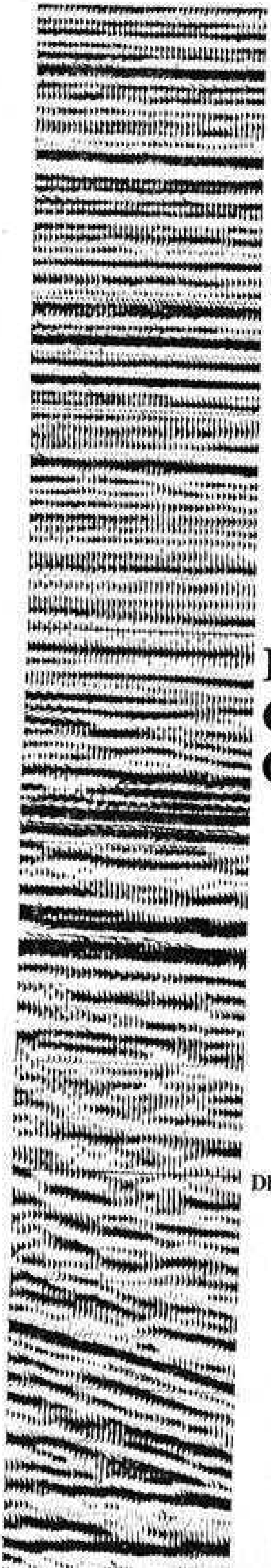


BPI REPORT # 15

BANGLADESH PETROLEUM INSTITUTE

RESOURCE ASSESSMENT OF THE KAILAS TILA GAS/CONDENSATE FIELD

Dhaka, October, 1992.

BPI Report 15 OCTOBER,1992

BANGLADESH PETROLEUM INSTITUTE

RESOURCE ASSESSMENT

KAILAS TILA GAS/CONDENSATE FIELD

EXECUTIVE SUMMARY

Bangladesh Petroleum Institute started working in the area of resource assessment from early in 1991. The first two studies were focussed on the Haripur oil discovery (see Reports 10 and 11). When the Minister for Petroleum and Mineral Resources reviewed BPI's 1992 activity schedule, during the annual mid-term meeting with NORAD Norwegian Petroleum Directorate and the Ministry of Petroleum and Mineral Resources, he indicated that there was a need for BPI to re-evaluate available reserves in some of the gas and gas/condensate fields of the country.

The main objectives of Resource Assessment are :

- To generate a reliable basis for economic forecasts and government planning
- To generate an adequate basis for planning and controlling petroleum exploration, development and production
- To establish the ability to perform resource assessment within BPI.

Resource assessment has a significant impact on field development policy and an equally important impact on production policy. Groups for resource assessment and reservoir evaluation were, therefore, set up in BPI to fulfil the new requirements of the Government and this was facilitated by the recruitment of additional junior professionals in BPI.

The review of the Kailas Tila field was thus taken up on a priority basis in BPI. One of the specific reasons for selecting this field as the first item in this programme of revision of reserves was the known fact that gas accumulations in Kailas Tila were not entirely controlled by structure alone as the northern limits of the various gas accumulations in the field could not be clearly demarcated. Therefore, there was every reason to expect the wide disparity that is being noted in assessment of reserves **unless** answers were found for the uncertainties in respect of the closure.

The most recent attempt to evaluate the reserves of Kailas Tila has been by the Canadian consultancy company IKM Ltd. But even that report leaves the question of the northern limit of the main gas pools of the field quite open. There is, therefore, no doubt that a fresh attempt, as recommended by the Minister for Petroleum and Mineral Resources, is necessary.

One of the biggest problems facing earlier workers has been the fact that clear gas/water contacts are not seen in the Upper as well as the Middle Gas Sands. The main interpretative input from this study in BPI is in the identification of "flat spots" delineating gas/water contacts which are, partially at least, confirmed by pressure gradient plots. These direct hydrocarbon indicators have also been useful in the current study in delineating pool limits. The current work has, therefore, been able to find answers to **some** of the problems faced in the earlier attempts including the problem of locating the limits of the main pool in the Upper Gas Sand of the Bokabil.

Log correlation shows that the sands below the Middle Gas Sand are lenticular in nature. Several pressure buildup surveys have been carried out in the field but, apart from the on-site preliminary reports, no detailed analyses were available. A careful analysis of the pressure buildup data from the test of the Lower Gas Sand in KT-3 has, during this study, permitted to locate multiple boundaries and confirm that this pool is in a lenticular sand thus providing additional weight to the argument that all the so-called "Lower" gas sands in all the three wells on the structure are unconnected from each other.

This report basically deals with precise estimations of volumes of gas initially in place (GIIP) and condensate initially in place (CIIP), the total for the field is seen to be, at 90% level of confidence, 1.689 trillion standard cubic feet gas AND 26.004 million stock tank barrels of condensate.

Condensate recovery is generally well over 50% of CIIP while gas recovery, in the context of adequate utilization in the Sylhet area itself, should not be expected to be less than 70% of GIIP (abandonment pressure of 1000 psi if there is no water influx). Reserves (recoverable as indicated above) should then be 13 MMSTB condensate (npv about US dollars 338 million at current diesel oil prices of USD 26/barrel) and 1.182 TCF gas (npv about US 1773 million at USD 1.5/MMbtu).

There are still some unanswered questions in regard to sand geometry. From the managerial standpoint it would be perhaps correct to assume, for the present at least, that aquifer size is not more than 2 or 3 times the pool size for even the Upper Gas Sand. As a corollary then it might be safe to assume that water expansion drive may contribute only very partially towards maintenance of reservoir pressure. If reservoir pressure is allowed to fall by even 200 or 300 psi there is then a clear danger of retrograde condensation in the reservoir.

LIST OF ATTACHMENTS

1. INTRODUCTION

1.1. Resource Evaluation in the context of resource management

Petroleum resources are valuable assets of the country for economic development. Their exploitation should, therefore, be conducted within a framework that serves best the interests of the country. In Bangladesh several agencies are involved in the process of managing the petroleum resources:

- Petrobangla, the organization over-all in charge of all the operations.

- BAPEX, a company under Petrobangla, for exploration.

- The Project Implementation Unit (PIU), under Petrobangla, which is responsible for implementation of the projects connected with gas field development, laying of long distance pipelines and erection of processing plants where funds are mainly from donor agencies like the World Bank, ODA, CIDA and the Netherlands Government.

- Foreign oil companies operating in areas under a contract with Petrobangla and the Government in carrying out exploration and development activities.

- Two gas producing companies (BGFCL & SGFL) and three gas marketing companies (TGTDCL, BGSF & JGTDS) all under Petrobangla are responsible for production and transmission, distribution and marketing of gas respectively.

- RPGCL, a company under Petrobangla to install LPG bottling plants and also to promote use of CNG.

- In addition, there are several consultancy companies employed largely with bilateral or multilateral aid funds whose functions are mainly in the fields of exploration programming, supervision of exploration activities, planning and supervision of appraisal and development programmes, assessment of reserves, planning and supervision of construction of distribution networks and process plants and many other related activities.

- The Government relies on one or several of the above agencies for the information required as well as for analyses of data bases while formulating the basic strategies as well as in monitoring the implementation of a given programme.

The evaluation of the petroleum resources base will always involve some element of subjectivity. The various agencies in the operations can have different strategic interests. Consequently they would tend to place different emphasis on either positive or negative factors in their assessment depending on their particular concern preference. For the benefit of the country it is essential to assess the resource potential as early and as objectively as possible.

The success of Government policies in the petroleum sector depends largely on the institutional framework it creates for operating and supervising the activities of the sector. The size and the composition of the framework depends on the volume of activity which in turn is a function of the prospectivity for petroleum resources. This is the background in which Government set up Bangladesh Petroleum Institute whose cardinal function is evaluation of resource potential, assessment of the resource base and maintenance of a major data base. All this is to help BPI in providing adequate technical assistance to the Ministry of Petroleum and Natural Resources.

The Norwegian aid programme utilized for the development of Bangladesh Petroleum Institute is mainly focussed on developing national capacity in an institution attached to the Ministry of Petroleum and Mineral Resources for providing Government with an independent assessment of all the parameters required for administering the petroleum sector. For this purpose, BPI is also being assisted by the Norwegian Petroleum Directorate through NORAD in developing skilled manpower as well as in acquiring the technical infrastructure for effective utilization of available skills.

In general, the speed with which commercially exploitable resources are discovered determines to a large extent the rate of resource development. Again, in general, prioritization of field development depends on the volumes found in given parts of the country as well as on the extent of development of the market in a given area. Specially, the discovery of the gas fields in the Bhakrabad trend is responsible for the formulation of plans to use large quantities of gas in the Chittagong area.

The possibility of a long-term short-fall of gas in the southern zone is the main reason for speeding up with development of Kailas Tila field and the North-South connector in Second Phase of the Gas Development Plans. Rational decision-making in this respect depends very much on the precision with which the Government knows the exact volumes of gas reserves in several fields in the area.

In addition to prioritization of field development it is important that the manner of depletion of individual fields is optimal. Optimality in this context means a careful balancing between the long-term benefits of increasing recovery of hydrocarbons from the field against the short-term advantages of maximizing the net present value of the produced (or recovered) resources. There is always a danger that ad-hoc formulation of plans could affect the long-term interests. **Resource assessment in this context also will have to be sufficiently accurate so as to enable proper economic assessment of the alternatives.**

1.2. Resource Assessment Problems - Kailas Tila

Biswas (IKM Report, 1991) states that "the discovery of the Kailas Tila field is a classic example of serendipity." The discovery well was drilled several years back on the basis of a geomorphic anomaly similar to Mama Bhagna (renamed as Beani Bazar) in the east and Sylhet in the north. The interpretation, at that time, was that Kailas Tila is a doubly plunging anticline with four-way dip closure.

Repeated interpretation of three separate seismic surveys failed to find a northerly plunge for the Kailas Tila structure. The separate gas sands were found in the discovery well. The two appraisal-cum-development wells, KT-2 and KT-3, were drilled very recently: Both had unexpected discoveries. KT-2 found a "New Sand" between the Upper and the Middle Gas Sands. The "Lower Gas Sand" in each of the appraisal wells were found to be unconnected with each other and with the Lower Gas Sand of KT-1.

The main reserves of Kailas Tila are in the Upper and the Middle Gas Sands. The spill point elevation on the north gives a far lesser height for the closure than is required by the thickness of the gas columns in each of these sands. There has to be a stratigraphic reason for the accumulations in both these sands as none of the north-south seismic lines give any indications of a fault of the orientation and magnitude required to explain the accumulations. No such indication, for stratigraphic reasons for the northerly closure, was proved by any of the earlier studies.

A gas/water contact has not been noted in either the Upper or the Middle sand in any of the three wells drilled. Consequently the *flankward* extension of gas was, until the present study, a matter of conjecture. The "New" gas sand of KT-2 has bottom water (GWC at 8900' tvdss) but sands at similar depths in KT-1 and KT-3 are most possibly water-bearing. The "Lower" gas sands of KT-1 and KT-2 have only a "gas/shale" contact, while, in KT-3, the "Lower" gas sand has a clear gas/water contact at 9991' tvdss.

It is clear that several questions need to be answered before any reliable estimates of **gas initially in place** (and also of **condensate initially in place**) can be made. This report is an attempt to refine reserves estimations.

1.3. Methodology

The "flow-chart" for the resource assessment operations is shown below and the study has been carried out using this approach.

SEISMIC INTERPRETATION
TIME STRUCTURE MAPS (SELECTED LEVELS)
CHECK SHOT SURVEYS
SYNTHETIC SEISMOGRAMS
DEPTHS MAPS

SAND CORRELATIONS USING LOGS
INTERPRETATION OF DIPMETER LOGS
DEPOSITIONAL ENVIRONMENT STUDIES

SEISMIC STRATIGRAPHIC INTERPRETATION
INTERPRETATION OF DIRECT HYDROCARBON INDICATORS ON SEISMIC SECTION
QUANTITATIVE INTERPRETATION OF WELL LOGS
CALCULATION OF WEIGHTED AVERAGES OF PETROPHYSICAL PROPERTIES AND FLUID CONTENT
NET/GROSS DATA FOR ALL PAY ZONES
FULL RESERVOIR DESCRIPTION FOR ALL SANDS

STRUCTURAL CONTOUR MAPS OF PAY HORIZONS

RE-INTERPRETATION OF PRESSURE DATA
PRESSURE GRADIENT PLOTS
PRESSURE BUILDUP ANALYSES

INTERPRETATION OF FLUID CONTACTS AFTER INTEGRATION OF ALL DATA

PREPARATION OF "GROSS PAY THICKNESS" MAPS

PLANIMETERING PAY THICKNESS MAPS
CALCULATION OF GROSS ROCK VOLUMES OF PAY SANDS (SIMPSONS OR TRAPEZOIDAL RULE)

CALCULATION OF CHPV (Hydrocarbon Pore Volume) FOR ALL PAY SANDS

EVALUATION OF TEST AND GAS ANALYSES DATA
FLUID PROPERTIES (PVT) AND CONDENSATE YIELD FOR DIFFERENT SANDS

DIRECT ESTIMATION OF GAS INITIALLY IN PLACE (GIIP) FOR ALL SANDS

DIRECT ESTIMATION OF CONDENSATE INITIALLY IN PLACE (CIIP) FOR ALL SANDS

MONTE CARLO SIMULATION FOR ESTABLISHING CONFIDENCE LEVELS

FINAL EVALUATION GIIP/CIIP FOR P90, P50 AND P10 LEVELS
OF CONFIDENCE FOR ALL SANDS

PRELIMINARY ESTIMATION OF POSSIBLE DRIVE MECHANISM AND ESTIMATION OF RESERVES

NET PRESENT VALUE OF RESERVES OF GAS AND CONDENSATE

When completed as shown above, the study, in general, be sufficient for the authorities to evaluate and comment upon the
field development plans, long-term production Prognosis, transmission and utilization options and, finally, the investment plans proposed by any or all of the various agencies involved in the management of the operations in the gas/condensate sector. In the present case, the BPI evaluation is valid to the point of estimating volumes of gas-initially-in-place and condensate-initially-in-place. More work is necessary before Reserves (the recoverable part of gas and condensate) are precisely estimated.

