Project name	**PROJECT COMMITMENT PROPOSAL FOR ASSA NORTH-OHAJI-SOUTH (PHASE-1)**
Business unit & company	Shell Petroleum Development Company
Group equity interest	100% in SPDC Ltd, 30% in SPDC-JV, 15% in AN-OH Unit[*NB: Provisional tract share of SPDC-JV and Chevron Nigeria Limited/NNPC Joint Venture (CNL-JV) is 50:50 in the AN-OH Unit*]
Shareholders / partners	National Petroleum Corporation (NNPC) 57.5%, Chevron Nigeria Limited (CNL) 20%, Total Exploration & Production Nigeria (TEPNG) 5%, NAOC (2.5%)
Business or Function	Upstream International – Operated (project executed by P&T Operated)
Amount	Reference ESFS nr. ANOH xxxxxxxxx

Estimate Type: 2	Previous Proposals		Current Proposal			Total Project (P50)
Accuracy: +25%/-15%	preFID		preFID		postFID	
USD mln SS (MOD)	Feasex	Capex	Feasex	Capex	Capex	
Shell Share	11.7	0	34.8	-	374.7	409.5 Note 1

Note 1 : CAPEX range is USD $ 348 – 512 mln

Assurance conclusion: The November 2014 ESAR concluded Amber on cost. All actions required Pre-DG3 have been closed. Above cost reflects the output of these actions

Key schedule dates	The phase 1 project schedule (P50) is DG3 – March 2015 SPA – July 2016 FID – November 2016 RFSU / OSD – March 2021
Objective and Value drivers	A significant requirement of the Federal Government of Nigeria (FGN) is the development of domgas for power generation. The Assa North - Ohaji South (ANOH) development is the largest domgas project in Nigeria at the present time. Its importance is stated at all high level engagements with government officials (through to and including Presidential level). Furthermore, the FGN/NNPC is currently building an East-West pipeline (OB3) with an OSD of 2016. The OB3 pipeline would be empty without gas from ANOH. The SPDC Domestic Supply Obligation (DSO) is 750 MMscfd in 2015 and rising to 1Bscfd in 2018 (not accounting for portfolio rationalisation). Current domgas potential is about 350MMscfd. The ANOH project will develop 4.3 Tcf of gas and 197 MMstb of condensate with domgas production of 500MMscfd (SPDC JV share 250 MMscfd). An important component of the project, is the proposed condensate refinery to be provided adjacent the ANOH gas plant by Borkir International (a subsidiary of the Dangote Group). The refinery scheme would minimise risk of condensate theft, provide significant multiplier effects to host communities, increase refining capacity within Nigeria and potentially allow for condensate to be taxed as gas. Cost has become the key Value Driver for the project approaching DG3. About $75 mln (Shell Share) reduction in cost, relative to earlier post-DG3 estimates, has been achieved mainly through the introduction of Turbo expander technology for hydrocarbon dewpointing (eliminating need for export gas compression), deletion of 52 km condensate export pipeline to TNP in favour of selling at the fence and optimising the contracting strategy. Further cost reductions will be pursued in the define phase through refinements in contracting strategy.
Project Scope Description	The project will be developed in two phases. The project scope for the first phase (this proposal) is: - Six wells in the H1000X and H4000X reservoirs. - Primary Treatment Facility (water and hydrocarbon dewpointing gas plant) and field logistics base.

- 28 inch gas pipeline of 22 km to the NNPC OB3 pipeline.

Phase 2 will provide field depletion compression to extend the production plateau beyond 15 years.

Alternatives were evaluated mainly with variations in well count, gas rate, and export options for condensate. The optimal concept was chosen and later confirmed at the Concept Select VAR in July 2014.

