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Distribution:
Nataraja
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Pearring
(Return to WM, 623-SS)

Dr. M. S. Nataraja
Engineering Branch
Division of Waste Management
U. S. Nuclear Regulatory Commission
7915 Eastern Avenue
Silver Spring, MD 20910

Dear Dr. Nataraja:

As mentioned in the May 1985 Monthly Report, for FIN A-1755, we are including at this time K. Wahi's Trip Report for his attendance to the Institute of Shaft Drilling Technology Meeting May 22-24, 1985.

Sincerely,

E. J. Bonano

E. J. Bonano
Waste Management Systems
Division 6431

EJB:6431:mg

Enclosure

2195

SFC A1755 6/24/85
TO Nataraja From
Bonano

TRIP REPORT

At NRC's request, Krishan Wahi recently attended the annual technical conference of the Institute of Shaft Drilling Technology (ISDT) held in Las Vegas, Nevada. The meeting dates were May 22 through May 24, 1985.

Introductory remarks were made by Paul Richardson, the current ISDT President. A copy of the agenda is attached at the back of this report. Also attached are copies of selected papers; not all speakers made copies of their papers available.

The first paper dealt with the concepts and programs for a proposed two-phased repository in basalt. H. B. Dietz of Rockwell presented an overview of the program. Under the two-phase concept, the DOE intends to provide an interim Phase I repository by 1998, with the Phase II (full scale) repository completed in 2001. The analysis assumes truck shipments only. A "new" waste package design is required for the two-phase concept. Two exploratory shafts, each one 6-ft in diameter, are planned to be constructed using blind drilling. The two shafts will be separated by 500 ft and the underground drift excavation during site characterization will be approximately 1700 ft. A total of nine shafts are proposed for the repository; two with 6-ft diameter, three with 12-ft diameter and four with 8.75-ft diameter. The stated conclusion was that the two-phase concept was viable and would enable a timely completion in compliance with NWPA. Two questions, that are relevant from NRC's perspective, were posed to the speaker: 1. Will the final EA contain more comprehensive analyses of the two-phase concept? and 2. Has there been previous large-hole drilling experience in a high-stress environment? The answer given to the first question was a "no"; DOE views it as a programmatic change that does not impact the determinations given in the Draft EA. The answer to the second question was that they were not aware of any previous experience, but did not anticipate problems (because of small exploratory hole drilling experience). However, C. T. Webster qualified that answer by saying that there has been previous experience at Amchitka.

The second presentation was by C. T. Webster of Rockwell Hanford Operations concerning "Exploratory Drilling in Basalt at Hanford". Mr. Webster is the Principal Engineer on the project. The following comments paraphrase selected parts of his talk. The Columbia Plateau contains the world's second largest basalt formation. The brittle nature of this basalt gives it good drillability with tungsten carbide drill bits. The drilling of DC-1 was a typical learning experience. In coring and core-recovery, the oil-field type of equipment (with diamond-bit drilling) failed to perform. Inflatable

packers worked extremely well in the core holes. Lost circulation is a major problem with core drilling; this problem is minimized with rotary drilling. Attempts were made to measure stress in these holes using hydrofracture techniques. There are at present 17 holes with depths between 1000 ft and 2000 ft; and 70 holes that are less than 1000 ft deep. For medium-hard formations with high compressive strength, the J44 bits work well giving drilling rates of 6 ft/hr. Pumping tests of 60- to 90-day duration are envisioned for the RRL-2 nest of holes. Rockwell has acquired two unique drill rigs. At the Hanford site these rigs will be run on electricity only. One of these rigs has been used to drill more than 30,000 ft on two occasions. The most important statement made by the speaker was that he does not believe that the presence of repository-quality basalt can be confirmed without drilling an exploratory shaft.

The next paper was on "Key Factors in Determining Rig and Equipment Requirements versus Shaft Size to be Drilled" by C. Presely (private consultant). Based on his experience and simple analyses, he identified important parameters and dimensions that are of practical value in carrying out drilling programs. He feels that rotary tables are the weakest link in the chain of large-hole drilling equipment because they are not designed for low-r.p.m./high torque operations. The torque is a function of number of cutters, rolling resistance, and radial location of the cutters. Disc cutters outperform any other cutter type, but must be loaded to the rock-failure load. Barrel-type cutters will cut at almost any load. It is possible to comfortably drill 15-ft dia. holes with tapered bottom bit and 19-ft dia. holes with flat bottom bit. Tapered bottom aids bottom hole cleaning which is essential as holes get larger.

Dave Becker of Rockwell-Hanford made the next presentation on "Large Diameter Shaft Steel Liner Design Concerns". He categorized the liner design concerns into three areas: fabrication and delivery, field preparation and installation, and outfitting and operations. The fabrication and delivery factors include liner weight, constructability, shipment to site, quality assurance/quality control and inspection, and cost. Field preparation and installation factors include liner weight, handling, lifting methods, hole mis-alignment etc. Weight curves for ring-stiffened steel casing for a 3900-ft shaft were presented. These curves (for different yield strength) present liner weight as a function of inside diameter. Alternate reinforcing ring designs were shown. Arc time versus liner thickness curves for different welding techniques were given. Reinforcement rings can be placed inside the liner instead of outside, which would reduce welding requirements. However, higher section thicknesses would be required when inside reinforcement rings are used.

Casing port hole drilling in a high pressure environment was discussed by D. Moak of Rockwell-Hanford. A copy of Moak's paper is attached. The first Exploratory shaft (ES-1) will provide access to the repository horizon. In-situ testing will take place from both shafts prior to breakout. Every borehole drilled will be continuously bored. The breakout is planned at a depth of 3150 ft. The temperature and water pressure near that depth are expected to be 124 degrees Fahrenheit and 1300 psi. Additional safety margins are planned to satisfy DOE and NRC concerns. A multi-level work deck will be built and E/H powered drill will be used for quiet operation. Six-hour work shifts will be used. A total of ninety-eight portholes, varying in length from 40 ft to 130 ft, are planned with 42 in flow tops and interbeds and 56 in flow interiors. Some of the holes will be inclined.

The remaining papers were unrelated to the BWIP project and are described very briefly in the following paragraphs. Wendell Mansel of Fenix and Scisson presented a paper on controlled bit tests. A copy of his paper is included. Two important conclusions were: 1. Increasing the circulation rate results in an increase of the rate of penetration; 2. When re-tipped cutters are used (instead of new cutters) both the penetration rate and the bit-wear increase. The increased penetration rate is speculated to be due to the re-tipping material. A presentation on "Big Hole Measurement While Drilling" was given by Karl Hahn of Reynolds Electrical and Engineering. They have used different kinds of drill bits and found polishing patterns on the bit paints. Different off-bottom distances of the pick-up tube, and various sizes of mudline and rotary hose have been tried to study their effect on penetrarion rates. Significant fuel savings resulted when larger diameter mudline and rotary hose were used. They hope to make real time MWD (measurement while drilling) using EPR (wire), mud pulse, acoustics and electromagnetics. The parameters of interest are the pressure and temperature in the bit region. J. R. Benjamin from the Wirth Company gave a talk on rotary drilling machines for shaft construction. They are manufacturers of drilling equipment, and his talk concentrated on drilling machines made by Wirth. A sequential raise boring machine and a box holing machine were described.

The Thursday, May 23, morning session started with a status report on ISDT membership. Two items of interest are a blind-drilling short course and a symposium on raise boring. The first talk of the day was given by T. Wilson from the Los Alamos National Laboratory (LASL). The subject of this talk was a numerical simulation of fluid flow and chip transport beneath a drill bit. A copy of this paper is attached. Based on the analysis, some possibilities for improved bottom-hole cleaning were suggested. These are: lower mouth of pickup tube, a shroud (i.e., false bottom), jets near hole wall, and experimentation with jet orientation. Alternate chip-removal

methods were proposed for assessment; namely, sweep pick ups, wipers and conveyors. Computer simulations were promoted as a relatively inexpensive tool for understanding and improving drilling performance.

Robert Parker, Jr., of Parker Drilling Company made a presentation titled, "A large Diameter Drilling Rig Design". According to Mr. Parker, his company has drilled the world's largest/deepest hole, which is 6200 ft deep with 7.5 ft diameter. The Parker Co. designed a new rig in mid-1982 for the BWIP project. This rig (Parker 221) is capable of drilling large diameter shafts and can handle 80-ft casing sections of 110" diameter. It has a static load capacity of 2 million pounds with a 3000-4000 h.p. (electric) draw-works. The substructure is 7 to 8 ft high, the drilling line is 2" dia. and the leg-span is 40 ft. The rotary table has 2000 h.p. motors and a diameter of 37.5 in. The largest drill rig owned by Parker is currently at a site in Oklahoma to drill a 33,000-ft deep hole; its rotary table has a diameter of 49.5 inches.

A presentation on understanding the tension-torque diagram was given by G. Alther of LOR, Inc. A copy of this paper is enclosed. The tension-torque curve is typically elliptical for tubular pipe without connections. A factor of safety is used such that the maximum operational limit is 75% of the material yield limit. When rotary shouldered connections are present, other considerations enter into the construction and interpretation of the tension-torque diagram.

Application of horizontal tunneling machines to vertical drilling was discussed by Milton Head of Head Development, Inc. The title of his talk was "Cutter on Casing Shaft Sinking Method". Torque capacities of 13 million ft-lb have been achieved with these tunneling machines. He showed many slides of tunneling machines and equipment and different types of liner design. Segmented, prefabricated reinforced concrete liner with wooden pins was cited as a very successful design. An application was shown where a 9-ft dia. shaft was drilled in shale/alluvium using tunneling equipment. The conclusion was that there is a lot of potential for using tunnel boring technology to shaft drilling and lining.

Euclid Worden from Drilco Industrial talked about developments in raise boring bit bodies. "Flat-bottomed" bodies are used for cutting in one plane. The term "flat" does not necessarily imply complete flatness or horizontal cutting plane. Frequent failure of threaded joint or drill stem has led to the development of replaceable stems. Although roller stablizers were popular in the past, they are no longer favored in raise boring.

Case histories of large diameter raise boring were presented by W. Harrison of Frontier-Kemper. One example was of a 20-ft diameter shaft for the Monterey Coal Project. Frontier-Kemper has a total of 3.5 miles of raise drilling experience and has a very large inventory of drills for raise

boring. B. Kirkpatrick, owner of Raisebor, Inc. gave a report on angle raise boring methods. Holes that are 75 to 85 degrees with respect to the horizontal plane are relatively free of complications. "Flatter" holes have several unique problems. Poor surveying of a project site can sometimes lead to a need for angled holes. Raisbor, Inc. has been involved in a number of 45-degree hole drilling jobs. Problems with angled holes that are not drilling related have to do with mechanical aspects of rig design, poor lubrication, increased bearing-wear, combined state-of-stress on load-bearing members, and bolt loosening. Some of the drilling related problems are the drill-bit wear and hole-direction deviation. Operator skill is extremely important in angled hole raise drilling.

The Friday morning session started with a talk by V. Valencia, President of International Ground Support Systems, on "Remote Shotcrete Linings". Mr. Valencia also runs a shotcrete training school. He had many practical tips on shotcreting. One warning was not to use shotcreting after everything else has failed. A pre-construction testing procedure that is followed by his company was shown. The water/cement ratio controls the strength of shotcrete; most of the mixes use the ASTM specifications. Ideal water/cement ratios fall in the 0.27-0.35 range. High strength should be achieved early on (i.e., quickly after application) without the use of "accelerators". On an NTS job, 8-in thick (average) shotcrete was placed remotely and an average compressive strength of 6200 psi was achieved. A video film of the whole operation was shown toward the end of the talk.

J. Neudecker of LASL discussed the application of water-jet cutting to shaft drilling. In water-jet cutting, pressures of 15,000 psi are considered moderate. Cutting rates are proportional to the ratio of water jet pressure and rock strength. Plots of drill rate versus jet pressure were shown for small diameter holes. There are advantages to using higher water jet pressure on the guage cutters. Additional power of about 400 h. p. is needed to provide extra jet pressure of approximately 10,000 psi. Some planned laboratory experiments were mentioned to perform parametric studies.

The use of a combination blind-raise drill in a gold mine operation in South Africa was described by J. Friant of the Robbins Co. The expected benefit of using raise-drilling technology was to reduce the amount of waste rock in the enlargement of a hole. The machine was a Robbins drill (Box Hole Drill Model 52R). It has a torque of 95,000 ft-lb and a thrust of 300,000 lb. Some problems were encountered that required an abnormal amount of interruption and maintenance. The main lesson was that a better cutter design is necessary for a rock of such high compressive strength.

The last presentation of the meeting was given by a team of speakers from Santa Fe Joint Venture on the AOSTRA (Alberta Oil Sands Technology and Research Authority) Project. Due to

unfavorable ground and underground conditions it was thought necessary to resort to blind drilling. An estimated 160 billion cubic meters of oil sands exist in Alberta. A shaft and Tunnel Access Concept (SATAC) has been developed to exploit this energy source. The initial shaft dimensions are 13 ft diameter and 722 ft depth for an underground test facility. Some drilling problems were encountered in the limestone formation. Specifically, the penetration rates were very low and no satisfactory explanation could be developed to explain these penetration difficulties. Efforts to log the hole were also not productive. On the positive side, the mud program was very successful and the surveying data were reliable. A second hole of the same dimensions is in the process of being completed. Although it is only 50m away from the first hole, the conditions are quite different. This observation has significant implications with respect to the spatial variability issues that are of concern to the NRC.

INSTITUTE OF SHAFT DRILLING TECHNOLOGY

A self-supporting non-profit organization dedicated to the advancement of shaft construction through large diameter drilling techniques

1985 ISDT ANNUAL TECHNICAL CONFERENCE
Frontier Hotel - Las Vegas, Nevada

Wednesday, May 22, 1985

07:30-08:30 a.m.	Registration - Americana West Room (Coffee will be served)
08:30-09:00 a.m.	Introduction and ISDT Business, Paul Richardson, President ISDT
09:00-09:45 a.m.	"Overview of Concepts and Programs for a Proposed Two-Phased Repository in Basalt", H.B. Dietz, Rockwell Hanford Operations
09:45-10:30 a.m.	"Exploratory Drilling in Basalt at Hanford", C. T. Webster, Rockwell Hanford Operations
10:30-10:45 a.m.	Coffee Break
10:45-11:30 a.m.	"Key Factors in Determining Rig and Equipment Requirements versus Shaft Size to be Drilled", C. K. Presley, Consultant and F.C. Larvie, Morrison-Knudsen
11:30-12:15 p.m.	"Large Diameter Shaft Steel Liner Design Concerns", Dave Becker, Rockwell Hanford Operations
12:15-1:45 p.m.	Lunch - Americana South Room
01:45-02:30 p.m.	"Casing Port Hole Drilling in High Pressure Environment", Greg McLellan and Don Moak, Rockwell Hanford Operations
02:30-03:15 p.m.	"Controlled Bit Test", ~~Wallace Hammer~~ Wendell MANSEL, Fenix & Scisson
03:15-03:30 p.m.	Coffee/Soda Break
03:30-04:15 p.m.	"Big Hole Measurement While Drilling", ~~Carl Hawn~~ Karl Hahn, Reynolds Electrical and Engineering
04:15-05:00 p.m.	"Rotary Drilling Machine for Shaft Construction", J. R. Benjamin, Wirth
06:00-08:00 p.m.	Cocktail Reception - Gold Room

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1985 ISDT ANNUAL TECHNICAL CONFERENCE
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Thursday, May 23, 1985

08:00-08:30 a.m.	Registration - Americana West Room (Coffee will be served)
08:30-09:15 a.m.	"Numerical Simulation of Fluid Flow and Chip Transport Beneath a 110-inch Diameter Large Shaft Drill Bit", T. L. Wilson and W. S. Gregory, Los Alamos National Laboratory
09:15-10:15 a.m.	"A Large Diameter Drilling Rig Design", Robert L. Parker, Jr., Parker Drilling Company
10:15-10:30 a.m.	Coffee Break
10:30-11:15 a.m.	~~"Interpretation of Rotary Shouldered Connections - Torque Tension Performance and Charts"~~, Jake McNeal and George Alther, LOR, Inc.
11:15-12:15 p.m.	"Cutter on Casing Shaft Sinking Method", Milton Head, Head Development, Inc.
12:15-02:00 p.m.	Lunch - Americana South Room
02:00-02:45 p.m.	"Development in Raise Boring Bit Bodies", Euclid Worden, Drilco Industrial
02:45-03:00 p.m.	Coffee/Soda Break
03:00-03:45 p.m.	"Large Diameter Raise Boring Case Histories", Warren Harrison, Frontier-Kemper
03:45-04:30 p.m.	"Report of Angle Raise Boring Methods", Bruce Kirkpatrick, Raisebor, Inc.

"Understanding Tension-Torque Performance Diagrams for Raise-Drill and Large Drill Pipe Connectors"

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1985 ISDT ANNUAL TECHNICAL CONFERENCE
Frontier Hotel - Las Vegas, Nevada

Friday, May 24, 1985

08:00-08:30 a.m.	Registration - Americana West Room
08:30-09:15 a.m.	"Remote Shotcrete Linings", Val Valencia and John Pye, International Ground Support Systems
09:15-10:00 a.m.	"Application of Water Jet Drilling to Shaft Drilling", Joe Neudecker, Jr., Los Alamos National Laboratory
10:00-10:15 a.m.	Coffee Break
10:15-11:00 a.m.	"A Combination Blind-Raise Drill", Jim Friant, The Robbins Company
11:00-11:45 a.m.	"AOSTRA Report at Fort McMurray, Alberta, Canada", John Hopkinson, Patrick Harrison, Lyle Cuthbert, Simmons - Santa Fe Joint Venture
11:45-12:00 p.m.	Wrap-up any remaining ISDT Business - Paul Richardson
12:00 p.m.	Lunch - Americana South Room

K. WAHI

ENGINEERING
CONSTRUCTION
MANAGEMENT

EVALUATION OF CONTROLLED BIT TESTS FOR 31,000 FEET OF 86" AND 96" DIAMETER HOLES DRILLED AT THE NEVADA TEST SITE FROM JUNE 1983 TO OCTOBER 1984

FOR

U. S. DEPARTMENT OF ENERGY

BY Wendell Mansel ~~Stengel~~

FENIX & SCISSON, INC.

MAY 15, 1985

FENIX & SCISSON, INC.
1401 S. BOULDER
TULSA, OKLAHOMA 74119

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U. S. DEPARTMENT OF ENERGY CONTRACT DE-AC08-84NV10322

EVALUATION OF CONTROLLED BIT TESTS FOR 31,000 FEET OF 86" AND 96" DIAMETER HOLES DRILLED AT THE NEVADA TEST SITE

TABLE OF CONTENTS

EVALUATION OF CONTROLLED BIT TESTS FOR 31,000 FEET OF 86" AND 96" DIAMETER HOLES DRILLED AT THE NEVADA TEST SITE

Abstract

This study was conducted on twenty-seven (27) 86" and 96" diameter holes drilled between June 1983 and October 1984. This is an evaluation of milltooth cutter bit performance drilling the Alluvium and Ash Flow formations at the Nevada Test Site.

Conclusions

Results of this study are as follows:

1. An increase in bit run time (Hrs/Run) for drilling the Alluvium is indicated.
2. For 86" and 96" diameter bits, an increase in the rate of penetration and bit wear was shown using re-tipped milltooth cutters versus new cutters.
3. Increasing the circulation rate results in an increase of the rate of penetration.
4. Performance of 96" diameter bits drilling the Alluvium show a lower penetration rate and shorter bit runs with increased bit wear versus 86" diameter bits.
5. Performance of 96" diameter bits drilling in the Ash Flow show increased bit wear and longer runs with the same penetration rate versus 86" diameter bits.

Introduction

This evaluation includes eighteen (18) 96" and nine (9) 86" diameter holes. The total depth ranged from 700' to 2250'. The 13-3/8" x 7" integral dual reverse drill string using air/water as a circulation media was used. This is the most efficient method for hole cleaning and for obtaining acceptable hole stability presently developed at the Nevada Test Site. This evaluation is based on fifty-

two (52) 96" diameter and twenty-six (26) 86" diameter bit runs. The parameters in this study are as follows:

1. Rate of penetration, ft/hr vs hours/bit run
2. Rate of penetration, ft/hr vs cutter wear, percentage
3. Rate of penetration, ft/hr vs GPM injection rate
4. Rate of penetration, ft/hr vs GPM/RPM, gal/rev
5. GPM injection rate vs cutter wear, percentage
6. Hours/bit run vs cutter wear, percentage
7. Cutter wear, percentage vs RPM x WT on bit (K-lbs)

Field Testing Equipment and Procedures

A. Equipment

1. Continuous recording instrumentation.
   - (a) Rate of penetration (ft/hr)
   - (b) Hook load (K-lbs)
   - (c) Pump pressure (psi)
   - (d) Rotary speed (RPM)
2. Instrumentation requiring manual readings and recording data.
   - (a) Fluid level above the bit (ft)
   - (b) Injection pressure gauge (psi)
3. Manual recording of data.
   - (a) Pump strokes (SPM, GPM-IN)
   - (b) Air (CFM)

B. Procedure

Maintain recorded data representative of normal drilling operations.

Data and Results

The accumulative data for this study is presented in Tables I through IX and figures 1 through 29.

Interpretation of Data

Cutter Wear - New Versus Re-tip Cutters

The average rate of penetration of the re-tip cutters compared with the new cutters, for both 86" and 96" diameter bits, shows a 17% increase. However, the average cutter wear, feet drilled/percent wear, shows a 9.5% increase using re-tip cutters vs new cutters.

Bit Performance Between Alluvium and Ash Flow Formations

The number of hours/bit run for both 86" and 96" diameter hole sizes, using either re-tips or new milltooth cutters, show that drilling Alluvium for an average of 65 hours/bit run, the rate of penetration ranges from 7 - 9 ft/hr resulting in a 30% average cutter wear. With an average injection rate of 411 GPM, new cutters resulted in an overall penetration rate of 8.2 ft/hr while the re-tipped cutters show an 8.7 ft/hr rate of penetration with a 385 GPM injection rate.

The number of hours/bit run for both 86" and 96" diameter hole sizes, using either re-tip of new cutters, show that drilling Ash Flow for an average of 40 hours/bit run, the rate of penetration ranges from 5 - 7 ft/hr resulting in a 25% cutter wear with an injection rate of 299 GPM. For an average GPM injection rate of 259, new cutters show an overall rate of penetration of 6.1 ft/hr for both 86" and 96" diameter holes.

Bit Performance in 86" and 96" Diameter Hole Sizes

For the Alluvium formation, 96" diameter bits show an average penetration rate of 7.8 ft/hr compared to 86" diameter bits with an average of 9.7 ft/hr. The average number of hours per bit run for the 96" and 86" diameter bits was 60 and 61 hours respectively. The average cutter wear for 96" diameter bits was 36.5% compared to 17.5% for the 86" diameter bits. The water injection rate averaged 425 GPM with a comparable penetration rate of 7.8 ft/hr for 96" diameter bits and a injection rate of 364 GPM averaging 9.7 ft/hr rate of penetration using 86" diameter bits.

For the Ash Flow formation, the 86" and 96" diameter bits averaged a comparable 6.1 ft/hr rate of penetration. The 96" diameter bits maintained a 32.5 hours/bit run average versus a 30.4 hours/bit run for the 86" diameter bits. Cutter wear for the 86" and 96" diameter bits was 16.5% and 29% respectively. Water injection rates averaged 286 GPM for 96" diameter bits with a rate of penetration of 6.1 ft/hr. The 86" diameter bits averaged 6.1 ft/hr with an injection rate of 214 GPM.

ACKNOWLEDGEMENTS

Appreciation is expressed to U. S. Department of Energy (USDOE) for their support and approval to present this paper.

TABLE 1

Summary of Footage Drilled into Alluvium and Ash Flow Formations using 86" and 96" Diameter Bits

Total Percentage of Footage Drilled by 96" Bits = 65.5%

Total Percentage of Footage Drilled by 86" Bits = 34.5%

ALLUVIUM FORMATION				
96" Bits	-	14,001'	=	64%
86" Bits	-	7,865'	=	36%
TOTAL ALLUVIUM		21,866'	=	70.5%
ASH FLOW				
96" Bits	-	6,319'	=	69.2%
86" Bits	-	2,819'	=	30.8%
TOTAL ASH FLOW		9,138'	=	29.5%
GRAND TOTAL		31,004'		

TABLE II - AN EVALUATION OF NEW CUTTER VS RE-TIP CUTTERS FOR 96" BIT #1 USING MILLTOOTH CUTTERS DRILLING IN ALLUVIUM FORMATION.

Total number bit runs	25
Total number hours drilling	1359
Total number feet drilled	11249
Average rate of penetration, Ft/Hr	8.3
Average number hours per bit run	54
USING 100% NEW CUTTERS	
Number of bit runs	13
Number of hours drilling	705
Number of feet drilled	5038
Average depth per bit run in, ft.	527
Average depth per bit run out, ft.	914
Average number feet per bit run	388
Average rate of penetration, Ft/Hr	7.2
Average number hours per bit run	54
Average cutter wear, percent	24
Per foot cutter wear, feet drilled/percent wear	210
USING 89 TO 100% RE- TIPCUTTERS	
Number of bit runs	12
Number of hours drilling	654
Number of feet drilled	5918
Average depth per bit run in, ft.	436
Average depth per bit run out, ft.	929
Average number feet per bit run	493
Average rate of penetration, Ft/Hr	9.1
Average number hours per bit run	54.5
Average cutter wear, percent	38
Per foot cutter wear, feet drilled/percent wear	156
INCREASE IN RATE OF PENETRATION RE-TIP VS NEW CUTTERS, PERCENT	21
INCREASE IN CUTTER WEAR RE-TIPS VS NEW CUTTERS, PERCENT	14

TABLE III - AN EVALUATION OF NEW CUTTERS VS RE-TIP CUTTERS FOR 96" BIT #1 USING MILLTOOTH CUTTERS DRILLING IN ASH FLOW FORMATION

Total number bit runs	20
Total number hours drilling	867
Total number feet drilled	4430
Average rate of penetration, Ft/Hr	5.1
Average number hours per bit run	43
USING 100% NEW CUTTERS	
Number of bit runs	13
Number of hours drilling	631
Number of feet drilled	2649
Average depth per bit run in, ft.	959
Average depth per bit run out, ft.	1165
Average number feet per bit run	204
Average rate of penetration, Ft/Hr	4.2
Average number hours per bit run	49
Average cutter wear, percent	15
Per foot cutter wear, feet drilled/percent wear	177
USING 89 TO 100% RE-TIP CUTTERS	
Number of bit runs	7
Number of hours drilling	236
Number of feet drilled	1781
Average depth per bit run in, ft.	857
Average depth per bit run out, ft.	1111
Average number feet per bit run	254
Average rate of penetration, Ft/Hr	7.5
Average number hours per bit run	34
Average cutter wear, percent	34
Per foot cutter wear, feet drilled/percent wear	52
INCREASE IN RATE OF PENETRATION RE-TIP VS NEW CUTTERS, PERCENT	44
INCREASE IN CUTTER WEAR RE-TIPS VS NEW CUTTERS, PERCENT	19

TABLE IV - AN EVALUATION OF NEW CUTTERS VS RE-TIP CUTTERS FOR 96" BIT #2 USING MILLTOOTH CUTTERS DRILLING IN ALLUVIUM FORMATION

Total number bit runs	3
Total number hours drilling	185.5
Total number feet drilled	1361
Average rate of penetration, Ft/Hr	7.3
Average number hours per bit run	62
USING 100% NEW CUTTERS	
Number of bit runs	2
Number of hours drilling	146
Number of feet drilled	1073
Average depth per bit run in, ft.	111
Average depth per bit run out, ft.	648
Average number feet per bit run	537
Average rate of penetration, Ft/Hr	7.4
Average number hours per bit run	73
Average cutter wear, percent	36
Per foot cutter wear, feet drilled/percent wear	30
USING 89 TO 100% RE-TIP CUTTERS	
Number of bit runs	1
Number of hours drilling	39.5
Number of feet drilled	288
Average depth per bit run in, ft.	111
Average depth per bit run out, ft.	399
Average number feet per bit run	288
Average rate of penetration, Ft/Hr	7.3
Average number hours per bit run	39.5
Average cutter wear, percent	53
Per foot cutter wear, feet drilled/percent wear	5.4
INCREASE IN RATE OF PENETRATION RE-TIP VS NEW CUTTERS, PERCENT	1
INCREASE IN CUTTER WEAR RE-TIPS VS NEW CUTTERS, PERCENT	17

TABLE V - AN EVALUATION OF NEW CUTTERS VS RE-TIP CUTTERS FOR 96" BIT #2 USING MILLTOOTH CUTTERS DRILLING IN ASH FLOW FORMATION

Total number bit runs	4
Total number hours drilling	87.7
Total number feet drilled	635
Average rate of penetration, Ft/Hr	7.2
Average number hours per bit run	22
USING 100% NEW CUTTERS	
Number of bit runs	2
Number of hours drilling	26.4
Number of feet drilled	170
Average depth per bit run in, ft.	923
Average depth per bit run out, ft.	1008
Average number feet per bit run	85
Average rate of penetration, Ft/Hr	6.4
Average number hours per bit run	13
Average cutter wear, percent	28
Per foot cutter wear, feet drilled/percent wear	6
USING 89 TO 100% RE-TIP CUTTERS	
Number of bit runs	2
Number of hours drilling	61.3
Number of feet drilled	465
Average depth per bit run in, ft.	303
Average depth per bit run out, ft.	535
Average number feet per bit run	233
Average rate of penetration, Ft/Hr	7.6
Average number hours per bit run	31
Average cutter wear, percent	43
Per foot cutter wear, feet drilled/percent wear	11
INCREASE IN RATE OF PENETRATION RE-TIP VS NEW CUTTERS, PERCENT	16
INCREASE IN CUTTER WEAR RE-TIPS VS NEW CUTTERS, PERCENT	15

TABLE VI - AN EVALUATION OF NEW CUTTER VS RE-TIP CUTTERS FOR 86" BIT #3 USING MILLTOOTH CUTTERS DRILLING IN ALLUVIUM FORMATION

Total number bit runs	8
Total number hours drilling	520
Total number feet drilled	5013
Average rate of penetration, Ft/Hr	9.6
Average number hours per bit run	65
USING 100% NEW CUTTERS	
Number of bit runs	4
Number of hours drilling	202
Number of feet drilled	2117
Average depth per bit run in, ft.	317
Average depth per bit run out, ft.	846
Average number feet per bit run	529
Average rate of penetration, Ft/Hr	10.5
Average number hours per bit run	51
Average cutter wear, percent	14.5
Per foot cutter wear, feet drilled/percent wear	146
USING 89 TO 100% RE-TIP CUTTERS	
Number of bit runs	4
Number of hours drilling	318
Number of feet drilled	2896
Average depth per bit run in, ft.	113
Average depth per bit run out, ft.	837
Average number feet per bit run	724
Average rate of penetration, Ft/Hr	9.1
Average number hours per bit run	80
Average cutter wear, percent	19
Per foot cutter wear, feet drilled/percent wear	152
INCREASE IN RATE OF PENETRATION NEW VS RE-TIP CUTTERS, PERCENT	13
INCREASE IN CUTTER WEAR RE-TIPS VS NEW CUTTERS, PERCENT	4.5

TABLE VII- AN EVALUATION OF NEW CUTTERS VS RE-TIP CUTTERS FOR 86" BIT #3 USING MILLTOOTH CUTTERS DRILLING IN ASH FLOW FORMATION

Total number bit runs	9
Total number hours drilling	258.7
Total number feet drilled	1765
Average rate of penetration, Ft/Hr	6.8
Average number hours per bit run	28.7
USING 100% NEW CUTTERS	
Number of bit runs	6
Number of hours drilling	166.4
Number of feet drilled	1228
Average depth per bit run in, ft.	907
Average depth per bit run out, ft.	1116
Average number feet per bit run	205
Average rate of penetration, Ft/Hr	7.4
Average number hours per bit run	28
Average cutter wear, percent	16
Per foot cutter wear, feet drilled/percent wear	76
USING 89 TO 100% RE-TIP CUTTERS	
Number of bit runs	3
Number of hours drilling	92.3
Number of feet drilled	537
Average depth per bit run in, ft.	768
Average depth per bit run out, ft.	960
Average number feet per bit run	179
Average rate of penetration, Ft/Hr	5.8
Average number hours per bit run	31
Average cutter wear, percent	26
Per foot cutter wear, feet drilled/percent wear	4
INCREASE IN RATE OF PENETRATION NEW VS RE-TIP CUTTERS, PERCENT	22
INCREASE IN CUTTER WEAR RE-TIPS VS NEW CUTTERS, PERCENT	10

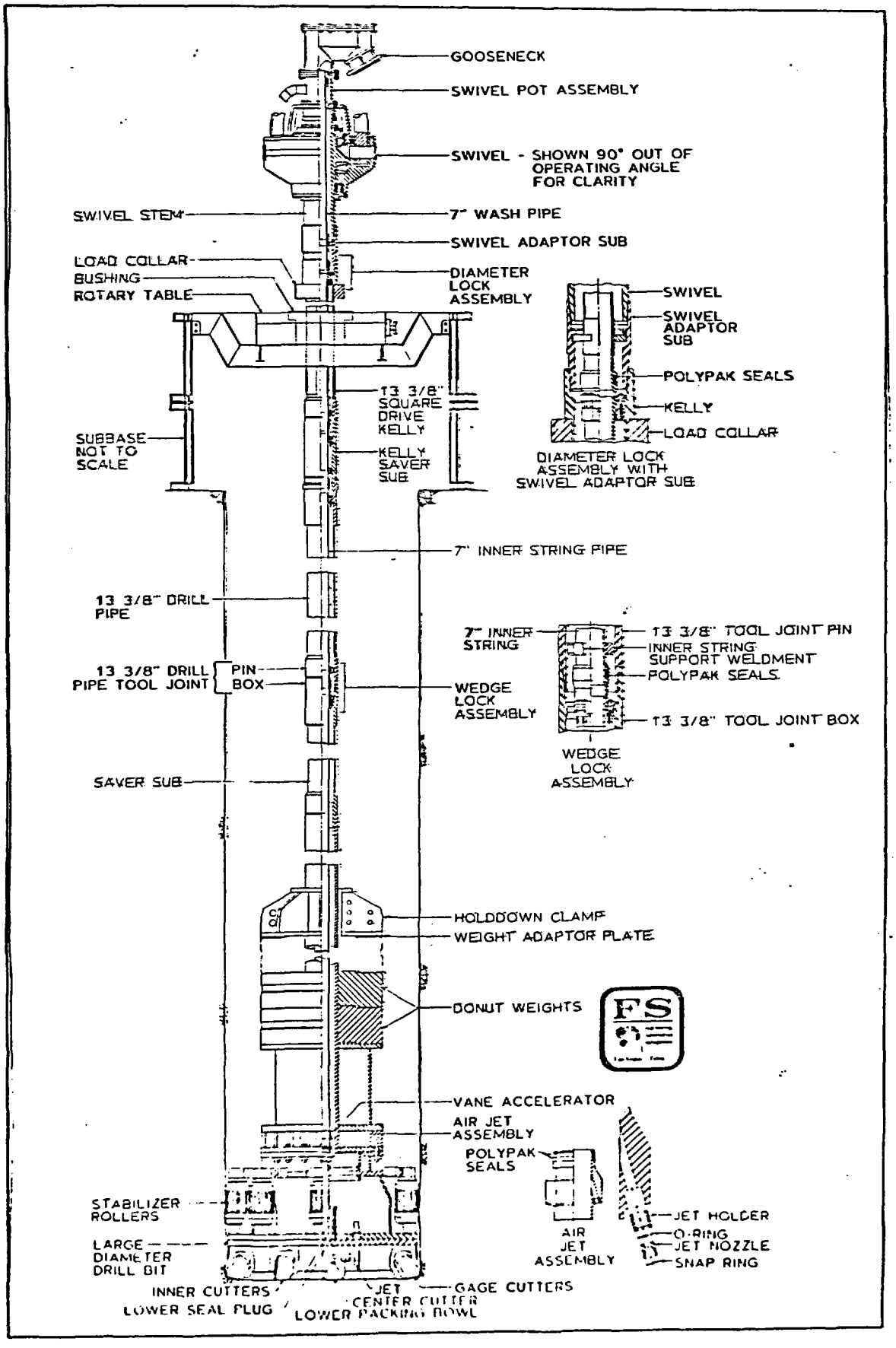
TABLE VIII- AN EVALUATION OF NEW CUTTERS VS RE-TIP CUTTERS FOR 86" BIT #4 USING MILLTOOTH CUTTERS DRILLING IN ALLUVIUM FORMATION

