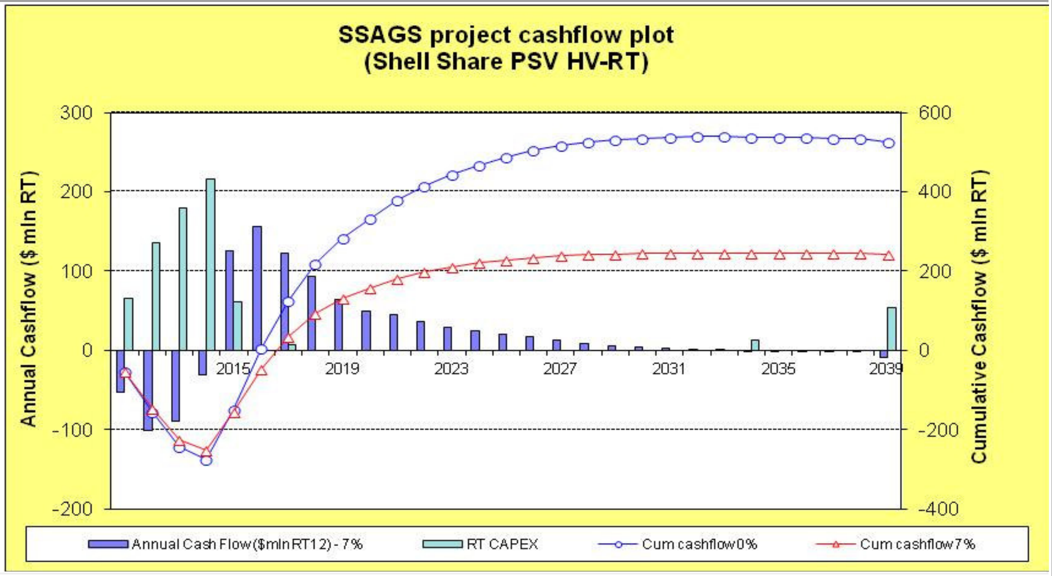
Group Investment Proposal

Summary information

<table>
<tr><td>Business unit and company</td><td>Shell Petroleum Development Company of Nigeria Limited (SPDC)</td></tr>
<tr><td>Group equity interest</td><td>100% in SPDC, whereas SPDC is the Joint Venture (JV) operator of an unincorporated JV with a 30% interest.</td></tr>
<tr><td>Other shareholders/partners</td><td>Nigerian National Petroleum Corporation (NNPC: 55%), Total E&P Nigeria Ltd (10%), and Nigerian Agip Oil Company (NAOC: 5%)</td></tr>
<tr><td>Business or Function</td><td>Upstream International (UI)</td></tr>
<tr><td>Amount</td><td>The headline size of US$711mln Shell Share MOD 50/50 composed of US$694 mln CAPEX Shell Share MOD and US$17.1 mln OPEX Shell Share is being requested for approval in this revised GIP. This is made up of US$52.3 mln approved in the pre-FID proposal and US$659 mln being requested for in this proposal (all the above in 100% JV).</td></tr>
<tr><td>Project</td><td>Southern Swamp AG Solutions Project Plus (SSAGS+), incorporating Kanbo, Opomoyo, Opukushi North, Opukushi, Benisede, Ogbotobo, Tunu, Agbaya, Ajatiton, Akono and Dodo North Fields</td></tr>
<tr><td>Main commitments</td><td>
<table>
<tr><th>Description</th><th>pre-FID proposal (100% JV)</th><th>This proposal (100% JV)</th><th>This proposal (Shell Share_Equity)</th><th>Total IP (100% JV)</th><th>Total IP (Shell Share_Equity)</th></tr>
<tr><td>Production Facilities</td><td>122</td><td>823</td><td>247</td><td>945</td><td>284</td></tr>
<tr><td>Flowlines/Bulklines/Pipeline</td><td>37</td><td>425</td><td>128</td><td>462</td><td>139</td></tr>
<tr><td>Location Preparation (Wells)</td><td>-</td><td>24</td><td>7</td><td>24</td><td>7</td></tr>
<tr><td>Owners Cost (excl. SCD)</td><td>15</td><td>150</td><td>45</td><td>166</td><td>50</td></tr>
<tr><td>Contingency (Surface Facilities)</td><td>-</td><td>210</td><td>63</td><td>210</td><td>63</td></tr>
<tr><td>SCD</td><td>-</td><td>35</td><td>11</td><td>35</td><td>11</td></tr>
<tr><td>20 New Wells, (Drilling, Completion & Testing 2 NAG Wells, 18 Oil Wells) & Recompletion of 1 NAG Well[1]</td><td>-</td><td>527</td><td>158</td><td>527</td><td>158</td></tr>
<tr><td>Total (50/50 MOD)</td><td>174</td><td>2,196</td><td>659</td><td>2,370</td><td>711</td></tr>
</table>
[1] Well Costs is net of SCD cost and also includes provision to recomplete one NAG Well n 2018
</td></tr>
<tr><td>Reserves/Resources</td><td>All 2C and 2P HC volumes covered by this GIP have been endorsed through a RAR-lead Resource Endorsement Session (RES).
- Already booked 2P NFA oil reserves of 27.21 MMboe SS from currently producing fields: Benisede, Kanbo, Opukushi, Opukushi North, Opomoyo and Tunu
- Further Oil and Gas development of 46.13 MMboe SS 2C resource volume in 8 fields (29.48 MMboe of Oil/NGL and 16.65 MMboe of Sales Gas)
- Ogbotobo Re-entry with total of 2.76 MMboe SS of 2C resource volume (2.59 MMboe Oil and 0.17 MMboe Sales Gas) and 3.40 MMboe SS of AG from currently producing NFA fields.
- Infrastructure from this project will enable further development of 243.3 MMboe SS contingent resources in the node.

