The Shell Petroleum Development Company of Nigeria Limited

Internal Investment Proposal

Summary Information

Directorate	Technical Directorate
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	Nigeria National Petroleum Company (NNPC: 55%), Total: 10%, Nigeria Agip Oil Company (NAOC: 5%) in SPDC-JV
Amount	USD 13.42 million Shell share, MOD, 50/50 (USD 44.73 million 100% JV)
Project	Utorogu K Sands NAG Development (Pre FID)
Main commitments	(see table below)

	Utorogu KLAK-2 US $ mln (MOD) (100% JV)	**Utorogu KUAF-2 US $ mln (MOD) (100% JV)**	**Total (100% JV) US $ mln (MOD)**	**Total (Shell Share) US $ mln (MOD)**
Drilling	13.63	15.57	29.20	8.76
Completion & testing/ Suspension of KUAF-2	6.36	1.33	7.69	2.31
Location preparation	4.50	2.40	6.90	2.07
SCD	0.51	0.43	0.94	0.28
Total	**25.00**	**19.73**	**44.73**	**13.42**

Source and form of financing	This investment will be financed with JV funding and Shell share capital expenditure will be met by SPDC's own cash flow. Formal JV partners' approval will therefore be obtained.
Summary cash flow	See economics grid
Summary economics	(see table below)

At Ranking PSV ($70/bbl RT11)	NPV7% ($m)	VIR7%	RTEP (%)
Base Case Pre-FID	**-9.2**	NA	NA
Value of information (VOI)	**39.6**	**NA**	**NA**

Section 1: The proposal (management summary)

This pre-FID Investment Proposal is required to obtain commitment to appraise the target Utorogu K sands starting Q3, 2011

Approval is sought to drill two appraisal wells, KLAK-2 and KUAF-2 proposed to prove about 1.0 Tcf expectation gas volume identified in the untested step out area of the target reservoirs (K6000Y, K6400Y and K7000Y) and develop about 125.3 Bscf of gas in Utorogu Field. This activity is in line with the PAR2 recommendation (May, 2010) to appraise the target reservoirs as part of the Utorogu K Sands NAG development project feasibility study, reduce identified subsurface uncertainties before going into the next phase of the opportunity maturation work. The two appraisal wells, currently on the 2011 short term drilling sequence (Q3 and Q4, 2011) are estimated to cost US$13.42 million 50/50 MOD Shell Share (US$ 44.73 JV 100%).

The target reservoirs are expected to deliver gas volume required to keep the Utorogu gas plant full in the short-term and sustain gas supply to the domestic market. The notional further gas development plan is to drill 4 NAG wells from existing locations, lay flowlines and hookup to existing Gas plant in 2014 subject to the outcome of the proposed appraisal drilling. The estimated cost of this development is US$47.9million 50/50 MOD Shell Share (US$ 159.67 JV 100%) subject to the appraisal results with an expected FID in Q4, 2012.

The first appraisal well (KLAK-2) is planned to test the structure at the crest (from UTOR-022 location), confirm gas presence, fluid composition and evaluate reservoir connectivity. In an appraisal success case, KLAK-2 is proposed to develop about 125.3 Bscf of Non associated Gas with technical potential of 70 MMscf/d from K6000Y. The drilling of the second well (KUAF-2) is contingent on the result of KLAK-2. If the target reservoirs are found to be gas bearing and in individual reservoir situation (i.e. unconnected reservoirs), KUAF-2 will be drilled to test the flank for oil-rim presence and firm up hydrocarbon column.
The contingency plan if the area under appraisal is found out to be wet, is to sidetrack KLAK-2 to drain the proved area. The main appraisal hole (KLAK-2) and the sidetrack are estimated to cost about US$8.49 million 50/50 MOD Shell Share (US$ 28.3 JV 100%) and this will be funded from the budget for KAUF-2.

