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REPORT TITLE/ TITTEL

Kerogen and TOC analysis of samples from well 35/3-4.

CLIENT/ OPPDRAGSGIVER

Saga Petroleum A/S

RESPONSIBLE SCIENTIST/ PROSJEKTANSVARLIG

Hauk Solli

AUTHORS/ FORFATTERE

K. Lind and H. Solli

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25.1.82	0-421	27	

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SUMMARY/ SAMMENDRAG

A total of 31 samples were subjected to TOC and Rock-Eval analysis and 20 samples were selected for flash (600^{o}C) pyrolysis gas chromatography (Py-GC).

Rock-Eval analysis suggests that all samples contain immature to moderate mature type III kerogens.

The Py-GC analysis of kerogen concentrates suggest that 14 samples are type III kerogens while 6 samples are algal type I/II kerogens.

KEY WORDS/ STIKKORD

EXPERIMENTAL

Total Organic Carbon (TOC)

A total of 31 samples were crushed and aliquots of the samples were then weighed into Leco crucibles and treated with hot 2N HCl to remove carbonate. The samples were washed twice with distilled water to remove traces of HCl. The crucibles were then placed in a vacuum oven at 50^{o}C and evacuated to 20 mm Hg for 12 hrs. The samples were then analysed on a Leco E C 12 carbon analyser, to determine the total organic carbon (TOC).

Rock-Eval Pyrolyses

100 mg crushed sample was put into a platinum crucible whose bottom and cover are made of sintered steel and analysed on a Rock-Eval pyrolyser.

Pyrolysis-GC

Instrumentation: CDS Pyroprobe 120 interfaced to a Varian 3740 GC.
Pyrolysis conditions: 600^{o}C in nitrogen for 5 sec.
GC conditions:
Column: 25m OV-101 fused silica capillary.
Carrier gas: Nitrogen with inlet pressure 8 psi; 0.7 ml/min.
Oven program: 40^{o}C/1 min.; to 260 at 4^{o}C/min.
Split: 1:30.
Kerogen concentrates were used for pyrolysis gas chromatography.

RESULTS AND DISCUSSION

Total Organic Carbon (TOC)

The TOC values are listed in Table 1 varying from 0.5% to 3.79%.

Rock-Eval Pyrolysis

A total of 31 samples were analysed on Rock-Eval including both a sandstone and a siltstone from 3400.75 m (M 190); Table 1. The results are discussed below.

M 189 showed a high oxygen index and a low hydrogen index. T_{max} is low and the data suggest an immature type III kerogen.

M 190. Picked sandstone and siltstone were analysed and the data suggest an immature to moderate mature type III kerogen in both samples.

M 191 - M 205. The analysis data suggest an immature to moderate mature type II kerogen in all samples.

M 206. The high T_{max} for this sample is caused by a very small and broad S_2 peak with no well defined maximum. The other data suggest an immature to moderate mature type III kerogen.

M 207 - M 214. The analysis data suggest an immature to moderate mature type III kerogen in all samples.

M 207 - M 217. T_{max} values suggest immature to moderate mature kerogens. Hydrogen index values are low to moderate (i.e. 260-362) suggesting a mixture; mostly of type III kerogen and some type II kerogen.

M 218 and M 219. Both samples have low hydrogen index and T_{max} values, suggesting immature to moderate mature type III kerogen.

Pyrolysis-Gas chromatography (Py-GC)

Twenty samples of solvent extracted (DCM) kerogen concentrates (prepared by treatment with HCl/HF) were analysed by pyrolysis-GC. The instrumental conditions are discussed in the experimental section. The results are discussed below.

Based on mass spectrometric-(MS) and retention data from Py-GC/MS of other kerogens, peaks in the pyrograms are tentatively identified;

The numbered peaks are n-alkene/n-alkane doublets of that carbon number. The n-alkenes have the shorter retention time. Tol=toluene; Xyl=m(+p)-xylene; Pr=pristenes; 1- and 2-MeN=1- and 2- methylnaphthalene; $C_2N=C_2$-alkylnaphthalenes; $C_3N=C_3$-alkylnaphthalenes; MePh=methylphenantrenes and DiMePh=dimethylphenantrenes.

M 189. The pyrogram shows an n-alkene/n-alkane homology ranging from C_7 to C_{23} with a relative high content of aromatics. The quality of the pyrogram is poor due to a high content of pyrite in the kerogen concentrate. Generally the pyrogram shows a type III kerogen fingerprint and it is very similar to that of sample M 190; Siltstone discussed below.

M 190; Siltstone. The pyrogram shows an high abundance of aromatics and the range of alkenes/alkanes is roughly from C_7 to C_{27}. The relative prominent aliphatic homology does not imply that the kerogen has a high input of lipid-rich algal material. Pyrograms of immature terrestrial derived materials like brown coals show a strong alkene/alkane homology. The pyrogram shows a type III fingerprint.

M 190; Sandstone. The abundance of aromatics is very high and the n-alkene/n-alkane homology is less prominent than in the siltstone i.e. type III kerogen.

M 192. This sample is very similar to M 190; Siltstone, i.e. type III kerogen.

M 196 and M 197. The pyrograms of these two samples are very similar showing the same general fingerprint as M 192 i.e. type III kerogen.

M 200. The pyrogram shows the same general fingerprint as M 192 i.e. type III kerogen.

M 201, M 202 and M 203. The pyrograms of these three samples are very similar. The abundance of aromatics is high with a weak n-alkene/n-alkane homology i.e. type III kerogens.

M 204. The n-alkene/n-alkane homology is more prominent than in the previous three pyrograms. The abundance of aromatics is smaller but generally it shows a type III fingerprint.

M 206. This pyrogram is less aromatic than M 204 relative to the aliphatic homology. Compared with Rock-Eval analysis it is difficult to explain this pyrogram which suggests a type II kerogen. An increased input from higher plant waxes might explain the strong n-alkene/n-alkane homology. Generally the pyrogram shows a type II fingerprint.

M 208. This pyrogram is very similar to M 204 i.e. type III kerogen fingerprint.

M 211. The pyrogram (not shown) of this sample was very poor due to a high content of pyrite in the kerogen concentrate, however, it does indicate a type III kerogen.

M 212 and M 213. The two pyrograms are very similar showing a prominent n-alkene/n-alkane homology and the abundance of aromatics is small suggesting a type II/I algal kerogen. The hydrogen index values from Rock-Eval analysis is slightly higher than for the previous discussed kerogens. However, this can not explain the characteristic type II/I pyrogram fingerprint of these two samples.

M 214. This pyrogram shows a prominent n-alkene/n-alkane homology. The abundance of aromatics is relative high suggesting a type III kerogen with input of lipid-rich type II/I kerogen.

M 215, M 216 and M 217. The pyrograms are very similar and exhibit a prominent n-alkene/n-alkane homology in the range C_7 to C_{27}. The abundance of aromatics is very low. Generally the pyrograms show type I/II kerogen fingerprints. This is not in agreement with the low to moderate hydrogen index values from the Rock-Eval analysis which suggest type III/II kerogens.

CONCLUSION

Rock-Eval analysis suggests an immature to moderate mature type III kerogen for all samples. Py-GC of kerogen concentrates suggests type III kerogen for most of the samples. However, samples M 206, 212, 213, 215, 216 and 217 show pyrogram fingerprints characteristic for lipid-rich (algal) type I/II kerogens.

Due to the complexity of kerogens, studies should ideally include both microscopic and physico chemical methods in order to more completely understand the nature and interrelationships of the contributing material.

Information form microscopic studies and analysis of the extracts might explain the disagreement between Rock-Eval and Py-GC analysis. It should also be mentioned that Rock-Eval analysis is basically a screening tool.

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TABLE I

ROCK EVAL PYROLYSES

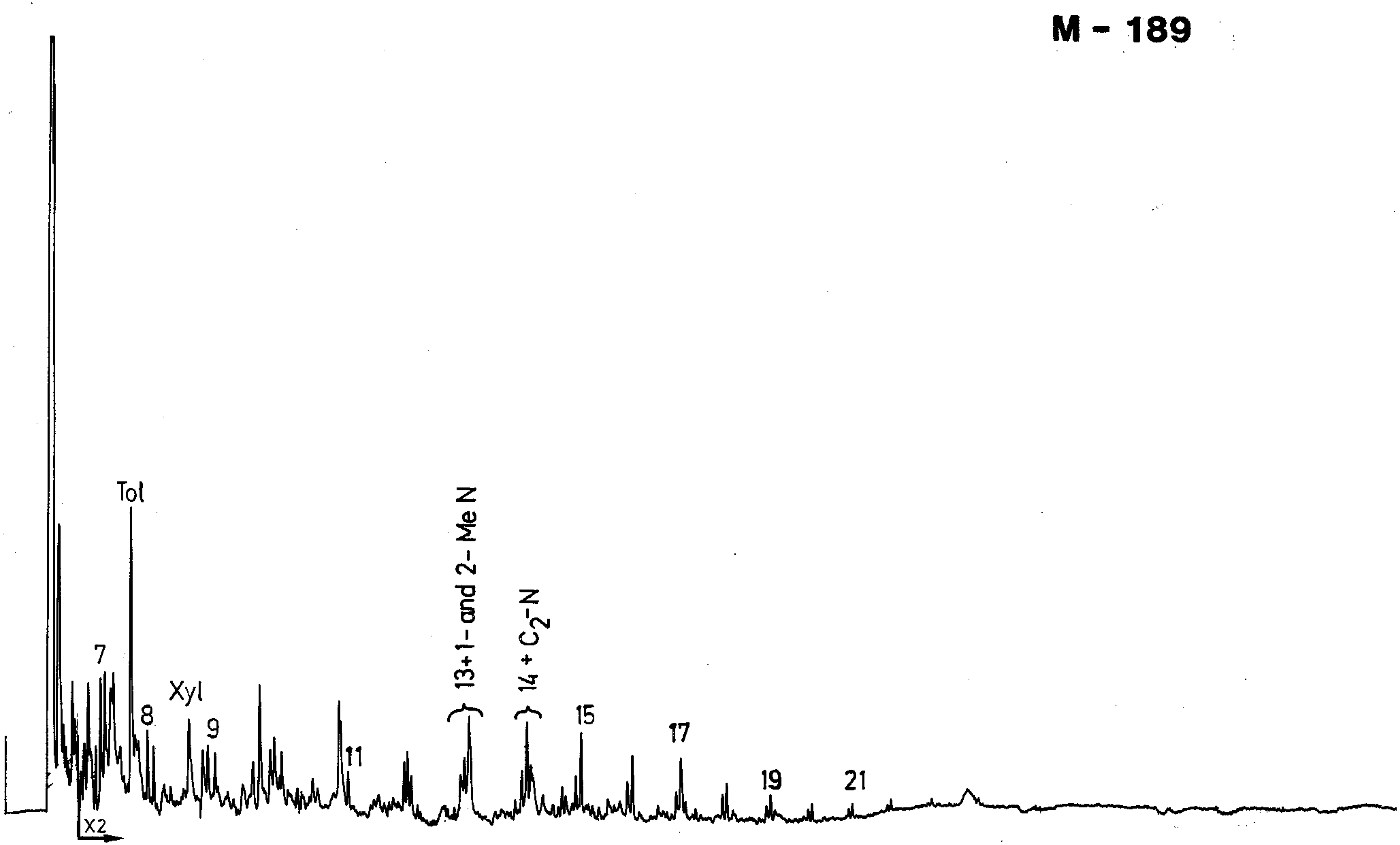
IKU No.	DEPTH (m)	S1	S2	S3	TOC (%)	HYDR. INDEX	OXYGEN INDEX	OIL OF GAS CONTENT S1+S2	PROD. INDEX S1/S1+S2	TEMP. max (C)
M189	3353	.14	.13	1.52	.72	18	211	.27	.52	417
M190 Sandstone	3400.75	.08	.14	.28	.71	20	39	.22	.36	436
M190 Siltstone	3400.75	.18	.70	.45	1.83	38	25	.88	.20	432
M191	3401.1	.06	.10	.64	.50	20	128	.16	.38	433
M192	3401.2	.10	.19	.52	.91	21	57	.29	.34	436
M194	3407	.10	.12	.52	.83	14	63	.22	.45	437
M195	3412	.12	.26	.59	.93	28	63	.38	.32	430
M196	3412.5	.18	.96	.45	1.68	57	27	1.14	.16	430
M197	3413.5	.12	.30	.46	.91	33	51	.42	.29	431
M198	3427	.80	1.10	.71	1.54	71	46	1.90	.42	431
M199	3439	.63	.39	1.15	1.21	32	95	1.02	.62	431
M200	3447	.59	.33	1.22	.66	50	185	.92	.64	424
M201	3450.2	.48	2.54	.33	3.05	83	11	3.02	.16	433
M202	3456.6	.31	1.06	.20	2.22	48	9	1.37	.23	435
M203	3456.7	.48	1.82	.38	2.41	76	16	2.30	.21	432
M204	3459.6	.45	3.29	.21	2.96	111	7	3.74	.12	432
M205	3552	.08	.02	.42	.52	4	81	.10	.80	437
M206	3565	.05	.07	.30	1.68	4	18	.12	.42	473
M207	3572	.06	.30	.35	1.62	19	22	.36	.17	435
M208	3583	.06	.15	.61	1.23	12	50	.21	.29	431
M209	3596	.19	2.11	.25	3.33	63	8	2.30	.08	437
M210	3637	.04	.06	.61	.55	11	111	.10	.40	441
M211	3652	.03	.14	.18	.64	22	28	.17	.18	433
M212	3688	.31	2.52	1.15	1.74	145	66	2.83	.11	432
M213	3690	.33	1.95	.64	1.38	141	46	2.28	.14	431

