INTERNATIONAL STANDARD

ISO 10407

First edition
1993-12-15

Petroleum and natural gas industries — Drilling and production equipment — Drill stem design and operating limits

Industries du pétrole et du gaz naturel — Étude des garnitures de forage et de leurs limites d'exploitation

Reference number
ISO 10407:1993(E)

Foreword

ISO (the International Organization for Standardization) is a worldwide federation of national standards bodies (ISO member bodies). The work of preparing International Standards is normally carried out through ISO technical committees. Each member body interested in a subject for which a technical committee has been established has the right to be represented on that committee. International organizations, governmental and non-governmental, in liaison with ISO, also take part in the work. ISO collaborates closely with the International Electrotechnical Commission (IEC) on all matters of electrotechnical standardization.

Draft International Standards adopted by the technical committees are circulated to the member bodies for voting. Publication as an International Standard requires approval by at least 75 % of the member bodies casting a vote.

International Standard ISO 10407 was prepared by the American Petroleum Institute (API) (as RP 7G, 14th edition) and was adopted, under a special "fast-track procedure", by Technical Committee ISO/TC 67, *Materials, equipment and offshore structures for petroleum and natural gas industries*, in parallel with its approval by the ISO member bodies.

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Introduction

International Standard ISO 10407:1993 reproduces the content of API RP 7G, 14th edition, 1990. ISO, in endorsing this API document, recognizes that in certain respects the latter does not comply with all current ISO rules on the presentation and content of an International Standard. Therefore, the relevant technical body, within ISO/TC 67, will review ISO 10407:1993 and reissue it, when practicable, in a form complying with these rules.

This standard is not intended to obviate the need for sound engineering judgement as to when and where this standard should be utilized and users of this standard should be aware that additional or differing requirements may be needed to meet the needs for the particular service intended.

Standards referenced herein may be replaced by other international or national standards that can be shown to meet or exceed the requirements of the referenced standards.

Appendix A forms an integral part of this standard.

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Petroleum and natural gas industries — Drilling and production equipment — Drill stem design and operating limits

1 Scope

This International Standard lays down the properties of drill pipe and tool joints, drill collars, kellys, and establishes principles for the design and use of drill stem and their components.

2 Requirements

Requirements are specified in:

> "API Recommended Practice 7G (RP 7G), Fourteenth Edition, August 1, 1990 — *Recommended Practice for Drill Stem Design and Operating Limits*",

which is adopted as ISO 10407.

For the purposes of international standardization, however, modifications shall apply to specific clauses and paragraphs of publication API RP 7G. These modifications are outlined below.

Throughout publication API RP 7G, the conversion of English units shall be made in accordance with ISO 31, in particular for the quantities listed hereafter.

LENGTH	1 inch (in) 1 foot (ft) 1 pound-force per square inch (lbf/in^2) NOTE 1 bar = 10^5 Pa	= 25,4 mm (exactly) = 304,8 mm or 0,304 8 m (exactly) = 6 894,757 Pa
STRENGTH OR STRESS	1 pound-force per square inch (lbf/in^2)	= 6 894,757 Pa
IMPACT ENERGY	1 foot-pound force (ft·lbf)	= 1,355 818 J
TORQUE	1 foot-pound force (ft·lbf)	= 1,355 818 N·m
TEMPERATURE	The following formula was used to convert degrees Fahrenheit (°F) to degrees Celsius (°C): °C = 5/9 (°F − 32)	
VOLUME	1 cubic foot 1 gal (US) 1 barrel (US)	= 0,028 316 8 m^3 or 28,316 8 dm^3 = 0,003 785 4 m^3 or 3,785 4 dm^3 = 0,158 987 m^3 or 158,987 dm^3
MASS	1 pound (lb)	= 0,453 592 37 kg (exactly)
LINEIC MASS	1 pound per foot (lb/ft)	= 1,488 163 9 kg/m

FORCE	1 pound-force (lbf)	= 4,448 222 N
FLOW RATE	1 barrel/day	= 0,158 987 m^3/day
	1 cubic foot per minute (ft^3/min)	= 0,028 316 85 m^3/min or 40,776 192 m^3/day

Page 7

Information given in the POLICY is relevant to the API publication only.

Page 76

Pipe manufacturer

The given list of pipe manufacturers may be used on a provisional basis. In the future, the symbols should be registered under an international registration scheme to be established according to Annex N of the ISO/IEC Directives, part 2.

Recommended Practice for Drill Stem Design and Operating Limits

API RECOMMENDED PRACTICE 7G (RP 7G)
FOURTEENTH EDITION, AUGUST 1, 1990

American Petroleum Institute
1220 L Street, Northwest
Washington, DC 20005

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Users of this publication should become completely familiar with its scope and content. This publication is intended to supplement rather than replace individual engineering judgment.

OFFICIAL PUBLICATION

REG. U.S. PATENT OFFICE

TABLE OF CONTENTS

NOTE: This edition supersedes the Thirteenth Edition of this recommended practice dated April 1, 1989. It includes changes adopted at the 1989 Standardization Conference as reported in Circ PS-1887, and as subsequently approved by letter ballot.

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RECOMMENDED PRACTICE FOR DRILL STEM DESIGN AND OPERATING LIMITS

FOREWORD

a. This recommended practice is under the jurisdiction of the API Committee on Standardization of Drilling and Servicing Equipment.

b. 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.

c. References are listed at the end of this publication.

Attention Users of this Publication: Portions of this publication have been changed from the previous edition. The location of changes has been marked with a bar in the margin. In some cases the changes are significant, while in other cases the changes reflect minor editorial adjustments. The bar notations in the margins are provided as an aid to users to identify those parts of this publication that have been changed from the previous edition, but API makes no warranty as to the accuracy of such bar notations.

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SECTION 1
SCOPE

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

1.2 Sections 2, 3, 4, and 5 provide a step-by-step procedure for selection of drill string members in normal, near-vertical holes. Sections 6, 7, 8, 9, and 12 are related to operating limitations which may reduce the normal capability of the drill string. Section 10 contains classification system for used drill pipe and used tubing work strings, and identification and inspection procedures for other drill string members. Section 11 contains statements regarding welding on down hole tools. Section 13 covers the classification system for rock (roller) bits.

SECTION 2
PROPERTIES OF DRILL PIPE AND TOOL JOINTS

2.1 This section contains a series of tables 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. Separate tables are included for Torsional and Tensile Data and for Collapse and Internal Pressure Data.

2.2 All drill pipe and tool joint properties tables are included in Section 2.

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

Tool Joint Drift Diameters

2.4 Recommended drift diameters for new drill string assemblies are shown in column 8 of Tables 2.10 and 2.11. 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.

Torsional Strength of Tool Joints

2.5 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 torque required to yield a rotary shouldered connection may be obtained from the equation in Par. A.8, Appendix A.

2.6 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.

2.7 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.

2.8 Minimum OD, box shoulder, and make-up torque values listed in Table 2.12 were determined using the following criteria:

a. Calculations for recommended tool joint make-up torque are based on the use of a thread compound containing 40-60% by weight of finely powdered metallic zinc applied to all threads and shoulders, and containing not more than 0.3% total active sulfur. Calculations are also based on a tensile stress of 50% of the minimum tensile yield for new joints and 60% for used joints.

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

c. Premium Class Drill String is based on drill pipe having a minimum wall thickness of 80%.

d. Class 2 drill string allows drill pipe with a minimum wall thickness of 70%.

e. 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 2.1
NEW DRILL PIPE DIMENSIONAL DATA

1	2	3	4	5	6	7
Size OD in. D	Nominal Weight Threads & Couplings lb/ft	Plain End Weight[1] lb/ft	Wall Thickness in.	ID in. d	Section Area Body of Pipe[2] sq. in. A	Polar Sectional Modulus[3] cu. in. Z
2⅜	4.85	4.43	.190	1.995	1.3042	1.321
	6.65	6.26	.280	1.815	1.8429	1.733
2⅞	6.85	6.16	.217	2.441	1.8120	2.241
	10.40	9.72	.362	2.151	2.8579	3.204
3½	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
4½	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
5½	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
6⅝	25.20	22.19	.330	5.965	6.5262	19.572

[1] lb/ft = 3.3996 x A (col. 6)
[2] $A = 0.7854\,(D^2 - d^2)$
[3] $Z = 0.19635\left(\frac{D^4 - d^4}{D}\right)$

TABLE 2.2
NEW DRILL PIPE TORSIONAL AND TENSILE DATA

1	2	3	4	5	6	7	8	9	10
Size OD In.	Nom. Weight Thds & Couplings lb.	Torsional Data* Torsional Yield Strength, ft-lb				Tensile Data Based on Minimum Values** Load at the Minimum Yield Strength, lb;			
		E	95	105	135	E	95	105	135
2⅜	4.85	4763.	6033.	6668.	8574.	97817.	123902.	136944.	176071.
	6.65	6250.	7917.	8751.	11251.	138214.	175072.	193500.	248786.
2⅞	6.85	8083.	10238.	11316.	14549.	135902.	172143.	190263.	244624.
	10.40	11554.	14635.	16176.	20798.	214344.	271503.	300082.	385820.
3½	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.	451685.	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.
4½	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.	659735.	948230.
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.
5½	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.
6⅝	25.20	70580.	89402.	98812.	127044.	489464.	619988.	685250.	881035.

*Based on the shear strength equal to 57.7% of minimum yield strength and nominal wall thickness.
Minimum torsional yield strength calculated from Formula A.15, Par. A.9, Appendix A.
**Minimum tensile strength calculated from Formula A.13, Par. A.7, Appendix A.

TABLE 2.3
NEW DRILL PIPE COLLAPSE AND INTERNAL PRESSURE DATA

1	2	3	4	5	6	7	8	9	10
Size OD in.	Nom. Weight Thds & Couplings lb.	Collapse Pressure Based On Minimum Values, psi.				Internal Pressure At Minimum Yield Strength, psi.			
		E	95	105	135	E	95	105	135
2⅜	4.85	11040.	13984.	15456.	19035.	10500.	13300.	14700.	18900.
	6.65	15599.	19759.	21839.	28079.	15474.	19600.	21663.	27853.
2⅞	6.85	10467.	12940.	14020.	17034.	9907.	12548.	13869.	17832.
	10.40	16509.	20911.	23112.	29716.	16526.	20933.	23137.	29747.
3½	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.
4½	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.
5½	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.
6⅝	25.20	4788.	5321.	5500.	6036.	6538.	8281.	9153.	11768.

NOTE: Calculations are based on formulas in API Bul 5C3.

TABLE 2.4
USED DRILL PIPE
TORSIONAL AND TENSILE DATA
API PREMIUM CLASS

1	2	3	4	5	6	7	8	9	10
Size OD in.	New Wt. Nom. W/ Thds & Couplings lb/ft	[1,2]Torsional Yield Strength Based On Uniform Wear, ft-lb				[2]Tensile Data Based On Uniform Wear Load At Minimum Yield Strength, lb,			
		E	95	105	135	E	95	105	135
2⅜	4.85	3725.	4719.	5215.	6705.	76893.	97398.	107650.	138407.
	6.65	4811.	6093.	6735.	8659.	107616.	136313.	150662.	193709.
2⅞	6.85	6332.	8020.	8865.	11397.	106946.	135465.	149725.	192503.
	10.40	8858.	11220.	12401.	15945.	166535.	210945.	233149.	299764.
3½	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.
4½	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.
5½	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.
6⅝	25.20	55766.	70637.	78072.	100379.	387466.	490790.	542452.	697438.

[1]Based on the shear strength equal to 57.7% of minimum yield strength.

[2]Torsional data based on 20% uniform wear on outside diameter and tensile data based on 20% uniform wear on outside diameter.

TABLE 2.5
USED DRILL PIPE COLLAPSE AND INTERNAL PRESSURE DATA
API PREMIUM CLASS

1	2	3	4	5	6	7	8	9	10
OD Size in.	Nominal Weight Thds. & Couplings lb/ft	[1]Collapse Pressure Based On Minimum Values, psi,				[1]Minimum Internal Yield Pressure At Minimum Yield Strength, psi			
		E	95	105	135	E	95	105	135
2⅜	4.85	8522.	10161.	10912.	12891.	9600.	12160.	13440.	17280.
	6.65	13378.	16945.	18729.	24080.	14147.	17920.	19806.	25465.
2⅞	6.85	7640.	9017.	9633.	11186.	9057.	11473.	12680.	16303.
	10.40	14223.	18016.	19912.	25602.	15110.	19139.	21153.	27197.
3½	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.
4½	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.
5½	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.
6⅝	25.20	2931.	3252.	3353.	3429.	5977.	7571.	8368.	10759.

[1]Data are based on minimum wall of 80% nominal wall. Collapse pressures are based on uniform OD wear. Internal pressures are based on uniform wear and nominal OD.

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

TABLE 2.6
USED DRILL PIPE TORSIONAL AND TENSILE DATA
API CLASS 2

1	2	3	4	5	6	7	8	9	10
Size OD in.	New Wt. Nom. W/ Thds. & Couplings lb/ft	[1,2]Torsional Yield Strength Based On Uniform Wear, ft-lb				[2]Tensile Data Based on Uniform Wear Load At Minimum Yield Strength, lb,			
		E	95	105	135	E	95	105	135
2⅜	4.85	3224.	4083.	4513.	5802.	66686.	84469.	93360.	120035.
	6.65	4130.	5232.	5782.	7434.	92871.	117636.	130019.	167167.
2⅞	6.85	5484.	6946.	7677.	9871.	92801.	117549.	129922.	167043.
	10.40	7591.	9615.	10627.	13663.	143557.	181839.	200980.	258403.
3½	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.
4½	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.
5½	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.
6⅝	25.20	48497.	61430.	67896.	87295.	337236.	427166.	472131.	607026.

[1]Based on the shear strength equal to 57.7% of minimum yield strength.
[2]Torsional data based on 30% uniform wear on outside diameter and tensile data based on 30% uniform wear on outside diameter.

TABLE 2.7
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 Thds & Couplings lb/ft	[1]Collapse Pressure Based On Minimum Values, psi.				[1]Minimum Internal Yield Pressure At Minimum Yield Strength, psi.			
		E	95	105	135	E	95	105	135
2⅜	4.85	6852.	7996.	8491.	9664.	8400.	10640.	11760.	15120.
	6.65	12138.	15375.	16993.	21849.	12379.	15680.	17331.	22282.
2⅞	6.85	6055.	6963.	7335.	8123.	7925.	10039.	11095.	14265.
	10.40	12938.	16388.	18113.	23288.	13221.	16746.	18509.	23798.
3½	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.
4½	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.
5½	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.
6⅝	25.20	2227.	2343.	2346.	2346.	5230.	6625.	7322.	9414.

[1]Data are based on minimum wall of 70% nominal wall. Collapse pressures are based on uniform OD wear. Internal pressures are based on uniform wear and nominal OD.

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

EDITORIAL NOTE: Tables 2.8 and 2.9 were deleted in 12th edition of RP 7G and the remaining Tables were *not renumbered*.

TABLE 2.10
MECHANICAL PROPERTIES OF NEW TOOL JOINTS AND NEW GRADE E DRILL PIPE

1	2	3	4	5	6	7	8	9	10	11	12
Drill Pipe Data				Tool Joint Data			Drift Diam-eter** in.	Mechanical Properties			
								Tensile Yield, lb		Torsional Yld, ft-lb	
Nom Size in.	Nom. Wt. lb/ft	Approx. Wt.* lb/ft	Type Upset	Conn.	OD in.	ID in.		[1]Pipe	[3]Tool Joint	[2]Pipe	Tool Joint [f]
2⅜	4.85	5.16	EU	NC26(IF)	3⅜	1¾	1.625	97817.	313681.	4763.	6478.b
		4.89	EU	OH	3⅛	2	1.807	97817.	206416.	4763.	4525.p
		4.97	EU	SLH90	3¼	2	1.850	97817.	202670.	4763.	5127.p
		5.06	EU	WO	3⅜	2	1.807	97817.	205369.	4763.	4533.p
	6.65	6.92	EU	NC26(IF)	3⅜	1¾	1.625	138214.	313681.	6250.	6478.b
		6.83	EU	OH	3¼	1¾	1.625	138214.	294774.	6250.	6298.b
		6.71	IU	PAC	2⅞	1⅜	1.250	138214.	238634.	6250.	4690.P
		6.73	EU	SLH90	3¼	2	1.670	138214.	202670.	6250.	5127.p
2⅞	6.85	7.36	EU	NC31(IF)	4⅛	2⅛	2.000	135902.	447130.	8083.	11869.p
		6.85	EU	OH	3¾	2 7/16	2.253	135902.	223937.	8083.	5589.P
		6.96	EU	SLH90	3⅞	2 7/16	2.296	135902.	260783.	8083.	7630.p
		7.19	EU	WO	4⅛	2 7/16	2.253	135902.	289264.	8083.	7511.p
	10.40	10.76	EU	NC31(IF)	4⅛	2⅛	1.963	214344.	447130.	11554.	11869.p
		10.51	EU	OH	3⅞	2 5/32	1.963	214344.	345705.	11554.	8818.P
		10.15	IU	PAC	3⅛	1½	1.375	214344.	273164.	11554.	5735.P
		10.51	EU	SLH90	3⅞	2 5/32	2.006	214344.	382551.	11554.	11294.p
		10.99	IU	XH	4¼	1⅞	1.750	214344.	516757.	11554.	13595.p
		10.28	IU	NC26(SH)	3⅜	1¾	1.625	214344.	313681.	11554.	6478.B
3½	9.50	10.44	EU	NC38(IF)	4¾	2 11/16	2.563	194264.	587308.	14146.	18107.p
		9.89	EU	OH	4½	3	2.804	194264.	392295.	14146.	11867.p
		10.05	EU	SLH90	4⅝	3	2.847	194264.	366445.	14146.	12646.p
		10.20	EU	WO	4¾	3	2.804	194264.	434198.	14146.	13333.p
	13.30	14.41	EU	H90	5¼	2¾	2.619	271569.	663633.	18551.	23847.p
		13.77	EU	NC38(IF)	4¾	2 11/16	2.457	271569.	587308.	18551.	18107.p
		13.77	EU	OH	4¾	2 11/16	2.414	271569.	559806.	18551.	17305.p
		13.40	IU	NC31(SH)	4⅛	2⅛	2.000	271569.	447130.	18551.	11869.P
		13.94	EU	XH	4¾	2 7/16	2.313	271569.	584542.	18551.	17493.p
	15.50	16.39	EU	NC38(IF)	5	2 9/16	2.414	322775.	649158.	21086.	20326.p
4	11.85	13.07	IU	H90	5½	2 13/16	2.688	230755.	914246.	19474.	35441.p
		13.51	EU	NC46(IF)	6	3¼	3.125	230755.	901164.	19474.	33625.p
		12.10	EU	OH	5¼	3 15/32	3.287	230755.	621623.	19474.	21967.b
		12.91	EU	WO	5¾	3 7/16	3.313	230755.	800590.	19474.	29469.p

[1]The tensile yield strength of Grade E drill pipe is based on 75,000 psi minimum yield strength.
[2]The torsional yield strength is based on a shear strength of 57.7% of the minimum yield strength.
[3]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 5/8 inch from the shoulder.
*Tool Joint plus drill pipe, for Range 2 steel pipe (See Appendix A for method of calculation).
**See Par. 2.4.
[f]: p=pin limited yield. b=box limited yield. P or B indicates that tool joint could not meet 80% of tube torsion yield.

TABLE 2.10 (continued)
MECHANICAL PROPERTIES OF NEW TOOL JOINTS AND NEW GRADE E DRILL PIPE

1	2	3	4	5	6	7	8	9	10	11	12
	Drill Pipe Data			Tool Joint Data			Drift	Mechanical Properties			
								Tensile Yield, lb		Torsional Yld, ft-lb	
Nom. Size in.	Nom. Wt. lb/ft.	Approx. Wt.* lb/ft	Type Upset	Conn.	OD in.	ID in.	Diameter** in.	[1]Pipe	[3]Tool Joint	[2]Pipe	Tool Joint[f]
4	14.00	15.06	IU	NC40(FH)	5¼	$2\frac{13}{16}$	2.688	285359.	711611.	23288.	23487.p
		15.41	IU	H90	5½	$2\frac{13}{16}$	2.688	285359.	914246.	23288.	35441.p
		15.85	EU	NC46(IF)	6	3¼	3.125	285359.	901164.	23288.	33625.p
		15.03	EU	OH	5½	3¼	3.125	285359.	760142.	23288.	27279.p
		14.37	IU	SH	4⅝	$2\frac{9}{16}$	2.438	285359.	525637.	23288.	15581.P
	15.70	16.81	IU	NC40(FH)	5¼	$2\frac{11}{16}$	2.563	324118.	776406.	25810.	25673.p
	15.70	17.07	IU	H90	5½	$2\frac{13}{16}$	2.688	324118.	914246.	25810.	35441.p
	15.70	17.51	EU	NC46(IF)	6	3¼	3.095	324118.	901164.	25810.	33625.p
4½	13.75	15.21	IU	H90	6	3¼	3.125	270034.	938984.	25907.	39021.p
		14.93	EU	NC50(IF)	6⅜	3¾	3.625	270034.	939095.	25907.	37676.p
		14.06	EU	OH	5¾	$3\frac{31}{32}$	3.770	270034.	555131.	25907.	20965.p
		14.79	EU	WO	6⅛	3⅞	3.750	270034.	868775.	25907.	34440.p
	16.60	18.14	IEU	FH	6	3	2.875	330558.	976156.	30807.	34780.p
		17.81	IEU	H90	6	3¼	3.125	330558.	938984.	30807.	39021.p
		17.98	EU	NC50(IF)	6⅜	3¾	3.625	330558.	939095.	30807.	37676.p
		17.10	EU	OH	5⅞	3¾	3.625	330558.	714267.	30807.	27272.p
		16.79	IEU	NC38(SH)	5	$2\frac{11}{16}$	2.563	330558.	587308.	30807.	18346.P
		18.37	IEU	NC46(XH)	6¼	3¼	3.125	330558.	901164.	30807.	33993.p
	20.00	21.63	IEU	FH	6	3	2.875	412358.	976156.	36901.	34780.p
		21.63	IEU	H90	6	3	2.875	412358.	1086246.	36901.	45258.p
		21.62	EU	NC50(IF)	6⅜	3⅝	3.452	412358.	1025980.	36901.	41235.p
		22.09	IEU	NC46(XH)	6¼	3	2.875	412358.	1048426.	36901.	39659.p
	22.82	24.07	EU	NC50(IF)	6⅜	3⅝	3.452	471239.	1025980.	40912.	41235.p
		24.59	IEU	NC46(XH)	6¼	3	2.875	471239.	1048426.	40912.	39659.p
5	19.50	22.26	IEU	5½FH	7	3¾	3.625	395595.	1448407.	41167.	61352.b
		20.89	IEU	NC50(XH)	6⅜	3¾	3.625	395595.	939095.	41167.	37676.p
	25.60	28.26	IEU	5½FH	7	3½	3.375	530144.	1619231.	52257.	61352.b
		26.89	IEU	NC50(XH)	6⅜	3½	3.375	530144.	1109920.	52257.	44673.p
5½	21.90	23.77	IEU	FH	7	4	3.875	437116.	1265802.	50710.	55933.p
	24.70	26.33	IEU	FH	7	4	3.875	497222.	1265802.	56574.	55933.p
6⅝	25.20	27.3	IEU	FH	8	5	4.875	489470.	1448800.	70580.	74200.p

[1]The tensile yield strength of Grade E drill pipe is based on 75,000 psi minimum yield strength.
[2]The torsional yield strength is based on a shear strength of 57.7% of the minimum yield strength.
[3]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 5/8 inch from the shoulder.
*Tool Joint plus drill pipe, for Range 2 steel pipe (See Appendix A for method of calculation).
**See Par. 2.4.
[f]: p=pin limited yield. b=box limited yield. P or B indicates that tool joint could not meet 80% of tube torsion yield.

TABLE 2.11
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			Drift Diameter** in.	Mechanical Properties			
								Tensile Yield, lb		Torsional Yld., ft-lb	
Nom. Size in.	Nom. Wt. lb/ft	Approx. Wt.* lb/ft	Type Upset and Pipe Grade	Conn.	OD in.	ID in.		Pipe	²Tool Joint	¹Pipe	Tool Joint^f
2⅜	6.65	7.01	EU-X	NC26(IF)	3⅜	1¾	1.625	175072.	313681.	7917.	6478.b
		6.89	EU-X	SLH90	3¼	1 13/16	1.670	175072.	270043.	7917.	6884.p
	6.65	7.01	EU-G	NC26(IF)	3⅜	1¾	1.625	193500.	313681.	8751.	6478.B
		6.89	EU-G	SLH90	3¼	1 13/16	1.670	193500.	270043.	8751.	6884.P
2⅞	10.40	10.96	EU-X	NC31(IF)	4⅛	2	1.875	271503.	495726.	14635.	13195.p
		10.84	EU-X	SLH90	4	2	1.875	271503.	443756.	14635.	13226.p
	10.40	10.96	EU-G	NC31(IF)	4⅛	2	1.875	300082.	495726.	16176.	13195.p
		10.84	EU-G	SLH90	4	2	1.875	300082.	443756.	16176.	13226.p
	10.40	11.38	EU-S	NC31(IF)	4⅜	1⅝	1.500	385820.	623844.	20798.	16944.p
		11.12	EU-S	SLH90	4⅛	1⅝	1.500	385820.	571874.	20798.	17226.p
3½	13.30	14.63	EU-X	H90	5¼	2¾	2.619	343988.	663633.	23498.	23847.p
		14.41	EU-X	NC38(IF)	5	2 9/16	2.438	343988.	649158.	23498.	20326.p
		14.07	EU-X	SLH90	4¾	2 9/16	2.438	343988.	595806.	23498.	20879.p
	13.30	14.49	EU-G	NC38(IF)	5	2 7/16	2.313	380197.	708063.	25972.	22213.p
		14.07	EU-G	SLH90	4¾	2 9/16	2.438	380197.	595806.	25972.	20879.p
	13.30	14.69	EU-S	NC38(IF)	5	2⅛	2.000	488825.	842440.	33392.	26022.B
		14.69	EU-S	SLH90	5	2⅛	2.000	488825.	789087.	33392.	28078.p
		15.04	EU-S	NC40(4FH)	5⅜	2 7/16	2.313	488825.	897161.	33392.	29930.p
	15.50	16.69	EU-X	NC38(IF)	5	2 7/16	2.313	408848.	708063.	26708.	22213.p
	15.50	16.88	EU-G	NC38(IF)	5	2⅛	2.000	451885.	842440.	29520.	26022.b
		16.96	EU-G	NC40(4FH)	5¼	2 9/16	2.438	451885.	838257.	29520.	27760.p
	15.50	17.56	EU-S	NC40(4FH)	5½	2¼	2.125	580995.	979996.	37954.	32943.p
4	14.00	15.30	IU-X	NC40(FH)	5¼	2 11/16	2.563	361454.	776406.	29498.	25673.p
		15.55	IU-X	H90	5½	2 13/16	2.688	361454.	914246.	29498.	35441.p
		16.14	EU-X	NC46(IF)	6	3¼	3.125	361454.	901164.	29498.	33625.p
	14.00	15.90	IU-G	NC40(FH)	5½	2 7/16	2.313	399502.	897161.	32603.	30114.p
		15.55	IU-G	H90	5½	2 13/16	2.688	399502.	914246.	32603.	35441.p
		16.14	EU-G	NC46(IF)	6	3¼	3.125	399502.	901164.	32603.	33625.p
	14.00	16.18	IU-S	NC40(FH)	5½	2	1.875	513646.	1080135.	41918.	36363.p
		15.55	IU-S	H90	5½	2 13/16	2.688	513646.	914246.	41918.	35441.p
		16.38	EU-S	NC46(IF)	6	3	2.875	513646.	1048426.	41918.	39229.p

¹The torsional yield strength is based on a shear strength of 57.7% of the minimum yield strength.
²The 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 ⅝ inch from the shoulder.
*Tool Joint plus drill pipe, for Range 2 steel pipe (See Appendix A for method of calculation).
**See Par. 2.4.
f: p=pin limited yield. b=box limited yield. P or B indicates that tool joint could not meet 80% of tube torsion yield.

TABLE 2.11 (continued)
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			Drift Diameter** in.	Mechanical Properties			
								Tensile Yield, lb		Torsional Yld., ft-lb	
Nom. Size in.	Nom. Wt. lb/ft	Approx. Wt.* lb/ft	Type Upset and Pipe Grade	Conn.	OD in.	ID in.		Pipe	[2]Tool Joint	[1]Pipe	Tool Joint[f]
4	15.70	17.55	IU-X	NC40(FH)	5½	2 7/16	2.313	410550.	897161.	32692.	30114.p
		17.17	IU-X	H90	5½	2 13/16	2.688	410550.	914246.	32692.	35441.p
		17.75	EU-X	NC46(IF)	6	3¼	3.125	410550.	901164.	32692.	33625.p
	15.70	17.55	IU-G	NC40(FH)	5½	2 7/16	2.313	453765.	897161.	36134.	30114.p
		17.17	IU-G	H90	5½	2 13/16	2.688	453765.	914246.	36134.	35441.p
		17.75	EU-G	NC46(IF)	6	3¼	3.125	453765.	901164.	36134.	33625.p
	15.70	18.03	EU-S	NC46(IF)	6	3	2.875	583413.	1048426.	46458.	39229.p
4½	16.60	18.62	IEU-X	FH	6	3	2.875	418707.	976156.	39022.	34780.p
		18.39	IEU-X	H90	6	3¼	3.125	418707.	938984.	39022.	39021.p
		18.34	EU-X	NC50(IF)	6⅝	3¾	3.625	418707.	939095.	39022.	37676.p
		18.88	IEU-X	NC46(XH)	6¼	3	2.875	418707.	1048426.	39022.	39659.p
	16.60	18.62	IEU-G	FH	6	3	2.625	462781.	976156.	43130.	34780.p
		18.39	IEU-G	H90	6	3	3.125	462781.	938984.	43130.	39021.p
		18.34	EU-G	NC50(IF)	6⅝	3¾	3.625	462781.	939095.	43130.	37676.p
		18.88	IEU-G	NC46(XH)	6¼	3	2.875	462781.	1048426.	43130.	39659.p
	16.60	19.28	IEU-S	FH	6¼	2½	2.375	595004.	1235337.	55453.	44769.p
		18.42	IEU-S	H90	6	3	2.875	595004.	938984.	55453.	39021.p
		18.61	EU-S	NC50(IF)	6⅝	3½	3.375	595004.	1109920.	55453.	44673.p
		19.09	IEU-S	NC46(XH)	6¼	2¾	2.625	595004.	1183908.	55453.	44871.p
	20.00	22.29	IEU-X	FH	6	2½	2.375	522320.	1235337.	46741.	43247.b
		21.79	IEU-X	H90	6	3¼	3.125	522320.	938984.	46741.	39021.p
		22.13	EU-X	NC50(IF)	6⅝	3½	3.375	522320.	1109920.	46741.	44673.p
		22.56	IEU-X	NC46(XH)	6¼	2¾	2.625	522320.	1183908.	46741.	44871.p
	20.00	22.29	IEU-G	FH	6	2½	2.375	577301.	1235337.	51661.	43247.b
		21.90	IEU-G	H90	6	3	2.875	577301.	1086246.	51661.	45258.p
		22.13	EU-G	NC50(IF)	6⅝	3½	3.375	577301.	1109920.	51661.	44673.p
		22.75	IEU-G	NC46(XH)	6¼	2½	2.375	577301.	1307608.	51661.	49630.p
	20.00	23.22	EU-S	NC50(IF)	6⅝	3	2.875	742244.	1416225.	66421.	55708.p
		22.93	IEU-S	NC46(XH)	6¼	2¼	2.125	742244.	1419527.	66421.	53936.p
	22.82	25.43	IEU-X	FH	6¼	2¼	2.125	596903.	1347256.	51821.	48912.p
		24.58	EU-X	NC50(IF)	6⅝	3½	3.375	596903.	1109920.	51821.	44673.p
		25.06	IEU-X	NC46(XH)	6¼	2¾	2.625	596903.	1183908.	51821.	44871.p

(Continued on page 16)

[1]The torsional yield strength is based on a shear strength of 57.7% of the minimum yield strength.
[2]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 ⅝ inch from the shoulder.
*Tool Joint plus drill pipe, for Range 2 steel pipe (See Appendix A for method of calculation).
**See Par. 2.4.
[f]: p=pin limited yield. b=box limited yield. P or B indicates that tool joint could not meet 80% of tube torsion yield.

