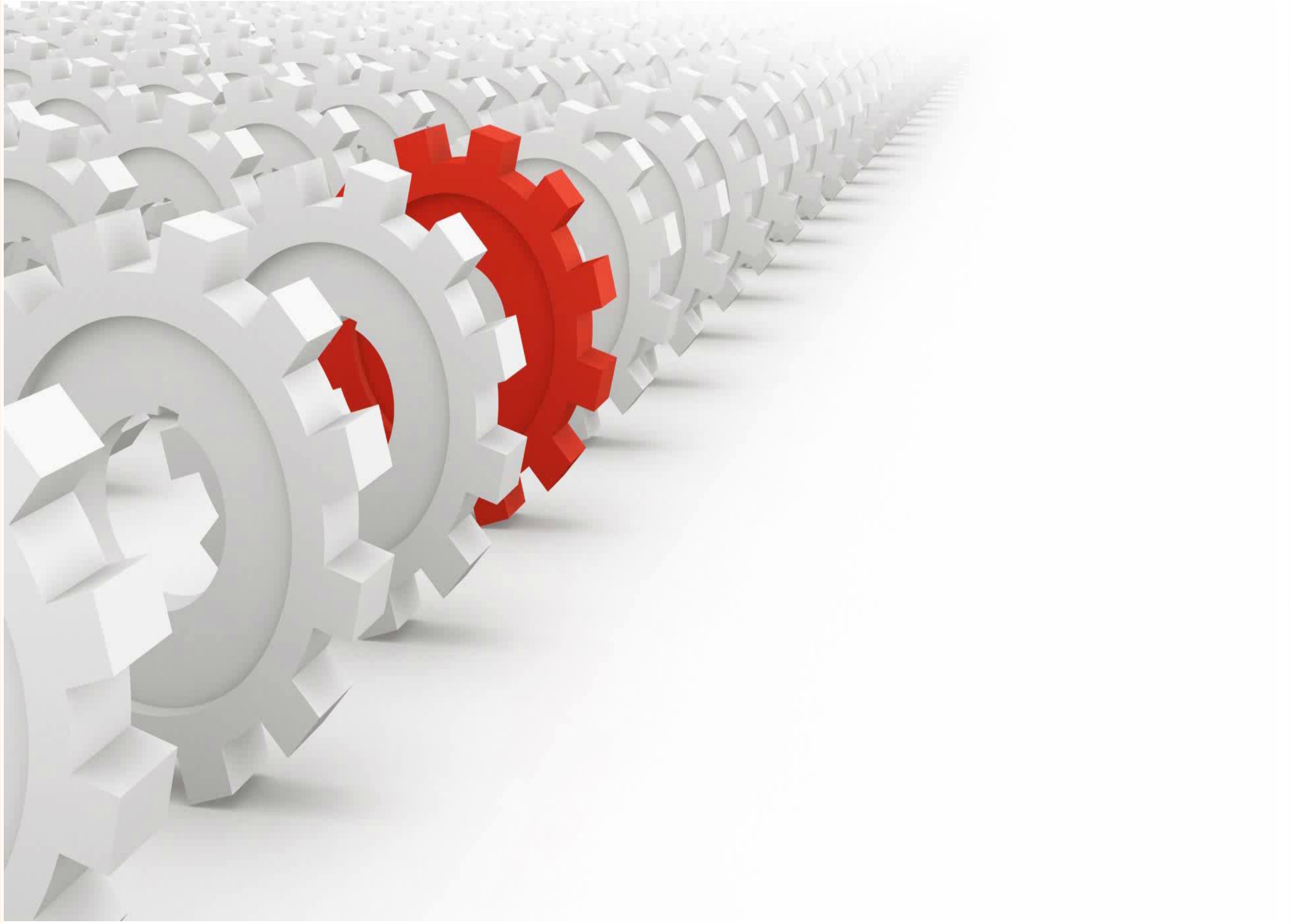


Auditing Upstream Petroleum Contracts

Terkimbi Ibunde

May 2022

About the Trainer

Terkimbi Ibunde is a Partner and the Chief Operating Officer of Execution Edge Ltd. He trained with PricewaterhouseCoopers (PwC) and worked with both Nigerian and US firms between 1997 and 2005. He joined Shell Nigeria Exploration and Production Company (SNEPCo) at the end of 2005 and held several local and regional (Nigeria and Gabon) Finance leadership roles. He also has over 20 years combined experience in oil and gas industry as well as in the provision of assurance, taxation, advisory and consulting services.
He has also provided Expert Witness services in Arbitrations in support of Expert Determination in Oil & Gas Disputes:

Terkimbi has a B.Sc. Accounting degree from the University of Calabar and an MBA from the Warwick Business School, UK.

He is also a member of the Chartered Institute of Management Accountants, UK (CIMA), a member of Association of International Certified Professional Accountants (AICPA) as well as the Institute of Chartered Accountants of Nigeria (ICAN).

Agenda

S/No	Start time	Stop time	Allotted Time	Activity
1	9:00 AM	9:30 AM	*30 minutes*	The Upstream Oil & Gas Sector and Major Accounting Issues
2	9:30 AM	9:50 AM	*20 minutes*	Accounting/Auditing Issues in Upstream Oil and Gas Industry
	9:50 AM	10:30 AM	*40 minutes*	Accounting/Auditing Issues in Upstream Oil and Gas Industry
	10:30 AM	**10:45 AM**	***15 minutes***	**Tea Break**
	10:45 AM	12:15 PM	*90 minutes*	Accounting/Auditing Issues in Upstream Oil and Gas Industry
	12:15 PM	**1:15 PM**	***60 minutes***	**LUNCH**
	1:15 PM	1:55 PM	*40 minutes*	Unique Accounting/Audit challenges during Develop & Operate phases
3	1:55 PM	2:15 PM	*20 minutes*	Evaluating the Performance of Upstream Oil and Gas
4	2:15 PM	2:45 PM	*30 minutes*	Auditing Upstream Contracts
	2:45 PM	**3:00 PM**	***15 minutes***	**Tea Break**
5	3:00 PM	4:30 PM	*90 minutes*	Auditing Upstream Contracts
				END

The Upstream Oil & Gas Sector and Major Accounting Issues

Section 1

- Overview of Upstream oil and Gas industry
- Overview of Upstream Business Model
- Acquisition, Exploration, Development and Production Costs
- Accounting Approaches

102

Overview of Upstream Oil and Gas industry

Facilitator	Terkimbi
Time	5 minutes

The Upstream Oil & Gas Sector and Major Accounting Issues

Overview of Upstream Oil & Gas industry

- ✓ Objective is to find, extract, refine and sell oil and gas, refined products and related products.
- ✓ Requires huge capital cost, long lead times, operating in challenging environmental conditions with uncertain outcomes.
- ✓ Exploration, development and production often take place in joint ventures (joint activities) to share risks.
- ✓ Industry exposed significantly to macroeconomic factors (commodity prices, currency fluctuations, interest rate risk and political developments.
- ✓ Commercial viability & technical feasibility to extract Oil + Gas is complex and includes a number of significant variables.
- ✓ Industry operations have a huge impact on the environment and is often obligated to remediate any resulting damage
- ✓ Increasing resource nationalism from host governments.

The Upstream Oil & Gas Sector and Major Accounting Issues

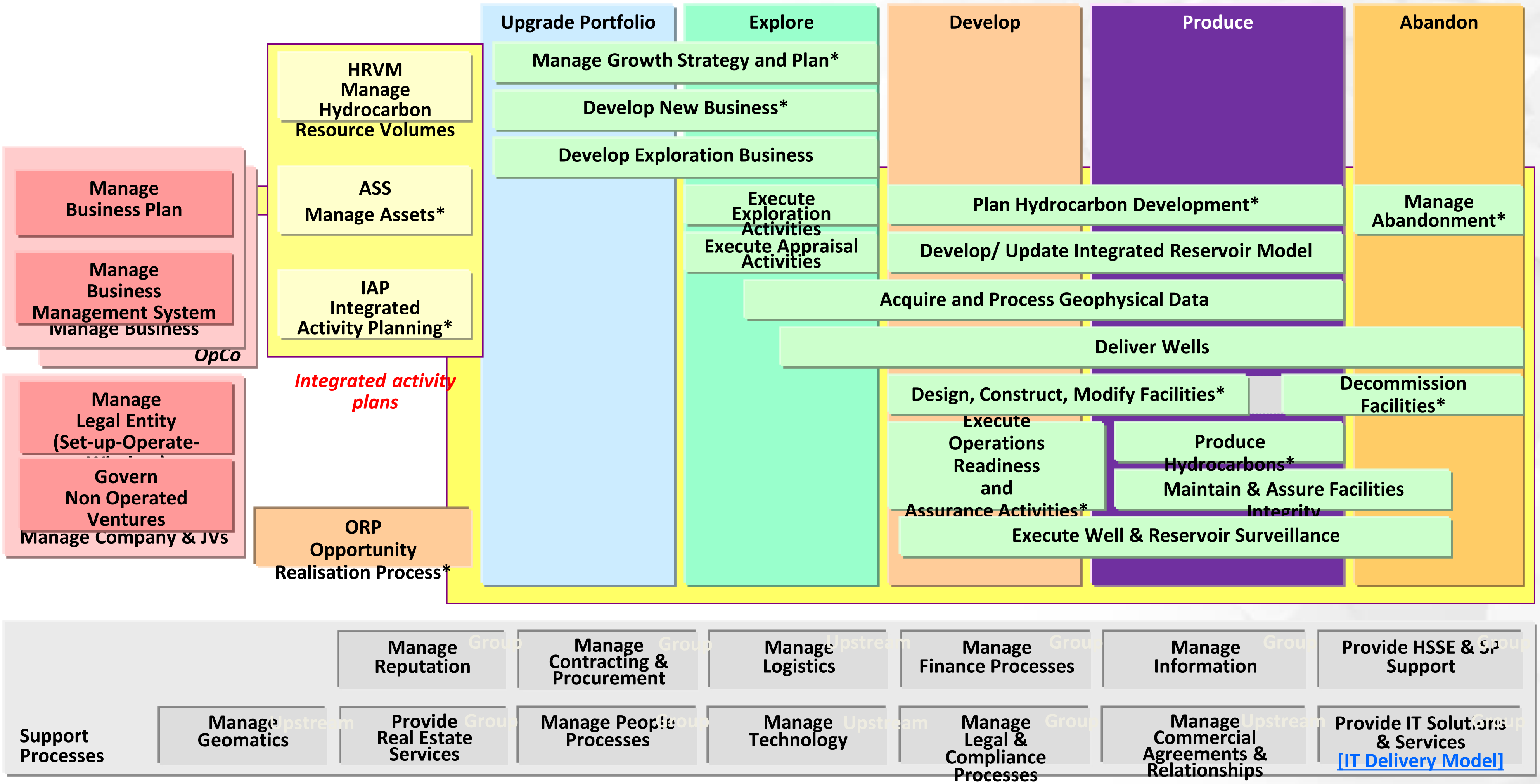
102

Overview of Upstream Business Process Model

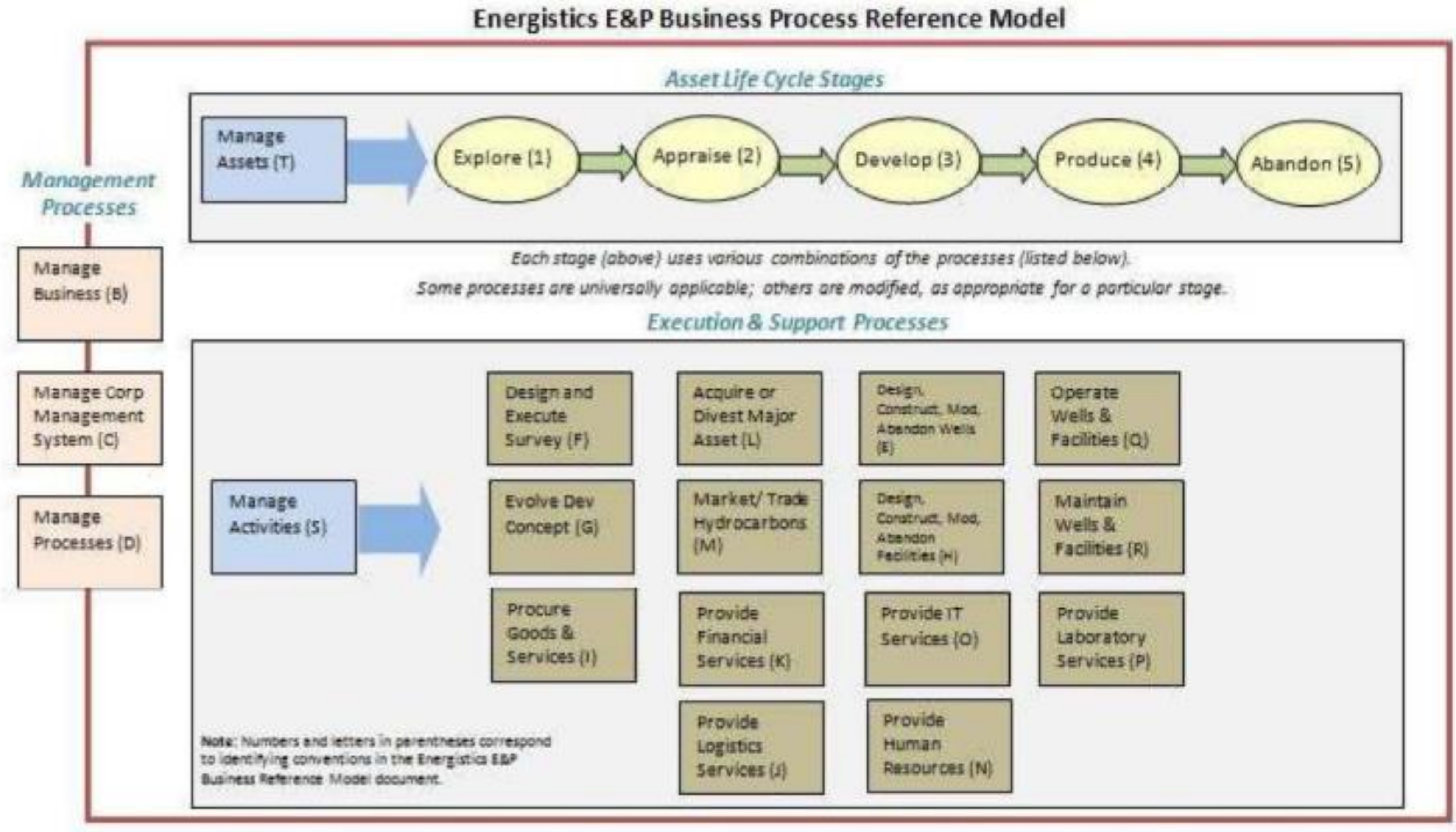
Facilitator	Terkimbi
Time	5 minutes

The Upstream Oil & Gas Sector and Major Accounting Issues

Overview of Upstream Business Process Model



Overview of Upstream Business Process Model



Play Choices in Upstream Oil and Gas Industry

	Explorer	Operator	Portfolio Player	
			Non Operator	Farm-out
Business Model Options / Features	• Exploratory Success • Lacks financial resource to operate/produce • Appetite for frontier/emerging areas/plays/basins	• Operational excellence • Excellent project management skills • Appetite for control • Full O&G value chain player	• Shareholder value focused • More risk averse • Disciplined, focused investments	• Farmor lacks financial and/or technical expertise • Appetite for 'set it & forget it' investment • Minimal involvement in management • Risk aversion
Critical Success Factors	• Geoscience expertise • Technology advance • Access to acreage with decent terms	• Technical Expertise • Cash flow • Operations Excellence • Stakeholder mgmt.	• Strict SLAs • Legal/financial expertise • Relationship capital	• Strict adherence to SLA between Farmor/farmee • Legal/financial/commercial expertise • Relationship mgmt.
Key Risks	• High entry costs • Potentially limited near-term success • Exploration failure costly	• Operational risks • Regulatory changes • Reputation risks	• Economic factors • Arbitration risk • Operational efficiency	• Complex set of agreements • Arbitration risk • Potential value erosion
Existing Coys	Anardako/Tullow	'Old' Shell	Esso	SunLink/Dajo Oil

Acquisition, Exploration, Development & Production Costs

102

Facilitator	Terkimbi
Time	10 minutes

Acquisition

<u>Activities:</u>

- ✓ Involves activities relating to securing the rights from the property owner to explore for and produce oil & gas in that field/area.
- ✓ Fiscal terms surrounding property acquisitions (what is owned by the oil companies versus original land owners/government) are complex;

Costs

- ✓ Identifying reserves that are economically viable to exploit and are therefore initially capitalised (in property, plant and equipment) while further exploration activities are carried out.

Exploration

Activities fall into two main types:

(a) Areas that may warrant examination, such as:

- topographical, geological and geophysical ('G & G') studies and related activities undertaken in the exploration and appraisal phases;
- carrying and retaining undeveloped concessions, such as delay rentals, legal costs for title defence and the maintenance of land and lease records;
- making dry hole and bottom hole contributions to other parties

(b) Areas that are considered to have prospects of containing oil and gas reserves, such as:

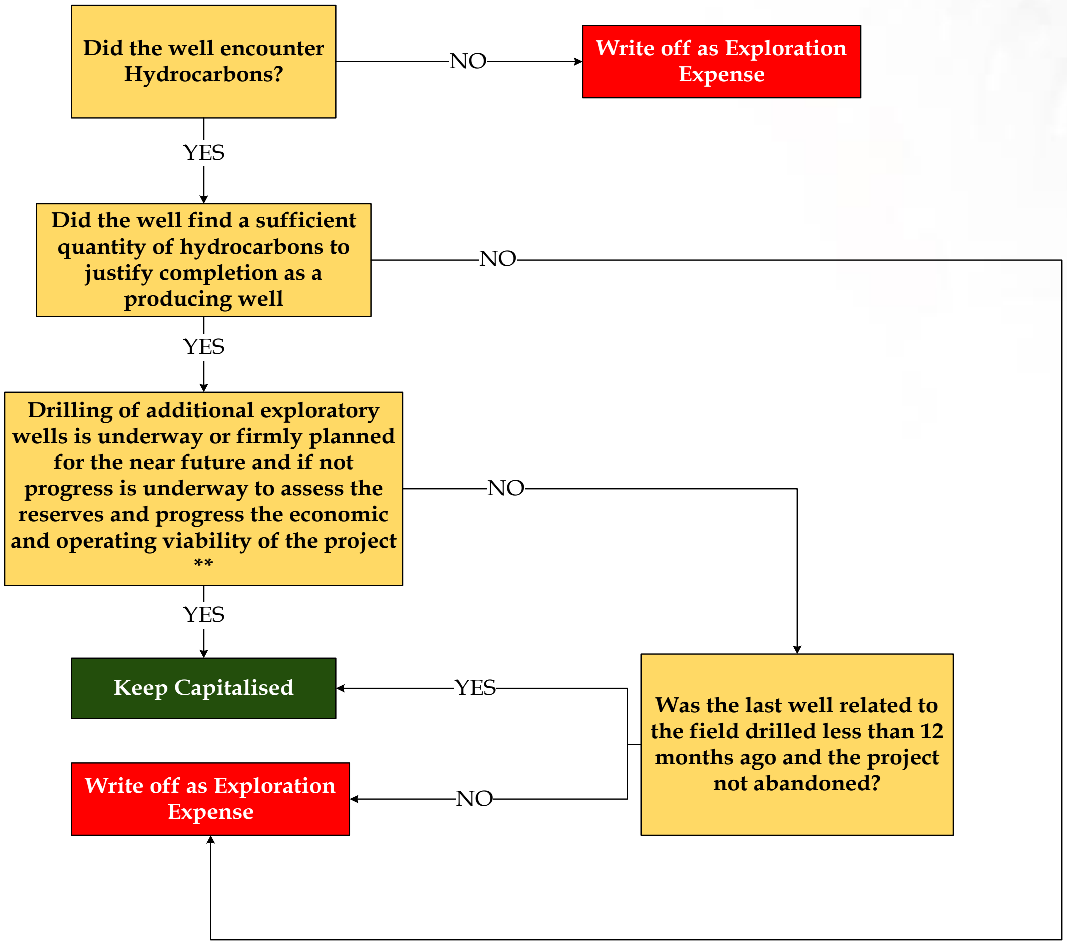
- drilling and equipping exploratory wells; and
- drilling exploratory-type stratigraphic test wells.

Costs:

- Costs in (a) above are more speculative in nature and are therefore expensed as incurred.
- costs in (b) above are incurred with the specific aim of identifying reserves that are economically viable to exploit and are therefore initially capitalised (in property, plant and equipment) while further exploration activities are carried out.

The Upstream Oil & Gas Sector and Major Accounting Issues

Exploration



Topographical, geological and geophysical ('G & G') studies and related activities (e.g. 3-D seismic surveys) undertaken to better assess and locate production wells (e.g. in-fill wells) in an area with proved reserves fall within the scope of development costs and are capitalised as for property, plant and equipment

Development

- ✓ Activities
  - preparing proved reserves for production, i.e. all activities undertaken to obtain access to proved reserves and to provide facilities for extracting, treating, gathering, and storing oil and gas
- ✓ Costs
  - incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas.
- ✓ Expenditures are capitalised to the extent that they are necessary to bring the property to commercial production.
- ✓ IAS 16 requires that the cost of abnormal amounts of labour or other resources involved in constructing an asset should not be included in the cost of that asset.
- ✓ Expenditures incurred after the point at which commercial production has commenced should only be capitalised if the expenditures meet the asset recognition criteria in IAS 16 or 38.

Production

<u>Activities</u>

- ✓ Pre-wellhead - lifting the oil and gas to the surface, operation and maintenance of wells, extraction rights, etc
- ✓ Post-wellhead - gathering, treating, field transportation, field processing, etc., up to the outlet valve on the lease or field production storage tank, etc

Costs:

- ✓ Costs incurred in lifting oil and gas to the surface and in gathering, treating, and storing oil and gas
  - Pre-wellhead costs: Costs of labour, repairs and maintenance, materials, supplies, fuel and power, property taxes, insurance, royalty, etc., in respect of lifting the oil and gas to the surface, operation and maintenance including servicing and work-over of wells
- ✓ Post-wellhead costs: Costs of labour, repairs and maintenance, materials, supplies, fuel and power, property taxes, insurance, etc., in respect of gathering, treating, field transportation, field processing, including cess up to the outlet valve on the lease or field production storage tank, etc.

