Testing Procedures: Well 7/12-6

1. Testing Procedures

1.1 This programme has been compiled in preparation for the production testing of NOCS Well 7/12-6. The programme is tailored to testing the target formation inside the 7" liner.

1.2 Test pressures are based on known pressure data from the Ula reservoir. At no time will the maximum rating of conventional 10M testing equipment be exceeded.

1.3 The BP Drilling Supervisor will be in overall charge throughout the test. The Drilling Supervisor will be advised and assisted by a BP Petroleum Engineer who will directly supervise the conduct of the test and contract personnel involved. Safety will be of the prime importance during all aspects of the test.

1.4 The testing and perforating procedures laid down in Sections 9 and 11 respectively of the BP Operations Manual will be observed at all times during the test.

2. Outline of General Programme

2.1 Run and cement the 7" liner. One short joint of 7" pipe should be included in the liner and located approximately 2 or 3 joints above the reservoir interval.

Run 7" and 9 5/8" casing scraper trips to clean cement out. Condition mud to 1.51 SG. There should be no decrease in mud weight following cementation.

On the final trip out of the hole strap the 5" drill pipe.

2.2 Run the CBL/VDL/CCL/GR over the entire 7" liner at least 24 hours after cementing. In the event that the cement bond and the zone isolation proves to be unsatisfactory a separate remedial cementation programme will be issued.

2.3 Pressure test the 9 5/8 casing and the 7" liner, and dry test the 7" liner overlap as per the programme outlined in section 3.

2.4 Conduct a full BOP test.

2.5 Make a dummy run with the Flopetrol EZ tree to check space out in the 10M BOP stack. Run a stand of drill collars below the EZ tree; the slick joint on the tree should be newly painted. Land the SSTT in the 9 5/8" bore protector, as per Figure 3. Close the 5" lower pipe rams and the 3 1/2" middle pipe rams, checking operating volumes on Koomey system totaliser, to ensure fully closed.

Open pipe rams, retrieve SSTT and check ram marks on slick joint.

Unlatch and relatch EZ tree to function test the latching mechanism. Ensure at least one stand of pipe above the tree when unlatching.

2.6 Rig up Schlumberger and perforate DST 1 interval:
(depth taken on the FDC/CNL Run No.). The perforating will be carried out with 4" casing guns at 4 shots per foot.

Run gauge ring/junk basket across the perforations.

2.7 Run DST string into the hole as per detailed programme outlined in Section 6. Space out the test string so that the packer is approximately 15 to 20m above the top perforation, and at least 2m from a casing collar.

2.8 Carry out DST1 programme as per procedure below following detailed procedures outlined in sections 7 to 10:

i) Open up well for 5 minute initial flow.

ii) Close well in for a 1 hour initial shut in period.

iii) Open well for main flow period. The flow period will be of sufficient time to produce approximately 400 bbls of formation fluid at surface, or 12 hours, whichever is later.

iv) Close well in for pressure buildup. This should be approximately equal in time to the flow period.

v) Open the well and commence the sea water injection period. This will last for approximately 20 hours.

vi) Close in the well and observe pressure fall off for approximately 20 hours.

vii) Reverse out contents of test string following the PFO.

2.9 Pull out of hole with test string. Set a balanced cement plug across perforations. Run in hole with a bit and scraper and dress cement plug. Rig up Schlumberger and run a gauge ring and a junk basket and then set a bridge plug above plug. Pressure test above bridge plug to 2000 psi.

2.10 Rig up Schlumberger and perforate DST 2 interval: (depth taken on the FDC/CNL Run No.). Run gauge ring/junk basket across the perforations.

2.11 Run DST string into the hole as per detailed programme outlined in Section 6. Space out the test string so that the packer is approximately 15 to 20m above the top perforation, and at least 2m from a casing collar.

2.12 Carry out DST 2 programme as per Section 2.8.

2.13 Pull out of hole with DST string and isolate perforated interval as per Section 2.9.

2.14 Rig up Schlumberger and perforate DST 3 interval: (depth taken on the FDC/CNL Run No.). Run gauge ring/junk basket across the perforations.

2.15 Run DST string into the hole as per detailed programme outlined in Section 6. Space out the test string so that the packer is approximately 15 to 20m above the top perforation, and at least 2m from a casing collar.

2.16 Carry out DST 3 programme as per Section 2.8. A 100 bbl slug of diesel should be pumped ahead of the seawater.

2.17 Pull out of hole with DST string and isolate perforated interval as per section 2.9.

2.18 Note that bottom hole sampling may be required following the oil production period on DST 3.

3. Pressure Testing and Dry Testing Programme

3.1 Close blind shear rams, and pressure test 9 5/8 casing and 7" liner to 3000 psi.

3.2 Run testing string as per Figure 1.

3.3 Run sufficient 5" drill pipe so that packer may be set approximately 100m above top of 7" liner. Connect up circulating head to top of drill pipe and connect to cement pump via choke manifold using chicksans. (The choke manifold will be used to circulate seawater out of string following dry test).

3.4 Set packer approximately 100m above top of liner, making sure that the circulating head is at least 4m above rig floor, and pressure test liner overlap to 3000 psi for 15 minutes on chart. (In addition this will also pressure test the string). Bleed off pressure.

3.5 Unset packer. Close lo torq valve and pressure test against the valve to 3000 psi. Bleed off pressure and open lo torq valve.

3.6 Displace 160 bbl seawater into test string using cement pump (approx. 9000 ft in 5" drill pipe). Close lo torq valve on top of test string. This volume of seawater will reduce the mud hydrostatic by approximately 2000 psi.

3.7 Set packer approximately 100m above top of liner. Open lo torq valve and observe for flow for 15 minutes. Close lo torq valve and observe PBU for 1 hour. Keep check on level of mud in annulus.

3.8 Unset packer and reverse out seawater via choke manifold. Control flow at choke manifold. POOH with test string.

4. <u>Surface Production Equipment: Hookup and Pressure Testing Prior to Running the Test String, Figure 4</u>

4.1 <u>Flowlines and Choke Manifold</u>

4.1.1 Pressure test the data header and choke manifold against the choke manifold inlet valves to 7500 psi. Pressure test lo torq valve between data header and choke manifold to 7500 psi.

Pressure test the down stream valves to 3000 psi.

4.1.2 Connect the flowline chicksans and pressure test to 7500 psi.

4.2 <u>Production Equipment and Pipework</u>

4.2.1 Install and connect separator, flowtank, transfer pump and associated pipework. Purge all lines with water. Wash out separator and tank to ensure no fluids or solids from previous test remains in the separator or tank.

4.2.2 Pressure test the rig test line from the rig floor, the chicksans upstream of the separator and up to the rig DST line outlet valve to 3000 psi.

4.2.3 Pressure up the separator slowly until the relief valve lifts at approximately 1440 psi. Retest to 1400 psi to ensure the relief valve is reseated.

4.2.4 Ensure the flow tank vent/relief line is clear.

4.3 <u>Burners</u>

4.3.1 Purge all burner lines with water to remove debris and ensure no blockages exist. Ensure no water spray nozzles are blocked, and check water supply to burners.

4.3.2 Pressure test oil lines to 1200 psi.

4.3.3 Connect up and function test the propane ignition pilot system for the burners.

4.3.4 Check air supply to burners.

4.3.5 Pump a few barrels of diesel to each burner in turn to check operation.

4.4 <u>Test Trees</u>

4.4.1 Make up slick joint to the Flopetrol EZ tree. Pressure test below the valves and with both valves open, to 7500 psi.

