THE SHELL PETROLEUM DEVELOPMENT COMPANY OF NIGERIA LIMITED

AGBADA-68 WELL CLEAN-UP/TEST PROPOSAL

July 2013

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1.0 BACKGROUND

Agbada-68 is a gas development well, which targets the G8000C reservoir in the Agbada field. It has a design off take rate of 40 MMscf/d with an expectation recovery of 47 Bscf non-associated gas (NAG) and 1.7 MMstb of associated condensate respectively. Agbada-68 was drilled and initially completed in March 2011

Agbada-68 was initially completed as a single (SSS) gas producer with 4½" 13Cr tubing equipped with non-self equalising tubing-retrievable surface-controlled subsurface safety valve (TRSCSSSV) and a Permanent Downhole Gauge (PDHG) for well and reservoir surveillance. External Gravel Pack (EGP) was deployed as sand control mechanism over an interval of ca. 30 ftah (11742 – 11775 ftah).

In June 2011, the well was cleaned up and tested to its potential of 40MMscf/d. However, during demobilization of the well test equipment, casing head pressure was observed in the A-annulus and it gradually increased to ca. 1000psi.The well was secured with an NRV plug.

Full investigation on the cause of the high casing head pressure was suspended when fire erupted on site while attempting to inflow test a plug and prong downhole in the tubing to ascertain leak point. However, it is suspected that there was a leak in the H533 tubulars.

Agbada 68 was re-entered on the 20th of January 2013 for workover to eliminate the casing head pressure and change out the (suspected leaky) tubing. The workover was completed on the 26th of February 2013 with the well re-completed using a 4½" 13% Cr H563 tubulars equipped with non-self equalising tubing-retrievable surface-controlled subsurface safety valve (TRSCSSSV) and Permanent Downhole Gauge (PDHG) for well and reservoir surveillance.

1.2 Clean-Up/Test Objectives

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

- Clean up the well to get rid of kill fluids used to kill the well and other debris.
- Conduct multi-rate test to a maximum of 40 MMscf/d to determine well deliverability.
- Conduct Build up Test to obtain data required for reservoir characterization.
- Conduct Static Gradient Survey to validate initial pressure estimated from invalidated test (in June 2011).

1.3 Justification

The well's objective is to provide additional gas for the Domestic Gas Project via the new Agbada Gas Plant. This will form part of Associated Gas (AG) coming from Agbada, Obigbo and Imo River gas plants which is collected at the Obigbo sales point and sold to domestic customers as Sales Gas. The clean-up is required to get rid of any remaining completion fluid and debris resulting from the workover operation which might lead to impairment, thus resulting in a compromise of the well's potential and expectation recovery.

The well will be tested to its design off take rate of 40 MMscf/d which is within the limits of the third party test facility.

2.0 WELL CLEAN-UP DESIGN

The clean-up will evacuate the contents of the well, which consists of completion brine in the wellbore. The clean-up operation would include the deployment of 1½" coiled tubing (CT) fitted with nozzle and 10% HCL system or its equivalent to clean out the screen by jetting across it in several passes.

The acid recipe will be prepared by Halliburton and should include the following acid and additives:

Chemical	***Function***
33% HCl	Raw acid
HAI-GE	Corrosion inhibitor
Losurf 300M	Surfactant
FE-2	Iron Control
Musol	Mutual Solvent

The clean-up will then commence on a minimum choke (8/64th). There will be gradual bean-up in stages of 4/64th every two hours up to choke 20/64 until WGR of ca. 0.3 bbl/MMscf and a maximum rate of ca. 40 MMscf/d is attained. Clean-up parameters are not accurately predictable, however, Table 1.0 provides a fair guide. Figures 1.1, 1.2 and 1.3 are snapshots from PROSPER showing a graphical display of the wellbore model results. The flow rates, BSW, 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 Waste treatment plant.

Table 1.0: Agbada-68 Well Clean-Up Guide

Estimated Rate (MMscf/d)	Expected Bean Size (1/64th)	Expected FTHP (psia)	WGR (bbl/MMscf)	Condensate Rate (bbl/d)	Flow Period (hr)	Expected Drawdown (psi)
10	24	3881	0.3	846	6	28
20	32	3811	0.3	1431	4	48
30	40	3669	0.3	2132	4	74
40	46	3565	0.3	2700	4	88

Note: Final BSW on each choke should be ca. 5% or until it is stabilized for more than 1 hour.

