SHELL PETROLEUM DEVELOPMENT COMPANY OF NIGERIA LIMITED

SOKU038T

TRSCSSV LOCK-OUT & NITROGEN LIFT (CONTIGENCY) WELL RESTORATION PROPOSAL

Document number:	SPDC-2021-10-00000010	**Prepared By:** **Contributors**	Uchenna Udobata (PT) Ogbunude, Basil (RE) Jude Ekwealor (PG) Maxwell-Amgbaduba, Sunday (PP) Conrad Ibekwe (CWI) Stone Ran (CWI Advisor, WRFM)
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I. TABLE OF AUTHORISATION

REVIEWED BY:

Name	Position
Biambo Tamunotonye	Production Technology TA2
Laoye, Abiodun	Petrophysics TA2
Okereke, Onyedikachi	Reservoir Engineering TA2
Etuk, Ubong	Production Geology TA2
Oluleye, John	Well Intervention Lead, SPDC WRFM

AGREED BY:

Name	Position	Signature
Okereke, Onyedikachi	FMT Lead Soku/NunR	Onyedikachi Okereke Digitally signed by Onyedikachi Okereke Date: 2021.11.01 09:24:31 +01'00'
Biambo Tamunotonye	Production Technology TA2	Tammy Biambo Digitally signed by Tammy Biambo Date: 2021.10.29 11:04:24 +01'00'
Leslie, Gavin	CWI Technical Authority 2	Gavin Leslie Digitally signed by Gavin Leslie Date: 2022.02.04 08:37:28 Z

APPROVED BY:

Name	Position	Signature
Fehintola, Tope	Asset Subsurface and Development Manager East	Temitope.Fehintola Digitally signed by Temitope.Fehintola Date: 2022.02.06 18:54:23 +01'00'

II. TABLE OF CONTENT

1. OBJECTIVE

WELL	SOKU038T
TYPE	Rigless Intervention
OBJECTIVE	To restore SOKU038T to production by carrying out a repair of the TRSCSSV and Nitrogen lifting if natural flow fails. This would unlock a risked potential of 65 MMscf/d and resource volume of 62.9 Bscf.
PROPOSAL	TRSCSSV lock-out and Insert or PB Valve installation, Annulus Investigation, BHP Survey, Nitrogen lift

2. WELL HISTORY/ PRESENT STATUS

SAND	INTERVAL (ftah)	INTERVAL (ftss)
E2400X	11,680 – 11,755 (MCUGP)	10477 – 10538

SOKU038T was drilled and Initially completed in September1998 as a single string gas producer on the E6000X reservoir. The E6000X interval quit in June 2004 due to declining productivity and was abandoned in 2005. The well was thereafter recompleted on the E2400X reservoir.
SOKU038T commenced production from the E2400X interval in July 2006 and produced satisfactorily with a peak rate of 133 MMscf/d achieved in October 2008. Declining rate and FTHP was observed with drop in reservoir pressure over time necessitating a switch from a HP producer to an LP producer (via compression).
Well rate as of April 12, 2019 was 89 MMscf/d (FTHP 1176 psi, Choke opening 44%, flowing via LP Manifold). During the Well integrity test in May 2019, the well was met closed-in and the TRSCSSV control line was not holding pressure. CITHP/CHP A/B was 1300psi/0psi/0psi. Inflow test of the TRSCSSV was successful. Well remained closed-in until it was successfully re-opened to flow on the 25th of June 2019 and ramped up from ca. 75MMscf/d (Choke 44%, 1029 psi FTHP) to 100 MMscf/d (Choke 59%, 955 psi FTHP).

Observation from Operations team indicated more fluid was required to open the control line (ca. 12-15 liters vs 4 liters of oil) and gas was recovered each time the control line pressure was bled off. Also, with each attempt to open, it is observed that the control line pressure remains okay even though the downhole safety valve has tripped. The period between successful re-opening attempts decreased from ca. 3-4 days to a few hours, indicating possible deterioration in valve status. A recent control line pressure build-up test indicated a build in pressure from 0 psi to 1545 psi in 8 days (ca. 8 psi/hr control line pressure build).

The last production record was on the 15th of August 2019 with the well producing at a flow rate of 88MMscf/d at 48% choke opening and FTHP of 1125 psi. The well has remained closed-in since August 2019 with attempts to reopen unsuccessful. In April 2021, attempt to re-enter the well for BHP survey was unsuccessful due to the inability to open the TRSCSSV. Attempt to drift the well with 2.73" GC indicated HUD at 154ft (TRSCSSV depth). CITHP/CHP A/B was 1200psi/ 700psi/200 psi. A repeat attempt in May 2021 was also unsuccessful as TRSCSSV was unable to sustain opening pressure. CITHP/CHP A/B was 1300psi/ 650psi/200 psi. Pressures recorded during the combined WITSIT in August 2021 are CITHP/CHP A/B was 1600psi/ 640psi/150 psi.

3. PROPOSED ACTION AND JUSTIFICATION

SOKU038T is one of 11 initial completions on the E2400X oil-rim reservoir. It is also the only gas completion on the reservoir. The other completions (oil producers) are no longer in production with the last oil producers (SOKU006T and SOKU009T) producing last in 2007.

The reservoir has a combination drive mechanism (water influx + gas cap expansion) and was initially hydrostatically pressured (4639 psia as @ 1971) with little pressure decline (ca. 7%) observed before the recompletion of SOKU038T in the E2400X reservoir. With the initiation of gas cap blowdown and further oil production, the pressure declined from initial by ca. 28% by 2008. Furthermore, with only gas production from the reservoir, the pressure declined significantly from initial by ca. 54 % as at 2013 and thereafter stabilized with reduced reservoir withdrawal. The current reservoir pressure is 2154 pisa. However, the well has been able to sustain flow via compression (ca. 600 psi inlet pressure) with FTHP ranging between 1000 -1130psi and observed CITHP of 1200 -1300 psig within the period of flow in 2019. Additionally, the estimated abandonment pressure is 1260 psi at CGR and WGR of 10bbl/MMscf and 15 bbl/MMscf respectively.

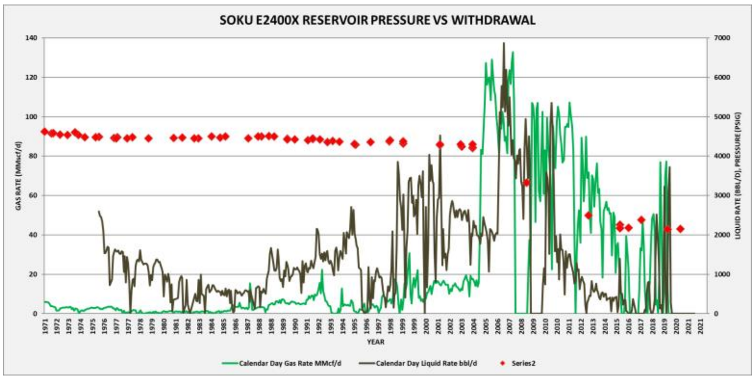


Figure 1: E2400X Reservoir Pressure Plot vs Withdrawal

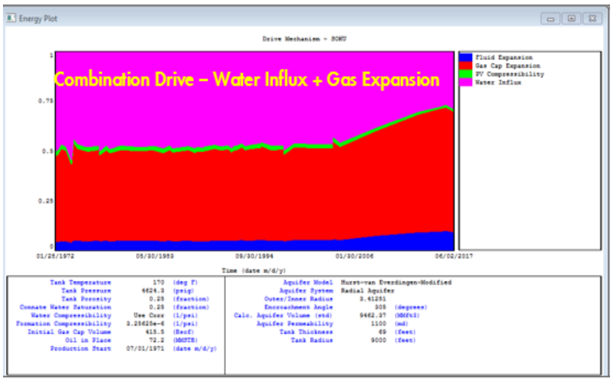


Figure 2: Reservoir Energy Plot

Recent intervention records indicate the TRSCSSV piston seals may not be integral, thus the ingress of gas into the control line, inability to maintain the TRSCSSV open and therefore the observed HUD at 154 ftah. Additionally, with the current CITHP (1300 -1600 psi) and observation of the valve performance by the operations team, there is a high likelihood that the issue at hand is mechanical and not reservoir related.

Historically, this well does not produce high volume of liquids, however there might be a need for kick-off assistance considering the history of Soku gas wells TRSCSSV equalization with water and uncertainty with current reservoir fluid contacts. The pressure observed in the A and B annulus also requires investigation to determine the nature/source and plan for remediation where applicable.

It is therefore proposed to carry out the following activities to restore the well production.

- Carry out an annulus investigation to determine the source of the A and B casing head pressure and remediate same where possible (e.g leak can be remediated by energizing hanger seals, injecting plastic in hanger seals or utilizing H2Zero to remediate packer leaks). Else, manage annulus pressure below CAOPL and plan for focused Rig/Rigless intervention to remediate annulus pressure build up.

