



THE SHELL PETROLEUM DEVELOPMENT COMPANY OF NIGERIA LIMITED

KOLO CREEK 043 WELL CLEAN-UP/TEST PROPOSAL

February 2017

Well No	KOLO CREEK 043
Reservoir	F2000X

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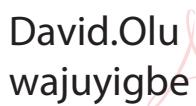
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1.0 BACKGROUND

Kolo Creek 043 is a gas development well that was drilled to provide a drainage point on the F2000X reservoir. The reservoir gas recoverable volume is 945.4 Bscf and KOCR043T will develop 468.9 Bscf with an initial gas production potential of 70 MMscf/d. The well was spudded on the 7th August 2013, drilled to a TD of 14,350 ftah (13,601 ftss), and completion operation ended on 25th January 2015. The well penetrated the F2000X sand at 13381 ftss as prognosticated in the sidetrack and encountered a gross gas column of 220 ft-tvt.

The well was drilled and completed as a Single String Single (SSS) gas producer on the F2000X gas reservoir with 7" 13Cr / VM110 HCSS tubing equipped with Tubing Retrievable Surface Controlled Subsurface Safety Valve (TRSCSSSV). Reslink standalone screen was installed across the sand face for effective sand control. Kolo Creek 043 was suspended with FIV shifted closed and 0.48 psi/ft NaCl brine in the tubing and 6" monolock plug set at 60 ftah. The fluid in the drainhole is POBM.

Two other wells: Kolo Creek 045 and Kolo Creek 046 are completed on the reservoir. However, no production has been recorded from the reservoir. The F2000 is an overpressured reservoir with expected pressure of 9430 psia. Well testing spread and procedure will therefore be designed to manage expected high surface pressures.

It is proposed to clean up the well to about 50 MMscf/d to remove drilling and completion debris and fluids and then conduct Multirate test to ca. 50 MMscf/d on the F2000 interval. This is due to environmental considerations. Results from the MRT will be used to calibrate the well deliverability and advise well operating envelope.

1.1 Clean-Up/Test Objectives

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

- Clean up the well to remove drilling mud, 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 Soku gas plant as part of the wells delivering gas to NLNG. 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 high level summary of the clean-up/well test work scope is given as follows:

- Pump treatment fluid and carry out well lift.
- Clean-up F2000X interval
- Carry out MRT on F2000X interval
- Carry out build-up and carry out SG survey

2.0 WELL CLEAN-UP DESIGN

During the clean-up operation, a specially formulated oil mud breaker solvent system will be pumped to displace the pseudo oil based mud in the open hole. This will be jetted across the Reslink standalone screen in a minimum of 3 passes. The well should be flowed long enough (ref Table 1 below) to allow sufficient

time to offload well on each bean while monitoring sand production. After every bean change, sand trap will be purged for inspection of well effluents.

If there is significant sand production (>0.5 lbs/MMscf), refer to Appendix 3D for contingency plan for excessive sand production.

All produced hydrocarbon (gas & condensate) will be burnt via the flare pit.

Note: No Open trucking of condensate is permitted.

Maximum Clean-up rate, constrained to 50 MMscf/d due to environmental considerations (Noise, vibration and flare intensity) is expected to create enough turbulence to lift all completion fluids and debris from the well. However, if there is need to clean up at higher rates, this will be done as a separate operation when the well is hooked up to the facility.

2.1 Clean-Up/Test Requirements

- Calibrated surface and downhole quartz gauges.
- Downhole Shut in tool
- Clamp on sand monitor
- Pressure let-down choke
- 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
- Mono- Ethyl Glycol (To mitigate hydrates at low rates)
* Note: Expected surface pressures in the range of 6900 – 7200 psi. All equipment upstream of choke manifold to be rated for 10,000 psi maximum pressure.

2.2 Well Clean-Up Operation

The well cleanup operation will commence with the opening of the FIV and unloading operation using coiled tubing. The clean-up will then commence from choke 28/64th (Note bean should be gradually increased). 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 expected minimum WGR ca. 0.7 bbl/MMscf is achieved (i.e. completion fluid fully evacuated). Thereafter, the well will be shut-in for a minimum of 24 hours for the reservoir pressure to stabilize, prior to conducting the Multirate test.

The flow back well effluent (completion brine and mud) will be evacuated with vacuum truck to the Gbaran Central Processing Facility (CPF) for disposal.

2.3 Clean-up Work Summary

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

- Check wellhead pressures – CITHP and CHP (A & B Annulus)
- Retrieve monolock plug at 60ft
- RIH CT to open the FIV, refer to appendix 3c on the FIV opening/treatment contingency plan
- Pump treatment fluid by jetting, making minimum of three passes across screen to dissolve POBM
- Allow treatment fluid to soak while monitoring pressures
- Pump nitrogen (if required) to lift until well is confirmed to sustain natural flow
- Clean-up well as per program (Table-1), ensuring stable flow on each advised bean
- Shut-in well for a minimum of 24 hours for initial reservoir stabilization

NOTE:

- Initial opening of well must be during daylight.

- Bean-up must be done gradually to achieve good bridging behind standalone screen.
- Bean-up should be carried out when flow stabilizes. At each stage, record bean size, gas flow rate, FTHP, FTHT, CGR, WGR, and sand rate.
- Bleed down A & B annulus when pressure exceeds 1000 psi for A annulus and 400 psi for B annulus. Record volume of fluids recovered from A & B annulus during all operations. (See Appendix 10 for expected incremental AFE pressures)
- Flow well until well is properly cleaned, not exceeding a maximum gas rate of 50 MMscf/d. Well is properly cleaned-up when clean up criteria is achieved as specified in Table 1 below.
- All temporary pipe connections must be properly secured and tested to expected pressures

Table 1: KOLO CREEK 043 Well Clean-up 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	24	0.7	7210	4	5	Take sample, check for sand, measure FTHP.
30	30	0.7	7139	4	7	Take sample, check for sand, measure FTHP.
40	34	0.7	7074	4	9	Take sample, check for sand, measure FTHP.
50	40	0.7	6993	5*	13	Take sample, check for sand, measure FTHP.

Stable flow should be achieved on each bean before moving to the next advised bean

*** Clean up criteria**

Stabilized THP for at least 1 hour, no mud returns, BSW of liquid sample < 5%

Tolerance Qg: ± 5 MMscf/d, Tolerance FTHP: ± 50 psia

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

Summary of MRT workscope is given below

- RIH Slickline to install memory P/T gauges with programmed DHSIT at RPT nipple (11,010 ftah).
- Open up well and conduct Multirate test as per program (Table 2)
- Shut in well for 48-hour final build-up test with DHSIT in closed position.
- Carry out SG survey.
- Secure well.
- Rig down equipment.

3.1 Initial Build-up Period

- Close in well at choke manifold for 24 hours for an initial build-up/stabilization 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) at "RPT – Nipple" (ca.11,010 ftah).
- Monitor CITHP for pressure stabilization before proceeding to MRT.

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) (1/64 th)	Assumed WGR (bbl/MMscf)	Expected FTHP (psia)	Flow Period* (hr)	Expected Drawdown (psi)	Comments
20	24	0.7	7210	4	5	Take sample, check for sand, measure FTHP.
30	30	0.7	7139	4	7	Take sample, check for sand, measure FTHP.
40	34	0.7	7074	4	9	Take sample, check for sand, measure FTHP.
50	40	0.7	6993	4	13	Take sample, check for sand, measure FTHP.
0	0	0	-	48	0	48hr shut in period

- 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 48 hours (Final Buildup duration determined from section 4.0) and subsequently commence Static Gradient Survey (See Table 3 below).
- All the other wells completed in the F2000X reservoir must be shut-in during the build-up of KOCR043T, this is to avoid interference from these wells.

3.3 Final Build-up and Static Survey Period

- Confirm well has been closed in 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.
- Duration of survey at each stop should be ca. 10mins.
- POOH with gauges and R/D S/line.
- Download wireline memory gauge.
- Close TRSCSSSV and line up well to production.
- Handover well to production.

Table 3: Static Gradient Survey Stops.

Depth Tag (d)	Depth (d)	Intervals	Duration at depth	Comment/Basis for Stops Selection
	ftah from DFE [DFE Elevation = 58 ft]	Ft	Minutes	
Deepest Survey Depth	11,010	-	0	Deepest Survey depth. R nipple Depth
1st Stop	10,990	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	10,970	20	10	
3rd Stop	10,950	20	10	
4th Stop	10,850	100	10	2nd Set of Stops: 3 Stops at 100ft intervals to ensure accurate estimate of well fluid gradient
5th Stop	10,750	100	10	
6th Stop	10,650	100	10	
7th Stop	10,150	500	10	3rd Set of Stops: 3 Stops at 500ft intervals to ensure accurate estimate of well fluid gradient
8th Stop	9,650	500	10	
9th Stop	9,150	500	10	
10th Stop	8,150	1000	10	4th Set of Stops: 3 Stops at 1000ft intervals to ensure accurate estimate of well fluid gradient
11th Stop	7,150	1000	10	
12th Stop	6,150	1000	10	
13th Stop	4,150	2000	10	5th Set of Stops: 3 Stops at 2000ft intervals to ensure accurate estimate of well fluid gradient
14th Stop	2,150	2000	10	
15th Stop	150	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 well and reservoir data as detailed in Table 4. Pressure simulations were generated based on the rates in Table 2. 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 about 0.01 psi/hr (as seen in SAPHIR). 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
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Parameter	Value	Unit	Comment
a. Reservoir Data			
Pay Zone Thickness	183	ft	
Average Formation Porosity	0.22	fraction	
Formation Compressibility	3.32E-06	psi-1	Estimated using Hall correlation.
Reservoir Pressure	9449	psi	Estimated current pressure based on RCI from KOCR039 (No production from reservoir)
Reservoir Temperature	229	deg°F	
Reservoir Permeability	1558	md	Mean reservoir permeability calculated from FZI analysis using logs acquired from KOCR039 and 39-ST
b. Well Data			
Well Orientation	Deviated		
Well Radius	0.27	ft	
Well bore Storage (WBS) Coefficient	0.018	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 0.0035 bbl/psi
c. Fluid data			
Fluid Type	Gas		
Gas gravity	0.71		
d. Others			
Reservoir Model	Homogeneous		
Wellbore Model	Constant storage		
Boundary Model	Fault/Dip closure		
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	48	Hrs	Flow @ 0 MMscf/day

4.2 Scenario/Sensitivity Formulation

PERMEABILITY:

The permeability values used in this design were based on FZI analysis which utilizes the porosity logs acquired from the well. A minimum, most likely and maximum value of 522mD, 1558mD and 2079mD respectively were derived and used in the design.

BOUNDARY MODEL:

The F2000X reservoir Map (Appendix 5) was digitized and used in the design. The reservoir has GWC at 13749 ftss. From the top structure map and cross section (Appendix 5 & 6), the structure has few intra-reservoir faults which are mostly interpreted as non-sealing. A review of the structure also show that the reservoir is fault bounded at the north-east by the boundary fault and at the west, south and south-east. The sealing factors of the major boundary faults are set to zero while intra-reservoir faults are set to 0.5.

SKIN:

Skin value range from the Gbaran Node (Zarama, Koroama, Gbaran and Kolo Creek) have been used to define the skin range for the design. The skin values are 15, 52 and 88 for low, mid and high respectively.

WELLBORE STORAGE:

A wellbore storage coefficient of 0.018 bbl/psi was estimated for surface shut in. The well test design was carried out using this well bore storage 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.

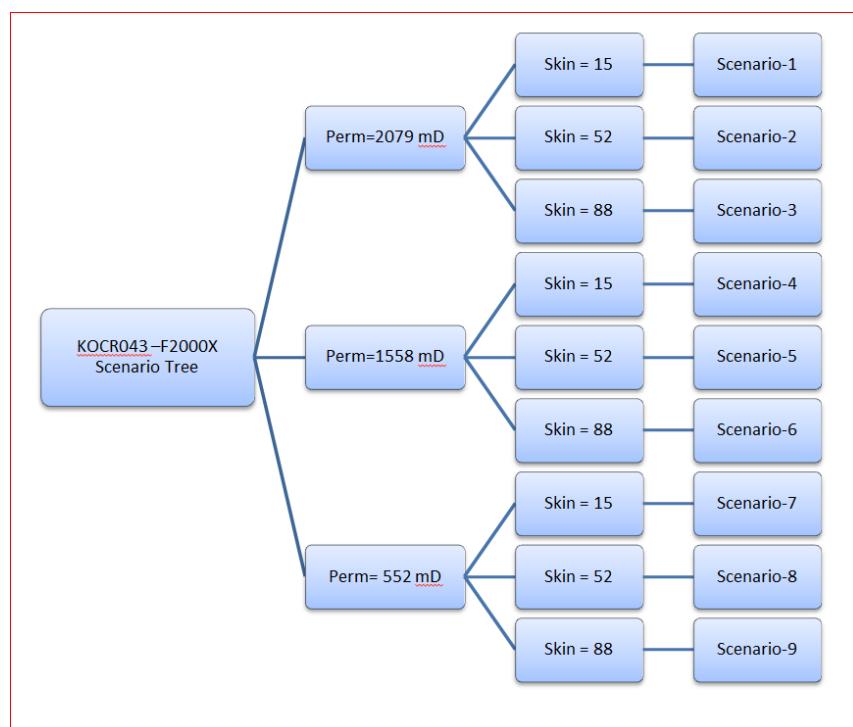


Figure 1: Scenario

4.3 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 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 available data from wells which were completed on the interval, the F2000X shows a permeability range of 522mD to 2079mD. These values were based on log data from KOCR039 and 39ST. The initial reservoir pressure value of 9449 psia used in the evaluation was based on RCI from KOCR039 as the reservoir has not produced. The Log-Log plots from the generated pressure are shown in Figure 2 and durations from the sensitivities are listed in Table 5.

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

1. The variation in the skin values did not result in significant distortion of the reservoir behaviour. As the infinite acting radial flow period is clearly observed.
2. The late time pressure response indicated an outer boundary primarily dominated by a boundary fault effect in the various scenarios.
3. With the assumed base-case permeability of 1558 mD, a minimum of 24 hours is required for the final build up test. For the permeability value of 552mD, a minimum of 48 hours is required for the outer boundary effects to be felt by the test and pressure stabilization achieved. The 48 hour build-up from the low permeability has been selected as the build-up duration for the well.

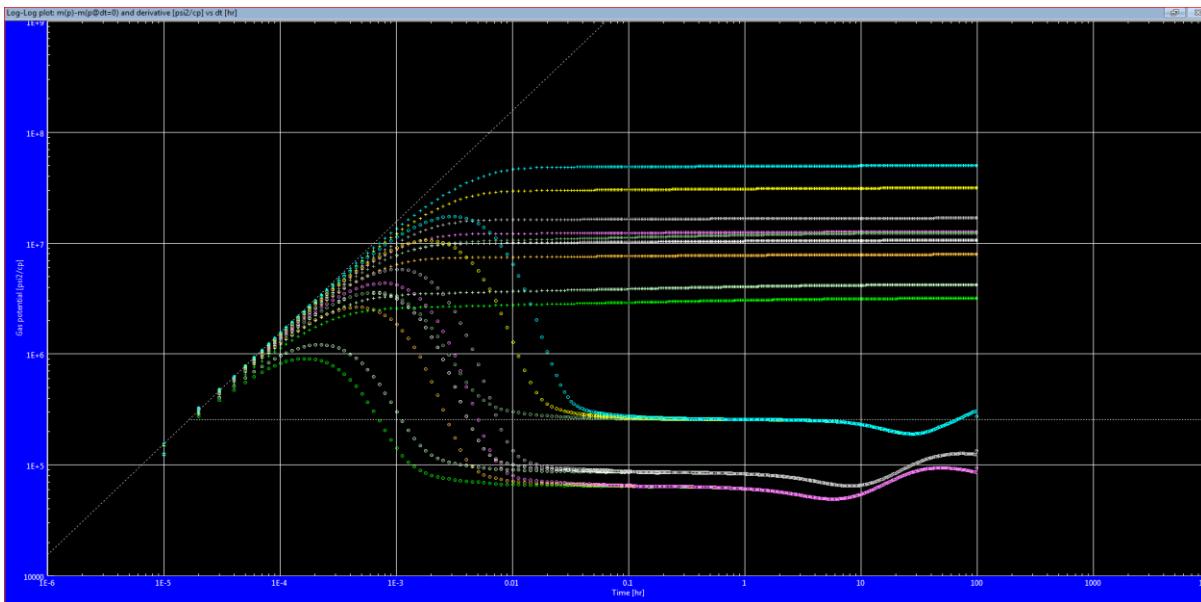


Figure 2: Log-Log plot for All Scenarios

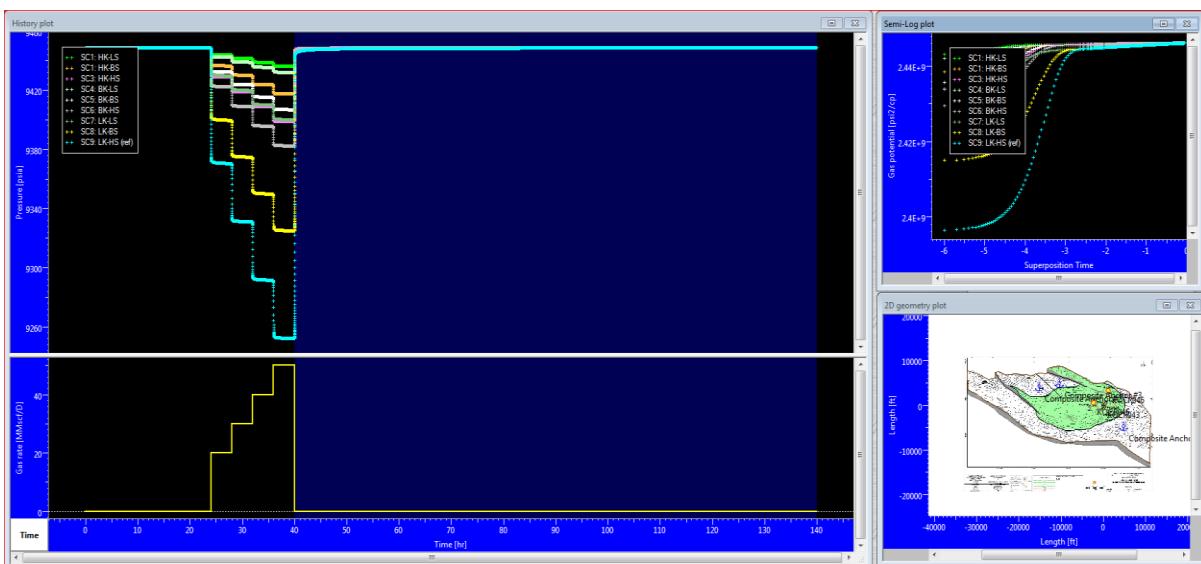


Figure 3: Cartesian, Semi-log plots and Digitized map.

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. The optimal test time selected is highlighted in Table 5.

Table 5: 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
S1	24	4	4	4	4	24	64
S2	24	4	4	4	4	24	64
S3	24	4	4	4	4	24	64
S4	24	4	4	4	4	24	64
S5	24	4	4	4	4	24	64
S6	24	4	4	4	4	24	64
S7	24	4	4	4	4	48	88
S8	24	4	4	4	4	48	88
S9	24	4	4	4	4	48	88

5.0 WORKSCOPE SUMMARY

The summary of the Clean-up & MRT work scope is given as follows:

Hold pre-job safety and work scope meeting.

- Check and record wellhead pressures.
- Retrieve monlock plug.
- Pressure and function test CT
- RIH CT to open the FIV, refer to appendix 3c on the FIV opening/treatment contingency plan
- Pump treatment fluid by jetting, making minimum of three passes across screen to dissolve POBM
- Allow treatment fluid to soak while monitoring pressures
- Lift well with Nitrogen if well does not come unaided.
- Commence well clean-up (Table1).
- Shut-in well for 24 hours for initial reservoir stabilization.
- RIH Slickline to install memory P/T gauges with programmed DHSIT at RPT nipple (11,010 ftah).
- Open up well and conduct Multirate test (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:

- Initial opening of well must be during daylight.
- Bean-up must be done gradually to achieve good bridging behind screen.
- 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 50 MMscf/d. Well is properly cleaned-up when at least 95% 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.

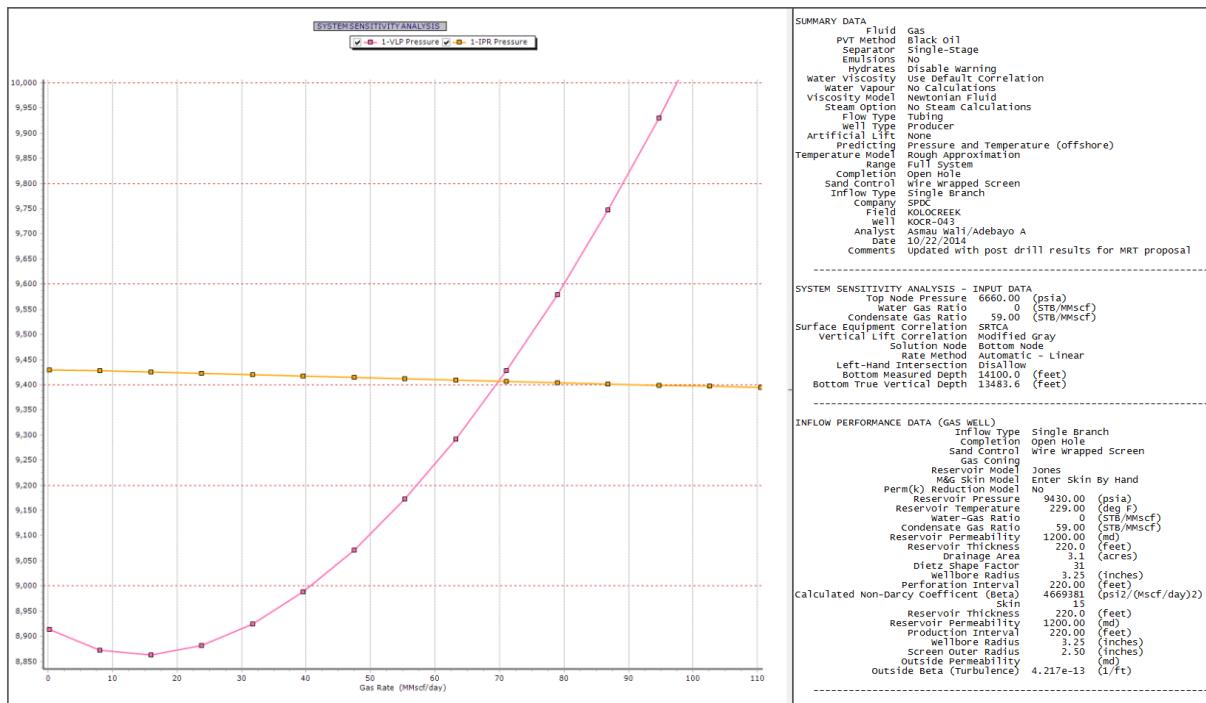
APPENDIX 1: RESERVOIR & COMPLETION DATA

Target Reservoir	F2000X
1. Casing size and Type	7''/Liner
2. Casing Setting Depth (ftah)	13450
3. Top of Sand [ftss/ftah]	13381/ 14100
4. Gross Sand Thickness (Gross) penetrated by KOCR043ST (ft tv)	220
5. Well TD (ftss/ftah)	13601/ 14350
6. a) Completion interval (ftss) b) Completion interval (fttv) c) Completion interval (ftah)	13381 – 13601 13439 – 13659 14100 – 14350
7. Length of Completion Interval (ftah)	250
8. a) Top of competent cement (ftah) b) Source of data	6,300 CBL
9. a) Was hole directionally drilled? b) Max deviation angle and depth (ftah)	Yes 32.39 deg @ 12550
10. Deviation at completion zone	30
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)	9449 13500 9449 229 13381 9430
12. Did RCI indicate abnormal pressures?	Yes (over pressured)
13. Pressure gradient @ top of sand (psi/ft)	0.705
14. a) Is the reservoir fully gas-bearing?	Yes
15. a) Is there original GWC in the reservoir b) What depth (ftss)? c) Change in PGWC from original OGWC (ft)	Yes (KOCR039ST) 13749 0
16. Distance between lowest completion interval and estimated GWC in well / reservoir (ftss)	154
17. Is there a barrier between lowest completion interval and the present estimated GWC?	No (there are baffles in the reservoir though)
18. Gas S.G. (air=1)	0.71
19. Condensate gravity (API)	39
20. Expected FTHP (psia)*	6660
21. Expected CITHP (psia)	7260
22. Expected Drawdown (psi)*	23
23. Expected PI (scf/d/psi^2)*	219
24. Is sand exclusion installed?	SAS (RESLNK)

