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Analysis of Spread Mooring Systems for Floating Drilling Units

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Foreword

The purpose of this document is to present a rational method for analyzing, designing or evaluating spread mooring systems used with floating drilling units. This method provides a uniform analysis tool which, when combined with an understanding of the environment at a particular location, the season of the year, the characteristics of the unit being moored, the type of hole being drilled, and other factors, can be used to determine the adequacy and safety of the mooring system. Although portions of the method may be useful in analyzing other types of mooring systems, its application to the design of mooring systems for lay barges, tankers, derrick barges, dredges, etc., is left to the discretion of the user.

The technology of mooring floating drilling units is continually evolving. This procedure is a compilation of those factors which are best understood and can be quantified at this time. It is felt that the method encompasses most of the major considerations known at this time. Conversely, designers or analysts should not construe that the omission of any particular phenomenon, calculation or other consideration from this document implies that it may not be significant for a particular situation. It is recognized that data can be, and is, appropriately developed from model tests. Wind, wave, and current tank data are routinely used in design and analysis. The utilization of data from model tests is encouraged when it clearly represents accurate information describing a phenomenon more precisely than the analytic method herein presented. It is further recognized that in special circumstances where precise environmental conditions, mooring loads, or mooring component design data are understood, the methodology and/or safety factors implied in this recommended design practice may not be appropriate.

Additionally, sophisticated computer analysis methods are being developed and employed in the industry.

These are also recognized as valuable contributions to the understanding of mooring systems.

But it is further the purpose of this document to present an analysis method which can be used by properly qualified people who may not have access to proprietary model tests or computer programs.

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SECTION 1
BASIC CONSIDERATIONS AND DATA REQUIREMENTS

1.1 Basic Considerations. Drilling operations require that horizontal displacement of the drilling vessel be restricted within a small radius of the wellbore centerline, primarily to protect the riser and the lower ball joint. The allowable vessel displacement from the wellbore should be determined by analysis of the drilling riser. Procedures described in API RP 2Q, "Design and Operation of Marine Drilling Riser Systems," should be used to determine allowable offsets for the drilling vessel. Generally speaking, the drilling vessel should be maintained within a watch circle with radius in the range of 3 to 6 percent of water depth when drilling is proceeding. This radius can be increased to 8 to 10 percent of water depth when drilling is suspended and the drilling riser is still connected to the seafloor. Should the riser be disconnected from the seafloor, there is no restriction on the size of the watch circle.

The analysis method presented assumes that all equipment is either new or in a like-new condition and has not been subjected to loading which would affect its fatigue life. The proper maintenance and careful inspection of all equipment is strongly encouraged. The recommended design procedure presupposes that winches, wildcats, fairleaders, pendants, buoys, etc., are also properly sized and in good working order.

Mooring systems should be properly deployed. Competent personnel with proper equipment should be utilized. Instrumentation for determining the amount of line out, tension in the lines, exact location of anchor drop points, etc., can be very valuable during the deployment of a mooring system. As part of the process of installing a mooring system, the mooring lines should be routinely tested. Mooring lines should be tensioned to values which represent the maximum expected value for the particular location. Lines which do not achieve this value should be reset and if necessary additional anchoring equipment should be added.

1.2 Purpose of Mooring Analysis. A floating drilling vessel held on location with a spread mooring is shown in Figure 1. When wind, current and waves act on the vessel, the total environmental force (F) pushes the rig a distance (x) away from its initial position over the hole. The vessel comes to an equilibrium position when the mooring develops a net restoring force equal to the steady-state environmental force.

As shown in Figure 1, wind, waves, and current induce movement of the vessel away from the wellbore and increase the tension in the windward mooring lines while decreasing tension in the leeward lines. Each mooring should be analyzed to ensure that developed tension (T_{max}) does not exceed the maximum safe working load and that the load placed on the anchor (A_{max}) does not exceed its holding power. The holding power of an anchor is significantly reduced when the anchor is subjected to a vertical load. To completely avoid vertical loads, the length of mooring line outboard of the fairlead (L_{max}) must be long enough to allow the line to remain tangent to the sea bottom at the anchor during periods of the highest expected line tensions. Also, the vessel movements should be kept within certain limits that can be tolerated by the drilling riser.

A mooring analysis is often performed in conjunction with a riser analysis to determine:

- Limiting environments for operating and survival conditions
- Recommended mooring pattern
- Required length of mooring line outboard of the fairlead
- Initial line tension
- Test load requirements for anchor
- Piggyback anchor requirements
- Operational concerns such as the need for slackening the leeward lines during a storm
- Special details such as the clearance between a mooring line and a nearby pipeline

1.3 Definitions. The industry recognizes four classifications of environmental conditions when evaluating mooring systems.

a. **Maximum Environmental Condition.** The maximum environmental condition for a given location and time period is defined as that combination of wind velocity, wave height and period, water depth and current velocity that will create the largest force on a fixed permanent structure. These values are generally the criteria used for designing fixed, permanent structures. They may not be the same values used for a floating drilling unit since it retains the option to leave location before these conditions develop.

b. **Maximum Design Condition.** The maximum design condition is defined as that combination of wind velocity, wave height and period, current velocity, water depth and vessel offset for which the mooring system is designed. Generally the drilling unit will likely be disconnected from seafloor drilling equipment as required so that large values of offset can be tolerated. The magnitude of these values should be known to those people responsible for the drilling unit's operation in order that abandonment of location can be achieved in a timely fashion. Generally these values will be equal or less than the values described in 1.3a above. The maximum design condition is the concurrent collinear combination of the design wind, design wave and design current.

c. **Maximum Operating Condition.** The maximum operating condition is defined as that combination of wind velocity, wave height and period, water depth, current and offset up to which the drilling unit can be expected to sustain drilling operations. These values should be known to the people responsible for the drilling unit's operations in order that timely plans to suspend operations can be performed. Generally these conditions will be less than those described in 1.3a or 1.3b above.

d. **Maximum Connected Condition.** The maximum connected condition is defined as that combination of wind velocity, wave heights and period, water depth, current and offset up to which the drilling unit can be expected to hold location with the riser connected to the BOP stack. Generally these conditions will be equal to or less than those described in 1.3a and 1.3b but are greater than those described in 1.3c.

1.4 List of Symbols

F_w = Wind Force

A = Vertical Projected Area

C_s = Wind Shape Coefficient

C_h = Wind Height Coefficient

V_w = Wind Speed

C_w = Wind Force Coefficient

F_{cx} = Current Force on the Bow

C_{cx} = Current Force Coefficient on the Bow

S = Wetted Surface Area

V_c = Surface Current Speed

F_{cy} = Current Force on the Beam

C_{cy} = Current Force Coefficient on the Beam

F_{cs} = Current Force on a Semisubmersible Hull

C_{ss} = Current Force Coefficient on a Semisubmersible Hull

A_c = Projected Area of Cylindrical Members

A_f = Projected Area of Flat Members

C_d = Current Drag Coefficient

F_{mdx} = Mean wave drift force on the bow

$(F_{mdx})_{REF}$ = Mean wave Drift Force on the bow for reference ship.

F_{mdy} = Mean Drift Force on the Beam

$(F_{mdy})_{REF}$ = Mean wave drift Force on the beam for reference ship

L = Length of ship

L_{REF} = Length of reference ship

H_s = Significant Wave Height

$(H_s)_{REF}$ = Reference significant wave height

x_s = RMS single amplitude low frequency surge

y_s = RMS single amplitude low frequency sway

$(x_s)_{REF}$ = RMS single amplitude low frequency surge of reference ship

$(y_s)_{REF}$ = RMS single amplitude low frequency sway of reference ship

k = Mooring system spring stiffness at mean offset position

$(x_s)_{1/3}$ = Significant single amplitude low frequency surge

$(y_s)_{1/3}$ = Significant single amplitude low frequency sway

$(x_s)_{max}$ = Maximum single amplitude low frequency surge

$(y_s)_{max}$ = Maximum single amplitude low frequency sway

F_R = Rayleigh factor

T_N = Natural period of surge or sway for the vessel/mooring system

Δ = Displacement of vessel

$S(\omega)$ = Ordinate of wave spectrum ft^2 sec (m^2 sec)

ω = Wave Frequency

C_1, C_2, C_3, C_4 = Wave Spectrum Coefficients

T_s = Significant wave period

$F\phi$ = Steady State Force for Quartering (45° off the bow or stern) Seas

F_x = Steady State Force for Bow or Stern Seas

F_y = Steady State Force for Beam Seas

ϕ = Direction of the Force, F, Relative to the Bow or Stern

z = Wave frequency motion due to quartering environment, ft (m)

x = Surge due to bow waves, ft (m)

y = Sway due to beam waves, ft (m)

φ = Arctan (y/x)

P_{cw} = Chain or Wire Rope Holding Power

f = Coefficient of Friction

L_{cw} = Length of Chain or Wire Rope on Bottom

w_{cw} = Submerged Weight of Chain or Wire Rope Per Unit Length

T = Tension in mooring line

δ_c = Elastic stretch of chain

D_c = Nominal chain diameter

S_c = Chain length

δ_w = Elastic stretch of wire rope

D_w = Nominal diameter of wire rope

S_w = Wire rope length

β = Coefficient for submerged weight of mooring line

X, Y = Coordinates of Mooring Line Catenary

s = Arc Length of Mooring Line Catenary

P_h = Horizontal Force in Mooring Line Catenary

1.5 Environmental Design Criteria

a. **Wind.** The design wind speed should be determined based on the statistical wind speed distribution for the most severe environment in which the mooring system must operate. Figure 2 illustrates a typical statistical wind speed distribution curve. Curves similar to Figure 2 are obtained from field data by plotting the cumulative probability versus wind speed, V_w, where the cumulative probability is the probability of a measured wind speed being equal to or less than V_w. It should be noted that a cumulative probability of 0.99 for a given V_w does not imply a 100-year storm condition. It does mean that for the specific population of wind speeds corresponding to the given site and the anticipated seasons of operation, only one percent of the time the wind speed will exceed V_w.

The design wind speed for use in the formulas of Section 3.2 should be selected in accordance with the following criteria:

(1) The average wind speed over a one-minute interval should be used.

(2) The wind speed should pertain to an elevation of 10 meters above still water level.

(3) The cumulative probability for the design wind speed should be 0.999.

(4) The design wind speed should be selected for the most severe season during which operations are to be conducted at a given site.

Figure 2 illustrates the method of determining the design wind speed from the statistical wind speed data. Wind speed data used to generate the distribution curve should include available measured data and storm hindcast data as well as ship's observations.

b. **Waves.** The design wave height should be determined based on the statistical wave height distribution for the most severe environment in which the mooring system must operate. Figure 3 illustrates a typical wave height distribution curve. Curves similar to Figure 3 are obtained from field data by plotting the cumulative probability versus significant wave height, H_s, where the cumulative probability is the probability that the significant wave height for an observed sea state will be equal to or less than H_s.

The design sea state is characterized by the design wave height. The design wave height should be selected in accordance with the following criteria:

(1) The cumulative probability for the design wave height should be 0.999.

(2) The design wave height should be the significant wave height for the design sea state, i.e., the average of the one-third highest waves.

(3) The design sea state should be selected for the most severe season during which operations are to be conducted at a given site.

Figure 3 illustrates the method of determining the design wave height from the statistical wave height data. The wave height data used to generate the distribution curve should include available measured data and storm hindcast data as well as ship's observations. The wave height versus wave period relationships for the design sea state should be accurately determined from oceanographic data for the area of operation. The period can significantly affect surge and sway amplitudes and mean drift forces. For cases where measured data are not available, Figure 4 provides characteristic wave period versus wave height relationships for wind generated waves and for predominant swell conditions.

c. **Currents.** Accurate data for the magnitude, direction, and seasonal variation of surface currents should be obtained for the area of operations. Based on this data the current speed for design and operating conditions should be selected.

d. **Ice Conditions.** Normally the hulls of floating drilling units are not designed to resist to ice loading in the moored condition.

e. **Basis and Special Consideration for the Environmental Design Criteria.** The two commonly used methods to designate the severity of a design environment are:

(1) The cumulative probability method which specifies the percentage of time during the average year that the environment (seas, wind, or current) will not exceed a given level; and

(2) The return period method which specifies the average recurrence interval between the occurrence of a given environment.

The cumulative probability method has been adopted by API RP 2P and a 99.9% probability of nonexceedance is specified as the maximum design environment for mobile drilling units.

As a point of comparison, a storm with a 100-year return period is often specified as the design environment for fixed platforms, floating production platforms, and floating units operating next to other offshore installations. However, it would be unduly conservative for mobile drilling units to use the 100-year environment for the reasons explained below.

There is, in general, no direct correlation between the return period and the probability of nonexceedance. However, for any given location, reasonable assumptions about the storm duration and the environmental data base would generally result in a 99.9% environment being considerably lower than the 100-year environment. The selection of the 99.9% environment is based on the operational experience of the offshore industry. This, we believe, is a sufficiently conservative design environment for mooring analysis of mobile drilling units for two reasons. Firstly, the analysis technique presented in Section 5.2 accounts for collinear environmental forces. However, when extreme environments are encountered, the winds and waves are generally collinear, but the currents may not necessarily be collinear with wind and waves.

Secondly, since these units are normally not operating in close proximity to other offshore structures, the consequences of vessel movement due to overloading the mooring system under an extreme environment are less severe than those associated with overloading fixed platforms or floating units which are nearby other structures. Also, since the anchor holding capacity of a mooring system is normally substantially lower than the breaking strength of the mooring line, a mooring "failure" normally consists of anchor slippage. Anchor slippage in the most loaded lines would cause a redistribution of loads among the other mooring lines and, in turn, would reduce the peak line tensions to substantially lower levels. Vessel displacement caused by this scenario can normally be tolerated by these units.

Special considerations of exposure risk should be made for drilling vessels operating for an extended period of time in a single location such as vessels for development drilling. For drilling programs operating for more than a full year, consideration should be given to the return period method. In this case, a return period of five times the exposure period should be considered. The return period environment should be compared to the 99.9% non-exceedance environment, and the most conservative value used.

1.6 Water Depth. The water depth at the drilling location should be determined. The slope and direction of the ocean floor should also be determined to establish the water depth at each anchor.

1.7 Soil Condition. Bottom soil conditions existing at the drilling location should be determined to provide data for evaluating anchor performance. In areas with extremely soft soils, piggy back anchors may be required. In areas with extremely hard bottoms, drilled or driven pile anchors may be necessary.

1.8 Mooring Equipment. The following information on the mooring equipment should be determined:

a. **Mooring Lines.** Number, diameter, maximum useable length out from fairlead, submerged weight per unit length, and catalog breaking strength of mooring lines.

b. **Anchors.** Number, size and type of anchors. Anchor piles may be evaluated for soil conditions where the use of conventional anchors is questionable.

c. **Pendants.** Number, diameter and length of pendants.

d. **Deck Machinery.** Maximum winch/wildcat pull (at stall) and maximum winch/wildcat brake capacity.

SECTION 2
MOORING SYSTEM

Typically, mooring systems for mobile drilling units are of the 'spread moored' type wherein fairleads are located around the periphery of the vessel. Figure 5 depicts a typical spread mooring system for semisubmersibles and drillships which consists of eight mooring lines with four double drum winches (or windlasses) located at the four corners of the vessel. Generally, the term winch refers to the machinery to spool and store wire rope, and a windlass is used to control the mooring chain. The chain is stored below the windlass in a compartment called chain locker. Some drilling vessels have a winch/windlass combination system for mooring lines consisting of both wire rope and chain. A mooring line is led to the seafloor by a fairlead which changes the direction of pull of a mooring line. An anchor is used to fix the line to the seafloor. A pendant buoy with a pendant line is used for marking and retrieving the anchor. The length of a mooring line is normally in the range of 3000 to 6000 feet.

A shipshape vessel is subjected to much smaller environmental forces when the weather approaches the vessel's bow or stern. One operational problem associated with spread moorings for drillships is the limited ability to rotate the vessel into the predominant weather, thus avoiding high environmental loads from the beam direction. A turret-moored drillship, as shown in Figure 6, can head into the predominant environment, minimizing the environmental forces imposed on the vessel. This capability is achieved by placing the wire rope winches on top of a turret which can rotate with relation to the hull of the vessel. Powered thrusters are used to rotate the vessel into the weather.

2.1 Mooring Pattern. Many possible arrangements are available for spacing the mooring lines around a drilling unit. Normally, orientation of the lines is based on consideration of the type of hull and the surfaces of the hull exposed to the environment. The beam or side areas of ships and barges are generally larger than the bow area, so that the mooring lines are arranged to provide greater support on the beam. For semisubmersibles, approximately the same area is exposed on both the bow and beam, and symmetric mooring patterns are frequently employed. Final selection of a mooring pattern should be based on hull type and the prevailing direction of wind, current, and waves. In some areas where strong winds or currents come from one direction only, strongly asymmetric mooring patterns with lines concentrated to one side have been used successfully.

Typical mooring patterns are shown in Figure 7. The most commonly used patterns are the 30-60° eight line (Figure 7a) and the symmetric eight line (Figure 7b). In some areas where strong wind or current comes from a predictable direction, skewed mooring patterns as illustrated in Figure 7g have been successfully used. Asymmetric mooring patterns are sometimes used when pipelines or shipping fairways are in close proximity of the drill site (Figure 7h).

2.2 Type of Mooring. Mooring systems of floating drilling vessels can be divided into three categories: an all wire rope system, an all chain system, and a chain/wire rope combination system. Advantages and limitations of each system are discussed below.

a. **All Wire Rope System.** Wire rope is more lightweight than chain. Therefore, in general, wire rope provides more restoring force in deep water than chain and requires lower pretensions. However, to prevent anchor uplift, much longer line length is required for an all wire rope system. Also, wear due to abrasion between wire rope and a hard seafloor can sometimes become a problem. Moreover, wire rope needs careful maintenance. Corrosion due to lack of lubrication or mechanical damage to the wire rope could cause mooring failure.

b. **All Chain System.** Chain has shown durability in offshore operations. It has better resistance to bottom abrasion and contributes significantly to anchor holding capacity. However, because of its heavy weight, it is undesirable for deepwater operations. During anchor deployment, chain requires windlasses with large shaft horsepower and brake capacities. In addition, anchor handling boats must have larger bollard pull capacities to deploy the anchors.

c. **Chain/Wire Rope Combination System.** In this system, the chain is outboard between the anchor and the wire rope. By proper selection of the length of wire rope, a combination system offers the advantages of low pretension requirement, high restoring force, added anchor holding capacity, and good resistance to bottom abrasion. These advantages make it the best system for deepwater operations. Semisubmersibles with chain/wire rope combination mooring which are capable of drilling in 5,000 feet of water in hostile environments have been built. Anchor deployment and retrieval are sometimes more time consuming with a combination system, and workboats with chain lockers are often required to store the chain. However, new combination winch/windlass systems that eliminate the need for workboats with chain lockers are available today, and the time for making the wire rope/chain connections can be markedly reduced or eliminated.

SECTION 3
ENVIRONMENTAL FORCES AND VESSEL MOTIONS

3.1 Basic Considerations. The recommended mooring analysis procedure outlined in Section 5 requires the evaluation of forces on the drilling unit due to wind, waves, and currents and the evaluation of oscillatory displacements due to waves. Wind, waves, and current each produces a steady state force. These forces are evaluated individually and summed to get the total steady state environmental force. This steady state force produces a steady state displacement which is a function of the stiffness of the mooring system. The total displacement is equal to the sum of the oscillatory wave displacement and the steady state displacement. The loads and stresses in the mooring system are then evaluated based on the total displacement and the stiffness of the mooring system.

Oscillatory wave displacements are computed for free floating hulls neglecting the restraint provided by the mooring system. For normal hull forms and mooring system configurations the restraint provided by the mooring system does not appreciably affect the wave frequency component of the horizontal displacement due to waves. However, it significantly affects the low frequency component.

3.2 Wind. The force due to wind may be determined by using wind tunnel model test data or equations given in this section. The wind speed used is defined in Section 1.5a.

a. **Model Tests.** Model test data may be used to predict wind loads for mooring system design provided that a representative model of the unit is tested, that the unit is tested in a credible facility, and that the condition of the model in the tests, i.e., draft, deck cargo arrangement, etc., closely matches the expected conditions that the unit will see in service. Care should also be taken to assure that the character of the flow in the model test is the same as the character of flow for the full scale unit.

b. **Wind Force Calculation.** The force due to wind acting on a moored drilling unit should be determined using Equation 3.1.

$$F_w = C_w \Sigma (C_s C_h A) V_w^2 \tag{3.1}$$

Where

F_w = wind force, lbs (N)
C_w = 0.0034 lb/(ft² • kt²) (0.615 Nsec²/m⁴)
C_s = shape coefficient
C_h = height coefficient
A = vertical projected area of each surface exposed to the wind, ft²(m²)
V_w = design wind speed, knots (m/sec)

The projected area exposed to the wind should include all columns, deck members, deck houses, trusses, crane booms, derrick substructure and drilling derrick as well as that portion of the hull above the waterline. (Except as noted below, no shielding should be considered.)

In calculating wind areas, the following procedures should be followed:

(1) The projected area of all columns should be included.

(2) The blocked-in projected area of several deck houses may be used instead of calculating the area of each individual unit. However, when this is done, a shape factor, C_s, of 1.10 should be used.

(3) Isolated structures such as derricks and cranes should be calculated individually.

(4) Open truss work commonly used for derrick mast and booms may be approximated by taking 60 percent of the projected block area of one face.

(5) Areas should be calculated for the appropriate hull draft for the given operating condition.

c. **Shape Coefficients.** The shape coefficients, C_s, of Table 1 should be used.

d. **Height Coefficients.** Wind velocity increases with height above the water. In order to account for this change, a height coefficient, C_h, is included. The height coefficients, C_h, of Table 2 should be used.

