Internal Investment Proposal (Pre FID IP)

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>30%, with SPDC as Operator of an incorporated Joint Venture (JV)</td></tr>
<tr><td>Other shareholders/ partners</td><td>Nigeria National Petroleum Corporation (NNPC: 55%), Total Exploration & Production Nigeria Limited (TEPNL: 10%), Nigeria Agip Oil Company (NAOC: 5%) in SPDC-JV</td></tr>
<tr><td>Business or Function</td><td>Upstream International (UI)</td></tr>
<tr><td>Amount</td><td>USD 36.7mln Shell share, MOD, 50/50 (USD 122.34mln 100% Unit)</td></tr>
<tr><td>Project</td><td>Pre FID for EA Further Oil Development (FOD) Project</td></tr>
<tr><td>Main commitments</td><td>
<table>
<tr><th>COST</th><th>100% SPDC JV(F$mln)</th><th>Shell Share(F$mln)</th></tr>
<tr><td>Pre-FID OPEX</td><td></td><td></td></tr>
<tr><td>Facilities Cost</td><td>9.37</td><td>2.81</td></tr>
<tr><td>Wells Cost</td><td>10.61</td><td>3.18</td></tr>
<tr><td>SUB-TOTAL</td><td>19.97</td><td>5.99</td></tr>
<tr><td>Pre-FID CAPEX</td><td></td><td></td></tr>
<tr><td>Facilities Cost</td><td>-</td><td>-</td></tr>
<tr><td>Wells Cost</td><td>102.37</td><td>30.71</td></tr>
<tr><td>SUB-TOTAL</td><td>102.37</td><td>30.71</td></tr>
<tr><td>TOTAL PRE-FID (OPEX+CAPEX)</td><td>122.34</td><td>36.70</td></tr>
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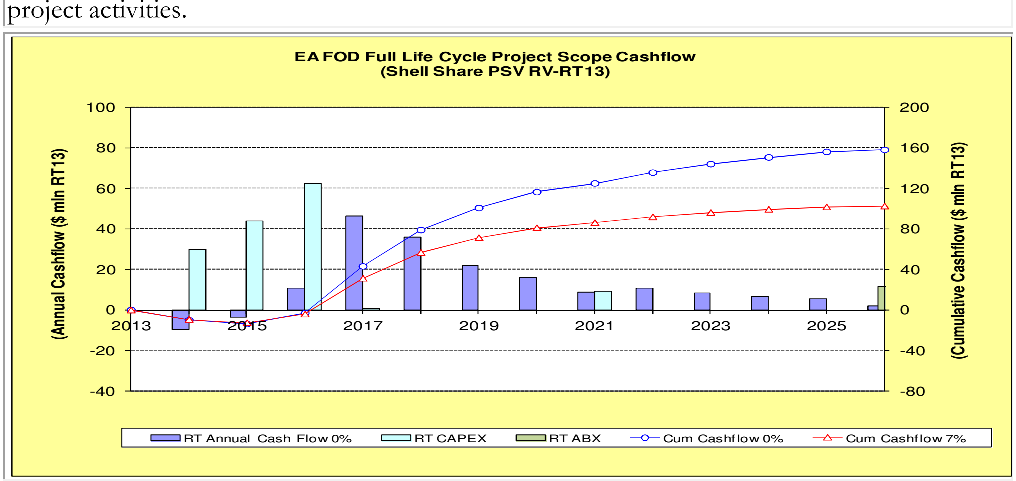
<tr><td>Reserves/Resources</td><td>The EA FOD project aligns with SPDC's strategic goals and priorities by developing OML 79 and thus makes the case for renewal of its license which expired in 2008. The project will develop additional 68.11MMstb of oil and 14.99Bscf associated sales gas contingent resource (2C) from EA and EJA fields via drilling and completion of 20 new development wells and 3 work over wells.
The project will however be executed in two phases, 15 new wells and 3 workovers first [54.26MMstb of oil and 14.11Bcf of sales gas] and 5 wells requiring a new platform [13.85MMstb of oil and 0.73Bcf of sales gas] will come later subject to management approval post value engineering exercise by end Q4 2013/Q1 2014. The development will also increase the Shell Group reserves in line with SEC regulations. The 1C and 3C volumes are 39MMstb & 11.9Bscf and 91.1MMstb & 30.1Bscf respectively.</td></tr>
<tr><td>Production</td><td>Incremental oil production from this project peaks at 36,356 bopd in 2018, with associated sales gas production reaching circa 10.6 MMscfd by 2017 (forecast on page 5). This will extend field life, improve cash flow from the asset, fill-up FPSO spare capacity and improve unit Opex.</td></tr>
<tr><td>Source and form of financing</td><td>This pre-FID investment will be funded by JV funding. Shell share capital expenditure will be met by SPDC's own cash flow and/or the existing shareholder facility. Formal JV Partners' approval will be obtained. All JV partners are fully on board and have participated in all key project activities.</td></tr>
<tr><td>Summary cash flow</td><td>
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Summary economics	Summary Economics (RV-RT13)	NPV7% (USD mln)	RTEP (%)	VIR7%
	Pre-FID - Base	14.1	>50	0.50
	Pre-FID - High Capex	13.0	>50	0.37
	15 New Wells +3 WO - Base Case	102.5	>50	0.83

Section 1: The proposal (management summary)

This Group Investment Proposal seeks approval for funding of $36.7mln Shell Share ($122.34mln, MOD, 50/50 100% JV) pre-FID funding for the define phase of the 15 wells and 3 workover project scope including drilling of the first 3 wells to guarantee early oil.

