THE SHELL PETROLEUM DEVELOPMENT COMPANY OF NIGERIA LIMITED

GBARAN-022T WELL CLEAN-UP/TEST PROPOSAL

December 2015

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Contents

Tables

Figures

Appendices

1.0 BACKGROUND

Gbaran-022 is a gas development well targeting the C4200B and C5200B reservoirs in the Gbaran field. It is expected to provide an optimum drainage point on the Gbaran C4200B and C5200B reservoirs to develop a total of 64.66 Bscf of Gas and 1.0 MMstb of Condensate at an initial off-take rate of 50 MMscf/d in order to supply gas to the Bayelsa state government IPP through the Gbaran CPF. The C4200B interval is expected to develop 42.96 Bscf of NAG and 0.71 MMstb of condensate while the C5200B interval will develop 21.7 Bscf and 0.36 MMstb of condensate. The intervals will be produced bottoms up each at an initial offtake of 50 MMscf/d and 1000 bopd (condensate) each. The well was spudded on the 13th of January 2013, drilled to a TD of 9,265 ftah (8,967 ftss), and completed on the 20th of March, 2013.

Gbaran-022 encountered the C4200B sand at 7,988 ftss, 15 ft deeper than prognosis while C5200B was encountered at 8923 ftss, 1 ft shallower than prognosis. The well partially penetrated the C5200B sand, encountering a gross gas column of 42 ftss (46 ftah).

Gbaran-022 was completed as a Single String Dual (SSD) gas producer across the C4200B and C5200B reservoir with a 4-1/2'' x 3-1/2'' 13 Cr tubing equipped with non-self-equalising tubing-retrievable surface-controlled subsurface safety valve (TRSCSSSV) and Permanent Downhole Gauge (PDHG) for well and reservoir surveillance. The lower completion consists of 5-1/2'' EGP across the C5200B and IGP across the C4200B for sand control.

It is proposed to clean up the well of drilling and completion debris and also conduct Multirate test to its design offtake of ca.50MMscf/d on the C5200B interval. The C4200B interval will be tested prior to open-up of that interval.

2.0 CLEAN-UP/TEST OBJECTIVES

The objectives of the well clean-up and test are as follows:

- Clean up the well to get rid of completion fluids and debris.
- Conduct multirate test to a maximum of 50 MMscf/d to determine well deliverability
- Conduct Build up Test to obtain data required for reservoir characterization
- Conduct Static Gradient Survey to obtain static datum pressure and temperature data.
- Acquire surface production data to facilitate further evaluation of well performance.

3.0 JUSTIFICATION

The well's objective is to provide export gas through the Gbaran CPF. The cleanup is required to get rid of any remaining drilling fluid, completion fluid and debris (cuttings, dope, weighting agent etc.) resulting from both drilling and completion operations, which might lead to impairment, thus, resulting to a compromise of the well's potential and expected recovery of the C5200B interval.
The well will be tested to its design offtake of 50 MMscf/d which is within the limits of the third party test facility.

3.1 Well Clean-Up Design

The aim of the cleanup operation is to pump specially formulated sand treatment recipe (10% HCl) to achieve 100% areal and linear cleanout by jetting across the gravel pack screen.

During the clean-up operation, the well should be flowed long enough to establish 80% of expected FTHP on each bean while monitoring sand production (using non-intrusive sand monitors' e.g clamp-on). If there is significant sand production, flow will be stopped and sand trap bled down for inspection after every bean change. All produced hydrocarbon (gas & condensate) will be burnt via the flare pit.

Note: No Open trucking of condensate is permitted.

3.2 Clean-Up/Test Requirements

- Calibrated surface and downhole quartz gauges.
- Liquid knock out vessel with minimum capacity of 5000bbls
- Vacuum transfer truck for initial completion fluid evacuation
- Surface Tanks - to receive initial well effluent; completion and kill brine, mud etc.)
- Coiled Tubing/Nitrogen
- Slick line
- Non-intrusive Sand monitors (to monitor sand production).
- Flare head burner where it is possible to install one
- Mono- Ethyl Glycol (To mitigate hydrates at low rates) or its equivalent)
- Fixed Beans sizes of 8/64th,12/64th,16/64th,20/64th,24/64th,34/64th,42/64th,50/64th,56/64th

3.3 Well Clean-Up Operation

The well cleanup operation will commence by pumping 10% HCL acid across gravel pack screen interval with followed by unloading operation via coiled tubing using Nitrogen. The well will be unloaded until 80% of expected FTHP is obtained on each clean up bean. The Unloading will be done on a minimum choke size of 8/64th.

The well will be gradually bean-up from bean 8/64th in stages of 4/64th up to choke 24/64 .FTHP stability on each bean should be used as an indicator of proper clean-up in addition to the unloading time that is specified in the Well clean up guide.

Clean-up parameters are not accurately predictable, however, Table 1 provides a fair guide. Appendix 2a & b are snapshots from PROSPER showing a graphical display of the wellbore clean up model results. The flow rates, WGR, sand production and FTHP will be measured and recorded to ensure adequate well clean-up until a stabilized FTHP and WGR ca. 0.3 bbl/MMscf is achieved. Thereafter, shut-in the well for 24 hours for the reservoir pressure to stabilize, prior to conducting the Multirate test. The flow back well effluent (completion brine) will be evacuated with vacuum truck to the Gbaran Central Processing Facility (CPF) for disposal.

Table 1: Gbaran-022 Well Clean-Up Guide

Estimated Rate (MMscf/d)	Expected Bean Size (1/64th)	Assumed WGR (bbl/MMscf)	Expected FTHP (psia)	Flow Period (hr)	Expected Drawdown (psi)	Comments
1.57	12	0.3	1971	4	1	Take sample, check for sand, measure FTHP.
3.75	16	0.3	2387	4	2	Take sample, check for sand, measure FTHP.
7.5	20	0.3	2928	4	5	Take sample, check for sand, measure FTHP.
10	24	0.3	2998	4	7	Take sample, check for sand, measure FTHP.

Note: WGR based on Gbaran– C4200B and C5200B Reservoir Development Plan, 2007

4.0 MULTI-RATE TEST AND FLOWING/BUILD-UP/SG SURVEY

4.1 Initial Build-Up Period

- Close in well at choke manifold for 24 hours for an initial build-up after well clean-up to allow for reservoir stabilization prior to multirate test. Record CITHP. Monitor surface read-out of SBHP for pressure stabilization before proceeding to MRT.
- RIH Slickline and install pressure/temperature memory gauge and Down Hole Shut-In Tool (DHSIT). Deepest gauge should be at "XN – Nipple" (ca.8290 ftah); also hook-up Fiber-optic PDHG to weatherford Mobile surface readout system for pressure and temperature calibration with third party gauge.

4.2 Flowing Period

- Open up well and carry out multi-rate test; starting at a rate of 20 MMscf/d, gradually bean up to a maximum rate of 50 MMscf/d in accordance with Table 2

Table 2: GBAR-022 Multi-rate Well Test Bean-up Sequence Guide

Estimated Rate (MMscf/d)	Expected Bean Size ($1/64^{th}$)	Assumed WGR (bbl/MMscf)	Expected FTHP (psia)	Flow Period (hr)	Expected Drawdown (psi)	Comments
20	34	0.3	2964	4	15	Take sample, check for sand, measure FTHP.
30	42	0.3	2916	4	22	Take sample, check for sand, measure FTHP.
40	50	0.3	2814	4	30	Take sample, check for sand, measure FTHP.
50	56	0.3	2701	6	37	Take sample, check for sand, measure FTHP. flow should be extended

Importance Note: Tolerance Qg: ± 5 MMscf/d, Tolerance FTHP: ± 150 psia

- Bean up should be carried out when flow stabilizes and FTHP are stable for at least 1 hour. The Dp should be tending towards zero over specific time interval as an indication of stabilization.
- At each choke, collect and analyse sample every 15 mins, record bean size, gas flow rate, FTHP, FTHT, CGR, WGR, and sand rate.
- After the last flow period, shut in well for 12 hrs (Final Buildup duration determined from section 5.0) and subsequently commence Static Gradient Survey (See Table **3**).

