

THE COMPOSITION OF STATOIL (NORWAY) GAS WELL

TROLL 31/6-6, JULY 1984

Nautilus Contract No. T-4362, Task Order 2

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SUMMARY

The Thornton split-phase sampling equipment has been used to perform a series of multi-stage separation tests on the gas stream from Statoil Well 31/6-6, offshore Norway.

The well-stream composition of the Troll formation has been determined from these tests whilst sampling the well-effluent from the well-head. Equilibrium and compositional data obtained experimentally at a single well-flow rate, are compared with phase compositions and properties predicted by an equation-of-state computer program. Generally, satisfactory agreement was reached between respective data thereby confirming that the well-streams, as described, are suitable for reliable predictive calculations.

Conventional surface samples for PVT analysis were acquired for Statoil using the first stage separator of the Thornton split-phase sampling equipment.

THORNTON RESEARCH CENTRE

Operations Equipment & Measurement Division

October 1984

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1. INTRODUCTION

The Troll hydrocarbon bearing formation within the North Sea concession area 31/6 warranted further production testing in order to deduce basic well-stream data to enable gas potential planning and process facility design. In-flow performance tests by Statoil (Norway), were undertaken from the semi-submersible rig "Deep Sea Bergen" during July 1984. Simultaneously, Nautilus Ventures (Thornton) studied the behaviour of the production fluid, with the following objectives. Firstly, from split-phase process simulation tests, obtain accurate equilibrium phase data under precise pressure/temperature conditions and secondly, from recombination calculations produce detailed and representative well-stream compositions under particular well-head conditions.

2. TEST PROGRAMME

In-flow performance tests by Statoil proceeded after perforation, in the following sequence:

- a) Well clean-up at maximum flow rate ca $763 \times 10^3 \text{ m}^3(\text{st})/\text{d}$.
- b) Multi-sequential flow test at three well-flow rates up to maximum; duration 4 hours at each rate.
- c) Well shut-in to run gauges.
- d) Rig up Nautilus manifold and laboratory on rig floor; pressure test.
- e) Prolonged flow test at single rate of $460 \times 10^3 \text{ m}^3(\text{st})/\text{d}$; duration 12 hours; all Thornton sampling undertaken during this period.

3. EXPERIMENTAL AND RESULTS

The process of identifying and quantifying the concentrations of heavier (i.e. C7+) hydrocarbon components in a natural gas cannot, in many cases, be achieved with any degree of accuracy by analysis of a conventional gas sample. This is because the actual amounts of these components present in the sample may approach, or be below the lower detectable limits.

It is therefore advisable to sample the gas in such a way that it is subjected to one or more sequential controlled separations, thereby

concentrating the heavier hydrocarbon fractions into liquid phases more amenable to detailed analysis and a vapour phase which is essentially free of the heavier hydrocarbons. Sequential recombination of the analysed phase compositions in the measured mole ratios appropriate to each separation will then yield a detailed composition of the original sample stream.

3.1 Multi-stage separations carried out on the well-head fluid

The Thornton well-head testing equipment is shown in Figures 1 and 2 and includes a sample manifold and miniature laboratory containing the split-phase sampling unit. The sampling manifold is positioned in the flow line between the well-head and choke manifold (Figure 3) and incorporates a mixing device in one leg to ensure thorough phase mixing of the well-effluent in the event of a two-phase regime. A sample probe is positioned downstream of the mixing device in a high velocity, highly turbulent region and a representative side-stream is directed at an isokinetic flow rate into the mini-lab. Here, small-scale liquid/gas separations can be made at predetermined pressure and temperature combinations, in sequence, up to a maximum of three separation stages.

Condensates collected at high pressures in the first two separation stages are quantitatively flashed to atmospheric pressure in order to determine the LGR's (liquid/gas ratio) for these separations and to provide samples which may be transported to Thornton for analysis with minimum risk of compositional changes taking place. The LGR for the much smaller third separation stage is determined gravimetrically both at test conditions and after venting to one atmosphere. Time-averaged gas samples are collected after the third separation stage and the total volume of gas which has been passed through the equipment is measured.

The conditions adopted for any series of sequential separations, are selected usually to simulate anticipated process conditions, for instance,

- 1st stage - offshore production separator
- 2nd stage - subsea pipeline

and conditions initially proposed by Statoil were:

- 1st stage - 69 bar/30°C
- 2nd stage - 45 bar/15°C.

However, from previous work on the Troll reservoir, Thornton considered such conditions as inappropriate for such a lean well-stream and suggested that the following alternative conditions would provide improved definition of the C7+ concentrations, namely:

- 1st stage - 70 bar/10°C
- 2nd stage - 35.5 bar/0°C.

Statoil accepted these proposals and so two sampling tests were undertaken on this basis. In addition two sampling tests were carried out adopting alternative P and T values as requested specifically by Statoil representatives, i.e.

1st stage - 70 bar/0°C
2nd stage - 46 bar/-15°C.

During all four tests, two stage separations were performed using the second and third separators shown in Figure 1.

Table 1 contains general information pertinent to each sampling test including liquid/gas ratios for each separation. The quoted figures are based on the gas volume passed through the Thornton equipment and measured by the gas meters shown in Figure 1. Vented LGR's are also expressed here in terms of total gas including measured flash gas.

Tables 2 to 5 give the equilibrium phase compositions for each test and separation stage and the well-head fluid compositions up to C17, as obtained from the recombination of measured downstream phases. These results are collated in Table 6.

Block diagrams giving an alternative presentation of the phase distributions are shown in Figures 4 to 7. Relevant SI conversion factors are given in Table 12.

3.2 PVT surface sampling

Conventional surface samples for PVT analysis are usually taken from the test separator at prevailing separator P and T conditions. The volume of sample gas is typically 20 litres and is collected from the outlet flow line of the separator. Simultaneously, condensate samples of 600 ml volume are acquired by mercury displacement via a suitable drain line below the liquid level of the separator. This procedure is widely practiced and valued particularly during well appraisal/production tests, since it provides much useful well-stream and reservoir data for process design. However, the method does suffer from various shortcomings which to varying degrees can invalidate results, for instance:

- a) Separator liquid and gas flow data used in phase recombination calculations, may be inaccurate.
- b) Sampled separator phases may not be at equilibrium due to poor separator efficiency.
- c) Apart from lean well-streams, analysed amounts of C7+ components in the separator gas phase, will be less than the true level.

