The Shell Petroleum Development Company of Nigeria Limited

Investment Proposal – Biseni Samabri UUOA.

Summary Information

<table>
<tr><td>Business and Company</td><td>The Shell Petroleum Development Company of Nigeria Limited (SPDC-Ltd.)</td></tr>
<tr><td>Group equity interest</td><td>100% in SPDC Ltd, which has a 30% interest in the unincorporated Joint Venture SPDC JV. The revised tract participation of the SPDC JV in the unit will be 64.1% resulting in an SPDC Ltd unit equity interest of 19.2%.</td></tr>
<tr><td>Other shareholders / partners</td><td>Unit partners: Nigerian National Petroleum Corporation (NNPC) 56.8%; Total Exploration & Production Nigeria Ltd (TEPNG) (6.4%); Nigerian Agip Oil Company (NAOC) 10.4% & Phillips Oil Company Nigeria Ltd (POCNL) (7.2%).</td></tr>
<tr><td>Business or Function</td><td>Upstream International – Sub Saharan Africa.</td></tr>
<tr><td>Amount</td><td>US$2.695US$Mln Shell Share MOD.</td></tr>
<tr><td>Project</td><td>Unitization & Unit Operating Agreement (UUOA) with tract participation increase for SPDC in Biseni-Samabri Unit.</td></tr>
<tr><td>Main commitments</td><td>
<table>
<tr><th>UUOA</th><th>US$Mln (SS)</th></tr>
<tr><td>CAPEX</td><td>2.333</td></tr>
<tr><td>OPEX</td><td>0.362</td></tr>
<tr><td>Total</td><td>2.695</td></tr>
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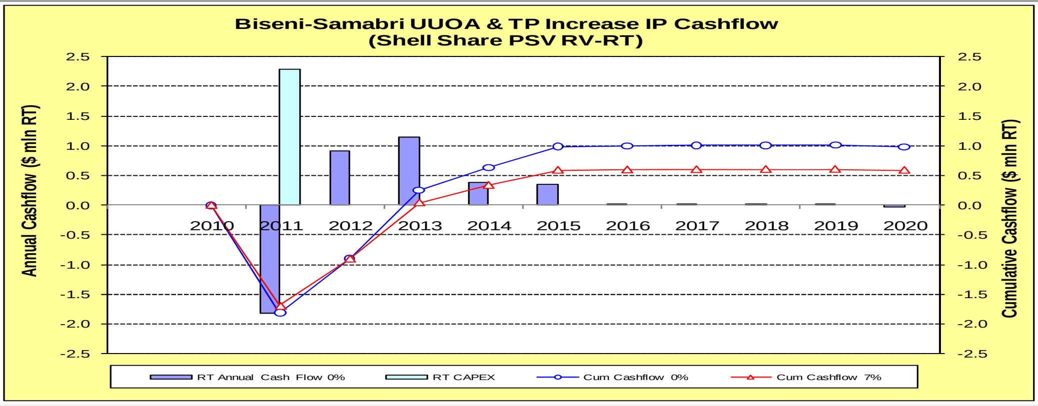
</td></tr>
<tr><td>Source & form of financing</td><td>This investment will be financed with Group equity funds through SPDC Ltd in Q4-2011.</td></tr>
<tr><td>Summary cash flow</td><td>


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<tr><td>Summary economics</td><td>
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<tr><th>Summary economics*
Project title: Biseni-Samabri UUOA & TP Increase</th><th>NPV (USD mln)</th><th>RTEP (%)</th><th>VIR</th></tr>
<tr><td>RV ($60/bbl RT09 & $1.66/mmbtu RT10)</td><td>0.59</td><td>25</td><td>0.28</td></tr>
<tr><td>SV ($50bbl RT09 & $1.39/mmbtu RT10)</td><td>0.20</td><td>13</td><td>0.09</td></tr>
<tr><td>HV ($80/bbl RT09& $2.19/mmbtu RT10)</td><td>1.37</td><td>50</td><td>0.64</td></tr>
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Section 1: The proposal

Management summary

The Investment Proposal ("IP") seeks approval for US$2.695Mln Shell share for (1) adjustment of past costs and recovery of past production share upon the increase in SPDC-ltd TP from 18% to 19.23% and (2) additional obligation arising on agreement of past costs in the Unitisation & Unit Operating Agreement ("UUOA").