Appraisal Work Scope:

The scope of the pre-FID expenditure will cover for the following:

a. Location Preparation
b. Drilling
c. Completion & Testing
d. Well suspension (KUAF-2)
e. Sustainable Community Development (SCD)

Section 2: Value proposition and strategic and financial context

The target K sands present an opportunity to add 1.0 Tcf to the gas volume initially in-place with appraisal scope. When realized, this volume will support the plan to develop more gas to keep the Utorogu Gas Plant full and sustain domestic supply in the short term.

Summary Economics

The base economics was evaluated on a forward-looking and cost only basis using 50/50 cost estimates for the appraisal activity with the assumption of successful appraisal outcome.

Table 1: Economics Grid - Pre-FID

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%**		**AT**
Base Case*								
RV ($70/bbl RT11)	-9.2	**-9.2**	NA	NA	NA	NA	NA	$9.5 (2011)
BEP ($/bbl)					NA	NA		
Sensitivities (using RV RT)								
1.5% cost markup due to BVA issues		**-9.9**	**NA**					
Pre-FID as CAPEX		**-2.4**	**-0.18**					
Side-track to proved area**		**1.5**	**0.05**	8%				

**Cost only, no SV & HV impact*

*** Appraisal failure, individual reservoirs case*

Key Project Parameter Data (Shell Share)

Parameter	**Unit**	**BP10 RV**	**Low**	**Mid**	**High**	**Comments**
Capex (MOD)	US$ mln	13.6	NA	NA	NA	BP10 Appraisal cost only
Investment Opex (MOD)	US$ mln	NA	NA	13.4	NA	Pre-FID only
Production Volume	mln boe	NA	NA	NA	NA	
Start Up Date	mmm-yy	NA	NA	NA	NA	
Production in first 12 months	mln boe			NA		

This appraisal is supported by the value of information (VOI) analysis that was carried out using Precision tree5.0 software from the Palisades decision tools suite. The range of appraisal outcomes[1] are presented in a Decision tree (Appendix 2- Fig.2) and the following decisions were assessed.

- Whether to or not to carry out an appraisal for Utorogu K-sands and
- Whether to or not to Side-track the 1st appraisal well to Proved area if the KLAK-2 appraisal fails i.e. Oil is found[2] rather than gas or Dry hole

.Appendix 2-Fig. 1 (PrecisionTree Policy Suggestion- optimal decision tree) shows the result of the evaluation of the decision tree. The result is in favor of the planned appraisal well(s) and also support the side-track of the KLAK-2 appraisal well to the proved area in the event of appraisal failure.

The value of information (VOI) = US$39.6mln (RT11, Shell share @ 7% DR)

The Cost of information (COI)[3] = US$13.4mln (RT11, Shell share @ 7% DR)

---

1 The production forecast and Probability of success (POS) for the outcomes were provided by the project team

2 Although finding oil is treated as failure wrt this project's objective, finding oil is success for SPDC and it is assumed the oil find will be matured as a different project from this Utorogu K-sand NAG development project. Hence Zero value from the potential oil development has been ascribed to this project.

3 The rule of thumb is that the VOI should be > than COI

A sensitivity on the POS for 'Yes-Gas bearing' shows that a POS of ~1% is required change the decision to 'do not appraise' i.e. develop proved area only.

Economics Assumptions

- Oil PSV includes Forcados offset –
  - $0.82/bbl, $1.36bbl and $1.87bbl @ SV, RV and HV respectively
- 2011 Domgas PSV based on Nigeria Gas Master Plan (NGMP) as advised by gas commercial
- Oil and condensate were assumed to be taxable under PPT
- Gas assumed to be taxable under CITA with AGFA (Associated Gas Framework Agreement) incentive
- 31/12/2010 ARPR (Annual Review of Petroleum Resources) OPEX for Utorogu gas plant $1.01/boe and 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
- NDDC levy of 3% total expenditure.
- Education tax of 2% assessable profit.
- GHV of 1000btu/scf
- Abandonment cost is estimated at 10% of total project RT CAPEX
- SCD was computed as 2.5% of total CAPEX
- Low C_{O2} blending volumes assumed to be available at no additional cost to utorogu K-sand project from an SPDC source