Economics used in this GIP to evaluate bookability of 2P for the SSAGS project are based on consolidated project costs and incremental resource volume estimates, resulting in the further oil and gas development to be classified as Contingent Resources. Once the FID has been taken on the AG facilities, the 2C volumes associated with further development activities can in principle be re-classified as Reserves.</td></tr>
</table>

<table>
<tr><td>Production</td><td>Incremental oil production from this project peaks at 30.1 Mbopd (100%) in 2016 with an accompanying sales gas production of about 105 MMScf/day (100%) .</td></tr>
<tr><td>Flaring</td><td>This project eliminates the flaring rate of 23 MMScfd from the Southern Swamp fields (amounting to 70 Bcf until end of field life)</td></tr>
<tr><td>Source and form of financing</td><td>This investment will be financed with JV funding. Total Shell commitments will be financed with SPDC Limited own generated funds and existing intra-group facilities. An MCA financing sensitivity is included in the economics section to evaluate the risk of NAPIMS inability to support the funding of the Step 2 activity - Oil development drilling under the JV base financing.</td></tr>
<tr><td>Summary cash flow</td><td>
</td></tr>
<tr><td>Summary economics</td><td><table>
<tr><td></td><td>NPV7%</td><td>VIR7%</td><td>RTEP</td></tr>
<tr><td>HV-RT</td><td>242.9</td><td>0.42</td><td>22%</td></tr>
<tr><td>RV-RT</td><td>139.8</td><td>0.24</td><td>16%</td></tr>
</table></td></tr>
</table>

Section 1: The proposal (management summary)

The Southern Swamp area comprises 16 fields (12 producing and 4 Partially Appraised) in OMLs 35, 36 & 46 with significant oil and gas resources; EUR of 1,636 MMstb (100%) and 2,138 Bscf (100%) of associated gas. Of this, 811 MMbbl with 456 Bscf associated gas has been produced from the fields in the period January 1976 to December 2011. The fields lay in the coastal swamp area, 65km South of Warri, currently with 100 oil wells and flow lines producing through 4 flow stations (Benisede, Opukushi, Ogbotobo and Tunu) and a new Field Logistics Base (FLB) at Tunu is at an advanced stage of completion. Oil evacuation is via the Trans Ramos pipeline to Forcados Terminal whilst associated gas is flared. NAG resources in the node have not been developed and the SSAGS+ project represents the first of such developments.

The Southern Swamp Associated Gas Solutions plus (SSAGS+) project is primarily aimed at providing AG solutions to secure NFA production (100.1 MMbbl + 69.3 Bcf associated gas, 100%) while also drilling 18 oil wells to utilise capacity in the flow stations, thereby developing 90.4 MMbbl (100%) new oil (with 54.3 Bcf AG). It also includes the drilling of 2 gas wells from Dodo North to guarantee the sustenance of the 100 MMScf/d supply (268Bcf of NAG). In support of an accelerated project delivery, a pre-FID IP of F$174.3m 100% JV (US$52.3mln SS) was approved in April 2011 to facilitate completion of FEED and placement of orders for Long Lead Materials. The project successfully passed DG4 in March 2012, following the close out of high urgency recommendations from VAR4 and ESAR4 held in January and March respectively.

The Gas Flaring (Prohibition and Punishment) Bill 2009, currently before the national assembly, specifies payment of fines by non-compliant companies, of not less than the cost of gas at the international market plus another 50% of the penalty sum to the Local Government Area for community development activities. The impact of the law could include shut-in of the assets post-flares out date (2012 proposed at the National assembly), the likelihood of non-renewal of expiring Acreage Licenses due in 2019, loss of surface assets to vandalisation (when left idle) and loss of opportunity to develop and book significant reserves (both NFA and FOD).

This FID Investment Proposal:
The scope of the FID expenditure will cover for the following:

1. Facilities:
    a. Provision of AG booster compression facilities as well as brown-field facilities upgrade for the Tunu, Benisede, Opukushi and Ogbotobo flowstations.
    b. Laying of pipelines for associated gas from Benisede (12" x 16 km), Opukushi (12" x 24 km) and Ogbotobo (8" x 16 km) to Tunu, where the CPF is located.
    c. A new 70 MMscf/d AG compression facility (with slug catcher) at Tunu.
    d. A new 120 MMscf/d slug catcher at Tunu for non-associated gas.
    e. A 160 MMscf/d hydrocarbon dew-pointing facility at Tunu for AG & NAG.
    f. A 160 MMScf/d Gas Compression and Metering system at Tunu to deliver gas to the domestic supply grid.
    g. Laying of 16"x 32km high-pressure gas pipeline for export from Tunu to EA-RPA.
    h. Condensate handling system, associated metering, instrumentation and electrical systems.
    i. Island power generation at all the Facility Locations to include community power supply in support of inter-dependencies with host communities.
2. Wells scope:
    a. Drilling, completion and hook-up of 2 NAG wells from Dodo North field to supplement and back-up AG production into the Nigerian Domestic Gas network. Recompletion of one of the NAG well in 2018.
    b. Drilling, completion and hook-up of 18 oil wells – to utilize the existing ullage in the facilities

The P50 onstream date, defined as first gas export from Tunu, is Jul 2015. The P90 date is Dec 2015.

