The Shell Petroleum Development Company of Nigeria Limited

Internal Investment Proposal

Summary Information

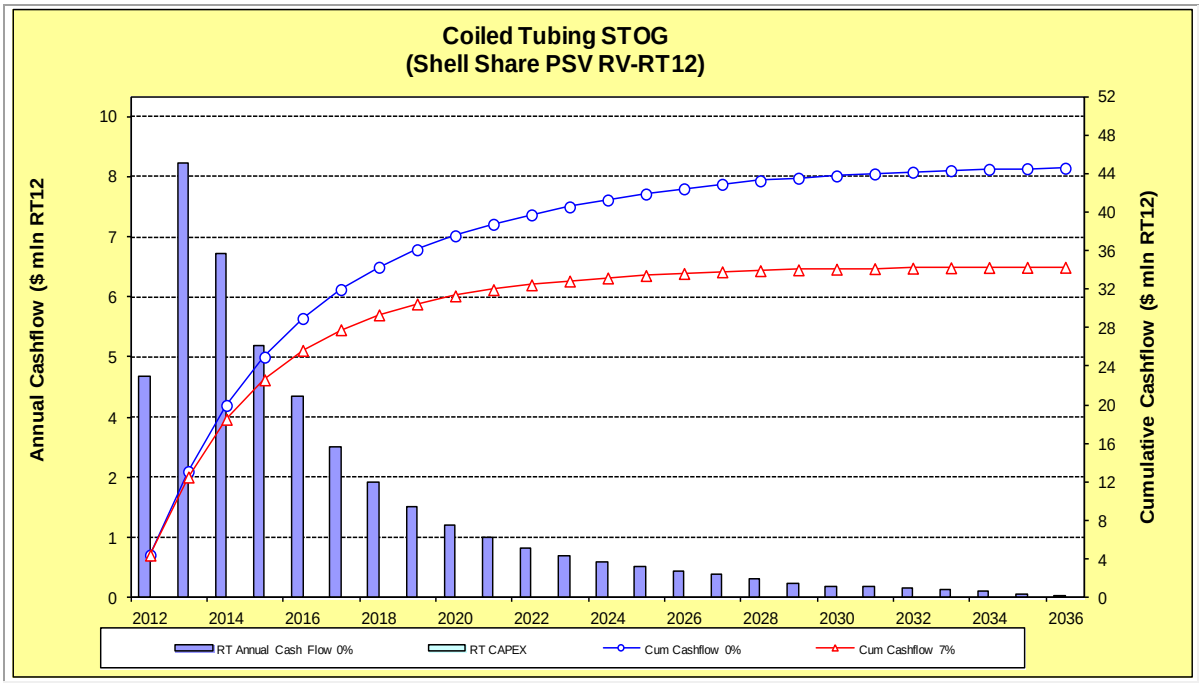
Directorate	Development
Group equity interest	100% in SPDC, whereas SPDC is the Joint Venture (JV) operator of an unincorporated JV with a 30% interest.
Other shareholders /partners	Nigeria National Petroleum Corporation (NNPC: 55%), Total Exploration & Production Nigeria Limited (TEPNL: 10%), Nigeria Agip Oil Company (NAOC: 5%) in SPDC-JV
Amount	USD 4.65 mln Shell Share, MOD, 50/50 (USD 15.5 mln 100% JV)
Project	Coiled Tubing (CT) Focused Result Delivery

Main commitments

Scope	100%JV (USD Mln MOD)	Shell Share (USD Mln MOD)
SCD	0.31	0.09
Dredging	3.00	0.90
Well Treatment	12.19	3.66
Total Cost (OPEX)	**15.50**	**4.65**

Source and form of financing	This investment will be financed with SPDC BP11 STOG budget.

Summary cash flow



Summary economics

Summary Economics (RV-RT12)	NPV7% (USD mln)	RTEP (%)	VIR
Base case	33.9	>50	NA
High OPEX	31.7	>50	NA

Section 1: The proposal

Management Summary

This investment proposal seeks support/organizational approval for US$ 15.5 million Opex (100 JV) US$ 4.65 million Opex (Shell share, P50, MOD) to enable SPDC fund the execution of 28 Coiled Tubing activities project. The objective of this project is to increase oil production by resuscitating non-producing wells and increasing production from existing wells through execution of Coiled Tubing activities.

