Memorandum to the Board of Royal Dutch Shell plc
Group Investment Proposal

Summary Information

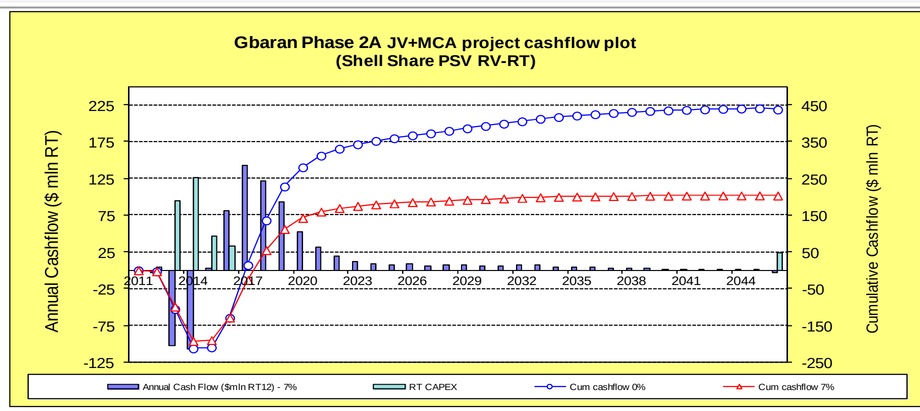
Business unit and company	Shell Petroleum Development Company of Nigeria Limited (SPDC)
Group equity interest	100% in SPDC, whereas SPDC is the Joint Venture (JV) operator of an unincorporated JV with a 30% interest.
Other shareholders / partners	Nigeria National Petroleum Company (NNPC: 55%), Total 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**

Source and form of financing	The source of funding for the project is being discussed with the JV partners; the proposal is for this investment to be financed via Alternative Funding (AF). 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)



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 SPDC JV gas supply commitment to NLNG trains 1-6 and Domestic gas supply.

RDS Board support for this project was secured in December 2012 as part of the GU2 bundle. Group CFO agreed that separate approvals of the individual GIPs by CEPV are not required as long as the overall headline size stays within the Board mandate. Tables 4 & 5 in Appendix 2, show that this GIP is aligned with the board approved GFP. The GIP is therefore proposed for sign-off by VP Projects Operated and VP Nigeria/Gabon

The scope of the Gbaran infill project includes 11 NAG wells: 1 well in Gbaran field; 7 wells in Koroama field (includes 1 appraisal and 1 appraisal re-completion); and 3 wells in Epu field (2 of which are appraisal/development). All the wells are on the approved short term drilling & workover sequence.

The project will also install 2 x 10MMscf/d booster compressors, two (2) slug catchers with associated process and utility tie-ins at the Gbaran CPF, six (6) remote sites with process and utility facilities, 40 km of inter-sites HV/FO composite cables, and circa 45 km of pipelines linking the remote well locations to the Gbaran CPF.

In a bid to optimize the Koroama drilling campaign, Koroama-6 well (TBUV-2) was drilled in Oct 2012 as an early opportunity and the Koroama-2 appraisal well was recompleted as a producer in January 2013. The balance of the Koroama wells is scheduled to be drilled between Jul 2013 and April 2014. The Gbaran VZTX-2 well is scheduled for spudding in February 2013, while the Epu wells will be drilled in 2014 and 2015

The facilities to produce the Gbaran well are scheduled to come on-stream in January 2015, with Koroama and Epu coming on-stream in December 2015 and August 2016 respectively with an estimated peak daily production in 2017 of 86kboe per day (455,315 Mscf/d of gas and 7,000 b/d of condensate). The detailed project scope and life cycle costs can be found in Appendix 2.

