Group Investment Proposal

Summary Information

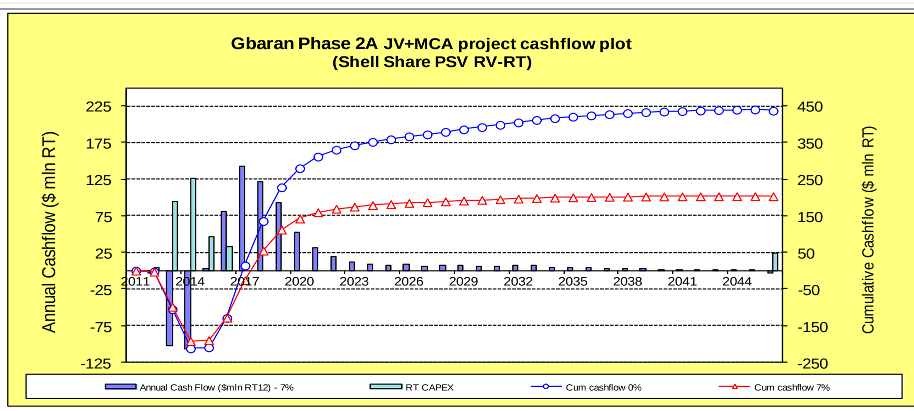
Business unit and company	Shell Petroleum Development Company of Nigeria Limited (SPDC)
Group equity interest	100% in SPDC, whereas SPDC is the Joint Venture (JV) operator of an unincorporated JV with a 30% interest.
Other shareholders / partners	Nigeria National Petroleum Company (NNPC: 55%), Total Exploration and Production Company Nigeria (TEPNL 10%), Nigeria Agip Oil Company (NAOC: 5%)
Amount	US$533.7mln Shell share, MOD, 50/50 is requested for approval in this proposal of the 100% JV estimate of US$831.8mln. US$93.1mln 100% JV has been approved in the Pre-FID proposals. This proposal includes Shell equity share (30%) of US$249.5mln and Shell's MCA commitment on NNPC Share of US$284.2mln
Project	Gbaran Infill (GU2A).

Main commitments

Description	Previously approved (100% JV)	Requested Budget (100% JV)	Complete Budget (100% JV)	Complete Budget (30% Shell Share)	Total NNPC MCA Carry (36.67% Shell Share)	Total Shell Share (Equity + Carry)	This Proposal NNPC MCA Carry (36.67% Shell Share)	This Proposal (30% Shell Share)	Total Shell Share (Equity + Carry) This Proposal
NAG Wells	46.3	213.2	259.5	77.8	89.3	167.1	78.2	64.0	142.1
Facilities & Pipelines*	46.1	605.6	651.7	195.5	207.7	403.2	206.0	181.7	387.7
Total CAPEX ($ mln)	**92.4**	**818.8**	**911.2**	**273.3**	**297.0**	**570.3**	**284.2**	**245.6**	**529.8**
SCD	0.7	13.0	13.7	4.1	0.0	4.1	0.0	3.9	3.9
Total OPEX ($ mln)	**0.7**	**13.0**	**13.7**	**4.1**	**0.0**	**4.1**	**0.0**	**3.9**	**3.9**
Total Project ($ mln)	**93.0**	831.8	924.8	277.4	297.0	574.4	284.2	249.5	533.7

*Includes PMT cost of US$45.9mln 100% (US$13.8mln SS) and Pre-FID cost of US$39.5mln 100% (US$11.9mln SS) which are not included in the MCA SS calculations - refer to Tables 2 & 3 in Appendix

Reserves / Resources:	The project will mature economic 2P reserves of 360.4Bscf Shell Share (10.2bln sm3) gas and 4.0MMstb of NGL (Shell share) to production and transferring equivalent SEC proved reserves from Proved Undeveloped (PUD) to Proved Developed (PD) with positive impact on SPDC's Reserves addition. The transfer of PUD reserves to PD will commence in 2014 with 19.8Bscf (0.56bln sm3) of gas and 0.7MMstb of NGL (Shell share) respectively
Production	Incremental gas production from this project peaks at 426.4MMscf/d with associated condensate production of 5.6kbopd (164.2MMscf/d and 2.1kbopd Shell share) in 2018, this would sustain gas supplies to the Gbaran CPF and meet SPDC JV gas supply commitments to NLNG Trains 1-6.
Source and form of financing	This project is to be financed via the Alternative Funding (AF) mechanism. The premise for this proposal is the Modified Carry Agreement (MCA) funding vehicle and the proposal is a part of the Gbaran-Ubie 2 MCA bundle.
Summary cash flow (Shell Share)	See chart below



Note: SPDC Upstream only (Midstream NLNG not included)

Summary economics (Shell Share)	Summary Economics (RV-RT12)	NPV7 (USD mln)	RTEP (%)	VIR7
	Base case	203.3	25	0.46
	High Capex	196.4	22	0.40

Section 1: The Proposal (Management Summary)