At this point, it might be necessary to discuss some aspects of "terminology". The industry has been operating for several decades on the basis of :

"Proved Reserves of oil or gas are generally taken to be those quantities which geological and engineering information indicate with reasonable certainty can be recovered in the future from known resources under existing economic and operating conditions".

It has been known for long that many of the words used in the above definition are somewhat vague and capable being used in a subjective fashion. There has never been a uniformly accepted basis for calculating volumes of resources initially-in-place and many of the problems connected with inadequately accurate definition of terms are on account of this factor.

Some years back the World Petroleum Congress set up a committee to go into the questions of terms used in any resource inventory system. The final recommendations, accepted by now by almost all governments and oil companies are that:

Volumes of stock-tank-oil-initially-in-place (STOIIP) would be generated after "several hundred Monte Carlo Simulations" are done on the ranges of all the parameters utilized in calculating STOIIP and would be reported for three levels of confidence:

P10 which gives a 10% chance that the volumes as calculated would be present
P50 which gives a 50% chance that the volumes as calculated would be present
P90 which gives a 90% chance that the volumes as calculated would be present

The same method is used to calculate the levels of confidence for gas-initially-in-place (GIIP) and condensate-initially-in-place(CIIP). The general practice for several probability of being correct for all planning purposes. **In the case of natural gas or gas/condensate fields of Bangladesh it would be advisable to limit investment to volumes of hydrocarbons known to be present at the 90% level of confidence.** In this study, BPI has used a simulation programme which does 5000 Monte Carlo operations.

1.4. Estimation of Recoverable Volumes of Natural Gas and Condensate

The term **RESERVES** should be used only for that part of STOIIP, GIIP or CIIP which can be recovered at the surface using currently available technology and in the current economic regime (costs of production and price of the recovered item). **Recoverable volumes of oil, gas or condensate can be estimated only if the drive mechanism chosen, natural or engineered drive, is technologically viable and economically optimal.** For reporting purposes, at least at the initial stage, the normal practice for similar fields in other parts of the country, or in the

When completed as shown above, the study, in general, be sufficient for the authorities to evaluate and comment upon the
field development plans, long-term production Prognosis, transmission and utilization options and, finally, the investment plans proposed by any or all of the various agencies involved in the management of the operations in the gas/condensate sector. In the present case, the BPI evaluation is valid to the point of estimating volumes of gas-initially-in-place and condensate-initially-in-place. *More work is necessary before Reserves (the recoverable part of gas and*

given part of the world, can be used to first estimate reserves of oil natural gas and condensate and then to estimate the net present value of such reserves.

The present study indicates that substantial volumes of condensate are available even in the Upper and the Middle Gas Sands of the Kailas Tila field. Recovery of condensate is entirely dependent on the economics of the operations. Normal practice worldwide has been to recycle gas after stripping the "distillates" and this operation has always been economical, even as far back in time as the 'thirties when petroleum products prices were quite low, to recover 50% or more of condensate-initially-in-place. At current prices of USD 26 or more for diesel oil, condensate recovery should play a significant part in programming the production profile of the field.

Recovery of non-associated natural gas, **after** recovery of the economically viable part of condensate, is dependent on the pressure at which the buyer wants gas delivery. Normally speaking, it would be necessary to ensure 700 or 750 psi at the delivery point. In the case of Kailas Tila it should be possible to produce around 70% of gas-initially-in-place **for delivery in the Sylhet area** at the required pressure.

The Kailas Tila gas/condensate field has already been appraised with two wells and, for all practical purposes, has also been "developed for production" The field has also been put on production although, at present, only one well is producing. Most surface installations for full-scale production have been put in place and the pipeline connecting the field with the southern part of the country have also been laid. Even an 6" NGL line has been laid from the field to Ashuuganj where a central NGL processing plant is being erected. In effect all the investment decisions have been taken prior to this study in BPI.

2. INTERPRETATION

2.1. Seismic Interpretation and Structure Contour Maps

The regional interpretation of the Chhatak, Sylhet, Kailas Tila areas have already been reported (BPI Reports 11 and 12). The Kailas Tila area was re-interpreted with specific emphasis on mapping carefully a level close to the top of the Miocene Upper Marine Shale Formation (Enclosure 1 on scale 1:12500). Utilizing the data from the synthetic seismograms of KT-2 this map was depth-converted and a proper structure contour map for the base of UMS - top of Upper Gas Sand (Enclosure 2) - was made. Using data from correlations shown on Table 1 a structural contour map on the top of the Middle Gas Sand was also made (Enclosure 5).

BPI is not aware of any earlier report of any direct hydrocarbon indications in the Kailas Tila area. The calculation of acoustic impedance (v*density) showed that although no major anomaly need be expected at the top of the gas sand, the gas/water contact should give rise to a significant reflection of incident energy. An examination of the seismic lines across the structure, particularly those lines crossing the drilled wells, showed a prominent "flat spot" anomaly exactly at the level where the gas/water contact was expected to be for the Upper Gas Sand - at around 1790 ms. Very clear indications of "velocity pull down" were seen in the sections beneath the Upper Gas Sand.

A detailed examination of **all** the lines showed that dip lines KT-1, KT-2, KT-3 and KT-4, located north of the possible northern limit of the gas accumulation in the Upper Gas Sand, **did not show any flat spot anomalies.**

To the south, flat spot anomalies are seen on all dip lines down to KT-10. The "strike-lines" KT-11 and SU-5 were then studied. On the former line, a fairly clear flat spot anomaly is seen all the way south to close to the intersection with dip line KT-15 (this line itself was not available for study). This indicates the possible southern limit of the Upper Gas Sand gas accumulation. Line SU-5 shows almost the same picture.

Earlier workers, particularly the consultants from IKM Ltd., had stated that there is no real indication on any of the lines studied of a generally east-west trending fault to explain the accumulation of gas in the Boka Bil sands of Kailas Tila. IKM report mentions that a study of lines KT-25, KT-26 and KT-27 might help in completely ruling out such a fault aiding the entrapment. These lines are still not available. The BPI study shows that lines SU-5 and KT-11 are perhaps adequate to rule out the presence of any such fault.

The "strike-lines" were then carefully studied. Line KT-11 shows seismic stratigraphic indications of sand "pinchout" (or "downlap" with shale to north - see P-283, Sheriff) a little to the south of the intersection with line KT-4. Note that the structural dip to south, the result of fairly recent movements, must be "removed" while identifying this seismic stratigraphic feature as a downlap instead of an onlap. There is perhaps a need for a much more detailed study of the seismic stratigraphic features in the Boka Bil and also in the Bhuban, but, **the general conclusions of this report in regard to resource assessment would continue to remain valid even after such a study.**

The velocity pull down effects for the deeper sections would need to be corrected if structural maps for those levels are to be made from seismic time maps of those levels. This report bases the deeper level structural maps on the "near-parallelism" of all the reservoir sands to the Upper Marine Shale.

2.2. Correlations

The general results of inter-well correlation are shown on Table 1. The Upper Marine Shale is well correlatable in all the wells. Another good marker shale has been termed in this report as the "Lower Marine Shale". In both cases dipmeter data clearly indicate deposition in relatively low energy environments and, if the Upper Shale is marine there should be little doubt that the Lower Shale is also marine.

Considering the conformity of the top of UMS to the LMS (see Table 1 and Enclosure 8) it would appear that there is a "sand buildup" from KT-1 to KT-2 for the "Upper Gas Sand". The top of UGS does "come down" a little again from KT-2 to KT-3. Dipmeter data from KT-2 indicates that there is "drape effect" in the lower part of the Upper Marine Shale. These facts, taken together with changes in the porosity with change in shale proportion in the UGS, coarsening as well as cleaning upward, indicate that the Upper Gas Sand was most probably deposited in a coastal environment. Several sub-units can be distinguished in the UGS and it is entirely possible that there are several elements in the UGS - some tidal channel fill sands, some point bar sands and at least one clear offshore bar.

One important but thin shale marks the level of LKG (Lowest known gas) in the Upper Gas sand of KT-1. This shale has been called "shale within UGS". This level is not clearly identifiable in KT-2 and LKG for the Upper Gas Sand is almost at the same depth, however, 76 ft shallower than in KT-2. As the gas/water contact has not been crossed in any of the three wells it should be assumed that GWC is at least deeper than 7602 ft below MSL.

Enclosure 8 shows the correlations of all the units listed in Table 1. Note that a clear gas/water contact is seen only in two cases: for the "New Sand" or KT-2 and for the Lower Gas Sand of KT-3. Although there is a possibility that the "Lower Gas Sands" of KT-1 and KT-2 could be connected there is little doubt that the LGS of KT-3 is an independent sand lens with hardly any possibility of hydrodynamic connection with sands to the south.

We have already noted (see section 2.1. above) that the UGS shales out to the north. There is less evidence of such a thing happening for the Middle Gas Sand but it is entirely possible that this sand too lenses out to the north.

2.3. Pressure Data Analyses

Enclosure 9 has been made from all available pressure data of all the three wells. Pressures of the Upper Gas Sand of wells KT-1 and KT-2 (with a gradient also available from KT-2's two separate tests) shows that this is one single accumulation with a possible **GWC** at 7700 ft sub-sea. The "pessimistic" water gradient of 0.436 psi/foot is being accepted for this purpose : the normal 0.433 psi/ft gradient would suggest **GWS** to be slightly lower. Gas compositions of the Upper and the Middle Gas Sands are closely comparable. The MGS pressure plot indicates that GWC is at around 9800 ft sub-sea.

The anomalous plot of KT-2 Lower Gas Sand pressure should be noted. The pressure is clearly less than hydrostatic and it is suspected, in this BPI study, that P* has been estimated too low by the testing company. Probably the buildup time was not long enough to record even a "second slope" on the semi-log Horner plot. If a boundary effect were to be "felt" on a longer shut-in then the second slope could be extrapolated to a pressure slightly higher than hydrostatic.

Enclosure 10 is pressure buildup plot of test data from the Lower Gas Sand of KT-3. The testing company's original Horner Plot was found to be not precise enough and, therefore, fresh calculations were made in BPI for this study. After the well-fill-up "goose-neck", pressure builds up on a straight line shown on the plot as slope m_1. After 2.116 hours of shut-in, pressure builds up on a second slope m_2. The first slope is 22 psi/log cycle while the second one is having a slope of **at least** 84 psi/log cycle. Theory states that if only one boundary is noted then the second slope should have a value exactly double that of the first slope. In this case it must be assumed that more than one boundary is being "felt". **As the second slope is not precisely defined it is not possible to extrapolate to P*.** Formation pressure is certainly more than 4200 psi and could even be a little over 4350 psi (the expected pressure at this depth as the gas/water contact is seen in the well at 9991 ft sub-sea).

KT-1 pressure for the Lower Gas Sand plots with an indication that **GWC 9960 ft** sub-sea if the water gradient is 0.433 psi/ft. As the lowest known gas (LKG) in KT-1 is at -9929 ft one could estimate the gas/water contact to be at around 9960 ft sub-sea.

2.4. Gross Pay Thickness Maps

Enclosures 3,4,6 and 7 are the gross pay thickness maps of the various gas sands of Kailas Tila. The zero contours for the Upper, New and Middle Gas Sands have been drawn on the basis of evidences for the limits of the gas accumulation from seismic (DHI) and pressure gradient plots to locate **GWC.** The Lower Gas Sands of the three wells are all shown together on Enclosure 7 and the zero contours are very subjectively located.

These maps were plannimetered to calculate gross volume. The results are shown on Table 2.

2.5. Quantitative Log Evaluation

Enclosures 11 and 12 show the results of the quantitative evaluation of reservoir properties and fluid saturations. Weighted average values of porosity and gas saturation were calculated from this data base. Again, the results are summarized on Table 2. The log evaluation software available in BPI is not very sophisticated and a quality control check (cross plotting ϕ_N and ϕ_D) shows that porosity values could have been slightly **under-estimated.**

2.6. Hydrocarbon Pore Volume (HCPV) Calculation

Net/Gross ratios were then calculated on a sand-wise basis for converting **gross rock volumes to net rock volumes.** Weighted average porosity and gas saturation values were calculated for each and for each well. Net pay thickness was picked using cut-off values for gas saturation, porosity and shaliness. **HCPV** was then calculated for each sand (see Table 2).

2.7. Gas Analyses Data

Only one representative analysis is available in BPI. This is from a test of the Upper Gas Sand of KT-1 by Shell. Gas properties were re-calculated in BPI :

Gas gravity	0.6055
Formation Temp	150°F
Formation pressure	3278 psig
T_c	357.7673
P_c	666.0903
B_g	0.0046 cu.ft/scf
Expansion factor	217 scf/reservoir cu.ft

The HP 41CX Petroleum Pac was used to obtain gas properties from the chromatographic analysis data.
Gas properties for the other sands are as used by earlier workers.

