

STUDY MANUAL
ENVIRONMENTAL, OIL AND GAS ACCOUNTING (PEA 6)



ASSOCIATION OF NATIONAL ACCOUNTANTS OF NIGERIA (ANAN)

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MODULE 1

1.00 ENVIRONMENTAL ACCOUNTING PROCESS

1.01 Learning Outcomes

On successful completion of this Module, Students should be able to:

- i. Determine the legal and regulatory frameworks underlying Oil and Gas Accounting;
- ii. Elucidate corporate social responsibility and social externalities;
- iii. Evaluate environmental monitoring and awareness;
- iv. Distinguish between environmental and resource accounting;
- v. Determine the relationship between environmental degradation and petroleum production.

1.02 Corporate Social Responsibility and Social Externalities

According to Young, Moon and Young (2003) "corporate social responsibility (CSR) was defined as business action which is not required by law, directed to alleviating or averting some social ill, and adjacent to the organization's main for-profit activity" (Young et al, 2003: 1).

CSR is defined as "A concept whereby companies integrate social and environmental concerns in their business operations and in their interaction with their stakeholders on a voluntary basis" (European Trade Union Confederation on Corporate Social Responsibility 2004).

The principal concerns of CSR is to address: " market failure: especially injustice; anti-democracy; information asymmetry and externalities and desire to change current practices" (Gray, Kouhy, & Lavers, 1995a: 51).

Most of the literature that explains the different aspects of CSR reflects a four- part model presented by Carroll (1991). According to the model, CSR constitutes four different but related aspects made up of economic, legal, ethical and philanthropic responsibilities. Carroll (1991) described the four aspects as "spectrum of obligations" businesses owe society. He used key words in differentiating between the four types of responsibilities. He described economic and legal responsibilities as required by society, ethical responsibilities as expected by society while philanthropic responsibilities as desired by society. He proposed the model with the hope that it will be "useful to executives who wish to reconcile their obligations to their shareholders with those to other competing groups claiming legitimacy" (Carroll, 1991:39). Carroll (1991) argued that a socially responsible corporation should combine the task of making profit, obeying the law, being ethical and a good citizen. CSR Disclosure (Adams, Frost, & Gray, 2008):

General Key performance Indicators (KPI):

- i. **Safety statistics**
This includes a number of countries in which their operations have staff forums and grievance procedures; country of origin of staff at senior executive and senior levels; gender balance at senior executive, senior, and middle management levels; numbers of suppliers to screen against the use of child labour; and use of security personnel.
- ii. **Equal opportunities**
It provides quantified data and shows the representation of ethnic minorities in the population as well as in the company itself. The representation of women is shown at various levels in the hierarchy and employees have been consulted on their views.
- iii. **Community**
The activities of companies have a major impact on local communities. The German chemical company Henkel takes particular care in consulting local communities. Exhibit 23.8 provides details of the number of complaints received by the company and the nature of those complaints.
- iv. **Verification.**
As mentioned earlier, there is concern that company reports do not fairly reflect their activities and impacts and that they may be used as a public relations and legitimating exercise. A recent trend with the issue of the separate report on social or environmental issues is the inclusion of some form of verification statement. A recent survey by KPMG of global mining companies found that 38% of companies surveyed produced a separate report, and that of the Canadian and Australian companies 40% included some form of external verification (or audit). An external audit is no guarantee that reports will not be used as a legitimating exercise.

1.03 Sustainability/Triple Bottom Line Reporting

An emerging trend in corporate reporting is the integration of accounting and reporting of social, environmental, and economic issues, which has been referred to as the “triple bottom line,” (Elkington, 1997) or “sustainability reporting” (GRI, 2000). Elkington argues: “Today we think in terms of a ‘triple bottom line,’ focusing on economic prosperity, environmental quality, and— the element which business has preferred to overlook—social justice” (Elkington, 1997). The Global Reporting Initiative (GRI) published its Sustainability Reporting Guidelines in 2000“ to design and build acceptance of a common framework for reporting on the linked aspects of sustainability—the economic, the environmental and the societal”(GRI, 2000). The key stated aims of the GRI guidelines are to facilitate decision making, to meet stakeholder needs and to provide a management tool. Organizations that integrate their reporting in this way argue that it improves reputation, decision making, performance, and risk

management and builds good relationships with key stakeholders. They also claim that it facilitates the ability to attract, motivate and retain high-quality staff and facilitates innovation, creativity and learning which allow a faster response to changing customer needs (Nelson, Singh, & Zollinger, 2001).

The UN Global Compact Launched in July 2000, the UN Global Compact is a leadership platform for the development, implementation and disclosure of responsible and sustainable corporate policies and practices. Endorsed by chief executives, it seeks to align business operations and strategies everywhere with ten universally accepted principles in the areas of human rights, labour, environment and anti-corruption. With nearly 8,000 corporate participants in over 140 countries, the UN Global Compact is the world's largest voluntary corporate sustainability initiative.

1.04 The Ten Principles of the United Nations Global Compact

The UN Global Compact asks companies to embrace, support and enact, within their sphere of influence, a set of core values in the areas of human rights, labour standards, the environment, and anti-corruption:

i. Human Rights

Principle 1: Businesses should support and respect the protection of internationally proclaimed human rights; and

Principle 2: Make sure that they are not complicit in human rights abuses.

ii. Labour

Principle 3: Businesses should uphold the freedom of association and the effective recognition of the right to collective bargaining;

Principle 4: The elimination of all forms of forced and compulsory labour;

Principle 5: The effective abolition of child labour; and

Principle 6: The elimination of discrimination in respect of employment and occupation.

iii. Environment

Principle 7: Businesses should support a precautionary approach to environmental challenges;

Principle 8: Undertake initiatives to promote greater environmental responsibility; and

Principle 9: Encourage the development and diffusion of environmentally friendly technologies.

iv. Anti-corruption

Principle 10: Businesses should work against corruption in all its forms, including extortion and bribery.

Source: The UN Global Compact, United Nations, DC2-612, New York City, NY 10017, USA January 2014 CSR Rating

FTSE4 Good is a CSR rating index and was launched in July 2001. The FTSE4Good criteria are designed to reflect a broad consensus on what constitutes good corporate responsibility practice globally.

FTSE4 Good Inclusion Criteria

Key Objectives

1. To provide a tool for responsible investors to identify and invest in companies that meet globally recognized corporate responsibility standards.
2. To provide asset managers with a socially responsible investment (SRI) benchmark and a tool for socially responsible investment products.
3. To contribute to the development of responsible business practice around the world. For inclusion, eligible companies must meet criteria requirements in five areas:
 - Working towards environmental sustainability
 - Developing positive relationships with stakeholders
 - Up-holding and supporting universal human rights
 - Ensuring good supply chain labour standards
 - Countering bribery

ENVIRONMENTAL CRITERIA

Companies are classified as high, medium or low impact based on the environmental footprint of their activities. The higher the environmental impact of the company's operations, the more stringent the inclusion Criteria

High Impact Sectors	Medium Impact Sectors	Low Impact Sectors
Agriculture	DIY & Building Supplies	Information Technology
Air Transport	Electronic and Electrical equipment	Media
Airports	Energy and Fuel Distribution	Consumer/Mortgage
Building Materials (includes	Engineering and Machinery	Property Investors
Chemicals and	Financials not elsewhere classified (see	Research & Development
Construction	Hotels, Catering and Facilities Management	Leisure not elsewhere
Major Systems Engineering	Manufacturers not elsewhere classified`	-(Gyms and Gamming)
Fast Food Chains	Ports	Support Services
Food, Beverages and Tobacco	Printing & Newspaper Publishing	Telecoms
Forestry and Paper	Property Developers	Wholesale Distribution
Mining & Metals	Retailers not elsewhere classified	
Oil & Gas	Vehicle Hire	
Power Generation	Public Transport	

Road Distribution and

Supermarkets

Vehicle Manufacture

Waste

Water

Pest Control

High Impact Companies

Medium Impact Companies

Low Impact Companies

High Impact Companies

Policy must cover the whole group and either:
one

. meet all five core indicators plus one desirable indicator

. or meet four core plus two desirable indicators

Core Indicators

- Policy refers to all key issues
- Responsibility for policy at board or department level
- Commitment to use of targets
- Commitment to monitoring and audit
- Commitment to public reporting

Medium Impact Companies

Policy must cover the whole group & meet four indicators, three of which must be core

Low Impact Companies

Companies must have published a policy statement including commitment indicator

Desirable Indicators

- globally applicable corporate standards
- Commitment to stakeholder involvement
- Policy addresses product or service impact
- Strategic moves towards sustainability

If environmental management systems (EMS) are applied to EMS must cover one third of the company and meet four indicators. No requirement. between one and two-thirds of company activities, all six indicators If the EMS Covers less than one third of the company's Operations must be met and targets must be quantified the company must meet six indicators, including quantitative If EMS are applied to more than two-thirds of company activities, objectives and targets. ISO14001 certified or EMAS registered the company must meet five of the indicators. One of these systems are considered to meet all six indicators. Indicators must be documented objectives and targets in all key areas. Companies with ISO certification and EMAS registrations are considered to meet all six indicators.

Indicators

- Presence of environmental policy

- Identification of significant impacts
- Documented objectives and targets in key areas
- Outline of processes and responsibilities, manuals, action plans, procedures
- Internal audits against the requirements of the system not limited to legal compliance)
- Internal reporting and management review

The Report must have been published within the last three requirement. Years, cover the whole group, and meet three core indicators. Reports which do not cover the whole group must meet all four indicators. Or three core indicators together with two desirable indicators.

No requirement. No

Core Indicators

- Text of environmental policy
- Description of main impacts
- Quantitative data
- Performance measured against targets
- Stakeholder dialogue
- Coverage of sustainability issues

Desirable Indicators

- Outline of an EMS
- Non-compliance, prosecution, fines, accidents
- Financial dimensions
- Independent verification

Financial Services companies with significant equity holdings/commercial loan provisions are classified as medium impact. Therefore, these companies can meet the Environmental Management Systems (EMS) as part of the criteria through the approach to environmental considerations in investments/lending. This could be through the following (not all below will be relevant for different types of financial services companies):

- Significant Socially Responsible Investment products (with environmental criteria)
- Engagement programme with investee companies based wholly or in part on environmental issues
- Incorporation of environmental credit risk assessment into the loans process (this needs to be beyond usual practices e.g. contaminated land)
- Provision of specialist environmental loans
- Integration of financial and environmental factors in fundamental analysis

Accountability and Reporting Frameworks

The Global Reporting Initiative's G4 Sustainability Reporting Guidelines offer Reporting Principles, Standard Disclosures and an Implementation Manual for the preparation of sustainability reports by organizations, regardless of their size, sector or location.

i. Reporting Principles

The Reporting Principles are fundamental to achieving transparency in sustainability reporting and therefore should be applied by all organizations when preparing a sustainability report. The Principles are divided into two groups: Principles for Defining Report Content and Principles for Defining Report Quality.

i. Principles for defining content report

a. Stakeholder inclusiveness

Principle: The organization should identify its stakeholders and explain how it has responded to their expectations and interests a responsible organisation.

Stakeholders are defined as entities or individuals that can reasonably be expected to be significantly affected by the organization's activities, products, and services; and whose actions can reasonably be expected to affect the ability of the organization to successfully implement its strategies and achieve its objectives. This includes entities or individuals whose rights under law or international conventions provide them with legitimate claims vis-à-vis the organization.

Stakeholders can include those who are invested in the organization (such as employees, shareholders, suppliers) as well as those who have other relationships to the organization (such as vulnerable groups within local communities, civil society).

b. Sustainability context

Principle: The report should present the organization's performance in the wider context of sustainability. Information on performance should be placed in context. The underlying question of sustainability reporting is how an organization contributes, or aims to contribute in the future, to the improvement or deterioration of economic, environmental and social conditions, developments and trends at the local, regional or global level.

c. Materiality

Principle: The report should cover Aspects that:

Reflect the organization's significant economic, environmental and social impacts; or substantively influence the assessments and decisions of stakeholders.

d. Completeness

Principle: The report should include coverage of material Aspects and their Boundaries, sufficient to reflect significant economic, environmental and social impacts, and to enable stakeholders to assess the organization's performance in the reporting period.

ii. Principles for defining report quality

This group of Principles guides choices on ensuring the quality of information in the sustainability report, including its proper presentation.

a. Balance

Principle: The report should reflect positive and negative aspects of the organization's performance to enable a reasoned assessment of overall performance.

b. Comparability

Principle: The organization should select, compile and report information consistently. The reported information should be presented in a manner that enables stakeholders to analyze changes in the organization's performance over time, and that could support analysis relative to other organizations.

c. Accuracy

Principle: The reported information should be sufficiently accurate and detailed for stakeholders to assess the organization's performance. Responses to economic, environmental and social Disclosures on Management Approach and Indicators may be expressed in many different ways, ranging from qualitative responses to detailed quantitative measurements. The characteristics that determine accuracy vary according to the nature of the information and the user of the information. For example, the accuracy of qualitative information is largely determined by the degree of clarity, detail, and balance in presentation within the appropriate Aspect Boundaries. The accuracy of quantitative information, on the other hand, may depend on the specific methods used to gather, compile, and analyze data.

d. Timeliness

Principle: The organization should report on a regular schedule so that information is available in time for stakeholders to make informed decisions.

e. Clarity

Principle: The organization should make information available in a manner that is understandable and accessible to stakeholders using the report.

f. Reliability

Principle: The organization should gather, record, compile, analyze and disclose information and processes used in the preparation of a report in a way that they can be subject to examination and that establishes the quality and materiality of the information.

Standard Disclosure

There are two different types of Standard Disclosures:

i. General standard disclosures Strategy and Analysis

a. Provide a statement from the most senior decision-maker of the organization (such as CEO, chair, or equivalent senior position) about the relevance of sustainability to the organization and the organization's strategy for addressing sustainability. The statement should present the overall vision and strategy for the short term, medium term, and long term, particularly with regard to managing the significant economic, environmental and social impacts that the organization causes and contributes to, or the impacts that can be linked to its activities as a result of relationships with others (such as suppliers, people or organizations in local communities). The statement should include:

1. Strategic priorities and key topics for the short and medium term with regard to sustainability, including respect for internationally recognized standards and how such standards relate to long term organizational strategy and success
2. Broader trends (such as macroeconomic or political) affecting the organization and influencing sustainability priorities
3. Key events, achievements, and failures during the reporting period
4. Views on performance with respect to targets
5. Outlook on the organization's main challenges and targets for the next year and goals for the coming 3–5 years
6. Other items pertaining to the organization's strategic approach.

b. Provide a description of key impacts, risks, and opportunities. The organization should provide two concise narrative sections on key impacts, risks, and opportunities.

Section one should focus on the organization's key impacts on sustainability and effects on stakeholders, including rights as defined by national laws and relevant internationally recognized standards.

This should take into account the range of reasonable expectations and interests of the organization's stakeholders. This section should include:

1. A description of the significant economic, environmental and social impacts of the organization, and associated challenges and opportunities. This includes the effect on stakeholders' rights as defined by national laws and the expectations in internationally recognized standards and norms.
2. An explanation of the approach to prioritizing these challenges and opportunities
3. Key conclusions about progress in addressing these topics and related performance in the reporting period. This includes an assessment of reasons for under-performance or over-performance.

4. A description of the main processes in place to address performance and relevant changes.

Section Two focuses on the impact of sustainability trends, risks, and opportunities on the long-term prospects and financial performance of the organization. This should concentrate specifically on information relevant to financial stakeholders or that could become so in the future. Section Two should include the following:

1. A description of the most important risks and opportunities for the organization arising from sustainability trends
2. Prioritization of key sustainability topics as risks and opportunities according to their relevance for long-term organizational strategy, competitive position, qualitative and (if possible) quantitative financial value drivers
3. Table(s) summarizing: Targets, performance against targets, and lessons learned for the current reporting period
4. Targets for the next reporting period and medium term objectives and goals (that is, 3–5 years) related to key risks and opportunities
5. Concise description of governance mechanisms in place specifically to manage these risks and opportunities, and identification of other related risks and opportunities

Commitments to external initiatives

- a. Report on how the precautionary approach or principle is addressed by the organization.
- b. List externally developed economic, environmental and social charters, principles, or other initiatives to which the organization subscribes or which it endorses.
- c. List memberships of associations (such as industry associations) and national or international advocacy organizations in which the organization:
 1. Holds a position on the governance body
 2. Participates in projects or committees
 3. Provides substantive funding beyond routine membership dues
 4. Views membership as strategic: This refers primarily to memberships maintained at the organizational level.
 5. Identified Material Aspects and Boundaries.
 6. Stakeholder Engagement: These Standard Disclosures provide an overview of the organization's stakeholder engagement during the reporting period. These Standard Disclosures do not have to be limited to engagement that was conducted for the purposes of preparing the report. The stakeholder report shall:
 - a. Provide a list of stakeholder groups engaged by the organization.

Examples of stakeholder groups are:

1. Civil society
2. Customers
3. Employees, other workers, and their trade unions
4. Local communities
5. Shareholders and providers of capital

6. Suppliers
7. Report Profile
8. Governance
9. Ethics and Integrity

ii. Specific standard disclosures

This relates to Disclosures on Management Approach and provision of indicator and Aspect-specific Disclosures on Management Approach

Improving Corporate Social Responsibility and Accountability: Corporate social responsibility is essentially a concept whereby companies decide voluntarily to contribute to a better society and a cleaner environment. The Sustainable Development Strategy for Europe agreed at the Göteborg European Council of June 2001, that in the long-term, economic growth, social cohesion and environmental protection go hand in hand.

Corporate Social Responsibility Theories

i. Agency Theory

Agency theory suggests the existence of a contract (Jansen & Meckling, 1976), and thus a fiduciary relationship between two people – the principal and the agent (Eisenhardt, 1989). Besides economic motives, there are other non-economic motives, which take into consideration economic, ethical and societal interests, the balance of which ensure economic growth and long-term survival of the firm. Questioning the assumption that the firm exists in order to maximize shareholders' wealth, Fontrodona and Sison (2006) argued that the fact that firms make profits at the end of a business cycle does not necessarily mean they exist to make profits, just as human beings do not exist to eat, even though we require food to stay alive. Profit is just one of the reflectors of doing well. Doing well extends to include contribution to the well-being of the society, through efficient production of goods and services that meet societal needs. The firm is therefore a multi-purpose entity, contrary to the assumption of the agency theory that conceives the firm as existing solely to maximize shareholders' wealth, a stance, which Kennedy (2000), describes as a short-term outlook, capable of jeopardizing the firm's long-term goal.

ii. The Stakeholder Theory

The idea of stakeholder theory was first hinted at by Johnson (1971) in his definition of CSR, where he conceives a socially responsible firm as being one which balances a multiplicity of interests, such that while striving for larger profits for its stockholders, it also takes into account, employees, suppliers, dealers, local communities and the nation. The theory was later developed by Freeman (1984).

Post et al. (2002: 8) contributed to understanding stakeholders, by their definition of the firm's stakeholders as individuals and constituencies that contribute to; either voluntarily or involuntarily, to wealth-creating capacity and activities, and who are therefore its potential beneficiaries and/or risk bearers.

iii. Social Contract Theory

The social contract theory was extrapolated from the political social contract theories of Hobbes, Locke, and Rousseau (Aras & Crowther, 2008; Hasnas, 1999) to explain

the business-society relationship (Aras & Crowther, 2008), and social responsibilities of businesses in particular (Hasnas, 1998). Latent in this normative agreement is a contract, between the members of the society and business, of which business is allowed to draw from the material and human resources in the society, and expected to reciprocate, minimally, by ensuring that the benefits of being allowed to exist outweigh its negative consequences (Hasnas, 1999).

IV. Normative Ethical Theories

Scholars have argued that understanding business ethics is prerequisite to understanding CSR; see for example, Kilcullen and Kooistra (1999). With a definition of business ethics, as a set of principles that guides business practices to reflect a concern for society as a whole while pursuing profit (Nisberg, 1988), and that of CSR as —the degree of moral obligation that may be ascribed to corporations beyond obedience to the laws of the state (Kilcullen & Kooistra, 1999).

Economic Consequences of CSD

It is clear that general awareness and concern in society for matters such as environmental degradation, habitat destruction, global climate change, human rights, and stakeholder involvement, continue to increase. It certainly seems likely that the number of potential areas in which social or environmental activity can have relatively direct financial consequences must increase. These consequences can be of a cost-saving nature, cost or liability avoidance, revenue-generating, or even simple signals of best-in-class management practices (Murray, Sinclair, Power, & Gray, 2006: 231).

1.05 Environmental Monitoring and Awareness

i. Environmental Monitoring

Environment includes all living and non-living objects. We live in the environment and use the environmental resources like air, land and water to meet our needs. Development also means meeting the needs of the people. While meeting the ever-growing needs, we put pressure on the environment. When the pressure exceeds the carrying capacity of the environment to repair or replace itself, it creates a serious problem of environmental degradation. Therefore, there is a need to monitor the environment and create awareness on environmental protection, conservation and sustainability. While efforts are being made at the national and international level to protect our environment, it is also the responsibility of every citizen and organization to use our environmental resources with care and protect them from degradation.

Environmental monitoring can be defined as the systematic sampling of air, water, soil, and biota in order to observe and study the environment, as well as to derive knowledge from this process (Wiersma, 2004). Monitoring is undertaken for a variety of reasons such as ensuring compliance with environmental legislation and regulatory requirements to protect and safeguard the environment and manage adverse environmental condition. This usually involves comparisons with environmental quality standards (Brandy, 2009).

Monitoring is also required for environmental management and process control as well as a response to complaints or for research purposes such as to establish environmental baselines, trends, and cumulative effects. It can also be used to create environmental awareness and to educate the public about environmental conditions which include environmental aspects and impacts. Environmental aspects are elements of a facility's activities, products, or services that can or does interact with the environment. These interactions and their effects may be continuous in nature, periodic, or associated only with events, such as emergencies. Environmental impact is any change to the environment, whether adverse or beneficial, resulting from a facility's activities, products, or services.

Monitoring can be used to inform policy design and decision-making for compliance with environmental standards; to assess the effects of environmental impact of human and industrial activities and to conduct an inventory of natural resources for their protection and management. Environmental monitoring can be carried out on different geographical scales and time period. For example, from compliance monitoring of oil spillage from individual petroleum company's production or emissions or individual industrial process; through ambient monitoring of regional geographical area such as the Niger delta or national flood emergency control across Nigeria. This can extend to supranational level (e.g., monitoring Ebola virus spread across West Africa). An endangered fish in a small stream and the viability of its short-term fate will require monitoring on short and localized temporal and spatial scales, while the management of natural resources that span a nation will require monitoring programs that are much broader in scale (Artiola, Pepper & Brusseau, 2004).

Programme of monitoring can vary significantly in scope, ranging from community-based monitoring on a local scale, to large-scale collaborative global monitoring programs such as those focused on climate change (Conrad & Daoust, 2008).

Environmental monitoring is conducted by stewardship organizations, concerned individuals, non-governmental environmental organizations, private consulting firms, and government agencies. It involves a collaborative effort by environmental management expert, environmental accounting and disclosure experts, scientists, statisticians, policy makers, and natural resource managers.

The objectives of environmental monitoring are as follows:

- i. ensure that the areas of environmental concern identified are considered and addressed appropriately;
- ii. provide a data base against which any short or long term environmental impacts can be determined;
- iii. provide an early indication should any environmental control measures or practices fail to achieve the acceptable standards
- iv. monitor environmental performance in project execution and the effectiveness of mitigating measures;
- v. verify the environmental impacts predicted in EIA Study;
- vi. determine compliance with environmental standards and regulations;
- vii. take remedial action if unexpected problems or unacceptable impacts arises;
- viii. provide data to enable an environmental audit to be performed.

The benefits of environmental monitoring are as follows: Natural resources protection, conservation and management; hazardous, non-hazardous and radioactive waste management; develop good environmental practice for mitigating global climate change; improving urban air quality; protection of public water supplies; Weather forecasting; protection of endanger species.

Environmental monitoring is critical to knowing whether the quality of our environment is getting better or worse. Information gathered through environmental monitoring is important to many different decision makers, inside and outside the federal government. With the results of monitoring, the government can make informed decisions about how the environment will affect people and how they are affecting the environment. Outside the government, the information is used by many people, such as municipal engineers to design flood control systems or public health experts to design effective policies. Timely and effective responses to environmental emergencies, such as spills, are impossible without adequate information. Farmers, hunters, foresters, and fishers all need to know what is happening to the natural resources they rely on. Environmental monitoring generates the critical information that is essential for the government to provide sound stewardship of the environment. The government uses the information to assess the current state of the environment, to predict the future environment, and to develop sound strategies for adapting to environmental change. For example, daily weather forecasts rely on the current state of the environment, to predict the future environment, and to develop sound strategies for adapting to environmental change. For example, daily weather forecasts rely on a complex set of linked environmental monitoring systems.

