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EXPLORATION AND PRODUCTION:

THE COMPOSITION OF NORWEGIAN GAS WELL TROLL 31/2-12

Req. No: Telex ref. HAG 181043 d. 18.5.83

Author : E.P. Knowles

Participants : R.G. Wilde, A.F. Sutton, and M.C. Macknay

Reviewed by : A.G. Dixon

SUMMARY

The Thornton split-phase sampling system has been used in the orwegian sector of the North Sea to perform a series of separation tests on as well 31/2-12, in the Troll field. The well-stream composition has been etermined from these tests, after recombining measured equilibrium phase ata obtained from controlled sequential separations at the well-head.

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THORNTON RESEARCH CENTRE

Operations Equipment and Measurement Division

November 1983

EXTERNAL REPORT

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SUMMARY

The Thornton split-phase sampling system has been used in the Norwegian sector of the North Sea to perform a series of separation tests on gas well 31/2-12, in the Troll field. The well-stream composition has been determined from these tests, after recombining measured equilibrium phase data obtained from controlled sequential separations at the well-head.

The experimental results are compared with downstream phase compositions and properties calculated using a computer program based on the Redlich-Kwong equation of state. Although reasonable agreement is obtained between respective data certain differences are present. These differences are attributed to the exclusion of a non-paraffinic contribution to the composition description. Adjusting fractions upto C_{15} to allow for the known aromatic/naphthenic nature of the Troll effluent produced in simulations, an improved reflection of the well-streams true behaviour.

The gas composition from well 31/2-12 is slightly leaner with a corresponding lower liquid/gas ratio than was observed in previous tests in the Troll field on wells 31/2-2, 31/2-3 and 31/2-6.

T H O R N T O N R E S E A R C H C E N T R E

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CONTENTS

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1. INTRODUCTION

In late July and early August 1983, Thornton carried out a series of well head tests on Troll well 31/2-12 during production testing of the gas zone by Norske Shell.

The objective of the Thornton work was to obtain a detailed, accurate well-stream composition and gas/liquid equilibrium data at precise temperature and pressure conditions.

Two sets of testing conditions were employed, (a) at temperatures and pressures designed to replicate previous Thornton 31/2 field test data[1,2,3] and (b) at conditions requested by Norske Shell.

2. EXPERIMENTAL

The Thornton well head testing equipment consists of a heavy duty sampling manifold containing a mixing device in one leg (Figure 1) which is placed in the well-effluent flow line between the well-head and choke manifold. After passing through the phase mixing device a homogeneous side stream is directed isokinetically, via a sample probe, to a miniature laboratory housing a series of small scale separators (Figure 2). Each separator is controlled at a predetermined temperature and pressure. Condensates were collected at test pressure in the 5 dm^3 capacity vessel shown in Figure 2 and also in the 0.15 dm^3 treatment stage. These condensates were either flashed quantitatively to atmospheric pressure for the larger separation, or measured gravimetrically in the case of the 0.15 dm^3 stage. In both instances "tank oil" and test condition condensate/gas ratios were calculated and these are reported based on 1×10^6 m^3(st) of gas passed through the Thornton equipment. Volumes of gas were measured by the gas meters shown in Figure 2.

All vented hydrocarbon phases were retained for subsequent compositional analysis using standard gas chromatographic techniques. The analytical data are recombined in the appropriate mole ratio for each separation which eventually yields a detailed description of the well-stream originally sampled.

The conditions of the 2-stage separations performed during earlier Thornton work on this reservoir, were closely reproduced here, that is:

	1st stage		2nd stage	
	pressure, bar	temperature, °C	pressure, bar	temperature, °C
Test 1	70.0	-3	35.5	-16
Test 2	70.0	0	35.5	-7
Test 3	70.0	1	35.5	-10

Norske Shell requested these additional separations to be made.

Test 4*	89.0	29	46.2	-12
Test 5	89.0	32	46.2	-12
Test 6	60.0	-19		

* Note: Test 4 was performed for trial purposes only.

3. RESULTS

Details of the tests performed including CGR's, both at test conditions and when vented to atmospheric pressure, are given in Table 1.

Tables 2-6 show the gas liquid equilibrium data for each test. The analytical data gives an isomeric split for butane (C4) and pentane (C5) and also describes the molar percentage of benzene, toluene and xylene. The recombined well-head fluid, phase compositions and equilibrium data for each test are given in the tables. Also shown are the Gross Heating Values (GHV) for each gas phase. The resulting measured well-head fluids obtained from recombination calculations were used in computer flash calculations to predict theoretical phase compositions at the first stage experimental conditions and the gas composition so derived was then sequentially flashed to the second stage test conditions. The resulting data obtained are shown in Tables 7 to 11.

In addition, a second series of computer simulation calculations was performed using the same well-head fluids but after reclassifying the C6 and C7 n-alkane fractions as cylcohexane and methyl cylcohexane. The C9+ fraction was also modified to include a 60% aromatic/naphthene content (benzene toluene and xylene proportions were determined experimentally). The predicted data using these adjusted streams are shown in Tables 12 to 16.

Experimental well-head fluid compositions from all tests are summarised in Table 17. Compositional data for tests 1-3 are very similar and Table 18 compares the well stream composition from test 2 with examples from the previous 31/2 gas well tests.

Schematic presentations of the gas/liquid equilibrium data for each test are given in Figures 3 to 7. Table 19 gives conversion factors for SI to FPS units.

4. DISCUSSION

Tests 1 to 3 (Tables 2-4) were performed to confirm results obtained during earlier work on 31/2 wells. The individual well-head fluid compositions compare well with each other. The corresponding 1st and 2nd stage phase compositions for tests 2 and 3 are also in general agreement as expected for nominally the same conditions of separation. Overall only minor variations were evident and these concern the second stage liquid data. The condensate gas ratio for test 1 is higher than in tests 2 and 3 but is to be expected in view of the first stage treatment temperature used during these tests. Similarly the test 3 first stage liquid yield is less than test 2 in line with the slightly higher temperature of test 3.

It is usual when performing computer flash calculations to assume that the feed composition is predominantly paraffinic in nature and that the boiling range of individual fractions fall within the bounds described by the preceeding n-paraffin and that used to identify the group. Such a procedure was employed for the flash calculations shown in Tables 7 to 11. Inspection of this data shows that whilst first stage gas compositions are in reasonable agreement with experimental figures some variation occurs in the 1st stage liquid compositions notably the C1, C6, C7 fractions.

It is known that the Troll fluid compositions are relatively low in n-hydrocarbon species and high in naphthenes and some aromatic groups, particularly in the C6 and C7 liquid fractions. For experimental phase behaviour to be reproduced realistically by flash calculations it is clearly necessary to allow for aromatic nature in the input data. It has been found that by the trial inclusion of various levels of aromaticity in the C9 to C16+ fractions, closer agreement can be achieved between measured and calculated results. Consequently a second series of flash calculations were carried out using feeds modified to include cyclohexane, methyl cyclohexane as the characteristic component for the C6 and C7 fractions respectively, and by inserting 60% aromaticity in the C9 to C16+ fractions. From the original analysis the C16+ fraction has been ascribed the properties of a C17 n-hydrocarbon. Tables 12 to 16 show that closer agreement is achieved between measured and predicted data by adjusting the well-stream characterisation in the above manner. Experimentally determined well-head fluid composition data for tests 1-3, 5 and 6 are summarised in Table 17.

It was requested for the final test (test 6) that the following conditions should be employed viz., 1st stage 126.8 bar/29°C, second stage 60 bar/-34°C. It was pointed out that the first stage conditions were approximately those at the well head and so the test was modified to a single stage at 60 bar/-34°C. In the event a temperature of -19°C was all that could be achieved with the time and materials available. The experimental well-fluid composition and LGR data are in satisfactory agreement with that predicted by computer calculations.

It is noted that the Troll 31/2-12 well composition and associated equilibrium data confirm previous work carried out in the Troll field.

Testing under similar conditions to those used previously produced comparable data but yielded a slightly leaner gas composition. A comparison of the data obtained under test 2 conditions is shown in Table 18. This table indicates that some variation in composition occurs across the formation and is illustrated by inspection of the respective carbon dioxide levels established by Thornton and independent determinations performed at the same time (see Table 18).

Test 5 was performed using separation conditions requested by Norske Shell. In this case the observed mol ratios and LGR data (Table 5) differ from those obtained in tests 1-3 (Tables 2-4) in line with the higher pressure and temperature in the first stage and lower temperature in the second stage.