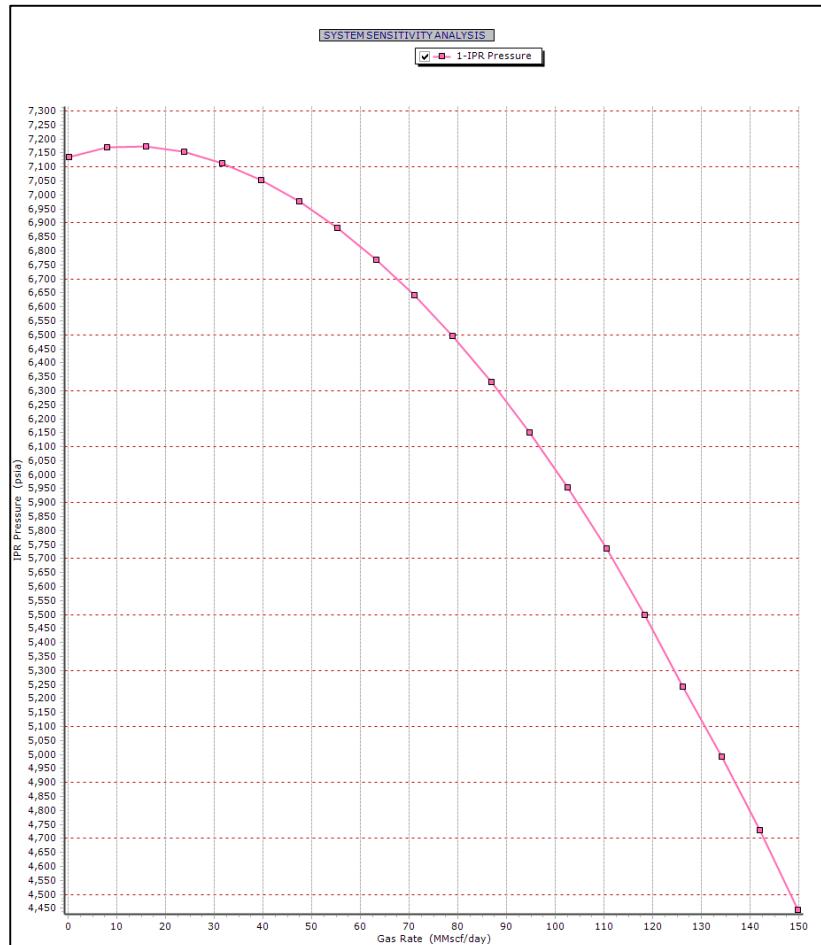
*Values are at well potential of 70 MMscf/d

APPENDIX 2: WELL PERFORMANCE PLOTS

KOCR043 Well Performance



KOCR043 P-Q Curve



APPENDIX 3A: WELL TEST RISKS AND MITIGATION

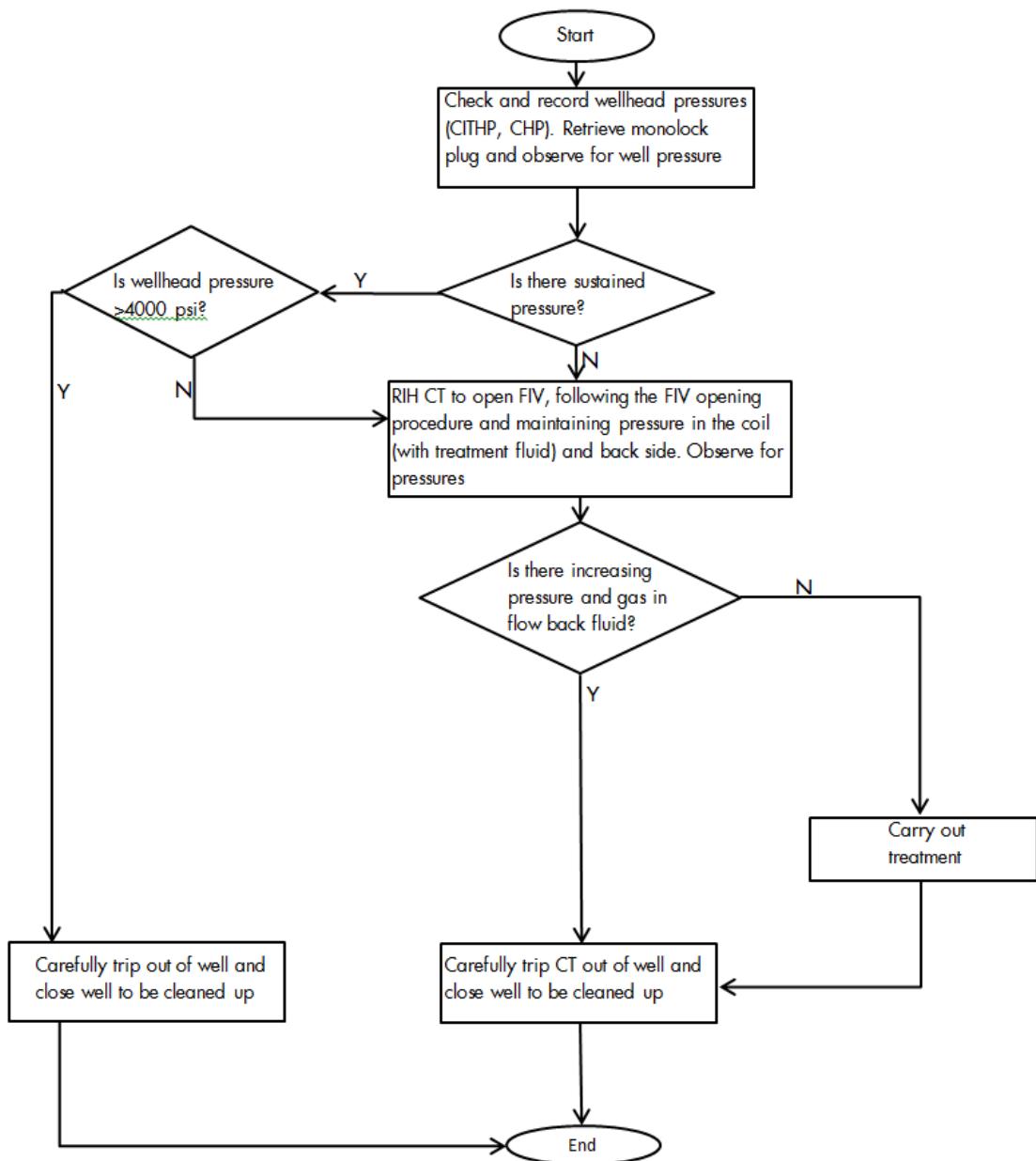
Risk	Consequence	Mitigation
Loss of containment	Blowout, explosion, injury, fatality, loss of equipment	<p>Ensure presence of minimum of 2-barriers at all time during clean-up/MRT operations.</p> <p>Also ensure all HAZID actions are closed-out prior to commencing operation</p> <p>Ensure BOP for the coil tubing unit and all pressure equipment are properly rated and tested at the contractor base and onsite, and these tests are witnessed by SPDC personnel. Check integrity of the valves on the wellhead and TRSCSSV. Install surface readout gauges to monitor pressures at all times</p>
Hydrate Formation	Blocked tubulars, increased pressure, blow-out, injury, and fatality.	Ensure that effective glycol is mobilized to site since a high pressure drop is expected, to prevent hydrate formation. Conduct tests on samples of glycol to be used to confirm its adequacy prior to mobilization.
Inappropriately sized coiled tubing tools	Downhole components/tools may not get to desired depths	Ensure the dimensions of the tools to be RIH are appropriately sized for 7" tubing accessories/profiles ID and 4" FIV and screen
Failure of Downhole Shut-in Tool at deployment, or failure to retrieve the Shut-in Tool and gauges	In-accurate estimate of wellbore storage, impact on well test results, Inability to open well for production.	Ensure tool is checked at the contractor's base and confirmed operational before deploying. Ensure proper and efficient deployment procedures are followed
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, scorching 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.	Wellhead have stainless steel clads. Also, acid would not be used during the operation.
Fire Outbreak	Fire outbreak, injury, and loss of equipment, fatality.	<p>Barricade work area, prohibit use of cell phone & smoking around well's perimeter fence, restrict movement of unauthorized persons around work area.</p> <p>Inspect bond wall periodically during and carry out repairs as required.</p>
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	Presence of 3-barrier containment Emergency Shut

Risk	Consequence	Mitigation
	equipment.	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 to the highest pressures expected at this operation
Community disturbance	Disruption of work, delay in execution, cost escalation	Ensure robust engagement of community stakeholders about expectations (flaring heat and noise) during the job execution

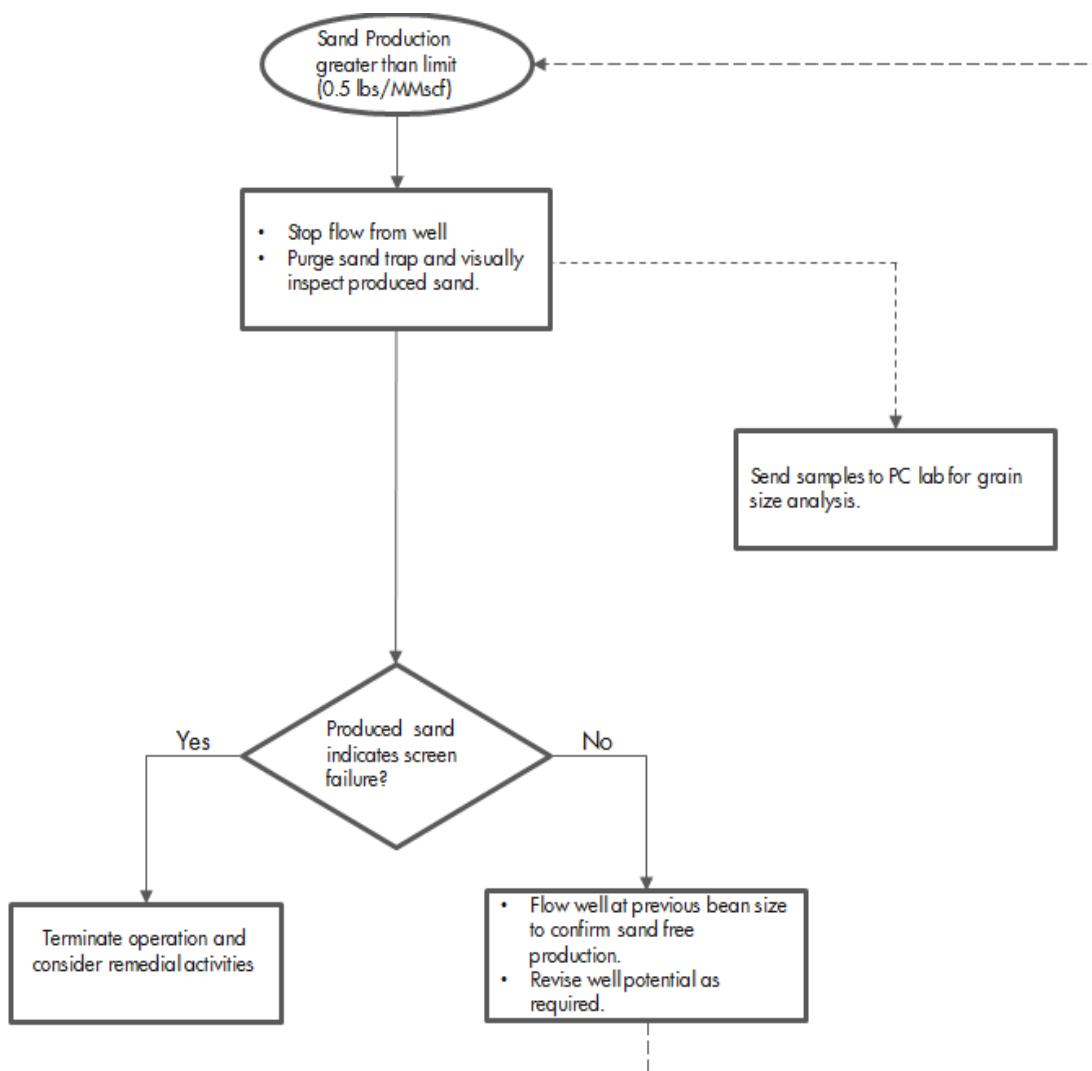
APPENDIX 3B: DEP Table

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 at the top of screen is 9430 psia (See Appendix 11)	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 KOCR043 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 208 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.	H ₂ S 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 carried out and the well completed with SAS installed for sand control. Sand monitoring would be in place during this clean-up and MRT. See Appendix 3D contingency plan for sand production.	PT

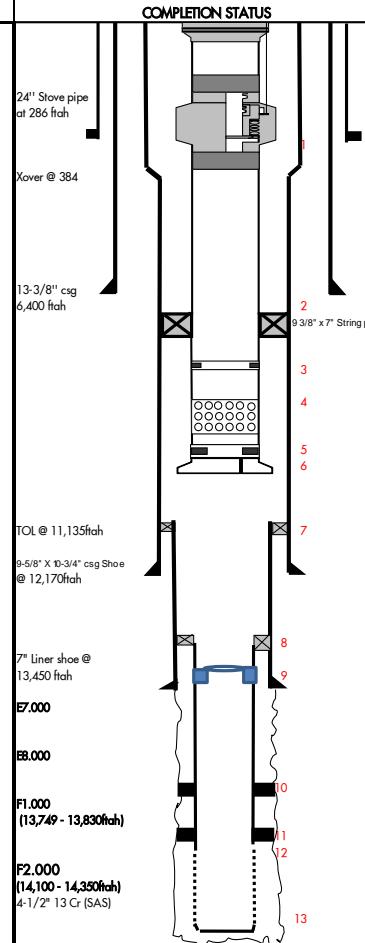
APPENDIX 3C: FIV Opening Contingency Plan



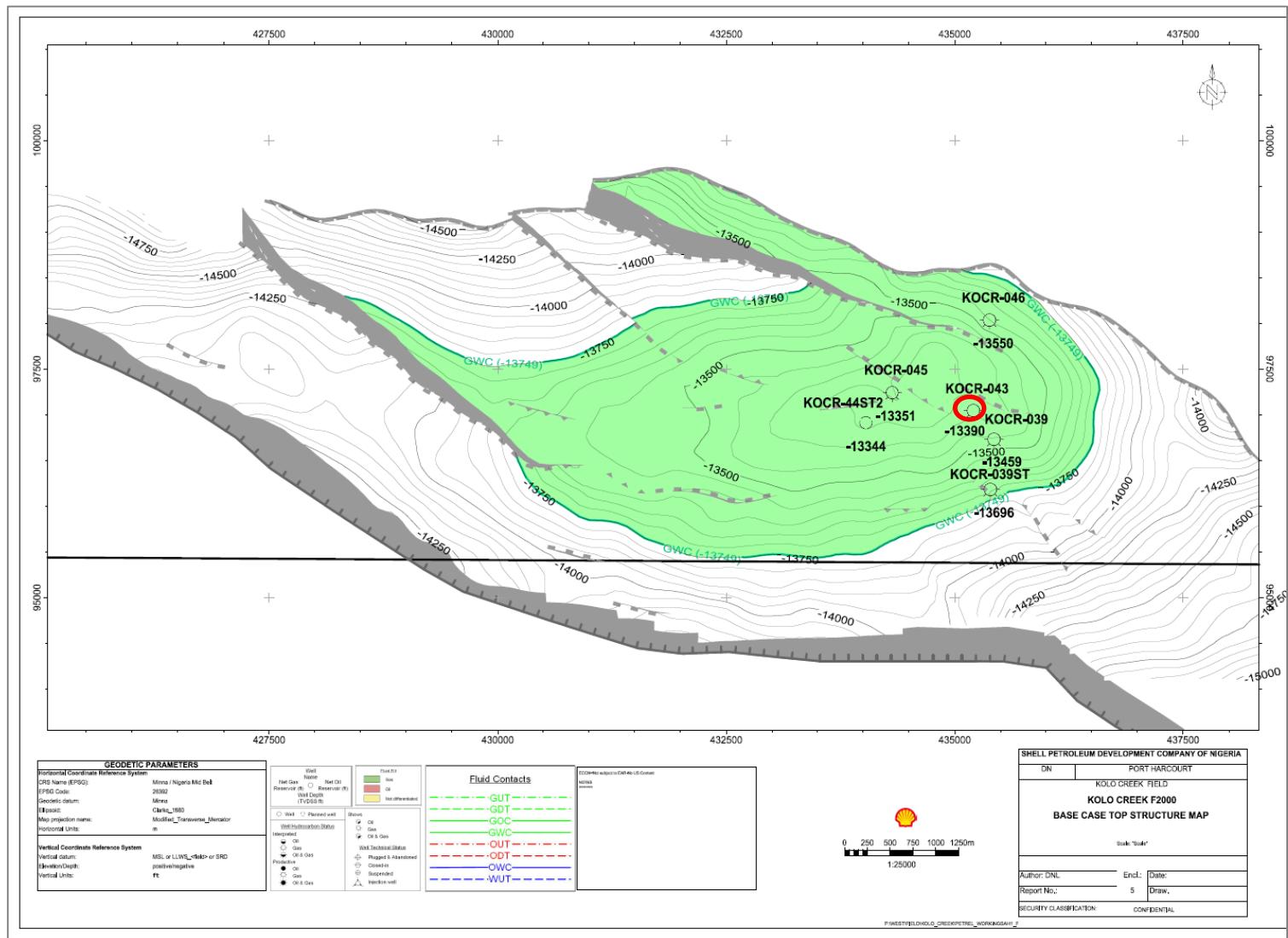
APPENDIX 3D: Kolo Creek 043 Sand production contingency plan



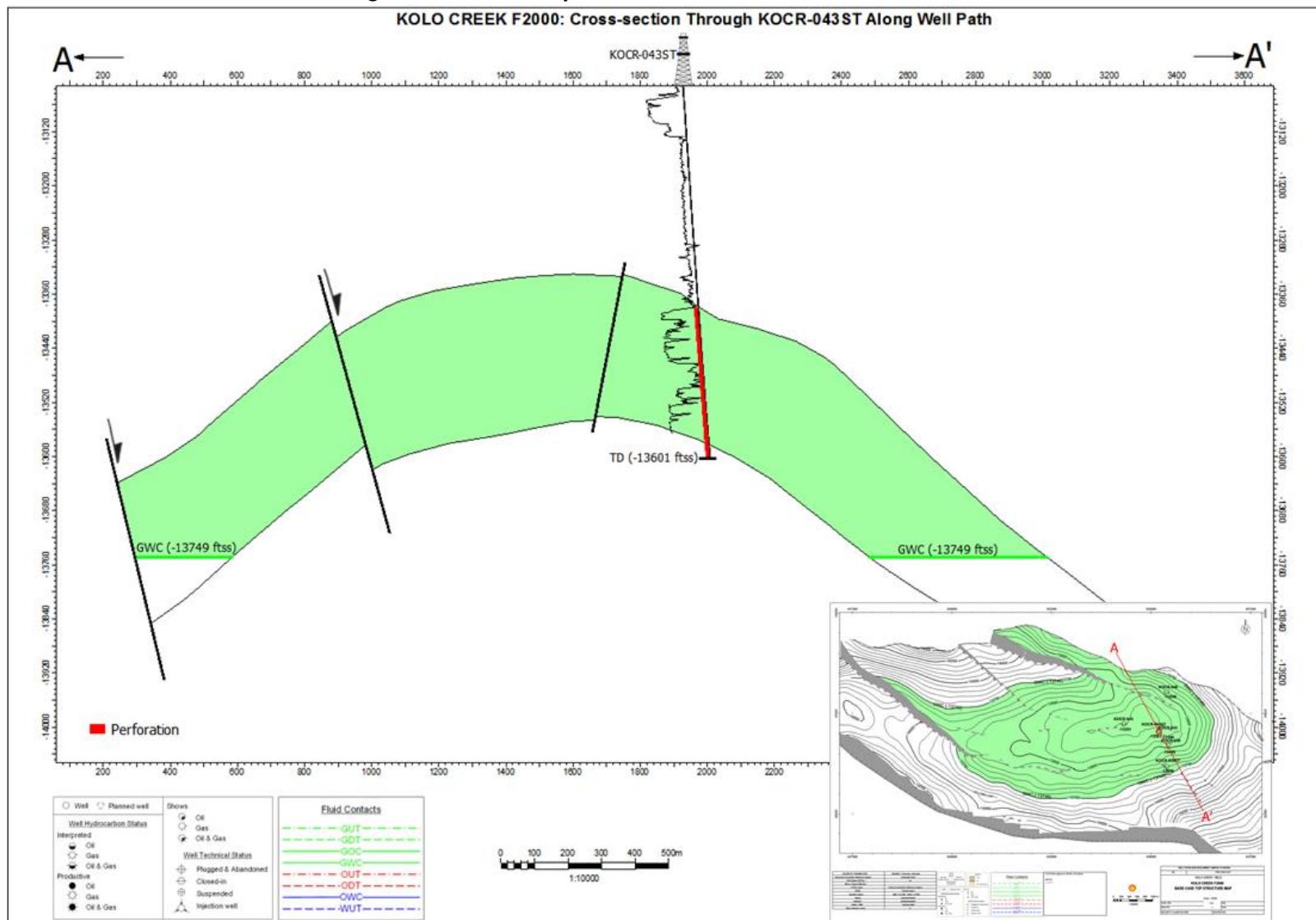
APPENDIX 4: Kolo creek 043 Final Completion Status Diagram

KOLOCREEK-43 FINAL COMPLETION STATUS DIAGRAM								WELLHEAD (CAMERON CONVENTIONAL)			25-Jan-15	
SIZE	GRADE	CASING			REMARKS	ITEM	TYPE	SIZE	WP (PSI)			
		WT (lbs/ft)	DEPTH (ft)	CEMENT								
24"	STOVEPIPE	186	454	Driven		STOVEPIPE	INST. FLANGE	7-1/16"	10,000psi			
13-3/8"	N80	68	6,500	CLASS G	BTC	Surface Csg	GATE VALVE	6-3/8"	10,000psi			
9-5/8"	Q125	54	12,500	CLASS G	SLX	Prod Csg	XMAS TREE CAP	6-3/8" Tree Cap x 5K	10,000psi			
7"	Q125	32	12,300 - 14,100	CLASS G	SLX	Prod Csg/liner	XMAS TREE	7" Compact XMT Assy x 6-3/8" Tree Cap	10,000psi			
							SEAL ASSY	7" NOM	10,000psi			
							TUBING HANGER	7"x 13 5/8" Compact; 13 Cr. Hyd 563	10,000psi			
							SEAL ASSY PACKOFF	13-5/8" Nom x 10-3/4" O.O csg	10,000psi			
							CSG HGR	13-5/8" x 10-3/4"	10,000psi			
							COMPACT HOUSING	13-3/8" BTcx 13-5/8" Flange Lock	10,000psi			
TUBING												
STRING	SIZE	WT.	GRAD.	TYPE	MAX Deviation: +/- 33.52 deg @ 8,610 TO 13,607 ftah		HOLE	DESCRIPTION	RESERVOIR			
SSS	7"	32/35	L80/P110		DPE (RT - CELLAR): 58 FT		N/A					
					RT - TOP XMT:xxxft			Open Hole with SAS Sand Control	F2000			
					Drill-in Fluid Type / Properties							
					RT - Compact H: xxx ft			Completion Fluid Type / Properties:				
					Gas Pressure Gradient / Pressure:							
7" PRODUCTION STRING												
SAND	COMPLETION STATUS				Top Depth (ftah)	Length (in)	ID (in)	OD (in)	DESCRIPTION			
					0.00	1.20	6.004	13.320	Tubing Hanger			
					3.00	4.36	6.094	7.660	Hanger Nipple			
					42.36	124.76	6.004	7.000	7" 35# VM110HCSS Vam Top tubing joint			
					182.00	8.71	4.562	7.990	7" TRSCSSV H563 13 Cr 29ppf w/c 'RQ' LOCK Profile			
					206.28	7,394.92	6.094	7.000	7" 35# VM110HCSS Vam Top tubing joint			
					7,601.20	407.66	6.094	7.000	7" 32# Cr P110 Vam Top tubing joint			
					8,008.86	2,959.92	6.094	7.000	7" 32# Cr L80 Vam Top tubing joint			
					2	10,980.82	5.34	5.875	Permanent Packer 9-5/8"x7", 13 Cr H563 bxp			
					3	11,010.18	1.98	4.500	RPT Nipple Vam Top B X P S13Cr			
					4	11,013.45	10.79	6.205	7" 13Cr L80 pup joint			
					4	11,024.21	40.34	6.185	7" Perforated Tubing Joint, 7" Vam Top box by pin			
					5	11,065.43	1.59	4.313	RN# Nipple 4-1/2" Fox-K, 13Cr [4,313" Bore, 4.1" NoGo]			
					6	11,080.36	1.04	6.460	Wireline re-entry guide, 7" 13Cr			
					6	11,081.14			End of Tubing			
					7	11,135.00	11.98	6.130	Cadmium EXR Liner Hanger 9-5/8" x7"			
									OPEN HOLE STANDALONE SCREEN ASSEMBLY			
					8	13,246.22	20.29	3.880	Crossovers + Pup joint + 7" VCA Packer			
					8	13,266.51	39.60	3.958	3.060 4-1/2" 12.6# Blanks Vamttop Box x Pin 13Cr L80			
					9	13,306.11	10.10	3.910	4.960 Pup joint 41/2" 12.6# vamttop HC pin x Vamttop Box 13Cr L80			
					9	13,316.21	16.78	2.940	41/2" 12.6# Vamttop HC X P FIV Assy			
					10	13,332.99	1.23	3.860	Crossover: 4-1/2" 12.6# vamttop HC Box x 4-1/2" Vamttop pin			
					10	13,334.22	10.44	3.910	4.960 Pup joint: 4-1/2" 12.6# vamttop Box x Pin 13Cr L80			
					10	13,344.66	367.86	3.958	4.500 4-1/2" 12.6# Blanks Vamttop Box x Pin 13Cr L80			
					10	13,712.52	42.77	3.900	4.500 4-1/2" 12.6# vamttop Box x Pin 13Cr L80 Swell packer			
					10	13,735.29	116.93	3.958	4.500 4-1/2" 12.6# Blanks Vamttop Box x Pin 13Cr L80			
					11	13,872.22	42.48	3.900	5.500 4-1/2" 12.6# vamttop Box x Pin 13Cr L80 Swell packer			
					11	13,914.70	157.94	3.958	4.500 4-1/2" 12.6# Blanks Vamttop Box x Pin 13Cr L80			
					12	14,072.64	276.46	3.958	5.060 4-1/2" 12.6# PRO-WELD TOP Direct Wire Wrap Vam Top Box x Pin, 225 micron Mesh			
					12	14,349.10	0.90		5.000 4-1/2" Bull Nose			
					13	14,350.00			Well TD			
NOTE: All depths are top depths along hole BDF. Completion materials are 13 Cr												
ID: 14,350ftah	AUTHOR: Ben Nwoya	DATE COMPLETED: 26-Jan-15	COMPLETED BY: Temitope Alalade	CHECKED BY: Oluwatobi Ughoh	APPROVED BY: Stanley Akanegbu							

