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$461mln Shell share, MOD, 50/50 is requested for approval in this proposal of the 100% JV estimate of US$733.4mln. US$9.0mln 100% JV has been approved in the Pre-FID proposal. This proposal includes Shell equity share (30%) of US$220mln and Shell's MCA commitment on NNPC Share of US$240.9mln
Project	Kolo Creek Deep Development and Evacuation to Soku gas plant.

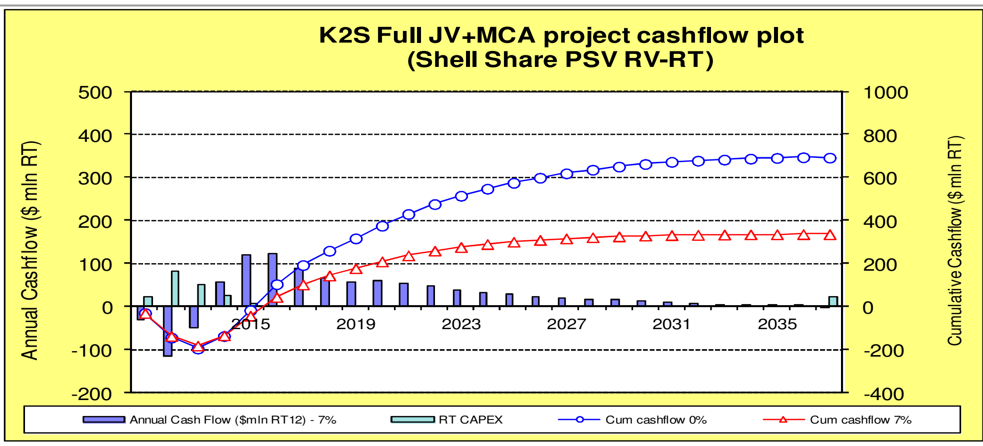
Main commitments

Description	Previously approved Pre-FID (100% JV)	Previously approved Pre-FID (30% Shell Share)	Requested Budget (100% JV)	Complete Budget (100%)	Complete Budget (30% Shell Share)	NNPC MCA Carry (36.67% Shell Share)	Total Shell Share (Equity + Carry)	Total Shell Share (Equity + Carry) This Proposal
NAG Wells			275.1	275.1	82.5	100.9	183.4	183.4
Facilities and Pipelines	9.0	2.7	447.2	456.2	136.9	140.1	276.9	274.2
Total CAPEX ($ mln)			**722.2**	**731.2**	**219.4**	**240.9**	**460.3**	**457.6**
SCD			11.2	11.2	3.4		3.4	3.4
Total OPEX ($ mln)			**11.2**	**11.2**	**3.4**		**3.4**	**3.4**
Total Project ($ mln)			**733.4**	**742.4**	**222.7**	**240.9**	**463.7**	**461.0**

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.

Summary cash flow (Shell Share)



Summary economics (Shell Share)

Summary Economics (RV-RT12)	NPV7 (USD mln)	RTEP (%)	VIR7
Base case	336.4	31	0.84
High Capex	327.9	29	0.74

Section 1: The Proposal (Management Summary)

1.1 Management Summary

This Group Investment Proposal requests approval for funding of US461mln Shell Share ($220mln Equity & $240.9mln Carry) to progress the execution of the Kolo Creek Deep field development Project. The approval is being sought based on conclusion of the commercial round of the contracting process with the eventual contractor already identified. The wells (Appraisal, F2 & F1) are on the approved Apr 2012 STDWS to be spudded by Mar 2013 and drilled back-to-back ending Dec 2014 on the HPEB129/ Replacement rigs. The HPEB129 rig is currently on a contract which will expire in Sep 2012. A one-year extension (till Sep 2013) is planned for HPEB129 while a replacement rig (Hilong19) has already been contracted. The existing contract rates (with escalation) have been used in estimating the well costs.

The Project will develop 1.5Tscf of gas from Kolo Creek Deep to the Soku Gas Plant for processing and sales to NLNG Trains 1 to 6. The project scope includes the drilling/completion of four (4) NAG wells into the F2 reservoir, three (3) NAG wells into the F1 reservoir as well as one (1) appraisal well in the F1 reservoir. A 20-inch x 40 km pipeline would be installed for evacuation of the production to the Soku gas plant. Peak production is planned at 400 MMscf/d and 40,000 bbl/day of liquid. Contingent upon GIP approval and fund availability by Jul 2012, P50 RFSU is Apr 2015 and P90 RFSU Jul 2015.

The project is in the Alternative Funding (AF) tranche in BP11. 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 in Appendix.

1.2 Project Background

In 2009 the Gbaran-Ubie Phase 2 project was re-framed and a number of alternative concepts evaluated for the evacuation of the Kolo Creek Deep gas. Taking into consideration the declining Soku production, the resource base in the Soku and Gbaran Nodes, the need to minimize capital investment and optimize SPDC's infrastructure usage, it was proposed that Kolo Creek Deep gas be processed at the existing Soku gas plant instead of building a new, third gas treatment train at the Gbaran CPF. This option has been presented and agreed by the DRB. The detailed scope and full life cycle costing for the full project work scopes can be found in Appendix 1 & Table 2.

1.3 Previous proposals

In April 2010, a pre-FID investment proposal of $ 2.7mln (Shell Share) was approved for the FEED, Survey, Land acquisition, and for conducting EIA studies for the Kolo Creek Deep to Soku Project. All of these have been completed except land acquisition which is expected to be completed in September 2012 and is, therefore, not on the critical path.