4.4.2 Pressure test the Flopetrol flowhead against the swab valve and both sidearm valve to 7500 psi. Pressure test below the master valve to 7500 psi.

4.4.3 Pressure test above and below the Flopetrol lubricator valve to 7500 psi.

5. <u>Surface Injection Equipment: Hookup and Pressure Testing, Fig. 5</u>

5.1 <u>Surface Lines</u>

Hookup system as indicated in Figure 5. Ensure that the seawater supply is capable of achieving up to 5000 BWPD at a delivery pressure of 70 psig.

5.2 <u>Water Treatment Plant</u>

5.2.1 <u>Preparation</u>

Make a trial run with the Serck plant of up to 40 hours, at varying throughputs.

The aim of the trial run will be to achieve stable flowing conditions and to monitor inlet and outlet water quality with and without chemical dosing.

The plant should be run for 10 hours at approximately 2500 BWPD, then 20 hours at 3500 BWPD and then 10 hours at the maximum feasible throughput. The inlet and outlet water quality should be monitored every 30 minutes using a coulter counter and turbidity meter.

The first 20 hours of the trial should be run without chemical treatment i.e. the first flowrate and the first half of the second flowrate. The next 10 hours should be run using all the necessary chemical treatments to achieve the stated specification. Finally the third flowrate, the maximum feasible, should be run with no chemical treatment.

The following chemicals will be used to achieve the required water quality:

i) sodium hypochlorite
ii) polyelectrolyte
iii) coagulant
iv) scale inhibitor

During the trial run the seawater will be run to the gauge tank to measure the throughput and then dumped overboard. At the end of the test sufficient water will be retained in the gauge tank so that the filter bed can be throughly back-flushed to prepare it for the next test.

Throughout the trial run the pressure drop across the filter bed should be recorded.

5.2.2 Operation

During each seawater injection period chemical treatment of the inlet seawater to the treatment plant will be utilised to achieve the required suspended solids removal of 98% down to 2 microns.

At the end of each injection period sufficient water should remain in the gauge tank to provide adequate back-flushing to prepare the filter bed for the next injection test.

If any problems with the treatment plant are experienced during the injection period, the plant will be bypassed and untreated seawater injected.

Inlet and outlet seawater samples should be taken every half hour during the plant operation to monitor water quality with a coulter counter and turbidity meter.

5.3 Charge Pumps

Operate the charge pumps with the gauge tank full to check for any leaks in the low pressure lines upstream of the injection pumps. Also check the operation of the charge pumps with the gauge tank low to check for any suction problems.

5.4 Injection Pumps

5.4.1 Preparation

Both injection pumps should be operated and pressure tested to 7500 psi, in preparation for the injection testing. The relief valve should be set at approximately 7700 psi.

Pressure test the injection line up to the rig floor to 7500 psi, then increase the pressure slowly until the relief valve lifts and the pressure drops, and then repeat the pressure test at 7500 psi to ensure that the relief valve has reset.

Ensure that all the high pressure injection lines are well lashed down to prevent any movement while injecting.

5.4.2 Operation

Near the end of the PBU close the flowline valve and the lo torq valve on the rig floor. Disconnect the surface flowline between the lo torq valve and the choke manifold.

If formation water has been produced, pump seawater up to the rigfloor via the injection pumps and injection lines and connect the injection line to the flowline at the disconnect point. If oil has been produced diesel should be pumped up to the rigfloor instead of seawater.

Pressure test the injection line against the lo torq valve and the flowline valve to 7500 psi.

A backup for the injection pump and the charge pump has been provided to reduce any delay that may occur due to equipment failure.

A flowmeter will be installed on the high pressure injection line. The flowmeter should be calibrated prior to the injection test.

6. Running the DST String

6.1 Running the Downhole Tools

6.1.1 Pick up the tailpipe, inserting the Halliburton and Flopetrol gauges, as per Figure 2.

6.1.2 Pick up the remaining Halliburton test tools. Fill string above APR-N tester valve with 10 bbl of highly viscous gel to prevent solids settling out on tools. Pressure test to 5000 psi on top of tools.

6.1.3 Run the drill collars filling with water cushion every 2 or 3 stands.

6.1.4 Pick up the Halliburton slip joints, and the first stand of 3 1/2" or 5" drill pipe. Pressure test internally to 5000 psi.

6.2 Running the Major Drillpipe String

6.2.1 Run the 3 1/2" 13.3 $lb.ft^{-1}$ (3 1/2" IF) grade E drill pipe to top of 7" liner. Run the 5" 19.5 $lb.ft^{-1}$ (4 1/2" IF) grade E drill pipe to 1500 mBRT and 5" 19.5 lb.ft^{-1} (4 1/2" IF) grade S135 to surface.

<u>ENSURE THAT THE BACK UP TONG IS TIGHT BEFORE MAKING UP EACH CONNECTION TO AVOID ANY POSSIBILITY OF ACCIDENTALLY OPENING RTTS REVERSING SUB.</u>

6.2.2 Run the drillpipe filling every stand with water cushion. Internally pressure test the string after running approximately half the 5" drill pipe to 6000 psi.

6.2.3 Space out the string so that with the packer 15-20m above the top perforation, (and at least 2m from a casing collar) 2 1/2 slip joints will be open.

6.2.4 To prevent any damage to the pressure gauges:

i) The test string should be run slowly.

ii) The string should be set in the slip carefully to prevent any jarring of the drill pipe.

iii) Care should be taken when approaching the top of the liner to avoid any jarring of the string.

6.3 <u>Running the SSTT and Flowhead</u>

6.3.1 Pick up the Flopetrol EZ tree. Internally pressure test the string to 7500 psi above the SSTT. The SSTT should be run with the valves in the open position.

6.3.2 Continue running the remaining drill pipe as in Section 6.2 taking care not to damage the Flopetrol EZ tree control hoses. Tape control hoses to drill pipe.

6.3.3 Space out the drill pipe above the SSTT so that the flowhead sidearms will be approximately 4m above the rigfloor. The flowhead should have the chicksans made up to it on the active and non-active sidearms. Pick up the Flopetrol flowhead and make up to the string.

6.4 Landing the String

6.4.1 Set the packer under the direction of the Halliburton tool operator. Space out the string so that with the packer set and subsea test tree landed 2 1/2 slip joints will be open. Maintain tension with the compensator to support the weight of the flowhead and drill pipe above the SSTT.

6.4.2 Connect up the flow and kill line chicksans from the Flopetrol flowhead. Pressure test the string, flow and kill lines against the choke manifold inlet valves to 7500 psi for 15 minutes. With the master valve closed, pressure test kill line and flowline valves, up to the choke manifold inlet valves to 7500 psi, the choke manifold outlet valves to 3000 psi and the fixed rig DST line to 3000 psi.

6.4.3 Close the middle 3 1/2" pipe rams on SSTT slick joint.

6.5 Operation of the Downhole Test Tools

6.5.1 Flopetrol Subsea Test Tree contains one ball valve and one flapper valve. The ball valve can be opened by applying pressure down the control hose, and fails to the closed position ie. if the control line pressure is bled off at surface (or the control line is accidentally damaged, releasing the pressure) the valve closes. In the event of bad weather the tree can be unlatched above the valves and the string above the sea floor recovered. The shear rams can be closed above the disconnect point.

