12. RFT Summary

Run 3/1

One run was made with the RFT tool as a part of the logging program before setting 9 5/8" casing. (Run no.1 was actually the third trip in the hole with the RFT tool, the first two trips resulted in tool failure). The purpose was to measure formation pressures in the Upper Jurassic sands and to take a fluid sample. Depth correlation was based on the GR of the DLL/MSFL/CAL log recorded during the same logging run.

RFT No.	Logging Run	TD metres	Max BHT
1	3	3538.2	100.3 DC

Each test has been given a two digit number indicating the run number and the test number, e.g. 1/2 indicates the second test taken during the first trip into the hole with the RFT tool. A 20,000 psi pressure gauge calibrated to 16,000 psi was used. (A 10,000 psi gauge was used on the first unsuccessful run into the hole and consistently gave erroneously high readings in the mud column and was therefore replaced with a back-up gauge).

A total of 27 pressure tests were attempted, 24 resulted in seal failure, 1 failed by probe plugging, and 2 were successful in measuring formation pressure (See table 4). A segregated sample using two 2 3/4 gallon chambers was taken at 3322m (test 1/27).

Pressure Interpretation (run 3/1): Formation pressures recorded by the RFT are 5281 psi at 3312m (hydrostatic = 7361 psi) and 5309 psi at 3322m (hydrostatic = 7380 psi) indicating an overbalance of approximately 2075 psi in the zones where formation pressures were recorded. Pore pressure calculated by d-exponent in this same zone is 6745 psi, indicating that the formation pressure is anomalously low. There are at least two possible explanations for this situation: 1) The sandstones in this interval, sandwiched between an upper overpressured shale section (Kimmeridge Clay) and a lower overpressured shale (Heather Shales), are in communication, up dip, with a normally pressured permeable zone or 2) the

parameters normally used for calculating d-exponent are not valid in this area. Further studies will be required to elaborate on this subject.

No interpretation of formation pressure gradient has been attempted due to the availability of only 2 data points separated by only 10 meters.

Sample Recovery

RFT 1/27 (3322m)

The lower chamber (2 3/4 gal) was opened first and filled in 44 minutes. The upper chamber (2 3/4 gal) was subsequently opened and filled in 51 minutes. The contents of both chambers were examined at the well-site. Recovery was as follows:

Lower Chamber (2 3/4 gal) 6 liters of mud and 4.2 liters of mudfiltrate.

Upper Chamber (2 3/4 gal) 10.3 liters of mud filtrate

R_{sample} = 0.0643 at 21°C, K^+ = ppb, Cl = 75,000 ppm, ph = 8.8
(Rmf = 0.0615 at 14°C, K^+ = 50 ppb, Cl = 78,000 ppm, ph = 10.0)

TABLE 4

PRE-TEST RESULTS (Run 3/1)

Well 35/8-2
Date: Dec. 26, 1981
Run 3/1

Mud weight: 12.8t

Test no.	Depth (m)	Test Failed	Final Build-up uncorrected	Final Build-up corrected	Mud Hydrostatic uncor. Before/After	Mud Hydrostatic cor. Before/After	Comments
1	3280.5	S			7292 7293	7287 7288	
2	3280	?(S)	7425	7420	7290 7292	7285 7287	Pres > hydro supercharge?
3	3306	S			7353 7356	7348 7351	
4	3308	S			7362 7365	7357 7360	
5	3307.6	S			7356 7353	7351 7348	
6	3312		5287	5281	7366 7363	7361 7358	Good Test
7	3314	S			7375 7376	7370 7371	
8	3313.6	S			7371 7370	7366 7365	
9	3318.9	S			7381 7381	7376 7376	
10	3321.8	S			7389 7391	7384 7386	
11	3321.4	S			7386 7386	7381 7381	
12	3322.2	S			7389 7393	7384 7388	

Test no.	Depth (m)	Test Failed	Final Build-up uncorrected	Final Build-up corrected	Mud Hydrostatic uncor. Before/After	Mud Hydrostatic cor. Before/After	Comments
13	3324.8	S			7399 7400	7394 7395	
14	3325	S			7393 7393	7388 7388	
15	3325	S			7393 7392	7388 7387	
16	3324	S			7399 7402	7394 7397	
17	3327.7	S			7405 7403	7400 7398	
18	3334.6	P			7414 7414	7409 7409	
19	3334.6	S			7414 7415	7409 7410	
20	3334.6	S			7420 7420	7415 7415	
21	3333	S			7412 7417	7407 7412	
22	3333.1	S			7412 7414	7407 7409	
23	3334.5	S			7413 7413	7408 7408	
24	3337	S			7418 7420	7413 7415	
25	3333	S			7409 7409	7404 7404	

Test no.	Depth (m)	Test Failed	Final Build-up uncorrected	Final Build-up corrected	Mud Hydrostatic uncor. Before/After	Mud Hydrostatic cor. Before/After	Comments
26	3327.7	S			7396 7396	7391 7391	
27	3322		5315	5309	7385 7383	7380 7378	Good Test Took Sample

Sample Summary

	Start	Finish	Pressure when sealed Uncorrected	Pressure when sealed Corrected
Lower Chamber	0335	0419	5318	5312
Upper Chamber	0420	0511	5295	5289

Pressure stabilized at 5297 psi (Corrected) after upper chamber sealed.

