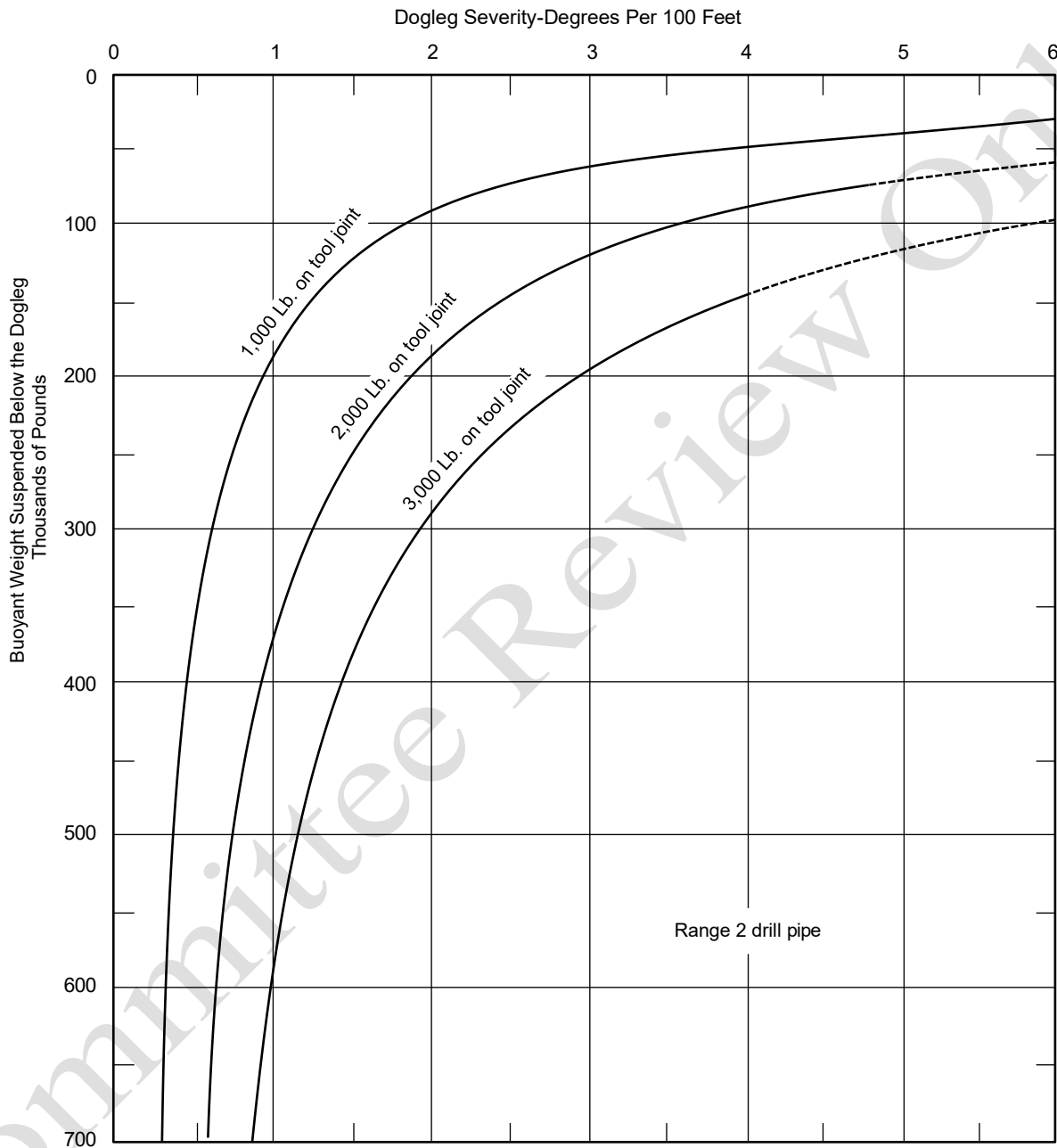


Figure 37—Dogleg Severity Limits for Fatigue of S-135 Drill Pipe



Note:  
Dashed curves correspond to condition when drill pipe may contact the hole between tool joints, and then the permissible dogleg severity may be greater than indicated.

Figure 38—Lateral Force on Tool Joint

### 8.3 ESTIMATION OF CUMULATIVE FATIGUE DAMAGE

Hansford and Lubinski<sup>5</sup> have developed a method for estimating the cumulative fatigue damage to joints of pipe which have been rotated through severe doglegs (see Figures 39 and 40). While insufficient field checks of the results of this method have been made to verify its reliability, it is available as a simple analytic device to use as a guide in the identification of suspect joints. A correction formula to use for other penetration rates and rotary speeds is as follows:

$$\% \text{ Life Expended} = \% \text{ Life Expended from}$$

Figure 39 or 40 x

$$\frac{\text{Actual RPM}}{100 \text{ RPM}} \times \frac{10 \text{ ft/hr}}{\text{Actual ft/hr}}$$

### 8.4 IDENTIFICATION OF FATIGUED JOINTS

As mentioned, insufficient data is available to verify the results of the method explained in 8.3. However, it is the only method presently available for estimating cumulative fatigue damage and should be used if it is possible to identify and classify fatigued joints. The difficulty lies in identifying and recording each separate joint fatigue history. Joints which have been calculated to have more than 100 percent of their fatigue life expended should be carefully examined and, if not downgraded or abandoned, watched as closely as possible. Such consideration should be finally governed by experience factors until such time as the analytical method for fatigue prediction gains more reliability.

### 8.5 WEAR OF TOOL JOINTS AND DRILL PIPE

When drill pipe in a dogleg is in tension it is pulled to the inside of the bend with substantial force. The lateral force will increase the wear of the pipe and tool joints. When abrasion is a problem it is desirable to limit the amount of lateral force to less than about 2000 lb on the tool joints by controlling the rate of change of hole angle. Values either smaller or greater than 2000 lb might be in order, depending on formation at the dogleg. Figure 38 shows curves for 1000, 2000, or 3000 lb lateral force on the tool joints; points to the left of these curves will have less lateral force, and points to the right more lateral force on the tool joints. Figures 41, 42, 43, and 44, developed by Lubinski, show lateral force curves for both tool joints and drill pipe for three popular pipe sizes. The first three figures are for three pipe sizes, Range 2. Figure 44 is for 5-inch, 19.5 lb per foot, Range 3 drill pipe.

**8.5.1** For conditions represented by points located to the left of Curve No. 1, such as Point A in Figure 41, only tool joints and not drill pipe between tool joints contact the wall of the hole. This should not be construed to mean the drill pipe

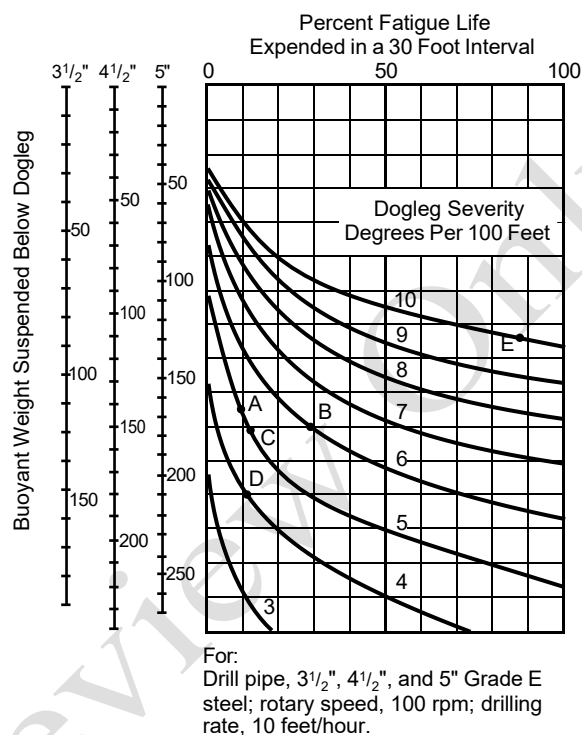


Figure 39—Fatigue Damage in Gradual Doglegs (Noncorrosive Environment)

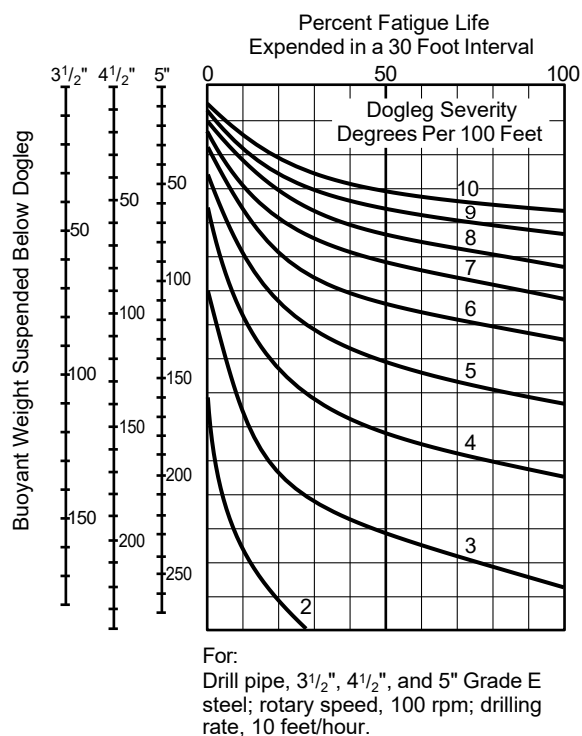


Figure 40—Fatigue Damage in Gradual Doglegs (In Extremely Corrosive Environment)

body does not wear at all, as Figure 41 is for a gradual and not for an abrupt dogleg. In an abrupt dogleg, drill pipe does contact the wall of the hole half way between tool joints, and the pipe body is subjected to wear. This lasts until the dogleg is rounded off and becomes gradual.

**8.5.2** For conditions represented by points located on Curve No. 1, theoretically the drill pipe contacts the wall of the hole with zero force at the midpoint between tool joints.

**8.5.3** For conditions represented by points located between Curve No. 1 and Curve No. 2, theoretically the drill pipe still contacts the wall of the hole at midpoint only, but with a force which is not equal to zero. This force increases from Curve No. 1 toward Curve No. 2. Practically, of course, the contact between the drill pipe and the wall of the hole will be along a short length located near the midpoint of the joint.

**8.5.4** For conditions represented by points located to the right of Curve No. 2, theoretically the drill pipe contacts the wall of the hole not at one point, but along an arc with increasing length to the right of Curve No. 2.

On each of the Figures 41, 42, 43, and 44, there are in addition to curves No. 1 and No. 2, two families of curves: one for the force on tool joint, and the other for the force on drill pipe body. As an example, consider Figure 41; Point B indicates that if the buoyant weight suspended below the dogleg is 170,000 lb, and if dogleg severity (hole curvature) is 10.1 degrees per 100 feet, then the force on tool joint is 6000 lb, and the force on drill pipe body is 3000 lb.

## 8.6 HEAT CHECKING OF TOOL JOINTS

Tool joints which are rotated under high lateral force against the wall of the hole may be damaged as a result of friction heat checking. The heat generated at the surface of the tool joint by friction with the wall of the hole when under high radial thrust loads may raise the temperature of the tool joint steel above its critical temperature. Metallurgical examination of such joints has indicated affected zones with varying hardness as much as  $\frac{3}{16}$ -in. below OD surface. If the radial thrust load is sufficiently high, surface heat checking can occur in the presence of drilling mud alternately being heated and quenched as it rotates. This action produces numerous irregular heat check cracks often accompanied by longer axial cracks sometimes extending through the full section of the joint and washouts may occur in these splits or windows. (See Lubinski, "Maximum Permissible Dog Legs in Rotary Boreholes," *Journal of Petroleum Technology*, 1961.)<sup>1</sup> Maintaining hole angle control so that 2000 lb lateral force is not exceeded will minimize or eliminate heat checking of tool joints.

## 9 Limitations Related To Floating Vessels

**9.1** All possible steps should be taken to avoid subjecting drill pipe to fatigue; i.e., to cyclic stresses due to rotation of the drill string under bending and tension. Two major factors which are specific to drilling from a floater that contribute to fatigue of drill pipe are as follows:

**9.1.1** The rotary table is not centered at all times exactly above the subsea borehole.

**9.1.2** The derrick is not always vertical but follows the roll and pitch motions of the floater.

**9.2** This text pertains to prevention of fatigue due to 9.1.2, above. When the derrick is inclined during a part of the roll or pitch motion, the upper extremity of the drill string is not vertical while the drill pipe at some distance below the rotary table remains vertical. Thus the drill string is bent. As drill pipe is much less rigid than the kelly, most of the bending occurs in the first length of drill pipe below the kelly. This subject is studied in a paper titled, *The Effect of Drilling Vessel Pitch or Roll on Kelly and Drill Pipe Fatigue*, by John E. Hansford and Arthur Lubinski.<sup>6</sup>

**9.3** Based on the Hansford and Lubinski paper<sup>6</sup>, the following practices are recommended to minimize bending and, therefore, fatigue of the first joint of drill pipe, due to roll and/or pitch of a floater.

**9.3.1** Multiplane bushings should not be used. Either a gamboled kelly bushing, or a one-plane roller bushing is preferable.

**9.3.2** An extended length kelly should be used to relieve the severe bending of the limber drill pipe through less severe bending of the rigid kelly extension. This extension may be accomplished by any of the following means:

- For Range 2 drill pipe, use a 54-foot kelly which is ordinarily used with Range 3 pipe, rather than the usual 40-foot kelly.
- Use a specially made kelly at least 8 feet longer than the standard length.
- Use at least 8 feet of kelly saver subs between the kelly and drill pipe.

**9.3.3** If b, above, is not implemented, avoid rotating off bottom with the kelly more than half way up for long periods of time if the maximum angular vessel motion is more than 5 degrees single amplitude. In this text, long periods of time are:

- More than 30 minutes for large hookloads.
- More than 2 hours for light hookloads.

**9.3.4** If conditions prevent implementing b or c, above, the first joint of drill pipe below the kelly should be removed from the string at the first opportunity and discarded.



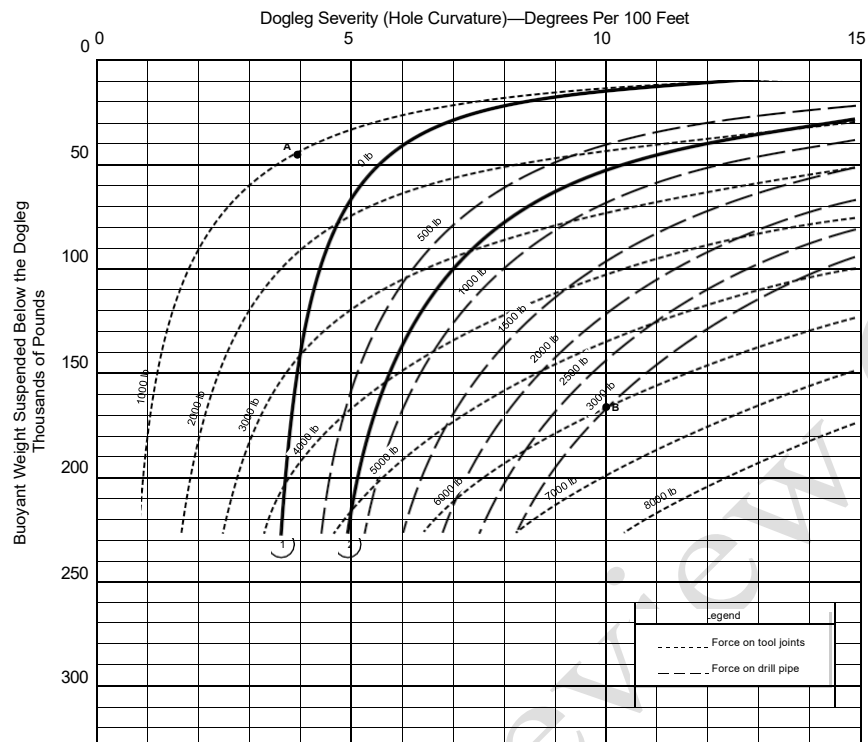


Figure 41—Lateral Forces on Tool Joints and Range 2 Drill Pipe 3 $\frac{1}{2}$ -Inch, 13.3 Pounds per Foot, Range 2 Drill Pipe, 4 $\frac{3}{4}$ -Inch Tool Joints

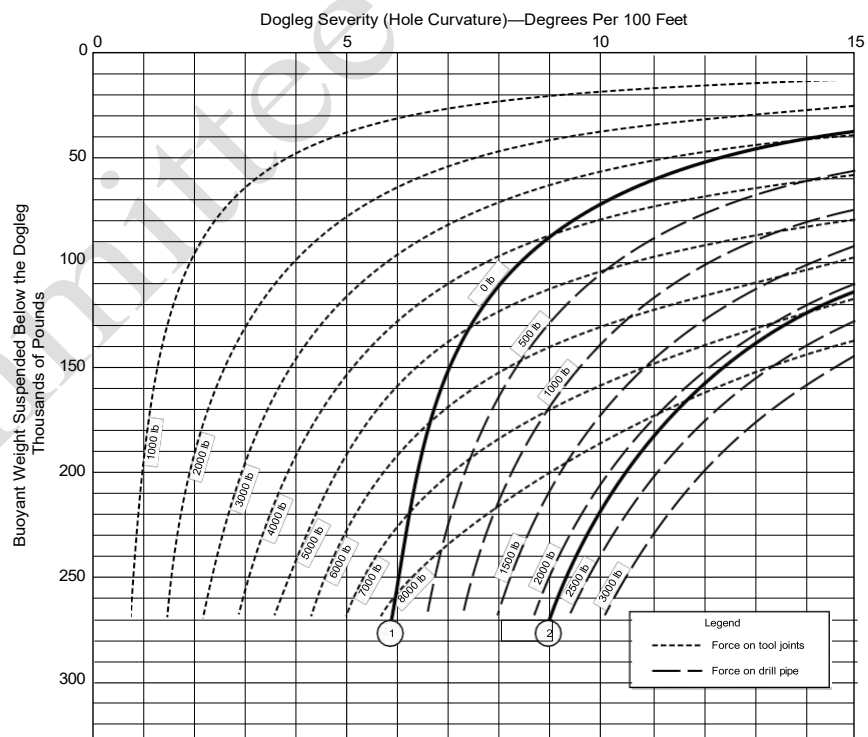


Figure 42—Lateral Forces on Tool Joints and Range 2 Drill Pipe 4 $\frac{1}{2}$ -Inch, 16.6 Pounds per Foot, Range 2 Drill Pipe, 6 $\frac{1}{4}$ -Inch Tool Joints



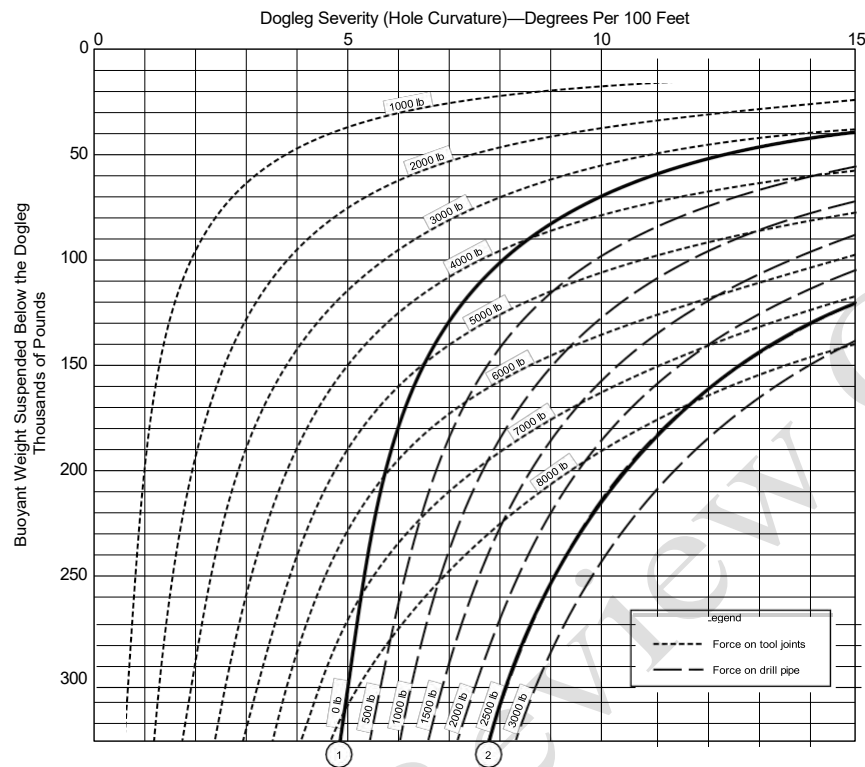


Figure 43—Lateral Forces on Tool Joints and Range 2 Drill Pipe 5-Inch, 19.5 Pounds per Foot, Range 2 Drill Pipe, 6<sup>3</sup>/<sub>8</sub>-Inch Tool Joints

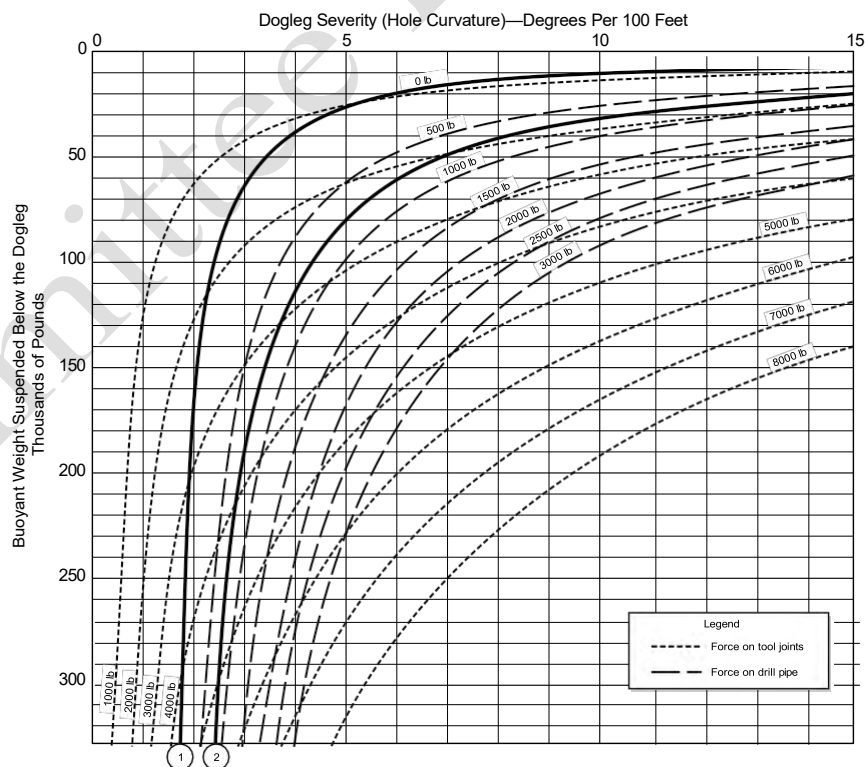


Figure 44—Lateral Forces on Tool Joints and Range 3 Drill Pipe 5-Inch, 19.5 Pounds per Foot, Range 3 Drill Pipe, 6<sup>3</sup>/<sub>8</sub>-Inch Tool Joints

## 10 Drill Stem Corrosion and Sulfide Stress Cracking

### 10.1 CORROSION

#### 10.1.1 Corrosive Agents

Corrosion may be defined as the alteration and degradation of material by its environment. The principal corrosive agents affecting drill stem materials in water-base drilling fluids are dissolved gases (oxygen, carbon dioxide, and hydrogen sulfide), dissolved salts, and acids.

##### 10.1.1.1 Oxygen

Oxygen is the most common corrosive agent. In the presence of moisture it causes rusting of steel, the most common form of corrosion. Oxygen causes uniform corrosion and pitting, leading to washouts, twistoffs, and fatigue failures. Since oxygen is soluble in water, and most drilling fluid systems are open to the air, the drill stem is continually exposed to potentially severe corrosive conditions.

##### 10.1.1.2 Carbon Dioxide

Carbon dioxide dissolves in water to form a weak acid (carbonic acid) that corrodes steel in the same manner as other acids (by hydrogen evolution), unless the pH is maintained above 6. At higher pH values, carbon dioxide corrosion damage is similar to oxygen corrosion damage, but at a slower rate. When carbon dioxide and oxygen are both present, however, the corrosion rate is higher than the sum of the rates for each alone.

Carbon dioxide in drilling fluids may come from the makeup water, gas bearing formation fluid inflow, thermal decomposition of dissolved salts and organic drilling fluid additives, or bacterial action on organic material in the makeup water or drilling fluid additives.

##### 10.1.1.3 Hydrogen Sulfide

Hydrogen sulfide dissolves in water to form an acid somewhat weaker and less corrosive than carbonic acid, although it may cause pitting, particularly in the presence of oxygen and/or carbon dioxide. A more significant action of hydrogen sulfide is its effect on a form of hydrogen embrittlement known as sulfide stress cracking (see 10.2 for details).

Hydrogen sulfide in drilling fluids may come from the makeup water, gas-bearing formation fluid inflow, bacterial action on dissolved sulfates, or thermal degradation of sulfur-containing drilling fluid additives.

##### 10.1.1.4 Dissolved Salts

Dissolved salts (chlorides, carbonates, and sulfates) increase the electrical conductivity of drilling fluids. Since most corrosion processes involve electrochemical reactions,

the increased conductivity may result in higher corrosion rates. Concentrated salt solutions are usually less corrosive than dilute solutions; however, because of decreased oxygen solubility. Dissolved salts also may serve as a source of carbon dioxide or hydrogen sulfide in drilling fluids.

Dissolved salts in drilling fluids may come from the makeup water, formation fluid inflow, drilled formations, or drilling fluid additives.

##### 10.1.1.5 Acids

Acids corrode metals by lowering the pH (causing hydrogen evolution) and by dissolving protective films. Dissolved oxygen appreciably accelerates the corrosion rates of acids, and dissolved hydrogen sulfide greatly accelerates hydrogen embrittlement.

Organic acids (formic, acetic, etc.) can be formed in drilling fluids by bacterial action or by thermal degradation of organic drilling fluid additives. Organic acids and mineral acids (hydrochloric, hydrofluoric, etc.) may be used during workover operations or stimulating treatments.

### 10.1.2 Factors Affecting Corrosion Rates

Among the many factors affecting corrosion rates of drill stem materials the more important are:

#### 10.1.2.1 pH

This is a scale for measuring hydrogen ion concentration. The pH scale is logarithmic; i.e., each pH increment of 1.0 represents a tenfold change in hydrogen ion concentration. The pH of pure water, free of dissolved gases, is 7.0. pH values less than 7 are increasingly acidic, and pH values greater than 7 are increasingly alkaline. In the presence of dissolved oxygen, the corrosion rate of steel in water is relatively constant between pH 4.5 and 9.5; but it increases rapidly at lower pH values, and decreases slowly at higher pH values. Aluminum alloys, however, may show increasing corrosion rates at pH values greater than 8.5.

#### 10.1.2.2 Temperature

In general, corrosion rates increase with increasing temperature.

#### 10.1.2.3 Velocity

In general, corrosion rates increase with higher rates of flow.

#### 10.1.2.4 Heterogeneity

Localized variations in composition or microstructure may increase corrosion rates. Ringworm corrosion, that is sometimes found near the upset areas of drill pipe or tubing that

has not been properly heat treated after upsetting, is an example of corrosion caused by nonuniform grain structure.

#### 10.1.2.5 High Stresses

Highly stressed areas may corrode faster than areas of lower stress. The drill stem just above drill collars often shows abnormal corrosion damage, partially because of higher stresses and high bending moments.

### 10.1.3 Corrosion Damage (Forms of Corrosion)

Corrosion can take many forms and may combine with other types of damage (erosion, wear, fatigue, etc.) to cause extremely severe damage or failure. Several forms of corrosion may occur at the same time, but one type will usually predominate. Knowing and identifying the forms of corrosion can be helpful in planning corrective action. The forms of corrosion most often encountered with drill stem materials are:

#### 10.1.3.1 Uniform or General Attack

During uniform attack, the material corrodes evenly, usually leaving a coating of corrosion products. The resulting loss in wall thickness can lead to failure from reduction of the material's load-carrying capability.

#### 10.1.3.2 Localized Attack (Pitting)

Corrosion may be localized in small, well-defined areas, causing pits. Their number, depth, and size may vary considerably; and they may be obscured by corrosion products. Pitting is difficult to detect and evaluate, since it may occur under corrosion products, mill scale and other deposits, in crevices or other stagnant areas, in highly stressed areas, etc. Pits can cause washouts and can serve as points of origin for fatigue cracks. Chlorides, oxygen, carbon dioxide, and hydrogen sulfide, and especially combinations of them, are major contributors to pitting corrosion.

#### 10.1.3.3 Erosion-Corrosion

Many metals resist corrosion by forming protective oxide films or tightly adherent deposits. If these films or deposits are removed or disturbed by high-velocity fluid flow, abrasive suspended solids, excessive turbulence, cavitation, etc., accelerated attack occurs at the fresh metal surface. This combination of erosive wear and corrosion may cause pitting, extensive damage, and failure.

#### 10.1.3.4 Fatigue in a Corrosive Environment (Corrosion Fatigue)

Metals subjected to cyclic stresses of sufficient magnitude will develop fatigue cracks that may grow until complete failure occurs. The limiting cyclic stress that a metal can sustain

for an infinite number of cycles is known as the fatigue limit. Remedial action for reducing drill stem fatigue is discussed in Section 8.

In a corrosive environment no fatigue limit exists, since failure will ultimately occur from corrosion, even in the absence of cyclic stress. The cumulative effect of corrosion and cyclic stress (corrosion fatigue) is greater than the sum of the damage from each. Fatigue life will always be less in a corrosive environment, even under mildly corrosive conditions that show little or no visible evidence of corrosion.

### 10.1.4 Detecting and Monitoring Corrosion

The complex interactions between various corrosive agents and the many factors controlling corrosion rates make it difficult to accurately assess the potential corrosivity of a drilling fluid. Various instruments and devices such as pH meters, oxygen meters, corrosion meters, hydrogen probes, chemical test kits, test coupons, etc. are available for field monitoring of corrosion agents and their effects.

The monitoring system described in Appendix A of API Recommended Practice 13B-1, *Recommended Practice Standard Procedure for Field Testing Water-Based Drilling Fluids*, can be used to evaluate corrosive conditions and to follow the effect of remedial actions taken to correct undesirable conditions. Preweighed test rings are placed in recesses at the back of tool joint box threads at selected locations throughout the drill stem, exposed to the drilling operation for a period of time, then removed, cleaned, and reweighed. The degree and severity of pitting observed may be of greater significance than the weight loss measurement.

The chemical testing of drilling fluids (see API Recommended Practices 13B-1 and 13B-2) should be performed in the field whenever possible, especially tests for pH, alkalinity, and the dissolved gases (oxygen, carbon dioxide, and hydrogen sulfide).

### 10.1.5 Procurement of Samples for Laboratory Testing

When laboratory examination of drilling fluid is desired, representative samples should be collected in a 1/2 to 1 gallon (2 to 4 liter) clean container, allowing an air space of approximately 1 percent of the container volume and sealing tightly with a suitable stopper. Chemically resisting glass, polyethylene, and hard rubber are suitable materials for most drilling fluid samples. Samples should be analyzed as soon as possible, and the elapsed time between collection and analysis reported. See ASTM D3370, *Standard Practices for Sampling Water*, for guidance on sampling and shipping procedures.

When laboratory examination of corroded or failed drill stem material is required, use care in securing the specimens. If torch cutting is needed, do it in a way that will avoid physical or metallurgical changes in the area to be examined. Spec-

imens must not be cleaned, wire brushed, or shot blasted in any manner; and should be wrapped and shipped in a way that will avoid damage to the corrosion products or fracture surfaces. Whenever possible, both fracture surfaces should be supplied.

### 10.1.6 Drill Pipe Coatings

Internally coating the drill pipe and attached tool joints can provide effective protection against corrosion in the pipe bore. In the presence of corrosive agents, however, the corrosion rate of the drill stem OD may be increased. Drill pipe coating is a shop operation in which the pipe is cleaned of all grease and scale, sand or grit blasted to white metal, plastic coated, and baked. After baking, the coating is examined for breaks or holidays.

### 10.1.7 Corrective Measures to Minimize Corrosion in Water-Base Drilling Fluids

The selection and control of appropriate corrective measures is usually performed by competent corrosion technologists and specialists. Generally, one or more of the following measures is used, but certain conditions may require more specialized treatments:

- a. Control the drilling fluid pH. When practical to do so without upsetting other desired fluid properties, the maintenance of a pH of 9.5 or higher will minimize corrosion of steel in water-base systems containing dissolved oxygen. In some drilling fluids, however, corrosion of aluminum drill pipe increases at pH values higher than 8.5.
- b. Use appropriate inhibitors and/or oxygen scavengers to minimize weight loss corrosion. This is particularly helpful with low pH, low solids drilling fluids. Inhibitors must be carefully selected and controlled, because different corrosive agents and different drilling fluid systems (particularly those used for air or mist drilling) require different types of inhibitors. The use of the wrong type of inhibitor, or the wrong amount, may actually increase corrosion.
- c. Use plastic coated drill pipe. Care must be exercised to prevent damage to the coating.
- d. Use degassers and desanders to remove harmful dissolved gases and abrasive material.
- e. Limit oxygen intake by maintaining tight pump connections and by minimizing pit-jetting.
- f. Limit gas-cutting and formation fluid inflow by maintaining proper drilling fluid weight.
- g. When the drill string is laid down, stored, or transported, wash out all drilling fluid residues with fresh water, clean out all corrosion products (by shot blasting or hydroblasting, if necessary), and coat all surfaces with a suitable corrosion preventive (see API Recommended Practice 5C1, *Recommended Practice for Care and Use of Casing and Tubing*).

### 10.1.8 Extending Corrosion Fatigue Life

While generally not affecting corrosion rates, the following measures will extend corrosion fatigue life by lowering the cyclic stress intensity or by increasing the fatigue strength of the material:

- a. Use thicker-walled components.
- b. Reduce high stresses near connections by minimizing dog-legs and by maintaining straight hole conditions, insofar as possible.
- c. Minimize stress concentrators such as slip marks, tong marks, gouges, notches, scratches, etc.
- d. Use quenched and tempered components.

## 10.2 SULFIDE STRESS CRACKING

### 10.2.1 Mechanism of Sulfide Stress Cracking (SSC)

In the presence of hydrogen sulfide ( $H_2S$ ), tensile-loaded drill stem components may suddenly fail in a brittle manner at a fraction of their nominal load-carrying capability after performing satisfactorily for extended periods of time. Failure may occur even in the apparent absence of corrosion, but is more likely if active corrosion exists. Embrittlement of the steel is caused by the absorption and diffusion of atomic hydrogen and is much more severe when  $H_2S$  is present. The brittle failure of tensile-loaded steel in the presence of  $H_2S$  is termed sulfide stress cracking (SSC).

### 10.2.2 Materials Resistant to SSC

The latest revision of NACE Standard MR-01-75, *Sulfide Stress Cracking Resistant Metallic Material for Oil Field Equipment*, should be consulted for materials that have been found to be satisfactory for drilling and well servicing operations.

Other chemical compositions, hardnesses, and heat treatments should not be used in sour environments without fully evaluating their SSC susceptibility in the environment in which they will be used. Susceptibility to SSC depends on the following:

#### 10.2.2.1 Strength of the Steel

The higher the strength (hardness) of the steel, the greater is the susceptibility to SSC. In general, steels having strengths equivalent to hardnesses up to 22 HRC maximum are resistant to SSC. If the chemical composition is adjusted to permit the development of a well tempered, predominantly martensitic microstructure by proper quenching and tempering; steels having strengths equivalent to hardnesses up to 26 HRC maximum are resistant to SSC. When strengths higher than the equivalent of 26 HRC are required, corrective measures (as shown in a later section) must be used; and, the higher the strength required, the greater the necessity for the corrective measures.



### 10.2.2.2 Total Tensile Load (Stress) on the Steel

The higher the total tensile load on the component, the greater is the possibility of failure by SSC. For each strength of steel used, there appears to be a critical or threshold stress below which SSC will not occur; however, the higher the strength, the lower the threshold stress.

### 10.2.2.3 Amount of Atomic Hydrogen and H<sub>2</sub>S

The higher the amount of atomic hydrogen and H<sub>2</sub>S present in the environment, the shorter the time before failure by SSC. The amounts of atomic hydrogen and H<sub>2</sub>S required to cause SSC are quite small, but corrective measures to control their amounts will minimize the atomic hydrogen absorbed by the steel.

### 10.2.2.4 Time

Time is required for atomic hydrogen to be absorbed and diffused in steel to the critical concentration required for crack initiation and propagation to failure. By controlling the factors referred to above, time-to-failure may be sufficiently lengthened to permit the use of marginally susceptible steels for short duration drilling operations (see Figure 45).

### 10.2.2.5 Temperature

The severity of SSC is greatest at normal atmospheric temperatures, and decreases as temperature increases. At operating temperatures in excess of approximately 135°F (57°C), marginally susceptible materials (those having hardnesses higher than 22 to 26 HRC) have been used successfully in potentially embrittling environments. (The higher the hardness of the material, the higher the required safe operating temperature.) Caution must be exercised, however—SSC failure may occur when the material returns to normal temperature after it is removed from the hole.

### 10.2.3 Corrective Measures to Minimize SSC in Water-Base Drilling Fluids

The selection and control of appropriate corrective measures is usually performed by competent corrosion technologists and specialists. Generally, one or more of the following measures is used, but certain conditions may require more specialized treatments:

- a. Control the drilling fluid pH. When practical to do so without upsetting other desired fluid properties, maintain a pH of 10 or higher.

Note: In some drilling fluids, aluminum alloys show slowly increasing corrosion rates at pH values higher than 8.5; and the rate may become excessive at pH values higher than 10.5. Therefore, in drill strings containing aluminum drill pipe, the pH should not exceed 10.5.

- b. Limit gas-cutting and formation fluid inflow by maintaining proper drilling fluid weight.

- c. Minimize corrosion by the corrective measures shown in 10.1.7.

Note: While use of plastic coated drill pipe can minimize corrosion, plastic coating does not protect susceptible drill pipe from SSC.

- d. Chemically treat for hydrogen sulfide inflows, preferably prior to encountering the sulfide.

- e. Use the lowest strength drill pipe capable of withstanding the required drilling conditions. At any strength level, properly quenched and tempered drill pipe will provide the best SSC resistance.

- f. Reduce unit stresses by using thicker walled components.

- g. Reduce high stresses at connections by maintaining straight hole conditions, insofar as possible.

- h. Minimize stress concentrators such as slip marks, tong marks, gouges, notches, scratches, etc.

- i. After exposure to a sour environment, use care in tripping out of the hole, avoiding sudden shocks and high loads.

- j. After exposure to a sour environment, remove absorbed hydrogen by aging in open air for several days to several weeks (depending upon conditions of exposure) or bake at 400° to 600°F (204° to 316°C) for several hours.

Note: Plastic coated drill pipe should not be heated above 400°F (204°C) and should be checked subsequently for holidays and disbonding.

The removal of hydrogen is hindered by the presence of corrosion products, scale, grease, oil, etc. Cracks that have formed (internally or externally) prior to removing the hydrogen will not be repaired by the baking or stress relief operations.

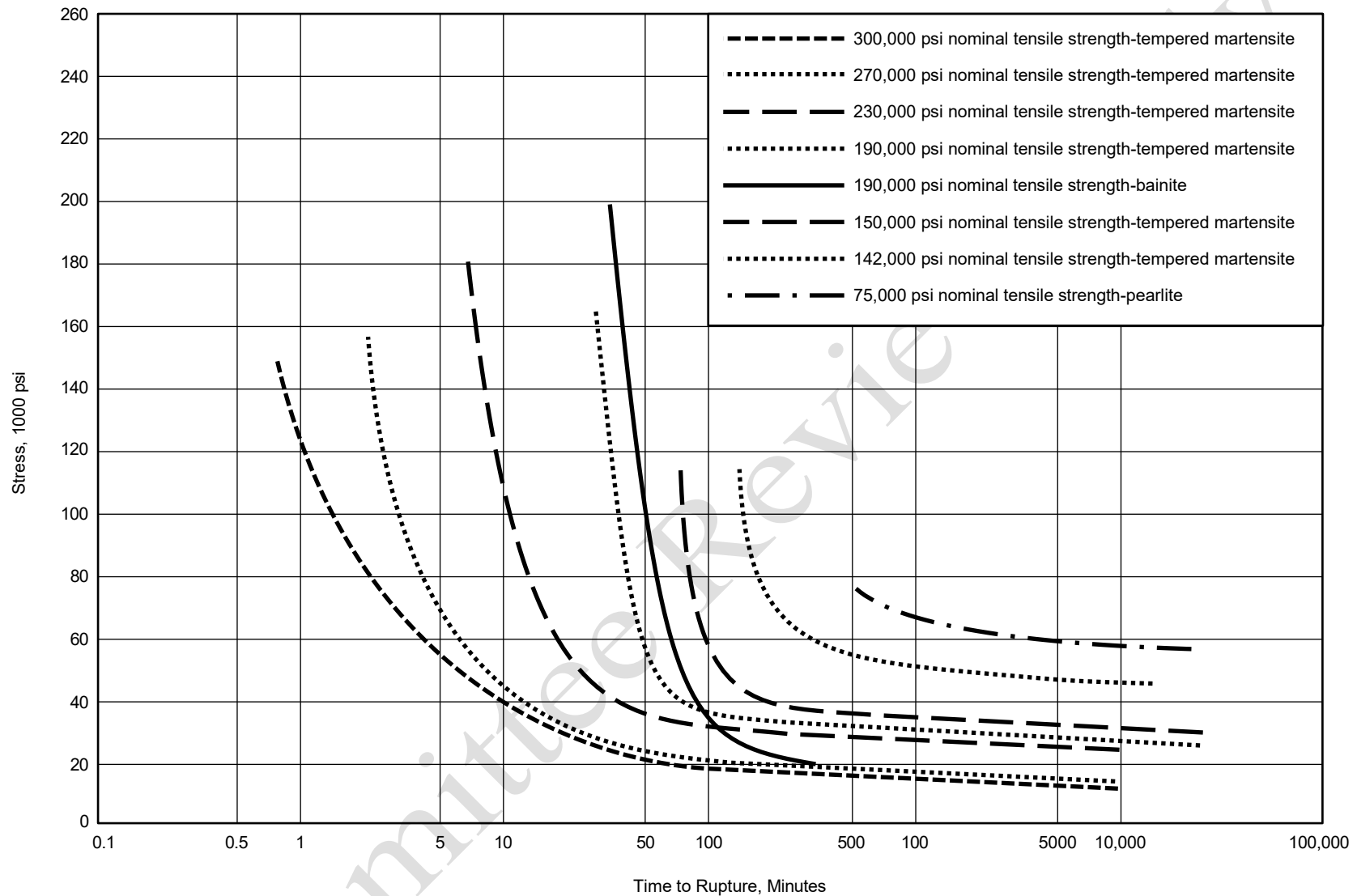
- k. Limit drill stem testing in sour environments to as brief a period as possible, using operating procedures that will minimize exposure to SSC conditions.

## 10.3 DRILLING FLUIDS CONTAINING OIL

### 10.3.1 Use of Oil Muds for Drill Stem Protection

Corrosion and SSC can be minimized by the use of drilling fluids having oil as the continuous phase. Corrosion does not occur if metal is completely enveloped and wet by an oil environment that is electrically nonconductive.