Figure 1.1: Bean Sensitivity Plot

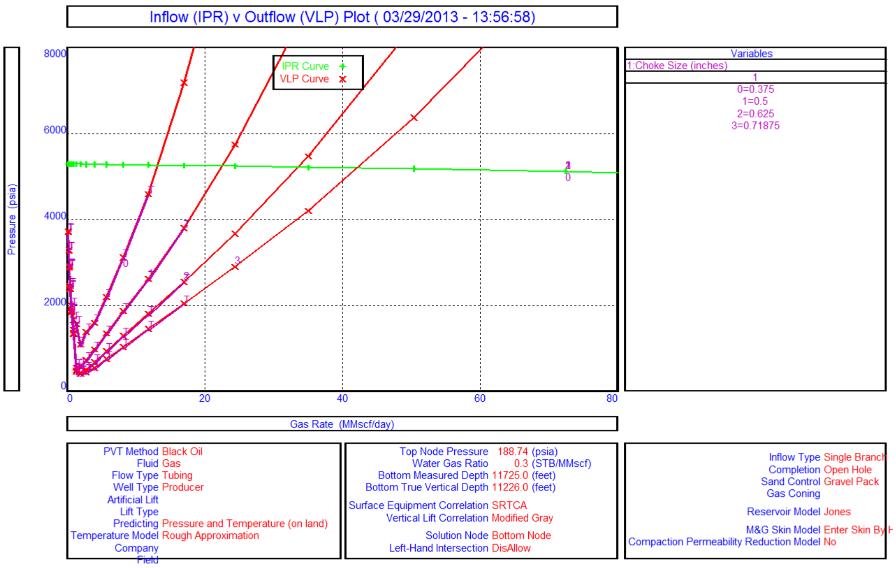


Figure 1.2 : Agbada-68 Performance Plot

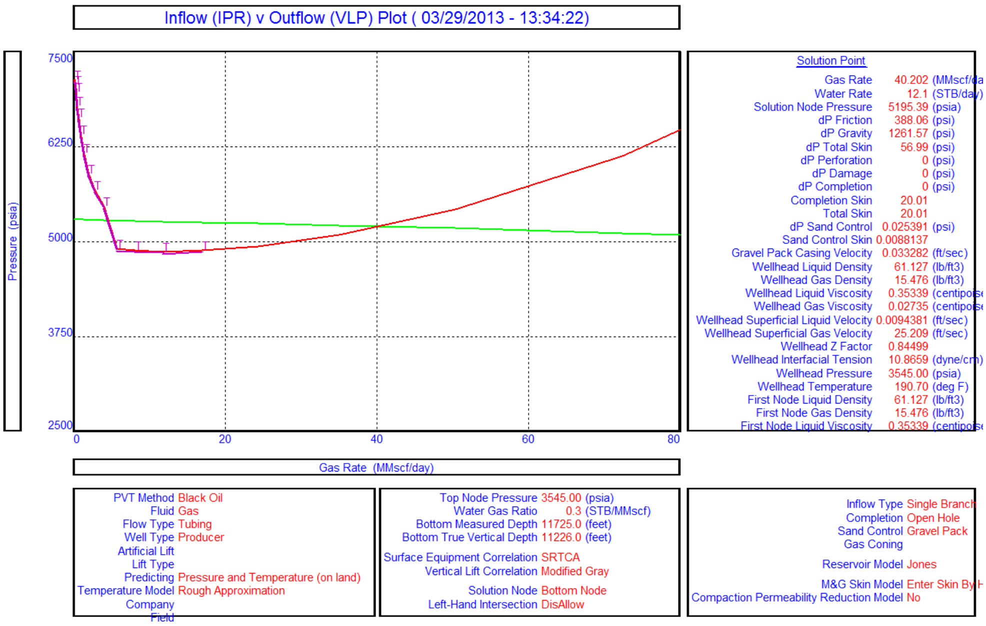
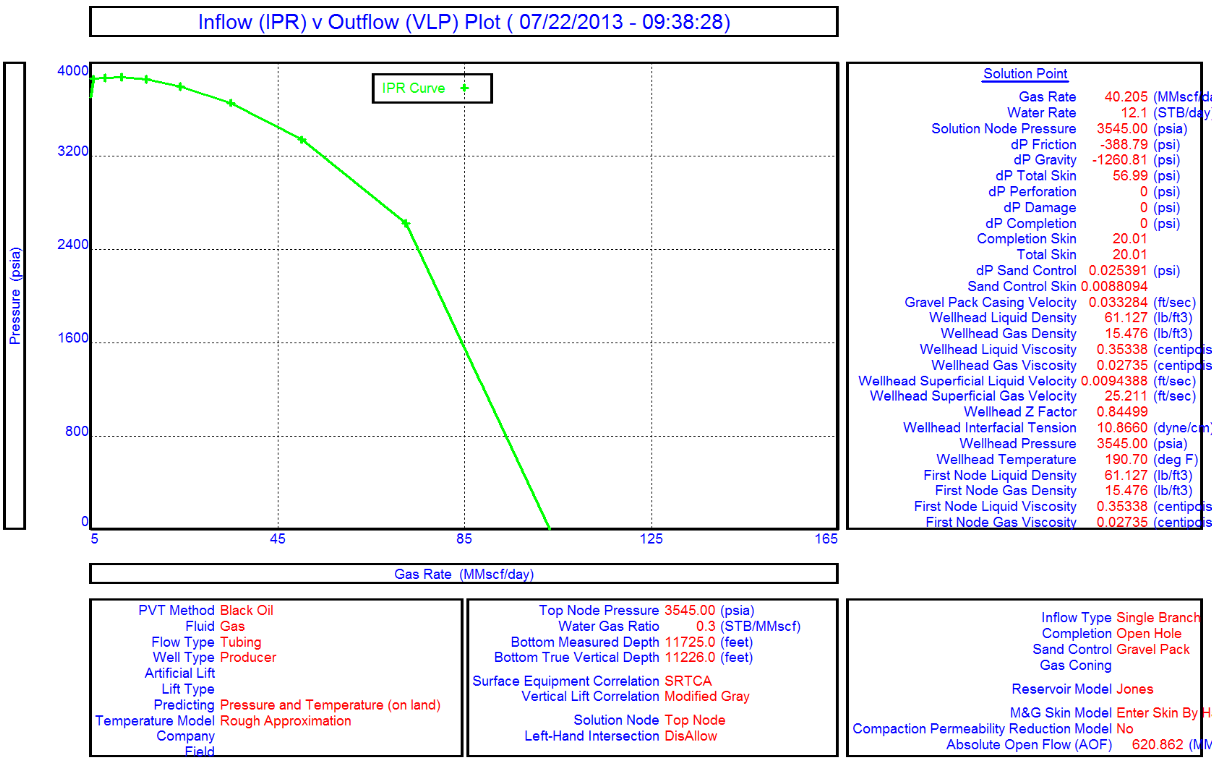


Figure 1.3: Agbada-68 P-Q curve



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

3.1 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 11,419 ftah (XN Nipple Depth); also hook-up Fibre-optic PDHG to Baker Mobile surface readout system.

3.2 Flowing Period

- Open well and carry out multi-rate test to a maximum of 40 MMscf/d as stated in Table 2.0 below:

Table 2.0: Agbada-68 Multi-rate Well Test Bean-up Sequence Guide

Estimated Rate (MMscf/d)	Expected Bean Size (1/64th)	Expected FTHP (psia)	WGR (bbl/MMscf)	Condensate Rate (bbl/d)	Flow Period (hr)
10	24	3881	0.3	846	4
20	32	3811	0.3	1431	4
30	40	3669	0.3	2132	4
40	46	3565	0.3	2700	4

Notes:

- At each stage, collect and analyse samples every 15 mins, record bean size, gas flow rate, FBHP, FBHT, estimate drawdown, FTHP, FTHT, CGR, WGR, and sand rate.
- Close in well gradually at the choke manifold.
- Commence rig down of well test equipment ONLY after flowing period

3.3 Final Build-up and Static Gradient Survey Period

- Confirm well has been closed in down-hole with programmed DHSIT for 48 hours build-up.
- Carry out static gradient (SG) survey while POOH wireline memory gauge and DHSIT at the depths as detailed in table 3.1
- 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 fibre optic data.
- Close TRSCSSSV and line up well to production.
- Handover well to production.

Table 3.0: Static Gradient Survey Stops

Depth Tag (d)	Depth (d) ftah from RT [RT Elevation = 106 ft]	Depth(d*) ftah from Top XMT [RT - Top XMT = 24ft]	Depth (d**) ftah from compact Housing [RT- Compact Housing = 30.10ft]	d_{i-1}-d_i ft	Time at depth Minutes	Comment
Deepest Survey Depth	11,419	11,395	11,389	-	0	Deepest gauge @ XN nipple
1st Stop	11,399	11,375	11,369	20	10	3 Stops at 20ft intervals closest to deepest survey point in line with BHP Guidelines (2009) to enable accurate extrapolation to reservoir pressure.
2nd Stop	11,379	11,355	11,349	20	10	
3rd Stop	11,359	11,335	11,329	20	10	
4th Stop	7,813	7,789	7,783	3,546	10	3 Stops at 200ft intervals to aid investigation of fluid regime just away from deepest survey point
5th Stop	7,613	7,589	7,583	200	10	
6th Stop	7,413	7,389	7,383	200	10	
7th Stop	4,006	3,982	3,976	3,406	10	3 Stops at 200ft intervals to aid investigation of possible condensate drop out in tubing. From 2013 ARPR Dew Point Pressure is 4858 psi. This pressure range is expected within this depth range given result of last test.
8th Stop	3,806	3,782	3,776	200	10	
9th Stop	3,606	3,582	3,576	200	10	
10th Stop	1,306	1,282	1,276	2,300	10	3 Stops at 200ft intervals to aid investigation of fluid regime close to surface.
11th Stop	1,106	1,082	1,076	200	10	
12th Stop	906	882	876	200	10	

4.0 SAPHIR TEST DESIGN

The focus of the test design is to determine the duration of the flow and optimal build up time required for the pressure perturbation to hit the boundaries/faults in the reservoir. Thus enabling the acquisition of fit for purpose data required to effectively describe (nature – open/close, distance from well, shape, etc) the boundaries. Furthermore, the test is designed to ensure that the permeability, permeability-thickness (kh), and near wellbore skin (damage/improvement) can be evaluated from analysis of the acquired field data. Kappa's Ecrin Saphir Software was used in this design.

The model was built based on the data as detailed in Table 4.1. Pressure simulations where generated based on the rates in section "e" of table 4.1. 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, boundary geometry, and skin. These sensitivities where collectively analyzed, and the optimal test time selected.

4.1 INPUT DATA

The test design input data are as detailed in the table 4.1 below:

Table 4.0: Test Design Input Parameters

Parameter	Value	Unit	Remarks
			a. Reservoir Data
Pay Zone Thickness	70	ft	Top of Reservoir as Penetrated by Agbada 68 to logged GWC (from Well Agbd 04)
Average formation Porosity	0.24	fraction	
formation Compressibility	3.E-06	psi-1	
Reservoir Pressure	5296	psi	
Reservoir Temperature	225	°F	
Reservoir Permeability	740	md	Assumed Base Case based on range of permeability in Agbada Field. Sensitivities were performed on permeability
			b. Well Data
Well Orientation	Vertical		
Well Radius	0.411	ft	
Well bore Storage (WBS) Coefficient	0.0036	bbl/psi	Estimated assuming Down-Hole-Shut-in (DHSIT) Tool deployment at XN Nipple. WBS coefficient could be as high as 0.05 bbl/psi with surface shut-in.
			c. Fluid Data
Fluid Type	Gas		
Gas gravity	0.67		
			d. Others
Reservoir Model	Homogeneous		
Wellbore model	Changing Storage		To capture possible fluid segregation (condensate dropout) and variations in density along wellbore
Boundary Model	Polygonal (GOC) and Parallel Faults		Digitized to capture geometry of reservoir in line with top structure map (see 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	@ 0 MMscf/day
1st Flow Period	4	Hrs	@ 10 MMscf/day
2nd Flow Period	4	Hrs	@ 20 MMscf/day

3rd Flow Period	4	Hrs	@ 30 MMscf/day
4th Flow Period	4	Hrs	@ 40 MMscf/day
Final Build up	96	Hrs	@ 0 MMscf/day

4.2 SCENARIO/SENSITIVITY FORMULATION

PERMEABILITY:

Based on the permeability ranges in the Agbada Field a minimum, median and maximum permeability of 500md, 740md, and 1200md[1] respectively were selected for this analysis.