6.5.2. Halliburton APR-N Tester Valve can be opened by applying approximately 1500 psi annulus pressure. The valve will close again if annulus pressure is released, and can be cycled repeatedly during a test.

6.5.3 Halliburton APR-M Safety/Reversing Valve will be run with one ball valve. The valve is normally open; when the annulus pressure is increased to around 2500 psi the ball valve closes and reverse circulating ports open. Once closed, the valve cannot be reopened and the string contents must be reversed out. For this reason it is <u>essential</u> that any increase in annulus pressure during the flow period is bled off.

6.5.4 <u>Halliburton RTTS Circulating Sub</u> has been included in the test string as a backup reversing device, to allow the contents of the test string to be reversed out if annulus pressure is lost (eg if a leak develops in the casing or liner overlap). The tool has a J-slot configuration and can be operated by picking up the string and applying right hand rotation. (Approximately 4 to 5 turns may be required at surface).

6.6 Annulus Pressure System

6.6.1 The rig mud pumps will be used during testing to pressure the annulus through the choke line, to activate the Halliburton test tools.

6.6.2 As indicated in Section 6.5, it is important that any increase in annulus pressure resulting from thermal effects during the flow period be bled off through the rig choke manifold as necessary.

6.6.3 An emergency bleed off line will be installed from the annulus pressure system to a point remote from the rig floor, to allow the annulus pressure to be vented to close the test tools if an accident renders the rig floor inaccessible.

7. Start Up Procedure

Testing may commence at the discretion of the BP Drilling Supervisor (see Operations Manual Part 9) once the string has been run and tested as outlined in Section 6 and the surface equipment hooked-up and tested as outlined in Sections 4 and 5.

7.1 Burners

7.1.1 Align valves to flow to leeward burner; open outboard valves on both burners, open air, water, oil and gas valves to leeward burner at rig test manifold, and close valves to windward burner.

7.1.2 Start compressed air, cooling sprays and light pilot on leeward burner.

7.2 Separator

7.2.1 Align valves to flow directly to gas line while unloading water cushion, bypassing separator and flowtank.

7.2.2 Align separator valves so that oil and water are directed to burner oil line once separation begins.

7.3 Choke Manifold

Align valves so that flow will be through adjustable choke. The adjustable choke should be initially closed.

7.4 Mud and Cement Pumps

Line up mud pumps to annulus to operate APR tools. Direct cement pump to non-active side of flowhead.

7.5 Flowhead

Close swab valve and non-active (kill) sidearm valve on flowhead. Open master valve and active (flow) sidearm valve.

7.6 Opening Well

7.6.1 There should be no requirement to reduce the underbalance differential pressure across the APR-N tester valve. However if this exercise is necessary, the procedure to pressure up the string will be as follows:

i) Close the inlet valve on choke manifold.
ii) Open non-active sidearm valve.
iii) Flopetrol EZ tree should be in the open position.
iv) Pressure up the string with cement pump.
v) Close non-active sidearm valve.

7.6.2 RECHECK ENTIRE SYSTEM STATUS PRIOR TO OPENING WELL, THEN:

i) Pressure up annulus to approximately 1500 psi using mud pumps to open APR-N tester valve.

ii) The Halliburton tool operator should monitor the annulus pressure continuously during the test and ensure it does not approach the APR-M activating pressure.

8. Flowing Procedures

8.1 Flowing back Water Cushion

Slowly open adjustable choke on choke manifold to 32/64". Monitor pressures upstream and downstream of choke manifold as water cushion flows overboard.

8.2 Water Production Tests

Adjust the choke to achieve the desired stable flowrate and then transfer to the fixed choke. A wellhead flowing pressure (WHFP) of approximately 500 psi should be be used. The flow will be directed via the separator and then to the gauge tank. If this is not possible then flow will be directed to the gauge tank. The produced formation water will be dumped overboard.

8.3 Oil Production Tests

When oil cut water cushion or sump mud reaches the surface, ensure burner pilots are alight.

Once the surface flow is mainly oil, adjust the choke to achieve the desired stable flowrate and WHFP and transfer to fixed choke. The WHFP should be greater than 3000 psi to ensure that single phase oil sampling can be achieved at the wellhead.

Monitor closely the wellhead flowing pressures to ensure that plugging is not occurring either at the perforations or at the choke manifold.

8.4 Flowing via Separator

8.4.1 Once stabilsed flowing conditions have been achieved, the flow may be directed via the separator.

i) Open gas line valves.
ii) Open separator inlet valves.
iii) Close separator by-pass valve.

8.4.2 Continue flowing to achieve test objectives. The test objectives are outlined in the summary sheet at the beginning of this programme.

8.5 Measurements during the Production Period

8.5.1 Flowing Water Cushion

Flowrate. The flow will be directed towards the gauge tank, and the flowrate will be recorded at that point.

Pressure and Temperature. These measurements will be made at the data header every 10 minutes while the water cushion is flowing. The pressure will be measured using a dead weight tester.

8.5.2 Water Production Tests

Flowrates. If the water is flowed via the separator then the flowrates will be metered at the separator and recorded every 15 minutes. If the water is flowed directly to the gauge tank the water flowrate will be recorded there.

Pressures. The WHFP will be measured every 10 minutes using the dead weight tester until stable flowing conditions are achieved, after which the measurements will be made every 15 minutes. If the flow is directed via the separator then the separator pressure will also be recorded every 10 minutes until stable flowing conditions are achieved after which it will be recorded every 15 minutes.

Temperatures. The WHFT will be recorded at the data header at the same frequency as the WHFP. Similarly the separator temperature will be recorded at the same frequency as the separator pressure.

8.5.3 Oil Production Tests

Flowrate. The oil and gas flowrates will be metered at the separator. The measurements will be made and recorded every 10 minutes until stable flowing conditions are achieved after which it will be recorded every 15 minutes.

Pressure. The WHFP and separator pressure will be measured and recorded initially every 10 minutes, then every 15 minutes when stable flowing conditions are achieved.

Temperature. The WHFT and the separator temperature will be measured and recorded at the same frequency as the pressure.

BS&W. This will be measured every 10 minutes until it becomes negligible, after which it will be measured every 30 minutes.

Oil Shrinkage Factor. This will be measured at the same time as the flowrate measurement.

9. Injection Procedures

9.1 General Procedure

The following procedure will be used for each injection test:

i) Towards the end of the main PBU hookup the surface injection system to the disconnect point and pressure test the high pressure injection line to 7500 psi against the lo torq valve and the flowline valve as set out in Section 5.4.2. Ensure that surface lines are filled with seawater or diesel.

ii) Equalise pressure across the flowline valve, then open flowline valve.

iii) Approximately equalise pressure across the APR-N tester valve, and then open the APR-N.

iv) Commence injection.

9.2 Water Production/Water Injection Tests

Formation water will be produced and seawater will be injected. No significant problems are anticipated with this type of injection test.

9.3 Oil Production/Water Injection Tests

To avoid the formation of any crude oil-seawater emulsions a 100 bbl diesel slug will be pumped ahead of the seawater.

The diesel should be placed in the gauge tank prior to the injection test, and the low pressure lines up to the injection pump and the high pressure line up to the rig floor should be filled with diesel. Care should be taken to avoid any contamination of the water treatment plant by diesel.

9.4 Operation of the Water Treatment Plant

Ideally the treatment plant should be operated at a constant throughput, which should always be slightly higher than the injection rate. If the gauge tank is full the treated seawater should be dumped via the overboard line rather than reducing the troughput of the treatment plant.