The CT opportunities in focus were identified by the Coiled Tubing Focused Result Delivery Team (CT FRD) set-up by GM Development in 2011.

The opportunities identified by the FRD are tabulated below in Table 1.

Table 1: Coiled Tubing Opportunities Identified by the CT FRD Team

S/N	Well	Activity	Potential Oil Gain bopd	Contingent Resource MMstb	Job Cost '000 USD
1	AGBD064S	Sand Wash/ Screen Installation	400	0.80	300
2	AGBD042S	Stimulation	200	*0.00	200
3	AGBD058L	Stimulation	150	0.00	200
4	AGBD012S	Stimulation	200	0.00	200
5	AGBD047S	Stimulation	300	0.00	200
6	AGBD035T	Sand/ acid wash	500	0.00	300
7	AGBD024L	Zone Change	180	0.43	600
8	OTUM055T	Sand Cleanout	740	0.00	450
9	OTUM057T	Dewaxing	1,000	0.00	250
10	AFRE014L	ScSSSV/PB Installation	2,800	0.00	200
11	AFRE014S	ScSSSV/PB Installation	1,000	0.00	200
12	CAWC039L	Recompletion	500	1.90	1,200
13	CAWC017T	Water Shutoff	300	0.37	1,200
14	AKOS012L	Recomplete on E2.0A	700	0.20	1,200
15	AGBD030L	Water Shutoff / Perf extension	200	0.20	250
16	AGBD061S	Reperforation/Perforation Extension	420	1.47	500
17	NEMC016L	Water Shutoff	200	2.30	1,200
18	NEMC034L	Water Shutoff	380	0.26	1,200
19	NEMC056L	Water Shutoff	300	0.24	1,200
20	TUNU003T	Water Shutoff	420	0.89	300
21	TUNU006T	Water Shutoff	700	0.75	300
22	FORC009S	N2 LIFT	750	0.00	600
23	FORC134S	N2 LIFT	800	0.00	600
24	FORC084S	Stimulation/GL	700	0.00	550

25	FORC046L	Stimulation/ Water Shutoff	500	0.00	700
26	FORC140T	Wellbore cleanout	2,000	0.00	850
27	OTUM002L	Dewaxing	300	0.00	250
28	OTUM038L	Dewaxing	400	0.00	250
		Total	17,040	9.81	15,450

* Acceleration project has zero reserves.

Section 2: Value proposition and strategic and financial context

The CTU FRD supports SPDC strategies of adding contingent resource volume of 9.81MMstb and increasing production from existing and non-producing with additional annualized production and production potential of 8.3 kbopd and 17,040 bopd respectively.

Summary Economics

The economics for this IP was carried out on a forward-looking basis using the project Latest Estimate (LE) cost and the production forecast from 9 wells in land east area; 5 wells in swamp east area and 14 wells in the swamp western area. The base case is the consolidation of 28 wells from their respective fields.

The following sensitivities were carried out to reflect how the project stands in different possible scenarios:

- High & low Reserves
- High & low OPEX
- 1-year production schedule delay
- 1.5% Cost mark-up due to BVA issues (provision for costs dispute by NAPIMS)

The Economic result is presented in Table 2, while the Profitability Plot is presented in Figure 1 below.

Table 2: Economics Grid (Shell Share)

PV Reference Date: 1/7/2012	NPV (S/S $ mln)		VIR	RTEP	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 RT12)	25.5	19.4						
RV ($70/bbl RT12)	44.0	33.9	NA*	>50	5.8	6.1	2012	NA
HV ($90/bbl RT12)	62.7	48.4						
Oil BEP (RT $/bbl)								
Sensitivities (using RV)								
High Reserves(+10%)		37.3	NA					
Low Reserves(-10%)		30.4	NA					
High Opex(+10%)		31.7	NA					
Low Opex(-10%)		34.3	NA					
1 Year Schedule Delay		32.1	NA					
1.5% cost markup due to BVA issues		32.6	NA					

