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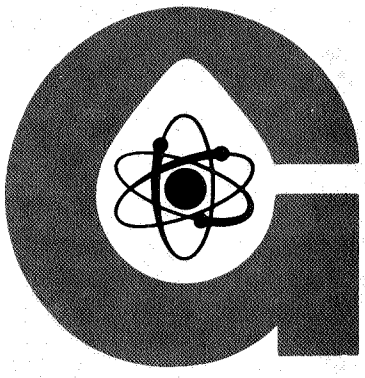
MULTIPLE SOURCE ROCKS FOR DRY GAS AND CRUDE OIL, GULF-GETTY 35/8-1 WELL, OFFSHORE NORWAY

1981



RESEARCH CENTER REPORT 81-154

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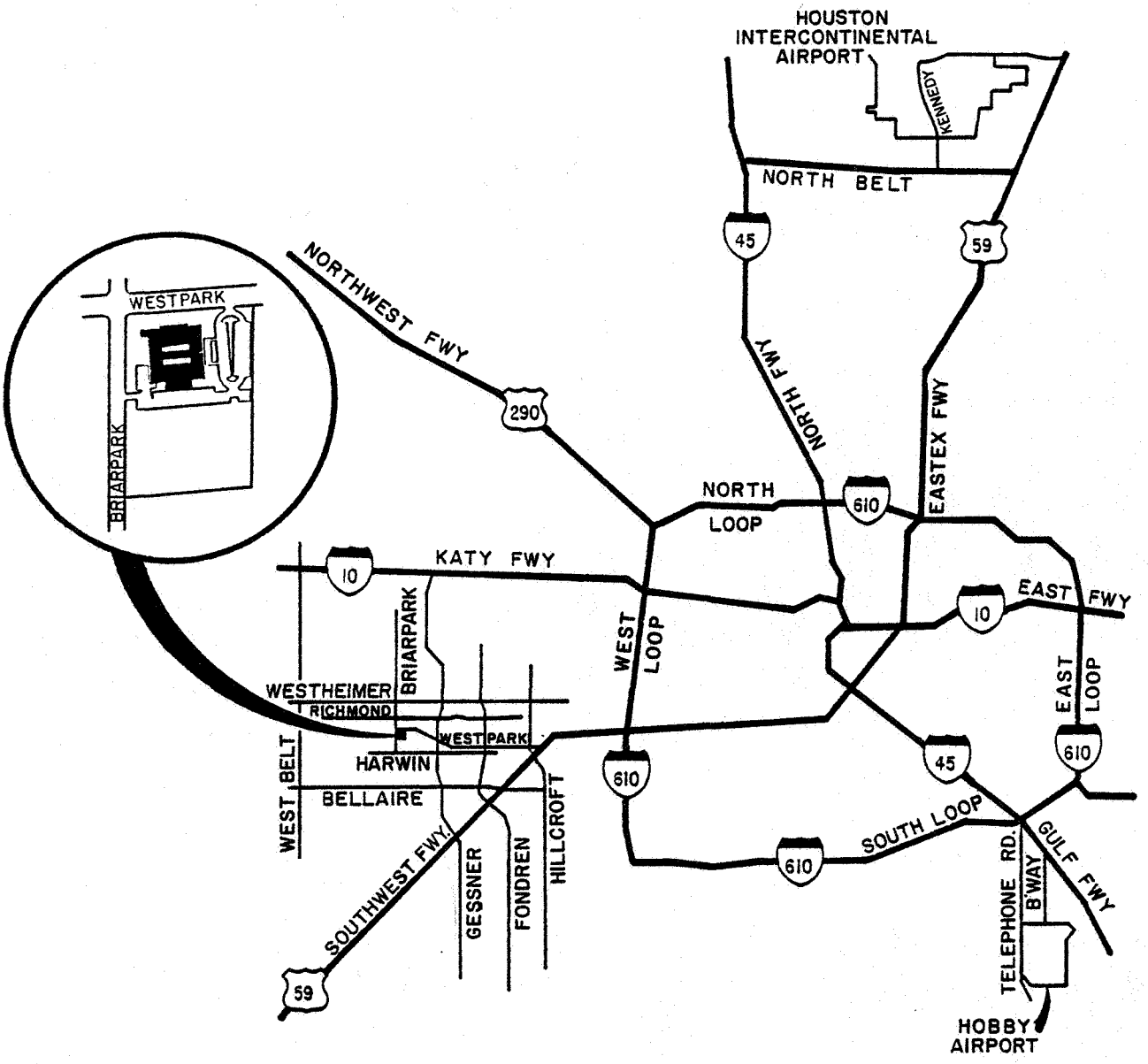

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MULTIPLE SOURCE ROCKS FOR DRY GAS AND CRUDE OIL, GULF-GETTY 35/8-1 WELL, OFFSHORE NORWAY

CONFIDENTIAL

RESEARCH CENTER REPORT 81-154

Houston, Texas
April 21, 1981

TO: MR. J. H. DURRIE

FROM: E. G. MILLER

SUBJECT: RESEARCH CENTER REPORT 81-154, "MULTIPLE SOURCE ROCKS FOR DRY GAS AND CRUDE OIL, GULF-GETTY 35/8-1 WELL, OFFSHORE NORWAY" -- NORSKE GETTY

This geochemical evaluation of source rocks and hydrocarbons encountered by the 35/8-1 discovery well was requested on August 11, 1980.

A particularly extensive analytical program was carried out on samples from this key well. Results of this study indicate the presence of multiple source rocks. The dry gas encountered in the Middle Jurassic Brent Sandstone (32.0 MMcfd) was derived from thermally mature Lower Jurassic coals. The well also flowed about 1,442 b/d of liquid hydrocarbons. Although widely reported to be condensate, the liquid from DST No. 3 is actually light crude oil. The light crude oil was derived from Middle and Upper Jurassic shales. The shales have good potential as source rocks for crude oil.

Because the oil-prone Middle and Upper Jurassic source rocks adjacent to reservoirs and deeper on the flanks of the structure approach overmaturity for crude oil, gas was the major hydrocarbon product tested. Given lower levels of maturity, crude oil accumulations could form. On this basis, the Norwegian North Sea in the general vicinity of the 35/8-1 well is not exclusively a gas and condensate province!

This report completes evaluation of the 35/8-1 well. However, using the data on the well and structure maps of the area, a report is forthcoming which includes source rock maps intended to predict where crude oil is more likely to be discovered.

Please fill out and return the attached Research Center questionnaire.

Ernest G. Miller.

RS/kg
cc: Messrs. V. E. Bartlett
D. F. Carlos
J. M. Cadden
M. W. Hansen
C. B. Cotton

GETTY OIL COMPANY

RESEARCH CENTER

MULTIPLE SOURCE ROCKS FOR DRY GAS AND CRUDE OIL, GULF-GETTY 35/8-1 WELL, OFFSHORE NORWAY

RESEARCH CENTER REPORT 81-154

Prepared by: Roger Sassen

Approved by: Claude C. Root

APRIL 21, 1981

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FIGURES

PLATE (in back pocket)

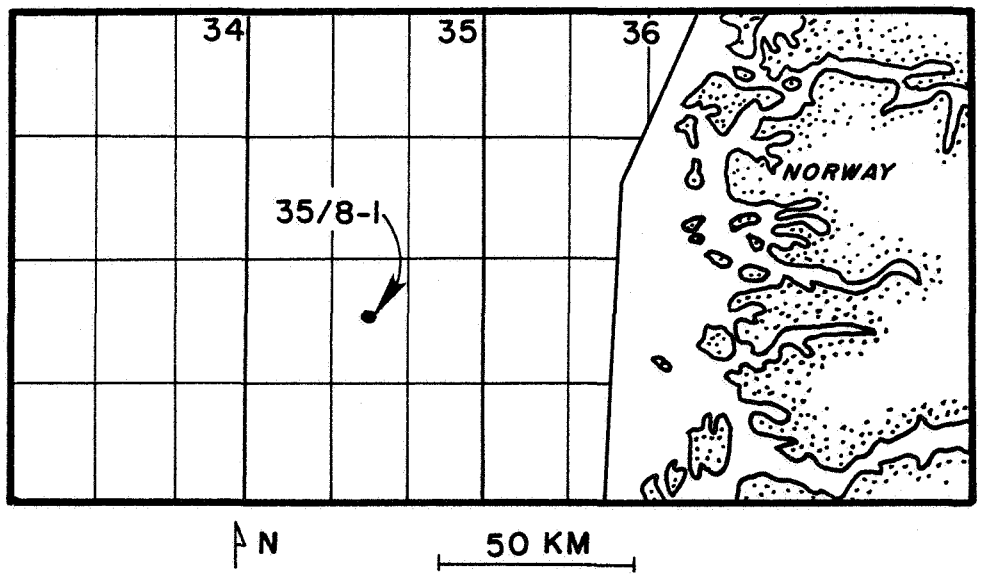


Figure 1. Sketch-map showing the location of the Gulf-Getty 35/8-1 discovery well, offshore Norway.

INTRODUCTION

The 35/8-1 well was spudded offshore Norway on July 27, 1980. Shortly thereafter, on August 11, 1980, a request for detailed source rock evaluation of the well was made by Mr. J. H. Durrie of Norske Getty Exploration A/S.

The location of the 35/8-1 discovery well is shown in Figure 1. Testing of Middle Jurassic reservoirs resulted in impressive flows of gas (32.0 MMcfd) and lesser flows of liquid hydrocarbons (1,442 b/d).

Organic geochemical analyses were performed by GeoChem Laboratories and by the Research Center as shipments of samples arrived. The extensive analytical program included organic carbon, pyrolysis, visual kerogen assessment, estimates of thermal maturity, C_1 to C_7 hydrocarbon analysis, and C_{15+} extraction with complete chromatographic characterization.

Preliminary interpretations of data were telexed to Mr. Durrie on February 12, March 5 and 13, and April 6, 1981. This report completes source rock evaluation of the Norwegian well.

CONCLUSIONS

1. The 35/8-1 well tested 32.0 MMcfd of dry gas and 1,442 b/d of liquid hydrocarbons from the Middle Jurassic Brent Sandstone. The hydrocarbons were derived from Lower, Middle and Upper Jurassic source rocks.

2. The dry gas was clearly derived from thermally mature Lower Jurassic coals which occur near total depth of the well (4,154m to 4,350m). The average organic carbon content of the coaly interval is about 12.2%, with individual values as high as 31.5%. Kerogens are prone to generation of gas with insignificant hydrocarbon liquids. Thermal maturity is optimal for dry gas generation, equivalent to a mean vitrinite reflectance of 1.00% or slightly higher.

3. Although widely reported in the open literature to be condensate, the tested hydrocarbon liquid is actually light crude oil. The light crude oil could not have been derived from the Lower Jurassic coals. Rather, the hydrocarbon liquids were derived from Middle and Upper Jurassic shales.

   The average organic carbon content of the Middle Jurassic shales (3,730m to 4,090m) is about 1.1% with individual values as high as 3.3%. Oil-prone amorphous kerogens dominate the indigenous organic matter of the Middle Jurassic shales. The thermal maturity of the interval is equivalent to mean vitrinite reflectances in the 0.90% to 1.00% range. This level of maturity is past the main

phase of oil generation, and much migration has already taken place. Time-temperature exposure has resulted in cracking of previously generated crude oil.

The average organic carbon content of the Upper Jurassic shales is about 2.4%, with one value as high as 5.6%. Oil-prone amorphous kerogens are present, although in lower relative abundance than in the Middle Jurassic shales. Thermal maturity is equivalent to reflectance values in the 0.80% to 0.90% range. Partial cracking of previously generated hydrocarbons has resulted in light crude oil.

4. Although effective source rocks occur adjacent to reservoirs sands, the structure penetrated by the 35/8-1 well has also received hydrocarbons from deeper source rocks on the flanks. The deeper source rocks on the flanks of the structure approach overmaturity for generation or preservation of liquid hydrocarbons. For this reason, gas was the major hydrocarbon product encountered by the 35/8-1 well.

5. The combined potential of Middle and Upper Jurassic shales for generation of medium-gravity crude oil is good, given lower levels of thermal exposure. On this basis, the Norwegian North Sea in the area of the 35/8-1 well is not exclusively a gas province. Given Middle and Upper Jurassic shales at shallower depths, economic accumulations of crude oil could be present.

CHARACTERISTICS OF TESTED HYDROCARBONS

Results of gas analysis carried out on fluids recovered from DST No. 3 and DST No. 4 are shown in Table 1. Both tests were in the Middle Jurassic Brent Sandstone (3,515m to 3,730m).

TABLE 1. Results of gas analysis provided by Mr. J. H. Durrie on March 30, 1981.

Component	DST No. 3	DST No. 4
CO2	2.05	2.05
N2	0.65	0.73
C1	82.14	84.23
C2	6.87	6.12
C3	3.42	3.03
C4	0.35	0.32
C4	1.00	0.84
C5	0.23	0.18
C5	0.32	0.23
C6	0.26	0.18
C7+	2.71	2.09
	100%	100%

The tested gas is relatively dry in that methane dominates the C_1 to C_7 composition. Dry gas at depth is generally derived from thermally mature source rocks characterized by hydrogen-poor terrestrial kerogens. Dry gas, however, can also result from cracking of previously generated liquid hydrocarbons.

A sample of liquid hydrocarbons recovered during DST No. 3 was also analyzed. Results are presented in Table 2.

TABLE 2. Geochemical analysis of hydrocarbon liquids

Gross Composition

Less than C_{15+}	49.1%
C_{15+}	50.9%

C_{15+} Composition

Saturate Hydrocarbons	69.8%
Aromatic Hydrocarbons	23.9%
NSO-compounds*	4.2%
Asphaltenes	2.1%

* NSO-compounds contain nitrogen, sulfur, or oxygen as well as carbon and hydrogen

The observation that about half the sample consists of components with more than 15 carbon atoms per molecule indicates light crude oil and not condensate. The chromatogram of C_{15+} saturate hydrocarbons isolated from the sample is shown in Figure 2. As can be seen, normal paraffins are present with carbon numbers as high as C_{33}. This is rare in a condensate, but not unusual in a light crude oil. Low percentages of NSO-compounds and asphaltenes suggest cracking as a consequence of thermal exposure. The high ratio of saturate to aromatic components could indicate an origin by cracking of a former medium-gravity paraffinic crude oil derived from marine kerogens.

There appears to be a disparity between the compositions of dry gas and light crude oil. The two are unlikely to have been derived from the same source rock.

SOURCE ROCK PROFILE

Interpretations of source rock potential are discussed below for Tertiary, Cretaceous, and Jurassic sediments encountered by the 35/8-1 well. The Jurassic sediments are of primary interest

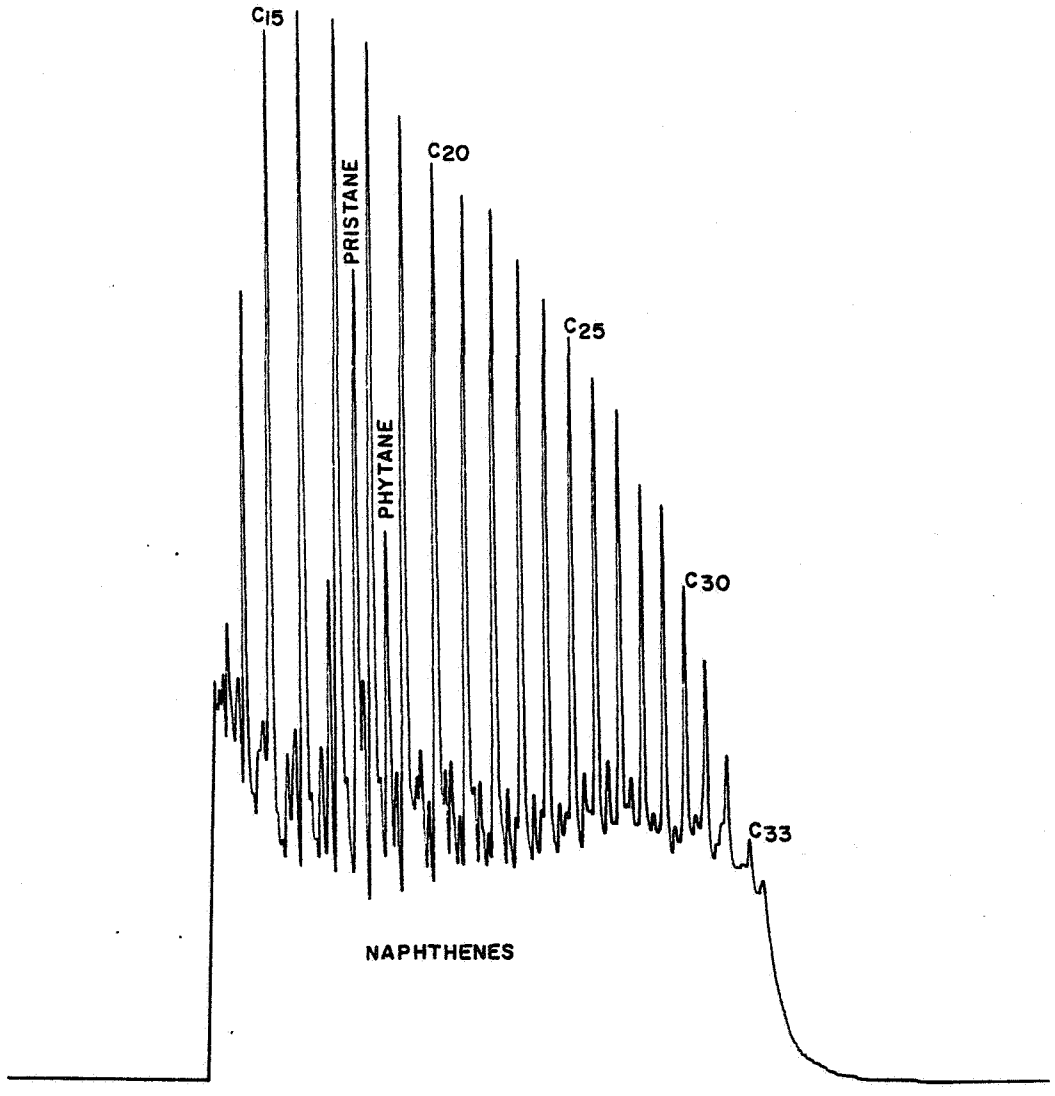


Figure 2. Chromatogram of C_{15+} saturate hydrocarbons isolated from light crude oil, DST No. 3.

because they are effective source rocks which have generated ga
and liquid hydrocarbons.

Most organic geochemical data concerning the 600m to 4,350m
(T.D.) interval of the 35/8-1 well are computer-plotted with
stratigraphy and brief interpretations in Plate 1. Analytical
data are presented in tabular form in the Appendices of this
report.

Thermally Immature Tertiary Sediments

Miocene to Eocene sediments were encountered within the
582m to 1,885m interval of the well. The average organic carbon
content of the Tertiary interval is 0.68%, with individual mea-
surements ranging from 0.1% to as high as 1.24%.

Visual kerogen assessment data indicate that the Miocene
interval is richer in oil-prone amorphous kerogens than the Eocene
interval. This difference in source potential is also evident in
pyrolysis data which suggest the Miocene organic matter to be
more hydrogen-rich.

Both vitrinite reflectance and spore coloration data show
the Tertiary sediments to be thermally immature, suggesting that
no significant thermal generation of hydrocarbons has taken place.
Gas wetness data support this conclusion in that wetness values
are low (< 30%). Moreover, low concentrations of C_1 to C_7 hydro-
carbons point to a lack of thermal generation.

C_{15+} extraction data further confirm immaturity. This is
shown by generally low ratios of extract to organic carbon, and
by the immature chromatographic characteristics of saturate
hydrocarbons.

Thermally Immature to Marginally Mature Cretaceous Sediments

Maastrichtian to Albian sediments were penetrated within the
1,885m to 3,185m interval of the well. The average organic carbon
content of the interval is about 0.75%, a value which is only
average for shales. Individual measurements range from 0.17% to
a very atypical 5.52%. However, the single high organic carbon
value is suspect. There is reason to believe that contamination
by drilling mud has enhanced the organic carbon content of the
sample.

The effective organic richness of the Cretaceous interval is
considerably lower than indicated by measured organic carbon
contents. This is attributable to high percentages of reworked
inertinite and woody kerogen. The reworked organic matter can be
assumed to have lost all hydrocarbon potential during weathering,
erosion, and transport to its ultimate site of deposition. It
should be mentioned that Cretaceous sediments of the U. K. North
Sea are also frequently characterized by abundant reworked material.

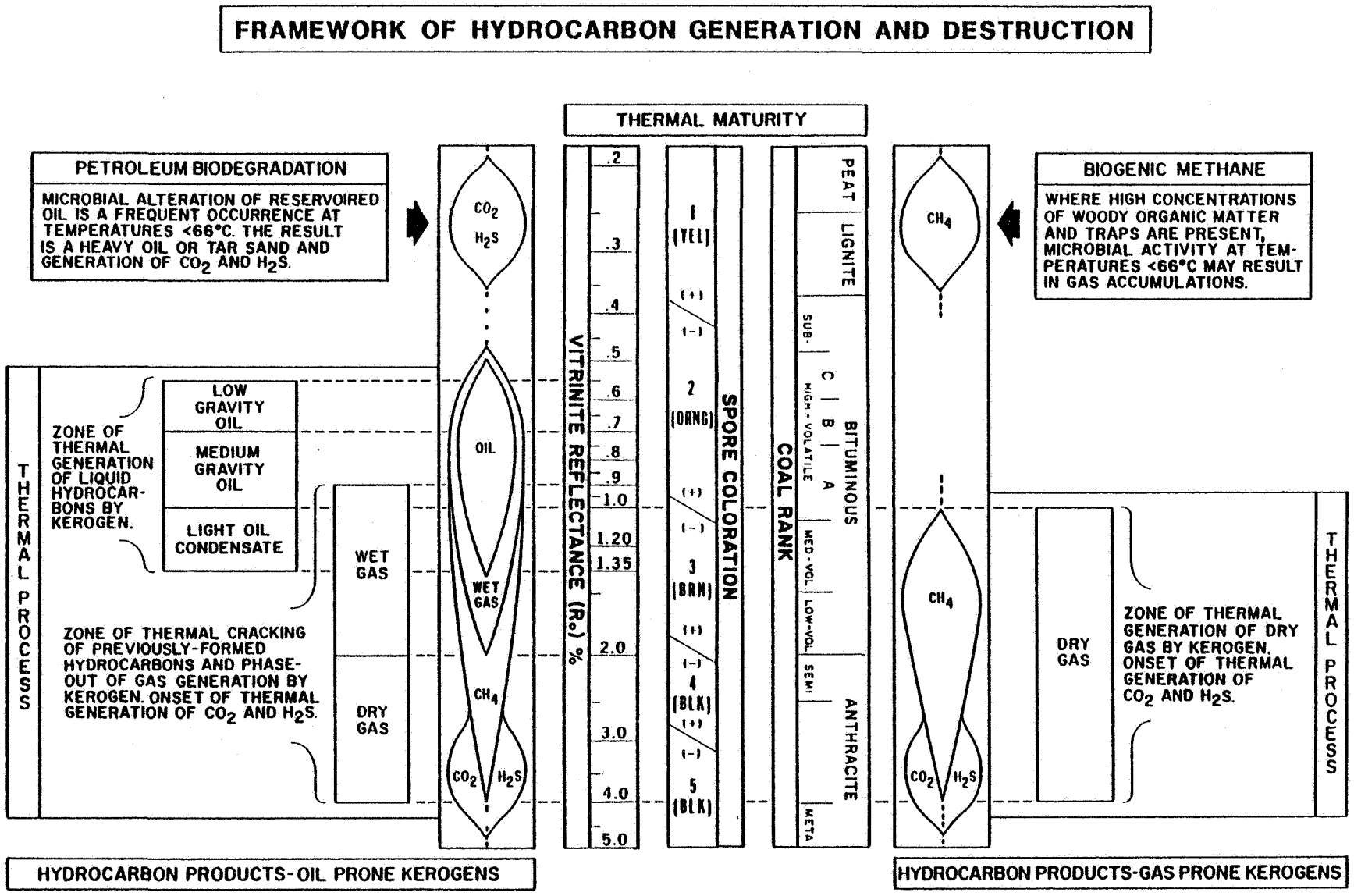


Figure 3. Generalized framework of hydrocarbon generation and destruction from oil-prone and gas-prone kerogens.

Pyrolysis data concerning the interval are not of good quality but can be interpreted to indicate little source potential except for small volumes of gas. This is shown by very low values of genetic hydrocarbon potential (S1 + S2) and by low values of hydrogen indices (mg hydrocarbons/g organic carbon). Measured oxygen values are too high to be correct, and probably are related to thermal decomposition of carbonate minerals during pyrolysis.

Interpretation of thermal maturity data on the Cretaceous interval was complex because of the abundant reworked kerogen. The reworked material was characterized by higher levels of thermal maturity than the indigenous material. Nevertheless, a thermal maturity break can be seen in Plate 1 which corresponds to an unconformity at the top of the Cretaceous. The break in the maturity profile reflects erosional loss of section.

The relationship between thermal maturity and hydrocarbon generation is summarized in Figure 3. The maturity at the top of the interval (1,885m) is equivalent to a mean reflectance of about 0.45%. At the very base of the interval (3,185m), vitrinite reflectance appears to closely approach a 0.70%. On this basis, the Cretaceous sediments are thermally immature to marginally mature for generation of liquid hydrocarbons.

Estimates of thermal maturity based on vitrinite reflectance and spore coloration are supported by other data. For example, the progressive increase in gas wetness values tracks increasing thermal maturity. Moreover, the immature characteristics of C_{15+} saturate hydrocarbons diminish with increasing maturity. There is some evidence that concentration of C_{15+} components increases near the base of the interval. However, part of this increase in concentration is the result of wellsite contamination.

Effective Upper Jurassic Source Rock for Wet Gas and Crude Oil

Upper Jurassic shales were encountered within the 3,185m to 3,515m interval. The average organic carbon content of the interval is about 2,38%, a value which lies well within the range of organic carbon contents of known source rocks. Results for individual measurements range from 0.27% to as high as 5.60%. It is probable that contamination by drilling mud (Soltex additive) has somewhat increased measured organic carbon contents. However, cuttings samples were washed prior to analysis for organic carbon content.

In contrast to the overlying Cretaceous, the bulk of the organic matter is indigenous to the Upper Jurassic environment of deposition. This is a positive factor, but the kerogens of the Upper Jurassic in the vicinity of the 35/8-1 well do not appear to be as oil-prone as is typical of equivalent sediments in much of the U. K. North Sea. Although oil-prone amorphous kerogen tends to increase in abundance with depth, it is diluted by herbaceous and woody kerogens. On this basis, the Upper

Jurassic interval would be predicted to generate moderate volumes of wet gas and crude oil, given optimal thermal maturity.

Pyrolysis data on the Upper Jurassic sediments are of poor quality and difficult to interpret. Hydrogen indices are clearly higher than in overlying Cretaceous sediments, an observation that agrees with visual assessment data. But, as is the case with many other pyrolysis samples from the well, oxygen indices are too high and cannot be interpreted.

Thermal maturity data concerning the Upper Jurassic interval indicate that part of its oil-generating potential has already been realized. The interpreted thermal maturity profile of Plate 1 indicates mean vitrinite reflectance values within the 0.80% to 0.90% range. As shown within Figure 3, this level of maturity is within the main phase of oil generation from hydrogen-rich kerogens.

It should be noted that the unconformity at the top of the Upper Jurassic interval is associated with a break in the thermal maturity profile. This suggests erosional loss of section.

Unfortunately, canned samples from the Upper Jurassic interval were not collected properly at the wellsite. No water was added to any canned cuttings samples from the interval, complicating analysis and interpretation. Nevertheless, the available gas wetness data are interpreted to indicate that intense generation of C_1 to C_7 hydrocarbons has occurred within the Upper Jurassic interval.

Values for wetness of combined headspace and cuttings gas are relatively high (> 60%), but not quite as high as one might expect. Several factors beyond possible analytical errors may be involved. First, migrating dry gas can have diluted wet gas components. Second, some indigenous dry gas is likely to have been generated within the Upper Jurassic sediments.

Although there will have been partial fractionation favoring retention of wet gas components, the gas fraction which is mechanically liberated from within cuttings chips should provide a truer picture. Within the 3,300m to 3,500m interval of the well, wetness values of indigenous C_1 to C_7 components average about 97.6%. Such high wetness values are almost always associated with liquid hydrocarbons.

Moreover, concentrations of the C_1 to C_7 hydrocarbons are quite high. If we look at the C_2 to C_7 fraction alone, which should be largely indigenous to the Upper Jurassic sediments, concentrations within the 3,300m to 3,500m interval of the C_2 to C_7 components range from 124,713 ppm (about 12.4% of rock volume) to 253,565 ppm (about 25.4% of rock volume). These gas concentrations should be accompanied by liquid hydrocarbons.

C_{15+} extraction data have been partially overprinted by contamination from Soltex drilling mud. However, because the Research Center was provided with a sample of the contaminant, analytical data are available so that its presence can be compensated for during interpretation of data on indigenous C_{15+} components. The main effect of the contamination has been to introduce some nonhydrocarbon components (NSO-compounds and asphaltenes). This has resulted in enhanced values for ratios of total extract to organic carbon, and has lowered ratios of hydrocarbons to total extract. Effects on indigenous hydrocarbon components -- especially on the saturate hydrocarbons -- have not been as significant.

The concentrations of total C_{15+} hydrocarbons within the Upper Jurassic interval are high, ranging from 1,538 ppm (0.15% of rock weight) to 2,551 ppm (0.26% of rock weight). When compared to organic carbon contents, total C_{15+} hydrocarbons comprise from 6% to 11.3% of organic carbon.

It should be emphasized that analytical techniques have concentrated on the C_1 to C_7 and C_{15+} components of the interval. No data are available on the C_8 to C_{14} components, which, at these levels of thermal maturity, should be an important constituent of the sediments. Taking this into account, there is little doubt that liquid hydrocarbons have been generated by the Upper Jurassic interval. Much of the already generated liquid hydrocarbons have since left the source rock.

The characteristics of the C_{15+} saturate hydrocarbons are quite oil-like, and indicate thermal maturity of the Upper Jurassic sediments. Moreover, and of particular significance, the chromatographic signatures of C_{15+} saturate hydrocarbons from the interval are very similar to the signature of light crude oil recovered from DST No. 3 of the well (Figure 4). On this basis, there is little doubt that at least part of the light crude oil has been derived from the Upper Jurassic sediments.

It is worth emphasizing that the source rock/reservoir relationship encountered by the 35/8-1 well is unusual. In the U. K. North Sea, most major accumulations of medium-gravity crude oil are found in reservoirs with considerable vertical separation from their underlying source rocks. The vitrinite reflectance of such reseroirs usually ranges from 0.45% to 0.65%, whereas source rocks will be characterized by reflectances of 0.70% and higher. Since reaction rate doubles with each rise of 10°C, the hydrocarbons in the hotter source rock will be cracked at a faster rate than the separated hydrocarbons in cooler reservoirs. Thus, if enough vertical separation can be invoked, it is possible to have medium-gravity crude oil in shallow reservoirs which has been derived from deep source rocks which are now overmature for generation of liquid hydrocarbons!

In the case of the 35/8-1 well, there has not been major separation of source rock and product by vertical migration.

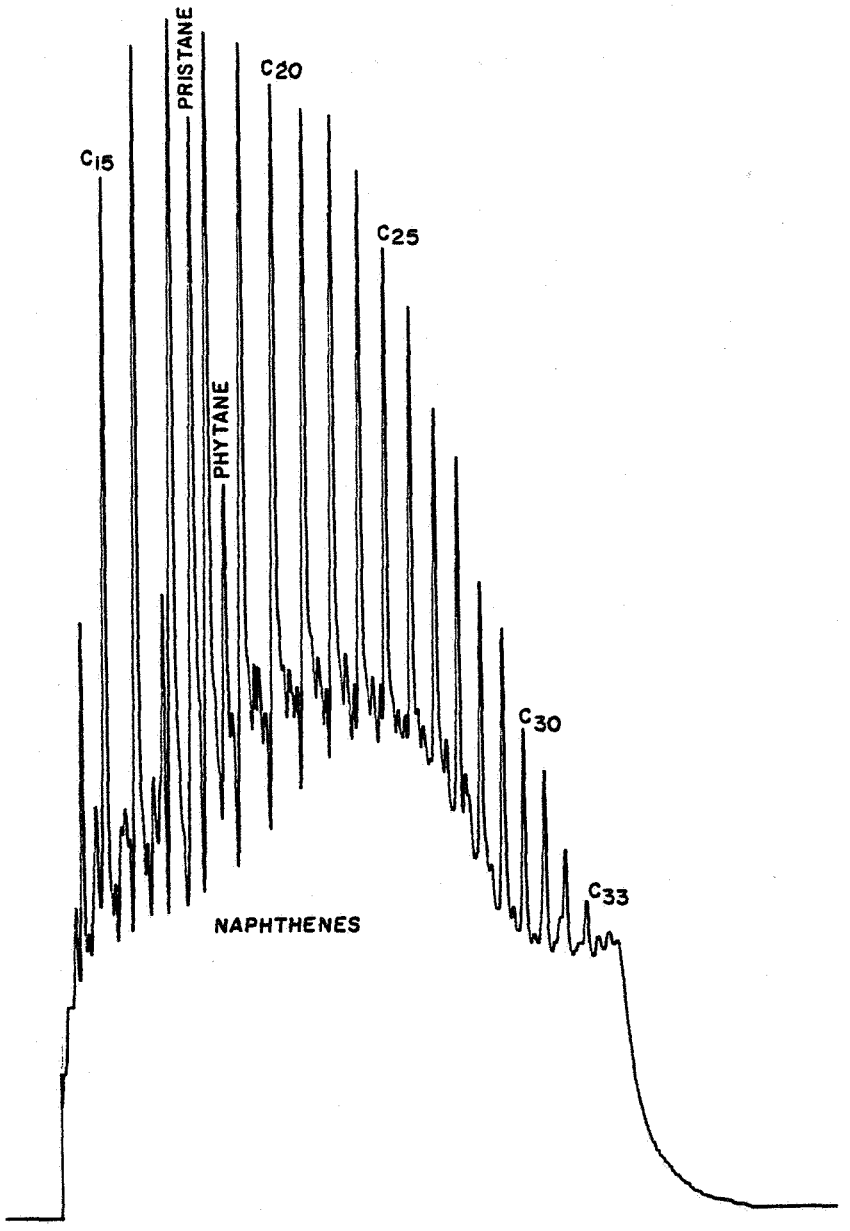


Figure 4. Chromatogram of C_{15+} saturate hydrocarbons isolated from Upper Jurassic shale at a depth of 3,500m. The chromatographic signature is very similar to that of light crude oil from DST No. 3 (See Figure 2).

The source rocks are characterized by relatively high levels of maturity, and this shows up in the characteristics of reservoired light crude oil. Although now characterized by an elevated API gravity (about 45°), the crude was probably originally medium-gravity (perhaps in the 30-35° API range) and has been cracked by time-temperature exposure in the reservoir. Concomitant with the cracking has been a loss of volume of the liquid hydrocarbons by conversion to gas.

Effective Middle Jurassic Source Rock for Wet Gas and Hydrocarbon Liquids

Middle Jurassic shales of the Dunlin Shale were encountered within the 3,730m to 4,090m interval of the well. The Dunlin Shale appears to be the best potential source rock for liquid hydrocarbons penetrated by the 35/8-1 discovery well. However, generation of crude oil commenced earlier during the burial history of the shales, and resultant crude oil has been largely cracked to lighter hydrocarbon components.

The average organic carbon content of the Middle Jurassic shales is about 1.05%, with individual values ranging from a low of 0.20% to a high of 3.26%. This average organic carbon content lies within the lower range of known major source rocks for crude oil. The organic richness of the interval is enhanced because all organic matter is indigenous to the Middle Jurassic environment of deposition.

Amorphous organic matter of algal origin dominates the kerogen distributions of the shales. Herbaceous kerogen and lesser amounts of woody material comprise the remainder. Given optimal thermal maturity, the interval would be predicted to generate moderate to large volumes of wet gas and crude oil. This conclusion is only partially supported by poor-quality pyrolysis data, however.

Vitrinite reflectance data on the Middle Jurassic interval are of good quality because of the near-absence of recycled organic matter. The thermal maturity of the interval is equivalent to mean vitrinite reflectance values in the 0.90% to 1.00%. As indicated in Figure 3, this level of maturity is past the peak phase of crude oil generation. Concentrations of liquid hydrocarbons in the sediments should now be decreasing as heavier molecules are progressively cracked and diluted by wet gas. Much of the generated petroleum has now left the source rock and resides in associated reservoirs.

Gas wetness values are high, as would be expected from oil-prone kerogens at relatively high levels of time-temperature exposure. Gas wetness of combined headspace and cuttings gas ranges between 92.8% and 97.6%. Values for the mechanically liberated fraction of the gas are slightly higher. Concentrations of C_1 to C_7 components are as high as 49,648 ppm (about 5% of rock volume).

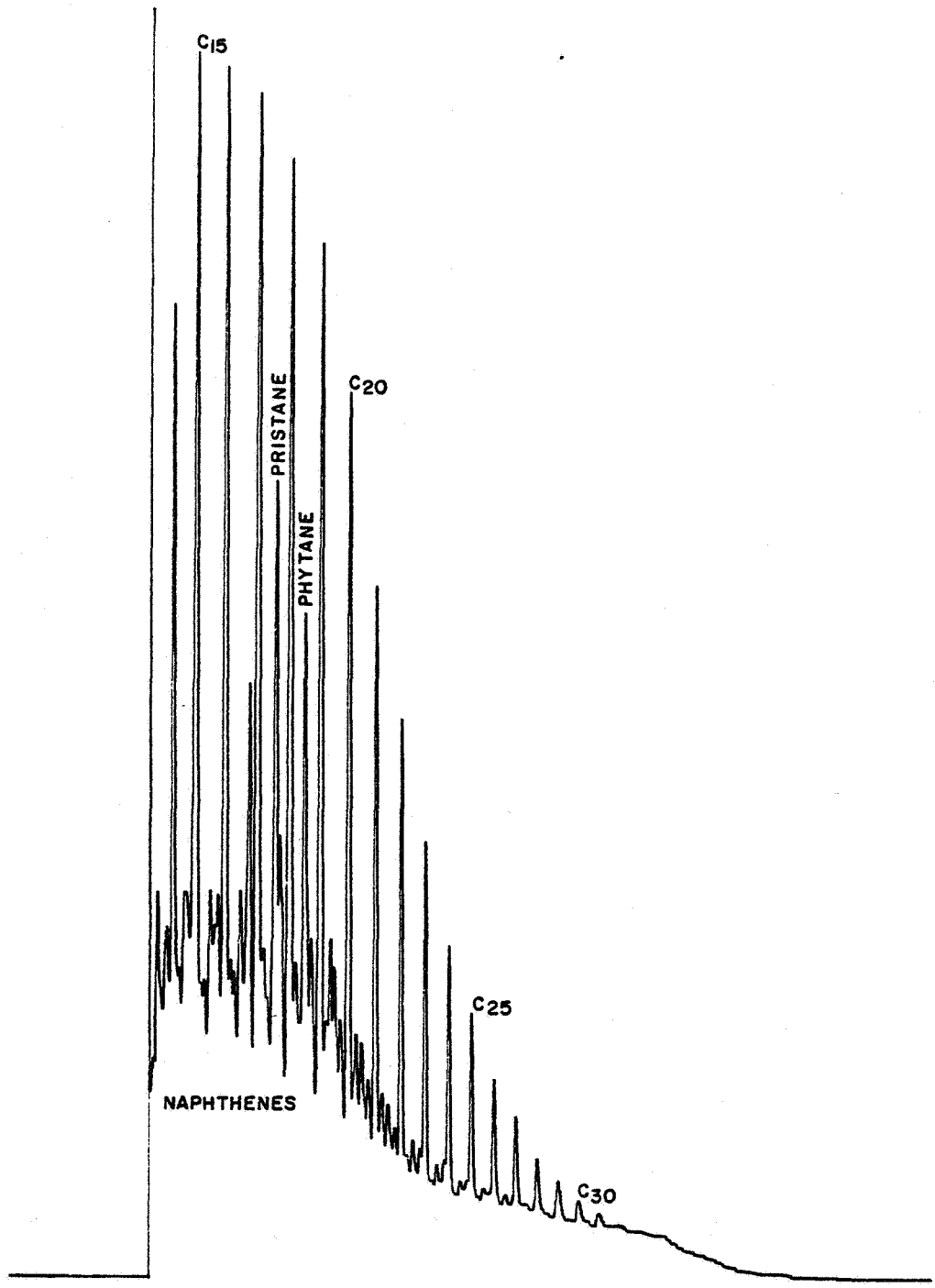


Figure 5. Chromatogram of C_{15+} saturate hydrocarbons isolated from Middle Jurassic shale at a depth of 4,000m. Note that relatively advanced maturity for liquid hydrocarbons has resulted in a chromatographic signature which approaches that of a condensate.

Concentrations of C_{15+} hydrocarbons and non-hydrocarbons are high. Contamination from the Soltex mud additive is not severe, and has had almost no effect on indigenous saturate hydrocarbons. Concentrations of total C_{15+} hydrocarbons are high, ranging from 1,920 ppm (0.19% of rock weight) to a maximum of 4,326 ppm (0.43% of rock weight). When compared to organic carbon contents, the excellent source quality of the Middle Jurassic sediments is apparent. Total C_{15+} hydrocarbons comprise between 19.0% and 26.6% of total organic carbon.

Chromatograms of C_{15+} saturate hydrocarbons from Dunlin Shale samples show evidence of more advanced thermal maturity than those of overlying Upper Jurassic sediments. The effects of thermal cracking manifest themselves in condensate-like chromatographic signatures. An example of one such thermally mature chromatographic signature from the Dunlin Shale is shown in Figure 5.

The cracking concomitant with relatively advanced thermal maturity has probably partly destroyed and diluted liquid hydrocarbons generated earlier in the burial history of this source rock. It is also possible that larger volumes of liquid hydrocarbons occur elsewhere on the trapping structure.

Effective Lower Jurassic Source Rock for Dry Gas

Lower Jurassic coals appear within the basal portion of the Statfjord sands and extend to total depth of the well (4,154m to 4,350m). The coals have generated large volumes of dry gas which have been trapped in overlying sands.

The average organic carbon content of the coaly interval is about 12.23%, with values as high as 31.53%. Contamination within this interval is minimal and has had no significant effect on organic carbon contents.

As would be expected in coals, nearly all organic matter is indigenous. Woody and herbaceous kerogens dominate, but small amounts of amorphous kerogen are also present. The coals are prone to generation of dry gas and perhaps very minor hydrocarbon liquids.

Vitrinite reflectance data on the coals are of excellent quality. Thermal maturity of the coal samples is equivalent to a mean reflectance of about 1.0% or slightly higher. As shown in Figure 3, this level of maturity should result in intense generation of dry gas from terrestrial kerogens.

Available data on C_1 to C_7 hydrocarbons and C_{15+} components support conclusions on kerogen types and on thermal maturity. As shown in Plate 1, gas wetness values decrease significantly within the coaly interval. The average gas wetness for the coals is about 21%. The gas is dry, but not exclusively composed of methane. This is appropriate for coals which include small amounts of amorphous material. The concentrations of gas within

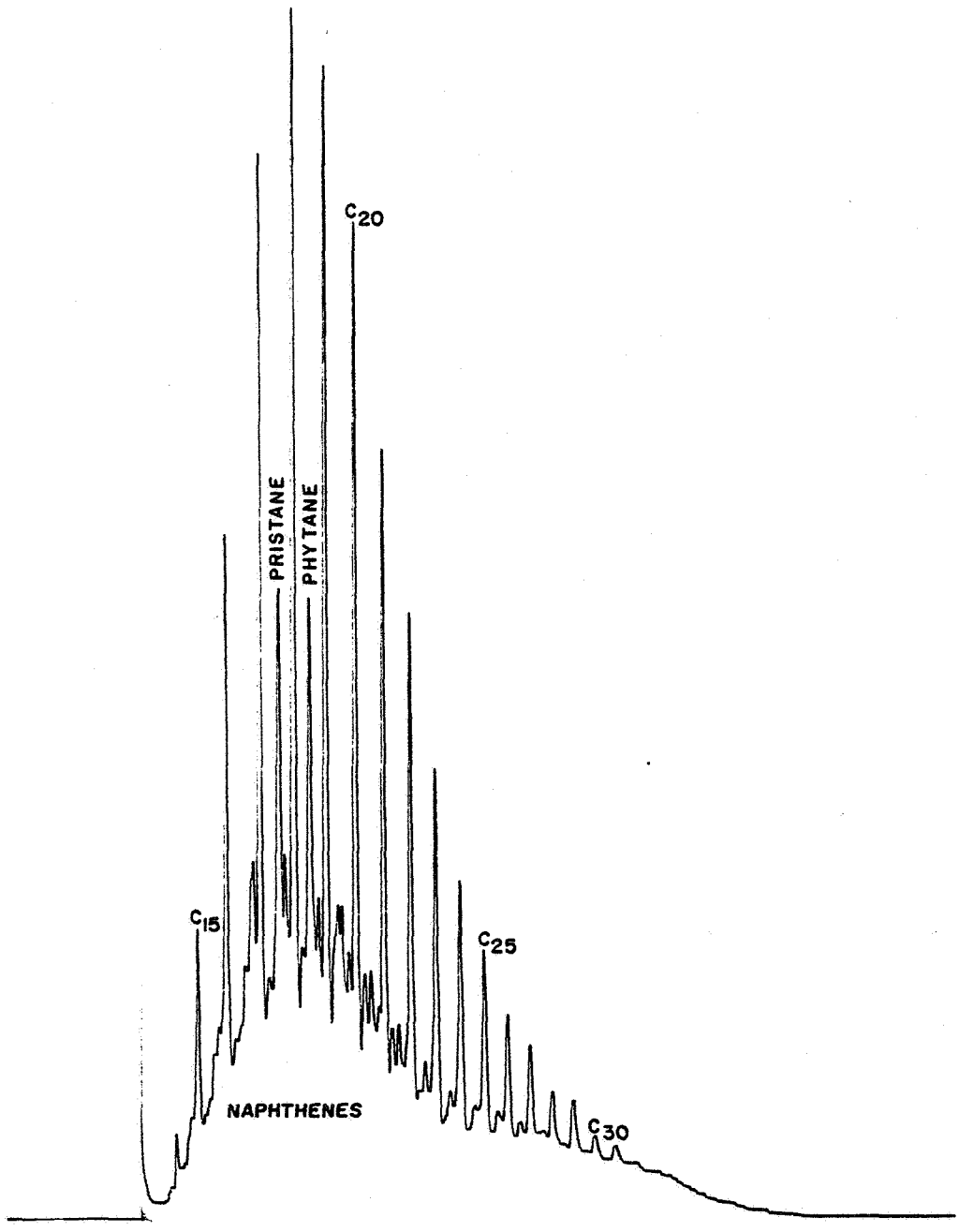


Figure 6. Chromatogram of C_{15+} saturate hydrocarbons isolated from a Lower Jurassic coal sample near total depth of the well (4,320m). This chromatographic signature indicates more advanced maturity than in overlying Jurassic sediments and is essentially that of a true condensate.

the coaly interval are exceptionally high. Values for concentration of C_1 to C_7 components are as high as 1,078,108 ppm (greater than 100% of rock volume at STP). This confirms that intense generation of gas has begun, and leaves little doubt that the Lower Jurassic coals are the source for the gas encountered by the 35/8-1 well.

C_{15+} extraction data exhibit a clear relationship to kerogen types in that concentrations of C_{15+} hydrocarbons decrease significantly within the coaly interval. This reflects the dominantly gas-prone nature of the kerogens and partial cracking of previously generated liquid hydrocarbons. Moreover, the chromatograms of C_{15+} saturate hydrocarbons show true condensate-like patterns which confirm relatively advanced thermal maturity (Figure 6).

APPENDIX I.

RESULTS OF ORGANIC CARBON ANALYSIS

ORGANIC CARBON ANALYSES AND GROSS LITHOLOGICAL DESCRIPTION

Sample Number	Well Interval (Meters)	Gross Lithological Description	GSA Color Code	Total Organic Carbon (% of Rock)
G096-001	600			0.31
-A		100% Sand, quartzose, coarse to very coarse, rounded, frosted grains, no show, light gray to medium light gray. Trace of fossil fragments. This sample is contaminated by casing cement.	N7 to N8	
G096-002	700			0.23
A		90% Sand, noncalcareous, quartzose, coarse to pebble, rounded to subangular, frosted grains, no show, light gray to medium gray.	N7 to N5	
-B		10% Varied lithology consisting of sandstone, shale, pyrite and fossil fragments.		
G096-003	800			0.10
-A		100% Sand, noncalcareous, quartzose, coarse to pebble, rounded to subangular, frosted grains, no show, light gray to medium gray. Trace of shale and fossil fragments.	N7 to N5	
G096-004	900			0.22
-A		100% Sand, noncalcareous, quartzose, coarse to pebble, rounded to subangular, frosted grains, no show, light gray to medium gray. This sample is extremely contaminated by casing cement.	N7 to N5	
G096-005	1000			1.29; 1.18R
-A		95% Mudstone, very slightly calcareous, very slightly micromicaceous, chunky, moderately soft, pale yellowish brown.	10YR 6/2	

ORGANIC CARBON ANALYSES AND GROSS LITHOLOGICAL DESCRIPTION

Sample Number	Well Interval (Meters)	Gross Lithological Description	GSA Color Code	Total Organic Carbon (% of Rock)
G096-005 -A	(cont.)	5% Sand, noncalcareous, quartzose, coarse to pebble, rounded to subangular, frosted grains, no show, light gray to medium gray.	N7 to N5	-
G096-006 -A	1100	100% Mudstone, very slightly calcareous, slightly micromicaceous, chunky, moderately soft, pale yellowish brown.	10YR 6/2	1.35
G096-007 -A	1200	100% Mudstone, very slightly calcareous, slightly micromicaceous, occasionally carbonaceous and pyritized, chunky, moderately soft, pale yellowish brown to brownish black. Trace of sand and sandstone.	10YR 6/2 to 5YR 2/1	1.19
G096-008 -A	1300	55% Sand, noncalcareous, quartzose, coarse to very coarse, rounded, frosted grains, light gray to medium gray.	N7 to N5	1.50
-B		40% Mudstone, very slightly calcareous, slightly micromicaceous, occasionally carbonaceous and pyritized, chunky, moderately soft, pale yellowish brown to brownish black.	10YR 6/2 to 5YR 2/1	
-C		5% Varied lithology consisting of sandstone, shale, pyrite and gauconite.		
G096-009 -A	1400	55% Shale, noncalcareous, slightly chloritic, ferrginous in part, slightly micromicaceous, chunky, flaky, moderately soft, light bluish gray to medium gray and pale brown to dusky yellowish brown.	5B 7/1 to N5 5YR 5/2; 10YR 2/2	0.62

ORGANIC CARBON ANALYSES AND GROSS LITHOLOGICAL DESCRIPTION

Sample Number	Well Interval (Meters)	Gross Lithological Description	GSA Color Code	Total Organic Carbon (% of Rock)
G096-009 -A	(cont.)	45% Sand, noncalcareous, quartzose, coarse to very coarse, rounded, frosted grains, light gray to medium gray. Trace of mudstone, sandstone and pyrite.	N7 to N5	
G096-010 -A	1500	100% Sand, noncalcareous, quartzose, coarse to very coarse, rounded, frosted grains, very light gray to light gray. Trace of mudstone and shale, This sample is contaminated by mica.	N8 to N7	0.19
G096-011 -A	1600	90% Shale, noncalcareous, slightly chloritic and glauconitic, ferruginous in part, slightly micromicaceous, chunky, flaky, moderately soft, light gray to greenish gray and moderate brown to dusky yellowish brown.	N7 to 5G 6/1 5YR 4/4 3/4; 10YR 2/2	0.82
-B		10% Sand, noncalcareous, quartzose, coarse to very coarse, rounded frosted grains, very light gray to light gray. Trace of sandstone and pyrite.	N8 to N7	
G096-012 -A	1700	100% Shale, noncalcareous, slightly chloritic and glauconitic, ferruginous in part, slightly micromicaceous, chunky, flaky, moderately soft, light gray to greenish gray and moderate brown to dusky yellowish brown. Trace of sand and pyrite.	N7 to 5G 6/1 5YR 4/4 3/4; 10YR 2/2	0.77
G096-013 -A	1800	100% Shale, noncalcareous, slightly chloritic, slightly micro-micaceous, flaky, moderately soft, medium light gray to medium gray. Trace of dolomite.	N6 to N5	0.33

ORGANIC CARBON ANALYSES AND GROSS LITHOLOGICAL DESCRIPTION

Sample Number	Well Interval (Meters)	Gross Lithological Description	GSA Color Code	Total Organic Carbon (% of Rock)
G096-014 -A	1900	100% Shale, noncalcareous, slightly chloritic and glauconitic, ferruginous in part, slightly micromicaceous, chunky, flaky, moderately soft, light gray to greenish gray and moderate brown to dusky yellowish brown. Trace of dolomite.	N7 to 5G 6/1 5YR 4/4 3/1; 10YR 2/2	0.54
G096-015 -A	2000	100% Shale, noncalcareous, slightly chloritic and glauconitic, ferruginous in part, slightly micromicaceous, chunky, flaky, moderately soft, light gray to greenish gray and moderate brown to dusky yellowish brown. Trace of limestone, sand and pyrite.	N7 to 5G 6/1 5YR 4/4 3/4; 10YR 2/2	0.51
G096-016 -A	2100	100% Shale, noncalcareous, slightly chloritic, ferruginous in part, slightly micromicaceous, chunky, flaky, moderately soft, medium bluish gray to medium dark gray and medium brown. Trace of limestone and pyrite.	5B 5/1 to N4; 5YR 3/4	0.47; 0.51R
G096-017 -A	2200	85% Shale, very slightly calcareous, partially glauconitic, slightly micromicaceous, chunky, flaky, moderately soft, medium gray to olive gray.	N5 to 5Y 4/1	0.84
-B		15% Varied lithology consisting of sand, dolomite and pyrite.		
G096-018 -A	2300	100% Shale, very slightly calcareous, partially glauconitic, slightly micromicaceous, chunky, flaky, moderately soft, medium gray to olive gray. Trace of dolomite, sand and pyrite.	N5 to 5Y 4/1	0.45

ORGANIC CARBON ANALYSES AND GROSS LITHOLOGICAL DESCRIPTION

Sample Number	Well Interval (Meters)	Gross Lithological Description	GSA Color Code	Total Organic Carbon (% of Rock)
G096-019 -A	2400	100% Shale, very slightly calcar- eous, slightly micromicaceous, chunky, flaky, moderately soft, medium light gray.	N6	0.72
G096-020 -A	2500	100% Shale, very slightly calcar- eous, slightly micromicaceous, chunky, flaky, moderately soft, medium light gray.	N6	0.80
G096-021 -A	2600	100% Shale, calcareous, slightly micromicaceous, chunky, flaky, moderately soft, medium light gray to medium gray.	N6 to N5	0.65
G096-022 -A	2700	100% Shale, calcareous, slightly micromicaceous, chunky, flaky, moderately soft, medium light gray to medium gray.	N6 to N5	0.58
G096-023 -A	2800	100% Shale, calcareous, slightly, micromicaceous, chunky, flaky, moderately soft, medium light gray to medium gray.	N6 to N5	0.64
G096-024 -A	2900	100% Shale, calcareous, slightly micromicaceous, chunky, flaky, moderately soft, medium light gray to medium gray.	N6 to N5	0.61
G096-025 -A	3000	100% Shale, calcareous, slightly micromicaceous, chunky, flaky, moderately soft, medium light gray to medium gray. Trace of limestone.	N6 to N5	0.70

ORGANIC CARBON ANALYSES AND GROSS LITHOLOGICAL DESCRIPTION

Sample Number	Well Interval (Meters)	Gross Lithological Description	GSA Color Code	Total Organic Carbon (% of Rock)
G096-026 -A	3100	100% Shale, noncalcareous, slightly carbonaceous, micromicaceous, occasionally pyritized, chunky, flaky, moderately soft, brownish black. Trace of limestone.	5YR 2/1	5.52
G096-027 -A	3200	60% Shale, extremely calcareous, grading to limestone, slightly micromicaceous, slightly pyritized, slightly chloritized, chunky, flaky, moderately soft, light gray to medium gray.	N7 to N5	0.29; 0.26R
-B		40% Limestone, micrite, occasionally chloritized, white to light bluish gray.	N9 to 5B 7/1	
G096-028 -A		100% Mud additive, soltex.		41.52

ORGANIC CARBON ANALYSES AND GROSS LITHOLOGICAL DESCRIPTION

Sample Number	Well Interval (Feet)	Gross Lithological Description	GSA Color Code	Total Organic Carbon (% of Rock)
G096-029 -A	3300	100% Shale, noncalcareous, micromicaceous, chunky, moderately soft, medium dark gray. This sample is very contaminated by drilling mud.	N4	2.66
G096-030 -A	3400	100% Shale, noncalcareous, micromicaceous, chunky, moderately soft, medium dark gray. This sample is very contaminated by drilling mud.	N4	2.25
G096-031 -A	3500	100% Shale, noncalcareous, micromicaceous, chunky, moderately soft, medium dark gray. This sample is very contaminated by drilling mud.	N4	3.38
G096-034 -A	3800	100% Shale, noncalcareous, micromicaceous, chunky, moderately soft, medium dark gray. This sample is very contaminated by drilling mud and asphalt.	N4	1.76
G096-035 -A	3900	90% Shale, noncalcareous, very micaceous, fissile, moderately soft, medium dark gray.	N4	1.00/1.03
-B		10% Sandstone, noncalcareous, quartzose, medium, subrounded, frosted grains, chunky, hard, tight, no show, medium light gray. Trace of sand. This sample is very contaminated by drilling mud.	N6	

ORGANIC CARBON ANALYSES AND GROSS LITHOLOGICAL DESCRIPTION

Sample Number	Well Interval (Feet)	Gross Lithological Description	GSA Color Code	Total Organic Carbon (% of Rock)
G096-036 -A	4000	100% Shale, noncalcareous, very micaceous, fissile, moderately soft, medium dark gray. Trace of sand and sandstone. This sample is very contaminated by drilling mud.	N4	1.13
G096-037 -A	4100	100% Sand, quartzose, coarse to very coarse, subrounded, frosted grains, consolidated in part, very poor show, light gray. This sample is very contaminated by drilling mud.	N7	0.67
G096-038 -A	4154	50% Shale, noncalcareous, extremely carbonaceous, coal interbedded, fissile, chunky, moderately soft, black.	N1	38.48
-B		50% Sandstone, noncalcareous, quartzose,unconsolidated in part, medium to very coarse, subrounded, frosted grains, chunky, hard, poor porosity, poor show, light gray to medium dark gray.	N7 to N4	
G096-039 -A	4230	100% Sand, noncalcareous, quartzose, poorly consolidated, coarse to very coarse, subrounded grains, good show, pinkish gray. Trace of shale.	5YR 8/1	2.17
G096-040 -A	4260	90% Sand, noncalcareous, quartzose, poorly consolidated, coarse to very coarse subrounded grains, very good show, pinkish gray.	5YR 8/1	12.14
-B		10% Shale, noncalcareous, extremely carbonaceous, coal interbedded, fissile, chunky, moderately soft, black.	N1	

ORGANIC CARBON ANALYSES AND GROSS LITHOLOGICAL DESCRIPTION

Sample Number	Well Interval (Feet)	Gross Lithological Description	GSA Color Code	Total Organic Carbon (% of Rock)
G096-041	4290			32.13
-A		90% Shale, noncalcareous, extremely carbonaceous, coal interbedded, fissile, chunky, moderately soft, black.	N1	
-B		10% Sand, noncalcareous, quartzose, poorly consolidated, coarse to very coarse, subrounded, frosted grains, fair show, pinkish gray.	5YR 8/1	
G096-042	4320			4.49
-A		100% Sand, noncalcareous, quartzose, poorly consolidated, coarse to very coarse, subrounded, frosted grains, good show, very pale orange to pale yellowish brown. Trace of shale and coal.	10YR 8/2 to 10YR 6/2	
G096-043	4320-4343.5			3.49
-A		100% Sand, noncalcareous, quartzose, poorly consolidated, coarse to very coarse, subrounded, frosted grains, good show, very pale orange to pale yellowish brown. Trace of shale and coal.	10YR 8/2 to 10YR 6/2	

RESULTS OF C_{15+} ORGANIC CARBON DETERMINATIONS

Sample Number	Organic Carbon, Wt. %
G096-001	0.25
G096-002	0.13
G096-003	0.12
G096-004	0.21
G096-005	1.29; 1.31R
G096-006	1.41
G096-007	1.14
G096-008	1.32
G096-009	0.59
G096-010	0.38
G096-011	1.09
G096-012	0.84
G096-013	0.48
G096-014	0.56
G096-015	0.53
G096-016	0.58; 0.61
G096-017	0.70
G096-018	0.46
G096-019	0.72
G096-020	0.79
G096-021	0.54
G096-022	0.57
G096-023	0.61
G096-024	0.56
G096-025	0.75
G096-026	4.39
G096-027	0.34; 0.36

RESULTS OF CARBON ANALYSES

SAMPLE NUMBER	DEPTH INTERVAL (METERS)	TOTAL ORGANIC CARBON
G096-029	3300	2.19
G096-030	3400	2.17
G096-031	3500	3.44
G096-034	3800	2.52
G096-035	3900	1.10
G096-036	4000	1.06
G096-037	4100	0.81
G096-038	4154	29.18; 33.88
G096-039	4230	0.48
G096-040	4260	11.76
G096-041	4290	24.65
G096-042	4320	2.74
G096-043	4320-4343.5	2.25; 2.21

ADDITIONAL ORGANIC CARBON DATA ON JURASSIC SEDIMENTS

Sample Number	Depth (meters)	% Organic Carbon	GSA Color
GO96-101	3010	0.38	N-5
-102 A	3040	0.81	N-4
-102 B	3040	0.17	N-8
-103 A	3070	0.65	N-5
-103 B	3070	0.17	N-8
-104 A	3100	0.40	N-5
-104 B	3100	0.18	5B 9/1
-105	3130	0.53	N-4
-106	3150	0.56	N-5
-107	3160	0.55	N-5
-108 A	3185	1.09	N-4
-108 B	3185	0.24	N-9
-109 A	3200	5.61	N-3
-109 B	3200	0.41	N-9
-110	3229	2.55	N-2
-111	3261	2.46	N-2
-112	3291	2.78	N-3
-113	3318	1.55	N-2
-114	3351	2.81	N-3
-115	3381	2.08	N-3
-116	3414	2.33	N-3
-117	3441	3.13	N-4
-118	3471	3.06	N-4
-119	3504	1.21	N-4
-120	3711	0.42	5YR 2/1
-121 A	3741	3.27	N-3
-121 B	3741	0.20	5YR 8/1
-122 A	3771	1.40	N-4
-122 B	3771	0.62	N-6
-123 A	3800	1.02	N-4
-123 B	3800	0.37	5YR 8/1
-124	3830	0.41	N-4
-125	3860	1.85	N-3
-126	3890	1.40	N-4
-127 A	3920	1.67	N-3
-127 B	3920	0.49	N-7
-128 A	3950	0.71	N-4
-128 B	3950	0.22	5YR 8/1
-129 A	3980	0.43	N-3
-129 B	3980	0.23	5Y 6/1
-130 A	4010	1.56	5YR 2/1
-130 B	4010	0.27	5YR 8/1

APPENDIX II.