Environmental monitoring systems are most successful when they are well coordinated with other systems, when the right partners participate, when quality is built in from the beginning, when reports are designed to be useful, and when resources are used efficiently. For example, some monitoring systems rely heavily on expensive tools and equipment, such as satellites or scientific research vessels that need to be managed carefully with respect to their long-term benefits and costs.

Well-managed environmental monitoring systems can provide a basis for Parliament to hold departments and agencies accountable for their environmental stewardship.

ii. Environmental Awareness

Environmental awareness involves communication campaigns for reaching various audiences, developing messages and selecting and/or producing the appropriate resources and media to reach these audiences. The aim of environmental awareness is to make people from all walks of life aware of specific issues related to their surroundings, including living and non-living elements, e.g. land, soil, plants, animals, air, water and other humans, as well as awareness of their built, social and economic surroundings, and the impacts of our actions on these. Awareness is a necessary but not a sufficient element of social change. The aims of awareness-raising activities are more limited in scope than environmental education and the processes should not be confused. While they cannot, on their own, achieve the required educational

outcomes, awareness-raising can be a component of broader and more in-depth education processes. In the past two decades, environment has attracted the attention of decision makers, scientists and even laymen in many parts of the world. They are becoming increasingly conscious of issues such as famines, droughts, floods, scarcity of fuel, firewood and fodder, pollution of air and water, problems of hazardous chemicals and radiation, depletion of natural resources, extinction of wildlife and dangers to flora and fauna. People are now aware of the need to protect the natural environmental resources of air, water, soil and plant life that constitute the natural capital on which man depends. The environmental issues are important because the absence of their solutions is more horrible. Unless environmental issues are not solved or not taken care of the coming generations may find earth worth not living. The need of the planet and the needs of the person have become one. There is no denying the fact that environment has to be protected and conserved so to make future life possible. Indeed, man's needs are increasing and accordingly the environment is also being altered, indeed, nature's capacity is too accommodating and too regenerative yet there is a limit to nature's capacity, especially when pressure of exploding population and technology keep mounting. What are required are the sustenance, conservation and improvement of the changing and fragile environment.

An increase in environmental awareness can be achieved through a range of communications and by supporting community actions and behavioural change programmes. Ultimately these actions will drive our society towards an ecologically sustainable life style and sustainable work practices.

Many actions can be employed to educate and raise environmental awareness in the community. These actions will empower people to participate effectively in change of attitude towards a clean and safe environment for all. In environmental education everyone has something to learn and something to contribute. Actions that aid environmental awareness are as follows:

1. Regular interaction with community groups and other relevant stakeholders to promote local environmental projects and local initiatives. Mobilize and build on learner's knowledge and competencies.
2. Offer financial support via grants schemes for projects / initiatives that raise community awareness and that promote a positive benefit on their local environment.
3. Support the Green Flag Schools Programme
4. Develop & disseminate educational materials and facts sheets for water protection, waste prevention, litter, climate change and biodiversity.
5. Support environmental award programmes & competitions.
6. Support environmental talks & information seminars that target the general public and businesses.
7. Sponsor such events & programmes that will increase waste minimisation, water & energy conservation.
8. Encourage private companies to have environmental education programmes as part of company policy.
9. Promote the waste hierarchy of waste avoidance and elimination.

10. Educate the public especially households and commercial entities in waste avoidance, diversion of waste streams and the correct separation of waste.
11. Promote waste prevention and minimize the production of harmful waste.
12. Encourage and support the recovery & reuse of waste.
13. Promote waste prevention and minimize the production of harmful waste.
14. Encourage and support the recovery & reuse of waste.
15. Work in partnerships with organizations and address the polluters- pay-principle in relation to waste disposal.

1.06 Environmental and Resource Accounting

Issues associated with accounting for the environment have become relevant to business as environment pollution has become a more prominent problem throughout the world. Steps are being taken as national and international levels to protect the environment and to reduce, prevent and mitigate the effect of pollution. Initiatives are being taken to facilitate the collection of data and increase companies' awareness of financial implication of environmental issues (Jones, 2005).

Environmental accounting deals with both economic and environmental information. The International Federation of Accountants (IFAC) (as cited in Uwuigbe, 2011) defined environmental accounting as the management of environmental and economic performance through the development and implementation of appropriate environmental related accounting system and practice. Environmental accounting can be conducted at the country level (through the National Accounts that provide an estimate of the Gross Domestic Product) or at corporate level (which focuses on the cost structure and environmental performance of a company). At the country level, it is referred to as National environmental and corporate environmental accounting at the corporate level. Corporate environmental accounting consists of environmental management accounting and environmental financial accounting. At the international scene, the United Nations Statistical Division developed into the System of Integrated Environmental and Economic Accounting (SEEA) for adoption by nation states.

The United State Environmental Protection Agency (US EPA) (1995) explains that environmental accounting as a means of measuring and reporting sustainability can be used in three different contexts. These are (1) National Income Accounting (the National Accounts produce the estimates of Gross Domestic), (2) Internal Business Managerial Accounting and (3) Financial Accounting.

The US EPA further explains that environmental accounting from context of National Income Accounting is used to measure macro- economic performance relating to usage of natural resources. For instance, environmental accounting can use physical or monetary units to refer to the consumption of a nation's natural resources, renewable and non- renewable. In this context environmental accounting has been termed 'Natural Resource Accounting' that is accounting for stock and flow of natural resources in both physical and monetary terms (Gupta, 2005).

Environmental and resource accounting is a much broader form of income and welfare accounting than conventional accounting. It has many policy benefits, since it clearly highlights important aspects such as environmental depletion and degradation. It then becomes possible to determine what kind of policy action is required to address the situation. The aim of environmental and resource accounting is to assess the sustainability of economic activities and economic growth by quantifying the depletion of natural resources and degradation of the environment. Natural Resource Accounting further aims to provide an information system linking the economic activities and uses of a resource to change in the natural resource base. The World Commission for Environment and Development has recommended that accounts of natural resources and state of the environment are developed and presented in addition to (traditional) national accounts. The UN Conference on Environment and Development in Rio de Janeiro in June 1992 emphasised natural resource and environmental accounting as important tools to obtain a sustainable development.

Developing a gross domestic product that includes the environment (Green GDP) is also a matter of controversy. Most people actively involved in building environmental accounts minimize its importance. Because environmental accounting methods are not standardized, a green GDP can have a different meaning in each project that calculates it, so values are not comparable across countries. Moreover, while a green GDP can draw attention to policy problems; it is not useful for figuring out how to resolve them. Nevertheless, most accounting projects that include monetary values do calculate this indicator. Great interest in it exists despite its limitations.

From the perspective of Environmental Management Accounting, environmental accounting refers to as the use of data about environmental costs and performance in business decisions and operation within an organisation. It focuses on divisions, facilities, product lines or systems. It deals with both physical information on the flows and use of energy, water and materials (including wastes) and monetary information on environmentally related costs, earnings and savings [5]. Moreover, the term environmental cost has at least two major dimensions: (1) it can refer solely to costs that directly impact a company's bottom line (here termed "private costs"), or (2) it also can encompass the costs to individuals, society, and the environment for which a company is not accountable (here termed "societal costs"). Private costs are the main focus of corporate environmental accounting because that is where companies starting to implement environmental accounting typically begin. However, companies also consider societal costs.

Environmental accounting from context of Financial Accounting refers to the estimation and public reporting of environmental liabilities and financially material environmental costs as well as related environmental information. Financial accounting enables companies to prepare financial reports for use by investors, lenders, and others interested parties such as regulatory agencies, host communities and environmental civil society groups. Publicly held corporations report information on their financial condition and performance through quarterly and annual reports, governed by rules set by the U.S. Securities and Exchange Commission (SEC) with

input from industry's self-regulatory body, the Financial Accounting Standards Board (FASB). Generally Accepted Accounting Principles (GAAP) are the basis for this reporting. Environmental accounting in this context refers to the estimation and public reporting of environmental costs. Management accounting is the process of identifying, collecting, and analyzing information principally for internal purposes.

1.07 Environmental Degradation and Petroleum Production

Environmental damage is the deterioration of the environment through the depletion of natural resources including the ozone layer; pollution of the air and water; soil erosion or contamination; the destruction of ecosystems and loss of biodiversity (Clarkson, Therival & Chadwick, 2007). Chertow (2001) developed an Environmental Impact Assessment equation ($I=PAT$) which explains that adverse environmental impact or damage (I) is caused by the combination of increasing human population (P), economic growth or per capita affluence (A), and the application of resource depleting and polluting technology (T). The United Nations International Strategy for Disaster Reduction (UNISDR) (2009) pointed out that damage done to the environment can alter the frequency and intensity of natural hazards and increase the vulnerability of communities. The types of damages done are varied and include land misuse, soil erosion and loss, desertification, wild land fire, loss of bio-diversity, deforestation, mangrove destruction, land, water, and air pollution, climate change, sea level rise and ozone depletion.

Environment constitutes a very important part of our life. To understand life without studying the impact of environment is simply impossible. The need to protect environment can be ignored only at our peril. We use environmental resources in our day to day life. These resources are renewable and non-renewable. We have to be more cautious in consuming non-renewable resources like coal and petroleum, which are prone to depletion. All human activities have an impact on environment. But in the last two centuries or so, the human influence on environment has increased manifold due to the rapid population growth and the fast development in science and technology. These two are the major factors in reducing the quality of environment and causing its degradation. The environmental degradation poses a great danger to man's own survival. Thus, the conservation and improvement of the environment are vital for the survival, and well being of mankind. Natural resources of land, air and water have to be used wisely as a trust to ensure a healthy environment for the present and future generations. Petroleum resource is one of such important natural resources. The exploration and production of this resource has brought tremendous income to oil producing countries but with huge environmental damage in many countries, especially the developing ones. For instance, Petroleum exploration and production in the Nigeria's Niger Delta region and export of oil and gas resources by the petroleum sector has substantially improved the nation's economy over the past five decades. However, activities associated with petroleum exploration, development and production operations have local detrimental and significant impacts on the atmosphere, soils and sediments, surface and groundwater, marine environment and terrestrial ecosystems in the Niger Delta (Ite, et al, 2013).

Discharges of petroleum hydrocarbon and petroleum–derived waste streams have caused environmental pollution, adverse human health effects, socio– economic problems and degradation of surrounding communities in many oil producing countries.

1.08 Review Questions

- i. Define and explain corporate social responsibility and social externalities
- ii. Describe and explain environmental monitoring and awareness
- iii. Describe and evaluate environmental and resource accounting
- iv. Explain the relationship between environmental degradation and petroleum production.

MODULE 2

2.00 ENVIRONMENTAL, OIL AND GAS ACCOUNTING

2.01 Learning Outcomes

On successful completion of this Module, Students should be able to:

- i. Elucidate community and responsibility accounting;
- ii. Explain polluter-pays-principles;
- iii. Evaluate environmental pollution and implication for developing countries;
- iv. Evaluate presentation and disclosure of environmental accounting.

2.02 Community and Responsibility Accounting

A company's continued existence depends heavily on its ability to deal effectively not with its financial stakeholders alone but also with its non- financial stakeholders such as local communities, civil society groups, the media and the general public. A company's activities must be in congruence with society's values, norms and beliefs. That is, the company should appear to consider the right of the public at large and not merely those of investors (Joshi, Suwaidan & Kumar, 2011). The business of an organisation should not be all about money, but also it should be about responsibility. It should be about public good, not private greed. All organisations have responsibilities to their people, their clients and society. A real commitment to social responsibility strengthens an organisation's reputation and creates vital links with and support from the communities in which it operates.

Social responsibility accounting is an aspect of accounting and reporting that measure the social effects (social costs and benefits) arising from the business enterprise activities. It is the process of communicating the social and environmental effects of organizations' economic actions to particular interest groups within society and to society at large (Gray, Owen, Maunders, 1997). It is commonly used in the context of corporate social responsibility. Since each business enterprise is part of a community that works and is constantly interacting with other community members, it is necessary for the business enterprise to be aware of its obligations and responsibilities and know their limits to protect investors' interests as well as that of other social groups such as employees, customers and vendors and groups in host community. The social responsibility accounting process collect, measure and report transactions and interactive effects of these transactions between business and society by measuring the effects of the business on its surrounding community. This is to assess the fulfilment of the entity social obligations.

Social accounting involves evaluating the social impact of business activities; Measuring the social costs and obligations of the entity; Measuring the social interests of the entity; Providing internal and external information systems in the community.

2.03 Polluter-Pays-Principle

The polluter pays principle is the commonly accepted practice that those who produce pollution should bear the associated costs of managing it to prevent damage to human health or the environment. In environmental law, the polluter pays principle is enacted to make the party responsible for producing pollution responsible for paying for the damage done to the natural environment. For instance, a factory that produces a potentially poisonous substance as a by-product of its activities is usually held responsible for its safe disposal. This principle underpins most of the regulation of pollution affecting land, water and air. Pollution is the contamination of the land, water or air by harmful or potentially harmful substances.

It is part of a set of broader principles to guide sustainable development worldwide. The polluter pays principle has also been applied more specifically to emissions of greenhouse gases which cause climate change. Greenhouse gas emissions are considered a form of pollution because they cause potential harm and damage through impacts on the climate. However, in this case, because society has been slow to recognise the link between greenhouse gases and climate change, and because the atmosphere is considered by some to be a 'global commons' (that everyone shares and has a right to use), emitters are generally not held responsible for controlling this form of pollution. However, it is possible to implement the 'polluter pays' principle through a so-called carbon price. This imposes a charge on the emission of greenhouse gases equivalent to the corresponding potential cost caused through future climate change. In this way, a financial incentive is created for a factory, for instance, to minimise its costs by reducing emissions. Environmental stakeholders have argued that a carbon price should be uniform across countries and sectors so that polluters do not simply move operations to countries with weak or no environmental regulation. "Damage to the environment" and "costs to the environment" are nebulous and subjective concepts where the use of any resource, including the air, water and one's own property, can be defined as harming or 'potentially harming' that resource and therefore the environment. Ultimately since all human activity involves altering (damaging) the natural environment, the PPP as defined by its most vocal advocates can be invoked as a justification for taxing all consumption and production activities.

Instruments to implement PPP includes Command and Control Law, Licensing procedures, Prohibitions Emission limit values Administrative orders & sanctions, Market based instruments, Subsidies/Feed-in-tariffs, Certificates, Tax alleviations, Liability rules Soft law and voluntary agreements.

2.04 Environmental Pollution and Implication for Developing Countries

Environmental pollution is the contamination of the physical and biological components of the earth/atmosphere system to such an extent that normal environmental processes are adversely affected. Pollution is the introduction of contaminants into the environment that cause harm or discomfort to humans or other living organisms, or that damage the environment. This comes in the forms of

chemical substances, or energy such as sound, heat or light, radioactivity. Pollution occurs in all habitats - land, sea, and fresh water and in the atmosphere.

Environmental pollution in developing nations, especially in densely populated urban areas and their surrounding slums, contributes to health risks resulting to the deaths and disabilities of millions of people annually. Such health risks are responsible for as much as one-fifth of the total burden of diseases in the developing world – more than the combined impacts of malnutrition and all other preventable risk factors and groups of diseases. This risk from environmental pollution affects billion of people in the developing countries of Latin America, South East Asia and sub-Saharan Africa.

Many people in developing countries lack adequate shelter, safe water, proper sanitation; they die each year from exposure to indoor air pollution and urban air pollution. One in five children in the developing world do not live to see their fifth birthday. There is a clear link between poverty and pollution. In developing countries, about one third of the population lives on less than one dollar per day. Poverty determines the environmental risks individuals face: where they live, their access to clean water and proper sanitation, and their exposure to various kinds of environmental pollutants, while limiting their access to adequate resources for dealing with those risks. Unable to afford clean fuels, the poor depend on dirty fuels for cooking and heating, filling their dwellings with smoke; their dwellings are usually located near roadways, waste dumps, or industrial areas, subjecting them to a daily barrage of air pollution, noise, and the risks of toxic spills.

Environmental threats to human health in the developing world fall into two broad categories: Traditional hazards associated with poverty and Underdevelopment, vector-borne diseases (e.g. malaria, yellow fever) and lack of access to essential environmental resources such as clean water, food, air, fuel, sanitary waste disposal, and adequate shelter. Modern hazards resulting from rapid development without environmental safeguards: Urban air pollution, contaminated water and soil, noise, and lack of proper sanitary disposal for increasing quantities of waste from household garbage to industrial and medical waste.

Until recently, most people suffering from “traditional” hazards have lived in rural areas of the developing world. With rapid, uncontrolled urbanization and the consequent unchecked growth of slums surrounding cities, these already severe threats are now combining with “modern” hazards to compound the risks to human health. Rapid, uncontrolled urbanisation magnifies the impacts of existing environmental problems, placing slum dwellers – sometimes up to one half of urban populations – under the double jeopardy of traditional diseases associated with unsanitary conditions and pollutants resulting from unchecked industrialisation. Drinking water becomes contaminated both by faeces and industrial chemicals. Air is polluted from households burning dirty fuels and unregulated industrial use of fossil fuels.

Properly regulated industrialization is the key to the economic and social prosperity of developing nations. However, this prosperity is being undermined by serious damage to the environment and human health occurring as the result of rapid, uncontrolled industrial expansion – annual growth rates of up to eighteen per cent

are common in some developing countries, far outstripping those of the developed world. In most of these countries, the legislative and regulatory structures that exist in the developed world are not yet in place, and toxic pollutants are released unchecked into the environment with little knowledge of or concern for their effects. Furthermore, substances having known risks to human health are still widely available in developing countries, and though banned in developed countries. The greatest threats to human health from industrialisation are injuries resulting from workplace accidents, acute chemical poisoning in the workplace or in surrounding areas, and long-term exposure to chemicals released into the general environment. In many of the developing world's cities and towns, sewage systems are either non-existent, limited to only affluent parts of town, and/or not functioning properly. Untreated human waste often flows directly into water supplies that are used for drinking, cooking, and bathing. Even where sewage systems do exist, overflows during rainy periods are common, leading to outbreaks of disease, the most prevalent of these being that diarrhea claims the lives of many people every year. Most of these deaths are children aged less than five years old. In many of the developing world's cities and towns, sewage systems are either non-existent, limited to only affluent parts of town, and/or not functioning properly.

Many of the developing world's children face daily exposure not only to hazards resulting from lack of access to essential environmental resources, but also to a barrage of toxic chemicals and other pollutants stemming from unchecked development. These pollutants include agricultural chemicals, heavy metals such as arsenic and lead, industrial chemicals, and a variety of air pollutants, which have all been linked with birth defects, cancer, and weakening of the human immune system.

In modern industrialized societies, fossil fuels (oil, gas, coal) transcended virtually all imaginable barriers and firmly established themselves in our everyday lives. Not only do we use fossil fuels for our obvious everyday needs (such as filling a car), as well as in the power-generating industry, they (specifically oil) are also present in such products as all sorts of plastics, solvents, detergents, asphalt, lubricating oils, a wide range of chemicals for industrial use, etcetera.

Combustion of fossil fuels produce extremely high levels of air pollution and is widely recognized as one of the most important "target" areas for reduction and control of environmental pollution. Fossil fuels also contribute to soil contamination and water pollution. For example, when oil is transported from the point of its production to further destinations by pipelines, an oil leak from the pipeline may occur and pollute soil and subsequently groundwater. When oil is transported by tankers by ocean, an oil spill may occur and pollute ocean water.

There are other natural resources whose exploitation is a cause of serious pollution; for example, the use of uranium for nuclear power generation produces extremely dangerous waste that would take thousands of years to neutralize. However, fossil fuels are among the most serious sources of environmental pollution. Power-generating plants and transport are probably the biggest sources of fossil fuel pollution. For instance, due to the cumulative impacts of past and present petroleum exploration and production operations, the Niger Delta has been seen as one of the most polluted places in the world due to severe contamination associated with the

operations of petroleum industries. The activities of the oil multinationals have adversely degraded the ecosystem and reduced the biodiversity of the Niger Delta area for several decades, thereby affecting the general ecology of the area. Petroleum exploration and production operations have impacted on agricultural soils, terrestrial ecosystem and pose potential human health risks in the oil-producing host communities in the Niger Delta. The environmental issues and human health risks associated with petroleum resources exploration and production has seriously influenced the interaction of the people of the Niger Delta with their natural environment. Petroleum contamination has negative impact on agricultural productivity and some people, who originally engaged in farming and fishing, are facing loss of livelihoods through contaminated land and marine environment.

Gas flaring and venting are widely used in the oil and natural gas industry to dispose of associated natural gases for safety reasons during petroleum development operations and/or where no infrastructure exists to bring it to market. The process of flaring (burning) and venting (releasing into the atmosphere without burning) of petroleum associated gas has been dramatically curbed in developed countries. Gas flaring and venting reduction strategies in Nigeria seems ineffective over the past years. Gas flaring and venting associated with petroleum exploration and production in the Nigeria's Niger Delta has continued to generate complex consequences in terms of energy, human health, natural environment, socio-economic environment and sustainable development over the past fifty years.

2.05 Presentation and Disclosure of Environmental Accounting

All organisations are required to produce some form of financial statements. That of companies-especially large ones is governed by both company acts and financial reporting standards. They are also subject to statutory audit. Financial statement (which includes a profit and loss account-sometimes called an income statement-and a balance sheet) are typically produced as part of the organisation's annual report-a document primarily intended for shareholders. Historically, there has been no requirement to separately recognise environmental issues of any sort in financial statements and, while this is still the case in most countries (including Nigeria), there is slow progress towards some limited acknowledgement of such matters as impairment of assets and environmental liabilities. For example, in the EU, the commission recommendation on the recognition, measurement and disclosure of environmental issues in the annual reports of companies emphasised the need to integrate financial and environmental reporting. This is still voluntary. Mandatory environmental reporting already applied in some countries-both inside and outside Europe. Countries with some mandatory requirement for environmental reporting include Denmark, the Netherlands, Sweden, France, Australia and Korea. There have been many guidelines issued on how to construct an environmental report and what such a report should contain. Of these it is probably the Global Reporting Initiative (GRI) that currently sets the pace. Most of these guidelines mention the same basic things. Brandy (2009) explains that a credible environmental report should contain (or at a minimum reference):

1. The organization's policy statement;

2. Identification of principal environmental impacts;
3. Plans, structure and organization-who is responsible for what?
4. Status and position of the Environmental Management System (EMS), levels of accreditation and so on (typical ISO14000);
5. Detailed data on targets and performance against those targets in key areas such as water, land, air, energy and other resources use.
6. Analysis of performance and plans for continual improvement;
7. Links to sustainable development; and
8. Probably an attestation (environmental audit statement).

Environmental accounting disclosure is the reporting of environmental information in order to communicate the impact of a company's activities on the environment. This could be in annual reports or separate environmental reports. A key reason for incorporating environmental information within annual report is to increase stakeholders' awareness, of the company's activities, performance and interaction with the environment (Pramanik, Shil and Das, 2008). The disclosure of environmental information is becoming an important aspect of corporate external reporting.

This has been an important development not only in terms of environmental management, but also more generally overall demonstration of corporate social responsibility, accountability and corporate governance. This is gaining prominence in the financial reporting communities in many countries, as a result many companies especially high public profile companies in environmental sensitive sectors have felt increasingly obliged to report externally information on their environmental performance to stakeholders (Sarumpaet, 2005). Ultimately, many companies in different countries have started the practice of making environmental disclosure in annual reports.

Jones (2005) explains that environmental issues related to financial reporting should only be disclosed in annual reports to the extent that they are material to the financial performance or financial position of a company; thus, environmental provisions should be shown in the balance sheet under the caption "other provisions" and if material, separately disclosed in the notes to account section. Jones (2005) also mentioned that in the notes, the followings should be given (1) valuation methods applied on environmental issue (2) Extraordinary environmental items. (3) Disclosure and details of "other provisions" and contingent liabilities including narrative information in sufficient details, so that the nature of the contingency can be understood; (4) amount of environmental expenditure charge to the profit and loss account, analyse in manner appropriate to the nature of business and types of environmental issues relevant to the company and amount of environmental expenditure capitalised; (5) amount of fines and penalties for non-compliance with environmental regulation and compensation to the third parties. The following can also be disclosed in the annual report.

Description of environmental issues relevant to the financial position of the company; environmental protection policy and measure; Improvements made in key area of environmental protection; Government incentives related to environmental protection measures such as grants and tax concessions; Reference to environmental

report if provided separately. Bakr (2010) mentioned that the US Security and Exchange Commission regulation requires companies to disclose the followings:

- a. The material cost of complying with government regulation in future.
- b. The cost of remediating contaminating site if a liability is likely to have been incurred and its magnitude can be approximately estimated.
- c. Other contingent liabilities arising from environmental exposure.
- d. Involvement as a party to a legal proceeding about environmental issue, especially with an agency of government.
- e. Any known trend or uncertainty involving environmental issues, including pending regulation that would materially affect the company's business.

In Japan, the Environmental Accounting Guideline issued by the Ministry of Environment requires companies to include separate statement to reflect environmental cost and environmental performance (MOE, Japan, 2005).