Total number bit runs	4
Total number hours drilling	228
Total number feet drilled	2228
Average rate of penetration, Ft/Hr	9.8
Average number hours per bit run	57
USING 100% NEW CUTTERS	
Number of bit runs	2
Number of hours drilling	119
Number of feet drilled	1234
Average depth per bit run in, ft.	113
Average depth per bit run out, ft.	730
Average number feet per bit run	617
Average rate of penetration, Ft/Hr	10.4
Average number hours per bit run	60
Average cutter wear, percent	16
Per foot cutter wear, feet drilled/percent wear	77
USING 89 TO 100% RE-TIP CUTTERS	
Number of bit runs	2
Number of hours drilling	109
Number of feet drilled	994
Average depth per bit run in, ft.	533
Average depth per bit run out, ft.	1030
Average number feet per bit run	497
Average rate of penetration, Ft/Hr	9.1
Average number hours per bit run	55
Average cutter wear, percent	20
Per foot cutter wear, feet drilled/percent wear	50
INCREASE IN RATE OF PENETRATION NEW VS RE-TIP CUTTERS, PERCENT	13
INCREASE IN CUTTER WEAR RE-TIPS VS NEW CUTTERS, PERCENT	4

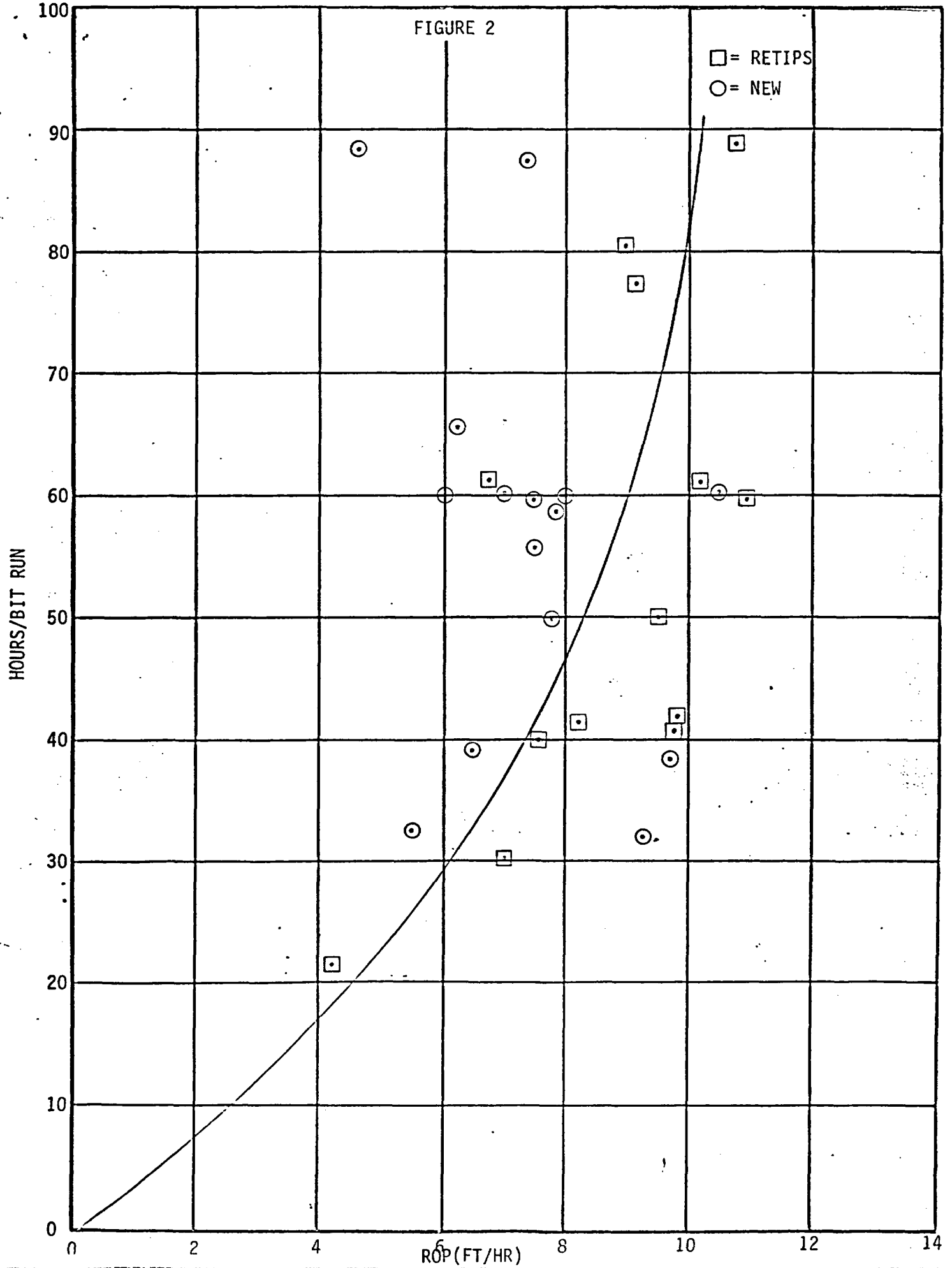
TABLE IX - AN EVALUATION OF NEW CUTTERS VS RE-TIP CUTTERS FOR 86" BIT #4 USING MILLTOOTH CUTTERS DRILLING ASH FLOW FORMATION

Total number bit runs	5
Total number hours drilling	162
Total number feet drilled	874
Average rate of penetration, Ft/Hr	5.4
Average number hours per bit run	32
USING 100% NEW CUTTERS	
Number of bit runs	3
Number of hours drilling	82
Number of feet drilled	476
Average depth per bit run in, ft.	865
Average depth per bit run out, ft.	1029
Average number feet per bit run	159
Average rate of penetration, Ft/Hr	5.8
Average number hours per bit run	41
Average cutter wear, percent	17.5
Per foot cutter wear, feet drilled/percent wear	27
USING 89 TO 100% RE-TIP CUTTERS	
Number of bit runs	2
Number of hours drilling	80
Number of feet drilled	398
Average depth per bit run in, ft.	1143
Average depth per bit run out, ft.	1392
Average number feet per bit run	199
Average rate of penetration, Ft/Hr	5.0
Average number hours per bit run	40
Average cutter wear, percent	8.5
Per foot cutter wear, feet drilled/percent wear	47
INCREASE IN RATE OF PENETRATION RE-TIP VS NEW CUTTERS, PERCENT	14
INCREASE IN CUTTER WEAR NEW VS RE-TIP CUTTERS, PERCENT	9

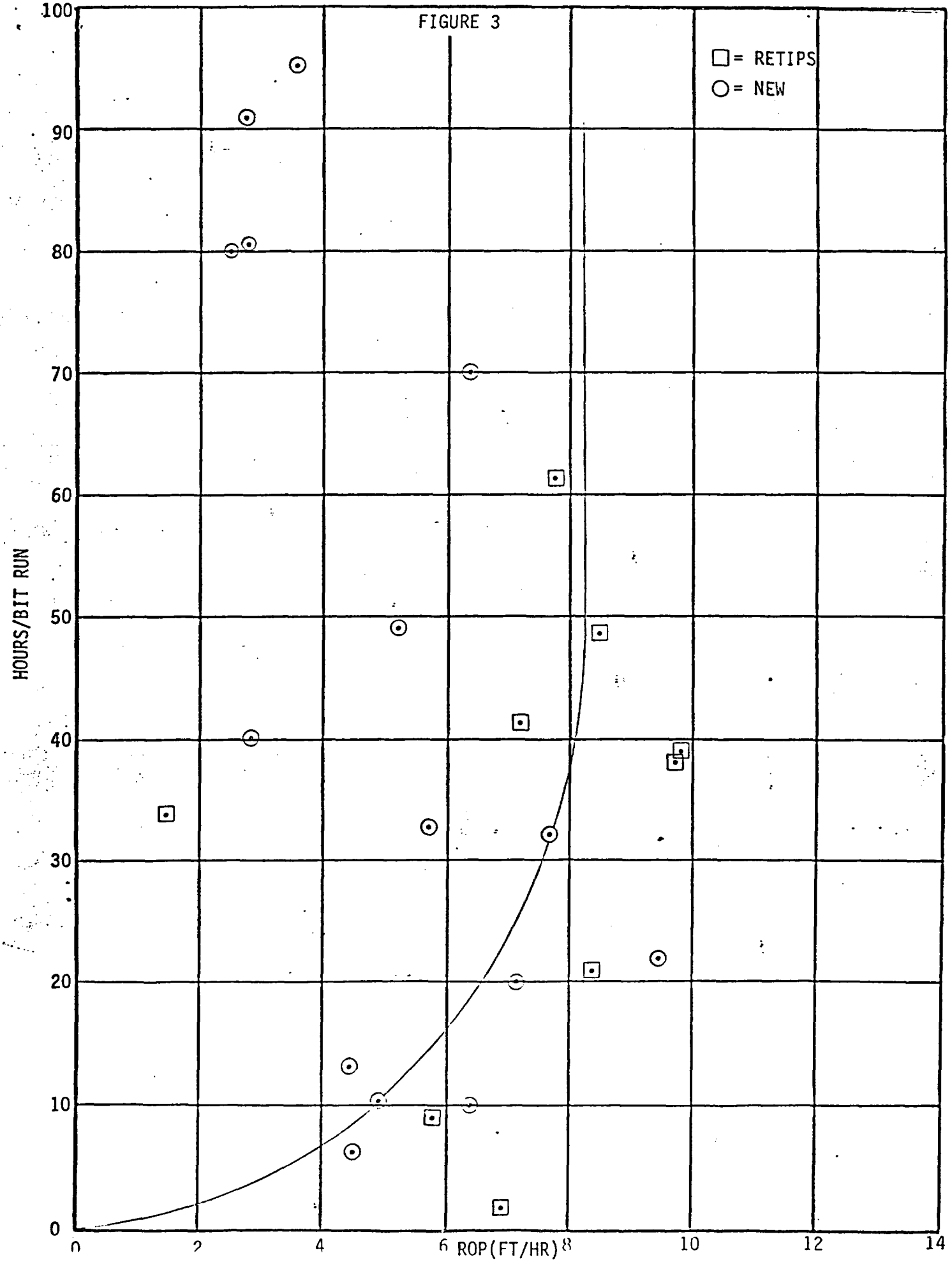
FIGURE 1


GOOSENECK
SWIVEL POT ASSEMBLY
SWIVEL - SHOWN 90° OUT OF OPERATING ANGLE FOR CLARITY
SWIVEL STEM
7" WASH PIPE
SWIVEL ADAPTOR SUB
LOAD COLLAR
BUSHING
ROTARY TABLE
DIAMETER LOCK ASSEMBLY
SWIVEL
SWIVEL ADAPTOR SUB
POLYPAK SEALS
KELLY
LOAD COLLAR
DIAMETER LOCK ASSEMBLY WITH SWIVEL ADAPTOR SUB
13 3/8" SQUARE DRIVE KELLY
SUBBASE NOT TO SCALE
KELLY SAVER SUB
7" INNER STRING PIPE
13 3/8" DRILL PIPE
7" INNER STRING
13 3/8" TOOL JOINT PIN
INNER STRING SUPPORT WELDMENT
POLYPAK SEALS
13 3/8" DRILL PIPE TOOL JOINT
PIN
BOX
WEDGE LOCK ASSEMBLY
13 3/8" TOOL JOINT BOX
WEDGE LOCK ASSEMBLY
SAVER SUB
HOLDDOWN CLAMP
WEIGHT ADAPTOR PLATE
DONUT WEIGHTS
VANE ACCELERATOR
AIR JET ASSEMBLY
POLYPAK SEALS
STABILIZER ROLLERS
LARGE DIAMETER DRILL BIT
AIR JET ASSEMBLY
JET HOLDER
O-RING
JET NOZZLE
SNAP RING
INNER CUTTERS
JET CENTER CUTTER
GAGE CUTTERS
LOWER SEAL PLUG
LOWER PACKING BOWL

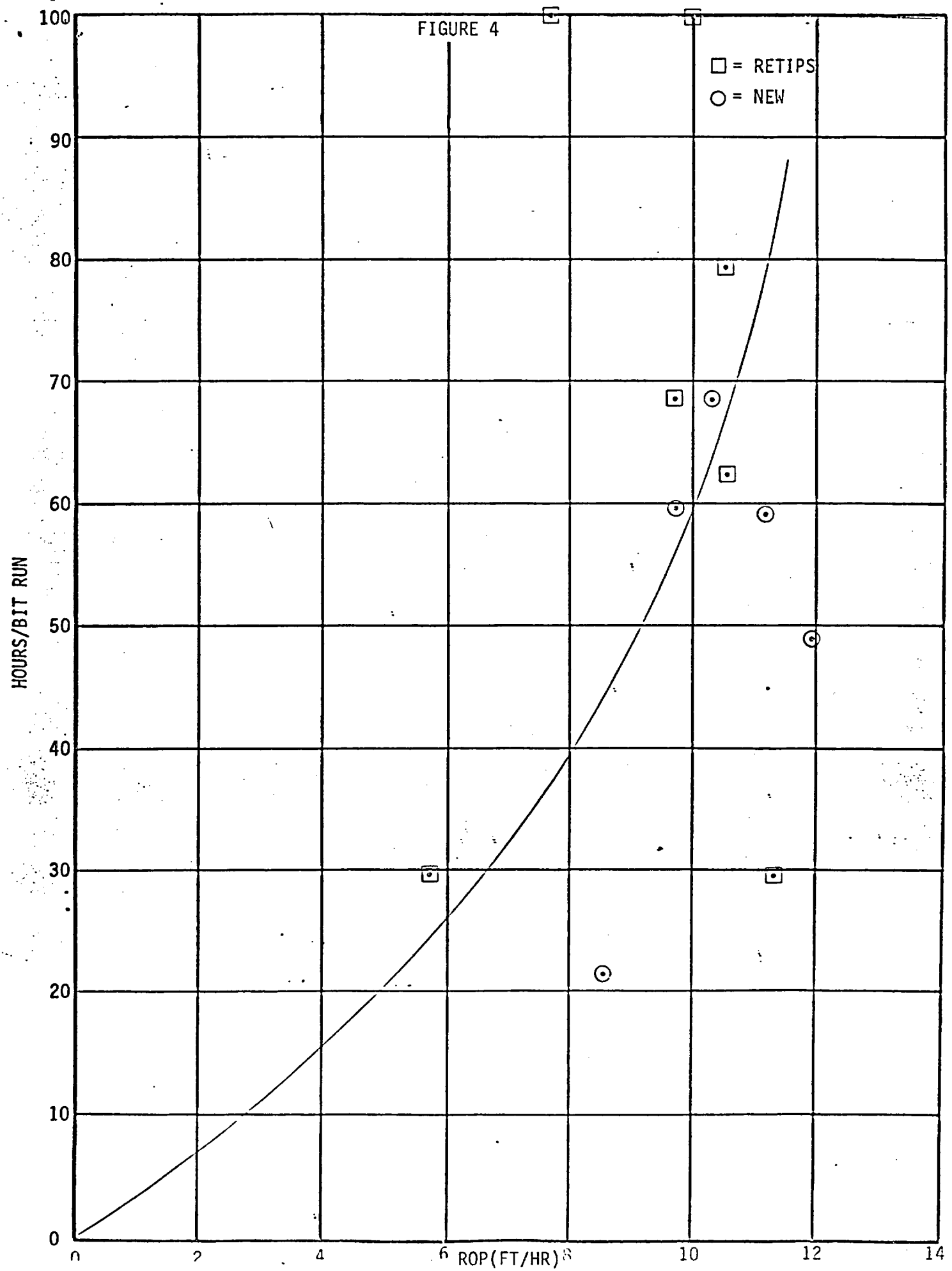
96" BITS DRILLING IN ALLUVIUM



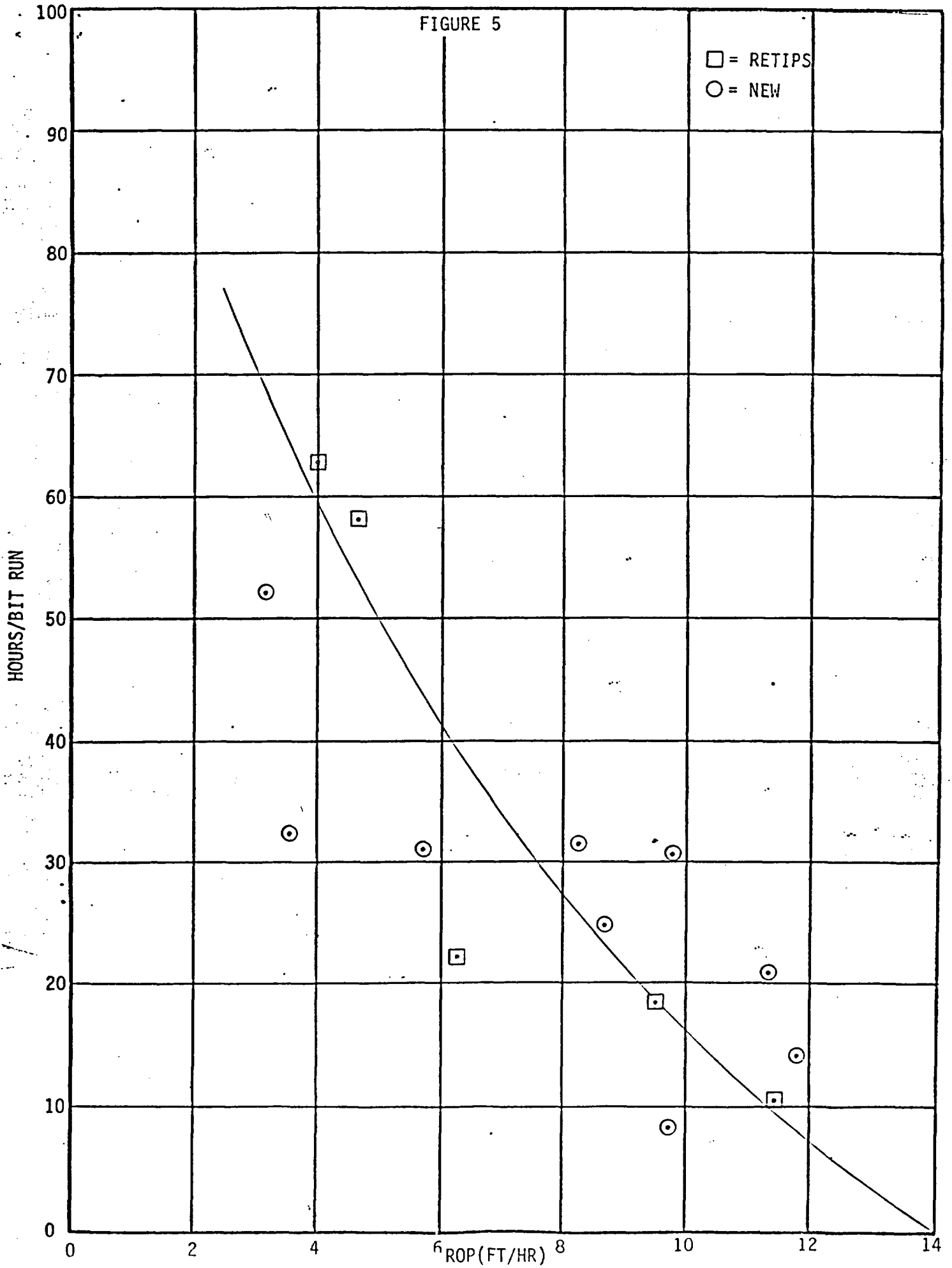
96" BITS DRILLING IN ASH FLOW



86" BITS DRILLING IN ALLUVIUM



86" BITS DRILLING IN ASH FLOW



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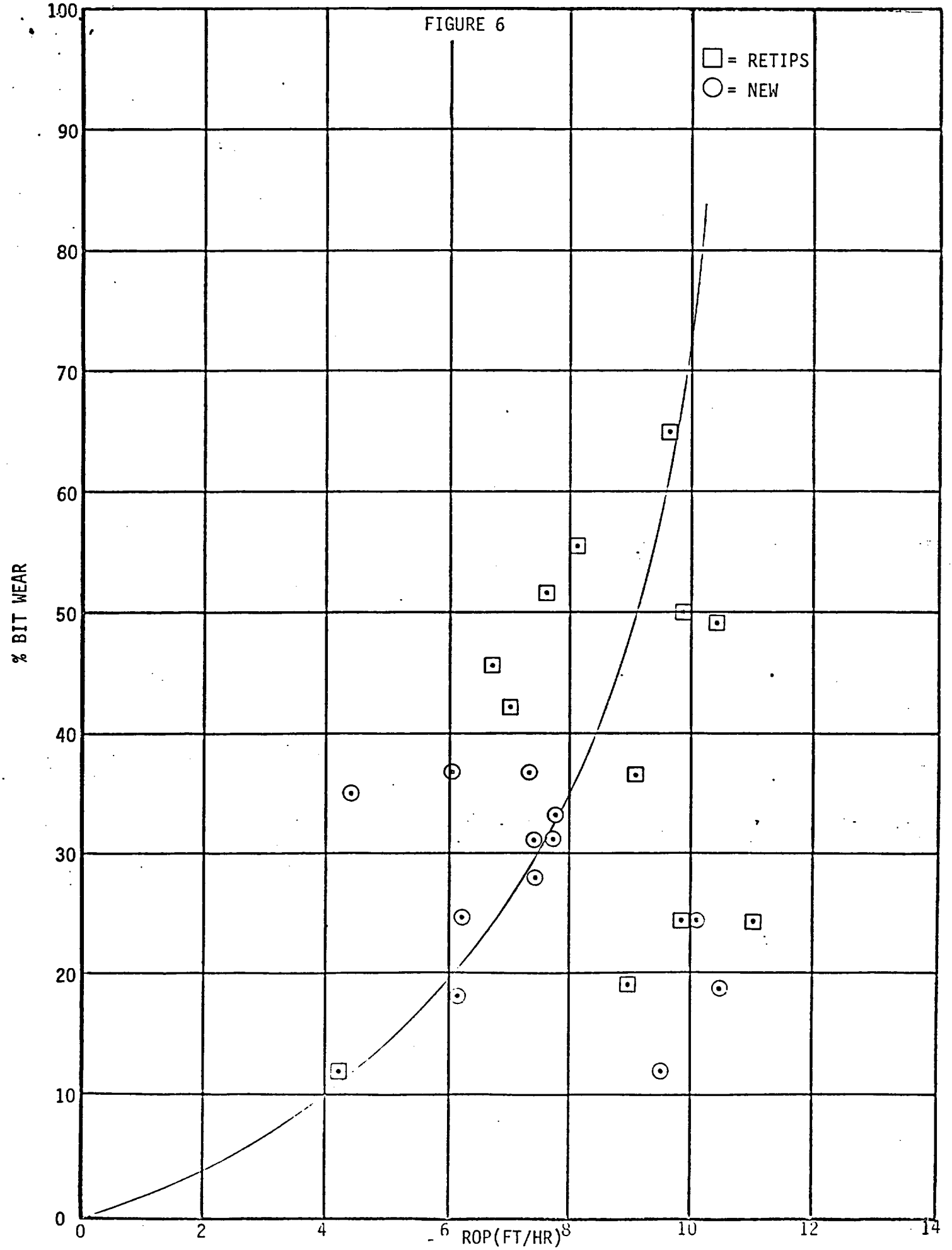
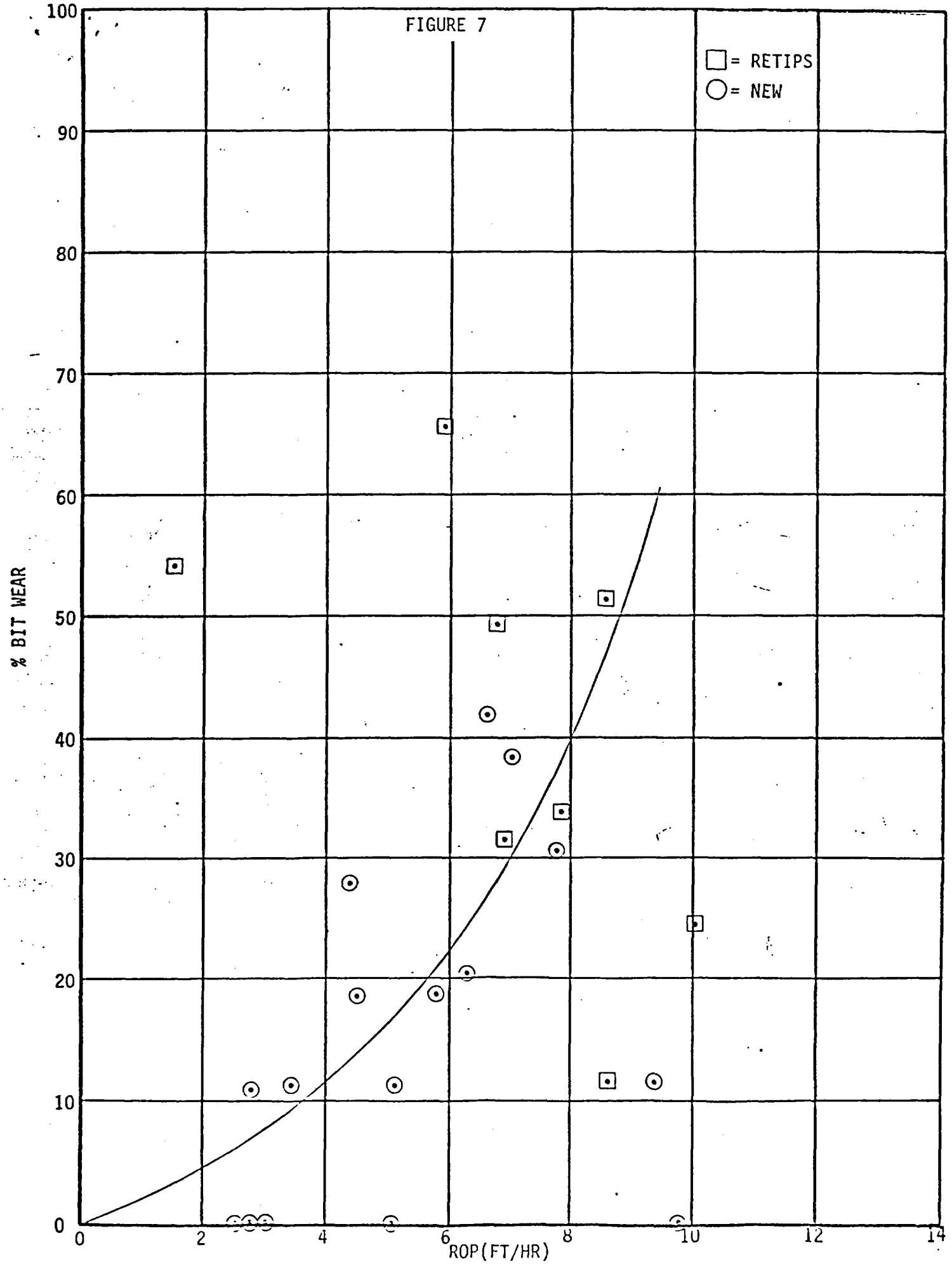


96" BITS DRILLING IN ASH FLOW



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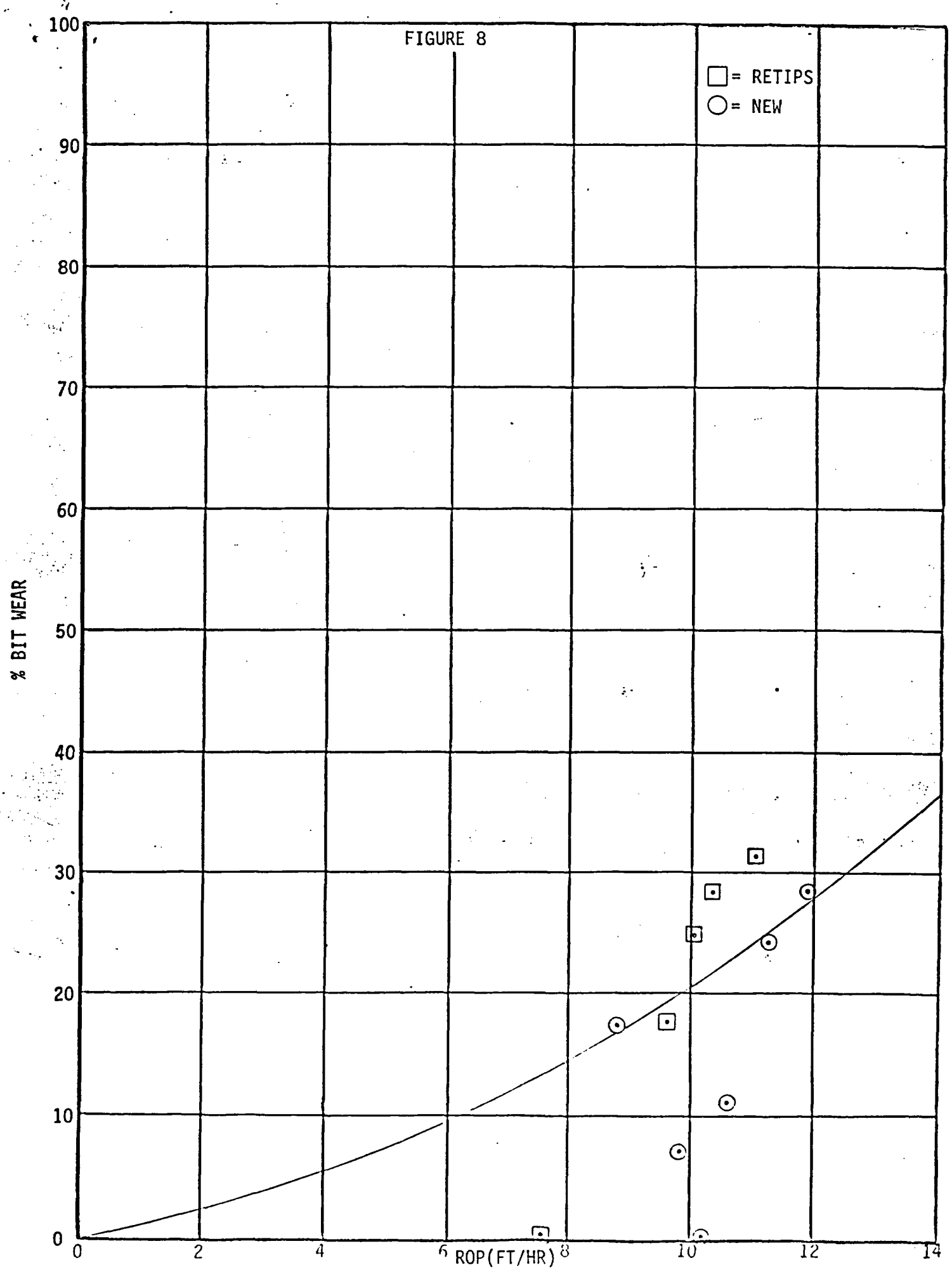
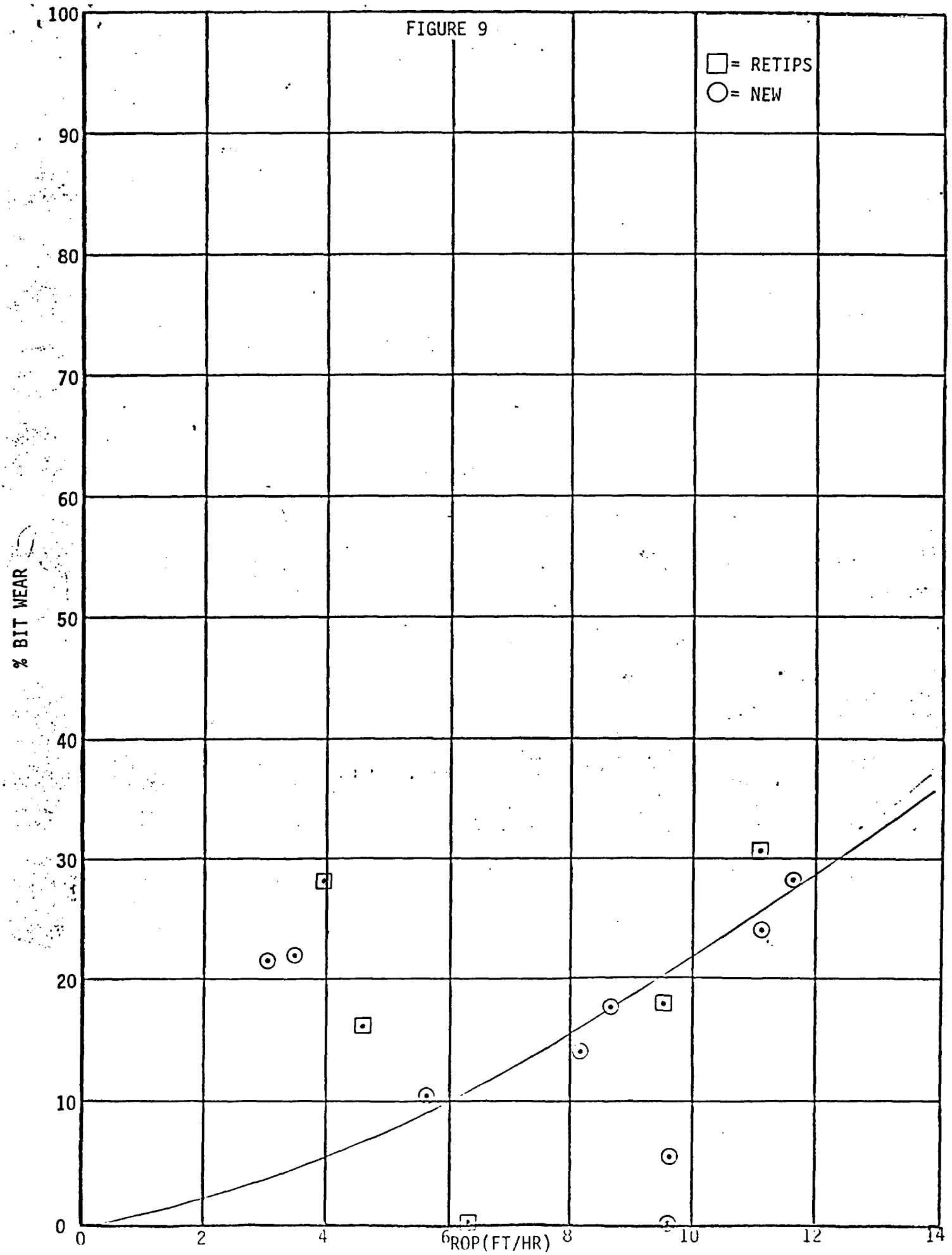