Oil systems used for drilling (oil-base or invert emulsion muds) contain surfactants that stabilize water as emulsified droplets and cause preferential oil-wetting of the metal. Agents that cause corrosion in water (dissolved gases, dissolved salts, and acids) do not damage the oil-wet metal. Therefore, under drilling conditions that cause serious problems of corrosion damage erosion-corrosion, or corrosion fatigue, drill stem life can be greatly extended by using an oil mud.



Note:

Batelle Charging Condition A:

Electrolyte: 4 percent by weight of  $H_2SO_4$  in water.

Poison: 5 drops per liter of cathodic poison composed of 2<sub>g</sub> phosphorous dissolved in 40 ml  $CS_2$ .

Current Density: 8 ma/in<sup>2</sup>.

Figure 45—Delayed-Failure Characteristics of Unnotched Specimens of an SAE 4340 Steel During Cathodic Charging with Hydrogen Under Standardized Conditions

### 10.3.2 Monitoring Oil Muds for Drill Stem Protection

An oil mud must be properly prepared and maintained to protect drill stem from corrosion and SSC. Water will always be present in an oil mud, whether added intentionally, incorporated as a contaminant in the surface system, or from exposed drilled formations. Corrosion and SSC may occur if this water is allowed to become free and to wet the drill stem. Factors to be evaluated in monitoring an oil mud include:

#### 10.3.2.1 Electrical Stability

This test measures the voltage required to cause current to flow between electrodes immersed in the oil mud (see API Recommended Practice 13B-2, *Recommended Practice Standard Procedure for Field Testing Oil-Based Drilling Fluids*, for details). The higher the voltage, the greater the stability of the emulsion, and the better the protection provided to the drill stem.

#### 10.3.2.2 Alkalinity

The acidic dissolved gases (carbon dioxide and hydrogen sulfide) are harmful contaminants for most oil muds. Monitoring the alkalinity of an oil mud can indicate when acidic gases are being encountered so that corrective treatment can be instituted.

#### 10.3.2.3 Corrosion Test Rings

Test rings placed in the drill stem bore are used to monitor the corrosion protection afforded by oil muds (see API Recommended Practice 13B-2 for details). A properly functioning oil mud should show little or no visual evidence of corrosion on the test ring.

## 11 Compressive Service Limits for Drill Pipe (see also Appendices A.15 and A.16)

### 11.1 COMPRESSIVE SERVICE APPLICATIONS

**11.1.1** Whenever drilling high angle, extended reach, or horizontal well bores it is desirable to use compressively loaded portions of the drill string. Drilling with drill pipe in compression causes no more damage to the drill pipe than conventional drilling operations as long as the operating conditions do not exceed the compressive service limits for the pipe.

**11.1.2** Drill strings are subject to compressive service conditions whenever significant portions of the borehole exceed the critical sliding hole angle as defined as follows:

$$\Sigma_c = \arctan \left( \frac{1}{f} \right),$$

where

$\Sigma_c$  = critical sliding hole angle,  
 $f$  = coefficient of friction.

**11.1.3** The critical sliding hole angle is the angle above which drill string components must be pushed into the hole. Although many factors affect the coefficient of friction between the drill string components and the wall of the hole, the type of drilling fluid used has the greatest impact (see Table 19). Water-based drilling fluids generate the highest coefficient to friction and produce critical hole angles of about 71 degrees. Synthetic-based drilling fluids provide the lowest coefficients of friction and produce critical hole angles of about 80 degrees.

**11.1.4** Operating significant lengths of the drill string in compression can cause the pipe to helically buckle and induce pipe curvatures larger than the curvature of the hole and may cause unacceptable bending stresses. Rotating drill pipe in curved portions of the hole generates cyclic bending stresses that can also cause fatigue failures. The most effective and efficient drill string design for extended reach and horizontal holes is the lightest weight drill string that can withstand the operating environment. Using heavier components or thicker wall tubulars often increases the operating loads without reducing the bending stresses.

Table 19—Effect of Drilling Fluid Type on Coefficient of Friction

Drilling Fluid	Typical Coefficient of Friction	Critical Hole Angle degrees
Water-base mud	0.35	71
Oil-base mud	0.25	76
Synthetic-base mud	0.17	80

### 11.2 DRILL PIPE BUCKLING IN STRAIGHT, INCLINED WELL BORES

#### 11.2.1 Overview

**11.2.1.1** The curves shown in Figures 46 through 66 give the approximate axial compressive loads at which sinusoidal buckling is expected to occur in drill pipe in straight, inclined wellbores. If the drill pipe is being rotated, limiting the drill pipe compressive load to below the estimated buckling load shown in these curves will significantly reduce the danger of fatigue damage to the pipe. Conversely, rotating drill pipe while it is buckled can lead to rapid fatigue damage and failure.

**11.2.1.2** These curves are based on the equations of Dawson and Paslay.<sup>27</sup> They are reproduced here with permission from Standard DS-1, *Drill Stem Design and Inspection*.<sup>28</sup> The assumptions behind these curves include:

a. Pipe weight is new nominal with X-grade tool joint dimensions (where applicable). If more than one tool joint is

(Text continued on page 78.)

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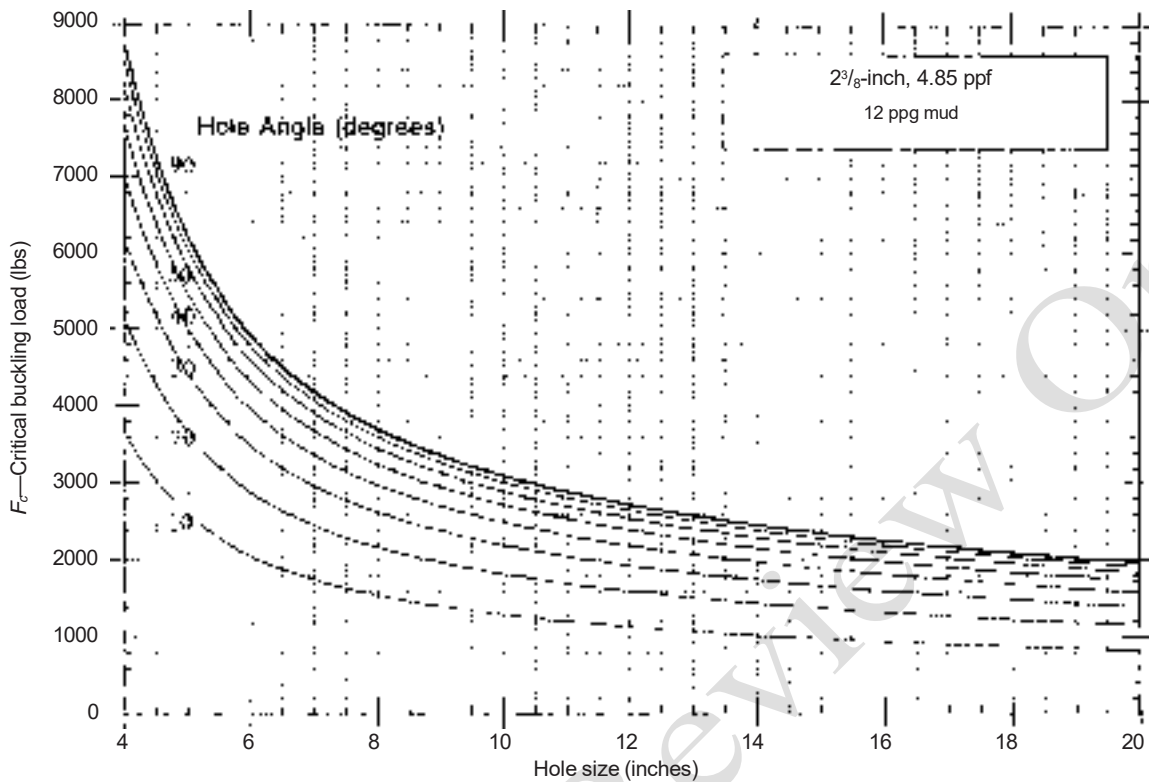


Figure 46—Approximate Axial Compressive Loads at which Sinusoidal Buckling is Expected to Occur

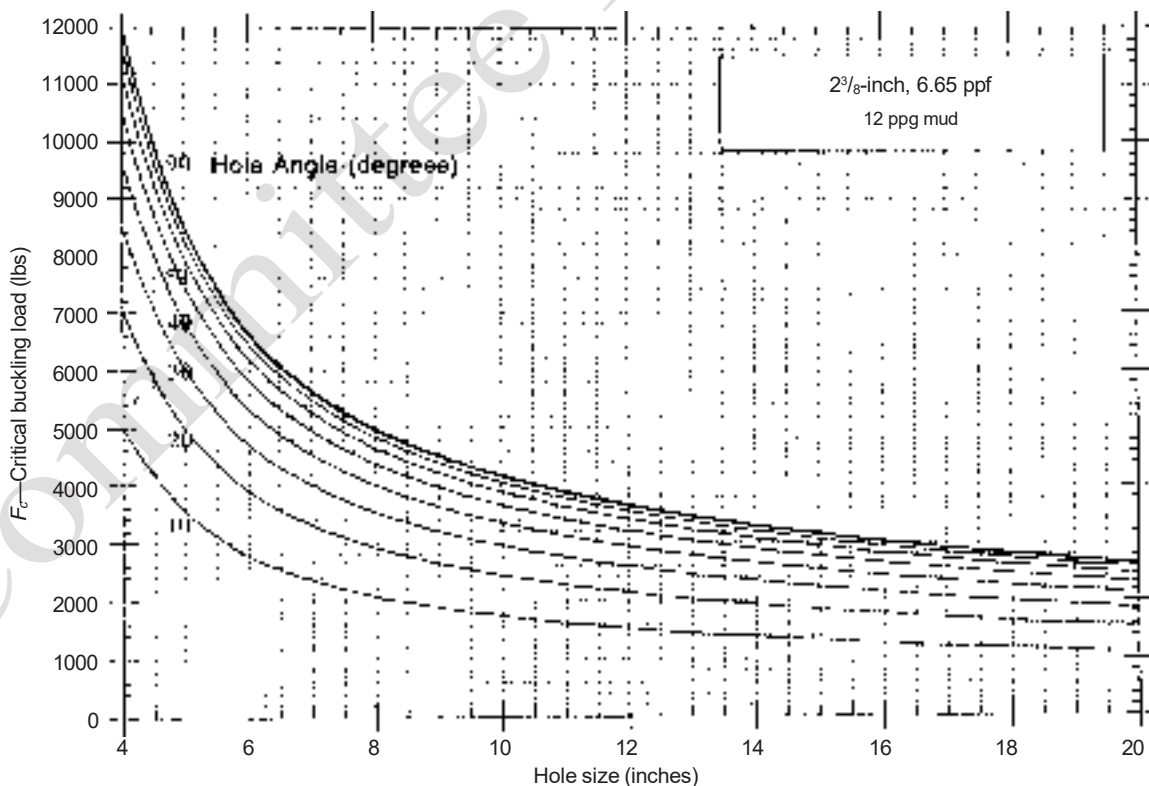


Figure 47—Approximate Axial Compressive Loads at which Sinusoidal Buckling is Expected to Occur

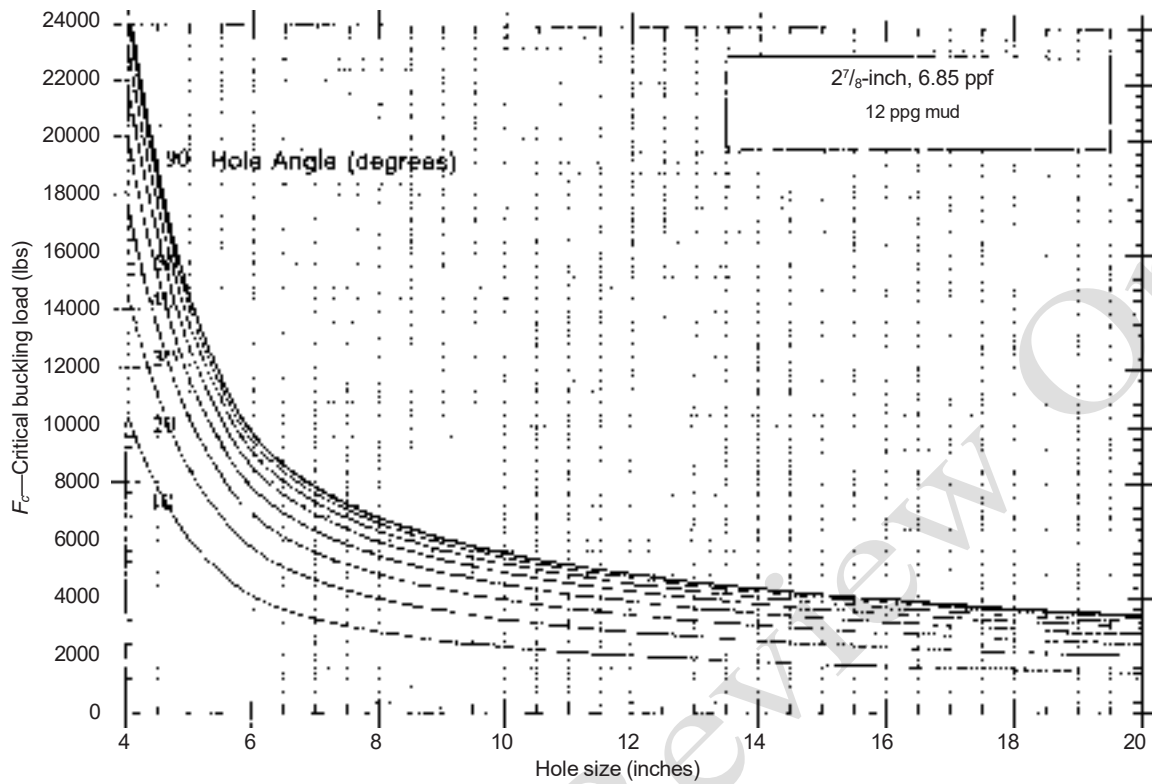


Figure 48—Approximate Axial Compressive Loads at which Sinusoidal Buckling is Expected to Occur

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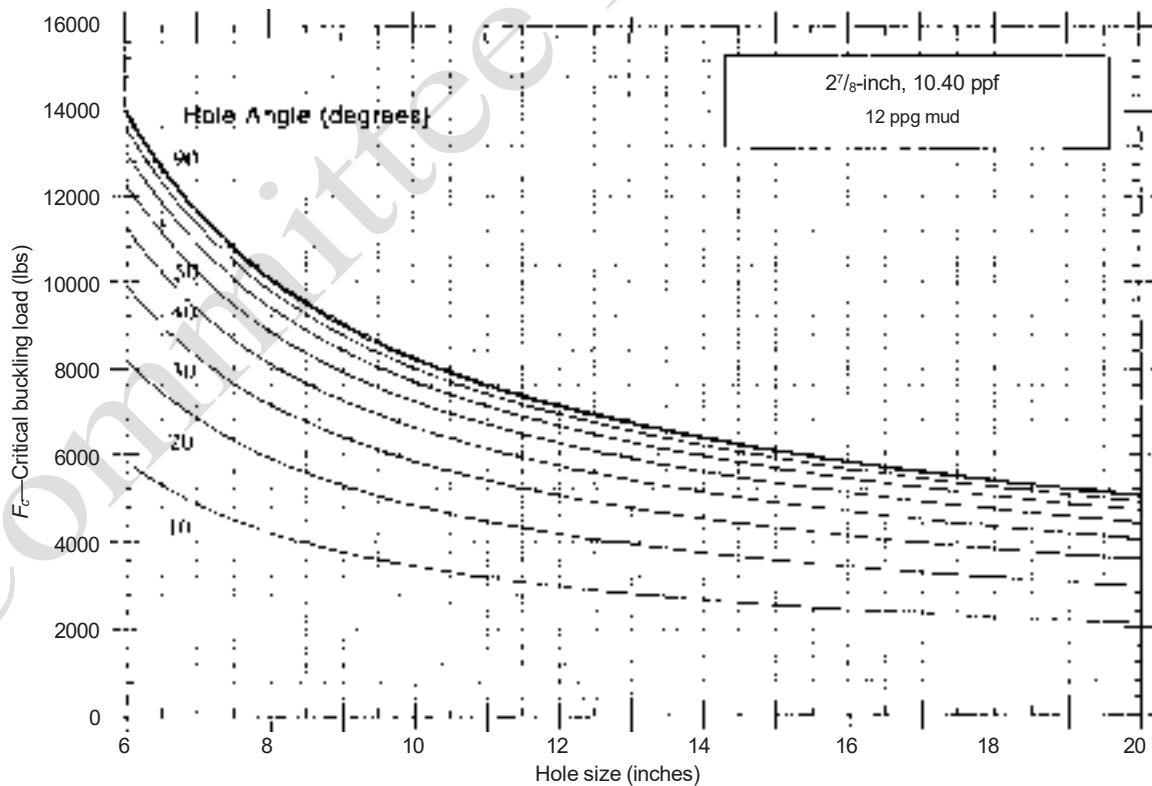


Figure 49—Approximate Axial Compressive Loads at which Sinusoidal Buckling is Expected to Occur

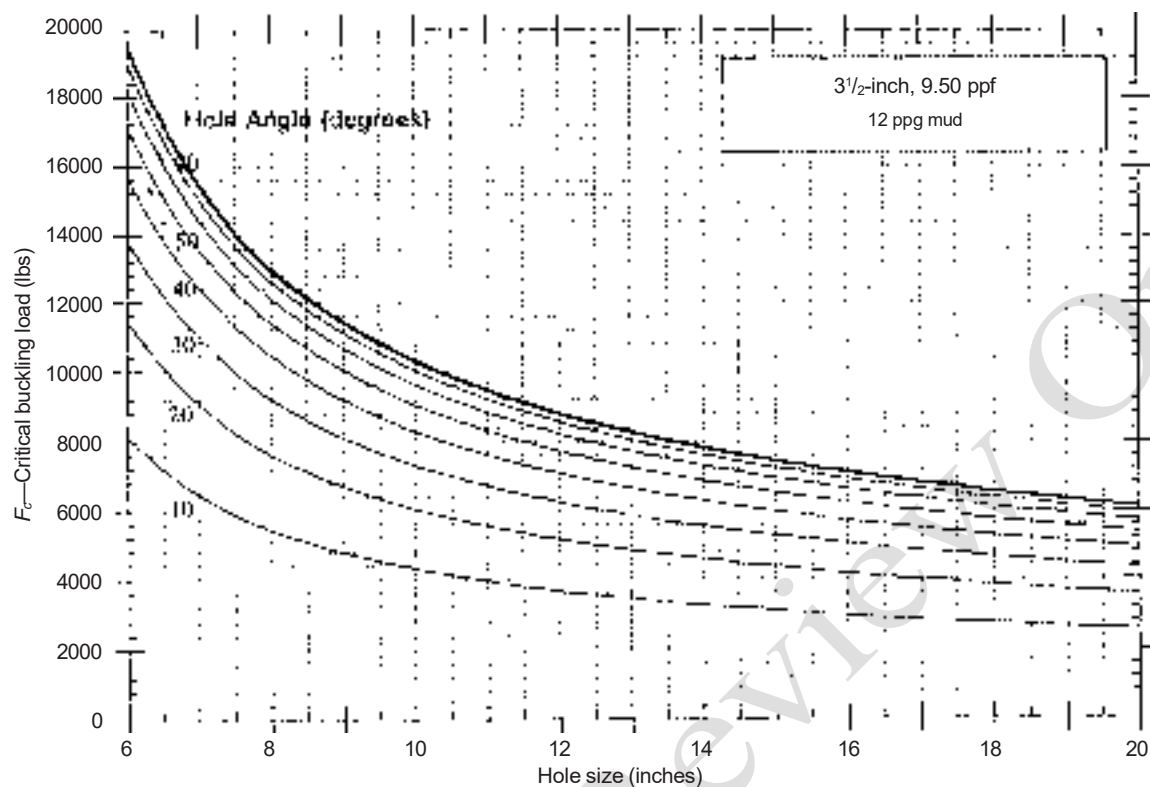


Figure 50—Approximate Axial Compressive Loads at which Sinusoidal Buckling is Expected to Occur

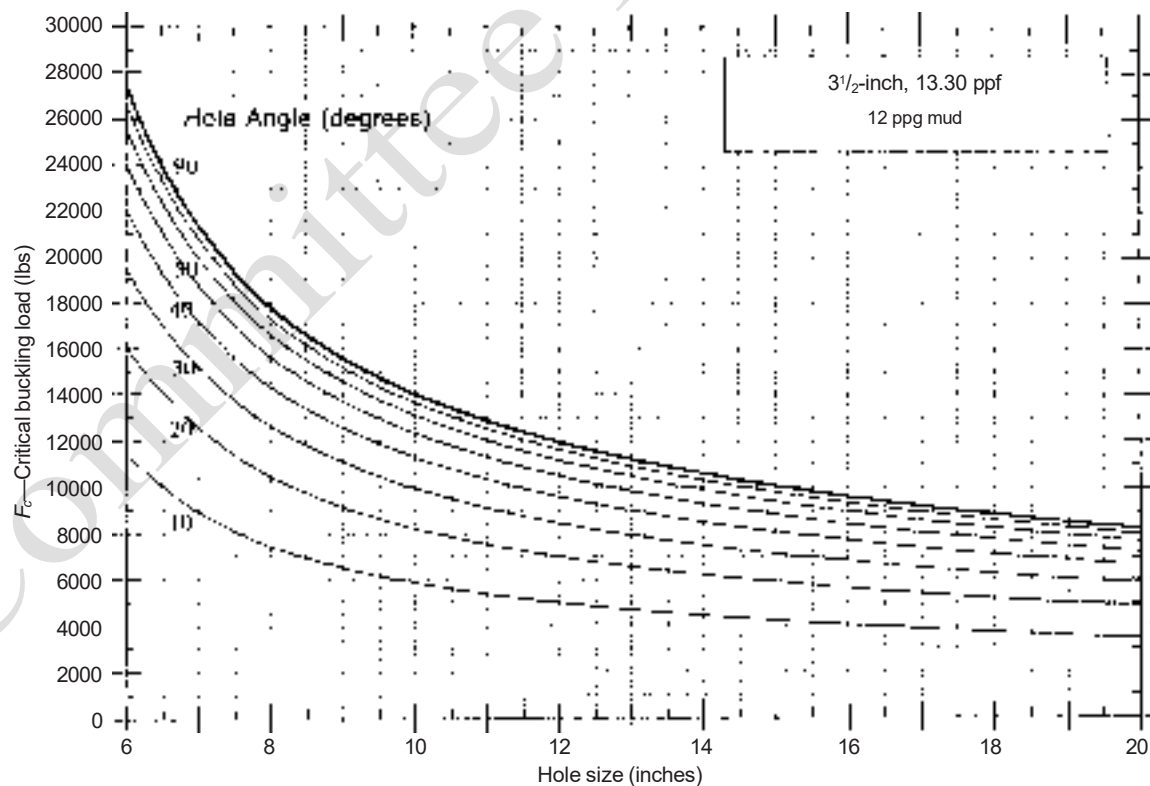


Figure 51—Approximate Axial Compressive Loads at which Sinusoidal Buckling is Expected to Occur

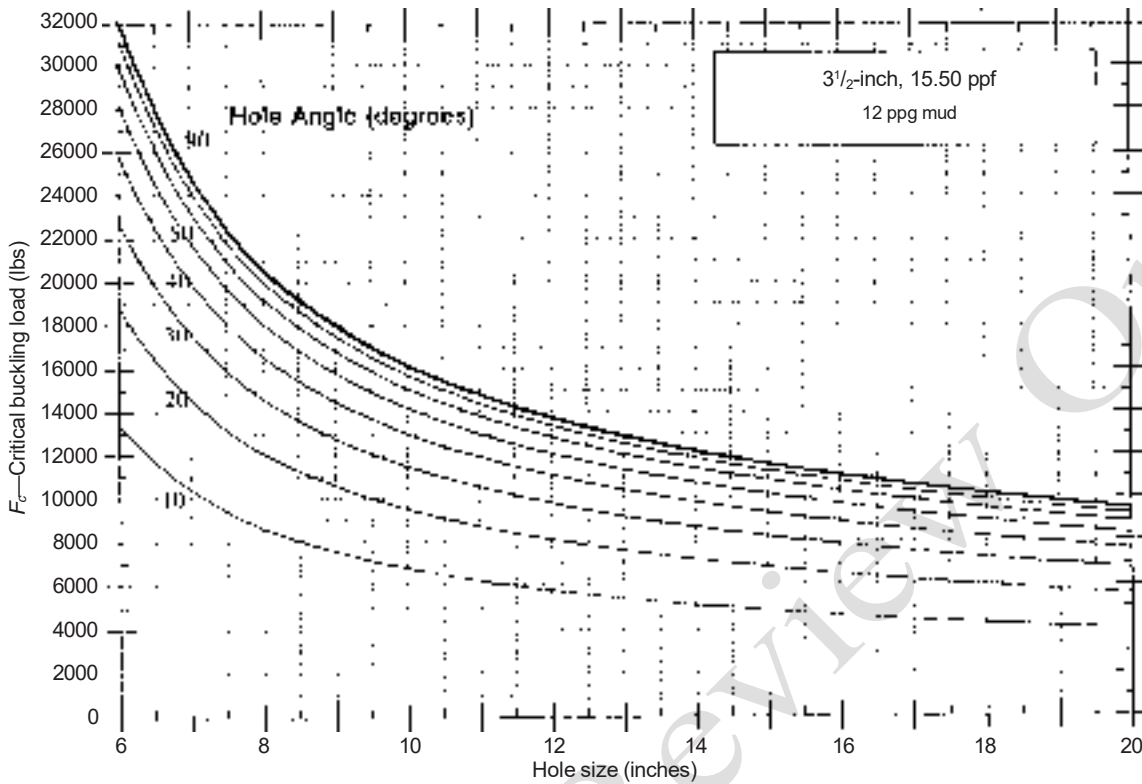


Figure 52—Approximate Axial Compressive Loads at which Sinusoidal Buckling is Expected to Occur

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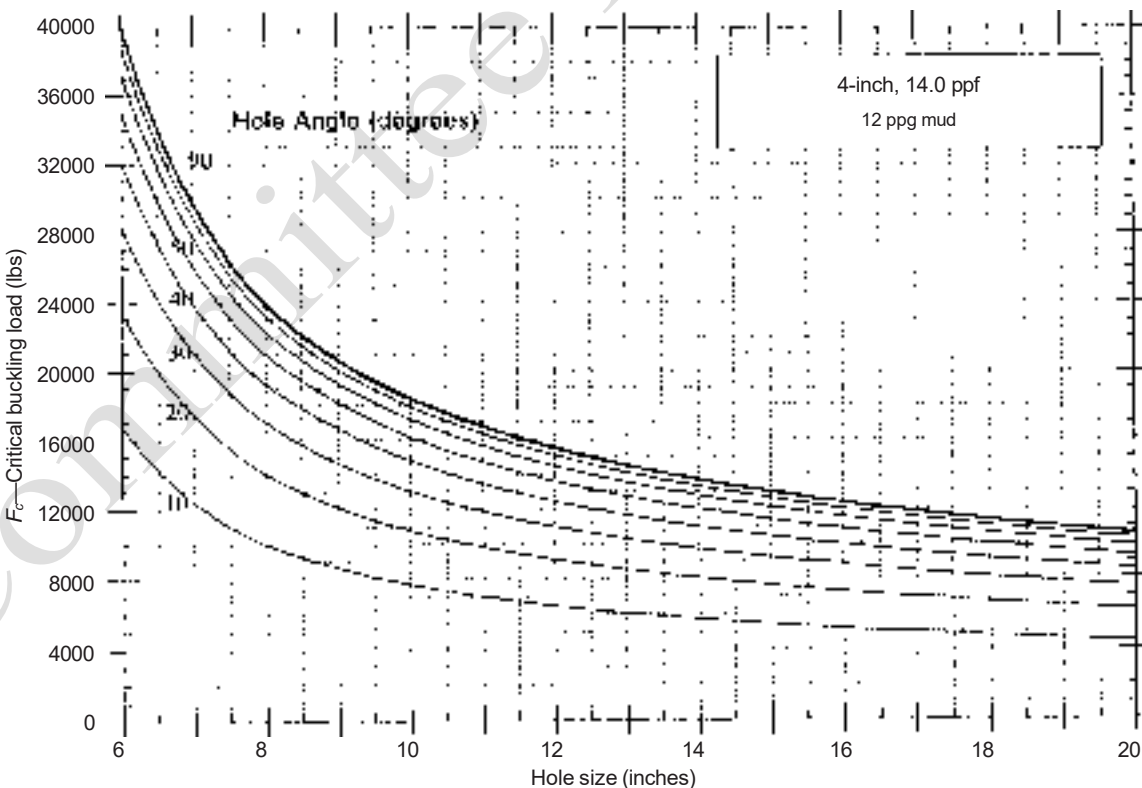


Figure 53—Approximate Axial Compressive Loads at which Sinusoidal Buckling is Expected to Occur

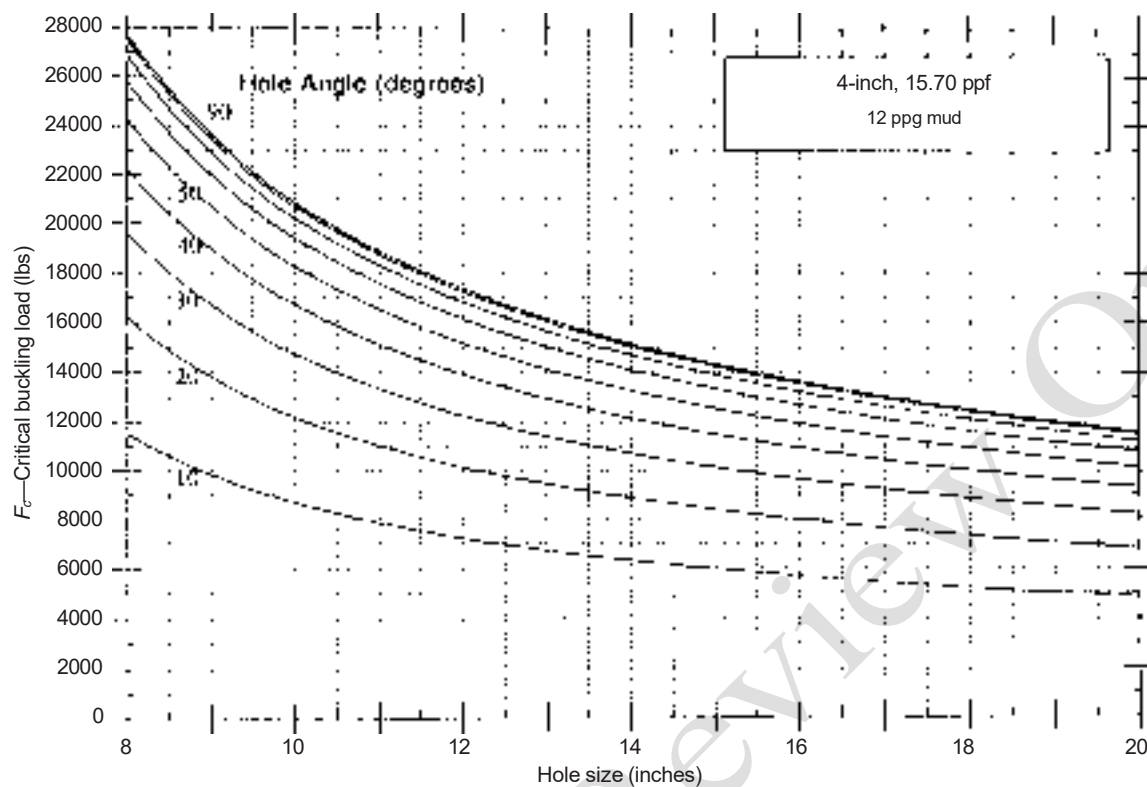


Figure 54—Approximate Axial Compressive Loads at which Sinusoidal Buckling is Expected to Occur

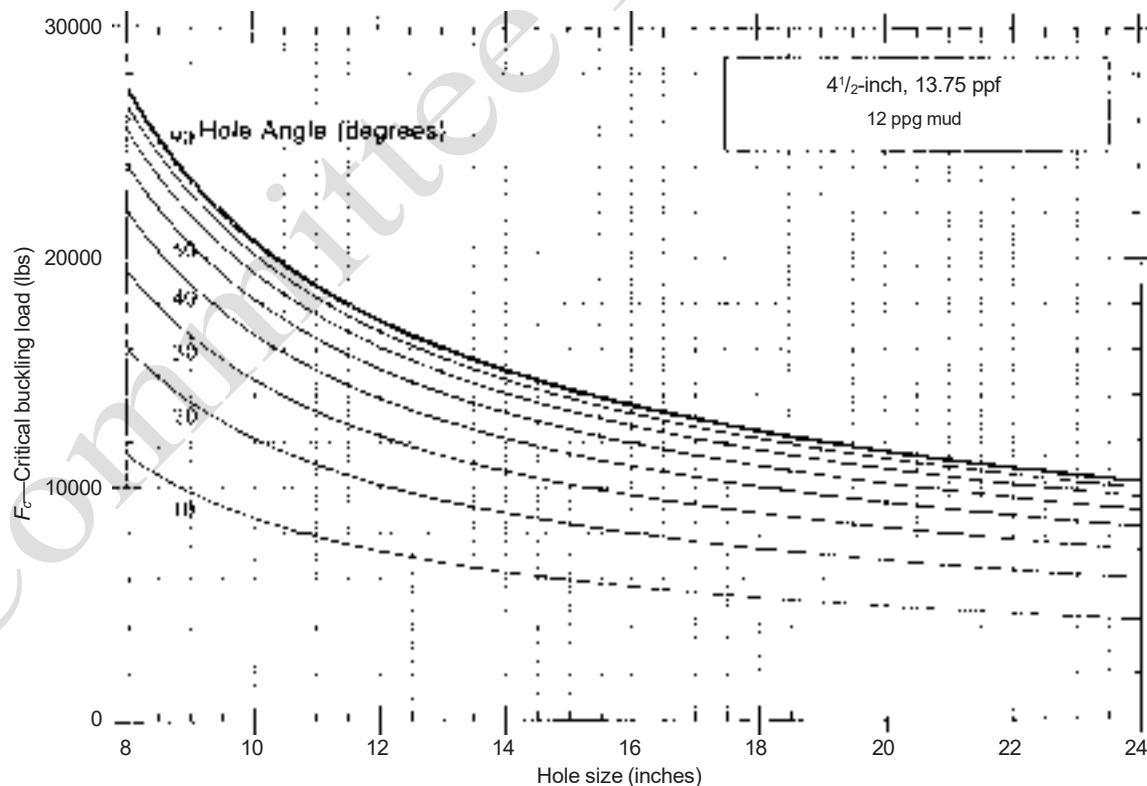


Figure 55—Approximate Axial Compressive Loads at which Sinusoidal Buckling is Expected to Occur

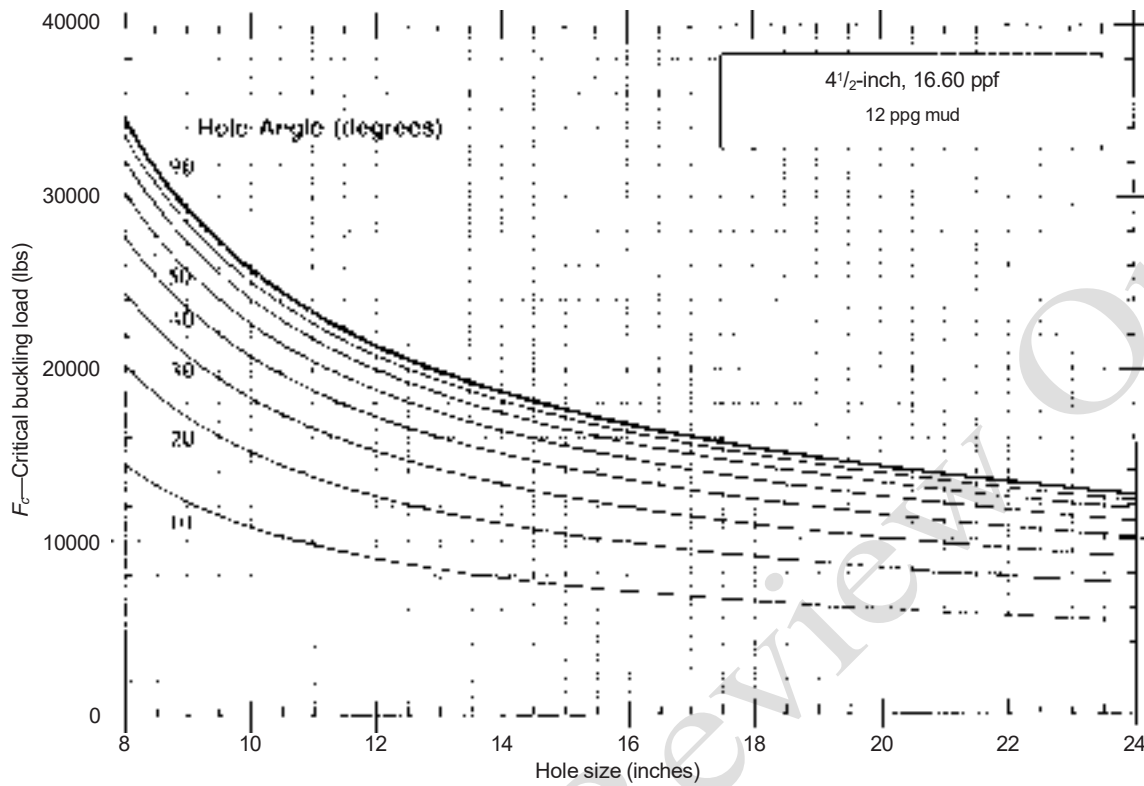


Figure 56—Approximate Axial Compressive Loads at which Sinusoidal Buckling is Expected to Occur

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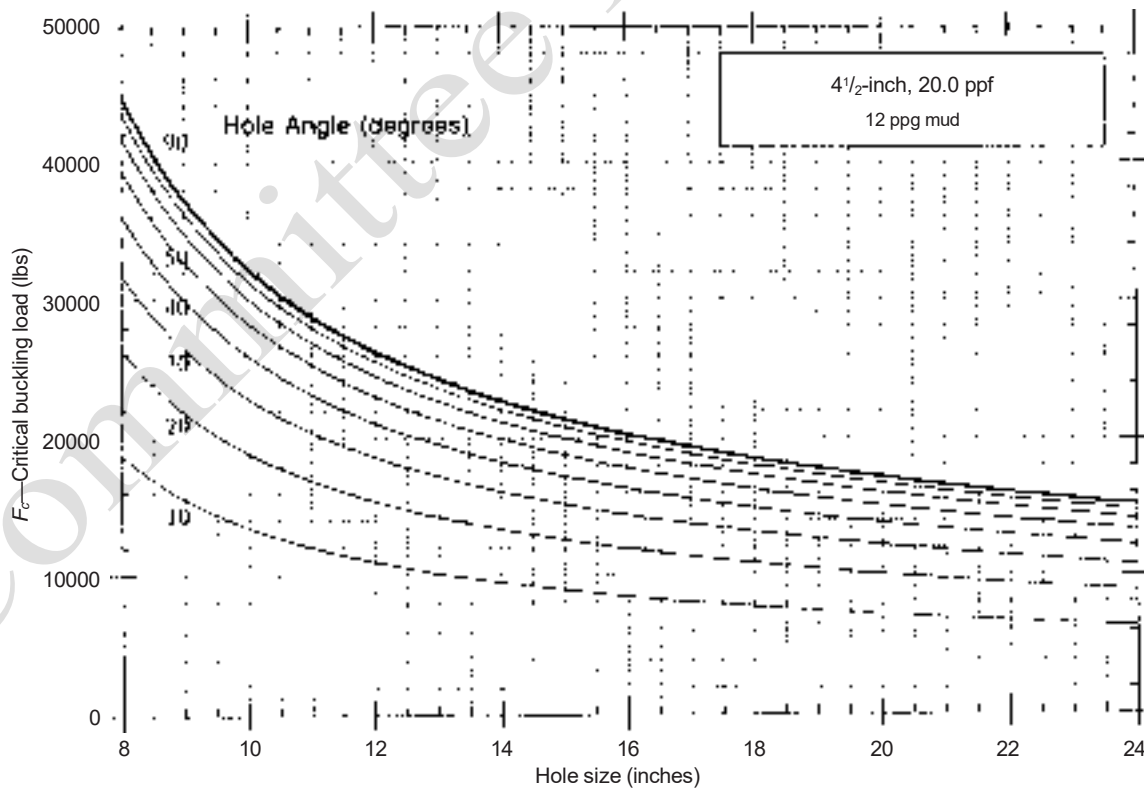


Figure 57—Approximate Axial Compressive Loads at which Sinusoidal Buckling is Expected to Occur

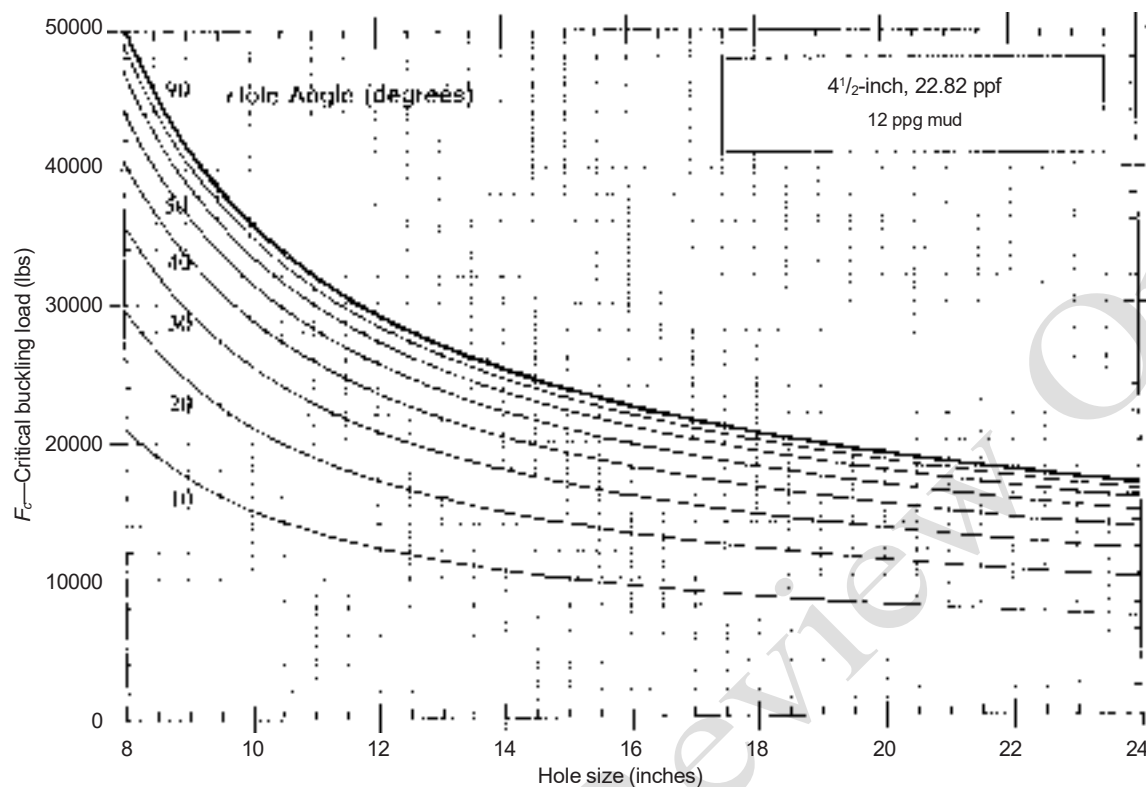


Figure 58—Approximate Axial Compressive Loads at which Sinusoidal Buckling is Expected to Occur

