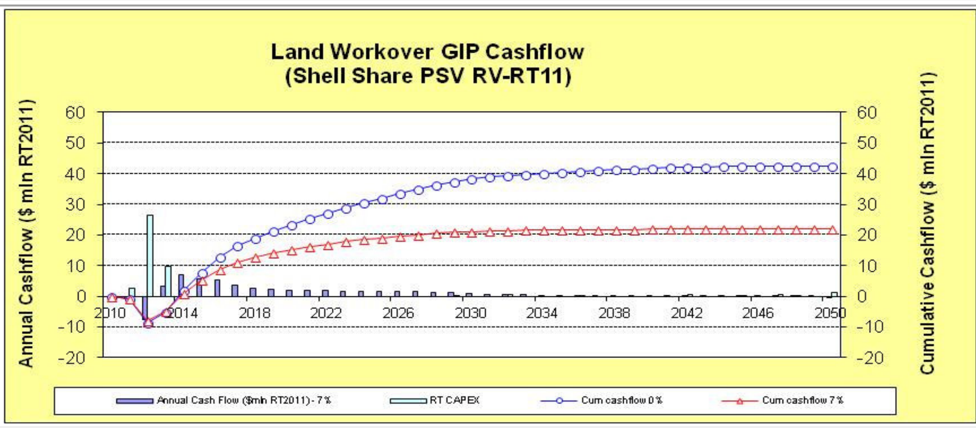
Group Investment Proposal

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%), TotalFinaElf (10%), and Nigerian Agip Oil Company (NAOC: 5%) in SPDC Joint Venture
Business or Function	UI
Amount	The headline size of **USD$40.4mln Shell Share (USD$134.6mln 100% JV)** MOD 50/50, made up by **CAPEX - USD$39.6mln** and **OPEX - USD$0.79mln**. To be funded by Shell Equity CAPEX and OPEX
Project	Land Workover Opportunities Project
Main commitments	(see table below)

Description	**Shell Share**	**100% JV**
CAPEX		
Oil Location Preparation	10,545	35,150
Oil Development Drilling	10,322	34,406
Oil Development Completion	4,122	13,739
Oil Recompletion	13,882	46,273
Oil Flowlines and Hookup	738	2,460
Total CAPEX	**39,609**	**132,028**
SCD	792	2,641
Total OPEX	**792**	**2,641**
Total CAPEX & OPEX	**40,401**	**134,669**

Source and form of financing	This investment will be financed with SPDC's own cash flow and/or existing loan facility, if required.
Summary cash flow	
Summary economics	(see table below)

Summary Economics (SS)	NPV (USD mln)	RTEP (%)	VIR (%)
Base case	21.9	52.0	0.61

Section 1: The proposal (management summary)

Approval is sought for US $132million **($39.6million - Shell share) CAPEX** and US $2.6million **($0.4million - Shell share) OPEX** to carry out six (6) workovers and four (4) sidetracks to existing wells in the Eastern Division of SPDC. The project is kicking off Q3 2011 (with advanced wells' location rehabilitation and access road repairs) followed by rig activities starting early 2012 and lasting for circa two years (see Appendix C). The project would increase production from the sidetracked wells, and in addition to production increases, restore the integrity of the worked-over wells. The project supports SPDC's strategy of maintaining well integrity, increasing production and growing reserves from existing wells. All proposed wells are in areas with actual or planned Associated Gas Gathering (AGG) facilities/solutions.

Four (4) additional development staff will need to be dedicated full time from mid 2011 to end 2012 to help mature and obtain relevant statutory approvals for the wells, while two (2) Civil Engineers would be required for location rehabilitation and access road repairs from mid 2011 up to end 2013. To ensure location readiness by rig activities start-up (early 2012), budget would have to be released for location preparation by August 2011. The recently contracted Deutag T-43 workover rig which will start rig operations by September 2011 (see Appendix C) will be used to execute the well construction activities (after initially working over 4-6 wells in Utorogu and Ughelli). The Well Engineering staff secured to man Deutag T-43 rig operations will be available till the end of the project. EIA approvals (though not required for workover activities) are required for sidetracks and have been obtained for the sidetrack wells in Agbada and Obigbo fields.