3.3 Current. Force due to current should be based on the results of model tests or the Equations 3.2, 3.3 or 3.4.

a. **Model Tests.** Model test data may be used to predict current loads for mooring system design provided that a representative underwater model of the unit is tested, that the unit is tested in a credible facility, and that the contribution to current load made by thrusters, anchor bolsters, bilge keels, and other appendages be accounted for. Care should be taken to assure that the character of the flow in the model test is the same as the character of the flow for the full-scale unit.

b. **Current Force Calculations.** If current forces are to be calculated, the following equations should be used:

(1) Force due to bow or stern current on ship-shaped hulls.

$$F_{cx} = C_{cx} S V_c^2 \quad (3.2)$$

Where

F_{cx} = current force on the bow, lb (N)

C_{cx} = current force coefficient on the bow = 0.016 lb/(ft² • kt²) (2.89 Nsec²/m⁴)

S = wetted surface area of the hull including appendages, ft² (m²)

V_c = design current speed, kts (m/sec)

(2) Force due to beam current on ship-shaped hulls.

$$F_{cy} = C_{cy} S V_c^2 \quad (3.3)$$

Where

F_{cy} = current force on the beam, lb (N)

C_{cy} = current force coefficient on the beam = 0.40 lb/(ft² • kt²) (72.37 Nsec²/m⁴)

(3) Force due to current on semisubmersible hulls.

$$F_{cs} = C_{ss}(C_d A_c + C_d A_f) V_c^2 \quad (3.4)$$

Where

F_{cs} = current force, lb (N)

C_{ss} = current force coefficient for semi-submersible hulls = 2.85 lb/(ft² • kt²) (515.62 Nsec²/m⁴)

C_d = drag coefficient (dimensionless) = 0.50 for circular members. See Figure 8 for members having flat surfaces.

A_c = summation of total projected areas of all cylindrical members below the waterline, ft² (m²)

A_f = summation of projected areas of all members having flat surfaces below the waterline, ft² (m²)

3.4 Steady Drift Force. Three wave related phenomena affect mooring system design. They are: 1) steady state mean drift force, 2) surge, sway, and yaw response at or near the predominant period of the waves, and 3) oscillatory drift forces at or near the natural period of the spring/mass system of the moored vessel.

The steady state mean drift forces are typically much smaller than the wave forces that excite surge and sway response. However, drift forces may still contribute significantly to the total mean environmental force acting on the vessel. Therefore, wave drift forces should be accounted for in the mooring system design.

Mean wave drift forces may be predicted using model tests or using advanced hydrodynamic computer analysis. In the absence of available wave drift force predictions, the following procedure for estimating mean wave drift force may be used. This procedure uses design curves for typical drillships and semisubmersibles to facilitate calculation. These design curves were generated by an advanced vessel motions computer program which has been verified and calibrated by extensive model test data.

a. **Mean Drift Force For Ship-Shaped Hulls.** The mean wave drift force for ship-shaped hulls in bow, quartering and beam seas can be estimated by Figures 9 through 20, according to the size of the vessel and the direction of the waves relative to the hull. Drift forces for stern and stern quartering seas are nearly equal to bow and bow quartering values, respectively.

The curves in these Figures are for drillships of 400 ft to 540 ft length. For drillships which are outside this length range, the mean drift force can be estimated by extrapolation or the procedure described below.

Let:

$$F_{mdx} = (F_{mdx})_{REF} \times \left(\frac{L}{L_{REF}}\right)^2 \quad (3.5a)$$

$$F_{mdy} = (F_{mdy})_{REF} \times \left(\frac{L}{L_{REF}}\right)^2 \quad (3.5b)$$

where $(F_{mdx})_{REF}$ and $(F_{mdy})_{REF}$ are bow mean wave drift force (Figures 9-14) and beam mean wave drift force (Figures 15-20), respectively, for the reference ship which most closely fits the ship at hand, taken at a significant wave height of

$$(H_s)_{REF} = H_s \times \left(\frac{L_{REF}}{L}\right) \quad (3.6)$$

The data presented in Figures 9 through 20 are appropriate for ship-shape vessels with normal hull form. Care should be used in applying this data to vessels with blunt bows or sterns or other unusual hull features.

b. **Mean Wave Drift Force For Semisubmersible Hulls.** The mean wave drift force for semisubmersible hulls may be evaluated by the curves in Figures 21-23. The drift force curve in each figure represents the upper bound of the mean wave drift forces generated by the advanced motions computer program for four semisubmersible designs including typical 4, 6, and 8 circular column twin hull designs and the pentagon design.

3.5 Low Frequency Vessel Motions. A moored vessel is subjected to two types of drift forces — the mean wave drift force produces a steady vessel offset and the oscillatory drift force produces low frequency surge, sway, and yaw motions about the mean vessel offset.

Low frequency motions can be predicted by model tests or by advanced analytical methods. In the absence of those tools, low frequency surge and sway motions can be estimated by the following procedure. Yaw motions are normally neglected in mooring analysis.

a. **Ship-Shape Hulls.** Figures 9-20 can be used to estimate the rms (root mean square) single amplitude low frequency motions for ship-shaped vessels. The curves in these Figures are for drillships of 400 ft to 540 ft length. For drillships which are outside this length range, the method described in Section 3.4 can be used to estimate the low frequency motions.

The curves presented are appropriate for mooring spring stiffness of 18 kips per foot of vessel offset. For other mooring stiffnesses, the results from Figures 9-20 should be adjusted by Equation 3.7a or 3.7b,

$$x_s = (x_s)_{REF}\left(\frac{18}{k}\right)^{1/2} \quad (3.7a)$$

$$y_s = (Y_s)_{REF}\left(\frac{18}{k}\right)^{1/2} \quad (3.7b)$$

where:

$(x_s)_{REF}$ is the rms single amplitude low frequency surge from Figures 9-14.

k is the mooring system spring stiffness in kips/ft taken at the vessel's mean position.

$(y_s)_{REF}$ is the rms single amplitude low frequency sway from Figures 15-20.

The significant single amplitude low frequency motions are given by Equations 3.8a and 3.8b.

$$(x_s)_{1/3} = 2\,x_s \quad (3.8a)$$
$$(y_s)_{1/3} = 2\,y_s \quad (3.8b)$$

The maximum single amplitude low frequency motions are given by Equations 3.9a and 3.9b.

$$(x_s)_{max} = (x_s)_{1/3} \times F_R \quad (3.9a)$$
$$(y_s)_{max} = (y_s)_{1/3} \times F_R \quad (3.9b)$$

where

$(x_s)_{max}$ and $(y_s)_{max}$ are the maximum single amplitude low frequency surge and sway, respectively, in 3-hour duration.

F_R is a Rayleigh factor which can be determined by Equation 3.9c.

$$F_R = \sqrt{1/2\ \ln\,(10800/T_N)} \quad (3.9c)$$

where T_N is the natural period of the moored vessel which can be estimated by Equation 3.10.

$$T_N = 2.0\sqrt{\frac{\Delta}{k}} \quad (3.10)$$

where Δ is the vessel displacement in long tons.

b. **Semisubmersible Hulls.** Figures 21-23 can be used to estimate the rms single amplitude low frequency surge and sway for semisubmersibles. Equations 3.7 thru 3.10 above can then be used to estimate significant and maximum single amplitude motions. The curve in each figure represents the upper bound of the low frequency vessel motions generated by the advanced motions computer program for four semisubmersible designs including typical 4, 6, and 8 circular column twin hull designs and the pentagon design.

3.6 Wave Frequency Vessel Motions. The motions of the vessel at the frequency of the waves is an important contribution to the total mooring system loads, particularly in shallow water. These wave frequency motions can be obtained from random wave model test data, or computer analysis using either time or frequency domain techniques. In the absence of these tools, the following approach can be used to estimate the wave frequency motions.

a. **Spectral Analysis Method.** The evaluation of wave displacement by the method of spectral analysis involves first determining the response spectrum as a function of frequency over the full range of wave frequencies. The response spectrum is then integrated and the square root is taken to determine the rms response. Finally the significant and maximum responses can be obtained by using appropriate Rayleigh factors. The specific recommended procedure is outlined in detail in the following sections, and an example calculation is provided in Section 6. The procedure has been simplified in the following respects.

(1) The wave spectrum is considered to be unidirectional, i.e., no wave spreading function is considered.

(2) No coupling of motions is considered.

The spectral analysis method has been shown to agree with measured wave displacements with errors on the order of 10% to 20%. This amount of error is considered "state of the art" and the safety factors of Section 4 have been selected to account for such errors and to yield designs which are consistent with proven field experience.

b. **The Design Wave Spectrum.** Appropriate design wave spectra for a specific geographical area may be available from meteorological consultants; however, it is more likely that sea state data will be available in the form of significant wave height, and period versus cumulative frequency of occurrence or in the form of wind speed versus cumulative frequency of occurrence as illustrated in Figures 2 and 3. In this case the significant wave height, significant wave period and design wind speed corresponding to the operating condition and the design condition should be determined as outlined in Section 1.5. Then for each condition, the corresponding wave spectrum may be evaluated using either Equation 3.11 or Equation 3.12.

$$S(\omega) = \frac{C_1 H_s^2}{T_s^4 \omega^5} e - \frac{C_2}{T_s^4 \omega^4} \qquad (3.11)$$

$$S(\omega) = \frac{C_3}{\omega^5} e - \frac{C_4}{Vw^4 \omega^4} \qquad (3.12)$$

Where

$S(\omega)$ = ordinate of wave spectrum ft^2 sec (m^2 sec)

H_s = significant wave height, ft (m)

C_1 = 263 (dimensionless)

C_2 = 1050 (dimensionless)

C_3 = 8.4 (0.78) ft^2/sec^4 (m^2/sec^4)

C_4 = 77300 (5414) kt^4/sec^4 (m^4/sec^8)

ω = wave frequency rad/sec (rad/sec)

T_s = significant wave period, sec (sec)

V_W = design wind speed, kts (m/sec)

Equations 3.11 and 3.12 will not normally yield exactly the same spectrum; one or the other should be selected depending on whether wave height data or wind speed data are considered to be more reliable for the geographical area under consideration. If the value of T_s is not available from oceanographic data, the appropriate value may be estimated using Figure 4. The design wave height, H_s, is the significant wave height in the statistical sense, i.e., the average of the 1/3 highest waves. The value of T_s is the corresponding wave period. The design wind speed is the same as defined in Section 1.5a.

The wave spectrum defined by Equations 3.11 and 3.12 is known as the ISSC spectrum. Other wave spectra such as the Pierson-Moskowitz spectrum, Bretschneider spectrum, and the Jonswap spectrum can be used if they are more appropriate for the drilling location under consideration.

c. **Response Amplitude Operators.** Motion response operators for surge in head seas and sway in beam seas should be available from carefully conducted model tests over a full range of wave frequencies. Analytical motion response operators obtained by integrating wave pressure over the wetted surface of the drilling unit and solving the basic equations of motion, may also be used. Care should be taken to assure that curves are for single amplitude response per unit wave amplitude. In the absence of model test data or analytical curves, the response operators of Figures 24, 25 and 26 may be used. Response operators are given for three classes of semisubmersible drilling units and two classes of ship-shape drilling units. Response operators for intermediate class units may be interpolated. Characteristics of the various classes of drilling units are tabulated in Table 3.

d. **Calculated Response.** The response spectrum is determined by multiplying each point on the wave spectrum by the square of the value of the response operator at the corresponding frequency. Once the response spectrum is determined over the complete range of wave frequencies, it can be integrated numerically to determine the rms single amplitude response. Based on the Rayleigh distribution of peak responses, the significant response is 2.0 times the rms response, and the maximum response is 1.86 times the significant response. The example mooring analysis of Section 6 illustrates the complete procedure for evaluating wave frequency motions by the spectral analysis method.

3.7 Oblique Environment. Wind and current force due to environments approaching from an oblique direction may be evaluated by Equation 3.13.

$$F_\phi = F_X \left[\frac{2\cos^2\phi}{1+\cos^2\phi}\right] + F_Y \left[\frac{2\sin^2\phi}{1+\sin^2\phi}\right] \qquad (3.13)$$

Where

F_ϕ = force due to oblique environment, lbs (N)

F_X = force on the bow due to a bow environment, lbs (N)

F_Y = force on the beam due to a beam environment, lbs (N)

ϕ = direction of approaching environment (degree off bow)

Oscillatory wave frequency motions due to oblique environments such as a quartering environment (45° off bow) should be obtained by computer programs which calculate surge and sway response operators for the oblique environment. Surge and sway motions for the response operators should be combined with proper phase. In the absence of these programs, Equation 3.14 can be used for quartering wave frequency motions.

$$z = \sqrt{x^2\cos^2\varphi + y^2\sin^2\varphi} \qquad (3.14)$$

Where

z = wave frequency motion due to quartering environment, ft (m)

x = surge due to bow waves, ft (m)

y = sway due to beam waves, ft (m)

φ = arctan (y/x)

SECTION 4
MOORING DESIGN CRITERIA

4.1 Offset

a. **Definition of Mean Offset.** The mean offset is defined as the vessel displacement due to the combination of wind, current, and mean wave drift forces.

b. **Definition of Maximum Offset.** The maximum offset is the mean offset plus appropriately combined wave frequency and low frequency vessel motions. Maximum offset can be determined by the following procedure.

Let:

$(WF)_{max}$ = Maximum wave frequency motion

$(WF)_{1/3}$ = Significant wave frequency motion

$(LF)_{max}$ = Maximum low frequency motion

$(LF)_{1/3}$ = Significant low frequency motion

(1) If $(LF)_{max} > (WF)_{max}$, then Maximum offset = Mean offset + $(LF)_{max}$ + $(WF)_{1/3}$

(2) If $(WF)_{max} > (LF)_{max}$, then Maximum offset = Mean offset + $(WF)_{max}$ + $(LF)_{1/3}$

A parametric study has been performed to assess the risk level associated with this method of combining wave and low frequency motions. The chance of exceeding the combined motions defined above was estimated using a probabilistic approach for different hull forms, water depths, environments, and types of mooring. The results of the study indicate that the combined low and wave frequency motions defined in this manner would be exceeded approximately once in three hours. This appears a proper risk level for the operations addressed by this Recommended Practice.

c. **Offset Limits.** The offsets of the drilling unit from the wellbore must be controlled to prevent damage to the drilling riser and the BOP stack.

(1) **Maximum Operating Condition.** The mean offset should be controlled under the operating condition because of its direct relevance to the mean ball joint angle. The allowable mean offset should be determined by a drilling riser analysis. Allowable mean offsets depend on many factors such as water depth, environment, and riser system. They normally fall in a range of 2.5% to 6% of water depth. Generally the lower bound applies to deepwater (1500-2000 ft) operations, and the upper bound applies to shallow water (200-300 ft) operations.

(2) **Maximum Connected Condition.** The maximum offset should be controlled under the maximum connected condition to prevent damage to the mechanical stop in the ball joint below the drilling riser. The allowable maximum offset should be determined by a drilling riser analysis. Allowable maximum offsets depend on many factors such as water depth, environment, and riser system. They normally fall in a range of 8% to 12% of water depth. Generally the lower bound applies to deepwater (1500-2000 ft) operations, and the upper bound applies to shallow water (200-300 ft) operations.

(3) **Maximum Design Condition.** For the maximum design condition, if the riser is disconnected from the well, there is no restriction on vessel offset. Design criteria for this condition consists only of restrictions on loads in the mooring lines.

4.2 Maximum Mooring Line Tension. The maximum mooring line tension is calculated at the maximum vessel offset. The tension in the most loaded line at the design condition should not exceed 50% of the ultimate strength of the line. The ultimate strength of the line may be taken as the catalog break strength (CBS) of the wire rope (provided it is new or in like-new condition). Worn rope should be limited to lesser design loads. The ultimate strength of chain may be taken as the break test load (BTL) provided the chain is new or in like-new condition. Used or worn chain should be limited to lesser design loads. The tension in the most loaded line at the maximum operating condition should not exceed 33% of the ultimate strength of the line. Mooring line adjustments to alleviate tensions can be considered in the analysis.

4.3 Line Length. The mooring line (outboard line) length should be sufficient to allow the lines to come in tangent to the ocean bottom at the anchor when the system reaches the maximum anticipated offset.

4.4 Drag Anchor Holding Power. Floating drilling units are commonly moored with drag anchors. In hard-to-anchor bottom soil conditions, anchor piles and explosive embedment anchors are sometimes used. The following discussion will address the holding power of drag anchors only.

The holding power of a drag anchor in a particular soil condition represents the maximum sustained horizontal load the anchor will resist in that soil before dragging. The length of mooring chain or wire connected to the anchor that remains on the bottom soil will also contribute to the holding power of that mooring line and will reduce the horizontal load imposed on the anchor.

a. **Anchor Holding Power.** Anchor holding power is a function of several factors, including the following:

1) Anchor type — Fluke area, fluke angle, fluke smoothness, anchor weight, tripping palms, stabilizer bars, etc.

2) Bottom soil condition — Soft mud, sand, gravel, clay, rock, coral, etc.

3) Anchor behavior during deployment — Opening of the flukes, penetration of the flukes, depth of burial of the anchor, stability of the anchor during dragging, soil behavior over the flukes, etc.

Due to the wide variation of these factors, the prediction of an anchor's holding power is difficult. Exact holding power can only be determined after the anchor is deployed and test loaded.

Anchor performance data for the specific anchor type and soil condition should be obtained if possible. In the absence of credible anchor performance data, Figures 27 and 28 may be used to estimate the holding power of anchors commonly used to moor floating drilling units.

Figures 27 and 28 are from "Handbook for Marine Geotechnical Engineering," Naval Civil Engineering Laboratory, 1985. There are other sources of data on anchor holding capacity. Sometimes there are significant differences among the prediction curves from different sources because of differences in test conditions (size of anchor, type of soil, and test hardware) and test data interpretation. Furthermore, some of the anchors such as the Bruce anchor and the Stevpris anchor have been modified recently. The performances of the modified anchors can be substantially different from those predicted by these figures.

b. **Chain and Wire Rope Holding Power.** The holding power of chain may be estimated using Equation 4.3.

$$P_{cw} = fL_{cw}\,w_{cw} \tag{4.3}$$

Where

P_{cw} = chain or wire rope holding power, lb (N)

f = coefficient of friction between chain and the ocean bottom, dimensionless

L_{cw} = length of chain or wire rope in contact with the ocean bottom, ft (m)

w_{cw} = submerged unit weight of chain or wire rope, lb/ft (kg/m)

The coefficient of friction, f, depends upon the actual ocean bottom at the anchoring location. Generalized friction factors for chain are given in Table 4. The starting friction factors may be used to compute the holding power of the chain. The sliding friction factor may be used to compute forces on the chain during deployment.

4.5 Comments on Mooring Design Criteria. Recommended Practice RP 2P has been written based on the probabilistic analysis method as opposed to the more traditional deterministic analysis method. This choice was made because the design environments and motions of a floating hull in a random sea can be more accurately described in probabilistic terms.

The three primary factors in any design for offshore installations are the environmental criteria, the load analysis procedures, and the allowable stress and deflection criteria. For example, API RP 2P specifies that the appropriately combined low and wave frequency vessel motions be used with a safety factor of 2.0 relative to the line breaking strength, for checking line tensions in conjunction with the 99.9% environment. The selection of this combination of design environment, statistical level of vessel motions, and safety factor is empirical and based on operational experience and judgment. It is important to note that the level of vessel motions (maximum, significant, etc.) and the safety factor cannot be selected independently of the maximum design environment since taken together they define the total risk level.

Since the RP 2P analysis method is somewhat of a break with tradition for the offshore industry, there may be a tendency to adopt certain portions of the method and reject the others; for instance, the mooring analysis procedures and tension criteria might be applied with the 100-year storm design environment. This would result in a gross, unwarranted increase in system reliability over what has proven safe and economical in many rig-years of experience. This Recommended Practice does not address an analysis method for evaluating the mooring system's capability in extreme events such as 100-year storm conditions in severe environmental areas, and therefore, it is recommended that this analysis method *not* be used for such analyses.

It should be emphasized that the selective use of the mooring analysis procedures out of context can lead to misleading results. In RP 2P, wind loads, current loads, mean wave loads, and vessel surge motions are specifically accounted for; however, contributions due to bending over fairleaders, line dynamics, vessel heave, pitch, and roll motions, etc., are not computed specifically. These contributions are usually not the major factors influencing mooring line loads in drilling applications, and are therefore lumped together and accounted for by a safety factor on the maximum allowable mooring line load. If a more comprehensive mooring analysis is made, for example, dynamic mooring analysis, corresponding change in allowable load can be justified.

SECTION 5
MOORING ANALYSIS PROCEDURE

5.1 Basic Considerations. The general procedure outlined below is recommended for the analysis of mooring systems for floating drilling units. Systems designed in accordance with this procedure and satisfying the design criteria as defined in Section 4 should be adequate for the selected environment. Use of this procedure is illustrated in the example of Section 6.

5.2 Preliminary Calculations

a. Determine wind and current velocities, significant wave heights and periods for the maximum design, connected and operating conditions. For many operations, the drilling riser stays connected under the maximum design condition. In this case, only the maximum design and operating conditions need to be analyzed since the maximum connected condition is the same as the maximum design condition.

b. Determine the mooring pattern, lengths of chain and wire rope to be deployed, and initial tension.

c. Determine the steady state environmental forces acting on the hull for the maximum operating, maximum connected, and maximum design condition using either model test data or the equations described in Section 3.2 through 3.4. Consider environmental forces to be simultaneous and collinear unless environmental data for an area show that other conditions are appropriate.

d. Determine the low frequency motions using the data and procedures described in Section 3.5. Since calculation of low frequency motions requires the knowledge of the mooring stiffness, the mooring stiffness at the mean offset should be determined first using the restoring force versus offset curves described in Section 5.3.

e. Determine the significant and maximum single amplitude wave frequency vessel motions using the data and procedures described in Section 3.6.

f. Determine the direction of approach for weather (relative to the bow). Bow, beam, and quartering (45° off the bow or stern) approaches should be considered unless local weather, hull design, or mooring design (turret mooring) dictate otherwise.

g. Determine the maximum allowable offset for maximum operating and maximum connected conditions.