2.8. Condensate Yield

Table 2 shows, for the present purposes, the "accepted" values of condensate yield (in barrels condensate per million standard cubic feet of gas). The IKM report shows results of one test of the Lower Gas Sand where the yield is stated to be as high as 95 bbl/MMscf. The more conservative figure of 25 bbl/MMscf is used in the present report. There is clear need to retest the Middle and Lower Gas Sands to establish more reliable bases for estimating volumes of **condensate-initially-in-place.**

2.9. Monte Carlo Simulations

Simulation is a powerful tool for obtaining solutions by numerical methods. As **random numbers** (from a "random number generator") are used this simulation the method is often called the "Monte Carlo" method. ***Simulation, in the sense used here, refers to the group of numerical methods characterized by the process of making repeated solutions.*** Values entering into the calculations are repeatedly selected by random numbers taken from an *appropriate range* of values.

From several hundred to several thousand trials are generally used to obtain suitable results. The technique is, therefore, not suitable for hand calculations and needs at least a PC. The technique is readily adapted to solving probability distributions **and constructing probability distributions.**

The choice of the ranges and distributions are important and should reflect actual circumstances as closely as possible. When only an upper and a lower limit of the range of the variable is enough (are being one such parameter) then a *uniform distribution* is chosen. Where, for porosity or gas saturation for example, an upper, lower and most likely values are possible to be selected then a *triangular distribution* would be applicable. Some probability distributions are not continuous - only particular values can occur and, in such cases, a *discrete distribution* is assumed. The last is not commonly used in calculations of expected volumes of hydrocarbons initially in place except in the case of "gross rock volumes" for cases with high confidence level for the structural map and location of gas/water contacts.

Dependent distributions, net pay thickness for productive area is a good example, are not used in this report because the gross rock volumes are being obtained directly by integration of volumes between each contour of the gross pay thickness map and net rock volumes are being obtained by using weighted average net/gross ratios for the field as such. *Log-normal* and *log-log* distributions are not expected for the various parameters used in estimating volumes of discovered resources-in-place. When estimating **discoverable oil or gas in a basin the log-normal distribution of sizes of pools has been a standard assumption, but this is not applicable for this report which deals with volumes in a known field.**

Table 3 shows the ranges of values for the different parameters used in the Kailas Tila simulations.

3. CONCLUSIONS

3.1. Gas and Condensate Initially In Place

The final results showing volumes expected to be present at 90%, 50% and 10% levels of confidence are :

Reservoir	GIIP (trillion cubic feet)			CIIP (million barrels)		
	P90	P50	P10	P90	P50	P10
Upper Gas Sand	1.028	1.118	1.203	10.79	11.74	12.63
New Gas Sand	0.014	0.015	0.016	0.15	0.16	0.17
Middle Gas Sand	0.556	0.582	0.610	12.79	13.39	14.03
Lower Gas Sands	0.091	0.097	0.104	2.28	2.43	2.60
TOTAL	1.689	1.812	1.933	26.01	27.01	29.43

3.2. Anticipated Drive Mechanism and Recovery Factors

The geological modelling of the Middle Gas Sands of Kailas Tila, partly confirmed by seismic stratigraphic arguments, indicates that the aquifer size would not be expected to be much larger than 2 or 3 times the pool sizes. Water expansion drive would then be expected to be much less effective than for the gas pools of the southern part of the Surma basin (fields like Rashidpur or Titas for example). The New as well as the Lower Gas Sands are more definitely of restricted extent with even lesser possibilities for water expansion drive.

A certain amount of pressure decline with production should then be accounted for while planning the production programme.

As gas utilization in the immediate neighbourhood of Sylhet is already quite considerable and is expected to increase with time there is every reason to assume that the gas pools could continue to produce even till formation pressure is as low as 1000-1200 psi. Recovery of around 70% of gas-initially-in-place is then a reasonable assumption.

For the Middle and Lower Gas Sands at least one could assume would be and economic analysis, not done in this study, could perhaps show that condensate from the Upper Gas Sand too is worth recovering. None of this, of course, can be assured to be possible if pressure decline is permitted in the pools. For the present a 50% recovery factor is being used for condensate.

3.3. Reserves of Gas and Condensate and Net Present Values

At 90% level of confidence the reserves are :

Gas	1.182 trillion standard cubic feet
Condensate	13.00 million stock tank barrels

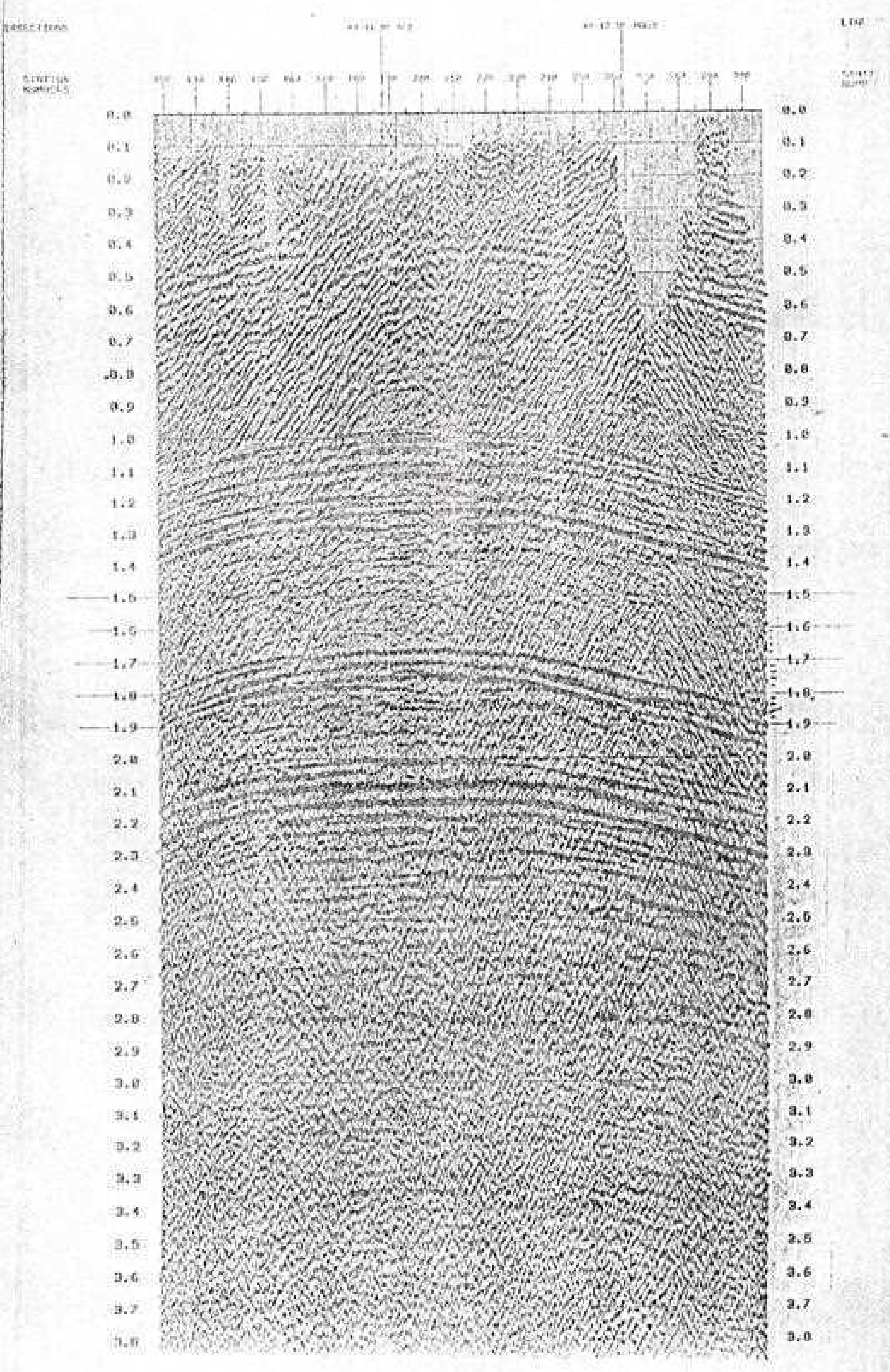
Note that condensate yield values are not known with a high degree of certainty and the actual reserves could be much larger: This needs to be verified very urgently.

Using an approximate price of USD 1.5 per million *btu* (1000scf) and USD 26 per barrel of condensate the *npv* would be :