RESULTS OF PYROLYSIS

T.O.C. = Total organic carbon, wt. %
S1 = Free hydrocarbons, mg HC/g of rock
S2 = Residual hydrocarbon potential (mg HC/g of rock)
S3 = CO2 produced from kerogen pyrolysis (mg CO2/g of rock)
S1+S2 = Genetic hydrocarbon potential (mg HC/g of rock)
Hydrogen Index = mg HC/g organic carbon
Oxygen Index = mg CO2/g organic carbon
S1/S1+S2 = Transformation ratio
Tmax = Temperature Index, degrees C.

RESULTS OF ROCK-EVAL PYROLYSIS

Sample No.	Depth Interval (M)	T.O.C. (wt.%)	S1 (mg/g)	S2 (mg/g)	S3 (mg/g)	S1+S2 (mg/g)	Hydrogen Index	Oxygen Index	S1/S1+S2	Tmax (°C)
G096-005	1000	1.24	0.13	1.85	1.36	1.98	149	110	0.07	390
G096-006	1100	1.35	Neg.	1.57	1.24	1.57	116	92	-	414
G096-007	1200	1.19	0.11	1.03	1.21	1.14	87	102	0.10	391
G096-008	1300	1.50	Neg.	1.06	1.20	1.08	71	80	-	391
G096-009	1400	0.62	Neg.	Neg.	0.70	-	-	113	-	-
G096-011	1600	0.82	Neg.	Neg.	1.41	-	-	172	-	-
G096-012	1700	0.77	Neg.	Neg.	0.65	-	-	84	-	-
G096-014	1900	0.54	Neg.	Neg.	0.39	-	-	72	-	-
G096-015	2000	0.51	Neg.	0.13	0.55	0.13	25	108	-	412
G096-016	2100	0.51	Neg.	Neg.	0.70	-	-	137	-	-
G096-017	2200	0.84	Neg.	0.25	3.52	0.25	30	419	-	421
G096-018	2300	0.45	Neg.	Neg.	2.55	-	-	567	-	-
G096-019	2400	0.72	Neg.	0.20	1.88	0.20	28	261	-	421
G096-020	2500	0.80	Neg.	0.33	1.34	0.33	41	168	-	427
G096-021	2600	0.65	0.13	Neg.	2.14	0.13	-	329	-	-
G096-022	2700	0.58	Neg.	0.07	2.16	0.07	12	372	-	425
G096-023	2800	0.64	Neg.	0.10	2.65	0.10	16	414	-	425
G096-024	2900	0.61	Neg.	0.19	1.88	0.19	31	308	-	425
G096-025	3000	0.70	Neg.	0.47	2.84	0.47	67	406	-	424
G096-026	3100	5.52	2.16	16.38	0.79	18.54	297	14	0.12	418
G096-027	3200	0.29	Neg.	Neg.	1.65	-	-	569	-	-
G096-028	0	41.52	0.99	196.42	2.23	197.41	473	5	0.01	418

RESULTS OF ROCK-EVAL PYROLYSIS

T.O.C. =Total Organic Carbon, Wt. %
S1 =Free hydrocarbons, mg HC/g of rock
S2 =Residual hydrocarbon potential (mg HC/g of rock)
S3 =CO2 produced from kerogen pyrolysis (mg CO2/g of rock)
S1+S2 =Genetic hydrocarbon potential (mg HC/g of rock)
Hydrogen Index =mg HC/g organic carbon
Oxygen Index =mg CO2/g organic carbon
S1/S1+S2=Transformation ratio
Tmax =Temperature Index, degrees C.

Sample No.	Depth (Meters)	T.O.C. (Wt. %)	S1 (mg/g)	S2 (mg/g)	S3 (mg/g)	S1+S2 (mg/g)	S2/S3	Hydrogen Index	Oxygen Index	$\frac{S1}{S1+S2}$	Tmax (^{0}C)
G096-029	3300	2.19	0.64	5.88	1.96	6.52	3.00	268	89	0.10	424;434
G096-030	3400	2.17	1.02	6.91	2.36	7.93	2.93	318	109	0.13	428
G096-031	3500	3.44	1.59	5.09	3.79	6.68	1.34	148	110	0.24	426
G096-034	3800	2.52	1.61	7.90	1.98	9.51	3.99	313	79	0.17	424
G096-035	3900	1.10	1.66	0.78	1.43	2.44	0.55	71	130	0.68	433
G096-036	4000	1.06	2.40	1.02	1.29	3.42	0.79	96	122	0.70	427
G096-037	4100	0.81	1.19	1.52	1.64	2.71	0.93	188	202	0.44	404;418
G096-038	4154	31.53	5.40	48.06	0.92	53.46	52.24	152	3	0.10	455
G096-039	4230	0.48	0.37	1.21	0.64	1.58	1.89	252	133	0.23	443
G096-040	4260	11.76	3.49	16.63	0.77	20.12	21.60	141	7	0.17	451
G096-041	4290	24.65	4.08	36.77	1.52	40.85	24.19	149	6	0.10	452
G096-042	4320	2.74	1.00	2.57	4.64	3.57	0.55	94	169	0.28	368;440
G096-043	4320-4343.5	2.25	0.25	2.34	1.64	1.89	1.43	104	73	0.13	375;445

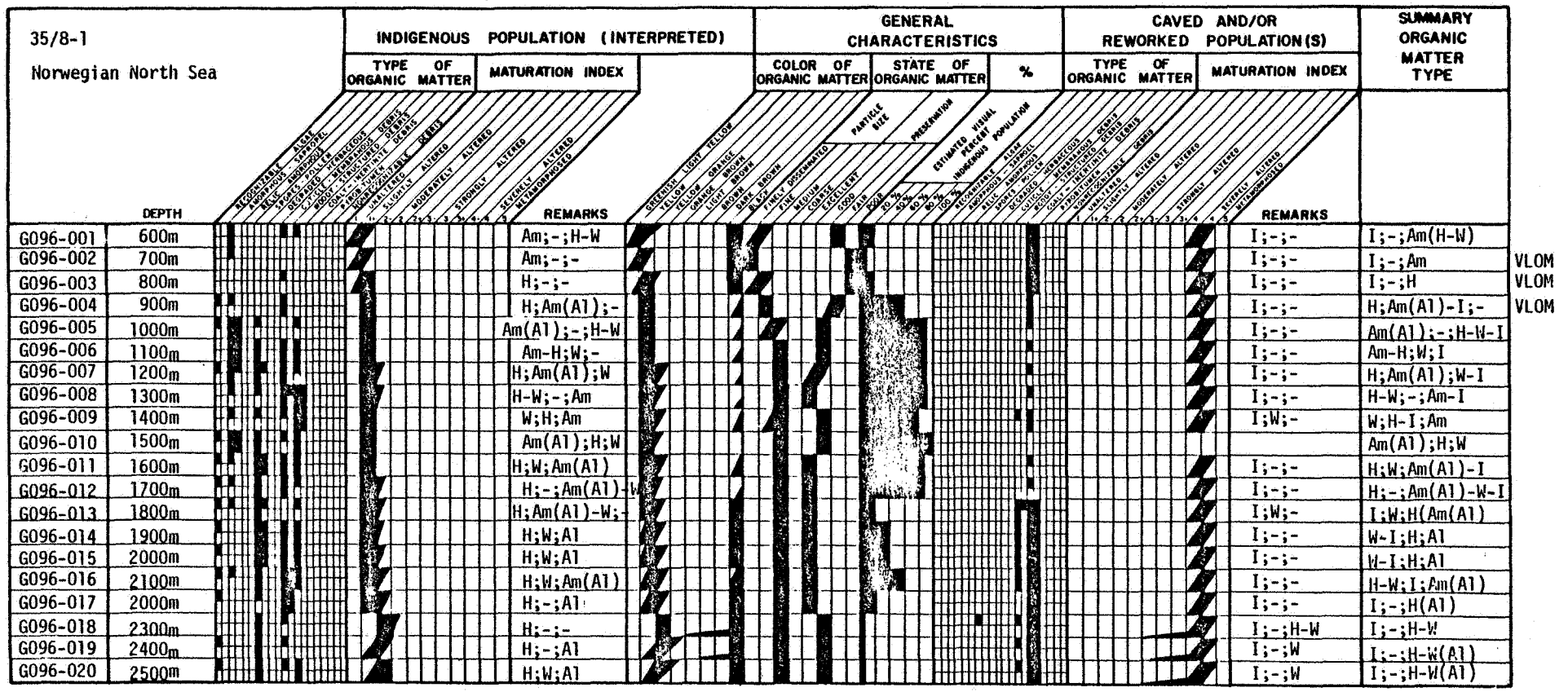
APPENDIX III.

RESULTS OF VISUAL KEROGEN ASSESSMENT

VISUAL KEROGEN ASSESSMENT WORKSHEET

35/8-1

Norwegian North Sea



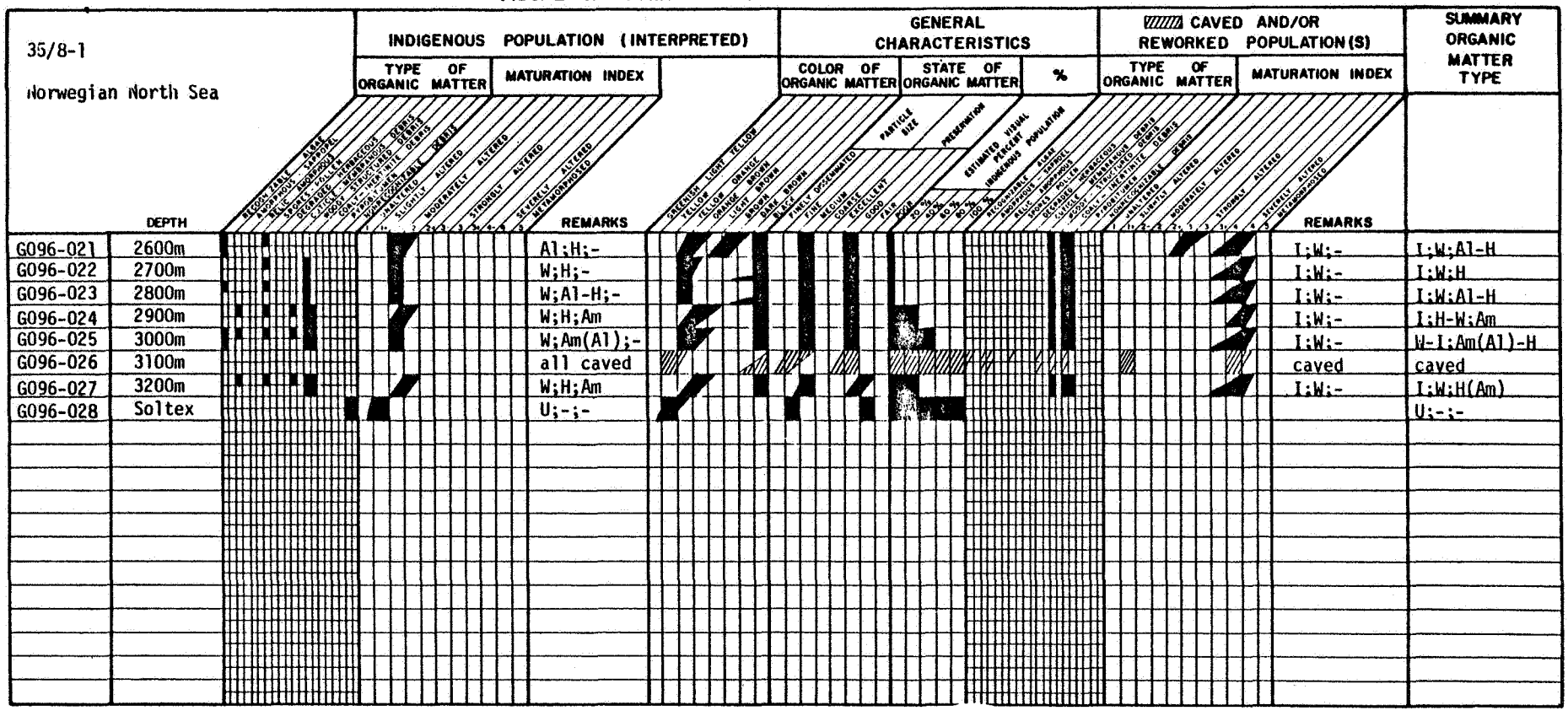
	DEPTH	REMARKS	REMARKS	SUMMARY ORGANIC MATTER TYPE	
G096-001	600m	Am;-;H-W	I;-;-	I;-;Am(H-W)	
G096-002	700m	Am;-;-	I;-;-	I;-;Am	VLOM
G096-003	800m	H;-;-	I;-;-	I;-;H	VLOM
G096-004	900m	H;Am(Al);-	I;-;-	H;Am(Al)-I;-	VLOM
G096-005	1000m	Am(Al);-;H-W	I;-;-	Am(Al);-;H-W-I	
G096-006	1100m	Am-H;W;-	I;-;-	Am-H;W;I	
G096-007	1200m	H;Am(Al);W	I;-;-	H;Am(Al);W-I	
G096-008	1300m	H-W;-;Am	I;-;-	H-W;-;Am-I	
G096-009	1400m	W;H;Am	I;W;-	W;H-I;Am	
G096-010	1500m	Am(Al);H;W		Am(Al);H;W	
G096-011	1600m	H;W;Am(Al)	I;-;-	H;W;Am(Al)-I	
G096-012	1700m	H;-;Am(Al)-W	I;-;-	H;-;Am(Al)-W-I	
G096-013	1800m	H;Am(Al)-W;-	I;W;-	I;W;H(Am(Al)	
G096-014	1900m	H;W;Al	I;-;-	W-I;H;Al	
G096-015	2000m	H;W;Al	I;-;-	W-I;H;Al	
G096-016	2100m	H;W;Am(Al)	I;-;-	H-W;I;Am(Al)	
G096-017	2000m	H;-;Al	I;-;-	I;-;H(Al)	
G096-018	2300m	H;-;-	I;-;H-W	I;-;H-W	
G096-019	2400m	H;-;Al	I;-;W	I;-;H-W(Al)	
G096-020	2500m	H;W;Al	I;-;W	I;-;H-W(Al)	

VLOM-Very little organic material.

VISUAL KEROGEN ASSESSMENT WORKSHEET

35/8-1

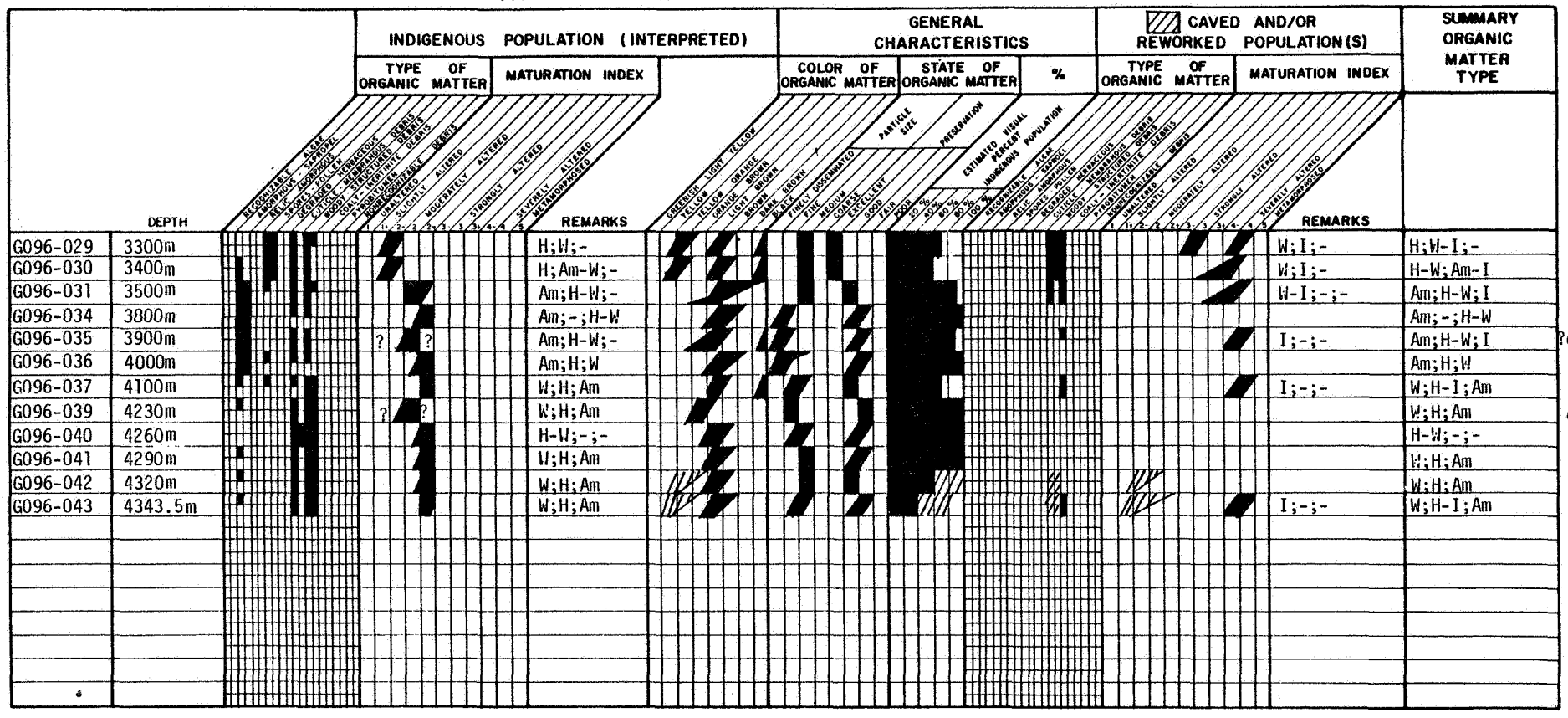
Norwegian North Sea



	DEPTH	REMARKS	REMARKS	SUMMARY ORGANIC MATTER TYPE
G096-021	2600m	Al;H;-	I;W;-	I;W;Al-H
G096-022	2700m	W;H;-	I;W;-	I;W;H
G096-023	2800m	W;Al-H;-	I;W;-	I;W;Al-H
G096-024	2900m	W;H;Am	I;W;-	I;H-W;Am
G096-025	3000m	W;Am(Al);-	I;W;-	W-I;Am(Al)-H
G096-026	3100m	all caved	caved	caved
G096-027	3200m	W;H;Am	I;W;-	I;W;H(Am)
G096-028	Soltex	U;-;-		U;-;-

Material in Soltex kerogen preparation looks like a soft resin.
In part, it thins out like some hydrocarbons; in other parts,
it is a soft (non-fractured) mass.

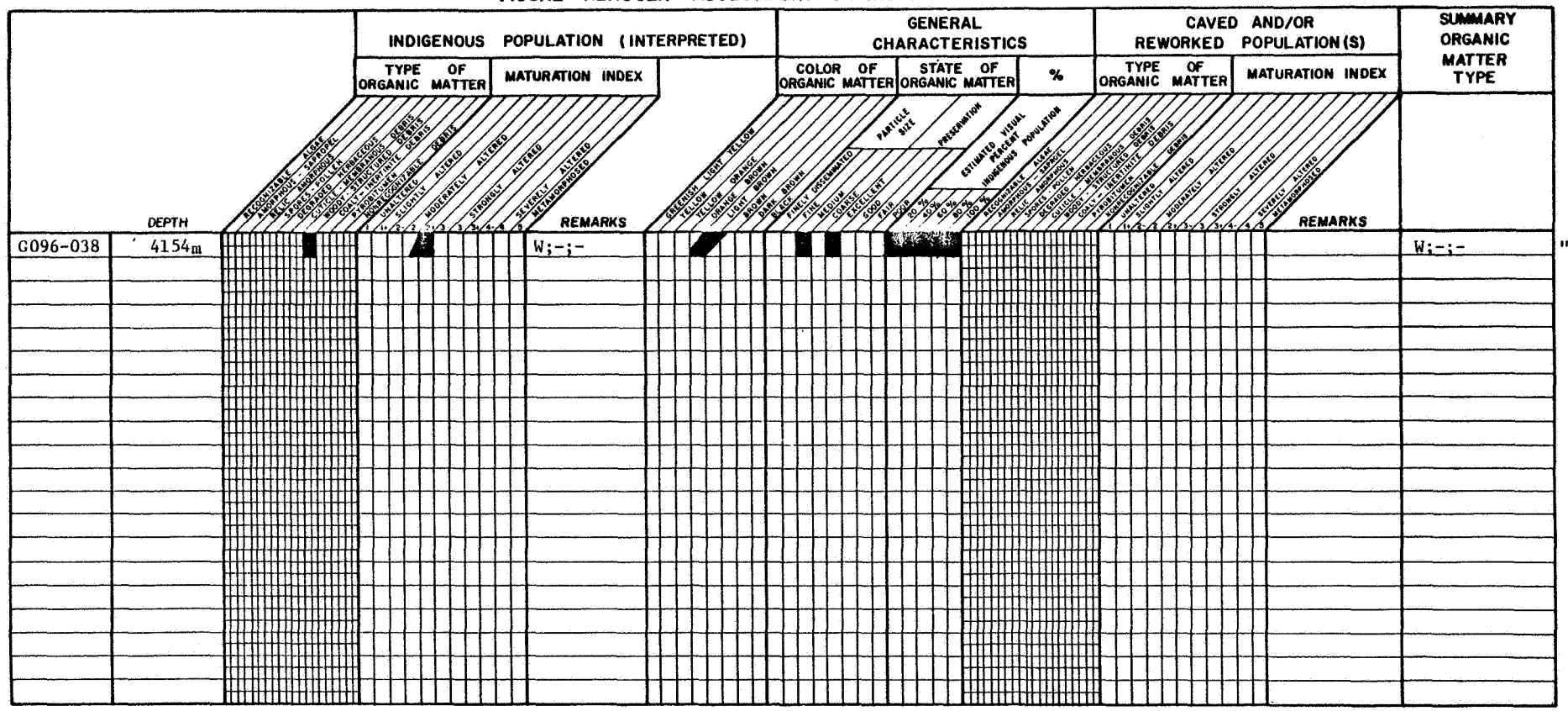
VISUAL KEROGEN ASSESSMENT WORKSHEET



	DEPTH	REMARKS	REMARKS	SUMMARY ORGANIC MATTER TYPE	
G096-029	3300m	H;W;-	W;I;-	H;W-I;-	
G096-030	3400m	H;Am-W;-	W;I;-	H-W;Am-I	
G096-031	3500m	Am;H-W;-	W-I;-;-	Am;H-W;I	
G096-034	3800m	Am;-;H-W		Am;-;H-W	
G096-035	3900m	Am;H-W;-	I;-;-	Am;H-W;I	?caved
G096-036	4000m	Am;H;W		Am;H;W	
G096-037	4100m	W;H;Am	I;-;-	W;H-I;Am	
G096-039	4230m	W;H;Am		W;H;Am	caved
G096-040	4260m	H-W;-;-		H-W;-;-	
G096-041	4290m	W;H;Am		W;H;Am	
G096-042	4320m	W;H;Am		W;H;Am	
G096-043	4343.5m	W;H;Am	I;-;-	W;H-I;Am	

In 034, 5% of sample are 10-15UM droplets of resin-oil like material.

VISUAL KEROGEN ASSESSMENT WORKSHEET



	DEPTH	REMARKS	REMARKS	SUMMARY ORGANIC MATTER TYPE	
G096-038	4154m	W;-;-		W;-;-	"coal"

Go with vitrinite on this; TAI based on slivers of wood is difficult.

APPENDIX IV.

RESULTS OF VITRINITE REFLECTANCE MEASUREMENTS

VITRINITE REFLECTANCE SUMMARY

SAMPLE NUMBER	DEPTH	TYPE OF SAMPLE	POPULATION	NUMBER OF READINGS	MINIMUM REFLECTANCE (% Ro)	MAXIMUM REFLECTANCE (% Ro)	MEAN REFLECTANCE (% Ro)	STD. DEV. (% Ro)	REMARKS
G096-001	600m	CTG	NO VITRINITE						
G096-002	700m	CTG	NO VITRINITE						
G096-003	800m	CTG	NO VITRINITE						
G096-004	900m	CTG	NO VITRINITE						
G096-005	1000m	CTG	(1)	57	0.17	0.36	0.24	0.033	
			(2)	3	0.50	0.88	0.65	0.204	
G096-006	1100m	CTG	(1)	57	0.19	0.36	0.26	0.040	
			(2)	3	0.48	0.56	0.51	0.042	
G096-007	1200m	CTG	(1)	2	0.18	0.19	0.19	-	
			(2)	45	0.22	0.40	0.29	0.050	
			(3)	13	0.44	0.80	0.61	0.129	
G096-008	1300m	CTG	(1)	42	0.22	0.37	0.29	0.040	
			(2)	8	0.46	0.91	0.63	0.184	
G096-009	1400m	CTG	(1)	46	0.23	0.42	0.32	0.049	
			(2)	10	0.45	0.59	0.51	0.055	
			(3)	4	0.75	1.04	0.88	0.124	
G096-010	1500m	CTG	(1)	56	0.25	0.48	0.36	0.068	
			(2)	4	0.55	0.93	0.67	0.178	
G096-011	1600m	CTG	(1)	1	0.22	0.22	0.22	-	
			(2)	19	0.27	0.38	0.32	0.036	
			(3)	10	0.42	0.54	0.47	0.041	
			(4)	4	0.69	1.03	0.83	0.143	

VITRINITE REFLECTANCE SUMMARY

SAMPLE NUMBER	DEPTH	TYPE OF SAMPLE	POPULATION	NUMBER OF READINGS	MINIMUM REFLECTANCE (% Ro)	MAXIMUM REFLECTANCE (% Ro)	MEAN REFLECTANCE (% Ro)	STD. DEV. (% Ro)	REMARKS
G096-012	1700m	CTG	(1)	3	0.25	0.27	0.26	0.012	
			(2)	28	0.29	0.38	0.34	0.029	
			(3)	9	0.43	0.58	0.49	0.064	
			(4)	8	0.80	1.20	0.99	0.150	
G096-013	1800m	CTG	(1)	18	0.29	0.37	0.33	0.020	
			(2)	9	0.38	0.50	0.43	0.038	
			(3)	33	0.57	2.06	0.94	0.274	
G096-014	1900m	CTG	(1)	10	0.28	0.36	0.32	0.029	
			(2)	13	0.39	0.51	0.44	0.036	
			(3)	37	0.57	1.39	0.90	0.208	
G096-015	2000	CTG	(1)	3	0.20	0.24	0.22	0.021	
			(2)	15	0.29	0.43	0.36	0.042	
			(3)	6	0.46	0.60	0.55	0.056	
			(4)	36	0.66	1.45	0.95	0.176	
G096-016	2100m	CTG	(1)	8	0.27	0.35	0.32	0.029	
			(2)	4	0.49	0.57	0.53	0.033	
			(3)	48	0.68	1.45	1.02	0.178	
G096-017	2200m	CTG	(1)	7	0.37	0.46	0.41	0.033	
			(2)	3	0.57	0.63	0.59	0.032	
			(3)	50	0.72	2.06	1.15	0.300	
G096-018	2300	CTG	(1)	1	0.27	0.27	0.27	-	
			(2)	3	0.38	0.49	0.43	0.056	
			(3)	13	0.52	0.66	0.60	0.046	
			(4)	43	0.72	1.79	1.13	0.245	
G096-019	2400m	CTG	(1)	1	0.35	0.35	0.35	-	
			(2)	23	0.50	0.65	0.56	0.049	
			(3)	36	0.68	1.43	1.01	0.232	

VITRINITE REFLECTANCE SUMMARY

SAMPLE NUMBER	DEPTH	TYPE OF SAMPLE	POPULATION	NUMBER OF READINGS	MINIMUM REFLECTANCE (% Ro)	MAXIMUM REFLECTANCE (% Ro)	MEAN REFLECTANCE (% Ro)	STD. DEV. (% Ro)	REMARKS
G096-020	2500m	CTG	(1)	7	0.43	0.53	0.48	0.040	
			(2)	21	0.57	0.72	0.63	0.046	
			(3)	32	0.74	1.56	1.02	0.212	
G096-021	2600m	CTG	(1)	11	0.45	0.59	0.52	0.045	
			(2)	13	0.64	0.76	0.70	0.039	
			(3)	36	0.80	1.75	1.19	0.235	
G096-022	2700m	CTG	(1)	5	0.61	0.76	0.70	0.063	
			(2)	55	0.90	2.20	1.32	0.272	
G096-023	2800m	CTG	(1)	3	0.51	0.53	0.52	0.012	
			(2)	15	0.62	0.74	0.69	0.042	
			(3)	42	0.77	2.03	1.21	0.280	
G096-024	2900	CTG	(1)	2	0.52	0.54	0.53	-	
			(2)	28	0.62	0.88	0.75	0.082	
			(3)	30	0.91	1.60	1.30	0.185	
G096-025	3000m	CTG	(1)	4	0.48	0.64	0.58	0.073	
			(2)	20	0.69	0.94	0.82	0.086	
			(3)	36	0.99	2.04	1.35	0.311	
G096-026	3100m	CTG	(1)	5	0.55	0.59	0.57	0.016	
			(2)	27	0.72	0.96	0.86	0.069	
			(3)	28	1.00	1.84	1.31	0.248	
G096-027	3200m	CTG	(1)	5	0.65	0.84	0.76	0.082	
			(2)	6	0.96	1.12	1.05	0.064	
			(3)	16	1.20	1.39	1.28	0.061	
			(4)	33	1.44	1.93	1.61	0.122	
G096-028	Soltex	Mud Additive							

VITRINITE REFLECTANCE SUMMARY

SAMPLE NUMBER	DEPTH	TYPE OF SAMPLE	POPULATION	NUMBER OF READINGS	MINIMUM REFLECTANCE (% Ro)	MAXIMUM REFLECTANCE (% Ro)	MEAN REFLECTANCE (% Ro)	STD. DEV. (% Ro)	REMARKS
G096-029	3300 M.	CTG	(1)	30	0.36	0.58	0.47	0.056	
			(2)	30	0.64	1.65	1.12	0.233	
G096-030	3400 M.	CTG	(1)	8	0.40	0.48	0.44	0.029	
			(2)	14	0.60	0.74	0.66	0.050	
			(3)	15	0.78	0.98	0.87	0.058	
			(4)	23	1.02	1.59	1.25	0.192	
G096-031	3500 M.	CTG	(1)	2	0.53	0.57	0.55	-	
			(2)	6	0.67	0.79	0.73	0.040	
			(3)	52	0.86	1.94	1.29	0.250	
G096-034	3800 M.	CTG	(1)	17	0.61	0.79	0.69	0.053	
			(2)	22	0.83	1.06	0.94	0.069	
			(3)	21	1.10	1.78	1.32	0.176	
G096-035	3900 M.	CTG	(1)	35	0.40	0.76	0.59	0.088	
			(2)	17	0.81	1.11	0.96	0.098	
			(3)	8	1.26	1.73	1.41	0.155	
G096-036	4100 M.	CTG	(1)	1	0.45	0.45	0.45	-	
			(2)	33	0.50	0.81	0.66	0.087	
			(3)	7	0.86	1.04	0.96	0.072	
			(4)	19	1.16	1.76	1.38	0.166	
G096-037	4100 M.	CTG	(1)	11	0.57	0.76	0.67	0.062	
			(2)	12	0.86	2.85	1.28	0.522	
G096-039	4230 M.	CTG	(1)	2	0.60	0.63	0.62	-	
			(2)	46	0.68	0.98	0.83	0.080	
			(3)	12	1.02	2.02	1.37	0.351	

VITRINITE REFLECTANCE SUMMARY

SAMPLE NUMBER	DEPTH	TYPE OF SAMPLE	POPULATION	NUMBER OF READINGS	MINIMUM REFLECTANCE (% Ro)	MAXIMUM REFLECTANCE (% Ro)	MEAN REFLECTANCE (% Ro)	STD. DEV. (% Ro)	REMARKS
G096-040	4260 M.	CTG	(1)	1	0.43	0.43	0.43	-	
			(2)	52	0.72	1.07	0.90	0.087	
			(3)	7	1.10	1.64	1.24	0.190	
G096-041	4290 M.	CTG	(1)	7	0.81	0.91	0.87	0.037	
			(2)	50	0.94	1.18	1.06	0.064	
			(3)	3	1.26	1.73	1.55	0.256	
G096-042	4320 M.	CTG	(1)	32	0.18	0.46	0.29	0.069	
			(2)	23	0.82	1.13	0.99	0.086	
			(3)	5	1.25	1.43	1.38	0.075	
G096-043	4343.5 M.	CTG	(1)	12	0.21	0.42	0.29	0.055	
			(2)	5	0.66	0.80	0.73	0.057	
			(3)	14	0.85	1.06	0.96	0.067	
			(4)	14	1.12	1.37	1.24	0.075	
			(5)	15	1.43	2.28	1.71	0.229	

VITRINITE REFLECTANCE SUMMARY

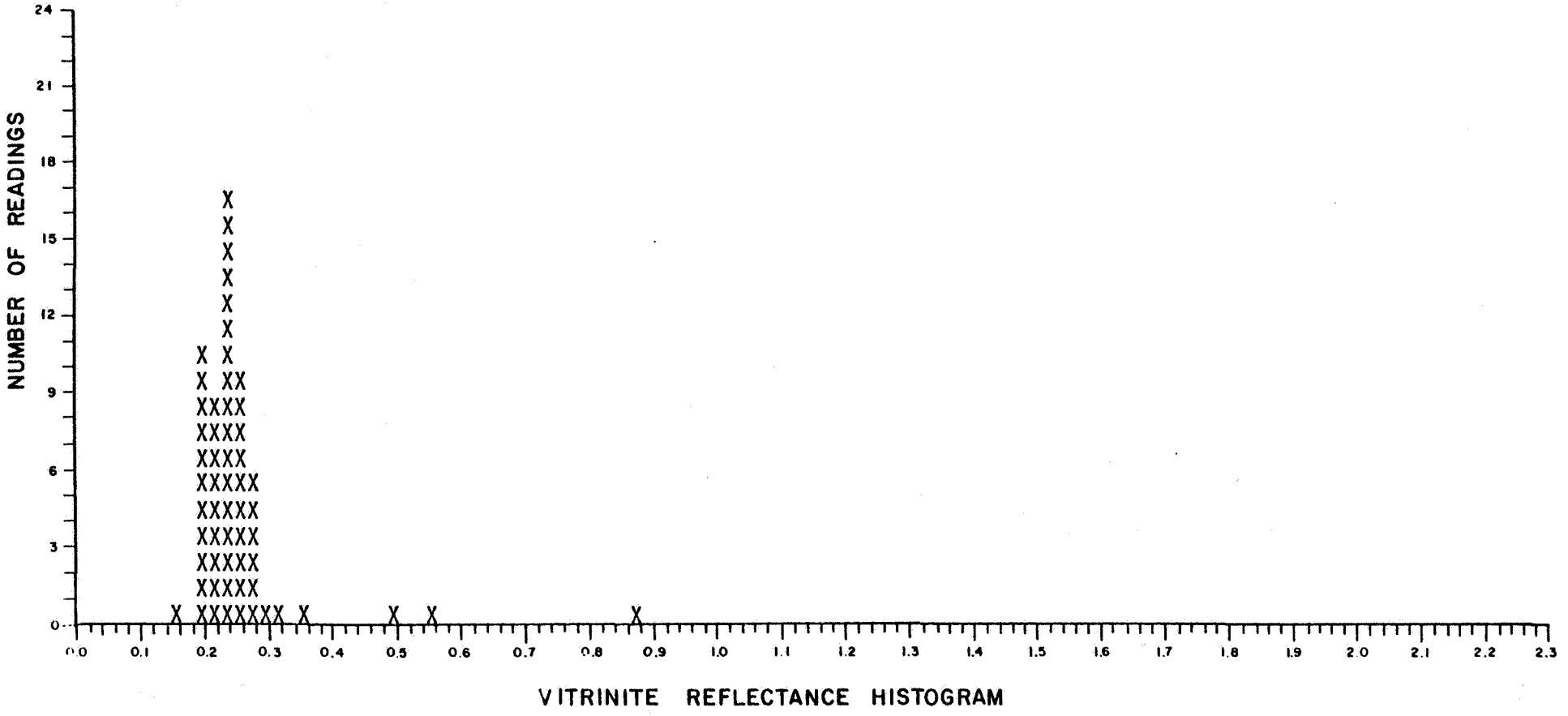
SAMPLE NUMBER	DEPTH (Meters)	TYPE OF SAMPLE	POPULATION	NUMBER OF READINGS	MINIMUM REFLECTANCE (% Ro)	MAXIMUM REFLECTANCE (% Ro)	MEAN REFLECTANCE (% Ro)	STD. DEV. (% Ro)	REMARKS
G096-038	4154	CTG	(1)	2	0.74	0.75	0.75	-	
			(2)	58	0.90	1.20	1.03	0.069	

NO. G096-005 TYPE OF SAMPLE: CTG DEPTH / SAMPLE NO. 1000 M.

NAME GETTY WELL NAME 35/8-1

(NO. OF READINGS = 60) 0.17 0.20 0.20 0.20 0.21 0.21 0.21 0.21 0.21 0.21 0.21 0.21 0.22 0.22
0.22 0.22 0.22 0.22 0.23 0.23 0.23 0.24 0.24 0.24 0.24 0.24 0.24 0.24 0.24 0.24 0.24 0.25
0.25 0.25 0.25 0.25 0.25 0.25 0.26 0.26 0.26 0.26 0.26 0.26 0.27 0.27 0.27 0.27 0.28 0.28
0.28 0.28 0.29 0.29 0.30 0.33 0.36 0.50 0.56 0.88

POPULATION	NO. OF READINGS	MIN. Ro (%)	MAX. Ro (%)	MEAN Ro (%)	STD. DEV. (%)	REMARKS
(1)	57	0.17	0.36	0.24	0.033	
(2)	3	0.50	0.88	0.65	0.204	

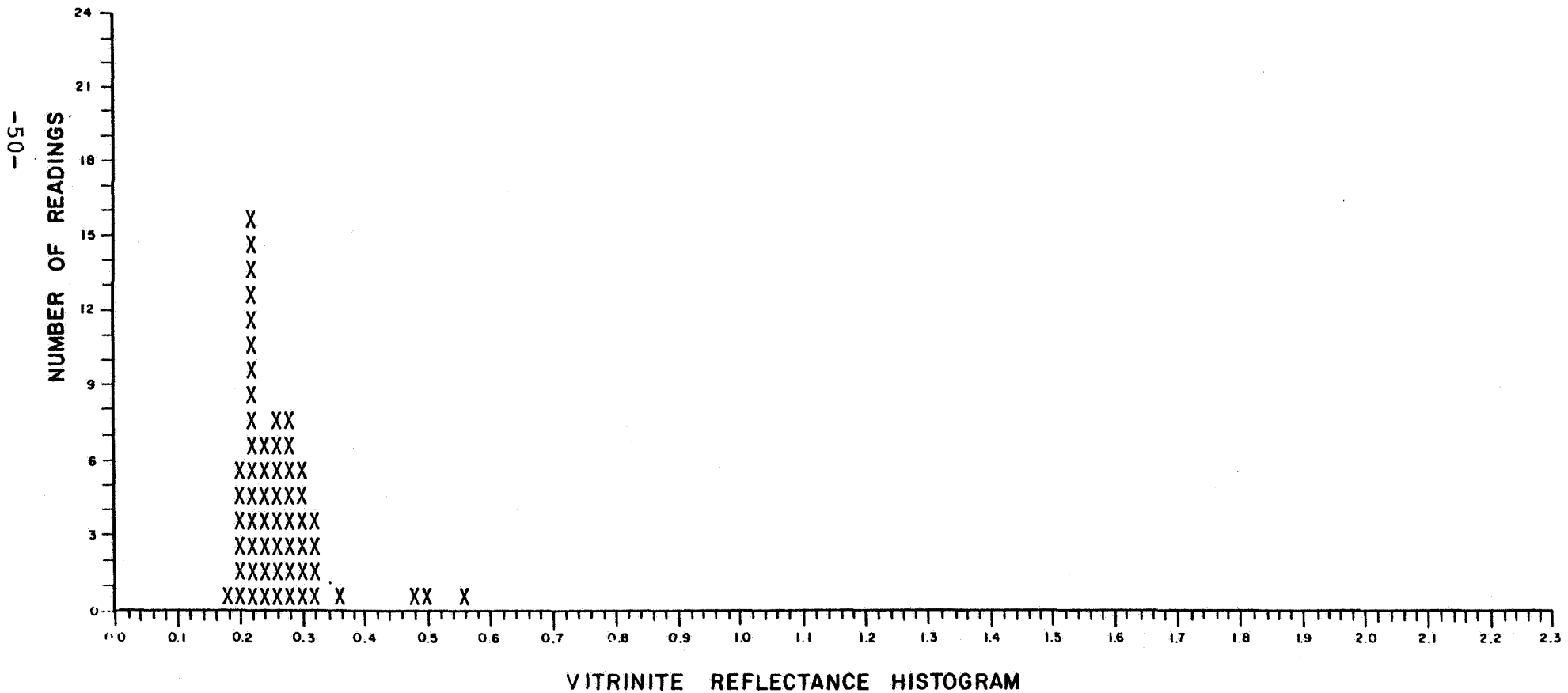


NO. G096-006 TYPE OF SAMPLE: CTG DEPTH / SAMPLE NO. 1100 M.

NAME GETTY WELL NAME 35/8-1

(NO. OF READINGS = 60) 0.19 0.20 0.20 0.21 0.21 0.21 0.21 0.22 0.22 0.22 0.22 0.22 0.22 0.23
0.23 0.23 0.23 0.23 0.23 0.23 0.23 0.23 0.23 0.24 0.24 0.25 0.25 0.25 0.25 0.25 0.26 0.26
0.26 0.26 0.26 0.27 0.27 0.27 0.28 0.28 0.28 0.29 0.29 0.29 0.29 0.29 0.31 0.31 0.31 0.31
0.31 0.31 0.32 0.32 0.33 0.33 0.36 0.48 0.50 0.56

POPULATION	NO. OF READINGS	MIN. Ro (%)	MAX. Ro (%)	MEAN Ro (%)	STD. DEV. (%)	REMARKS
(1)	57	0.19	0.36	0.26	0.040	
(2)	3	0.48	0.56	0.51	0.042	

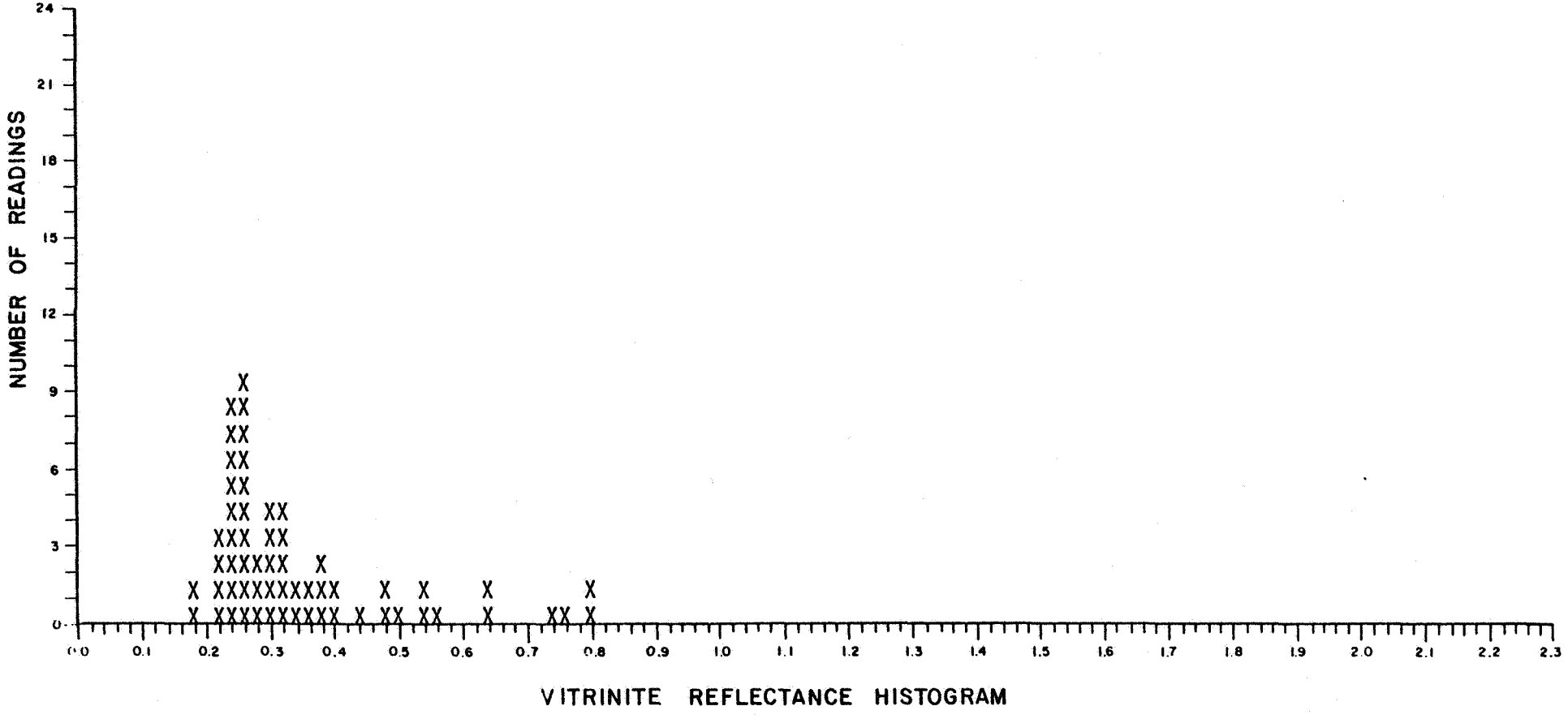


NO. G096-007 TYPE OF SAMPLE: CTG DEPTH / SAMPLE NO. 1200 M.

NAME GETTY WELL NAME 35/8-1

(NO. OF READINGS = 60) 0.18 0.19 0.22 0.23 0.23 0.23 0.24 0.24 0.24 0.24 0.24 0.25 0.25 0.25
0.25 0.26 0.26 0.26 0.26 0.27 0.27 0.27 0.27 0.27 0.27 0.28 0.28 0.29 0.30 0.30 0.30 0.30
0.31 0.32 0.32 0.32 0.33 0.33 0.34 0.35 0.36 0.36 0.38 0.38 0.38 0.40 0.40 0.44 0.48 0.49
0.50 0.54 0.55 0.56 0.64 0.65 0.74 0.77 0.80 0.80

POPULATION	NO. OF READINGS	MIN. Ro (%)	MAX. Ro (%)	MEAN Ro (%)	STD. DEV. (%)	REMARKS
(1)	2	0.18	0.19	0.19	-	
(2)	45	0.22	0.40	0.29	0.050	
(3)	13	0.44	0.80	0.61	0.129	

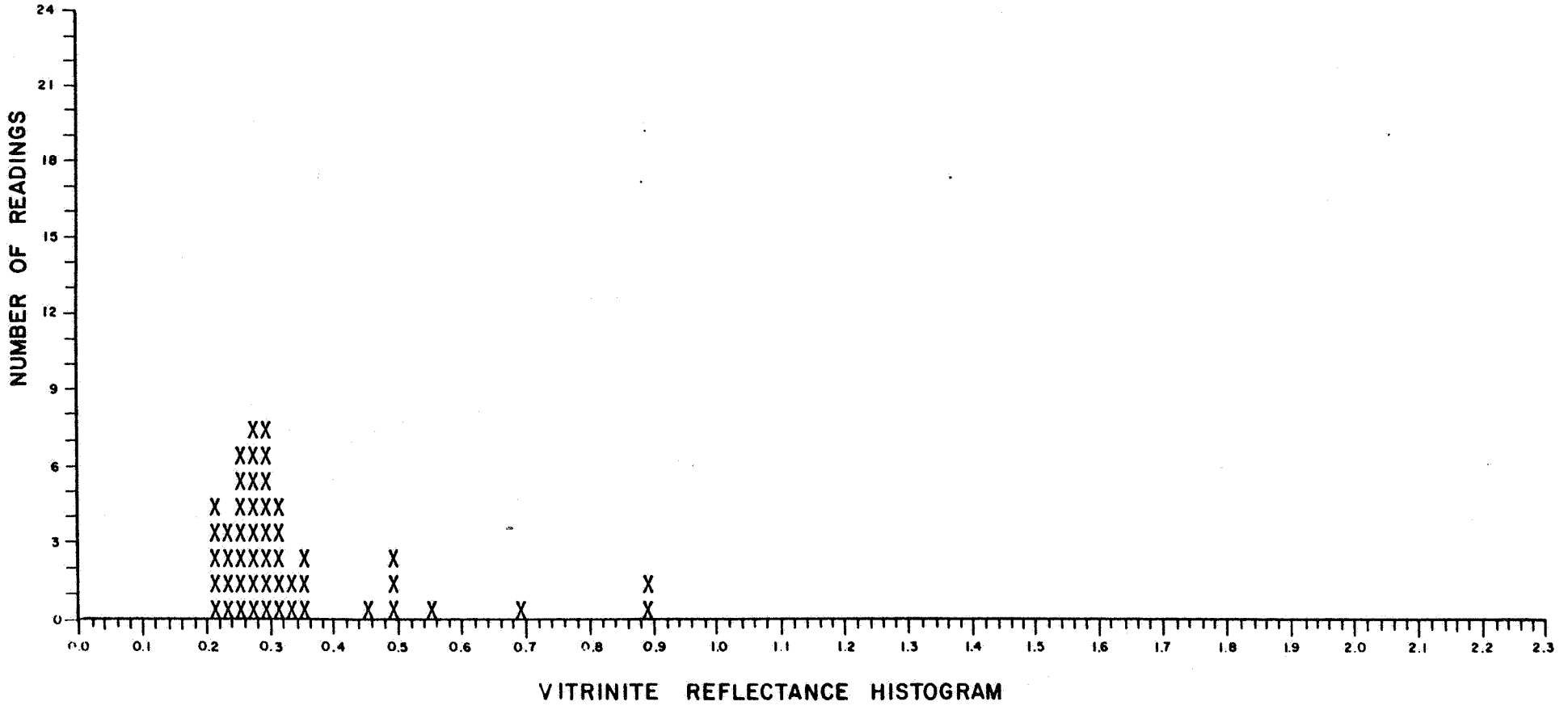


NO. G096-008 TYPE OF SAMPLE: CTG DEPTH / SAMPLE NO. 1300 M.