    - Possible leak paths include tubing hanger seals (Tubing to A-annulus, A to B-annulus), TRSCSSV control line (Tubing to A-annulus), Tubing (Tubing to A-annulus) and Packer (A annulus)
- Investigate the status of the TRSCSSV and attempt to restore functionality by exercising the flow tube. (If exercising fails, the valve will be locked out and an insert or PB valve installed, depending on control line pressure supply status to the TRSCSSV).
    - *Completion and Well Intervention team is to conduct an independent troubleshooting with support from Halliburton Engineer onsite before confirmation of lock-out requirements ahead of mobilization for the proposed intervention.*
- Once access is gained to the tubing, carry out a BHP survey to determine current pressure profile and liquid level.
- Attempt to flow well via the compressor. If unsuccessful, lift the well to flow using Nitrogen.

These activities will unlock a risked potential of 65 MMscf/d of gas on the LP header. In addition, the offtake from the well will be managed to ensure minimal reservoir pressure depletion.

4. PROPOSAL SUMMARY

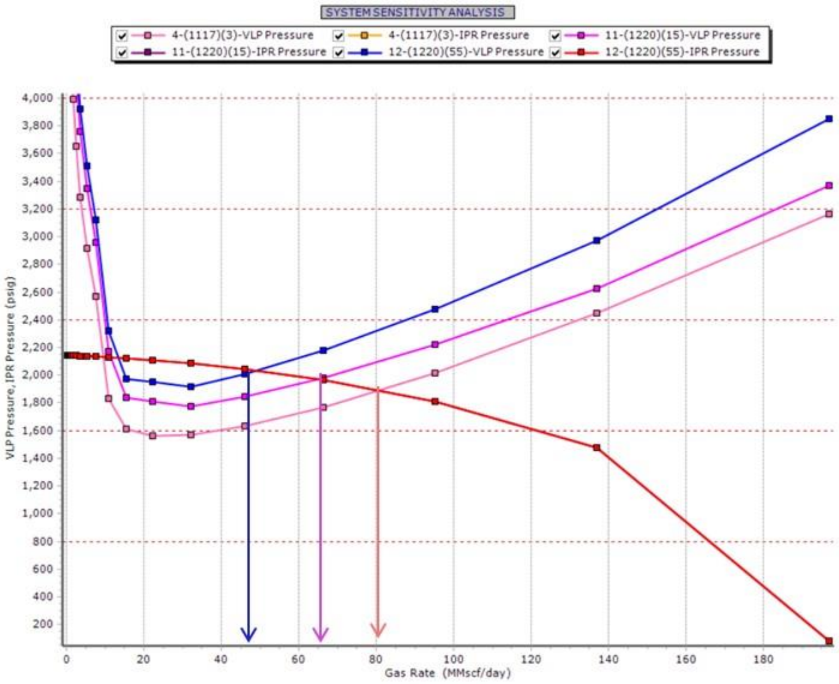
1. Carry out Wellhead Maintenance
2. Carry out blow down annulus Investigation and remediation (reenergize seals or inject plastic if applicable)
    - Capture outcome in eWIMS
3. Carry out TRSCSSV investigation; exercise TRSCSSV and confirm functionality (CWI and Halliburton Engineer)
    - Confirm status of TRSCSSV control line
4. If exercising fails, lock out the TRSCSSV.
   Note: If control line is leaking, PB valve will be installed (Control line will be isolated with chemical seal). Else, wireline retrievable insert valve would be installed.
5. Carry out drift run and tag liquid level.
6. Carry out BHP survey as per Appendix 8.
7. If annulus pressure build-up persists, install deep-set plug in the XN nipple @ 10,268ftah and repeat annulus build-up test. Else, proceed to step 9
8. If annulus pressure builds up with deep-set plug installed, carry out packer leak repair with H2Zero
    - If leak persists, uninstall deep-set plug and proceed with step 9. Well annulus pressure will be managed below CAOPL while preparing for Rig/Rigless intervention to remediate annulus pressure.
9. Attempt to flow via test separator at minimum static pressure.
10. If flow attempt is unsuccessful, and liquid is confirmed in the tubing, lift the well to flow via the test separator using Nitrogen.
    - If Nitrogen lifting is unsuccessful, install Insert valve and abort operations.
11. Install Insert valve and end operation.
12. Handover well to operations team

See Appendix 10 for decision tree

5. POTENTIAL ESTIMATION

The expected potential of the well was determined using Prosper Modelling tool. The key assumptions for the modelling work and estimated technical potential is captured in the table below.

The sensitivity showed that the SOKU038T could be produced at rates between 50 - 80 MMscf/d against the LP header pressure.



Case	Gas Rate	Condensate Rate	Water Rate	Liquid Rate	Well Head Pressure	WGR
	(MMscf/day)	(STB/day)	(STB/day)	(STB/day)	(psig)	(bbl/MMscf)
Low	49	488	2686	3175	1220	55
Base	65	650	975	1625	1220	15
High	80	804	241	1045	1117	3
Model Calibration Comments	Well head pressure benchmarked with historical data.					
Risking Assumptions	CGR assumed constant at 10 bbl/MMscf; sensitivity on WGR of 55, 15 and 3 bbl/MMscf to replicate low, base and high case scenarios.					

6. RESOURCE ESTIMATION

Reserves estimation for SOKU038T on E2400X was carried out using Material Balance evaluation methodology. Good pressure and production performance history match was achieved by regression of the uncertain reservoir parameters within acceptable range. Using the prevailing surface constraints, a forecast was performed on a well basis taking into consideration the well schedule, inflow potential and lift profile of the well. This generated a BC reserves of 62.9 Bscf for this opportunity. Below is a summary of the results of the evaluation.

Interval	Reservoir	Planned DUR (for the interval)	Np (for the interval)	Reserves to be Developed by activity (Bscf)		
		Bscf	Bscf	Low	Base	High
SOKU038T	E2400X	337	274	47	63	86

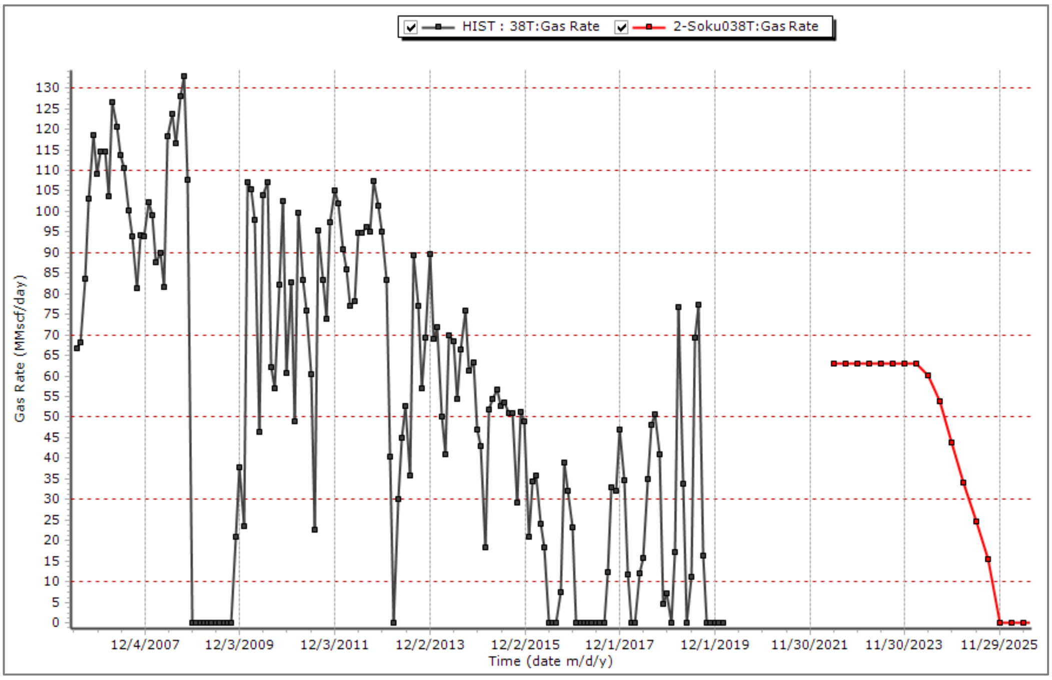


Figure 3: SOKU038T BC MBal Forecast

7. WELL & RESERVOIR DATA SHEET

S/N	WELL/SAND:	UNIT		SOKU038T (E2400X)
1	a) Perforated interval b) Perforated interval	ftah ftss	PP	11,680 – 11,755 10,477 – 10,538
2	a) Maximum Deviation Angle and Depth b) Derrick Floor Elevation c) Vertical Correction to mid- Perforation + DFE	° @ ft ft ft	PT	40.7° @9600 ftah 67.73 -
3	a) Last Production Rate	MMscf/d	PT	80 (@15 Aug 2019)
4	a) Reference Depth for Reservoir Pressures b) Original Reservoir Pressure * c) Present Reservoir Pressure d) Present Gradient e) Specific Gravity of Oil 60/60 f) Gas gradient g) Gas Expansion Factor, Ei h) Oil Viscosity at Reservoir Condition i) Static Reservoir Temperature	ftss psia psia psi/ft SG psi/ft scf/cf cP ° F	RE	10600 4625 2154 (SOKU010S @June 2020) 0.20 0.85 0.086 267 0.5 172
5	a) Other Wells Producing From the same Block b) Daily Production from Block (@ Sept 2021)	- bopd	RE/ PT	None No production since August 2019
6	a) Tubing Size/Weight b) Casing Size/Weight	in/ibs/ft in/ibs/ft	PT	7 / 29 9-5/8 / 47