1.1 Management Summary

This Group Investment Proposal requests approval for funding of US$533.7mln Shell Share (US$249.5mln Equity & US$284.2mln Carry) for the execution of the Gbaran Infill Project, which aims to develop 1.3Tscf of gas to keep the Gbaran Central Processing Facility (CPF) full to meet the SPDC JV gas supply commitment to NLNG trains 1-6 and Domestic gas users. The project P50 cost estimate 100%JV is $924.8mln and P90 100%JV is $1,002mln

RDS Board support for this project was secured in December 2012 as part of the GU2 MCA (Modified Carry Agreement) Project bundle. Tables 4 & 5 in Appendix 2, show that this GIP is aligned with the board approved GFP, in which it was stated that individual investment proposals for the projects part of the Bundle would be approved at the right authority level, for a Final Investment Decision (FID). With the Modified Carry Agreement now signed 16 May 2013 between NNPC, NAOC, TOTAL and SPDC agreeing the financing mechanism, this FID support is now requested.

The JV Partners (NAPIMS & IOCs) have been engaged and are aligned on the cost estimates (facilities, wells and owners cost) and delivery schedule. The funding vehicle is the agreed Modified Carry Agreement (MCA).

1.2 Project Background

The Gbaran Infill Project is part of the initial Gbaran-Ubie Phase 2 project, which passed DG3 in July 2007. After completing FEED in December 2008, the project was put on hold due to funding constraints until a reframing workshop was held with Joint Venture Partners in March 2009. The reframing workshop resulted in splitting the Gbaran-Ubie Phase 2 project into three separate opportunities (a) Gbaran Infill - GU2A (Gbaran, Koroama, and Epu fields) (b) Kolo Creek Deep Field development to Soku - GU2B, (c) Ubie/Oshi field development - GU2C. The split minimized overall capital investment, optimized SPDC's infrastructure usage, and provided better focus for the individual sub-opportunities. The Project passed VAR4 in September 2011 and all high urgency actions have been successfully closed out

The scope of the project includes the drilling and completion of 11 NAG wells: 1 well in Gbaran field; 7 wells in Koroama field (includes an appraisal and re-completion of an existing appraisal well); and 3 wells in Epu field (2 of which are appraisal/development). The project will also install process and utility facilities at the remote manifolds/well locations, approximately 45 km of pipelines and 40 km of inter-site High Voltage/Fibre Optic Composite (HV/FOC) cables linking the remote well locations to the Gbaran CPF. At the Gbaran CPF, slug catchers, associated process and utility tie-ins, pipeline end-facilities and 2 additional 10MMscf/d booster compressors will be installed.

The Detailed design for the facilities was completed in 2011, in line with the contracting strategy agreed with NAPIMS that design must be completed prior to receipt of the commercial bids. Tendering of the procurement and construction scope was concluded in 2012. The award recommendations (package 1 and 2) have been approved by NAPIMS Contract Review Committee (CRC) and NNPC GEC and are awaiting NNPC board approval.

All the wells for the project are on the approved drilling sequence. However, in order to optimize the Koroama drilling campaign, Koroama-6 well (TBUV-2) was drilled in Oct 2012 along with the Gbaran Phase 1 wells (TBUR1, 2 & 3) as an early opportunity which will be hooked up to existing facilities installed by the Gbaran Phase 1 project – the well is expected to be on-stream by Oct 2013. The Koroama-2 appraisal well was also re-completed as a producer in January 2013 and the Gbaran VZTX-2 well was drilled/completed in February 2013. The balance Phase 2 Koroama wells are scheduled to be drilled between September 2013 and July 2014 while the Epu wells will be drilled in 2014 and 2015.

1.3 Targets

Economics evaluation was based on BP12 production forecast and maturation schedule which had FID in January 2013 and P50 RFSU in December 2014, December 2015 and August 2016 for Gbaran VZTX2, Koroama and Epu respectively. However, due to the delay in concluding MCA discussions, FID has been revised to June 2013 with attendant impact on project P50 RFSU dates. The Gbaran well (VZTX2) is now scheduled to come on-stream in April 2015, with Koroama and Epu coming on-stream in February 2016 and December 2016 respectively. The project cost and schedule targets are outlined in Table 1 below while the detailed project scope and life cycle costs are shown in Appendix 2.

	P50	P90
Total Project Cost (F$mln)		
Capex + Opex	925	1002
RFSU (Surface facilities completed, wells drilled & hooked up)		
Gbaran C4 - VZTX2	Apr-15	Oct-15
Koroama	Feb-16	Jul-16
Epu	Dec-16	Apr-17

Table 1: Project Targets

1.4 Previous proposals

A total of $27.9mln (Shell share) has been previously approved for this project which is made up of:

1. Pre-FID IP of $16.6mln (Shell share) approved in April 2010 for detail design, survey, location preparation for Koroama field, land acquisition, Environmental Impact Assessment studies and line pipe pre-payment. The approval also covered the Gbaran Infill Project's share of the initial Gbaran-Ubie Phase 2 project sunk costs related to Front-End Engineering Design. Of these planned activities, land acquisition and location preparation works are still ongoing

2. US$11.3mln Shell share investment consisting of US$8.01mln approved in August 2012 to accelerate the drilling, completion and hook-up of Koroama 6 (TBUV-2) NAG well as an early opportunity and US$3.29mln approved in November 2012 for the re-completion of the KOMA 002T well which was accelerated as a result of location imposed constraints (inaccessibility of planned well locations as a result of flooding and unusually high water levels)

Section 2: Value proposition, strategic and financial context

The proposal aligns with the SPDC JV contractual commitment to supply gas to NLNG.