The project has a **VIR of 0.61 and a Shell Share NPV of $22 million,** (with a PIB sensitivity of 0.53 and $19 million respectively), and would deliver incremental oil production of **1.88 Mbopd (Shell Share)** at its peak in **2014**. There are no budget provisions for the candidate wells in 2011, but circa $13.5million ($4.5million - Shell Share) offset would be sought from SPDC 2011 budget to fund location and access road repairs (estimated at $8.5million), and purchase long lead materials (worth about $5million) for the first three wells on the sequence.

The six (6) workovers consist of oil-generation activities in five (5) wells (in Imo River, Etelebou, Adibawa North East and Kolo Creek fields) and integrity workover & conversion of Obigbo-41 gas-lift water well to an electric submersible pump (ESP) water well. Obigbo-41 water well will provide sufficient water for optimum water injection in Obigbo North field, through the existing 3 water-injector wells. The workover activities are expected to increase oil production by 1,300 bopd (Shell share) and also help in restoring integrity. In terms of reserves, these workover wells are expected to add an estimated 5.2 MMboe (Shell Share) of expectation reserves relative to 31.12.2010 ARPR. The four (4) sidetrack candidates in Obigbo North and Agbada fields are expected to add an estimated 3.0 MMboe of expectation reserves (Shell Share) relative to 31.12.2010 ARPR, and also increase oil production by 578 bopd (Shell Share). The total production potential of the project (from the workover and sidetrack wells) is 13,900 bopd – 100% (4,170 bopd - Shell Share).

The major risk with this proposal is the inherent security and community risks associated with the Niger Delta which might affect access to the candidate wells. SPDC has mitigation processes (Global Memorandum of Understanding - GMoU, security plans and assessments, etc) to ensure that these risks are eliminated or managed at ALARP. Experiences from SPDC operation (including routine rig-less activities) in the fields of interest indicate that reasonable understanding exists with the host communities. 2% of the project CAPEX has been earmarked to cater for any legacy community relation issues to assure freedom to operate.

Specific risks associated with this proposal are, location and access roads readiness before rig arrival in 2012, funding, cost over runs (eroding profitability) and manpower resourcing for the project.

Section 2: Value proposition and strategic and financial context

This project which helps to restore the integrity of 4 wells (KOCR-16 &19, ETEL-7 and OGBN-41), will also add 8.2 MMboe (Shell Share) of expectation reserves. In addition, it also generates an additional peak oil production of about 1.88 Mbopd (Shell Share) by 2014. This will help to arrest the production decline in these fields.

The project aligns with SPDC's strategic goals and priorities:

- Contribute incremental expectation reserves of 8.2 MMboe (Shell Share).
- Add 290 bopd oil productions (Shell Share) in 2012 increasing to a peak rate of 1,878 bopd (Shell Share) in 2014.
- Restore integrity to existing wells.
- Support reservoir pressure maintenance in Obigbo North field.

Summary Economics

The economics analysis for this project was carried out on a forward look basis using production forecast from the wells. The base case assumes gas sales to the Domestic Gas (DOMGAS) network.

Sensitivity analysis was carried out to determine the value of the project under low and high reserves conditions, and high CAPEX. Additional sensitivity was carried out to show the impact of delay in production/schedule and license expiry in 2019. Given the issue of cost dispute by NNPC, BVA (Benchmark, Verify and Approve) sensitivity was also done. The impact of the proposed Petroleum Industry Bill (based on current PIB assumptions as detailed in the economic assumptions below) was also carried out.

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

Table 1: Project GIP Economics Grid (Shell Share)