5.3 Mooring Analysis Procedure

a. Prepare force versus offset and suspended line length versus offset curves for the most loaded line and the horizontal restoring force for the multi-line system using the basic catenary relationships of Figure 29 and the mooring pattern geometry as illustrated in Figure 30. The curves should properly account for stretch in the mooring lines. For mooring lines with non-uniform weight (i.e., combined chain and wire rope systems), the catenary relationships become more complex and computer analysis is normally employed.

Recommended values for elasticity of mooring lines are given below. For chain, the elasticity, T/δ_c, in lbs of tension per foot of stretch is:

$$T/\delta_c = 1.2 \times 10^7 D_c^2/S_c \qquad (5.1)$$

where:

T = mooring line tension (lbs)
δ_c = elastic stretch of chain (feet)
D_c = nominal chain diameter (in)
S_c = chain length (feet)

For wire rope:

$$T/\delta_w = 7.7 \times 10^6 D_w^2/S_w \qquad (5.2)$$

where:

δ_w = elastic stretch of wire rope (feet)
D_w = nominal diameter of wire rope (in.)
S_w = wire rope length (feet)

The stretch coefficient for wire rope in Equation (5.2) is appropriate for six strand wire ropes commonly used in mooring applications. For other types of wire rope such as spiral strand the stretch coefficient may differ.

The recommended values for the submerged weight of wire rope or chain per unit length can be calculated by Equation 5.3.

$$\text{Submerged weight} = \text{weight in air} \times \beta \qquad (5.3)$$

β = 0.87 (chain)
β = 0.83 (wire rope)

b. Enter the force versus offset curve for the total mooring system at the restoring force required to withstand the steady state environmental force.

c. Determine the vessel's mean offset and mean line tension corresponding to the above steady state force.

d. Add the maximum single amplitude motion to the mean offset to determine the maximum vessel offset and maximum line tension. The maximum single amplitude motion is defined as the properly combined wave frequency and low frequency motions. (Section 4.1)

e. Determine the maximum suspended line length. To avoid anchor uplift, the maximum suspended line length should be less than the outboard mooring line length.

f. Determine the maximum anchor load.

Maximum anchor load = maximum line tension - (unit submerged weight of mooring line) × (water depth) - friction between mooring line and seafloor. (5.4)

Compare the calculated anchor loads with those predicted by Fig. 28 and 29 or by other available data for anchor holding power. Because of the uncertainties in anchor performance prediction, a factor of safety may be considered.

g. Check the calculated line tensions and offsets against the mooring design criteria. If the mooring criteria are not met, change the mooring system and perform the analysis again. Possible mooring system changes include changes in initial tension, mooring line length, and mooring pattern.

SECTION 6
EXAMPLE ANALYSIS

6.1 Example Definition. The following example demonstrates the use of this Recommended Practice.

a. **Drilling Unit Description.** The drilling unit is a 10,000-ton drillship, 360 ft. × 70 ft. × 24 ft., and operates at a draft of 17.0 ft. Beam and bow profiles are shown in Figure 31. The total wetted area of the submerged hull, S, corrected for all appendages, is 36,600 ft.^{2}

b. **Mooring System Description**

(1) Mooring Lines: 8 — 6,000 ft. 2.75 in. IWRC wire rope. Catalogue breaking strength (CBS) = 695 kips; Weight = 13.4 lb/ft. in air, and 11.1 lb/ft. in water; AE = 58,231 kips.

(2) Anchor: 8 — 30 kip LWT type.

(3) Mooring Pattern: 30°-60°

(4) Initial Line Tension: 75 kips.

c. **Environmental Condition.** Table 5 presents the maximum operating and the maximum design environmental conditions. The maximum connected condition is assumed to be the same as the maximum design condition.

6.2 Mooring Analysis for the Maximum Design Condition

a. **Wind Force**

(1) Beam Wind Force (Fig. 31)

	C_s	C_h	A	C_sC_hA
A1	1.00	1.00	5600	5600
A2	1.25	1.10	(0.6)1650	1361
A3	1.25	1.20	(0.6)1350	1215
A4	1.25	1.30	(0.6)1050	1024
A5	1.25	1.37	(0.6) 600	617
A6	1.00	1.00	600	600
A7	1.25	1.00	(0.6) 480	360
A8	1.25	1.00	(0.6) 200	150
			ΣC_sC_hA =	10927

$$F_{wy} = 0.0034\ C_sC_hAV_w^2 \qquad \text{(Equation 3.1)}$$
$$= 0.0034\,(10927)\,(54)^2$$
$$= 108{,}300 \text{ lbs.}$$

(2) Bow Wind Force. By similar procedure, we obtain:

$$F_{wx} = .0034\,(9380)\,(54^2)$$
$$= 93{,}000 \text{ lb.}$$

(3) Quartering Wind Force (Equation 3.13)

$\phi = 45°$

$$F_{wz} = F_{wx}\left[\frac{2\cos^2\phi}{1+\cos^2\phi}\right] + F_{wy}\left[\frac{2\sin^2\phi}{1+\sin^2\phi}\right] \text{(Eq. 3.13)}$$
$$= 93{,}000\left[\frac{2\cos^2 45°}{1+\cos^2 45°}\right] + 108{,}300\left[\frac{2\sin^2 45°}{1+\sin^2 45°}\right]$$
$$= 2/3\,(93{,}000 + 108{,}300) = 134{,}200 \text{ lbs.}$$

b. **Current Force**

(1) Bow Current Force (Eq. 3.2)

$$F_{cx} = C_{cx}SV_c^2$$
$$= 0.016\,(36{,}600)\,2^2$$
$$= 2340 \text{ lbs.}$$

(2) Beam Current Force (Eq. 3.3)

$$F_{cy} = C_{cy}SV_c^2$$
$$= 0.4\,(36{,}600)\,2^2$$
$$= 58{,}560 \text{ lbs.}$$

(3) Quartering Current Force. Using Equation 3.13, with $\phi = 45°$, we obtain

$$F_{cz} = 2/3\,(F_{cx} + F_{cy})$$
$$= 40{,}600 \text{ lbs.}$$

c. **Mean Wave Drift Force**

(1) Bow Wave Drift Force. To simplify calculation, this can be classified as a small size vessel. Using Fig. 9, for a significant wave height of 20 ft., we obtain:

$$F_{mdx} = 10.5 \text{ kips}$$

Note that the ship length at hand is 360 ft. while the length of the reference ship in Fig. 9 is 400 ft. If more accurate results are desired, adjustments for ship length should be made using Eqs. 3.5 and 3.6.

(2) Beam Wave Drift Force. By similar procedure, we obtain:

$$F_{mdy} = 70.5 \text{ kips (Fig. 18)}$$

(3) Quartering Wave Drift Force

$$F_{mdx} = 9.7 \text{ kips (Fig. 12)}$$
$$F_{mdy} = 41.3 \text{ kips (Fig. 15)}$$
$$F_{mdz} = \sqrt{F_{mdx}^2 + F_{mdy}^2}$$
$$= \sqrt{9.7^2 + 41.3^2}$$
$$= 42.4 \text{ kips}$$

d. Wave Frequency Motion (Single Amplitude)

(1) Design Wave Spectrum

$$s(\omega) = \frac{C_1 H_s^2}{T_s^4 \omega^5} e - \frac{C_2}{T_s^4 \omega^4} \quad \text{(Equation 3.11)}$$

$$S(\omega) = \frac{263\,(20)^2}{(9.5)^4\,\omega^5} e - \frac{1050}{(9.5)^4\,\omega^4} \quad (6.1)$$

(2) Surge Response Evaluation (Bow Sea). The surge response can be evaluated by the following steps:

Step 1 — Select a frequency range and an increment. For this example problem, a frequency range of 0.12 -1.44 rad/sec and an increment Δw of 0.12 rad/sec are selected.

Step 2 — Determine the surge response amplitude operator (RAO) at each frequency by using the Class I curve in Figure 25.

Step 3 — Determine $S(\omega)$ at each frequency using Equation 6.1.

Step 4 — Determine the response spectrum which is equal to $(RAO)^2 \cdot S(\omega)$.

Step 5 — Find the area under the response spectrum and calculate the rms single amplitude response.

Step 6 — Apply proper Rayleigh factors to obtain the significant and maximum responses.

This procedure is illustrated by the following table.

ω	RAO	$S(\omega)$	Response Spectrum $RAO^2 \cdot S(\omega)$
.12	1.10	.0	.00
.24	1.02	.0	.00
.36	.88	1.0	.77
.48	.66	44.6	19.43
.60	.38	61.3	8.85
.72	.18	41.2	1.34
.84	.14	23.8	.47
.96	.12	13.6	.20
1.08	.10	8.0	.08
1.20	.10	4.9	.05
1.32	.10	3.1	.03
1.44	.10	2.0	.02
			Σ = 31.23

$x_{rms} = \sqrt{\Delta\omega . \Sigma} = \sqrt{0.12 \times 31.23} = 1.94$ ft

$x_{1/3} = 2(x_{rms}) = 3.87$ ft

$x_{max} = 1.86 \times {}_{1/3} = 7.20$ ft

(3) Sway Response Evaluation (Beam Sea). By similar procedure, we obtain the following sway responses:

$y_{rms} = 4.59$ ft. $y_{1/3} = 9.19$ ft. $y_{max} = 17.09$ ft.

(4) Response Evaluation for Quartering Sea

$x_{1/3} = 3.87$ ft.

$y_{1/3} = 9.19$ ft.

$\phi = \arctan(9.19/3.87)$

$= 67.2°$

$z_{1/3} = \sqrt{(x_{1/3})^2 \cos^2\phi + (y_{1/3})^2 \sin^2\phi}$ (Equation 3.14)

$= \sqrt{3.87^2 \cos^2 67.2 + 9.19^2 \sin^2 67.2}$

$= 8.6$ ft.

$z_{max} = 1.86 \times 8.6 = 16.0$ ft.

e. Low Frequency Motion (Single Amplitude)

(1) Mean (static) Offset and Mooring Stiffness. Tables 6 and 7 give the mean offset and the mooring system stiffness at the mean offset.

(2) Surge Response Evaluation (Bow Sea). From Figure 9 the rms low frequency motion corresponding to the wave height of 20 ft. is

$(x_s)_{REF} = 1.3$ ft.

$x_s = 1.3\,(18/k)^{1/2} = 2.08$ ft. (Equation 3.7a)

$(x_s)_{1/3} = 2\,x_s$ (Equation 3.8a)

$= 4.16$ ft.

$T_N = 2\sqrt{\Delta/K} = 2\sqrt{10{,}000/7}$ (Equation 3.10)

$= 75.6$ seconds

$F_R = \sqrt{\tfrac{1}{2}\ln(10800/T_N)} = 1.58$ (Equation 3.9c)

$(x_s)_{max} = (x_s)_{1/3} \bullet F_R$

$= 6.55$ ft.

(3) Sway Response Evaluation (Beam Sea). By similar procedure, we obtain:

$(y_s)_{1/3} = 11.08$ ft.

$(y_s)_{max} = 17.62$ ft.

(4) Quartering Response Evaluation. Using Figures 12 and 15, the rms surge and sway corresponding to a significant wave height of 20 ft. are 1.3 ft. and 2.2 ft., respectively.

$(z_S)_{REF} = \sqrt{1.3^2 + 2.2^2} = 2.5$ ft.

$(z_S)_{REF} = 2.5\,(18/K)^{1/2}$

$= 2.5\,(18/8.8)^{1/2} = 3.59$ ft.

$(z_S)_{1/3} = 2\,z_S$

$= 7.18$ ft.

$T_N = 2\sqrt{\Delta/K} = 2\sqrt{10{,}000/8.8} = 67.4$ sec.

$F_R = \sqrt{\tfrac{1}{2}\ln(10800/T_N)} = 1.59$

$(z_S)_{max} = (z_S)_{1/3} \bullet F_R$

$= 11.44$ ft.

f. Summary of Environmental Forces and Vessel Motions. Table 6 summarizes the environmental forces and vessel motions.

g. Calculation of Vessel Offset, Maximum Line Tension, Suspended Line Length, and Maximum Anchor Load.

(1) Bow Environment. The total steady state force is 105.8 kips (Table 6). Using Fig. 32, the mean offset corresponding to this force is 16.5 ft. Adding the maximum combined wave and low frequency motion of 11.4 ft. (Table 6), we obtain the maximum vessel offset of 27.9 ft. The maximum line tension corresponding to this offset is 128.4 kips (18.5% of CBS), and the maximum suspended line length is 3518 ft. (Fig. 32). The holding capacity of wire rope is:

$$P_{wc} = f L_{wc} W_{wc} \qquad \text{(Equation 4.3)}$$

$$= 0.6\,(6000\text{-}3518)\,11.1$$

$$= 16{,}500 \text{ lbs.}$$

By Equation 5.4,

Maximum anchor load $= 128{,}400 - 11.1 \times 550 - 16{,}500$

$= 105{,}800$ lbs.

(2) Beam Environment and Quartering Environment. By similar procedure, we obtain the results for beam and quartering environments as presented in Table 7..

6.3 Mooring Analysis for the Maximum Operating Condition. By similar procedure and using Figures 33 and 34, we obtain the results for the maximum operating condition as presented in Tables 8 and 9. Table 8 summarizes the environmental forces and vessel motions; Table 9 summarizes the vessel offset, maximum line tension, suspended line length, and maximum anchor load.

6.4 Summary and Discussion of Mooring Analysis Results. Table 10 summarizes the mooring analysis results. The most critical environment is the beam environment. The maximum line tension under the maximum operating condition is 20.6% of CBS, which is less than the recommended tension limit of 33% of CBS. The maximum line tension under the maximum design condition is 35.5% of CBS, which is less than the recommended tension limit of 50% of CBS.

The mean offset of 3.0% of water depth under the maximum operating condition and the maximum offset of 11.2% of water depth under the maximum design condition should be checked against offset limits determined by a drilling riser analysis.

The maximum suspended line length is 4926 ft., which is less than the total outboard line length of 6000 ft. Therefore, no anchor uplift is expected.

The maximum anchor load is 236 kips which is less than the holding capacity of 280 kips predicted by Figure 27 for the 30-kip LWT anchor in sand. The mooring line should be test loaded to the maximum calculated line tension of 249 kips to achieve an anchor test load of 236 kips.

6.5 Comments on the Analysis for Quartering Environments. Environmental forces and vessel motions for a quartering environment (45° off the bow) may not have the same direction as the environment. However, for simplification, they are assumed to be collinear and in the direction of 45° off the bow. This assumption would be a good approximation for semisubmersibles, but appears conservative for drillships. However, the conservatism for drillships can be significantly offset by the practice of neglecting yaw moments in the analysis. Yaw moments for drillships under a quartering environment can be substantial.

SECTION 7
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TABLE 1
WIND FORCE SHAPE COEFFICIENTS

Exposed Area	C_s
Cylindrical shapes	0.50
Hull (surface above waterline)	1.00
Deck house	1.00
Isolated structural shapes (cranes, channels, beams, angles)	1.50
Under deck areas (smooth surfaces)	1.00
Under deck areas (exposed beams and girders)	1.30
Rig derrick	1.25

TABLE 2
WIND FORCE HEIGHT COEFFICIENTS

Height of area centroid above water level

Feet Over—Not Exceeding	Meters Over—Not Exceeding	C_h
0 — 50	.0 — 15.3	1.00
50 — 100	15.3 — 30.5	1.10
100 — 150	30.5 — 46.0	1.20
150 — 200	46.0 — 61.0	1.30
200 — 250	61.0 — 76.0	1.37

TABLE 3
CLASS CHARACTERISTICS OF FLOATING DRILLING UNITS

Type	Drilling Displacement (Long Tons)	Class
Semisubmersible	9000 - 14000	I
	14000 - 24000	II
	24000 - 40000	III
Ship Shape	9000	I
	22000	II

TABLE 4
COEFFICIENT OF FRICTION FOR CHAIN AND WIRE ROPE

	Starting	Sliding
Chain	1.0	0.7
Wire Rope	0.6	0.25

TABLE 5
ENVIRONMENTAL CONDITION

	Maximum Operating Condition	Maximum Design Condition
Wind Velocity (1-minute, knot)	35	54
Significant Wave Height (ft)	10	20
Significant Wave Period (Figure 4, Section 1.5)	6.8	9.5
Current Velocity (knot)	1	2
Water Depth (ft)	550	550
Bottom Soil Condition	Sand	Sand

Wind, wave and current have no predominant directions; therefore, collinear environments are applied to bow, quartering and beam seas.

TABLE 6
MAXIMUM DESIGN CONDITION
ENVIRONMENTAL FORCES AND VESSEL MOTIONS

	Bow	Beam	Quartering
FORCE (kip)			
Wind	93.0	108.3	134.2
Current	2.3	58.6	40.6
Mean Wave Drift	10.5	70.5	42.4
Total Steady State Force	105.8	237.4	217.2
MOORING SYSTEM STIFFNESS (kip/ft) (Using Figures 32, 33 and 34)	7.0	8.5	8.8
VESSEL MOTION (ft)			
Sig. Wave Frequency Motion	3.87	9.19*	8.60
Max. Wave Frequency Motion	7.20*	17.09	16.00*
Sig. Low Frequency Motion	4.16*	11.08	7.18*
Max. Low Frequency Motion	6.55	17.62*	11.44
Combined Wave Frequency and Low Frequency Motions (Section 4.1)	11.36	26.81	23.18

*Used to obtain the combined wave frequency and low frequency motions.

TABLE 7
MAXIMUM DESIGN CONDITION
MOORING ANALYSIS RESULTS — INITIAL TENSION 75 KIPS

	Bow	Beam	Quartering
Mean Vessel Offset (ft)	16.5	34.7	31.4
Maximum Vessel Offset (ft)	27.9	61.5	54.6
Most Loaded Line			
Maximum Line Tension (kip)	128.4	249.1	245.9
Percent of CBS	18.5	35.8	35.4
Suspended Line Length (ft)	3518.	4926.	4895.
Maximum Anchor Load (kips)	106.4	235.8	232.4

TABLE 8
MAXIMUM OPERATION CONDITION
ENVIRONMENTAL FORCES AND VESSEL MOTIONS

	Bow	Beam	Quartering
FORCE (kip)			
Wind	39.1	45.5	56.4
Current	0.6	14.6	10.1
Mean Wave Drift	7.3	46.2	25.4
	47.0	106.3	91.9
MOORING SYSTEM STIFFNESS (kip/ft) (Using Figures 32, 33 and 34)	6.5	7.0	7.0
VESSEL MOTION (ft)			
Sig. Wave Frequency Motion	0.80	3.59	3.51
Max. Wave Frequency Motion	1.49	6.68	6.53
Sig. Low Frequency Motion	2.70	8.31	5.72
Max. Low Frequency Motion	4.23	13.09	9.00
Combined Wave Frequency and Low Frequency Motions (Section 4.1)	5.03	16.68	12.51

TABLE 9
MAXIMUM OPERATION CONDITION
MOORING ANALYSIS RESULTS — INITIAL TENSION 75 KIPS

	Bow	Beam	Quartering
Mean Vessel Offset (ft)	7.5	16.6	14.3
Maximum Vessel Offset (ft)	12.5	33.3	26.8
Most Loaded Line			
Maximum Line Tension (kip)	94.7	143.1	133.5
Percent of CBS	13.6	20.6	19.2
Suspended Line Length (ft)	3010.	3718.	3588.
Maximum Anchor Load (kips)	68.7	121.8	111.3

TABLE 10
SUMMARY OF MOORING ANALYSIS RESULTS

Environmental Condition	Offset, ft. (% W.D.) Mean	Max.	Max. Line Tension Kips (% of CBS)	Max. Suspended Line Length (ft)	Max. Anchor Load (kips)
Maximum Operating					
Bow	7.5 (1.4)	12.5 (2.3)	94.7 (13.6)	3010.	68.7
Beam	16.6 (3.0)	33.3 (6.1)	143.1 (20.6)	3718.	121.8
Quartering	14.3 (2.6)	26.8 (4.9)	133.5 (19.2)	3588.	111.3
Maximum Design					
Bow	16.5 (3.0)	27.9 (5.1)	128.4 (18.5)	3518.	105.8
Beam	34.7 (6.3)	61.5 (11.2)	249.1 (35.8)	4926.	235.8
Quartering	31.4 (5.7)	54.6 (9.9)	245.9 (35.4)	4895.	232.4