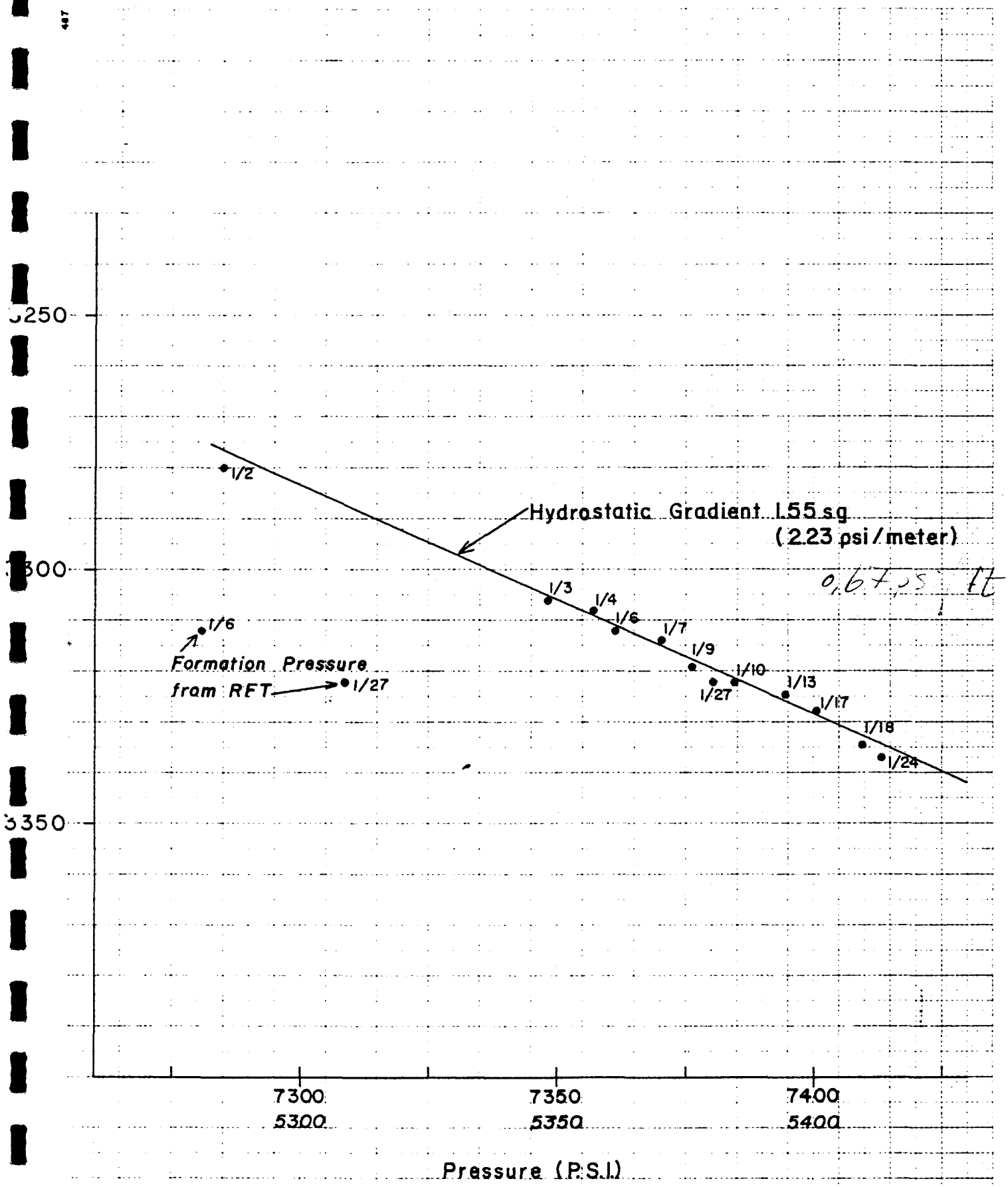
Lower chamber contained mud (6.0 liters) and mud filtrate (4.2 liters).

Upper chamber contained mud filtrate (10.3 liters). Mud Engineer's analysis of sample UC-1 (upper chamber)

K^+ = 50 ppb
Cl = 75,000 ppm
ph = 8.8

Analysis of mud filtrate from flow line:

K^+ = 50 ppb
Cl = 78,000
ph = 10.0



Results from pressure tests-RFT run no. 3/1.

To read hydrostatic pressures use scale drafted in block numerals.

To read formation pressures use scale drafted in italic numerals.

Fig. 25

Run 4/2

One run was made with the RFT tool as a part of the logging program before setting the 7" liner. The purpose was to measure formation pressures in the Brent and Cook sands. Depth correlation was based on the GR of the ISF/BHC/GR log recorded during the same logging run.

RFT No.	Logging Run	TD metres	Max BHT
2*	4	3954	125.0 DC

(*RFT No.1 was run during logging run no.3)

Each test has been given a two digit member indicating the run number and the test number, e.g. 2/3 indicates the third test taken during the second trip into the hole with an RFT tool. A 10,000 psi gauge calibrated to 11,000 psi was used. No formation fluid sampling was attempted, only formation pressure testing.