8. RECENT PRODUCTION PERFORMANCE DATA

Well	Date	Choke	BS&W	Gas Rate (MMscf/d)	FTHP	CHP
SOKU038T	15/09/2019	47.6 %	-	80	1117	-

**Source PI data extract*

9. COST ESTIMATE

S/N	Activity	Unit cost $	QTY	Unit	Cost $
1	Mobilization	21,723.60	Days	5	108,618.00
2	WHM Package	1,847.50	Days	26	48,035.00
3	Slickline Package Opr	1,500.00	Days	6	9,000.00
4	Slickline Package Standby	1,400.00	Days	20	28,000.00
5	Coiled Tubing package Opr	12,218.00	Days	7	85,526.00
6	Coiled Tubing package Standby	4,888.00	Days	19	92,872.00
7	TRSV LOT (Operating)	1,200.00	Days	5	6,000.00
8	TRSV Exercise Tool (Operating)	1,260.00	Days	5	6,300.00
9	TRSV LOT (Standby)	720.00	Days	21	15,120.00
10	TRSV Exercise Tool (Standby)	756.00	Days	21	15,876.00
11	Redress Kit	1,300.00	Each	2	2,600.00
12	Lockout Tool Specialist	1,805.76	Days	15	27,086.40
13	Wireline insert valve	197,372.35	Each	1	197,372.35
14	Swamp logistics	19,508.10	Days	30	585,243.00
15	Security Escort	2,089.27	Days	6	12,535.62
16	Scaffold	80.00	Days	26	2,080.00
17	Accom + feeding	6,000.00	Days	26	156,000.00
18	HSE Officer	550.00	Days	26	14,300.00
19	Liquid Nitrogen	18,000.00	Each	4	72,000.00
20	Personnel Logistics	12,000.00	Each	8	96,000.00
21	Demobilization	21,723.60	Days	3	65,170.80
22	FTO/ Security	5,263.15	Days	26	136,841.90
23	OH Personnel	550.00	Days	26	14,300.00
24	AGO	0.76	Litres	11000	8,360.00
25	7" PXN Plug	37,000.00	1	1	37,000.00
	TOTAL				**$1,842,237.07**

10. HSSE/ SPECIAL WELL/LOCATION CONDITION

Condition of wellhead	*Okay. (Ref Cmb WIT/SIT report 13/08/2021)*
Last annulus pressure measurement/Date	*650 psi (A-annulus); 150 psi (B-annulus) / 13/08/2021*
MAASP	*A- 1661 psi* *B- 260 psi*
Well integrity summary	*Action code 0; Well is closed -in*
Any problem during last re-entry	*TRSCSSV not holding open long enough*
Location condition	*No issues*
Flowline status	*Flowline is Okay*
Seasonally flooded	*N/A*

11. RISK AND MITIGATION

RISKS	LIKELIHOOD / IMPACT	EFFECT	IMPACT ON COSTS OR REWARDS	MITIGATION
TRSCSSV Control line leaking	L/M	TRSCSSV does not stay open for a suitable duration or control line pressure not through to TRSCSSV and unable to pressurize to the required opening pressure. Source of annulus pressure in the well	WRSCSSV might be unsuitable for the well as an insert valve. Well has sustained annulus pressure	• Lock out TRSCSSV and install PB valve
TRSCSSV Control line leaking to the annulus post lockout and PB valve installation	L/M	Access is restored to the tubing however there will be communication with the annulus	Well has sustained annulus pressure Additional cost for annulus pressure remediation	• Use chemical seal to isolate control line • Straddle across the control line if the chemical seal fails • Workover well to restore integrity
Sustained Annular Pressure	M/M	Uncontrolled annulus pressure can result in a well integrity failure impacting people, asset, community, or environment.	Lost production gain due if well becomes a high risk well	• Upfront annulus investigation and remediation • Spectral noise log if attempts to reenergize tubing hanger seal fails • Risk assessment to identify and mitigate risks to ALARP
Flow Impairment	L/M	Impaired flow can result to poor production performance	Well production rate might be lower than predicted or well fails to flow post Nitrogen lifting	• Carry out BU/FG survey or injectivity test with brine and methanol • Stimulate the well if impairment is confirmed

Stuck tool/BHA in hole	M/H	Stuck tools can result in HUD that further limit access into the well and result in extended fishing operation	Loss of production potential and high cost incurred with indefinite fishing	Verify BHA dimensions against the Tubing ID profile. Follow standard procedures for tool make up. Use experienced staff and adhere to appropriate standards and procedures to minimize chances of failure. Ensure all BHA to be run are properly sketched with ODs and length correctly captured prior to run in hole and have basic fishing tools available onsite during intervention
Unexpected HUD	L/M	Objectives may be aborted if BHA is unable to reach target depth	Cost overrun due to longer execution time Constrained gas production	Run LIB to determine nature of HUD and plan for remediation operations
Facility is unavailable for flowback prior to Nitrogen lift	M/M	Well cannot be unloaded with Nitrogen	NPT incurred and increased cost of operation.	• Co-ordinate execution of the activity to ensure facility is available for the period • Attempt to flowback to the minimum test separator static pressure
No pressure build-up after lifting with 1 tank of Nitrogen	L/H	Well is unable to flow or sustain flow unaided.	No reward from operation.	• Monitor liquid and gas returns to surface from the test separator. • Use gas tester to determine the components of return gas • Both FMT & CWI Execution to engage Production Operations via the Asset Management Integration team and ensure seamless integration in ensuring the use of the Test Separator to unload well upon attaining stable flow post N2 lift.
Limited Compressor Capacity	M/L	Limited Compressor capacity implies the LP header would not be available for flowing the well post Nitrogen lift	Well would be closed-in temporarily post TRSCSSV repair and production is threatened if well is liquid loaded.	• When LP compressor capacity is available, route well to test separator and flow back at minimum static pressure until flow stabilises

12. LIST OF APPENDICES

Appendix 1: WELL STATUS DIAGRAM

PROPOSED SOKU SOKU-38 RE-COMPLETION STATUS

30 AUG. 2005

CASING

SIZE	GRADE	WT. (lbs/ft)	DEPTH	CEMENT
24"	STOVE PIPE		410	DRIVEN
13 3/8"	N80	68	5784	CLASS G
10 3/4"	C90	55.5	200	
9 5/8"	N80	47	200 - 10399	CLASS G

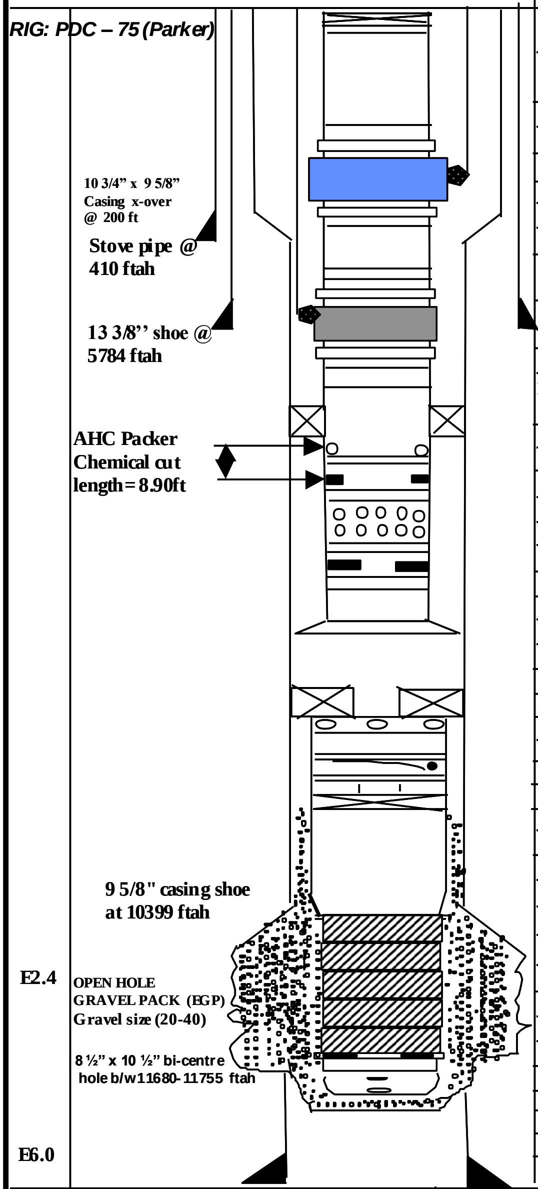
WELLHEAD [COOPER].