Section 3: Risks, opportunities and alternatives

The key risks to this investment are mainly technical and subsurface in nature. They are -

a. Structural Definition & Gas presence in target area
b. Reservoir connectivity
c. Fluid distribution and
d. Fluid composition

Mitigation: The proposed appraisal wells are expected to provide data required to reduce these risks.

Other project risks identified and mitigation plans are presented in the Risk & Opportunity Register, Appendix – 3.

Opportunities

The potential upside in gas volume (about 1.0 Tcf) expected from the target Utorogu K sands supports the current strategy to keep the Utorogu Gas Plant full in the short term and sustain supply to the Domestic market where the Nigerian Federal government has expressed significant interest.

Alternatives

Alternatives considered are described under the value of information (VOI) analysis summary (reference Section -2).

Section 4: Corporate structure, and governance

The project, currently at Feasibility stage will be managed in line with the ORP. It fits within the existing SPDC corporate structure and governance.

Section 5: 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, sustainable development, supplies chain management, HSE, operations /maintenance, legal, treasury and tax functions.

Section 6: Project management, monitoring and review

Assurance Events/Gates	Date
PIN/DG1	Aug 18, 2009
ITR	Mar 29-31, 2010
PAR 2	May 26-28, 2010
Look Ahead – DG2	Q1, 2012

Section 7: Budget provision

The project is in BP10 base plan and approved JV 2011 programme.

Section 8: Group financial reporting impact

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

US$ Million	2011	2012	2013	2014	2015	2016
Total Commitment	**13.42**					
Cash Flow						
SCD Expenditure	0.28					
Pre-FID Expenditure (OPEX)	13.14					
Capital Expenditure						
Operating Expenditure	0.40					
Cash flow From Operations	(11.85)	2.63				
Cash Surplus/(Deficit)	(11.85)	2.63				
Profit and Loss						
NIBIAT +/-	(9.22)					
Balance Sheet						
Avg Capital Employed	1.32	1.32				

Section 9: Disclosure

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

Section 10: Financing

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

Section 11: Taxation

There are no unusual taxation features at this stage.

Section 12: Key Parameters

The following is the main aspect of this proposal:
Approval for $13.42mln, MOD, Shell Share (i.e. $44.73mln, 100% JV) to cover Utorogu K sands NAG Development Pre-FID activities (appraisal) costs.

Section 13: Signatures

This Proposal is submitted to UIG VP Technical for approval.

Supported by:	Approved by :
....	....
Bernard Bos (FUI/F)	Bart Lismont (UIG/T)
Date ..../..../....	Date ..../..../....

Initiator: ____________________

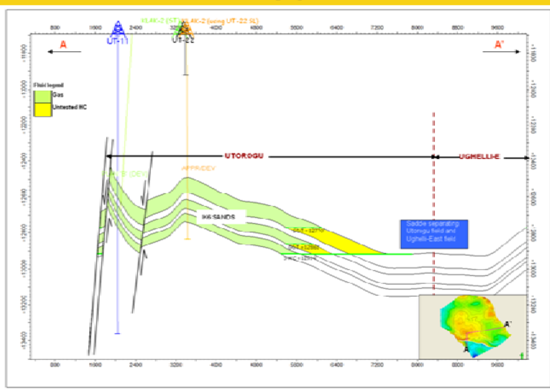
Odegbesan, Oluseyi (UIG/T/DFDG)

Date: 01/04/2011

Appendices:

1. Utorogu K sands appraisal work scope

K Sands Appraisal – Work Scope

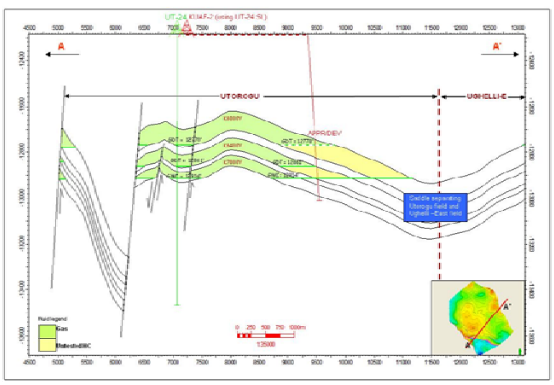


Proposed 2 Appraisal wells

1. KLAK-2 is planned to test the structure at the crest (from UTOR-022 location)

a. To confirm gas presence (about 1 Tcf),
b. Evaluate reservoir connectivity and
c. Fluid composition

If gas is absent, KLAK-2 is proposed to sidetrack and develop the proved area.



2. KUAF-2 is planned to test the structure at the flank (from UTOR-024 location)

a. To test the flank for oil-rim presence and,
b. firm up hydrocarbon column

KUAF-2 shall only be drilled
- If KLAK-2 confirms gas presence in unconnected reservoirs

Appendix 2

Fig. 1: **Utorogu K-sands decision tree analysis result – PrecisionTree Policy suggestion (Optimal decision tree).**