4.3 Final Build-Up and Static Survey Period

- Confirm well has been closed in for 12 hours build-up.
- Carry out static gradient (SG) survey while POOH wireline memory gauge and DHSIT at the depths as detailed in table 3.
- Duration of survey at each stop should be ca. 10mins.
- POOH with gauges and R/D S/line.
- Download wireline memory gauge and compare to real time fiber optic data.

- Close TRSCSSSV and line up well to production.
- Handover well to production.

Table 3: Static Gradient Survey Stops.

Depth Tag (d)	Depth (d) ftah from RT [RT Elevation = 55 ft]	Depth(d*) ftah from Top XMT [RT - Top XMT = 26.20ft]	Depth (d**) ftah from compact Housing [RT- Compact Housing = 29.55ft]	$d_{i-1}-d_i$ ft	Time at depth Minutes	Comment/Basis for Stops Selection
Deepest Survey Depth	8291	8262	8266	-	0	Deepest Survey depth. XN nipple Depth
1st Stop	8271	8242	8246	20	10	**1st Set of Stops:** 3 Stops at 20ft intervals closest to deepest survey point in line with BHP Guidelines (2009) to enable accurate regression/extrapolation to reservoir pressure.
2nd Stop	8251	8222	8226	20	10	
3rd Stop	8231	8202	8206	20	10	
4th Stop	8031	8002	8006	200	10	**2nd Set of Stops:** 3 Stops at 200ft intervals to investigate possible condensate drop out in well bore. Dew Point Pressure is ca. 3895 psia.
5th Stop	7831	7802	7806	200	10	
6th Stop	7631	7602	7606	200	10	
7th Stop	7131	7102	7106	500	10	**3rd Set of Stops:** 3 Stops at 200ft intervals to aid investigation of fluid regime at pressures expected to be below the dew point pressure.
8th Stop	6931	6902	6906	200	10	
9th Stop	6731	6702	6706	200	10	
10th Stop	5731	5702	5706	1000	10	**4th Set of Stops:** 3 Stops at 200ft intervals to aid investigation of fluid regime close to surface and provide data to calibrate/validate 3rd set of stops and 5th set of stops.
11th Stop	5531	5502	5506	200	10	
12th Stop	5331	5302	5306	200	10	
13th Stop	3831	3802	3806	1500	10	**5th Set of Stops:** 3 Stops at 200ft intervals to aid investigation of fluid regime close to surface.
14th Stop	3631	3602	3606	200	10	
15th Stop	3431	3402	3406	200	10	

Total Duration		**150**	**Minutes (2.5 hrs)**

5.0 SAPHIR TEST DESIGN

The focus of the test design is to determine the duration of the flow and optimal build up time, such that there is appreciable amount of data to enable the determination of reservoir properties (Permeability-height product-kh, skin, etc) and possible existence and nature of any boundary(ies)/discontinuity(ies) (fault/Baffles/GWC).

Kappa's Ecrin Saphir Software was used in this design. The model was built based on the data as detailed in Table 4. The Pressure response was a function of the rates in Table 4. Section (e). The generated pressure responses were subsequently analyzed using derivative plots to determine the time taken for the pressure perturbations to be felt at the possible boundaries. Various scenarios (sensitivities) were built to test what the pressure response would be given the uncertainties in permeability, and skin. These sensitivities where collectively analyzed, and the optimal test time selected.

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5.1 Input Data:

The test design input data are as detailed in the table 4 below.
Table 4: Test Design Input Parameter

Parameter	Value	Unit	Comment
a. Reservoir Data			
Pay Zone Thickness	42	ft	GBAR-022 EOWR
Average Formation Porosity	0.24	fraction	GBAR-022 EOWR
Formation Compressibility	3.00E-06	psi-1	Estimated from equation of state.
Reservoir Pressure	3944	psi	GBAR-022 EOWR
Reservoir Temperature	140	F	GBAR-022 EOWR
Reservoir Permeability	1400	md	Average permeability from Gbaran C4200B & C5200B Reservoirs Development Plan
b. Well Data			
Well Orientation	Vertical		
Well Radius	0.3	ft	
Well bore Storage (WBS) Coefficient	0.03	bbl/psi	Estimated in accordance with BHP & Gas Well test Guidelines, 2009 Assuming surface shut-in and a gas gradient of 0.1 psi/ft (based on SG analysis done recently in Gbaran 25 E3000B reservoir). WBS could be as low as 0.0067 bbl/psi if down hole shut-in tool is used.
c. Fluid data			
Fluid Type	Gas		
Gas gravity	0.65		GBAR-022 EOWR
d. Others			
Reservoir Model	Homogeneous		
Wellbore Model	Constant storage		
Boundary Model	Constant pressure boundary model		Digitized map to capture geometry of reservoir in line with C5200B top structure map (Appendix 5)
Modelling Approach	Numerical		To capture complexities (fault count and orientation) in the reservoir structure
e. Flow Data for Model Pressure Simulation			
Initial Build Up	24	Hrs	Flow @ 0 MMscf/day
1st Flow Period	4	Hrs	Flow @ 20 MMscf/day
2nd Flow Period	4	Hrs	Flow @ 30 MMscf/day
3rd Flow Period	4	Hrs	Flow @ 40 MMscf/day
4th Flow Period	6	Hrs	Flow @ 50 MMscf/day
Final Build up	12	Hrs	Flow @ 0 MMscf/day

5.2 Scenario/Sensitivity Formulation

PERMEABILITY:

Based on the permeability ranges in the Gbaran Field, a minimum, most likely and maximum permeability of 500mD, 1400mD and 2300mD respectively were selected for this analysis and sensitized on.

BOUNDARY MODEL:

The TOP structure Map (Appendix 5) was digitized and used in the design. The reservoir is bounded by an OGWC at 8997 ftss .From the top structure map and cross section (Appendix 6), the reservoir geometry is relatively simple. Appendix 7 shows the digitized map.

SKIN:

No data was available to evaluate the possible skin values that may exist in reality. However skin values of 3, 7, and 10 (selected based on expected skin range for internal gravel pack) was studied.

WELLBORE STORAGE:

A wellbore storage coefficient of 0.03 bbl/psi was estimated for surface shut in. For down-hole shut in at the XN Nipple, the wellbore storage was estimated to be ca. 0.0067 bbls/psi.

The well test design was carried out using well bore storage of 0.03 bbl/psi as a worst case scenario, in the event of failure or unavailability of the DHSIT. From the derivative plot generated in this test design, this wellbore storage effect (where the well is shut-in at surface), will not mask the reservoir pressure response. However, it is recommended to have the DHSIT to reduce the wellbore storage co-efficient.

Given the above, the scenarios as shown in Figures 1 below were simulated and the generated pressure responses analyzed.

Table 5: Reservoir Model & Wellbore model Parameters

Parameter	Value	Unit
Well & Well Bore Parameters		
Well bore Model	Constant Wellbore Storage	N/A
Wellbore Storage Coefficient (C)	0.03	bbl/psi
Skin Factor	7 (base case sensitivity)	N/A
Reservoir & Boundary Parameters		
Pi	3944	Psia
K.h	58800 (base case sensitivity)	md.ft
Reservoir Model	Homogenous	N/A

5.3 ANALYSIS

Numerical method was used in the test design. The top structure map was digitized and imported into the design model. This ensures that the structural configuration of the reservoir is captured adequately, accounting for the minute details often approximated in the analytical method.