NAME GETTY WELL NAME 35/8-1

(NO. OF READINGS = 50) 0.22 0.23 0.23 0.23 0.23 0.24 0.24 0.24 0.25 0.26 0.26 0.27 0.27 0.27
0.27 0.27 0.28 0.28 0.28 0.28 0.28 0.29 0.29 0.29 0.30 0.30 0.30 0.30 0.31 0.31 0.31 0.31
0.32 0.32 0.33 0.33 0.33 0.34 0.35 0.37 0.37 0.37 0.46 0.50 0.50 0.51 0.57 0.70 0.90 0.91

POPULATION	NO. OF READINGS	MIN. Ro (%)	MAX. Ro (%)	MEAN Ro (%)	STD. DEV. (%)	REMARKS
(1)	42	0.22	0.37	0.29	0.040	
(2)	8	0.46	0.91	0.63	0.184	

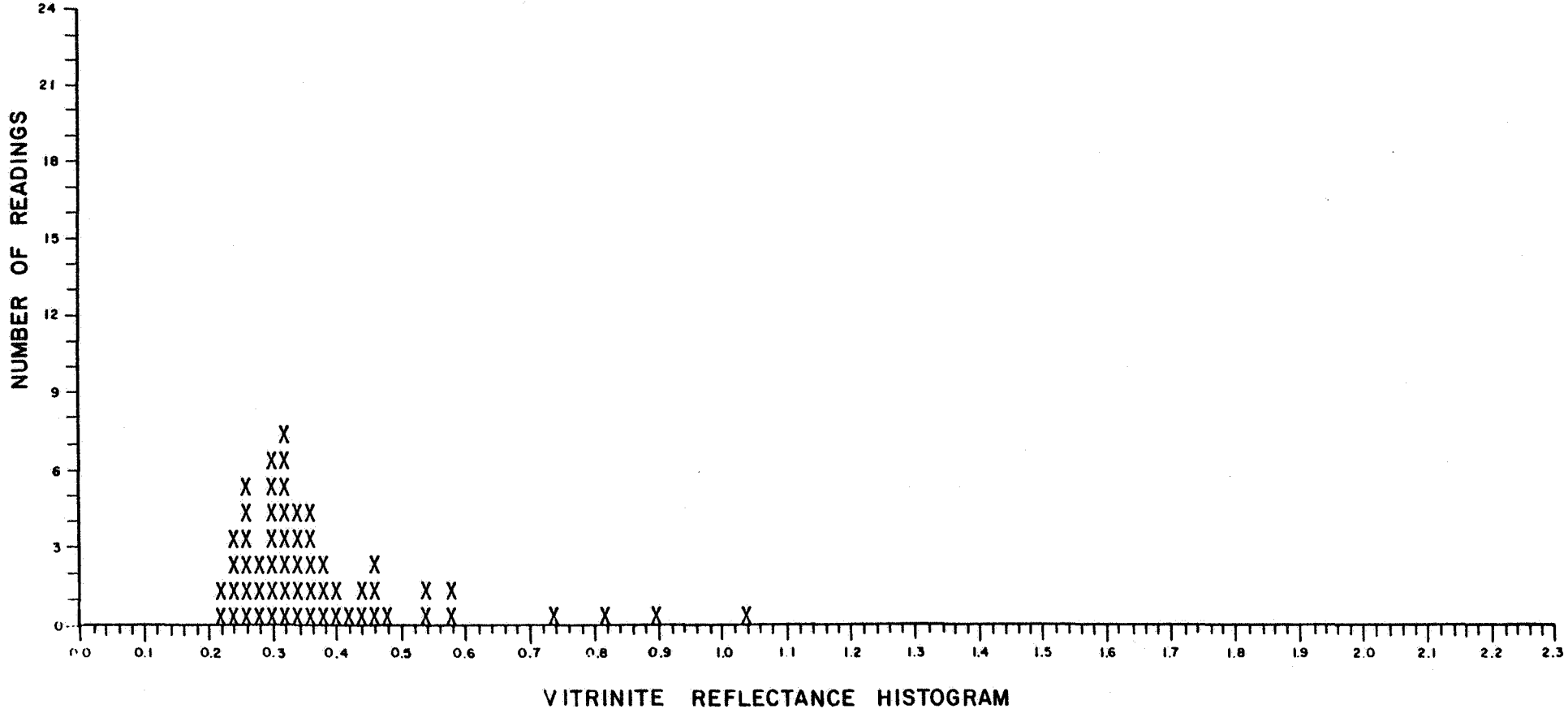


NO. G096-009 TYPE OF SAMPLE: CTG DEPTH / SAMPLE NO. 1400 M.

NAME GETTY WELL NAME 35/8-1

(NO. OF READINGS = 60) 0.23 0.23 0.24 0.24 0.25 0.25 0.26 0.26 0.27 0.27 0.27 0.27 0.28 0.29
0.29 0.30 0.30 0.30 0.30 0.31 0.31 0.31 0.32 0.32 0.33 0.33 0.33 0.33 0.33 0.33 0.34 0.34
0.34 0.35 0.35 0.36 0.36 0.36 0.37 0.37 0.38 0.38 0.38 0.40 0.41 0.42 0.45 0.45 0.46 0.47
0.47 0.49 0.55 0.55 0.58 0.59 0.75 0.82 0.90 1.04

POPULATION	NO. OF READINGS	MIN. Ro (%)	MAX. Ro (%)	MEAN Ro (%)	STD. DEV. (%)	REMARKS
(1)	46	0.23	0.42	0.32	0.049	
(2)	10	0.45	0.59	0.51	0.055	
(3)	4	0.75	1.04	0.88	0.124	

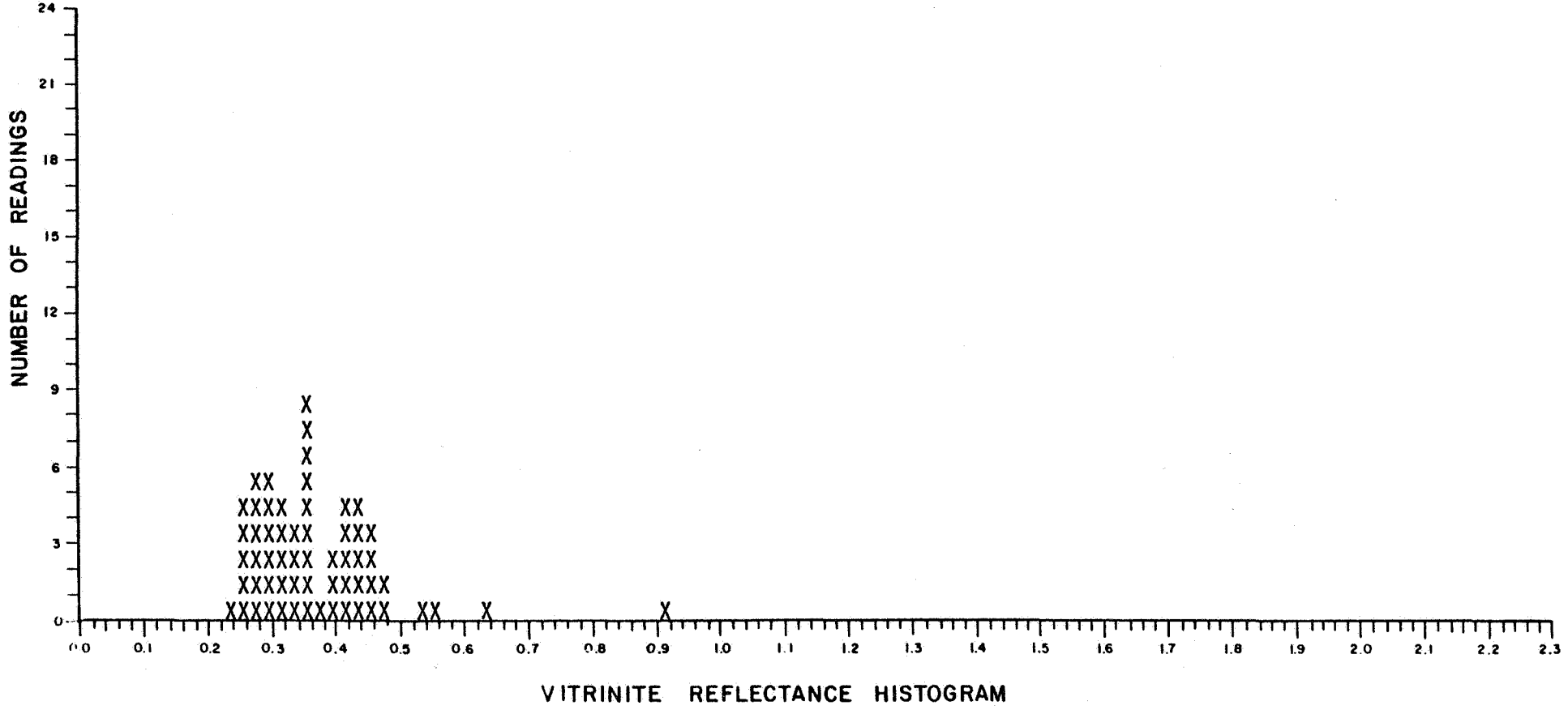


NO. G096-010 TYPE OF SAMPLE: CTG DEPTH / SAMPLE NO. 1500 M.

NAME GETTY WELL NAME 35/8-1

(NO. OF READINGS = 60) 0.25 0.26 0.26 0.27 0.27 0.27 0.28 0.28 0.28 0.28 0.28 0.29 0.30 0.30
0.30 0.31 0.31 0.31 0.32 0.32 0.32 0.33 0.33 0.34 0.34 0.35 0.35 0.36 0.36 0.36 0.36 0.36
0.37 0.37 0.37 0.37 0.38 0.40 0.40 0.41 0.42 0.42 0.42 0.43 0.43 0.44 0.44 0.45 0.45 0.45
0.46 0.46 0.46 0.47 0.48 0.48 0.55 0.56 0.64 0.93

POPULATION	NO. OF READINGS	MIN. Ro (%)	MAX. Ro (%)	MEAN Ro (%)	STD. DEV. (%)	REMARKS
(1)	56	0.25	0.48	0.36	0.068	
(2)	4	0.55	0.93	0.67	0.178	

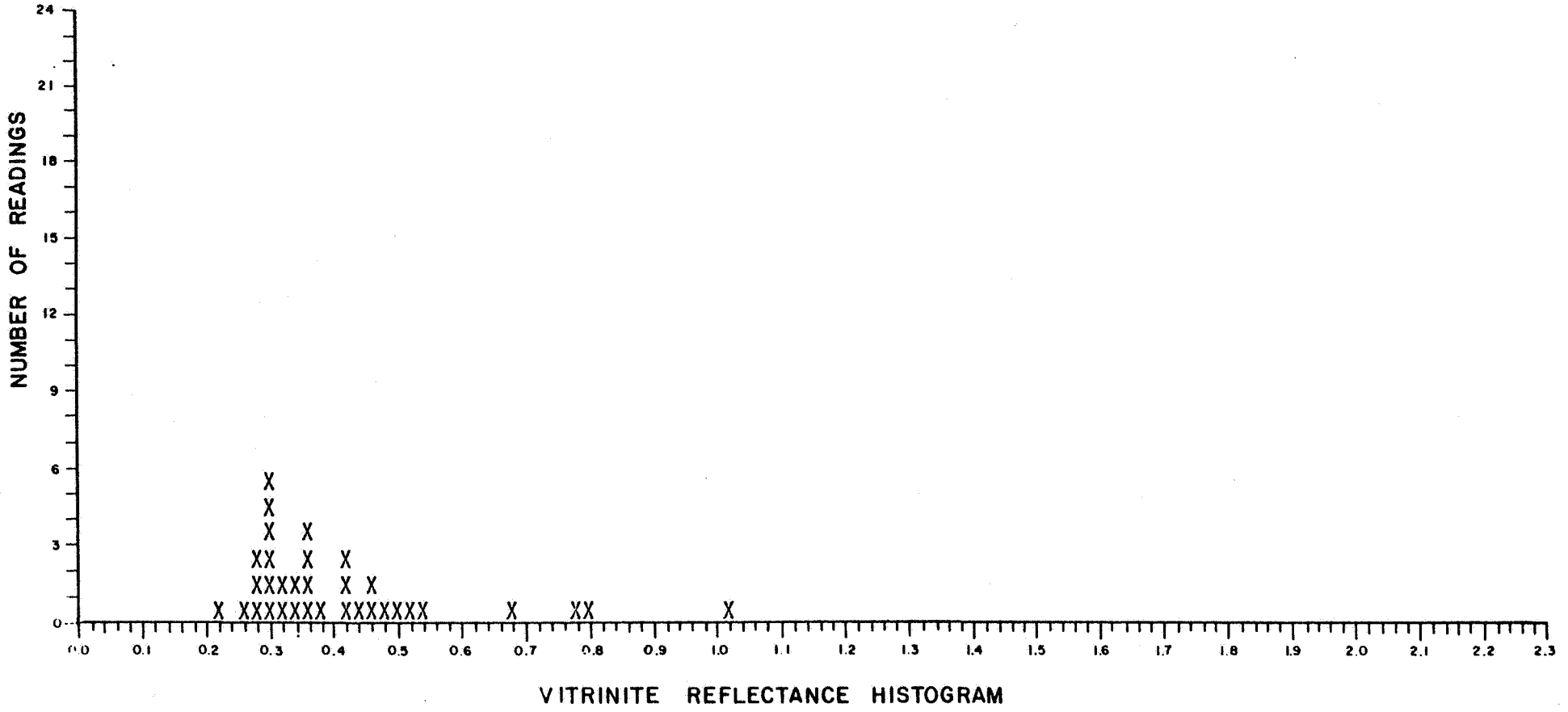


NO. G096-011 TYPE OF SAMPLE: CTG DEPTH / SAMPLE NO. 1600 M.

NAME GETTY WELL NAME 35/8-1

(NO. OF READINGS = 34) 0.22 0.27 0.28 0.28 0.28 0.30 0.30 0.30 0.31 0.31 0.31 0.32 0.33 0.34
0.35 0.36 0.37 0.37 0.37 0.38 0.42 0.43 0.43 0.44 0.46 0.47 0.48 0.50 0.52 0.54 0.69 0.79
0.81 1.03

POPULATION	NO. OF READINGS	MIN. Ro (%)	MAX. Ro (%)	MEAN Ro (%)	STD. DEV. (%)	REMARKS
(1)	1	0.22	0.22	0.22	-	
(2)	19	0.27	0.38	0.32	0.036	
(3)	10	0.42	0.54	0.47	0.041	
(4)	4	0.69	1.03	0.83	0.143	

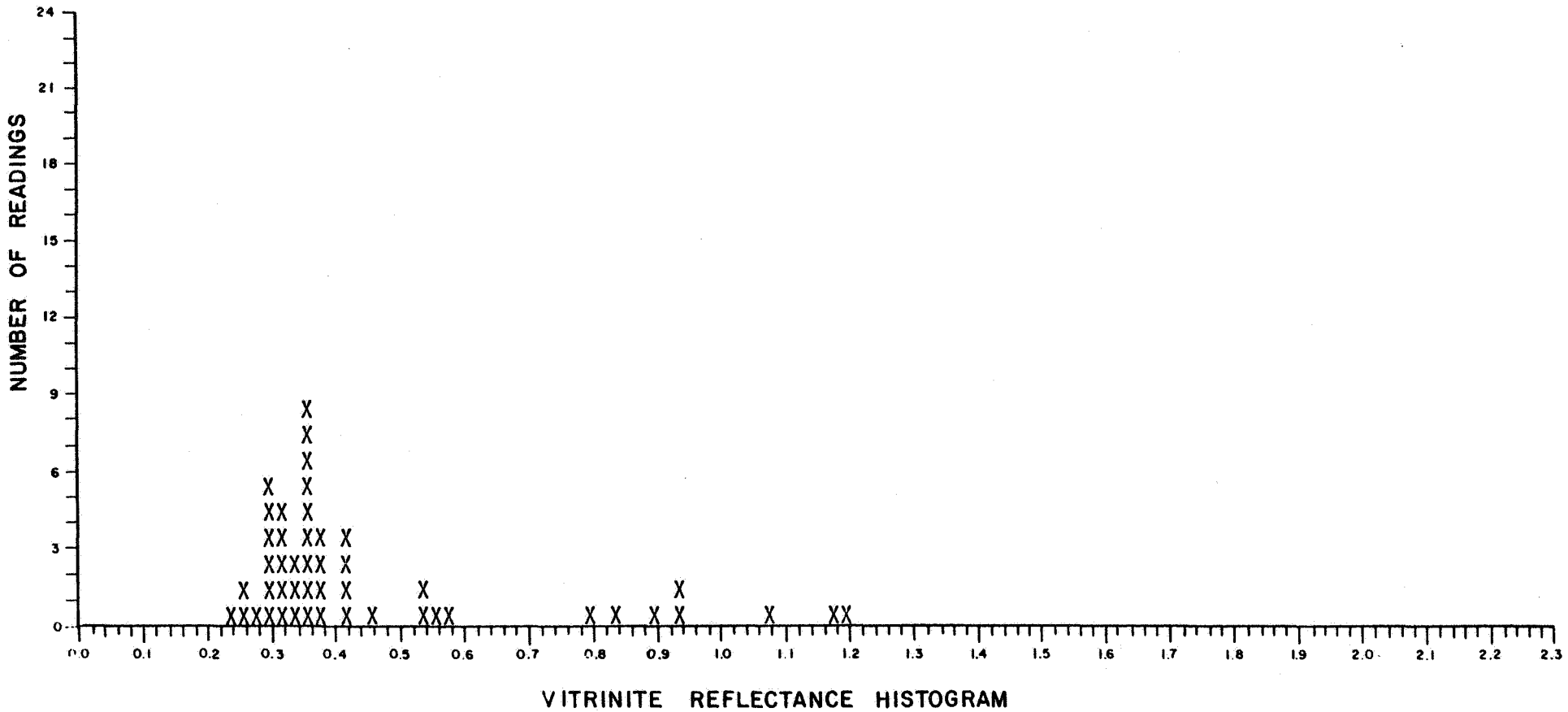


NO. G096-012 TYPE OF SAMPLE: CTG DEPTH / SAMPLE NO. 1700 M.

NAME GETTY WELL NAME 35/8-1

(NO. OF READINGS = 48) 0.25 0.27 0.27 0.29 0.30 0.30 0.30 0.30 0.31 0.31 0.32 0.33 0.33 0.33
0.33 0.34 0.34 0.34 0.36 0.36 0.36 0.36 0.36 0.36 0.36 0.37 0.37 0.38 0.38 0.38 0.38 0.43
0.43 0.43 0.43 0.47 0.54 0.54 0.56 0.58 0.80 0.85 0.90 0.94 0.94 1.08 1.18 1.20

POPULATION	NO. OF READINGS	MIN. Ro (%)	MAX. Ro (%)	MEAN Ro (%)	STD. DEV. (%)	REMARKS
(1)	3	0.25	0.27	0.26	0.012	
(2)	28	0.29	0.38	0.34	0.029	
(3)	9	0.43	0.58	0.49	0.064	
(4)	8	0.80	1.20	0.99	0.150	

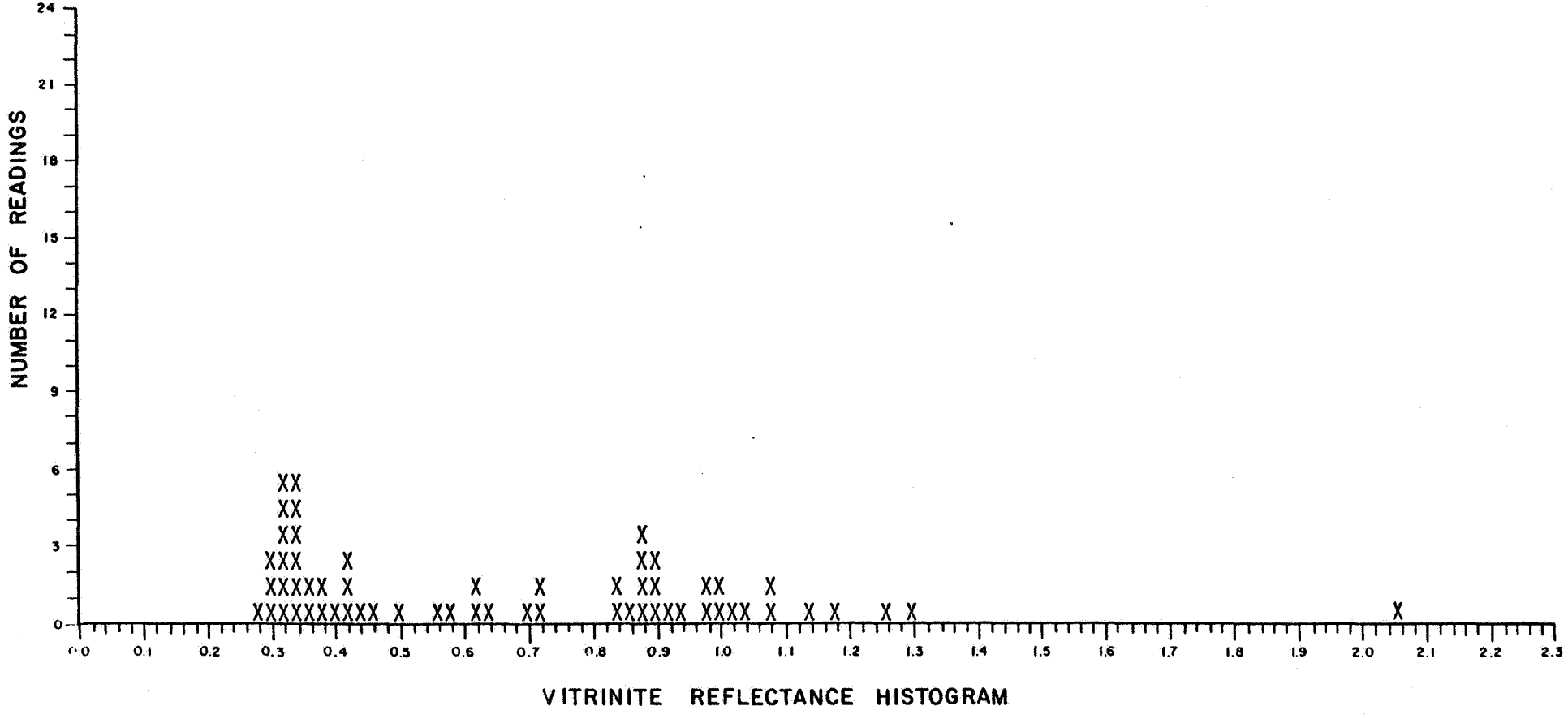


NO. G096-013 TYPE OF SAMPLE: CTG DEPTH / SAMPLE NO. 1800 M.

NAME GETTY WELL NAME 35/8-1

(NO. OF READINGS = 60) 0.29 0.31 0.31 0.31 0.32 0.32 0.32 0.33 0.33 0.33 0.34 0.34 0.34 0.35
0.35 0.35 0.36 0.37 0.38 0.39 0.40 0.42 0.42 0.43 0.45 0.46 0.50 0.57 0.58 0.62 0.63 0.64
0.71 0.72 0.73 0.85 0.85 0.86 0.88 0.88 0.88 0.89 0.90 0.90 0.91 0.92 0.94 0.98 0.98 1.01
1.01 1.02 1.04 1.08 1.09 1.14 1.19 1.26 1.31 2.06

POPULATION	NO. OF READINGS	MIN. Ro (%)	MAX. Ro (%)	MEAN Ro (%)	STD. DEV. (%)	REMARKS
(1)	18	0.29	0.37	0.33	0.020	
(2)	9	0.38	0.50	0.43	0.038	
(3)	33	0.57	2.06	0.94	0.274	

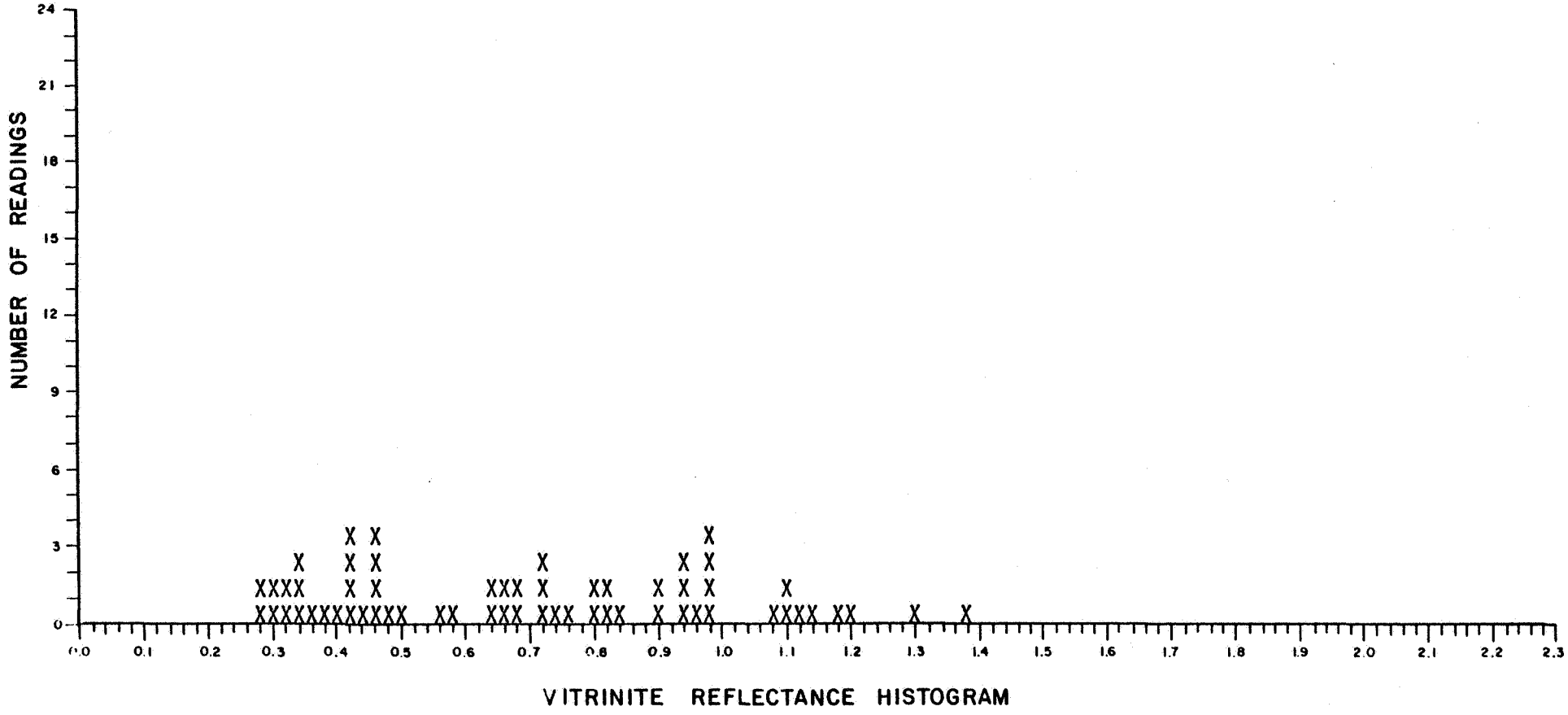


NO. G096-014 TYPE OF SAMPLE: CTG DEPTH / SAMPLE NO. 1900 M.

NAME GETTY WELL NAME 35/8-1

(NO. OF READINGS = 60) 0.28 0.28 0.30 0.31 0.32 0.33 0.34 0.35 0.35 0.36 0.39 0.40 0.42 0.42
0.42 0.42 0.45 0.46 0.46 0.47 0.47 0.49 0.51 0.57 0.58 0.64 0.64 0.67 0.67 0.68 0.68 0.72
0.73 0.73 0.74 0.77 0.80 0.81 0.83 0.83 0.85 0.90 0.90 0.95 0.95 0.95 0.97 0.98 0.99 0.99
0.99 1.08 1.11 1.11 1.12 1.14 1.18 1.21 1.30 1.39

POPULATION	NO. OF READINGS	MIN. Ro (%)	MAX. Ro (%)	MEAN Ro (%)	STD. DEV. (%)	REMARKS
(1)	10	0.28	0.36	0.32	0.029	
(2)	13	0.39	0.51	0.44	0.036	
(3)	37	0.57	1.39	0.90	0.208	

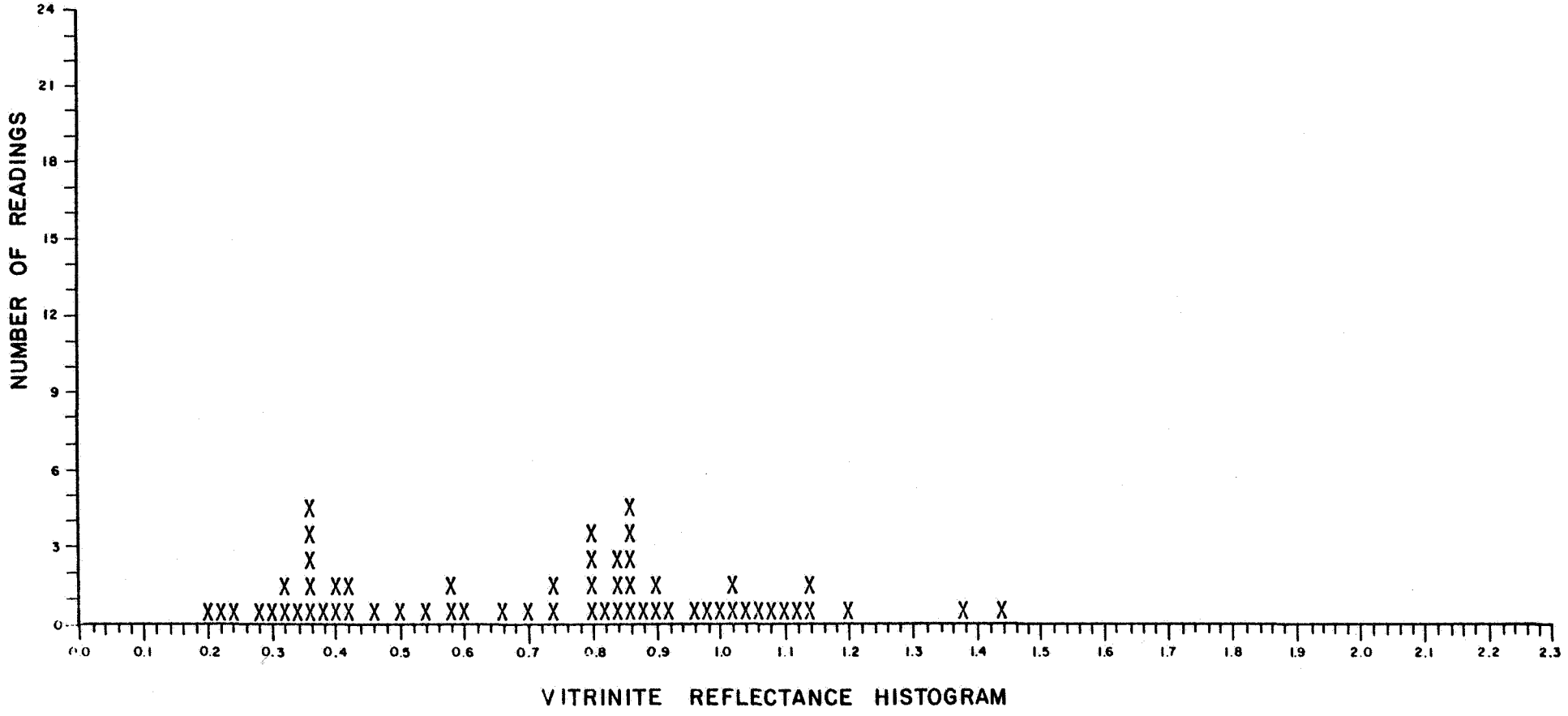


NO. G096-015 TYPE OF SAMPLE: CTG DEPTH / SAMPLE NO. 2000

NAME GETTY WELL NAME 35/8-1

(NO. OF READINGS = 60) 0.20 0.23 0.24 0.29 0.30 0.33 0.33 0.35 0.36 0.36 0.36 0.36 0.36 0.39
0.41 0.41 0.42 0.43 0.46 0.51 0.54 0.59 0.59 0.60 0.66 0.71 0.74 0.75 0.80 0.81 0.81 0.81
0.83 0.84 0.84 0.84 0.86 0.86 0.87 0.87 0.87 0.88 0.90 0.91 0.93 0.97 0.98 1.00 1.02 1.02
1.04 1.06 1.08 1.11 1.13 1.14 1.14 1.21 1.38 1.45

POPULATION	NO. OF READINGS	MIN. Ro (%)	MAX. Ro (%)	MEAN Ro (%)	STD. DEV. (%)	REMARKS
(1)	3	0.20	0.24	0.22	0.021	
(2)	15	0.29	0.43	0.36	0.042	
(3)	6	0.46	0.60	0.55	0.056	
(4)	36	0.66	1.45	0.95	0.176	

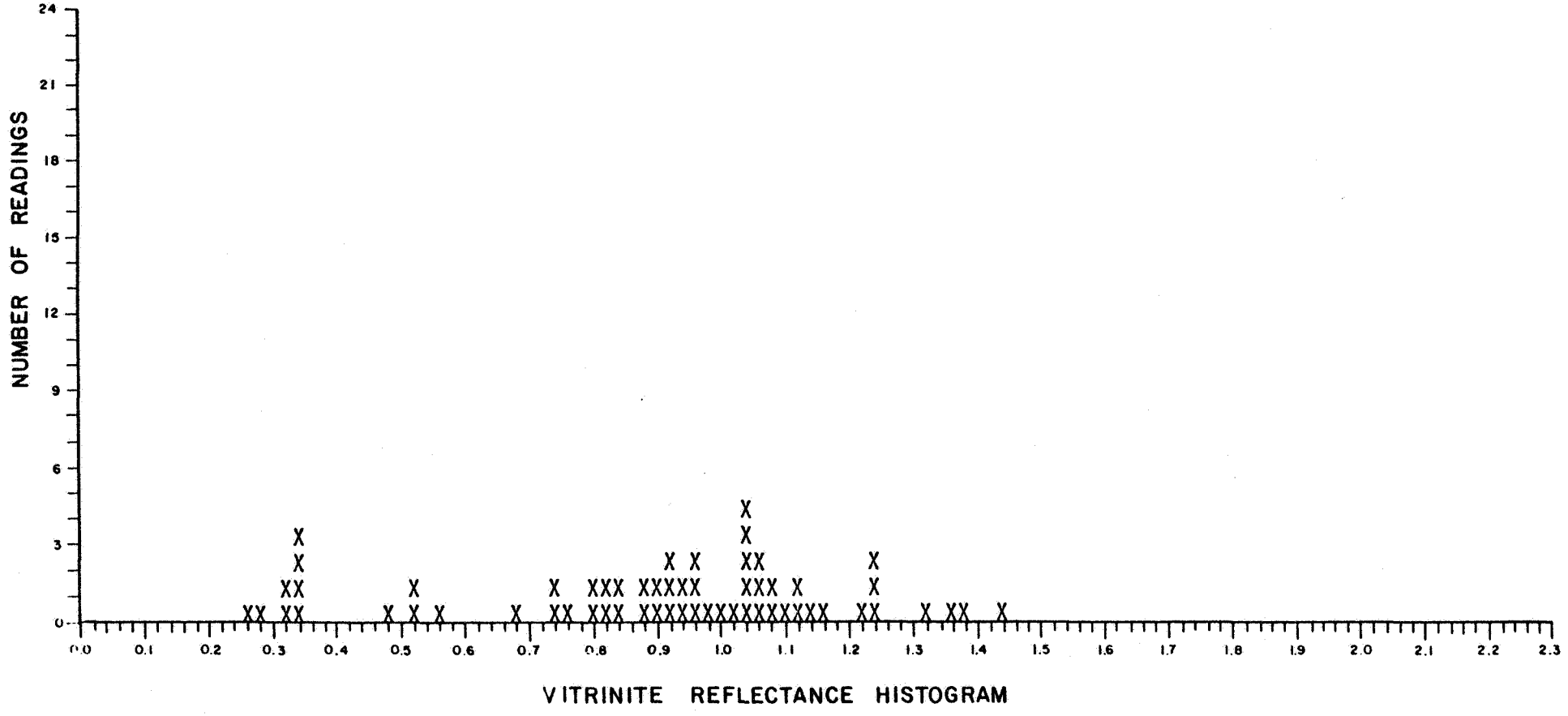


NO. G096-016 TYPE OF SAMPLE: CTG DEPTH / SAMPLE NO. 2100 M.

NAME GETTY WELL NAME 35/8-1

(NO. OF READINGS = 60) 0.27 0.29 0.32 0.33 0.34 0.34 0.35 0.35 0.49 0.52 0.53 0.57 0.68 0.75
0.75 0.77 0.80 0.80 0.82 0.82 0.84 0.85 0.88 0.89 0.90 0.90 0.92 0.93 0.93 0.94 0.94 0.97
0.97 0.97 0.98 1.00 1.02 1.04 1.04 1.04 1.05 1.05 1.07 1.07 1.07 1.09 1.09 1.10 1.12 1.13
1.15 1.16 1.23 1.25 1.25 1.25 1.33 1.36 1.38 1.45

POPULATION	NO. OF READINGS	MIN. Ro (%)	MAX. Ro (%)	MEAN Ro (%)	STD. DEV. (%)	REMARKS
(1)	8	0.27	0.35	0.32	0.029	
(2)	4	0.49	0.57	0.53	0.033	
(3)	48	0.68	1.45	1.02	0.178	

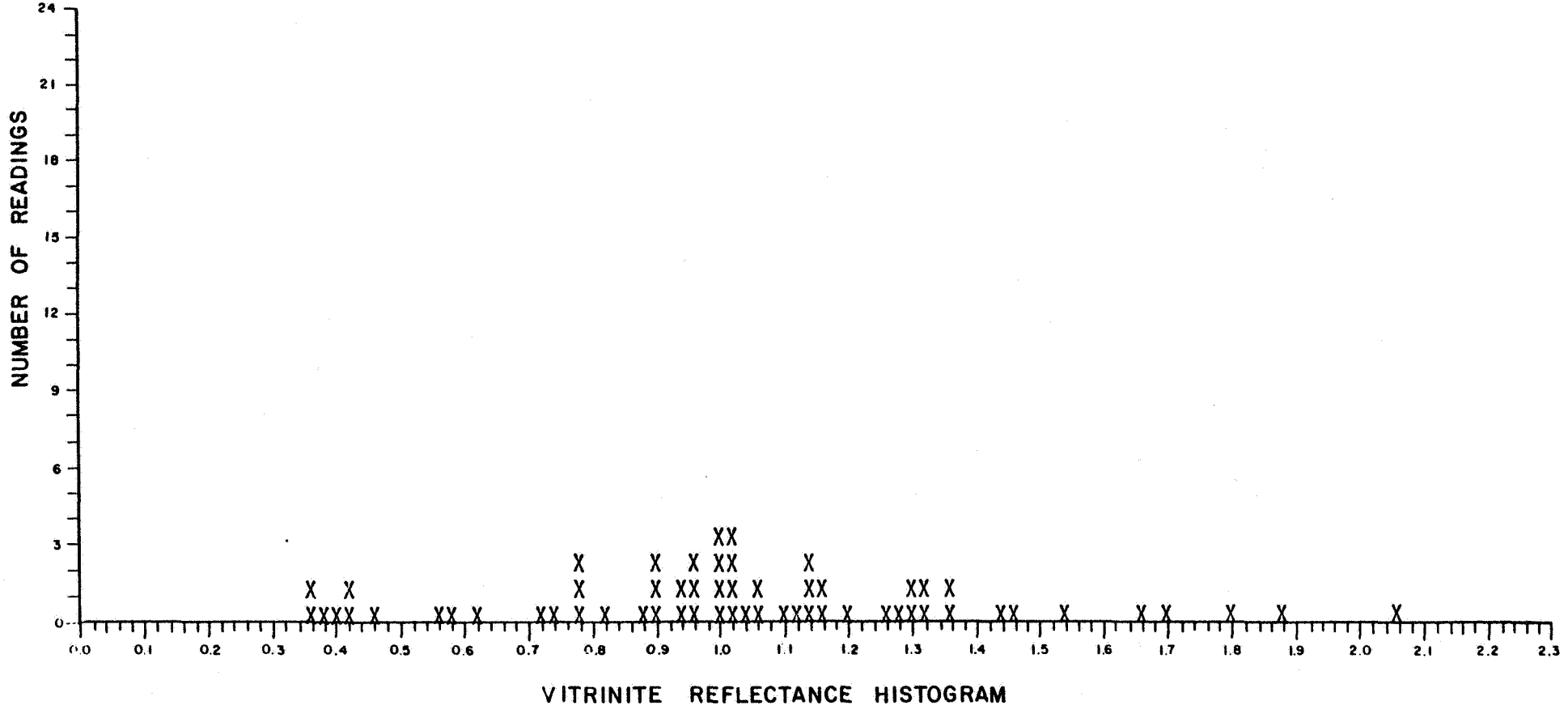


NO. G096-017 TYPE OF SAMPLE: CTG DEPTH/SAMPLE NO. 2200 M.

NAME GETTY WELL NAME 35/8-1

(NO. OF READINGS = 60) 0.37 0.37 0.39 0.41 0.42 0.43 0.46 0.57 0.58 0.63 0.72 0.75 0.78 0.78
0.79 0.83 0.88 0.90 0.91 0.91 0.94 0.95 0.96 0.96 0.97 1.00 1.00 1.01 1.01 1.02 1.02 1.02
1.02 1.04 1.06 1.06 1.11 1.13 1.15 1.15 1.15 1.17 1.17 1.20 1.27 1.28 1.30 1.30 1.33 1.33
1.36 1.36 1.44 1.47 1.55 1.67 1.70 1.80 1.88 2.06

POPULATION	NO. OF READINGS	MIN. Ro (%)	MAX. Ro (%)	MEAN Ro (%)	STD. DEV. (%)	REMARKS
(1)	7	0.37	0.46	0.41	0.033	
(2)	3	0.57	0.63	0.59	0.032	
(3)	50	0.72	2.06	1.15	0.300	

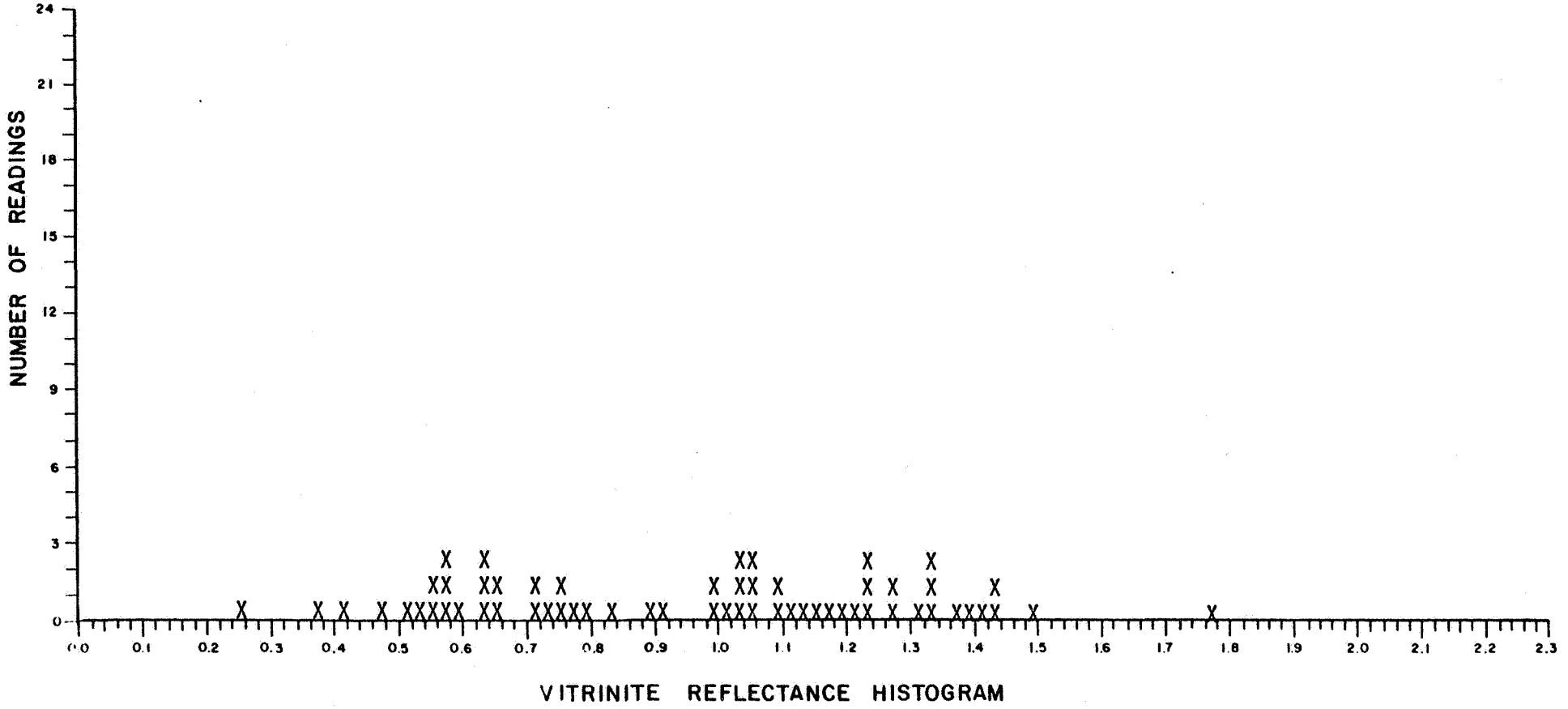


NO. G096-018 TYPE OF SAMPLE: CTG DEPTH / SAMPLE NO. 2300

NAME GETTY WELL NAME 35/8-1

(NO. OF READINGS = 60) 0.27 0.38 0.42 0.49 0.52 0.54 0.56 0.57 0.59 0.59 0.59 0.61 0.64 0.64
0.65 0.66 0.66 0.72 0.72 0.74 0.76 0.76 0.79 0.80 0.85 0.91 0.93 1.00 1.01 1.02 1.04 1.04
1.05 1.07 1.07 1.07 1.10 1.11 1.12 1.14 1.17 1.18 1.20 1.22 1.24 1.24 1.25 1.28 1.28 1.32
1.35 1.35 1.35 1.38 1.41 1.42 1.45 1.45 1.50 1.79

POPULATION	NO. OF READINGS	MIN. Ro (%)	MAX. Ro (%)	MEAN Ro (%)	STD. DEV. (%)	REMARKS
(1)	1	0.27	0.27	0.27	-	
(2)	3	0.38	0.49	0.43	0.056	
(3)	13	0.52	0.66	0.60	0.046	
(4)	43	0.72	1.79	1.13	0.245	

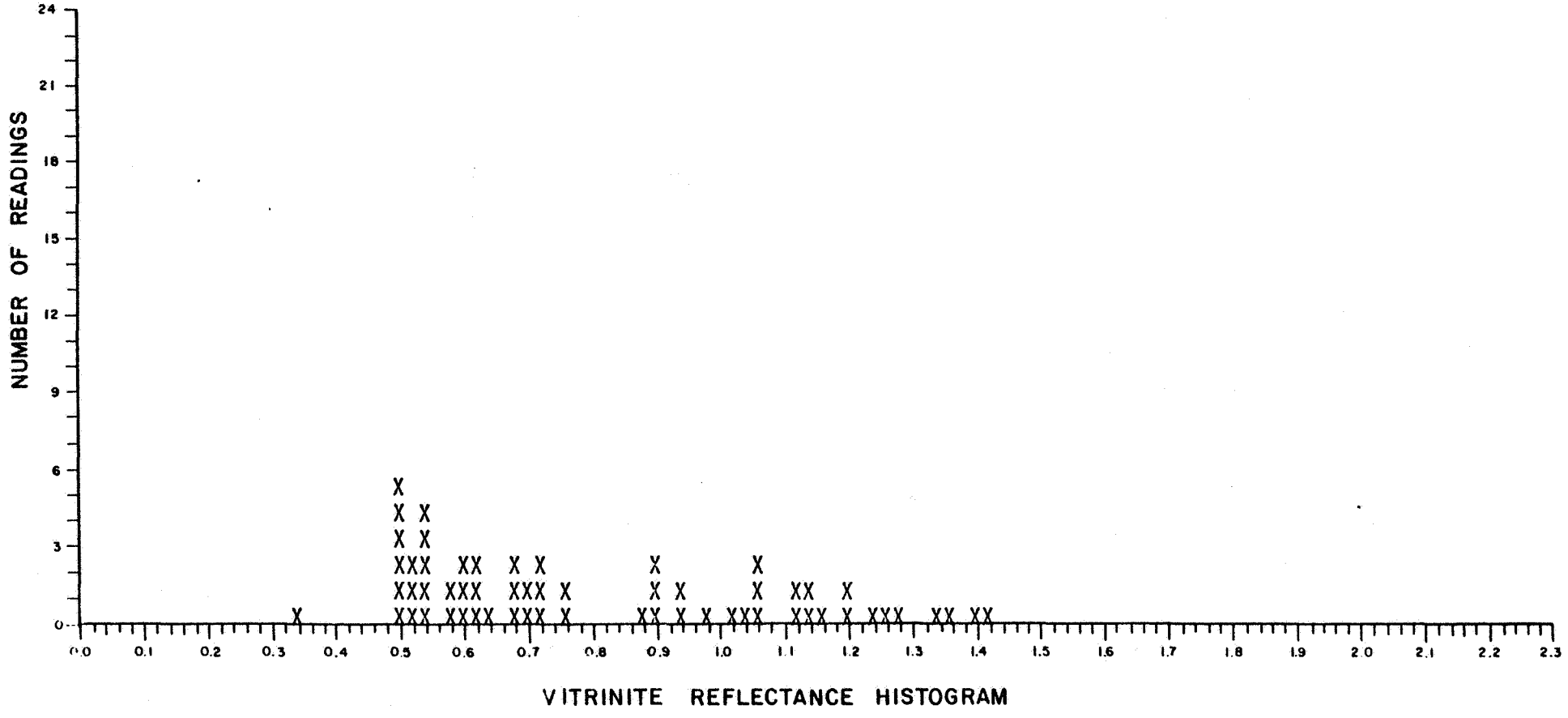


NO. G096-019 TYPE OF SAMPLE: CTG DEPTH / SAMPLE NO. 2400 M.

NAME GETTY WELL NAME 35/8-1

(NO. OF READINGS = 60) 0.35 0.50 0.50 0.50 0.50 0.50 0.51 0.52 0.53 0.53 0.54 0.54 0.54 0.55
0.55 0.58 0.59 0.60 0.61 0.61 0.62 0.62 0.63 0.65 0.68 0.69 0.69 0.71 0.71 0.72 0.72 0.73
0.76 0.76 0.89 0.90 0.90 0.91 0.94 0.94 0.99 1.02 1.05 1.06 1.07 1.07 1.12 1.13 1.14 1.15
1.17 1.21 1.21 1.25 1.26 1.29 1.35 1.37 1.41 1.43

POPULATION	NO. OF READINGS	MIN. Ro (%)	MAX. Ro (%)	MEAN Ro (%)	STD. DEV. (%)	REMARKS
(1)	1	0.35	0.35	0.35	-	
(2)	23	0.50	0.65	0.56	0.049	
(3)	36	0.68	1.43	1.01	0.232	

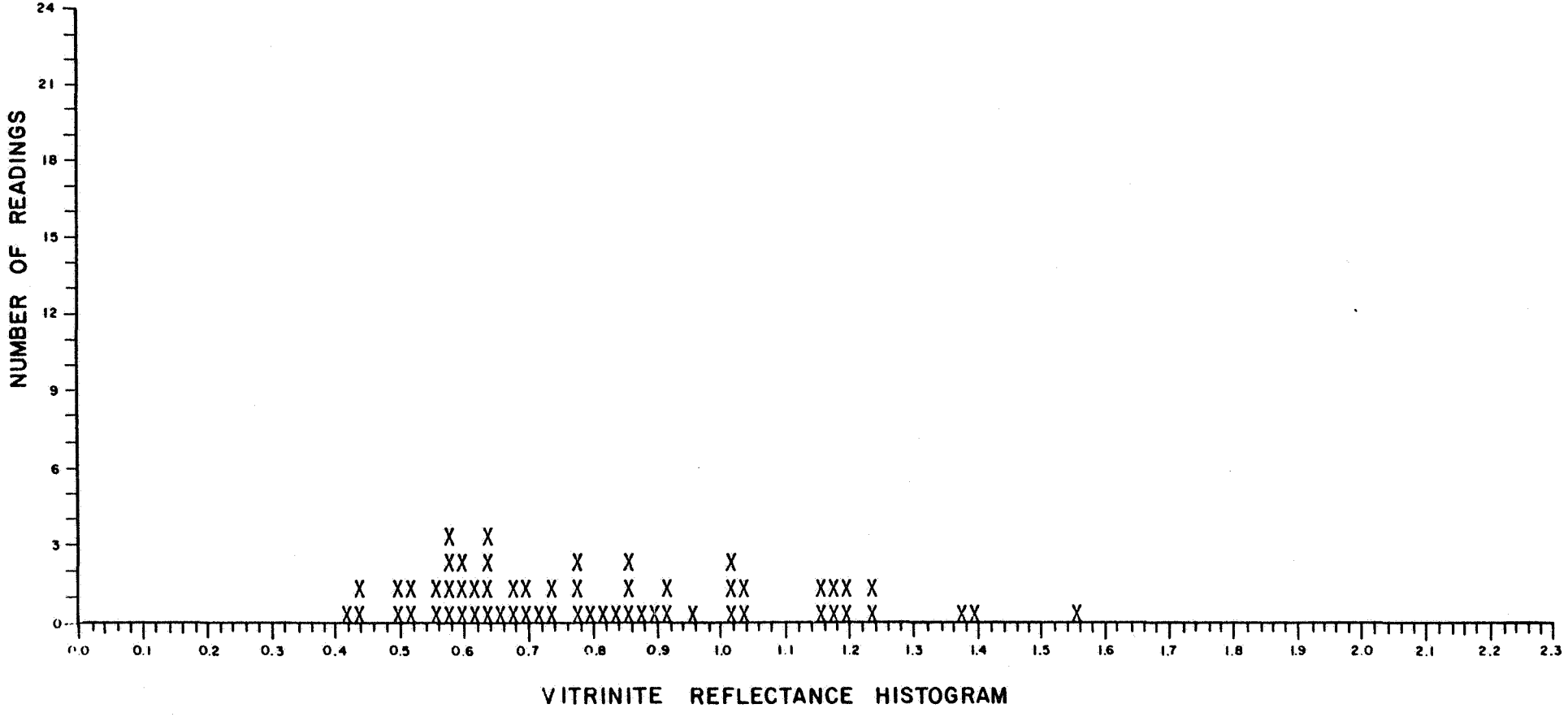


NO. G096-020 TYPE OF SAMPLE: CTG DEPTH / SAMPLE NO. 2500 M.

NAME GETTY WELL NAME 35/8-1

(NO. OF READINGS = 60) 0.43 0.45 0.45 0.50 0.51 0.52 0.53 0.57 0.57 0.58 0.59 0.59 0.59 0.60
0.61 0.61 0.63 0.63 0.64 0.64 0.64 0.65 0.66 0.68 0.69 0.70 0.71 0.72 0.74 0.75 0.78 0.78
0.79 0.80 0.83 0.84 0.86 0.87 0.87 0.89 0.90 0.92 0.93 0.96 1.02 1.02 1.02 1.04 1.05 1.16
1.16 1.19 1.19 1.20 1.20 1.25 1.25 1.38 1.40 1.56

POPULATION	NO. OF READINGS	MIN. Ro (%)	MAX. Ro (%)	MEAN Ro (%)	STD. DEV. (%)	REMARKS
(1)	7	0.43	0.53	0.48	0.040	
(2)	21	0.57	0.72	0.63	0.046	
(3)	32	0.74	1.56	1.02	0.212	

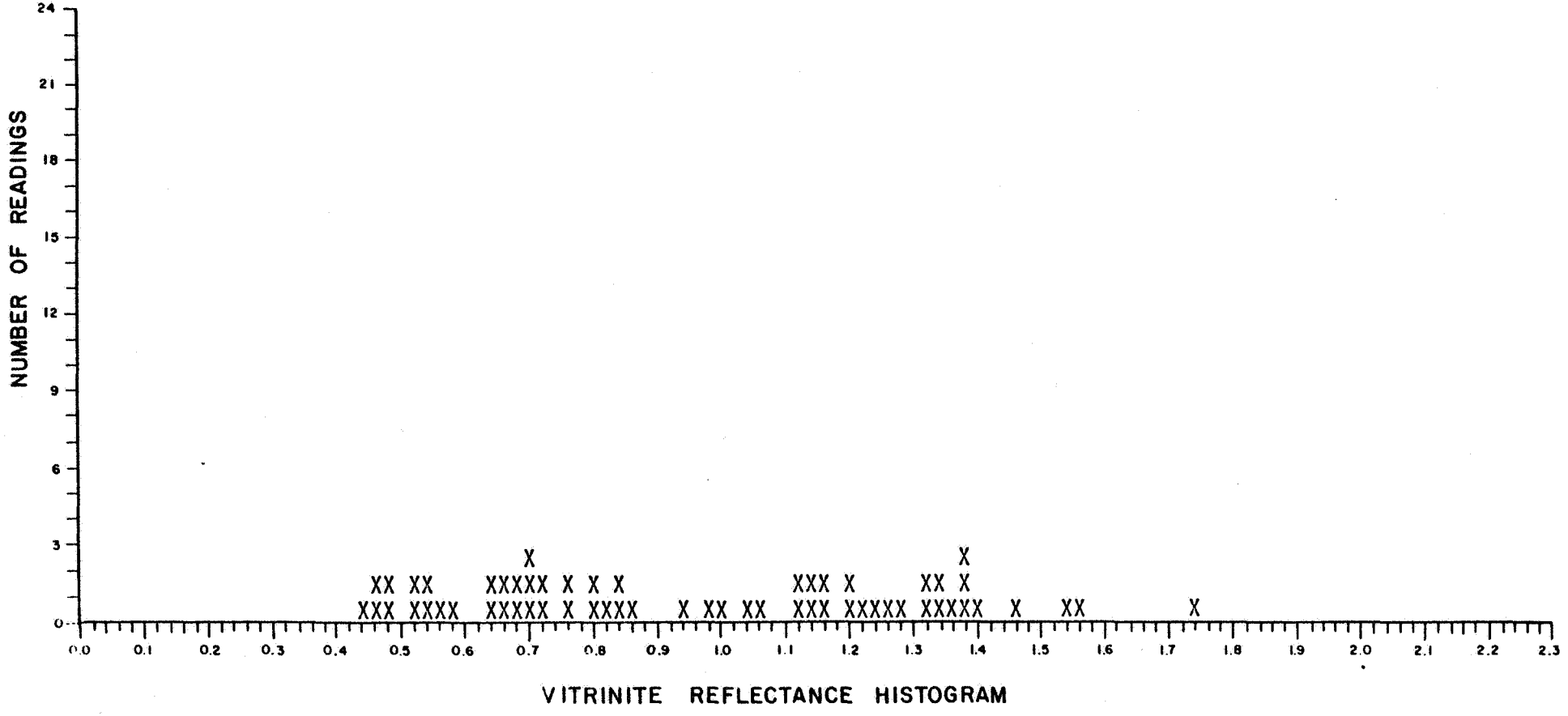


NO. G096-021 TYPE OF SAMPLE: CTG DEPTH / SAMPLE NO. 2600 M.