Gas	1772 million US Dollars
Condensate	338 million US Dollars

ABBREVIATIONS USED IN THIS REPORT

Abbreviation	Full word
npv	Net Present Value
GTP	Gross Pay Thickness
GIIP	Gas Initiallly In Place
MMSTB	Million Stock Tank Barrel
bbl	Barrel (of oil or condensate)
IKM	Intercomp Kanata Management
TVDSS	True Vertical Depth Sub-Sea
STOIIP	Stock Tank of Oil Initially In Place
NGL	Liquified Natural Gas
LKG	Lowest Known Gas
GWC	Gas Water Contact
MSL	Mean Sea Level
P*	Initial Pressure
psi	pounds per square inch (pressure)
HCPV	Hydro Carbon Pore Volume
Pc	Critical Pressure
Bg	Gas Volume Factor
MMSCF	Million Standard Cubic Feet (of gas)
TCF	Trillion Cubic Feet
md feet	meassured depth in feet
KB	Kelly Bushing
RT	Rotary Table
ϕN	Neutron Porosity
UMS	Upper Marine Shale
Tc	Critical Temperature
ϕD	Density Porosity
LMS	Lower Gas Sand
UGS	Upper Gas Sand
MGS	Middle Gas Sand
LGS	Lower Gas Sand
NGS	New Gas Sand
MWS	Middle Water Sand
N/G	Net to Gross Ratio
1/Bg	Gas Expansion Factor
Sg	Saturation of Gas
KT	Kailashtila
BAPEX	Bangladesh Petroleum Exploration Company Limited
BGFCL	Bangladesh Gas Fields Comapny Limited
BGSL	Bakhrabad Gas System Limited
TGTDCL	Titas Gas Transmission and Distribution Company Limited
JGTDS	Jalalabad Gas Transmission and Distribution System
SGFL	Sylhet Gas Fields Limited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0.9
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1.8
1.9
2.0
2.1
2.2
2.3
2.4
2.5
2.6
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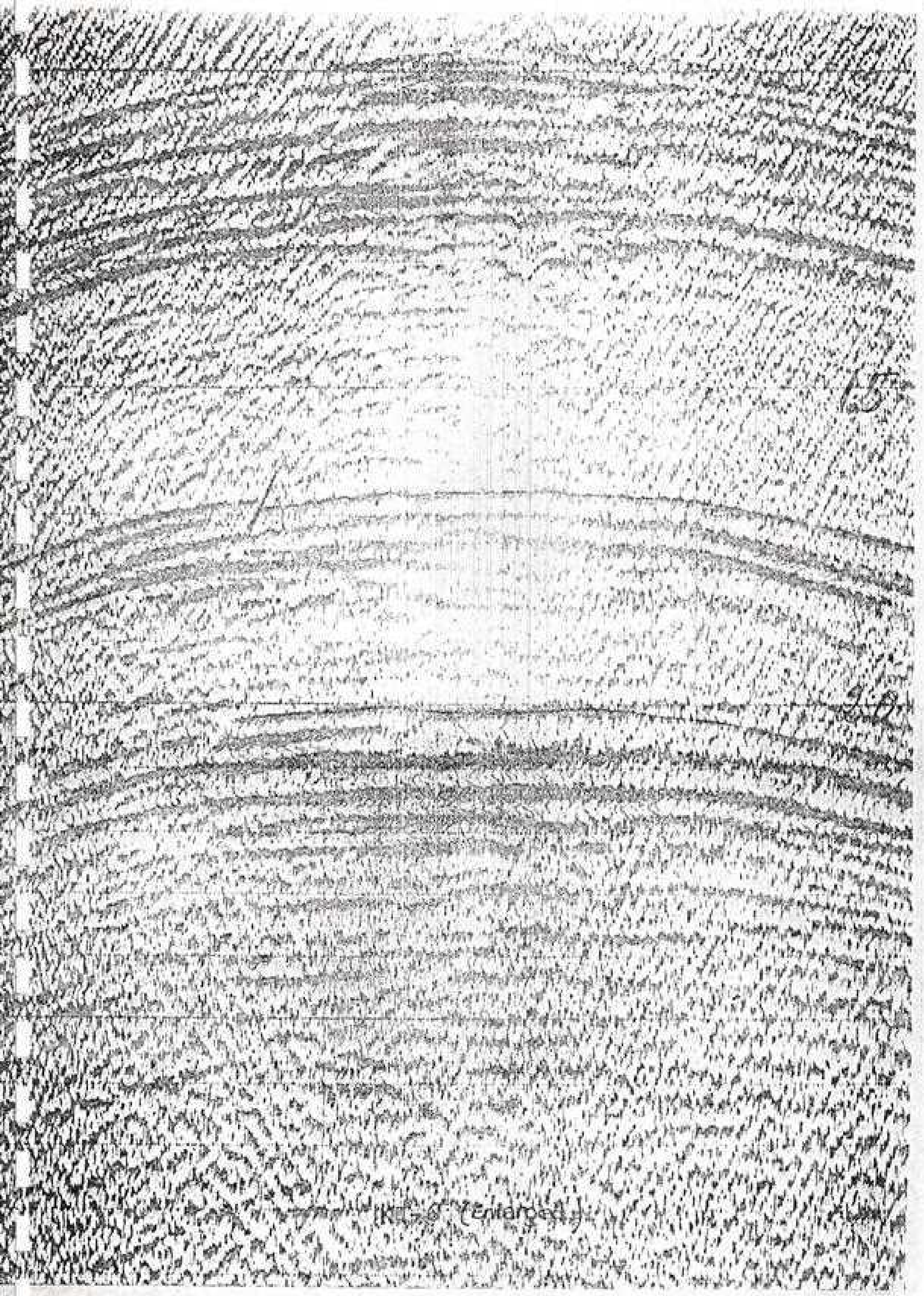
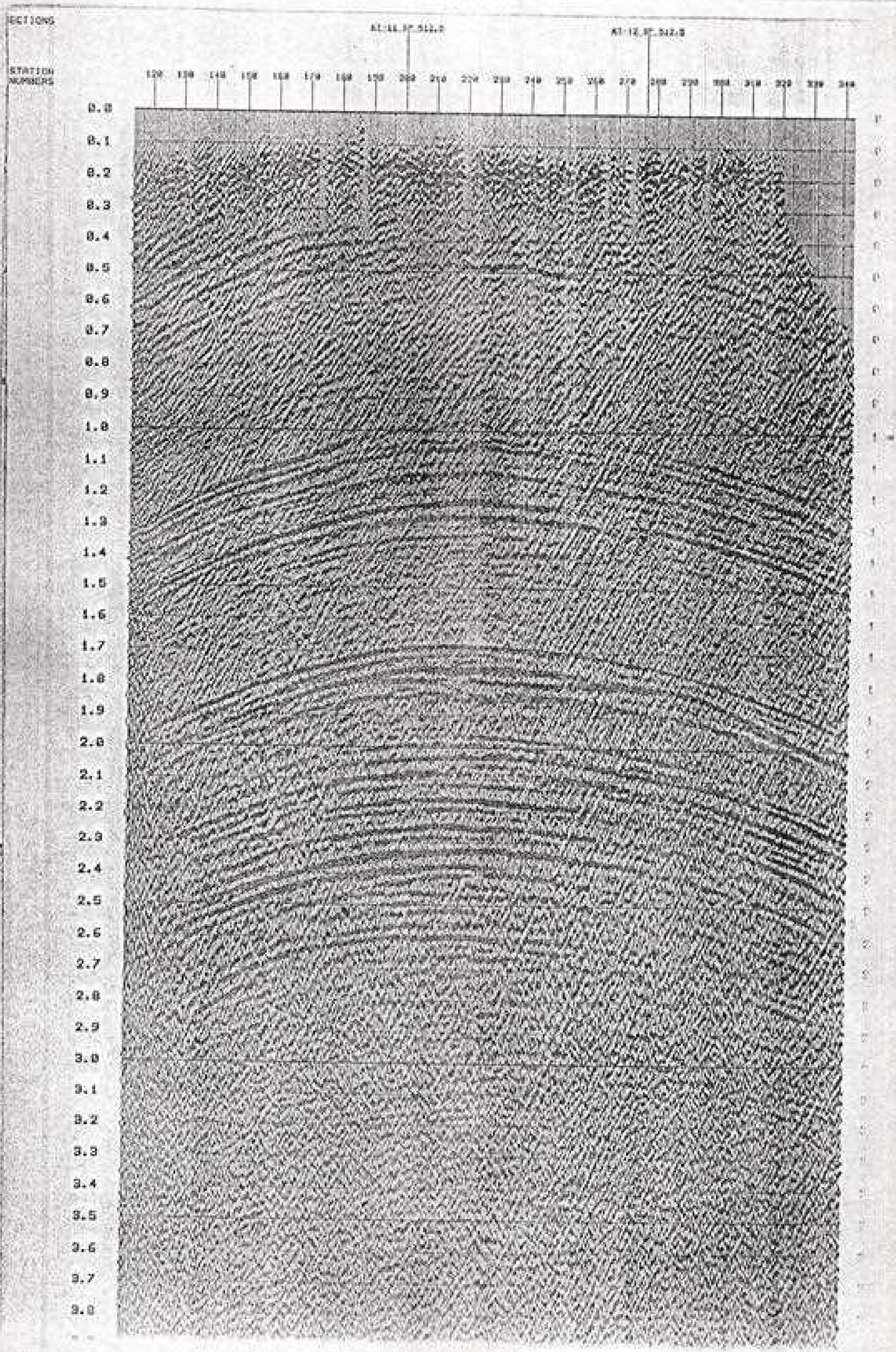
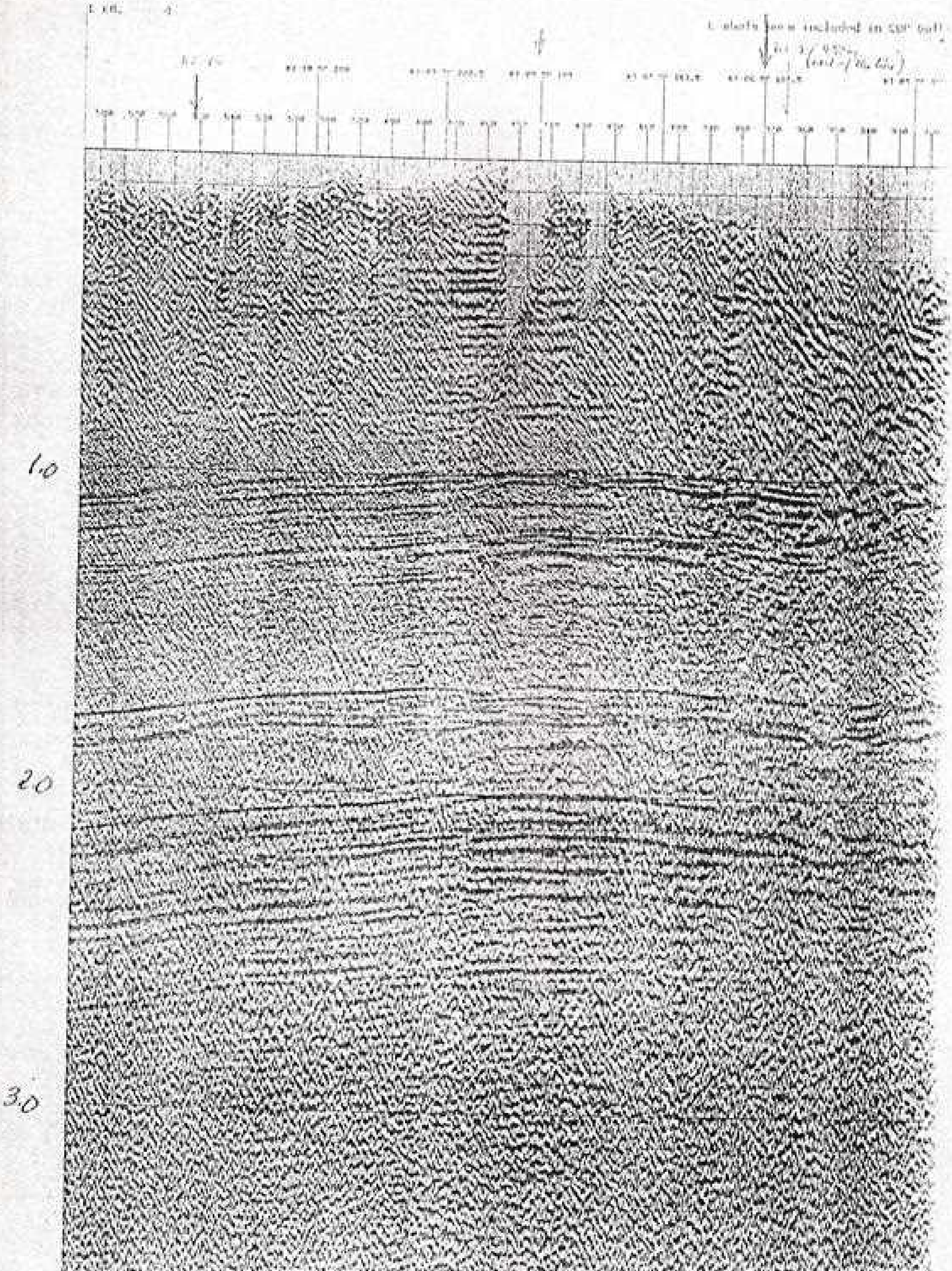


(FIG. 8 (enlarged))



SECTIONS
STATION NUMBERS
120 130 140 150 160 170 180 190 200 210 220 230 240 250 260 270 280 290 300 310 320 330 340
0.0 0.1 0.2 0.3 0.4 0.5 0.6 0.7 0.8 0.9 1.0 1.1 1.2 1.3 1.4 1.5 1.6 1.7 1.8 1.9 2.0 2.1 2.2 2.3 2.4 2.5 2.6 2.7 2.8 2.9 3.0 3.1 3.2 3.3 3.4 3.5 3.6 3.7 3.8

KT-10



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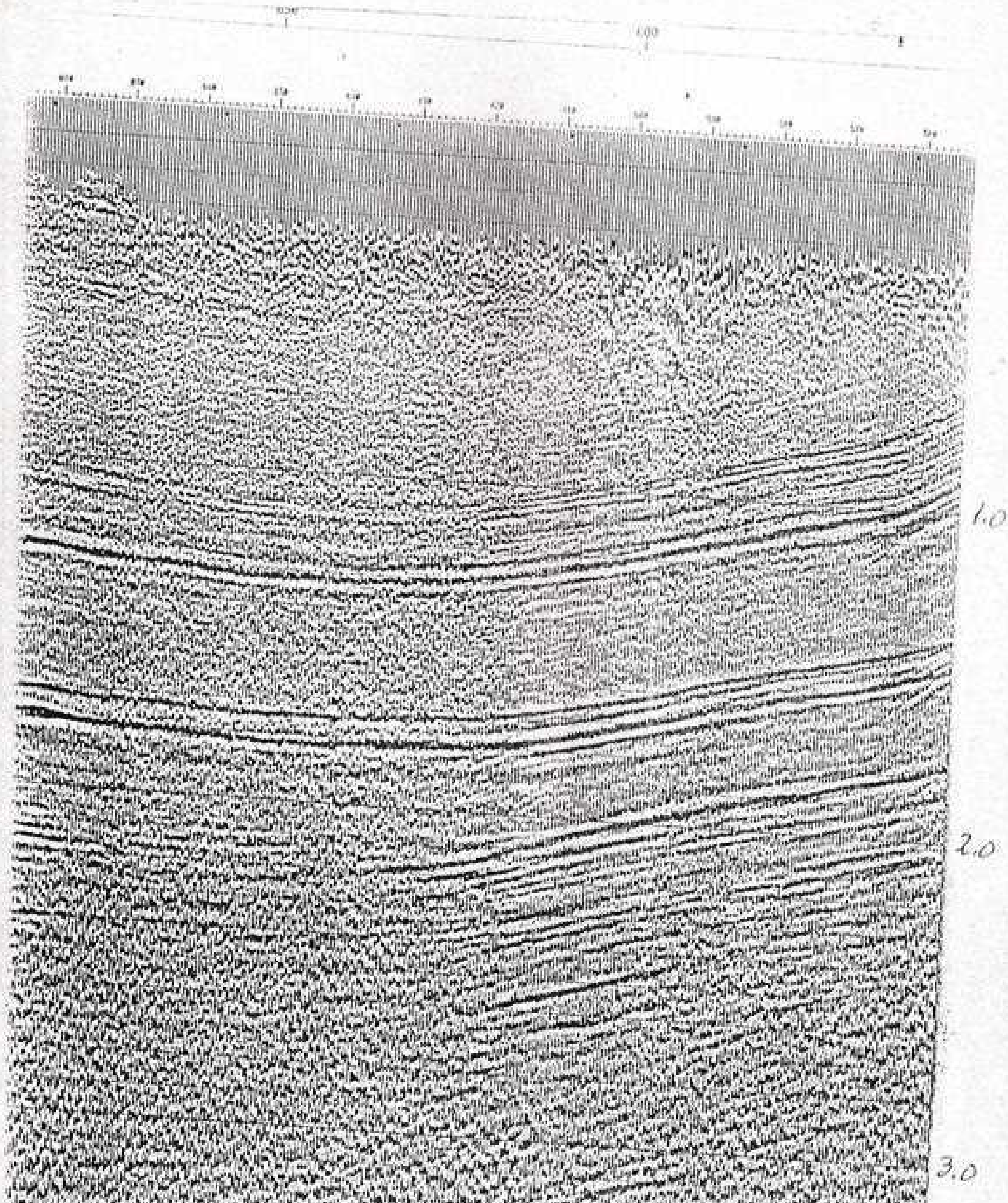
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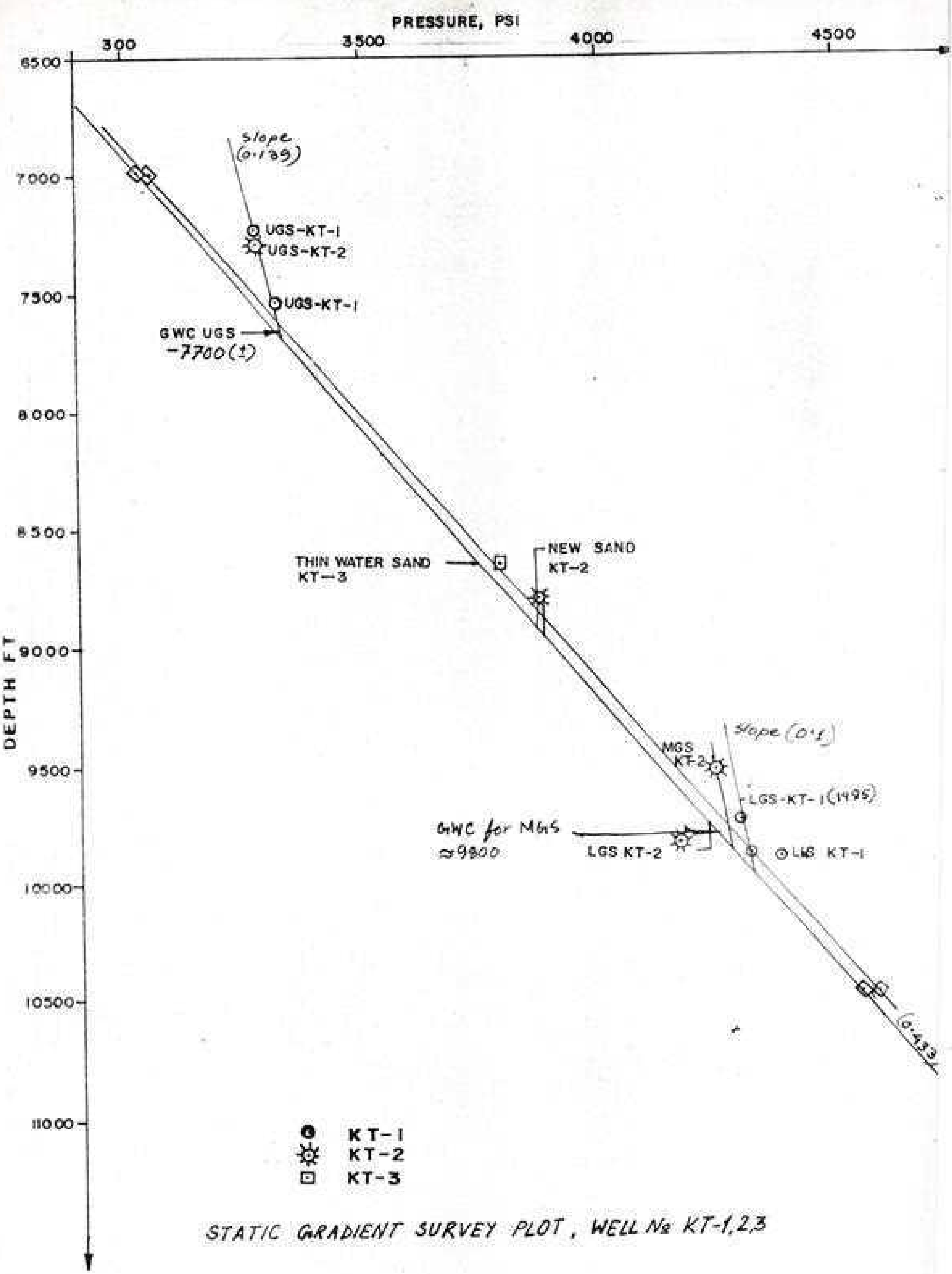


