THE SHELL PETROLEUM DEVELOPMENT COMPANY OF NIGERIA LIMITED

KOROAMA-007 WELL CLEAN-UP/TEST PROPOSAL

September 2016

Well No	KOROAMA-007
Reservoir	D7000X
Estimated Duration	18 days
Cost	$1,451,865.99 mln

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1.0 BACKGROUND

Koroama-007 is a gas development well that was drilled to provide a drainage point on the D7000X reservoir and develop 24.04 Bscf of gas reserves at an initial production potential of 90 MMscf/d. The well was spudded on the 7th of October 2013, drilled to a TD of 9,916 ftah (8,798 ftss), and completion operation ended on 3rd June 2014. The well partially penetrated the D7000X sand at 8,736 ftss, 18 ft deeper than prognosis and encountering a gross gas column of 62 ft tvd.

It was drilled and completed as a Single String Single (SSS) gas producer on the D7000X gas reservoir with 7" 13Cr tubing equipped with Tubing Retrievable Surface-Controlled Subsurface Safety Valve (TRSCSSSV). A 7" PDHG was initially planned but could not be run in the well due to operational constraints. External gravel pack (EGP) was installed across the sand face for effective sand control.

Koroama D7000 reservoir is one of the major reservoirs in the Koroama field accounting for 15% of the total Gas initially in place in the field with a GIIP of 337 Bscf. Production started in the reservoir July 2013 with the coming on-stream of Koroama-004 well. As at May 2016, the cumulative production from the reservoir was 72.5Bscf.

It is proposed to clean up the well to about 50 MMscf/d to remove drilling and completion debris and fluids and also conduct Multirate test to ca. 50 MMscf/d on the D7000X interval. This is due to the limit of the contractor's facilities, as the proposed offtake of the well is 90 MMscf/d of gas production.

1.1 Clean-Up/Test Objectives

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

- Clean up the well to get rid of mud filter cake, 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.

1.2 Justification

The well's objective is to provide gas to the Gbaran CPF as part of the wells delivering gas to the NLNG T1 – T6. The cleanup is required to get rid of any remaining 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.

1.3 Work Summary

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

- RIH CT with impact hammer to break the flapper at 9,747 ftah (Confirm flapper is completely broken and no any other restriction through the EGP)
- RIH CT to 5 feet above TD (9,911 ftah) while pumping KCl to displace Thixsal mud.
- Clean up by making minimum of three passes, jetting 10% HCl across the screen
- Circulate hole with KCl to displace spent acid after 30 mins and POOH CT
- Pump nitrogen (if required) to lift until well is confirmed to sustain natural flow
- Clean-up well as per program (Table-1)
- Shut-in well for 24 hours for initial reservoir stabilization (KOMA004T producing from same reservoir should also be closed-in to avoid interference).
- RIH Slickline to install memory P/T gauges with programmed DHSIT at R nipple (9518 ftah).
- Open up well and conduct Multirate test
- Shut in well for 25 hour final build-up test with DHSIT in closed position.
- Carry out SG survey.
- Secure well.
- RD equipment.

NOTE:

- Initial opening of well must be during daylight.
- Neutralize acid in flow back tank using soda ash (K-35) before dumping at the flow station.
- 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 50 MMscf/d. Well is properly cleaned-up when at least 80% of expected FTHP is achieved on any bean shown in Table-1 above
- All temporary pipe connections must be properly secured and tested to expected pressures

2.0 WELL CLEAN-UP DESIGN

During the clean-up operation, KCl will be pumped to displace Thixsal mud. Then, 10% HCL is jetted across the gravel pack screen in several passes. The well should be flowed long enough to allow sufficient time to offload well on each bean and while monitoring sand production. 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.

2.1 Clean-Up/Test Requirements

- Calibrated surface and downhole quartz gauges.
- Liquid knock out vessel
- Surface Tanks - to receive initial well effluent; completion and kill brine, mud etc.)
- Coiled Tubing/Nitrogen
- Slick line
- Flare head burner (Compulsory requirement)
- Mono- Ethyl Glycol (To mitigate hydrates at low rates)

2.2 Well Clean-Up Operation

The well cleanup operation will commence with unloading operation via coiled tubing. The clean-up will then commence from choke 36/64th (Note bean should be gradually increased to 36/64th). There will be gradual bean-up in stages of 4/64th up to choke 64/64. 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 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 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: KOROAMA-007 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
20*	40	0	2358	6	48	Take sample, check for sand, measure FTHP.
30	48	0	2353	3	68	Take sample, check for sand, measure FTHP.
40	56	0	2336	3	91	Take sample, check for sand, measure FTHP.
50	64	0	2296	4	120	Take sample, check for sand, measure FTHP.

*Clean-up criteria as shown below must be achieved on bean 40/64 as a minimum

Clean up criteria
Stabilized THP for 1 hour
BSW of liquid sample </= 5%
Tolerance Qg: ± 5 MMscf/d, Tolerance FTHP: ± 20 psia

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.
- RIH Slickline and install pressure/temperature memory gauge and Down Hole Shut-In Tool (DHSIT). Deepest gauge should be at "R – Nipple" (ca.9518 ftah).
- Monitor surface read-out of CITHP for pressure stabilization before proceeding to MRT. Also KOMA004T which is producing from the same reservoir should be shut-in to minimize interference.

3.2 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. See Table 2 below for guide on production parameters during the flow period.

Table 2 MRT data

Estimated Rate (MMscf/d)	Expected Bean Size (fixed choke) (1/64th)	Assumed WGR (bbl/MMscf)	Expected FTHP (psia)	Flow Period* (hr)	Expected Drawdown (psi)	Comments
20*	40	0	2358	4	48	Take sample, check for sand, measure FTHP.
30	48	0	2353	4	68	Take sample, check for sand, measure FTHP.
40	56	0	2336	4	91	Take sample, check for sand, measure FTHP.
50	64	0	2296	4	120	Take sample, check for sand, measure FTHP.

**Note KOMA004T (producing from same reservoir) should be closed-in after clean-up, kept close until MRT/Build-up are completed. Bean up should be carried out when flow stabilizes and FTHP & BSW are stable for at least 1 hour.*

- At each choke, collect and analyze sample every 15 minutes, record gas flow rate, FTHP, FTHT, CGR, WGR, and sand rate.
- After the last flow period, shut in well for 25 hours (Final Buildup duration determined from section 4.0) and subsequently commence Static Gradient Survey (See Table 3 below).

3.3 Final Build-up and Static Survey Period

- Confirm well has been closed in for 25 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)	di-1-di	Time at depth	Comment/Basis for Stops Selection
	ftah from DFE [DFE Elevation = 34 ft]	ft	Minutes	
Deepest Survey Depth	9518	-	0	Deepest Survey depth. R nipple Depth
1st Stop	9498	20	10	1st Set of Stops: 3 Stops at 20ft intervals closest to deepest survey point enable accurate regression/ extrapolation to reservoir pressure.
2nd Stop	9478	20	10	
3rd Stop	9458	20	10	
4th Stop	9258	200	10	2nd Set of Stops: 3 Stops at 200ft intervals to ensure accurate estimate of well fluid gradient
5th Stop	9058	200	10	
6th Stop	8858	200	10	
7th Stop	8658	200	10	3rd Set of Stops: 3 Stops at 500ft intervals to ensure accurate estimate of well fluid gradient
8th Stop	8158	500	10	
9th Stop	7658	500	10	
10th Stop	7158	500	10	4th Set of Stops: 3 Stops at 1000ft intervals to ensure accurate estimate of well fluid gradient
11th Stop	6158	1000	10	
12th Stop	4158	2000	10	
13th Stop	2158	2000	10	5th Set of Stops: 3 Stops at 2000ft intervals to ensure accurate estimate of well fluid gradient
14th Stop	158	2000	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, 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 production data as detailed in Table 2. Pressure simulations were generated based on the rates in section "e" of Table 4. 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 and also achieve stabilization of 0.01 psi/hr as seen in SAPHIR (Note that priority was given to the time to seeing an outer boundary effect). Various scenarios (sensitivities) were built to test what the pressure response would be given the uncertainties in permeability and skin. These sensitivities were collectively analyzed, and the optimal test time selected.