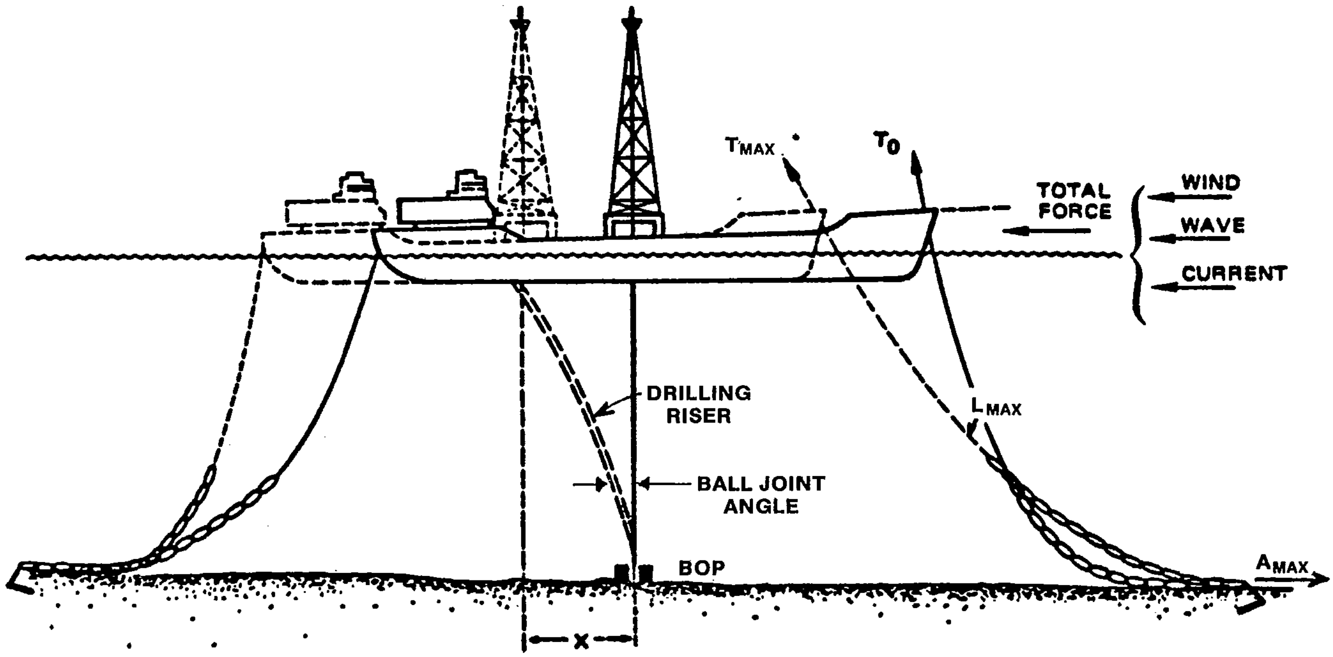


FIG. 1
DRILLING VESSEL MOORING SYSTEM

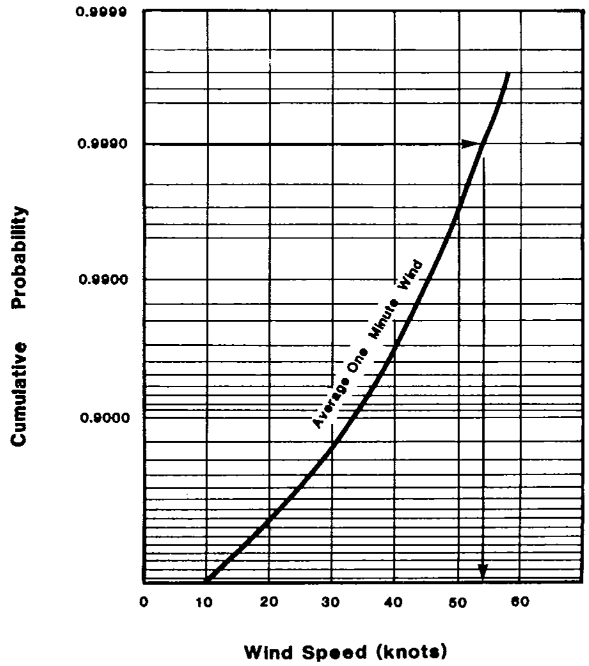


FIG. 2
TYPICAL DESIGN WIND SPEED DATA

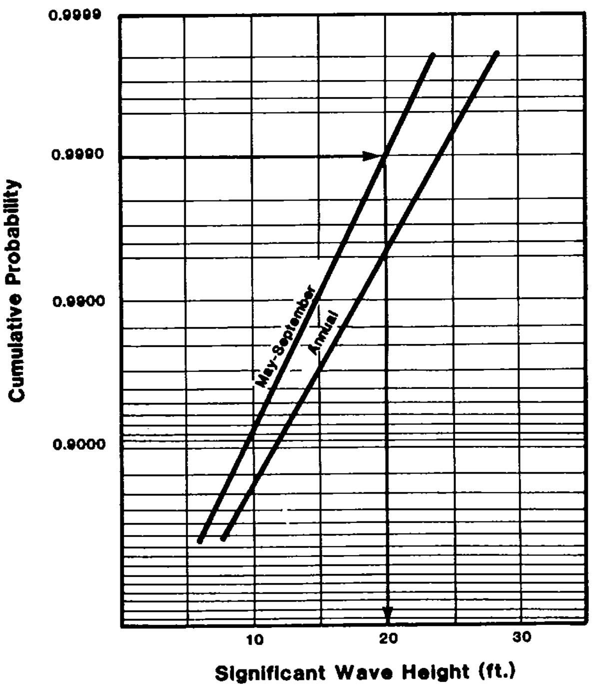


FIG. 3
TYPICAL DESIGN WAVE HEIGHT DATA

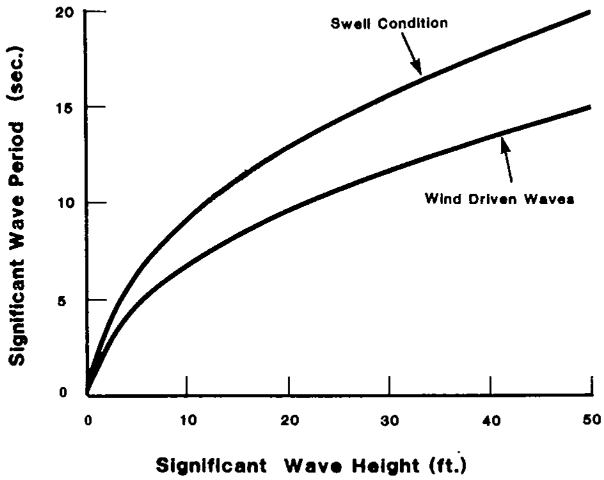


FIG. 4
WAVE HEIGHT/WAVE PERIOD RELATIONSHIPS

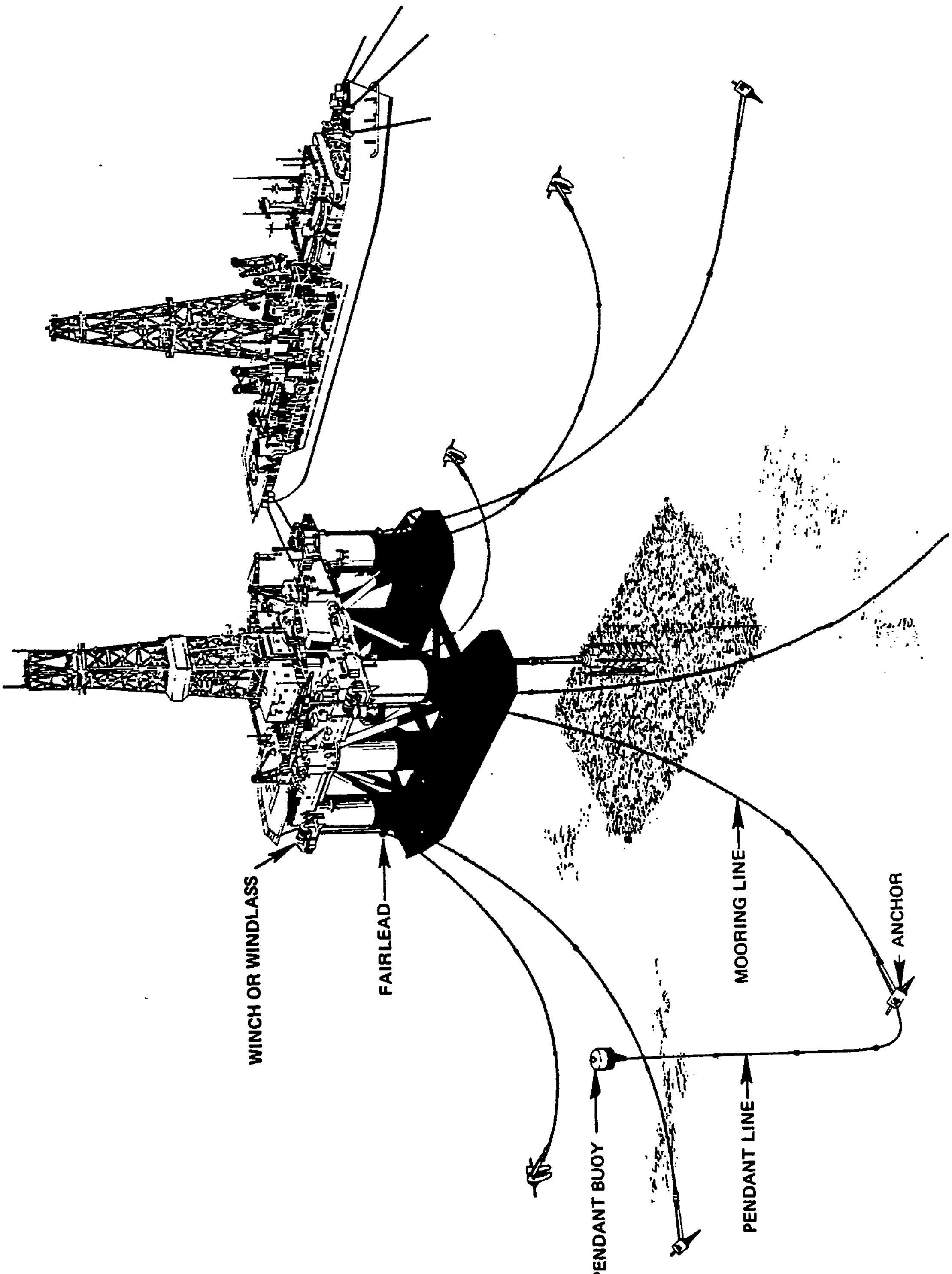


FIG. 5
SPREAD MOORING FOR SEMISUBMERSIBLES AND DRILLSHIPS

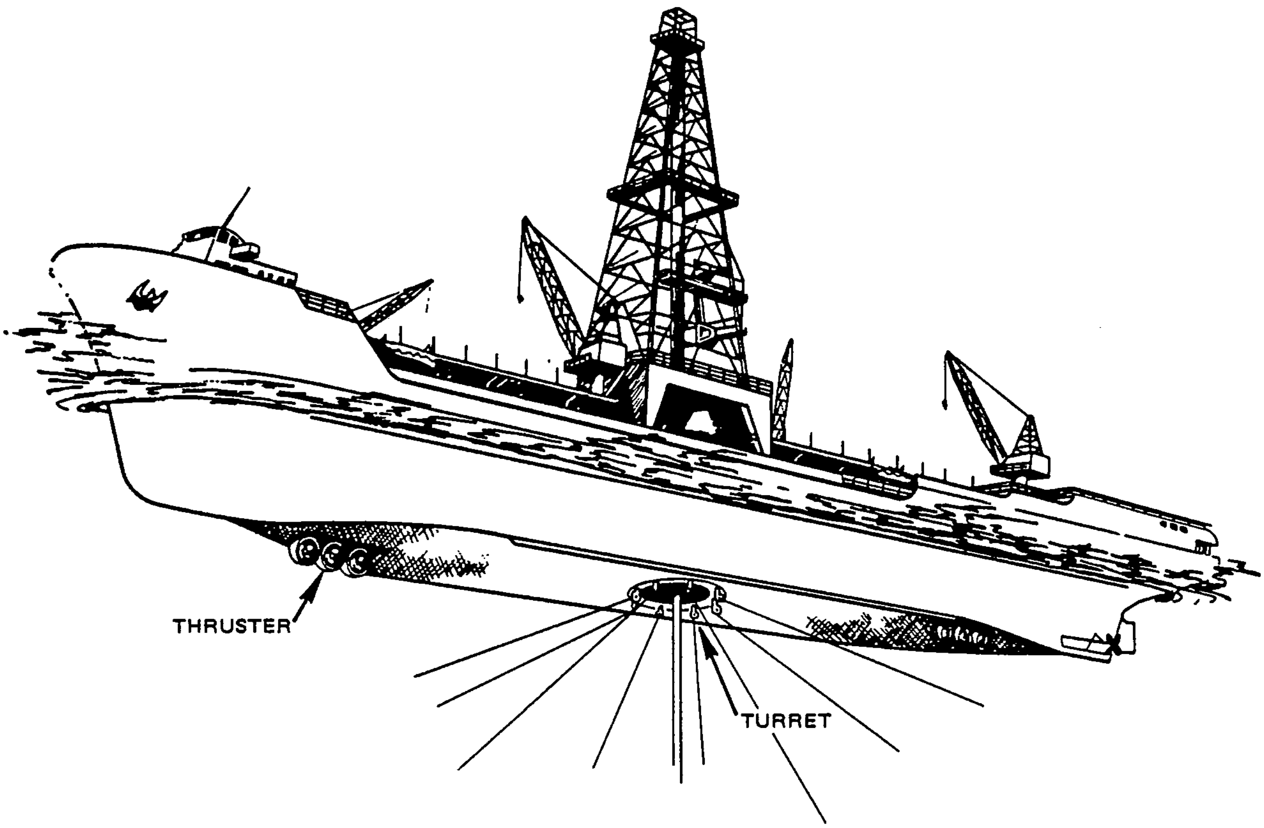


FIG. 6
TURRET MOORED DRILLSHIP

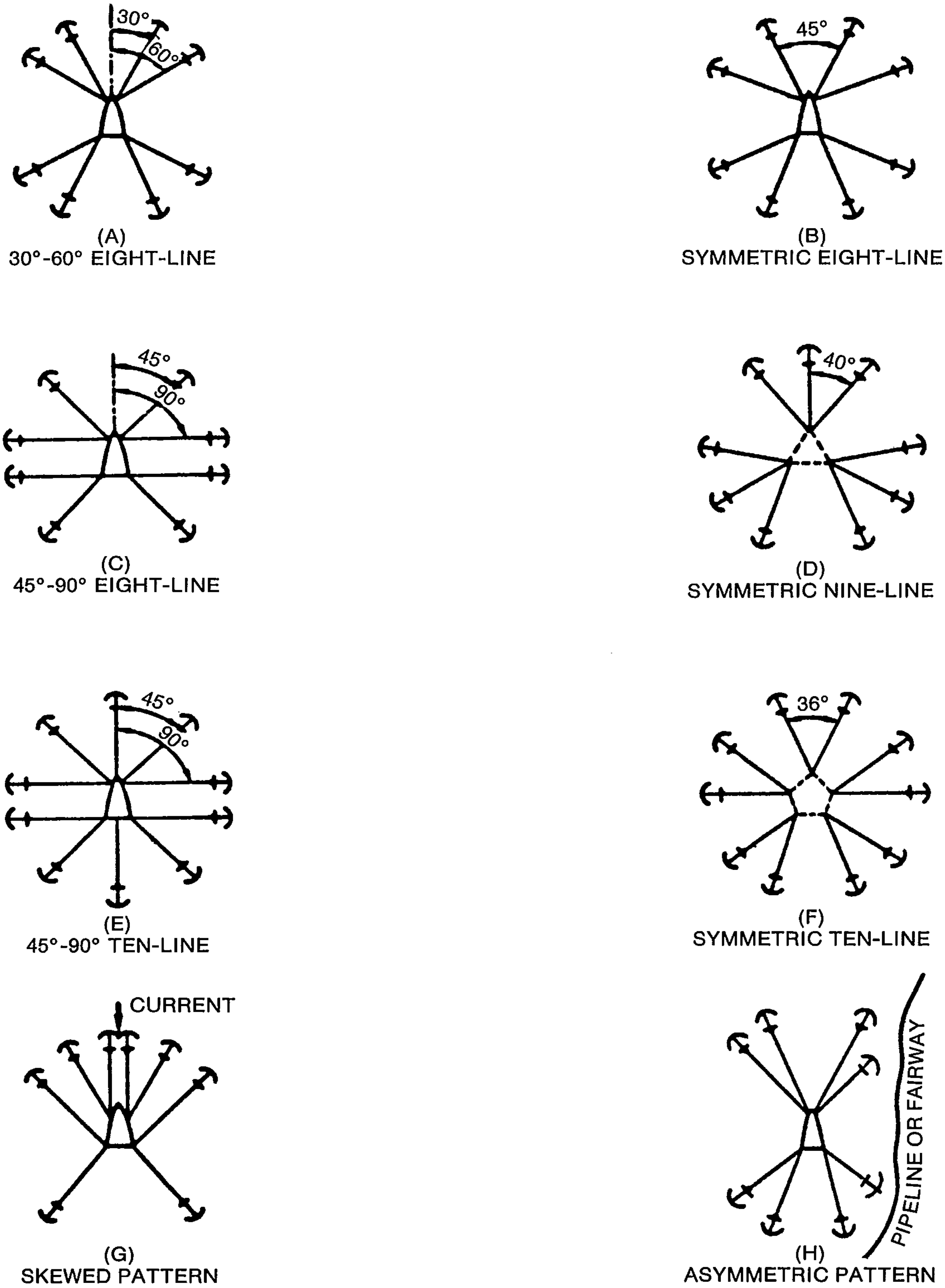


FIG. 7
MOORING PATTERNS

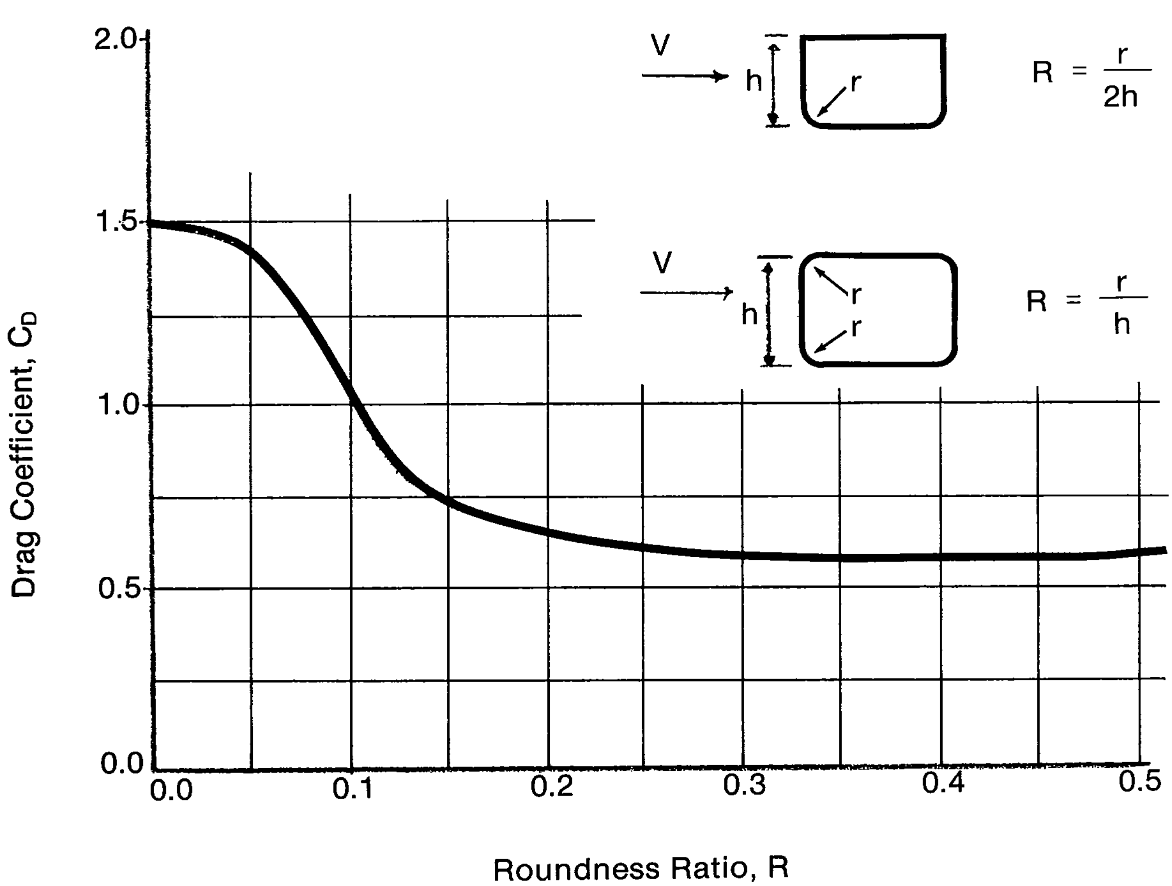


FIG. 8
SEMISUBMERSIBLE CURRENT DRAG COEFFICIENT FOR MEMBERS HAVING FLAT SURFACES