The Upstream Oil & Gas Sector and Major Accounting Issues

Summary

O&G costs

- Acquisition Costs
  - Capitalized (B/S) Amortized (I/S)
- Exploration Costs
  - Depends
- Development Costs
  - Capitalized (B/S) Amortized (I/S)
- Production Costs
  - Expensed (I/S)

Accounting Approaches

102

Facilitator	Terkimbi
Time	10 minutes

- Successful Efforts Method
- vs Full Cost Methods

Full Cost Method

- ✓ All property acquisition, exploration and development costs, even dry hole costs, are capitalized as oil and gas properties.
- ✓ These costs are amortized using a unit-of-production method based on volumes produced and remaining proved reserves.
- ✓ The philosophy behind FCM is that costs of acquisition, exploration and development are necessary for the production of oil and gas.
- ✓ Dry-holes are an inevitable part of exploration effort
- ✓ Both, successful and unsuccessful costs are capitalized, even though unsuccessful costs have no future benefits

Successful Efforts Method

- ✓ Costs that do not result in discovery of reserves (dry hole costs) are charged as expenses of the period
- ✓ Only those costs lead directly to discovery of oil and gas are capitalized
- ✓ The following:
  - ✓ acquisition costs
  - ✓ drilling exploration costs and
  - ✓ development costs

  should be treated as capital work-in-progress when incurred
- ✓ All costs other than these should be charged as expense of the period

Temperature Check

Cost items	SE	FC
Geological and Geophysical Costs (G&G)		
Acquisition costs		
Exploratory dry hole		
Exploratory well, successful		
Development dry hole		
Development well, successful		
Production costs		

Suggested Solution

Cost items	SE	FC
Geological and Geophysical Costs (G&G)	E	C
Acquisition costs	C	C
Exploratory dry hole	E	C
Exploratory well, successful	C	C
Development dry hole	C	C
Development well, successful	C	C
Production costs	E	E

Temperature Check

O & G Ltd. began its operation on April 1, 2019, with the acquisition of a lease in the Benue Trough. During the first year the following revenue was earned and costs were incurred:

Revenue	US$2,45,000
Acquisition costs related with dry-holes	US$4,00,000
Acquisition costs related with successful wells	US$1,00,000
Exploratory dry-hole costs	US$18,00,000
Exploratory successful wells	S$5,00,000
Development costs- resulted in dry-holes	US$25,000
Development costs- resulted in development wells	US$75,000
Production costs	US$75,000
Depreciation and depletion under SEM	US$70,000
Depreciation and depletion under FCM	US$2,90,000

The Upstream Oil & Gas Sector and Major Accounting Issues

Suggested Solution - Profit and Loss A/c

Expenses	SEM US$	FCM US$	Revenues	SEM US$	FCM US$
Acquisition costs	4,00,000	-	Revenue	2,45,000	2,45,000
Exploratory dry-hole costs	18,00,000	-	Net loss	21,00,000	1,20,000
	75,000	75,000			
	70,000				
Production Costs		2,90,000			
D & D					
	23,45,000	3,65,000		23,45,000	3,65,000

Suggested Solution - Partial Balance Sheet

Liabilities	Assets	SEM US$	FCM US$
	Acquisition costs	1,00,000	5,00,000
	Exploratory dry-hole costs	-	18,00,000
	Development costs	1,00,000	1,00,000
	Exploratory successful wells	<u>5,00,000</u>	<u>5,00,000</u>
		7,00,000	29,00,000
	D & D	<u>70,000</u>	<u>2,90,000</u>
		6,30,000	26,10,000

IFRS issues Upstream Oil and Gas Industry

Section 2

- Exploration and evaluation
- Reserves and resources and audit considerations
- Assets, Depletion, Depreciation & Amortization (“DD&A”)
- Impairment of development, production and downstream assets

IFRS issues Upstream Oil and Gas Industry

102

Reserves and Resources

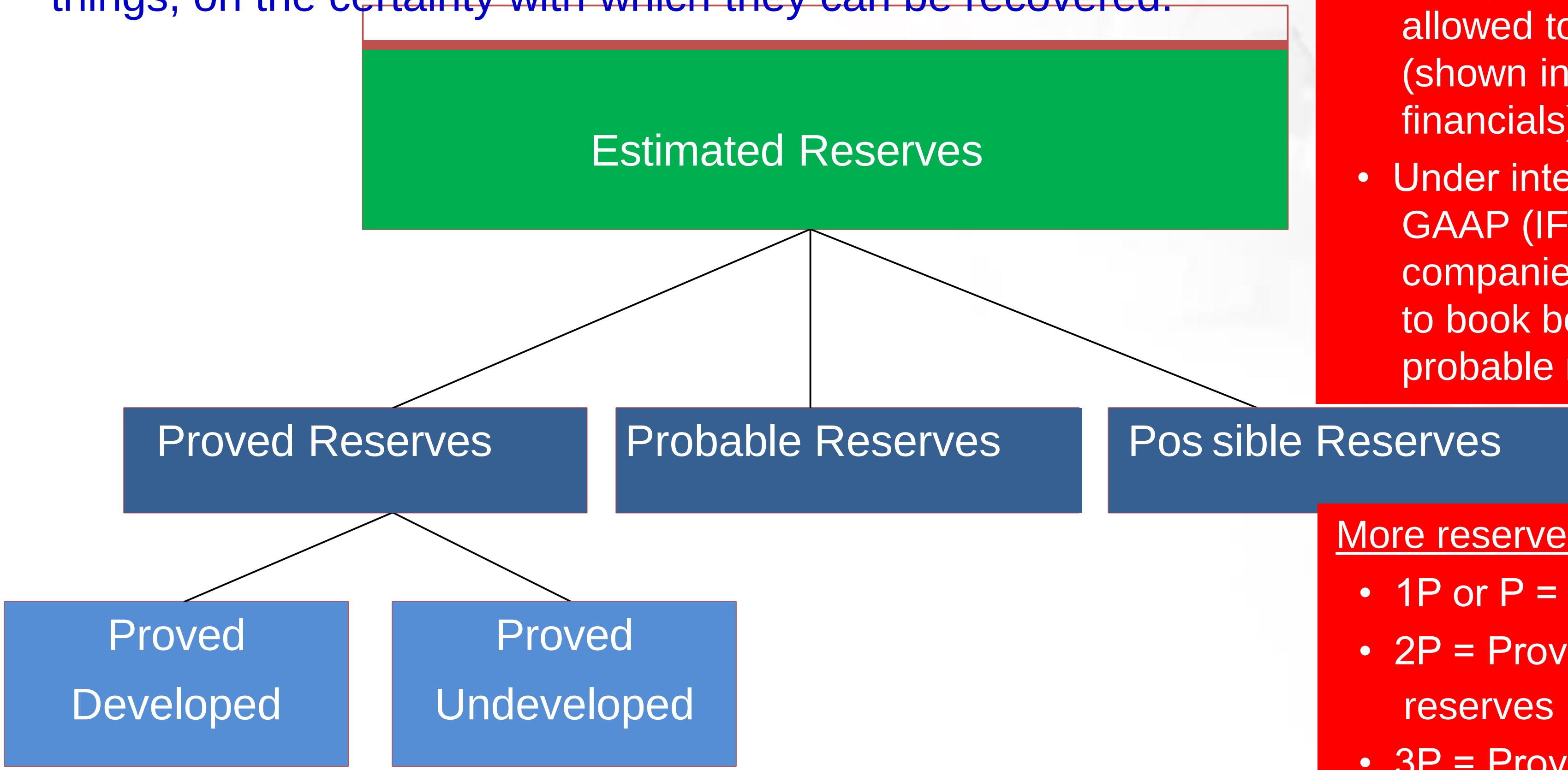
Facilitator	Terkimbi
Time	20 minutes

IFRS issues Upstream Oil and Gas Industry

Reserves and Resources

Reserves – the lifeline of the E&P industry

Can be classified differently depending, among several other things, on the certainty with which they can be recovered:



Reserve talk

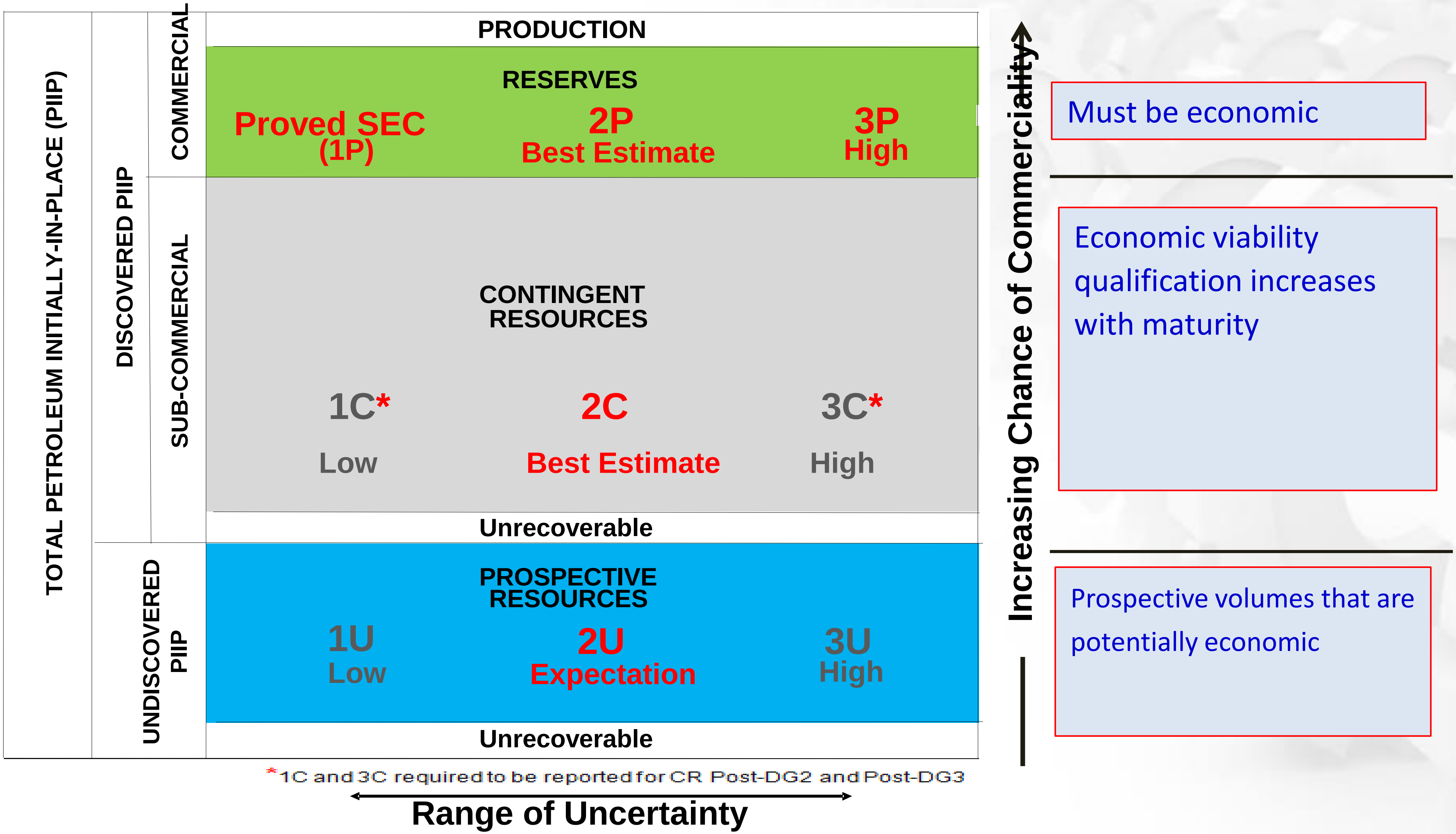
- Under U.S. GAAP rules, only proved reserves are allowed to be booked (shown in companies' financials)
- Under international GAAP (IFRS) rules, companies are allowed to book both proved and probable reserves.

More reserve talk

- 1P or P = proved reserves
- 2P = Proved + probable reserves
- 3P = Proved + probable + possible reserves

IFRS issues Upstream Oil and Gas Industry

The Petroleum Resource Classification System (PRCS)



PRCS Main Classes and Categories

Resources can be reported only if the company *has or shares development rights and obligations*

Reserves: Proved SEC (1P), 2P, 3P

- Technically and Commercially Mature
- SEC Proved Reserves are used for external disclosure and are evaluated using SEC economic rules

Contingent Resources: 1C, 2C, 3C

- Discovered but not yet “Technically & Commercially Mature”

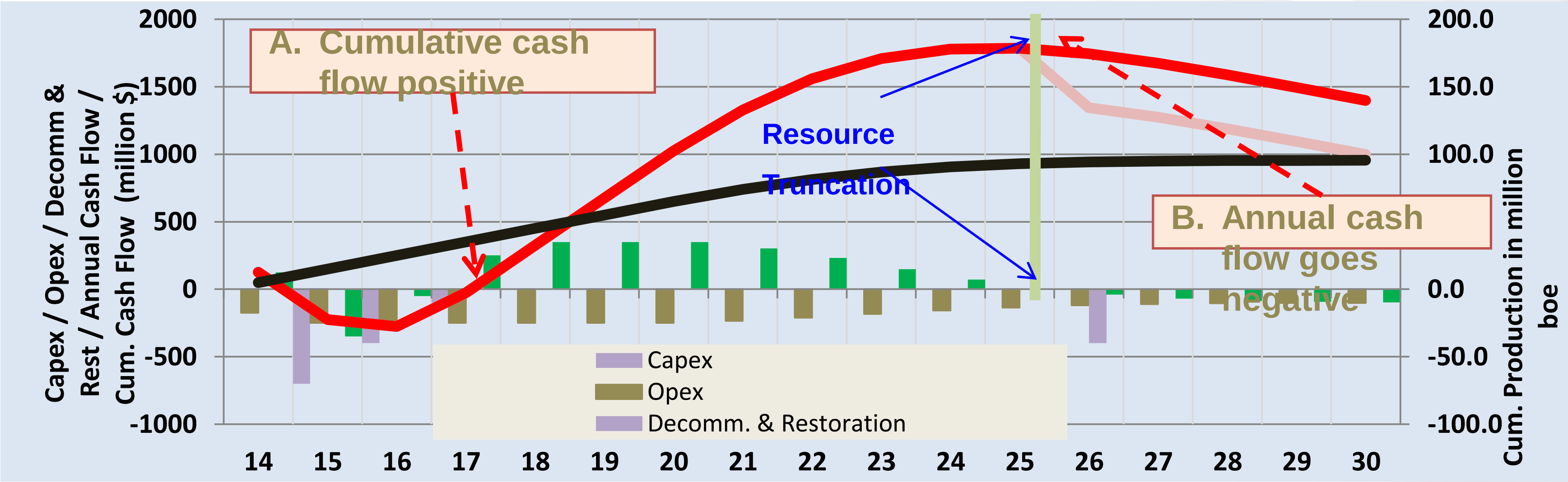
Prospective Resources: 1U, 2U, 3U

- Undiscovered potentially economic

IFRS issues Upstream Oil and Gas Industry

Reserves must be Economic

– Best & High (2P-3P) estimates are evaluated at company's Economics (PSV, post-tax, discounted)
– SEC Proved Reserves are evaluated at SEC economics (YAP, pre-tax, undiscounted)
– Projects must be economic, i.e. yield a positive cumulative cash flow
– Reserves are defined up to truncation point (unless license or technical cut-off precedes)



Disclosure of Reserves and Resources

The disclosure of key assumptions and key sources of estimation uncertainty at the balance sheet date is required by IAS 1 as follows:

- ✓ the methodology used and key assumptions made for hydrocarbon resource and reserve estimates
- ✓ the range of reasonably possible outcomes within the next financial year in respect of the carrying amounts of the assets and liabilities affected
- ✓ an explanation of changes made to past hydrocarbon resource and reserve estimates, including changes to underlying key assumptions.
- ✓ potential future costs to be incurred to acquire, develop and produce reserves may help users of financial statements to assess the entity’s performance.
- ✓ Exploration and development costs that are capitalised should be classified as non-current assets in the balance sheet

Disclosure of Reserves and Resources - 2

SEC guidance on the disclosure of reserves is viewed by the industry as a best practice approach and is based on Final Rule:

- ✓ Disclosure of estimates of proved developed reserves, proved undeveloped reserves and
- ✓ total proved reserves by geographical area and for each country representing 15% or more of a company's overall proved reserves
- ✓ Disclosure of reserves from non-traditional sources (i.e. bitumen, shale, coalbed methane) as oil and gas reserves
- ✓ Optional disclosure of probable and possible reserves
- ✓ Optional disclosure of the sensitivity of reserve numbers to price
- ✓ Disclosure of the company's progress in converting proved undeveloped reserves into proved developed reserves. This is to include those that are held for five years or more and an explanation of why they should continue to be considered proved.
- ✓ Disclosure of technologies used to establish reserves in a company's initial filing with the SEC and in filings which include material additions to reserve estimates.
- ✓ The company's internal controls over reserve estimates and the qualifications of the technical person primarily responsible for overseeing the preparation or audit of the reserves estimates.

IFRS issues Upstream Oil and Gas Industry

Exploration and Evaluation (IFRS 6, IAS 16 & IAS 38)

Facilitator	Terkimbi
Time	20 minutes

Initial recognition under IFRS 6 Framework

The capitalization point is the earlier of:

- ✓ the point at which the fair value less costs to sell of the property can be reliably determined as higher than the total of the expenses incurred and costs already capitalised (such as licence acquisition costs); and
- ✓ an assessment of the property demonstrates that commercially viable reserves are present and hence there are probable future economic benefits from the continued development and production of the resource.

- ✓ Costs incurred after probability of economic feasibility is established are capitalised only if the costs are necessary to bring the resource to commercial production. Subsequent expenditures are not capitalised after commercial production commences, unless they meet the asset recognition criteria.
- ✓ E&E assets recognised should be classified as either tangible or intangible according to their nature . A test well is considered a tangible asset.
- ✓ Clear disclosure of the accounting policy chosen and consistent application of the policy chosen are important for users’ understanding of bthe financial statements.

Impairment of E&E assets

- ✓ An entity assesses E&E assets for impairment only when there are indicators that impairment exists.

- ✓ Indicators of impairment include, but are not limited to:
  - Rights to explore in an area have expired or will expire in the near future without renewal.
  - No further exploration or evaluation is planned or budgeted.

- ✓ A decision to discontinue exploration and evaluation in an area because of the absence of commercial reserves.

- ✓ Sufficient data exists to indicate that the book value will not be fully recovered from future development and production.

- ✓ The affected E&E assets are tested for impairment once indicators have been identified.

Sidetracks

Costs of side tracks – Should they be expensed?

An entity is drilling a new well in the development phase. It has drilled to spot 1, incurring costs of $5 million, but no reserves were found. Based on test data from the drilling, and a geological study, an alternative drill target was identified (spot 2). The entity could side track to this from a point in the existing drill hole instead of drilling an entirely new well. Reserves were found at spot 2.

Question

How much cost should entity's management write off?

Suggested Solution - Sidetracks

Performing exploratory drilling at a particular location can indicate that reserves are present in a nearby location rather than the original target. It may be cost-effective to “side track” from the initial drill hole to the location of reserves instead of drilling a new hole. If this side track is successful in locating reserves, the cost previously incurred on the original target can remain capitalised instead of being written off as a dry hole. The additional costs of the side track are treated in accordance with the company’s accounting policy which should be followed consistently. The asset should be considered for impairment if the total cost of the asset has increased significantly. If the additional drilling is unsuccessful, all costs would be expensed.

Solution to side track question

No costs will be written off as the drilling has proved successful.

IFRS issues Upstream Oil and Gas Industry

Suspended well

IFRS

- ✓ No specific guidance.
- ✓ Principles of IFRS 6 on impairment testing would apply

FASB

- ✓ FASB ASC-932 Extractive Activities – Oil and Gas includes guidance
- ✓ Capitalised drilling costs can continue to be capitalised when:
  - – the well has found a sufficient quantity of reserves to justify completion as a producing field and,
  - – sufficient progress is being made in assessing the reserves and viability of the project
- ✓ If either criterion is not met, or substantial doubt exists about the economic or operational viability of the project, the exploratory well costs are considered impaired and are written off

Post Balance Sheet Events

Post balance sheet dry holes – Should the asset be impaired?

Background

An entity begins drilling an exploratory well in October 2010. From October 2010 to December 2010 drilling costs totalling GBP 550,000 are incurred and results to date indicate it is probable there are sufficient economic benefits (i.e. no indicators of impairment). During January 2011 and February 2011, additional drilling costs of GBP 250,000 are incurred and evidence obtained indicates no commercial deposits exist. In the month of March 2011, the well is evaluated to be dry and abandoned. Financial statements of the entity for 2010 are issued on April 2011.

Question

How should the entity account for the exploratory costs in view of the post balance sheet event?

Post balance sheet events

Post balance sheet dry holes – Should the asset be impaired?

Solution

- Since there were no indicators of impairment at period end, all costs incurred up to December 2010 amounting to GBP 550,000 should remain capitalised by the entity in the financial statements for the year ended 31 December, 2010. However, if material, disclosure should be provided in the financial statements of the additional activity during the subsequent period that determined the prospect was unsuccessful.

- The asset of GBP 550,000 and costs of GBP 250,000 incurred subsequently in the months of January 2011 to February 2011 would be expensed in the 2011 financial statements.

IFRS issues Upstream Oil and Gas Industry

License Relinquishment

- ✓ Licenses for exploration (and development) usually cover a specified period of time and contain conditions relating to achieving certain milestones on agreed deadlines.

- ✓ Terms of licenses specify condition precedents for keeping or relinquishing them. When an entity fails to meet the CPs. relinquishment of the licence occurs.