The UUOA will increase Shell's share in future production by 1.2% from 18% to 19.23% and entitle SPDC Ltd to lift a corresponding share of past production recovery of approximately 0.35MMbbls.

A proposal to commence negotiations ("PCN") of April-2009 mandated the negotiation of a UUOA to resolve issues from prior audits including past costs, to enable lifting of higher SPDC production share and to provide proper governance of the unit operation.

A draft UUOA and tract participation split based on straddling and non-straddling reservoirs, and supported by the Unit Partners was refused by NNPC legal with the reasons given being that the inclusion of the non-straddling reservoir contravenes "Regulation 48" of the Petroleum Drilling and Production Act of 1969. All efforts by DPR and other unit IOC partners to convince NNPC otherwise have been unsuccessful. The UUOA has therefore been amended to include straddling fields only with the option for commercial arrangement for non-straddling fields.

The economic analysis was carried out on an incremental/forward-look basis using the required past costs figure of US$2.695Mln MOD Shell Share, TP increase 18% to 19.23% for NFA volumes with recovery of underlifted past production share from 50% of ongoing production.

The base case economics assume a flare fee of $3.50/mscf. On this assumption, maximum value would be derived by delaying Tract Participation & past production recovery increase until the AG solution is operational. However if the flare fee that is currently being paid of N10/mscf continues then accelerating increased production increases value. At any flaring fee less than $2.70/mscf it is economically preferable not to delay later than Jan 2011. There are also non-economic considerations concerning the UUOA execution date which include (i) it is required to close an audit exception (ii) conclusion is an enabler to progress other required unitisations for NAOC (also causing audit exceptions) (iii) SPDC has pushed for unitisations to mitigate capture risk (iv) the DPR in January 2008 issued guidelines for unitisations and SPDC has sought DPR support to speed up the process (v) NAOC has operated Biseni-Samabri for 17 years since the original LOI stated the UUOA should be concluded.

Section 2: Value proposition, strategic and financial context

Value proposition:

Approval of this IP will enable SPDC to (1) sign a UUOA that improves governance and addresses the risk of reserves capture by NAOC, (2) provides the governance structure that allows SPDC protects its possible investment in $1.4bn Biseni Samabri ph2 (3) resolves all past costs issues to ensure a TP adjustment can be implemented without dispute (4) ensure the recovery of past production upon TP revision of circa. 0.35MMbbls (under NFA assumptions) (5) receive a higher share of future production, and (6) address the prime audit exception relating to the current asset governance and control framework.

Strategic & financial context:

The Biseni-Samabri field straddles SPDC JVs OML27 & NAOC's OML61. After drilling of Phase 1 wells, NAOC JV & SPDC JV carried out a study on how to further develop the unitised field (Phase 2) for an Integrated Oil & Gas Development ("IOGD"). The study updated estimates for field hydrocarbon in-place volumes: expectation STOIIP 1064 MMStb; expectation GIIP 3.6 Tcf. It also calculated new TPs assigning 73% to SPDC-JV & 27% to NAOC-JV for all resources. Due to the concern raised by NNPC Legal a straddling reservoirs only equity split was also calculated at 64.08% to SPDC-JV and 35.92% to NAOC-JV.

This straddling reservoir only TP becomes effective upon the signing of the UUOA. Thereafter a commercial agreement will be required to develop the non-straddle resources.

From late 2007, SPDC started to lobby for UOC meetings to be reinstated (none were held from mid 2005 to mid 2008) to ensure improved upstream unit governance separated from the Brass LNG project. Despite the pressure at the time to progress the upstream ready for Brass LNG FID, TEPNG and then NAPIMS ultimately supported SPDC's approach since it was demonstrated that without a functioning unit governing body. NAPIMS had approved inconsistent budgets & performance in NAOC JV OPCOM and SPDC JV OPCOM.