Such uncertainties are widely understood and so often generate misgivings as to the reliability of subsequent calculations. Therefore, if PVT sampling is to be retained in its present form it can be beneficial to

take an alternative approach and acquire conventional PVT samples from Thornton's small scale phase separators (ref. 18 or 5 dm³ capacity vessels in Figure 1). Statoil have often adopted this technique during Thornton's past association with the Troll tests, and have again done so, since:

- measured LGR's under particular P and T conditions will be accurate, and
- fully equilibrated phases will be sampled.

Additional advantages of the method include:

- conditions of separation (P and T) may be varied to suit any anticipated extremes of use, i.e. summer and winter conditions, and
- additional downstream separation on the gas and liquid phases is possible in order to describe accurately the heavy-end concentration, i.e. above C7+.

Three sets of PVT samples were collected for Statoil during the current 31/6-6 flow tests, one at 70 bar/10°C and two at 70 bar/0°C. Recombination of these phases would be undertaken using the appropriate test condition LGR's recorded in Table 1, i.e. 20.67 and 24.84 m³/10⁶m³(st) respectively.

3.3 Computer flash predictions

The measured well-fluid compositions from tests 1 to 4 have been sequentially flashed in a computer program based on an advanced equation of state. The predicted phase results obtained at the corresponding pressure/temperature separation conditions used experimentally, are reported in Tables 7 to 10. Because of uncertainties in theoretical density calculations, the predicted separator LGR measurements in a number of these tables have been determined using the experimental test condition densities listed in Table 11.

4. DISCUSSION

The well-stream compositions collated in Table 6 are consistent with only minor differences occurring between compared molecular masses and individual component concentrations. Nevertheless, comparison of C7+ quantities, again in Table 6, showed that marginally richer well-streams were obtained from duplicate tests 3 and 4 than from duplicate tests 1 and 2. These differences were considered to be solely a function of the different gas treatment temperatures used (ref. Table 1), since the lower separation temperatures in tests 3 and 4 produced total, first and second stage liquids averaging 30.63 m³/10⁶m³(st) i.e. 5 m³/10⁶m³(st) higher than the corresponding results from tests 1 and 2 (ref. Tables 1 to 5). The improved weighting of the C7+ fractions in tests 3 and 4 as a consequence of optimising process conditions has served to provide more accurate well-stream data and therefore enable more reliable calculations, we suggest the use of test 3 and 4 results in preference to tests 1 and 2.

Furthermore, the agreement between measured first stage separator phases in Tables 2 to 5, and corresponding calculated data in tables 7 to 10, was satisfactory. Therefore the well-stream components when characterised as n-paraffins are considered in this form, to be realistic for process calculations.

Differences in measured and predicted second stage data are sometimes larger than normal, particularly with regards to compared liquid molar ratios and LGR's which are consistently higher in the measured results. A definitive explanation of these differences is currently unavailable but since the second stage separations were performed purely for analytical reasons, to describe accurately the composition of the first stage gas phase, we do not consider the differences described are likely to be of practical significance in any subsequent process simulations.

Table 1

Liquid/gas ratios for multi-stage gas separation test on Statoil Well 31/6-6

Test No.	Well flow rate $10^3 \text{m}^3(\text{st})/\text{d}$	Date/time	Separation conditions bar/°C	Measured liquid/gas ratios $\text{m}^3/10^6 \text{m}^3(\text{st})$		
				At test conditions	Vented to atm/15.6°C	
					Excluding flash gas	Including flash gas
1	461.0	14.7.84 0045	70/10 35.5/0	20.51 5.18	16.94 4.44	16.91
2	458.8	14.7.84 0230	70/9 35.5/0	20.67 4.91	16.62 4.21	16.60
3	460.5	14.7.84 0850	70/1 46.2/-12	24.39 5.97	19.48 4.88	19.44
4	461.3	14.7.84 1040	70/1 46.2/-12	24.84 5.96	19.79 4.83	19.75

Table 2

Test-1 Experimental Phase Compositions (mol%)

Component	Well-head fluid	Separator 1 70.0 bar 10 °C		Separator 2 35.5 bar 0 °C	
		Liq.	Gas	Liq.	Gas
C1	93.563	26.399	93.842	17.573	93.916
C2	3.430	4.944	3.424	4.142	3.423
C3	0.306	1.561	0.301	1.345	0.300
iC4	0.267	2.783	0.257	2.896	0.254
nC4	0.022	0.400	0.020	0.331	0.020
iC5	0.039	1.275	0.034	1.274	0.033
nC5	0.008	0.335	0.006	0.353	0.006
C6	0.104	10.126	0.063	15.796	0.047
C7	0.119	18.362	0.043	29.682	0.014
C8	0.046	8.251	0.012	12.612	
C9	0.041	8.088	0.007	7.284	
C10	0.028	5.960	0.003	3.008	
C11	0.016	3.565	0.001	1.015	
C12	0.010	2.434		0.227	
C13	0.006	1.509		0.197	
C14	0.005	1.069		0.101	
C15	0.003	0.760		0.063	
C16	0.002	0.377		0.038	
C17	0.001	0.256		0.048	
C18		0.060		0.022	
C19		0.030		0.020	
C20		0.008		0.013	
C21				0.010	
C22				0.009	
C23				0.008	
C24				0.007	
C25				0.006	
C26				0.005	
C27				0.004	
BENZ		0.002			
TOL	0.002	0.396	0.001	0.646	
XYL	0.004	0.702	0.001	1.015	
N2	1.709	0.177	1.715	0.100	1.717
CO2	0.269	0.171	0.270	0.150	0.270
Mol. ratio		0.0041	0.9959	0.0010	0.9949
Mol. mass kg/kmol	17.413	84.025	17.136	84.044	17.070
C7+	0.283	51.827	0.068	56.040	0.014
GHV(calc) MJ/m ³ (st)	39.13		38.57		38.49
T/C LGR m ³ /10 ⁶ m ³ (st)		20.51		5.18	

Compositions on a water free basis.