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

The proposed expenditure is required for the drilling/completion of four (4) NAG wells into the F2 reservoir, three (3) NAG wells and one (1) appraisal well into the F1 reservoir as well as the infrastructure for evacuation of the production to the Soku gas plant. These activities must be pursued to prevent the risk of shortfall of gas supplies to the Soku gas plant and the risk of not being able to maintain SPDC JV gas contractual commitments to NLNG Trains 1 to 6 (See Fig 1).

2.2 Production and Reserves

The Kolo Creek Deep development to Soku will develop 1.5 Tscf of gas and 52 MMSTB of condensate from the Kolo Creek F1 and the F2 reservoirs to sustain gas supplies to the Soku gas plant and meet SPDC JV gas supply commitments to NLNG Trains 1 to 6.

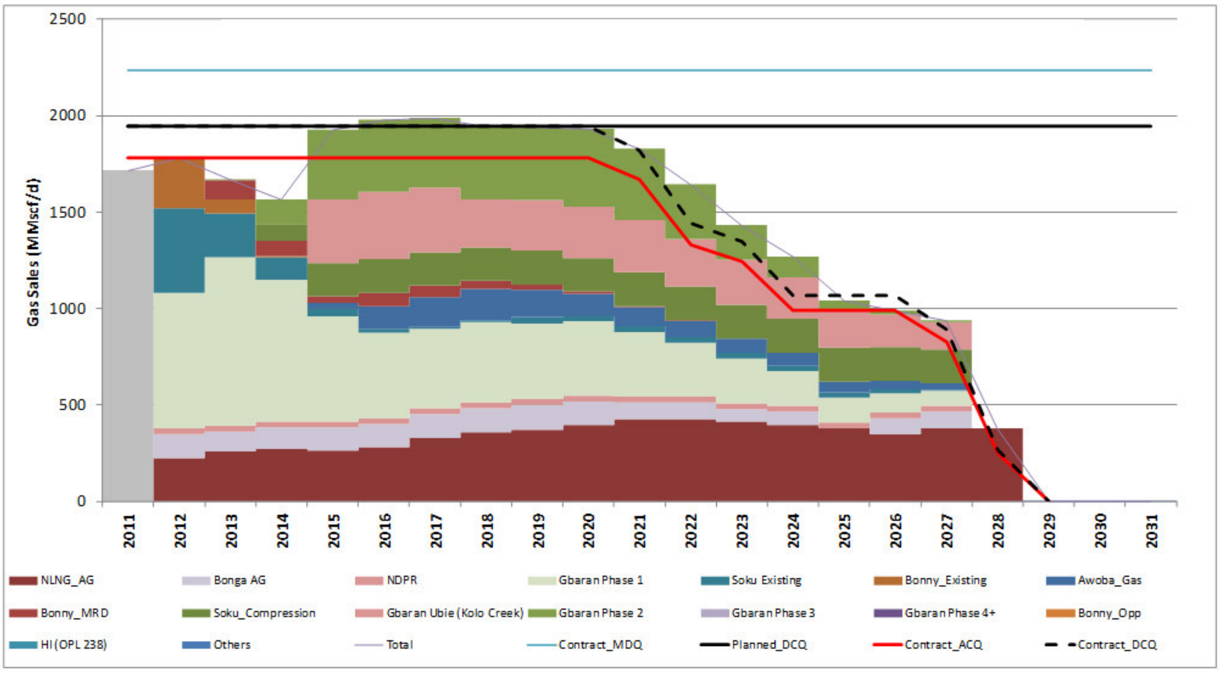


Figure 1: NLNG Trains 1 to 6 supply plot with the optimized 400 MMscf/d Kolo Creek to Soku option

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. Additional risk and uncertainty analysis was also carried out and it shows a 100% chance of the project returning a positive NPV. The evaluation assumed funding under the 2008 Modified Carry Arrangement (MCA) terms.

A sensitivity analysis of the current view of the PIB is also included. Results show that the project is still robust (passes the VIR hurdle) even without inclusion of production allowances.

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

Table 1a: Summary economics grid for Kolo Creek deep to Soku

Cash flow forward from: 1/1/2012	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 & $1.31/mmbtu RT12)	505.8	**234.7**	**0.59**						
RV ($70/bbl & $1.74/mmbtu RT12)	692.2	**336.4**	**0.84**	31	2.88	2.70	4.05	2015	*114.5(2013)*
HV ($90/bbl & $2.10/mmbtu RT12)	851.4	**423.5**	**1.06**						
Oil BEP (RT $/bbl)									
Sensitivities (using RV)									
High CAPEX (P90)		**327.9**	**0.74**						
High Volumes		**421.4**	**1.05**						
Low Volumes		**207.1**	**0.52**						
1.5% BVA		**326.6**	**0.80**						
1 year Schedule Delay		**309.6**	**0.77**						
Full Life Cycle		**335.2**	**0.83**						
PIB		**111.4**	**0.28**						
JV Funding		**339.7**	**1.79**						
Additional Uncertainty and Risk Analysis - using RV									
NPV(P10)		**494.1**	**1.26**						
NPV(P90)		**246.3**	**0.63**						
EMV at RV		**377.7**							
Probability of NPV > 0 at RV		**100%**							
Dispersion = EMV / (NPVP10-NPVP90) at RV		**1.3**							