Pressure Interpretation (run 4/2):

Formation pressures measured with the RFT are plotted on figure 1. Hydrostatic pressure measured in the mud column are plotted on figure 2. The symbols indicate the following: X = good test, (X) affected by supercharging, /X/ probably affected by supercharging. Four tests in the hydrocarbon zone (3/4, 2/5, 2/20, 2/7) and one test in water zone (2/16) are valid tests. Test nos. 2/6 and 2/19 are definitly affected by supercharging (pre-test chambers were by-passed in an attempt to get readings in tight zones) and test nos. 2/14 and 2/15 are probably affected by supercharging.

Pressures in the hydrocarbon zone range from 7797 psi at 3671m to 7831 psi at 3723m. The gradient between these two points is 0.64 psi/meter which corresponds to a fluid density of 0.45 sg. This value is comparable to fluid densities calculated in the Brent Formation in 35/8-1. The reservoir is overpressured by approximately 2300 psi (assuming formation water density of 1.05 sg.).

Three pressure measurements were recorded below the hydrocarbon/water contact (3726m). It is felt that pressure tests 2/14 and 2/15 are probably affected by supercharging while test 3/16 is probably valid. If a visual best-fit line is drawn through these points, the resulting gradient is 2.59 psi/meter, which corresponds to a fluid density of 1.82 sg. (15.1 lbs/gal). This value far exceeds the density of common formation fluids thus either the pressure readings are erroneous, or the three points are separated by impermeable barriers. Test 2/16 was recorded at 3788.5m and test 2/14 recorded at 3811m. Only thin streaks of shale lie between these points thus it is doubtful that different pressure regimes could exist between these points. Between tests 2/4 and 2/15 (Cook Sand) a significant shale section does exist and it is conceivable that differential pressuring could occur in this zone but this phenomena is not supported by other pressure detecting methods, e.g. decreasing resistivity, increasing transit time, or d'exponents. Therefore the pressure gradient observed between tests 2/16, 2/14, and 2/15 is interpreted to be due to the supercharging effect on tests 2/14 and 2/15, rather than overpressure.

Test 2/16 is interpreted to be valid because the gradient between 2/16 and 2/7 is 1.06 psi/meter (fluid density = 0.71 sg.), which is actually lower than expected since 2/7 is at the base of the hydrocarbon zone and 2/16 is in the water zone (gradient in a water zone with a fluid density of 1.05 sg. is 1.49 psi/meter). Since supercharging results in erroneously high formation pressure measurements, a much higher gradient would have been observed had supercharging affected the test. One could interpret the anomalously low gradient between 2/7 and 2/16 as indicating that the hydrocarbon/water contact lies between these two points, the low gradient resulting from averaging the hydrocarbon fluid density (0.45 sg.) and the formation water density (1.05 sg.). To determine where the theoretical hydrocarbon/water contact does occur from analysing pressure data alone, a formation water gradient of 1.49 psi/meter (fluid density 1.05 sg.) is drawn through 2/16. Next, the hydrocarbon gradient of 0.64 psi/meter (fluid density = 0.45 sg.) is extended downward from 2/7 until it intersects with the formation water gradient. This pivot point, the "theoretical" hydrocarbon/water contact, occurs at 3759m. This is 23 meters lower than the hydrocarbon/water contact (3726m) observed from resistivity logs. It is possible that residual hydrocarbons below the hydrocarbon/water contact at 3526m have lowered the formation fluid density enough to cause the discrepancy but one cannot be certain especially since there is only one valid point in the water zone to work with.

Thus the following conclusions can be made from the RFT results:

1) Reservoir pressure in the hydrocarbon zone ranges from 7797 psi at 3671 meters to 7831 psi at 3723 meters.

2) Hydrocarbon density as calculated from RFT measurements is 0.45 sg.

3) The reservoir is overpressured with respect to normal hydrostatic by 2300 psi.

4) Formation pressure in the Cook sand is no greater than 8328 psi. This pressure test (2/15) appears to have been affected by supercharging and is probably erroneously high.

5) Drawdown permeability are listed on table 6 but the absolute values are not valid. They may be useful in a qualitative sense however. A list of buildup permeabilities will be appended to this report when computation is completed.

Table 5

Pre-test results (run 4/2)

Well: 35/8-2

Date: March 4, 1982

Mud weight: 14.5 lb/gal

Run 4/2

Test no	Depth	Test Failed	Final Build up (psi) uncorrected	corrected	Mud Before/ after	Hydro-static cor. Before/ after	Comments
1	3667	T			9170 9170	9160 9160	
2	3667.5	T			9170 9168	9160 9158	
3	3666.6	T			9167 9168	9157 9168	
4	3671		7812	7797	9178 9180	9168 9170	Good
5	3677.5		7814	7799	9194 9194	9184 9184	Good
6	3708		7851	7836	9270 9270	9260 9260	Supercharge
7	3723		7846	7831	9308 9306	9298 9296	Good
8	3754	T			9383 9383	9373 9373	
9	3753.5	T			9383 9383	9373 9373	
10	3745	T			9364 9360	9354 9350	
11	3792	T			9477 9477	9467 9467	
12	3791.5	T			9477 9477	9467 9467	