5. REFERENCES

1. N. Coleclough, Exploration and Production: Gas tests offshore Norway, North West Venture, TNTR.81.021, March 1981.

2. N. Coleclough, Exploration and Production: Gas tests offshore Norway, Borgny Dolphin, TNTR.81.014, March 1981.

3. E.P. Knowles, Exploration and Production: Gas tests offshore Norway, Gas Well 31/2-6, TNER.82.029, May 1982.

Table 1

Summary of condensate gas ratios determined in Thornton tests

Test	Date/ Time	Well flowrate $10^6 m^3$ (st)/d (MMscf/d)[1]	Test conditions, bar/°C	Condensate gas ratio $m^3/10^6\ m^3$ (st) At test conditions	At atmospheric[2] conditions
1	29.7.83 08.30 h	0.576 (20.33)	stage 1 70/-3	29.46	24.40
			stage 2 35.5/-16	6.60	5.82
2	1.8.83 22.37 h	0.540 (19.06)	stage 1 70/0	26.12	21.22
			stage 2 35.5/-7	4.56	3.70
3	2.8.83 07.29 h	0.546 (19.28)	stage 1 70/1	25.80	21.18
			stage 2 35.5/-10	5.39	4.55
5	2.8.83 14.34 h	0.546 (19.28)	stage 1 88.9/32	11.52	9.37
			stage 2 46.2/-12	23.06	19.40
6	2.8.83 18.00 h	0.523 (18.47)	stage 1 60/-19	36.63	29.03

Note (1) Flopetrol data

Note (2) Amount of liquid at atmospheric conditions relative to separation gas

TABLE 2

Test 1 Experimental Phase Compositions (mol%)

Component	Well-head fluid	Separator 1 70.0 bar -3 °C		Separator 2 35.5 bar -16 °C	
		Liq.	Gas	Liq.	Gas
C1	93.287	25.820	93.705	20.787	93.811
C2	3.435	4.624	3.428	5.893	3.424
C3	0.309	1.745	0.300	2.121	0.297
IC4	0.263	3.318	0.244	4.667	0.238
NC4	0.026	0.652	0.022	0.618	0.021
IC5	0.038	1.580	0.029	1.857	0.026
NC5	0.007	0.415	0.005	0.444	0.004
C6	0.136	12.459	0.060	21.202	0.029
C7	0.169	19.701	0.047	29.965	0.004
C8	0.052	6.960	0.008	5.885	
C9	0.042	6.139	0.004	3.003	
C10	0.033	4.998	0.002	1.227	
C11	0.015	2.342		0.318	
C12	0.013	2.133		0.142	
C13	0.007	1.034		0.058	
C14	0.004	0.653		0.043	
C15	0.003	0.438		0.007	
C16	0.002	0.332			
C17		0.078			
C18		0.063			
C19		0.044			
BENZ		0.012		0.021	
TOL	0.010	1.568		0.233	
XYL	0.016	2.326	0.002	1.124	
N2	1.577	0.195	1.586	0.085	1.588
CO2	0.556	0.371	0.558	0.300	0.558
Mol.ratio		0.0062	0.9938	0.0014	0.9924
Mol.mass kg/kmol	17.576	80.250	17.184	73.918	17.102
C7+	0.366	48.809	0.063	42.005	0.004
GHV MJ/m^3(st)	39.26		38.48		38.36
T/C LGR $m^3/10^6\ m^3$ (st)		29.46		6.60	

Compositions on a water free basis.

Table 3

Test 2 Experimental Phase Compositions (mol%)

Component	Well-head fluid	Separator 1 70.0 bar 0 °C		Separator 2 35.5 bar -7 °C	
		Liq.	Gas	Liq.	Gas
C1	93.146	25.208	93.515	18.744	93.579
C2	3.435	4.613	3.428	4.911	3.427
C3	0.313	1.674	0.305	1.708	0.304
IC4	0.266	3.082	0.251	3.701	0.248
NC4	0.026	0.608	0.022	0.489	0.022
IC5	0.038	1.483	0.030	1.526	0.029
NC5	0.007	0.399	0.005	0.417	0.005
C6	0.119	12.111	0.055	19.688	0.037
C7	0.146	19.972	0.040	31.724	0.012
C8	0.045	7.151	0.007	7.658	
C9	0.038	6.374	0.004	4.390	
C10	0.029	5.235	0.002	1.901	
C11	0.014	2.480		0.468	
C12	0.012	2.169		0.178	
C13	0.006	1.086		0.099	
C14	0.004	0.696		0.075	
C15	0.003	0.479		0.026	
C16	0.002	0.367			
C17	0.001	0.102			
C18	0.001	0.105			
C19		0.052			
BENZ		0.013		0.019	
TOL	0.009	1.586		0.297	
XYL	0.014	2.381	0.001	1.634	
N2	1.763	0.221	1.771	0.089	1.773
CO2	0.563	0.353	0.564	0.258	0.564
Mol.ratio		0.0053	0.9947	0.0009	0.9938
Mol.mass kg/kmol	17.544	81.584	17.203	78.497	17.148
C7+	0.324	50.235	0.054	48.450	0.012
GHV MJ/m^3(st)	39.09		38.40		38.33
T/C LGR $m^3/10^6\ m^3$ (st)		26.12		4.56	

Compositions on a water free basis.

TABLE 4

Test 3 Experimental Phase Compositions (mol%)

Component	Well-head fluid	Separator 1 70.0 bar 1 °C		Separator 2 35.5 bar -10 °C	
		Liq.	Gas	Liq.	Gas
C1	93.429	25.896	93.791	19.680	93.875
C2	3.421	4.464	3.415	5.251	3.413
C3	0.305	1.623	0.298	1.816	0.296
IC4	0.261	3.038	0.246	3.967	0.242
NC4	0.025	0.603	0.022	0.512	0.021
IC5	0.037	1.491	0.029	1.588	0.027
NC5	0.008	0.397	0.006	0.455	0.005
C6	0.120	11.975	0.057	20.332	0.034
C7	0.149	19.705	0.045	31.117	0.010
C8	0.045	6.995	0.008	6.886	
C9	0.038	6.289	0.004	3.825	
C10	0.030	5.262	0.002	1.683	
C11	0.014	2.488		0.435	
C12	0.013	2.359		0.204	
C13	0.006	1.196		0.106	
C14	0.004	0.794		0.087	
C15	0.003	0.556		0.032	
C16	0.002	0.433			
C17	0.001	0.120			
C18	0.001	0.126			
C19		0.057			
BENZ		0.013		0.019	
TOL	0.007	1.243		0.221	
XYL	0.014	2.343	0.002	1.436	
N2	1.521	0.169	1.528	0.080	1.530
CO2	0.546	0.365	0.547	0.268	0.547
Mol.ratio		0.0053	0.9947	0.0011	0.9936
Mol.mass kg/kmol	17.511	81.763	17.169	76.830	17.102
C7+	0.327	49.966	0.061	46.032	0.010
GHV MJ/m^3(st)	39.19		38.50		38.41
T/C LGR $m^3/10^6\ m^3$ (st)		25.80		5.39	

Compositions on a water free basis.

TABLE 5

Test 5 Experimental Phase Compositions (mol%)

Component	Well-head fluid	Separator 1 88.9 bar 32 °C		Separator 2 46.2 bar -12 °C	
		Liq.	Gas	Liq.	Gas
C1	92.953	29.055	93.092	24.139	93.443
C2	3.583	4.346	3.581	6.404	3.567
C3	0.326	1.260	0.324	2.128	0.315
IC4	0.278	1.949	0.275	4.379	0.254
NC4	0.027	0.328	0.026	0.590	0.023
IC5	0.038	0.740	0.036	1.647	0.028
NC5	0.008	0.204	0.007	0.455	0.005
C6	0.133	6.803	0.119	16.427	0.036
C7	0.172	13.730	0.143	26.467	0.009
C8	0.047	6.059	0.034	6.760	
C9	0.039	7.215	0.023	4.574	
C10	0.030	8.057	0.013	2.501	
C11	0.013	4.324	0.004	0.706	
C12	0.012	5.032	0.002	0.308	
C13	0.006	2.566	0.001	0.114	
C14	0.004	1.735		0.099	
C15	0.003	1.203		0.023	
C16	0.002	0.907			
C17	0.001	0.242			
C18	0.001	0.236			
C19		0.089			
BENZ		0.008		0.016	
TOL	0.002	0.581		0.079	
XYL	0.015	2.746	0.009	1.716	
N2	1.722	0.238	1.725	0.113	1.733
CO2	0.585	0.347	0.586	0.355	0.587
Mol.ratio		0.0022	0.9978	0.0050	0.9928
Mol.mass kg/kmol	17.608	88.998	17.454	73.143	17.171
C7+	0.347	54.722	0.229	43.347	0.009
GHV MJ/m^3(st)	39.22		38.89		38.38
T/C LGR $m^3/10^6\ m^3$ (st)		11.52		23.06	

Compositions on a water free basis.