2.1 Justification for Expenditure

This proposal seeks approval of funding to cover the drilling of nine (9) of the eleven (11) NAG wells (drilling of Koroama TBUV2 and Koroama 2 recompletion are covered under separate GIPs - ref section 1.4 above) as well as the installation of the pipelines and facilities required to produce the wells to the Gbaran CPF. These activities must be progressed to keep the Gbaran CPF full and avoid penalties for not meeting SPDC JV gas contractual commitments to NLNG Trains 1-6 (See Fig 1) and domestic gas supply.

2.2 Production and Reserves

The Project will develop 1.3Tscf of gas and 13 Mmbbls of condensate from the Gbaran, Koroama, and Epu fields to sustain gas supplies to the Gbaran CPF and meet SPDC JV gas supply commitments to NLNG Trains 1-6 and domestic gas supply.

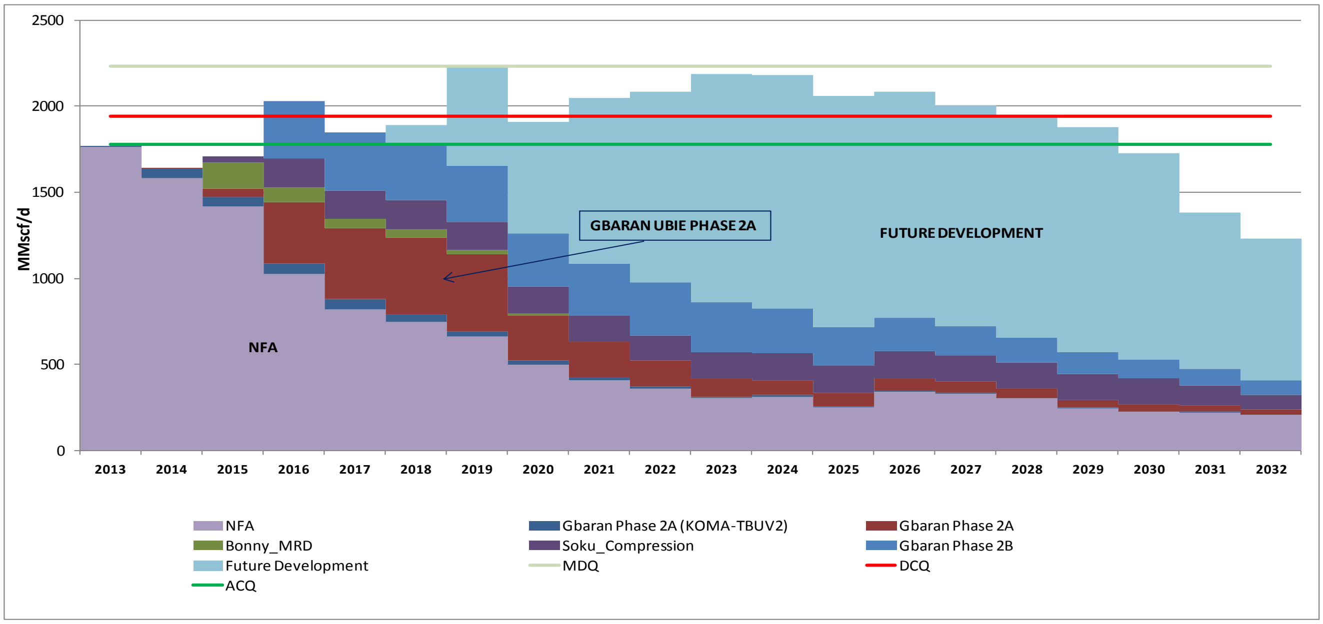


Figure 1: NLNG Trains 1 to 6 supply Profile

2.3 Summary Economics

The FID economics evaluation was carried out on a forward-looking basis using production forecast and contractors cost provided by the project team. Sensitivity analysis was carried out to determine the values of the project at different production volumes and high CAPEX. Analysis has confirmed that the project returns a positive NPV against a wide range of risks and uncertainties. The evaluation assumed funding under the agreed Modified Carry Arrangement (MCA) terms with full Shell share costs reflected (Shell equity + Shell share of the Carry). Economics is Upstream only (does not capture midstream value) and is based on 2012 PSVs.
The details of the results are in Table 1 and the Tornado Plot and Profitability Plots are shown in Figures 2 & 3 in Appendix 1.