86" BITS DRILLING IN ASH FLOW



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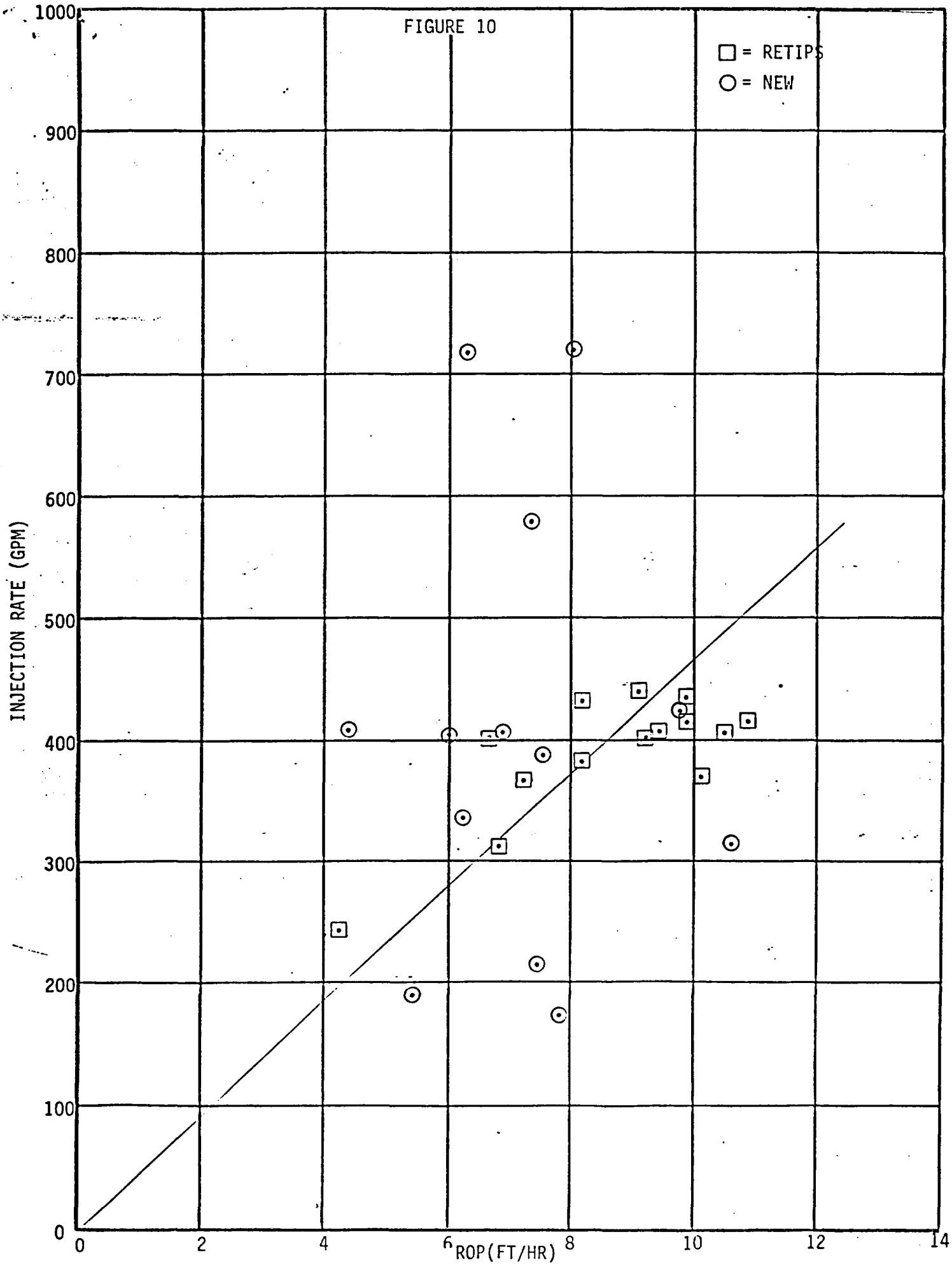
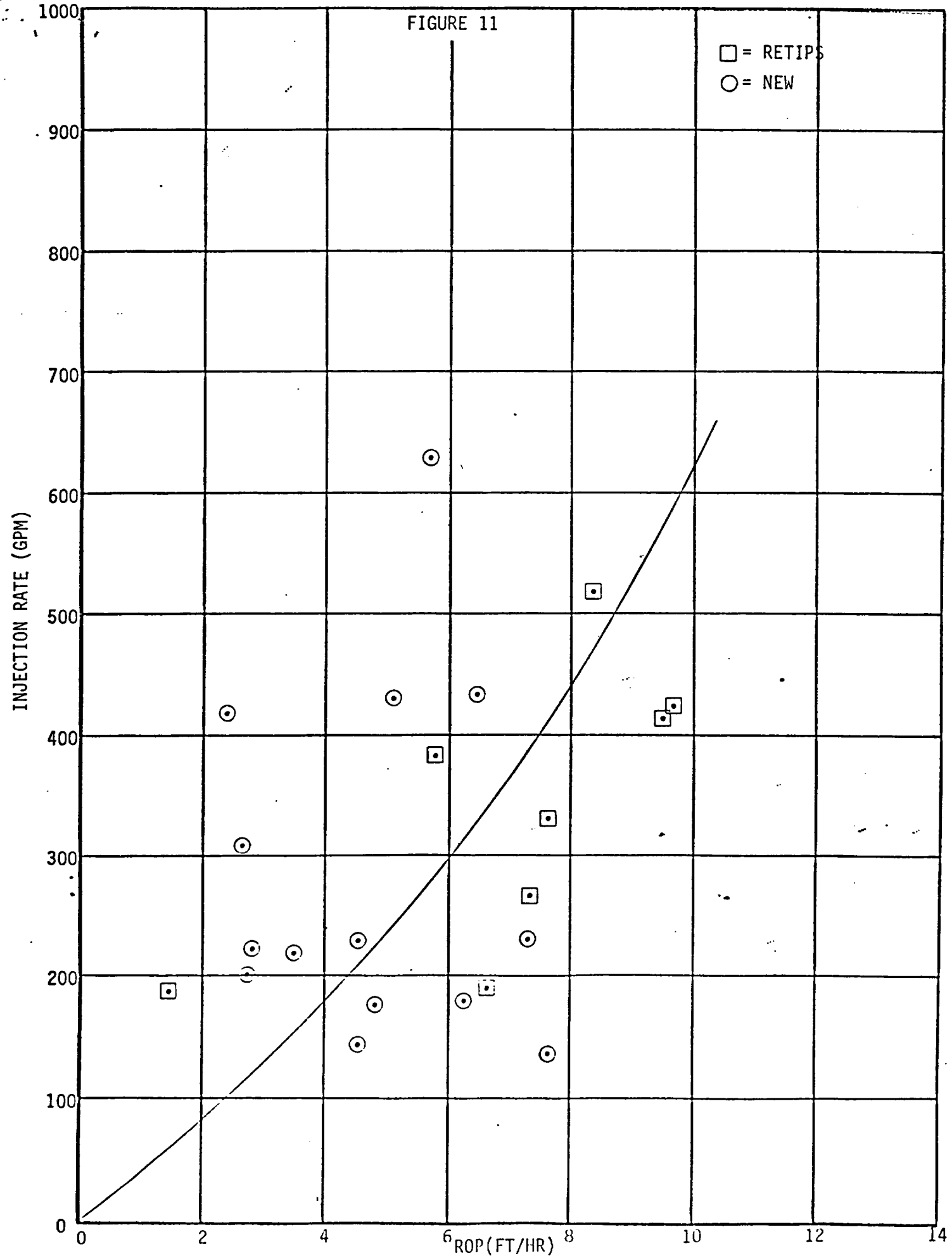


96" BITS DRILLING IN ASH FLOW



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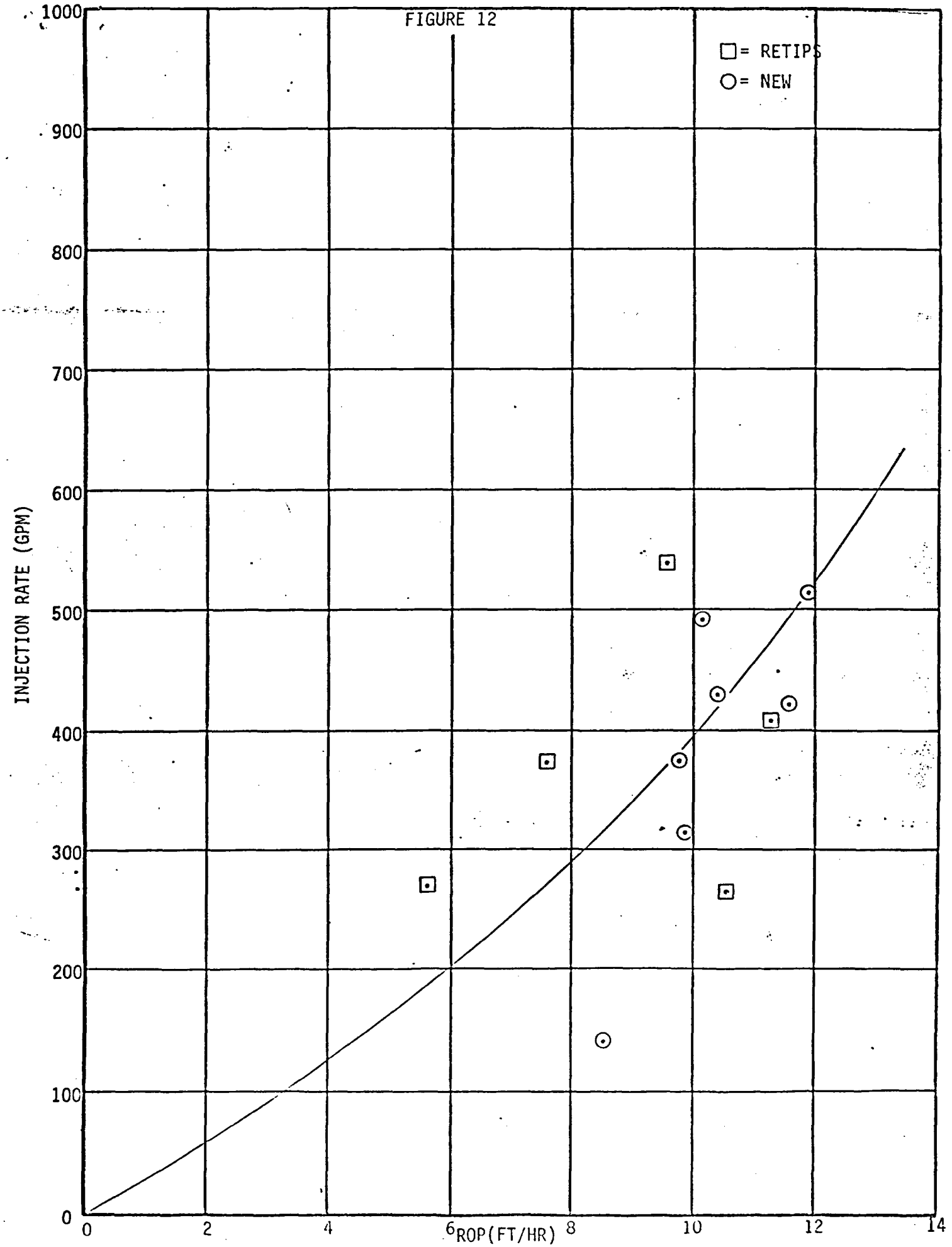
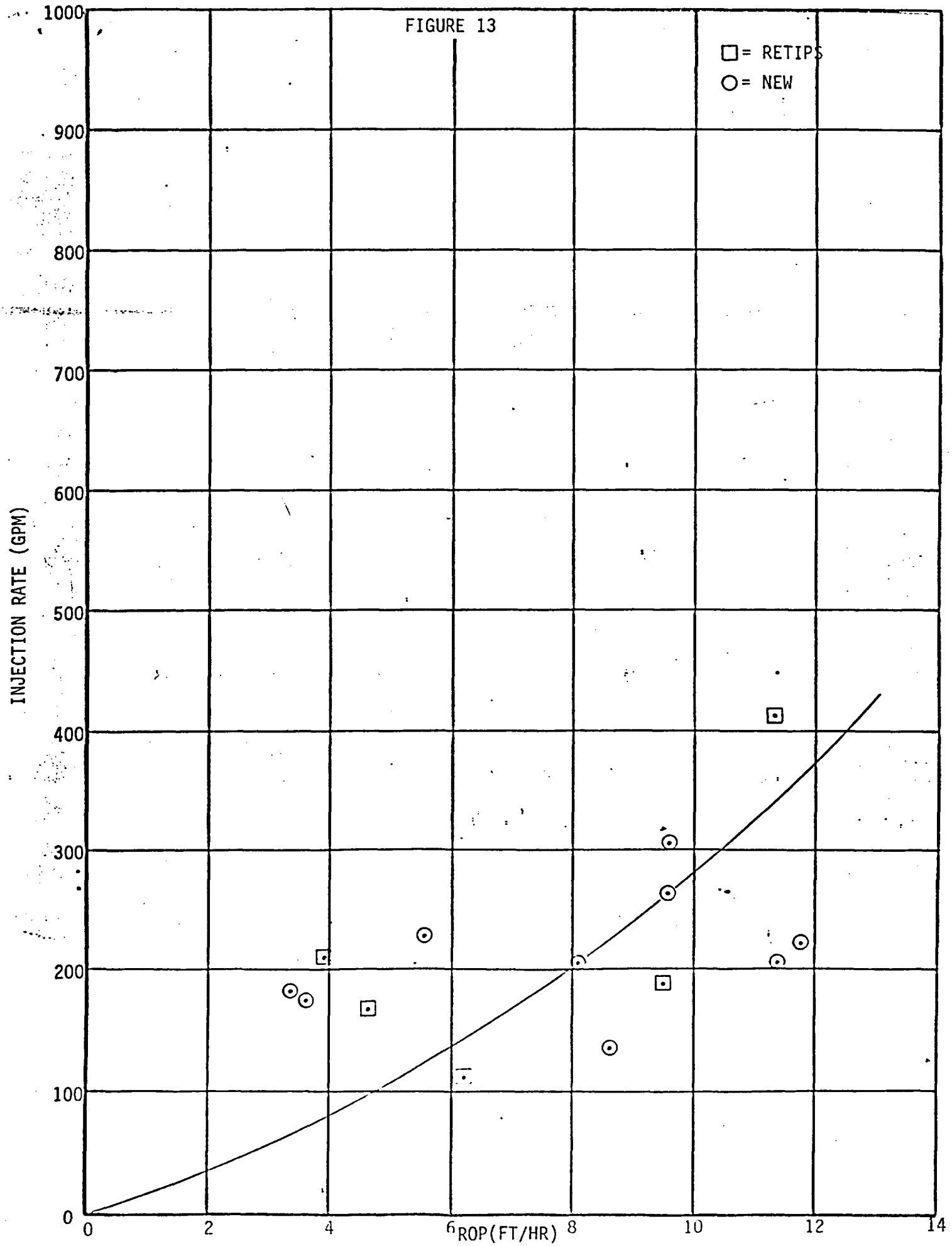
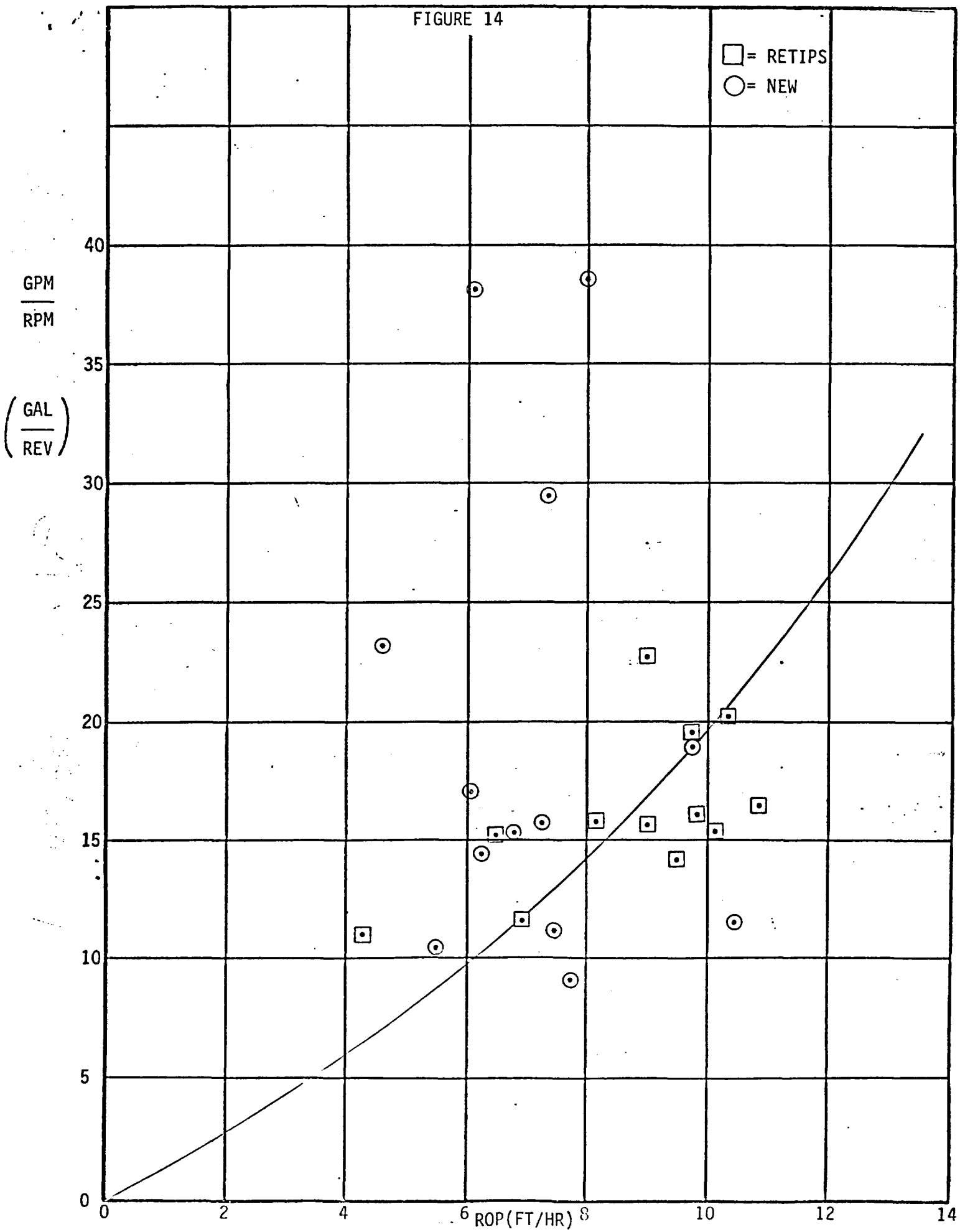