TABLE 2.11 (continued)
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			
							Drift	Tensile Yield, lb		Torsional Yld., ft-lb	
Nom. Size in.	Nom. Wt. lb/ft	Approx. Wt.* lb/ft	Type Upset and Pipe Grade	Conn.	OD in.	ID in.	Diam-eter** in.	Pipe	²Tool Joint	¹Pipe	Tool Joint^f
4½	22.82	25.13	EU-G	NC50(IF)	6½	3¼	3.125	659735.	1268963.	57276.	51447.p
		25.25	IEU-G	NC46(XH)	6¼	2½	2.375	659735.	1307608.	57276.	49630.p
	22.82	25.83	EU-S	NC50(IF)	6⅝	2¾	2.625	848230.	1551706.	73641.	62387.b
5	19.50	22.46	IEU-X	5½ FH	7	3¾	3.625	501087.	1448407.	52144.	61352.b
		22.08	IEU-X	H90	6½	3¼	3.125	501087.	1176429.	52144.	51870.p
		21.44	IEU-X	NC50(XH)	6⅜	3½	3.375	501087.	1109920.	52144.	44673.p
	19.50	22.46	IEU-G	5½ FH	7	3¾	3.625	553833.	1448407.	57633.	61352.b
		22.32	IEU-G	H90	6½	3	2.875	553833.	1323691.	57633.	58469.p
		21.92	IEU-G	NC50(XH)	6½	3¼	3.125	553833.	1268963.	57633.	51447.p
	19.50	23.40	IEU-S	5½ FH	7¼	3½	3.375	712070.	1619231.	74100.	72483.p
		22.60	IEU-S	NC50(XH)	6⅝	2¾	2.625	712070.	1551706.	74100.	62387.b
	25.60	28.45	IEU-X	5½ FH	7	3½	3.375	671515.	1619231.	66192.	61352.b
		27.86	IEU-X	NC50(XH)	6½	3	2.875	671515.	1416225.	66192.	55708.b
	25.60	29.01	IEU-G	5½ FH	7¼	3½	3.375	742201.	1619231.	73159.	72483.p
	25.60	28.32	IEU-G	NC50(XH)	6⅝	2¾	2.625	742201.	1551706.	73159.	62387.b
	25.60	29.35	IEU-S	5½ FH	7¼	3¼	3.125	954259.	1778274.	94062.	77151.b
5½	21.90	24.37	IEU-X	FH	7	3¾	3.625	553681.	1448407.	64233.	61352.b
		24.64	IEU-X	H90	7	3½	3.125	553681.	1269528.	64233.	59185.p
	21.90	25.21	IEU-G	FH	7¼	3½	3.375	611963.	1619231.	70994.	72483.p
	21.90	26.33	IEU-S	FH	7½	3	2.875	786809.	1925536.	91278.	87170.p
	24.70	27.76	IEU-X	FH	7¼	3½	3.375	629814.	1619231.	71660.	72483.p
	24.70	27.76	IEU-G	FH	7¼	3½	3.375	696111.	1619231.	79204.	72483.p
	24.70	28.87	IEU-S	FH	7½	3	2.875	894999.	1925536.	101833.	87170.p

¹The torsional yield strength is based on a shear strength of 57.7% of the minimum yield strength.
²The 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 ⅝ inch from the shoulder.
*Tool Joint plus drill pipe, for Range 2 steel pipe (See Appendix A for method of calculation).
**See Par. 2.4.
f: p=pin limited yield. b=box limited yield. P or B indicates that tool joint could not meet 80% of tube torsion yield.

TABLE 2.12
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	
DRILL PIPE			NEW TOOL JOINT DATA				PREMIUM CLASS			CLASS 2		
NOM SIZE in.	NOM WT. lb/ft	TYPE UPSET AND GRADE	CONN.	NEW OD in.	NEW ID in.	MAKE-UP TORQUE 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
2⅜	4.85	EU 75	NC26	3⅜	1¾	3,438 B	3⅛	3/64	1,945	3 3/32	1/32	1,689
	4.85	EU 75	W.O.	3⅜	2	2,155 P	3 1/16	1/16	1,994	3 1/32	3/64	1,746
	4.85	EU 75	2⅜ OH	3⅛	2	2,263 P	3 1/32	1/16	1,967	3	3/64	1,723
	4.85	EU 75	2⅜ SL-H90	3¼	2	2,563 P	2 31/32	1/16	1,998	2 15/16	3/64	1,726
2⅜	6.65	IU 75	2⅜ PAC	2⅞	1⅜	2,344 P	2 25/32	9/64	2,455	2 23/32	7/64	2,055
	6.65	EU 75	NC26	3⅜	1¾	3,438 B	3 3/16	5/64	2,467	3 5/32	1/16	2,204
	6.65	EU 75	2⅜ SL-H90	3¼	2	2,572 P	3 1/32	3/32	2,560	2 31/32	1/16	1,998
	6.65	EU 75	2⅜ OH	3¼	1¾	3,153 B	3 3/32	3/32	2,468	3 1/16	5/64	2,216
2⅜	6.65	EU 95	NC26	3⅜	1¾	3,438 B	3¼	7/64	3,005	3 7/32	3/32	2,734
2⅜	6.65	EU 105	NC26	3⅜	1¾	3,438 B	3 9/32	⅛	3,279	3¼	7/64	3,005
2⅞	6.85	EU 75	NC31	4⅛	2⅛	5,935 P	3 11/16	5/64	3,154	3 21/32	7/64	2,804
	6.85	EU 75	2⅞ WO	4⅛	2 7/16	3,598 P	3⅝	5/64	3,216	3 19/32	1/16	2,876
	6.85	EU 75	2⅞ OH	3¾	2 7/16	2,463 P	3 15/32	3/32	3,242	3 7/16	5/64	2,927
	6.85	EU 75	2⅞ SL-H90	3⅞	2 7/16	3,814 P	3½	3/32	3,399	3 7/16	1/16	2,666
2⅞	10.40	EU 75	NC31	4⅛	2⅛	5,935 P	3 13/16	9/64	4,597	3¾	7/64	3,867
	10.40	EU 75	2⅞ XH	4¼	1⅞	6,681 P	3 23/32	9/64	4,379	3 21/32	7/64	3,664
	10.40	EU 75	NC26	3⅜	1¾	3,438 B	3 13/32	3/16	4,415	3 11/32	5/32	3,839
	10.40	EU 75	2⅞ OH	3⅞	2 5/32	4,064 P	3 19/32	5/32	4,542	3 17/32	⅛	3,884
	10.40	EU 75	2⅞ SL-H90	3⅞	2 5/32	5,646 P	3 19/32	9/64	4,531	3 17/32	7/64	3,770
	10.40	EU 75	2⅞ PAC	3⅛	1½	2,866 P	3⅛	15/64	3,439	3 3/32	7/32	3,841
	10.40	EU 95	NC31	4⅛	2	6,598 P	3 29/32	3/16	5,726	3 27/32	5/32	4,969
	10.40	EU 95	2⅞ SL-H90	3⅞	2 5/32	5,646 P	3 11/16	3/16	5,704	3⅝	5/32	4,918
2⅞	10.40	EU 105	NC31	4⅛	2	6,598 P	3 15/16	13/64	6,110	3⅞	11/64	5,345
2⅞	10.40	EU 135	NC31	4⅜	1⅝	8,664 P	4 1/16	17/64	7,694	4	15/64	6,893
3½	9.50	EU 75	NC38	4¾	3	6,407 P	4 13/32	⅛	5,773	4 11/32	3/32	4,882
	9.50	EU 75	NC38	4¾	2 11/16	9,096 P	4 13/32	⅛	5,803	4 11/32	3/32	4,822
	9.50	EU 75	3½ OH	4¾	3	6,014 P	4 9/32	⅛	5,340	4¼	7/64	4,868
	9.50	EU 75	3½ SL-H90	4⅝	3	6,322 P	4 3/16	7/64	5,521	4 5/32	3/32	5,006
3½	13.30	EU 75	NC38	4¾	2 11/16	9,054 P	4½	11/64	7,274	4 7/16	9/64	6,268
	13.30	IU 75	NC31	4⅛	2⅛	5,935 P	4	15/64	6,893	3 15/16	13/64	6,110
	13.30	EU 75	3½ OH	4¾	2 11/16	8,655 P	4 13/32	3/16	7,278	4 11/32	5/32	6,299
	13.30	EU 75	3½ H90	5¼	2¾	1,299 P	4 17/32	⅛	7,064	4½	7/64	6,487
	13.30	EU 95	NC38	5	2 9/16	10,163 P	4 19/32	7/32	8,822	4 17/32	3/16	7,785
	13.30	EU 95	3½ SL-H90	4⅝	2 11/16	9,284 P	4⅜	13/64	8,742	4 5/16	11/64	7,650
	13.30	EU 95	3½ H90	5¼	2¾	11,933 P	4⅝	11/64	8,839	4 9/16	9/64	7,646
3½	13.30	EU 105	NC38	5	2 7/16	11,106 P	4 21/32	¼	9,879	4 19/32	7/32	8,822

TABLE 2.12 (continued)
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	
DRILL PIPE			NEW TOOL JOINT DATA				PREMIUM CLASS			CLASS 2		
NOM SIZE in.	NOM WT. lb/ft	TYPE UPSET AND GRADE	CONN.	NEW OD in.	NEW ID in.	MAKE-UP TORQUE 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
3½	13.30	EU 135	NC40	5⅜	2 7/16	14,965 P	5	9/32	12,569	4 29/32	15/64	10,768
	13.30	EU 135	NC38	5	2⅛	13,258 P	4 13/16	21/64	12,614	4 23/32	9/32	10,957
3½	15.50	EU 75	NC38	5	2 9/16	10,163 P	4 17/32	3/16	7,785	4 15/32	5/32	6,769
3½	15.50	EU 95	NC38	5	2 7/16	11,106 P	4 21/32	¼	9,879	4 19/32	7/32	8,822
3½	15.50	EU 105	NC38	5	2⅛	13,258 P	4 23/32	9/32	10,957	4⅝	15/64	9,348
	15.50	EU 105	NC40	5¼	2 9/16	13,880 P	4 15/16	¼	11,363	4 27/32	13/64	9,595
3½	15.50	EU 135	NC40	5½	2¼	16,472 P	5 3/32	21/64	14,419	4 31/32	17/64	11,963
4	11.85	EU 75	NC46	6	3¼	16,813 P	5 7/32	7/64	7,843	5 5/32	5/64	6,476
	11.85	EU 75	4 WO	5¾	3 7/16	14,405 P	5 7/32	7/64	7,843	5 5/32	5/64	6,476
	11.85	EU 75	4 OH	5¼	3 15/32	10,950 P	5	⅛	7,839	4 15/16	9/64	6,571
	11.85	EU 75	4 H90	5½	2 13/16	17,709 P	4⅞	7/64	7,640	4 27/32	3/32	6,971
4	14.00	IU 75	NC40	5¼	2 13/16	11,744 P	4 13/16	3/16	9,017	4¾	5/32	7,877
	14.00	EU 75	NC46	6	3¼	16,813 P	5 9/32	9/64	7,832	5 7/32	7/64	7,843
	14.00	IU 75	4 SH	4⅝	2 9/16	7,585 P	4 7/16	15/64	8,782	4⅜	13/64	7,817
	14.00	EU 75	4 OH	5½	3¼	13,598 P	5 1/16	11/64	9,131	5	9/64	7,839
	14.00	EU 75	4 H90	5½	2 13/16	17,709 P	4 15/16	9/64	8,997	4⅞	7/64	7,640
4	14.00	IU 95	NC40	5¼	2 11/16	12,836 P	4 15/16	¼	11,363	4 27/32	13/64	9,595
	14.00	EU 95	NC46	6	3¼	16,813 P	5⅜	3/16	11,363	5 5/16	5/32	9,937
	14.00	IU 95	4 H90	5½	2 13/16	17,709 P	5 1/32	3/16	11,065	4 31/32	5/32	9,685
4	14.00	IU 105	NC40	5½	2 7/16	15,057 P	5	9/32	12,569	4 29/32	15/64	10,768
	14.00	EU 105	NC46	6	3¼	16,813 P	5 7/16	7/32	12,813	5 11/32	11/64	10,647
	14.00	IU 105	4 H90	5½	2 13/16	17,709 P	5 3/32	7/32	12,497	5 1/32	3/16	11,079
	14.00	EU 135	NC46	6	3	19,615 P	5 9/16	9/32	15,787	5½	¼	14,288
4	15.70	IU 75	NC40	5¼	2 11/16	12,836 P	4⅞	7/32	10,179	4 25/32	11/64	8,444
	15.70	EU 75	NC46	6	3¼	16,813 P	5 5/16	5/32	9,937	5¼	⅛	8,535
	15.70	EU 75	4 H90	5½	2 13/16	17,709 P	4 31/32	5/32	9,673	4 29/32	⅛	8,316
4	15.70	IU 95	NC40	5½	2 7/16	15,057 P	5	9/32	12,569	4 29/32	15/64	10,791
	15.70	EU 95	NC46	6	3	19,615 P	5 7/16	7/32	12,813	5 11/32	11/64	10.773
	15.70	IU 95	4 H90	5½	2 13/16	17,709 P	5 3/32	7/32	12,497	5 1/32	3/16	10,310
4	15.70	EU 105	NC46	6	3	19,615 P	5 15/32	15/64	13,547	5 13/32	13/64	12,085
	15.70	IU 105	4 H90	5½	2 13/16	17,709 P	5 5/32	¼	13,939	5 1/16	13/64	11,785
4	15.70	IU 135	NC46	6	2⅝	22,485 B	5 21/32	21/64	18,083	5 17/32	17/64	15,035
	15.70	EU 135	NC46	6	2⅞	20,932 P	5 21/32	21/64	18,083	5 17/32	17/64	15,035

TABLE 2.12 (continued)
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	
DRILL PIPE			NEW TOOL JOINT DATA				PREMIUM CLASS			CLASS 2		
NOM SIZE in.	NOM WT. lb/ft	TYPE UPSET AND GRADE	CONN.	NEW OD in.	NEW ID in.	MAKE-UP TORQUE 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
4½	16.60	EU 75	4½ FH	6	3	17,390 P	5⅝	13/64	12,125	5 9/32	5/32	10,072
	16.60	EU 75	NC46	6¼	3¼	16,997 P	5 13/32	13/64	12,085	5 11/32	11/64	10,647
	16.60	EU 75	4½ OH	5⅞	3¾	13,629 P	5 7/16	13/64	11,861	5⅜	11/64	10,375
	16.60	EU 75	NC50	6⅝	3¾	18,838 P	5 23/32	19/64	11,591	5 11/16	9/64	10,773
	16.60	EU 75	4½ H-90	6	3¼	19,497 P	5 11/32	21/64	12,215	5 9/32	5/32	10,310
4½	16.60	IEU 95	4½ FH	6	2¾	21,419 P	5½	17/64	14,945	5 13/32	7/32	12,821
	16.60	IEU 95	NC46	6¼	3¼	16,997 P	5 17/32	17/64	15,035	5 7/16	7/32	12,813
	16.60	EU 95	NC50	6⅝	3¾	18,838 P	5 27/32	7/32	14,927	5 25/32	3/16	13,245
	16.60	IEU 95	4½ H-90	6	3	22,616 P	5 15/32	¼	15,115	5⅜	13/64	13,102
4½	16.60	IEU 105	4½ FH	6	2¾	19,869 P	5 9/16	19/64	16,391	5 15/32	¼	14,321
	16.60	IEU 105	NC46	6¼	3	19,829 P	5 19/32	19/64	16,546	5½	¼	14,288
	16.60	EU 105	NC50	6⅝	3¾	18,623 P	5 29/32	¼	16,634	5 13/16	13/64	14,083
	16.60	IEU 105	4½ H-90	6	3	22,616 P	5½	17/64	16,264	5 7/16	15/32	14,625
4½	16.60	IEU 135	NC46	6¼	2¾	22,436 P	5 25/32	23/64	21,230	5 21/32	21/64	18,083
	16.60	EU 135	NC50	6⅝	3½	22,336 P	6 1/16	31/64	21,018	5 31/32	9/32	18,368
4½	20.00	IEU 75	4½ FH	6	3	17,390 P	5 15/32	¼	14,231	5⅜	13/64	12,125
	20.00	IEU 75	NC46	6¼	3	19,829 P	5½	¼	14,288	5 13/32	13/64	12,085
	20.00	EU 75	NC50	6⅝	3⅝	20,617 P	5 13/16	13/64	14,082	5¾	11/64	12,415
	20.00	IEU 75	4½ H-90	6	3	22,616 P	5 13/32	7/32	13,815	5 11/32	3/16	12,215
4½	20.00	IEU 95	4½ FH	6	2½	22,133 P	5⅝	21/64	17,861	5 17/32	9/32	15,665
	20.00	IEU 95	NC46	6¼	2¾	22,436 P	5 21/32	21/64	18,083	5 9/16	9/32	15,787
	20.00	EU 95	NC50	6⅝	3½	22,336 P	5 15/16	17/64	17,497	5⅞	15/64	15,776
	20.00	EU 95	4½ H-90	6	3	22,616 P	5 9/16	19/64	17,929	5 15/32	¼	15,441
4½	20.00	IEU 105	NC46	6¼	2½	24,815 P	5 23/32	23/64	19,644	5⅝	5/16	17,311
	20.00	EU 105	NC50	6⅝	3½	22,336 P	6 1/32	5/16	20,127	5 29/32	¼	16,634
4½	20.00	EU 135	NC50	6⅝	2⅞	30,332 P	6 7/32	13/32	25,569	6 3/32	11/32	21,914
5	19.50	IEU 75	NC50	6⅝	3¾	18,838 P	5⅞	15/64	15,776	5 13/16	13/64	14,083
5	19.50	IEU 95	NC50	6⅝	3½	22,345 P	6 1/32	5/16	19,919	5 15/16	17/64	17,497
	19.50	IEU 95	5 H-90	6½	3¼	25,932 P	5 27/32	19/64	19,862	5¾	¼	17,136
5	19.50	IEU 105	NC50	6½	3¼	25,724 P	6 3/32	11/32	21,914	6	19/64	19,244
	19.50	IEU 105	5 H-90	6½	3	29,231 P	5 29/32	21/64	21,727	5 13/16	9/32	18,961
5	19.50	IEU 135	NC50	6⅝	2¾	31,703 P	6 5/16	29/64	28,381	6 3/16	25/64	24,645
	19.50	IEU 135	5½ FH	7¼	3½	36,241 P	6¾	⅜	28,737	6⅝	5/16	24,413

TABLE 2.12 (continued)
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	
DRILL PIPE			NEW TOOL JOINT DATA				PREMIUM CLASS			CLASS 2		
NOM SIZE in.	NOM WT. lb/ft	TYPE UPSET AND GRADE	CONN.	NEW OD in.	NEW ID in.	MAKE-UP TORQUE 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
5	25.60	IEU 75	NC50	6⅜	3½	22,337 P	6 1/32	5/16	20,127	5 15/16	17/64	17,497
	25.60	IEU 75	5½ FH	7	3½	31,452 B	6½	¼	20,205	6 13/32	13/64	17,126
5	25.60	IEU 95	NC50	6½	3	28,492 B	6 7/32	13/32	25,569	6 3/32	11/32	21,914
	25.60	IEU 95	5½ FH	7	3½	34,947 B	6 21/32	21/64	25,450	6 17/32	15/64	21,246
5	25.60	IEU 105	NC50	6⅝	2¾	31,703 P	6 9/32	7/16	27,438	6 5/32	⅜	23,729
	25.60	IEU 105	5½ FH	7¼	3½	36,241 P	6 23/32	23/64	27,644	6⅝	5/16	24,412
5	25.60	IEU 135	5½ FH	7¼	3½	39,358 B	6 15/16	15/32	35,446	6 13/16	13/32	30,943
5½	21.90	IEU 75	5½ FH	7	4	27,967 P	6 15/32	¼	19,172	6 13/32	13/32	17,127
5½	21.90	IEU 95	5½ FH	7	3¾	31,452 B	6 21/32	21/64	25,483	6 17/32	17/64	21,246
	21.90	IEU 95	5½ H-90	7	3½	29,576 P	6 7/32	11/32	25,478	6 3/32	9/32	21,349
5½	21.90	IEU 105	5½ FH	7¼	3½	36,241 P	6 23/32	23/64	27,645	6 19/32	19/32	23,350
5½	21.90	IEU 135	5½ FH	7½	3	43,585 P	6 15/16	15/32	35,446	6 13/16	13/32	30,943
5½	24.70	IEU 75	5½ FH	7	4	27,967 P	6 9/16	9/32	22,294	6 15/32	15/64	19,172
5½	24.70	IEU 95	5½ FH	7¼	3½	31,452 B	6 23/32	23/64	27,645	6 19/32	19/64	23,350
5½	24.70	IEU 105	5½ FH	7¼	3½	31,452 B	6 25/32	25/64	29,836	6 11/16	11/32	26,560
5½	24.70	IEU 135	5½ FH	7½	3	43,585 P	7 1/32	33/64	38,901	6⅞	7/16	33,180

① The use of outside diameters (OD) smaller than those listed in the table may be acceptable on Slim Hole (SH) tool joints due to special service requirements.

② Tool joint with dimensions shown has a lower torsional yield ratio than the 0.80 which is generally used.

③ Recommended make-up torque is based on 72,000 psi stress.

④ 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.

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

★ 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 2.13
BUOYANCY FACTORS

1	2	3
Mud Density lb/gal	Mud Density lb/cu ft	Buoyancy Factor, K_b,
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
20.0	149.61	.694

2.9 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:

TABLE 2.14
ROTARY SHOULDERED CONNECTION INTERCHANGE LIST

Common Name		Pin Base Diameter	Threads	Taper	Thread	Same As or
Style	Size	(Tapered)	Per in	in/ft	Form*	Interchanges With
Internal Flush (I.F.)	2⅜"	2.876	4	2	V-0.065 (V-0.038 rad)	2⅞" Slim Hole N.C. 26**
	2⅞"	3.391	4	2	V-0.065 (V-0.038 rad)	3½" Slim Hole N.C. 31**
	3½"	4.016	4	2	V-0.065 (V-0.038 rad)	4½" Slim Hole N.C. 38**
	4"	4.834	4	2	V-0.065 (V-0.038 rad)	4½" Extra Hole N.C. 46**
	4½"	5.250	4	2	V-0.065 (V-0.038 rad)	5" Extra Hole N.C. 50** 5½" Double Streamline
Full Hole (F.H.)	4"	4.280	4	2	V-0.065 (V-0.038 rad)	4½" Double Streamline N.C.40**
Extra Hole (X.H.) (E.H.)	2⅞"	3.327	4	2	V-0.065 (V-0.038 rad)	3½" Double Streamline
	3½"	3.812	4	2	V-0.065 (V-0.038 rad)	4" Slim Hole 4½" External Flush
	4½"	4.834	4	2	V-0.065 (V-0.038 rad)	4" Internal Flush N.C.46**
	5"	5.250	4	2	V-0.065 (V-0.038 rad)	4½" Internal Flush N.C.50** 5½" Double Streamline
Slim Hole (S.H.)	2⅞"	2.876	4	2	V-0.065 (V-0.038 rad)	2⅜" Internal Flush N.C. 26**
	3½"	3.391	4	2	V-0.065 (V-0.038 rad)	2⅞" Internal Flush N.C. 31**
	4"	3.812	4	2	V-0.065 (V-0.038 rad)	3½" Extra Hole 4½" External Flush
	4½"	4.016	4	2	V-0.065 (V-0.038 rad)	3½" Internal Flush N.C. 38**
Double Streamline (DSL)	3½"	3.327	4	2	V-0.065 (V-0.038 rad)	2⅞" Extra Hole
	4½"	4.280	4	2	V-0.065 (V-0.038 rad)	4" Full Hole N.C. 40**
	5½"	5.250	4	2	V-0.065 (V-0.038 rad)	4½" Internal Flush 5" Extra Hole N.C. 50**
Numbered Conn (N.C.)	26	2.876	4	2	V-0.038 rad	2⅜" Internal Flush 2⅞" Slim Hole
	31	3.391	4	2	V-0.038 rad	2⅞" Internal Flush 3½" Slim Hole
	38	4.016	4	2	V-0.038 rad	3½" Internal Flush 4½" Slim Hole
	40	4.280	4	2	V-0.038 rad	4" Full Hole 4½" Double Streamline
	46	4.834	4	2	V-0.038 rad	4" Internal Flush 4½" Extra Hole
	50	5.250	4	2	V-0.038 rad	4½" Internal Flush 5" Extra Hole 5½" Double Streamline
External Flush (E.F.)	4½"	3.812	4	2	V-0.065 (V-0.038 rad)	4" Slim Hole 3½" Extra Hole

* Connections with two thread forms shown may be machined with either thread form without affecting gaging or interchangeability.

** Numbered connections (N.C.) may be machined only with the V-0.038 radius thread form.

2.10 The curves of Figures 2.1 through 2.25 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. The make-up torque should be based on a tensile stress level of 50% of the minimum yield for new tool joints and 60% for used tool joints.

2.11 The curves may be used by taking the following steps:

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

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

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

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

e. 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.

f. 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.

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

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

b. Extend a horizontal line from the O.D. under consideration to the curve and read the recommended make-up torque representing the box.

c. Extend a vertical line from the I.D. under consideration to the curve and read the recommended make-up torque representing the pin.

d. The smaller of the two recommended make-up torques thus obtained is the recommended make-up torque for the tool joint.

e. A make-up torque higher than recommended may be required under extreme conditions.