- ✓ A relinquishment may occur
  - ✓ subsequent to balance sheet date but before the issuance of the financial statements (assessed as an adjusting or non-adjusting event), or
  - ✓ subsequent to the balance sheet date but before the issuance of the financial statements, (assessed as an adjusting or non-adjusting event)

We’ll resume our meeting in:

15 Minutes

We’ll resume our meeting in:

14 Minutes

We’ll resume our meeting in:

13 Minutes

We’ll resume our meeting in:

12 Minutes

We’ll resume our meeting in:

11 Minutes

We’ll resume our meeting in:

10 Minutes

We’ll resume our meeting in:

9 Minutes

We'll resume our meeting in:

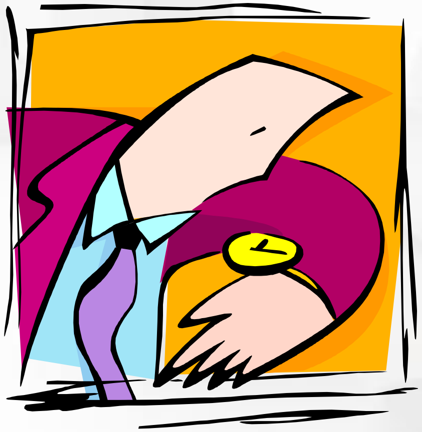
8 Minutes

We’ll resume our meeting in:

7 Minutes

We'll resume our meeting in:

6 Minutes

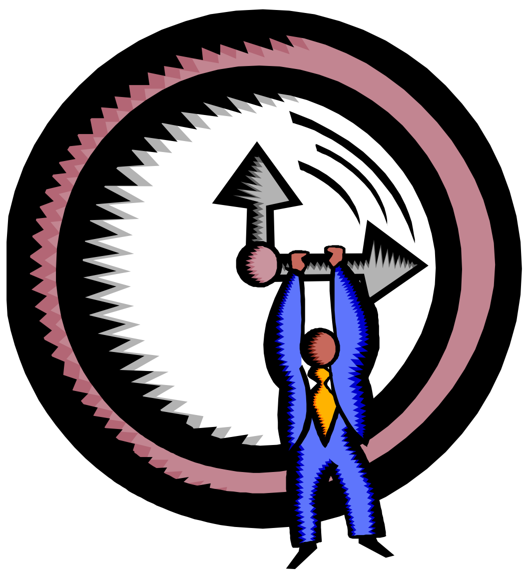


We’ll resume our meeting in:

5 Minutes

We’ll resume our meeting in:

4 Minutes

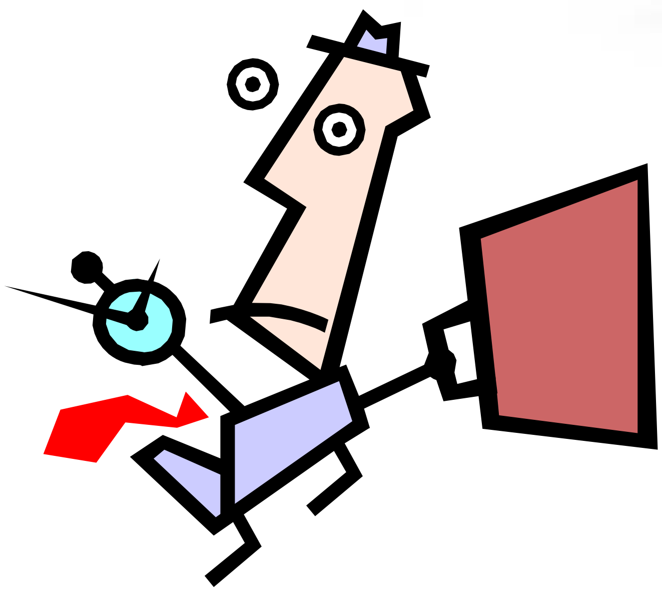


We’ll resume our meeting in:

3 Minutes

We’ll resume our meeting in:

2 Minutes




We'll resume our meeting in:
1 Minute

Break time is over! Lets get started!

102

Depletion, Depreciation & Amortization (IFRS 6, IAS 8)

Facilitator	Terkimbi
Time	5 minutes

E&E and Development Phase Costs

Accounting Treatment

- ✓ Accumulated capitalised costs from E&E and development phases are amortised using Units of production (UOP) basis.
- ✓ UOP is the most appropriate method as it reflects the pattern of consumption of the reserves' economic benefits.

Change in the basis of reserves

- ✓ A change from proved to total reserve acceptable under IFRS.
- ✓ A change in the basis of reserves constitutes a change in accounting estimate under IAS 8.

Background

Entity D is preparing its first IFRS financial statements. D’s management has identified that it should amortise the carrying amount of its producing properties on a unit of production basis over the reserves present for each field.

However, D’s management is debating whether to use proved reserves or proved and probable reserves for the unit of production calculation.

Suggested Solution - Background

Entity D’s management may choose to use either proved reserves or proved and probable reserves for the unit of production amortisation calculation.

The IASB Framework identifies assets on the basis of probable future economic benefits and so the use of probable reserves is consistent with this approach. However, some national GAAPs have historically required only proved developed reserves be used for such calculations.

Whichever reserves definition D’s management chooses it should disclose and apply this consistently to all similar types of production properties. For example, some entities used proved reserves for conventional oil and gas extraction and proved and probable for unconventional properties. If proved and probable reserves are used, then an adjustment must be made to the amortisation base to reflect the estimated future development costs required to access the undeveloped reserves.

IFRS issues Upstream Oil and Gas Industry

DD&A Summary

Depreciation

- A method by which the cost of long-term fixed assets (over 1 year) is spread over a future period (number of years), when these assets are expected to be in service and help generate revenue for a company.
- An allocation of the costs of an original purchase of fixed assets over the estimated useful lives of those fixed assets.

What's depreciated?

Fixed assets:

- Plants
- Machinery
- Drilling equipment
- Pipelines

Depletion

- O&G industry specific
- Same concept as depreciation that is applied to mineral resources.

What's depleted?

- O&G reserves

Amortization

- Amortization is the systematic allocation of the cost of acquired intangible assets over a period of time that these assets are expected to be in service and help generate revenue for a company.

What's amortized?

Acquired intangible assets:

- Brand
- Franchise
- Trademarks
- Patents

All 3 appear on the income statement

- Combined into 1 line item: Depreciation, Depletion, and Amortization (or DD&A).

Impairment of Development & Production assets (IAS 36)

Facilitator	Terkimbi
Time	10 minutes

IFRS issues Upstream Oil and Gas Industry

Impairment indicators in Oil and gas industry

✓ If the following impairment indicators are concluded to exist, IAS 36 requires that the entity perform an impairment test:

- significant reductions in estimates of reserves;
- significant decline in the market capitalization of the entity or other entities producing the same commodity;
- a decline in long-term market prices for oil and gas;
- a significant adverse movement in foreign exchange rates;
- a significant increase in production costs;
- a large cost overrun on a capital project such as an overrun during the development and construction of new wells;
- operation issues which may require significant capital expenditure to remediate;
- a significant increase in the expected cost of dismantling assets and restoring the site, particularly towards the end of a field’s life;
- a significant revision of the plan for the development of the fiels
- production difficulties;
- problems with securing infrastructure necessary to transport product to market;
- adverse changes in government regulations and environmental law, including a significant increase in the tax or royalty burden payable;
- increased security or political risk for the relevant area.

Impairment indicators (1)

Is a decline in market prices of oil and gas always an indicator of impairment?

Background

An entity has producing oil and gas fields. There has been a significant decline in the prices of oil and gas during the last six months.

Is such a decline in the prices of oil and gas an indicator of impairment of the field?

Suggested Solution - Impairment indicators (1)

Price decreases are not automatically impairment indicators. The nature of oil and gas assets is that they often have a long useful life and the price point at which producing fields become uneconomic varies widely. Commodity price movements can be volatile and move between troughs and spikes. Price reductions can assume more significance over time. If a decline in prices is expected to be prolonged and for a significant proportion of the remaining expected life of the field, an impairment indicator will likely have occurred.

Short-term market fluctuations may not be impairment indicators if prices are expected to return to higher levels within the near future. Such assessments can be difficult to make, with price forecasts becoming difficult where a longer view is taken. Entities should approach this area with care. In particular, entities should consider any downward movements carefully for fields which are high cost producers.

Impairment indicators (2)

Might a change in government be an indicator of impairment?

Background

An upstream company has a production sharing contract (PSC) in a small country in equatorial Africa. The company's investment in the PSC assets is substantial. There is a coup in the country and the democratically elected government is replaced by a military regime. Management of the national oil company (NOC), partner in the PSC, is replaced. The NOC has been paying income tax on behalf of the operator of the PSC.

Suggested Solution - Impairment indicators (2)

Yes. The change in government is a change in the legal and economic environment that will have a substantial negative impact on expected cash flows. The PSC assets should be tested for impairment.

Impairment indicators (3)

New management of the NOC announces that it will no longer pay the income taxes on behalf of the operator. The operator will be required to pay income taxes and the petroleum excess profits tax from its share of the PSC profit oil. The combined effective tax rate is 88%.The operator of the PSC expects that operating costs will increase principally due to increased wages and bonuses for expatriate employees and will not be recovered under the terms of the PSC.

Does the change in government constitute an indicator of impairment?

Suggested Solution - Impairment indicators (3)

Yes. The change in government is a change in the legal and economic environment that will have a substantial negative impact on expected cash flows. The PSC assets should be tested for impairment.

102

Borrowing Costs (IFRS 6, IAS 23)

Facilitator	Terkimbi
Time	5 minutes

Borrowing costs:

- ✓ Should be capitalize under IFRS 6 as a cost of E&E if capitalized under previous GAAP.
- ✓ May also capitalise on any E&E assets that meet the asset recognition criteria in their own right and are qualifying assets under IAS 23.
- ✓ Cost of an item of property, plant and equipment may include borrowing costs incurred for the purpose of acquiring or constructing it. IAS 23 Borrowing costs requires that borrowing costs be capitalised in respect of qualifying assets.
  - ✓ Qualifying assets are those assets which take a substantial period of time to get ready for their intended use.
- ✓ Should be capitalised while acquisition or construction is actively underway.
- ✓ include the costs of specific borrowings for the purpose of financing the construction of the asset, and those general borrowings that would have been avoided if the expenditure on the qualifying asset had not been made.

IFRS issues Upstream Oil and Gas Industry

102

Foreign Currency Gains and Losses (!AS 21, 23)

Facilitator	Terkimbi
Time	5 minutes

Foreign Currency Gains and Losses

- ✓ Two possible methods are:
  - ✓ The portion of the foreign exchange movement to capitalise may be estimated based on forward currency rates at the inception of the loan.
  - ✓ The portion of the foreign currency movement to capitalise may be estimated based on interest rates on similar borrowings in the entity’s functional currency.
- ✓ Management must use judgement to assess which foreign exchange differences can be capitalised.
- ✓ The method used is a policy choice which should be applied consistently to foreign exchange differences whether they are gains or losses.

Exchange differences on foreign currency borrowings

Background

- ✓ An upstream oil and gas entity domiciled in the UK, with GBP functional currency, has a US$1 million foreign currency loan at the beginning of the period. The interest rate on the loan is 4% and is paid at the end of the period. An equivalent borrowing in sterling would carry an interest rate of 6%. The spot rate at the beginning of the year is £1 = US$1.55 and at the end of the year it is £1 = US$1.50.

Question

- ✓ What exchange difference could qualify as an adjustment to the interest cost?

IFRS issues Upstream Oil and Gas Industry

Solution

The expected interest cost on a sterling borrowing would be £645,161 @ 6% = £38,710

The actual cost of the US$ loan is:

Loan at the beginning of the year: US$1 million @ 1.55	645,161
Loan at the end of the year: US$1 million @ 1.50	666,667
Exchange loss	21,506
Interest paid: US$1 million @ 4% = $40,000 @ 1.5	26,667
TTtal	48,173
Interest on sterling equivalent	38,710
Difference	9,463

- ✓ The total actual cost of the loan exceeds the interest cost on a sterling equivalent loan by £9,463. Therefore, only £12,043 (£21,506 - £9,463) of the exchange difference of £21,506 may be treated as interest eligible for capitalisation under IAS 23.
- ✓ The correlation between the exchange rate and interest rate differential should be demonstrable and remain consistent over the life of the borrowing to continue to allow capitalisation of foreign exchange differences.

102

Revenue Recognition (IFRS 15)

Facilitator	Terkimbi
Time	15 minutes

IFRS issues Upstream Oil and Gas Industry

Overlift and underlift

- ✓ Overlift and underlift are in effect a sale of oil at the point of lifting by the underlifter to the overlifter.
- ✓ Overlift is treated as a purchase of oil by the overlifter from the underlifter.
- ✓ The sale of oil by the underlifter to the overlifter should be recognised at the market price of oil at the date of lifting .The overlifter should reflect the purchase of oil at the same value.
- ✓ Underlift by a partner is an asset in the balance sheet and Overlift is reflected as a liability.
- ✓ An underlift asset is the right to receive additional oil from future production without the obligation to fund the production of that additional oil. An Overlift liability is the obligation to deliver oil out of the entity’s equity share of future production.

Overlift and underlift

- ✓ The initial measurement of the Overlift liability and underlift asset is at the market price of oil at the date of lifting, consistent with the measurement of the sale and purchase. Subsequent measurement depends on the terms of the JV agreement. JV agreements that allow the net settlement of Overlift and underlift balances in cash will fall within the scope of IAS 39 unless the ‘own use’ exemption applies [IAS 39 para 5]. Overlift and underlift balances that fall within the scope of IAS 39 must be remeasured to the current market price of oil at the balance sheet date. The change arising from this remeasurement is included in the income statement as other income/expense rather than revenue or cost of sales.

- ✓ Overlift and underlift balances that do not fall within the scope of IAS 39 are measured at the lower of
  - ✓ carrying amount and current market value. Any remeasurement should be included in other income/expense rather than revenue or cost of sales.
  - ✓ The sale of oil by the underlifter to the overlifter should be recognised at the market

Recognition of underlift

How should underlift be accounted for where the imbalance is routinely net settled?

Background

Entity A and entity B jointly control a producing property. A has a 70% interest and B a 30% interest. At the start of the year there is no overlift or underlift.

During the first half of the year, production costs of US$7,500 are jointly incurred and 500 barrels of oil are produced. The cost of producing each barrel is therefore US$15. There is no production in the second half of the year.

During the first half of the year A has taken 300 barrels and B has taken 200 barrels. Each sold the oil they took at US$32 per barrel, the market price at the time. Entity A has underlifted by 50 barrels at year end and B has overlifted by 50 barrels. The market price of a barrel of oil at year end is US$35.

The joint venture agreement allows for net cash settlement of the overlift/underlift balance at the market price of oil at the date of settlement. Net settlement has been used by the JV partners in the past.

How should A account for the underlift balance?

Solution

- ✓ The underlift position represents an amount receivable by A from B in oil or in cash depending on the settlement mechanism selected. The value of the underlift position will change with movements in the oil price. A has the contractual right to demand cash for the underlift balance. The underlift balance is therefore a financial asset (receivable) which should be measured at amortised cost. Amortised cost should reflect A's best estimate of the amount of cash receivable. The best estimate will be the current spot price. The receivable is revised at each balance sheet date to reflect changes in the oil price.

- ✓ Entity A should recognise a sale to B for the volume that B has overlifted. The substance of the transaction is that A has sold the overlift oil to B at the point of production. The criteria set out in IAS 18 paragraph 14(a)-(e) are met and revenue should therefore be recognised by A.

IFRS issues Upstream Oil and Gas Industry

A's income statement and balance sheet:

		Interim, C		Full year / year end, C
Income statement				
Revenue	(500 * C32 * 70%)	11,200		11,200
Cost of sales	C7,500 * 70%)	(5,250)		(5,250)
Gross profit		5,950		5,950
Other income / (expense)		–	(50 * [35 – 32])	150
Net income		5,950		6,100
Balance sheet (extract)				
Underlift receivable	(50 * C32)	1,600	(50 * C35)	1,750

Onerous contracts

- ✓ The factors which give rise to an onerous contract would likely be an impairment trigger and lead toan impairment assessment under IAS 36
- ✓ Assessing the appropriate unit of account is important in the evaluation of such contracts.
- ✓ Contracts will be evaluated individually in certain cases (e.g. where an underlying purchase contract or lease of space is not expected to be needed).
- ✓ Contracts may be factored into the assessment of impairment for the overall cash generating unit in other cases.
- ✓ Considering whether an onerous contract should be provided for is often complex.

Onerous contracts

Illustrative example

- ✓ An oil and gas company entered into a fixed price long-term supply contract with a customer. The cost of extraction and/or production increases subsequently and the total cost to fulfil the contract is expected to exceed the contract price.

Solution

- ✓ An impairment trigger results. The cash flows from this contract will be factored into the value in use or fair value less cost of disposal of the underlying cash generating unit. It is unlikely that an onerous contract would exist in this scenario before the carrying amount of the underlying CGU is zero.

Presentation of revenue

- ✓ The factors which give rise to an onerous contract would likely be an impairment trigger and lead toan impairment assessment under IAS 36

Background

- ✓ Entity A conducts business through a variety of joint arrangements and is subject to various taxes. These are summarised below.

How would each of the following scenario's be recognized in the income statement?

IFRS issues Upstream Oil and Gas Industry

Presentation of revenue

Business Activity	Income statement	Other Comment
1. Jointly controlled assets: Entity A is responsible for selling its share of the oil produced from the jointly controlled assets.		
2. Jointly controlled entity: The JCE sells the oil produced and entity A receives its share of the profits earned by the JCE. The JCE represents 35% of entity A's operations. Entity A actively participates in the joint management of the JCE. Entity A applies equity accounting to JCEs.		
3. Royalty on product sold Entity A pays in kind 30% of the sales proceeds to the government for each litre of product sold.		

Presentation of revenue – Suggested solutions

Business Activity	Income statement	Other Comment
1. Jointly controlled assets: Entity A is responsible for selling its share of the oil produced from the jointly controlled assets.	Recognise revenue earned on the sale of share of oil.	The sales are made by entity A and meet the IAS 18 definition of revenue.
2. Jointly controlled entity: The JCE sells the oil produced and entity A receives its share of the profits earned by the JCE. The JCE represents 35% of entity A's operations. Entity A actively participates in the joint management of the JCE. Entity A applies equity accounting to JCEs.	Record share of profit earned by the JCE using equity accounting. Do not record revenue in respect of share of sales made by JCE.	Disclose JCE's revenues in notes to financial statements, together with other summary financial information.
3. Royalty on product sold Entity A pays in kind 30% of the sales proceeds to the government for each litre of product sold.	The royalty should be excluded from the revenue recognised by the entity [IAS18.8] i.e. if gross sales were C100, and the royalty was C10, the reported revenue would be C90.	The royalty collected by the entity is received on behalf of government. Entity A is acting as agent for the government.

102

Business Combinations (IFRS 3)

Facilitator	Terkimbi
Time	10 minutes

IFRS issues Upstream Oil and Gas Industry

Overview

- ✓ A business combination will usually result in the recognition of goodwill and deferred tax.
- ✓ If the assets purchased do not constitute a business, the acquisition is accounted for as the purchase of individual assets. The distinction is important because, in an asset purchase:
  - no goodwill is recognised;
  - deferred tax is generally not recognised for asset purchases (initial recognition exemption (IRE) in IAS 12 Income taxes does not apply to business combinations);
  - transaction costs are generally capitalised; and
  - asset purchases settled by the issue of shares are within the scope of IFRS 2 Share-based payments.

Difference between business combinations and purchase of assets

- ✓ IFRS 3 defines a business as “consisting of inputs and processes applied to those inputs that have the ability to create output”. All three elements – input, process and output – should be considered in determining whether a business exists.

Practical applications – Temperature Test

Conclude whether each the following is a business combination or an asset

Acquisition	Inputs	Processes	Outputs	Conclusion
Incorporated entity which has one asset in the early exploration phase but the group does not have a production licence yet. No proven reserves.				
Listed company with a portfolio of properties. Active exploration program in place and there are prospective resources. Company normally develops properties to production.				

IFRS issues Upstream Oil and Gas Industry

Acquisition	Inputs	Processes	Outputs	Conclusion
Listed company with a portfolio of properties. All exploration activities have been suspended and no properties have moved forward into development				
Listed company with a portfolio of properties. Active exploration program and prospective resources. Company's policy is to hold portfolio of properties and sell in and out of them after undertaking exploration. The company does not hold the properties to development.				

IFRS issues Upstream Oil and Gas Industry

Acquisition	Inputs	Processes	Outputs	Conclusion
Listed company. Property in development phase. Some reserves and resources.				
Producing asset owned by a listed company. Only the asset is purchased.				
Alliance with another company to develop a property.				

IFRS issues Upstream Oil and Gas Industry

Acquisition	Inputs	Processes	Outputs	Conclusion
Listed company with a portfolio of properties. All exploration activities have been suspended and no properties have moved forward into development	No inputs.	No processes, because there is not active exploration program in place.	There is no plan for further exploration and no development plans.	Judgment required
Listed company with a portfolio of properties. Active exploration program and prospective resources. Company's policy is to hold portfolio of properties and sell in and out of them after undertaking exploration. The company does not hold the properties to development.	Portfolio of properties with successful exploration activities and employees.	Exploration program	Exploration asset with associated resource information.	Judgement required.

IFRS issues Upstream Oil and Gas Industry

Acquisition	Inputs	Processes	Outputs	Conclusion
Incorporated entity which has one asset in the early exploration phase but the group does not have a production licence yet. No proven reserves.	No inputs, because the entity is at the exploration stage. Employees insignificant in number.	Exploration programme but no processes in place to convert inputs. No production plans.	There is no development plan yet and no planned production. The only potential output might be results of early exploration work.	Likely to be an asset, because there is a lack of the business elements (e.g. inputs, processes and outputs).
Listed company with a portfolio of properties. Active exploration program in place and there are prospective resources. Company normally develops properties to production.	Portfolio of properties and employees.	Exploration programme, O&G engineers and expertise, development programme, management and administrative processes.	Production has not begun: however, since there is an active portfolio, it might be that exploration results could be viewed as output. Consideration required as to whether market participant could produce outputs with the established inputs and processes.	Judgement required.

IFRS issues Upstream Oil and Gas Industry

Acquisition	Inputs	Processes	Outputs	Conclusion
Listed company. Property in development phase. Some reserves and resources.	O&G reserves and employees.	Operational processes associated with mineral production.	Revenues from O&G production.	Judgement required, but likely to be a business – all three elements exist.
Producing asset owned by a listed company. Only the asset is purchased.	O&G reserves and employees.	Operational processes associated with mineral production.	Revenues from O&G production.	Judgement required, but likely to be a business – all three elements exist. Although the 'asset' does not constitute an incorporated entity, it is a business.
Alliance with another company to develop a property.	None	None	None	Jointly controlled asset. Assets acquired do not meet the definition of a business.