4.1 Input Data

The test design input data are as detailed in the table 4 below:

Table 4: Test Design Input Parameters.

Parameter	Value	Unit	Comment
a. Reservoir Data			
Pay Zone Thickness	80	ft	Average D7000 Reservoir thickness
Average Formation Porosity	0.25	fraction	KOMA-07 EOWR
Formation Compressibility	3.32E-06	psi-1	Estimated using Hall correlation.
Reservoir Pressure	3025	psi	Estimated current pressure based on MBAL
Reservoir Temperature	153	F	KOMA-07 EOWR
Reservoir Permeability	1680	md	Mean reservoir permeability seen by well logs across D7000 Reservoir
b. Well Data			
Well Orientation	Vertical		
Well Radius	0.35	ft	
Well bore Storage (WBS) Coefficient	0.1041	bbl/psi	Estimated using the total volume of fluids expected in the wellbore if the shut-in was carried out at the surface. If DHSIT is used at the Nipple, C can be as low as 0.005 bbl/psi
c. Fluid data			
Fluid Type	Gas		
Gas gravity	0.74		KOMA-07 EOWR
d. Others			
Reservoir Model	Homogeneous		
Wellbore Model	Constant storage		
Boundary Model			
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	4	Hrs	Flow @ 50 MMscf/day
Final Build up	25	Hrs	Flow @ 0 MMscf/day

4.2 Scenario/Sensitivity Formulation

PERMEABILITY:

The permeability values used in this design represent P10, P50 and P50 average Permeability estimates from log evaluation in 3 wells (KOMA 001, 002 & 010). A minimum, most likely and maximum value of 450mD, 1680mD and 3640mD respectively were derived and used in the design.

BOUNDARY MODEL:

The TOP structure Map (Appendix 5) was digitized and used in the design. The reservoir is bounded by an OOWC at 8844 ftss but also has an OGOC at 8833 ftss, giving rise to a small oil rim of 11 ft. From the top structure map and cross section (Appendix 5&6), the reservoir geometry is relatively simple. A review of the structure shows that the reservoir is fault bounded in all direction. This formed the basis for digitizing the map with closed boundaries. This is supported by the behaviour of the pressure as seen in this reservoir which indicates that the reservoir is bounded on all sides and therefore no pressure support. Also, with no intra reservoir faults, the outer boundary to be seen by the well will likely be the boundary faults.

SKIN:

No data was available to evaluate the possible skin values that may exist in reality. However skin values of 5, 7 and 10 (selected based on expected skin range for External Gravel pack completion) was studied.

WELLBORE STORAGE:

A wellbore storage coefficient of 0.1041 bbl/psi was estimated for surface shut in. For down-hole shut in at the R Nipple, the wellbore storage was estimated to be ca. 0.005 bbls/psi.
The well test design was carried out using well bore storage of 0.1041 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 Figure 1 below were simulated and the generated pressure responses analyzed.

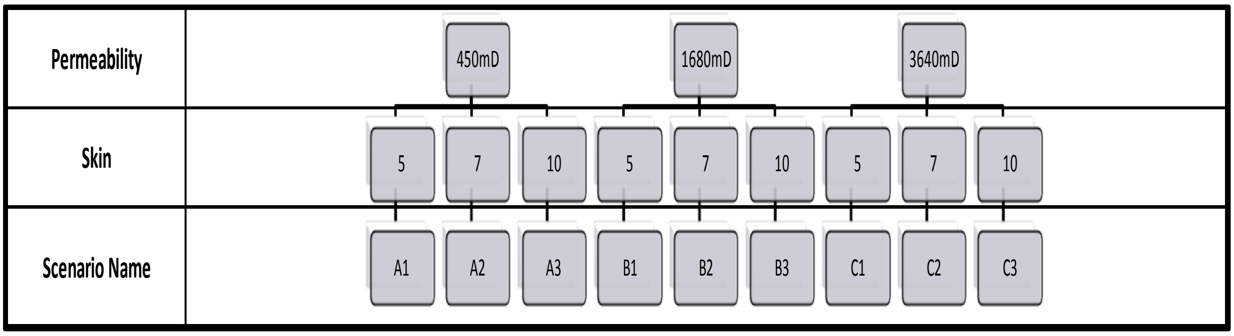


Figure 1: Scenario

Table 5: Reservoir Model & Wellbore model Parameters

Parameter	Value	Unit
Well & Well Bore Parameters		
Well bore Model	Constant Wellbore Storage	
Wellbore Storage Coefficient (C)	0.1041	bbl/psi
Skin Factor	7 (base case sensitivity)	
Reservoir & Boundary Parameters		
Pi	3025	Psia
K.h	134,400 (base case sensitivity)	md.ft
Reservoir Model	Homogenous	

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 (20, 30, 40, & 50 MMscf/d respectively).

Based on study conducted for Koroama field as captured in the Koroama FDP of 2007, the D7000 reservoir show a permeability range of 500mD to 3500mD. These values were based on log data from KOMA 002. However, the reservoir permeability range used in the design was based on the range of permeability derived from well logs as seen by 3 wells (KOMA001, 002 and 010). KOMA 004 MRT result would have helped in the choice of a permeability range, it was however inconclusive. Design sensitivity analyses were carried out for reservoir permeability values of 450mD, 1680mD, 3640mD. A reservoir pressure value of 3025 psia was used in the evaluation based predicted pressure from material balance modeling for the reservoir at September 2016. The initial reservoir pressure of 3,841 psia could not be used considering that KOMA 004 completed on this reservoir is in production.

The derivative plots for the different scenarios can be seen in figures 2, 3 and 4. From the figures, the following can be deduced

1. The variation in the skin values will not result in any significant distortion to the expected reservoir behaviour and no impact on the time to the outer boundary from the test.
2. The late time pressure response indicated an outer boundary primarily dominated by initially a parallel fault boundary effect and then an intersecting fault behaviour in the case of permeability of 1680mD.in the 450mD permeability scenario, the type of outer boundary effect is most likely the parallel fault within the time frame of test, however, it requires more time to see the other boundaries. In the 3640mD permeability scenario, a slight deviation was observed around 40 - 50 hours of shut-in. this is most likely to be caused by the effects of the pressure transient seeing all the boundaries of the reservoir. However, more time is required to be able to define properly the outer boundary effect seen by that response.

3. With the assumed base-case permeability of 1680mD, a minimum of 10 hours is required for the final build up test to start seeing the outer boundary effect. For the permeability value of 450mD, a minimum of 25 hours is required for the outer boundary effects to be felt by the test and pressure stabilization achieved. The outer boundary effects will be felt as early as 5 to 10 hours for the high permeability value scenario. Based on the above, a minimum of 25 hours is required by the test in all scenario to feel the effect of the outer boundary effect.