Key project Parameters (Shell share)

Parameter	Unit	BP11 Provision	Low	Mid	High	Comments
Capex (MOD)	US$ mln	209.7	416.5	457.6	502.2	JV +MCA
Opex (MOD)_Project	US$ mln	NA	NA	40.37	NA	ABC + SCD
Production Volume	mln boe	87.31	42.10	96.80	121.91	improved deferments
Start Up Date	mm/yy	Oct-15		Apr-15		mitigate NLNG gas supply
Production in first 12 months	mln boe			8.8		

Section 3: Risks, Opportunities and alternatives

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 and schedule accordingly. The top project risks and mitigation plans are described below

Funding risks (C, E)

The proposal is for this project to be financed via Alternative Funding (AF) as it is currently not carried on the JV base budget. However delays to conclusion of funding discussions with JV partners could cost additional money and time as project bid validity is due to expire in August 2012

Mitigation: A contingency of 3mths delay to FID and contract award have been included in Schedule Risk analysis (cost within this GIP). Efforts have been intensified at all levels to ensure that the funding discussions are concluded timely

HSE and Security Risks (P, T):

HSE risks of executing a complex project with novel technologies e.g. use of API 10,000 piping class and the drilling of HPHT wells in complex environment i.e. geographic complexities (project transverses land, seasonally swamp and swamp terrains across 2 states) 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. 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 Soku gas plant and Kolocreek Oil/ NAG manifold. 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.

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 risk level will be assessed from to time to determine necessary line of action when there is a change in risk level.

- All of the identified mitigation measures are backed up by emergency response preparedness, in the event of unforeseen incidents.
- In addition, HSE requirements were included and evaluated during the tendering process. The project will also develop strong joint HSE Leadership by SPDC Management Team and Contractors Management Team as well as leverage on successful HSE initiatives such as the Injury Free Club.

Delay in obtaining NCDMB waiver for Line pipe procurement (E, C, P)

The Nigerian Content Directive (NCD) Act requires that a waiver be obtained for out of country procurement of line pipes less than 24”. SPDC has an existing Corporate Line pipe procurement waiver based on the Corporate Line pipe procurement call off contract. However based on NAPIMS directive, line pipe procurement strategy for the project is for EPC contractor to procure. There is therefore the need for the project to obtain the required waiver from NCDMB

Mitigation: Time lost to Contractor ordering of line pipes has been included in the project schedule, to further mitigate the risk; the plan is for Contractor to place the order for the line pipes as soon as EPC contract is awarded. Project is also investigating the possibility of extending SPDC’s waiver to cover 3rd party procurement.

Community related Risks (P)

The project straddles 2 states and over 14 main communities, hence the community stakeholder base is large and diverse. Legacy issues from the EGGS2 project have also been identified as the project pipeline largely follows the same RoW. This may lead to community agitations, work stoppages and reputational damage.

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. The Soku end of the project has an existing steady state GMoU and the KoloCreek GMoU is being negotiated. The project will leverage on these. Also an allowance has been made in the project budget for funding of social investment programmes

Pressure on Contractor Capacity due to Workload (T, O)

EPC Contractor has multiple contracts and contractor's capacity might be stretched

Mitigation: Contractor's capacity to be reviewed prior to mobilization to site and additional project management resources will be mobilized to support contractor. In addition, Contractor performance will be monitored closely to enable early intervention on appearance of any red flags

Changes to drilling sequence for F1 wells (T, P)

Based on the directive from DPR, there is a requirement to drill an appraisal well prior to drilling the F1 wells. However, during BP11, the F1 wells were accelerated to fill gaps in the drilling sequence, in essence, the F2 and F1 wells will now be drilled back-to-back

Mitigation: The appraisal well has now been sequenced for drilling before the F2 wells. The results will be available and presented to DPR before the F1 wells are spudded, following completion of the F2 wells

Alternatives

A. Processing Facility

Following the reframing workshop of Mar 2009, a decision was taken to process the Kolo Creek Deep gas at the existing Soku gas plant rather than at a new, third gas treatment train at the Gbaran CPF as originally conceptualized, for the following reasons

1. Declining Soku production
2. Resource base in the Soku and Gbaran Nodes
3. Need to minimize capital investment and optimize SPDC's infrastructure usage

B. Production Rate

Production rates of 500, 400 and 300 MMscf/d from Kolo Creek to Soku were considered.

The 500 MMscf/d Kolo Creek to Soku option would require a finger type slug catcher and additional condensate stabilization capacity at the Soku CPF since it would be competing with the Awoba NAG project for liquid handling space.

The 300 MMscf/d Kolo Creek Deep to Soku option results in minimum CAPEX, but will not fulfill SPDC supply obligations to the NLNG Trains 1 to 6 in the short term.

Short/Medium term supply obligations can be met with the 400 MMscf/d Kolo Creek to Soku as an optimum production rate.

Section 4: Carbon Management

Green House Gas (GHG) Emissions for the Kolo Creek Deep Well Development Project over the 10 year forecast period are estimated at 35,510 tonnes of CO2eq, when average production is about 24,000 stbpd (net condensate) and 400 MMSCFD. Fuel gas combustion by the gas engines for electricity generation accounts for 90.8 % of the total emissions, and is the major source of emission in the project. Fugitive emissions from valves and flanges account for 8.95 % of the total GHG emissions. Venting at Kolo Creek Remote Field Manifold (RFM) due to routine maintenance depressurizing accounts for less than 0.3 % of the total GHG emissions, while Flaring emissions at Soku LGSP due to pig trap depressuring is insignificant.

