INVESTMENT PROPOSAL

FOR THE UZU WPUX-1 WELL APPRAISAL DRILLING

The Shell Petroleum Development Company of Nigeria Limited

Summary Information

Business unit and company	The Shell Petroleum Development Company of Nigeria Limited (SPDC)
Group equity interest	100% in SPDC, whereas SPDC is the Joint Venture (JV) operator of an unincorporated JV with a 30% interest.
Other shareholders / partners	Nigerian National Petroleum Corporation (NNPC: 55%), Total E&P: 10%, Nigeria Nigerian Agip Oil Company (NAOC: 5%) in SPDC-JV.
Business or Function	Upstream International Operated (UIO).
Amount Requested	US$ 8.12 mln Shell Share (i.e. US$ 27.06 mln 100% JV), 50/50, MOD.
Project	Uzu Appraisal Well Drilling on E1000X, E7000X and F1000X Reservoirs.
Main commitments $ mln (MOD) See Table 1 for expenditure phasing.	

Description	**JVUS $mln (100%)**	**US $mln (Shell Share)**
CAPEX		
1 no's Appraisal Drilling	13.99	4.20
1 no's Completion & Testing	10.70	3.21
1 no's Side track (contingency)	1.71	0.51
OPEX		
SCD	0.66	0.20
Total	**27.06**	**8.12**

Source and form of financing	This investment will be financed from JV funding. Shell share capital expenditure will be met by SPDC's own cash flow and/or the existing shareholder facility.
Summary cash flow	Cost only Project

Summary Economics (RV-RT13)	NPV7% (USD mln)	RTEP (%)	VIR7%
Base Case	-1.7	NA	-0.21

Section 1: The proposal (management summary)

This Investment Proposal (approval for funding of US$8.12 mln Shell Share - US$ 27.06 mln 100% JV) is required for the execution of the Uzu WPUX-1 well appraisal drilling, completion and testing. If the appraisal objectives are successful, a further Investment Proposal will be prepared for the hook-up.

The Uzu field is a Partially Appraised Field (PAF) situated in the Eastern border of OML-28 within the seasonal fresh-water swamp area of the Niger Delta. It is part of the Gbaran / Ubie Phase 3 nodal project scheduled to keep the Gbaran CPF full and supply feed stock gas to NLNG trains 1-6.

The 2012 integrated Uzu reservoir development plan and technical review was triggered off by the acquisition of new seismic data and new well data from Zarama wells. The Development Plan proposes the drilling of a well to appraise the E1000X, E7000X and F1000X reservoirs, plug back on the F1000X oil bearing reservoir but develop the E1000X and E7000X NAG reservoirs as gas producers with the same well.

There are three well penetrations in the Uzu field; Zarama-01 and Zarama-08 (from the neighbouring Zarama field which encountered the field wet) and Uzu-01 which is the only well that has logged hydrocarbons in the field. The E1000X and E7000X reservoirs have a total expectation GIIP of 227 Bscf and 146 Bscf respectively, while the F1000X has a STOIIP of 76 MMstb.

This well is expected to test the structural definition towards the eastern flank of the reservoirs and also resolve the uncertainty in fluid contact (OWC) in the F1000X reservoir. The well is also planned to develop 114.9/49.2 Bscf of gas and 2.4/1.9 MMstb of condensate from the E1000X / E7000X reservoirs respectively at an initial production potential of 50MMscf/d. Production will be routed to the Gbaran Central Processing Facility via the Zarama NAG manifold. The appraisal well expenditure is discussed in Section 2.

The Uzu appraisal well drilling and completion is in synergy with the Uzu field development which is part of the larger Gbaran Ubie Phase 3 project. If a viable oil column is confirmed in the F1000X reservoir, the well will be logged and the acquired data will form the basis for future oil development of the F1000X reservoir. The target drilling date for the appraisal well is May 2013 (April 2013 STWDS).

The result of the appraisal well is expected to significantly reduce uncertainties and is therefore pivotal to the future life cycle development optimization of the Uzu field.

Section 2: Value proposition and strategic and financial context

The outcome of the appraisal drilling will reduce contact uncertainties and support full field development objectives. This proposed appraisal and follow-up NAG development in Uzu aligns with SPDC's oil and gas production growth drive and also contributes to NLNG gas supply. The cost summary is given in Table 1.

- Uzu appraisal drilling and completion well cost is US$ 8.12 mln Shell Share i.e., US $27.06 mln (100% JV MOD). Flowline/hook-up costs (notional) is US$ 27 mln (100%).