FIG. 9
WAVE DRIFT FORCE AND MOTION FOR DRILLSHIPS
BOW SEAS

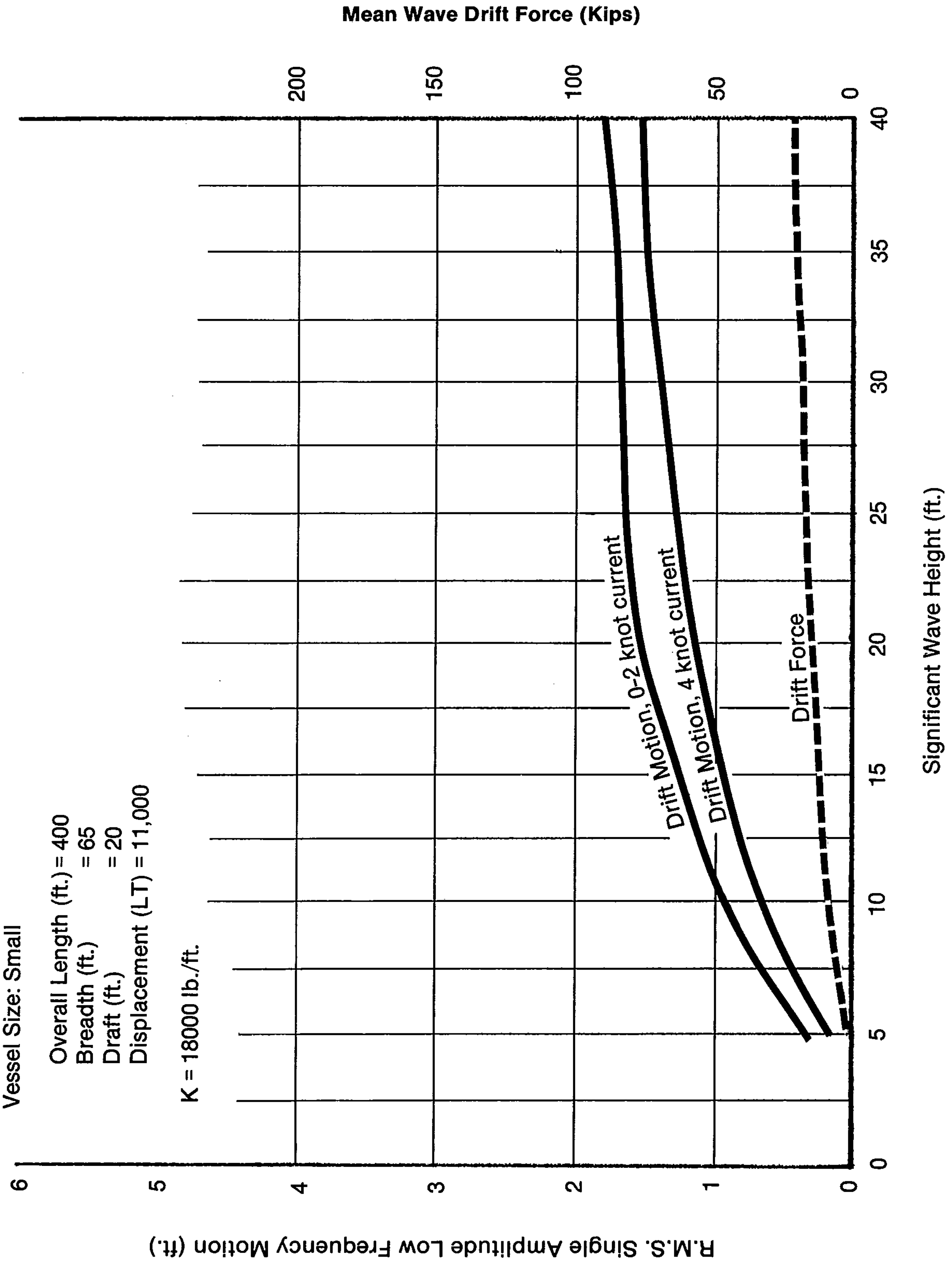


FIG. 10
WAVE DRIFT FORCE AND MOTION FOR DRILLSHIPS
BOW SEAS

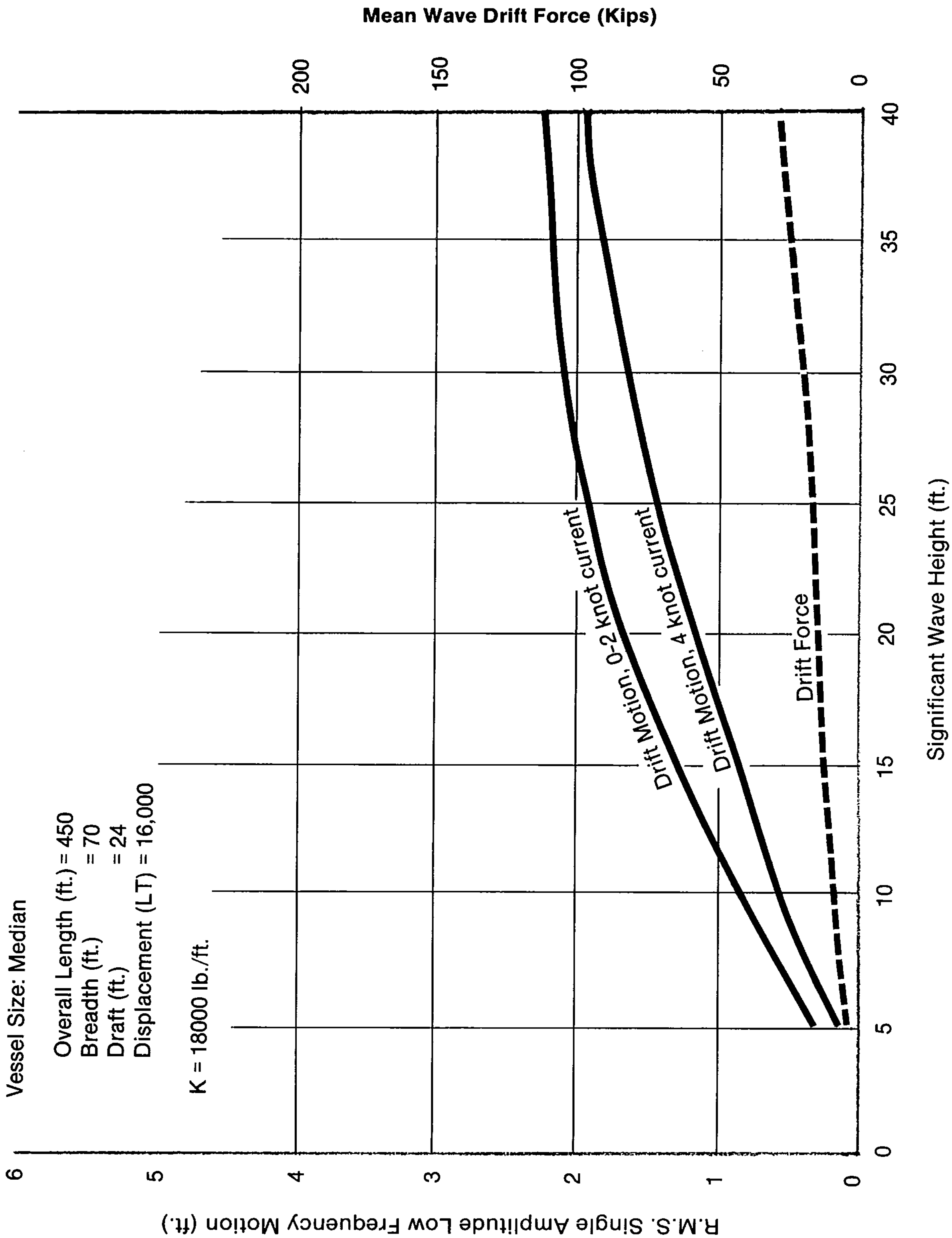


FIG. 11
WAVE DRIFT FORCE AND MOTION FOR DRILLSHIPS
BOW SEAS

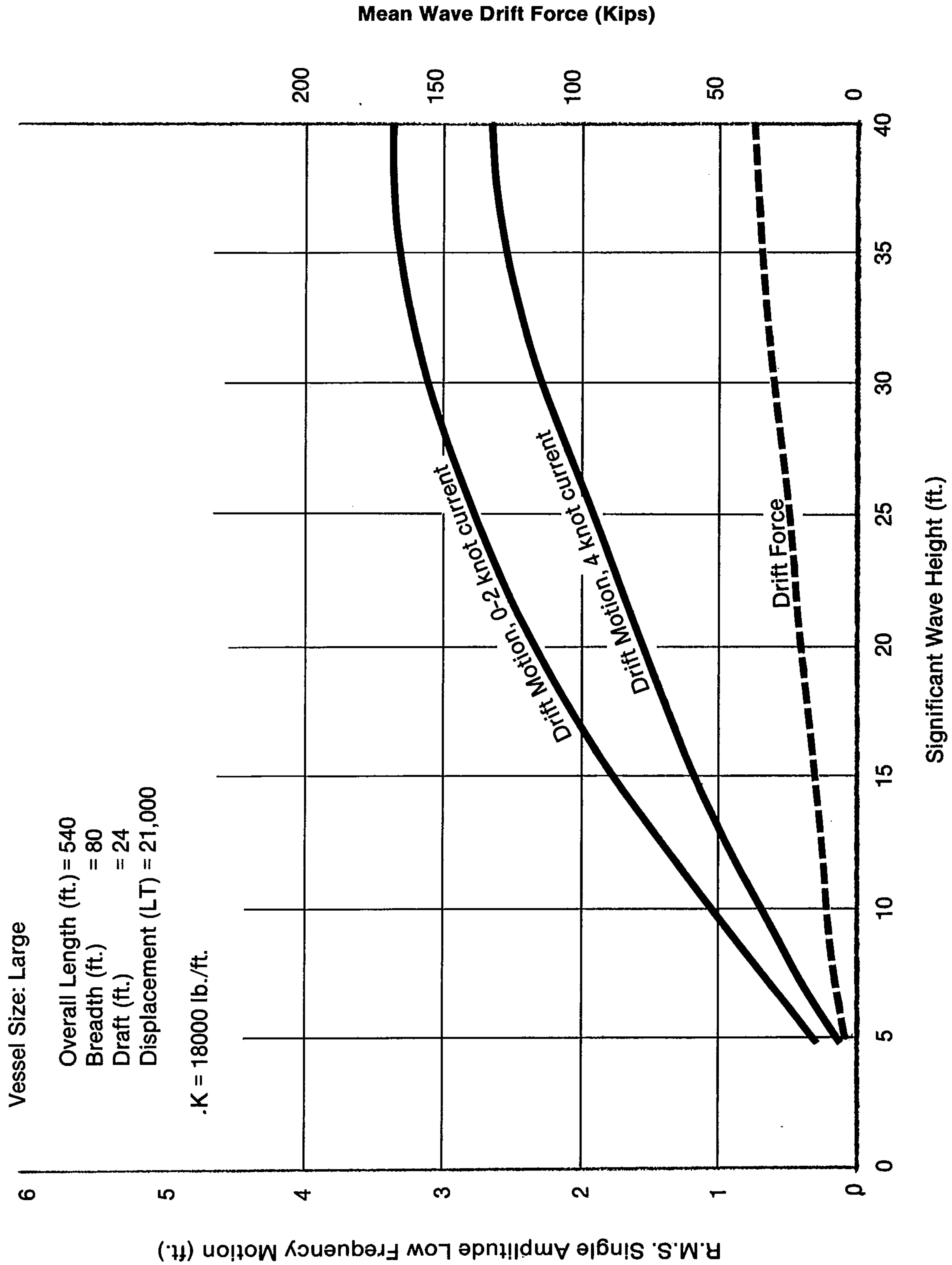


FIG. 12
WAVE DRIFT FORCE AND MOTION FOR DRILLSHIPS
QUARTERING SEAS, SURGE

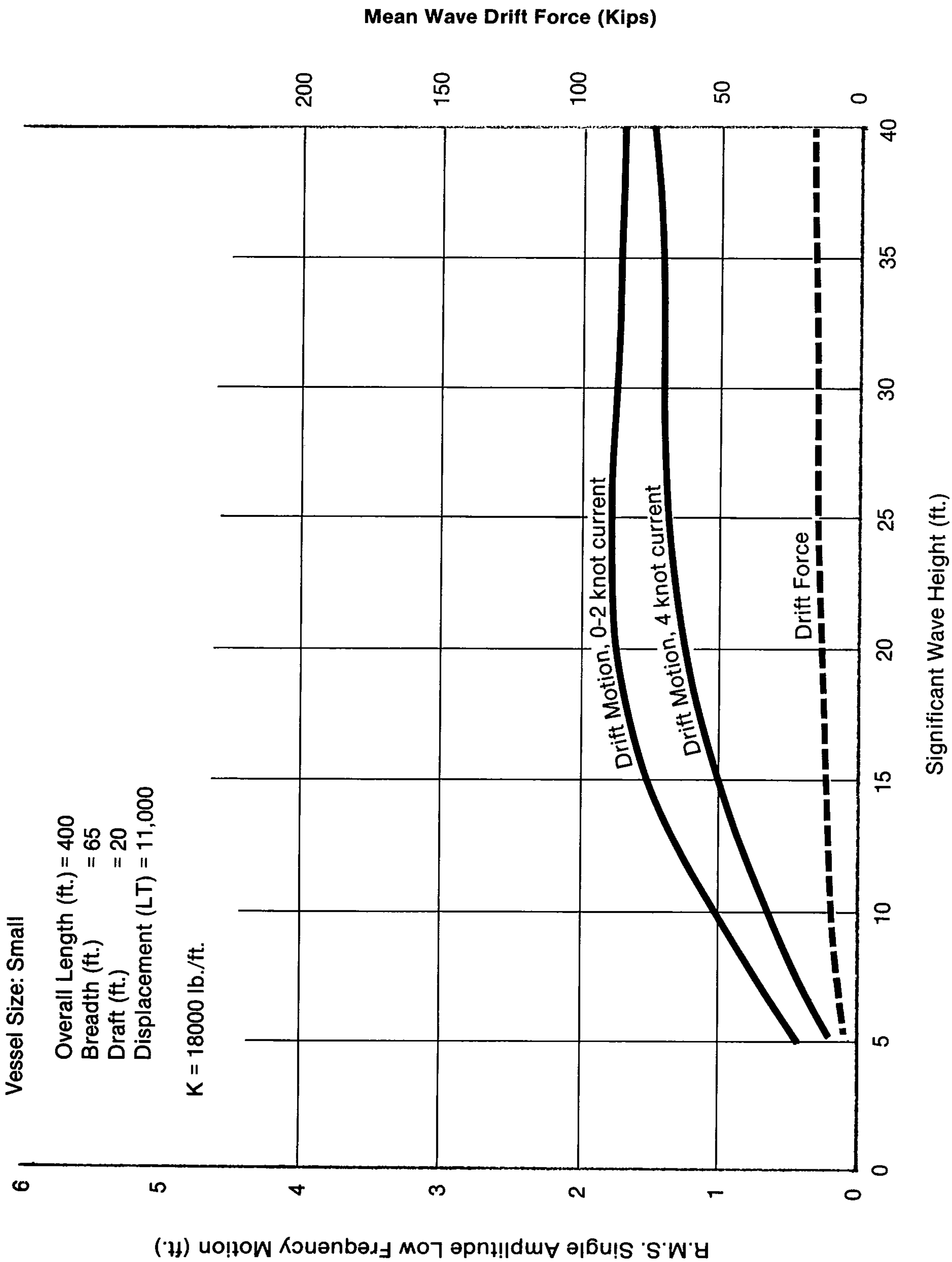


FIG. 13
WAVE DRIFT FORCE AND MOTION FOR DRILLSHIPS
QUARTERING SEAS, SURGE

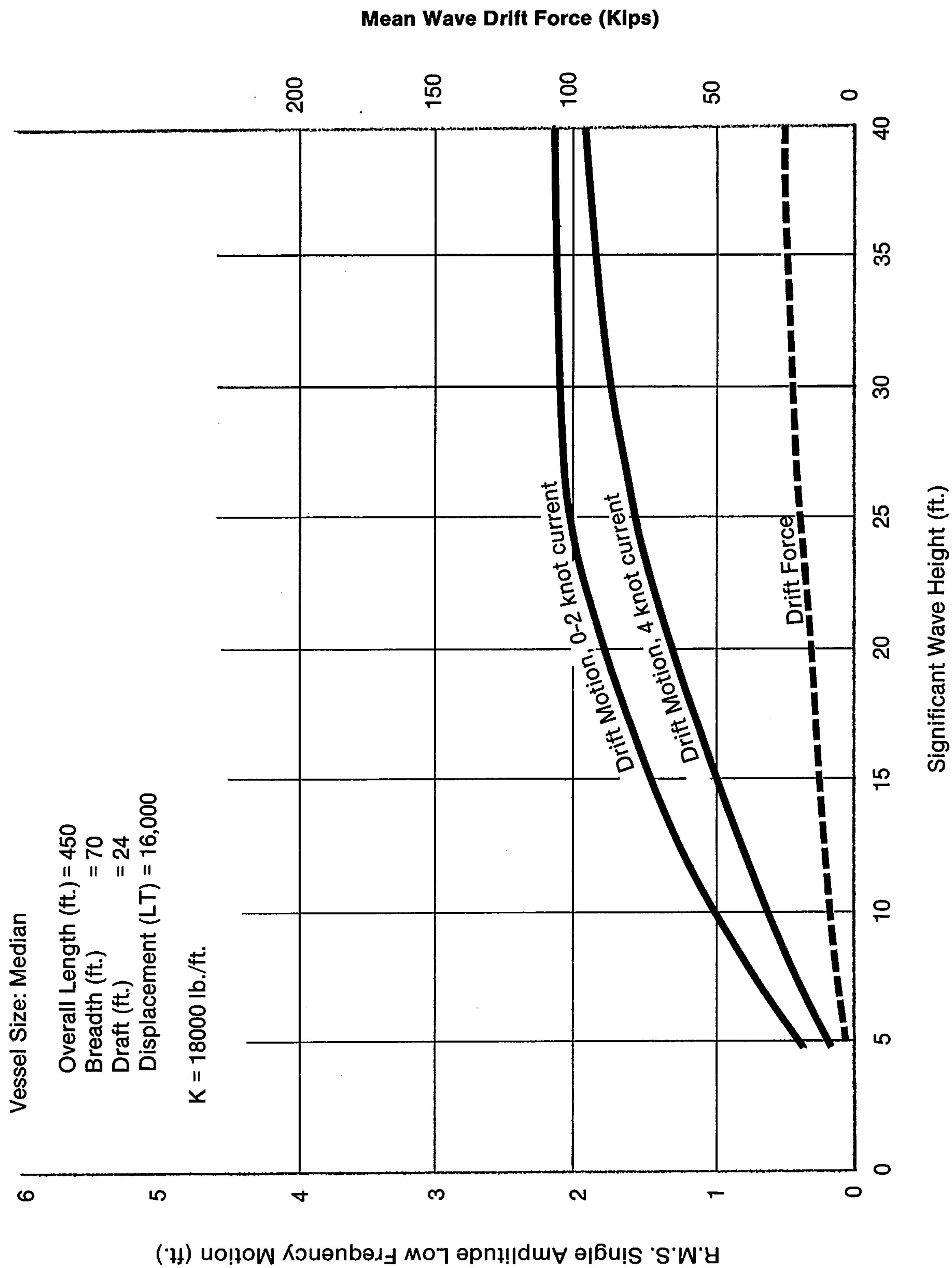


FIG. 14
WAVE DRIFT FORCE AND MOTION FOR DRILLSHIPS
QUARTERING SEAS, SURGE

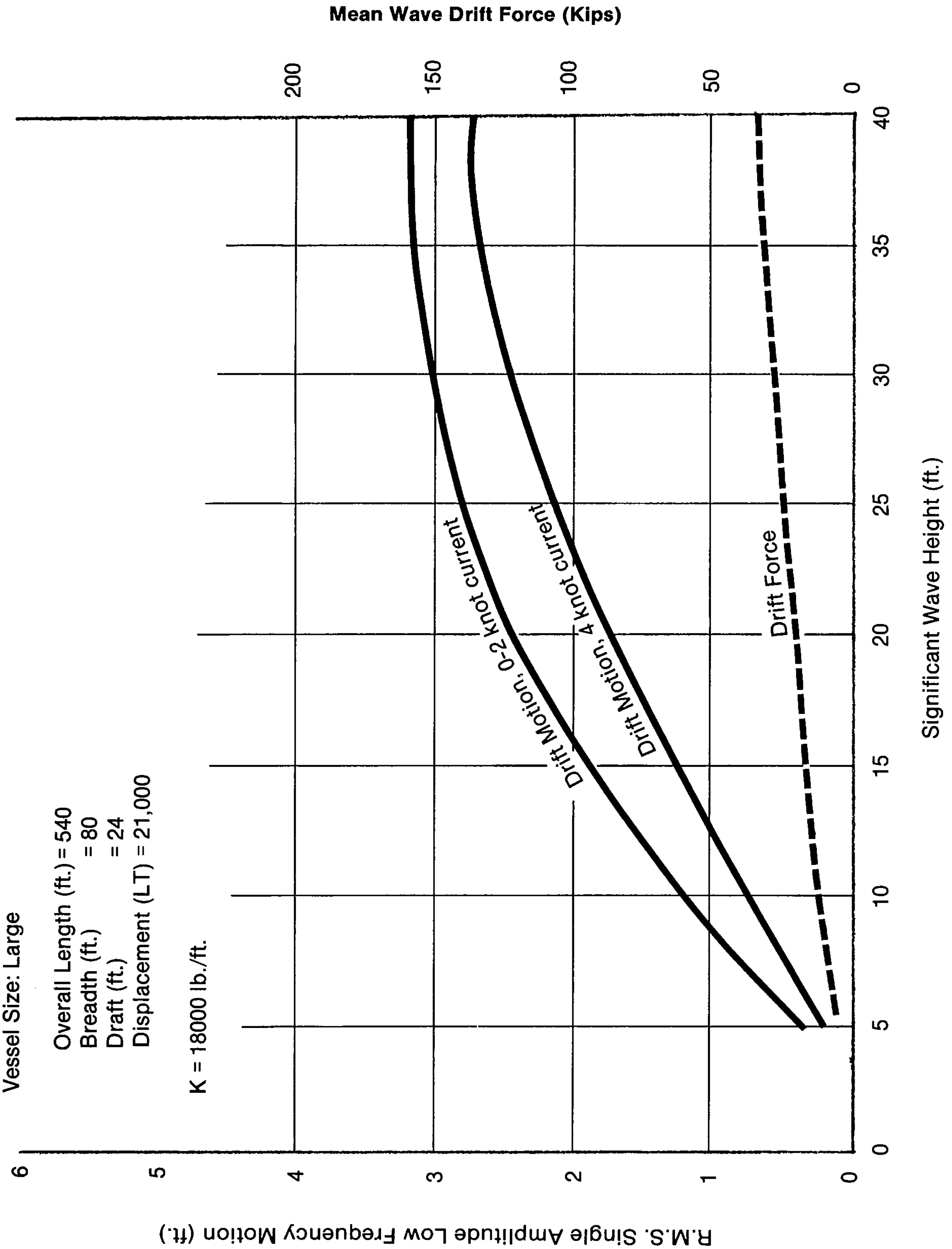
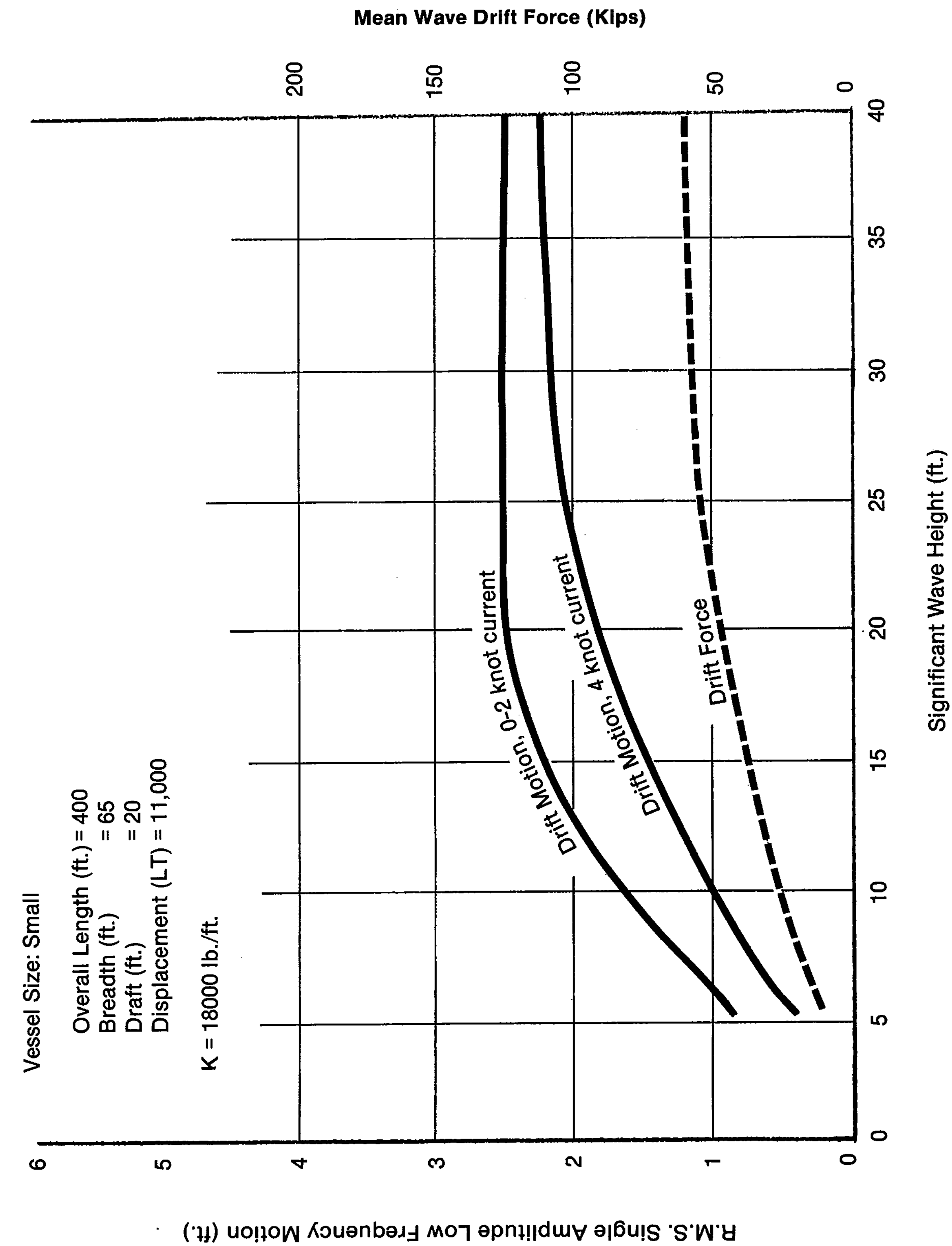