13	3796.5	T			9488 9490	9878 9480	
14	3811		8080	8065	9524 9518	9514 9508	Prob. Supercharge
15	3932.5		8341	8328	9817 9815	9808 9805	Prob. Supercharge
16	3788.5		7908	7893	9460 9456	9450 9446	Good
17	3765.5	T			9410 9412	9400 9402	
18	3770	T			9420 9422	9410 9412	
19	3732		7913	7898	9328 9321	9318 9311	Supercharge
20	3700		7824	7809	9244 9244	9234 9234	Good

15. Mud Report (Anchor Drilling Fluids)

Summary

OPERATOR: NORWEGIAN GULF EXPLORATION CO. A/S

WELL NO. 35/8-2

36" **HOLE/** _____ **CASING INTERVAL**

This section was drilled with seawater and pre-hydrated Bentonite pills with returns going to the sea floor. 1160 bbls of spud mud at 100± viscosity was mixed initially.

25' was drilled into the seabed with 26" bit and then a 17½" pilot hole was drilled to 1900'. The hole was then opened up with a 26" bit and 36" hole opener to a depth of 1466'. A guideline was wrapped around the drill string and had to be straightened. 25 bbls HiVis pills were spotted on connections.

Tight hole was encountered with 36" hole opener at 1535'. A total of 400 bbls HiVis mud had been spotted. With 17½" bit and 26" hole opener the hole was drilled to 1900' and displaced with 50 bbls of mud. The hole was then opened to 1565' with a twist off at the same depth. Fished for 8" collars and BHA. 400 bbls of mud was weighted to 12.0 ppg.

After retrieving drill collars the rig was moved 100' west in order to respud.

Drilled to 1900' with 17½" bit with HiVis pills on every second connection. Ran in the hole with 26" bit and 36" hole opener, drilled to 1767' and made a trip. Tight spots were found at 1803' and 1833' while drilling to 1901'. The hole was then cleaned with viscous slugs and displaced with 11 ppg HiVis mud. After clean out trip 13' of fill was found and reamed to T.D. 100 barrels of HiVis mud was pumped before pulling out of hole. Ran 30" casing with no returns when circulating with mud. Cemented 30" casing with no returns at seabed. After pressure testing perforations were made at 1590-1595'.

After squeezing through perforations with no returns to seabed, ran 26" bit to clean out and ran temperature log. Perforated at 1475' - 1480'. Squeezed perforations with cement and ran in hole to clean out to 1876'. Ran temperature logs and perforated at 1390'-1395'. Cemented with no returns. Cleaned out and ran temperature logs. Cemented twice with Mica in cement. Cleaned out and tagged cement at 1379'.

Pulled out cement from 1379' to 1418'. Cleaned out casing and ran temperature log. Perforated again at 1364' to 1367' and cemented. Ran in hole at 1876' with no cement in casing. Cemented for last time with 700 sxs at 15.5 ppg. POOH and started on next section of hole.

OPERATOR: NORWEGIAN GULF EXPLORATION CO. A/S

WELL NO. 35/8-2

17½" PILOT/ 26" HOLE

This section was drilled with seawater and native clays with additions of pre-hydrated Bentonite for viscosity. Cement was tagged at 1876' and the shoe was drilled.

New hole was made from 1876' to 1910' with HiVis pills being pumped to keep the hole clean. Two hundred barrels of gel mud was mixed to displace the hole and 30' riser and pin connector were prepared to be run. While running riser the flex-joint parted and was dropped to the seafloor with guidelines parted. After latching up to guideline the pin connector and flex-joint were searched for on the seabed. At this point the rig was re-positioned and pin connector located. The pin connector was landed on beames and the riser was run after waiting on weather for 1 day. After running in, the hole was reamed to 1910' and drilled to 2763'. Water was added to the system to control fluid weight. A wiper trip was made and Schlumberger was rigged up and run.

After logging a 26" under-reamer was run to 1350' and riser was displaced with seawater. We then ran in the hole to 30" casing shoe and completely displaced with fresh water, and after flow check displaced with 9.3 ppg gel mud.

The hole was opened up to 26" to 2763' and displaced with 10.6 ppg gel mud. The riser was then pulled and a 26" bit was run to bottom with no fill. Made sure the hole was filled with mud by pumping 50 bbls of 10.6 ppg gel mud on the way in and out.

After waiting on weather the hole was again filled with 10.6 ppg mud (550 bbls) and 20" casing was run.

After cement job BOP's were run and 750 bbls gel mud was mixed and treated with Soda Ash for possible cement contamination.

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WELL NO. 35/8-2

17½" **HOLE/** _____ **CASING INTERVAL**

This section was drilled with a seawater Polymer mud and pre-hydrated Bentonite. After the leak off test we drilled to 3612'. The mud was treated with Soda Bicarbonate when drilling cement and broken over gradually with more Polymer and LF-5 for fluid loss.

Four hundred barrels of kill mud were built at 10.8 ppg. We continued to drill to 4246' with some tight spots and viscosity problems. Water was added to reduce gels and viscosity. Tight spots were reamed and some lignosulphonate was added to the mud to keep rheology in line. Drilled to 5882' and circulated bottoms up; when pulling out of the hole the maximum overpull initially was 90.000 lbs. Tight spots were encountered at 4797', 4020', 3045' and 2950' with a maximum overpull of 100.000 lbs. When running in the hole tight spots were reamed at 2856', 3107' and 4010'.