ITEM	TYPE	SIZE (INS)	WP (PSI)
INST. FLANGE		7-1/16"	5000
GATE VALVE	CAM.FL(CC)	6 3/8" CAMERON ACTUATOR	5000
XMAS TREE CAP	WKM(BO)compact	7 1/16" Flange hammer lock	5000 w/2clp
XMAS TREE		13 5/8" flange lock x 7 1/16" out let x 6 3/8" bore	5000
TUBING HANGER	SSMC	13 5/8" NOM x 7" Hydril 563 rfb	5000
SEAL ASSY	SRL	7" NOM	5000
SEAL ASSY PACKOFF	COMPACT	13 5/8" Nom x 10 3/4" O.D Csg.	5000
HOUSING	SSMC	13 3/8" flange lock 13 3/8" BTC	5000
CSG HGR	SSMC	13 5/8 x 10 3/4" NK3SB	5000

TUBING

STRING	SIZE	WT	GRADE	TYPE		HOLE		RESERVOIR
					MAX Deviation: =/- 6.8° st 400 ftah	16"		
						12 1/4"	7" H563 CPLG OD = 7.66"	
SSS	7"	29	L80	13 Cr H563 RFB	*DFE 67.73 ft*			
					ORDF-TOP 44.92 ft	10.5" inch (U/REAMED)	OPEN HOLE GRAVEL PACK	E2.0
					PARKER-75 SWAMP BARGE	8 1/2" Rat hole		

SAND | COMPLETIONS. | STATUS

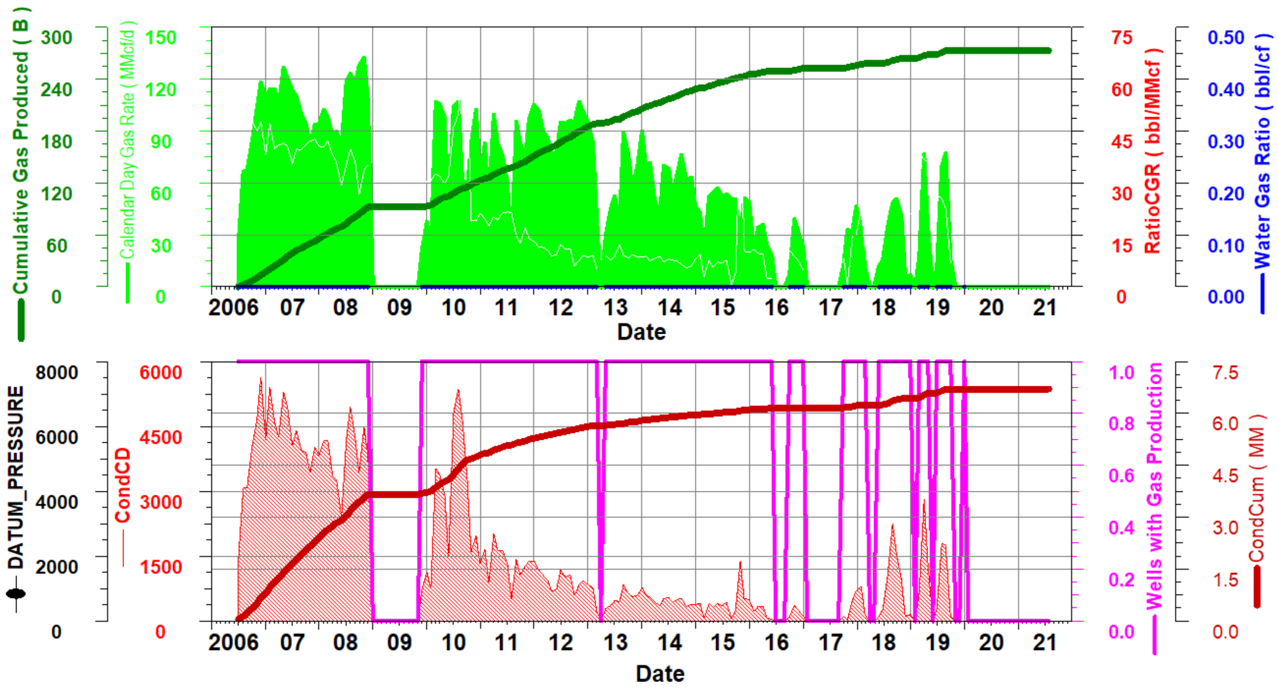


TOP DEPTH FT AHBDF	Length	O.D	I.D (min)	DESCRIPTION
				7" Completion Production String
00.00	67.73			**DFE(Elevation)**
67.73	1.75	7.05	6.184	Compact SSMC hanger, 7" Hyd 563 b, 13Cr, **RIGHT HAND RELEASE**
69.48	4.33	7.05	6.184	Hanger nipple Hydril 563 RFB 13Cr, 29ppf, pin x pin
73.81	117.0	7.05	6.184	**(3) Tubing Jts 7" Hydril 563 RFB, 13Cr**
190.81	6.25	7.05	6.184	**Pup Joint 7" 13Cr H563 b x p**
197.06	10.00	7.65	6.184	Flow coupling 7" Hydril 563 RFB 13Cr, 29ppf.
207.06	11.94	8.353	5.875	**Slim TRScSSSV 7" Hydril 563 RFB 13Cr, 29# w/c 'RQ' Wire insert profile.**
219.00	10.00	7.65	6.184	Flow coupling 7" Hydril 563 RFB 13Cr
229.00	6.25	7.05	6.184	**Pup joint 7" 13Cr H563 b x p**
235.25	9970	7.05	6.184	**(250) Tubing Jts 7" 13Cr H563 b x p**
10137.43	9.70	7.05	6.184	Pup Joint 7" 13Cr H563 b x p
10147.13	6.67	8.464	6.184	**Permanent Downhole Gauge(Weatherford): 7'' H563**
10153.80	6.25	7.05	6.184	Pup Joint 7" 13Cr H563 b x p
10160.05	80.00	7.05	6.184	**(2) Tubing Joints 7" H563 b x p**
10240.05	10.15	7.05	6.13	Pup Joint 7" H563 bxp
10250.20	11.55	8.33	6.04	**HES 'AHC' Perm-Retr. Pkr, 9 5/8" x 7", 13Cr bxp**
10261.75	6.28	7.05	6.184	Pup Joint 7" 13Cr H563 b x p
10268.03	1.38	7.68	5.875	S-2 Nipple Locating :- 7'' 13Cr H563 b x p
10269.41	6.34	7.05	6.184	**Pup Joint 7" 13Cr H563 b x p**
10275.75	20.00	7.05	6.184	**Perforated Production Tubing , 7" Hydril 563 RFB , 13Cr**
10295.75	10.08	7.05	6.184	Pup Joint 7'' 13Cr H563 b x p
10305.83	2.07	7.66	5.500	'RN' Nipple 7" Hydril 563 RFB, 13 Cr (5.625" bore, 5.50" NOGO)
10307.90	6.27	7.05	6.184	Pup Joint 7'' 13Cr H563 b x 7'' New Vam p
10314.17	0.83	8.31	6.184	Wire line re-entry guide , 13Cr 7'' New Vamb
10315				
				Open Hole Gravel Pack Assembly
10346.35	5.62	8.30	6.00	SLB Quantum Packer 9 5/8" X 6.0 X 7" SA (B) DOWN for 47# csg
10351.97	4.62	7.66	6.62	SLB Upper Mill out Ext. 7'' ACME b X p
10356.59	1.70	8.04	6.00	SLB GP Ports w/Closure Sleeve 7" ACME b X p
10358.29	2.20	7.62	6.00	SLB Lower Seal Bore 7" ACME p X 7" LTC p
10360.49	1.92	7.32	6.24	SLB Middle Extension 7" LTC b X p
10362.41	1.10	7.62	6.00	SLB Indicating Collar Coupling 7" LTC b x b
10363.51	4.33	7.37	6.26	SLB Lower Casing Extension 7'' LTC p x p
10367.84	0.80	7.63	5.78	SLB Casing X/over Sub:7'' LTC b X 6 5/8" LTC p
10368.64	1.00	7.31	5.81	X/over:6 5/8" LTC b X 7" BTC p
10369.64	2.98	8.12	4.99	HES Ceramic Flapper 7'' BTC b x p
10372.62	2.09	7.66	5.00	HES Shear-out Safety Jt: 7'' BTC b X 6 5/8" BTC p
10374.71	0.96	7.40	4.79	X/over:6 5/8" BTC b X 5 ½' LTC p
10375.67	30.18	7.28	4.778	SLB All pac 13Cr Blank Pipe 5 ½"20#LTC b x p
10405.85	**100**	**7.28**	**4.778**	SLB All pac Wire Wrap Screen Gauge-12 13Cr 5 ½'' LTC b x p
10495.85	4.73	6.03	4.00	HES Seal Bore Receptacle 13Cr 5 ½" LTC b x p
10500.58	5.08	5.50	4.92	Casing Extension 13Cr 5 ½' LTC b X p; OD Coupling 6.07"
10505.66	2.34	6.06	N / A	HES Double Seal Float shoe 5 ½'' LTC b
10508				**Bottom of float shoe**
13,008				**T.D. of 10 1/2" pilot hole**