2.06 Review Questions

- i. Define and explain community and responsibility accounting
- ii. Describe and explain polluter-pays-principles
- iii. Evaluate environmental pollution and implication for developing countries
- iv. Describe and explain presentation and disclosure of environmental accounting

MODULE 3

3.00 HISTORICAL EVOLUTION OF ACCOUNTING PRINCIPLES AND PRACTICES

3.01 Learning Outcomes

On successful completion of this Module, Students should be able to:

- i. Appraise the history of oil and gas operations in Nigeria;
- ii. Elucidate the unique features of oil and gas accounting;
- iii. Distinguish accounting concepts, principles and standards in petroleum accounting;
- iv. Analyse the classification of costs;
- v. Evaluate the methods of accounting;
- vi. Analyse the chart of accounts.

3.02 History of Oil and Gas Operations in Nigeria

i. Historical Progression

This first successful oil exploration in Nigeria started in the Niger Delta in 1937 by shell D'arcy (now, Shell Petroleum Development Company of Nigeria Ltd). The company was granted/given exclusive exploration rights and licence by the British colonial government over the entire Nigerian territory. The operative law at the time was the Mineral Ordinance No.17 of 1914 which allows British registered entities or entities from its protectorates the prospective right in Nigeria. This sole exploration right by shell (SPDC) lasted up to 1959 when other entities of other nationalities were granted exploration rights.

The search by SPDC was, however, preceded by an unsuccessful exploration for oil in Okitipupa, Ogun State in 1908 by the Nigerian Bitumen Corporation, a German entity licenced to prospect for oil and gas in the area. The company's operation was forced to an end in 1914 with the eruption/outbreak of the First World War.

After the Second World War, a fruitless/unsuccessful first deep exploration well (a dry hole) was drilled in 1951 at Iho, Owerri to a depth of 11,228 feet. Shell succeeded in finding oil in a commercial quantity at Oloibiri, Rivers State (now in Bayelsa State) in 1956 after several exploration activities and huge investment. The first consignment of 5,000 Barrels of crude oil was shipped from Nigeria to Britain following the installation of pipeline from Oloibiri to Port Harcourt. Extensive oil exploration between 1957 and 1959 gave rise to the emergence of Ebubu and Bornu Oil fields in River State. In Delta State, West of the Niger, the first hydrocarbon was found in Ughelli.

The attainment of independence by Nigeria from Britain and the initial breakthrough by SPDC opened up the industry for some other entities of other nationalities to join or to partake in the exploration. A number of companies like Mobil producing, Chevron (formerly Gulf), Agip, Elf (formerly Safrap), Texaco (formerly Tenneco and Amoseas) joined in both onshore and offshore exploration drive in 1961.

This progress or feat or development was facilitated by the extension of the concessionary rights earlier monopolized by SPDC to the new partakers in exploration. The first offshore oil industry was recorded in 1964 in Okan field in Delta State. All the foremost explorers have made reasonable progress, found and are producing oil. As it is now, many more entities both indigenous and foreign have secured concessionary rights and are producing. The numbers of producing oil wells in country have passed the 2,374 recorded in 1999. Before the feat, Nigeria had earlier in 1972 attained the feat of a 7th position among the oil producing majors in the world and have since progressed to the 6th largest oil producing country the world over.

ii. Oil and Gas Revenue and the Nigerian Economy

Oil and Gas revenue accounts for more than 90% of the country's total export earnings and close to 70% of total government revenue and 40% of Gross Domestic Product in 1999 fiscal year. From an initial production of 5100 barrels of crude oil per day in 1958, which qualify the country to join the league of oil producing nations, it rose steadily to 2.0 million barrels per day in 1972 and peaked at 2.4 million barrels per day in 1979. The core producing areas cover almost 60% of the confirmed total acreage of approximately 31,105 sq.km with the laying areas yet unexploited.

The harnessable crude oil reserve based on a 2003 estimate stood at 34 billion barrels. Additional exploration activities were embarked upon with the target to achieve a 40 billion barrels reserve by 2010.

The following categories of revenue accrue to the government from the oil and gas industry:

1. Royalties
2. Rents
3. Signature bonuses
4. Oil pipeline and licence fees
5. Petroleum profits tax
6. NNPC earnings from direct sales
7. Proceeds from local sales of crude oil to NNPC
8. Proceeds from export sales of crude oil and gas
9. Penalties from gas flared.

iii. Nigerian Liquefied Natural Gas (NLNG)

The Nigeria LNG project is phased. The initial production from two trains is located at Bonny Islands. A ready market exists for its output from its base project and train three. The majority of the gas for base project is mainly NAG supplied from gas supplier fields, viz:

SPDC – SOKU

NAOC – OBIAFU OBIKROM

EPNL - OBITE

The LNG and LPG production will be actualized from the gas for train three that mainly contain associated gas.

The NLNG entered into Gas Supply Agreements (GSAs) with the following three upstream joint venture gas producers in

1992:

1. The Shell Petroleum Development Company of Nigeria Limited (SPDC)- NNPC/SPDC/NAOC/EPNL JV: operator and sellers' representative-SPDC (shell affiliate);
2. Nigerian Agip Oil Company Limited (NAOC) - NNPC/NAOC/POCNL JV: operator and sellers' representative-NAOC (Agip affiliate).
3. ELF Petroleum Nigerian Limited (ELF), (the ELF Nigerian Limited)- NNPC/EPNL JV: operator and sellers' representative-EPNL (ELF affiliate).

The target is for the three joint ventures to supply the gas need for the project for the next 22^{1/2} years. The expected supply will be a total of about 302.17 billion standard cubic metres (BSCM) of feed-gas requirement for the three trains of the NLNG project in the form a combination of associated and mainly non-associated gas.

By the time the NLNG's train three attains full capacity utilization, a total of over 41 million standard cubic metres will be needed daily by the plant.

Two types of licenses are issued to oil producers in Nigeria. They include;

1. The Oil Prospecting License (OPL), and
2. The Oil Mining Licence (OML).

The validity periods range from five (5) to twenty (20) years respectively.

Note: Details of the oil production and exports, and oil reserve/production ratio on an annual basis can be found in NNPC statistical Bulletin and OPEC statistical Bulletin respectively.

3.03 Historical Evolution of Accounting Practices in the Oil and Gas Industries

i. Introduction

Generally, oil and gas accounting covers accounting for the four fundamental costs incurred by entities involved in oil and gas exploration and producing activities. These four fundamental costs include:

- a. Acquisition costs:** - This covers costs incurred in securing the right to explore, drill, and produce oil and natural gas, that is, property acquisition. Entities usually obtain these rights by securing an oil, gas and mineral lease.
- b. Exploration costs:** - This covers costs incurred in evaluating property prospects which involves identifying portions that may require investigation and investigating definite portions including exploratory wells drilling.
- c. Development costs:** – This covers costs incurred in getting ready proved reserves for production. It includes costs undertaken to secure access to proved reserves and to put in place facilities for extracting, processing, assembling and storing oil and gas.

- d. Production costs:** – This covers costs incurred in extracting the oil and gas to the surface and in assembling, processing and storing same.

Two historical cost methods used to account for oil and gas production are generally accepted. They include:

- i. Successful Efforts (SE) accounting method, and
- ii. Full Cost (FC) accounting method.

The main accounting consideration with respect to the four basic costs is the timing in benefit derivable from the cost incurred - whether to write off the cost incurred as expenses within the year or to capitalize the costs. If expensed, the costs are treated as period expenses and are charged against revenue in the current accounting period. If capitalized, the costs are gradually expensed as depletion when production activity runs, or as benefit derivable expires either through impairment, or abandonment.

Hence, the basic difference is the timing of the expense or loss charged against revenue. Therefore, the basic difference between the successful efforts accounting method and the full cost accounting method is whether a cost is written off, that is, expensed in the period incurred or capitalized.

The other fundamental difference between the two historical cost methods is the size of the cost centre where the costs are accumulated and amortized. Under the successful efforts accounting method, the cost centre is a lease, field, or reservoir. This cost centre is usually much smaller when compared to the cost centre for full cost accounting method which is a country as a whole.

The size of a cost centre has serious involvement in considerations for computing amortization, depletion and depreciation and also in writing down ceiling determination.

Successful efforts accounting flows from and is largely consistent with financial accounting theory and framework.

Non-monetary assets normally are accounted for at the cost to acquire or construct them. If costs do not result to an asset with traceable future benefits, they are charged to expense or written off as a loss.

For a cost to be capitalized under successful efforts accounting method, a direct link or relationship between the costs incurred and reserves found should be established. Hence, for successful efforts accounting only fruitful searching costs that directly gave rise to the location of proved reserves are recognized as part of the cost of locating oil and gas and are capitalized.

Else, the costs are expensed as period costs when incurred because it did not meet up with the criteria for asset recognition as specified in the financial accounting framework under the International Financial Reporting Standard (IFRS).

On the other hand, full cost accounting method accommodates both successful and unsuccessful costs in the search effort as part of the cost of locating oil and gas. Hence, both successful and unsuccessful efforts costs are capitalized under the full cost accounting approach. The direct link between costs incurred and reserves located is not a requirement for full cost accounting method.

Some specific accounting treatments under the two methods need to be highlighted. For successful efforts approach, exploration costs that do not directly connect oil and gas location, that is unsuccessful costs, are treated as period expenses while successful costs are treated as capital expenditures. Whereas, following full cost approach, all exploration costs whether successful or unsuccessful efforts are capitalized. Both methods have the same treatment for acquisition, development and production costs. The acquisition and development costs are capitalized, while the production costs are expensed. All development costs including those pertaining to unsuccessful wells are capitalized under the successful efforts approach. It is so treated because they are deemed to be contributing towards the establishment of a production system of wells and associated equipment's and facilities instead of oil and gas exploration.

ii. Historical Evolution of Accounting Practices in the Oil and Gas Industries

After the Second World War in 1945, a number of oil and gas companies employed some level of successful efforts accounting method in accounting for oil and gas exploration, development and production activities. The practice by those adopting the successful efforts approach was to capitalize the costs of acquiring property, wells and equipment and to write off costs of dry hole and intangible drilling on productive wells. If the exploration is successful (reserve located) the capitalized costs are amortized or written off if unsuccessful.

When in the 1960's a more complex technology for exploration and large-scale public markets emerged, a new accounting approach followed for oil and gas operations. The new approach is termed full-cost accounting method. Here all costs incurred in searching for, acquiring and developing oil and gas reserves were capitalized in a cost centre irrespective of whether reserve were found, that is successful exploration, or not.

The two different accounting methods for oil and gas operations that evolved had justifiable grounds for their adoption. Those inclined to full cost accounting approach canvass that locating hydrocarbons in commercial quantity is general focus that should not be assessed on individual well basis while supporters of successful efforts accounting approach argue that any drilling operation that is unsuccessful is a loss that should be written off without delay.

The actual practical application of the two approaches varied to some degree from company to company since there was no consensus. A number of adoptors of successful effort accounting approach had all geological and geophysical exploration costs while some write-off all exploration costs as period expenses. Accounting treatment of dry holes also varies. A good number of successful effort accounting adoptors write-off exploration dry hole costs, a handful of adoptors capitalized

development dry hole. More so, the proponents of full cost could not agree on what should comprise a cost centre. All these conflicting practices created the need for uniformity and standardization of accounting treatment for the oil and gas industry operations.

3.04 Development of Standard Accounting Treatment Of Oil and Gas Operations

Some professional and regulatory bodies like the American Institute of Certified Public Accountants (AICPA), US Securities and Exchange Commission (SEC), and the Financial Accounting Standard Board (FASB) of the United States made initial move to bring uniformity and reduce differing accounting treatments of comparable transactions. The AICPA commissioned Robert Field to carryout research in financial accounting treatment and reporting in the extractive industry. Field's report recommended the use of successful efforts accounting approach and asserted that the full cost accounting approach is an inappropriate accounting approach. The controversy that trailed the report made it unsuccessful. After the Financial Accounting Standard Board came into existence, it waded into the matter and issued the Statement of Financial Accounting Standards NO.19 (FAS 19) in December 1977. The standard handled the accounting treatment of cost capitalization, conveyances, inter-period allocation of income taxes and disclosures for oil and gas reserves quantities and costs with the adoption of a form of successful efforts approach.

All parties did not agree to the accounting treatments recommended in FAS19. As a result, in August 1978, SEC disclosed its dissatisfaction with the two methods and proposed the development of an entirely new accounting approach termed Reserve Recognition Accounting (RRA). This was intended to remedy the anomalies and weakness discovered in the two methods already in use. The value of proved oil and gas reserves was recognized as assets and reductions in the reserve values as earnings in the financial statements under the RRA. The RRA did not last long before being severely criticized for its inadequacies; the first being that the oil and gas reserves measurement was mere unsubstantiated estimates that may never materialize. The second point is that it allowed the recognition of revenues before it is received thereby negating or neglecting the realization principle.

As a result of the non-acceptance of the RRA, the SEC decided in February 1981 to discard the RRA and endorse the successful efforts accounting and full cost accounting approaches. It then directed FASB to embark on a project to develop additional disclosures for oil and gas companies' operations. This assignment resulted in the emergence of FAS 69 in November 1982.

The contributions of the UK Oil Industry Accounting Committee need to be captured. The committee published four Statements of Recommended Practice (SORP) to be applied by oil companies. The statements include:

1. Disclosures about oil and gas exploration and production operations (issued April 1986).
2. Accounting for oil and gas exploration and development operations (issued December, 1987).
3. Accounting for abandonment costs (issued June 1988).

4. Accounting for various financing, revenue and other transactions/ activities of oil and gas exploration and production companies (issued January 1991).

In the local scene, the Nigerian Accounting Standards Board (NASB) inaugurated a steering committee on Oil and Gas Accounting in Nigeria to develop an accounting standard for the petroleum industry. The committee headed by Chief R.U. Uche produced a draft document that was later released by NASB as SAS14 termed: Accounting in the Petroleum Industry: Upstream Activities. It became operational on January 1, 1994. Barely a year later, in 1995, the NASB constituted another steering committee on Accounting in the Petroleum Industry to cover the Downstream Activities. Again it has Chief R.U. Uche as the chairman. The committee came up with the draft document that was later released by NASB as SAS17, termed: Accounting in the Petroleum Industry: Downstream Activities. This became effective on January 1, 1998.

At present Nigeria has adopted the International Financial Reporting Standards (IFRS) since 2012 financial year for all significant public entities. The implication is that the IFRS is the primary standard that guides the preparation and presentation of financial statements by reporting entities in Nigeria. The relevant legal framework underlying Oil and Gas Accounting is the Financial Reporting Council of Nigeria Act, NO.6, 2011.

The relevant legal framework underlying Oil and Gas Accounting is the Financial Reporting Council of Nigeria Act, NO.6, 2011. The Act established an agency of the federal government called the Financial Reporting Council (FRC) and charged with setting accounting standards in Nigeria.

3.05 Unique Features of Oil and Gas Accounting

(a) Definitions

The following definitions apply to the terms listed below as they are used in this section:

- (1) Oil and gas producing activities: (i) such activities include:
 - (i) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations.
 - (ii) The acquisition of property rights or properties for the purpose of further exploration and/or for the purpose of removing the oil or gas from existing reservoirs on those properties.
 - (iii) The construction, drilling and production activities necessary to retrieve oil and gas from its natural reservoirs, and the acquisition, construction, installation, and maintenance of field gathering and storage systems -- including lifting the oil and gas to the surface and gathering, treating, field processing (as in the case of processing gas to extract liquid hydrocarbons) and field storage. For purposes of this section, the oil and gas production function shall normally be regarded as terminating at the outlet valve on the lease or field storage tank; if unusual physical or operational circumstances exist, it may be appropriate to regard the production functions as terminating at the first point at which oil, gas, or gas liquids are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal.

Oil and gas producing activities do not include:

- (i) The transporting, refining and marketing of oil and gas.
 - (ii) Activities relating to the production of natural resources other than oil and gas.
 - (iii) The production of geothermal steam or the extraction of hydrocarbons as a by-product of the production of geothermal steam or associated geothermal resources.
 - (iv) The extraction of hydrocarbons from shale, tar sands, or coal.
- (2) Proved oil and gas reserves: Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.
- (i) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes:
 - (a) That portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and
 - (b) The immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.
 - (ii) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the “proved” classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.
 - (iii) Estimates of proved reserves do not include the following:
 - (a) Oil that may become available from known reservoirs but is classified separately as “indicated additional reserves”;
 - (b) Crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors;
 - (c) Crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and
 - (d) Crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.
- (3) Proved developed oil and gas reserves: Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved

recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as “proved developed reserves” only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

- (4) Proved undeveloped reserves: Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.
- (5) Proved properties - Properties with proved reserves should be capitalized.
- (6) Unproved properties - Properties with no proved reserves should be expensed.
- (7) Proved area- the part of a property to which proved reserves have been specifically attributed.
- (8) Field: An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms “structural feature” and “stratigraphic condition” are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.
- (9) Reservoir: A reservoir is a porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.
- (10) Exploratory well: A well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir. Generally, an exploratory well is any well that is not a development well, a service well, or a stratigraphic test well. These items are defined below.
- (11) Development well: A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.
- (12) Service well: A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

- (13) Stratigraphic test well: A drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intention of being completed for hydrocarbon production. This classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as:
- (i) "exploratory- type," if not drilled in a proved area, or
 - (ii) "Development-type," if drilled in a proved area.
- (14) Acquisition of properties: Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.
- (15) Exploration costs: Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:
- (i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
 - (ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, advalorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
 - (iii) Dry hole contributions and bottom hole contributions
 - (iv) Costs of drilling and equipping exploratory wells
 - (v) Costs of drilling exploratory-type stratigraphic test wells
- (16) Development costs: Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities are costs incurred to:
- (i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
 - (ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.
 - (iii) Acquire, construct and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production

storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.

(iv) Provide improved recovery systems.

(17) Production costs

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

- (A) Costs of labor to operate the wells and related equipment and facilities
- (B) Repairs and maintenance
- (C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
- (D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
- (E) Severance taxes

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(b) Successful Efforts Method

A reporting entity that follows the successful efforts method shall comply with the accounting and financial reporting disclosure requirements of Statement of Accounting Standards No. 14.

(c) Full Cost Method

Application of the full cost method of accounting: A reporting entity that follows the full cost method shall apply that method to all of its operations and to the operations of its subsidiaries, as follows:

- (1) Determination of cost centres: Cost centres shall be established on a country-by-country basis.
- (2) Costs to be capitalized: All costs associated with property acquisition, exploration, and development activities (as defined in paragraph (a) of this section) shall be capitalized within the appropriate cost centre. Any internal costs that are capitalized shall be limited to those costs that can be directly identified with acquisition, exploration, and development activities undertaken by the reporting entity for its own account, and shall not include any costs related to production, general corporate overhead, or similar activities.

- (3) Amortization of capitalized costs: Capitalized costs within a cost center shall be amortized on the unit-of-production basis using proved oil and gas reserves, as follows: Costs to be amortized shall include:
 - (A) All capitalized costs, less accumulated amortization, other than the cost of properties described in paragraph (ii) below;
 - (B) The estimated future expenditures (based on current costs) to be incurred in developing proved reserves; and
 - (C) Estimated dismantlement and abandonment costs, net of estimated salvage values.

3.06 Accounting Concepts, Principles and Standards in Petroleum Accounting

Generally, companies follow either the successful efforts method or the full cost method of accounting. Both of these methods are part of SAS 14. Successful efforts accounting in various forms has been used for over 79 years. Full cost accounting began to be applied in the 1950s. By the mid-1960s, accountants and analysts were concerned about the diverse accounting methods in use by oil and gas producers. Not only were full cost and successful efforts methods utilized, but many variations in applying them had evolved.

3.07 Classification of Costs

The distinguishing features of successful efforts and full cost methods centre on which costs are to be capitalized and how to properly amortize them. Costs incurred in oil and gas producing activities are classified into four categories:

1. Property acquisition costs
2. Exploration costs
3. Development costs
4. Production costs

Support facilities and equipment, such as trucks, field service units, warehouses, camp facilities, and other facilities, may serve more than one of the four activities. Facilities and equipment costs are capitalized and related depreciation and operating costs are allocated to those functions. Depreciation of the capitalized facilities and equipment costs, as well as related operating expenses, is allocated as costs of acquisition, exploration, development, or production as appropriate. Accounting for support facilities and equipment is not unique to the oil and gas industry and, therefore, is not discussed in detail.

i. Acquisition Costs

Acquisition costs include the costs incurred to purchase, lease, or otherwise acquire a property or mineral rights. These costs generally include:

- i. Lease bonuses
- ii. Options to purchase or lease properties
- iii. Costs applicable to minerals when land and mineral rights are purchased in fee: Broker fees, recording costs, and legal expenses
- iv. Miscellaneous costs incurred in obtaining mineral rights

Costs are initially capitalized as unproved property acquisition costs, which mean the property has not yet been evaluated as to whether it has proved reserves. After exploration, drilling, or lapse of the lease, and if no proved reserves are found, then

acquisition costs are removed from the unproved property account and become costs of abandoned or worthless property.

ii. Exploration Costs

Exploration costs are incurred in:

- i. Identifying areas that may warrant examination
- ii. Examining specific areas that might contain oil and gas reserves

They can include drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before the related property is acquired (sometimes referred to as prospecting costs) and after the property is acquired. Exploration costs can include the costs of topographical or geophysical studies, and salaries and expenses of geologists, geophysical crews, and others conducting the studies.

Expenses of carrying and retaining undeveloped properties, such as delay rentals and ad valorem taxes on properties, are included in exploration costs as are dry hole and bottom-hole contributions.

iii. Development Costs

Development costs are incurred to obtain access to proved reserves and provide facilities for extracting, treating, gathering, and storing oil and gas. They include the costs of development wells to produce proved reserves, as well as costs of production facilities, such as lease flow lines, separators, treaters, heaters, storage tanks, improved recovery systems, and nearby gas processing facilities.

iv. Production Costs

Production costs are the costs of activities that involve lifting oil and gas to the surface, and gathering, treating, processing, and storage in the field. In a broad sense, production costs include all costs of acquisition, exploration, development, and production. However, for successful efforts and full cost accounting, the term production costs (or lifting costs) refer only to those costs incurred to operate and maintain wells, related equipment, and facilities that are expensed as incurred as part of the cost of oil and gas produced.

Production costs include the labour to operate wells and facilities, repair and maintenance expense, materials and supplies consumed ad valorem taxes and insurance on property, and severance or production taxes.

3.08 Methods of Accounting

i. Successful Efforts Accounting: Capitalization Overview

Costs of acquiring unproved properties are initially capitalized to the Unproved Property Acquisition Costs account. At least once a year, unproved properties are examined to determine whether their costs have been impaired. Impairment is recorded as an exploration expense and credited to the Allowance for Impairment account, a contra account to Unproved Property Acquisition Costs. Capitalized costs are amortized as the petroleum is produced from the property. If an unproved property is deemed to be worthless or is abandoned, its cost is removed from the Unproved Property Acquisition Costs account and charged to Allowance for Impairment (or Exploration Expense depending on the type of impairment allowance procedure followed).

All exploration costs, except the costs of exploratory wells, are charged to expense as they are incurred. Costs of exploratory wells (including stratigraphic test wells) are initially capitalized (deferred) pending the outcome of the drilling operation. If the test well finds proved reserves, its costs are capitalized to the Proved Property Well and Development Costs account to be amortized as the related reserves are produced. If the test well is dry, accumulated drilling costs are charged to Exploration Expense.

All development costs, including the costs of development of dry holes, are capitalized to the Proved Property Well and Development Costs account. Such costs are amortized as the related proved developed reserves are produced.

- i. Enhanced recovery injectant costs are capitalized as deferred charges when related to future production
- ii. Production costs are capitalized as deferred charges when associated with future gas production under the sales method of accounting for gas imbalances. A portion of production costs may also be capitalized as the cost of crude oil inventory.

The rules to be used in computing amortization of mineral property acquisition costs and the cost of wells, related equipment, and facilities under successful efforts accounting are:

1. Mineral property costs are amortized as the proved developed and undeveloped reserves from the entire property are produced. Such amortization is equivalent to depreciation and, for income tax reporting, is called cost depletion. Hence, amortization of oil and gas property, well, and development costs is often called DD&A, meaning depreciation, depletion, and amortization.
2. Proved property well and development costs are amortized as the proved developed reserves are produced. In computing amortization, properties in a common geological structure (such as a reservoir or field) may be combined into a single amortization centre. If both oil and gas are produced from the same property, the capitalized costs should be amortized on the basis of total production of both minerals. This requires that the two minerals be equated to an equivalent barrel or equivalent Mcf. If only one mineral is produced in sufficient quantities, the other mineral is considered de minimis; since minerals produced are assumed to be in proportion to reserves in the ground, the single producing mineral may be used in the computation.

Many of the accounts found in the Chart of Accounts are not unique to the petroleum industry; they apply to a variety of industries. However, accounts used to record transactions related to exploration, acquisition, development, and production are significantly different. The following analysis of accounts is presented first for the successful efforts method followed by a brief explanation of accounts unique to full cost.