After reaming, the hole was drilled to 6588'. Bottoms up was circulated and tight spots at 6285', 5845', 5624' and 5341' occured when pulling out of hole. Water and appropriate chemicals were used to keep the mud in condition. When running in the hole tight spots were at 2874' and 2578'. The 17½" hole was drilled to casing point at 7071'.

During wiper trip tight spots were found at 5500' and 5410' and 5373' with a maximum overpull of 75.000 lbs. The first logging run was unsuccessful past a depth of 6344'. Mud was then reconditioned and logs were successfully run. 13 3/8" casing was run and cemented after a clean out trip. On the second stage of the cement job circulation was lost after 380 bbls of cement was pumped. A CBL log was run after the cement and we rigged down to prepare for the next section of the hole.

OPERATOR: NORWEGIAN GULF EXPLORATION CO. A/S

WELL NO. 35/8-2

12 1/4" **HOLE/** _____ **CASING INTERVAL**

This section was drilled with KCl Polymer mud with an initial mud weight of 10.0 ppg.

The float and cement of 13 3/8" casing was drilled out with seawater and then casing was displaced with fresh KCl mud. A CBL log was run at this time.

When circulating mud approximately 40-50 bbls of mud was lost due to cement contamination. A bridge plug that was run stuck in the DV collar and was drilled out. A similar plug was set at 7016'and casing was perforated at 7010' - 7012' for a squeeze job. The first squeeze job was unsuccessful and another one was completed.

The riser was then displaced with seawater, and riser and BOP's were pulled. BOP's and waiting on parts accounted for 14 days. Retainers from 7005 - 7016' and cement from 7016 - 7022' was drilled out. Cement and 13 3/8" shoe were drilled with 12 1/4" bit to 7075'. Ran leak off test at this time with 13.8 ppg equivalent mud weight and drilled ahead.

A tight spot was encountered at 7087'. The KCl content was increased from 38 ppg to 45 ppg. While pulling out of hole tight spots were encountered at 7620' and 7400'. KCl content was then increased to 50 ppg. 12 1/4" hole was then drilled to 9014' with tight spots at 8565' and 8625' while pulling out of hole. Riser was then pulled and anchor winches were worked on for 6 days. Ran in hole washed to bottom and drilled ahead.

At 9905' the mud weight was increased to 10.9 ppg. At 9987' the riser was displaced and drill string hung off due to weather for 2 days. After displacing riser we drilled ahead to 10.129' where mud weights were increased to 12.0 ppg. While drilling we increased mud weight to 12.6 at 10.500'.

At 10.875' a drilling break occured and we pulled out of hole to core. Coring was done from 10.882 - 10.884' when barrel jammed at 10.885'. At this point we changed over to a drill bit and drilled to 10.885'. Due to poor weather the riser was displaced with seawater for 1 day. After changing back to mud we drilled ahead to 11460' and pulled out of hole after 300 psi pressure with maximum of 35 units gas. After running back in

OPERATOR: NORWEGIAN GULF EXPLORATION CO. A/S

WELL NO. 35/8-2

12 1/4" **HOLE/** _____ **CASING INTERVAL**

hole we drilled to 11.518', then waited on weather for 1 day. Drilled ahead to 11.552' with maximum gas at 46 units on bottoms up.

At 11.608' logging was carried out. After logging and circulating bottoms up, 9 5/8" casing was run and two stage cement job was carried out.

OPERATOR: NORWEGIAN GULF EXPLORATION CO. A/S

WELL NO. 35/8-2

8 ½" **HOLE/** _____ **CASING INTERVAL**

Drilled the 9 5/8" shoe at 11.585' with KCl Polymer, 13.7 ppg mud weight and tagged bottom at 11.608'.

Took a leak off test at 11.610', giving an equivalent mud weight of 16.4 ppg.

The total system was weighted up to 14.2 ppg and increased to 14.5 at 11.893'. Three hundred barrels of pre-hydrated Bentonite was added slowly for treatment of mud (HTHP) at the depth of 12.020'. Coring started at 12.047' and continued to 12.304' when pipe got stuck during running in hole after recovery of core no. 7.

Pipe stuck at 12.015'. Mixed 50 bbls IMCO spot to be used for stuck pipe. Kelly parted from Kelly cock when working drill pipe. Replaced Kelly and bushings and started fishing for drill string. Increased yield point and funnel viscosity at this time for better lifting capacity of metal cuttings. Milling and use of fishing tools retrieved most of drill string. Schlumberger run to engage fish with no success. Set cement plug at 11.408'.

Ran whipstock and mill window from 11.424' to 11.448'.

Mixed 36 bbls. SSP in mud for better lubrication properties. Mud weight was cut back to 14.4 at 12.152' while drilling. Mud in this section was gradually changed over to a dispersed system with Lignosulphonate and Lignite.

Mixed a Walnut/SSP pill for open hole before running and cementing liner at 12.974'.

