A CASE STUDY ON WELL COMPLETION AND TESTING IN HIGH PRESSURE HIGH TEMPERATURE WELL

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ABSTRACT

Search for new hydrocarbon resources has led to discovery of several High Pressure High Temperature (HPHT) fields in. Drilling, completion, testing and production in HPHT environment are technically complex operations with very high risk and exhibits major HSE issue and are further aggravated with the presence of H_2S and CO_2. The problem is more challenging in off-shore environments. The completion of HPHT wells is a further challenging task with reference to equipment selection, especially when significant pipe movement, compression loads and tubing stresses are expected. The effect of HPHT conditions on packers, elastomers, sliding sleeves, injection subs, mechanical & fluid friction and reliability of electronics plays an important role in gathering of down hole data, formation evaluation, completion & testing of such wells. Testing phase requires careful considerations of several key issues such as flow assurance, fluid contaminants- H_2S, CO_2, sand, hydrate, sealing requirements viz: equipment component sealing, well bore sealing, sealing of plugs, and stresses in tubular. In HPHT environment it is essential to evaluate effect of pressure-temperature-depth on reliability of safety valves, sliding sleeves, operation of slick line, lubricator packing, coil tubing, remote control, pressure, temperature and flow measurement tools during prolonged exposure. The well control issues include hydraulic calculations like Equivalent Circulating Density, kick tolerances like swabbed, drilled & pressured fault kicks, gas migration, gas diffusion, kill methods, surface flow parameters, mud gas separator, comparing kick behavior in brine water v/s oil based mud. Handling HPHT fluid in surface equipment is also a major challenge with reference to corrosion, erosion, sand, wax and hydrate formation. Further it is also important to evaluate impact of these ingredients on measuring instruments. There are number of HPHT wells drilled in ONGC both onshore and offshore. These have been tested and some wells have produced. There are some cases where testing has not been successful. Completions, testing, operational issues all over the world and case study learnt in ONGC are briefly.

KEY WORDS: HPHT, pressure, temperature , packers, oil based mud, flow, circulation

GENERAL WELL DATA

Well name: HPHT#

OBJECTIVE: Sands with in GP and RP Formations

Target Depth: 5450m

Drilled Depth: 5462m

Logger's Depth: 5459.6m

CASING DETAILS

Sl No	CASING/ LINER SIZE	20"	16" Liner	13 3/8"	9 5/8"	7" Liner	7" TIE BACK
1	Depth / Dia of open hole	910m / 26"	1783m / 20"	2605m (Enlarged to 2523m) / 17 ½"	3955 / 12¼"	5462m / 8½"	Tie back of 7" liner
2	Casing shoe depth	905m	1778m H/TOP: 842m	2503m	3929.40m	5456.71m H/TOP: 3792.26m	7" H/TOP: 3792.01m
3	Number of casing joints	70	76	213	315	132	303

TEMPERATURE GRADIENT

Maximum-recorded log head temperatures and the calculated static bottom hole temperatures from extrapolated log head temperature of different runs (wherever available) were used for temperature gradient plot. The surface temperature has been taken as 30°C. Maximum recorded temperature at 5459m was 235°C (after extrapolation).

Depth	Temperature recorded °C	Remarks
1779m	60.28 oC	Extrapolated Temperature
2593m	97.7oC	Extrapolated Temperature
3944m	143.33 o C	Log head temperature
5116.6mm	225.6º C	Log head temperature during production testing (dummy run)
5459.6m	235º C	Extrapolated Temperature

Depth interval(m)	Temperature gradient °C/100m
0-1779	1.76
1779-2593	4.44
2593-3944	3.40
3944-5459	6.05
OVER ALL GRADIENT from surface to 5459.6m	**3.75**

PRODUCTION TESTING

HERMETICAL TESTING

After cementation of 7” casing tie back, casing integrity was tested up to 4500psi surface pressure in 1.96 sp.gr mud. BOP was nippled down. X-mass tree was installed and its flanges were pressure tested up to 12000psi. Well volume of mud was changed over to water and negative test was carried out and found O.K. 7” casing was hermetically tested up to 10,000 psi pressure in stages and found hermetically sealed. Plugs, orifice and cement were cleared down to 3787m and cement top was tagged at 5410m. Casing integrity and tie back hanger portion was tested up to 3500psiand found holding. 7” casing was scrapped down to 5410m (cement top). Water cushion was placed from 5410m to 3600m both in the string and in the annulus. Negative test was carried out and found ok. Bottom portion of the 7”casing was hermetically tested up to 5500psi in stages and found hermetically sealed.