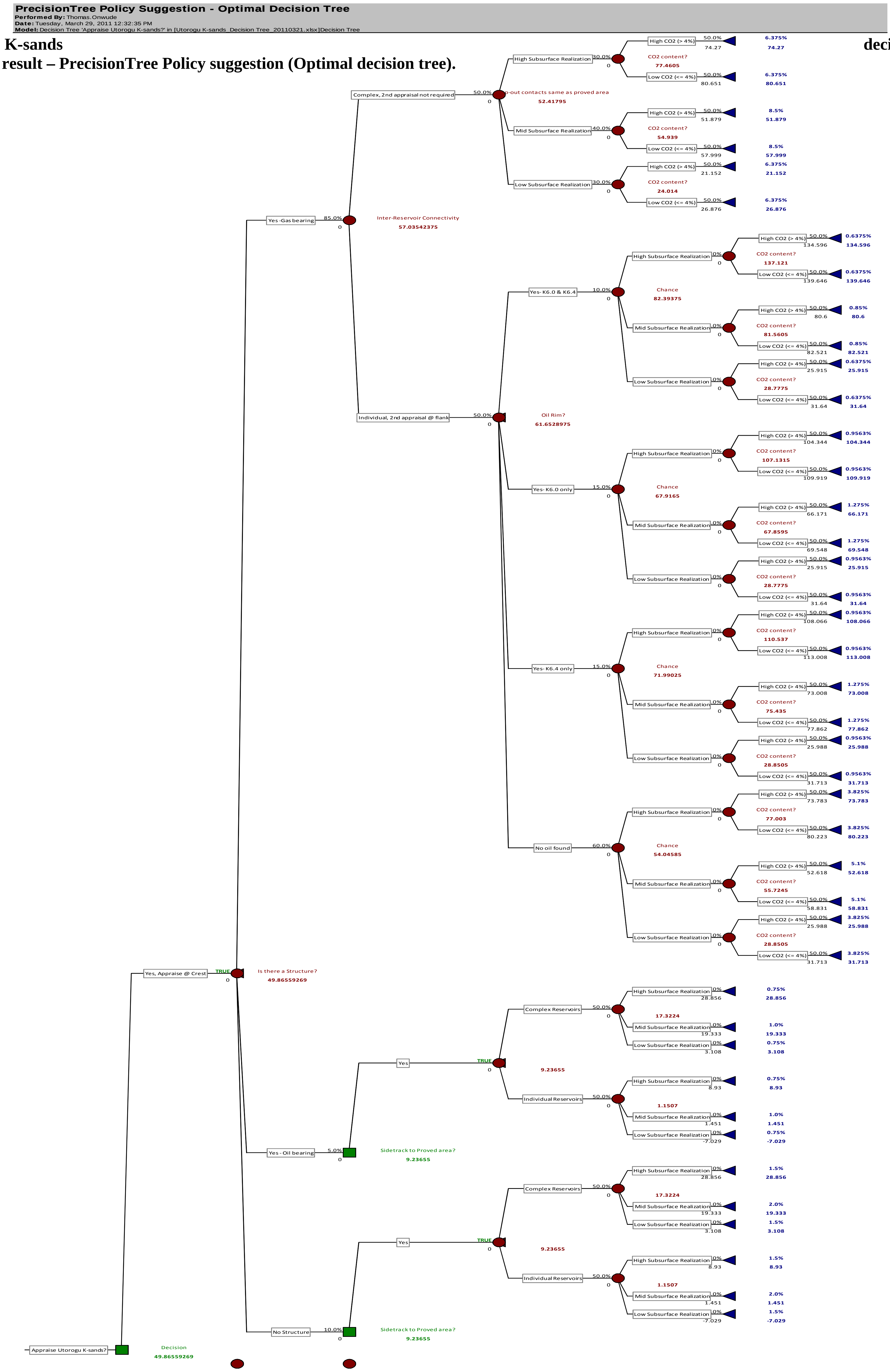