TOOL JOINT TORSIONAL STRENGTH AND RECOMMENDED MAKE-UP TORQUE CURVES
(All curves based on 120,000 psi minimum yield strength and 60% of minimum yield strength for recommended make-up torque)

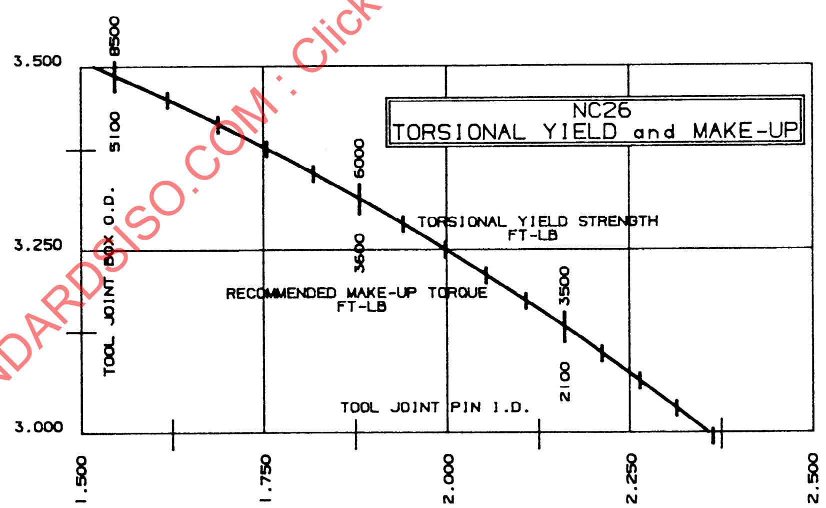


FIG. 2.1

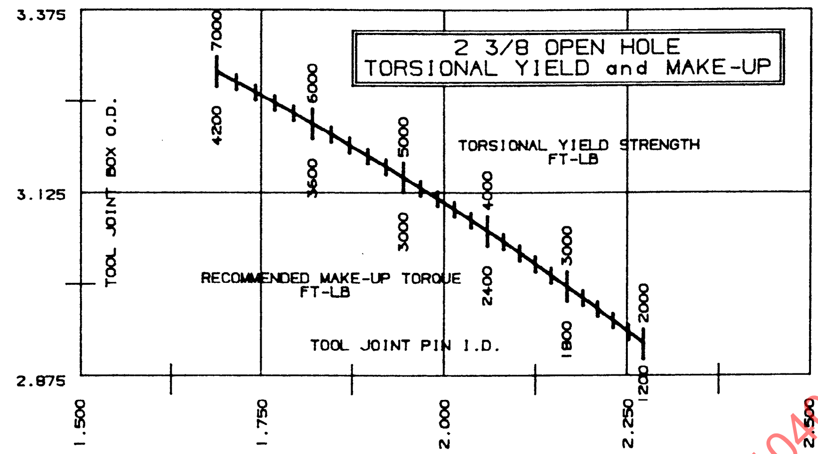


FIG. 2.2

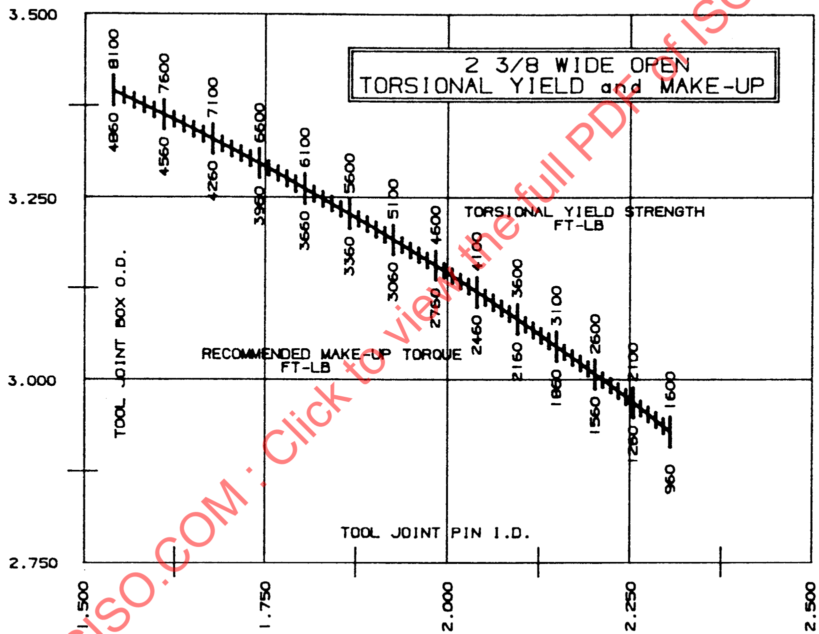


FIG. 2.3

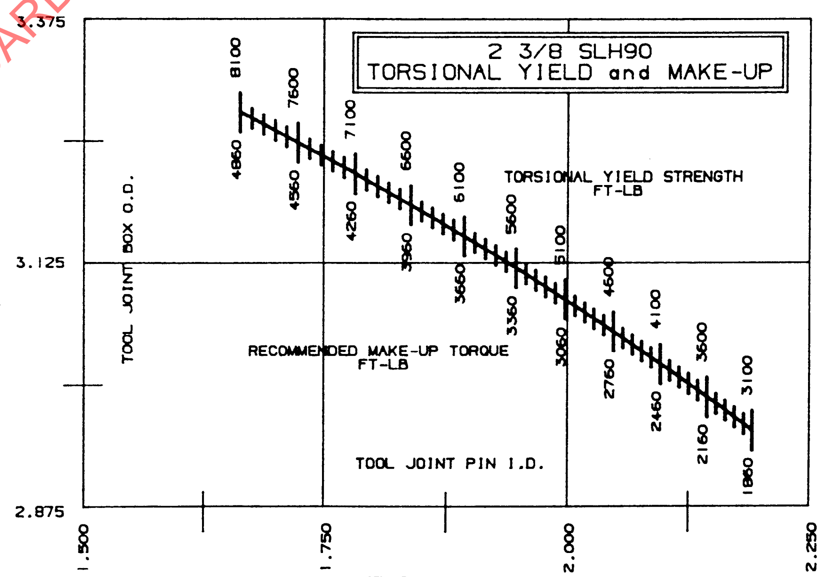


FIG. 2.4

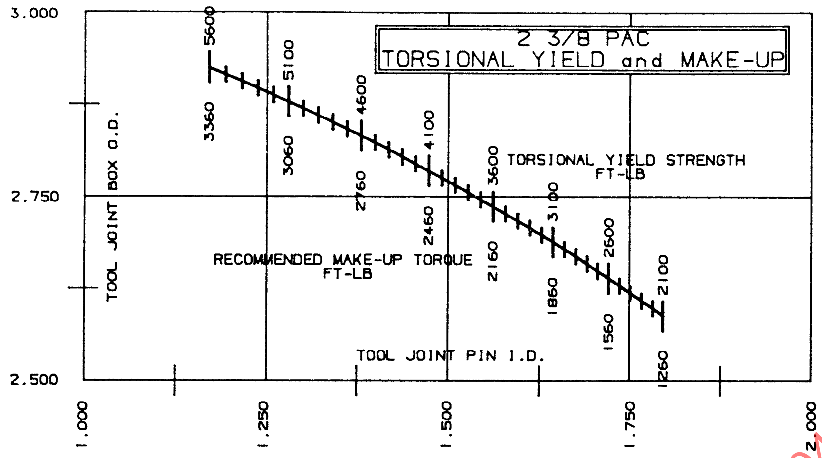


FIG. 2.5

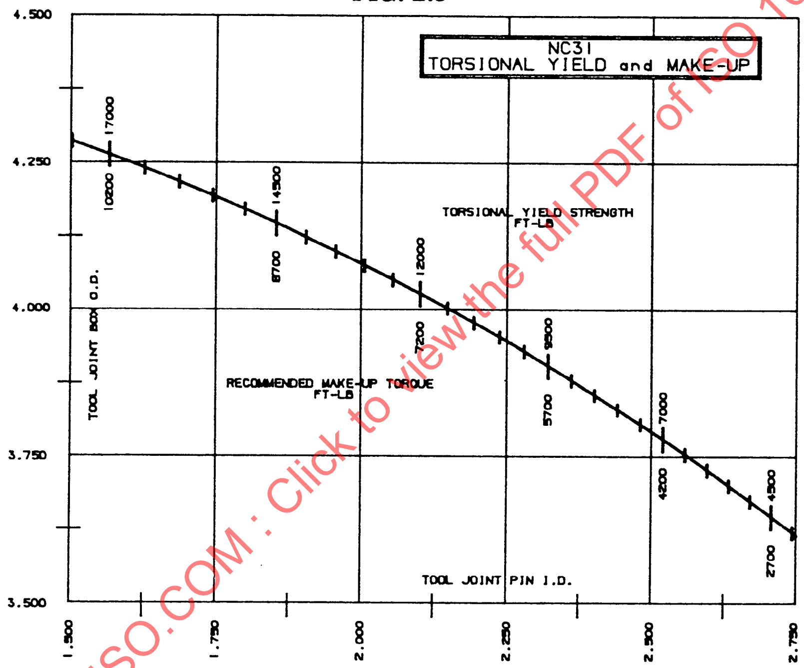


FIG. 2.6

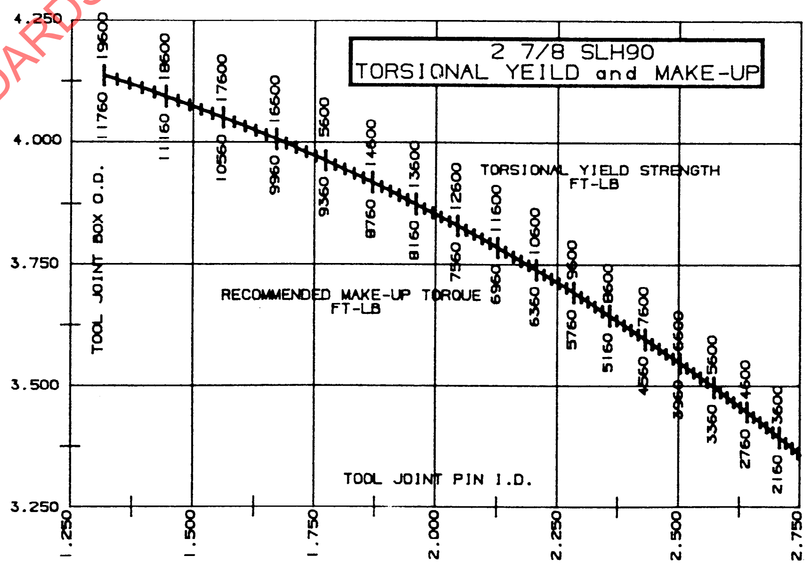


FIG. 2.7

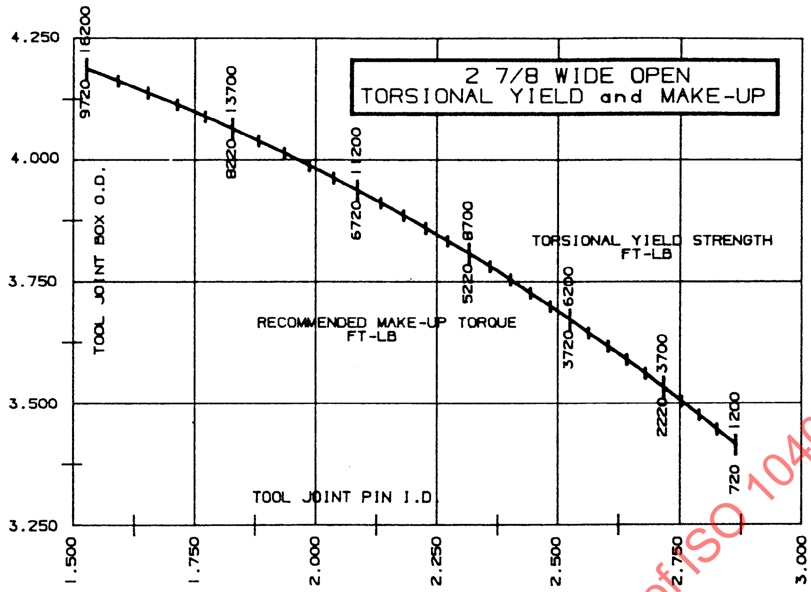


FIG. 2.8

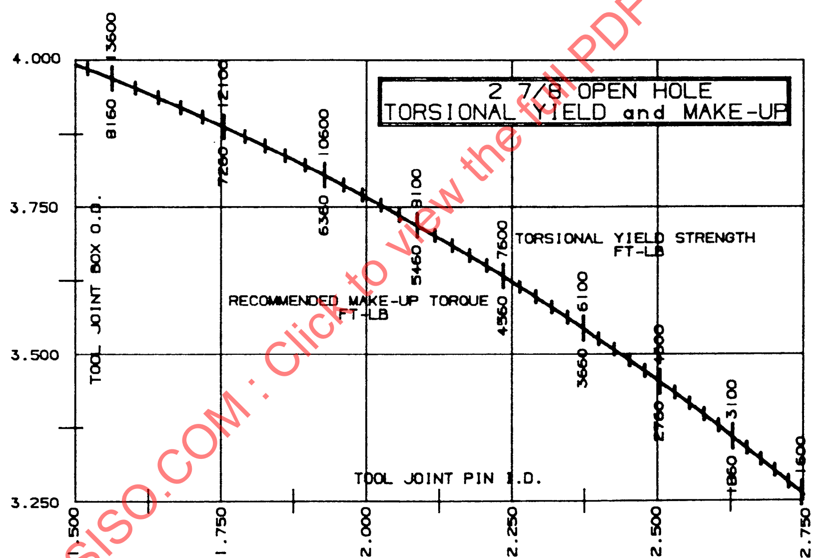


FIG. 2.9

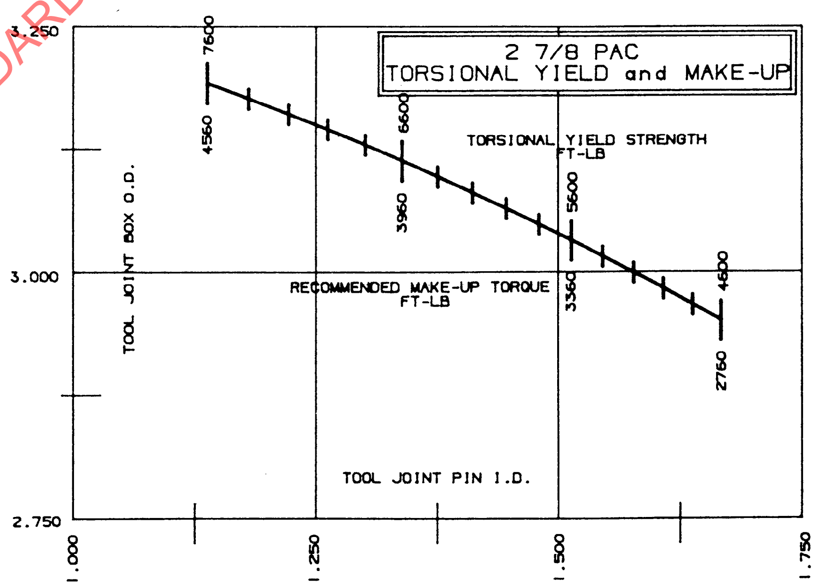


FIG. 2.10

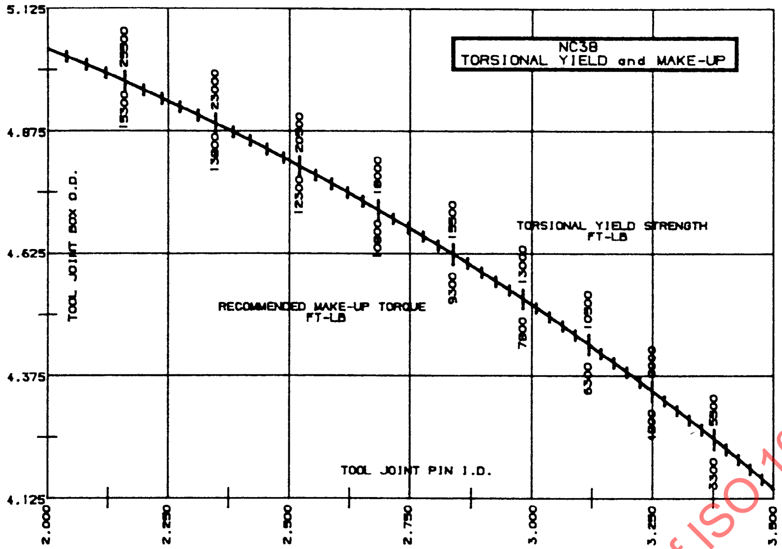


FIG. 2.11

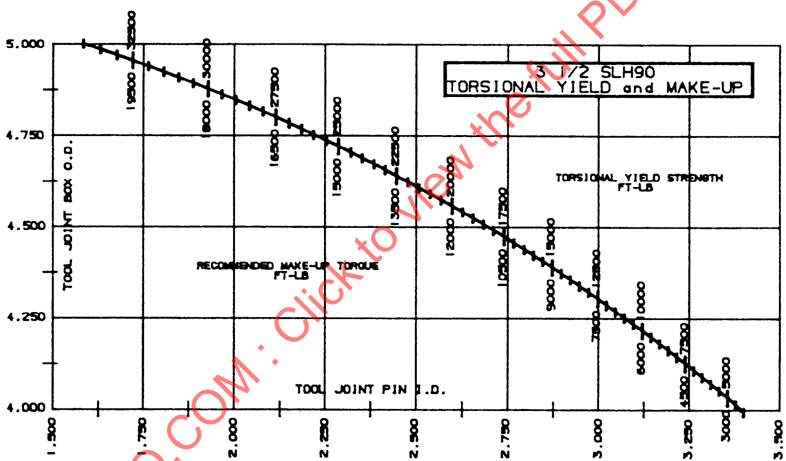


FIG. 2.12

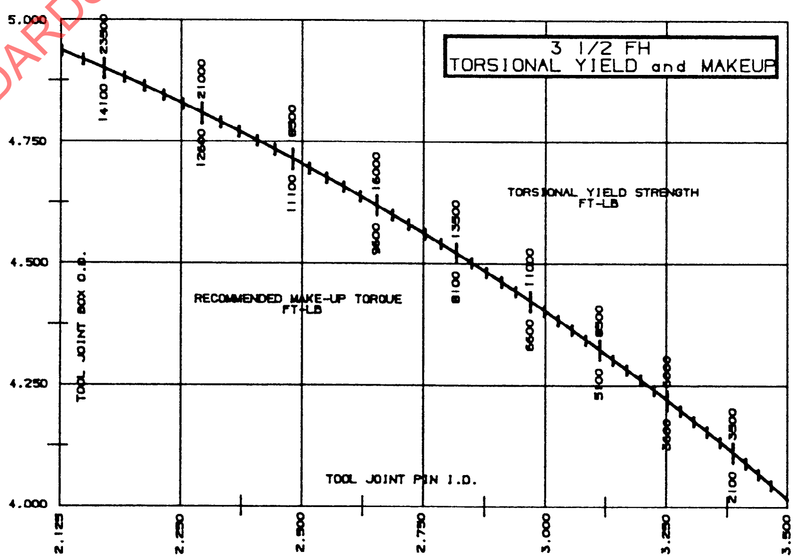


FIG. 2.13

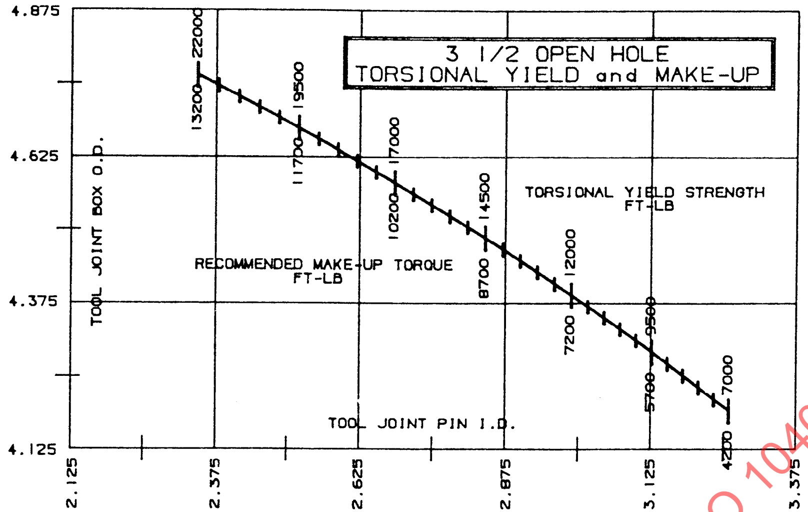


FIG. 2.14

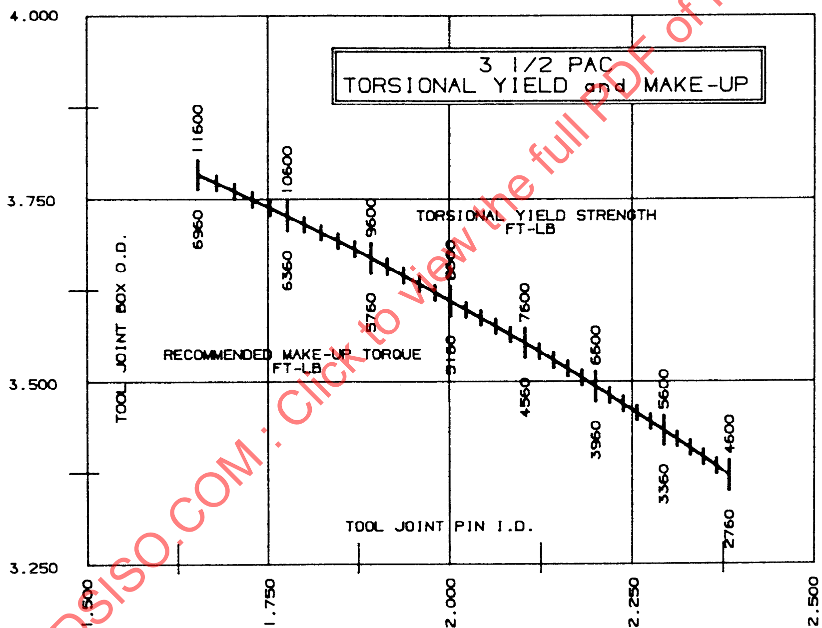


FIG. 2.15

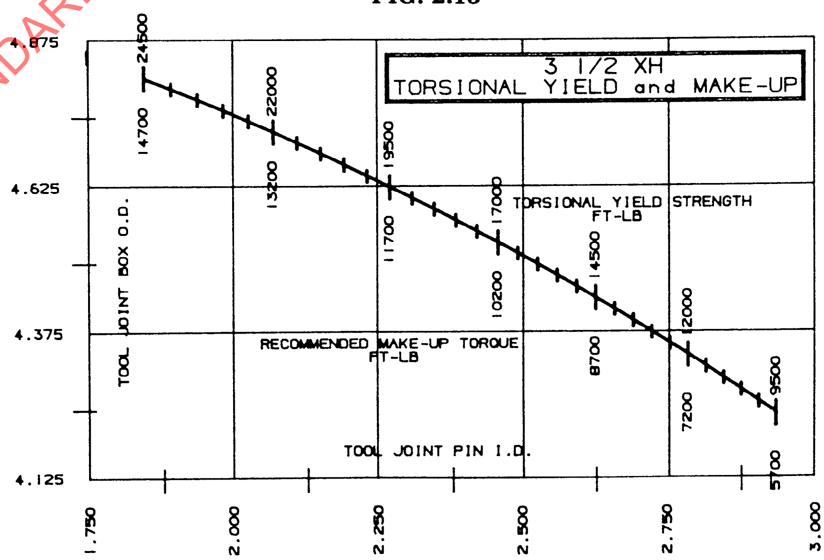


FIG. 2.16

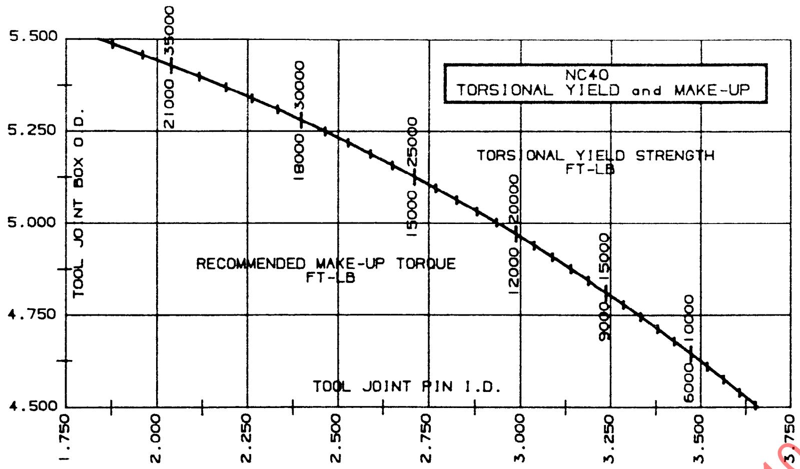


FIG. 2.17

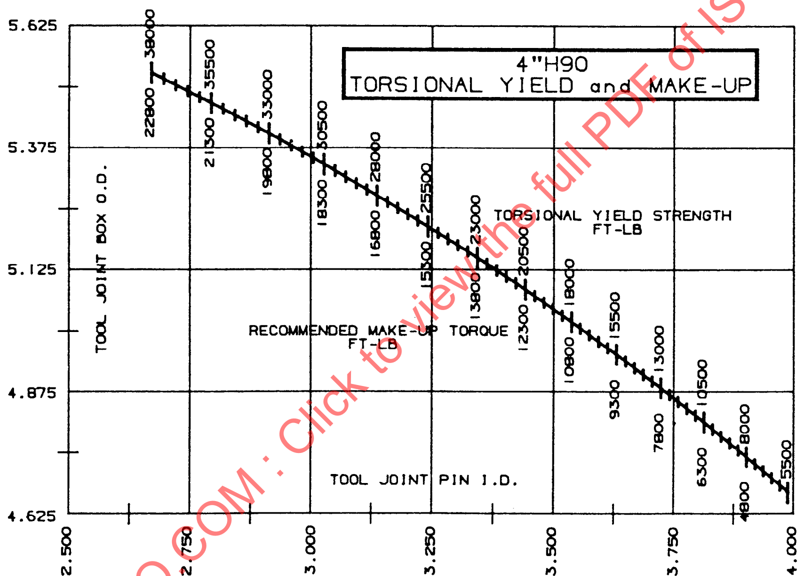


FIG. 2.18

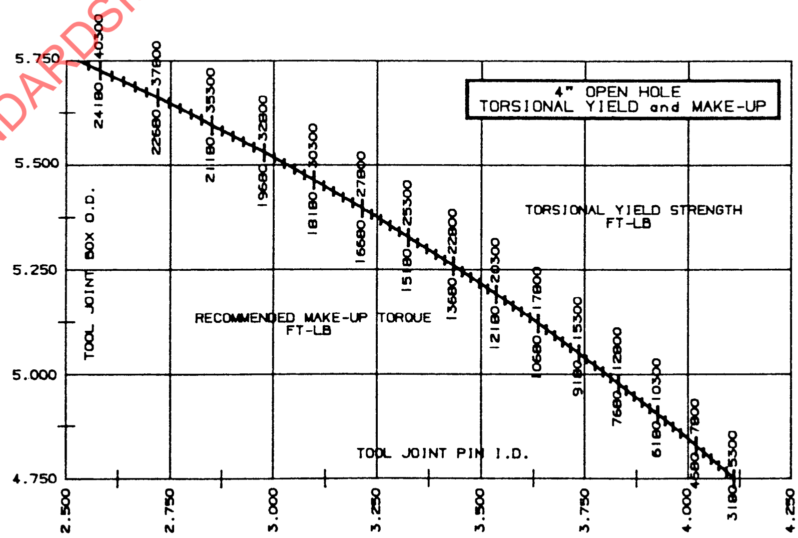


FIG. 2.19

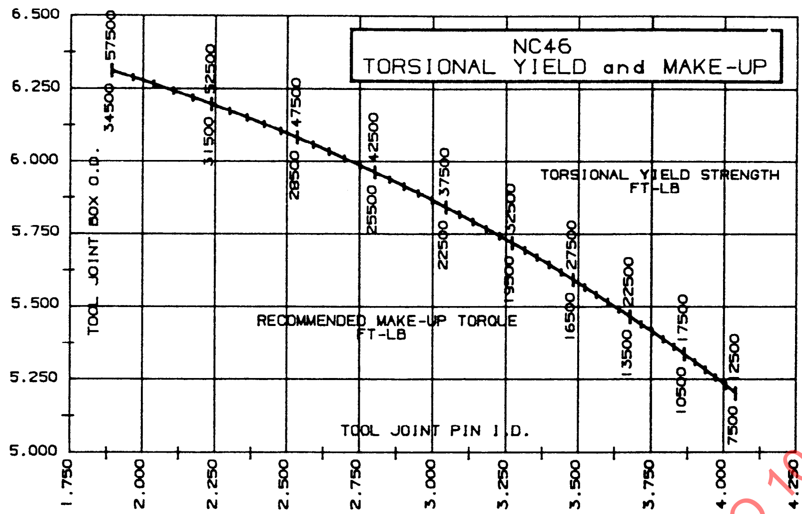


FIG. 2.20

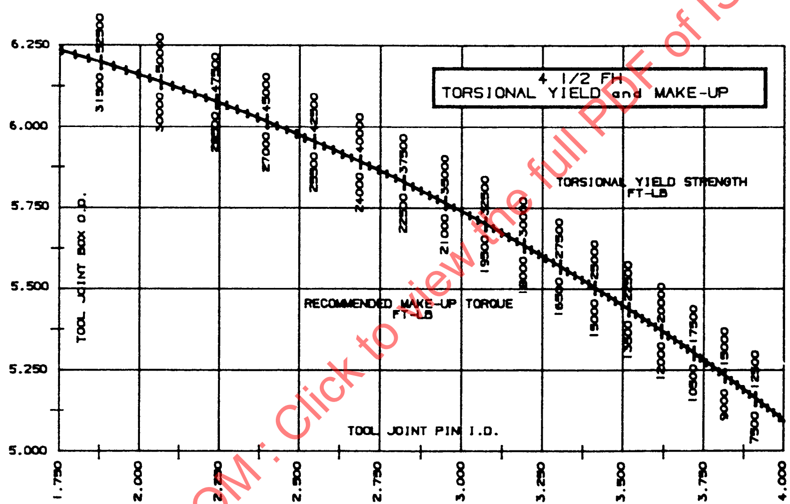


FIG. 2.21

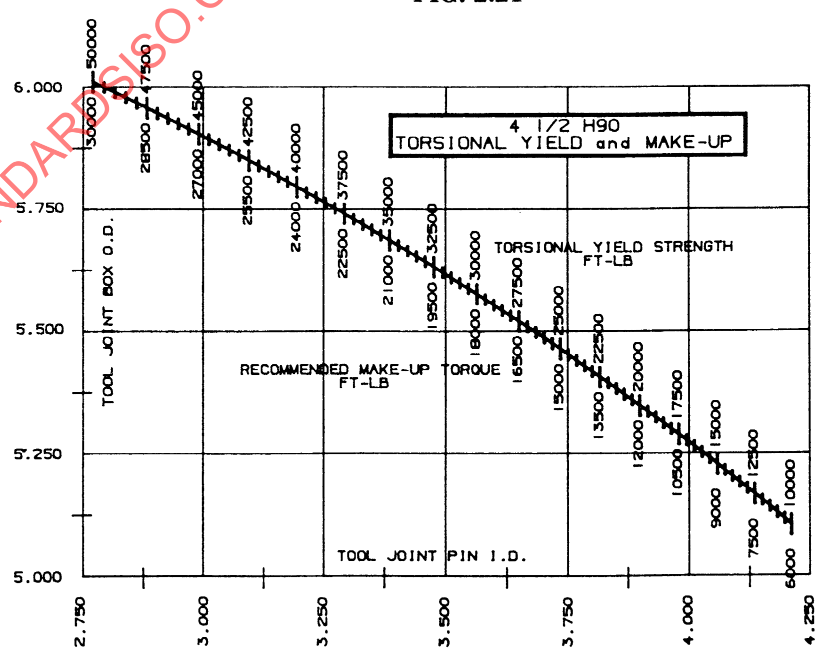


FIG. 2.22

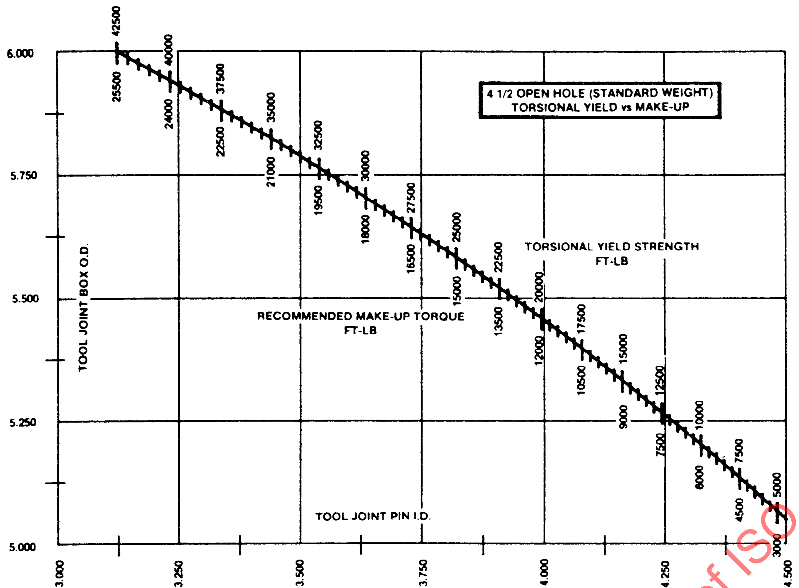


FIG. 2.23

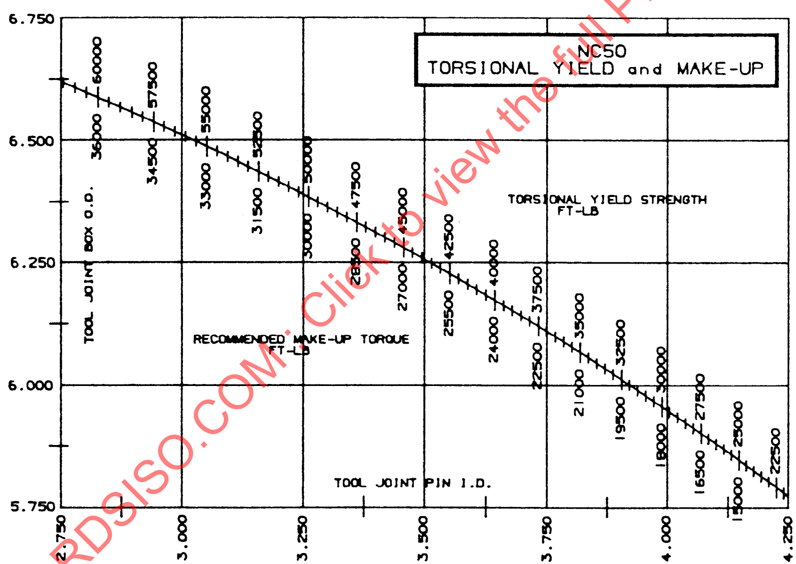


FIG. 2.24

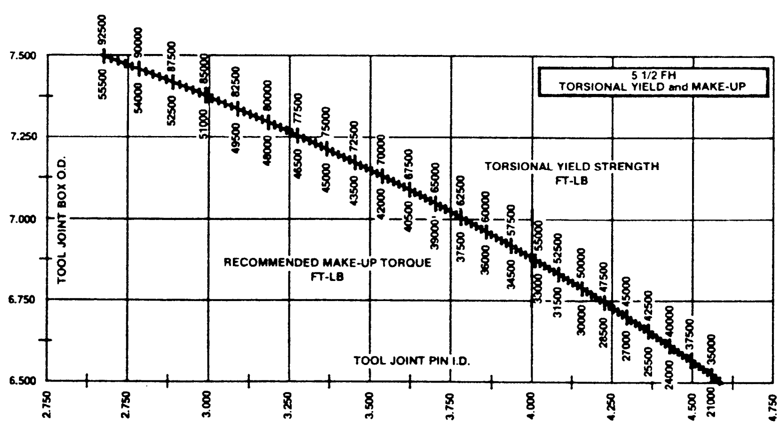


FIG. 2.25

SECTION 3
PROPERTIES OF DRILL COLLARS

3.1 Table 3.1 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.

3.2 Recommended make-up torque values for rotary shouldered drill collar connections are listed in Table 3.2. 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.

