Group Investment Proposal

Summary Information

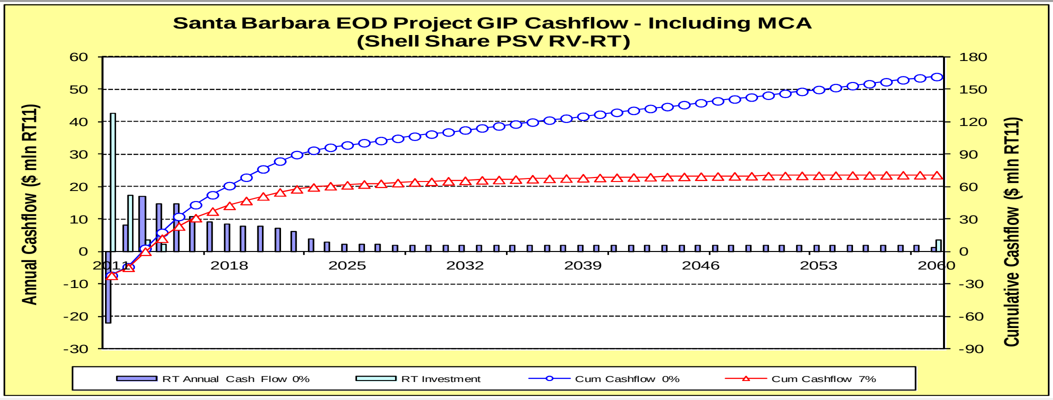
Business Unit and Company	Shell Petroleum Development Company of Nigeria Limited (SPDC)
Group Equity Interest	100% in SPDC, whereas SPDC is the Joint Venture (JV) operator of an unincorporated JV with a 30% interest.
Other Shareholders / Partners	Nigerian National Petroleum Corporation (NNPC: 55%), Total E&P Nigeria Ltd (10%), and Nigeria Agip Oil Company Limited (NAOC: 5%)
Business or Function	Upstream International (UI)
Amount	The headline size of U$114.84 mln Shell Share MCA MOD 50/50 composed of US$113.55 mln Shell Share MOD CAPEX and US$1.29 mln Shell Share MOD OPEX is being requested for approval in this revised GIP. This is made up of US$42.08 mln Shell share approved in the previous proposal and US$72.76 mln Shell share being requested to complete the project in this GIP. The total Shell commitment of $114.84 is composed of Shell Equity contribution of US$64.59 mln and MCA contribution of US$50.25 mln.
Project	Santa Barbara Further Oil Development, FOD Phase 1 (also known as Early Oil Development, EOD)

Main Commitments

50/50 MOD	100% JV ($'mln) MOD_Revised GIP					Shell Share ($'mln) MOD_Revised GIP				
Description	Previous IP_JV Spent not part of MCA	Previous IP_JV spent but part of MCA	Incremental IP Request_ JV Funding	Incremental IP Request_ MCA Funding	**Total IP**	Shell Share_Previous IP	Shell Share_Incremental IP	Shell Share_Equity	Shell Share_MCA	**Total Shell Share**
Flowline & Hookups	1.20	2.51		11.45	**15.16**	2.03	7.63	4.55	5.12	**9.67**
Facilities	-	0.99		16.99	**17.98**	0.66	11.33	5.39	6.59	**11.99**
Facilities (MPF Refurbishment)			28.50		**28.50**	-	8.55	8.55		**8.55**
Wells & Location Prep.	39.24	40.69		58.91	**138.84**	38.90	39.27	41.65	36.52	**78.17**
PMT	-	-	5.03		**5.03**	-	1.51	1.51	-	**1.51**
Contingency	-	-		5.50	**5.50**	-	3.67	1.65	2.02	**3.67**
Total CAPEX	**40.44**	**44.19**	**33.53**	**92.85**	**211.01**	**41.59**	**71.96**	**63.30**	**50.25**	**113.55**
SCD (OPEX)	**1.62**	**-**	**2.67**		**4.29**	0.49	0.80	**1.29**	**-**	**1.29**
Total Cost	**42.06**	**44.19**	**36.20**	**92.85**	**215.30**	**42.08**	**72.76**	**64.59**	**50.25**	**114.84**

Reserves/Resources	This project is aligned with SPDC's strategic goals and priorities by maturing economic truncated 2P reserves of 11.58 MMstb of oil and 0.18 bln sm3 of gas (SS) to production and transferring of equivalent SEC Proved reserves of 9.75 MMstb of oil and 0.14 bln sm3 of gas (SS) from PUD to Proved Developed in 2012 with positive impact on SPDC DD&A (This includes economic truncated 2P and proved oil reserves of 2.18 MMstb and 1.85MMstb (SS) respectively for the SBAR-10T well re-categorized as NFA, Ref Page 3 & HCM table attached). In addition, 0.23 MMstb PUD associated with the MCA had been booked in 2010 (Ref 31.12.2010).
Production	Incremental annualized oil production peaks at 8.8 Mbopd with associated gas production of 2.8 MMscf/d (2.64 Mbopd and 0.84 MMscf/d SS) by 2013 thus increasing the effective utilization of the new NCTL pipeline and contributing to SPDC's gas supply to NLNG.
Source and Form of Financing	This investment will be financed through the agreed MCA funding for NCTL Bundle reference GFP approved by the RDS Board on 22.07.2008. Total Shell commitments including NNPC carry under the MCA will be financed with SPDC limited own generated funds. The MCA terms do not include PMT CAPEX and all OPEX related expenditures.