Once the UOC was re-convened in Aug 2008, SPDC & TEPNG blocked UOC approval of any (past or future) expenditure on Phase 2 activities until a UUOA was in place. SPDC sought to include in the UUOA agreement the resolution of all past cost to enable the tract participation readjustment be implemented without dispute after UUOA execution.

The UUOA provides for the underlifted unit partners to retrieve past production using 50% of the current total unit production, whilst all past costs for past production are to be paid within 60 days of the UUOA sign-off. The increased lifting however potentially exposes SPDC JV to flaring fees in the absence of AG solution.

In Dec 09, SPDC received a letter from DPR titled, *"Notice of Assessment of non cost recoverable penalty for the continuous flaring of gas contrary to section 3 of the associated gas re-injection act CAP A25 of the FGN".* This Letter invoiced SPDC Ltd as operator of the SPDC JV for flared gas since April 2008 at a rate of $3.50/mscf. A letter of 29 January 2010 requested that SPDC Ltd stays action on payment though it did not expressly state a reversal from $3.50 to the prior flaring fee level of N10/mscf.

SPDC JV has consistently requested from the unit operator (NAOC) for an AG Solutions project. At the Unit DEVCOM of 22 Jan 09 partners recommended budget in 2009 for the implementation of AG Solution to safeguard existing production in compliance with government regulation. At the UOC of 30 Oct 2009 partners approved the other recommended 2009 budget items, but the approval of the 2009 amount for AG Solution was noted as still requiring unit operator to submit the detailed work programme and a contractual strategy.

NAOC's letter of 2 Dec 2009 advised partners that it intends to synergise all the activities for flares down at Idu to achieve economy of scale, avoid safety issues and achieve flares down by the beginning of 2011 with NAOC JV making 100% of the investment. SPDC letter of 22 Dec 2009 indicated its willingness to consider this late change provided it achieves the flares down by Q1 2011 and requesting the corresponding commercial proposal for the use of NAOC JV facilities, which was re-affirmed by letter of 18 Mar 2010. The 28 Mar 2010 DEVCOM requested for NAOC to propose a tariff for the use of Idu AG Solutions facility by latest end-June 2010.

On the 15 July 2010 after an initial engagement with the unit partners, NAOC presented a commercial proposal for transportation and processing of SPDC-JV gas at tariff of $0.5/mscf with GTS-4 inlet as the delivery point. A proposal to commence negotiations on this basis is currently in draft form.

Summary Economics

The economics analysis was carried out on an incremental/forward-look basis using the US$2.33Mln MOD Shell exclusive CAPEX and incremental OPEX ($0.36Mln) spend as per the UUOA and moving from 18% to 19.23% for NFA volumes with recovery of underlifted past production share from 50% of ongoing production. It is on the basis of an increase in TP from the time of UUOA signature

The base case assumes the proposed TP increase from January 2012. The AG solution is expected to be in place by end 2011, while flaring fee is assessed until then at US$3.5/mscf. Shell will take its share of the AG related to its oil liftings, while AG tariff of US$0.9/mscf (being $0.5/mscf to GTS4 inlet plus $0.4/mscf from GTS4 inlet to NLNG Bonny) is assumed paid to NAOC for processing and transporting the AG volumes to NLNG pending the availability of the domestic gas market.

The difference of two views, (i) maintaining status quo of current equity of SPDC JV 60% and (ii) the TP increase and recovery of past crude from January 2012, represents the base case.

The economics are sensitive to the assumption for flaring fees considering that much production recovery is made in the first year when the AG solution is not expected to be available. The issue over the level of flare fees and reliance on NAOC to deliver the AG Solution represents a risk to the value that will be gained from higher future lifting and recovery of past production and through TP increase. The higher the flaring fee the greater the negative impact of a delay between when the TP increase is implemented and when AG solution is in place.