NAME GETTY WELL NAME 35/8-1

(NO. OF READINGS = 60) 0.45 0.47 0.47 0.48 0.49 0.53 0.53 0.55 0.55 0.56 0.59 0.64 0.64 0.66
0.67 0.69 0.69 0.70 0.71 0.71 0.72 0.73 0.76 0.76 0.80 0.81 0.82 0.84 0.84 0.86 0.94 0.98
1.00 1.04 1.06 1.12 1.12 1.14 1.15 1.16 1.16 1.20 1.21 1.22 1.25 1.27 1.29 1.32 1.32 1.34
1.35 1.37 1.38 1.39 1.39 1.41 1.47 1.54 1.56 1.75

POPULATION	NO. OF READINGS	MIN. Ro (%)	MAX. Ro (%)	MEAN Ro (%)	STD. DEV. (%)	REMARKS
(1)	11	0.45	0.59	0.52	0.045	
(2)	13	0.64	0.76	0.70	0.039	
(3)	36	0.80	1.75	1.19	0.235	

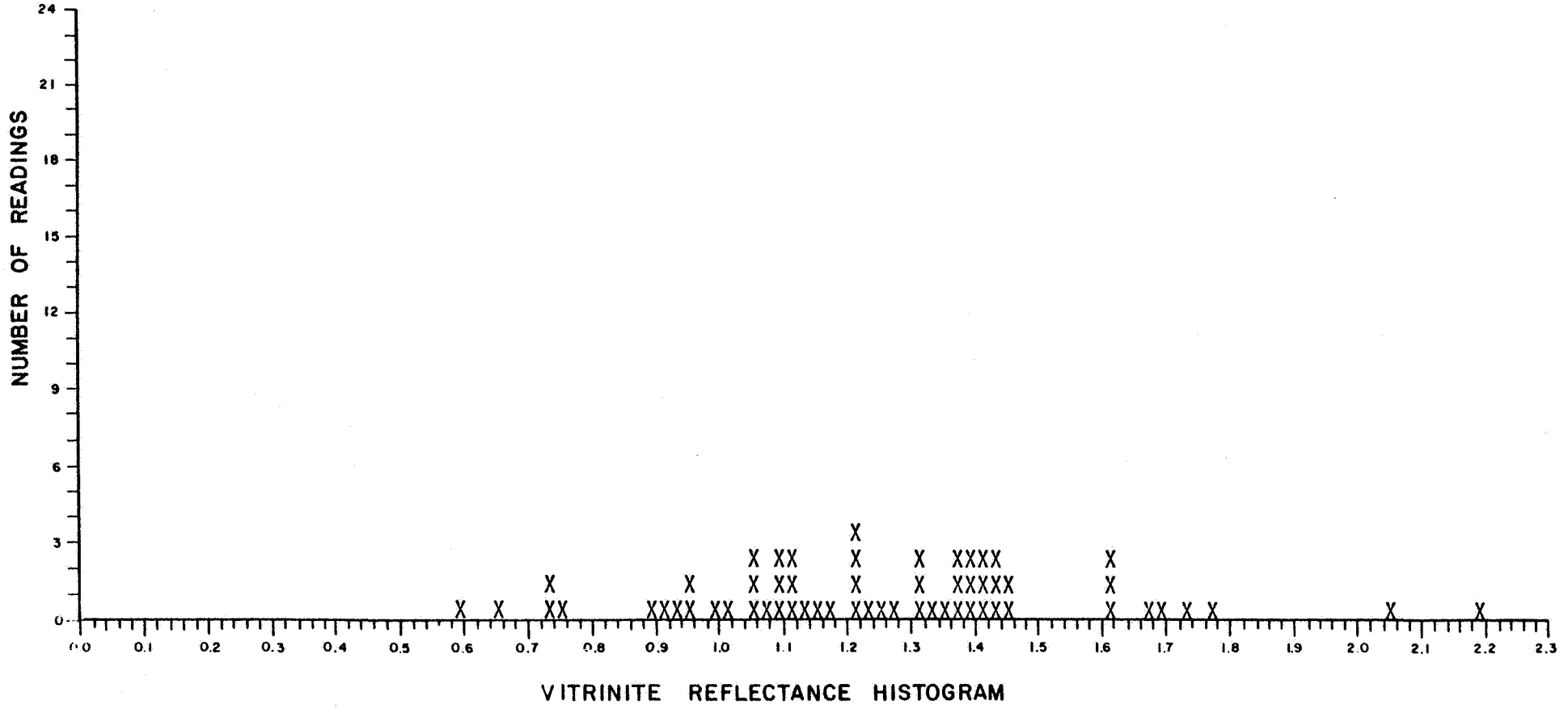


NO. G096-022 TYPE OF SAMPLE: CTG DEPTH / SAMPLE NO. 2700 M.

NAME GETTY WELL NAME 35/8-1

(NO. OF READINGS = 60) 0.61 0.67 0.74 0.74 0.76 0.90 0.92 0.95 0.96 0.97 1.01 1.02 1.06 1.06
1.06 1.08 1.10 1.11 1.11 1.13 1.13 1.13 1.14 1.16 1.19 1.22 1.22 1.23 1.23 1.24 1.26 1.29
1.32 1.32 1.33 1.35 1.37 1.38 1.39 1.39 1.40 1.40 1.41 1.42 1.42 1.43 1.44 1.44 1.45 1.47
1.47 1.62 1.63 1.63 1.68 1.71 1.74 1.79 2.06 2.20

POPULATION	NO. OF READINGS	MIN. Ro (%)	MAX. Ro (%)	MEAN Ro (%)	STD. DEV. (%)	REMARKS
(1)	5	0.61	0.76	0.70	0.063	
(2)	55	0.90	2.20	1.32	0.272	

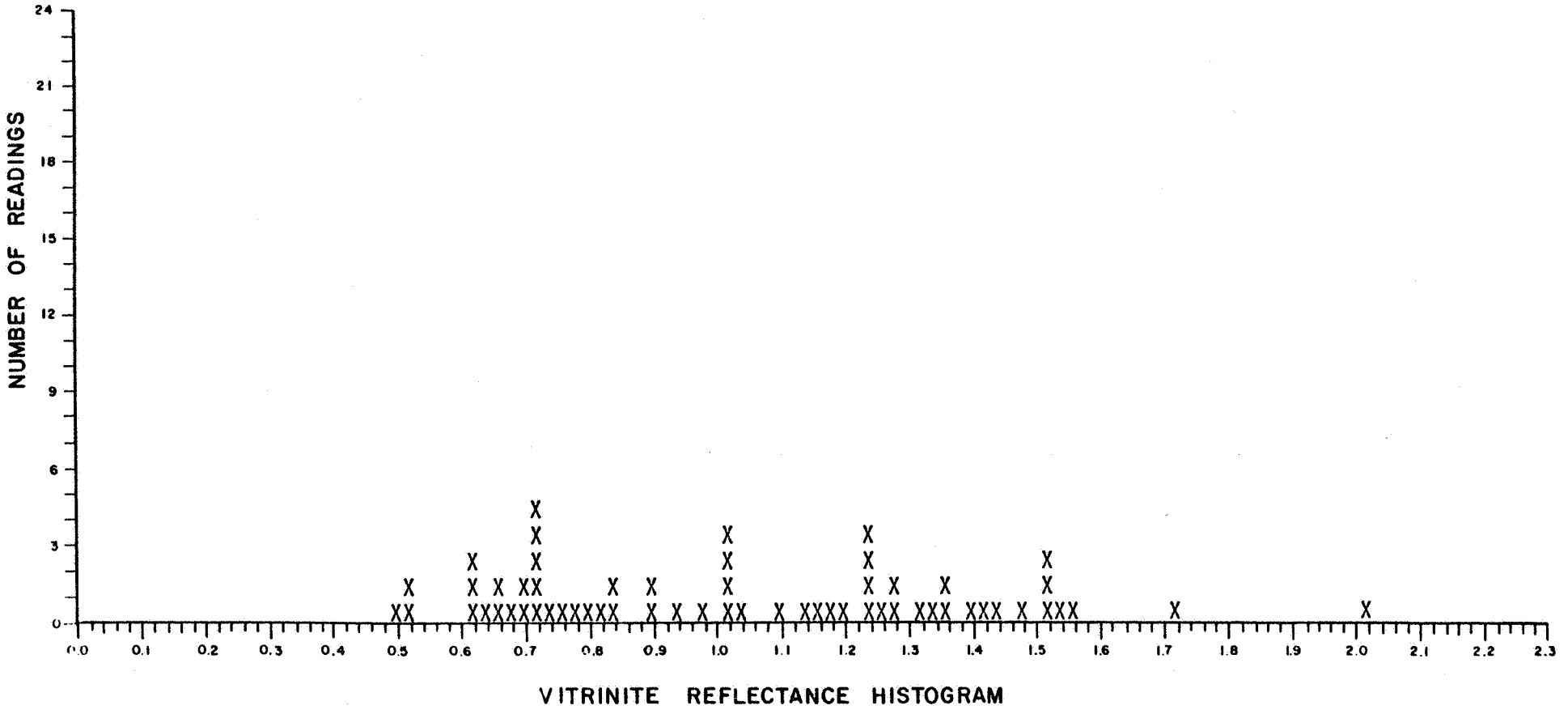


NO. G096-023 TYPE OF SAMPLE: CTG DEPTH / SAMPLE NO. 2800 M.

NAME GETTY WELL NAME 35/8-1

(NO. OF READINGS = 60) 0.51 0.53 0.53 0.62 0.62 0.63 0.65 0.66 0.67 0.69 0.70 0.71 0.72 0.72
0.72 0.72 0.73 0.74 0.77 0.78 0.81 0.83 0.84 0.85 0.91 0.91 0.95 0.98 1.02 1.03 1.03 1.03
1.05 1.10 1.14 1.16 1.18 1.21 1.24 1.24 1.25 1.25 1.26 1.28 1.28 1.33 1.35 1.36 1.37 1.40
1.42 1.45 1.48 1.52 1.53 1.53 1.55 1.56 1.72 2.03

POPULATION	NO. OF READINGS	MIN. Ro (%)	MAX. Ro (%)	MEAN Ro (%)	STD. DEV. (%)	REMARKS
(1)	3	0.51	0.53	0.52	0.012	
(2)	15	0.62	0.74	0.69	0.042	
(3)	42	0.77	2.03	1.21	0.280	

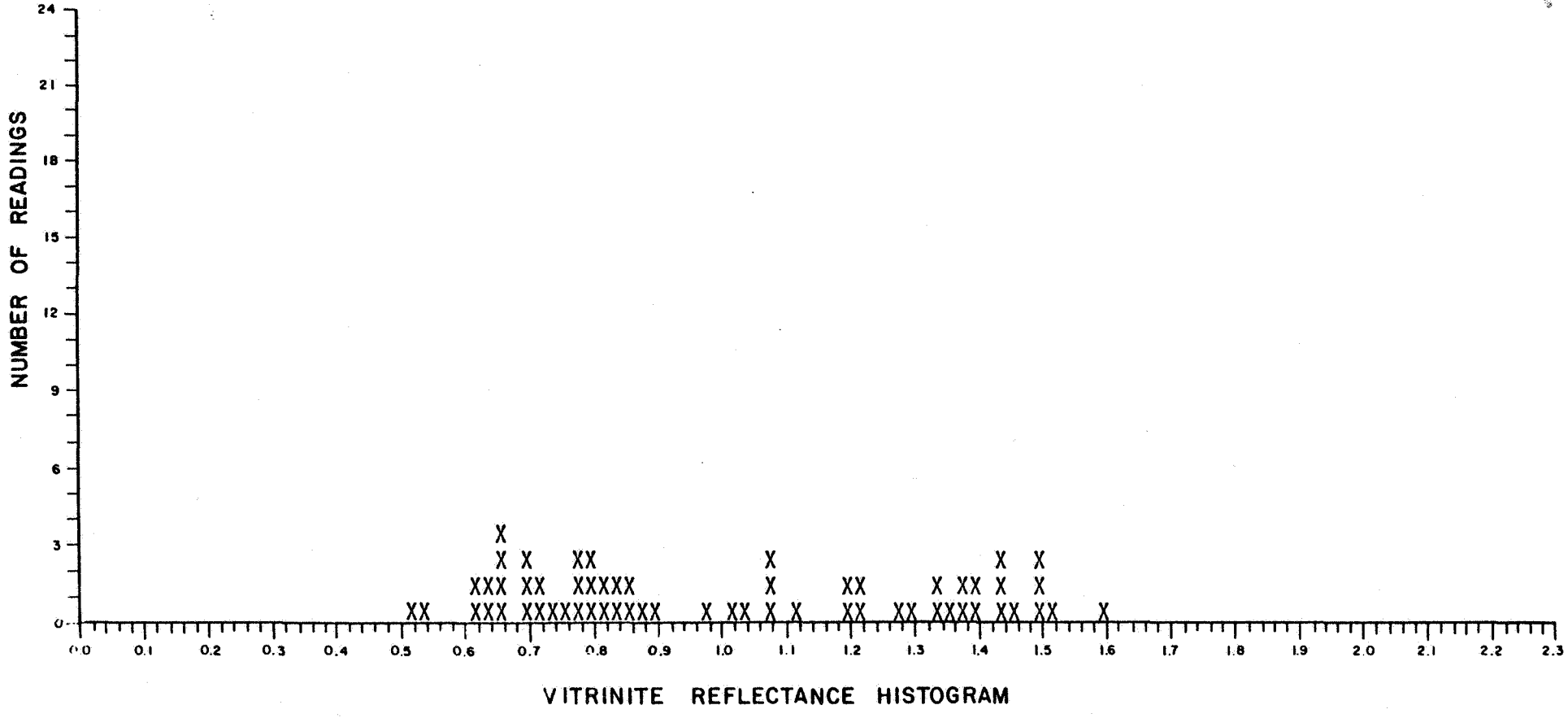


NO. G096-024 TYPE OF SAMPLE: CTG DEPTH / SAMPLE NO. 2900

NAME GETTY WELL NAME 35/8-1

(NO. OF READINGS = 60) 0.52 0.54 0.62 0.62 0.64 0.64 0.66 0.66 0.66 0.67 0.71 0.71 0.71 0.72
0.73 0.74 0.76 0.78 0.78 0.78 0.80 0.81 0.81 0.82 0.83 0.85 0.85 0.86 0.87 0.88 0.91 0.98
1.02 1.05 1.08 1.09 1.09 1.13 1.21 1.21 1.22 1.22 1.28 1.31 1.34 1.35 1.37 1.39 1.39 1.41
1.41 1.44 1.44 1.44 1.47 1.50 1.50 1.51 1.52 1.60

POPULATION	NO. OF READINGS	MIN. Ro (%)	MAX. Ro (%)	MEAN Ro (%)	STD. DEV. (%)	REMARKS
(1)	2	0.52	0.54	0.53	-	
(2)	28	0.62	0.88	0.75	0.082	
(3)	30	0.91	1.60	1.30	0.185	

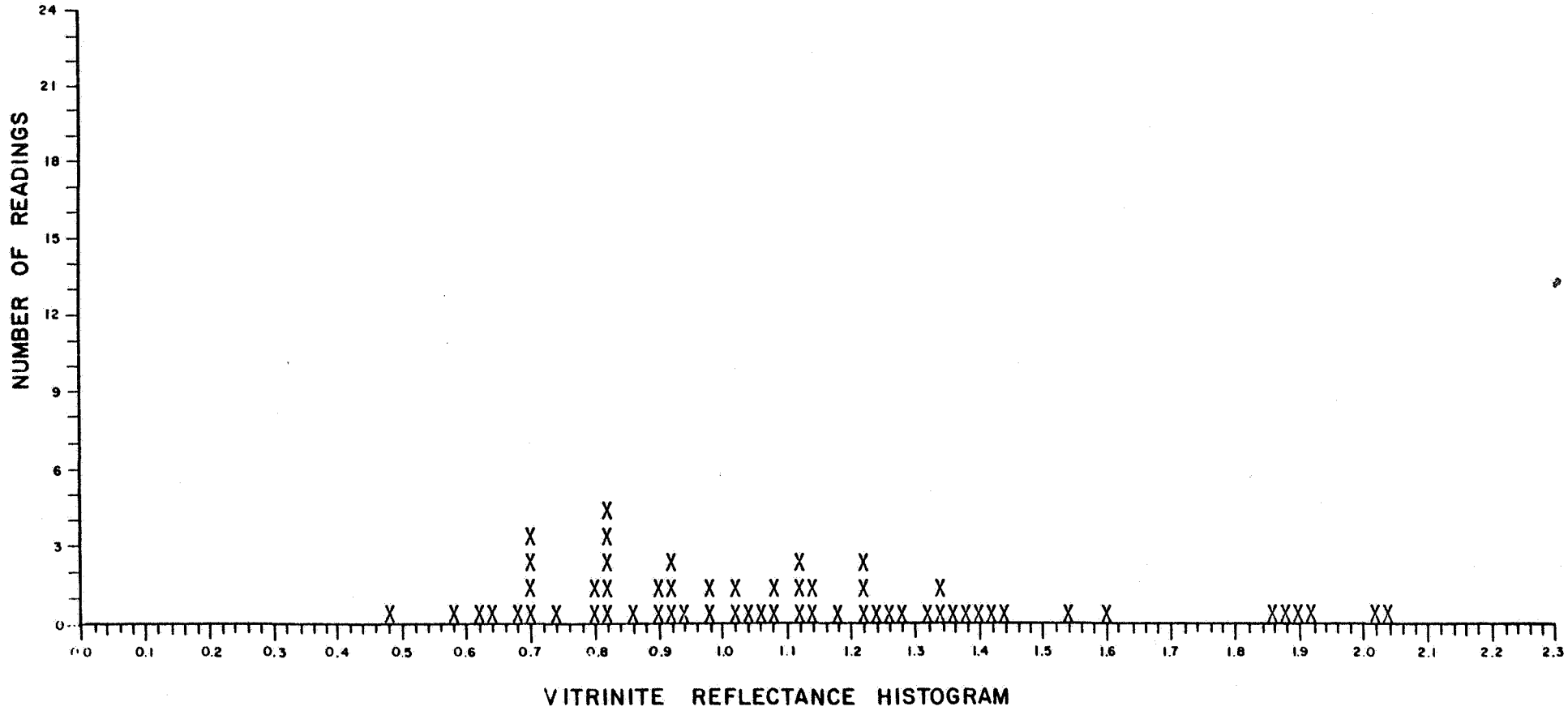


NO. G096-025 TYPE OF SAMPLE: CTG DEPTH / SAMPLE NO. 3000 M.

NAME GETTY WELL NAME 35/8-1

(NO. OF READINGS = 60) 0.48 0.58 0.63 0.64 0.69 0.70 0.70 0.71 0.71 0.75 0.80 0.80 0.82 0.83
0.83 0.83 0.83 0.87 0.90 0.91 0.92 0.93 0.93 0.94 0.99 0.99 1.02 1.03 1.04 1.06 1.09 1.09
1.12 1.12 1.13 1.15 1.15 1.18 1.22 1.22 1.23 1.25 1.26 1.29 1.32 1.34 1.35 1.37 1.39 1.40
1.42 1.45 1.54 1.61 1.87 1.89 1.90 1.93 2.03 2.04

POPULATION	NO. OF READINGS	MIN. Ro (%)	MAX. Ro (%)	MEAN Ro (%)	STD. DEV. (%)	REMARKS
(1)	4	0.48	0.64	0.58	0.073	
(2)	20	0.69	0.94	0.82	0.086	
(3)	36	0.99	2.04	1.35	0.311	

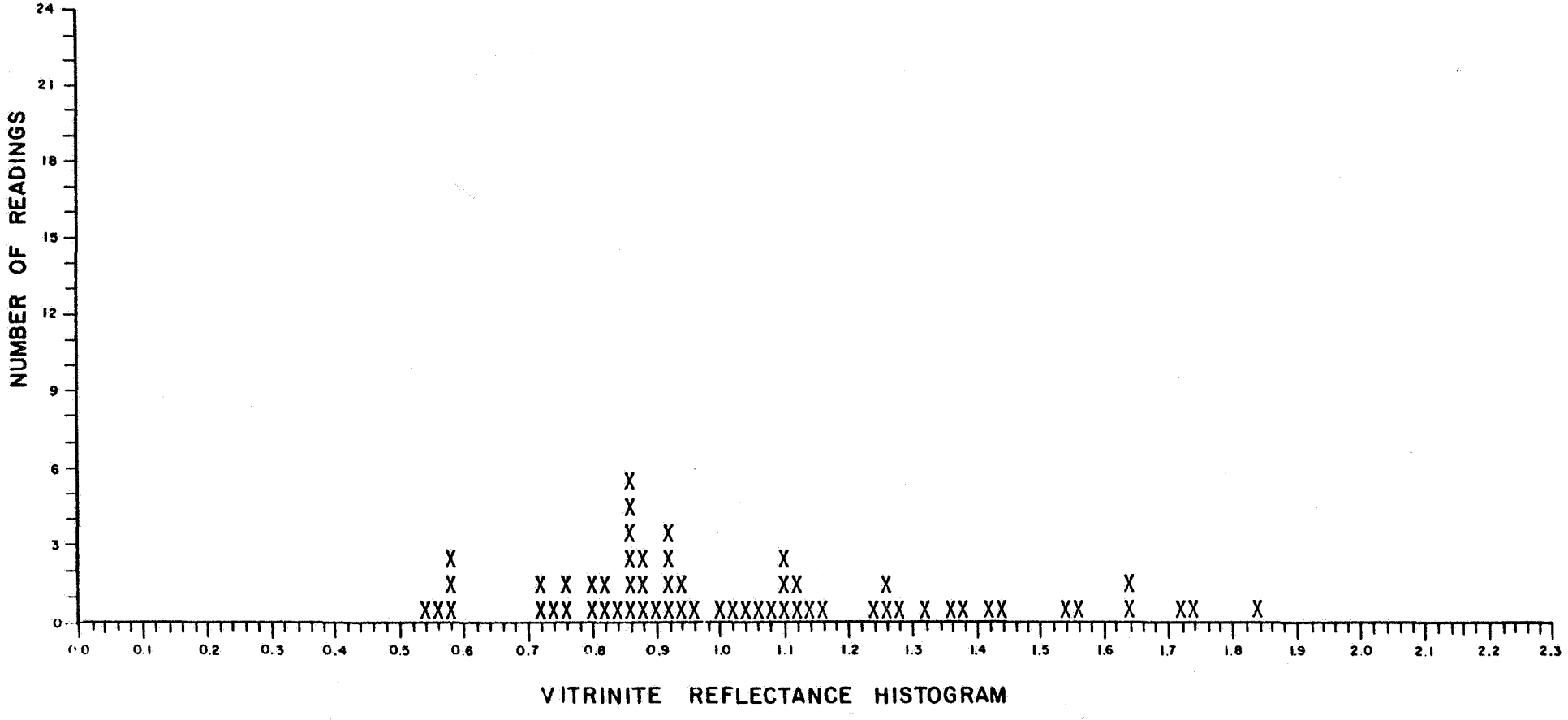


NO. G096-026 TYPE OF SAMPLE: CTG DEPTH / SAMPLE NO. 3100 M.

NAME GETTY WELL NAME 35/8-1

(NO. OF READINGS = 60) 0.55 0.56 0.58 0.58 0.59 0.72 0.73 0.74 0.76 0.76 0.80 0.81 0.82 0.82
0.84 0.86 0.87 0.87 0.87 0.87 0.87 0.88 0.88 0.89 0.91 0.92 0.92 0.92 0.93 0.94 0.94 0.96
1.00 1.02 1.05 1.07 1.08 1.10 1.10 1.11 1.12 1.13 1.14 1.16 1.24 1.26 1.27 1.28 1.32 1.36
1.39 1.43 1.44 1.54 1.57 1.65 1.65 1.73 1.75 1.84

POPULATION	NO. OF READINGS	MIN. Ro (%)	MAX. Ro (%)	MEAN Ro (%)	STD. DEV. (%)	REMARKS
(1)	5	0.55	0.59	0.57	0.016	
(2)	27	0.72	0.96	0.86	0.069	
(3)	28	1.00	1.84	1.31	0.248	

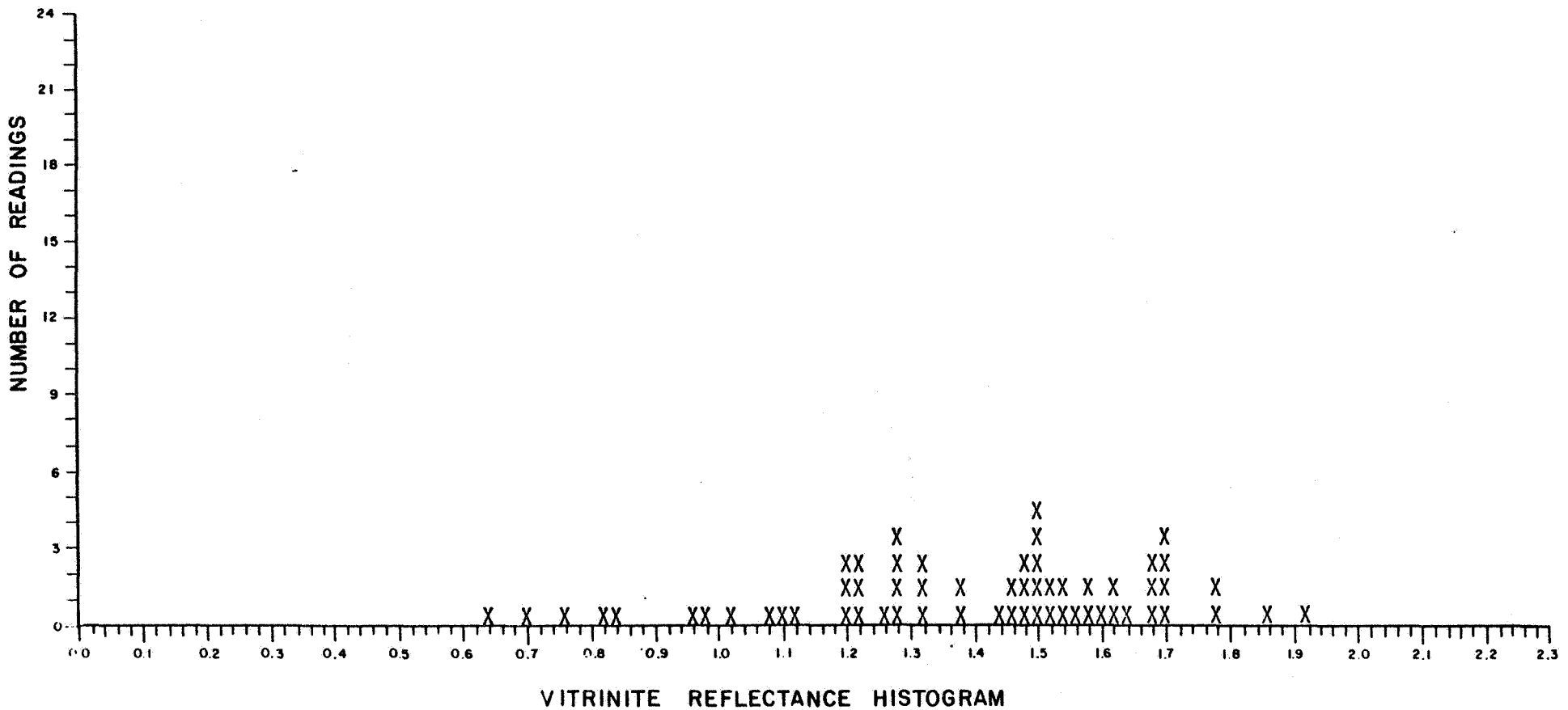


NO. G096-027 TYPE OF SAMPLE: CTG DEPTH / SAMPLE NO. 3200 M.

NAME GETTY WELL NAME 35/8-1

(NO. OF READINGS = 60) 0.65 0.70 0.76 0.83 0.84 0.96 0.99 1.03 1.08 1.10 1.12 1.20 1.20 1.21
1.22 1.23 1.23 1.27 1.28 1.28 1.29 1.29 1.32 1.32 1.33 1.39 1.39 1.44 1.46 1.47 1.49 1.49
1.49 1.50 1.51 1.51 1.51 1.51 1.52 1.53 1.54 1.55 1.57 1.58 1.58 1.61 1.62 1.62 1.64 1.68
1.68 1.69 1.70 1.70 1.71 1.71 1.79 1.79 1.86 1.93

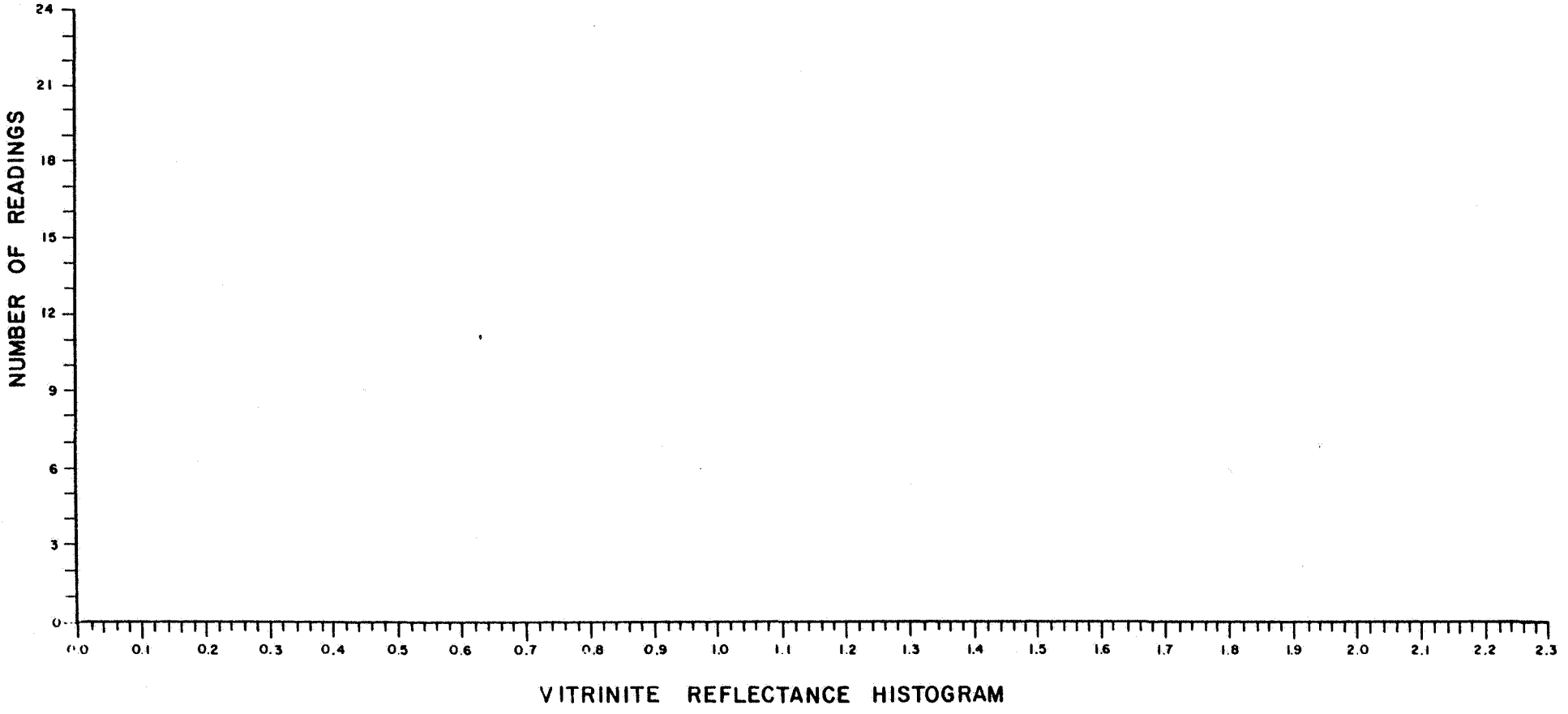
POPULATION	NO. OF READINGS	MIN. Ro (%)	MAX. Ro (%)	MEAN Ro (%)	STD. DEV. (%)	REMARKS
(1)	5	0.65	0.84	0.76	0.082	
(2)	6	0.96	1.12	1.05	0.064	
(3)	16	1.20	1.39	1.28	0.061	
(4)	33	1.44	1.93	1.61	0.122	



NO. G096-028 TYPE OF SAMPLE: MUD ADDITIVES DEPTH / SAMPLE NO. SOLTEX

NAME GETTY WELL NAME 35/8-1

POPULATION	NO. OF READINGS	MIN. Ro (%)	MAX. Ro (%)	MEAN Ro (%)	STD. DEV. (%)	REMARKS

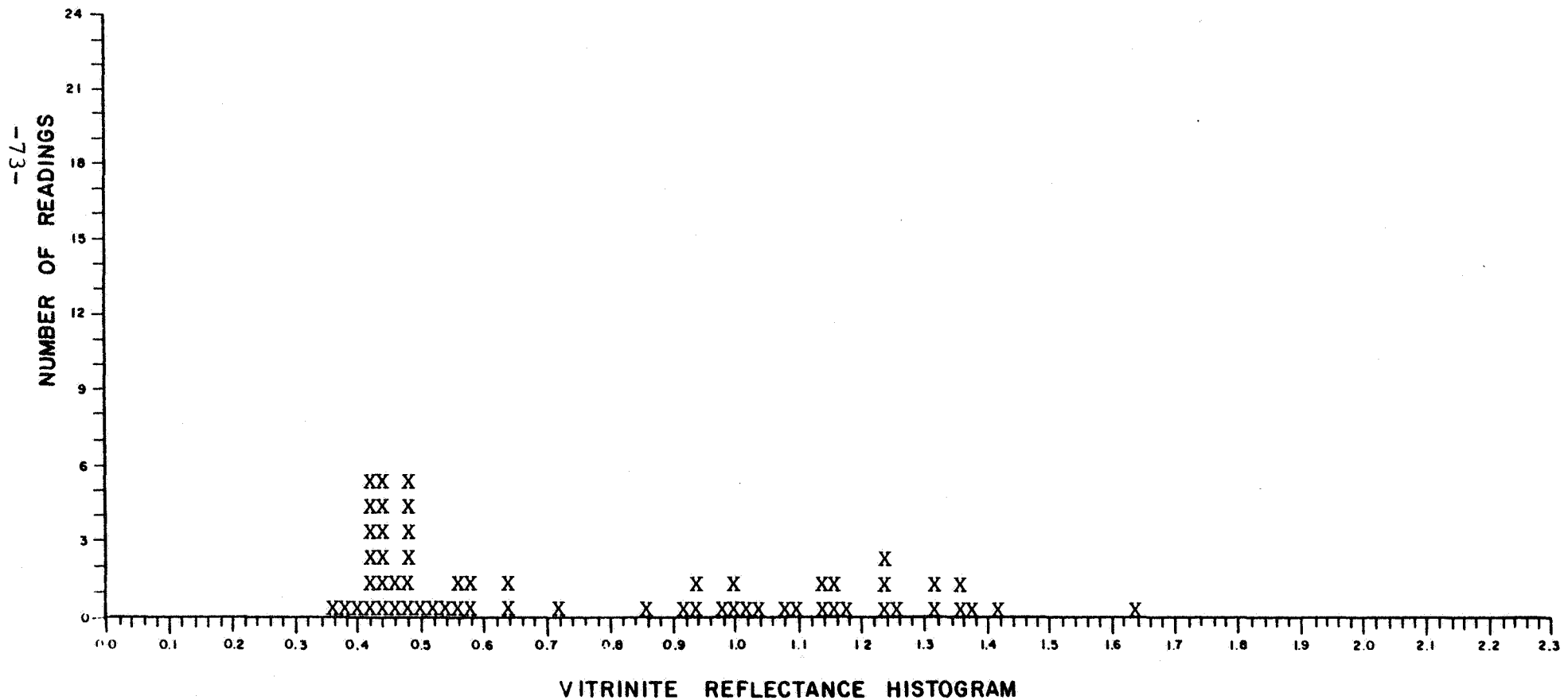


NO. G096-029 TYPE OF SAMPLE: CTG DEPTH / SAMPLE NO. 3300 M.

NAME GETTY WELL NAME 35/8-1 NORWEGIAN NORTH SEA

(NO. OF READINGS = 60) 0.36 0.39 0.41 0.42 0.42 0.43 0.43 0.43 0.43 0.44 0.44 0.44 0.44 0.45
0.45 0.46 0.46 0.48 0.48 0.48 0.49 0.49 0.49 0.50 0.52 0.55 0.56 0.56 0.58 0.58 0.64 0.64
0.72 0.86 0.93 0.94 0.95 0.99 1.01 1.01 1.03 1.05 1.08 1.11 1.14 1.15 1.16 1.16 1.19 1.24
1.24 1.25 1.27 1.33 1.33 1.36 1.37 1.38 1.43 1.65

POPULATION	NO. OF READINGS	MIN. Ro (%)	MAX. Ro (%)	MEAN Ro (%)	STD. DEV. (%)	REMARKS
(1)	30	0.36	0.58	0.47	0.056	
(2)	30	0.64	1.65	1.12	0.233	



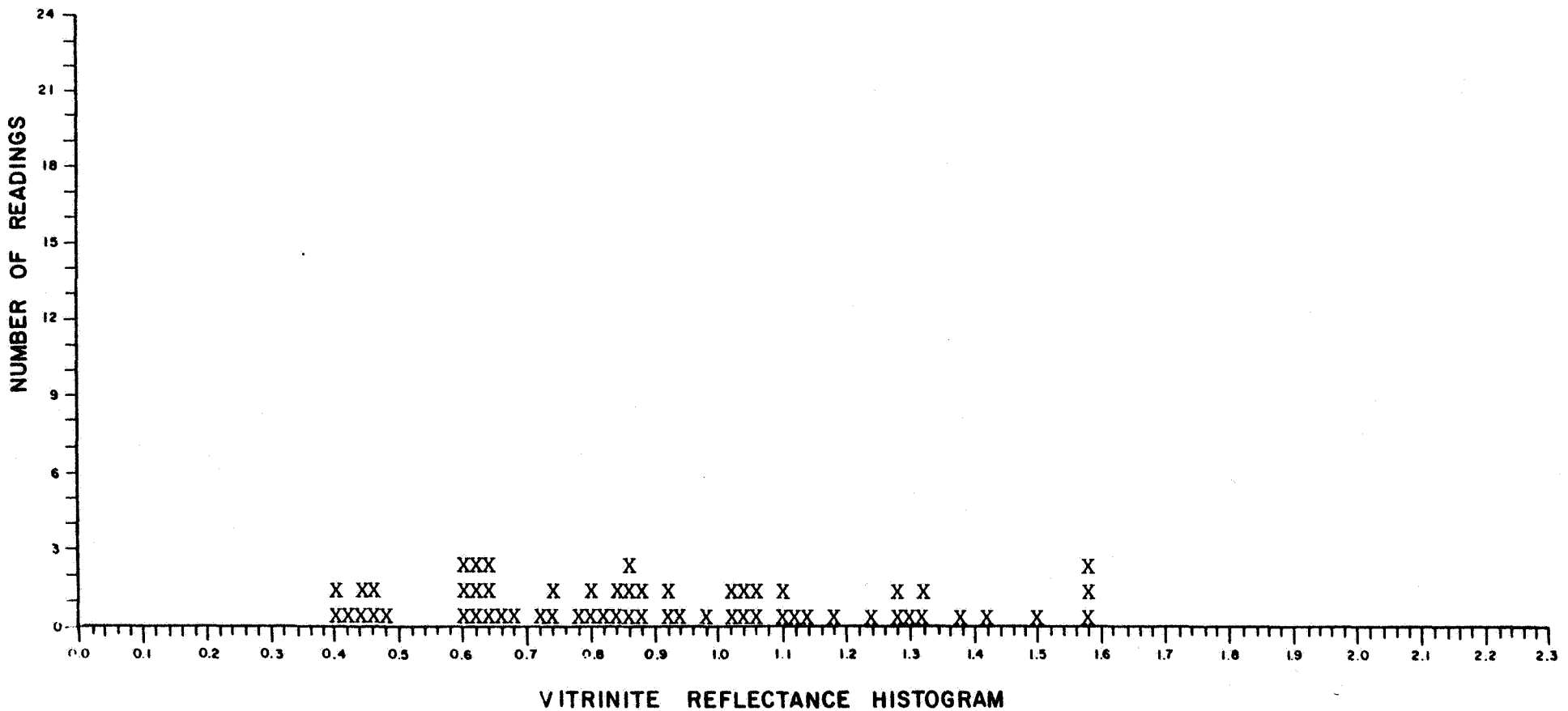
VITRINITE REFLECTANCE HISTOGRAM

NO. G096-030 TYPE OF SAMPLE: CTG DEPTH / SAMPLE NO. 3400

NAME GETTY WELL NAME 35/8-1 NORWEGIAN NORTH SEA

(NO. OF READINGS = 60) 0.40 0.41 0.43 0.44 0.45 0.47 0.47 0.48 0.60 0.60 0.61 0.62 0.63 0.63
0.64 0.65 0.65 0.66 0.69 0.73 0.74 0.74 0.78 0.80 0.81 0.83 0.84 0.84 0.86 0.86 0.87 0.89
0.89 0.93 0.93 0.95 0.98 1.02 1.02 1.04 1.05 1.06 1.06 1.10 1.10 1.12 1.14 1.19 1.24 1.29
1.29 1.31 1.32 1.33 1.39 1.42 1.50 1.58 1.59 1.59

POPULATION	NO. OF READINGS	MIN. Ro (%)	MAX. Ro (%)	MEAN Ro (%)	STD. DEV. (%)	REMARKS
(1)	8	0.40	0.48	0.44	0.029	
(2)	14	0.60	0.74	0.66	0.050	
(3)	15	0.78	0.98	0.87	0.058	
(4)	23	1.02	1.59	1.25	0.192	



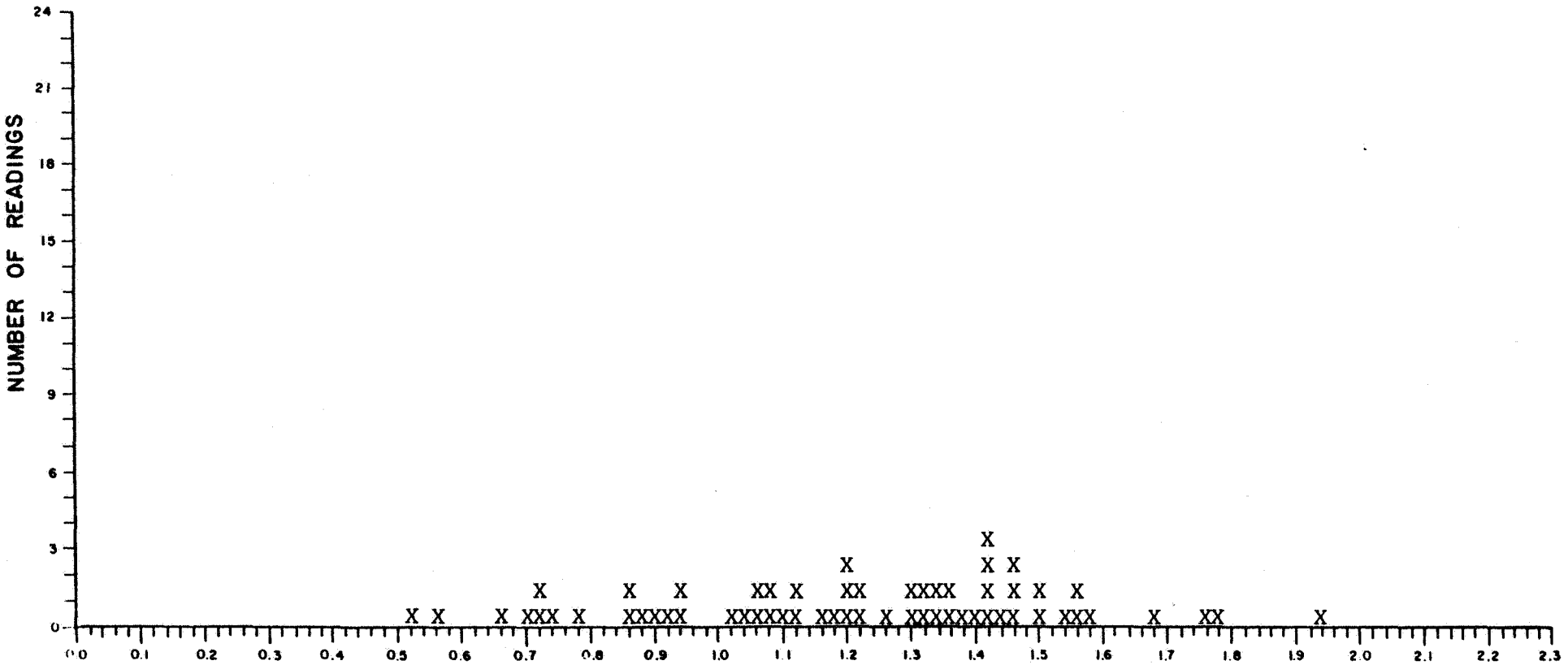
VITRINITE REFLECTANCE HISTOGRAM

NO. G096-031 TYPE OF SAMPLE: CTG DEPTH / SAMPLE NO. 3500 M.

NAME GETTY WELL NAME 35/8-1 NORWEGIAN NORTH SEA

(NO. OF READINGS = 60) 0.53 0.57 0.67 0.70 0.72 0.73 0.74 0.79 0.86 0.87 0.88 0.90 0.92 0.94
0.94 1.03 1.05 1.07 1.07 1.08 1.09 1.11 1.12 1.13 1.16 1.18 1.20 1.21 1.21 1.22 1.23 1.27
1.30 1.30 1.32 1.32 1.34 1.34 1.36 1.36 1.39 1.41 1.42 1.42 1.42 1.43 1.45 1.46 1.46 1.47
1.50 1.51 1.55 1.57 1.57 1.59 1.69 1.76 1.78 1.94

POPULATION	NO. OF READINGS	MIN. Ro (%)	MAX. Ro (%)	MEAN Ro (%)	STD. DEV. (%)	REMARKS
(1)	2	0.53	0.57	0.55	-	
(2)	6	0.67	0.79	0.73	0.040	
(3)	52	0.86	1.94	1.29	0.250	



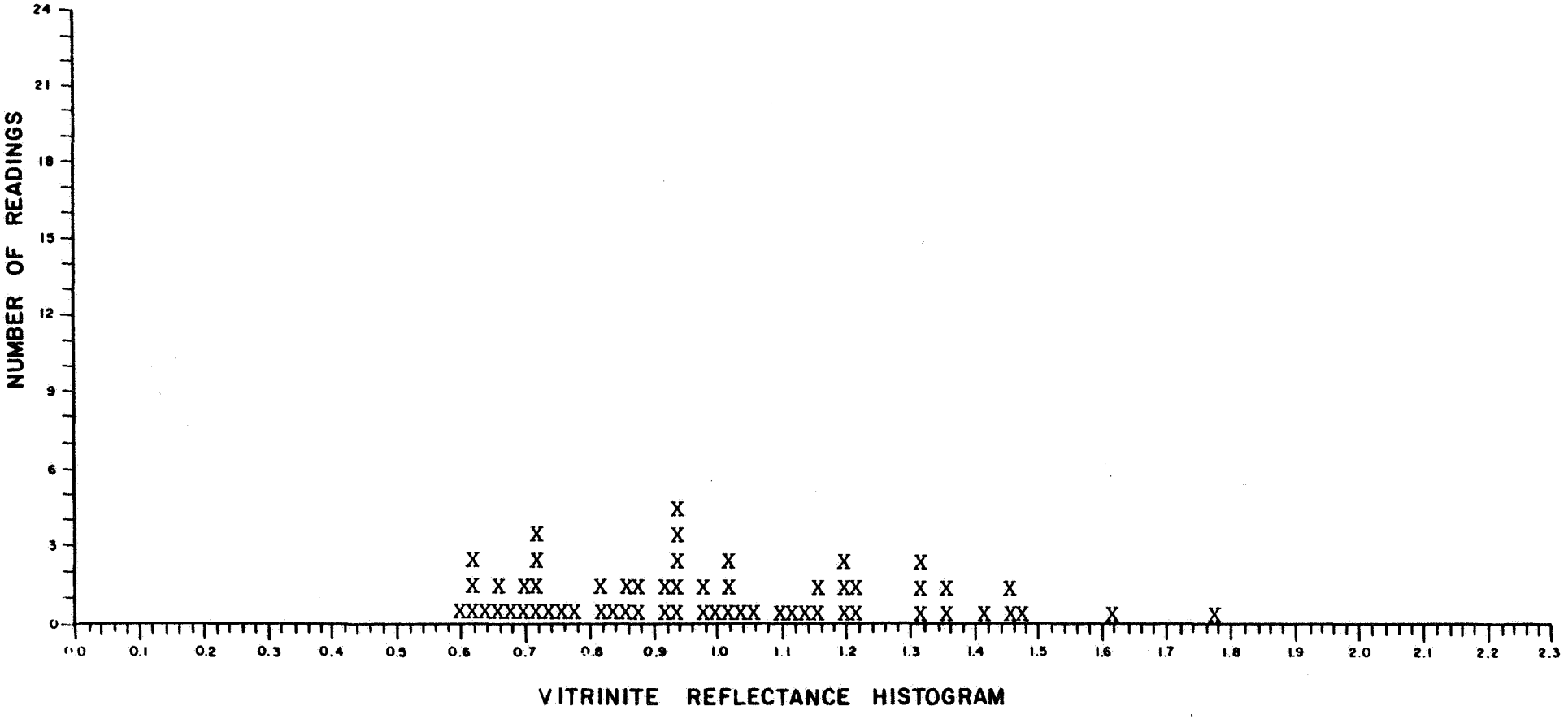
VITRINITE REFLECTANCE HISTOGRAM

NO. G096-034 TYPE OF SAMPLE: CTG DEPTH / SAMPLE NO. 3800

NAME GETTY WELL NAME 35/8-1 NORWEGIAN NORTH SEA

(NO. OF READINGS = 60) 0.61 0.62 0.63 0.63 0.65 0.66 0.67 0.68 0.70 0.71 0.72 0.72 0.73 0.73
0.75 0.76 0.79 0.83 0.83 0.85 0.87 0.87 0.88 0.89 0.92 0.93 0.94 0.94 0.94 0.94 0.95 0.98
0.98 1.00 1.02 1.02 1.02 1.05 1.06 1.10 1.13 1.14 1.16 1.17 1.20 1.21 1.21 1.22 1.23 1.33
1.33 1.33 1.36 1.36 1.42 1.47 1.47 1.49 1.63 1.78

POPULATION	NO. OF READINGS	MIN. Ro (%)	MAX. Ro (%)	MEAN Ro (%)	STD. DEV. (%)	REMARKS
(1)	17	0.61	0.79	0.69	0.053	
(2)	22	0.83	1.06	0.94	0.069	
(3)	21	1.10	1.78	1.32	0.176	

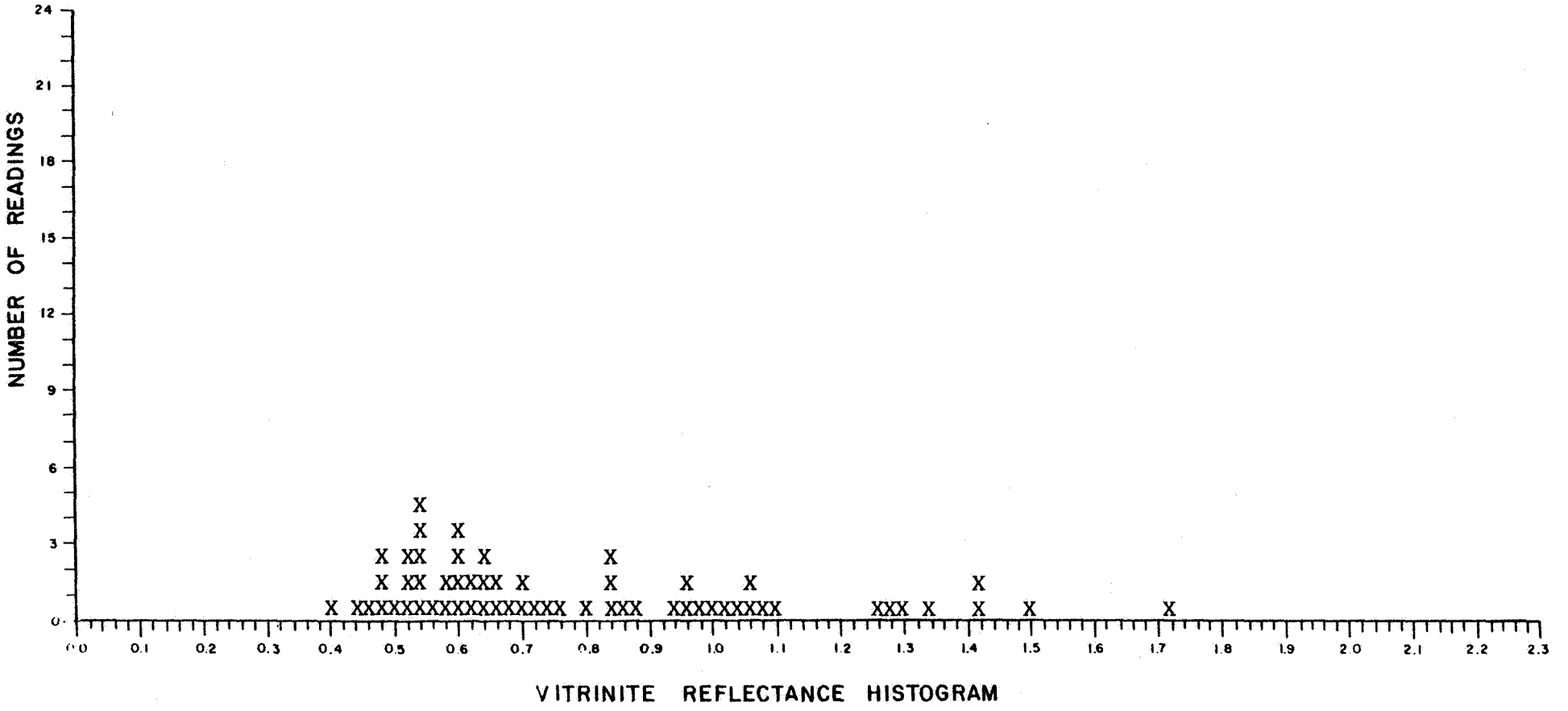


NO. G096-035 TYPE OF SAMPLE: CTG DEPTH / SAMPLE NO. 3900 M.