IKU

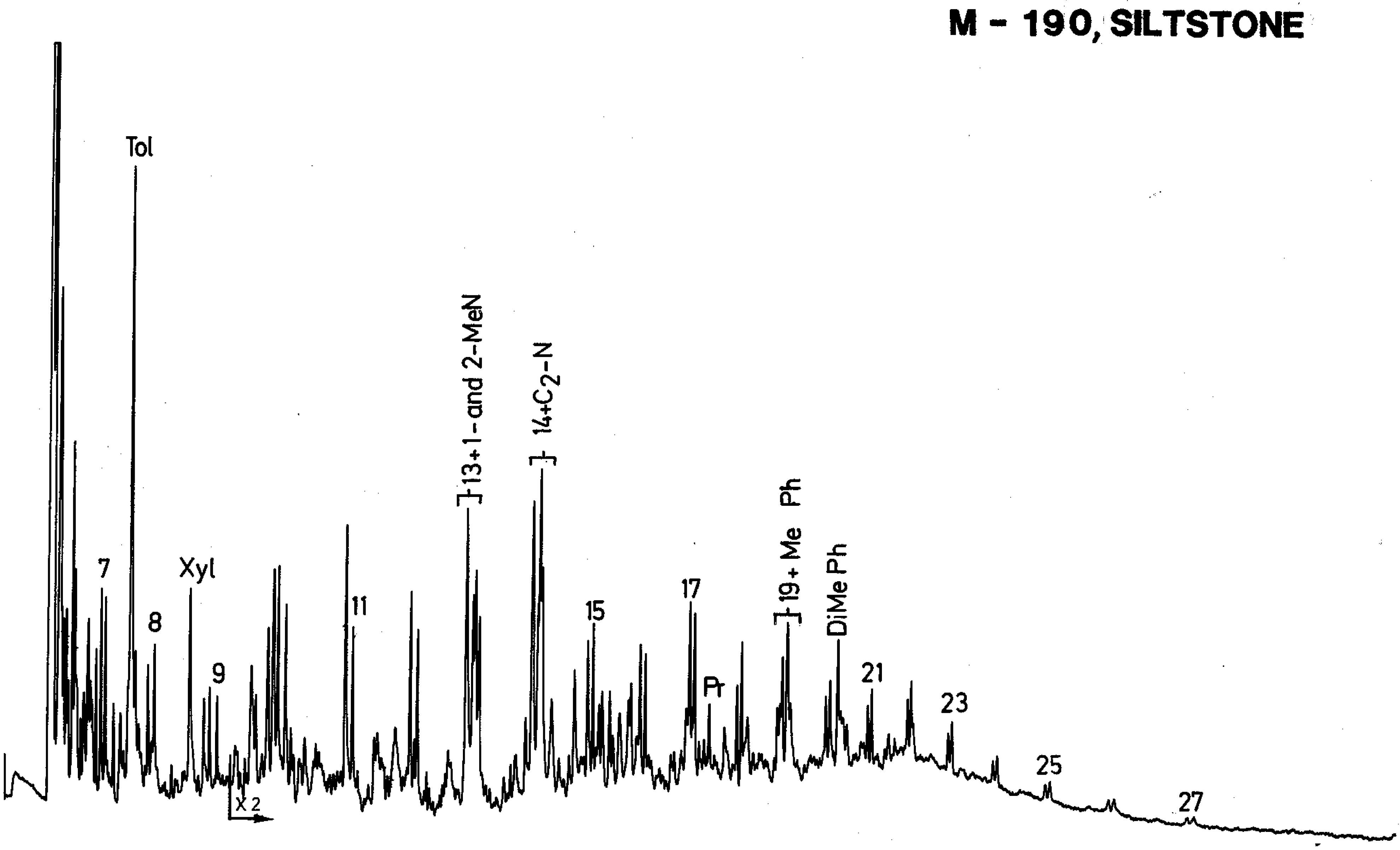
TABLE I

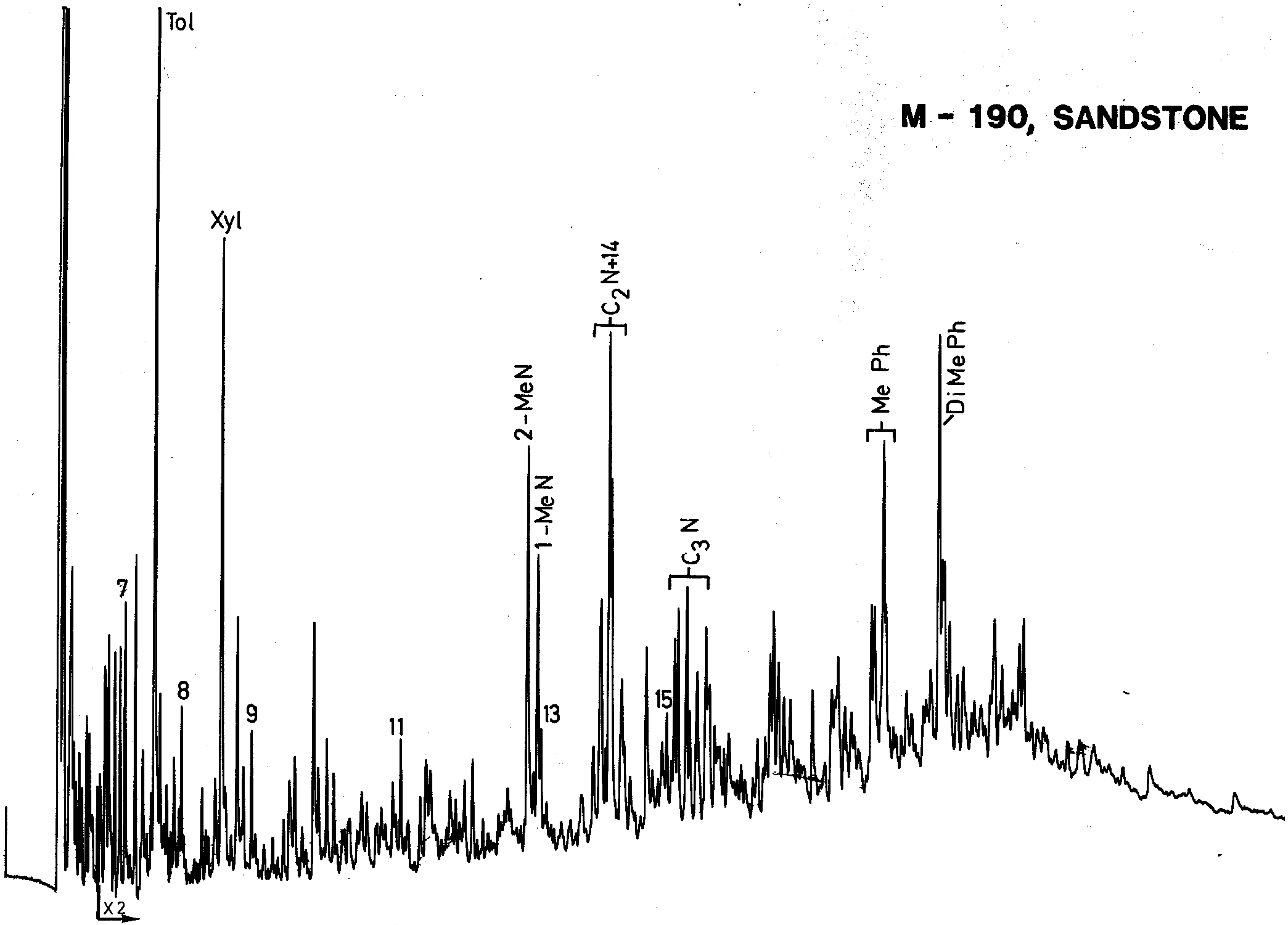
ROCK EVAL PYROLYSES

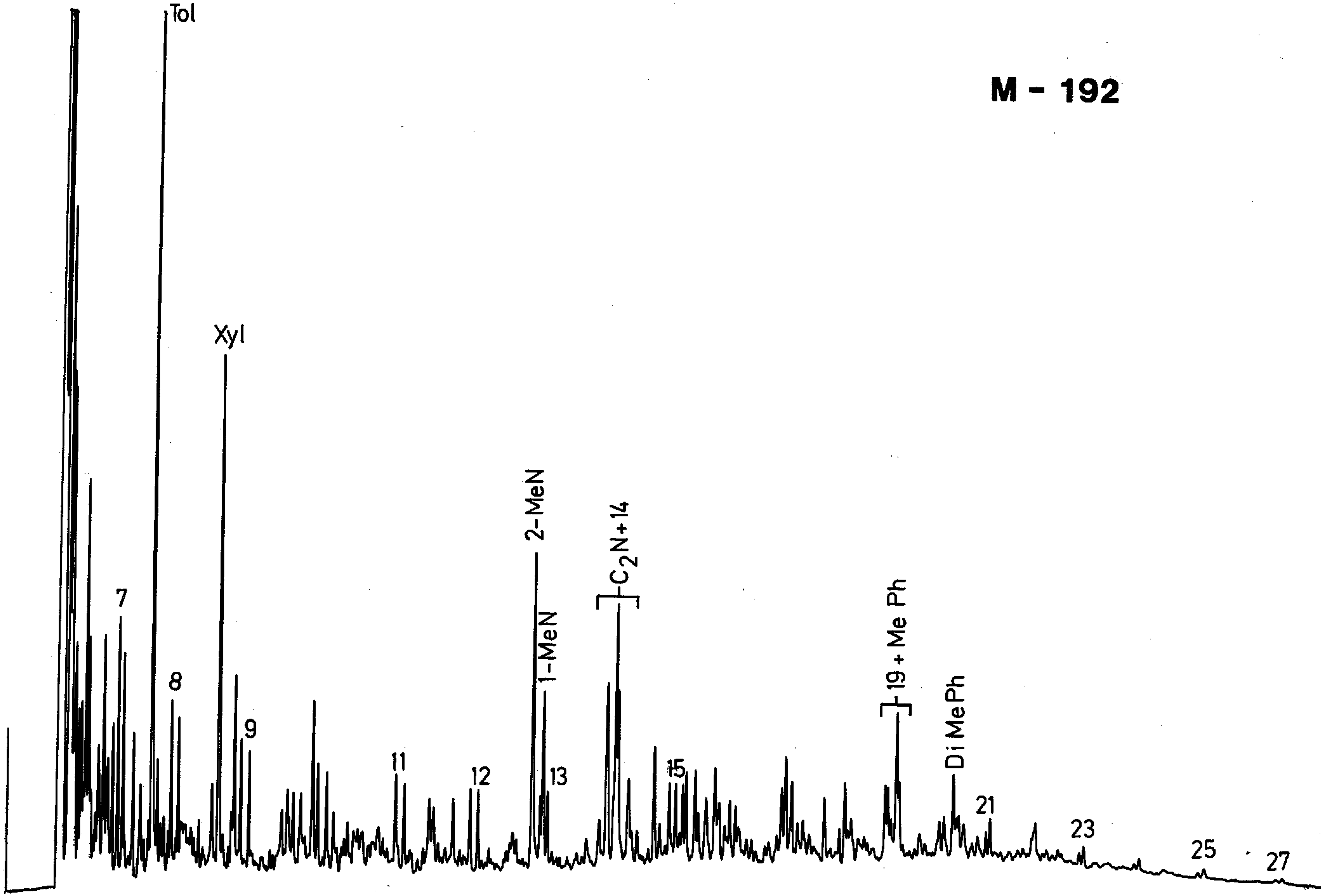
IKU No.	DEPTH (m)	S1	S2	S3	TOC (%)	HYDR. INDEX	OXYGEN INDEX	OIL OF GAS CONTENT S1+S2	PROD. INDEX S1/S1+S2	TEMP. max (C)
M214	3693	.20	.91	1.16	1.86	49	62	1.11	.18	433
M215	3695	.87	8.10	.52	3.11	260	17	8.97	.10	431
M216	3710	1.28	13.17	.33	3.64	362	9	14.45	.09	433
M217	3725	1.43	11.34	.17	3.79	299	4	12.77	.11	431
M218	3770	.53	.73	.94	1.55	47	61	1.26	.42	434
M219	3794	.53	.53	1.09	1.80	29	61	1.06	.50	436