Simulated pressure responses were generated for the test design using 4-hourly four stepped rates (10, 20, 30, & 40 MMscf/d respectively).

Existing study on Gbaran C4200B and C5200B, (Gbaran C4200B & C5200B Reservoirs Development Plan) show a permeability range from 500mD to 2300mD. These were generated using log data from Gbaran 2 well and available core data from Gbaran D7000X reservoir. Design sensitivity analyses were carried out for reservoir permeability values of 500mD, 1400mD, 2300mD. Also, Pi was imposed on the assumption that the reservoir is still at initial condition (no production from the reservoir).

The results from the build-up period predict the following;

i. In all scenarios tested, the well bore storage phase will not mask the transient flow phase.
ii. With the assumed base-case permeability of 1400mD, it would take about 12 hours before the closest reservoir boundaries can be detected.
iii. For the low-case scenario of 500md, at least 12 hours will be required for boundary effects to be felt
iv. The high-case scenario of 2300mD shows that boundary signatures can be detected from 11 hours
v. It is recommended that the well be shut-in for 12 hours for the final build-up in the event that the low case permeability range is encountered in this reservoir.
   See figures 2

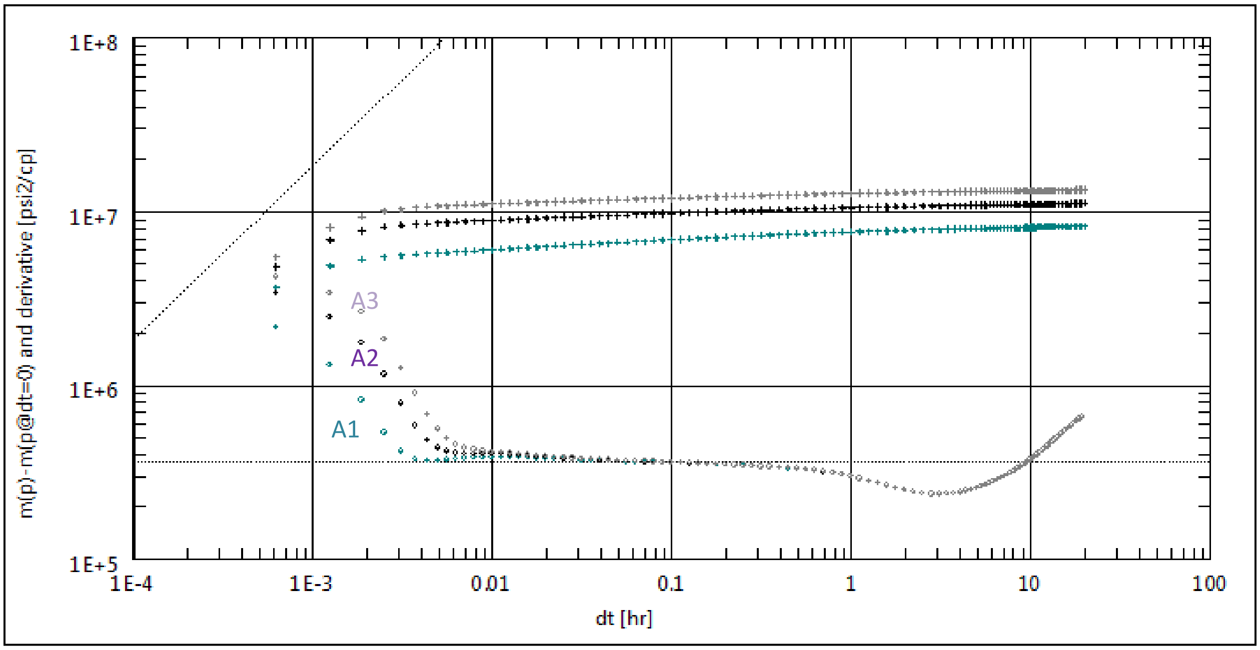


Figure 1: Log-Log plot for scenario A1 (Perm/skin: 1400md/3), A2 (Perm/skin: 1400md/7), A3 (Perm/skin: 1400md/10)

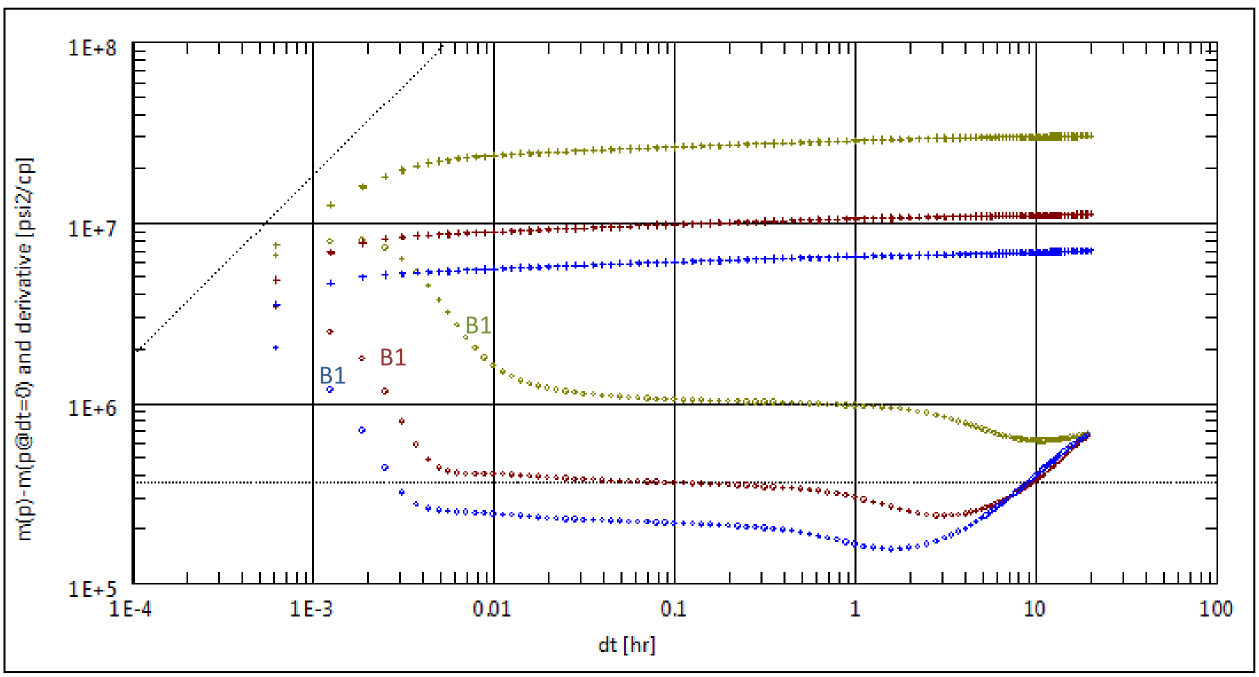


Figure 2 : Log-Log plot for scenario B1 (Perm/skin: 500md/7), B2 (Perm/skin: 1400md/7), B3 (Perm/skin: 2300md/7)

6.0 WORKSCOPE SUMMARY

The summary of the clean-up/MRT work scope is given as follows:

1. Hold pre-job safety meeting
2. Retrieve NRV from tubing hanger
3. Trip open TRSCSSSV at 206 ftah.
4. Carry out a drift run on slick line.
5. Check and record pressures and temperatures at the wellhead.
6. Rig up CT and carry out pressure and function test.
7. RIH CT to top of screen at 9185 ftah, pump the solvent and make several passes across the screen.
8. Allow solvent to soak for ca. 12hours.
9. Open up well and offload well. If well does not come in, Nitrogen lift well.
10. Commence well clean-up *(Table 1*).
11. Shut in well for 24 hours for reservoir stabilization.
12. RIH and install Quartz pressure and temperature memory gauges at RN landing nipple at 8290 ftah.
13. Open up well, activate the PDHG and conduct multi-rate test starting at ca. 20 MMscf/d on bean 34/64" to maximum rate of 50 MMscf/d using third party facilities. *(See Table 2).*
14. Shut in well and carry out 12 hours final build-up test with DHSIT in closed position and de-activate the PDHG subsequently.
15. Carry out Static Gradient surveys while POOH the gauges at the depths in table 3
16. Secure well and RD equipment.