Identifying a Business Combination

- ✓ Transactions could be purchase of shares, purchase of net assets, a new company that takes over existing businesses and restructuring of existing entities.
- ✓ A number of transactions linked together, or contingent on completion of each other, need to be considered as a whole.
- ✓ Focus is on substance of transactions and not the legal form .
- ✓ Exemptions to applying business combination accounting under IFRS are:
  - when the assets acquired do not constitute a business (as discussed above);
  - formation of a joint arrangement in the financial statements of the joint arrangement itself and
  - businesses that are under common control (where no change in ownership takes place).
- ✓ A business combination occurs when control is obtained. Both existing voting rights and capacity to control in the form of currently exercisable options and rights are considered in determining when control or capacity to control exists.

Accounting for Purchase of an Interest in a Producing Field

Should the acquisition of an interest in a producing field be accounted for as a business combination?

Background

There are three participants in a jointly controlled asset, Infinity, that is a business. The ownership interest of the participants is as follows:

Entity A	40%
Entity B	40%
Entity C	20%

The terms of the joint operating agreement (JOA) require unanimous approval of decisions relating to the development. The carrying value of the asset in entity A's financial statements is US$15 million.

Entity A purchases entity B's interest of 40%. It has paid consideration equivalent to its fair value of US$20 million. Entity A now holds 80% of the participating interest.

Should entity A account for this as a business combination?

Suggested Solution: Accounting for Purchase of an Interest in a Producing Field

Yes.

The producing field would represent a business.

Acquisition of an interest in a joint operation that is a business represents a business combination.

A fair value assessment would be performed of the ‘business’, and the company would consolidate its 60% share of this.

The total fair value of the asset has been assessed as US$50 million.

Entity A will recognise an asset of US$35 million, which consists of the US$20 million paid for entity B’s share and US$15 million for the carrying value of the 40% previously recognised.

The previously held interest is not remeasured, because the company retained joint control.

Deferred tax will also need to be considered.

Accounting for Purchase of Interest in a Non-Producing Field

Should the acquisition of an interest in a non-producing field be accounted for as a business combination?

Background

There are three participants in a jointly controlled asset, Omega, that is in the early exploration phase. A production licence has not yet been obtained. There are no proven reserves and no development plan in place. The ownership interest of the participants is as follows:

Entity A	40%
Entity B	40%
Entity C	20%

The terms of the joint operating agreement (JOA) require unanimous approval of decisions relating to the exploration. Entity A purchases entity C's interest of 20% and now holds 60% of the participating interest.

Should entity A account for this as a business combination?

Accounting for Purchase of Interest in a Non-Producing Field

Solution

- No.
- The field is in the early exploration phase.
- A production licence has not yet been obtained.
- There are no proven reserves and no development plan in place.
- The field is not a business.
- Acquisition of an interest in a joint operation that is not a business would represent an asset acquisition.
- The consideration for the interest will be capitalised, and no deferred tax or goodwill will arise.

Joint Arrangements

Facilitator	Terkimbi
Time	10 minutes

Joint Arrangements

- ✓ Widely used in Oil and gas setting

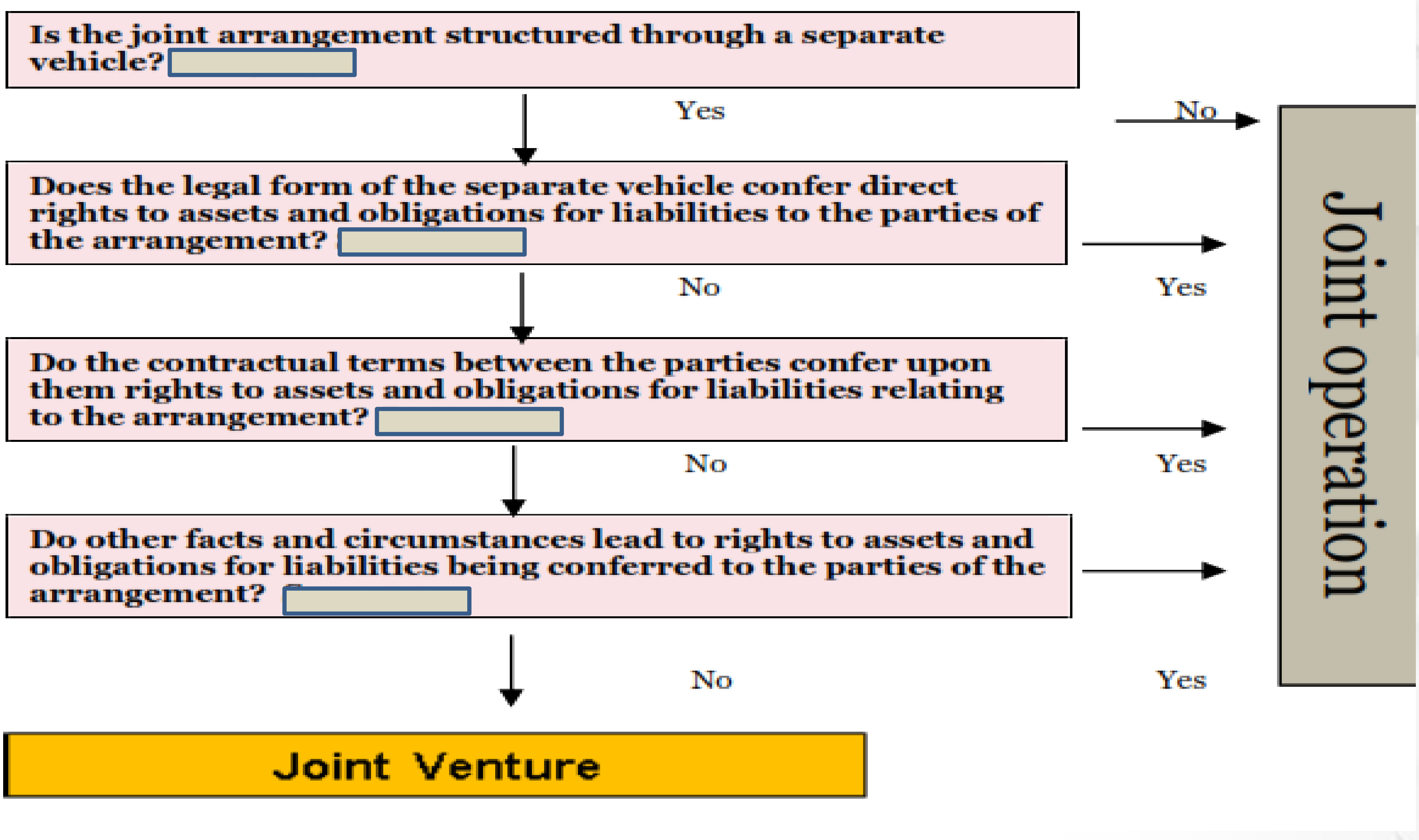
Term	IFRS 11 definition
Joint operation	Parties have rights to the assets and obligations for the liabilities relating to the arrangement
Joint venture	Parties have rights to the net assets of the arrangement

- ✓ Determining the classification of joint arrangements is a four - step process as shown below:

Indicators of a Joint Operations in a contractual relationship

- Rights to assets
  - The parties share all interests (e.g. rights, title or ownership) in the assets in a specified proportion (e.g. in proportion to the parties' ownership interest in the arrangement or in proportion to the activity carried out through the arrangement that is directly attributed to them).
- Obligations for liabilities
  - The parties share all liabilities, obligations, costs and expenses in a specified proportion as in the case of rights to assets.
- Revenues and expenses
  - Contractual arrangement establishes allocation of revenues and expenses on the basis of the relative performance of each party to the joint arrangement.
  - Parties may agree to share the profit or loss relating to the arrangement on the basis of a specified proportion such as the parties' ownership interest in the arrangement. This would not prevent the arrangement from being a joint operation if the parties have rights to the assets, and obligations for the liabilities, relating to the arrangement.

Classification of Joint Ventures



Indicators of a joint venture in contractual arrangements

Rights to assets

Generally the contractual terms establish that the assets acquired by the arrangement are those of the arrangement and the parties do not have any direct interests in the title or ownership of the assets.

Obligations for liabilities

The contractual terms establish that the arrangement is liable for the debts and obligation of the arrangement and that the parties are only liable to the extent of unpaid capital and guarantees. The creditors of the joint arrangement do not have a right of recourse against the joint venture parties.

Revenues and expenses

The contractual arrangement establishes each party's share in the net profit or loss relating to the activities of the arrangement.

Accounting for Joint Operations (JOs)

- ✓ Investors in a joint operation are required to recognise the following:
  - its assets, including its share of any assets held jointly;
  - its liabilities, including its share of liabilities incurred jointly;
  - its revenue from the sale of its share of the output arising from the joint operation;
  - its share of the revenue from the sale of the output by the joint operation;
  - its expenses, including its share of any expenses incurred jointly
- ✓ An investor should not additionally account for its shareholding in joint operations. It should account for the activity of the JO in its own financial statements.

Accounting for Joint Ventures (JVs)

- IFRS 11
  - requires equity accounting for all JVs.
  - Doesn't allow for choice between equity accounting and proportionate consolidation
- key principles of the equity method of accounting (IAS 28):
  - investment in the JV is initially recognised at cost;
  - changes in the carrying amount of investment are recognised based on the venturer's share of the profit or loss of the JV after the date of acquisition;
  - the venturer only reflects their share of the profit or loss of the JV; and
  - distributions received from a JV reduce the carrying amount of the investment.
- Results of the JV are are incorporated by the venturer on the same basis as the venturer's own results.
- Basis of accounting should be set out in the formation documents of the joint venture.

IFRS issues Upstream Oil and Gas Industry

102

Farm-Outs

Facilitator	Terkimbi
Time	5 minutes

IFRS issues Upstream Oil and Gas Industry

Accounting by the farmor

- ✓ Farm out agreements are largely non-monetary transactions at the point of signature
- ✓ No specific guidance exists in IFRS.
- ✓ Different accounting treatments have evolved as a response. The accounting depends on the specific facts and circumstances of the arrangement, particularly the stage of development of the underlying asset.

Assets with proven reserves

- Farm-in accounted for in accordance with the principles of IAS 16. The farm out will be viewed as an economic event, as the farmor has relinquished its interest in part of the asset in return for the farmee delivering a developed asset in the future. There is sufficient information for there to be a reliable estimate of fair value of both the asset surrendered and the commitment given to pay cash in the future.
- Rights and obligations of parties need to be understood while determining the accounting treatment.
- The consideration received by the farmor in exchange for the disposal of their interest is the value of the work performed by the farmee plus any cash received. This is presumed to represent the fairvalue of the interest disposed of in an arm's length transaction.

IFRS issues Upstream Oil and Gas Industry

Farm-Outs

Assets with no proven reserves

- Asset still subject to IFRS 6 Exploration for and evaluation of mineral resources rather than IAS 16.
- The reliable measurement test in IAS 16 for non-cash exchanges may not be met.
- Neither IFRS 6 nor IFRS 11 gives specific guidance on the appropriate accounting for farm outs.

Accounting by the farmee

- The farmee will only recognise costs as incurred, regardless of the stage of development of the asset.
- The farmee is required to disclose its contractual obligations to construct the asset and meet the farmor's share of costs.
- The farmee should follow its normal accounting policies for capitalisation, and also apply them to those costs incurred to build the farmor's share.

Farm-Outs

Background

Company N and company P participate jointly in the exploration and development of an oil and gas deposit located in Venezuela. Company N has an 18% share in the arrangement, and company B has an 82% share. Companies N and P have signed a joint arrangement agreement that establishes the manner in which the area should operate. N and P have a joint operation under IFRS 11. The assets of the joint operation comprise the oil and gas field, machinery and equipment.

There are no proven reserves.

The companies have entered into purchase and sale agreements to each sell 45% of their participation to a new investor – company R. Company N receives cash of C4 million and company P receives cash of C20 million. The three companies entered into a revised 'joint development agreement' to establish the rights and obligations of all three parties in connection with the funding, development and operations of the asset.

IFRS issues Upstream Oil and Gas Industry

	Company N	Company P	Company R	Total
Before transaction	18%	82%	–	100%
After transaction	10%	45%	45%	100%
Cash received	C4 million	C20 million	–	C24 million

Each party to the joint development agreement is liable in proportion to their interest for costs subsequent to the date of the agreement. However, 75% of the exploration and development costs attributable to companies N and P must be paid by company R on their behalf. The total capital budget for the exploration and development of the asset is C200 million. Company N's share of this based on its participant interest would be C20 million; however, company R will be required to pay C15 million of this on behalf of company N.

The carrying value of the asset in Company N's financial statements prior to the transaction was C3 million.

Question

How should company N account for such transaction?

How should company N account for such transaction?

IFRS issues Upstream Oil and Gas Industry

Solution

This transaction has all the characteristics of a farm out agreement. The cash payments and the subsequent obligation of company R to pay for development costs on behalf of companies N and P appear to be part of the same transaction. Companies N and P act as farmors and company R acts as the farmee. The structure described is a joint operation. Company N should account for its share of the assets and liabilities and share of the revenue and expenses.

IFRS issues Upstream Oil and Gas Industry

The gain on disposal could be accounted for by company N using one of three approaches, as follows:

1. Recognise only cash payments received.

Company N will reduce the carrying value of O&G asset by the C4 million cash received. The C1 million excess over the carrying amount is credited to the income statement as a gain. The C15 million of future expenditure to be paid by company R on behalf of company N is not recognised as an asset. As noted above, this approach would be consistent with common industry practice.

2. Recognise cash payments plus the value of the future assets at the agreement date.

Company N will recognise the C4 million as above. In addition, it will recognise a 'receivable' or intangible asset for the future expenditure to be incurred by company R on company N's behalf, with a further gain of this amount recognised in the income statement. Company N would have to assess the expected value of the future expenditure. Although one method to estimate this would be the budgeted expenditure of C15 million, company N would need to assess whether this would be the actual expenditure incurred. Any difference in the final amount would require revision to the asset recognised and also the gain, creating volatility in the income statement.

3. Recognise cash payment plus the value of future assets received when construction is completed.

Company N will recognise the C4 million cash received as in '1.' above. When the future assets are completed, these are recognised in the balance sheet, and a gain of the same amount is recognised in the income statement. This approach would avoid the volatility issue associated with approach '2'.

102

Unitisation

Facilitator	Terkimbi
Time	5 minutes

Unitisation agreements

- Entities that own straddling assets or exploration rights in adjacent areas enter into a contract to combine these into a larger area and share the costs of exploration, development and extraction.
- Often required by governments to reduce the overall cost of extraction through a more efficient deployment of infrastructure.
- share of output allocated to each participant will depend on the contribution their existing asset made to the total production of this area. This is known as a ‘unitization
- preliminary assessment of the allocated interest is made on the initial unitisation and the entity will be responsible for future expenditure for the area in accordance with its allocated interest.
- interest subsequently amended as more certainty is obtained and redeterminations are made.
- Adjustments to future production entitlement or cost contributions may be made accordingly

Unitisation Agreements

- Cash payments may be made between the participants where there is insufficient production or development remaining to true up contributions to date.
- The initial unitisation is accounted for as a contribution of assets. No change is recorded in the carrying amount of existing interests unless cash payments have been made on unitization
- The unitisations and redeterminations will also affect the relevant reserves base to be used for the purposes of the DD&A calculation

Redetermination of a unitization

How should an entity account for a redetermination of a unitisation?

Background:

Company A and B owned the adjoining oil prospects Alpha and Delta respectively. Both prospects were in the exploration phase with no proven reserves. The companies entered into an agreement to develop the prospects jointly and the combined area, Omega, which is considered to be a joint operation.

The initial unitisation agreement stated that each was entitled to 50% of the output of the combined area. This allocation was subject to future redetermination when the exploration of Alpha and Delta was complete and proven reserves were determined. Additional redetermination would take place on an ongoing basis after that as production commenced and reserve estimates were updated.

The exploration of the two prospects was completed. Both were found to have proven reserves and based on these results the following redetermination was performed:

IFRS issues Upstream Oil and Gas Industry

	Company A	Company B	Total
Initial unitisation	50%	50%	100%
Redetermination	40%	60%	100%
Exploration cost to date	$5 mln	$5 min	$10 mln
Future development expenditure			$40 mln

The companies have agreed that they will take a share of future production in line with the new determination of interests. Additionally, the true-up of costs incurred to date will be made via adjustments to future expenditure rather than an immediate cash payment.

Prior to redetermination company A had capitalised the $5 million cost incurred as an exploration asset, and transferred this to tangible assets when proven reserves were discovered.

How should company A account for this redetermination?

IFRS issues Upstream Oil and Gas Industry

Suggested Solution

Company A has incurred expenditure of $1 million greater than the share required by the revised allocation of interest. In theory, it has a $1 million receivable from company B. The agreement between the companies indicates that this will be trued-up via adjustment to future development expenditure i.e. company A will only be responsible for $15 million of future spend rather than $16 million ($40 million*40%). It would be appropriate for company A to retain this $5 million asset as a development asset with no adjustment for the $1 million. It should consider whether the change in the reserve estimates indicates any impairment has occurred in the carrying value of the asset. Based on the revised share of future production and the development costs still to come,
impairment would be unlikely.

102

Production Sharing Arrangements

Facilitator	Terkimbi
Time	15 minutes

IFRS issues Upstream Oil and Gas Industry

Overview

- ✓ The legal form of the PSA or concession should not impact the principles underpinning the recognition of exploration and evaluation (E&E) assets or production assets.
- ✓ Costs that meet the criteria of IFRS 6, IAS 38 or IAS 16 should be recognised in accordance with the usual accounting policies where the entity is exposed to the majority of the economic risks and has access to the probable future economic benefits of the assets.

Entity bears the exploration risk

Cost capitalization

- ✓ Capitalise expenditure in the exploration and development phase in accordance with the requirements of IFRS 6, IAS 16 and IAS 38.
- ✓ The reserves used for depreciating the constructed assets should be those attributable to the reporting entity for the period of the PSA or concession.
- ✓ The probable hydrocarbon resources and current prices should provide evidence that E&E, development and fixed asset investment will be recovered during the concession period.
- ✓ A PSA is a separate CGU for impairment testing purposes once in production.
- ✓ Impairment testing is IFRS 6 for E&E phase and IAS 36 for Development & Production phases

Offshore Field PSA for 25 years

The legal form of the PSA should not impact the recognition of exploration and evaluation (E&E) assets or production assets. How should those assets be accounted for?

Background

Entity A is party to a PSA related to an offshore field. The term of the agreement is 25 years. Entity A will operate the assets during the term of the PSA but the government retains title to the assets constructed. A is entitled to full cost recovery. However, if the resources produced in the future do not cover the costs incurred, the government will not reimburse A.

Entity A’s management proposes to account for the expenditure as a financial receivable rather than as property, plant and equipment because the government is retaining the title of the assets constructed. Is this appropriate?

Solution - Offshore Field PSA for 25 years

No.

Entity A controls the assets during the life of the PSA through its right to operate them. The construction costs that meet the recognition criteria of IFRS 6, IAS 38 or IAS 16 should be recognised in accordance with those standards:where the entity is exposed to the majority of the economic risks and has access to the probable future economic benefits of the assets; and the period of the PSA is longer than the expected useful life of the majority of the constructed assets; and the probable mineral resources at current prices provide evidence that E&E, development and fixed asset investment will be recovered through the cost recovery regime of the PSA.

All assets recognised are then accounted for under entity A's usual policies for subsequent measurement, depreciation, amortisation, impairment testing and de-recognition. The assets should be fully depreciated or amortised on a units-of-production basis by the date that the PSA ends.

Revenue Recognition

- ✓ In PSAs where an entity bears the exploration risk, it will record its share of oil or gas as revenue (both cost oil and profit oil) only when the oil or gas is produced and sold.
- ✓ The entity records revenue only when oil production commences and only to the extent of the oil to which it is entitled and sells. Oil extracted on behalf of a government is not revenue or a production cost. The entity acts as the government's agent to extract and deliver the oil or sell the oil and remit the proceeds.
- ✓ An entity follows the same approach to revenue recognition for royalty agreements

IFRS issues Upstream Oil and Gas Industry

Background

The upstream company (or contractor) typically bears all the costs and risks during the exploration phase. The government (or the government-owned oil company) shares in any production. The upstream company generally receives two components of revenue; cost oil and profit oil. Cost oil is a ‘reimbursement’ for the costs incurred in the exploration phase and some (or all) of the costs incurred during the development and production phase. Profit oil is the company’s share of oil after cost recovery or as a result of applying a profit factor

The PSA typically specifies, among other items, which costs are recoverable, the order of recoverability, any limits on recoverability, and whether costs not recovered in one period can be carried forward into a future period. Total revenue of the PSA is recognised upon the delivery of the volumes produced to a third party (i.e. the purchaser of the volumes) based on the price as set forth in the PSA. The price could be either a market-based price or a fixed price depending on the specific terms of the PSA. The revenue of the PSA is then split between the parties based on the specific sharing terms of the PSA. The formation of a PSA does not commonly create an entity that would qualify as a joint venture under IFRS.

The issue is not usually recognition of revenue – the oil has been delivered to third parties and the criteria in IAS 18 paragraph 14 are met. The question is how the revenue from oil sold should be split between the operator, the government oil company and any others.

IFRS issues Upstream Oil and Gas Industry

Solution

The operator is entitled to the oil it has earned as reimbursement for costs (exploration and its share of development and production) and its share of profit oil. The government's share of oil does not form part of revenue even if the operator collects the funds and remits them to the government oil company. Any royalties or excise taxes that are collected on behalf of the government or any other agency of the state do not form revenue of the operator because of the explicit guidance in IAS 18 paragraph 8.

Entity bears the Contractual Performance Risk

Cost capitalization

- Capitalise E&E and development costs,
- Costs of constructing the fixed assets are capitalised but not classified as PPE but receivable from the government where it is allowed to retain oil extracted to the extent of costs incurred plus a profit margin in line with IAS 39/IFRS 9 rather than IAS 16.

Impairment assessment

- Asset accounted as a receivable so impairment testing rules on financial assets in IAS 39/IFRS 9 would be applicable.

Revenue recognition

- If the entity bears the risks of performing the contract rather than the actual exploration activity, expenditure incurred on the exploration and development of the asset is capitalised as a receivable from the government rather than as a fixed asset. When the outcome of the contract can be reliably estimated, the percentage of completion method will be used to determine the amount of revenue to be recognised. The expected profit margin will be included in this calculation.