- Potential recoverable volumes from the appraisal project are ca. 164 Bscf of gas and 4.3 MMstb of condensate.

- Initial production potential is 50MMscf/d.

Table 1: Appraisal Well Drilling and Completion Expenditure (US $mln MOD JV 100%*)*

Activity	**2013**
WELL COST ESTIMATE ($mln)	
CAPEX	
Drilling Costs	13.99
Sidetrack Costs	1.71
Completion, Testing & suspension Costs	10.7
Total ($MOD)	**26.40**
Opex ($mln)	
SCD	0.66
Overall Project Cost ($ MOD)	**27.06**

Summary Economics

The base case economics for the Uzu Appraisal well was evaluated on a forward-looking basis using 50 /50 cost level III for drilling/completion and notional cost estimates for the hook-up. A full scope economics (Forward Look) was done using the stated cost and expected production forecast.

The decision to appraise was already taken prior to this evaluation; however, the EMV (risked NPV) of the appraisal drilling was determined, using cost estimates for drilling/completion, notional hook-up cost estimates, production forecast and the Probability of Appraisal Success (POAS) through the decision tree method. The EMV of the appraisal decision is US$mln 18.4 (see Appendix 1).

The evaluation has assumed that there will be ullage in the receiving facility thus additional facility costs were not considered.

The following sensitivities were carried out on the base case to reflect the impact on the project under different possible scenarios:

- High Capex (+40%).
- Full Life Cycle cost
- 1.5% Cost mark-up due to BVA issues (provision for costs dispute by NAPIMS)

Similar sensitivities were carried out on the full scope view including 1 year Production delay, High volumes (+51%) and Low volumes (-82%).

Due to the notional costs assumed for flow lines and hook up, sensitivities were carried out on the said costs testing it against mark up as high as 50 % (Appendix 2).

The Base Case and Full Scope Economic result is presented in Tables 2 & 3 and a profitability chart for the full scope in Fig 1 below:

Table 2: Drilling and Completion only Economics Grid (Shell Share)

Cash flow forward from: 1/1/2013	NPV (S/S $ mln)		VIR	RTEP	UTC (RT $/boe)		Payout-Time (RT)	Maximum Exposure (RT- AT)
Cash flow forward from: 1/1/2013	**0%**	**7%**	**7%**	**%**	**0%**	**7%**	**(yyyy)**	**$mln (yyyy)**
Base Case								
RV ($90/bbl & $2.01/mmbtu RT13)	-1.5	-1.7	-0.21	NA	NA	NA	NA	*7.4(2013)*
Sensitivities (using RV)								
High CAPEX		-2.4	-0.21				2015	*10.3(2013)*
Full Life Cycle		-1.7	-0.21				2015	*7.4(2013)*
1.5% BVA		-2.1	-0.25					