Main commitments

Approval for pre-FID commitments USD 34.8 mln, Shell share, MOD, 50/50, of which USD 11.7 mln has been approved by earlier GIP's. The commitments are requested for the Front End Engineering Design, Surveys (e.g. EIA, Geo-Technical), SGSi support and Project Management costs in Define phase (USD 14.1mln) and acquisition of land (USD 9.0mln) pre-FID – all Shell Share

Reserves / Resources

GES Volumes	Low P90 (MMboe)	Mid P50 (MMboe)	High P10 (MMboe)
ARPR 31.12.14 (This proposal/Full Life Cycle)	78.91/94.28	101.69/105.79	109.74/109.76
PCP Headline (This proposal/Full Life Cycle)	78.91/99.70	103.29/134.19	127.60/163.61
SEC Proved @ FID	Note 2		

The difference between the ARPR 31.12.14 and the PCP Headline is the ARPR volume truncation for one license extension period by 2039 and PCP truncation at economic limit-cut off year by 2055

Note 2 – Volumes to be provided at FID

Assurance conclusion: The volumes are assured and supported by RAR (January 2015).

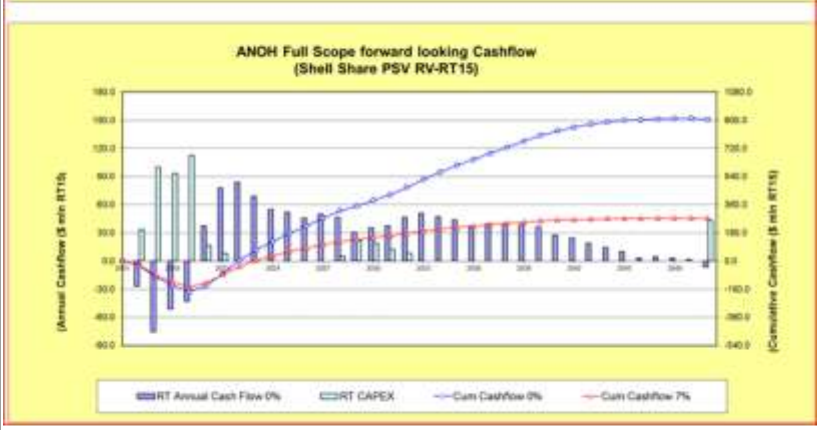
Production

Appendix 1 - Assa North Production Prof

Production Shell share	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Condensate kbopd	3.71	5.33	5.33	5.34	5.34	5.32	5.33	5.16	4.37	3.98	3.53	3.15	2.71	2.47	2.29
Gas MMscfd	51.76	69.69	69.72	69.75	69.68	68.89	68.81	69.66	69.78	69.78	69.78	69.78	69.78	69.78	69.78
Total kboepd	12.63	17.35	17.35	17.37	17.35	17.19	17.19	17.17	16.40	16.01	15.56	15.18	14.74	14.50	14.32

See insert for production profile for Full life-cycle.

Summary cash flow



Summary economics

Phase I – This proposal								
PV Refrence Date: 1/7/2015	NPV ($/$ $ mln)		VIR	RTEP	UTC (RT $/bbl or $/mln btu)		Payout Time (RT)	Maximum Exposure (RT)
Cash Flow forward from :1/1/2015	0%	7%	7%	%	0%	7%		
Base Case								
SV ($61.05/bbl)	507	165	0.64	18.9%	4.8	7.9		
RV ($81.48/bbl)	723	246	0.83	21.1%	5.4	8.9	2022	197
HV ($101.9/bbl)	817	274	0.75	20.5%	6.4	10.7		
RV PSV With LE Cost Outlook	719	242	0.77	20.5%	5.6	9.3		
Sensitivities (using RV)								
High Capex (+25%)		226	0.61					
Low Reserves (Prob < 0.90)		195	0.65					
High Reserves (Prob < 0.10)		300	1.01					
Condensate taxed as gas		640	2.15					
Condensate taxed at $91.48		148	0.50					
Altenative Development Scenarios (at RV PSV)								
Deterrent Gas Pipeline to GTS-4/Rumuji	863	283	0.83	21.4%	5.9	9.2	2022	200
Plus Shell Trading Margin		296	0.87					
Deterrent Gas Pipeline to EGGS/Gbaran	765	269	0.77	21.5%	6.2	9.6	2022	200
Plus Shell Trading Margin		280	0.80					
Deterrent Gas Pipeline to Bonny	759	264	0.72	21.3%	6.6	10.1	2022	200
Plus Shell Trading Margin		275	0.75					