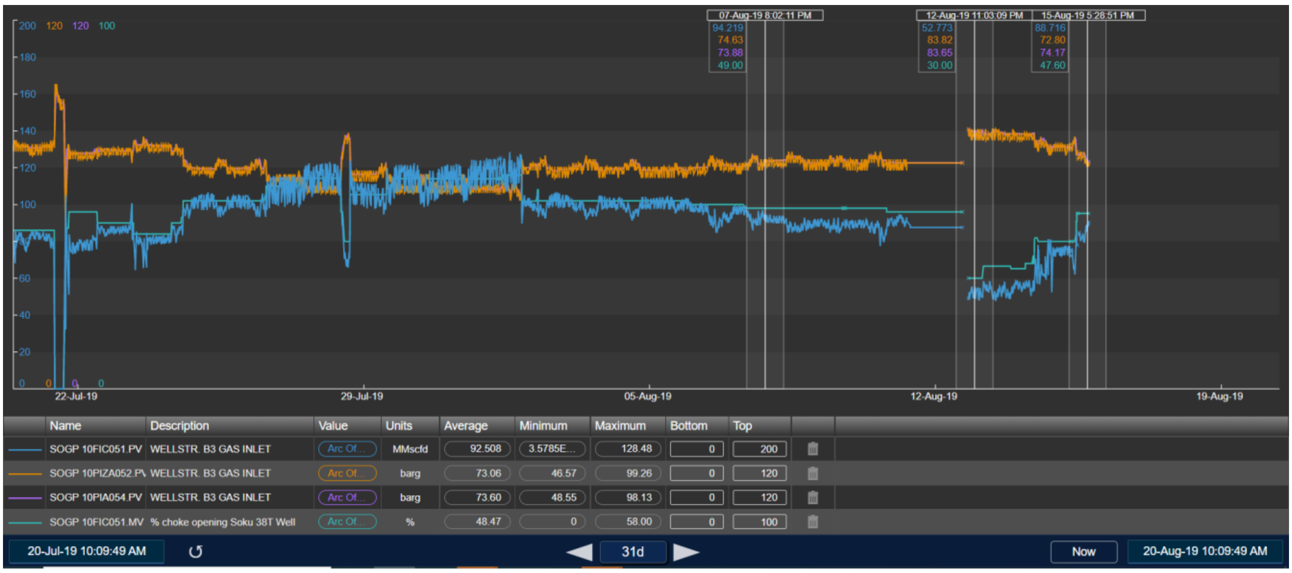
TD13,008ftah	AUTHOR: TWS	DATE: 30 SEPT., 2005	WELLS DEPARTMENT : EPG-PN-TWS

Appendix 2: PRODUCTION PERFORMANCE DATA

OFM Performance Plot

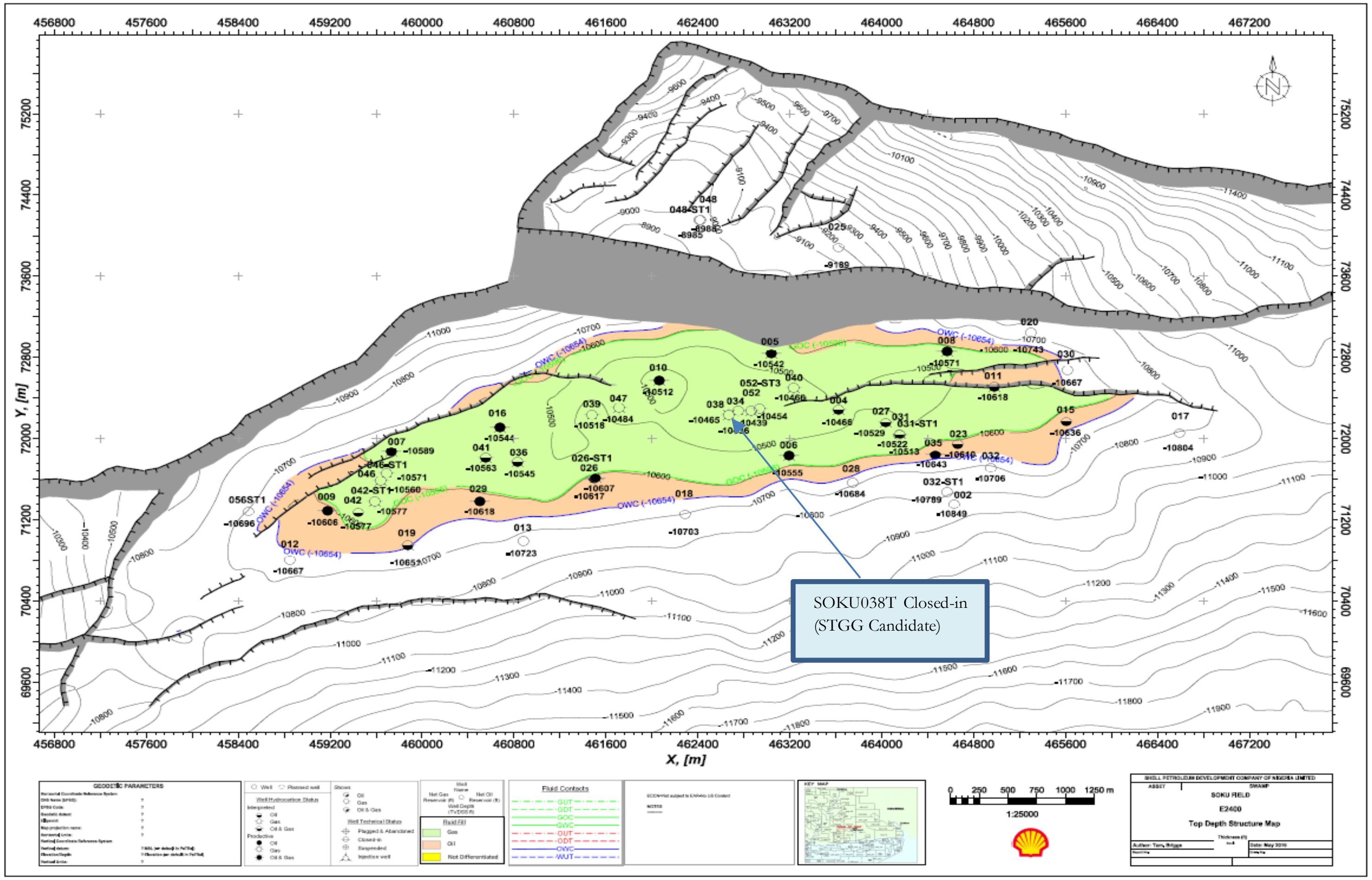


PI Data (20th July to 20th August)