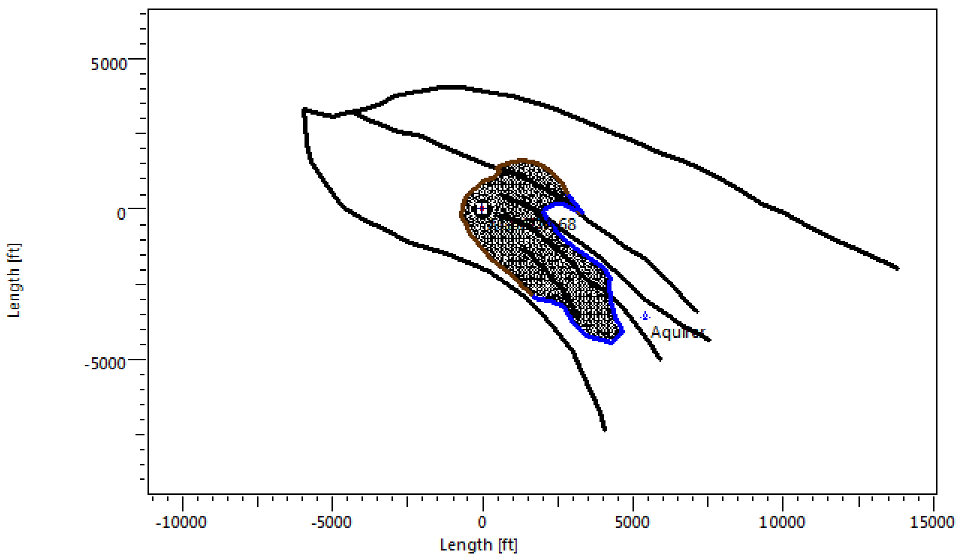
BOUNDARY MODEL:

The boundary model was digitized from the top structure map (Appendix 5). The reservoir is bounded by a GWC at 11205 ftss. Depending on the aquifer strength the GWC may be seen as a constant pressure boundary (if aquifer is very active) or a no-flow boundary (if the aquifer is immobile). From the Top Structure Map and Cross Section (Appendix 6 and 7), it can be inferred with reasonable certainty that the aquifer will offer very little or minimal support from the North, West, and South-west of the structure; this is due to the existence and orientation of faults A, E and F. Thus the aquifer charge, if any, would most likely be from the Eastern and South-eastern direction. The faults on the structure were also digitized and captured as sealing faults. In view of the above, two major boundary models where tested:

a) Aquifer active and offers support from the East/South-east direction only with faults incorporated as in top structure map. See figure 4.1 for the digitized map representing this boundary model. The blue line on the GWC indicates that the aquifer is active along that section of the GWC.
b) Aquifer inactive all-round with faults incorporated as in top structure map. See figure 4.2 for the digitized map of this boundary model.

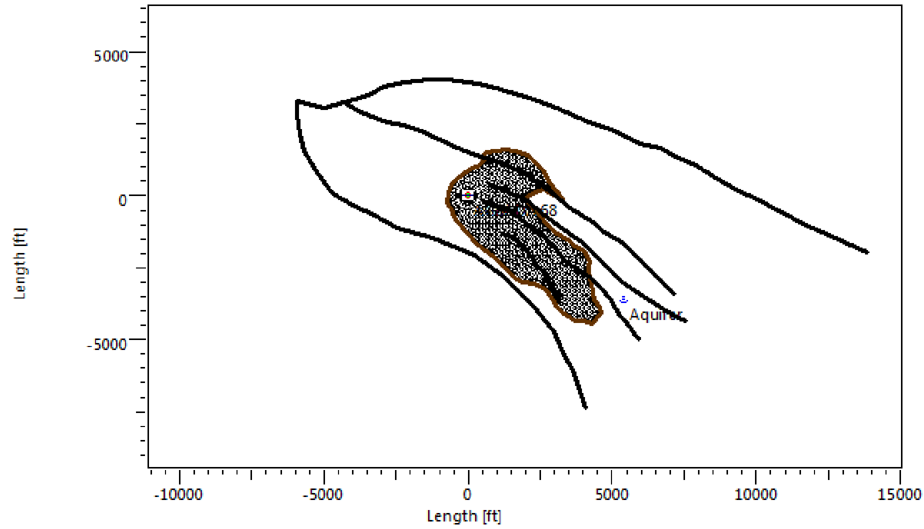
A third boundary condition was also tested were the GWC was represented as a constant pressure boundary (i.e. aquifer was active in all direction, see figure 4.10)

Figure 4.1: Map Digitization Showing Active Aquifer with Support from the East/South-East.



[1] Source: Agbada G sands Reservoir Development Plan, July 2008

Figure 4.2: Map Digitization Showing Inactive Active Aquifer.

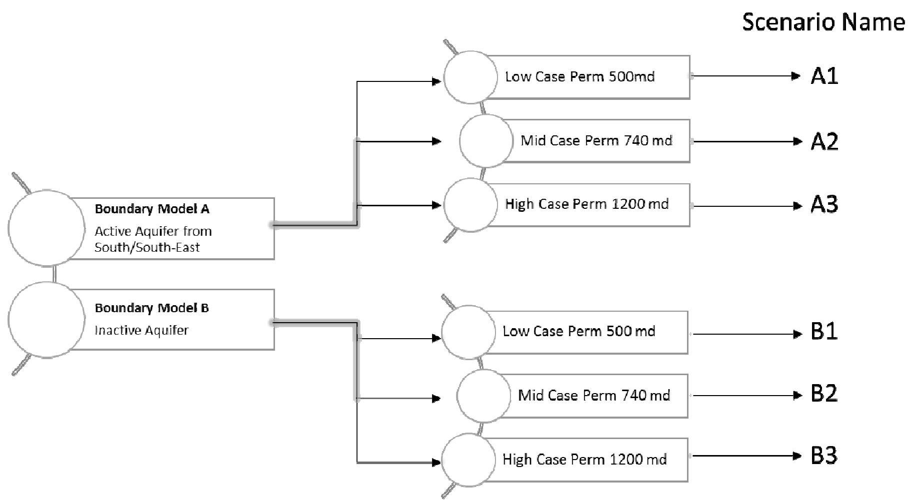


SKIN:
No data was available to evaluate the possible skin values that may exist in reality. However, sensitivity to skin values of 5, 10, 15, and 20 (selected based on expected skin range for External Gravel Pack Completion) were tested on the base case permeability and active aquifer model.

WELLBORE STORAGE:
A wellbore storage coefficient of 0.0036 bbl/psi was estimated with the Downhole Shut-in Tool (DHSIT) at the XN-Nipple (11,684.63 ftah). A high estimate of 0.05 bbl/psi was also established assuming the well will be shut in at surface to cover the possibility of DHSIT deployment failure. WBS sensitivity was run using the above WBS coefficient values and a median case of 0.03 bbl/day.

Given the above the scenarios as shown in Figure 4.3 below were simulated and the generated pressure responses analyzed.

Figure 4.3: Scenarios



4.3 ANALYSIS

Boundary Model A

The pressure responses generated from the simulation were analyzed using the pressure derivative plot. The generated pressure response for scenario A2 is as shown in Figure 4.4. As can be seen from the figure, during the final buildup the average reservoir pressure recharged to initial giving an indication of the support provided by the aquifer. The derivative plot for scenarios A1, A2 and A3 are plotted together to aid comparison on figure 4.5. In general it takes longer time for the pressure perturbation to hit the boundary for the case with the low permeability (ie A1).

Boundary Model B

The generated pressure response for the scenario B2 is as shown in Figure 4.6. As can be seen from the figure, during the final buildup the average reservoir pressure did not recharge to initial giving an indication that there is very weak support from the aquifer (no flow/closed boundary). The derivative plot for scenarios B1, B2 and B3 are plotted together to aid comparison on Figure 4.7.

The derivative plot generated from the case with the whole boundary (GWC) acting as a constant pressure boundary is as shown in figure 4.12. From this figure, it takes about 2 hrs (after the final shut-in) for the boundary to be felt. This case is very unlikely and was just examined for completeness.