TABLE 6

Test 6 Experimental Phase Compositions (mol%)

Component	Well-head fluid	Separator 60.0 bar -19 °C Liq.	Separator 60.0 bar -19 °C Gas
C1	92.867	26.647	93.411
C2	3.429	6.035	3.408
C3	0.316	2.397	0.299
IC4	0.269	4.621	0.233
NC4	0.028	0.882	0.021
IC5	0.042	2.079	0.025
NC5	0.008	0.519	0.004
C6	0.143	13.093	0.036
C7	0.182	19.187	0.025
C8	0.048	5.900	
C9	0.041	5.003	
C10	0.033	4.047	
C11	0.015	1.869	
C12	0.014	1.749	
C13	0.007	0.887	
C14	0.005	0.583	
C15	0.003	0.403	
C16	0.002	0.299	
C17	0.001	0.072	
C18		0.056	
BENZ		0.013	
TOL	0.010	1.258	
XYL	0.015	1.870	
N2	1.977	0.122	1.992
CO2	0.545	0.409	0.546
Mol.ratio		0.0082	0.9918
Mol.mass kg/kmol	17.643	75.554	17.165
C7+	0.376	43.183	0.025
GHV $MJ/m^3(st)$	39.16		38.21
T/C LGR $m^3/10^6\ m^3$ (st)		36.63	

Compositions on a water free basis.

Table 7

Test 1 - Computer predicted phase compositions (mol %)

Component	Well-head fluid	Separator 1 70.0 bar/-3°C Liquid	Separator 1 70.0 bar/-3°C Gas	Separator 2 35.5 bar/-16°C Liquid	Separator 2 35.5 bar/-16°C Gas
C1	93.287	31.74	93.706	20.84	93.773
C2	3.435	6.09	3.417	5.88	3.415
C3	0.309	1.66	0.300	2.12	0.298
IC4	0.263	2.99	0.244	4.73	0.240
NC4	0.026	0.40	0.023	0.68	0.023
IC5	0.038	1.08	0.031	2.12	0.029
NC5	0.007	0.26	0.005	0.55	0.005
C6	0.136	9.97	0.070	21.58	0.050
C7	0.169	17.95	0.048	29.76	0.020
C8	0.052	6.75	0.006	5.73	0.001
C9	0.042	5.88	0.002	2.28	
C10	0.033	4.78	0.001	0.73	
C11	0.015	2.20		0.15	
C12	0.013	1.92		0.05	
C13	0.007	1.03		0.01	
C14	0.004	0.59			
C15	0.003	0.44			
C16	0.002	0.30			
C17					
C18					
C19					
C20					
BENZ					
TOL	0.010	1.22	0.002	1.34	
XYL	0.016	2.21	0.001	1.06	
N2	1.577	0.16	1.587	0.09	1.588
CO2	0.556	0.38	0.557	0.30	0.557
Mol. ratio		0.0068	0.9932	0.0009	0.9923
Mol. mass kg/kmol	17.576	74.29	17.18	72.89	17.13
C7+	0.366	45.27	0.06	41.11	0.03
T/C LGR $m^3/10^6\ m^3$ (st)		29.59		4.23	

Compositions on a water free basis

Table 8

Test 2 - Computer predicted phase compositions (mol %)

Component	Well-head fluid	Separator 1 70.0 bar/0°C		Separator 2 35.5 bar/-7°C	
		Liquid	Gas	Liquid	Gas
C1	93.146	30.86	93.489	18.82	93.529
C2	3.435	5.86	3.422	4.90	3.42[illegible]
C3	0.313	1.61	0.306	1.71	0.305
IC4	0.266	2.92	0.251	3.71	0.250
NC4	0.026	0.39	0.024	0.52	0.024
IC5	0.038	1.06	0.032	1.66	0.03[illegible]
NC5	0.007	0.26	0.006	0.43	0.005
C6	0.119	9.15	0.069	17.23	0.060
C7	0.146	17.45	0.050	31.78	0.034
C8	0.045	6.91	0.007	8.77	0.003
C9	0.038	6.44	0.003	4.46	
C10	0.029	5.14	0.001	1.54	
C11	0.014	2.52		0.34	
C12	0.012	2.18		0.11	
C13	0.006	1.09		0.02	
C14	0.004	0.73		0.01	
C15	0.003	0.55			
C16	0.002	0.37			
C17	0.001	0.18			
C18	0.001	0.18			
C19					
C20					
BENZ					
TOL	0.009	1.28	0.002	1.78	0.00[illegible]
XYL	0.014	2.32	0.001	1.86	
N2	1.763	0.18	1.772	0.09	1.773
CO2	0.563	0.37	0.564	0.26	0.564
Mol. ratio		0.0055	0.9945	0.0005	0.9940
Mol. mass kg/kmol	17.544	77.00	17.22	78.38	17.187
C7+	0.324	47.34	0.064	50.67	0.038
T/C LGR $m^3/10^6\ m^3$ (s)		25.31		2.49	

Compositions on a water free basis

Table 9

Test 3 - Computer predicted phase compositions (mol %)

Component	Well-head fluid	Separator 1 70.0 bar/1°C Liquid	Separator 1 70.0 bar/1°C Gas	Separator 2 35.5 bar/-10°C Liquid	Separator 2 35.5 bar/-10°C Gas
C1	93.429	30.70	93.772	19.59	93.827
C2	3.421	5.76	3.408	5.21	3.407
C3	0.305	1.55	0.298	1.81	0.297
IC4	0.261	2.80	0.247	4.01	0.244
NC4	0.025	0.37	0.023	0.56	0.023
IC5	0.037	1.02	0.032	1.79	0.030
NC5	0.008	0.30	0.006	0.55	0.006
C6	0.120	9.09	0.071	18.84	0.057
C7	0.149	17.71	0.053	32.02	0.029
C8	0.045	6.93	0.008	7.48	0.002
C9	0.038	6.49	0.003	3.47	
C10	0.030	5.37	0.001	1.19	
C11	0.014	2.55		0.25	
C12	0.013	2.39		0.09	
C13	0.006	1.11		0.02	
C14	0.004	0.74			
C15	0.003	0.55			
C16	0.002	0.37			
C17	0.001	0.18			
C18	0.001	0.18			
C19					
C20					
BENZ					
TOL	0.007	0.99	0.002	1.28	0.001
XYL	0.014	2.34	0.001	1.50	
N2	1.521	0.15	1.528	0.08	1.530
CO2	0.546	0.36	0.547	0.26	0.547
Mol. ratio		0.0054	0.9946	0.0008	0.9938
Mol. mass kg/kmol	17.511	77.68	17.18	76.35	17.138
C7+	0.327	47.90	0.068	47.3	0.032
T/C LGR $m^3/10^6\ m^3$ (st)		24.94		3.56	

Compositions on a water free basis

Table 10

Test 5 - Computer predicted phase compositions (mol %)

Component	Well-head fluid	Separator 1 88.9 bar/32°C		Separator 2 46.2 bar/-12°C	
		Liquid	Gas	Liquid	Gas
C1	92.953	30.20	93.114	24.95	93.394
C2	3.583	4.57	3.581	6.43	3.568
C3	0.326	1.06	0.324	2.13	0.317
IC4	0.278	1.71	0.274	4.44	0.257
NC4	0.027	0.22	0.027	0.62	0.024
IC5	0.038	0.55	0.037	1.74	0.030
NC5	0.008	0.15	0.008	0.50	0.006
C6	0.133	5.46	0.119	16.18	0.053
C7	0.172	13.71	0.137	26.68	0.028
C8	0.047	6.77	0.030	6.76	0.002
C9	0.039	8.32	0.018	4.22	
C10	0.030	8.46	0.008	2.02	
C11	0.013	4.24	0.002	0.52	
C12	0.012	4.30	0.001	0.24	
C13	0.006	2.25		0.06	
C14	0.004	1.53		0.02	
C15	0.003	1.16		0.01	
C16	0.002	0.78			
C17	0.001	0.39			
C18	0.001	0.38			
C19					
C20					
BENZ					
TOL	0.002	0.24	0.001	0.29	
XYL	0.015	3.03	0.007	1.72	
N2	1.722	0.20	1.726	0.12	1.733
CO2	0.585	0.32	0.586	0.35	0.587
Mol. ratio		0.0026	0.9974	0.0045	0.9929
Mol. mass kg/kmol	17.61	88.12	17.427	73.12	17.20
C7+	0.347	55.56	0.204	42.54	0.03
T/C LGR $m^3/10^6\ m^3$ (st)		13.45		16.28	