7.0 SUPERVISING PERSONNEL

Full time representatives from SPDC, made up of Completion/well test Supervisor and Land East Asset team Production Technologist or Reservoir Engineer will be on site. This is to ensure the well is properly cleaned prior to the Multi-rate test and that acquired data are of top quality and meet the objectives of the clean-up/well test operations.

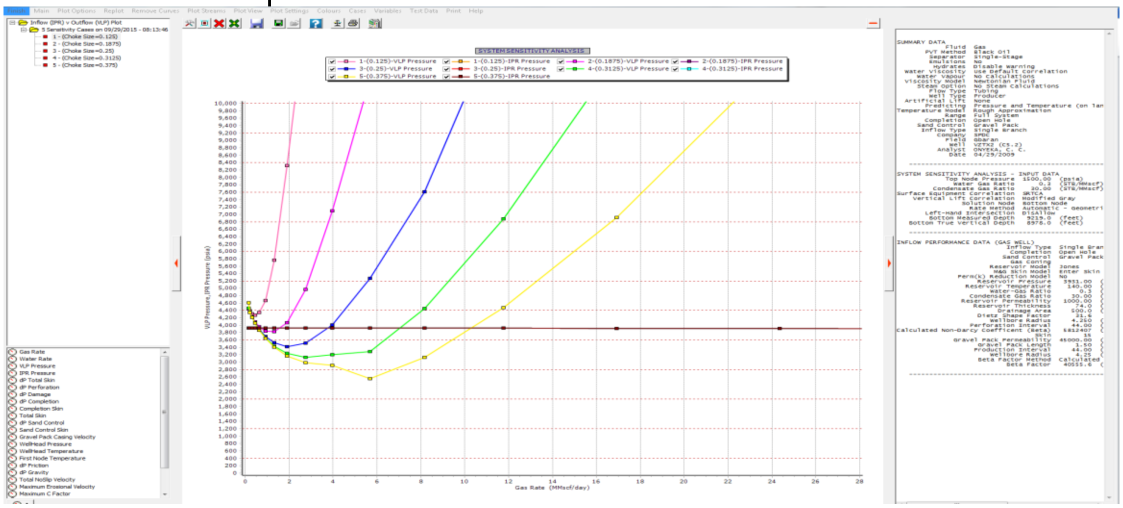
Appendix 1: C5200B Reservoir & Completion Data

Target Reservoir	C5200B
1. Casing size and Type	9-$^5/_8$''/Production casing
2. Casing Setting Depth (ftah)	9195
3. Top of Sand [ftss/ftah]	8923/9219
4. Gross Sand Thickness (Gross) penetrated by GBARAN-022(ft tv)	42*
5. Well TD (ftss/ftah)	9265/8967
6. a) Completion interval (ftss) b) Completion interval (ft tv) c) Completion interval (ftah)	8923 - 8967 8998 - 9022 9219 - 9265
7. Length of Completion Interval (ftah)	46
8. a) Top of competent cement (ftah) b) Source of data	6200 SBT
9. a) Was hole directionally drilled? b) Max deviation angle and depth (ftah)	Yes 22.34° @ 9,240
10. Deviation at completion zone	22.34°
10. a) Original reservoir pressure @ datum depth (psia) b) Datum Depth (ftss) c) Present reservoir pressure (psia) @ datum d) Reservoir Temperature (deg F) e) Top of Sand (ftss) f) Reservoir Pressure @ Top of Sand (psia)	3944 8997 3944 140 8923 3938
11. Did RCI indicate abnormal pressures?	No
12. Pressure gradient @ top of sand (psi/ft)	0.44
13. Is the reservoir fully gas-bearing?	Yes
14. a) Is there original GWC in the reservoir b) What depth (ftss)? c) Change in PGWC from original OGWC (ft)	Yes 8997 No (no production)
15. Distance between lowest completion interval and estimated GWC in well / reservoir (ftss)	30
16. Is there a barrier between lowest completion interval and the present estimated GWC?	No
17. Gas S.G. (air=1)	0.648
18. Condensate gravity (API)	44
19. Expected FTHP (psia)	2690
20. Expected CITHP (psia)	3100
21. Expected Drawdown (psi)	37
22. Expected PI (scf/d/psi2)	168
23. Is sand exclusion installed?	Yes (EGP)

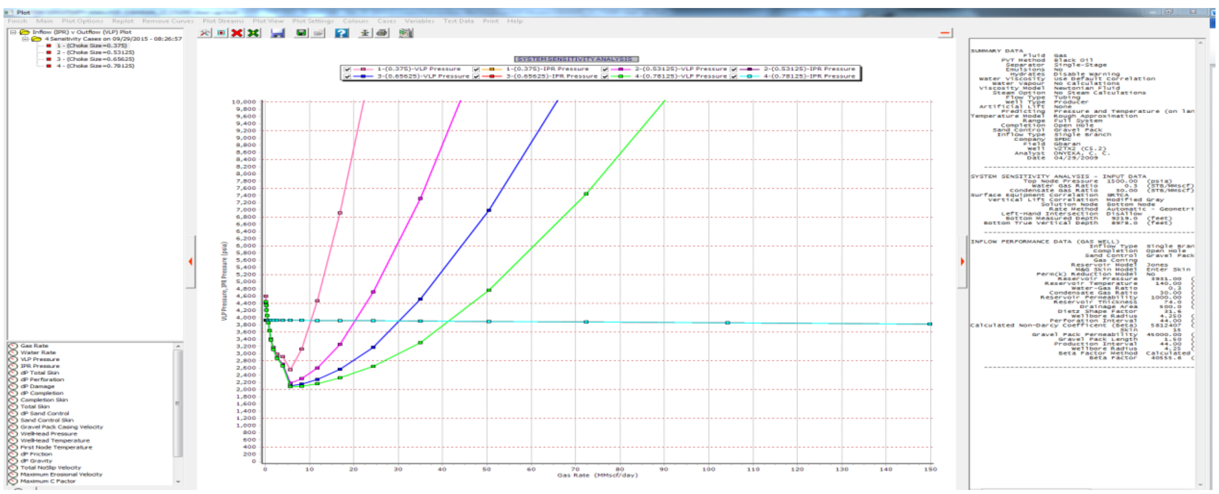
*Partial penetration

Appendix 2: Well Performance plots.