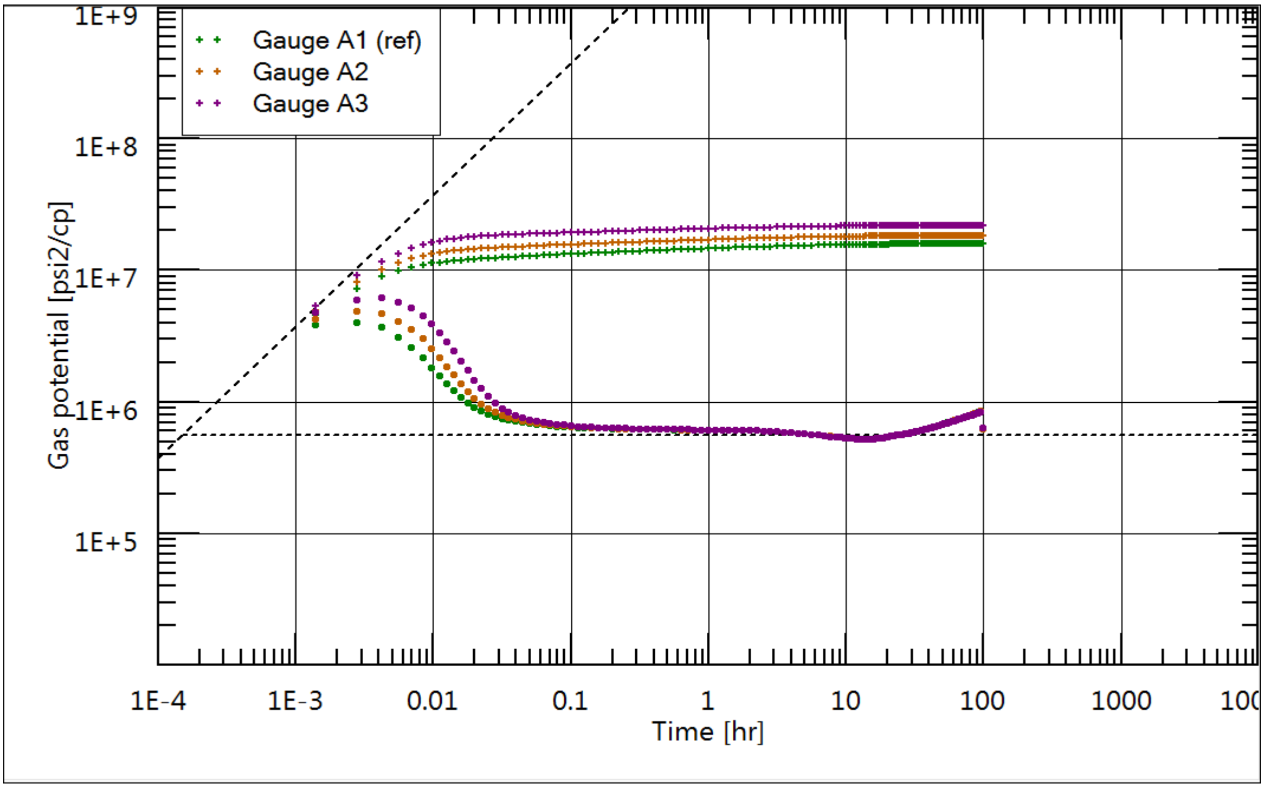


Figure 2: Log-Log plot for Scenario A1 (Perm/Skin: 450mD/5), A2 (Perm/Skin: 450mD/7), A3 (Perm/Skin: 450mD/10)

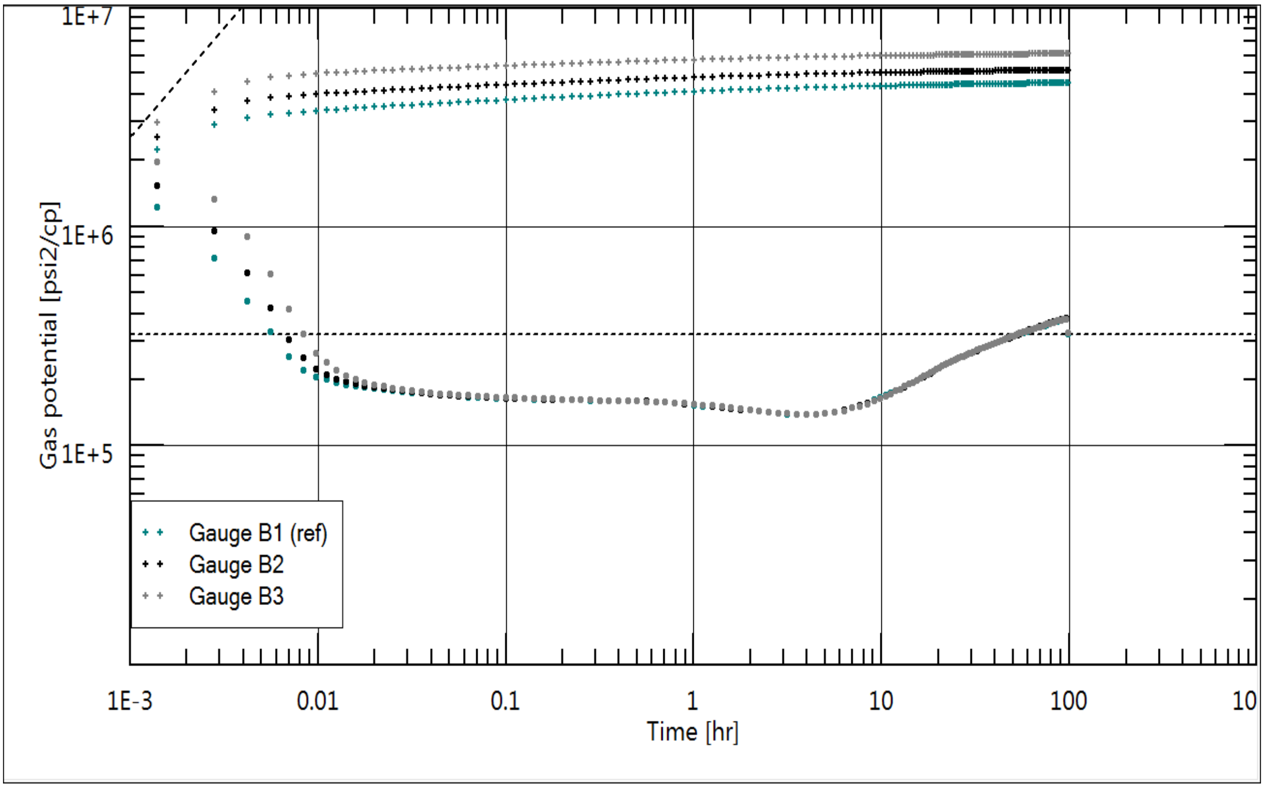


Figure 3: Log-Log plot for Scenario B1 (Perm/Skin: 1680mD/5), B2 (Perm/Skin: 1680mD/7), B3 (Perm/Skin: 1680mD/10)