Assets

Accounts receivable—Gas Imbalances recognizes a receivable for gas volumes owed from a joint venture partner or from the gas transporter. Inventories - In many circumstances, the amount of crude oil located in lease tanks is not significant. Accordingly, it is not recorded as an item of inventory on the company's books. However, if such crude oil is a significant amount, an inventory figure would be entered based on the cost of production. Natural gas inventory recognition is also uncommon since gas is not stored at the lease surface, like oil; however, gas injected in gas storage fields may be a significant inventory item for some companies. Prepaid expenses - Prepaid insurance, prepaid rents, and similar costs recognized by businesses comprise the prepaid expenses account. Although delay rentals are typically prepaid expenses in economic substance, it is industry practice to expense them under successful efforts (and capitalize under full cost) when paid.

Unproved property acquisition costs. These are used to accumulate the costs of the company's mineral rights in unproved properties (properties on which oil or gas reserves do not exist with enough certainty to be classified as proved). There can be a general ledger account for every major type of unproved mineral interest.

Detailed records are maintained to record cost data for each separate property interest. These accounts are charged with applicable costs (purchase price or leasehold bonus, option costs, and incidental acquisition costs) of unproved properties acquired. Similarly, the accounts are credited with the cost of unproved properties surrendered, sold, or transferred to proved properties when proved reserves are found. If a portion of an unproved property is sold for less than the total purchase price of the entire property, the appropriate account is credited for the proceeds up to the property's cost.

Unproved property purchase suspense – This is used to accumulate costs incurred in acquiring mineral interests, but to which title has not yet been acquired. The account is credited either when the interest involved is acquired or when it is ascertained that the interest will not be acquired. For example, if ABC Oil Company pays a landowner N10,000 for the option to lease a mineral property within six months, Account 210 is charged with the option cost. Later, if the acreage is actually leased, the N10,000 option cost is credited to Account 210 and charged to Unproved Property Acquisition Costs (Account 211). If the acreage under option is abandoned, the N10,000 held in suspense is credited to Account 210 and is charged to Exploration Expense (Account 806).

The allowance for impairment and amortization of unproved properties is more complex. Unproved properties are subjected to an impairment test that is essentially a comparison between capitalized costs and value. If the value is less than the cost, impairment must be recognized. This impairment is recorded by a charge to expense (Account 806) and a credit to the allowance account. Impairment may be measured by comparing the cost and value of individual unproved properties (this procedure must be used for properties whose costs are individually significant). Impairment of costs of groups of individually significant properties may be measured and recorded

by amortization, based on prior experience, of the total cost of the group of properties.

If impairment of individual properties is recorded, detailed records of the impairment of each individual property must be maintained. If group amortization is used, a single impairment allowance is kept for the entire group (or for each group if there is more than one group). If impairment is recorded on individual properties, Account 219 is charged with the accumulated impairment on a property that is sold, surrendered, or assigned or becomes proved (and the related unproved property cost account is credited to remove the sold property's cost).

If impairment is based on a group method: For a property that becomes proved, its capitalized acquisition costs are reclassified to prove property and Account 219 is unchanged. For surrendered or abandoned property, its capitalized acquisition costs are charged against Account 219. For sold unproved property, Account 219 is charged to the extent that sales proceeds are less than the property's capitalized acquisition costs.

Proved property acquisition costs – These are costs and accumulated amortization of costs of proved mineral interests, i.e., those properties that are producing oil or gas or on which, based on known geological and engineering data, oil and gas reserves are reasonably certain to exist.

When a property is found to have proved reserves, its cost is reclassified from unproved property acquisition costs to prove property acquisition costs. For a property on which impairment has been recorded individually, only net book value (i.e., cost less the impairment allowance) is transferred to the proved property account. Account 226 reflects the cumulative amortization of the costs of proved mineral interests.

When amortization is recorded, it is charged to expense (Account 726) and is credited to Account 226. Amortization (depletion) of proved mineral interests is to be based on production and may be computed for each separate proved property, or may be computed on the total cost of properties that have been grouped together on some common geological basis, such as a field. If amortization is based on the individual property, a separate detailed record will be maintained for the amortization accumulated on that property. Similarly, if amortization is based on groups of properties, the subsidiary records must provide for accumulated amortization applicable to each group. If amortization is based on the individual property, Account 226 is charged with the accumulated amortization on that property upon disposal. On the other hand, if proved properties are grouped for amortization purposes, Account 226 is charged with the total cost (less any proceeds realized) when disposition of a property occurs.

Proved property well and development costs- These are costs and accumulated amortization of the costs of wells, production equipment, and facilities on proved properties. Costs of exploratory wells that do not find proved reserves (dry holes) are not capitalized, but rather are charged to expense (Account 804 or 805). Primarily for

income tax determination, costs have been divided into two categories: Intangible Costs (Account 231) and Tangible (or Equipment) Costs (Account 233).

Intangible costs are all those costs (such as rig rental and fuel) that have no physical existence or salvage value, but are nevertheless incurred in drilling the well. Because of tax definitions, labour costs to install casing or other equipment in the well (up through the point that valves are installed to control production) are generally considered to be intangibles and are charged to Account 231. However, costs to install flow lines, separators, tanks, and other lease equipment are classified for income tax purposes as equipment and charged to Account 233. Accounts 232 and 234 are credited with accumulated amortization of intangibles and equipment, respectively. Amortization of well and development costs may be based on individual properties (leases) or on groups of properties if the grouping is related to geological conditions such as a reservoir or field. Accounts 232 and 234 are charged with the amount of depreciation accumulated on a property that is disposed of if impairment has been recorded individually. On the other hand, if group amortization is used, Accounts 232 and 234 are charged with the total capitalized costs (less proceeds from disposition) of intangibles and equipment, respectively, when a disposition occurs for a developed property included in the group.

Account 235 may be used in lieu of liability Account 410 to recognize the additional cumulative depreciation from increasing the amortization base for estimated future plugging and abandonment costs.

Work-in-progress—An important part of the accounting system of an oil and gas company is its work in progress accounts and the procedures related to them. In some companies, these accounts are referred to as work in process or incomplete construction. Work in progress accounts are closely related to the authorization for expenditures system under which every major construction project or asset acquisition project is controlled by a properly approved authorization for expenditures. Thus, subsidiary accounts are kept for each project and for major cost classifications for each project.

Account 240 is sometimes used to accumulate the cost of major geological and geophysical exploration projects. Each major project is approved by an Authorization for Expenditure (AFE); thus, costs related to each project are properly analysed and classified. Accumulated costs are closed at the end of the period to expense. Some companies do not use an AFE system for exploration projects, but may nevertheless have a work in progress account for such activities.

Account 241, Work in progress—Intangible Costs, is charged for all intangible costs incurred in drilling wells. Each drilling project is properly authorized and costs are accumulated for each AFE. The detailed classification of expenditures is identical to the classification used in Account 231. If an exploratory well finds proved reserves, the accumulated costs are charged to Account 231. If, on the other hand, the exploratory well is unsuccessful, accumulated costs are charged to Exploration expenses, Account 804 or 805.

Account 244, Work in progress—Workovers, is used to accumulate the costs of well workovers controlled by AFEs. Most companies establish some maximum amount for workover jobs that can be expensed without an AFE. If the total cost of the workover job is estimated to be no more than the amount specified, costs will be charged directly to production expense, Account 710-002. If an AFE is required, costs are accumulated for the AFE in Account 244. Upon completion of the job, accumulated costs are removed from Account 244 and charged either to a production expense account or an asset account. A general rule is that if the workover does not increase the total proved reserves of the well, the costs are charged to expense (Account 700.002), but if the job does increase total proved reserves from the well, the costs are capitalized. Usually, the costs involved are intangible in nature, but may include well equipment.

Support equipment and facilities - Account 258 is charged with the capitalized costs of equipment and facilities used in oil and gas operations that serve more than one property or field or more than one function (acquisition, exploration, development, or production). District camps, regional shops, trucks, barges, warehouses, and electric power systems are examples of field service equipment and facilities. Appropriate detailed records are kept for individual units and groups of assets.

Liabilities

Revenue distributions payable and revenues held in suspense—Accounts 302 and 304 recognize liabilities to other joint interest owners or royalty owners for their share, if any, of revenues received by the company on the venture's behalf. Suspended revenues may relate to disputed or unknown ownerships or to nominal payables paid out quarterly or annually.

Production payments and prepaid as production occurs, oil and gas companies are obligated to: (1) deliver specified production volumes, or (2) pay specified cash amounts. Companies may agree to make future production payments in return for receiving assets immediately, such as cash or producing property. A receipt of cash in exchange for a production payment payable in oil or gas volumes is called a Volumetric Production Payment, or VPP. It is regarded as the sale of a mineral interest and sales proceeds are credited to Account 431, Deferred Revenue for Volume Production Payments. The account's credit balance is proportionately reduced, and revenue is credited as VPP volumes are delivered.

Receipt of cash in exchange for future production payments payable in specified cash amounts is considered a borrowing: the cash account is debited and Account 404, Production Payments Payable as Debt, is credited. Occasionally, cash is received in exchange for a production payment created from unproved mineral interests where the cash is credited to the unproved property account.

Account 430, deferred revenue for prepaid, reflects prior cash received for an obligation to deliver oil or gas in the future regardless of production. The prepaid transaction is not the sale of a mineral interest since the delivery obligation may require the company to purchase the oil or gas for delivery under the obligation.

Clearing, apportionment, and control accounts-Many expenses cannot be charged readily to a single drilling operation, individual lease, or other individual operating function. They must be accumulated and subsequently distributed to other expense or asset accounts by using clearing and apportionment accounts.

Clearing accounts are used to accumulate expenses during a given period such as a month; at the end of the period, the balance of the account is allocated to other accounts on a predetermined basis. An apportionment account is also used to accumulate costs, but in this case credits to the account are made on the basis of fixed rates for services rendered. The balance of an apportionment account, which should be small if rates have been properly established, will normally be carried forward from month to month, but will be closed to miscellaneous expense or miscellaneous income at year- end. The use of Control accounts (360 and 361) enhances accounting controls over joint venture revenues and billings received and processed. E&P companies do not normally invoice for oil and gas sales; instead, they accrue estimated receivables. When net sales proceeds are received, E&P companies should use internal information to check the accuracy of the oil (or gas) purchaser's calculations. Remittances can be reviewed for accuracy by entering the well's identity, sales month, gross production volume, and cash received by the company from the payer's remittance advice. Assume that N30,000 is received by the company for one well's oil production in June. The company's computer generated entries are:

101 Cash	30,000
360 Revenue Control	30,000
360 Revenue Control*	33,120
710.009 Production Taxes	2,880
601 Oil Revenue	36,000

*Computer calculated as 5,000 barrels sold x N60/bbl [price per company pricing file] x 12% net revenue interest [from the company's master division of interest file] x (1.0 - .08) production tax rate [from the company's tax rate file].

The control account indicates a ~~N~~3,120 discrepancy which may be due to an error. A balance in the control account helps the company identify the error and correct it. Normally, control accounts have nominal balances. Some companies classify revenue control accounts in the accounts receivable section of the chart of accounts.

Revenues

Revenue accounts unique to oil and gas production (accounts 600 through 607) are designed to reflect the company's share of revenues from each major type of mineral interest owned. Revenues applicable to mineral interests owned by other parties (for example, revenues applicable to a royalty interest owned by the lessor in a lease operated by the company) are not included in revenue.

Expenses

Expense accounts unique to oil and gas exploration and production are typically found in accounts 700 through 806. Direct expenses of operating producing oil and gas properties are charged to Account 710, Lease Operating Expenses. The classification of lease operating expenses varies by company, but in each case is designed to assist in the control of expenses. Items charged to Account 710 are generally referred to as lifting costs. Costs are accumulated for each mineral property so that net income can be computed for management oversight and income tax accounting. Depreciation, depletion, and amortization are not included in Account 710, but are separately shown in accounts 725 through 749.

ii. Overview of Full Cost Accounting

Under the full cost method, all acquisition, exploration, and development costs are considered necessary for the ultimate production of reserves. Many of these costs are tied to activities not directly related to finding and developing reserves. Yet, the company expects that the benefits obtained from successful prospects, together with benefits from past discoveries, will be adequate to recover all costs and yield a profit. Establishing a direct cause-and-effect relationship between costs incurred and specific reserves discovered is not relevant to the full cost concept.

3.09 Cost Centers

Capitalized costs are aggregated and amortized by cost centre.

Costs to be capitalized

All costs associated with property acquisition, exploration, and development activities (as defined in paragraph (a) of this section) shall be capitalized within the appropriate cost centre. Any internal costs that are capitalized shall be limited to those costs that can be directly identified with acquisition, exploration, and development activities undertaken by the reporting entity for its own account, and shall not include any costs related to production, general corporate overhead, or similar activities.

All geological and geophysical costs, carrying costs (such as delay rental and maintenance of land and lease records), dry hole and bottom-hole contributions, costs of exploratory wells (both dry and successful), costs of stratigraphic test wells, costs of acquiring properties, and all development costs are capitalized. When leases are surrendered or abandoned, their costs remain a part of the net capitalized costs of the cost centre.

Costs to be amortized as DD&A include the sum of three costs:

- i. Capitalized costs, net of accumulated amortization, but excluding all unevaluated acreage and unevaluated exploratory costs, as well as significant investments in major development projects in progress
- ii. Estimated future development costs applicable to proved undeveloped reserves
- iii. Estimated dismantling and abandonment costs, net of salvage Unproved Properties and exploratory costs excluded from the amortization base should be periodically assessed for impairment until it can be determined whether proved reserves are attributable to the properties. If impairment is indicated,

the impairment amount should be included in the amortization base. Unevaluated costs applicable to properties that are not individually significant may be placed in a group (or more than one group) and amortized into the amortization base.

Amortization under full cost is calculated on a unit-of-production basis using physical units of proved oil and gas reserves converted to a common unit based on relative energy (Btu) content. Economic circumstances may indicate that using gross revenues rather than physical units' results in a more appropriate basis for computing amortization.

A cost ceiling on capitalized costs for companies using the full cost method is placed. Any excess is charged to expense. For each cost centre, net unamortized costs, less related deferred income taxes, shall not exceed the sum of:

The present value at a 10 percent discount of future net revenues of proved reserves using hedge-adjusted prices Plus unproved property costs and preproduction costs not being amortized Plus the lower of cost or estimated fair value of unproved properties included in costs being amortized Less: income tax effects related to differences between: The sum of (a), (b), and (c), and the tax basis of the properties involved.

Accounts for full cost accounting

In applying the full cost method for an E&P company, few accounts are unique to full cost accounting. Since all costs incurred in exploration, acquisition and development activities are capitalized, there are no exploration expense accounts for a full cost company. When an unproved lease is abandoned as unsuccessful, related costs are moved from the Unproved Property Acquisition Costs account and charged to the appropriate cost centre's Account 227 as a capitalized cost of unsuccessful efforts.

Exploration costs and similar carrying costs are allocated to individual unproved properties or proved properties and become part of the cost of individual properties. Some costs, such as regional G&G costs, cannot be reasonably allocated and may simply be charged to Account 229, Unsuccessful Exploration Costs. Account 236 is used to accumulate amortization as a single figure for each cost centre, and Account 725 reflects this charge. Thus, there is no separate allowance for amortization of each type of capitalized cost.

Under the full cost method, a ceiling is placed on capitalized costs. Any write-down required because a cost centre ceiling is less than net capitalized costs is charged to Account 761 and credited to Account 237 with appropriate adjustment of deferred income taxes. Finally, no gain or loss is customarily recognized on the sale or abandonment of oil and gas assets under the full cost method.

3.10 Chart of Accounts

Illustrative Chart of Accounts

The Illustrative Chart of Accounts is a comprehensive document: it includes categories used by both the successful efforts and full cost methods of accounting.

Accounts unique to successful efforts companies are noted by an SE in the left margin, while FC denotes accounts unique to full cost companies.

Chart of accounts

100-109 Cash

101 Cash in First National Bank

102 Cash in First State Bank

105 Special Deposits

106 Payroll Account

107 Petty Cash

110-119 Short-Term Investments

110 Marketable Securities

111 Overnight Interest-Bearing Accounts

120 - 129 Accounts Receivable

120 Accounts Receivable—Oil and Gas Sales

121 Accounts Receivable—Gas Imbalances (if using entitlement method)

122 Accounts Receivable—Gas Marketing

123 Accounts Receivable—Joint Interest Billings

124 Accounts Receivable—Employees

126 Accounts Receivable—Other Receivables

127 Accrued Receivables

127.001 Oil and Gas Sales

127.002 Accrued Interest

127.003 Other

129 Allowances for Doubtful Accounts

130 -139 Inventories

130 Inventory of Crude Oil (account used infrequently)

131 Inventory of Natural Gas Held in Storage

132 Inventories of Materials and Supplies

132.001 Field Yards (detailed by location and type of material)

132.002 Trucking Yards (detailed by location and type of material)

132.003 Warehouse Inventories (detailed by location and type of material)

132.004 Lower-of-Cost-or-Market Reserve

140-149 Other Current Assets

140 Prepaid Expenses

141 Current Portions of Long-Term Receivables

142 Margin Accounts for Futures Trading

143 Other

210-219 Unproved Property Acquisition Costs*

210 Unproved Property Purchase Suspense (detailed by project)

211 Unproved Property Acquisition Costs

211.001 Lease Bonus

211.002 Commissions

211.003 Landsman Services and Expenses

211.004 Abstracting Fees

211.005 Capitalized Interest

FC 211.006 Delay Rentals

FC 211.007 Other Carrying Costs

220-226 Proved Property Acquisition Costs

221 Proved Property Acquisition Costs (detailed by lease) Additional proved property accounts may be used for other types of economic interests, such as Account 222 for fee interests, Account 223 for royalty interests, and Account 224 for overriding royalty interests.

225 Proved Production Payments

SE 226 Accumulated Amortization of Proved Property Acquisition Costs (detailed by property interest or by geological structure)

227-229 Capitalized Costs of Unsuccessful Efforts

FC 227 Abandoned and Worthless Properties FC 228 Impairment of Unproved Properties FC 229 Unsuccessful Exploration Costs

230- 239 Proved Property Well and Development Costs

230 Capitalized Asset Retirement Obligations (ARO) at Inception

231 Intangible Costs of Wells and Development (detailed by well or field) FC 231.001 Well Drilling and Completion

SE 231.001 Successful Exploratory Wells

SE 231.002 Successful Development Wells

SE 231.003 Development Dry Holes

231.005 Enhanced Recovery Projects

231.006 Other Intangibles

233 Tangible Costs of Wells and Development (detailed by well or field) FC 233.001 Well Drilling and Completion

SE 233.001 Successful Exploratory Wells

SE 233.002 Successful Development Wells

SE 233.003 Development Dry Holes

233.004 Tangible Workover Costs (infrequently used)

233.005 Development Support Equipment and Facilities

233.006 Gas Processing Facilities (may be a separate section)

233.007 Enhanced Recovery Projects

233.008 Other Field Equipment

233.009 Allocated Tangible Cost of Acquired Properties

FC 237 Accumulated Impairment of Oil and Gas Property Cost Centres (by country)

FC 238 Deferred Losses (Gains) on Sales of Properties

240-249 Work in Progress

240 Work in Progress—Geological and Geophysical Exploration (detailed by project or AFE)

240.001 Geological and Geophysical Contract Work

240.002 Geological and Geophysical Services Other

240.003 Field Party Salaries and Wages

240.004 Field Party Supplies

240.005 Other Field Party Expenses

240.006 Charges for Support Facilities

240.007 Shooting Rights and Damages

240.008 Mapping Expenses

240.009 Equipment Rental

240.010 Other Geological and Geophysical Costs

240.011 Purchased Geological and Geophysical Data

240.012 Overhead
 240.015 Transfers to Exploration Expense
 241 Work in Progress—Intangible Costs of Wells and Related Development (detailed by AFE)
 241.001 Drilling Contract
 241.002 Site Preparation, Roads, Pits
 241.003 Bits, Reamers, Tools
 241.004 Labor, Company
 241.005 Labor, Other
 241.006 Fuel, Power, Water
 241.007 Drilling Supplies
 241.008 Mud and Chemicals
 241.009 Drill Stem Tests
 241.010 Coring, Analysis
 241.011 Electric Surveys, Logs
 241.012 Geological and Engineering
 241.013 Cementing
 241.014 Completion, Fracturing, Acidizing, Perforating
 241.015 Rig Transportation, Erection, Removal
 241.016 Environmental and Safety
 241.017 Other Services
 241.018 Overhead
 241.019 Miscellaneous
 241.025 Capitalized Interest
 241.028 Transfers to Exploration Expense—Dry Holes
 241.029 Transfers to Proved Property Well and Development Costs
 243 Work In Progress—Tangible Costs of Wells and Related Development
 243.030 Tubular Goods
 243.031 Wellhead and Subsurface Equipment
 243.032 Pumping Units
 243.033 Tanks
 243.034 Separators and Heater-Treaters
 243.035 Engines and Power Equipment
 243.036 Flow Lines
 243.037 Miscellaneous
 243.038 Installation Costs—Surface Equipment
 243.045 Capitalized Interest
 243.048 Transfers to Exploration Expense—Dry Holes
 243.049 Transfers to Prove Well and Development Costs
 244 Work in Progress—Workovers (usually a production expense)
 245 Work in Progress—Support Equipment and Facilities
 246 Work in Progress—Gas Processing Facilities
 247 Work in Progress—Enhanced Recovery Projects
 248 Work in Progress—Other Field Equipment (Subaccounts are not illustrated.)
 258-259 General Support Equipment and Facilities
 258 Cost of General Support Equipment and Facilities (detailed by facility or unit)

259 Accumulated Depreciation of General Support Equipment and Facilities (detailed by facility or unit)
 260-269 Other Plant and Equipment (detailed by asset and location)
 261 Autos
 262 Office Equipment
 263 Buildings
 264 Land
 268 Other
 269 Accumulated Depreciation (detailed by type of equipment and by asset)
 270-279 Notes Receivable
 270 Notes Receivable—Trade
 271 Notes Receivable—Production Payments
 272 Notes Receivable—Co-owners
 273 Notes Receivable—Officers and Employees
 274 Notes Receivable—Other
 280-289 Other Assets
 280 Pipeline Demand Charges
 281 Stocks of Subsidiaries
 282 Other Stock Investments
 283 Cash Surrender Value of Life Insurance
 284 Investments in Hedging Instruments
 289 Other
 290-299 Deferred Charges
 290 Deferred Tax Assets
 291 Deferred Losses on Hedging of Future Production
 292 Deferred Expenses Recoverable Under Foreign Production Sharing Contracts
 293 Other Deferred Charges
 300-349 Current Liabilities (appropriately detailed in subaccounts)
 301 Vouchers Payable
 302 Revenue Distributions Payable
 303 Lease Bonuses Payable
 304 Revenues Held in Suspense
 305 Advances from Joint Interest Owners
 306 Gas Imbalance Payables (if using entitlement method)
 307 Accrued Liabilities
 310 Short-Term Debts
 311 Current Portion of Long-Term Debt
 320 Production Taxes Payable
 321 Ad Valorem Taxes Payable
 330 Federal Income Taxes Payable
 331 State Income Taxes Payable
 332 Payroll Taxes Payable
 335 Other Current Liabilities
 350-369 Clearing, Apportionment, and Control Accounts
 350 District Expenses
 351 Region Expenses
 352 Support Facility Expenses

360 Revenue Control Account
 361 Billing Control Account
 400-409 Long-Term Debt
 401 Notes Payable
 402 Mortgages Payable
 403 Bonds Payable
 404 Production Payments Payable as Debt
 405 Commercial Paper
 406 Capitalized Lease Obligations
 407 Debt Premiums
 408 Debt Discount
 409 Portions Reclassified as Current
 410-419 Other Long-Term Liabilities
 410 Asset Retirement Obligations (ARO)
 411 Other Environmental Liabilities
 412 Accrued Pension Liabilities
 420 Deferred Income Taxes
 430-439 Other Deferred Credits
 430 Deferred Revenue for Prepaids
 431 Deferred Revenue for Volume Production Payments
 432 Deferred Gain (for future commitments on certain property sales)
 433 Deferred Gains on Hedging of Future Production
 500-599 Stockholders' Equity
 500 Preferred Stock
 501 Common Stock
 505 Additional Paid -in-Capitals
 525 Retained Earnings
 530 Dividends
 600-699 Revenues (typically presented net of royalties due to others)
 601 Crude Oil Revenues
 602 Gas Revenues
 603 NGL Revenues
 604 Royalty Oil Revenues
 605 Royalty Gas Revenues
 606 Royalty NGL Revenues
 607 Revenues from Net Profits Interests
 610 Gain (Loss) on hedging the Company's Revenues (using futures, options, derivatives, etc.)
 615 Gain (Loss) on Trading of Futures, Options, and Derivatives (speculative trades)
 620 Gains on Property Sales (rarely used for full cost method)
 625 Interest Incomes
 630 Other Income
 701-709 Marketing Expenses
 701 Oil Marketing Expenses
 702 Gas Marketing Expenses
 703 NGL Marketing Expenses
 710 Lease Operating Expenses