Chemical treatment of the seawater feed will be required throughout the test to achieve the required seawater specification of 98% suspended solids removal down to a particle size of 2 microns. The chemical required are given in Section 5.2.1.

9.5 Pumping

9.5.1 General

Stable seawater injection will not be achieved until seawater has started entering the formation or in the case of the oil production tests when a certain volume of seawater has already entered the formation. Stable pumping conditions will be achieved by setting a steady pump rate and allowing the WHIP to stabilise. The pump rate should only be altered if the WHIP increases significantly above the maximum recommended WHIP to avoid fracturing, or the WHIP drops significantly. When increasing the injection rate care should be taken so as not to exceed the throughput of the seawater treatment plant, which in some instances could be the rate limiting step.

9.5.2 Water Production/Water Injection Tests

The maximum wellhead injection pressure WHIP to avoid fracturing will be approximately 3500 psi with a column of formation water and approximately 4000 psi with a column of seawater.

When pumping is commenced the maximum WHIP will be 3500 psi increasing to 4000 psi when seawater begins to enter the formation.

9.5.3 Oil Production/Water Injection Tests

When pumping is commenced the maximum WHIP will be 5500 psi with a crude oil/diesel column to surface, decreasing to 4000 psi when seawater begins to enter the formation.

9.5.4 Wellhead Fracture Pressures (WHFRP)

The following table summarises the approximate WHFRP:

Fluid in Testing String	Approx. WHFRP psi
Formation Water	4000
Seawater	4500
Oil/diesel	6000

9.6 Measurements During the Injection Period

Water Quality. The inlet and outlet seawater quality at the treatment plant will be measured and recorded every 15 minutes until stable conditions are achieved, after which the measurements will be made every 30 minutes. The water quality will be measured using a coulter counter and a turbidity meter.

Flowrate. The primary measurement of seawater injection rate will be the gauge tank. Initially, until stable injection condition are achieved the times and volumes should be recorded approximately every 10 minutes for every 5, 10 etc. barrels of seawater pumped. Once stable pumping conditions are achieved the times and volumes should be recorded approximately every 20 to 30 minutes for every 10, 20 etc. barrels of seawater pumped.

The secondary means of recording pumprate will be a Halliburton turbine flowmeter downstream of the injection pumps. This will give an instantaneous record of flowrate on a paper chart and flow volume totaliser on a digital recorder. A flow volume totaliser reading should be made every time a gauge tank reading is recorded.

Pressure. The WHIP will be recorded every 15 minutes using the dead weight tester, until stable pumping conditions are achieved, after which the measurements will be recorded every 30 minutes.

A continuous record of pressure will be made by a Halliburton pressure gauge recorder in the injection line downstream of the injection pumps.

As a contingency measure if a PFO is to be observed at surface then an RPG-3 will be hooked up to the data header to record a PFO.

Temperature. The wellhead temperature will be recorded every time a measuerment of pressure is made with the dead weight tester.

10. Shutdown Procedures

10.1 After 5 minute initial flow

After the short initial flow, close in the well for the initial build up period as follows:

i) Simultaneously close APR-N valve (by bleeding off annulus pressure) and choke manifold inlet valve.

ii) Leave flowhead open to be able to monitor wellhead closed-in pressure.

10.2 After the main flow period

Upon completion of the main flow period, shut in the well to observe a pressure build up:

i) Close the APR-N valve by bleeding off annulus pressure.

ii) As soon as the WHFP starts to drop, close the choke manifold inlet valve.

iii) Monitor WHCIP to ascertain the the APR-N tester valve has completely closed.

10.3 After the Injection period

Upon completion of the injection period, shut in the well to observe a pressure fall off:

i) Shut down the injection pump and close the APR-N valve immediately afterwards by bleeding off annulus pressure. Close the lo torq valve on the rig floor.

ii) Bleed off the pressure at the injection pump.

iii) Monitor the WHCIP to ascertain that the APR-N tester valve has been completely closed.

10.4 Reversing out String

10.4.1 The contents of the string will be reversed out after the pressure fall off period has been completed.

10.4.2 Disconnect the injection line at the rig floor at the disconnect point and hookup to the surface production system at the choke manifold.

10.4.3 Bypass separator:

i) open by-pass valve,
i) close separator gas line valve,
iii) close separator inlet valve.

10.4.4 Increase annulus pressure to 2500 psi to activate the APR-M safety/ reversing valve.

10.4.5 Maintaining annulus full of mud and annulus pressure below 1000 psi throughout circulation, flow contents of test string to surface. The seawater may be dumped overboard.

10.4.6 Condition mud to pits. If plugging occurs during reversing out, activate RTTS reversing valve.

11. Contingency Measures

11.1 Surface Leak

11.1.1 In the event of excessive pressure or a leak developing in the surface system, relief valve lifting etc during the flowtest, the well should immediately be closed in at the flowhead.

11.1.2 Immediately following shutdown, the APR-N tester valve should be closed by bleeding off annulus pressure either at the choke manifold or remote bleed off.

11.1.3 If the test may be safely continued after the plugging or leak has been rectified, repressure test the system as necessary.

11.1.4 CHECK OUT THE COMPLETE SYSTEM PRIOR TO RECOMMENCING TEST.

11.1.5 If all is correct, re-initiate the start-up procedure at Section 7.2.

11.1.6 If the test is to be terminated, rectify the plugging or leak to the extent necessary to allow the string contents to be reversed out by-passing the separator. Repressure test as necessary. Follow reversing-out procedures from Section 10.4.

11.2 Downhole Leak

11.2.1 A downhole leak will become apparent from an increase or decrease of annulus pressure.

11.2.2 If a minor leak is indicated, choke back the well at the choke manifold until the WHFP approaches shut in pressure. Close well in simultaneously downhole and at surface. If the leak is confirmed, the test should be terminated following the normal procedures from Section 10.4.

11.2.3 If a major leak occurs, close in the well immediately at surface. Maintain the annulus full and activate the APR-M safety/reversing valve as quickly as possible (this may already have occured).

11.2.4 Once the annulus is full, commence normal reversing out procedures from Section 10.4. Ensure that all mud in the drill pipe and annulus is fully conditioned by reversing and circulating prior to pulling the test tools. Care should be exercised when pulling the tools since the leak may have washed out the pipe body or a connection, thus weakening the string.

11.3 Hydrogen Sulphide

11.3.1 The presence of H_2S may be indicated in the mud or in the RFT samples prior to the test. During the test, samples should be taken and checked for H_2S using detector tubes immediately hydrocarbons reach surface and subsequently throughout the flow period.

11.3.2 If H_2S levels in excess of 20 ppm are detected, the BP Drilling Supervisor and Rig Manager should be informed.

11.3.3 Air breathing apparatus should be made available at the rig floor and separator area. Rig personnel should be directed to keep clear of areas downwind of the test equipment and pipework.

11.3.4 If H_2S is detected around the rig, the BP Drilling Supervisor and Rig Manager should be informed and the level checked immediately using detector tubes. If the presence of H_2S is confirmed the well should be closed in immediately at surface and any leaks in the system traced and remedied. Air breathing apparatus should be worn when checking H_2S levels around the rig, and locating leaks if H_2S levels in the produced gas exceed 100 ppm.

11.3.5 If the 20 ppm level of H_2S around the rig should persist, then the test should be terminated, and if necessary, the test fluids bullheaded back into the formation.