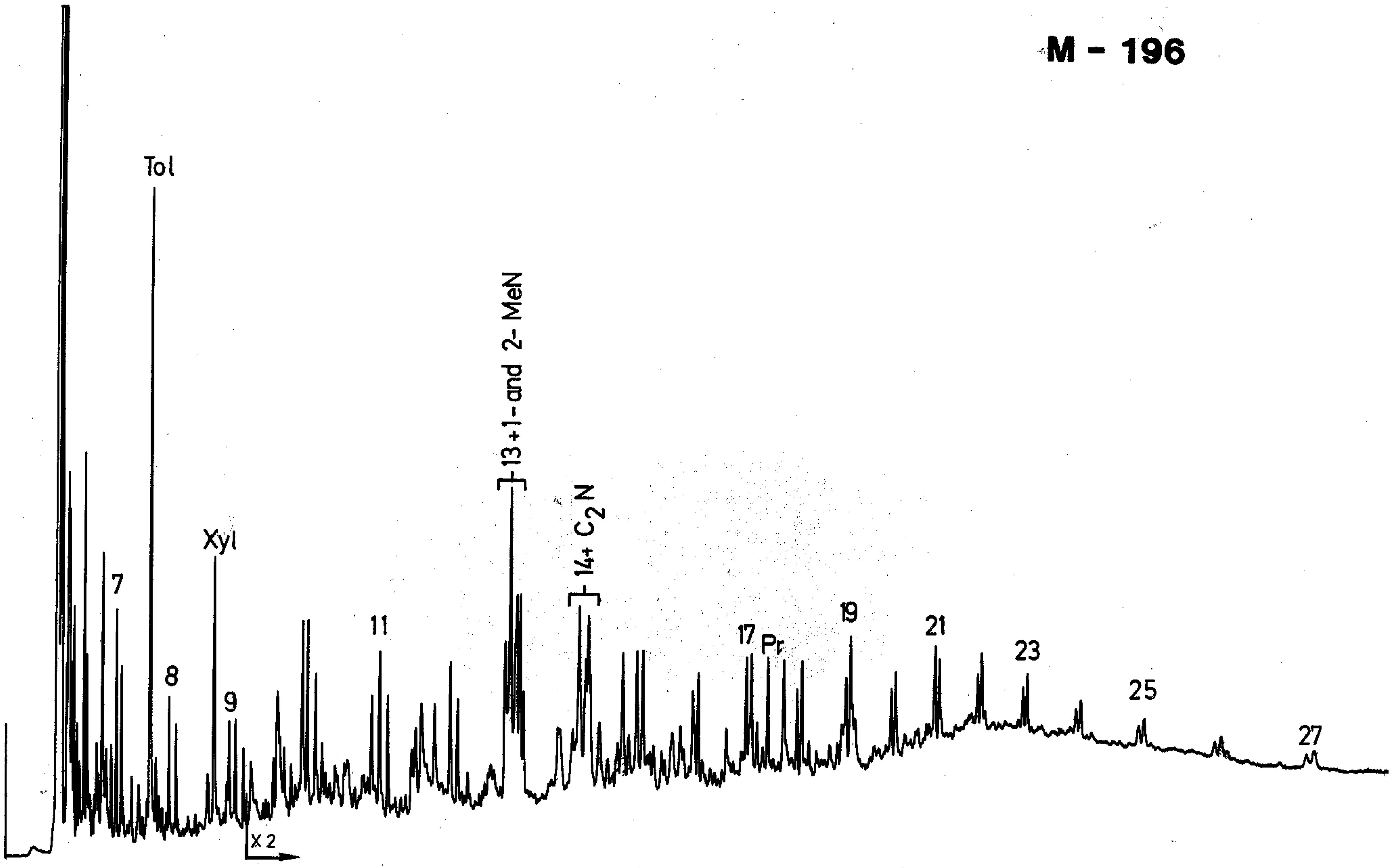
M - 189
Tol
7
8
Xyl
9
11
13+1- and 2- Me N
14 + C2-N
15
17
19
21
X2

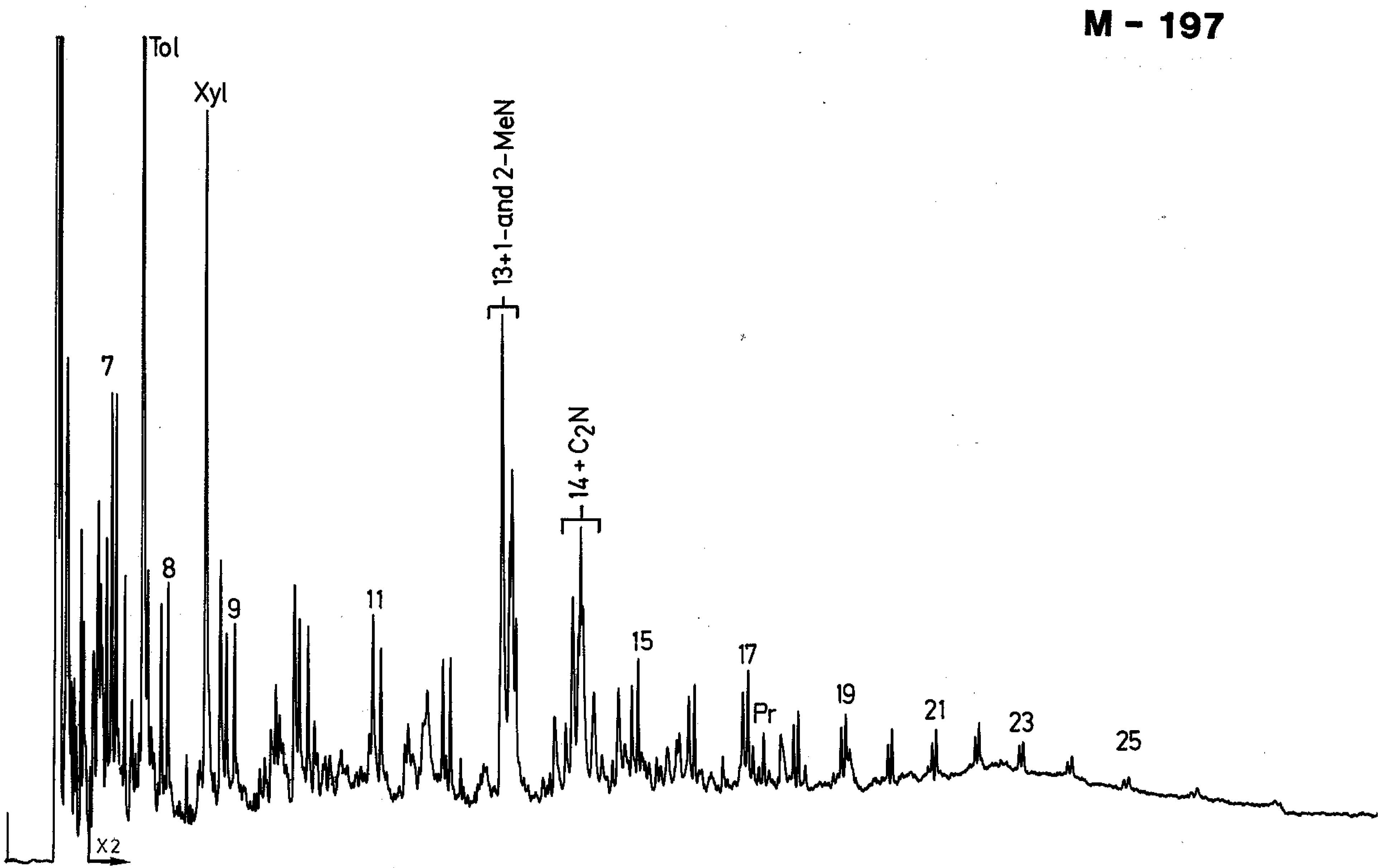

M - 190, SILTSTONE
Tol
7
8
Xyl
9
X 2
11
13+1-and 2-MeN
14+C_2-N
15
17
Pr
19+ Me Ph
DiMe Ph
21
23
25
27


M - 190, SANDSTONE
Tol
Xyl
7
8
9
11
13
15
2-MeN
1-MeN
C_2N+14
C_3N
Me Ph
Di Me Ph
X2

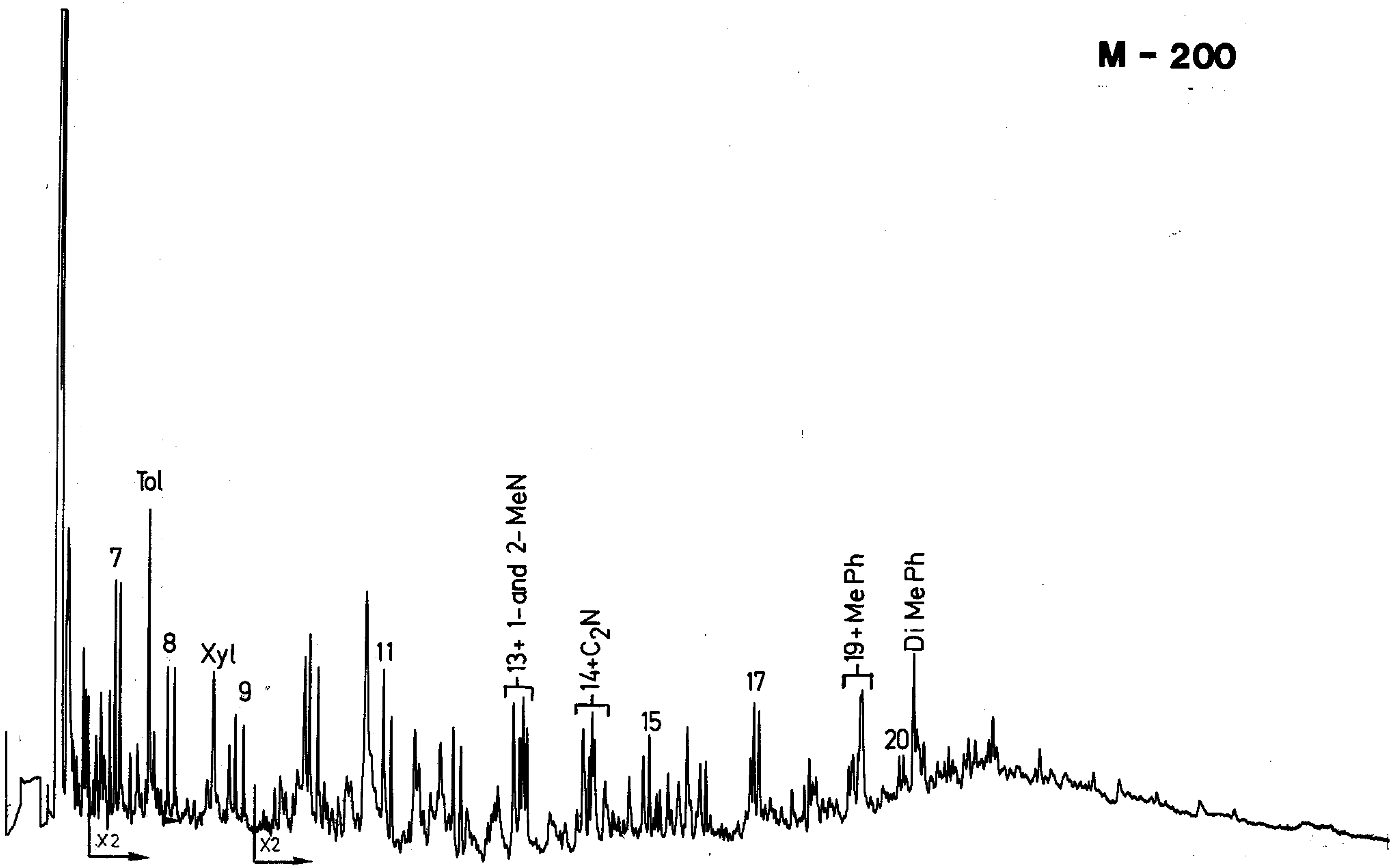


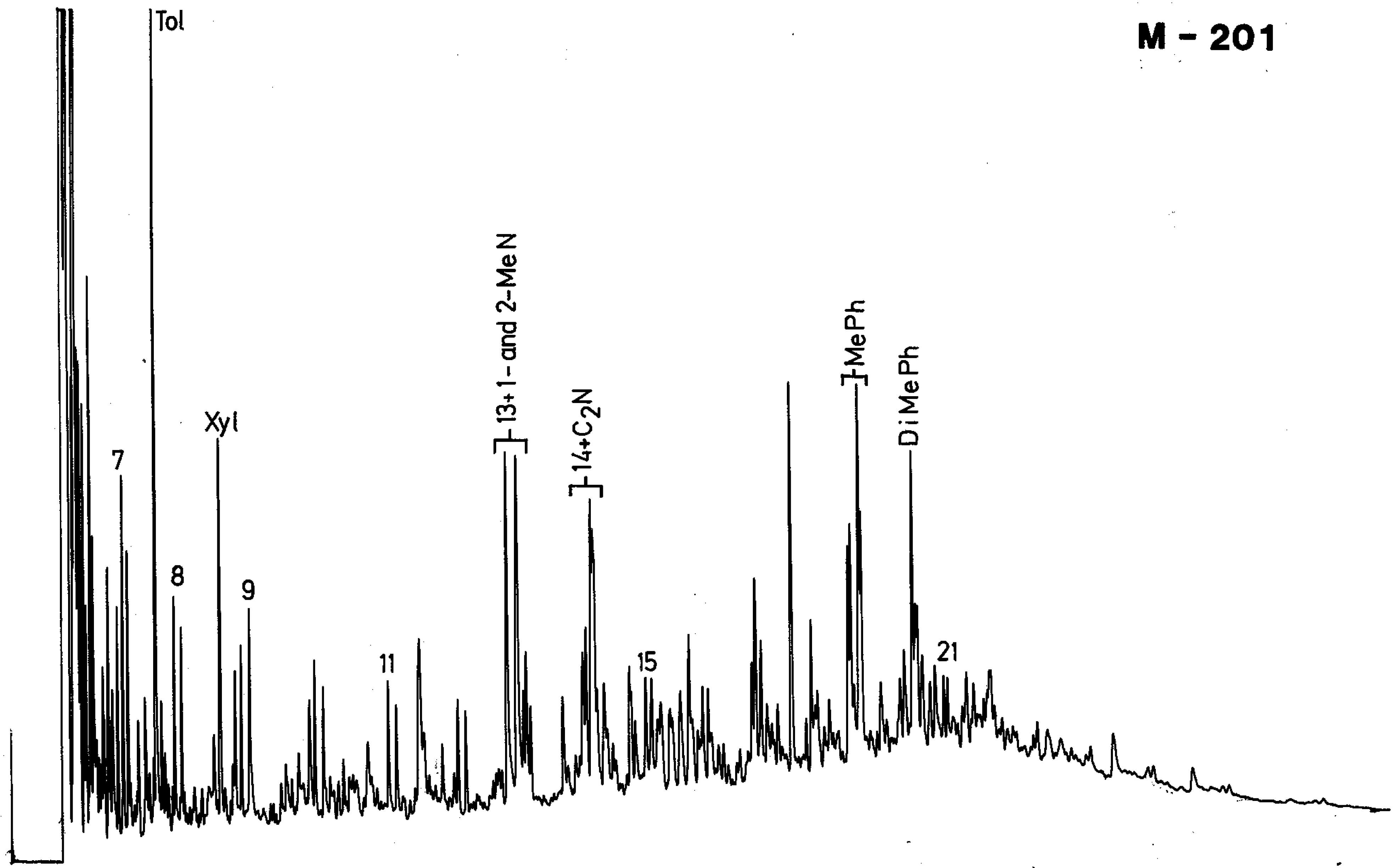
M - 192
Tol
Xyl
7
8
9
11
12
2-MeN
1-MeN
13
C_2N+14
15
19 + Me Ph
Di Me Ph
21
23
25
27