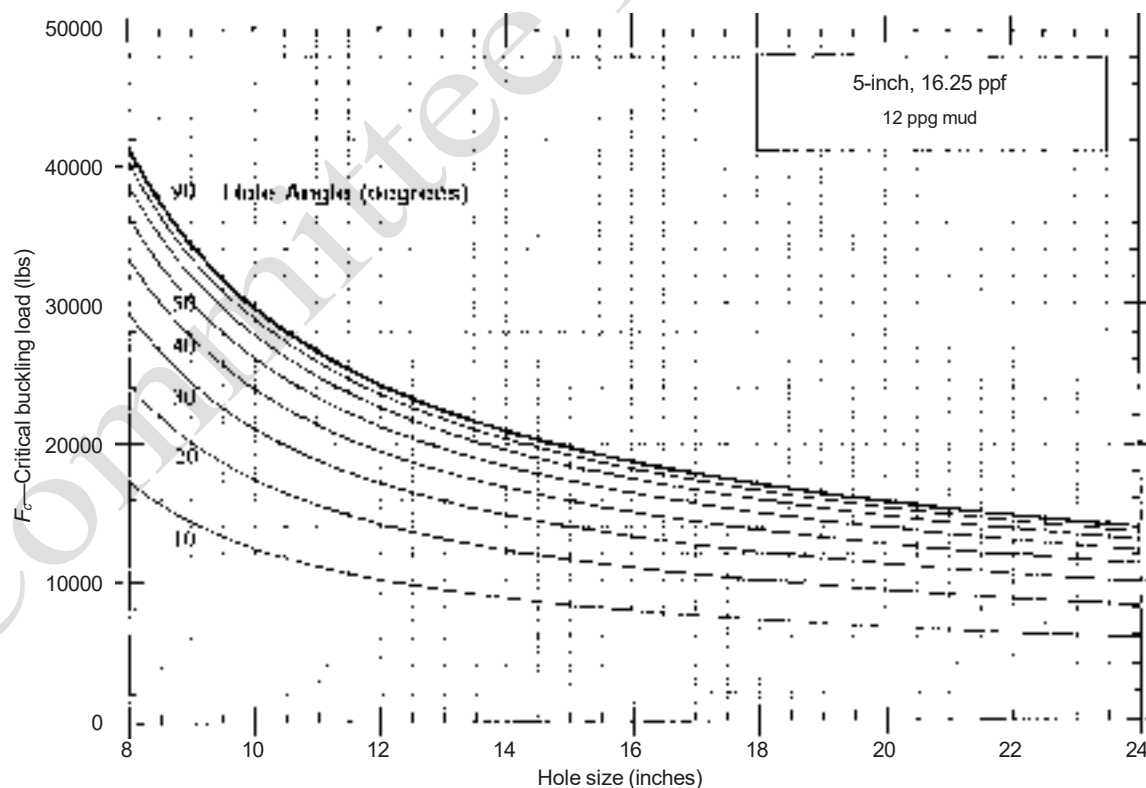


Figure 59—Approximate Axial Compressive Loads at which Sinusoidal Buckling is Expected to Occur



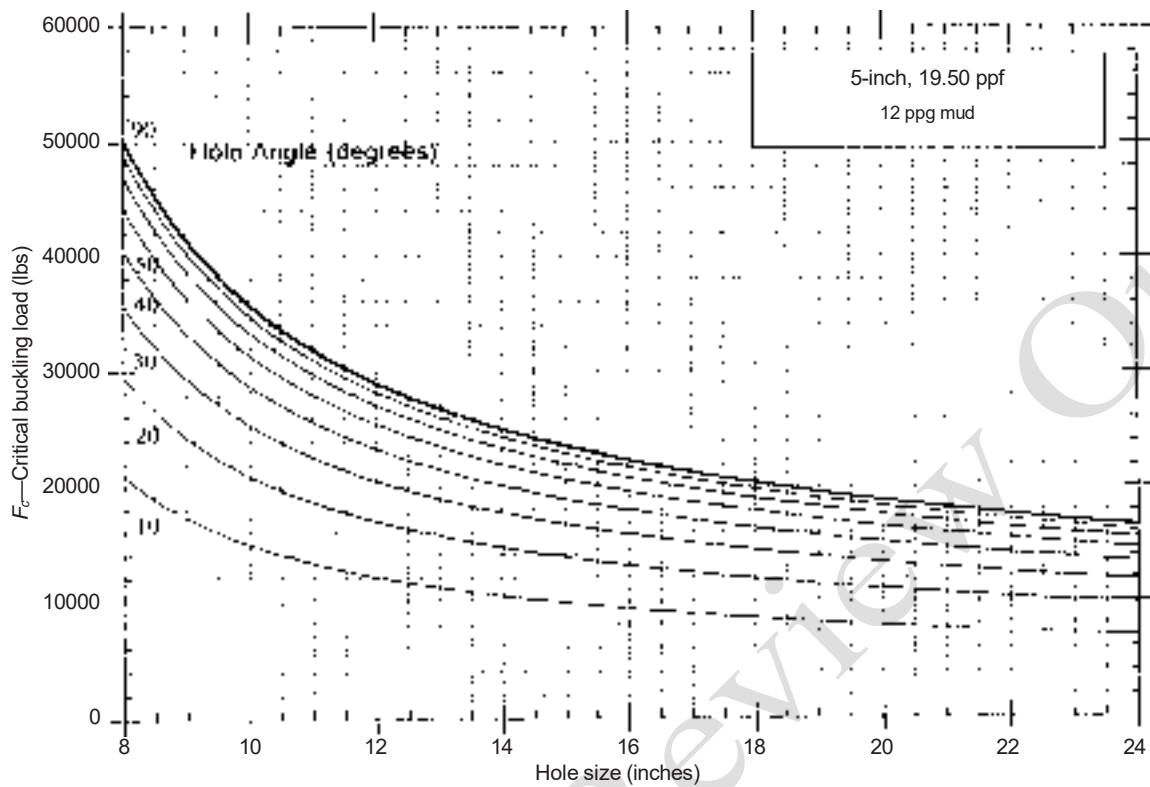


Figure 60—Approximate Axial Compressive Loads at which Sinusoidal Buckling is Expected to Occur

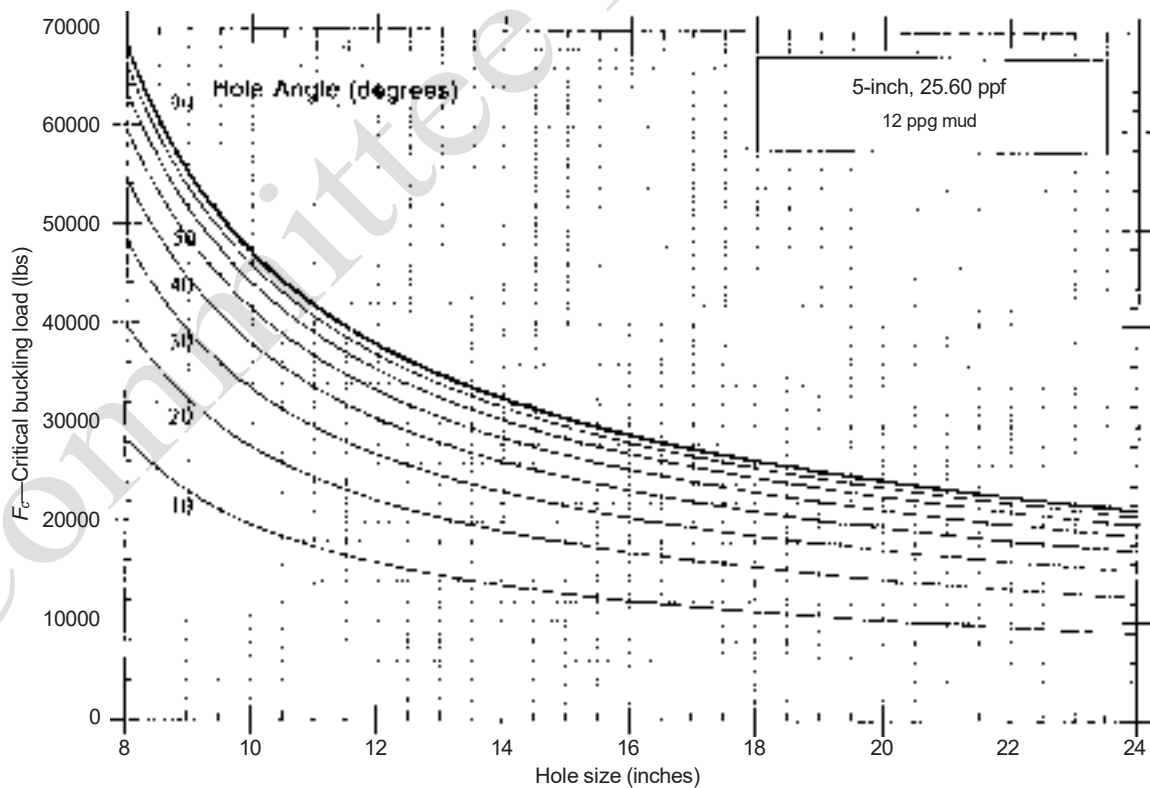


Figure 61—Approximate Axial Compressive Loads at which Sinusoidal Buckling is Expected to Occur



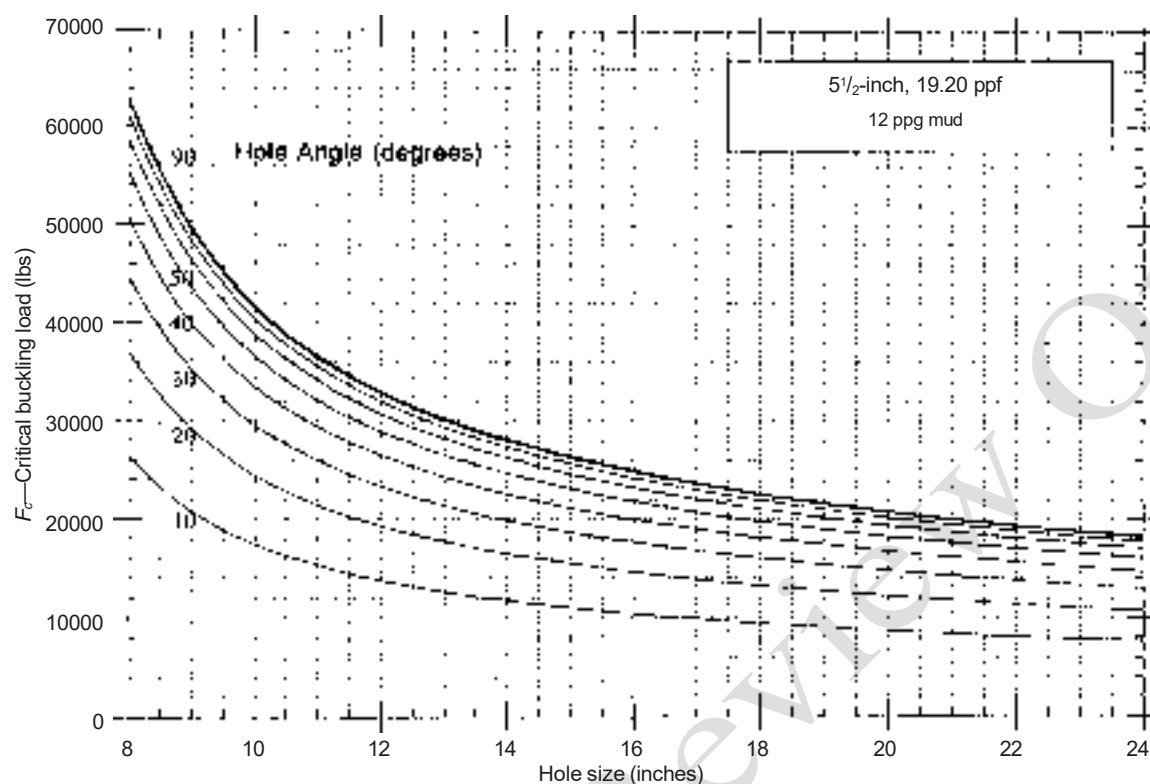


Figure 62—Approximate Axial Compressive Loads at which Sinusoidal Buckling is Expected to Occur

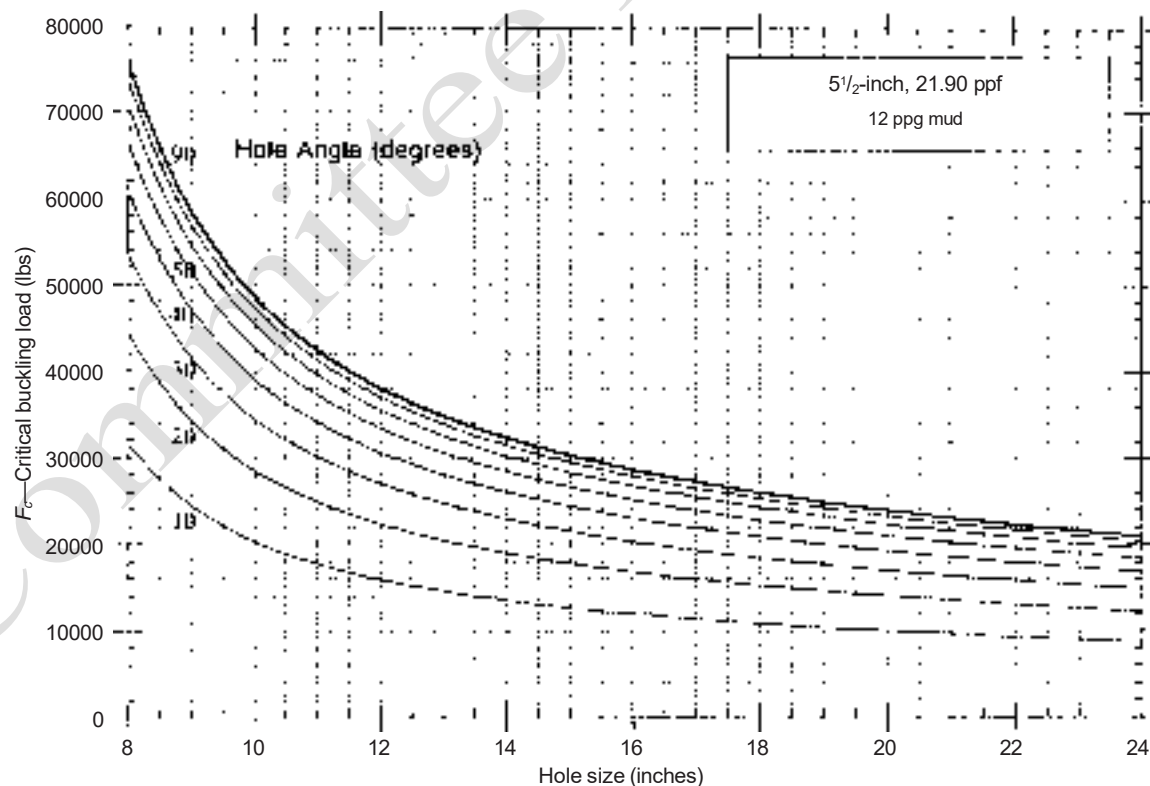


Figure 63—Approximate Axial Compressive Loads at which Sinusoidal Buckling is Expected to Occur

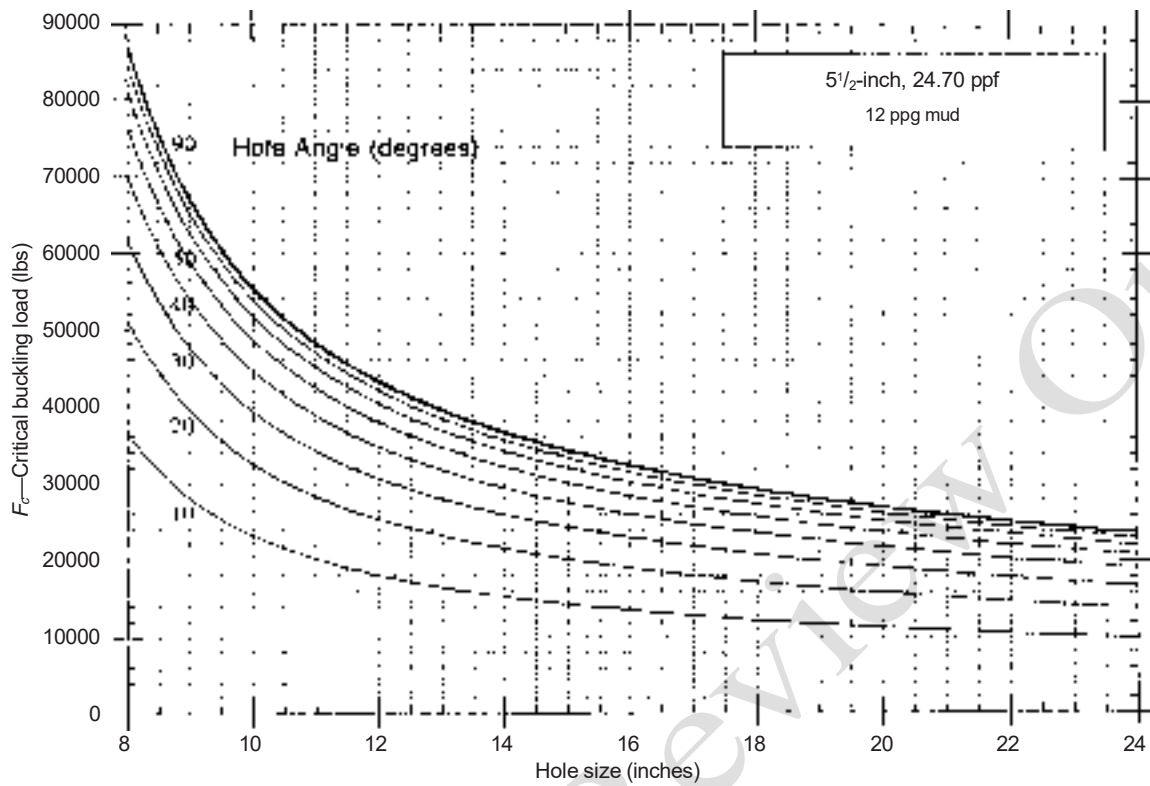


Figure 64—Approximate Axial Compressive Loads at which Sinusoidal Buckling is Expected to Occur

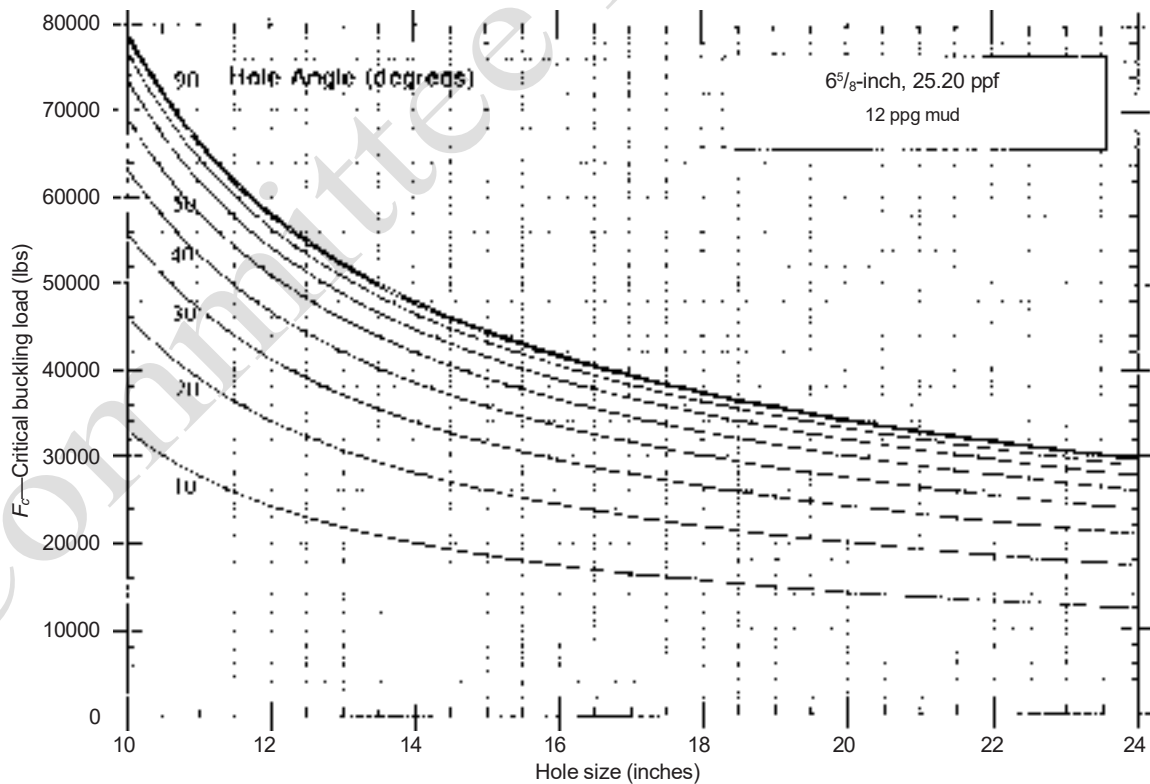


Figure 65—Approximate Axial Compressive Loads at which Sinusoidal Buckling is Expected to Occur

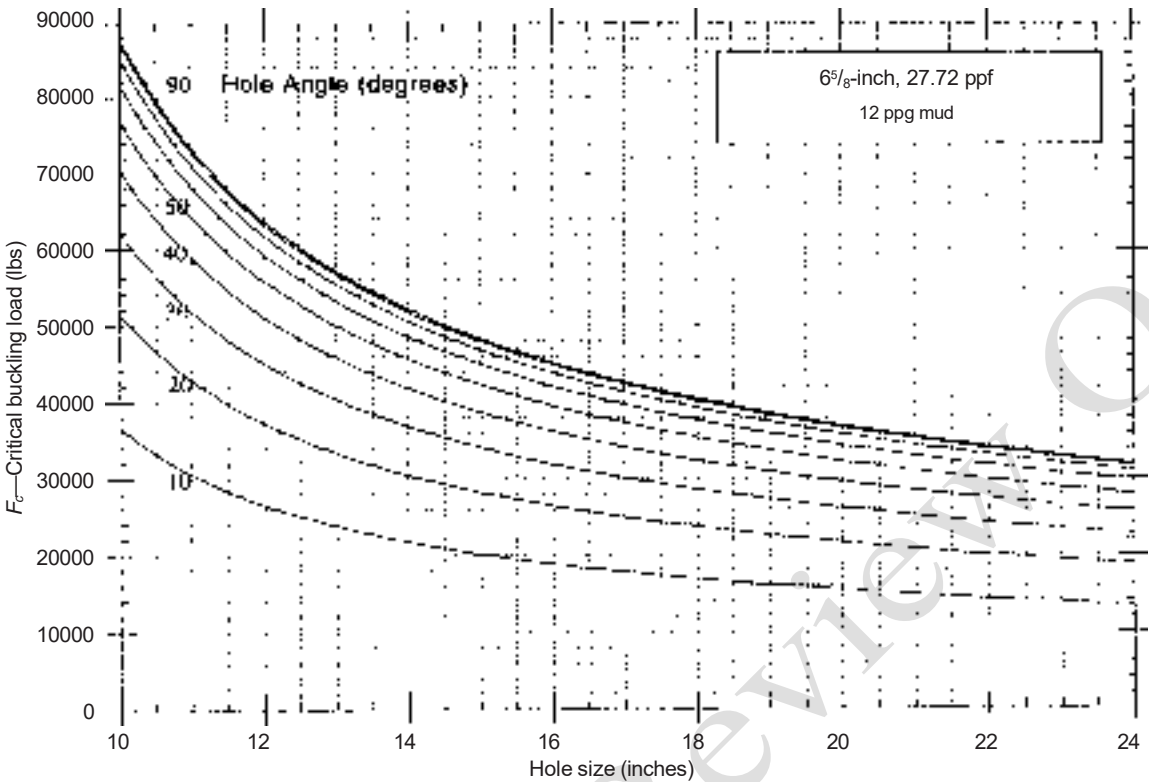


Figure 66—Approximate Axial Compressive Loads at which Sinusoidal Buckling is Expected to Occur

used on a particular pipe, the most common one was selected. Tool joint diameter is the minimum for Premium Class. Radial clearance is the distance between the tool joint OD and the hole.

- b. Pipe wall thickness is new nominal.
- c. The well bore is straight.
- d. The effects of torque are neglected.
- e. Mud weight is 12.0 lb/gal.

11.2.2 Compensating for Different Mud Weight

If the actual mud weight is not 12.0 lb/gal, critical buckling load may be adjusted by the following formula:

$$(F_{crit-adj}) = (F_{crit})(f_{mw})$$

where

- $F_{crit-adj}$  = adjusted critical buckling load (lbs),
- $F_{crit}$  = critical buckling load from curve (lbs),
- $f_{mw}$  = (buoyancy factor/0.817)<sup>0.5</sup> (see below),

Mud Weight		Mud Weight	
(lb/gal)	$f_{mw}$	(lb/gal)	$f_{mw}$
8.0	1.04	14.0	0.98
9.0	1.03	15.0	0.97
10.0	1.02	16.0	0.96
11.0	1.01	17.0	0.95
12.0	1.00	18.0	0.94

### 11.2.3 Using the Drill Pipe Buckling Curves

Enter the curve for the correct pipe size and weight at the hole diameter. Read vertically to intersect the hole angle, then horizontally to read critical buckling load. Compensate the value obtained for mud weight being used.

#### 11.2.3.1 Example

How much compressive load may be applied to 5-inch, 19.50 lb/ft drill pipe in a  $12\frac{1}{4}$ -inch horizontal hole before the drill pipe buckles? Mud weight is 9.0 lb/gal.

#### 11.2.3.2 Solution:

98

Reading from the figure for the drill pipe in question (Figure 60), the critical buckling load is about 28,200 pounds. Adjusting to 9.0 lb/gal mud:

$$F_{crit-adj} = 28,200 \text{ lbs} (1.03) = 29,000 \text{ lbs}$$

### 11.3 CRITICAL BUCKLING FORCE FOR CURVED BOREHOLES<sup>27,29,30,31,32</sup>

The critical buckling force of compressively loaded drill pipe is also significantly influenced by the curvature of the borehole. In angle building intervals the upward curvature of the borehole increases the critical buckling force. In turning intervals the hole curvature also increases the buckling force of the drill pipe. Table 20 shows the hole curvature rates that prevent buckling for a range of pipe and hole sizes.

Table 20—Hole Curvatures that Prevent Buckling

Hole Size in.	Drill Pipe OD in.	Drill Pipe ID in.	Nominal Weight lb/ft	Tool Joint OD in.	Axial Load							
					5 Mlbs °/100ft.	10 Mlbs °/100ft.	15 Mlbs °/100ft.	20 Mlbs °/100ft.	25 Mlbs °/100ft.	30 Mlbs °/100ft.	40 Mlbs °/100ft.	50 Mlbs °/100ft.
4.000	2.375	1.815	6.7	3.125	1.2	2.5	3.7	4.9	6.2	7.4	9.9	12.3
4.750	2.875	2.151	10.4	4.125	0.4	0.8	1.2	1.6	2.0	2.4	3.2	3.9
6.000	2.875	2.151	10.4	4.125	1.2	2.4	3.5	4.7	5.9	7.1	9.5	11.8
6.000	3.500	2.764	13.3	5.000	0.3	0.6	1.0	1.3	1.6	1.9	2.6	3.2
6.750	3.500	2.764	13.3	5.000	0.6	1.1	1.7	2.3	2.8	3.4	4.5	5.6
6.750	4.000	3.340	14.0	5.250	0.3	0.7	1.0	1.3	1.7	2.0	2.7	3.4
7.875	4.000	3.340	14.0	5.250	0.6	1.2	1.8	2.4	3.0	3.5	4.7	5.9
7.875	4.500	3.826	16.6	6.250	0.2	0.5	0.7	1.0	1.2	1.5	2.0	2.5
8.750	4.500	3.826	16.6	6.250	0.4	0.8	1.1	1.5	1.9	2.3	3.0	3.8
8.750	5.000	4.276	19.5	6.375	0.2	0.5	0.7	1.0	1.2	1.4	1.9	2.4
8.750	5.500	4.778	21.9	7.500	0.1	0.2	0.3	0.4	0.5	0.6	0.8	0.9
8.750	5.500	4.670	24.7	7.250	0.1	0.2	0.3	0.4	0.5	0.6	0.8	1.0
9.875	5.000	4.276	19.5	6.375	0.4	0.7	1.1	1.4	1.8	2.1	2.8	3.6
9.875	5.500	4.778	21.9	7.500	0.2	0.4	0.5	0.7	0.9	1.1	1.4	1.8
9.875	5.500	4.670	24.7	7.250	0.2	0.4	0.5	0.7	0.9	1.1	1.4	1.8
9.875	6.625	5.965	25.2	8.000	0.1	0.2	0.3	0.3	0.4	0.5	0.7	0.8
12.250	5.000	4.276	19.5	6.375	0.6	1.2	1.8	2.4	3.0	3.6	4.8	6.0
12.250	5.500	4.778	21.9	7.500	0.4	0.7	1.1	1.4	1.8	2.1	2.9	3.6
12.250	5.500	4.670	24.7	7.250	0.3	0.7	1.0	1.3	1.7	2.0	2.7	3.4
12.250	6.625	5.965	25.2	8.000	0.2	0.4	0.6	0.8	1.0	1.1	1.5	1.9

### 11.3.1 Example

Will 5-inch drill pipe buckle in a 10-degrees-per-100-foot build curve of a horizontal well? The hole size is 8.75 inches and the maximum required bit load is 30,000 pounds.

### 11.3.2 Solution

Table 20 shows that 5-inch, 19.5 lb/ft drill pipe in an 8.75-inch hole will not buckle in hole curvatures greater than 1.4 degrees per 100 feet with a 30,000 pound load.

## 11.4 BENDING STRESSES ON COMPRESSIVELY LOADED DRILL PIPE IN CURVED BOREHOLES<sup>33,34</sup>

Rotating compressively loaded drill pipe in curved portions of the borehole generates cyclic bending stresses that, if large enough, may cause fatigue damage. Compressive loading may also cause a portion of the pipe body to contact the wall of the hole. In abrasive formations, pipe body contact can erode the body of the pipe and further magnify the bending stresses. The maximum bending stress caused by compressively loading drill pipe in curved boreholes is affected by the size of the tool joints, the size of the pipe body, and the spac-

ing of the tool joints, as well as the axial compressive load on the pipe and the curvature of the hole.

The application of compressive loads on tool jointed drill pipe in curved boreholes progresses through three stages. Under light loads, the maximum bending stress occurs in the center of the pipe span but only the tool joints are in contact with the wall of the borehole. As loading is increased, the center of the pipe comes into contact with the wall of the hole. Under this loading condition the maximum bending stress occurs at two positions that are located on either side of the point of pipe body contact. As the load is further increased, the length of pipe body contact increases from point contact to wrap contact along a length of pipe located in the center of the joint.

Figures 67 through 74 provide solutions to the bending stress, pipe body contact, and lateral contact loads for the most common sizes of 6<sup>5</sup>/<sub>8</sub>-inch to 2<sup>3</sup>/<sub>8</sub>-inch drill pipe. There are four plots for each size of drill pipe. The plot in figures 67-74 (figures a) show the maximum bending stress as a function of axial compressive load for a range of hole curvatures. The type of loading is shown by the style of the plotted lines. For no pipe body contact, the bending stress curve is shown as a solid line. For point contact the bending stress relation is shown as a dashed line and for wrap contact the

(Text continued on page 96.)

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6.625-in. 25.2 lb/ft Drill Pipe, 8-in. Tool Joint  
10 ppg mud, 90-degree 12.25-in. hole

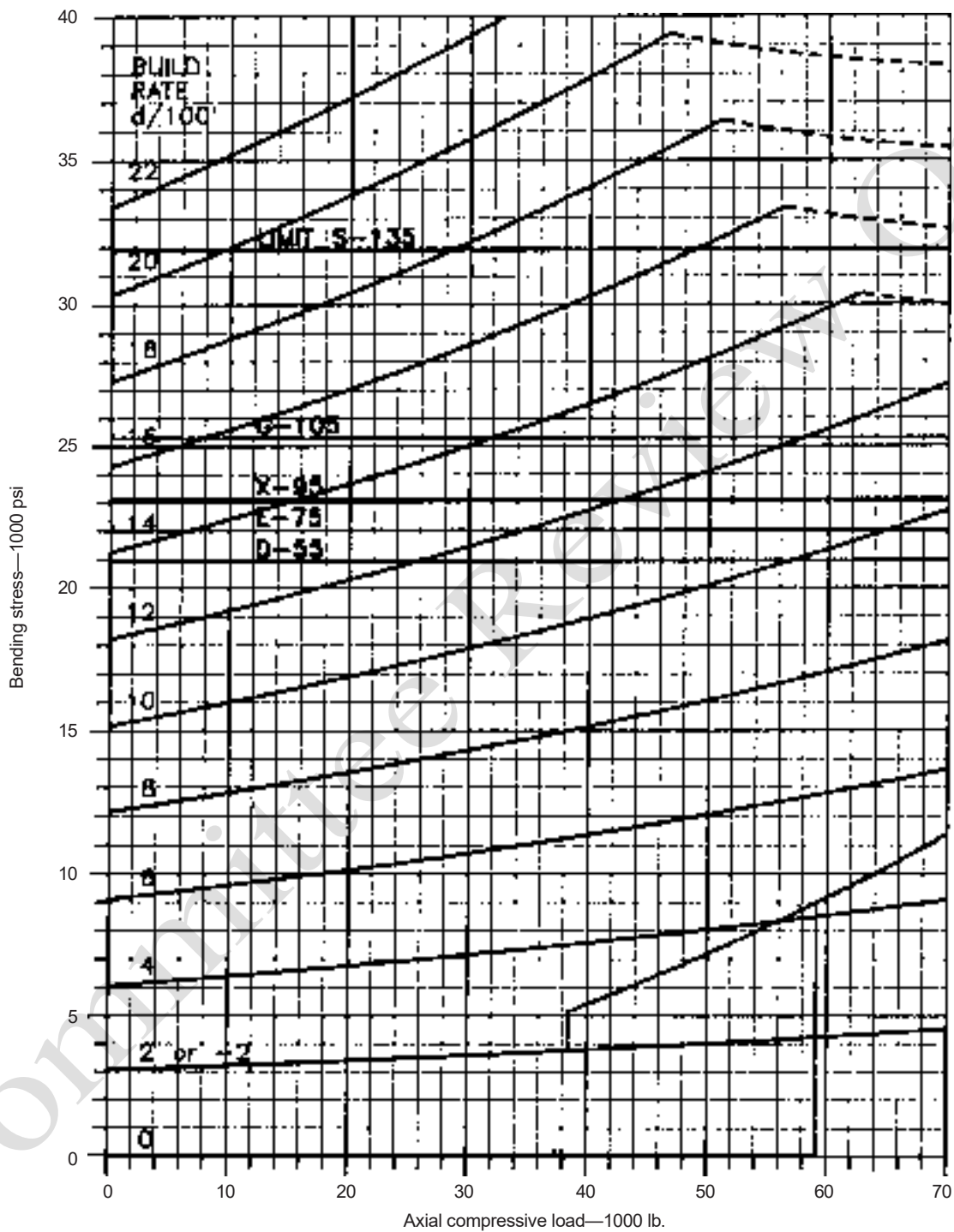


Figure 67a—Bending Stress and Fatigue Limits

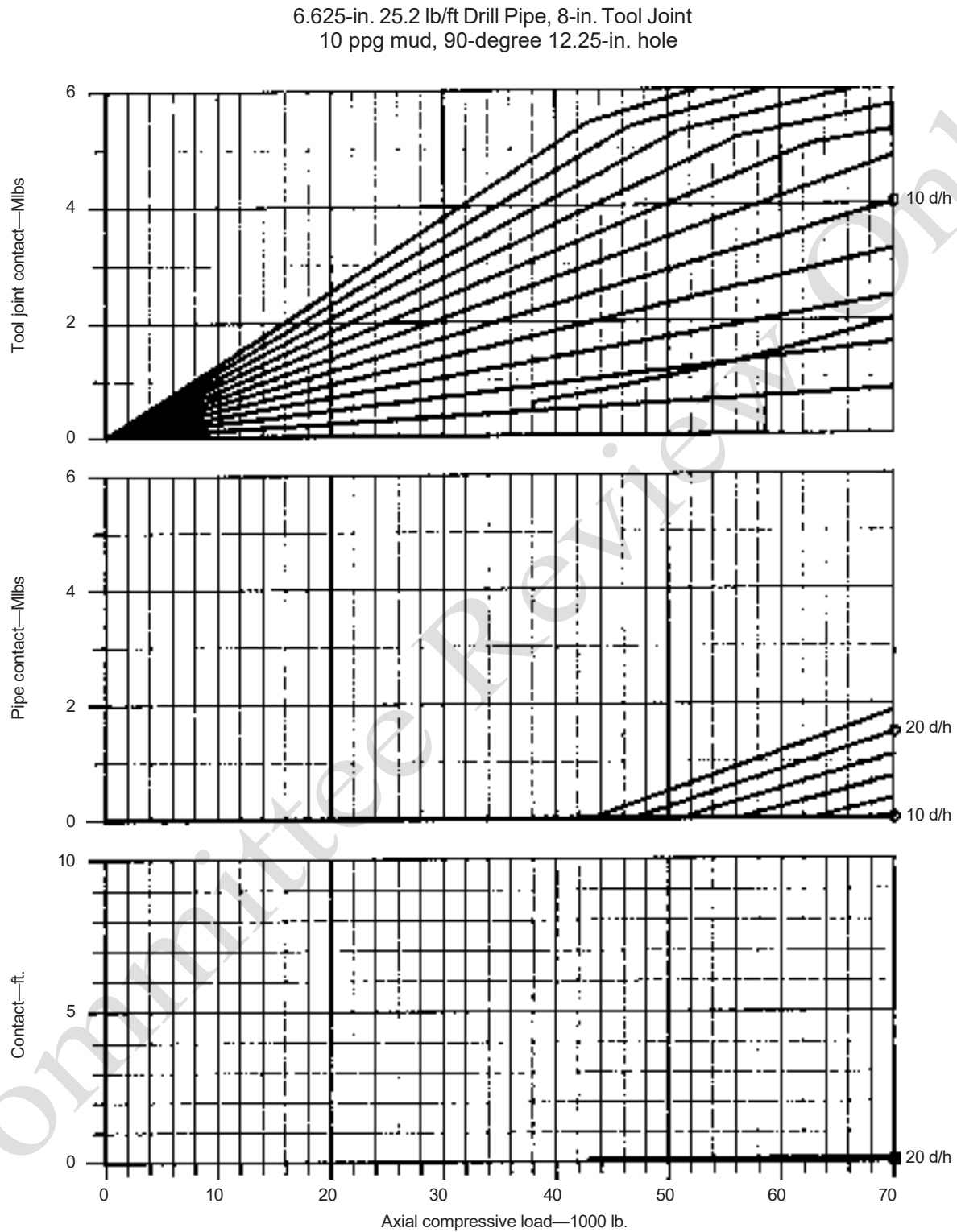


Figure 67b—Lateral Contact Forces and Length



5.5-in. 21.9 lb/ft Drill Pipe, 7.5-in. Tool Joint  
10 ppg mud, 90-degree 9.875-in. hole

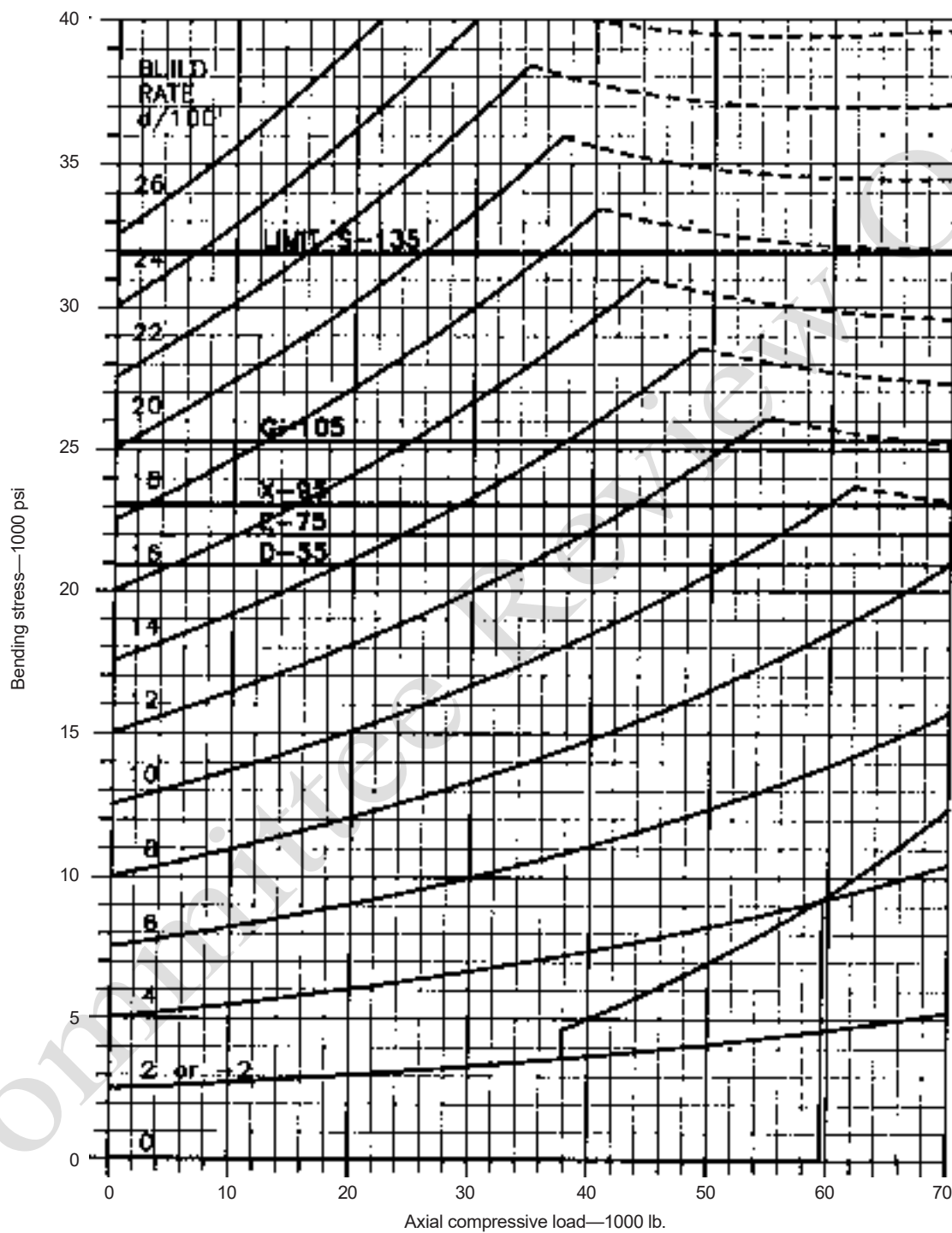


Figure 68a—Bending Stress and Fatigue Limits

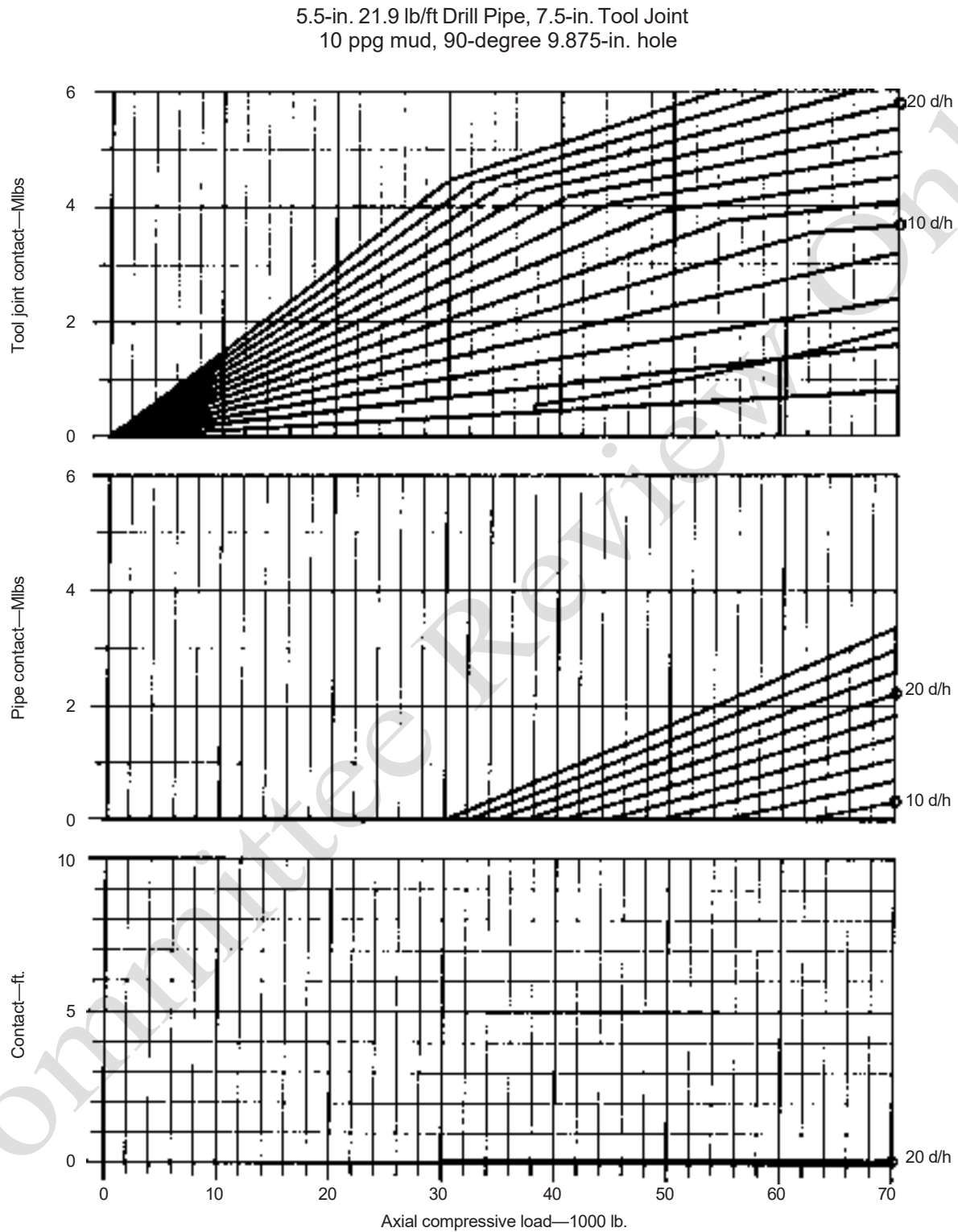


Figure 68b—Lateral Contact Forces and Length

5-in. 19.5 lb/ft Drill Pipe, 6.375-in. Tool Joint  
10 ppg mud, 90-degree 8.50-in. hole