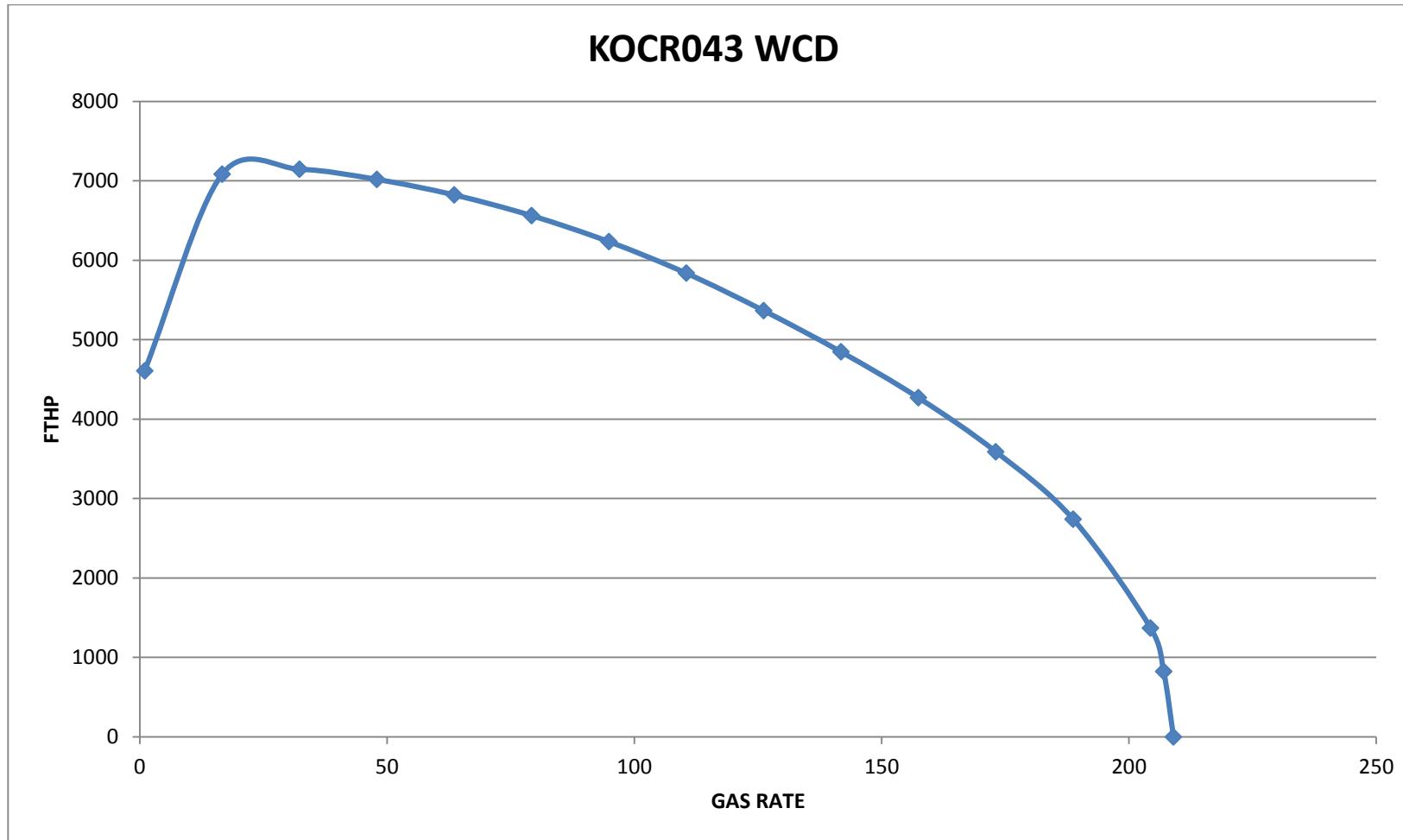
APPENDIX 5: Top Depth Map of the F2000X sand



APPENDIX 6: Cross section along KOCR043 well path



APPENDIX 7: Worst Case Discharge Plot



APPENDIX 8: KOCR043 H₂S Prediction

KOCR043T H₂S PREDICTION

Introduction

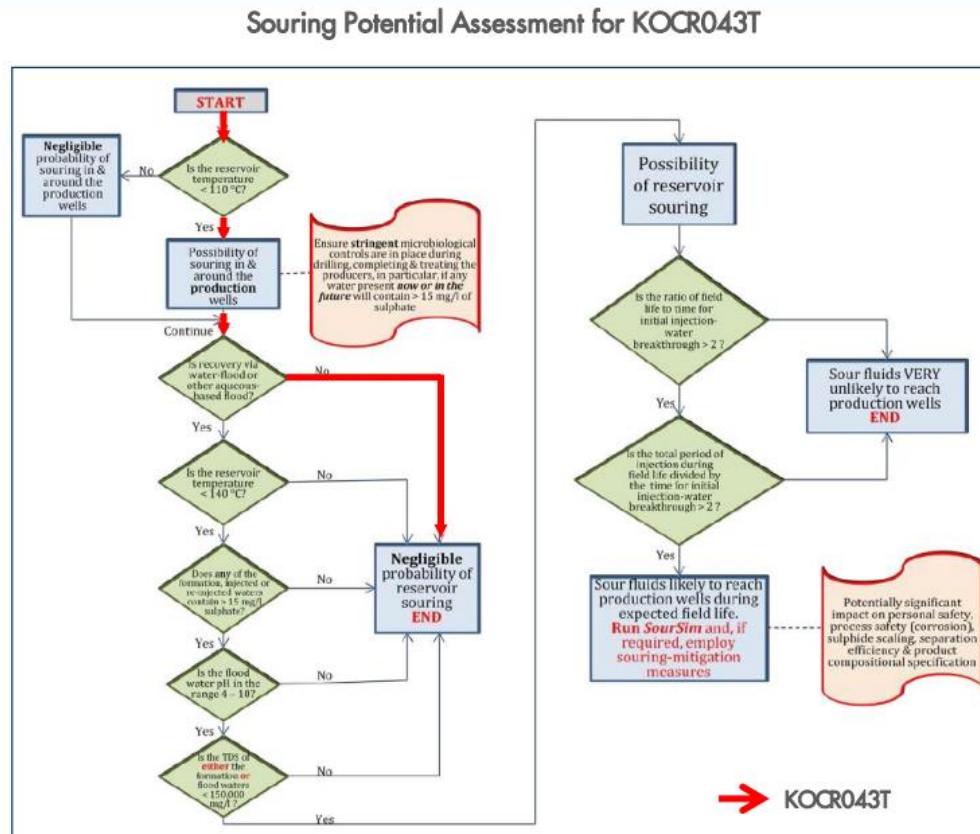
The consequence of the presence of H₂S is loss of life and material integrity. This document contains prediction of naturally occurring H₂S concentration and souring potential for KOCR043T well based on available data.

Naturally Occurring H₂S Concentration

- KOCR043T is completed on the F2000 reservoir.
- PVT analysis available for F2000X reservoir shows no presence of H₂S
- H₂S has not been encountered in KOCR oil & NAG wells producing in the Gbaran nodal area.
- Naturally occurring H₂S concentration is therefore predicted to be 0%mol

Souring Potential

- Souring potential is a function of expected reservoir temperature
- Expected reservoir temperature is 109 °C, (229°F) however, no waterflood is planned for the field.
- Hence, the souring potential is negligible. (see SPA tool)
- Gas testers and appropriate PPE's will be utilized during completion and well open up as additional mitigation.



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Checked by: Emesi, John Nnadi, Magnus Akunesiobike, Jonathan	Nwankwo, Cosmas Oluwajuyigbe, David	Ugboaja, Remmy
UGBOAJ A REMMY	Digital signature by UGBOAJA REMMY Date: 2017.01.26 19:35:50 +01'00'	

APPENDIX 9: KOCR043 Clean up and Well Test Cost Estimate

S/N	Service Description	Minimun Cost (\$)
1	Well Test Services	\$486,134.28
2	WHM Ops	\$32,928.98
3	CT/N2 Services	\$241,567.97
4	HP Pumping Ops	\$85,956.80
5	WT Support	\$394,780.93
6	SL Support	\$54,611.44
7	Water Facilities	\$16,931.81
8	IT Support	\$4,412.10
9	SPDC Logistics	\$98,675.02
10	FTO	\$9,266.67
11	Security	\$26,600.00
	TOTAL	\$1,451,865.99

APPENDIX 10: KOCR043 Expected Annular Fluid Expansion

Estimated Incremental AFE pressure and volume for 50 MMscf/d flow without annulus bleed down

String Annulus	Incremental AFE pressure (psi)	Incremental AFE Volume (bbl)
9-5/8" Production Casing (B annulus)	4665	7.8
7" Production Tubing (A annulus)	5877	5.6

Notes:

1. If CHP exceeds expected AFE pressure or bled down volume exceeds AFE volume then, CHP investigation required.
2. Casing should be monitored closely and bled down as per program because expected AFE pressure exceeds the MAASP calculated for A & B annulus.

APPENDIX 11: F2000 Pore Pressure Estimation

The pore pressures for the F2000 reservoir were estimated using pressure cell method. RCI data from KOCR-039ST was used to obtain the pore pressure model.

The pressure at the top of screen was obtained by extrapolating the pressure from the datum depth (13500 ftss) using fluid gradients measured from the F2000 reservoir in KOCR-039ST.

Uncertainty in fluid gradient was considered in estimating the high, base and low case pore pressures. The top of screen was established based on the completion tally, thus uncertainty in depths was eliminated.

All reservoirs shallower than the F2000 have been cased-off (please see appendix 4), thus the pore pressure estimation was carried out for only the F2000 which will be open to flow during the Clean-up / MRT operation. The table below presents the range of formation gradients estimated for the F2000 reservoir based on KOCR-043ST, 045 & 046.

Reservoir	Min formation gradient, KOCR046 (psi/ft)	Ref formation gradient KOCR043ST (psi/ft)	Max formation gradient, KOCR045 (psi/ft)
F2000	0.698	0.704	0.706

The pore pressure table and plot are presented below.

Pore Pressure Estimation Plot

FIELD : **KOLO CREEK**

Well : **043ST**

Revision : **3.0**

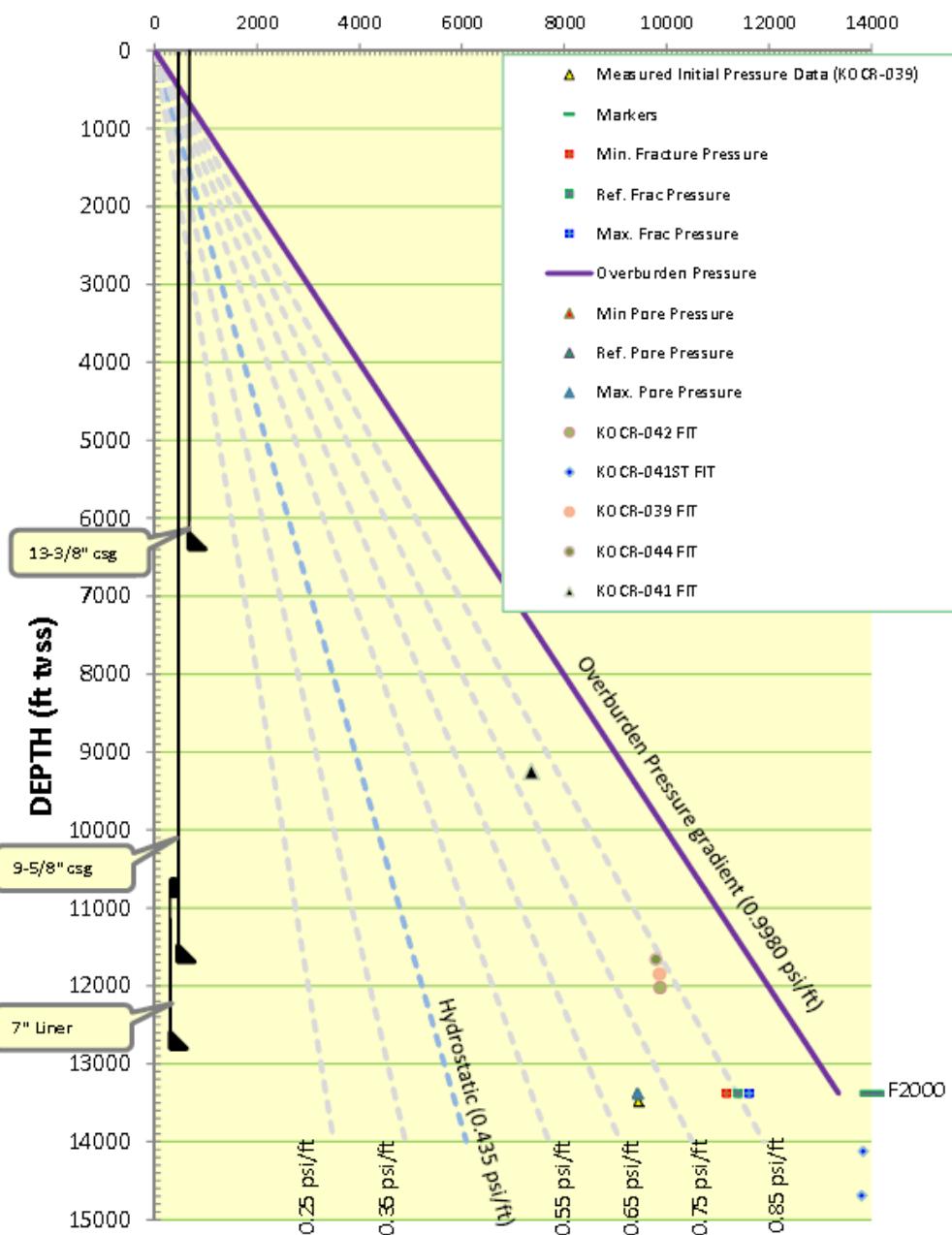
Issue Date: **30 JAN. 2017**

Exp Date: **29 JUL 2017**

Pore/Fracture Pressure Prediction Plot

(Pressure at Top Reservoir Depth)

PRESSURE (psia)



Prepared by : _____ DIKE, AHUNANYA Date: 30/1/2017

Digitally signed by
Oluseyi Odegbesan
Date 2017.01.31
11:26:42 +0100

PP Check/Approved by: LAOYE, ABIODUN / ODEGBESAN, OLUSEYI Date: _____

Pore Pressure Estimation Table

FIELD:	KOLO CREEK
WELL NAME:	043ST
PLATFORM/RIG :	Mobile Test Separator
PREPARED BY / CHECKED BY	DIKE AHUNANYA/LAOYE ABOODUN
ISSUED DATE:	00 January 2017
REVISION NO.:	3.0
SPUD DATE:	07 August 2013
EXPIRY DATE:	29 July 2017

Pore Pressure Prediction at Top Reservoir for KOCR-043ST

TV-Depth of Pressure Prediction and Reference Depth (e.g., ss or bft)				Fluid Type Prognosis at Top of Sand along Well Trajectory	Is Reservoir Developed	Formation Pore Pressure Prognosis at Top of Screen along Well Trajectory					Formation Pore Pressure Gradient at TOS					Fracture Gradient Prognosis at Top of Screen along Well Trajectory					
Formation	Shallow (ft:ss)	Most Likely (ft:ss)	Deep (ft:ss)			Reference Case	(Y/N)	Minimum (psia)	Reasonable Low (psia)	Reference Case (psia)	Reasonable High (psia)	Maximum (psia)	Minimum (psi/ft)	Reasonable Low (psi/ft)	Reference Case (psi/ft)	Reasonable High (psi/ft)	Maximum (psi/ft)	Minimum (psi/ft)	Reasonable Low (psi/ft)	Reference Case (psi/ft)	Reasonable High (psi/ft)
F2000	13381	13381	13381	Gas	N	9427	9427	9430	9434	9434	0.704	0.704	0.705	0.705	0.705	0.835	0.835	0.851	0.868	0.868	Reservoir is in the Over-pressured regime. All shallower reservoirs have been cased off.

Prepared By: DIKE AHUNANYA SPDC-UPO/G/DNF Name Team Indicator Date 30/01/2017

PP Check/Approved By: LAOYE, ABOODUN / ODEGBESAN, OLUSEYI Name Signature Date

Validity Date: 29-Jul-17



THE SHELL PETROLEUM DEVELOPMENT COMPANY OF NIGERIA LIMITED

KOLO CREEK 045 WELL CLEAN-UP/TEST PROPOSAL

February 2017

Well No	KOLO CREEK 045
Reservoir	F2000X

Document Number:	SPDC-2017-02-00000005	Contributors:	Adebayo, Adejoke (PT) Kassim Hamzat (PT) Nnadi, Magnus (RE) Nwabueze, Chuks (PG) Ahunanya Dike (PP)
Document Owner:	UPO/G/DNL		
Issue Date:	February 2017	Version:	1.0
Record Type Name:	Reservoir Data	Record Series Code:	FOP.05.02
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DISTRIBUTION: ADM, TWCC, DNL, Document Control.

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1.0 BACKGROUND

Kolo Creek 045 is a gas development well that was drilled to provide a drainage point on the F2000X reservoir. The reservoir gas recoverable volume is 945.4 Bscf and KOCR045T will develop 219.3 Bscf with an initial gas production potential of 120 MMscf/d. The well was spudded on the 25th February 2014, drilled to a TD of 14,080 ftah (13,555 ftss), and completion operation ended on 7th December 2014. The well penetrated the F2000X sand at 13,351 ftss, 56 ft shallower than prognosis and encountered a gross gas column of 204 ft tvt.

The well was drilled and completed as a Single String Single (SSS) gas producer on the F2000X gas reservoir with 7" 13Cr tubing equipped with Tubing Retrievable Surface-Controlled Subsurface Safety Valve (TRSCSSSV). Reslink standalone screen was installed across the sand face for effective sand control. Kolo Creek 045 was suspended with 2 sets of FIV shifted closed and 0.49 psi/ft NaCl brine in the tubing with a 5.88" monolock plug set at 100 ftah. The fluid in the drainhole is POBM.

Two other wells: Kolocreek 43 and Kolocreek 46 are completed on the reservoir. However, no production has been recorded from the reservoir. The F2000 is an overpressured reservoir with expected pressure of 9430 psia. Well testing spread and procedure will therefore be designed to manage expected high surface pressures.

It is proposed to clean up the well to about 50 MMscf/d to remove drilling and completion debris and fluids and then conduct Multirate test to ca. 50 MMscf/d on the F2000 interval. This is due environmental considerations. Results from the MRT will be used to calibrate the well deliverability and advise the well operating envelop.

1.1 Clean-Up/Test Objectives

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

- Clean up the well to remove mud, 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 Soku gas plant as part of the wells delivering gas to NLNG. 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 high level summary of the clean-up/well test work scope is given as follows:

- Pump treatment fluid and carry out well lift.
- Clean-up F2000X interval
- Carry out MRT on F2000X interval
- Carry out build-up and carry out SG survey

2.0 WELL CLEAN-UP DESIGN

During the clean-up operation, a specially formulated oil mud breaker solvent system will be pumped to displace the pseudo oil based mud in the open hole. This will be jetted across the Reslink standalone screen in a minimum of 3 passes. The well should be flowed long enough (ref Table 1) to allow sufficient time to

offload well on each bean while monitoring sand production. After every bean change, sand trap will be purged for inspection of well effluents.

If there is significant sand production (>0.5 lbs/MMscf), refer to Appendix 3D for contingency plan for excessive sand production..

All produced hydrocarbon (gas & condensate) will be burnt via the flare pit.

Note: No Open trucking of condensate is permitted.

Maximum Clean-up rate, constrained to 50 MMscf/d due to environmental considerations (Noise, vibration and flare intensity) is expected to create enough turbulence to lift all completion fluids and debris from the well. However, if there is need to clean up at higher rates, this will be done as a separate operation when the well is hooked up to the facility.

2.1 Clean-Up/Test Requirements

- Calibrated surface and downhole quartz gauges.
 - Downhole Shut in tool
 - Pressure let-down choke
 - Clamp on sand monitor
 - 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
 - Mono- Ethyl Glycol (To mitigate hydrates at low rates)
- * Note: Expected surface pressures in the range of 6900 – 7200 psi. All equipment upstream of choke manifold to be rated for 10,000 psi maximum pressure.

2.2 Well Clean-Up Operation

The well cleanup operation will commence with the opening of the two FIVs and unloading operation using coiled tubing. The clean-up will then commence from choke 24/64th (Note bean should be gradually increased). 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 expected minimum WGR ca. 0.7 bbl/MMscf is achieved (i.e. completion fluid fully evacuated). Thereafter, the well will be shut-in for a minimum of 24 hours for the reservoir pressure to stabilize, prior to conducting the Multirate test.

The flow back well effluent (completion brine and mud) will be evacuated with vacuum truck to the Gbaran Central Processing Facility (CPF) for disposal.

2.3 Clean-up Work Summary

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

- Check wellhead pressures – CITHP and CHP (A & B Annulus)
- Retrieve monlock plug
- RIH CT to open the two FIVs, refer to appendix 3c on the FIV opening/treatment contingency plan
- Pump treatment fluid by jetting, making minimum of three passes across screen to dissolve POBM
- Allow treatment fluid to soak while monitoring pressures
- Pump nitrogen (if required) to lift until well is confirmed to sustain natural flow
- Clean-up well as per program (Table-1), ensuring stable flow on each advised bean
- Shut-in well for a minimum of 24 hours for initial reservoir stabilization

NOTE:

- Initial opening of well must be during daylight.