The project is in the Alternative Funding (AF) tranche in BP12. The JV Partners (NAPIMS & IOCs) have been engaged regarding the cost estimates (facilities, wells and owners cost) and alignment reached. Proposed funding vehicle is the Modified Carry Agreement (MCA). The agreed costs are as outlined in table 2 of appendix 2

1.2 Project Background

The Gbaran Infill Project is part of the initial Gbaran-Ubie Phase 2 project, which passed VAR3 in November 2006, DG3 in July 2007, and completed in-house FEED in December 2008 but was put on hold due to funding constraints until a reframing workshop with Joint Venture Partners in March 2009. The reframing workshop resulted in the splitting of the initial Gbaran-Ubie Phase 2 opportunity into three separate scopes (a) Gbaran, Koroama, and Epu fields (Gbaran infill), (b) Kolo Creek Deep Fields, (c) Ubie/Oshi filed) to minimize overall capital investment, optimize SPDC's infrastructure usage, and provide a better focus for the individual sub-opportunities.

Detail design for the Gbaran Infill project was completed in 2011, in line with the contracting strategy agreed with NAPIMS that required the completion of detail design prior to receipt of the commercial bids in support of the FID decision. Tendering of the procurement and construction scope has been concluded and the selected contractors known. Project VAR4 was completed in September 2011 and all high urgency actions have been successfully completed.

1.3 Previous proposals

In April 2010, a pre-FID investment proposal of $ 16.6mln (Shell Share) was approved 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.
In addition to the pre-FID approvals, US$11.3mln Shell share investment was approved consisting of US$8.01mln 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 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 and strategic and financial context

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

2.1 Justification for Expenditure

Having taken the opportunity to accelerate Koroama TBUV2 & Koroama 002T recompletion, this proposal only seeks approval for the drilling of eight (8) NAG development wells (including one appraisal well) in Gbaran (1 NAG development well), Koroama (4 NAG development wells and 1 appraisal well) and Epu (1 NAG development well and 2 NAG development/appraisal wells), as well as the installation of the infrastructure required to evacuate the production to the Gbaran CPF. These activities must be pursued 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 Gbaran Infill 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.

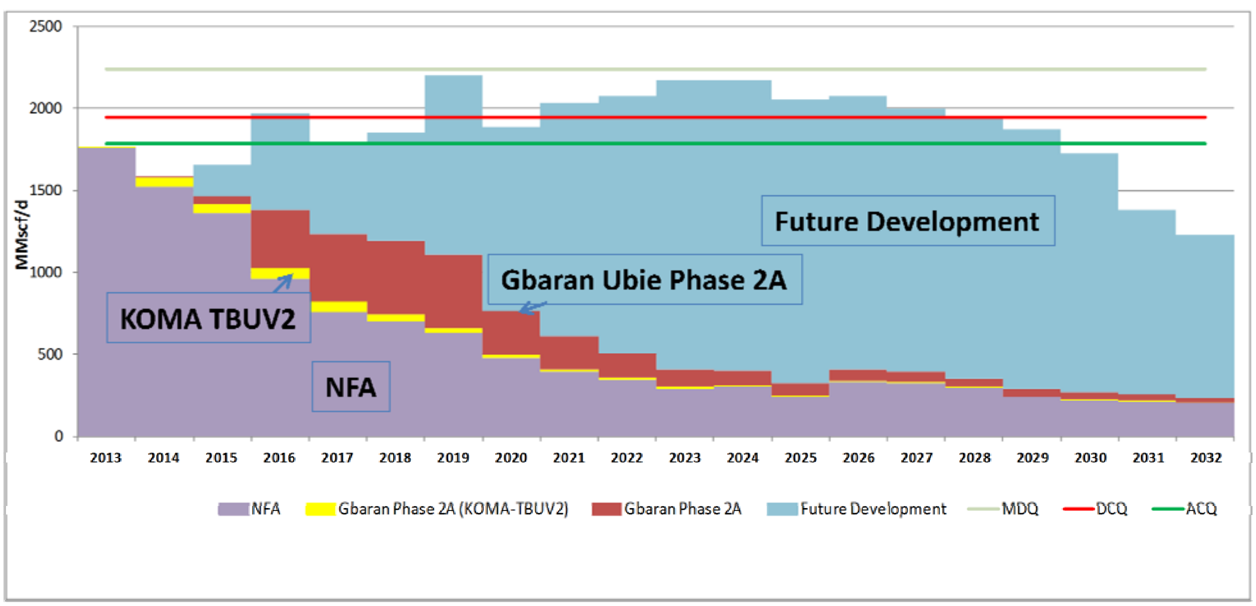


Figure 1: NLNG Trains 1 to 6 supply plot

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 2008 Modified Carry Arrangement (MCA) terms.