Sl.No:	Interval (m)	Short Density (SPF)	Formation	Remarks
1	5365-5360 5356-5349 5328-5321 5316-5309 5291-5286	6 spf	Sand stone	. Tested with TCP-DST & while retesting with TCP-DST, tubing with assembly got stuck. Later tested conventionally
2	5245-5240 5231-5226 5219-5214 5209-5207 5192-5186 5181-5176	6 SPF -		With water based mud
3	5103-5094 5112-5108	6 SPF-		With water based mud
4	4845.5-4843 4224-4219 3578-3574 3566-3568	-	shale	Not tested

Water column below 3600m was displaced with 1.96 sp. gr mud. M/S Schlumberger recorded CBL-VDL-GR-CCL logs from 5411-4100m & 3800-3600m under "0" psi. While lowering tool for pressure pass recording held up was observed at 5308m. So CBL-VDL-GR- CCL logs under 700 psi pressure were recorded from 5303-4100mand from 3800-3600m. Maximum log head temperature recorded was 4220 F at 5417m. Well was conditioned with thorough circulation. While lowering CBL-VDL tool for recording pressure pass below 5303m by Ms. Schlumberger, held up was observed at 5230m. While lowering VSP tool by Ms. Schlumberger, held up was observed at 2950m. Well was conditioned and scrapped down to 5410m. Ms. Schlumberger recorded CBLVDL-GR- CCL logs under 700 psi pressures were recorded from 5300-4000m as the tool got held up at 5300m. Zero offset VSP was recorded from 5410m to 3300m with high temperature tool and from 3000m to 45.52m with normal temperature tool at 15.24m interval by Ms. Schlumberger. Well was conditioned and fresh mud was placed from 5000 to bottom. M/S Schlumberger recorded CBL-VDL-GR- CCL logs from 5412m to 4700m under 700psi pressure. Well was scrapped down to bottom. Well volume of mud was changed over to 1.81 sp gr clear fluids (Calcium Bromide Brine.)

TESTING DETAILS OF OBJECT - I:

Interval: 5365-5360m, 5356-5349m, 5328-5321m 5316-5309m & 5291-5286m

II) Quality of cement: Poor

III) Type of Perforation**:** TCP (Deep penetration charges) using hydraulic Firing System.

IV) Perforation medium: 1.81 sp. Gr. Calcium Bromide brine

V) TCP-DST assembly Bottom: 5365.28m

VI) Shot density: 6 SPF

VII) Salinity of mud filtrates: SOBM used. 28000 ppm as Cl

VIII) Result: Flowed gas at FTHP of 400 to 800 psi and ceased due to communication from annulus.

PACKER SETTING AND PERFORATION OF OBJECT-I:

String consisting of 3 ½" TSH 3SB tubing's and DST assembly (Gauge carrier, TST tool, circulating valve) were lowered in singles rabbi ting each joint down to 5310m. Flexing operation was carried out in stages up to 12500 psi. The TST valve was unlocked by pressurizing annulus up to 3500psi. String volume was reversed out with 1.81sp. gr. Calcium Bromide brine. Tubing with DST assembly was pulled out. 7" FB-3permanent packer (Baker made) & Halliburton gauge carrier was lowered with 3 ½" drill pipe by rabbi ting each stand to 2900m. GR-CCL logs were recorded from 2900m to1700m for depth correlation. 7" packer was further lowered down to 5246m and GR-CCL logs were recorded from 4260m to 3200m for depth correlation. Packer was spaced out as per log correlation. Packer was set at 5246m and was tested at 5000psi annulus Pressure. Packer setting tool was released and the same was pulled out. TCP gun with 2 7/8 tubing, LTSA and Halliburton's" DST assembly were made up and the assembly was tested up to 12500psi. RD TST valve#1 was ruptured by applying 1200psi annulus pressure and the same was confirmed by direct circulation of 5bbl brine through tubing. Teflon seal of RD TST valve#2 was retrieved. TCP-DST-LTSA was lowered with 3½" TSH- 3SB tubing to 2670m. 20bbls of 1.81 sp gr brine was reverse circulated through RD-TST valve#2 and the valve was tested up to 12500psi. GR-CCL logs were recorded up to 2495m for depth correlation by ONGC production logging unit. TCP-DST-LTSA was further lowered down by rabbi ting each stand to 5332m. 10bbls of 1.81 sp gr brine was reverse circulated. String was tested against RD-TST valve up to 12500 psi pressure. GR-CCL logs were recorded from 4260m to 3110m for depth correlation by ONGC production logging unit. String was spaced out as per log correlated depth. 10bbls of brine was reverse circulated through annulus. String was tested against RD-TST valve#2 up to 12500psi. RD TST valve# 2 was ruptured by applying 2200psipressure through annulus and the same was confirmed by direct circulation through. string. String was spaced out w.r.t packer NO Go. Tubing hanger was made up and the same was landed by keeping TCP guns against object-I intervals. LTSA was tested by applying 1000psi annulus pressure. BOP stack was nippled down. X-mass tree was installed and its flanges were tested up to 12000psi pressure. Surface lines were tested up stream @ 10000psi and downstream @ 1000psi. Select tester valve (STV) was closed by applying

2800psi annulus pressure and the pressure was bled off to zero. Omni valve was brought from well test mode to circulating mode (i.e. communication between annulus & tubing) by applying 1500psi annulus pressure six times and releasing it. 1.35 specific gravity calcium chloride brine was placed inside the tubing. Omni valve was again brought to well test mode from circulating mode by applying 1500psi annulus pressure six times and releasing it (i.e. no Communication between annulus & tubing). Annulus was pressurized by 1500psipressure and select test valve was brought to open position.