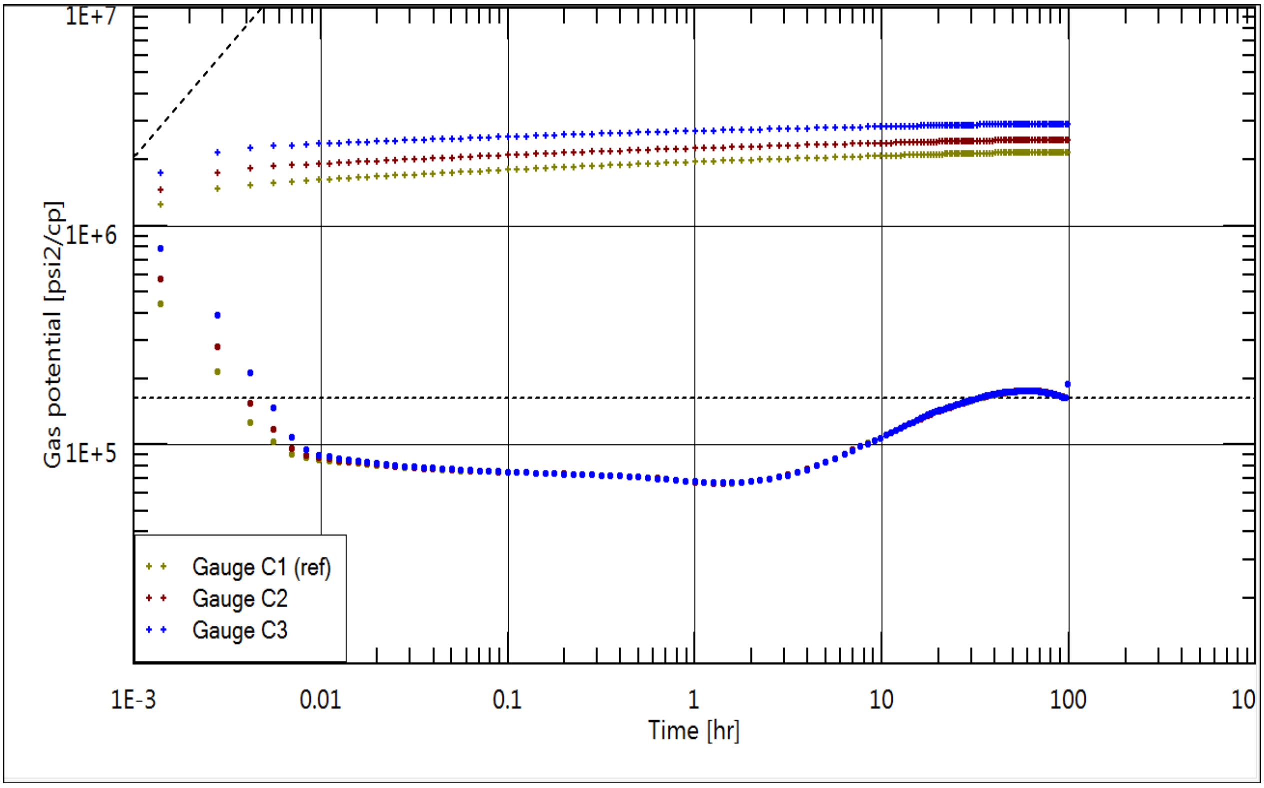


Figure 4: Log-Log plot for Scenario C1 (Perm/Skin: 3640mD/5), C2 (Perm/Skin: 3640mD/7), C3 (Perm/Skin: 3640mD/10)

Table 6: Scenario Test Times

Scenario	Initial Buildup (Pre Test) hrs	1st Flow Period Hrs	2nd Flow Period Hrs	3rd Flow Period Hrs	4th Flow Period Hrs	Final Build Up (Time to boundary) Hrs	Total Time Hrs
A1	24	4	4	4	4	30	70
A2	24	4	4	4	4	30	70
A3	24	4	4	4	4	30	70
B1	24	4	4	4	4	20	60
B2	24	4	4	4	4	20	60
B3	24	4	4	4	4	20	60
C1	24	4	4	4	4	10	50
C2	24	4	4	4	4	10	50
C3	24	4	4	4	4	10	50

The optimal time for the final build-up was selected based on the need to ensure that the objectives of the test are achieved regardless of the scenario experienced during the actual test and considering that the low case starts to feel the effect of the outer boundary effect around 25 hours, the optimal time will be that minimum. The optimal test time selected is as detailed in the table below.

Table 7: Optimal Test Timing

Scenario	Initial Buildup (Pre Test) hrs	1st Flow Period Hrs	2nd Flow Period Hrs	3rd Flow Period Hrs	4th Flow Period Hrs	Final Build Up (Time to boundary) Hrs	Total Time Hrs
A1	24	4	4	4	4	25	65

5.0 WORKSCOPE SUMMARY

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

- Hold pre-job safety and work scope meeting.
- Check and record wellhead pressures.
- Retrieve NRV.
- Pressure and function test CT.
- RIH CT to 5 feet above TD (9,911 ftah) while pumping KCl to displace Thixsal mud.
- Confirm ceramic flapper at 9747 ftah is completely broken and no any other restriction though the EGP
- At TD, switch over to 10% HCl acid, make three passes across the screen and allow to soak for 30 mins.
- Lift well with Nitrogen if well does not come unaided.
- Commence well clean-up (Table 1).
- Shut-in well for 24 hours for initial reservoir stabilization.
- RIH Slickline to install memory P/T gauges with programmed DHSIT at R nipple (9,5 18 ftah).
- Open up well and conduct Multirate test (Table 2).
- Shut in well for 25 hour final build-up test with DHSIT in closed position.
- Carry out SG survey.

- Secure well.
- RD equipment.

NOTE:

- Initial opening of well must be during daylight.
- Neutralize acid in flow back tank using soda ash (K-35) before dumping.
- 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, to a maximum gas rate of 60 MMscf/d. Well is properly cleaned-up when at least 90% of expected FTHP is achieved and WGR is less than 1 stb/MMscf on any bean shown in Table-1 above

6.0 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.

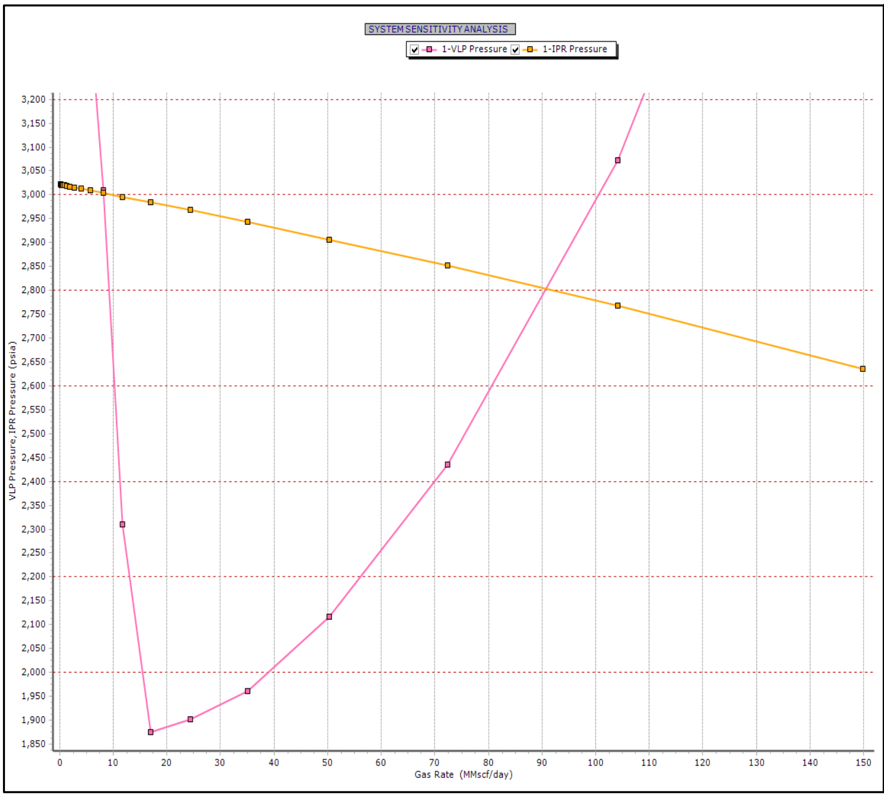
APPENDIX 1: RESERVOIR & COMPLETION DATA

Target Reservoir	D7000X
1. Casing size and Type	9-$^{5}/_{8}$''/Production casing
2. Casing Setting Depth (ftah)	9,841
3. Top of Sand [ftss/ftah]	8,736/9,830
4. Gross Sand Thickness (Gross) penetrated by Koroama-007 (ft tv)	62
5. Well TD (ftss/ftah)	8,798/9,916
6. a) Completion interval (ftss) b) Completion interval (fttv) c) Completion interval (ftah)	8,740 - 8,798 8,811- 8,869 9,841 - 9,916
7. Length of Completion Interval (ftah)	75
8. a) Top of competent cement (ftah) b) Source of data	7,300 CAST-CBL
9. a) Was hole directionally drilled? b) Max deviation angle and depth (ftah)	Yes 39.73° @ 8,832
10. Deviation at completion zone	39.51^{0}
11. 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)*	3,841 8,833 3,025 153 8,736 3,025
12. Did RCI indicate abnormal pressures?	No (ref KOMA-010 RCI)
13. Pressure gradient @ top of sand (psi/ft)	0.4147
14. a) Is the reservoir fully gas-bearing?	No
15. a) Is there original GWC in the reservoir b) What depth (ftss)? c) Change in PGWC from original OGWC (ft)	Yes 8,833 (KOMA-002) No (11 ft oil rim)
16. Distance between lowest completion interval and estimated GOC in well / reservoir (ftss)	35
17. Is there a barrier between lowest completion interval and the present estimated GWC?	No
18. Gas S.G. (air=1)	0.74
19. Condensate gravity (API)	44
20. Expected FTHP (psia)**	2103
21. Expected CITHP (psia)	2450
22. Expected Drawdown (psi)**	223
23. Expected PI (scf/d/psi^2)**	70
24. Is sand exclusion installed?	Yes (EGP)