Entity bears the Contractual Performance Risk

Background

Government ‘V’ believes they might find oil reserves on the western coast of the country, designated ‘Beta’. After the process, entity ‘A’ was awarded with the offshore block. The government and company A signed a 15-year PSA to explore, develop and exploit this block under the following terms:

- Company ‘A’ will undertake exploration, development and production activities.
- Government ‘V’ will remunerate A for performance of the contracted construction services regardless of the success of the exploration and hold title to the assets constructed.
- National law indicates that the title of all hydrocarbons found in the country remains with government ‘V’.
- Government ‘V’ will reimburse for all expenditures incurred by company ‘A’ at the following milestones: - Completion of seismic study programme
    - ✓ Approval of exploration work programme
    - ✓ Completion of development work programme
    - ✓ Commencement of commercial production

Entity bears the contractual performance risk

Background

- Reimbursement is based on approved costs incurred plus an uplift of 5%.
- Reimbursement will be performed in the form of oil produced. Quantities provided will be based on market price. Where insufficient quantities are produced, the government can settle the amount due in cash or oil from another source.

How will entity ‘A’ recognise revenue on this project?

Entity bears the contractual performance risk

Solution

The terms of the agreement are such that company A carries a ‘contract performance’ risk rather than bearing the risk of exploration. Accordingly, costs will be capitalised as a recoverable from the government. There are multiple performance obligations within the agreement, and the company can only recognise revenue as each of these obligations is achieved. As the terms provide that approved costs can be recovered with a 5% uplift, the company will initially carry the costs incurred as work in progress. When the entity is able to reliably estimate the outcome of the contract, it may use the percentage of completion method to recognise revenue, which will include the expected uplift of 5% on costs incurred.

102

Decommissioning (Assets Retirement Obligations)

Facilitator	Terkimbi
Time	5 minutes

Decommissioning – IAS 37

- An entity that promises to remediate damage or has done so in the past, even when there is no legal requirement, may have created a constructive obligation and thus a liability under IFRS

Decommissioning provisions

- A provision is recognised when an obligation exists to perform the clean-up].
- Legal regulations should be taken into account when determining the existence and extent of the obligation.
- Obligations to decommission or remove an asset are created at the time the asset is put in place.
- Some diversity in practice as to whether the entire expected liability is recognised when activity begins, or whether it is recognised in increments as the development activity progresses.
- also diversity in whether decommissioning liabilities are recognised during the exploration phase of a project.
- The asset and liability recognised at any particular point in time needs to reflect the specific facts and circumstances of the project and the entity's obligations.

Revisions to Decommissioning Provisions

- Decommissioning provisions are updated at each balance sheet date for changes in the estimates of the amount or timing of future cash flows and changes in the discount rate [IAS 37 para 59].
- Changes to provisions that relate to the removal of an asset are added to or deducted from the carrying amount of the related asset in the current period [IFRIC 1 para 5]
- The asset cannot decrease below zero and cannot increase above its recoverable amount [IFRIC 1 para 5]:
  - if the decrease in provision exceeds the carrying amount of the asset, the excess is recognised immediately in profit or loss;
  - adjustments that result in an addition to the cost of the asset are assessed to determine if the new carrying amount is fully recoverable or not. An impairment test is required if there is an indication that the asset may not be fully recoverable.
- The accretion of the discount on a decommissioning liability is recognised as part of finance expensein the income statement.

Deferred tax on decommissioning provisions

- consistent policy should be adopted for deferred tax accounting for decommissioning liabilities and finance leases [IAS 8 para 13].

Decommissioning funds

- IFRIC 5 Rights to interests arising from decommissioning, restoration and environmental rehabilitation funds provides guidance on the accounting treatment for these funds in the financial statements of the oil and gas entity.
- Management must recognise its interest in the fund separately from the liability to pay closure and environmental costs.
- Offsetting is not appropriate unless the contributor is not liable to pay decommissioning costs even if the fund fails to pay.
- Any movements in a fund accounted for as a reimbursement are recognised in the income statement.
- The movements in the fund (based on the IFRIC 5 measurement) are assessed separately from the measurement of the provision (under IAS 37).

Accounting for Performance Guarantees

Background

In Ukraine, upstream gas entity A's subsidiary has recognised a closure and rehabilitation provision in respect of an abandonment liability for a field. .Entity A has also been required by law to place a parental performance guarantee equivalent to the estimated total amount required to fulfil the abandonment liabilities at the end of the life of the field it operates.

How should entity A account for this performance guarantee?

Solution

The performance guarantee should be disclosed in the consolidated financial statements as security for the obligation. The related decommissioning liability has already been accounted for under IAS 37.

We'll resume our meeting in:

60 Minutes

We'll resume our meeting in:

59 Minutes

We’ll resume our meeting in:

58 Minutes

We'll resume our meeting in:

57 Minutes

We’ll resume our meeting in:

56 Minutes

We'll resume our meeting in:

55 Minutes

We’ll resume our meeting in:

54 Minutes

We'll resume our meeting in:

53 Minutes

We’ll resume our meeting in:

52 Minutes

We’ll resume our meeting in:

51 Minutes

We’ll resume our meeting in:

50 Minutes

We'll resume our meeting in:

49 Minutes

We'll resume our meeting in:

48 Minutes

We'll resume our meeting in:

47 Minutes

We’ll resume our meeting in:

46 Minutes

We'll resume our meeting in:

45 Minutes

We'll resume our meeting in:

44 Minutes

We’ll resume our meeting in:

43 Minutes

We'll resume our meeting in:

42 Minutes

We’ll resume our meeting in:

41 Minutes

We’ll resume our meeting in:

40 Minutes

We’ll resume our meeting in:

39 Minutes

We’ll resume our meeting in:

38 Minutes

We'll resume our meeting in:

37 Minutes

We'll resume our meeting in:

36 Minutes

We'll resume our meeting in:

35 Minutes

We'll resume our meeting in:

34 Minutes

We'll resume our meeting in:

33 Minutes

We’ll resume our meeting in:

32 Minutes

We'll resume our meeting in:

31 Minutes

We'll resume our meeting in:

30 Minutes

We’ll resume our meeting in:

29 Minutes

We’ll resume our meeting in:

28 Minutes

We’ll resume our meeting in:

27 Minutes

We'll resume our meeting in:

26 Minutes

We’ll resume our meeting in:

25 Minutes

We’ll resume our meeting in:

24 Minutes

We’ll resume our meeting in:

23 Minutes

We’ll resume our meeting in:

22 Minutes

We’ll resume our meeting in:

21 Minutes

We'll resume our meeting in:

20 Minutes

We'll resume our meeting in:

19 Minutes

We'll resume our meeting in:

18 Minutes

We’ll resume our meeting in:

17 Minutes

We'll resume our meeting in:

16 Minutes

We'll resume our meeting in:

15 Minutes

We’ll resume our meeting in:

14 Minutes

We’ll resume our meeting in:

13 Minutes

We'll resume our meeting in:

12 Minutes

We'll resume our meeting in:

11 Minutes

We'll resume our meeting in:

10 Minutes

We’ll resume our meeting in:

9 Minutes

We'll resume our meeting in:

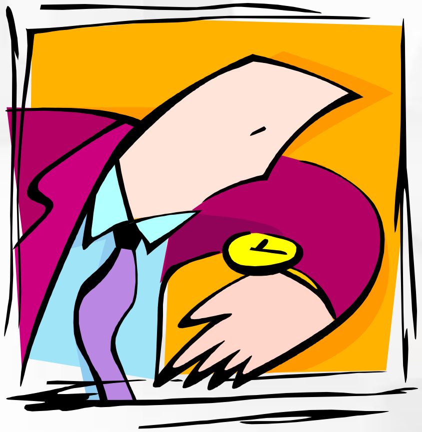
8 Minutes

We’ll resume our meeting in:

7 Minutes

We’ll resume our meeting in:

6 Minutes

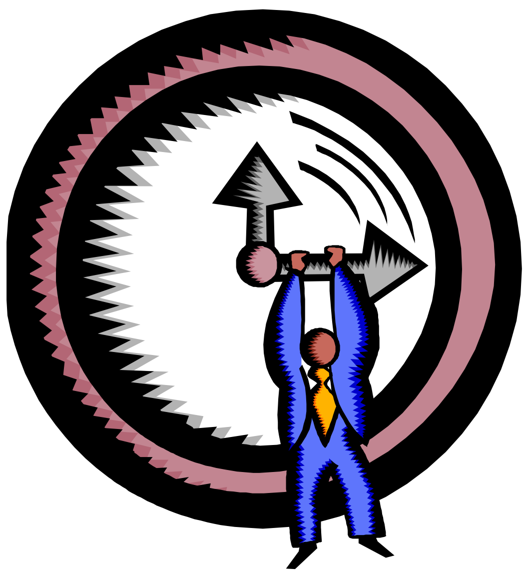


We’ll resume our meeting in:

5 Minutes

We’ll resume our meeting in:

4 Minutes

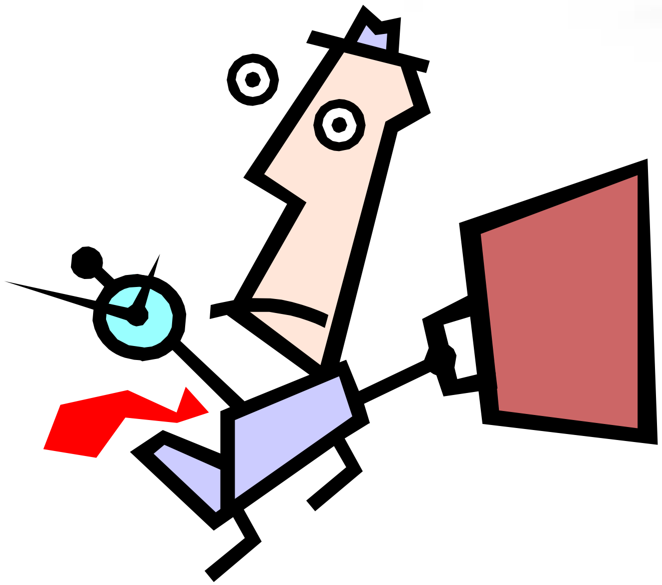


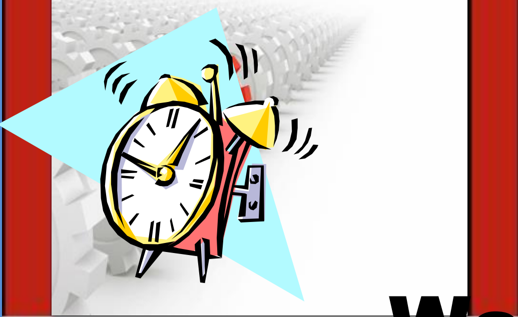
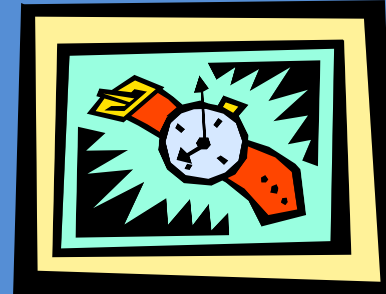
We'll resume our meeting in:

3 Minutes

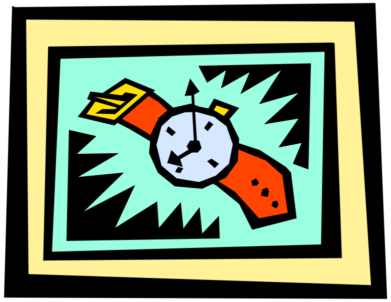
We'll resume our meeting in:

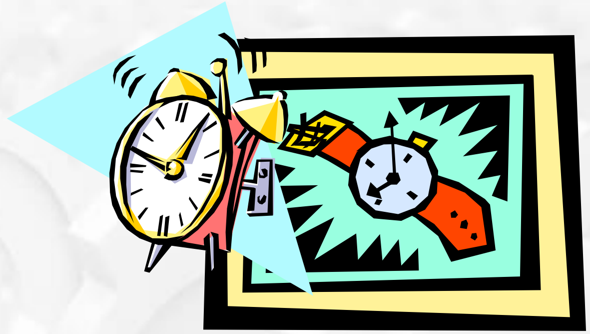
2 Minutes



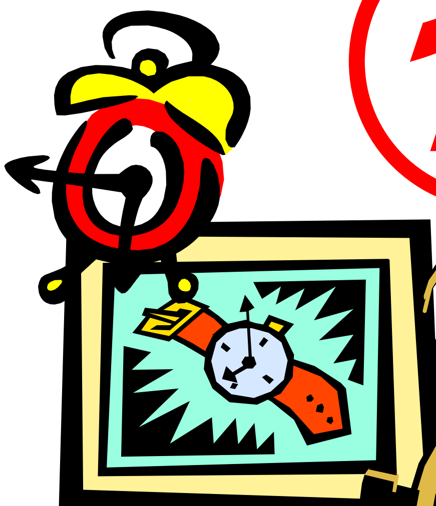
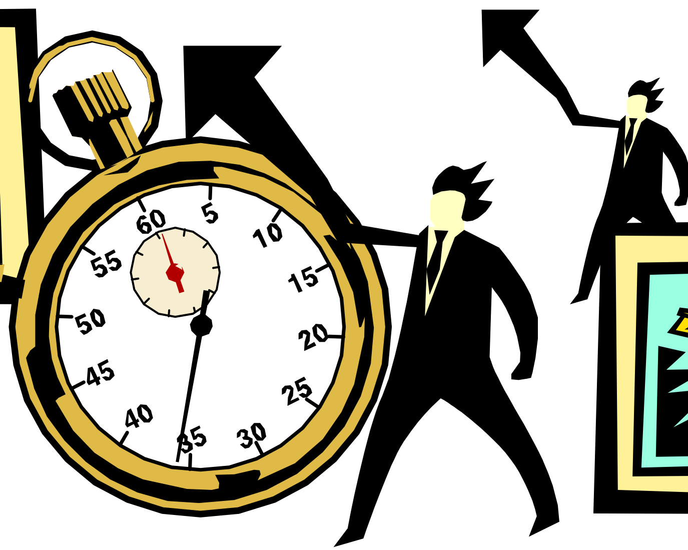



We’ll resume our meeting in:





1 Minute


Accounting issues: Pre-FID, Post-FID & Operate Phases

Section 3

- Overview of Opportunity Maturation Process
- Pre-FID & Post FID Issues
- Operate phase issues
- Movables

Accounting issues: Pre-FID, Post-FID & Operate Phases

102

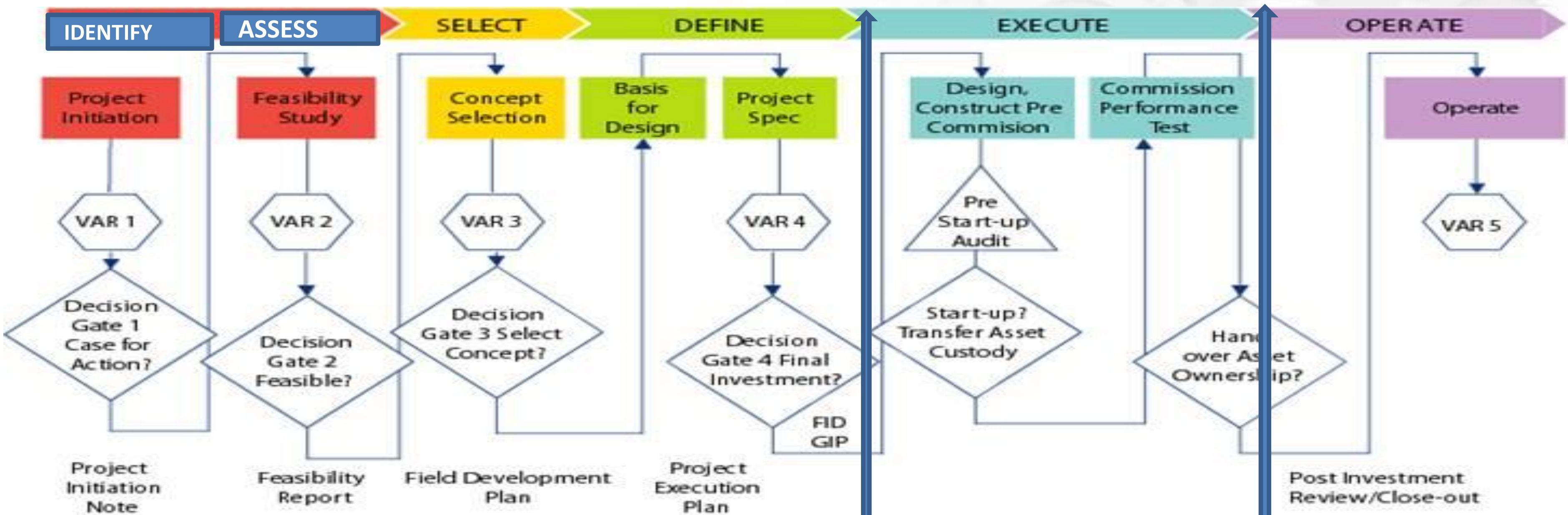
Overview of Opportunity Maturation Process

Facilitator	Terkimbi
Time	10 minutes

Accounting issues: Pre-FID, Post-FID & Operate Phases

Overview of Opportunity Maturation Process

The different stages of a project are as shown:



Pre-FID Costs ⟷ | Post-FID Costs ⟷ | Operating Costs ⟷

General Rule - **EXPENSE**, | **CAPITALIZE** | **EXPENSE**

Accounting issues: Pre-FID, Post-FID & Operate Phases

102

Pre-FID Phases (Identify, Assess, Select and Define)

Facilitator	Terkimbi
Time	3 minutes

Accounting issues: Pre-FID, Post-FID & Operate Phases

Pre-FID - Identify, Assess, Select and Define

- ✓ All costs incurred to drill and equip
  - ✓ Development wells,
  - ✓ Development-type stratigraphic test wells, and
  - ✓ Service wells

  are field development costs and are to be capitalised, regardless whether the well is successful or unsuccessful / gives rise to additional proved developed or proved undeveloped reserves.

- ✓ Cost of long lead items procured in anticipation of securing Final Investment Decision (FID)

Accounting issues: Pre-FID, Post-FID & Operate Phases

102

Post-FID - Execute

Facilitator	Terkimbi
Time	5 minutes

Accounting issues: Pre-FID, Post-FID & Operate Phases

Post-FID - Execute

- ✓ Starting point for capitalization is when proved reserves are booked.
- ✓ Costs incurred to correct design errors are to be expensed
- ✓ costs incurred in the replacement of identical insurance spares are charged to the P&L
- ✓ Costs incurred in the replacement of identical spare capacity and stand-by equipment are charged to the P&L
- ✓ Cost incurred in the asset start-up phase which are charged to the P&L:
  - Process materials supplied during commissioning that contribute towards production.
  - Replacement of process materials.
  - Pre-production training of operations personnel
  - First year operating spares (as opposed to insurance spares
- ✓ Following Joint Venture agreements) capital projects may attract general overhead, but administrative – or general overhead of the company are expensed.
- ✓ Demolition of existing Sites where there are no plans to replace the facilities
  - Expenditure is classified as abandonment costs and can therefore be booked against the abandonment provision
  - If there is no such provision, these demolition costs are expensed.

Accounting issues: Pre-FID, Post-FID & Operate Phases

102

Operate Phase - Production

Facilitator	Terkimbi
Time	10 minutes

Accounting issues: Pre-FID, Post-FID & Operate Phases

- ✓ If the intended purpose and the actual results of the subsequent expenditure represent a functional addition or enhancement (betterments as defined below) to the asset unit, the costs should be capitalised assuming they are above the minimum capital threshold identified.
- ✓ Assuming no change in technology (as defined below), the general rule is that expenditures, which represent a 'betterment' of an asset unit when compared against the assets units’ original specification, should be capitalised.
- ✓ Expenditures that increase the proved developed reserves of a field, including those directly related to bringing on-line those reserves that were previously matured to proved developed pending future development activity;
- ✓ Expenditures that increase an asset’s life over the original designed service life;
- ✓ Expenditures incurred to meet changed governmental rules with respect to the asset’s performance, i.e. safety or environmental requirements (costs incurred in the maintenance of existing governmental requirements are charged to the P&L);

Accounting issues: Pre-FID, Post-FID & Operate Phases

- ✓ Expenditures that increase operational performance of the asset unit above the original installed production capacity;
- ✓ Expenditures that decrease normal operating costs of the asset unit beyond the original standard of performance;
- ✓ Expenditures which enhance the product quality associated with the asset unit compared to its original design. The unit of measurement will vary depending on the asset unit.
- ✓ Expenditures that change the nature of an asset or change its original use (for example, from flowing to pumping or gas lift or from producing to injection for secondary recovery)

Workovers

- ✓ If a well has not been perforated or did not produce, the remedial activities undertaken to get production would be regarded as a continuation of the development process and should be capitalised.

Multi purpose sidetrack / workover

- ✓ Additional, incremental costs for the sidetrack drilling to give access to newly developed reserves as under (B) are to be capitalised

Accounting issues: Pre-FID, Post-FID & Operate Phases

Remedial sidetrack

- ✓ Remedial sidetracks are capitalised when expected to result in an increase in proven developed reserves.
- ✓ If a well as resulted in the removal of associated reserves from the proven developed category, any sidetrack to re-access these reserves will therefore be developing new reserves and is to be capitalised.

Replacement of wells

- ✓ Wells drilled with the purpose of replacing a failing well, regardless of whether or not proven developed reserves are expected to increase, are capitalised (treatment in line with all new wells drilled in development areas, including dry holes).

Multi purpose sidetrack / workover

- ✓ Additional, incremental costs for the sidetrack drilling to give access to newly developed reserves as under (B) are to be capitalised

Plug and Abandon

- ✓ On occasion it may be needed to abandon a particular wellbore zone or structure in order to perform other operations (i.e. new sidetrack). If a well is abandoned with the intention of reusing the slot for a new well, then the abandonment costs and slot recovery follow the accounting treatment of the new well

Accounting issues: Pre-FID, Post-FID & Operate Phases

Well deepening and converting a well

- ✓ Considered an addition or extension (and therefore capitalised)
- ✓ If re-completion adds to proved, developed reserves or if such re-completion aims to bring on-line the reserves that were previously matured to proved developed pending future development activity.
- ✓ Cost of converting oil/gas production wells that are taken off-production to water production wells or formation-water disposal wells (water injection wells) are also capitalised.