PV Reference Date: 1/7/2011	**NPV (S/S $ mln)**		**VIR**	**RTEP**	**UTC (RT $/bbl or $/mln btu)**		**Payout-Time (RT)**	**Maximum Exposure (S/S $ mln)**
Cash flow forward from: 1/1/2011	**0%**	**7%**	**7%**	**%**	**0%**	**7%**		**AT**
Base Case								
SV ($50/bbl RT11)	24.7	**11.9**	**0.33**	32.26	11.4	13.3		
RV ($70/bbl RT11)	42.4	**21.9**	**0.61**	52.02	11.4	13.3	2014	24.4(2012)
HV ($90/bbl RT 11)	59.5	**31.7**	**0.89**	71.54	11.4	13.3		
BEP (RT $/boe)					NA	NA		
Sensitivities (using RV)								
High Capex(+15%)		**20.7**	**0.50**				2014	28.1(2012)
Low Reserves (-20%)		**20.1**	**0.56**				2015	24.4(2012)
High Reserves (+20%)		**22.9**	**0.64**				2014	24.4(2012)
1Yr Production Schedule Delay		**18.5**	**0.52**				2015	26.6(2012)
License Expiration(2019)		**13.8**	**0.39**				2014	24.4(2012)
1.5% markup due to BVA* issues		**19.2**	**0.51**					
PIB Sensitivity(House Version 12)		**19.1**	**0.53**					

*BVA: Benchmark ,Verify, Approve

Key Project Parameter Data Ranges (Shell Share)						
Parameter	**Unit**	**Bus Plan (BP10)**	**Low**	**Mid**	**High**	**Comments**
CAPEX (MOD)	US$ mln	NA	4.0	39.6	5.9	
Investment OPEX (MOD)	US$ mln	NA	0.7	0.8	0.9	SCD
Production Volume	mln boe	NA	7.2	8.6	10.0	
Start Up Date	mm/yyyy	NA	2012	2012		
Production in first 12 months	mln boe			0.124		Jan - Dec 2012

**** Mid-case 8.6 MMboe Shell Share is the total production volume (i.e. including flare & own-use gas). The sales volume (which is reserves) is 8.2 MMboe Shell Share.***

Figure 1: Project GIP Tornado Plot (Shell Share)