M - 196
Tol
Xyl
7
8
9
x 2
11
13 + 1- and 2- MeN
14+ C2N
17
Pr
19
21
23
25
27

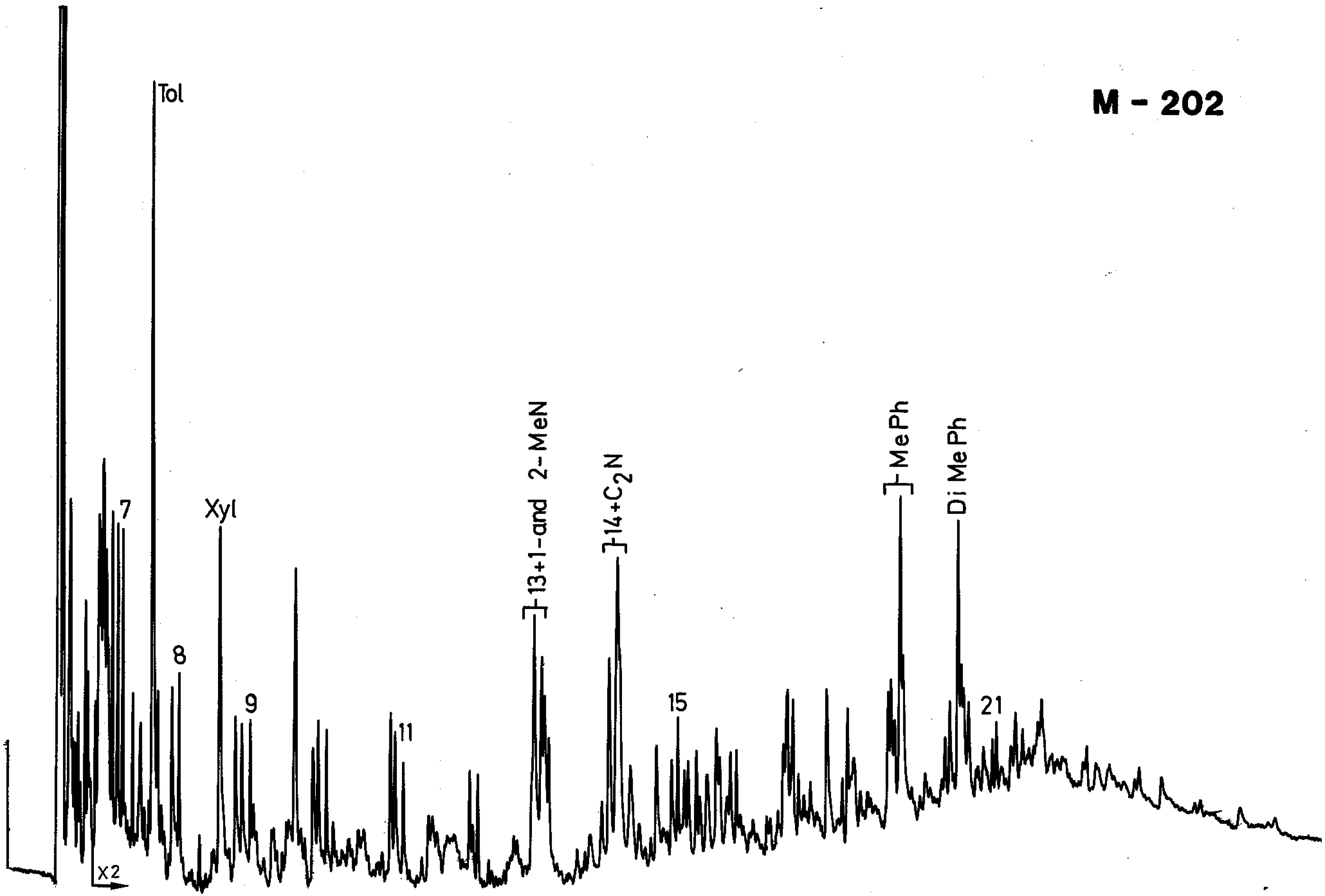


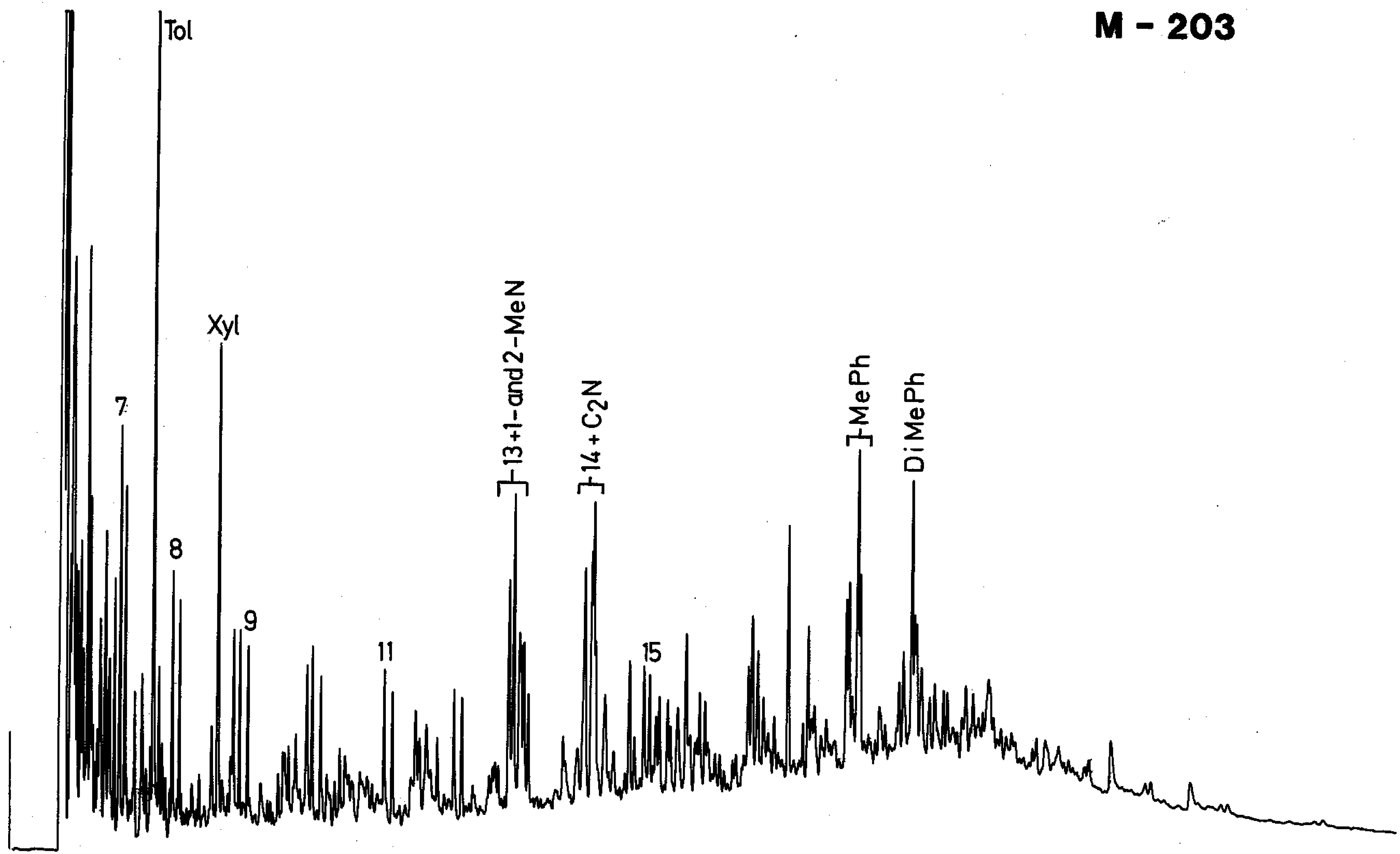
M - 197
Tol
Xyl
13+1-and 2-MeN
7
14 + C2N
8
9
11
15
17
Pr
19
21
23
25
X2