Object-I was perforated hydraulically by applying 9000 psi pressure through tubing and the pressure was bled off to 2500 psi. Later pressure came down to zero and the firing indication was felt at surface. After perforation, pressure increased to 3700 psi.Annulus pressure was maintained around 1500 psi.

TESTING DETAILS OF OBJECT-I:

Well was opened through tubing through 5 mm choke slowly tubing pressure became zero. Well knocked out brine @ 720 lts/ hr at „0‟ psi and later brine along with gas in surges. Till hrs, annulus pressure was constant and later annulus pressure was found to be decreasing. Around 7 m3 calcium bromide brine was pumped in to annulus to maintain 1500 psi annulus pressure. Gradually annulus was taking more brine to maintain the pressure (i.e. 200lts/min) and tubing pressure also showed corresponding increase. Communication between annulus and tubing was suspected, pumping into annulus was stopped and annulus pressure was bled off to "0"psi. Tubing pressure was increased to 1600psi. Well initially knocked out only brine and later only gas was flowed and pressure became zero. Well showed no surface activity and FTHP/CHP was "0"psi.

Subduing of well: Tubing was topped up with 2m3 calcium chloride brine of 1.35 specific gravity and was pressurized to 2500psi. Annulus was filled with 7.5m3 calcium bromide brine of1.81 specific gravity. Omni valve was brought to circulation mode after pressurizing the annulus several times and releasing the pressure. Well volume of 1.81 to 1.79 sp. gr. brine was pumped in to annulus in stages to subdue the well. Returns from tubing were found to be containing feeble gas and the same was flared. Well was kept open through tubing and found feeble gas flow with FTHP of "0" psi. Well was kept open both through tubing and annulus. No surface activity was seen initially, but feeble gas flow was observed from annulus later. Well was subdued with SOBM of 1.96 specific gravity and was reverse circulated till mud weight in & out was 1.96. Pressure was applied in to annulus to bring Omni valve from circulatory mode to well test mode, but was not successful. Pressure was applied through annulus (up to 3500psi) and ruptured RD safety circulation valve & RD circulation valve discs. Well was reverse circulated with 1.96 specific gravity SOBM and found to be stable during observation. X-mass tree was nippled down and BOP stack was installed. String was stabbed out from the packer. Tubing hanger, 2 pup joints & one single were pulled out. After circulation, continuous back flow was observed from the string. Well was circulated again and continuous bubbling was observed at well mouth. Mud wt. in/out was 1.94/1.89. Flow was diverted through gas buster and intermittent gas flow was observed during circulation and the gas was flared. After direct circulation, mud returns without any gas indications from tubing were observed. Mud wt. in/out was 1.96/1.95.

Well was reverse circulated for one cycle and Mud wt. in/out was 1.96/1.96 and viscosity in/out was 90/90. Well was observed and found to be stable. BOP stack was pressure tested with Schlumberger cementing unit. 3 ½ tubing along with DST assembly, LTSA and TCP guns were pulled out. While pulling out, DST assembly & TCP guns were broke off and laid down.

OBSERVATIONS AFTER PULL OUT OF DST- LTSA AND TCP ASSEMBLY:

LTSA seals were found to be damaged. RD safety circulation valve and Omni valves were found to be in open condition. STV was in closed condition and RD circulation valve (below STV), which was considered to be open, but was found to be in closed condition. All the guns with the charges were found to be fired. It is assumed that damage to LTSA seals resulted in communication between annulus and tubing during the well cleaning stage. 3 ½" drill pipe along with 10 singles of 2 ⅞" EUE tubing as tail pipe was lowered and well (including below packer) was circulated with 1.96 SOBM.100m Calcium Bromide brine of 1.82 sp. gr. was placed below the packer at bottom. 6 stands of 3 ½ drill pipe was pulled out above the packer and observed gas flow through annulus. Well was circulated with 1.96 sp. gr. SOBM till the well became stable. The string was pulled out of hole.

RE-TESTING DETAILS OF OBJECT-I:

The locator tool seal assembly (LTSA) was tested at surface up to 10000 psi. Mule shoe and LTSA and DST tools along with 3 ½ " TSH-3SB tubing were run in by rabbiting each stand down to 2600m. The string was reversed circulated with 40 bbl. Of SOBM and was tested up to 12500psi. The string was further lowered down to 5235m.Prior to stab in LTSA in to packer, attempted to reverse out 40 bbls of SOBM. But during reverse circulation at this depth, returns were observed initially and stopped subsequently. Line between tubing and choke manifold was choked and suddenly that hose got burst with severe gushing of mud and gas from the tubing. The blind ram was operated and the string was sheared) for safety and to secure the well.