EA Further Oil Development (FOD) will be executed in two phases of drilling, completion and hook-up of 15 wells and 3 work-overs from existing platforms first and subsequent drilling and completion of additional 5 wells from a new platform with a tie back to existing platform. The project is in continuation of the planned phased development of EA/EJA fields as documented in the 1999 pre-production FDP. The original phase I has been on stream since December 2002 with declining production and rapid water cut development (see Figure 1 below).

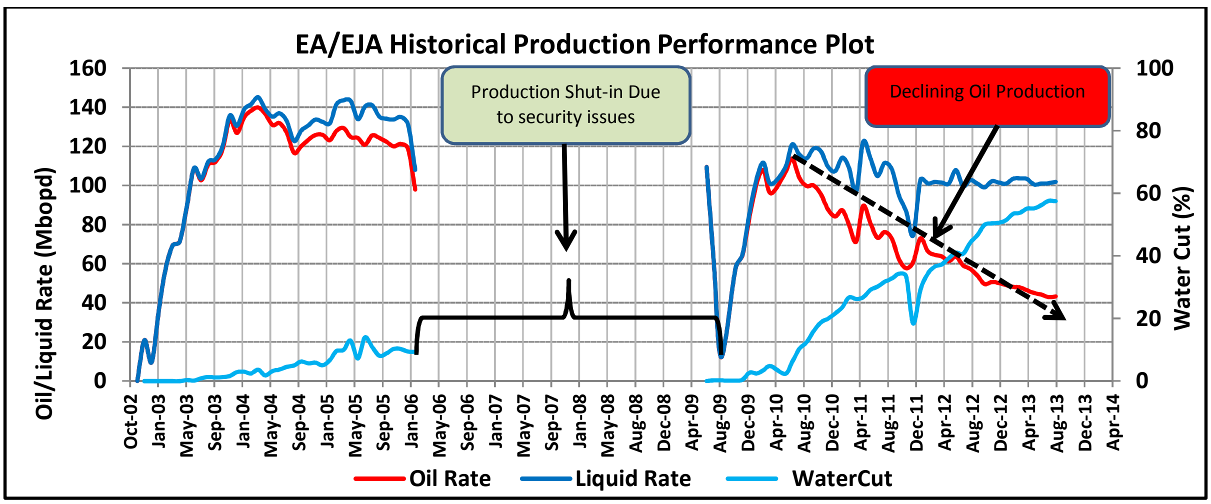


Figure 1: EA FOD Historical Production Performance Plot

A phase III study had already been matured to SELECT Phase with approved FDP in 2008, but hibernated due to funding. It was de-hibernated in May 2011 leading to a phase II and III development studies in 2011/2012 with phase III including EJA deep prospect development in a success case. Later in 2012 it was decided to name the original phase II and III developments as EA FOD going into DG2 in August 2012.

During VAR/ESAR-3 in the SELECT phase in October 2012, it was recommended to de-couple EJA deep exploration from EA FOD. EJA deep prospect development will be the subject of a separate study in an exploration success case. This recommendation was subsequently endorsed by the DE/DRB. The EJA deep exploration well will however be drilled during the development drilling of EA FOD in 2015.

EA Further Oil Development (FOD) is expected to develop additional 68.11MMstb of oil and 14.99Bscf associated sales gas contingent resource (2C) in the EA/EJA fields within the expected production life of the FPSO (Sea Eagle). The increased production will address the fields' production decline, maximize recovery (full-field development), utilize the available spare capacity in the production facility (FPSO) and reduce the unit operating cost with onstream date of May 2015. In an EJA deep success case, the development will provide an upside volume of ca. 20MMstb (2U) to the 68.11MMstb from this FOD.

Figure 1, shows the field further development architecture in line with the selected development concept. The selected concept is to drill 15 new wells and carry out 3 workovers from existing platforms. Drill 5 wells from a new platform (DP-C) and tie-back to existing platform B (DP-B). To reduce the project development CAPEX, value engineering is being carried out in the define phase as part of the concept definition. The ongoing Value Engineering work has yielded a reduction in Surface Facilities cost from $352m to $181m via detailed optimization to the Contracting, Procurement & Execution Strategy and Concept optimization reviews - as at July 2013. The value engineering exercise is planned to be concluded in Q4 2013, after which it will be decided whether to implement the 5 wells scope.

