INVESTMENT PROPOSAL

FOR THE KFMY-3 WELL APPRAISAL DRILLING

The Shell Petroleum Development Company of Nigeria Limited

Summary Information

Business unit and company	The Shell Petroleum Development Company of Nigeria Limited (SPDC)
Group equity interest	100% in SPDC, whereas SPDC is the Joint Venture (JV) operator of an unincorporated JV with a 30% interest.
Other shareholders / partners	Nigerian National Petroleum Corporation (NNPC: 55%), Total E&P: 10%, Nigeria Nigerian Agip Oil Company (NAOC: 5%) in SPDC-JV.
Business or Function	Upstream International Sub Saharan Africa (UIG)
Amount	US$ 10.0 mln Shell Share (i.e. US$ 33.3 mln 100% JV), 50/50, MOD.
Project	Awoba NAG Appraisal Well Drilling on K3000A/K6400A Reservoir

Main commitments $ mln (MOD)

See Table 1 for expenditure phasing.

Description	**JVUS $mln (100%)**	**US $mln (Shell Share)**
1 nos Appraisal Drilling & Completion	25.8	7.74
1 nos Side track	2.2	0.66
Location Preparation	1.8	0.54
1 Flowline/Hookup	2.4	0.72
SCD	1.1	0.33
Total	**33.3**	**10.0**

Source and form of financing	This investment will be financed from JV funding. Shell share capital expenditure will be met by SPDC's own cash flow and/or the existing shareholder facility.

Economics Summary for KFMY-3 Appraisal Well Drilling

There is a marginal difference (SS) of -US$0.03 mln between the Value of Information and the Cost of acquiring the Information (US$9.72 – US$ 9.75) for the Appraisal well drilling. However, as indicated in the value proposition the appraisal well drilling is aimed at addressing both the subsurface uncertainty and satisfying of regulatory requirement before further reservoir development can take place.

Shell Share, RT-11	NPV7% (USD mln)	VIR7%	RTEP
Base case	-6.3	NA	NA

Section 1: The proposal (management summary)

This Pre-FID Investment Proposal (approval for funding of US$10.0 mln Shell Share - US$ 33.3 mln 100% JV) is required for the execution of the Awoba KFMY-3 NAG well appraisal drilling. In May 2007, the DRB supported the drilling of an appraisal well to confirm fluid contacts (GWC or GOC) in the K3000A reservoir to unlock the contingent resource volumes and also satisfy regulatory requirement before further reservoir development can take place.

The appraisal well drilling will test presence or absence of an oil rim in the K3000A reservoir and the structural definition of the eastern flanks of the K6400A reservoir. Five wells had earlier penetrated and encountered the K3000A reservoir in a gas-down-to (GDT) situation. The accumulation as presently defined by a GDT at 13,918 ftss has initial in place gas volume of about 145 Bscf. This appraisal drilling could provide an additional recoverable volume of 83.4 Bscf of gas and 2.94 MMstb of oil in the event of commercial oil rim discovery. The appraisal well expenditure phasing is discussed in Section 2.

The appraisal well drilling and completion is in synergy with the Awoba FOD and North West Appraisal. If a viable oil column is confirmed in the K3000A reservoir, the well will be logged and completed as Single String Single oil well. However, in the course of drilling the appraisal well if the un-penetrated column seen between GDT and WUT/FWL is greater than 20ft and no contact is confirmed, it will be sidetracked to fully meet the objectives. The target drilling date for the appraisal well is April 2013 (Growth August 2011 STDS).

The Awoba NAG FDP outlines a base case plan to mature 319 Bscf of gas using 3 SMART development wells. If no oil rim is found in the K3000A reservoir, an additional well will be required to develop this reservoir because of the sub-optimal location of the appraisal well. In the case of no economically viable oil find, sidetracking the appraisal well upwards for gas production will be hindered by the non- readiness/unavailability of surface facility. A new well will increase the well count from 3 to 4 new development gas wells and subsequently increase the recoverable volume to about 402.4 Bscf.

Section 2: Value proposition and strategic and financial context

The outcome of the appraisal drilling will reduce contact uncertainties and satisfy regulatory requirement which otherwise would hinder development of the reservoir. This proposed appraisal and follow-up NAG development in Awoba aligns with SPDC's oil and gas production growth drive and also contributes to NLNG gas supply. The cost summary is given below whilst Tables 1 and 2 show the appraisal expenditure phasing and Awoba NAG full scope development expenditure phasing respectively.