Summary Cash Flow



Summary Economics

Summary economics* Project title: Santa Barbara EOD Project GIP	NPV (USD mln)	RTEP (%)	VIR
RV ($70/bbl & $1.73/mmbtu RT11)	70.9	54	1.10
SV ($50/bbl & $1.30/mmbtu RT11)	47.0	40	0.73
HV ($80/bbl & $2.27/mmbtu RT11)	95.1	68	1.48

Section 1: The proposal (Management Summary)

This revised Group Investment Proposal (GIP) seeks support/approval for the headline size of $114.84 mln being the required funding level to fully execute Santa Barbara Further Oil Development FOD Project Phase 1 (also known as Santa Barbara Early Oil Development, EOD) and the refurbishment of the Mobile Production Facility, MPF. This funding level is composed of US$64.59 mln Shell Equity Share MOD and additional contribution of US$50.25 million as NNPC carry under MCA. The sum of $42.06 had been approved in the previous proposal with $72.78 mln to be approved in this revised proposal.

The GIP revision is necessitated by the change in funding scope from Shell Equity Share only to Shell equity plus NNPC carry under MCA agreement, project cost increase resulting from higher than anticipated Rig and materials cost, cost re-categorisation based on MCA guidelines and the need to re-run the economics.

Santa Barbara and Santa Barbara South fields are located in OML 25 and 29, about 60 km South-West of Port Harcourt. The fields have expectation STOIIP of 1084.1 MMstb, Expectation Ultimate Recovery (100%) of 445.2 MMstb (reference NNS ARPR 31/12/2010). The cumulative production as at 31/12/2010 was 32.3 MMstb from 8 wells. Undeveloped Expectation oil Reserves of 83.3 MMstb and 61.03 Bscf of gas (nipRes ARPR 31/12/2010) exist in the field which are made up of Santa Barbara EOD project and existing conduits closed-in because of facility unavailability.

Santa Barbara EOD project aims to drill and complete 5 wells (4 horizontal, 1 conventional well), install flowlines, hookup wells to flowstations, facility refurbishment and upgrade. Of these, three wells were drilled and completed in 2008. The original objective of the EOD project (ref 2007 GIP) was to develop 52 MMstb (100%) expectation oil reserves. However, based on the BP10 HCM forecast, the project will develop economic truncated 2P reserves of 38.6 MMstb of oil (100%) having drilled, hooked-up and produced SBAR-10T before now.

Santa Barbara field has an AG infrastructure in-place which delivers produced gas to Soku Gas Plant via an existing gas export pipeline. The produced water will be disposed of at the Bonny terminal. The total liquid processing capacity of existing Santa Barbara Mobile Production Facility (MPF) is 30 Mbpd. Crude will be evacuated from the field via the new Nembe Creek Trunkline (NCTL). However, the Santa Barbara Flowstation will not be available until Q1 2012 as it is currently undergoing refurbishment.

In April 2007, approval was sought and obtained for US$21.3 mln CAPEX Shell Share (with US$ 4.6 approved in 2006 pre FID-IP) bringing the total Shell Share to US$25.9 to drill 5 Oil producers (4 horizontal and 1 Conventional wells) and carry out minor facility upgrade in Santa Barbara field in 2007. As at June 2008, 3 horizontal wells were drilled/hooked up and have developed economic truncated 2P reserves of 18.92 MMstb (100%, BP10). The actual spend (Shell Share) prior to MCA, for the facility is US$0.4mln, while that of the 3 wells already drilled was US$26.2 mln (including US$0.7 location preparation). This spend is already above 2007 approved budget for the project (US$25.9 mln SS). The increase in the project cost is attributed to:

- Increased rig maintenance cost as against the number planned and executed.
- Higher than anticipated Rig and materials cost, Drilling Contractor (Lonestar) internal management problems leading to high NPT, as well as escalating security challenges in the Niger Delta.

Though the revised Investment Proposal is in line with capital expenditure allocated to the Santa Barbara phase-1 project in the business plan, there is shortfall of US$ 23.56 mln (100%) when compared to the costs per the 2008 MCA agreement. The shortfall in the JV funded cost is US$31.87 mln due to additional facility scope.

Drilling is planned to start in October 2011 with MCA pickup rig, based on the signed June 2011 Short-Term Drilling and Workover Sequence. The 1st oil is expected in April 2012 when SBAR MPF will come on stream.

Santa Barbara MPF facility refurbishment comprises re-entry activities to restore the integrity of the facility in order to produce current locked-in oil potential of 20.7 Mbopd at the shortest possible time. Re-entry activities involve refurbishment of all major equipments like generators, pumps, compressors, replacement of control system, electrical/instrument cables, UPS systems and transformers and procurement/replacement of 25 km of flowlines. The re-entry activities commenced in September 2010.