NAME GETTY WELL NAME 35/8-1 NORWEGIAN NORTH SEA

(NO. OF READINGS = 60) 0.40 0.45 0.46 0.48 0.49 0.49 0.51 0.52 0.52 0.53 0.54 0.54 0.55 0.55
0.55 0.57 0.58 0.59 0.60 0.60 0.60 0.61 0.62 0.63 0.64 0.64 0.64 0.66 0.66 0.68 0.70 0.71
0.73 0.75 0.76 0.81 0.84 0.84 0.85 0.86 0.89 0.95 0.96 0.96 0.98 1.01 1.03 1.05 1.06 1.07
1.08 1.11 1.26 1.28 1.30 1.35 1.42 1.42 1.51 1.73

POPULATION	NO. OF READINGS	MIN. Ro (%)	MAX. Ro (%)	MEAN Ro (%)	STD. DEV. (%)	REMARKS
(1)	35	0.40	0.76	0.59	0.088	
(2)	17	0.81	1.11	0.96	0.098	
(3)	8	1.26	1.73	1.41	0.155	

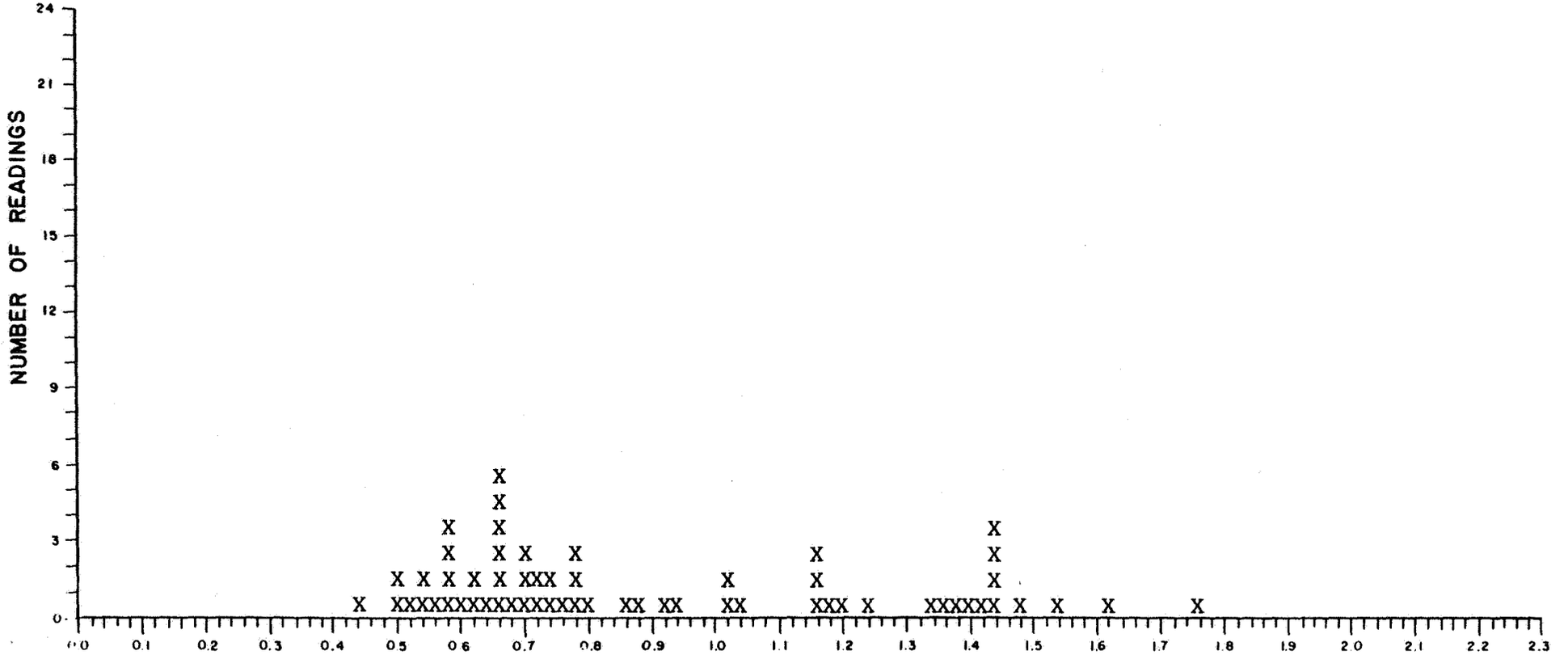


NO. G096-036 TYPE OF SAMPLE: CTG DEPTH / SAMPLE NO. 4000 M.

NAME GETTY WELL NAME 35/8-1 NORWEGIAN NORTH SEA

(NO. OF READINGS = 60) 0.45 0.50 0.51 0.52 0.54 0.55 0.56 0.58 0.58 0.59 0.59 0.60 0.62 0.63
0.64 0.66 0.66 0.67 0.67 0.67 0.67 0.69 0.70 0.71 0.71 0.72 0.73 0.74 0.74 0.77 0.78 0.78
0.78 0.81 0.86 0.89 0.92 0.95 1.02 1.03 1.04 1.16 1.16 1.17 1.18 1.21 1.24 1.35 1.37 1.39
1.41 1.43 1.44 1.45 1.45 1.45 1.48 1.55 1.63 1.76

POPULATION	NO. OF READINGS	MIN. Ro (%)	MAX. Ro (%)	MEAN Ro (%)	STD. DEV. (%)	REMARKS
(1)	1	0.45	0.45	0.45	-	
(2)	33	0.50	0.81	0.66	0.087	
(3)	7	0.86	1.04	0.96	0.072	
(4)	19	1.16	1.76	1.38	0.166	



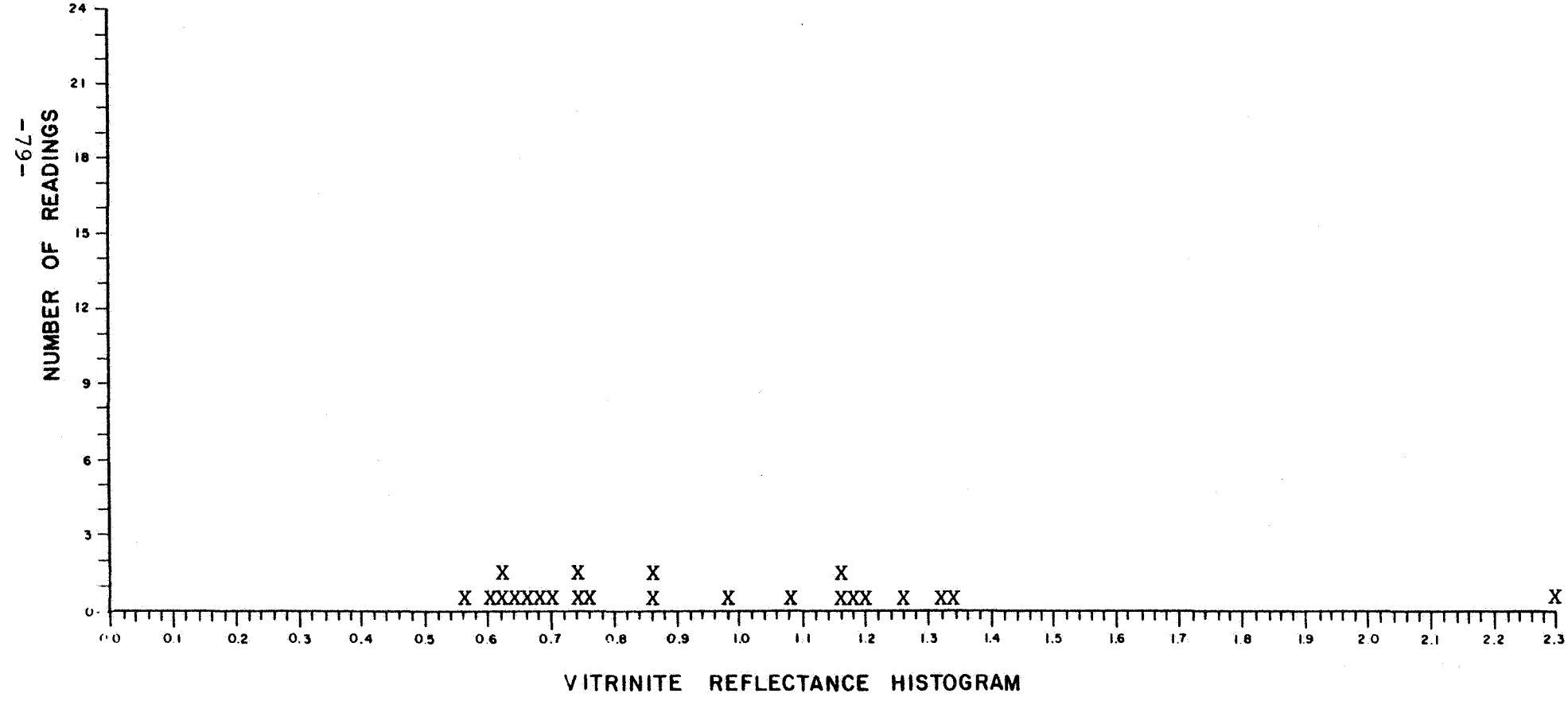
VITRINITE REFLECTANCE HISTOGRAM

NO. G096-037 TYPE OF SAMPLE: CIG DEPTH / SAMPLE NO. 4100 M.

NAME GETTY WELL NAME 35/8-1 NORWEGIAN NORTH SEA

(NO. OF READINGS = 23) 0.57 0.61 0.62 0.63 0.65 0.67 0.68 0.70 0.74 0.75 0.76 0.86 0.86 0.98
1.08 1.17 1.17 1.18 1.21 1.26 1.33 1.35 2.85

POPULATION	NO. OF READINGS	MIN. Ro (%)	MAX. Ro (%)	MEAN Ro (%)	STD. DEV. (%)	REMARKS
(1)	11	0.57	0.76	0.67	0.062	
(2)	12	0.86	2.85	1.28	0.522	



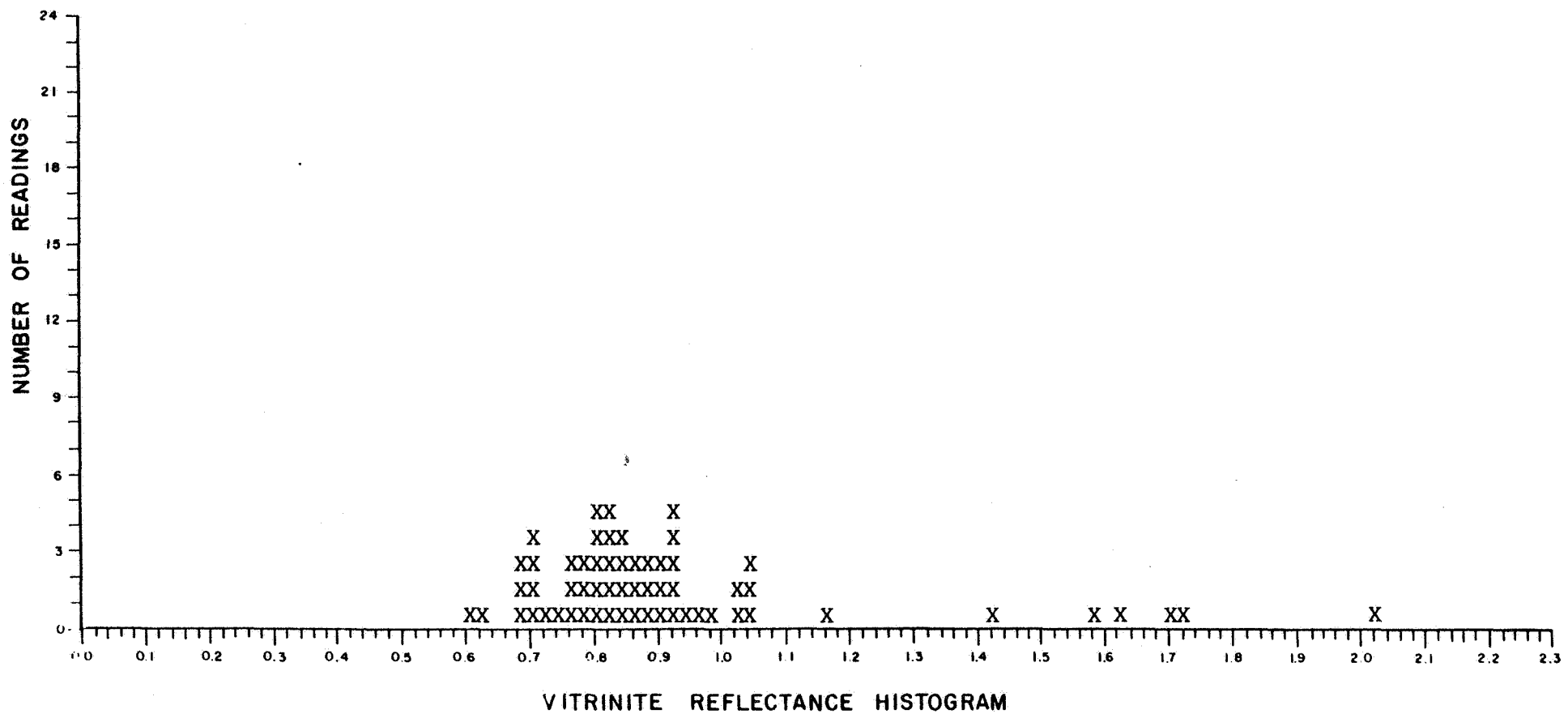
VITRINITE REFLECTANCE HISTOGRAM

NO. G096-039 TYPE OF SAMPLE: CTG DEPTH / SAMPLE NO. 4230 M.

NAME GETTY WELL NAME 35/8-1 NORWEGIAN NORTH SEA

(NO. OF READINGS = 60) 0.60 0.63 0.68 0.68 0.69 0.71 0.71 0.71 0.71 0.73 0.74 0.76 0.77 0.77
0.78 0.78 0.79 0.80 0.80 0.80 0.81 0.81 0.82 0.82 0.83 0.83 0.83 0.84 0.84 0.84 0.85 0.87
0.87 0.87 0.88 0.89 0.89 0.90 0.91 0.91 0.92 0.92 0.92 0.92 0.93 0.95 0.96 0.98 1.02 1.03
1.05 1.05 1.05 1.17 1.43 1.58 1.62 1.70 1.73 2.02

POPULATION	NO. OF READINGS	MIN. Ro (%)	MAX. Ro (%)	MEAN Ro (%)	STD. DEV. (%)	REMARKS
(1)	2	0.60	0.63	0.62	-	
(2)	46	0.68	0.98	0.83	0.080	
(3)	12	1.02	2.02	1.37	0.351	

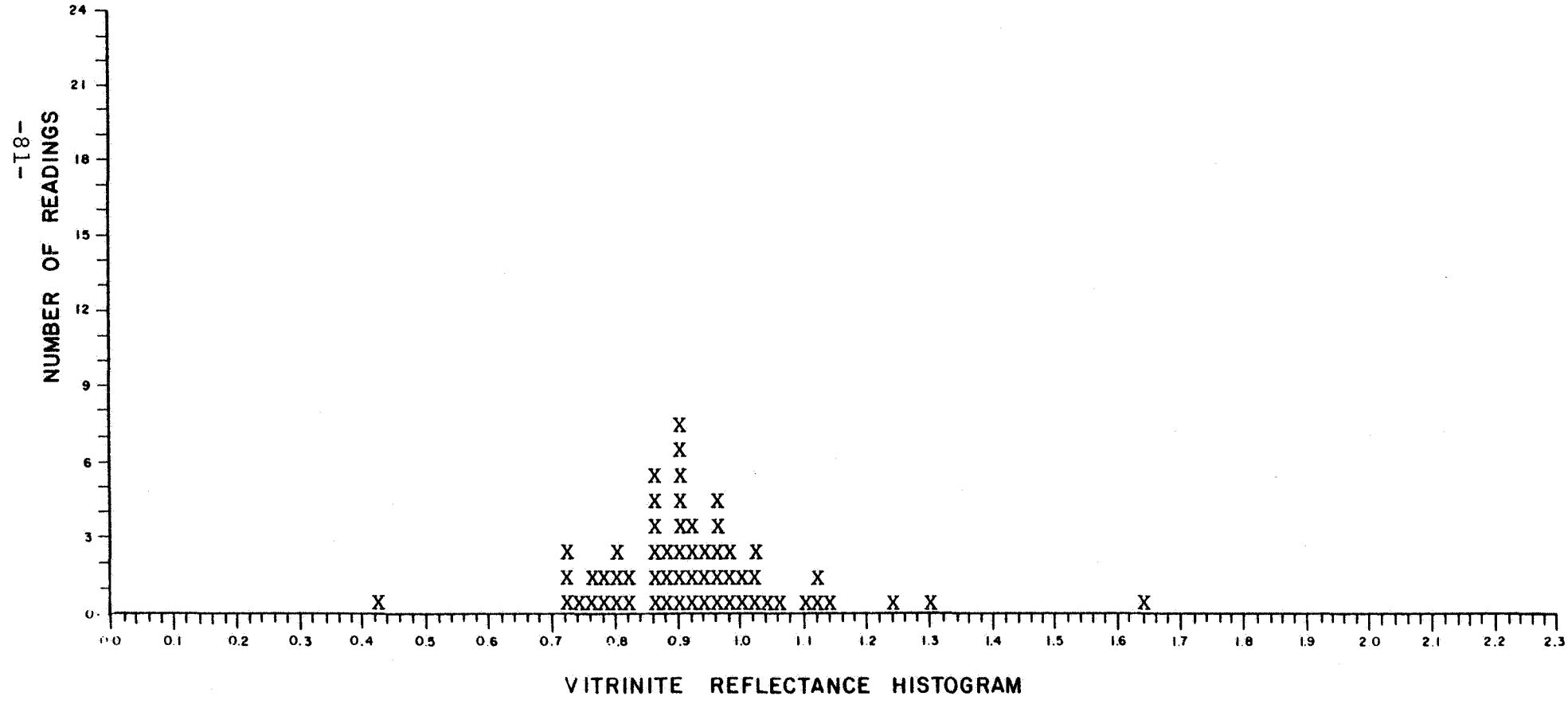


NO. G096-040 TYPE OF SAMPLE: CTG DEPTH / SAMPLE NO. 4260 M.

NAME GETTY WELL NAME 35/8-1 NORWEGIAN NORTH SEA

(NO. OF READINGS = 60) 0.43 0.72 0.73 0.73 0.75 0.77 0.77 0.79 0.79 0.80 0.81 0.81 0.82 0.83
0.86 0.86 0.86 0.87 0.87 0.87 0.88 0.88 0.89 0.90 0.90 0.90 0.90 0.90 0.91 0.91 0.91 0.92
0.92 0.92 0.93 0.94 0.95 0.95 0.96 0.96 0.96 0.97 0.97 0.98 0.99 0.99 1.00 1.01 1.02 1.02
1.03 1.04 1.07 1.10 1.13 1.13 1.15 1.24 1.31 1.64

POPULATION	NO. OF READINGS	MIN. Ro (%)	MAX. Ro (%)	MEAN Ro (%)	STD. DEV. (%)	REMARKS
(1)	1	0.43	0.43	0.43	-	
(2)	52	0.72	1.07	0.90	0.087	
(3)	7	1.10	1.64	1.24	0.190	



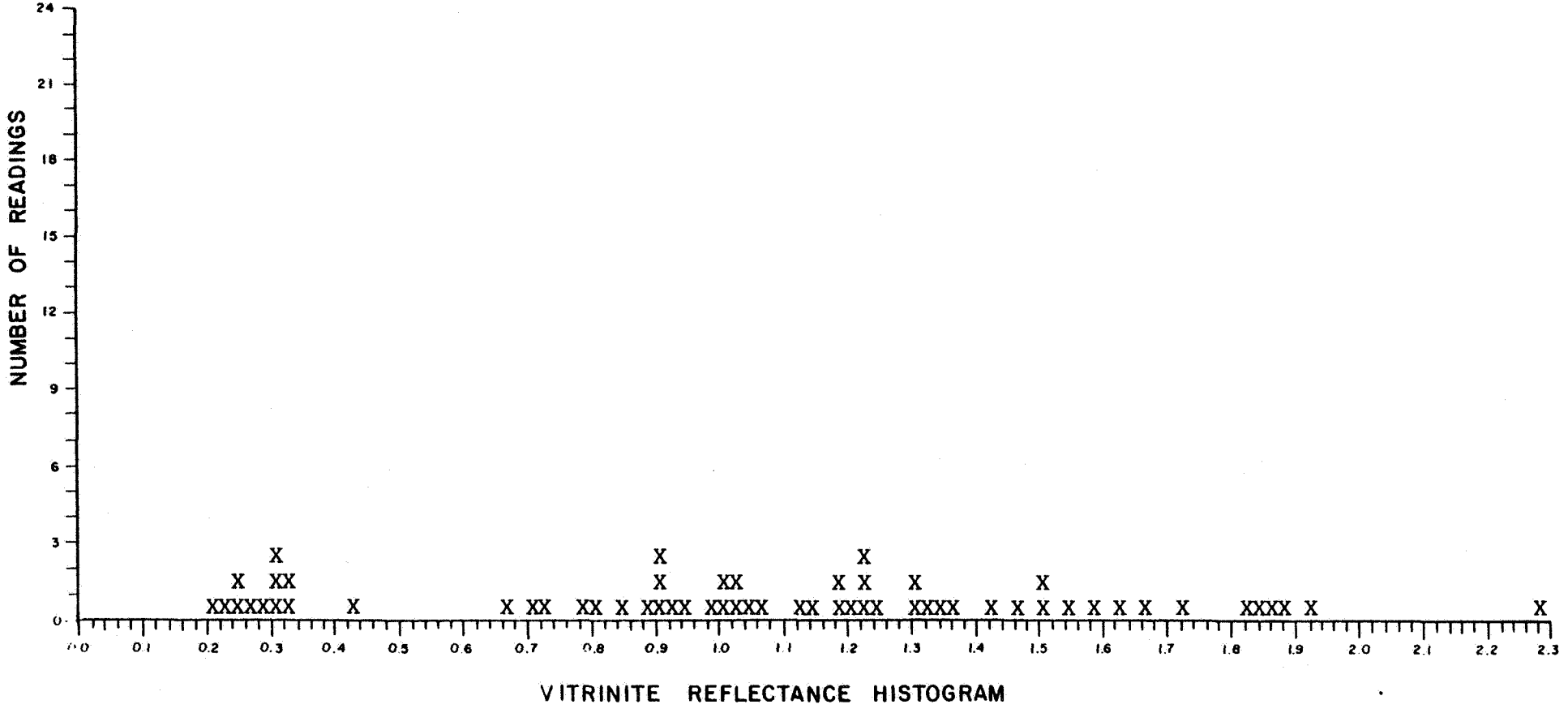
VITRINITE REFLECTANCE HISTOGRAM

NO. G096-043 TYPE OF SAMPLE: CTG DEPTH/SAMPLE NO. 4343.5 M.

NAME GETTY WELL NAME 35/8-1 NORWEGIAN NORTH SEA

(NO. OF READINGS = 60) 0.21 0.23 0.25 0.25 0.26 0.28 0.30 0.31 0.31 0.32 0.32 0.42 0.66 0.70
0.73 0.78 0.80 0.85 0.88 0.90 0.91 0.91 0.92 0.94 0.98 1.00 1.01 1.02 1.03 1.04 1.06 1.12
1.15 1.18 1.19 1.21 1.22 1.22 1.23 1.24 1.30 1.31 1.33 1.34 1.37 1.43 1.47 1.50 1.51 1.54
1.58 1.62 1.66 1.72 1.83 1.84 1.87 1.88 1.93 2.28

POPULATION	NO. OF READINGS	MIN. Ro (%)	MAX. Ro (%)	MEAN Ro (%)	STD. DEV. (%)	REMARKS
(1)	12	0.21	0.42	0.29	0.055	
(2)	5	0.66	0.80	0.73	0.057	
(3)	14	0.85	1.06	0.96	0.067	
(4)	14	1.12	1.37	1.24	0.075	
(5)	15	1.43	2.28	1.71	0.229	



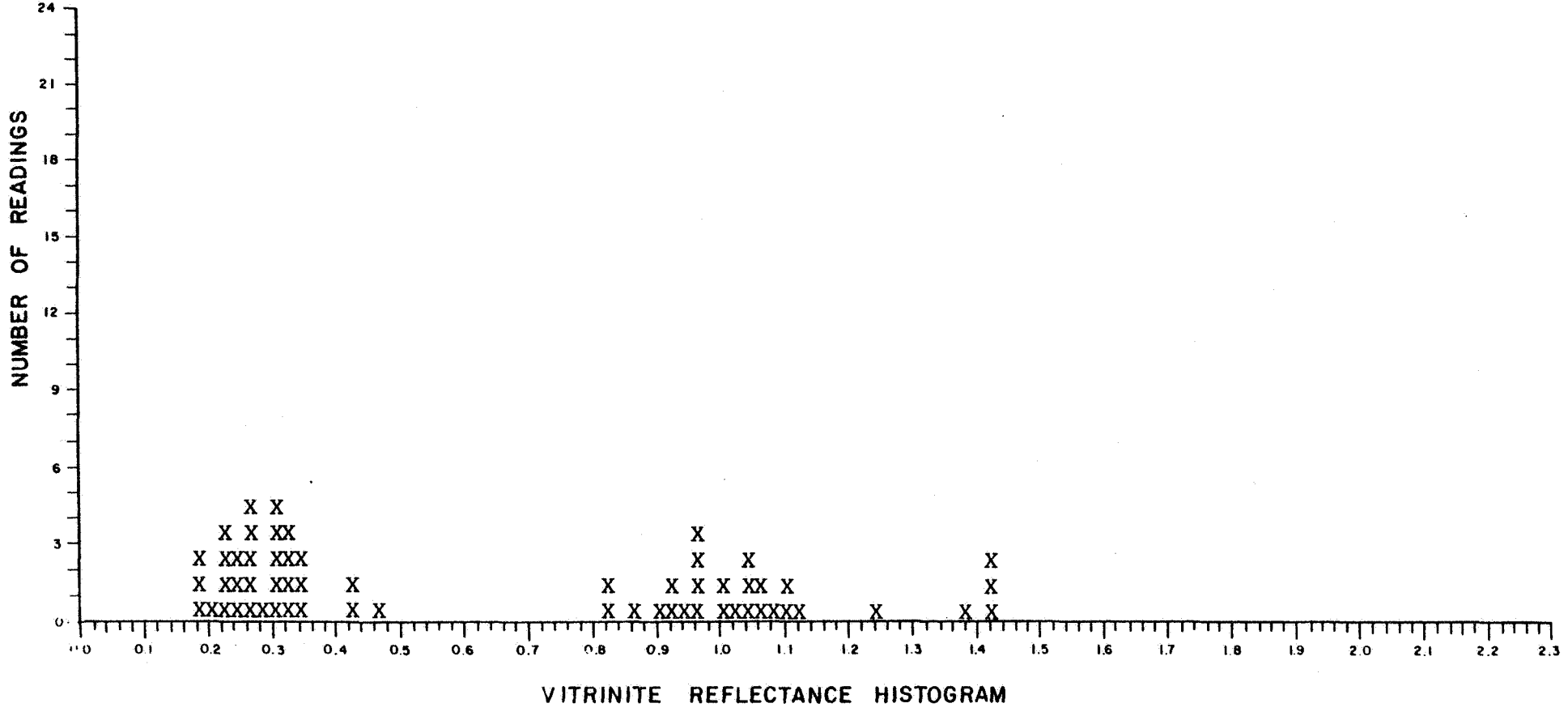
VITRINITE REFLECTANCE HISTOGRAM

NO. G096-042 TYPE OF SAMPLE: CTG DEPTH / SAMPLE NO. 4320 M.

NAME GETTY WELL NAME 35/8-1 NORWEGIAN NORTH SEA

(NO. OF READINGS = 60) 0.18 0.19 0.19 0.21 0.22 0.22 0.22 0.23 0.24 0.24 0.24 0.26 0.26 0.26
0.27 0.27 0.28 0.30 0.30 0.30 0.31 0.31 0.32 0.32 0.33 0.33 0.34 0.35 0.35 0.42 0.42 0.46
0.82 0.83 0.87 0.91 0.93 0.93 0.95 0.96 0.96 0.97 0.97 1.00 1.00 1.02 1.05 1.05 1.05 1.06
1.06 1.09 1.10 1.10 1.13 1.25 1.38 1.42 1.42 1.43

POPULATION	NO. OF READINGS	MIN. Ro (%)	MAX. Ro (%)	MEAN Ro (%)	STD. DEV. (%)	REMARKS
(1)	32	0.18	0.46	0.29	0.069	
(2)	23	0.82	1.13	0.99	0.086	
(3)	5	1.25	1.43	1.38	0.075	



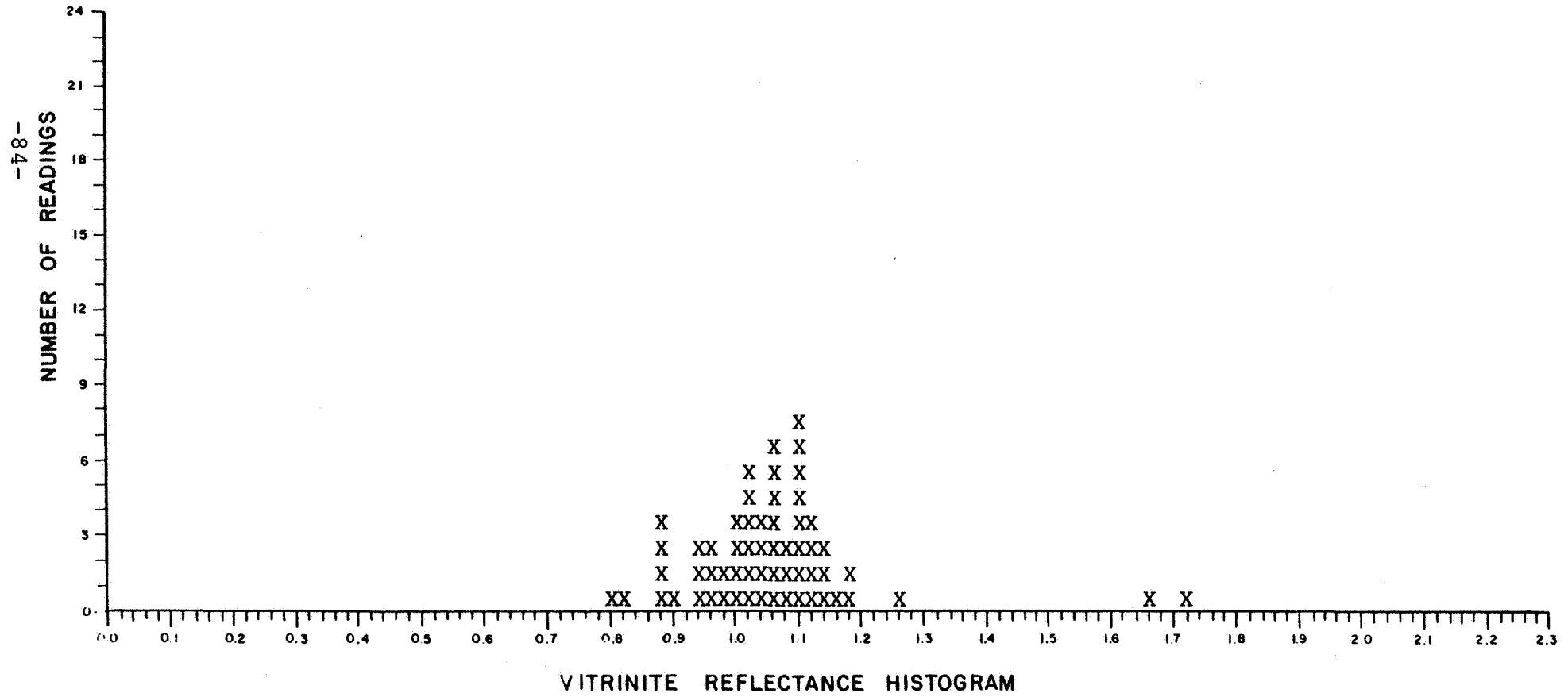
NO. G096-041 TYPE OF SAMPLE: CTG DEPTH / SAMPLE NO. 4290 M.

NAME GETTY WELL NAME 35/8-1 NORWEGIAN NORTH SEA

(NO. OF READINGS = 60)

0.81	0.83	0.88	0.89	0.89	0.89	0.91	0.94	0.95	0.95	0.96	0.97	0.97	0.98	0.98	1.00	1.00
1.00	1.01	1.02	1.02	1.02	1.03	1.03	1.03	1.05	1.05	1.05	1.05	1.06	1.06	1.06	1.06	1.07
1.07	1.07	1.08	1.08	1.09	1.10	1.11	1.11	1.11	1.11	1.11	1.11	1.11	1.12	1.13	1.13	1.13
1.14	1.14	1.15	1.16	1.18	1.18	1.26	1.67	1.73								

POPULATION	NO. OF READINGS	MIN. Ro (%)	MAX. Ro (%)	MEAN Ro (%)	STD. DEV. (%)	REMARKS
(1)	7	0.81	0.91	0.87	0.037	
(2)	50	0.94	1.18	1.06	0.064	
(3)	3	1.26	1.73	1.55	0.256	



VITRINITE REFLECTANCE HISTOGRAM

APPENDIX V.

RESULTS OF LIGHT HYDROCARBON ANALYSIS ON CANNED SAMPLES

C1-C7 HYDROCARBON ANALYSES OF AIR SPACE

Sample Number	Well Interval*	Methane C1 PPM	Ethane C2 PPM	Propane C3 PPM	Isobutane iC4 PPM	Butane nC4 PPM	Total C5-C7 PPM	Total C1-C4 PPM	Total C2-C4 PPM	Gas Wetness %	iC4/nC4
G096-001	600	412.5	11.1	14.9	9.4	15.4	85.6	463.6	51.0	11.0	0.61
G096-002	700	390.0	8.1	20.4	22.0	15.8	94.9	456.4	66.4	14.6	1.39
G096-003	800	608.5	14.6	6.6	4.8	6.8	56.2	641.4	32.9	5.1	0.71
G096-004	900	45.4	0.0	16.6	20.2	19.8	66.3	102.1	56.6	55.5	1.02
G096-005	1000	129.5	2.4	2.5	0.6	3.0	3.4	138.3	8.7	6.3	0.22
G096-006	1100	162.7	1.8	1.4	0.2	0.8	1.8	167.1	4.3	2.6	0.34
G096-007	1200	67.2	1.9	3.4	5.0	10.8	17.0	88.5	21.3	24.1	0.47
G096-008	1300	1439.5	3.1	2.7	1.0	3.3	8.9	1449.8	10.2	0.7	0.31
G096-009	1400	1897.2	5.7	2.8	0.6	2.2	5.9	1908.7	11.4	0.6	0.28
G096-010	1500	160.2	16.5	11.3	22.6	16.7	50.6	227.5	67.2	29.6	1.35
G096-011	1600	421.3	1.5	1.0	0.4	0.6	1.3	424.8	3.5	0.8	0.68
G096-012	1700	687.4	16.4	4.5	3.5	2.5	28.5	714.4	26.9	3.8	1.41
G096-013	1800	417.7	15.2	6.6	7.7	5.1	35.5	452.5	34.8	7.7	1.49
G096-014	1900	613.9	19.5	11.9	10.9	9.4	57.3	665.9	51.9	7.8	1.16
G096-015	2000	451.0	13.9	8.3	5.6	5.4	30.9	484.4	33.4	6.9	1.05
G096-016	2100	322.6	18.9	22.8	18.7	26.7	81.7	409.9	87.2	21.3	0.70
G096-017	2200	36.6	0.0	4.3	6.3	19.9	82.6	67.2	30.6	45.5	0.32
G096-018	2300	12.1	0.0	0.0	2.4	1.4	2.9	16.0	3.8	24.2	1.65
G096-019	2400	7.5	0.0	0.7	0.7	0.8	11.0	9.8	2.3	23.7	0.86
G096-020	2500	4210.0	374.4	320.9	130.7	91.6	75.3	5127.8	917.7	17.9	1.43
G096-021	2600	1904.6	220.7	166.9	48.0	44.2	27.4	2384.6	479.9	20.1	1.09
G096-022	2700	3.3	0.8	1.6	1.3	0.9	2.0	8.1	4.8	59.4	1.54
G096-023	2800	3.7	1.2	5.5	1.8	8.2	8.4	20.7	17.0	82.0	0.23
G096-024	2900	596.4	120.1	129.6	56.5	44.4	33.8	947.2	350.7	37.0	1.27
G096-025	3000	671.4	274.8	229.9	87.1	74.6	68.6	1338.1	666.6	49.8	1.17
G096-026	3100	15256.5	6462.1	5836.3	836.4	2434.2	1980.8	30825.7	15569.2	50.5	0.34
G096-027	3200	253.3	100.5	183.8	60.4	97.6	1324.9	695.8	442.4	63.6	0.62

PPM values expressed as volumes of gas per million volumes of cuttings

*METERS

C1-C7 HYDROCARBON ANALYSES OF AIR SPACE

Sample Number	Well Interval*	Methane C1 PPM	Ethane C2 PPM	Propane C3 PPM	Isobutane iC4 PPM	Butane nC4 PPM	Total C5-C7 PPM	Total C1-C4 PPM	Total C2-C4 PPM	Gas Wetness %	iC4/nC4
G096-029	3300	16628.1	9627.7	17680.4	25726.6	10167.4	20348.7	79830.3	63202.2	79.2	2.53
G096-030	3400	25675.9	17996.7	31632.6	33165.6	11731.2	20510.2	120202.2	94526.3	78.6	2.83
G096-031	3500	58441.2	42881.3	44454.9	40866.0	10078.1	16379.5	196721.8	138280.5	70.3	4.05
G096-034	3800	49.8	29.8	55.7	107.3	49.9	638.1	292.6	242.8	83.0	2.15
G096-035	3900	32.1	31.1	57.8	111.9	40.4	440.5	273.4	241.2	88.2	2.77
G096-036	4000	2435.5	2319.7	3444.3	5139.9	1606.5	3074.3	14946.0	12510.5	83.7	3.20
G096-037	4100	392.2	135.4	191.4	348.2	107.7	511.3	1175.1	782.8	66.6	3.23
G096-038	4154	896386.9	9689.9	1183.4	1163.8	122.5	137.3	908546.7	12159.7	1.3	9.49
G096-039	4230	69088.0	7143.0	1687.9	1346.8	226.7	111.8	79492.7	10404.6	13.1	5.94
G096-040	4260	196958.6	24864.3	2940.5	2247.2	295.8	401.5	227306.6	30348.0	13.4	7.60
G096-041	4290	32316.5	19590.6	2895.7	2985.1	269.1	385.4	58057.2	25740.7	44.3	11.09
G096-042	4320	54141.4	3801.5	996.9	489.6	107.3	470.0	59536.9	5395.4	9.1	4.56
G096-043	4343.5	45237.0	4247.3	684.4	320.1	69.6	201.2	50558.4	5321.4	10.5	4.60

PPM values expressed as volumes of gas per million volumes of cuttings

C1-C7 HYDROCARBON ANALYSES OF CUTTINGS GAS

Sample Number	Well Interval*	Methane C1 PPM	Ethane C2 PPM	Propane C3 PPM	Isobutane iC4 PPM	Butane nC4 PPM	Total C5-C7 PPM	Total C1-C4 PPM	Total C2-C4 PPM	Gas Wetness %	iC4/nC4
G096-001	600	705.1	31.0	23.1	6.4	22.4	646.0	788.2	83.0	10.5	0.29
G096-002	700	223.4	26.0	24.2	5.7	18.9	82.7	298.4	75.0	25.1	0.31
G096-003	800	413.8	27.6	17.9	4.5	17.0	74.8	481.0	67.2	14.0	0.27
G096-004	900	274.5	9.6	14.1	4.1	15.2	81.2	317.7	43.1	13.6	0.27
G096-005	1000	140.1	8.2	8.1	1.6	4.8	24.8	163.1	22.9	14.1	0.34
G096-006	1100	252.0	31.0	14.9	2.2	7.9	49.5	308.2	56.2	18.2	0.29
G096-007	1200	168.8	40.4	24.1	5.1	17.9	64.7	256.4	87.6	34.2	0.29
G096-008	1300	419.3	40.0	21.7	4.5	15.9	54.7	501.5	82.1	16.4	0.28
G096-009	1400	430.5	19.3	12.8	3.1	18.3	44.1	484.2	53.6	11.1	0.17
G096-010	1500	354.8	14.3	9.0	3.9	10.3	37.5	392.6	37.7	9.6	0.38
G096-011	1600	137.7	5.8	5.0	2.3	4.6	33.7	155.5	17.8	11.5	0.52
G096-012	1700	128.4	12.7	8.2	4.8	10.0	101.4	164.4	35.9	21.9	0.48
G096-013	1800	93.1	3.9	3.5	3.4	5.2	60.6	109.3	16.2	14.8	0.66
G096-014	1900	94.8	10.2	10.5	8.0	9.1	74.1	132.7	37.9	28.6	0.87
G096-015	2000	110.0	13.9	11.5	7.8	15.3	84.3	158.7	48.7	30.7	0.51
G096-016	2100	75.5	7.6	6.7	4.1	6.5	74.1	100.5	25.0	24.9	0.63
G096-017	2200	63.9	4.3	3.7	2.0	4.2	34.6	78.3	14.4	18.4	0.50
G096-018	2300	147.4	10.8	9.5	7.4	16.4	79.4	191.6	44.2	23.1	0.45
G096-019	2400	87.3	7.5	17.5	26.6	33.1	93.6	172.1	84.8	49.3	0.80
G096-020	2500	131.3	31.3	96.6	67.7	72.8	89.8	399.9	268.5	67.1	0.93
G096-021	2600	340.2	82.2	90.4	38.4	55.9	84.0	607.2	267.0	44.0	0.69
G096-022	2700	249.4	71.0	108.1	39.0	59.5	126.8	527.2	277.7	52.7	0.66
G096-023	2800	119.7	27.0	102.5	58.0	77.5	72.3	385.0	265.2	68.9	0.75
G096-024	2900	431.2	138.1	201.9	92.5	114.8	174.5	978.7	547.4	55.9	0.81
G096-025	3000	485.3	232.7	401.3	180.8	209.2	273.5	1509.5	1024.1	67.8	0.86
G096-026	3100	10179.9	11379.8	20978.0	4274.4	13615.5	12272.0	60427.8	50247.8	83.2	0.31
G096-027	3200	161.0	34.5	90.1	53.6	87.0	157.7	426.4	265.4	62.2	0.62

PPM values expressed as volumes of gas per million volumes of cuttings

*METERS

C1-C7 HYDROCARBON ANALYSES OF CUTTINGS GAS

Sample Number	Well Interval*	Methane C1 PPM	Ethane C2 PPM	Propane C3 PPM	Isobutane iC4 PPM	Butane nC4 PPM	Total C5-C7 PPM	Total C1-C4 PPM	Total C2-C4 PPM	Gas Wetness %	iC4/nC4
G096-029	3300	686.1	540.7	3389.0	12377.2	6317.4	18537.5	23310.6	22624.4	97.1	1.96
G096-030	3400	1266.4	2358.0	1406.9	37655.5	15396.8	38350.8	58083.9	56817.4	97.8	2.45
G096-031	3500	1651.7	6257.3	19149.7	34741.4	11634.5	27121.3	73434.9	71783.1	97.8	2.99
G096-034	3800	525.8	404.8	3151.5	10001.9	3280.8	9409.3	17365.0	16839.2	97.0	3.05
G096-035	3900	399.5	787.4	2906.2	11341.2	2657.9	11393.4	18092.4	17692.8	97.8	4.27
G096-036	4000	1050.1	1300.3	6095.9	18736.3	6051.2	16314.4	33233.9	32183.8	96.8	3.10
G096-037	4100	1092.7	204.1	651.3	2473.6	720.2	2515.4	5142.2	4049.4	78.7	3.43
G096-038	4154	113001.1	35477.6	8490.1	7590.9	1274.4	3589.0	165834.4	52833.2	31.9	5.96
G096-039	4230	12140.1	4933.2	2514.1	3922.2	667.8	1390.2	24177.6	12037.4	49.8	5.87
G096-040	4260	53148.0	16213.8	4593.0	5978.3	823.9	2183.8	80757.1	27609.1	34.2	7.26
G096-041	4290	172547.9	80105.5	30882.7	13798.9	1549.4	2163.5	298884.7	126336.7	42.3	8.91
G096-042	4320	10086.0	4844.0	1865.8	2036.1	375.2	1011.0	19207.3	9121.3	47.5	5.43
G096-043	4343.5	13703.9	4928.9	1935.9	2287.7	414.8	1417.9	23271.4	9567.5	41.1	5.51

PPM values expressed as volumes of gas per million volumes of cuttings

C1-C7 HYDROCARBON ANALYSES OF AIR SPACE AND CUTTINGS GAS

Sample Number	Well Interval*	Methane C1 PPM	Ethane C2 PPM	Propane C3 PPM	Isobutane iC4 PPM	Butane nC4 PPM	Total C5-C7 PPM	Total C1-C4 PPM	Total C2-C4 PPM	Gas Wetness %	iC4/nC4
G096-001	600	1117.7	42.2	38.1	15.8	37.8	731.6	1251.8	134.1	10.7	0.42
G096-002	700	613.4	34.1	44.7	27.8	34.7	177.6	754.9	141.5	18.7	0.80
G096-003	800	1022.3	42.2	24.5	9.4	23.8	131.1	1122.5	100.1	8.9	0.40
G096-004	900	320.0	9.6	30.7	24.3	35.1	147.6	419.8	99.8	23.8	0.69
G096-005	1000	269.7	10.7	10.7	2.3	7.8	28.2	301.4	31.7	10.5	0.30
G096-006	1100	414.8	32.8	16.4	2.5	8.7	51.3	475.4	60.6	12.8	0.29
G096-007	1200	236.0	42.3	27.5	10.2	28.8	81.7	345.0	108.9	31.6	0.35
G096-008	1300	1858.8	43.1	24.4	5.5	19.2	63.6	1951.3	92.4	4.7	0.29
G096-009	1400	2327.8	25.0	15.7	3.7	20.6	50.1	2392.9	65.1	2.7	0.18
G096-010	1500	515.1	30.9	20.3	26.5	27.1	88.1	620.1	104.9	16.9	0.98
G096-011	1600	559.0	7.3	6.0	2.7	5.2	35.1	580.4	21.4	3.7	0.54
G096-012	1700	815.9	29.1	12.8	8.3	12.5	129.9	878.9	62.9	7.2	0.66
G096-013	1800	510.8	19.2	10.2	11.1	10.3	96.2	561.9	51.0	9.1	1.07
G096-014	1900	708.8	29.7	22.4	18.9	18.6	131.4	798.7	89.9	11.3	1.02
G096-015	2000	561.0	27.8	19.9	13.5	20.8	115.3	643.1	82.1	12.8	0.65
G096-016	2100	398.1	26.5	29.5	22.8	33.2	155.8	510.4	112.2	22.0	0.69
G096-017	2200	100.5	4.3	8.0	8.3	24.1	117.3	145.6	45.0	30.9	0.35
G096-018	2300	159.5	10.8	9.5	9.8	17.9	82.4	207.6	48.0	23.2	0.55
G096-019	2400	94.8	7.5	18.3	27.3	34.0	104.7	182.0	87.2	47.9	0.80
G096-020	2500	4341.4	405.8	417.5	198.4	164.5	165.1	5527.7	1186.3	21.5	1.21
G096-021	2600	2244.9	302.9	257.3	86.5	100.1	111.5	2991.9	747.0	25.0	0.86
G096-022	2700	252.7	71.9	109.8	40.4	60.4	128.8	535.3	282.6	52.8	0.67
G096-023	2800	123.5	28.3	108.1	59.9	85.8	80.8	405.8	282.3	69.6	0.70
G096-024	2900	1027.7	258.3	331.5	149.0	159.3	208.4	1926.0	898.2	46.6	0.94
G096-025	3000	1156.8	507.6	631.2	268.0	283.9	342.2	2847.6	1690.8	59.4	0.94
G096-026	3100	25436.4	17841.9	26814.3	5110.8	16049.8	14252.8	91253.5	65817.0	72.1	0.32
G096-027	3200	414.3	135.0	274.0	114.1	184.6	1482.7	1122.2	707.9	63.1	0.62

PPM values expressed as volumes of gas per million volumes of cuttings

*METERS

C1-C7 HYDROCARBON ANALYSES OF AIR SPACE AND CUTTINGS GAS

Sample Number	Well Interval*	Methane C1 PPM	Ethane C2 PPM	Propane C3 PPM	Isobutane iC4 PPM	Butane nC4 PPM	Total C5-C7 PPM	Total C1-C4 PPM	Total C2-C4 PPM	Gas Wetness %	iC4/nC4
G096-029	3300	17314.3	10168.4	21069.4	38103.8	16484.9	38886.2	103141.0	85826.6	83.2	2.31
G096-030	3400	26942.4	20354.7	33039.6	70821.2	27128.1	58861.1	178286.1	151343.7	84.9	2.61
G096-031	3500	60093.0	49138.7	63604.7	75607.5	21712.7	43500.9	270156.8	210063.7	77.8	3.48
G096-034	3800	575.6	434.6	3207.3	10109.3	3330.8	10047.4	17657.7	17082.0	96.7	3.04
G096-035	3900	431.6	818.5	2964.0	11453.1	2698.3	11834.0	18365.8	17934.1	97.6	4.24
G096-036	4000	3485.6	3620.0	9540.3	23876.2	7657.7	19388.7	48179.9	44694.3	92.8	3.12
G096-037	4100	1485.0	339.6	842.7	2821.9	827.9	3026.7	6317.3	4832.3	76.5	3.41
G096-038	4154	1009388.1	45167.5	9673.6	8754.8	1397.0	3726.4	1074381.1	64993.0	6.0	6.27
G096-039	4230	81228.1	12076.2	4202.1	5269.1	894.6	1502.1	103670.3	22442.1	21.6	5.89
G096-040	4260	250106.7	41078.1	7533.6	8225.5	1119.8	2585.3	308063.8	57957.1	18.8	7.35
G096-041	4290	204864.4	99696.2	33778.4	16784.1	1818.6	2548.9	356941.9	152077.4	42.6	9.23
G096-042	4320	64227.5	8645.6	2862.8	2525.8	482.5	1481.1	78744.3	14516.8	18.4	5.23
G096-043	4343.5	58940.9	9176.2	2620.3	2607.8	484.4	1619.1	73829.8	14888.9	20.2	5.38

PPM values expressed as volumes of gas per million volumes of cuttings

Notes on quality - canned cuttings

Samples 029 through 036, and 041 arrived with no water in with the cuttings.

Sample 034 had a loose lid.

APPENDIX VI.

RESULTS OF C_{15+} EXTRACTION AND LIQUID CHROMATOGRAPHY

Summary of C15+ Soxhlet Extraction, Deasphaltening and Liquid Chromatography

A. Weights of Extracts and Chromatographic Fractions

Sample Number	Well Interval*	Weight of Rock Extd. (grams)	Total Extract (grams)	Precipitated Asphaltenes (grams)	N-C5 Soluble (grams)	Sulfur (grams)	Paraffins-Naphthenes (grams)	Aromatics (grams)	Eluted NSO'S (grams)	Noneluted NSO'S (grams)
G096-001	600	58.6	0.0516	0.0129	0.0387	0.0128	0.0157	0.0059	0.0029	0.0014
G096-002	700	17.6	0.0134	0.0090	0.0044	N.D.	N.D.	N.D.	N.D.	N.D.
G096-003	800	64.6	0.0191	0.0098	0.0093	N.D.	N.D.	N.D.	N.D.	N.D.
G096-004	900	95.7	0.0202	0.0094	0.0108	N.D.	0.0034	0.0024	0.0017	0.0033
G096-005	1000	91.6	0.0330	0.0246	0.0084	N.D.	N.D.	N.D.	N.D.	N.D.
G096-006	1100	91.3	0.0805	0.0486	0.0319	0.0004	0.0005	0.0054	0.0194	0.0062
G096-007	1200	94.7	0.0474	0.0262	0.0212	N.D.	0.0008	0.0032	0.0141	0.0031
G096-008	1300	91.7	0.0454	0.0297	0.0157	0.0004	0.0007	0.0026	0.0077	0.0043
G096-009	1400	92.5	0.0322	0.0223	0.0099	N.D.	N.D.	N.D.	N.D.	N.D.
G096-010	1500	100.0	0.0168	0.0098	0.0070	N.D.	N.D.	N.D.	N.D.	N.D.
G096-011	1600	100.0	0.0237	0.0150	0.0087	N.D.	N.D.	N.D.	N.D.	N.D.
G096-012	1700	96.6	0.0191	0.0123	0.0068	N.D.	N.D.	N.D.	N.D.	N.D.
G096-013	1800	95.3	0.0140	0.0091	0.0049	N.D.	N.D.	N.D.	N.D.	N.D.
G096-014	1900	96.6	0.0184	0.0135	0.0049	N.D.	N.D.	N.D.	N.D.	N.D.
G096-015	2000	95.5	0.0234	0.0171	0.0063	N.D.	N.D.	N.D.	N.D.	N.D.
G096-016	2100	96.6	0.0162	0.0115	0.0047	N.D.	N.D.	N.D.	N.D.	N.D.
G096-017	2200	97.7	0.0276	0.0167	0.0109	0.0009	0.0029	0.0023	0.0033	0.0015
G096-018	2300	96.6	0.0220	0.0134	0.0086	N.D.	N.D.	N.D.	N.D.	N.D.
G096-019	2400	100.0	0.0344	0.0227	0.0117	0.0030	0.0012	0.0021	0.0042	0.0012
G096-020	2500	95.8	0.0464	0.0338	0.0126	0.0004	0.0029	0.0041	0.0039	0.0013
G096-021	2600	94.2	0.0152	0.0093	0.0059	N.D.	N.D.	N.D.	N.D.	N.D.
G096-022	2700	92.3	0.0234	0.0138	0.0096	N.D.	N.D.	N.D.	N.D.	N.D.
G096-023	2800	96.0	0.0503	0.0304	0.0199	0.0056	0.0018	0.0023	0.0068	0.0034
G096-024	2900	90.0	0.0402	0.0254	0.0148	0.0003	0.0024	0.0029	0.0068	0.0024
G096-025	3000	93.3	0.1661	0.0865	0.0796	0.0033	0.0054	0.0274	0.0365	0.0070
G096-026	3100	98.9	0.6673	0.1790	0.4883	0.0340	0.1161	0.2021	0.1281	0.0080
G096-027	3200	98.6	0.0803	0.0409	0.0394	0.0022	0.0020	0.0130	0.0179	0.0043
G096-028		8.0	3.1440	2.5635	0.5805	0.0165	0.0425	0.3587	0.1581	0.0047

*METERS

B. Concentration of Extracted Materials in Rock

Sample Number	Well Interval*	Total Extract (ppm)	Hydrocarbons: Paraffin-Naphthene (ppm)	Hydrocarbons: Aromatic (ppm)	Hydrocarbons: Total (ppm)	Hydrocarbons: Sulfur (ppm)	Nonhydrocarbons: Precipitd. Asphaltene (ppm)	Nonhydrocarbons: Eluted NSO'S (ppm)	Nonhydrocarbons: Noneluted NSO'S (ppm)	Nonhydrocarbons: Total (ppm)
G096-001	600	881	268	101	369	218	220	49	24	512
G096-002	700	761	-	-	-	-	511	-	-	-
G096-003	800	296	-	-	-	-	152	-	-	-
G096-004	900	211	36	25	61	-	98	18	34	150
G096-005	1000	360	-	-	-	-	269	-	-	-
G096-006	1100	882	5	59	65	4	532	212	68	817
G096-007	1200	501	8	34	42	-	277	149	33	458
G096-008	1300	495	8	28	36	4	324	84	47	459
G096-009	1400	348	-	-	-	-	241	-	-	-
G096-010	1500	168	-	-	-	-	98	-	-	-
G096-011	1600	237	-	-	-	-	150	-	-	-
G096-012	1700	198	-	-	-	-	127	-	-	-
G096-013	1800	147	-	-	-	-	95	-	-	-
G096-014	1900	190	-	-	-	-	140	-	-	-
G096-015	2000	245	-	-	-	-	179	-	-	-
G096-016	2100	168	-	-	-	-	119	-	-	-
G096-017	2200	282	30	24	53	9	171	34	15	229
G096-018	2300	228	-	-	-	-	139	-	-	-
G096-019	2400	344	12	21	33	30	227	42	12	311
G096-020	2500	484	30	43	73	4	353	41	14	411
G096-021	2600	161	-	-	-	-	99	-	-	-
G096-022	2700	254	-	-	-	-	150	-	-	-
G096-023	2800	524	19	24	43	58	317	71	35	481
G096-024	2900	447	27	32	59	3	282	76	27	388
G096-025	3000	1780	58	294	352	35	927	391	75	1429
G096-026	3100	6747	1174	2043	3217	344	1810	1295	81	3530
G096-027	3200	814	20	132	152	22	415	182	44	662
G096-028		392997	5313	44838	50150	2063	320437	19763	588	342848

*METERS

C. Composition of Extracts

Sample Number	Well Interval*	Hydrocarbons: Paraffin-Naphthene %	Hydrocarbons: Aromatic %	Hydrocarbons: PN/Arom	Hydrocarbons: Sulfur %	Nonhydrocarbons: Eluted NSO'S %	Nonhydrocarbons: Noneluted NSO'S %	Nonhydrocarbons: Precipitd. Asphaltene %	Nonhydrocarbons: Asph/NSO	HC'S %	HC/Non HC
G096-001	600	30.4	11.4	2.66	24.8	5.6	2.7	25.0	3.00	41.9	0.72
G096-002	700	-	-	-	-	-	-	67.2	-	-	-
G096-003	800	-	-	-	-	-	-	51.3	-	-	-
G096-004	900	17.	11.8	1.45	-	8.5	16.1	46.5	1.89	28.9	0.41
G096-005	1000	-	-	-	-	-	-	74.5	-	-	-
G096-006	1100	0.6	6.7	0.09	0.5	24.1	7.7	60.4	1.90	7.3	0.08
G096-007	1200	1.7	6.8	0.25	-	29.7	6.5	55.3	1.52	8.4	0.09
G096-008	1300	1.5	5.7	0.27	0.9	17.0	9.5	65.4	2.48	7.3	0.08
G096-009	1400	-	-	-	-	-	-	69.3	-	-	-
G096-010	1500	-	-	-	-	-	-	58.3	-	-	-
G096-011	1600	-	-	-	-	-	-	63.3	-	-	-
G096-012	1700	-	-	-	-	-	-	64.4	-	-	-
G096-013	1800	-	-	-	-	-	-	65.0	-	-	-
G096-014	1900	-	-	-	-	-	-	73.4	-	-	-
G096-015	2000	-	-	-	-	-	-	73.1	-	-	-
G096-016	2100	-	-	-	-	-	-	71.0	-	-	-
G096-017	2200	10.5	8.3	1.26	3.3	12.0	5.4	60.5	3.48	18.8	0.23
G096-018	2300	-	-	-	-	-	-	60.9	-	-	-
G096-019	2400	3.5	6.1	0.57	8.7	12.2	3.5	66.0	4.20	9.6	0.11
G096-020	2500	6.3	8.8	0.71	0.9	8.4	2.8	72.8	6.50	15.1	0.18
G096-021	2600	-	-	-	-	-	-	61.2	-	-	-
G096-022	2700	-	-	-	-	-	-	59.0	-	-	-
G096-023	2800	3.6	4.6	0.78	11.1	13.5	6.8	60.4	2.98	8.2	0.09
G096-024	2900	6.0	7.2	0.83	0.7	16.9	6.0	63.2	2.76	13.2	0.15
G096-025	3000	3.3	16.5	0.20	2.0	22.0	4.2	52.1	1.99	19.7	0.25
G096-026	3100	17.4	30.3	0.57	5.1	19.2	1.2	26.8	1.32	47.7	0.91
G096-027	3200	2.5	16.2	0.15	2.7	22.3	5.4	50.9	1.84	18.7	0.23
G096-028		1.4	11.4	0.12	0.5	5.0	0.1	81.5	15.75	12.8	0.15

*METERS

Summary of C15+ Soxhlet Extraction, Deasphaltening and Liquid Chromatography

A. Weights of Extracts and Chromatographic Fractions

Sample Number	Well Interval	Weight of Rock Extd. (grams)	Total Extract (grams)	Precipitated Asphaltenes (grams)	N-C5 Soluble (grams)	Sulfur (grams)	Paraffins-Naphthenes (grams)	Aromatics (grams)	Eluted NSO'S (grams)	Noneluted NSO'S (grams)
G096-029	3300	96.0	0.3976	0.0882	0.3094	N.D.	0.0834	0.0642	0.1168	0.0450
G096-030	3400	100.0	0.5210	0.0902	0.4308	N.D.	0.1453	0.1098	0.1199	0.0558
G096-031	3500	99.0	0.5336	0.1247	0.4088	N.D.	0.1464	0.0824	0.1236	0.0564
G096-034	3800	83.8	0.8452	0.1040	0.7412	N.D.	0.1145	0.2480	0.2207	0.1580
G096-035	3900	100.0	0.3441	0.0797	0.2644	N.D.	0.1216	0.0704	0.0332	0.0392
G096-036	4000	99.7	0.5090	0.0907	0.4183	N.D.	0.2058	0.0937	0.0552	0.0636
G096-037	4100	100.0	0.3738	0.1349	0.2389	N.D.	0.1316	0.0554	0.0219	0.0300
G096-038	4154	98.4	1.1145	0.6490	0.4655	N.D.	0.0711	0.2457	0.0776	0.0711
G096-039	4230	100.0	0.2509	0.1317	0.1192	N.D.	0.0511	0.0390	0.0170	0.0121
G096-040	4260	100.0	0.4694	0.2673	0.2012	N.D.	0.0518	0.1046	0.0351	0.0097
G096-041	4290	100.0	1.1497	0.7859	0.3638	N.D.	0.0618	0.2065	0.0590	0.0365
G096-042	4320	100.0	0.2115	0.1345	0.0570	N.D.	0.0152	0.0211	0.0180	0.0027
G096-043	4343.5	100.0	0.2185	0.1688	0.0497	N.D.	0.0105	0.0199	0.0172	0.0021

B. Concentration of Extracted Materials in Rock

Sample Number	Well Interval	Total Extract (ppm)	Hydrocarbons: Paraffin-Naphthene (ppm)	Hydrocarbons: Aromatic (ppm)	Hydrocarbons: Total (ppm)	Sulfur (ppm)	Nonhydrocarbons: Precipitd. Asphaltene (ppm)	Nonhydrocarbons: Eluted NSO'S (ppm)	Nonhydrocarbons: Noneluted NSO'S (ppm)	Nonhydrocarbons: Total (ppm)
G096-029	3300	4142	869	669	1538	-	919	1217	469	2604
G096-030	3400	5210	1453	1098	2551	-	902	1199	558	2659
G096-031	3500	5390	1479	832	2311	-	1260	1248	570	3079
G096-034	3800	10086	1366	2959	4326	-	1241	2634	1885	5760
G096-035	3900	3441	1216	704	1920	-	797	332	392	1521
G096-036	4000	5105	2064	940	3004	-	910	554	638	2101
G096-037	4100	3738	1316	554	1870	-	1349	219	300	1868
G096-038	4154	11326	723	2497	3220	-	6596	789	723	8107
G096-039	4230	2509	511	390	901	-	1317	170	121	1608
G096-040	4260	4694	518	1046	1564	-	2673	351	97	3130
G096-041	4290	11497	618	2065	2683	-	7859	590	365	8814
G096-042	4320	2115	152	211	363	-	1345	180	27	1752
G096-043	4343.5	2185	105	199	304	-	1688	172	21	1881

C. Composition of Extracts

Sample Number	Well Interval	Hydrocarbons: Paraffin-Naphthene %	Hydrocarbons: Aromatic %	Hydrocarbons: PN/Arom	Hydrocarbons: Sulfur %	Nonhydrocarbons: Eluted NSO'S %	Nonhydrocarbons: Noneluted NSO'S %	Nonhydrocarbons: Precipitd. Asphaltene %	Nonhydrocarbons: Asph/NSO	HC'S %	HC/Non HC
G096-029	3300	21.0	16.1	1.30	-	29.4	11.3	22.2	0.55	37.1	0.59
G096-030	3400	27.9	21.1	1.32	-	23.0	10.7	17.3	0.51	49.0	0.96
G096-031	3500	27.4	15.4	1.78	-	23.2	10.6	23.4	0.69	42.9	0.75
G096-034	3800	13.5	29.3	0.46	-	26.1	18.7	12.3	0.27	42.9	0.75
G096-035	3900	35.3	20.5	1.73	-	9.6	11.4	23.2	1.10	55.8	1.26
G096-036	4000	40.4	18.4	2.20	-	10.8	12.5	17.8	0.76	58.8	1.43
G096-037	4100	35.2	14.8	2.38	-	5.9	8.0	36.1	2.60	50.0	1.00
G096-038	4154	6.4	22.0	0.29	-	7.0	6.4	58.2	4.36	28.4	0.40
G096-039	4230	20.4	15.5	1.31	-	6.8	4.8	52.5	4.53	35.9	0.56
G096-040	4260	11.0	22.3	0.50	-	7.5	2.1	56.9	5.97	33.3	0.50
G096-041	4290	5.4	18.0	0.30	-	5.1	3.2	68.4	8.23	23.3	0.30
G096-042	4320	7.2	10.0	0.72	-	8.5	1.3	63.6	6.50	17.2	0.21
G096-043	4343.5	4.8	9.1	0.53	-	7.9	1.0	77.3	8.75	13.9	0.16

APPENDIX VII.