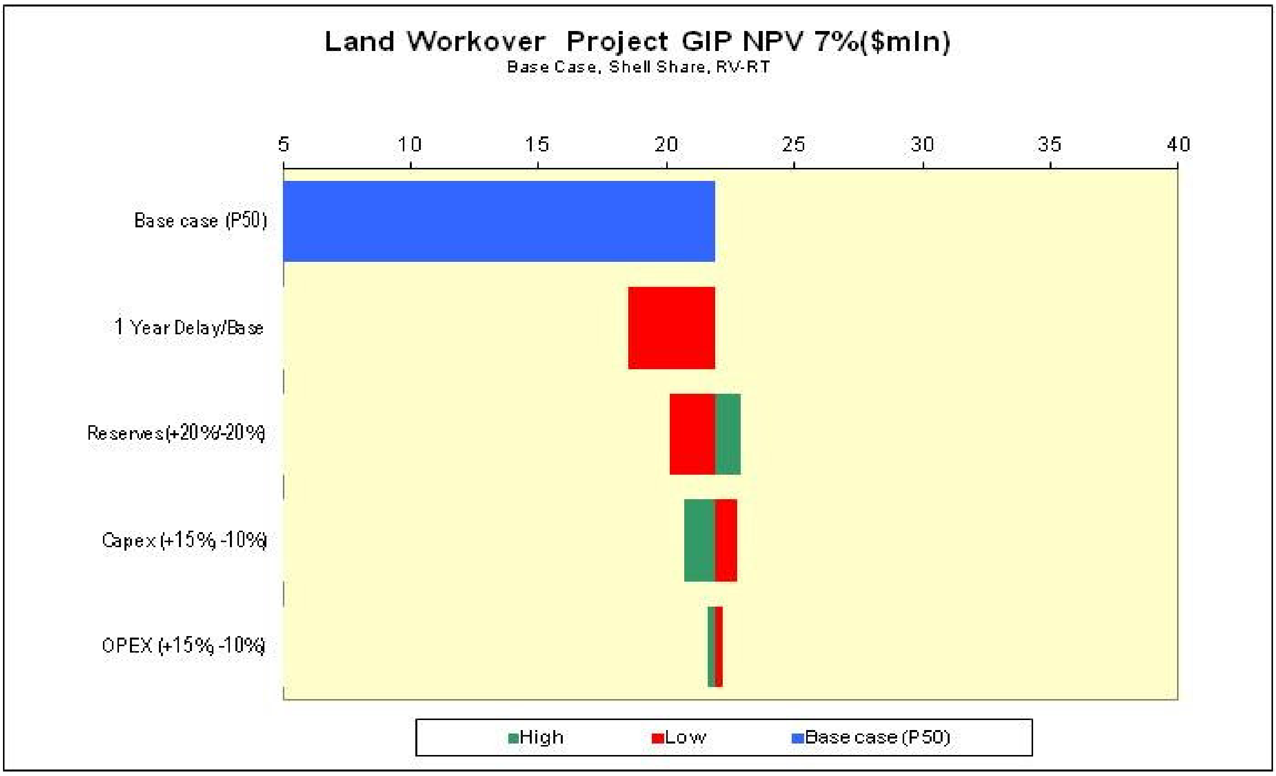
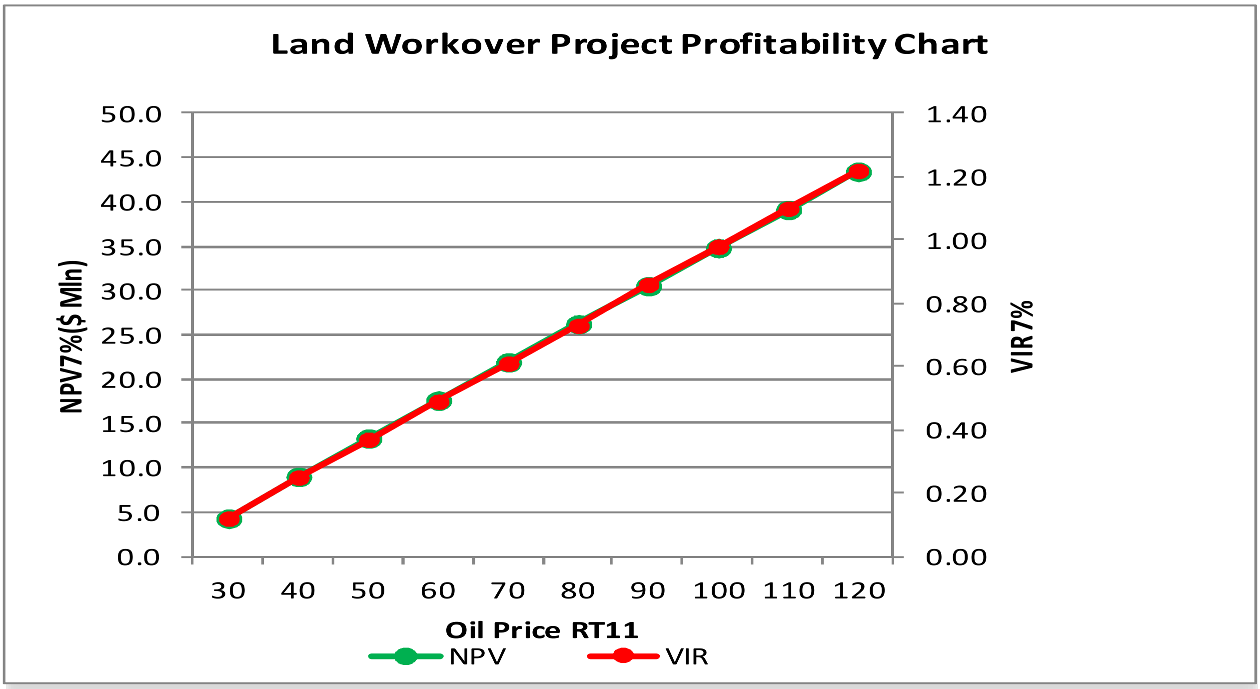


Figure 2: Project Profitability Plot



Economics Assumptions

- Oil PSV of $70/bbl RT11 and Domgas price based on NGMP framework
- Condensate taxed at PPT.
- Gas taxed under CITA with Associated Gas Framework Agreement (AGFA) incentive
- ARPR 31-12-2010 Variable OPEX applied.
- SPDC generic fixed and variable OPEX used on the fields where ARPR OPEX was unavailable
    - Oil variable and fixed OPEX - $1.92/bbl and 3% of cum. oil CAPEX respectively
    - Gas variable and fixed OPEX - $0.33/Mscf and 3.5% of cum. gas CAPEX respectively
- Flare Penalty of US $3.5/mscf non-tax deductible.
- GHV of 1000Btu/scf.
- 10% of total project RT CAPEX assumed as abandonment cost.
- NDDC levy 3% of total expenditure.
- 2% of MOD CAPEX expenditure treated as SCD.
- Education tax of 2% assessable profit.