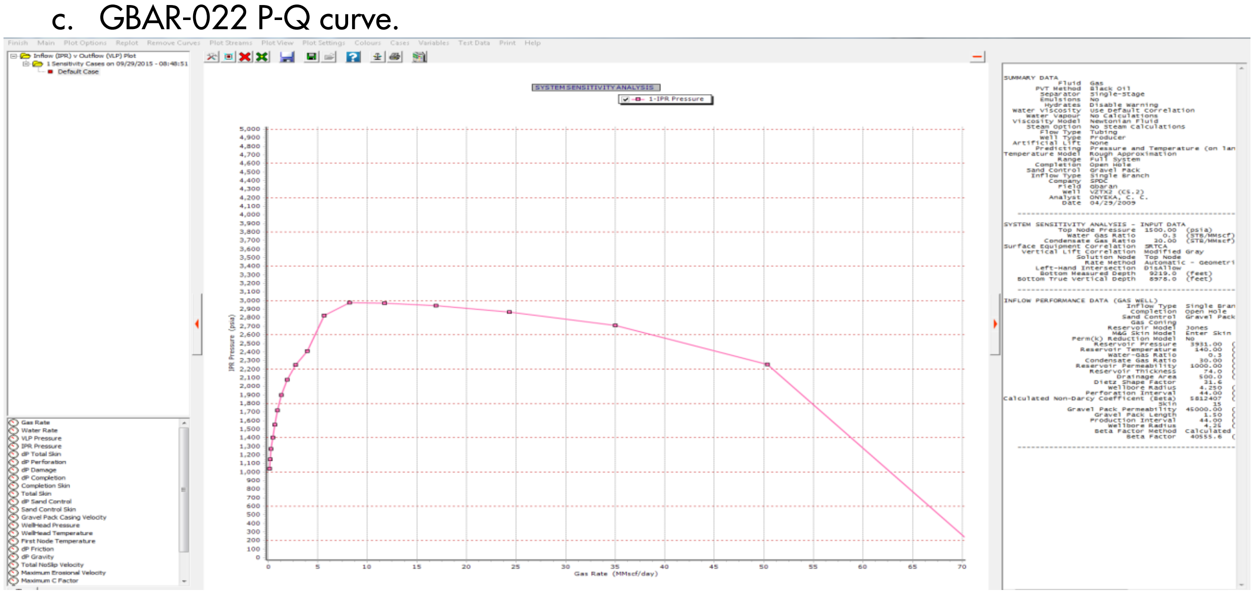
a. GBAR-022 Clean-up Well Performance



b. GBAR-022 MRT Well Performance



c. GBAR-022 P-Q curve.



Appendix 3: Critical Well Test Operations Risks/Mitigation.

Risk	Risk description	Consequence	Likelihood /Impact	Mitigation
Poor well clean up	Inability to completely get rid of debris from the wellbore that may cause damage	Unable to attain well potential	H/M	Ensure that 80% of modeled FTHP is attained during clean up (Ref BONT-003
Noise from flare	Flare bums produced severe noise when flaring high rate gas.	Damage to personnel ear drum, partial or permanent deafness	H/M	Certified ear plugs to be worn by personnel on site.
Ill-defined Operating Envelope	Operating Envelop defines the well operating conditions within which the Integrity of the well is ensured. Therefore ill-defined operating envelop may compromise well integrity	Loss of well integrity, wellhead area & surrounding environment.	L/H	Modelled well, established CITHP and specified appropriately rated wellhead.
Inappropriately Sized Tools	Using tools size that are not appriopriate may cause wireline tools to be held up at depths	Downhole components/tools may not get to desired depths.	L/H	Ensure the dimensions of tools to be RIH are appropriately sized for 7" tubing and accessories/profiles ID.
Use of solvent chemicals and liquid Nitrogen during clean up & Unloading	Solvents such as HCl used during clean up are corrosive and dangerous. if not handled properly will cause harm to environment and personnel.	Environmental contamination and harm to personnel.	L/M	Ensure safe handling of acid or treatment fluid, its constituents and liquid Nitrogen as per standard handling procedures.
Crude load out	Crude oil spill may occur during crude load out/transfer to vacuum trucks	Spill, slippery floor, fire outbreak, injury and fatality	L/H	Ensure that all pumping and piping connections are leak tight. Produced gas during clean-up & unloading will be vented. Effluent will be transported and discharged at Gbaran CPF

	using pumps if not handled properly.			
Fire Source	Natural Gas is explosive and highly flammable.	Fire outbreak, injury, and loss of equipment, fatality.	L/H	Barricade work area, prohibit use of cell phone & smoking around well's perimeter fence, restrict movement of unauthorized persons around work area.
Blow out of high Pressure Vessels	The well is expected to produce at high FTHP and rate this can cause equipment to be blow out if not properly guided.	Loss of equipment, injury, fatality	L/H	Chain down high pressure pipes, restrict movement of personnel around HP vessels
Emergency due to spill, loss of containment etc	In the event of loss of containment without proper emergency management system may cause severe damage to equipments and personnel	Loss of order, injury, fatality, loss of equipment	L/H	Presence of three barrier containment. Emergency shut down (ESD) system for wellhead, wellsite and test skid. Adopt MOPO (Manual of Permitted Operations) specifying when operations should be stopped if hazard mitigation is not being met.
Hydrocarbon under Pressure	Hydrocarbon under pressure are explosive and uncontrol release will result in fire out or spill	Explosion, loss of containment, injury, fatality and environmental pollution.	L/H	Check integrity of the valves on the wellhead and TRScSSSV to ensure they are integral; install surface read-out gauges to monitor pressures and ensure BOP for the coil tubing unit is fully functional.
Hydrate formation	Hydrates cause blockage in pipes and restrict the flow of gas result to pressure build up.	Blocked tubular , increased pressure, blow out, injury, fatality	L/H	Inject glycol at low gas rates to combat hydrate formation. Use heat exchangers at high gas rates, tubing temperature are high enough to combat hydrate
Explosion on surface due to gas flaring	Explosion of gas during flaring of gas may cause fire break	Damage to facility, vegetation around facility	L/H	Proper positioning of the flare stack, Adherence to 12 Life saving rules, on-site extinguishers at possible flash points.
Sand Production	Sand production in has wells causes severe erosion of tubings,surface chokes, flowlines etc	Tubing and pipeline erosion	M/H	Ensure gradually Bean up and proper sand monitoring

Appendix 4: GBAR-022 Final Completion Status Diagram

GBARAN-22 FINAL SCHEMATICS

11-Mar-13

CASING

SIZE	GRADE	WT (lbs/ft)	DEPTH (ft)	CEMENT	Conn	
20"	Stove Pipe		289	Driven		Stovepipe
13-3/8"	N80	68	6,263	Class G	SLX	Surf Csg
9-5/8"	N80	47	9,195	Class G	SLX	Prod Csg

WELLHEAD (Surface Metal Seal 2 Step System)

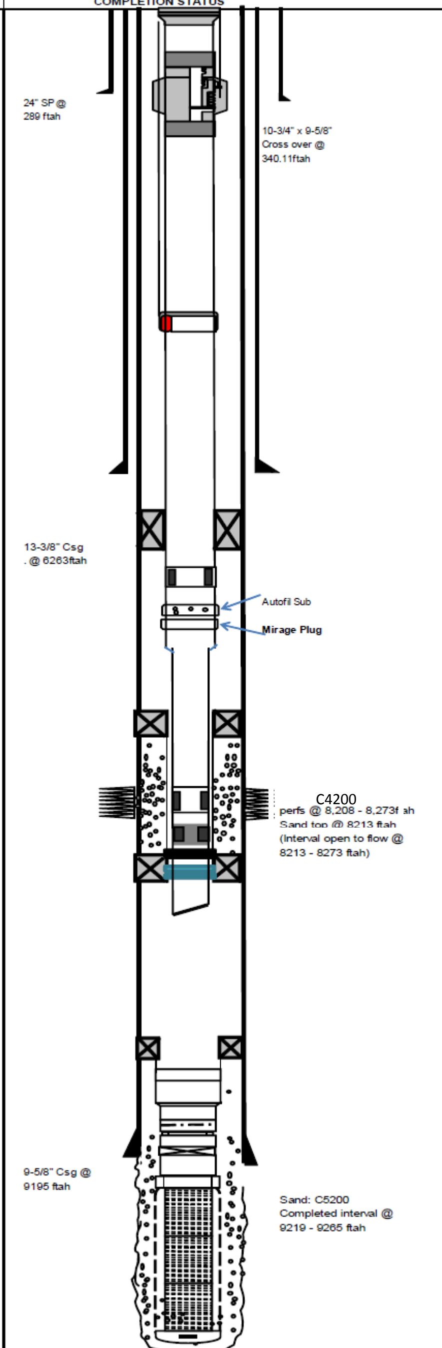
ITEM	TYPE	SIZE	WP
INST.FLANGE			
GATE VALVE	Compact Wellhead	TWO-STAGE 'SSMC' COMPACT HOUSING, 13-5/8" CW	10,000 psi
XMAS TREE CAP		CF-13' FASTLOCK HUB TOP X 13-3/8" 68 LB/FT	
XMAS TREE		BUT BTM	10,000 psi
TUBING HANGER	TB Hanger	TUBING HANGER, 'SSMC', 13-5/8 NOM	10,000 psi
SEAL ASSY PACKOFF	Xmas tree	4-1/16" x 13-5/8" Bottom x 10k	
COMPACT HOUSING			
CSG HANGER			