FIG. 15
WAVE DRIFT FORCE AND MOTION FOR DRILLSHIPS
QUARTERING SEAS, SWAY



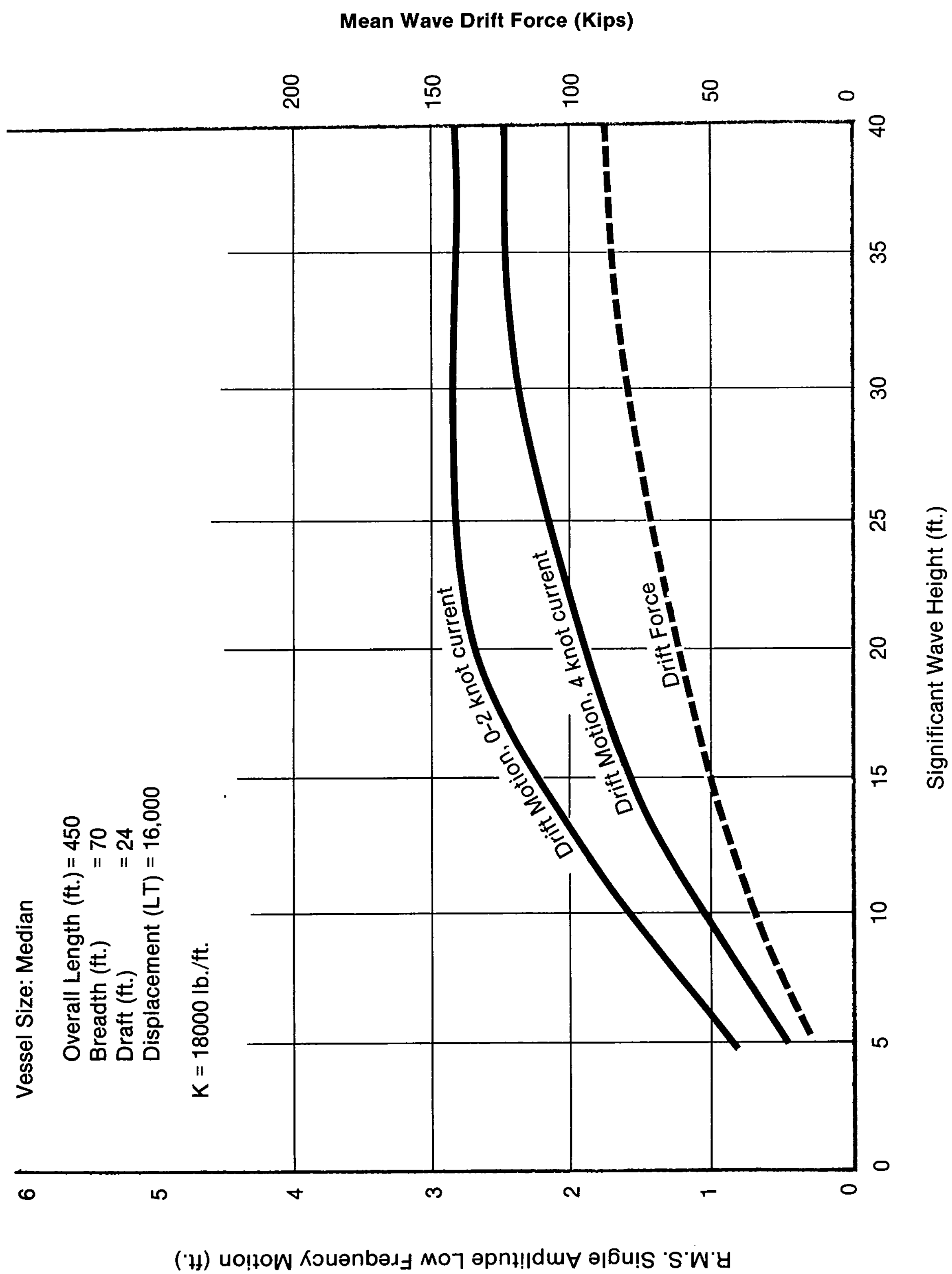


FIG. 16
WAVE DRIFT FORCE AND MOTION FOR DRILLSHIPS
QUARTERING SEAS, SWAY

FIG. 17
WAVE DRIFT FORCE AND MOTION FOR DRILLSHIPS
QUARTERING SEAS, SWAY

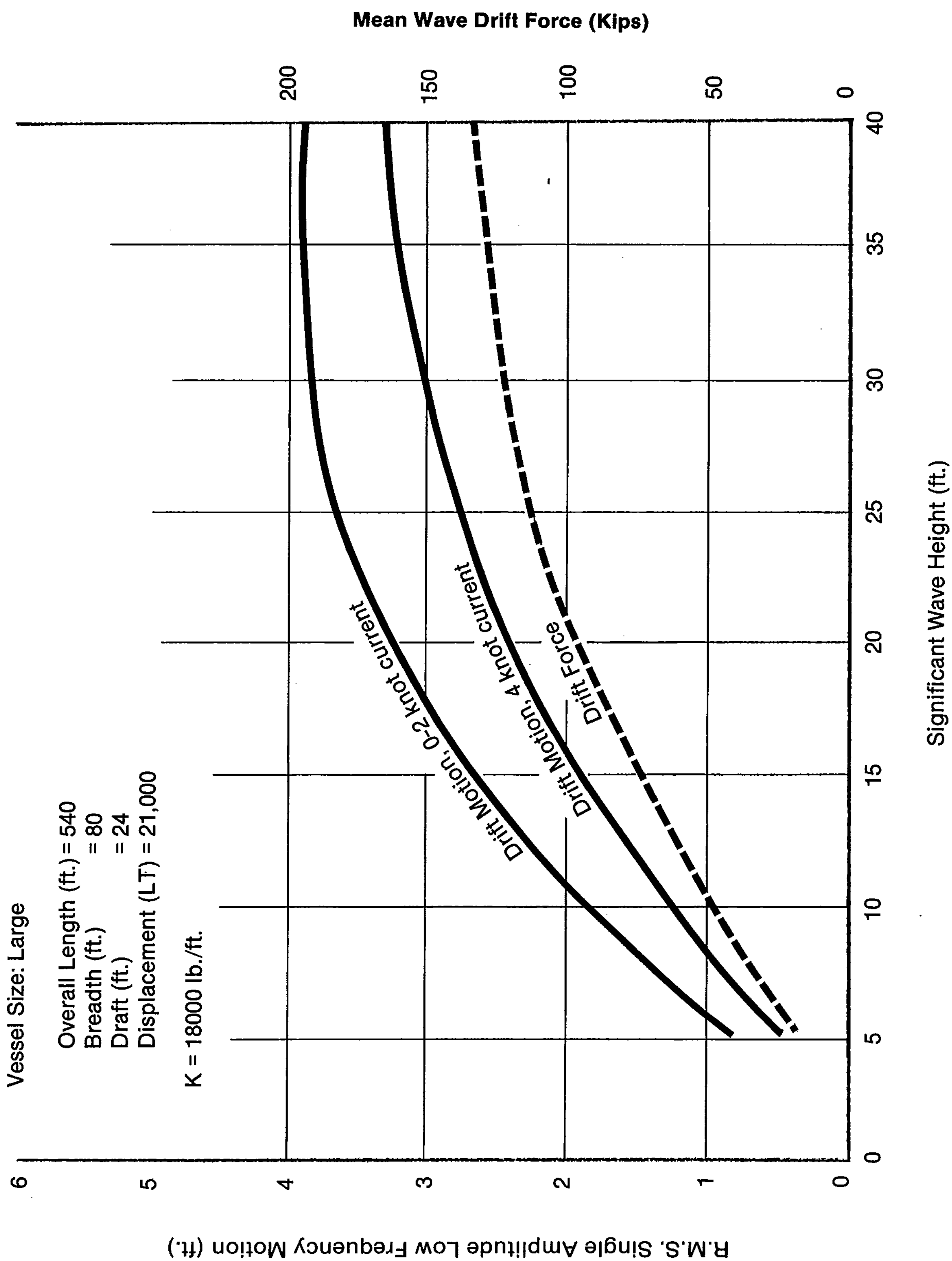


FIG. 18
WAVE DRIFT FORCE AND MOTION FOR DRILLSHIPS
BEAM SEAS

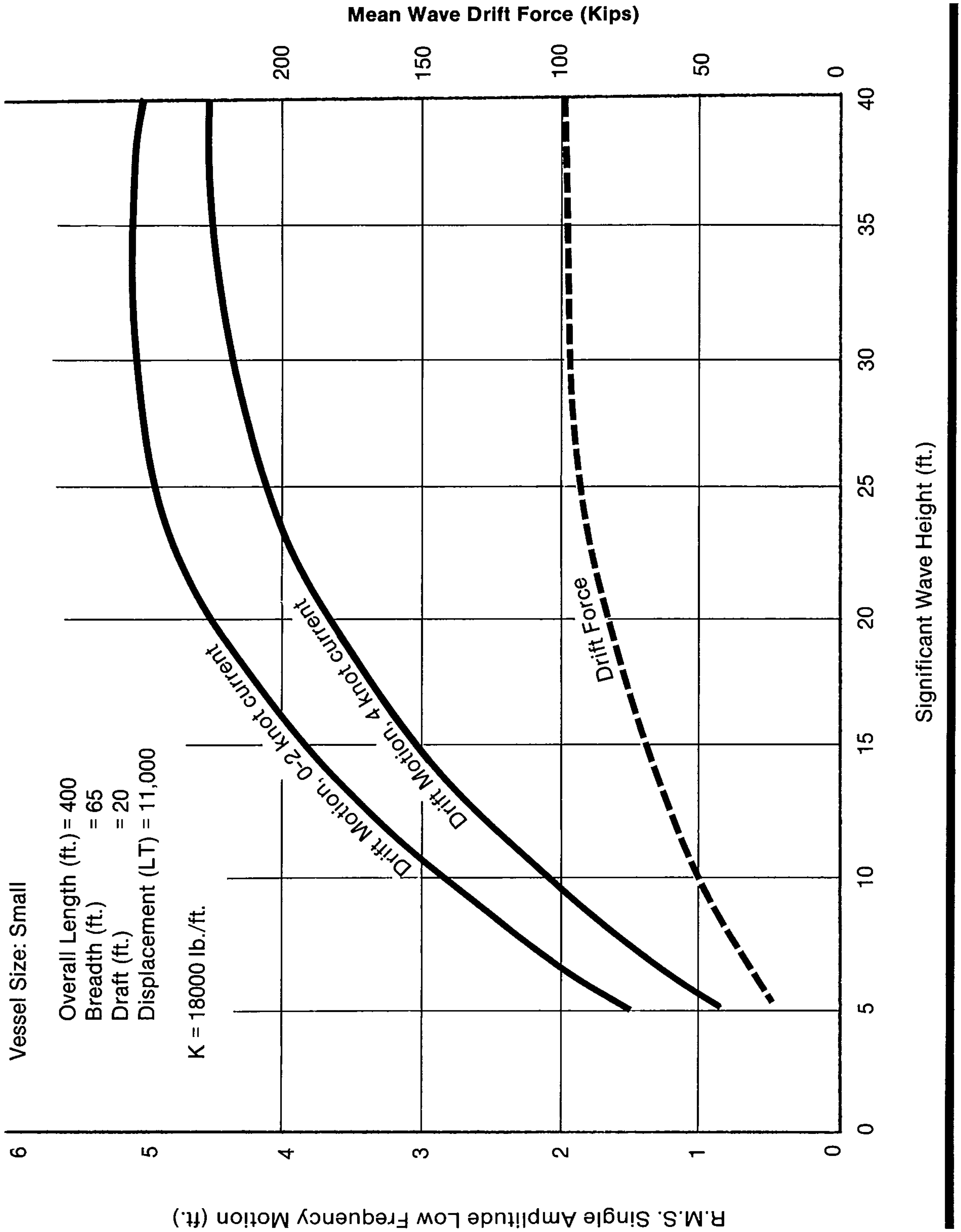
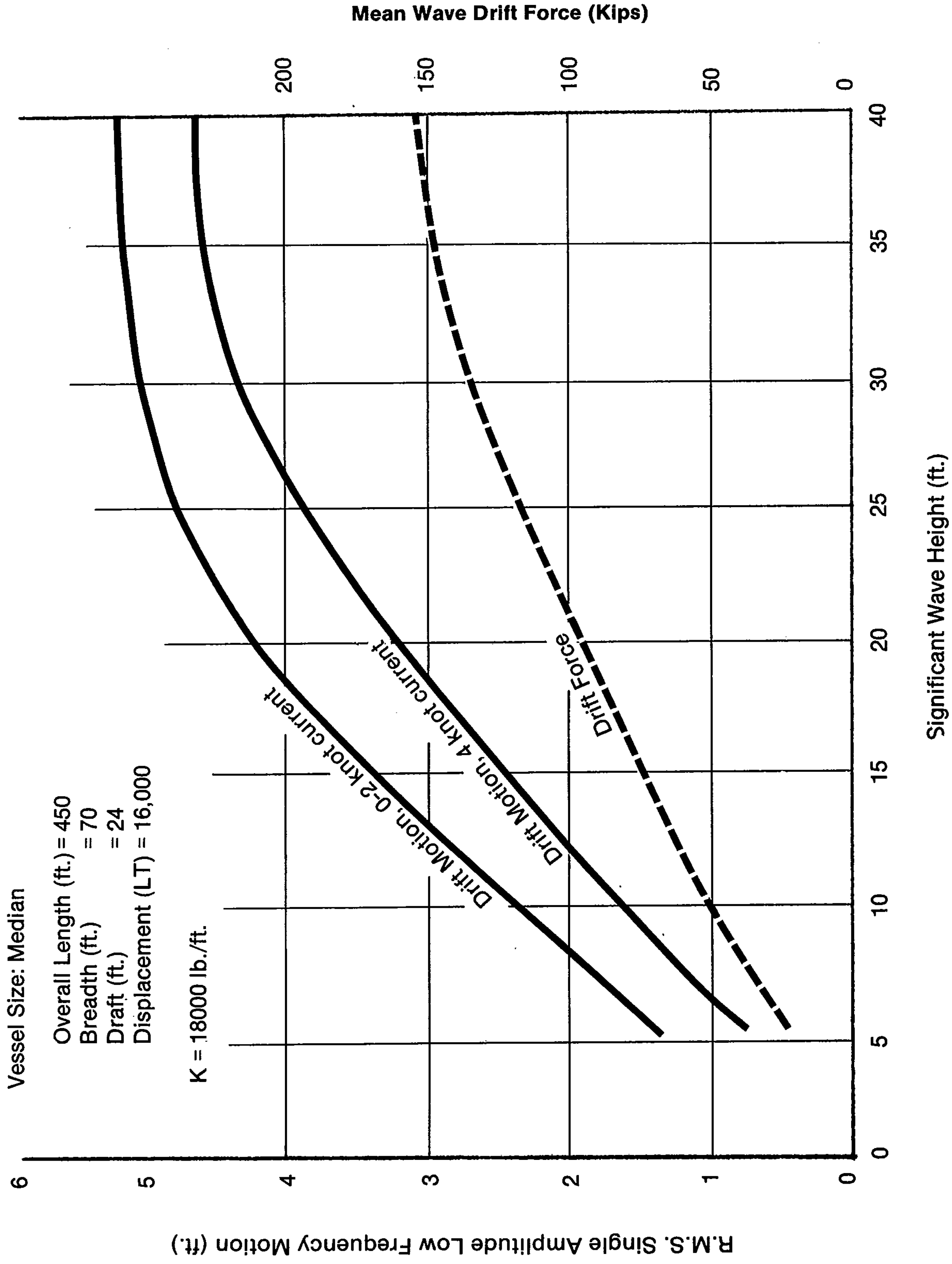