86" BITS DRILLING IN ASH FLOW



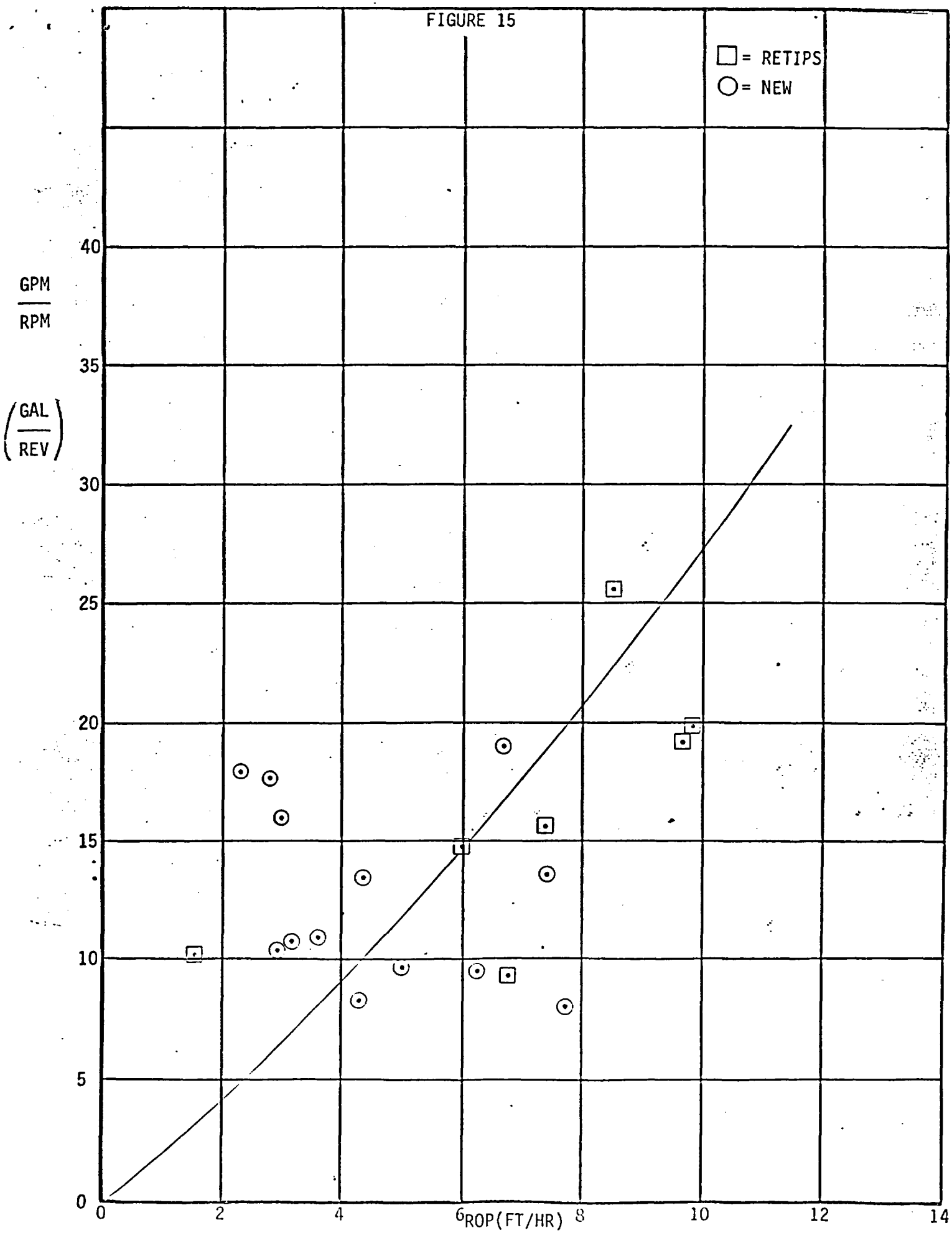
96" BITS DRILLING IN ALLUVIUM

FIGURE 14

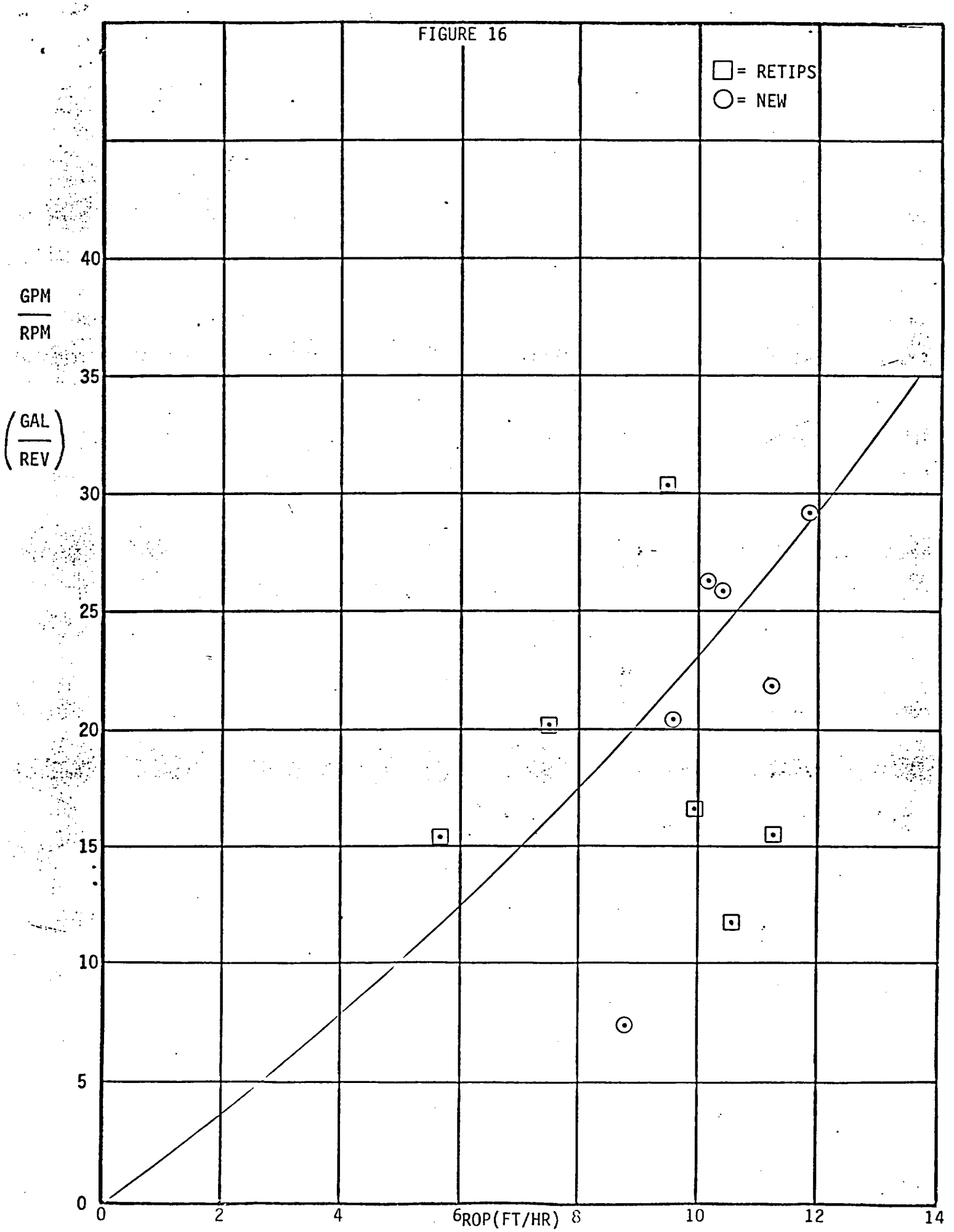


96" BITS DRILLING IN ASH FLOW

FIGURE 15

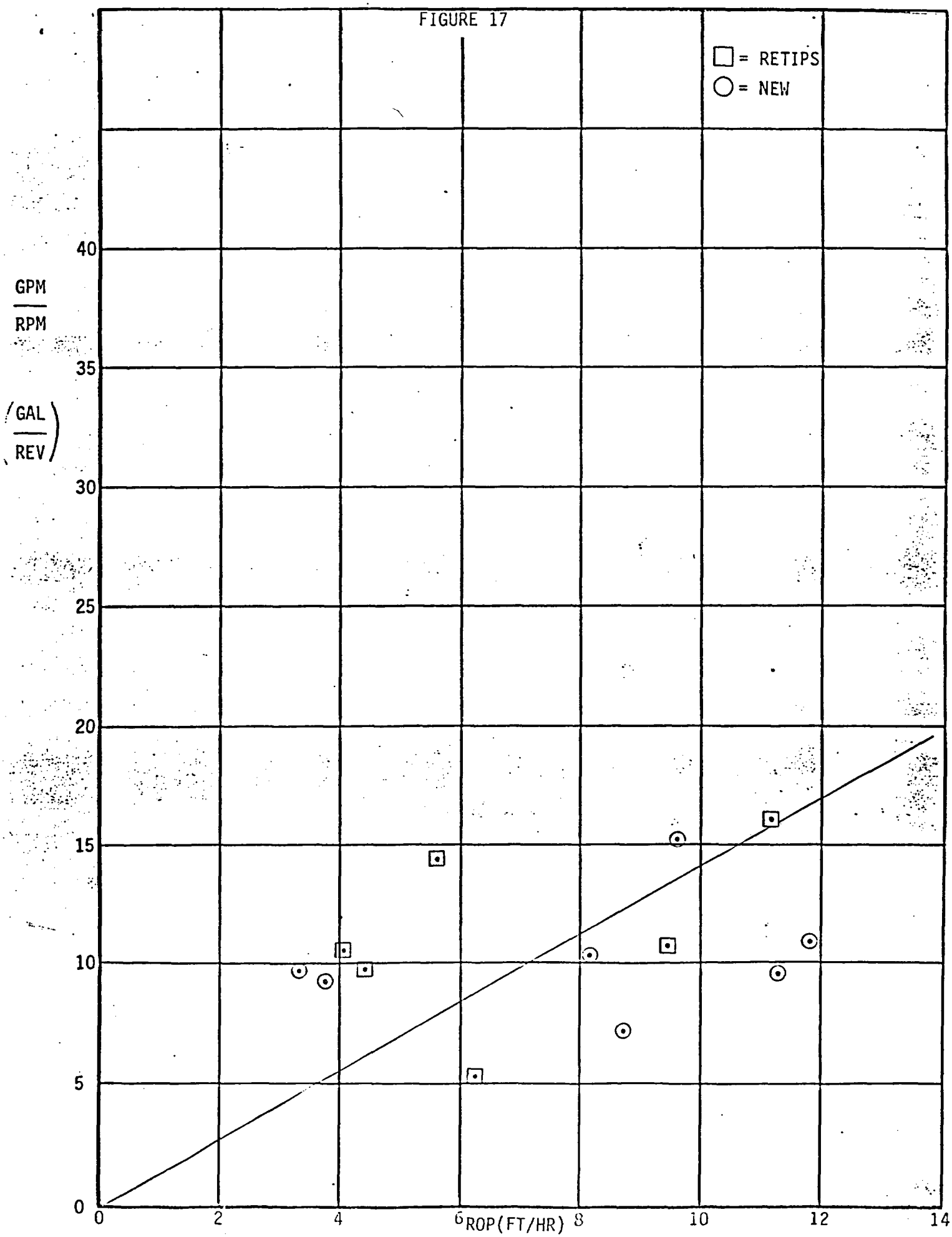


86" BITS DRILLING IN ALLUVIUM



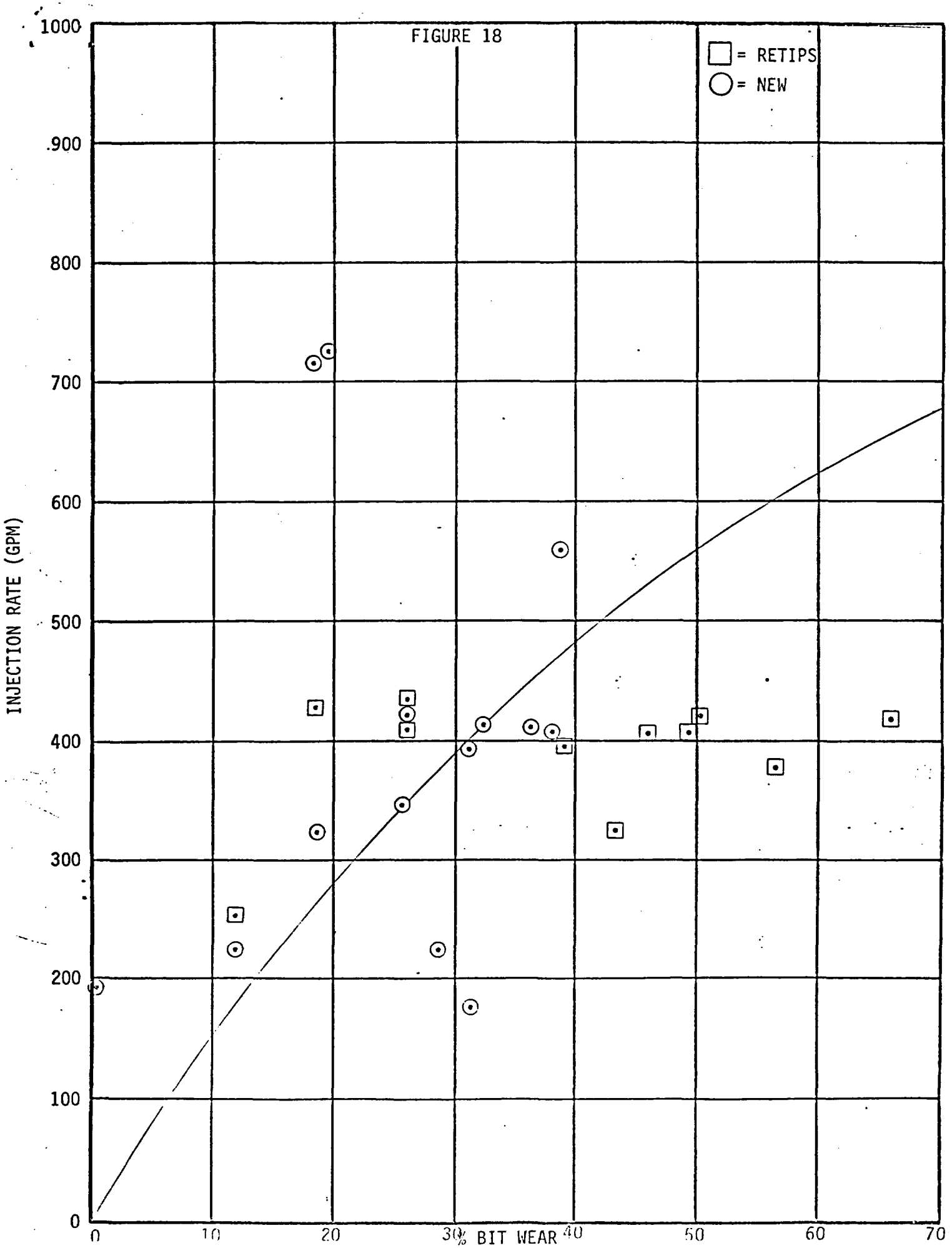
86" BITS DRILLING IN ASH FLOW

FIGURE 17

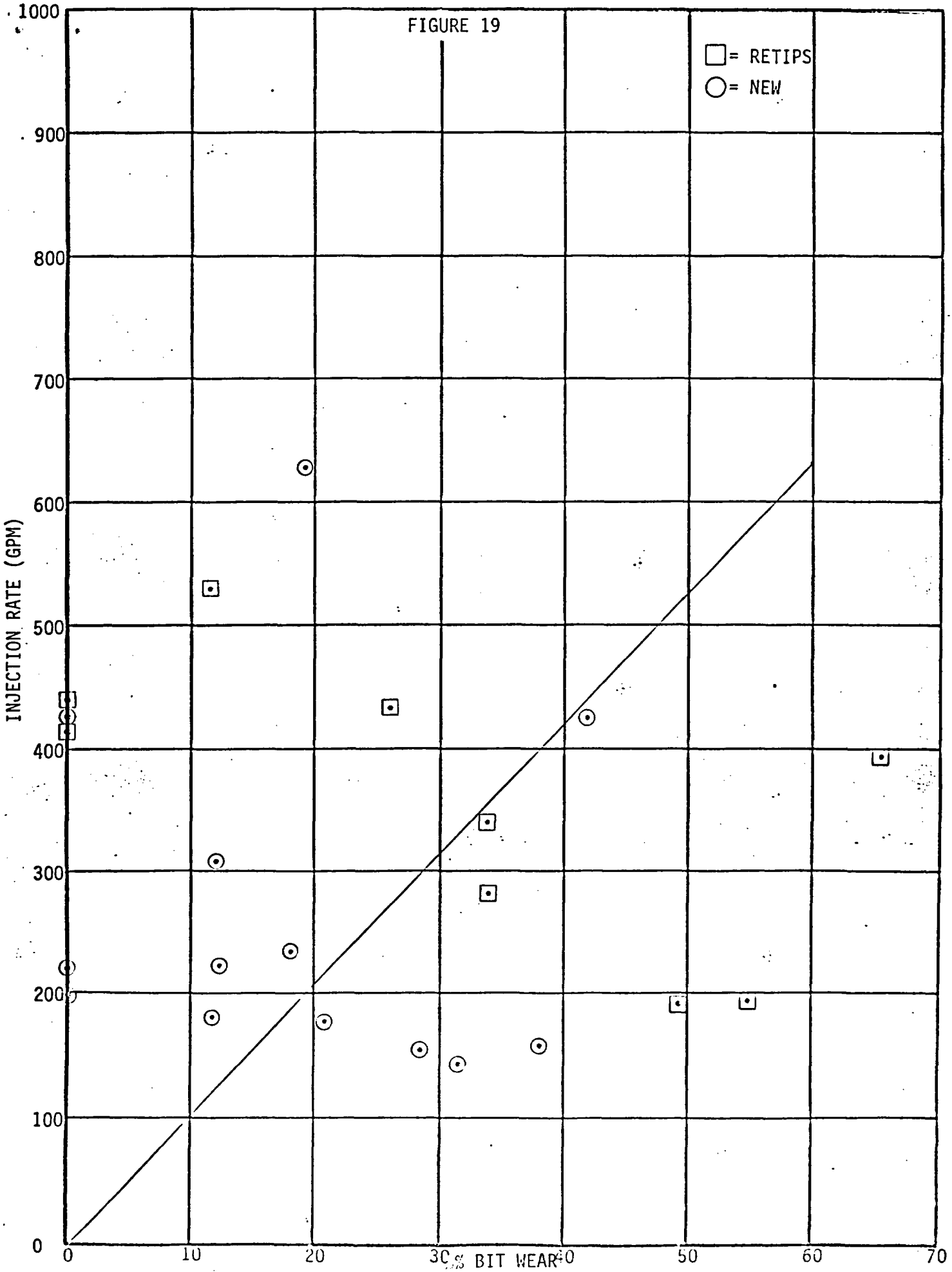


96" BITS DRILLING IN ALLUVIUM

FIGURE 18



96" BITS DRILLING IN ASH FLOW



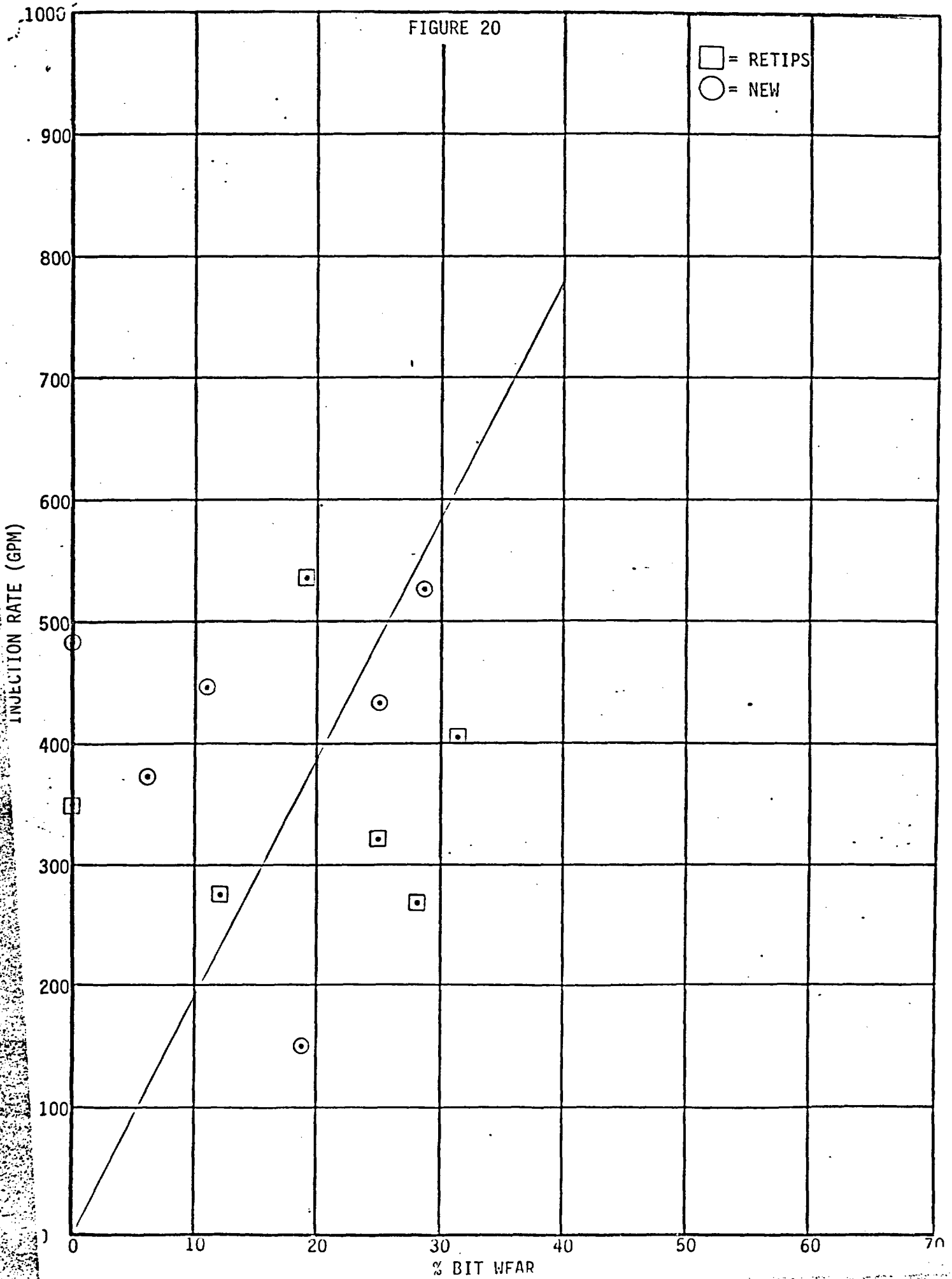
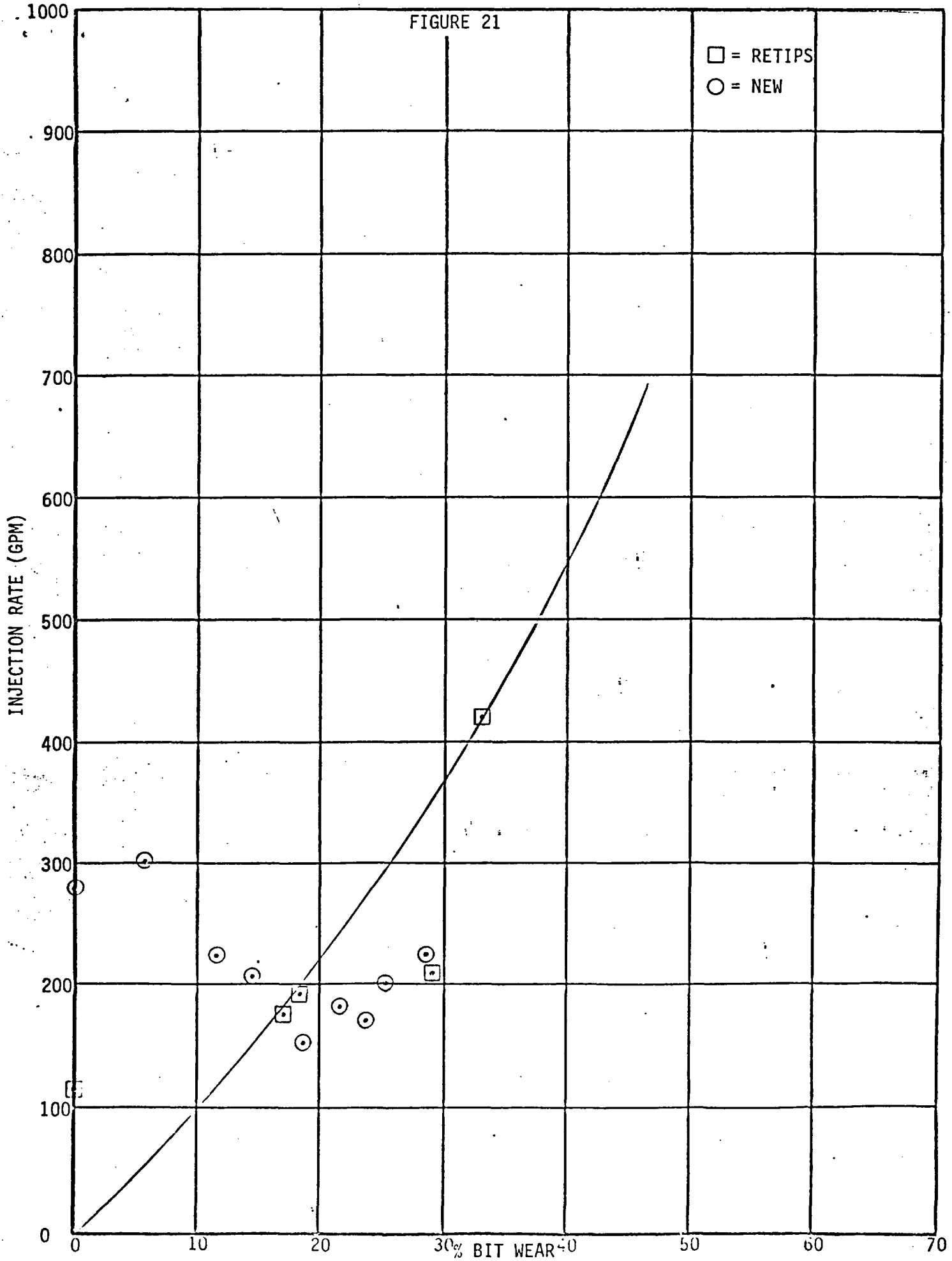


FIGURE 20
= RETIPS
= NEW
INJECTION RATE (GPM)
1000
900
800
700
600
500
400
300
200
100
0
0
10
20
30
40
50
60
70
% BIT WEAR

86" BITS DRILLING IN ASH FLOW



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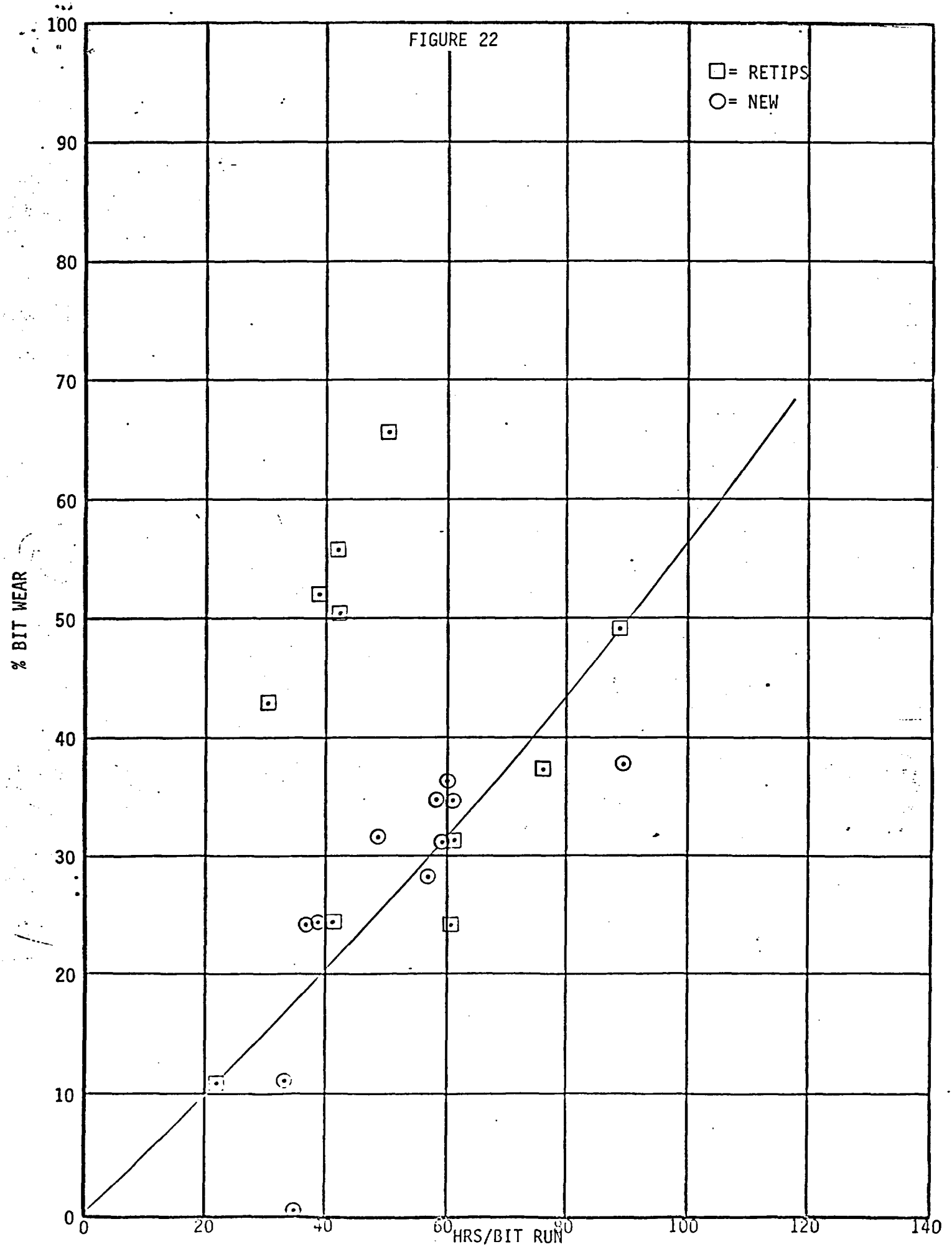
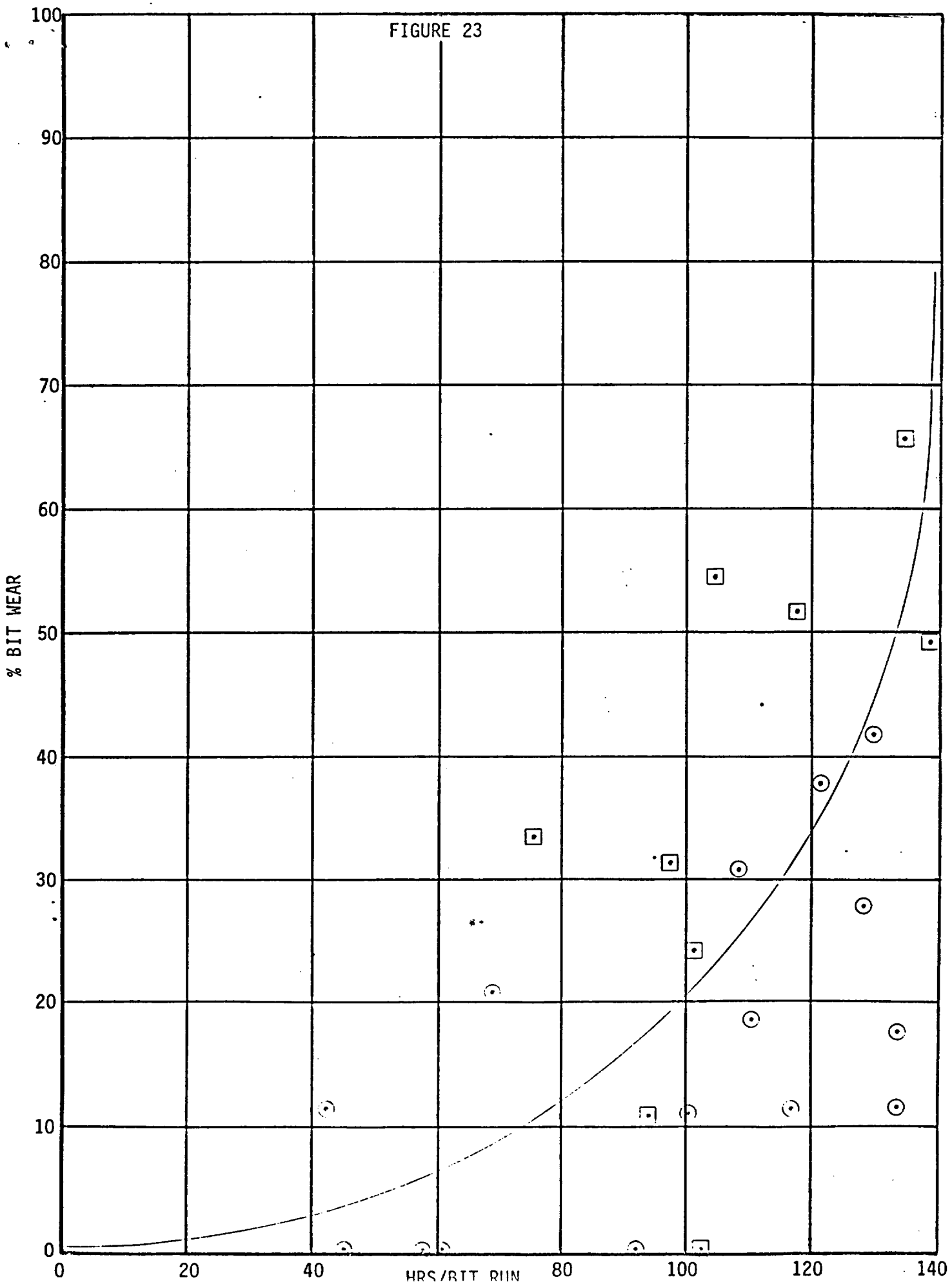


96" BITS DRILLING IN ASH FLOW

FIGURE 23



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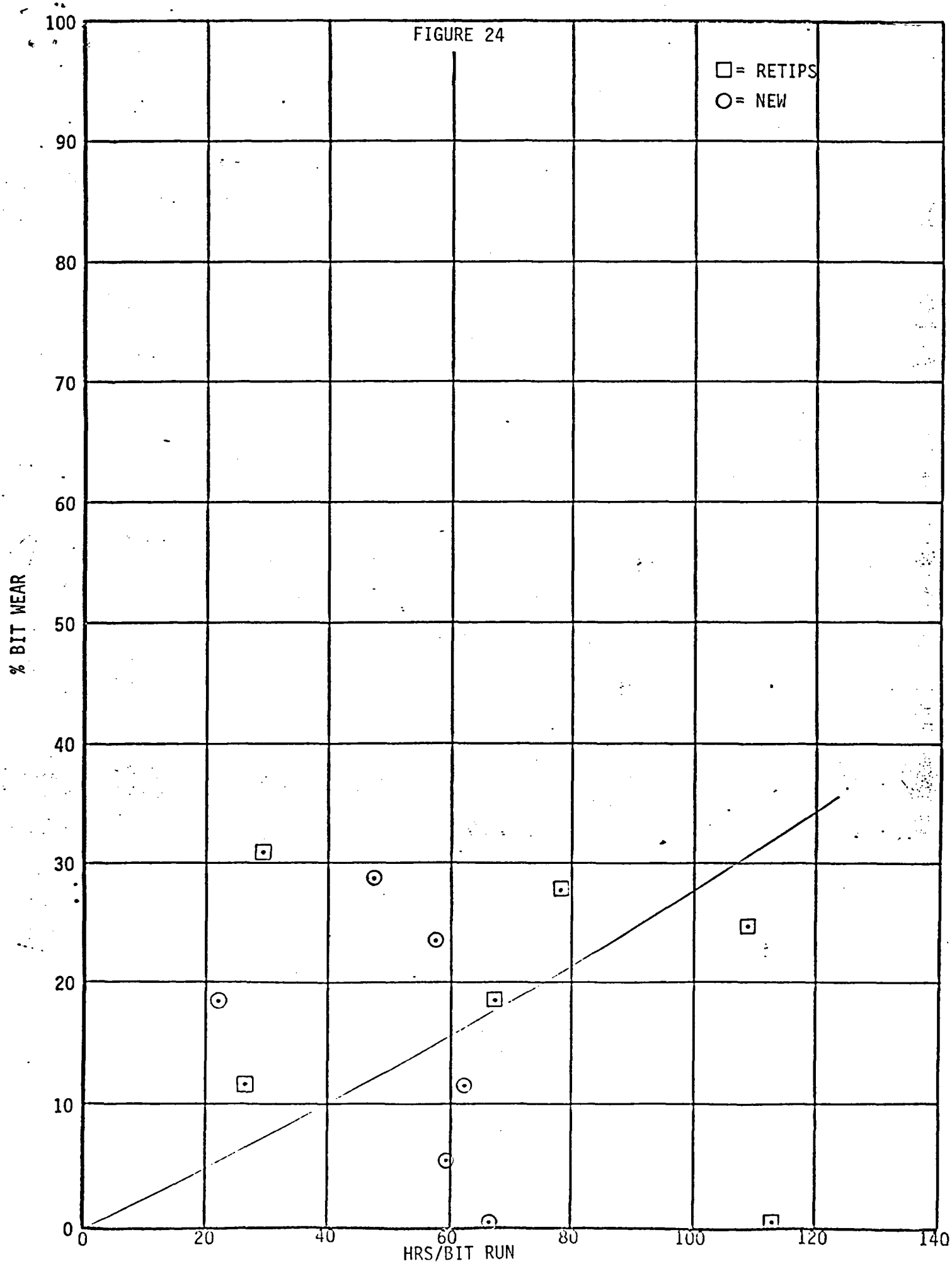

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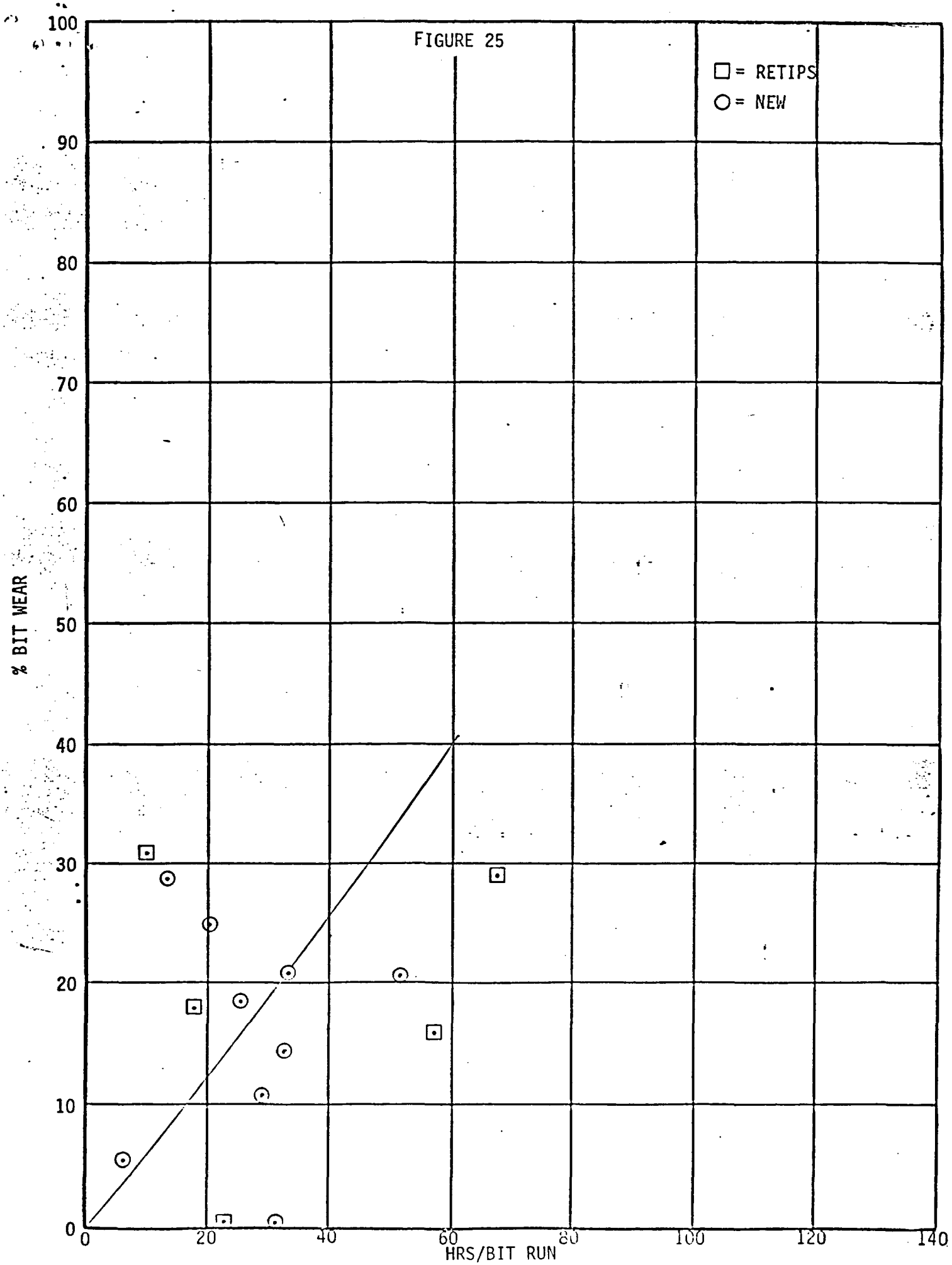

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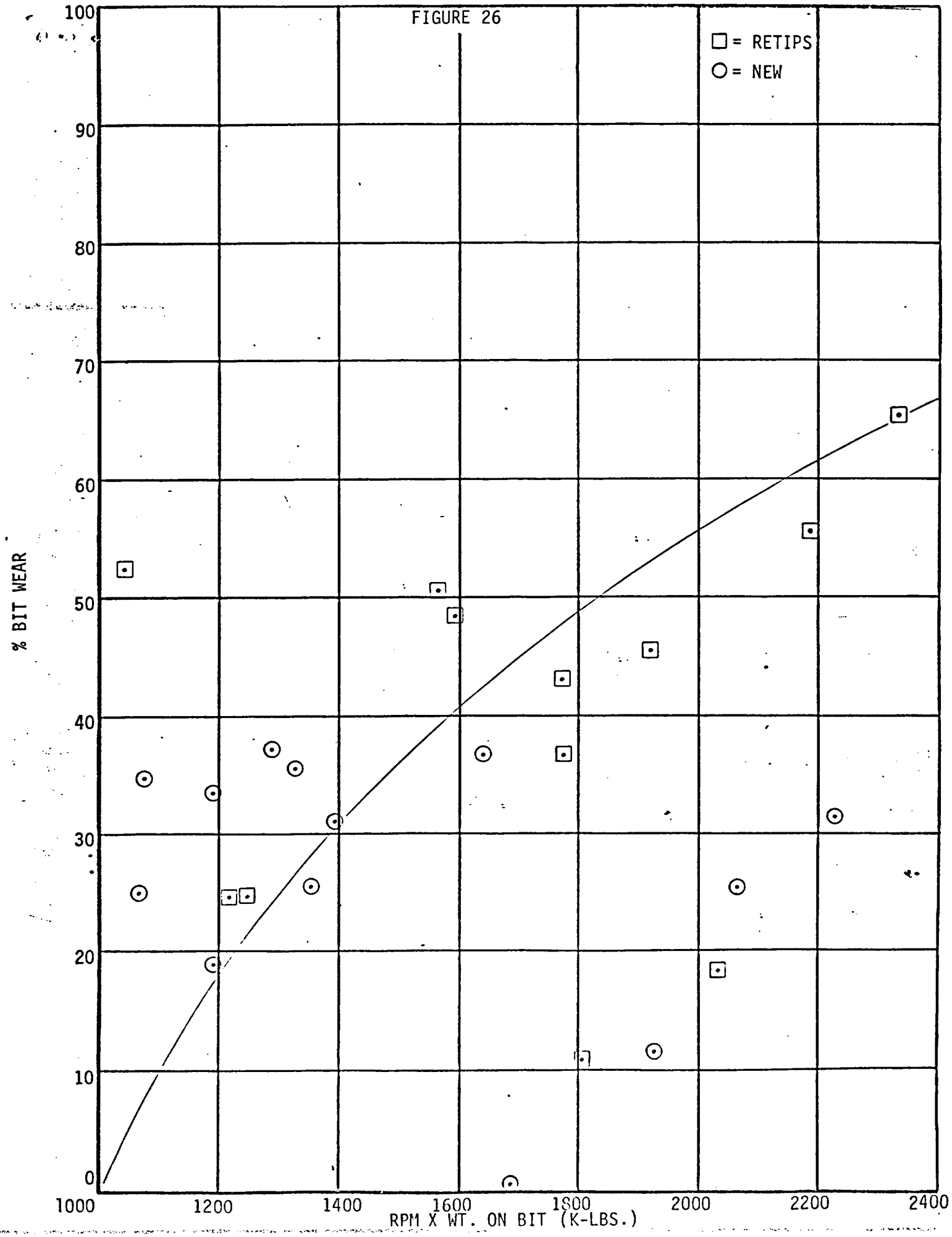
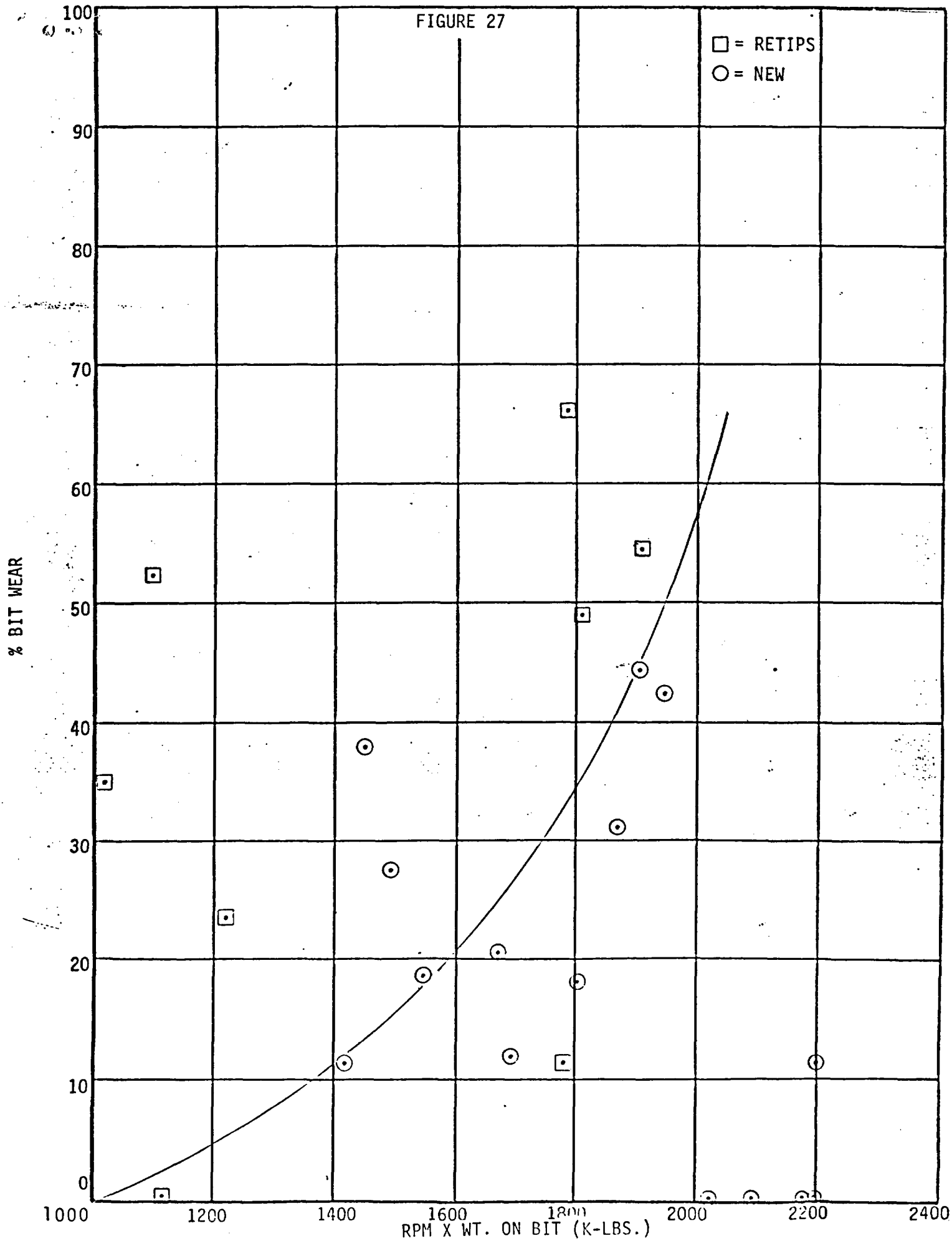
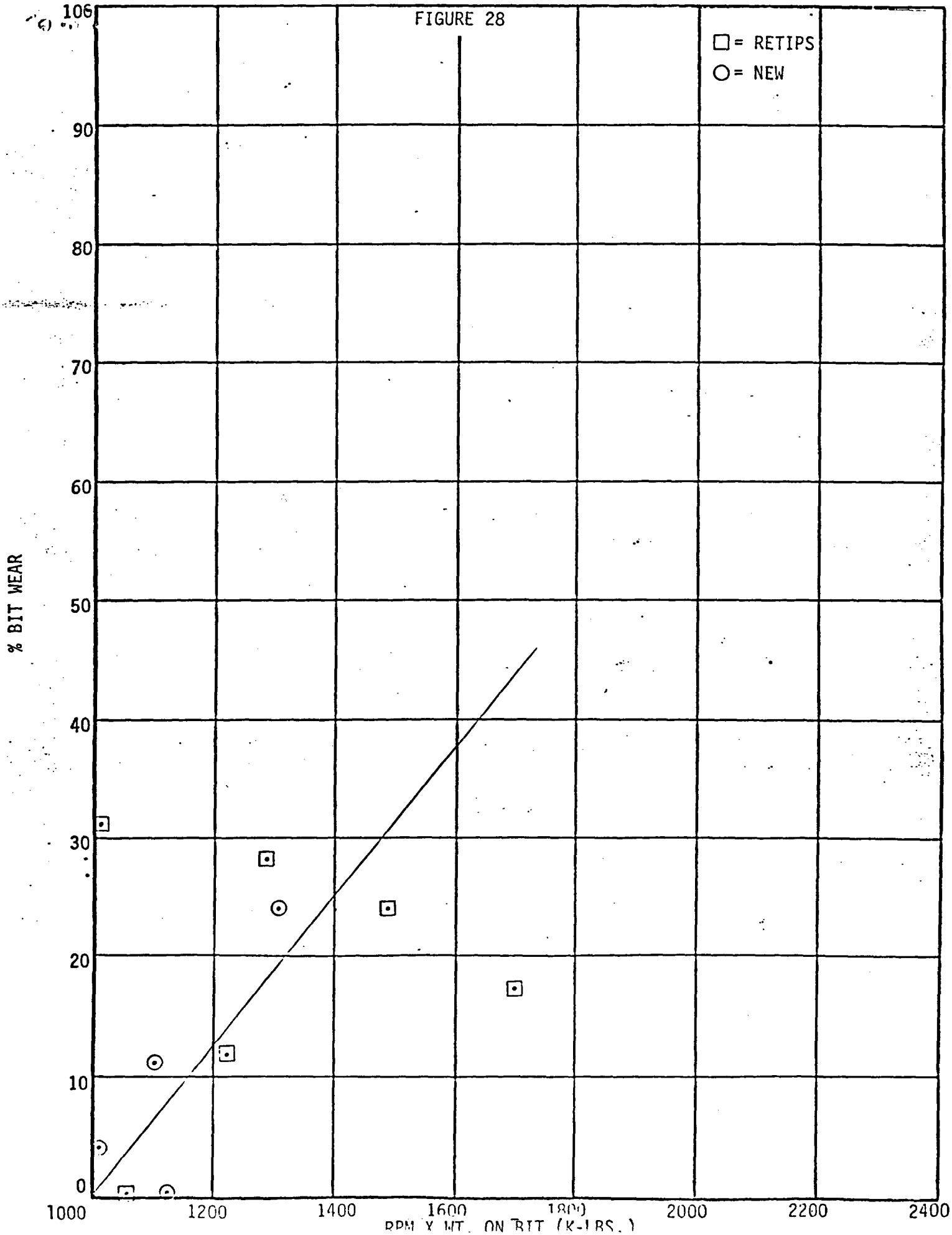