Over the forecast period, the total emissions and energy intensities are 0.8 kg CO2 equiv. and 0.013 GJ per Tonne of hydrocarbon produced respectively. Also the SCEI and UEEI are 43 and 0.52 respectively. These are generally low compared to peer facilities in the group. Regarding GHG emissions and energy consumption therefore, this project is considered ALARP.

In addition there are other design considerations or elements, which either have direct impact on emissions or are implemented in order to enable accurate measurement and analysis of energy use and GHG emissions. These include;

1. Use of HIPPS instead of relief valve as ultimate safeguard for overpressure protection of downstream facility to avoid relief vent load at Kolo Creek. Depressurization philosophy is to depressurize the Kolo Creek flowlines at Soku gas plant, where it will be flared.
2. Installation of pressure protection on the slug catcher at Soku to reduce demand on installed relief valve. This reduces relief events and consequently reduces flaring emissions at the Soku.
3. Provide Vent and Flare Gas Meter respectively to measure and Monitor venting/flaring incidents, frequency and flow rates
4. Provide individual fuel gas meters for each gas engine power generator to measure the fuel gas consumed by individual gas engines.
5. Provide individual electricity meters for each gas engine power generator to measure the power produced by individual gas engines.

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, Supply Chain Management, HSE, Operations, Legal, Security, Treasury and Tax functions.

Section 7: Project management, monitoring and review

This is a "P&T executed" project delivered by the UIG/T/PD Major Projects team. The ORP compliant governance structure is in place, including a project specific DRB, DE and BOM. A Project Control and Assurance Plan (PCAP) has been approved to define the applicable controls for the EXECUTE phase.

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

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 estimated yearly expenditure phasing for the full project work scopes is indicated in Table 1.

US$ mln	Prior Years	2012	2013	2014	2015	2016	Post 2016
Total Commitment	+0.0	+40.3	+200.7	+169.8	+42.0	+10.9	+0.0
SCD OPEX	+0.0	+0.6	+1.3	+0.8	+0.5	+0.1	+0.0
Pre-FID	+0.0	+2.7	+0.0	+0.0	+0.0	+0.0	+0.0
Cash Flow							
Capital expenditure	+0.0	+37.0	+199.4	+169.1	+41.5	+10.7	+0.0
Cash Flow from Operations	+0.0	+4.5	+72.3	+112.2	+122.5	+152.9	+927.7
Cash Surplus/(Deficit)*	+0.0	-32.4	-127.1	-56.8	+81.0	+142.2	+927.7
Profit and Loss							
NIBIAT +/-	+0.0	-0.1	+8.8	+7.8	+73.3	+106.9	+756.3
Balance Sheet							
Average Capital Employed	+0.0	+16.2	+100.3	+200.5	+229.0	+207.5	+49.7
Impact on ROACE (EP)	+0.0	-0.04%	0.19%	0.09%	2.01%	3.31%	n/a

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. Formal sign-off is being finalized with JV partners. However, it is planned to make commitments upon NAPIMS approval of MCA figures.

Section 12: Taxation
For all the tax consequences associated with the MCA, reference is made to the tax section of the PCN covering MCA. A possible entry into force of PIB has a significant impact on the value of this project. Other than the foregoing, there are no unusual tax features to this proposal.

Section 13: Key Parameters
Approval is sought for additional US$461mln Shell Share ($220mln Equity & $240.9mln Carry), to progress Engineering, Procurement and Construction works, drilling/completion of 7 NAG and 1 appraisal wells and the infrastructure for evacuation of production to the Soku Gas Plant from the Kolo Creek Deep field.

Section 14: Signatures
This Proposal is submitted for approval.

Supported by:

....
Bichsel, Matthias
ECMBi
Date.... /.... /....

For Business Support:

....
Andrew, Brown
ECAB
Date.... /.... /....

Supported by:

....
Henry, Simon
Chief Financial Officer
Date.... /.... /...

For Business Approval:

....
Voser, Peter
Chief Executive Officer
Date.... /.... /....

Economics Assumptions

- Oil price at the three Project Screening Values (PSVs): SV, RV and HV ($50/bbl, $70/bbl and $90/bbl respectively) with applicable offsets.
- NLNG Gas PSV
- Gas taxed under Company Income Tax Act (CITA) with Associated Gas Framework Agreement (AGFA) incentive.
- 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
- No facility upgrade/replacement required for the project until economic limit.
- SCD Cost was provided by project team
- Activity Based Cost (ABC) Opex provided by project team
- Condensate 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 cost gas and condensate.
- Current agreement for recovery of carry costs is maintained
- $70.22/bbl – Condensate at PSV RV-RT in 2012
- OPEX and PMT not carried under current MCA arrangement.
- P50 Schedule is premised on funding available by end 2012

PIB Assumptions

- May 2012 version (Technical Committee draft)
- Production Royalty based on Company production rates
- SPDC – Oil & Condensate 22% - Gas 12.5%
- Price Royalty – 4% for Oil/Condensate RV, 0% for Gas RV
- Nigerian Hydrocarbon Tax 50%; Corporate Income Tax 30%
- Community Fund (PHCF) treated as Tax Credit
- No Production Allowances granted for this development.