The scope for the planned upgrade of the MPF will entail installation of new facilities such as pumps, generators, platform extension, control systems, de-bottlenecking etc to accommodate the increased production from the field. Detailed design and procurement is planned to start in Q3 2011. A project/category contracting and procurement strategy will be developed that follows Global Standards for CP in projects by the end of September 2011. All contracts and purchase orders that are generated as a result of the approved project CP strategy will be tendered and awarded in compliance with the Global CMCP requirements and guidelines and any exceptions to this will be properly escalated through a SME as required.

The 2007 IP economics returned a life cycle project NPV of US$28.5 mln at a Project Screening Value (PSV) of $30/bbl, compared to the full lifecycle evaluation of this updated IP at US$47 mln NPV (7%) at a higher PSV of $50/bbl based on different cost premises (ref. Summary Economics section Table 1).

Section 2: Value proposition and strategic and financial context

This project is aligned with SPDC's strategic goals and priorities by:

- Maturing economic truncated 2P reserves of 11.58 MMstb of oil and 0.18 bln sm3 of gas (SS) to production and transferring equivalent SEC Proved reserves of 9.75 MMstb of oil and 0.14 bln sm3 of gas (SS) from PUD to Proved Developed in 2012 with positive impact on SPDC DD&A. The reserves of SBAR-10T was excluded in the HCM forecast attached since the well is categorised as NFA having been drilled, completed, hooked-up and produced shortly before the flowstation outage. Though the HCM forecast includes the Santa Barbara Appraisal well (SBAR-ABNB1) 2C Oil resources of 3.5 MMstb (SS), the current GIP update does not include the appraisal well as there is already a separate approved IP for the well.
- Increasing oil production and peaking at 8.8 Mbopd by 2013 thus increasing the effective utilization of the new NCTL pipeline.

The additional oil will partly arrest the production decline in Santa Barbara field while the associated gas will also contribute to gas sales. It will also lower the bulk water volume flowing through the Nembe Creek Trunk Line (NCTL) considerably due to increased volume of dry oil being produced.

Summary Economics

The base case economics is a forward-look evaluation and assumes that Shell will fund its NNPC share of the Carry (MCA) component of the costs and its Equity share of the project cost. This evaluation considered the Shell Equity forward-look spend of US$64.59 mln (including US$1.29 mln OPEX) and MCA Shell Share of US$50.25 mln (i.e. Total cost of $114.84 mln out of $215.3 mln MOD 100% JV). The Project Management (PMT) CAPEX and Social Performance OPEX are excluded from MCA funding (treated as JV cost) as they are not originally part of the agreed carry cost under the arrangement. Consistent with the terms of the MCA, the sensitivity assumes the extra cost will be recovered through cost oil only as SPDC may not be able to receive profit oil. The 100 % Capex phasing (including Social Performance Opex of US$4.29 mln) at 50/50 MOD estimate is shown in Table 1:

Table 1: SBAR FOD Phase 1 project Cost Phasing MOD 100% JV and Shell Share

P50 Estimate & Expenditure Phasing	JV Funded								MCA Funded							PROJECT TOTAL
	2007	2008	2009	2010	2011	2012	2013	2014	2008	2009	2010	2011	2012	2013	2014	
Facilities	1.84	0		3.55	20.15	4.80	-	-	5.03	-	-	15.50	7.71	5.00	3.00	66.58
PMT					0.11	1.20	2.40	1.32	-	-	-					5.03
Wells	38.6			-	-	-	-	-	45.10	-	-	33.47	16.73			133.90
Contingency							-	-	-	-	-	5.50	-	-	-	5.50
OPEX (SCD)	1.62	1.19	-	-	1	0.28	0.1	0.1		-	-					4.29
100% CAPEX Phasing	**40.44**	**0.00**	**0.00**	**3.55**	**20.26**	**6.00**	**2.40**	**1.32**	**50.13**	**0.00**	**0.00**	**54.47**	**24.44**	**5.00**	**3.00**	**211.01**
100% Cost Phasing	**42.06**	**1.19**	**0**	**3.55**	**21.26**	**6.28**	**2.5**	**1.42**	**51.32**	-	-	**55.47**	**24.72**	**5.10**	**3.10**	**215.30**
Years / Phasing (Shell Share)	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**PROJECT TOTAL**
JV_Cost Phasing (Shell Share)_CAPEX	12.13	0.00	0.00	1.07	6.08	1.80	0.72	0.40	15.04	-	-	16.34	7.33	1.50	0.90	**63.30**
JV_Cost Phasing (Shell Share)_OPEX	0.486	0.36			0.30	0.08	0.03	0.03								1.29
Total JV_Cost Phasing	**12.618**	**0.36**	**0.00**	**1.07**	**6.378**	**1.884**	**0.75**	**0.43**	**15.04**	-	-	**16.34**	**7.33**	**1.50**	**0.90**	**64.59**
MCA_Cost Phasing (Shell Share)_CAPEX									**18.38**	-	-	**19.97**	**8.96**	**1.83**	**1.10**	**50.25**
Total Shell Share_JV & MCA	**12.62**	**0.36**	**0.00**	**1.07**	**6.38**	**1.88**	**0.75**	**0.43**	**33.42**	**0.00**	**0.00**	**36.31**	**16.29**	**3.33**	**2.00**	**114.84**

The headline number covers the 2007 - 2014 CAPEX required for the project execution, and the Shell share of the NNPC portion of the project cost, bringing Shell Share of the project cost, to approximately 53% of the SPDC JV 100% cost of $215.3mln MOD.