96" BITS DRILLING IN ASH FLOW



86" BITS DRILLING IN ALLUVIUM



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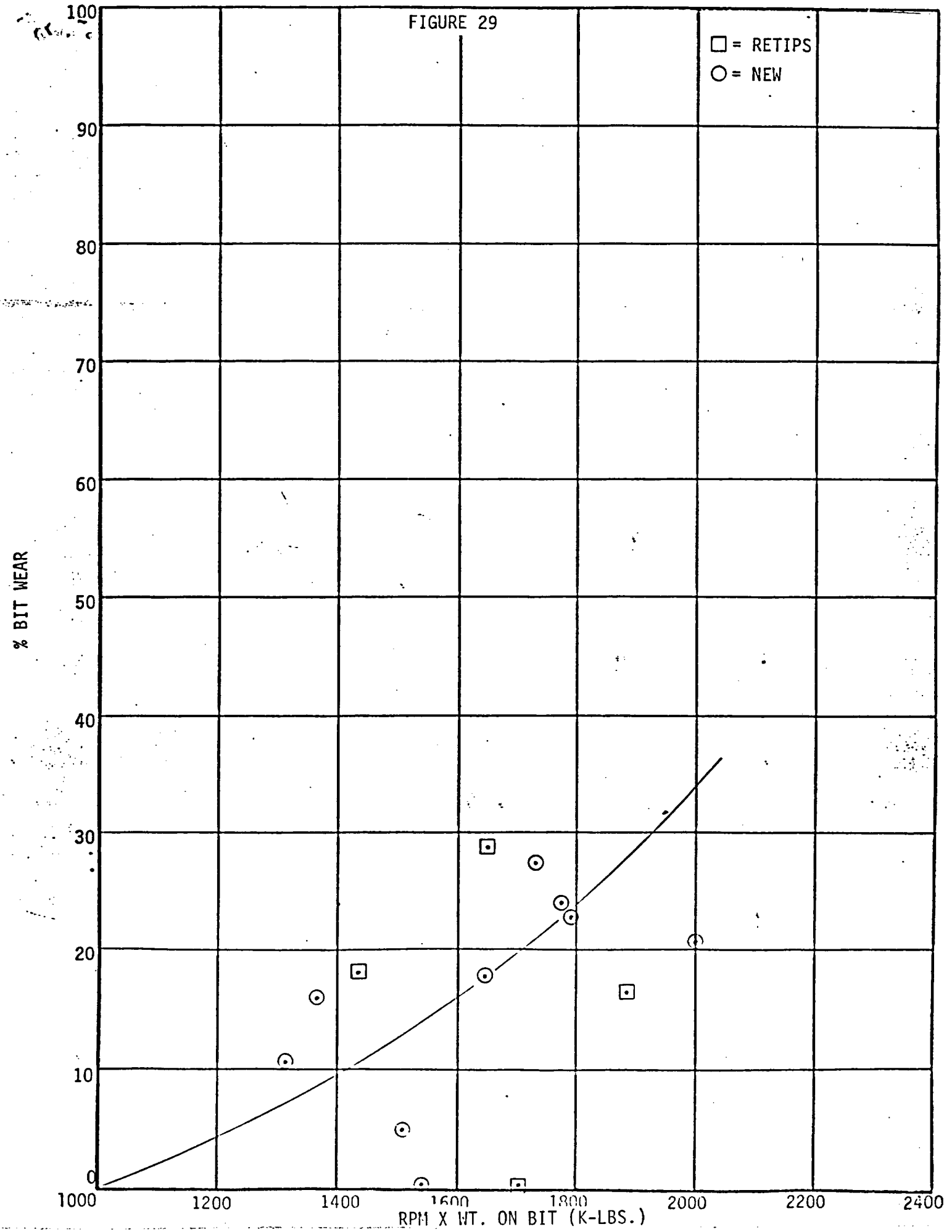

RHO-BW-SA-471

Casing Porthole Drilling in High Pressure Environment

D. J. Moak
G. W. McLellan

Drilling and Testing Group
Basalt Waste Isolation Project

April 1985

Prepared for the United States
Department of Energy under
Contract DE-AC06-77R101030

Rockwell International
Rockwell Hanford Operations
North American Space Operations
Richland, Washington 99352

CONTENTS

INTRODUCTION

In 1976, the U.S. Energy Research and Development Administration (ERDA), the predecessor to the U.S. Department of Energy (DOE), established the Nuclear Waste Technical Storage (NWTS) Program, the predecessor to the Office of Civilian Radioactive Waste Management (OCRWM) to investigate a number of geologic rock types to determine their suitability for the disposal of radioactive waste. Its mission was to provide multiple repository facilities in various deep geologic formations within the United States for the terminal storage of nuclear waste. The Columbia River basalts that underlie the Hanford Site were among those selected for study. Rock types under investigation in addition to basalt are granite, tuff, and bedded and domal salt.

The DOE has continued the study of sites for mined geologic disposal systems suitable for terminal and retrievable storage of commercially generated high-level and transuranic radioactive wastes and continued the research and development of the technology necessary to ensure the safe long-term containment of isolation of these wastes. The Nuclear Waste Policy Act of 1982 requires that the DOE recommend three sites for characterization for the first geologic repository. Through the DOE, the OCRWM is pursuing investigations of several media and sites; among them is the U.S. government-owned Hanford Site. The Hanford Site program is presently the responsibility of the U.S. Department of Energy, Richland Operations Office (DOE-RL). Rockwell Hanford Operations (Rockwell) is the prime contractor responsible for this work. The Basalt Waste Isolation Project (BWIP) within Rockwell has been chartered with the responsibility of conducting the Hanford Site investigations.

The BWIP mission is to determine if potential geologic repository sites exist in basalt under the Hanford Site and to identify and develop the associated facilities and technology required for the permanent isolation of radioactive waste in one of these potential sites. If feasibility is shown, the DOE may proceed, consistent with the Nuclear Waste Policy Act of 1982, with the detailed design, construction, and operation of a geologic repository (i.e., a Mined Geologic Disposal System) licensed to store nuclear waste within the Columbia River basalts and to conduct the engineering studies required to design such a facility. Studies have been conducted to define the boundaries of a reference repository location (RRL) in the west-central part of Hanford Site (Figure 1) to be considered for siting of a nuclear waste repository in basalt (NWRB). A preliminary report (Long and WCC, 1983) on the selection of candidate repository horizons and a preferred candidate repository horizon, the Cohassett flow, has been completed. The OCRWM program guidance calls for the development of test facilities in phased increments that support progressive assessment of the suitability of a reference location for a repository. One such facility planned for the Hanford Site will be the Exploratory Shaft (ES) facility that will provide personnel access to the preferred horizon for the purpose of in situ characterization testing to provide data for use in determining site suitability.

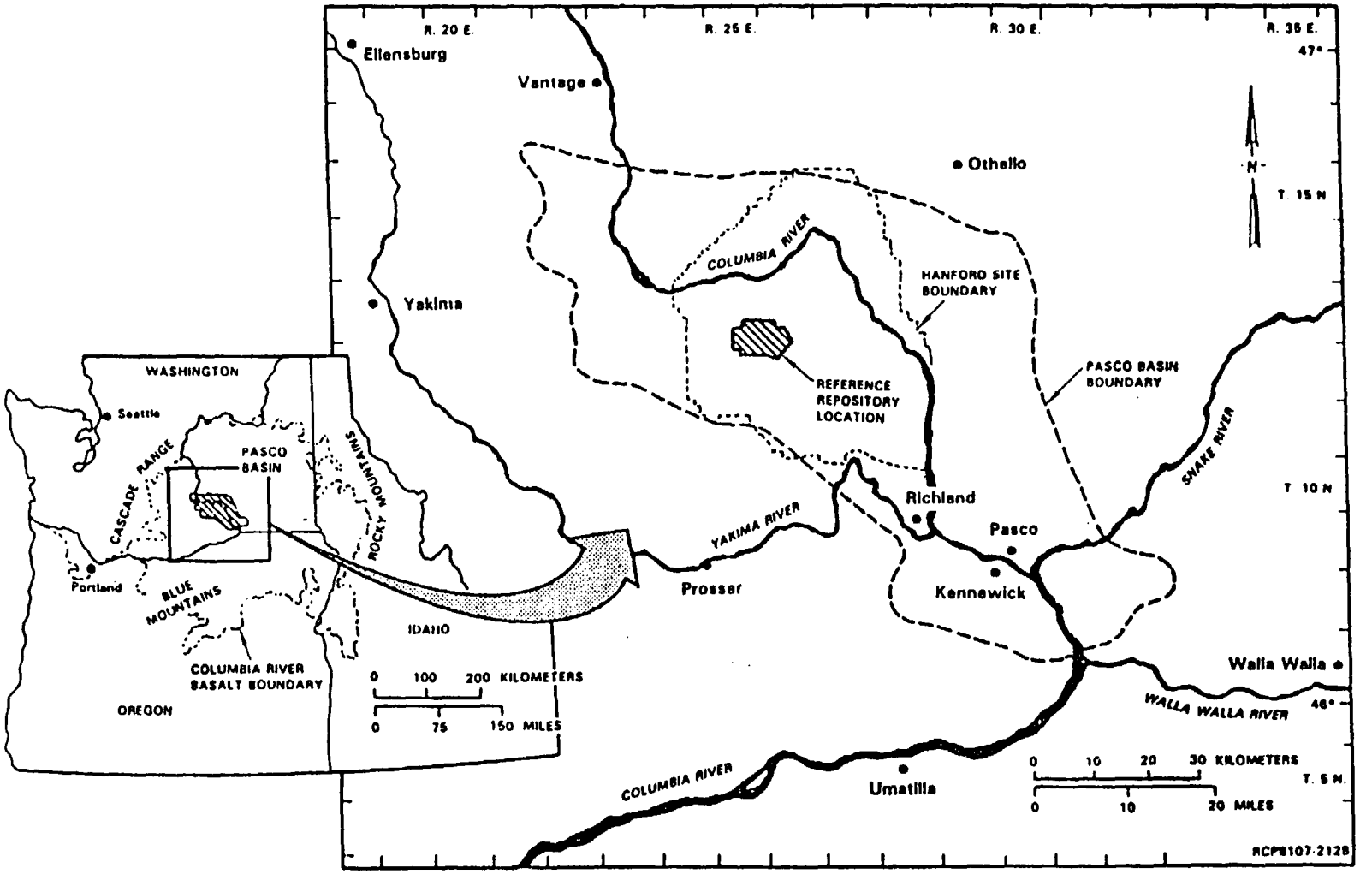

FIGURE 1. Reference Repository Location Map.

The ES Test Program will be developed in two phases. Phase I (ES-I) is to provide access to the preferred horizon and conduct the preliminary characterization test. Phase II (ES-II) of the test program includes a second shaft and extensive in situ tests for site characterization. Both Phase I and Phase II of the ES Test Program will provide input to the Draft Environmental Impact Statement (DEIS) and the Construction Authorization Application (CAA). In situ tests conducted as part of Phase I and Phase II of the ES Test Program will be supplemented by laboratory and other field tests.

OBJECTIVES OF EXPLORATORY SHAFT TESTING

The overall hydrology objectives for ES-I as stated in the ES Test Plan are:

Objective I-3: Evaluate the shaft liner seal to assure the safety of personnel from potential water inflow during breakout.

Objective I-3 is a direct extension of the liner installation program. This objective is designed to verify the effective emplacement of the cement grout in the shaft annulus. In order to verify successful grout emplacement, portholes have been located in the steel shaft liner through which will be cored a series of boreholes.

Objective I-4, Shaft Station Geohydrology: Assess the geohydrologic properties of the candidate horizon to assure safety of personnel from potential water inflow during breakout.

To meet these objectives, hydrologic studies are being directed to evaluate the in situ characteristics of the preferred horizon, the Cohassett flow and selected shallower stratigraphic zones. This is the rationale for the following two subobjectives:

- Assess the hydrologic properties of the preferred horizon to help evaluate its waste isolation potential.
- Assess the hydrologic properties of selected stratigraphic zones lying above the candidate horizon.

The cored boreholes shall have the multiple purpose of:

- Cement grout seal testing
- Hydrology testing
- Rock mechanics testing

Every borehole drilled shall examine the cement grout annulus for integrity. All boreholes will recover cored samples from the grouted annulus

and potentially damaged rock zone around the shaft to a distance of about 4 m (approximately 12 feet). This zone is the most sensitive interval regarding the potential for interconnection of water bearing layers intercepted by shaft construction.

A series of observations and tests are to be performed in the lateral boreholes. These activities are to evaluate the groundwater flow, cement strength, and description of the rock and cement core.

LOGISTICS AND IN SITU CONDITIONS

The following conditions will exist in the preferred repository horizon at the breakout area: a depth of approximately 3,150 feet, a high in situ rock temperature (124oF), and confined aquifers (1,300 psi) known to exist 160 feet above and 80 feet below the shaft breakout zone in the Cohassett flow top and flow bottom. An additional factor is the floor space available inside the shaft to setup a core drill, it is only 43-inches x 36-1/2-inches.

It had been questioned whether the BWIP could conduct the required tests in an area this small and under these conditions. Also because of the sensitivity to safety and the adverse reactions that even a minor mishap could cause, a drilling and testing system was designed that had substantial safety factors built in. This was so that any unpredicted in situ anomalies could be easily and safely handled as well as allow the two man crew to operate in an atmosphere devoid of unnecessary noise, mental and physical fatigue. With adequate training and simulated testing, personnel will conduct the drilling, hydrologic tests and do preliminary geotechnical analysis of the core. The two man crew has complete responsibility for their safety and the success of the shaft. With these factors in mind, the equipment was designed as identified in Table 1.

PROPOSED EQUIPMENT

To conduct the porthole drilling program in a safe and effective manner, several specially designed drilling components are currently being tested to determine their ability to function properly under maximum in-hole conditions. These include a drill unit, API drill rods, an AW34 core barrel system, a high pressure circulating pump, a valve and blowout preventer, and several auxiliary items.

The drill is a modified Watson 750 manufactured in Grants, New Mexico. It features a remotely located hydraulic unit powered by a 60 hp electric motor. The hydraulic system is controlled by a remote sequencing valve. The

TABLE 1. Environmental Factors and Mitigating Measures.

Confined "Tin-Can" Atmosphere	o Electric powered drill for quiet operation. o Two foot long core rods with modified API-tool joints with o-ring seals for easy make-up and breakout. o Multi-level work deck anchored to shaft casing and attached to the skip overhead.
124°F In Situ Temperature	o Eight-inch air line in shaft for cooling. o Six hour working shifts.
1,300 psi Unlimited Reservoir Potential	o Blowout preventer and water control system. o Drill's thrust capability is 8,000 psi. o Drill hydraulic system designed to allow insertion of core tools, test tools, etc. o 6,000 psi check valves in drilling string.

hydraulic motors are mounted within the reservoir to minimize noise, and overall power unit size. The entire unit including reservoir, water cooler, and pressure manifold is 22" wide x 25" long x 70" high. This unit will be located on the lower level of the work deck.

The rotation unit on the drill is a top head drive spindle which maximizes the 28-inch feed stroke. An additional advantage with the drive unit is the elimination of slippage under maximum loading which commonly occurs with an open spindle design. Rotation speed is infinitely variable, both forward and reverse, from 0-1,850 rpm. The feed system is chain driven and will provide bi-directional thrust exceeding 8,000 pounds. This will provide a 1.9 to 1 safety factor, since the maximum thrust condition due to water pressure is 4,250 pounds.

The rod clamp operates in conjunction with a dual piloted check valve which maintains positional control in the event of a sudden hydraulic system failure.

A centrally located control panel provides master control levers, water and hydraulic system pressure gauges. The drill is divided into three circuits with the rotation unit powered by the main pump and the feed system and rod clamp driven by the auxiliary pump. The feed and rotation circuits each have bi-directional fine feed flow control valves beyond the master control.

The drill string will consist of an AW34 thin kerf conventional core barrel system. This will provide a 1.32-inch core size while minimizing the overall borehole size, thus reducing the discharge potential. A back flow preventer valve will be installed at the rear of the core barrel assembly. The AW size drill rods with API modified threads were designed for this application. These units also incorporate a check valve to prohibit the reverse flow of drilling fluid.

An auxiliary electric hydraulic power unit with a high pressure circulating pump will provide the cooling water while drilling. The hydraulic system design is similar to the main power unit, since it also functions through remote sequencing which minimizes noise levels. The water pump is an FMC bean triplex plunger type pump, which utilizes spring loaded disk valves to maintain positive displacement during high pressure conditions. The pump has a maximum displacement of 4.5 gallons per minute (gpm) and is capable of 5,000 psi. The power unit, which is driven by a 30 hp electric motor will provide the maximum gpm rating at 2,250 psi. This permits a 1.5 to 1 safety factor over in situ conditions.

A high pressure ball valve and blowout preventer assembly has been designed specifically for this program. The key to drilling in a pressurized environment is the ability to control and divert the water pressure and associated flow. The blowout preventer utilizes a dual sealing system which through the use of an inner bearing loaded cylinder permits the drill string and inner cylinder assembly to rotate independently from the outer housing. A

static seal isolates the bearings from water contamination while an inner rotating elastometer provides the seal around the drill string. This one piece cylindrical seal contracts and expands as borehole water pressure fluctuates. This permits the assembly to instantaneously self-adjust to sudden increases in borehole pressure. Since the elastometer rotates at the drill string speed, the drill unit only has to overcome the thrust value to penetrate in high pressure, as opposed to both thrust and torque, which exists when a static stuffing box is in use. The valve assembly mounts directly to the blowout preventer utilizing American National Standards Institute (ANSI) 300 pressure flanges. A pressure relief port is located on the rear ball valve flange to divert fluid discharge during drilling. This relief circuit provides greater than twice the annular area along the drill string, thus allowing a pressure reduction on the rotating seal surface. The ball valve is designed to function manually or through electric actuation. A pressure gauge is mounted on the front flange of the valve next to the casing liner providing the ability to monitor borehole pressure fluctuations. The ball valve and blowout preventer assembly has an internal loading chamber between the rotating seals and the ball assembly. This allows for the installation and removal of porthole plugs in an enclosed environment, always working within the assembly and utilizing the preventative elastometer. The valve and blowout preventer mount directly to the rod clamp, thus providing a direct connection between the casing liner and the drill unit. In the event of a seal failure in the blowout preventer, the drill string will be extracted from the borehole and the ball valve closed. Drilling will resume following repairs to the unit.

Several auxiliary components will be used. These include porthole plugs for monitoring, grouting, and borehole completion. The installation and removal tools utilize j-lock connections and attach directly to the rotation head on the drill. A separate grout pump will be used to conduct remedial and completion cementing.

PROPOSED GEOTECHNICAL TESTING AND MONITORING

As a minimum, 13 holes will be cored through portholes located opposite the shaft station prior to breakout (Figure 2). These boreholes will be along the centerline of the shaft station breakout to verify the integrity of the grout seal, to ascertain the in situ characteristics of the host rock for geotechnical evaluation, and to ensure the rock mass is adequate for a safe breakout.

To meet the objectives of the porthole program, the holes will use the drill-test-drill approach. The borehole will be cored initially to a depth of 18-inches. Water will then be circulated across the grout seal and the rate of inflow and outflow will be precisely measured (± .001 gm). The difference is the rate of production or loss from the test interval. If the flow test

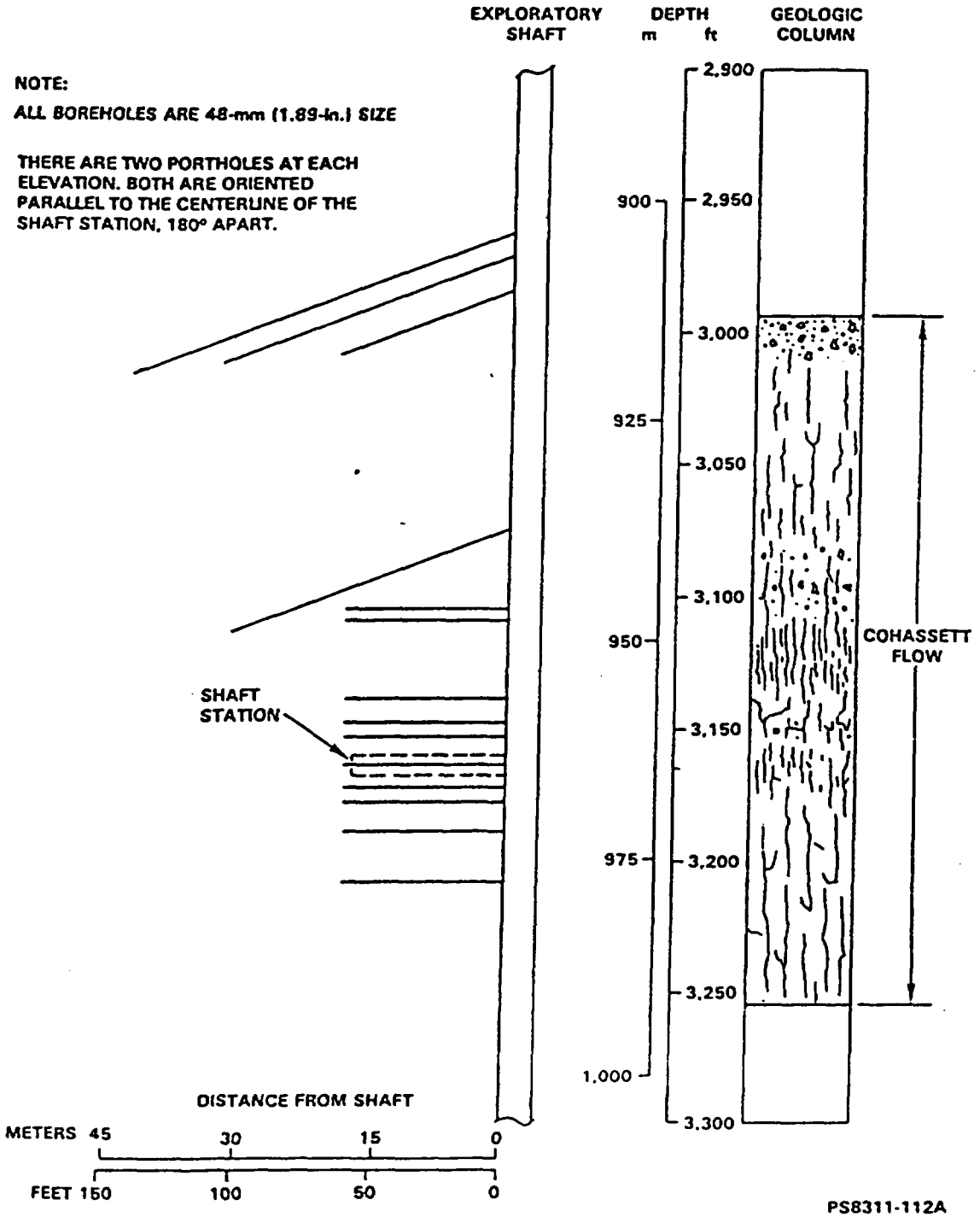

FIGURE 2. Hydrologic Testing Porthole Locations.

indicates the boreholes is producing water at a rate greater than that expected, a constant head injection test will be performed. The rate will be determined by modeling the expected inflow into the hole using design seal criteria for hydraulic conductivity and porosity. If the inflow rate is above the amount needed to assure isolation and grout integrity, remedial grouting will take place. If not needed, the hole will be extended to 6 feet in depth and the same sequence of testing will be performed. The core hole will be advanced from 6 feet to 12 feet in depth and tested. This interval is believed to be the maximum extent of the disturbed rock zone as a result of the drilling process. The hole will then be cored to its final depth of 60 feet. Additional testing will take place using a modified straddle or a single packer system.

Upon completion, the borehole will be converted into a monitoring facility to record any change in pressure and the hydrologic properties of the grout and rock mass (Figure 3). This will be accomplished by installing a 0.25-inch high pressure tube in the borehole. A swedgelock or other appropriate device will seal the borehole at the port hole. The tube will be fed through the swedgelock to a high pressure valve. From the valve the tube will be extended to a point where pressure and temperature transducers can be installed to monitor in situ pressure results. The transducers will be electrically wired to a multiplexer which will be located along the shaft liner wall. It is planned to tie all 13 boreholes into one multiplexer. The multiplexer (and other facilities) will be small enough to preclude the possibility of damage by the operation of the skip. A data transmission line will transfer data to the surface to the data acquisition system.

All core will be geologically logged in detail to support another objective of the ES; geologic characterization. This detailed core logging will label and define the structural characteristics and infilling material of each fracture, whether broken or intact.

Physical properties of the grout will be determined in the laboratory. Tests will include compressive strength, porosity and ultrasonic velocities. A shear strength test will also be conducted to determine the interface bond between the grout and the basalt.

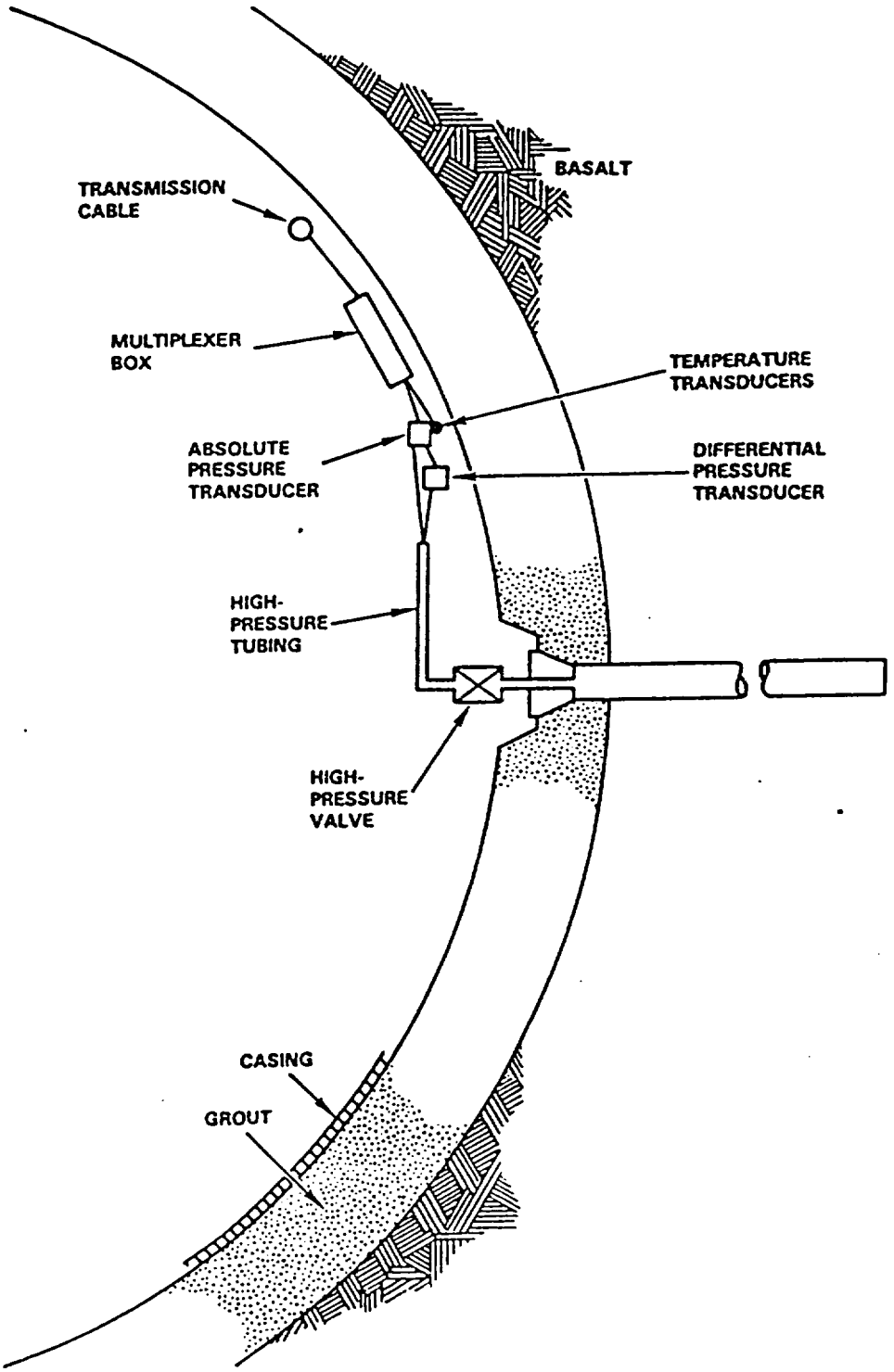

FIGURE 3. Conceptual Setup for Hydrologic Testing of Lateral Boreholes in the Phase I Shaft.

ACKNOWLEDGEMENTS

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UNDERSTANDING THE TENSION-TORQUE PERFORMANCE DIAGRAM FOR RAISE-DRILL AND LARGE-DIAMETER DRILL PIPE CONNECTORS

May 1, 1985

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A Newpark Company

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I. INTRODUCTION

Large diameter shaft drilling, whether it is accomplished by the raise-drill technique or the blind-shaft technique, requires the application of combined high torques and tension to the drill string during the drilling process. Modern drilling machines, in many cases, are capable of producing continuous driving torques which exceed the safe capacity of the drill string in use. When combined with high tension, the situation becomes even more critical.

The tubular drill pipe itself (excluding connections) normally does not limit drill string strength, unless the pipe is thin walled or of much smaller diameter than the connection. The threaded connection normally limits the high torque-tension performance of mining drill strings. Therefore, it is desirable to know the operation capacity of the threaded connection ahead of time to prevent overstressing. This data is supplied by several manufacturers in the form of "Tension-Torque" Performance Charts.

A typical tension-torque performance diagram for a solid tubular section is shown in Figure 1. This diagram, as opposed to one for a threaded connection, is simple to understand and use. It simply shows a curved line defining the maximum limit of combined tension and torque. Any combination of tension and torque beneath the line is permissible. The dashed line identified as "Material-Yield Limit" defines operation where the combined stresses, due to tension and torque, produce yield in the pipe material.

It is hazardous to operate at such high stresses, therefore, it is wise to limit operation to something less. The example shows an operational limit of two-thirds the yield limit, thus providing a safety factor of 1.5. (Safety factors less than or greater than 1.5 may be used to suit the application.)

A typical tension-torque chart for a rotary-shouldered threaded connection is shown in Figure 2. Although it appears similar to the solid tubular pipe chart in Figure 1, it is not as straightforward to understand and use. The reason for this is that the element of "make-up torque" enters the picture and it is mandatory that this be accounted for in the generation and use of the diagram.

This paper addresses itself to the correct use of the threaded connection tension-torque diagram and the importance of the use of correct thread compound to produce desired results.

II. THE ROTARY SHOULDERED CONNECTION - HOW IT WORKS

A brief understanding of what happens inside the rotary shouldered connection when make-up torque is applied will be most helpful before proceeding further. Referring to Figure 3, the qualitative stress distribution is shown for a made-up tool joint. Notice the pin is in tension and the box in compression. Notice further, that the neck of the pin and the first few threads "see" the highest concentration of tensile stress. A stress distribution exists across the cross section of the pin neck with very high stress levels existing on the surface of the neck (relief groove) and diminishing inward toward the bore. The box counterbore and first few threads of the box see the highest concentration of compressive stress, and this diminishes outward toward the O.D. Tensile and

compressive stress levels both are highest in the areas near the shoulder and pin neck and diminish as they travel lengthwise toward the end of the box and pin. As make-up torque is increased, these stress levels increase. Operation at torques lower than make-up torque does not alter the existing prestressed levels induced by make-up torque, unless a torsional impact load or brief overload is encountered in which case further make-up (and overstressing) may result.

When tension is applied to the drill string, the existing prestress levels due to make-up torque are altered. After a connection has been "made-up" and prestressed, the pin neck "sees" the prestress due to torque plus some additional stress when tension is added to the string. The pin and box, when tightly torqued together, act as a single unit in responding to applied tension. By referring to Figure 3, if the cross sectional area of the pin neck (pin critical area) is equal to the cross sectional area of the box in the counterbore (box critical area) the pin critical area will see an increase of one-half of the applied tension or a one-half pound for each pound applied, and the box critical area will see a decrease in compression, also equal to one-half of the applied tension load. If the pin and box areas are unequal, and they usually are, then the pin sees an increase in load proportional to the ratio of pin area to the total combined pin plus box areas. For example, if the pin area were twice the box area, the pin area would then be two-thirds the total area. The pin neck would then see an increase of two-thirds pound for each pound tension applied and the box shoulder would see a decrease of one-third pound compression for each pound tension applied.