Funding
The estimated total Capex for the SSAGS+ project is $2.370 bln (MOD, 100%) plus SCD (Opex) cost of $35 mln (100%). The project is phased into 2 discrete steps for funding in installments under the Domgas tranche (Step 1: Gas Infrastructure plus NAG wells) and JV Base tranche (Step 2: Oil Development drilling – 18 Wells) as a base case. A funding sensitivity for MCA funding is included in the economics to evaluate the impact of NAPIMS in-ability to fund the oil related development activity. It is noteworthy that circa 80% of the funding comes under the Domgas funding tranche (for Step 1), which has been fully supported by the Government and continues to enjoy priority during the annual budgeting cycle.

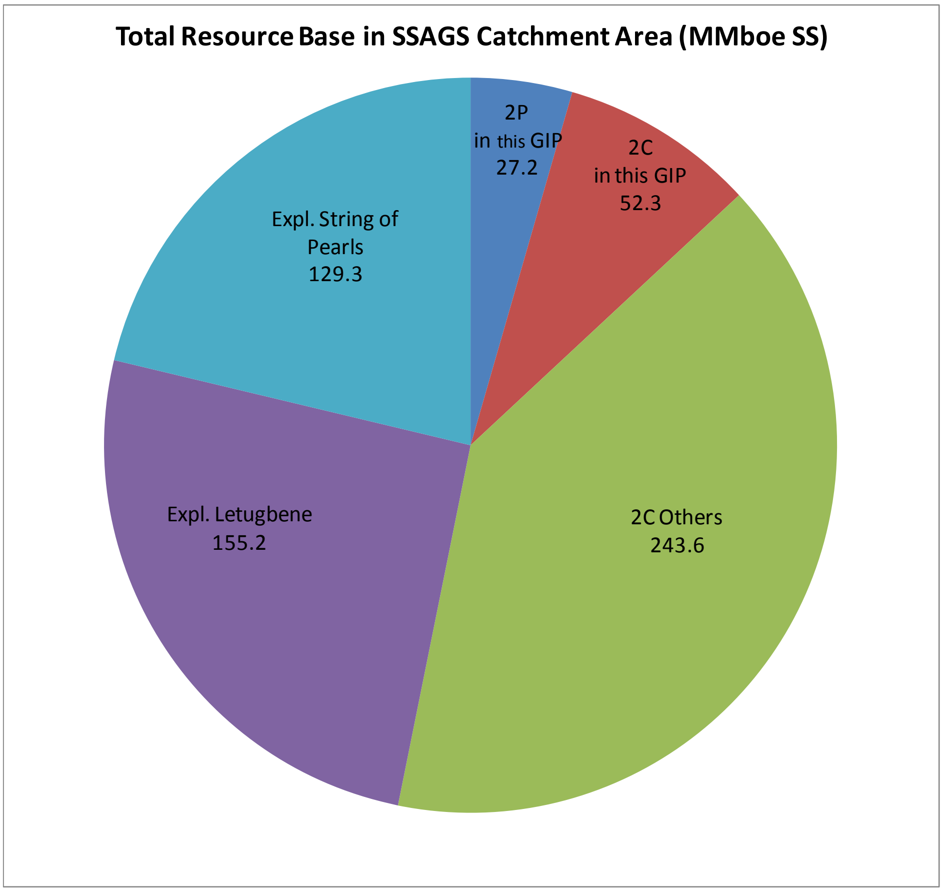
The total project expenditure and phasing is shown below. These figures are updates to BP11 reflecting the final outcome of VAR4 and ESAR4 concluded in January and March 2012 respectively.

Table 1: Full Project COST phasing

SSAGS P50 Estimate and Expenditure Phasing												
		Cost $million										
	Funding Tranche	Pre-FID Opex			Post FID Capex - JV Funded							
Scope		2010	2011	2012	2012	2013	2014	2015	2016	2017	2018	Total
Step_1 Gas Facility / Infrastructure Incl. 2 NAG Wells + 1 Recompletion	Domgas/IPP	2	19	2	218	463	489	477	188	-	25	1,881
Step_2 Oil Development (18 wells)	Base JV						131	265	58	-	-	454
SCD (Opex)	Domgas/IPP	-	-		4	9	13	7	3			35
Total		**2**	**19**	**2**	**222**	**472**	**628**	**737**	**247**	**-**	**25**	**2,370**

Section 2: Value Proposition and financial context

The implementation of this project will eliminate flaring and enable continued production of 27.2 MMstb (SS) NFA oil (+16.3 Bcf associated gas) by securing the surface assets and also enable further growth in the affected fields once AG gathering facilities are in place. This project will develop 52.3 MMboe (SS) of contingent resources comprising 46.13 MMboe from further oil and gas development, 2.76 MMboe from Ogbotobo re-entry and 3.40 MMboe of AG sales from existing wells by securing the surface assets. The AG gathering and NAG development will enable SPDC JV to meet Government aspiration for Domestic Gas for power generation.



The total resource volume covered in this phase of development is only a small fraction of the total resource base in the area and hence significant opportunity still exists for future development.