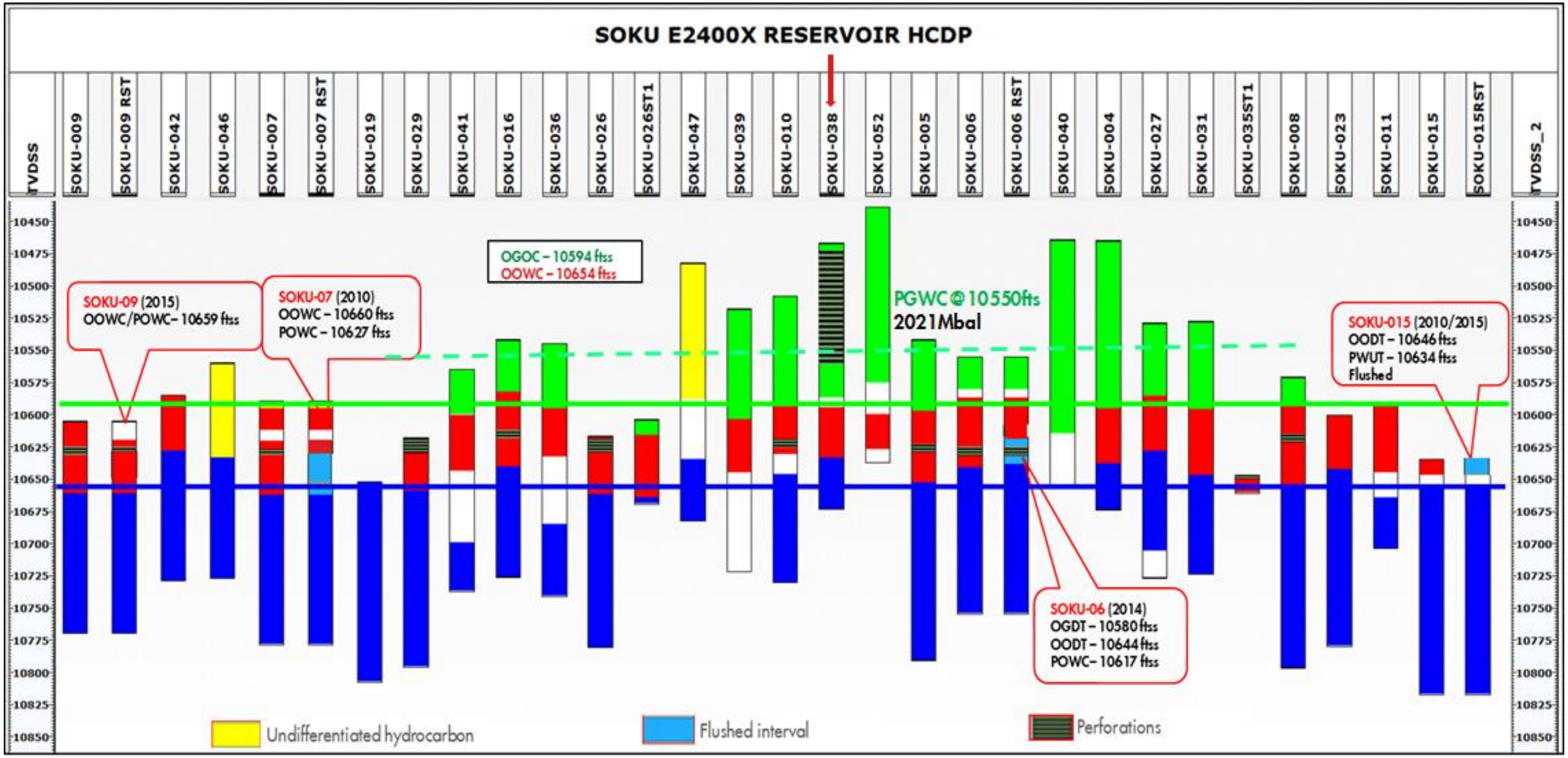


Production performance trend indicating well production rate prior to closure in August 2019. The Blue line represents the well rate (actual wet gas rates measured with wet gas meters - between 60 – 120 MMscf/d).
Teal line indicates the percentage choke opening (0 -100%)
The orange line represents the Well head pressure in barg (0 – 120 barg on the scale)
The purple line represents the Flowline pressure in barg (0 – 120 barg on the scale)

Appendix 3: TOP STRUCTURE MAP

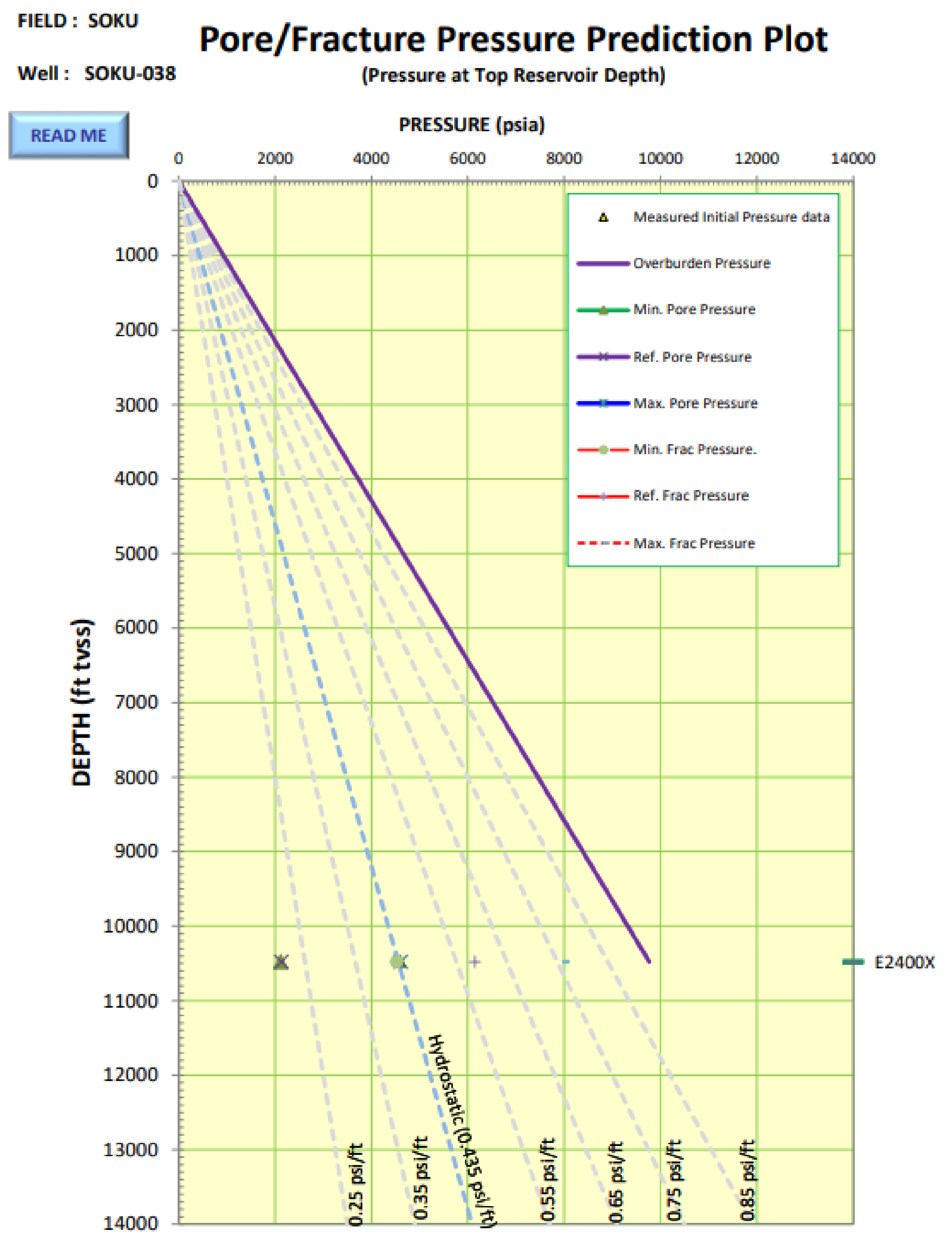


Appendix 4: E2400X HYDROCARBON DISTRIBUTION PLOT



Appendix 5: PORE PRESSURE PREDICTION

Pore Pressure Prediction Plot



Prepared by : BASIL OGBUNUDE Date: 23-09-2021

PP Check/Approved by: n/a Date:

RE Check/Approved by: ONYEDIKACHI OKEREKE Onyedikachi Okereke Date: Digitally signed by Onyedikachi Okereke

Validity Date: 23-09-2022 (PPP to be revalidated before re-entry)

Pore Pressure Prediction Table

FIELD:	SOKU
WELL NAME:	SOKU-038
PLATFORM/RIG:	RIGLESS
PREPARED BY / CHECKED BY	BASIL OGBUNUDE / ONYEDIKACHI OKEREKE
ISSUED DATE :	23 September 2021
REVISION NO:	0
RE-ENTRY DATE:	15 February 2022
EXPIRY DATE:	23 September 2022

Pore Pressure Prediction at Top Reservoir for well SOKU-038

	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 Presure Prognosis at Top of perforation 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)
E2400X	10477	10477	10477	Gas	Y	2119	2119	2136	4490	4610

	Formation Pore Presure Gradient Prognosis at Top of Perforation along Well Trajectory					Fracture Pressure Prognosis at Top of Perforation along Well Trajectory				
Formation	Minimum (psi/ft)	Reasonable Low (psi/ft)	Reference Case (psi/ft)	Reasonable High (psi/ft)	Maximum (psi/ft)	Minimum (psia)	Reasonable Low (psia)	Reference Case (psia)	Reasonable High (psia)	Maximum (psia)
E2400X	0.202	0.202	0.204	0.429	0.440	4528	5481	6146	7670	7972

	Fracture Gradient Prognosis at Perforation of Sand along Well Trajectory					
Formation	Minimum (psi/ft)	Reasonable Low (psia/ft)	Reference Case (psi/ft)	Reasonable High (psi/ft)	Maximum (psi/ft)	Remarks
E2400X	0.432	0.523	0.587	0.732	0.761	Depleted reservoir

Prepared By: BASIL OGBUNUDE (Name) UPV/C/NEC (Team Indicator) 23-Sep-2021 (Date)

PP/GM Check: N/A (Name) ____ (Signature)

RE Check: ONYEDIKACHI OKEREKE (Name) Onyedikachi Okereke Digitally signed by Onyedikachi Okereke Date: 2021.10.28 08:21:35 +01'00' (Signature)

Validity Date: 23-09-2022 (Note: PP/FP must be revalidated prior to RE-ENTRY)

Appendix 6: H_2S PREDICTION

SOKU038T E2400 H_2S PREDICTION

- SOKU038T completed on E2400X reservoir is proposed for rigless well intervention (TRScSSV Repair, BHP Survey and Nitrogen Lift).