PV Reference Date: 1/7/2012	**NPV (S/S $ mln)**		**VIR**	**RTEP**	**VTE**	**UTC (RT $/boe)**		**Payout-Time (RT)**	**Maximum Exposure (RT- AT)**
Cash flow forward from: 1/1/2012	**0%**	**7%**	**7%**	**%**		**0%**	**7%**	**(yyyy)**	**$mln (yyyy)**
Base Case									
SV ($50/bbl RT12)	318.3	**135.2**	**0.30**			4.6	6.3		
RV ($70/bbl RT12)	437.3	**203.3**	**0.46**	25		4.6	6.3	2018	*192.4(2014)*
HV ($90/bbl RT12)	534.0	**258.7**	**0.58**			4.6	6.3		
Sensitivities (using RV-RT12)									
Low Volumes (P90)		**66.5**	**0.15**						
High Volumes (P10)		**266.0**	**0.60**						
High CAPEX (P90)		**196.4**	**0.40**						
Project funded under JV		**207.4**	**1.01**						
1.5% cost markup due to BVA		**192.6**	**0.40**						
1 Year Production Delay		**186.4**	**0.42**						
PIB		**16.5**	**0.04**						
Additional Uncertainty and Risk Analysis - using RV ***(only required for proposals > $ 300 mln S/S)***									
NPV(P10)		**265.7**	**0.61**						
NPV(P90)		**77.4**	**0.17**						
EMV at RV		**180.6**							
Probability of NPV > 0 at RV		**97%**							
Dispersion = EMV / (NPVP10-NPVP90) at RV		**0.96**							

Table 2: Summary economics grid for Gbaran Infill Project

Parameter	Unit	BP12 Provision	Low	Mid	High	Comments
Capex (MOD)	US$ mln	531.6	487.5	529.8	591.4	JV +MCA
Opex (MOD)_Project	US$ mln	NA	38.0	72.1	115.9	ABC + SCD
Production Volume	mln boe	68.7	23.9	62.4	118.6	latest Data set as per ARPR
Start Up Date	mm/yy	Dec-14	NA	Dec-14	NA	
Production in first 12 months	mln boe		5.2	5.1	4.8	The optimizer pulls more volumes from the Low and Base cases to ensure that the CPF is kept full, hence the higher volumes in the 1st

Table 3: Key project Parameters (Shell share) used for the economics analysis

The economics for the entire GU2 MCA Project Bundle, as approved by the RDS Board in December 2012, for the upstream and midstream (NLNG) elements is summarized below, and are still the same for the overall project MCA bundle:

	Upstream Only		Integrated Up/Midstream	
Summary Economics (RT12)	NPV7 ($mln)	VIR7	NPV7 ($mln)	VIR7
Base case (RV-RT $70/bbl)	706	0.54	1656	1.26
Base case (HV-RT $90/bbl)	903	0.69	2038	1.55
PIB case (RV-RT $70/bbl)	91	0.07	1041	0.81
PIB case (HV-RT $90/bbl)	168	0.13	1303	1.01

Section 3: Risks, Opportunities and alternatives

3.1 Risks and Mitigation Plans

The project employs a comprehensive Risk and Opportunity Management system, with Risks affecting the Cost and schedule analyzed and worked into the project cost estimate and schedule accordingly. The top project risks and mitigation plans are described below.

NNPC Cost Overrun Risk

MCA funding is available for the P50 cost as agreed in 2012. With the project having other material risks to be mitigated, any overrun on the P50 estimate will trigger funding challenges

Mitigation: Enforce rigorous cost control & Management of Change process. However, in a situation where overrun of the cost in the AF (MCA) agreement is envisaged, NAPIMS and IOC Partners will be engaged and upon agreement, additional budget will be sought from equity contribution of the JV Partners via the base JV budget or Carrying Parties (IOCs) in line with the AF (MCA) agreement. All efforts will be made to ensure that any cost overrun can be justified for base JV funding.

Petroleum Industry Bill (PIB)

For over 10 years now Nigeria is considering to change their Petroleum Laws (PIB) including fiscal terms. A sensitivity based on the July 2012 PIB draft version, which was submitted to the National Assembly for consideration, was carried out as part of the economic evaluation. It showed the project will not meet the screening hurdle rates (upstream only) if this version of the PIB is passed into law. It should be noted that on an integrated bases (including the Shell share midstream NLNG value) the projects are still attractive and will meet the screening hurdle rates even under the PIB July 2012 version (as indicated in the economic table above under 'PIB case').

Mitigation: The Shell PIB team in collaboration with Industry Group (OPTS/CIG) have combined to continue dialogue and engagement, based on a structured and detailed plan across all stakeholders group locally and internationally. The government has openly acknowledged the need for an investment friendly Act and changes are being collated for submission to the National Assembly (parliament). If indeed a PIB passes during the present administration (election planned in 2015) which is still highly uncertain, it is reasonable to assume a more investor friendly PIB will emerge in the end.

HSSE & SP Risks:

The safety and environmental risks of executing relatively complex project (project transverses land and seasonally swamp terrains across several communities) have been identified and assessed using the HEMP processes /tools. The threats, controls measures, and, recovery measures have been identified, with responsible action parties assigned. In addition, HSSE requirements were included and evaluated during the tendering process. The project will emphasize strong HSSE Leadership by SPDC and Contractor Management team as well as leverage on lessons learnt from Gbaran Ubie Phase 1 project, and successful HSE initiatives such as the Injury Free Club.

Land Acquisition

Acquisition of land required for right-of-way is yet to be completed. The Lands Compensation Board has approved rates for compensation of the land owners and discussions with the Land owners have been completed. Payment has been initiated. Ideally land acquisition should be completed prior to FID as land owners' leverage increases considerably afterwards.