The 243.6 MMboe SS (58% Oil) of '2C Others' are discovered Contingent Resources not part of this SSGAS+ GIP. In addition there are some 284.5 MMboe SS (100% Gas) of undiscovered Exploration hydrocarbons volumes sitting within the same development area as the SSAGS+.

Summary Economics

The economic evaluation for the Southern swamp project was on a forward-look basis using NFA plus further development production forecast from July 2015 (Oil and NAG) for the affected fields and 50/50 level 3 CAPEX LE. Base case assumes Joint Venture funding for both Steps 1 and 2 and HV price scenario. The project value was also determined at RV-RT price scenarios.

The value of the project is greatly enhanced by executing both Steps 1 and 2; Step 2 brings about 2/3 of the overall value and the VIR above the hurdle. It is imperative to achieve license renewal since only 36% of the value is realized within the current license period. Oil contributes 97% of the total revenue; therefore no sensitivity on domestic gas price has been considered. Having to fund Step 2 with an MCA, would preserve 96% of the value, but brings the VIR below the hurdle.

Table 2: Economics Grid

PV Reference Date: 1/7/2012	NPV (S/S $ mln)		VIR	RTEP	VTE	UTC (RT $/boe)		Payout-Time (RT)	Maximum Exposure (RT- AT)
Cash flow forward from: 1/1/2012	0%	7%	7%	%		0%	7%	(yyyy)	$mln (yyyy)
Base Case									
SV ($50/bbl & NGMP based gas price)	195.4	47.3	0.08	11%	0.17	13.4	16.2		
RV ($70/bbl & NGMP based gas price)	351.0	139.8	0.24	16%	0.49	13.4	16.2		
HV ($90/bbl & NGMP based has price)	524.6	242.9	0.42	22%	0.86	13.4	16.2	2016	*252.0(2015)*
BEP (RT $/bbl)						26.3	40.3		
Sensitivities (using HV-RT12)									
Step 1 under JV and step 2 under MCA funding		232.4	0.33						
Above sensitivity with 2019 licence expiry		76.5	0.10						
All capex from 2014 onwards funded under MCA		219.7	0.21						
Low Reserves (Prob < 0.90)		145.1	0.25					2016	*276.4 (2015)*
High Reserves (Prob < 0.10)		268.4	0.47					2016	*252.0 (2015)*
Low CAPEX		257.6	0.49					2016	*247.9 (2015)*
High CAPEX		222.0	0.33					2018	*323.6(2015)*
6-months delay (OSD Jan 2016)		227.8	0.40					2018	*325.0 (2015)*
Subtracting NFA volumes to be prod by end Dec 2012		220.7	0.38					2017	*252.0 (2015)*
Subtracting NFA volumes to be produced by Jul 2015		174.9	0.30					2018	*282.3 (2015)*
Base Case w'out already booked NFA production		81.0	0.14					2018	*281.7 (2015)*
Full Life Cycle		228.2	0.41	22%	0.80			2016	*257.3 (2015)*
2019 License expiry		87.3	0.15					2016	*252.0 (2015)*
Step -1 Standalone		89.8	0.19					2018	*231.2 (2015)*
Step-2 Standalone		153.0	1.37					2016	*20.5 (2015)*
Step-1Standalone with licence expiry		4.9	0.01					2018	*231.2 (2015)*
Step 2- stand alone with licence expiry		82.4	0.74					2016	*20.5 (2015)*
NFA standalone (No AG facility)		132.6	NA					NA	*NA*
2C volumes evaluated alone		185.9	1.00					2017	*99.5 (2015)*
Project evaluated under ring fenced condition.		213.3	0.37					2017	*416 (2015*
Base case including Trans Ramos pipeline replacement		210.2	0.30					2018	*407.9 (2015)*
PIB IAT Version		134.0	0.20						
PIB House_v12		250.8	0.44						
Additional Uncertainty and Risk Analysis - using HV									
NPV(P10)		269.0	0.48						
NPV(P90)		154.0	0.24						
EMV at HV / eVIR at HV		218.8							
Probability of NPV > 0 at HV		100%							
Dispersion = EMV / (NPVP10-NPVP90) at HV		1.9							

***Probabilistic analyses have been based on uncertainty in reserves, Capex and Opex**

Key Project Parameter Data (Shell Share)

`	Unit	Bus Plan (BP11)	Low	Mid	High	Comments
Capex (MOD)	US$ mln	671;9	628.6	693.4	810.5	
Production Volume	mln boe	96.4	55.9	79.5	85.7	
Start Up Date	mm/yyyy	Dec-14	Dec-14	Jul-15	Dec-15	
Production in first 12 months	mln boe			12.6		Forward Looking

Section 3: Risks, opportunities and alternatives

The key risks and opportunities identified in the project are as follows:

Under-delivery of gas in the medium to long term (T)

The under-performance of identified NAG gas wells from Dodo North would result in low capacity utilization in the longer term.

Mitigation: Pre-DG1 work has been initiated to identify additional gas resources for possible acceleration to back-up Dodo North (incl Opukushi gas cap blow down (F3 & F5), Opukushi Deep, NAG development in Orobou and Egunabo). Also, huge potential exists in nearby Tolugbene exploration.