Table 3

Test-2 Experimental Phase Compositions (mol%)

Component	Well-head fluid	Separator 1 70.0 bar 9 °C		Separator 2 35.5 bar 0 °C	
		Liq.	Gas	Liq.	Gas
C1	93.623	26.823	93.896	17.583	93.969
C2	3.440	5.155	3.433	4.154	3.432
C3	0.308	1.597	0.303	1.354	0.302
iC4	0.270	2.799	0.260	2.930	0.257
nC4	0.022	0.396	0.020	0.313	0.020
iC5	0.043	1.287	0.038	1.429	0.037
nC5	0.008	0.325	0.006	0.353	0.006
C6	0.106	10.090	0.065	16.100	0.050
C7	0.118	18.269	0.043	30.098	0.015
C8	0.045	8.189	0.012	12.428	
C9	0.040	7.972	0.007	7.443	
C10	0.027	5.877	0.003	2.970	
C11	0.015	3.495	0.001	0.819	
C12	0.010	2.358		0.194	
C13	0.006	1.458		0.050	
C14	0.004	1.025			
C15	0.003	0.740			
C16	0.002	0.367			
C17	0.001	0.252			
C18		0.061			
C19		0.024			
C20		0.005			
BENZ		0.002			
TOL	0.002	0.416	0.001	0.758	
XYL	0.004	0.728	0.001	0.779	
N2	1.635	0.125	1.642	0.096	1.643
CO2	0.268	0.165	0.269	0.149	0.269
Mol. ratio		0.0041	0.9959	0.0009	0.9950
Mol. mass kg/kmol	17.403	83.235	17.131	83.161	17.069
C7+	0.277	51.236	0.068	55.539	0.015
GHV(calc) MJ/m ³ (st)	39.16		38.61		38.53
T/C LGR m ³ /10 ⁶ m ³ (st)		20.67		4.91	

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 46.2 bar -12 °C	
		Liq.	Gas	Liq.	Gas
C1	93.539	28.760	93.871	23.919	93.963
C2	3.437	5.408	3.426	6.015	3.423
C3	0.310	1.752	0.302	1.946	0.300
iC4	0.271	3.159	0.256	4.169	0.251
nC4	0.022	0.481	0.020	0.461	0.019
iC5	0.041	1.469	0.033	1.751	0.031
nC5	0.007	0.378	0.006	0.439	0.005
C6	0.118	10.790	0.063	17.113	0.041
C7	0.144	18.326	0.050	27.224	0.015
C8	0.051	7.685	0.012	9.070	
C9	0.042	7.081	0.006	4.411	
C10	0.028	5.045	0.002	1.553	
C11	0.016	2.957	0.001	0.491	
C12	0.010	1.974		0.029	
C13	0.006	1.223			
C14	0.004	0.864			
C15	0.003	0.628			
C16	0.002	0.296			
C17	0.001	0.216			
C18		0.053			
C19		0.041			
C20		0.009			
BENZ		0.002			
TOL	0.003	0.392	0.001	0.487	
XYL	0.004	0.655	0.001	0.562	
N2	1.668	0.173	1.676	0.134	1.678
CO2	0.273	0.183	0.274	0.226	0.274
Mol. ratio		0.0052	0.9948	0.0013	0.9935
Mol. mass kg/kmol	17.452	79.096	17.132	73.031	17.060
C7+	0.314	47.445	0.073	43.827	0.015
GHV(calc) MJ/m ³ (st)	39.22		38.59		38.49
T/C LGR m ³ /10 ⁶ m ³ (st)		24.39		5.97	

Compositions on a water free basis.

Table 5

Test-4 Experimental Phase Compositions (mol%)

Component	Well-head fluid	Separator 1 70.0 bar 1 °C		Separator 2 46.2 bar -12 °C	
		Liq.	Gas	Liq.	Gas
C1	93.599	28.695	93.941	23.961	94.032
C2	3.409	5.700	3.397	5.956	3.394
C3	0.304	1.831	0.296	1.905	0.294
iC4	0.267	3.262	0.251	4.080	0.246
nC4	0.021	0.490	0.019	0.437	0.018
iC5	0.040	1.484	0.032	1.695	0.030
nC5	0.008	0.376	0.006	0.439	0.005
C6	0.117	10.765	0.061	17.820	0.038
C7	0.141	18.229	0.045	27.334	0.010
C8	0.052	7.614	0.011	8.891	
C9	0.042	6.999	0.005	4.115	
C10	0.028	4.984	0.002	1.463	
C11	0.016	2.925	0.001	0.411	
C12	0.010	1.955		0.029	
C13	0.006	1.214			
C14	0.005	0.856			
C15	0.003	0.621			
C16	0.002	0.310			
C17	0.001	0.212			
C18		0.051			
C19		0.040			
C20		0.009			
BENZ		0.002			
TOL	0.003	0.388	0.001	0.547	
XYL	0.004	0.647	0.001	0.565	
N2	1.656	0.160	1.664	0.132	1.666
CO2	0.266	0.181	0.267	0.220	0.267
Mol.ratio		0.0053	0.9947	0.0013	0.9934
Mol.mass kg/kmol	17.439	78.761	17.113	72.832	17.041
C7+	0.313	47.054	0.066	43.355	0.010
GHV(calc) MJ/m ³ (st)	39.22		38.56		38.46
T/C LGR m ³ /10 ⁶ m ³ (st)		24.84		5.96	

Compositions on a water free basis.

Table 6
Experimental well-head fluid compositions

Component	Test 1	Test 2	Test 3	Test 4
C1	93.563	93.623	93.539	93.599
2	3.430	3.440	3.437	3.409
3	0.306	0.308	0.310	0.304
14	0.267	0.270	0.271	0.267
n4	0.022	0.022	0.022	0.021
15	0.039	0.043	0.041	0.040
n5	0.008	0.008	0.007	0.008
6	0.104	0.106	0.118	0.117
7	0.119	0.118	0.144	0.141
8	0.046	0.045	0.051	0.052
9	0.041	0.040	0.042	0.042
10	0.028	0.027	0.028	0.028
11	0.016	0.015	0.016	0.016
12	0.010	0.010	0.010	0.010
13	0.006	0.006	0.006	0.006
14	0.005	0.004	0.004	0.005
15	0.003	0.003	0.003	0.003
16	0.002	0.002	0.002	0.002
17	0.001	0.001	0.001	0.001
Benzene				
Toluene	0.002	0.002	0.003	0.003
Xylene	0.004	0.004	0.004	0.004
N2	1.709	1.635	1.668	1.656
CO2	0.269	0.268	0.273	0.266
C7+	0.283	0.277	0.314	0.313
Mol. mass kg/kmol	17.413	17.403	17.452	17.439

Table 7

Test-1 Predicted Phase Compositions (mol%)