M - 200
Tol
7
8
Xyl
9
11
13+ 1-and 2-MeN
14+C2N
15
17
19+MePh
20
Di MePh
X2
X2

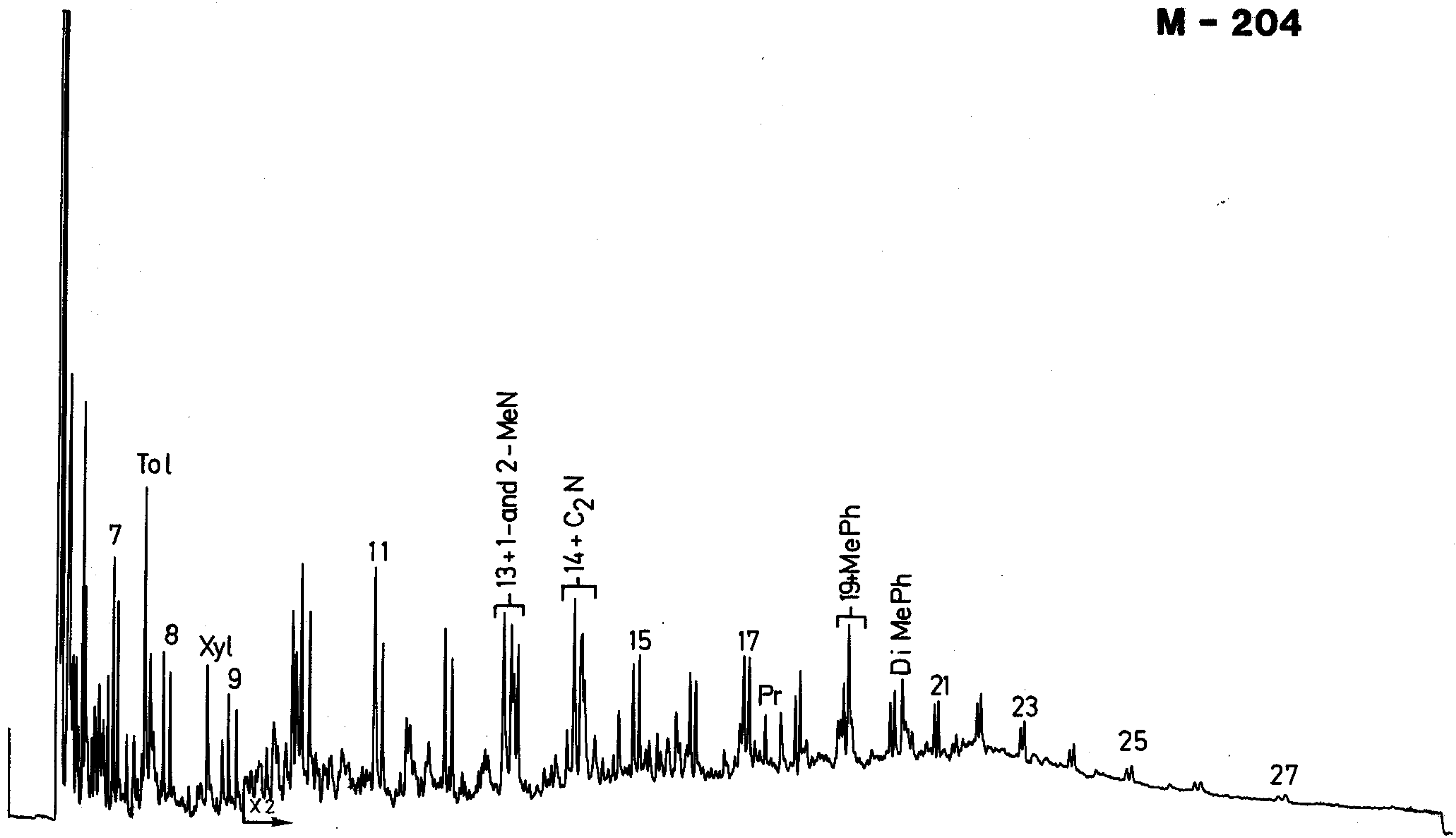


M - 201
Tol
7
8
Xyl
9
11
13+1- and 2-MeN
14+C2N
15
MePh
DiMePh
21

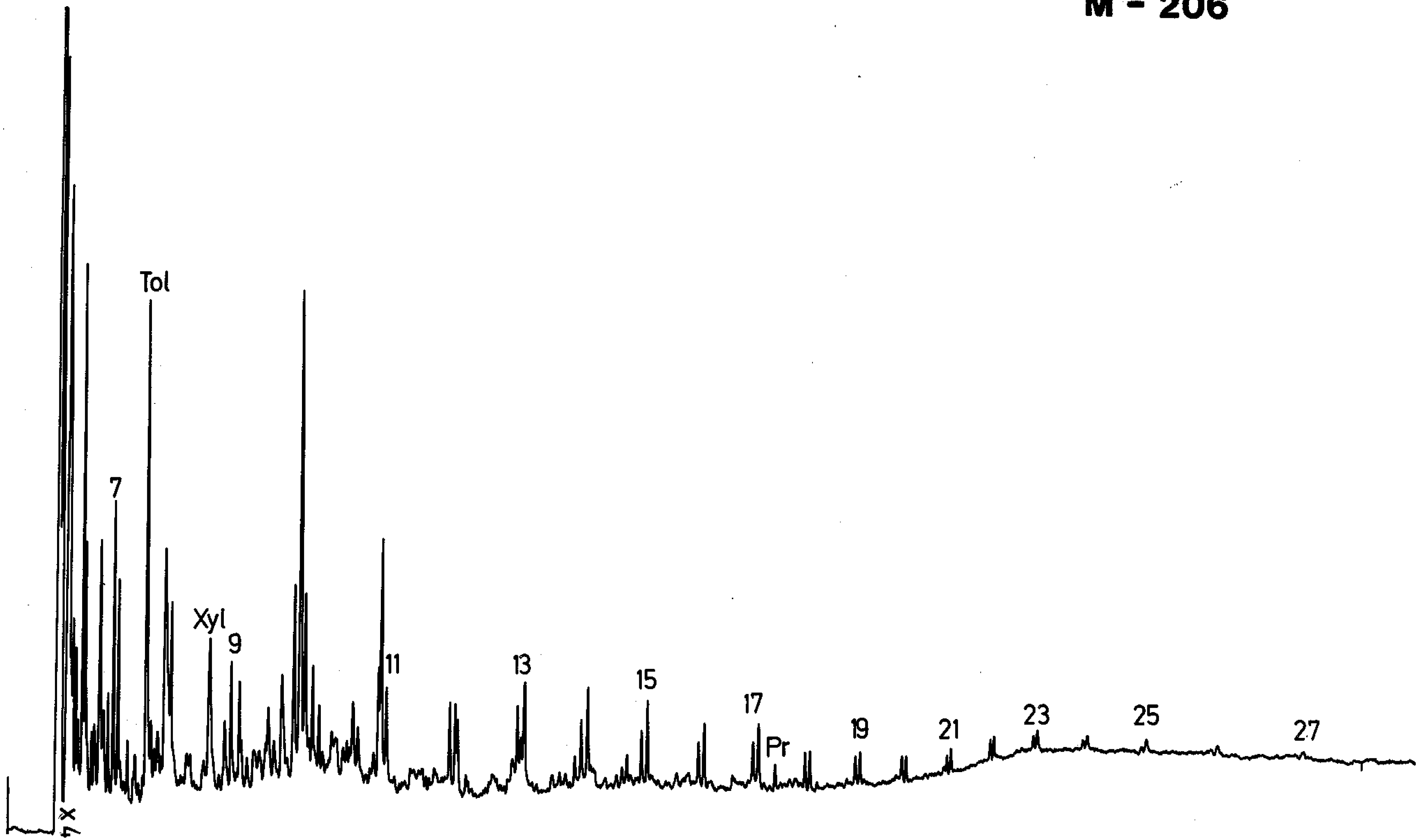

M - 202
Tol
7
Xyl
8
9
11
13+1-and 2-MeN
14+C2N
15
MePh
Di MePh
21
x2



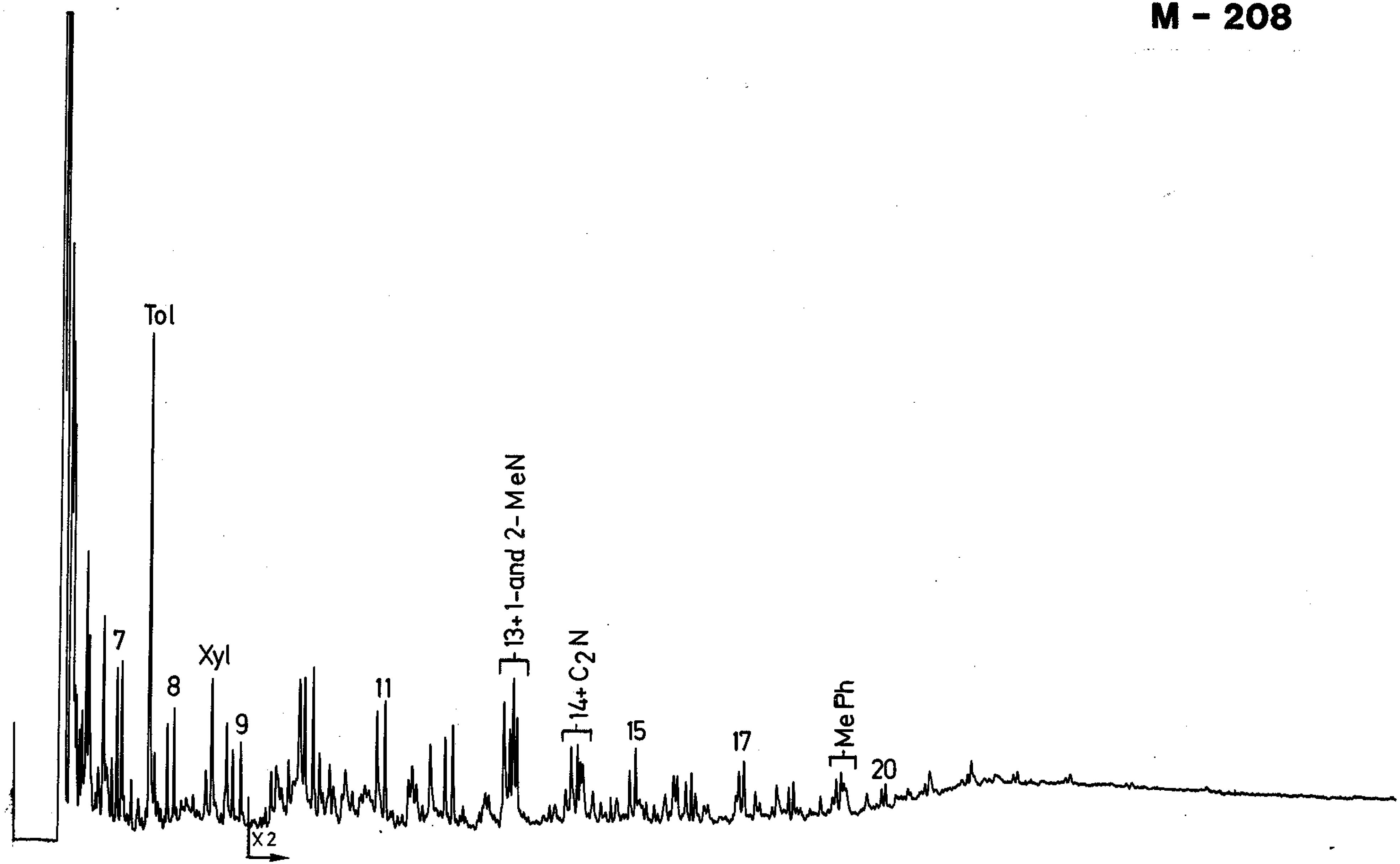
M - 203
Tol
Xyl
7
8
9
11
13 + 1- and 2-MeN
14 + C2N
15
MePh
DiMePh

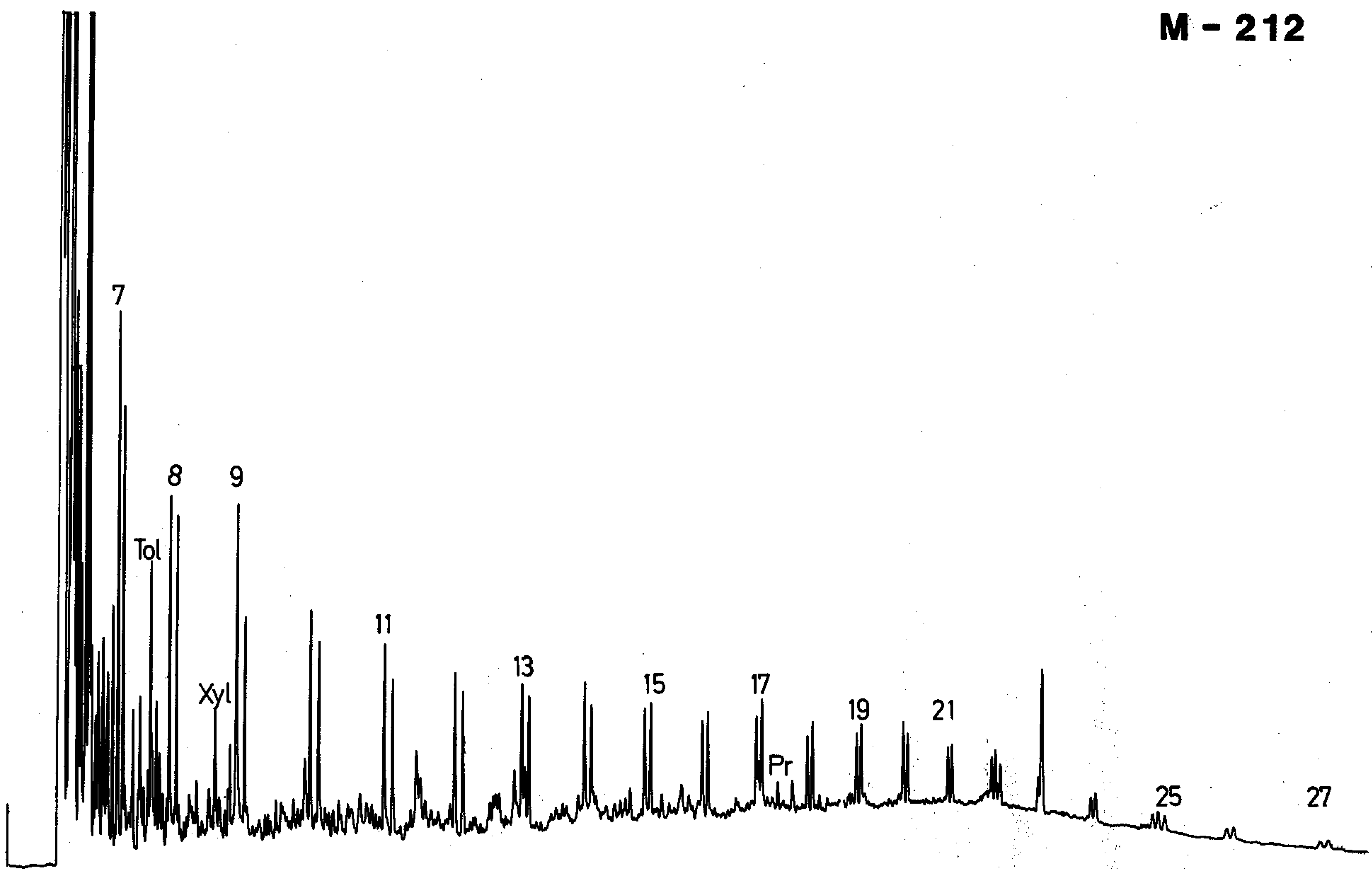

M - 204
Tol
7
8
Xyl
9
x2
11
13+1-and 2-MeN
14+C_2N
15
17
Pr
19+MePh
Di MePh
21
23
25
27