Security & Social Risks (P, E)

The project is located in the swamp of the Nigeria Delta; community interfaces, HSE and security issues are particularly significant in these areas, highlighted by cases of hostage taking, and armed attacks and sabotage of, especially, pipeline systems. There is also a risk of community agitations outside agreed GMOU terms that could lead to SCD related cost growth.

Mitigation: The amnesty programme of the federal government has helped to calm the security situation although uncertainty still pervades. Community interfaces will be managed through the Global Memorandum of Understanding (GMoU) mechanism to be deployed in alignment with the project schedule. An allowance has been made in the project budget for funding of social investment programmes (including a community interdependency power supply project).

NCD Act Implementation (E, C, P)

The requirement to comply with the Nigerian Content Directive (NCD) Act could result in project cost and schedule overrun due to limited in-country material manufacturing capacity and capability.

Mitigation: A detailed NCD compliance Plan has been worked out together with the EPC contractors and approved by the Nigerian Content Development and Monitoring Board (herein after referred to as Board).

NNPC Award Approvals for EPC Contracts (C, E)

To safeguard the project schedule it is necessary to award the two major EPC contracts within Q2 2012 (1st May 2012). With the conclusion of commercial negotiation with bidders, award approval by SPDC MTB is possible within the required time period but approval protocols within NAPIMS/NNPC easily take 6 to 12 months period to process.

Mitigation: SPDC has maintained close and rigorous engagement with NAPIMS to ensure common understanding of project priorities and urgencies. Against this background the proposal is to secure Shell approval to award the EPC contracts once NAPIMS Tender Board endorses the award approvals to NNPC GEC / Board. The estimated exposure 9-months after award is circa 20% of the contract ceiling (or F$240Mln for the 2 EPC contracts).

Funding (C, E,)

The base proposal is to fund the 18 oil wells in step 2 under the JV base. However, there is a concern that NNPC may be unable to provide JV funding for some or all of the oil wells due to funding constraints and competition for JV funds from other projects. *Mitigation* A sensitivity included in the Economics section shows that, when the oils wells are funded under MCA (2008) terms, project VIR is 0.33. Three of the wells have been pulled forward in the drilling sequence to early 2013 with preparatory expenditure in 2012 already thereby setting a precedent for JV funding. As an upside, other Alternative Funding mechanisms may be available from 2014, which could offer better economic terms compared with MCA.

Licence Expiry in 2019 (C, E, P)

The OMLs (35, 36 & 46) expires in 2019. *Mitigation:* A sensitivity has been included in the Economics to show that payout period occurs before the licence expiry date of 2019 under JV and MCA funding scenarios as well as for the NFA only case. Every opportunity will be leverage to press for this licence renewal. Indeed, recent renewal of Shallow Water Licenece for Exxon looks like a good sign.

Integrity of Trans Ramos Pipeline for Oil Evacuation (T)

Although the Trans Ramos pipeline is only 17 years old, the integrity of the pipeline is impaired due to sabotage and possible corrosion.. An Intelligent Pig (IP) run was carried out in 2000 and a defect assessment was performed with Pipe Risk Base Assessment. resulting in derating of the line to 32 bar.

Mitigation: The current pressure rating of 32 bar can support a flow rate from Southern Swamp up to 200kb/d, which is higher than the maximum gross liquid production expected from the Southern Swamp node. A sectional replacement of the dented section of the pipeline is in BP11 (to be executed in 2012) to enable an IP run which will form the basis for further assessment and required upgrade programme. The ballpark cost for full replacement of the line is $600 mln. In the worst case outcome where full replacement of the line is required in 2014, this reduces the VIR of the project to 0.30.

Crude Theft (P)

An estimated 7 to 10% of crude production in the SPDC Western Division is currently lost due to bunkering, and therefore the oil volumes from the project could be reduced due to theft.

Mitigation: A thorough review of additional security measures to combat oil theft will be conducted.

Exploration Scope and Future Development (T/C)

Opportunities exist in Orobou, Egunabo and Opukushi (deep) fields to develop 620 Bcf of NAG in the short to medium term, as already included in BP11.

In the long term, additional gas could be matured from currently un-appraised prospects within the node. There is also an exploration potential of some 3 Tcf (100%) in Letugbene.

Section 4: Carbon management

The project will recover some 124 Bscf of associated gas that would otherwise have to be flared to produce 190.5 MMbbl oil (from NFA and new Oil). This will translate in removal of circa 8Million tonnes CO_2 that would have otherwise been released to the atmosphere during routine flaring. However, post project implementation, the limited residual CO_2 emissions will primarily (96%) come from gas-fired and Mechanical drivers (exhausts) used in the plant and also from flaring during emergencies accounts for the remaining 4% of CO_2 emission. This will be managed through proper equipment selection at the design stage and implementing appropriate operating practices to comply with extant regulations and company policies on emission limits including the SPDC's flaring policy.

Section 5: Corporate structure, and governance

This project fits within the existing SPDC corporate structure and governance. Consequently, it will comply and respect all relevant and existing governance.

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

This proposal complies with Group Business Principles, policies and standards. Functional support from P&T, HSSE, Finance, Legal, IT, CP and SPCA has been obtained for the full project scope. Additionally, there will be a focus on Nigerian Content Development (NCD) as already indicated above.

Section 7: Project management, monitoring and review

This is a "P&T executed" project delivered by the UIG/T/PD Major Projects team. The ORP compliant governance structure is in place, including a project specific DRB, DE and BOM. A Project Control and Assurance Plan (PCAP) has been approved to define the applicable controls for the EXECUTE phase.