Sensitivity to Skin

Sensitivity to Skin was evaluated, as shown in figure 4.8 and 4.9 on scenarios A2 and B2 respectively. The analysis showed that the ranges of skin values (0 – 20) considered does not greatly impact on the time for the pressure perturbation to hit the boundaries. However, it does affect the time to the end of wellbore storage (WBS), and at very high skins the WBS period may be long thus masking the Infinite Acting Radial Flow (IARF) period.

Sensitivity to WBS

Sensitivity to WBS coefficient was evaluated as shown in figure 4.10 and 4.11 on scenarios A2 and B2 respectively. The analysis showed that variations in WBS coefficient (within the expected range of values) do not impact the time taken for the pressure perturbation to hit the boundary. However, the higher the WBS coefficient, the longer the time to the end of WBS, and the shorter the Infinite Acting Radial Flow (IARF) period. The (low) WBS coefficient of 0.0036 bbl/day (with DHSIT deployed) resulted in the shortest WBS effect and longest IARF period; thus the usage of DHSIT will provide quality data for determination of the reservoir permeability.

The data from the test conducted in June 2011 was analyzed. The derivative plot obtained from the data is as shown in figure 4.13. From the figure, it can be seen that for the 36 hours build up, the boundaries signature was not clearly captured. Although the test was invalidated due to the leak in the tubing, this data was taken into consideration in selecting the optimal final build up time for this test.

Table 4.2 details the timings required for the final buildup to hit the boundaries for each of the scenarios as extracted from the derivative plots.

Table 4.1: Scenario Test Times.

Scenario	Initial Build Up (Pre Test) Hrs	1st Flow Period Hrs	2nd flow Period Hrs	3rd Flow Period Hrs	4th Flow Period Hrs	Final Build Up Hrs	Total Time Hrs
A1	24	4	4	4	4	50	90
A2	24	4	4	4	4	40	80
A3	24	4	4	4	4	30	70
B1	24	4	4	4	4	60	100
B2	24	4	4	4	4	50	90
B3	24	4	4	4	4	40	80

Following a detailed analysis of the derivative plots and the invalidated test data, the optimal final build up time was selected as 48 hrs. The Optimal Timings are tabulated in Table 4.3 below:

Table 4.3: Optimal Test Timings

Initial BuildUp (Pre Test) Hrs	1st Flow Period Hrs	2nd flow Period Hrs	3rd Flow Period Hrs	4th Flow Period Hrs	Final Build Up Hrs	Total Time Hrs
24	4	4	4	4	48	88

Figure 4.4: Simulated Pressure Response for Scenario A2

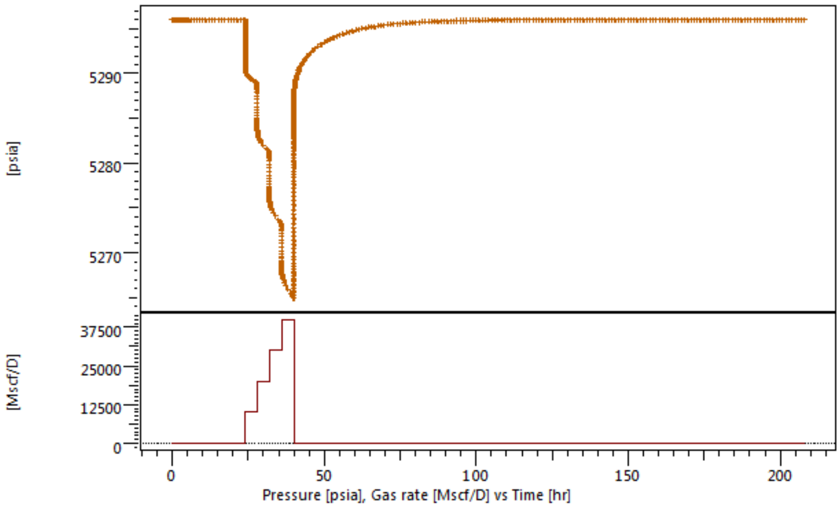
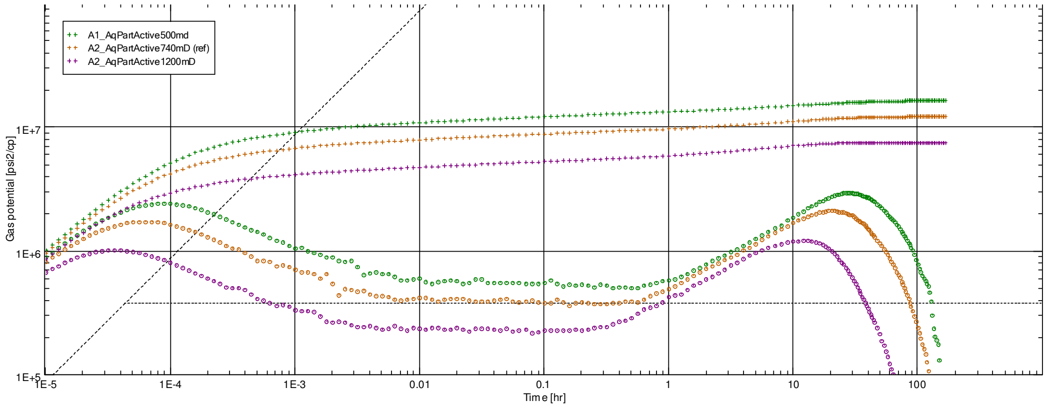


Figure 4.5: Derivative Pressure Response for Scenario A1, A2, A3



Log-Log plot: m(p)-m(p@dt=0) and derivative [psi2/cp] vs dt [hr]

Figure 4.6: Simulated Pressure Response for Scenario B2

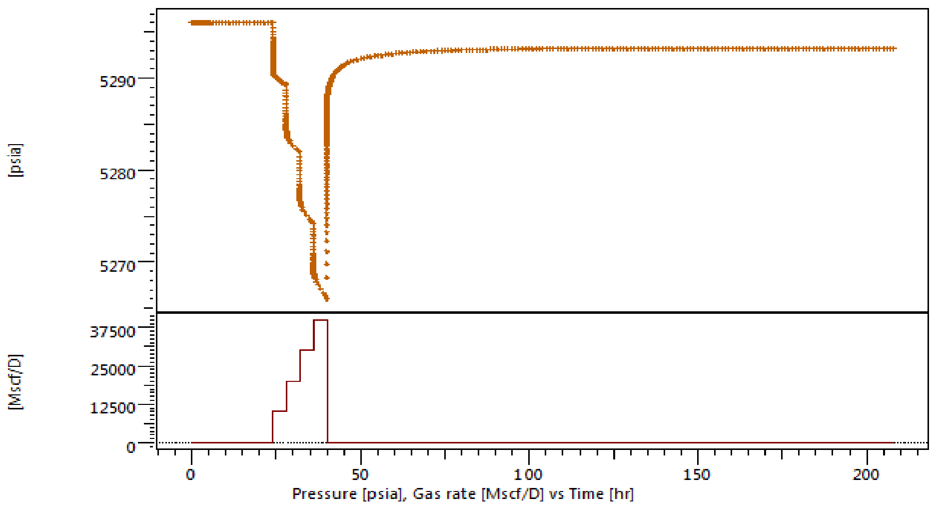
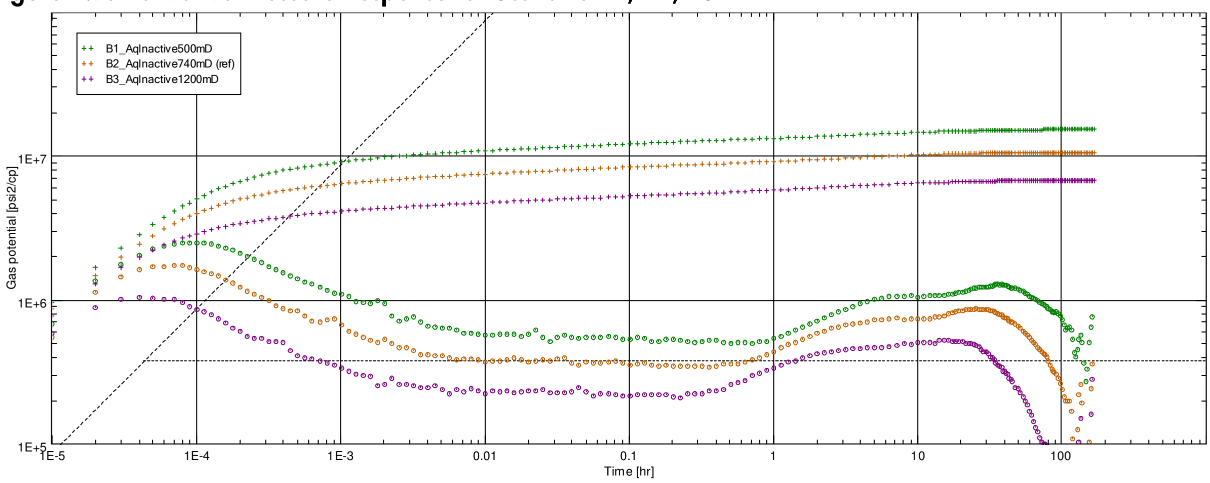
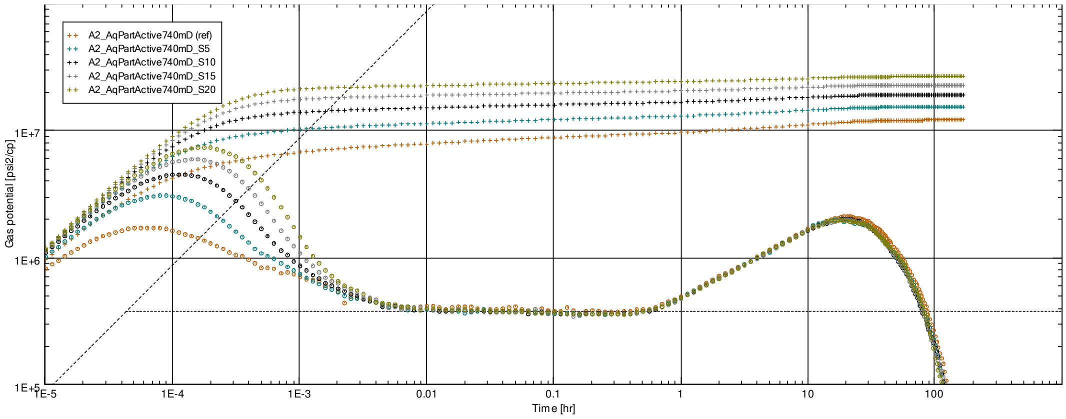


