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 to NNPC of US$240.9mln
Project	Kolo Creek Deep Development and Evacuation to Soku gas plant.

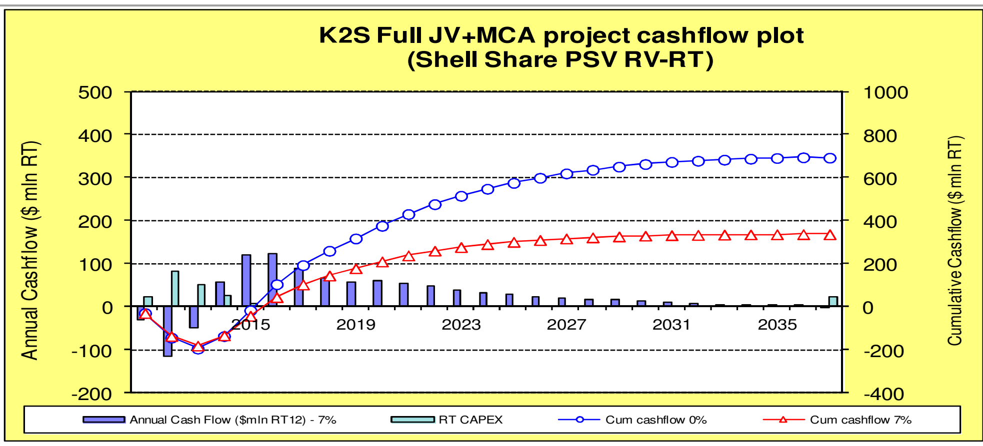
Main commitments

Description	Previously approved Pre-FID (100% JV)	Previously approved Pre-FID (30% Shell Share)	Requested Budget	Complete Budget (100%)	Complete Budget (30% Shell Share)	This Proposal (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	82.5	100.9	183.4	183.4
Facilities and Pipelines	9.0	2.7	447.2	456.2	136.9	134.2	140.1	276.9	274.2
Total CAPEX ($ mln)			**722.2**	**731.2**	**219.4**	**216.7**	**240.9**	**460.3**	**457.6**
SCD			11.2	11.2	3.4	3.4		3.4	3.4
Total OPEX ($ mln)			**11.2**	**11.2**	**3.4**	**3.4**		**3.4**	**3.4**
Total Project ($ mln)			**733.4**	**742.4**	**222.7**	**220.0**	**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	33	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 & $240.95mln 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, an additional three (3) NAG wells into the F1 reservoir as well as 1F1 appraisal well. 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. Production from the F1 and F2 reservoirs will start in Apr 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).

Considering the strict fiscal and governance regimes surrounding MCA, further review of the project costs and schedule were carried out. The revised costs (post-BP11) are as outlined in Table 1 below.

Table 1: Yearly estimated expenditure (FUS$ mln)

Description	COST PHASING							
	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

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, the approved concept is 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. 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.

1.3 Previous proposals

In April 2010, a pre-FID investment proposal of $ 2.7mln (Shell Share) was approved for the Front End Engineering Design, Survey, Land acquisition, and for conducting Environmental Impact Assessment studies for the Kolo Creek Deep to Soku Project.

Section 2: Value proposition and strategic and financial context

Project proposal remains consistent with Shell's strategy of sharper delivery and profitable upstream growth. The proposal also aligns with SPDC JV contractual commitment to supply gas to NLNG.

2.1 Justification for Expenditure

The proposed expenditures are required for the drilling/completion of four (4) gas wells into the F2 reservoir, an additional 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 enable the start of drilling of the Kolo Creek F2 wells in 2013 and therefore 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 (Figures 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.