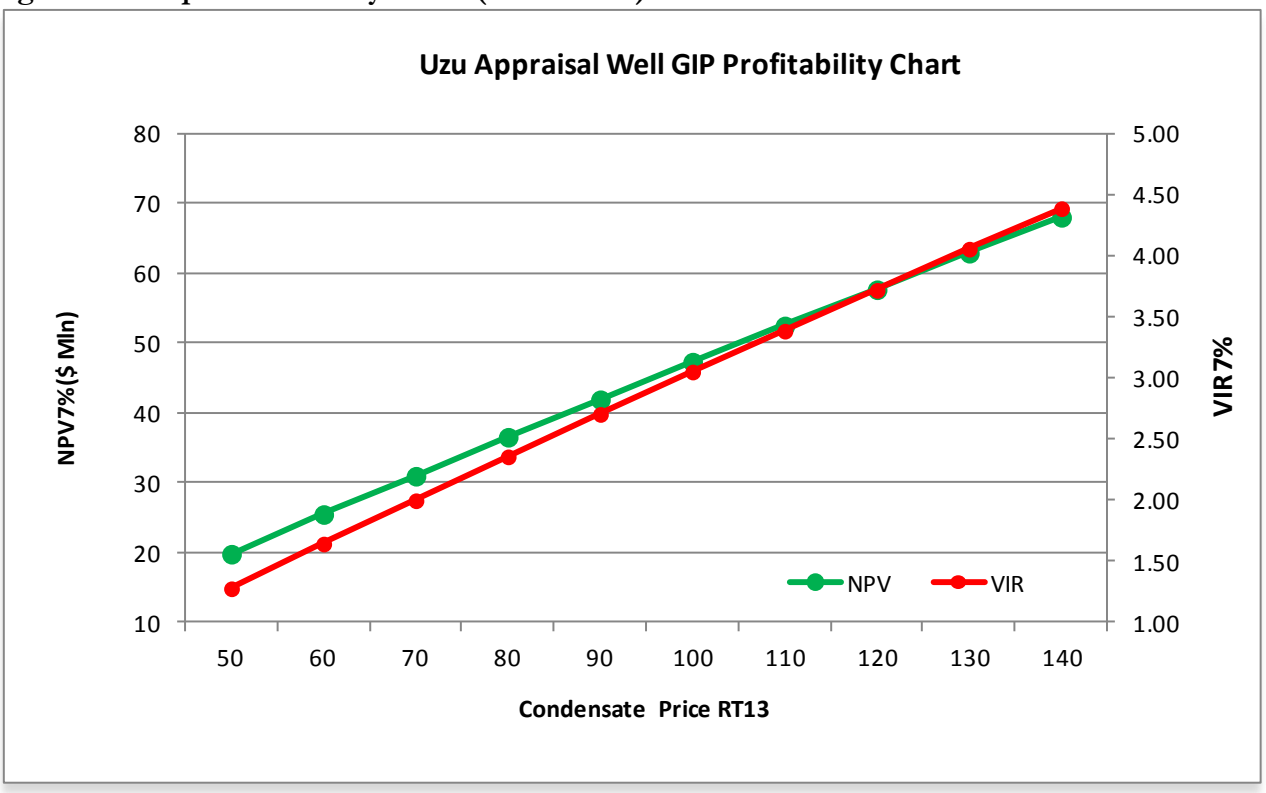
Key Project Parameters Data Ranges (Shell Share)

Parameter	Unit	BP12 Provision	Low	Mid	High	Comments
Capex (MOD)	US$ mln	8.2	NA	7.9	11.1	
Opex (MOD)_Project	US$ mln	NA	NA	0.4	0.6	SCD
Production Volume	mln boe	NA	NA	NA	NA	
Start Up Date	mm/yy		Jan. 2015			
Production in first 12 months	mln boe					

Table 3: Full Scope Economics Grid (Shell Share)

Cash flow forward from: 1/1/2013	EMV (S/S $ mln)	NPV (S/S $ mln)		VIR	RTEP	UTC (RT $/boe)		Payout-Time (RT)	Maximum Exposure (RT- AT)
Cash flow forward from: 1/1/2013	**7%**	**0%**	**7%**	**7%**	**%**	**0%**	**7%**	**(yyyy)**	**$mln (yyyy)**
Base Case									
SV ($70/bbl & $1.58/mmbtu RT13)		54.4	**31.0**	**2.00**					
RV ($90/bbl & $2.01/mmbtu RT13)	18.4	72.6	**41.9**	**2.70**	>50	3.4	4.3	2015	*15.0(2013)*
HV ($110/bbl & $2.42/mmbtu RT13)		90.3	**52.5**	**3.39**					
Sensitivities (using RV)									
High CAPEX			**39.2**	**1.81**				2015	*20.9(2013)*
High Volumes			**56.6**	**3.65**				2015	*15.0(2013)*
Low Volumes			**2.2**	**0.14**				2017	*15.0(2013)*
1 Yr Production Delay			**32.3**	**2.08**				2017	*15.9(2013)*
1.5% BVA			**40.8**	**2.50**					

Fig 1: Full Scope Profitability Chart (Shell Share)



Economic Assumptions

- Oil & Condensate PSVs of $70/bbl @SV-RT13; $90/bbl @RV-RT13 and $110/bbl @HV-RT13 with applicable offsets applied.
- 2013 NLNG PSV was used for gas sold to NLNG.
- Oil & Condensate was taxed under PPT (PPT tax rate of 85%).
- Gas was taxed under CITA with AGFA incentives.
- SPDC Generic Fixed OPEX assumptions applied as follow:
  - ✓ Oil fixed - 3.0% of cum. oil CAPEX.
  - ✓ Gas fixed - 3.5% of cum. gas CAPEX.
- ARPR 31/12/2012 Variable Opex for Gbaran is applied.
- Gas Flare Penalty of US $3.5/mscf was applied and is non-tax deductible.
- GHV of 1150Btu/scf.
- 10% of total project RT CAPEX assumed as abandonment cost.
- NDDC levy 3% of total expenditure.
- Education tax of 2% assessable profit.
- Notional US$27mln flowline/hook-up cost for full scope economics.