- Bean-up must be done gradually to achieve good bridging behind standalone screen.
- Bean-up should be carried out when flow stabilizes. At each stage, record bean size, gas flow rate, FTHP, FTHT, CGR, WGR, and sand rate.
- Bleed down A & B annulus when pressure exceeds 1000 psi for A annulus and 400 psi for B annulus. Record volume of fluids recovered from A & B annulus during all operations. (See Appendix 10 for expected incremental AFE pressures)
- Flow well until well is properly cleaned, not exceeding a maximum gas rate of 50 MMscf/d. Well is properly cleaned-up when clean up criteria is achieved as specified in Table 1 below.
- All temporary pipe connections must be properly secured and tested to expected pressures

Table 1: KOLOCREEK 045 Well Clean-up 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	24	0.7	7239	4	3	Take sample, check for sand, measure FTHP.
30	30	0.7	7210	4	5	Take sample, check for sand, measure FTHP.
40	34	0.7	7193	4	7	Take sample, check for sand, measure FTHP.
50	40	0.7	7158	5*	9	Take sample, check for sand, measure FTHP.

Stable flow should be achieved on each bean before moving to the next advised bean

*** Clean up criteria**

Stabilized THP for at least 1 hour, no mud returns, BSW of liquid sample < 5%

Tolerance Qg: ± 5 MMscf/d, Tolerance FTHP: ± 50 psia

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

Summary of MRT workscope is given below

- RIH Slickline to install memory P/T gauges with programmed DHSIT at RPT nipple (11,586 ftah).
- Open up well and conduct Multirate test as per program (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.

3.1 Initial Build-up Period

- Close in well at choke manifold for 24 hours for an initial build-up/stabilization 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) at "RPT – Nipple" (ca.11,586 ftah).
- Monitor CITHP for pressure stabilization before proceeding to MRT.

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) (1/64 th)	Assumed WGR (bbl/MMscf)	Expected FTHP (psia)	Flow Period* (hr)	Expected Drawdown (psi)	Comments
20	24	0.7	7257	4	3	Take sample, check for sand, measure FTHP.
30	30	0.7	7250	4	5	Take sample, check for sand, measure FTHP.
40	34	0.7	7241	4	7	Take sample, check for sand, measure FTHP.
50	40	0.7	7213	4	9	Take sample, check for sand, measure FTHP.
0	0	0	-	48	0	48 hr shut in period

- 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 48 hours (Final Buildup duration determined from section 4.0) and subsequently commence Static Gradient Survey (See Table 3 below).
- All the other wells completed in the F2000X reservoir must be shut-in during the build-up of KOCR045T, this is to avoid interference from these wells.

3.3 Final Build-up and Static Survey Period

- Confirm well has been closed in 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.
- Duration of survey at each stop should be ca. 10mins.
- POOH with gauges and R/D S/line.
- Download wireline memory gauge.
- Close TRSCSSV and line up well to production.
- Handover well to production.

Table 3: Static Gradient Survey Stops.

Depth Tag (d)	Depth (d)	Intervals	Duration at depth	Comment/Basis for Stops Selection
	ftah from DFE [DFE Elevation = 58 ft]	Ft	Minutes	
Deepest Survey Depth	11,586	-	0	Deepest Survey depth. R nipple Depth
1st Stop	11,566	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	11,546	20	10	
3rd Stop	11,526	20	10	
4th Stop	11,426	100	10	2nd Set of Stops: 3 Stops at 100ft intervals to ensure accurate estimate of well fluid gradient
5th Stop	11,326	100	10	
6th Stop	11,226	100	10	
7th Stop	10,726	500	10	3rd Set of Stops: 3 Stops at 500ft intervals to ensure accurate estimate of well fluid gradient
8th Stop	10,226	500	10	
9th Stop	9,726	500	10	
10th Stop	8,726	1000	10	4th Set of Stops: 3 Stops at 1000ft intervals to ensure accurate estimate of well fluid gradient
11th Stop	7,726	1000	10	
12th Stop	6,726	1000	10	
13th Stop	4,726	2000	10	5th Set of Stops: 3 Stops at 2000ft intervals to ensure accurate estimate of well fluid gradient
14th Stop	2,726	2000	10	
15th Stop	726	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 well and reservoir data as detailed in Table 4. Pressure simulations were generated based on the rates in Table 2. 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 about 0.01 psi/hr (as seen in SAPHIR). 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	170	ft	

Parameter	Value	Unit	Comment
Average Formation Porosity	0.22	fraction	
Formation Compressibility	3.32E-06	psi ⁻¹	Estimated using Hall correlation.
Reservoir Pressure	9449	psi	Estimated current pressure based on BHP Data (No production history from reservoir)
Reservoir Temperature	229	deg°F	
Reservoir Permeability	1558	md	Mean reservoir permeability calculated from FZI analysis using logs acquired from
b. Well Data			
Well Orientation	Deviated		
Well Radius	0.27	ft	
Well bore Storage (WBS) Coefficient	0.017	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 0.0035 bbl/psi
c. Fluid data			
Fluid Type	Gas		
Gas gravity	0.71		
d. Others			
Reservoir Model	Homogeneous		
Wellbore Model	Constant storage		
Boundary Model	Fault/Dip closure		
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	48	Hrs	Flow @ 0 MMscf/day

4.2 Scenario/Sensitivity Formulation

PERMEABILITY:

The permeability values used in this design were based on FZI analysis which utilizes the porosity logs acquired from the well. A minimum, most likely and maximum value of 522mD, 1558mD and 2079mD respectively were derived and used in the design.

BOUNDARY MODEL:

The F2000X reservoir Map (Appendix 5) was digitized and used in the design. The reservoir has GWC at 13749 ftss. From the top structure map and cross section (Appendix 5&6), the structure has few intra-reservoir faults which are mostly interpreted as non-sealing. A review of the structure also show that the reservoir is fault bounded at the north-east by the boundary fault and at the west, south and south-east. The sealing factors of the major boundary faults are set to zero while intra-reservoir faults are set to 0.5.

SKIN:

Skin value range from the Gbaran Node (Zarama, Koroama, Gbaran and Kolo Creek) have been used to define the skin range for the design. The skin values are 15, 52 and 88 for low, mid and high respectively.

WELLBORE STORAGE:

A wellbore storage coefficient of 0.017 bbl/psi was estimated for surface shut in. The well test design was carried out using this well bore storage 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.

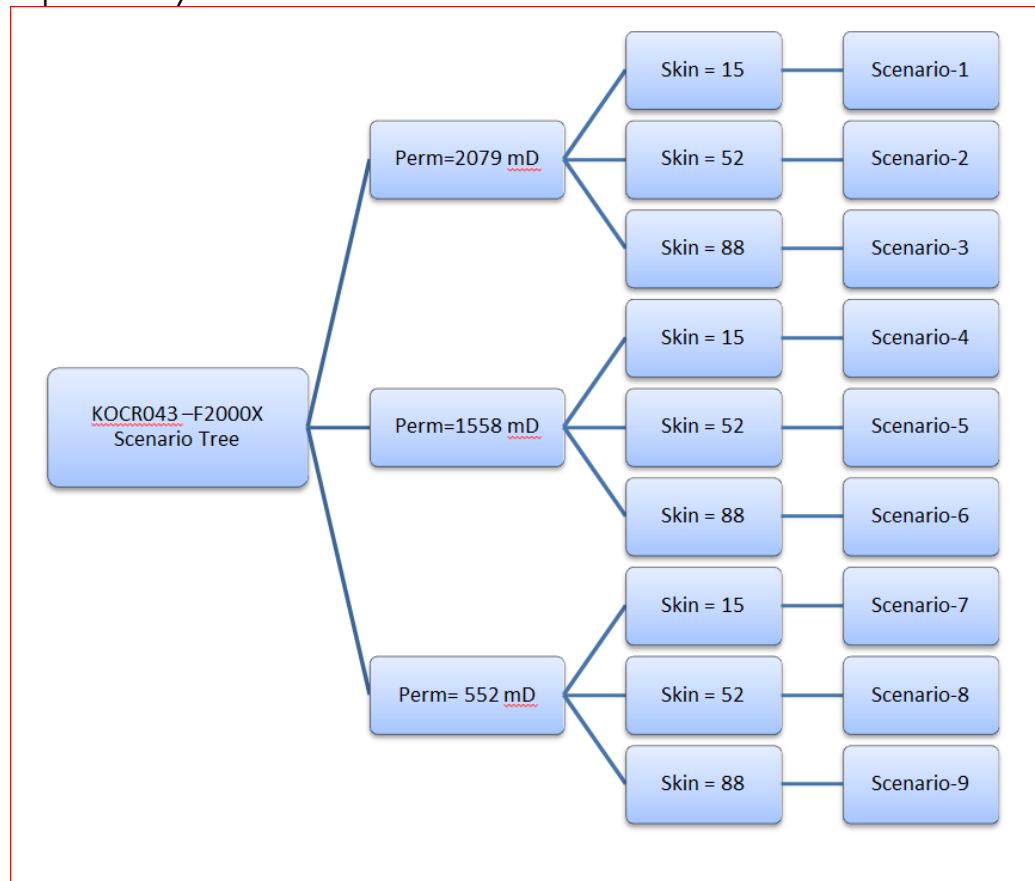


Figure 1: Scenario

4.3 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 available data from wells which were completed on the interval, the F2000X shows a permeability range of 522mD to 2079mD. These values were based on log data from KOCR039 and, 39ST. The initial reservoir pressure value of 9449 psia used in the evaluation was based on RCI from KOCR039 as the reservoir has not produced. The Log-Log plots from the generated pressure are shown in Figure 2 and durations from the sensitivities are listed in Table 5.

The derivative plots for the different scenarios can be seen in Figures 2 and 3. 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. As the infinite acting radial flow period is clearly observed.
2. The late time pressure response indicated an outer boundary primarily dominated by the effect of mobility changes at the water-gas interface in the various scenarios.
3. With the assumed base-case permeability of 1558 mD, a minimum of 24 hours is required for the final build up test. For the permeability value of 552mD, a minimum of 48 hours is required for the outer boundary effects to be felt by the test and pressure stabilization achieved. The 48 hour build-up from the low permeability has been selected as the build-up duration for the well.

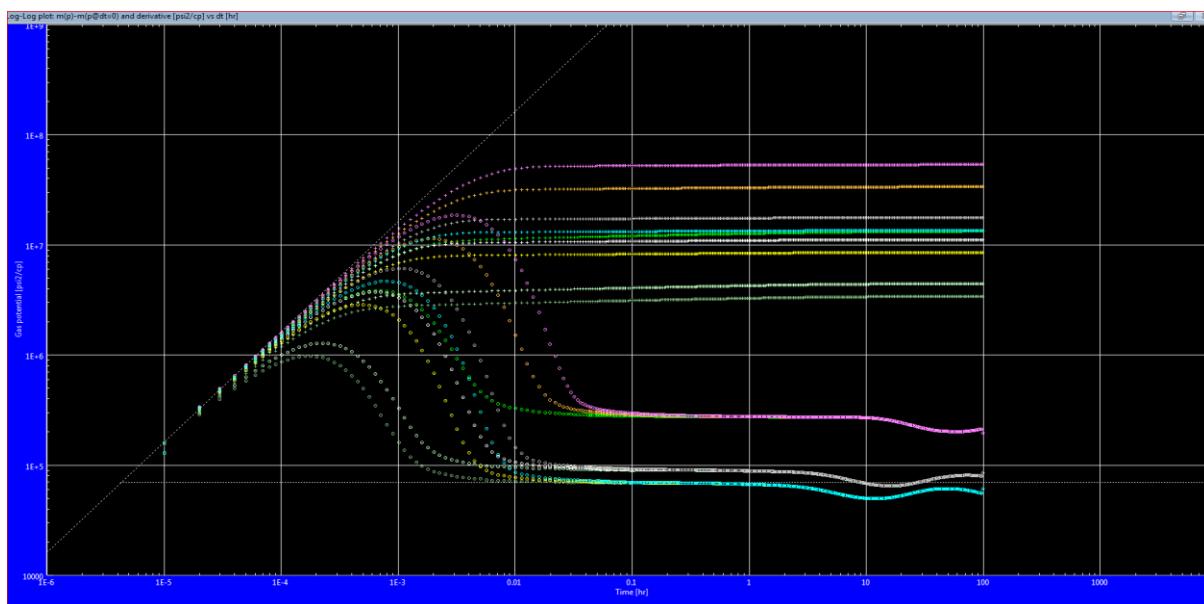


Figure 2: Log-Log plot for All Scenarios

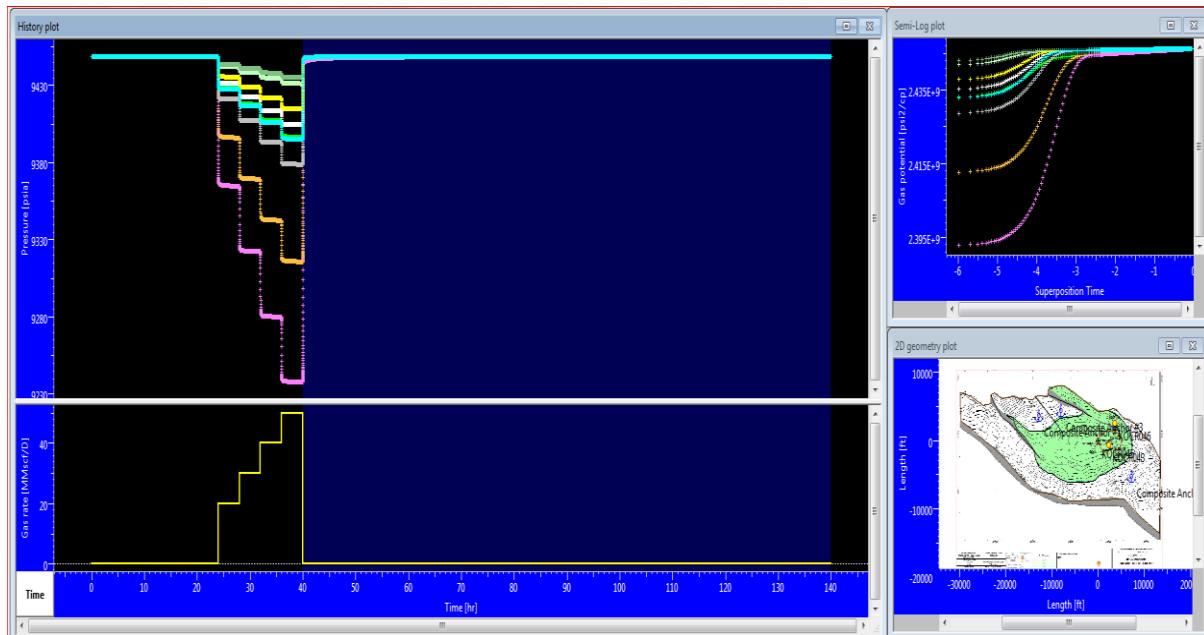


Figure 3: Cartesian, Semi-log plots and Digitized map.

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. The optimal test time selected is highlighted in Table 5.

Table 5: 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
S1	24	4	4	4	4	24	64
S2	24	4	4	4	4	24	64
S3	24	4	4	4	4	24	64
S4	24	4	4	4	4	24	64
S5	24	4	4	4	4	24	64
S6	24	4	4	4	4	24	64
S7	24	4	4	4	4	48	88
S8	24	4	4	4	4	48	88
S9	24	4	4	4	4	48	88

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. The optimal test time selected is as detailed in the Table 6 below.

5.0 WORKSCOPE SUMMARY

The summary of the Clean-up & MRT work scope is given as follows:

Hold pre-job safety and work scope meeting.

- Check and record wellhead pressures.
- Retrieve monolock plug.
- Pressure and function test CT
- RIH CT to open the two FIVs, refer to appendix 3c on the FIV opening/treatment contingency plan
- Pump treatment fluid by jetting, making minimum of three passes across screen to dissolve POBM
- Allow treatment fluid to soak while monitoring pressures
- Lift well with Nitrogen if well does not come unaided.
- Commence well clean-up (Table1).
- Shut-in well for 24 hours for initial reservoir stabilization.
- RIH Slickline to install memory P/T gauges with programmed DHSIT at RPT nipple (11,586 ftah).
- Open up well and conduct Multirate test (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:

- Initial opening of well must be during daylight.
- Bean-up must be done gradually to achieve good bridging behind screen.
- 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 50 MMscf/d. Well is properly cleaned-up when at least 95% 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.

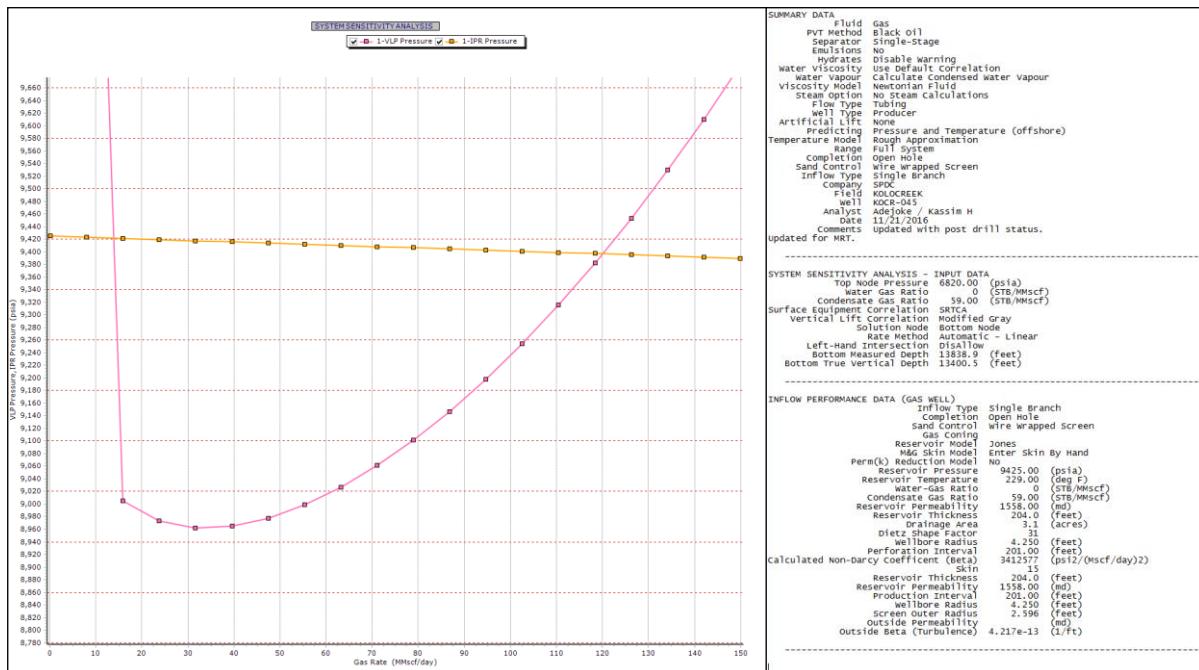
APPENDIX 1: RESERVOIR & COMPLETION DATA

Target Reservoir	F2000X
1. Casing size and Type	7''/Liner
2. Casing Setting Depth (ftah)	13848
3. Top of Sand [ftss/ftah]	13351 / 13848
4. Gross Sand Thickness (Gross) penetrated by KOCR045 (ft tv)	204
5. Well TD (ftss/ftah)	13555 / 14080
6. a) Completion interval (ftss) b) Completion interval (fttv) c) Completion interval (ftah)	13351 – 13555 13409 – 13613 13848 – 14080
7. Length of Completion Interval (ftah)	232
8. a) Top of competent cement (ftah) b) Source of data	6,402 CBL
9. a) Was hole directionally drilled? b) Max deviation angle and depth (ftah)	Yes 30.14 deg @ 14,047
10. Deviation at completion zone	30
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)	9449 13500 9449 229 13351 9426
12. Did RCI indicate abnormal pressures?	Yes
13. Pressure gradient @ top of sand (psi/ft)	0.71
14. a) Is the reservoir fully gas-bearing?	Yes
15. a) Is there original GWC in the reservoir b) What depth (ftss)? c) Change in PGWC from original OGWC (ft)	Yes (KOCR039ST) 13749 0
16. Distance between lowest completion interval and estimated GWC in well / reservoir (ftss)	194
17. Is there a barrier between lowest completion interval and the present estimated GWC?	No (there are baffles in the reservoir though)
18. Gas S.G. (air=1)	0.71
19. Condensate gravity (API)	39.2
20. Expected FTHP (psia)*	6820
21. Expected CITHP (psia)	7260
22. Expected Drawdown (psi)*	28
23. Expected PI (scf/d/psi^2)*	303
24. Is sand exclusion installed?	SAS (RESLINK)

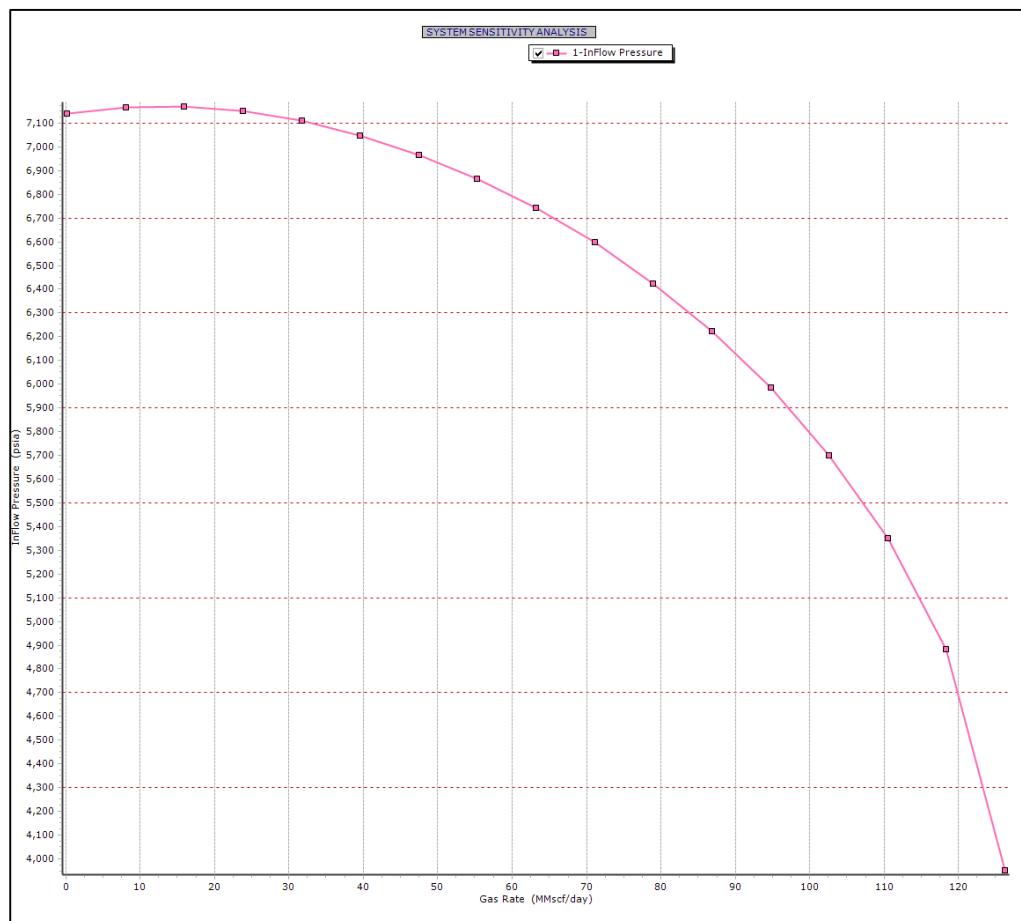
*Values are at well potential of 120 MMscf/d