STATIC GRADIENT SURVEY PLOT, WELL № KT-1,2,3

FIG-10

FIG-11

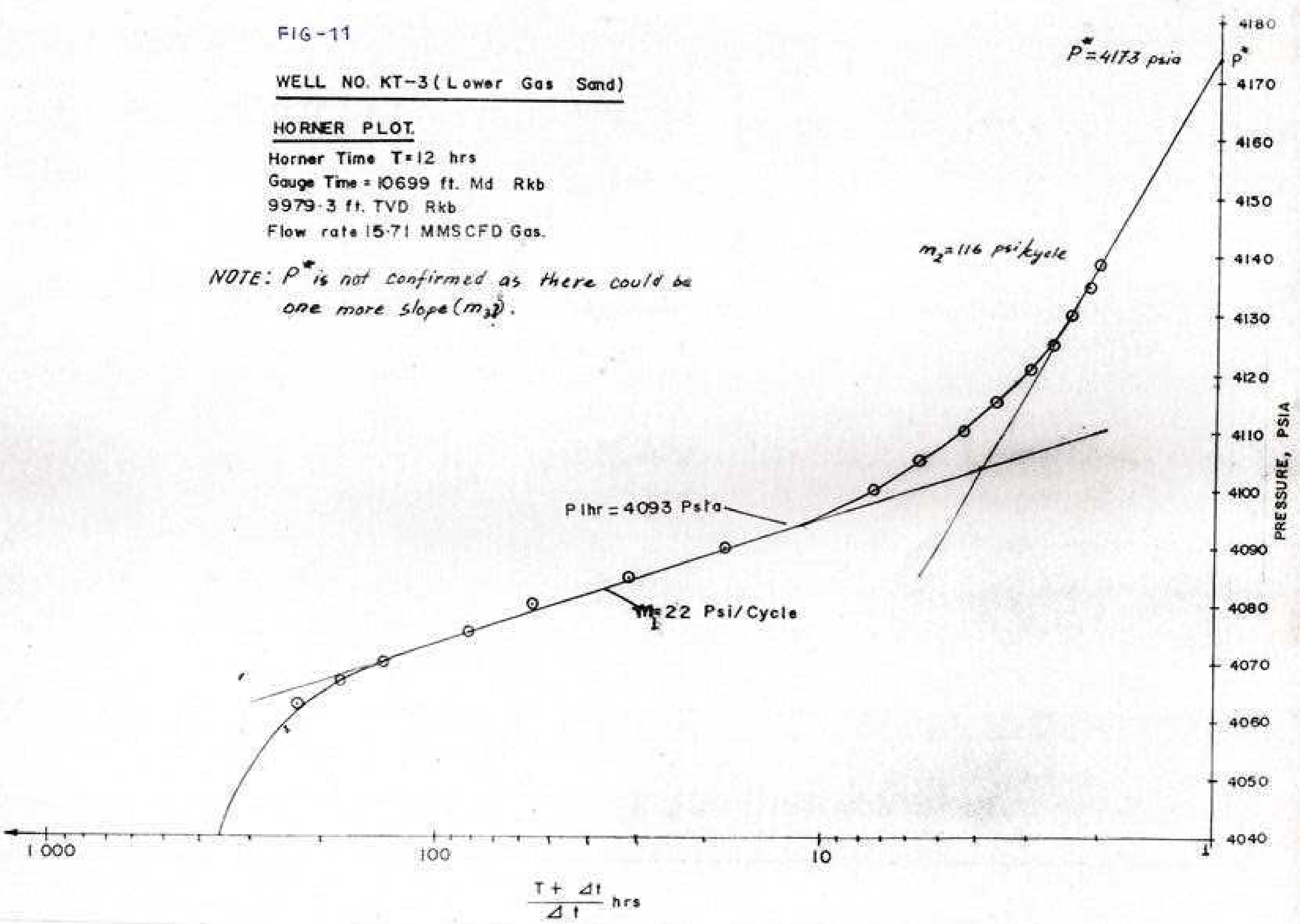

WELL NO. KT-3 (Lower Gas Sand)
HORNER PLOT.
Horner Time T=12 hrs
Gauge Time = 10699 ft. Md Rkb
9979.3 ft. TVD Rkb
Flow rate 15.71 MMSCFD Gas.
NOTE: P* is not confirmed as there could be one more slope (m_3).
P* = 4173 psia
P*
m_2 = 116 psi/cycle
P 1hr = 4093 Psia
m_1 = 22 Psi/Cycle
4180
4170
4160
4150
4140
4130
4120
4110
4100
4090
4080
4070
4060
4050
4040
PRESSURE, PSIA
1000
100
10
1
$\frac{T + \Delta t}{\Delta t}$ hrs

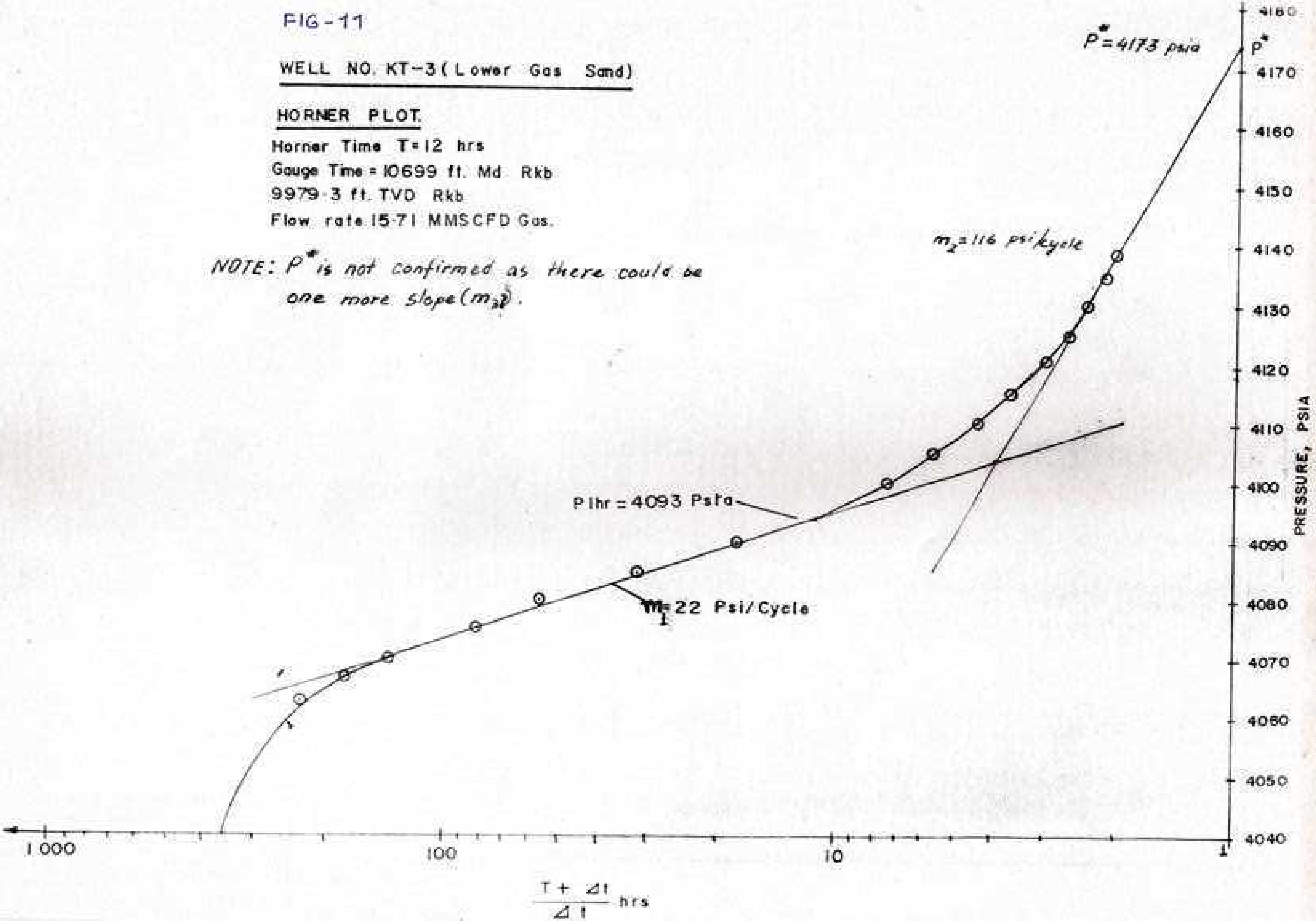
FIG-11

WELL NO. KT-3 (Lower Gas Sand)

HORNER PLOT.