Sensitivities evaluated are:

a. CAPEX variation (though the relevant CAPEX will be fixed in the UUOA),
b. OPEX variation,
c. High Reserves where Shell is able to recover additional 20% of the current recovery level,
d. Low Reserves where Shell recovers 20% less than planned recoverable past volume,
e. Production Acceleration from Jan, 2011,
f. Production Schedule Delay by 1year from Jan, 2013,
g. Production Acceleration from June, 2011,
h. SPDC JV Concession Expires in 2019 without renewal,
i. Flaring fees @ N10/mscf,

j. Flaring fees @ $5.25/mscf due to indication of stiffer penalty,
k. No Flare impact where NAOC takes the AG at no cost to Shell,
l. Payment of Carbon Tax rate of $40/Tonne,
m. Payment of same tariff of $2.51/bbl on oil and water volumes,
n. AG is taken by NAOC at no cost and Shell pays no tariff for AG solution,
o. Payment of $0.50/mscf to NAOC for transporting the AG to NLNG,
p. Net back effect of $0.10/mscf from NAOC for taking over the AG volumes, and.
q. PIB sensitivity evaluation.

Details of the results are in table 1 below. Figures 1 and 2 shows the cash flow and Tornado plots.

Table 1: EP Summary Economic Grid. (Shell Share)

PV Reference Date: 1/7/2010	**NPV (S/S $ mln)**		**VIR**	**RTEP**	**UTC (RT $/boe**		**Payout-Time (RT)**	**AT Maximum Exposure (RT)**
Cash flow forward from: 1/1/2010	**0%**	**7%**	**7%**	**%**	**0%**	**7%**	**0%**	**0%**
Base Case								
SV ($50bbl RT09 & $1.39/mmbtu RT10)	0.52	**0.20**	**0.09**	13	15	16		
RV ($60/bbl RT09 & $1.66/mmbtu RT10)	0.98	**0.59**	**0.28**	25	15	16	2013	*$2.3 mln in 2011*
HV ($80/bbl RT09& $2.19/mmbtu RT10)	1.92	**1.37**	**0.64**	50	15	16		
Oil BEP (RT $/bbl)						40.9		
Sensitivities (using RV)								
High Capex +20%		**0.48**	**0.19**				2013	*$2.7 mln in 2011*
High Reserves (Additional 20% Recovery)		**0.84**	**0.39**				2013	*$2.3 mln in 2011*
Low Reserves (Less 20% Recovery)		**0.34**	**0.16**				2014	*$2.3 mln in 2011*
Production Acceleration_Jan, 2011		**-0.37**	**-0.17**				N/A	*$2.3 mln in 2011*
Production Schedule Delay_1year_Jan, 2013		**0.52**	**0.24**				2014	*$2.3 mln in 2011*
Production Acceleration_June, 2011		**-0.02**	**-0.01**				2015	*$2.3 mln in 2011*
Concession Expiry in 2019		**0.59**	**0.27**				2013	*$2.3 mln in 2011*
AG Received with Tariff Payment, Flare Penalty @ N10/mscf		**1.25**	**0.59**				2013	*$2.3 mln in 2011*
AG Received with Tariff Payment, Flare Penalty at $5.25/mscf		**0.25**	**0.12**				2014	*$2.3 mln in 2011*
No Flare impact - NAOC takes the AG at no cost to Shell		**1.00**	**0.47**				2013	*$2.3 mln in 2011*
Payment of Carbon Tax at rate of $40/Tonne		**0.72**	**0.34**				2013	*$2.3 mln in 2011*
Payment of same tariff of $2.51/bbl on Oil & Water Volumes		**0.36**	**0.17**				2014	*$2.3 mln in 2011*
Payment of $0.50/mscf to NAOC for delivery to NLNG		**0.70**	**0.33**				2013	*$2.3 mln in 2011*
Netback effect of $0.1/mscf from AG sales to NAOC		**0.35**	**0.17**				2014	*$2.3 mln in 2011*
PIB Evaluation_IAT Version		**0.69**	**0.32**					
Statusquo / TP Change Views								
Value at Statusquo - 60% JV Equity		**1.97**	**N/A**				N/A	*N/A*
Combined Value of Statusquo @ 60% JV Equity & Equity Change from January 2012		**2.56**	**1.20**				2013	*$2.3 mln in 2011*
PIB Evaluation of Statusquo - 60% JV equity		**2.27**	**N/A**					
PIB Evaluation of Statusquo @ 60% JV Equity & Equity Change from January 2012		**2.96**	**1.38**					