M - 206



M - 208

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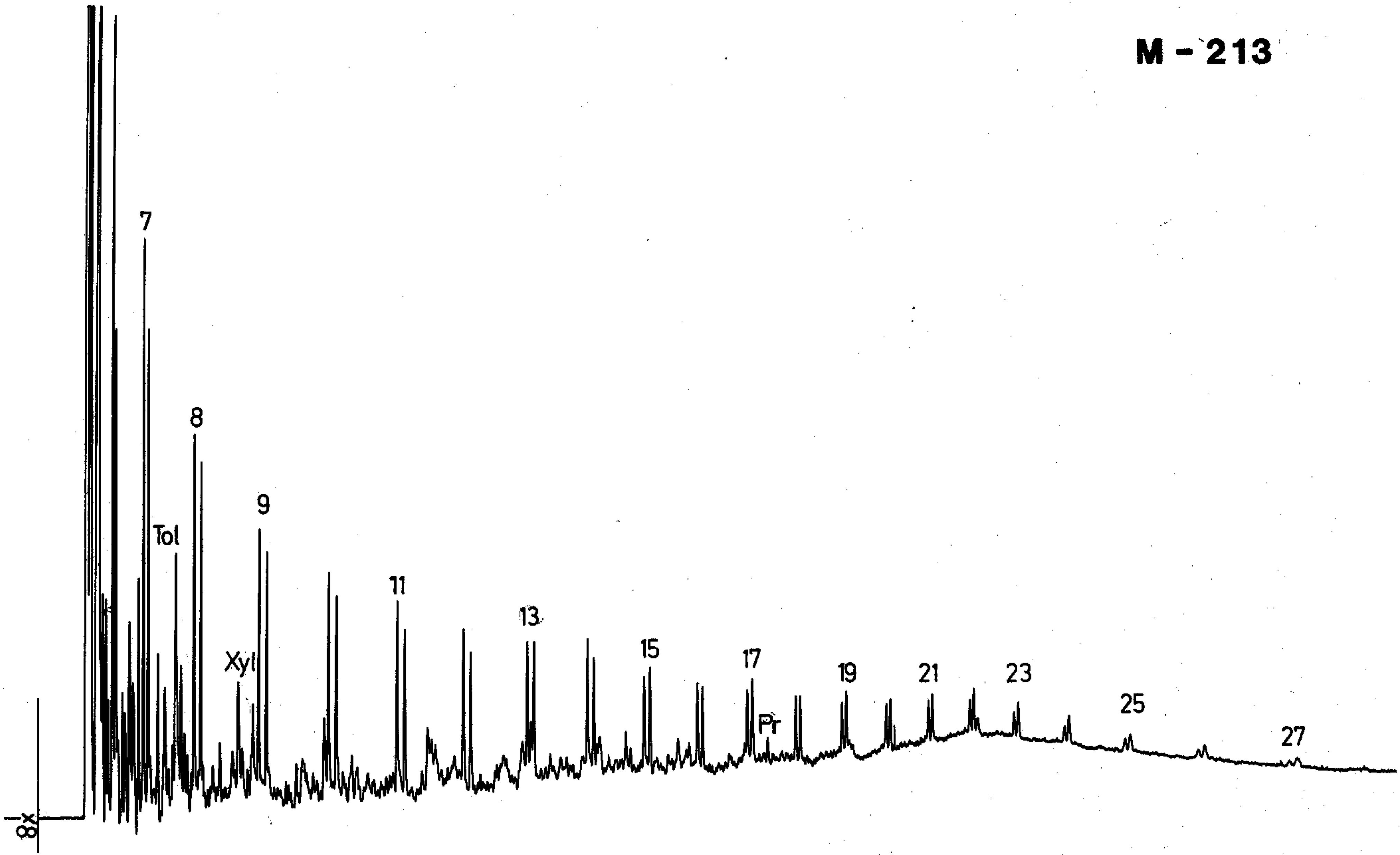
7
Tol
8
9
Xyl
11
13
15
17
Pr
19
21
25
27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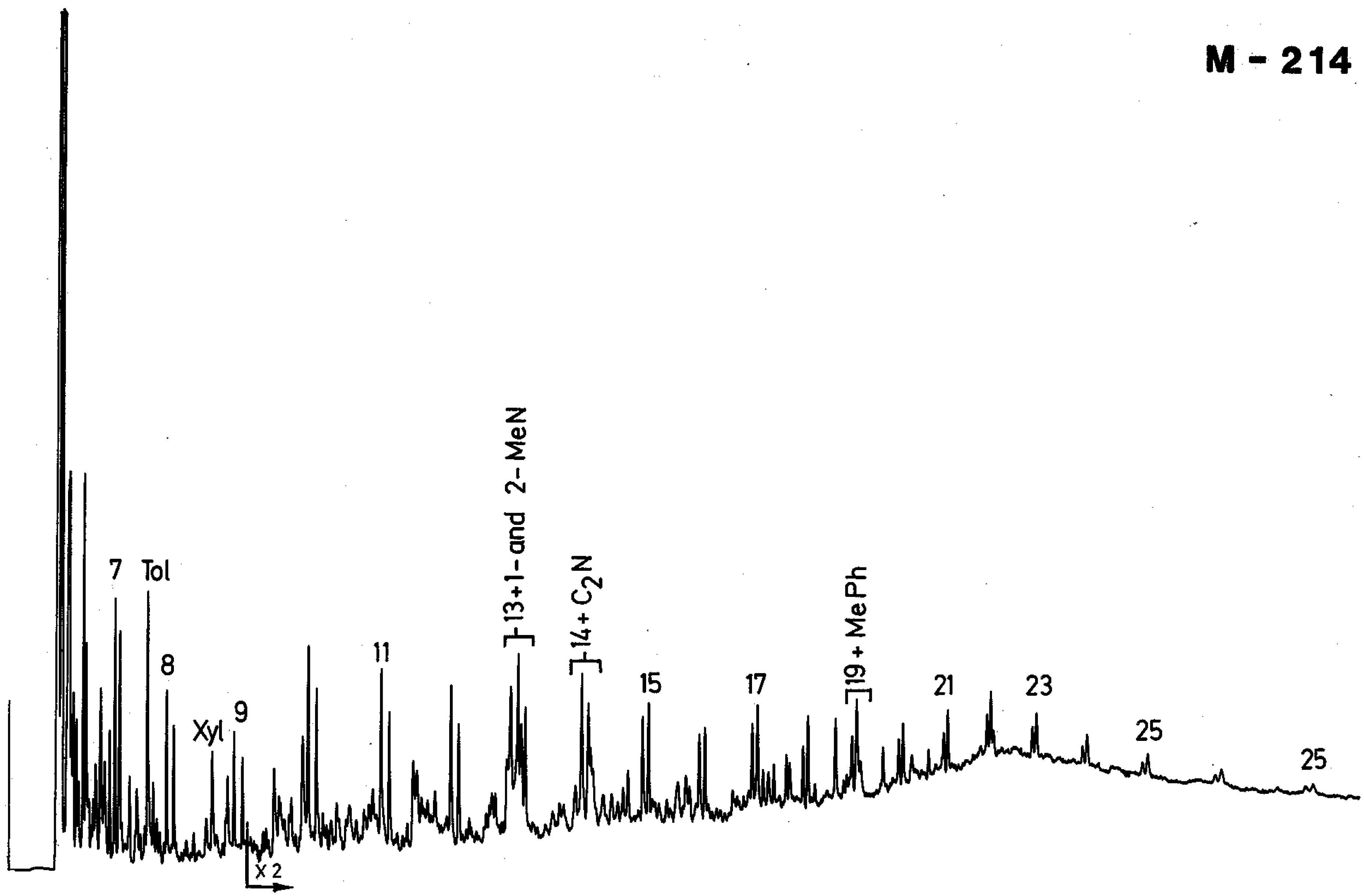
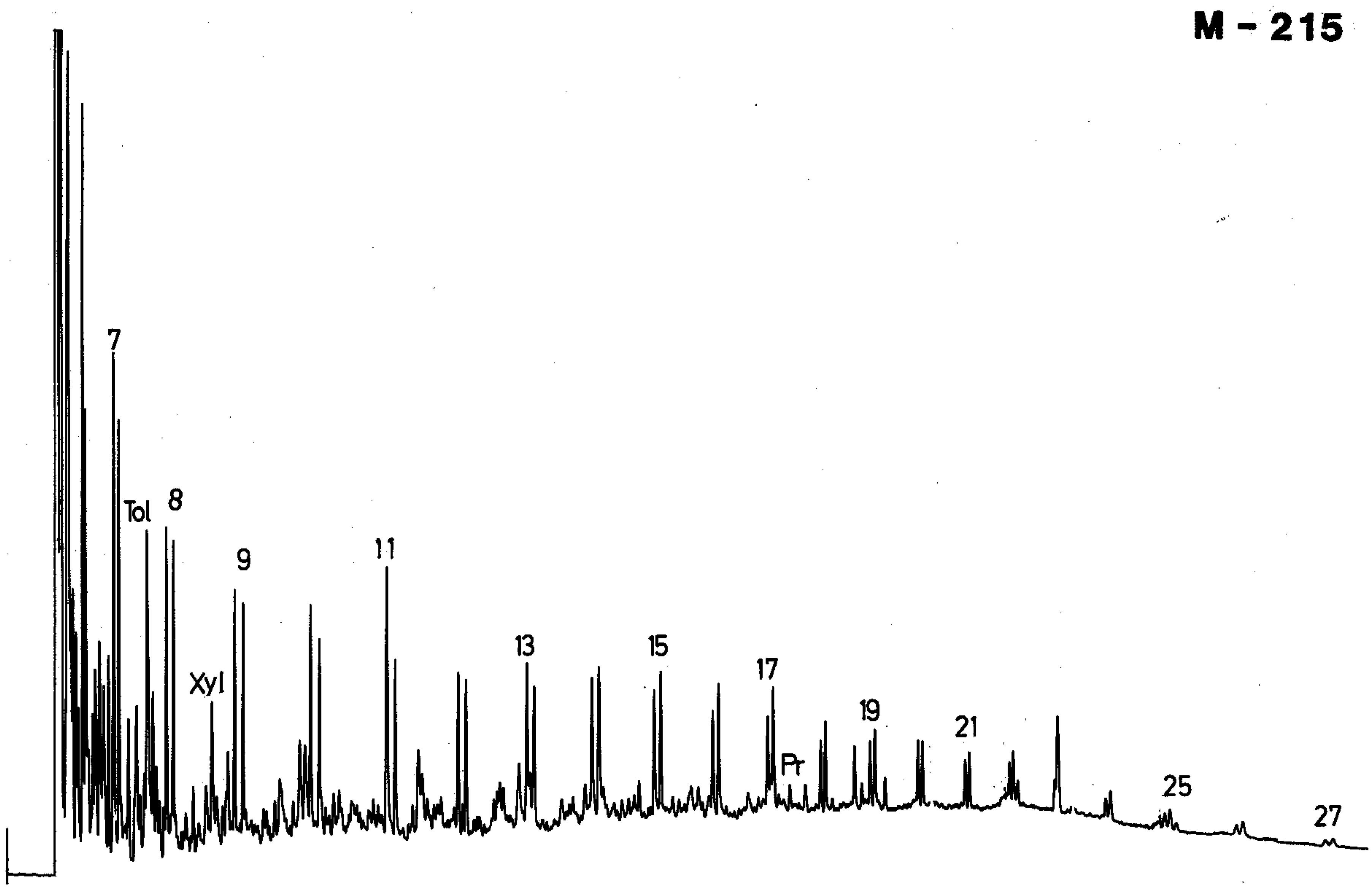
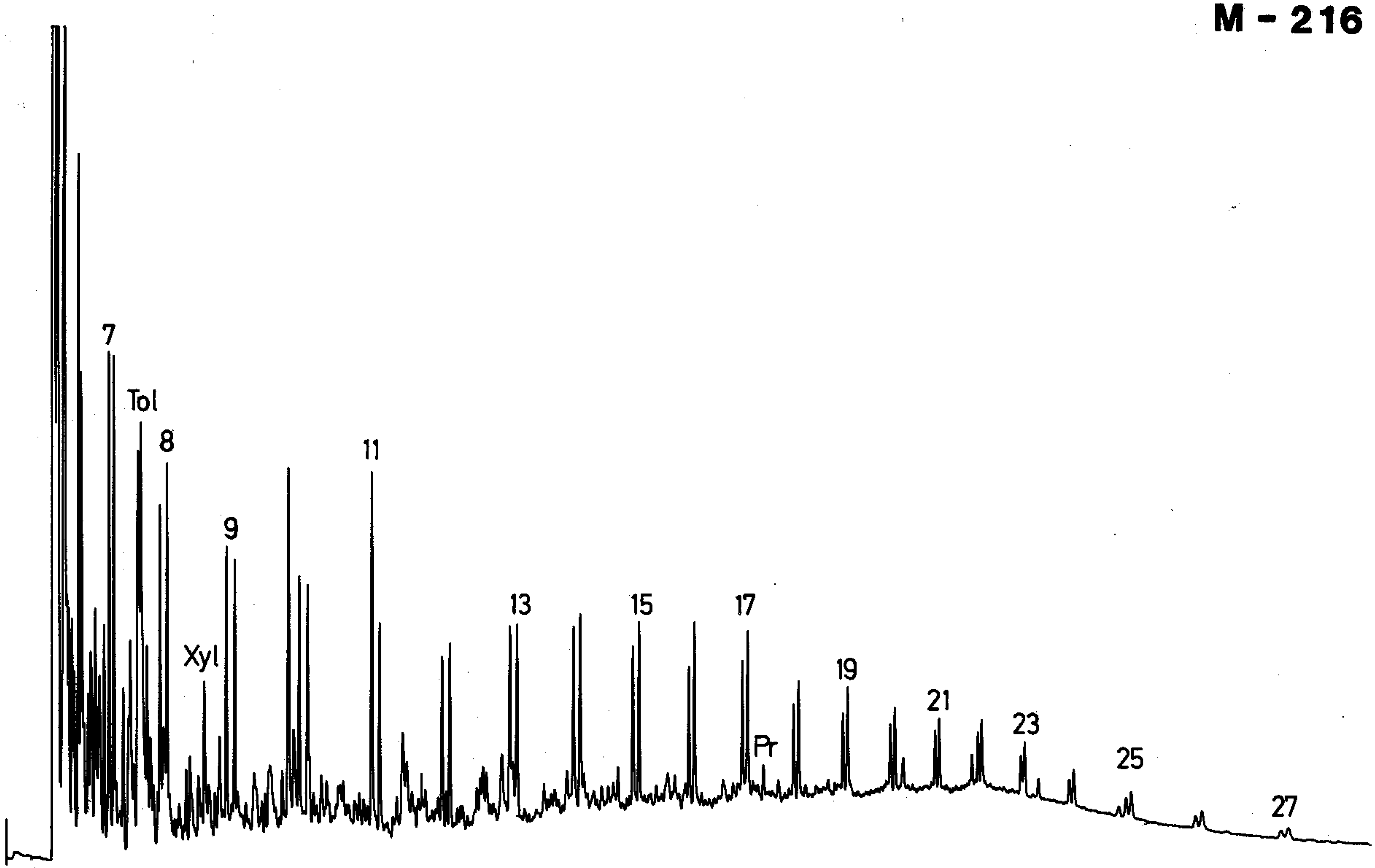
7
Tol
8
Xyl
9
11
13
15
17
Pr
19
21
23
25
27
8x