* Estimated reservoir pressure is based om MBAL prediction as at October 2016
**Values are at well potential of 90 MMscf/d

APPENDIX 2: WELL PERFORMANCE PLOTS

KOMA-7 MRT Well Performance

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SUMMARY DATA
           Fluid  Gas
      PVT Method  Black Oil
       Separator  Single-Stage
       Emulsions  No
        Hydrates  Disable Warning
 Water Viscosity  Use Pressure Corrected Correlation
     Water Vapour  Calculate Condensed Water Vapour
 Viscosity Model  Newtonian Fluid
    Steam Option  No Steam Calculations
       Flow Type  Tubing
       Well Type  Producer
 Artificial Lift  None
      Predicting  Pressure and Temperature (on land)
Temperature Model  Rough Approximation
           Range  Full System
      Completion  Open Hole
    Sand Control  None
     Inflow Type  Single Branch
            Date  17/11/2006

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SYSTEM SENSITIVITY ANALYSIS - INPUT DATA
           Top Node Pressure  1464.70  (psia)
Surface Equipment Correlation  SRTCA
     Vertical Lift Correlation  Modified Gray
               Solution Node  Bottom Node
                 Rate Method  Automatic - Geometric
      Left-Hand Intersection  DisAllow
         Bottom Measured Depth   9841.0  (feet)
    Bottom True Vertical Depth   8811.0  (feet)

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INFLOW PERFORMANCE DATA (GAS WELL)
            Inflow Type  Single Branch
             Completion  Open Hole
           Sand Control  None
             Gas Coning
         Reservoir Model  MultiLayer - dP Loss In WellBore
Perm(k) Reduction Model  No
   Reservoir Temperature  145.00  (deg F)

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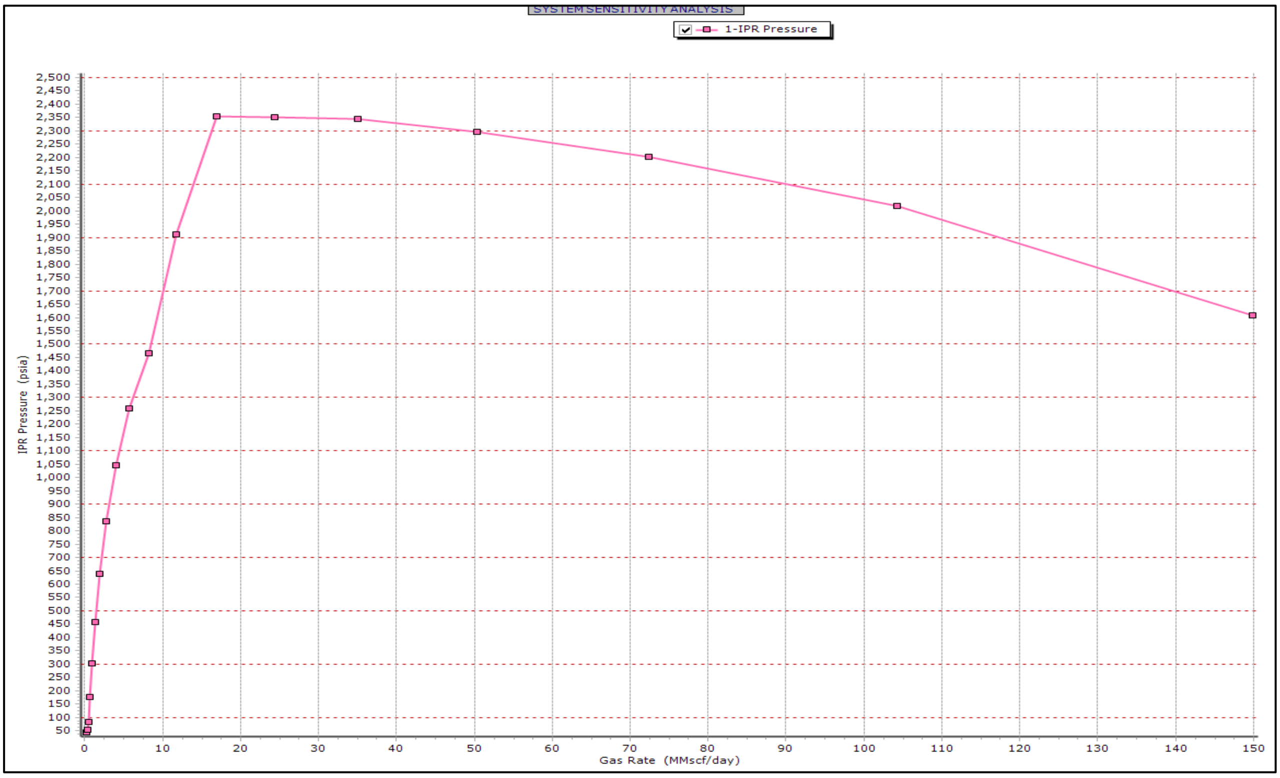
KOMA-7 P-Q Curve.



APPENDIX 3A: CRITICAL WELL TEST OPERATIONS RISKS/MITIGATION

Risk/Description	Consequence	Likelihood / Impact (L/M/H)	Mitigation
Inappropriately sized coiled tubing tools	Downhole components/tools may not get to desired depths	L/M	Ensure the dimensions of the tools to be RIH are appropriately sized for 3-1/2" tubing accessories/profiles ID
Emergency to spill, loss of containment	Loss of order, injury, fatality, loss of equipment	L/H	Ensure presence of 3-barriers at all time during clean-up/MRT operations. Also ensure all HAZID actions are closed-out prior to commencing operation
Hydrocarbon under pressure from kick or blowout	Explosion, loss of containment, injury, fatality and environmental pollution	L/H	Check integrity of the valves on the wellhead and WRSCSSV are integrity. Install surface readout gauges to monitor pressures and ensure BOP for the coil tubing unit is fully functional
Corrosive cleaning chemicals	Corrosion, environmental contamination.	L/H	Confirm that Nitrogen for lifting is tolerated by tubing/casing material.
Failure of Downhole Shut-in Tool	In-accurate estimate of wellbore storage, impact on well test results	M/M	Ensure tool is checked at the contractor's base and confirmed operational before deploying

APPENDIX 3B: GAS WELL TEST RISKS/MITIGATION

Risk	Consequence	Mitigation
Hydrate Formation	Blocked tubulars, increased pressure, blow-out, injury, and fatality.	Glycol will be injected at low gas rates to combat possible hydrate formation. At gas high rates, tubing temperatures are high enough to combat hydrate.
Noise (Flare)	Damage to personnel eardrum, partial or permanent deafness.	Certified earplugs to be worn by personnel on site.
Radiation/Heat	Unconducive work environment, environmental degradation (loss of economic trees, scotching of flora, fauna migration & death).	Conduct pre-well test modelling of wind flow and speed for optimal location of flare boom. Wear appropriate personal protective equipment at all times in the location. Mobilize water-spraying machines to reduce impact of heat radiation.
Corrosion	Compromised well integrity, uncontrolled emission, harm to flora & fauna population, loss of well, injury, fatality, loss of reputation.	13%Cr, completion material eliminates the need for corrosion inhibitor injection. Also wellhead have stainless steel clads.
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.
Night Operations	Poor emergency response, damage to asset, injury, fatality	Obtain night operation approvals, Deploy Emergency Shut Down (ESD) system. Appoint competent Night operations Supervisor.
Emergency	Loss of order, injury, fatality, loss of equipment.	Presence of 3-barrier containment Emergency Shut Down (ESD) system for wellhead, wellsite & test skid. Adopt MOPO (Manual of Permitted Operations) specifying when operations should be stopped if hazard mitigation is not being met. Emergency phone contact will be displayed on site.
Temporary pipe work failure	Uncontrolled flow of hydrocarbon into the environment	Ensure all temporary pipe works are properly secured and tested before commencing operation