APPENDIX 2: WELL PERFORMANCE PLOTS

KOCR045 Well Performance



KOCR045 P-Q Curve



APPENDIX 3A: WELL TEST RISK AND MITIGATION

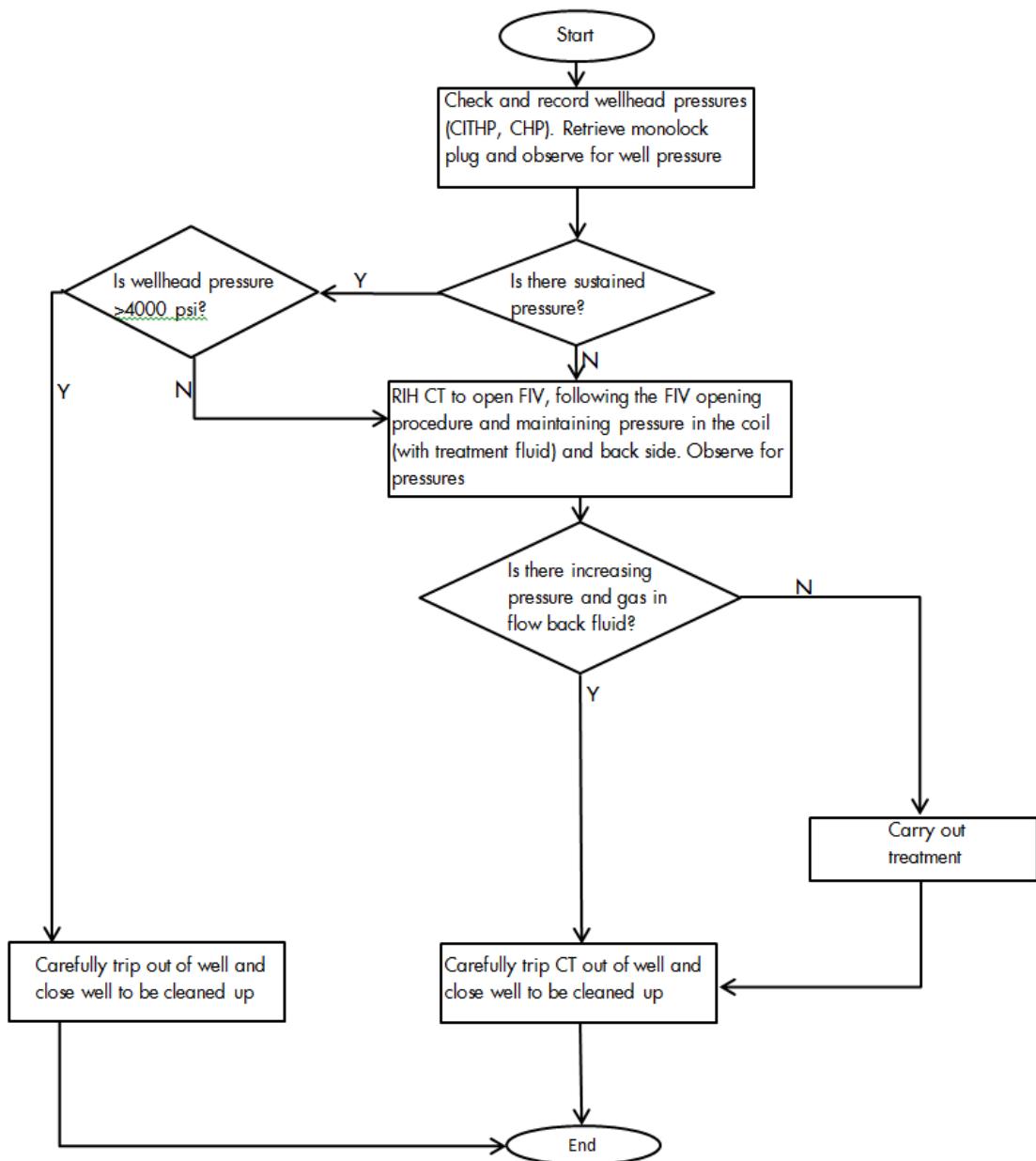
Risk	Consequence	Mitigation
Loss of containment	Blowout, explosion, injury, fatality, loss of equipment	<p>Ensure presence of minimum of 2-barriers at all time during clean-up/MRT operations.</p> <p>Also ensure all HAZID actions are closed-out prior to commencing operation</p> <p>Ensure BOP for the coil tubing unit and all pressure equipment are properly rated and tested at the contractor base and onsite, and these tests are witnessed by SPDC personnel. Check integrity of the valves on the wellhead and TRSCSSV. Install surface readout gauges to monitor pressures at all times</p>
Hydrate Formation	Blocked tubulars, increased pressure, blow-out, injury, and fatality.	Ensure that effective glycol is mobilized to site since a high pressure drop is expected, to prevent hydrate formation. Conduct tests on samples of glycol to be used to confirm its adequacy prior to mobilization.
Inappropriately sized coiled tubing tools	Downhole components/tools may not get to desired depths	Ensure the dimensions of the tools to be RIH are appropriately sized for 7" tubing accessories/profiles ID and 4" FIV and screen
Failure of Downhole Shut-in Tool at deployment, or failure to retrieve the Shut-in Tool and gauges	In-accurate estimate of wellbore storage, impact on well test results, Inability to open well for production.	Ensure tool is checked at the contractor's base and confirmed operational before deploying. Ensure proper and efficient deployment procedures are followed
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, scorching 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.	Wellhead have stainless steel clads. Also, acid would not be used during the operation.
Fire Outbreak	Fire outbreak, injury, and loss of equipment, fatality.	<p>Barricade work area, prohibit use of cell phone & smoking around well's perimeter fence, restrict movement of unauthorized persons around work area.</p> <p>Inspect bond wall periodically during and carry out repairs as required.</p>
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.

Risk	Consequence	Mitigation
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 to the highest pressures expected at this operation
Community disturbance	Disruption of work, delay in execution, cost escalation	Ensure robust engagement of community stakeholders about expectations (flaring heat and noise) during the job execution

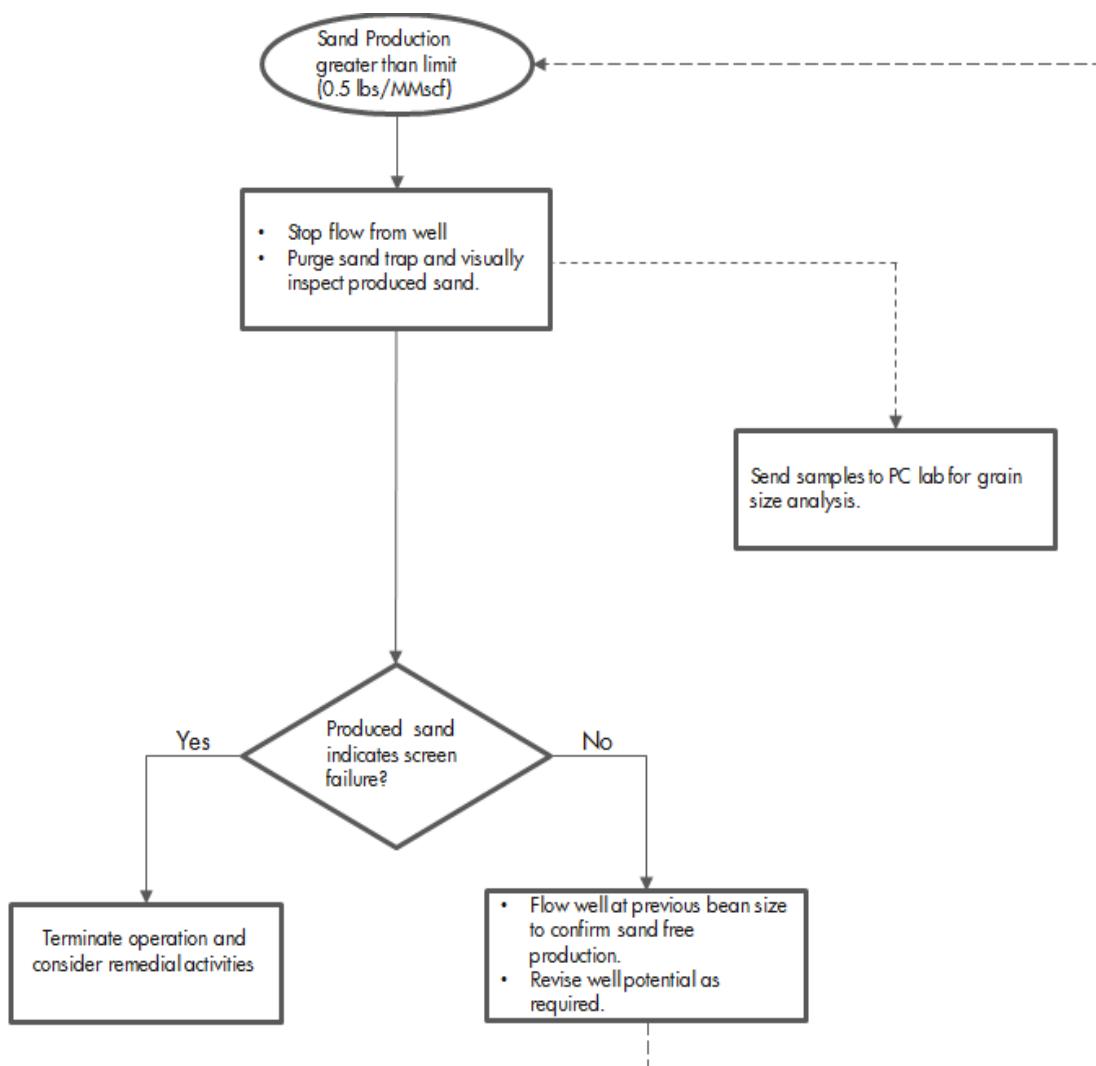
APPENDIX 3B: DEP Table

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 at the top of screen is 9426 psia (See Appendix 11)	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 KOCR045 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 380 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.	H ₂ S 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 carried out and the well completed with SAS installed for sand control. Sand monitoring would be in place during this clean-up and MRT.	PT

APPENDIX 3C: FIV Opening Contingency Plan

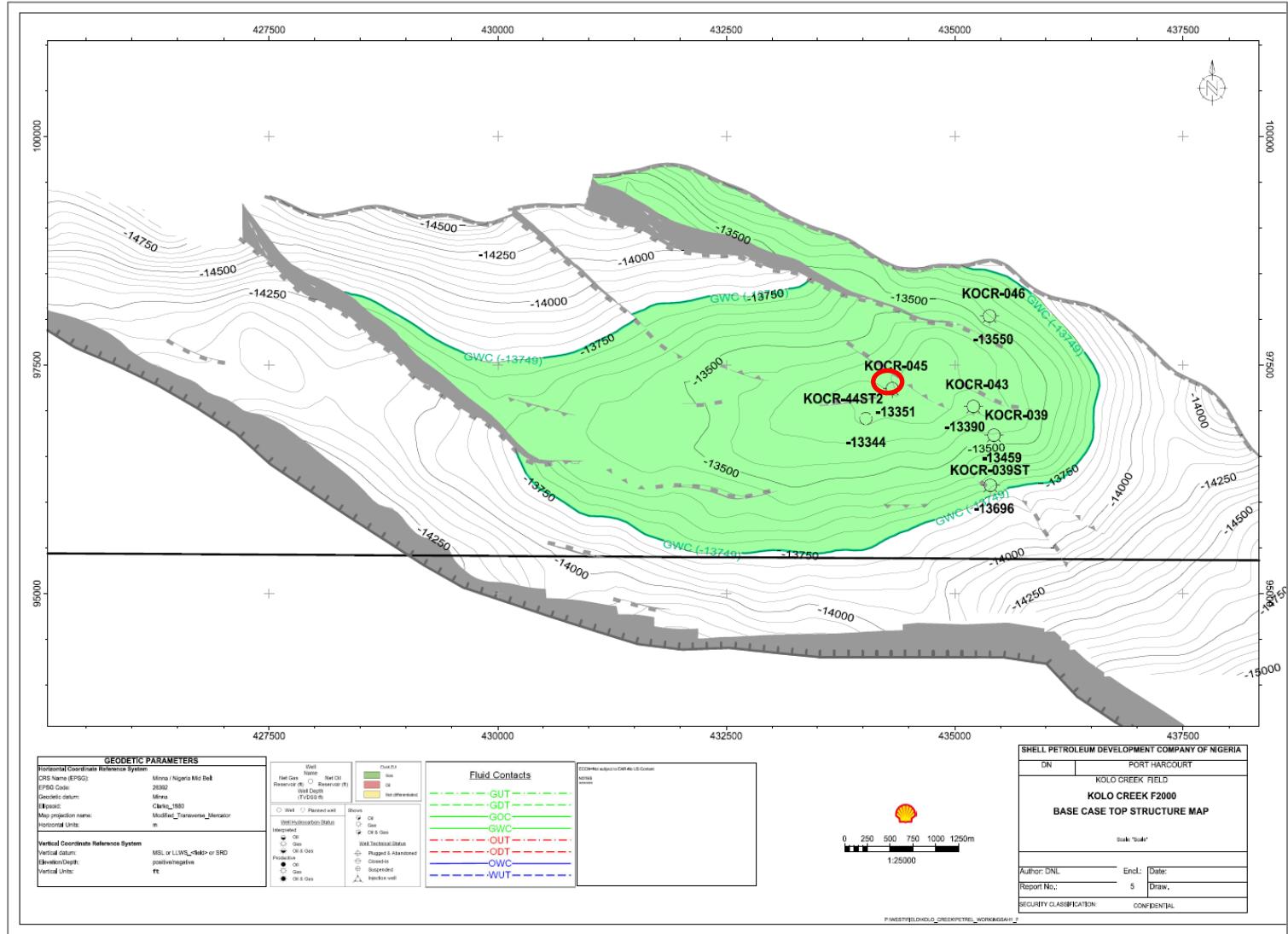


APPENDIX 3D: Kolo Creek 045 Sand production contingency plan

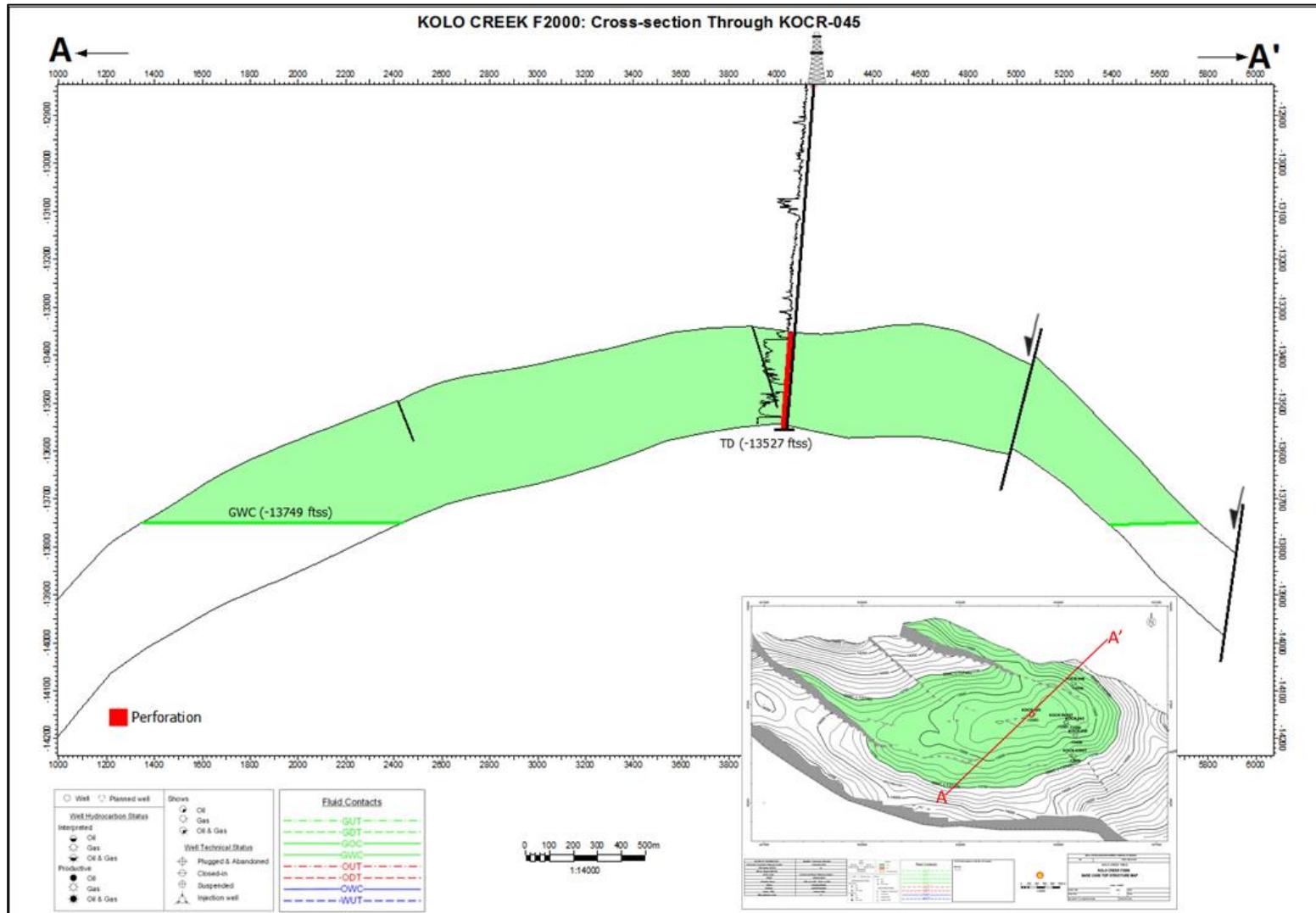


APPENDIX 4: Kolo creek 045 Final Completion Status Diagram

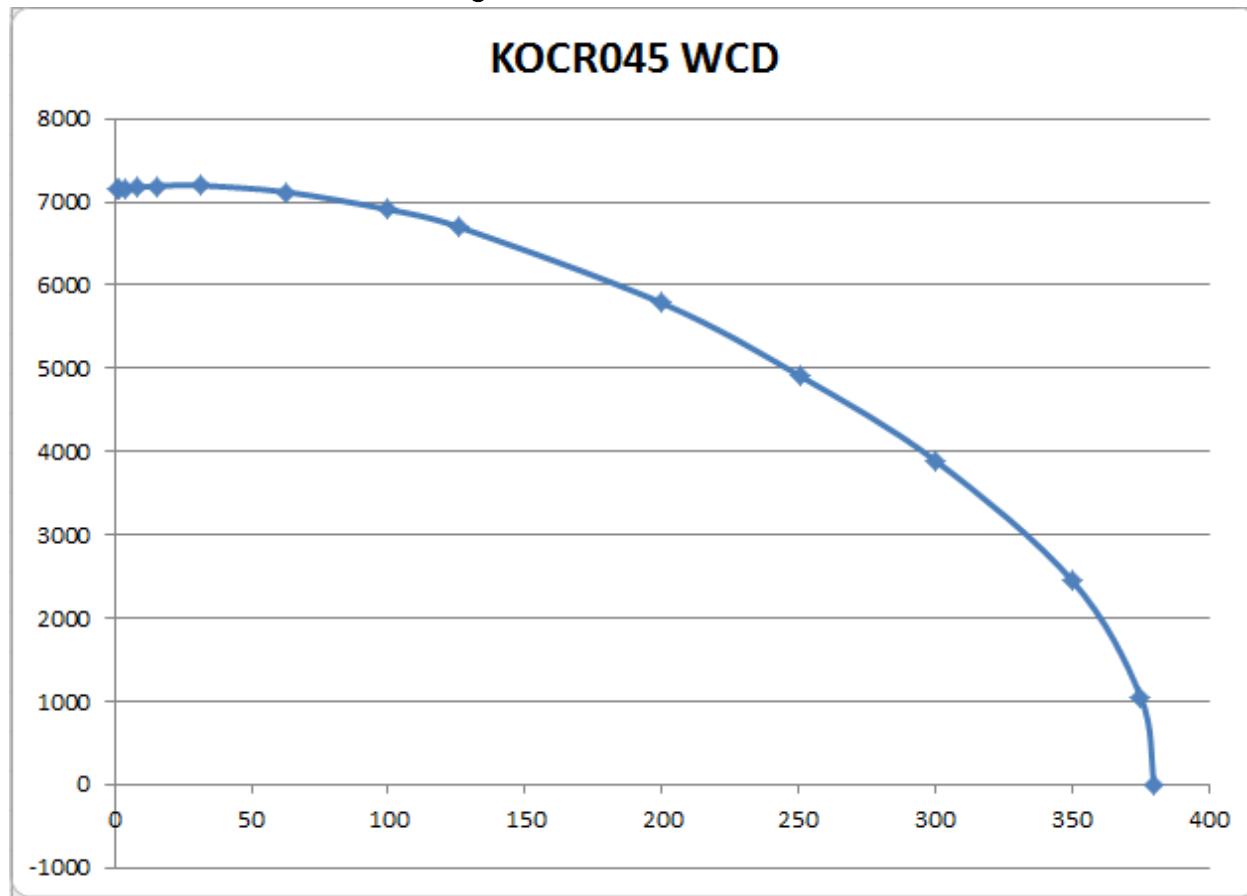
APPENDIX 5: Top Depth Map of the F2000X sand



APPENDIX 6: Cross section along KOCR045 well path



APPENDIX 7: Worst Case Discharge Plot



APPENDIX 8: KOCR045 H₂S Prediction

KOCR045T H₂S PREDICTION

Introduction

The consequence of the presence of H₂S is loss of life and material integrity. This document contains prediction of naturally occurring H₂S concentration and souring potential for KOCR045T well based on available data.

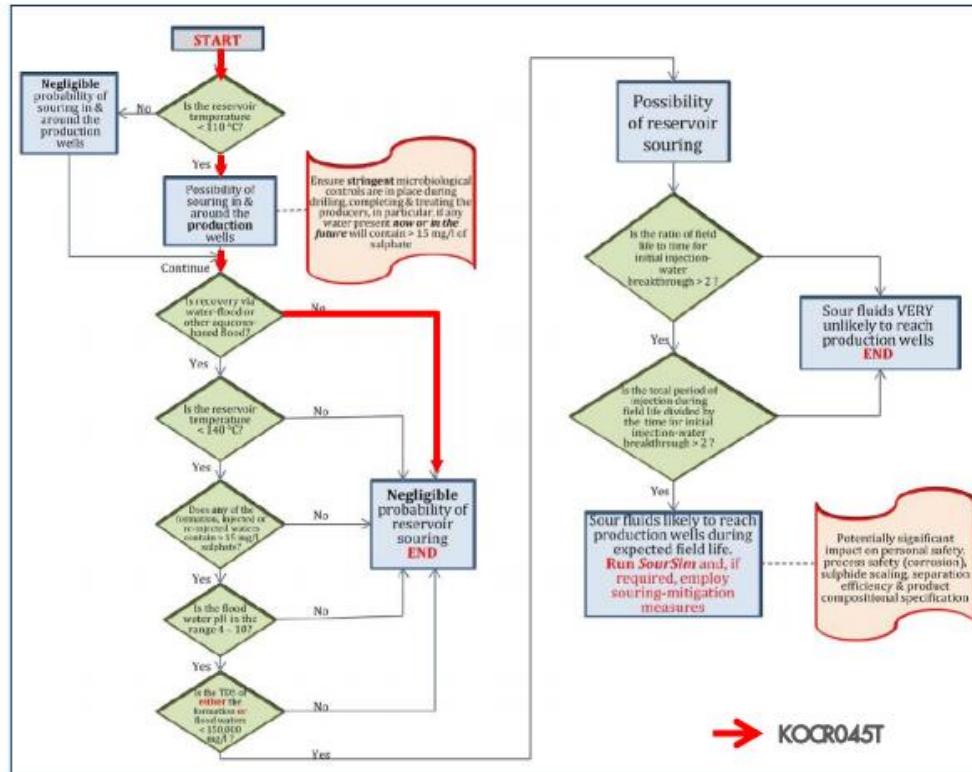
Naturally Occurring H₂S Concentration

- KOCR045T is completed on the F2000 reservoir.
- PVT analysis available for F2000X reservoir shows no presence of H₂S
- H₂S has not been encountered in KOCR oil & NAG wells producing in the Gbaran nodal area.
- Naturally occurring H₂S concentration is therefore predicted to be 0%mol

Souring Potential

- Souring potential is a function of expected reservoir temperature
- Expected reservoir temperature is 109 °C, (229°F) however, no waterflood is planned for the field.
- Hence, the souring potential is negligible. (see SPA tool)
- Gas testers and appropriate PPE's will be utilized during completion and well open up as additional mitigation.

Souring Potential Assessment for KOCR045T



Prepared by:	Reviewed by:	Approved by:
Kassim Hamzat		
Checked by:		
Emesi, John Nnadi, Magnus Akunesiobike, Jonathan	Nwankwo, Cosmas Oluwajuyigbe, David	Ugboaja, Remmy
UGBOAJA REMMY	Digitally signed by UGBOAJA REMMY Date: 2017.01.26 19:36:40 +01'00'	

APPENDIX 9: KOCR045 Clean up and Well Test Cost Estimate

S/N	Service Description	Minimun Cost (\$)
1	Well Test Services	\$486,134.28
2	WHM Ops	\$32,928.98
3	CT/N2 Services	\$241,567.97
4	HP Pumping Ops	\$85,956.80
5	WT Support	\$394,780.93
6	SL Support	\$54,611.44
7	Water Facilities	\$16,931.81
8	IT Support	\$4,412.10
9	SPDC Logistics	\$98,675.02
10	FTO	\$9,266.67
11	Security	\$26,600.00
	TOTAL	\$1,451,865.99

APPENDIX 10: KOCR045 Expected Annular Fluid Expansion

Estimated Incremental AFE pressure and volume for 50 MMscf/d flow without annulus bleed down

String Annulus	Incremental AFE pressure (psi)	Incremental AFE Volume (bbl)
9-5/8" Production Casing (B annulus)	3576	6.9
7" Production Tubing (A annulus)	5565	5.5

Notes:

1. If CHP exceeds expected AFE pressure or bled down volume exceeds AFE volume then, CHP investigation required.
2. Casing should be monitored closely and bled down as per program because expected AFE pressure exceeds the MAASP calculated for A & B annulus.