TUBING

STRING	SIZE	WT.	GRAD.	TYPE	
					MAX Deviation: 22.34 deg at 9240 ftah
					RT - Top XMT = 26.2ft
SSD	4 1/2"	12.75#	13Cr	H563	DFE (RT - Compact Housing)= 29.55ft
	4 1/2"	12.6#	13Cr	VAMTOP	XMT = 7ft
	3 1/2"	9.3#	13Cr	HCS	

	HOLE	DESCRIPTION	RESERVOIR
	12 1/4"	IGP	C4200
	8 1/2"	EGP	C5200
Drill-in Fluid Type / Properties			
Completion Fluid Type / Properties:	0.48 psi/ft		
Workover Fluid Type / Properties:			

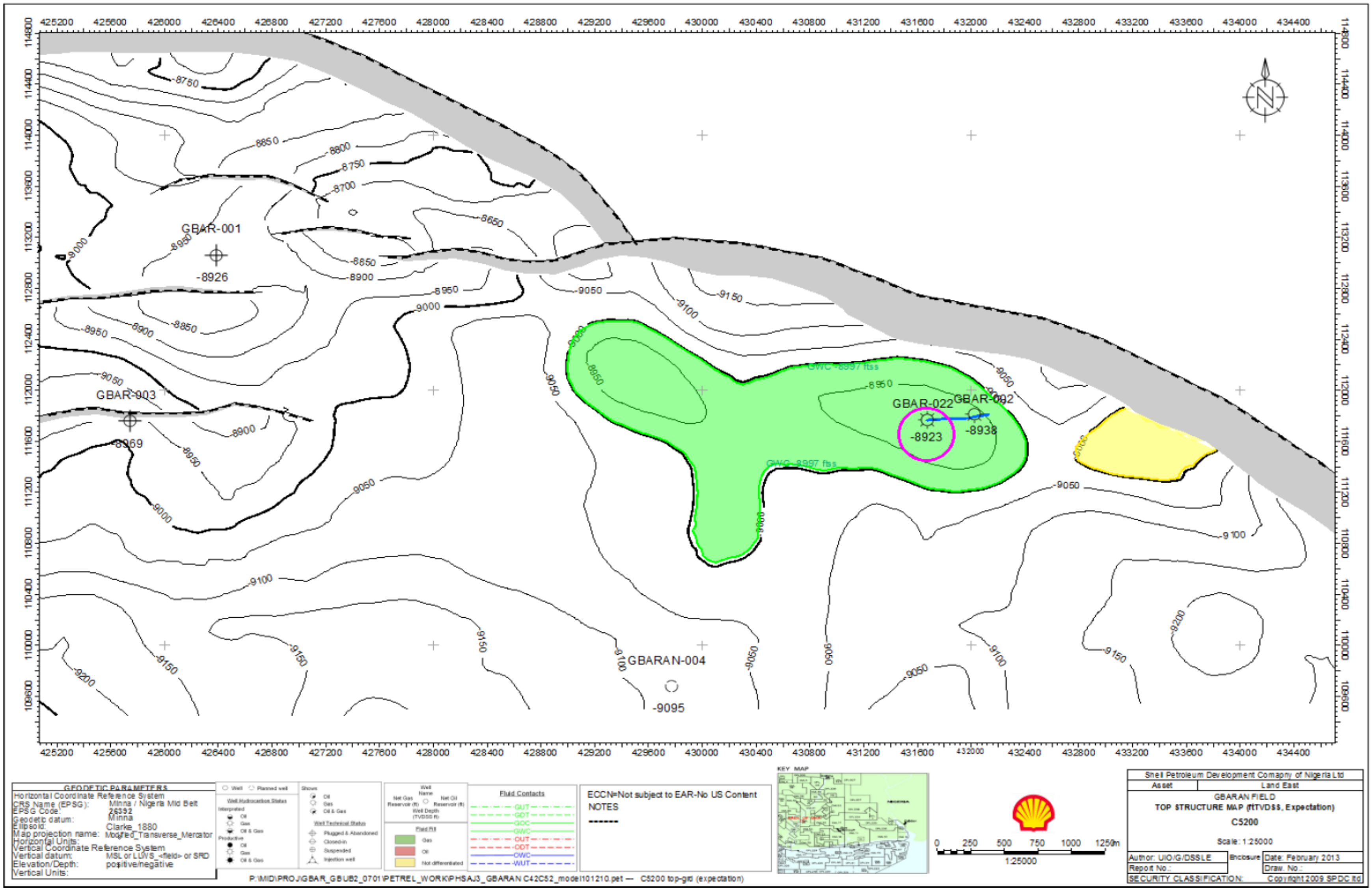
SAND | COMPLETION STATUS



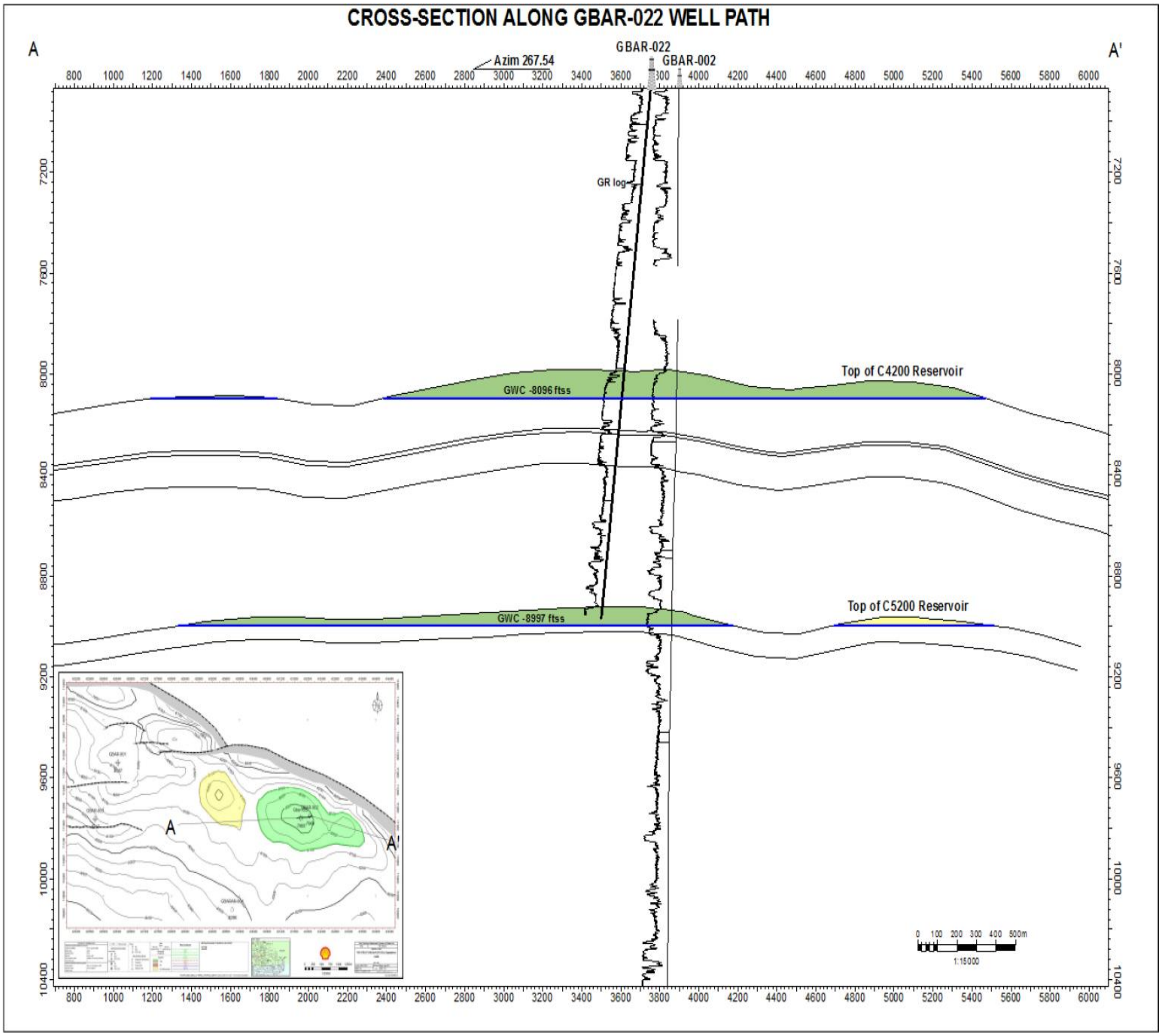
Top Depth	Length	O.D.	I.D.	DESCRIPTION
				4 1/2" Completion Production String
0.00	29.55			Elevation (RKB)
29.55	**1.90**	**13.38**	**3.903"**	**Tubing Hanger; 4 1/2" 12.6#Vam Top Box**
31.45	5.53	4.500"	3.958"	Tubing Nipple: Pup Jt; 4 1/2" 12.6# Vam Top (P) x (P) 13cr
36.98	3.00	4.500"	3.958"	Space out pup joint 4 1/2" 12.6# Vam Top Box X Pin 13 cr
39.98	21.33	4.500"	3.958"	Space out pup joint 4 1/2" 12.6# Vam Top Box X Pin 13 cr
61.31	124.53	4.50	3.96	Tubing Joint; 4-1/2" 12.6# Vam Top (B) X (P) 13cr (3 JOINTS)
185.84	10.12	4.951"	3.924"	Pup Jt; 4-1/2" 12.6# Vam Top (B) X (P) 13cr
195.96	1.10	4.934"	3.884"	Adapter: 4-1/2" 12.6# Vam Top (B) x 4-1/2" 12.6# CSH (P) 13Cr (S/N: MY 2745520)
197.06	9.76	4.935"	3.848"	Flow Coupling; 4-1/2" 12.6# CSH (B) X (P) 13cr (S/N: HES#2821277)
206.82	7.38	7.348"	3.813"	**HES SP TRSV(Non Equalizing): 4 1/2", 12.75 # HCS Box x Pin, 13Cr (S/N: S 2836178-04)**
214.20	9.77	4.935"	3.848"	Flow Coupling; 4-1/2" 12.6# CSH (B) X (P) 13cr (S/N: HES#2821277)
223.97	1.15	4.934"	3.884"	Adapter: 4-1/2" 12.60# CSH (B) x 4-1/2" Vam Top (P), 13Cr (S/N: MY 2770200)
225.12	6.11	4.948"	3.924"	Pup Jt; 4 1/2" 12.6# Vam Top (B) x (P) 13cr
231.23	7630.04	4.965"	3.916"	Tubing Joint; 4-1/2" 12.6# VamTop (B) X (P) 13cr (184 Joints)
7861.27	1.24	4.965"	3.916"	X/O 4-1/2" 12.75# VamTop (B) X (H563 (P) 13cr
7862.51	32.47	4.965"	3.916"	Tubing Joint; 4-1/2" 12.6# TSH563 (B) X (P) 13cr
7894.98	9.93	5.245"	3.914"	Pup Jt; 4-1/2" 12.6# TSH 563 (B) x (P) 13cr
7904.91	0.68	5.225"	N/A	Coupling; 4-1/2" 12.6# TSH 563 (B) x (B) 13cr
7905.59	4.47	5.756"	3.904"	WDFD PDHG; 4-1/2" 12.6# TSH 563 (P) x (P) 13cr (S/N: 12101-06)
7910.06	32.51	4.50	3.96	Tubing Joint; 4-1/2" 12.6# TSH 563 (B) X (P) 13cr (1 JOINT)
7942.57	2.12	4.961"	3.970"	X/O Pup Jt; 4-1/2" 12.6# TSH 563 (B) X 4-1/2" 12.6# Vam Top (P) 13cr
7944.69	10.11	4.973"	3.918"	Pup Jt; 4 1/2" 12.6# Vam Top (B) x (P) 13cr
7954.80	**6.40**	**8.134"**	**3.923"**	**HES THT Packer** ; 9 5/8" 36-59.4# x 4 1/2" Vam Top (B) x (P) 13cr (S/N: MY 2779256-3)
7961.20	5.59	4.973"	3.918"	Pup Jt; 4 1/2" 12.6# Vam Top (B) x (P) 13cr