- Awoba appraisal well cost (including location preparation, flowline/hook-up and SCD costs) is US $33.3 mln (100% JV MOD).
- Awoba NAG project cost including appraisal drilling, completion and sidetrack option is US $473 mln (100% JV MOD).
- Potential additional recoverable volume from appraisal project is ca 83.4 Bscf of gas and 2.94 MMstb of oil
- Likely peak oil and gas production is ca. 2400 bopd of oil and 146 MMscf/d of gas

Table 1: Appraisal Well Expenditure Phasing (US $mln MOD JV 100%*)*

	100% Total	Prior Years	2012	2013
SURFACE FACILITY COST ESTIMATE ($mln)				
Location Preparation	1.82		1.82	
Flow line/Hook up	2.40			2.40
Total Surface Facilities ($MOD)	**4.22**		**1.82**	**2.40**
WELL COST ESTIMATE ($mln)				
Drilling Costs	20.90		20.90	0.00
Sidetrack Costs	2.18		2.18	
Completion Costs	4.90			4.90
Total Wells ($MOD)	**27.98**		**23.08**	**4.90**
SURFACE FACILITIES & WELL COST ESTIMATE ($mln)				
SCD	**1.10**		**0.70**	**0.40**
Overall Project Cost ($ MOD)	**33.30**		**25.60**	**7.70**

Table 2: Awoba NAG full scope Development (US $mln MOD JV 100%*)*

	100% Total	Prior Years	2012	2013	2014	2015	2016	2017
SURFACE FACILITY COST ESTIMATE ($mln)								
Location Preparation	9.17		1.82		5.65		1.70	
Flowlines/Bulkline	239.70		1.50	36.34	70.47	93.96	37.44	
Fow line/Hook up	14.10					11.2		2.90
NAG Manifold	29.90			4.49	8.97	11.96	4.49	
Total Surface Facilities ($MOD)	**292.87**		**3.32**	**40.82**	**85.09**	**117.12**	**43.62**	2.90
WELL COST ESTIMATE ($mln)								
Drilling Costs	127.22		20.90	0.00		72.31		34.01
Sidetrack Costs	7.68		2.18					5.50
Completion Costs	33.89					30.99		2.90
Total Wells ($MOD)	**168.79**		**23.08**	**0.00**	**0.00**	**103.30**	**0.00**	**42.41**
SURFACE FACILITIES & WELL COST ESTIMATE ($mln)								
SCD	**11.54**		**0.66**	**1.02**	**2.13**	**5.51**	**1.09**	**1.13**
Overall Project Cost ($ MOD)	**473.20**		**27.06**	**41.84**	**87.22**	**225.93**	**44.71**	**46.45**

Summary Economics

The Pre-FID economics for the Awoba Gas development KFMY-3 appraisal drilling was evaluated on a forward looking basis as a cost only using the 50/50 level III cost estimates.

Sensitivities carried out include:

- High OPEX.
- 1 year cost schedule delay.
- Project with ring fencing.
- 1.5% cost mark up due to NNPC cost disputes on bench marked verified approved (BVA) issues.
- PIB.

Further analysis was carried out on the appraisal by evaluating a Value of Information (VOI) for the KFMY-3 appraisal drilling on a forward-looking basis using 50/50 cost estimates, production forecast and Probability of success (POS) provided by the project team.

Precision tree5.0 software from the Palisades decision tools suite was used to build and evaluate a decision tree (see Appendix 1 – Figure 1) that captured the range of outcomes for the key decision.

- Decision on whether to or not to appraise Awoba Gas Development KFMY-3 based on
    a. Value with appraisal information.
    b. Value without information/appraisal.
- Value with information EMV= US$67.17 mln.
- Value without information EMV= US$57.45 mln.
- The total value of the Information = (US$ 67.17 mln- US$ 57.45 mln) = US$9.72 mln.

The VOI of $9.72 mln Shell Share RT11 is marginally lower than the Cost of the Information (COI) of US$9.75 mln Shell Share RT11 (US$9.72 – US$ 9.75= -US$0.03). The details of the VOI analysis are presented in Appendices 1 and 2. As indicated in the value proposition the appraisal well drilling is aimed at addressing both the subsurface uncertainty and satisfying of regulatory requirement before further reservoir development can take place.