Replacement and renewal of assets

- ✓ Costs incurred in the replacement or renewal of an existing asset unit in its entirety are capitalised..

Alterations and modifications:

- ✓ Cost of the re-siting of a pipeline, or part thereof, that is carried out at the same time as other changes (e.g. the provision of additional protection by burying or supporting on sleepers) the costs of the respective operations are separated and treated in accordance with the principles for additions, replacements or alterations.

102

Operate Phase - Movables

Facilitator	Terkimbi
Time	10 minutes

Accounting issues: Pre-FID, Post-FID & Operate Phases

Overview

- In determining whether or not small movable items should be capitalised it is important to consider what the minor asset actually is.
- A component purchased for USD200 would normally not be capitalised. However if it can only be used in conjunction with other items, the purchased component and the other items should be taken in totality when determining if the asset should be capitalised or not.

Computing and Software costs

- Per intangible assets other than Goodwill

Research and Development

- Per Intangible Assets other than Goodwil
- ‘Development’ refers to “the application of research findings or other knowledge to a plan or design for the production of new or substantially improved materials, devices, products, processes, systems or services before the start of commercial production or use

Evaluating Performance of Oil and Gas Company

Section 4

- Importance of Balance Sheet of Upstream Oil and gas
- Measuring Performance
- Understanding Scorecard Architecture

Evaluating Performance of Oil and Gas Company

102

Why Balance Sheet of Upstream Oil & Gas Company Matter?

Facilitator	Terkimbi
Time	5 minutes

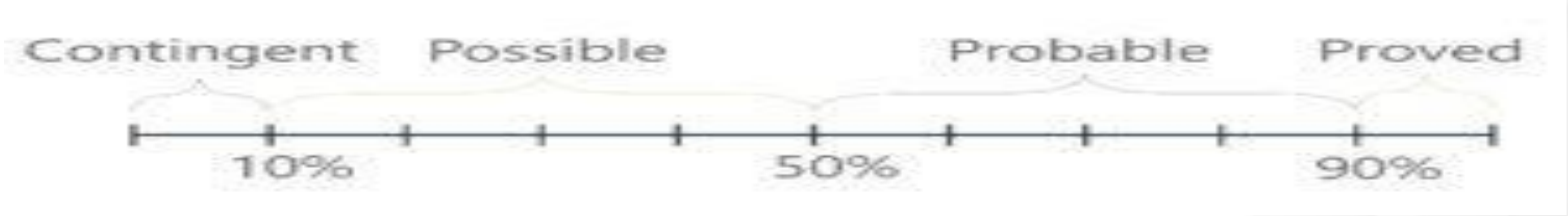
Evaluating Performance of Oil and Gas Company

Why Balance Sheet of Upstream Oil & Gas Company Matter?

- Key items that show up on oil and gas company balance sheets include proved reserves, probable reserves, possible reserves, asset retirement obligation, and the derivative fair value items.
- They are important when assessing and comparing oil and gas companies and can be used to better understand the individual company.

Proved, Probable, and Possible Reserves

Proved reserves, probable reserves, and possible reserves refer to the potential crude oil that can be extracted by an oil and gas company.



- Proved reserves: Greater than 90% probability of recovery
- Probable Reserves: Between 50% and 90% probability of recovery
- Possible Reserves: Between 10% and 50% probability of recovery
- Contingent Reserves: Less than 10% probability of recovery

The three-line items above are classified as a long-term asset and show up on the balance sheet under property, plant, and equipment.

Evaluating Performance of Oil and Gas Company

Asset Retirement Obligation (ARO)

- legal obligation to clean up, shut down, or retire a long-lived asset
- activities include:
    - The removal of any production equipment
    - The removal of facilities at each oil well site
    - The restoral of surface land to its original state prior to extraction
- recorded in the period in which it is incurred if a reasonable approximation of the fair value can be made. - acquisition or during construction.
- If a reasonable approximation cannot be made,, then ARO recorded when it can be approximated.
- Shows up in the balance sheet under long-term liabilities.

Derivative Fair Value

- a very commonly seen item on oil and gas company balance sheets.
- include forwards, futures, and options.
- Derivative fair value line can be either an asset or a liability.
    - If a company has hedged its position and has entered into a derivative contract to sell at a set price, the derivative fair value item will show up as an asset.
    - If a company has hedged its position and entered into a contract to buy at a set price, the derivative fair value item will show up as a liability.

Evaluating Performance of Oil and Gas Company

Why are Oil and Gas Company Balance Sheet Items Important?

- Since such companies are very dependent on the finite resource they are extracting, assessing the availability and probability it can be extracted at can help give a proxy to the company valuation. For example, when screening companies, one may look at how many proved reserves they own. Reserves can also be made into valuation multiples to compare different companies.
- Understanding the asset retirement obligation is also very important in assessing an oil and gas company. The asset retirement obligation line item can be monitored over time to determine the costs of retiring the facilities that are constructed over the period of extraction. If a known number of facilities or equipment will be used for future extraction, understanding the line item can help forecast the future costs of the company.
- Finally, identifying and assessing the derivative fair value items that may be present on the company balance sheets can give an idea as to how hedged the company's position may be. It can be a component that factors into the risk profile of a company. It can also be an indicator of how prices are capped at a company, i.e., in situations where oil prices increase dramatically.

Evaluating Performance of Oil and Gas Company

Measuring Performance

102

Facilitator	Terkimbi
Time	5 minutes

Evaluating Performance of Oil and Gas Company

Key result Areas for an Oil and gas company

1. Return on Capital Employed (ROCE)

Indicator measures the company efficiency with which the capital is employed to generate income and earnings (not only the current year but future earnings).

Upstream oil and gas is a capital-intensive business, from acquisition, exploration, development and production.

2. Cash Margin/Operating Cash per barrel/boe

The performance indicator measures company operational efficiencies (cash flow from operating activities) to produce a barrel of oil or gas (oil equivalent) and generate $1 of revenue on entitlement basis, excluding working capital and non operational expenses and special items.)

Key result Areas for an Oil and gas company

3. **Free Cashflow Generation**
   Measures how effective the company is controlling its expenditure- both operating and capital expenditure and provides which cost needs to be controlled such as variable cost- (volume vs. price) The indicator that basically challenge company to achieve more with less- via cost savings.

4. **Per boe Finding Cost and Development Cost**
   Measures unit exploration cost and development cost for every proved reserves added during the period.

5. **Reserves Replacement rates**
   Measures the company's ability to replace its reserves consumed in production and is a measure of long term sustainability of the company

Evaluating Performance of Oil and Gas Company

Key result Areas for an Oil and gas company

6. Total Shareholders Return

- Indicator measures how share price reacts as a result of both external and internal factors such as macro and micro-economics that effect demand and supply, geopolitical situations that may effect the oil price.
- In addition, internal factors within the organisation i.e.operational and financial such as project delivery including exploration success, production target, reserve addition, plant availability, HSE performance and financial indicators also have effect on the share price movement during the year.
- Key Performance Indicators to be monitored and eventually reported to the stakeholders. It is very important also what to develop indicators that are meaningful, provide insights to the investors and that benchmark among the peers can be conducted to know where the company stands among the peers, and be the darling of the investors.

102

Understanding Scorecard Architecture

Facilitator	Terkimbi
Time	10 minutes

Evaluating Performance of Oil and Gas Company

2015 SHELL SCORECARD Architecture

MEASURES	UNIT	Staff WEIGHT	RANGE BELOW	RANGE ON TARGET	RANGE OUTSTDG
TOTAL SHAREHOLDER RETURN	**Rank**	**20%**	5	3	1
OPERATIONAL CASHFLOW	**$ bln**	**25%**	22	28	34
OPERATIONAL EXCELLENCE		**35%**			
Project Delivery	%	10%	55%	75%	95%
Production	kboe/d	10%	2,730	2,814	2,898
LNG sales	mtpa	5%	21.3	21.9	22.6
Refinery and Chemicals Availability	%	10%	86.5	88.5	90.5
SUSTAINABLE DEVELOPMENT		**20%**			
Total Recordable Case Frequency	TRCF(+)	20%	1.43	1.13	0.83
OVERALL PERFORMANCE		**100%**			

Evaluating Performance of Oil and Gas Company

Key result Areas for Shell

There are four components to the Scorecard, each with a different weighting:

- Total Shareholder Return
- Operational Cashflow
- Operational Excellence
- Sustainable Development

The scorecard aims to be balanced, supporting growth, discipline, operational excellence and safe and environmentally sound performance. The measures and weightings are unchanged compared to last year. The scorecard enables all employees to be clear about what is important and to work together towards achieving the same goals.

Key result Areas for Shell

1. Total Shareholder Return (TSR)
   Measure of share price movement and dividends paid during the year. It is a relative measure against major peers. The TSR score is based on a simple ranking against BP, Chevron, ExxonMobil and Total.

2. Operational Cashflow
   Cashflow from Operations (CFFO) adjusted for tax paid on divestments. It reflects the company's business performance and is based primarily on earnings and working capital movement. Operational Cashflow is also influenced by the oil price and margin environment, relative to the assumptions used in planning.

Evaluating Performance of Oil and Gas Company

Key result Areas for Shell

3. Operational Excellence

   Excellence measures are focused on the drivers of company’s business performance, which are directly affected by how well the company delivers on business objectives

   - Project Delivery

     is a measure ability to bring projects on stream within budget and schedule. The projects included in the scorecard are major projects executed post-Final Investment Decision projects.

   - Production

     reflects the growth and operational performance of upstream assets. ar

Evaluating Performance of Oil and Gas Company

Key result Areas for an Oil and gas company

4. Sustainable Development (SD)

   Measure is based on Total Recordable Case Frequency (TRCF) or number of injuries per million working hours. In determining the final SD score, the Chief Executive Officer also takes into account our overall SD performance. This aspect is covered by the “+” in the measure.

Auditing Upstream Contracts

Section 5

- Joint Venture (JV) Audit
- Production Sharing Contract (PSC) Audit

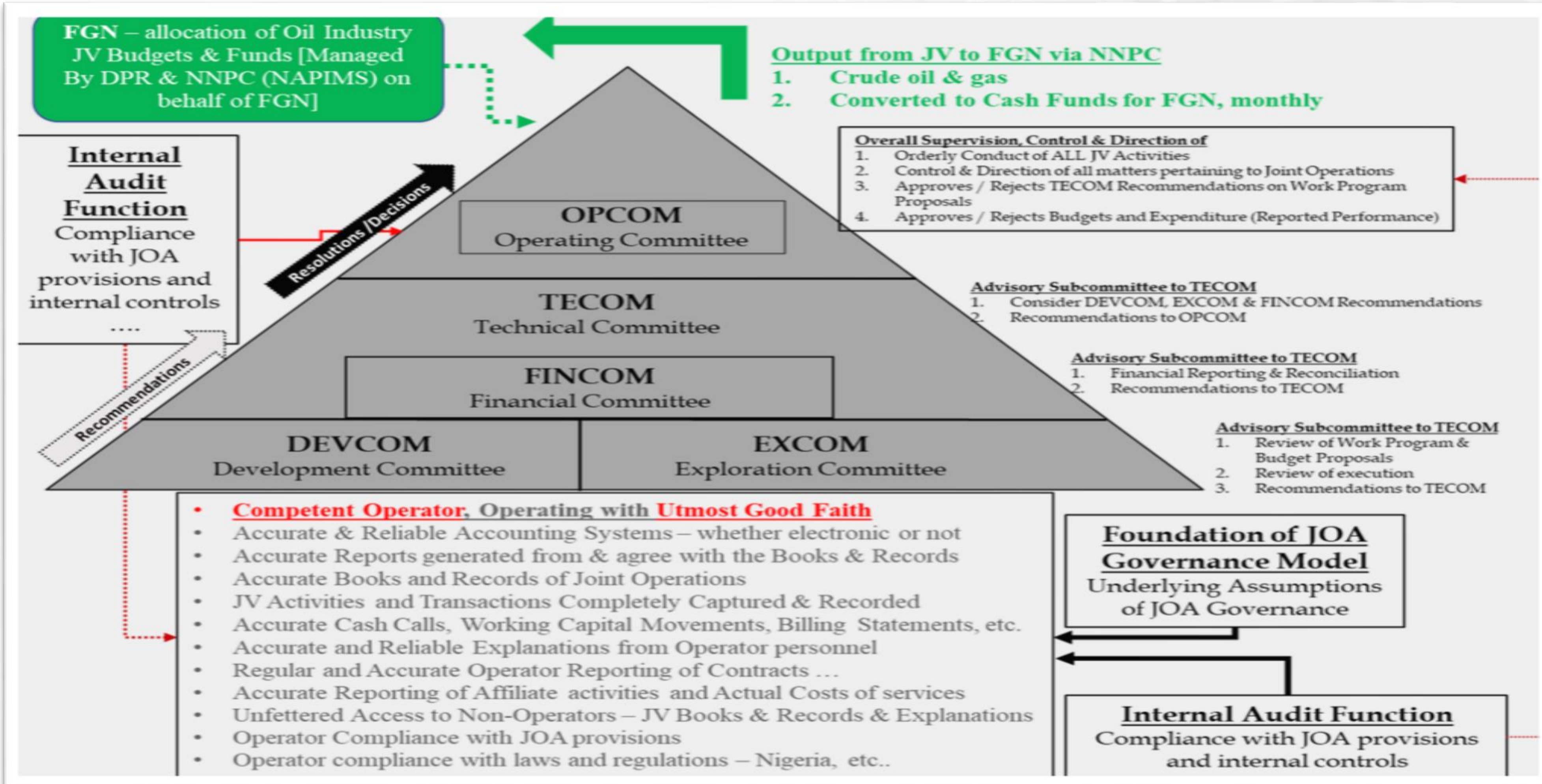
JV Audit

102

Facilitator	Terkimbi
Time	30 minutes

Auditing Upstream Contracts

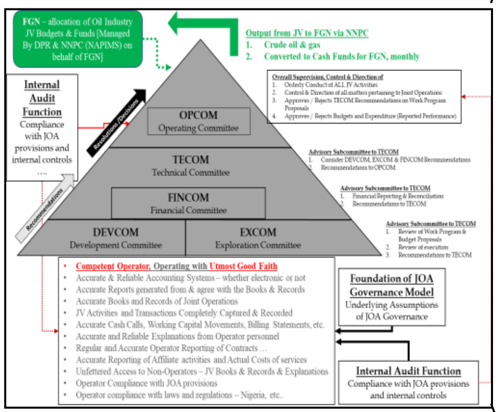
JOA Governance



Key Points to Note about JOA Governance Model

1. FGN is cash called and gets cash back from crude oil & gas proceeds directly into FGN Bank Accounts (& via NNPC). **IOC JVs Operators are subject to high degree of competence, probity, transparency and accountability**
2. OPCOM + Approval Framework: provides assurance on Operator technical competence, assurance & accountability
3. Internal Audit Function envisaged – **Compliance & Assurance** that resources will be used efficiently and processes, laws and regulations and JOA complied with. ***Operator is regularly evaluated*!**
4. Foundation of JOA Governance Model – based on many assumptions key of which are that the Operator:
   i. Is Competent Operator [technically, commercially & administratively)
   ii. Will operate with Utmost Good Faith
   iii. Complies with oversight processes and procedures in JOA
   iv. Holds itself accountable to Non-Operators
   v. Conforms with industry best practices
   vi. Adds value through competence – technical and administrative
   vii. Safeguards JV investment and assets through effective risk management
   viii. Records all activities of Joint Operations timely and accurately
   ix. Ensures unfettered access to JV Books and Records and information to non-operators, their representatives and auditors without limitation, in conformance with the many JOA provisions on such access rights
   x. Facilitates Audit Rights exercise by Non-Operators

Auditing Upstream Contracts



1. OPCOM + Approval Framework: provides assurance on technical competence, assurance & accountability
2. Internal Audit Function envisaged – **Compliance & Assurance** that resources will be used efficiently and processes, laws and regulations and JOA complied with. ***Operator is regularly evaluated*!** – assurance, competence
3. Foundation of JOA Governance
   i. Competent Operator, operating with Utmost Good Faith -
   ii. Annual WP&B – plan of activities based on objectives (e.g. production growth)
   iii. Accurate & Reliable Accounting systems – to keep Accurate Books & Records – *Accounting Controls* – provide assurance
   iv. Accurate Reports – Billing Statements, Working Capital Analysis, … *Reconciliations* provide assurance, oversight
   v. Unfettered access to books and records at all times to Non-Operators – oversight and assurance to Non-Operators
   vi. Operator compliance with JOA provisions - accountability
   vii. Effective Internal controls – assurance,
   viii. Effective Internal Audit function – transparency, accountability
   ix. Effective Risk Management – competence, accountability
   x. All Joint Operations activities are recorded – probity, transparency, accountability and administrative competence
   xi. Operator conforms to Industry Standards. – transparency, competence

Auditing Upstream Contracts

Oversight

Key Non-Operator Rights in JOA

1. Participate in OPCOM – **unanimous vote**
2. Receive Annual WP & Budgets
3. *Receive Cash Call Requests*
4. Receive Defined JV Activity Reports – Monthly, Quarterly, Annually
5. Responsiveness from Operator on enquiries at all times
6. Unfettered Access to Books & records by Non-Operators
7. Unfettered Access to Information by Non-Operators
8. Unencumbered access for Non-Operators to exercise Audit Rights

1 + 2 + 3

These 3 rights clusters provide a good basis for effective non-operator oversight of Operator

4

Audit Rights trump all other rights and can be used to make claims & prep for a show down at OPCOM (decision is by unanimous vote)

Exercise of Rights & Obligations in Relationship

1. OPCOM+ participation [effective]
2. Technically Competent reviews
3. Rights to block any and everything at OPCOM is the Nuclear Option; it is there to be used
4. Understanding JOA provisions and own Rights
5. Monthly oversight of Operator CCR, Reports & Output
6. Vigilance and nit-picking on every item of non-compliance and infraction.
7. Unfettered access to Books & Records is unfettered Access
8. Assertive follow up on own requests of Operator
9. Audit Rights are unlimited in time and scope, yet, limited in terms of discrepancies (36 months), unless fraud can be ascertained. How do a JV partner ascertain fraud when it does not have access to the books & records?

Basic Building Block for JV Audit

Focus of Joint Venture Audits:

- To maximize efficiencies and reduce potential burden for Operator, JV audits are jointly performed by Non-Operator Joint Venture Participants (NOJVP's) and address charges to the Joint Venture (JV) accounts relevant to the License
- The audit is conducted in accordance with the spirit and intent of the JOA and at the expense of the NOJVPs.
- To assess whether the Operator has materially complied with the JV Operating Agreement
- Scope is defined by Operator Billing Statements / P&L and Balance Sheet
- Ensure that partner's net cash position is correctly reflected in the billing statements

Objectives of the NOJVP Audit

- The primary objective of the audit is to provide assurance to the NOJVP's that expenditures charged to the joint accounts and underlying business activities comply with the JOA;
- Are consistent with generally accepted accounting practices used in the Petroleum Industry; and
- Represent the actual cost of Joint Operations.
- To assess whether the Operator has materially complied with the JV Operating Agreement
- Ensure that partner's net cash position is correctly reflected in the billing statements

Auditing Upstream Contracts

Scope

- Reviewing expenditures charged to the Joint Account to ensure that they are applicable to the respective licences and were incurred within the Terms & Conditions of both the relevant supplier contracts and the JOA.

- Reviewing commitments and expenditures against approved budgets and AFE’s to provide assurance such business processes facilitate an effective control framework.

- The audit will **not** extend to determining or verifying the amount or value of salary or remuneration package of any Operator Affiliate personnel in accordance with section in JOA Accounting Procedure.

Auditing Upstream Contracts

Process

To facilitate an effective and efficient audit process, the Operator is requested to provide:

- A Detailed Transaction Listing (preferred excel format) and preliminary audit planning information / documentation by (agreed date).
- Information / documentation by Day 1 of the audit fieldwork.
- A brief presentation to the NOJVP Audit Team at the opening meeting to raise awareness as to: Organisational structure, facilities & Overview of joint operation / major project activities during the audit period;
- Accounting systems, records, document archival & retrieval system; and
- Indirect cost allocation methodologies (PCO / Common Costs).

Auditing Upstream Contracts

Process

During the fieldwork phase the audit team will:

- Review reports, records, vouchers and all other pertinent supporting documentation relevant to the selected audit transactions.
- Discuss and clarify with relevant Operator personnel any audit related concerns and/or preliminary audit observations or findings.
- Raise monetary findings (MF) where audit team dispute expenditure charged to the Joint Account (amount and/or basis of expenditure).
- Raise procedural findings (PF) should there be any observed non-compliance to any relevant agreement based on Operator’s practice for period covered under the NOA.
- Issue Information Request’s (IR’s) to Operator for further clarification or justification on relevant matters. A list of Issued / Completed/ Outstanding IR’s will be provided, discussed and Reconciled with Operator on a weekly basis.

Auditing Upstream Contracts

Process

- After a mutually agreed ‘close-out’ period (after completion of fieldwork) any remaining ‘open’ IR’s will be converted into either a MF or PF for inclusion in the report.

- In accordance with Section in JOA, an audit report outlining all MF/PF’s raised during the fieldwork will be issued to the Operator within (for e.g.,90) days of fieldwork completion. Operator will then provide a formal response within 90 days from receipt of the audit report.