Component	Well-head fluid	Separator 1 70.0 bar 10 °C		Separator 2 35.5 bar 0 °C	
		Liq.	Gas	Liq.	Gas
C1	93.563	29.127	93.808	16.872	93.848
C2	3.430	4.992	3.424	4.182	3.424
C3	0.306	1.295	0.302	1.367	0.302
iC4	0.267	2.367	0.259	2.967	0.258
nC4	0.022	0.261	0.021	0.349	0.021
iC5	0.039	0.886	0.036	1.367	0.035
nC5	0.008	0.245	0.007	0.408	0.007
C6	0.104	7.394	0.076	14.341	0.069
C7	0.119	15.387	0.061	30.603	0.045
C8	0.046	8.895	0.012	13.398	0.005
C9	0.041	9.409	0.005	8.343	0.001
C10	0.028	6.964	0.002	2.961	
C11	0.016	4.125		0.762	
C12	0.010	2.617		0.201	
C13	0.006	1.580		0.051	
C14	0.005	1.320		0.017	
C15	0.003	0.793		0.004	
C16	0.002	0.529		0.001	
C17	0.001	0.264			
C18					
C19					
C20					
C21					
C22					
C23					
C24					
C25					
C26					
C27					
BENZ					
TOL	0.002	0.301	0.001	0.515	0.001
XYL	0.004	0.824	0.001	1.033	
N2	1.709	0.200	1.715	0.103	1.716
CO2	0.269	0.225	0.269	0.154	0.269
Mol.ratio		0.0038	0.9962	0.0005	0.9957
Mol.mass kg/kmol	17.413	84.278	17.155	84.360	17.120
C7+	0.283	53.008	0.082	57.889	0.052
GHV(calc) MJ/m ³ (st)	39.13		38.62		38.56
T/C LGR m ³ /10 ⁶ m ³ (st)		18.71		2.73	

Compositions on a water free basis.

Table 8

Test-2 Predicted Phase Compositions (mol%)

Component	Well-head fluid	Separator 1 70.0 bar 9 °C		Separator 2 35.5 bar 0 °C	
		Liq.	Gas	Liq.	Gas
C1	93.623	29.294	93.866	16.891	93.904
C2	3.440	5.077	3.434	4.195	3.433
C3	0.308	1.325	0.304	1.375	0.304
iC4	0.270	2.438	0.262	2.999	0.260
nC4	0.022	0.267	0.021	0.349	0.021
iC5	0.043	0.998	0.039	1.506	0.039
nC5	0.008	0.251	0.007	0.407	0.007
C6	0.106	7.702	0.077	14.597	0.070
C7	0.118	15.536	0.060	30.392	0.045
C8	0.045	8.808	0.012	13.247	0.005
C9	0.040	9.253	0.005	8.292	0.001
C10	0.027	6.751	0.002	0.731	
C11	0.015	3.883		0.206	
C12	0.010	2.626		0.052	
C13	0.006	1.585		0.014	
C14	0.004	1.059		0.004	
C15	0.003	0.795		0.001	
C16	0.002	0.530			
C17	0.001	0.265			
C18					
C19					
C20					
BENZ					
TOL	0.002	0.305	0.001	0.516	0.001
XYL	0.004	0.833	0.001	1.046	
N2	1.635	0.192	1.640	0.098	1.641
CO2	0.268	0.226	0.268	0.153	0.268
Mol. ratio		0.0038	0.9962	0.0005	0.9957
Mol. mass kg/kmol	17.403	83.437	17.150	84.179	17.117
C7+	0.277	52.229	0.081	54.501	0.052
GHV(calc) MJ/m ³ (st)	39.16		38.66		38.59
T/C LGR m ³ /10 ⁶ m ³ (st)		18.90		2.55	

Compositions on a water free basis.

Table 9

Test-3 Predicted Phase Compositions (mol%)

Component	Well-head fluid	Separator 1 70.0 bar 1 °C		Separator 2 46.2 bar -12 °C	
		Liq.	Gas	Liq.	Gas
C1	93.539	30.442	93.866	23.086	93.922
C2	3.437	5.683	3.425	6.099	3.423
C3	0.310	1.520	0.304	1.990	0.302
iC4	0.271	2.822	0.258	4.287	0.255
nC4	0.022	0.309	0.021	0.495	0.020
iC5	0.041	1.090	0.036	1.947	0.034
nC5	0.007	0.250	0.006	0.475	0.005
C6	0.118	9.111	0.071	18.103	0.057
C7	0.144	17.923	0.052	29.688	0.028
C8	0.051	8.337	0.008	7.688	0.002
C9	0.042	7.587	0.003	3.343	
C10	0.028	5.272	0.001	1.033	
C11	0.016	3.069		0.246	
C12	0.010	1.933		0.062	
C13	0.006	1.163		0.015	
C14	0.004	0.776		0.004	
C15	0.003	0.583		0.001	
C16	0.002	0.388			
C17	0.001	0.194			
C18					
C19					
C20					
BENZ					
TOL	0.003	0.413	0.001	0.563	
XYL	0.004	0.678	0.001	0.506	
N2	1.668	0.202	1.676	0.139	1.677
CO2	0.273	0.254	0.273	0.228	0.273
Mol.ratio		0.0051	0.9949	0.0008	0.9941
Mol.mass kg/kmol	17.452	78.243	17.131	72.556	17.086
C7+	0.314	48.316	0.066	43.149	0.030
GHV(calc) MJ/m ³ (st)	39.22		38.60		38.51
T/C LGR m ³ /10 ⁶ m ³ (st)		23.89		3.70	

Compositions on a water free basis.