The significance of selecting the correct amount of make-up torque is now more apparent for several reasons:

(1) An adequate amount of make-up torque which exceeds the operating torque is desirable to prevent further make-up and overstressing due to torsional overloads.

(2) A minimum value of make-up torque is necessary to prevent the shoulder load decreasing to zero (and shoulders separating) when operating tension is applied to the string.

(3) Make-up torque must be limited to some maximum value to prevent overstressing the pin neck when tension is applied.

III. DEFINITION OF THE TENSION-TORQUE PERFORMANCE CHART FOR ROTARY SHOULDERED CONNECTIONS

The combined tension-torque operational limits with recommended make-up torques for all operating conditions of a connection can be displayed in a variety of graphical forms. To provide a single usable chart which gives all this information clearly has proven to be a difficult task. In any case, if the user does not understand how the chart was developed, the information contained can easily be misinterpreted. LOR, Inc., has elected to publish charts for certain sizes of raise-drill steel and has available charts for various large diameter pipe connections. A description of the development of each segment of a typical LOR, Inc., tension-torque performance chart follows.

Reference Figure 4:

Calculate the maximum make-up torque allowable based on material yield strength using an empirical formula developed by A. P. Farr (published by the ASME in 1957, Reference ASME Paper 57-Pet-19 and also published in API RP7G, Appendix A).

This formula has proven to be reliable in predicting torsional strength of rotary shouldered connections in general and has been accepted by the API as a valid method. The torque calculated by this method defines Point 1 on the chart known as the yield torque and represents the make-up torque which produces an average tensile yield stress across the pin critical area. No drill string tension may be applied at this point without exceeding the yield stress in the pin area. If the connection is initially made up to some value lower than yield torque, say Point A, then the pin area "sees" less than the yield-stress value and some amount of tension may be applied to the string, up to Point B, at which point the combined affects of torque and tension develop yield stress in the pin area. If an even lower value of make-up torque is initially applied, say Point C, an even greater value of tension, Point D, may be added before pin-yield stress is developed. Calculation of numerous make-up torque-tension combinations to produce yield stress in the pin will generate a series of points describing the straight line, shown in Figure 4.

Reference Figure 5:

If the box critical area happens to be less than the pin critical area, then yield torque is limited by the compressive stress developed in the box shoulder as shown by Point 2 in Figure 5. This now becomes the maximum make-up torque allowed, and a value of tension, Point A, can be safely added to the drill string before yield-tensile stress is developed in the pin. (Point A falls on the same line described in Figure 4.) The initial box compressive yield stress formed at make-up safely decreases as tension is added.

Reference Figure 6:

As we continue to combine lower values of initial make-up torque and higher values of tension (beginning with Torque 2 and moving toward Torque A) the pin-yield, limit line is formed. However, as applied tension increases, shoulder-load compressive stress decreases, until eventually a value of tension is reached (Point 3) where shoulder stress becomes zero and shoulder separation begins. This value also defines the maximum tension (Point 4) which can be carried by the connection.

If a still lower value of make-up torque, "B", is applied, separation will occur at Tension C. With an even lower value of make-up torque, "D", separation occurs at Tension E, and so on. These points describe a straight line identified as "separation" in Figure 6.

Reference Figure 7:

To illustrate the significance of the "separation" line, consider a combined make-up torque, "B", and tension, "C", which plots Point D on the diagram. Make-up Torque B is applied first, then tension is applied toward "D". Shoulder load (box compressive stress) becomes zero when Tension E is reached. At Tension C (Point D) the shoulders are well separated.

If it is desired to operate at a value of Tension C, the minimum make-up torque required to maintain shoulder contact is Torque F. Maximum permissible make-up torque at Tension C would be Torque G. (Tension C and Torque G combined will produce yield stress in the pin critical area.)

Reference Figure 8:

Experience with rotary shouldered connections, in general, has shown that localized yielding in the threads, and in the pin and box critical areas, begins to occur at approximately two-thirds of the yield torque calculated by the Farr empirical formula. Using this experience, the safe limit on the LOR Tension-Torque Charts is defined by a line which represents a combined stress due to make-up torque and tension of two-thirds of material yield strength. This line, labeled "2/3 YIELD" in Figure 8, now becomes the limiting envelope which we will work with as opposed to the "(100%) YIELD LIMIT" described previously in Figures 4 through 7.

Reference Figure 9:

Up until this point, the generation of the tension-torque diagram has only considered make-up torque. It is desirable to limit operating torque to some value less than make-up, as discussed earlier, to prevent occasional torsional overloads from causing additional make-up and overstressing. The greater the spread between make-up and operating torque, the greater the protection. It would be nice to limit operational torque to half or less of make-up torque. This would provide safe protection from torsional impacts in most cases, and this is actually achieved in oilfield drill collar application. However, in the case of raise-drill operations, in particular, this amount is not practical in view of the drilling torques required with the common sizes of drill steelbeing used to carry these torques.

We have established, so far, the safe tension/make-up torque limit based on two-thirds yield stress in the pin. LOR, Inc., has elected to limit operational torques to 90 percent of applied make-up torque. This provides 10 percent over-torque protection and does not severely limit the useful torque capacity of the connection. By referring to Figure 9, the original tension/make-up torque line set at two-thirds yield, will move to the left 10 percent and now represents the operational tension-torque limit. Make-up torque is now displayed on a separate make-up torque axis below the original axis, now representing operating torque. Guidelines are furnished between the two axis which direct the user down from the operating torque value to a make-up torque value of 10 percent greater than operating torque. In the example in Figure 9, if the driller plans to use Value A pounds of tension in the string, the maximum operating torque allowable will be "B", and the desired make-up torque is "C".

The make-up torque axis also shows Points D and E. Point D is the maximum make-up torque allowed to limit pin stress to two-thirds yield. Point E is a minimum make-up torque which eliminates the need to display the "separation" line. If the connection is made-up to this minimum value, separation cannot occur regardless of tension applied within the limits shown on the diagram.

Reference Figure 10:

The diagram now appears as shown in Figure 10. If the anticipated string tension is "B" and operational torque is "C", combined operation will be at Point A. Minimum make-up torque is "D". Maximum allowable operating torque is "E" and maximum make-up torque is "F".

Conversely, if maximum operating torque is expected to be "E", then required make-up torque is "F" and maximum permissible tension is "B".

Reference Figure 11:

LOR, Inc., has elected to impose one additional limit into the diagram for further protection. This is related to the estimated fatigue limit of the pin in tension.

The material fatigue limit of the pin is estimated based on 500,000 full-load-tension cycles. The combined tension-torque loads are then calculated so as not to exceed this value and plotted on the diagram. If this line falls anywhere inside the existing limit of two-thirds yield, which it does for some raise-drill connections, then it becomes the upper tension limit of the connection.

A "full-load-tension" cycle is defined as cycling the tension load from zero to the maximum allowed on the diagram and back to zero again. The value of 500,000 cycles was selected for estimating fatigue life because it is more realistic than estimating fatigue life based on a higher value, such as one million or more. At the same time, it is a conservative value. For example, if 50 full-load-tension cycles were applied each day to the drill string, exclusive of weekends, it would take 38 years to reach 500,000 cycles. Thus, the upper tension limits defined by this method are generous, yet conservative.

IV. USE OF THE TENSION-TORQUE DIAGRAM

Fundamentally, it is difficult to know beforehand exactly what operating rotary torques will be developed while drilling. Tensile loads in the drill string, however, are easier to predict. In the case of raise drilling, desired tension can be based primarily on the raise-head diameter cutters being used, and type of formation being drilled. In the case of blind-shaft drilling, tensile loads can be calculated based on desired weight-on-bottom, mud weights, bottom-hole assembly

weight, and drill-string weight. Therefore, one approach to using the tension-torque diagrams is to begin with estimated maximum tension load, and then determine what maximum operating and make-up torques result.

Reference Figure 12:

Figure 12 shows the tension-torque performance diagram for 10" raise-drill steel using the 8.25 LOR 215 Connection. Superimposed on the diagram for reference is the maximum continuous tension and torque capability of the Robbins 73R Drill Machine which is typically used with 10" raise-drill steel. Note that the torque capacity of the drill machine exceeds the safe-torque capacity of the connection, thereby requiring the use of the torque and tension limiters on the machine.

- Example 1 (Figure 12):

  If full tension, 860,000 lbs. were expected to to used, the maximum operating torque allowed would be "A" and the required make-up would be "B". Make-up Torque B should be applied to each joint as it is being added to the string during pilot hole drilling. Once make-up Torque B is applied, any combination of tension not exceeding 860,000 lbs. and torque not exceeding "A" may be used.

- Example 2 (Figure 12):

  If a maximum of Tension F is expected to be used, the maximum operating torque now becomes "D" and make-up torque "C". Combinations not exceeding Tension F and Torque A are now permissible.

- Example 3 (Figure 12):

  Consider the case where the connections have previously been made-up to Torque C as in Example 2. If it is now desired to increase tension from "F" up to 860,000 lbs., then the driller has a big problem. To safely operate the string at 860,000 lbs., the connections must be broken out and remade to Torque B. If this is not done, operation would effectively be at Point E, since the pin has been prestressed to make-up Torque C and this is outside of the safe operational envelope. So having a knowledge of the maximum tension needed beforehand is important in selecting correct initial make-up torque.

- Example 4 (Figure 12):

  If it is known that maximum operation will be at Point G, then any make-up torque between "I" and "C" can be used. (The minimum required would be "I".) In this case "B" make-up would be best, since this gives operational tension capability to the maximum of the drill machine, if it should be needed, and gives additional torque protection to "A".

Reference Figure 13:

Shown is the tension-torque limit diagram for the pipe and connection designed by LOR, Inc., for a recent large-diameter, shaft-drilling proposal. In this case, the estimated connection-fatigue limit, based on 500,000 full-load-tension cycles, was in excess of the two-thirds yield limit and not critical to the safe operating envelope. The yield tension-torque limit of the drill pipe is shown since it forms the upper operating limit of the pipe-connection system.

As can be seen, the estimated tension-torque envelope of the drilling program is well within the safe envelope of the pipe-connection systems. Therefore, LOR, Inc., recommended a single value of make-up torque of 650,000 ft-lbs. for optimum protection. Minimum make-up torque recommended is 500,000 ft-lbs. for operation at the specified 450,000 ft-lbs.

V. THE IMPORTANCE OF PROPER THREAD LUBRICANT AND ITS ROLE IN CONNECTION PERFORMANCE

The empirical-torque formula developed by A. P. Farr for calculating torque capacity of a connection was based on the energy absorbed by the connection from applied torque. Derivation of the formula begins with:

$$W = W_a + W_t + W_s$$

Where: W = work applied to joint
W_a = useful work absorbed by joint (to prestress pin and box)
W_t = work to overcome thread friction
W_s = work to overcome shoulder friction

After all the necessary algebra is completed, the final formula results as follows:

$$\text{Torque} = S\,A\left(\frac{P}{2\pi} + \frac{R_t\,f}{\cos\theta} + R_s\,f\right)$$

Where: S = stress developed in critical area
f = coefficient of friction (normally 0.08)
A, P, R_t, R_s, θ, are physical dimensions of the particular connection.

The terms contained in the parenthesis can give us a clue as to the large affect friction has on connection make-up:

(a) The term $\frac{P}{2\pi}$ is analogous to the useful work absorbed by the connection, i.e., prestressing the pin and box.

(b) The term $\frac{R_t f}{\cos\theta}$ is analogous to work overcoming thread friction.

(c) The term $R_s f$ is analogous to work overcoming shoulder friction.

When analyzing a typical raise-drill connection or large pipe connection (with a coefficient of friction of 0.08) it is found that the ratio of the value of $\frac{P}{2\pi}$ to the total value of the terms in the parenthesis is about 19 percent. This means that only about 19 percent of the work applied in torquing the connection together is used in actually tightening the connection. <u>The remaining 81 percent of the work applied is used in overcoming thread and shoulder friction.</u> The importance of controlling the coefficient of friction between the threads and shoulders should now be more apparent.

The "standard" value of coefficient of friction used to calculate make-up torque is 0.08, and is based on thread compounds which contain 60 percent by weight of finely powdered lead, or 40-60 percent by weight of finely powdered zinc. If a "slick" compound should be used (such as teflon) which has a coefficient of friction much less than 0.08, then at least two undesirable things may happen:

(1) The connection can easily be overstressed. The usual values of make-up torque will develop much higher stresses. If the coefficient were 0.04 (half the normal), connection stresses would almost double.

(2) The make-up torque can be reduced to limit the stresses, but then the connection is also limited to lower operational torques. Also, the resistance to breakout will be less and the connection could loosen in service.

Conversely, if a thread compound with a higher coefficient of friction is used, the connection will be too loose when made-up to normal torques. It is most important that the characteristics of the thread lubricant be known before applying large make-up or operating torques to the drill string. This can be critical, especially in operations involving raise-drill or large-shaft drill pipe where make-up and operating torques commonly approach the safe limit of the connection in service.

Remember, almost all torque data supplied by manufacturers is based on an assumed coefficient of friction of 0.08. If a lubricant is selected for use which varies significantly from this value, the torque data must be adjusted accordingly.

The most desirable compounds to use are those presently on the market containing 60% or more of finely powdered lead, and with dispersion hardening additives. These compounds offer the optimum protection from seizing and galling, provide the best sealing characteristics, are the most stable in the presence of chemicals and heat, and provide the most consistant

and reliable frictional coefficients corresponding to a desired value of 0.08.

In summary, the thread lubricant plays a vital role in connection torque performance. When drill strings are expected to perform to their maximum, the lubricant should be considered as one of the primary components in the system.

TYPICAL TENSION-TORQUE CAPACITY OF PIPE SECTION ONLY

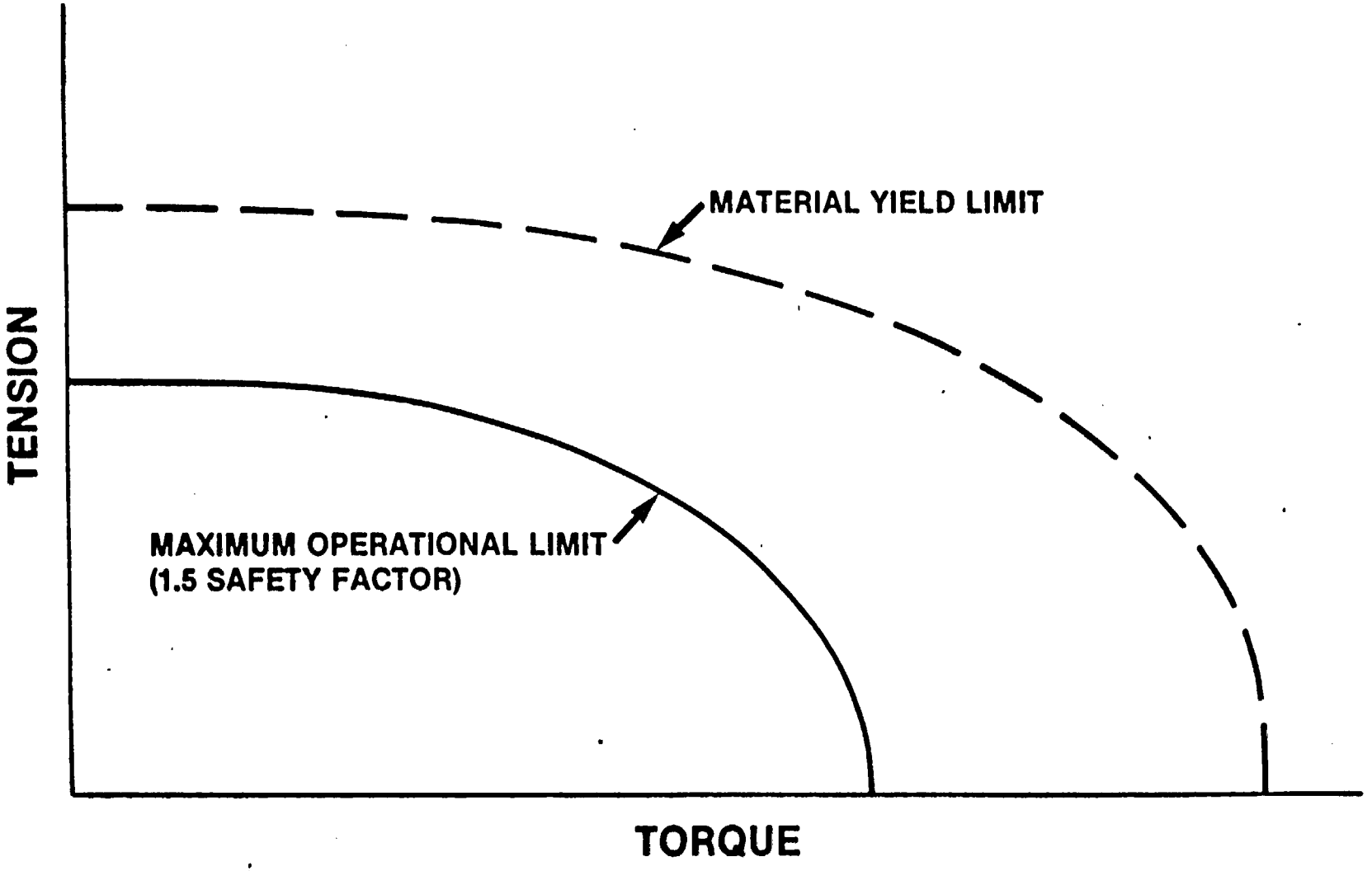


FIG. 1

TYPICAL TENSION-TORQUE LIMIT ENVELOPE OF ROTARY SHOULDERED CONNECTION

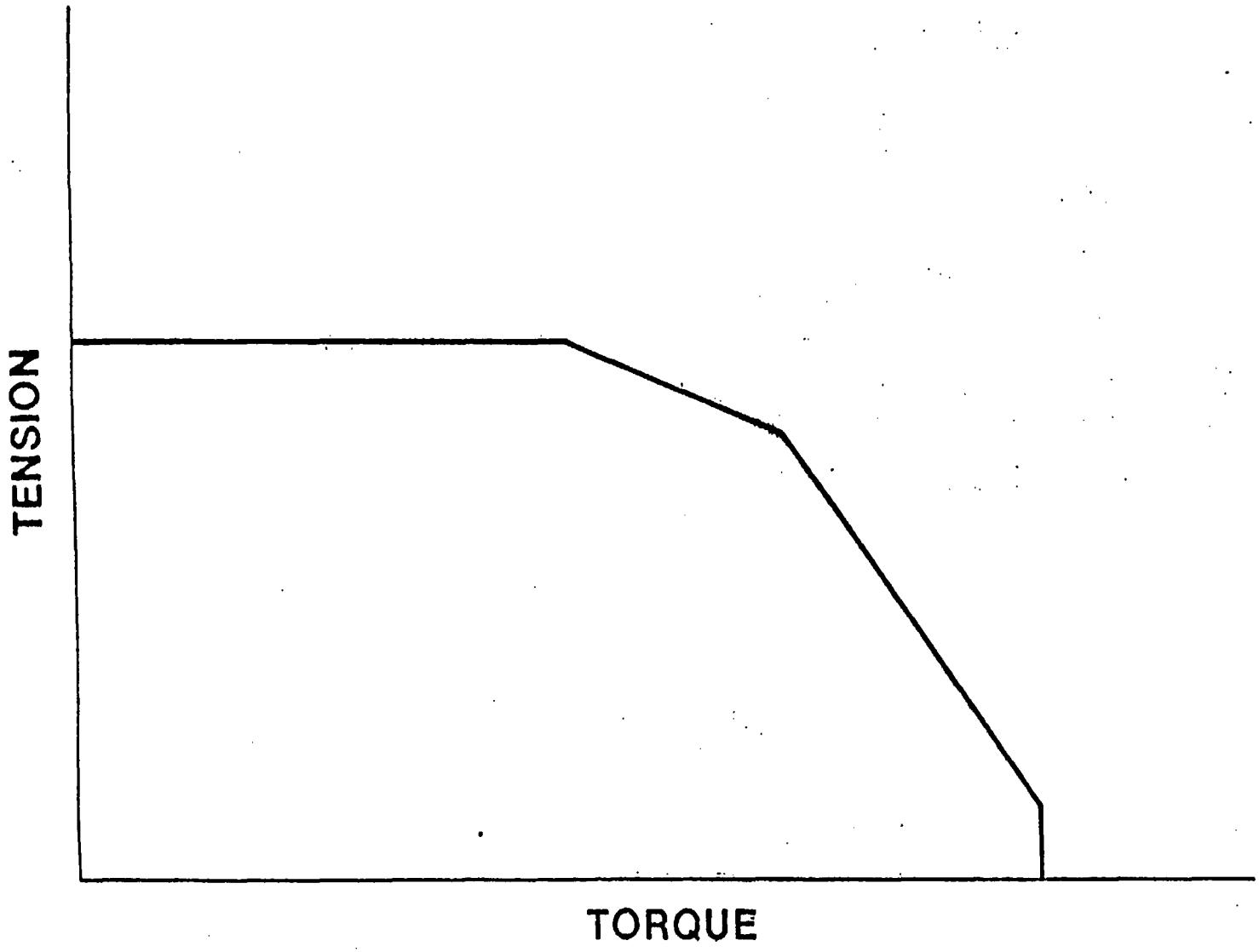


FIG. 2

CROSS SECTION OF A ROTARY SHOULDERED CONNECTION
STRESS DISTRIBUTION IN MADE-UP CONDITION

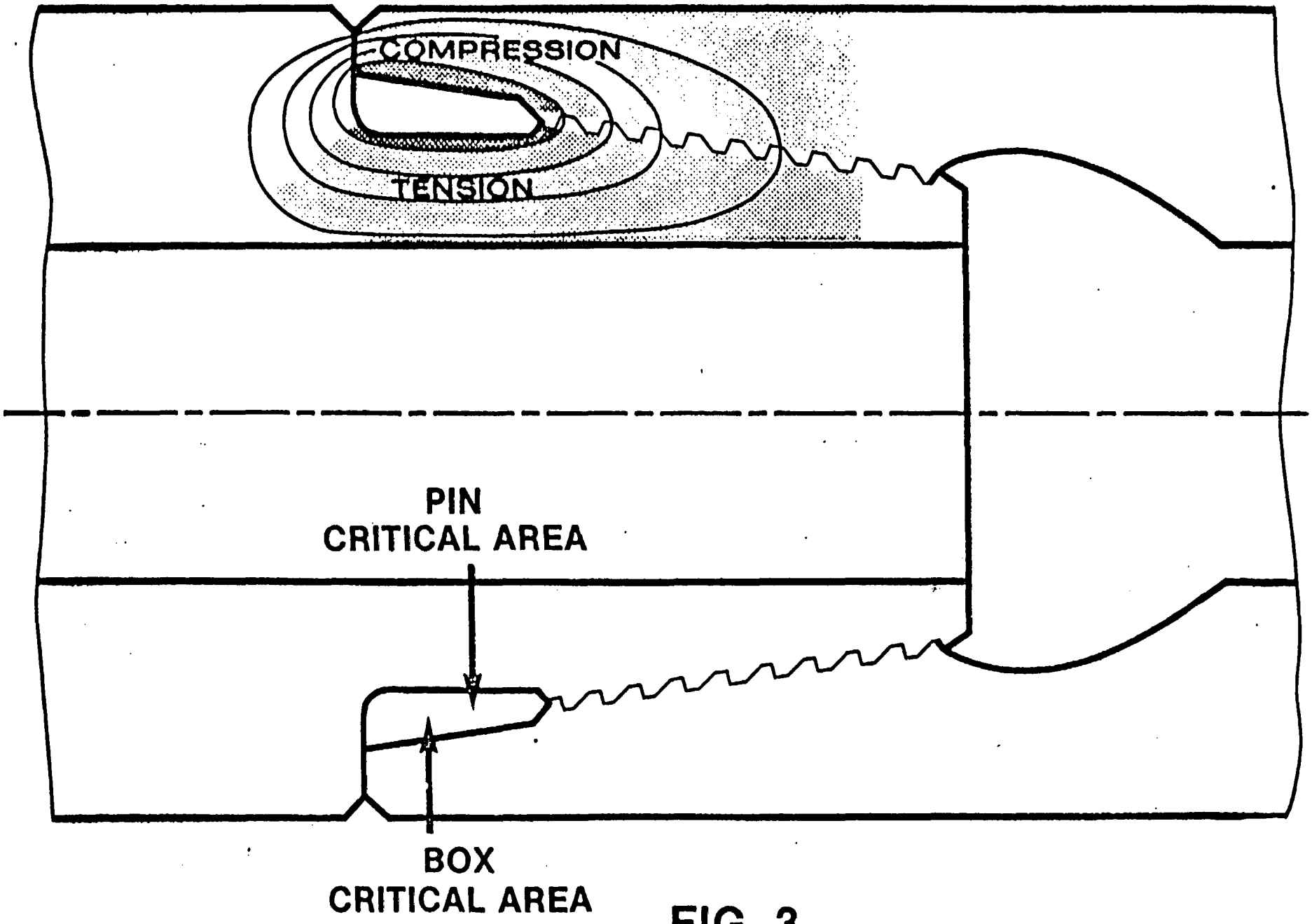


FIG. 3

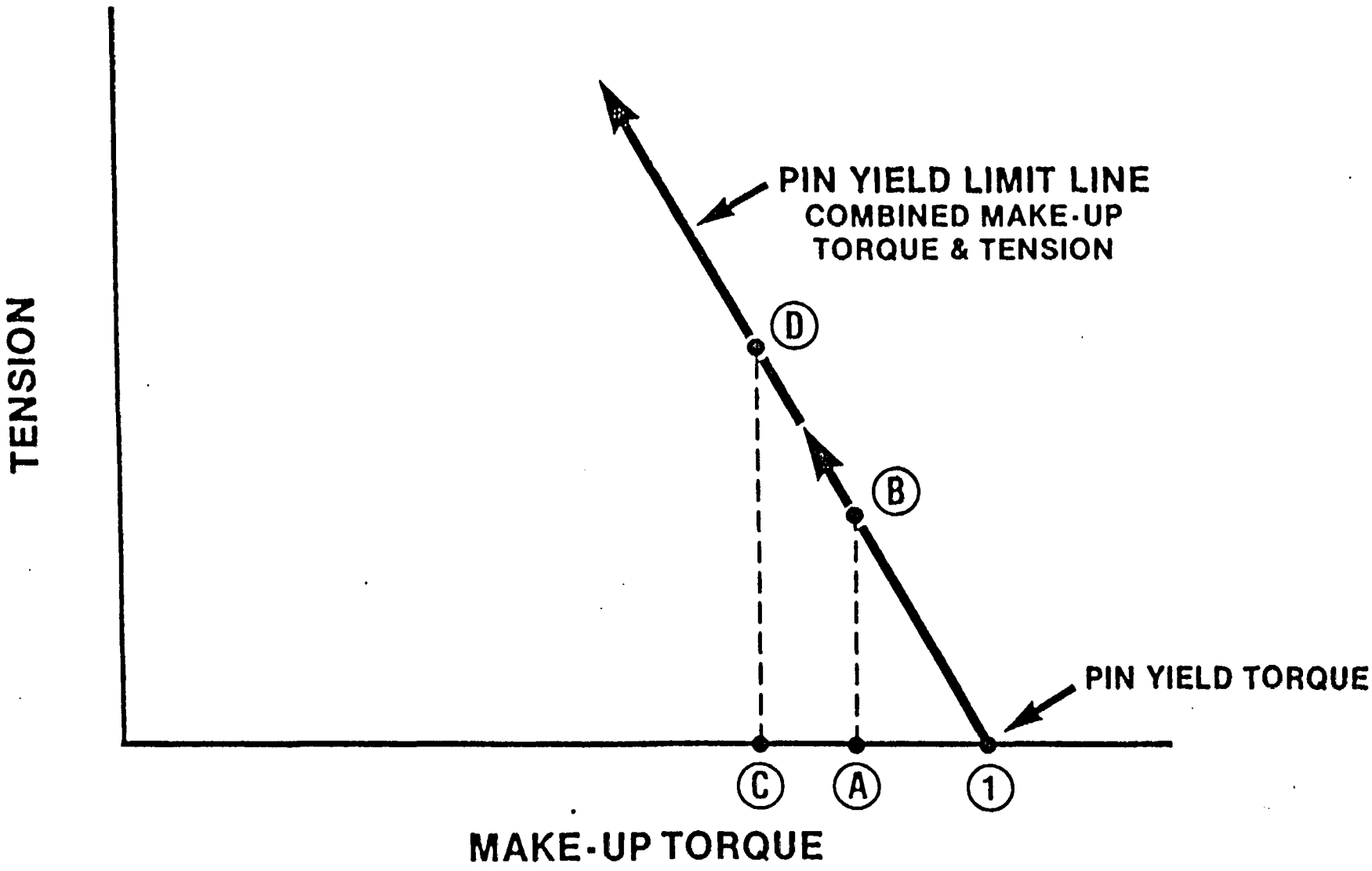

PIN YIELD LIMIT LINE
COMBINED MAKE-UP
TORQUE & TENSION
D
B
PIN YIELD TORQUE
TENSION
C
A
1
MAKE-UP TORQUE

FIG. 4

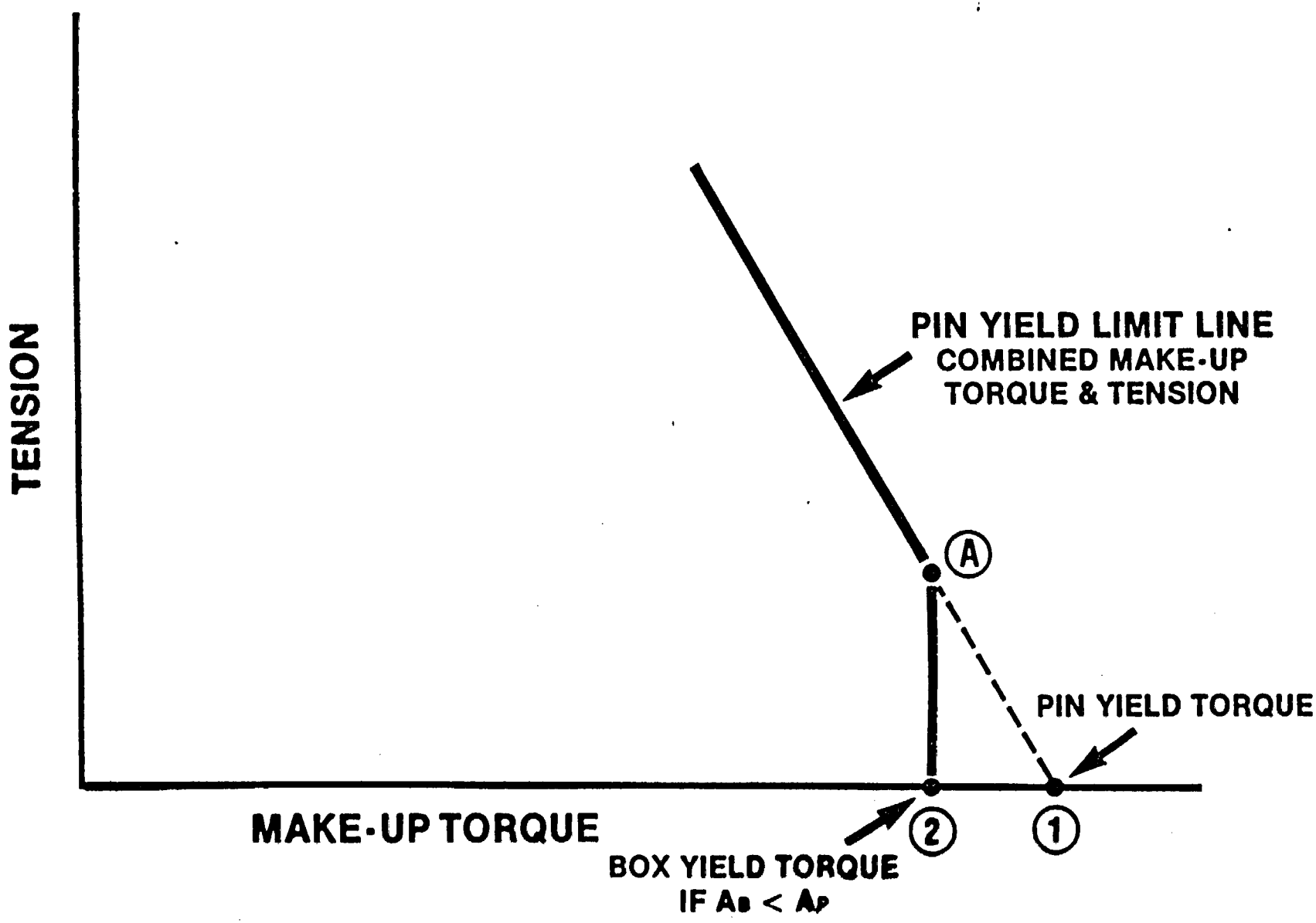

TENSION
PIN YIELD LIMIT LINE
COMBINED MAKE-UP
TORQUE & TENSION
A
PIN YIELD TORQUE
MAKE-UP TORQUE
2
1
BOX YIELD TORQUE
IF Ab < Ap