The details of the results are in Table 1 and the Tornado Plot and Profitability Plots are shown in Figures 2 & 3 in the appendix.

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**						
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 1: 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 2: Key project Parameters (Shell share)

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 Funding constraints risks (C, E)

The proposal is for this project to be financed via Alternative Funding (AF) as agreed with Joint Venture Partners. However, the MCA agreement is yet to be signed off by the JV Partners

Mitigation: Approval for this Investment proposal is premised on the MCA agreement being in place. Based on level of progress achieved on the funding discussions with the JV Partners, there is a high probability of the MCA/Funding being in place by Jan 2013. The final requirement for the MCA sign-off (which is the NAPIMS CRC support for the execution contract award) is being worked.

HSSE & SP Risks (P, T):

HSE risks of executing relatively complex project (project transverses land, seasonally swamp and swamp terrains across several communities) have been identified and assessed using the HEMP processes /tools. Upon analysis, the threats, controls measures, top events, recovery measures were identified, with responsible action parties assigned. In addition, HSSE requirements were included and evaluated during the tendering process. The project will develop strong HSSE Leadership by SPDC and Contractor Management Team as well as leverage on National and SPDC corporate security plans, lessons learnt from Gbaran Ubie Phase 1 project, and successful HSE initiatives such as the Injury Free Club. A few Examples of the top risks includes: Risk of Hydrocarbon under pressure (Gas); Transportation (Land & Marine); Lifting and Hoisting; Security etc:

Risk of Hydrocarbon under pressure (Gas): Project involves work at the Gbaran CPF. Approved Concurrent operations plan and Matrix of Permitted Operations (MOPO) will be enforced, including robust procedure for managing Hydrocarbon under pressure (Gas) alongside Permit to work system, Positive isolation requirements, Gas testing, equipment selection/certification with 100% site supervision, etc.

Risk of Transportation (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, especially, pipeline systems. Additionally, deteriorating Security situation in the Northern part of the Country, in the form of targeted bombing, could migrate down south and requires that this risk be carefully monitored

The amnesty programme of the federal government has helped to calm the security situation although uncertainty still pervades. Based on outcome of security risk assessment, a detailed project security plan for the project has been developed which dovetails into relevant operations security plan. The security operating level of risk will be assessed from to time to determine necessary line of action when there is a change in risk level.

In the event of unforeseen incidents, all of the identified mitigation measures are backed up by emergency response preparedness, both on the part of the contractors and in collaboration with SPDC depending on severity.

Community related Risks (P)

The project straddles 11 main communities; hence the community stakeholder base is large and diverse. Also there are delays in completing some Gbaran Phase 1 GMoU Projects, deploying GMOUs (Steady State) in the Operating areas, and the fact that project will impact new activity area (Epu) may lead to community agitations, 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. 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 (T, O)**

  The high activity level and limited EPC contractor base puts pressure on contractors' capacity as they are involved in executing multiple contracts at the same time, and lead to Government pressuring IOCs to contract out with untested local emerging contractors in the effort to build local contractor base capability.

  Mitigation: The project work scope has been divided in two separate work packages. Package 1 covers the facilities scope, which drives the project schedule, and Package 2 covers the flowlines and pipelines scope. The facilities scope has been recommended for award to a contractor with experience of working with SPDC whilst the flowline and pipeline scope has been recommended for award to a contractor that will be working for SPDC for the first time. The Contractors' capacities will be reviewed prior to mobilization to site and additional SPDC project management resources mobilized to support the package 2 contractor. In addition, contractor's performance will be monitored closely to enable early intervention on appearance of any red flag.