Well was kept under observation. SICP gradually rose to 350psi and was bled off to 100 psi. Again SICP increased up to 250 psi in 2hrs and the pressure was bled off. Well was observed and found to be stable. BOP was opened. String was lifted and found to be sheared. 5 ¾" overshot with 3 ½" basket grapple and mill control packer was lowered with3 ½" drill pipe and fish was engaged, but found to be stuck. During working on string to release the stuck up, suddenly, activity was observed in annulus and communication between tubing and annulus was suspected. SIDP and SICP increased to 3300 psi. Pressure was bled off several times and mud was filled. Omni valve was brought in to circulatory mode. Well was circulated, but, circulation was suspected from overshot and above.

String was worked on to disengage the overshot from the fish top at 42m, but couldn't be disengaged. String was backed off mechanically, and 53 ton weight gain was observed and well became active. While pumping 2 m3 kill mud (2.10 sp. gr.), pressure was shoot up. During bleeding off pressure, string weight was dropped from 53 tons to 32 tons. 3 ½" TSH-3SB tubing was lowered and fish top was tagged at 41.23m. String was pulled out and total 47 stands of 3 ½ "tubing were recovered. Fish couldn't be engaged with 5 ¾" overshot with 4 ⅛" basket grapple and later with Fabricated guide with inward fins on left hand male Tap. Modified Male TAP was Lowered and, fish was engaged and 35 tons weight gain was observed. 47 stands of 3 ½” drill pipe were pulled out. Fishing tool along with one single of 3 ½” tubing was pulled out and found fish engaged to the fishing tool. Several attempts were made to establish direct and reverse circulation through tubing (i.e. fish), but was unsuccessful. Held up was cleared with coil tubing from 96m to 111m. 11 singles of 3½” tubing were pulled out and in the 12th single, settled barite powder plug found. Tubing could be cleared from 4m to 193m with coil tubing and the cleared tubing was pulled out. Tubing was further cleared down by coil tubing down to 100m and communication between tubing and annulus was observed. 3 ½ tubing was pulled out and 2029m fish was recovered. Total fish recovered was 3681m and fish remaining in the well was 1543m. Several fishing attempts were made with TAP, Die collar, Left hand caliber, fabricated fishing tools and 3½” tubing with RD TST Valve No.2, RD Safety Circulating Valve, Two Drain Valves, Omni Circulating Valve & STV, RD circulating valve, two numbers of gauge carriers, and RDTST valve and 0.525m length of one X-over were recovered. Fish including one X-over, NOGO, NOGO locator, packer seal assembly, one tubing joint and mule shoe are still left in the well. Fish was milled down with 5 ¾” peripheral milling tool from 5234.80m to 5235.60m. Fish was engaged with 5 ⅞” left hand die collar and worked on fish to release the packer, but was not successful. String was mechanically backed off and after pull out, 22cm tubing coupling was recovered from die collar. 62cm+5cm+5cm+2cm fish was milled with 5 ⅞” Flat Mill and 5 ⅞” Peripheral Milling tools. Further 5m were cleared from fish top with 3 ½” TSH tubing single with fabricated entry guide.

GR-CCL log was recorded by Schlumberger from 5272.70m to 5150m and Packer top was found at 5252.70m i.e. the packer moved down from the initial set depth of 5246m. 5 ⅞” Peripheral Milling tool was lowered to fish top (5240.40m) and 20 cm was milled down to 5240.60m. 5 ⅞” bit was run with 3 ½” left hand drill pipe to fish top. Several attempts were made to push down the packer using compression, but were not successful. 3 ½” left hand drill pipe was pulled out in singles and laid down. Further fishing and milling of packer was called off and decided to test the object-I conventionally.

CONVENTIONAL TESTING OF OBJECT-I:

5 ⅞” bit with near stabilizer and junk sub were run in with 3 ½” right hand drill pipe to packer top. String was pulled out after circulation and junk collection, but no junk was found in junk sub. Well was scrapped down to packer top with 7” scrapper by running in 3 ½” TSH tubing in singles. Well volume of 2.10 sp. Gr. SOBM was changed over to 2.05 sp. gr. Water based mud. 3 ½” TSH tubing with WLEG at bottom and Schlumberger gauge carrier at 4198.84m was lowered down to packer top. Tubing hanger was made up and landed the same by keeping shoe at 5243.06m. BOP stack was nippled down. X mass tree was installed and its flanges were pressure tested up to 12,000psi pressure. Cement surface lines were made up and were tested up to 13,000 psi pressure. Production surface lines were made up and down stream lines were tested up to 1,000 psi & up stream lines were tested up 9,000psi. Well volume of 2.05 sp. gr. mud was displaced with1.40 sp.gr. mud. Well kept open through tubing for