11.4 Deteriorating Weather

11.4.1 The test string will only be run once acceptable weather has been forecast for the expected duration of the test. Once the tools have been run, rapidly deteriorating weather may necessitate delay or termination of the test.

11.4.2 If the weather deteriorates while running the test string, the hang-off tool should be made up and, if necessary, the string hung off.

11.4.3 Should it prove necessary to unlatch the string at the SSTT during testing, every effort should be made to reverse out the contents of the string, following the procedures from Section 10.4. If time permits after reversing out the SSTT should be pulled and the hang-off tool run, enabling the blind rams to be closed above the string.

11.5 Means of Closing-In

In general, an emergency shutdown will follow procedures described above. Should circumstances dictate that other methods of closing in are necessary, the following alternatives exist;

11.5.1 Surface Valves

Manually close one of the surface valves.

11.5.2 Flopetrol Subsea Test Tree

Bleed off opening pressure from SSTT control hose.

11.5.3 Halliburton Test Tools

a) Bleed off annulus pressure at rig choke manifold or remote bleed-off.

b) APR-M Safety Valve. Increase annulus pressure to approximately 2500 psi (this will close safety valve, and open integral reverse circulating ports) reverse circulate string contents.

11.5.4 Bullheading

Bullhead down the string by pumping with the cement pump, after opening the manual non-active sidearm wing valve.

11.5.5 Lift string

a) RTTS Reversing Sub; lift the string about 15 ft to extend all slip joints above collars - rotate to right to open RTTS reversing sub: reverse circulate string contents.

b) Unseat Packer: lift string until all slip joints are extended, and unseat the packer, thereby dumping annulus mud into sump. Pump to annulus until annulus level stops falling. To reverse circulate, reset the packer and open the APR-M valve and reverse out the contents of the string.

12. Bottom Hole Sampling

12.1 Preparation of Equipment

Pressure test the flowhead with wireline BOP attached against the BOP, with slick rod in place, to 7500 psi. The flowhead should be run without the BOP.

12.2 Pressure Testing of Surface Equipment

12.2.1 Following PBU, close lubricator valve and make sure that any pressure above it is bled off through active sidearm. Close the flowline valve.

12.2.2 Change out bales for matched pair of wireline slings. Attach wireline BOP to flowhead with slick rod removed.

12.2.3 Open swab valve and kill line valve and pump water up to BOP from cement pump via kill line.

12.2.4 Put slick rod in place and pressure test against wireline BOP, lubricator valve and flowline valve to 7000 psi. Bleed off pressure, and remove slick rod.

12.2.5 Make up Schlumberger lubricator and grease injection head and run wireline through it.

12.2.6 Make up bottom hole samplers (holding them vertical in the mousehole) and pull the samplers into the grapple and hold them there. A clock setting of 4 hours should be made for the Flopetrol sampler.

12.2.7 Open swab valve (ensuring prior to opening that there is no pressure beneath). Pick up lubricator and grease injection head assembly with a rigfloor winch and run sampler into test string.

12.2.8 Make up connection between lubricator and wireline BOP, ensuring that there is sufficient slack on Schlumberger wireline to prevent sampler moving inside test lubricator.

12.2.9 Pressure test to 7000 psi via kill line against the flowline valve, grease injection head and the lubricator valve.

12.2.10 If all pressure tests are satisfactory, bleed off pressure, close non-active sidearm valve, open flowline valve and lubricator valve and RIH with samplers.

12.3 Sampling Procedure

12.3.1 When the samplers are on depth, open the flowline sidearm valve and close the kill line sidearm valve.

12.3.2 Line up the valves to flow the well while running in with the samplers.

12.3.3 RECHECK THE ENTIRE SYSTEM STATUS PRIOR TO RE-OPENING THE WELL.

12.3.4 Re-open the well at the APR-N tester valve by increasing annulus pressure to 1500 psig.

12.3.5 Commence flowing by slowly opening the adjustable choke. The well should be flowed through the adjustable side of the choke manifold at an appropriate flowrate.

12.3.6 When the samples have been taken close the well in at the APR-N tester valve by bleeding off annulus pressure.

12.3.7 Pull out of the hole with the samplers. When the samplers are at surface close the lubricator valve, bleed off the lubricator and recover the sampling tools.

12.3.8 Pick up the second set of bottom hole samplers.

12.3.9 Remake connection between the wireline lubricator and BOP.

12.3.10 Close the flowline sidearm valve and open the kill line sidearm valve. Pressure test the connection against the lubricator valve and grease injection head to 7000 psi.

12.3.11 If satisfactory, open the lubricator valve and run the samplers.

12.3.12 Close the kill line sidearm valve and make the sampling run as before from Section 12.3.1.

12.3.13 Following the retrieval of the samplers the well should be reversed out in accordance with the procedures laid down in Section 10.4.

13. Sampling Requirement

13.1 Introduction

Table 1 outlines the total sampling requirement, on the planned series of tests, that will satisfy the requirements of the subsequent studies to be undertaken.

13.2 Water Production tests

Water Cushion Samples

Water cushion samples will be taken at the data header every 20 or 30 barrels until the sump mud reaches the surface. The samples will be taken in 10 litre plastic containers.

Data Header Samplers - Formation Water

When formation water is flowing at surface sampling will continue at one sample every 30 minutes, at the data header. The WHFT is anticipated to be as high as 200^{o}F, and the water samples will be initially taken in stainless steel buckets and then stored in plastic 10 litre containers when cool.

Separator/Gauge Tank Samples - Formation Water

Samples of formation water will also be taken at the separator or at the gauge tank every 30 minutes while the flow period lasts.

Gauge Tank Samples

At the end of the flow periods in each DST the gauge tank will be full of formation water. This will be used to provide 3000 litres (fifty 60 litre drums) of formation water ie. 6000 litre in total.

13.3 Oil Production Test

Water Cushion Samples

As above, water cushion samples will be taken at the data header until the sump mud reaches the surface.

Atmospheric Oil Samples

The following samples will be taken during the flow period:

i) At the data header: a 1 litre sample every 20 minutes.

ii) At the separator: a 1 litre sample every 20 minutes.

iii) At the stock tank: at the end of the flow period, twenty 3 litre cans, three 10 litre cans and forty five 45 gallon drums. Sufficient oil will be left in the gauge tank to satisfy these requirements.

Pressurised Surface Samples

Four sets of oil and gas recombination samples should be taken at the separator. The oil should be taken in 600 ml bottles and the gas in 20 litre bottles.

In addition four 20 litre gas samples will be taken at the separator in preconditioned bottles. The bottles will be shipped to the wellsite with nitrogen containing 200 ppm H_2S.

Two 20 litre samples of separator oil will be taken by displacement with water.

Single Phase Oil Samples

The WHFP will be greater than the bubble point of Ula crude oil, and twelve single phase 600 ml oil samples will be taken at the data header.