Sensitivities evaluated include:

- High CAPEX
- 1yr schedule delay
- Full Life Cycle
- PIB House Version
- High & Low reserves
- Concession expiration in 2019
- 1.5% cost mark up as provision for costs dispute by NNPC.

The impact of earlier approved expenditure of $86.25mln and additional expenditures of $10.68mln (Wells - $5.94mln, MPF - $3.55mln, and OPEX – $1.19mln), i.e. $96.93mln 100% JV MOD on the base case economics is shown under the Full Life Cycle sensitivity. Details are shown in Table 2 below. The tornado and the profitability plots are shown in Figures 1 and 2.

Table 2: Economic indicators for the full scope of Santa Barbara EOD Phase 1

PV Reference Date: 1/7/2011	**NPV (S/S $ mln)**		**VIR**	**RTEP**	**UTC (RT $/boe**		**Payout-Time (RT)**	**Maximum Exposure (RT)**
Cash flow forward from: 1/1/2011	**0%**	**7%**	**7%**	**%**	**0%**	**7%**	**0%**	**0%**
Base Case + MCA								
SV ($50/bbl & $1.30/mmbtu RT11)	110.3	**47.0**	**0.73**	40	6	9		
RV ($70/bbl & $1.73/mmbtu RT11)	161.6	**70.9**	**1.10**	54	6	9	2013	*$22.1mln in 2011*
HV ($90/bbl & $2.27/mmbtu RT11)	210.8	**95.1**	**1.48**	68	6	9		
Oil BEP (RT $/bbl)						6.2		
Sensitivities (using RV)								
High CAPEX (P90)		**70.1**	**0.98**				2013	*$24.5mln in 2011*
High Reserves		**73.6**	**1.15**				2013	*$17.3mln in 2011*
Low Reserves		**57.5**	**0.89**				2014	*$26.9mln in 2012*
1-Yr Production Schedule Delay		**65.7**	**1.02**				2014	*$26.9mln in 2012*
Concession Expiration (2019)		**46.8**	**0.73**				2013	*$22.1mln in 2011*
Full Life Cycle		**37.6**	**0.30**				2015	*$51.3mln in 2011*
1.5% cost markup due to BVA issues		**68.2**	**1.03**					
PIB House_v12		**82.7**	**1.29**					

Key Project Parameter Data Ranges (Shell Share)

Parameter	Unit	BP10 Provision	Low	Mid	High	Comments
Capex (MOD)	US$ mln	72.76	68.34	72.76	80.99	Incremental CAPEX under MCA Funding of $34.04mln and JV Funding of $38.72mln. FLC CAPEX under MCA Funding is $50.25mln and FLC JV Funding is $64.59mln
Opex (MOD)_Project	US$ mln	0.80	0.72	0.80	0.96	Incremental project OPEX under JV Funding. FLC OPEX is $1.29mln
Production Volume	mln boe	21.61	16.13	21.61	21.82	Production volume forecast till end of fields' lives
Start Up Date	mm/yy	Apr-12	Apr-13	Apr-12	Jul-11	Base re-start Up production
Production in first 12 months	mln boe			1.67		Production vloume from April, 2012 - March, 2013