Key Project Parameter Data Ranges (Shell Share)

Parameter	Unit	BP09 Data	Low	Mid	High	Comments
Capex (MOD)	US$ mln	N/A	1.87	2.33	2.80	Development CAPEX for Past Crude Recovery up to a maximum of 50% of production till end of field life & TP Change.
Opex (MOD)	US$ mln	N/A	0.29	0.36	0.43	Payment of Past OPEX consequent upon TP increase ($0.36mln)
Production Volume	mln boe	N/A	0.32	0.40	0.48	Incremental Production volume due TP change from 18% to 19.23% Shell Share
Start Up Date	mm/yy	N/A	Jan-11	Jan-12		Base re-start up production date
Production in first 12 months	mln boe			0.21		Production volume from Jan to Dec, 2012

Figure 1: Biseni-Samabri UUOA / TP Change IP Cashflow Plot

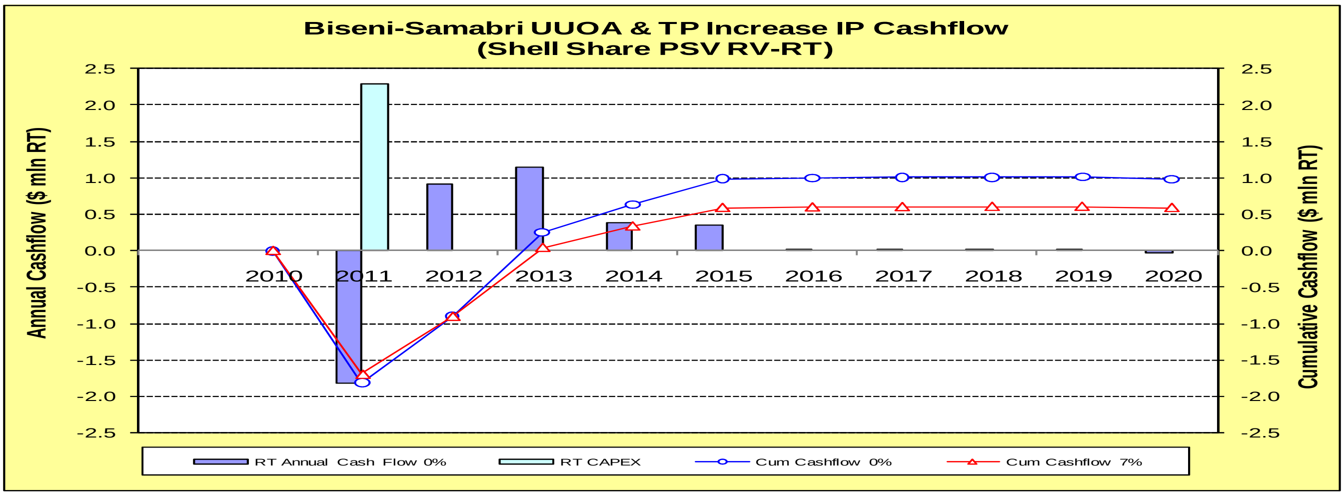
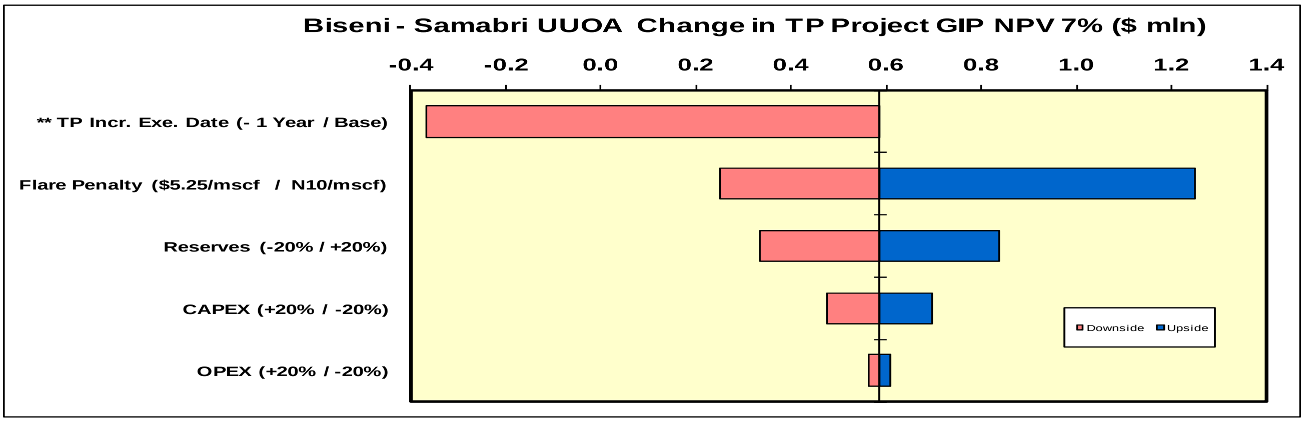