TABLE 3.1
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	1¼	1½	1¾	2	2¼	2½	2 13/16	3	3¼	3½	3¾	4
2⅞	19	18	16										
3	21	20	18										
3⅛	22	22	20										
3¼	26	24	22										
3½	30	29	27										
3¾	35	33	32										
4	40	39	37	35	32	29							
4⅛	43	41	39	37	35	32							
4¼	46	44	42	40	38	35							
4½	51	50	48	46	43	41							
4¾			54	52	50	47	44						
5			61	59	56	53	50						
5¼			68	65	63	60	57						
5½			75	73	70	67	64	60					
5¾			82	80	78	75	72	67	64	60			
6			90	88	85	83	79	75	72	68			
6¼			98	96	94	91	88	83	80	76	72		
6½			107	105	102	99	96	91	89	85	80		
6¾			116	114	111	108	105	100	98	93	89		
7			125	123	120	117	114	110	107	103	98	93	84
7¼			134	132	130	127	124	119	116	112	108	103	93
7½			144	142	139	137	133	129	126	122	117	113	102
7¾			154	152	150	147	144	139	136	132	128	123	112
8			165	163	160	157	154	150	147	143	138	133	122
8¼			176	174	171	168	165	160	158	154	149	144	133
8½			187	185	182	179	176	172	169	165	160	155	150
9			210	208	206	203	200	195	192	188	184	179	174
9½			234	232	230	227	224	220	216	212	209	206	198
9¾			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

NOTE 1: Refer to API Spec 7, Table 6.1 for API standard drill collar dimensions.
NOTE 2: For special configurations of drill collars, consult manufacturer for reduction in weight.

TABLE 3.2
RECOMMENDED MAKE-UP TORQUE ① 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
Connection			Minimum Make-up Torque ft-lb②									
			Bore of Drill Collar, inches									
Size, in.	Type	OD, in.	1	1¼	1½	1¾	2	2¼	2½	2 13/16	3	3¼
API	NC 23	3	*2,500	*2,500	*2,500							
		3⅛	*3,300	*3,300	2,600							
		3¼	4,000	3,400	2,600							
2⅜	Regular	3		*2,200	*2,200	*2,200						
		3⅛		*3,000	*3,000	2,600						
		3¼		*3,900	*3,300	2,600						
2⅞	PAC③	3		*3,800	*3,800	2,900						
		3⅛		*4,900	4,200	2,900						
		3¼		5,200	4,200	2,900						
2⅜	API IF	3½		*4,600	*4,600	3,700						
API	NC 26	3¾		5,500	4,700	3,700						
2⅞	Regular	3½		*3,800	*3,800	*3,800						
		3¾		*6,000	5,800	5,000						
		3⅞		6,500	5,800	5,000						
2⅞	Slim Hole											
2⅞	Extra Hole	3¾		*4,100	*4,100	*4,100						
3½	Dbl. Streamline	3⅞		*5,300	*5,300	*5,300						
2⅞	Mod. Open	4⅛		*8,000	*8,000	7,400						
2⅞	API IF	3⅞		*4,600	*4,600	*4,600	*4,600					
API	NC 31	4⅛		*7,300	*7,300	*7,300	6,800					
3½	Regular	4⅛		*6,500	*6,500	*6,500	*6,500	*6,500				
		4¼		*7,900	*7,900	*7,900	*7,900	7,200				
		4½		*10,900	10,500	9,600	8,500	7,300				
3½	Slim Hole	4¼		*8,800	*8,800	8,100	6,800					
		4½		10,000	9,300	8,100	6,800					
API	NC 35	4½				*8,900	*8,900	*8,900	7,400			
		4¾				12,100	10,800	9,200	7,400			
		5				12,100	10,800	9,200	7,400			
3½	Extra Hole	4¼				*5,100	*5,100	*5,100	*5,100			
4	Slim Hole	4½				*8,400	*8,400	*8,400	8,200			
3½	Mod. Open	4¾				*11,900	11,700	10,000	8,200			
		5				13,200	11,700	10,000	8,200			
		5¼				13,200	11,700	10,000	8,200			
3½	API IF	4¾				*9,900	*9,900	*9,900	*9,900	8,300		
API	NC 38	5				*13,800	*13,800	12,800	10,900	8,300		
4½	Slim Hole	5¼				16,000	14,600	12,800	10,900	8,300		
		5½				16,000	14,600	12,800	10,900	8,300		
3½	H-90④	4¾				*8,700	*8,700	*8,700	*8,700	*8,700		
		5				*12,700	*12,700	*12,700	*12,700	10,400		
		5¼				*16,900	16,700	15,000	13,100	10,400		
		5½				18,500	16,700	15,000	13,100	10,400		
4	Full Hole	5				*10,800	*10,800	*10,800	*10,800	*10,800		
API	NC 40	5¼				*15,100	*15,100	*15,100	14,800	12,100		
4	Mod. Open	5½				*19,700	18,600	16,900	14,800	12,100		
4½	Dbl. Streamline	5¾				20,400	18,600	16,900	14,800	12,100		
		6				20,400	18,600	16,900	14,800	12,100		
4	H-90④	5¼					*12,500	*12,500	*12,500	*12,500		
		5½					*17,300	*17,300	*17,300	16,500		
		5¾					*22,300	21,500	19,400	16,500		
		6					23,500	21,500	19,400	16,500		
		6¼					23,500	21,500	19,400	16,500		
4½	API Regular	5½					*15,400	*15,400	*15,400	*15,400		
		5¾					*20,300	*20,300	19,400	16,200		
		6					23,400	21,600	19,400	16,200		
		6¼					23,400	21,600	19,400	16,200		
API	NC 44	5¾					*20,600	*20,600	*20,600	18,000		
		6					25,000	23,300	21,200	18,000		
		6¼					25,000	23,300	21,200	18,000		
		6½					25,000	23,300	21,200	18,000		
4½	API Full Hole	5½					*12,900	*12,900	*12,900	*12,900	*12,900	
		5¾					*17,900	*17,900	*17,900	*17,900	17,700	
		6					*23,300	*23,300	22,800	19,800	17,700	
		6¼					27,000	25,000	22,800	19,800	17,700	
		6½					27,000	25,000	22,800	19,800	17,700	
4½	Extra Hole	5¾						*17,600	*17,600	*17,600	*17,600	
API	NC 46	6						*23,200	*23,200	22,200	20,200	
4	API IF	6¼						28,000	25,500	22,200	20,200	
4½	Semi IF	6½						28,000	25,500	22,200	20,200	
5	Dbl. Streamline	6¾						28,000	25,500	22,200	20,200	
4½	Mod. Open											
4½	H-90④	5¾						*17,600	*17,600	*17,600	*17,600	
		6						*23,400	*23,400	23,000	21,000	
		6¼						28,500	26,000	23,000	21,000	
		6½						28,500	26,000	23,000	21,000	
		6¾						28,500	26,000	23,000	21,000	
5	H-90④	6¼						*25,000	*25,000	*25,000	*25,000	
		6½						*31,500	*31,500	29,500	27,000	
		6¾						35,000	33,000	29,500	27,000	
		7						35,000	33,000	29,500	27,000	

(continued on next page)

TABLE 3.2 (continued)
RECOMMENDED MAKE-UP TORQUE① FOR ROTARY SHOULDERED DRILL COLLAR CONNECTIONS
(See footnotes for use of this table.)

1	2	3	4	5	6	7	8	9	10
Connection			Minimum Make-up Torque, ft-lb②						
			Bore of Drill Collar, inches						
Size, in.	Type	OD, in.	2¼	2½	2 13/16	3	3¼	3½	3¾
4½	API IF	6¼	*22,800	*22,800	*22,800	*22,800	*22,800		
API	NC 50	6½	*29,500	*29,500	*29,500	*29,500	26,500		
5	Extra Hole	6¾	*36,000	35,500	32,000	30,000	26,500		
5	Mod. Open	7	38,000	35,500	32,000	30,000	26,500		
5½	Dbl. Streamline	7¼	38,000	35,500	32,000	30,000	26,500		
5	Semi-IF								
5½	H-90④	6¾	*34,000	*34,000	*34,000	34,000			
		7	*41,500	40,000	36,500	34,000			
		7¼	42,500	40,000	36,500	34,000			
		7½	42,500	40,000	36,500	34,000			
5½	API Regular	6¾	*31,500	*31,500	*31,500	*31,500			
		7	*39,000	*39,000	36,000	33,500			
		7¼	42,000	39,500	36,000	33,500			
		7½	42,000	39,500	36,000	33,500			
5½	API Full Hole	7		*32,500	*32,500	*32,500	*32,500		
		7¼		*40,500	*40,500	*40,500	*40,500		
		7½		*49,000	47,000	45,000	41,500		
		7¾		51,000	47,000	45,000	41,500		
API	NC 56	7¼		*40,000	*40,000	*40,000	*40,000		
		7½		*48,500	48,000	45,000	42,000		
		7¾		51,000	48,000	45,000	42,000		
		8		51,000	48,000	45,000	42,000		
6⅝	API Regular	7½		*46,000	*46,000	*46,000	*46,000		
		7¾		*55,000	53,000	50,000	47,000		
		8		57,000	53,000	50,000	47,000		
		8¼		57,000	53,000	50,000	47,000		
6⅝	H-90④	7½		*46,000	*46,000	*46,000	*46,000		
		7¾		*55,000	*55,000	53,000	49,500		
		8		59,500	56,000	53,000	49,500		
		8¼		59,500	56,000	53,000	49,500		
API	NC 61	8		*54,000	*54,000	*54,000	*54,000		
		8¼		*64,000	*64,000	*64,000	61,000		
		8½		72,000	68,000	65,000	61,000		
		8¾		72,000	68,000	65,000	61,000		
		9		72,000	68,000	65,000	61,000		
5½	API IF	8		*56,000	*56,000	*56,000	*56,000	*56,000	
		8¼		*66,000	*66,000	*66,000	63,000	59,000	
		8½		74,000	70,000	67,000	63,000	59,000	
		8¾		74,000	70,000	67,000	63,000	59,000	
		9		74,000	70,000	67,000	63,000	59,000	
		9¼		74,000	70,000	67,000	63,000	59,000	
6⅝	API Full Hole	8½			*67,000	*67,000	*67,000	*67,000	66,500
		8¾			*78,000	*78,000	76,000	72,000	66,500
		9			83,000	80,000	76,000	72,000	66,500
		9¼			83,000	80,000	76,000	72,000	66,500
		9½			83,000	80,000	76,000	72,000	66,500
API	NC 70	9			*75,000	*75,000	*75,000	*75,000	*75,000
		9¼			*88,000	*88,000	*88,000	*88,000	*88,000
		9½			*101,000	*101,000	100,000	95,000	90,000
		9¾			107,000	105,000	100,000	95,000	90,000
		10			107,000	105,000	100,000	95,000	90,000
		10¼			107,000	105,000	100,000	95,000	90,000
API	NC 77	10				*107,000	*107,000	*107,000	*107,000
		10¼				*122,000	*122,000	*122,000	*122,000
		10½				*138,000	*138,000	133,000	128,000
		10¾				143,000	138,000	133,000	128,000
		11				143,000	138,000	133,000	128,000
7	H-90④	8			*53,000	*53,000	*53,000	*53,000	
		8¼			*63,000	*63,000	*63,000	60,500	
		8½			71,500	68,500	65,000	60,500	
7⅝	API Regular	8½				*60,000	*60,000	*60,000	*60,000
		8¾				*71,000	*71,000	*71,000	*71,000
		9				*83,000	*83,000	79,000	74,000
		9¼				88,000	83,000	79,000	74,000
		9½				88,000	83,000	79,000	74,000
7⅝	H-90④	9				*72,000	*72,000	*72,000	*72,000
		9¼				*85,500	*85,500	*85,500	*85,500
		9½				*98,000	*98,000	*98,000	95,500
8⅝	API Regular	10				*108,000	*108,000	*108,000	*108,000
		10¼				*123,000	*123,000	*123,000	123,000
		10½				139,000	134,000	129,000	123,000

(continued on next page)

TABLE 3.2 (continued)
RECOMMENDED MAKE-UP TORQUE① FOR ROTARY SHOULDERED DRILL COLLAR CONNECTIONS
(See footnotes for use of this table.)

1	2	3	4	5	6	7	8	9	10
Connection			Minimum Make-up Torque ft-lb②						
			Bore of Drill Collar, inches						
Size, in.	Type	OD, in.	2¼	2½	2 13/16	3	3¼	3½	3¾
8⅝	H-90④	10¼				*112,500	*112,500	*112,500	*112,500
		10½				*128,500	*128,500	*128,500	*128,500
7	H-90④	8¾			*67,500	*67,500	66,500	62,000	
	(with low torque face)	9			74,000	71,000	66,500	62,000	
7⅝	API Regular	9¼				*72,000	* 72,000	* 72,000	* 72,000
	(with low torque face)	9½				*85,000	* 85,000	82,000	77,000
		9¾				91,000	87,000	82,000	77,000
		10				91,000	87,000	82,000	77,000
7⅝	H-90④	9¾				* 91,000	* 91,000	* 91,000	* 91,000
	(with low torque face)	10				*105,000	*105,000	103,500	98,000
		10¼				112,500	108,000	103,500	98,000
		10½				112,500	108,000	103,500	98,000
8⅝	API Regular	10¾				*112,000	*112,000	*112,000	*112,000
	(with low torque face)	11				*129,000	*129,000	*129,000	*129,000
8⅝	H-90④	10¾				* 92,500	* 92,500	* 92,500	* 92,500
	(with low torque face)	11				*110,000	*110,000	*110,000	*110,000
		11¼				*128,000	*128,000	*128,000	*128,000

*NOTE 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.

NOTE 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. 2⅜ API IF, API NC 26, and 2⅞ Slim Hole connections used with 3½ x 1¼ drill collars all have the same minimum make-up torque of 4600 ft. lb., and the BOX is the weaker member.

① Basis of calculations for recommended make-up torque assumed the use of a thread compound containing 40-60% by weight of finely powdered metallic zinc or 60% by weight of finely powdered metallic lead, with not more than 0.3% total active sulfur, applied thoroughly to all threads and shoulders and using the modified Screw Jack formula in Appendix A, paragraph A.8, and a unit stress of 62,500 psi in the box or pin, whichever is weaker.

② Normal torque range is tabulated value plus 10%. Higher torque values may be used under extreme conditions.

③ Make-up torque for 2⅞ PAC connection is based on 87,500 psi stress and other factors listed in footnote①.

④ Make-up torque for H-90 connection is based on 56,200 psi stress and other factors listed in footnote①.

Drill Collar Bending Strength Ratio

3.3 Many drill collar connection failures are a result of bending stresses rather than torsional stresses. Fig. 3.1 through 3.7 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.

3.4 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.

3.5 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.

3.6 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.

3.7 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.

3.8 Minor differences between measured inside diameter and inside diameters in Fig. 3.1 through 3.7 are of little significance; therefore select the figure with the inside diameter closest to measured inside diameter.

3.9 The curves in Fig. 3.1 through 3.7 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 equation, its derivation, and an example of its use are included in Par. A.10, Appendix A.