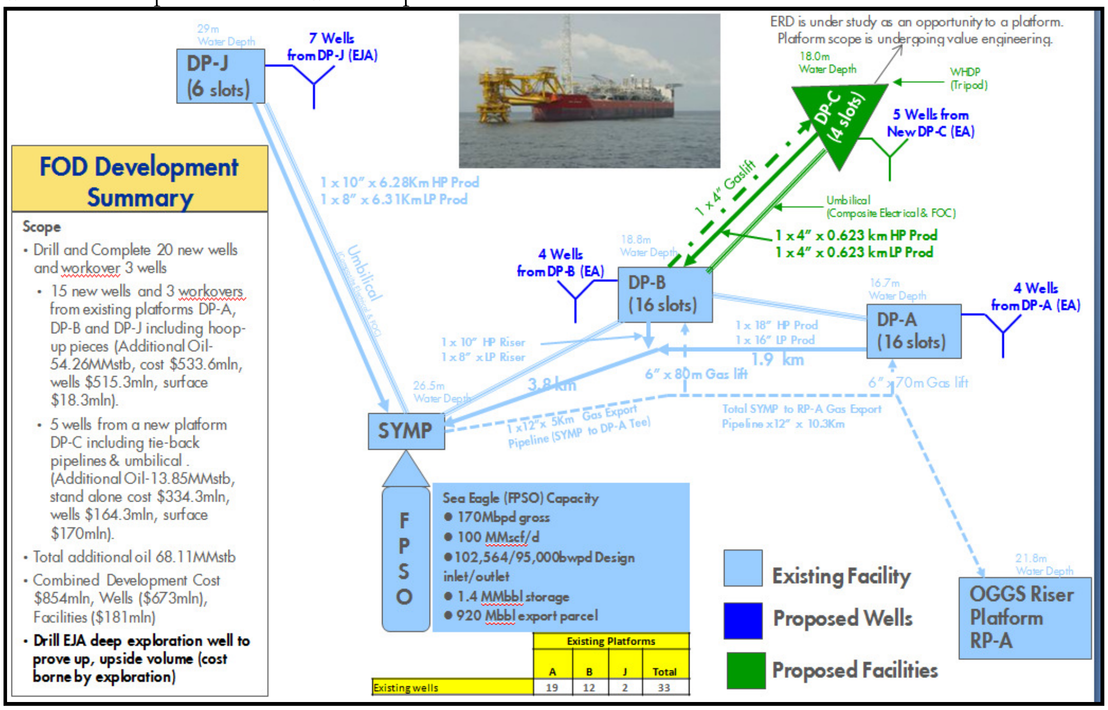


Figure 2: EA FOD Development Concept

This proposal for USD122.34mln (MOD) is for the pre-FID works to mature the project definition after DG3, up to VAR-4 and FID. It covers activities described in Table 1 below:

Table 1: Expenditure Description and Phasing (MOD)

EXPENDITURE DESCRIPTION AND PHSASING (MOD)						
DESCRIPTION	**Proposal (100%)**	**Proposal (Shell)**	**2013 (100%)**	**2013 (Shell)**	**2014 (100%)**	**2014 (Shell)**
FEED (15 wellscope)	0.61	0.18	0.61	0.18	0.00	0.00
Detailed Engineering (15 wellscope)	0.52	0.16	0.20	0.06	0.32	0.10
Procurement (15 wellscope)	2.40	0.72	0.00	0.00	2.40	0.72
Fabrication/hook-up of 3 wells (part of 15 wellscope)	0.05	0.01	0.00	0.00	0.05	0.01
Scope Definition/FEED (5 wellscope)	1.00	0.30	0.50	0.15	0.50	0.15
LLI-Wellhead & Xmas Tree (CSW & SSMC)	5.91	1.77	0.00	0.00	5.91	1.77
LLI-OCTG	12.83	3.85	0.00	0.00	12.83	3.85
LLI-Well Completions	10.91	3.27	0.00	0.00	10.91	3.27
Geophysical & Geotechnical Surveys & Miscellaneous Studies	5.22	1.57	1.57	0.47	3.65	1.10
Statutory SCD Component (2.5% of CAPEX)	2.56	0.77	0.00	0.00	2.56	0.77
Permits /Pre&Post Route Survey	0.33	0.10	0.33	0.10	0.00	0.00
Geomechanics & ERD Well Planning Charges	0.71	0.21	0.71	0.21	0.00	0.00
Obtain EIA approval	0.46	0.14	0.46	0.14	0.00	0.00
Obtain drilling permits	2.83	0.85	0.00	0.00	2.83	0.85
Drilling of 3 Development wells	76.01	22.80	0.00	0.00	76.01	22.80
TOTAL	122.34	36.70	4.38	1.31	117.97	35.39

This proposal is for the 15 new wells and 3 workover workscope. It excludes any significant costs on the new platform scope with the exception of cost for ERD study as an opportunity to a platform concept and early scope definition (Concept Plus) to provide adequate specification for the platform in order to obtain an early market quote.

<u>Business Objectives Full Project</u>

The business objective of this project is to develop additional 68.11MMstb of oil and 14.99Bscf associated sales gas contingent resource (2C) in the EA/EJA fields within the expected production life of the FPSO (Sea Eagle). The main business drivers for the EA Further Oil Development project include:

- Achieving full filled developed (i.e. maximizing the recovery from the discovered resource)
- Improves cash flow from operating asset and contribute to SPDC growth aspiration
- Utilize the available ullage in the FPSO to maximize asset utilization
- Reduce the unit operating cost by increasing the production in the field
- Test the EJA Deep exploration scope with circa 20MMstb (2U) potential upside.