Table 10

Test-4 Predicted Phase Compositions (mol%)

Component	Well-head fluid	Separator 1 70.0 bar 1 °C		Separator 2 46.2 bar -12 °C	
		Liq.	Gas	Liq.	Gas
C1	93.599	30.439	93.924	23.080	94.980
C2	3.409	5.635	3.398	6.047	3.395
C3	0.304	1.491	0.298	1.952	0.297
iC4	0.267	2.782	0.254	4.227	0.251
nC4	0.021	0.295	0.020	0.473	0.019
iC5	0.040	1.064	0.035	1.903	0.033
nC5	0.008	0.287	0.007	0.544	0.006
C6	0.117	9.058	0.071	18.069	0.057
C7	0.141	17.613	0.051	29.446	0.028
C8	0.052	8.536	0.008	7.995	0.002
C9	0.042	7.621	0.003	3.420	
C10	0.028	5.296	0.001	1.059	
C11	0.016	3.083		0.252	
C12	0.010	1.942		0.063	
C13	0.006	1.168		0.015	
C14	0.005	0.975		0.005	
C15	0.003	0.585		0.001	
C16	0.002	0.390			
C17	0.001	0.195			
C18					
C19					
C20					
BENZ					
TOL	0.003	0.415	0.001	0.571	
XYL	0.004	0.681	0.001	0.516	
N2	1.656	0.200	1.663	0.138	1.665
CO2	0.266	0.248	0.266	0.223	0.266
Mol.ratio		0.0051	0.9949	0.0008	0.9941
Mol.mass kg/kmol	17.439	78.596	17.119	72.736	17.075
C7+	0.313	48.500	0.065	43.343	0.030
GHV(calc) MJ/m ³ (st)	39.22		38.59		38.50
T/C LGR m ³ /10 ⁶ m ³ (st)		23.88		3.62	

Compositions on a water free basis.

Table 11Test condition liquid densities

Test No.	Separation 1 kg/m ³	Separation 2 kg/m ³
1	723.24	680.0*
2	706.81	678.0*
3	717.33	667.0*
4	717.41	666.0*

* values determined by computerised equation-of-state

Table 12
Conversions

$\text{psig} = \frac{\text{bar} - 1.01325}{0.06895}$	$^{\circ}\text{F} = (^{\circ}\text{C} \times \frac{9}{5}) + 32$
$\text{bb1} = \frac{\text{m}^3}{0.15899}$	$\text{scf} = \frac{\text{m}^3 (\text{st})}{0.02826}$
$\text{bb1/MMscf} = \frac{\text{m}^3/10^6 \text{ m}^3 (\text{st})}{5.6254}$	$\text{Btu/scf} = \frac{\text{MJ/m}^3 (\text{st})}{37.3307 \times 10^{-3}}$

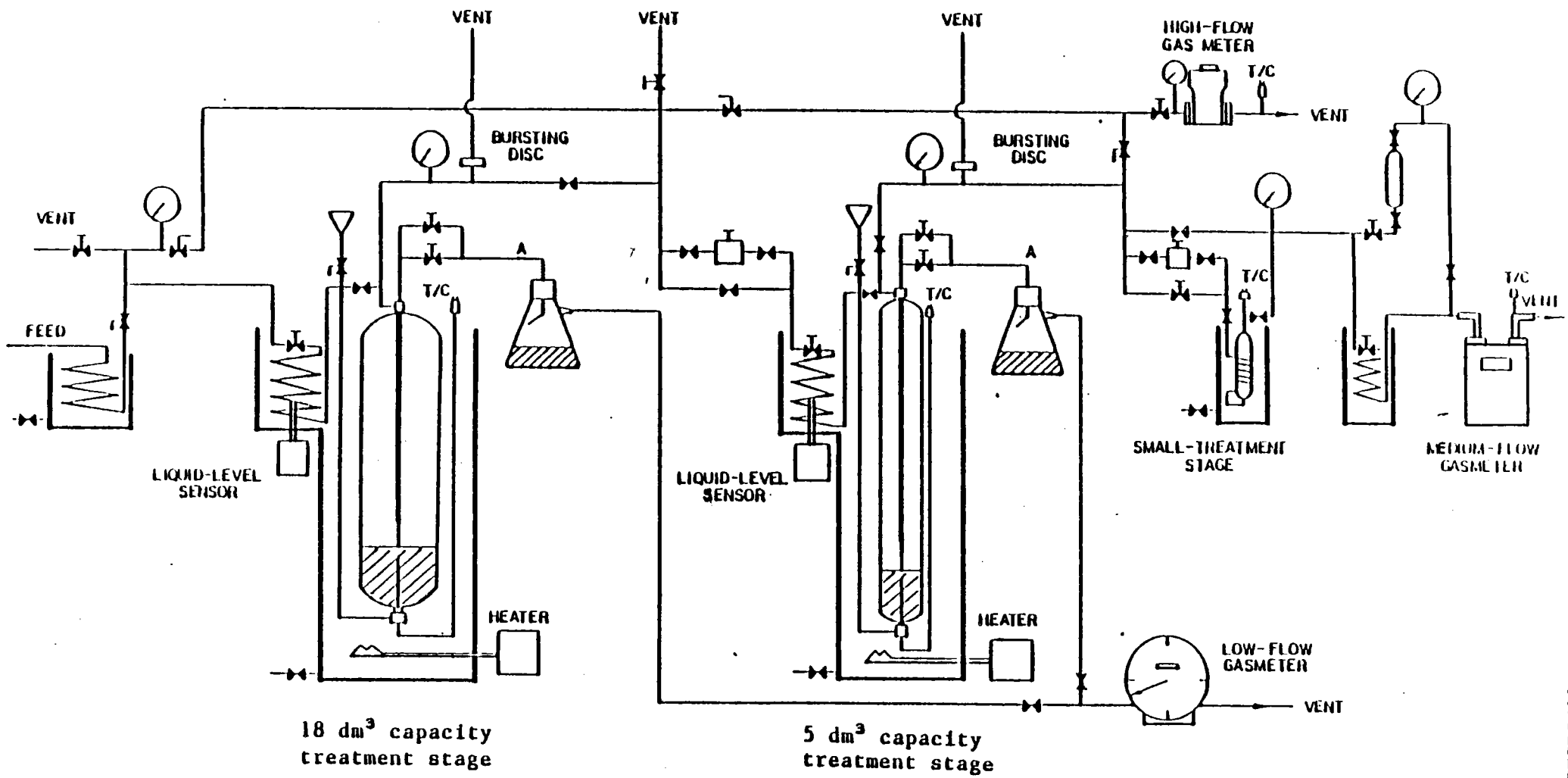
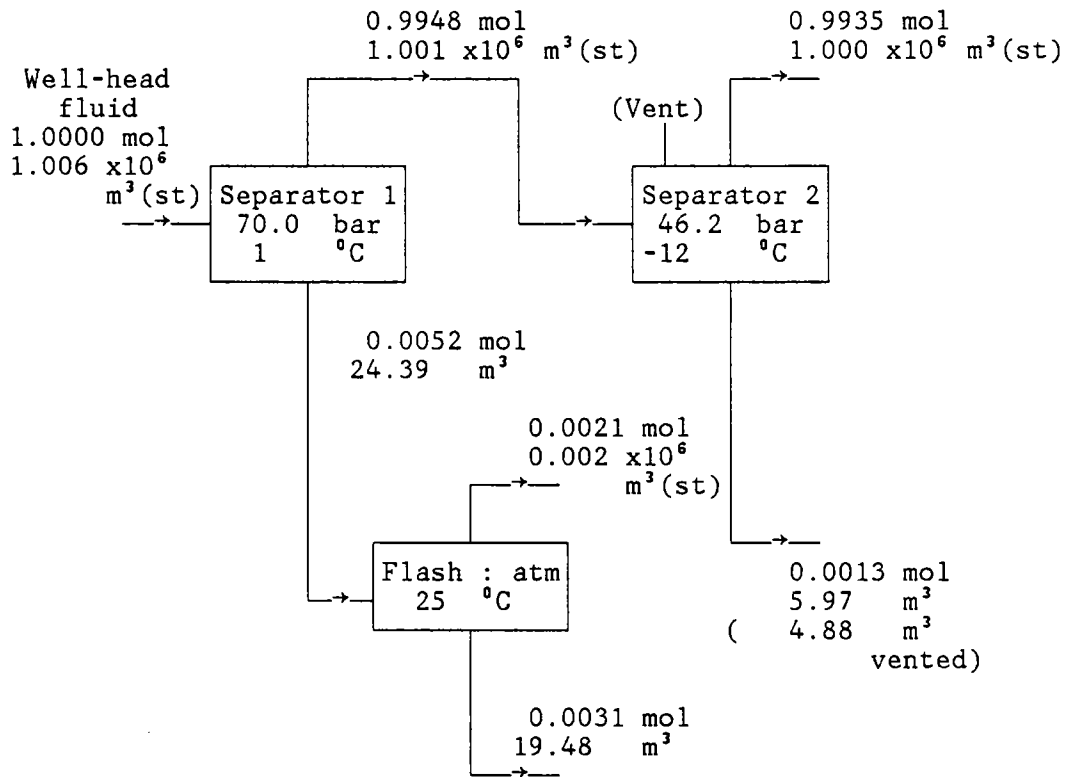