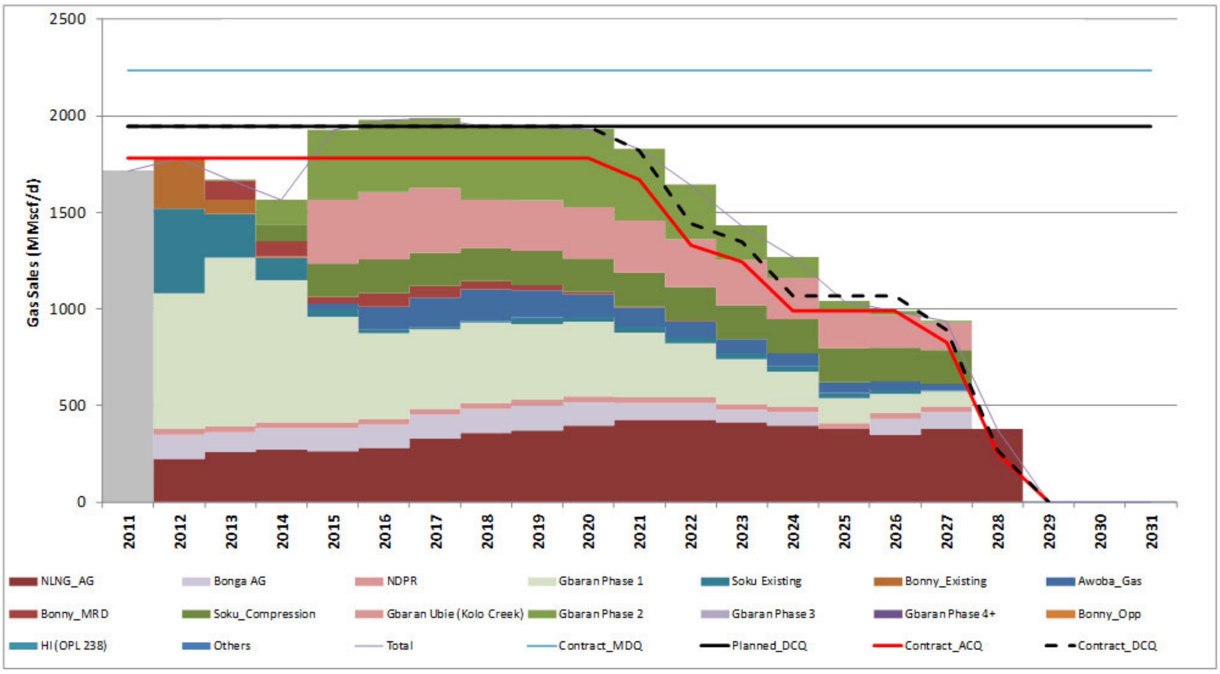


Figure 1: NLNG Trains 1 to 6 supply plot with the optimized 400 MMscf/d Kolo Creek to Soku option

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 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 2 and the Tornado Plot and Profitability Plot are shown in Figures 2 & 3 below.