<u>Project Scope</u>

A. 15 Wells & 3 Workovers Work scope (Project Define Phase) [54.26MMstb**;** 14.11Bcf**]**

Drill, complete and workover wells

a. Drill and complete 15 wells from existing platforms DP-A (4), DP-B (4) and DP-J (7)
b. Work over 3 wells from existing platform DP-A

B. 5 Wells Work scope [13.85MMstb**;** 0.73Bcf**]**

Construct new platform, tie-back bulkline and well hook-up

a. Construct and install 1 WHDP for 5 wells (DP-C)
b. Contruct and install a total of 3km tie-back pipeline (DP-C to DP-B)
   i. 1x6-inch 1.5km LP bulkline
   ii. 1x4-inch 1.5km gaslift line
   iii. 1.5km Umbilical
c. Fabricate hook-up pieces and connect wellheads to the bulklines on the platforms
d. Drill and complete 5 wells from DP-C

C. Drill EJA deep exploration well to prove up, upside volume of 20MMstb (cost borne by exploration)

<u>Funding</u>

The existing EA asset carry agreement was terminated in December 2012 and the asset made JV funded with NNPC 55%, Shell 30%, TEPNL 10% and NAOC 5%. For EA FOD, is the same JV funding formula

The estimated total CAPEX for the combined EA FOD is approximately $834.74mln (MOD) 100% JV, excluding Pre-FID (OPEX) cost of $19.97mln (MOD) 100% JV. This is following CAPEX reduction of $171mln total CAPEX. Table 2 shows the full project phasing.

Table 2: Full Project COST phasing

Scope	Cost $ Million											Total
	Pre-FID OPEX		Pre-FID CAPEX		Post FID CAPEX							
	2013	2014	2013	2014	2015	2016	2017	2018	2019	2020	2021	
Well hook-up to existing manifolds on the platforms - FEED, DED, Procurement, Fabrication & Installation	3.30	5.13	-	-	8.04							
SPDC Project Management	0.37	0.57	-	-	0.89							
Facilities Cost summary	**3.67**	**5.70**	-	-	**8.93**				-	-	-	**18.30**
Well studies	0.71	6.61	-	-	-	-	-	-	-	-	35.63	
Rig mob/demob				4.00		2.00						
Well LLI	-	3.29	-	26.36	16.14	10.57	-	-	-	-	-	
Drilling	-	-	-	72.01	127.73	210.34		-	-	-	-	
Wells Cost Summary	**0.71**	**9.90**	-	**102.37**	**143.87**	**222.91**	-	-	-	-	**35.63**	**515.38**
TOTAL	**4.38**	**15.59**	**-**	**102.37**	**152.80**	**222.91**	**-**	**-**	**-**	**-**	**35.63**	**533.67**

Section 2: Value Proposition and financial context

The primary objective of the EA FOD project is full field development maximizing the recovery from the discovered resource in EA/EJA fields. In doing so, the project also contributes to the case for the shallow water license (SWL) renewal under negotiation. By incorporating the EJA exploration drilling to the FOD drilling campaign, it serves to prove up early the upside to EA FOD.

Implementation of this project will address the declining EA field production, utilize existing ullage in the FPSO, reduce the unit operating cost of the field and extend the economic/productive life of the field. Incremental oil production from this project will peak at 36,356bopd in 2018, with associated sales gas production reaching circa 10.6 MMscf/d by 2017 (see EA FOD production forecast).