APPENDIX 3C: DEP Table

DEP	Title	Remarks	Accountable DP
25.80.10.10-Gen	Formation Pore Pressure, Fracture Gradient (PP/FG) and Borehole Stability Prediction.	Current reservoir pressure estimate is 3,150 psia (ref KOMA-11 PPP –April 2016) Note: No drilling activity would be carried out during the operation	RE/PP
25.80.10.11-Gen	Formation Tops, Fault Intersections and Fluid Fill Prediction.	Well already drilled and cased off. Formation tops and fluid prediction as contained in KOMA007 EoWR.	PG
25.80.10.12-Gen	Prepare and Maintain Data in Support of Well Emergencies.	The data to support well emergencies are stored in SharePoint. (See Link) Worst case discharge is estimated at 210 MMscf/d. Please refer to Appendix-7 for WCD plot	PT/WE
25.80.10.14-Gen	Geohazard Assessment for Onshore Exploration, Appraisal and Development.	No geohazard risk. Well is already completed.	PG
25.80.10.15-Gen	Design Logging Program.	No logging operation is planned	PP
25.80.10.18-Gen	Hydrogen Sulphide Prediction for Produced Fluids from New and Existing Wells in Oil and Gas Fields.	No H_2S production reported in KOMA004 producing the same reservoir H_2S Prediction carried out and signed off. Please refer to Appendix 8.	PG/PT
25.80.10.19-Gen	Sand Failure Assessment for Wells to be Completed and Produced.	Sand failure assessment has been done as an input to the Well proposal. Well has been completed with OHGP installed for sand control	PT

APPENDIX 4: Koroama-007 Final Completion Status Diagram

KOROAMA 7 (ex TBUV 5) COMPLETION SCHEMATIC

4-Jun-14

CASING

SIZE	GRADE	WT (lbs/ft)	DEPTH (ft)	CEMENT	Conn	
20"	Stove Pipe		350	Driven		Stovepipe
13-3/8"	K55	68	5,545.00	Class G	BTC	Surf Csg
10-3/4"	C90	60.7	300.00	Class G	SLX	Prod Csg
9-5/8"	N80	47	10,760	Class G	SLX	Prod Csg

WELLHEAD (Surface Metal Seal 2 Step System)

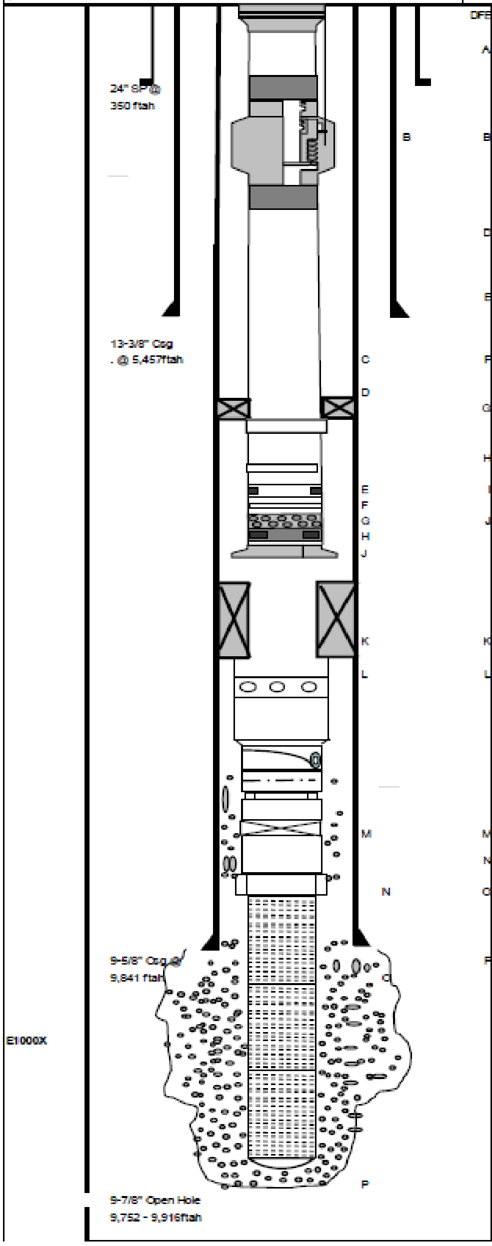
ITEM	TYPE	SIZE	WP
XMAS TREE	SMS UNITIZED	7-1/16" x 13-5/8" Flange block x 7-1/16" outlet	5,000 psi
TREE CAP	Cameron	7-1/16" c/w 7.060" Bore	5,000 psi
GATE VALVE	Cameron	7-1/16" c/w 7.060" Bore	5,000 psi
ACTUATOR VALVE	Cameron	7-1/16" c/w 7.060" Bore	5,000 psi
TUBING HANGER	Cameron	13-5/8" Nom X 7" w/CL Prep and optic fibre	5,000 psi
COMPACT HOUSING	Cameron	13-5/8"	5,000 psi
GATE VALVE	Cameron	2-1/16" c/w 2.060" Bore	5,000 psi

TUBING

STRING	SIZE	WT.	GRAD.	TYPE		HOLE	DESCRIPTION	RESERVOIR
					MAX Deviation: 25.84 deg at 7003ftah			
					RT - Top XMT = 23 ft	9-7/8"	EGP	E1000X
SSS	7"	29#	13Cr	HYDRIL 563	DFE (RT - Compact Housing)= 34 ft			
					XMT = 7ft			

Drill-In Fluid Type / Properties	Thixal Mud 0.49 - 0.52 psi.ft, YP 22 -26 lb/100 ft2
Completion Fluid Type / Properties:	Filtered Inhibited NaCl Brine _ 0.47psi/ft
Workover Fluid Type / Properties:	