Table 7.1: Sampling Requirement for Well 7/12-6 Testing

Sample required by	Type of sample required	Total volume of sample required	Number and volume of containers	Study for which sample required
1. BP Pet Dev Norway	Single phase well head oil sample	7.2 litre	twelve 600 ml bottles	PVT analysis and Special core analysis.
2. "	Sets of oil and gas samples from the separator	2.4 litre oil 80 litre gas	four 600 ml bottles of oil and four 20 litre bottles of gas	PVT analysis (backup)
3. "	Stock tank oil	1000 litre	five 45 gallon drums	spares
4. "	Separator gas	80 litre	four 20 litre conditioned bottles	gas analysis
5. "	Stock tank formation water	500 litre	five 100 litre polythene drums	water analysis etc.
6. BP Research Centre	Separator oil	40 litre	two 20 litre bottles	wax studies (P109)
7. "	Stock tank oil	60 litre	none - taken from item 10	"
8. "	Stock tank oil	6000 litre	thirty 45 gallon drums	WOSP studies (P978)
9. "	Stock tank formation water	4000 litre	forty 100 litre polythene drums	"
10. "	Stock tank oil	2000 litre	ten 45 gallon drums	emulsion studies (P173)
11. "	Stock tank formation water	10 litres	none - to be taken from item 9	scaling tests (P172)
12. Phillips Petroleum	not yet known	-	-	-
13. IKU, Trondheim (ref 596.01)	Stock tank oil	-	none to be taken from item 3	Decomposition data for oil

14. Code of Practice for the Control of Mercury during Hydrocarbon Sampling

14.1. Objectives

The aim of the Code of Practice is to protect the health of all rig personnel, and particularly well testing personnel, by controlling their exposure to mercury during welltest sampling and sample transfer operations, and monitoring the absorption of mercury by the individual so that he may be removed from work which exposes him to mercury before his health has been affected.

14.2. Operations Having A High Risk Of Mercury Exposure

The Code applies to all work which exposes persons to mercury in any form such that it may be ingested, inhaled or otherwise absorbed. The rigsite operations considered to be high risk are;

1) Transfer of samples from bottom hole samplers.

2) Transfer of samples from the test separator.

3) General mercury handling operations.

14.3. Code Of Practice

1. The Norwegian Petroleum Directorate (Seksjon for Arbeidervern og Arbeids Miljø) will be informed of the commencement and termination of any well test operations which involves the use of mercury for hydrocarbon sampling.

2. Sampling and sample transfer operations will be undertaken by four members of the service company test team throughout the test operations. This individual will provide a certificate proving that he has been medically examined not more than six months previously, and the mercury content within his body does not exceed the required limits.

3. All service company personnel will have been given adequate information and training in the handling of mercury. Service company personnel will use the equipment and facilities provided by their own company and the Operator, and will co-operate at all times with the Operator in restricting contamination of any areas by mercury.

4. The sampling and transfer operations will be supervised by the BP Wellsite Petroleum Engineer, who will be fully conversant with the procedures involved, and will carry the BP Safety Kit (see Attachment) for use in dealing with large mercury spills. He will have the authority to terminate any operation involving the use of mercury in the event of unsafe practice.

5. Shipping containers holding sample transfer equipment and mercury will be correctly stowed and will only be accessible by authorised service company and Operator personnel.

6. Protective clothing, and clothing storage should be provided by the service company along with suitable disposal bags for the clothing following the operation. Changing facilities will be provided by the Operator. Emergency protective clothing will be provided by the Operator.

7. Air monitoring will be carried out on a regular basis by service company and Operator personnel to check that the mercury in air standard is not exceeded.

8. Food and drink are not to be consumed in any place liable to be contaminated by mercury.

9. Personal hygiene will be maintained, and the use will be made of the washing facilities provided.

10. The transfer of samples will be undertaken using an adequate, purpose-built sample transfer bench.

11. All unauthorised persons will be kept clear of sampling or sample transfer operations at all times.

12. Sufficient time will be allowed for the rigging-up, and dismantling of, equipment using or containing mercury.

13. Regular biological testing will be carried out to detect any absorption of mercury before clinical effects become evident.

Urine samples will be taken from the person designated to undertake sample transfer operations at the following times;

i) When the person arrives on board the rig.

ii) Each morning throughout the test period.

iii) A final test before departure from the installation.

14. Following the test operations a report will be sent to the NPD on the service company report form giving the following details;

i) Name of involved personnel, address and date of birth.

ii) Name of installation, block and well number.

iii) Description of the work which has involved the use of mercury, duration, reports of spillage, risk of exposure etc.

iv) Name of appointed BP representative.

v) Urine specimen check list.

Urine speciments, check list, and a copy of the service company report form should be forwarded to;

Yrkeshygienisk Institutt Lab
P.O. Box 8149
Oslo 1

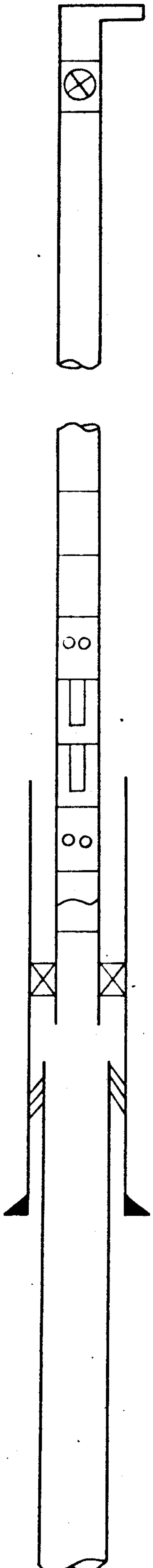
Contents of BP Safety Kit for Mercury Spillage

This kit will be held by the BP representative responsible for witnessing sampling and sample transfer operations.

The safety kit will contain the following equipment items;

i)	Dust mask for mercury	- 12
ii)	Gas mask	- 1
iii)	Gas mask filters	- 3
iv)	Draeger Multi Gas Detector Pump CH304	- 1
v)	H_2S detector tubes 50-600 ppm CH29801	- 20
vi)	Mercury vapour detector tubes CH23101	- 20
vii)	Rubber gloves (prs)	- 3
viii)	Protective coveralls	- 3
ix)	Urine sample bottles	- 30
x)	Sheet containing details of mercury toxicity	- 1
xi)	BP Mercury Exposure Control Form	- 10 copies
xii)	Copy of Code of Practice for Control of Mercury during Hydrocarbon Sampling	- 1

Figure 1 : 7"/9 5/8" PRESSURE TESTING / DRY TESTING STRING



CIRCULATING HEAD

LO TORQ VALVE

5" DRILL PIPE

DRILL COLLARS TO PROVIDE APPROX
25000 lb TO SET PACKER

APR - A REVERSE CIRCULATING VALVE

AP BT PRESSURE GAUGE 15000 PSI GAUGE

AP BT PRESSURE GAUGE 15000 PSI GAUGE

RTTS CIRCULATING VALVE (BYPASS)