Section 3: Risks, opportunities and alternatives

Opportunity	Reduced uncertainty of fluid type.
	To establish clear contact on the F1000X reservoir. Properly define the structural configuration of the E1000X and E7000X reservoirs.
	Appraisal is pivotal to full life cycle development of the field.
	Unlock contingent resources. The F1000X accumulation definition is currently restricted by oil-down-to at 9840 ftss and water-up-to at 9881 ftss.
Risks / Mitigation	If the appraisal well is drilled and the low case volume is encountered, the development objective for the appraisal well will be regretted. Notional hook-up cost and sensitivity around US$27 mln has been used to evaluate EMV for the full scope economics. The final hook-up costs would be dependent on the results of the well. This amount however is not being requested in this IP.
	To prevent hole collapse and stuck pipe incidents as a result of wellbore stability issues, we should ensure the following: • Use appropriate mud weight – guided by OPTIWELL model and offset well review. • Minimize Logging time by reducing number of logs to be taken Minimize stationary time of drill string sand logging tools.
	There is a likely chance of encountering the targeted reservoirs shallower or deeper than prognosed because the subsurface targets are located down dip of the eastern flank where there is no well control. The depth uncertainty for these reservoirs is +/-100ft.
	From offset wells review, there are no indications of significant down-hole losses. However, it is recommended that we keep appropriate LCM stock and monitor the well closely for losses, particularly when drilling the surface hole section.
	Owing to the high inclination of the well, 44.1deg , hole cleaning challenges are expected. For effective hole cleaning, ensure mud pumps are in top condition and employ optimum pump rate. The use of rotary steerable system will also assist in effective hole cleaning.
	There is a risk of regulators not allowing plug back to develop the shallower reservoirs (E1000X and E7000X reservoirs) if significant oil column is found on the F1000X reservoir.

Non Technical Risk	The existing GMoU for Gbaran Cluster will be used for continuous engagement of the communities. Social impact management, community engagement and grievance resolution including any legacy issues will be managed through the GMOU interface model and in compliance with the HSSE & SP Control Framework requirements to create a positive presence in the communities and an enabling environment for uninterrupted operations. In addition, the rig will support temporary employment for community workers and provision of local contracting opportunities as agreed in the GMoU. Security Plan agreed and signed off by Security will be in place prior to commencement of activities.

Section 4: Carbon Management

The main impact on Green house Gas emissions is at the surface facility as a result of increased energy consumption and associated increased flaring. In the event of oil rim discovery, well testing following the drilling campaign will be done through the existing facilities. There is a plan to carry out well test in the event of gas discovery.

The Impact on Greenhouse Gas emissions resulting from the hookup of additional production into the existing surface facilities have been addressed by the Greenhouse Gas and Energy Management Plan (GHGEMP) for the facilities covered in the Gbaran GHG management Plan. The GHGEMP also contains the 10 years GHG emission and Energy use forecast for the facilities in the Gbaran district together with a number of recommended abatement proposals. With the Gbaran CPF fully operational emission from flaring is largely reduced.

Section 5: Corporate structure, and governance

The existing corporate structure and arrangements of SPDC-JV (with SPDC as operator) will be used as the vehicle for the investment and operations.

An SPDC Decision Review Board (DRB) will continue to advice.

Section 6: Functional Support and consistency with Group and Business Standards

This proposal complies with Group Business Principles, policies and standards. Functional support for this proposal has been provided by Finance, Social Performance, Supply Chain Management, HSE.

Section 7: Project management, monitoring and review

This IDP is a subset of the Uzu field development plan being studied by FES

Assurance Events/Gates (Uzu WPUX-1 Appraisal/Development)	Date
ITR	Nov. 2011

The Land East Asset Team is fully involved in this project and will monitor the well execution.

Section 8: Budget provision
The project is in BP12 Base Plan for JV Funding.