Figure 4.7: Derivative Pressure Response for Scenario B1, B2, B3



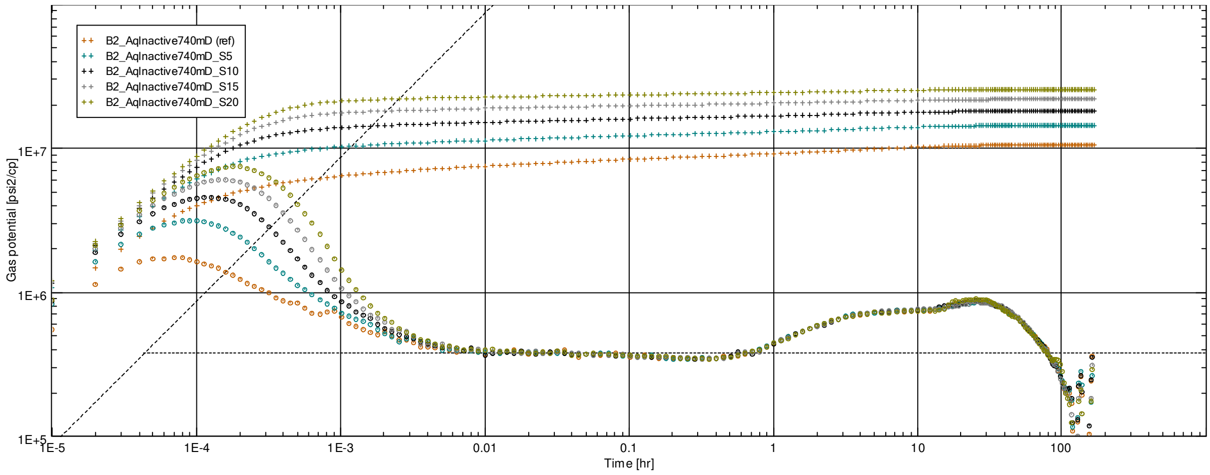
Log-Log plot: m(p)-m(p@dt=0) and derivative [psi2/cp] vs dt [hr]

Figure 4.8: Sensitivity to Skin on Scenario A2



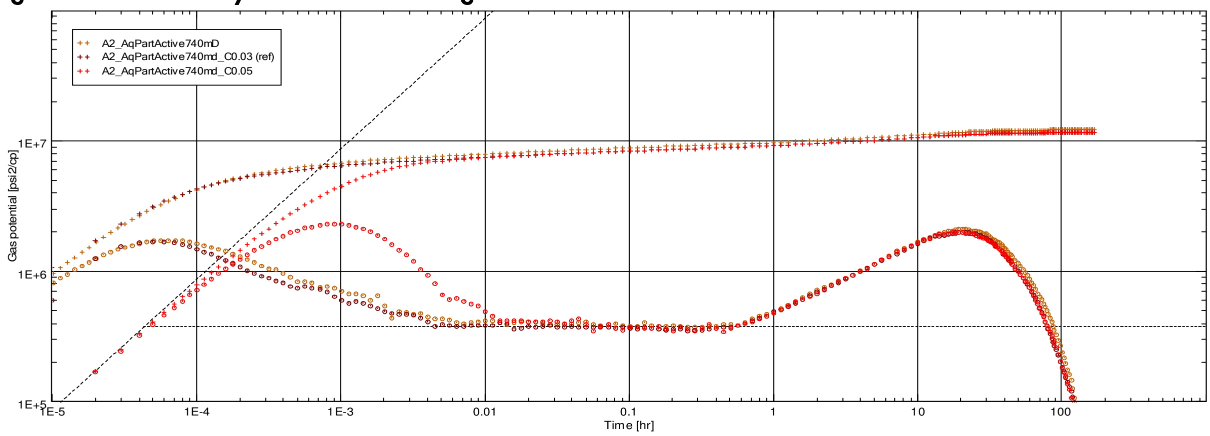
Log-Log plot: m(p)-m(p@dt=0) and derivative [psi2/cp] vs dt [hr]

Figure 4.9: Sensitivity to Skin on Scenario B2



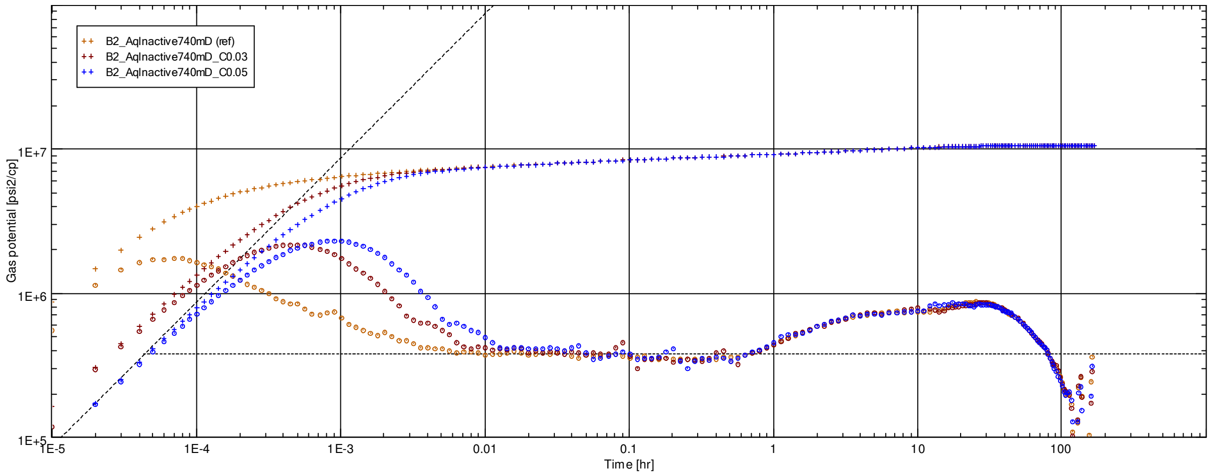
Log-Log plot: m(p)-m(p@dt=0) and derivative [psi2/cp] vs dt [hr]