SAFETY JOINT

Drg. Nr. 5326

Figure 2 : DOWNHOLE TESTING STRING

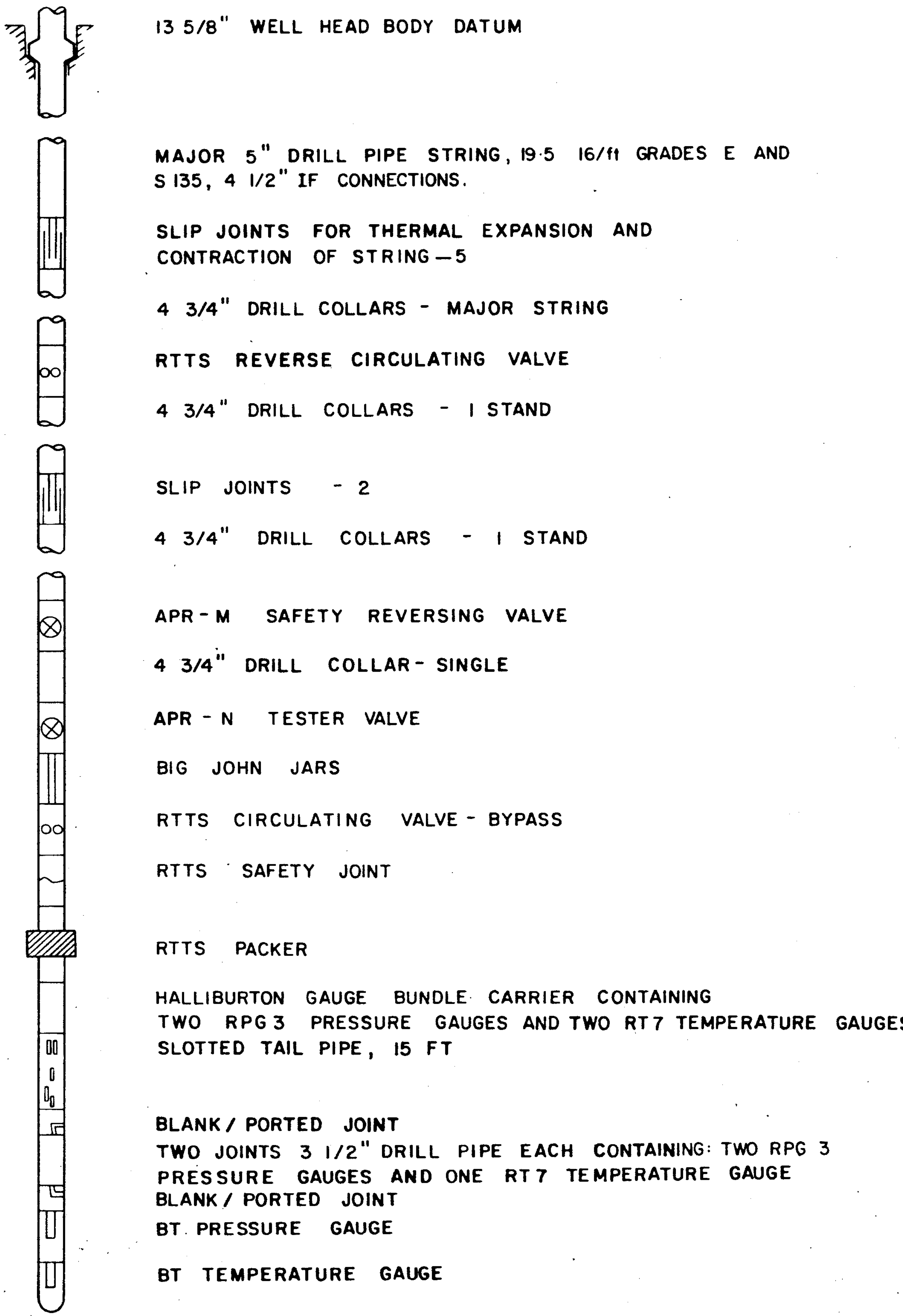
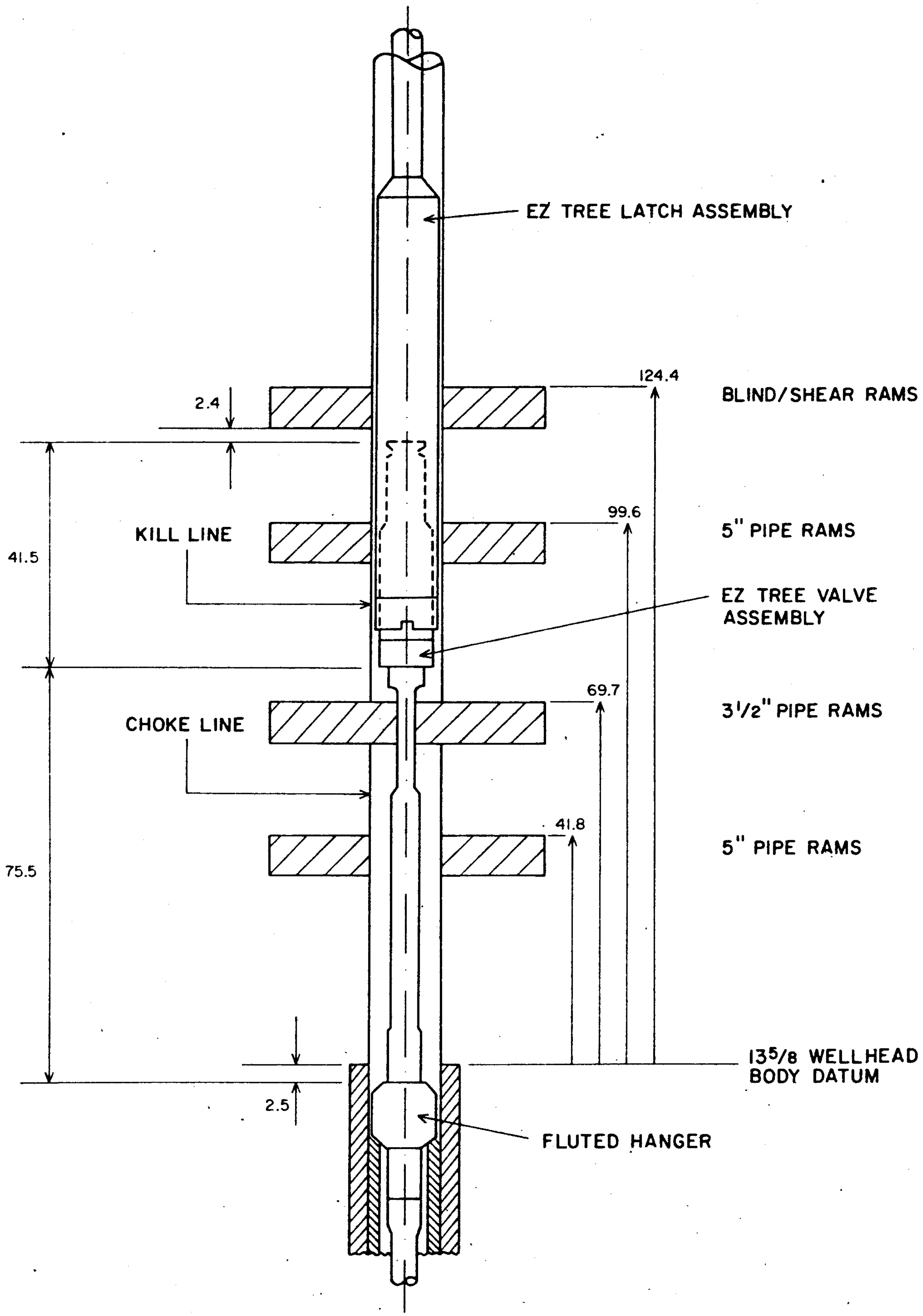


FIGURE 3: SPACE-OUT OF FLOPETROL SUB SEA TEST TREE (EZ TREE) IN SEDCO 707 10M BOP STACK

(all dimensions in inches.)