Figure 2: Tornado Plot for Biseni-Samabri UUOA/TP Change IP



*** Value of accelerated production before Jan, 2012 is lower than base due to huge flaring fee as AG solution will be in place end 2011, while deferred production beyond base year will have lower NPV.*

Economics Assumptions

- AGFA fiscal treatment applied.
- AG received by SPDC with tariff payment to NAOC.

- TP increase under UUOA takes place in January 2012
- AG Solution in place end of 2011 (Flaring fees until AG Solution on-stream).
- NDDC Levy of 3% of total expenditure excluding flaring fees
- Education Tax of 2% assessable profit
- Flaring fee of $3.5/mscf
- 10% of total project RT CAPEX assumed as abandonment cost
- Fixed and variable OPEX used as advised.
    - Tariff of $2.51/bbl MOD of oil, AG tariff of $0.90/mscf.
    - Shell exclusive fixed $0.67Mln MOD
- Water tariff of $0.50/bbl

Assumptions specific to some Sensitivities include:

- Tariff of $2.51/bbl MOD of oil, Tariff of $2.51/bbl MOD of Water
- 85% of produced AG is sold to NLNG
- Gross Heating Value (GHV) of 1150/btu/scf for export market.

PIB assumptions:

- Royalty rates based on product (value) prices and production rates per PML (assumed equal to a field).
- NHT depreciation schedule is 4x20%, 19% for qualifying expenditure.
- No capital investment credit/allowance (ITC or ITA) or uplift is granted under the PIB
- NHT amount is the lesser of applicable tax rate multiplied by the taxable income and 2% of total revenue.
- CIT depreciation schedule is 3x25%, 24%, for qualifying expenditure.
- CIT is 30% of taxable income and is not deductible from NHT
- Education tax calculated as 2% of its assessable profit and it is not deductible for CIT, but deductible for NHT.
- Withholding tax is applicable at a rate of 7.5%
- 20% of overseas cost is non-deductible for determination of NHT taxable income
- Costs that are not benchmarked, verified and approved are not tax deductible.

Section 3: Risks, opportunities and alternatives

The main future opportunity results from the governance framework agreed in the UUOA that enables SPDC to seek value through future investments and mitigate potential exposures. The UUOA will require funding of the unit by each of the parties and not via the SPDC JV and NAOC JV budgets as occurred previously. Securing payment from NAPIMS will become NAOC's responsibility, as operator and SPDC Ltd will be able to fund attractive opportunities without the constraints imposed by SPDC JV budget.