Figure 4.10: Sensitivity to Well Bore Storage on Scenario A2



Log-Log plot: m(p)-m(p@dt=0) and derivative [psi2/cp] vs dt [hr]

Figure 4.11: Sensitivity to Well Bore Storage on Scenario B2



Log-Log plot: m(p)-m(p@dt=0) and derivative [psi2/cp] vs dt [hr]

Figure 4.12: Derivative Plot for Constant Pressure Boundary GWC

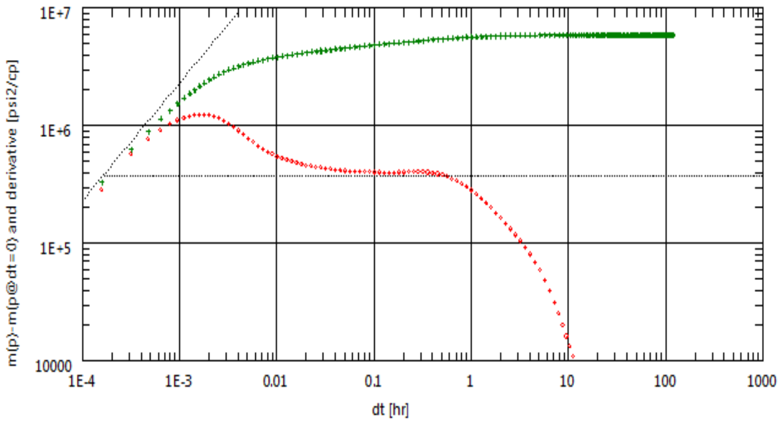
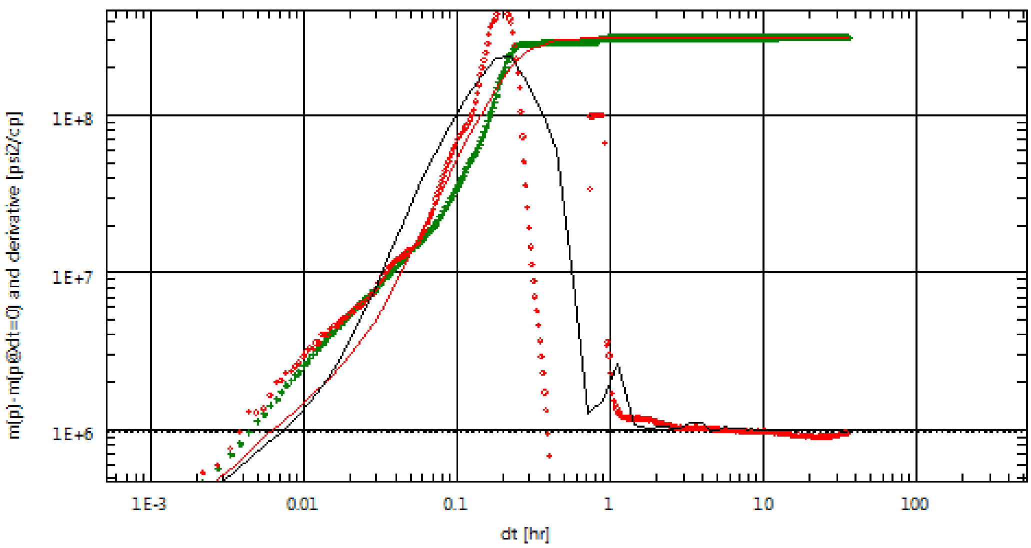


Figure 4.13: Derivative Plot from Invalidated Test Conducted in June 2011.



6.0 WORKSCOPE SUMMARY

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

- Hold pre-job safety and work scope meeting.
- Check and record wellhead pressures.
- Retrieve NRV.
- Carry out drift run with Slickline
- Pressure and function test CT.
- Run in hole with CT and carry out acid wash treatment by jetting across the screen in 3-passes and allow to soak for 1hour.
- Lift well with Nitrogen if well does not come unaided.
- Commence well clean-up (Table 1.0).Minimum BS&W requirement for cleanup is 5% (condensate volume)
- Shut-in well for 24 hours for initial reservoir stabilization.
- RIH Slickline to install memory P/T gauges with programmed DHSIT 11,575 ftah (10 ftah from XN nipple 11,585 ftah).
- Open up well and conduct Multirate test (See Table 2).
- Shut in well for 48-hour final build-up test with DHSIT in closed position.
- Carry out SG survey.
- Secure well.
- RD equipment.

NOTE:

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- Bean-up must be done gradually to achieve good bridging behind EGP.
- Bean-up should be carried out when flow stabilizes. At each stage, record bean size, gas flow rate, FBHP, FBHT, estimated drawdown, FTHP, FTHT, CGR, WGR, and sand rate.
- Flow well until well is properly cleaned, not exceeding a maximum gas rate of 40 MMscf/d. Well is properly cleaned when WGR is between 0.3 - 0.5 bbl/MMscf.

7.0 REFERENCES

1. Agbada G Sands Reservoir Development Plan, July 2008.
2. Agbada 68 Workover Proposal, August 2012.

APPENDIX 1: RESERVOIR & COMPLETION DATA

Completion Sand Name	**G8000**
Casing Size/Type	9-5/8" / Production Casing
Setting Depth (ftah)	11725
Top Sand (ftss/ftah)	11135/11742
Well TD (ftss/ftah)	11165/11775
Sand Thickness (ft tvd)	75
Gas/Condensate Reserves to be Developed by well (Bscf/MMstb)	47/1.7
Gas Gravity (air = 1)	0.67
Reservoir Pressure @ datum depth of 11205 ftss (psia)	5296
Reservoir Pressure gradient	0.476
Is reservoir fully gas bearing? What Type	Yes/Primary
Present GWC (ftss) – (RCI-Agbada-68)	11205
Actual Completion Interval (ftss)	11134 – 11163
Actual Completion Interval (ftah)	11741 - 11773
Expected FTHP [psia]	3545
Expected CITHP [psia]	3860
Expected Initial Offtake [MMscf/d]	40
Expected WGR [bbl/MMscf]	0.3
CGR [bbl/MMscf]	64
Expected FBHP (psia)	5195
Drawdown at Potential (psi)	90
Tubing size [inches]/Material	4-½"/13Cr
Tubing Accessories	TRSCSSSV
Sand Exclusion Type	EGP

APPENDIX 3: Gas Well Test Risks/Mitigation

Risk	Consequence	Mitigation
Hydrate Formation	Blocked tubular, increased pressure, blow-out, injury, and fatality.	Inject glycol at low gas rates to combat hydrate formation. Use heat exchangers at high gas rates, tubing temperatures are high enough to combat hydrate.
Ill-defined Operating Envelope	Loss of well integrity, wellhead area & surrounding environment.	Modelled well, established CITHP and MAASP.
Inappropriately Sized Tools	Downhole components/tools may not get to desired depths.	Ensure the dimensions of tools to be RIH are appropriately sized for 4-1/2" tubing and accessories/profiles ID.
Use of chemicals and liquid Nitrogen during clean up & Unloading	Environmental contamination and harm to personnel.	Ensure safe handling of treatment fluid, its constituents and liquid Nitrogen as per standard handling procedures.
Fire Source	Fire outbreak, injury, and loss of equipment, fatality.	Barricade work area, prohibit use of cell phone & smoking around well's perimeter fence, restrict movement of unauthorized persons around work area.
Hydrocarbon under Pressure	Explosion, loss of containment, injury, fatality and environmental pollution.	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.
Emergency	Loss of order, injury, fatality, loss of equipment.	Presence of 2 - barrier containment Emergency Shut Down (ESD) system for wellhead, well site & test skid. Adopt MOPO (Manual of Permitted Operations) specifying when operations should be stopped if hazard mitigation is not being met.