Mitigation: Expedite compensation payment to land owners

Risk of Hydrocarbon under pressure (Gas): Project involves Brownfield construction and commissioning at the Gbaran CPF and existing remote locations. Approved Concurrent operations plan and Matrix of Permitted Operations (MOPO) will be enforced, including robust procedure for managing hydrocarbons under pressure (Gas), Permit To Work system, positive isolation requirements, gas testing, equipment selection/certification and 100% site supervision.

Transportation Risks (Land and Marine): A journey management procedure and plan will be instituted with Journey Managers appointed to implement the procedures. Monitoring systems and feedback processes will be in place for continuous improvement. In addition, every journey request will be challenged, and optimized where possible, to reduce exposure. Prior to embarking on any journey, the Security Operating Level (SOL) shall be confirmed.

Security Risk: The project is located in the Niger Delta, where security issues are particularly significant. This is highlighted by cases of hostage taking, armed attacks and sabotage of pipeline systems. Additionally, deteriorating Security situation in the Northern part of the Country, in the form of targeted bombing, could migrate southwards and requires that this risk be carefully monitored

Mitigation: The amnesty programme of the federal government had helped to calm the security situation in the Niger Delta although uncertainty still pervades. Based on the outcome of security risk assessment, a detailed project security plan for the project has been developed which dovetails into relevant corporate operational security plans. The security operating risk level will be assessed regularly when there is a change in risk level, contingency action will be initiated

All identified mitigation measures will be backed up by emergency response preparedness, on the part of the contractors and SPDC depending on severity.

The flowlines and pipelines are inter-field lines transporting unprocessed fluid from the wellheads to the Gas Supply Plant at Soku. As there is no record of attack on inter-field gas lines (probably because they do not transport processed Condensate), the lines will be laid 1.5m below grade as per standard construction specification. However, surveillance contracts which have so far proven to be effective for inter-field gas lines will be put in place for the new lines.

Community related Risks

The project straddles 11 communities; hence the community stakeholder base is large, diverse and includes new impacted communities in Epu where there is no existing GMoU. In addition, there are delays in completing some

Gbaran Phase 1 GMoU Projects, which may lead to work stoppages and reputational damage. There is also a risk of community agitations outside agreed GMOU terms that could lead to delay and cost growth.

Mitigation: Community interfaces will be managed through the Global Memorandum of Understanding (GMoU) mechanism (as detailed in the project SP Plan); this will be deployed in alignment with the project schedule. GMOU is in place for all communities along the pipeline right of way except Epu where a Project GMOU is being negotiated. Also an allowance has been made in the project budget for funding of social investment programmes. Contractors were also directed to engage labour unions for applicable wages in all work areas and use in estimating project management costs in contract bids while reference to wages have been expunged from the GMoUs.

Contractor Capacity

The project work scope is divided into two work-packages for Facilities (Package 1) and Pipelines/flowlines (Package 2). The facilities scope has been recommended for award to Daweoo whilst the flowline and pipeline scope has been recommended for award to Morpol/Jaihind/Zakhem JV who have no experience installing pipelines for SPDC.

Mitigation: Additional SPDC project management resources will be mobilized to support the Morpol/Jaihind/Zakhem JV. In addition, contractor's performance will be monitored closely to enable early intervention on appearance of any red flags.

NNPC Award Approvals for EPC Contracts

To safeguard the project schedule it is necessary to award the contract packages by Q2 2013. The award recommendations have been submitted to NAPIMS and received the endorsement of the NAPIMS Contract Review Committee (CRC) and NNPC GEC pending NNPC board approval. The approval protocols within NAPIMS/NNPC can take upwards of 6-12 months to process and contract award ahead of the formal NNPC approval could expose Shell to cost recovery issues (if NAPIMS declines to honour cash calls or approve end of year performances at OPCOM).

Mitigation: SPDC will continue engaging NNPC to ensure alignment of project priorities and urgencies. Recent experience shows low probability of NNPC Board not approving proposals that have passed and obtained the endorsement of the NAPIMS CRC (tender board) & NNPC GEC (Group Executive Committee).

Need for sufficient tax base of SPDC Ltd

The MCA recovery mechanism is largely dependent on having a sufficient tax base within SPDC Ltd to absorb the capital allowances associated with the carry amounts. Analysis shows that SPDC Ltd has sufficient tax base to recover the MCAs and achieve the desired IRR of 8% at/or above US$1.56m/scf RT12 based on the BP12 production forecast, which is well below RV price assumptions.

<u>Opportunities</u>

The project scope includes the drilling of the Koroama SPUU-1 appraisal well, which will be completed and hooked up if successful. The potential production volume of 100MMScf/d for this well has not been accounted for in the project base case economics and therefore represents an upside.

<u>Alternatives</u>

SPDC has committed to supply NLNG (trains 1 to 6) for a 20-year period and gas supply to the CPF, which is expected to deliver about half of the required volumes, will decline from 2013. The alternative to developing the Gbaran Node further development is to develop the Gbaran Deep reservoirs. However these projects are still in the exploration stage. Efforts are being made to align these Gbaran Deep exploration wells with the Gbaran Ubie projects to save costs and to be able to hook-up these exploration wells up if prospects are promising.