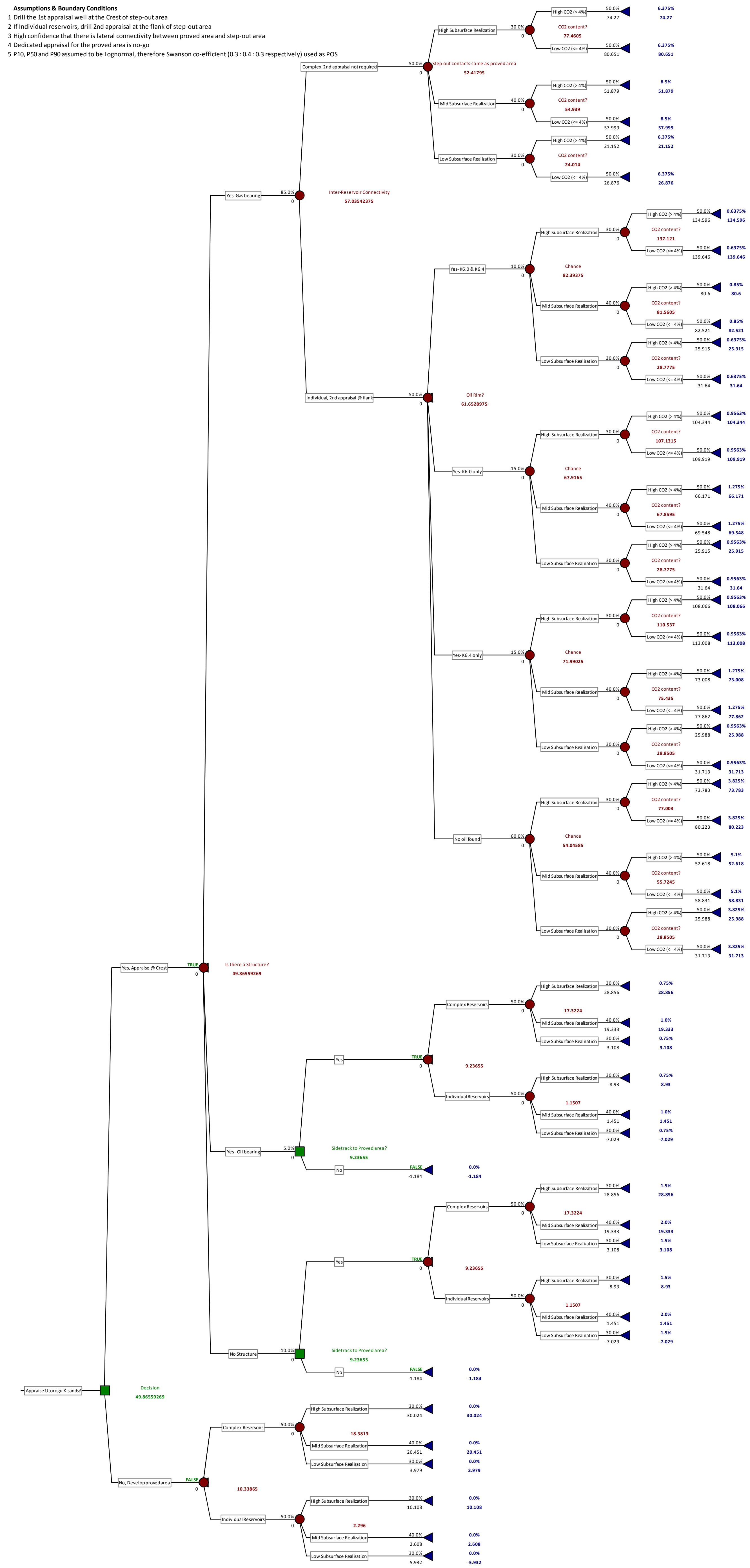