APPENDIX 11: F2000 Pore Pressure Estimation

The pore pressures for the F2000 reservoir were estimated using pressure cell method. RCI data from KOCR-039ST was used to obtain the pore pressure model.

The pressure at the top of screen was obtained by extrapolating the pressure from the datum depth (13,500 ftss) using fluid gradients measured from the F2000 reservoir in KOCR-039ST.

Uncertainty in fluid gradient was considered in estimating the high, base and low case pore pressures. The top of screen was established based on the completion tally, thus uncertainty in depths was eliminated.

All reservoirs shallower than the F2000 have been cased-off (please see appendix 4), thus the pore pressure estimation was carried out for only the F2000 which will be open to flow during the Clean-up / MRT operation. The table below presents the range of formation gradients estimated for the F2000 reservoir based on KOCR-043ST, 045 & 046.

Reservoir	Min formation gradient, KOCR046 (psi/ft)	Ref formation gradient KOCR043ST (psi/ft)	Max formation gradient, KOCR045 (psi/ft)
F2000	0.698	0.704	0.706

The pore pressure table and plot are presented below.

F2000 Pore Pressure Estimation Plot

FIELD : **KOLO CREEK**

Well : **045**

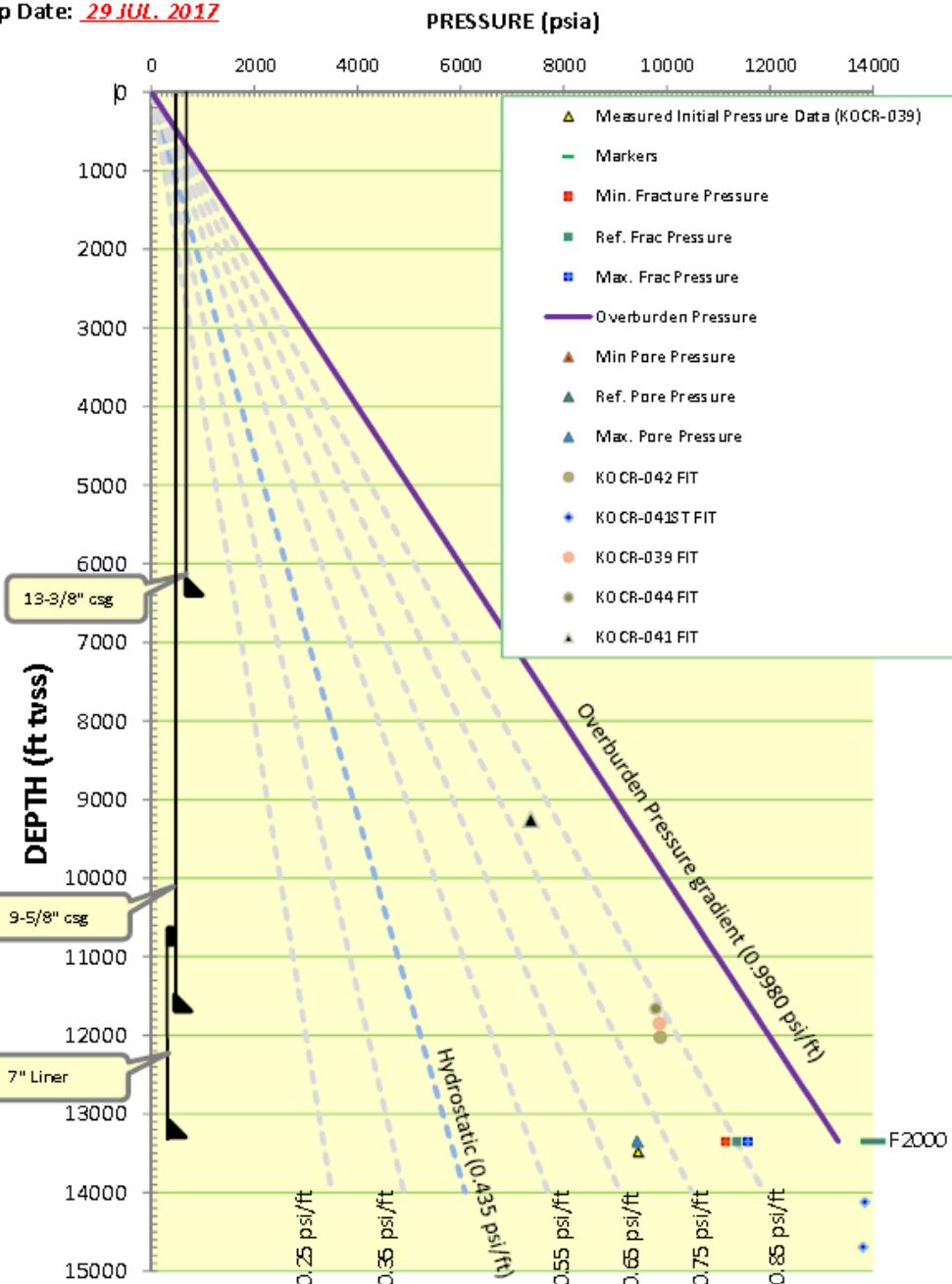
Revision : **3.0**

Issue Date: **30 JAN. 2017**

Exp Date: **29 JUL. 2017**

Pore/Fracture Pressure Prediction Plot

(Pressure at Top Reservoir Depth)



Prepared by : DIKE, AHUNANYA Date: 30/1/2017

PP Check/Approved by: LAOYE, ABIODUN / ODEGBESAN, OLUSEYI Date: 30/1/2017

Digitally signed by
Oluseyi
Date: 2017.01.31
Odegbesan 11:32:57 +01'00'

F2000 Pore Pressure Estimation Table

FIELD:	KOLO CREEK
WELL NAME:	45
PLATFORM/RIG:	Mobile Test Separator
PREPARED BY/	DIKE AHUNANYA / LAOYE ABIODUN
CHECKED BY:	
ISSUED DATE:	30 January 2017
REVISION NO.:	3.0
SPUD DATE:	25 February 2014
EXPIRY DATE:	29 July 2017

Pore Pressure Prediction at Top Reservoir for KOCR-045

Formation	TV-Depth of Pressure Prediction and Reference Depth (e.g., ss or bdf)			Fluid Type Prognosis at Top of Sand along Well Trajectory	Is Reservoir Developed	Formation Pore Pressure Prognosis at Top of Sand along Well Trajectory					Formation Pore Pressure Gradient at TOS					Fracture Gradient Prognosis at Top of Sand along Well Trajectory					Remarks	
	Shallow (ft:ss)	Most Likely (ft:ss)	Deep (ft:ss)			Reference Case	(Y/N)	Minimum (psia)	Reasonable Low (psia)	Reference Case (psia)	Reasonable High (psia)	Maximum (psia)	Minimum (psi/ft)	Reasonable Low (psi/ft)	Reference Case (psi/ft)	Reasonable High (psi/ft)	Maximum (psi/ft)	Minimum (psi/ft)	Reasonable Low (psi/ft)	Reference Case (psi/ft)	Reasonable High (psi/ft)	Maximum (psi/ft)
F2000	13351	13351	13351	Gas	N	9422	9422	9426	9426	9430	9430	0.706	0.706	0.706	0.706	0.706	0.834	0.834	0.851	0.867	0.867	Reservoir is in the Over-pressured regime. All shallower reservoirs have been cased off.

Prepared By: DIKE AHUNANYA SPDC-UPO/GJDNF Date: 30/01/2017

Name: Team Indicator: Date: 30/01/2017

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Date: 2017/01/31 11:28:17
Signature: _____

Validity Date: 29-Jul-17



THE SHELL PETROLEUM DEVELOPMENT COMPANY OF NIGERIA LIMITED

KOLO CREEK 046 WELL CLEAN-UP/TEST PROPOSAL

February 2017

Well No	KOLO CREEK 046
Reservoir	F2000X

Document Number:	SPDC-2017-02-00000006	Contributors:	Adebayo, Adejoke (PT) Kassim Hamzat (PT) Nnadi, Magnus (RE) Esharegharan, Ovoke (PG) David, Olayinka (PP)
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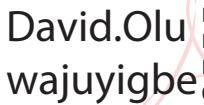
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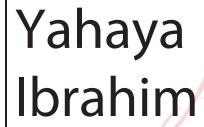
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1.0 BACKGROUND

Kolo Creek 046 is a gas development well that was drilled to provide a drainage point on the F2000X reservoir. The reservoir gas recoverable volume is 945.4 Bscf and KOCR046T will develop 257.2 Bscf with an initial gas production potential of 120 MMscf/d. The well was spudded on the 9th April 2014, drilled to a TD of 14,026 ftah (13,686 ftss), and completion operation ended on 24th December 2014. The well penetrated the F2000X sand at 13,550 ftss, 113 ft deeper than prognosis and encountered a gross gas column of 136 ft tvd.

The well was drilled and completed as a Single String Single (SSS) gas producer on the F2000X gas reservoir with 7" 13Cr tubing equipped with Tubing Retrievable Surface-Controlled Subsurface Safety Valve (TRSCSSV). Reslink standalone screen was installed across the sand face for effective sand control. Kolo Creek 046 was suspended with FIV shifted closed and 0.49 psi/ft NaCl brine in the tubing and 5.88" monolock plug set at 70 ftah. The fluid in the drainhole is POBM.

Two other wells: Kolocreek 43 and Kolocreek 45 are completed on the reservoir. However, no production has been recorded from the reservoir. The F2000 is an overpressured reservoir with expected pressure of 9430 psia. Well testing spread and procedure will therefore be designed to manage expected high surface pressures.

It is proposed to clean up the well to about 50 MMscf/d to remove drilling and completion debris and fluids and then conduct Multirate test to ca. 50 MMscf/d on the F2000 interval. This is due to environmental considerations. Results from the MRT will be used to calibrate the well deliverability and advise well operating envelop.

1.1 Clean-Up/Test Objectives

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

- Clean up the well to remove mud, 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 Soku gas plant as part of the wells delivering gas to NLNG. 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 high level summary of the clean-up/well test work scope is given as follows:

- Pump treatment fluid and carry out well lift.
- Clean-up F2000X interval
- Carry out MRT on F2000X interval
- Carry out build up and carry out SG survey

2.0 WELL CLEAN-UP DESIGN

During the clean-up operation, a specially formulated oil mud breaker solvent system will be pumped to displace the pseudo oil based mud in the open hole. This will be jetted across the Reslink standalone screen in a minimum of 3 passes. The well should be flowed long enough (ref Table 1) to allow sufficient time to

offload well on each bean while monitoring sand production. After every bean change, sand trap will be purged for inspection of well effluents.

If there is significant sand production (>0.5 lbs/MMscf), refer to Appendix 3D for contingency plan for excessive sand production.

All produced hydrocarbon (gas & condensate) will be burnt via the flare pit.

Note: No Open trucking of condensate is permitted.

Maximum Clean-up rate, constrained to 50 MMscf/d due to environmental considerations (Noise, vibration and flare intensity) is expected to create enough turbulence to lift all completion fluids and debris from the well. However, if there is need to clean up at higher rates, this will be done as a separate operation when the well is hooked up to the facility

2.1 Clean-Up/Test Requirements

- Calibrated surface and downhole quartz gauges.
- Downhole Shut in tool
- Pressure let-down chock
- Clamp on sand monitor
- 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)
* Note: Expected surface pressures in the range of 6900 – 7200 psi. All equipment upstream of choke manifold to be rated for 10,000 psi maximum pressure.

2.2 Well Clean-Up Operation

The well cleanup operation will commence with the opening of the FIV and unloading operation using coiled tubing. The clean-up will then commence from choke 24/64th (Note bean should be gradually increased). 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 expected minimum WGR ca. 0.7 bbl/MMscf is achieved (i.e. completion fluid fully evacuated). Thereafter, the well will be shut-in for a minimum of 24 hours for the reservoir pressure to stabilize, prior to conducting the Multirate test.

The flow back well effluent (completion brine and mud) will be evacuated with vacuum truck to the Gbaran Central Processing Facility (CPF) for disposal.

2.3 Clean-up Work Summary

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

- Check wellhead pressures – CITHP and CHP (A & B Annulus)
- Retrieve monolock plug
- RIH CT to open the FIV, refer to appendix 3c on the FIV opening/treatment contingency plan
- Pump treatment fluid by jetting, making minimum of three passes across screen to dissolve POBM
- Allow treatment fluid to soak while monitoring pressures
- Pump nitrogen (if required) to lift until well is confirmed to sustain natural flow
- Clean-up well as per program (Table-1), ensuring stable flow on each advised bean
- Shut-in well for a minimum of 24 hours for initial reservoir stabilization

NOTE:

- Initial opening of well must be during daylight.

- Bean-up must be done gradually to achieve good bridging behind standalone screen.
- Bean-up should be carried out when flow stabilizes. At each stage, record bean size, gas flow rate, FTHP, FTHT, CGR, WGR, and sand rate.
- Bleed down A & B annulus when pressure exceeds 1000 psi for A annulus and 400 psi for B annulus. Record volume of fluids recovered from A & B annulus during all operations. (See Appendix 10 for expected incremental AFE pressures)
- Flow well until well is properly cleaned, not exceeding a maximum gas rate of 50 MMscf/d. Well is properly cleaned-up when clean up criteria is achieved as specified in Table 1 below.
- All temporary pipe connections must be properly secured and tested to expected pressures

Table 1: KOLOCREEK 046 Well Clean-up 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	24	0.7	7248	4	6	Take sample, check for sand, measure FTHP.
30	30	0.7	7246	4	9	Take sample, check for sand, measure FTHP.
40	34	0.7	7215	4	11	Take sample, check for sand, measure FTHP.
50	40	0.7	7135	5*	16	Take sample, check for sand, measure FTHP.

Stable flow should be achieved on each bean before moving to the next advised bean

*** Clean up criteria**

Stabilized THP for at least 1 hour, no mud returns, BSW of liquid sample <5%

Tolerance Qg: ± 5 MMscf/d, Tolerance FTHP: ± 50 psia

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

Summary of MRT workscope is given below

- RIH Slickline to install memory P/T gauges with programmed DHSIT at RPT nipple (11,532 ftah).
- Open up well and conduct Multirate test as per program (Table 2)
- Shut in well for 24-hour final build-up test with DHSIT in closed position.
- Carry out SG survey.
- Secure well.
- RD equipment.

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) at "RPT - Nipple" (ca.11,532 ftah).
- Monitor CITHP for pressure stabilization before proceeding to MRT.

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) (1/64 th)	Assumed WGR (bbl/MMscf)	Expected FTHP (psia)	Flow Period* (hr)	Expected Drawdown (psi)	Comments
20	24	0.7	7248	4	6	Take sample, check for sand, measure FTHP.
30	30	0.7	7246	4	9	Take sample, check for sand, measure FTHP.
40	34	0.7	7215	4	11	Take sample, check for sand, measure FTHP.
50	40	0.7	7135	4	16	Take sample, check for sand, measure FTHP.
0	0	0	-	48	0	48hr shut in period

- 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 24 hours (Final Buildup duration determined from section 4.0) and subsequently commence Static Gradient Survey (See Table 3 below).
- All the other wells completed in the F2000X reservoir must be shut-in during the build-up of KOCR046T, this is to avoid interference from these wells.

3.3 Final Build-up and Static Survey Period

- Confirm well has been closed in for 24 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
- 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 DFE [DFE Elevation = 58 ft]	Intervals Ft	Duration at depth Minutes	Comment/Basis for Stops Selection
Deepest Survey Depth	11,532	-	0	Deepest Survey depth. R nipple Depth
1st Stop	11,512	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	11,492	20	10	
3rd Stop	11,472	20	10	
4th Stop	11,372	100	10	2nd Set of Stops: 3 Stops at 100ft intervals to ensure accurate estimate of well fluid gradient
5th Stop	11,272	100	10	
6th Stop	11,172	100	10	
7th Stop	10,672	500	10	3rd Set of Stops: 3 Stops at 500ft intervals to ensure accurate estimate of well fluid gradient
8th Stop	10,172	500	10	
9th Stop	9,672	500	10	
10th Stop	8,672	1000	10	4th Set of Stops: 3 Stops at 1000ft intervals to ensure accurate estimate of well fluid gradient
11th Stop	7,672	1000	10	
12th Stop	6,672	1000	10	
13th Stop	4,672	2000	10	5th Set of Stops: 3 Stops at 2000ft intervals to ensure accurate estimate of well fluid gradient
14th Stop	2,672	2000	10	
15th Stop	672	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 well and reservoir data as detailed in Table 4. Pressure simulations were generated based on the rates in Table 2. 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 about 0.01 psi/hr (as seen in SAPHIR). 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	113	ft	
Average Formation Porosity	0.22	fraction	

Parameter	Value	Unit	Comment
Formation Compressibility	3.32E-06	psi-1	Estimated using Hall correlation.
Reservoir Pressure	9449	psi	Estimated current pressure based on RCI from KOCR039 (No production from reservoir)
Reservoir Temperature	229	deg°F	
Reservoir Permeability	1558	md	Mean reservoir permeability calculated from FZI analysis using logs acquired from KOCR039 and 39-ST
b. Well Data			
Well Orientation	Deviated		
Well Radius	0.27	ft	
Well bore Storage (WBS) Coefficient	0.017	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 0.0035 bbl/psi
c. Fluid data			
Fluid Type	Gas		
Gas gravity	0.71		
d. Others			
Reservoir Model	Homogeneous		
Wellbore Model	Constant storage		
Boundary Model	Fault/Dip closure		
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	24	Hrs	Flow @ 0 MMscf/day

4.2 Scenario/Sensitivity Formulation

PERMEABILITY:

The permeability values used in this design were based on FZI analysis which utilizes the porosity logs acquired from the well. A minimum, most likely and maximum value of 522mD, 1558mD and 2079mD respectively were derived and used in the design.

BOUNDARY MODEL:

The F2000X reservoir Map (Appendix 5) was digitized and used in the design. The reservoir has GWC at 13749 ftss. From the top structure map and cross section (Appendix 5&6), the structure has few intra-reservoir faults which are mostly interpreted as non-sealing. A review of the structure also show that the reservoir is fault bounded at the north-east by the boundary fault and at the west, south and south-east. The sealing factors of the major boundary faults are set to zero while intra-reservoir faults are set to 0.5.

SKIN:

Skin value range from the Gbaran Node (Zarama, Koroama, Gbaran and Kolo Creek) have been used to define the skin range for the design. The skin values are 15, 52 and 88 for low, mid and high respectively.

WELLBORE STORAGE:

A wellbore storage coefficient of 0.017 bbl/psi was estimated for surface shut in. The well test design was carried out using this well bore storage 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.

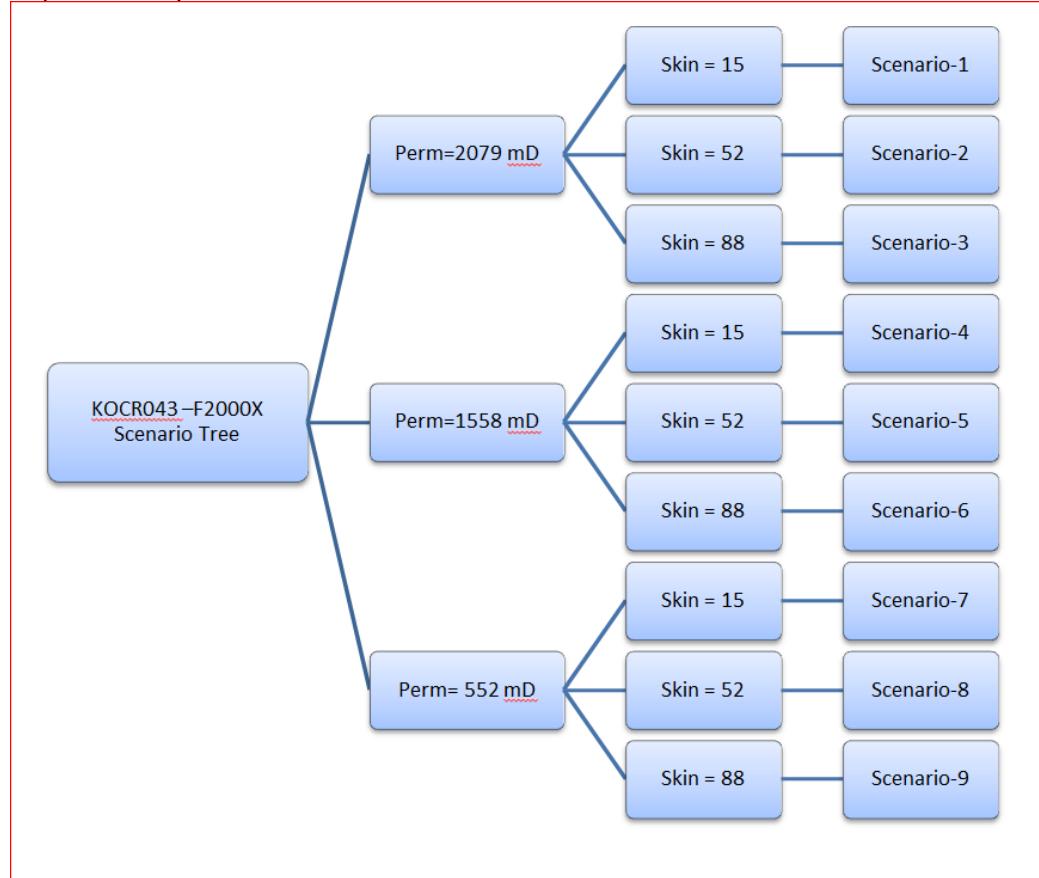


Figure 1: Scenario

4.3 ANALYSIS

Numerical method was used in the test design. The reservoir 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 available data from wells which were completed on the interval, the F2000X shows a permeability range of 522mD to 2079mD. These values were based on log data from KOCR039 and 39ST. The initial reservoir pressure value of 9449 psia used in the evaluation was based on RCI from KOCR039 as the reservoir has not produced. The Log-Log plots from the generated pressure are shown in Figure 2 and durations from the sensitivities are listed in Table 5.

The derivative plots for the different scenarios can be seen in Figures 2 and 3. 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.
2. The late time pressure response indicated an outer boundary primarily dominated by a boundary fault effect in the various scenarios.
3. With the assumed base-case permeability of 1558 mD, a minimum of 24 hours is required for the final build up test. For the permeability value of 552mD, a minimum of 24 hours is as well required for the outer boundary effects to be felt by the test and pressure stabilization achieved. The 24 hours of build-up from the permeability ranges have been selected as the build-up duration for the well.