FIG. 19
WAVE DRIFT FORCE AND MOTION FOR DRILLSHIPS
BEAM SEAS



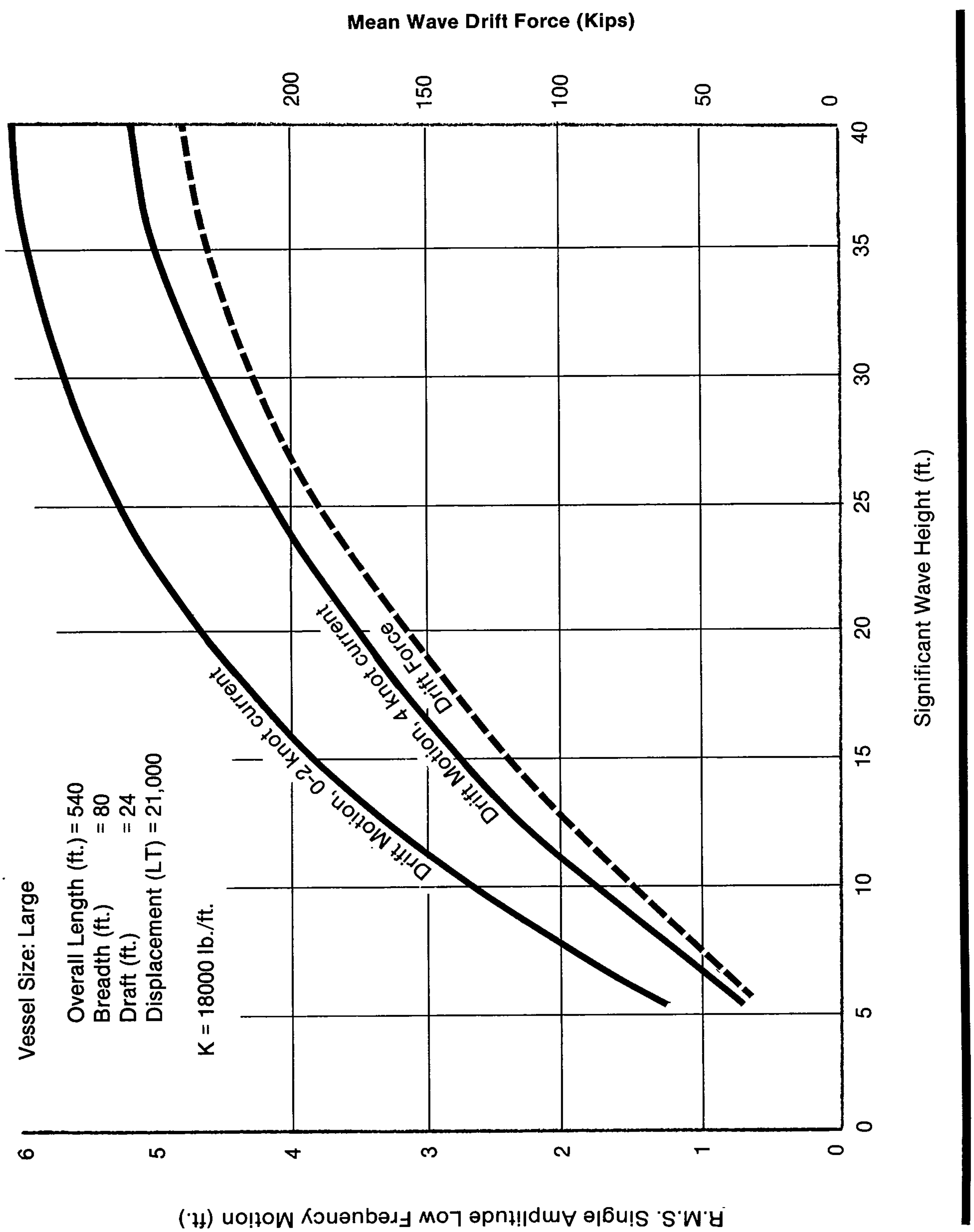


FIG. 20
WAVE DRIFT FORCE AND MOTION FOR DRILLSHIPS
BEAM SEAS

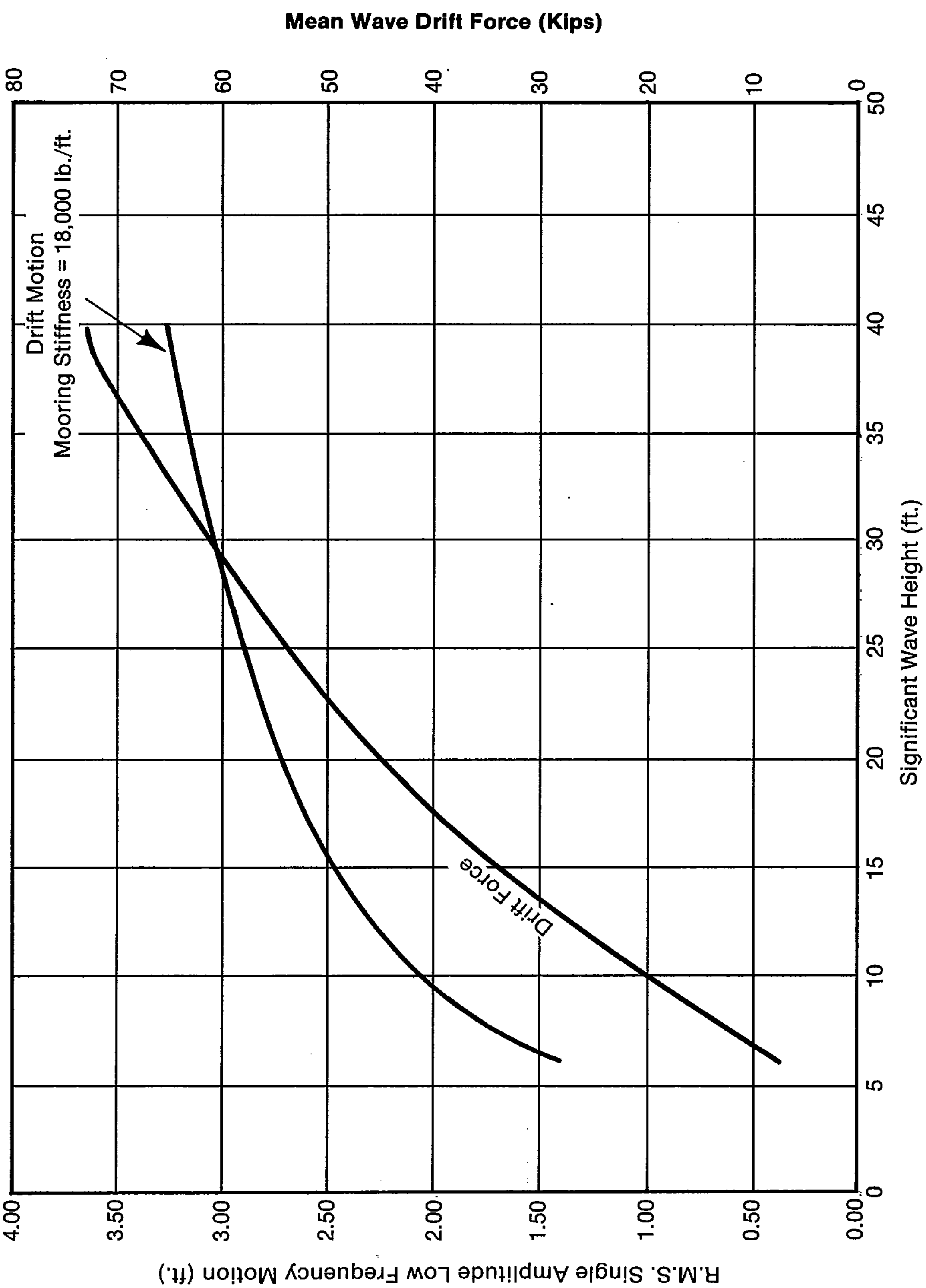


FIG. 21
WAVE DRIFT FORCE AND MOTION FOR SEMISUBMERSIBLES — BOW SEAS

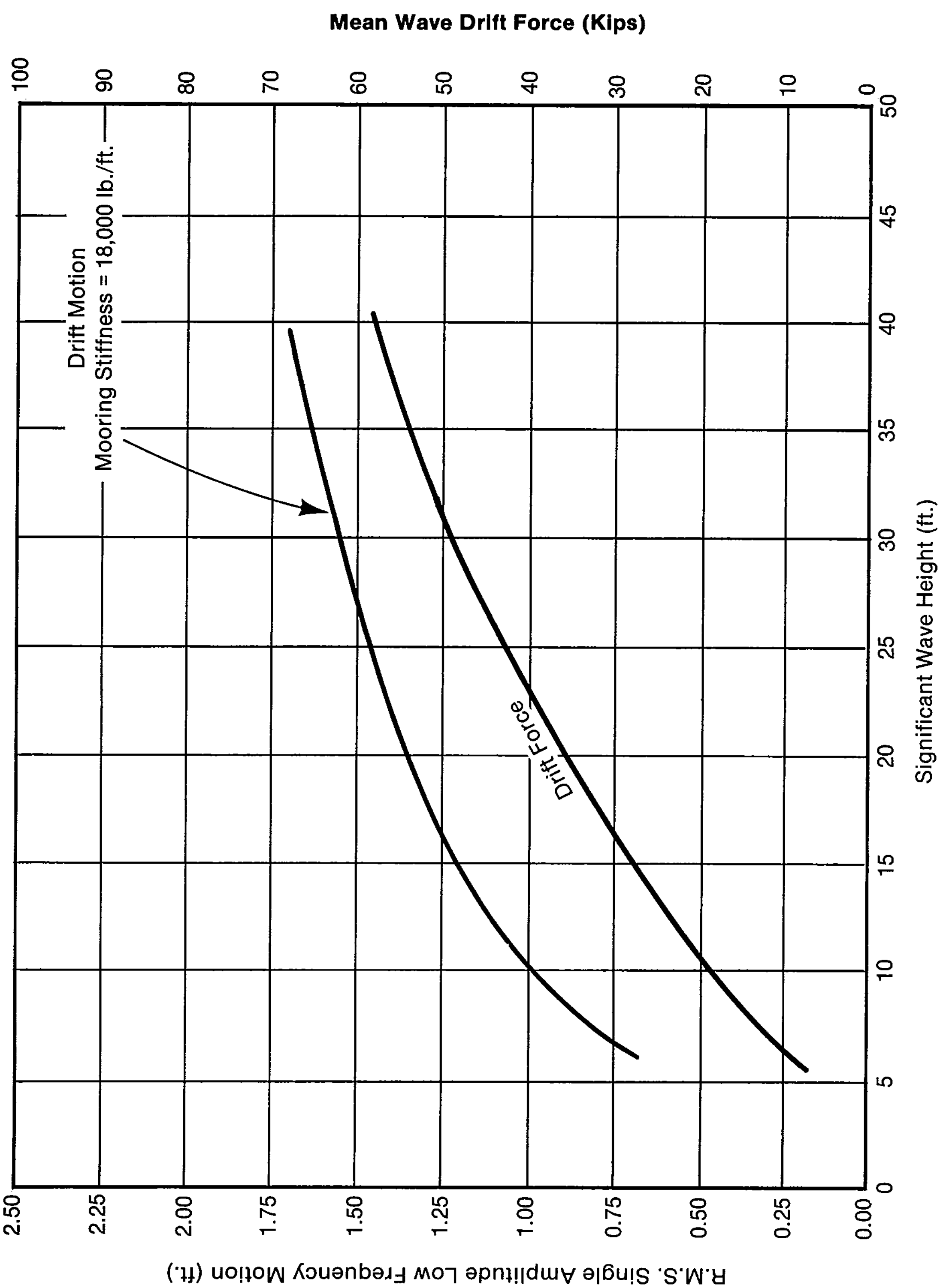


FIG. 22
WAVE DRIFT FORCE AND MOTION FOR SEMISUBMERSIBLES — QUARTERING SEAS

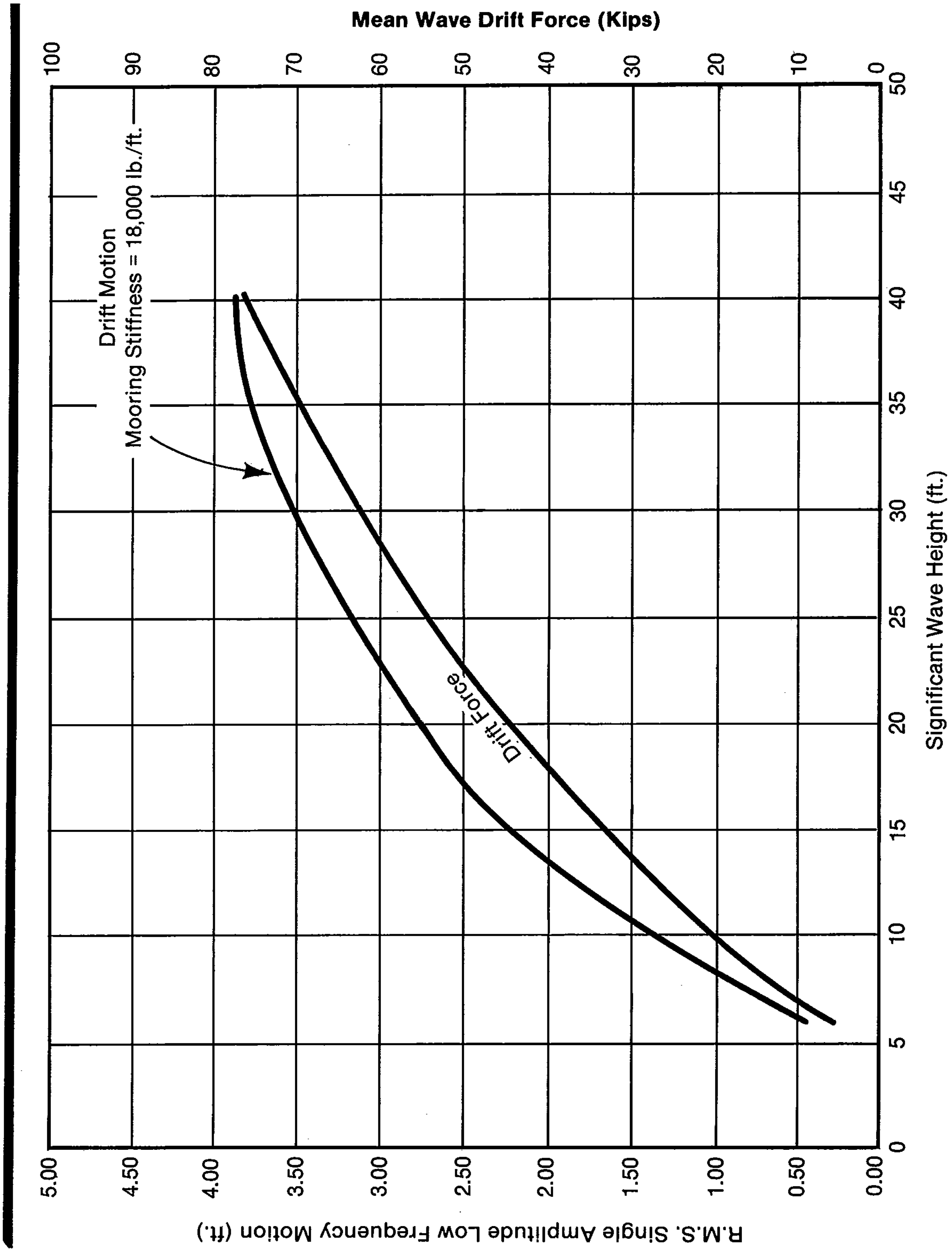


FIG. 23
WAVE DRIFT FORCE AND MOTION FOR SEMISUBMERSIBLES — BEAM SEAS

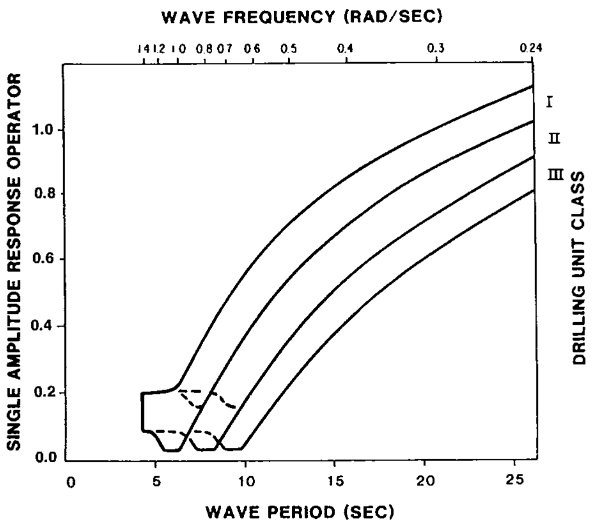


FIG. 24
SURGE OR SWAY
RESPONSE AMPLITUDE OPERATORS
FOR SEMISUBMERSIBLE DRILLING UNITS

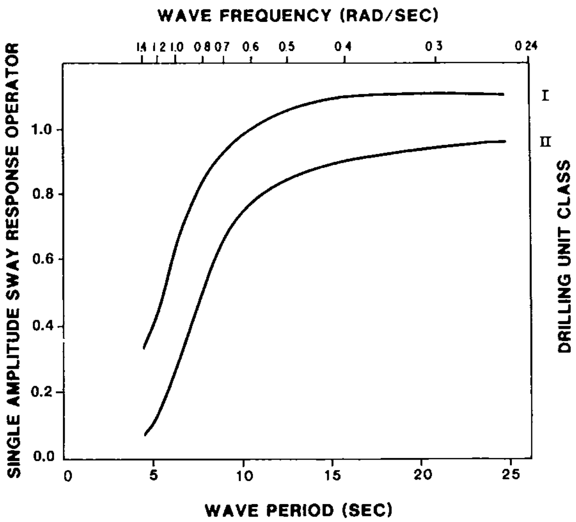


FIG. 26
SWAY RESPONSE
AMPLITUDE OPERATORS
FOR SHIP-SHAPE DRILLING UNITS

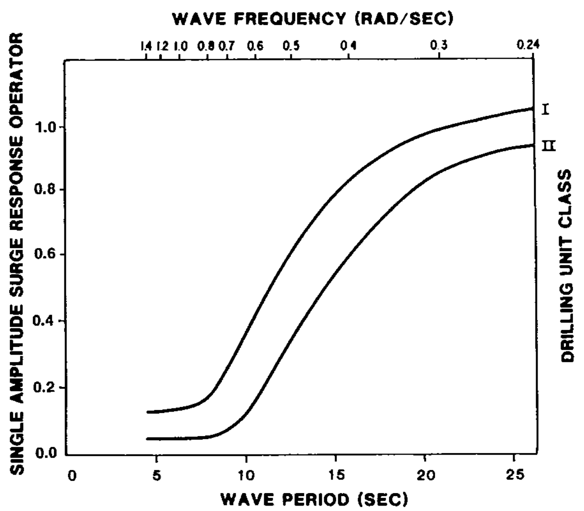


FIG. 25
SURGE RESPONSE
AMPLITUDE OPERATORS
FOR SHIP-SHAPE DRILLING UNITS

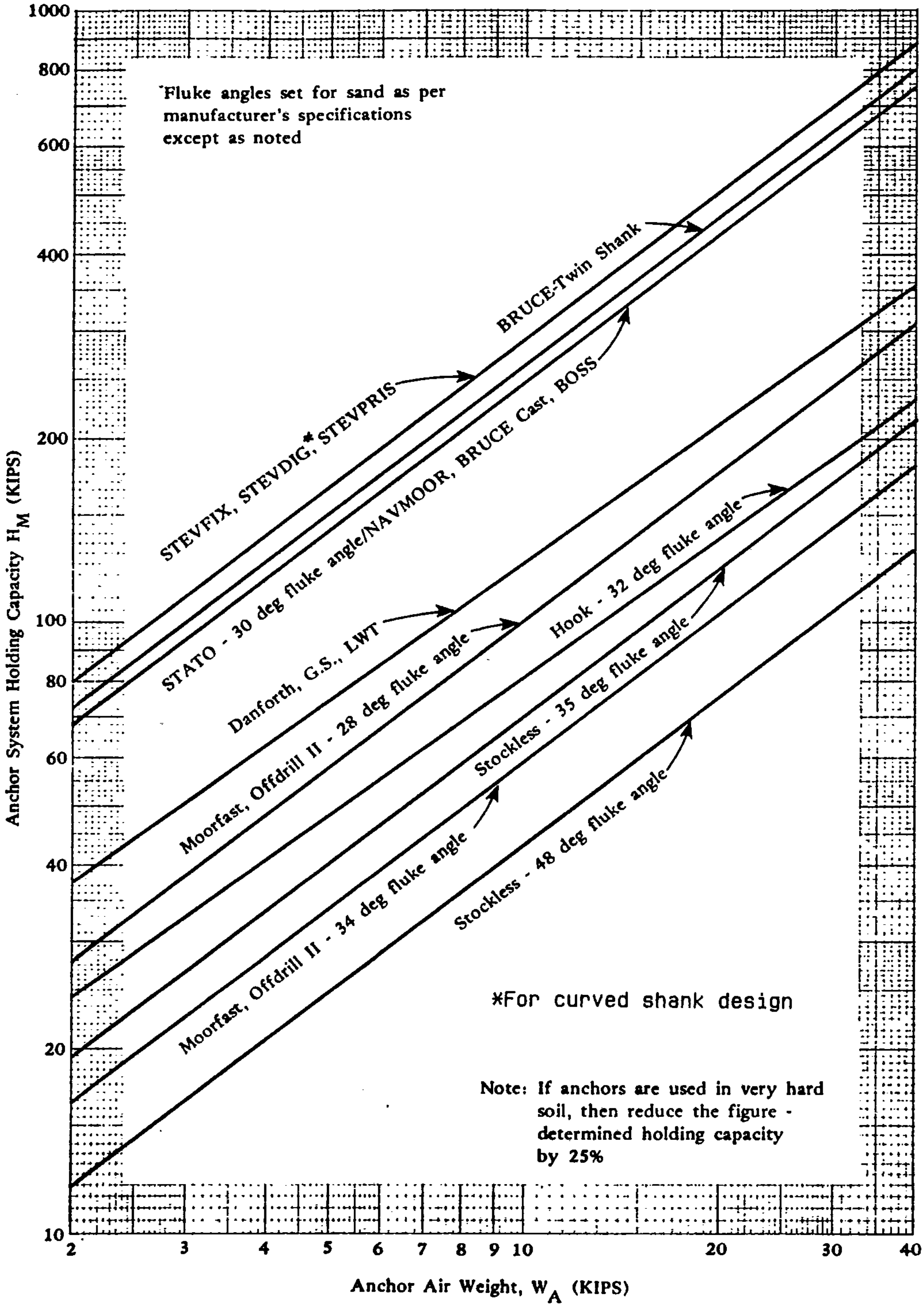


FIG. 27
ANCHOR CHAIN SYSTEM HOLDING CAPACITY AT THE MUD LINE IN HARD SOILS (SAND AND STIFF CLAY)

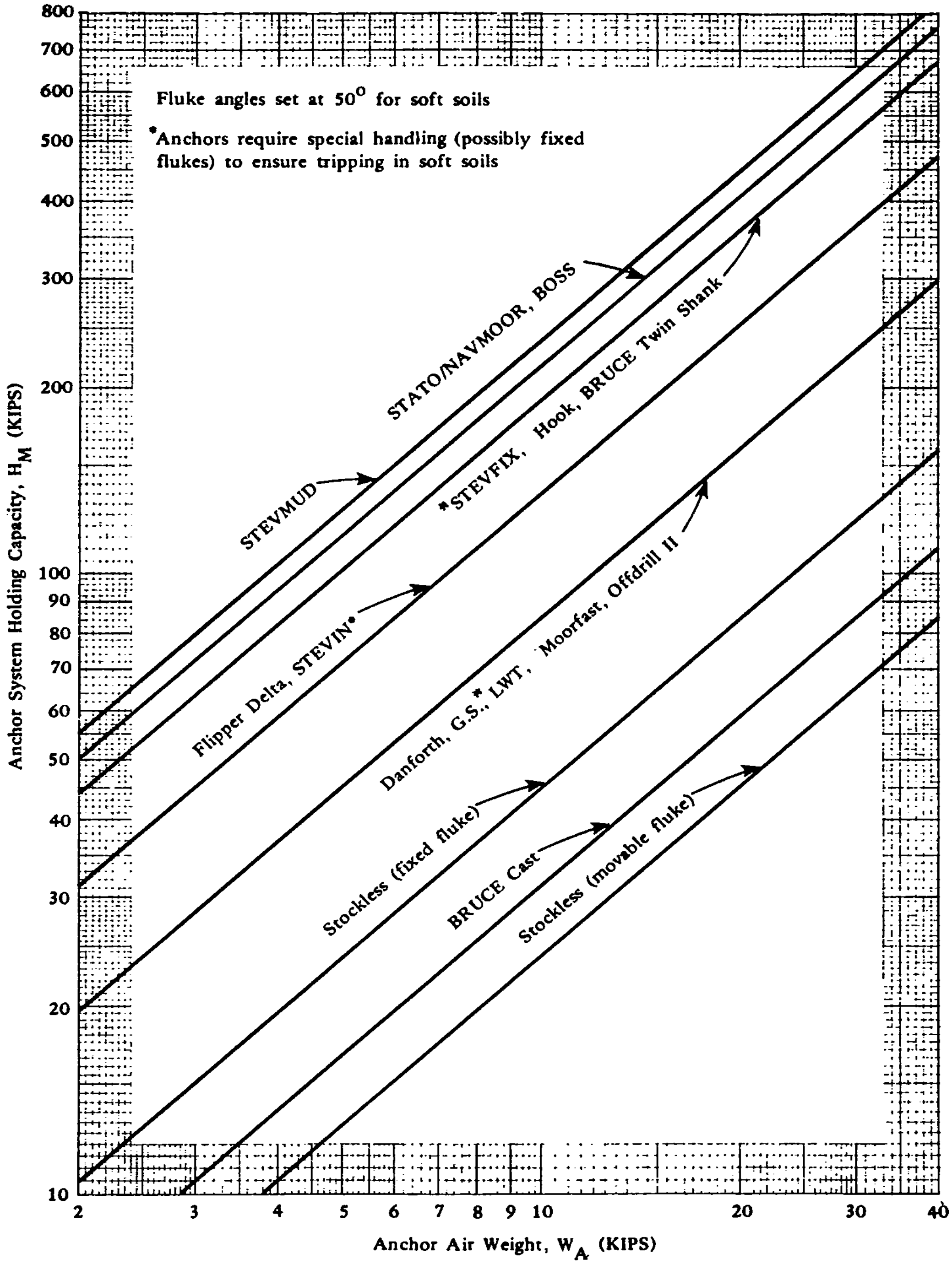
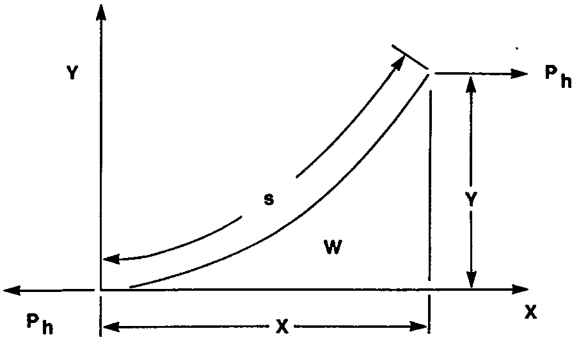