37 hrs. No surface activity was found. Well volume of 1.40sp. gr. mud was displaced with water. Well opened through tubing. Well trickled water @20 lts/hr and gradually reduced to 4 lts/hr. of water was pumped through annulus for circulation and normal water returns were observed through tubing. At bottom up time, water came through tubing in surges with gas and no surface activity was observed later. Surging was carried out twice at 2000 psi, but no surface activity was observed. Surging was attempted again, but circulation could be established after several attempts only at 3200 psi and at 2bbls/min pumping. 90 bbl. of water was pumped through annulus for circulation and water and gas in surges were observed through tubing. Well was open through tubing and flowed feeble gas at 0 psi for around 2 hrs. only. 150 bbl. of water was pumped twice through annulus for circulation and water in surges was observed through tubing. Surging was carried out twice at 2000 psi @ 2bbls/min. 150 bbl. of water was pumped twice through annulus for circulation and water in surges was observed through tubing. N2 was applied through annulus up to 2600psi and was bled off through 3mmchoke. Well was kept open through tubing through 5 mm choke. No surface activity was observed, well flowed feeble gas through tubing through 5mm choke. FTHP&CHP: „0" psi. Well was kept open through tubing through 12/64". Well flowed feeble gas. FTHP was 50-30 psi & CHP gradually increased to 40-50 psi. Well was kept open through tubing through 6 mm choke from. Well flowed feeble gas. FTHP was 30 psi & CHP gradually increased to 4200 psi. Annulus gas diverted in to tubing through by pass line to clear the suspected tubing choking After diversion, THP/CHP: 2500/3000 psi.

Well was closed. STHP/SCHP: 2500/3150 psi. Well was opened through tubing through 6mm choke well flowed gas and tubing pressure dropped from 2500 psi to 100 psi in one hour and CHP was 3500 psi.

Well was opened through annulus through 5mm choke . Well flowed gas and annulus pressure dropped from 3500 psi to 250psi. Well knocked out muddy water along with gas through annulus .till the annulus pressure came down from 250 psi to 0 psi. At 0 psi,well was intermittently knocking out muddy water in surges. Closed tubing pressure was increased from 100 psi to 300 psi. Well was opened through tubing through 5mm choke. Tubing pressure came down from 300 psi to 0 psi in 5 minutes and well flowed feeble gas at „0" psi. Closed annulus pressure increased to 3350psi. Well was kept open through annulus through 5 mm Well flowed initially gas & later knocked out muddy water along with gas. Annulus pressure decreased from 3350 psi to 600 psi and closed THP increased from „0" psi to 250 psi. Well was opened through tubing through 5 mm and tubing pressure reduced to „0" psi with gas flow. Well was opened through annulus through 5 mm choke. Well flowed gas along with muddy water with FCHP ranging from 800 to 550 psi and THP was „0" psi. Muddy water quantity was gradually reduced to trickling and well flowed gas only. The choke was reduced from 5 mm to 4 mm and the well flowed gas only through annulus at 350 psi and closed THP was „0" psi. Well was opened through tubing through 5 mm choke . Well flowed feeble gas only at „0" psi and SCHP increased to 1400 psi. Well was opened through annulus through 4 mm choke

. Well flowed gas at 1400 to 900 psi FCHP and STHP increased from „0" to 1400 psi.

WELL WAS OPENED THROUGH TUBING: through 5 mm choke at. Well flowed gas and FTHP dropped from 1400 psi to 0 psi and later flowed feeble gas only at „0‟ psi. Closed annulus pressure was 1050 psi..Reservoir dummy tool (1½") was lowered with wire line down to 4900m (till the available cable length) to know the depth of tubing choking, if any, and was pulled out Reservoir memory gauge tool was lowered and Flowing Bottom Hole Gradient survey was carried out up to 3600m. Maximum BHT recorded was 335°F at 3600m.

WELL WAS KEPT OPEN THROUGH TUBING through 5 mm choke. Well flowed feeble gas at „0‟ psi and closed annulus pressure increased up to 2300 psi.

WELL WAS KEPT OPEN THROUGH ANNULUS through 5 mm choke. Well flowed gas @22,334 m3/d at 2300 psi FCHP decreased to 13,068 m3/d at 550 psi FCHP. Well flowed gas through annulus through 4mm choke. Qg was 5775m3/d at 350 psi FCHP with depleting trend and closed THP was „0‟ psi., 210 bbl. of water was pumped through annulus, but circulation couldn't be established by pressurizing both annulus and tubing up to 3300 psi. Well was kept open through tubing. FTHP and CHP was "0" psi. Circulation couldn't be established by pressurizing tubing up to 6000 psi and annulus at 3200 psi and bleeding off annulus. Surface lines were tested up to 10000 psi. Tubing was pressurized up to 6000 psi, keeping annulus in open condition. Tubing pressure was dropped to 2000 psi in 2 hours time and no indication was seen at annulus. Tubing was again pressurized up to 8000 psi keeping annulus in open condition. Tubing pressure again dropped to „0‟ psi in 2 ½ hours. Annulus was filled by pumping 230 bbl. Of water. Surface lines were tested up to 11,500 psi. Tubing was pressurized up to 6000 psi keeping annulus in open condition. Tubing pressure dropped to „0‟ psi water knocked out @ 20 lt/min from annulus. Tubing was pressurized up to 8000 psi, keeping annulus in open condition. Tubing pressure dropped to „0‟ psi in 4 hrs time. Well flowed, initially gas only at „0‟ psi and later gas with intermittent trickle of muddy water through annulus. Tubing was pressurized several times up to 10,000 psi, keeping annulus in open condition. Tubing pressure dropped to around 2000 psi in 45 minutes to 2 hrs. time, after each pressurization. Feeble gas flowed through annulus at „0‟ psi during this operation, but circulation couldn't be established. Schlumberger unit lowered dummy and held up was observed at 5116.6 m (tubing shoe: 5243.06m). BHT recorded at 5116.6 m was 438°F and in the 2nd run, 320°F at 3500 m.