Section 4: Carbon Management

Green House Gas (GHG) Emissions for the Gbaran Infill Project over a 25 year period is estimated at 227,000tonnes of CO_2Eq; for an expected average production of about **24,000 bpd** (net condensate) and **450MMscf/d NAG**. Combustion emissions are the main source of emission amounting to about 70% of the total emissions. Fugitive emissions account for 29% while Venting due to routine maintenance and depressurization accounts for the remaining 1%. Over a forecast period of ten years, projected energy intensity is 49 Kg CO2 Equivalent per tonnes of hydrocarbon produced. Regarding GHG emissions and energy consumption, this project is considered ALARP.

Section 5: Corporate structure, and governance

The existing corporate structure and governance arrangements of SPDC-JV with SPDC as operator still subsist for this investment.

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

This proposal complies with Shell Group Business Principles, policies and standards. Functional support for this proposal is provided by Projects & Technology (P&T), Finance, Social Performance, Contracting & Procurement, HSE, Operations, Legal, Security, Treasury, Controllers and Tax functions. Reserves/Production/HCM confirmation and the Cost / Schedule Fact sheets have been duly signed off and available in the file.

Section 7: Project management, monitoring and review

Project Assurance is in place for all work scope and management of change. The Opportunity Assurance Plan (OAP) has been established and signed off by the Decision Executive, with active roles for Partners, UI Nigeria and P&T. This is a "P&T executed" project with P&T being accountable for the delivery of technical project integration and execution. A DRB with UI Nigeria and P&T participation is in place. A TQ plan is in place and approved by the DE. Key gaps have been identified and a gap closure plan put in place and being worked.

Section 8: Budget Provision

At FID, the project budget requirement will be from the alternative funding tranche. In line with current AF agreements, it is expected that project FID OPEX and project management costs will continue to be funded via the regular JV budgetary process.

Section 9: Group Financial Reporting Impact

MCAs are accounted for in the same way as ordinary course investments in JV projects i.e. recording resulting CAPEX, depreciation, gross revenues, royalties and taxes and associated production and reserves in line with Group Policy. The financial impact of the project is calculated in line with the base case MCA specific assumptions and is indicated in the table below.

US$ mln	2012	2013	2014	2015	2016	Post 2016
Total Commitment	4	76	190	159	72	32
SCD OPEX	0	1	1	1	1	0
Pre-FID	0	0	0	0	0	0
Cash Flow						
Capital expenditure	4	75	189	158	71	32
Cash Flow from Operations	1	23	64	89	142	745
Cash Surplus/(Deficit)*	-3	-52	-125	-69	71	713
Profit and Loss						
NIBIAT +/-	0	3	10	31	79	431
Balance Sheet						
Average Capital Employed	2	31	126	244	298	69

Table 3: Financial implications of the Project

Section 10: Disclosure

Material disclosures, if any, will be done in line with the Group Disclosure Guidelines.

Section 11: Financing

The pre-FID portion of this investment has been financed with JV funding. Financing for the main project scopes shall be through the MCA funding mechanism. NNPC approval has been obtained for project scope and cost and MCA signed-off by all JV partners.

Section 12: Taxation

MCAs are no longer unusual in the oil and gas fiscal structure with the FIRS. SPDC Ltd will ensure that all information required for the tax return and tax audit robustness can be accessed. Relevant tax/fiscal risks are as discussed under Section 3 above.

Section 13: Key Parameters

Approval is sought for additional US$533.7mln (Shell Share), for the drilling/completion of 9 NAG wells and the construction of infrastructure for evacuation of production to the Gbaran CPF.

Section 14: Signatures

This Proposal is submitted for approval.

Supported by:

Simon Henry
ECSH Chief Financial Officer
Date 10/06/2013

For Shareholder Approval:

Peter Voser
CEPV Chief Executive Officer
Date 13/06/2013

Sponsor:

Andrew Brown
Upstream International Director
Date 07/06/2013

Sponsor:

Matthias Bichsel
Projects & Technology Director
Date 01/06/2013

Initiator: Toyin Olagunju, SPDC GM Major Projects

Appendix 1: Assumptions

Economics Assumptions

- Oil PSVs of $50/bbl @SV-RT12, $70/bbl @RV-RT12 (Base) and $90/bbl @HV-RT12 with Bonny offset applied.
- 2012 NLNG T1-6 price was used for gas sales to NLNG.
- Education Tax of 2% assessable profit.
- NDDC levy of 3% total expenditure.
- Gas Heating Value (GHV) of 1150btu/scf for Export gas.
- Flare Penalty of $3.5/Mscf was applied and is not tax deductible.
- Abandonment estimated as 10% of total RT CAPEX.
- Condensate was treated as oil and taxed under Petroleum Profit Tax - PPT (PPT tax rate of 85%).

MCA Assumptions

- Profit gas ceiling of 8% IRR on carried costs.
- All costs on the MCA would be recovered through carry tax relief, cost Gas and Condensate
- $70.22/bbl – Condensate at PSV RV-RT in 2012.
- OPEX and PMT not carried under current MCA arrangement.