FIG. 5

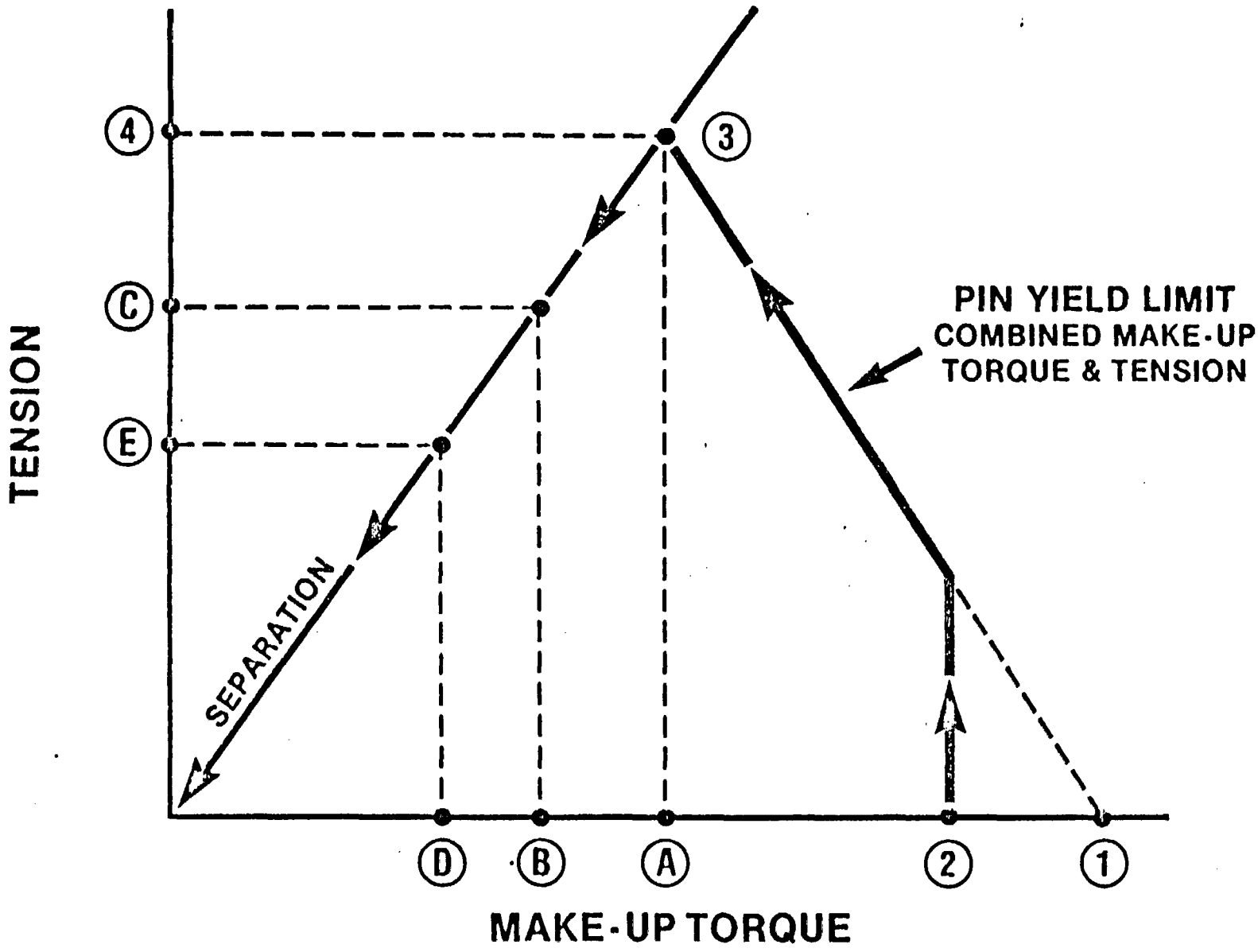

TENSION
4
C
E
3
PIN YIELD LIMIT
COMBINED MAKE-UP
TORQUE & TENSION
SEPARATION
D
B
A
2
1
MAKE-UP TORQUE

FIG. 6

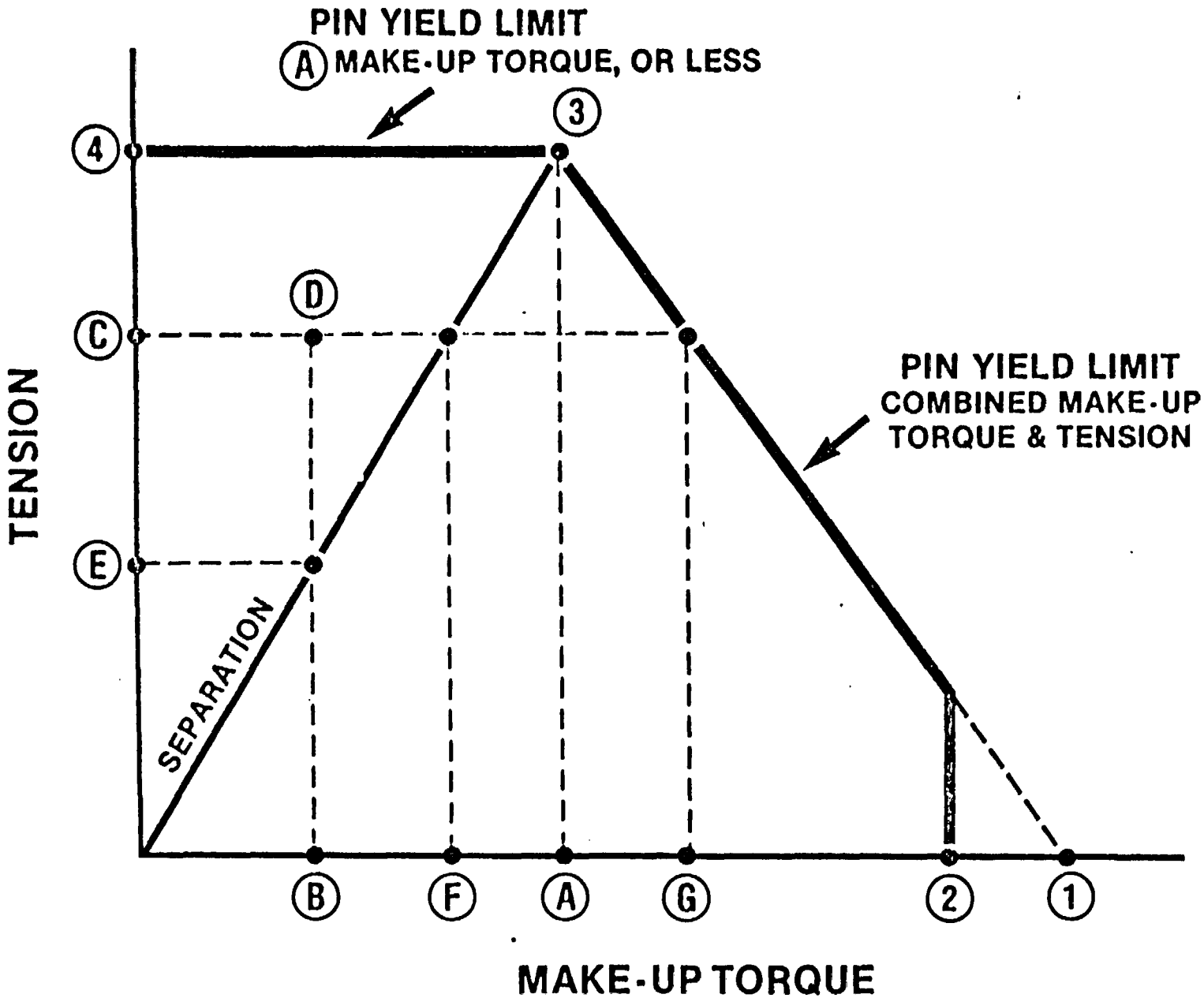


FIG. 7

TO OPERATE AT TENSION C
F = MINIMUM MAKE-UP REQUIRED
G = MAXIMUM TORQUE ALLOWED

MAXIMUM FIELD USE MAKE-UP TORQUE

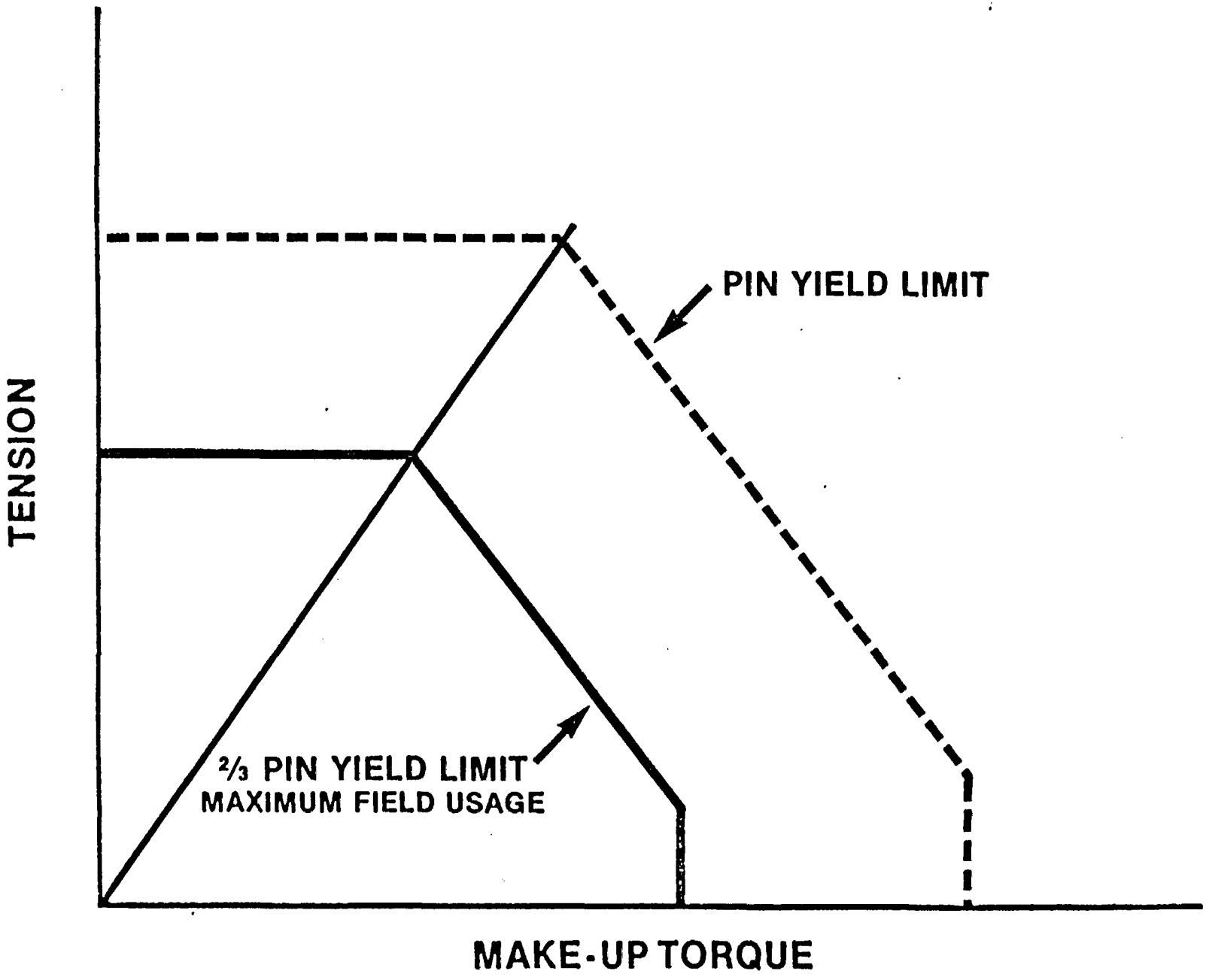


FIG. 8

MAXIMUM OPERATING TORQUE LIMITED TO 90% OF MAKE-UP TORQUE

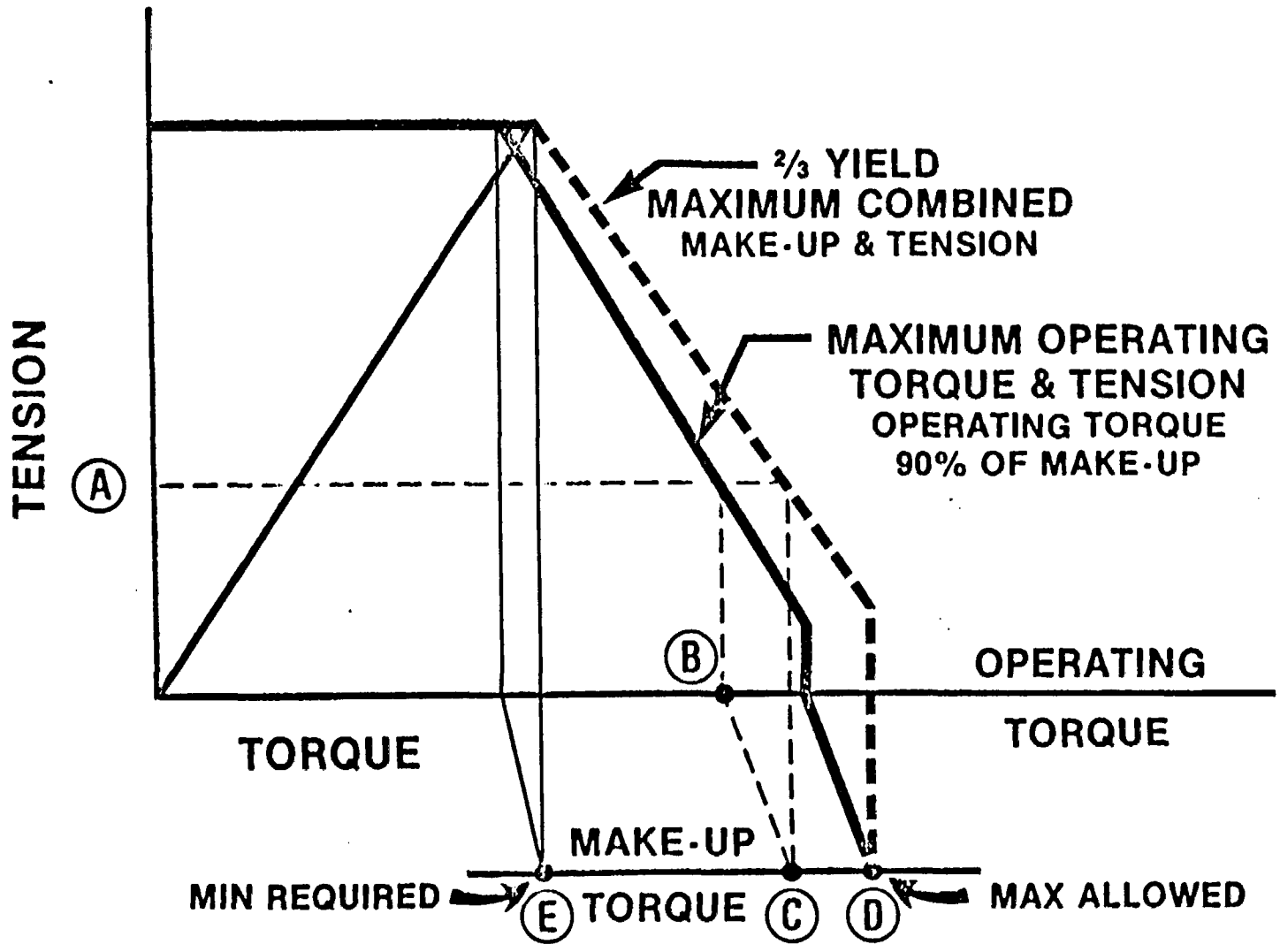


FIG. 9

FIELD TENSION-TORQUE LIMIT

OPERATING TORQUE 90% OF MAKE-UP TORQUE

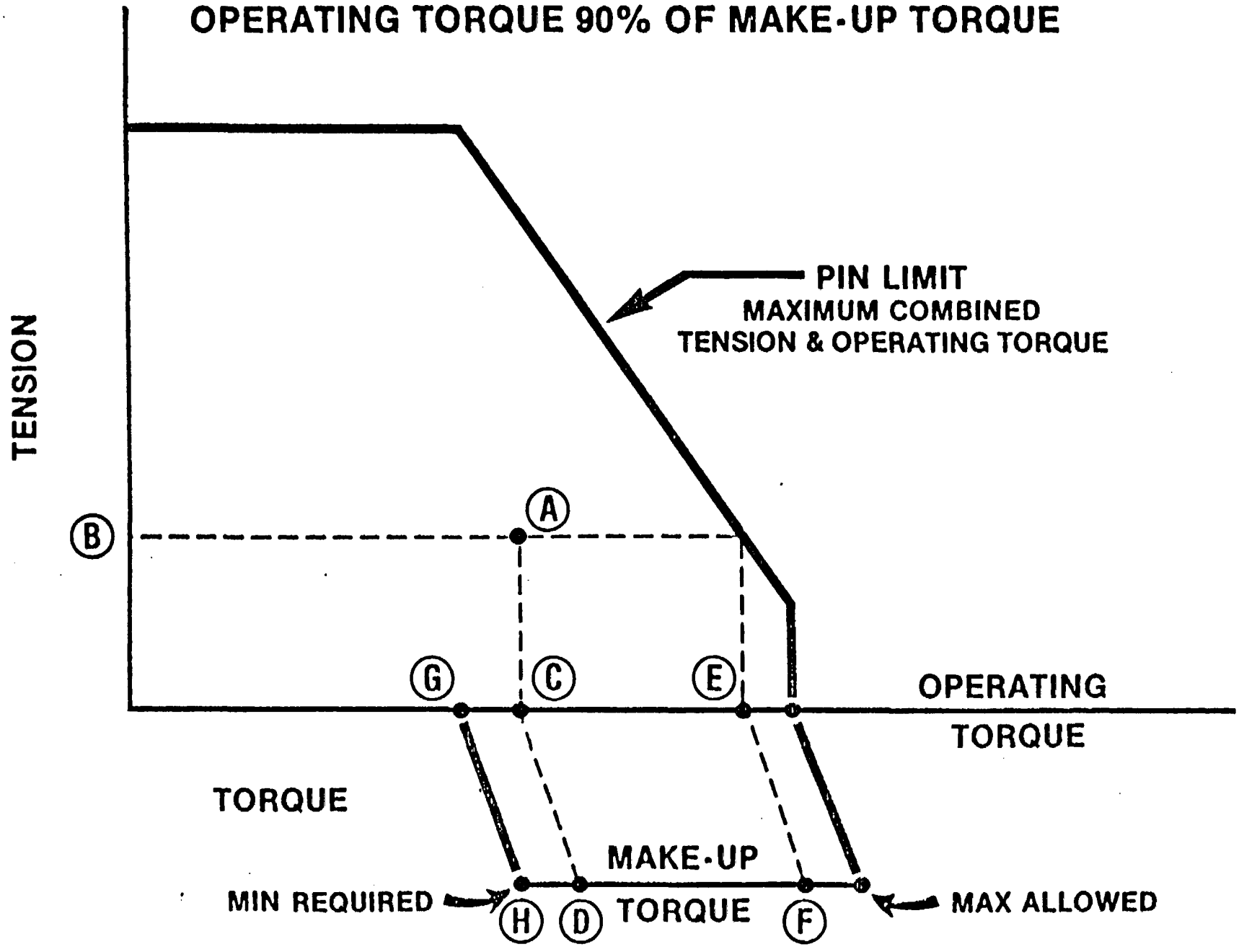


FIG. 10

FINAL LOR TENSION-TORQUE CONFIGURATION

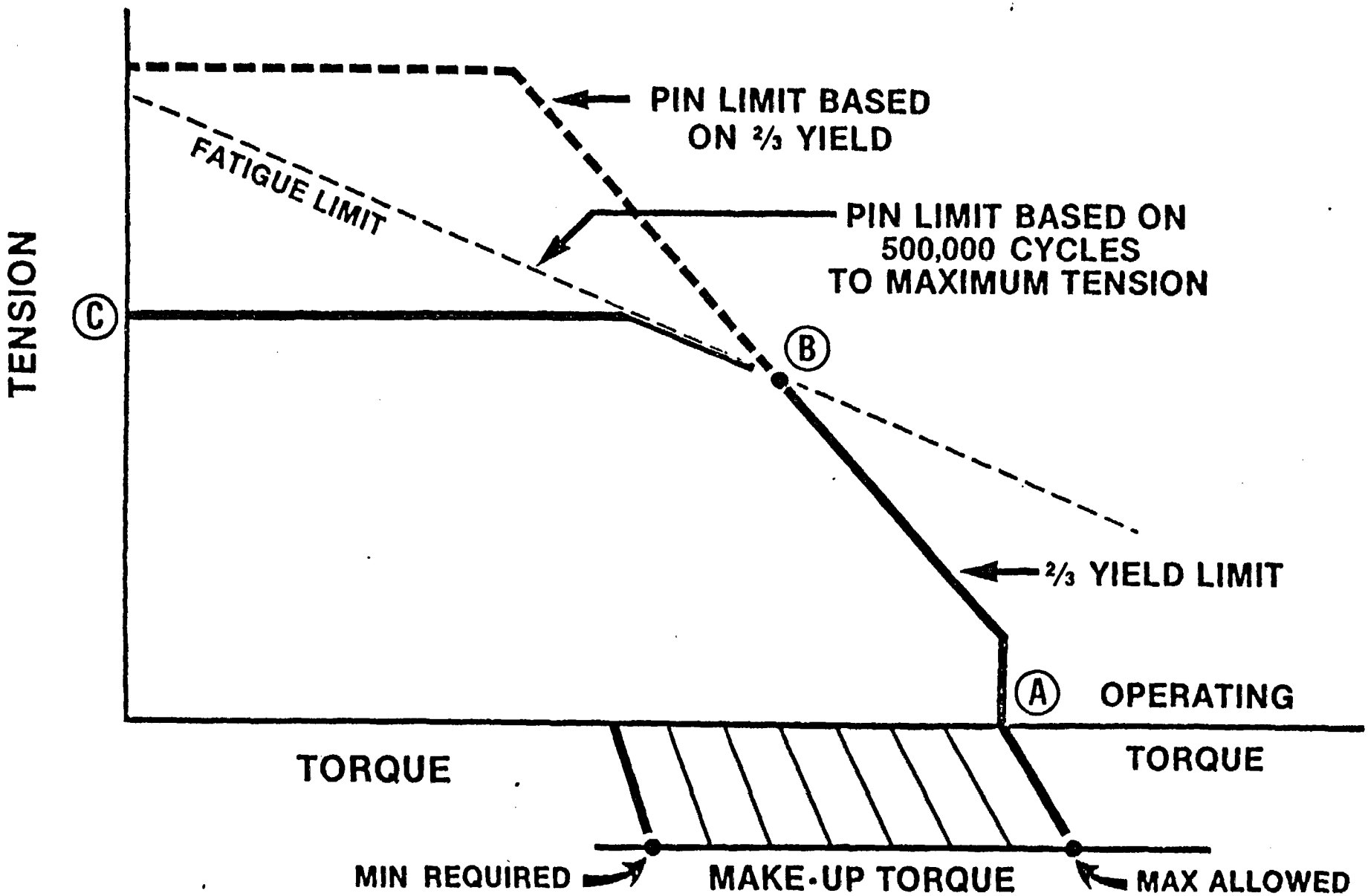


FIG. 11

TENSION VS. TORQUE

10" H.S. RAISE DRILL STEEL
8.25" LOR 215 CONNECTION

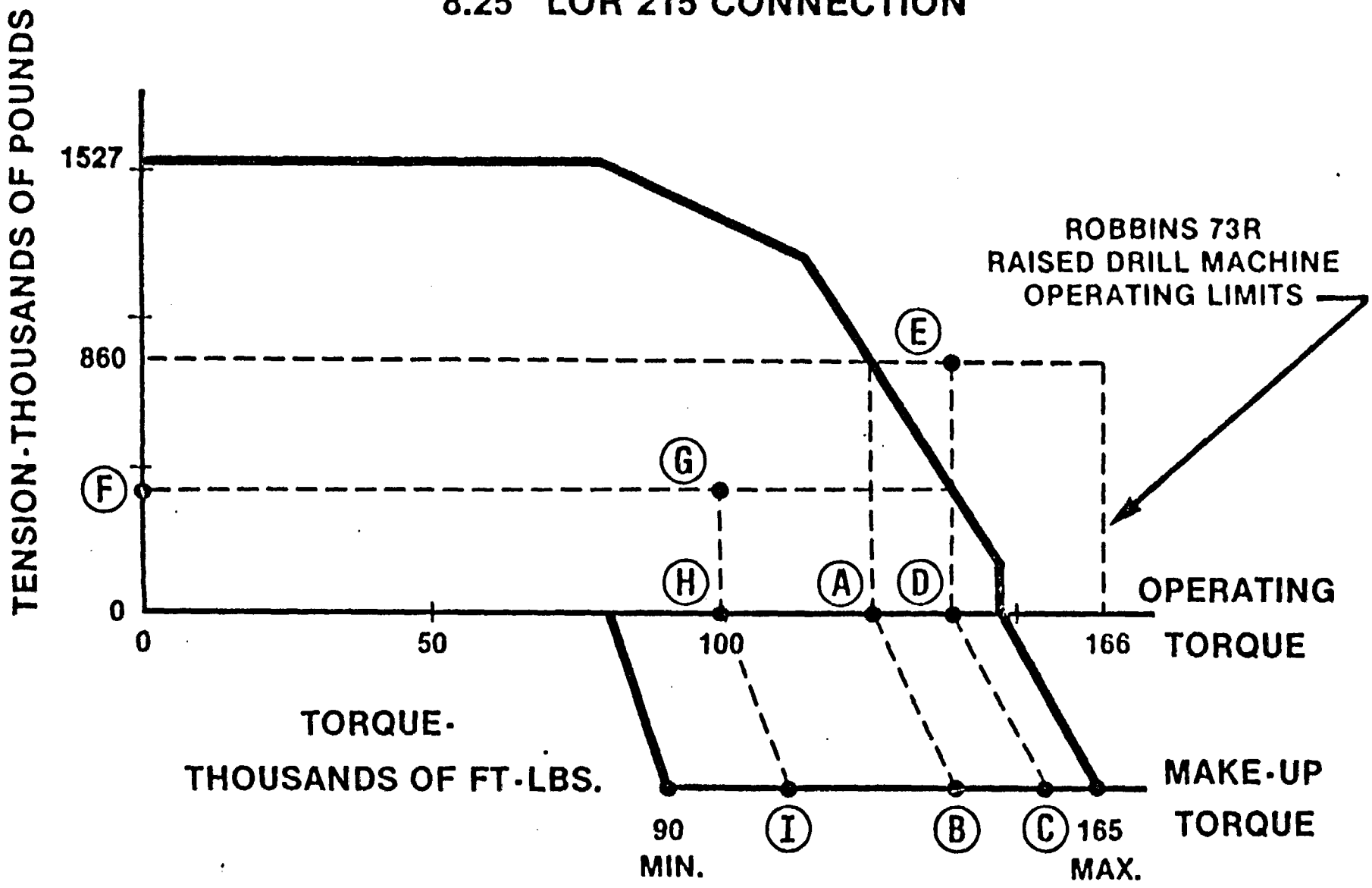


FIG. 12

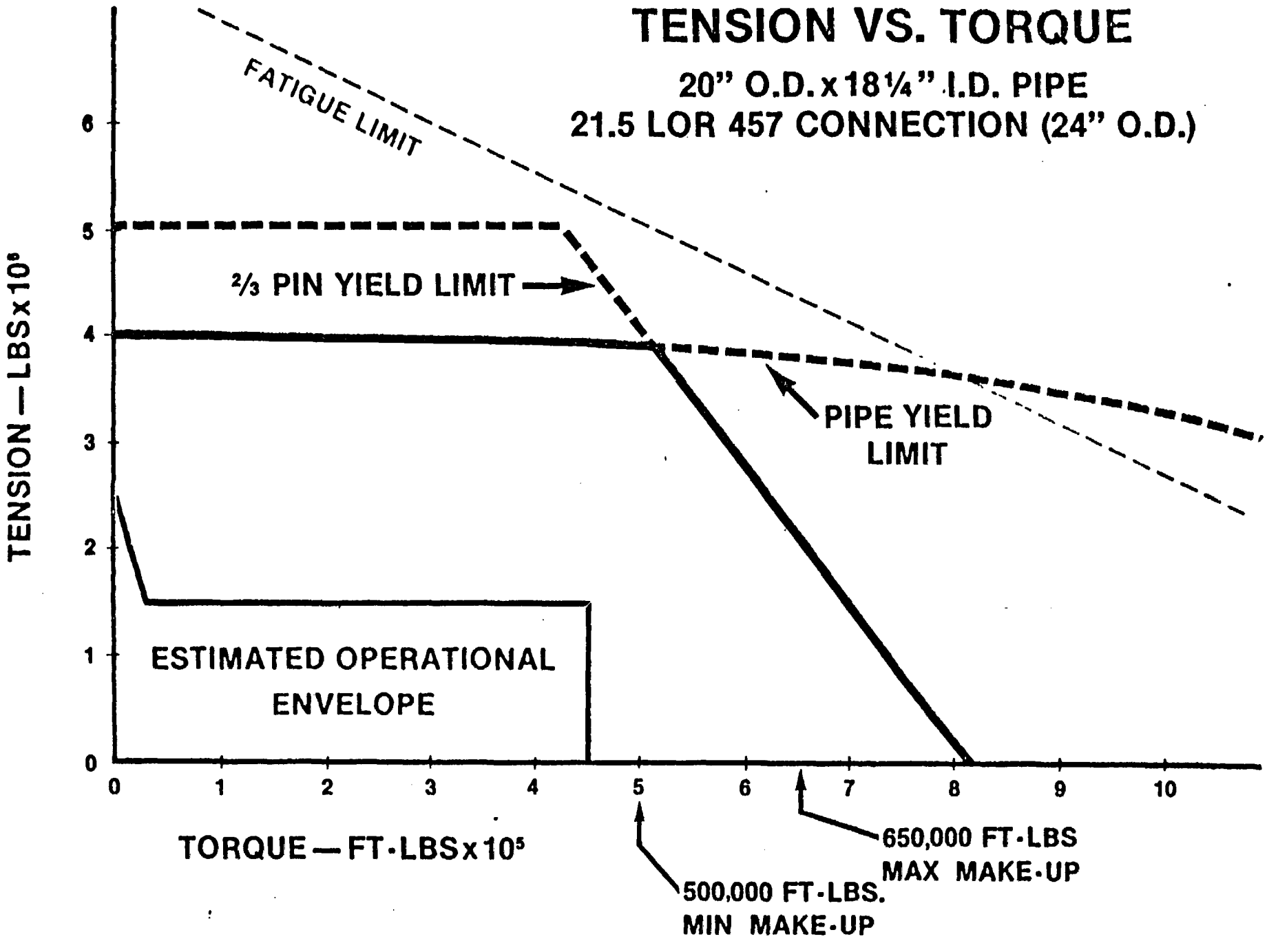

TENSION VS. TORQUE
20" O.D. x 18¼" I.D. PIPE
21.5 LOR 457 CONNECTION (24" O.D.)
FATIGUE LIMIT
⅔ PIN YIELD LIMIT
PIPE YIELD LIMIT
ESTIMATED OPERATIONAL ENVELOPE
TENSION — LBS x 10⁶
TORQUE — FT·LBS x 10⁵
0
1
2
3
4
5
6
7
8
9
10
500,000 FT·LBS. MIN MAKE-UP
650,000 FT·LBS MAX MAKE-UP

FIG. 13

EFFECT OF FRICTION ON MAKE-UP TORQUE

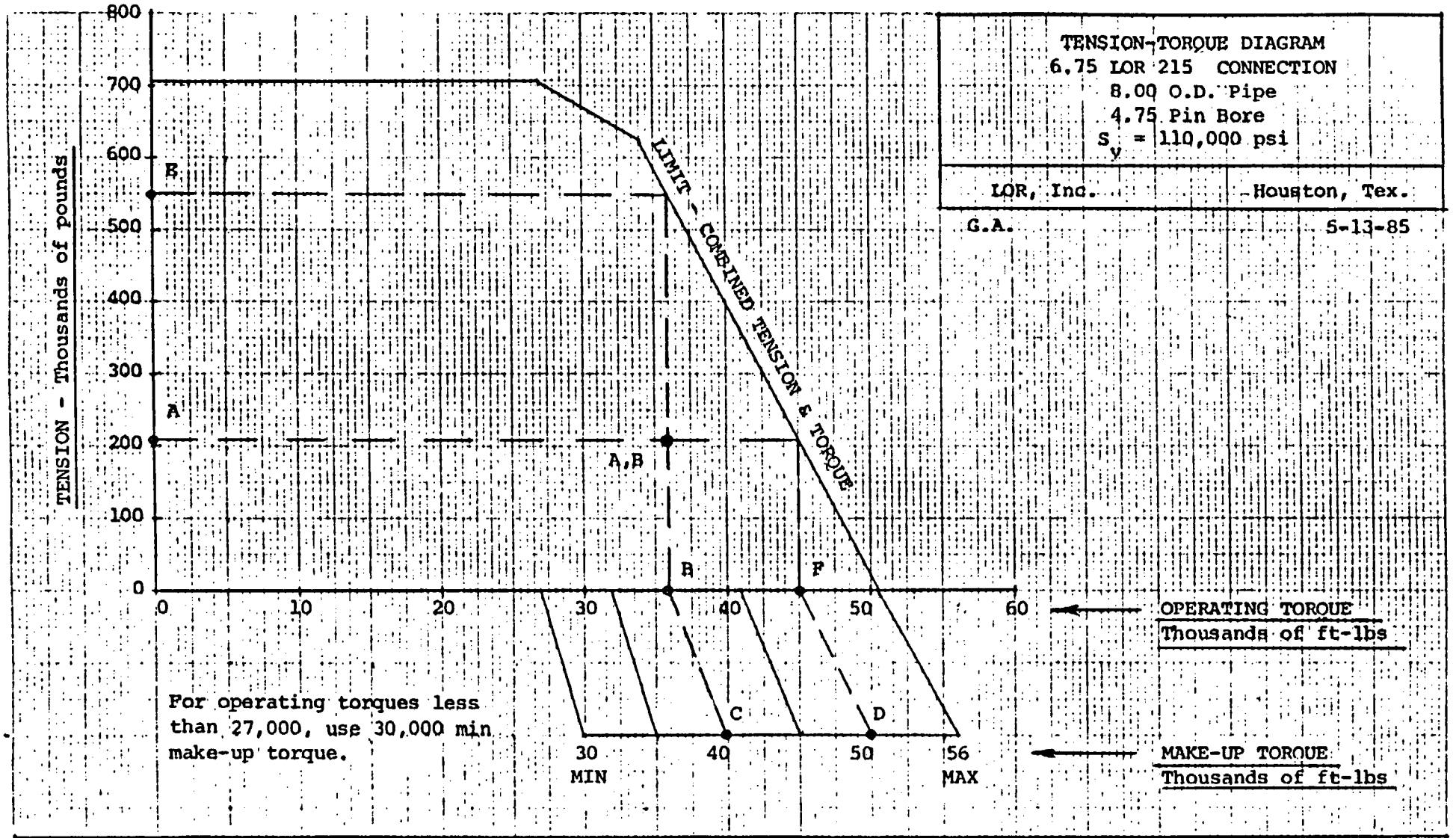
$$\text{TOTAL WORK} = \underset{\text{USEFUL WORK}}{} + \underset{\text{THREAD FRICTION}}{} + \underset{\text{SHOULDER FRICTION}}{}$$

$$\text{TORQUE} = SA \left(\frac{P}{2\pi} + \frac{R_t f}{\cos \theta} + R_s f \right)$$

19% 38% 43% (f = .08)