Table 3: Awoba NAG Appraisal Well Drilling Pre-FID- Economics Grid (Shell Share)

PV Reference Date: 1/7/2011	**NPV (S/S $ mln)**		**VIR**	**RTEP**	**UTC (RT $/boe)**		**Payout-Time (RT)**	**Maximum Exposure (RT)**
Cash flow forward from: 1/1/2011	**0%**	**7%**	**7%**	**%**	**0%**	**7%**	**yyyy**	**mln**
Base Case								
RV-RT ($70/bbl RT11)*	-6.9	**-6.3**	NA	NA	NA	NA	NA	US$ 6.89 mln (2013)
Sensitivities (on base case)								
High Opex (+ 15%)		-7.3	NA					US$ 7.93 mln (2013)
1 Year schedule delay		-5.8	NA					US$ 6.76 mln (2013)
Project with ring fencing		-9.1	NA					US$ 9.85 mln (2013)
1.5% cost mark up due to BVA		-6.8	NA					
PIB (Version 12.0)		-2.2	NA					

Note: No revenue stream, hence SV-RT, RV-RT and HV-RT has same values

Table 4: Awoba NAG Development Full Project Economics Grid (Shell Share)

PV Reference Date: 1/7/2011	NPV (S/S $ mln)		VIR	RTEP	UTC (RT $/boe)		Payout-Time (RT)	Maximum Exposure (RT)
Cash flow forward from: 1/1/2011	0%	7%	7%	%	0%	7%	yyyy	mln
Base Case								
SV-RT ($50/bbl RT11)	93.3	**44.8**						
RV-RT ($70/bbl RT11)	154.5	**80.7**	0.86	38.8	7.9	8.9	2017	US$ 57.03 mln (2015)
HV-RT ($90/bbl RT11)	232.5	**124.2**						
Sensitivities (on base case)								
High Capex (+ 15%)		74.1	0.69					US$ 66.33 mln (2015)
Low Capex (- 10%)		84.8	1.00					US$ 50.83 mln (2015)
1 Year schedule delay		75.5	0.86					US$ 56.58 mln (2016)
Project with ring fencing		74.9	0.80					US$ 82.82 mln (2015)

Key Project Parameter Data Ranges

	Unit	Bus Plan BP11	Low	Mid	High	Comments
Capex (MOD)	US$ mln	NA	NA	NA	NA	
Opex (MOD)	US$ mln	10.0	9.0	10.0	11.5	Provided in BP11
Production volume	Mmboe	NA	NA	NA	NA	
On-stream Date	mm/yyyy	Dec-13	NA	Dec-13	NA	

Economics Assumptions

Base Case

- Project 50/50 Pre-FID costs treated as a cost only.
- SCD Opex provided by the project team.
- NDDC levy 3% of total expenditure.

Value of Information (VOI) analysis

- Oil PSV of $70/bbl RT11.
- Export gas price OF US$1.73 RT11 for supply to NLNG.
- Condensate was treated and taxed as Oil.
- Gas taxed under CITA with Associated Gas Framework Agreement (AGFA) incentive.
- 1/12/2010 ARPR (Annual Review of Petroleum Resources) variable OPEX for Awoba was used.
- SPDC generic fixed OPEX was used for new facilities.
- SPDC generic OPEX assumptions:
  - Oil fixed OPEX - 3% of cum. oil CAPEX
  - Gas fixed OPEX – 3.5% of cum. gas CAPEX
- Flare Penalty of US $3.5/mscf non-tax deductible.
- GHV of 1150Btu/scf.
- SCD Opex provided by the project team.
- NDDC levy 3% of total expenditure.
- Education tax of 2% assessable profit.

PIB (House Version 12.0) Assumptions

- CIT is 30% of taxable income.
- Depreciation schedule for qualifying expenditure is 4 x 20% and 19%.
- NDDC levy calculated as 3% of total expenditure.
- SCD Opex provided by the project team and treated as Opex.
- Overseas Capex fraction assumed at 14%.