Section 8: Budget provision

The project is fully funded in BP11 base plan although under-funded in the 2012 JV programme, principally because NAPIMS concern that EPC contract has not been awarded yet. The additional requirements will be addressed in the course of the year during budget re-alignment. The understanding kept with NAPIMS, during DEVCOM, was that they are willing to support the additional funds once contracts have been awarded in good time.

Section 9: Group financial reporting impact

The Financial impact of this activity on Shell Group Financials is as indicated in the Table below:

US$ mln	Prior years	2012	2013	2014	2015	2016	Post 2016	Cumulative
Total Commitment	6	68	141	190	232	67	7	**711**
Cash Flow								
SCD Expenditure	0	1	3	4	2	1	0	**11**
Pre-FID Expenditure	6	1	0	0	0	0	0	7
Capital Expenditure		65	139	186	230	66	7	693
Operating Expenditure		2	4	16	22	18	325	387
Cash flow From Operations		0	21	73	151	193	695	1,133
Cash Surplus/(Deficit)		(65)	(118)	(113)	(79)	126	688	**439**
Profit and Loss								
NIBIAT +/-		1	3	1	44	78	461	
Balance Sheet								
Avg Capital Employed		33	127	244	363	400	157	

Section 10: Disclosure

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

Section 11: Financing

This investment is expected to be financed with JV partners funding (within the IPP/Domgas and JV base budget), and Shell Share of capital expenditure will be met by SPDC's own cash flow.

Section 12: Taxation

There are no unusual taxation features at this stage

Section 13: Key Parameters

The following is the main aspect of this proposal:

Approval for the total revised headline size of $711mln Shell Share (2,370 mln 100%JV) 50/50 MOD for the execution of AG Solutions to protect NFA production in Kanbo, Opomoyo, Opukushi North, and further oil development drilling in the Opukushi, Benisede, Ogbotobo, Agbaya, Ajatiton, Akono and Tunu fields as well as NAG development drilling in Dodo North field.

Section 14: Signatures

This Proposal is submitted for approval.

Supported by:

....

Bichsel, Matthias F RDS-ECMBI

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

For Business Support:

....

Brown, Andrew RDS-ECAB

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

Supported by:

....

Henry, Simon P RDS-ECSH

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

For Business Approval:

....

Voser, Peter R RDS-CEPV

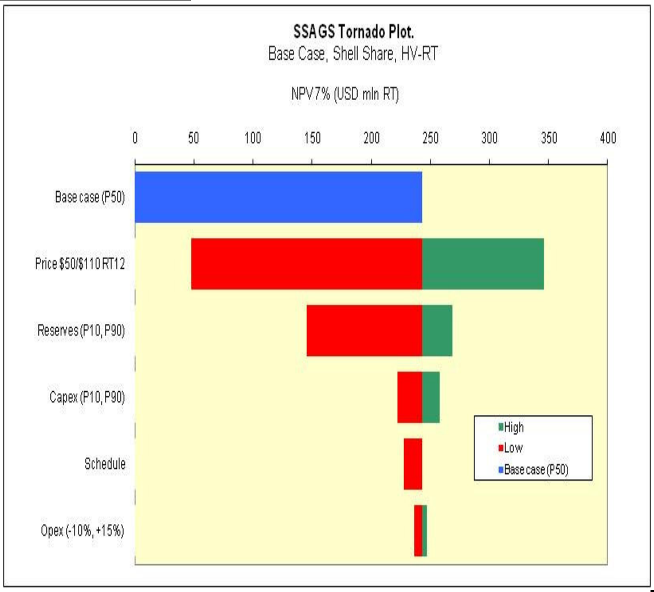
Date.... /.... /....

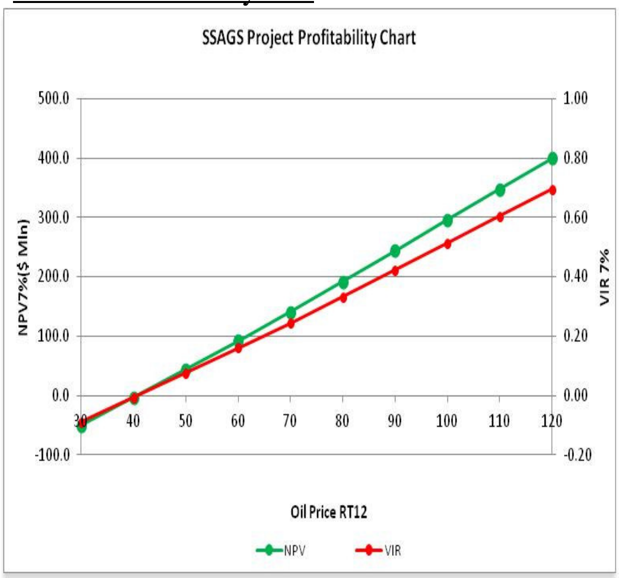
Appendix-1: PIB and MCA Assumptions.