OPERATOR: NORWEGIAN GULF EXPLORATION CO. A/S

WELL NO. 35/8-2

6.125" **HOLE/** _____ **CASING INTERVAL**

Prior to drilling the 7" liner shoe the mud was treated with 5% SSP (Peanut Oil) for lubriaction of the Turbine/Diamond drilling to come. The cement and liner shoe was drilled with a rock bit and a leak off test made to 16.9 ppg maximum, but no leak-off limit was reached.

The Turbine/Diamond bit was then run and this was used to drill the entire 6 1/8" hole section.

A split-flow circulating sub was used to enable good riser cleaning without excessive flow rates at the collars. However, several trips were made to replace the split flow sub due to its' habit of becoming washed out after ± 25 hrs.

The upper section of the hole was drilled relatively quickly - up to 50 ft/hr, but the average rate of penetration was about 23 ft./hr, dropping to below 10 ft/hr over the final 150 ft. of drilling.

The mud generally performed its' task well with no hole problems encountered. The peanut oil, whilst providing good lubrication, did present considerable difficulties and this included some problems with pump pressures whilst drilling. At first it was not difficult to obtain good properties with 5% SSP present but after about 24 hours the mud became more and more aireated and this led to problems with mud weight readings using a regular mud balance. This was not easily noticeable at first and it was thought that the mud weight was dropping due to the Thule unit removing Barite. As a result Barite was added, but on checking the mud weight with a pressure balance the true mud weight was as much as 0.4 ppg higher than the 14.2 ppg required. This error was corrected over 2 circulations with water being added and the mud weight was checked with the pressure balance only thereafter. Use of conventional defoamers proved ineffective in reducing the ever increasing amount of air and the de-gasser was only modestly successful when used. Additions of chemicals were also affected in so far as the high air content created artificial properties, such as high funnel viscosity and a slightly artificial yield point. Prior to this problem becoming apparent, the MBT value was being raised towards 18/20 ppb but at 16 ppb it was thought unwise to proceed with further additions of pre-hydrated Bentonite. Despite these difficulties, the mud properties were more than adequate, and although it was virtually impossible to do an accurate mud check

OPERATOR: NORWEGIAN GULF EXPLORATION CO. A/S

WELL NO. 35/8-2

6.125" **HOLE/** _____ **CASING INTERVAL**

continued .....

due to the time it took to allow the air to escape from the mud, great pains were taken to find the true properties. Despite not being able to remove the very fine solids generated by the Turbine/Diamond bit, the low gravity solids never presented a serious problem.

Additions of Lignite were deliberately held back for purposes of geological correlation, but when added to the mud towards T.D. created such a severe foaming problem that pump pressure was temporarily lost and only fully regained after switching suction to a different pit. Thereafter, all hopper mixing ceased and drilling was completed with as little shear as possible in the pits to accomodate the air problem. The hole was then logged with ease and cement plugs were set as the testing program commenced.

NOTE :

During trips, the air gradually escaped from the mud and resulted in normal funnel viscosity (53), lower yield point and plastic viscosity. In considering the air problem, no mixing or shearing activity in the pits was of an unusual nature. Other properties did not seem affected by the high air content.

TESTING

18. Formation Testing Report (Gaffney, Cline & Assoc.)

Gulf Oil Exploration and Production, Houston, asked Gaffney, Cline and Associates (GCA) to provide on-site petroleum engineering supervision and evaluation for the duration of drill-stem testing operations at the exploration well 35/8-2 in the Norwegian sector of the North Sea (Fig 1). The licence block is jointly owned by Norwegian Gulf Exploration Company A/S (30%), Getty Oil Corporation (20%) and Statoil (50%), Gulf being the operator.

The testing programme had two prime objectives. Firstly, to test a selected sand within the Brent Formation and to confirm that the reservoir fluid was wet gas, as had been established for the corresponding interval in well 35/8-1 on a similar structure 9.5 km away to the north. Secondly, to determine if the Heather Formation contained produceable hydrocarbons; these were potentially considered to be oil by preliminary log and sidewall core analysis.

Operations commenced on the 25th April and gas condensate was tested from the Brent during a successful drill-stem test (DST-1). Following an invalid test (DST-2) on the Heather formation, during which sections of the Brent were inadvertently retested, the initial programme was suspended on the 4th May. A remedial cement squeeze job was required to isolate the Heather from the Brent formation because of an inadequate primary cementing operation. A successful rerun (DST-2A) proved that permeability of the Heather reservoir sand was very low and too small to allow formation fluids to be recovered in the drillpipe.

Testing operations were completed by the 15th May, after which the well was prepared for abandonment.