Sand/ Deviation | **COMPLETION STATUS**

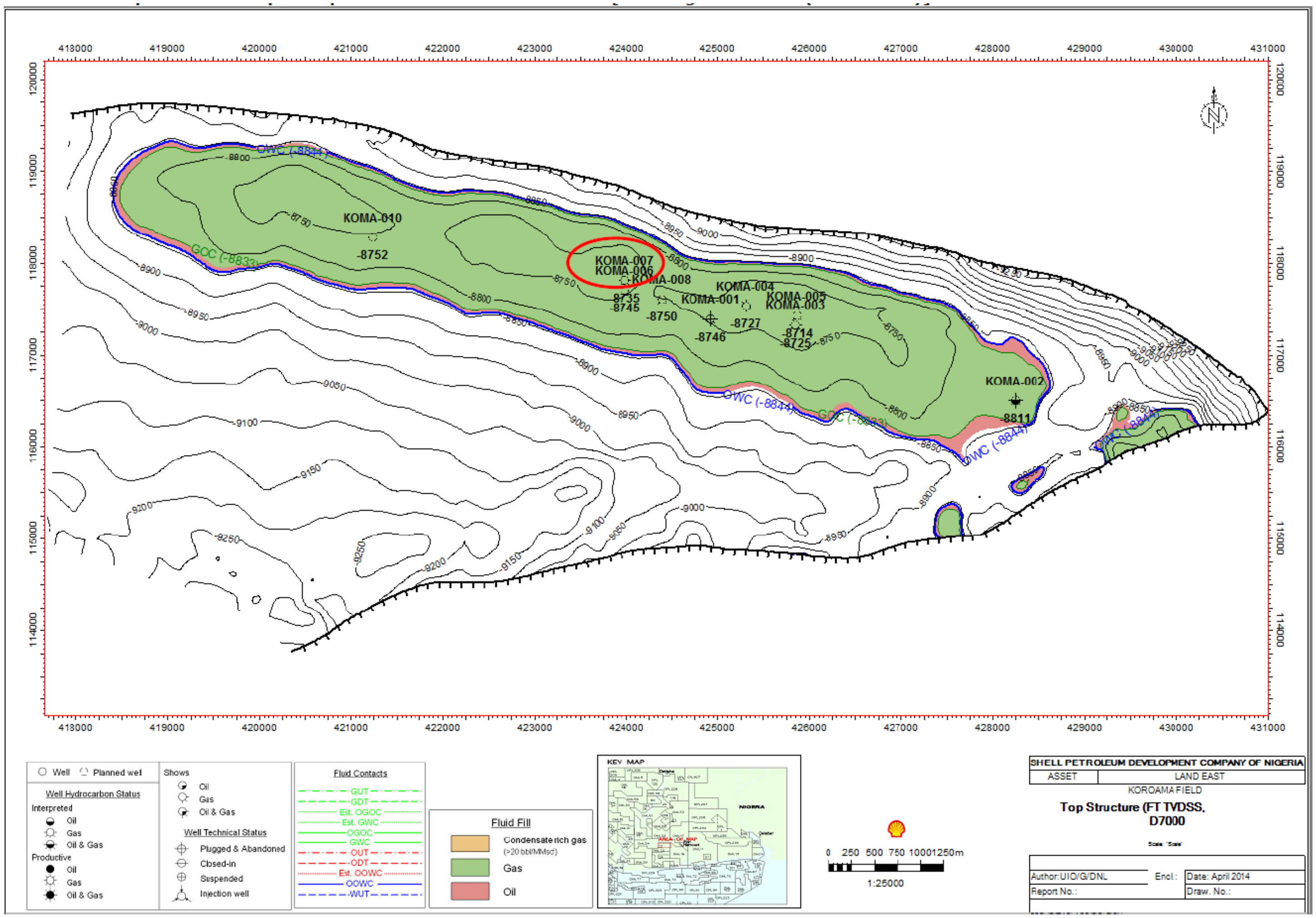


7" Completion Production String

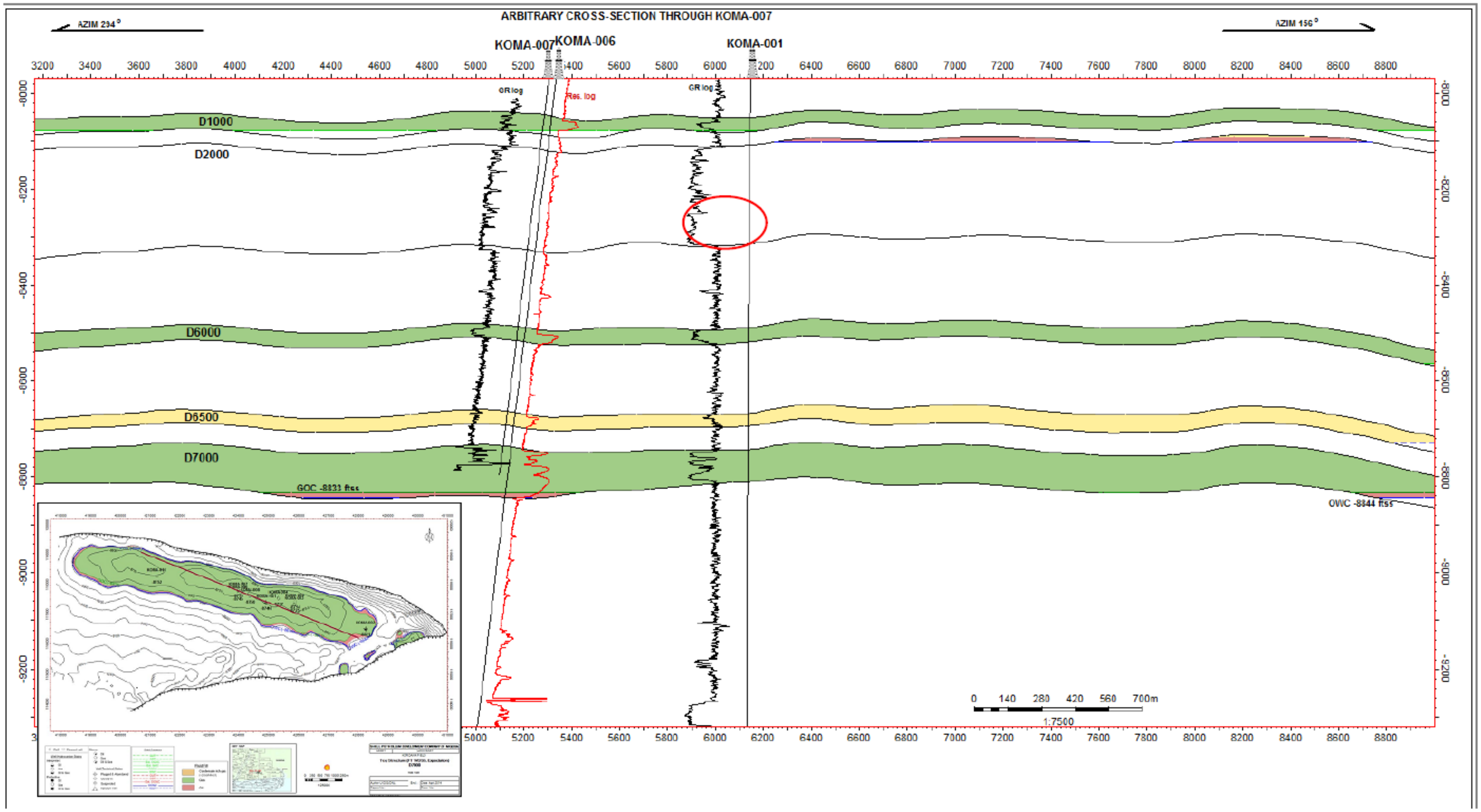
Disc	Top Depth	Length	O.D.	I.D.	DESCRIPTION
DFE	0.00	34			**ELEVATION**
A	**34.00**	**0.86**	**13.32**	**6.184**	**Cameron SSMC Hanger, 7" H563 B, 13Cr. RIGHT HAND RELEASE**
	34.86	8.57	7.660	6.179	Pup Joint, 7" 29# H563 P-P 13CR L80
	43.43	122.76	7.670	6.190	Tubing Joint, 7" 29# H563 B-P 13CR L80
	166.19	9.69	7.670	6.190	Pup Joint, 7" 29# H563 B-P 13CR L80
	175.88	9.69	7.670	6.120	Flow Coupling; 7" H563 B-P 13CR L80
B	**185.57**	**11.89**	**8.380**	**5.875**	**HES SP TRSV(Non Equalizing) 7", 29 # H563 Box x Pin, 13Cr**
	197.46	9.35	7.670	6.122	Flow Coupling; 7" H563 B-P 13CR L80
	206.81	4.56	7.670	6.197	Pup Joint, 7" 29# H563 B-P 13CR L80
	211.37	9,236.81	7.670	6.170	Tubing Joint, 7" 29# Vam Top B-P 13CR L80 (c/w with H56 X/Os)
	9,448.18	9.69	7.670	6.170	Pup Joint, 7" 29# H563 B-P 13CR L80
	9,457.87	**5.90**	**8.220**	**5.870**	**HES THT Packer 9-5/8", 47-58.4#: 7" 29# NS-CC Box x Pin, 13Cr**
D	9,463.77	4.91	7.670	6.200	Pup Joint, 7" 29# H563 B-P 13CR L80
	9,468.68	40.92	7.670	6.190	Tubing Joint, 7" 29# H563 B-P 13CR L80
	9,509.60	9.65	7.670	6.170	Pup Joint, 7" 29# H563 B-P 13CR L80
	9,519.25	**1.71**	**7.680**	**5.825**	**HES R Nipple,5.825": 7",29# H563 Box x Pin,13Cr**
E	9,520.96	4.91	7.670	6.170	Pup Joint, 7" 29# H563 B-P 13CR L80
	9,525.87	40.91	7.670	6.190	Tubing Joint, 7" 29# H563 B-P 13CR L80
	9,566.78	9.67	7.680	6.160	Pup Joint, 7" 29# H563 B-P 13CR L80
	9,576.45	**5.17**	**8.260**	**6.080**	**HES Auto-Fill Sub: 7", 29# H563 Box x Pin,13Cr**
F	9,581.62	5.86	7.68	6.160	Pup Joint, 7" 29# H563 B-P 13CR L80
	9,587.48	9.66	7.68	6.160	Pup Joint, 7" 29# H563 B-P 13CR L80
	9,597.14	**5.17**	**8.260**	**6.080**	**HES Mirage Plug: 7", 29# H563 Box x Pin,13Cr**
G	9,602.31	5.68	7.690	6.18	Pup Joint, 7" 29# H563 B-P 13CR L80
	9,607.99	41.08	7.170	6.184	Perforated Tubing, 7" 29# H563 Box x Pin 13Cr
H	**9,649.07**	**2.21**	**7.676**	**5.500**	**RN Landing-Nipple 5.825, 7" 29# H563, Box x Pin 13Cr, NO-GO = 5.500" Pressure Rating: 7900 Psi**
I	9,651.28	4.86	7.690	6.184	Pup Joint, 7" 29# H563 Box x Pin 13Cr
	9,656.14	0.83	8.310	6.450	**Wireline Re-entry Guide, 7" 29# H563 Box, 13Cr**
J	**9,656.97**				
	9,694.13	**7.88**	**8.434**	**6.000**	Range, 8.450 In. Max OD, 6.000 In. Min ID, 6.000 In. Seal Bore ID-Min, 94.7 In. Length, 325 Deg. F, Std/CO2 Service, 13% Chrome Matl, 80000 psi Min Yield, HNBR Element Matl, 6 7/8-4 ACME-LH Latch Type, 7 5/8 API-STC Box, 812VGP9012-F
K	9,702.01	6.55	7.701	6.880	Upper Extension,7 5/8" 29.7# BTC Pin x Pin 13Cr L80
	9,708.56	4.56	8.108	6.000	Closing Sleeve,7 5/8" BTC Box x 7" BTC Pin,13Cr L80
L	9,713.12	21.64	7.695	6.540	6.509 In. Min ID, S13Cr p110, 10730 psi Pressure Rating, Std/CO2 Service,
	9,734.76	1.75	7.674	5.812	Indicator Coupling/Receptacle, 7 5/8-39.00 AB-HD-L Box x Pin, 7.655 In. Max OD, 5.800 In. Min ID, 25.52 In. Length, 101290789 (12MPC12) Mating Collet, Std/CO2 Service, 12P98580 (S/N: 82636928-05)
	9,736.51	9.63	7.692	6.646	Lower Extension,7"29# Pin x Pin 13Cr L-80
	9,746.14	1.13	8.139	6.270	Adapter: 7 5/8" 39# BTC Box x 7" 26# BTC Pin,13Cr (S/N: MS 18382-1-3/3)
	9,747.27	2.97	8.121	5.009	Ceramic Flapper Valve,7" BTC Box x Pin,13Cr L-80
	9,750.24	2.05	7.668	5.052	Shear Out Safety Joint,7" BTC x 5 1/2" Pin,13Cr L-80
M	9,752.29	0.96	7.426	4.882	Adapter, 6 5/8" 24# BTC Box x 5 1/2" 17# LTC Pin,13Cr (S/N: 18382-2-1/3)
N	9,753.25	80.70	8.250	4.694	BLANK ASSEMBLY, 5 1/2-20.00 API-LC, HAL GRADE L-80 13% CHROME, 480 - SPIROLIZER
O	9,833.95	81.05	8.250	4.694	Gauge,HAL Grade L-80 13Cr,Centralizer Type: Spirolator with stop rings set screw type
	9,915.00	0.97	6.130	N/A	Bull Plug, 5 1/2" 24# LTC Box,13Cr
	9,916.00				
P					