Economics Assumptions

- Oil taxed under PPT (PPT tax rate of 85%)
- Oil price at the three PSVs: SV, RV and HV ($50/bbl, $70/bbl and $90/bbl respectively) with applicable offsets.
- Gas price at SV, RV and HV forecasts from the Nigeria Gas Master Plan (NGMP) profile with 15%, 40% and 65% implementation assumed for SV, RV and HV respectively.
- Gas taxed under CITA with Associated Gas Framework Agreement (AGFA) incentive.
- Education Tax of 2% assessable profit
- NDDC levy of 3% total expenditure
- GHV of 1000btu/scf for Domgas
- Flare Penalty of $3.5/Mscf was applied and is not tax deductible
- Abandonment estimated as 10% of total RT CAPEX
- No facility upgrade/replacement required for the project until economic limit.
- SCD Cost was provided by project team
- ABC OPEX.

Tornado Plot. **Profitability Plot**





PIB Assumptions (House Version)

- No production allowance used in analysis.
- CIT is 30% of taxable income with a depreciation schedule of 3x25%, 24% for qualifying expenditure and it is not deductible for NHT calculation
- NHT is 50% with a depreciation schedule of 4x20%, 19% for qualifying expenditure.
- 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
- 15% cost overseas applied.

PIB Assumptions (IAT version)

- No production allowance used in analysis
- NHT depreciation schedule is 4x20%, 19% for qualifying expenditure.
- No capital investment credit/allowance (ITC or ITA) or uplift is granted under the PIB
- 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 & 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%
- 20% of overseas cost is non-deductible for determination of NHT taxable income.

MCA Assumptions

- All step 2 costs on the MCA would be recovered through cost oil.
- Profit oil ceiling of 8% IRR on carried costs
- Current agreement for recovery of carry costs is maintained
- $91.69/bbl – oil at PSV HV-RT in 2012 for HV MCA Economics
- OPEX and PMT not carried under current MCA arrangement.

Appendix-2: Estimate & schedule Fact Sheet

ESTIMATE & SCHEDULE FACT SHEET

to be included in GIP and PCN submissions

<Southern Swamp AGS+ Project >

<SPDC Western Swamp Location>

Version 2.5 Confidential

Approved Cost & Schedule Estimate

Project No.: <C12001>

Estimator: Augustine Oleru

Planner: James Magluyan

Case: Base

Rates of Exchange are as per SI-SX Data Set

Market Scenario: LI

Estimate Type: 3

Costs are in: USD Millions

Estimate Start / End: FID Apr 2012 / RFSU Jul-2015

LDM Date: 1-Jul-11

Category		Total Costs
Facilities		981
<Wells>		316
Enterprise Framework Agreements (EFA's):	Project Applied / Verified, Not Applied	129 /
Owners Cost (i)	(incl. Insurance, pre-FID, Taxes & Capitalized interest)	188
EPC Premium (ii)		205
Contingency	[illegible]	210
Inflation		116

	P10	P50	P90
[illegible]	[illegible]	[illegible]	[illegible]
	-10%	OK	15%

Assumptions:

Estimate & Schedule Premise
Processing plant major equipment part of the facilities cost estimates have been built using [illegible] based on [illegible] from the [illegible] deliverables. Pipeline estimates were based on ongoing as well as recently completed swamp pipeline installation contracts. Civil infrastructure estimates were built using corporate civil call-out contracts. The Q1 2012 latest [illegible] escalation factors have been applied in line with provisions of the [illegible] 2012 Capital Cost Outlook. Probabilistic cost risk analysis using @Risk has been used to calculate project contingencies and overrun allowance. Owners costs were derived bottom up using approved project manning profile. Well costs have been calculated using SPDC well cost estimating template by well engineering function and has been adopted in line with agreed in-house SPDC methodology. Schedule durations were based on recently completed and ongoing projects with similar activities. Risk analysis was carried out on the schedule.

Execution Strategy Premise
The execution is premised on award of two EPC packages (Facilities and Pipelines) while the Gas delivery line will be executed in conjunction with the FYP Offshore Pipelines - cost included in this estimate. location preparation for well drilling will be undertaken using SPDC corporate dredging call out contract.

Contract Strategy
Two EPC contract packages have been negotiated on lump sum prices for the processing plant and pipelines. Enterprise Frame Agreements (EFA) have been deployed for procurement of long lead items (LLI) including main compressors, line pipes and Twister modules. A Project Management Services Contract will be used to provide quality assurance & control as well as certification services in the design, procurement/expediting, fabrication, construction, precommissioning/commissioning of the Project.

Key Project Risks
Security/communities issues, [illegible] and external interface management

Exclusions
Customs and excise duties. SPDC financing of interest during construction.

3 months management adjustment have been applied to the [illegible] "1st Gas" and "Project Complete" dates to accommodate any force majeure though no adjustment has been made to the P90 costs.

Benchmarking & Metrics
Pipeline & facilities benchmarked with completed projects. [illegible]

Capex Phasing and Planned Progress:

Key Schedule Dates:

Phase	Finish (P50)	Finish (P90)
FID	Apr-2012	[illegible]
<Detailed Eng.>	[illegible]	[illegible]
<Procurement -LLI>	[illegible]	[illegible]
<Installation -Twister>	[illegible]	[illegible]
<Construction>	[illegible]	[illegible]
<Commissioning CPF & Booster Stns>	[illegible]	[illegible]
<1st Gas>	[illegible]	[illegible]
Project Complete	[illegible]	[illegible]
RFSU	Jul2015	[illegible]

GCAF IA 1
Date : 23-03-12
Name : Nwaokpese, Imeka
Signature : [signature]