Checked: GA
Approved:
Date: June '82

WELL TEST SUMMARY

Test No.	1	2	2A
Formation	Brent	Brent	Heather
Perforated Interval (m RKB)	3694.0-3703.0	3306.0-3315.0	3306-3315 3321-3327
Main Flow, Identification Data			
Choke (64th's)	44.0	40.0	-
Gas Flow - Separator (MMSCFD)	15.8	7.6	-
Gas Condensate Ratio (SCF/STB)	8244.0	5891.4	-
Condensate Flow (STBD)	1920.0	1290.0	
Gas gravity (air = 1)	0.67	0.67	-
Stock Tank Gravity (°API)	46.0	46.0	-
Separator temperature (°F)	85.0	72.0	-
Separator pressure (psig)	640.0	400.0	-
Wellhead temperature (°F)	112.0	54.0	-
Wellhead pressure (psig)	2200.0	2060.0	-
Production time (hours)	15.75	12.79	-
Analysis Results			
In-situ fluid phase	Gas	Gas	Unknown
Extrapolated pressure - initial (psig)	7803.0	7085.0	-
final (psig)	7830.0	7425.0	5505.0
Gauge depth for pressure measurement (MRKB)	3689.0	3273.0	3269.5
Estimated Bottom hole temperature (°F)	272.0	260.0	224.0
Flow capacity (md-ft)	328.0	106.0	>0.7
Permeability (md)	4.55	-	0.014
Skin Factor	14.4	-	-
Productivity Index (SCFD/psi)	4954.0	-	-
Completion efficiency	0.32	-	-
Radius of investigation (m)	223.0	-	-
Turbulence factor - calculated	5.45x10	-	-
Inertial turbulent factor - calculated	0.091	-	-

Notes

1. No flow to surface on DST-2A, extremely tight formation indicated.
2. Due to mechanical communication behind casing, DST-2 (an attempted test of the Heather) was a Brent test.
3. Brent test produced condensate rich gas, probably near critical point at initial conditions.
4. Skin factor calculated includes inertial/turbulent effects.

CONCLUSIONS

1. The Brent Formation

i) DST-1 successfully tested a selected reservoir sand within the Brent, which produced gas and condensate to the surface. The gas/liquid ratio was lower than was obtained during testing of a corresponding interval in well 35/8-1, though the gas and condensate properties were similar.

ii) The reservoir sand exhibited a low flow capacity and an effective permeability to the in situ fluid (probably gas) of 4.55 md.

iii) The extrapolated reservoir pressure was 7830 psig at 3689 m RKB, this agrees well with the data obtained from RFT analysis and confirms the test section to be considerably overpressured.

iv) The sequence of operations during DST-1 did not allow the direct evaluation of turbulent and inertial effects. However, calculation using the available test results indicated that these factors are potentially significant.

v) DST-2, an attempted test in the Heather Formation, resulted in a second Brent test. This was due to mechanical communication between the two formations in the wellbore.

vi) It is likely that DST-2 tested a Brent sand interval other than that of DST-1; a low flow capacity, approximately one third of that calculated for the latter, being indicated by analysis. Moreover, a liquid/gas ratio significantly higher than that observed during DST-1 was witnessed and also extrapolated reservoir pressures for DST-2 are considered indicative of a zone less overpressured than that tested by DST-1.

2. The Heather Formation

i) Subsequent to the failure of DST-2 to test the selected section of the Heather Formation, the remedial squeeze job successfully isolated that section from the underlying Brent Formation.

ii) DST-2A successfully tested the selected Heather sands.

iii) The tested sands proved to have a very low effective permeability, in the order of 0.014 md. This precluded significant formation fluids from being produced into the wellbore.

Saga Petroleum a.s.

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Title

GEOCHEMICAL DATA REPORT FOR WELL 35/8-2

Authors(s)

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Abstract

Thirteen samples from the cored interval in well 35/8-2 have been analysed by Iatroscan (TLC-FID) and the saturated hydrocarbon fractions from two samples were analysed by GC-FID and GC/MS. Four samples (one claystone and three coals) were analysed by LECO (TOC) and Rock Eval. Their maturity was estimated by vitrinite reflectance.

Key Words

35/8-2, geochemistry, TOC, Rock Eval, vitrinite reflectance, GC-FID, GC/MS

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1 Objectives

The objective of this study was to characterise the extractable hydrocarbons in 13 core samples from well 35/8-2, and characterise the quality of the organic matter in four of the samples.

2 General well information

The well was drilled by Gulf as operator of licence 058 from 11/9-81 and 21/5-82 and reached a total depth of 4335 mRKB. The KB of the rig was 25 metres and the water depth was 381 metres.

3 Samples and analytical scheme

13 samples were picked from the cored interval in the well on the 28th of April 1992 at NPD's store in Stavanger. All samples were analysed by Iatroscan (TLC-FID), and the saturated hydrocarbon fractions from two samples (3667.2 and 3702.5 mRKB core depth) were analysed by GC-FID and GC/MS. The maturity and quality of the organic matter were analysed on four samples.

4 Vitrinite reflectance

Four samples were analysed, and the data are summarized in table 1 and plotted in figure 1.

5 TOC and Rock Eval

Four samples were analysed.

Depth	Lith.	S1 mg/g	S2 mg/g	S3 mg/g	Tmax	TOC %	Prod. In.	Hyd. In.
3690.5	Clst	2.21	13.29	0.58	452	8.53	0.14	155
3719.4	Coal	12.27	204.00	3.06	449	76.30	0.06	267
3734.2	Coal	17.08	203.00	2.60	451	82.80	0.08	244
3742.1	Coal	6.60	91.6	2.00	453	61.4	0.07	149

6 Iatroscan (TLC-FID)

13 samples were analysed, and the results are tabulated in Table 2.