NNPC Award Approvals for EPC Contracts (C, E)

To safeguard the project schedule it is necessary to award the contract packages by Q1 2013. The commercial bids have been evaluated and award recommendation made to NAPIMS. However, 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 has and will continue to maintain close and rigorous engagement with NAPIMS to ensure common understanding of project priorities and urgencies. There is also a high chance of NNPC GEC /Board approvals for proposals that have passed and obtain the endorsement of the NAPIMS Contract Review Committee (CRC), which in most cases are given in a timely manner. Against this background the proposal is to secure Shell LDL approval to award the contracts packages once NAPIMS CRC endorses and forwards the award approvals to NNPC GEC / Board. It is also noteworthy that a couple of recent awards were similarly made under LDL e.g. FYIP Ph1 Offshore and Otumara pipeline and these were later approved by NNPC board some 9 – 12 months after submission as well as the Southern Swamp which is still awaiting approval. It is estimated that the risk of exposure becomes minimal once the support of the NAPIMS CRC is received.

Support from the Ministry of Finance / FIRS / Appropriation risk (E)

Specific/formal clearance from the FIRS needs to be obtained and this will be a condition precedent to the execution of any new MCA facility. Such clearance was received for the first MCA batch, but the Minister of Finance (MoF) has expressed reservation to sign more MCAs given the short term negative impact it has on fiscal revenues. SPDC and NNPC have closely worked together to mitigate this risk by jointly engaging FIRS and MoF on a number of occasions, giving reason to be cautiously optimistic that these new MCA will be supported. There is some uncertainty about whether this MCA fits into the Budget Appropriation however we have been assured by NNPC that this issue is being addressed.

Need for sufficient tax base of SPDC Ltd (C, E)

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.

Opportunities

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.

Alternatives

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 the 25 year forecasted project life are estimated at 227,168 tonnes of CO2eq; for an expected average production of about 24,000 bpd (net condensate) and 600 MMSCFD NAG. Fugitive emissions are the main source of emission amounting to about 82% of the total emissions. Venting due to routine maintenance and depressurization accounts for 14%, and the fuel gas combustion by the gas engines, for electricity generation, accounts for the remaining 4%.

Over a forecast period of ten years, projected energy intensity is 4.245E-07 GJ per tonnes of hydrocarbon produced. Regarding GHG emissions and energy consumption, this project is considered ALARP.

In addition, the following proposals have been made which will have a direct impact on emissions reduction as well as enabling accurate measurement and analysis of energy use. These include;

1. Use of fully pressure rated facilities which will eliminate the need for relief valve as ultimate safeguard for overpressure protection of facilities downstream of the wellhead. Depressurization philosophy is to depressurize the flowlines at the Gbaran CPF, where it will be flared.
2. Installation of pressure protection on the slug catcher at the Gbaran CPF to reduce demand on installed relief valve. This reduces relief events and consequently flaring emissions.
3. Provide Vent and Flare Gas Meters respectively to measure and Monitor venting/flaring incidents, frequency and flow rates

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.

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 been worked.

Section 8: Budget Provision

It is proposed that 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 disclosure, 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. It is expected that financing for the main project scopes shall be through the MCA funding mechanism. NNPC approval has been obtained for project scope and amount; however formal sign-off is being finalized with JV partners. Commitments will be made upon NNPC sign off of MCA

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:

....
Bos, Bernard
FM Nigeria & Gabon
Date.... /.... /....

For Business Approval:

....
Henley, Graham
VP Projects Operated
Date.... /.... /...

For Business Approval:

....
Droll, Marcus
VP Nigeria & Gabon
Date.... /.... /....