710.001 Salaries and Wages
 710.002 Employee Benefits
 710.003 Contract Pumping Services
 710.004 Well Services and Workovers
 710.005 Repairs and Maintenance of Surface Equipment
 710.006 Fuel, Water, and Lubrication
 710.007 Supplies
 710.008 Auto and Truck Expenses
 710.009 Supervision
 710.010 Ad Valorem Taxes
 710.011 Production Taxes and Severance Taxes
 710.012 Other Taxes
 710.013 Compressor Rentals
 710.014 Insurance
 710.015 Salt Water Disposal
 710.016 Treating Expenses
 710.017 Environment and Safety
 710.018 Overhead
 710.019 Shut-in and Minimum Royalties
 710.020 Other Royalties (where appropriate)
 710.021 Pressure Maintenance
 710.022 Other
 725-749 DD&A
 FC 725 Depreciation, Depletion, and Amortization
 SE 726 Amortization of Proved Property Acquisition Costs
 SE 732 Amortization of Intangible Costs of Wells and Development
 SE 734 Amortization of Tangible Costs of Wells and Development
 735 Amortization of Capitalized Asset Retirement Obligations
 739 Depreciation of General Support Equipment and Facilities
 749 Depreciation of Other Plant and Equipment
 760-761 Loss on Impairment of Long-Lived Assets
 760 Losses on Impairment of Long-Lived Assets
 FC 761 Provisions for Impairment of Oil and Gas Assets
 SE 800-899 Exploration Expenses
 SE 801 Geological and Geophysical Expenses
 SE 801.001 Geological and Geophysical Contract Work SE 801.002 Geological and Geophysical Services Other SE 801.003 Field Party Salaries and Wages
 SE 801.004 Field Party Supplies
 SE 801.005 Other Field Party Expenses
 SE 801.007 Shooting Rights and Damages
 SE 801.008 Mapping Expenses
 SE 801.009 Equipment Rentals
 SE 801.010 Other Geological and Geophysical Costs
 SE 801.011 Purchased Geological and Geophysical Data
 SE 801.012 Overhead
 SE 802 Carrying and Retaining Undeveloped Properties
 SE 802.001 Rentals (also called Delay Rentals) SE 802.002 Ad Valorem Taxes

SE 802.003 Title Defense
SE 802.004 Record Maintenance
SE 803 Test Well Contributions
SE 803.001 Dry Hole Costs
SE 803.002 Bottom-Hole Costs
SE 804 Unsuccessful Exploratory Wells (i.e., Dry Holes) SE 804.001 Intangibles
SE 804.002 Tangibles
SE 805 Unsuccessful Exploratory Stratigraphic Test Wells
SE 805.001 Intangibles
SE 805.002 Tangibles
SE 806 Impairment, Amortization and Abandonment of Unproved Properties
900-919 General and Administrative Expenses
901 Officers' Salaries
902 Other Salaries
903 Employee Benefits
904 Rents
905 Office Supplies
906 Utilities
907 Dues and Subscriptions
908 Travels and Entertainment
909 Legal and Auditing
910 Insurance
911 Taxes Other Than Income
912 Contributions
918 Miscellaneous G&A Expense
919 Operator's Overhead Recovery
920-929 Interest Expense
920 Interest on Debts
921 Other Interest
922 Gain (Loss) on Hedging of Interest Expense
923 Transfer for Interest Capitalized
924 Accretion Cost on Asset Retirement Obligations
930 Losses on Sales of Property
931 Provisions for Restructuring
933 Casualty Loss
40-949 Income Tax Provision
940 Current Federal Income Taxes
941 Current State and Local Income Taxes
942 Current Foreign Income Taxes
945 Deferred Federal Income Taxes
946 Deferred State and Local Income Taxes
947 Deferred Foreign Income Taxes
960 Extraordinary Items

3.11 Review Questions

- I. Trace and explain the history of oil and gas operations in Nigeria
- II. Explain the unique features of oil and gas accounting
- III. Explain the accounting concepts, principles and standards in petroleum accounting
- IV. Analyze the classification of costs
- V. Describe and explain the methods of accounting
- VI. Explain and analyze the chart of accounts.

MODULE 4

4.00 ACCOUNTING FOR UNPROVED PROPERTIES ACQUISITION OF MINERAL PROPERTIES

4.01 Learning Outcomes

On successful completion of this Module, Students should be able to:

- i. Compute accounting for acquisition cost of unproved properties;
- ii. Evaluate the typical provisions of OPL's and OML's
- iii. Determine impairments of unproved properties
- iv. Compute surrender and abandonment of unproved properties

4.02 Accounting for Acquisition Costs of Unproved Properties

Accounting for Unproved Mineral Leasehold Acquisitions

Account 211—Unproved Property Acquisition Costs reflect the total costs of unproved mineral leaseholds for the purpose of the following example:

Bonus payments

A lease bonus, ordinarily the initial investment in an unproved lease, is capitalized as part of the property cost for financial accounting purposes. Assume ABC Oil Company acquires a lease on 640 acres from Landowner Smithers and pays a lease bonus of N100 per acre. The lease is assigned number 24002. The ~~N~~64,000 lease bonus becomes the initial capitalized cost of the lease. Acquisition of the Smithers' lease is recorded as follows:

211 Unproved Property Acquisition Costs, Lease No. 24002	64,000
301 Vouchers Payable	64,000

To record lease bonus on acquisition of Smithers lease.

Incidental lease acquisition costs

The cost of a mineral property includes such incidental costs as "broker's fees, recording fees, legal costs, and other costs incurred in acquiring properties." A legal fee of ~~N~~400 was paid in connection with acquiring the Smithers lease and is recorded as follows:

211 Unproved Property Acquisition Costs, Lease No. 24002	N 400
301 Vouchers Payable	400

To record legal fee incurred in connection with acquisition of Smithers lease.

Similar entries are made for recording fees and other acquisition costs, unless the amounts are insignificant. In that case, companies charge such costs to expense at the time incurred. Most companies require a minimum amount (such as N100 or ~~N~~250) for expenditures to be capitalized. In identifying and acquiring leases, an E&P company may incur interval costs for scouting, civil engineering, surveying, and mapping. One problem faced in properly accounting for such costs, usually referred to as leasing costs, is that personnel are often engaged not only in lease activities, but also in servicing leases already acquired, assisting in drilling operations, working in exploration activities, and even working on producing leases.

Costs incurred by a company's own leasing staff can be accounted for in one of three ways:

- i. Expense all leasing costs at the time incurred
- ii. Capitalize all leasing costs by allocating them on an acreage basis or equally to all leases taken during the period
- iii. Capitalize those costs that can be associated with specific lease acquisitions and charge the balance to current operating expense

From the viewpoint of accounting theory, the third method is perhaps the most desirable; however, practical difficulties often make it prohibitive. Detailed time sheets can help determine labor costs directly applicable to specific properties. Operating costs of equipment may be charged to individual properties if adequate records are kept. In reality, the bulk of leasing costs cannot be traced to specific leases, and must be allocated on a predetermined basis if they are to be capitalized. Several alternatives are available to the petroleum accountant. One is to accumulate all leasing costs applicable to an area of interest in a suspense account. This would occur in much the same way that exploration costs are accumulated by areas of interest for tax purposes. Then the entire amount applicable to an area can be capitalized on an acreage basis to any leases acquired.

A second alternative provides for accumulated costs to be allocated between acreage leased (capitalized) and not leased (expensed) based on acreage. Finally, it might be argued that all leasing costs should be capitalized with the total outlay divided among all leases acquired during the year; however, this practice would certainly not be suitable for companies using the successful efforts method. Because of the practical difficulty involved, ABC Oil Company treats all leasing overhead costs as current operating expenses. The 2001 Price Waterhouse-Coopers Survey of U.S. Petroleum

Any internal costs that are capitalized shall generally be limited to those costs that can be directly identified with acquisition, exploration, and development activities undertaken by the reporting entity for its own account, and shall not include any costs related to production, general corporate overhead, or similar activities.

Options to acquire leasehold

An operator may not be sufficiently interested in an area to pay bonuses necessary to acquire leases; instead it may wish to acquire rights to shoot seismic with an option to lease any part or all of the acreage covered by the option. It is an acceptable practice to (a) expense shooting rights and capitalize lease option costs. The option agreement may specify an amount to be paid for each. Nevertheless, any costs assigned should be based on a reasonable allocation. If none of the acreage is leased, the option's entire cost is charged to expense. A full cost company capitalizes all option payments regardless of whether any acreage is taken.

As an example, on June 12, 2006, ABC Oil Company pays Landowner Klein N1 an acre for the right to explore a 1,200-acre tract and ~~N2~~ per acre for the right to take five-year leases within the next six months on any part of the 1,200 acres by paying a lease bonus of ~~N450~~ per acre at the time the option is exercised. On December 12,

2006, ABC exercises the option on 500 acres, acquiring one lease—No. 24019—and allows the option on the remaining 700 acres to lapse. The following journal entries illustrate these transactions.

	₦	₦
June 12:		
210 Unproved Property Purchase Suspense	2,400	
801 G&G Expenses, Shooting Rights	1,200	
301 Vouchers Payable		3,600
To record lease option and G&G rights on Klein tract.		

December 12:		
211 Unproved Property Acquisition Costs, Lease No. 24019	26,000	
806 Impairment, Amortization, and Abandonment of Unproved Properties		1,400
201 Unproved Property Purchase Suspense		2,400
301 Vouchers Payable	25,000	
To record exercise of option on 500 acres of Klein property (No.24019) and lapse of option on the remaining 700 acres.		

If no acreage was leased by December 12, the amount held in suspense is expensed as follows:

806 Impairment, Amortization, and Abandonment of Unproved Properties	2,400	
210 Unproved Property Purchase Suspense		2,400
To record lapse of options on Klein 1,200-acre tract.		

Accounting for Acquisition of Fee Interests in Property

Although an oil operator typically obtains mineral rights through an oil and gas lease, there may be occasions when a fee interest in a property (i.e., outright ownership of both minerals and the surface) is obtained. In this case, the purchase price (including incidental acquisition costs) should be equitably allocated between the minerals and surface rights. Theoretically, the allocation would be made on the relative fair market values of the two interests. However, it may be simpler to allocate to that element whose value is more clearly determinable, and then allocate the residual cost to the other property interest.

For example, assume that ABC paid ~~₦~~1,000 per acre for the fee interest in 500 acres, with the surface to be held for investment purposes. In recent transactions in the immediate vicinity of the property, surface rights in similar land without any minerals attached had sold for N900 per acre. The entry could be as follows:

	₦
184 Land	450,000
212 Unproved Fee Interests	50,000
301 Vouchers Payable	500,000
To record purchase of the fee interest in land and minerals	

4.03 Accounting for Maintenance and Carrying Costs of Unproved Properties

In addition to the acquisition of leases, the land department is responsible for maintaining accurate property records. Leases must be kept in force with good title

until either the property becomes productive or a decision is made to surrender or abandon the acreage. Delay rentals, ad valorem taxes, legal fees for title defense, and clerical costs are considered maintenance or carrying costs, which must be expensed as incurred.

Rentals

Assuming the lease is not a paid-up lease, on or before the first anniversary of the lease a rental (delay rental) must be paid to defer commencement of drilling operations for an additional year within the primary term. If operations have not commenced or the delay rental is not paid by the anniversary date, the lease automatically terminates on that day. For a successful efforts company, the delay rentals must be charged to expense as incurred. A full cost company capitalizes delay rentals and all other maintenance costs of unproved properties.

For example, the 640-acre Landers lease No. 24078 calls for an annual delay rental of ₦1,280. Operations have not commenced on the first anniversary of the lease, but the company wishes to keep the lease in force. It pays the rental and records the following entry to record the voucher payment:

802 Carrying and Retaining Undeveloped Properties—

Delay Rentals, Lease 24078 ₦1,280

301 Vouchers Payable ₦1,280

To record annual delay rental expense on the Landers lease.

When unproved properties are bought or sold, it is important to realize that the industry accounting practices of fully expensing (successful efforts) or capitalizing (full cost) delay rentals are at odds with the economic substance of delay rentals being prepaid expenses. An acquired property's nominal price is typically increased for the seller's prepaid expenses at closing. If the property's nominal price is adjusted upwards for delay rentals as prepaid expenses, the rental would typically be prorated over a 12-month period. For example, an unproved, undeveloped lease with an anniversary date of March 31 is sold for a ₦20,000 nominal price as of June 30. The ₦4,000 delay rental paid in the preceding February or March provides a ₦3,000 ($\text{₦4,000} \times 9/12$) prepaid expense as of June 30, and increases the sales price to ₦23,000.

Unless clarified in the sales agreement, a property seller and buyer may disagree on whether rentals should be considered prepaid expenses. Rentals are not expressly viewed as prepaid expenses under successful efforts or full cost accounting. If sales agreements call for adjusting the nominal sales price for prepaid expenses including rentals, buyers should be cautious that the nominal sales price does not already reflect such amounts. Contrary to some professional opinions, delay rentals can enhance the future benefits of the lease. Postponing drilling operations for several months could significantly reduce drilling costs, or increase potential production, by allowing additional time to assess the outcome of drilling and production on nearby properties. Valuable additional information could become available on whether to drill and, if so, how best to accomplish it.

By commencing drilling on or before the rental due date and continuing drilling operations, a company eliminates the need for paying a delay rental. From year to year, accrual based accounting for recurring, relatively small prepaid expenses (such as a typical E&P company's delay rentals as a group) is immaterial to the company's annual income. Thus, the nature and economic substance of delay rentals does not significantly affect financial reporting practices.

Property Taxes on Unproved Leases

Property taxes on mineral rights owned by a lessee are merely another carrying cost of the property and are charged to expense. Taxes involved in this situation are incurred after the lessee has acquired the mineral rights, and are not to be confused with any delinquent taxes assumed by the lessee at the time of acquiring the lease. If property taxes assessed on the Landers lease are ₦500, the entry to record the expense is:

	₦
802.002 Ad Valorem Taxes, Lease No. 24078	500
301 Vouchers Payable	500
To record property taxes on the Landers lease.	

Other Carrying Costs

Other types of lease maintenance and carrying costs, such as clerical and recordkeeping costs and legal fees for title defense, are charged to expense under the successful efforts method in the same manner as delay rentals and property taxes; these same expenditures are capitalized under full cost.

4.04 Typical Provisions of OPLs and OMLs

Upstream oil and gas development in Nigeria involves exploration, prospecting and production. At the level of exploration, an Oil Exploration License (OEL) is granted which enables the company to undertake exploration for petroleum, especially to obtain seismic data for the purpose of determining the likelihood of obtaining petroleum in commercial quantities.

This data provides support for an application for an Oil Prospecting License (OPL). An OPL authorizes exploration and prospecting activities within the concession area, which usually does not exceed 2,590 square kilometers. In relation to these core activities, the OPL grants the holder exclusive rights. It also authorizes the holder to carry away and sell petroleum won during the duration of the OPL. Though an OPL is a reference to petroleum, in practice an OPL entitles the holder to win the gas found in the concession area over which there is an OPL. At this stage, if oil is discovered in commercial quantities, upon meeting the stipulated conditions, which include financial capability, technical expertise and environmental competence, the company may be granted an Oil Mining Lease (OML). This confers exclusive right to the company within the leased area to conduct exploration and prospecting operations and to win, get, work, store, carry away, transport, export or otherwise treat petroleum discovered in or under the leased area.

4.05 IFRS 6: Exploration for and Evaluation of Mineral Resources

Overview

IFRS 6 *Exploration for and Evaluation of Mineral Resources* has the effect of allowing entities adopting the standard for the first time to use accounting policies for exploration and evaluation assets that were applied before adopting IFRSs. It also modifies impairment testing of exploration and evaluation assets by introducing different impairment indicators and allowing the carrying amount to be tested at an aggregate level (not greater than a segment).

IFRS 6 was issued in December 2004 and applies to annual periods beginning on or after 1 January 2006.

Amendments under consideration by the IASB Intangible assets

Summary of IFRS 6

Exploration for and evaluation of mineral resources means the search for mineral resources, including minerals, oil, natural gas and similar non-regenerative resources after the entity has obtained legal rights to explore in a specific area, as well as the determination of the technical feasibility and commercial viability of extracting the mineral resource. [IFRS 6. Appendix A]

Exploration and evaluation expenditures are expenditures incurred in connection with the exploration and evaluation of mineral resources before the technical feasibility and commercial viability of extracting a mineral resource is demonstrable. [IFRS 6. Appendix A]

Accounting policies for exploration and evaluation

IFRS 6 permits an entity to develop an accounting policy for recognition of exploration and evaluation expenditures as assets without specifically considering the requirements of paragraphs 11 and 12 of IAS 8 *Accounting Policies, Changes in Accounting Estimates and Errors*. [IFRS 6.9] Thus, an entity adopting IFRS 6 may continue to use the accounting policies applied immediately before adopting the IFRS. This includes continuing to use recognition and measurement practices that are part of those accounting policies.

Impairment

IFRS 6 effectively modifies the application of IAS 36 *Impairment of Assets* to exploration and evaluation assets recognised by an entity under its accounting policy. Specifically:

- Entities recognising exploration and evaluation assets are required to perform an impairment test on those assets when specific facts and circumstances outlined in the standard indicate an impairment test is required. The facts and circumstances outlined in IFRS 6 are non-exhaustive, and are applied instead of the 'indicators of impairment' in IAS 36 [IFRS 6.19-20]

- o Entities are permitted to determine an accounting policy for allocating exploration and evaluation assets to cash-generating units or groups of CGUs. [IFRS 6.21] This accounting policy may result in a different allocation than might otherwise arise on applying the requirements of IAS 36
- o If an impairment test is required, any impairment loss is measured, presented and disclosed in accordance with IAS 36. [IFRS 6.18]

Presentation and disclosure

An entity treats exploration and evaluation assets as a separate class of assets and make the disclosures required by either IAS 16 *Property, Plant and Equipment* or IAS 38 *Intangible Assets* consistent with how the assets are classified. [IFRS 6.25]

IFRS 6 requires disclosure of information that identifies and explains the amounts recognised in its financial statements arising from the exploration for and evaluation of mineral resources, including: [IFRS 6.23–24]

- a. its accounting policies for exploration and evaluation expenditures including the recognition of exploration and evaluation assets
- b. the amounts of assets, liabilities, income and expense and operating and investing cash flows arising from the exploration for and evaluation of mineral resources.

4.05 Impairments of Unproved Properties

Unproved properties must be assessed periodically, at least annually, to determine whether their book values have been impaired. If impairment has occurred, a valuation allowance is established to reflect the reduction in value. A property would likely be impaired, for example, if a dry hole had been drilled on it and the enterprise has no firm plans to continue drilling. Also, the likelihood of partial or total impairment of a property increases as the expiration of the lease term approaches if drilling activity has not commenced on the property or on nearby properties.

Similarly, The U.S. SEC's Codification of Financial Reporting Releases, §406.01.c.i, adds that “. . . unevaluated properties are required to be assessed periodically for impairment and to have value at least equal to their carrying costs (including any capitalized interest). . .”; however, the term value is not defined. Impairment of value can be recognized in two ways. It is done on an individual property basis or a group basis, depending on whether the cost of an individual property is significant. The method chosen also determines how costs of abandoned leases and leases transferred to prove properties should be handled.

Recording Impairment of Individual Properties

If costs associated with an individual property are significant, impairment is assessed on a property-by-property basis. Individual impairment may also be recorded on leases that are not individually significant (although there is no requirement to do so). For successful efforts, the definition of an individually significant property is unclear; however, under full cost accounting, the U.S. SEC has stated that it generally means a property with capitalized costs exceeding 10 per cent of the net capitalized costs of the country-wide cost centre.

Responses to the 2001 Price Water house Coopers Survey of U.S. Petroleum

Accounting Practices indicated that companies typically use various criteria for determining significance. Some companies have established a specific dollar amount as a minimum cost for a property to be deemed significant. Presumably, a company has arrived at a floor after considering the size of its enterprise, total assets, and total investments in oil and gas properties, net income, and similar factors. Each year acquired leases are examined in light of the factors previously listed. The aforementioned survey found that companies considered various factors in assessing impairment. Over 90 per cent of the respondents considered whether the company still intended to drill on the lease. The majority of respondents also considered: (1) other wells drilled in the area, (2) the geologist's valuation of the lease, and (3) remaining months in the lease's primary term. Only three of 14 respondents considered the market value of similar acreage in the area.

Consideration for impairment assessment can include:

- i. If the company has definite plans to drill on a lease, its assessed value might be equal to net book value, and no impairment is recognized. If drilling is somewhat likely, the company's assessed value of the lease may be significantly less than original cost.
- ii. If the company has no plans to drill on a lease due to recent dry holes on or adjacent to the company lease, then that lease may have little or no assessed value and be substantially impaired.

A company's impairment policy might recognize partial impairment as time elapses on the primary term of each lease.

To illustrate impairment of significant leases, assume that a company has five significant leases for which no impairment has previously been recorded. Costs and assessed values on December 31, 2005, are:

	Cost	Assessed Value	Impairment
	₦	₦	₦
Lease A	100,000	85,000	15,000
Lease B	110,000	100,000	10,000
Lease C	400,000	300,000	100,000
Lease D	125,000	190,000	0
Lease E	<u>45,000</u>	<u>500,000</u>	<u>0</u>
	<u>780,000</u>	<u>1,175,000</u>	<u>125,000</u>

Since each lease is deemed to be significant, assessments must be made on a lease-by-lease basis. Even though the total value exceeds total cost, impairment of any single lease is still recognized. The entry to record the impairment of value at December 31 is:

806 Impairment, Amortization, and Abandonment of Unproved Properties 125,000

219 Allowances for Impairment of Unproved Properties 125,000

To record loss on impairment of individual leases for the period

Net	Cost	Value Calculated	Impairment
Lease C	₦ 300,000	₦680,000	₦ 0
Lease E	45,000	500,000	0

After impairment is recorded, the net book value of unproved properties is:

	₦
Unproved Properties	780,000
Less: Allowance for Impairment, Unproved Properties	<u>(125,000)</u>
Net	655,000

4.06 Surrender and Abandonment of Unproved Properties

When an impaired significant property is surrendered, the net carrying value (capitalized cost minus valuation allowance) of that lease is charged to expense under successful efforts, or to Account 227, Abandoned Properties, under the full cost method. Assume in 2006, leases A and D in the preceding example are abandoned.

	₦
219 Allowance for Impairment of Unproved Properties	15,000
806 Impairment, Amortization, and Abandonment of Unproved Properties	85,000
211 Unproved Property Acquisition Costs	100,000
To record surrender of lease A.	

806 Impairment, Amortization, and Abandonment of Unproved Properties	125,000
211 Unproved Property Acquisition Costs	125,000
To record surrender of lease D.	

The Interplay among Impairment, Surrender and Abandonment of Unproved Properties

Subsequent Impairment evaluation

After recording impairment, a company cannot record any recovery in value. For example, assume that on December 31, 2006, the company in the preceding illustration prepares the following schedule of unproved properties:

Lease F (new)	1,000,000	800,000	200,000
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An impairment of ~~N~~200,000 would be recorded on lease F acquired in early 2006 by the usual entry. Even though the value of lease C now exceeds its cost, the allowance for impairment of ~~N~~100,000 set up on December 31, 2005, would not change. No gains on increases in value of such properties are recorded.

Recording Impairment on a Group Basis

For companies using the successful efforts method: When an enterprise has a relatively large number of unproved properties whose acquisition costs are not individually significant, it may not be practical to assess impairment on a property-by-property basis, in which case the amount of loss to be recognized and the amount of the valuation allowance needed to provide for impairment of those properties shall be determined by amortizing those properties, either in the aggregate or by groups, on the basis of experience of the entity in similar situations and other information about such factors as the primary lease terms of those properties, the average holding period of unproved properties, and the relative proportion of such properties on which proved reserves have been found in the past. In computing amortization to reflect impairment, all of an entity's unproved properties may be placed in a single group, or multiple groups may be used. If multiple groups are used, the aggregation may be based on geographic location (such as onshore, offshore, Gulf Coast); dollar cost (N500,000 or less; N500,000 to 1,000,000; N1,000,000 to N10,000,000); geologic area (Tuscaloosa Trend, Permian Basin); year of acquisition (2004, 2005, 2006); or another logical basis. The purpose is to derive an overall estimate of impairment that would reflect impairments if assessed on individual properties.

Several approaches are used to estimate the annual impairment provision on a group basis. They fall into two categories depending on what is emphasized in the calculations:

- i. Expense computations based on the average holding period for properties in each group
- ii. Balance sheet valuation by maintaining the valuation account at some predetermined percentage of the unproved properties account

Impairment Procedures Emphasizing Amortization Expense

The basic notion underlying group amortization is this: properties that will not become productive over time should be considered impaired, while properties that will become productive should not. Using this methodology, the portions of properties that will not be productive are estimated based on the company's past experience. If activities or strategies of exploration have changed, or if the company has little history, it may utilize industry-wide experience.