Figure 2: Tornado Chart

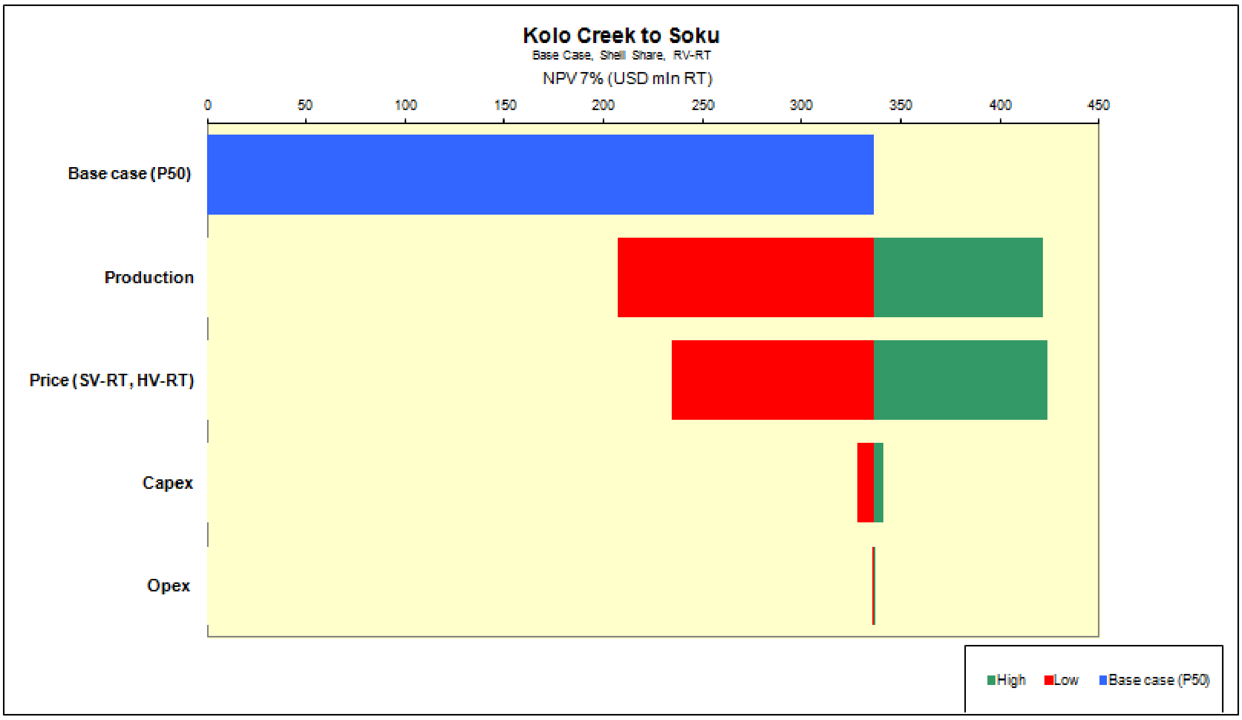
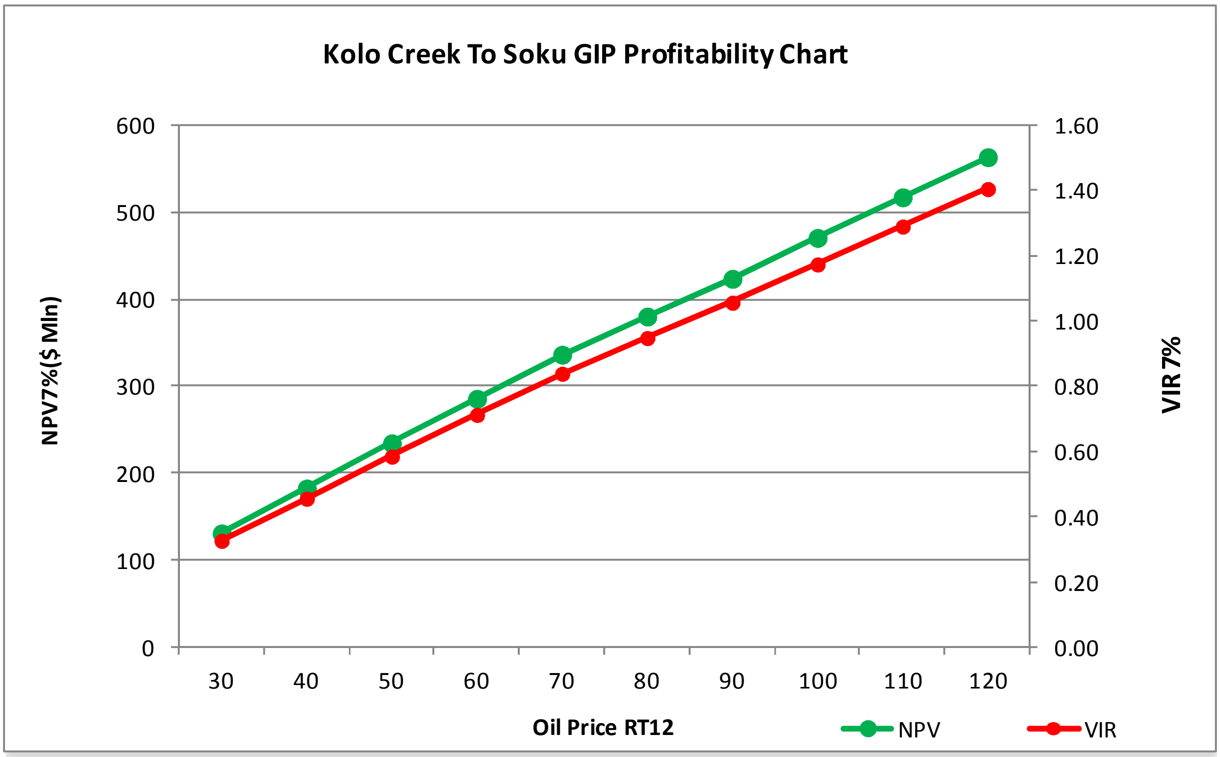


Figure 3: Project Profitability Plot



Appendix 1: Details and Cost Estimate (MOD 100% JV) for the Kolo Creek Deep Field Development to Soku

The scope of the Kolo Creek Deep field development consists of the following:

1. Drilling and completing of four NAG wells to develop 0.92Tscf from the Kolo Creek Deep F2 reservoir.
2. Drilling of one appraisal well into the F1 reservoir
3. Drilling and completing of three NAG wells to develop 0.54Tscf from the Kolo Creek Deep F1 reservoir.
4. Construct a remote field manifold at the Kolo Creek Oil and NAG Manifold Location
5. Install (on-plot) flowlines from the wells to the Kolo Creek NAG manifold
6. Install a 20-inch diameter, 40 km long carbon steel pipeline from the Kolo Creek Manifold to the Soku gas plant designed to evacuate 400 MMscf/d of gas and 40,000 bbl/d of condensate from Kolo Creek NAG Manifold.
7. Installation of a slug catcher at the Soku gas plant and connection to existing production, control and safeguarding systems.

Table 2: Details of the cost estimate (MOD 100% JV) for the full scope of the Kolo Creek Deep Field Development to Soku Project can be found below.

50/50 MOD Cost Estimate (US$ mln)	
Description	
Location Preparation	35.8
Drilling and Completion	239.3
Pipeline and Hook-up	104.2
NAG Facilities* (inclusive of PMT, VAT & Owners Cost)	352.0
Total CAPEX (100% JV)	**731.2**
SCD	11.2
Total OPEX (100% JV)	**11.2**
Total (100% JV)	**742.4**
Total (Shell Share)	**463.7**

Table 3: Yearly estimated expenditure (FUS$ mln)

	COST PHASING							
Description	Previously approved Pre-FID	2012	2013	2014	2015	2016	2017	Total
Facilities Capex 100% JV (FUS$mln) - less PMT& SCD	6.4	50.0	177.7	85.2	55.5	13.6		388.4
Wells Capex 100% JV (FUS$mln)		0.0	114.1	160.9	0.0	0.0		275.1
Total Capex 100% JV (FUS$mln) - less PMT&SCD	6.4	50.0	291.8	246.1	55.5	13.6		663.5
PMT 100% JV (FUS$mln)	2.6	12.2	16.0	16.6	14.8	5.5		67.8
Opex 100% JV (FUS$mln)		2.0	4.4	2.5	1.8	0.5		11.2
Total 100% JV (FUS$ mln)	**9.0**	**64.2**	**312.3**	**265.2**	**72.1**	**19.6**		**742.4**
Shell Share Equity (30%)	2.7	19.2	93.7	79.6	21.6	5.9		222.7
MCA Carry Shell Share (36.67%)		18.3	107.0	90.3	20.4	5.0		240.9
Total Shell Share (FUS$ mln)	**2.7**	**37.6**	**200.7**	**169.8**	**42.0**	**10.9**		**463.7**
This proposal Total Shell Share excluding Pre-FID (FUS$ mln)								**461.0**

GLOSSARY

AF – Alternative Funding

CPF – Central Processing Facility

DPR – Department of Petroleum Resources

DRB – Decision Review Board

FEED – Front End Engineering Design

GHG – Green House Gas

GMoU – Global Memorandum of Understanding

HEMP – Hazard & Effects Management Process

HIPPS – High Integrity Pipeline Protection System

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 & Workover Sequence

SV – Screening Value

VAT – Value Added Tax

VIR – Value Investment Ratio

ESTIMATE & SCHEDULE FACT SHEET

Version 2.5 Confidential

to be included in OP and FCN submissions

Kolo Creek to Soku Project Type 3 CAPEX Estimate

SWAMP, East.

Approved Cost & Schedule Estimate

Project No.: C-11031

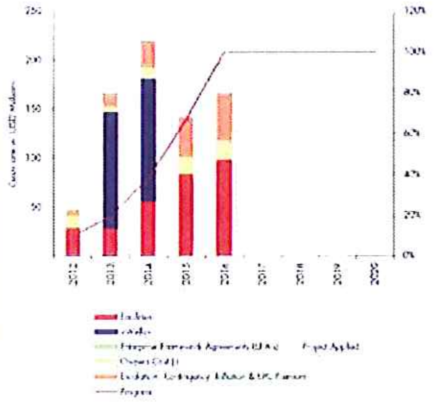
Estimator:	Akubo, Arome	Planner:	Harry, Bateyim
Case:	Base		Rates of Exchange are as per SI-SX Data
Market Scenario: LE	Estimate Type: 3		Costs are in: USD Millions
Estimate Start / End: FID Jul-2012 /	Project Completion Aug-2016		EDM Date: 1-Jul-11

				Total Costs
Facilities				296
<Wells>				244
Enterprise Framework Agreements (EFA's) : Project Applied / Verified, Not Applied				/
Owners Cost (i)	(incl. Insurance, pre FID, Taxes & Capitalised Interest)			62
Market Escalation & EPC Premium (ii)				49
Contingency	(i) 17.28%, (ii) 0%	Facilities: 17%	<Wells>: 0%	58
Inflation				33

P10	P50	P90
670	742	843
-14%		20%

OK

Estimate & Schedule Premise	Duplex flowlines & manifold, slug catcher, pig trap systems and tie-in estimates have been built using CAPCO$T based on MTO list from the FEED deliverables. Pipeline estimates were based on ongoing as well as recently completed pipeline installation contracts. Civil insfrastructure estimates were built using corporate civil call-out contracts. The Q2 2012 Latest Estimate (LE) escalation factors 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 wells based on the advice from Well Engineering and their assured input. Schedule durations were based on recently completed and ongoing projects with similar activties. Probabilistics risk analysis was carried out on the schedule.
Execution Strategy Premise	A single EPC package will be used for pipelines, 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 package have been negotiated on lumpsum prices for facilities and pipeline. 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.
Benchmarking & Metrics	Pipeline & facilities costs have been benchmarked with completed projects. IPA benchmarking undertaken.



Key Schedule Dates:

Phase	Finish (P50)	Finish (P90)
FID	Jul-2012	Aug-2012
MTO for LLI	Aug-2012	Sep-2012
Contract award	Oct-2012	Nov-2012
Bulk line Pipe PO issued	Feb-2013	Mar-2013
Detailed layout & construction design	May-2013	May-2013
Bulk line Pipe delivered	Mar-2014	Jun-2014
Mechanical completion	Oct-2015	Feb-2016
RFSU	Feb-2016	May-2016
Project Completion	Aug-2016	Nov-2016

DCAF TA 1		Project Manager	
Date :	27-06-2012	Date :	27. 06. 2012
Name :	Nwakaeze, Emeka	Name :	Ojo, Afolabi
Signature :	[signature]	Signature :	[signature]

VP Project Services		EVP Projects	
Date :	28th June 2012	Date :	
Name :	P.P. Mes, Hans	Name :	Kretzers, Rob
Signature :	[signature]	Signature :	

Lifecycle HCM Forecast Sheet Version 2.0 Confidential

Gbaran Ubie Phase 2B (KoloCreek to Soku) Project

Gbaran Nigeria

Project No.: 06629

Mandatory for Upstream and mandatory for Exploration, Development and NBD projects ≥ US$ 100 mln SS, but strongly recommended for all projects < 100 mln US$

OIL/NGL [mln bbl] DG/Key event	Date (mm)-yy	2U Prospective Resources Additions: Play and/or Lead	2U: Prospect	2C Contingent Resources Additions: Dev. Not Viable	2C: Dev. Unclarified or On Hold: Unclarified	2C: Dev. Unclarified or On Hold: On Hold	2C: Dev. Pending Pre-DG1	2C: Dev. Pending Post-DG1	2C: Dev. Pending Post-DG2	2C: Dev. Pending Post-DG3	PRMS 2P Reserves Additions: Undeveloped: Post DG3	PRMS 2P: Undeveloped: Post-DG4	PRMS 2P: Developed	SEC Proved Reserves Additions: Undev	SEC Proved: Developed	Annual Production
DG1	Jun-05															
DG2	Jun-06															
DG3	Aug-09										16.8			4.4		
FID	Nov-12															
OSD	Oct-15															
	2013															0.0
	2014															0.0
	2015	0.0	0.0	0.0		0.0	0.0	0.0	0.0	0.0	-10.9		10.9	-3.0	3.0	1.0
	2016										-5.9		5.7	-1.4	1.7	2.1
	2017	0.0	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0	3.4	2.0
	2018	0.0	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0	5.0	1.6
	2019	0.0	0.0	0.0		0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0	2.6	1.6
	2020												0.0		1.0	1.4
	2021												0.3		0.3	1.4
	2022															1.2
	2023															0.9
	2024															0.7
	2025															0.6
	2026															0.5
	2027															0.4
	2028															0.3
	2029															0.2
	2030															0.2
	2031															0.1
	2032															0.1
	2033															0.1
	2034															0.1
	2035															0.0
	2036															0.0
	2037															0.0
	2038															0.0
	2039															0.0
	2040															0.0
	2041															0.0
	2042															0.0
	2043															0.0
	2044															0.0
	2045															0.0
	2046															0.0
later years																0.0
Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.8	0.0	16.8	16.8

CHECK

developed reserves additions minus cum produciton: 2P Reserves Developed	SEC Proved Developed
0.0	0.0
0.0	0.0
0.0	0.0
0.0	0.0
0.0	0.0
0.0	0.0
0.0	0.0
0.0	0.0
0.0	0.0
0.0	0.0
0.0	0.0
0.0	0.0
0.0	0.0
0.0	0.0
0.0	0.0
0.0	0.0
0.0	0.0
9.8	1.3
11.4	1.5
11.4	2.5
9.7	8.2
8.1	7.1
6.7	6.7
5.5	5.5
4.5	4.5
3.4	3.4
2.6	2.6
2.1	2.1
1.5	1.6
1.2	1.2
1.0	1.0
0.7	0.7
0.5	0.5
0.4	0.4
0.3	0.3
0.2	0.2
0.1	0.1
0.1	0.1
0.1	0.1
0.0	0.0
0.0	0.0
0.0	0.0
0.0	0.0
0.0	0.0
0.0	0.0
0.0	0.0
0.0	0.0
0.0	0.0
0.0	0.0
0.0	0.0

negative numbers are incorrect

OIL/NGL [mln bbl]		2U Prospective Resources: Play and/or Lead	2U: Prospect	2C Contingent Resources: Dev. Not Viable	2C: Dev. Unclarified or On Hold: Unclarified	2C: On Hold	2C: Dev. Pending Pre-DG1	2C: Dev. Pending Post-DG1	2C: Dev. Pending Post-DG2	2C: Dev. Pending Post-DG3	PRMS 2P Reserves: Undeveloped: Post DG3	PRMS 2P: Undeveloped: Post-DG4	PRMS 2P: Developed	SEC Proved Reserves: Undev	SEC Proved: Developed
ARPR 1.1.2011	before last	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	17.6	0.0	0.0	4.4	0.0
ARPR 1.1.2012	last	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.8	0.0	0.0	4.4	0.0

GAS [bln sm3] DG/Key event	Date (mm)-yy	2U Prospective Resources Additions: Play and/or Lead	2U: Prospect	2C Contingent Resources Additions: Dev. Not Viable	2C: Dev. Unclarified or On Hold: Unclarified	2C: Dev. Unclarified or On Hold: On Hold	2C: Dev. Pending Pre-DG1	2C: Dev. Pending Post-DG1	2C: Dev. Pending Post-DG2	2C: Dev. Pending Post-DG3	PRMS 2P Reserves Additions: Undeveloped: Post DG3	PRMS 2P: Undeveloped: Post-DG4	PRMS 2P: Developed	SEC Proved Reserves Additions: Undev	SEC Proved: Developed	Annual Production
DG1	Jun-05															
DG2	Jun-06															
DG3	Aug-09										12.65			3.76		
FID	Nov-12															
OSD	Oct-15															
	2013	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00						0.00
	2014	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00						0.00
	2015	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	-8.28		8.28	-2.67	2.67	0.50
	2016										-4.35		4.35	-1.09	1.15	1.09
	2017	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	1.09
	2018	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	2.07	0.97
	2019	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	3.86	1.03
	2020												0.50		1.87	1.00
	2021															1.07
	2022														0.00	1.02
	2023														0.00	0.88
	2024														0.00	0.75
	2025														1.00	0.65
	2026														0.50	0.56
	2027															0.48
	2028															0.41
	2029															0.36
	2030															0.31
	2031															0.26
	2032															0.21
	2033															0.12
	2034															0.11
	2035															0.09
	2036															0.08
	2037															0.07
	2038															0.03
	2039															
	2040															
	2041															
	2042															
	2043															
	2044															
	2045															
	2046															
later years		0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00		0.00	0.00	0.00	
Total		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.1	0.0	13.1	13.13

CHECK

developed reserves additions minus cum produciton: 2P Reserves Developed	SEC Proved Developed
0.00	0.00
0.00	0.00
0.00	0.00
0.00	0.00
0.00	0.00
0.00	0.00
0.00	0.00
0.00	0.00
0.00	0.00
0.00	0.00
0.00	0.00
0.00	0.00
0.00	0.00
0.00	0.00
0.00	0.00
0.00	0.00
0.00	0.00
7.73	2.17
11.04	2.23
9.84	1.14
8.97	2.24
7.94	5.07
7.44	5.54
6.37	4.87
5.53	3.86
4.48	2.98
3.72	2.22
3.08	2.58
2.63	2.52
2.04	2.04
1.63	1.63
1.27	1.27
0.97	0.97
0.71	0.71
0.50	0.50
0.38	0.38
0.27	0.27
0.18	0.18
0.10	0.10
0.03	0.03
0.00	0.00
0.00	0.00
0.00	0.00
0.00	0.00
0.00	0.00
0.00	0.00
0.00	0.00
0.00	0.00
0.00	0.00
0.00	0.00

negative numbers are incorrect

Gas [bln sm3]		2U Prospective Resources: Play and/or Lead	2U: Prospect	2C Contingent Resources: Dev. Not Viable	2C: Dev. Unclarified or On Hold: Unclarified	2C: On Hold	2C: Dev. Pending Pre-DG1	2C: Dev. Pending Post-DG1	2C: Dev. Pending Post-DG2	2C: Dev. Pending Post-DG3	PRMS 2P Reserves: Undeveloped: Post DG3	PRMS 2P: Undeveloped: Post-DG4	PRMS 2P: Developed	SEC Proved Reserves Additions: Undev	SEC Proved: Developed
ARPR 1.1.2011	before last	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.89	0.00	0.00	3.83	0.00
ARPR 1.1.2012	last	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.13	0.00	0.00	3.76	0.00

	VP Technical (or VP-X)		RDL-RE (RXC or RXHM)
Date :	27-6-2012	Date :	21-June-2012
Name :	OJULARI, B	Name :	Osayande Igiehon
Signature :	[signature]	Signature :	[signature]

Note: Production forecast and PDRA forecast need to be fully consistent with economic and financial evaluations and results presented in the GIP. HCM forecast need to be captured in HRV-MS, which is the single data source for HCM.