Water was pumped and tubing was pressurized several times up to 12,000 to 7000psi, keeping the annulus in open condition each time after tubing pressure dropped down to 6000 psi. Well flowed feeble gas only through annulus, but circulation couldn't be established. High viscous gel was pumped and tubing was pressurized four times up to 10,000 psi, keeping annulus in open condition. Each time no pressure drop was observed in tubing and tubing pressure was bled off to „0‟ psi. Feeble gas flow with mild intermittent trickling of water at "0" psi was observed through annulus during this operation. Coil tubing was lowered with water circulation down to 3300 m and further lowering couldn‟t be done due to heavy load on CTU. Schlumberger unit lowered dummy tool and recorded 400°F at 4600m depth. In the 2nd run, tubing was punctured in the interval 4586.6m to 4587.52m @4 SPM. Circulation was established and the well volume of water was displaced with 2.05 sp. Gr. mud. 100m high viscous gel was placed at bottom. Well was observed and found stable. X-mass tree was nippled down. 11" X 15M BOP stack was installed and tested the same. Tubing hanger was picked up with FOSV above rotary table. Tubing pressure was increased to 800psi and the same was bled off and no gas was found during bleed off. Tubing was pulled out up to 1773m. Coil tubing was lowered with circulation of 2.05 sp. Gr. Mud and found held up at 1638m. Tubing was cleared down from 1638m to 1659m with 0.5 bbl/min pumping rate at 5500 psi pressure. Further clearing couldn"t be done with 0.53 bbl/min pumping rate at 6000 psi pressure. Tubing was pulled out completely with bottom 5 stands of 3 ½" tubing was pulled out in singles. Bottom 9 singles were free from choking and above 5 singles were fully choked and one single was partially choked with settled barite. Feeble gas was found trapped in the barite. Well was cleared own to packer top with 5 7/8" bit and scrapped down to 5273m with 7" scrapper. Packer appeared to have slipped down from earlier log depth of 5252.70m. Further testing of Object-I was called off.

TESTING DETAILS OF OBJECT - II

1 Interval : 5245-5240m, 5231-5226m, 5219-5214m,
5207-5209m (not perforated), 5192 5186m& 5181-5176

II) Quality of cement: Poor

III) Type of **Perforation:** Conventional

IV) Perforation medium: 2.05 sp. Gr. Water based mud.

V) WLEG Bottom: 5153m

VI) Shot density: 6 SPF

VII). Salinity of mud filtrates: SOBM used. 31,000 ppm as Cl

VIII Result: Flowed feeble gas at 0 psi

Object- I couldn't be tested conclusively by TCP-DST and also by conventional method. 180m high viscous gel was placed from 5273m above before pullout of 7" scrapper. Carried out a dummy run and CCL log was recorded. BHT recorded was 4200F and Packer top was observed at 5269m during CCL run. Perforated object-II conventionally in 2.05 sp gr mud in the interval 5245-5240m, 5231-5226m. Well was conditioned and 150m high viscous gel was placed from 5225m to 5075m. Perforated object-II in the interval 5219-5214m, 5192-5186m, and 5181-5176m @ 6 SPF. 5209-5207m interval couldn't be perforated as the gun was not fired and further perforation of this interval was skipped.

3 ½" TSH tubing with WLEG and Schlumberger gauge carrier was lowered by rabbiting each stand and landed the tubing hanger by keeping shoe at 5153m. BOP stack was nippled down & X-mas tree was installed. While testing the flanges of Xmas tree, leakage in tubing hanger seal was observed and the same couldn't be rectified after several attempts. X-mass tree was nippled down and the tubing hanger was replaced. Again X-mass tree was installed and its flanges were tested at 12000 psi.

Well volume of 2.05 SG mud was displaced with 1.40 SG mud. During displacement, gas cut mud was found and the gas was flared. Well was open through tubing through 6mm choke and observed intermittent trickling of mud @ 1.25 LPM with „0" psi FTHP and SCHP was 850 psi at 06:00hrs on 15.10.13. Well volume of 1.40 SG mud was displaced with 1.05 SG betonite gel.

Well was kept open through tubing through 6mm choke. Well flowed feeble gas along with trickling of gel at„0" psi. Gas flow stopped and gel was trickled @ 4to 10 LPM with „0" psi SCHP & FTHP. Well knocked out gel intermittently along with gas. Well flowed feeble gas only with FTHP-100 to 200 psi and SCHP of 0- 500 psi .