Straight-line amortization: If a company carried out drilling on a relatively even basis over the terms of its leases, it might be appropriate to record impairment of the expected worthless leases on a straight-line basis over the lease terms. Some

companies using straight-line amortization apply the rate to the balance of the unproved property account (which reflects additions, surrenders, and transfers to proved properties). Others apply the rate to the net book value of unproved properties (balance of unproved properties minus the total allowance for impairment). However, since the amortization rate is usually based on original acquisitions, that amount should be the basis for the computation. If a group includes properties acquired in more than one year, the amortization rate is applied separately to the leases acquired each year. To illustrate a basic application of the group method of recording impairment using a straight-line rate, assume: that a company includes all of its unproved properties in a single group and records amortization on that basis. The company keeps a record of leases acquired each year and makes a separate computation of amortization for each year's acquisitions. An analysis of leases acquired in only one year, 2005, shows that acquired unproved property acquisition costs of ₦1,200,000 were charged, along with leases acquired in other years, to the Unproved Property Acquisition Costs account. As of December 31, 2005, the balances of the Unproved Property Acquisition Costs account and Allowance for Impairment account were ₦4,000,000 debit and ₦1,980,000 credit, respectively. Experience indicates that ultimately 20 per cent of the leases will become productive and that the average holding period of the remaining leases is four years. Thus, ₦960,000 ($\text{₦1,200,000} \times 80\%$) of the leases acquired in 2005 will ultimately be abandoned over an average period of four years (beginning in 2006). Note that in this calculation the beginning balance in the Allowance for Impairment of Unproved Properties account is ignored. Amortization of ₦240,000 may be recorded for 2006 as shown in the following entry:

806 Impairments and Abandonments of Unproved Properties	₦240,000	
219 Allowance for Impairment of Unproved Properties		₦240,000
To record amortization of unproved properties.		

Similar calculations are made for leases acquired in each year, and the amortization is recorded in the same way. Assume amortization on other leases totaled ₦560,000 for 2006, so that the total amortization for 2006 was ₦800,000 ($\text{₦240,000} + \text{₦560,000}$). When impairment of individually insignificant properties is measured and recorded on a group basis,

Accounting for the surrender of unproved properties and transfers to proved properties is simplified. The original capitalized cost of a surrendered lease is charged to the Allowance for Impairment account and removed from the Unproved Property Acquisition Costs account at the time of surrender. The Proved Leaseholds account is charged and the Unproved Property Acquisition Costs account is credited for the cost of a property that is proved during the period. For example, continuing the above illustration, assume that the following occurred in 2006:

Additional unproved properties were leased for ₦1,600,000. Leases that cost ₦750,000 were surrendered. Leases that cost ₦320,000 were proved.

211 Unproved Property Acquisition Costs	1,600,000
306 Vouchers Payable	1,600,000
To record cost of leases acquired during year.	

219 Allowance for Impairment of Unproved Properties	750,000
211 Unproved Property Acquisition Costs	750,000

To record cost of surrendered leases.

221 Proved Leaseholds	320,000
211 Unproved Property Acquisition Costs	320,000

To record cost of properties proved during the year.

After these transactions have been entered, the Unproved Property Acquisition Costs account and the Allowance for Impairment account would appear as follows:

Account 211 Unproved Property Acquisition Costs

	₦
12/31/05 Balance	4,000,000
2006 Surrenders	(750,000)
2006 Additions	1,600,000
2006 Proved	(320,000)
12/31/06 Balance	4,530,000

Account 219 Allowance for Impairment of Unproved Properties

12/31/05 Balance	1,980,000
2006 Surrenders	(750,000)
2006 Amortization	800,000
12/31/06 Balance	2,030,000

The amortization for 2007 on leases acquired in 2005 would again be ~~₦~~240,000, and assuming that the company's estimate of surrenders has not changed, amortization on leases acquired in 2006 would be ~~₦~~320,000 ($1/4 \times 80\% \times \text{₦}1,600,000$). Those amounts, along with amortization on acquisitions of other years, would be charged to Account 806, Impairments and Abandonments of Unproved Properties, and credited to Account 219, Allowance for Impairment of Unproved Properties. If the allowance previously provided is inadequate to absorb the cost of a surrendered lease, a loss equal to the difference between the cost of the property surrendered and the balance in the Allowance for Impairment account should be recognized upon the surrender of a property.

Amortization based on analysis of yearly surrenders. Another approach for computing amortization is to use annual rates based on past experience. In developing its experience pattern, a company should use at least one complete cycle of lease acquisition and exploration. All leases acquired during the base period should be included; if not feasible, a representative sample of leases is permissible. Calculations can be based on monetary amounts or on acreage (when leasehold costs per acre fluctuate widely). Assume a company has analysed its cycle for leases with primary terms of four years. A three-year recurring analysis as of early 2006, based on acreage, is shown below.

Property Found to be Non-productive Ultimately

Year						
Acquired	Total Cost	in Year:	1	2	3	4
Prod. Property						
2001	N45,000	*	*	*	N16,000	N
4,000						
2002	60,000	*	*	N21,000	20,000	
6,000						
2003	50,000	*	N 8,500	17,000	10,000	
6,000						
2004	100,000	N 7,000	14,500	31,000	**	**
2005	70,000	6,800	15,500	**	**	**
2006	80,000	7,500	**	**	**	**
Totals		N21,300	N38,500	N69,000	N46,000	
	N16,000					
3 yr avg %***		9%	18%	33%	30%	
10%						

* Known but not part of the latest three-year average.

** Unknown at the time of analysis in early 2006.

*** For example, $21,300 / (100,000 + 70,000 + 80,000) = 9\%$.

History suggests that 90 per cent of the costs relate to leases that are ultimately non-productive, and become partially impaired as time passes, until the leases are found to be worthless. Three different methods can be used to calculate annual amortization rates for the 90 per cent of costs expected to be found worthless. First, the petroleum accountant can use a straight-line calculation over the four-year primary term;

Annual amortization is one-fourth of 90 per cent or 22.5 per cent as shown in the following Table 1. Second, annual amortization rates can be calculated by allocating costs over the properties' expected lives; e.g., for the 18 per cent of costs related to properties expected to be found worthless and abandoned in Year 2, assume half is impaired and expensed in Year 1 and half in Year 2 as shown in Table 2. Third, calculate amortization by allocating a specific portion (say 20 per cent) in each year prior to the expected year of abandonment; e.g., for the 18 per cent of costs related to properties expected to be abandoned in Year 2, assume 20 per cent of 18 per cent, or 3.6 per cent, is impaired and expensed in Year 1 and 14.4 per cent in Year 2 as shown in Table 3. The third approach should reflect management's judgment and experience that leases retain much of their value until the year when they are found to be non-productive.

Table 1: Allocated Straight-Line over Four Years

Aban. %	1	2	3	4
90.0%	22.5%	22.5%	22.5%	22.5%

Table 2: Year After

Acquisition Allocated Straight-Line over Expected Life

Aban. %	1	2	3	4	
1	9.0%	9.0%			
2	18.0	9.0	9.0%		
3	33.0	11.0	11.0	11.0%	
4	30.0	7.5	7.5	7.5	7.5%
	90.0%	36.5%	27.5%	18.5%	7.5%

Table 3: Year After

Acquisition Allocated at 20%/yr until Worthless

Aban. %	1	2	3	4	
1	9.0%	9.0%			
2	18.0	3.6	14.4%		
3	33.0	6.6	6.6	19.8%	
4	30.0	6.0	6.0	6.0	12.0%
	90.0%	25.2%	27.0%	25.8%	12.0%

Notice in the tables that first-year amortization varies from 22.5 per cent to 36.5 per cent, but always exceeds the nine per cent of costs that is attributable to leases expected to be found worthless in Year 1. For this example, one should not calculate first-year amortization as simply nine per cent of costs; otherwise, the accounting is merely expensing the estimated costs of worthless property in the year found worthless. Amortization is intended to reflect lease impairment, including partial impairment after one year for leases expected to be found worthless in years two, three, and four. First-year amortization needs to reflect both: (1) the nine per cent of costs, and (2) a portion of the 81 per cent of total lease acquisition costs that will be found worthless in the primary term.

Impairment procedure emphasizing asset valuation: A simple approach to measure the impairment of a group of unproved properties is to adjust the Allowance for Impairment account to some predetermined percentage of Unproved Property Acquisition Costs. Lease acquisitions, abandonments, and transfers to unproved properties are handled in the way described earlier. For example, assume that past experience indicates that approximately 80 per cent of its unproved leases are abandoned. The company has adopted a policy of maintaining the Allowance for Impairment account at 80 per cent of the Unproved Property Acquisition Costs account. This approach is conservative in that N80 is immediately considered impaired for every N100 of new lease acquisition costs. Some companies adjust the allowance account to only 40 per cent of the Unproved Property Acquisition Costs account on the theory that, on average, only one half of the leases that will ultimately be worthless are impaired at any balance sheet date. For example, assume that as of December 31, 2006, the two balance sheet accounts involved are as follows before annual impairment is recorded:

Account 211 Unproved Property Acquisition Costs

	N
11/30/06 Balance	10,000,000
12/06/06 Acquisitions	
5,000,000	

12/31/06 Balance 15,000,000

Account 219 Allowance for Impairment of Unproved Properties

12/31/06 Balance ~~15~~4,000,000

Since the allowance account balance on December 31, 2006, is only ~~15~~4,000,000 and a balance of ~~15~~6,000,000 (40% of ~~15~~15,000,000) is needed, the following entry adjusts it:

806 Impairment and Abandonment of Unproved Properties	200,000
219 Allowance for Impairment of Unproved Properties	200,000
To adjust allowance account to desired balance.	

This simplified procedure is appropriate only if acquisitions and surrenders are relatively stable from year to year and the company has many unproved properties which are not individually significant.

Measuring impairment of individual properties under full cost accounting Under full cost, companies may (but are not required to) exclude from the amortization pool the acquisition costs of unevaluated properties and unevaluated exploration costs. If this procedure is followed, the entity is required to begin immediate amortization of any amount of impairment. Similar to successful efforts accounting, impairment of unproved properties must be on a property-by-property basis for individually significant properties. As mentioned previously, the U.S. SEC has stated that for full cost companies the term individually significant identifies a property or project where costs exceed 10 per cent of the net capitalized costs of the cost centre. Individual impairment is allowed for insignificant properties. Note that impairment of unproved properties does not give rise to an expense or loss for a full cost company; it merely accelerates the costs subject to amortization.

Utilizing post-balance-sheet events in assessing impairment

Information that becomes available after the end of the period covered by the financial statements but before those financial statements are issued shall be taken into account in evaluating conditions that existed at the balance sheet date, for example in assessing unproved properties [for impairment].

Suppose ABC Oil Company owns a leasehold that is individually significant (cost N500,000), and has an estimated value on December 31, 2006, of N1,200,000. No impairment recognition seemed necessary on December 31, 2006. However, in February 2007, before the financial statements for 2006 are issued, another company abandoned as a dry hole a well drilled on a contiguous lease. An assessment reveals that the lease is now worth only N100,000. This post-balance-sheet-date information requires recognition of an impairment loss of N400,000 in the 2006 income statement, and establishment of an impairment allowance of N400,000 in the balance sheet as of December 31, 2006.

Transfers to proved property

Transfers of unproved property acquisition costs to proved property acquisition costs take three forms:

An unproved property individually impaired has its net book value (NBV) transferred to proved property costs:

219 Allowance for Impairment	10,000
221 Proved Property Acquisition Costs	
(also called Proved Leasehold Costs)	90,000
211 Unproved Property Acquisition Costs	100,000

An unproved property subject to a group impairment allowance has its gross acquisition cost reclassified:

221 Proved Property Acquisition Costs	100,000
211 Unproved Property Acquisition Costs	100,000

A vast single property, such as a foreign concession, has reclassified only that portion of its costs (or NBV) deemed related to the proved reserves. For example, for a 50,000-acre concession including a 1,000-acre proved field, only two per cent of an assumed N10,000,000 in unproved property acquisition costs are reclassified:

221 Proved Property Acquisition Costs	200,000
211 Unproved Property Acquisition Costs	200,000

Top Leases and Lease Renewals

In some cases the operator may be unable to or unwilling to drill on an unproved property before expiration of its primary term; however, it may wish to retain the property for possible future drilling. In this event, the operator can negotiate with the mineral owner to extend the primary term of the original lease or sign a new lease contract. Under both full cost and successful efforts accounting, the bonus for signing a new lease is capitalized. A new lease signed before expiration of the original contract is called a top lease. Under the successful efforts method, the book value of the original lease may be treated as a part of the capitalized cost of the top lease. If, however, the original lease expires and the lessee gives up all rights before obtaining a new lease, the expiration of the old lease should be treated as abandonment. Under full cost, the cost of the original lease remains capitalized as part of the cost pool.

Tax Treatment of Unproved Property Acquisition, Maintenance, and Abandonment Costs

For income tax purposes, the bonus payment and incidental acquisition costs, such as recording fees and broker's commissions, must be capitalized as depletable mineral costs. Historically, the operator has had a year-by-year and property-by-property election to either charge carrying costs, including delay rentals, to expense as they are paid or incurred, or to capitalize them as depletable leasehold costs. Almost universally, taxpayers have elected to charge carrying costs to expense. However, international tax position is that delay rentals must be capitalized as depletable leasehold costs. Costs of unproved properties must be charged off in the

year they become worthless, which may be either at the same time or before the time they are abandoned or surrendered.

Also, for tax purposes, there is no deduction for partial worthlessness or impairment or for amortization of unproved property costs. When a property becomes productive, its costs become subject to depletion as the reserves are produced.

4.07 Review Questions

- i. Explain the accounting process for acquisition cost of unproved properties
- ii. Describe the typical provisions of OPL's and OML's
- iii. Explain and describe accounting procedure for impairments of unproved properties
- iv. Explain the concept of surrender and abandonment of unproved properties

MODULE 5

5.00 ACCOUNTING FOR EXPLORATION, DRILLING AND DEVELOPMENT COSTS

5.01 Learning Outcomes

On successful completion of this Module, Students should be able to:

- i. Distinguish between drilling and development cost;
- ii. Apply the accounting principles and application for all types of drilling and non-drilling exploration cost;
- iii. Compute and account for intangible drilling and development cost (IDC) and equipment cost;
- iv. Assess and discuss the accounting framework for development cost.

5.02 Preparation for Development and Drilling

The difference between exploratory well and development well must be understood in order to simplify this topic. The purpose of an exploratory well is to search for oil and gas and for such a well to become an asset, the future benefit can only be determined when oil and gas reserves are found. An exploratory well is drilled outside a proved area or within proved area which has not been tested before. Therefore, an exploratory well is not directly associated with specific proved reserves until drilling is completed and it must be independently assessed in order to determine whether it has future benefits or not (i.e., proved reserves).

However, a development well is drilled as part of the effort to build a producing system of wells and related equipment and facilities. The purpose of a development well is to extract previously discovered proved oil and gas reserves. A development well can be defined as a well drilled within the proved area of a reservoir to a depth known to be productive. Unlike an exploratory well, a development well is associated with a proved reserve which is the future benefit to be derived by oil firm. The reason is that it is drilled in a proved area and therefore majority of development wells are successful. Therefore, the costs of both successful development wells and development dry holes are capitalized. While the cost of exploratory successful well is capitalized because it is related to the discovery of oil and gas reserves, the costs of exploratory unsuccessful (Dry hole) wells are expensed because it does not produce oil and gas reserves. From the foregoing, it is discovered that the way to account for the costs of exploratory well is different from that of the development well particularly, the difference between the costs of exploratory dry holes and development dry holes. This shall be further analyzed.

5.03 Accounting for Exploration and Drilling Cost

Exploration and drilling involve:

- (a) Identifying areas that may warrant evaluation; and
- (b) Evaluating specific areas that are considered to have petroleum prospects, largely through drilling of exploratory wells.

Exploration cost may be incurred both before obtaining concessions (sometimes referred to in parts as pre-license costs) and after acquiring concessions.

i. Types of Exploration and Drilling Cost

There are 2 types of Exploration and drilling costs as follows;

1. Non-Drilling exploration Costs

2. Drilling Exploration costs

1. **Non-Drilling Exploration Costs:** These are costs not directly associated with drilling of oil and gas exploratory wells. The non-drilling exploration costs or activities are:

- (a) Costs of geological and geophysical studies, right of access to properties to conduct those studies, and salaries and other expense of geologist, geophysical crews, and others conducting those studies;
- (b) Cost of carrying and retaining undeveloped properties, such as rentals, legal costs for title deeds, stamp duties, and the maintenance of lease record
- (c) Dry hole contributions and bottom hole contributions;
- (d) Other associated costs such as resettlement of local communities, compensation for economic crops, surface rights and road building.

2. **Drilling Exploration Costs:** These are costs directly associated with the drilling of exploratory well.

It can be divided into 2 as follows:

- (a) The costs of drilling and equipping exploratory wells and
- (b) The costs of drilling exploratory – type stratigraphic test wells

Accounting for Non-Drilling Exploration Costs

(A) Costs of Geological and Geophysical (G&G) Studies

The purpose of geophysical and geological (G&G) exploration is to locate or identify areas with the potential of producing oil and/gas in commercial quantities. Both surface and subsurface G&G techniques are used to locate these areas. Surface techniques are used to evaluate the surface for evidence of subsurface formation in which the characteristic is favorable to the accumulation of oil or gas. Subsurface techniques identify formation capable of containing oil or gas by utilizing the fact that all types of rocks have different characteristics and respond differently to stimuli such as sound or magnetic waves.

There are two types of survey or study to be conducted under G&G, the first is called reconnaissance survey which is a survey covering a large or broad area. The second is known as a detailed survey, which is G&G study covering a smaller area. G&G studies may be conducted either before or after a property is acquired. If a company wants to explore an onshore area prior to obtaining a mineral lease on the property, right to access the property, called shooting right, must first be obtained from the property owner. The exploration company pays a fee for the shooting rights, and typically, the rights are coupled with an option to lease, in order for the company performing the G&G activities to have the right to lease the property if the G&G data are promising.

All the costs related to conducting G&G studies and the cost of access rights to properties to conduct those studies, including any damages or rent paid to the surface interest owner. These G&G costs must be expensed as incurred regardless of whether they were incurred before or after acquisition of a working interest in the property. G&G costs are similar to research costs because they are incurred to provide information. To a large extent the G&G costs are incurred prior to property acquisition. In many cases, surveyed property is never acquired or, if acquired, is subsequently abandoned. Correlation of G&G costs with specific discoveries (months or year later) is very difficult or impossible, and cannot be made at the time the G&G costs are incurred. Therefore, the accounting principle provided by SAS 14 and SFAS 19 is that G&G costs should be expensed as incurred i.e., debited to income statement (P&L account).

Illustration 5-1 & Suggested solution

G&G Costs

- a. Bello Oil Company obtained shooting right-access rights to a property so G&G studies may be conducted-to 100,000 acres, paying ₦0.30 per acre. Prepare the necessary accounting entry.

Entry	DR	CR
G&G expense (100,000 x ₦0.30)	30,000	
Cash		30,000

- b. Bello Oil Company then hired ABC Company to conduct the G&G work and paid the company ₦25,000. Prepare the necessary accounting entry.

Suggested Solution

Entry	DR	CR
G&G expense	25,000	
Cash		25,000

The Scientific techniques developed for G&G are 3D and 4D seismic methods. These methods are much more expensive and much more accurate than the old 2D seismic studies. The new 3D and 4D methods are used not only to locate new reservoirs, but are also used on existing producing reservoirs. When used on existing producing reservoir, the costs are analogous to development costs. According to a 1999 price water house coopers survey, 63% of the successful effort companies responding to the survey capitalize G&G costs used on producing reservoirs as a development cost instead of expensing the cost as an exploration expense.

G&G studies may also be conducted on a property owned by another party in exchange for an interest in the property if proved reserves are found – if not found, the G&G costs incurred are reimbursed. In this situation, the G&G costs should be recorded as a receivable when incurred and, if proved reserves are found, should be transferred to become part of the cost of the proved property acquired (SFAS No. 19, par. 20,). If proved reserves are not found, reimbursement is received.

Illustration 5-2

G&G Studies Exchange for Interest in Property

During 2005, Denny Company paid for G&G studies to be performed on two leases owned by other parties. The agreements provided that Denny company would receive $\frac{1}{2}$ of each WI if proved reserves were found and would be reimbursed for G&G costs incurred if proved reserves were not found. The G&G costs incurred by Denny were as follows:

Lease A ₦200,000

Lease B ₦300,000

Drilling activities on the leases in 2005 were as follows:

Lease A: Drilling resulted in a dry hole and the lease was abandoned. The owner of lease reimbursed Denny for the G&G costs.

Lease B: Drilling resulted in discovering proved reserves and, as per the agreement, Denny received $\frac{1}{5}$ of the WI.

Required: Prepare the necessary accounting entries.

Suggested Solution 5-2

Entry	DR	CR
Lease A:		
Receivable – Lease A	200,000	
Cash		200,000
Cash	200,000	
Receivable – Lease A		200,000
Lease B:		
Receivable – Lease B	300,000	
Cash		300,000
Proved property – Lease B	300,000	
Receivable – Lease B		300,000

G&G studies may also be performed before drilling a well to determine the location of the specific drill site. This type of costs, although involving G&G activity, is considered part of the drilling process and is accounted for as drilling cost rather than a non-drilling exploration cost.

(b) Carrying and Retaining Costs

Carrying and retaining costs are incurred primarily to maintain the lessee's property rights, not to acquire those rights. Common carrying and retaining costs include:

- i. Delay rentals
- ii. Property taxes
- iii. Legal cost for title defense
- iv. Lease record maintenance

Delay rentals are costs paid on or before the anniversary date of the lease in order to delay drilling operations for a year. Ad valorem taxes or property taxes are assessed on the economic interest owned by the working interest and are levied by government agency, i.e., city, country school, district, etc. These property taxes are incurred to maintain the property. Legal costs for title defense paid by the lessee include attorney's fees, court costs, etc., incurred when the royalty interest owner is involved in a legal dispute regarding claim to title to the property. Lease record maintenance costs are incurred by the land department in maintaining, evaluating, and updating the company's lease records. Employees' salaries, materials, and supplies are the major of these maintenance costs.

Carrying costs do not increase the potential recoverable amount of oil and gas and do not enhance future benefit to be derived from the acquired properties. Instead, carrying and retaining cost are incurred primarily for the purpose of keeping the property interest and keeping a clear title. For these reasons, carrying and retaining costs are expensed as incurred.

The carrying and retaining costs under conversation are related to unproved properties and are usually insignificant in terms of cost.

Illustration 5-3 & Suggested solution

Carrying and Retaining Costs

- a. Denny company acquired a 500-acre lease in Ughelli in Delta State. During the first year, the company did not develop the lease, i.e. no drilling was done. Therefore, to retain the lease Denny Oil Company paid a delay rental payment of ₦1,000,000. Prepare the Journal entry.

Journal Entry

Delay rental expense	1,000,000	
Cash		1,000,000

- b. Denny company paid ₦1,200,000 in ad valorem taxes, i.e., property taxes assessed on Denny's economic interest in the lease. Prepare the journal entry.

Journal Entry

Ad valorem tax expense	1,200,000	
Cash		1,200,000

- c. The land department incurred allocable costs of ₦5,000,000 in maintaining land and lease records and allocated ₦500,000 of that cost to the property. Prepare the journal entry.

Journal Entry

Record maintenance expense	500,000	
Cash		500,000

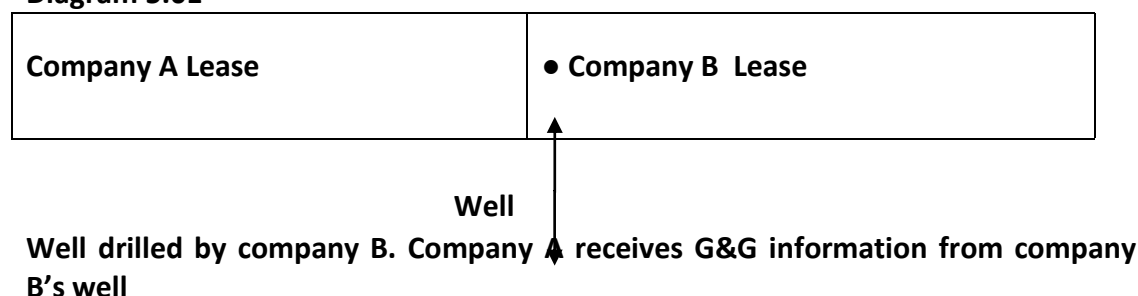
The carrying and retaining cost discussed above are associated with unproved properties and are classified as exploration costs. If Ad valorem taxes or lease record maintenance costs are associated with proved properties, they are classified as a production cost, not an exploration cost

(C) Test – Well Contribution

Test well contribution occurs when one company drills a well and another company, which owns the working interest (WI) in a near oil property, agrees to pay the drilling company for certain G&G information. For instance, Company B drilled a well and provides a specified G&G information to company A (an unrelated company with a WI in property nearby). Company A receives the information and, in turn pays a test well contribution to company B. since test well contributions are in essence of G&G costs, they are also expensed as incurred.