Compositions on a water free basis

Table 11

Test 6 - Computer predicted phase compositions (mol %)

Component	Well-head fluid	Separator 1 60.0 bar/-19°C Liquid	Separator 1 60.0 bar/-19°C Gas
C1	92.867	32.540	93.422
C2	3.429	7.48	3.392
C3	0.316	2.31	0.298
IC4	0.269	4.37	0.231
NC4	0.028	0.62	0.023
IC5	0.042	1.65	0.027
NC5	0.008	0.40	0.004
C6	0.143	11.45	0.039
C7	0.182	17.72	0.020
C8	0.048	5.06	0.002
C9	0.041	4.42	0.001
C10	0.033	3.59	
C11	0.015	1.64	
C12	0.014	1.53	
C13	0.007	0.77	
C14	0.005	0.55	
C15	0.003	0.33	
C16	0.002	0.22	
C17	0.001	0.11	
C18			
C19			
C20			
BENZ			
TOL	0.010	1.03	0.001
XYL	0.015	1.61	
N2	1.977	0.19	1.994
CO2	0.545	0.43	0.546
Mol. ratio		0.0091	0.9909
Mol. mass kg/kmol	17.643	69.069	17.163
C7+	0.376	43.196	0.024
T/C LGR $m^3/10^6$ m^3 (st)		37.70	

Compositions on a water free basis

Table 12

Test 1 - Computer predicted phase compositions assuming 60% aromatic content in C9 to C16+ fractions (mol %)

Component	Well-head fluid	1st stage separation at 70 bar/-3°C	
		Liquid	Gas
C1	93.287	28.73	93.726
2	3.435	5.67	3.420
3	0.309	1.59	0.300
i4	0.263	2.92	0.245
n4	0.026	0.40	0.023
i5	0.038	1.08	0.031
n5	0.007	0.26	0.005
*6	0.136	12.45	0.053
*7	0.169	18.95	0.041
8	0.052	6.80	0.006
9	0.017	2.36	0.001
9A	0.025	3.60	0.001
10	0.013	1.91	
10A	0.020	2.89	
11	0.006	0.88	
11A	0.009	1.32	
12	0.005	0.77	
12A	0.008	1.15	
13	0.003	0.41	
13A	0.004	0.62	
14	0.002	0.24	
14A	0.002	0.35	
15	0.001	0.18	
15A	0.002	0.27	
16+	0.002	0.30	
Benzene			
Toluene	0.01	1.22	0.002
Xylene	0.016	2.21	0.001
N_2	1.577	0.14	1.587
CO_2	0.556	0.33	0.557
Mol. ratio		0.0068	0.9932
Mol. mass kg/kmol	17.558	75.38	17.163
C7+		46.43	0.049
T/C LGR $m^3/10^6$ m^3 (st)		30.04	

Compositions on a water free basis

* C6 as cyclohexane, C7 as methyl cyclohexane.

Table 13

Test 2 - Computer predicted phase compositions assuming 60% aromatic content in C9 to C16+ fractions (mol %)

Component	Well-head fluid	1st stage separation at 70 bar/0°C	
		Liquid	Gas
C1	93.146	27.97	93.510
2	3.435	5.47	3.424
3	0.313	1.54	0.306
i4	0.266	2.84	0.252
n4	0.026	0.38	0.024
i5	0.038	1.06	0.032
n5	0.007	0.26	0.006
*6	0.119	11.74	0.054
*7	0.146	18.49	0.044
8	0.045	6.89	0.007
9	0.015	2.56	0.001
9A	0.023	3.92	
10	0.012	2.03	
10A	0.017	3.08	
11	0.006	1.00	
11A	0.008	1.50	
12	0.005	0.86	
12A	0.007	1.29	
13	0.002	0.43	
13A	0.004	0.65	
14	0.002	0.29	
14A	0.002	0.43	
15	0.001	0.22	
15A	0.002	0.32	
17	0.004	0.72	
Benzene			
Toluene	0.009	1.27	0.002
Xylene	0.014	2.30	0.001
N_2	1.763	0.16	1.772
CO_2	0.563	0.33	0.564
Mol. ratio		0.0056	0.9944
Mol. mass kg/kmol	17.535	77.86	17.198
C7+		48.25	0.055
T/C LGR $m^3/10^6\ m^3$ (st)		25.99	

Compositions on a water basis

* C6 as cylcohexane, C7 as methyl cyclohexane

Table 14

Test 3 - Computer predicted phase compositions assuming 60% aromatic content in C9 to C16+ fractions (mol %)

Component	Well-head fluid	1st stage separation at 70 bar/1°C Liquid	Gas
C1	93.429	27.82	93.792
2	3.421	5.36	3.410
3	0.305	1.47	0.299
i4	0.261	2.73	0.247
n4	0.025	0.36	0.023
i5	0.037	1.01	0.032
n5	0.008	0.29	0.006
*6	0.120	11.72	0.056
*7	0.149	18.78	0.046
8	0.045	6.90	0.007
9	0.015	2.57	0.001
9A	0.023	3.95	0.001
10	0.012	2.12	
10A	0.018	3.22	
11	0.006	1.01	
11A	0.008	1.51	
12	0.005	0.94	
12A	0.008	1.41	
13	0.002	0.44	
13A	0.004	0.65	
14	0.002	0.29	
14A	0.002	0.44	
15	0.001	0.22	
15A	0.002	0.33	
17	0.004	0.73	
Benzene			
Toluene	0.007	0.99	0.002
Xylene	0.014	2.30	0.001
N_2	1.521	0.13	1.529
CO_2	0.546	0.31	0.547
Mol. ratio		0.0055	0.9945
Mol. mass kg/kmol	17.497	77.975	17.162
C7+		48.8	0.058
T/C LGR $m^3/10^6\ m^3$ (st)		25.60	

Compositions on a water basis

* C6 as cylcohexane, C7 as methyl cyclohexane

Table 15

Test 5 - Computer predicted phase compositions assuming 60% aromatic content in C9 to C16+ fractions (mol %)

Component	Well-head fluid	1st stage separation at 88.9 bar/32°C	
		Liquid	Gas
C1	92.952	27.32	93.148
2	3.583	4.23	3.581
3	0.326	1.00	0.324
i4	0.278	1.64	0.274
n4	0.027	0.21	0.026
i5	0.038	0.54	0.037
n5	0.008	0.15	0.008
*6	0.133	8.00	0.110
*7	0.172	15.81	0.126
8	0.047	6.66	0.028
9	0.016	3.20	0.006
9A	0.023	5.53	0.007
10	0.012	3.17	0.003
10A	0.018	5.23	0.001
11	0.005	1.56	0.001
11A	0.008	2.43	
12	0.005	1.56	
12A	0.007	2.37	
13	0.002	0.81	
13A	0.004	1.22	
14	0.002	0.55	
14A	0.002	0.82	
15	0.001	0.41	
15A	0.002	0.62	
17	0.004	1.39	
Benzene			
Toluene	0.002	0.24	0.001
Xylene	0.015	2.87	0.007
N_2	1.722	0.18	1.726
CO_2	0.585	0.28	0.586
Mol. ratio		0.0029	0.9961
Mol. mass kg/kmol	17.596	87.512	17.394
C7+		56.45	0.180
T/C LGR $m^3/10^6\ m^3$ (st)		14.96	

Compositions on a water basis

* C6 as cylcohexane, C7 as methyl cyclohexane

Table 16

Test 6 - Computer predicted phase compositions assuming 60% aromatic content in C9 to C16+ fractions (mol %)