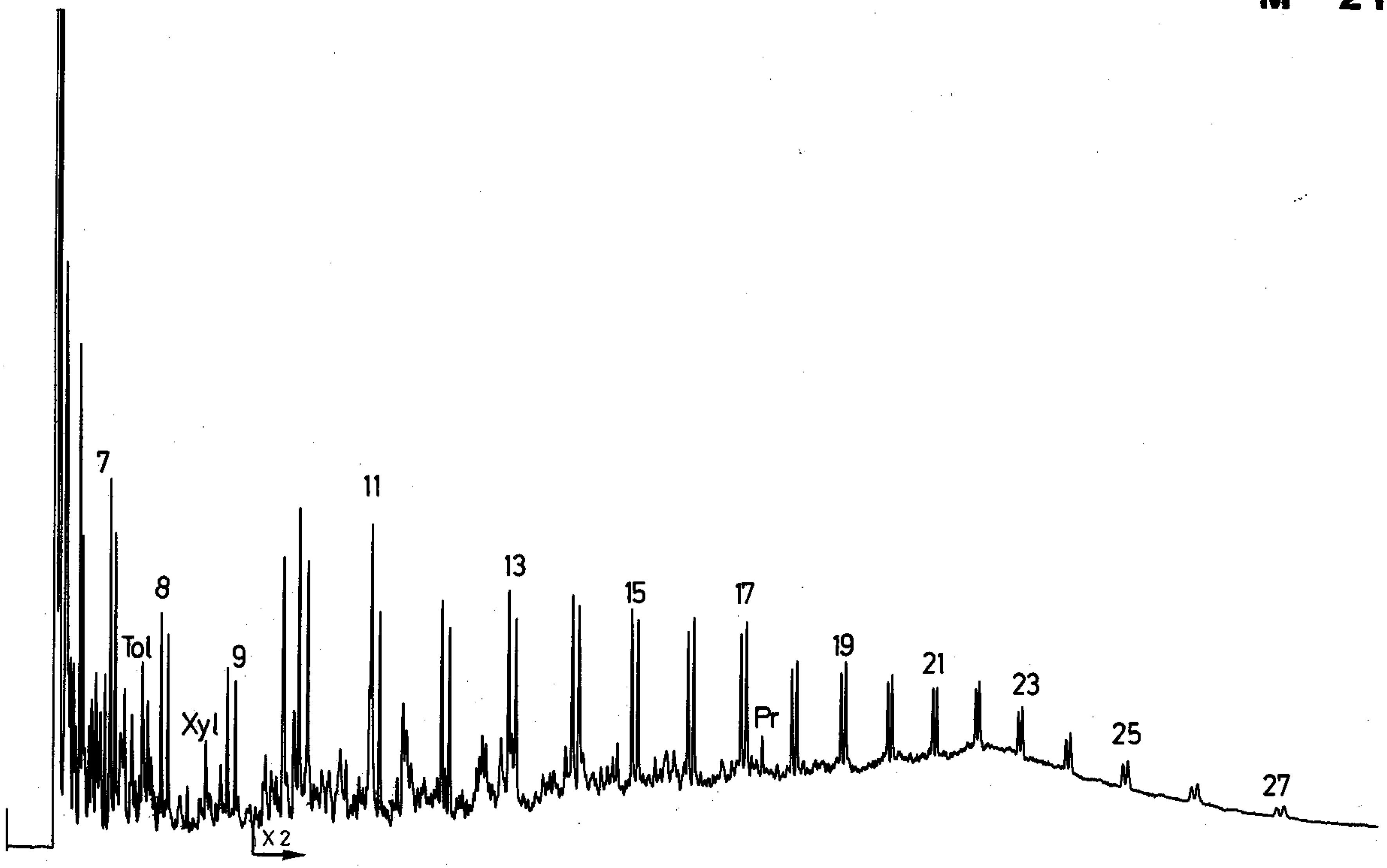

M - 214
7
Tol
8
Xyl
9
x 2
11
13+1- and 2-MeN
14+C2N
15
17
19+MePh
21
23
25
25

M - 215
7
Tol
8
9
Xyl
11
13
15
17
Pr
19
21
25
27




M - 216
7
Tol
8
Xyl
9
11
13
15
17
Pr
19
21
23
25
27

M - 217



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GEOCHEMICAL SERVICE REPORT

Prepared for

SAGA PETROLEUM A.S.

GEOCHEMICAL EVALUATION OF THE SAGA PETROLEUM 35/3-4 WELL, NORWEGIAN NORTH SEA

BA 81-6217-1

21 DES 1981

November 1981

CHESTER STREET · CHESTER CH4 8RD · ENGLAND

COMPANY PROPRIETARY

GEOCHEMICAL EVALUATION OF THE SAGA PETROLEUM

35/3-4 WELL, NORWEGIAN NORTH SEA

SUMMARY

An hydrocarbon screen of the sediments between 1200 metres and 2400 metres suggests that they are poor source rocks.

The interval between 1200 metres and 4088 metres has been more comprehensively evaluated. Down to 3200± metres the shales are poor, immature to marginally mature and have a limited potential for gas/condensate. At 3200-3650± metres the dominant medium to dark grey shales are effectively immature and have a negligible potential for gas.

Abundant medium to dark grey and dark olive grey shales occur within the interval 3650-34088± metres. Although they are generally poor source rocks scattered fair and good to very good interbeds are also present, notably above 3700± metres and below 4000± metres. Their marginal maturity will, however, limit hydrocarbon generation on-structure to minor volumes of gas and associated liquids.

Shows of a medium gravity crude oil were detected at 3353-3362± metres and at 3416-3425± metres. Scattered traces of wet gas occur between 3200± metres and 3650± metres and good shows of dry to marginally wet gas are present below 3650± metres. More mature

equivalents of the Zone D shales are believed to be the source of the gas/condensate shows but the presence of crude oil suggests a facies change to more oil prone sediments down dip.

M.J. Sauer

M.J. Sauer
GEOCHEM LABORATORIES (UK) LIMITED

INTRODUCTION

This report presents a geochemical evaluation of the section between 2400± metres and 4088 metres and the results of a light hydrocarbon screen on the interval 1200-2400± metres in the Saga Petroleum A.S. 35/3-4 well, drilled in the Norwegian Sector of the North Sea.

The study was designed to investigate the hydrocarbon source potential of the section in terms of richness, maturity and potential for oil or gas. Shows of migrated hydrocarbons were also investigated.

This project was authorised by Mr. T. Throndsen, Saga Petroleum A.S., Stavanger.

A. ANALYTICAL

Two hundred and twenty five (225) canned cuttings samples were received from the interval 890-4088 metres in the 35/3-4 well. A condensate sample was subsequently received from this well. The samples were assigned the Geochem job number 553.

During sample washing operations an oily smell was observed at 2670-2830± metres and an oily fleck at 3407-3488± metres.

At the request of the client the sediments were screened (at intervals of 40 metres above 2400 metres and at 20 metres below this depth) using the light hydrocarbons analysis. Samples for subsequent analysis were selected (by the client) on the basis of the screen results. This analysis schedule was generally adhered to although, due to the leanness of certain sediments, alternative samples were selected for some of the detailed gasoline range analyses. A total of two hundred and nine light hydrocarbons analyses, two hundred and forty organic carbon determinations, thirteen detailed gasoline range analyses, fourteen visual kerogen analyses, fourteen extractions with chromatography, fourteen paraffin-naphthene analyses and forty eight mini-pyrolysis analyses were performed in this study.

The data are presented in tables 1 to 8 and graphically in figures 1 to 6. A brief description of the analytical techniques employed is included in the back of this report.

B. GENERAL INFORMATION

Three copies of this report have been forwarded to Mr. T. Throndsen, Saga Petroleum, Stavanger, together with the kerogen slides prepared for this study. A copy of the report has been retained for future consultation with authorised Saga personnel.

The remaining sample material will be returned as requested.

All of the results of this study are proprietary to Saga Petroleum A.S., Stavanger.

RESULTS AND DISCUSSION

Light hydrocarbons analyses are reported for the section between 1200 metres and 4088 metres but only the interval below 2400± metres have been examined in detail. Analyses within this interval were specified by the client.

A. ZONATION

Within the specified interval this zonation is based upon the light hydrocarbons data. A brief description of the sediments above the specified interval is included in this section only. Four (4) zones are recognised.

Between 1200 metres and 1500± metres the sediments consist of interbedded sands, mudstones and light olive grey shales. They overlie an interval dominated by medium to dark grey and olive grey shales which extends down to 2400± metres.

The hydrocarbon gases are sparse (less than 1000 ppm) and in general very dry although below 2000± metres they contain up to 28.9% C_{2+} hydrocarbons.

Zone A — 2400-2830± metres is a sequence of pale grey and medium-dark grey shales and mudstones. The mudstones are shaly above 2650± metres but are generally silty below this depth; they range in colour from pale grey to light brownish grey and light olive grey. Lost circulation material is common in these samples which also contain traces of (caved?) limestone.

No fluorescence was detected.

Poor (less than 1000 ppm) quantitites of C_1-C_4

hydrocarbons are present in Zone A. These gases are dry (less than 20% C_{2+} hydrocarbons) although a modest improvement in gas wetness, peaking at 43% at 2650± metres, is apparent between 2510± metres and 2790± metres. Between 258 ppm and 2162 ppm C_5-C_7 hydrocarbons are present at 2670-2810± metres; the heavier hydrocarbons were not detected elsewhere in the Zone. Isobutane to normal butane ratios vary erratically between 0.6 and 4.6.

Zone B lies between 2830± metres and 3200± metres. Medium to dark grey shales and lighter coloured (silty) mudstones overlie at 3000± metres a medium grey shale unit which extends, with interbeds of darker grey shales below 3100± metres, down to the base of the Zone.

With two exceptions, 700 ppm at 2890-2910± metres and 924 ppm at 2950-2970± metres the C_1-C_4 hydrocarbons are of fair (1050-6836 ppm) abundance. The gasoline fraction, however is almost totally absent (468 ppm at 3110-3120± metres). The gases are relatively dry (6.6-27.5% C_{2+} hydrocarbons) and have isobutane to normal butane ratios (0.61-2.32) which decrease irregularly with depth.

Zone C 3200± metres down to 3650± metres, is dominated by shales although interbeds of medium to light grey mudstone (above 3344± metres) and sandstone (at 3326-3614± metres), and traces of limestone, are also present. The shales vary in colour from medium to dark grey and a significant proportion of them appear to be caved above 3440± metres.

Fluorescence, generally patchy and yellow in colour, but stronger and associated with oil staining at

3416-3425± metres, was detected in the sands at 3335-3344± metres and at 3416-3452± metres.

The gaseous hydrocarbons are of poor abundance (582-939 ppm) at 3299-3326± metres, good (18755 ppm) at 3416-3425± metres but in general are fair at 1007-8293 ppm. Furthermore, with few exceptions (e.g. at 3200± metres, 3470± metres-3506± metres) they are wet to very wet (50-87.6% C_{2+} hydrocarbons). Gasoline range (C_5-C_7) hydrocarbons are sparse (less than 500 ppm) above 3335± metres, fair to good (780)1070-11423 ppm between 3335± metres and 3533± metres and poor (187-934 ppm, 1247 ppm at 3587-3596± metres) below this depth. There is an approximate correlation between enhanced gas wetness and richness, notably at 3353-3362± metres and at 3416-3434± metres. Significantly, the isobutane to normal butane ratios which range from 0.16 up to 1.57 are lower in the intervals affected by wet gas.

Zone D extends from 3650± metres down to the deepest sample at 4088 metres. Shales predominate in this interval although interbeds of mudstone, at 3821-3866± metres, and of sandstone, (dominant in basal 20± metres) below 3857± metres, are also present. Medium to dark grey shales occur at 3830-3974± metres but above and below this interval the shales are commonly dark olive grey or, in the basal 30± metres, medium to dark grey in colour. Varying amounts of lost circulation material, chiefly cement and metal turnings, were present in the samples.

No fluorescence was observed.

Abundances of C_1-C_4 hydrocarbons are commonly good to very good (10851-51337 ppm) but drop to 9311-9721 ppm at 3776-3821± metres and to 3495-8810 ppm below 4073± metres. They are somewhat drier than the gaseous hydrocarbons in Zone C and rarely exceed 50% wetness (12.8-85.7% C_{2+} hydrocarbons). Intervals of above average (greater than 60%) gas wetness are thinly scattered (i.e. at 3659± metres, 3803-3821± metres and at 4082± metres). The heavier (C_5-C_7) fraction varies in abundance from generally fair (1416-8863 ppm) to good at 3686-3713± metres (10142-14074 ppm). The ratio of isobutane to normal butane is comparatively low, ranging narrowly from 0.11 to 0.50(0.82 at 3794± metres).

B. AMOUNT AND TYPE OF ORGANIC MATTER

The amount of organic matter within a sediment is measured by its organic carbon content. Average shales contain approximately one percent organic carbon, and this is the standard to which these samples will be compared.

Organic matter type influences not only source richness but also the character of the hydrocarbon product (oil, gas) and the response of the organic matter to thermal maturation. Richness and oiliness decrease in the order: amorphous-algal-herbaceous-woody. Wood has a primary (but not exclusive) potential for gas whilst inertinitic (oxidised, mineral charcoal) material has only a limited hydrocarbon potential.

Organic carbon values are below average (0.28-0.98%) within Zone A although it is generally the lighter grey-olive shales and mudstones below 2590± metres which have poor (less than 0.50%) values. The pale grey mudstones, represented by the sample at 2470-2490± metres contain organic matter which is largely composed of inertinite, with significant algal but only minor proportions of woody, amorphous and herbaceous kerogen.