Table 2a: 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		

Figure 2: Tornado Chart

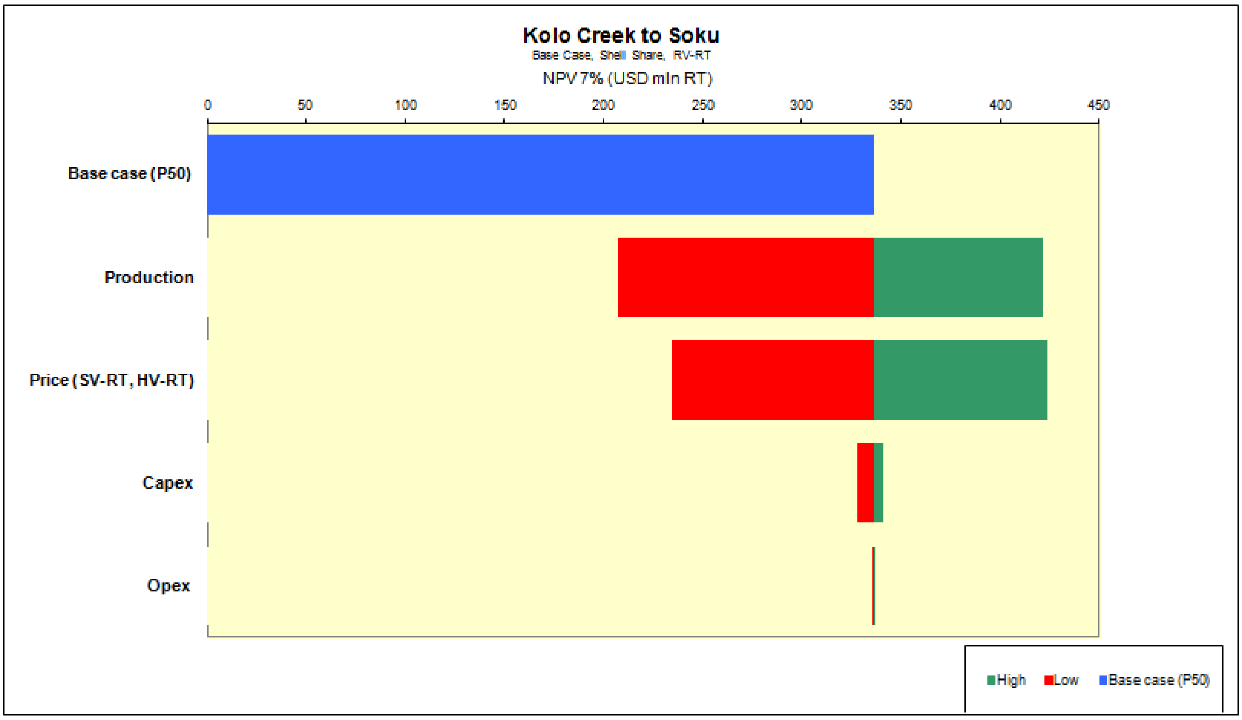
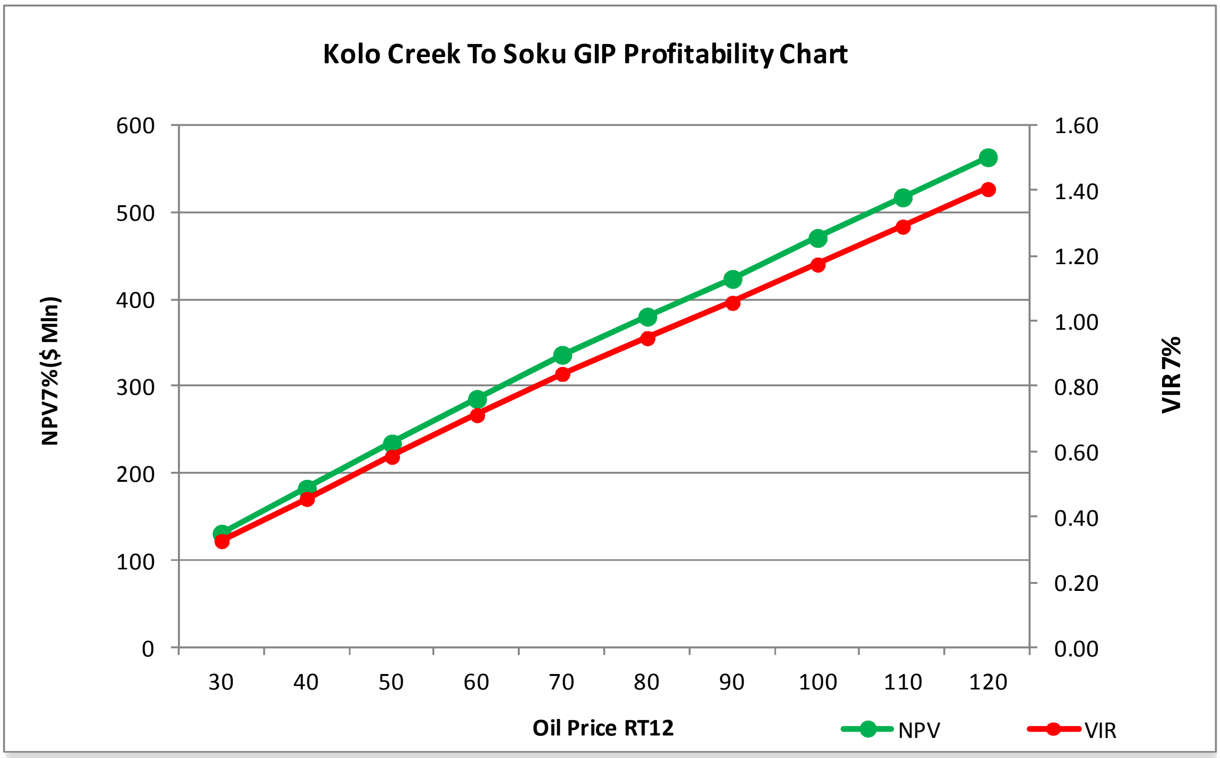