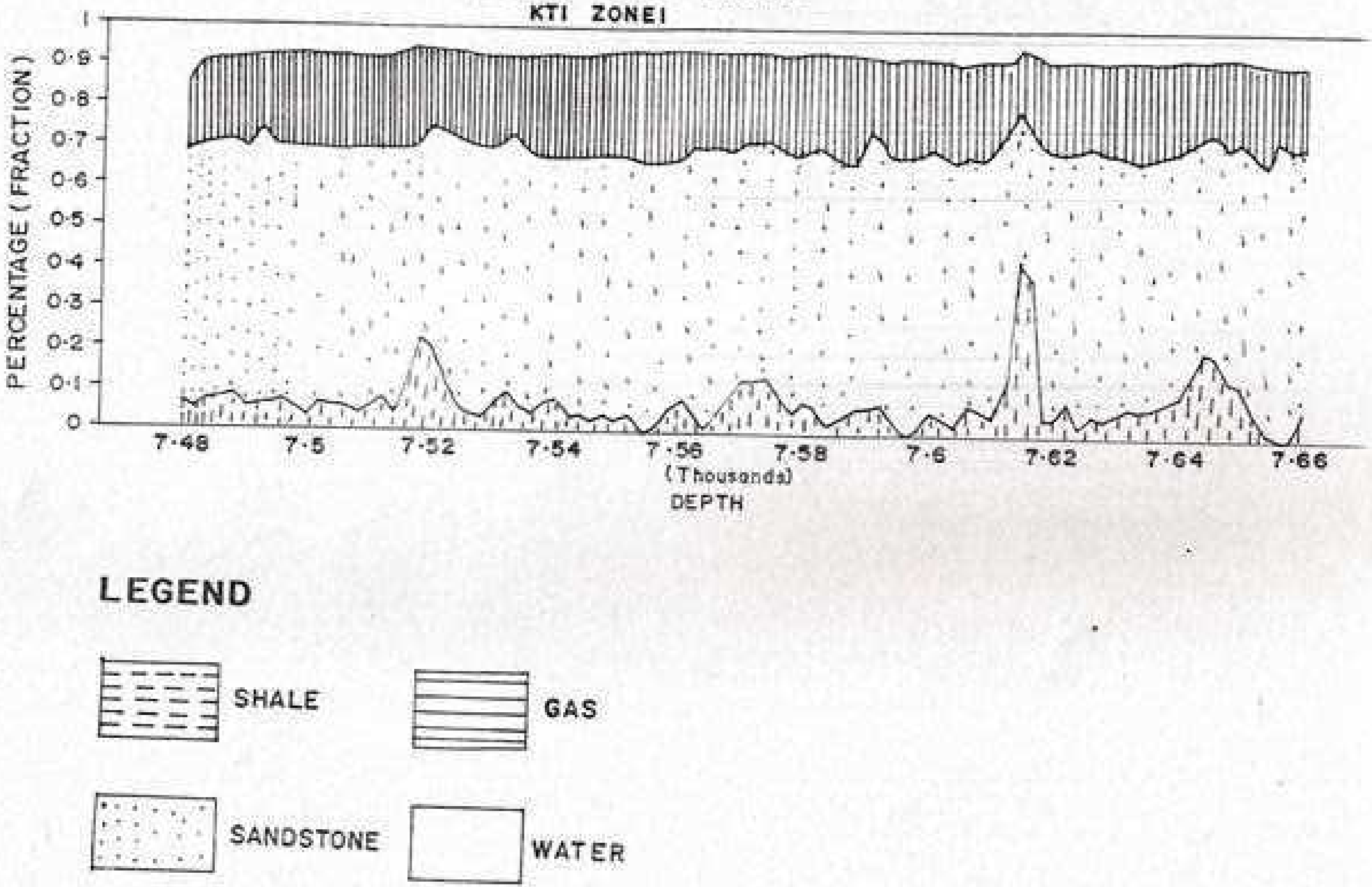
Horner Time T=12 hrs
Gauge Time = 10699 ft. Md Rkb
9979.3 ft. TVD Rkb
Flow rate 15.71 MMSCFD Gas.

NOTE: P^* is not confirmed as there could be one more slope (m_3).

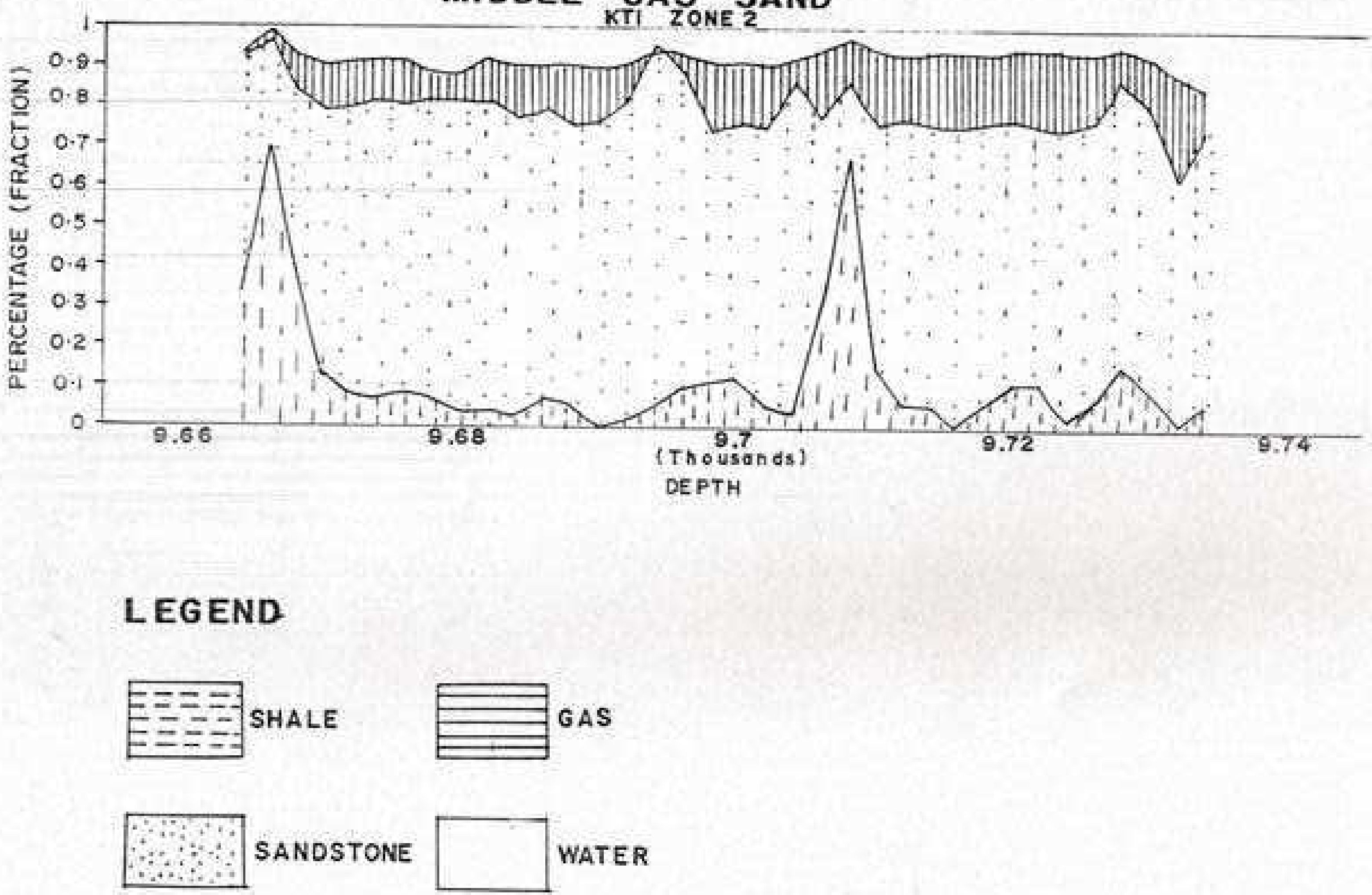


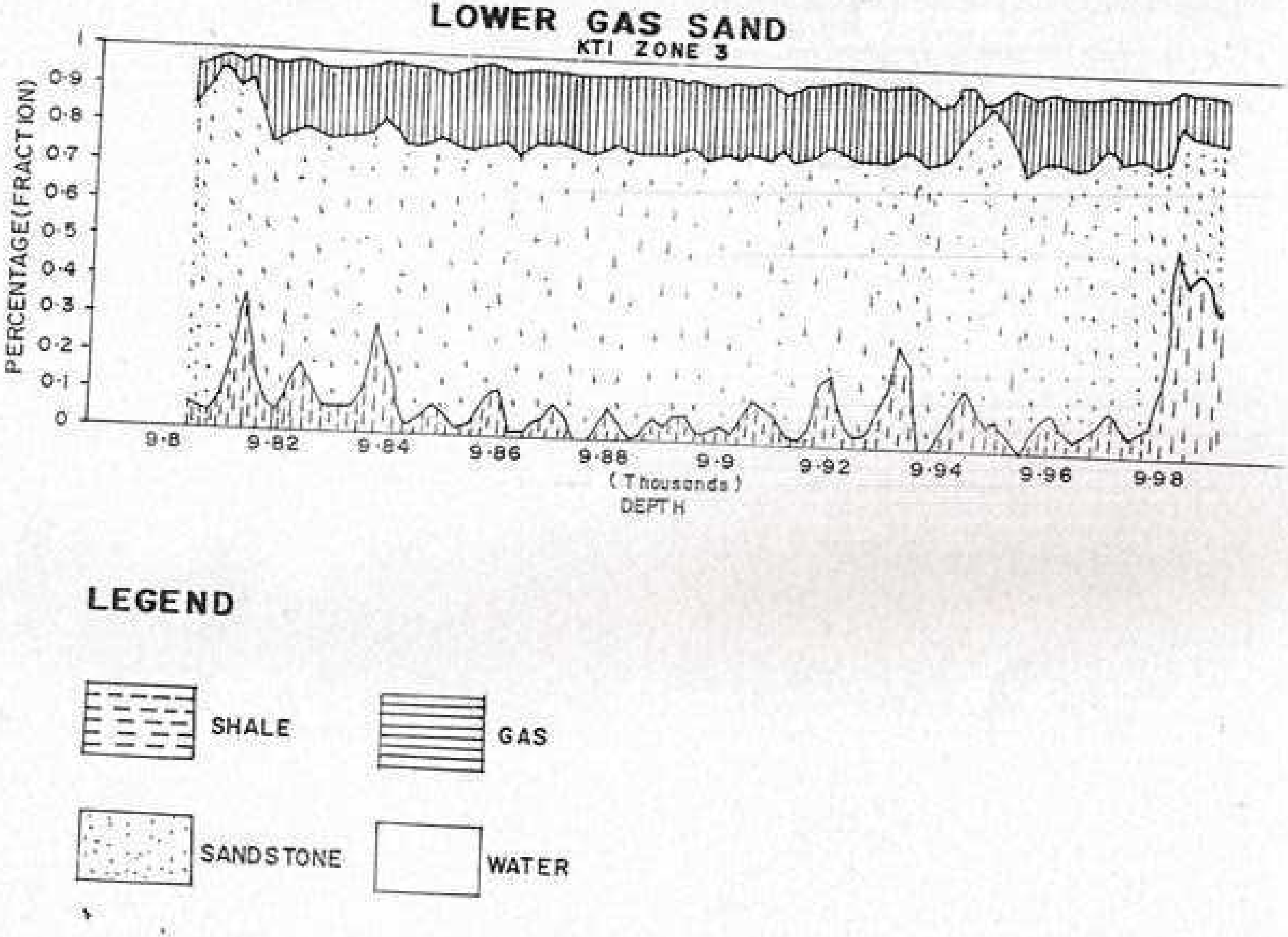
UPPER GAS SAND

KTI ZONE I



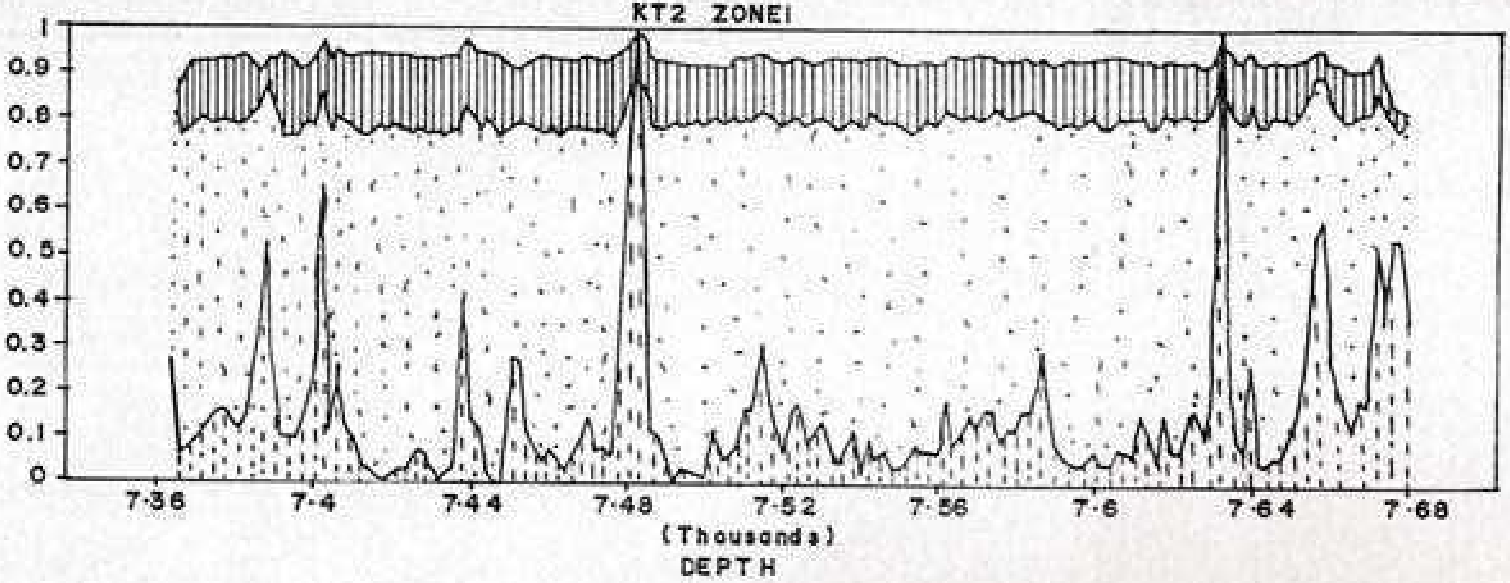
MIDDLE GAS SAND



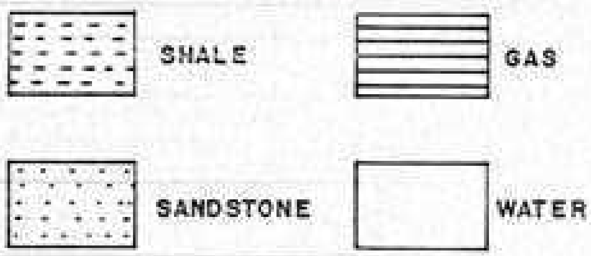


LOWER GAS SAND
KTI ZONE 3
PERCENTAGE(FRACTION)
1
0·9
0·8
0·7
0·6
0·5
0·4
0·3
0·2
0·1
0
9·8
9·82
9·84
9·86
9·88
9·9
9·92
9·94
9·96
9·98
(Thousands)
DEPTH
LEGEND
SHALE
GAS
SANDSTONE
WATER