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

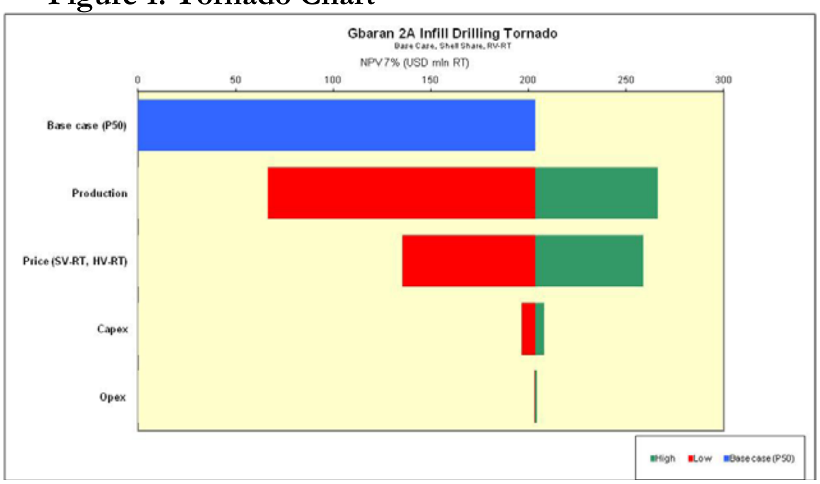
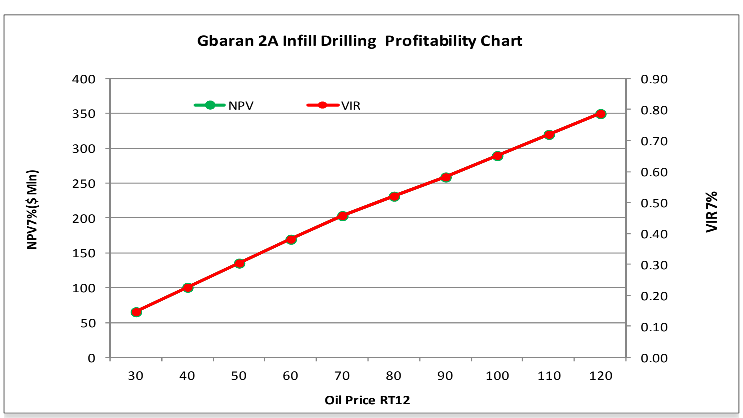


Figure 2: Project Profitability Plot



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

SCOPE

A. Wells

1. Drilling of Nine (9) NAG wells from three fields (1 in the Gbaran, 5 in the Koroama; including the Kororama SPUU-1 appraisal well, and 3 in Epu)

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

1. 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.
2. Construction of (on-plot) DSS piping, and utilities facilities at 6 remote well locations, including Field Auxiliary Rooms, Electrical substations, drain & vent vessels, corrosion inhibition packages, utility water tower and distribution systems, etc.
3. Installation of two (2) 55m microwave tower and telecommunication infrastructure at Epu-1 and Koroama manifold areas, including telecom cabinets PAGA and CCTV and radio field equipments.
4. Installation of CCTV, LAN/WAN, microwave and phone systems for all the remote locations..

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

1. Construct approximately 45km network of seven carbon steel pipelines 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 five 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.

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

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 2: Prior Approvals (FUS$ 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 3: Yearly estimated expenditure (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 4: Excerpt from Group Finance Proposal showing projects with the MCA2 Bundle

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 5: Reconciliation between the GFP and the GIP

	BASIS FOR THE GFP 100% JV cost	Shell Equity Share	SPDC Ltd Share	Total Headline Size	BASIS FOR THE INFILL GIP 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

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

ESTIMATE & SCHEDULE FACT SHEET
to be included in GIP and PCN submissions

Version 2.6 Confidential

Gbaran Ubie Infill Project
LAND, East.