Note: NA: OPEX only project thus VIR doesn't apply

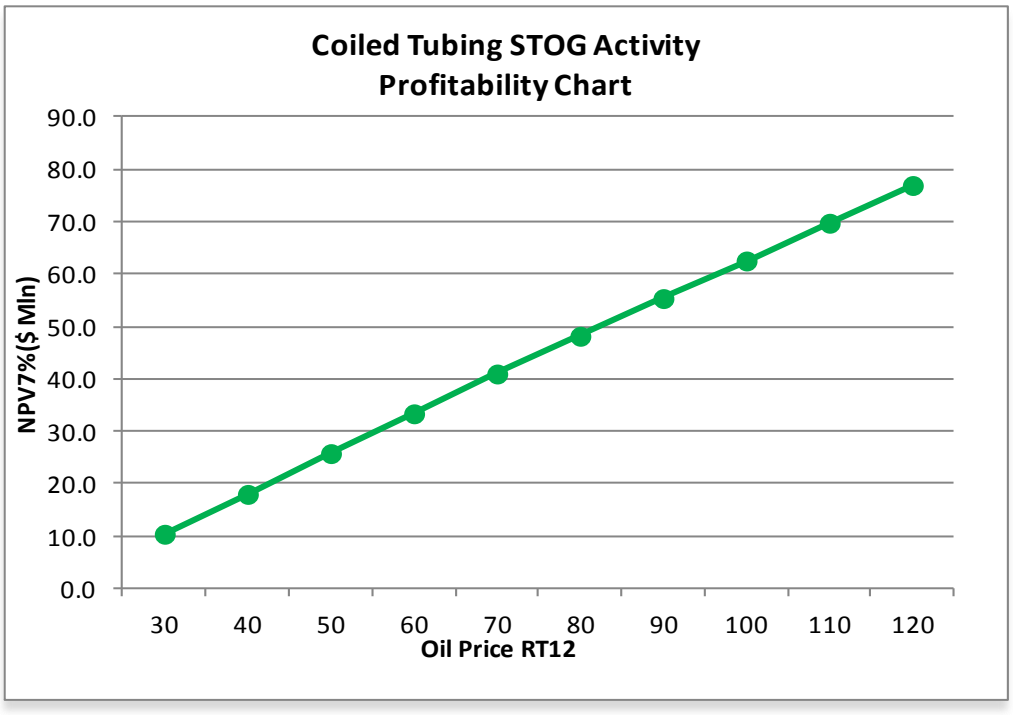
Table 3: Key Project Parameter Data (Shell Share)

Parameter	Unit	BP11 Provision	Low	Mid	High	Comments
Capex (MOD)	US$ mln	NA	NA	NA	NA	OPEX only project
Opex (MOD)_Project	US$ mln	NA	4.4	4.8	5.3	Not available in BP11 as a stand-alone.SCD cost is Inclusive
Production Volume	mln boe	NA	7.7	8.5	9.4	Not available in BP11 as a stand-alone project.
Start Up Date	mm/yy	NA	NA	Oct-12	NA	Not available in BP11 as a stand-alone project.
Production in first 12 months	mln boe			3.5		Not available in BP11 as a stand-alone project.

Economics Assumptions:

- Oil PSVs of $50/bbl @SV-RT12, $70/bbl @RV-RT12 (Base) and $90/bbl @HV-RT12 with Bonny offset applied.
- 2012 NLNG T1-6 price was used for gas sales to NLNG.
- Gas sales to domestic market Aggregate Domgas Profile (based on Nigeria Gas Market Plan (NGMP) framework as at 14/06/2012).
- Oil taxed under PPT (PPT tax rate of 85%).
- Gas taxed under CITA with Associated Gas Framework Agreement (AGFA) incentive.
- Condensate was treated as oil and taxed under PPT.
- GHV of 1000Btu/scf for DOMGAS and 1150Btu/scf for export gas.
- Flare Penalty of US $3.5/mscf non-tax deductible.
- OPEX assumptions as follows:
    - 31/12/2011 variable ARPR (Annual Review of Petroleum Resources) OPEX was used for Agbada, Cawthorne Channel, Forcados, Nembe, Otumara and Tunu facilities.
    - SPDC Generic variable OPEX was used for the remaining facilities
- Gas taxed under CITA with Associated Gas Framework Agreement (AGFA) incentive. .
- NDDC levy 3% of total expenditure.
- Education tax of 2% assessable profit.

Figure 1: Profitability Chart (Shell Share)



Section 3: Risks, opportunities and alternatives

Risks and Mitigation

The key risks and mitigation factors for the project are discussed in the table 4 below.