Component	Well-head fluid	1st stage separation at 60 bar/-19°C	
		Liquid	Gas
C1	92.867	29.53	93.429
2	3.429	7.01	3.397
3	0.316	2.23	0.299
i4	0.269	4.32	0.233
n4	0.028	0.62	0.023
i5	0.042	1.67	0.004
n5	0.008	0.41	0.027
*6	0.143	13.25	0.017
*7	0.182	18.72	0.001
8	0.048	5.27	
9	0.016	1.84	
9A	0.025	2.77	
10	0.013	1.49	
10A	0.020	2.25	
11	0.006	0.68	
11A	0.009	1.02	
12	0.006	0.64	
12A	0.008	0.95	
13	0.003	0.32	
13A	0.004	0.48	
14	0.002	0.23	
14A	0.003	0.34	
15	0.001	0.14	
15A	0.002	0.20	
17	0.003	0.34	
Benzene			
Toluene	0.010	1.07	0.001
Xylene	0.015	1.67	
N_2	1.977	0.16	1.993
CO_2	0.545	0.38	0.546
Mol. ratio		0.0088	0.9912
Mol. mass kg/kmol	17.625	70.763	17.153
C7+		40.42	0.019
T/C LGR $m^3/10^6$ m^3 (st)		35.55	

Compositions on a water basis

* C6 as cylcohexane, C7 as methyl cyclohexane

Table 17

Summary of experimentally determined well head fluid compositions (mol%)

Component	Test 1	Test 2	Test 3	Test 5	Test 6
C1	93.286	93.146	93.429	92.952	92.867
2	3.435	3.435	3.421	3.583	3.429
3	0.309	0.313	0.305	0.326	0.316
i4	0.263	0.266	0.261	0.278	0.269
n4	0.026	0.026	0.025	0.027	0.028
i5	0.038	0.038	0.037	0.038	0.042
n5	0.007	0.007	0.008	0.008	0.008
6	0.137	0.119	0.120	0.133	0.143
7	0.169	0.146	0.149	0.172	0.182
8	0.052	0.045	0.045	0.047	0.048
9	0.042	0.038	0.038	0.039	0.041
10	0.033	0.029	0.030	0.030	0.033
11	0.015	0.014	0.014	0.013	0.015
12	0.013	0.012	0.013	0.012	0.014
13	0.007	0.006	0.006	0.006	0.007
14	0.004	0.004	0.004	0.004	0.005
15	0.003	0.003	0.003	0.003	0.003
16	0.002	0.002	0.002	0.002	0.002
17		0.001	0.001	0.001	0.001
18		0.001	0.001	0.001	
Benzene	0.010	0.009	0.007	0.002	0.010
Toluene	0.016	0.014	0.014	0.015	0.015
N_2	1.577	1.763	1.521	1.722	1.977
CO_2	0.556	0.563	0.546	0.585	0.545
C7+	0.366	0.324	0.327	0.347	0.376

Compositions on a water free basis

Table 18

Comparison of Troll 31/2-12 Test 2 with examples of previous test results from Troll 31/2 gas wells (mol %)

Component	Well test number			
	*31/2 - 2(T3)	*31/2 - 3(T6)	*31/2 - 6(T1)	*31/2-12 (T2)
C1	92.141	92.851	92.569	93.146
2	3.868	3.528	3.437	3.435
3	0.395	0.420	0.304	0.313
i4	0.362	0.363	0.342	0.266
n4	0.063	0.047	0.029	0.026
i5	0.081	0.112	0.090	0.038
n5	0.004	0.024	0.014	0.007
6	0.181	0.199	0.203	0.119
7	0.242	0.227	0.212	0.146
8	0.060	0.070	0.051	0.045
9	0.040	0.051	0.050	0.038
10	0.034	0.046	0.039	0.029
11	0.014	0.022	0.021	0.014
12	0.007	0.013	0.012	0.012
13	0.004	0.009	0.008	0.006
14	0.002	0.005	0.006	0.004
15	0.001	0.003	0.004	0.003
16		0.001	0.002	0.002
17				0.001
18				0.001
Benzene				
Toluene	0.001	0.001	0.005	0.009
Xylene	0.020	0.024	0.009	0.014
N_2	1.903	1.560	1.702	1.763
CO_2	0.577 (0.400)	0.424	0.896 (1.000)	0.563 (0.600)
Mol. ratio	0.0064	0.0076	0.0068	0.0053
LGR $m^3/10^6\ m^3$ (st)	30.83	35.89	31.84	26.10

* Troll 31/2-2 Test 3, 21/9/80, Ref. TNTR.81.021[1]
Troll 31/2-3 Test 6, 8/7/80, Ref. TNTR.81.014[2]
Troll 31/2-6 Test 1, 7/10/81, Ref. TNER.82.029[3]
Troll 31/2-12 Test 2, This report