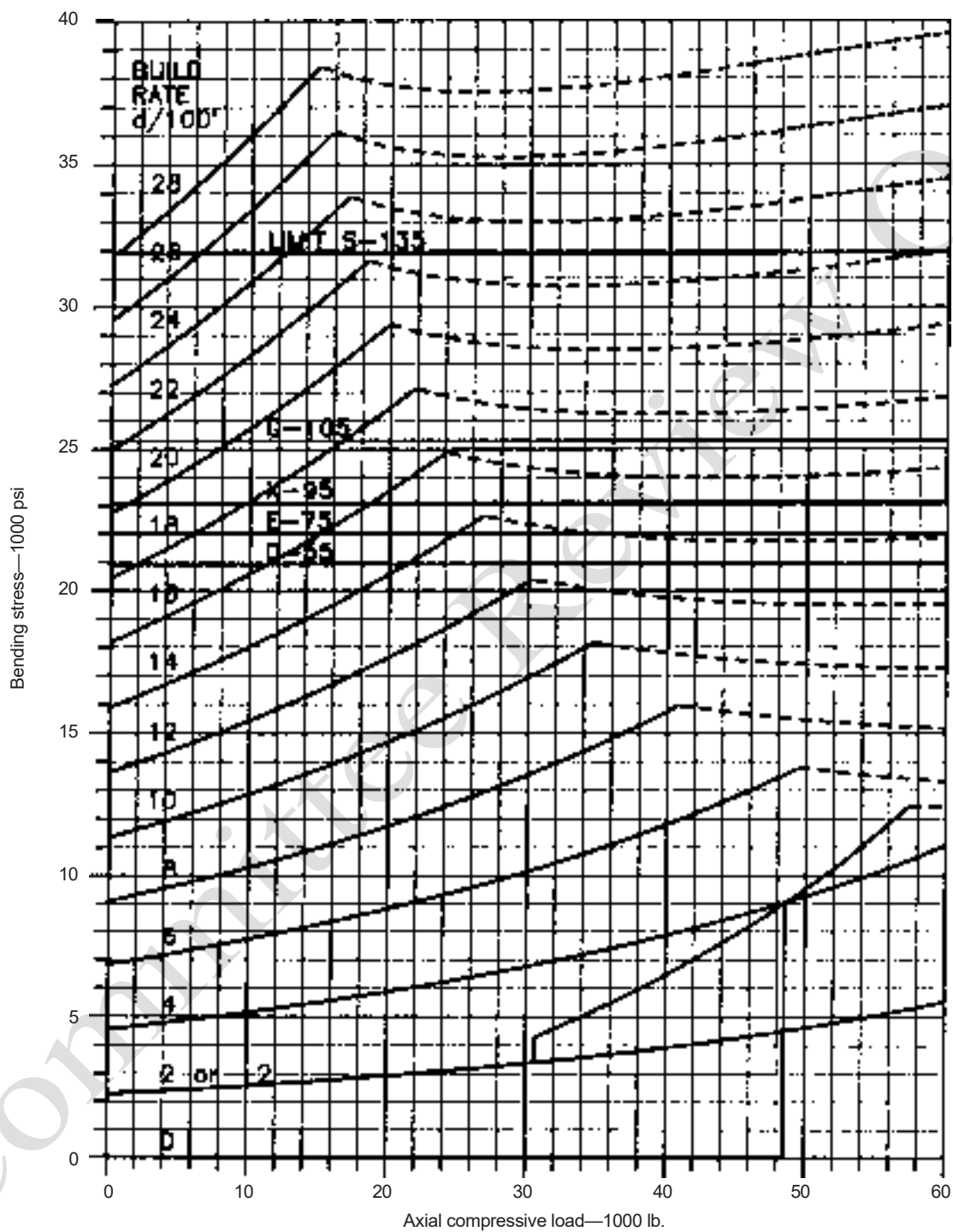


Figure 69a—Bending Stress and Fatigue Limit

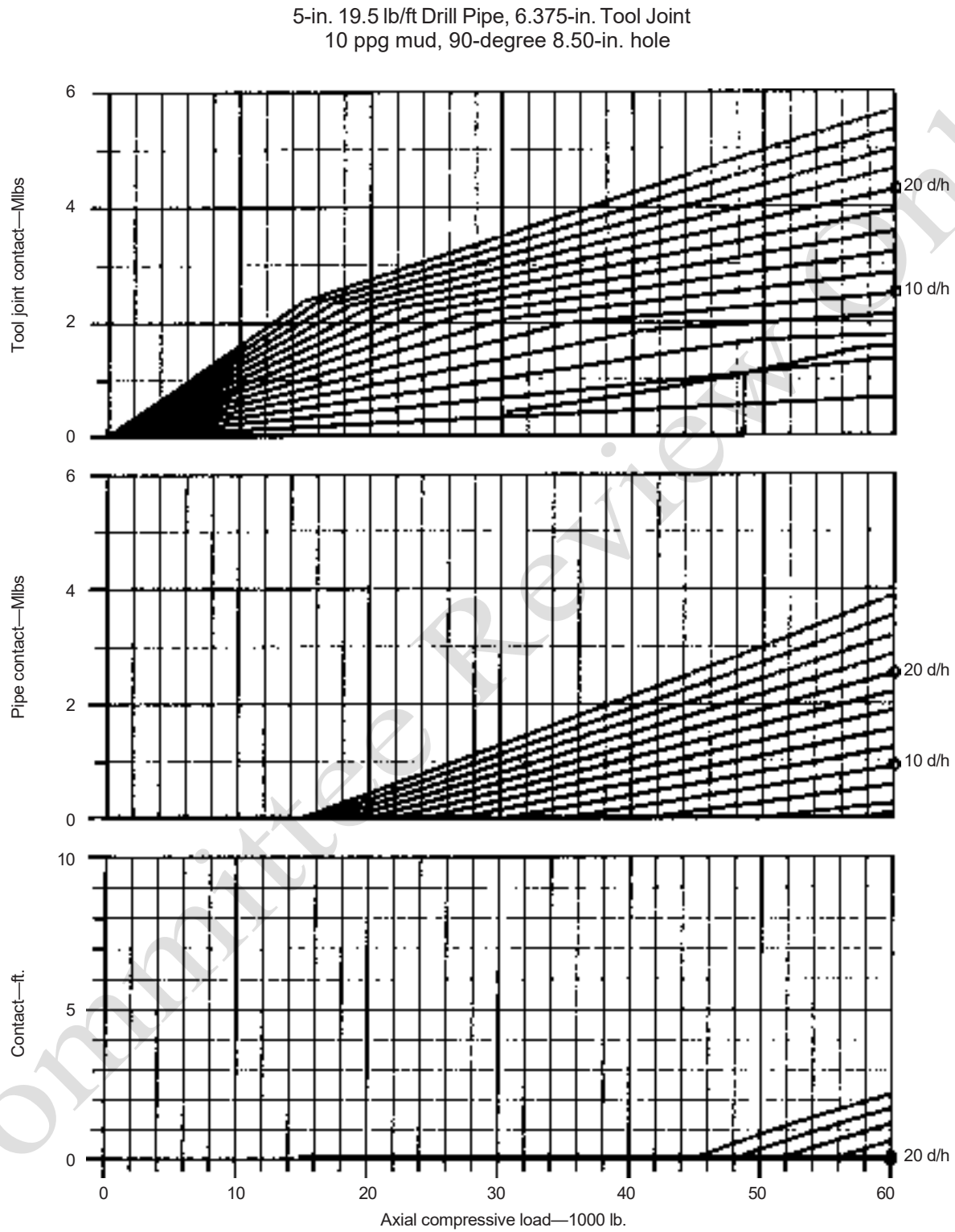


Figure 69b—Lateral Contact Forces and Length

4.5-in. 16.6 lb/ft Drill Pipe, 6.25-in. Tool Joint  
10 ppg mud, 90-degree 8.50-in. hole

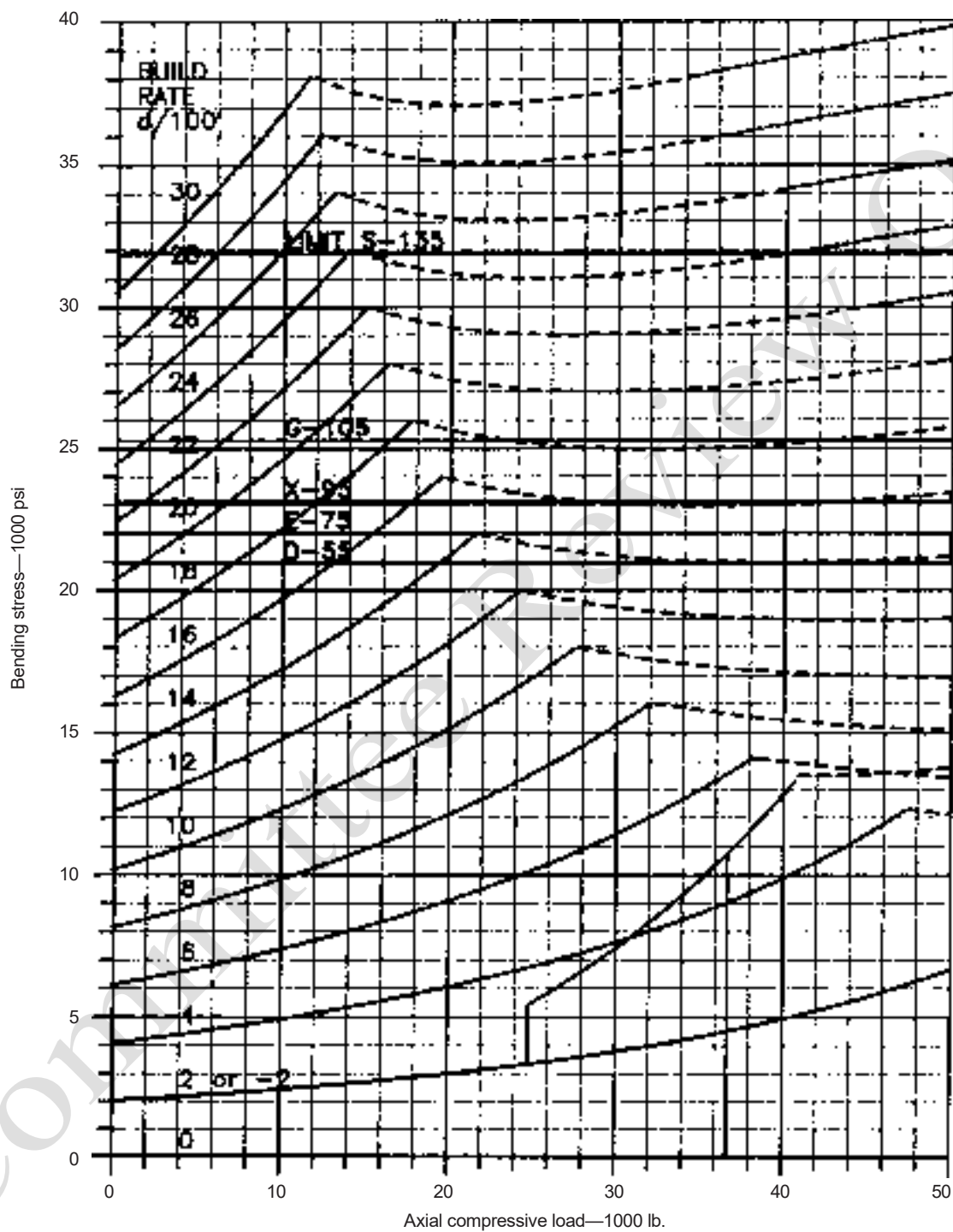


Figure 70a—Bending Stress and Fatigue Limits

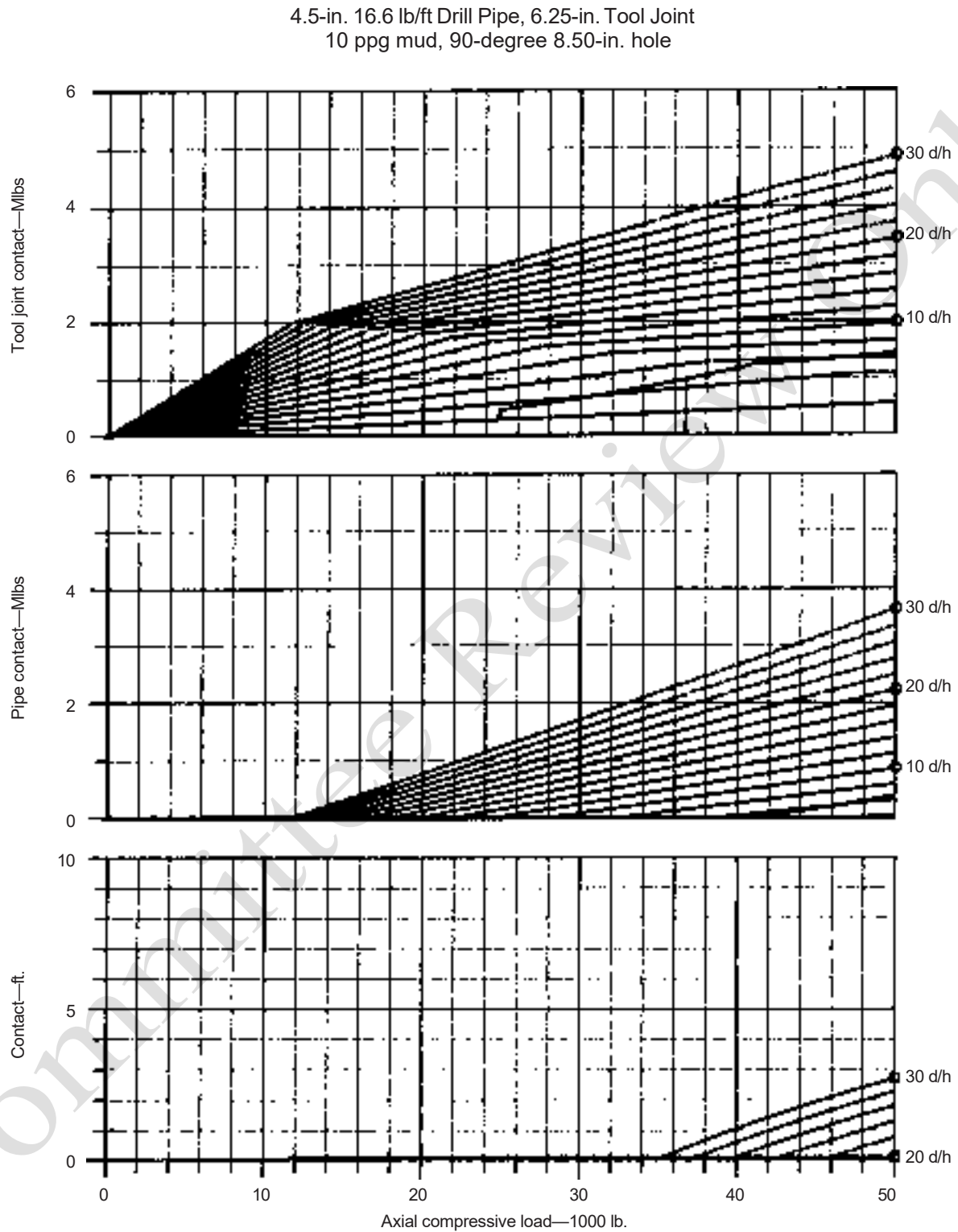


Figure 70b—Lateral Contact Forces and Length

4.0-in. 14.0 lb/ft Drill Pipe, 5.25-in. Tool Joint  
with 10 lb/gal mud in a 6.75-in. hole

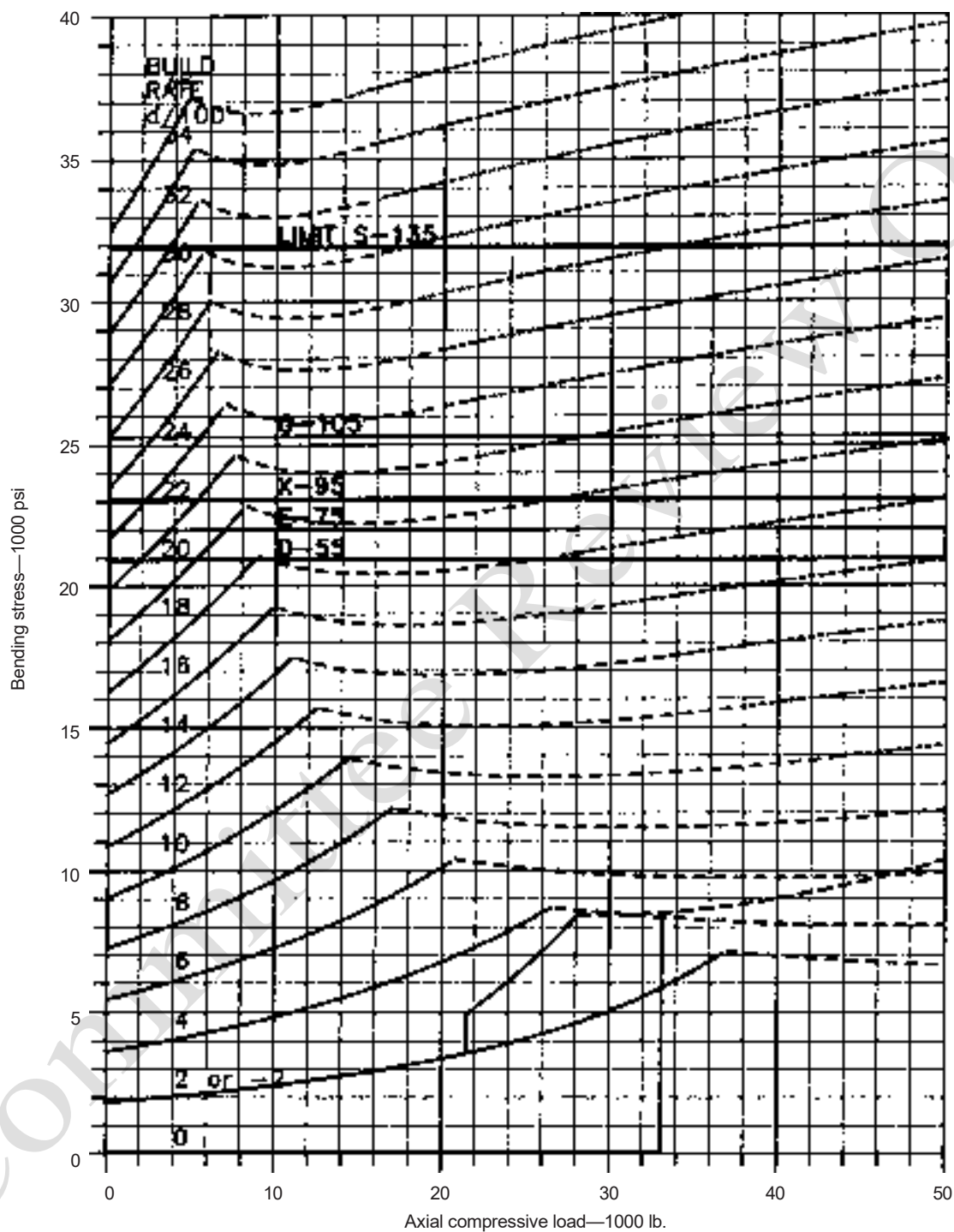


Figure 71a—Bending Stress and Fatigue Limits

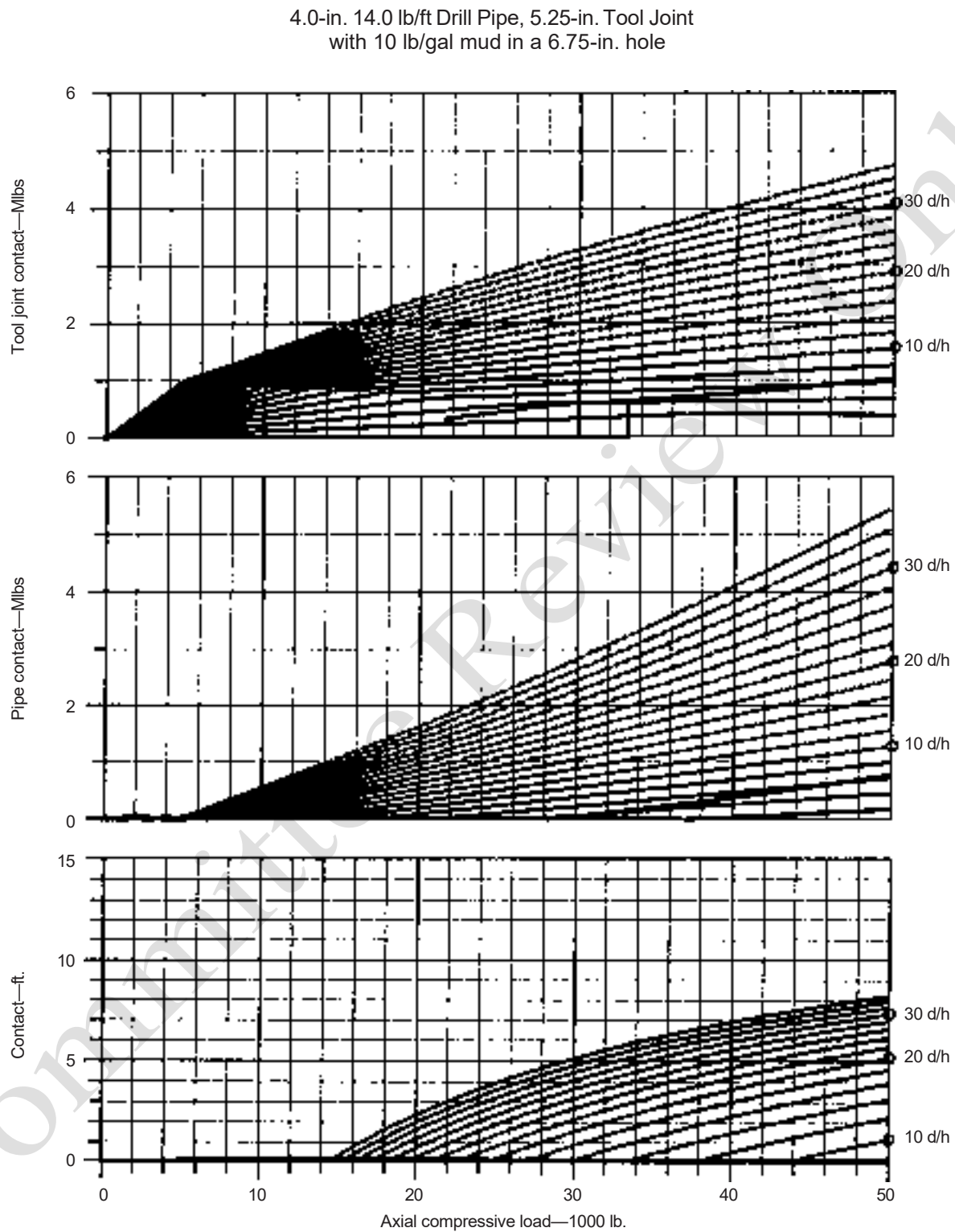


Figure 71b—Lateral Contact Forces and Length



3.5-in. 13.3 lb/ft Drill Pipe, 4.75-in. Tool Joint  
with 10 lb/gal mud in a 6-in. hole

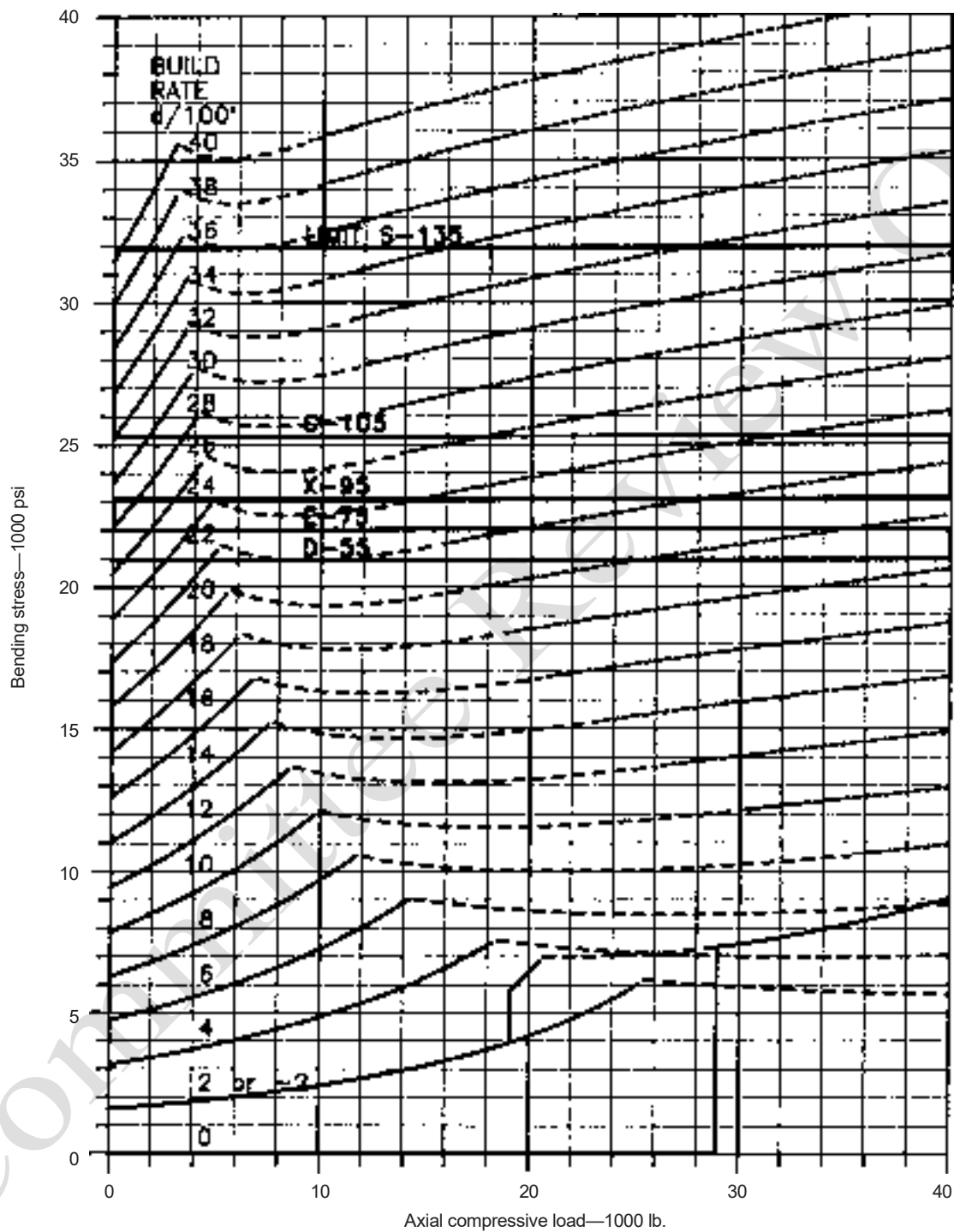


Figure 72a—Bending Stress and Fatigue Limits

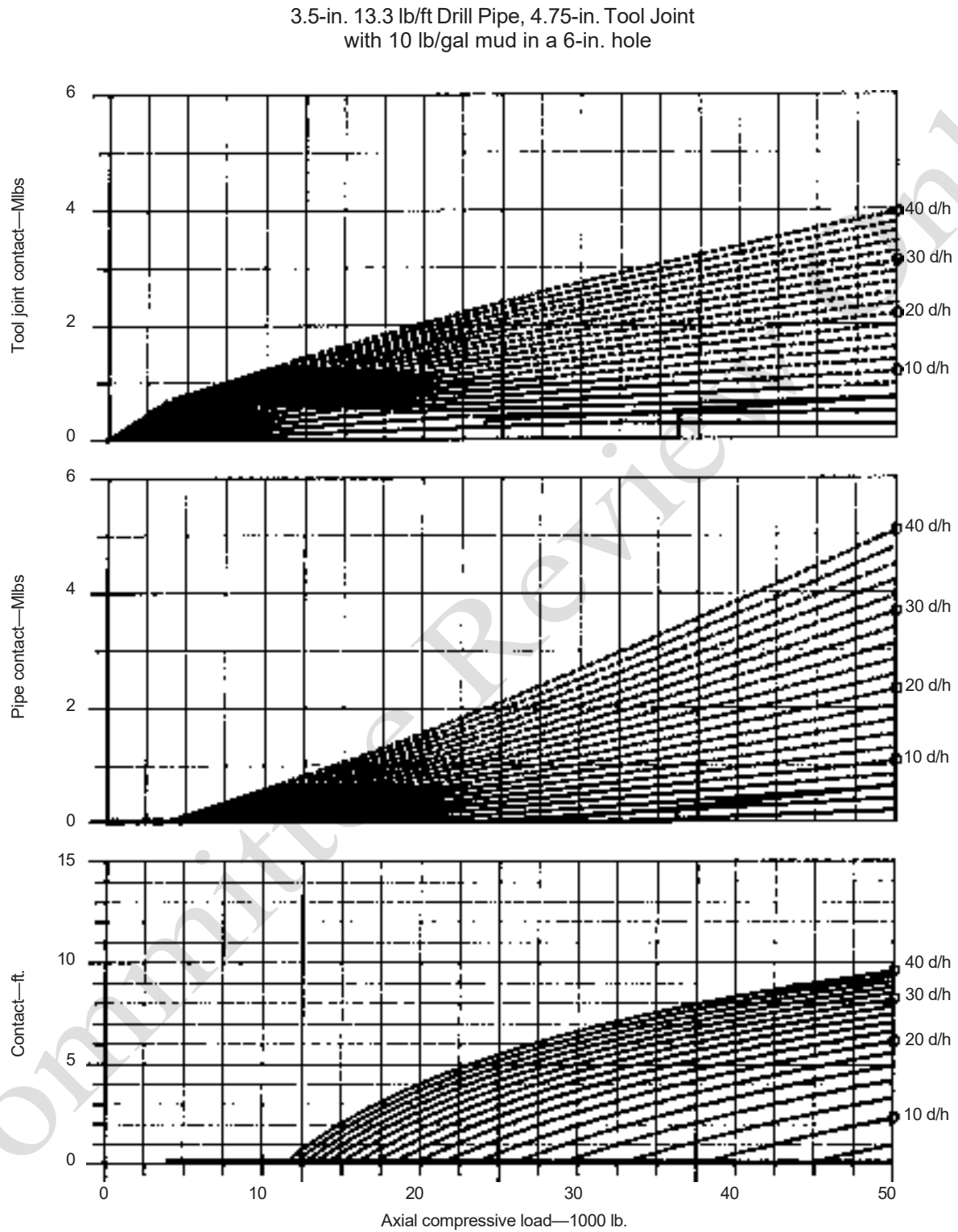


Figure 72b—Lateral Contact Forces and Length

2.875-in. 10.4 lb/ft Drill Pipe, 4.125-in. Tool Joint  
with 10 lb/gal mud in a 4.75-in. hole

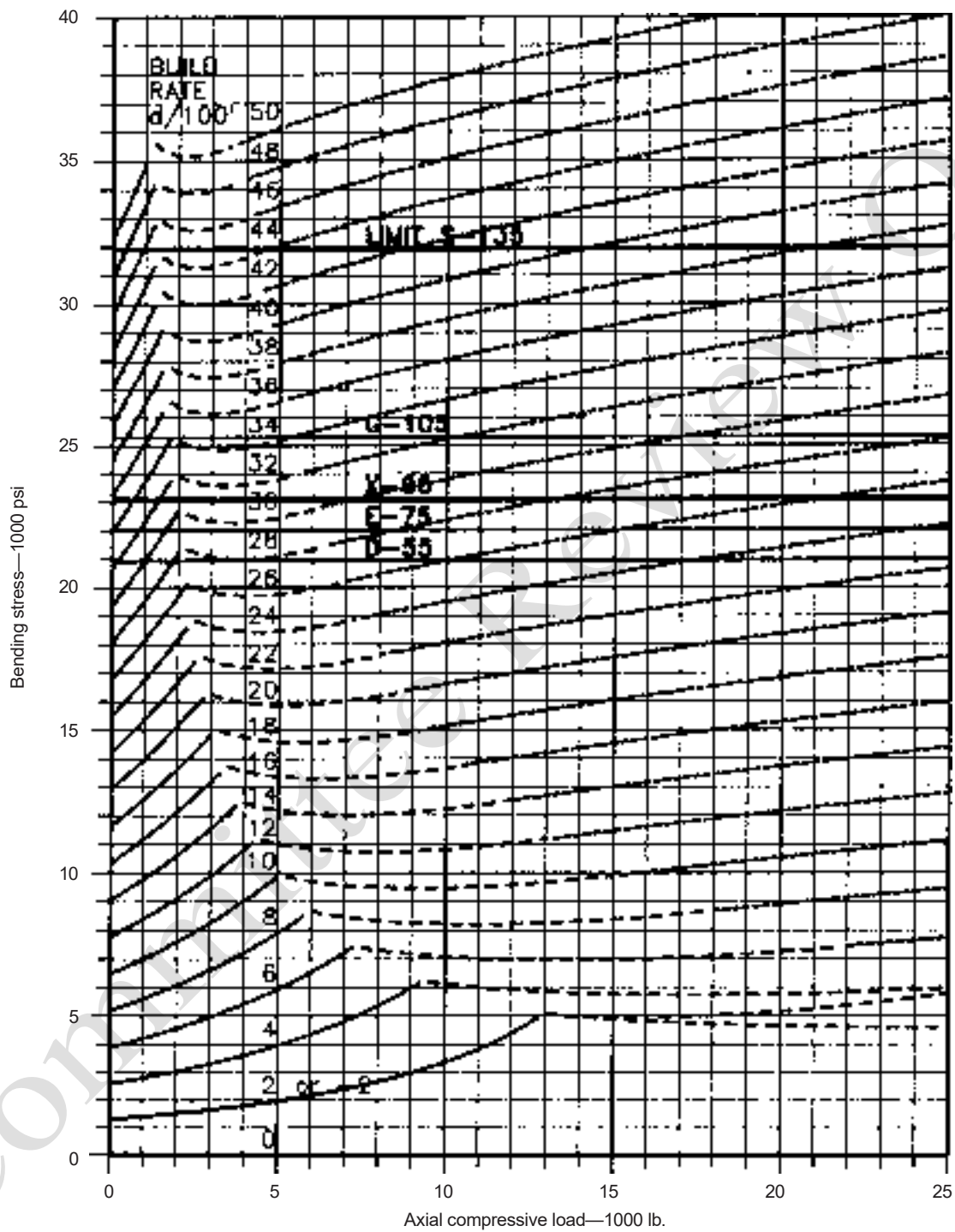


Figure 73a—Bending Stress and Fatigue Limits

2.875-in. 10.4 lb/ft Drill Pipe, 4.125-in. Tool Joint  
with 10 lb/gal mud in a 4.75-in. hole

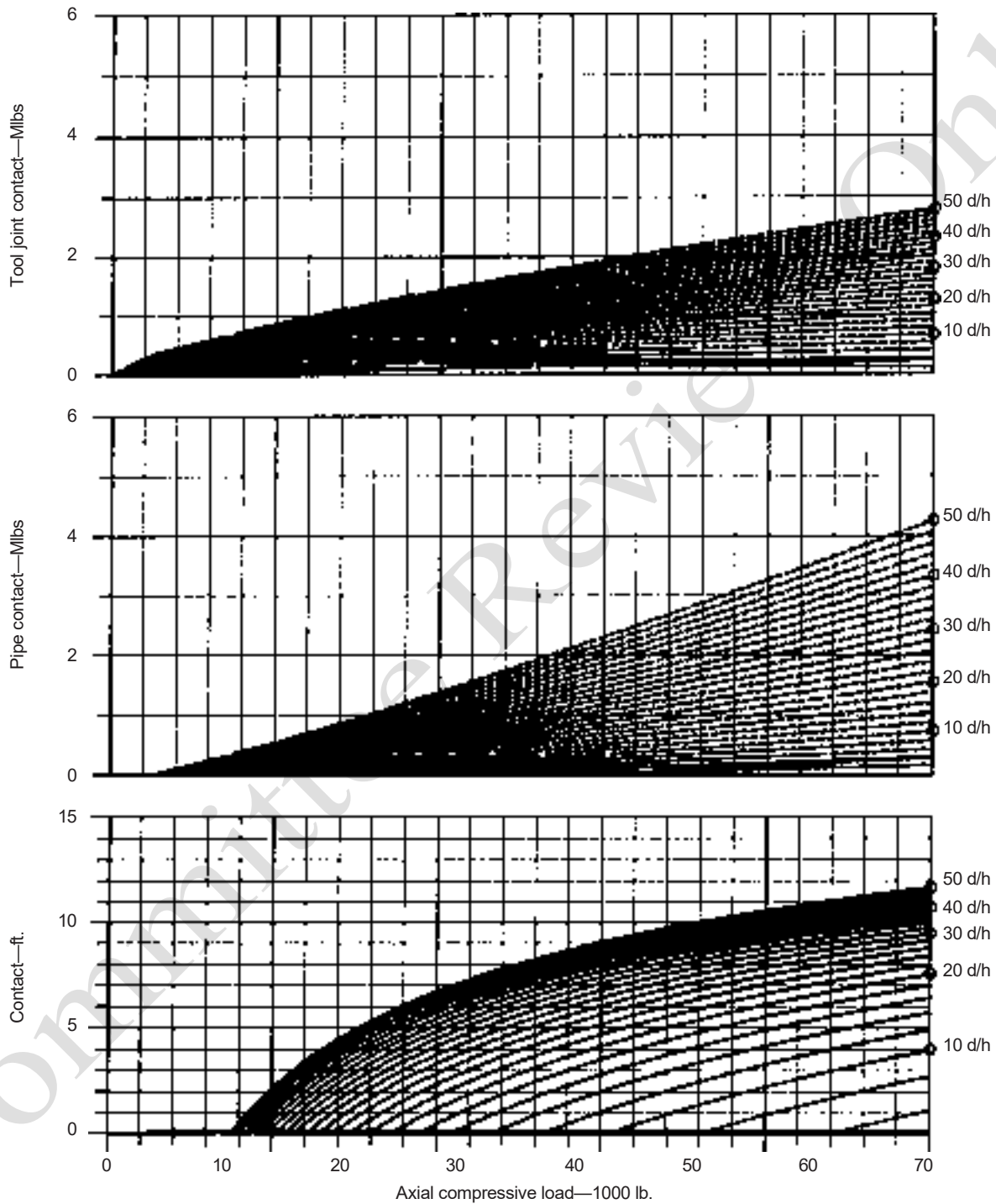


Figure 73b—Lateral Contact Forces and Length

2.375-in. 6.65 lb/ft Drill Pipe, 3.125-in. Tool Joint  
with 10 lb/gal mud in a 3.875-in. hole

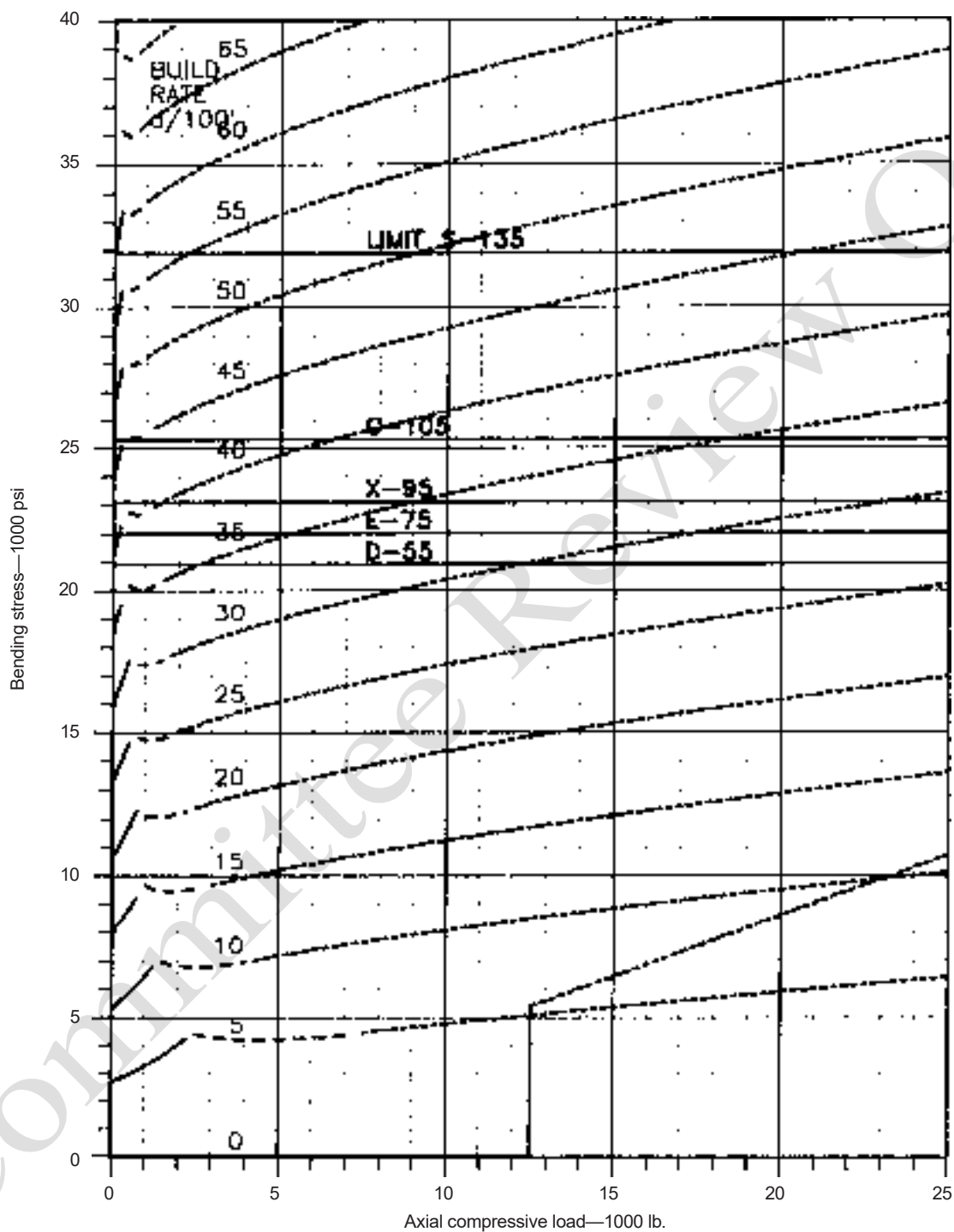


Figure 74a—Bending Stress and Fatigue Limits

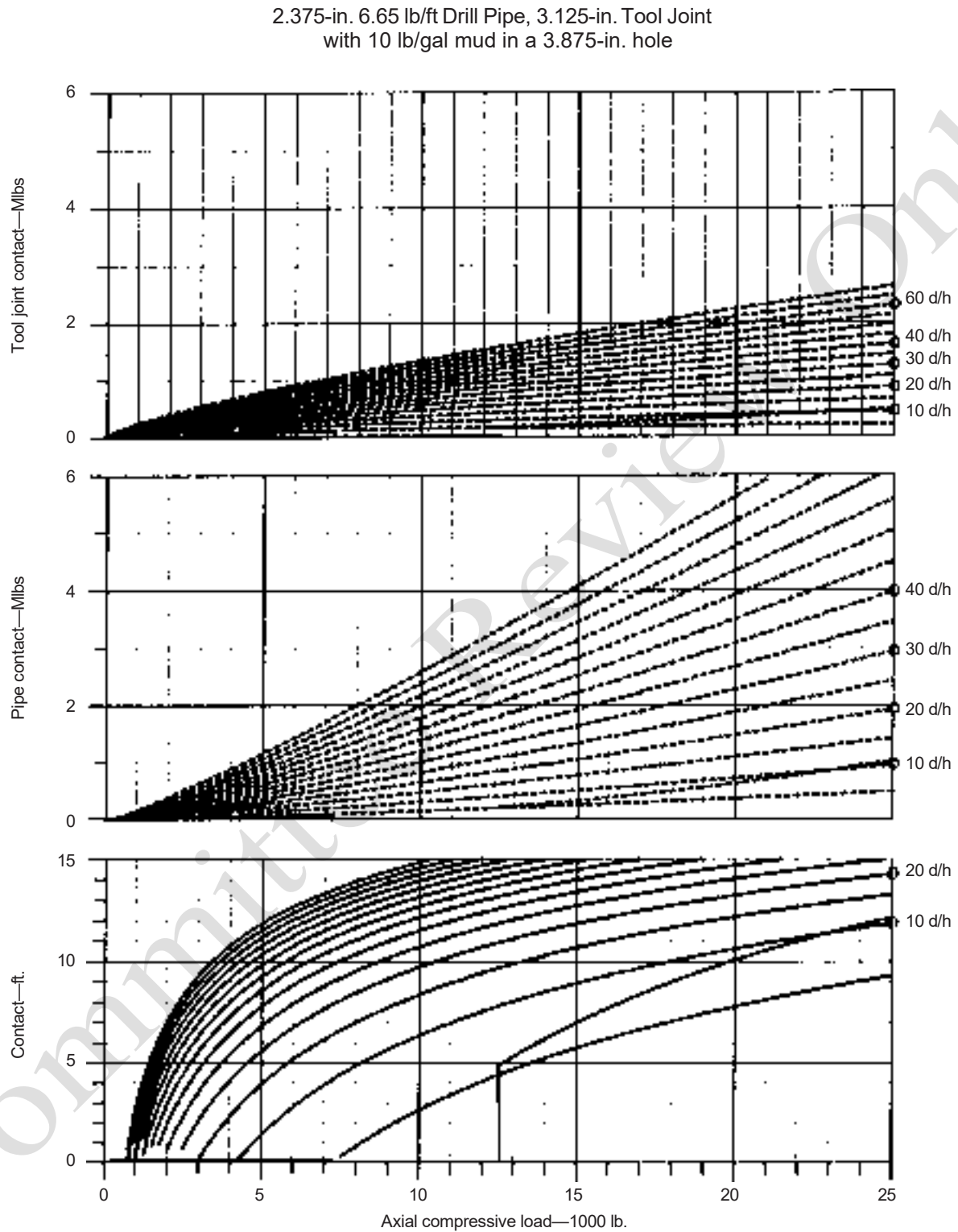


Figure 74b—Lateral Contact Forces and Length

plotted stress is shown as a dotted line. The plots also include the fatigue endurance bending stress limits from Section 11.5. The plots assume a 10 lb/gal mud, 90-degree hole angle, and a defined hole size. The mud density, hole angle, and hole size do not affect the bending stresses unless the pipe buckles. On most of the plots the critical buckling force is only exceeded for cases with zero or negative build rate. The bending stresses for buckled pipe are independent of the hole curvature and generally follow curves in which the bending stress increases more rapidly with increased axial load than for the constant hole curvature cases.