PIB assumptions

- PIB as per July 2012 draft version
- Gas royalty rate increased from 7% to 12.5%
- Gas tax rate increased from 30% to 80% (NHT 50% and CIT 30%)
- No ITA

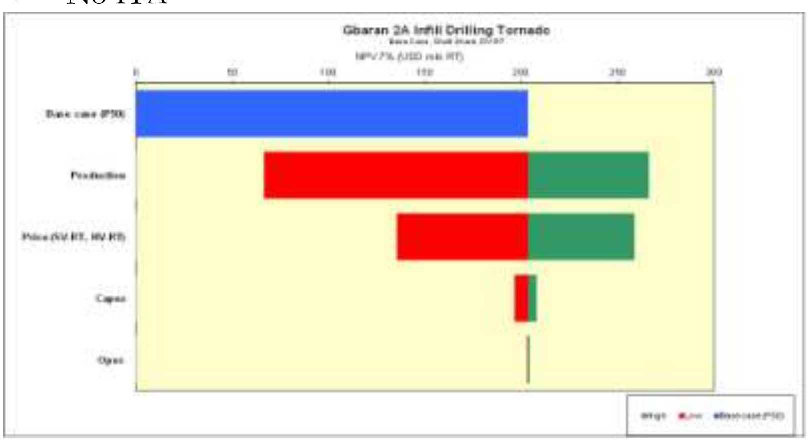


Figure 1: Tornado Chart

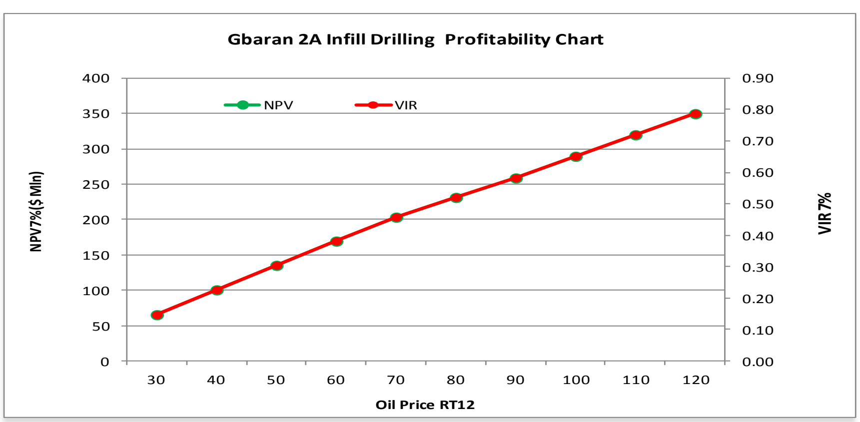


Figure 2: Project Profitability Plot

Appendix 2: Scope and Cost Estimate for the Gbaran Infill Project

SCOPE

A. Wells

1. Drilling of Eleven (11) NAG wells from three fields (1 in the Gbaran, 7 in the Koroama; including the Kororama SPUU-1 appraisal well, and 3 in Epu)

B. Gbaran CPF & Remote Sites Facilities – Package 1 Contract

1. Construction of facilities at 6 remote well locations, including (on-plot) DSS piping, and utilities, Field Auxiliary Rooms, Electrical substations/RMU, drain vessels & vents stacks, corrosion inhibition packages, utility water storage and distribution systems, etc.
2. Installation of two (2) 55m microwave towers and telecommunication infrastructure at Epu-1 and Koroama manifold areas, including telecom cabinets PAGA and CCTV and radio field equipments.
3. Installation of CCTV, LAN/WAN, microwave and phone systems for all the remote locations.
4. . Installation of 2 x 10MMscf/d booster compressors, and two slug catchers at the Gbaran CPF and tie-in to the existing process, electrical, control and safeguarding systems

C. Pipelines and Inter-Site Composite Cables – Package 2 Contract

1. Construct of seven carbon-steel pipelines totaling approximately 45km linking the remote well locations to the existing Gbaran CPF. (pipelines dimensions are 1 off 8km x 10-inch, 2 off 5.5km x 8-inch, 2 off 6km x 12-inch, 1 off 5.0km x 6-inch, and 1 off 4.2km x 10-inch)
2. Install a 40km network of HV/Fiber Optic inter-site composite cables linking the remote well locations to the existing Gbaran CPF (1 x 8km, 2 x 5.5km, 1 x 6km, and 1x 4.2km)

D. Accelerated scope

1. Drilling, completion and hookup of 1 NAG well (TBUV2)
2. Recompletion of 1 NAG well (Koroama 002T)

COST ESTIMATE

The cost estimate (MOD 100% JV) for the full scope Gbaran Infill Scope is as shown below.