Figure 3: Project Profitability Plot



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.

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.

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

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.

Security Risks (P)

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

Mitigation: The amnesty programme of the federal government has helped to calm the security situation although uncertainty still pervades. Detailed project security plan for the project dovetails into relevant operations security plans and would continue to be improved as necessary

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

Project works in Live plant (T)

Project involves work at Soku gas plant and Kolocreek Oil/ NAG manifold. Therefore risks associated with working in and around hydrocarbon and Concurrent operations (COP) work would require careful and focused consideration

Mitigation: COP Requirements included in technical ITT. Also Concurrent operations management plan to be included in the project construction HSE case e.g. tie-in/ interface meetings, JHA and PTW etc.

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

EPC Contractor has multiple worksites and might be over-stretched, leading to possibility of poor performance and slow work progress with attendant impact on cost and schedule

Mitigation: Contractor's capacity and competence to be reviewed during mobilization to site. Also, adequate project management and record keeping during construction will be enforced. In addition, regular updates will be sent to NAPIMS on contractor performance to enable rapid 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

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 RFM due to routine maintenance depressuring accounts 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 Depressuring philosophy to depressurise the Kolo Creek flowlines at Soku 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
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
There are no unusual taxation features.

Section 13: Key Parameters
Approval is sought for additional US$461mln (Shell Share), 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 to the Board of Royal Dutch Shell plc for shareholder approval.

Supported by:	For Submission:
....	....
Simon Henry	Peter Voser
Chief Financial Officer	Chief Executive Officer
Date: ..../..../....	Date: ..../..../....

Supported

…………………..	…………
Andrew Brown	Mathias Bischel
ECAB	ECMBi
Date: ..../..../....	Date:…/…/…

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.

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**

ESTIMATE & SCHEDULE FACT SHEET

Version 2.5 Confidential

to be included in GIP and PCN 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

Market Scenario: LE

Estimate Type: 3

Rates of Exchange are as per SI-SX Data Set

Costs are in: USD Millions

Estimate Start / End: FID Jul-2012 / Project Completion Aug-2016

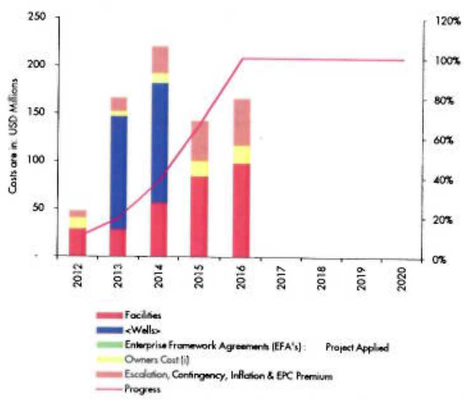
EDM Date: 1-Jul-11

		Total Costs
Facilities		296
<Wells>		244
Enterprise Framework Agreements (EFA's) : Project Applied / Verified, Not Applied		/
Owners Cost (i)	(incl. Insurance, pre-FID, Taxes & Capitalized 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. 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 : 06-JUNE 2012
Name : Nwakaeze, Emeka
Signature : [signature]