CHROMATOGRAPHIC DATA, C_{15+} SATURATE HYDROCARBONS

NORMAL PARAFFIN DISTRIBUTIONS - JOB G096

Component	001	002	003	004	005	006	007	008	009	010
C 15	-	-	0.4	-	-	-	-	-	-	-
C 16	0.6	1.6	1.2	1.0	1.0	0.2	-	1.7	0.3	-
C 17	4.2	4.4	5.0	2.4	1.4	1.1	1.5	3.1	3.9	2.6
ip 19	2.9	2.8	2.8	1.5	1.0	0.9	1.2	1.5	2.0	2.1
C 18	9.9	9.1	8.9	5.3	4.9	2.5	2.9	5.2	8.1	6.1
ip 20	6.5	0.9	1.5	3.9	2.7	1.2	2.0	2.6	2.7	3.4
C 19	13.3	13.4	11.7	6.3	6.2	3.3	4.0	5.2	7.8	7.1
C 20	14.2	16.4	12.8	7.9	7.8	4.5	5.6	5.7	7.6	8.7
C 21	12.2	16.7	13.7	7.6	8.8	7.2	7.6	9.1	7.4	11.8
C 22	10.7	11.4	9.7	7.7	9.9	8.0	8.8	8.7	7.1	16.1
C 23	7.3	5.5	4.2	6.7	9.6	11.7	8.6	11.7	6.2	13.7
C 24	3.9	2.6	2.9	5.0	4.9	6.3	5.3	5.2	4.1	8.1
C 25	1.8	1.1	1.5	4.2	5.3	9.4	7.1	7.8	3.6	4.2
C 26	0.6	0.7	2.5	3.3	3.7	5.7	3.7	3.3	1.4	1.4
C 27	0.3	0.6	1.2	3.7	6.0	9.9	6.5	8.3	6.3	1.1
C 28	-	0.6	2.1	3.6	1.3	1.9	3.1	2.7	0.8	0.5
C 29	-	0.4	1.7	4.5	7.2	10.1	6.5	6.8	9.0	1.7
C 30	-	-	2.3	3.1	2.0	1.7	2.2	1.1	2.3	0.9
C 31	-	-	-	3.2	5.2	9.0	5.0	3.3	5.5	1.8
C 32	-	-	-	1.8	0.2	0.4	0.5	-	0.3	0.1
C 33	-	-	-	1.5	2.3	2.7	2.4	-	1.8	0.3
C 34	-	-	-	0.9	-	-	0.05	-	-	-
C 35	-	-	-	0.8	-	-	0.7	-	-	-

NORMAL PARAFFIN DISTRIBUTIONS - JOB G096

Component	011	012	013	014	015	016	017	018	019	020
C 15	-	-	-	-	-	-	-	-	-	1.3
C 16	0.1	-	0.2	-	-	-	0.5	0.7	0.7	4.6
C 17	1.4	0.9	1.3	1.2	2.6	3.8	4.0	5.6	4.8	13.0
ip 19	1.1	0.6	1.9	1.1	3.7	2.3	3.1	1.9	4.8	11.03
C 18	4.8	4.9	5.4	4.1	8.2	8.7	8.7	7.6	9.9	19.9
ip 20	2.3	3.5	3.3	2.4	5.4	4.4	4.3	3.3	4.5	6.8
C 19	6.4	7.3	8.1	7.1	11.2	9.8	10.9	8.8	9.7	21.0
C 20	7.7	8.5	9.5	9.8	12.2	9.2	11.4	9.6	9.0	15.8
C 21	8.8	10.4	10.1	12.3	11.9	9.1	10.3	10.5	9.2	7.8
C 22	8.1	10.1	9.7	14.0	9.7	7.6	8.7	10.2	8.3	5.1
C 23	8.0	9.2	8.7	11.4	6.9	6.8	6.9	8.3	7.6	2.1
C 24	3.8	6.0	4.4	6.5	3.6	3.7	3.3	4.7	4.7	0.4
C 25	5.3	4.9	5.1	4.4	3.4	4.7	4.0	4.0	4.5	0.2
C 26	2.9	2.9	2.9	2.6	1.4	2.0	3.1	3.4	2.9	0.01
C 27	5.4	4.4	5.1	3.3	3.1	5.0	4.7	7.8	5.5	0.01
C 28	2.7	1.4	2.5	1.3	0.9	2.0	2.2	0.9	0.7	-
C 29	7.6	6.7	6.7	4.2	3.4	7.1	2.7	2.3	4.2	-
C 30	3.8	0.7	1.6	1.5	1.1	1.2	0.5	0.9	1.3	-
C 31	8.3	3.2	3.9	2.2	1.8	2.0	0.9	-	-	-
C 32	0.5	-	0.4	-	-	-	1.1	-	-	-
C 33	2.2	-	1.3	-	-	-	-	-	-	-
C 34	-	-	-	-	-	-	-	-	-	-
C 35	-	-	-	-	-	-	-	-	-	-

NORMAL PARAFFIN DISTRIBUTIONS - JOB G096

Component	021	022	023	024	025	026	027	028	029	030
C 15	-	-	-	-	-	7.3	-	2.8	3.8	5.2
C 16	-	2.9	0.8	1.8	0.7	10.4	2.1	7.7	5.8	6.5
C 17	3.0	13.1	4.1	8.2	4.9	13.1	7.0	6.6	7.2	9.9
ip 19	2.2	8.5	4.4	7.3	5.0	18.9	5.5	4.5	8.0	8.2
C 18	17.2	25.5	7.1	14.0	12.9	11.5	10.1	6.6	6.6	8.8
ip 20	7.0	9.7	3.5	5.8	5.6	13.5	5.8	3.1	2.8	3.2
C 19	26.2	18.3	8.8	15.7	16.1	10.0	9.7	6.6	6.2	7.7
C 20	17.7	8.5	9.6	13.5	13.9	8.9	10.9	6.3	5.3	6.7
C 21	8.8	5.1	9.9	9.5	10.4	7.1	10.4	7.0	4.8	4.0
C 22	6.0	1.5	9.6	6.8	7.8	6.3	9.6	7.7	4.8	4.1
C 23	2.5	0.5	7.6	4.2	5.5	5.5	7.0	6.6	4.5	3.7
C 24	0.8	-	4.3	2.1	2.9	4.3	3.9	7.3	3.6	3.2
C 25	-	-	2.7	1.3	2.7	3.3	2.4	5.6	3.5	2.8
C 26	-	-	1.3	0.7	1.4	2.8	1.6	1.4	2.5	2.4
C 27	-	-	1.1	0.4	1.8	2.9	1.3	1.7	3.4	2.6
C 28	-	-	0.7	-	0.5	2.8	0.3	2.8	2.3	1.9
C 29	-	-	0.6	-	0.5	1.2	1.3	1.0	3.0	2.2
C 30	-	-	-	-	-	0.9	0.3	1.7	1.9	1.5
C 31	-	-	-	-	-	0.8	0.2	2.4	2.5	1.4
C 32	-	-	-	-	-	0.2	-	2.1	0.6	0.6
C 33	-	-	-	-	-	0.1	-	1.7	0.3	0.3
C 34	-	-	-	-	-	-	-	2.1	0.4	0.2
C 35	-	-	-	-	-	-	-	-	0.5	-

NORMAL PARAFFIN DISTRIBUTIONS - JOB G096

Component	031	034	035	036	037	038	039	040	041	042	043
C 15	5.9	6.2	8.6	8.6	8.0	5.8	5.3	6.3	-	2.3	1.5
C 16	6.9	8.3	9.3	8.8	8.7	7.9	8.1	8.4	8.4	6.2	4.5
C 17	7.2	9.1	9.3	8.6	9.1	8.3	9.3	8.9	10.2	10.0	8.1
ip 19	6.3	6.1	6.4	4.6	5.3	3.3	5.3	4.4	4.8	4.4	3.4
C 18	6.6	9.3	9.3	8.7	9.1	8.3	9.4	8.9	10.7	11.5	10.4
ip 20	2.3	3.9	4.2	4.0	4.7	1.7	4.8	3.1	2.6	4.3	3.2
C 19	6.1	7.9	8.1	7.9	8.7	8.0	9.3	8.4	10.0	11.3	10.6
C 20	5.3	7.1	6.9	6.8	7.6	7.5	8.2	7.4	8.7	9.6	9.7
C 21	5.1	5.5	5.2	5.2	5.6	7.1	6.2	6.4	7.3	7.1	8.0
C 22	4.9	4.9	4.4	4.1	4.3	7.0	4.8	5.6	6.5	5.6	7.3
C 23	4.5	3.7	3.3	3.2	2.9	5.3	3.5	4.9	4.8	4.1	5.8
C 24	3.9	2.9	2.4	2.2	2.0	4.8	2.3	4.0	3.6	4.0	4.3
C 25	3.4	2.4	1.8	1.7	1.4	3.8	1.7	3.3	2.6	3.2	3.4
C 26	2.9	1.8	1.5	1.1	1.0	2.9	1.1	2.5	1.9	2.1	3.4
C 27	2.8	1.4	1.1	0.9	0.7	2.0	0.7	1.9	1.3	1.6	3.0
C 28	2.3	1.0	0.8	0.5	0.4	1.7	0.5	1.3	1.3	0.8	1.6
C 29	2.3	0.8	0.7	0.4	0.3	1.3	0.3	1.1	1.5	0.8	1.8
C 30	1.7	0.8	0.5	0.2	0.2	1.1	0.2	0.7	0.8	0.3	0.9
C 31	1.4	0.6	0.5	0.1	0.04	0.6	0.1	0.5	0.5	0.3	0.8
C 32	0.6	0.1	0.5	-	-	0.3	-	0.2	0.3	0.2	0.2
C 33	0.4	0.7	-	-	-	-	-	-	-	-	0.05
C 34	1.7	-	-	-	-	-	-	-	-	-	-
C 35	1.6	-	-	-	-	-	-	-	-	-	-

SATURATE HYDROCARBONS - JOB G096

	001	002	003	004	005	006	007	008
CPI-A	-	-	0.96	1.03	1.32	1.65	1.35	1.72
CPI-B	-	-	0.54	1.19	2.65	3.20	2.20	2.08
Pris/Phy Ratio	0.4	3.0	1.93	0.4	0.38	0.74	0.61	0.60
% Normal Paraffins	22.4	16.5	14.1	21.1	22.8	33.5	39.0	15.8
% Isoprenoids	2.7	0.7	0.7	1.4	0.98	0.7	1.6	0.7
% Naphthenes	71.7	80.3	86.7	73.9	73.6	64.9	52.4	81.9
% Branched-Chain	3.2	2.4	2.4	3.6	2.6	0.8	7.0	1.5

SATURATE HYDROCARBONS - JOB G096

	009	010	011	012	013	014	015	016
CPI-A	1.46	1.04	1.40	1.23	1.29	1.12	1.29	1.40
CPI-B	3.97	1.97	2.37	2.79	2.33	1.91	2.55	2.86
Pris/Phy Ratio	0.77	0.63	0.5	0.19	0.58	0.45	0.67	0.53
% Normal Paraffins	17.6	13.9	27.1	16.0	18.4	23.1	16.5	20.8
% Isoprenoids	0.98	0.9	1.1	0.8	1.1	0.9	1.8	1.7
% Naphthenes	78.9	83.8	69.0	80.4	28.7	23.1	79.7	74.9
% Branched-Chain	2.5	1.4	2.7	2.8	1.7	2.9	1.9	2.6

SATURATE HYDROCARBONS - JOB G096

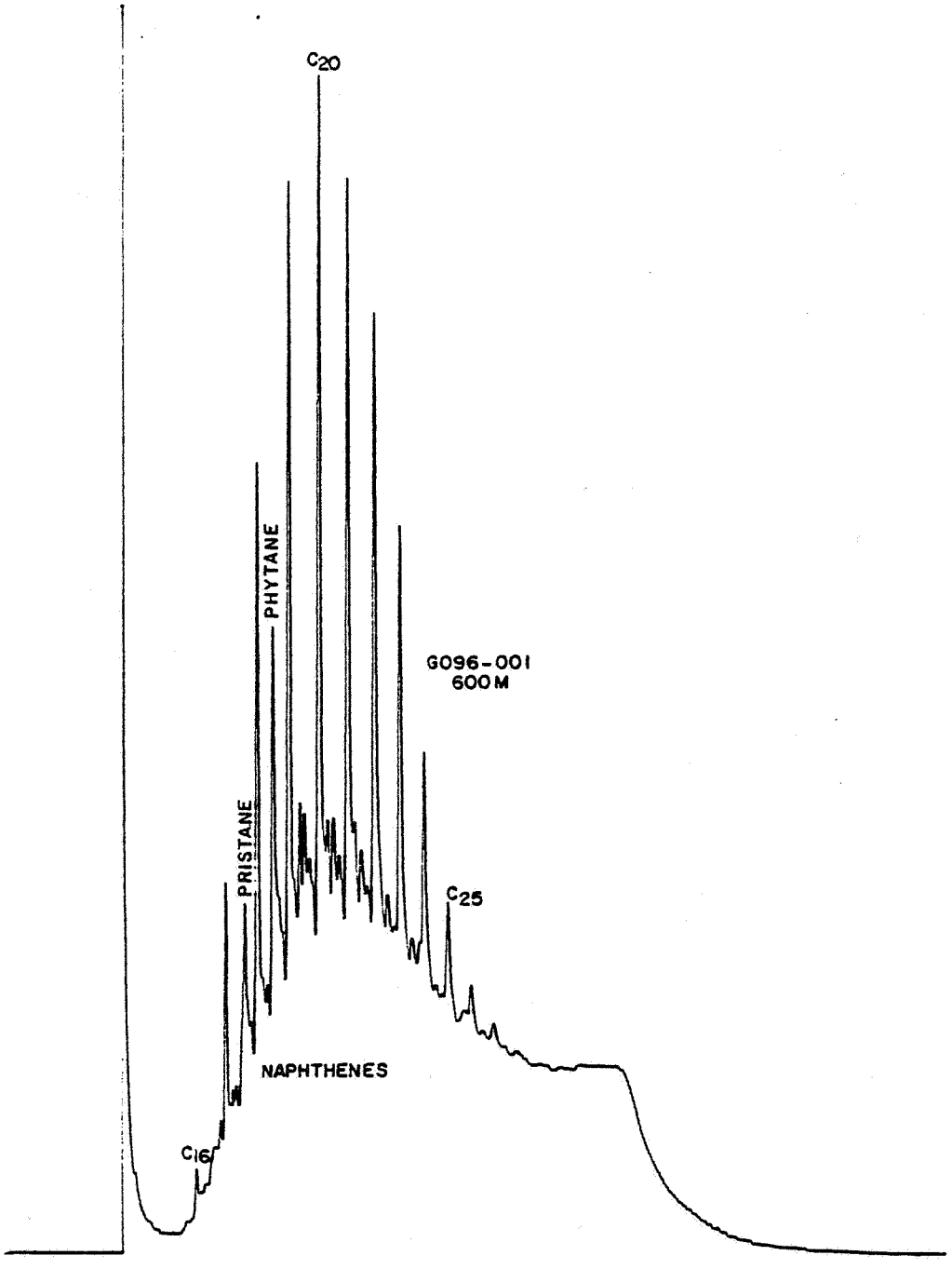
	017	018	019	020	021	022	023	024
CPI-A	1.24	1.3	1.35	1.16	-	-	1.09	1.13
CPI-B	1.58	0.0	2.18	10.76	-	-	1.45	1.51
Pris/Phy Ratio	0.7	0.6	1.1	1.6	0.3	0.9	1.3	1.3
% Normal Paraffins	9.4	19.4	17.6	30.4	28.1	31.7	2.2	29.0
% Isoprenoids	0.8	1.2	2.0	7.7	3.1	7.6	1.8	4.9
% Naphthenes	88.7	77.2	78.7	57.1	65.9	58.1	77.1	62.7
% Branched-Chain	1.0	2.2	1.7	4.8	2.9	2.5	1.9	3.4

SATURATE HYDROCARBONS - JOB G096

	025	026	027	028	029	030	031	034
CPI-A	1.22	1.0	1.1	1.00	1.12	0.97	1.03	1.00
CPI-B	1.91	0.9	1.6	1.08	1.45	1.21	1.14	1.08
Pris/Phy Ratio	0.9	1.4	0.9	1.4	2.86	2.6	2.74	1.55
% Normal Paraffins	23.0	26.4	2.0	0.6	16.4	26.6	25.3	34.4
% Isoprenoids	3.0	8.6	1.9	0.3	2.4	4.0	2.8	4.6
% Naphthenes	71.9	59.3	13.8	7.0	77.7	65.0	67.4	53.7
% Branched-Chain	2.1	5.8	82.3	92.0	3.4	4.4	4.5	7.2