7 GC-FID

The saturated hydrocarbon fractions from two samples (3667.2 and 3702.5 mRKB core depth) were analysed by GC-FID.

Since the evaporative loss has affected the relative concentration of individual compounds, no ratios were calculated.

The GC-FID chromatograms are shown in figure 2.

8 GC/MS

The saturated hydrocarbon fractions from the samples were analysed by GC/MS and the mass chromatograms for m/z 191, 177, 217 and 218 are shown in figure 3.

Selected biological marker parameters are given in table 3.

9 Stable carbon isotopes

No samples were analysed.

Tab. 1

SAGLAB RESULTS MANAGEMENT : VITRINITE ANALYSIS RESULTS

Data for Well 35/8-2 Page 1

Type	St.Depth	En.Depth	VRo 1	Pop	VRo 2	Pop	VRo 3	Pop	Sample ID	Dup
CCP	3690.50	3690.50	.85	10					86269	1
CCP	3719.40	3719.40	.68	19					86271	1
CCP	3734.20	3734.20	.81	20					86273	1
CCP	3742.10	3742.10	.78	30					86275	1

4 RESULT(s) selected ..., from the following search criteria:
Company: IFE, Nat: NOR, Well:
35/8-2, Depth between: 0.000 and
99999.990 m

Tab. 2

0 WELL NAME	1 NATIONALITY	2 LABORATORY	3 U.DEPTH	4 L.DEPTH	5 SAMPLE TYPE	6 LITHOLOGY	7 EOM mg/g
1 35/8-2	NOR	SAGA	3316.90	3316.90	CCP	SST	0.06
2 35/8-2	NOR	SAGA	3318.10	3318.10	CCP	SST	0.08
3 35/8-2	NOR	SAGA	3667.20	3667.20	CCP	SST	2.16
4 35/8-2	NOR	SAGA	3672.80	3672.80	CCP	SST	0.85
5 35/8-2	NOR	SAGA	3674.20	3674.20	CCP	SST	1.63
6 35/8-2	NOR	SAGA	3687.55	3687.55	CCP	SST	1.34
7 35/8-2	NOR	SAGA	3690.50	3690.50	CCP	SHALE	2.57
8 35/8-2	NOR	SAGA	3695.60	3695.60	CCP	SST	0.87
9 35/8-2	NOR	SAGA	3702.50	3702.50	CCP	SST	1.29
10 35/8-2	NOR	SAGA	3708.60	3708.60	CCP	SST	0.35
11 35/8-2	NOR	SAGA	3719.40	3719.40	CCP	COAL	30.20
12 35/8-2	NOR	SAGA	3734.20	3734.20	CCP	COAL	59.82
13 35/8-2	NOR	SAGA	3742.10	3742.10	CCP	COAL	19.64

0 WELL NAME	8 SAT (mg/g)	9 ARO (mg/g)	10 POL (mg/g)	11 SAT %	12 ARO %	13 POLARS %	14 SAT ARO	15 METHODS
1 35/8-2	0.00	0.00	0.06	0.000000	0.000000	100.000000		Iatroscan
2 35/8-2	0.00	0.00	0.08	0.000000	0.000000	100.000000		Iatroscan
3 35/8-2	1.73	0.30	0.14	79.698743	13.780295	6.520961	5.783529	Iatroscan
4 35/8-2	0.65	0.09	0.12	75.838312	10.118122	14.043566	7.495295	Iatroscan
5 35/8-2	1.35	0.10	0.17	82.797226	6.446793	10.755981	12.843165	Iatroscan
6 35/8-2	1.04	0.13	0.16	78.232112	9.820159	11.947729	7.966481	Iatroscan
7 35/8-2	0.21	0.71	1.64	8.320385	27.786524	63.893091	0.299440	Iatroscan
8 35/8-2	0.69	0.10	0.09	78.378321	11.461438	10.160241	6.838437	Iatroscan
9 35/8-2	1.02	0.15	0.11	79.442597	11.734298	8.823105	6.770119	Iatroscan
10 35/8-2	0.29	0.00	0.06	84.015181	0.000000	15.984819		Iatroscan
11 35/8-2	0.92	3.42	25.86	3.030245	11.336746	85.633008	0.267294	Iatroscan
12 35/8-2	0.83	12.03	46.96	1.388980	20.114368	78.496652	0.069054	Iatroscan
13 35/8-2	0.70	12.42	6.52	3.561417	63.226772	33.211811	0.056328	Iatroscan

Tab. 3

0 WELL NAME	1 CONS.	2 UPPER DEPTH	3 DEPTH	4 LITH	5 SAMPLE TYPE	6 Q/E	7 Ts/Tm	8 Z/C	9 ab/ab+ba
1 35/8-2	SAGA_RR	3667.20	3667.20	SST	CCP	0.27	1.22	0.10	0.90
2 35/8-2	SAGA_RR	3702.50	3702.50	SST	CCP	0.16	1.19	0.19	0.90

0 WELL NAME	10 %22S	11 %20S	12 %bb	13 a/a+j	14 C27st	15 C28st	16 C29st
1 35/8-2	0.60	0.54	0.59	0.83	32.34	26.98	40.67
2 35/8-2	0.59	0.56	0.60	0.88	30.93	30.30	38.77