UPPER GAS SAND

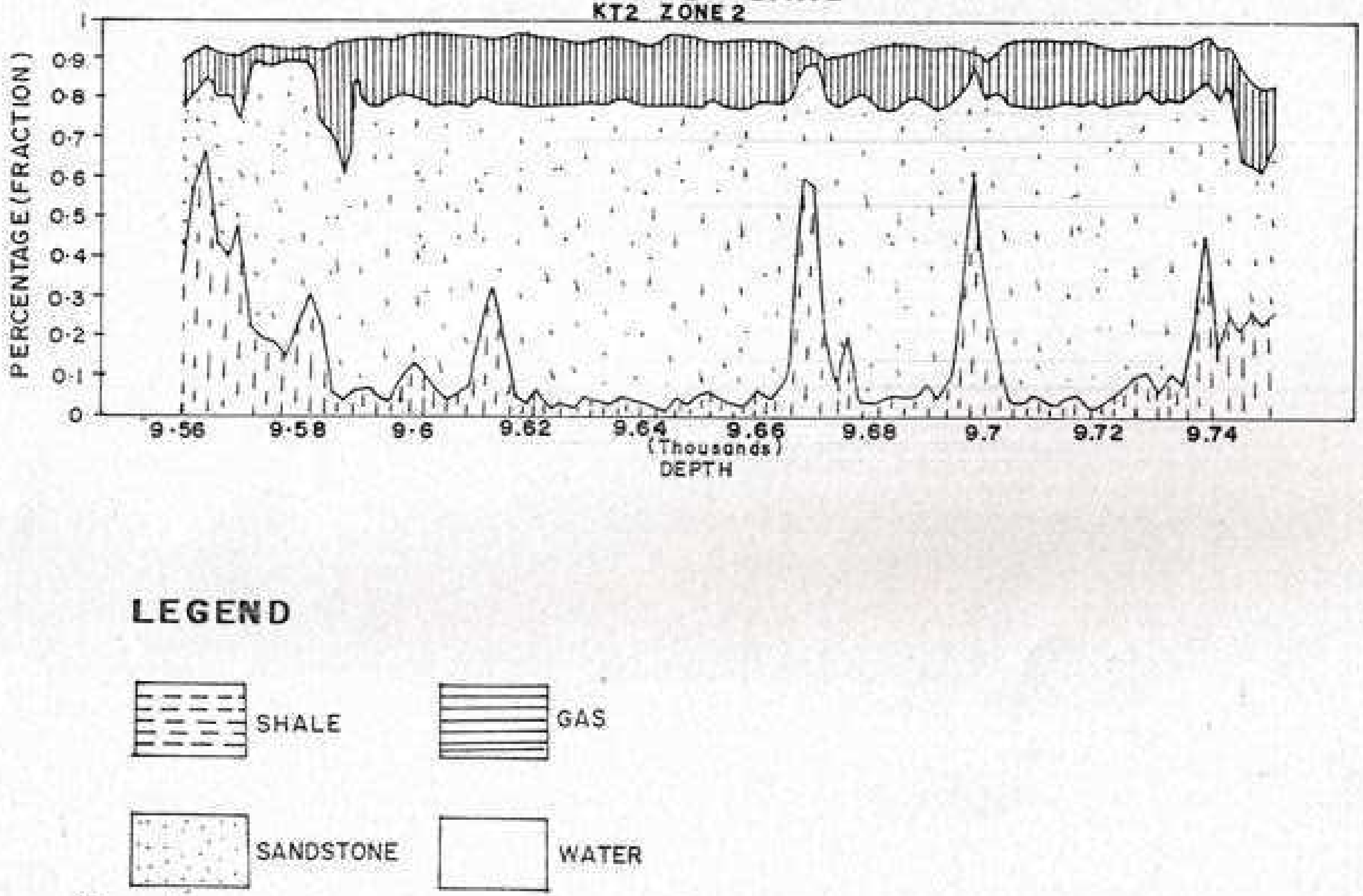


LEGEND



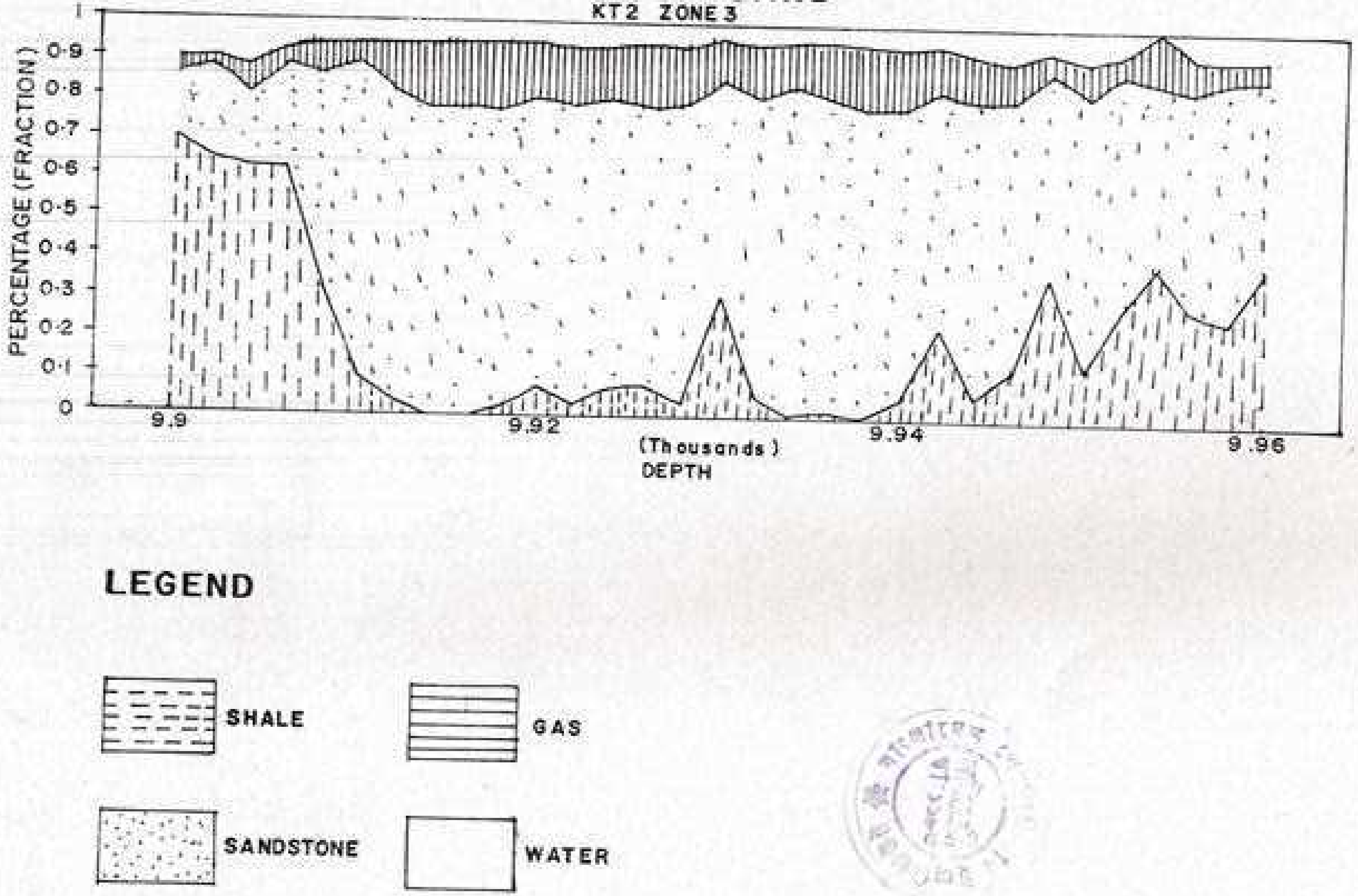
MIDDLE GAS SAND

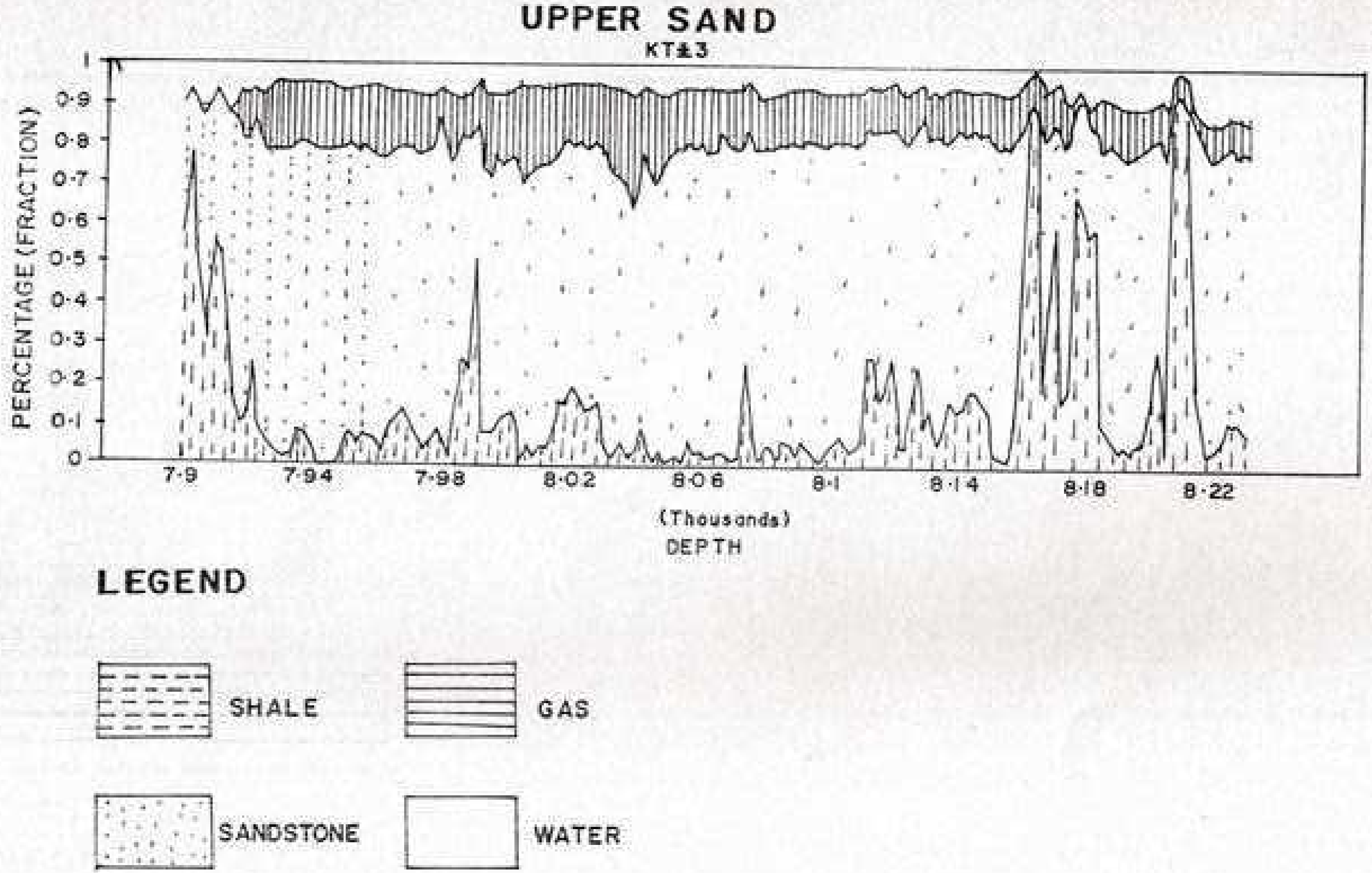
KT2 ZONE 2



LOWER GAS SAND

KT2 ZONE 3

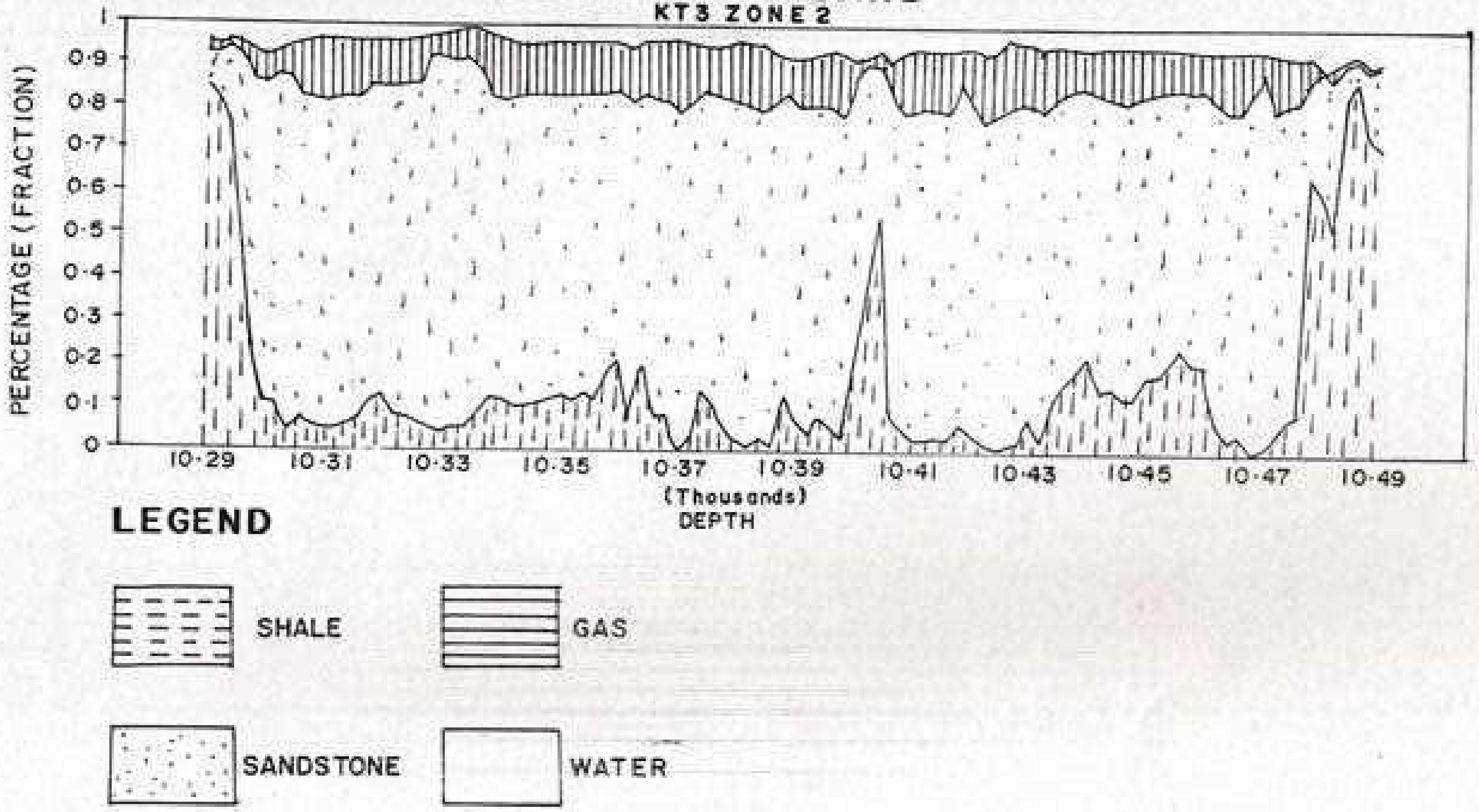




UPPER SAND
KT±3
PERCENTAGE (FRACTION)
1
0·9
0·8
0·7
0·6
0·5
0·4
0·3
0·2
0·1
0
7·9
7·94
7·98
8·02
8·06
8·1
8·14
8·18
8·22
(Thousands)
DEPTH
LEGEND
SHALE
GAS
SANDSTONE
WATER

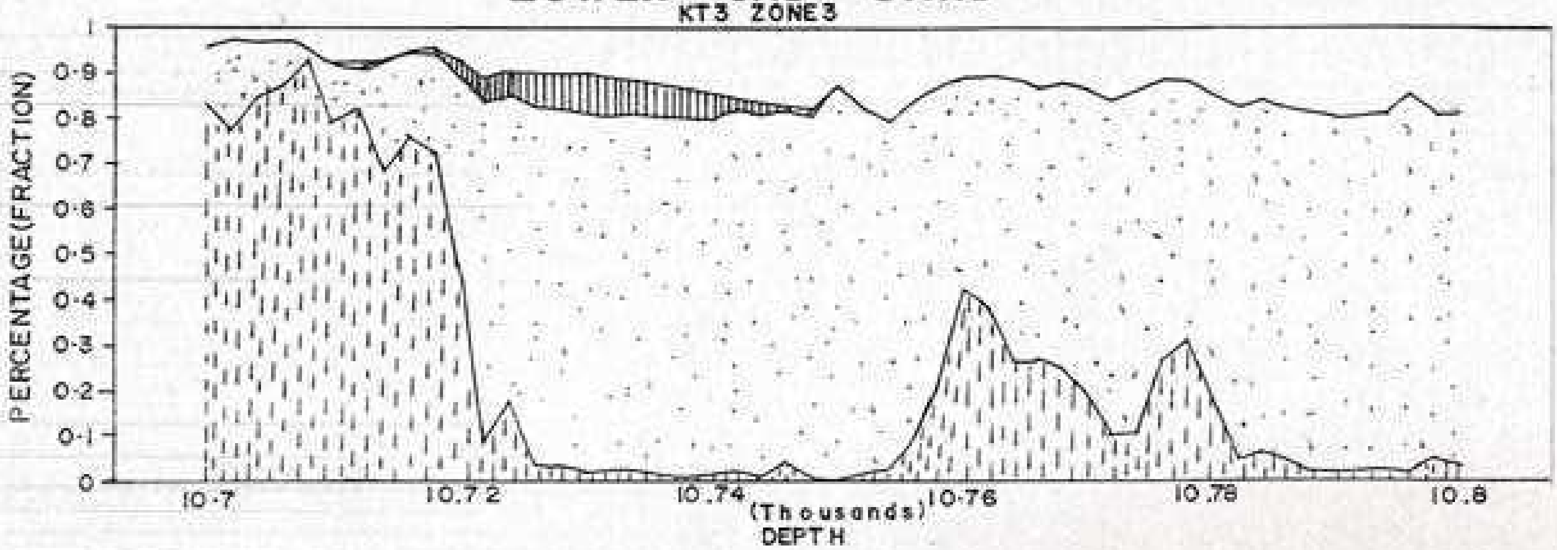
MIDDLE GAS SAND

KT3 ZONE 2



LOWER GAS SAND

KT3 ZONE 3



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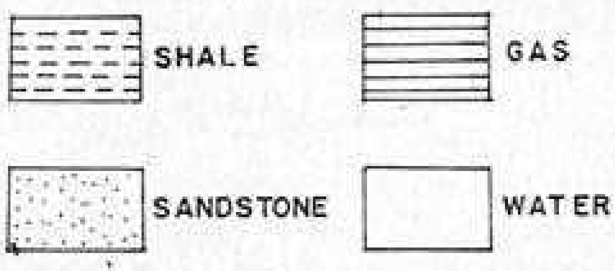

TABLE - 1

KAILASTILA CORRELATION

Strat. level	Kailas	Tila-1	Kailas	Tila-2	Kailas	Tila-3	
	md feet	tvdss ft	md feet	tvdss ft	md ft	tvdss ft	tvdss ft
Top of UMS	7039	6978	7030	6958 [1]		7013	6940
Base of UMS	7494	7433	7364	7292 [2]		7357	7284
UMS thickness		455		334			344
Base of Upper Gas Sand	7660	7599	7674	7602		7599	7526
Upper Gas Sand thickness		166		310			242
Base of shale within UGS	7670	7609	7606	7534		7609	7536
Top Lower Marine Shale (marker)	7726	7665	7674	7602		7662	7589
Base Lower Marine Shale	7744	7683	7693	7621		7688	7615
LMS thickness		18		19			26
Base "Shaly Sand" (below LMS)	8697	8636	8690	8618		8698	8625
Top of New Gas Sand (where present) OR Base of Marine (?) Shale above "New" Gas Sand	8888	8827	8885	8813		8919	8846
Base of "New" Gas Sand OR top of "Shale below NGS"	8971	8910	9010	8938		9029	8956
Base of "Shale below NGS" OR Top of Middle Water Sand (when present)	9120	9059	9100	9028		9184	9111
Base of "Middle Water Sand"	9476	9415	9398	9028		9369	9111
Thickness of MWS		356		0			0
Top of Middle Gas Sand (base of Shale above MGS)	9664	9603	9584	9512 [3]		9581	9508
Base of MGS	9734	9673	9744	9672 [4]		9754	9681
Thickness of MGS		70		160			173
Top of Lower Gas Sand	9804	9743	9908	9836		9983	9910
Base of LGS	9990	9929	9946	9874		10120	10047
Thickness of LGS		186		38			137
Base LMS to Top MGS		967		894			883
Base LMS to Top LGS		1107		1218			1285
Base of "Shale within UGS" to Base LMS		74		87			79
Top of UMS to base of "Shale within UGS"		631		576			596
In KT1 and KT3 Base UGS is at top of "Shale within UGS"			In KT2 "Shale within UGS" is Missing			KT3 "TVD log" of Schlumb. has 21' error	

In Kailastilla 2 :

[1] 6958 tvdss feet is equivalent to 1650-1660 ms on seismic section KT -
[2] 7292 tvdss feet is equivalent to 1720 ms on seismic section KT -
[3] 9512 tvdss feet is equivalent to 2080 ms on seismic section KT -
[4] 9672 tvdss feet is equivalent to 2100 ms on seismic section KT -

TABLE - 2

BANGLADESH PETROLEUM INSTITUTE

KAILASHTILLA RESOURCE ESTIMATION , JUNE, 1992.

Reservoir	Area sqkm	Rock Volume MMcubm (plani-metered)	N/G Ratio	Net Rock Vol. MM cubm	Net Rock Vol. M Acrft	Wted Av. ϕ Frac-tion	Pore Vol. MM cubm	Wted Av. Gas Satura-tion Fraction	HC Pore Vol. MM cubm	1/Bg scf/cubft	GIIP MM cubm	GIIP MMscf	GIIP TCF	Cond-te Yield bbl/mscf
Upper Gas Sand	20.617	1025.52	0.94	963.9888	781.5789	0.202	194.725	0.583	113.525	250	28381.27	1002426.6	1.0024	10.5