The beneficiary of a test well contribution (company B) treats the amount received as a reduction of intangible drilling cost incurred as the well is drilled.

Diagram 5.01



Accounting

Types of Test Well Contribution

A test – well contribution has 2 types and they are;

- i. **Dry – hole contribution-** Payment is made only if the well is dry or not commercially producible;
- ii. **Bottom-hole contribution-** Payment is made when an agreed upon depth is reached, regardless of the outcome of the well

It is important to note that a company receiving a test well contribution records it as a reduction in intangible drilling costs.

A dry hole contribution is paid only if the well does not find proved reserves. However, whether oil and gas reserves are found or not, the driller is obligated to furnish G&G information to the other company involved in the dry-hole contribution agreement. A dry hole contribution is entered into if the company seeks to offset the cost of drilling the well if the well is dry. The assumption being if the well finds reserves, the company drilling the well does not need the reimbursement.

A bottom-hole contribution is paid when the driller reaches the predetermined contract depth, even if proved reserves are not found. The bottom-hole contribution will not be paid if the driller fails to drill to the predetermined depth. Depending on contract terms, the bottom-hole contributor may receive G&G information even if the well is not drilled to contract depth and no payment is made. In a bottom-hole contribution situation, the company drilling the well wants to minimize its cost regardless of the outcome.

The primary reason for making a test-well contribution is that valuable information (well logs, drill stem test, etc.) can be obtained without the cost of drilling a well. On the other hand, the company receiving the contribution receives money to help offset the cost of drilling the well.

Illustration 5-4

Test – well contributions

Several wells were being drilled on leases in close proximity to an undeveloped lease owned by Usman Oil Company. In order to obtain G&G information from the wells, Usman Oil Company entered into the following agreements:

Well 1: dry-hole contribution of ₦150,000 but the well is dry after drilling

Well 2: dry-hole contribution of ₦250,000 and the well is successful after drilling

Well 3: bottom-hole contribution of ₦100,000 and the well is drilled to agreed depth but determined to be dry

Well 4: bottom-hole contribution of ₦200,000 and the well was abandoned before reaching the agreed depth

Required: Prepare the necessary accounting journals for the above transactions

Suggested Solution

Well 1 – dry

Journal Entry (dry-hole contribution)

Test-well contribution expense	150,000	
Cash		150,000

Well 2- well is successful

Journal Entry (dry-hole contribution)

None

Well 3-drilled to agreed depth and determined to be dry

Journal Entry (bottom – hole contribution)

Test – well contribution expense	100,000	
Cash		100,000

Well 4-well abandoned before reaching agreed depth

Entry (bottom-hole contribution)

None

(D) Other Associated Costs Such as Resettlement Of Local Communities, Compensation For Economic Crops, Surface Rights And Road Building: These costs should also be expensed into income statement as incurred.

Comprehensive Illustration 5-5 & Suggested Solution

- a. Denny Company was interested in large section of land in West Texas and obtained shooting rights to 6,000 acres for ₦1.50 per acre. (G&G cost)

Entry

G&G expense (6,000 x ₦1.50) 9,000

Cash 9,000

- b. Denny paid a geological firm ₦50,000 to conduct a reconnaissance survey on the area. (G&G cost)

Entry

G&G expense 50,000

Cash 50,000

- c. Based on the results of that study, Denny acquired one 700-acre lease and immediately commissioned the same geological firm to conduct detailed G&G studies on the lease at a cost of ₦150,000 (G&G cost)

Entry

G&G expense 150,000

Cash 150,000

- d. During the first year, Denny had to pay ₦200,000 in Ad valorem taxes and ₦1,000,000 for title defense in connection with the property (carrying and retaining costs).

Entry

Ad valorem tax expense 200,000

Cash 200,000

Legal expense-exploration 1,000,000

Cash 1,000,000

- e. By the end of the first year, Denny had not begun any drilling efforts and, wanting to retain the lease, paid the first delay rental of ₦60,000 (carrying and retaining cost).

Entry

Delay rental expense 60,000

Cash 60,000

- f. Early in the second year, drilling began on a well on a nearby property. Denny entered into a bottom hole contribution agreement to obtain the G&G information from the well. The depth specified in the agreement was reached two months later, and Denny paid ₦80,000 as per arrangement (test-well contribution)

Entry

Test – well contribution expense	80,000
Cash	80,000

Exploratory Drilling Costs

The Exploratory Drilling costs can be divided into 2 as follows:

- (a) The costs of drilling and equipping exploratory wells and
- (b) The costs of drilling exploratory – type stratigraphic test wells

The accounting principles for the two exploratory drilling costs mentioned above is covered by SFAS No. 19, par, 19, which states that “The cost of drilling exploratory wells and the cost of drilling exploratory- type stratigraphic test wells shall be capitalized as part of the enterprises uncompleted well, equipment and facilities, pending determination of whether the well has found proved reserves. If the well has found proved reserves, the capitalized cost of drilling the well shall become part of the enterprises wells and related equipment facilities (even though the well may not be completed as a producing well); if, however, the well has not found proved reserves, the capitalized costs of drilling the well, net of every salvage value, shall be charged to expense”

For better understanding of this topic the following concepts must be properly comprehended:

Intangible Drilling and Development Costs Versus Equipment Costs (IDC)

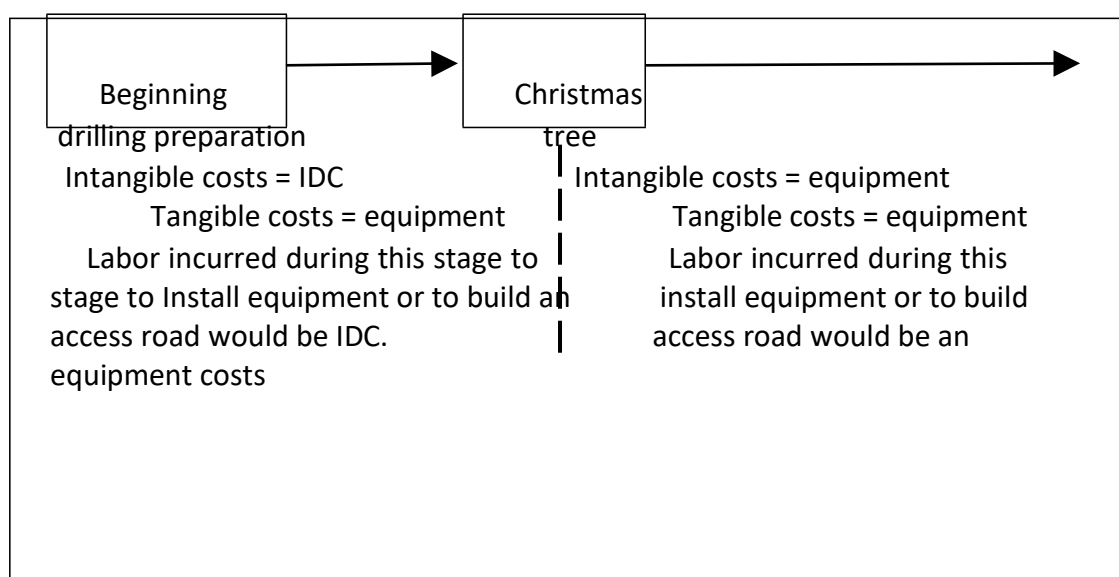
Drilling and development costs are classified as either intangible drilling and development costs (IDC) or equipment costs (lease and well equipment). The distinction between IDC and equipment costs is very important because for tax purpose all or most of the IDC may be expensed as incurred, whereas equipment costs must be capitalized and depreciated. (The tax payer makes a one-time election to either expense or capitalizes IDC. Regardless of whether the election is to expense or to capitalize IDC, IDC of dry holes may be expensed. This election is per tax payer and applies to all the tax payers’ properties. Rules for integrated producers are modified somewhat, in that a specified percentage of all productive IDC must be capitalized, regardless of the election made.

In contrast, independent producers may deduct all of the IDC in the year incurred. **IDC** is defined as expenditure for drilling and developing that in themselves do not have a salvage value and are “incident to and necessary for the drilling of wells and the preparation of wells for the production of oil and gas”. In general, IDC included the intangible or non-salvageable costs of drilling up to and including the cost of installing the Christmas tree.

The term Christmas tree refers to the valves, pipes, and fittings assembly that is used to control the flow of oil and gas from the wellhead. In many cases, the physical arrangement of the valves, pipes, and fitting resembles a Christmas tree. The Christmas tree is located at the top of the well on the surface of the land.

In general, equipment costs include all tangible or salvageable costs of drilling and development up to and including the Christmas tree, plus both intangible and tangible costs past or after the Christmas tree. In considering whether an item is before or after the Christmas tree, the physical flow of the oil and gas should be considered, not the time of incurrence. Note that neither the word “salvageable” nor the word “tangible” is completely correct in defining which costs are IDC rather than equipment. Some tangible costs such as casing, which are usually not salvage, are still considered equipment. On the other hand, other tangible costs such as cement or drilling mud, which also are not salvageable, are considered to be IDC. The distinction between IDC and equipment costs appears to be whether a tangible cost in itself has a salvage value.

Diagram 5.02



The diagram above shows the purpose for constructing a lease road in order to determine whether the costs of constructing the road are considered IDC or Equipment cost.

Illustration 5-6 & SUGGESTED SOLUTION IDC versus equipment

Determine whether the following drilling and development costs are IDC or Equipment costs.

- Denny Company incurred acquisition (purchase) costs of ₦40,000 for casing and installation cost of ₦5,000.

Note that Casing is surface well equipment and is, therefore, before the Christmas tree.

IDC = ₦5,000, installation costs

Equipment = ₦40,000, purchase cost

- Denny Company purchased flow lines and storage tanks at a cost of ₦10,000. Installation costs were ₦2,000. Flow lines and tanks are non-well equipment and are past the Christmas tree.

IDC = ₦0, all cost are considered to be equipment costs since these costs are past the Christmas tree

Equipment = ₦12,000. Purchase cost and installation costs

c. Denny Company incurred ₦15,000 in labor costs in building an access road to a drill site. This cost is related to drilling a well and is, therefore, before the Christmas tree.

IDC = ₦15,000

Equipment = ₦0

d. Denny Company Incurred ₦15,000 in labor costs in building an access road to a producing well. This cost is past the Christmas tree.

IDC = ₦0, all costs are considered to be equipment costs since this cost is past the Christmas tree.

Equipment = ₦15,000

Item 1 and 2 below list costs related to drilling an exploratory or development well that are usually considered IDC. These costs are given in the order in which they are usually incurred. Note that the costs listed in item 2 are past the Christmas tree, but because they are intangible and directly related to the process of drilling a well, the costs are considered IDC. Item 3 lists other types of wells for which IDC is incurred.

1. Up to and including installation of the Christmas
 - a. Prior to drilling
 - i. G&G to determine specific drill site
 - ii. Preparation of the site, such as leveling, clearing, and building access roads and disposal pits.
 - iii. Rigging up
 - b. During drilling
 - i. Drilling contractors charges (when the drilling contractor furnishes equipment such as casing, part of the charges is equipment)
 - ii. Drilling mud, chemicals, cements and supplies
 - iii. Wages and fuel
 - iv. Well testing such as core analysis and analysis of cuttings
 - c. At target depth and during completion
 - i. Well testing such as well logs and drill stem tests
 - ii. Perforating and cementing
 - iii. Swabbing, acidizing, and fracturing
 - iv. Installing subsurface equipment to the well head and installation of the Christmas tree
 - v. If the well is dry, plugging and abandoning costs
2. After the Christmas tree, following the completion
 - a. Removal of drilling rig
 - b. Restoration of land and damages paid to the surface owner
3. Wells and other original exploration or

4. development wells
 - a. Intangible costs (those listed above) incurred in deepening a well
 - b. Intangible costs incurred in drilling a water or gas injection well
 - c. Intangible costs of drilling a water supply or injection well where water is to be used for drilling an exploration or development well or for injection.

In financial accounting, the cost of a machine, for example, includes not only the purchase cost, but also the intangible costs necessary to get the machine up and running. Thus, for financial accounting purpose, the cost of well includes both the tangible and intangible costs. Consequently, the distinction between IDC and equipment costs has no meaning for financial accounting. However, because of the importance of the classification of costs as either intangible drilling or development costs or equipment costs for tax, the distinction between IDC and equipment costs is usually made in financial accounting as well as tax accounting.

COMPREHENSIVE ILLUSTRATION 5-7 & SUGGESTED SOLUTION

Exploratory Drilling Costs

- a. On January 2, 2008, as a result of G&G work done in 2007, Denny Company decided to lease 1,000 acres at ₦20 per acre. The lease was underdeveloped.

Entry

Unproved property	20,000	
Cash		20,000

- b. Early in 2008, Denny Company decided to begin drilling operations and incurred G&G costs of ₦50,000 to select a specific drill site. (Even though G&G work has been done to locate a possible reservoir, additional detailed G&G work must be done to select the drill site. This G&G work to select the drill site is considered part of the cost of drilling the well and not G&G expense)

Entry

Wells in progress (WIP) – IDC	50,000	
Cash		50,000

- c. In preparing the drilling site, Denny Company incurred costs of ₦12,000 in clearing and leveling the site and in building an access road. (These activities normally would be performed by a drilling contractor)

Entry

WIP – IDC	12,000	
Cash		12,000

- d. Additional preparation costs of ₦4,000 were incurred in digging a mud pit and installing a water line. Pipes for the water line cost ₦2,000 (These activities normally would be performed by a drilling contractor.)

Entry

WIP – IDC	4,000	
WIP – lease and well equipment (L&WE)	2,000	
Cash		6,000

- e. Denny Company purchased pipe and casing for the well at a cost of ₦60,000

Entry

WIP – L&WE	60,000	
Cash		60,000

- f. Lucky company had hired a drilling contractor on a footage-rate contract and, as is usual in such an agreement, payment was contingent upon the contractor drilling to a specified depth. The well was spudded (i.e. drilling was begun) early in June and contract depth was reached in late July. Denny company paid the contractor ~~₦~~140,000. (In a footage-rate contract, a specified amount is paid per foot drilled. In contrast, in a day-rate- contract, a specified amount is paid per day, typically a different amount for a drilling day versus a standby day.)

Entry

WIP – IDC	140,000	
Cash		140,000

- g. In evaluating the well, Denny Company incurred costs of ~~₦~~8,000. A well log was run and a drill stem test was made.

Entry

WIP – IDC	8,000	
Cash		8,000

- h. Based on the well log and drill stem test, as well as other tests performed as the well was drilled, Denny Company decided to complete the well. Casing was set (i.e. installed by cementing between the pipe and well bore) at a cost of ~~₦~~35,000 for casing for the well and ~~₦~~6,000 for cementing services.

Entry

WIP – IDC	6,000	
WIP – L&WE	35,000	
Cash		41,000

- i. Denny incurred acquisition costs of ~~₦~~8,000 and installation costs of ~~₦~~1,000 for a string of production tubing through which the oil and gas will be produced. (Although oil and gas can be produced through casing, tubing is usually used because it is much easier than casing to remove and repair.)

Entry

WIP – IDC	1,000	
WIP – L&WE	8,000	
Cash		9,000

- j. Denny Company incurred acquisition (purchase) cost of ~~₦~~5,000 for a Christmas tree and installation costs of ~~₦~~3,000.

Entry

WIP – IDC	3,000	
WIP – L&WE	5,000	
Cash		8,000

- k. Denny Company incurred ₦500,000 for perforating and acidizing services. (Perforating involves using a perforating gun to make a perforations or holes through the casing and cement so that oil and gas can flow from the formation into the well bore. Acidizing is a method used to increase the permeability of the information by introducing acid into the formation.)

Entry

WIP – IDC	500,000
Cash	500,000

- l. The work on the well is finished and proved reserves have been found. Two entries are necessary: one to transfer the cost of the well from an unfinished goods account and one to reclassify the lease as proved.

Summarized Journal Entry 1

Wells and related equipment and facilities (E&F) – IDC	742,000	
Wells and related E&F – L&WE	110,000	
WIP – IDC		742,000
WIP – L&WE		110,000

	WIP-IDC	
B	50,000	
C	12,000	
D	4,000	
F	140,000	
G	8,000	
H	6,000	
I	1,000	
J	3,000	
k	500,000	
	<u>742,000</u>	

	WIP-L&WE	
D	2,000	
E	60,000	
H	35,000	
I	8,000	
j	5,000	
	<u>110,000</u>	

Summarized Journal Entry 2 (check question a above)

Proved property	20,000
Unproved property	20,000

- m. Denny Company purchase pipes (flow line to lease tanks), storage tanks and separators (separates the gas from the oil) for a cost of ₦15,000. Installation costs were ₦1,000

Entry

Wells and related E&F – L&WE	16,000
Cash	16,000

Note that the cost centre under SE is a lease or field, not an individual well.

- n. If instead, after evaluating the well in part g, Denny Company had decided the well was dry, only costs in part a-g would have been incurred and the entry to record the dry hole would have been:

Entry

Dry hole expense – IDC	214,000	
Dry hole expense – L&WE	62,000	
WIP – IDC		214,000
WIP – L&WE		62,000

- o. Costs of \$2,000 were incurred in plugging and abandoning the hole.

Entry

Dry hole expense – IDC	2,000	
Cash		2,000

It is important to distinguish between abandonment of the well and abandonment of the lease. In this case only the well has been abandoned and therefore no entry would be made relating to the lease, i.e. the unproved or proved property account.

Flowing from above, the difference between the following two wells is essential.

- 1. Exploratory well:** A well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir. Generally, an exploratory well is a well that is not a development well, a service well, or stratigraphic test well as those items are defined.
- 2. Stratigraphic test well:** A drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intention of being completed for hydrocarbon production. This classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as (i) “exploratory part”, if not drilled in a proved area or (ii) “development-type”, if drilled in a proved area.

Exploratory wells and exploratory-type stratigraphic test wells are accounted for as follows:

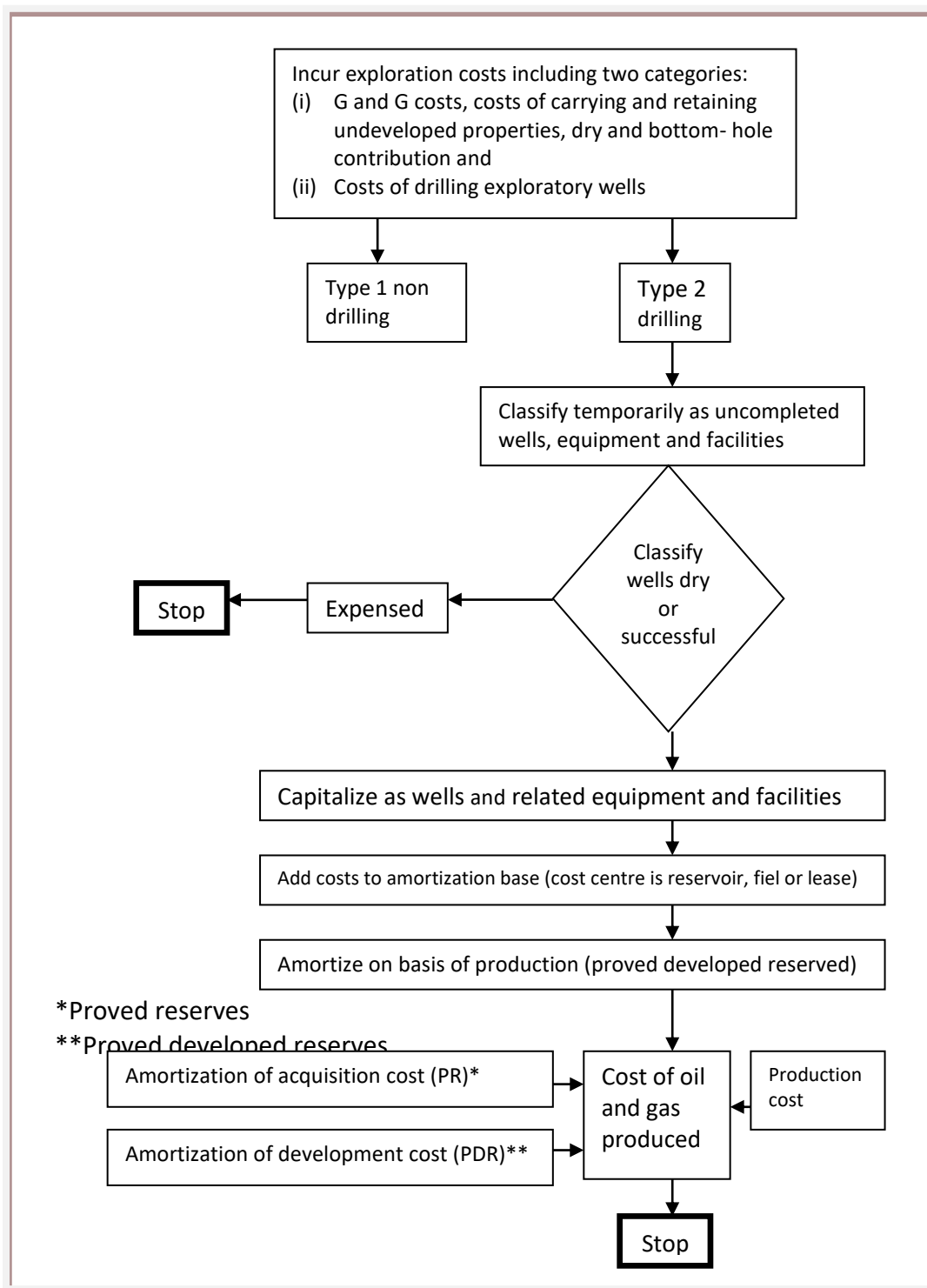
The following example illustrates typical drilling and completion costs and their accounting treatment under SE. as shown in the example, drilling cost are temporarily classified as (1) wells in progress – IDC or (2) wells in progress – lease and well equipment. (The term wells in progress is used in place of the FASB terminology uncompleted wells, equipment, and facilities. Note that wells in progress therefore include not only unfinished wells, but also unfinished equipment and facilities.)

When drilling reaches the targeted depth, a decision must be made as to whether the well has found proved reserves. If proved reserves have been found, both wells in progress account balance would be transferred to wells and related equipment and facilities accounts. In addition, if the well is the first exploratory well drilled on the property, the unproved property account will be

classified or transferred into a proved property account because proved reserves have been found and are now attributed to that property.

If proved reserves have not been found, the well must be plugged and abandoned. Equipment in the hole is salvaged when possible. However, installed casing cannot usually be removed because of either regulatory requirements or physical constraints. If the well is an exploratory well as in the following example, the cost of Plugging and abandoning, in addition to the capitalized costs in the wells in progress accounts (net of any salvaged equipment), must be written off to dry-hole expense. If the lease is also abandoned, the net amount capitalized as unproved property will be written off as surrendered lease expense or charged to the allowance account, depending upon whether the property is significant or insignificant.