Note: CO_2 values in parenthesis measured independently using Draeger tube

Table 19

Conversion factors

$$\text{psig} = \frac{\text{bar} - 1.01325}{0.06895}$$

$$^\circ F = {}^\circ C \times \frac{9}{5} + 32$$

$$\text{bbl} = \frac{m^3}{0.15899}$$

$$\text{scf} = \frac{m^3\ (\text{st})}{0.02826}$$

$$\text{bbl/MMscf} = \frac{m^3/10^6\ m^3\ (\text{st})}{5.6254}$$

$$\text{Btu/scf} = \frac{\text{MJ}/m^3\ (\text{st})}{37.3307 \times 10^{-3}}$$

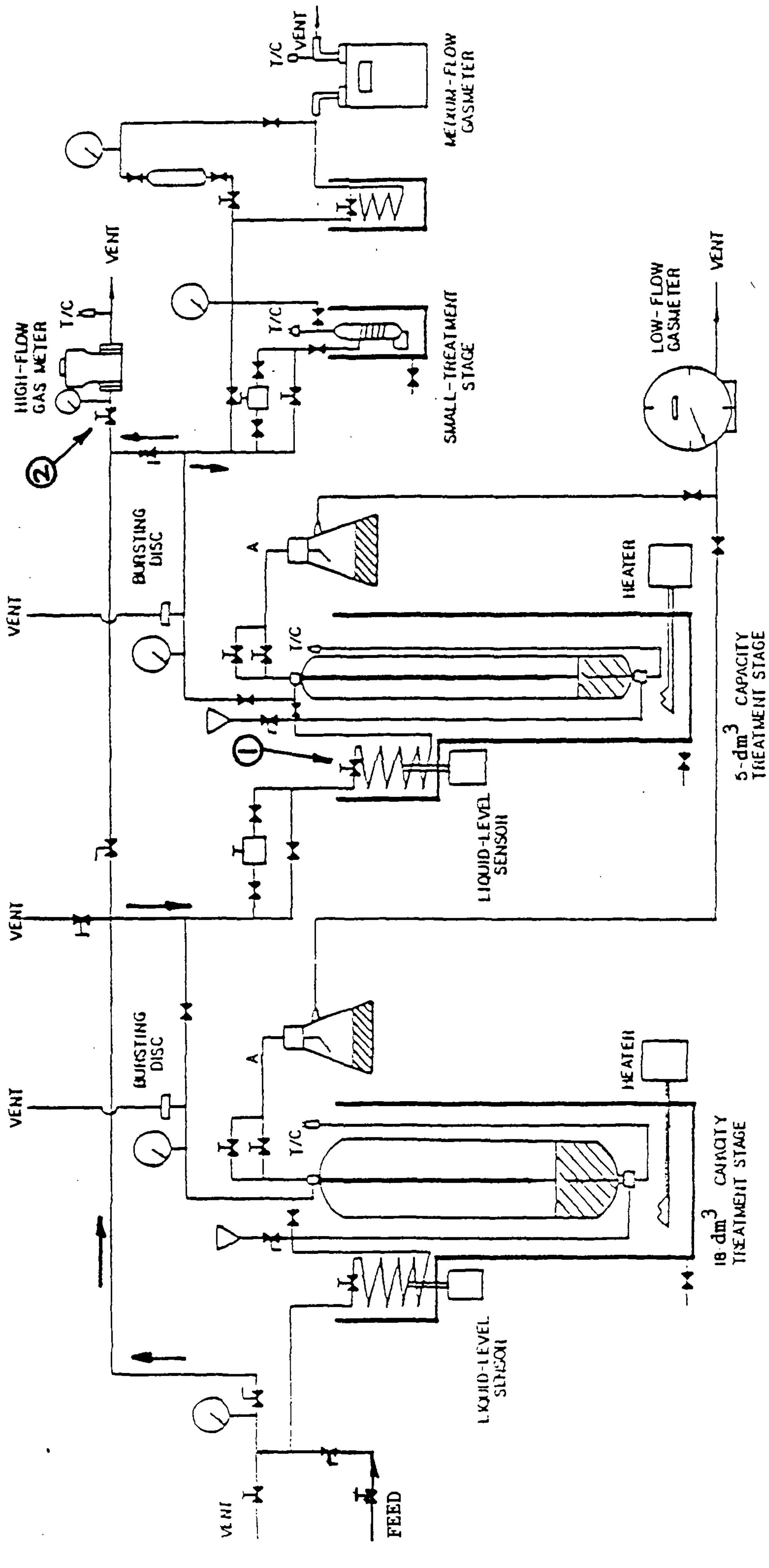


FIG.1-Well-head testing unit

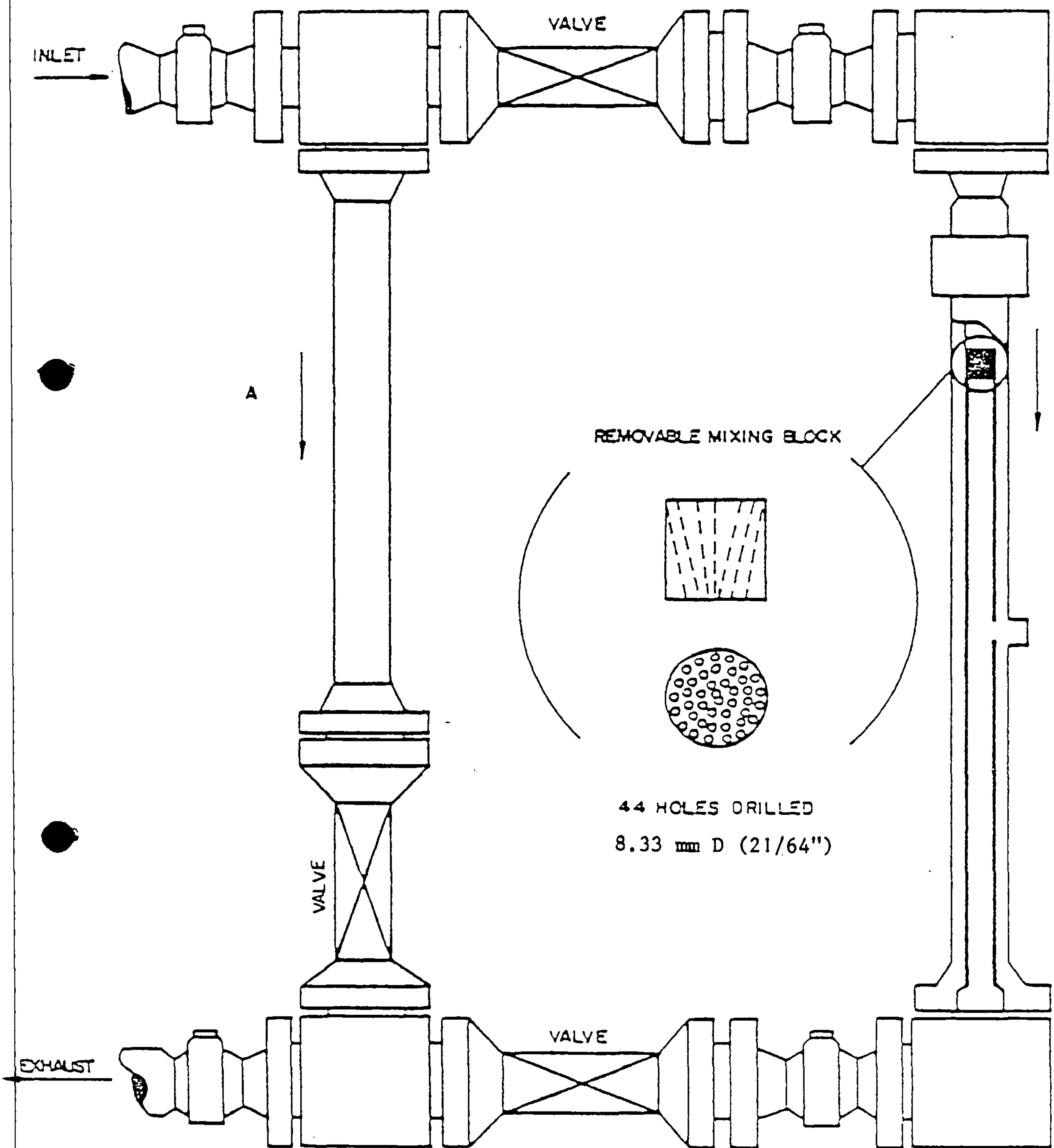
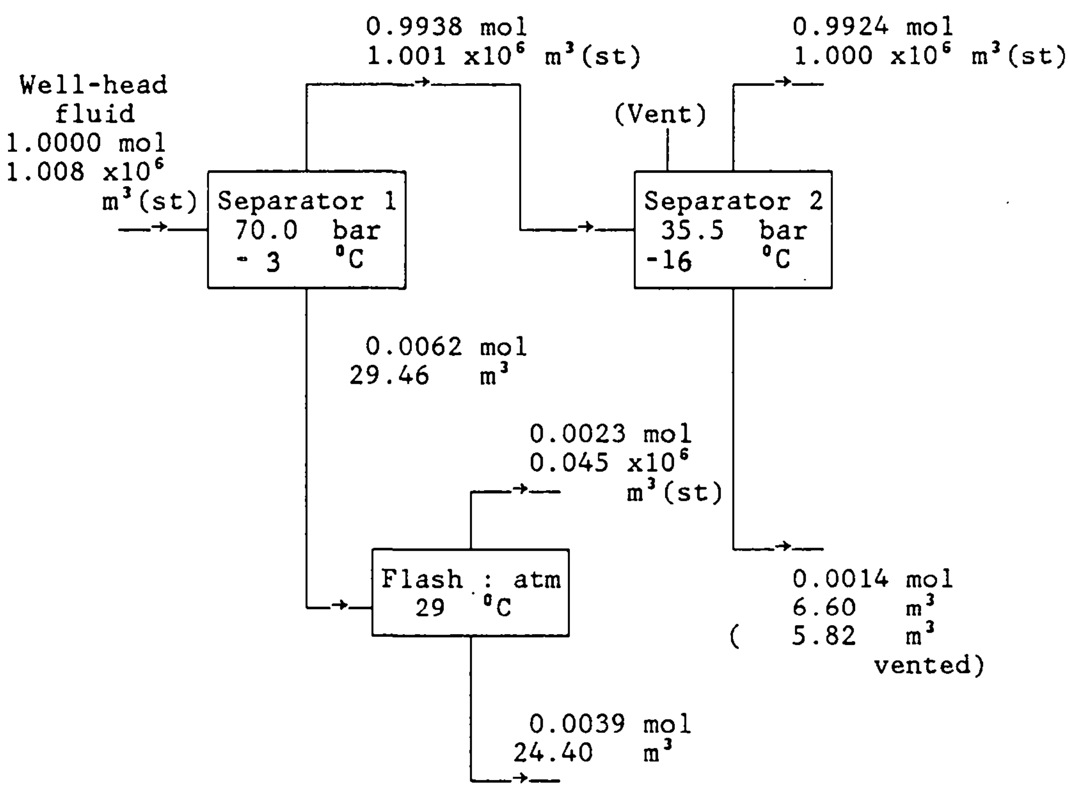