PIB Assumptions:

- Overseas_CAPEX_Fraction_assumed at 30%
- 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
- 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
- Existing field hence no production allowance is applicable.

Section 3: Risks, Opportunities and Alternatives

The principal risks associated with this proposal are community disturbance and insecurity which could prevent access to the candidate wells. These risks are not peculiar to the project but are inherent in Oil & Gas business in the Niger Delta.

Community Interference: The project activities are covered under the Global Memorandum of Understanding (GMoU) between SPDC and the host communities for those areas where GMoUs currently exist. For these areas, Cluster Development Boards (CDBs) and Community Trusts (CTs) will (prior) be informed of the planned activities for the campaign.

Where there is no GMoU, steps will be taken to secure Freedom to Operate (FTO) via negotiations with the host communities in line with SPCA guidelines. Experiences from recent SPDC activities in the focused areas indicate that reasonable understanding exists with the host communities, so there is no reason to believe that this risk would be a show stopper for the project. Provisions are made in this proposal to cater for any legacy community issues that might still be existing in the host communities where known. In addition, 2% of the CAPEX is budgeted for SCD.

Insecurity – The project will latch onto the existing security arrangement in the area of operation and the project activities will be guided by deployment of duly approved Site Specific Security Plans (SSSP) based on risk assessment of the area. Controls will be put in place to mitigate the identified security hazards and effects, but these will be subjected to continual supervision and assessment to ascertain their adequacy and effectiveness throughout the execution phase. Furthermore, the Project Security Plan will address and also recommend appropriate security emergency response to manage potential incidents in the event of occurrence.

As per SPDC procedures the contractors involved in the project will develop their security plan, to be agreed to by the Contract Holder and then sent to the Area Security Adviser for review; thereafter, the reviewed plan will be sent to the Security Coordinator/Asset Manager for approval. It is only then that the contractor can mobilize to site to commence activities.

Specific risks associated with this project include:

Rig Availability: Deutag T-43 workover rig has been recently contracted and will start rig operations by September 2011. The rig will be used for the rig activities after initially completing some 4-6 workovers. The project wells have been added to the SPDC Short Term Drilling and Workover Sequence under rig T-43.

Manpower Resourcing: A project team has been set up to carry out the initial work leading to obtaining necessary internal approvals for the project. Dedicated staff will be required for maturing the wells (as timely approval of the well proposals will be a critical success factor) and ensuring location and access roads readiness by early 2011. The well engineering manpower used for manning the Deutag T-43 rig in 2011 will be available to complete the campaign.

Funding: Location rehabilitation and access road repairs need to start-off (in advance) by Q3, 2011 and offsets from delayed projects will be required to finance this activity in 2011. Budget provisions will then be made in BP11 to include all the remaining required funds for the project. The expected expenditure for 2011 (which is circa $13.5million – 100% JV), is for advanced location rehabilitation & access road repairs, and wells' long lead material ordering.

Costs Overrun: The budget estimate for the project is in line with BP11 estimating methodology and also reflects current reality in SPDC. However, the wells will go through further value challenges while maturing them with the potential of reducing well cost.

Opportunities
This campaign is hinged on getting oil through workover and sidetrack of existing wells which makes it quite attractive. Currently in SPDC portfolio, there exists additional workover and sidetrack candidates that can be matured (if they meet the economic screening criteria) to become part of the campaign thus maximizing the campaign benefits. Efforts are ongoing to mature these candidate wells to allow the possibility of completing them as part of this project. There exist enough wells in the currently identified portfolio to last the remaining Deutag T-43 rig contract duration but there is also an early termination opportunity (with minimal or no cost) in the T-43 rig contract that can be exploited in the unlikely situation of the campaign being aborted earlier than proposed.

Alternatives
Workover and sidetrack of wells are core business activities in any E&P Company. The candidate wells will undergo all quality checks and assurances to ensure that all subsurface and well engineering risks are identified and mitigated. The project also offers the opportunity to restore the integrity of SPDC wells while also benefitting from oil generation which would help argument SPDC oil production in 2012 and beyond. The alternative is a "Do-Nothing" scenario which is not acceptable considering the safety enhancement opportunity and the value of the opportunity.