SATURATE HYDROCARBONS - JOB G096

	035	036	037	038	039	040	041	042	043
CPI-A	1.01	1.07	1.05	0.97	1.06	1.03	0.98	1.01	1.02
CPI-B	1.05	1.22	1.11	1.7	1.15	1.11	1.05	1.29	1.18
Pris/Phy Ratio	1.53	1.13	1.13	1.92	1.09	1.43	1.85	1.01	1.08
% Normal Paraffins	34.2	35.2	36.0	47.0	17.5	21.7	46.9	41.2	39.9
% Isoprenoids	4.9	4.4	5.1	2.8	2.5	2.0	4.0	4.4	3.08
% Naphthenes	53.9	49.1	48.6	43.9	75.4	73.0	44.8	49.2	53.2
% Branched-Chain	7.1	11.4	10.3	6.4	4.5	3.3	4.2	5.2	3.8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C25
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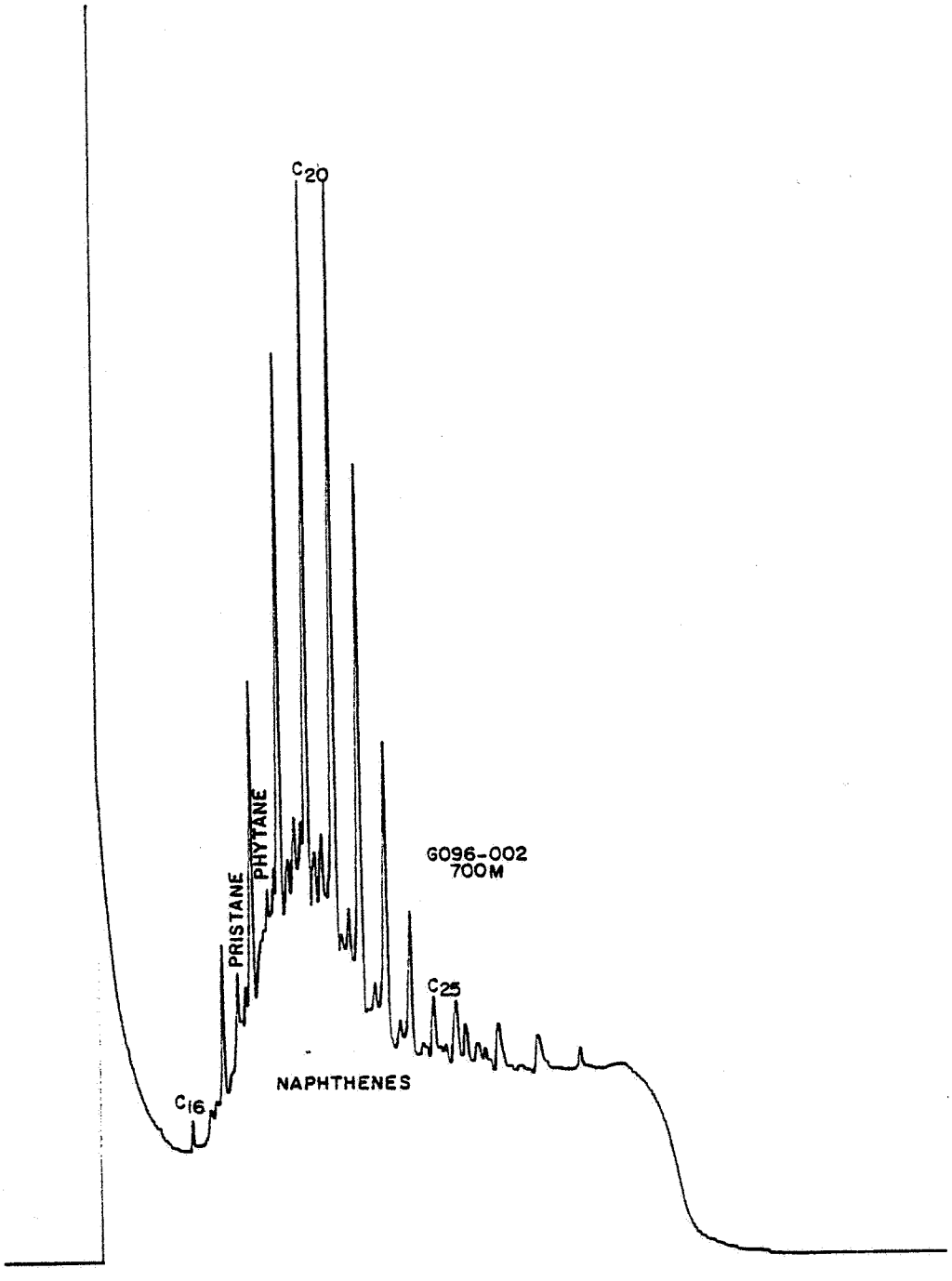
C16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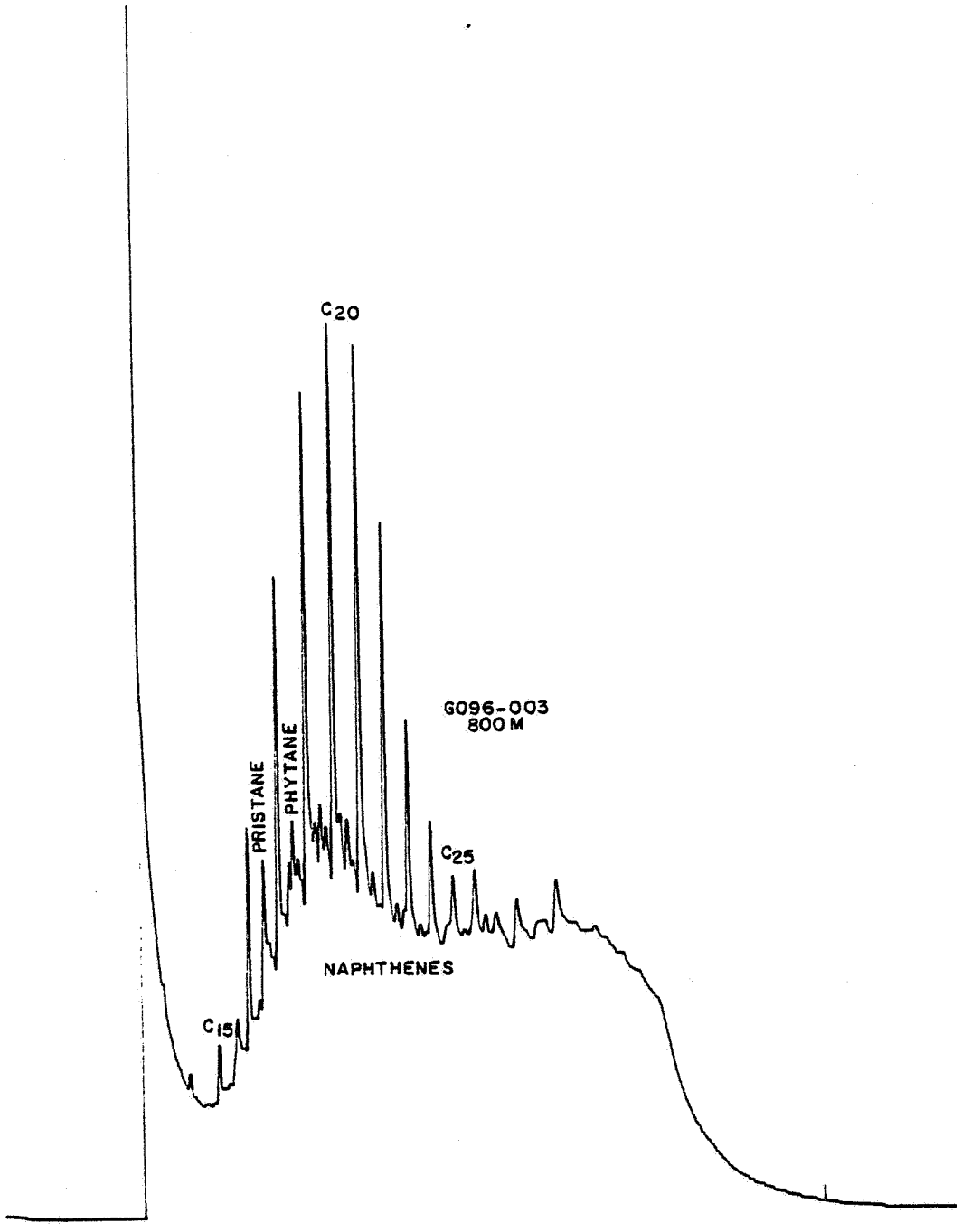
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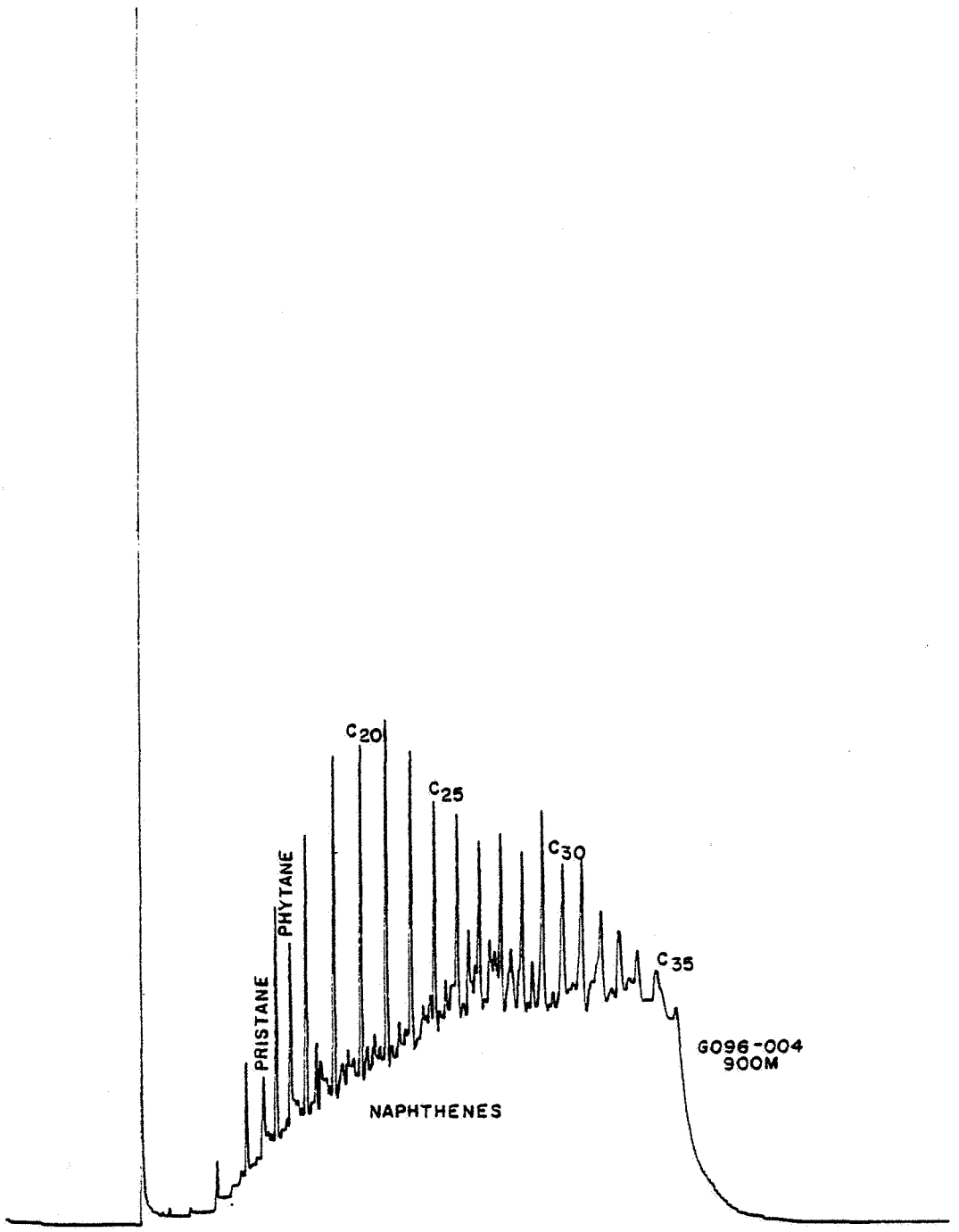
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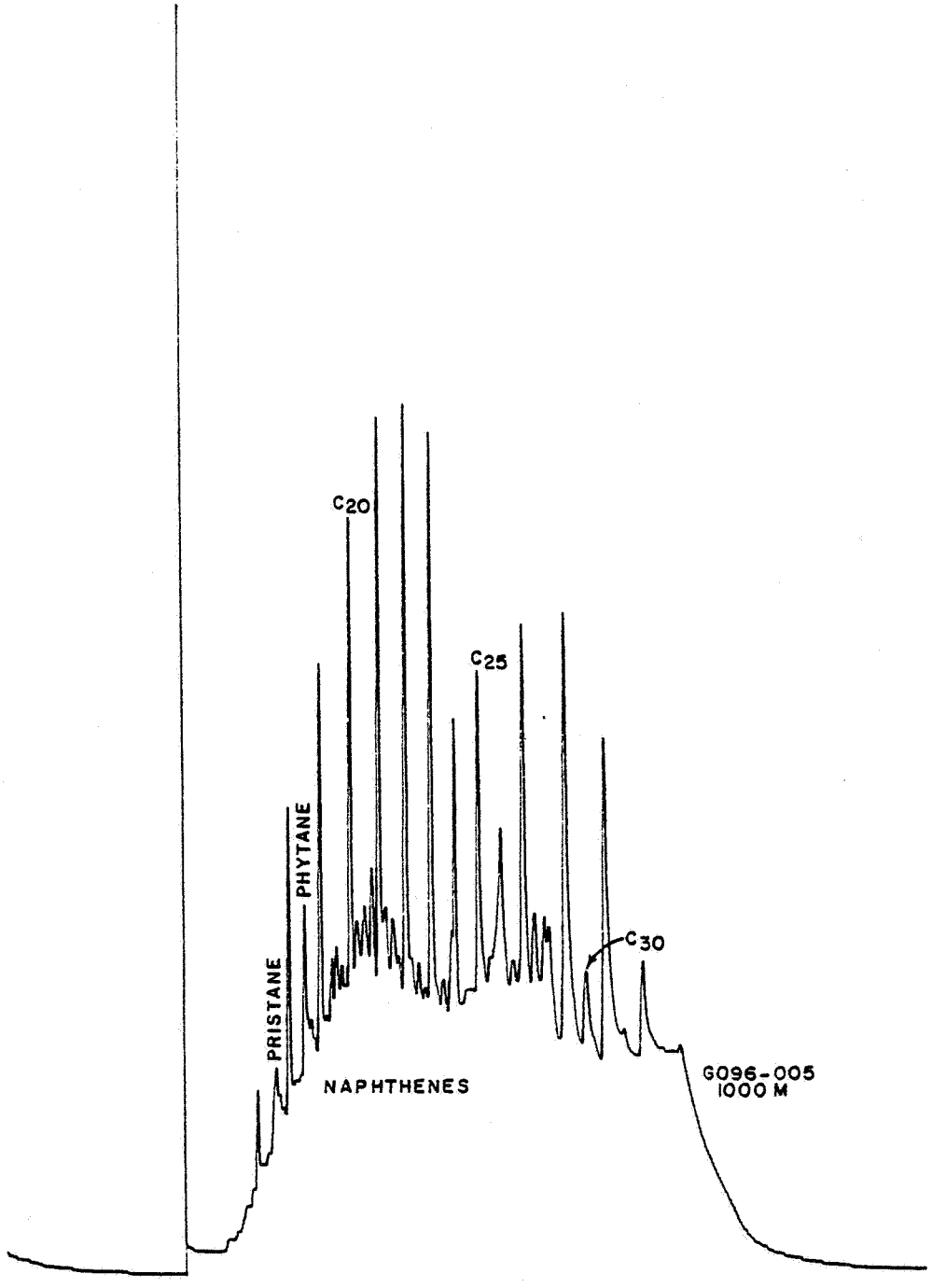
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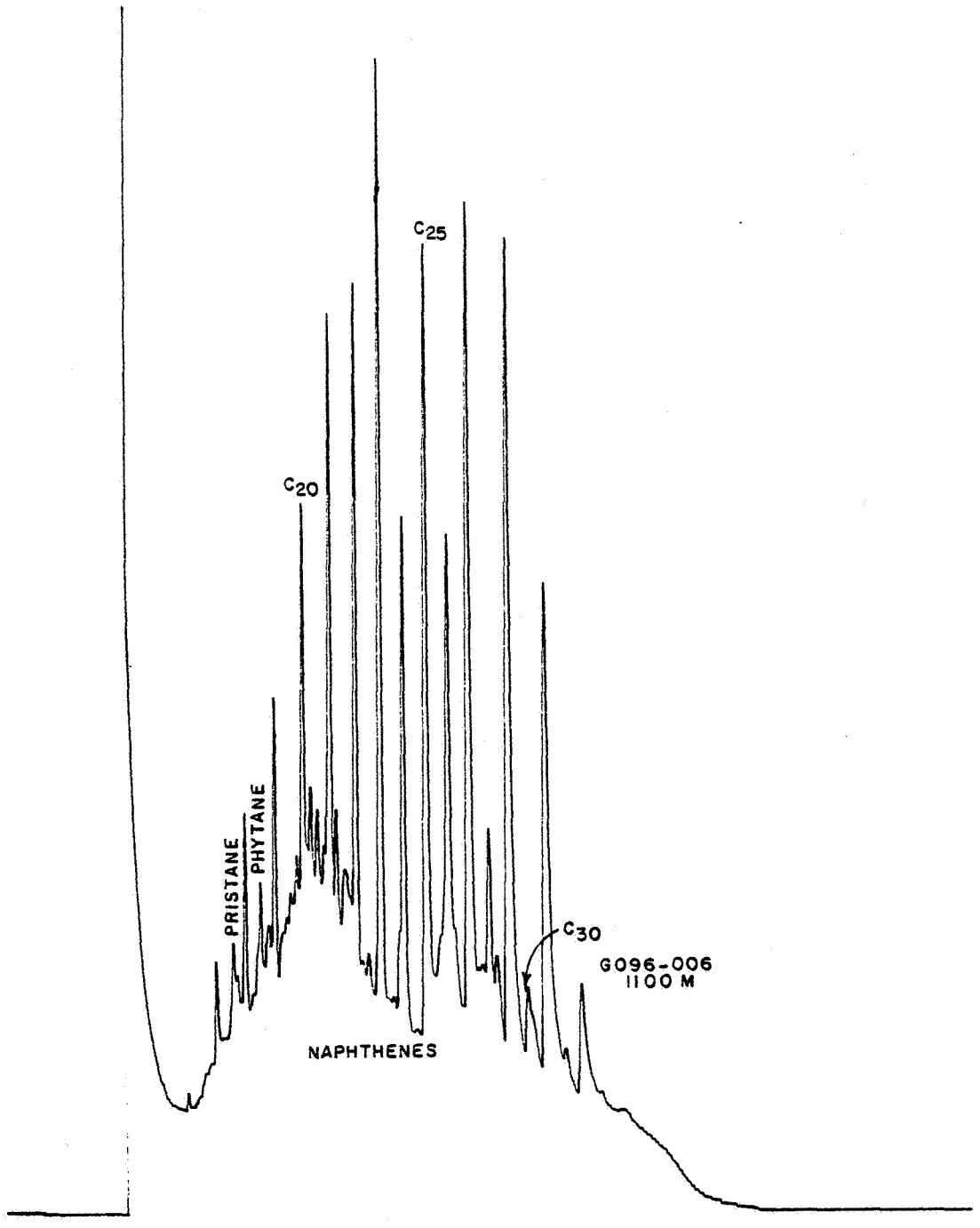
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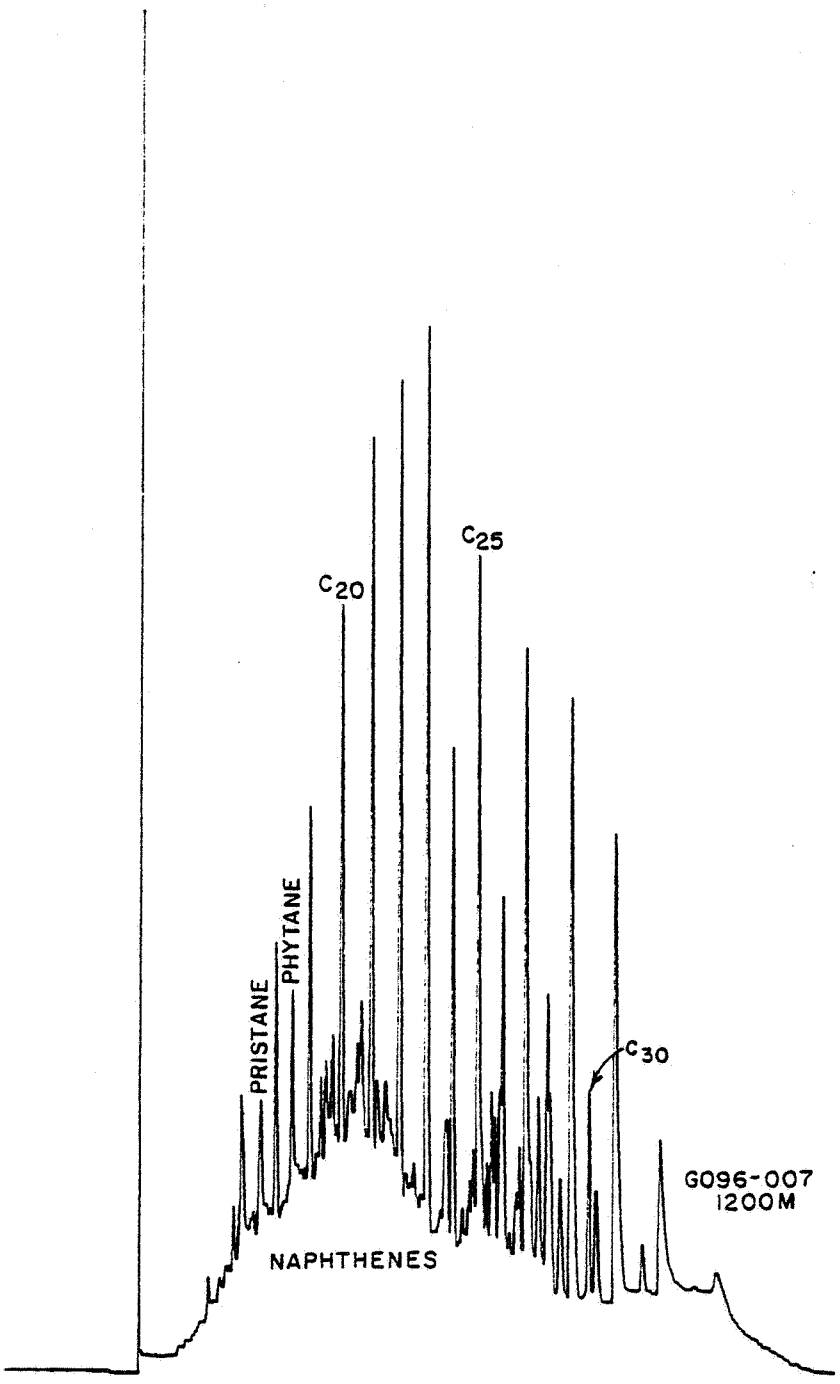
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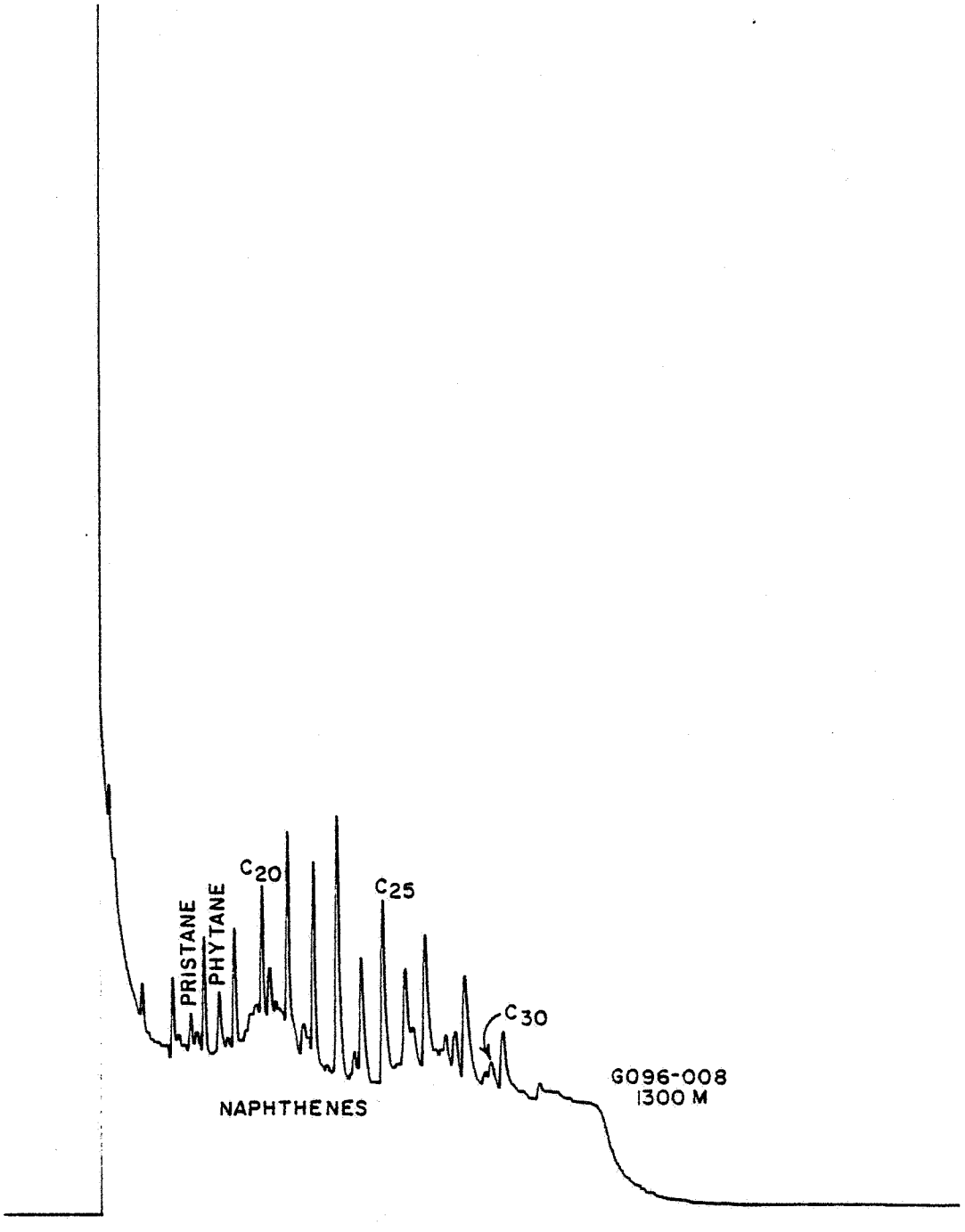
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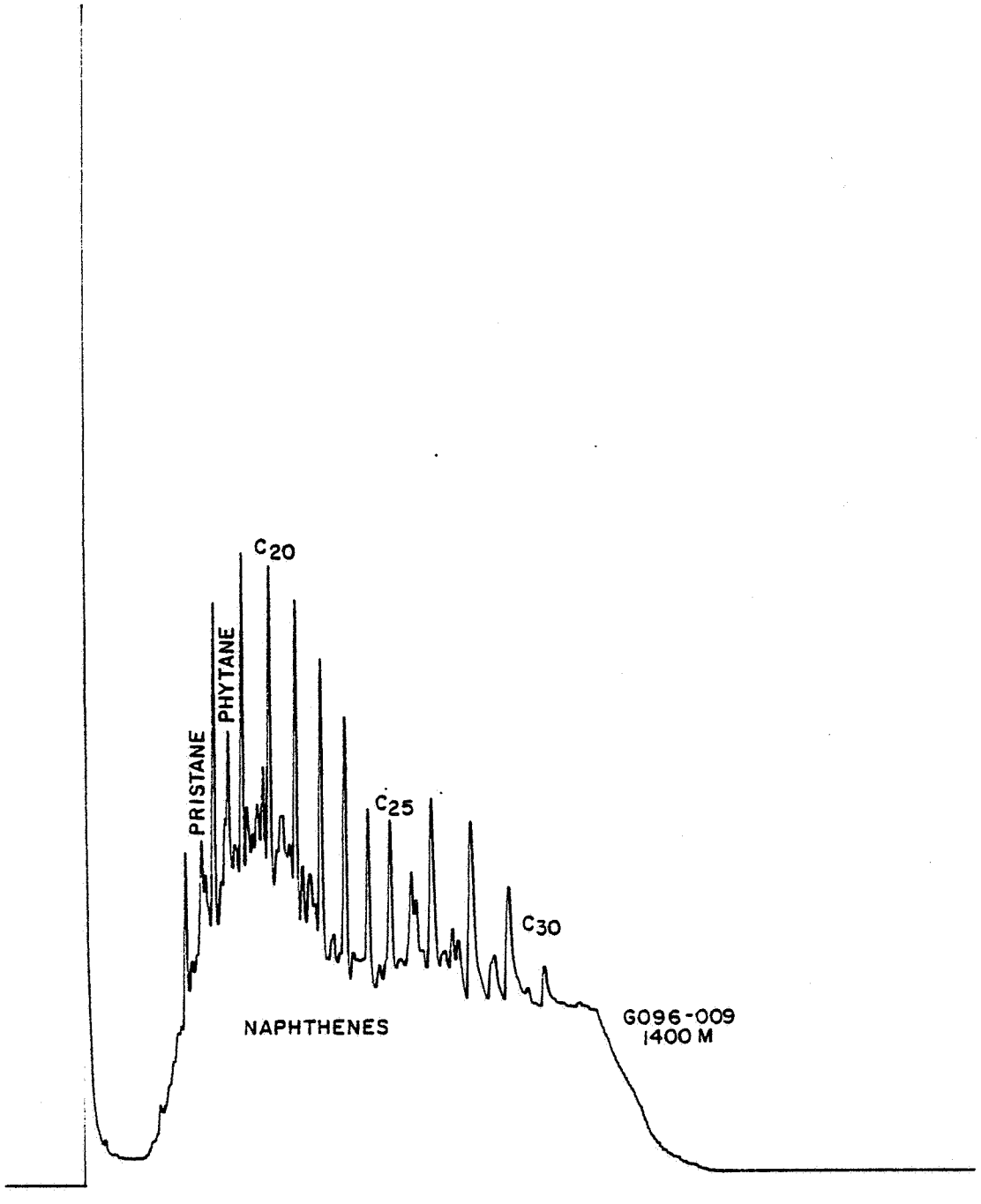
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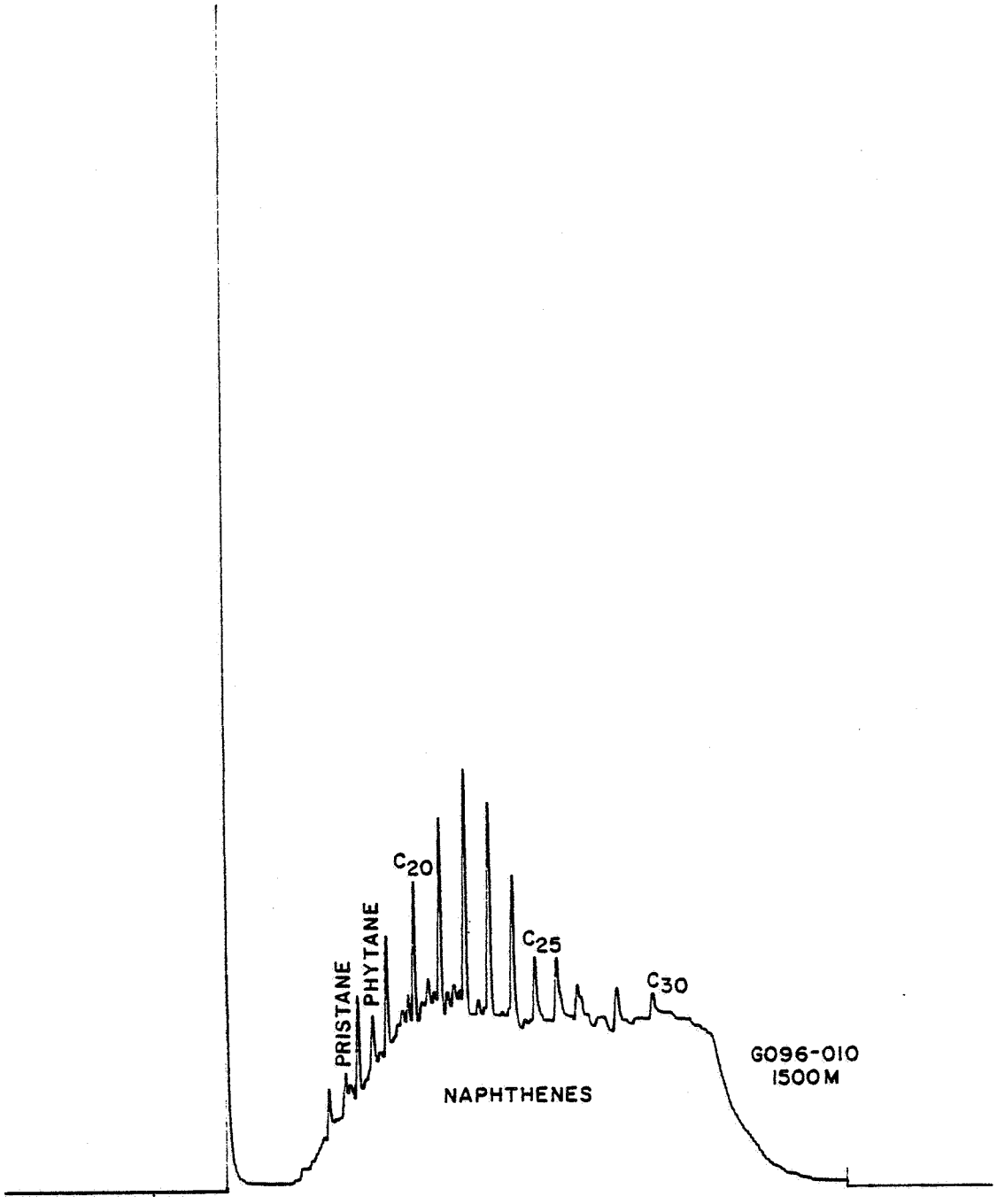
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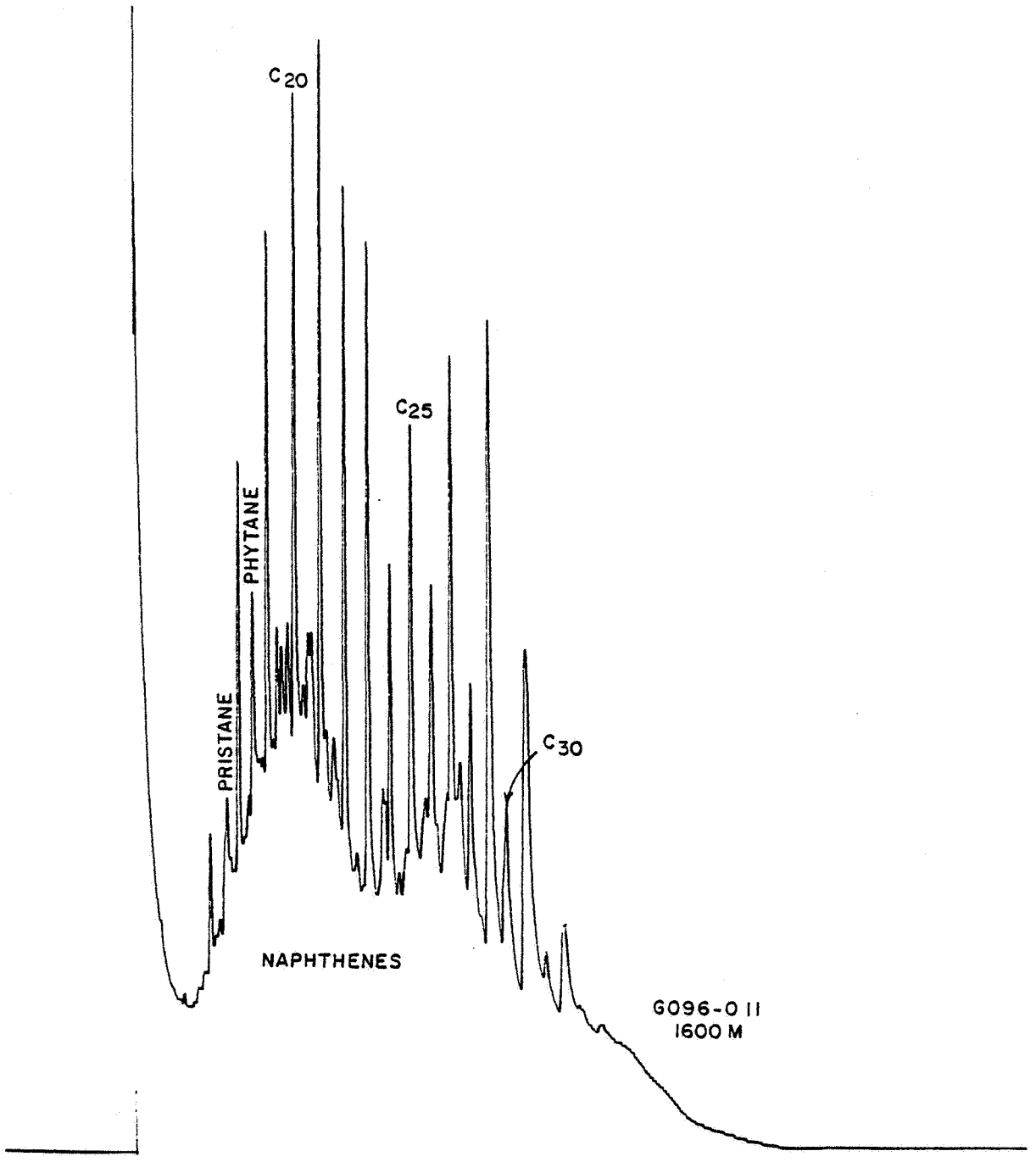
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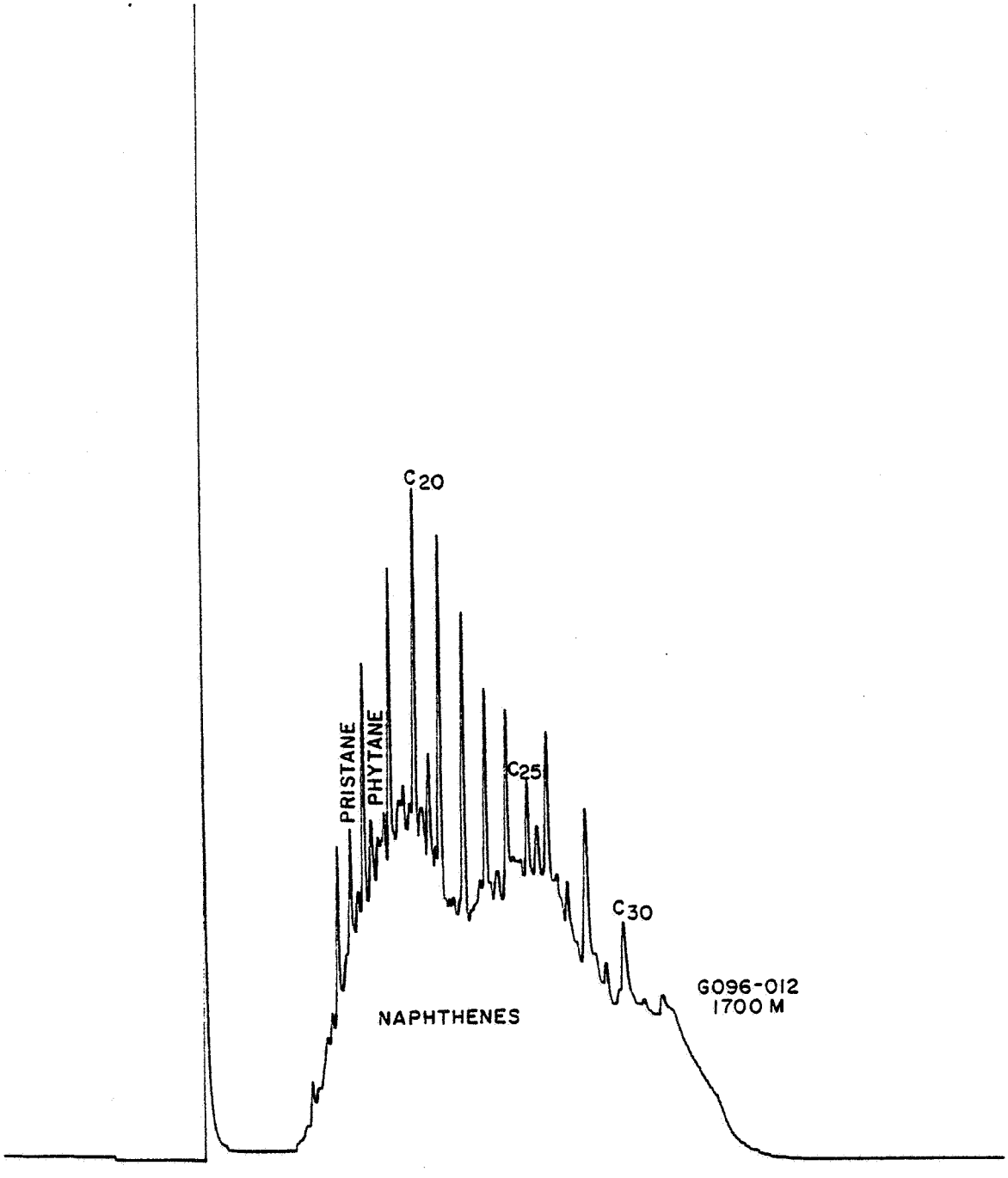
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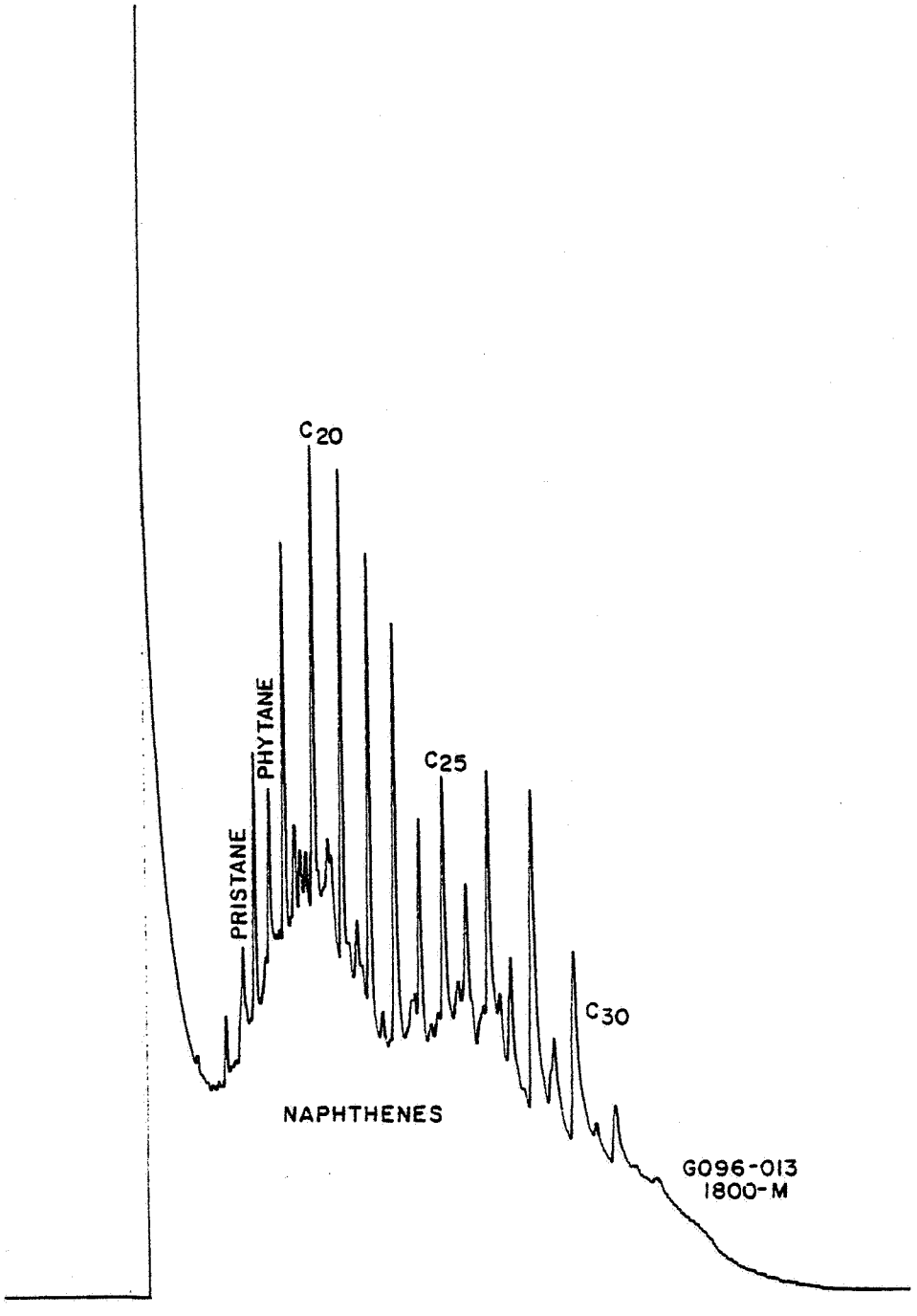
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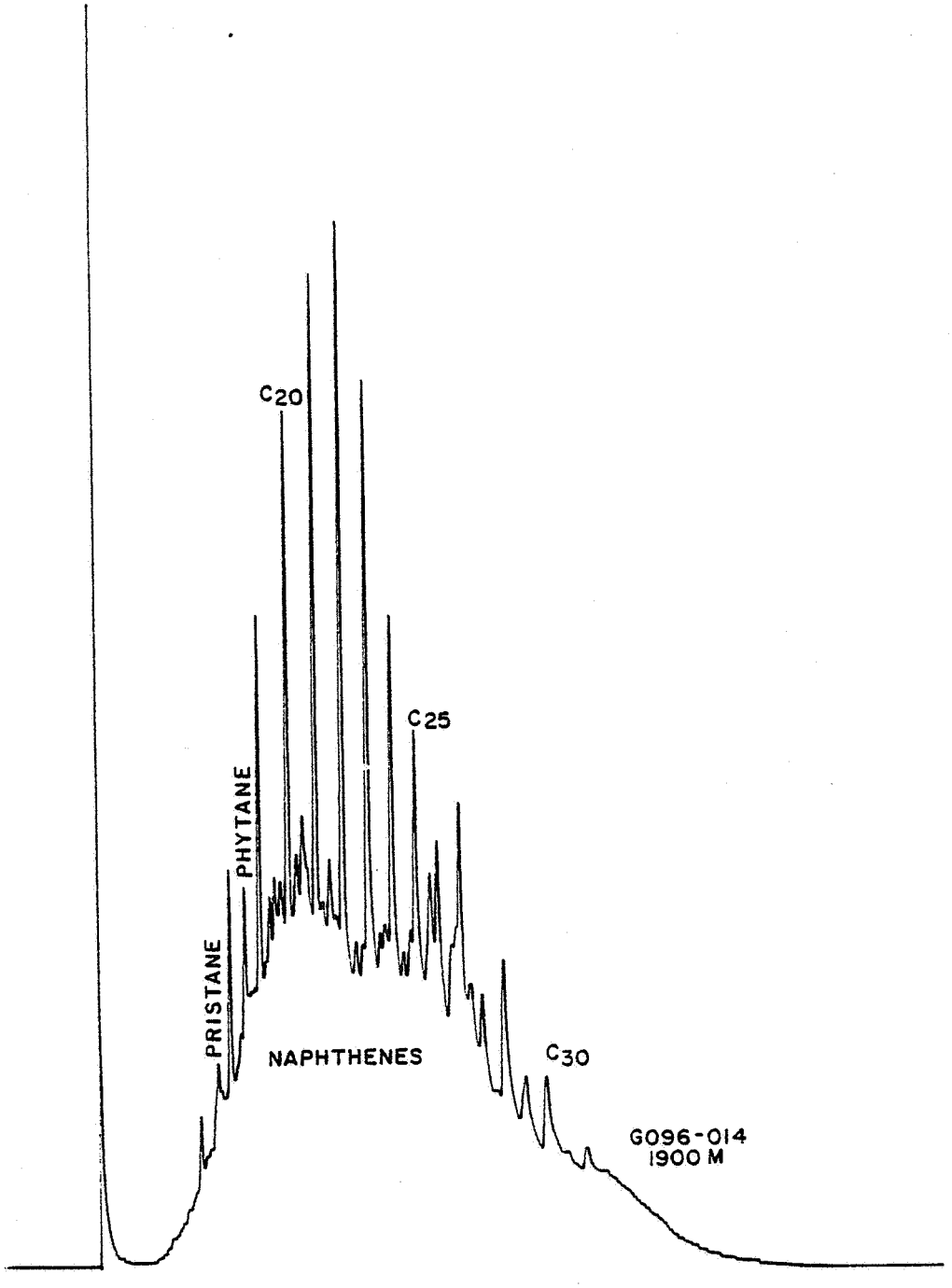
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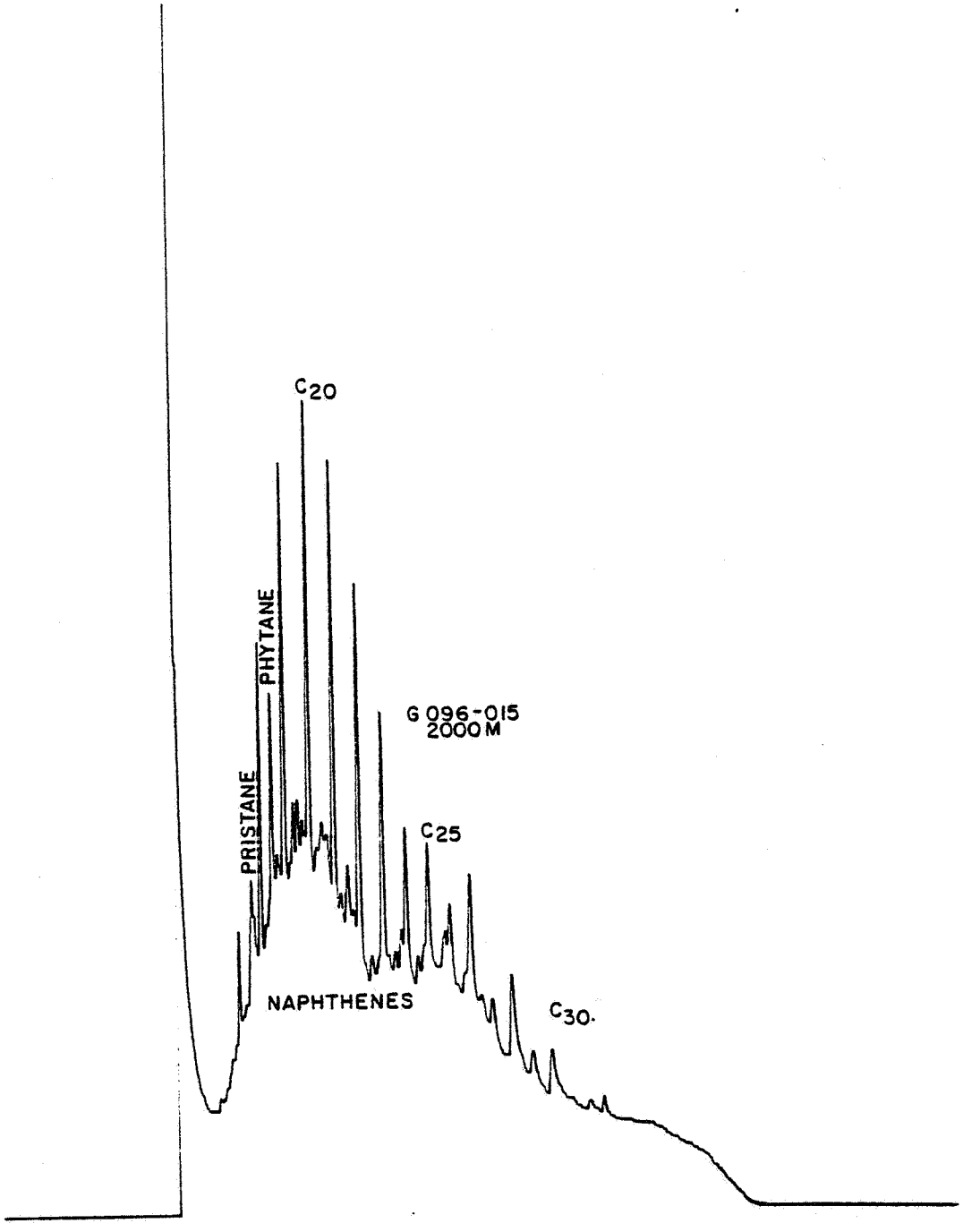
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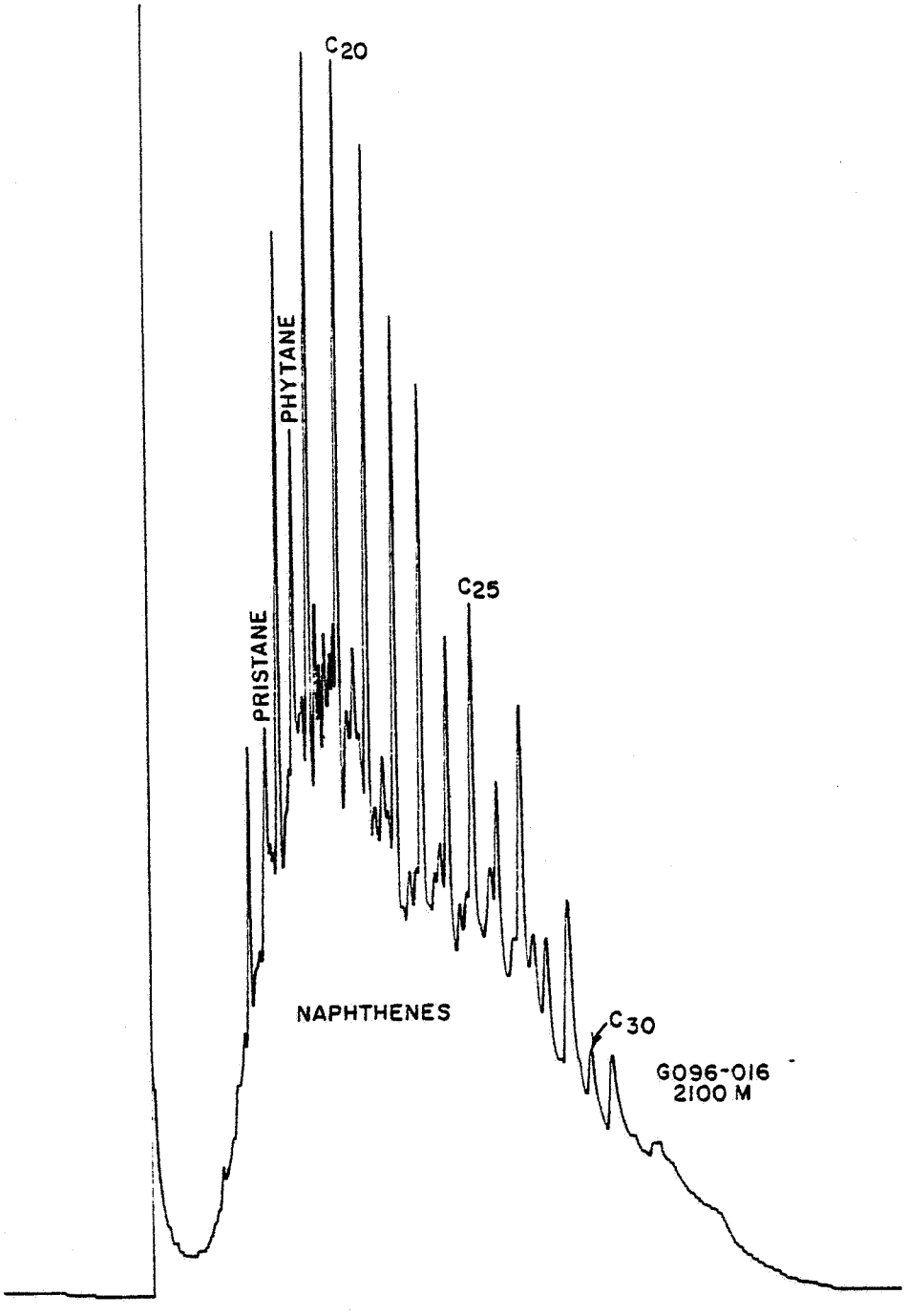
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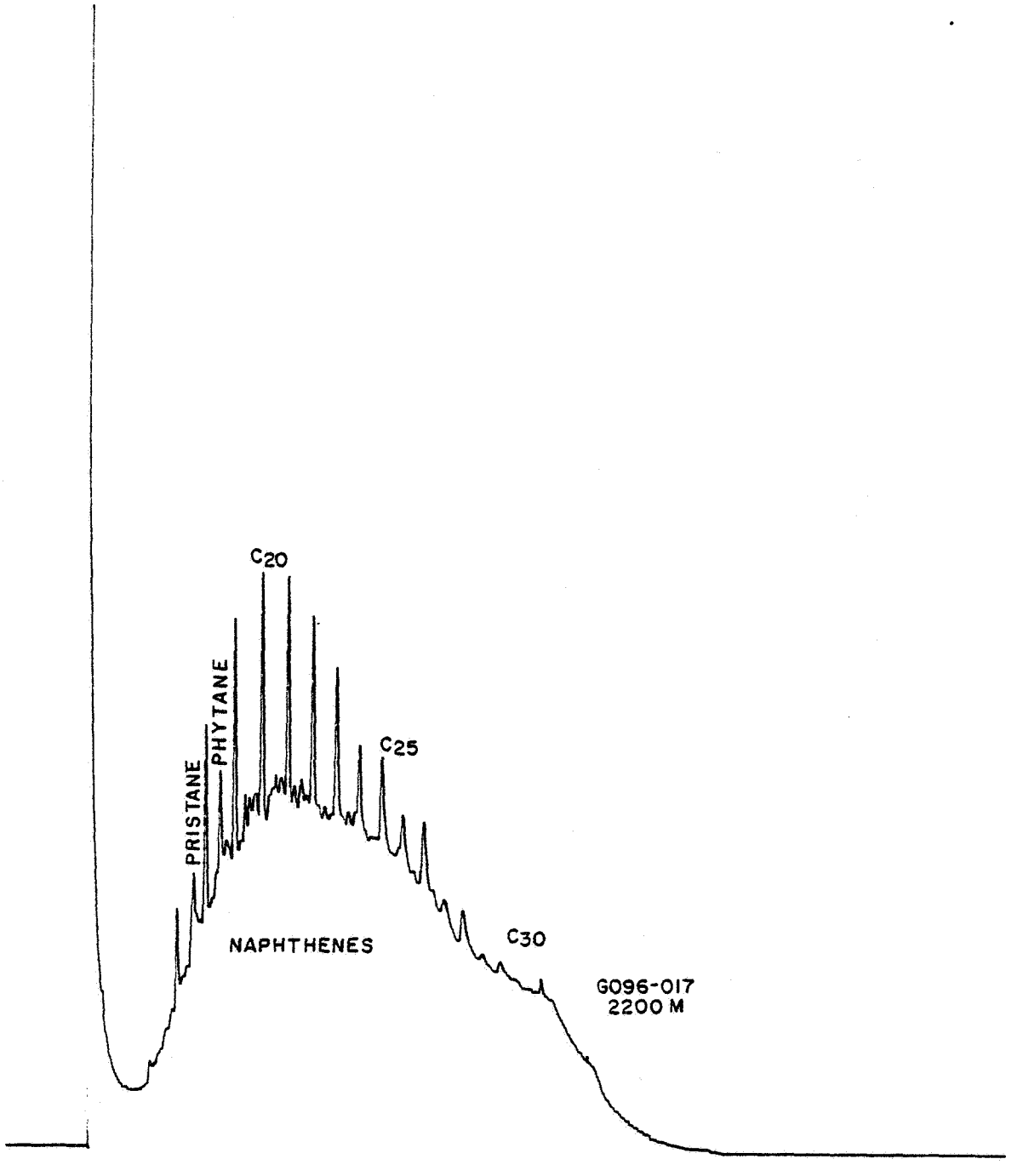
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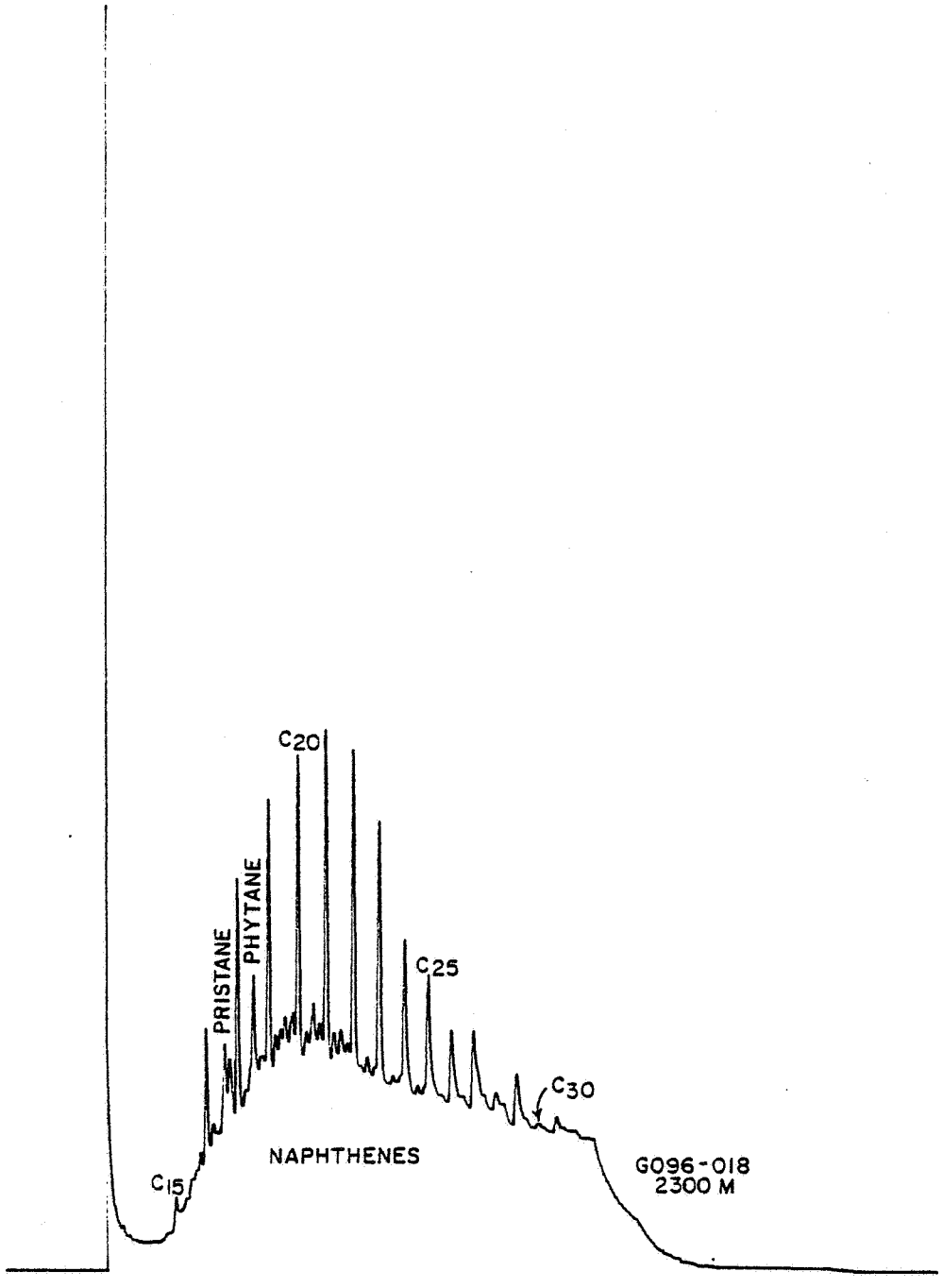
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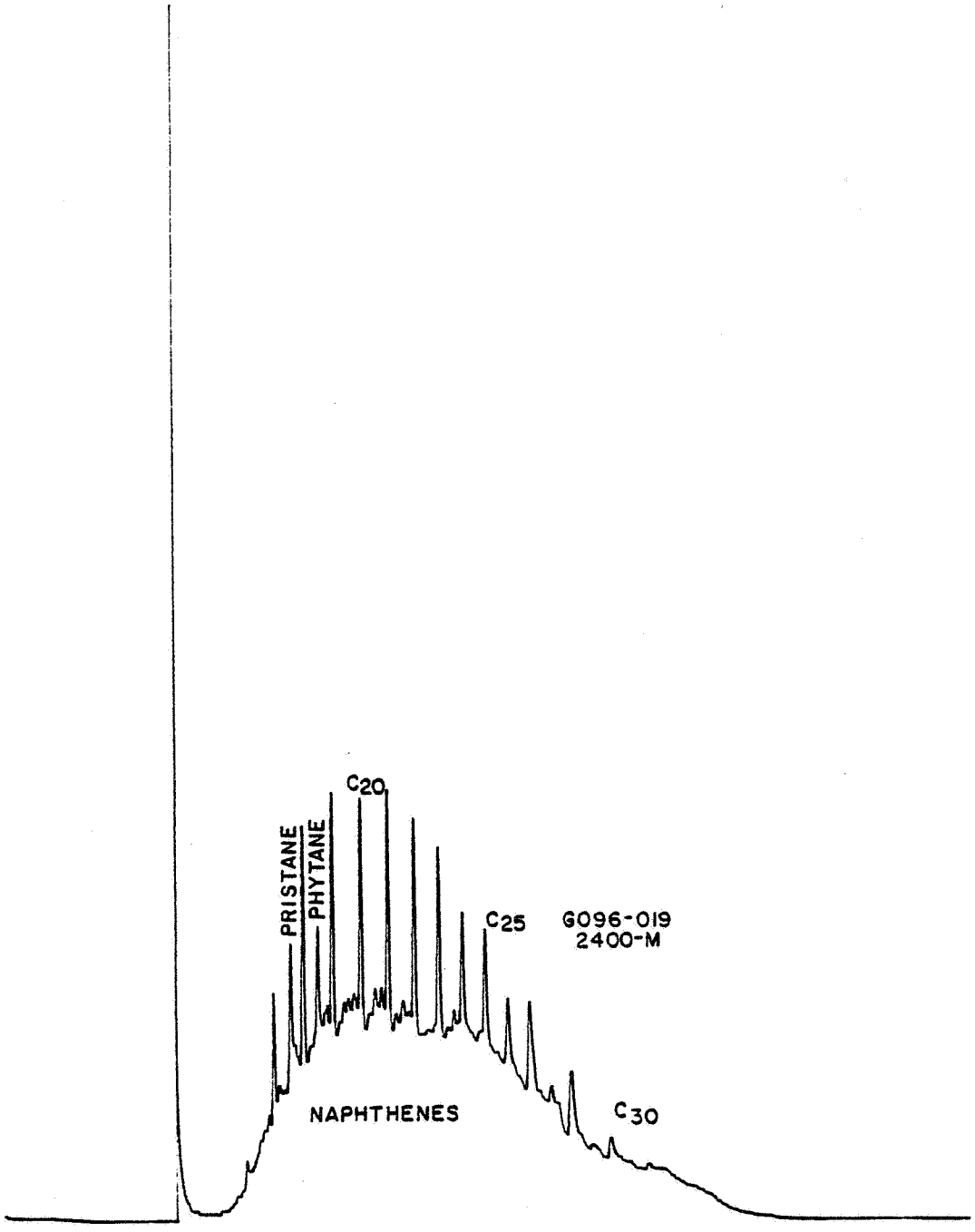