The PCN identified the risk from NAOC and SPDC's differing drivers to complete the UUOA. NAOC principally sees agreement of a UUOA as removing an obstacle to developing the field to supply Brass LNG whereas SPDC sees the UUOA as a governance requirement prior to considering further investment and as protecting its reserves from capture. NAOC and SPDC have differing planned gas destinations for the field and once the UUOA is in place NAOC may seek to move forward with its plans to take FID on the upstream project for supply to Brass LNG (for which it intends to take FID in Q1-2011 prior to the April 2011 elections) whereas SPDC has identified SPDC JV share of gas to contribute to its supply of domestic demand. Other risks are as shown in the table below.

The lack of clarity on the actual flaring fee to be paid (NGN10, US$3.50/mscf or higher) provides a key challenge to the timing of the tract participation increase.

Risks

ISSUE	RISK	MITIGATION ACTION
AG-Solutions delay.	Payment of flaring fee further than the Q4-2011 (AG-Solutions ready date) can reduce the derived value to below the No TP increase levels.	NAOC has presented an own AGS plan through Idu FS, with commitment that facility will be ready by Q4-2011. Project is currently at 78% VOWD. The PCN to negotiate a commercial proposal is currently in draft form. Shell representatives to ensure project delivery through continued monitoring at governance/steering meetings.
Exclusion of non-straddled reservoirs from Current UUOA.	DPR support may be contingent on the proof that further unit development will demonstrate optimum field hydrocarbon development which current UUOA may not meet due to the exclusion of the non-straddled reservoirs.	Current UUOA provides for automatic accommodation of non-straddling reservoirs as a result of the expected change in Law (PIB). Otherwise a commercial proposal to include non-straddling reservoirs will be commenced immediately after UUOA Sign-off.
No Agreement on AG Solutions	NAOC proposes a high tariff or that erodes SPDC value.	A draft PCN to negotiate the NAOC GSA/GHA is currently in draft. If no reasonable tariff can be agreed with NAOC, SPDC will seek leverage through NAPIMS support for infrastructure access and tariff setting.
NAOC present FID proposal for supply to Brass LNG.	SPDC may face NAPIMS & partners expectations that SPDC fund its share of Biseni-Samabri Phase-2 investments for Brass LNG supply against it wish for domestic gas supply	The UUOA provides for unanimity in case decisions such as these are required. SPDC and other partners have full rights to determine destination of their hydrocarbons. SPDC to continue engagement of its JV partners on the destination of BS-Gas.
ISSUE	**OPPORTUNITY**	**ACTION**
Current UUOA excludes the non-straddling resources.	Inclusion of non-straddled resources in the unit if permitted by law will increase SPDC-JV tract participation and enable consequent higher past production recovery.	Influence PIB to allow the unitisation of straddling and non-straddling assets. Whilst PIB is yet to be passed, commence negotiations on the commercial construct to include the non-straddled resources in future development.
The incremental economics result of the "execute UUOA in Jan-2011 case" results in negative NPV at a flaring fee of $3.50/mscf.	The negative NPV in the "execute UUOA in Jan-2011 case" starts becoming positive if flaring fee is less than $2.70/mscf	Execute UUOA early, if expected flaring fee is lower than $2.70/mscf to take advantage of the resultant economic and non-economic benefits of the UUOA.
NAOC has presented a request to the UOC to drill work over wells in 2012.	Additional production arising from this activity is currently not part of the base case.	Shell representative seeks to ensure budgetary provisions are supported for work over wells in 2012

Alternatives Considered.

Not agreeing to a UUOA is not an option as unitisation is a regulatory requirement.

Agreement of a UUOA without resolution of past costs could lead to later dispute and delay or inability to implement the TP adjustment.

Section 4: Corporate structure, and governance

A Unit Operating Committee (UOC), a Technical Committee (TECOM), a Development Committee (DEVCOM) and a finance & audit committee are in place to govern the unit. The UUOA will provide the legally agreed basis for the constitution and powers of these bodies and provide for how work programmes and budgets are to be approved and funded for the unit.