Full Lifecycle – including Phase II depletion compression								
PV Refrence Date: 1/7/2015	NPV ($/$ $ mln)		VIR	RTEP	UTC (RT $/bbl or $/mln btu)		Payout Time (RT)	Maximum Exposure (RT)
Cash Flow forward from :1/1/2015	0%	7%	7%	%	0%	7%		
Base Case								
SV ($61.05/bbl)	628	182	0.65	18.8%	4.9	7.8		
RV ($81.48/bbl)	906	273	0.85	21.1%	5.4	8.7	2022	197
HV ($101.9/bbl)	1,027	308	0.81	20.7%	6.0	10.0		
RV PSV With LE Cost Outlook	903	269	0.80	20.4%	5.5	9.1		
Sensitivities (using RV)								
High Capex (+25%)		252	0.63					
Low Reserves (Prob < 0.90)		217	0.67					
High Reserves (Prob < 0.10)		313	0.97					
Condensate taxed as gas		686	2.13					
Condensate taxed at $91.48		169	0.52					
Altenative Development Scenarios (at RV PSV)								
Deterrent Gas Pipeline to GTS-4/Rumuji	982	305	0.82	21.5%	5.7	9.2	2022	200
Plus Shell Trading Margin		317	0.85					
Deterrent Gas Pipeline to EGGS/Gbaran	975	303	0.79	21.3%	5.9	9.4	2022	200
Plus Shell Trading Margin		313	0.82					
Deterrent Gas Pipeline to Bonny	969	298	0.75	21.1%	6.2	9.8	2022	200
Plus Shell Trading Margin		310	0.78					

- The economics for the selected concept have improved from those in the condensate sale PCN primary because of reduction in OPEX costs. The OPEX used in PCN was less mature, taken as a factor of CAPEX, while the OPEX which is now carried is based on the Activity Based Cost (ABC) model.
- DTG alternatives are based on Type 1 cost estimates (+40/-25), as costs to tie in to NAOC GTS4 pipeline at Rumuji and NLNG facilities at Bonny have been estimated without TECOP discussions with the parties, in line with DRB steers. It is also assumed that ullage will be available in the GTS pipelines and at NLNG from DTG OSD.
- Economic Assumptions shown below
  - Condensate contractual assumption PSV's of $81.48/bbl RV-RT15(base), $61.05 SV-RT15 and $101.9HV-RT15
  - Condensate PSV of $91.48/bbl RV-RT15 applied on alternative cases
  - Gas sales to domestic market Aggregate Domgas PSV-RT15 based on Nigeria Gas Market Plan (NGMP).
  - 2015 NLNG Contracted Price RT15 was used for deterrent gas going to bonny
  - Condensate treated and taxed as Oil

Front-End Loading (FEL)

IPA FEL @ DG3	**Reservoir**	**Facilities**	**Wells**
Target	5.8	7.5	8.8
Actual	5.5	7.5*	6.74

In October 2014 the IPA pacesetter benchmark concluded that the project was poised for 'Optimal' FEL/definition at DG3.

Note 6. The Facilities FEL at the time of the review was 9.5 but would meet Team target of 7.5 and reach 'Optimal' once agreements for gas and condensate and funding from NNPC are in place. GSAs already exist (and are being updated) for gas supply; HoA for the condensate sale has been negotiated and funding agreed (with ANOH receiving highest priority in NNPC's DOMGAS budget) has been agreed with NNPC.