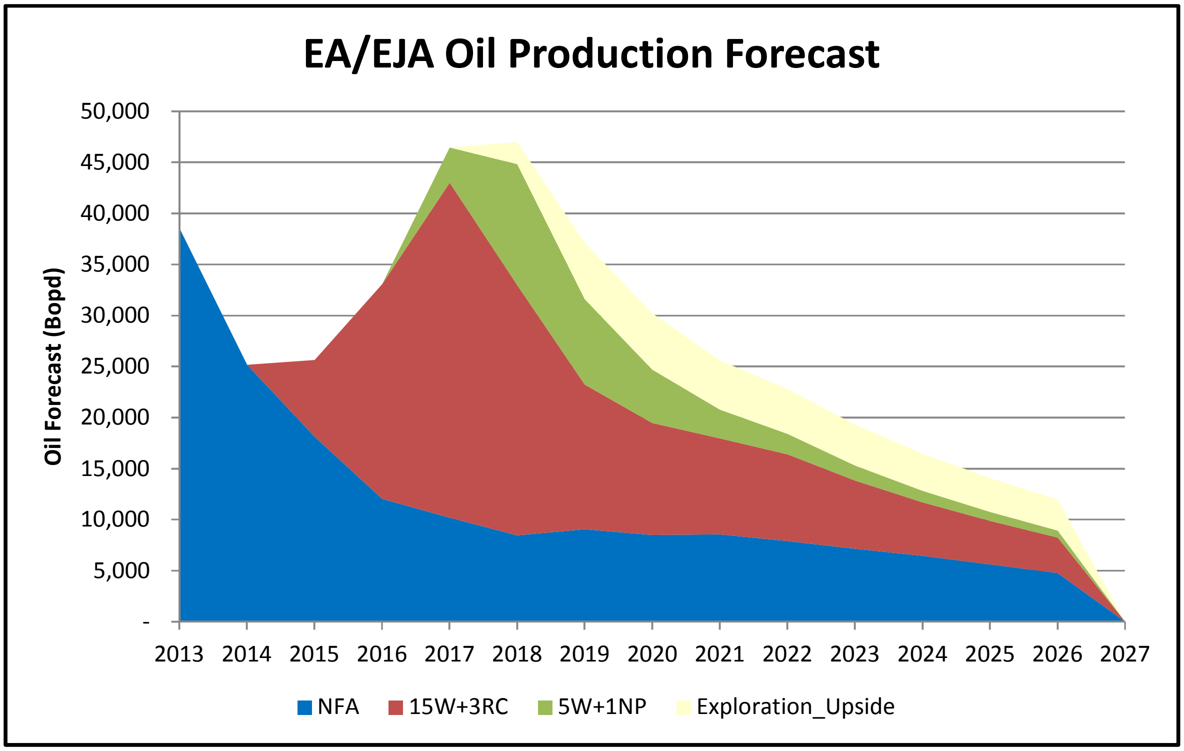


Figure 3: EA Production Forecast

Summary Economics

The Pre-FID economic evaluation was carried out using a 50/50 level II cost estimate. The pre-FID cost of ($19.97) was treated as OPEX, whereas ($102.37mln) was treated as CAPEX. This is because, 3 wells are already in the drilling sequence for 2014 which will be drilled before FID in Nov 2014, as such will be hooked up in event FID is not taken. Details of economics results (at Shell Share of 30%) are shown in Table 1 below. The following sensitivities were carried out on the **pre-FID base** case to show the impact of the various scenarios on the value of the project.

- Pre-FID High CAPEX (25%)
- 1.5% cost markup due to Benchmark Verified and Approved (BVA) issues with NNPC.

Further analysis was carried out to ascertain the value of the project's define phase (part of the larger full project scope) base case when the project takes FID in 2014 using a 50/50 level II cost estimate and the production forecast. The project define phase which is made up of 15 wells and 3 workovers and drilled from existing platforms has been considered as the key economic driver for the pre-FID request. Thus the following sensitivities were also carried out on the on this phase to show their impact on the value:

- High and low CAPEX.
- High and Low Production
- One year Production delay
- Project with ring fence (i.e. project without tax incentives).
- 20 Wells with $351Mln Facility Costs (Cost pre-Value Engineering)
- 20 Wells with $181Mln Facility Costs (VE Line assured cost as at end Q3 2013)
- 5 Wells stand alone with $335Mln Facility Costs (Cost pre-Value Engineering)
- 5 Wells stand alone with $170Mln Facility Costs. (VE Line assured cost as at end Q3 2013)
- 1.5% cost markup provision due to dispute by NNPC on Benchmark Verified and Approved (BVA) issues.

Based on the economics results, the base scope VIR7% of 0.83 meets the hurdle at PSV-RV at DG4

Table 1: EA FOD Pre-FID Economic Grid (Shell Share), 3 Wells.

PV Reference Date: 1/7/2013	NPV (S/S $ mln)		VIR	RTEP	UTC (RT $/boe)		Payout-Time (RT)	Maximum Exposure (RT- AT)
Cash flow forward from: 1/1/2013	**0%**	**7%**	**7%**	**%**	**0%**	**7%**	(yyyy)	$mln (yyyy)
Base Case								
SV ($70/bbl RT13)	13.7	**9.6**	**0.34**					
RV ($90/bbl RT13)	19.6	**14.1**	**0.50**	>50	16.7	19.6	2016	*27.1 (2014)*
HV ($110/bbl RT13)	25.5	**18.6**	**0.66**					
Sensitivities (using RV)								
High Capex (+25%)		**13.0**	**0.37**				2016	*33.7 (2014)*
1.5% Cost mark-up due to BVA issues		**12.4**	**0.40**					

Table 2: EA FOD Pre-FID Key Project Parameters (Shell Share)

Parameter	Unit	BP12 Provision	Low	Mid	High	Comments
Capex (MOD)	US$ mln	N/A	N/A	30.71	38.39	No provision for Pre-FID in BP12
Opex (MOD)_Project	US$ mln	N/A	N/A	5.99	7.49	No provision for Pre-FID in BP12
Production Volume	mln boe					
Start Up Date	mm/yy					
Production in first 12 months	mln boe					