Figure 1: Tornado Plot for Santa Barbara EOD Project GIP

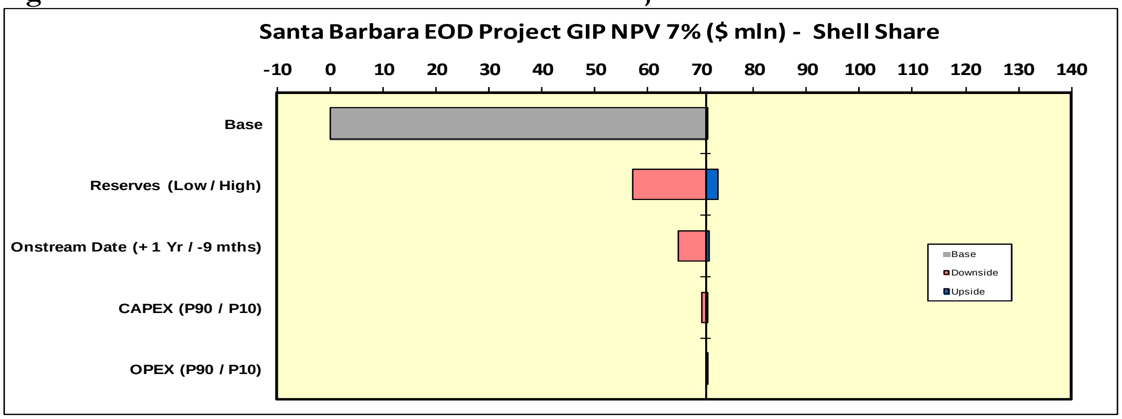
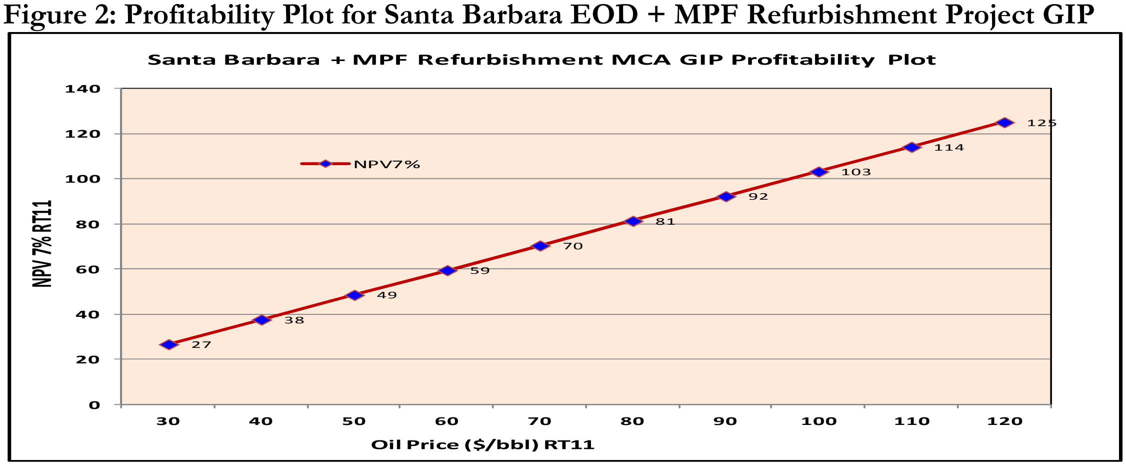


Figure 2: Profitability Plot for Santa Barbara EOD + MPF Refurbishment Project GIP



Key Economic Assumptions:

- Gas taxed under CITA with AGFA fiscal incentive applied.
- Gas Supply to NLNG T1-6 assumed Gas Sales Price $1.73/mmbtu at PSV RV-RT in 2011.
- Gross Heating Value (GHV) of 1150btu/scf applied.
- ARPR OPEX of 31/12/2010 was applied in addition to project Social Performance OPEX.
- NDDC Levy of 3% of total expenditure excluding flare penalty
- Education Tax of 2% assessable profit
- Flare penalty of $3.5/Mscf applied.
- Water treatment cost at $0.50/bbl applied.
- 10% of total project RT CAPEX assumed as abandonment cost

MCA assumptions:

- All costs over the MCA ceiling would be recovered through cost oil.
- Project management costs were not included among the carried cost.

- Profit oil ceiling of 8% IRR on carried costs
- Current agreement for recovery of carry costs is maintained

PIB assumptions:

- Overseas_Capex_Fraction_Assumed at 30%
- 70$/bbl – oil at PSV RV-RT in 2011
- 1.73$/mmbtu – gas (export) at PSV RV-RT in 2011
- NHT depreciation schedule is 4x20%, 19% for qualifying expenditure.
- CIT depreciation schedule is 3x25%, 24%, for qualifying expenditure.
- Royalty rates based on product (value) prices and production rates per PML (assumed equal to a field).
- Education tax calculated as 2% of its assessable profit and it is not deductible for CIT, but deductible for NHT.
- NDDC levy calculated as 3% of expenditure
- Withholding tax is applicable at a rate of 7.5% for IAT version but not for the alternate version
- Flaring penalty is calculated at $3.5mln/Btu MOD flat and it is not tax deductible for both CIT and NHT
- 20% of overseas cost is non-deductible for determination of NHT taxable income
- NHT rate is 50% for onshore and shallow water, and 30% for frontier acreages and Deep Water.
- CIT is 30% of taxable income and is not deductible from NHT
- Santa Barbara is an existing field hence no production allowance is applicable.

Section 3: Risks, opportunities and alternatives

The principal risks associated with this proposal, key mitigation measures and opportunities are as follows:

3.1 Risks

- **Funding:** There is the risk that project value to Shell will be eroded if the MCA-approved cost estimate is exceeded. There is also the risk that costs above the approved cost estimate may not be approved by NNPC and therefore become a Shell exclusive charge.
  Mitigation: Project will be executed based on approved budget. Partners would be engaged early where there is variation.
- **Community and Enabling Environment (Security, Sabotage, Political and Environment):** Hostage taking, existence of militant groups and threat of insurgence are current realities in the Niger Delta especially in the swamp which could threaten project execution.
  Mitigation: General Memorandum of Understanding (GMoU) has been signed with the community and 2 % of the total project cost will be used for Community project. With improvements in the Niger Delta security following Amnesty programme, it is envisaged that there will be a reduction in community related NPT. Specific threats will be managed through the Security & Surveillance Centre (SIS) and communicated in good time to those that need to "Know" and "act".
- **HSE:** The project will be executed under challenging circumstances in the Niger Delta Eastern Swamp.
  Mitigation: There will be site specific HSE adviser and existing HSE-MS culture will be sustained during the project.
- **Cost Overrun:** Increase in the rig cost as a result of shortage of suitable swamp rigs, Non-productive time while drilling, escalation of facility upgrade and material costs.
  Mitigation: The well and facility costs have been updated to reflect current reality. .
- **Delayed Completion of Flow-station refurbishment Project:** The vandalization of the Santa Barbara Flowstation and flowlines resulted in the inability to open up the station post NCTL repairs.
  Mitigation: Currently, Flow-station refurbishment is ongoing and Latest Estimated Completion (LEC) date is Q1 2012. A dedicated project team and DRB members are in place to ensure on-time delivery.
- **Early Water Breakthrough:** Early water breakthrough from new wells resulting in reduced incremental oil recovery.