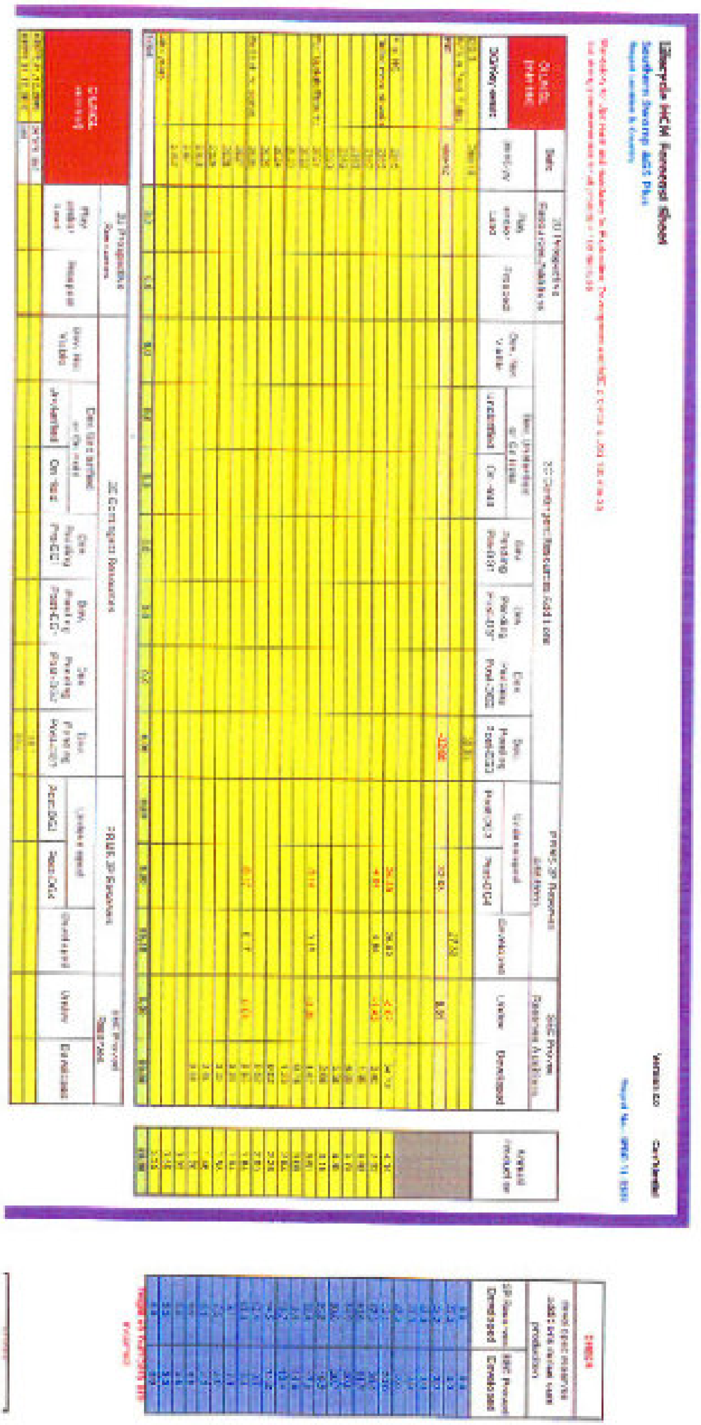
VP Project Services
Date : 23/3/2012
Name : Hans, Mes
Signature : [signature]

EVP Projects
Kretzers, Rob

Development lead
Date : 23-03-2012
Name : Ezugwore, Chibogwu
Signature : [signature]

Project Manager
Date : 23-03-12
Name : Caroline Rockall
Signature : [signature]

Appendix-3: Lifecycle HCM forecast Sheet



Oil [bl.scf]	Date	2U Prospective Resources Additions		3C Contingent Resources Additions							PRMS 2P Reserves Additions			SEC Proved Reserves Additions		Annual Production
DG/Res event	[illegible]	Play and/or Lead	Prospect	Dev. Not Viable	Dev. Unclarified or On Hold: Unclarified	Dev. Unclarified or On Hold: On Hold	Dev. Pending Pre-DG1	Dev. Pending Post-DG1	Dev. Pending Post-DG2	Dev. Pending Post-DG3	Undeveloped: Post-DG3	Undeveloped: Post-DG4	Developed	Undev.	Developed	
[illegible]	[illegible]									[illegible]						
[illegible]	[illegible]									[illegible]		[illegible]		[illegible]		
[illegible]	[illegible]											[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]											[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Total		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Developed reserves additions minus sum production: 2P Reserves Developed	SEC Proved Developed
[illegible]	[illegible]

Gas [bl.scf]	2U Prospective Resources		2C Contingent Resources							PRMS 2P Reserves			SEC Proved Reserves Additions	
	Play and/or Lead	Prospect	Dev. Not Viable	Dev. Unclarified or On Hold: Unclarified	Dev. Unclarified or On Hold: On Hold	Dev. Pending Pre-DG1	Dev. Pending Post-DG1	Dev. Pending Post-DG2	Dev. Pending Post-DG3	Undeveloped: Post-DG3	Undeveloped: Post-DG4	Developed	Undev.	Developed
[illegible]									439.18					
[illegible]									[illegible]					

Date: 26.3.12
Name: [illegible]
Signature: [illegible]

Date: 21-Mar-2012
Name: [illegible]
Signature: [illegible]

Note: [illegible]