The plots in Figures 67-74 (figures b) show the pipe body contact length and the lateral contact forces between the pipe body and the tool joints with the wall of the hole.

#### 11.4.1 Example

An 8<sup>1</sup>/<sub>2</sub>-inch horizontal well will be drilled with 5-inch 19.50 lb/ft drill pipe with 6<sup>3</sup>/<sub>8</sub>-inch tool joints in an 8<sup>1</sup>/<sub>2</sub>-inch hole with 10 lb/gal mud. The maximum hole curvature will be 16 degrees per 100 feet. The horizontal interval will be drilled with surface rotation with loads up to 35,000 pounds. What grade of drill pipe is required for this example?

#### 11.4.2 Solution

**11.4.2.1** Figure 69a shows the bending stresses and fatigue limits for 5-inch, 19.5 lb/ft drill pipe, with 6<sup>3</sup>/<sub>8</sub>-inch tool joints in a 90-degree, 8<sup>1</sup>/<sub>2</sub>-inch hole with 10 lb/gal mud. For a hole curvature of 16-degrees-per-100-feet and an axial compressive load of 35,000 pounds, the maximum bending stress is 24,000 psi. A slightly higher bending stress of 25,000 psi is produced by a 24,000 pound axial load. The maximum bending stresses exceeds the fatigue endurance limits for API Grade E75, X95, and D55 pipe, but is less than the fatigue endurance limits for grades G105 and S135 pipe. Figure 69b shows that at 35,000 pound axial load, the tool joint contact forces would be about 2,600 pounds with a 16 degrees per 100 foot curvature rate. The pipe body contact force will be about 600 pounds under a 35,000 pound axial load. For this curvature rate the contact will be at the center of the span.

**11.4.2.2** The maximum bending stresses for point and wrap contact are directly proportional to the hole curvatures and radial clearances between the pipe body and the tool joints. This allows us to use the existing bending stress plots to estimate the bending stresses for tool joint dimensions other than used in preparing the plots. No adjustment is necessary unless the loading condition produces point or wrap contact. If this is the case, we can compute an adjustment factor from the actual size of the tool joint and use that to compute an equivalent hole curvature to determine the correct bending stress.

#### 11.4.3 Example

Determine the maximum bending stresses for 4-inch, 14 lb/ft drill pipe with 5<sup>3</sup>/<sub>8</sub>-inch tool joints in 20-degrees-per-100-foot hole curvature, and a 20,000 pound axial compressive load.

#### 11.4.4 Solution

Figure 71a shows the bending stresses for 4-inch, 14 lb/ft drill pipe, with 5<sup>1</sup>/<sub>4</sub>-inch tool joints. The actual tool joint outside diameter is 5<sup>3</sup>/<sub>8</sub>-inch or <sup>1</sup>/<sub>8</sub>-inch larger. Figure 75 shows the hole curvature adjustment factors for various sizes of drill pipe as a function of the difference in the tool joint outside diameters. For an actual tool joint, <sup>1</sup>/<sub>8</sub>-inch larger than nominal, Figure 75 shows that with 4-inch drill pipe the curvature adjustment factor is 1.1. To determine the maximum bending stress for the <sup>1</sup>/<sub>8</sub> inch larger tool joint in a 20-degrees-per-100-foot hole curvature at 20,000 pound load, multiply the actual hole curvature by the adjustment factor, 20-degrees-per-100-feet times 1.1 = 22-degrees-per-100-feet. Using 22-degrees-per-100-feet at 20,000 pounds on Figure 71a, the bending stress for 5<sup>3</sup>/<sub>8</sub>-inch tool joints is 24,500 psi.

### 11.5 FATIGUE LIMITS FOR API DRILL PIPE

R. P. Morgan and M. J. Roblin<sup>35</sup> developed a method of measuring fatigue limits from small drill pipe samples. Their technique preserves the effect of the "as produced" drill pipe hot finish surfaces. They reported on the testing of API Grades E75, X95, G105, and S135 as well as an experimental high strength tubular identified as V180. Their test program showed that the fatigue endurance limits for drillpipe correlate well with the tensile strength of the pipe. Table 21 shows some of the results of their test program.

Table 21—Youngstown Steel Test Results\*

Grade	API Minimum Yield Strength	API Yield Strength Maximum	API Tensile Strength Minimum	Average Tensile Strength of Test Samples	Endurance Limit	
	ksi	ksi	ksi		Minimum Test Value	Median Test Value
E75	75	105	100	123	30	32
X95	95	125	105	132	32	35
G105	105	135	115	144	34	38
S135	135	165	145	167	36	40

\*Youngstown Sheet and Tube Company, 1969 ASME Conference, Tulsa, Oklahoma.

Casner<sup>36</sup> has utilized their test results to determine the minimum fatigue endurance limits for API drillpipe that meets the API minimum strength requirements. See Table 22.

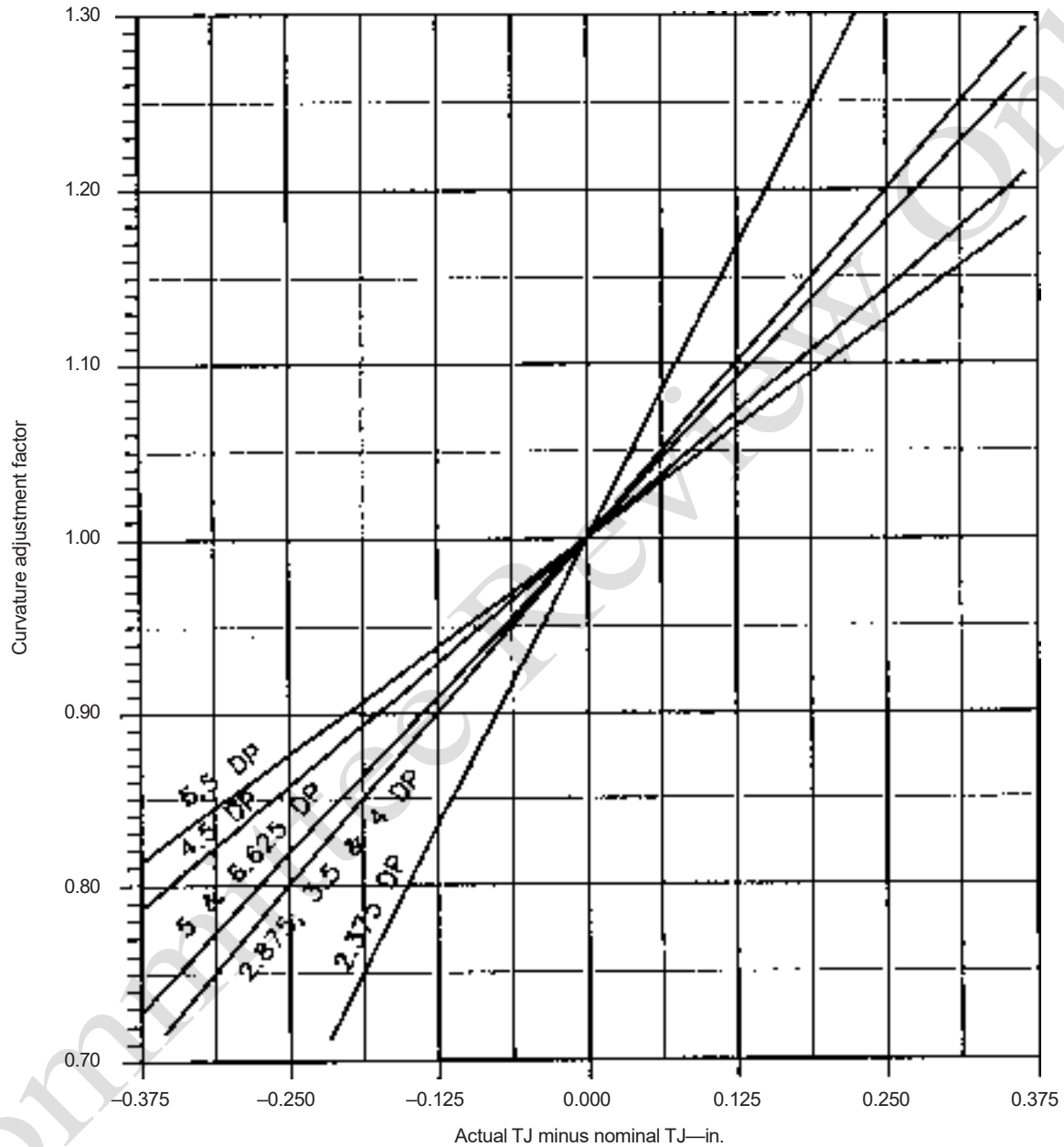


Figure 75—Hole Curvature Adjustment Factor To Allow for Differences in Tooljoint ODs



Table 22—Fatigue Endurance Limits Compressively Loaded Drill Pipe

Grade	API Minimum Yield Strength ksi	API Minimum Tensile Strength ksi	Minimum Fatigue Endurance Limit ksi
E75	75	100	22.0
X95	95	105	23.1
G105	105	115	25.3
S135	135	145	31.9

Table 23—Values Used in Preparing Figure 77

Grade	Typical Yield Strength ksi	Expected Ultimate Strength and Fatigue Stress Limit for One Revolution ksi	Minimum Fatigue Stress Limit for 1,000,000 Revolutions ksi
E75	87.5	121.5	26.7
X95	103.0	131.5	28.9
G105	124.0	149.5	32.9
S135	150.0	159.0	35.0

## 11.6 ESTIMATING CUMULATIVE FATIGUE DAMAGE

An interesting alternative to operating below the fatigue endurance limits for drill pipe is to monitor the cumulative fatigue damage caused by rotating in high curvature intervals of the borehole and retire the pipe before failures occur. The concepts for tracking the cumulative fatigue damage have been well developed by Hansford and Lubinski.<sup>37,38</sup> The key towards successful use of this technique is establishing the appropriate stress versus revolutions to failure curves for the various grades of API drill pipe. Figures 76 and 77 provide estimates of the median expected failure limits found by Morgan and Roblin and an estimate of the minimum failure limits of API drill pipe that has been manufactured to average API properties. We would expect that half of the drill pipe exposed to the limits shown in Figure 76 would fail. The minimum failure limits in Figure 77 should avoid fatigue failures on typical API drill pipe. The median failure limits are based on an exponential relationship that connects the average tensile strength of the tested specimens representing one revolution to failure with the median fatigue endurance limits representing one million cycles to failure. The average tensile strength values and the median fatigue endurance limits from Table 21 were used to develop the stress versus revolutions to failure curves shown in Figure 76.

The equation is of the form:  $S = \frac{TS}{N^x}$

where

$S$  = bending stress limit, psi,

$TS$  = tensile strength of pipe, psi,

$N$  = revolutions to failure,

$x$  = a fractional exponent of about 0.1.

The curves of minimum failure limits are also based on the Morgan and Roblin data. Their report includes a table that defines the typical yield and ultimate tensile strengths for normalized Grade E75, normalized and tempered Grades X95 and G105, and quenched tempered Grade S135 API drill pipe. Using Casner's defined 0.22 ratio we computed the

fatigued endurance limits for these tensile strengths. The SN curve was computed by using the exponential relationship described above with the tensile strength equal to the fatigue endurance limit for one revolution and the fatigue endurance limit values to represent the stress limit for one million revolutions. The values used to prepare Figure 77 are summarized in Table 23.

The cumulative fatigue damage is determined by counting the revolutions of pipe in highly curved portions of the borehole where the stresses exceed the fatigue endurance limits. If, for example, the revolutions in a particular section of hole represent 20 percent of the predicted revolutions to failure for that dogleg severity it is judged that 20 percent of the fatigue life has been consumed. Figures 76 and 77 can be used to judge inspection levels and ultimate retirement levels. The ultimate life can be judged from the plot of the median fatigue limits of Figure 76. The appropriate minimum inspection levels can be judged from the minimum fatigue limits of Figure 77. After exposure to this level of fatigue, inspection and removal of damaged joints can extend the remaining string life to or beyond the expected median life levels.

Figures 78 through 80 are plots of the bending stresses for 3<sup>1</sup>/<sub>2</sub>-inch, 2<sup>7</sup>/<sub>8</sub>-inch, and 2<sup>3</sup>/<sub>8</sub>-inch drill pipe in highly curved boreholes. The bending stresses determined from these plots are used to determine the total number of revolutions that the pipe can withstand from Figures 76 and 77. These are then compared to the observed number of revolutions to determine the level of fatigue damage. The ratio of the revolutions to the predicted median revolutions to failure defines the fraction of the drillpipe fatigue life consumed in drilling through the high curvature hole.

### 11.6.1 Example

An example of the cumulative fatigue damage calculations is given by the following. Consider drilling a 500-foot horizontal hole below a 100-foot radius build curve with 3<sup>1</sup>/<sub>2</sub>-inch S135 drill pipe. Drill pipe will be rotated at 30 RPM with 10,000 WOB, and is expected to drill at 15 feet per hour. The equivalent build rate is given by:

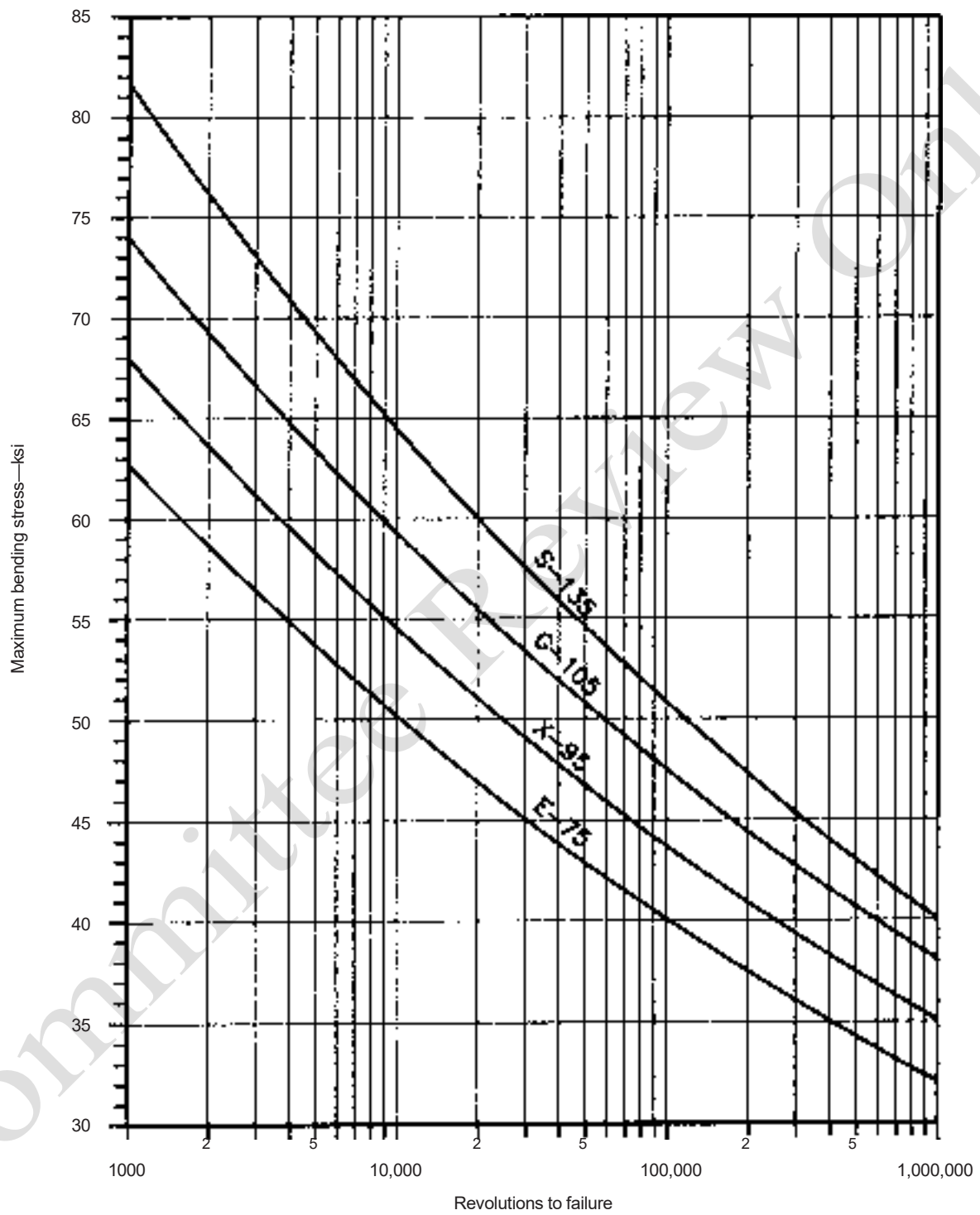


Figure 76—Median Failure Limits for API Drillpipe Noncorrosive Service

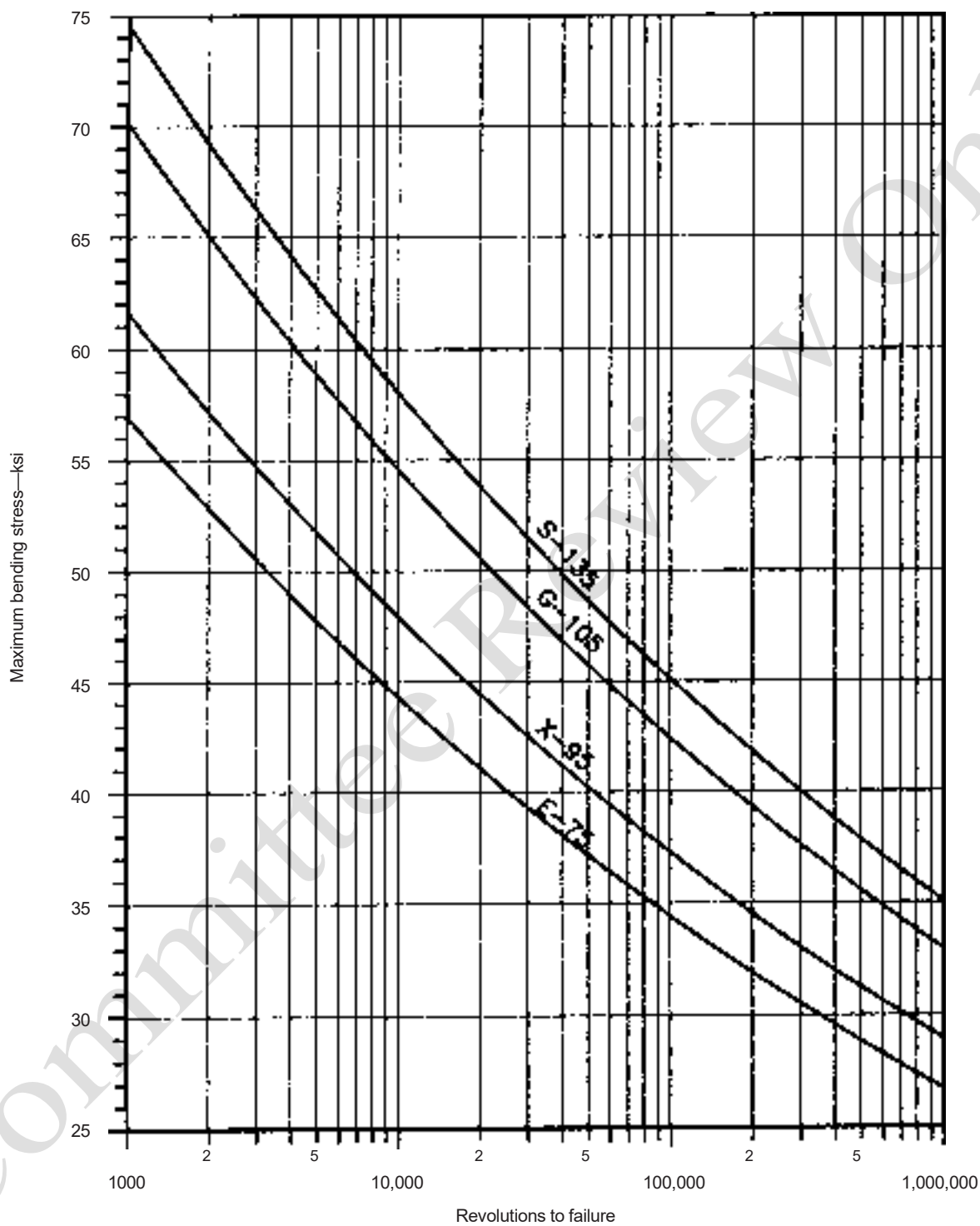


Figure 77—Minimum Failure Limits for API Drillpipe Noncorrosive Service

$$B = \frac{5730}{R}$$

where

$B$  = build rate, degrees/100 ft.,

$R$  = build radius, ft.

$$\text{For this case: } B = \frac{5730}{100} = 57.3 \text{ degrees/100ft.}$$

### 11.6.2 Solution

Figure 78a shows that at 10,000 pound axial compressive load and a 57-degrees-per-100-foot build rate the maximum bending stress is 50,000 psi. Figure 76 predicts that half of the S135 pipe will fail under a 50,000 psi bending stress after 110,000 revolutions. The minimum failure limits of Figure 77 predict that S135 pipe can be rotated 39,000 revolutions without failure.

The number of revolutions of exposure is given by:

$$N = \frac{60 \xi L \xi RPM}{ROP}$$

where

$N$  = revolutions of exposure,

$L$  = length of high curvature hole, ft.,

$RPM$  = rotary speed, rev/min,

$ROP$  = penetration rate, ft/hr.

The length of  $L$  of our 90 degree build curve is equal to:

$$L = \frac{9\pi}{2} \xi R = \frac{9\pi}{2} \xi 100 = 157 \text{ ft.}$$

Therefore, the number of revolutions of exposure for the pipe that is rotated through the build curve is equal to:

$$N = \frac{60 \xi 157 \xi 30}{15} = 18,840 \text{ revolutions}$$

The cumulative damage can be computed by comparing the revolutions of exposure to the 110,000 revolutions required to cause half of the pipe to fail. This suggests that 17 percent of the fatigue life of the affected pipe has been consumed in drilling one well. Comparing the revolutions of exposure to the minimum fatigue limit of 39,000 revolutions evaluates the risk of a failure. For this case, the 18,840 revolutions of exposure represents 48 percent of the minimum fatigue life expected for the S135 pipe. This suggests that two wells could be drilled with this string before inspecting and downgrading or removing fatigue damaged joints from service. Continued use of the string will require removing significant portions of the affected pipe in order to prevent failures.

## 11.7 BENDING STRESSES ON BUCKLED DRILL PIPE

The bending stresses on buckled drill pipe must account for both the mechanics of buckling and the additional bending caused by the axial load and the tool joints. The curvature produced by buckling is given by:

$$B_{bc} = \frac{F \xi h \xi 57.3 \xi 12 \xi 100}{2 \xi E \xi I}$$

$$B_{buc} = \frac{17190 \xi F(D_h - D_{ij})}{E \xi I}$$

where

$B_{buc}$  = curvature of buckled pipe, °/100 ft.,

$F$  = axial load, lb.,

$D_h$  = hole diameter, in.,

$D_{ij}$  = tool joint OD, in.,

$h_c$  = radial clearance

$$= \frac{D_h - D_{ij}}{2}, \text{ in.,}$$

$I$  = area moment of inertial of pipe, in.<sup>4</sup>,

$E$  = Young's modulus, psi

= 30 x 10<sup>6</sup> psi for steel.

This curvature can be used in place of the hole curvature in the equations covered in Section 11.4.

## 12 Special Service Problems

### 12.1 SEVERE DOWNHOLE VIBRATION<sup>26</sup>

Downhole vibration is inevitable. In many cases, low levels of vibration go undetected and are harmless. However, severe downhole vibration can cause drillstring fatigue failure (washout/twist-off), crooked drillstrings, premature bit failure, and reduced penetration rates. The main sources of excitation are provided by the interaction of the bit with the formation and the drillstring with the wellbore. The drillstring response to these excitation sources is very complex.

Vibration can induce three components of motion in the drillstring and the bit, namely: axial (motion along drillstring axis), torsional (motion causing twist/torque) and lateral (side to side motion). All three dynamic motions may coexist and one motion may cause another.

While theories exist, there is no general agreement on how to predict (calculate) when damaging vibrations will occur. However, by observing the symptoms of severe downhole vibrations, probable mechanisms may be determined and appropriate corrective actions taken.

Severe downhole vibration is often accompanied by symptoms belonging to more than one mechanism. This fact makes the detection of the primary mechanism more difficult. For

(Text continued on page 108.)

Committee Review Only

3.5 in. 13.3 lb/ft Drill Pipe, 4.75 in. Tool Joint  
with 10 lb/gal mud in a 6 in. hole

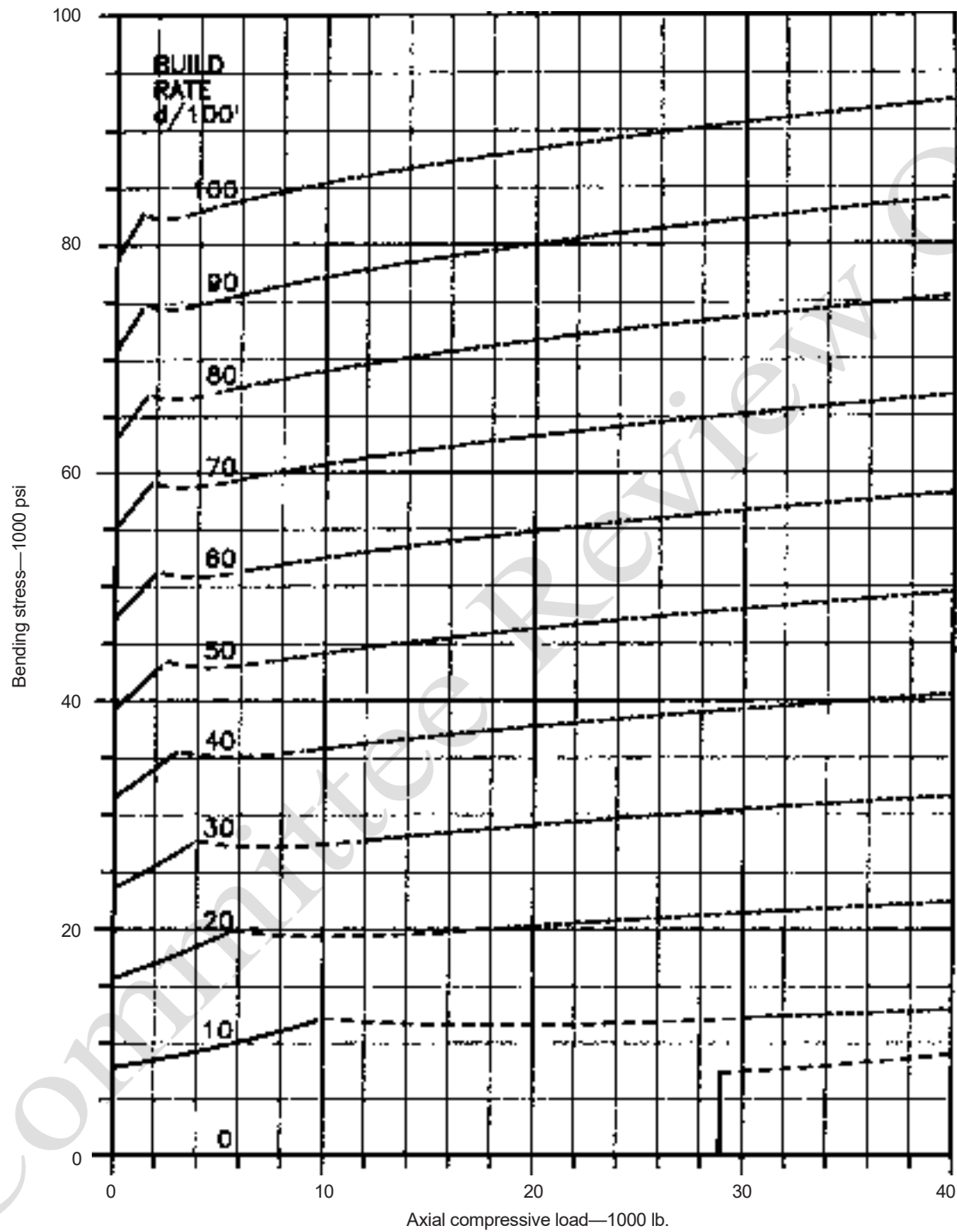


Figure 78a—Bending Stress for High Curvatures

3.5 in. 13.3 lb/ft Drill Pipe, 4.75 in. Tool Joint  
with 10 lb/gal mud in a 6 in. hole

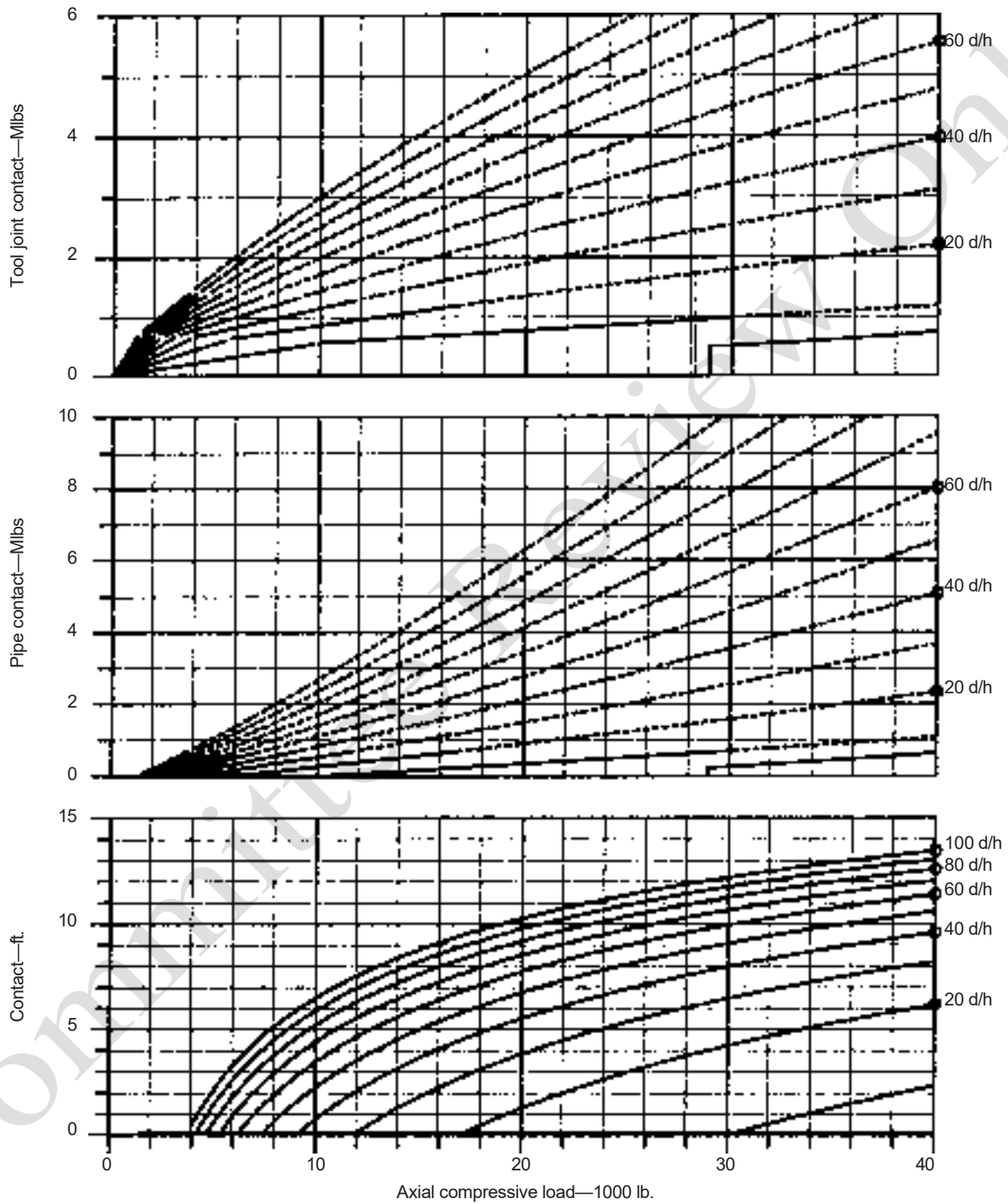


Figure 78b—Lateral Contact Forces and Length

2.875 in. 10.4 lb/ft Drill Pipe, 4.125 in. Tool Joint  
with 10 lb/gal mud in a 4.75 in. hole

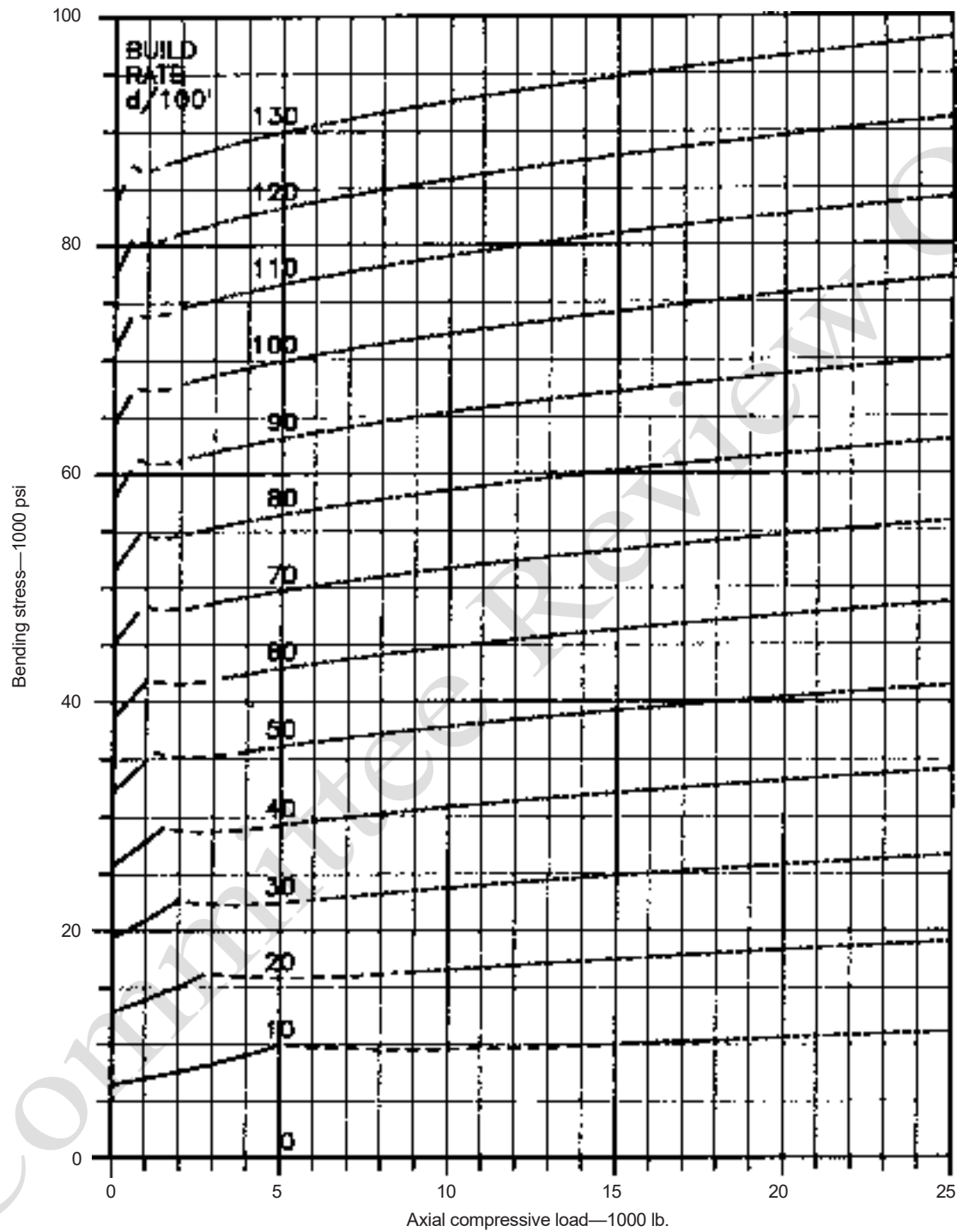


Figure 79a—Bending Stress for High Curvatures



2.875 in. 10.4 lb/ft Drill Pipe, 4.125 in. Tool Joint  
with 10 lb/gal mud in a 4.75 in. hole