Drg no 5333

SURFACE PRODUCTION TESTING HOOK UP

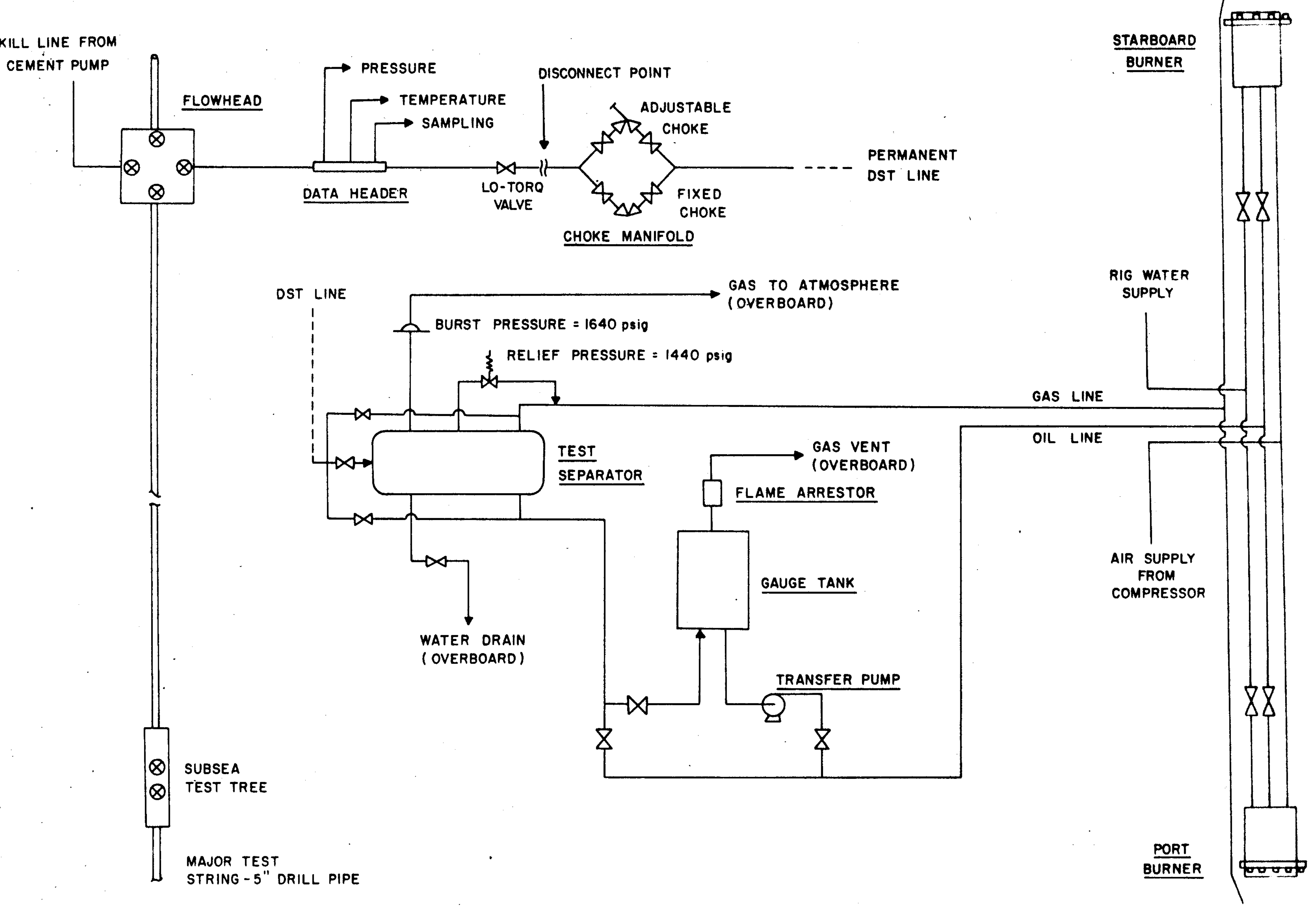


FIGURE 4

SURFACE INJECTION TESTING HOOK UP

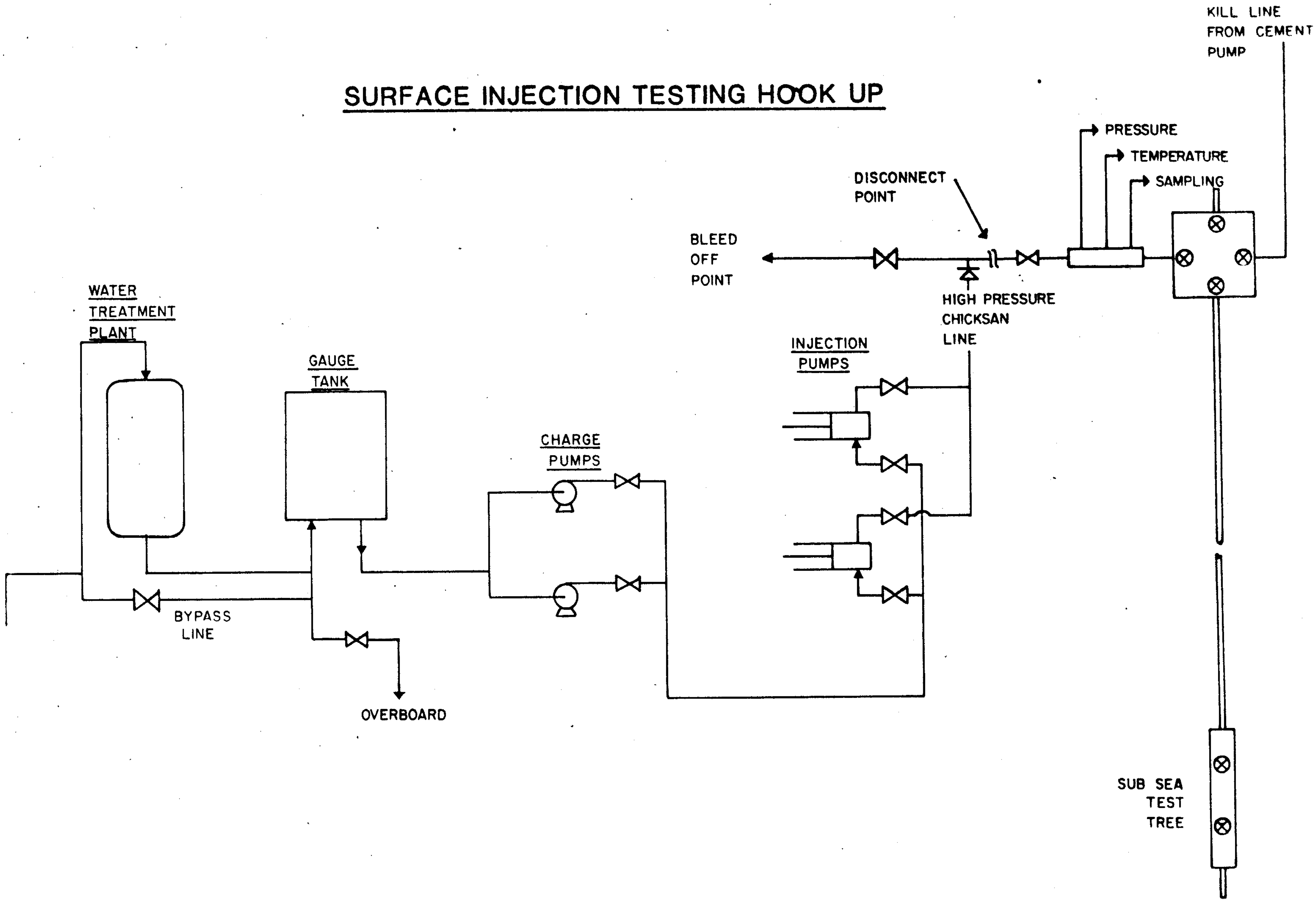


FIG. 5

Drw no 5038