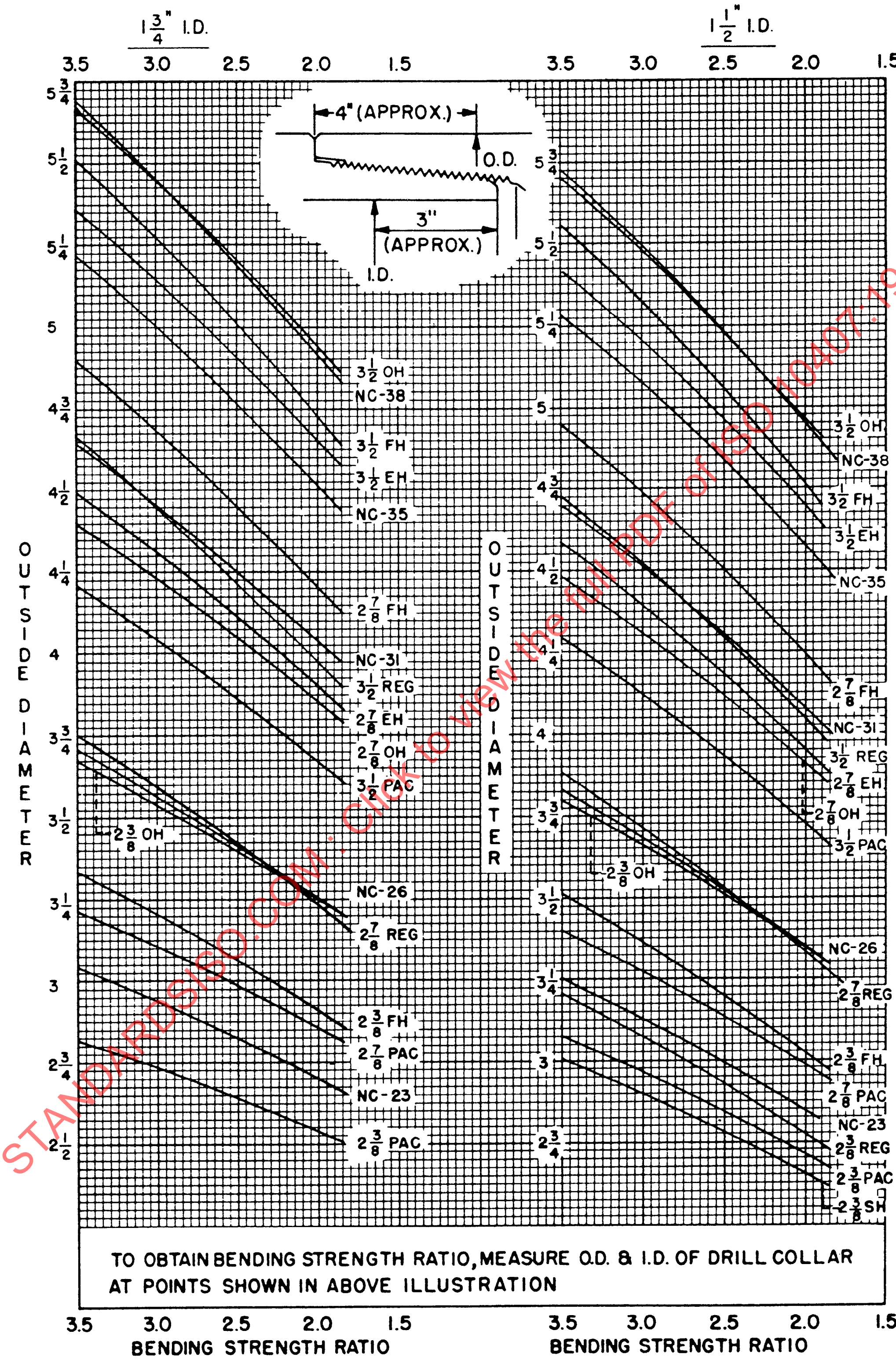


FIG. 3.1
DRILL COLLAR BENDING STRENGTH RATIOS, 1 1/2 AND 1 3/4 INCH ID

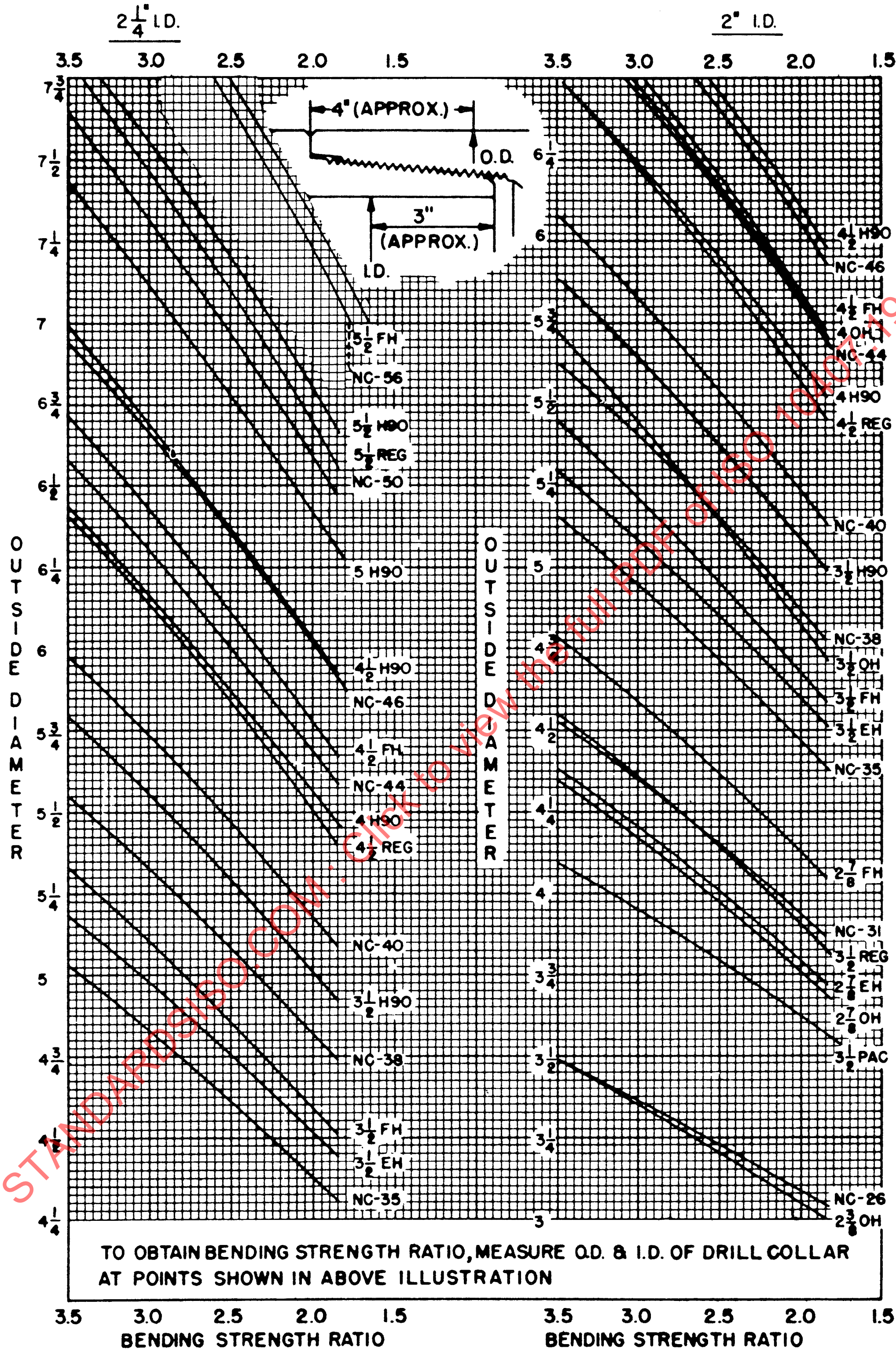


FIG. 3.2
DRILL COLLAR BENDING STRENGTH RATIOS, 2 AND 2 1/4 INCH ID

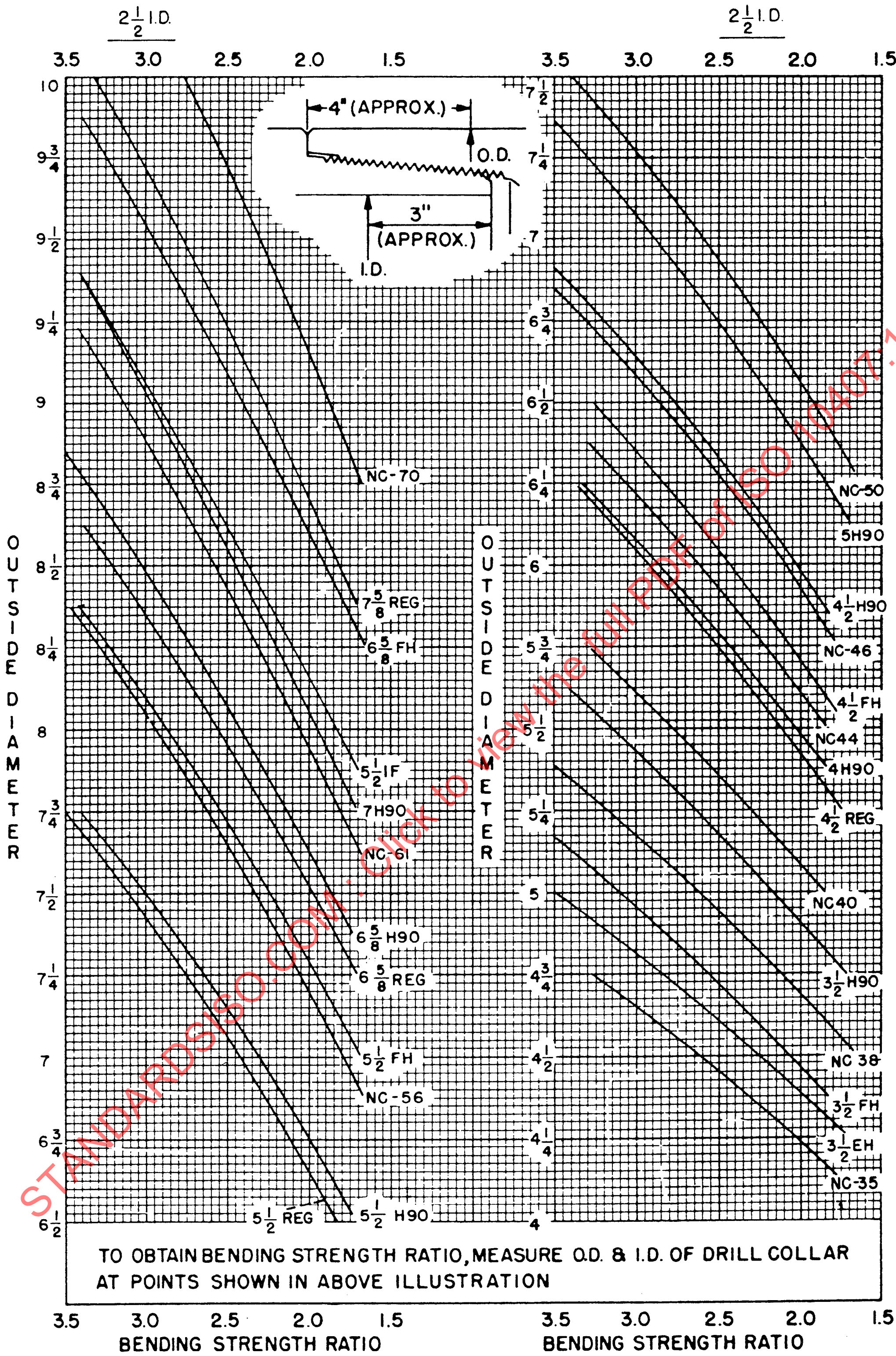


FIG. 3.3
DRILL COLLAR BENDING STRENGTH RATIOS, 2 1/2 INCH ID

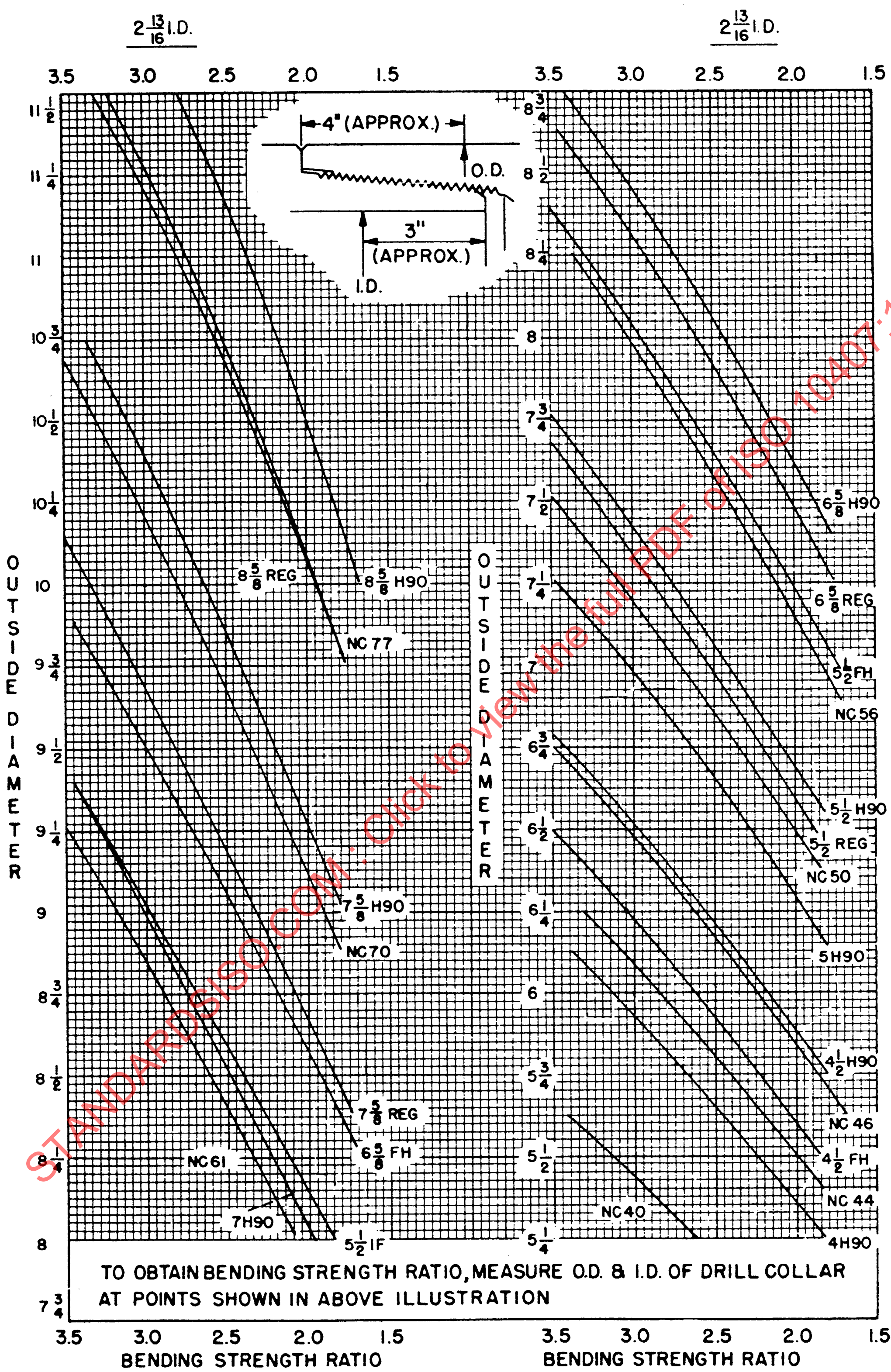


FIG. 3.4
DRILL COLLAR BENDING STRENGTH RATIOS, $2\frac{13}{16}$ INCH ID

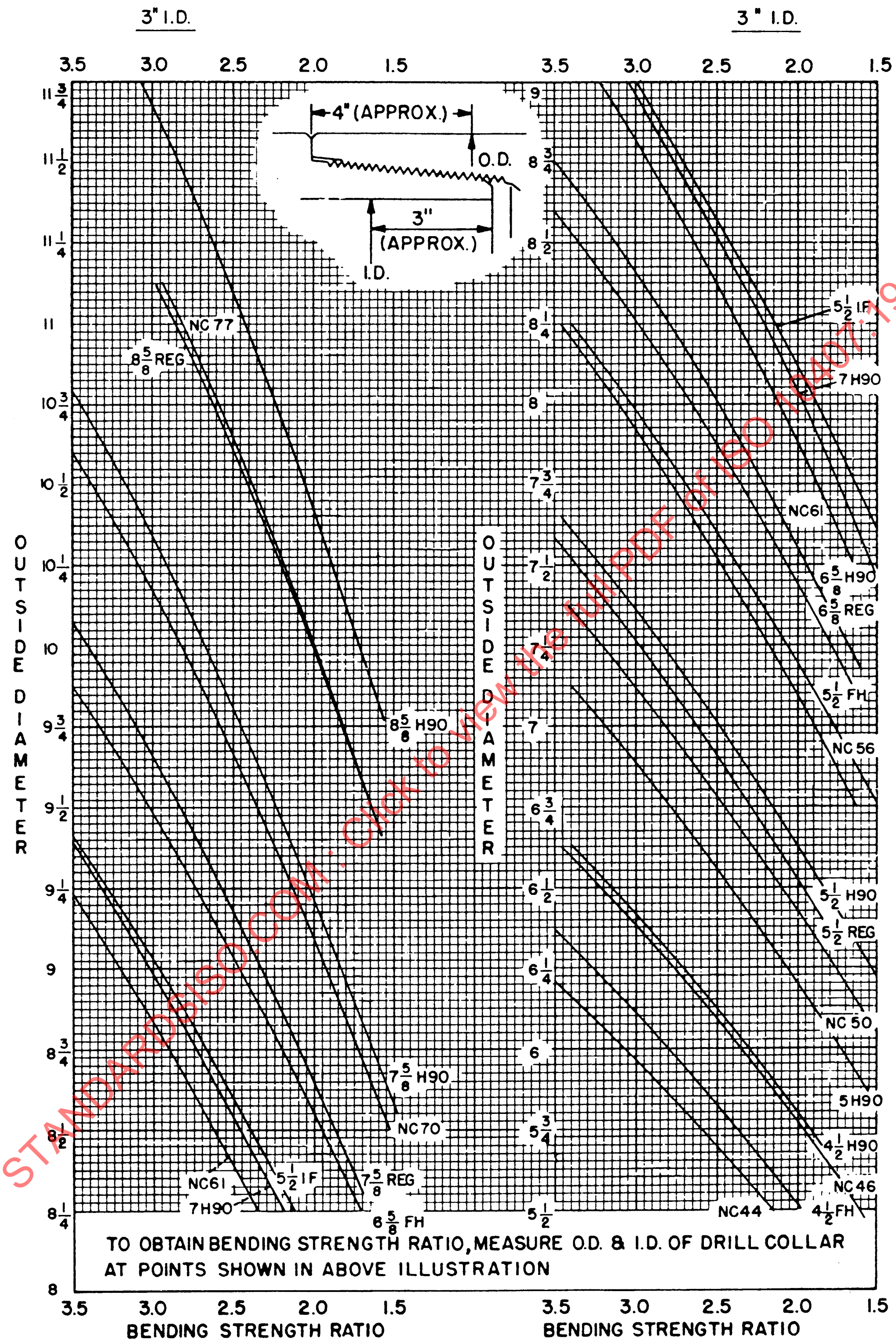


FIG. 3.5
DRILL COLLAR BENDING STRENGTH RATIOS, 3 INCH ID

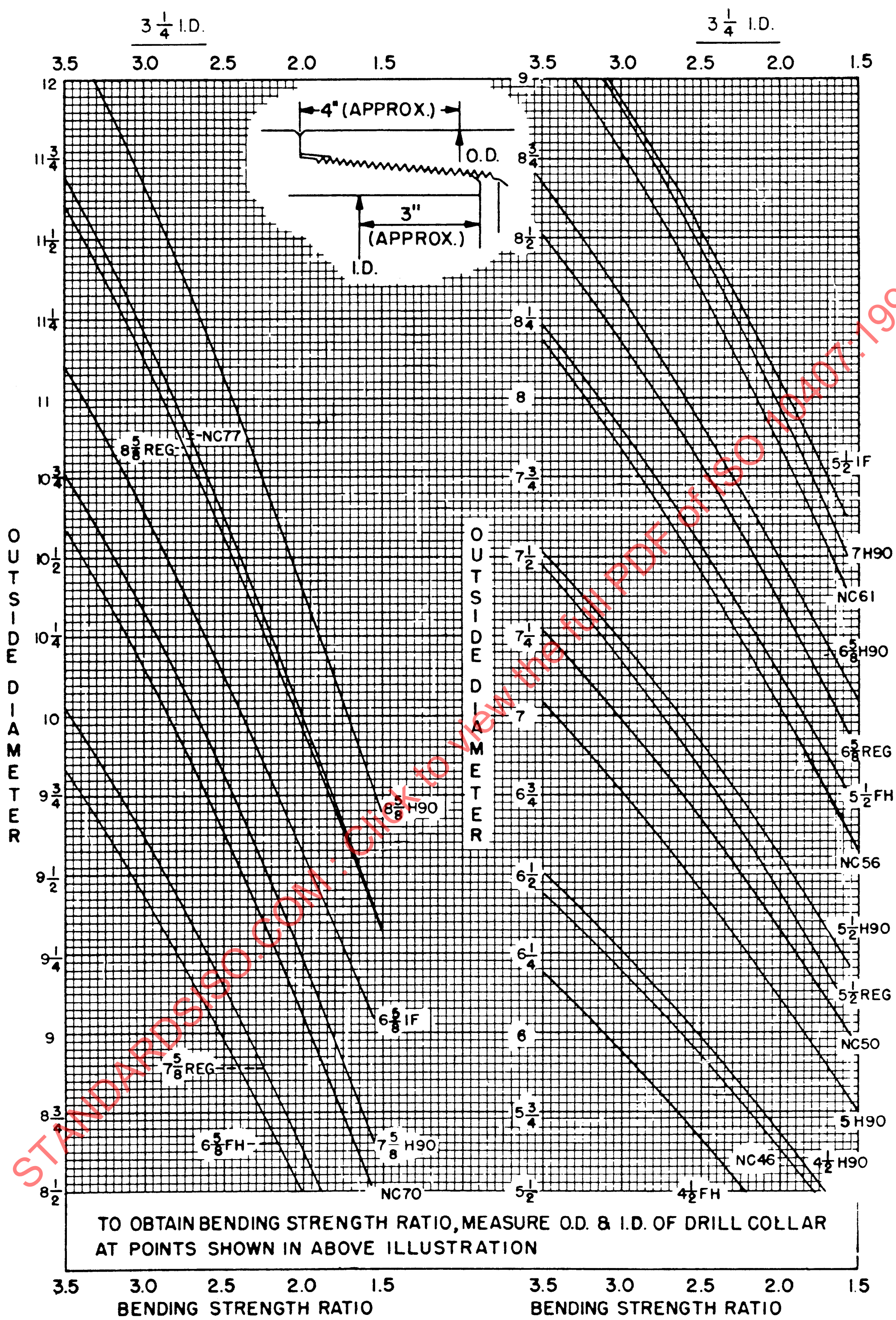


FIG. 3.6
DRILL COLLAR BENDING STRENGTH RATIOS, 3 1/4 INCH ID

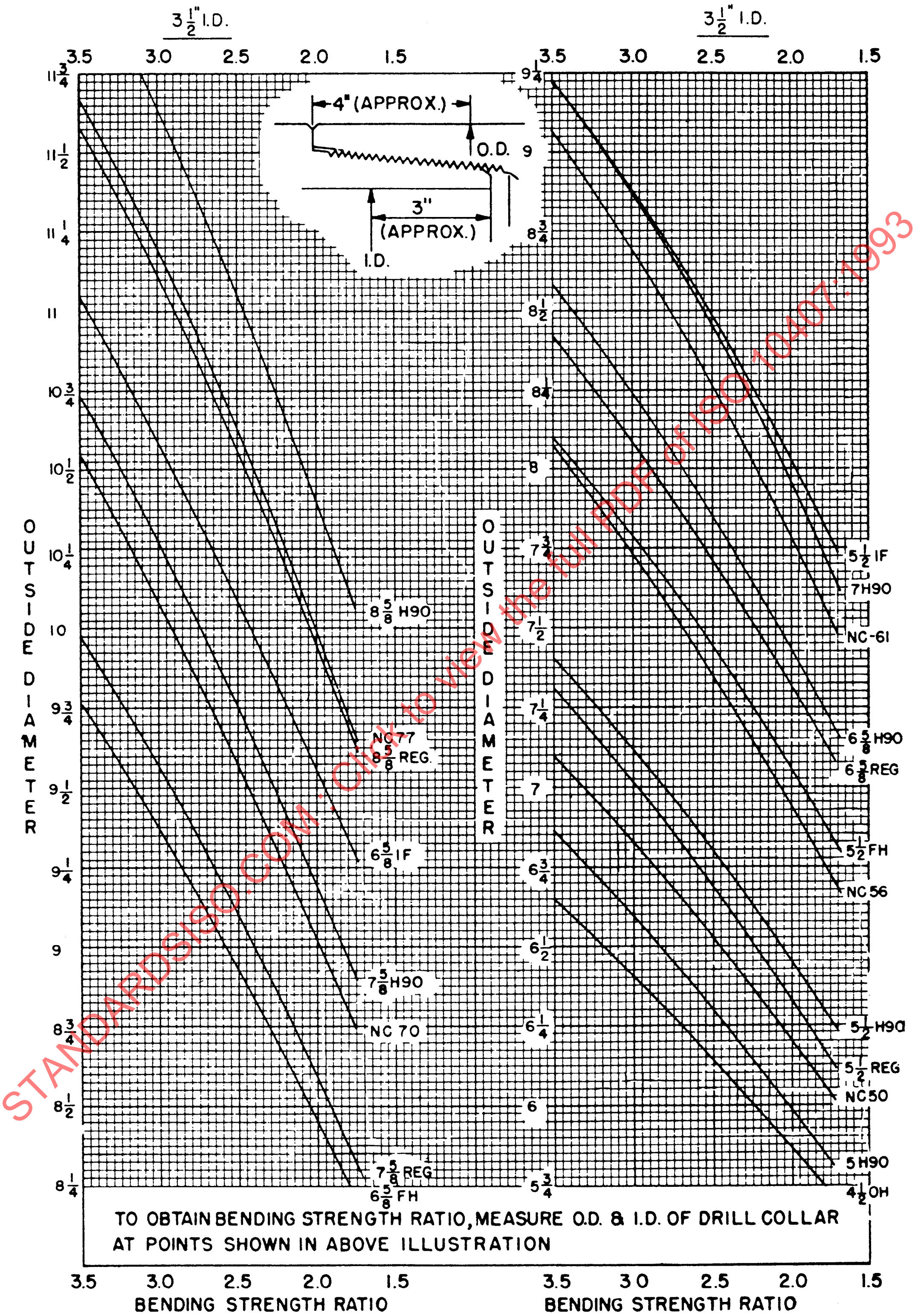


FIG. 3.7
DRILL COLLAR BENDING STRENGTH RATIOS, 3 1/2 INCH ID

SECTION 4
PROPERTIES OF KELLYS

4.1 Kellys are manufactured with one of two drive configurations, square or hexagonal. Dimensions are listed in Table 3.2 and 3.3 of API Spec 7.

4.2 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.

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

a. Full length quenched and tempered before machining, or

b. 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.

4.4 The following criteria should be considered in selecting square or hexagonal kellys.

a. It may be noted from Table 4.1 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 4¼ inch square kelly or a 5¼ inch hexagonal kelly would be selected for use in 8⅝ 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.

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

c. 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.

d. 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.

e. 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.

f. 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. Fig. 4.1 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 4.2. The information in Table 4.2, Figures 4.1 and 4.2 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.

Example: At the time of evaluation, the wear pattern width for a 5¼ inch hexagonal kelly is 1.00 inches.

This could mean one of two conditions exist.

(1) If the contact angle is less than 8° 37 minutes, the original clearances were acceptable. The wear pattern is not fully developed.

(2) If the contact angle is greater than 8° 37 minutes, the wear pattern is fully developed. The clearance is greater than is recommended and should be corrected.

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

a. **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. (Reference Table 4.3 for drive section dimensions and strengths.)

b. **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.

4.6 The internal pressure at minimum yield for the drive section may be calculated from formula A.9 listed in Par. A.5, Appendix A.

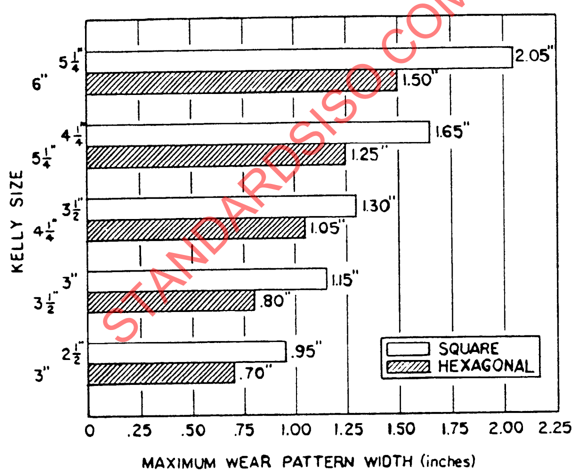
TABLE 4.1
STRENGTH OF KELLYS①

1	2	3	4	5	6	7	8	9	10	11
		Lower Pin Connection			Tensile Yield		Torsional Yield		Yield in Bending	Internal Pressure at Minimum Yield
Kelly Size and Type in.	Kelly Bore in.	Size and Style	OD in.	Minimum② Recom-mended Casing OD in.	Lower Pin Connection③ lb	Drive Section lb	Lower Pin Connection ft-lb	Drive Section ft-lb	Through Drive Section ft-lb	Drive Section psi
2½ Square	1¼	NC26 (2⅜ IF)	3⅜	4½	416,000	444,400	9,650	12,300	13,000	29,800
3 Square	1¾	NC31 (2⅞ IF)	4⅛	5½	535,000	582,500	14,450	19,500	22,300	25,500
3½ Square	2¼	NC38 (3½ IF)	4¾	6⅝	724,000	725,200	22,700	28,300	34,200	22,200
4¼ Square	2 13/16	NC46 (4 IF)	6¼	8⅝	1,054,000	1,047,000	39,350	49,100	60,300	19,500
4¼ Square	2 13/16	NC50 (4½ IF)	6⅝	8⅝	1,375,200	1,047,000	55,810	49,100	60,300	19,500
5¼ Square	3¼	5½ FH	7	9⅝	1,609,000	1,703,400	72,950	99,400	117,000	20,600
3 Hex	1½	NC26 (2⅜ IF)	3⅜	4½	356,000	540,500	8,300	20,400	20,000	26,700
3½ Hex	1¾	NC31 (2⅞ IF)	4⅛	5½	495,000	710,000	13,400	31,400	31,200	25,500
4¼ Hex	2¼	NC38 (3½ IF)	4¾	6⅝	724,000	1,046,600	22,700	56,600	56,000	25,000
5¼ Hex	3	NC46 (4 IF)	6¼	8⅝	960,000	1,507,600	35,450	101,900	103,000	20,600
5¼ Hex	3¼	NC50 (4½ IF)	6⅝	8⅝	1,162,000	1,397,100	46,750	95,500	99,300	20,600
6 Hex	3½	5½ FH	7	9⅝	1,463,000	1,935,500	66,350	149,800	152,500	18,200

①All 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% of the minimum tensile yield strength.

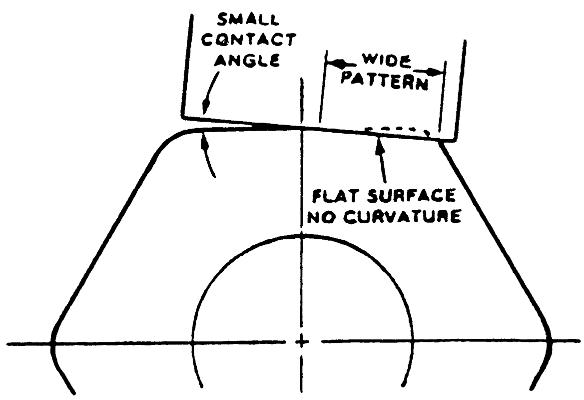
②Clearance between protector rubber on kelly saver sub and casing inside diameter should also be checked.

③Tensile area calculated at root of thread ¾ 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 4.2 and is accurate within 5%.

FIG. 4.1
NEW KELLY-NEW DRIVE ASSEMBLY



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

FIG. 4.2
NEW KELLY-NEW DRIVE ASSEMBLY

TABLE 4.2
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 Min. Clearance in.	Contact Angle Deg. Min.	For Max. Clearance in.	Contact Angle Deg. Min.	For Min. Clearance in.	Contact Angle Deg. Min.	For Max. Clearance in.	Contact Angle Deg. Min.
2½	---	---	---	---	.015	6°10′	.107	16°29′
3	.015	5°41′	.060	11°22′	.015	5°39′	.107	15°5′
3½	.015	5°16′	.060	10°32′	.015	5°14′	.107	14°2′
4¼	.015	4°48′	.060	9°34′	.015	4°45′	.123	13°36′
5¼	.015	4°19′	.060	8°37′	.015	4°17′	.123	12°16′
6	.015	4°2′	.060	8°4′	---	---	---	---

TABLE 4.3
STRENGTH OF REMACHINED KELLYS[1]

1	2	3	4	5	6	7	8	9	10
			Lower Pin Connection		Tensile Yield		Torsional Yield		Yield in Bending
Original Kelly Size and Type in.	Remachined Kelly Size and Type in.	Kelly Bore in.	Size and Style	OD in.	Lower Pin Connection[2] lb.	Drive Section lb.	Lower Pin Connection ft/lb	Drive Section ft/lb	Through Drive Section ft/lb
4¼ Square	4 Square	2⅞	NC50 (4½ IF)	6⅜	1,344,200	834,400	55,500	36,200	47,800
4¼ Square	4 Square	2⅞	NC46 (4 IF)	6¼	1,011,600	834,400	38,300	36,200	47,800
5¼ Square	5 Square	3¾	5½ IF	7⅜	1,924,300	1,217,600	92,700	65,000	90,200
5¼ Square	5 Square	3¾	5½ FH	7	1,356,800	1,217,600	58,900	65,000	90,200
5¼ Hex	$4\frac{27}{32}$ Hex	3¼	NC46 (4 IF)	6¼	809,800	1,077,100	30,600	68,600	74,000
5¼ Hex	5 Hex	3¼	NC46 (4 IF)	6¼	809,800	1,196,800	30,600	78,500	83,300
5¼ Hex	5 Hex	3½	NC50 (4½ IF)	6⅜	999,900	1,077,600	40,800	71,100	78,400
6 Hex	5¾ Hex	4	5½ FH	7	1,189,500	1,443,400	51,300	109,100	119,900
6 Hex	5¾ Hex	4⅛	5½ IF	7⅜	1,669,200	1,371,500	80,400	103,800	116,200

[1] 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% of the minimum tensile yield strength.
[2] Tensile area calculated at root of thread ¾ inch from pin shoulder.
[3] Kelly bushings are normally available for kellys in above table.

SECTION 5
DESIGN CALCULATIONS

5.1 Design Parameters. It is intended to outline a step-by-step procedure to insure complete consideration of factors, and to simplify caculations. 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, O.D., I.D., and weight per foot.
g. Desired drill pipe sizes, and inspection class.

5.2 **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.

5.3 **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.

5.4 **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 weight of the collars, stabilizer, and bit. This load may be calculated as shown in Equation 5.31. The bit and stabilizer weights are either neglected or included with the drill collar weight.

$$P = [(L_{dp} \times W_{dp}) + (L_c \times W_c)]\ K_b \qquad 5.31$$

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 2.13.

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 2.13, a one-pound weight submerged in a 14 lb./gal. mud would have an apparent weight of .786 lb.

Tension load data is given in Tables 2.2, 2.4, 2.6, and 2.8 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% 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.

$$P_a = P_t \times 0.9 \qquad 5.32$$

Where: P_a = max. 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 (M.O.P.).

$$M.O.P. = P_a - P \qquad 5.33$$

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

$$S.F. = \frac{P_a}{P} \qquad 5.34$$

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 5.31 and either equation 5.32 or 5.33 the following equations result:

$$\frac{P_t \times 0.9}{S.F. \times W_{dp} \times K_b} - \frac{W_c L_c}{W_{dp}} = L_{dp} \qquad 5.35$$

and/or

$$\frac{P_t \times 0.9 - M.O.P.}{W_{dp} \times K_b} - \frac{W_c L_c}{W_{dp}} = L_{dp} \qquad 5.36$$

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 W L term in equation 5.35 or 5.36 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 Par. 5.8.

5.5 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 2.3, 2.5, 2.7, and 2.9. The tabulated values should be divided by a suitable factor of safety in order to establish the allowable collapse pressure.

$$\frac{P_p}{S.F.} = P_{ac} \qquad 5.41$$

Where: P_p = theoretical collapse pressure from tables, psi.
S.F. = 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.

$$P_c = \frac{L\ W_g}{19.251} \qquad 5.42$$

or

$$P_c = \frac{L\ W_f}{144} \qquad 5.43$$

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:

$$P_c = \frac{L\ W_g - (L-Y)\ W'_g}{19.251} \qquad 5.44$$

or

$$P_c = \frac{L\ W_f - (L-Y)\ W'_f}{144} \qquad 5.45$$

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

5.6 Internal Pressure. Occasionally the drill pipe may also be subjected to a net internal pressure. Tables 2.3, 2.5, 2.7, and 2.9 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.

5.7 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 Section 6, *Limitations Related to Hole Deviation* and Section 9, *Special Service Problems.* Calculated values of torsional strength for various sizes, grades, and inspection classes of drill pipe are provided in Tables 2.2, 2.4, 2.6, and 2.8. 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.

$$T = \frac{HP \times 5{,}250}{RPM} \qquad 5.61$$

Where: T = torque delivered to drill pipe, ft-lbs
HP = horse power used to produce rotation of pipe
RPM = 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 2.12.*

5.8 Example Calculation of a Typical Drill String Design — Based on Margin of Overpull.

Design Parameters

- **a.** Depth—12,700 feet
- **b.** Hole Size—7⅞ inches
- **c.** Mud Weight—10 lb/gal
- **d.** Margin of Overpull (MOP)—50,000 lb. (Assumed for this calculation.)
- **e.** Desired Safety Factor in Collapse—1⅛ (Assumed for this calculation.)
- **f.** Length of Drill Collars—630 feet
  O.D.—6¼ inches
  I.D.—2¼ inches
  Weight Per Foot—90 lb.

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

$$L_c = \frac{Bit_{wm}}{\text{Cos}\,\alpha \times NP \times k_b \times W_c}$$

Where:

L_c = Length of Drill Collars, feet

Bit_{wm} = Maximum Weight on Bit, lb.

α = Hole Angle From Vertical, 3°

NP = Neutral Point Design Factor
Determines neutral point position e.g., .85 means the neutral point will be 85% of the drill collar string length measured from the bottom. (.85 assumed for this calculation.)

K_b = Buoyancy Factor, See Table 2.13, RP 7G

W_c = Weight Per Foot of Drill Collars In Air, lb.

$$L_c = \frac{40{,}000}{.998 \times .85 \times .847 \times 90}$$

= 618 feet. Closest length based on 30 foot collars = 630 feet or 21 drill collars

- **g.** Pipe Size, Weight and Grade — 4½ in. x 16.60 lb/ft x Grade E, with 4½ in. Tool Joints, 6¼ in. O.D. x 3¼ in. I.D.

Inspection Class 2

From Equation 5.35:

$$L_{dp_1} = \frac{(P_{t_1} \times .9) - MOP}{W_{dp_1} \times K_b} - \frac{W_c \times L_c}{W_{dp_1}}$$

$$= \frac{(225{,}771 \times .9) - 50000}{18.40 \times .847} - \frac{90 \times 630}{18.40}$$

$$= 9830 - 3082 = 6748 \text{ feet}$$

It is apparent that drill pipe of a higher strength will be required to reach 12,700 feet. Add 4½ in. x 16.60 lb/ft Grade X-95, with 4½ in. X.H. Tool Joints, 6¼ in. O.D. x 3 in. I.D. (18.51 lb/ft)
Inspection Class Premium.

Air weight of Number 1 drill pipe and drill collars:

$$\text{Total Weight} = (L_{dp_1} \times W_{dp_1}) + (L_c \times W_c)$$

$$= (6748 \times 18.40) + (630 \times 90)$$

$$= 124{,}163 + 56{,}700 = 180{,}863 \text{ lb.}$$

From Equation 5.35:

$$L_{dp_2} = \frac{(P_{t_2} \times .9) - MOP}{W_{dp_2} \times K_b} - \frac{(L_{dp_1} \times W_{dp_1}) + (L_c \times W_c)}{W_{dp_2}}$$

$$= \frac{(329{,}542 \times .9) - 50{,}000}{18.51 \times .847} - \frac{180{,}863}{18.51}$$

$$= 15728 - 9771 = 5957 \text{ feet}$$

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 6¼″ O.D. x 2¼″ I.D.	630	56,700	48,025
No. 1 DRILL PIPE 4½″ x 16.60 lb, Grade E, Class 2	6748	124,163	105,166
No. 2 DRILL PIPE 4½″ x 16.60 lb, Grade X-95, Premium Class	5322	98,510	83,438
	12,700	279,373	230,629

Torsional Yield of 4½″ x 16.60 lb x Grade E x Inspection Class 2 = 20,902 ft-lb.

Collapse Pressure of 4½″ x 16.60 lb x Grade E x Inspection Class 2 = 5951 psi.

Collapse Pressure of 4½″ x 16.60 lb x Grade X-95 x Premium Inspection Class = 8868 psi.