Approved Cost & Schedule Estimate

Project No.: C-12060

Estimator: Emaviwe, Anthony
Planner: Harry, Bateyim
Case: Base

Market Scenario: LE Estimate Type: 3
Rates of Exchange are as per SI-SX Data Set
Estimate Start / End: FID Apr-2013 / Project Completion Dec-2016
Costs are in: USD Millions
EDM Date: 1-Jul-11

Category		Total Costs
Facilities		408
Wells		217
Owners Cost (i)	(incl. Insurance, pre-FID & Taxes)	103
EPC Premium (ii)		78
Contingency	(i) 16.44%, (ii) 0% Facilities 16% Wells: 0%	84
Inflation		35

P10	P50	P90
867	925	1,002
-8%		11%

Enterprise Framework Agreement Effects — Project Applied / Verified, Not Applied

EFA Effects incorporated in the P50 above: 12

Assumptions

OK

Estimate & Schedule Premise: Flowlines & manifold of duplex steel material, slug catcher, pig trap systems and tie-in estimates have been built using CAPCO$T based on MTO list from FEED deliverables. Pipeline estimates were prepared based on ongoing as well as recently completed pipeline installation contracts. Civil infrastructure estimates were built using corporate civil call-out contracts. Latest Estimate (LE) escalation factors data set have been applied in line with provisions of the Jan 2012 Capital Cost Outlook. Probabilistics cost risk analysis using @Risk has been used to calculate project contingencies. Owners costs were derived bottoms up using approved project manning profile. Well costs have been calculated using SPDC well cost estimating template by well engineering and has been adopted in line with agreed in-house SPDC methodology. Zero contingency has been applied to well estimate based on advice from Well Engineering and their assured input. Schedule durations were based on recently completed and ongoing projects with similar activities. Probabilistics risk analysis using Primavera risk analysis tool has been carried out on the schedule to derive the contingencies.

Execution Strategy Premise: Two EPC packages will be used for the execution of this project, one for pipelines and the other for facilities and tie-in works. Site preparation required for well drilling operations will be undertaken using SPDC Corporate Civil works call-out contracts.

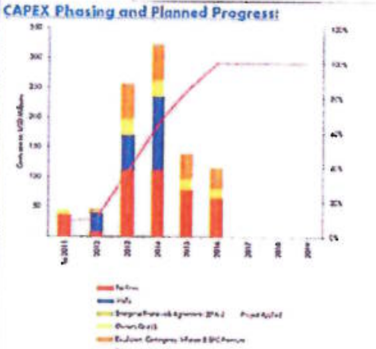
Contract Strategy: EPC contract packages on lumpsum basis will be instituted for facilities and pipeline works. A project management services contract will be used to provide quality assurance & control as well as certification services in the design, procurement, fabrication, construction, pre-commissioning/commissioning of this project.

Key Project Risks: Security/communities issues, Funding issues (could impair contractors' cash flow resulting in delays), HSE risks, Internal and external interface.

Exclusions: SPDC financing of interest during construction. Management adjustment of 2 - 4 months have been applied on P90 dates, also calculated milestones were moved to the nearest next quarter.The applied management adjustments are to accommodate for any force majeure, no adjustment has been made to the P90 costs.

Benchmarking & Metrics: Pipeline & facilities costs have been benchmarked with recently completed projects. Schedule durations have been benchmarked with completed projects. IPA external benchmarking was undertaken for this project.

CAPEX Phasing and Planned Progress:



Key Schedule Dates:

Phase	Finish (P50)	Finish (P90)
FID	Apr-2013	Jun-2013
Detailed Design	Jul-2013	Sep-2013
Contract Award	Jul-2013	Sep-2013
Procurement	Oct-2014	Feb-2015
Mechanical Completion (VZTX-2)	Dec-2014	May-2015
Mechanical Completion (Koroama)	Oct-2015	Feb-2016
Mechanical Completion (Epu)	Jul-2016	Nov-2016
RFSU (VZTX-2)	Jan-2015	Aug-2015
RFSU (Koroama)	Dec-2015	May-2016
RFSU (Epu)	Oct-2016	Feb-2017
Project Completion	Dec-2016	May-2017

Project Services Manager
Date: 29-NOV-2012
Name: Nwakaeze, Emeka
Signature:

Project Manager
Date: 29. 11. 12
Name: Ojo, Afolabi
Signature:

VP Project Services
Date: 29/11/2012
Name: Mes, Hans
Signature:

EVP Projects
Date:
Name: Kretzers, Rob
Signature: