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

Summary Information

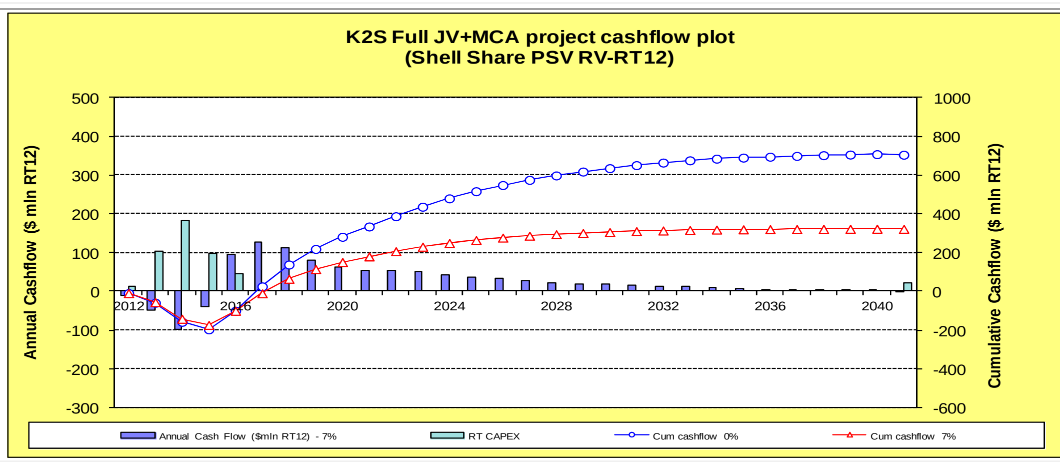
Business unit and company	Shell Petroleum Development Company of Nigeria Limited (SPDC)
Group equity interest	100% in SPDC, whereas SPDC is the Joint Venture (JV) operator of an unincorporated JV with a 30% interest.
Other shareholders / partners	Nigeria National Petroleum Company (NNPC: 55%), Total Exploration and Production Company Nigeria (TEPNL 10%), Nigeria Agip Oil Company (NAOC: 5%)
Amount	US$463.5mln 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$243.5mln
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% JV)	Complete Budget (30% Shell Share)	NNPC MCA Carry (36.67% Shell Share)	Total Shell Share (Equity + Carry)	This Proposal (30% Shell Share)	Total Shell Share (Equity + Carry) This Proposal
NAG Wells			244.0	244.0	73.2	89.5	162.7	73.2	162.7
Facilities and Pipelines	9.0	2.7	477.5	486.5	145.9	154.0	300.0	143.2	297.3
Total CAPEX ($ mln)			**721.5**	**730.5**	**219.1**	**243.5**	**462.6**	**216.4**	**459.9**
SCD			12.0	12.0	3.6		3.6	3.6	3.6
Total OPEX ($ mln)			**12.0**	**12.0**	**3.6**		**3.6**	**3.6**	**3.6**
Total Project ($ mln) excl Capitalized interest	**9.0**	**2.7**	**733.4**	**742.4**	**222.7**	**243.5**	**466.2**	**220.0**	**463.5**
Note Capitalized interest on SS + MCA Carry ($ mln)									**48.9**

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

Summary Economics (RV-RT12)	NPV7 (USD mln)	RTEP (%)	VIR7
Base Case	322.2	31.0	0.84
High CAPEX	315.6	29.1	0.75

Section 1: The Proposal (Management Summary)

1.1 Management Summary

This Group Investment Proposal requests approval for funding of US463.5mln Shell Share ($220mln Equity & $243.5mln 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 Jul 2012 STDWS to be spudded by Aug 2013 and drilling completed Apr 2015 on the HPEB129/ Replacement rigs. The HPEB129 rig is currently on contract till Sep 2013 while a replacement rig (Hilong19) has already been contracted. The existing contract rates (with escalation) have been used in estimating the well costs.

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 3 & 4 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 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. GIP is based on BP12 P50 RFSU of 29th Jan 2016 and P90 RFSU of May 2016.

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 in Appendix 2.

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 2 & Table 1 of Appendix 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 by Mar 2013 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 eight (8) NAG wells (including one appraisal well) and infrastructure for evacuation of the production to the Soku gas plant (See Figure 1: location map). 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.

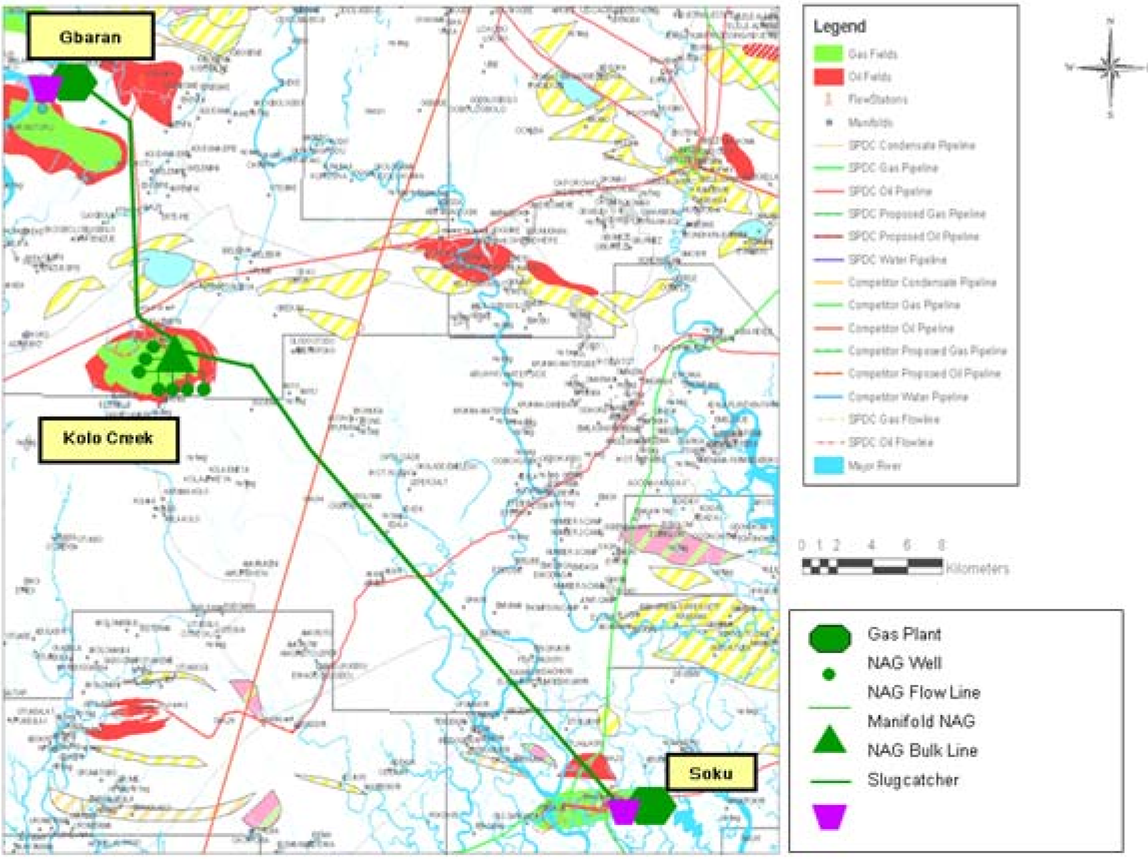


Figure 1: Location Map

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 (See Figure 2).

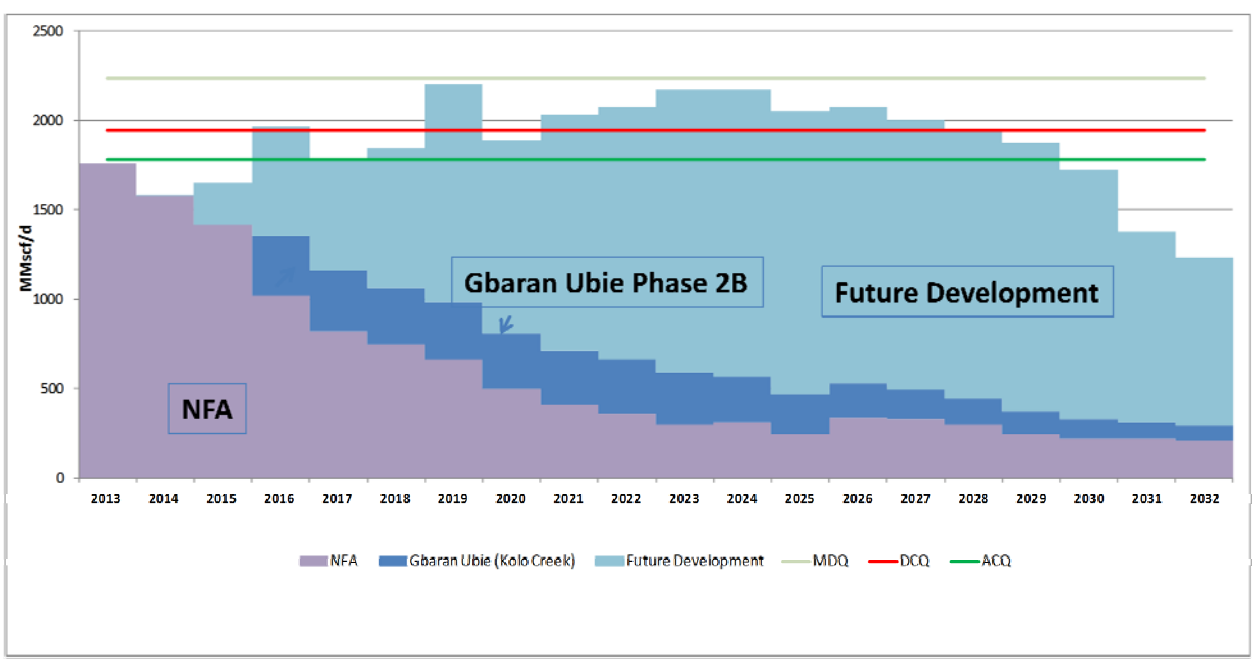


Figure 2: NLNG Trains 1 to 6 supply plot

2.3 Summary Economics

The economic evaluation was carried out on a forward-looking basis using production forecast and contractors cost. Sensitivity analysis was carried out to test the robustness of the project at different production volumes and CAPEX. Additional risk and uncertainty analysis was also carried out and 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. The details of the results are in Table 1 while the Tornado Plot and Profitability Plot are shown in the appendix 1 (Figures 1 & 2)

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)	513.8	224.3	0.59						
RV ($70/bbl)	704.6	322.2	0.84	31.0	1.6	2.6	4.0	2017	196.5 (2015)
HV ($90/bbl)	864.2	404.5	1.06						
BEP* (RT $/bbl)									
Sensitivities (using RV-RT12)									
High CAPEX (P90)		315.6	0.75						
Low CAPEX (P10)		326.3	0.94						
High Reserves (P10)		398.9	1.04						
Low Reserves (P90)		203.2	0.53						
Full Life Cycle		321.4	0.83						
Project with ring fencing		305.7	0.80						
JV Funding		325.3	1.81						
PIB(May 2012 version Technical Committee draft)		119.3	0.29						
1-Yr Scehdule Acceleration		347.8	0.91						
1-Yr Production delay		299.5	0.82						
1.5% cost markup due to BVA issues		312.9	0.77						
Additional Uncertainty and Risk Analysis - using RV									
NPV(P10)		445.6	1.23						
NPV(P90)		172.8	0.40						
EMV at RV & eVIR at RV		312.6	0.82						
Probability of NPV > 0 at RV		100%							
Dispersion = EMV / (NPVP10-NPVP90) at RV		1.1							

Table 1: Summary economics grid for Kolo Creek Deep to Soku (Shell Share)

Parameter	Unit	BP12 Provision	Low	Mid	High	Comments
Capex (MOD)	US$ mln	459.9	413.9	459.9	505.9	JV+MCA
Opex (MOD)_Project	US$ mln	NA	34.3	41.8	52.0	ABC+SCD
Production Volume	mln boe	96.9	57.2	97.2	122.6	Reduced Deferments
Start Up Date	mm/yy	Jan-16	Dec-15	Jan-16	May-16	
Production in first 12 months	mln boe			8.2		

Table 2: Key project Parameters (Shell share)

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

NNPC 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. While awaiting NAPIMS approval of award recommendation, bid validity was extended from 7 Sep 2012 to 31 Dec 2012 and an interim contract for Detailed Engineering Design was signed 4 Oct 2012.

Delays to conclusion of funding discussions with JV partners could result in additional cost in the event contractors refuse to extend bid validity beyond Dec 2012 at the same price. Secondly, the NAPIMS budget recommendation of US$684.4mln excludes prior year costs and part of the P50 contingency in the cost estimate.

Mitigation: Efforts will be intensified at all levels to ensure that the funding discussions are concluded and fund available by Jan 2013. In addition, effort will be made to achieve project execution within the NAPIMS mandate. 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.

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 HP 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 time 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. 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. 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. 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.

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.

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

NNPC Award Approvals for EPC Contracts (C, E)

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: In a bid to safeguard the project schedule, Shell has approved a limited LDL to commence detailed design via an Interim contract. Additionally, SPDC has and will continue to maintain close and rigorous engagement with NAPIMS to ensure common understanding of project priorities and urgencies. However, given that the delay in obtaining approvals from the NAPIMS board may be protracted, the proposal is to secure additional LDL approval to progress with the project once the NAPIMS CRC endorses and forwards the award approvals to NNPC GEC / Board as 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

Specification for a new piping class (API 10000Ibs) was developed in partnership with SGSI. This will be useful going forward as Shell explores deeper reservoirs.

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 flow lines 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.

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

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 (AF) tranche. In line with current AF (MCA) agreements, it is expected that project FID OPEX and project management costs will continue to be funded via the regular JV budgetary process. These costs are fully captured in BP12 under AF.

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 below

US$ mln	2012	2013	2014	2015	2016	Post 2016
Total Commitment	12.0	104.6	192.0	105.2	49.6	
SCD OPEX		0.7	1.3	1.0	0.6	
Pre-FID						
Cash Flow						
Capital expenditure	12.0	104.0	190.7	104.2	49.1	
Cash Flow from Operations	2.1	44.4	83.1	69.4	138.2	1007.4
Cash Surplus/(Deficit)*	-9.9	-59.6	-107.6	-34.8	89.1	1007.4
Profit and Loss						
NIBIAT +/-	0.6	4.1	8.2	6.0	97.7	795.3
Balance Sheet						
Average Capital Employed	5.2	42.3	132.0	210.3	235.0	57.4

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 scope shall be through the MCA funding mechanism. NAPIMS & JV Partners approval of MCA figures has been received. Commercial terms are being finalized prior to formal sign-off.

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$463.5mln Shell Share ($220mln Equity & $243.5mln 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:

....
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.
- No facility upgrade/replacement required for the project until economic limit.
- 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 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
- Capital allowance for all CAPEX (except drilling intangibles) at On-stream date

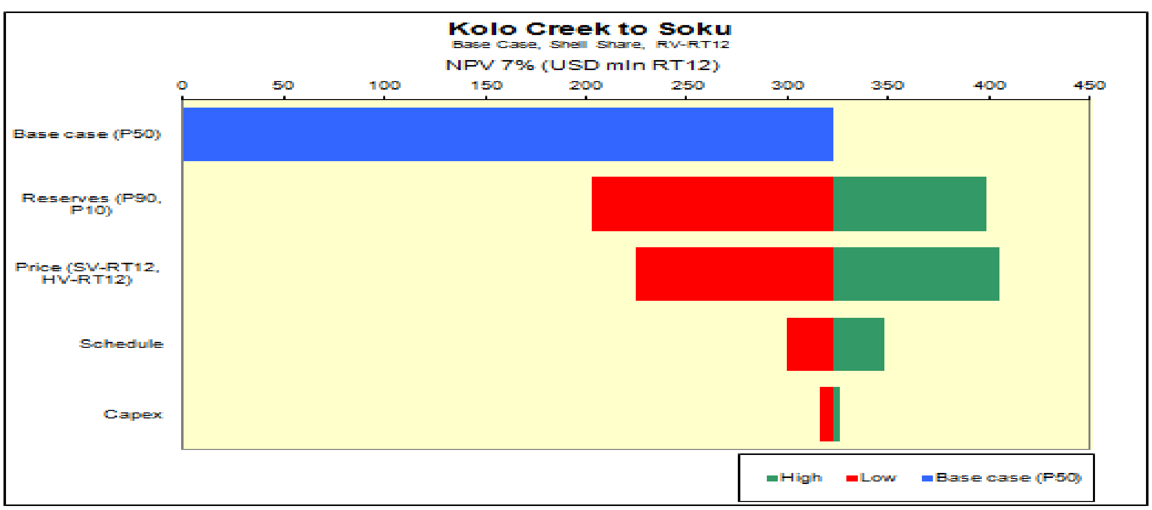


Figure 1: Tornado Chart

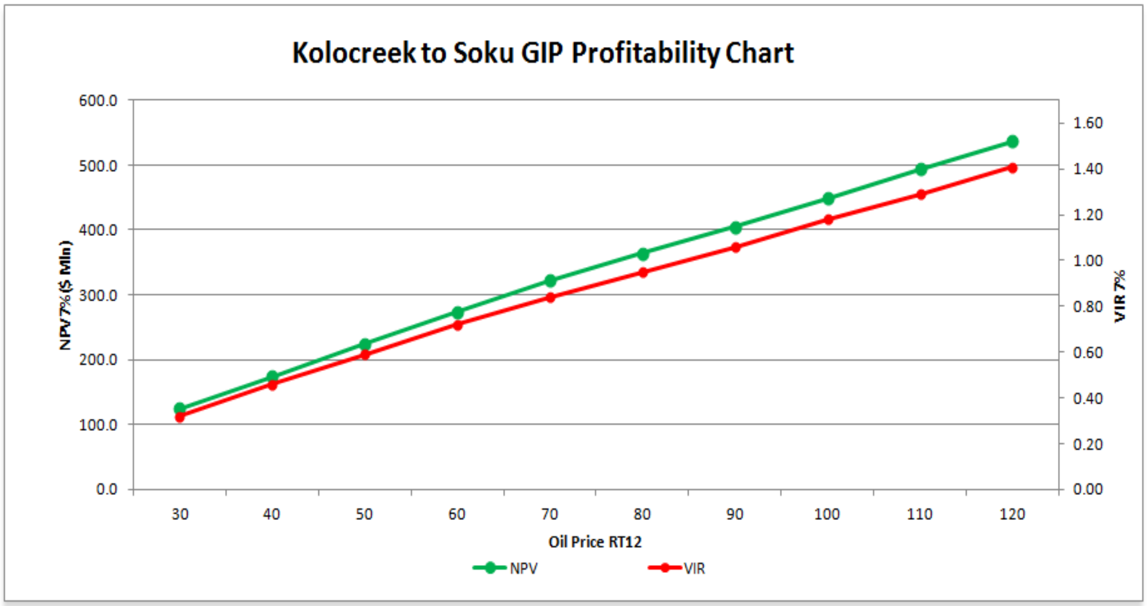


Figure 2: Project Profitability Plot

Appendix 2: Scope and Cost Estimate for the KoloCreek Deep Field Development to Soku Project

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.

Description	
Location Preparation	35.7
Drilling and Completion	208.3
Pipeline and Hook-up	49.2
NAG Facilities* (inclusive of PMT, VAT & Owners Cost)	428.26
Total CAPEX (100% JV)	**721.5**
SCD	11.95
Total OPEX (100% JV)	**11.95**
Total (100% JV)	**733.4**
Total (Shell Share)	**463.5**

Table 1: Details of the cost estimate (MOD 100% JV) for the full scope of the Project

Description	COST PHASING						
	Previously approved Pre-FID	2012	2013	2014	2015	2016	Total
Facilities Capex 100% JV (FUS$mln) - less PMT& SCD	6.4	15.00	55.92	155.53	121.08	72.50	426.4
Wells Capex 100% JV (FUS$mln)			94.94	121.51	27.56		244.0
Total Capex 100% JV (FUS$mln) - less PMT&SCD	6.4	15.0	150.9	277.0	148.6	72.5	670.4
PMT 100% JV (FUS$mln)	2.6	6.7	11.4	19.9	17.1	2.4	60.1
Opex 100% JV (FUS$mln)			2.2	4.4	3.4	1.9	12.0
Total 100% JV (FUS$ mln)	**9.0**	**21.7**	**164.5**	**301.4**	**169.1**	**76.8**	**742.4**
Total 100% JV (FUS$ mln) excluding Pre-FID							**733.4**
Shell Share Equity (30%)	2.7	6.5	49.3	90.4	50.7	23.0	222.7
(36.67%)		5.5	55.3	101.6	54.5	26.6	243.5
Total Shell Share (FUS$ mln)	**2.7**	**12.0**	**104.7**	**192.0**	**105.2**	**49.6**	**466.2**
This proposal Total Shell Share excluding Pre-FID (FUS$ mln)							**463.5**

Table 2: 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 3: 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 project cost	742	223	272	495	742	223	272	495
Pre-FID (JV Funded)	(9)	(3)	(3)	(6)	(9)	(3)	(3)	(6)
SCD	(12)	(4)	(4)	(8)	(12)		(4)	(4)
	721	216	265	481	721	220	264	485
PMT Element	(58)		(20)	(20)			(20)	(20)
			245	461	721	220	244	464

Table 4: 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

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

VIR – Value Investment Ratio

ESTIMATE & SCHEDULE FACT SHEET

to be included in OIP and FCN submissions

Version 2.5 Confidential

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

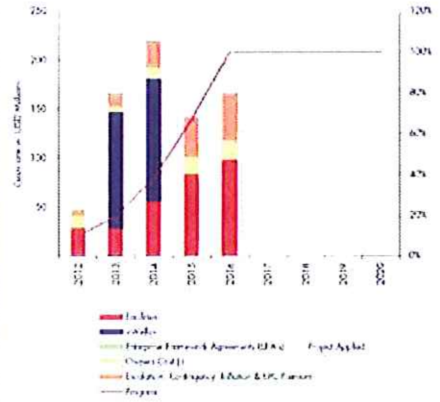
EDM Date: 1-Jul-11

				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

Date : 27-06-2012

Name : Nwakaeze, Emeka

Signature :

Project Manager

Date : 27.06.2012

Name : Ojo, Afolabi

Signature :

VP Project Services

Date : 28th June 2012

Name : P.P. Mos, Hans

Signature :

EVP Projects

Date :

Name : Kretzers, Rob

Signature :