Section 3: Risks, opportunities and alternatives

Opportunity	Reduced uncertainty of fluid type and become enabler for DPR approval of FDP.
	To establish fluid type, contact information and structural depth in the K3000A reservoir, and also reservoir properties and structural depth in the K6400A reservoir.
	Synergy between Awoba FOD and North west Appraisal. Complete as oil well if viable oil rim is found
	Unlock contingent resources. The K3000A accumulation definition is currently restricted by a gas-down-to at 13,918 ftss with initial in place gas volume of about 145 Bscf and contingent resource volume of ca 83.4 Bscf.
Risks / Mitigation	This well will likely encounter some faults. Drilling through these faults may lead to mud losses. However, nearby Awoba-04 successfully drilled through all these faults so learning from Awoba-04 well drilling operation are being integrated into this appraisal well.
	Main hole is planned with an inclination of 19 deg. Hence circulation issues are unlikely. Side track hole is planned with 45 deg inclination and hence circulation issues like lack of cutting transport, formation of cutting beds etc are not expected.
	In the reservoir sequence from surface to the TD of this well, only H7100 reservoir has been identified as significantly depleted (minimum pressure gradient of 0.376). This will be managed with appropriate mud weight. All pressures for the remaining reservoirs are expected to be hydrostatic.
	There is a likely chance of encountering the targeted reservoirs shallower or deeper than prognosed because the subsurface targets are located down deep of the eastern flank where there is no well control. The depth uncertainty for these reservoirs ranges from +/- 110ft to +/-150ft.
	Encountering developable oil rim is a risk to the Awoba NAG project in that it will change the development strategy which is strictly NAG development, but an opportunity for the FOD project to develop the oil rim.
	Delay in procuring Wells long lead materials is a risk to the project delivery. Early procurement of materials is necessary.

Section 4: Carbon Management

The main impact on Green house Gas emissions is at the surface facility as a result of increased energy consumption and associated increased flaring. In the event of oil rim discovery, well testing following the drilling campaign will be done through the existing facilities. There is plan to carry out well test in the event of gas discovery.

The Impact on Greenhouse Gas emissions resulting from the hookup of additional production into the existing surface facilities have been addressed by the Greenhouse Gas and Energy Management Plan (GHGEMP) for the facilities covered in the CAWC GHG management Plan.
The GHGEMP also contains the 10 years GHG emission and Energy use forecast for the facilities in the CAWC district together with a number of recommended abatement proposals. The main proposal for this facility (Awoba) is to restart AG Plan. This proposal is now being implemented. With the AG Plant fully operational, up and running by Q1 2012, emission from flaring would be largely reduced.

Section 5: Corporate structure, and governance

The existing corporate structure and arrangements of SPDC-JV (with SPDC as operator) will be used as the vehicle for the investment and operations.

An SPDC Decision Review Board (DRB) will continue to advice.

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

This proposal complies with Group Business Principles, policies and standards. Functional support for this proposal has been provided by Finance, Social Performance, Supply Chain Management, HSE. The Swamp East Asset Team is fully aligned with the project.

Section 7: Project management, monitoring and review

Assurance Events/Gates (Awoba NAG KFMY-3 Appraisal/Development)	Date
DG1	Nov. 2005
VAR2	June 2006
DG2	July 2006
VAR3	Feb. 2007
DG3	May 2007

The Swamp East Asset Team is fully involved in this project and will monitor the well execution.

Section 8: Budget provision

The project is in BP11 Base Plan for Alternative Funding. The table below shows the previous Pre-FID approval that was granted, of which $2.75 mln dollars was spent to complete FEED in 2007.

SN	Item	Pre-FID Cost Shell Share (US$mln, MOD)	Pre-FID Cost (100% JV) (US$mln, MOD)
1	Front End Engineering Design (FEED)	1.7	5.7
2.	Detailed Design / Early Procurement Activities	2.0	6.7
3.	Survey / Land Acquisition	0.8	2.7
4	Project Management	0.5	1.7
	Total (US$mln, Shell Share MOD)	5.0	16.7

Section 9: Group financial reporting impact (Shell Share – US$mln)

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

Year	**2011**	**2012**	**2013**	**2014**	**2015**
Total Commitment		7.68	2.311		
Cash Flow					
SCD Expenditure		0.21	0.12		
Pre-FID Expenditure		7.47	2.191		
Capital Expenditure					
Operating Expenditure		0.23	0.069		
Cash flow From Operations		-6.26	-1.05	0.25	
Cash Surplus/(Deficit)		-6.26	-1.05	0.25	
Profit and Loss					
NIBIAT +/-	-5	-10.43	-6.63		-5
Balance Sheet					
Avg Capital Employed	-2.5	-7.08	-11.96	-14.88	-17.5

Section 10: Disclosure

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

Section 11: Financing

The project will be funded with JV funding and Shell share capital expenditure will be met by SPDC's own cash call.