We'll resume our meeting in:

15 Minutes

We’ll resume our meeting in:

14 Minutes

We'll resume our meeting in:

13 Minutes

We’ll resume our meeting in:

12 Minutes

We'll resume our meeting in:

11 Minutes

We'll resume our meeting in:

10 Minutes

We'll resume our meeting in:

9 Minutes

We'll resume our meeting in:

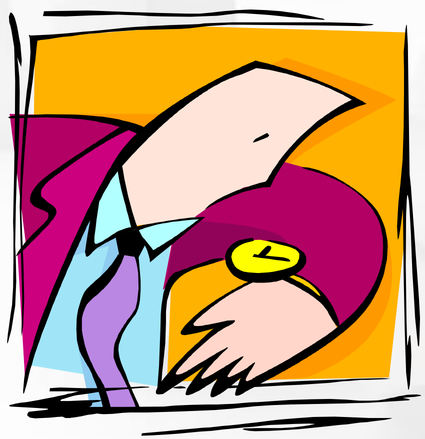
8 Minutes

We'll resume our meeting in:

7 Minutes

We’ll resume our meeting in:

6 Minutes

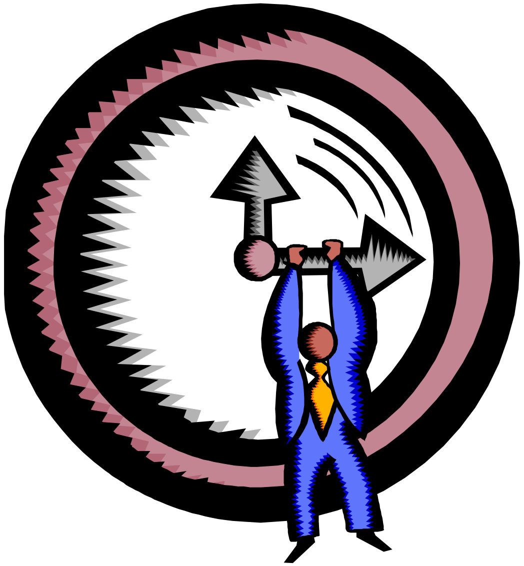


We'll resume our meeting in:

5 Minutes

We’ll resume our meeting in:

4 Minutes

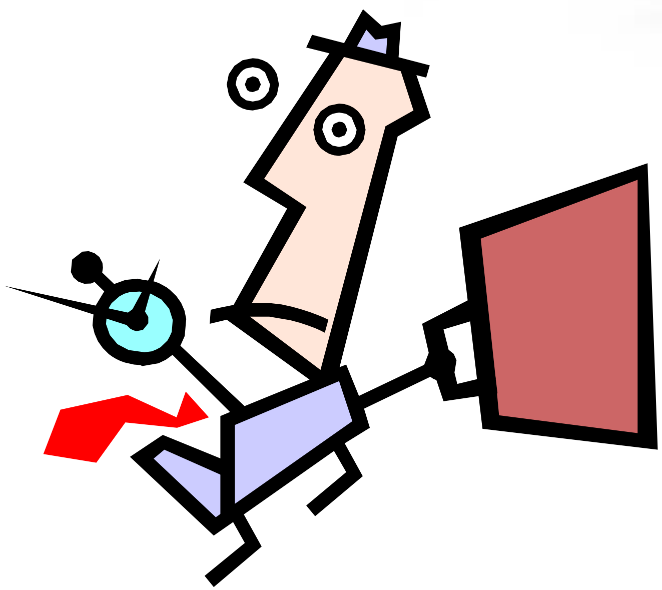


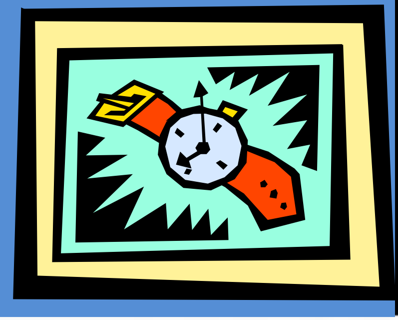
We’ll resume our meeting in:

3 Minutes

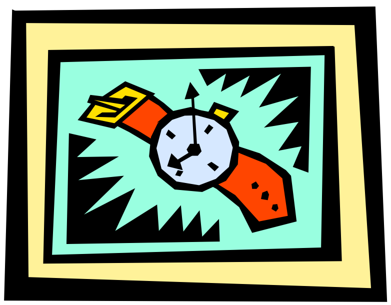
We’ll resume our meeting in:

2 Minutes

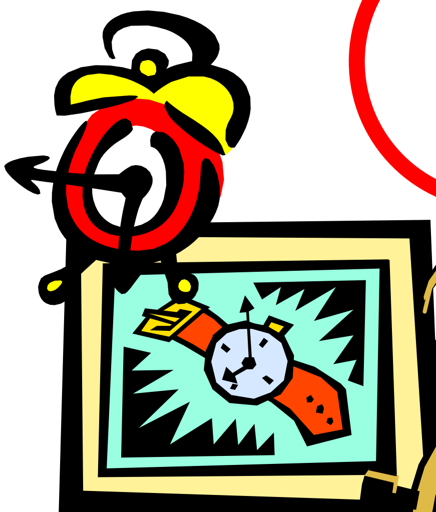


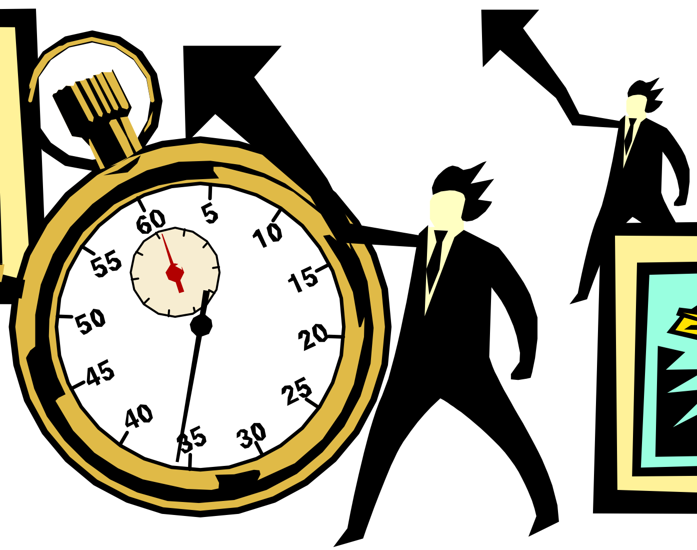


We’ll resume our meeting in:



1 Minute





Break time is over! Lets get started!

Working Capital Matters

102

Facilitator	Terkimbi
Time	20 minutes

Working Capital Matters

- Cash Over/Under Call position of JV partners is fundamental to funding Cash Calls.
- Working Capital Analysis & Reconciliation with Actual Expenditure in Billing Statements is fundamental to establishing JV partner’s Cash Over/Under Call
- No JV Partner should be paying cash calls without knowing their indebtedness to the JV – ie. their Cash Over/Under Call position.

Auditing Upstream Contracts

1. In a JV the Operator makes cash calls on partners based on **Estimated Expenditure for the month in line** with the Article 6.2.1 of the JOA, (see table).
2. The supply of cash (cash calls) by partners for planned purchases like inventory and other items that have a time consumption impact before they show up as costs in the Performance Reports and Billing Statement, must be properly articulated and tracked so that JV partners know that they are not being asked to pay for things twice and that the Operator is keeping accurate records of JV-partner funding and Cash Call Overs and Unders.
3. At the end of the month, **Actual Expenditure and how they were funded (JV Partner Funding – working capital)** is reported by the Operator through the billing statement (BS).

SN	Cash call for the month per Article 6.2.1 JOA			US$
1	**Estimated Expenditure**			xx
a	Cash available	-	subtract	(xx)
b	Cash deficits	+	add	xx
c	Expected receipts for the month	-	subtract	(xx)
d	Other credits	-	subtract	(xx)
2	**Cash Call for the month - JV**			xx
	Each JV Partner is allocated its PI share of the Cash Call for the Month			

4. The reconciliation of Actual Expenditure with the cash paid provides an idea of JV partner over payment or underpayment of cash called based on Estimated Expenditure. Over time, this cash over/under call builds up and must be factored into A Cash Call reset. The built-up Cash Over/Under Call position is determined and reported in Billing Statement Reconciliations with Working Capital Analysis

Auditing Upstream Contracts

What is working capital and why does it matter?

1. Working Capital is defined as Current Assets less Current Liabilities (thus it includes, inventory, accounts receivable, accounts payables, prepayments, accruals, cash, various credits and debits…)
2. In a JV context, an Operator incurs expenditure in addition to paying creditors for past credit purchases, prepaying for future services, and holding on to purchases of materials and equipment without issuing them to projects immediately they were procured for the JV.
3. These give rise to reconciliation issues because Actual Expenditure (costs) are reported (Capex and Opex) and the funding – whether by Accounts Payable (AP) or by cash or by issue from inventory, is often ignored in the scheme of things. The import of this is that costs are funded from inventory and accounts payable as well as cash, and accounts receivable when received, and income when received – the net change in these "working capital" items is key to funding the JV.
4. In the meantime, partners are asked to dole out more cash (calls) without having a clear idea about what the cash calls of the past have fully funded and whether there is any leftover cash or shortfall that they will still have to make up. Or, whether they are being called again to fund what they had funded previously.

SN	Reconciliation to Cash Calls/Funding Position			US$
1	**Actual Performance**			xx
a	JV Revenues & credits		subtract	(xx)
b	Wk.Capital Movement		add/subtra	xx/(xx)
c	Audit Adjustments		add/subtra	xx/(xx)
d	Cat 3B (rejected) items		subtract	(xx)
A	Billables			xx
e	**Cash Calls Paid**		subtract	(xx)
2	**CASH Over/(Under) CALL**			xx/(xx)

By allocating A and 2 appropriately JV Partner position is establsihed.

- As the JOA requires partners to pay cash call in advance, to enable the Operator to fund the activities for the month, it is a fundamental requirement by Operators in Nigeria Upstream Oil and Gas industry to prepare and submit Billing Statements that show the expenditure incurred and the amount due from/to each partner - cash over/under call.
- The Billing Statements contain a Working Capital Reconciliation in order to determine the amounts owed due from/to each partner – **Cash Over/Under Call**.

Auditing Upstream Contracts

1. Proper Accounting for inventory will also ensure that material inventory between multiple JVs managed by the Operator are not commingled and are properly segregated and accounting for.
2. Billing Statements must therefore always have working capital adjustments so that all items previously paid for by the JV-partners are not charged to them again; meaning that JV Partners are not made to pay for items that they had already paid for.
3. This a fundamental and inviolate principle of the Billing Statement.
4. Billing Statements that do not account for the impact of working capital movements are just plainly incorrect.

Working Capital Proofing of JV CASH CALL OVER / UNDER CALL					
					Year
SN	Subject Matter Information For Year			US$	Naira
1	**Actual Performance**			xx	xx
	Capital Expenditure	xx			
	Operating Expenditure	xx			
a	Joint Revenues	-	subtract	(xx)	(xx)
b	Working Capital Movement	+/-	add/subtract	xx/(xx)	xx/(xx)
	Restated Full Year Performance	[=1 - a ± b]	sum	xxx	xxx
c	Audit Adjustments	+/-	add/subtract	xx/(xx)	xx/(xx)
d	Category 3B items	-	subtract	(xx)	(xx)
	Restated Billable Expenditure		sum	xxx	xxx
e	**Cash Calls Paid**	-	subtract	(xx)	(xx)
2	**Over/(Under) CASH CALL**			xx/(xx)	xx/(xx)

PSA Issues for Audit Consideration

102

Facilitator	Terkimbi
Time	50 minutes

PSA: Principles and Terminology

i. Cost Recovery or ‘Cost Oil’

Mechanism within the PSC by which the contractor is allowed to recover cost (exploration, development, production) out of gross revenues. Cost oil is the maximum amount of production available for cost recovery in a specific period.

ii. Cost Recovery Ceiling or Cost Oil Ceiling

Limit to the amount of revenues the contractor may claim for cost recovery in a particular period, calculated as a % of gross revenues, typically ranging from 30% - 60%.

iii. Excess Cost Oil

Occurs when the total actual cost available for recovery is smaller than the cost oil ceiling, representing the capacity to recover more costs. It normally cannot be carried forward to subsequent periods and is a "lost opportunity" for recovery.

iv. Cost Carry Forward

Occurs when the total actual cost available for recovery is greater than the cost oil ceiling. Unrecovered cost may be carried forward to a subsequent period for recovery, normally subject to a maximum ceiling.

PSA: Principles and Terminology

v. **Profit Oil:** Remaining production or revenues after royalty and cost recovery.

vi. **Entitlement**: Shares of production which the oil company and the government are authorised to lift.

vii. **Contractor PSC Entitlement:** Cost Oil + Share in Excess Cost Oil + Share in Profit Oil.

viii. **Government PSC Entitlement:** Royalties + Share in Profit Oil + Taxes.

ix. **Government participation:** Government share of the project's equity.

x. **Carry:** Government share whose costs are covered by the contractor.

xi. **Abandonment:** Costs related to the decommissioning of the oil & gas infrastructure at the end of the project.

NOC Perspectives

NOC wants to achieve certain objectives

- Minimise development cost
- Increase reserves and production
- Encourage investment
- Training/development of national staff
- Utilising the most adequate technology
- Protection of health, safety and environment
- Better insight/improved understanding of hydrocarbon resources
- Infrastructure development (sum of all projects form total infrastructure)
- Develop local industry
- Social improvement of development area

Auditing Upstream Contracts

IOC/LOC Perspectives

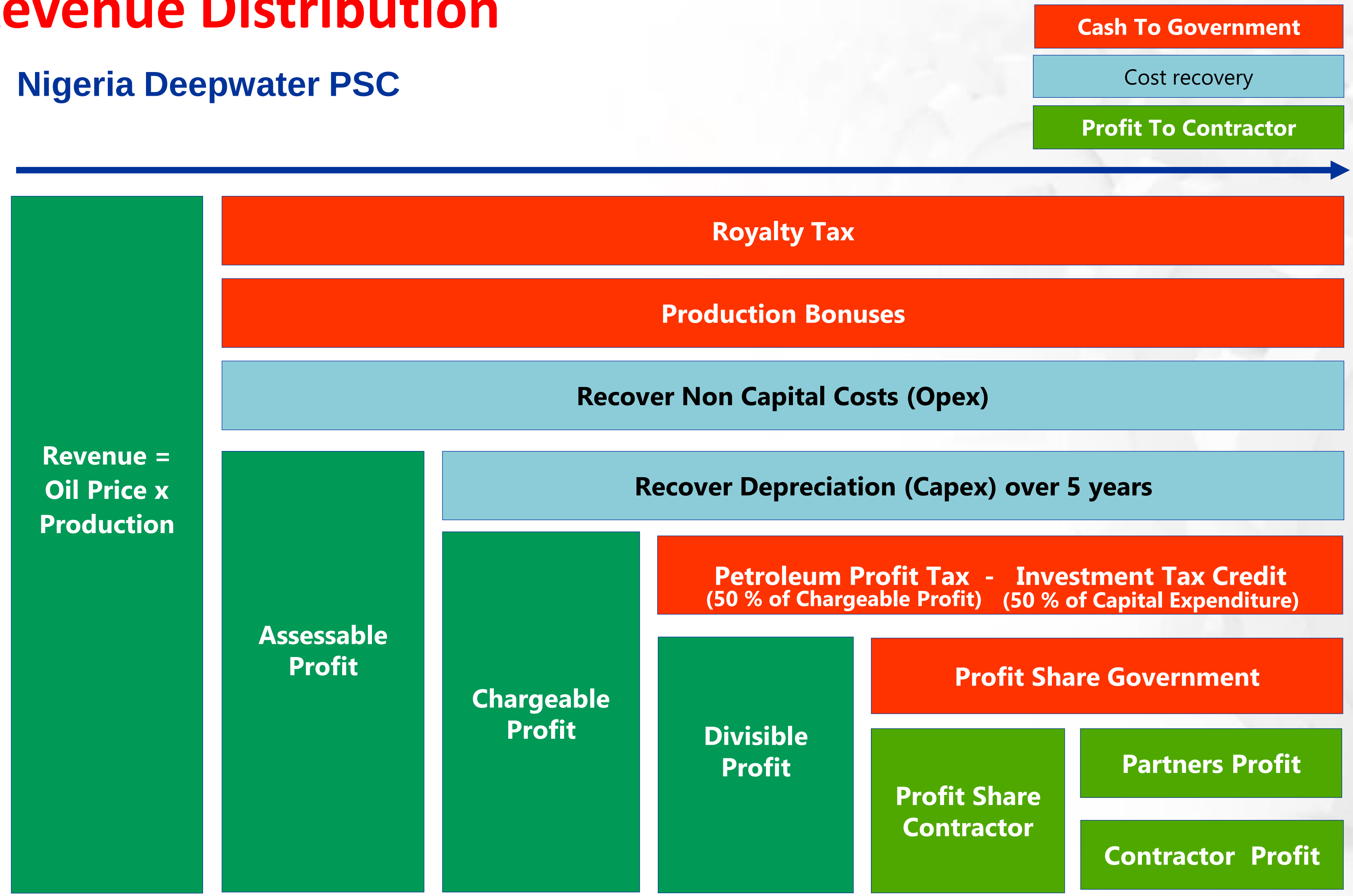
IOC has to taking into account:

- Shareholder/Financial Market requirements
- Business principles and reputation
- Existing commitments
- Strategic fit
- Health, safety, security and environment
- Licence to operate through engagement with local people
- Ability to manage investments and returns
- Need to increase reserves and production capacity
- Long term relationships and sustainable development
- Efficient use of resources (human, finance, technology etc.)
- Contractual, legal and fiscal stability

Auditing Upstream Contracts

Revenue Distribution

Nigeria Deepwater PSC



Reserves Measurement

<u>RESERVES</u> are the sum of

- <u>forecast equity crude entitlements</u> for each period
- until exhaustion of the field or
- until end of the PSC
- whichever is earlier

Taxation and Tax Paid PSCs

- **Tax Paid PSC**
  - Government assumes, pays, and discharges corporation tax on behalf of the contractor
    - Payment will come from government's share of profit oil

- **Non Tax Paid PSC**
  - Contractor is directly liable to corporation tax
  - Government take = royalty + profit oil + corporation tax

Tax Paid PSC

CONTRACTOR TAX PAID OUT OF GOVERNMENT SHARE OF PROFIT OIL

- Government faces the economic (oil price) risks and rewards with respect to the tax barrels.
- Group Accounting Practice:
  - Account for income tax on a net basis.
  - No income tax is recorded in the P/L account.
  - Revenues are not grossed up with the tax amount.
  - Current Income tax liability is not recognised nor disclosed in the Group Accounts.

TAX PAYING IN KIND PSC

- Taxes payable in kind (‘tax oil’)
- Tax liability calculated on project’s total income then converted into barrels using prevailing oil price
- Barrels are specifically allocated to the government
- Government pays the tax liability on Contractor’s behalf out of the proceeds of the tax oil.
- Contractor expected to be ultimately liable and bears economic risk. Risks

Tax Paying in Kind PSC

Accounting Practice:

- Company recognises a current tax charge in the P/L account
- Company recognises revenues at a gross pre-tax level (i.e., including proceeds used in settlement of its fiscal liability)
- Production and reserves associated with tax liability disclosed to reflect total company entitlement
- These reserves form part of the basis for depreciation based on UoP

WIS AND ES : Basic Building Blocks

- **Working Interest Share (WIS)**
  - Company's working interest share as a Contractor under a PSC
  - % pays of all capex and opex as per PSC
  - Excludes subsequent intercompany carry arrangements (due to farm ins or farm outs).

PSC Entitlement Model – Sole Operator

Scenario 1: has no partner; WI= 100%

Royalty in Kind	10
Cost Oil Contractor Share	25
Profit Oil Government Share	35
Profit Oil Contractor Share	30
Total Gross Production	**100**

Total Gross Operated Production (100%)	100	A
Less: Partner's working interest (PWIS)	0	B
Gross Operated Production (WIS)	**100**	**C=A-B**
Less: Production Royalty (WIS)	10	D
Net Operated Production (WIS)	**90**	**E=C-D**
Less: Government Take (WIS)	35	F
Net Production (ES)	**55**	**G=E-F**
Components of ES:		
Cost Oil (ES)	25	
Profit Oil (ES)	30	
	55	

PSC Entitlement Model – Multi-Operator

Scenario 2: WI (80%), JV Partner WI (20%)

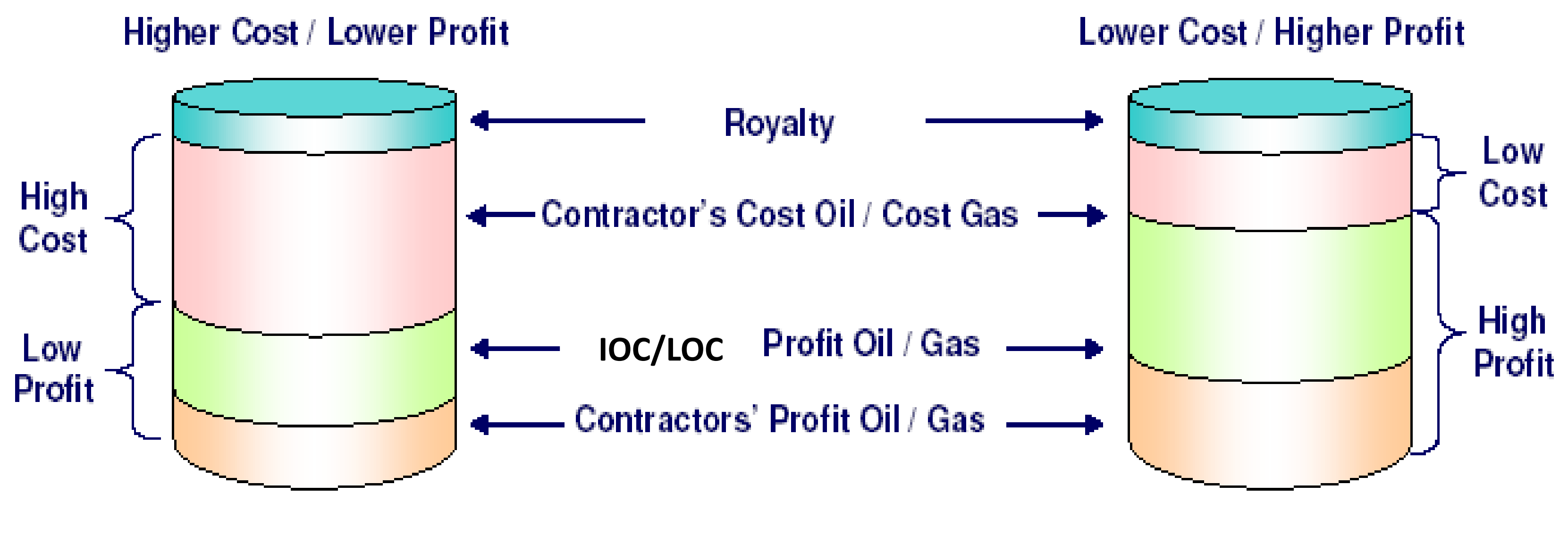
Royalty in Kind	10
Cost Oil Contractor Share	25
Profit Oil Government Share	35
Profit Oil Contractor Share	30
Total Gross Production	**100**