PVT Report and Production History

- Available PVT data in SOKU producing reservoirs (including E2400 reservoir) & nearby fields do not indicate H_2S presence. The PVT for the E2400 reservoir also indicates absence of H_2S.

Souring Potential

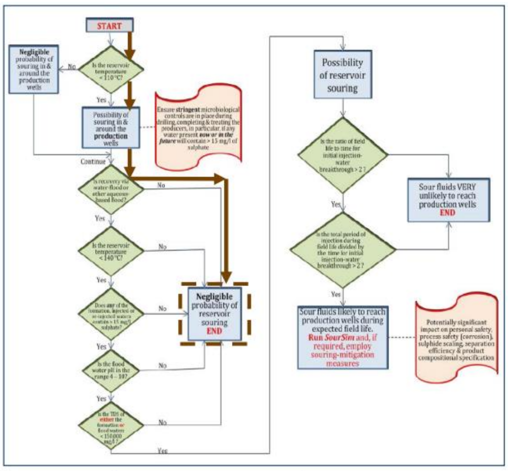
- Due to the following reasons stated below the souring tendency of the reservoirs is minimal (refer to the souring potential chart below);.
  - The maximum reservoir temperature for the target sand is 77.8 degC (below 172 °F)
  - No secondary or tertiary recovery processes practiced in the field.
  - However, there is a water disposal well injecting produced water into the B1000 reservoir (ca. 4350 ft shallower than the E2400X).
  - There is a reservoir souring risk in the B1000, but the E2400X reservoir is properly isolated in this well (good cement and Inter- reservoir shale zonal Isolation).

External Risks

- There is a risk of the Equipment (e.g., Rig, CT, tanks) to be used in this operation introducing some H_2S based on residue from their previous operations.

Mitigations

- Check and confirm that previous use of the equipment would not intentionally give rise to H_2S.
- H_2S Gas monitors will be utilized during the activity execution to alert the crew of any latent threats.
- Appropriate PPE's will also be utilized as mitigation.



Prepared by:	Uchenna Udobata (PT)		
Approved by:	Biambo Tamunotonye(PT TA2)	Tammy Biambo	Digitally signed by Tammy Biambo Date: 2021.10.09 00:44:03 +01'00'
Approved by:	Etuk Ubong (PG TA2)	Etuk, Ubong A.	Digitally signed by Etuk, Ubong A. Date: 2021.10.08 18:36:39 +01'00'

PVT Composition for SOKU E2400X

FLOPETROL

SERVICES FOR THE OIL INDUSTRY

Fig n° Page

WELL : 5 (2ND FIT) COMPANY : SHELL-BP Report 78/LN/086

FORMATION : E2.4 STATE :

FIELD : SOKU COUNTRY : NIGERIA

TABLE II.

MOLECULAR COMPOSITION OF RESERVOIR FLUID

Components	Stock Tank Condensate Mole %	G a s Mole %	Reservoir Fluid Mole %
Nitrogen	-	traces	traces
Carbon dioxide	-	0.24	0.24
Methane	-	91.24	90.23
Ethane	0.12	4.38	4.33
Propane	0.24	1.28	1.27
Iso Butane	0.33	0.61	0.61
Normal Butane	0.52	0.56	0.56
Iso Pentane	1.19	0.41	0.42
Normal Pentane	1.13	0.26	0.27
Hexanes	4.88	0.34	0.39
Heptanes	12.59	0.55	0.68
Octanes	37.58	0.13	0.54
Nonanes	18.85	-	0.21
Decanes	10.40	-	0.11
Undecanes	6.48	-	0.07
Dodecanes+	5.69	-	0.07
T o t a l	100.00%	100.00%	100.00%
Molecular Weight	121.83	18.79	19.92
Dodecanes+ Molecular Weight	187.17	-	187.17
Molar Ratio	0.01102	0.98898	1.00000

SG = 0.917 from extrapolation

14.12 bbl/MM...

Density of dodecanes+ - 0.8362

- There is no indication of H_2S in the compositional analysis.

Appendix 7: EMERGENCY RESPONSE DATA AND CONTACT

Emergency Data Set Content			Data Owners /Accountable Discipline	Names	Email
People Contacts and Procedures	1	Duty roaster (weekend duty/leave plan)	Development – Planning Weekend duty Coordination	Akpovine Otughwor Eric Ezenobi	Akopovine.otughwor@shell.com Eric.C.Ezenobi@shell.com
	2	Emergency response contact details: Subsurface team, operations team, wells, OU and external emergency responders.	Soku/ Nun River Node FMT PT PP PG RE WRFM CWI	Okereke Onyedikachi Udobata Uchenna Maxwell-Amgbaduba Sunday Jude Ekwealor Basil Ogbunude Esther Briggs	onyedikachi.okereke@shell.com U.Onyemannadi@shell.com S.Maxwell-Amgbaduba@shell.com Jude.Ekwealor@shell.com B.Ogbunude@shell.com Esther.Briggs@shell.com
	3	SOKU038T Well Restoration Proposal	Soku/ Nun River Node FMT PT PP PG RE WRFM CWI	Okereke Onyedikachi Udobata Uchenna Maxwell-Amgbaduba Sunday Ekwealor Jude Basil Ogbunude Ran Stone	onyedikachi.okereke@shell.com u.onyemannadi@shell.com S.Maxwell-Amgbaduba@shell.com Jude.Ekwealor@shell.com B.Ogbunude@shell.com Stone.Ran@shell.com
	4	Well tops and fluid fill interpretation	PG/PP	Jude Ekwealor/ Maxwell-Amgbaduba Sunday	Jude.Ekwealor@shell.com S.Maxwell-Amgbaduba@shell.com
	5	Subsurface map	PG	Jude Ekwealor	Jude.Ekwealor@shell.com
	6	Pore pressure prediction	RE/PP	Basil Ogbunude/ Maxwell-Amgbaduba Sunday	B.Ogbunude@shell.com S.Maxwell-Amgbaduba@shell.com
	7	Intervention work scope	PT/WE	Udobata Uchenna /Conrad Ibekwe	U.Onyemannadi@shell.com Conrad.Ibekwe@shell.com
	8	Correlation Panel	PG	Jude Ekwealor	Jude.Ekwealor@shell.com
	9	Cross section through the STOG well.	PG	Jude Ekwealor	Jude.Ekwealor@shell.com
	10	Petrophysical logs for well & nearby wells	PP	Maxwell-Amgbaduba Sunday	S.Maxwell-Amgbaduba@shell.com
	11	Worst Case Discharge	PT	Udobata Uchenna	u.onyemannadi@shell.com
	12	Well Status Diagram	PT	Udobata Uchenna	u.onyemannadi@shell.com
Overall responsible focal point for Duty and Emergency Response Files					
Name	Arnold Obomanu				
Contact Details	a.obomanu@shell.com / +2348070221066				