Section 5: Functional Support and consistency with Group Standards

Functional support is sought from discipline in line with the provisions of electronic investment proposal system. The Legal, Development, Commercial, Gas, Finance and Economics disciplines have reviewed this IP. The UUOA will provide SPDC with increased rights to influence the operator in accordance with the Group NOV Manual.

Section 6: Project management, monitoring and review

Operator's project management will be monitored and reviewed in accordance with the UUOA and under the authority of the Unit Operating Committee; one member of which is the Shell's shareholder representative.

Section 7: Budget provision

Agreement in the UUOA will allow all past unresolved costs to be confirmed as performance and enable SPDC to obtain approval for her share from her JV Partners and make payments to the operator NAOC. Current budget provisions for costs arising from TP adjustment was phased in BP09 and for 2011. However, should the unresolved expenditures and past costs adjustment be firmed up and become due for payment in 2010, then the Shell exclusive NOV budget for Egbema projects has been identified as an offset source to meet this end.

Section 8: Group financial reporting impact.

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

US$ mln	2011	2012	2013	2014	Post 2014
Total Commitment	2.70	0.00	0.00	0.00	0.00
Cash Flow					
SCD Expenditure	0.36	0.00	0.00	0.00	0.00
Capital Expenditure	2.33	0.00	0.00	0.00	0.00
Operating Expenditure	0.00	0.00	0.00	0.00	0.00
Cash Flow from Operations	0.31	1.65	1.62	0.65	0.60
Cash Surplus/(Deficit)	(2.02)	1.65	1.62	0.65	0.60
Profit and Loss					
NIBIAT +/-	0.06	1.44	1.14	0.01	(0.13)
Balance Sheet					
Average Capital Employed	1.42	2.74	2.48	2.12	4.96

Section 9: Disclosure

NAOC is a subsidiary of the ENI group of companies and are bound by the ENI "Code of Practice" published in 1998, which is similar in intent to the Shell Group's Business Principles.

Section 10: Financing

This investment will be financed by group equity in response to operator's cash calls under the UUOA through SPDC Ltd.

Section 11: Taxation

There are no unusual taxation features.

Section 12: Key Parameters

Approval of US$2.695Mln to resolve past costs and sign the UUOA to enable asset governance and the implementation of SPDC Ltd's increased unit share for Biseni-Samabri Unit. Timing of execution of the UUOA to be at the discretion of the decision executive (DE) taken cognisance of other partner timing, AG solution readiness and the regulated flare-fees.

Section 15: Signatures

This proposal is submitted to UIG for approval.

Supported by:	Approved by:
....	....
Echefu Ezenwa	Jerry Jackson
FUI/FP	*UIG/T/E*
Date ..../..../....	Date ..../..../....

Initiator: __________________

Nicholas Tombs - *UIB/G/N*

Date …/…. /….

Appendix –1: Biseni-Samabri past Cost Obligation and TP adjustment Costs. (RT2010)

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	TOTAL
Capex 100%	7,554	1,386	-	-	12,636	-	87	27,450	38,925	57,966	20,160	10,708	5,184	4,058	1,554	1,971	189,638
Opex 100%	-	-	-	-	-	-	-	-	-	-	3,281	4,276	2,628	3,157	3,942	3,500	20,784
Concept Definition (phs 2)	-	-	-	-	-	-	-	-	-	-	-	-	1,626	7,029	-	-	8,655
Total Opex 100%	-	-	-	-	-	-	-	-	-	-	3,281	4,276	4,254	10,186	3,942	3,500	29,439
SPDC Ltd's Share (Old TP)																	
Capex	1,360	249	-	-	2,274	-	16	4,941	7,007	10,434	3,629	1,927	933	730	280	355	34,135
Opex	-	-	-	-	-	-	-	-	-	-	591	770	766	1,833	710	630	5,299
TP Adjustment Cost SPDC Ltd																	
Capex	93	17	-	-	155	-	1	338	479	713	248	132	64	50	19	24	**2,333**
Opex	-	-	-	-	-	-	-	-	-	-	40	53	52	125	48	43	**362**

Appendix –2: Production Profile Biseni-Samabri (NFA)