Zone B has organic carbon contents which are comparable to those in Zone A. Thus, the shales and (silty) mudstones above 2930± metres contain (0.5)0.7-1.20% organic carbon whilst the underlying shales have values of (0.44)0.54-1.06% (1.78% in minor dark grey shale at 3100± metres). Organic matter consisting mainly of amorphous, with minor proportions of inertinitic, woody, algal and herbaceous, kerogen is present in the grey shales. The amorphous organic matter, however, is of poor quality (dark and atypical) and includes partially developed material.

With few exceptions the dominant dark grey and medium-dark grey shales of Zone C have organic carbon contents which range from 0.82% up to 2.12%, and increase with depth. Notable are the interbeds of greyish black shale at 3461-3506± metres at 1.80-1.98% and the underlying dark grey shales at 1.46-1.86% organic carbon. The mudstones, and a few of the grey shales in this Zone have fair (0.52-1.02%) organic carbon contents. However, despite this "above average" richness the organic matter is largely composed of reworked inertinite and wood; algal and herbaceous (± amorphous) kerogen are minor fractions of the total organic matter. Disseminated "amorphous" material (suspected contaminant) was also isolated from the Zone C shales.

The dark olive grey shales above 3794± metres in Zone D have good (1.10-2.80% organic carbon) contents of amorphous, with significant algal, inertinitic and woody, organic matter. Between 3794± metres and 4046± metres the medium-dark grey shales also have good (0.90-2.96%) organic carbon values. These shales contain organic matter which is largely amorphous in character, only traces of algal, woody and inertinitic material are present. Somewhat richer (1.06-3.99%) organic carbon shales occur in the basal 40± metres. Their organic matter principally consists of algal, inertinitic and woody debris, with traces of amorphous and herbaceous kerogen. Throughout this zone the amorphous organic matter is dark, grainy (atypical) in appearance and of poor quality. It is not the more normal 'oil prone' amorphous kerogen.

C. LEVEL OF THERMAL MATURATION

Thermal maturity has been assessed by the visual kerogen (spore colour) method. A maturation index of 2- is achieved at approximately 3000± metres and 2- to 2 by 3360± metres. There is no further apparent increase in maturity within the analysed well section. This lack of precision in the determination of thermal maturity is due to the poorly preserved state of the organic matter in most of the analysed sediments.

Amorphous and herbaceous organic matter becomes marginally mature at an index of 2- and moderately mature (significant hydrocarbon generation) at 2. The corresponding values for woody kerogen are 2 and 2 to 2+. From the foregoing it is evident that the sediments above 3000± metres are totally immature but are believed to be marginally mature, and capable of generating minor volumes of hydrocarbons, in Zone D. The dominance of immature, inertinitic and woody, kerogen in the Zone C shales dictates their effective maturity.

D. SOURCE RICHNESS

Preliminary assessments of source richness are based upon the abundance of light hydrocarbons and organic carbon.

The light hydrocarbon data indicate poor source richness above 2830± metres whilst Zones B and C (2830-3650± metres) are potentially fair, and Zone D good, intervals.

From the organic carbon values Zone A is rated as poor to fair, Zone B as fair, and Zones C and D as good, potential hydrocarbon sources. The rating for Zone C is optimistic since the dominantly inertinitic organic matter in these sediments has a minimal hydrocarbon potential.

Source richness may also be deduced from the abundance of indigenous C_{15+} hydrocarbons. A selection of shale, or shale and sandstone, samples when solvent extracted yielded 161-898 ppm C_{15+} hydrocarbons. The proportion of hydrocarbons in the total extract, however, commonly exceeds 40% (21.3-58.6%) and is higher than expected for immature or marginally mature sediments - non indigenous hydrocarbons are suspected. Hydrocarbon to organic carbon ratios of 9.5 and 12.0, at 3353-3362± metres and at 3416-3425± metres respectively, are also somewhat anomalous. Normal paraffins in the C_{15+} paraffin-naphthene fraction chromatograms have a strong front end bias, commonly die at C_{25}-C_{30} and rarely show the carbon preference normally assoicated with relatively immature sediments. The traces generally resemble diesel oil (abundant C_{25-} paraffins and baseline hump) and/or a suspected mud additive (ubiquitous and intense non-normal paraffin fingerprint). A discernable odd paraffin preference at 3209± metres, 3740± metres and at 4064± metres indicates contributions from immature source related hydrocarbons. However, the indigenous hydrocarbons are almost invariably enhanced or masked by non indigenous species and their abundance cannot, therefore, be used to assess source richness.

Mini-pyrolysis analyses performed on a suite of forty seven selected samples indicate that Zones A and B, apart from a slight improvement in the basal 20± metres, have a poor hydrocarbon potential (less than 1278 ppm pyrolysate). Interbeds of fair shale occur at 3560-3569± metres (2054 ppm pyrolysate) and at 3596-3605± metres (2511 ppm) but Zone C is generally poor with values of less than 1882 ppm (commonly less than 1250 ppm). Pyrolysate yields suggest that wide variations in source richness occur within Zone D. Thus, shales at 3667-3704± metres, 3900-3920± metres, 4000-4040± metres are fair (2054-2790 ppm) at 3812-3830± metres and at 4040-4090 are good (3096-4395 ppm) and at 3650-3659± metres very good (5837 ppm). With these exceptions Zone D is poor.

To summarise:

Zones A-C are poor source intervals although interbeds of fair shale are present in the basal 100± metres.

Zone D apart from interbeds of fair, good and very good shale is poor.

Potential hydrocarbon products (deduced from the type of organic matter since pyrolysis-GC was not requested) are gas/condensate in Zones A-C, minor gas in Zone C and gas/condensate in Zone D.

D. MIGRATED HYDROCARBONS

Interbeds of sandstone at 3326-3614± metres and below 3857± metres (dominant in basal 20± metres) represent potential reservoir facies.

Yellow fluorescence was detected in the oil stained sands at 3416-3425± metres and, patchily, in the sands at 3335-3342± metres and at 3425-3452± metres.

Hydrocarbon gases are sparse and dry above 3200± metres; they do not suggest that migrated hydrocarbons are present. Between 3200± metres and 3335± metres gas wetness occasionally exceeds 60% but the poor light hydrocarbon abundances indicate only scattered traces of wet gas.

Although only of fair abundance (good at 3416-3425± metres) the C_1-C_4 hydrocarbons are, commonly, very wet at 3335-3434± metres. Gasoline range hydrocarbons achieve abundances of 9676 ppm at 3353-3362± metres and of 11423 ppm at 3416-3425± metres but are generally fair (less than 4781 ppm). Thus, the combined light hydrocarbon data indicate traces of wet gas above 3335± metres in Zone C and a show of wet gas/condensate plus, possibly, crude oil in the two richest intervals. Anomalously high C_{15+} hydrocarbon abundances (512-898 ppm), hydrocarbon to total extract (52.1-58.6) and hydrocarbon to organic carbon ratios (9.5 and 12.0) suggest heavy non-indigenous hydrocarbons at 3353-3362± metres and at 3416-3425± metres. The corresponding C_{15+} paraffin-naphthene fraction chromatograms resemble a medium gravity crude oil.

Fair, occasionally good, volumes of moderately wet gas are present in the sediments down to 3650± metres but, with one exception, the C_5-C_7 fraction is sparse. Enhanced gas wetness at 3506-3542± metres coincides with a modest improvement in the gasoline range hydrocarbon abundances. This "richness" does not extend into the C_{15+} fraction (242 ppm) which suggests that crude oil is not present at this depth. Confirmation comes from the paraffin-naphthene trace which largely resembles drilling introduced contamination. A concensus of the available data indicates fair quantities of moderately wet gas at 3434-3650± metres.

Gaseous hydrocarbons are abundant within Zone D. They commonly exceed 10,000 ppm, peaking at 3677-3731± metres (15177-27166 ppm) and at 3821-3965± metres (20990-51337 ppm). The gasoline fraction is generally fair (1406-8863 ppm) but values of 10111-12070 ppm are achieved at 3686-3713± metres, 11438 ppm at 3740-3749± metres and 10142-14074 ppm at 3939-3965± metres. There is no corresponding increase in gas wetness within these interval - suggesting that the enhancements in C_5-C_7 hydrocarbons may be due to contamination (see below). Although the abundance of C_{15+} hydrocarbons suggest out of place species in Zone D, in all but the lowermost 30± metres they consist of traces of source indigenous hydrocarbons and contamination. The latter is recognised by the smooth paraffin distribution terminating at nC_{25}, baseline hump and detailed iso-paraffin fingerprint. At 4064-4073± metres the chromatogram suggests contributions from contamination (as above), indigenous organic matter (odd carbon preference) and, possibly, traces of condensate. This correlation with the produced fluid is rather tenuous since the C_{15+} hydrocarbons constitute a very small fraction of the total condensate. It is based upon the shape of the n-paraffin envelope (terminating at nC_{30}) and isoparaffin fingerprint. Significantly, there is an increasing gas wetness trend in the basal 40± metres - suggesting that the hydrocarbons may have diffused upwards from the underlying sands. Thus, combining the various sets of hydrocarbon data - good shows of dry to moderately wet gas occur throughout Zone D, possible traces of condensate resembling the produced fluid were detected at 4064-4088± metres.

Organic matter in the Zone D shales is not typically oil prone but is believed to have a potential for gas/condensate nonetheless. These shales contain fair to good, and occasionally very good, interbeds but, due to their marginal maturity, are unlikely to be the source of the shows in Zones C and D. Their source is postulated to be in more mature off-structure equivalents of the Zone D shales.

The medium gravity crude oil detected at 3353-3362± metres and at 3416-3425± metres has an almost inperceptable odd carbon preference and does not appear to be a 'young' oil resulting from a localised redistribution of hydrocarbons. Mature oil prone sediments were not found in the analysed well section, which indicates a facies change off-structure. The restricted distribution of crude oil shows, when compared to those of gas and condensate, suggests that, in addition to a distinct source facies, a separate migrational pathway may be involved.

Detailed gasoline range analyses were performed on a suite of washed cuttings samples to determine what, if any, correlations exist between the liquid hydrocarbons in the host sediments. Total abundances so obtained differ markedly from those of the analagous C_5-C_7 fraction measured in the screen analysis. The discrepancy is believed to be due to hydrocarbons (as additives, e.g. diesel oil, or entrained from shows) from the drilling mud in the screen analysis. For this reason several of the specified samples could not be analysed.

Gasoline range (C_4-C_7) hydrocarbon abundances are generally less than 1000 ppm within Zone C (3200-3650± metres) but in Zone D (3650-4088± metres) they rise to 2361-4632 ppm. Grossly, there appears to be little systematic variation in the total normal or isoparaffins, they vary erratically from 19.1% to 78.7% and from 16.6% to 46.4%, respectively. With three exceptions, however, the naphthenic hydrocarbons are less than 10% of the C_4-C_7 fraction in the richer Zone D sediments. An inspection of the individual hydrocarbon ratios (e.g. methylcyclopentane to benzene etc.) shows little if any correlation between the samples. A statistical pairwise comparison (based upon 27 peaks) confirms that the samples are uncorrelated by this parameter. This lack of correlation between the various gasoline fractions suggests varying inputs from several sources viz. traces of indigenous hydrocarbon (the sediments in Zone D are occasionally of fair to good richness), migrated hydrocarbons (condensate associated with the shows of moderately wet gas in Zone D) and contaminant hydrocarbons from the mud system (e.g. diesel oil and entrained hydrocarbons from shows).

To summarise:

there is no evidence of migrated hydrocarbons within Zones A and B.

shows of wet gas/condensate were detected at 3335-3434± metres and of a medium gravity crude oil at 3353-3362± metres and at 3416-3425± metres, traces of wet gas occur throughout Zone C.

good shows of dry to moderately wet gas occur throughout Zone D, notably at 3677-3731± metres and at 3821-3965± metres.

F. CONCLUSIONS

Four (4) zones are recognised between 2400± metres and 4088 metres in the 35/3-4 well.

Zone A (2400-2830± metres) is a sequence of pale grey mudstones and medium to dark grey shales. Organic carbon contents rarely exceed 1% (0.28-0.98%, 1.67% at 2710± metres) and are frequently less than 0.5%. Poorly preserved, largely inertinitic (with significant algal, and traces of woody, amorphous and herbaceous) organic matter in the mudstones at 2470± metres is, apparently immature. Hydrocarbon generation does not appear to have commenced in Zone A and even in the mature state these sediments would have a negligible hydrocarbon potential.

Zone B lies between 2830± metres and 3200± metres. Interbeds of medium grey (silty) mudstone occur above 3000± metres but the interval is dominated by medium-dark grey shales. In general they have fair (0.44-1.06%, 1.2% at 2850± metres, organic carbon) contents of organic matter which chiefly consists of poor quality amorphous material. The sediments do not appear (the organic matter is poorly preserved and its maturity uncertain) to be generating significant volumes of hydrocarbons on-structure and, furthermore, have a poor hydrocarbon potential.

Zone C, 3200± metres down to 3650± metres is, apart from interbeds of sandstone at 3326-3614± metres and of mudstone (above 3344± metres), dominated by dark grey shales. The shales have fair to good organic carbon contents (0.82-2.12%) but their organic matter is chiefly composed of immature inertinitic and woody debris; algal, herbaceous and amorphous kerogen is sparse. Inertinite has a negligible hydrocarbon potential and this is evident in the results of the pyrolysis analyses which, except for a few fair interbeds below 3550± metres, confirm that the sediments are a poor source for gas and associated liquids.