TQ Assessment

TQ Metric	UDC [US$/boe]	Schedule FID to RFSU [months]	Replication Index [%]	Recovery Factor [%]
Target	5.00	54	>60%	77
Actual	4.66	52		tbc
Index*[Note 3]	0.70	1.0		

The Primary TQ metric for this phase is UDC. This was benchmarked as Top Quartile using Woodmac dataset.
According to IPA the project team schedule (P50/Level 2) is longer than industry average for the Select and Define phase and industry average for the Execute phase.
*Note 3. Index determined against Industry average (Source for UDC is Woodmac, Source for schedule IPA)

Robustness and residual optionality

VAR3/ESAR was conducted in November 2014 which concluded CCP (Continue Current Phase) with 21 High Urgency recommendations to be closed before DG3: These have been closed and assurance sign off received from the VAS - team

Risks and Opportunities

See insert for the Project Top-Ten Risks. Mitigations are in place and are continually updated/improved. There are however three significant residual risks going across DG3;

Assa North Top Ten Risks

ANOH_Top10Risks.pptx

<u>OML53 Divestment:</u> The CNL divestment has been approved by MoP. However, there is legal challenge to the divestment. This may constrain Unit partners' consent to the divestment (as required by the UUOA) and may therefore, affect CNL/SEPLAT funding for the project. When consent is formally sought, SPDC will seek clarity from Chevron on how the litigation has been handled/resolved vis-à-vis conclusion of the divestment to ascertain whether there are any risks to SPDC providing consent. In addition, SEPLAT, after the transfer is completed, may challenge SPDC costs and schedule for the development, and may request operatorship of the Unit on basis of better competitiveness. The best mitigation here is NNPC/FGN aspiration for project acceleration as any delays in funding or re-opening of the UUOA, operatorship, project concept etc, would have significant delays on the project. In the event of any changes to operatorship, the SPDC IOC-JV partners may also reconsider their interest in the Unit.

<u>Failure of 3rd Party Refinery Scheme:</u> In the event of failure of 3rd party refinery scheme, a condensate theft solution using deterrent gas (DTG) to protect condensate has been developed with support from Group SME's. This would require an additional pipeline (cost of about $80 mln Shell Share). Therefore, evacuation via TNP (at no additional cost) would be implemented as a first back-up, until NNPC (and other partners) are convinced on the need to move to the DTG option. This option has been assessed in the economics (provided above) with a DTG-OSD of about 3 years after the gas plant OSD.

<u>Funding:</u> Prior experience in Nigeria showed inconsistency in funding projects on time and on multi-year basis. The ANOH project represents a deal where Shell with 15% equity has a potential of 57.5% NNPC funding exposure due delay payments on both SPDC JV and CNL JV shares. Despite agreements with NNPC to fund ANOH through the Domestic Gas Budget, effort will be made to develop back-up plans, such as project finance or MCA funding, in case Domestic Gas Budget will be further constrained which may be more likely in the current low oil price environment

<u>Opportunities:</u> An opportunity exists to tax condensate as gas. This is possible given that the condensate is not injected into oil pipeline but sold to a (local) refinery. Effort would be made prior to FID to secure approval of this tax regime from the Federal Inland Revenue Service (FIRS). This arrangement is already (informally) supported by (relevant directors) of NNPC. A second opportunity may present itself should the 3rd party refinery scheme fail and there is no improvement in TNP availability. In this event, the need for sustained domgas supply for power generation may require NNPC to support funding for the deterrent-gas (DTG) pipeline. This would provide midstream value from the circa 50mmscfd (deterrent) gas flowing to NLNG with the condensate.

<u>Signatures</u>

<u>Approve</u>	**<u>Support</u>**	**<u>Support</u>**
UI Business	Finance	P&T
Director	EVP	EVP PTU
____________	____________	____________