FIG.1-Well-head testing unit

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Figure 6

Test-3 Mass and Volume Balance

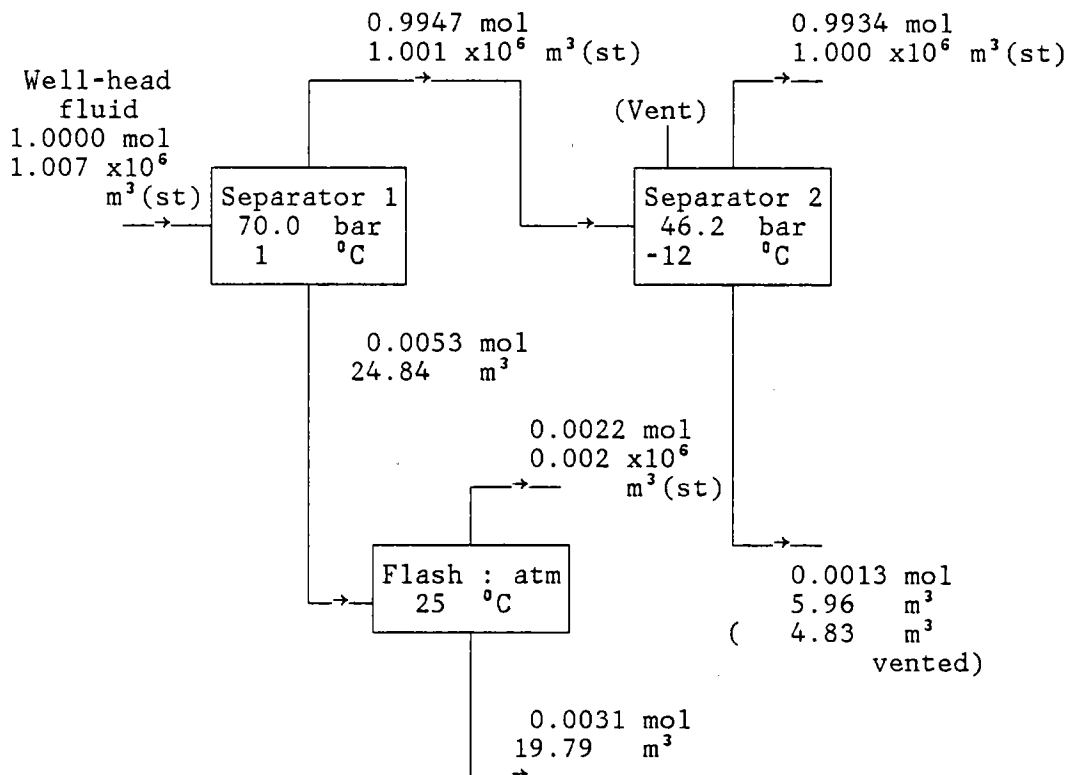


NOTE. The mass and volume balances, based on 1 mol of input fluid and 10⁶ m³(st) of final gas respectively, are not equivalent.

Flash : atm implies flash to prevailing atmospheric pressure.