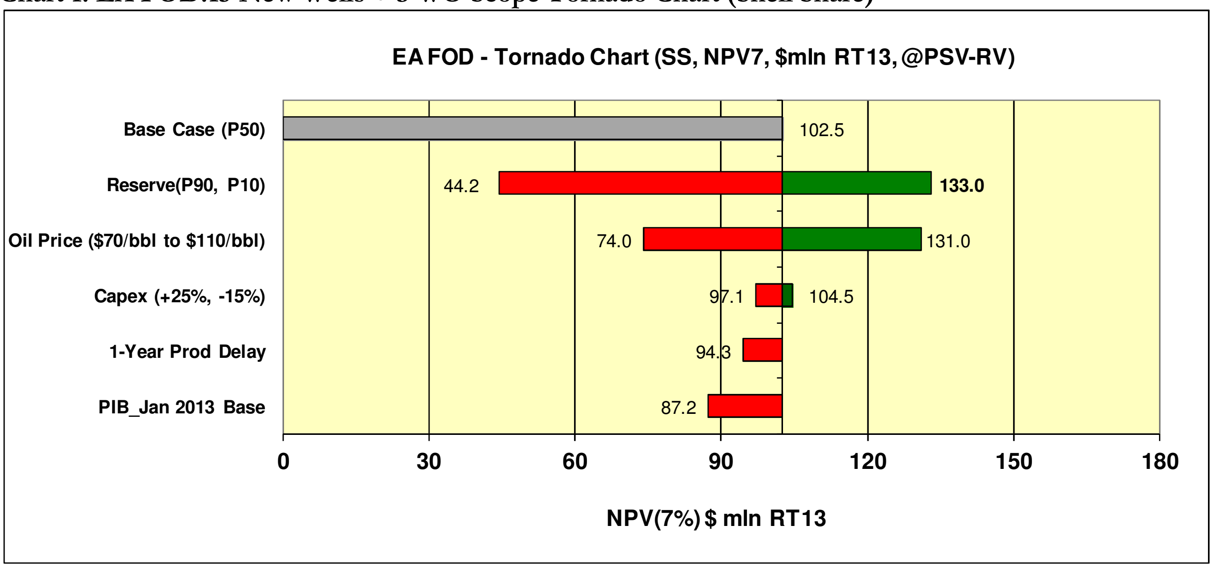
Table 3: EA FOD: 15 New Wells + 3 WO Scope Economic Grid (Shell Share)

PV Reference Date: 1/7/2013	NPV (S/S $ mln)		VIR	RTEP	UTC (RT $/boe)		Payout-Time (RT)	Maximum Exposure (RT- AT)
Cash flow forward from: 1/1/2013	**0%**	**7%**	**7%**	**%**	**0%**	**7%**	(yyyy)	$mln (yyyy)
Base Case								
SV ($70/bbl & $1.58/mmbtu RT13)	116.5	**74.0**	**0.60**					
RV ($90/bbl & $2.01/mmbtu RT13)	158.0	**102.5**	**0.83**	>50	10.7	12.5	2017	*55.7 (2016)*
HV ($110/bbl & $2.42/mmbtu RT13)	199.4	**131.0**	**1.06**					
Oil BEP (RT $/bbl)					13.5	17.9		
Sensitivities (using RV)								
High Capex (+25%)		**97.1**	**0.63**				2017	*74.9 (2016)*
Low Capex (-15%)		**104.5**	**1.09**				2016	*44.2 (2016)*
High Production (P10)		**133.0**	**1.08**				2016	*52.1 (2016)*
Low Production (P90)		**44.2**	**0.36**				2018	*74.5 (2016)*
1-Yr Production Delay		**94.3**	**0.77**				2017	*73.6 (2016)*
Project with Ring Fencing		**99.7**	**0.81**				2017	*52.9 (2015)*
20 Wells_$351Mln-Facility Costs		**108.1**	**0.46**				2018	*115.7 (2016)*
20 Wells_$181Mln-Facility Costs		**116.9**	**0.60**				2017	*86.6 (2016)*
5 Wells_$335Mln-Facility Costs		**5.2**	**0.05**				2020	*95.8 (2017)*
5 Wells_$170Mln-Facility Costs		**13.5**	**0.18**				2019	*66.2 (2017)*
PIB July 2012 - Base		**87.2**	**0.78**					
1.5% Cost mark-up due to BVA issues		**95.8**	**0.63**					

Table 4: EA FOD: 15 New Wells + 3 WO Scope Key Project Parameters (Shell Share)
Key Project Parameter Data (Shell Share)

Parameter	Unit	BP12 Provision	Low	Mid	High	Comments
Capex (MOD)	US$ mln	276.4	131.0	154.1	192.6	Reduced well count and slimmer platform configuration
Opex (MOD)_Project	US$ mln	58.7	12.9	15.2	19.0	Generic Opex was used in BP12 for full project scope, whereas ABCM is used for this evaluation for 15 wells in define phase. Opex includes SCD, Pre-FID and ABCM.
Production Volume	mln boe	29.7	13.6	18.1	20.8	Implementation of integrated technical review, brought about lower well count and production volume
Start Up Date	mm/yy	May-15	Jan-16	May-15	NA	Production acceleration not considered, EIA/LLI issues
Production in first 12 months	mln boe	0.6	0.7	1.0	1.1	

Chart 1: EA FOD:15 New Wells + 3 WO Scope Tornado Chart (Shell Share)



<u>Economics Assumptions</u>

<u>Pre-FID</u>

- Pre-FID evaluation is treated as a cost only.
- Pre-FID Cost treated as mainly CAPEX.
- NDDC levy 3% of total expenditure.