Section 9: Group financial reporting impact (Shell Share – US$mln)

There are no unusual accounting issues related to this GIP. Expenditure related to the project will be accounted for in line with Group Policy. The financial impact of this proposal on Shell Group Financials is as indicated in the table below:

US$ mln	2013	2014	2015	2016	Post 2016
Total Commitment	8.12				
Cash Flow					
SCD Expenditure	0.2				
Pre-FID Expenditure					
Capital Expenditure	7.92				
Operating Expenditure	0.24				
Cash flow From Operations	5.25	0.34	0.34	-0.52	1.05
Cash Surplus/(Deficit)	-2.67	0.34	0.34	-0.52	1.05
Profit and Loss					
NIBIAT +/-	5.25	0.34	0.34	0.34	1.05
Balance Sheet					
Avg Capital Employed	3.96	7.92	7.92	8.35	17.11
Impact on ROACE (OU)	1.32	0.04	0.04	0.04	0.13

Section 10: Disclosure
Material disclosures, if any, will be done in line with the Group and SPDC Disclosure policies and guidelines.

Section 11: Financing

The project will be funded with JV funding and Shell Share capital expenditure will be met by SPDC's own cash call.

Section 12: Taxation

The income tax from the project will be in accordance with Petroleum Profit Tax Rate and relevant income tax applicable.

Section 13: Key Parameters

This investment proposal seeks approval for US$8.12 mln Shell Share (US$ 27.06 mln 100% JV MOD) which is required for the execution of the Uzu WPUX-1 appraisal well drilling and completion.

Section 14: Signatures

This proposal is submitted to GM Development for approval.

For shareholder approval:

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Jan Van Bunnik (FUI/OG)

Date …../……/…...

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Ojulari, Bayo (UIG/T/D)

Date …../…../…..

BOM:

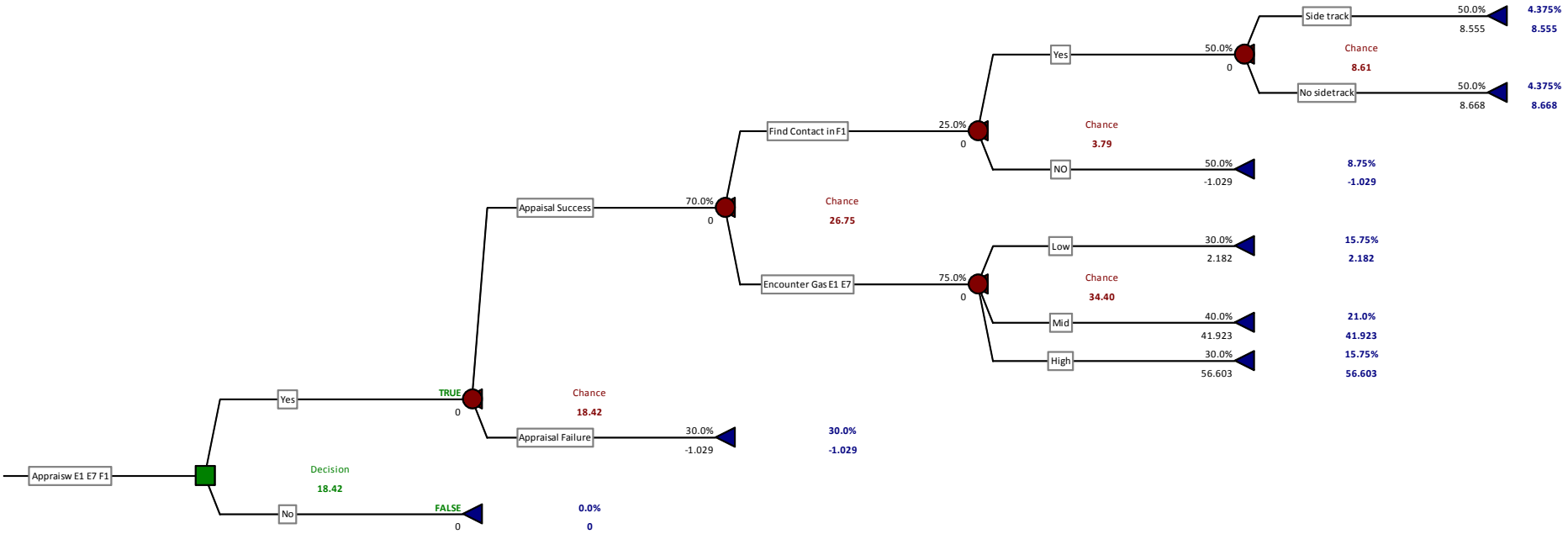
Howard Mackay

Asset Development Lead, Land East (UIG/T/DSLE)

Initiator:

Etokakpan, Eteobong

APPENDIX 1: FIG 1- Full ScopeUzu Appraisal Well DECISION TREE



APPENDIX 2: FIG 1-Full Scope Uzu Appraisal Well Flowline & Hook up Cost Sensitivity Chart