From Equation 5.42:

$$\text{Pressure at bottom of Drill Pipe: } P_c = \frac{LW_g}{19.251}$$

L = 12,070 feet W_g = 10 lb/gal

$$P_c = \frac{12{,}070 \times 10}{19.251} = 6230 \text{ psi}$$

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 5.42 for maximum length of drill pipe, and dividing by the Safety Factor in Collapse of 1⅛:

$$L_{max} = \frac{P_c \times 19.251}{W_g} \div 1.125$$

$$= \frac{5951 \times 19.251}{10} \div 1.125$$

$$= 11{,}456 \div 1.125 = 10{,}183 \text{ feet}$$

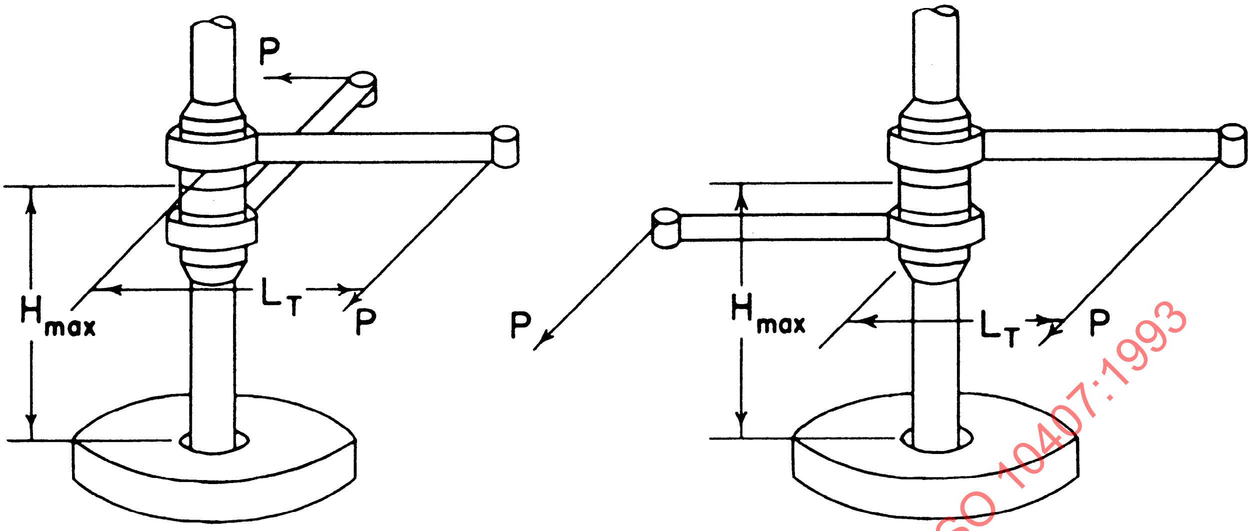


FIG. 5.1
MAXIMUM HEIGHT OF TOOL JOINT ABOVE SLIPS TO PREVENT BENDING DURING TONGING

5.9 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 during 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 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:

(1) The angle of separation between the make-up and break-out tongs, illustrated by Case I and Case II, Fig. 5.1. Case I indicates tongs at 90° and Case II indicates tongs at 180°.
(2) The minimum yield strength of the pipe.
(3) The length of the tong handle.
(4) The maximum recommended make-up torque.

$$H_{max} = \frac{.053\ Y_m\ L_T\ (I/C)}{T} \quad \text{(Case I)} \ldots\ldots 5.81$$

$$H_{max} = \frac{.038\ Y_m\ L_T\ (I/C)}{T} \quad \text{(Case II)} \ldots\ldots 5.82$$

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 ($P_x L_T$)—lb ft
I/C = Section Modulus of pipe—in.^{3}

Constants .053 and 0.038 include a factor of 0.9 to reduce Y_m to proportional limit. (See Par. 5.3)

Sample Calculation:

Assume: 4½ in., 16.60 lb/ft, Grade E drill pipe, with 4½ in. X.H. 6¼ in. OD, 3¼ in. ID tool joints.
Tong arm 3½ ft
Tongs at 90° (Case I)

Using equation 5.81:

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

Y_m = 75,000 psi (for Grade E)
I/C = 4.27 in.^{3} (Table 5.1)
L_T = 3.5 ft
T = 16,997 ft-lb (from Table 2.12)

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

TABLE 5.1
SECTION MODULUS VALUES

1	2	3
Pipe O.D. in.	Pipe Weight Nominal lbs/ft	I/C cu. in.
2⅜	4.85	0.66
	6.65	0.87
2⅞	6.85	1.12
	10.40	1.60
3½	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
4½	13.75	3.59
	16.60	4.27
	20.00	5.17
	22.82	5.68
	24.66	6.03
	25.50	6.19
5	16.25	4.86
	19.50	5.71
	25.60	7.25
5½	19.20	6.11
	21.90	7.03
	24.70	7.84
6⅝	25.20	9.79

SECTION 6
LIMITATIONS RELATED TO HOLE DEVIATION

6.1 Fatigue Damage. Most drill pipe failures are a result of fatigue. (See Par. 9.2). 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 upon:

a. Tensile load in the pipe at the dogleg.

Example

(1) **Data.**

4½ inch, 16.60 lb/ft, Grade E, Range 2 drill pipe (actual weight in air including tool joints, 17.8 lb/ft) 7¾ inch OD, 2¼ 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

(2) **Solution.**

Tensile load in the pipe at the dogleg:
[(11,000 - 3,000) 17.8 + 100 x 147] 0.771 = 121,124 lb

b. The severity of the dogleg.

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

Since 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[1] and Nicholson[2] have published methods of calculating forces on tool joints and conditions necessary for fatigue damage to occur. Referring to Fig. 6.1 and 6.2 it is noted 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[3] and Wilson[4]. Such programs are necessary to reduce fatigue damage.

The curves on Fig. 6.1, 6.2 and 6.3 (also Fig. 6.6, 6.7 and 6.8) 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.[14] The curves on Fig. 6.1, 6.2 and 6.3 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 Fig. 6.1 and 6.3) 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 curves Fig. 6.1 and 6.2[1,4].

$$c = \frac{432{,}000}{\pi} \frac{\sigma_b}{ED} \frac{\tanh KL}{KL} \qquad \textbf{(6.1)}$$

$$K = \sqrt{\frac{T}{EI}} \qquad \textbf{(6.2)}$$

in which:

c = Maximum permissible dogleg severity (Hole curvature), degrees per 100 feet.
E = Young's modulus, psi,
= 30 x 10^6 psi, for steel,
= 10.5 x 10^6 psi, for aluminum.
D = drill pipe OD, inches
L = half the distance between tool joints, inches,
= 180 in., for range 2.
NOTE: Equation 6.1 does not hold true for Range 3.[14]
T = buoyant weight (including tool joints) suspended below the dogleg, pounds.
σ_b = maximum permissible bending stress, psi.
I = drill pipe moment of inertia with respect to its diameter, in^4, calculated by Equation 6.3.

$$I = \frac{\pi}{64}(D^4 - d^4) \qquad \textbf{(6.3)}$$

in which:
D = drill pipe OD, inches.
d = drill pipe ID, inches.

The maximum permissible bending stress, σ_b, is calculated from the buoyant tensile stress, σ_t (psi), in the dogleg with Equations 6.5 and 6.6 below. σ_t is calculated with Equation 6.4:

$$\sigma_t = \frac{T}{A} \qquad \textbf{(6.4)}$$

in which:
A = cross sectional area of drill pipe body, square inches.

For Grade E:[14]

$$\sigma_b = 19500 - \frac{10}{67}\sigma_t - \frac{0.6}{(670)^2}(\sigma_t - 33500)^2 \qquad \textbf{(6.5)}$$

Equation 6.5 holds true for values of σ_t up to 67,000 psi.

For Grade S-135:[2]

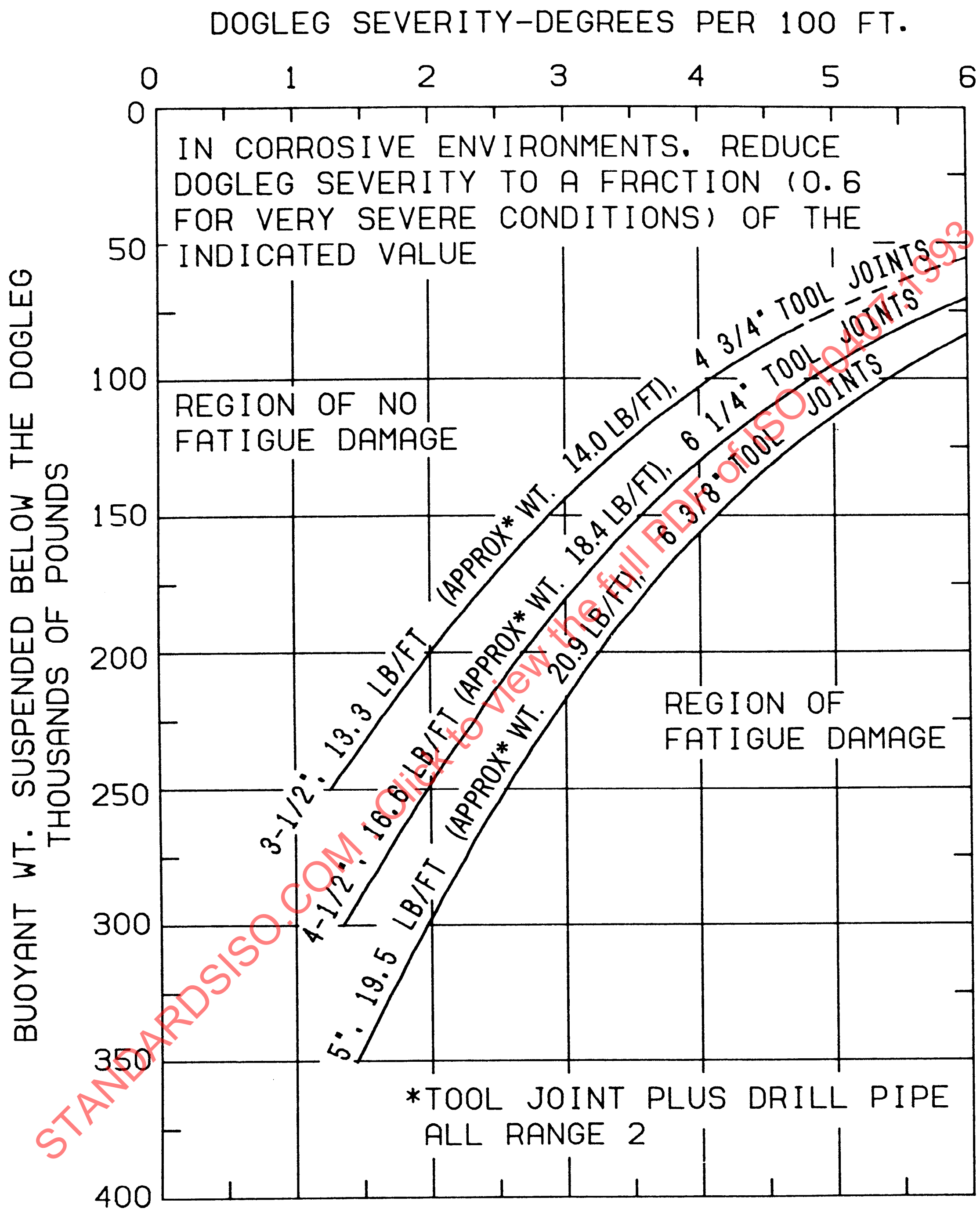
$$\sigma_b = 20000\left(1 - \frac{\sigma_t}{145000}\right) \qquad \textbf{(6.6)}$$

Equation 6.6 holds true for values of σ_t up to 133,400 psi.

The following equation may be used instead of Fig. 6.3:

$$c = \frac{108000}{\pi L}\frac{F}{T} \qquad \textbf{(6.7)}$$

in which F is the lateral force on tool joint (1000, 2000 or 3000 pounds in Fig. 6.3), and the meaning of the other symbols is the same as previously.



DASHED CURVE CORRESPONDS TO CONDITION WHEN DRILL PIPE CONTACTS THE HOLE BETWEEN TOOL JOINTS, AND THEN THE PERMISSIBLE DOGLEG SEVERITY IS GREATER THAN INDICATED.

FIG. 6.1
DOGLEG SEVERITY LIMITS FOR FATIGUE OF GRADE E DRILL PIPE

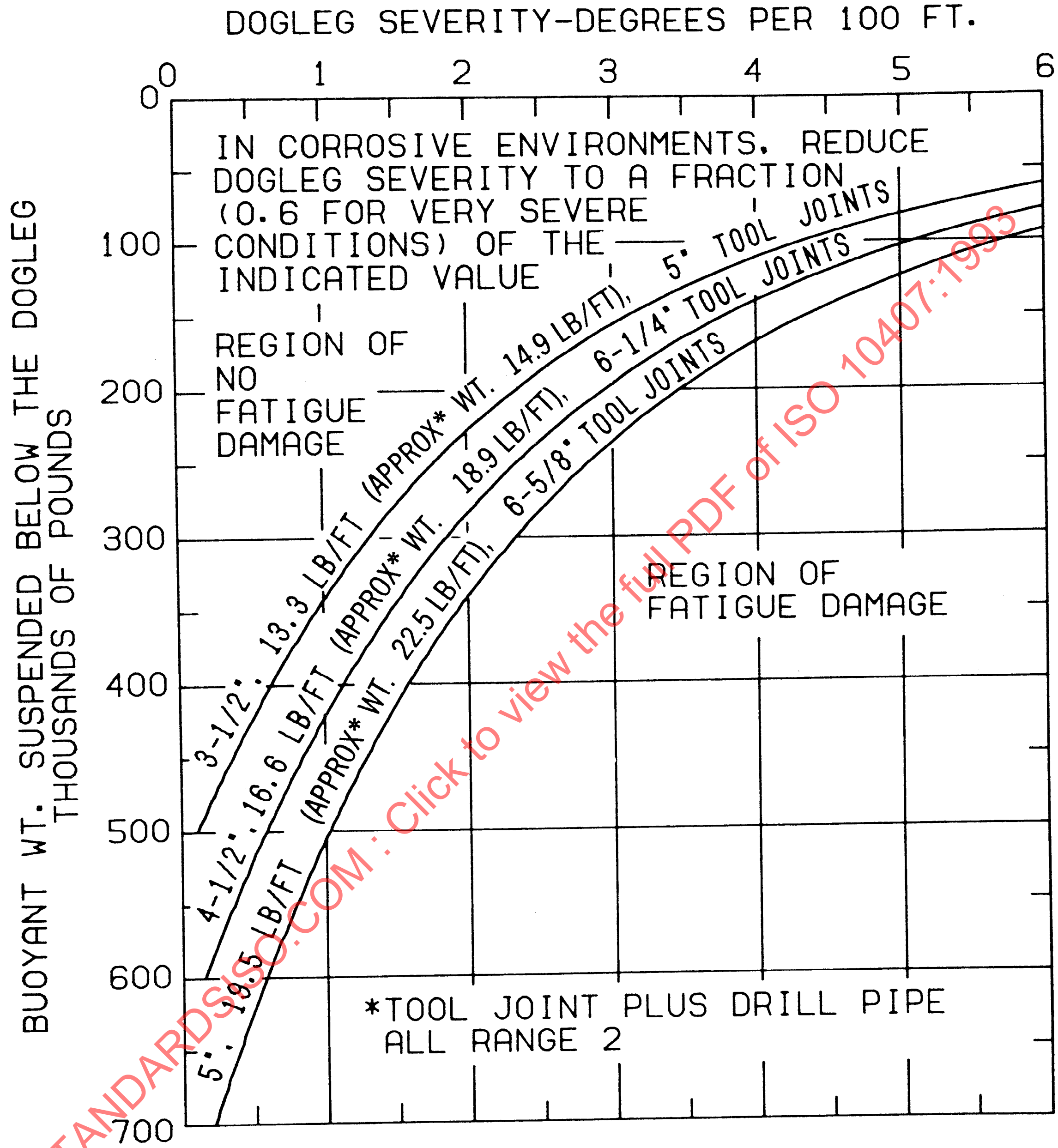
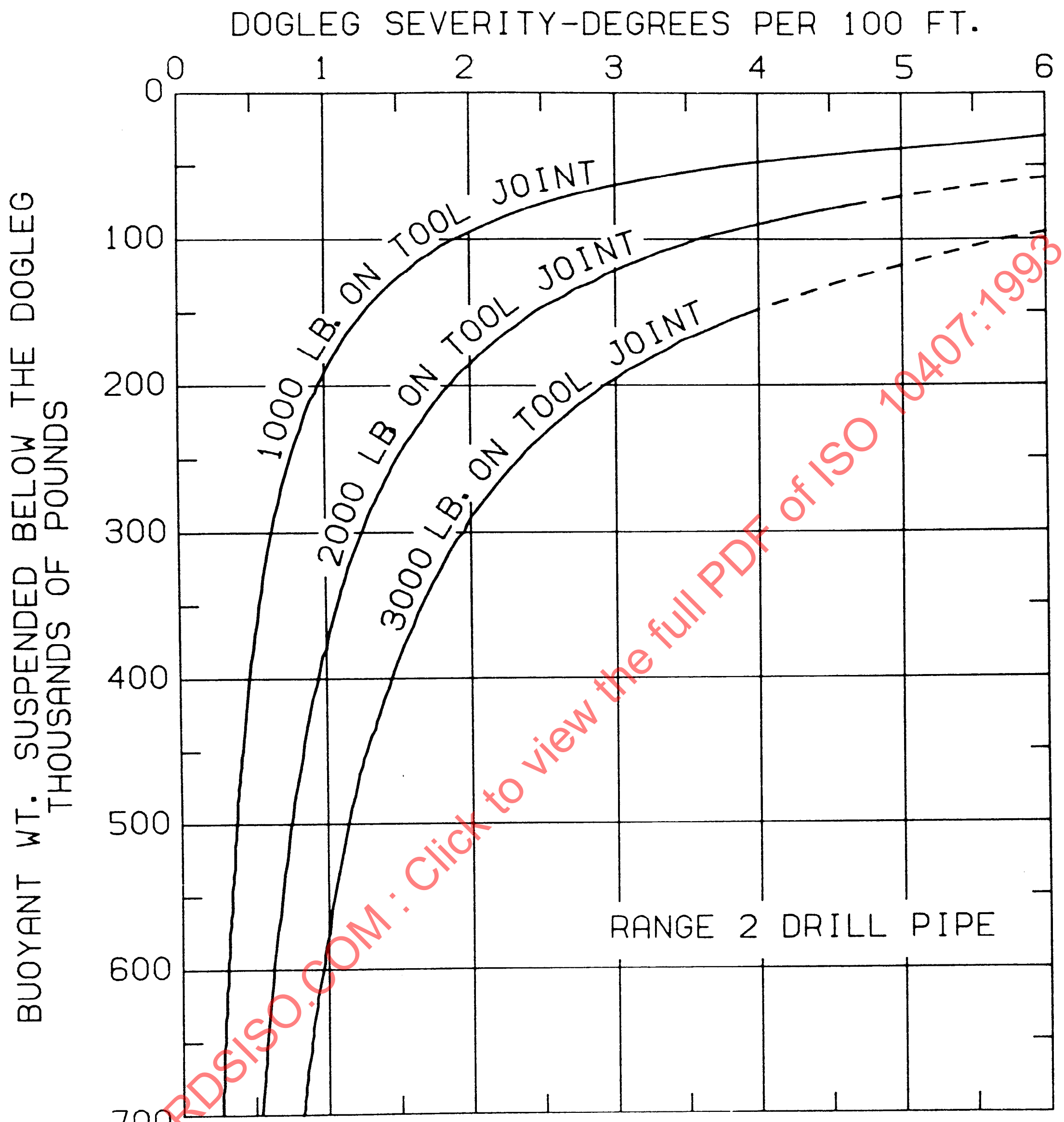


FIG. 6.2
DOGLEG SEVERITY LIMITS FOR FATIGUE
OF S—135 DRILL PIPE



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.

FIG. 6.3
LATERAL FORCE ON TOOL JOINT

6.2 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 6.5, 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 Par. 8.4 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 RP 13B: *Standard Procedure for Testing Drilling Fluids.*

6.3 Estimation of Cumulative Fatigue Damage. Hansford and Lubinski[5] have developed a method for estimating the cumulative fatigue damage to joints of pipe which have been rotated through severe doglegs (See Figures 6.4 and 6.5). 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:

$$\%\ \text{Life Expended} = \%\ \text{Life Expended from Fig. 6.4 or 6.5} \times \frac{\text{Actual RPM}}{100\ \text{RPM}} \times \frac{10\ \text{ft/hr}}{\text{Actual ft/hr}}$$

6.4 Identification of Fatigued Joints. As mentioned, insufficient data is available to verify the results of the method explained in Par. 6.3. 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% 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.

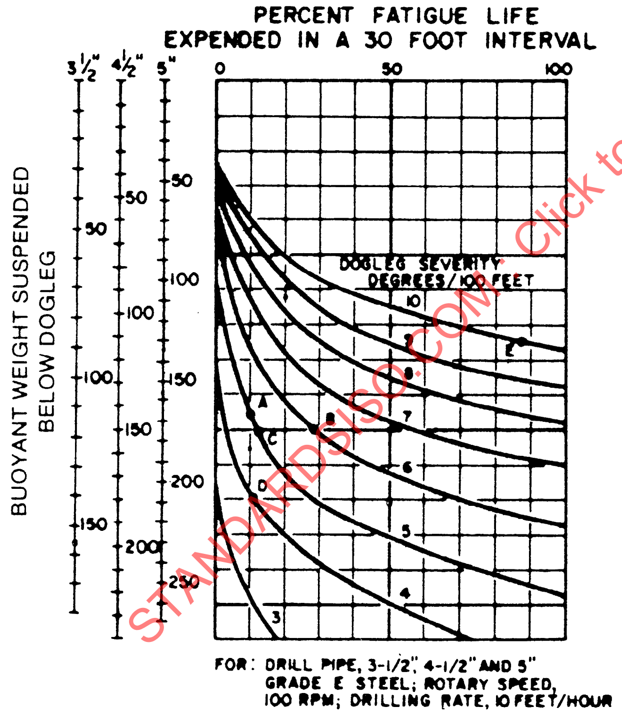


FIG. 6.4
FATIGUE DAMAGE IN GRADUAL DOGLEGS
(NON CORROSIVE ENVIRONMENT)

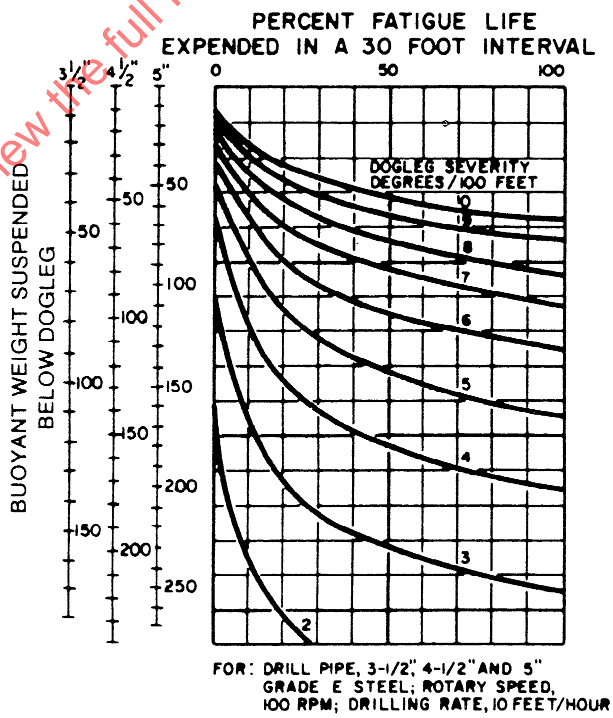


FIG. 6.5
FATIGUE DAMAGE IN GRADUAL DOGLEGS
(IN EXTREMELY CORROSIVE ENVIRONMENT)

6.5 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. Fig. 6.3 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 6.6, 6.7, 6.8, and 6.9, developed by Lubinski, show lateral force curves for both tool joints and drill pipe for 3 popular pipe sizes. The first three figures are for three pipe sizes, Range 2. Fig. 6.9 is for 5″, 19.5 lb per foot, Range 3 drill pipe.

a. For conditions represented by points located to the left of Curve No. 1, such as Point A in Fig. 6.6, 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 body does not wear at all, as Fig. 6.6 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.

b. 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.

c. 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.

d. 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 6.6, 6.7, 6.8, and 6.9, 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 Fig. 6.6; 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 6,000 lb, and the force on drill pipe body is 3,000 lb.

6.6 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.) Maintaining hole angle control so that 2000 lb lateral force is not exceeded will minimize or eliminate heat checking of tool joints.