Description	(US$ mln)
Location Preparation, Drilling and Completion	259.5
Pipeline and Hook-up	66.4
NAG Facilities* (inclusive of PMT, VAT & Owners Cost)	585.3
Total CAPEX (100% JV)	**911.2**
SCD	13.7
Total OPEX (100% JV)	**13.7**
Total (100% JV)	**924.8**
Total (Shell Share)	**533.7**

Table 1: 50/50 MOD Cost Estimate (US$ mln)

PRIOR APPROVALS				
F$mln	**Pre-FID**	**TBUV2**	**Koma 002T**	**Total**
Facilities	39.5	4.5		44.0
Wells	15.9	19.4	11.0	46.3
PMT		2.1		2.1
SCD		0.7		0.7
Total	**55.4**	**26.7**	**11.0**	**93.1**
Shell Share Equity (30%)	16.6	8.0	3.3	27.9
MCA Carry Shell Share (36.67%)		8.8	4.0	12.8
Total Shell Share	16.6	16.8	7.3	40.7

Table 2: Prior Approvals (FUS$ mln)

Description	COST PHASING						
	2012 (Incl TBUV2 & Koma 002T)	2013 (Incl TBUV2)	2014	2015	2016	Total	Total (Incl Prior approvals)
Facilities Capex 100% JV (FUS$mln) - less PMT& SCD	2.0	74.6	213.5	193.0	83.2	566.3	605.8
Wells Capex 100% JV (FUS$mln)	30.4	90.1	123.0	0.0	0.0	243.6	259.5
Total Capex 100% JV (FUS$mln) - less PMT&SCD	32.4	164.8	336.5	193.0	83.2	809.9	865.3
PMT 100% JV (FUS$mln)	11.4	12.9	12.7	6.8	2.1	45.9	45.9
Opex 100% JV (FUS$mln)	0.6	3.8	4.5	2.7	2.1	13.7	13.7
Total 100% JV (FUS$ mln)	44.4	181.5	353.7	202.5	87.4	869.4	924.8
Total 100% JV (FUS$ mln) excluding Pre-FID & Prior Approvals							831.8
Shell Share Equity (30%)	13.3	54.4	106.1	60.7	26.2	260.8	277.5
MCA Carry Shell Share (36.67%)	11.9	60.4	123.4	70.8	30.5	297.0	297.0
Total Shell Share (FUS$ mln)	25.2	114.9	229.5	131.5	56.7	557.8	574.4
This proposal Total Shell Share excluding Pre-FID & Prior approvals (FUS$ mln)							533.7

Table 3: Yearly estimated expenditure (FUS$ mln)

Gbaran Ubie Phase 2 MCA 2 Projects	100% SPDC JV	Shell Equity Share	SPDC LTD MCA Share	Total Headline Size
Bonny NAG Minor Reservoirs Devt.	116	35	42	77
Gbaran Ubie 2A (C4+Epu+ Koroama+NB)	1018	305	352	657
Gbaran Ubie 2 B (Kolo Creek)	721	216	245	461
Soku NAG Compression	92	28	33	60
Soku Pipeline (All 4 loops)	460	138	159	297
Total – Gbaran Ubie 2 MCA 2 Bundle	2407	722	831	1553
All Values in $Million				

Table 4: Excerpt from Group Finance Proposal showing projects with the MCA2 Bundle

	BASIS FOR THE GFP				BASIS FOR THE INFILL GIP			
	100% JV cost	Shell Equity Share	SPDC Ltd Share	Total Headline Size	100% JV cost (GIP)	Shell Equity Share	SPDC Ltd Share	Current IP Request -
Total Infill project cost	925	277	339	617	925	277	339	617
Total NB project cost	165	50	61	110				
Total cost	**1,090**	**327**	**400**	**727**	**925**	**277**	**339**	**617**
Pre-FID (JV Funded)	(55)	(17)	(20)	(37)	(55)	(17)	(20)	(37)
SCD - Infill	(14)	(4)	(5)	(9)	(14)		(5)	(5)
SCD - NB	(4)	(1)	(1)	(2)				-
	1,018	**305**	373	678	856	261	314	574
PMT Element - Infill	(45)		(17)	(17)			(17)	(17)
PMT Element - NB	(10)		(4)	(4)				
Previously approved IP excluded from current request					(38)	(11)	(13)	(24)
			352	**657**	**818**	**250**	**284**	**533.7**

Table 5: Reconciliation between the GFP and the GIP

GLOSSARY

AF – Alternative Funding

CPF – Central Processing Facility

DPR – Department of Petroleum Resources

DRB – Decision Review Board

ESFS – Estimate & Schedule Fact Sheet

FEED – Front End Engineering Design

GHG – Green House Gas

GMoU – Global Memorandum of Understanding

HEMP – Hazard & Effects Management Process

HSE – Health, Safety & Environment

HV – High Value

IOC – International Oil Companies

MCA – Modified Carry Agreement

MOD – Money of the Day

MOPO – Matrix of Permitted Operations

NAG – Non Associated Gas

NAPIMS – National Petroleum Investment Management Services

NCDMB – Nigerian Content Development Management Board

NLNG – Nigeria Liquefied Natural Gas Limited

NPV – Net Present Value

PIB – Petroleum Industry Bill

PMT – Project Management Cost

PPT – Petroleum Profit Tax

PSV – Project Screening Value

RFSU – Ready For Start Up

RT – Real Term

RTEP – Real Term Earning Power

RV – Ranking Value

SCD – Sustainable Community Development

STDWS – Short Term Drilling & Work over Sequence

SV – Screening Value

VIR – Value Investment Ratio