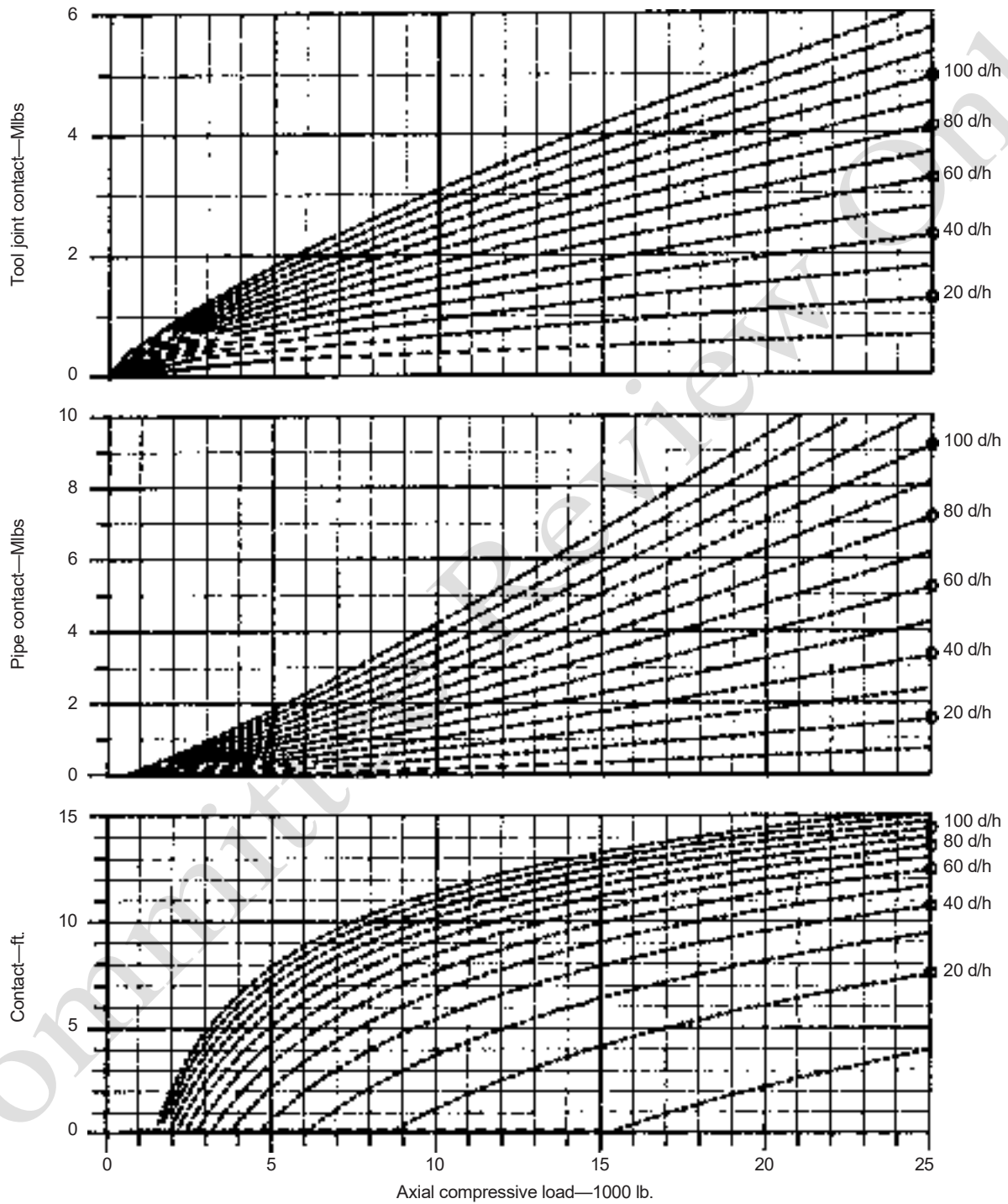


Figure 79b—Lateral Contact Forces and Length

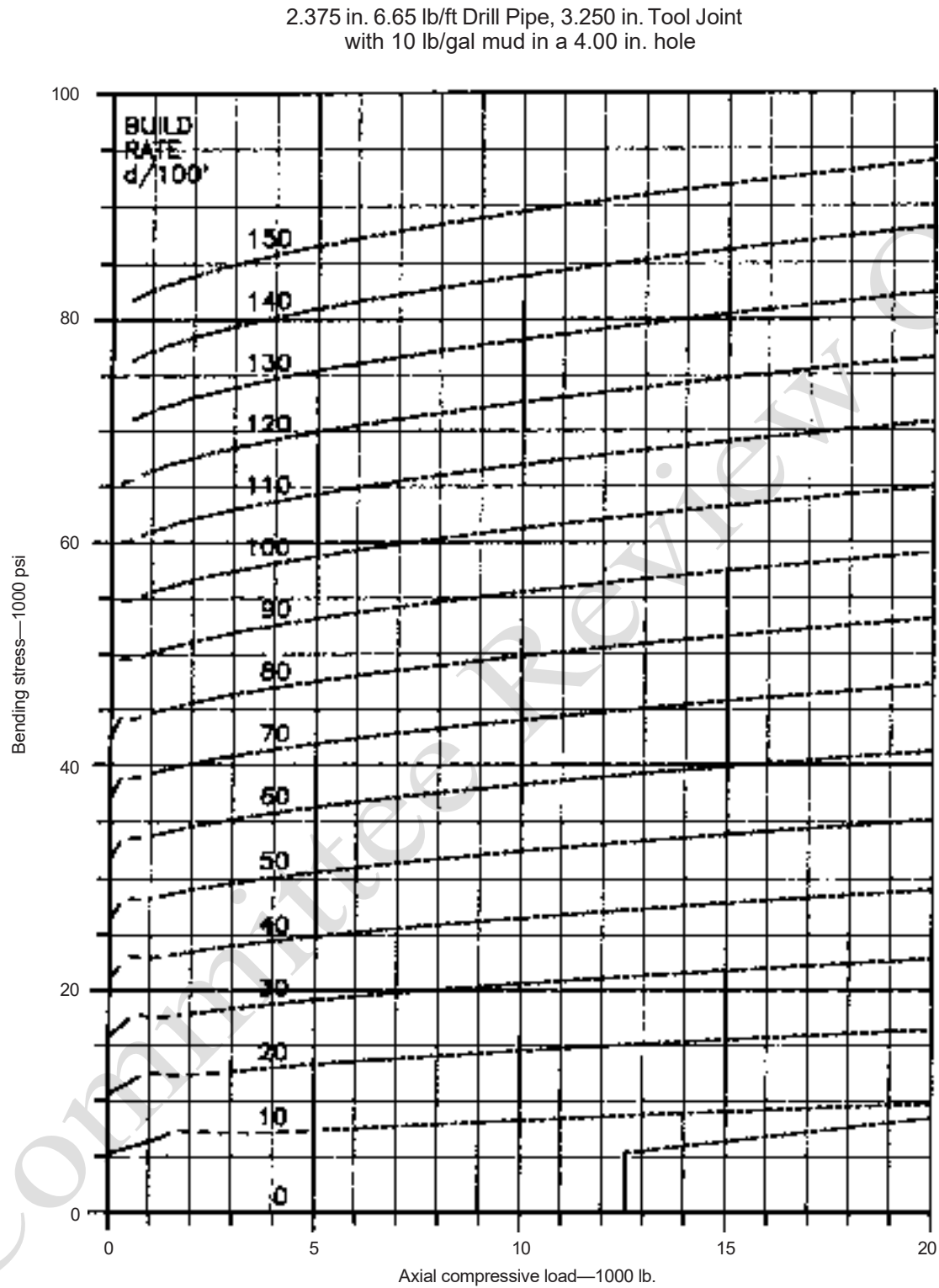


Figure 80a—Bending Stress for High Curvatures

2.375 in. 6.65 lb/ft Drill Pipe, 3.250 in. Tool Joint  
with 10 lb/gal mud in a 4.00 in. hole

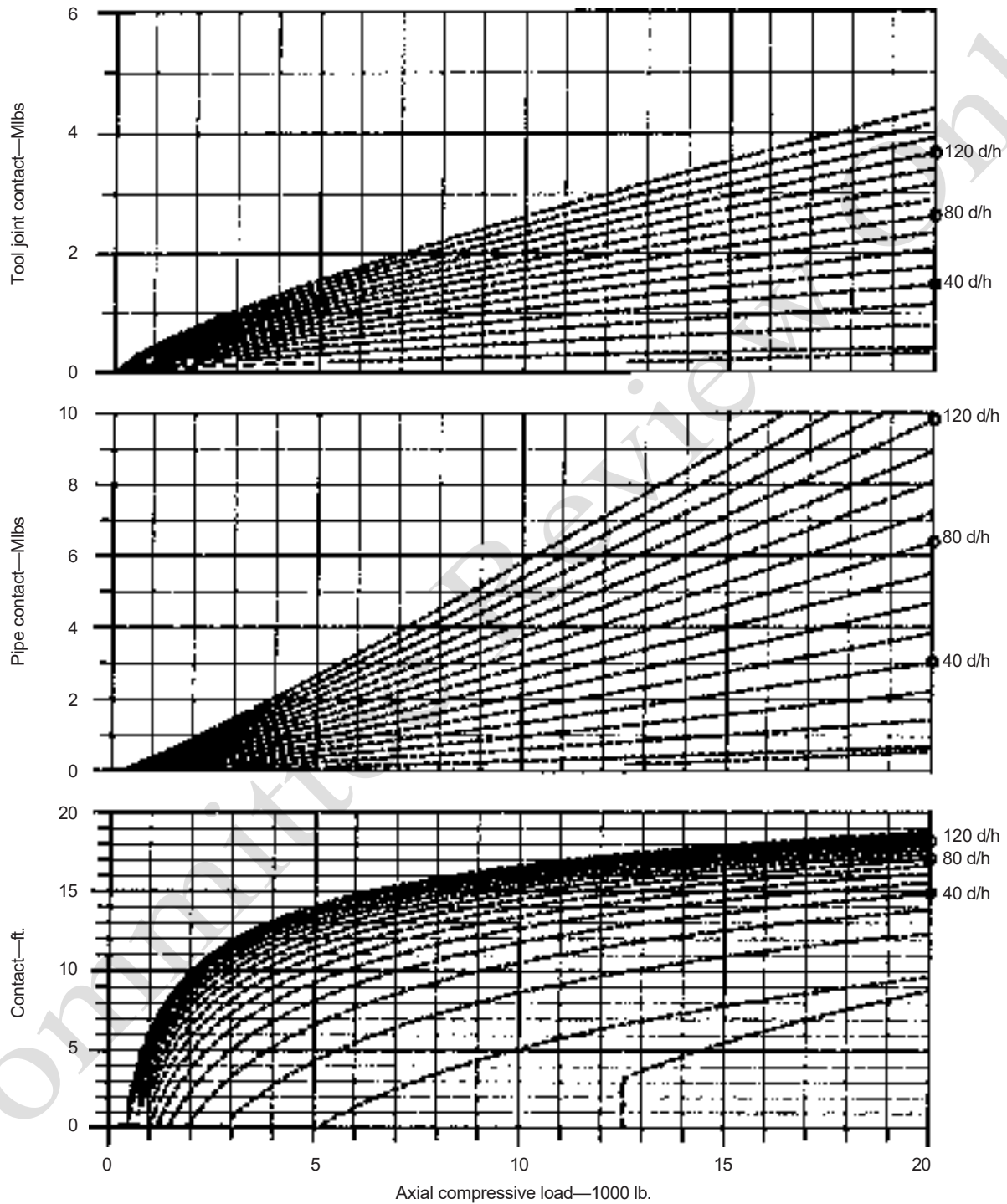


Figure 80b—Lateral Contact Forces and Length

example, an increase in MWD shock counts, which is indicative of BHA lateral vibration, can be caused by BHA Whirl, Bit Bounce, or other mechanisms. Additional clues, such as bit tooth breakage, for this example, are required for the identification of the primary vibration mechanism.

There are a number of mechanisms which can cause severe downhole vibration. For mechanisms, their symptoms, and methods of control are described below:

a. Slip stick:

1. Mechanism—Non-uniform bit rotation in which the bit slows or even stops rotating momentarily, causing the drillstring to periodically torque up and then spin free. This mechanism sets up the primary torsional vibrations in the string.
2. Symptoms—surface torque fluctuations >15 percent of average (below 1 Hz or stalling), increased MWD shock counts, cutter impact damage, drillstring washouts/twist-offs, connection over-torque or back-off.

Note: 1 Hz is one cycle per second.

3. Actions—reduce WOB and increase RPM, consider a less aggressive bit, modify mud lubricity, reduce stabilizer rotational drag (change blade design or number of blades, use non-rotating stabilizer or roller reamer), adjust stabilizer placement, smooth well profile, add rotary feedback system.

b. Drillstring whirl:

1. Mechanism—the BHA (or drillpipe) gears around the borehole. The violent whirling motion slams the drillstring against the borehole. The mechanism can cause torsional and lateral vibrations.
2. Symptoms—drillstring washouts/twist-offs, localized tool joint and/or stabilizer wear, increased average torque, 5 to 20Hz lateral vibrations even if bit off-bottom.
3. Actions—lift bit off bottom and stop rotation, then reduce RPM, avoid drill collar weight in excess of 1.15 to 1.25 times WOB, use packed hole assembly, reduce stabilizer rotational drag, adjust stabilizer placement, modify mud properties, consider drilling with a downhole motor.

c. Bit whirl:

1. Mechanism—eccentric rotation of the bit about a point other than its geometric center caused by bit/wellbore gearing (analogous to a planetary gear). This mechanism induces high frequency lateral and torsional vibration of the bit and drillstring.
2. Symptoms—cutter impact damage, uneven bit gauge wear, over-gauge hole, reduce ROP, 10 to 50 Hz lateral/torsional vibrations.
3. Actions—lift bit off bottom and stop rotation, then reduce RPM and increase WOB, consider changing bit (flatter profile, anti-whirl), use slow RPM when tagging bottom and when reaming, pickoff bottom before stop-

ping rotation, use stabilized BHA with full gauge near-bit stabilizer or reamer.

d. Bit bounce:

1. Mechanism—large weight-on-bit fluctuations causing the bit to repeatedly lift off and impact the formation. This mechanism often occurs when drilling with roller cone bits in hard formations.
2. Symptoms—large axial 1 to 10 Hz vibrations (shaking of hoisting equipment), large WOB fluctuations, cutter and/or bearing impact damage, fatigue cracks, reduced ROP.
3. Actions—run shock sub or hydraulic thruster, adjust WOB/RPM, consider changing bit style, change length of BHA.

e. Other mechanisms—some field data and theoretical studies indicate that certain “critical speeds” exist which excite resonant vibrations. Previous editions of Recommended Practice 7G gave formulas and graphs for predicting these critical speeds. However, severe vibrations have been routinely measured at RPM other than those give by these simple calculations.

## 12.2 TRANSITION FROM DRILL PIPE TO DRILL COLLARS

Frequent failure in the joints of drill pipe just above the drill collars suggests abnormally high bending stresses in these joints. This condition is particularly evident when the hole angle is increasing with depth and the bit is rotated off bottom. Low rates of change of hole angle combined with deviated holes may result in sharp bending of the first joint of drill pipe above the collars. When joints are moved from this location and rotated to other sections, the effect is to lose identity of these damaged joints. When these joints later fail through accumulation of additional fatigue damage, every joint in the string becomes suspect. One practice to reduce failures at the transition zone and to improve control over the damaged joints is to use nine or ten joints of heavy wall pipe, or smaller drill collars, just above the collars. These joints are marked for identification, and used in the transition zone. They are inspected more frequently than regular drill pipe to reduce the likelihood of service failures. The use of heavy wall pipe reduces the stress level in the joints and ensures longer life in this severe service condition.

## 12.3 PULLING ON STUCK PIPE

It is normally not considered good practice to pull on stuck drill pipe beyond the minimum tensile yield strength for the size, grade, weight, and classification of the pipe in use (see Tables 4, 6, and 27). For example, assuming a string of 5-in., 19.5 lb/ft Grade E drill pipe is stuck, the following approximate values for maximum hook load would apply:

Premium Class: 311,535 lbs  
Class 2: 270,432 lbs

The stretch in the drill pipe due to its own weight suspended in a fluid should be considered when working with drill pipe and the proper formulas to use for stretch when free or stuck should be used.

### 12.3.1 Example I (see A.6 for derivation):

Determine the stretch in a 10,000 foot string of drill pipe freely suspended in 10 lb/gal drilling fluid.

$$\begin{aligned} e &= \frac{L_1^2}{9.625 \times 10^7} [65.44 - 1.44 W_g] \quad (22) \\ &= \frac{10,000^2}{9.625 \times 10^7} [65.44 - 1.44 \times 10] \\ &= 53.03 \text{ in.,} \end{aligned}$$

where

$L_1$  = length of free drill pipe, feet,  
 $W_g$  = weight of drilling fluid, lb/gal,  
 $e$  = stretch, inches.

### 12.3.2 Example II (see A.4 for derivation):

Determine the free length in a 10,000 foot string of 4<sup>1</sup>/<sub>2</sub>-in. OD 16.60 lb/ft drill pipe which is stuck, and which stretches 49 in. due to a differential pull of 80,000 lbs.

$$\begin{aligned} L_1 &= \frac{735,294 \times e \times W_{dp}}{P} \quad (23) \\ &= \frac{735,294 \times 49 \times 16.60}{80,000} \\ &= 7476 \text{ ft.,} \end{aligned}$$

where

$L_1$  = length of free drill pipe, feet,  
 $e$  = differential stretch, inches,  
 $W_{dp}$  = weight of drill pipe, pounds per foot,  
 $P$  = differential pull, pounds.

## 12.4 JARRING

It is common practice during fishing, testing, coring and other operations to run rotary jars to aid in freeing stuck assemblies. Normally, the jars are run below several drill collars which act to concentrate the blow at the fish. It is necessary to take the proper stretch to produce the required blow. The momentum of the moving mass of drill collars and stretched drill pipe returning to normal causes the blow after the jar hammer is tripped. A hammer force of three to four times the excess of pull over pipe weight is possible depending on type and size of pipe, number (weight) of drill collars, drag, jar travel, etc. This force may be large enough to damage the stuck drill pipe and should be considered when jarring operations are planned.

## 12.5 TORQUE IN WASHOVER OPERATIONS

Although little data are available on torque loads during washover operations, they are significant. Friction and drag on the wash pipe cause considerable increases in torque on the tool joints and drill pipe, and should be considered when pipe is to be used in this type service. This is particularly true in directionally drilled wells and deep straight holes with small tolerances. (See 12.6.)

## 12.6 ALLOWABLE HOOKLOAD AND TORQUE COMBINATIONS

Allowable hookloads and torque combinations for stuck drill strings may be determined by use of the following formula:

$$Q_T = \frac{0.096167J}{D} \sqrt{\frac{Y_m}{A^2} - \frac{P^2}{A^2}}, \quad (24)$$

where

$Q_T$  = minimum torsional yield strength under tension, lb-ft.,

$J$  = polar moment of inertia:

$$= \frac{\pi}{32} (D^4 - d^4) \text{ for tubes,}$$

$D$  = outside diameter, inches,

$d$  = inside diameter, inches,

$Y_m$  = minimum unit yield strength, psi,

$S_s$  = minimum unit shear strength, psi:

$$(S_s = 0.577 Y_m),$$

$P$  = total load in tension, pounds,

$A$  = cross section area.

An example of the torque which may be applied to the pipe which is stuck while imposing a tensile load is as follows:  
 Assume:

- 3<sup>1</sup>/<sub>2</sub>-in. OD 13.30 lb Grade E drill pipe.
- 3<sup>1</sup>/<sub>2</sub>-in. IF tool joints.
- Stuck point: 4000 feet.
- Tensile pull: 100,000 pounds.
- New drill pipe.

Then:

$$Q_T = \frac{0.096167 \times 9.00}{3.5} \sqrt{(75,000)^2 - \frac{(100,000)^2}{(3.62)^2}}$$

$$Q_T = 17,216 \text{ lb-ft.}$$

For further information on allowable hookloads, torque application, and pump pressure use, see Stall and Blenkarn: *Allowable Hook Load and Torque Combinations For Stuck Drill Strings*.<sup>12</sup>

## 12.7 BIAXIAL LOADING OF DRILL PIPE

The collapse resistance of drill pipe corrected for the effect of tension loading may be calculated by reference to Figure 81 and the use of formulas and physical constants contained in 12.8, 12.9, 12.10, and 12.11.

## 12.8 FORMULAS AND PHYSICAL CONSTANTS

The ellipse of biaxial yield stress shown in Figure 46 is for use in the range of plastic collapse only, and gives the relation between axial stress (psi) in terms of average yield stress (psi) and effective collapse resistance in terms of nominal plastic collapse resistance. This relationship is depicted in the following formula:

$r^2 + rz + z^2 = 1$ , having solutions as follows:

$$z = \frac{r + \sqrt{4 - 3r^2}}{2}, \text{ and} \quad (1)$$

$$r = \frac{z + \sqrt{4 - 3z^2}}{2}, \quad (2)$$

where

$$r = \frac{\text{Effective collapse resistance under tension (psi)}}{\text{Nominal plastic collapse resistance (psi)}}, \quad (3)$$

$$z = \frac{\text{Total tensile loading (pounds)}}{\text{Cross section area} \times \text{Average yield strength}}, \quad (4)$$

Average yield strengths in psi are as follows:

Grade E75.....	85,000
Grade X95.....	110,000
Grade G105.....	120,000
Grade S135 .....	145,000

## 12.9 TRANSITION FROM ELASTIC TO PLASTIC COLLAPSE

Material in the elastic range when under no tensile load, transfers to the plastic range when subjected to sufficient axial load. Axial loading, below the transition load, has no effect on elastic collapse. At transition point, the collapse resistance under tension equals the nominal elastic collapse, and also equals a tension factor ( $r$ ) times collapse resistance as calculated from the nominal plastic formula.

Method: Determine values for both elastic and plastic collapse from applicable formulas in Appendix A, substitute in formula (3), 12.8 and solve for  $r$ . Then, solve formula (1), 12.8, for  $z$ . For the total tension (transition) load, substitute value of  $z$  in formula (4), 12.8.

## 12.10 EFFECT OF TENSILE LOAD ON COLLAPSE RESISTANCE

The effect of tensile load applies only to greater than transition load on normally elastic items, and to any load on plastic collapse items. In either case, the value determined from the plastic collapse formula (Appendix A) is to be modified.

Method: Substitute the tensile load value in formula (4), 12.8, to find a value for  $z$ . Substitute this value in formula (2), 12.8, to permit solution for  $r$ . Next, substitute the value of  $r$  in formula (3), 12.8, to obtain the effective collapse resistance under tension.

## 12.11 EXAMPLE CALCULATION OF BIAXIAL LOADING

An example of the calculation of drill pipe collapse resistance, corrected for the effect of tensile load is as follows:

Given: String of 5-inch OD, 19.50 lb per ft, Grade E Premium Class drill pipe.

Required: Determine the collapse resistance corrected for tension loading during drill stem test, with drill pipe empty and 15 lb per gal. mud behind the drill pipe. Tension of 50,000 lb on the joint above the packer.

Solution: Find reduced cross section area of Premium Class drill pipe as follows:

- Nominal OD = 5 inches, nominal wall thickness = 0.362 inches.
- Nominal ID = 4.276 inches.
- Reduced wall thickness for premium.
- Class =  $(0.8)(0.362) = 0.2896$  inches.
- Reduced OD for premium class = 4.8552 inches.
- Cross-sectional area for premium.
- Class = reduced OD area - nominal ID area =  $18.5141 - 14.3603 = 4.1538$  sq. inches.
- Tension load on bottom joint =  $50,000 : 4.1538 = 12037$  psi.
- Average yield strength for Grade E drill pipe = 85,000 psi.
- Percent tensile stress to average yield strength =  $\frac{12,037}{85,000} \times 100 = 14.16$  percent

k. Enter Figure 81 at 14.16 percent on upper right horizontal scale and drop vertically to intersect right-hand portion of the ellipse. Proceed horizontally to the left and intersect Nominal Collapse Resistance (center vertical scale) at 92 percent.

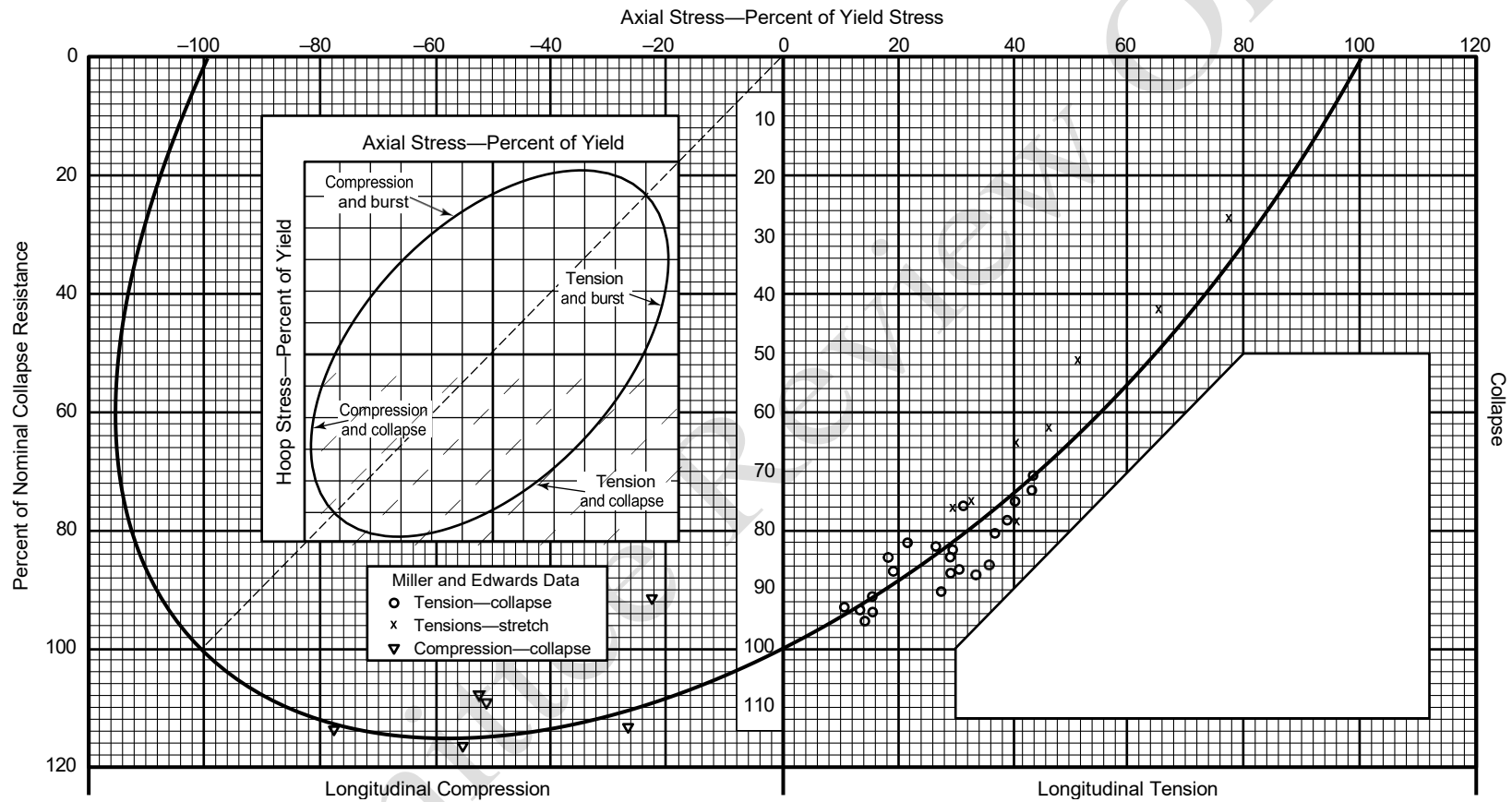
l. Minimum collapse resistance for premium class (Table 5) = 7041 psi.

m. Corrected collapse resistance for effect of tension =  $(7041)(.92) = 6478$  psi.

**CAUTION:** No safety factors are included in this example calculation.

Note: Use reduced values for cross sectional area, tension and collapse rating for the appropriate class (Premium, Class 2) of used drill pipe being considered.





Note: Applies only in a noncorrosive environment.

Figure 81—Ellipse of Biaxial Yield Stress<sup>12</sup> or Maximum Shear-Strain Energy Diagram  
After Holmquist and Nadai, Collapse of Deep Well Casing, API Drilling and Production Practice (1939)

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**Table 27—Hook-Load at Minimum Yield Strength for New, Premium Class (Used), and Class 2 (Used) Tubing Work Strings**

(Hook load values in this table vary slightly from tensile data for the same pipe size and class listed in Tables 2, 4, 6, 8, and 9 because of differences in rounding procedures used in calculations.)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
Size OD	Weight	Original OD	Wall Thickness	ID	New			Premium Class				Hook Load	Class 2				
					Original Cross-Section Area	Yield	Hook Load	OD with 20% Wall Reduction	Minimum Remaining Wall (80%)	Reduced Cross-Section Area	Cross-Section Area Ratio		OD with 30% Wall Reduction	Minimum Remaining Wall (70%)	Reduced Cross-Section Area	Cross-Section Area Ratio	Hook Load
in.	lb/ft	in.	in.	in.	sq. in.	psi	lb	in.	in.	sq. in.	%	lb	in.	in.	sq. in.	%	lb
3/4	1.20	1.050	0.113	0.824	0.3326	55000.	18295.	1.0048	0.090	0.2597	78.07	14283.	0.9822	0.079	0.2244	67.47	12343.
						75000.	24948.					19477.					16832.
						80000.	26611.					20775.					17954.
						105000.	34927.					27267.					23564.
3/4	1.50	1.050	0.154	0.742	0.4335	55000.	23842.	0.9884	0.123	0.3349	77.25	18418.	0.9576	0.108	0.2878	66.39	15829.
						75000.	32512.					25115.					21585.
						80000.	34679.					26790.					23024.
						105000.	45516.					35161.					30219.
1	1.80	1.315	0.133	1.049	0.4939	55000.	27163.	1.2618	0.106	0.3862	78.20	21242.	1.2352	0.093	0.3340	67.64	18372.
						75000.	37041.					28966.					25053.
						80000.	39510.					30897.					26724.
						105000.	51857.					40552.					35075.
1	2.25	1.315	0.179	0.957	0.6388	55000.	35135.	1.2434	0.143	0.4950	77.48	27222.	1.2076	0.125	0.4260	66.69	23432.
						75000.	47912.					37122.					31953.
						80000.	51106.					39596.					34083.
						105000.	67077.					51970.					44734.
1 1/4	2.40	1.660	0.140	1.380	0.6685	55000.	36769.	1.6040	0.112	0.5250	78.53	28873.	1.5760	0.098	0.4550	68.07	25027.
						75000.	50140.					39373.					34128.
						80000.	53482.					41998.					36403.
						105000.	70196.					55122.					47779.
1 1/4	3.02	1.660	0.191	1.278	0.8815	55000.	48481.	1.5836	0.153	0.6868	77.92	37776.	1.5454	0.134	0.5930	67.27	32613.
						75000.	66110.					51513.					44472.
						80000.	70517.					54947.					47437.
						105000.	92554.					72118.					62261.
1 1/4	3.20	1.660	0.198	1.264	0.9094	55000.	50018.	1.5808	0.158	0.7078	77.83	38930.	1.5412	0.139	0.6107	67.16	33590.
						75000.	68206.					53087.					45805.
						80000.	72753.					56626.					48858.
						105000.	95489.					74322.					64126.
1 1/2	2.90	1.900	0.145	1.610	0.7995	55000.	43970.	1.8420	0.116	0.6290	78.68	34595.	1.8130	0.101	0.5457	68.26	30016.
						75000.	59959.					47175.					40931.
						80000.	63957.					50320.					43660.
						105000.	83943.					66045.					57304.
1 1/2	4.19	1.900	0.219	1.462	1.1565	55000.	63610.	1.8124	0.175	0.9011	77.92	49562.	1.7686	0.153	0.7779	67.26	42787.
						75000.	86741.					67584.					58345.
						80000.	92523.					72090.					62235.
						105000.	121437.					94618.					81684.
2 1/16	3.25	2.063	0.156	1.751	0.9346	55000.	51403.	2.0006	0.125	0.7354	78.69	40450.	1.9694	0.109	0.6382	68.28	35099.
						75000.	70095.					55158.					47862.
						80000.	74768.					58836.					51053.
						105000.	98133.					77222.					67007.
2 3/8	4.70	2.375	0.190	1.995	1.3042	55000.	71733.	2.2990	0.152	1.0252	78.61	56388.	2.2610	0.133	0.8891	68.17	48903.
						75000.	97817.					76893.					66686.
						80000.	104339.					82019.					71132.
						105000.	136944.					107650.					93360.
2 3/8	5.30	2.375	0.218	1.939	1.4773	55000.	81249.	2.2878	0.174	1.1579	78.38	63686.	2.2442	0.153	1.0027	67.88	55150.
						75000.	110794.					86844.					75205.
						80000.	118181.					92634.					80218.
						105000.	155112.					121581.					105286.



**Table 27—Hook-Load at Minimum Yield Strength for New, Premium Class (Used), and Class 2 (Used) Tubing Work Strings (Continued)**

(Hook load values in this table vary slightly from tensile data for the same pipe size and class listed in Tables 2, 4, 6, 8, and 9 because of differences in rounding procedures used in calculations.)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
Size OD	Weight	Original OD	Wall Thickness	ID	New		Hook Load	Premium Class				Hook Load	Class 2				Hook Load
					Original Cross-Section Area	Yield		OD with 20% Wall Reduction	Minimum Remaining Wall (80%)	Reduced Cross-Section Area	Cross-Section Area Ratio		OD with 30% Wall Reduction	Minimum Remaining Wall (70%)	Reduced Cross-Section Area	Cross-Section Area Ratio	
in.	lb/ft	in.	in.	in.	sq. in.	psi	lb	in.	in.	sq. in.	%	lb	in.	in.	sq. in.	%	lb
2 <sup>7</sup> / <sub>8</sub>	5.95	2.375	0.254	1.867	1.6925	55000.	93087.	2.2734	0.203	1.3216	78.08	72686.	2.2226	0.178	1.1422	67.49	62820.
						75000.	126936.					99117.					85663.
						80000.	135399.					105725.					91374.
						105000.	177711.					138764.					119928.
2 <sup>3</sup> / <sub>8</sub>	6.50	2.875	0.217	2.441	1.8120	55000.	99661.	2.7882	0.174	1.4260	78.69	76427.	2.7448	0.152	1.2374	68.29	88054.
						75000.	135902.					106946.					92801.
						80000.	144962.					114076.					98988.
						105000.	190263.					149725.					129922.
2 <sup>7</sup> / <sub>8</sub>	8.70	2.875	0.308	2.259	2.4839	55000.	136612.	2.7518	0.246	1.9394	78.08	106667.	2.6902	0.216	1.6761	67.48	92186.
						75000.	186289.					145455.					125709.
						80000.	198708.					155152.					134089.
						105000.	260805.					203637.					175992.
2 <sup>7</sup> / <sub>8</sub>	9.50	2.875	0.340	2.195	2.7077	55000.	148926.	2.7390	0.272	2.1081	77.85	115945.	2.6710	0.238	1.8192	67.18	100053.
						75000.	203080.					158106.					136436.
						80000.	216619.					168647.					145532.
						105000.	284313.					221349.					191011.
2 <sup>7</sup> / <sub>8</sub>	10.70	2.875	0.392	2.091	3.0578	55000.	168180.	2.7182	0.314	2.3690	77.47	130296.	2.6398	0.274	2.0391	66.68	112151.
						75000.	229337.					177676.					152933.
						80000.	244626.					189522.					163128.
						105000.	321072.					248747.					214106.
2 <sup>7</sup> / <sub>8</sub>	11.00	2.875	0.405	2.065	3.1427	55000.	172848.	2.7130	0.324	2.4317	77.38	133744.	2.6320	0.283	2.0917	66.56	115042.
						75000.	235702.					182378.					156875.
						80000.	251415.					194536.					167334.
						105000.	329983.					255329.					219626.
3 <sup>1</sup> / <sub>2</sub>	12.80	3.500	0.368	2.764	3.6209	55000.	199151.	3.3528	0.294	2.8287	78.12	155577.	3.2792	0.258	2.4453	67.53	134492.
						75000.	271569.					212150.					183398.
						80000.	289674.					226293.					195624.
						105000.	380197.					297010.					256757.
3 <sup>1</sup> / <sub>2</sub>	12.95	3.500	0.375	2.750	3.6816	55000.	202485.	3.3500	0.300	2.8746	78.08	158101.	3.2750	0.263	2.4843	67.48	136637.
						75000.	276117.					215592.					186323.
						80000.	294524.					229965.					198745.
						105000.	386563.					301828.					260853.
3 <sup>1</sup> / <sub>2</sub>	15.80	3.500	0.476	2.548	4.5221	55000.	248715.	3.3096	0.381	3.5038	77.48	192708.	3.2144	0.333	3.0160	66.69	165879.
						75000.	339156.					262783.					226198.
						80000.	361767.					280302.					241278.
						105000.	474819.					367897.					316678.
3 <sup>1</sup> / <sub>2</sub>	16.70	3.500	0.510	2.480	4.7906	55000.	263484.	3.2960	0.408	3.7018	77.27	203596.	3.1940	0.357	3.1818	66.42	175001.
						75000.	359296.					277631.					238638.
						80000.	383249.					296140.					254547.
						105000.	503015.					388684.					334093.
4 <sup>1</sup> / <sub>2</sub>	15.50	4.500	0.337	3.826	4.4074	55000.	242409.	4.3652	0.270	3.4689	78.70	190788.	4.2978	0.236	3.0103	68.30	165565.
						75000.	330558.					260165.					225771.
						80000.	352595.					277509.					240823.
						105000.	462781.					364231.					316080.
4 <sup>1</sup> / <sub>2</sub>	19.20	4.500	0.430	3.640	5.4981	55000.	302396.	4.3280	0.344	4.3055	78.31	236805.	4.2420	0.301	3.7267	67.78	204968.
						75000.	412358.					322916.					279502.
						80000.	439848.					344443.					298135.
						105000.	577301.					452082.					391302.

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## 14—Special Processes

### 14.1—DRILL STEM SPECIAL PROCESSES

**14.1.1** Usually the materials used in the manufacture of down hole drilling equipment (tool joints, drill collars, stabilizers and subs) are AISI 4135, 4137, 4140, or 4145 steels.

**14.1.2** These are alloy steels and are normally in the heat treated state, these materials are not weldable unless proper procedures are used to prevent cracking and to recondition the sections where welding has been performed.

**14.1.3** It should be emphasized that areas welded can only be reconditioned and cannot be restored to their original state free of metallurgical change unless a complete heat treatment is performed after welding, which cannot be done in the field.

### 14.2—CONNECTION BREAK-IN

Based on field experience, it has been observed that used rotary shouldered connections are less likely to gall than new connections. It is believed that this is due to work hardening the connection surfaces. The process of Connection Break-In is a make up and break out of the connection under controlled conditions in order to provide surface work hardening prior to use. Connection Break-In may be done on the rig, as an optional manufacturing step, or at a service facility.

Since many factors effect connection galling, Connection Break-In does not eliminate the possibility of galling.

#### 14.2.1—Preparation for Connection Break-In

Remove any storage or rust preventative coatings. Make sure that the connections are free of dirt or other debris. Thoroughly coat the threads and shoulders of both pin and box connections with a thread compound suitable for rotary shouldered connections. Determine the recommended make-up torque of the connection. Make note of the friction factor of the thread compound and any adjustment required to the applied make-up torque. See API Specification 7, Appendix G and API Recommended Practice 7A1 for further information on thread compounds and friction factor.

#### 14.2.2—Connection Break-In at the Rig

Taking care to align the connection, stab and make up the connection slowly. Spinning in with a chain or high speed power spinner may cause galling. Using a calibrated torque gage or line pull indicator, slowly make up to the recommended make-up torque. With manual tongs, use both sets of tongs and keep lines at 90 degrees for the final torque. Slowly break out the connection. During both make-up and break-

out, watch for excessive resistance or other signs that could indicate the possibility of galling. Wipe clean the pin and box connections and visually inspect for evidence of galling in the threads or sealing shoulders. If galling occurs, rework the connection prior to use.

#### 14.2.3—Connection Break-In During Manufacturing

When performing break in at the factory or service facility, the connection should be finished machined, inspected, cold rolled (if specified) and preferably coated with an anti-gall material such as a phosphate or copper.

Note: Break-in will change thread gage standoff.

Slowly make up three times to the recommended torque. Between each make up, break out only far enough to apply additional thread compound to the shoulders and last engaged threads. Break out the connection after final make-up. Wipe clean the pin and box and visually inspect for galling on the threads or shoulder. If galling occurs, the connection is rejected.

## 15 Dynamic Loading Of Drill Pipe

Note: For quantitative results, see Reference 15, Appendix B.

**15.1** When running a stand of drill pipe into or out of the hole, the pipe is subjected not to its static weight, but to a dynamic load.

**15.2** The dynamic load oscillates between values which are greater and smaller than the static load (the greater values may exceed the yield), which results in fatigue, i.e., shortening of pipe life.

**15.3** Dynamic loading may exceed yield in long strings, such as 10,000 feet.

**15.4** Dynamic loading increases with the length of drill collar string.

**15.5** In the event the smallest value of the dynamic load tries to become negative, the pipe is kicked off the slips, and the string may be dropped into the hole.

**15.6** The likelihood of dynamic loading resulting in a jumpoff (kicking of the slips) increases as the drill pipe string becomes shorter and the collar string becomes longer.

**15.7** For a long drill pipe string, such as 10,000 feet, a jumpoff is possible only if drill pipe, after having been pulled from the slips, is dropped at a very high velocity, such as 16 ft/sec.

**15.8** Dynamic phenomena are severe only when damping is small, which may be the case in exceptional holes, in which there are no doglegs, the deviation is small, the cross-

sectional area of the annulus is large, and the mud viscosity and weight are low.

**15.9** In case of small damping, the running time of a stand of drill pipe should not be less than 15 seconds.

## **16—Classification Size and Make-Up Torque for Rock Bits**

**16.1** A classification system for designating roller cone rock bits according to the type of bit (steel tooth or insert), the type of formation drilled, and mechanical features of the bit, was developed by a special subcommittee within the International Association of Drilling Contractors (IADC). The system was accepted by IADC in March 1987 and approval by API was proposed by the IADC subcommittee. Following API task group review it was recommended that API accept this system of classification for bit designation. The task group recommendation was adopted by the Committee on Standardization of Drilling and Servicing Equipment and subsequently approved by letter ballot. It was further determined that the approved form be included in API Recommended Practice 7G.

**16.2** Bits may be classified and designated by an alpha-numeric code on the bit carton with a series of three numbers and one letter keyed to the classification system shown in Tables 30 and 31.

**16.3** Series numbers 1, 2, and 3 are reserved for milled tooth bits in the soft, medium, and hard formation categories. Series numbers 4, 5, 6, 7, and 8 are for insert bits in the soft, medium, hard, and extremely hard formations.

**16.4** Type numbers 1 through 4 designate formation hardness subclassification from softest to hardest within each series classification.

**16.5** The seven column listings under the heading, Features, include seven features common to the milled tooth and insert bits of most manufacturers. Columns 8 and 9 have been removed and reserved for future bit development.

**16.6** The form is designed to include only one manufacturer's listing on each sheet, and to allow each specific bit designation in only one classification position. It is recognized, however, that many bits will drill efficiently in a range of types and perhaps in more than one series. Particular attention is therefore invited to the note on the form which contains a statement of this principle. It is the responsibility of the manufacturer and user to determine the range of efficient use in specific instances.

**16.7** In using the form shown in Table 30, in conjunction with Table 31, the manufacturer assigns to each bit design three numbers and one letter that correspond with a specific block on the form. The sequence to be followed is:

First number designates Series.

Second number designates Type.

Third number designates Feature.

Letter designates additional features, as shown in Table 31.

**16.8** Classification forms are available from: International Association of Drilling Contractors (IADC), P.O. Box 4287, Houston, Texas 77210.

**16.9** Recommended torque for roller cone bits is shown in Table 32. Recommended torque for diamond drill bits is shown in Table 33.

**16.10** Common sizes for roller bits are listed in Table 34. Sizes other than those shown may be available in limited cutting structure types.