Section 4: Carbon management

The workover and sidetrack candidate wells were deliberately selected in areas with existing or planned Associated Gas Gathering (AGG) solutions to ensure that there will not be any increase in flared gas as a result of production from these wells. For wells in fields not currently with AGG solutions, the well delivery has been timed to be after an AGG solution is in place in the field.

Section 5: Corporate structure, and governance

Existing corporate structure and arrangements of SPDC-JV with SPDC as operator will be used as the vehicle for the investment and operations. SPDC Decision Review Board (DRB) will continue to advice.

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

This proposal complies with Group Business Principles, policies and standards. Functional support for this proposal is provided by Finance, Sustainable Development, Supply Chain Management, HSE, Operations, Legal, Treasury and Tax functions. This project also offers the opportunity to improve SPDC wells integrity, give life to old wells and increase production. In addition, the project contributes to sustainable development of Nigerian people through Nigerian Content Development (NCD) as most of the contractors to be used for the project are Nigerian Contractors with the attendant benefit to the local communities.

The project will utilize the existing GMoU for the fields of interest for continuous community engagement (including resolution of any legacy issues) and development intervention in the impacted areas. This will be in line with the new GMoU interface model and SCD principles/rules-to guarantee Freedom To Operate (FTO) and mitigate community related down time. All aspects of the project will be executed in line with the Statement of General Business Principles and other SPDC policies.

The HSE plan for the project will be consistent with SPDC's HSE targets. The project will ensure that all persons employed directly or by contractors (including third parties); will comply with all relevant SPDC policies. All land transport activities shall comply with the procedures and standards set out in

The Shell Transport Management system (LT-MS) Manual Doc. No SPDC 2000-082. Waste disposal shall be in accordance with ISO 14001 standards. Work force shall imbibe the Life Saving, HSE Golden and Goal Zero rules in all their activities at all time.

Section 7: Project management, monitoring and review

This project is consistent with the routine SPDC business of delivering production wells and thus falls in the frame of the SPDC Well Delivery Process. Execution of the project will be managed jointly between Development and Well Engineering. Following successful completion of any well, it will be handed back to the Asset Teams and subsequently to Production.

Section 8: Budget provision

The project currently has no budget cover in 2011 as it is an incremental opportunity to the BP10 programme, offset from the delayed start-off of projects will be used to fund this project in 2011 without any additional cash requirements. The 100% CAPEX phasing estimate is shown in the table below:

Table 2: Project CAPEX Expenditure Phasing (100 % JV)

	$ MOD			
Years	**2011**	**2012**	**2013**	**Total**
Location Preparation	8,500,000	21,650,000	5,000,000	**35,150,000**
Drilling	2,000,000	32,405,931		**34,405,931**
Initial Completion	2,000,000	11,739,249		**13,739,249**
Recompletion	1,000,000	17,538,624	27,734,624	**46,273,248**
Flowlines and Hookup		1,530,000	930,000	**2,460,000**
Year Total	**13,500,000**	**84,863,804**	**33,664,624**	**132,028,428**

Section 9: Group financial reporting impact

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

US$ Million	2011	2012	2013	2014	2015	Post 2015
Total Commitment	**2.60**	**27.50**	**10.30**	**0.00**	**0.00**	**0.00**
Cash Flow						
SCD Expenditure	0.05	0.54	0.20			
Capital Expenditure	2.55	26.96	10.10			
Operating Expenditure	0.09	1.59	3.75	3.77	3.29	54.48
Cash flow From Operations	1.07	12.06	14.88	9.99	6.98	47.44
Cash Surplus/(Deficit)	(1.48)	(14.89)	4.78	9.99	6.98	47.44
Profit and Loss						
NIBIAT +/-	0.07	1.51	5.93	5.88	4.50	43.44
Balance Sheet						
Avg Capital Employed	0.78	9.75	18.53	17.04	13.75	8.61

Section 10: Disclosure

Disclosures, if required, will be done in line with existing Group and SPDC policies and guidelines.

Section 11: Financing

The project will be funded from SPDC's own cash flow.