N2 was applied through annulus to empty 40% of well volume. During N2 application, well flowed gas only from 400-1000 psi & gas with surges of gel mud from 1000-3050 psi. N2 was bled off through annulus through 4mm choke. Well was open through tubing through 6mm. Well flowed feeble gas only at „0" psi FTHP and CHP gradually increased from 400 to 1800 psi. N2 application was planned to empty 70% of well volume. During N2 application, well flowed gas with surges of gel from 1800 psi to 2650 psi and knocked out gel mud only from 2650 psi to 3200 psi. At 3200 psi, pressure build was observed in tubing and N2 application was stopped. Well was opened through tubing through 6 mm choke. Well knocked out gel mud with FTHP increased from 1000 psi to 2300psi and N2 pressure in casing reduced from 3200psi to 2700 psi from. Later well knocked out gel mud along with gas with FTHP decreased from 2300 psi to 1950psi and N2 pressure in casing reduced from 2700psi to 2200 psi from. Well flowed only gas with FTHP decreased from 1950 psi to 1200psi and N2 filled annulus pressure decreased from 2200psi to 1500psi.

Only N2 came out from tubing from 1200psi till it became „0" psi and annulus pressure came down to 400psi. Well was opened through annulus and remaining N2 was bled off to „0" psi. Well was open through tubing through 6 mm choke. Well flowed feeble gas only at „0" psi & SCHP was 400 psi. Well was closed for buildup study. STHP/SCHP after 56hrs shut in was 2250/2400psi. Reservoir gradient survey was carried out up to 4150m during shut in and only gas gradient was observed up to that depth. BHT recorded at 4150m was 3500 F. Well was kept open through tubing through 3mm choke after build up Well flowed gas initially from STHP of 2250 psi to 1000psi and gas with gel from 1000-1500psi (FTHP increased). Later well flowed only gas and FTHP decreased to 0 psi Well flowed feeble gas only at „0" psi. At, FTHP/CHP: 0/900psi. Annulus and tubing pressures were bled off to „0" psi for subduing the well. During bleed off, well flowed only gas. Well was subdued by pumping 2.05 sp gr mud through tubing and returns from annulus. Well flowed only gas till entire well volume of 512bbls was pumped in to well and no liquid influx was observed during subduing the well. First returns from well after 512 bbl, mud pumping was water with salinity ranging from 350 ppm to 460ppm as Na Cl. From 524 bbl. to 539 bbl., mud contaminated water with salinity ranging from 6435 ppm to 38610 ppm as Na Cl was observed from the well. Mud surfaced from annulus after pumping of 539 bbl through tubing. Technical water salinity was 400 to 700 ppm as Na Cl, Bentonite gel and subduing mud salinity was 700 ppm as Na Cl and mud filtrate salinity during drilling was 31,000 ppm as Cl. Well was thoroughly circulated and found stable. Further testing of Object-II is planned with hydro fracturing job at later stage.

X-mass tree was nippled down. BOP stack was installed and pressure tested. Tubing hanger was nippled down. While lowering 3 ½" tubing to packer top, held up was observed at 5154m and was cleared with circulation. During further lowering of tubing to packer top, held up was observed at 5181.54m and the same couldn"t be cleared with circulation. 3 ½" tubing was pulled out. 5 ⅞" bit with 3 ½" drill pipe was lowered and held up from 5190m to 5276m (packer top as per drill pipe tally) was cleared with circulation, reciprocation and rotation. Schlumberger unit recorded CBL-VDL-GR-CCL logs from 5176m to 4800m. Maximum temperature recorded at 5255m was 4170F. A cement plug was placed from 5275m to 5100m in 7" casing for isolation of object-II. Cement top was tagged with 5 ⅞" bit at 5091m and the cement was cleared down to 5150m. Isolation cement plug was tested at 2150 psi in 2.05 sp gr mud.

TESTING DETAILS OF OBJECT - III

I) Interval : 5103-5094m & **5112-5108m (not perforated)**
II) Quality of cement : Poor
III) Type of Perforation : Conventional
IV) Perforation medium : 1.90 sp. Gr. Water based mud.
V) WLEG Bottom : 5070m
VI) Shot density : 6 SPF
VII)) Salinity of mud filtrate : SOBM used. 31,000 ppm as Cl
VIII)) Type of flow : Flowed feeble gas at 0 psi.

Well was scrapped down to 5150m after testing of isolation cement plug and mud weight was cut down from 2.05 to 1.90 sp. Gr during scrapper trip. Schlumberger unit perforated Object-III, in the interval 5103-5097m and 5097-5094m in two runs at 6spf with HNS chargers. Object-III interval 5112-5108m was not perforated, because of poor cement bond. 3 ½" TSH tubing with WLEG and Schlumberger pressure gauges at 4205m was lowered and landed tubing hanger by keeping shoe at 5070m. BOP was nippled down. X-mass tree was nippled up and its flanges were tested at 12000psi. Well volume of 1.90 sp. gr mud was changed over to 1.40 sp gr mud. During change over, feeble gas was observed after pumping 112 bbl. Well was opened through