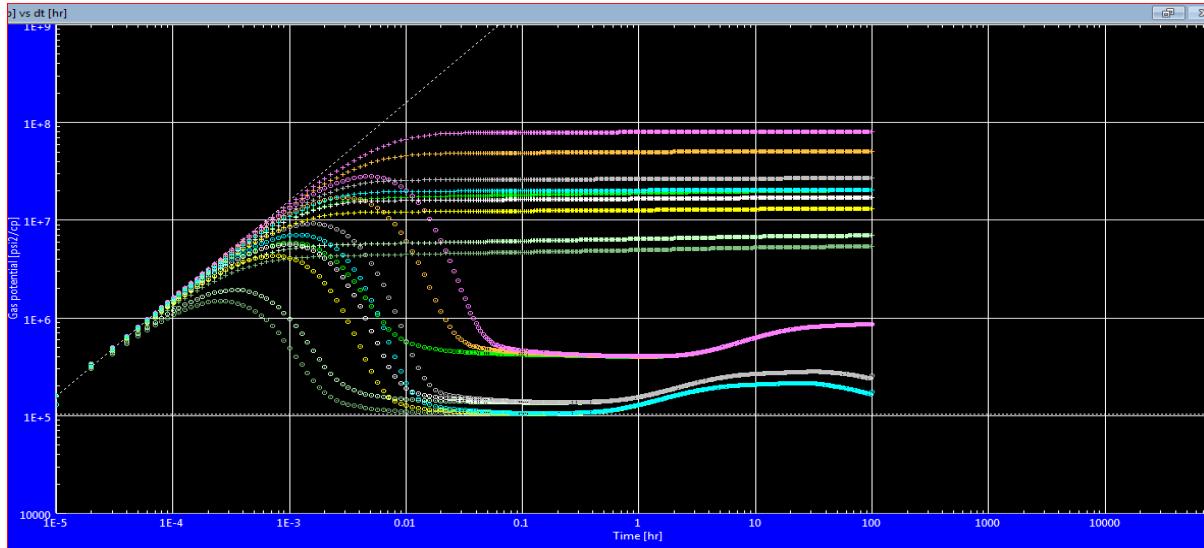


Figure 2: Log-Log plot for All Scenarios

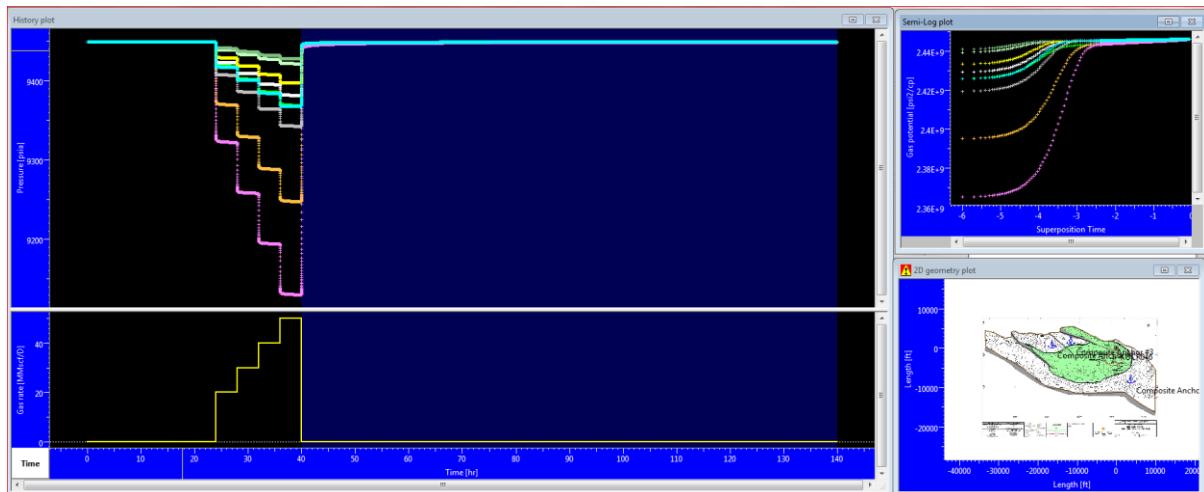


Figure 3: Cartesian, Semi-log plots and Digitized map.

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. The optimal test time selected is highlighted in Table 5.

Table 5: 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
S1	24	4	4	4	4	12	52
S2	24	4	4	4	4	12	52
S3	24	4	4	4	4	12	52
S4	24	4	4	4	4	12	52
S5	24	4	4	4	4	12	52
S6	24	4	4	4	4	12	52
S7	24	4	4	4	4	24	64
S8	24	4	4	4	4	24	64
S9	24	4	4	4	4	24	64

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. The optimal test time selected is highlighted in Table 5.

5.0 WORKSCOPE SUMMARY

The summary of the Clean-up & MRT work scope is given as follows:

Hold pre-job safety and work scope meeting.

- Check and record wellhead pressures.
- Retrieve monolock plug.
- Pressure and function test CT
- RIH CT to open the FIV, refer to appendix 3c on the FIV opening/treatment contingency plan
- Pump treatment fluid by jetting, making minimum of three passes across screen to dissolve POBM
- Allow treatment fluid to soak while monitoring pressures
- Lift well with Nitrogen if well does not come unaided.
- Commence well clean-up (Table1).
- Shut-in well for 24 hours for initial reservoir stabilization.
- RIH Slickline to install memory P/T gauges with programmed DHSIT at RPT nipple (11,532 ftah).
- Open up well and conduct Multirate test (Table 2).
- Shut in well for 24-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.
- Bean-up must be done gradually to achieve good bridging behind screen.
- 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 50 MMscf/d. Well is properly cleaned-up when at least 95% 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.

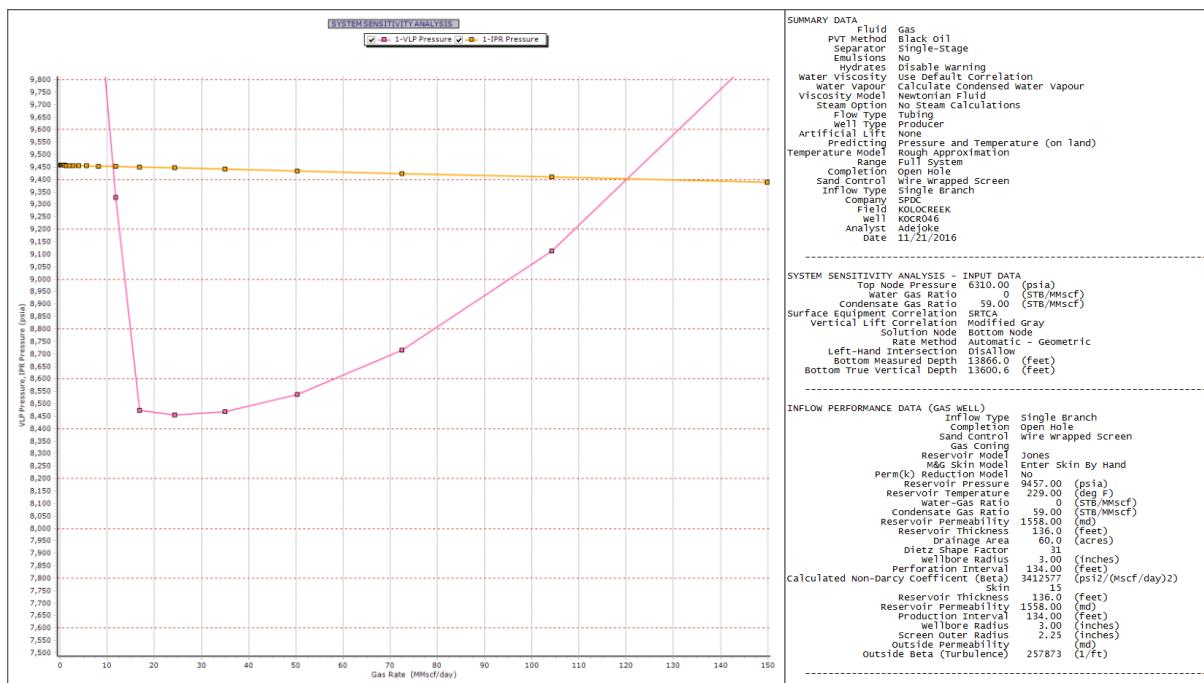
APPENDIX 1: RESERVOIR & COMPLETION DATA

Target Reservoir	F2000X
1. Casing size and Type	7''/Liner
2. Casing Setting Depth (ftah)	13869
3. Top of Sand [ftss/ftah]	13550/ 13874
4. Gross Sand Thickness (Gross) penetrated by KOCR045 (ft tv)	136
5. Well TD (ftss/ftah)	13686/ 14026
6. a) Completion interval (ftss) b) Completion interval (fttv) c) Completion interval (ftah)	13550 – 13686 13608 – 13744 13874 – 14025
7. Length of Completion Interval (ftah)	151
8. a) Top of competent cement (ftah) b) Source of data	7,334 CBL
9. a) Was hole directionally drilled? b) Max deviation angle and depth (ftah)	Yes 26.44 deg @ 13983
10. Deviation at completion zone	26
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)	9449 13500 9449 229 13550 9457
12. Did RCI indicate abnormal pressures?	Yes
13. Pressure gradient @ top of sand (psi/ft)	0.697
14. a) Is the reservoir fully gas-bearing?	Yes
15. a) Is there original GWC in the reservoir b) What depth (ftss)? c) Change in PGWC from original OGWC (ft)	Yes (KOCR039ST) 13749 0
16. Distance between lowest completion interval and estimated GWC in well / reservoir (ftss)	63
17. Is there a barrier between lowest completion interval and the present estimated GWC?	No (there are baffles in the reservoir though)
18. Gas S.G. (air=1)	0.71
19. Condensate gravity (API)	39.2
20. Expected FTHP (psia)*	6310
21. Expected CITHP (psia)	7260
22. Expected Drawdown (psi)*	47
23. Expected PI (scf/d/psi^2)*	177
24. Is sand exclusion installed?	SAS (RESLNK)

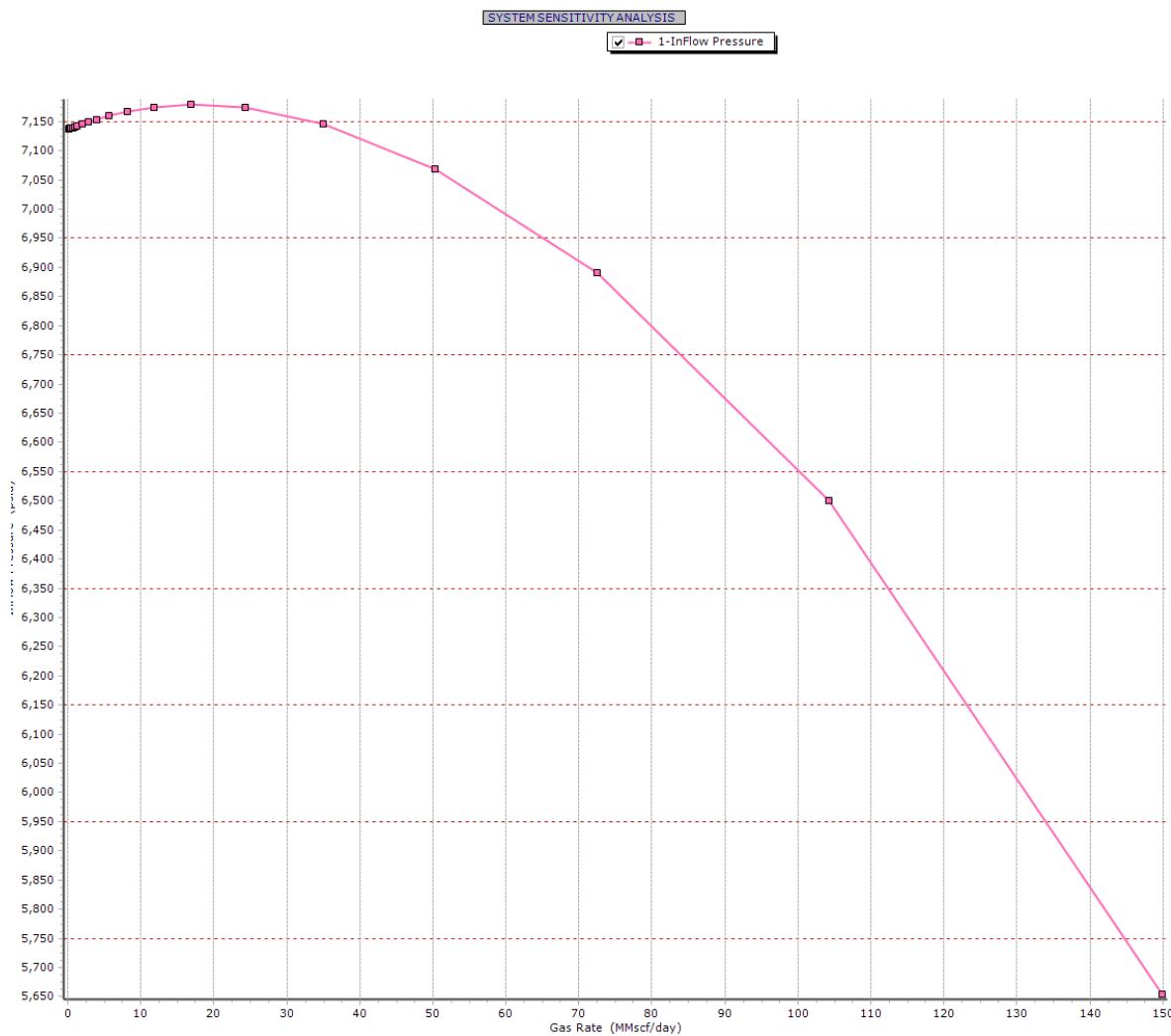
*Values are at well potential of 120 MMscf/d

APPENDIX 2: WELL PERFORMANCE PLOTS

KOCR046 Well Performance



KOCR046 P-Q Curve



APPENDIX 3A: WELL TEST RISK AND MITIGATION

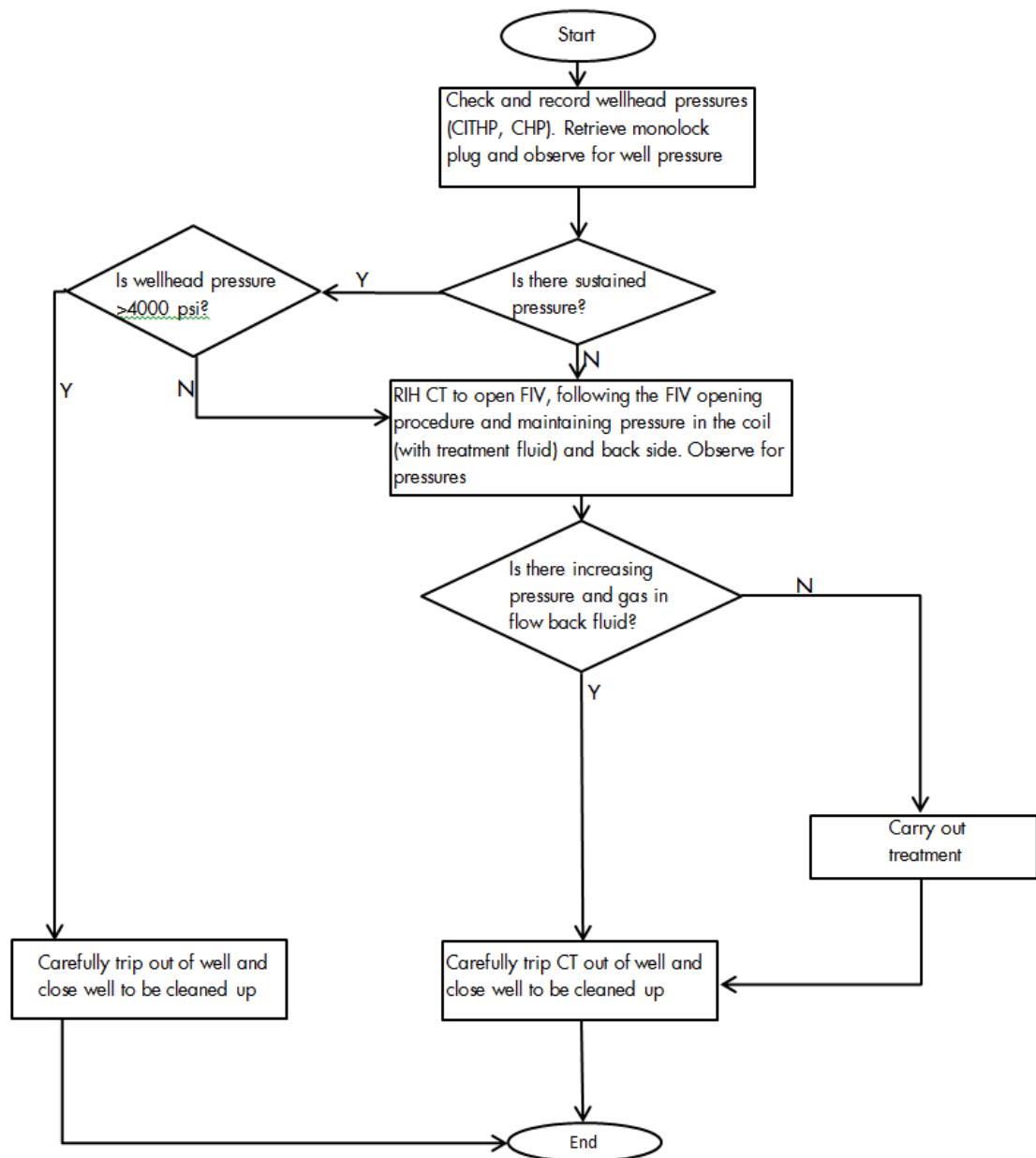
Risk	Consequence	Mitigation
Loss of containment	Blowout, explosion, injury, fatality, loss of equipment	<p>Ensure presence of minimum of 2-barriers at all time during clean-up/MRT operations.</p> <p>Also ensure all HAZID actions are closed-out prior to commencing operation</p> <p>Ensure BOP for the coil tubing unit and all pressure equipment are properly rated and tested at the contractor base and onsite, and these tests are witnessed by SPDC personnel. Check integrity of the valves on the wellhead and TRSCSSV. Install surface readout gauges to monitor pressures at all times</p>
Hydrate Formation	Blocked tubulars, increased pressure, blowout, injury, and fatality.	Ensure that effective glycol is mobilized to site since a high pressure drop is expected, to prevent hydrate formation. Conduct tests on samples of glycol to be used to confirm its adequacy prior to mobilization.
Inappropriately sized coiled tubing tools	Downhole components/tools may not get to desired depths	Ensure the dimensions of the tools to be RIH are appropriately sized for 7" tubing accessories/profiles ID and 4" FIV and screen
Failure of Downhole Shut-in Tool at deployment, or failure to retrieve the Shut-in Tool and gauges	In-accurate estimate of wellbore storage, impact on well test results, Inability to open well for production.	Ensure tool is checked at the contractor's base and confirmed operational before deploying. Ensure proper and efficient deployment procedures are followed
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, scorching 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.	Wellhead have stainless steel clads. Also, acid would not be used during the operation.
Fire Outbreak	Fire outbreak, injury, and loss of equipment, fatality.	<p>Barricade work area, prohibit use of cell phone & smoking around well's perimeter fence, restrict movement of unauthorized persons around work area.</p> <p>Inspect bond wall periodically during and carry out repairs as required.</p>
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.

Risk	Consequence	Mitigation
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 to the highest pressures expected at this operation
Community disturbance	Disruption of work, delay in execution, cost escalation	Ensure robust engagement of community stakeholders about expectations (flaring heat and noise) during the job execution

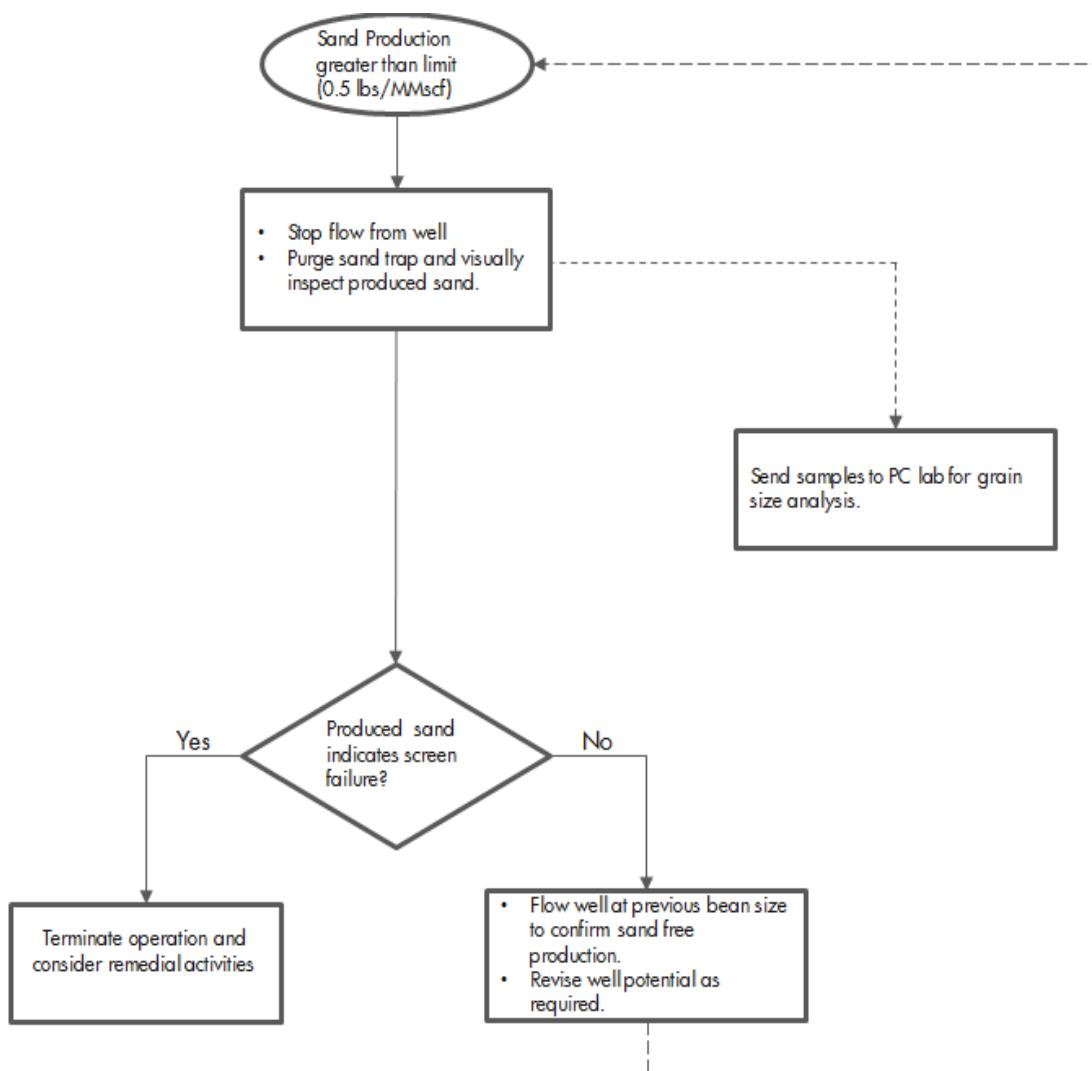
APPENDIX 3B: DEP Table

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 at the top of screen is 9457 psia (See Appendix 11)	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 KOCR046 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 298 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.	H ₂ S 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 carried out and the well completed with SAS installed for sand control. Sand monitoring would be in place during this clean-up and MRT.	PT

APPENDIX 3C: FIV Opening Contingency Plan



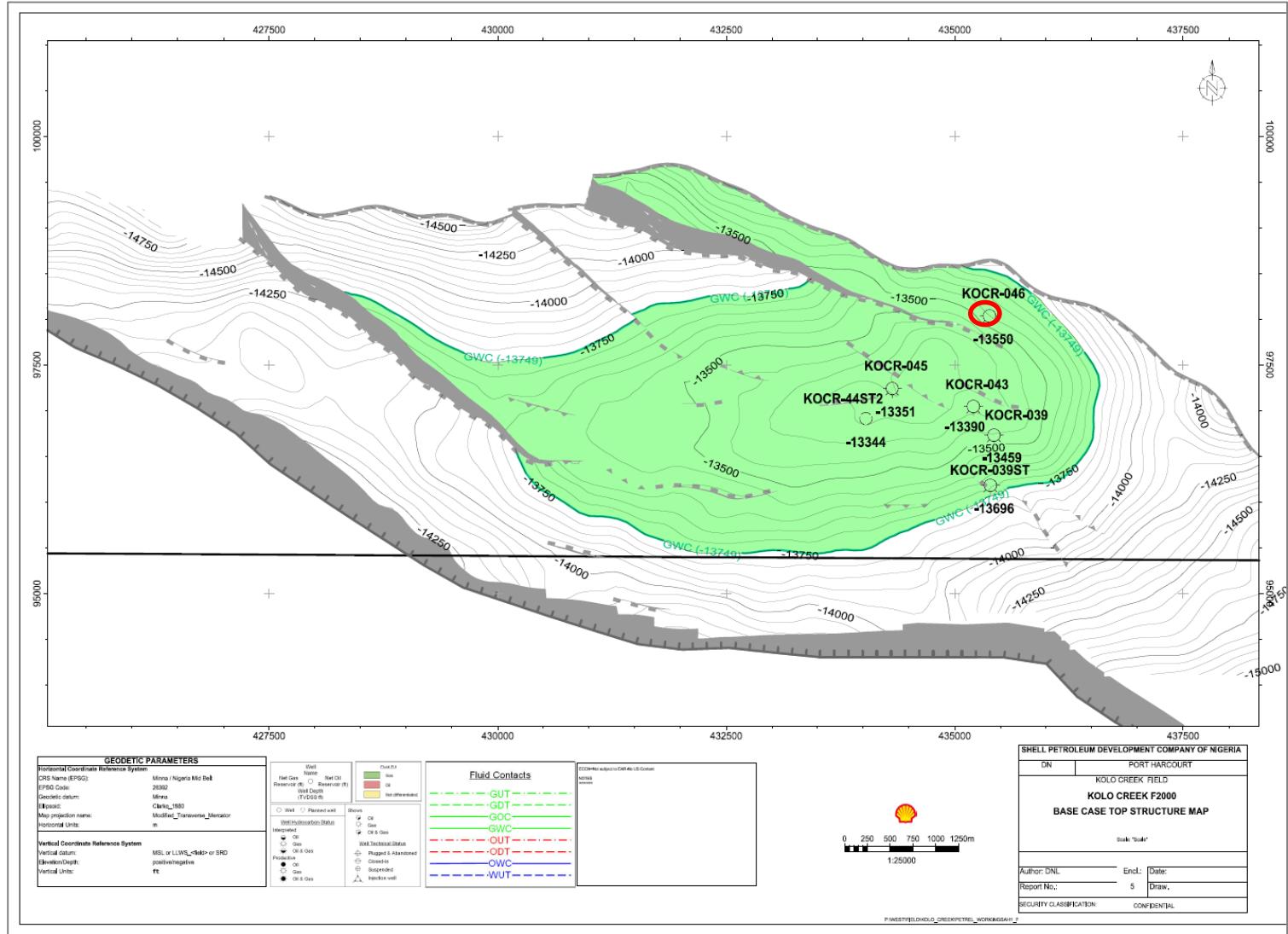
APPENDIX 3D: Kolo Creek 046 Sand production contingency plan