FIG. 2—Mixing manifold

FIGURE 3

Test 1 Mass and Volume Balance

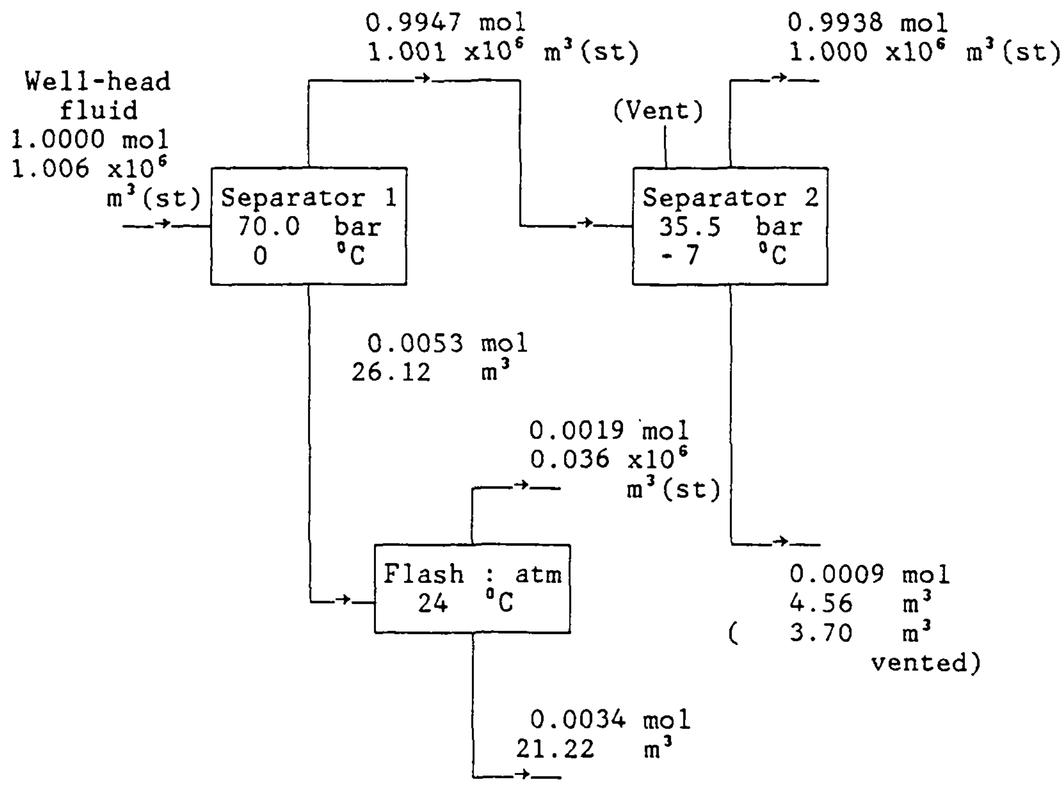


NOTE. The mass and volume balances, based on 1 mol of input fluid and 10^6 m^3(st) of final gas respectively, are not equivalent.

Flash:atm implies flash to prevailing atmospheric pressure.

FIGURE 4

Test 2 Mass and Volume Balance

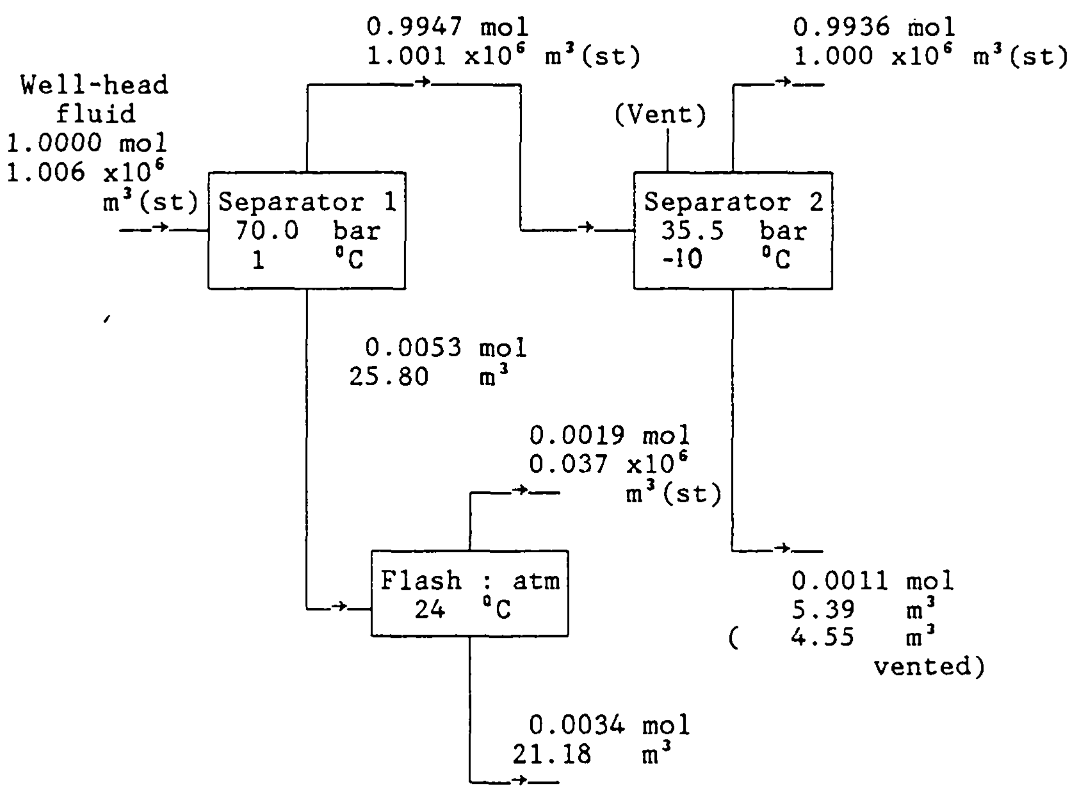


NOTE. The mass and volume balances, based on 1 mol of input fluid and 10^6 m^3(st) of final gas respectively, are not equivalent.

Flash:atm implies flash to prevailing atmospheric pressure.

FIGURE 5

Test 3 Mass and Volume Balance

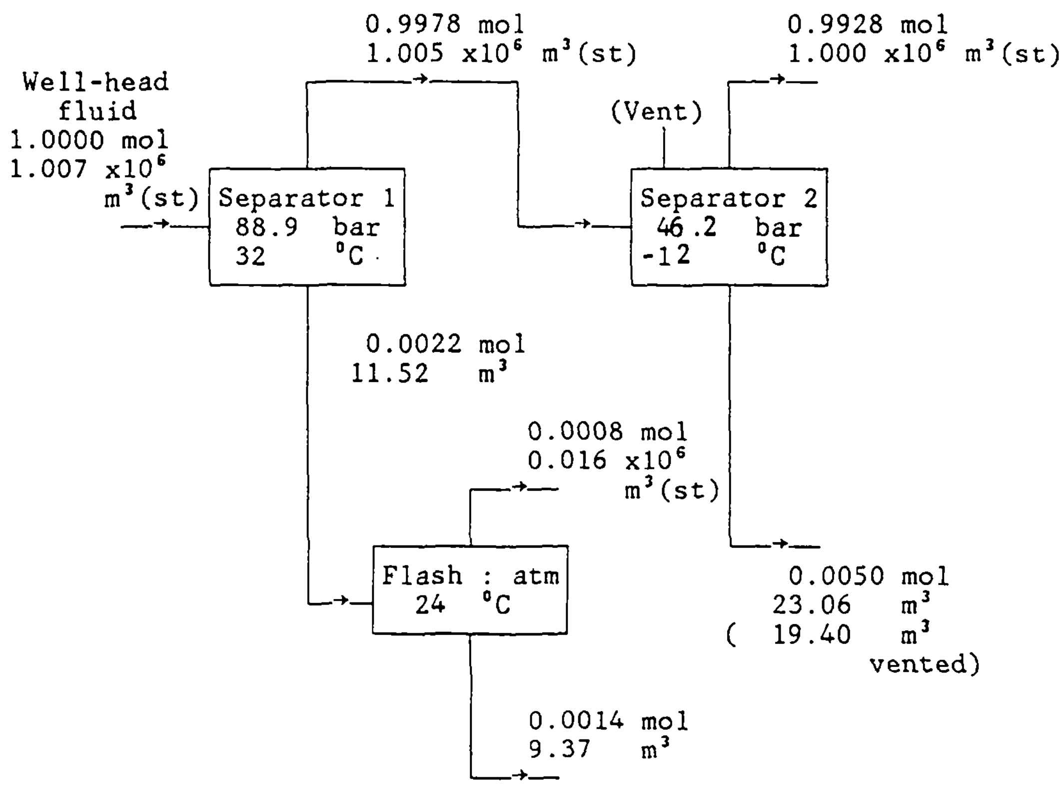


NOTE. The mass and volume balances, based on 1 mol of input fluid and 10^6 m^3(st) of final gas respectively, are not equivalent.

Flash:atm implies flash to prevailing atmospheric pressure.