Section 12: Taxation

The income tax from the project will be in accordance with Petroleum Profit Tax Rate and relevant income tax applicable.

Section 13: Key Parameters

This investment proposal seeks approval for US$10.0 mln Shell Share (US$ 33.3 mln 100% JV MOD) which is required for the execution of the Awoba KFMY-3 appraisal well drilling.

Section 14: Signatures

This proposal is submitted to GM Development for approval.

For shareholder approval:

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Lawal Olujinmi (FUI/FB)

Date …../…../…...

.....

Ojulari, Bayo (UIG/T/D)

Date …../…../…..

BOM:

Sam Ezugworie

Senior Front End Project Manager (UIG/T/DFEG)

Initiator:

Etokakpan, Eteobong

Front End Project Manager (UIG/T/DFEG)

APPENDIX 1: FIG 1- AWOBA GAS DEVELOPMENT VOI ANALYSIS DECISION TREE

Keys

Table 1a: Total Project Expenditure Phasing: 3 SMART NAG wells & Appraisal Drilling, Completion, Oil reward, no sidetrack

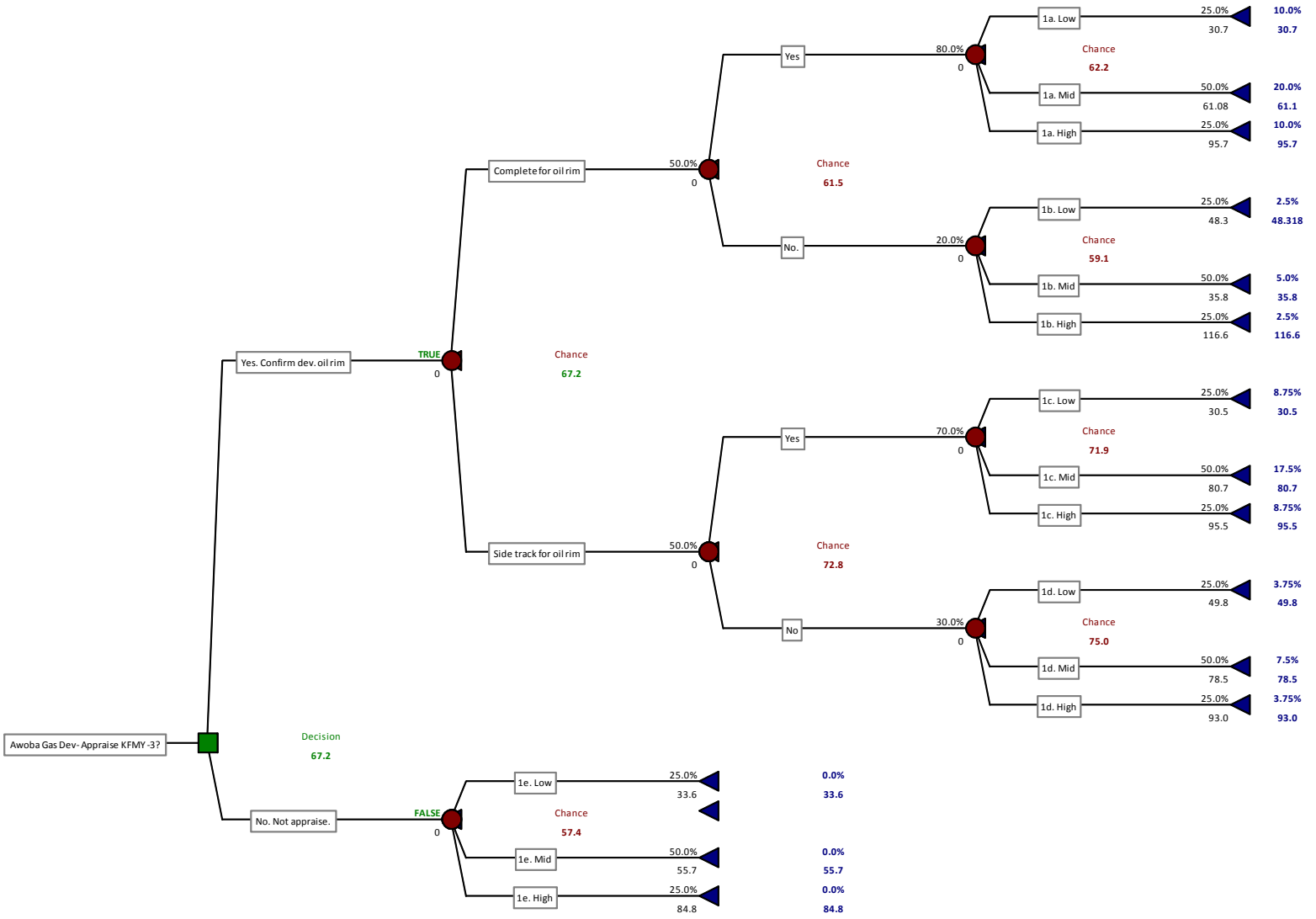
Table 1b: Total Project Expenditure Phasing: 3 SMART NAG + K3 Dev. Well +Appraisal Drilling, No Completion, No Oil reward, No sidetrack