Table 30—IADC Roller-Bit Classification Chart

Manufacturer _____		Revised: _____								
	Series	Formations	Type	Features						
				Standard-Roller-Bearing-(1)	Roller-Bearing,-Air-Cooled (2)	Roller-Bearing,-Gauge Protected-(3)	Sealed-Roller-Bearing-(4)	Sealed-Roller Bearing,-Gauge Protected (5)	Sealed-Friction-Bearing-(6)	Sealed-Friction Bearing,-Gauge Protected (7)
Milled Tooth-Bits	1	Soft formations with low-compressive strength and high-drillability	1 2 3 4							
	2	Medium to medium hard-formations with high compressive strength	1 2 3 4							
	3	Hard semi-abrasive and abrasive formations	1 2 3 4							
Insert Bits	4	Soft formations with low-compressive strength and high-drillability	1 2 3 4							
	5	Soft to medium formations with low compressive strength	1 2 3 4							
	6	Medium hard formations with high compressive strength	1 2 3 4							
	7	Hard semi-abrasive and abrasive formations	1 2 3 4							
	8	Extremely hard and abrasive formations	1 2 3 4							

Notes:

Bit classifications are general guidelines only. All bit types may drill effectively in formations other than these specified.

**Table 31—IADC Bit Classification Codes—  
Fourth Position**

The following codes are used in the 4th position of the 4-character IADC bit classification code to indicate additional design features:

Code Feature	Code Feature
A—Air application <sup>1</sup>	N
B	O
C—Center Jet	P
D—Deviation Control	Q
E—Extended Jets <sup>2</sup>	R Reinforced Welds <sup>3</sup>
F	S Standard Steel Tooth Model <sup>4</sup>
G—Extra Gauge/Body Protection	T
H	U
I	V
J—Jet Deflection	W
K	X Chisel Inserts
L	Y Conical Insert
M	Z Other Insert Shapes

<sup>1</sup>Journal bearing bits with air circulation nozzles.

<sup>2</sup>Full extension (welded tubes with nozzles). Partial extensions should be noted elsewhere.

<sup>3</sup>For percussion applications.

<sup>4</sup>Milled tooth bits with none of the extra features listed in this table.

As an example, a milled tooth bit designed for the softest series, softest type in that series, with standard gauge, and no extra features, will be designated 1-1-1-S on the bit carton. The manufacturer will also list this bit designation in this block on the form.

Common sizes for fixed cutter bits are listed in Table 35. Sizes other than those shown may be available in limited cutting structure types.

**Table 32—Recommended Make-up Torque Ranges  
for Roller Cone Drill Bits**

Connection	Minimum— Make-up Torque ft-lb	Maximum— Make-up Torque ft-lb
2 <sup>3</sup> / <sub>8</sub> -API REG	3000	3500
2 <sup>7</sup> / <sub>8</sub> -API REG	4500	5500
3 <sup>1</sup> / <sub>2</sub> -API REG	7000	9000
4 <sup>1</sup> / <sub>2</sub> -API REG	12000	16000
6 <sup>5</sup> / <sub>8</sub> -API REG	28000	32000
7 <sup>5</sup> / <sub>8</sub> -API REG	34000	40000
8 <sup>5</sup> / <sub>8</sub> -API REG	40000	60000

Note:

Basis of calculations for recommended make-up torque assumed the use of a thread compound containing 40 to 60 percent by weight of finely powdered metallic zinc or 60 percent by weight of finely powdered metallic lead, with not more than 0.3 percent total active sulfur, applied thoroughly to all threads and shoulders (see the caution regarding the use of hazardous materials in Appendix G of API Specification 7). Due to the irregular geometry of the ID bore in roller cone bits, torque values are based on estimated cross-sectional areas and have been proven by field experience.

**Table 33—Recommended Minimum Make-up Torques for Diamond Drill Bits**

	Connection	Maximum Pin-ID in.	Bit Sub OD in.	Minimum— Make-up Torque ft-lb
00	1-API Reg	0.75	1.56	185
03	1 $\frac{1}{2}$ -API REG	1.00	2.00	665
	2 $\frac{3}{8}$ -API REG	1	3	1791*
			3 $\frac{1}{8}$	2419*
			3 $\frac{1}{4}$	3085*
	2 $\frac{7}{8}$ -API REG	1 $\frac{1}{4}$	3 $\frac{1}{2}$	3073*
			3 $\frac{3}{4}$	4617
			3 $\frac{7}{8}$	4658
	3 $\frac{1}{2}$ -API REG	1 $\frac{1}{2}$	4 $\frac{1}{8}$	5171*
			4 $\frac{1}{4}$	6306*
			4 $\frac{1}{2}$	7660
	4 $\frac{1}{2}$ -API REG	2 $\frac{1}{4}$	5 $\frac{1}{2}$	12451*
			5 $\frac{3}{4}$	16476*
			6	17551
			6 $\frac{1}{4}$	17757
	6 $\frac{5}{8}$ -API REG	3 $\frac{1}{4}$	7 $\frac{1}{2}$	37100*
			7 $\frac{3}{4}$	37857
			8	38193
			8 $\frac{1}{4}$	38527
	7 $\frac{5}{8}$ -API REG	3 $\frac{3}{4}$	8 $\frac{1}{2}$	48296*
			8 $\frac{3}{4}$	57704*
			9	59966
			9 $\frac{1}{4}$	60430
			9 $\frac{1}{2}$	60895

\*Note:

Torque figures followed by an asterisk indicate that the weaker member for the corresponding outside diameter (OD) and bore is the BOX. For all other torque values the weaker member is the PIN.

Basis of calculations for recommended make-up torque assumed the use of a thread compound containing 40 to 60 percent by weight of finely powdered metallic zinc or 60 percent by weight of finely powdered metallic lead, with not more than 0.3 percent total active sulfur, applied thoroughly to all threads and shoulders (reference the *CAUTION* regarding the use of hazardous materials in Appendix G of API Specification 7) and using the modified

**Table 34—Common Roller Bit Sizes**

Size of Bit, in.	Size of Bit, in.
3 $\frac{3}{4}$	9 $\frac{1}{2}$
3 $\frac{1}{8}$	9 $\frac{1}{8}$
4 $\frac{3}{4}$	10 $\frac{5}{8}$
5 $\frac{7}{8}$	11
6	12 $\frac{1}{4}$
6 $\frac{1}{8}$	13 $\frac{1}{2}$
6 $\frac{1}{4}$	14 $\frac{3}{4}$
6 $\frac{1}{2}$	16
6 $\frac{3}{4}$	17 $\frac{1}{2}$
7 $\frac{7}{8}$	20
8 $\frac{3}{8}$	22
8 $\frac{1}{2}$	24
8 $\frac{3}{4}$	26

**Table 35—Common Fixed Cutter Bit Sizes**

Size of Bit, in.	Size of Bit, in.
3 $\frac{7}{8}$	8 $\frac{1}{2}$
4 $\frac{1}{2}$	8 $\frac{3}{4}$
4 $\frac{3}{4}$	9 $\frac{1}{2}$
5 $\frac{1}{8}$	9 $\frac{7}{8}$
6	10 $\frac{5}{8}$
6 $\frac{1}{8}$	12 $\frac{1}{4}$
6 $\frac{1}{4}$	14 $\frac{3}{4}$
6 $\frac{1}{2}$	16
6 $\frac{3}{4}$	17 $\frac{1}{2}$
7 $\frac{1}{8}$	

03 | Screw Jack formula in A.9 and a unit stress of 50,000 psi in the box or pin, whichever is weaker.

Normal torque range is tabulated value plus 10 percent. Higher torque values may be used under extreme conditions.

*Committee Review Only*

## APPENDIX A—STRENGTH AND DESIGN FORMULAS

### A.1 Torsional Strength of Eccentrically Worn Drill Pipe

Assume 1: Eccentric hollow circular section (see Figure A-1).  
Reference: *Formulas for Stress & Strain*, Roark, 3rd Edition.

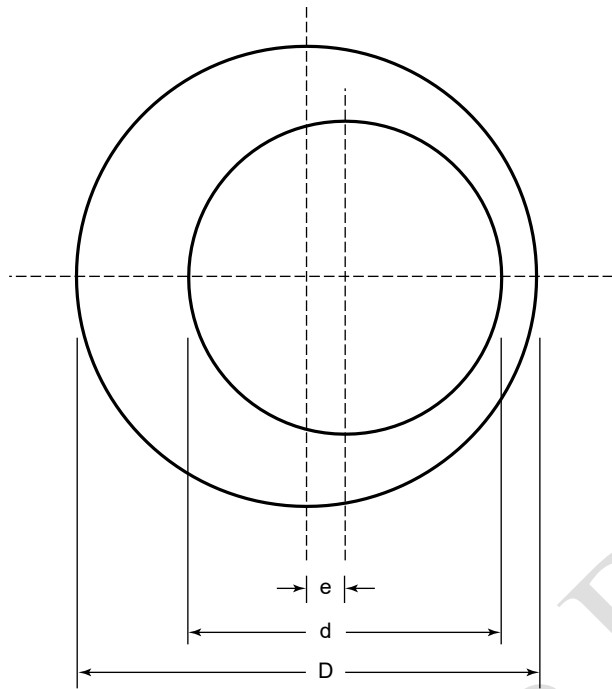


Figure A-1—Eccentric Hollow Section of Drill Pipe

$$T = \frac{\rho S_s (D^4 - d^4)}{12 \xi 16 \xi D \xi F}, \quad (\text{A.1})$$

where

$$F = 1 + \frac{4N^2 \chi \pi}{(1 - N^2)} + \frac{32N^2 \chi \pi^2}{(1 - N^2)(1 - N^4)} + \frac{48N^2 (1 + 2N^2 + 3N^4 + 2N^6)^3}{(1 - N^2)(1 - N^4)(1 - N^6)} \chi \pi,$$

$$N = d/D,$$

$$\chi \pi = \frac{e}{D},$$

$T$  = torque, ft-lbs.,

$S_s$  = minimum shear strength, psi,

$D$  = outside diameter, in.,

$d$  = inside diameter, in.

Assume 2: The internal diameter,  $d$ , remains constant and at the nominal ID of the pipe throughout its life.

Assume 3: The external diameter  $D$  is  $d + t$  nominal  $+ t$  minimum; i.e., all wear occurs on one side. This diameter is not the same as diameter for uniform wear.

Note: Torsional yield strengths for Premium Class, Table 4, and Class 2, Table 6 were calculated from Equation A.1, using the assumption that wear is uniform on the external surface.

### A.2 Safety Factors

Values for various performance properties of drill pipe are given in Tables 2 through 7. The values shown are minimum values and do not include factors of safety. In the design of drill pipe strings, factors of safety should be used as are considered necessary for the particular application.

### A.3 Collapse Pressure for Drill Pipe

Note: See API Bulletin 5C3 for derivation of equations in A.3.

The minimum collapse pressures given in Tables 3, 5, and 7 are calculated values determined from equations in API Bulletin 5C3. Equations A.2 through A.5 are simplified equations that yield similar results. The  $D/t$  ratio determines the applicable formula, since each formula is based on a specific  $D/t$  ratio range.

For minimum collapse failure in the plastic range with minimum yield stress limitations: the external pressure that generates minimum yield stress on the inside wall of a tube.

$$P_c = 2Y_m \left[ \frac{(D/t) - 1}{(D/t)} \right] \quad (\text{A.2})$$

Applicable  $D/t$  ratios for application of Equation A.2 are as follows:

Grade	$D/t$ Ratio
E75	13.60 and less
X95	12.85 and less
G105	12.57 and less
S135	11.92 and less

For minimum collapse failure in the plastic range:

$$P_c = Y_m \left[ \left( \frac{A'}{D/t} - B' \right) - C \right] \quad (\text{A.3})$$

Factors and applicable  $D/t$  ratios for application of Equation A.3 are as follows:

Grade	Formula Factors			$D/t$ Ratio
	A'	B'	C	
E75	3.054	0.0642	1806	13.60 to 22.91
X95	3.124	0.0743	2404	12.85 to 21.33
G105	3.162	0.0794	2702	12.57 to 20.70
S135	3.278	0.0946	3601	11.92 to 19.18

For minimum collapse failure in conversion or transition zone between elastic and plastic range:

$$P_c = Y_m \left[ \frac{A}{D/t} B \right] \quad (\text{A.4})$$

Factors and applicable  $D/t$  ratios for application of Equation A.4 are as follows:

Grade	Formula Factors		$D/t$ Ratio
	A	B	
E75	1.990	0.0418	22.91 to 32.05
X95	2.029	0.0482	21.33 to 28.36
G105	2.053	0.0515	20.70 to 26.89
S135	2.133	0.0615	19.18 to 23.44

For minimum collapse failure in the elastic range:

$$P_c = \frac{46.95 \times 10^6}{(D/t)[(D/t) - 1]^2} \quad (\text{A.5})$$

Applicable  $D/t$  ratios for application of Equation A.5 are as follows:

Grade	$D/t$ Ratio
E75	32.05 and greater
X95	28.36 and greater
G105	26.89 and greater
S135	23.44 and greater

where

$P_c$  = minimum collapse pressure, psi,

\* $D$  = nominal outside diameter, in.,

\* $t$  = nominal wall thickness, in.,

$Y_m$  = material minimum yield strength, psi.

Notes:

\*Collapse pressures for used drill pipe are determined by adjusting the nominal outside diameter,  $D$ , and wall thickness,  $t$ , as if the wear is uniform on the outside of the pipe body and the inside diameter remains constant. Values of  $D$  and  $t$  for each class of used drill pipe follow. These values are to be used in applicable Equation A.2, A.3, A.4, or A.5, depending on the  $D/t$  ratio, to determine collapse pressure.

Premium Class:  $t = (0.80)$  (nominal wall),  $D = \text{nominal OD} - (0.40)$  (nominal wall)

Class 2:  $t = (0.70)$  (nominal wall),  $D = \text{nominal OD} - (0.60)$  (nominal wall)

## A.4 Free Length of Stuck Pipe

98 The relation between differential stretch and free length of a stuck string of steel pipe due to a differential pull is:

$$L_1 = \frac{E \xi e \xi W_{dp}}{40.8 P}, \quad (\text{A.6})$$

where

$L_1$  = length of free drill pipe, ft.,

$E$  = modulus of elasticity, lb/in.<sup>2</sup>,

$e$  = differential stretch, in.,

$W_{dp}$  = weight per foot of pipe, lbs/ft.,

$P$  = differential pull, lbs.

Where  $E = 30 \times 10^6$ , this formula becomes:

$$L_1 = \frac{735,294 \xi e \xi W_{dp}}{P} \quad (\text{A.7})$$

## A.5 Internal Pressure

### A.5.1 DRILL PIPE

$$P_i = \frac{2 Y_m t}{D}, \quad (\text{A.8})$$

where

$P_i$  = internal pressure, psi,

$Y_m$  = material minimum yield strength, psi,

$t$  = remaining wall thickness of tube, in.,

$D$  = nominal outside diameter of tube, in.

Notes:

1. Internal pressures for new drill pipe in Table 3 were determined by using the nominal wall thickness for  $t$  in the above equation and multiplying by the factor 0.875 due to permissible wall thickness tolerance of minus 12½ percent.
2. Internal pressures for used drill pipe were determined by adjusting the nominal wall thickness according to footnotes below Table 5 and 7 and using the nominal outside diameter, in the above Equation A.8.

### A.5.2 KELLYS

$$P_i = \frac{Y_m [D_{FL}^2 - (D_{FL} - 2t)^2]}{\sqrt{3(D_{FL})^4 + (D_{FL} - 2t)^4}}, \quad (\text{A.9})$$

where

$P_i$  = internal pressure, psi,

$Y_m$  = material minimum yield strength, psi,

$D_{FL}$  = distance across drive section flats, in.,

$t$  = minimum wall, in.

Note: The dimension  $t$  is the minimum wall thickness of the drive section and must be determined in each case through the use of an ultrasonic thickness gauge or similar device.

## A.6 Stretch of Suspended Drill Pipe

When pipe is freely suspended in a fluid, the stretch due to its own weight is:

$$e = \frac{L_1^2}{24E} [W_a - 2W_f(1 - \mu)] \quad (\text{A.10})$$

where

$e$  = stretch, in.,

$L_1$  = length of free drill pipe, ft.,

$E$  = modulus of elasticity, psi,  
 $W_a$  = weight of pipe material, lb/cu ft.,  
 $W_f$  = weight of fluid, lb/cu ft.,  
 $\mu$  = Poisson's ratio.

00

For steel pipe where  $W_s = 489.5$  lb/cu ft,  $E = 30 \times 10^6$  psi and  $\mu = 0.28$ , this formula will be:

$$e = \frac{L_1^2}{72 \times 10^7} [489.5 - 1.44W_f], \quad (\text{A.11})$$

or

$$e = \frac{L_1^2}{9.625 \times 10^7} [65.44 - 1.44W_g], \quad (\text{A.12})$$

where

$W_f$  = weight of fluid, lb/cu ft.,  
 $W_g$  = weight of fluid, lb/gal.

### 03 | A.7 Tensile Strength of Drill Pipe Body

$$P = Y_m A, \quad (\text{A.13})$$

where

$P$  = minimum tensile strength, lbs.,  
 $Y_m$  = material minimum yield strength, psi,  
 $A$  = cross-section area, sq. in. (Table 1, Column 6, for drill pipe).

### A.8 Torsional Yield Strength of Drill Pipe Body

#### A.8.1 PURE TORSION

$$Q = \frac{0.096167 J Y_m}{D}, \quad (\text{A.14})$$

where

$Q$  = minimum torsional yield strength, ft lb.,  
 $Y_m$  = material minimum yield strength, psi,  
 $J$  = polar moment of inertia  
 $= \frac{\pi}{32} (D^4 - d^4)$  for tubes  
 $= 0.098175 (D^4 - d^4)$ ,  
 $D$  = outside diameter, in.,  
 $d$  = inside diameter, in.

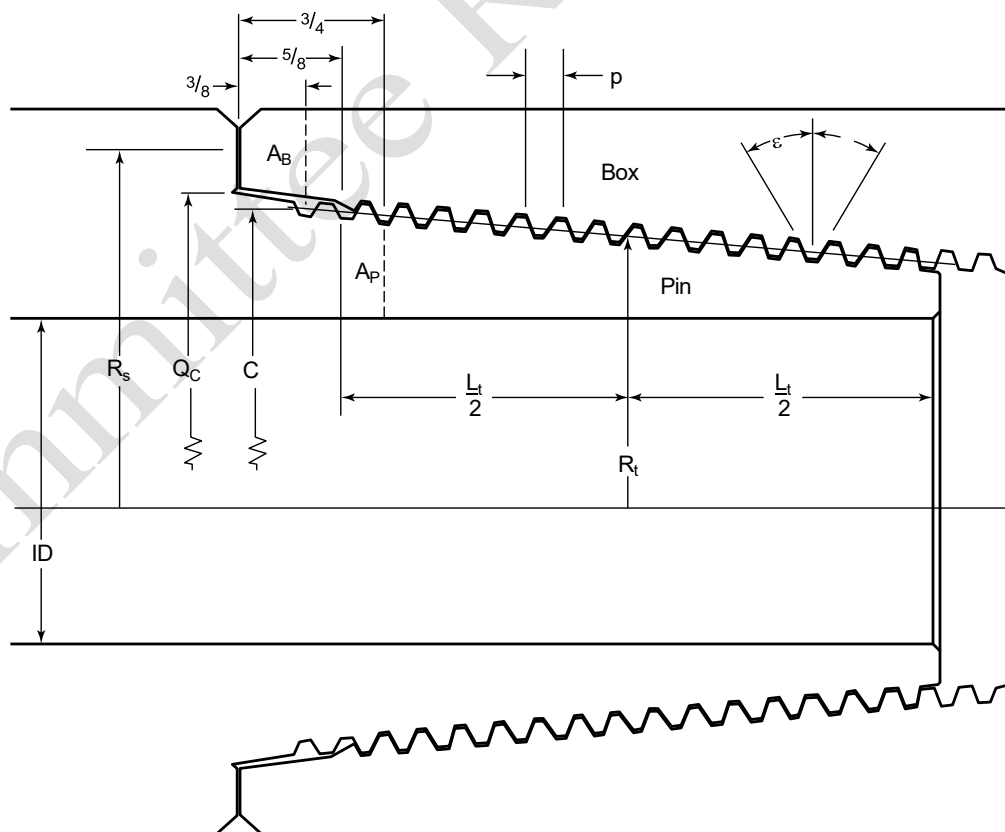


Figure A-2—Rotary Shouldered Connection

## A.8.2 TORSION AND TENSION

$$Q = \frac{0.096167J}{D} \sqrt{Y_m^2 - \frac{P^2}{A^2}} \quad (\text{A.15})$$

where

$Q_T$  = minimum torsional yield strength under tension, ft-lb.,

$J$  = polar moment of inertia

$$= \frac{\pi}{32} (D^4 - d^4) \text{ for tubes}$$

$$= 0.098175 (D^4 - d^4);$$

$D$  = outside diameter, in.,

$d$  = inside diameter, in.,

$Y_m$  = material minimum yield strength, psi,

$P$  = total load in tension, lbs.,

$A$  = cross section area, sq. in.

## A.9 Torque Calculations for Rotary Shouldered Connections (see Table A-1 and Figure A-2)

### A.9.1 TORQUE TO YIELD A ROTARY SHOULDERED CONNECTION

$$T_y = \frac{Y_m A_p p R_f}{12 \pi \cos 8} + R_s f \quad (\text{A.16})$$

where

$T_y$  = turning moment or torque required to yield, ft-lbs.,

$Y_m$  = material minimum yield strength, psi,

$p$  = lead of thread, in.,

$f$  = coefficient of friction on mating surfaces, threads and shoulders, assumed 0.08 for thread compounds containing 40 to 60 percent by weight of finely powdered metallic zinc. (Reference the caution regarding the use of hazardous materials in Appendix G of Specification 7.);

$8$  =  $\frac{1}{2}$  included angle of thread (Figures 21 or 22, Specification 7), degrees;

$$R_f = \frac{C + [C - (L - .625) \xi tpr \xi \frac{1}{12}]}{4}$$

$L_{p\pi}$  = length of pin (Specification 7, Table 25, Column 9), in.,

$$R_s = \frac{1}{4} (OD + Q_c), \text{ in.}$$

The maximum value of  $R_s$  is limited to the value obtained from the calculated OD where  $A_p = A_b$ ,

$A$  = cross section area  $A_b$  or  $A_p$  whichever is smaller, sq. in.

where

$$A_p = \frac{\pi}{4} (C - B)^2 - ID^2 \text{ without relief grooves,}$$

or

$$A_p = \frac{\pi}{4} (D^2 - ID^2) \text{ with relief grooves,}$$

where

$D_{RG}$  = diameter of relief groove (Specification 7, Table 16, Column 5), in.,

$C$  = pitch diameter of thread at gauge point (Specification 7, Table 25, Column 5), in.,

$ID$  = inside diameter, in.,

$$B = \frac{1}{2} \left( \frac{H}{S_{rs} + tpr \times \frac{1}{8} \times \frac{1}{125}} \right)$$

$H$  = thread height not truncated (Specification 7, Table 26, Column 3), in.,

$S_{rs}$  = root truncation (Specification 7, Table 26, Column 5), in.,

$tpr$  = taper (Specification 7, Table 25, Column 4), in./ft.,

$$A_b = \frac{\pi}{4} (OD^2 - (Q_c - E)^2),$$

where

$OD$  = outside diameter, in.,

$Q_c$  = box counterbore (Specification 7, Table 25, Column 11), in.,

$$E = tpr \times \frac{1}{8} \times \frac{1}{125}$$

### A.9.2 MAKE-UP TORQUE FOR ROTARY SHOULDERED CONNECTIONS

$$T = \frac{SA(p + R_f)}{12 \pi \cos 8} + R_s f \quad (\text{A.17})$$

where

$A$  =  $A_b$  or  $A_p$  whichever is smaller;  $A_p$  shall be based on pin connections without relief grooves, sq. in.,

$S$  = recommended make-up stress level, psi.

Note: For values of  $S$ , see 4.8.1 for Tool Joints and 5.2 for Drill Collars.

## A.10 Combined Torsion and Tension to Yield Rotary Shouldered Connection and Drill Pipe Body

### A.10.1 INTRODUCTION

Field operating practice should always maintain operating torque below the make-up torque. Since there is no margin of safety applied in these curves, the actual dimensions of the tool joint and tube (inspection classification) must be used in the construction of the curve. Always be aware of the operating limits of the pipe in combination with the tool joint.



### A.10.2 DRILL PIPE SELECTION AND NORMAL OPERATIONS (SEE FIGURE A-3a)

At torque levels up to the make-up torque of the tool joint, the Make-up Torque THEN Tension curves are used to determine the capacity. These curves are used when the maximum torque a connection will experience is the torque applied before tension is applied. The torque value used in this set of curves is the make-up torque or the applied torque, whichever is greater.

### A.10.3 SPECIAL OPERATIONS (SEE FIGURE A-3b)

For operations where the applied downhole torque to the drill string might exceed the tool joint make-up torque (fishing, back reaming, etc.), use the Tension THEN Torque

curves. In these cases, the horizontal axis will represent the torque applied after tension is applied.

**CAUTION:** The dynamic loads considered in this simplified approach are different than static loads. API recommends staying in safe zone of operations. Going outside this zone or getting close to the boundaries can result in a catastrophic failure.

### A.10.4 EQUATION DEFINITIONS

The variables used in the equations below are defined in A.9.1.

$$P1 = Y_m A_p \quad (A.18)$$

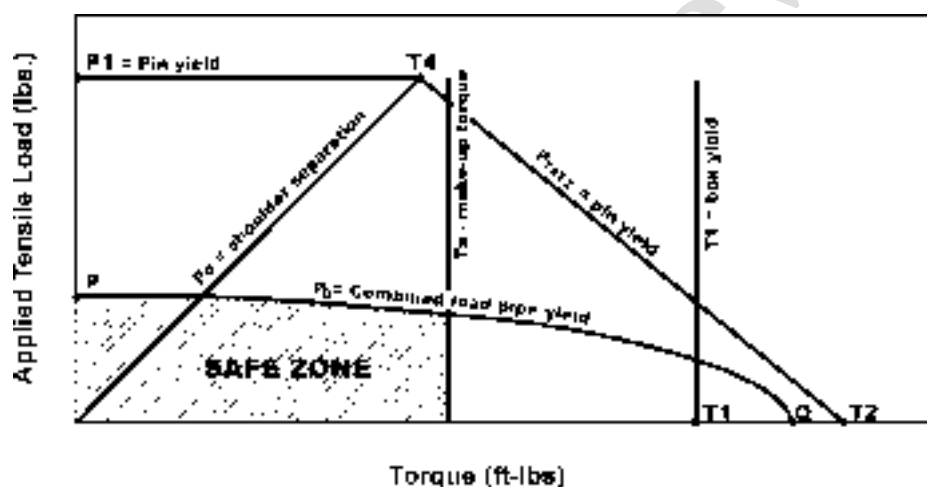


Figure A-3a—Make-up Torque Then Tension

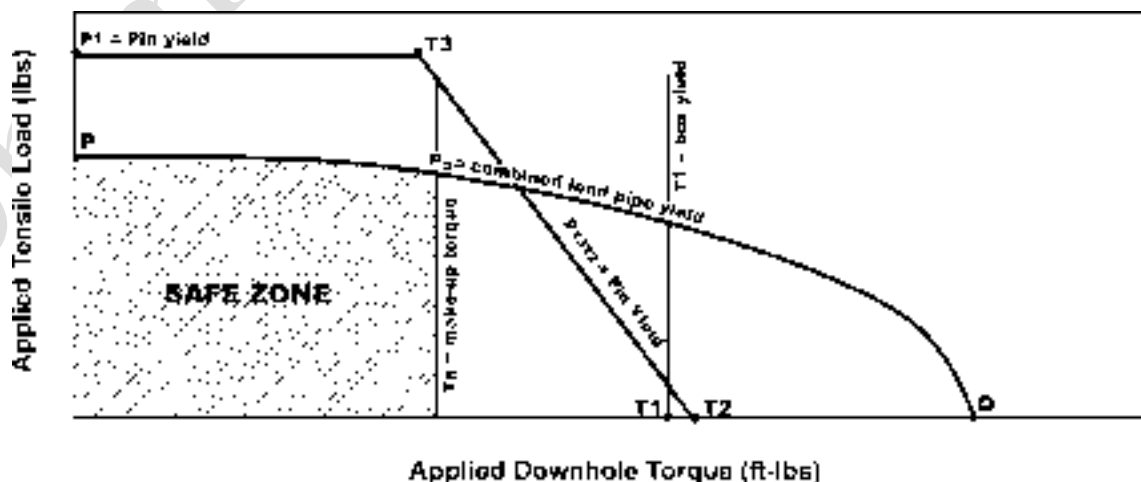


Figure A-3b—Tension Then Torque

$$P_o = \frac{12(A_b + A_p)T_a}{A \left( \frac{p}{2v} + \frac{R_t f}{\cos \delta} + R_s f \right)} \quad (\text{A.19})$$

$$P_{T4T2} = (A_b + A_p) \left[ \frac{Y_m}{12} \left( \frac{p}{2v} + \frac{R_t f}{\cos \delta} + R_s f \right) - \frac{T_{4T2}}{A \left( \frac{p}{2v} + \frac{R_t f}{\cos \delta} + R_s f \right)} \right] \quad (\text{A.20})$$

$$P_{T3T2} = \frac{\frac{Y_m}{12} \left( \frac{p}{2v} + \frac{R_t f}{\cos \delta} + R_s f \right) - 12T_{DH}}{R_s f} \quad (\text{A.21})$$

$$T1 = \left( \frac{Y_m}{12} \right) \left[ A_b \left( \frac{p}{2v} + \frac{R_t f}{\cos \delta} + R_s f \right) \right] \quad (\text{A.22})$$

$$T2 = \left( \frac{Y_m}{12} \right) \left[ A_p \left( \frac{p}{2v} + \frac{R_t f}{\cos \delta} + R_s f \right) \right] \quad (\text{A.23})$$

$$T3 = \left( \frac{Y_m}{12} \right) \left[ A_p \left( \frac{p}{2v} + \frac{R_t f}{\cos \delta} \right) \right] \quad (\text{A.24})$$

$$T4 = \left( \frac{Y_m}{12} \right) \left[ \left( \frac{A_p A_b}{A_p + A_b} \right) \left( \frac{p}{2v} + \frac{R_t f}{\cos \delta} + R_s f \right) \right] \quad (\text{A.25})$$

$$P_Q = A \sqrt{Y_m^2 - \left( \frac{QD}{0.096167 \bullet J} \right)^2} \quad (\text{A.26})$$

A description of the values calculated above and those used to plot the curves are:

$T_a$  = torque that is applied to the tool joint before tension is applied, make-up torque, ft-lbs

$T_{DH}$  = applied downhole torque, ft-lbs

$P1$  = yield strength of the tool joint pin at  $\frac{5}{8}$ " from the make-up shoulder, lbs

$P_o$  = tension required to separate the tool joint shoulders after  $T_a$  is applied, lbs.  $P_o$  is represented by the line from the origin to the point  $T4$ . Do not use this formula if  $T_a$  is greater than  $T4$  since  $P_o$  will be greater than  $P1$

$P_{T4T2}$  = tension required to yield pin after  $T_a$  is applied, lbs.  $P_{T4T2}$  is represented by the line from  $T4$  to  $T2$

$P_{T3T2}$  = tension required to yield pin after  $T_{DH}$  is applied, lbs.  $P_{T3T2}$  is represented by the line from  $T3$  to  $T2$

$T1$  = torsional strength of the box of the tool joint and is represented by a vertical line at that value on the x-axis, ft-lbs

$T2$  = torsional strength of the pin of the tool joint, ft-lbs  
 $T3$  = torsional load required to produce additional make-

up of the connection when the shoulders are separated by an external tensile load on the pipe that produces yield stress in the tool joint pin, ft-lbs

$T4$  = make-up torque at which pin yield and shoulder separation occur simultaneously with an externally applied tensile load, ft-lbs

$p$  = yield of the drill pipe tube in the presence of torsion represented by the elliptical curve, lbs. Equation was produced by rearranging Equation A.15

### A.10.5 FAILURE MODES

The failure modes under combined torsion/tension loads are:

1. Pin yield.
2. Box yield.
3. Shoulder separation (seal failure).
4. Tube yield.

### A.10.6 USING THE CURVES

Calculate the above values using the actual dimensions of the tool joints and tube. Use these values to plot a working curve.

#### Example 1: Drilling an Extended Reach Well (See Figure A.3c)

Assume:

Anticipated Maximum Drilling Torque = 25,000 ft-lbs

Drill Pipe string is 5", 19.50 ppf, Grade S, Premium Class with NC50 tool joints (6 $\frac{5}{16}$ " OD  $\times$  2 $\frac{3}{4}$ " ID)

Calculated values:

$P$  = 560,764 lbs

$Q$  = 58,113 ft-lbs

$T_a$  (make-up torque) = 28,381 ft-lbs

$P1$  = 1,532,498 lbs

$T1$  = 47,302 ft-lbs

$T2$  = 62,608 ft-lbs

$T4$  = 26,945 ft-lbs

Questions

Is the drill pipe string adequate for the anticipated torque? {{Yes}}

What is the allowable hook load at anticipated maximum drilling torque? {{ $P$  = 504,772 lbs at 25,000 ft-lbs}}

#### Example 2: Fishing Drill Pipe String in Example 1 (See Figure A.3c)

Question:

What is the maximum pull without exceeding yield strength in the absence of torque? {{With a straight pull and no torque, the maximum pull is the tensile capacity of the tube which is  $P$  = 560,764 lbs.}}

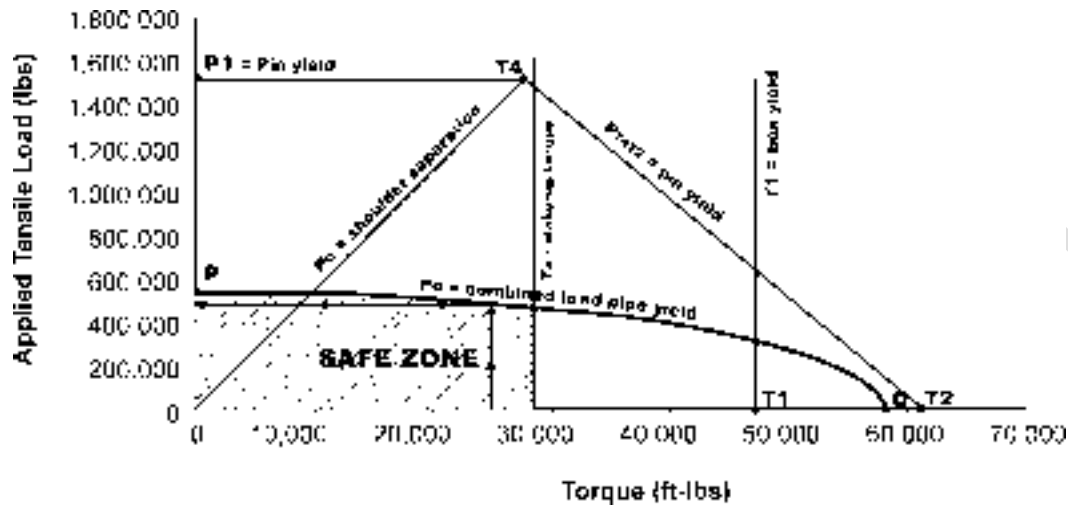


Figure A-3c—Make-up Torque Then Tension

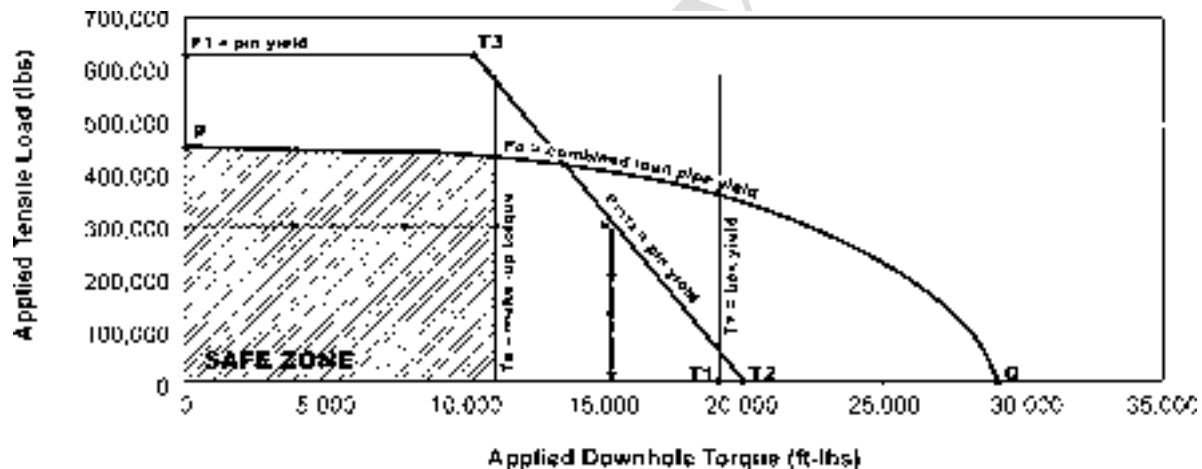


Figure A-3d—Tension Then Torque

### Example 3: Back-reaming Hole with Drill Pipe Stinger (See Figure A.3d)

Assume:

Back-reaming Pull = 300,000 lbs

Drill pipe stinger is 3½", 15.50 ppf, Grade S, Premium Class with NC38 tool joints (4¾" OD & 2⅞" ID)

Calculated values:

$P = 451,115$  lbs

$Q = 29,063$  ft-lbs

Make-up Torque = 11,504 ft-lbs

$P_1 = 634,795$  lbs

$T_1 = 19,174$  ft-lbs

$T_2 = 20,062$  ft-lbs

$T_3 = 10,722$  ft-lbs

Question:

What is yield torque if back-reaming pull is 300,000 lbs?  
( $T_{DH} = 15,648$  ft-lbs)

**CAUTION:** If a back-reaming pull of 300,000 lbs has a torque exceeding make-up torque (11,054 ft-lbs), the chance of pin failure increases as you approach  $P_{T,T2}$ . Always use a safety factor.

**A.10.7 CAUTION:** The loads considered in this simplified approach are torsion and tension. These curves are approximations that do not consider the effects of internal pressure or bending. For this reason, the answers from these curves should be derated. A safety factor of one was used.

## A.11 Drill Collar Bending Strength Ratio

The bending strength ratios in Figures 26 through 32 were determined by application of Equation A.27. The effect of stress-relief features was disregarded.

$$BSR = \frac{Z_B}{Z_P} = \frac{0.098 \frac{(OD^4 - b^4)}{OD}}{0.098 \frac{(R^4 - ID^4)}{R}} \quad (A.27)$$

$$= \frac{OD^4 - b^4}{\frac{R^4 - ID^4}{R}}$$

where

$BSR$  = bending strength ratio,  
 $Z_B$  = box section modulus, cu. in.,  
 $Z_P$  = pin section modulus, cu. in.,  
 $OD$  = outside diameter of pin and box (Figure A-4), in.,  
 $ID$  = inside diameter or bore (Figure A-4), in.,  
 $b$  = thread root diameter of box threads at end of pin (Figure A-4), in.,  
 $R$  = thread root diameter of pin threads  $3/4$  inch from shoulder of pin (Figure A-4), in.

To use Equation A.27, first calculate:

$Dedendum$ ,  $b$ , and  $R$

$$Dedendum = \frac{H}{2} - f_{rm} \quad (A.28)$$

where

$H$  = thread height not truncated, in.,  
 $f_{rm}$  = root truncation, in.

$$b = C \frac{tpr(L_{pe} - 0.625)}{12} + (2 \xi Dedendum) \quad (A.29)$$

where

$C$  = pitch diameter at gauge point, in.,  
 $tpr$  = taper, in./ft.

$$R = C - (2 \times dedendum) - (tpr \times \xi^{-1/8} \times \xi^{-1/12}) \quad (A.30)$$

An example of the use of Equation A.27 in determining the bending strength of a typical drill collar connection is as follows:

Determine the bending strength ratio of drill collar NC46-62 ( $6^{1/4}$ -OD  $\times$   $2^{13/16}$ -ID) connection.

$D = 6.25$  (Specification 7, Table 13, Column 2),

$d = 2^{13/16} = 2.8125$  (Specification 7, Table 13, Column 3),

$C = 4.626$  (Specification 7, Table 25, Column 5),

$Taper = 2$  (Specification 7, Table 25, Column 4),

$L_{pe} = 4.5$  (Specification 7, Table 25, Column 9),

$H = 0.216005$  (Specification 7, Table 26, Column 3),

$f_{rm} = 0.038000$  (Specification 7, Table 26, Column 5).

First calculate dedendum,  $b$ , and  $R$

$$Dedendum = \frac{H}{2} - f_{rm} = \frac{.216005}{2} - .038000 = .0700025$$

$$b = C \frac{tpr(L_{pe} - 0.625)}{12} + (2 \xi Dedendum)$$

$$b = 4.626 \frac{2(4.5 - .625)}{12} + (2 \xi .0700025)$$

$$b = 4.120,$$

$$R = C - (2 \times dedendum) - (tpr \xi^{-1/8} \xi^{-1/12})$$

$$R = 4.626 - (2 \times .0700025) - (2 \xi^{-1/8} \xi^{-1/12})$$

$$R = 4.465.$$

Substituting these values in Equation A.27 determines the bending strength ratio as follows:

$$BSR (NC46-62) = \frac{OD^4 - b^4}{\frac{R^4 - ID^4}{R}} = \frac{(6.25)^4 - (4.120)^4}{\frac{(4.465)^4 - (2.8125)^4}{4.465}} = 2.64:1$$

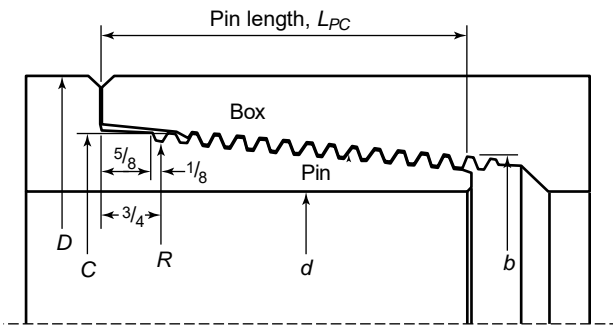


Figure A-4—Rotary Shouldered Connection Location of Dimensions for Bending Strength Ratio Calculations

### A.12 Torsional Yield Strength of Kelly Drive Section

The torsional yield strength of the kelly drive section values listed in Tables 15 and 17 were derived from the following equation:

$$Y = \frac{0.577Y_m [0.200(a^3 - b^3)]}{12}$$

where

$Y_m$  = tensile yield, psi;

$a$  = distance across flats, in.;

$b$  = kelly bore, in.

### A.13 Bending Strength, Kelly Drive Section

The yield in bending values of the kelly drive section listed in Tables 15 and 17 were determined by one of the following equations:

a. Yield in bending through corners of the square drive section,  $Y_{BC}$ , ft-lb:

$$Y_{BC} = \frac{Y_m (0.118a^4 - 0.069b^4)}{12a}$$

b. Yield in bending through the faces of the hexagonal drive section  $Y_{BF}$ , ft-lb:

$$Y_{BF} = \frac{Y_m (0.104a^4 - 0.085b^4)}{12a}$$

### A.14 Approximate Weight of Tool Joint Plus Drill Pipe

Approximate Weight of Tool Joint Plus Drill Pipe Assembly, lb/ft =

$$\frac{(\text{Approximate Adjusted Weight of Drill Pipe} \times 29.4) + (\text{Approximate Weight of Tool Joint})}{\text{Tool Joint Adjusted Length} + 29.4}$$

(A.31)

where

Approximate Adjusted Weight of Drill Pipe, lb/ft =

$$\frac{\text{Plain End Weight} + \text{Upset Weight}}{29.4}$$

(A.32)

Plain end weight and upset weight are found in API Specification 5D.