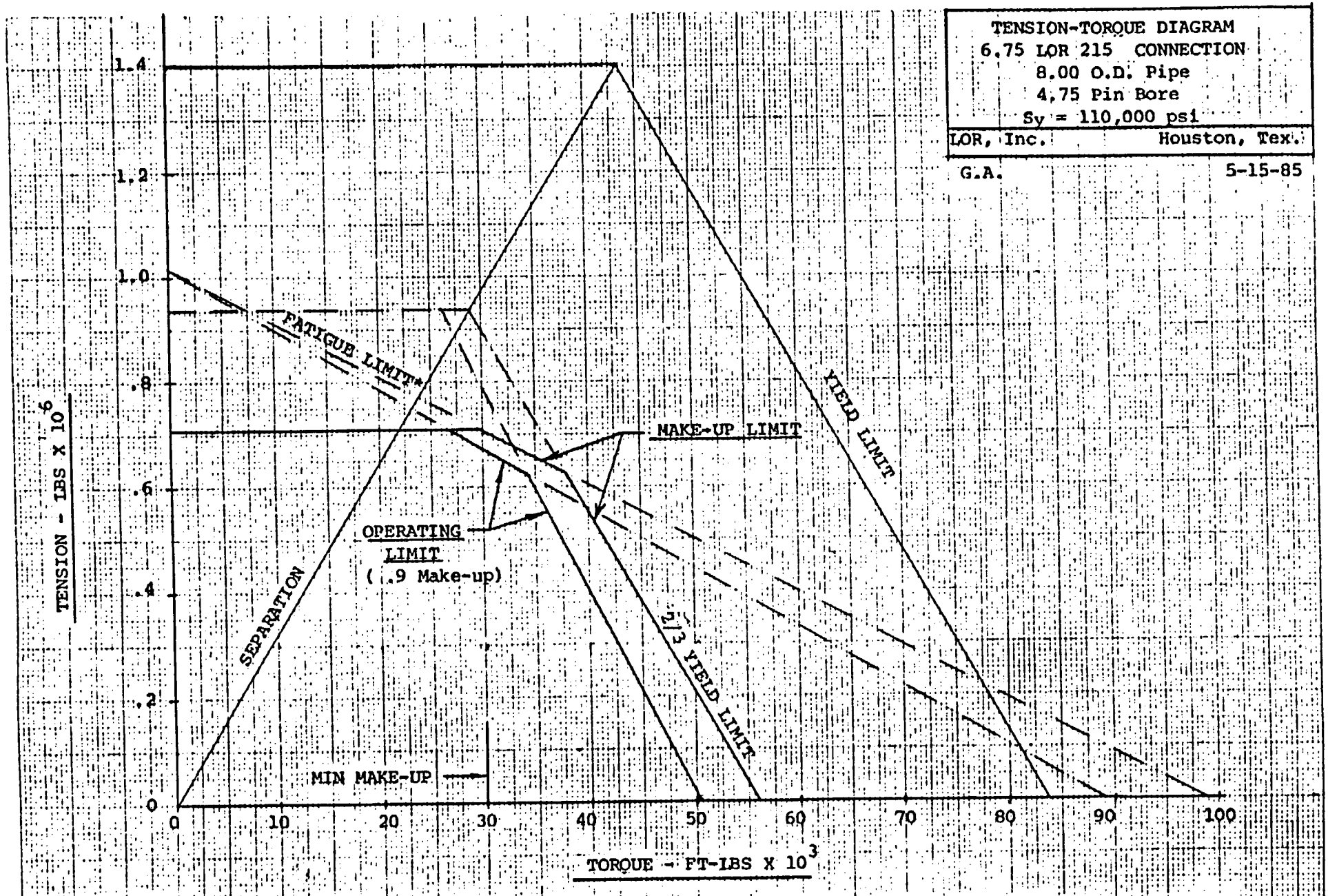
81%

FIG. 14

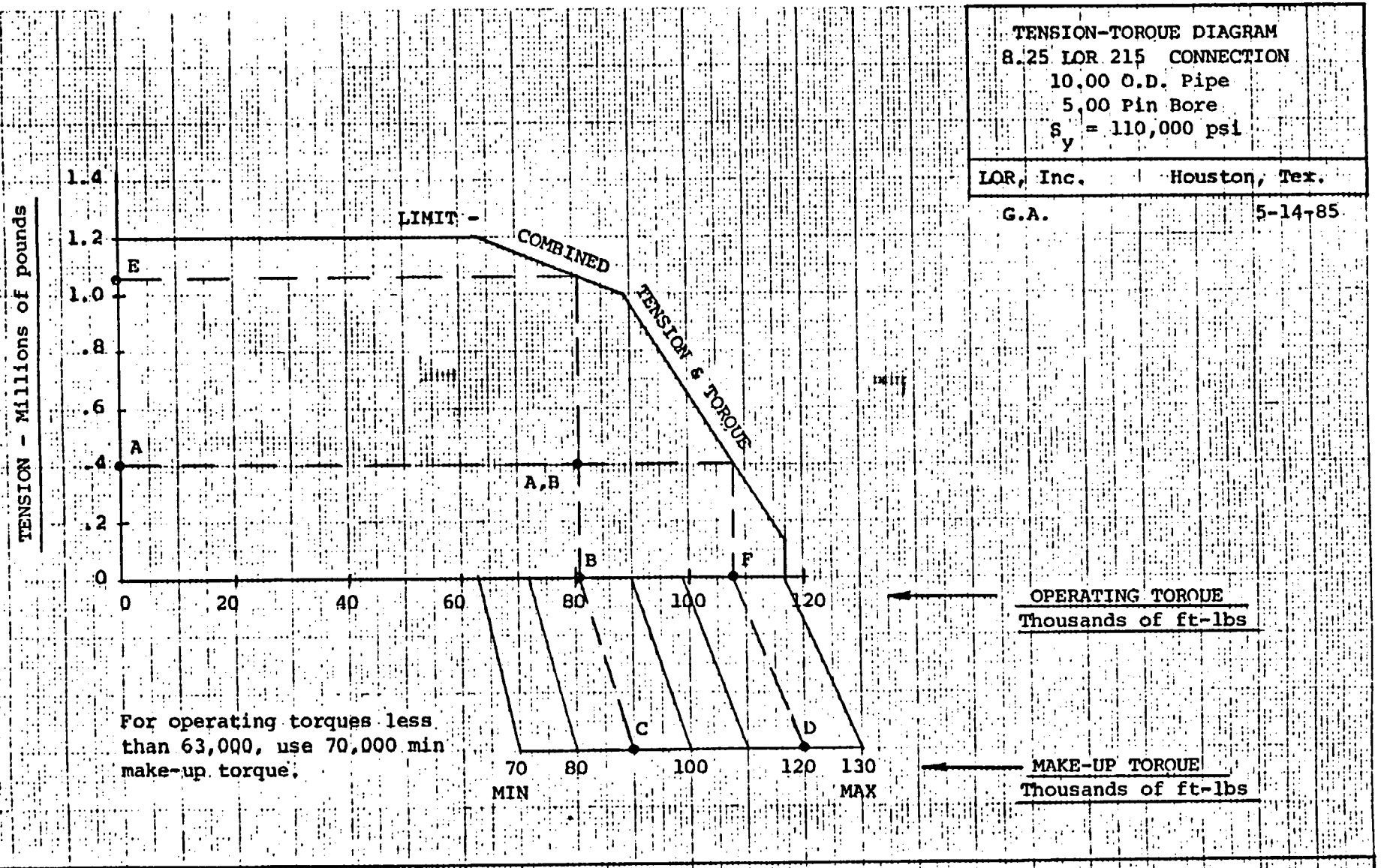


EXAMPLES:

1. To operate at tension A & torque B, min req'd make-up is C, Max allowed make-up is D.
2. With make-up C, max operating torque is B. Max permissible tension is E.
3. With make-up D, max operating torque is F. Max permissible tension is A.
4. If connection is first made-up to D and it is desired to operate at tension E, connection must be broken-out and remade to C. Torque is then limited to B.

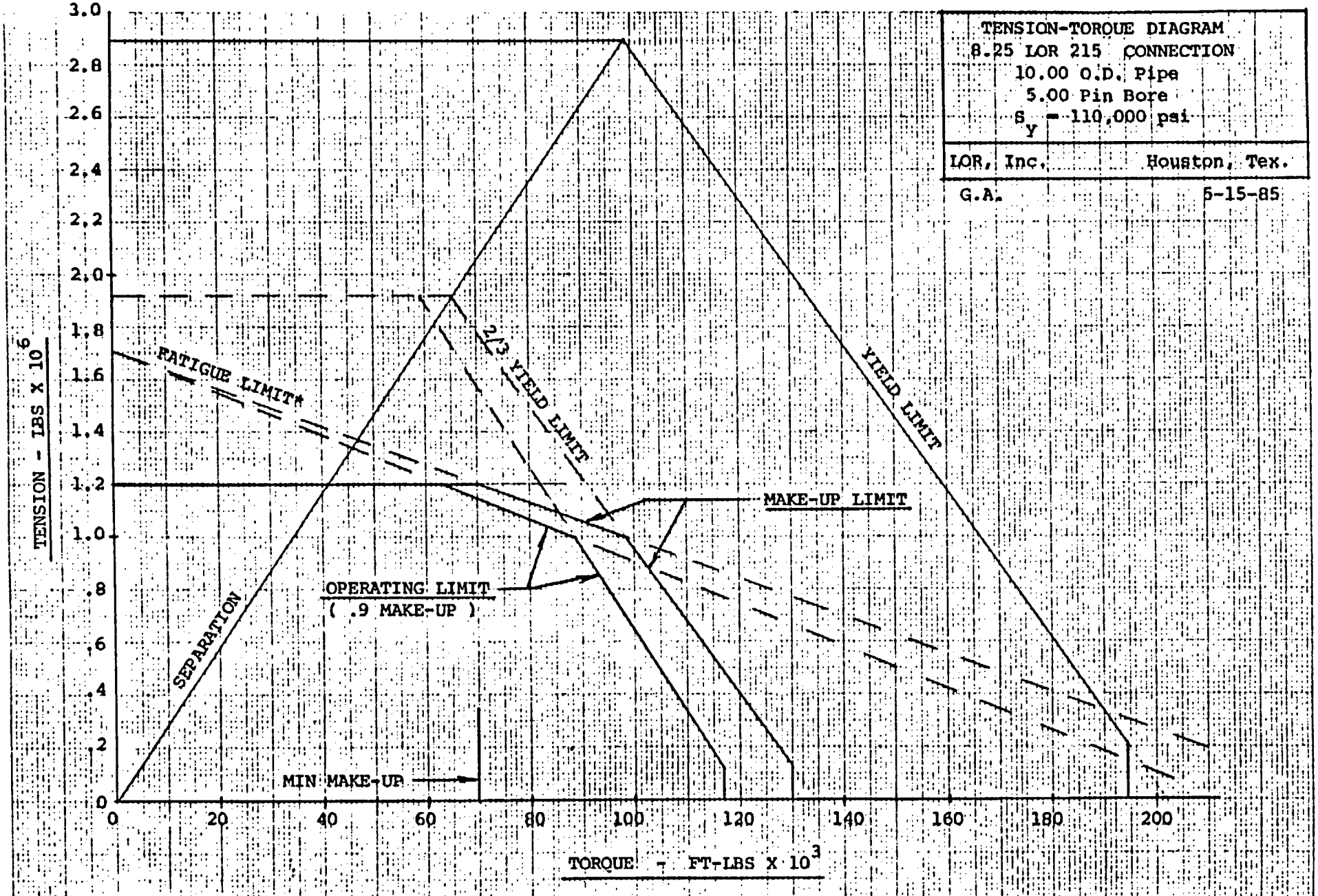


* FATIGUE LIMIT - Estimated fatigue strength based on 500,000 tension cycles from zero to max tension combined with limit make-up torque.

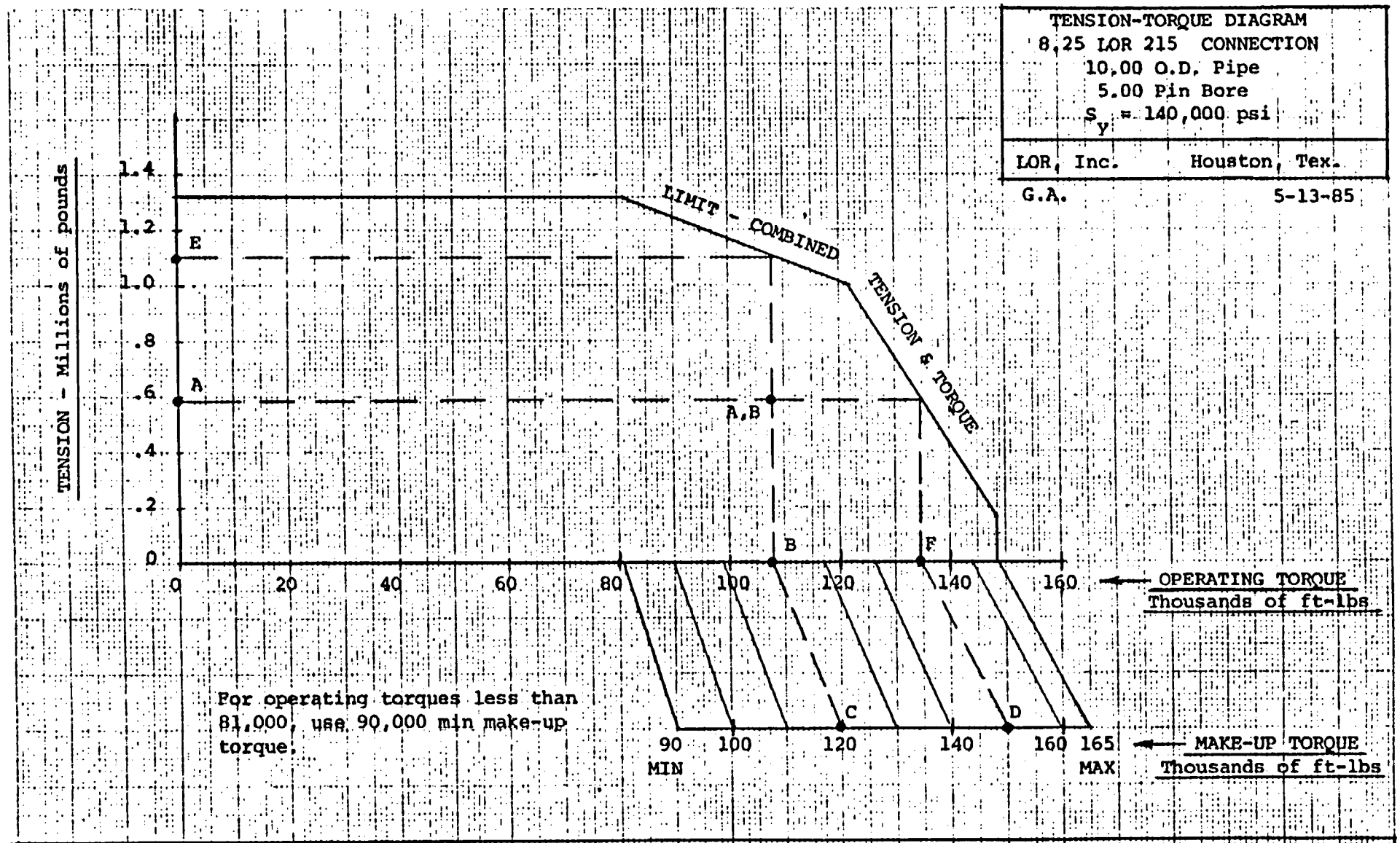


EXAMPLES:

1. To operate at tension A & torque B, min req'd make-up is C. Max allowed make-up is D.
2. With make-up C, max operating torque is B. Max permissible tension is E.
3. With make-up D, max operating torque is F. Max permissible tension is A.
4. If connection is first made-up to D and it is desired to operate at tension E, connection must be broken-out and remade to C. Torque is then limited to B.

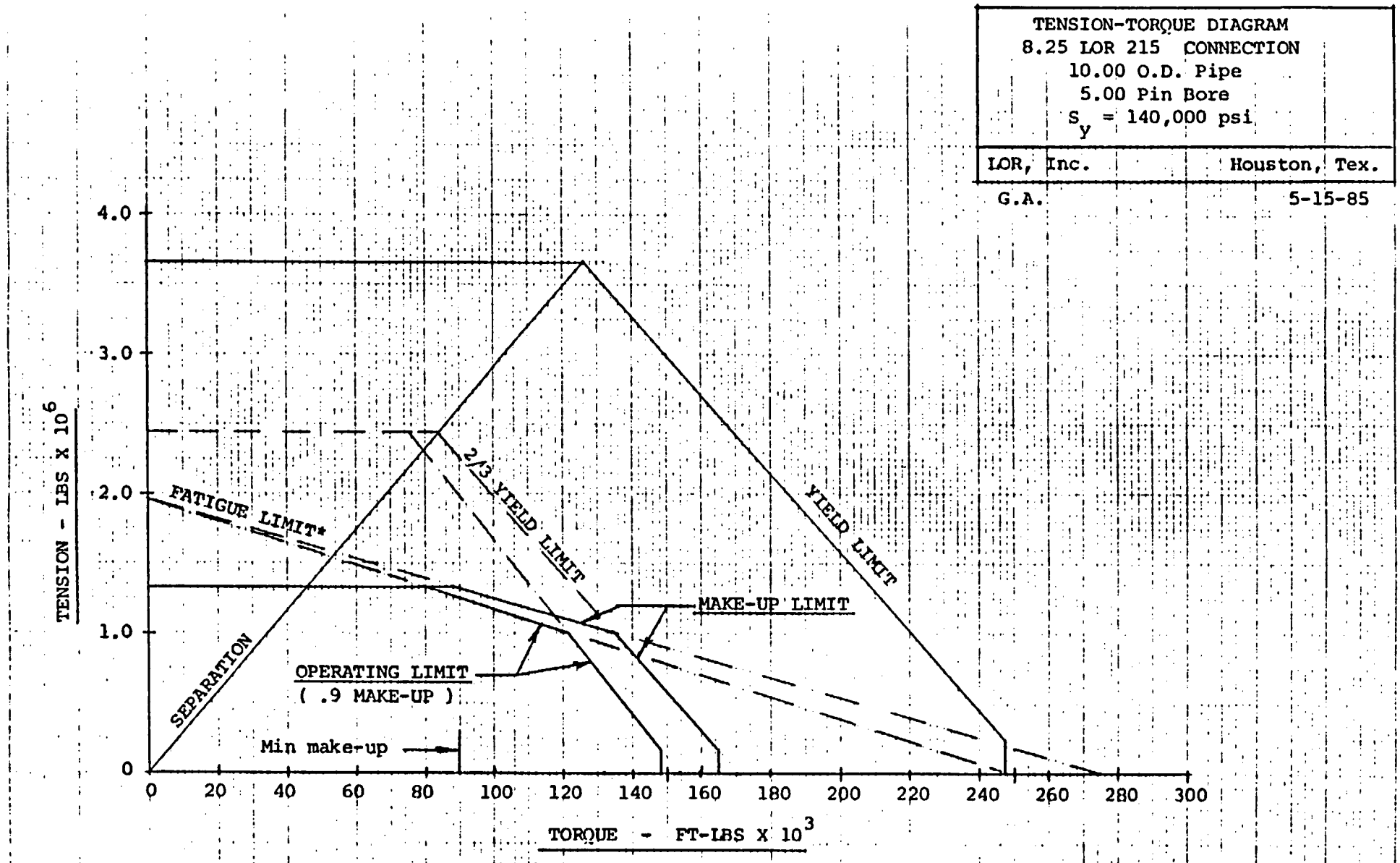


* FATIGUE LIMIT - Estimated fatigue strength based on 500,000 tension cycles from zero to max tension combined with limit make-up torque.

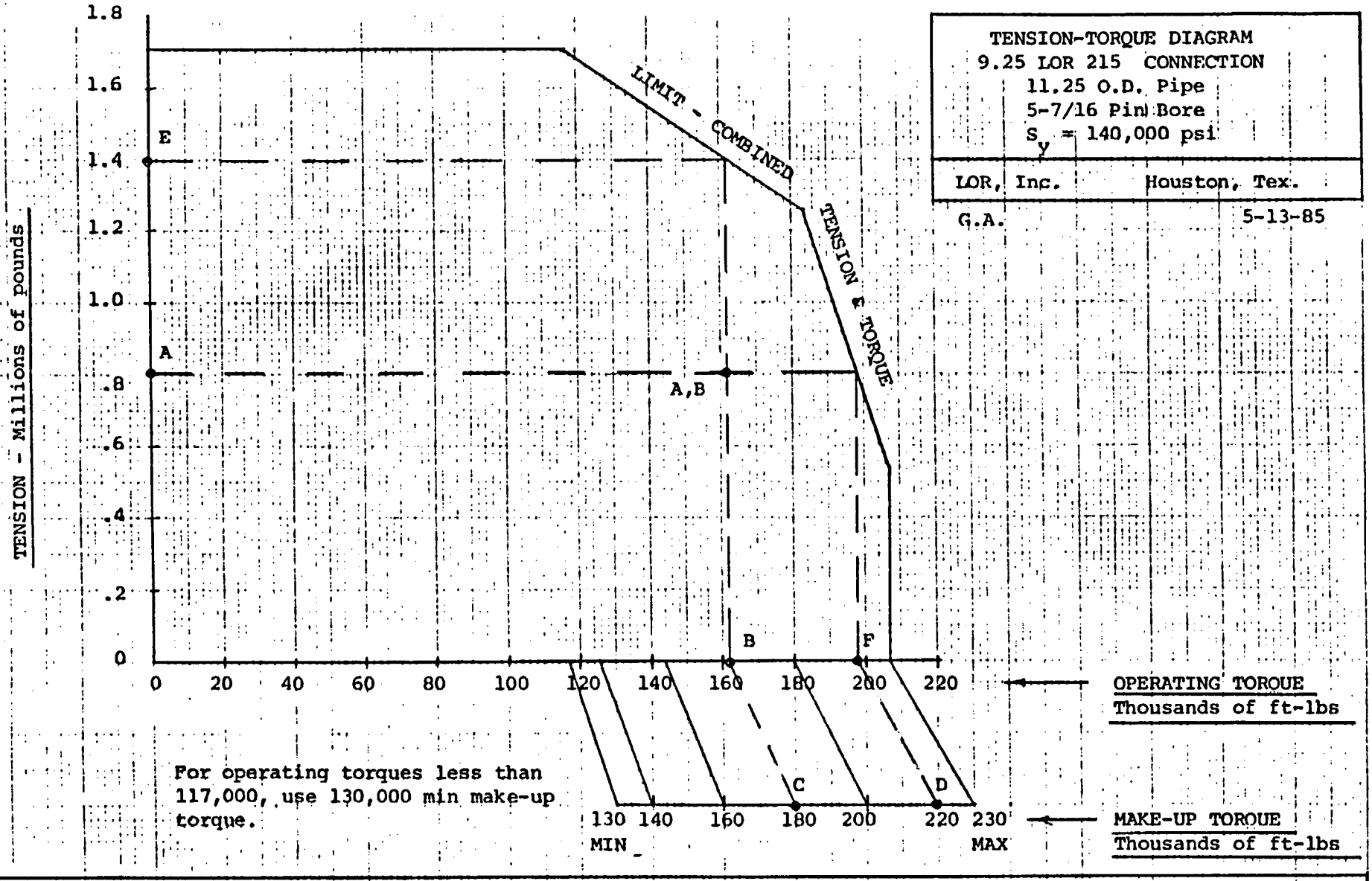


EXAMPLES:

1. To operate at tension A & torque B, min req'd make-up is C. Max allowed make-up is D.
2. With make-up C, max operating torque is B. Max permissible tension is E.
3. With make-up D, max operating torque is F. Max permissible tension is A.
4. If connection is first made-up to D and it is desired to operate at tension E, connection must be broken-out and remade to C. Torque is then limited to B.

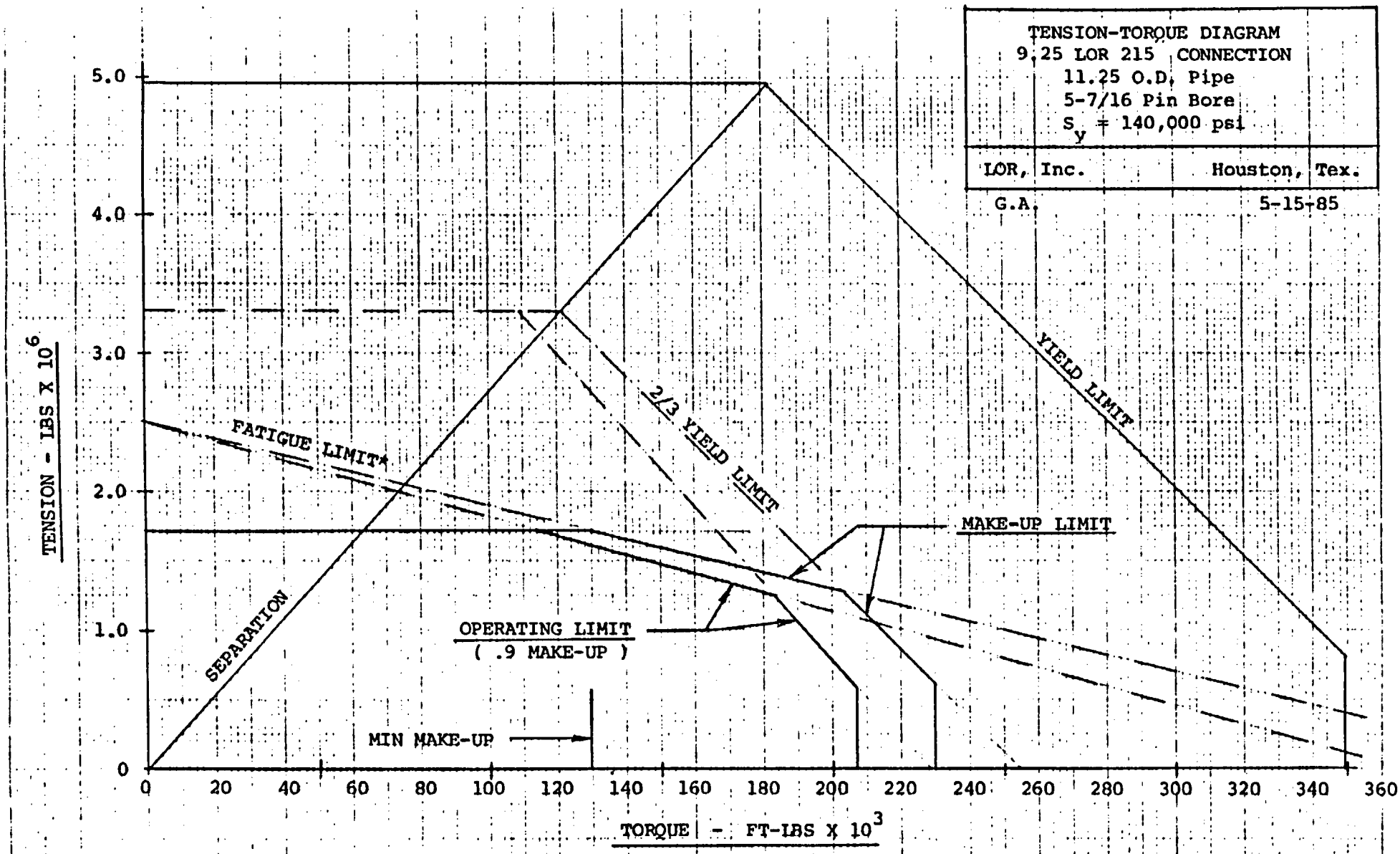


* FATIGUE LIMIT - Estimated fatigue strength based on 500,000 tension cycles from zero to max tension combined with limit make-up torque.

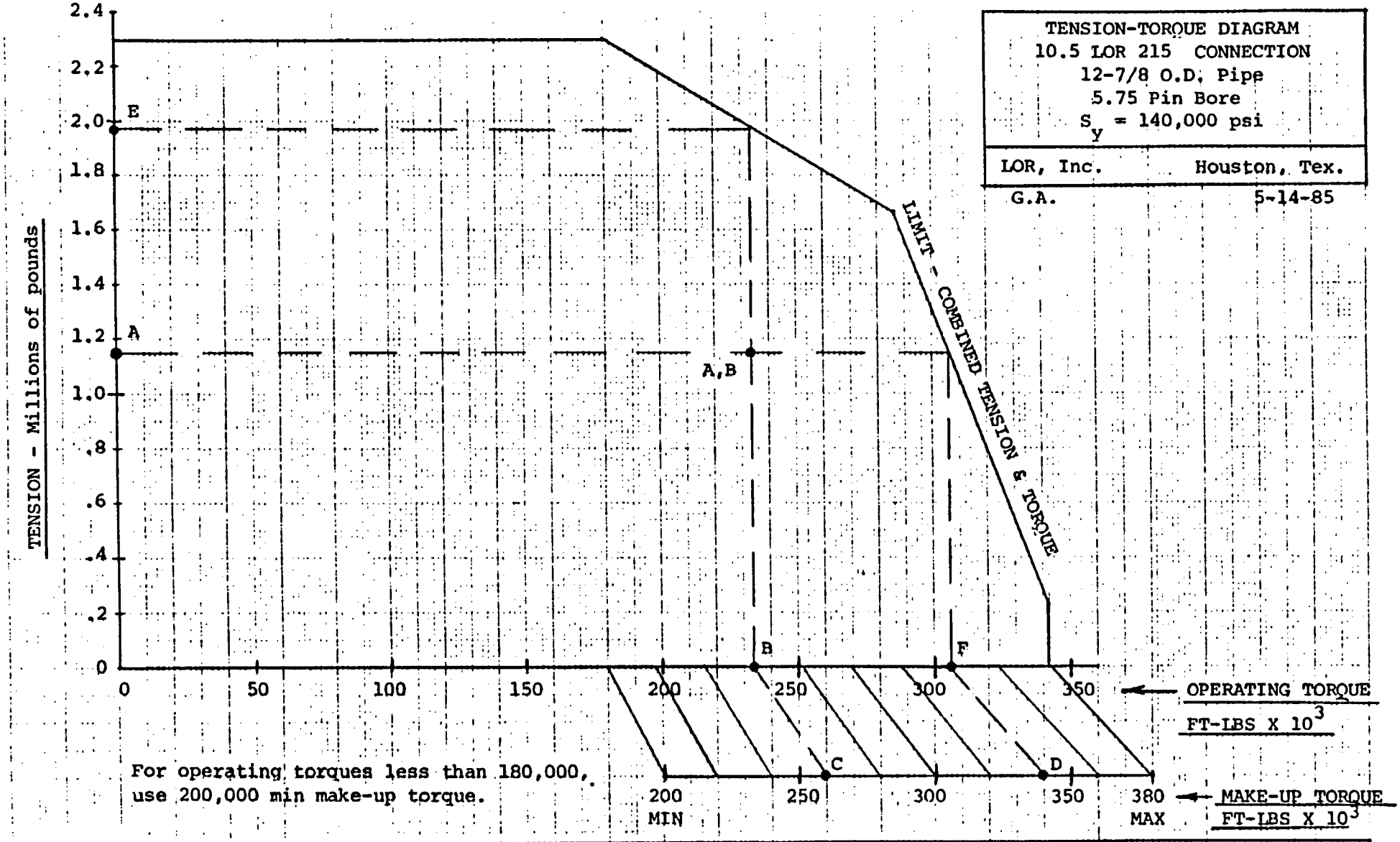


EXAMPLES:

1. To operate at tension A & torque B, min req'd make-up is C. Max allowed make-up is D.
2. With make-up C, max operating torque is B. Max permissible tension is E.
3. With make-up D, max operating torque is F. Max permissible tension is A.
4. If connection is first made-up to D and it is desired to operate at tension E, connection must be broken-out and remade to C. Torque is then limited to B.

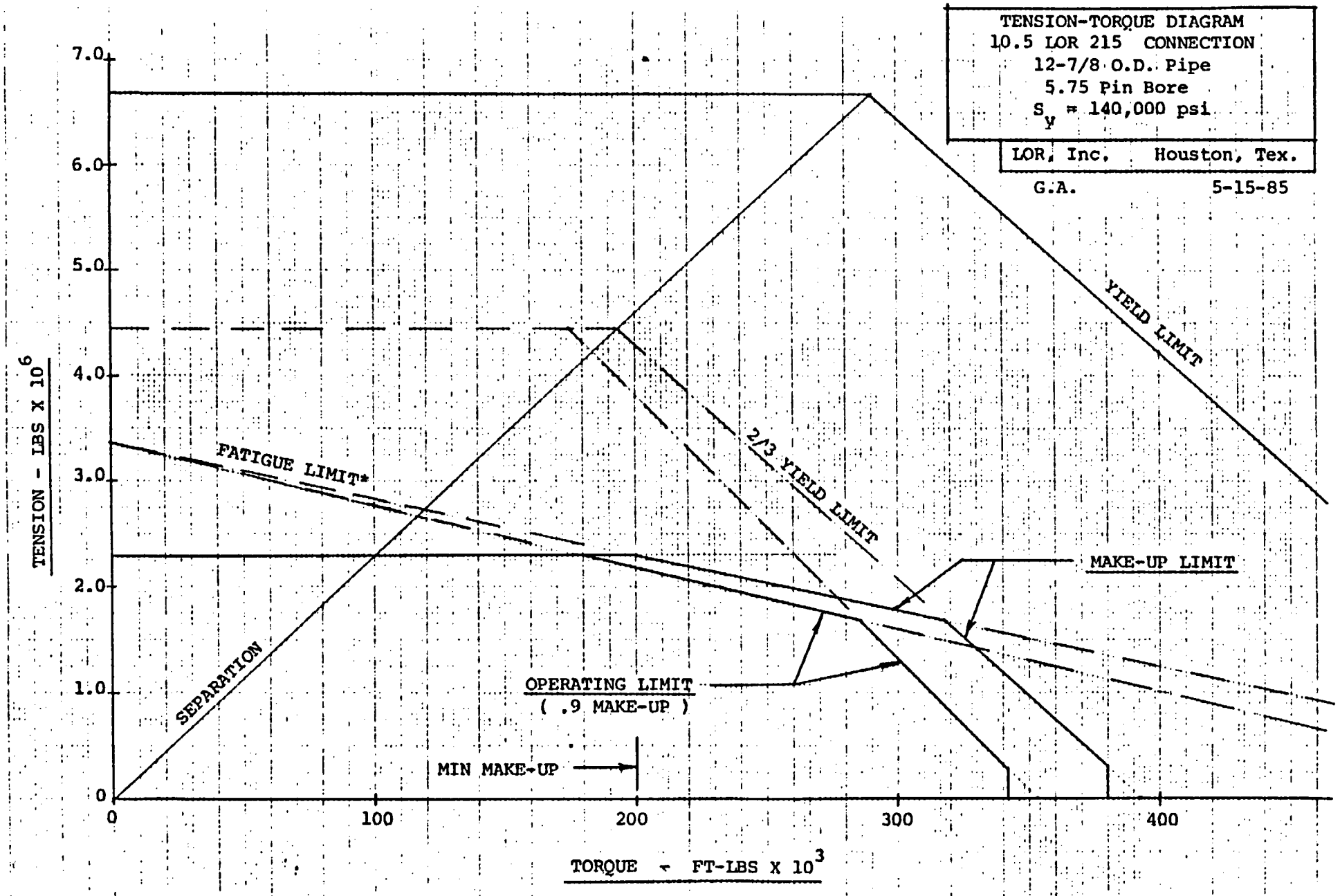


* FATIGUE LIMIT - Estimated fatigue strength based on 500,000 tension cycles from zero to max tension combined with limit make-up torque.



EXAMPLES:

1. To operate at tension A & torque B, min req'd make-up is C. Max allowed make-up is D.
2. With make-up C, max operating torque is B. Max permissible tension is E.
3. With make-up D, max operating torque is F. Max permissible tension is A.
4. If connection is first made-up to D and it is desired to operate at tension E, connection must be broken-out and remade to C. Torque is then limited to B.



* FATIGUE LIMIT - Estimated fatigue strength based on 500,000 tension cycles from zero to max tension combined with limit make-up torque.