Fig. 2– Utorogu K-Sands Decision Tree.



APPENDIX - 3: Utorogu - K Sands NAG Development Risk & Opportunity Register

Legend: H = H; M = M; L = L

S/N	TECOP+	Category	Title	Description of Issue	Consequence	Risk / Opportunity	Probability of Occurrence	Impact	Action to Reduce Risk/Uncertainty (Mitigation Plans)
1	T	**Technical**	Large SFR	Large SFR exists in the K Sands (block Y) mainly based on the 3D seismic re-interpretation and limited well penetrations. The opportunity is to be produced through existing facility.	Profitable project that meets short to medium term domestic gas supply requirements.	O	M	H	Plan appraisal drilling to determine hydrocarbon extent and for structural control.
2	T	**Technical**	Subsurface structural definition	There are only 3 well penetrations located in SE corner of the structure and no DHI.	The step-out area of the structure is uncalibrated making the estimated GRV uncertain.	R	H	H	Carried out Subsurface & surface realisation mapping during the study. Planned appraisal drilling to determine hydrocarbon distribution, extent, connectivity, fluid composition and for structural control.
3	T	**Technical**	Oil rim in K6000 & K6400-sands reservoir	The 3 wells penetrated K6000 and K6400 reservoirs in GDT situation. This presents a chance for presence of oil rim in these reservoirs.	Presence of commercial oil rim will delay development of the gas cap and change the notional (NAG) development plan.	R	L	H	Confirm hydrocarbon fluid distribution and extent through the planned appraisal drilling.
4	T	**Technical**	Reservoir Connectivity	The 3 wells penetrated K6000 and K6400 reservoirs in GDT situation and GWC in K7000.	There are two scenarios, a. Individual Reservoirs and b. Complex reservoirs. This will affect the UR, number of development wells and completion strategy.	R	M	M	Carry out Subsurface & surface realisation mapping during the study. Plan appraisal drilling to determine hydrocarbon extent and for structural control.
5	T	**Technical**	Aquifer Strength	Limited data in block Y precludes conclusive assessment of the aquifer strength.	Active aquifer or lack of it affect the reservoir ultimate recovery.	R	M	M	Evaluate data from the producing X-block to assess aquifer strength observed in the field. Carry out aquifer sensitivity in MBal models to determine aquifer size required for similar pressure depletion observed in the X-block
6	T	**Technical**	Project Schedule	Execution of selected CO_2 Management option (Blending or Extraction/Disposal) will impact the OSD.	Delay in the K Sands First Hydrocarbon date. Erosion in project value.	R	M	H	The selected CO2 management solution will align with the Group guidelines, in a robust economic scenario.
7	T	**Facilities**	Concurrent Operation	The strategy to use existing locations for drilling or cluster new wells leads to minimal land take and envornmental impact.	This co-locates new wells and producing wells and exposes us to the possibility of delayed well hook up due to inability to secure shutdown window of producing wells.	R	L	H	The plan is to set up a concurrent operations team made up of the Asset Team D, Operations Team Leader(s) in Utorogu field and the Project Team Leader. A concurrent operations document or manual highlighting all potential risks and mitigation plans should be developed before execution
8	T	**Wells**	Rig availability and performance	Defective/inadequate rig equipment may result in suboptimal well delivery. In the case of availability or New/Hi-tech rig, competence in Rig operations and maintenance may result in project schedule delays.	This will lead to Non Productive Time, Well cost over runs and erosion of project economics.	R	M	L	Ensure proper and thorough Technical Evaluation of New rig. Give adequate training on rig equipment to rig staff in the event of picking up a hi-tech rig
9	T	**Wells**	Unavailability of long lead well items.	Some of the well items to be used for drilling operation require long time to be ordered.	This will amount to slip in project timing	R	M	H	Order long lead well items early enough to ensure project timing does not slip.
10	T	**Facilities**	Use of existing facilities	Suboptimal scoping of the project as a result of not fully understanding the state of existing facilities. The existing facility integrity (exposed to high CO_2 levels > 2% mol), potential interface/connectivity problems with the new 150 MMscf/d gasplant must be assured.	This would lead to cost overrun, project delays and value erosion.	R	H	M	Reviewed existing facilities and included plan to connect 150 MMscf/d gas plant in the feasibility study.
11	T	**Technical**	Low experience of deployment of smart well technology in SCIN	Level of experience in deployment of smart well technology in SCIN is very low as at today. One trial was conducted in EA.	This would lead to cost overrun, project delays.	R	M	M	Leverage competitors/OU experience and provide training on ICV operation. Undergo an FMECA study for proposed smart wells.
12	T	**Technical**	Smart Wells completion - Failure of ICVs; to open or close	ICVs are usually installed in open position, however Loss of connection with the surface, Improper/Inadequate installation of ICV accessories, Lack of operational experience of ICVs in gas wells.	Loss of production and Uncontrollable water production	R	M	M	Leverage competitors/OU experience and provide training on ICV operation. Undergo an FMECA study for proposed smart wells.
13	T	**Technical**	Reservoir Connectivity	The proved area of the reservoir penetrated by wells UT-1, UT-11 & UT-24 may not be connected to the unproved area.	There may be reduction in volume because the unproved area may not have HC.	R	L	M	Appraisal well needed to verify