FIGURE 6

Test 5 Mass and Volume Balance

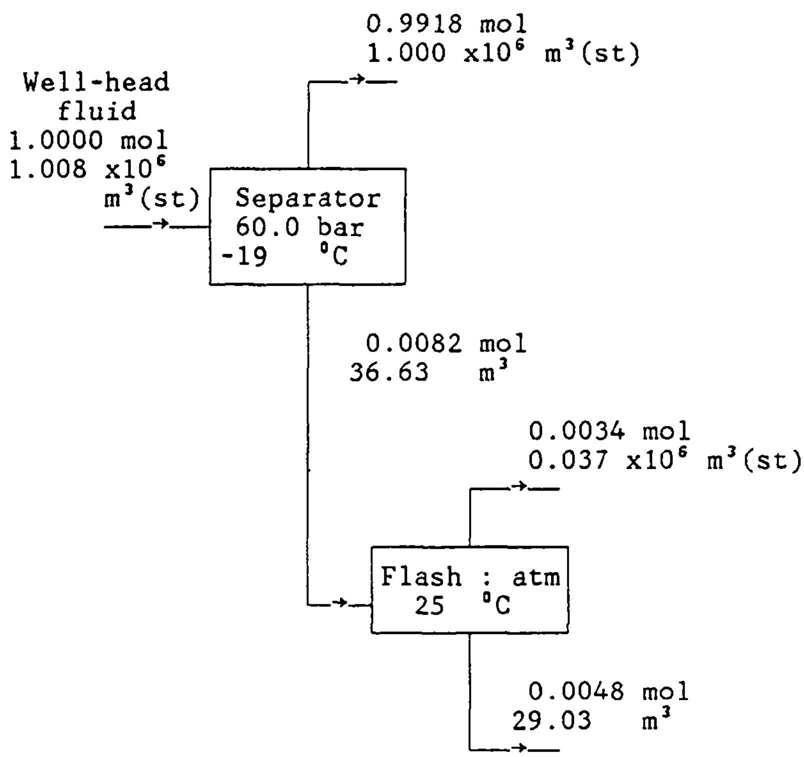


NOTE. The mass and volume balances, based on 1 mol of input fluid and 10^6 m^3(st) of final gas respectively, are not equivalent.

Flash:atm implies flash to prevailing atmospheric pressure.

FIGURE 7

Test 6 Mass and Volume Balance



NOTE. The mass and volume balances, based on 1 mol of input fluid and 10^6 m^3(st) of final gas respectively, are not equivalent.

Flash:atm implies flash to prevailing atmospheric pressure.

AMER.83.052

EXPLORATION AND PRODUCTION TEST ON GAS FROM WELL 31/2-12 IN OFFSHORE TROLL FIELD, NORTH SEA, NORWAY.

Sampling and analysis of gas and condensate

by

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Approved by: M.E. van Kreveld

SUMMARY

During a production test in the offshore Troll field, North Sea, Norway, sampling and analysis of gas and condensate have been carried out. The present report describes the sampling and the analytical procedures applied, and presents the results obtained.

September 1983

C O N T E N T S

AMER.83.052

EXPLORATION AND PRODUCTION TEST ON GAS
FROM WELL 31/2-12 IN OFFSHORE TROLL FIELD,
NORTH SEA, NORWAY.

Sampling and analysis
of gas and condensate

1. INTRODUCTION

A production test was carried on gas from the 31/2-12 well in the offshore Troll field, North Sea, Norway. Detailed information about the following trace components was obtained:

In the gas: Hydrogen sulphide, other sulphur components, mercury, radon-222, carbon dioxide, helium and nitrogen.

In the condensate: Mercury, total sulphur and polonium-210.

The present report describes briefly the sampling procedures followed and presents the results obtained.

2. EXPERIMENTAL

The gas/condensate mixture coming from the well was separated in a high-pressure test separator. The gas samples were taken from the gas outlet of the separator. The hydrogen sulphide, mercury, radon and carbon dioxide contents were determined on the rig. Separate gas samples were sent to a research laboratory for the determination of other sulphur compounds, helium and nitrogen. Since no water was produced in the separator, no water analyses have been performed.

The condensate samples, originating from the first stage of the separator were collected in glass bottles. The mercury content was determined on the rig. The total sulphur and polonium contents were determined at a research laboratory.

Table I summarizes the analytical methods used and Table II gives a survey of the results obtained.

3. RESULTS

The results obtained during the production test are presented below. Throughout this section volumes of gas are considered at standard conditions (15 ^{o}C, 1.01325 bar). SI-units or SI-accepted units are used as far as possible.

3.1. Flow period 1

Well open: 26/7/1983, 11.00 - 18.00 hr.

Separator conditions:	temperature	: 115 ^{o}F (46 ^{o}C)
	pressure	: 40 bar (580 psig)
	rate	: 12 MMSCF (0.33 x 10^6 m^3)

Well open: 26/7/1983, 18.00 - 21.30 hr.

Separator conditions:	temperature	: 136 ^{o}F (59 ^{o}C)
	pressure	: 29 bar (420 psig)
	rate	: 23 MMSCF (0.65 x 10^6 m^3)

a. Gas

	Content	Sampling time, h
H_2S	$<0.01 \times 10^{-6}$ m^3/m^3	16.45
	$<0.01 \times 10^{-6}$ m^3/m^3	17.10
	$<0.01 \times 10^{-6}$ m^3/m^3	20.05
CO_2	0.75 % (v/v)	17.00
	0.70 % (v/v)	20.00

3.2. Flow period 2

Well open: 29/7/1983, 00.00 - 12.00 hr.

Separator conditions:	temperature	: 136 ^{o}F (59 ^{o}C)
	pressure	: 29 bar (420 psig)
	rate	: 24 MMSCF (0.68 x 10^6 m^3)

a. Gas

	Content	Sampling time, h
H_2S	0.01×10^{-6} m^3/m^3	03.00
	0.02×10^{-6} m^3/m^3	04.00

	0.04×10^{-6} m^3/m^3	06.30
	0.05×10^{-6} m^3/m^3	07.10
	0.06×10^{-6} m^3/m^3	08.35
	0.04×10^{-6} m^3/m^3	09.30
	0.05×10^{-6} m^3/m^3	11.05
Other sulphur compounds	$< 0.1 \times 10^{-6}$ m^3/m^3	11.25
Mercury	0.23 $\mu g/m^3$	04.35 - 05.00
	0.28 $\mu g/m^3$	05.30 - 06.00
	0.29 $\mu g/m^3$	07.35 - 07.55
	0.27 $\mu g/m^3$	08.05 - 08.30
	0.26 $\mu g/m^3$	09.50 - 10.20
	0.22 $\mu g/m^3$	10.30 - 11.00
Rn-222	28.5 Bq/m^3	04.30
CO_2	0.6 % (v/v)	03.00
	0.6 % (v/v)	04.00
	0.6 % (v/v)	06.20
	0.6 % (v/v)	07.05
	0.6 % (v/v)	08.45
	0.6 % (v/v)	09.45
	0.6 % (v/v)	11.30
He	150×10^{-6} m^3/m^3	11.30
N_2	1.53 % (v/v)	11.30

b. Condensate

	Content	Sampling time, h
Mercury	< 0.001 g/m^3	10.00
Total sulphur	58 g/m^3	10.00
Po-210	< 1 kBq/m^3	10.00

Amsterdam, September 1983
(HH)/RHP

TABLE I

SURVEY OF THE ANALYTICAL METHODS USED

1. Gas phase

Hydrogen sulphide (H_2S)	Dräger tube No. CH 298
Other sulphur compounds	GC with microcoulometric detection
Mercury (Hg)	Flameless atomic absorption spectrophotometry
Radon-222 (Rn)	Radiochemical analysis
Carbon dioxide (CO_2)	Dräger tube No. CH 25101
Helium (He)	GC with thermal conductivity detection
Nitrogen (N_2)	GC with thermal conductivity detection

2. Condensate

Mercury (Hg)	Flameless atomic absorption spectrophotometry
Total sulphur	Microcoulometric analysis
Polonium-210 (Po)	Radiochemical analysis

TABLE II

SURVEY OF FINAL RESULTS

Gasphase		
1. H_2S,	10^{-6} m^3/m^3	0.05
2. Other sulphur compounds,	10^{-6} m^3/m^3	<0.1
3. Hg,	$\mu g/m^3$	0.26
4. Rn,	Bq/m^3	28.5
5. CO_2,	%(v/v)	0.6
6. He,	10^{-6} m^3/m^3	150
7. N_2,	%(v/v)	1.53
Condensate		
1. Hg,	g/m^3	<0.001
2. Total sulphur,	g/m^3	58
3. Po,	kBq/m^3	<1