Project Manager

Date : 07 JUNE 2012
Name : Ojo, Afolabi
Signature : [signature]

VP Project Services

Date :
Name : Mes, Hans
Signature :

EVP Projects

Date :
Name : Kretzers, Rob
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 Prospective Resources Additions: 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	CHECK developed reserves additions minus cum produciton: 2P Reserves Developed	CHECK: SEC Proved Developed
DG1	Jun-05																0.0	0.0
DG2	Jun-06																0.0	0.0
DG3	Aug-09										16.8			4.4			0.0	0.0
FID	Nov-12																0.0	0.0
OSD	Oct-15																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
	2013															0.0	0.0	0.0
	2014															0.0	0.0	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	9.8	1.9
	2016										-5.9		5.7	-1.4	1.7	2.1	13.4	1.5
	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	11.4	2.8
	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	9.7	6.2
	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	8.1	7.1
	2020												0.0		1.0	1.4	6.7	6.7
	2021												0.3		0.3	1.4	5.5	5.5
	2022															1.2	4.3	4.3
	2023															0.9	3.4	3.4
	2024															0.7	2.6	2.6
	2025															0.6	2.1	2.1
	2026															0.5	1.6	1.6
	2027															0.4	1.2	1.2
	2028															0.3	1.0	1.0
	2029															0.2	0.7	0.7
	2030															0.2	0.5	0.5
	2031															0.1	0.4	0.4
	2032															0.1	0.3	0.3
	2033															0.1	0.2	0.2
	2034															0.1	0.1	0.1
	2035															0.0	0.1	0.1
	2036															0.0	0.1	0.1
	2037															0.0	0.0	0.0
	2038															0.0	0.0	0.0
	2039															0.0	0.0	0.0
	2040															0.0	0.0	0.0
	2041															0.0	0.0	0.0
	2042															0.0	0.0	0.0
	2043															0.0	0.0	0.0
	2044															0.0	0.0	0.0
	2045															0.0	0.0	0.0
	2046															0.0	0.0	0.0
later years																0.0	0.0	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		

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 Prospective Resources Additions: 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	CHECK developed reserves additions minus cum produciton: 2P Reserves Developed	CHECK: SEC Proved Developed
DG1	Jun-05																0.00	0.00
DG2	Jun-06																0.00	0.00
DG3	Aug-09										12.63			3.76			0.00	0.00
FID	Nov-12																0.00	0.00
OSD	Oct-15																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
	2013	0.00	0.00	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	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	7.78	2.17
	2016										-4.35		4.35	-1.09	1.15	1.09	11.04	2.23
	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	9.94	1.14
	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	8.97	2.24
	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	7.94	5.07
	2020												0.50		1.87	1.00	7.44	5.94
	2021															1.07	6.37	4.87
	2022														0.00	1.02	5.35	3.85
	2023														0.00	0.88	4.48	2.98
	2024														0.00	0.75	3.72	2.22
	2025														1.00	0.65	3.08	2.58
	2026														0.50	0.56	2.52	2.52
	2027															0.48	2.04	2.04
	2028															0.41	1.63	1.63
	2029															0.36	1.27	1.27
	2030															0.31	0.97	0.97
	2031															0.26	0.71	0.71
	2032															0.21	0.50	0.50
	2033															0.12	0.38	0.38
	2034															0.11	0.27	0.27
	2035															0.09	0.18	0.18
	2036															0.08	0.10	0.10
	2037															0.07	0.03	0.03
	2038															0.03	0.00	0.00
	2039																0.00	0.00
	2040																0.00	0.00
	2041																0.00	0.00
	2042																0.00	0.00
	2043																0.00	0.00
	2044																0.00	0.00
	2045																0.00	0.00
	2046																0.00	0.00
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		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		

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 Techncical (or VP-X)		RDL-RE (RXC or RXHM)
Date :		Date :	21-June-2012
Name :		Name :	Osayande Igiehon
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 foecast need to be captured in HRV-MS, which is the single data source for HCM.