Mitigation: The wells will be optimally placed as possible to reduce the risk of water breakthrough. Learning from the previous wells drilled will be incorporated. Data from permanent down-hole gauges will aid reservoir surveillance to optimize the off-take.

- **Facility Uptime Improvement:** Facility uptime improvement from 55% to 85%
  Mitigation: As at June 2011, facility uptime is 0% (No recent data as station has been down since July 2008). Activities are currently ongoing to improve the uptime to expected minimum of 85%. These activities include Station power generator and control system change out and are expected to be delivered by end 2014.
- **Risk around unapproved incremental MCA Costs:** There is a risk that un-approved MCA costs would be disallowed for tax deductions by the FIRS.
  Mitigation: Upstream Commercial Finance would re-negotiate and ensure that incremental costs are approved by NNPC.

3.2 Opportunities

- **Resources**
  All the critical positions required to deliver the project have been resourced.
  Swamp East Asset Development (DSSE) Field Development and Execution Team will support the execution. Engineering support will be provided by both Major project Corporate Matrix and Asset Engineering Teams.
- **Project support:**
  This project will provide data for the optimization of Santa Barbara Phase 2 FDP wells.
- **Knowledge Sharing**
  This project will provide a very good opportunity for the new well-site PEs to have requisite operations experience under the close supervision of their senior PEs and SDEs.

3.3 Alternatives

There are no alternatives to drilling these wells to develop the reserves and implement current re-entry refurbishment activities for early production given in this proposal.

Section 4: Carbon Management

The main impact on Greenhouse Gas emissions is at the surface facilities due to increased energy consumption and low compressor uptime. Santa Barbara EOD project would raise the 10-year average Green House Gas (GHG) emissions by 8.9 KtCO2eq/year. However, if the compressor uptime, measurement device and rotating equipment improvement proposals set out in the facilities GHG & EM plan are executed successfully the average incremental emissions from the project would be 3.6 KtCO2eq/year.

Section 5: Corporate Structure, and Governance

This proposal is within the SPDC corporate structure and governance framework.

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

This proposal and the execution of the project are consistent with the Group Business standards. Functional support for this proposal has been provided by Technical, Finance, Legal, Treasury, Contracting/Procurement, Social Performance and Tax functions etc.

Section 7: Project Management, Monitoring and Review

The execution of the project is managed through the DSSE Field Development & Execution Team, Wells and Engineering Hub Teams in line with the SPDC organizational model. Following successful completion, the wells will be handed back to the Swamp East Production Operations Team. There will be regular progress report of the well delivery activities to Asset Development Manager, the Development General Manager and to the JV Partners. All significant reviews and follow up actions had been done in the Development and Engineering Teams. Details of the ORP review gates are shown below:

- VAR2 (Nov. 2004) and DG2 (May. 2005)
- VAR3/DG3 completed in Oct. 2005/ Dec. 2005, respectively
- VAR4 /DG4 in Aug. 2006/ Nov 2006 respectively and comments have been closed out.

Section 8: Budget provision

This project has budget cover and is included in BP10 and BP11 as well as the 2011/12 JV Programme. Though the revised Investment Proposal is in line with capital expenditure allocated to the Santa Barbara phase-1 project in the business plan, there is shortfall of US$ 23.56 mln (100%) when compared to the costs per the 2008 MCA agreement. The shortfall in the JV funded cost is US$31.87 mln due to additional facility scope. In line with MCA agreement, NAPIMS will be engaged on the shortfall in order to reach an agreement on how to fund the additional cost.

Section 9: Group financial reporting impact

The financial impact of this proposal on Shell Group financial is as outlined in the table below:

US$ mln	Prior Years	2011	2012	2013	2014	2015	Post 2015
Total Commitment	47.46	42.69	18.18	4.08	2.43	0.00	0.00
Cash Flow							
SCD Expenditure	0.84	0.30	0.08	0.03	0.03	0.00	0.00
Capital Expenditure	46.62	42.39	18.09	4.05	2.40	0.00	0.00
Operating Expenditure	0.00	1.72	2.83	4.28	2.76	2.26	62.79
Cash Flow from Operations	11.55	15.89	27.63	32.20	30.07	21.56	187.46
Cash Surplus/(Deficit)	(35.07)	(26.51)	9.54	28.15	27.67	21.56	187.46
Profit and Loss							
NIBIAT +/-	2.13	2.74	12.59	14.74	10.84	7.24	178.73
Balance Sheet							
Average Capital Employed	56.03	81.43	118.62	133.16	136.61	122.36	422.93

Section 10: Disclosure

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

Section 11: Financing

Both SPDC's direct share of expenditure and its contribution to NNPC's share will be funded from SPDC's own cash flow and existing intra-group facilities.