Section 12: Taxation

Taxation will be in accordance with SPDC's tax rules for CAPEX and OPEX, there are no unusual taxation features.

Section 13: Key Parameters

Approval is being sought for the amount of $40.4mln - Shell Share ($134.6mln - 100% JV) MOD 50/50, comprising of $39.6mln CAPEX and $0.79mln OPEX for a project starting Q3, 2011 (with well operations in early 2012) to:

- Carry out workover on 5 wells to restore production (and integrity) in the wells.
- Sidetrack 4 existing wells to increase production from these wells.
- Change a water well in Obigbo field from a gas-lift well to electric submersible pump (ESP) well. The water well will help to maintain reservoir pressure in some 8 existing wells in Obigbo North field.

These activities will add 290 bopd oil production (Shell Share) in 2012 increasing to a peak rate of 1,878 bopd (Shell Share) in 2014.

Section 14: Signatures

This Proposal is submitted to UIG REVP for approval.

Supported by:	For Business Approval:
....	....
Bernard Bos	**Ian Craig**
(FUI/F - VP Finance Africa)	(UIG - EVP Sub-Saharan Africa)
Date ..../..../....	Date ..../..../....

Initiator: ____________________

Goke Akinrinmade

(UIG/T/DS)

Date …/…./….

Appendix A: Project Wells

S/No.	WELL NAME	WELL TYPE	ESTIMATE DELIVERY DATE
1	OBGN-4ST	Sidetrack	Mar-12
2	OBGN-55ST	Sidetrack	May-12
3	OBGN-41	Water Workover	Jul-12
4	OBGN-54ST	Sidetrack	Sep-12
5	IMOR-14	Workover	Oct-12
6	AGBD-57ST	Sidetrack	Dec-12
7	ETEL-7	Workover	Jan-13
8	KOCR-19	Workover	Mar-13
9	KOCR-16	Workover	Apr-13
10	ADNE-2	Workover	Jun-13

Appendix B: Economic Results for Individual Wells (Shell Share RVRT11)

Case Name	ADNE002	AGBD057	IMOR014	KOCR016	KOCR019	OBGN041	OBGN054	ETEL007	OBGN004	OBGN055
NPV0% ($mln)	3.9	2.8	3.8	6.8	7.0	5.6	5.0	0.0	4.6	3.0
NPV7% ($mln)	2.2	1.7	2.4	3.1	3.9	2.6	2.2	0.9	2.1	0.9
VIR7%	0.62	0.39	0.68	0.86	1.06	1.25	0.54	0.28	0.56	0.23
Max Oil rate (Mbopd)	0.29	0.24	0.34	0.18	0.22	0.16	0.21	0.38	0.13	0.08
Max Gas Prd rate (MMscf/d)	0.24	0.18	0.34	0.50	1.29	0.06	0.24	0.41	0.31	0.08
Max Gas Sales rate (MMscf/d)	0.12	0.15	0.26	0.42	1.09	0.04	0.17	0.35	0.22	0.06
Tot Oil Prod (MMstb)	0.69	0.51	0.59	0.84	0.78	0.76	0.77	0.11	0.69	0.52
Tot Gas Prod (Bscf)	0.71	0.39	0.77	3.14	5.17	0.28	0.91	0.19	2.23	0.53
Tot Gas Sales (Bscf)	0.35	0.31	0.57	2.66	4.39	0.20	0.63	0.16	1.58	0.36
Tot OPEX ($m)	4.5	5.3	4.7	6.6	7.1	2.7	6.0	3.3	6.1	5.1
Tot CAPEX excl Aband ($m)	4.0	4.7	3.8	4.0	4.1	2.2	4.4	3.3	4.1	4.3
UDC0% ($/boe)	5.8	9.1	6.0	3.4	2.9	3.0	5.5	25.8	4.6	8.0
UDC7% ($/boe)	7.9	12.1	7.8	5.7	4.2	5.4	9.1	12.9	7.6	15.4
UTC0% ($/boe)	11.7	18.6	12.8	8.5	7.5	6.4	12.2	49.3	11.0	16.7
UTC7% ($/boe)	13.3	18.9	13.2	10.5	8.8	9.2	15.3	20.6	13.7	23.9
RTEP	61%	43%	83%	53%	73%	44%	45%	0%	40%	20%