14	T	**Technical**	No Operational experience in CO2 removal technology and Low CO_2 management experience in the Shell group	Level of experience in CO_2 management in SCIN is very low as at today. A CO_2 extraction plant is on trial in NLNG Bonny. Potential for availability, integrity problems.	Inability to develop Utorogu K sands gas volumes. Time slip to project. Loss of production and HSE implications during operate phase.	R	M	M	Possibility of blending with Okpokunou node gas volumes or CO2 extraction & Disposal plants. Provide robust training/exposure on chosen CO2 removal technology and maintain competent O&M support for first few years.
15	T	**Technical**	Required volumes from nearby fields for CO_2 blending	The unavailability of sufficient volumes from nearby field like Ughelli-East; Delayed blending volumes from Okpokunou node.	Inability to fill existing capacity	R	M	H	Evaluate other possible sources of low CO2 gas volumes from nearby clusters
16	T	**Operations**	Inability to sustain CO2 disposal during operate phase.	Potential injectivity problems or non availability of local market for CO2 sales If those concepts are chosen.	Low availability and loss of production.	R	M	H	Avoid disposal concepts that have sustainability issues
17	T	**Technical**	Establish liquid handling capacity for existing Utorogu gas plant /planned utorogu gas plant upgrade.	Existing liquid handling facility in Utorogu gas plant to be verified such that it is proven to be sufficient to handle a combination of the existing liquid production and the liquid production forecasted for the K-sands development.	Constraints in the existing Utorogu liquid handling facility will erode the project value.	R	M	H	The existing as-built capacity for the condensate system is 10Mbl/d and the expansion has an additional 10Mbl/d nominal capacity making a total of 20Mbl/d of nominal capacity. There is provision to flow the condensate to the flowstation for stabilization.
18	T	**Technical**	Appraisal well not getting into the drilling sequence.	Appraisal well not getting into the drilling sequence.	Project timelines slip; Increased CAPEX	R	M	H	Proper rig selection to handle drilling and mud engineering
19	T	**Facilities**	Issue with pipeline Integrity due to poor handling of CO_2 blending	Issue with pipeline Integrity due to poor handling of CO_2 blending	Low availability and loss of production.	R	L	H	CO2 blending will be automated to elliminate human intervention.
20	T	**Technical**	Inability to secure shutdown window for tie-in	Due to criticality of Utorogu gas plant to natural gas supply, shutdown window may not be approved by government authorities when required.	Project start-up delay.	R	L	H	Maximise off line fabrication works and seek window opportunities to pre-install tie-in isolation points. Effectively use the IAP process.
21	C	**Commercial**	Change in Gas sales agreement (GSA)	Change in Gas sales agreement (GSA)	Gas sales agreement improves project economics	R	M	H	Engage economics and commercial team
22	C	**Commercial**	Improper contracting strategy	Improper contracting strategy	Exposure to higher costs and risk to project schedule	R	M	H	Review existing contracts and put in place robust contracting strategy
23	C	**Commercial**	Unavailability of CO_2 extraction and disposal plant	The budget of the domestic gas project may not be sufficient to accommodate acquisition of CO_2 extraction and disposal plant.	Limits CO2 management option to blending	R	M	L	Solution with the lowest technical cost will be explored.
24	C	**Commercial**	Sale of Asset (divestment)	The company may include Utorogu asset in it's list of assets for diverstment.	This would lead to termination of the project.	R	L	H	Decision to review DOMGAS strategy is at the Group level while portfolio action continues.
25	P	**Management**	Security in Project Area	Unaligned interests among host communities, Political/Socio-economic agitations leads to instability in the operating area.	Work stoppage leading to delay in project delivery and loss of expected revenue.	R	L	H	Proactive management of community issues before they escalate into violence. Deployment of security cover at project site. Conduct security risk assessment and development of project specific security plan.
26	P	**Political**	Sabotage and vandalisation of company's pipelines	The heightened security in the Niger delta caused by sabotage and vandalisation of SPDC's pipelines .	May delay or even stop project.	R	L	H	Proactive management of community issues before they escalate into violence and continous engagement of all stakeholders.
27	P	**Political**	Change in statutory fiscal terms	Change in statutory fiscal terms	May delay or even stop project.	R	M	H	Continually engage commercial and economics team
28	P	**Management**	Inadequate / non funding to execute project	Inadequate / non funding to execute project	May delay or even stop project.	R	M	H	Consider alternative funding
29	P	**Political**	Non renewal of licence-to-operate	Non renewal of licence-to-operate	May delay or even stop project.	R	M	H	Continually engage commercial team
30	P	**Community**	ESHIA approval by FMEnv and DPR	Delay in securing Environmental Permit from the two Regulatory bodies (FME & DPR) due to late commencement of EIA process.	This may cause a delay in project delivery	R	H	H	Obtained waivers to cover Appraisal activities. To commence early EIA process to obtain approval to cover the full development activities.