Table 1c: Total Project Expenditure Phasing: 3 SMART NAG + Appraisal Drilling +Completion+Oil reward + sidetrack

Table 1d: Total Project Expenditure Phasing: 3 SMART NAG + K3 Dev. Well +Appraisal Drilling, No Completion, No Oil reward, sidetrack

Table 1e: Total Project Expenditure Phasing: 3 SMART NAG wells

Appedix 1: Fig 1- Awoba Gas Development Value of Information Analysis Decision Tree



Appendix 2: Table 2- Awoba Gas Development Economics Results Summary (Shell Share RT11)

Case Name	1A Low	1A Mid	1A high	1B Low	1B Mid	1B high	1C Low	1C Mid	1C high	1D Low	1D Mid	1D high	1E Low	1E Mid	1E high
NPV0% (US$mln)	65.7	115.1	177.3	99.1	98.7	217.2	65.4	154.5	176.9	101.8	150.4	171.4	69.4	106.7	158.6
NPV7% (US$mln)	30.7	61.1	95.7	48.3	35.8	116.6	30.5	80.7	95.5	49.8	78.5	93.0	33.6	55.7	84.8
VIR7%	0.33	0.66	1.03	0.49	0.37	1.19	0.33	0.86	1.02	0.50	0.79	0.94	0.40	0.66	1.00
RTEP	23%	34%	43%	29%	17%	50%	22%	39%	43%	29%	39%	43%	25%	34%	43%
Tot Oil Prod (MMstb)	5.3	8.0	11.4	7.5	10.0	13.1	5.3	10.0	11.4	7.5	10.0	11.4	5.4	7.2	9.3
Tot Gas Prod (Bscf)	70.0	98.7	130.1	88.5	119.4	156.9	70.0	119.4	130.1	88.5	118.7	130.1	70.6	95.0	124.3
Tot Gas Sales (Bscf)	68.8	97.2	128.1	87.1	116.2	154.4	68.8	117.5	128.1	87.1	116.9	128.1	69.4	93.5	122.3
Tot OPEX (US$m)	83.0	101.5	115.1	115.7	163.4	129.5	83.3	110.1	115.6	92.7	112.6	121.6	81.1	97.1	106.5
Tot CAPEX excl Aband (US$m)	117.5	117.5	117.5	125.6	125.6	125.6	118.2	118.2	118.2	127.0	127.0	127.0	108.7	108.7	108.7
Gas Well (US$m)	38.3	38.3	38.3	46.3	46.3	46.3	39.0	39.0	39.0	47.7	47.7	47.7	30.2	30.2	30.2
Gas FAC CAP (US$m)	79.2	79.2	79.2	79.3	79.3	79.3	79.2	79.2	79.2	79.3	79.3	79.3	78.5	78.5	78.5
Aband CAP (US$m)	12.0	12.0	12.0	12.8	12.6	12.8	12.0	12.0	12.0	12.9	12.9	12.9	11.1	11.1	11.1
UDC0% (US$/boe)	7.5	5.2	3.9	6.1	4.6	3.5	7.6	4.3	3.9	6.2	4.6	4.2	6.9	5.1	3.9
UTC0% ($/boe)	12.3	9.3	7.3	11.3	10.0	6.7	12.4	7.9	7.3	10.3	8.4	7.8	11.6	9.3	7.4