<u>Full Scope Project</u>

- Oil PSVs of $70/bbl @SV-RT13, $90/bbl @RV-RT13 (Base) and $110/bbl @HV-RT13 with Bonny offset applied.
- 2013 NLNG PSV was used.
- GHV of 1150 BTU/Scf used.
- Oil was taxed under PPT (PPT tax rate of 85%).
- Gas was taxed under CITA with AGFA incentives.
- Abandonment cost is estimated at 10% of total project RT CAPEX.
- SCD cost of 2.5% of MOD CAPEX.
- NDDC levy of 3% total expenditure.
- Education tax of 2% assessable profit.
- Gas flare penalty of $3.5 /Mscf was applied and is not tax deductible

Section 3: Risks, opportunities and alternatives

Key Risks-Technical

- Environmental Impact Assessment [EIA] Approval: The drilling schedule is premised on receipt of provisional EIA approval by July 2014, which in turn is based on a one-season field data gathering. Where this is not met, the spud date for the wells may slip.
- Early procurement of Wells Long Lead Items. Early issue of purchase order for the wells long lead items is required to ensure the drilling starts in august 2014. The NAPIMS approved project contracting and procurement strategy enables the use of single source contracts for the Well LLI work scope. A fall back option is to use existing well engineering contracts where budget offsets exist. In addition, the contractor for splitter wellheads has been engaged to implement a staggered delivery to optimise schedule and minimize impact on drilling start date.
- Recoverable volumes: There is the risk of having lower than expected oil volumes which may occur in the event of encountering small oil accumulations than predicted. Structural uncertainties due to inadequate well coverage in the flanks of some EA FOD target reservoirs coupled with no clear contacts logged in some reservoirs leave significant subsurface uncertainties. This is mitigated by building Low and High case models for Low and High recoverable volumes.
- Concurrent Operations: Planned wells will be drilled concurrently with production on existing platforms to manage down deferment. This will be mitigated by incorporating lessons from phase 1 concurrent operations and adequate HSSE controls in design and execution of the project to reduce risks to ALARP. Competent contractors will be used along with fit for purpose Contracting Strategy to incorporate this.
- Brown field integration: EA operations already exist and the FOD will tie-back to the existing operations. There is the risk of obsolescence in automation & controls, conventions, etc. This is mitigated by carrying out a brown field integration study and identifying the item for which modifications may be required.
- Shallow gas hazard: There is the presence of shallow gas as evident during the phase 1 drilling. This is mitigated with shallow gas response that has been put in place and the drilling of the wells and location of the new platform based on shallow gas study.

Key Risks - Economic

- Cost escalation: Bid price escalation is now frequent in drilling and facilities tenders due to global market demand and a perceived increase in country risk due to the Niger Delta security situation. This is mitigated by ensuring that the right contingency, risks premium and inflation are incorporated in the level 2 cost estimate. The Well LLI prices are based on prices from existing well engineering contracts which are competitive. The on-going value engineering exercise provides a better scope definition for the 5 well work scope and will lead to material and quantity based cost estimation which will be adequately benched marked to ensure competitiveness for the work. In addition to these, the contracting strategy defines a fall back approach of selected bid list where target project cost is not achieved on the 5 well scope.
- Schedule slippage: The project economics is sensitive to schedule slippage. On stream is May 2015. This is mitigated with an integrated schedule developed in Primavera and the items on the critical path identified and given the right focus. The key critical path item is the ordering of the splitter wellhead.

Key Risks - Commercial

- Shallow water license (SWL): SCiN shallow water license expired in 2008 of which EA is one of the Assets. Non-Renewal of the license may prevent taking FID on this project. There is high confidence that the license will be renewed in Q4 2013.
- Funding: The EA FOD project funding structure for NNPC’s share is not yet agreed. Total and NAOC may have concerns to take FID ahead of lease renewal. Non-approval may prevent or delay taking FID on this project. To mitigate this, the agreement signed with NNPC in 2012 as part of the EA Carry normalization, provides that SPDC JV Partners:
  1. Work collectively to progress the EA/EJA Further Oil Development (FOD) Project, recognizing that FID would be awaiting the result of the full technical and commercial review and the renewal of the lease; and
  2. Work together to put in place a financing solution to finance the NNPC share of the capital costs of the FOD project. A joint funding team has been set up and discussing the modalities for securing fund for the project. A proposal has been discussed with the team and NAPIMS preferred option is being awaited. FDP has been submitted to partners and reviewed with NAPIMS. Final approval from NAPIMS is imminent and this is not seen as a risk or show stopper.

Key Risks - Organizational

There are no organizational risks associated with this project. There is a governance structure and the project team is working to be fully resourced.

Key Risks - Political

- Nigerian Content (NC): The NC requirements can create higher project execution risk and schedule slippage can result. This is mitigated by putting a detailed NC plan in place and ensuring that the project contracting and execution strategies incorporate the NC requirements. The only waiver item is the 4" bulkline for which there are no local mills capable of producing line pipes of this size. Currently, NCDMB approval is being awaited for a corporate waiver extension as local capacity for this size of linepipe is still not available.