FIG. 28
ANCHOR CHAIN SYSTEM HOLDING CAPACITY AT THE MUD LINE IN SOFT SOILS
(SILT AND CLAY)



$$(Y+P_h/W)^2 = s^2 + (P_h/W)^2$$

$$Y = (P_h/W)(\cosh(WX/P_h)-1)$$

$$s = (P_h/W)\sinh(WX/P_h)$$

FIG. 29
BASIC CATENARY RELATIONSHIPS

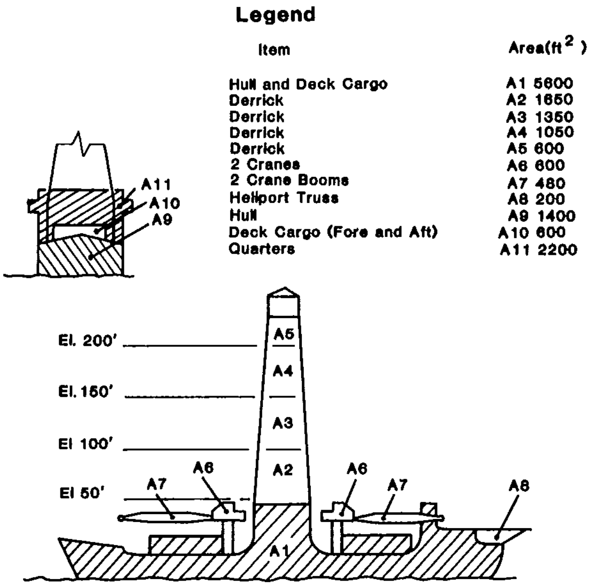


FIG. 31
EXAMPLE ANALYSIS WIND AREAS

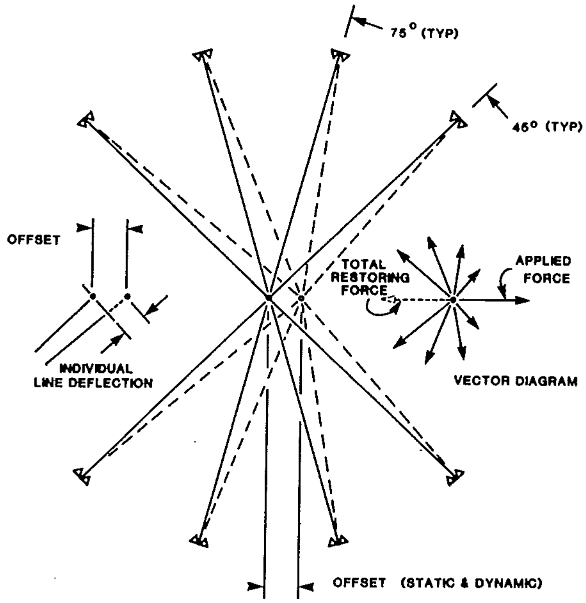


FIG. 30
FORCE GEOMETRY AND VECTOR DIAGRAM

RP 2P-87 0732290 0000542 8

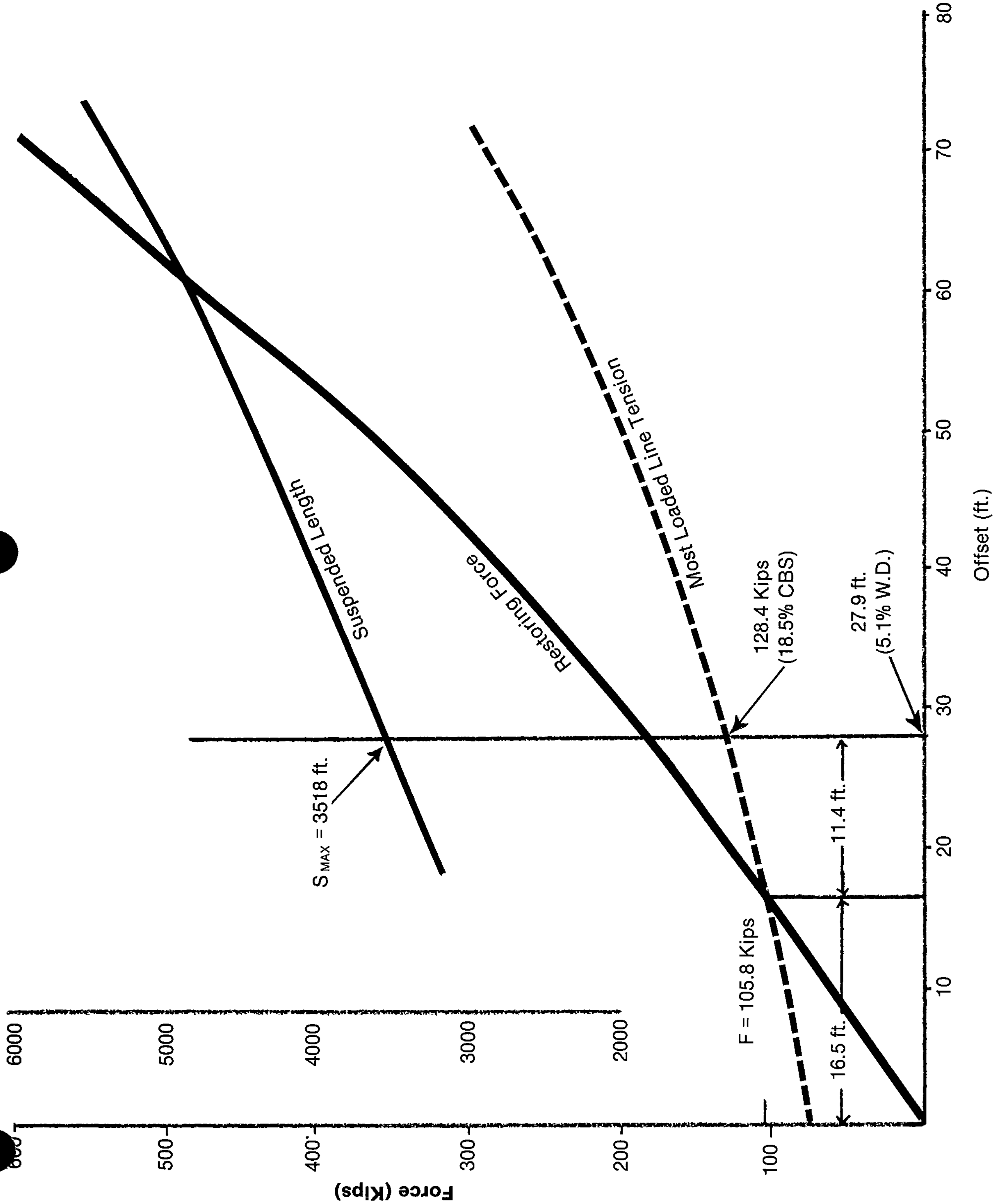


FIG. 32
FORCE AND SUSPENDED LINE LENGTH CURVES
BOW SEAS

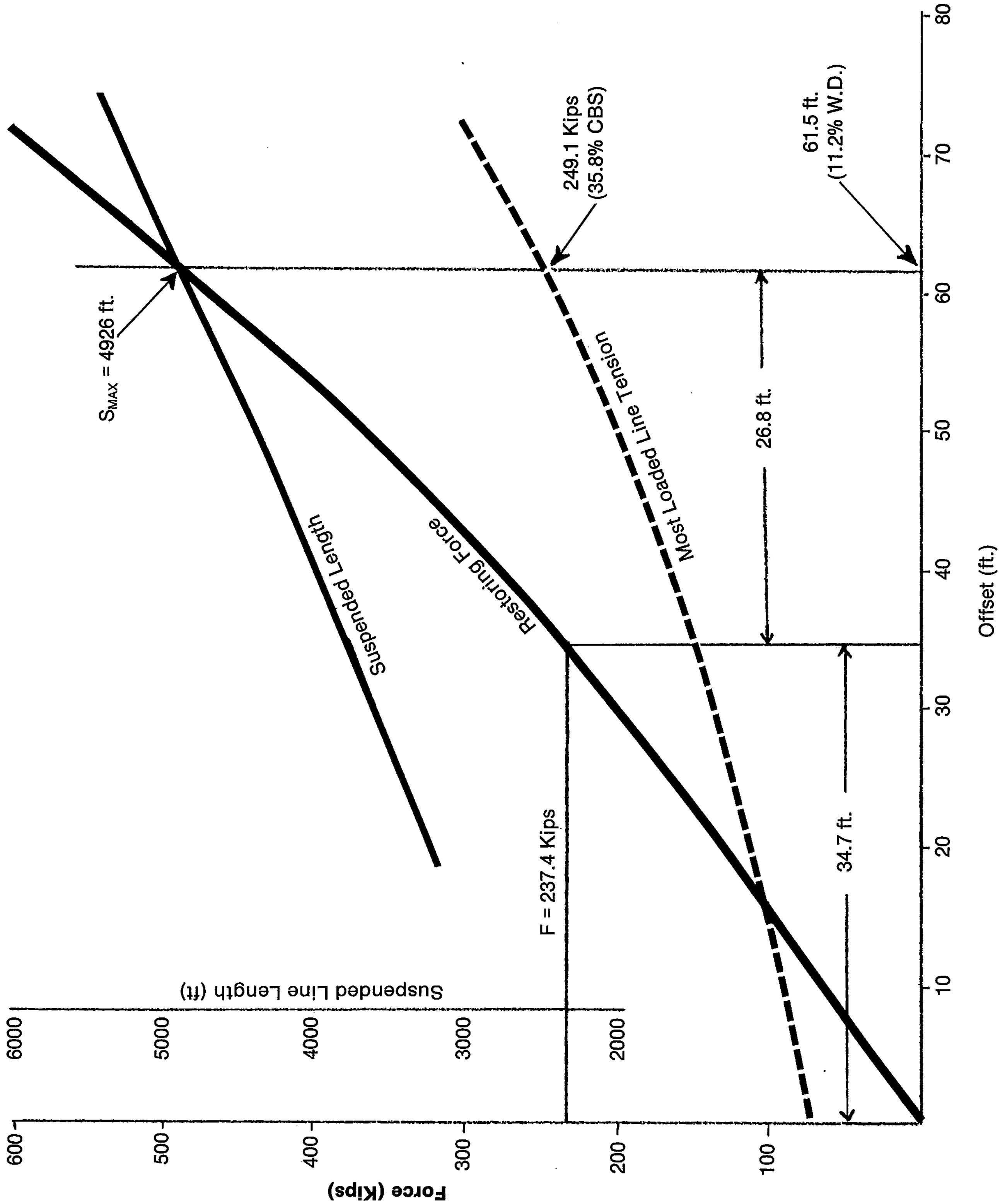


FIG. 33
FORCE AND SUSPENDED LINE LENGTH CURVES

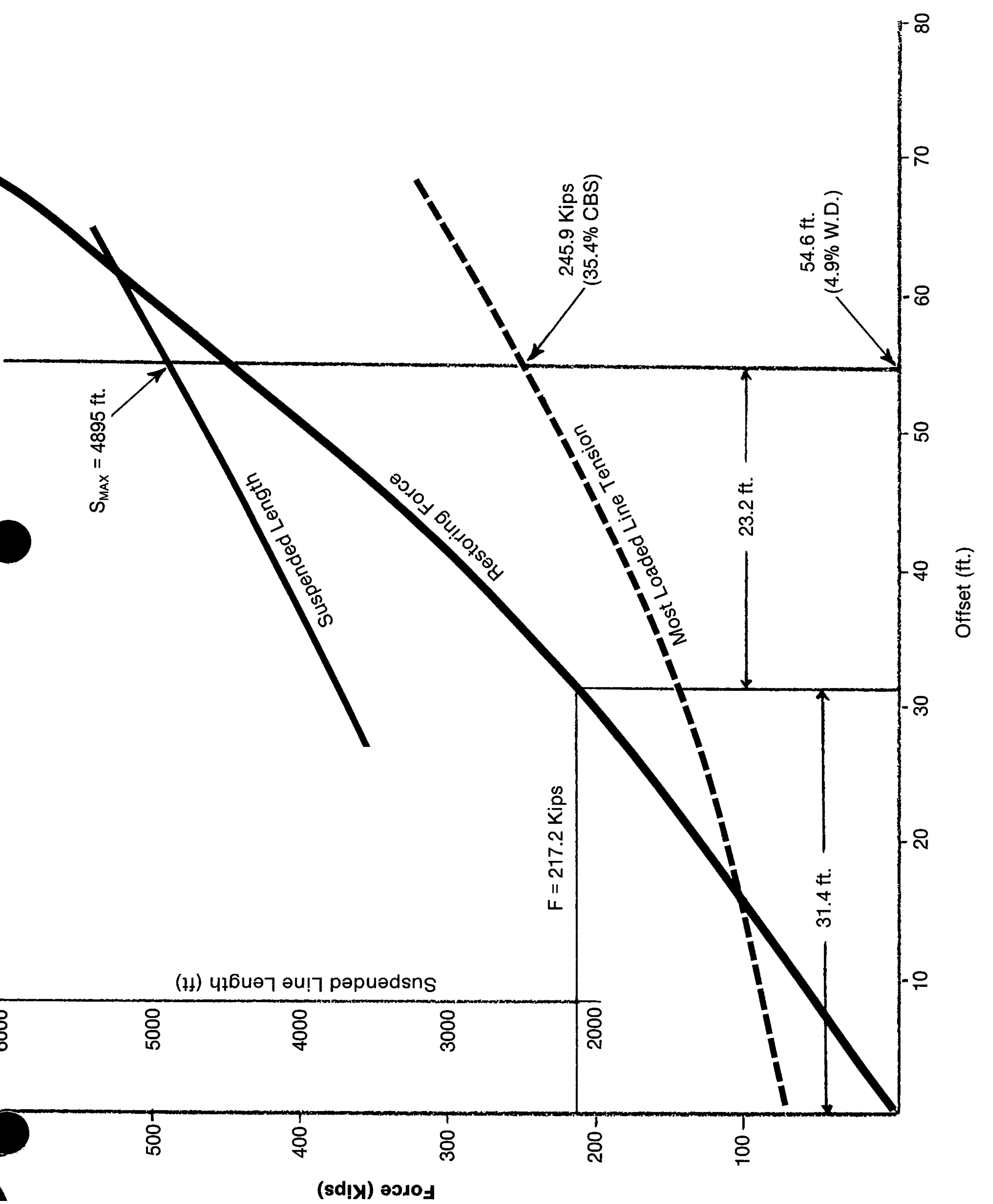


FIG. 34
FORCE AND SUSPENDED LINE LENGTH CURVES
QUARTERING SEAS

The following publications are under the jurisdiction of the API Committee on Standardization of Offshore Structures and are available from the American Petroleum Institute, 1220 L Street, N. W., Washington, D.C. 20005.

RP 2A, Recommended Practice for Planning, Designing, and Constructing Fixed Offshore Platforms
Contains engineering design principles and good practices that have evolved during the development of offshore oil resources.

Spec 2B, Specification for Fabricated Structural Steel Pipe
Covers requirements for structural steel pipe fabricated from plate for use in the construction of welded offshore fixed platforms.

Spec 2C, Specification for Offshore Cranes
Provides a uniform method for establishing rated loads for offshore cranes.

RP 2D, Recommended Practice for Operation and Maintenance of Offshore Cranes
Covers recommendations for developing safe operating practices and procedures compatible with operation of pedestal-mounted revolving cranes used offshore on bottom-supported platforms, floating drilling tenders, semi-submersible rigs, and other types of floating drilling equipment.

Spec 2E, Specification for Drilling Rig Packaging for Minimum Self-Contained Platforms
Provides dimensions and equipment arrangement for the packaging of the necessary drilling rig components for economic installation and efficient job performance on most minimum self-contained platforms. The check list of interacting rig-platform consideration provides the designer with early definition of contractor rig requirements avoiding costly rig and/or platform field modifications.

Spec 2F, Specification for Mooring Chain
Covers flashwelded chain used for mooring of offshore floating vessels such as drilling vessels, pipe lay barges, derrick barges, and storage tankers.

RP 2G, Recommended Practice for Production Facilities on Offshore Structures
The intent of this Recommended Practice is to assemble into one document useful Procedures and Guidelines available in Industry pertaining to planning, designing, and arranging production equipment on offshore structures for safe, pollution free and efficient production of oil and gas.

Spec 2H, Specification for Carbon Manganese Steel Plate for Offshore Platform Tubular Joints
Covers intermediate strength steel plates up to 3 in. thick for use in welded tubular construction of offshore platforms, in selected critical portions which must resist impact, plastic fatigue loading, and lamellar tearing.

RP 2I, Recommended Practice for In-Service Inspection of Mooring Hardware for Floating Drilling Units
Covers recommended practices for in-service inspection of mooring hardware including mooring chain, anchor jewelry, mooring wire rope and anchor handling equipment.

Bul. 2J, Bulletin on Comparison of Marine Drilling Riser Analyses
Provides a comparison of existing computer programs for design of marine drilling risers.

RP 2K, Recommended Practice for Care and Use of Marine Drilling Risers
Covers recommendations for operations, transportation, handling, storage, field inspection, and maintenance of drilling marine risers.

RP 2L, Recommended Practice for Planning, Designing, and Constructing Heliports for Fixed Offshore Platforms
Provides the basic criteria to be considered in the design and construction of heliports on offshore platforms.

RP 2M, Recommended Practice for Qualification Testing of Steel Anchor Designs for Floating Structures
Provides procedures for testing and qualification of the structural integrity of steel anchors.

Bul. 2N, Bulletin for Planning, Designing and Constructing Fixed Offshore Structures in Ice Environments
Contains considerations for the planning, designing, and construction of fixed offshore structures intended for use in ice environments. Used in conjunction with API RP 2A, this bulletin will be helpful in providing guidance to those involved in the design of offshore structures in ice-laden areas.

RP 2P, Recommended Practice for The Analysis of Spread Mooring Systems for Floating Drilling Units
Contains a rational method for analyzing, designing, or evaluating spread mooring systems used with floating drilling units.

RP 2Q, Recommended Practice for Design and Operation of Marine Drilling Riser Systems
This recommended practice pertains to the design, selection, and operation of equipment for marine riser systems for floating drilling operations. Its purpose is to serve as a reference for designers and those responsible for the selection of system components.

RP 2R, Recommended Practice for Design, Rating and Testing Marine Drilling Riser Couplings
This recommended practice pertains to the design, rating, and testing of marine drilling riser couplings. Its purpose is to serve as a reference for designers and those responsible for the selection of marine riser couplings.

RP 2T, Recommended Practice for Planning, Designing and Constructing Tension Leg Platforms
This document summarizes available information and guidance for the design, fabrication and installation of a Tension Leg Platform.

Bul. 2U, Bulletin on Stability Design of Cylindrical Shells
This Bulletin contains semi-empirical formulations for evaluating buckling strength of stiffened and unstiffened cylindrical shells.

Bul. 2V, Bulletin on Design of Flat Plate Structures
This Bulletin provides guidance for the design of steel flat plate structures.

Spec 2W, Specification for Steel Plates for Offshore Structures, Produced by Thermomechanical Control Processing (TMCP)
Covers four grades of intermediate strength steel plates used in welded construction of offshore structures, in selected critical portions which must resist impact, plastic fatigue loading and lamellar tearing. Grades 42, 50 and 50T are covered in thicknesses up to 6 in. (150mm) inclusive, and Grade 60 is covered in thicknesses up to 4 in. (100mm) inclusive.

RP 2X, Recommended Practice for Ultrasonic Examination of Offshore Structural Fabrication and Guidelines for Qualification of Ultrasonic Technicians
Contains recommendations for determining the qualifications of technicians conducting inspections on offshore structural fabrication using ultrasonic pulse echo inspection devices. Recommendations are also given for control of ultrasonic inspections into a general quality control program. The interrelationship between joint design, significance of flaws in welds, and the ability of an ultrasonic technician to detect critical size defects are also discussed.

Spec 2Y, Specification for Steel Plates, Quenched-and-Tempered, for Offshore Structures
Covers four grades of intermediate strength steel plates used in welded construction of offshore structures, in selected critical portions which must resist impact, plastic fatigue loading and lamellar tearing. Grades 42, 50 and 50T are covered in thicknesses up to 6 in. (150mm) inclusive, and Grade 60 is covered in thicknesses up to 4 in. (100mm) inclusive.

RP 2Z, Recommended Practice for Preproduction Qualification for Steel Plates for Offshore Structures
Covers requirements for preproduction qualification, by special welding and mechanical testing, of specific steelmaking and processing procedures for the manufacture of steel by a specific producer. It was developed in conjunction with, and is intended primarily for use with, API Specs 2W and 2Y. However, it may be used to supplement API Spec 2H.