Figure 7

Test-4 Mass and Volume Balance

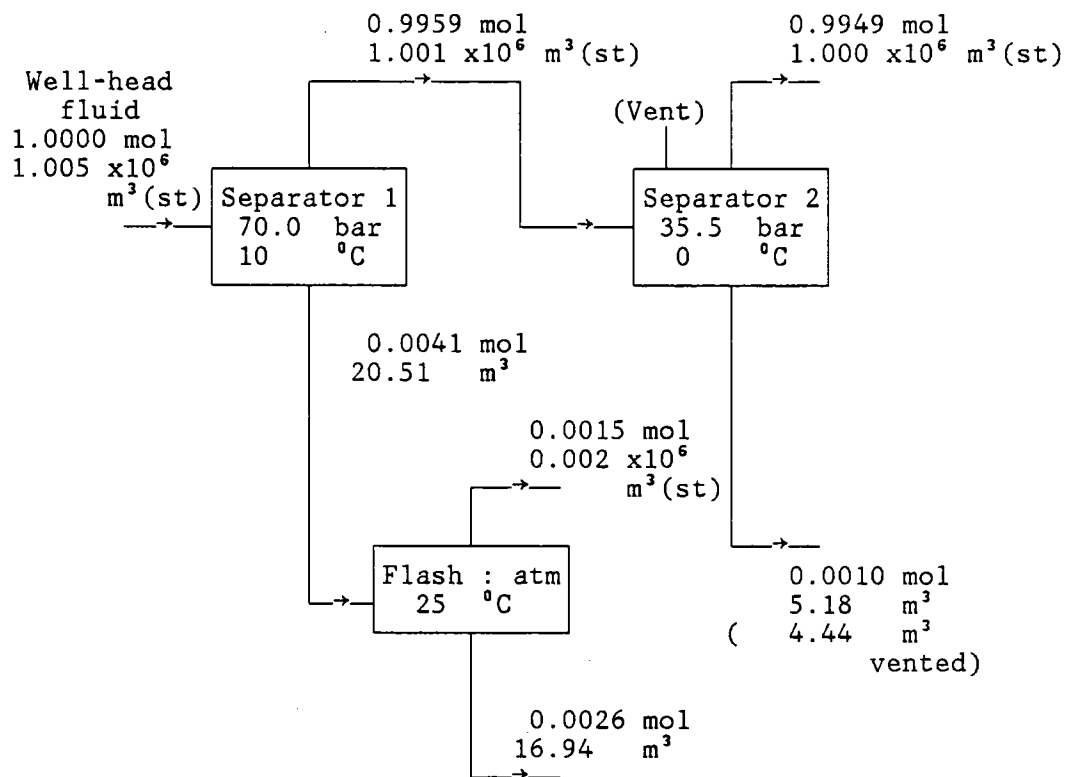


NOTE. The mass and volume balances, based on 1 mol of input fluid and 10^6 m³(st) of final gas respectively, are not equivalent.

Flash : atm implies flash to prevailing atmospheric pressure.

Figure 4

Test-1 Mass and Volume Balance

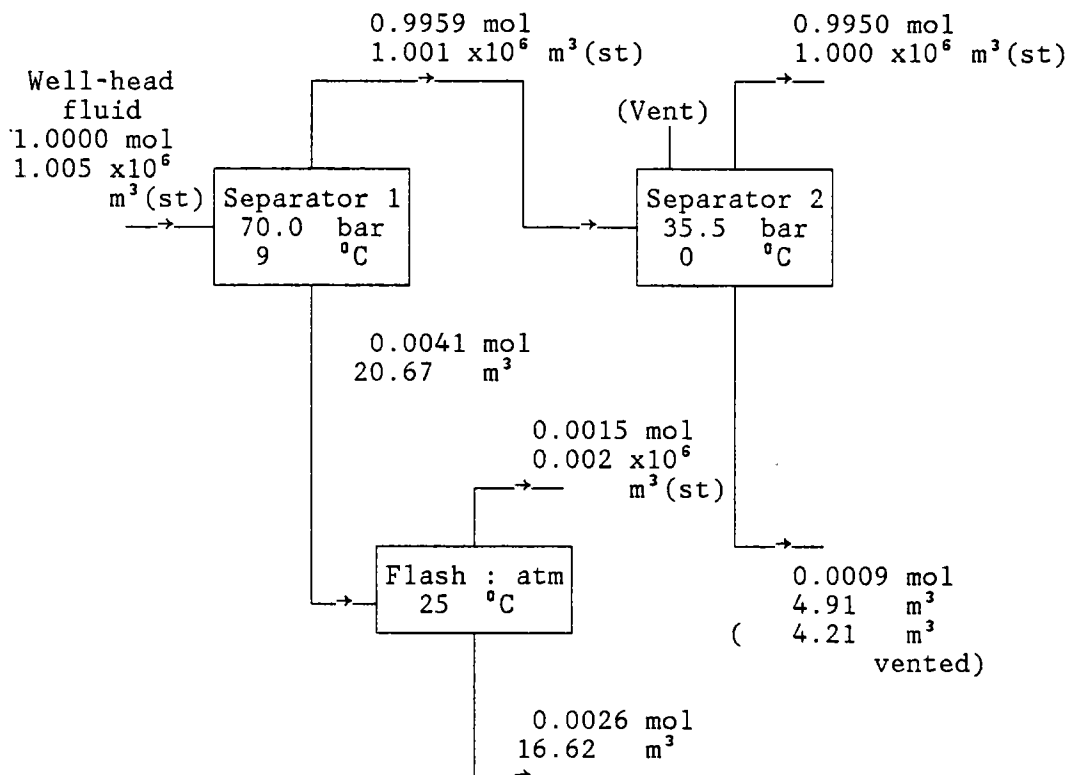


NOTE. The mass and volume balances, based on 1 mol of input fluid and 10⁶ m³(st) of final gas respectively, are not equivalent.

Flash : atm implies flash to prevailing atmospheric pressure.

Figure 5

Test-2 Mass and Volume Balance



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

Flash : atm implies flash to prevailing atmospheric pressure.