- The Petroleum Industry Bill (PIB): The PIB has not yet been signed off and the fiscal terms might change. This could potentially have negative impact on the economics of this project. The effect of PIB has been incorporated in the economics sensitivity to understand the risks.
- Security: Security incident in EA area led to the shut-down of the facility from 2006 to 2009. As mitigation, a security plan has been put in place incorporating the learning from the 2006 incident and the Niger Delta. The security plan for the project has been signed off.

Key Opportunities:
The key opportunities in this project are technical, organizational and political.
Technical

- EJA deep exploration prospect with 20MMstb upside: To harness this opportunity, the EJA deep exploration well drilling is planned in 2015 same time as the FOD development wells drilling. In a success case, it has an upside of 20MMstb in addition to the FOD volume of 68.11MMstb.
- Extended Reach Drilling (ERD): This can be used to develop the 5 wells that cannot be drilled conventionally from existing platforms as an alternative to the planned new platform (DP-C). To harness this opportunity, an ERD study is planned with a roadmap for completion in Q4 2013.

Organization

- Post DG3 organization: At the start of select phase, EA FOD already had the post DG-3 project manager appointed. The post DG-3 PM and Project leader have been working with the opportunity team to co-create the project scope definition and execution planning with the FEDM.
- H-Block project: H block is about 120km from EA and the project has some scope that is similar to EA FOD, and there is scope for synergy.

Political

- EA FOD operation is within the existing EA asset area. This means small foot print and limited impact.
- Social Performance/SCD: The Global Memorandum of Understanding (GMoU) is the corporate platform for managing community interface as well as delivering benefits to communities. Currently, SPDC has a functional steady-state GMoU (Iduwini/Kor/Bassan West & Mein Development Foundations) covering the project area neighbouring communities. The project will latch onto the existing GMoU as a platform for stakeholder management and social investment delivery. The SP risks associated with the project, which currently rank below the top 5 risks, will be mitigated in compliance with the SP Manual Requirements of the HSSE&SP Control Framework by delivering a social investment, impact mitigation and stakeholder engagement Plan. SCD costs have been captured in the Pre-FIP IP cost estimates.

Section 4: Carbon management

An integrated Greenhouse Gas Management Plan will be drawn up and implemented as part of the project's detail engineering. The proposal would include an estimate of incremental potential greenhouse gas emissions resulting from the project. The proposal would also include a plan for carbon management (including options considered, together with their cost estimates).

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 project governance.

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

This proposal complies with Group Business Principles, policies and standards. Full functional support covering SCD is provided for in the pre-FID and full project scope. In addition, there will be a focus on Nigerian Content Development (NCD) as already indicated above. Relevant Functions have provided functional support for this Investment Proposal.

Section 7: Project management, monitoring and review

The Major Projects Team – Corporate Matrix Projects under PTP/O/NM is managing the project. The ORP compliant governance structure is in place, including a project specific DRB, DE and BOM. A Project Control and Assurance Plan (PCAP) is under development to define the applicable controls for DEFINE phase.

Section 8: Budget provision

The project is in the AF category in BP12. F$46.9mln 100% JV was carried in BP12 for EA FOD as 2013 Budget. This was revised based on the joint recommended (JR) budget for 2013 approved by NAPIMS to F$15.93mln. However, the project budget commitment for 2013 is **$4.38mln**.

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 5 below:

Table 5: EA FOD Group Financial Reporting Impact

US$ mln	2013	2014	2015	2016	Post 2016
Total Commitment	1.31	35.39			
Cash Flow					
SCD Expenditure		0.77			
Pre-FID Expenditure	1.31	3.91			
Capital Expenditure		30.71			
Operating Expenditure	1.35	5.74	0.2	0.25	0.54
Cash flow From Operations	-0.2	25.35	6.37	6.73	14.07
Cash Surplus/(Deficit)	-0.2	-5.36	6.37	6.73	14.07
Profit and Loss					
NIBIAT +/-	-0.2	25.35	6.37	6.73	17.96
Balance Sheet					
Avg Capital Employed		15.35	30.71	30.71	64.55

Section 10: Disclosure

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

Section 11: Financing

This investment is expected to be financed through the JV base whereas the post FID IP will be financed by an alternative funding arrangement which is currently undergoing discussion 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 funding of $36.7mln Shell Share ($122.34mln, MOD, 50/50 100% JV) pre-FID funding for the define phase.

Section 14: Signatures

This Proposal is submitted to UI for approval.

Supported by:	For Business Approval:
....	....
Guy Janssens, SEPA-FUI/F	Markus Droll, SEPA-UIO/G
FM Nigeria & Gabon	VP Nigeria & Gabon
Date.... /.... /...	Date.... /.... /....

Initiator: Segun Owolabi, -UIO/G/DSFOS (BOM)

Appendix:

1) Estimate Fact Sheet – Approved cost and schedule estimate as per IDM chapter 4
2) Lifecycle HCM forecast Sheet – Approved HCM Forecast as per IDM chapter 4