Emergency Data Set Content			Update Timing	Medium/Location	Data Owners /Accountable Discipline
People Contacts and Procedures	1	Duty roaster (weekend duty/ leave plan)	Annually/after staff rotations	Electronic/SharePoint and ERO Portal	Development - Planning
	2	Emergency response contact details: Subsurface team, operations team, wells, OU and external emergency responders.	After staff rotations	Electronic/ ERO Portal	ERT
	3	Communication Protocol	No special communication protocol is required. This is a conventional operation that will be executed by in-house experts/ERO Portal		ERT
	4	SOKU038T Well Restoration Proposal	Dependent on availability of new information	Electronic/ Sirus Catalog SOKU038T Well Restoration Proposal 2021	PG/ PP/ RE/PT/WE
	5	Well tops and fluid fill interpretation		Electronic/CDS, ERO Portal	PG/PP
	6	Subsurface map		Electronic/SOKU038T Well Restoration Proposal, ERO Portal and Sirus Catalog	PG
	7	Pore pressure prediction	6 months prior to activity	Electronic/SOKU038T Well Restoration Proposal	RE/PP
	8	Intervention work scope	Dependent on availability of new information	Electronic/SOKU038T Well Restoration Proposal and Sirus Catalog	PT/WE
	9	Correlation Panel			PG
	10	Cross section through the Workover well.			PG
	11	Petrophysical logs for well & nearby wells	Not Applicable	Electronic/RECALL, Hardcopy/Log Room	PP
	12	Worst Case Discharge	When Pore pressure prediction is updated prior to activity	Electronic/ SOKU038T Well Restoration Proposal and Share point	PT
	13	Well Status Diagram	Dependent on availability of new information	Electronic/EDM, Sirus Catalog & SOKU038T Well Restoration Proposal	PT
Overall responsible focal point for Duty and Emergency Response Files					
Name	Arnold Obomanu				
Contact Details	a.obomanu@shell.com / +2348070221066				

Note: In order to ensure that all Soku-038 offset wells are compliant with all required emergency response data requirements, all ERO data will be updated prior to the activity execution date.

Appendix 8: BHP Survey Program

1. Carry out SG stops as specified in the table below.

SURVEY STOPS

	Max Survey Depth	Stops											
SG STOPS (ftah)	10268	10258	10248	10198	10148	9648	8648	7148	5648	4148	2648	1648	648
Time (mins)	30	10	10	10	10	10	10	10	10	10	10	10	10

Appendix 9: HSE Critical Activities

TABLE OF AUTHORISATION

HSSE CRITICAL ACTIVITIES (Rigless Activities -Wells) SIGN-OFF:

Position	**Activity Number(s) Reviewed**	**Name**	**Ref Ind.**	**Signature**
Production Geosciences ATA2	4a,24	Etuk, Ubong	UPV/C/NW	Elias Arochukwu Digitally signed by Elias Arochukwu Date: 2021.11.01 13:00:10 +01'00'
Petrophysics Discipline ATA2	5b, 7a, 7b, 7c,7d, 8, 10, 17a, 18.	Laoye, Abiodun	UPC/G/UC	Laoye Abiodun Digitally signed by Laoye Abiodun Date: 2022.01.24 14:54:59 +01'00'
Reservoir Engineering ATA2	5b, 5c	Okereke, Onyedikachi	UPV/C/NE	Onyedikachi Okereke Digitally signed by Onyedikachi Okereke Date: 2021.11.01 09:30:19 +01'00'
Production Technology ATA2	4a, 11, 12, 13a, 13b, 14, 15,16, 17b, 24	Biambo, Tamunotonye	UPV/C/NE	Tammy Biambo Digitally signed by Tammy Biambo Date: 2021.10.29 11:55:59 +01'00'
CWI ATA2	11, 15, 26	Leslie, Gavin	SUKEP-PTW/N/M	Gavin Leslie Digitally signed by Gavin Leslie Date: 2022.02.04 08:48:39 Z

HSE Critical Task			Disc	Close Out of HSSE Critical Task
Activity		**Potential HSE Impact**		
4a	Predict H2S presence. **DEP 25.80.10.18**	Loss of life and material integrity.	PT/PG	See appendix 6
5b	Predict pore and fracture pressure in an undeveloped reservoir **DEP 25.80.10.10**	Loss of Well Control and Integrity	RE*/PP	The reservoirs are developed. Hence not Applicable.
5c	Predict pore and fracture pressure in an already developed reservoir **DEP 25.80.10.10**	Loss Well Control and Integrity.	RE	See appendix 5
7a	Plan logging – Wireline and LWD operations **DEP 25.80.10.15**	Well control, human exposure	PP	Logging risk and mitigation plan will be captured in detailed Logging proposal. Proper pre-job safety meeting to hold prior to running in hole and well-trained personnel to deploy tool at well site. Well control enforcement will be the accountability of the CWI team and it will be enforced by pre-work meeting and the adoption of appropriate BOP's and lubricator.
7b	Plan logging – radioactive Sources **DEP 25.80.10.15**	Environment impact, surface handling risks to people, loss of sources in the hole	PP	C/O logging not planned.
7c	Plan logging – explosives **DEP 25.80.10.15**	Potential for loss of life. HSSE management of surface and downhole operations	PP	No planned logging or use of explosives
7d	Plan logging - Pressurised formation fluid samples. **DEP 25.80.10.15**	surface handling: potential for loss of life.	PP	None planned
7e	Plan logging - TZ and VSP survey operations **DEP 25.80.10.15**	Explosives, Airguns – Potential loss of life.	PP/PG	Not applicable.
10	Interpret cement bond integrity and casing wear log.	Zonal isolation and potential casing integrity.	PP	CBL interpretation indicates zonal isolation above the E2400X sand. Well is open hole completion.
11	Plan perforation and guns retrieval. (**Integrated as part of DEP 25.80.10.21)**	Hazards to life and facilities (misfired or unfired charges to surface).	PT*/WE	Not applicable.
12	Predict sand production. **DEP 25.80.10.19**	Facility / flow-line integrity and loss of containment (LOC)	PT	Sand control was installed at initial completion. No sand production issues noted despite pressure decline over years of production. No new FIST analysis was conducted, and no remedial sand control is being proposed. If deemed necessary post rigless activity execution, sand management will be applied to manage the drawdown and hence safeguard the well and facilities from possible erosion.

13a	Predict produced fluid composition, especially contaminants like CO2, H2S, and mercury and potential formation water composition.	Corrosion and material integrity.	PT	This well was completed with 13 Cr tubing in line with the material selection plan. No significant corrosion has been observed in this well and in the existing Soku wells. No major risk for corrosion and asset integrity. Fluid sample analysis indicates that there is no presence of H_2S and 0.24 mole % CO_2 in the reservoir as seen in E2400 PVT report.
13b	Predict and manage scaling + reservoir souring impact from water flooding /water injection	Corrosion and material integrity including hazard to life	PT	Not Applicable. Water flooding / water injection is not planned for this reservoir. Hence the souring and scaling potential as a result of water flooding/injection is minimal.
14	Predict well-head and produced fluid temperature.	Well head growth, surface flowlines limitation and stress integrity.	PT	The predicted / expected wellhead fluid temperature of between 80 - 95degF falls within the range seen in Wells in the nearby fields and are not expected to pose a threat during the life of the well. Also, the surface casing is cemented in place and no wellhead movement have been seen or expected.
15	Plan (and execute) stimulation. **DEP 25.80.10.21**	Unsafe handling of chemicals (SHOC), equipment failure due to acid corrosion.	PT*/WE	SHOC card procedures will be strictly adhered to and appropriate PPE will be used. Tool box talk and job hazard analysis will be conduction. Appropriate and pre-mobed equipment will be used.
16	Establish safe operating boundaries (MAASP, closed in pressure, erosion and corrosion limits, etc.) for well integrity management.	Loss of well integrity. (see also Appendix 5)	PT	Material selection was done before initial completion and operating boundaries have been established and well integrity activities carried out at stipulated times. MAASP calculations have been done and documented.
17a	Top-seal integrity assessment for primary recovery, waterflood, EOR and CO2 storage DEP 25.80.10.22	Human exposure, environmental and asset damage	PP	The risk of top-seal leakage due to primary recovery is considered low based on field and regional assessment conducted in 2016. Waterflood, EOR and CO_2 storage are not planned in this field.
17b	Prepare Abandonment Design option and program	Human exposure, environmental and asset damage.	PT	Not applicable.
18	Predict and monitor reservoir compaction and subsidence. DEP 25.80.10.16	Loss of wells, facility/platform integrity.	PP	The risk of compaction and subsidence is considered low based on field and regional assessment conducted in 2016. A new study is being conducted and preliminary results do not indicate any additional risk.
24	Prepare and maintain data to support emergency response. **DEP 25.80.10.12**	Lack of data or wrong data during emergency response may aggravate the emergency.	PT/PG	See Appendix 7 All relevant well data and latest well information have been uploaded unto the ERO portal. The relevant well data includes completion diagram, well status, reservoir pressure and temperature, blow out rate, well performance curves etc. http://sww.scin.eroportal.shell.com/
26	Identify Hazards (HAZID) and prepare Hazard Register	Integral part of HSSE Case development. To confirm selected concept/process can be developed into a safe and operable plant.	WE	This is an STOG activity in an existing well. Hence, well design is not applicable. HSSE risks and mitigation has been built into the execution program

Appendix 10: Activity Decision Tree