tubing through 6mm choke for 12 hrs. and no surface activity was observed. Well volume of 1.40 sp gr mud was displaced with 1.05 sp gr bentonite gel. Well was opened through tubing through 6mm choke for 23 hrs. and no surface activity was observed except intermittent gas fumes. N2 was applied up to 4400 psi through annulus and emptied around 60% well volume of bentonite gel. N2 was completely bled off through annulus through 4mm choke. Well was opened through tubing through 6mm choke for. Well flowed feeble gas at „0"psi and SCHP was 0 psi. Well was closed for build up. After 39hrs, STHP was 120 psi and SCHP was 0 psi. Tubing pressure was bled off to 0 psi and well was subdued with 1.90 sp gr mud by direct circulation. No liquid influx was observed during subduing the well. Bottom sample salinity was 1287 ppm as Na Cl, Bentonite gel salinity was 785 ppm as Na Cl, Technical water salinity was 585 ppm as Na Cl. Mud filtrate salinity during drilling was 31,000ppm as Cl. Further testing of Object-III was called off and well was temporarily abandoned to test later after hydro fracturing.

TEMPORARY ABANDONMENT:

After testing of **object-III**, well was subdued with 1.90 sp gr mud. X-mass tree was nippled down. BOP was installed and pressure tested. Tubing hanger was pulled out. While lowering down 3 ½" tubing to 5150m, held up was observed at 5081m and the same couldn"t be cleared with circulation. 3 ½" open end drill pipe was lowered, but held up at 5081m couldn"t be cleared. 175m bottom isolation cement plug was placed above object-III from 5076m to 4901m instead of planned 150m plug against object-III from 5149-4999m. Cement plug was tagged with 5 7/8" bit at 4791m and tested at 3000 psi. 3 ½" drill pipe and 3 ½" tubing not reqired were broke off and laid down. 120m top isolation cement plug was placed from 496m to 376m. Cement plug was tagged with 5 7/8" bit at 300m and tested at 1000 psi. Remaining 3 ½" drill pipes were laid down. BOP stack was nippled down. X-mass tree was installed and its flages were tested. 7 stands of 3 ½ tubing were lowered. All the valves of X-mass tree and well head were closed.

ACHEIVEMENT

Obj-I was conventionally tested with water base mud, during which tubing got choked with barite and well could not be cleaned completely. Well flowed feeble gas with technical water.

Due to non availability of packer, Obj-I was not isolated and Object-II was tested conventionally in the interval 5245-5240,5231-5226,5219-5214,5192-5186 & 5181-5176m.

Obj-II flowed feeble gas at FTHP of „0" psi with no water contribution from the zones.

Object-III (5094-5103m) on conventional testing flowed feeble gas with no water contribution from the zone.

Testing of the three objects proved that all the tested zones in the rift-fill sediments of G sand stone Formation are gas bearing with no water contribution. The feeble gas flow with no surface pressure indicates very poor permeability of the zones.

The objective of HPHT # has been achieved by proving the zones in G Formation gas bearing. However, commercial exploitation from G Formation in HPHT# requires

HP-HT hydro fracturing.

CONCLUSION

Object-I in the interval 5365-5360m, 5356-5349m, 5328-5321m, 5316-5309m & 5291- 5286m (G Sandstone Formation) was perforated @ 6SPF with TCP-DST method under positive head after setting 7" FB-3 permanent packer at 5046m. During initial knock out of 1.35 sp gr Calcium Chloride brine along with gas from tubing, communication between 1.81 sp gr Calcium Bromide brine filled annulus and 1.35 sp gr brine filled tubing was established due to LTSA seals damage. This resulted in self killing of well.

In 2nd attempt of object-I testing, LTSA and DST tools were lowered down to 5235m and during testing of string, line between tubing and choke manifold was choked and suddenly that hose got burst with severe gushing of mud and gas from the tubing. Blind ram was operated and string was sheared. After several fishing attempts, string up to packer top was recovered or milled. NOGO, NOGO locator, packer seal assembly, one tubing joint and mule shoe were left in the well.

Object-I was conventionally tested in 2.10 sp gr water based mud with 3 ½" tubing shoe at 5243.06m. After emptying around 40% well volume with N2 , well knocked out mud along with gas and later **flowed feeble gas only at '0' psi**. Maximum shut in casing pressure recorded was 4200 psi. Tubing was found to be choked from 5116.6m and below. Circulation was established only after puncturing tubing at 4586.6m to 4587.52m.

Object –I testing was called off and was inconclusive as the communication of
Object-I below packer to tubing above packer couldn't be conclusively established.

Object-II was conventionally tested in the interval 5245-5240m, 5231-5226m, 5219- 5214m, 5207-5209m (not perforated), 5192-5186m& 5181-5176 m and emptied around 3000m well volume with N2 . Well knocked out gel mud and later **flowed only feeble gas at '0' psi**. STHP/SCHP after 56hrs shut in was 2250/2400psi. No liquid influx was found during subduing and further testing of object-II is to be done later, with hydro fracturing job.

Object-III was conventionally tested in the interval, 5103-5094m. Well was emptied around 60% volume with N2.. Well flowed only feeble gas at „0" psi and maximum STHP/SCHP after 39hrs shut-in was 120/0 psi**.** No liquid influx was observed during subduing the well.

Well was temporarily abandoned by placing bottom & top cement plugs and object-II to be tested later with hydro fracturing job.

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