Section 12: Taxation

MCA fiscal arrangements are acceptable to the Tax authorities, provided their sign off is obtained before implementation.

Section 13: Key Parameters

The following are the main aspects of this proposal:

Approval for the total revised headline size of US$114.84 mln Shell Share 50/50 MOD. This is made up of US$42.08 mln (SS MCA) previously approved in 2007 GIP and US$72.76 mln (SS MCA) in this revised GIP (incremental IP). The Shell only Equity contribution is US$64.59 mln while Shell MCA contribution is US$50.25 mln.

Section 14: Signatures

This Proposal is submitted to ECMB for approval.

Supported by:	For Business approval:
....	....
Maarten Wetselaar (FUI)	Malcolm Brinded (ECMB)
Date ..../..../....	Date ..../..../....

Initiator: ____________________

Ime Uyouko (UIG/T/DSSE)
Date: 31/07/2011

Lifecycle HCM Forecast Sheet Version 2.0 Confidential

Santa Barbara FOD Phase 1

Project Location & Country Project No.: SPDC-11-2581

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: Prospect	2C Contingent Resources Additions: Dev. Pending Post-DG1	2C Contingent Resources Additions: Dev. Pending Post-DG2	PRMS 2P Reserves Additions: Undeveloped Post DG3	PRMS 2P Reserves Additions: Undeveloped Post-DG4	PRMS 2P Reserves Additions: Developed	SEC Proved Reserves Additions: Undev	SEC Proved Reserves Additions: Developed	Annual Production
DG 2	Sep-05			12.8						
DG 3	Sep-05			-9.4	9.4					
FID	Apr 07				-9.4	9.4		7.9		
	2010									
Appraisal Well Drillin	2011			-3.4		3.4				
First HC	2012					-12.8	12.8	-7.9	7.9	0.8
	2013								0.0	1.1
	2014								0.0	0.8
	2015								0.0	0.7
	2016								0.0	0.7
	2017								0.0	0.7
Perf Update	2018								2.0	0.7
	2019								0.0	0.7
	2020								0.0	0.7
Perf Update	2021								1.8	0.7
	2022								0.0	0.5
	2023								0.0	0.4
Perf Update	2024								0.7	0.2
	2025								0.0	0.2
	2026								0.0	0.2
Perf Update	2027								0.5	0.2
later years									0.0	3.6
Total		0.0	0.0	0.0	0.0	0.0	12.8	0.0	12.8	12.8

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
12.0	7.1
10.9	6.0
10.2	5.3
9.5	4.6
8.8	3.9
8.1	3.2
7.3	4.4
6.7	3.7
6.0	3.0
5.3	4.1
4.8	3.6
4.4	3.2
4.1	3.6
4.0	3.5
3.8	3.3
3.6	3.6
0.0	0.0

negative numbers are incorrect

OIL/NGL [mln bbl]		2U Prospective: Prospect	2C Contingent Resources: Dev. Pending Post-DG1	2C Contingent Resources: Dev. Pending Post-DG2	PRMS 2P Reserves: Undeveloped Post DG3	PRMS 2P Reserves: Undeveloped Post-DG4	PRMS 2P Reserves: Developed	SEC Proved Reserves: Undev	SEC Proved Reserves: Developed
ARPR 31.12.2009	before last					16.5		9.8	
ARPR 31.12.2010	last					12.4		7.7	

GAS [bln sm3] DG/Key event	Date (mm)-yy	2U Prospective: Prospect	2C Contingent Resources Additions: Dev. Pending Post-DG1	2C Contingent Resources Additions: Dev. Pending Post-DG2	PRMS 2P Reserves Additions: Undeveloped Post DG3	PRMS 2P Reserves Additions: Undeveloped Post-DG4	PRMS 2P Reserves Additions: Developed	SEC Proved Reserves Additions: Undev	SEC Proved Reserves Additions: Developed	Annual Production
DG 2	Sep-05			0.19						
DG 3	Sep-05			-0.16	0.16					
FID	Apr 07				-0.16	0.16		0.12		
	2010									0.00
Appraisal Well Drillin	2011			-0.04		0.04				0.00
First HC	2012					-0.20	0.20	-0.12	0.12	0.01
	2013								0.00	0.01
	2014								0.00	0.01
	2015								0.00	0.01
	2016								0.00	0.01
	2017								0.00	0.01
	2018								0.00	0.01
	2019								0.00	0.01
Perf Update	2020								0.03	0.01
	2021								0.00	0.01
Perf Update	2022								0.03	0.01
	2023								0.00	0.01
	2024								0.00	0.00
	2025								0.00	0.00
	2026								0.00	0.00
	2027								0.00	0.00
later years									0.02	0.07
Total		0.0	0.0	-0.0	0.0	0.0	0.195	0.0	0.195	0.195