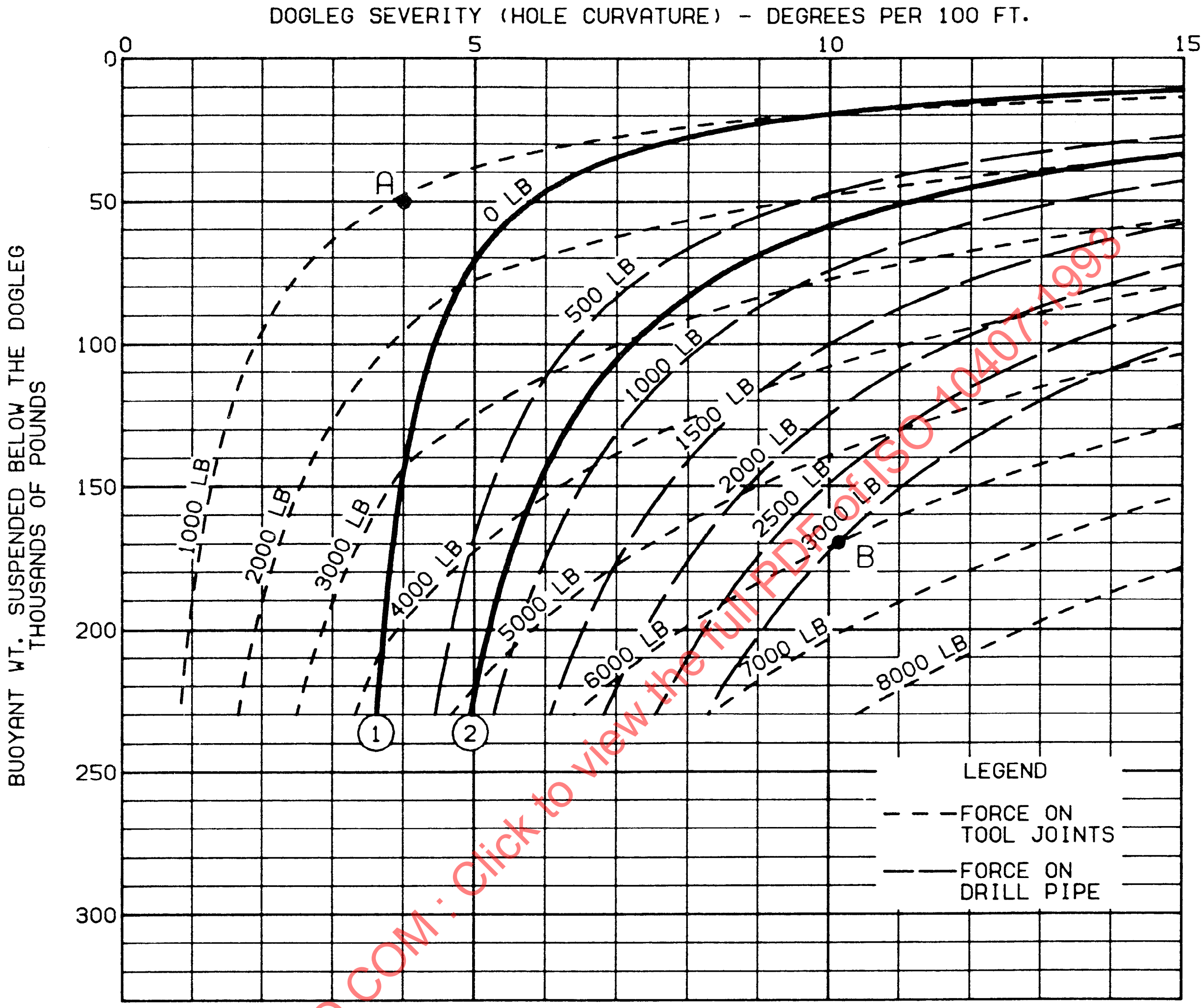


FIG. 6.6
LATERAL FORCES ON TOOL JOINTS AND RANGE 2 DRILL PIPE
3½", 13.3 LB PER FOOT, RANGE 2 DRILL PIPE, 4¾" TOOL JOINTS

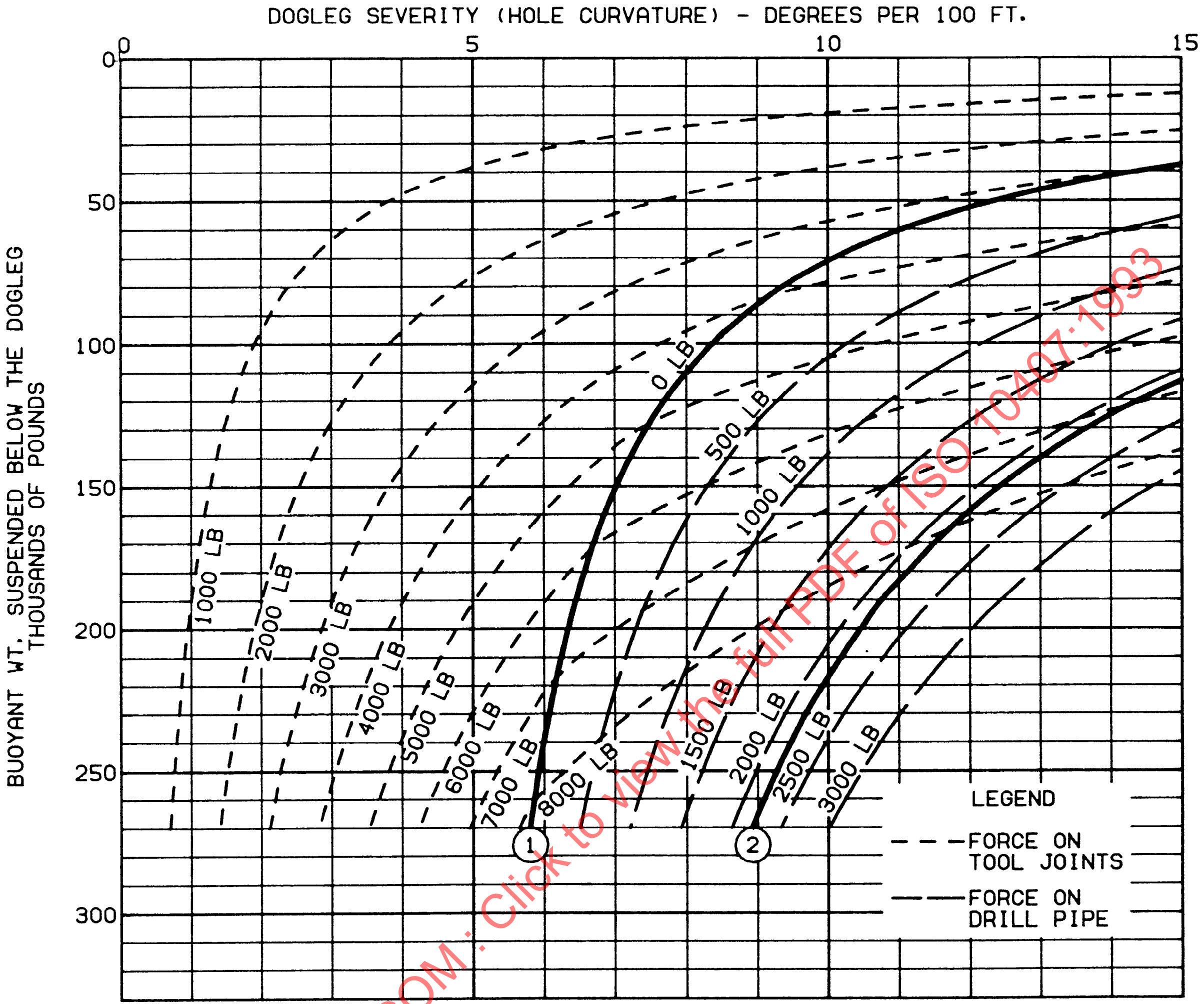


FIG. 6.7
LATERAL FORCES ON TOOL JOINTS AND RANGE 2 DRILL PIPE
4½", 16.6 LB PER FOOT, RANGE 2 DRILL PIPE, 6¼" TOOL JOINTS

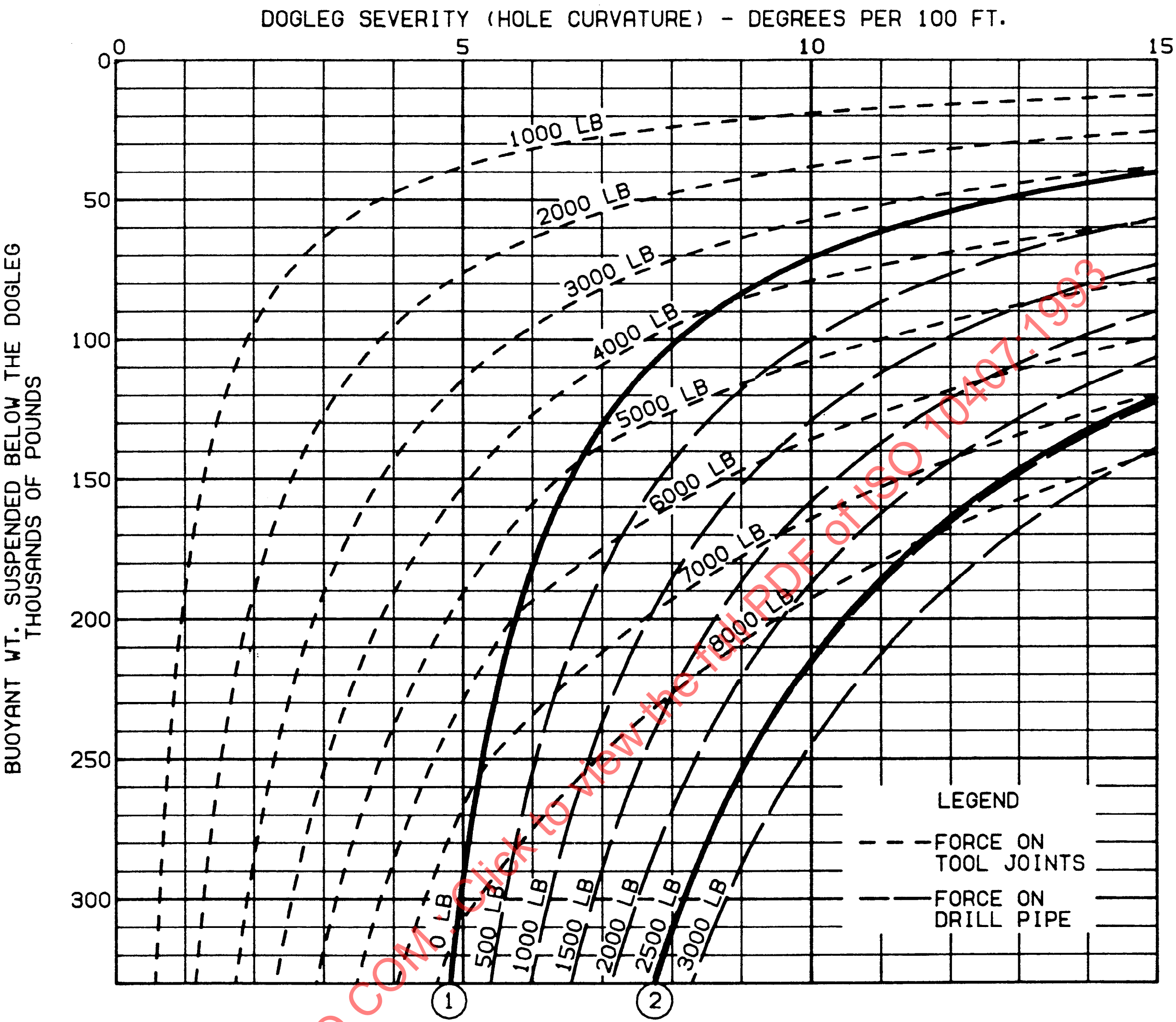


FIG. 6.8
LATERAL FORCES ON TOOL JOINTS AND RANGE 2 DRILL PIPE
5", 19.5 LB PER FOOT, RANGE 2 DRILL PIPE, 6⅜" TOOL JOINTS

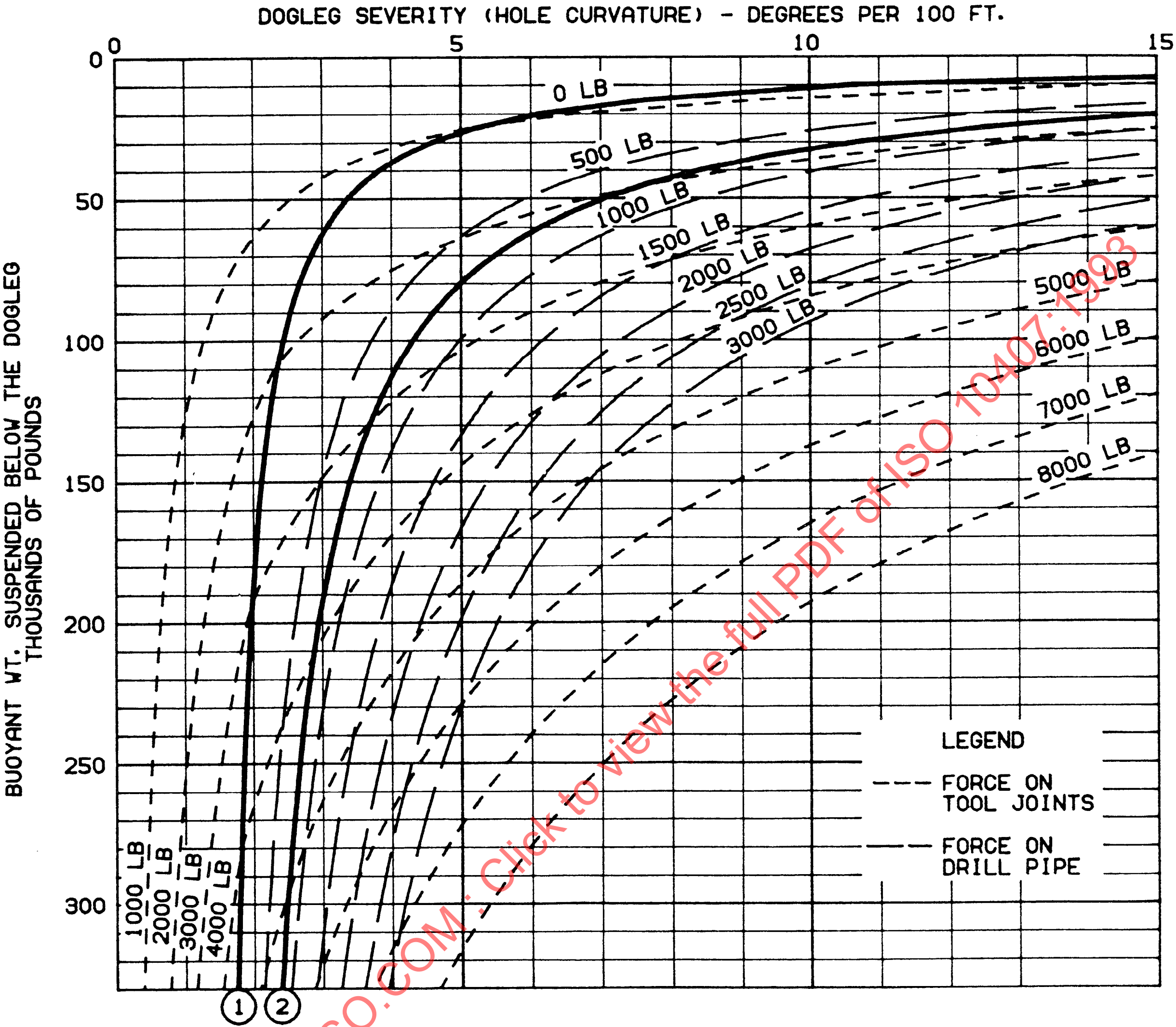


FIG. 6.9
LATERAL FORCES ON TOOL JOINTS AND RANGE 3 DRILL PIPE
5", 19.5 LB PER FOOT, RANGE 3 DRILL PIPE, 6⅜" TOOL JOINTS

SECTION 7
LIMITATIONS RELATED TO FLOATING VESSELS

7.1 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:

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

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

7.2 This text pertains to prevention of fatigue due to factor b, 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 [6].

7.3 Based on the Hansford and Lubinski paper[6], 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.

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

b. An extended length kelly should be used in order 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:

(1) 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.

(2) Use a specially made kelly at least 8 feet longer than the standard length.

(3) Use at least 8 feet of kelly saver subs between the kelly and drill pipe.

c. 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:

(1) more than 30 minutes for large hookloads,

(2) more than 2 hours for light hookloads.

d. 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.

SECTION 8
DRILL STEM CORROSION AND SULFIDE STRESS CRACKING

CORROSION

8.1 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.

a. 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.

b. 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.

c. 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 Par. 8.8 through 8.10 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.

d. 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, due to 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.

e. 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.

8.2 Factors Affecting Corrosion Rates. Among the many factors affecting corrosion rates of drill stem materials the more important are:

a. **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.

b. **Temperature.** In general, corrosion rates increase with increasing temperature.

c. **Velocity.** In general, corrosion rates increase with higher rates of flow.

d. **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.

e. **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 due to higher stresses and high bending moments.

8.3 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:

a. **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.

b. **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.

c. **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.

d. **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 6.

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.

8.4 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 RP 13B: *Standard Procedure for Testing 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 RP 13B) should be performed in the field whenever possible, especially tests for pH, alkalinity, and the dissolved gases (oxygen, carbon dioxide, and hydrogen sulfide).

8.5 Procurement of Samples for Laboratory Testing. When laboratory examination of drilling fluid is desired, representative samples should be collected in a ½ to 1 gallon (2 to 4 litre) clean container, allowing an air space of approximately 1% 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.

*American Society for Testing and Materials, 1916 Race Street, Philadelphia, Pa. 19103.

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. Specimens 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.

8.6 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 O.D. 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.

8.7 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, since 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 RP 5C1: *Recommended Practice for Care and Use of Casing and Tubing*).

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:

(1) Use thicker walled components.

(2) Reduce high stresses near connections by minimizing doglegs and by maintaining straight hole conditions, insofar as possible.

(3) Minimize stress concentrators such as slip marks, tong marks, gouges, notches, scratches, etc.

(4) Use quenched and tempered components.

SULFIDE STRESS CRACKING

8.8 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).

8.9 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 upon:

a. 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.

b. 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.

*National Association of Corrosion Engineers, P.O. Box 986, Katy, TX 77450.

c. **Amount of Atomic Hydrogen and H_2S.** The higher the amount of atomic hydrogen and H_2S present in the environment, the shorter the time before failure by SSC. The amounts of atomic hydrogen and H_2S required to cause SSC are quite small, but corrective measures to control their amounts will minimize the atomic hydrogen absorbed by the steel.

d. **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.

e. **Temperature.** The severity of SSC is greatest at normal atmospheric temperatures, and decreases as temperature increases. At operating temperatures in excess of approximately 135F *(57C)*, 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, since SSC failure may occur when the material returns to normal temperature after it is removed from the hole.

8.10 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 Par. 8.7. 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 600F *(204 to 316C)* for several hours. Note: Plastic coated drill pipe should not be heated above 400F*(204C)* 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.

DRILLING FLUIDS CONTAINING OIL

8.11 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.

8.12 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:

a. **Electrical Stability.** This test measures the voltage required to cause current to flow between electrodes immersed in the oil mud (See API RP 13B for details). The higher the voltage, the greater the stability of the emulsion, and the better the protection provided to the drill stem.

b. **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.

c. **Corrosion Test Rings.** Test rings placed in the drill stem bore are used to monitor the corrosion protection afforded by oil muds (See API RP 13B for details). A properly functioning oil mud should show little or no visual evidence of corrosion on the test ring.

SECTION 9
SPECIAL SERVICE PROBLEMS

9.1 Critical Rotary Speeds. Critical rotating speeds in drill pipe strings which cause vibrations are often the cause of crooked drill pipe, excessive wear, and rapid deterioration and fatigue failure. Critical speeds will vary with length and size of drill stem and collars and hole size. There is evidence in recent field tests that excessive power is required at the rotary to maintain a constant speed at critical conditions. This power indicator, plus surface evidence of vibration, should warn the crew that they are in the critical range.

Various types of vibration may occur. The pipe between each tool joint may vibrate in nodes, as a violin string.

Another type of vibration is of the spring pendulum type. Other types of vibrations may occur. Each vibration type has critical speeds at which they occur. Numerous field cases have indicated that previous formulations given in Section 9.1 of API RP 7G, 12th Edition (May 1, 1987) did not accurately predict critical rotary speeds and thus have been removed. Presently no generally accepted method exists to accurately predict critical rotary speeds.

9.2 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.

Fishing Techniques

9.3 Pulling on Stuck Pipe. It is normally not considered good practice to pull on stuck drill pipe beyond the limit derived from the API-IADC Used Drill Pipe Classification System (Table 10.1) utilizing remaining cross sectional area as an important criteria. It must be assumed that the pipe is near the minimum cross sectional area of its class and will fail in tension if the load is excessive. 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.

Example I: (see Appendix A, Par. A.6 for derivation)

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

$$e = \frac{L_1^2}{9.625 \times 10^7}[65.44 - 1.44\, W_g] \qquad 9.31$$

$$= \frac{10{,}000^2}{9.625 \times 10^7}[65.44 - 1.44 \times 10]$$

$$= 53.03 \text{ in.}$$

Where: L_1 = length of free drill pipe, feet
W_g = weight of drilling fluid, lb/gal
e = total elongation, inches

Example II: (see Appendix A, Par. A.4 for derivation)

Determine the free length in a 10,000 ft string of 4½ in. O.D. 16.60 lb/ft drill pipe which is stuck, and which stretches 49 in. due to a differential pull of 80,000 lbs.

$$L_1 = \frac{735{,}294 \times e \times W_{dp}}{P} \quad 9.32$$

$$= \frac{735{,}294 \times 49 \times 16.60}{80{,}000}$$

$$= 7476 \text{ ft}$$

Where: L_1 = length of free drill pipe, feet
e = total elongation, inches
W_{dp} = weight of drill pipe, pounds per foot
P = load, pounds

9.4 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.

9.5 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 Par. 9.6)

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

$$Q_T = \frac{.096167\,J}{D}\sqrt{Y_m^2 - \frac{P^2}{A^2}} \quad 9.61$$

Where Q_T = Minimum Torsional Yield Strength Under Tension, lb-ft
J = Polar Moment of Inertia
$= \frac{\pi}{32}(D^4 - d^4)$ For Tubes
D = Outside Diamenter—inches
d = Inside Diameter—inches
Y_m = Minimum Unit Yield Strength—psi
S_s = Minimum Unit Shear Strength—psi (S_s = .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: (1) 3½ in. O.D. 13.30 lb Grade E drill pipe
(2) 3½ IF tool joints
(3) Stuck point: 4000 feet
(4) Tensile pull: 100,000 pounds
(5) New drill pipe

$$\text{Then: } Q_T = \frac{.096167 \times 9.00}{3.5}\sqrt{(75{,}000)^2 - \frac{(100{,}000)^2}{(3.62)^2}}$$

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

For further information on allowable hookloads, torque application, and pump pressure use, refer to Stall and Blenkarn: *Allowable Hook Load and Torque Combinations For Stuck Drill Strings.*[12]

Biaxial Loading of Drill Pipe

9.7 The collapse resistance of drill pipe corrected for the effect of tension loading may be calculated by reference to Fig. 9.3 and the use of formulas and physical constants contained in Par. 9.8, 9.9, 9.10, and 9.11.

9.8 Formulas and Physical Constants. The ellipse of biaxial yield stress shown in Fig. 9.3 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:

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

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

Where:

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

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

Average yield strengths in psi are as follows:

Grade E	85,000
Grade X95	110,000
Grade G105	120,000
Grade S135	145,000

9.9 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), Par 9.8 and solve for r. Then, solve formula (1), Par 9.8, for z. For the total tension (transition) load, substitute value of z in formula (4), Par. 9.8.

9.10 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), Par. 9.8, to find a value for z. Substitute this value in formula (2), Par. 9.8, to permit solution for r. Next, substitute the value of r in formula (3), Par. 9.8, to obtain the effective collapse resistance under tension.

9.11 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 = .362 inches

Nominal ID = 4.276 inches

Reduced wall thickness for Premium

Class = (0.8)(.362) = .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

$$= \frac{12037}{85,000} \times 100$$

= 14.16%

Enter Fig. 9.3 at 14.16% 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%.

Minimum collapse resistance for Premium Class (Table 2.5) = 7041 psi.

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.

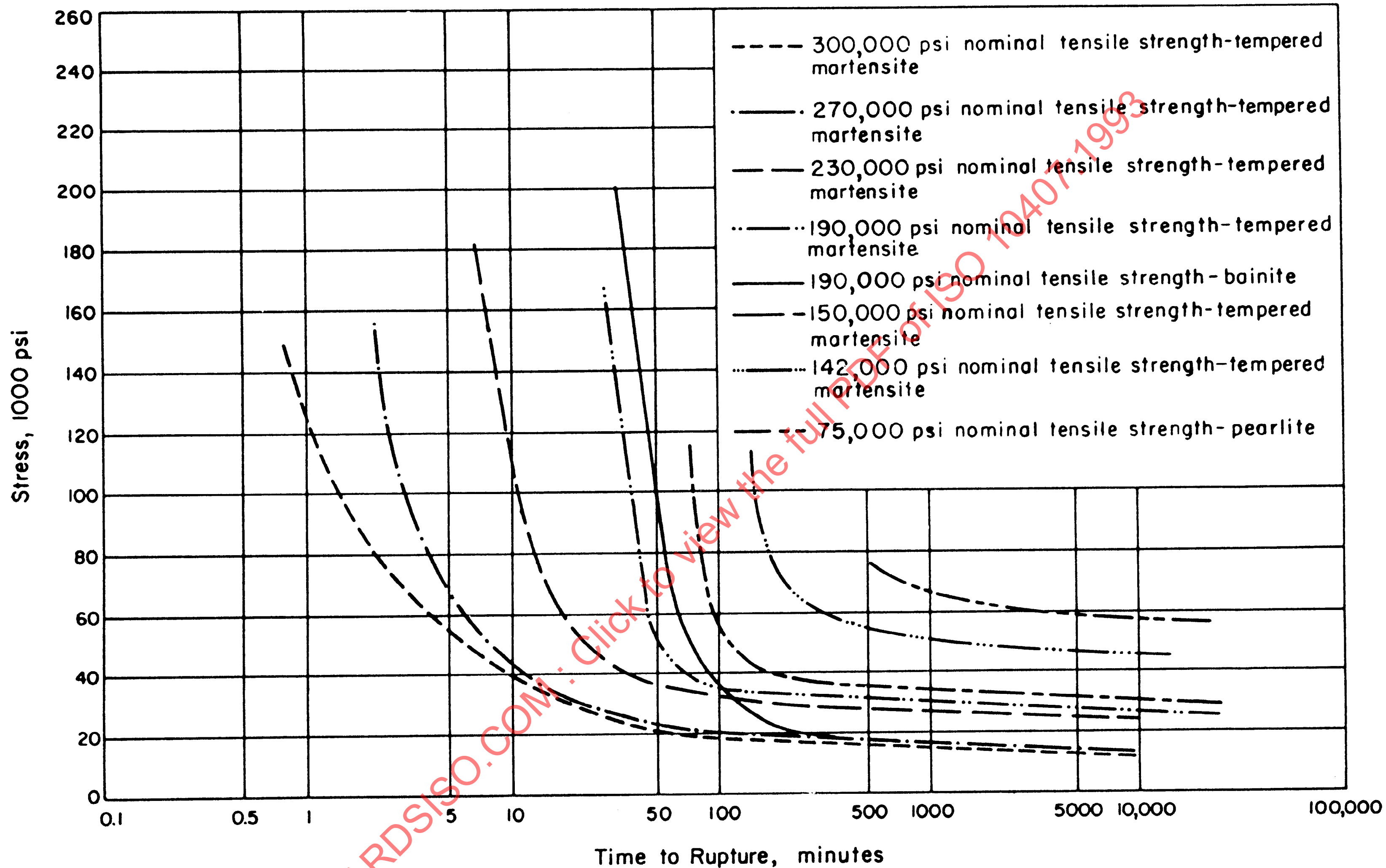


FIG. 9.1

DELAYED-FAILURE CHARACTERISTICS OF UNNOTCHED SPECIMENS OF AN SAE 4340 STEEL DURING CATHODIC CHARGING WITH HYDROGEN UNDER STANDARDIZED CONDITIONS

Batelle Charging Condition A:

Electrolyte: 4 per cent by weight of H_2SO_4 in water

Poison: 5 drops per liter of cathodic poison composed of 2_g phosphorous dissolved in 40 ml CS_2

Current Density: 8 ma/in.^{2}

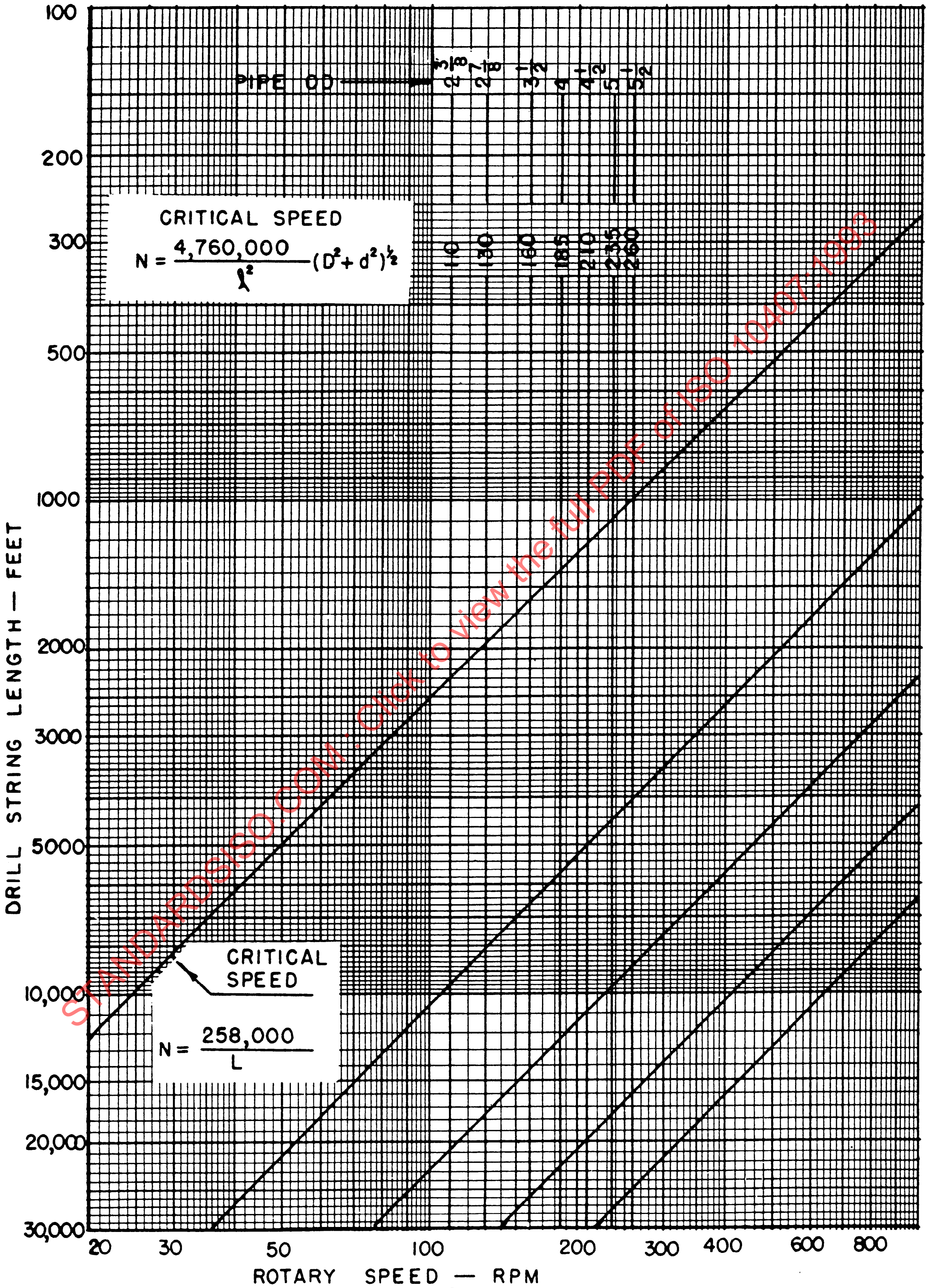


FIG. 9.2
CRITICAL ROTARY SPEEDS IN DRILL PIPE

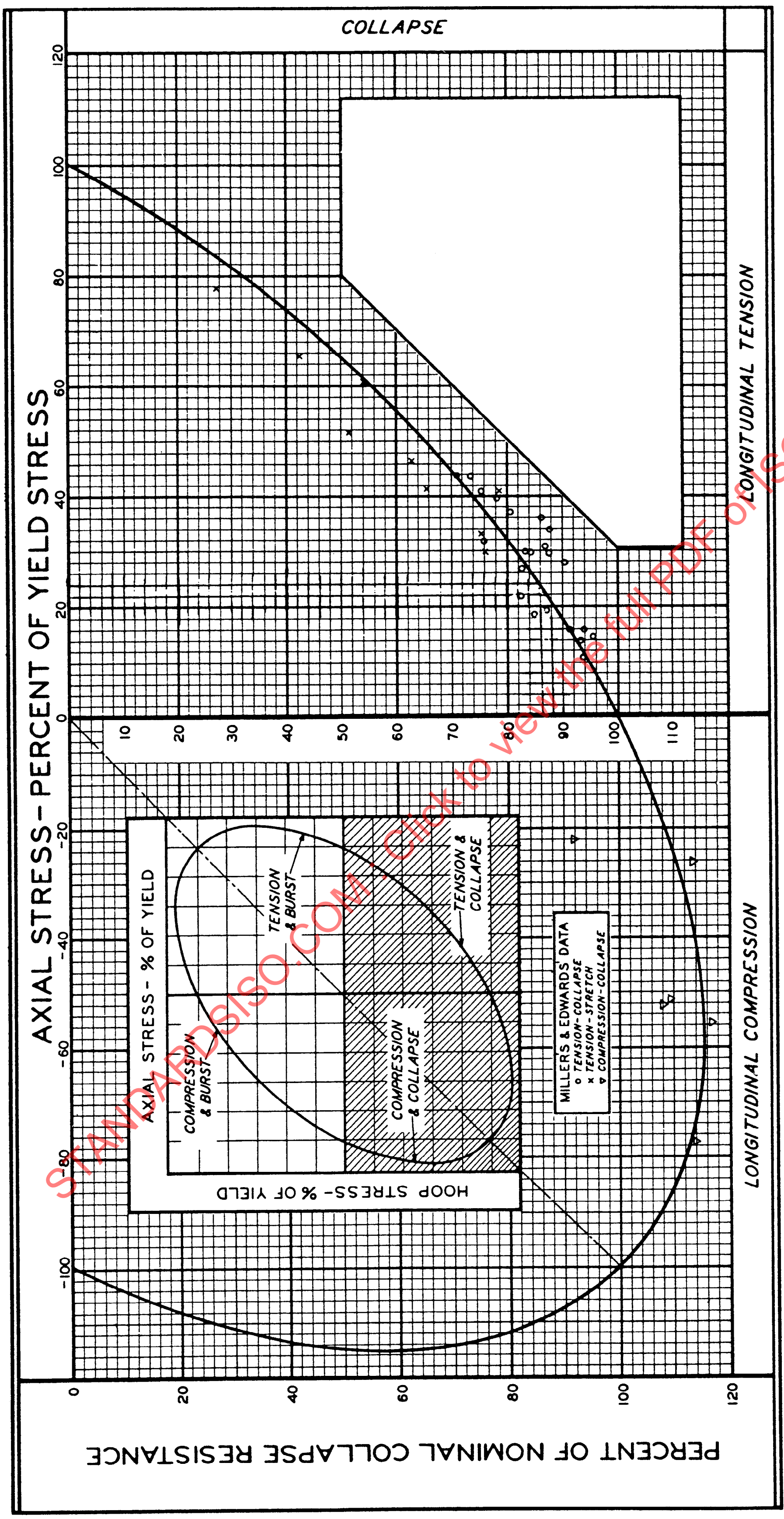


FIG. 9.3
ELLIPSE OF BIAXIAL YIELD STRESS[12]
OR
MAXIMUM SHEAR — STRAIN ENERGY DIAGRAM
After Holmquist and Nadai, Collapse of Deep Well Casing, API Drilling and Production Practice (1939)
NOTE: Applies only in a non-corrosive environment

SECTION 10
IDENTIFICATION, INSPECTION AND CLASSIFICATION OF DRILL STEM COMPONENTS

10.1 Drill String Marking and Identification. Sections of drill string manufactured in accordance with API Spec 7 are identified with the markings shown in Fig. 10.1. It is recommended that drill string members not covered by Spec 7 also be stencilled at the base of the pin as shown in Fig. 10.1. It is also recommended that drill string other than standard weight Grade E, be marked using the mill slot and groove method for identifying grade and weight of drill pipe as shown in Fig. 10.2. In the latter method, the pipe grade and weight code symbols are stamped in the mill slot of specified dimensions and specified location on the tool joint.