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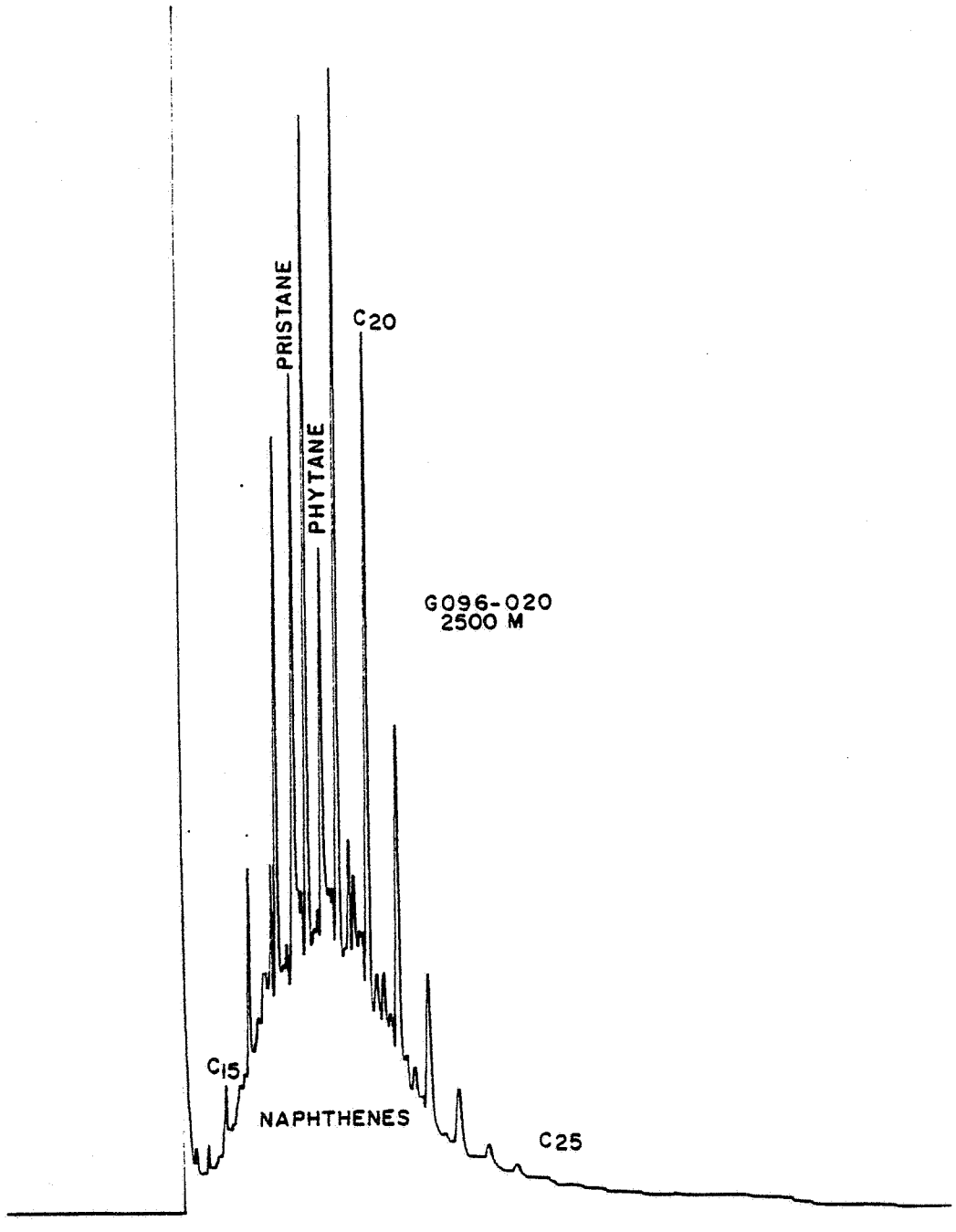
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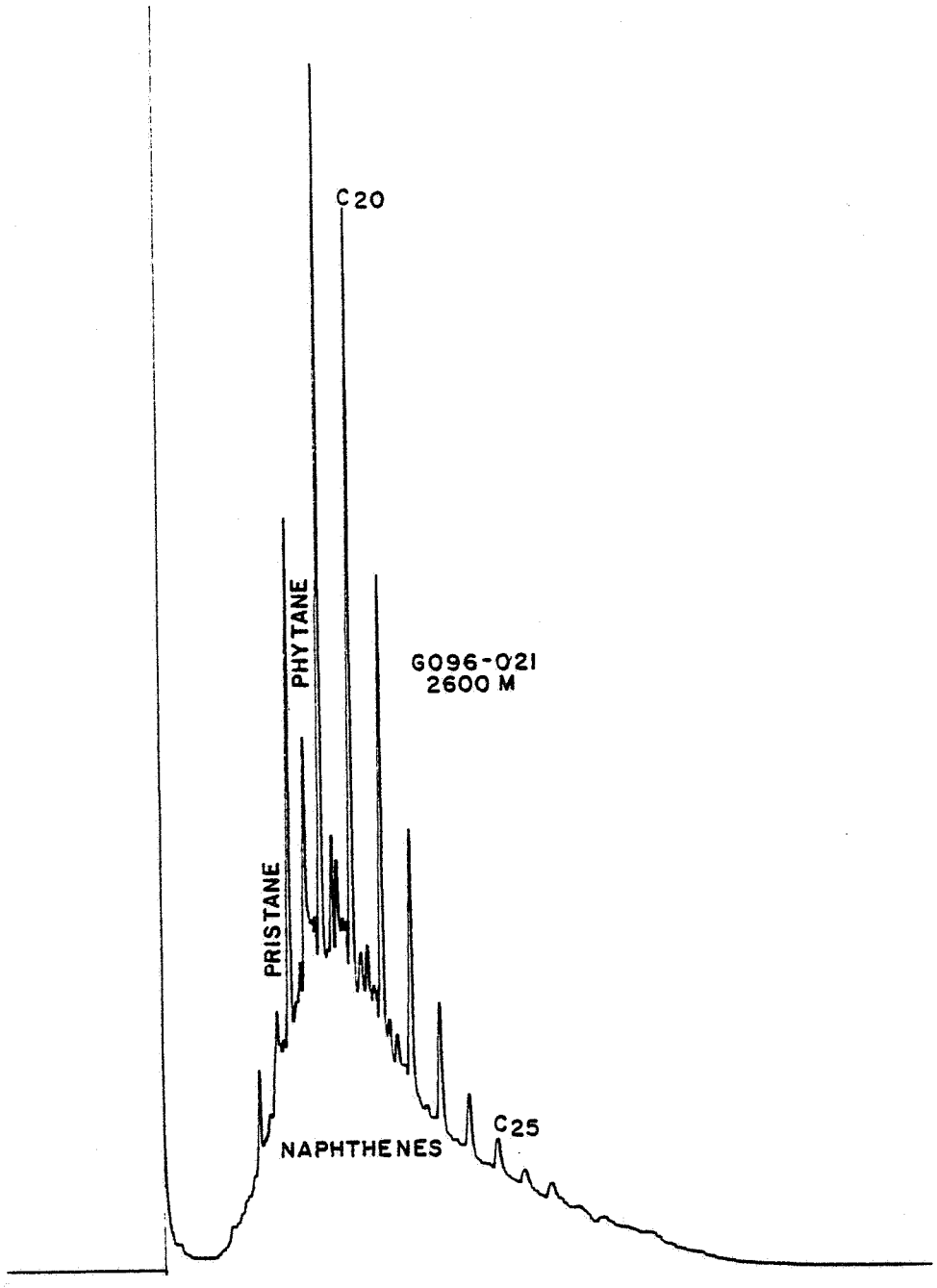
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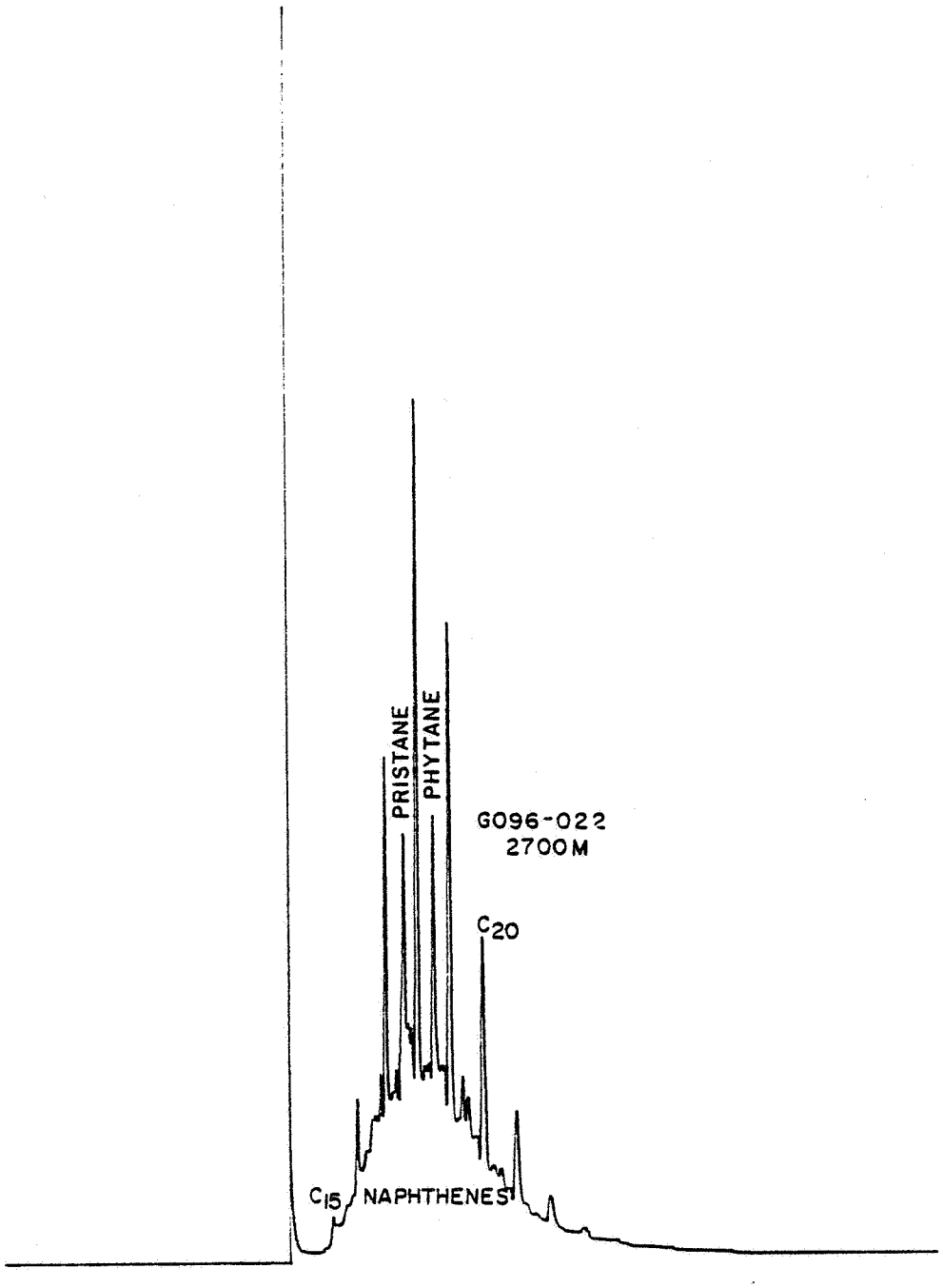
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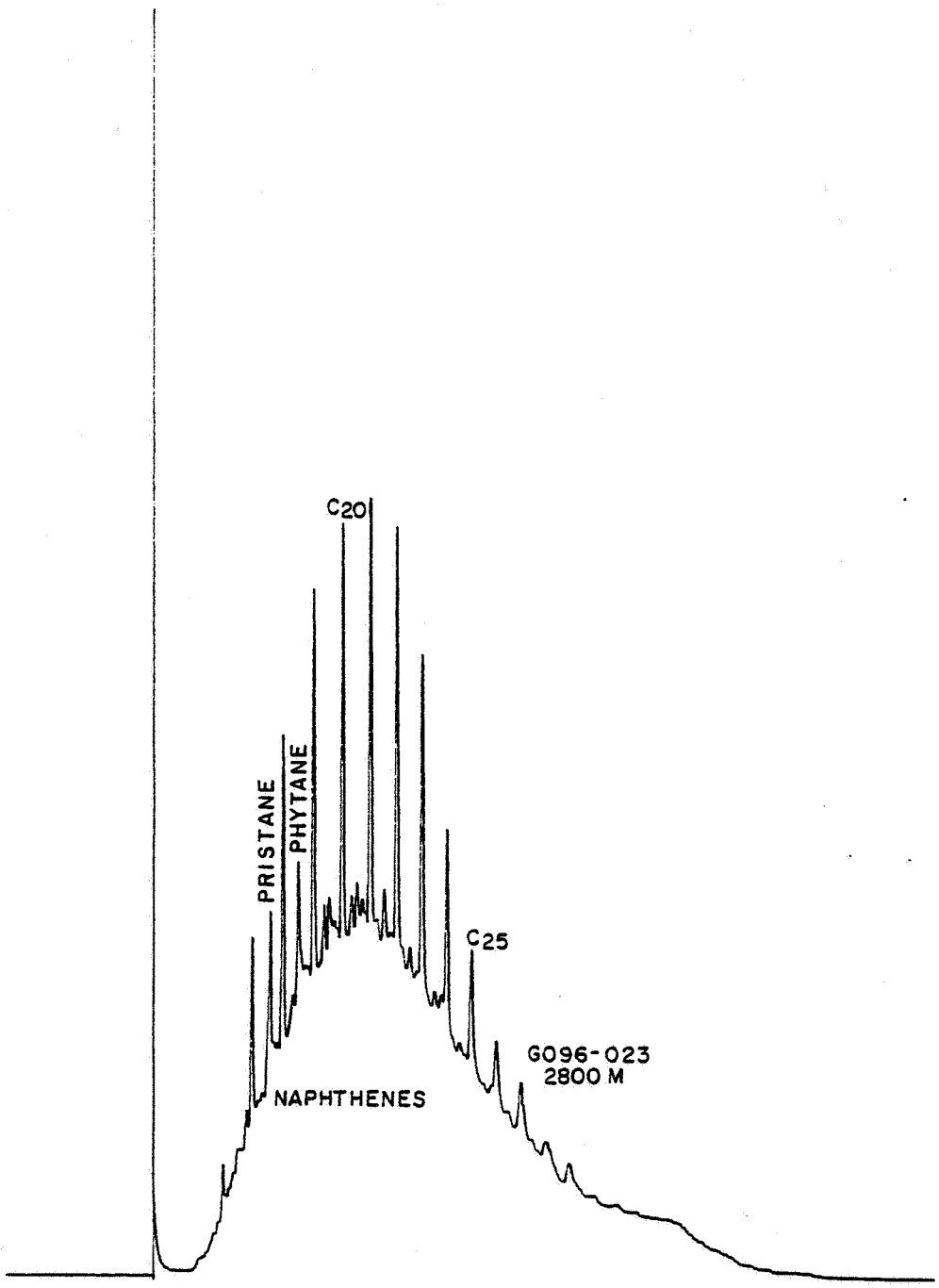
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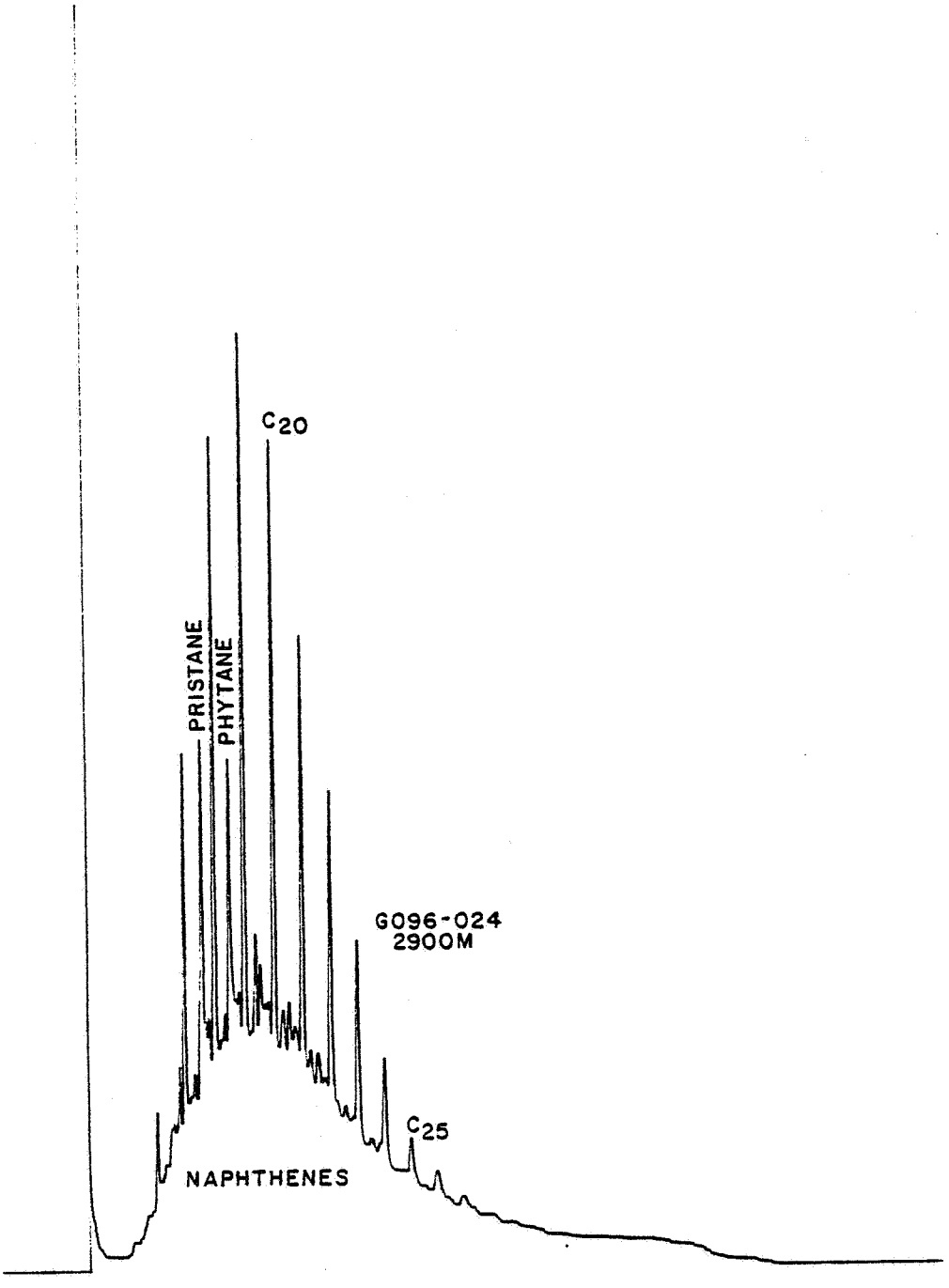
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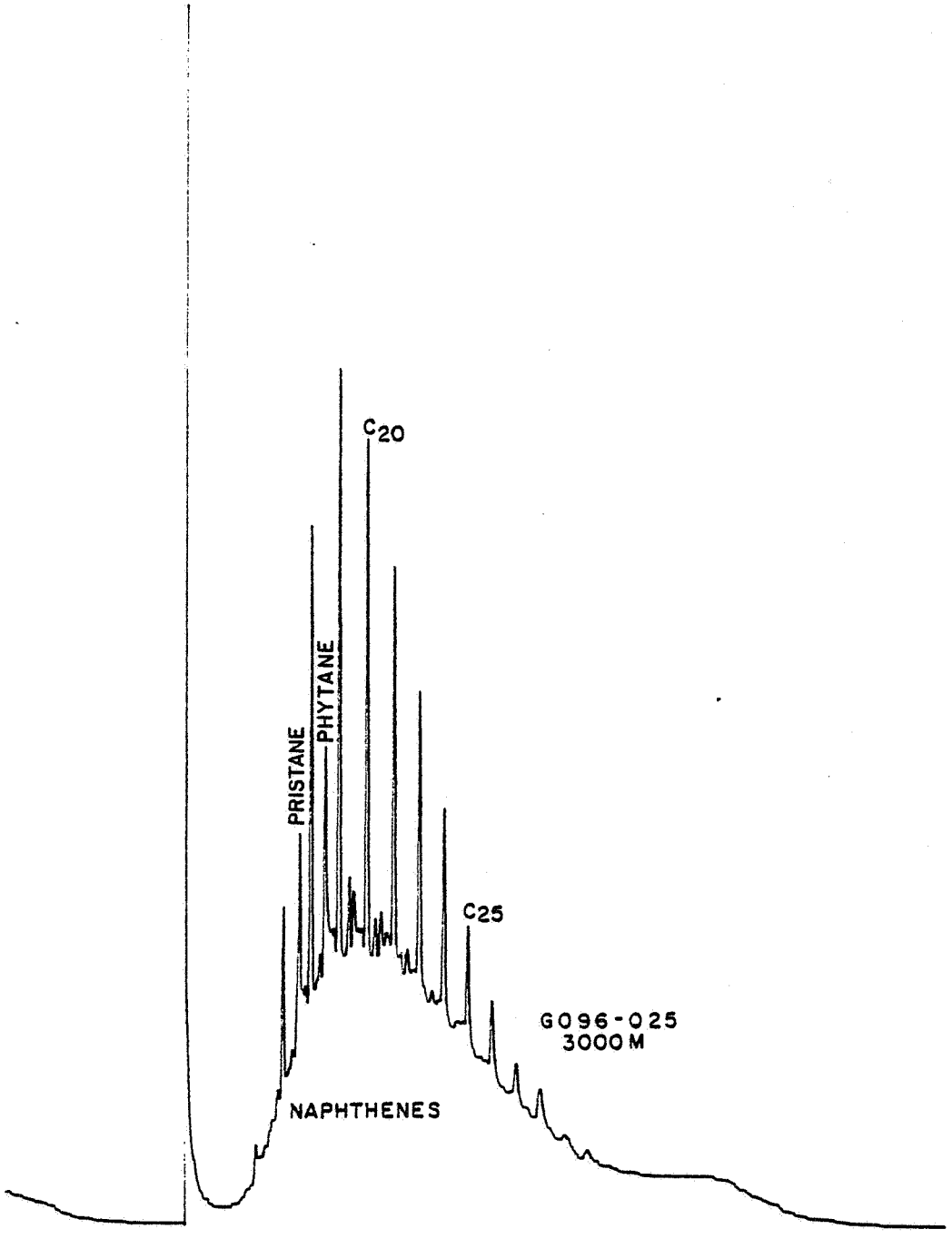
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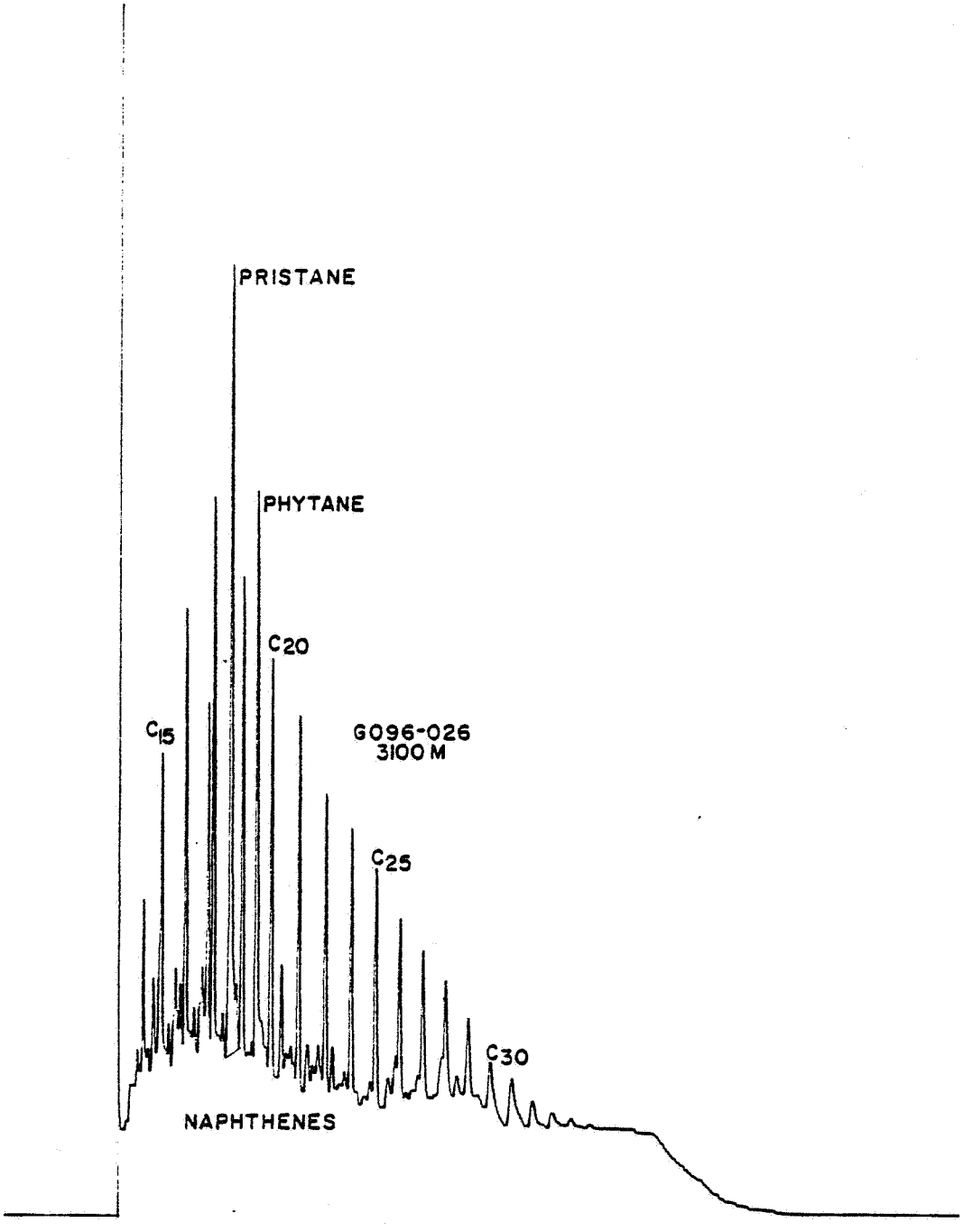
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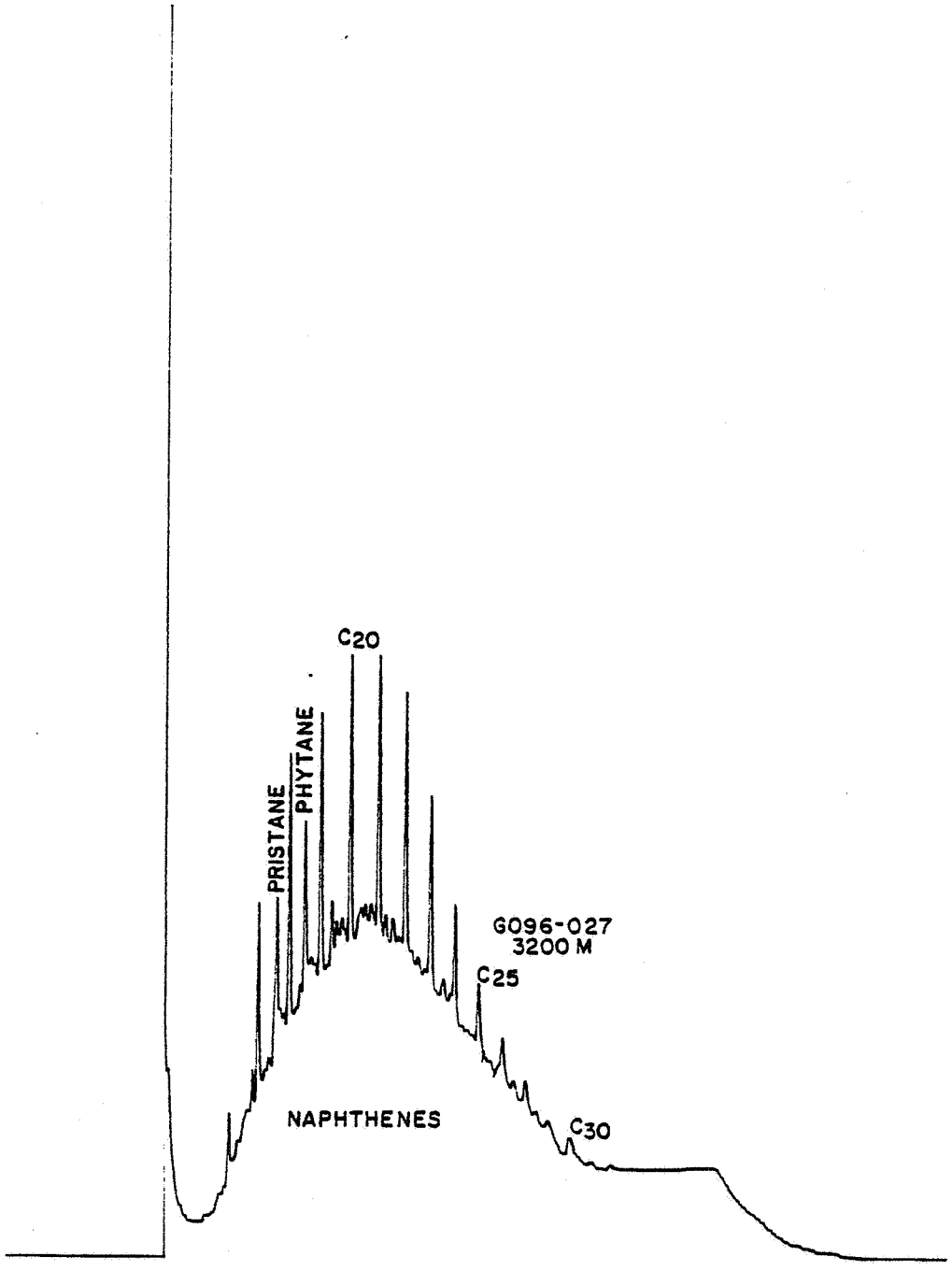
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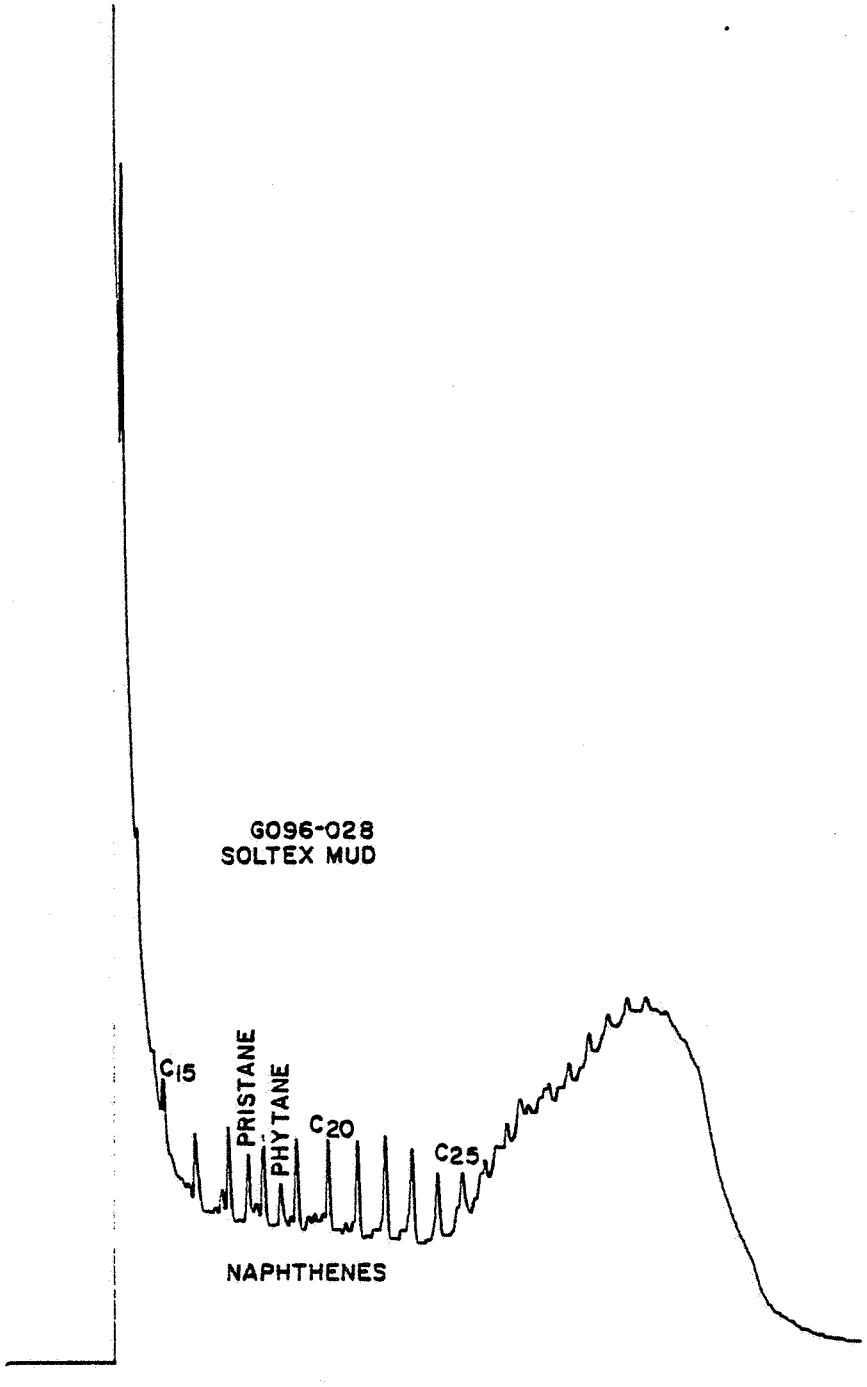
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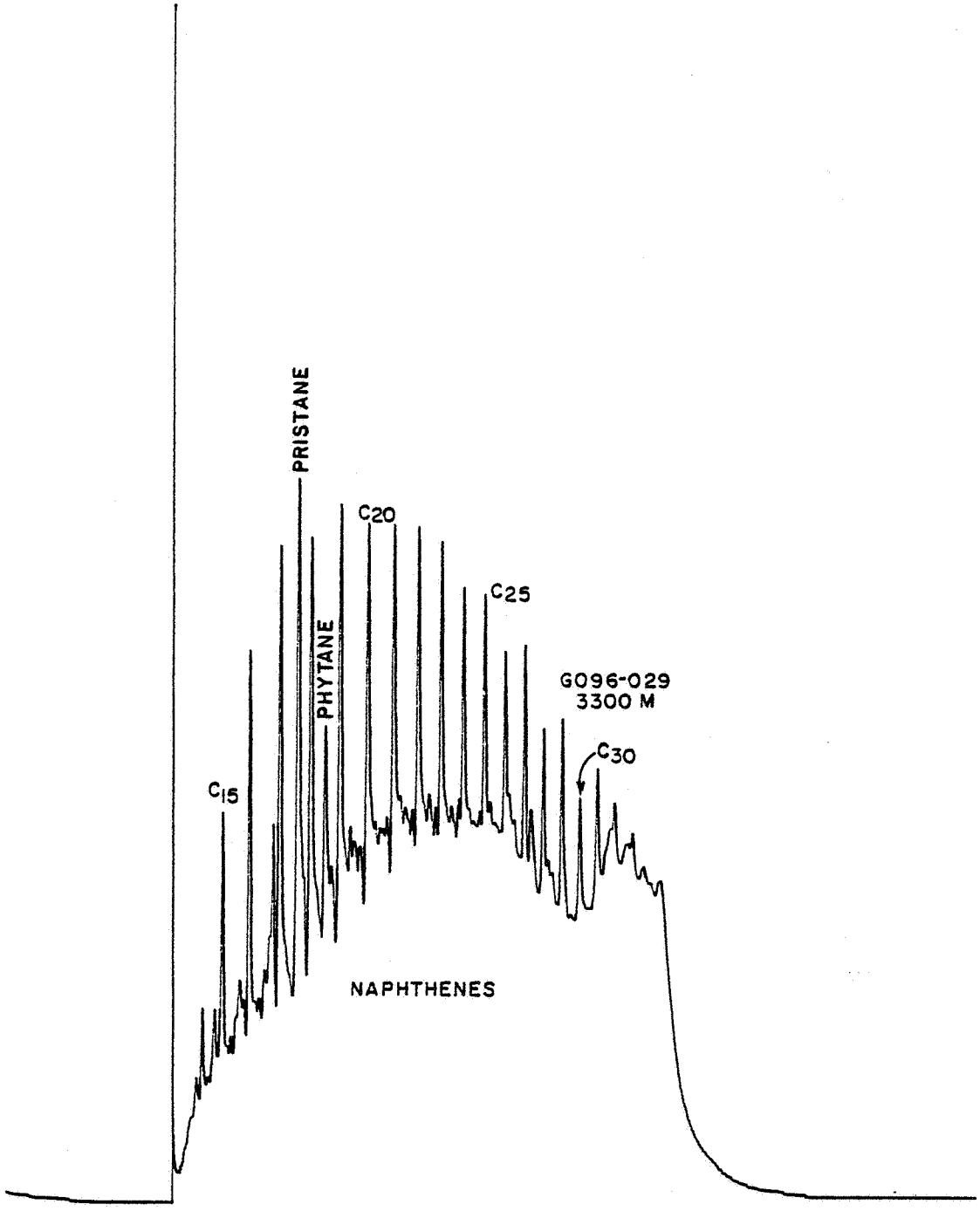
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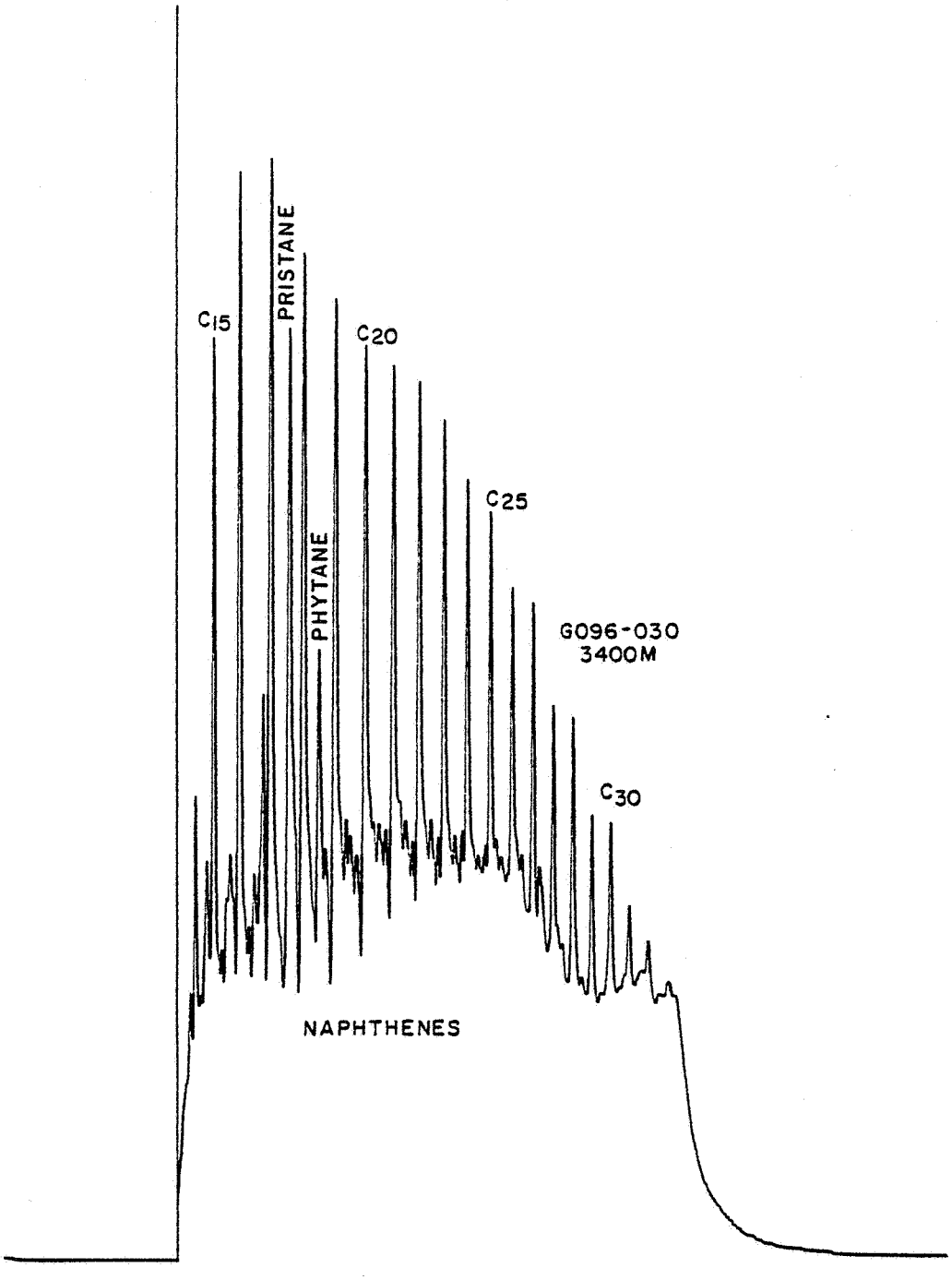
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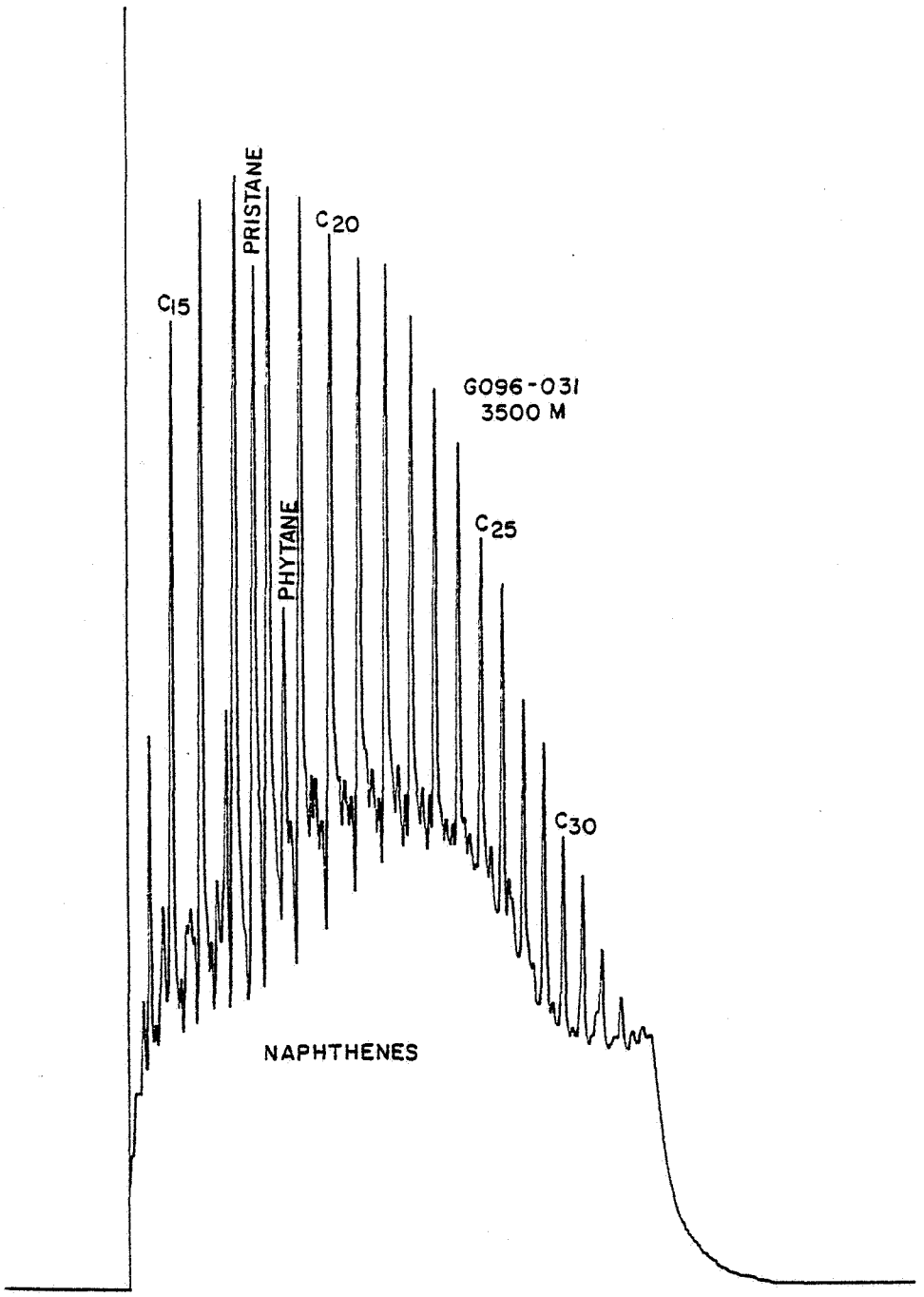
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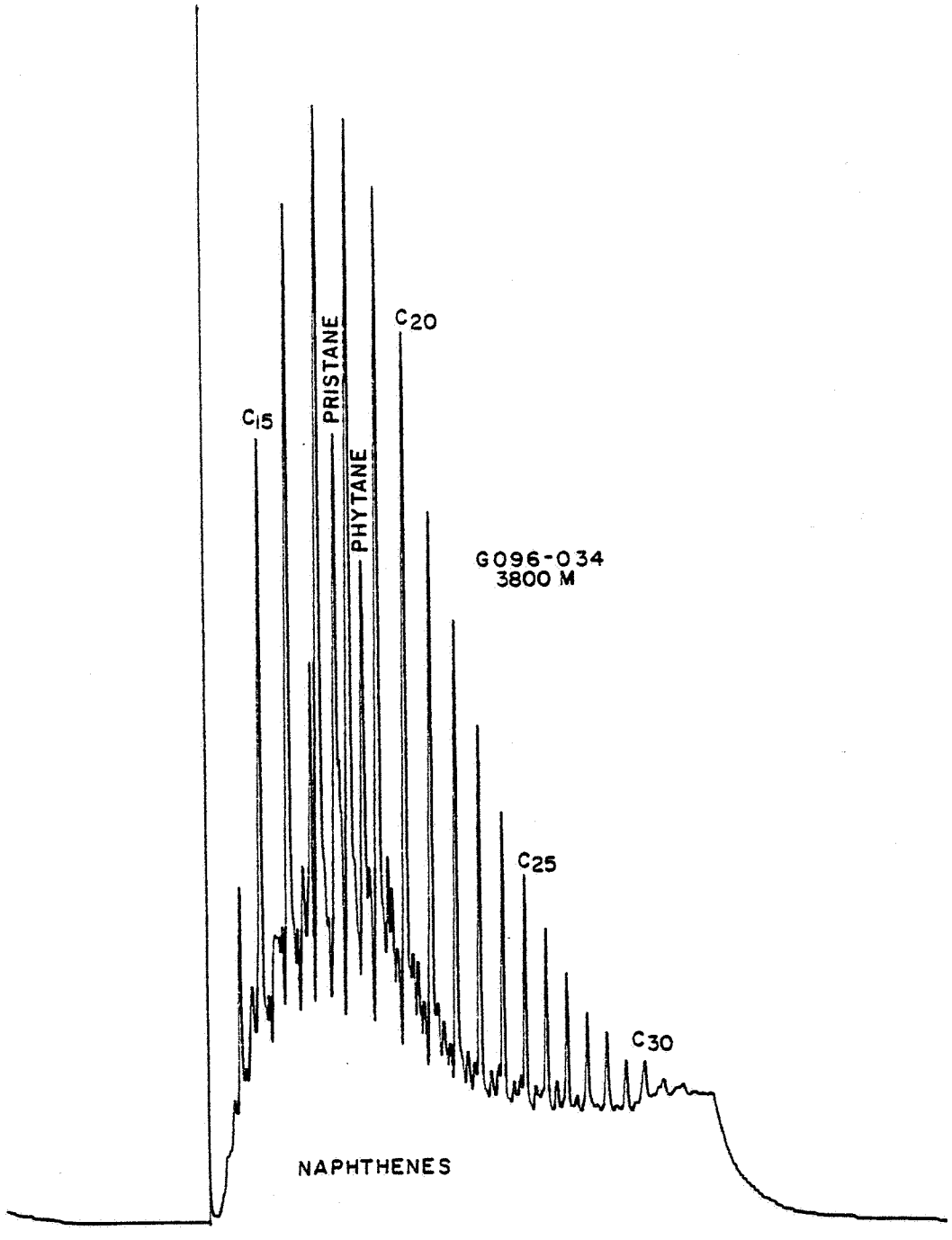
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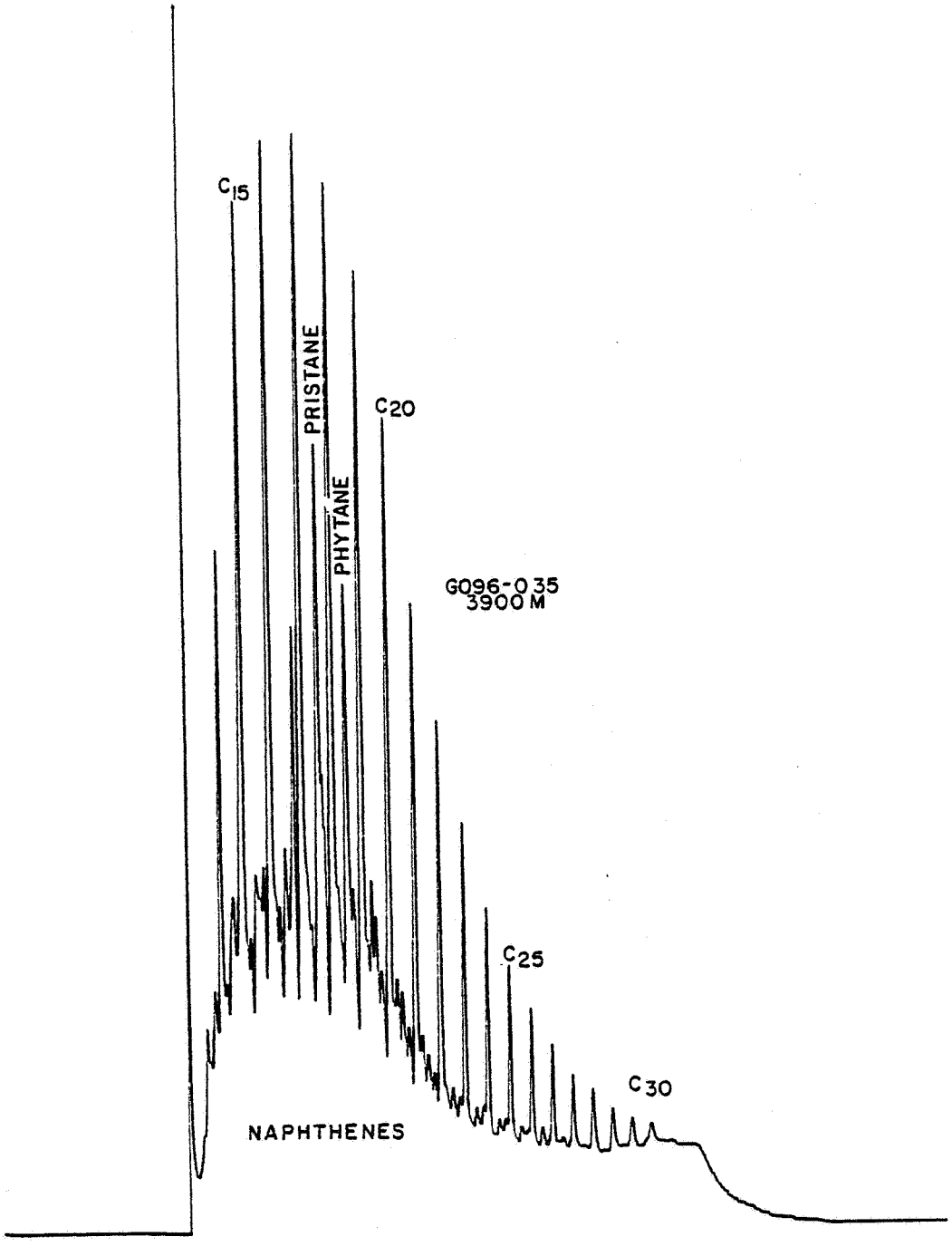
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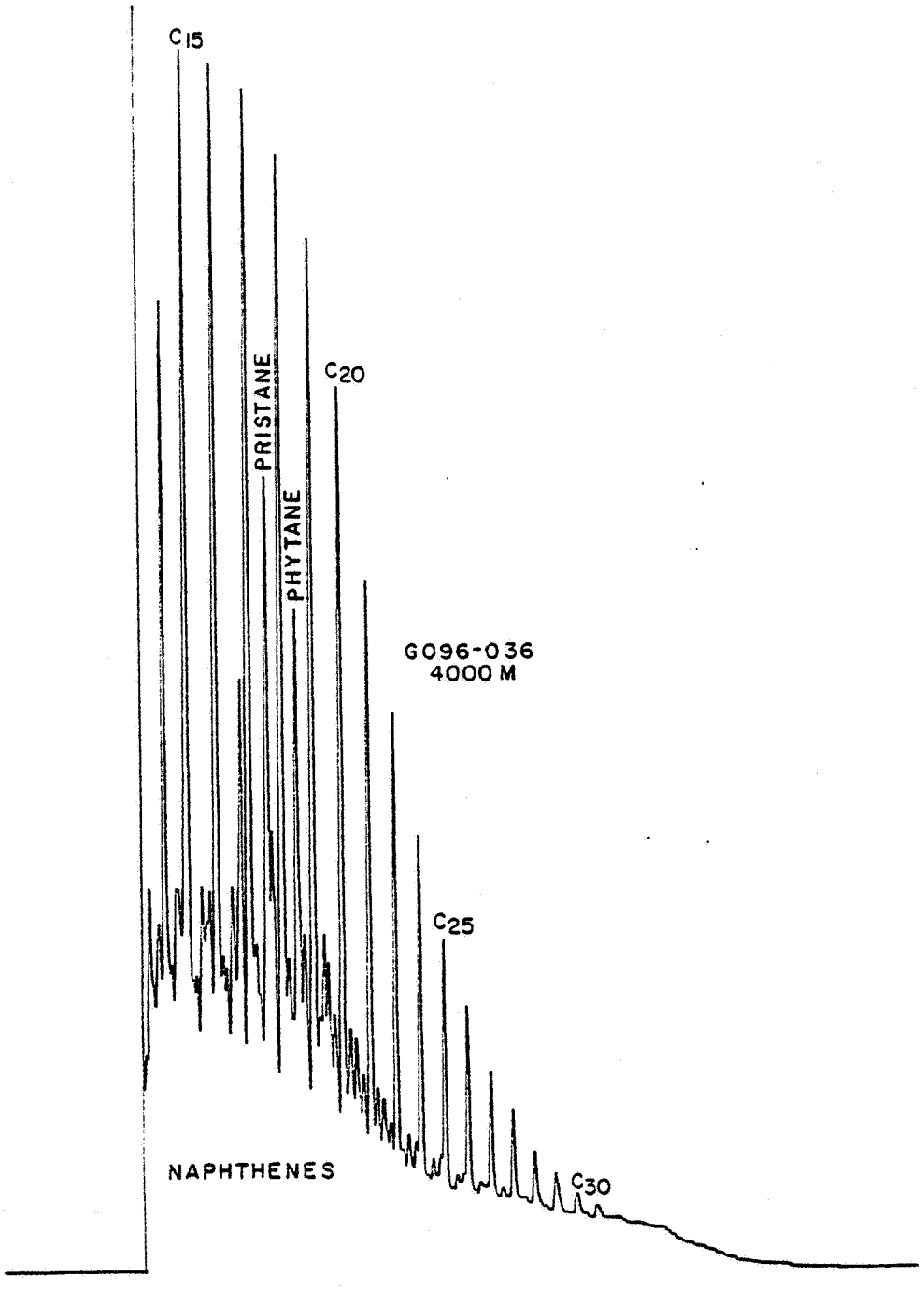
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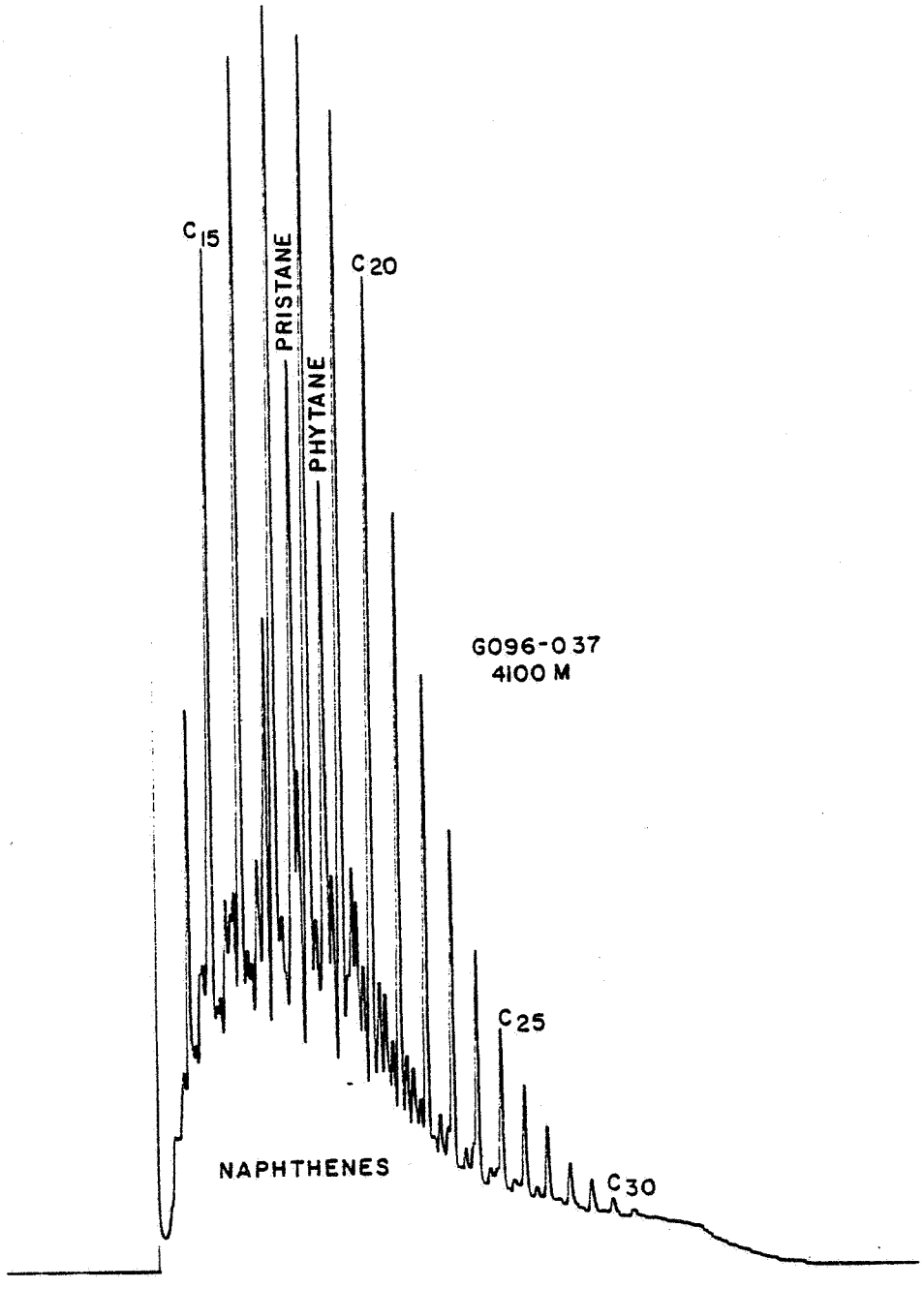
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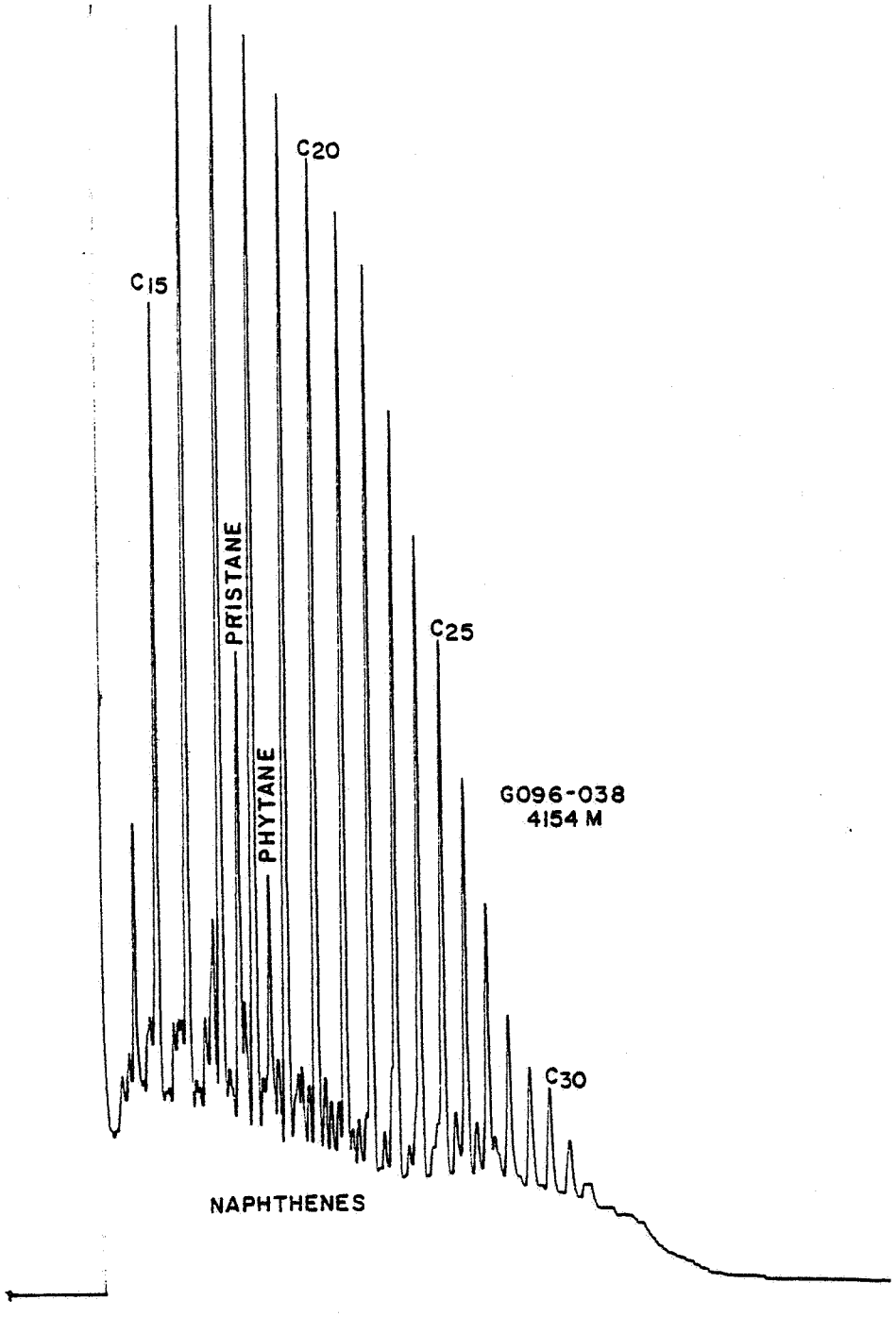
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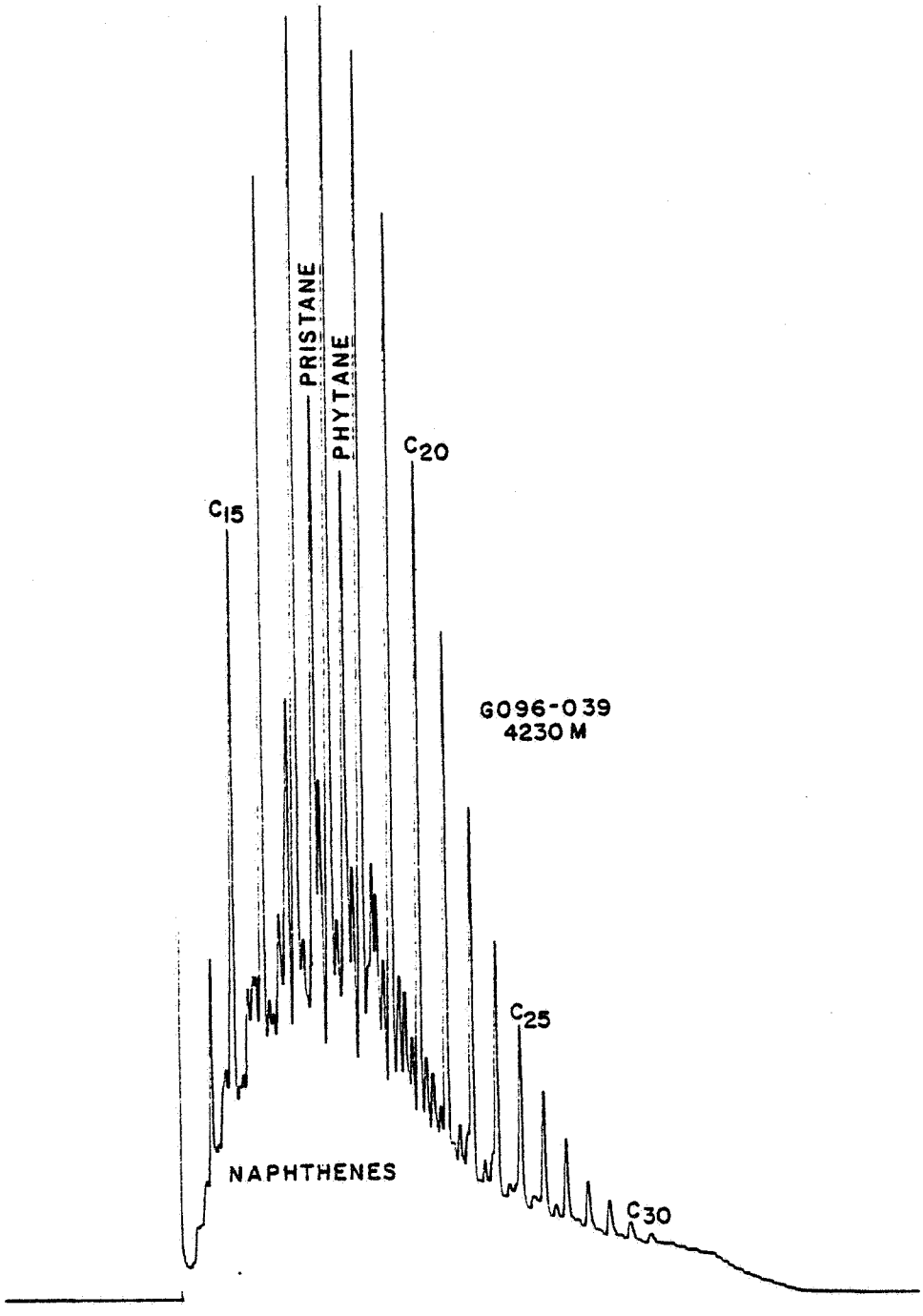
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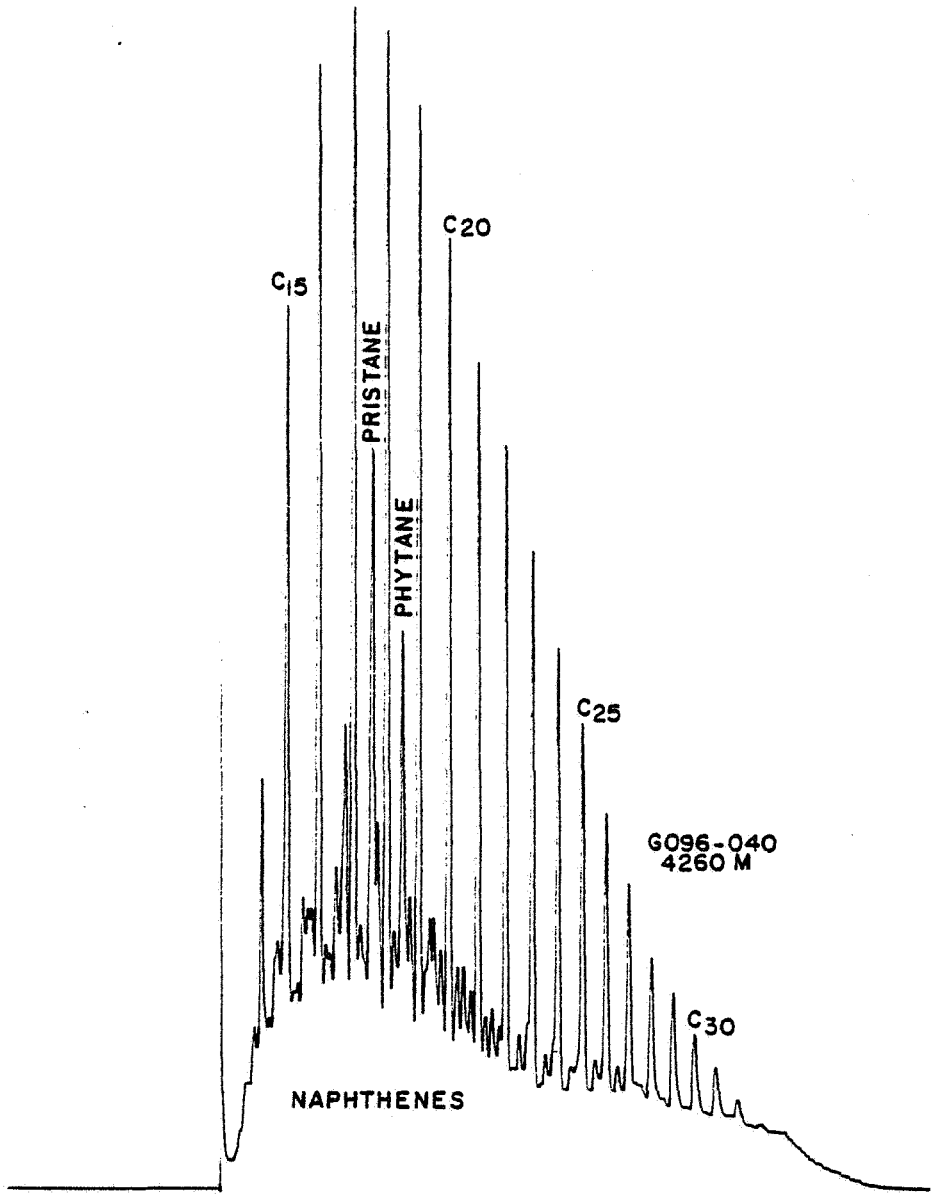
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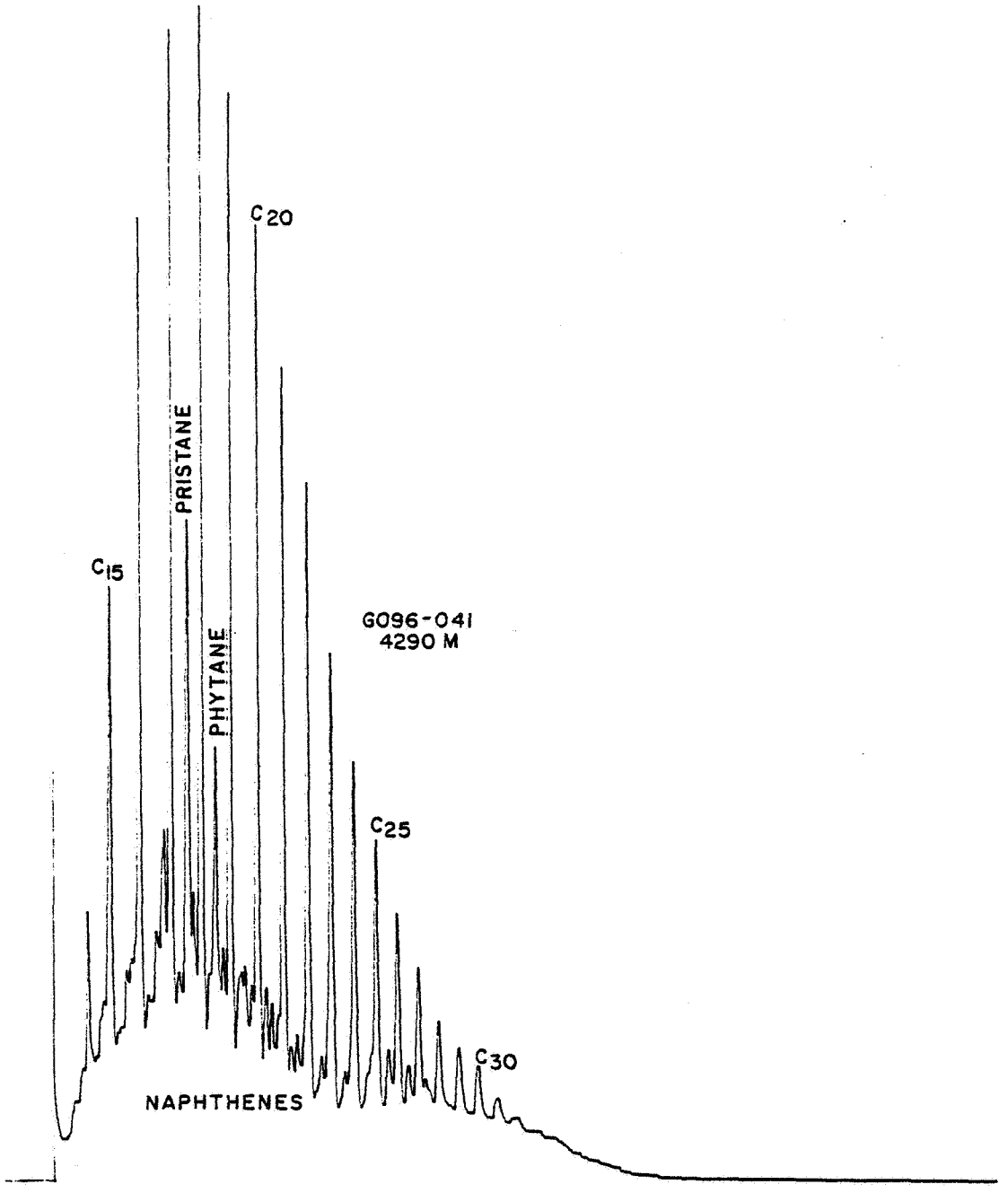
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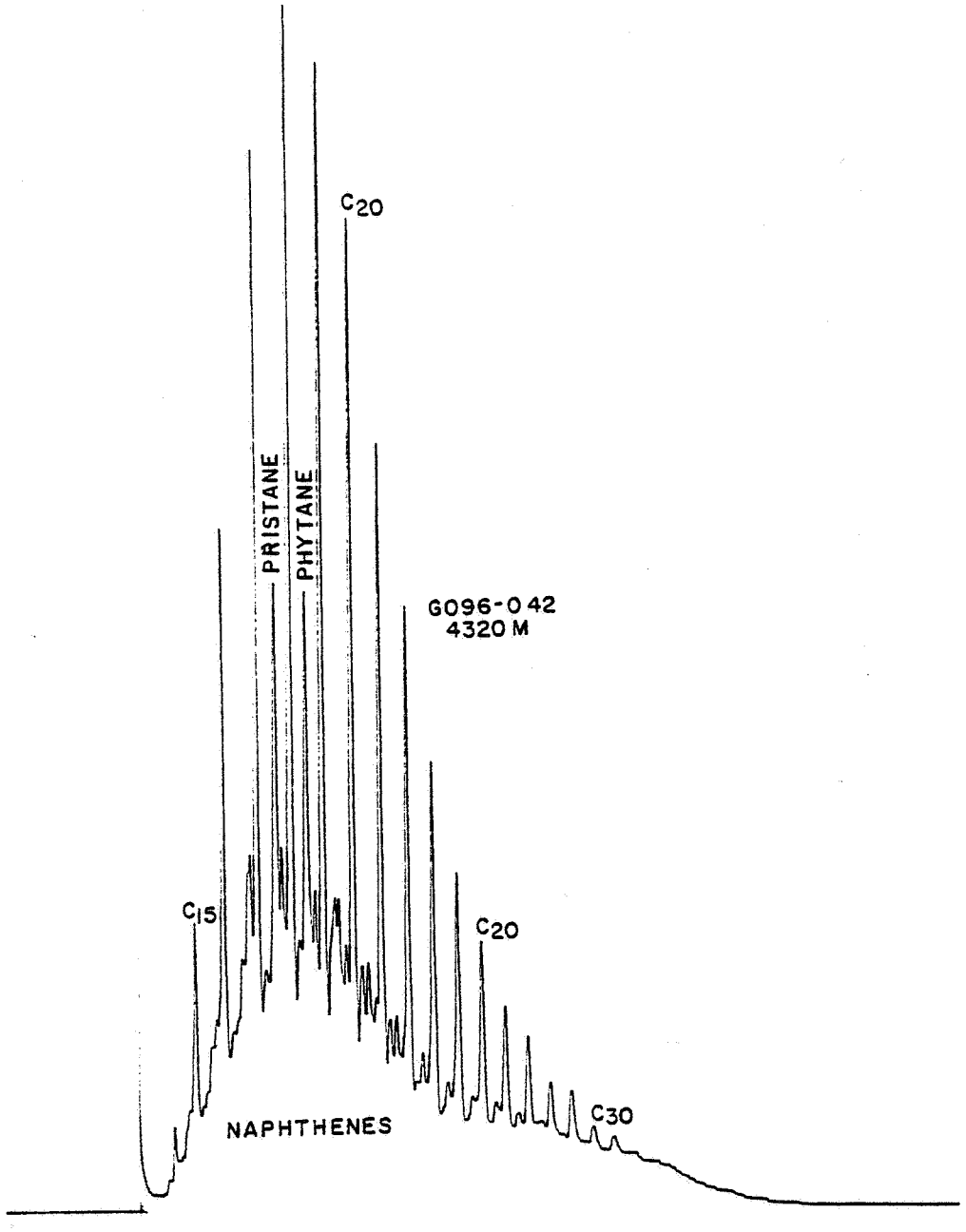
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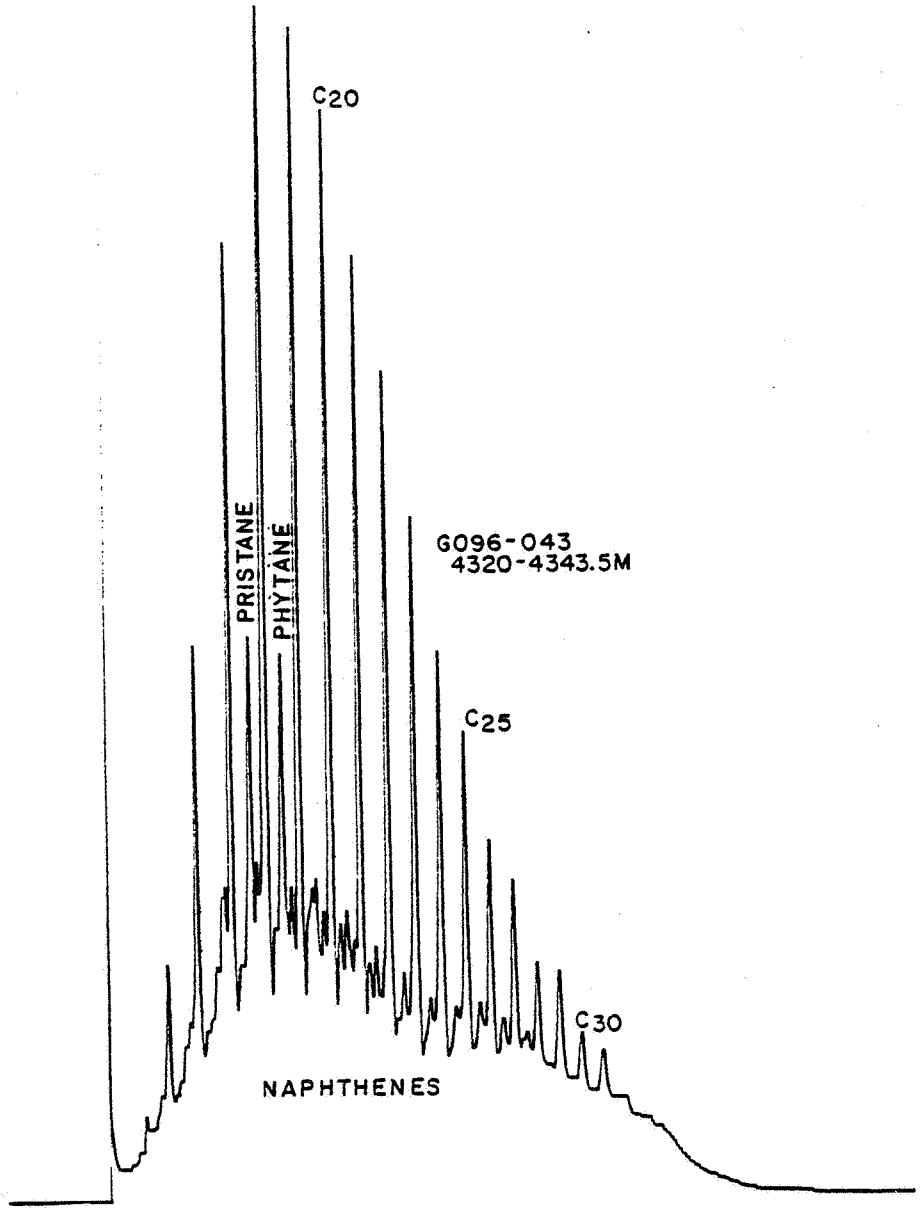
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