Approximate Weight of Tool Joint, lbs =

$$0.222 L(D^2 - d^2) + 0.167 (D^3 - D_{TE}^3) - 0.501 d^2 (D - D_{TE})$$

(A.33)

Dimensions for  $L$ ,  $D$ ,  $d$ , and  $D_{TE}$  are in API Specification 7, Figure 6 and Table 7.

Adjusted Length of Tool Joint, ft =

$$\frac{L + 2.253 (D - D_{TE})}{12}$$

(A.34)

### A.15 Critical Buckling Force for Curved Boreholes<sup>27,29,30,31,32</sup>

**A.15.1** The following equations define the range of hole curvatures that buckle pipe in a three dimensionally curved borehole. The pipe buckles whenever the hole curvature is between the minimum and maximum curvatures defined by the equations.

$$\text{if } F_b < \frac{4 \xi E \xi I}{12 \xi h_c \xi R_L} \text{ pipe not buckled,}$$

$$\text{if } F_b \geq \frac{4 \xi E \xi I}{12 \xi h_c \xi R_L},$$

$$W_{eq} = \frac{12 \xi h_c \xi F_b^2}{4 \xi E \xi I},$$

$$B_{Vmin} = \frac{-5730}{F_b} \left[ \left( W_{eq}^2 - \frac{(F_b)^{2.1/2}}{R_L} \right) + W_m \xi \sin 8 \right],$$

$$B_{Vmax} = \frac{5730}{F_b} \left[ \left( W_{eq}^2 - \frac{(F_b)^{2.1/2}}{R_L} \right) - W_m \xi \sin 8 \right],$$

where

$F_b$  = critical buckling force (+ compressive) (lb),

$B_{Vmin}$  = minimum vertical curvature rate to cause buckling (+ building, - dropping) ( $^{\circ}/100$  ft),

$B_{Vmax}$  = maximum vertical curvature rate that buckles pipe (+ building, - dropping) ( $^{\circ}/100$  ft),

$W_{eq}$  = equivalent pipe weight required to buckle pipe at  $F_b$  axial load,

$E = 29.6 \times 10^6$  psi,

$$I = \frac{0.7854(OD^4 - ID^4)}{16},$$

$$W_m = W_a \left( \frac{65.5 - MW}{65.5} \right) \text{ buoyant weight of pipe (lb/ft),}$$

$W_a$  = actual weight in air (lb/ft),

$MW$  = mud density (lb/gal),

$$h_c = \left( \frac{D_H - TJOD}{2} \right) \text{ radial clearance of tool joint to hole (in.),}$$

$D_H$  = diameter of hole (in.),

$TJOD$  = OD tool joints (in.),

$$B_L = \sqrt{B_T^2 - B_V^2} \text{ lateral curvature rate } (^{\circ}/100 \text{ ft}),$$

$B_T$  = total curvature rate ( $^{\circ}/100$  ft),

$$R_L = \frac{5730}{B_L} \text{ lateral build radius (ft),}$$

$8$  = inclination angle (deg).

**A.15.2** If the hole curvature is limited to the vertical plane, the buckling equations simplify to the following:

$$W_{eq} = \frac{12 \xi h_c \xi F^2}{4 \xi E \xi I},$$

$$B_{Vmin} = \frac{5730 \xi (W_{eq} + W_m \xi \sin 8)}{F_b},$$

$$B_{Vmax} = \frac{5730 \xi (W_{eq} - W_m \xi \sin 8)}{F_b},$$

where

$B_{Vmin}$  = minimum vertical curvature rate for buckling (+ building, - dropping) ( $^{\circ}/100$  ft),

$B_{Vmax}$  = maximum vertical curvature rate for buckling (+ building, - dropping) ( $^{\circ}/100$  ft),

$F_b$  = buckling force (lb),

$E = 29.6 \times 10^6$  (psi),

$$I = \frac{\pi}{64} (OD^4 - ID^4),$$

$W_{eq}$  = buoyant weight equivalent for pipe in curved borehole (lb/ft),

$$W_m = W_a \left( \frac{65.5 - MW}{65.5} \right) \text{ buoyant weight of pipe (lb/ft),}$$

$W_a$  = actual weight of pipe in air (lb/ft),

$MW$  = mud density (lb/gal),

$$h_c = \left( \frac{DH - TJOD}{2} \right) \text{ radial clearance of tool joint to hole (in.),}$$

$DH$  = diameter of hole (in.),

$TJOD$  = OD of tool joint (in.),

$8$  = inclination angle (deg).

**A.15.3** Figures A-5 and A-6 show the effect of hole curvature on the buckling force for 5-inch and 3 1/2-inch drillpipe. Figure A-7 shows the effect of lateral curvatures on the buckling force of 5-inch drillpipe. For lateral and upward curvatures, the critical buckling force increases with the total curvature rate.

## A.16 Bending Stresses on Compressively Loaded Drillpipe in Curved Boreholes<sup>33,34</sup>

**A.16.1** The type of loading can be determined by comparing the actual hole curvature to calculated values of the critical curvatures that define the transition from no pipe body contact to point contact and from point contact to wrap contact. The two critical curvatures are computed from the following equations.

$$B_c = \frac{57.3 \xi 100 \xi 12 \xi \iota D}{J \xi L \left[ \tan \left( \frac{57.3 \xi L}{4 \xi J} \right) - \frac{L}{4 \xi J} \right]},$$

where

$B_c$  = the critical hole curvature that defines the transition from no pipe body contact to point contact ( $^{\circ}/100$  ft),

$\iota D = (TJOD - OD)$ ,

$TJOD$  = tool joint OD (in.),

$OD$  = pipe body OD (in.),

$$J = \left( \frac{E \xi I}{F} \right)^{1/2} \text{ (in.),}$$

$L$  = length of one joint of pipe (in.),

$E$  = Young's modulus  $30 \times 10^6$  for steel (psi),

$I$  = moment of inertia of pipe body (in.)

$$= \frac{\pi \xi (OD^4 - ID^4)}{64},$$

$F$  = axial compressive load on pipe (lb),

$ID$  = pipe body ID (in.).

$$B_w = \frac{57.3 \xi 100 \xi 12 \xi \iota D}{J \xi L \left[ \frac{4J}{L} + \frac{L}{4J \xi \tan \left( \frac{57.3L}{4J} \right)} - \frac{2}{\tan \left( \frac{57.3L}{4J} \right)} \right]},$$

where

$B_w$  = the critical curvature that defines the transition from point contact to wrap contact ( $^{\circ}/100$  ft),

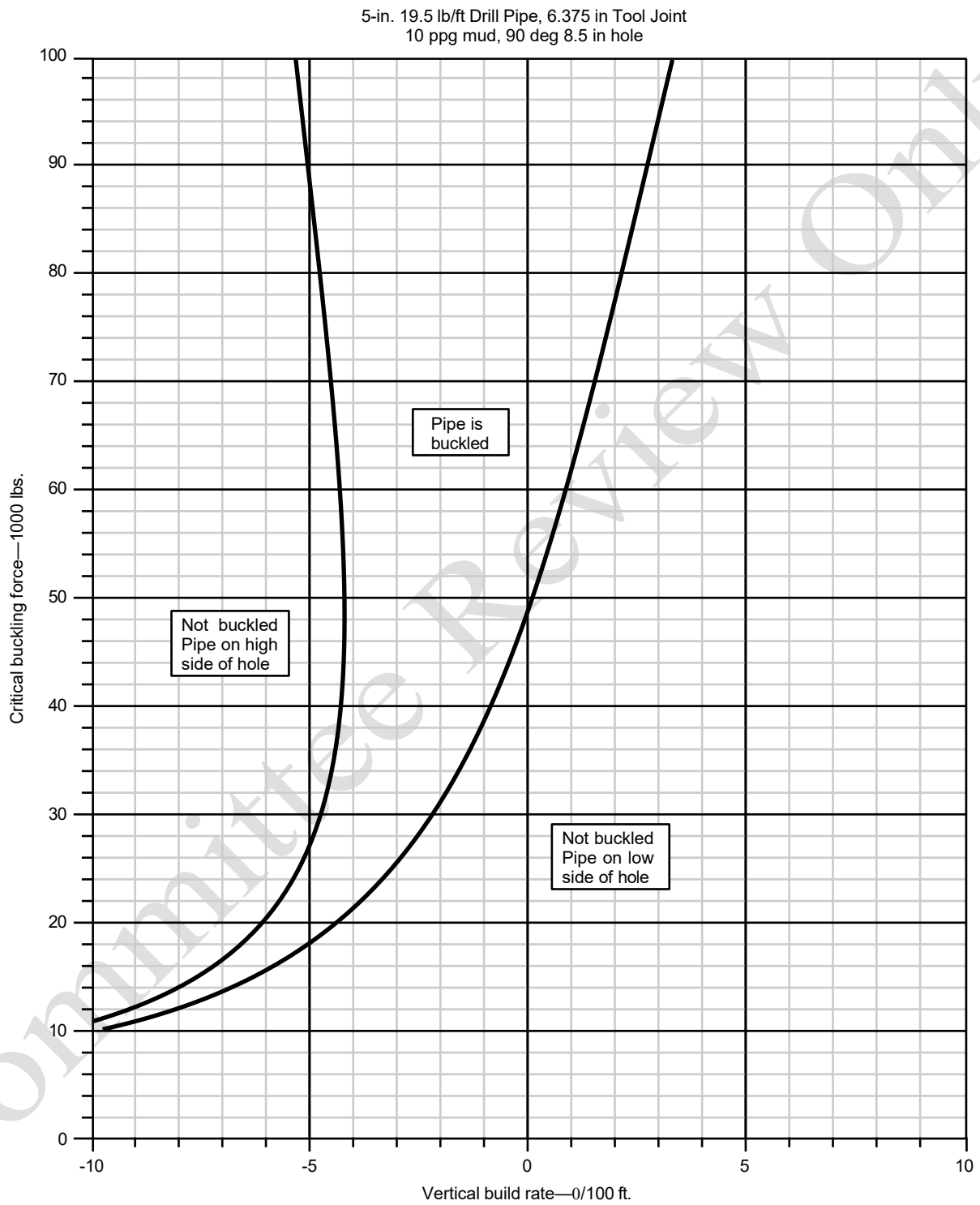


Figure A-5—Buckling Force vs Hole Curvature

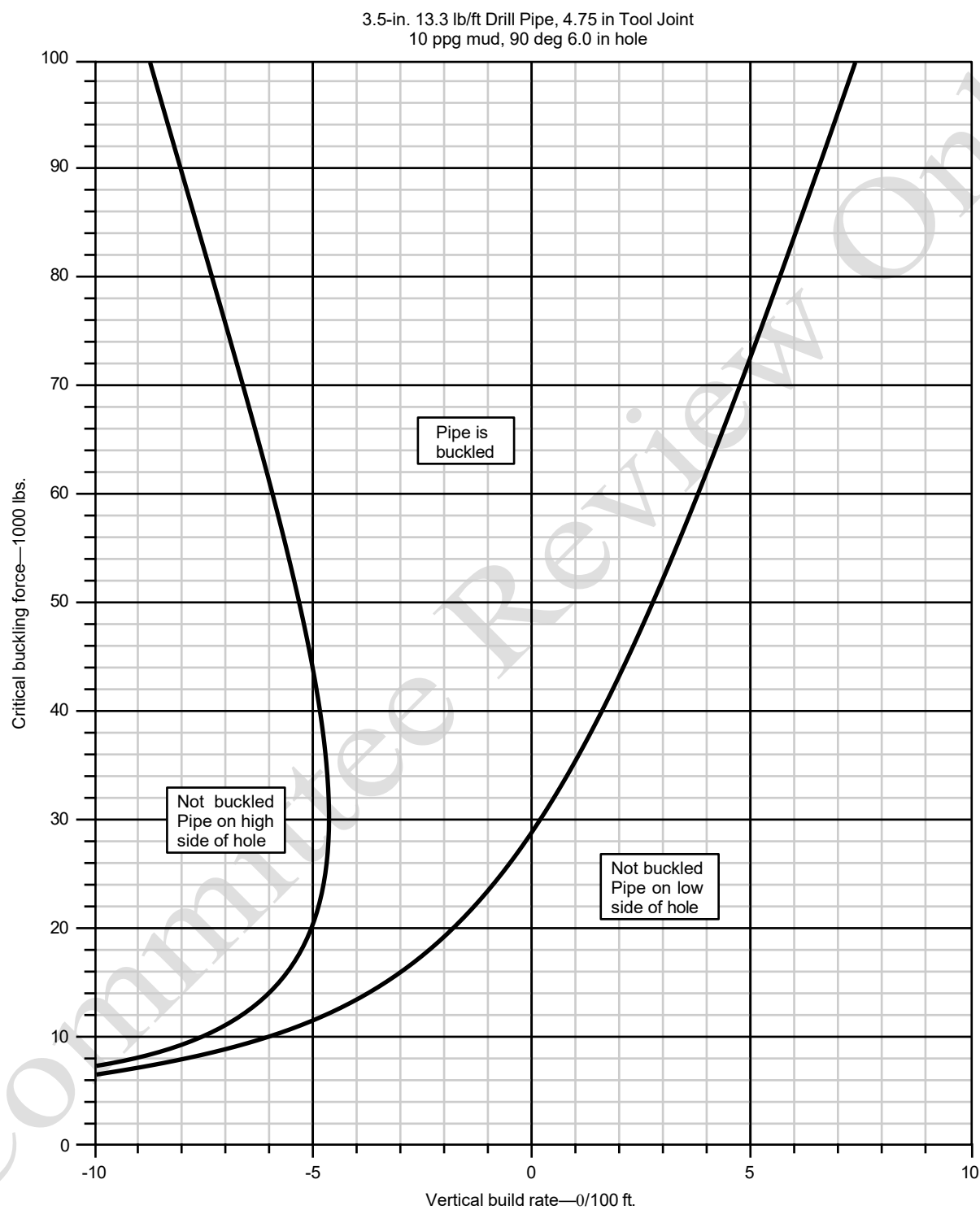


Figure A-6—Buckling Force vs Hole Curvature



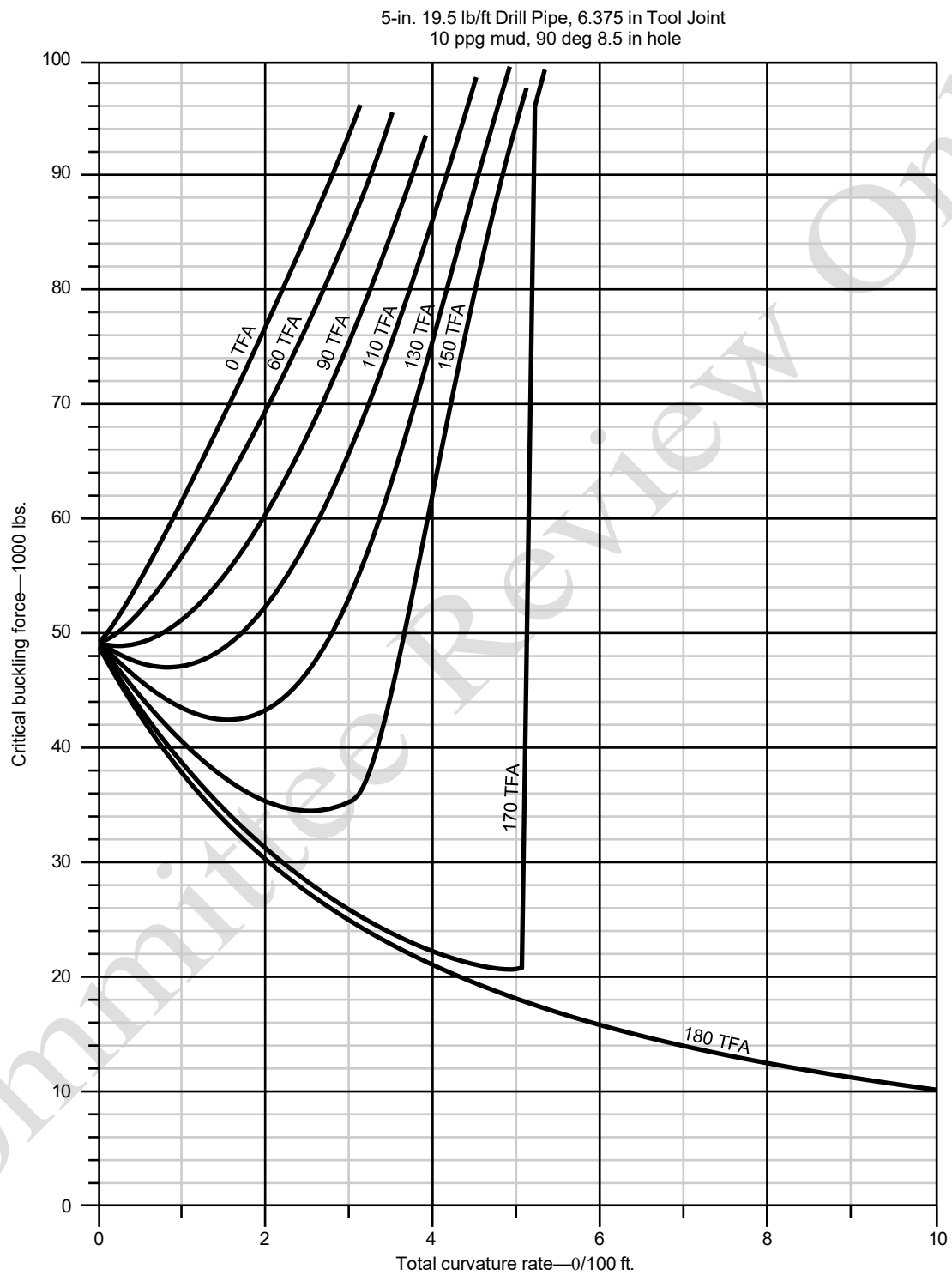


Figure A-7—Buckling Force vs Hole Curvature

$$11D = (TJOD - OD),$$

$TJOD$  = tool joint  $OD$  (in.),

$OD$  = pipe body  $OD$  (in.),

$$J = \left( \frac{E \xi I}{F} \right)^{1/2} \text{ (in.)},$$

$L$  = length of one joint of pipe (in.),

$E$  = Young's modulus  $30 \times 10^6$  for steel (psi),

$$I = \frac{\text{moment of inertia of pipe (in.}^4\text{)}}{v(OD^4 - ID^4)} = \frac{\text{---}}{64},$$

$F$  = axial compressive load on pipe (lb),

$ID$  = pipe body  $ID$  (in.).

**A.16.2** If the hole curvature is less than the critical curvature required to begin point contact, the maximum bending stress is given by the following:

$$S_b = \frac{B \xi OD \xi F \xi J \xi L}{57.3 \xi 100 \xi 12 \xi 4 \xi I \xi \sin \left( \frac{57.3L}{2J} \right)},$$

where

$S_b$  = maximum bending stress (psi),

$B$  = hole curvature,

$F$  = axial compressive load on pipe (lb),

$$J = \left( \frac{E \xi I}{F} \right)^{1/2} \text{ (in.)},$$

$E$  = Young's modulus  $30 \times 10^6$  for steel (psi),

$$I = \frac{\text{moment of inertia (in.}^4\text{)}}{v(OD^4 - ID^4)} = \frac{\text{---}}{64},$$

$OD$  = pipe body  $OD$  (in.),

$ID$  = pipe body  $ID$  (in.).

$L$  = length of one joint of pipe (in.),

**A.16.3** If the hole curvature is between the two critical curvatures calculated, the pipe will have center body point contact and the maximum bending stress is given by the following equation:

$$S_b = \frac{E \xi OD \xi U^2}{4R} \left[ \frac{A \xi \sin 8 + B \xi \cos 8}{U \xi \sin U - 4 \xi \sin^2 \left( \frac{U}{2} \right)} \right],$$

where

$E$  = Young's modulus,  $29.6 \times 10^6$  for steel (psi),

$OD$  = pipe body  $OD$  (in.),

$ID$  = pipe body  $ID$  (in.),

$$U = \frac{L}{2J},$$

$L$  = length of one joint of drillpipe for point contact of pipe body (in.),

$L = L_e$  for wrap contact (in.),

$$A = \left( 1 + \frac{4 \xi R \xi 11D}{L^2} \right) \sin U - \frac{4}{U} \xi \sin^2 \left( \frac{U}{2} \right),$$

$$B = 2 \left[ 1 - \frac{\sin U}{U} - \left( 1 + \frac{4 \xi R \xi 11D}{L^2} \right) \sin^2 \left( \frac{U}{2} \right) \right],$$

$$8 = \arctan \left( \frac{A}{B} \right),$$

$$J = \left( \frac{E \xi I}{F} \right)^{1/2} \text{ (in.)},$$

$$I = \frac{v}{64} (OD^4 - ID^4) \text{ (in.}^4\text{)},$$

$11D$  = diameter difference tool joint minus pipe body  $OD$ ,

$11D = (TJOD - OD)$  (in.),

$TJOD$  = tool joint  $OD$  (in.),

$R = 57.3 \times 100 \times 12B$ ,

$B$  = hole curvature ( $^\circ/100$  ft.).

**A.16.4** If the hole curvature exceeds the critical curvature that separates point contact from wrap contact, we need to first compute an effective pipe length in order to calculate the maximum bending stress. The effective pipe span length is calculated from the following equation by trial and error until the calculated curvature matches the actual hole curvature:

$$B = \frac{57.3 \xi 100 \xi 12 \xi 11D}{J \xi L_e \left[ \frac{4J}{L_e} + \frac{L_e}{4J \xi \tan^2 \left( \frac{57.3L}{4J} \right)} - \frac{2}{\tan \left( \frac{57.3L}{4J} \right)} \right]},$$

where

$L_e$  = effective span length (in.),

$B$  = hole curvature ( $^\circ/100$  ft.),

$11D$  = diameter difference between tool joint and pipe body,

$11D = TJOD - OD$  (in.),

$TJOD$  = tool joint  $OD$  (in.),

$OD$  = pipe body  $OD$  (in.),

$ID$  = pipe body  $ID$  (in.).

$$J = \left( \frac{E \xi I}{F} \right)^{1/2} \text{ (in.)},$$

$E$  = Young's modulus  $29.6 \times 10^6$  for steel (psi),

$$I = \frac{v}{64} (OD^4 - ID^4),$$

$F$  = axial compressive load (lb),

$L_w$  = length of pipe body touching hole (in.),

$L_w = L - L_e$ ,

$L$  = length of one joint of pipe (in.).

**A.16.5** The maximum bending stresses can then be computed using the equation for point contact and a pipe body length equal to the effective span length.

**A.16.6** One of our major concerns when drilling with compressively loaded drillpipe is the magnitude of the lateral contact forces between the tool joints and the wall of the hole and the pipe body and the wall of the hole. Various authors have suggested operating limits in the range of two to three thousand pounds or more for tool joint contact faces. There are no generally accepted operating limits for compressively loaded pipe body contact forces. For loading conditions in which there is no pipe body contact, the lateral force on the tool joints is given by:

$$LF_{TJ} = \frac{F_{TJ} L_{TJ} B}{57.3 \xi 100 \xi 12},$$

where

- $F_{TJ}$  = lateral force on tool joint (lb),
- $L$  = length of one joint of pipe (in.),
- $B$  = hole curvature ( $^{\circ}/100$  ft.).

**A.16.7** For loading conditions with point or wrap contact, the following equations give the contact forces for the tool joint and the pipe body:

$$LF_{TJ} = \frac{2 \xi E \xi I \xi U^2}{R \xi L_e} \left[ \frac{\left(1 - \frac{4R \xi 11D}{L_e^2}\right) \sin U - \frac{4 \sin^2(\frac{U}{2})}{U}}{\sin U - \frac{4 \sin^2(\frac{U}{2})}{U}} \right],$$

where

- $LF_{pipe} = \frac{F_{TJ} L_{TJ}}{R} - LF_{TJ}$
- $LF_{TJ}$  = lateral force on tool joint (lb),
- $LF_{pipe}$  = lateral force on pipe body (lb),
- $L_w = L - L_e$ ,
- $L_w$  = length of pipe for wrap contact (in.),
- $L_e = L$  for point contact (in.),
- $L_e$  = effective span length for wrap contact,
- $R = \frac{57.3 \xi 100 \xi 12}{B}$
- $B$  = hole curvature ( $^{\circ}/100$  ft.),
- $U = \frac{L_e}{2J}$
- $J = \left( \frac{E \xi I}{F} \right)^{1/2}$  (in.),
- $11D$  = diameter difference tool joint minus pipe OD (in.),
- $11D = TJOD - OD$  (in.),
- $I = \frac{\pi}{64} (OD^4 - ID^4)$ .

Table A-1—Rotary Shouldered Connection Thread Element Information

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Connection Type	Pitch Diameter C	Taper	Pin Length	Thread Height Not Truncated	Root Truncation	Nominal Counterbore	Thread Pitch	Thread Angle 8	Stress Relief Groove Diameter	Bore-Back Cylinder Diameter	Low Torque Counterbore	Low Torque Bevel Diameter
NC10	1.063000	1.500000	1.500000	0.144100	0.040600	1.204000	.166667	30	—	—	—	—
NC12	1.265000	1.500000	1.750000	0.144100	0.040600	1.406000	.166667	30	—	—	—	—
NC13	1.391000	1.500000	1.750000	0.144100	0.040600	1.532000	.166667	30	—	—	—	—
NC16	1.609000	1.500000	1.750000	0.144100	0.040600	1.751000	.166667	30	—	—	—	—
NC23	2.355000	2.000000	3.000000	0.216005	0.038000	2.625000	.250000	30	2.140625	2.218750	—	—
NC26	2.668000	2.000000	3.000000	0.216005	0.038000	2.937500	.250000	30	2.375000	2.531250	—	—
NC31	3.183000	2.000000	3.500000	0.216005	0.038000	3.453125	.250000	30	2.890625	2.953125	—	—
NC35	3.531000	2.000000	3.750000	0.216005	0.038000	3.812500	.250000	30	3.231000	3.234375	—	—
NC38	3.808000	2.000000	4.000000	0.216005	0.038000	4.078125	.250000	30	3.508000	3.468750	—	—
NC40	4.072000	2.000000	4.500000	0.216005	0.038000	4.343750	.250000	30	3.772000	3.656250	—	—
NC44	4.417000	2.000000	4.500000	0.216005	0.038000	4.687500	.250000	30	4.117000	4.000000	—	—
NC46	4.626000	2.000000	4.500000	0.216005	0.038000	4.906250	.250000	30	4.326000	4.203125	—	—
NC50	5.041700	2.000000	4.500000	0.216005	0.038000	5.312500	.250000	30	4.742000	4.625000	—	—
NC56	5.616000	3.000000	5.000000	0.215379	0.038000	5.937500	.250000	30	5.277000	4.796875	—	—
NC61	6.178000	3.000000	5.500000	0.215379	0.038000	6.500000	.250000	30	5.839000	5.234375	—	—
NC70	7.053000	3.000000	6.000000	0.215379	0.038000	7.375000	.250000	30	6.714000	5.984375	—	—
NC77	7.741000	3.000000	6.500000	0.215379	0.038000	8.062500	.250000	30	7.402000	6.546875	—	—
5½ IF	6.189000	2.000000	5.000000	0.216005	0.038000	6.453125	.250000	30	5.890625	5.687500	—	—
6⅝ IF	7.251000	2.000000	5.000000	0.216005	0.038000	7.515625	.250000	30	6.953125	6.750000	—	—
03 1 REG	1.154000	1.500000	1.500000	1.441000	0.040600	1.301000	1.66667	30	—	—	—	—
1½ REG	1.541000	1.500000	2.000000	1.441000	0.040600	1.688000	1.66667	30	—	—	—	—
2⅜ REG	2.365370	3.000000	3.000000	0.172303	0.020000	2.687500	.200000	30	2.015625	2.062500	—	—
2⅞ REG	2.740370	3.000000	3.500000	0.172303	0.020000	3.062500	.200000	30	2.390625	2.312500	—	—
3½ REG	3.239870	3.000000	3.750000	0.172303	0.020000	3.562500	.200000	30	2.906250	2.718750	—	—
4½ REG	4.364870	3.000000	4.250000	0.172303	0.020000	4.687500	.200000	30	4.013000	3.718750	—	—
5½ REG	5.234020	3.000000	4.750000	0.215379	0.025000	5.578125	.250000	30	4.869000	4.500000	—	—
00 6⅝ REG	5.757800	2.000000	5.000000	0.216005	0.025000	6.062500	.250000	30	5.417000	5.281250	—	—
7⅝ REG	6.714530	3.000000	5.250000	0.215379	0.025000	7.093750	.250000	30	6.349000	5.859375	7.750000	9.250000
8⅝ REG	7.666580	3.000000	5.375000	0.215379	0.025000	8.046875	.250000	30	7.301000	6.781250	9.000000	10.500000
03 2⅞ FH	3.365400	3.000000	3.500000	0.172303	0.020000	3.687500	.200000	30	—	—	—	—
3½ FH	3.734000	3.000000	3.750000	0.172303	0.020000	4.046875	.200000	30	3.421875	3.218750	—	—
00 4½ FH	4.532000	3.000000	4.000000	0.172303	0.020000	4.875000	.200000	30	4.180000	3.953125	—	—
5½ FH	5.591000	2.000000	5.000000	0.216005	0.025000	5.906250	.250000	30	5.250000	5.109375	—	—
6⅝ FH	6.519600	2.000000	5.000000	0.216005	0.025000	6.843750	.250000	30	6.171875	6.046875	—	—
03 2⅜ SL-H90	2.578000	1.250000	2.812500	0.166215	0.034107	2.765625	.333333	45	2.328125	2.531250	—	—

Table A-1—Rotary Shouldered Connection Thread Element Information

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
Connection Type	Pitch Diameter C	Taper	Pin Length	Thread Height Not Truncated	Root Truncation	Nominal Counterbore	Thread Pitch	Thread Angle 8	Stress Relief Groove Diameter	Bore-Back Cylinder Diameter	Low Torque Counterbore	Low Torque Bevel Diameter
2 <sup>7</sup> / <sub>8</sub> SL-H90	3.049000	1.250000	2.937500	0.166215	0.034107	3.234375	.333333	45	2.671875	2.984375	—	—
3 <sup>1</sup> / <sub>2</sub> SL-H90	3.688000	1.250000	3.187500	0.166215	0.034107	3.875000	.333333	45	3.312500	3.593750	—	—
3 <sup>1</sup> / <sub>2</sub> H-90	3.929860	2.000000	4.000000	0.141865	0.017042	4.187500	.285710	45	3.656250	3.562500	—	—
4 H-90	4.303600	2.000000	4.250000	0.141865	0.017042	4.562500	.285710	45	4.031250	3.875000	—	—
4 <sup>1</sup> / <sub>2</sub> H-90	4.637600	2.000000	4.500000	0.141865	0.017042	4.890625	.285710	45	4.359375	4.187500	—	—
5 H-90	4.908100	2.000000	4.750000	0.141865	0.017042	5.171875	.285710	45	4.625000	4.406250	—	—
5 <sup>1</sup> / <sub>2</sub> H-90	5.178600	2.000000	4.750000	0.141865	0.017042	5.437500	.285710	45	4.906250	4.687500	—	—
6 <sup>5</sup> / <sub>8</sub> H-90	5.803600	2.000000	5.000000	0.141865	0.017042	6.062500	.285710	45	5.531250	5.265625	—	—
7 H-90	6.252300	3.000000	5.500000	0.140625	0.016733	6.562500	.285710	45	6.031250	5.265625	7.125000	8.250000
7 <sup>5</sup> / <sub>8</sub> H-90	7.141100	3.000000	6.125000	0.140625	0.016733	7.453125	.285710	45	6.906250	6.000000	8.000000	9.250000
8 <sup>5</sup> / <sub>8</sub> H-90	8.016100	3.000000	6.625000	0.140625	0.016733	8.328125	.285710	45	7.781250	6.750000	9.375000	10.500000
2 <sup>3</sup> / <sub>8</sub> PAC	2.203000	1.500000	2.375000	0.216224	0.057948	2.406250	.250000	30	1.984375	2.171875	—	—
2 <sup>7</sup> / <sub>8</sub> PAC	2.369000	1.500000	2.375000	0.216224	0.057948	2.578125	.250000	30	2.156250	2.343750	—	—
3 <sup>1</sup> / <sub>2</sub> PAC	2.884000	1.500000	3.250000	0.216224	0.057948	3.109375	.250000	30	—	—	—	—
2 <sup>3</sup> / <sub>8</sub> SH	2.230000	2.000000	2.875000	0.216005	0.038000	2.500000	.250000	30	1.937500	2.093750	—	—
2 <sup>7</sup> / <sub>8</sub> SH	2.668000	2.000000	3.000000	0.216005	0.038000	2.937500	.250000	30	2.375000	2.531250	—	—
3 <sup>1</sup> / <sub>2</sub> SH	3.183000	2.000000	3.500000	0.216005	0.038000	3.453125	.250000	30	2.890625	2.953125	—	—
4 SH	3.604000	2.000000	3.500000	0.216005	0.038000	3.875000	.250000	30	3.312500	3.375000	—	—
4 <sup>1</sup> / <sub>2</sub> SH	3.808000	2.000000	4.000000	0.216005	0.038000	4.078125	.250000	30	3.508000	3.468750	—	—
2 <sup>7</sup> / <sub>8</sub> XH	3.119000	2.000000	4.000000	0.216005	0.038000	3.359375	.250000	30	2.828125	2.781250	—	—
3 <sup>1</sup> / <sub>2</sub> XH	3.604000	2.000000	3.500000	0.216005	0.038000	3.875000	.250000	30	3.312500	3.375000	—	—
5 XH	5.041700	2.000000	4.500000	0.216005	0.038000	5.312500	.250000	30	4.742000	4.625000	—	—
2 <sup>3</sup> / <sub>8</sub> OH SW	2.588000	1.500000	2.375000	0.216224	0.057948	2.796875	.250000	30	—	—	—	—
2 <sup>3</sup> / <sub>8</sub> OH LW	2.588000	1.500000	2.375000	0.216224	0.057948	2.796875	.250000	30	—	—	—	—
2 <sup>7</sup> / <sub>8</sub> OH SW	2.984000	1.500000	2.875000	0.216224	0.057948	3.203125	.250000	30	—	—	—	—
2 <sup>7</sup> / <sub>8</sub> OH LW	2.984000	1.500000	2.500000	0.216224	0.057948	3.203125	.250000	30	—	—	—	—
3 <sup>1</sup> / <sub>2</sub> OH SW	3.728000	1.500000	3.250000	0.216224	0.057948	3.953125	.250000	30	—	—	—	—
3 <sup>1</sup> / <sub>2</sub> OH LW	3.728000	1.500000	3.250000	0.216224	0.057948	3.953125	.250000	30	—	—	—	—
4 OH SW	4.416000	1.500000	4.000000	0.216224	0.057948	4.640625	.250000	30	—	—	—	—
4 OH LW	4.416000	1.500000	3.500000	0.216224	0.057948	4.640625	.250000	30	—	—	—	—
4 <sup>1</sup> / <sub>2</sub> OH SW	4.752000	1.500000	3.750000	0.216224	0.057948	4.953125	.250000	30	—	—	—	—
4 <sup>1</sup> / <sub>2</sub> OH LW	4.752000	1.500000	3.750000	0.216224	0.057948	4.953125	.250000	30	—	—	—	—
2 <sup>3</sup> / <sub>8</sub> WO	2.605000	2.000000	2.375000	0.216005	0.038000	2.859375	.250000	30	—	—	—	—
2 <sup>7</sup> / <sub>8</sub> WO	3.121000	2.000000	3.000000	0.216005	0.038000	3.375000	.250000	30	—	—	—	—
3 <sup>1</sup> / <sub>2</sub> WO	3.808000	2.000000	3.500000	0.216005	0.038000	4.078125	.250000	30	—	—	—	—
4 WO	4.626000	2.000000	4.500000	0.216005	0.038000	4.906250	.250000	30	—	—	—	—

4½ WO 5.041700 2.000000 4.500000 0.216005 0.038000 5.312500 .250000 30 — — —

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## APPENDIX B—ARTICLES AND TECHNICAL PAPERS

Many of the topics covered in Recommended Practice 7G have been the subject of significant investigation by various parties in the industry. Following is a partial list of articles and technical papers on topics related to items found in Recommended Practice 7G.

1. Arthur Lubinski, "Maximum Permissible Dog-Legs in Rotary Boreholes," *Journal of Petroleum Technology*, February 1961.
2. Robert W. Nicholson, "Minimize Drill Pipe Damage and Hole Problems. Follow Acceptable Dogleg Severity Limits," *Transactions of the 1974 International Association of Drilling Contractors (IADC) Rotary Drilling Conference*.
3. K. D. Schenk, "Calco Learns About Drilling Through Excessive Doglegs," *Oil and Gas Journal*, October 12, 1964.
4. G. J. Wilson, "Dogleg Control In Directionally Drilled Wells," *Transactions of The American Institute of Mining, Metallurgical, and Petroleum Engineers (AIME)*, 1967, Vol. 240.
5. Hansford, John E. and Lubinski, Arthur, "Cumulative Fatigue Damage of Drill Pipe in Dog Legs," *Journal of Petroleum Technology*, March 1966.
6. Hansford, John E. and Lubinski, Arthur: "The Effect of Drilling Vessel Pitch or Roll on Kelly and Drill Pipe Fatigue," *Transactions of AIME*, 1964, Vol. 231.
7. Thad Vreeland, Jr., "Dynamic Stresses In Long Drill Pipe Strings," *The Petroleum Engineer*, May 1961.
8. Henry Bourne, Continental Oil Co., Ponca City, Oklahoma, *Drilling Fluid Corrosion*, Unpublished.
9. Edward R. Slaughter, E. Ellis Fletcher, Arthur R. Elsear, and George K. Manning, "An Investigation of the Effects of Hydrogen on the Brittle Failure of High Strength Steels," WADC TR 56-83, June 1955.
10. H. M. Rollins, "Drill Stem Failures Due to H<sub>2</sub>S," *Oil and Gas Journal*, January 24, 1966.
11. Walter Main, Discussion of Paper by Grant and Texter, "Causes and Prevention of Drill Pipe and Tool Joint Troubles," *World Oil*, October 1948.
12. J. C. Stall and K. A. Blenkarn, "Allowable Hook Load and Torque Combinations For Stuck Drill String," Mid-Continent API District Meeting, Paper No. 851-36-M, April 6, 1962.
13. Armco Steel Corporation, "Oil Country Tubular Products-Engineering Data," 1966.
14. Arthur Lubinski, "Fatigue of Range 3 Drill Pipe," *Revue de L'Institut Francais du Petrole*, November 2, 1977 (English translation).
15. Arthur Lubinski, "Dynamic Loading of Drill Pipe During Tripping," *Journal of Petroleum Technology*, August 1988.
16. Huang T., Dareing D.W., "Buckling and Lateral Vibration of Drill Pipe," *Journal of Engineering for Industry*, November 1968, pp. 613-619.
17. Dareing D. W., Livesay B. J., "Longitudinal and Angular Drillstring Vibrations With Damping," *Journal of Engineering for Industry*, November 1968, pp. 671-679.
18. Combes J. D., Baxter V. R., "Critical Rotary Speeds Can Be Costly," *Petroleum Engineer*, September 1969, pp. 60-63.
19. Besaisow A. A., et. al., "Development of a Surface Drillstring Vibration Measurement System," Society of Petroleum Engineers (SPE) SPE 14327, presented at the 1985 Technical Conference, Las Vegas, September 22-25, 1985.
20. Burgess T. M., McDaniel G. L., Das P. K., "Improving Tool Reliability with Drillstring Vibration Models-Field Experience and Limitations," SPE/IADC 16109, presented at the 1987 SPE/IADC Drilling Conference, New Orleans, March 1987.
21. Halsey G. W., et. al., "Torque Feedback Used to Cure Slip-Stick Motion," SPE 18049, presented at the 1988 Technical Conference, New Orleans, March 1987.
22. Cook R. L., Nicholson J. W., Sheppard M. C., and Westlake W., "First Real Time Measurements of Downhole Vibrations, Forces, and Pressures Used to Monitor Directional Drilling Operations," SPE/IADC 19651, presented at the 1989 SPE/IADC Drilling Conference, New Orleans, February 28 to March 3, 1989.
23. Warren T. M., Brett J. F., and Sinor L. A., "Development of a Whirl-Resistant Bit," SPE 19572, presented at 1989 SPE Annual Technical Conference and Exhibition, San Antonio, October 8-11.
24. Yanglie Zhang, Zaiyang Xiao, "Motion of Reviewing the Section 9 of API RP 7G," presented at the API Standardization Conference, June 1993.
25. Nicholson J. W., "An Integrated Approach to Drilling Dynamics Planning, Identification, and Control," SPE/IADC 27537, presented at the SPE/IADC Drilling Conference, Dallas, February 15-18, 1994.
26. Fereidoun Abbassian, "Drillstring Vibration Primer," *BP Exploration*, Unpublished.
27. Dawson, Rapier, and Paslay, P.R., "Drillpipe Buckling in Inclined Holes," *JPT*, October 1984.
28. *Standard DS-1, Drill Stem Design and Inspection, Second Edition*, T.H. Hill Associates, Inc., Houston, Texas, August 1997.
29. Mitchell, R.F., "Effects of Well Deviation on Helical Buckling," SPE 29462, SPE Production Operations Sympo-



sium, Oklahoma City, April 1995.

Committee Review Only

30. Schuh, F.J., "The Critical Buckling Force and Stresses for Pipe in Inclined Curved Boreholes," SPE/IADC 21942, SPE/IADC Drilling Conference, Amsterdam, March 11-14, 1991.
31. Kyllingstad, Aage, "Buckling of Tubular Strings in Curved Wells," *Journal of Petroleum Science and Engineering*, 12, 1995, pp. 209-218.
32. Suryanarayana, P.V.R.; McCann, R.C., "An Experimental Study of Buckling and Post-Buckling of Laterally Constrained Rods," *Journal of Energy Resources Technology*, Vol. 177, June 1995, pp. 115-124.
33. Paslay, P.R.; Cernocky, E.P., "Bending Stress Magnification in Constant Curvature Doglegs with Impact on Drilling and Casing," SPE 22547, the SPE 66th Annual Technical Conference and Exposition, Dallas, Texas, October 6-9, 1991.
34. Acknowledgment: Subcommittee appreciates the use of Shell Exploration and Production Company proprietary BSM Bending Stress Code.
35. Morgan, R.P.; Roblin, M.J., "A Method for the Investigation of Fatigue Strength in Seamless Drillpipe," ASME Conference, Tulsa, Oklahoma, September 22, 1969.
36. Casner, John, A., "Endurance Limit of Drill Pipe," letter 1/21/95 to John Altermann.
37. Hansford, J.E.; Lubinski, A., "Cumulative Fatigue Damage of Drillpipe in Doglegs," *Journal of Petroleum Technology*, March 1966, pp. 359-363.
38. Lubinski, Arthur A., "Maximum Permissible Dog-Legs in Rotary Boreholes," *Journal of Petroleum Technology*, February 1961.
39. Acknowledgment: Subcommittee appreciates the release by Mobil Exploration and Production Technical Center, Dallas, Texas of the report, "Buckling of a Rod Confined to be in Contact with a Toroidal Surface, Parts I and II," by Paul R. Paslay, October 15, 1993.

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