Total Gross Operated Production (100%)	100	A
Less: Partner's working interest (PWIS)	20	B=A x 20%
Gross Operated Production (WIS)	**80**	**C= A - B**
Less: Production Royalty (WIS)	8	D=10 x 80%
Net Operated Production (WIS)	**72**	**E= C- D**
Less: Government Take (WIS)	28	F= 35 x 80%
Net Production (ES)	**44**	**G= E - F**
Components of ES:		
Cost Oil (ES)	20	25 x 80%
Profit Oil (ES)	24	30 x 80%
	44	

Auditing Upstream Contracts

Cost Recovery

- Wrong notion about the cost of expenditure: “it’s alright; we get it back from cost oil.”
- For every cost oil claimed, contractors lose in terms of profit.
- Cost oil is merely a reimbursement of cost already spent.
- Profit oil is the compensation for the risk taken



Areas for Audit Focus - Recoverable Costs

Typical recoverable costs

- Exploration costs
- Appraisal costs
- Capital costs
- Operating costs
- Yearly decommissioning costs
- Costs carried forward

Common issues

- Redundancy/restructuring costs
- Entertainment
- Shareholders / Central Office Costs
- Publicity / public relations costs
- Donations
- Expatriate-related costs
- Affiliate companies’ costs
- Budget overrun / unbudgeted costs
- Non-compliance with contractual procedures
- Inadequate audit trail
- General expenditures not related to Petroleum Operations

Auditing Upstream Contracts

Areas for Audit Focus - Alignment of Interests

- There is an inherent nonalignment between the Host Country and the Investor
- Causes of Nonalignment
  - Recovery of capital and cost of capital
  - Cost overruns sometimes capped
  - Determining and allocating profits
  - Approval standards
  - Bearing the costs of decommissioning
  - Contract termination
    - Example: Malaysia PSCs
  - Contractor profit share linked to cost recovery & cumulative threshold volumes (oil – 300mmbbl)

Auditing Upstream Contracts

Areas for Audit Focus – PSC Risks and Issues

- Direct involvement of government & JV partners in daily operations
- Wide range of contractual commitments, obligations, and reporting requirements
- Complicated profit oil sharing mechanisms
- Risk of losing cost recovery due to poor control framework
- Lack of understanding from government and company staff on the implementation of production sharing (cost oil, profit oil)
- Accounting systems not fit to support PSC implementation
- Mixed contractual arrangement (Tax/Royalty, PSC)
- Delayed cost recovery - government not equipped to perform cost validation
- Vague or no policy on abandonment
- Effects of oil price, production and costs on entitlement
- PSC performance vulnerable to cost recovery & oil price

Areas for Audit Focus – Basic PSA Considerations

- Balance between government involvement and management control
- Adequate set up of organisation and implementation of procedures
- Adherence to expenditures authorisation
- Set up of adequate accounting system: balance between good audit trail and cost efficiency
- Manage and plan production, activities, expenditure levels
- Arbitrage and cost restructuring opportunities
- Materials and Asset Management
- Manage pre-funding of disputed/rejected costs

– Manage audit process and optimise tax planning

- Create awareness in both the Oil Company and Government
- Ensure correct implementation of contract terms by ALL parties

Auditing Upstream Contracts

Areas for Audit Focus – Basic PSA Considerations

- ✓ **Adequate set up of Organisation and implementation of procedures**
  - Inventory of contractual obligations and compliance checklist
  - Set up and implement management system and organisational framework – prime aim is to **safeguard costs recovery**
    - **Business Controls Framework**
    - **Performance Monitoring and Review (budget analysis)**
    - **Risk Management and Internal Audit Policies**
  - Agree early on documentation procedures between the government, State auditors and IOCs/OCs
    - Link to generally accepted standards used in the International Oil and Gas Industry
  - Audit Trail (cost recovery support) & adherence to documentation procedures

Auditing Upstream Contracts

Areas for Audit Focus – Basic PSA Considerations

- ✓ **Areas of common cost recovery issues**
  - Redundancy / restructuring costs
  - Entertainment
  - Shareholders / Central Office Costs
  - Publicity / public relations costs
  - Donations
  - Expatriate-related costs
  - Affiliate companies' costs
  - Budget overruns / unbudgeted costs
  - Non-compliance with Contract procedures
  - Un-insured / under-insured liabilities
  - Inadequate audit trail
  - General expenditures not related to Petroleum Operations

Areas for Audit Focus – Basic PSA Considerations

- ✓ Adequate accounting system : balance between good audit trail and cost efficiency
  - – Should be able to handle specific reporting requirements :
    - PSC reporting (cost recovery, expenditure, production statements)
    - Joint Venture billing
    - Management accounting – PSC specific internal reporting
    - Local Corporate Statutory and Fiscal reporting
  - – Robust & equitable cost allocation system – charge out mechanism across PSCs and ventures
  - – Adopt classifications, definitions, and allocations of Petroleum Operations costs that are generally accepted in the Oil & Gas industry
  - – Avoid ambiguity in the classification of capex and opex , especially if the former is not immediately cost recoverable
- ✓ Manage the (pre) funding of disputed or rejected costs
  - – Acquire entitlement when cost oil is received not when audit approval is granted
  - – Avoid terms wherein entitlement is dependent upon completion of government audit

Areas for Audit Focus – Basic PSA Considerations

✓ **Production, activities, expenditure levels**

- Managing the three main determinants of cost recovery: ***Price***, ***Expenditure*** and ***Production***.
- Excess cost oil situations by accelerating projects
- Maximise the use of the total cost ceiling
  - Cost oil provides 100% Contractor entitlement
  - Excess cost oil either mean 0% entitlement or only a % Contractor take
  - If there is a need to incur additional costs, best to do it in an excess cost oil situation
- Avoid long periods of **unrecovered costs**.
  - Increase production to avoid cost carry forward situation
  - Accelerated cost recovery mechanism
- Avoid **huge expenditures** at **project tail end** (e.g. decommissioning)
  - Abandonment issue (especially if PSC is silent)
  - Accounting provision for abandonment - amortised and cost recoverable

Auditing Upstream Contracts

Areas for Audit Focus – Basic PSA Considerations

- ✓ Production, activities, expenditure levels
  - – Production
    - ○ Increase production during a cost carry forward situation
    - ○ Production increase = higher cost oil ceiling = additional cost recovery = additional volumes for profit oil
    - ○ Production increase = higher excess cost oil = higher profit oil
    - ○ Assess opportunities to apply for cross recovery
- ✓ Tax Planning
  - – Tax Credits
  - – Tax Paid PSC
    - ○ Tax receipt issued in the name of the Company evidencing tax payment
    - ○ Tax return prepared by the Company in accordance with local tax law
    - ○ Tax liability calculated on an individual company basis – not for the total venture
    - ○ Government should earn sufficient profit from its share of Profit Oil to meet tax liability of the Contractor

Auditing Upstream Contracts

Abandonment

102

Facilitator	Terkimbi
Time	20 minutes

Auditing Upstream Contracts

In the next 15-25 years, approximately 175 offshore installations would be due for D&R worldwide

The oil and gas industry requires large installations for its activities that may be hazardous to the environment and must be removed when activities have ceased and/or are no longer economic.

Globally, countries put up robust regulatory and fiscal frameworks that ensure adequate funds are in place for meeting D&R obligations

- The oil and gas industry requires large permanent installations for its exploration, development and production activities. These installations are potentially hazardous to the environment in a variety of ways: they can be noisy, can cause visual impact and with the passage of time may release pollutants into the immediate environment. Governments must therefore ensure the removal of the installations after exploration and production activities have ceased and are no longer economic.
- The removal or D&R of facilities generate significant costs for oil and gas companies hence the need for proactive funding to restore the environment has now become a major issue for the industry globally. It is estimated that in the next 15-25 years, almost all of the existing worldwide offshore installations (over 6,600, with Nigeria accounting for approximately 285 and counting) would have been due for D&R.
- In Nigeria, for instance, most of the offshore installations are governed by the various production sharing contracts/ Agreements (PSC/PSA)

Countries around the world continuously update their fiscal and regulatory frameworks to ensure proper funding is in place

Various countries (including the UK, Canada, China and Asia Pacific region) have recently updated their regulatory and fiscal framework to address the D&R and restoration obligations, in particular the timing and management of D&R funds during the economic life of the asset. A key challenge of government authorities is ensuring accountability by defining clear and fair financial responsibilities related to D&R and closure – and ensuring that appropriate funding is available upon cessation of operations to begin closure activities. However, simply establishing accountability is not enough; the host governments also have to proactively ensure that whoever is deemed liable, is able to afford the costs.

Auditing Upstream Contracts

Risks of inadequate funds to meet D&R obligations has increased with divestments by IOCs

The Time for Nigeria to Act is Now!

The Department of Petroleum Resources (DPR) annual oil and gas report of 2017 indicated that Nigeria has 285 fields. 184 of these fields are producing while 101 were shut in. Many of these fields are approaching the end of their expected lifetime.

Whilst there are no reliable estimates of total costs of D&R in Nigeria's oil and gas facilities, these will not be insignificant based on experience from other jurisdictions. In July 2019, the UK Oil & Gas Authority estimated that it would cost **£49 billion** to decommission the remaining UK's oil and gas facilities whilst The U.N. estimates that total cost of completely removing the over 6,500 existing offshore platforms will be over **$40 billion** U.S dollars. It can therefore be inferred that it will cost between **$15 – $20 billion** U.S dollars for decommissioning and restoration of oil and gas facilities in Nigeria.

More importantly, setting up D&R funds will shore up Nigeria's foreign reserves and the escrow accounts will be domiciled in Nigeria.

Nigeria therefore needs to urgently:

- Move to put a halt to all divestments by IOCs to allow for an independent determination of total D&R obligations in Nigeria
- Appoint independent consultants to estimate the D&R obligations for each of the oil and gas operating companies, especially the IOCs
- Develop a robust regulatory framework that ensures that D&R obligations are fully funded going forward, taking note of the success stories in UK, Canada as well as the Asia Pacific countries that operate similar contractual arrangements to Nigeria's.

Auditing Upstream Contracts

Countries around the world continuously update their fiscal and regulatory frameworks to ensure proper funding is in place

Various countries (including the UK, Canada, China and Asia Pacific region) have recently updated their regulatory and fiscal framework to address the Abandonment and restoration obligations, in particular the timing and management of Abandonment funds during the economic life of the asset.

- A key challenge of government authorities is:
  - ensuring accountability by defining clear and fair financial responsibilities related to Abandonment and Closure, and
  - ensuring that appropriate funding is available upon cessation of operations to begin closure activities.
- However, simply establishing accountability is not enough; the host governments also must proactively ensure that whoever is deemed liable, is able to afford the costs.

Auditing Upstream Contracts

Nigeria needs a robust framework for funding Abandonment obligations

- The main concern is that in Nigeria the existing provisions are not sufficiently robust to address the issues in its totality, especially in the provisions for setting aside adequate funds to ensure that restoration and Abandonment liabilities can be funded when the time comes.
- The problem is exacerbated by the fact that with regards to the operation of such funds, there is no international legal or governance framework that establishes how Abandonment funds should be administered.
- Effective and transparent management of the funding scheme is required to prevent any undue influence by the ulterior interests of the parties to the fund.
- Incidentally, Nigeria's Oil and Gas industry is largely dominated by IOCs who keep their funds primarily offshore and are more inclined to ensure that the fund, when eventually set aside, will be domiciled offshore to the disadvantage of the country.
- Such funds when retained in the economy assist in making long term funds in foreign currencies available as these funds are kept long-term. They also boost the nation’s foreign currency reserves.

Many governments continue to grapple with managing Abandonment of offshore platforms

Governments around the world are having to contend with ways of handling abandonment both from environmental and fiscal perspectives.

Abandonment , until recently, was a topic of less significance to the extent that most host governments did not make adequate provisions in their contractual agreements with Oil and Gas companies to cater for this very important area.

Some governments have introduced fiscal and environmental provisions for abandoning offshore installations, however, these are yet to be tested in practice.

Offshore Abandonment remains a major issue for the international Oil and Gas industry. In the next 30 years, almost all of the existing worldwide offshore installations will be decommissioned[1]. The industry's adherence to the International Maritime Organization (IMO) guidelines and the United Nations Convention on the Law of the Sea means that the cost of abandonment will be high.

In fact, the U.N. estimates that total cost of completely removing the over 6,500 existing offshore platforms will be over US$40 billion. This issue is further compounded by the fact that only 22% of Oil and Gas companies have plans in place for the retirement phase of their assets[1].

Only 22% of Oil and Gas companies have plans in place for the retirement phase of their assets

Source: 1. Oil and Gas Journal – Aberdeen Group

Auditing Upstream Contracts

Nigeria needs a framework to operationalize and enforce regulatory provisions for Abandonment…

The reasons for this are not far fetched; most agreements require Oil and Gas companies to set up and make periodic payments into an Abandonment fund from commencement of production, and during the life of the field while Oil and Gas companies tend to prefer a system that allows a straight tax deduction or cost recovery in the last year due.

This preferred approach allows the companies access to the funds, and thus a return, during field life, even if these periodic payments into the abandonment fund are fully cost recoverable in the year they are provided. However, Abandonment usually happens when little or no revenues are being generated by the field.

It is therefore important for national governments to enforce the setting aside of funds early-on into the field life to ensure adequate funds are available to fund Abandonment when required.

This is also very key when divestments are being made by operators. The national government is satisfied that funds have already been set aside by the selling operator e as the incoming operator continues to build the funds going forwards.

Sources - Nigeria Model PSC contracts, 1993, 2000, 2005, EE Analysis

Summary of Abandonment Practices globally

United Kingdom

- Principal legislation is the Petroleum Act, 1998 complemented by guidance issued from time to time
- Liability for Abandonment is joint and several for all the contracting parties
- Sellers can be liable for a share of costs post divestment in the event of buyer default or even another company's default under the relevant operating agreement
- Exposure is not technically limited to proportionate share
- Standard practice is to try to negotiate a Abandonment Security Agreement (DSA) for each asset
    - Tend to be negotiated only at time of asset divestment

In the event of a failure to comply with requirement to prepare and submit Abandonment plan by an Operator, the Secretary of State may prepare a Abandonment plan, and get a reimbursement for the cost of preparing the programme from the defaulting party

Auditing Upstream Contracts

United States of America

- Reviewed centrally and viewed on a company wide basis rather than field by field i.e. your ability to cover Abandonment is viewed on country wide exposure
- Strict rules on financial strength (linked to net worth) but ensure that small parties can continue to compete i.e. Only one of lease holders needs to cover the liability upfront – size small upfront but determined by relevant ministry
- Supplemental bonds are required to cover abandonment requirements, reviewed annually
- Once 80% of recoverable reserves have been produced, Abandonment account must be funded - 50% upfront, with specific funding plan

The Netherlands

- Operator is solely responsible for completing Abandonment program
- Operator is solely responsible for provision of security to Ministry of Economic Affairs (MEA)
- MEA can request financial security on demand
- Any M&A activity requires MEA approval – once change of operatorship is approved by MEA, earlier licensees are no longer liable – liability does not continue post divestment
- We understand that one of the IOCs, Shell, uses standard terms in agreements to allow it to request security from partners if MEA were to call on financial security from it. However, there is no formal fund structure or security in place

Auditing Upstream Contracts

Norway

- All relevant parties joint and severally liable for Abandonment on a pro rata basis
- Similar to the UK under divestment scenarios but with a lighter touch:
    - Sellers remain liable for their share of Abandonment costs in the event of buyer default i.e. Equity share pre-divestment
    - Exposure limited to Seller's interest of post-tax economic costs associated with the Abandonment of installations existing at divestment
    - No retrospective liability for divestments pre 1st July 2009
    - Obligations post divestment clearly go to the previous owner first vs UK which is not clear on this point

Denmark

- The license operator is responsible for Abandonment
- If one of the Commission Partners default, the other partners are proportionately exposed to cover the default, including Abandonment
- Any new partners are required to be approved by the remaining partners and the Danish State
- Divestment means that the seller is exposed for 3 years post divestment for any Abandonment which occurs during this period
- Market is not wide and therefore limited development on Abandonment solutions

Auditing Upstream Contracts

Fiscal provisions for selected countries with similar provisions

Country	Abandonment environmental	Abandonment security	Abandonment liability	Fiscal provision
Angola	Contractor must abandon the wells In accordance with normal industry practice	Reserve fund – Unit of production funds are placed Into a reserve fund every quarter, according to an equation	The contractor must abandon the wells In accordance with normal industry practice	Unit of Production. Costs can be placed into a fund after government approval
Congo	Upon expiration of a permit all wells and fixtures must be abandoned in compliance with a decree	Reserve fund: The contractor must set up a fund to cover estimated removal costs		Reserve fund for abandonment costs must be established with costs being recoverable
Gabon			Contractor is held liable to fulfill Its obligations even after the termination of the contract	Site cleaning costs included in recoverable costs at a rate of 5%, 7.5% of the purchase value of the material to be removed
Indonesia	Contractor to remove all field facilities and carry out site restoration	A contractor must make deposits into a fund to cover abandonment costs		Site restoration costs are placed into a fund and are treated as part of operating costs for cost recovery purposes
Malaysia	Contractor is responsible for the removal or salvage of any petroleum facility and a plan must be submitted for approval	Payments are made directly to Petronas	Contractor is responsible for the removal or salvage of any petroleum facility, also Petronas indemnified against any action.	All abandonment costs are cost recoverable.
Nigeria	The right holder must restore the sites on which they operate on termination of its rights	A special fund may be created to cover abandonment expenses		A special fund may be created to cover abandonment expenses, with costs recoverable
Vietnam	Upon relinquishment, Operator may be required to remove fixed installations and equipment		Upon relinquishment the contractor may be instructed to remove fixed installations	An agreed proportion of annual production may be allocated to meet abandonment costs

Source: Petroconsultants Acreage Law and Tax 1997

Key abandonment funding considerations

- Contractor to establish funding mechanism for long-term future Abandonment activities
- Funding should be set up in a timely manner to meet Abandonment obligations under PSC
- Contractor should provide periodic confirmations that sufficient volumes remain available to cover Abandonment costs
- Abandonment funding from Contractor to be securely and robustly managed and be available as at when required
- Fund used solely for purposes of paying for Abandonment activities
- Availability of funds in time for Abandonment work, while reserves is available to achieve cost recovery (cost oil)
- Demonstration of commitment to environmental protection and readiness for total compliance with provisions of the PSC
- Annual review of contribution vs. requirement will ensure adequacy and appropriateness of annual contribution
- Deepen Nigeria financial sectors' access to long term source of finance by domiciling significant chunk of Abandonment funds in Nigeria

Key Questions

- How will Contractors recover cost of Abandonment if there is insufficient production of petroleum?
- How will Contractors recover cost of abandonment if there is insufficient Abandonment Fund to bear cost of Abandonment?
- What is Contractors' liability for Abandonment cost for cross PSC facilities sharing?
- PSC has not expired but Contractors wish to abandon facility which is still required by another PSC, who should be liable for Abandonment?
- Who is liable for Abandonment of facilities in an expired PSC which are still required by other PSCs?

Abandonment Funding options

The following options have been considered and form the crux of the various industry discussions at the workshops held between oil and gas companies and NAPIMS, DPR and Federal Inland Revenue Services (FIRS) over the last 3 Years:

- Insurance policy
- Letters of credit
- Establishment of trust funds or identification of other assets to satisfy requirements of assets retirement obligations
- Guarantees from Parent Company (PCG) or other entities
- Surety bonds or bank acceptance guarantees
- Cash in escrow

Key points:

- Would there be cost recovery outside of the non-cash backed funding?
- Would there be tax deductibility if it can be demonstrated that funds:
  - are being set aside in cash?
  - would neither be controlled by the oil and gas company nor revert to them after completion of Abandonment?

Auditing Upstream Contracts

Both the 1993 and 2000 provisions require the set up of fund to cover future end of field Abandonment…

There are two broad Abandonment provisions under the PSCs, the 1993 and 2000 provisions. All others (2005, etc) are variants of these two broad requirements.

Excerpts of the two provisions are shown in the table below.

Dimension	1993 provisions	2000 provisions
Commencement	At contractor's instance	Determined by the MACOM
Rate of contribution	The rate shall take into account the relationship between the estimated total abandonment cost and the anticipated production revenues	The rate shall take into account the relationship between the estimated total abandonment cost and the anticipated production revenues
Category of bank to use	Silent about the category of bank to use	Very specific about the category of bank to use
Currency to Use	Silent about the currency	Specified the use of U.S. Dollars
Escrow Account	Silent about the use of Escrow account	Specified the use of Escrow account
Investment of funds	Silent about the investment of the fund	Stated that the fund can invested by joint agreement of both parties to the PSC
Review of Abandonment contribution	Silent about subsequent review of the amount to be contributed to the fund	Suggested that the amount is subject to annual review as part of budgeting process

Why Nigeria must act now!

- From a legal perspective (Azaino, E.U, 2012), it is the states, and not private entities or individuals, that are bound by obligations imposed by International law to ensure Abandonment after end of field life.
- Accordingly, even if Nigeria transfers the obligation to abandon either in whole or in part to the oil companies, it still retains accountability for Abandonment. A classic example of this is the Malaysian situation where the country found itself bearing the costs of the maintenance of redundant offshore facilities after several failed attempts to transfer the obligation to the oil companies (Amakiri, C.O, 1997).
- Sufficient funds must be set aside during the producing life of the field
- Increasing number of divestments resulting in licenses assignments from large international oil and gas companies to smaller ones.
  - This phenomenon, whilst deepening local participation in the oil and gas industry has also exposed the tax payers to an unacceptable risk of default in meeting the costs associated with Abandonment.
  - Accordingly, Government needs to ensure the achievement of these twin objectives by developing frameworks that assure adequate security for Abandonment costs exists.

Nigeria is ultimately liable for Abandonment even if primary liability has been legally transferred to the Oil companies

Auditing Upstream Contracts

There is an urgent need for a framework for funding the Abandonment and abandonment of offshore platforms

The framework must address the following:

- Fund structure (governance, security, frequency of set aside, etc.)
- Formula for accreting to the fund (monthly, quarterly, bi-annually or annually)
- Management of the fund set aside including investment options where these are not prescribed already in the underlying contract
- Trigger points for release of funds
- Proposal for dealing with underfunding situation
- Tax/cost recovery implications
- Implementation plan

Source - EE Analysis

Questions