7966.79	2.12	4.961"	3.975"	X/O Pup Jt; 4-1/2" 12.6# Vam Top (B) X 4-1/2" 12.6#TSH 563 (P) 13cr
7968.91	64.96	4.50	3.96	Tubing Joint; 4-1/2" 12.6# TSH 563 (B) X (P) 13cr (2 Joints)
8033.87	2.09	4.978"	3.913"	X/O Pup Jt; 4-1/2" 12.6# TSH 563 (B) X 4-1/2" 12.6# Vam Top (P) 13cr
8035.96	10.11	4.988"	3.905"	Pup Jt; 4-1/2" 12.6# Vam Top (B) x (P) 13cr
8046.07	1.10	4.96	3.856"	**Adapter**: 4-1/2" 12.6# Vam Top Box x 4-1/2" 12.75# TSH CS Pin 13cr (S/N: My2745521)
8047.17	**1.26**	**4.91**	**3.813"**	**HES X-Nipple** ; 4-1/2" 12.75# OECO-A (B) x (P) 13cr (S/N: MY 2820028-7)
8048.43	1.06	4.94	3.856"	**Adapter**: 4-1/2" 12.75# TSH CS B x 4-1/2" 12.6# Vam Top P 13cr (S/N: MY 2770200)
8049.49	1.96	4.98	3.915	X/O Pup Jt; 4-1/2" Vam Top X H563 B-P
8051.45				
8051.45	1.04	5.22	3.927	X/O 4 1/2" 12.6# H563 B X Vam Top P
8052.49	6.14	4.97	3.927	Pup Joint; 4 1/2" 12.6# Vam Top B-P 13Cr
8058.63	2.47	5.88	3.884	HES Mirage plug 12.6# Vam Top (B) X (P) S/N C2853748
8061.10	10.12	4.97	3.927	Pup joint 4 1/2" Vam Top (B) X (P)
8071.22	4.95	5.89	3.884	HES Auto-fil 12.6# Vam Top (B) X (P) S/N MY 2745314-1
8076.17	3.02	4.97	3.927	Pup Joint; 4 1/2" 12.6# Vam Top B-P 13Cr
8079.19	1.22	4.98	3.913"	X/O Pup Jt; 4-1/2" 12.6# Vam Top (B) X 4-1/2" 12.6#TSH 563 (P) 13cr
8080.41				
8080.41	9.95	5.245"	3.925"	Pup Joint; 4-1/2" 12.6#TSH 563 (B) x (P) 13cr
8090.36	1.22	5.245"	3.925"	**X/O Sub; 4-1/2" 12.6# TSH 563 B x 4-1/2" 12.6# Vam Top P 13Cr (S/N: MS 818760-3-2/2)**
8091.58	1.71	6.493"	2.936"	No-Go Loc; 4-1/2" 12.6# Vam Top B x 3-1/2" 9.3# TSH 563 P, 13Cr (S/N: MS 18760-9-1/1
8093.29	1.20	4.254"	2.935"	X/O Sub; 3-1/2" H563 B X 3-1/2" CSH P
8094.49	19.40	3.900"	2.920"	Blast Joint; 3-1/2" CSH (Box) X SK-Bear (Pin) (1 JOINT)
8113.89	157.49	3.900"	2.920"	Blast Joint; 3-1/2" SK-Bear (Box) X (Pin) (8 JOINTS)
8271.38	19.35	3.900"	2.920"	Blast Joint; 3-1/2" SK-Bear (Box) X CSH CSH (Pin) (1 JOINT)
8290.73	**1.34**	**3.930"**	**2.635"**	**XN Nipple: 3 1/2" 9.3#OECO-B BxP, 13Cr**
8292.07	1.31	3.938"	2.901"	Locator; 3-1/2" CSH (B) X UNS 13%cr
8293.38	7.97	3.860"	3.064"	Seal 3.88" - 3 1/2" 12UNS BxP, 13Cr
8301.35	1.14	3.860"	2.390"	Cross Over; 3-1/2" UNS (B) X 2-7/8" CSH (P)
8302.49	1.11	2.874"	2.370"	Muleshoe: 2-7/8" HCS Box, 13Cr
8303.60				
				CASED HOLE IGP ASSEMBLY
8116.11	7.88	8.48	6.00	**HES VGP Packer, 9 5/8" 43.5 - 47# x 6.00" bore with 7 5/8" 29.7# BTC Box.13Cr**
8123.99	6.59	7.70	6.88	Upper extension, 7 5/8" 29.7# STC P xP, 13Cr
8130.58	4.57	8.11	6.00	Closing sleeve assy, 7 5/8" 29.7#STC Box x 7 5/8" 39#AB HD-L Pin, 13Cr
8135.15	21.66	7.70	6.54	Middle extension, 7 5/8" 39#AB HD-L BxP, S13Cr
8156.81	1.75	7.67	5.81	Indicator coupling, 7 5/8" 39#AB HD-L BxP, 13Cr