APPENDIX 4: AGBADA-68 Final Completion Status Diagram

AGBADA 68 FINAL COMPLETION STATUS DIAGRAM

26-Feb-13

CASING

SIZE	GRADE	WT (lbs/ft)	DEPTH (ft)	CEMENT	Conn	
24"	Stove Pipe		354	Driven		Stovepipe
13-3/8"	K55	68	5,191	Class G	BTC	Surf Csg
10-3/4"	C90	60.7	3	Class G	AMS	Prod. Csg
9-5/8"	N80	47	11,725	Class G	SLX	Prod Csg

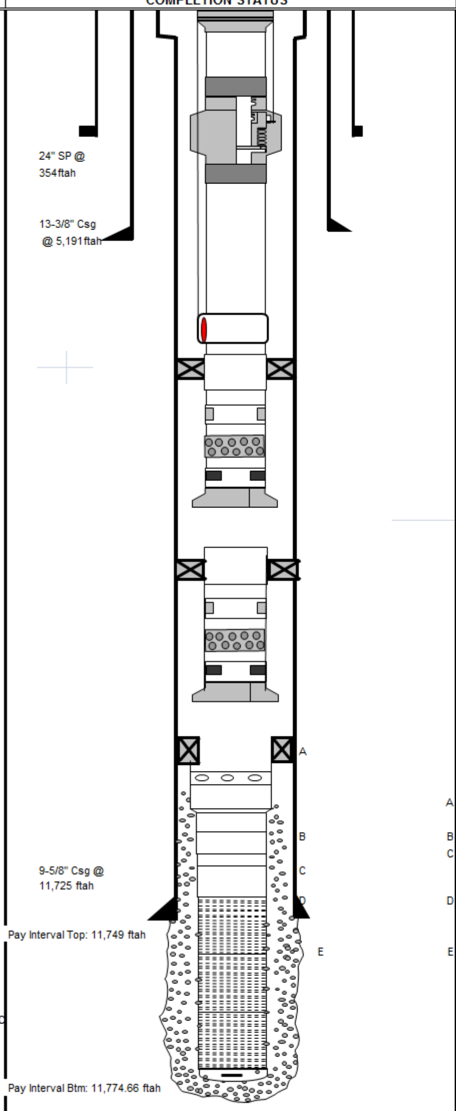
WELLHEAD (Surface Metal Seal 2 Step System)

ITEM	TYPE	SIZE	WP
XMAS TREE	SMS UNITIZED	4-1/16" x 13-5/8" Flange block x 4-1/16" outlet	5,000 psi
TREE CAP	Kvaerner	4-1/16" c/w 4.060" Bore	5,000 psi
GATE VALVE	Kvaerner	4-1/16" c/w 4.060" Bore	5,000 psi
ACTUATOR VALVE	Kvaerner	4-1/16" c/w 4.060" Bore	5,000 psi
TUBING HANGER		11" Nom X 4-1/2" w/CL & fibre optic cable prep	5,000 psi
COMPACT HOUSING	Unitized	13-5/8"	5,000 psi
GATE VALVE	Kvaerner	2-1/16" c/w 2.060" Bore	5,000 psi

TUBING

STRING	SIZE	WT. (lbs/ft)	GRAD.	TYPE	MAX Deviation: 23.451 deg @ 6763.37ftah	HOLE	DESCRIPTION	RESERVOIR
					RT - Top XMT = 24ft	10	Johnson Allpac screens / Gravel Pack	G8000C
SSS	4.5"	12.60	13Cr	Hydril 563	T-209 RIG - Elevation (RT - Compact Housing)= 30.10ft			
					T-43 RIG ELEVATION = 21.86ft	Drill-in Fluid Type / Properties	Thixsal Mud _ 0.51psi/ft _ PV/YP = 17 / 28 _ pH = 10	
					ODF = 8.24ft	Completion Fluid Type / Properties:	Filtered Inhibited KCl Brine _ 0.51psi/ft _ pH = 10	
					XMT = 6.8ft	Gas Pressure Gradient / Pressure:	0.473psi/ft _ 5,322psi @ Sand Top	

SAND | **COMPLETION STATUS**



	Top Depth	Length	O.D.	I.D.	DESCRIPTION
	29.24	**2.70**	**13.13**	**3.958**	**Tubing Hanger, 10-1/4" SSMC Mandrel Type, x 4.5" 12.75# 13Cr Hydril 533 Pin down.**
	31.94	0.64	4.930	3.958	Tbg Hanger Nipple, 4.5" 12.75# 13Cr L-80 Hydril 563 Box x Pin
	32.58	10.03	4.930	3.958	4.5" H563 B x H563 P Pup joint, 12.60# L80
	42.61	97.39	4.930	3.958	3 Tubing Joints, 4.5" 12.60# 13Cr Hydril 563 box by pin
	140.00	3.35	4.930	3.958	X/O; 4.5" 12.60# Vam Top pin X H563 box, 13Cr
	143.35	10.03	4.930	3.958	Pup Joints, 4.5" 12.60# 13Cr Vam Top box by pin
	153.38	1.10	4.930	3.985	X/O; 4.5" 12.60# Vam Top box X OECO pin, 13Cr
	154.48	9.77	4.930	3.985	Flow Coupling, 4.5" 12.60# 13Cr L-80 Hydril OECO Box x Pin
	164.25	**7.39**	**4.500**	**3.813**	**Non Equalizing SP TRSCSSSV, 4.5" 12.60# L-80 OECO bxp, 3.813" Bore**
	171.64	9.76	4.930	3.985	Flow Coupling, 4.5" 12.60# 13Cr L-80 Hydril OECO Box x Pin
	181.40	1.06	4.930	3.985	X/O; 4.5" 12.60# Vam Top pin X OECO box, 13Cr
	181.40	6.15	4.930	3.958	Pup Joints, 4.5" 12.60# 13Cr Vam Top box by pin
	182.46	6.15	4.930	3.958	Pup Joints, 4.5" 12.60# 13Cr Vam Top box by pin
	188.61	3.38	4.930	3.958	X/O; 4.5" 12.60# Vam Top pin X H563 box, 13Cr
	191.99	11,060.74	5.00	3.958	341 Tubing Joints, 4.5" 12.60# 13Cr Hydril 563 box by pin
	11,252.73	9.92	4.930	3.958	Pup Joints, 4.5" 12.75# 13Cr Hydril 563 box by pin
	11,262.65	0.69	5.00	3.958	Coupling, 4.5" 12.60# H563 Box X Box
	11,263.34	**5.43**	**6.062**	**3.833**	**Baker PDHG mandrel, 4.5",12.60# H563 Pin X Pin c/w fitted PDHG (quartz)**
	11,268.77	2.96	4.930	3.958	Pup Joints, 4.5" 12.75# 13Cr Hydril 563 box by pin
	11,271.73	32.47	4.930	3.958	1 Tubing Joint, 4.5" 12.60# 13Cr Hydril 563 box by pin
	11,304.20	3.43	4.930	3.958	X/O; 4.5" 12.60# Vam Top pin X H563 box, 13Cr
	11,307.63	**22.75**	**8.340**	**3.958**	**9 5/8" HES THT Packer Sub Assy., : 4.5" Vam Top box X pin**
	11,330.38	3.35	4.930	3.958	X/O; 4.5" 12.60# Vam Top box X H563 pin, 13Cr
	11,333.73	32.75	4.930	3.958	1 Tubing Joint, 4.5" 12.60# 13Cr Hydril 563 box by pin
	11,366.48	3.44	4.930	3.958	X/O; 4.5" 12.60# Vam Top pin X H563 box, 13Cr
	11,369.92	**16.64**	**4.930**	**3.958**	**4.5" X-Landing Nipple Sub Assy, 12.60# 13Cr Vam Top box X pin**
	11,386.56	**18.60**	**4.930**	**3.958**	**4 5" HES Auto-fill Sub Assy, 12.60# 13Cr Vam Top box X pin**
	11,405.16	**14.20**	**4.930**	**3.958**	**4 5" HES Mirage Plug Sub Assy, 12.60# 13Cr Vam Top box X pin**
	11,419.36	**49.90**	**4.930**	**3.958**	**4 5" W/L+XN Nipple+Perf. Tubg. Sub Assy, 12.60# 13Cr Vam Top box X pin**
	11,469.26		4.930	3.958	**Tail of New Completions String**
	11,470.00	20.00	4.930	3.958	**Top of Cut Tubing Joint, 4.5" 12.75# 13Cr Hydril 533 box by pin**
	11,490.00	**2.31**	**7.700**	4.790	**Ratch Latch, 4.5" 12.75# 13Cr L-80 H563 Box up SN:C1497631**
	11,492.31	**6.64**	**8.125**	**4.860**	**HES 9-5/8" x 4.85" MHR Packer, 40 - 47#, 13Cr New Vam Box SN:C1397845**
	11,498.95	6.57	7.030	6.180	Mill out extension + crossover
	11,505.52	12.36	4.930	3.958	Pup Joints, 4.5" 12.75# 13Cr Hydril 533 box by pin
	11,517.88	**1.13**	**5.220**	**3.813**	**Otis 4.5" X-Nipple,12.75# 13Cr L-80 H533 Box x Pin.**
	11,534.60	**2.47**	**5.880**	**3.813**	**HES Autofill sub, 4.5" 12.6ppf, VAM TOP 13Cr, Bst:7200psi, Cllpse:6500psi.**
	11,549.22	4.95	5.200	3.958	**4.5" HES Mirage plug, (expended), 13Cr 12.6ppf, VAM TOP Bst:6700psi, Cllpse:5000psi**
	11,584.53	31.55	4.500	3.958	**Perforated Pup Joint, 4.5" 12.75# 13Cr, H563 L-80 Box x Pin**
	11,585.65	**1.12**	**5.000**	**3.785**	**Otis 4.5" XN Landing Nipple, No-Go, 4.5" 12.75# H533 Box x Pin,13Cr.**
	11,589.64	1.30	5.200	3.958	**Mule shoe, 4.5", 12.75# 13Cr Hydril 533 Box x Pin.**
A	11,628.00	5.90	8.450	4.000	**9.625" x 4.75" BJ Compset pkr, # Packer, 4.00" Sealbore, 13Cr.**
B	11,633.00	10.00	5.500	3.750	**Upper extension, 7", 13Cr**
C	11,643.89	3.35	7.530	4.730	**5.5" Shear Out Safety Joint, " 13Cr (Not pinned)**
D	(11649 - 11641)	90.00	7.470		5.5" Blank Pipe, NU Box by Pin
E	**11,741.00**	**30.00**	**5.520**	**3.440**	**5.5" Johnson Allweld Screen, Gauge 270 micron NU Box by Pin**
	(11725 - 11774.66)		N/A	9.875	9-7/8" Open Hole
	11,773.00		4.780	N/A	Bull Plug, 5.5" # NU Box Up
	11,775.00				**TD**