Drill Pipe and Tubing Work Strings

10.2 Inspection Standards. Through efforts of joint committees of API and IADC (formerly AAODC), inspection standards for the classification of used drill pipe have been established. The procedure outlined in Table 10.1 was adopted as tentative at the 1964 Standardization Conference and was revised and approved as *standard* at the 1968 Standardization Conference. Additional revisions were made at the 1970 Standardization Conference to add Premium Class. At the 1971 Conference it was determined that the drill pipe classification procedure be removed from an appendix to API Spec 7 and placed in API RP 7G. At the 1979 Standardization Conference, Table 10.1 was revised to also cover classification of used tubing work strings.

10.3 Limitations of Inspection Capability. Most failures of drill pipe result from some form of metal fatigue. A fatigue failure is one which originates as a result of repeated or fluctuating stresses having maximum values less than the tensile strength of the material. Fatigue fractures are progressive, beginning as minute cracks that grow under the action of the fluctuating stress. The rate of propagation is related to the applied cyclic loads and under certain conditions may be extremely rapid. The failure does not normally exhibit extensive plastic deformation and is therefore difficult to detect until such time as considerable damage has occurred. There is no accepted means of inspecting to determine the amount of accumulated fatigue damage or the remaining life in the pipe at a given stress level.

Presently accepted means of inspection are limited to location of cracks, pits, and other surface marks; measurement of remaining wall thickness; measurement of outside diameter; and calculation of remaining cross sectional area. Drill pipe which has just been inspected and found free of cracks may develop cracks after very short additional service through the addition of damage to previously accumulated fatigue damage.

10.4 Definition of a Fatigue Crack. A fatigue crack is a single line rupture of the pipe surface. The rupture shall (1) be of sufficient length to be shown by magnetic iron particles used in magnetic particle inspection or (2) be identifiable by visual inspection of the outside of the tube and/or by optical inspection of the inside of the tube.

10.5 Measurement of Pipe Wall. Tube body conditions will be classified on the basis of the lowest wall thickness measurement obtained and the remaining wall requirements contained in Table 10.1. The only acceptable wall thickness measurements are those made with pipe-wall micrometers, ultrasonic instruments, or gamma-ray devices that the operator can demonstrate to be within 2 per cent accuracy by use of test blocks sized to approximate pipe wall thickness. When using a highly sensitive ultrasonic instrument, care must be taken to ensure that detection of an inclusion or lamination is not interpreted as a wall thickness measurement.

10.6 Determination of Cross Sectional Area (Optional). Determine cross sectional area by use of a direct indicating instrument that the operator can demonstrate to be within 2 per cent accuracy by use of a pipe section approximately the same as the pipe being inspected. In the absence of such an instrument, integrate wall thickness measurements taken at 1 inch intervals around the tube.

10.7 Procedure. Used drill pipe should be classified according to the procedure of Table 10.1 and as illustrated in Fig. 10.3, dimension A. Maximum allowable hook loads for Class 1, Premium and Class 2 drill pipe are listed in Table 10.2. These hook load values were taken from the IADC Tool Pusher's Manual (now Drilling Manual), 1970 edition. Values recommended for minimum OD and make-up torque of weld-on tool joints used with the Class 1, Premium and Class 2 drill pipe are listed in Table 2.12. Maximum allowable hook loads for Class 1, Premium and Class 2 tubing work strings (also classified in accordance with Table 10.1) are listed in Table 10.3.

10.8 Inspection Classification Marking. A permanent mark or marks signifying the classification of the pipe (for example, refer to Table 10.1, Note 1) should be stamped:

a. On the 35 degree sloping shoulder of the tool joint pin (or on the 18 degree sloping shoulder of the pin, if the 18 degree angle is furnished).

b. On the end of the tool joint pin on flush OD drill pipe.

c. Or in some other *low-stressed* section of the tool joint where the marking will normally carry through operations.

d. Cold steel stenciling should be avoided on outer surface of drill pipe.

Tool Joints

10.9 Color Coding. The classification system for used drill pipe outlined in Table 10.1 includes a color code designation to identify the drill pipe class. The same system is recommended for tool joint class identification. In addition, it is recommended that the tool joint be identified as (1) field repairable, or (2) scrap or shop repairable. This color code system for tool joints and for drill pipe is shown in Fig 10.4.

10.10 The following recommended inspection standard for used tool joints was initially included as an appendix to API Spec 7. It was moved to API RP7G by committee action at the 1971 Standardization Conference.

Tool Joint Manufacturer's symbol, Month welded, Year welded, Pipe Manufacturer and Drill Pipe Grade code shall be stencilled at the base of the pin as shown in Figure 10.1. Pipe Manufacturer symbol and Drill Pipe Grade code applied shall be as represented by Manufacturer, Supplier, Owner or User documents such as mill certification papers or purchase orders.

PIPE MANUFACTURER*

Pipe Mill	Symbol
Armco	A
British Steel	B
CF&I Steel Corp.	C
Dalmine S.P.A., Italy	D
Falck, Italy	F
Kawasaki Steel	H
Nippon Steel Corp.	I
J&L Steel	J
Nippon Kokan Kabushiki	K
Lone Star	L
Mannesmannrohren-Werke	M
U.S. Steel	N
Ohio Steel Tube	O
Wheeling-Pittsburgh	P
Republic Steel	R
Sumitomo Metal Ind.	S
TAMSA	T
Vallourec	V
Babcock & Wilcox	W
Algoma	X
Youngstown	Y
TI Steel Tube Div.	Z
American Seamless Tube	AI
Tubemeuse	TU
Voest	VA
Used	U

NOTE: These codes are provided for pipe manufacturer identification and have been assigned at pipe manufacturers' requests. Manufacturers included in this list may not be current API licensed pipe manufacturers. A list of current licensed pipe manufacturers is available in the *Composite List of Manufacturers Licensed for use of the API monogram.*

MONTH AND YEAR WELDED

Month	Year
1 Through 12	Last two digits of year

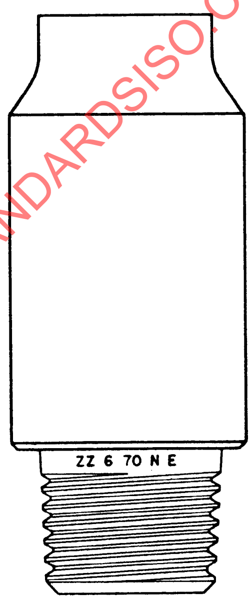
DRILL PIPE GRADE CODE

Grade	Symbol
N-80	N
E	E
C-75	C
X-95	X
G-105	G
S-135	S
V-150	V

HEAVY WEIGHT DRILL PIPE
(Double Stencil Pipe Grade Code.)

SAMPLE MARKINGS AT BASE OF PIN

1	2	3	4	5
ZZ	6	70	N	E



1—Company Symbol
ZZ Company (Fictional for example only)

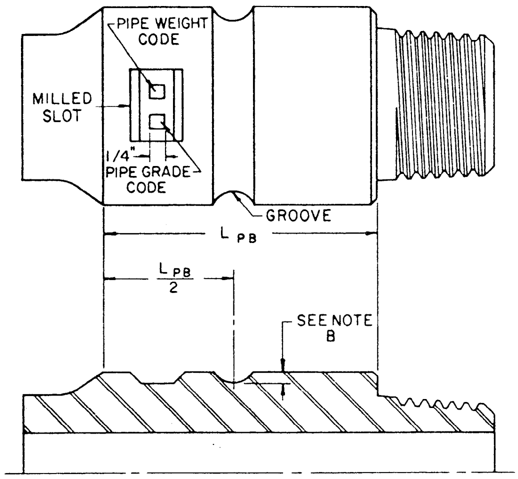
2—Month Welded
6—June

3—Year Welded
70—1970

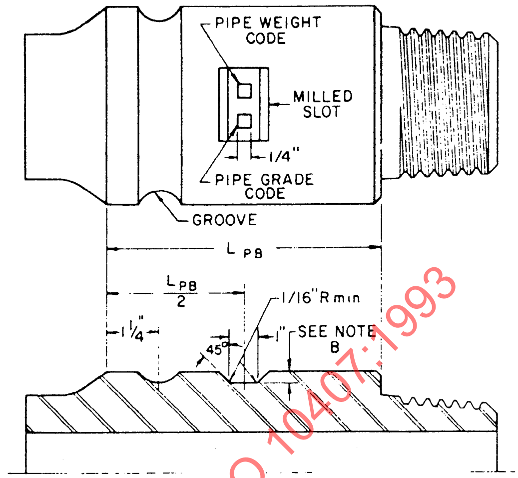
4—Pipe Manufacturer
N—United States Steel Company

5—Drill Pipe Grade
E—Grade E Drill Pipe

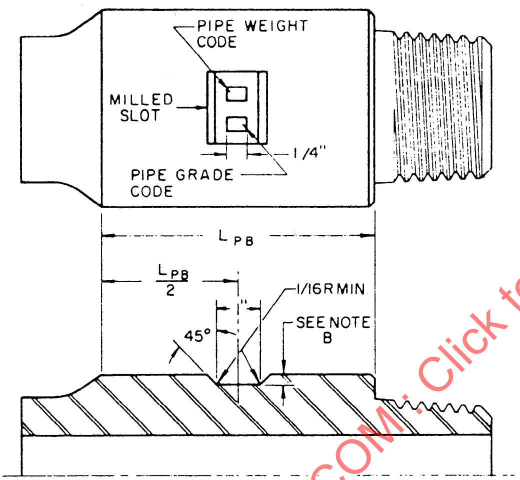
FIG. 10.1
MARKING ON TOOL JOINTS
FOR IDENTIFICATION OF DRILL STRING COMPONENTS



STANDARD WEIGHT
HIGH STRENGTH DRILL PIPE



HEAVY WEIGHT
HIGH STRENGTH DRILL PIPE



HEAVY WEIGHT
GRADE E DRILL PIPE

NOTE A: Standard weight Grade E drill pipe designated by an asterisk (*) in the drill pipe weight code will have no groove or milled slot for identification. Grade E heavy weight drill pipe will have a milled slot only, in the center of the tong space.

NOTE B: Groove radius approximately 3/8 inch. Groove and milled slot to be 1/4 in. deep on 5 1/4 in. OD and larger tool joints, 3/16 in. deep on 5 in. OD and smaller tool joints.

NOTE C: Stencil the grade code symbol and weight code number corresponding to grade and weight of pipe in milled slot of pin. Stencil with 1/4 in. high characters so marking may be read with drill pipe hanging in elevators.

L_{PB} = Pin Tong Space Length (See Table 4.2, API Spec 7).

DRILL PIPE GRADE CODE

STANDARD GRADES

Grade	Symbol
N-80	N
E	E
C-75	C

HIGH STRENGTH GRADES

Grade	Symbol
X-95	X
G-105	G
S-135	S
V-150	V

DRILL PIPE WEIGHT CODE

1	2	3	4
Size, OD inches	Nominal Wt. lb per ft	Wall Thickness inches	Weight Code Number
2⅜	4.85	.190	1
	6.65*	.280	2
2⅞	6.85	.217	1
	10.40*	.362	2
3½	9.50	.254	1
	13.30*	.368	2
	15.50	.449	3
4	11.85	.262	1
	14.00*	.330	2
	15.70	.380	3
4½	13.75	.271	1
	16.60*	.337	2
	20.00	.430	3
	22.82	.500	4
	24.66	.550	5
	25.50	.575	6
5	16.25	.296	1
	19.50*	.362	2
	25.60	.500	3
5½	19.20	.304	1
	21.90*	.361	2
	24.70	.415	3
6⅝	25.20*	.330	2

*Designates standard weight for drill pipe size.

FIG. 10.2
RECOMMENDED PRACTICE FOR MILL SLOT AND GROOVE METHOD
OF DRILL STRING IDENTIFICATION

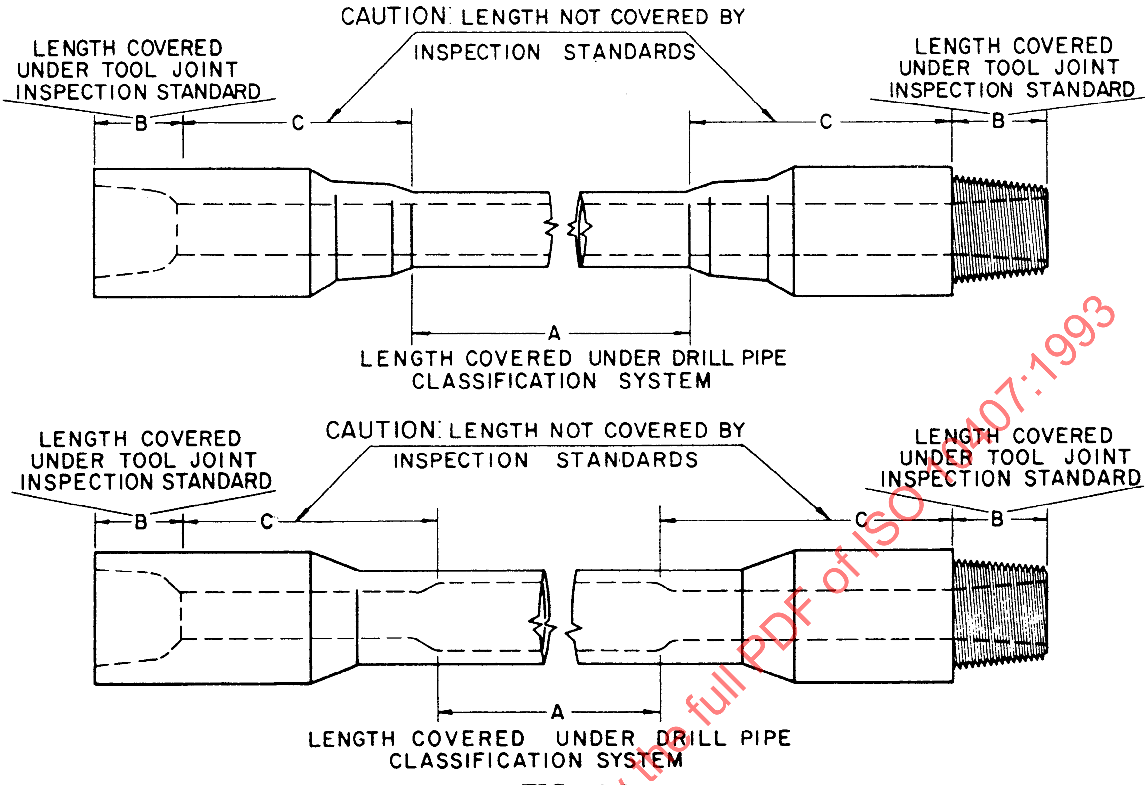
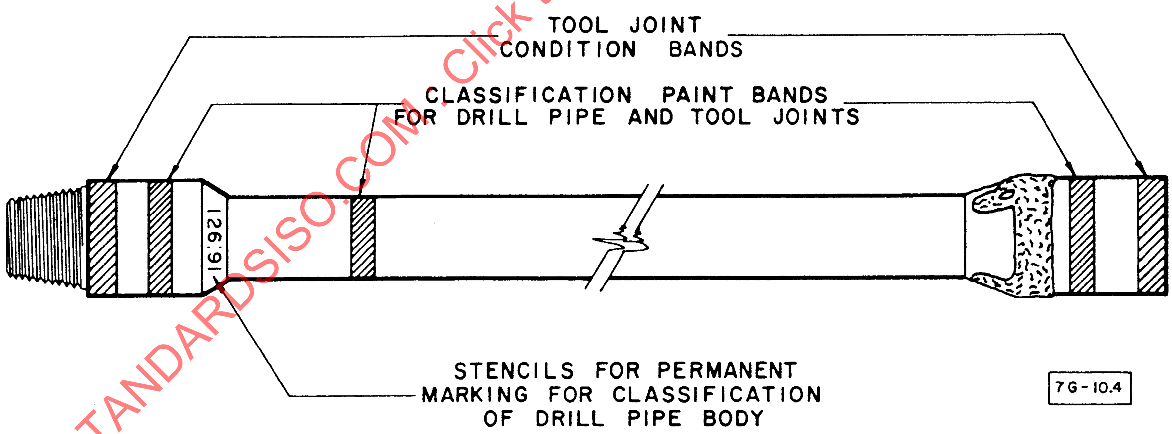


FIG. 10.3
IDENTIFICATION OF LENGTHS COVERED BY INSPECTION STANDARDS



TOOL JOINT AND DRILL PIPE CLASSIFICATION	NUMBER AND COLOR OF BANDS
Premium Class	Two White
Class 2	One Yellow
Class 3	One Orange
Scrap	One Red

TOOL JOINT CONDITION	COLOR OF BANDS
Scrap or Shop Repairable	Red
Field Repairable	Green

FIG. 10.4
DRILL PIPE AND TOOL JOINT COLOR CODE IDENTIFICATION

a. Required.

(1) Outside Diameter Measurement
Measure tool joint outside diameter at a distance of 1 inch from the shoulder and determine classification from data in Table 2.12. Minimum shoulder width should be used when tool joints are worn eccentrically.

(2) Shoulder Condition
Check shoulders for galls, nicks, washes, fins, or any other matter which would affect the pressure holding capacity of the joint and conditions which may affect joint stability. Make certain joint has proper bevel diameter.

(3) Joint Check
Random check 10 per cent of the joints for manufacturer markings and date of tool joint installation to determine if the tool joint has been reworked.

b. Optional

(1) Shoulder Width
Using data in Table 2.12, determine minimum shoulder width acceptable for tool joint in class as governed by the outside diameter.

(2) Thread Profile
Will pick up indications of over-torque, insufficient torque, lapped threads, galled threads, and stretching. The lead gage is the only standard method for measuring pin stretch.

(3) Box Swell and/or Pin Stretch
These are indications of over-torquing and their presence greatly affects the future performance of the tool joint. On used tool joints, it is recommended that pins having stretch which exceeds .006 inch in 2 inches should be recut. All pins which have been stretched should be inspected for cracks.

It is recommended that used boxes having more than .031 inch (1/32 inch) measurable OD swell be recut. Compare the OD at the make-and-break shoulder to the OD 2 inches from the make-and-break shoulder.

Since wear may decrease the amount of OD swell which can be measured, it is recommended that the box counterbores (Qc), API Spec 7, Table 9.1, be checked. If the Qc diameter is more than .031 inch (1/32 inch) outside the allowed tolerance, then the box should be recut.

(4) Minimum Tong Space
Refer to figure 10.5. The recommended minimum tong space for pins is 75% of the OD but not less than 4 inches. The recommended minimum tong space for non-hardfaced boxes is the measured L_{BC} + 1 inch. On hardbanded joints, the space may need to be longer to provide adequate gripping space for tongs.

(5) Magnetic Particle Inspection
If evidence of stretching or swelling is found, magnetic particle inspection should be made of both box and pin threaded area, especially last engaged thread area to determine if cracks are present.

c. General

(1) Gaging
Thread wear, plastic deformation, mechanical damage and lack of cleanliness may all contribute to erroneous figures when plug and ring gages are applied to *used* connections. Therefore, ring and plug standoffs *should not* be used to determine rejection or continued use of rotary shouldered connections. Smooth sealing shoulders are more critical to joint operation than gage standoff.

(2) Repair of Damaged Shoulders

a. When refacing a damaged tool joint shoulder, a minimum of material should be removed.

b. It is suggested that a benchmark be provided for the determination of the amount of material which may be removed from the tool joint makeup shoulder. This benchmark should be applied to new or recut tool joints after facing to gage. The form of the benchmark may be a $^3/_{16}$ diameter circle with a bar tangent to the circle parallel to the makeup shoulder, as shown in Figure 10.5. The distance from the shoulder to the bar should be ⅛ inch. Variations of this benchmark or other type benchmarks may be available from tool joint manufacturers or machine shops.

c. It is good practice not to remove more than 1/32 inch from a box or pin shoulder at any one refacing and not more than 1/16 inch cumulatively.

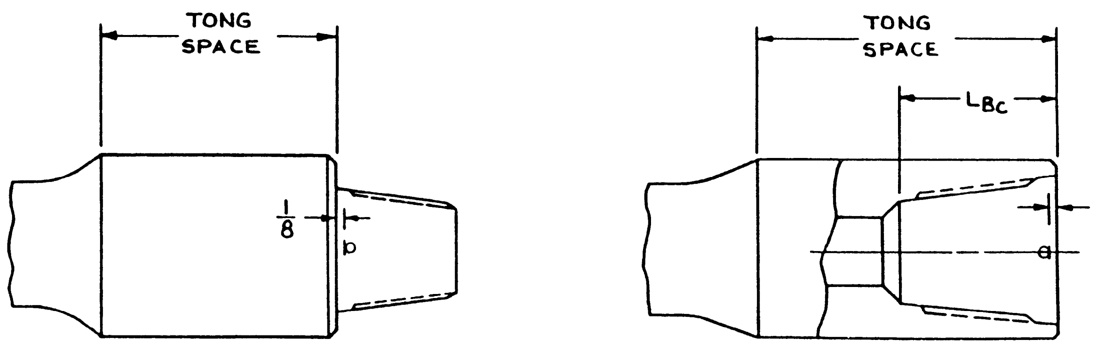


FIG. 10.5
TONG SPACE AND BENCH MARK POSITION

TABLE 10.1
CLASSIFICATION OF USED DRILL PIPE
(All Sizes, Weights and Grades. Nominal dimension is basis for all calculations)

1	2	3	4
PIPE CONDITION	PREMIUM CLASS[1] Two White Bands	CLASS 2 Yellow Bands	CLASS 3 Orange Bands
I. EXTERIOR CONDITIONS			
A. OD Wear			
Wall	Remaining wall not less than 80%	Remaining wall not less than 70%	Any imperfections or damages exceeding CLASS 2
B. Dents & Mashes	Diameter reduction not over 3% of OD	Diameter reduction not over 4% of OD	
C. Slip Area Mechanical Damage			
1. Crushing[2], Necking	Diameter reduction not over 3% of OD	Diameter reduction not over 4% of OD	
2. Cuts[3], Gouges[3]	Depth not to exceed 10% of the average adjacent wall[6]	Depth not to exceed 20% of the average adjacent wall[6]	
D. Stress Induced Diameter Variations			
1. Stretched	Diameter reduction not over 3% of OD	Diameter reduction not over 4% of OD	
2. String Shot	Diameter increase not over 3% of OD	Diameter increase not over 4% of OD	
E. Corrosion, Cuts & Gouges			
1. Corrosion	Remaining wall not less than 80%	Remaining wall not less than 70%	
2. Cuts & Gouges			
Longitudinal	Remaining wall not less than 80%	Remaining wall not less than 70%	
Transverse	Remaining wall not less than 80%	Remaining wall not less than 80%	
F. Fatigue Cracks[4]	None	None	None
II. INTERIOR CONDITIONS			
A. Corrosive Pitting			
Wall	Remaining wall not less than 80% measured from base of deepest pit	Remaining wall not less than 70% measured from base of deepest pit	
B. Erosion & Wear			
Wall	Remaining wall not less than 80%	Remaining wall not less than 70%	
C. Fatigue Cracks[4]	None	None	None

[1]The premium classification is recommended for service where it is anticipated that torisional or tensile limits for Class 2 drill pipe and tubing work strings will be exceeded. These limits for Premium Class and Class 2 drill pipe are specified in Tables 2.4 and 2.6, respectively. Premium Class shall be identified with two white bands, plus one center punch mark on the 35 sloping shoulder of the tool joint pin (or the 18 sloping shoulder of the pin, if the 18 angle is furnished).

[2]Inspection of this condition should be made to detect presence of longitudinal and transverse cracks inside and outside.

[3]Remaining wall shall not be less than the value in I.E.2, defects may be ground out providing the remaining wall is not reduced below the value shown in I.E.1 of this table and such grinding to be approximately faired into outer contour of the pipe.

[4]In any classification where fatigue cracks or washouts appear, the pipe will be identified with the red band and considered unfit for further drilling service.

[5]An API RP 7G inspection cannot be made with drill pipe rubbers on the pipe.

[6]Average adjacent wall is determined by measuring the wall thickness on each side of the cut or gouge adjacent to the deepest penetration.

TABLE 10.1A
CLASSIFICATION OF USED TUBING WORK STRINGS

1	2	3	4
PIPE BODY CONDITION	CRITICAL SERVICE CLASS One White Band	PREMIUM CLASS[2] Two White Bands	CLASS 2 Blue Bands
I. EXTERIOR CONDITIONS	(Tube Only)		
A. OD Wear Wall	Remaining wall not less than 87½%	Remaining wall not less than 80%	Remaining wall not less than 70%
B. Dents & Mashes	Diameter reduction not over 2% of OD	Diameter reduction not over 3% of OD	Diameter reduction not over 4% of OD
C. Slip Area, Tong Area Mechanical Damage			
1. Crushing[3], Necking	Diameter reduction not over 2% of OD	Diameter reduction not over 3% of OD	Diameter reduction not over 4% of OD
2. Cuts[4], Gouges[4]	Depth not to exceed 10% of the average adjacent wall[6]	Depth not to exceed 10% of the average adjacent wall	Depth not to exceed 20% of the average adjacent wall
D. Stress Induced Diameter Variations			
1. Stretched	Diameter reduction not over 2% of OD	Diameter reduction not over 3% of OD	Diameter reduction not over 4% of OD
2. String Shot	Diameter increase not over 2% of OD	Diameter increase not over 3% of OD	Diameter increase not over 4% of OD
E. Corrosion, Cuts & Gouges			
1. Corrosion	Remaining wall not less than 87½%	Remaining wall not less than 80%	Remaining wall not less than 70%
2. Cuts & Gouges Longitudinal	Remaining wall not less than 87½%	Remaining wall not less than 80%	Remaining wall not less than 70%
Transverse	Remaining wall not less than 87½%	Remaining wall not less than 80%	Remaining wall not less than 80%
F. Fatigue Cracks[5]	None	None	None
II. INTERIOR CONDITION (Tube & Upset)			
A. Corrosive Pitting Wall	Remaining wall not less than 87½% measured from base of deepest pit	Remaining wall not less than 80% measured from base of deepest pit	Remaining wall not less than 70% measured from base of deepest pit
B. Erosion & Wear Wall	Remaining wall not less than 87½%	Remaining wall not less than 80%	Remaining wall not less than 70%
C. Drift External Upset Internal Upset[7]	API dimensions $^1/_{16}$" less than specified bored ID	API dimensions $^1/_{16}$" less than specified bored ID	API dimensions $^1/_{16}$" less than specified bored ID
D. Fatigue Cracks[5]	None	None	None

[1]The critical service classification is recommended for service where new or like new specifications apply. Critical service classification tubing work strings shall be identified with one white band.

[2]The premium classification is recommended for service where it is anticipated that torsion or tensile limits for Class 2 tubing work strings will be exceeded. Premium classification tubing work strings shall be identified with two white bands.

[3]Inspection of this condition should be made to detect presence of longitudinal and transverse cracks inside and outside.

[4]Remaining wall shall not be less than the value in I.E.2. Defects may be ground out providing the remaining wall is not reduced below the value shown in I.E.1 of this table and such grinding to be approximately faired into outer contour of the tubing.

[5]In any classification where fatigue cracks or washouts appear, the tubing will be identified with the red band and considered unfit for further service.

[6]Average adjacent wall is determined by measuring the wall thickness on each side of the cut or gouge adjacent to the deepest penetration.

[7]Applicable to Internal Upsets which have been bored.

TABLE 10.2
HOOK-LOAD AT MINIMUM YIELD STRENGTH FOR NEW, PREMIUM CLASS (USED), AND CLASS 2 (USED) DRILL PIPE

(Hook load values in this table vary slightly from tensile data for the same pipe size and class listed in Tables 2.2, 2.4, 2.6, 2.8, 2.10, and 2.11 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
		NEW						PREMIUM CLASS					CLASS 2				
Size O.D. in.	Weight lb/ft	Original O.D. in.	Wall Thickness in.	I.D. in.	Orig. Cross-Section Area sq. in.	Yield psi	Hook Load lb	O.D. w/20% Wall Reduction in.	Minimum Remaining Wall (80%) in.	Reduced Cross-Section Area sq. in.	Cross-Section Area Ratio per cent	Hook Load lb	O.D. w/30% Wall Reduction in.	Minimum Remaining Wall (70%) in.	Reduced Cross-Section Area sq. in.	Cross-Section Area Ratio per cent	Hook Load lb
2⅜	4.85	2.375	0.190	1.995	1.3042	75000.	97817.	2.2990	0.152	1.0252	78.61	76893.	2.2610	0.133	0.8891	68.17	66686.
						95000.	123902.					97398.					84469.
						105000.	136944.					107650.					93360.
						135000.	176071.					138407.					120035.
2⅜	6.65	2.375	0.280	1.815	1.8429	75000.	138214.	2.2630	0.224	1.4349	77.86	107616.	2.2070	0.196	1.2383	67.19	92871.
						95000.	175072.					136313.					117636.
						105000.	193500.					150662.					130019.
						135000.	248786.					193709.					167167.
2⅞	6.85	2.875	0.217	2.441	1.8120	75000.	135902.	2.7882	0.174	1.4260	78.69	106946.	2.7448	0.152	1.2374	68.29	92801.
						95000.	172143.					135465.					117549.
						105000.	190263.					149725.					129922.
						135000.	244624.					192503.					167043.
2⅞	10.40	2.875	0.362	2.151	2.8579	75000.	214344.	2.7302	0.290	2.2205	77.70	166535.	2.6578	0.253	1.9141	66.97	143557.
						95000.	271503.					210945.					181839.
						105000.	300082.					233149.					200980.
						135000.	385820.					299764.					258403.
3½	9.50	3.500	0.254	2.992	2.5902	75000.	194264.	3.3984	0.203	2.0397	78.75	152979.	3.3476	0.178	1.7706	68.36	132793.
						95000.	246068.					193774.					168204.
						105000.	271970.					214171.					185910.
						135000.	349676.					275363.					239027.
3½	13.30	3.500	0.368	2.764	3.6209	75000.	271569.	3.3528	0.294	2.8287	78.12	212150.	3.2792	0.258	2.4453	67.53	183398.
						95000.	343988.					268723.					232304.
						105000.	380197.					297010.					256757.
						135000.	488825.					381870.					330116.
3½	15.50	3.500	0.449	2.602	4.3037	75000.	322775.	3.3204	0.359	3.3416	77.65	250620.	3.2306	0.314	2.8796	66.91	215967.
						95000.	408848.					317452.					273558.
						105000.	451885.					350868.					302354.
						135000.	580995.					451115.					388741.