DATE COMPLETED:	DRAWN BY:	CHECKED BY:	APPROVED BY:
	Ibitomihi S. Mike	**Imoyo Olusola**	**Ibrahim Yahaya**

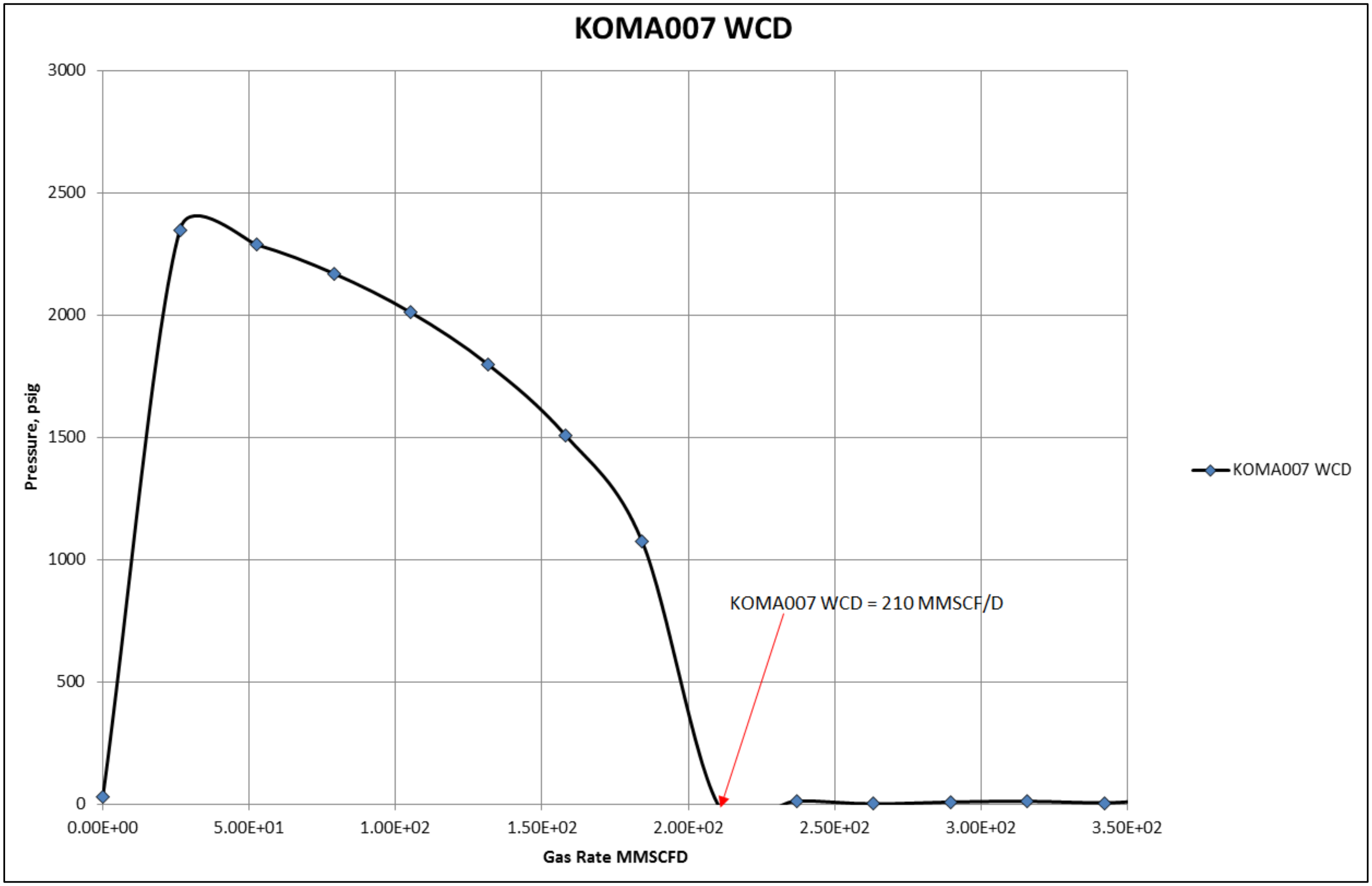
APPENDIX 5: Top Depth Map of the KOMA-007 D7000X sand.



APPENDIX 6: Cross section along KOMA-007 well path



APPENDIX 7: Worst Case Discharge Plot



APPENDIX 8: H2S Prediction