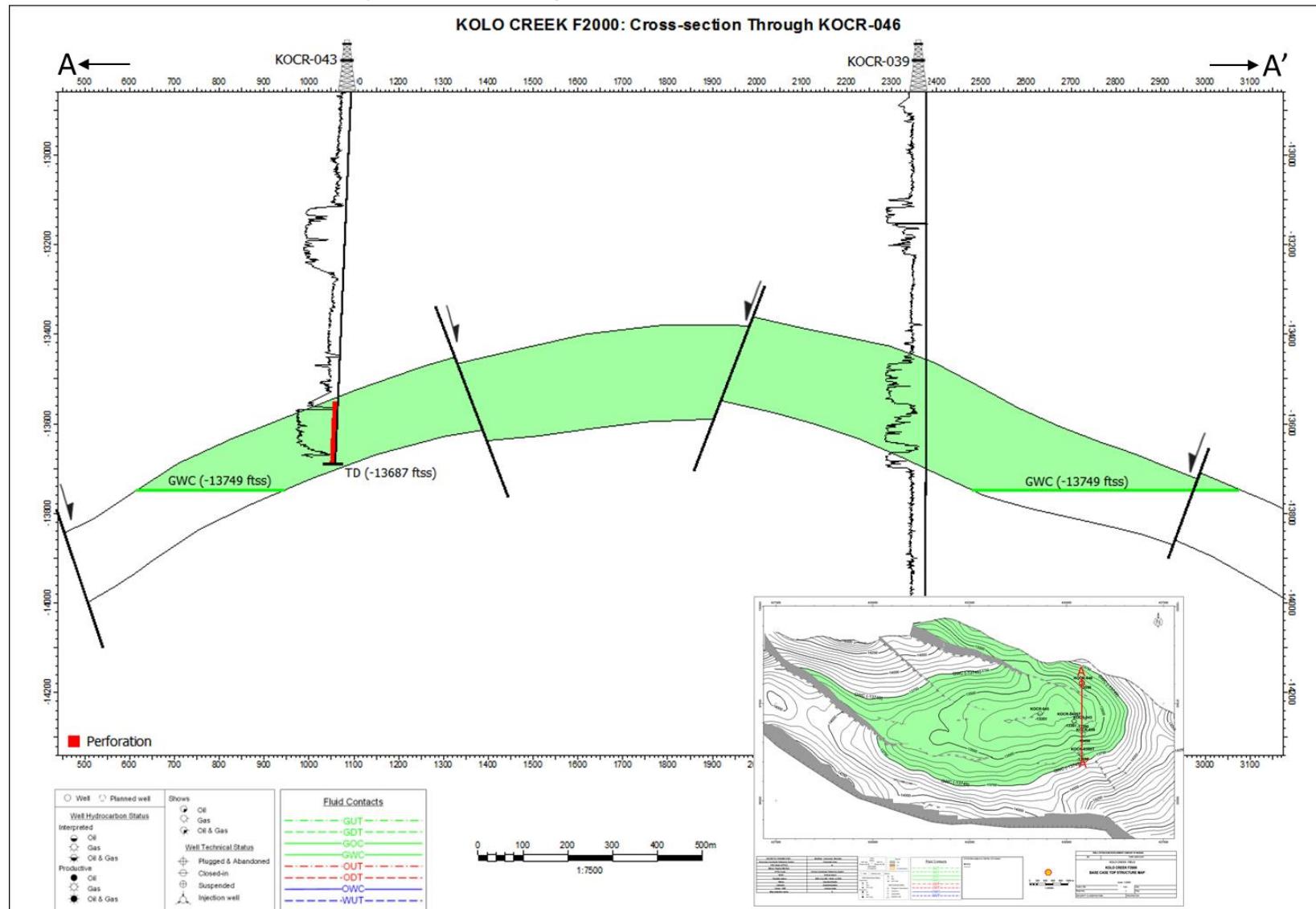
APPENDIX 4: Kolo creek 046 Final Completion Status Diagram

KOLOCREEK-46 FINAL COMPLETION SCHEMATICS							24-Dec-14		
SIZE	GRADE	CASING		ITEM	TYPE	SIZE	WELLHEAD (CAMERON CONVENTIONAL)		
		WT (lbs/ft)	DEPTH (ft)				WF (PSI)		
24"	STO/EP/PE	166	288	Driven	STO/EP/PE	INST. FLANGE	7-1/16"	10,000psi	
						GATE VALVE	6-3/8"	10,000psi	
13-3/8"	N80	68	6,311	CLASS G	BTC	Surface Csg	XMAS TREE CAP	10,000psi	
						XMAS TREE	6-3/8" Tree Cap x 5K	10,000psi	
9-5/8"	Q125	54	11,919	CLASS G	SLX	Prod Csg	SEAL ASSY	10,000psi	
						TUBING HANGER	7" x 13 5/8" Compact; 13 Cr. Hyd 563	10,000psi	
7"	Q125	32	11,672 - 13,879	CLASS G	SLX	Prod Csg	SEAL ASSY PACKOFF	10,000psi	
						CSG HGR	13-5/8" x 10-3/4"	10,000psi	
						COMPACT HOUSING	13-3/8" BTx 13-5/8" Flange Lock	10,000psi	
TUBING									
STRING	SIZE	WT.	GRAD.	TYPE	MAX Deviation: +/- 33.52 deg @ 8,610 To 13,607 ftah	HOLE	DESCRIPTION	RESERVOIR	
					DFE (RT - CELLAR): XX FT	N/A			
SSS	7"	32	N80		RT - TOP XMT:xxxft		Open Hole w/ RESLINK Sand Control	F2000	
	7	35	VM110		Drill-in Fluid Type / Properties				
					Completion Fluid Type / Properties:				
					Gas Pressure Gradient / Pressure:				
7" PRODUCTION STRING									
SAND	COMPLETION STATUS			Top Depth (ftah)	Length (in)	ID (in)	OD (in)	DESCRIPTION	
				1	0.00	35.00		ELEVATION	
				2					
				3	35.00	1.20	6.184	7,050	
				4	36.20	1.80	6.170	7,660	
				5	38.00	10.75	6.004	7,000	
				6	48.75	130.51	6.00	7,000	
				7	179.26	6.09	7,000	3Jts 7" 32# Cr P110 Vam Top tubing joint	
				8	190.00	5.46	6.13	7,660	
				9	195.46	8.72	4.56	7,799	
				10	204.18	5.20	6.09	7,000	
				11	209.38	6,894.44	6.094	7,000	
				12	7,103.82	4,386.68	6.094	7,000	
				13	11,490.50	10.73	5.625	7,760	
				14	11,501.23	1.26	6.185	7,680	
				15	11,502.49	5.29	5.875	8,310	
				16	11,507.78	1.26	6.325	7,802	
				17	11,509.04	10.73	6.305	7,760	
				18	11,519.77				
				19	11,519.77	10.69	6.285	7,760	
				20	11,530.46	1.68	6.285	7,850	
				21	11,532.14	1.59	4.500	7,060	
				22	11,533.73	1.28	6.225	7,050	
				23	11,535.01	10.72	6.205	7,760	
				24	11,545.73	39.94	6.185	7,760	
				25	11,585.67	1.31	6.080	7,830	
				26	11,586.98	1.60	4.313	6,150	
				27	11,588.58	1.24	6.185	7,760	
				28	11,589.82	9.75	5.625	7,760	
				29	11,599.57	1.35	6.185	7,850	
				30	11,600.92	1.04	6.460	8,300	
				31	11,601.96				
				32	11,616.00	11.98	6.13	8,400	
				33				Cadmium EXR Liner Hanger 9-5/8" x7"	
				34				OPEN HOLE STANDALONE SCREEN ASSEMBLY	
				35	13,689.10	6.95	3,880	5,820	
				36	13,696.05	11.43	3,960	5,530	
				37	13,707.48	2.66	3,916	4,940	
				38	13,710.14	39.76	3,960	4,500	
				39	13,749.90	9.77	3,960	4,500	
				40	13,759.67	16.78	3,675	5,150	
				41	13,776.45	1.25	3,960	4,500	
				42	13,777.70	10.47	3,960	4,500	
				43	13,788.17	77.82	3,640	4,500	
				44	13,865.99	158.11	3,958	5,060	
				45	14,024.10	0.90	6,000	Bull plug 4 1/2" VamTop Box	
				46	14,025.00			END OF ASSEMBLY	
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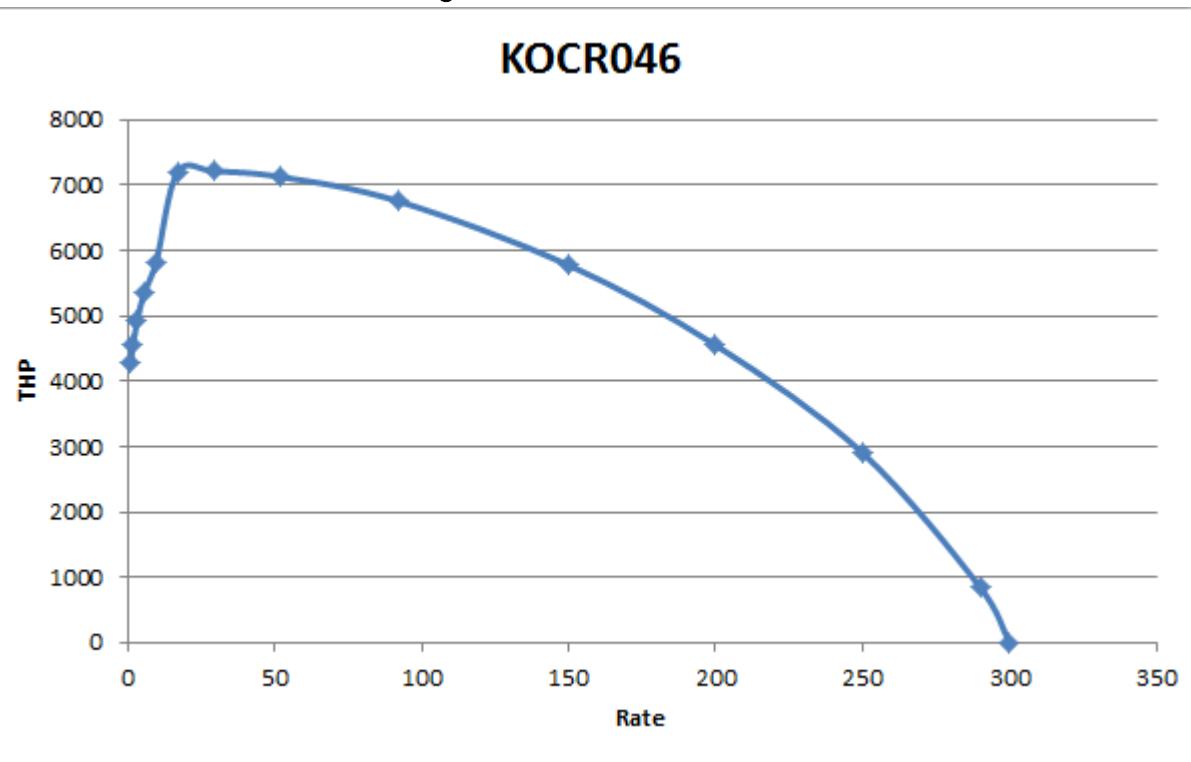
APPENDIX 5: Top Depth Map of the F2000X sand



APPENDIX 6: Cross section along KOCR046 well path



APPENDIX 7: Worst Case Discharge Plot



APPENDIX 8: KOCR046 H₂S Prediction

KOCR046T H₂S PREDICTION

Introduction

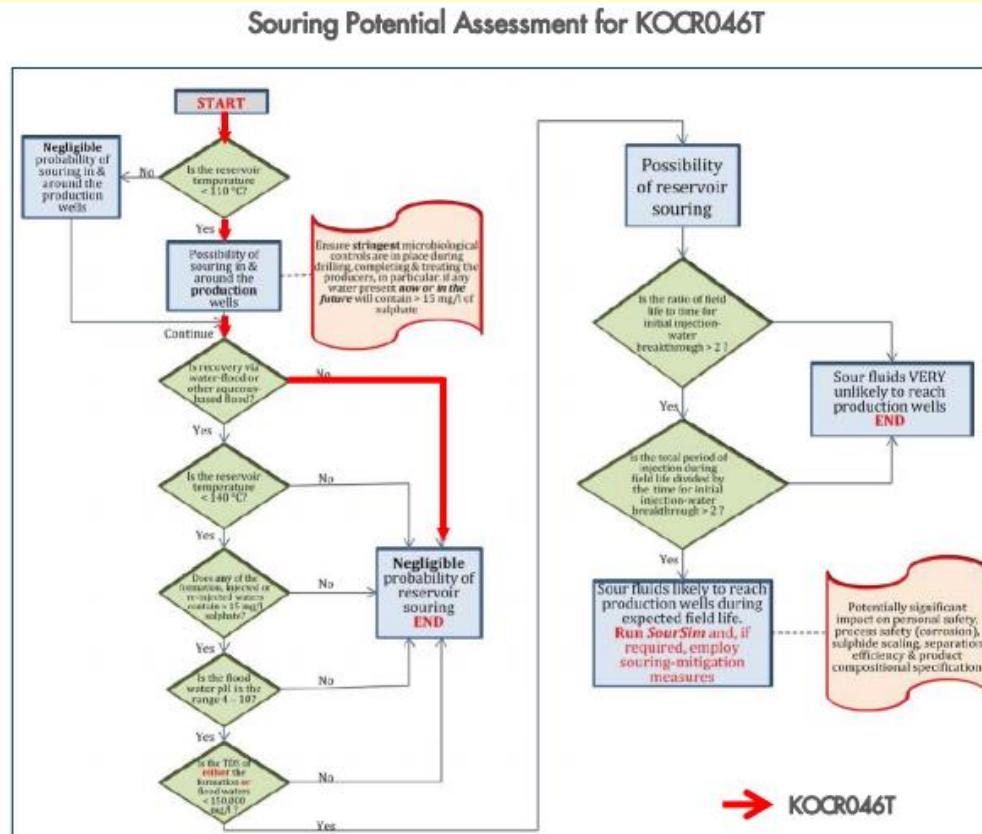
The consequence of the presence of H₂S is loss of life and material integrity. This document contains prediction of naturally occurring H₂S concentration and souring potential for KOCR046T well based on available data.

Naturally Occurring H₂S Concentration

- KOCR046T is completed on the F2000 reservoir.
- PVT analysis available for F2000X reservoir shows no presence of H₂S
- H₂S has not been encountered in KOCR oil & NAG wells producing in the Gbaran nodal area.
- Naturally occurring H₂S concentration is therefore predicted to be 0%mol

Souring Potential

- Souring potential is a function of expected reservoir temperature
- Expected reservoir temperature is 109 °C, (229°F) however, no waterflood is planned for the field.
- Hence, the souring potential is negligible. (see SPA tool)
- Gas testers and appropriate PPE's will be utilized during completion and well open up as additional mitigation.



Prepared by:	Reviewed by:	Approved by:
Checked by: Emesi, John Nnadi, Magnus Akunesiobike, Jonathan	Nwankwo, Cosmas Oluwajuigbe, David	Ugboaja, Remmy
UGBOAJ	Digitally signed by UGBOAJA REMMY Date: 2017.01.26 19:37:30 +01'00'	A REMMY

APPENDIX 9: KOCR046 Clean up and Well Test Cost Estimate

S/N	Service Description	Minimun Cost (\$)
1	Well Test Services	\$486,134.28
2	WHM Ops	\$32,928.98
3	CT/N2 Services	\$241,567.97
4	HP Pumping Ops	\$85,956.80
5	WT Support	\$394,780.93
6	SL Support	\$54,611.44
7	Water Facilities	\$16,931.81
8	IT Support	\$4,412.10
9	SPDC Logistics	\$98,675.02
10	FTO	\$9,266.67
11	Security	\$26,600.00
	TOTAL	\$1,451,865.99

APPENDIX 10: KOCR046 Expected Annular Fluid Expansion

Estimated Incremental AFE pressure and volume for 50 MMscf/d flow without annulus bleed down

String Annulus	Incremental AFE pressure (psi)	Incremental AFE Volume (bbl)
9-5/8" Production Casing (B annulus)	4025	6.7
7" Production Tubing (A annulus)	5258	5.0

Notes:

1. If CHP exceeds expected AFE pressure or bled down volume exceeds AFE volume then, CHP investigation required.
2. Casing should be monitored closely and bled down as per program because expected AFE pressure exceeds the MAASP calculated for A & B annulus.

APPENDIX 11: F2000 Pore Pressure Estimation

The pore pressures for the F2000 reservoir were estimated using pressure cell method. RCI data from KOCR-039ST was used to obtain the pore pressure model.

The pressure at the top of screen was obtained by extrapolating the pressure from the datum depth (13,500 ftss) using fluid gradients measured from the F2000 reservoir in KOCR-039ST.

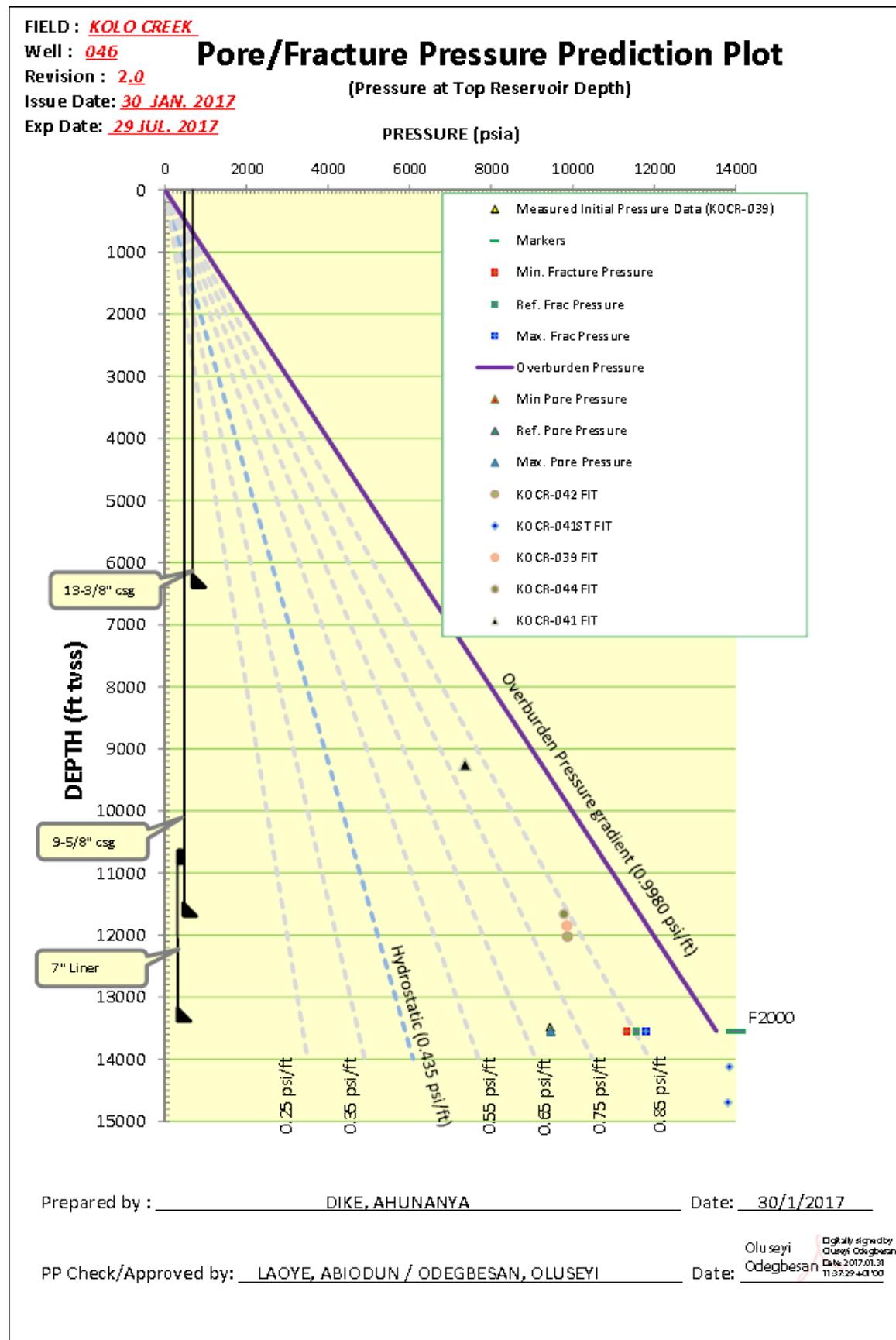
Uncertainty in fluid gradient was considered in estimating the high, base and low case pore pressures. The top of screen was established based on the completion tally, thus uncertainty in depths was eliminated.

All reservoirs shallower than the F2000 have been cased-off (please see appendix 4), thus the pore pressure estimation was carried out for only the F2000 which will be open to flow during the Clean-up / MRT operation. The table below presents the range of formation gradients estimated for the F2000 reservoir based on KOCR-043ST, 045 & 046.

Reservoir	Min formation gradient, KOCR046 (psi/ft)	Ref formation gradient KOCR043ST (psi/ft)	Max formation gradient, KOCR045 (psi/ft)
F2000	0.698	0.704	0.706

The pore pressure table and plot are presented below.

F2000 Pore Pressure Estimation Plot



F2000 Pore Pressure Estimation Table

FIELD:	KOLO CREEK
WELL NAME:	46
PLATFORM/RIG:	Mobile Test Separator
PREPARED BY / CHECKED BY:	DIKE AHUNANYA / LAOYE ABIODUN
ISSUED DATE:	30 January 2017
REVISION NO.:	3.0
SPUD DATE:	09 April 2014
EXPIRY DATE:	29 July 2017

Pore Pressure Prediction at Top Reservoir for KOCR-046

Formation	TV-Depth of Pressure Prediction and Reference Depth (e.g., ss or bdf)			Fluid Type Prognosis at Top of Sand along Well Trajectory	Is Reservoir Developed	Formation Pore Pressure Prognosis at Top of Sand along Well Trajectory				Formation Pore Pressure Gradient at TOS				Fracture Gradient Prognosis at Top of Sand along Well Trajectory				Remarks				
	Shallow (ft-ss)	Most Likely (ft-ss)	Deep (ft-ss)			Reference Case	(Y/N)	Minimum (psia)	Reasonable Low (psia)	Reference Case (psia)	Reasonable High (psia)	Maximum (psia)	Minimum (psi/ft)	Reasonable Low (psi/ft)	Reference Case (psi/ft)	Reasonable High (psi/ft)	Maximum (psi/ft)	Minimum (psi/ft)	Reasonable Low (psi/ft)	Reference Case (psi/ft)	Reasonable High (psi/ft)	Maximum (psi/ft)
F2000	13550	13550	13550	Gas	N	9455	9455	9457	9459	9459	9459	0.698	0.698	0.698	0.698	0.698	0.836	0.836	0.853	0.871	0.871	Reservoir is in the Over-pressured regime. All shallower reservoirs have been cased off.

Prepared By: DIKE AHUNANYA SPDC-UPO/GDNF
Name: _____ Team Indicator: _____ Date: 30/01/2017

PP Check/Approved By: LAOYE, ABIODUN / ODEGBESAN, OLUSEYI
Name: _____ Signature: _____ Date: _____

Validity Date: _____ 29-Jul-17