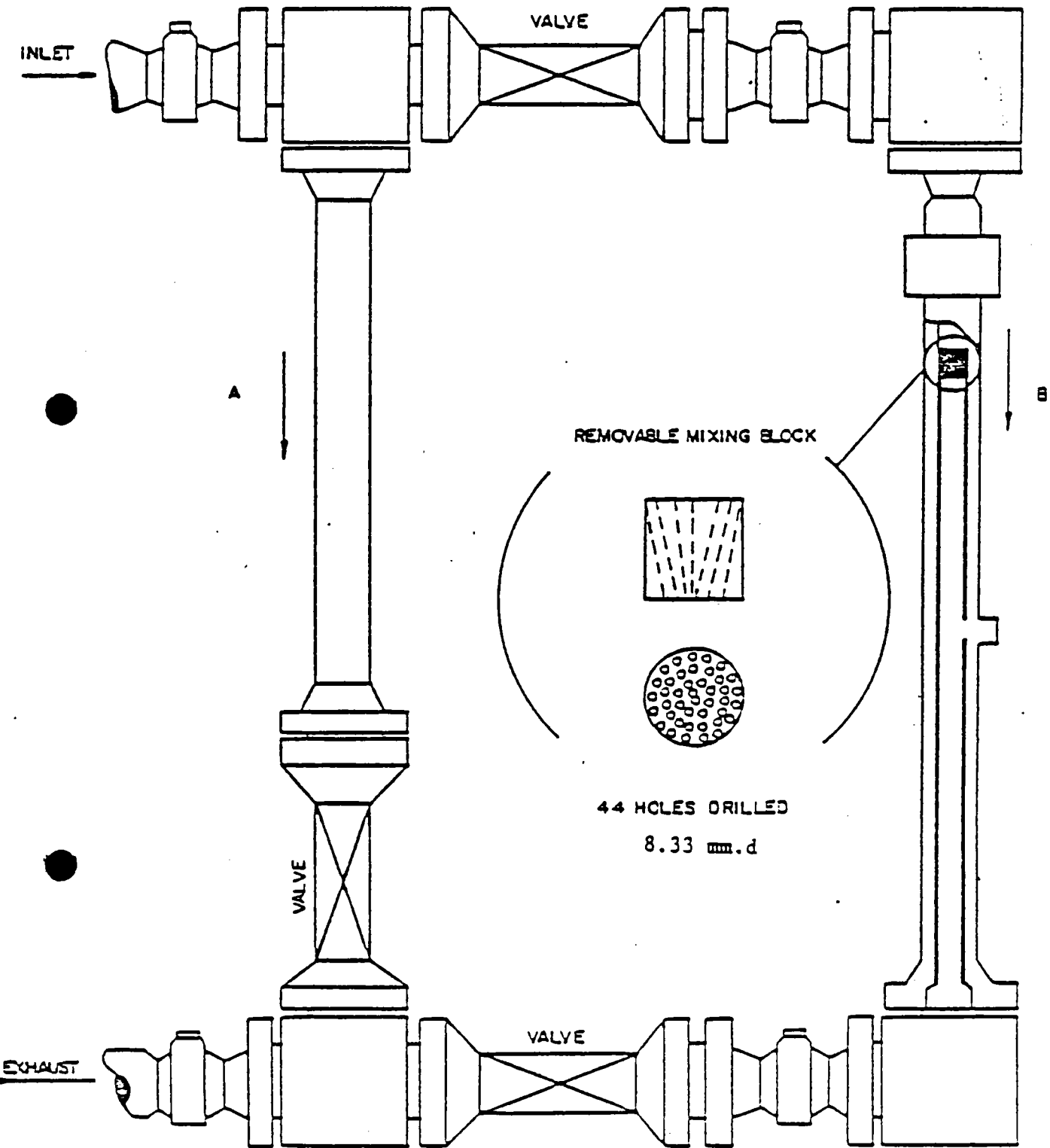


FIG. 2 - Mixing manifold

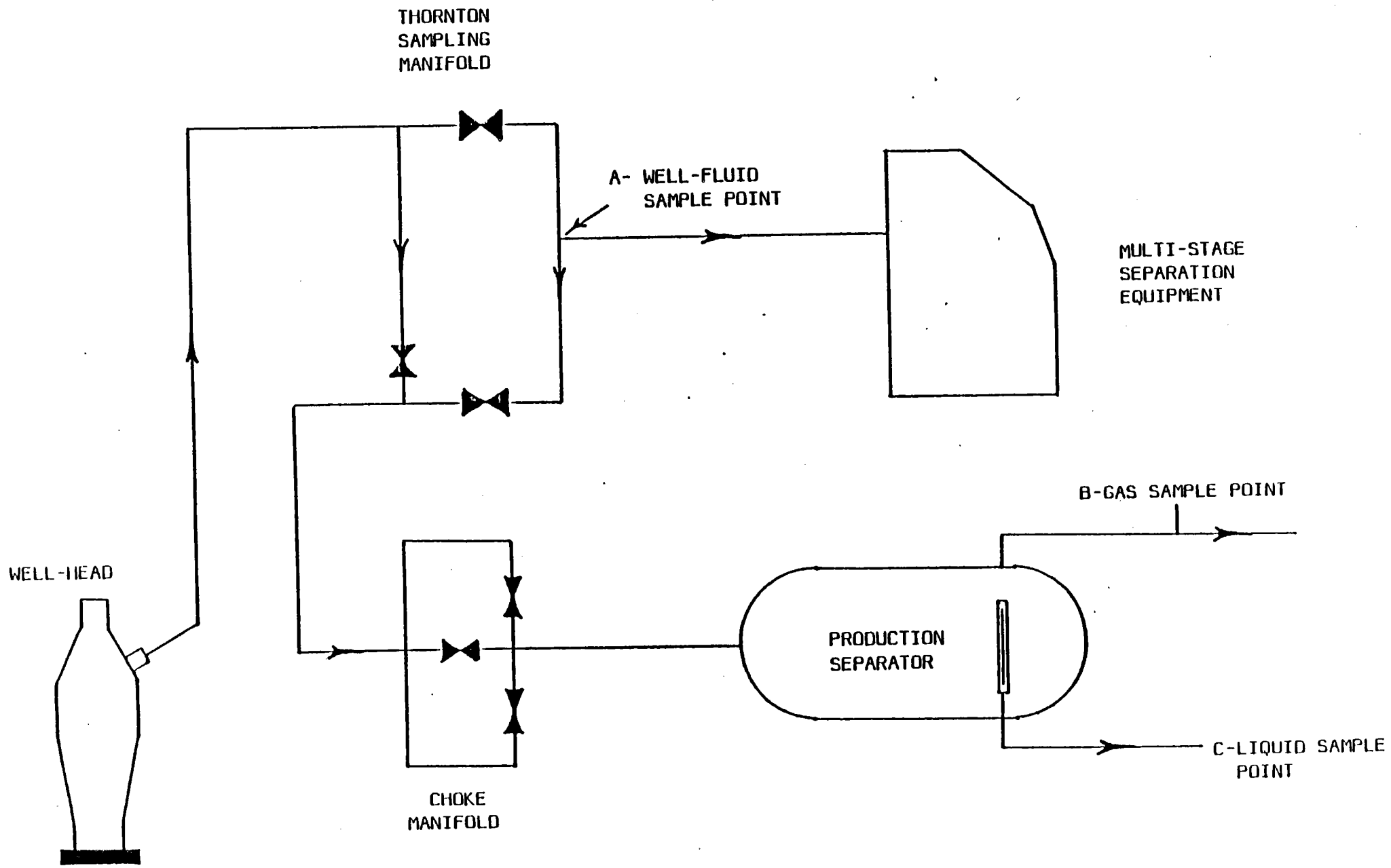


FIG 3 CONFIGURATION OF SPLIT- PHASE SAMPLING EQUIPMENT

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