8158.56	9.71	7.70	6.51	Lower extension 7 5/8" 39#AB HD-L BxP, 13Cr
8168.27	1.15	7.70	6.26	Adapter; 7-5/8" AB-HDL x 7" BTC (B-P)
8169.42	3.00	8.14	5.00	EGF with 7" 26# BTC Box x Pin 13Cr Ceramic Flapper Valve;
8172.42	2.08	7.67	5.05	Shear joint 7" 26#BTC Box x 6 5/8" 28#BTC Pin, 13Cr
8174.50	0.96	8.25	4.69	Adapter ; 6-5/8 API-BC (B) X 5-1/2" LTC (P).
8175.46	19.59	6.03	4.90	Blank 5 1/2" 20# LTC BxP, 13Cr
8195.05	97.98	6.12	4.78	Screen Poromax 250micron: 5 1/2" 20# LTC BxP, 13Cr
8293.03	3.75	6.11	3.88	**SBE 3.88", 5 1/2" VAMTOP BOX x LTC PIN, 13Cr**
8296.78	1.22	6.64	4.88	Adapter; 5-1/2" LTC (B) X 6-5/8" Vam Top (P)
8298.00	4.00	6.60	4.86	Collet Latch Locator 5 1/2" 17#LTC BxP, 13Cr
8302.00	5.09	6.00	4.86	Seal assy, 5 1/2" 17#LTC BxP 13Cr
8307.09	3.51	5.96	4.86	Self aligning muleshoe 5 1/2" LTC Box, 13Cr
8310.60				END OF IGP ASSEMBLY
				SUMP PACKER ASSEMBLY
8298.00	7.88	8.48	6.00	HES VGP Packer, 9 5/8" 43.5 - 47# x 6.00" bore with 7 5/8" 29.7# STC Box.13Cr
8305.88	6.39	7.70	6.88	Millout extension, 7 5/8" 29.7# STC P xP, 13Cr (cut to half muleshoe)
8312.27				END OF SUMP PACKER ASSEMBLY
				OPEN HOLE EGP ASSEMBLY
9003.11	7.89	8.48	6.00	HES VGP Packer, 9 5/8" 43.5 - 47# x 6.00" bore with 7 5/8" 29.7# BTC Box.13Cr
9011.00	6.58	7.69	6.86	Upper extension, 7 5/8" 29.7# STC P xP, 13Cr
9017.58	4.56	8.11	6.04	Closing sleeve assy, 7 5/8" 29.7#STC Box x 7 5/8" 39#AB HD-L Pin, 13Cr
9022.14	21.70	7.67	6.57	Middle extension, 7 5/8" 39#AB HD-L BxP, S13Cr
9043.84	1.75	7.67	5.81	Indicator coupling, 7 5/8" 39#AB HD-L BxP, 13Cr
9045.59	9.45	7.68	6.64	Lower extension 7 5/8" 39#AB HD-L BxP, 13Cr
9055.04	1.29	8.13	6.28	X-Over 7 5/8" 39#AB HD-L Box x 7" 26# BTC pin, 13Cr
9056.33	2.97	8.13	5.03	EGF Ceramic Flapper with 7" 26# BTC Box x Pin 13Cr
9059.30	2.06	7.66	4.97	Shear joint 7" 26#BTC Box x 6 5/8" 28#BTC Pin, 13Cr
9061.36	1.29	7.41	4.88	Adapter, 6 5/8" 24# BTC Box x 5 1/2" 20# LTC Pin,13Cr
9062.65	121.55	6.03	4.90	Blank 5 1/2" 17# LTC BOX x Pin, 13Cr
9184.20	1.03	6.12	4.79	Adapter, 5 1/2" 17# LTC Box x 5 1/2" 20# Vam Top Pin,13Cr
9185.23	77.96	6.12	4.78	Poromax Screen: 5 1/2" 20# Vam Top Box x Pin,250 micron Mesh Centalized for 7 5/8" 26.4 S
9263.19	0.81	6.11	0.00	Bull plug 5 1/2" 17# Vam top Box 13 Cr
9264.00				END OF EGP ASSEMBLY

AHTD:	AUTHOR:	DATE COMPLETED:	DRAWN BY:	CHECKED BY:	APPROVED BY:
9,265 ft	PTW/O/NG, SPDC, NIGERIA	21st March 2013	Godwin Lawson/ Yimam Orhemba	Ireti/ Ricky	Ibrahim Yahaya

Appendix 5: Top Depth Map of the GBAR-022 C5200B sand.



Appendix 6: Cross section along GBAR-022 well path



Appendix 7: Digitized Top Depth Map of the GBAR-022 C5200B sand