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
0.19	0.11
0.17	0.10
0.16	0.09
0.15	0.08
0.14	0.07
0.13	0.06
0.13	0.05
0.12	0.04
0.11	0.06
0.10	0.05
0.09	0.07
0.08	0.06
0.08	0.06
0.07	0.05
0.07	0.05
0.07	0.05
0.00	-0.00

negative numbers are incorrect

Gas [bln sm3]		2U Prospective: Prospect	2C Contingent Resources: Dev. Pending Post-DG1	2C Contingent Resources: Dev. Pending Post-DG2	PRMS 2P Reserves: Undeveloped Post DG3	PRMS 2P Reserves: Undeveloped Post-DG4	PRMS 2P Reserves: Developed	SEC Proved Reserves Additions: Undev	SEC Proved Reserves Additions: Developed
ARPR 31.12.2009	before last					0.24		0.14	
ARPR 31.12.2010	last					0.16		0.09	

	VP Technical (or VP-X)		For RDL-RE (RXC or RXHM)
Name :	Lismont, Bart	Name :	Emelle, Chima
Signature :	Bar...	Signature :	NGCEM3 Digitally signed by NGCEM3 DN: cn=NGCEM3 Date: 2011.06.09 17:28:06 +01'00'

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.

ESTIMATE FACT SHEET to be included in GIP and PCN submissions | **Version 2.4** | Confidential

Santa Barbara FOD Phase 1 (Early Oil Development) | Approved Cost & Schedule Estimate

<Please enter Project Location> | **Project No.:** C11043

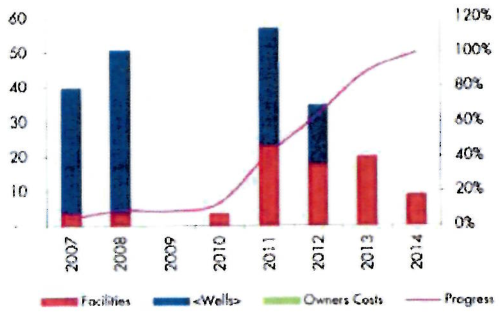
Estimator:	Olaribigbe, Elias	**Planner:**	Dadi, Musa
Case:	Base		Rates of Exchange are as per SI-5X Data Set
Market Scenario: RV	Estimate Type: 3		Cost are in: USD Millions
Estimate Start / End: FID Apr-2007 / RFSU Oct-2014		EDM Date:	1-Jul-10

Category			Total Costs	
Facilities			48	
<Wells>			135	
Owners cost (incl. insurance, pre-FID, Capitalized interest)			14	
Market Escalation, EPC Premium & Taxes			7	
Contingency	Facilities: 18%	<Wells>: 0%	8	
Inflation			3	
		P10	P50	P90
Approved Total Project Estimate, MOD		189	215	258
		-12%		20%
		OK		

Assumptions:

Est. and Schedule Premise	About 25% of total Surface Facilities cost estimate is based on actual costs. The outstanding estimates are based on awarded contracts/POs and other recent/ongoing contracts. Wells cost estimate includes wells contingency included by Well Engineering in line with agreed methodology in-house SPDC. Surface Facilities P50 and P90 contingencies are deterministically determined using the TECOP Tool - they have not been applied on the actuals parts of the overall estimate. The shedule is based on early drill to fill using three wells that will back out other high GOR and water cut wells. When the facility is upgraded in 2014, the back-out wells will be re-produced
Execution Strategy Premise	The Concrete Barge refurbishment and flowlines construction part of the project are in execution based on a DIY strategy involving award of multiple POs and installation contracts, mostly using existing call-out contracts. EPC strategy is proposed for the Off-barge facilities part of the project for which detailed design is being carried out
Contract Strategy	Use of existing call-out contracts, award of Pos for procurement and proposed EPC for Off-Barge facilities
Key Project Risks	Security/community issues, Poor contractor quality, HSE Risks, Internal and external interface management
Exclusions	SPDC financing of interest during construction
Benchmarking & Metrics	Estimate is largely based on awarded contracts/Pos and existing call-out contracts for similar activities

Capex Phasing and Planned Progress:



Key Schedule Dates:		
Phase	Finish (P50)	Finish (P90)
FID	Apr-2007	
Detailed Eng.	Dec-2011	Jan-2012
Procurement	Sep-2011	Sep-2011
Proc. of Bulk Mat.	Sep-2013	Dec-2013
Construction	Aug-2014	Nov-2014
Commissioning	Oct-2014	Jan-2015
RFSU	Oct-2014	Jan-2015

DCAF TA 1		Project Manager	
Date :	5/7/2011	Date :	22-06-2011
Name :	Bensley Andrew PP George Wilk	Name :	Uyouko Ime
Signature :		Signature :	

VP Project Services		Business Opportunity Manager	
Date :	5/7/2011	Date :	22-06-2011
Name :	Hans Mes	Name :	Nwabueze Vincent PP
Signature :		Signature :	