Middle Gas Sand	15.922	504.12	0.92	463.7904	376.0301	0.192	89.0477	0.807	71.8615	254	18252.83	644689.99	0.8446	23
Lower Gas sands	4.65	95.11	0.99	94.1589	76.34177	0.179	16.8544	0.725	12.2194	245	2993.770	105739.97	0.1057	25
TOTAL	41.189	1624.75		1521.938	1233.950		300.627		197.606		49627.87	1752856.6	1.75	

Condensate Yield for Lower Gas Sand is also reported as 95 bbl/MMscf. This fiqure is considered too high and must be rechecked. New Gas Sand is separately evaluated (see report)

											MONTE CARLO P90	UGS	1.028	10.5
												NGS	0.014	10.5
												MGS	0.556	23
												LGS(N)	0.002	25
												LGS(C)	0.005	25
												LGS(S)	0.084	25
													1.689	

TABLE - 2

BANGLADESH PETROLEUM INSTITUTE

KAILASHTILLA RESOURCE ESTIMATION , JUNE, 1992.

Reservoir	Area sqkm	Rock Volume MMcubm (plani-metered)	N/G Ratio	Net Rock Vol. MM cubm	Net Rock Vol. M.Acrft	Wted Av. φ Frac-tion	Pore Vol. MM cubm	Wted Av. Gas Satura-tion Fraction	HC Pore Vol. MM cubm	1/Bg scf/ cubft	GIIP MM cubm	GIIP MMscf	GIIP TCF	Cond-te Yield bbl/mscf	CIIP MM STBC
Upper Gas Sand	20.617	1025.52	0.94	963.9888	781.5789	0.202	194.725	0.583	113.525	250	28381.27	1002426.6	1.0024	10.5	10.52548
Middle Gas Sand	15.922	504.12	0.92	463.7904	376.0301	0.192	89.0477	0.807	71.8615	254	18252.83	644689.99	0.8446	23	14.82786
Lower Gas sands	4.65	95.11	0.99	94.1589	76.34177	0.179	16.8544	0.725	12.2194	245	2993.770	105739.97	0.1057	25	2.643499
TOTAL	41.189	1624.75		1521.938	1233.950		300.627		197.606		49627.87	1752856.6	1.75		28

Condensate Yield for Lower Gas Sand is also reported as 95 bbl/MMscf. This fiqure is considered too high and must be rechecked.
New Gas Sand is separately evaluated (see report)

											MONTE CARLO P90	UGS	1.028	10.5	10.794
												NGS	0.014	10.5	0.147
												MGS	0.556	23	12.788
												LGS(N)	0.002	25	0.05
												LGS(C)	0.005	25	0.125
												LGS(S)	0.084	25	2.1
													1.689		26.004

TABLE 3

KAILASTILA	RESOURCE ASSESSMENT	MONTE CARLO SIMULATIO N			
PARAMETER RANGES	GROSS ROCK VOLUME (thousands acre-feet)	N/G %	ϕ %	Sg %	1/Bg scf/res.cu.ft
UPPER GAS SAND	831.5	90-92-94	20-22-23	55-65-70	240-250
MIDDLE GAS SAND	409	90-92	18-19-20	70-75-80	250-255
NEW GAS SAND	16.7	60-65-70	17-18-19	65-70-75	250-255
LOWER GAS SAND (NORTH)	2.01	80-90-98	17-18-19	70-75	250-255
LOWER GAS SAND (CENTRAL)	3.8-4.3	80-90-98	17-18-19	70-75	250-255
LOWER GAS SAND (SOUTH)	70	80-90-98	17-18-19	70-75	250-255

TABLE 3

KAILASTILA	RESOURCE ASSESSMENT	MONTE CARLO SIMULATIO N			
PARAMETER RANGES	GROSS ROCK VOLUME (thousands acre-feet)	N/G %	ϕ %	Sg %	1/Bg scf/res.cu.ft
UPPER GAS SAND	831.5	90-92-94	20-22-23	55-65-70	240-250
MIDDLE GAS SAND	409	90-92	18-19-20	70-75-80	250-255
NEW GAS SAND	16.7	60-65-70	17-18-19	65-70-75	250-255
LOWER GAS SAND (NORTH)	2.01	80-90-98	17-18-19	70-75	250-255
LOWER GAS SAND (CENTRAL)	3.8-4.3	80-90-98	17-18-19	70-75	250-255
LOWER GAS SAND (SOUTH)	70	80-90-98	17-18-19	70-75	250-255