Risk		**Mitigation**
Technical	Operational risks Lower productivity	The 28 CT activities are technical and annual routine within SPDC overall standards and execution capacity. Surplus back-up LIO activities available to make up for the risks identified. Risked LIO potentials with 25% annual decline.
Community disturbances	Delay in project execution	Large LIO portfolio. Weekly WRFM integrated reviews to provide replacement candidates

HSE management	Compliance	The HSE management of the project shall be coordinated by the CWI team with implementation actions agreed by key stakeholders. All activities are to be planned and delivered under the current drive to achieve 'Goal Zero'. Controls will be put in place to mitigate the identified hazards and effects, subjected to continual supervisory oversight to ascertain their adequacy and effectiveness throughout the execution phase. Recent experience has shown that, poor attitude and non-compliance with procedures remain the main root causes in most of the HSE incidents recorded in SPDC. On a company-wide scale, huge exposures have also been identified in non-core drilling contractors and secondary logistics activities. These areas require closer supervision. Learning from incidents is important to bring about the desired improvements in HSE practice during repair and restoration of the wells. The learning will be disseminated to all the staff involved in the project, including contractors and their sub-contractors to avoid incidents.
General	Interface Management	As per SPDC procedures the contractor handling the project will develop a security plan, agreed to by the Contract Holder, and then sent to the Area Security Adviser for review. Thereafter, the reviewed plan is sent to the Security Coordinator/Asset Manager for approval. It is only then that the contractor mobilizes to site to commence well operations.

Opportunities

The dynamic nature of the LIO portfolio will enable additional opportunities to be included in the LIO portfolio. These opportunities will be executed provided they meet or exceed base plan screening criteria. Due to multiple risks (access, technical, security, community) the initiative has been taken to prepare all outstanding opportunity proposals in order to mature the portfolio and allow execution on a first-come-first serve basis pending overall readiness until the budget is exhausted or additional budget is secured.

Alternatives

The activities under discussion are core business activities in any E&P environment and as such there is no alternative for not executing them. For the LIO opportunities, the Do-Nothing scenario will impact negatively on SPDC's 2012 production target.

Proposed activities will increase contingent resource by 9.81MMstb, increase production by 17kbopd oil potential and increase well utilization.

Section 4: Carbon Management

The execution of these activities will not increase flared gas in the fields.

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

For all LIO, a dedicated, 3-staff team working together with respective Asset teams and CWI team, will have single point accountability for driving execution, and managing the budget. The CT FRD team will monitor performance and ensure delivery of the oil gains associated with this IP.

Weekly progress reporting is done to a wide audience within SPDC.

Section 8: Budget provision

There was no budget provision for these activities in BP11; however they will be ranked with the base BP11 short term oil opportunities. The high ranking opportunities will executed.

Section 9: Group financial reporting impact

There are no unusual accounting issues related to this GIP. Expenditure related to the project will be accounted for in line with Group Policy. The financial impact of this proposal on Shell Group Financials is as indicated in the table below:

USD Million	2012	2013	2014	2015	2016	Post 2016
Total Commitment	**0.09**					
Cash Flow						
SCD	0.09					
Pre-FID Expenditure						
Project Opex	4.56					
Operating Expenditure	5.74	8.97	6.89	4.99	3.95	14.76
Cash flow From Operations	-1.56	7.01	8.71	6.84	5.14	22.11
Cash Surplus/(Deficit)	-1.56	7.01	8.71	6.84	5.14	22.11
Profit and Loss						
NIBIAT +/-	4.39	8.77	7.03	5.24	4.27	18.55
Balance Sheet						
Avg Capital Employed	2.97	6.83	6.87	5.23	3.99	0.39

Section 10: Disclosure

Material disclosures, if any, will be done in line with the Group and SPDC Disclosure policies and guidelines.

Section 11: Financing

The project will be funded from SPDC BP11 STOG budget.

Section 12: Taxation

Taxation will be in accordance with SPDC's general tax for opex activities.

Section 13: Key Parameters

This proposal seeks organizational support and approval to carry out:

Carry out SPDC's 28 CT activities (Treatments and Dredging) to generate 8.3kbopd (100% JV) annualized oil gain for 2012.

Section 14: Signatures

This Proposal is submitted to the undersigned for approval.

Supported by:

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Agwae, Agomatigho

(SPDC-FUI/FB)

Date ..../..../....

For Business approval:

.....

Bayo Ojulari

(SPDC-T-D)

Date ..../..../.....

Initiator: _____

Tope Tunde

(UIG/T/DET)

Date …/…. /….