NOTE: All depths are top depths along hole except were specified. Completion materials are 13% Chrome.

TD:	AUTHOR:	DATE COMPLETED:	COMPLETED BY:	CHECKED BY:	APPROVED BY:
11,775.00	CWI SPDC, NIGERIA	26/02/2013	SESAN ALAKE	CHINWE UCHENDU	YAHAYA IBRAHIM

APPENDIX 5: Agbada 68 Proposed Timeplan & Cost Estimate

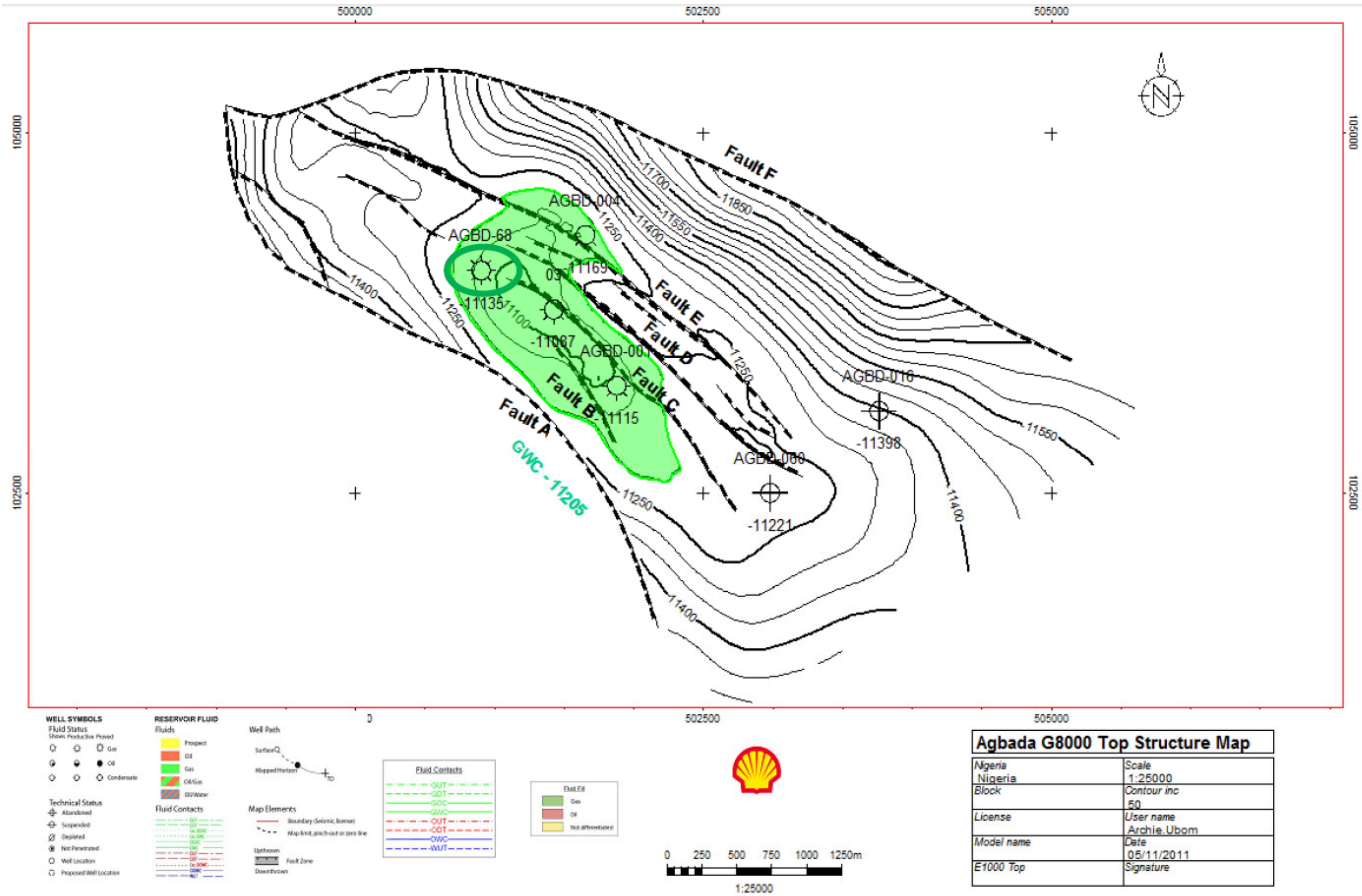
AGBADA-68 PROPOSED TIMEPLAN

	Activity	50/50 Time Estimate (Hrs)	50/50 Time Estimate (Days)
1	Mobilize Coiled tubing, WH & ancillary spread to site	24	1.0
2	Spot equipment on location	12	0.5
3	Equipment Rig up & pressure test	36	1.5
4	RIH CT to well TD @ 11,775 ft. Carry out sand face treatment	12	0.5
5	Allow solvent to soak for 1 hours	1	0.04
6	RIH CT & lift well	24	1.0
7	RD & demobilize CT from site	24	1.0
8	Mobilize MRT spread to site	24	1.0
9	Spot/RU MRT Spread.	60	2.5
10	Carry out HAZID exercise	6	0.3
11	Carry out well clean up	36	1.5
12	Shut-in well for 24 hours for initial reservoir stabilization. (RU slickline offline)	24	1.0
13	RIH slickline & drift well to xN nipple @ 11,491 ftah (can be done offline during build up)	12	0.5
14	Run in hole downhole pressure gauge and hang off at XN-nipple @ +/- 11,491 ftah	12	0.5
15	Carry out Multi-rate test	26	1.1
16	Final Build Up Survey. (commence equipment demobilization- except slickline)	24	1.0
17	Carry out Static Survey	24	1.0
18	Secure well & demobilise all equipment	24	1.0
	TOTAL TIME	**405**	**16.84**

AGBADA-68 COST ESTIMATE

S/N	Service Description	Maximum Cost ($)
1	Well test Equipment	405,625
2	WHM Operations	43,555
3	Pumping Services	219,608
4	Well test Support Services	441,840
5	Slickline Services	141,633
6	Water Facilities	16,932
7	IT Support	4,264
8	FTO	15,000
9	Security	68,600
10	Diesel	23,000
11	CT Well lift	154,385
12	Down hole gauges	36,408
13	Glycol	8,545
	Total	1,579,393.49

APPENDIX 6: AGBADA G8000 Top Structure Map



APPENDIX 7: Dip Oriented Composite Cross Section through Well 68 (focused on G4000, G6000 & G8000 sands)