Diagram 5-03: Accounting for Drilling and Non-drilling Exploration Costs



5.04 Accounting for Development Cost

Development costs are incurred to obtain access to proved reserves and to provide facilities for extracting, gathering, treating and storing the oil and gas reserves. Development costs are usually capitalized as part of the costs of a company's wells and related equipment and facilities. Consequently, all costs incurred to drill and

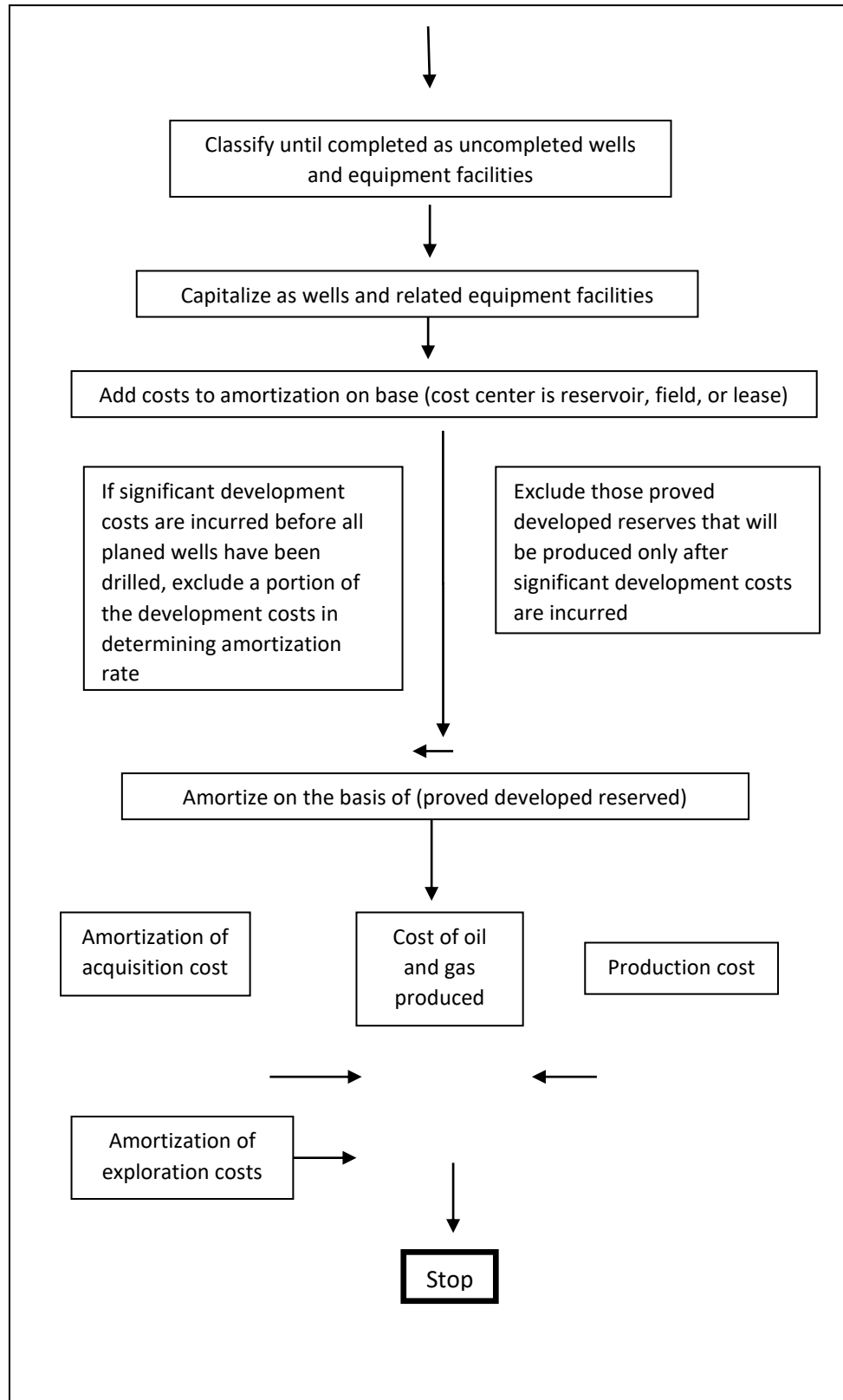
equip development wells and service wells are capitalized whether the well is successful or unsuccessful.

Development well is a well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive. Also Service well can be defined as a well drilled for the purpose of supporting production, e.g. a gas injection well, a water injection well or a salt-water disposal well.

The two types of development cost are drilling and non-drilling development costs. Under SE accounting, a direct relationship is required between costs incurred and specific reserves discovered before costs are ultimately identified as assets. Consequently, with respect to exploration costs, only successful exploration costs incurred in the search for oil and gas considered to be part of the cost of finding oil and gas.

In contrast to exploration costs, the purpose of development activities is considered to be building a producing system of wells and related equipment and facilities rather than searching for oil and gas. Hence, both successful and unsuccessful development costs are capitalized as part of the cost of the oil and gas.

Diagram 5-04: Accounting for Development Costs



Development drilling

During 2006 and 2007, Yemi Oil Company drilled several successful exploratory wells on Lease A. as a result, Lease A was classified as a proved property and the estimated boundaries of the reservoir were delineated. Danny Company decided in 2008 to drill an additional well within the proved area, a development well and hired a drilling contractor under a **turnkey contract**. The drilling contract specified that the contractor was to perform all services and furnish all materials up to completion. Required: prepare the necessary accounting entries for the transactions below.

- a. The well is drilled and equipped to the point of completion, and Danny Company pays the contractor under turnkey contract the agreed – upon amount of ₦150,000. Of this ₦150,000, IDC was ₦120,000 and equipment costs were ₦30,000. (**Unlike footage – rate contract and a day rate contract**, under a turnkey contract, the drilling contractor assumes all the responsibility and furnishes all the necessary materials and equipment.)

Entry

WIP – IDC	120,000	
WIP – L&WE	30,000	
Cash		150,000

- b. Assuming the well was determined to be dry and plugged and abandoned for an additional ₦2,000.

Entry to record plugging and abandoning costs

WIP – IDC	2,000	
Cash		2,000

Entry to record completion of work on well, i.e. to close out WIP accounts

Wells and related E&F – IDC (₦120,000 +	122,	
Wells and related E&F – L&WE	30,0	
WIP – IDC		122
WIP – L&WE		30,

- c. Assuming instead that the well was successful and the additional IDC of ₦15,000 and equipment costs of ₦70,000 were incurred to complete the well

Entry to record completion costs

WIP – IDC	15,000
WIP – L&WE	70,000
Cash	85,000

Entry to record completion of work on well

Wells and related E&F – IDC (₦120,000 + ₦15,000)	135,000
Wells and related E&F – L&WE (₦30,000 + ₦70,000)	100,000
WIP – IDC	135,000
WIP – L&WE	100,000

5.05 Controversial Issues in Accounting for Exploration and Development Cost

There are some problems of treatment of certain costs arising from either after thought decision from earlier plans or decision arising from an early success in drilling dept as against planned depth. These issues are treated as follows:

1. Deeper Drilling Beyond Producing Horizon

There could be a situation where oil companies discovers reserves within a planed depth but

decided to drill further to see if it could discover more reserves at a deeper level. For instance if it planned depth discovered reserves is at 5,000 ft and at that 5,000ft oil was discovered but later decided to go further deep at 1,500ft beyond the planned dept; here we have

- a. Additional dept of 1,500ft and
- b. Additional cost due to increase depth has arisen.

The problem here is the treatment of the additional cost, should it be capitalized or expensed with, if the additional depth of 1,500ft results in dry hole.

In the **Full cost method**, all exploration, acquisition drilling and development cost are usually capitalized whether the reserves is proved or unproved. In the case of **successful effort**, the additional cost that results in a dry hole should be expensed with.

2. Plug Back and Completion at a Lower Depth

Situation arise where oil is discovered below the planned depth; then what happens to the treatment of cost incurred beyond the point reached i.e. the point the oil was discovered to the planned depth, though within the planned depth.

For instance, if the planned depth was 8,000ft and in the course of drilling, the reserves were discovered at 6,000ft. This is below the planned depth; if the company decides to go further to the planed depth of 8,000ft, there is 2,000ft beyond the discovered point; but the remaining 2,000ft is within the planned depth; how is the cost of this 2,000ft treated, should it be capitalized or expensed. It has been suggested that the incremental cost of 6,000ft to 8,000ft and plug in back be expensed with while the cost of the 6,000ft be capitalized; though there are different practices between companies.

3. Well in Progress

The cost of unsuccessful exploratory cost should be expensed with while the cost of successful exploration should be capitalized under successful effort of accounting. The problems that actually arise here is whether the cost should be expensed with or capitalized.

4. Interest Capitalization

When a loan is sourced for property exploration, drilling and development, the practice required that it be capitalized apart of the cost of such assets.

SFAS No. 34 requires capitalizing interest as part of the cost of assets that require a period of time to be prepared for their intended use. Essentially, SFAS No. 34 requires interest capitalization for all qualifying assets, where qualifying assets are

defined as assets constructed by an entity for its own uses. To obtain the amount of interest to capitalize each period, the interest rate is applied to the average amount of accumulated capital expenditure. Capitalized interest cannot exceed actual interest costs.

The interest capitalization period begins when the three following conditions are met:

1. Expenditure for the asset have been made
2. Activities necessary to get the asset ready for its intended use are in progress
3. Interest cost is being incurred

The term activities used in condition 2 above, is to be constructed broadly encompassing technical and administrative activities such as obtaining permits. The interest capitalization period should end when the asset is substantially complete and ready for productive use.

Applying this statement to an industry as unique as the oil and gas industry creates interpretation problems. In fact, according to a survey of successful – effort companies, application of this statement has been quite varied. The starting point used as range from the time a prospect is acquired to the spud-in date. The stopping point, which is less varied, has ranged from the time proved reserves are found to the time when production begins. Activity cost has included leasehold costs and tangible and intangible drilling costs or IDC and tangible equipment only.

Specifically, capitalized interest is computed as follows: Average accumulated Expenditure during construction x interest rate x construction period

Average accumulated capitalized expenditure is computed by adding the beginning balance and ending balance of capitalized expenditures and dividing by two. A simple example of one interpretation of interest capitalization for an oil and gas company follows:

Illustration 5-09 and Suggested Solution

Interest Capitalization

Jack Company has unproved property costs of ₦60,000 for lease A at January 1, 2007, drilling costs are incurred on lease A in the amount of ₦300,000. A 10%, ₦400,000 note is outstanding during the entire year and was specifically obtained for the acquisition and drilling program related to Lease A. compute the interest capitalization amount and prepare the entry to record the interest.

Interest to be capitalized during 2007: Average

Accumulated expenditure: $\frac{₦60,000 + ₦360,000}{2} \times 12/12^* = \underline{₦210,000}$

Interest costs to be capitalized: $₦210,000 \times 0.10 = \underline{₦21,000}$

Entry

WIP – IDC	21,000	
Interest expense		21,000

*Because the property was acquired on January 1, 2007, the capitalization period is a fully year or 12/12.

In the above entry, WIP – IDC is debited although it is unlikely that the same amount would be considered IDC for tax. In practice, when taxes are prepared, companies

generally make relevant adjustments to the accounts to accommodate tax and financial accounting differences such as this one.

5.06 Review Questions

- i. Differentiate between drilling and development costs.
- ii. Mention and explain the accounting principles and application for all types of drilling and non-drilling exploration cost.
- iii. Explain the accounting procedure for intangible drilling and development cost (IDC) and equipment cost.

MODULE 6

PRODUCTION ACCOUNTING

6.00

6.01 Learning Outcomes

On successful completion of this Module, Students should be able to:

- i. Determine the types of economic interests in oil and gas properties;
- ii. Elucidate production costs and how to account for it;
- iii. Apply the concept and procedures for production accounting;
- iv. Evaluate special problems in production accounting;
- v. Determine the viability of an oil property through profitability;
- vi. Compute and measure revenue from oil;
- vii. Assess and discuss the contents of gas sale contracts and agreements.

6.02 General Overview

After an oil company has identified an area with potential, the company will seek to acquire the right to explore, develop and produce any minerals that might exist beneath the property, unless the company already holds those rights. The rights simply allow the means to share in the proceeds from the sales of any mineral produce and are referred to as MINERAL INTEREST or ECONOMIC INTEREST.

Under Nigerian laws, for ownership purpose, the surface of a piece of property must be separated from the minerals that exist underneath the surface. When a piece of land is purchased, one may acquire ownership of the surface right only and become SURFACE RIGHT OWNER through the acquisition of Certificate of Occupancy (C of O) or acquire the mineral interest only in order to become **Mineral Right Owner** or acquire both the ownership of surface right and the minerals underneath, and this is called FEE INTEREST OWNER.

Mineral or economic interest or ownership of mineral in place given the owner the right to share of the mineral produce either in kind or proceeds from the sales of the mineral Sharing In kind means that the original lessor or owner of the oil and gas property has elected to receive oil and gas as royalty rather than the proceeds from the sales of the mineral discovered.

6.03 Types of Economic Interests on Oil and Gas Properties Revenues

(1) **Royalty interest (RI)** – This is created by lease agreement or leasing. It is a basic type of mineral interest in production that is retained by the mineral interest owner, when he leases the property to another party called the lessee. It is a non working interest or non operating interest, because the owner or lessor is entitled to receive a fraction of the oil produced or the revenue, free and clear of development and production costs. The lessee is responsible for the exploration, development and production costs. However, the lessor will be responsible for the tax element associated with the royalty paid by the lessee.

(2) **Working Interest (WI)** – This is created by lease and is responsible for the exploration, development and operation of a property. While the working interest owner pays all the percentage at a cost of exploring, drilling, development and producing the property, the working interest shares of the revenue is the amount that remains after deducting the share of royalty interest (RI) and other non – working interest. It is important to note that WI is the same as operating interest. Working interest could either be divided or undivided. The undivided working interest arises when multiple owners of a property have the same share.

(3) **Overriding Royalty Interest (ORI)** – This is a non – working interest created out of working interest. It occurs when a working interest sells off his interest and retains his overriding royalty interest. In this arrangement, the ORI owner does not pay for any cost of exploring, drilling, developing and producing oil. The fundamental difference between a royalty interest and an ORI is that the royalty interest was created from the original mineral rights and the ORI is created from the WI. The ORI's share of revenue is stated percentage of the share of revenue belonging to the WI from which it was created. An ORI is created by either being retained or carved out. A retained ORI is created when the WI owner sells or conveys its working interest in a property and in the same transaction retains an ORI. A carved out ORI is created when the WI owner keeps the working interest but creates an ORI that is conveyed to another party.

(4) **Production Payment Interest (PPI)** – A PPI is a non-operating interest created out of the WI and is usually expressed in terms of a certain amount of money, a certain period of time, or a certain quantity of oil or gas. In other words, a PPI is limited to a specified amount of money, time, or quantity of oil or gas, after which the PPI ceases to exist. Therefore, unlike the other non-operating interests, a PPI generally terminates before the reservoir is depleted. The owner of a PPI is not responsible for any of the cost of exploring, developing or producing a property. If a PPI is payable with money, the payment is stated as a percentage of the working interest's share of revenue since the PPI was created from the WI. If a PPI is payable in product (i.e., oil, gas, etc) payment is typically stated as a percentage of the working interest's share of current production. Like ORIs PPIs are created by being carved out or by being retained.

(5) **Net Profit Interest** – A net profit interest is a non operating interest normally created out of the WI by either carve-out or retention, but more commonly by retention. A net profits interest may also be created when the mineral rights owner leases his interest. This type of interest is common offshore. A net profits interest is similar to an ORI except rather than being paid a percentage of the WI's share of production; the net profit interest owner receives a stated share of the WI owner's share of the net profit from the net property. The holder of this type of interest is not responsible for paying his share of losses; however, such losses may be recovered by the working interest owner out of future net profit payments. The calculation of net profits, i.e., the allowed deductions from gross revenue to compute net profit, should be clearly indicated in the contract.

(6) **Joint WI (JI)** –This is a situation where two or more parties, each owns an undivided fraction of the working interest in a single lease. A joint working interest may result from the following methods; (1) Leasing (2) Sales of exchanges or (3) Sharing arrangement. The joint interest format is very popular because it provides a means of sharing the high risk and high capital investment associated with oil and gas ventures.

One party usually the party with the largest percentage of the working interest has the responsibility of developing and operating the property. This party is known as the operator. In a joint interest situation, the WI parties enter into a joint operating agreement that specifies the rights and obligations of each party.

(7) **Non Working Interest** – The interest owner that is not responsible for exploration, drilling, developing and producing costs is referred to as non-working interest on non-operating interest.

6.04 Accounting for Production Costs

Production involves lifting the oil and gas to the surface, gathering, treating, field processing and storage. Production costs are usually determined to be all costs incurred from the maintenance of the wells and well heads to the storage facilities when the oil and gas are ready for export or delivery to a refinery.

Production costs are those costs incurred to operate and maintain a company's wells and related equipment and facilities including depreciation, depletion and applicable operating cost of support equipment and facilities. Examples of production costs include:

- i. Costs of personnel engaged in the operation of wells and related equipment and facilities;
- ii. Repairs and maintenance of production facilities;
- iii. Materials, supplies, fuel consumed and services utilized in such operation and
- iv. Royalties;
- v. Property taxes and insurance applicable to proved properties and wells and related equipment and facilities,
- vi. Severance taxes.

Accounting Treatment

Production costs **are expensed** as incurred by companies using successful-effort accounting and as well as by those using full-cost accounting.

Example

Bala Nigeria Limited paid wages of ₦1,000,000 to employees engaged in operating the well and equipment solely on lease A.

Accounting Entry

Lease operating expense	1,000,000
Cash	1,000,000

It is instructive to note that all costs relating to production activities, including workover costs incurred solely to maintain or increase levels of production from an

existing completion interval, shall be charged to expense as incurred under both SE and FC method.

Classification of Production Costs

Production cost can be divided into those that are (1.) directly associated to a specific well or lease (direct costs) and (2.) those that must be assigned to the well or lease through some method of allocation. For costs such as repair to a specific well, or wages and benefit of an employee working solely on one lease, accumulation of production cost by lease is straight forward: the costs are simply charged directly to the well or lease involved. Allocable cost such as the cost of a salt water disposal facility serving multiple leases must be allocated to each well or lease on some reasonable basis. Common allocation base include the number of wells or number of barrels produced. Other reasonable allocation bases for different type of allocable costs include:

1. Number of direct labor hours
2. Amount of direct labor costs
3. Number of miles driven for transportation and hauling
4. Gallons of water used for water flooding
5. Miles traveled by boat for transportation.

The Direct and Indirect costs are summarized in the table 6.1 below

Direct costs	Indirect or allocable cost
<p>a. Direct materials, supplies, and fuel wells and leases involved identified in the invoices.</p> <p>b. Direct labor (pumpers), guagers, etc. employees who work on one lease only or who designate hours worked on certain wells or leases</p> <p>c. Contract labor or service for oxidizing, scrubbing, etc. invoices indicate wells</p> <p>d. Repairs and maintenance that can be traced to individual wells and leases</p> <p>e. Property taxes and insurance traceable from tax receipt or property descriptions on insurance policies</p> <p>f. Production of severance taxes reports to the state identify these taxes to specific leases</p> <p>g. Operating costs of water flooding system – only one lease involved.</p>	<p>a. Field offices and facilities serving several leases</p> <p>b. salaries and fringe benefits of field or operations center supervisor of several leases or fields</p> <p>c. Depreciation – support facilities, gathering systems – several leases involved</p> <p>d. Transportation and hauling – several leases involved</p> <p>e. Operating costs of saltwater disposal system – several lease involved</p> <p>f. Boat and fuel expenses, offshore operation – several leases involved</p> <p>g. Operating cost of water flooding system – Several leases involved.</p>

Illustration 6-01

Allocation of cost

The following field office expenses related to Udoh Oil Company amounted to ₦100,000 for the month of September. The field office has supervision over the following leases and wells:

	Number of wells	Barrels of Oil
A	1	10,000
	3	5,000
C	4	20,000
D	<u>2</u>	<u>15,000</u>
Tot	<u>10</u>	<u>50,000</u>

You are required to allocate the field office expenses on the basis of

1. Number of wells
2. The barrels of oil

Suggested Solution 6.01

1. Allocation of field office expenses based on number of wells

<u>Lease</u>	<u>Computation</u>	<u>Amount</u>
		₦
A	(1/10 x 100,000)	10,000
B	(3/10 x 100,000)	30,000
C	(4/10 x 100,000)	40,000
D	(2/10 x 100,000)	<u>20,000</u>
To		<u>100,000</u>

2. Allocation of field office expenses based on the barrels of oil

<u>Lease</u>	<u>Computation</u>	<u>Amount</u>
A	(10,000/50,000 x 100,000)	20,000
B	(5,000/50,000 x 100,000)	10,000
C	(20,000/50,000x100,000)	40,000
D	(15,000/50,000x100,000)	<u>30,000</u>
To		<u>100,000</u>

Revenues

The revenue of oil and gas industry are derived from two main source. In the upstream industry, the revenues are derived from sales of oil and gas. They also get some revenues from services rendered to others such as storing crude oil in their tank farm for marginal producer.

In the downstream industry they get their revenue from direct refining and sales of refined products. Another source of revenue for them (downstream sector) is refining of third crude oil for a fee.

Revenue from Oil

An important step in accounting for revenue from oil is the determination for the volume lifted. Although field personnel such as gaugers, perform the actual

measurement of volume. The accountant must be familiar with measurement procedures in order to meaningfully record revenues in the book of account.

Measurement of Oil

The measurement of oil is determined by the specific gravity of oil expressed in degree called API. (American Petroleum Institute). Temperature, pressure are key element in the determination of API the thinner the oil the higher the API gravity (volume); the higher the API gravity (volume) of the oil, the more valuable the oil. This is because higher gravity oil usually produces higher yield (return) of white product and requires less complex operation to refine into usable product.

API gravity is inversely related to specific gravity and oil with 10° API gravity will have a specific gravity of one (1), the same as specific gravity of water and therefore the formula for API gravity is:

$$\text{API} = \frac{141.5}{\text{Specific gravity}} - 131.5$$

Specific gravity

Temperature has a dual effect on the measurement of crude oil. Not only can temperature change gravity of oil, it can also change the volume. The gravity changes because oil will become lighter when it is heated.

Decision to Complete a Well

In making a decision whether to complete a well, the incremental costs to complete the well should be compared with the future net cash flows expected to be received from the sale of oil or gas produced from the well. This comparison entails estimating the following items:

1. Quantity of oil or gas recoverable from the reservoir
2. Timing of future production of the oil and gas
3. Future selling price of the oil or gas
4. Future production cost of the oil or gas, including severance taxes
5. Completion costs
6. Cost of capital

Reserves estimates are usually made by a reservoir engineer, who may be an employee of the company or an independent contractor. Some factors or characteristics taken into account by the reservoir engineer in preparing a reserves estimate are as follows:

1. Size of the reservoir
2. Porosity and permeability of the reservoir
3. Pressure and temperature in the reservoir
4. Oil, gas, and water contained in the reservoir pores

Note that if the expected future net revenue is greater than the expected completion costs, the well is usually completed and if otherwise, the well should not be completed. It is also important to state that costs already incurred i.e., sunk costs are not relevant to decision making and should be ignored.

Illustration 6-02

Francis oil limited has the following data relating to 3 wells, A, B, and C:

Proved property cost (acquisition cost)	₦40,000
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Drilling cost incurred to date	200,000
Estimated completion cost	150,000
Estimated selling price per bbl	20
Estimated lifting cost per bbl	4
State severance tax	5%
Working interest share of revenue	90%
Royalty interest percentage	10%

The production for each well is as follows:

Well A: 7,500 bbl

Well B: 15,000 bbl

Well C: 30,000 bbl

Required: Which of the wells should be completed, assuming the reserves estimate of well B is 30% off on the down side?

Suggested Solution 6.02

Computation

	Well A	Well B	Well C
Total revenue (bbl x ₦20)	₦150,000	₦300,000	₦600,000
Less: RI's revenue (10%)	<u>(15,000)</u>	<u>(30,000)</u>	<u>(60,000)</u>
Revenue to WI	135,000	270,000	540,000
Less: Severance tax (5% x revenue to	<u>(6,750)</u>	<u>(13,500)</u>	<u>(27,000)</u>
Net revenue before lifting costs	128,250	256,500	513,000
Less: Lifting costs (₦4 x bbl)	<u>(30,000)</u>	<u>(60,000)</u>	<u>(120,000)</u>
Net revenue to WI owner	<u><u>₦98,250</u></u>	<u><u>₦196,500</u></u>	<u><u>₦393,000</u></u>

Decision:

Well A: should not be completed because its net revenue of ₦98,250 is less than the estimated completion costs of ₦150,000.

Well B: Based on the down side estimate of 30% off reserves, well B is not viable and should not be completed because completion cost would not be recovered.

Well C: Should be completed because the net revenue off ₦393,000 is more than the completion cost of ₦150,000.

Profitability of an Oil Well or Property

Due to the fact that a decision is made to complete a well because future net revenue is expected to be greater than completion costs, the well may still not be profitable. In order to be profitable, the net revenue from the well must exceed not only completion costs but all other costs as well. The costs incurred before deciding to complete a well, such as drilling costs etc, are sunk cost and do not enter into the completion decision. These costs are relevant, however, in determining whether the well has ultimately been profitable. The data from the preceding example excepts for changes in reserves and production amounts, are used in the two following similar examples. These examples illustrate an analysis to determine the ultimate profitability of a well and an analysis to determine the ultimate profitability of a property.

Illustration 6-03

The following information applies to a well drilled and produced by Akin's company:

Drilling cost	₦200,000
Completion cost	150,000
Selling price per bbl	20
Lifting costs per bbl	4
State severance tax	5%
Working interest share of revenue	90%
Royalty interest	10%

Production

Well 1. 750 bbl per month for 30 months

Well 2. 1,200 bbl per month for 30 months

Required: Determine whether the well was profitable.

Suggested Solution 6-03

Computation

	Well 1	Well 2
Total revenue per month	₦15,000	₦24,000
Less: RI's revenue	(1,500)	(2,400)
Revenue to WI	13,500	21,600
Less: Severance tax	(675)	(1,080)
Net revenue before lifting costs	12,825	20,520
Less: Lifting costs	(3,000)	(4,800)
Net revenue to WI owner per month	₦ 9,825	₦15,720
Total net revenue (revenue x 30 months)	₦294,750	₦471,600

Costs to cover:	Estimated drilling cost	₦200,000
	Estimated completion cost	150,000
		<u>₦350,000</u>

Well 1: The well was not profitable - ₦294,750 net revenue, compared to ₦350,000 total costs. Well 2: The well was profitable - ₦471,600 net revenue, compared to ₦350,000 total costs.

Comprehensive Illustration 6.04

The following information relates to Mustang Oil Company, a full cost company as at 31st December, 2008.

Cost of exploration drilling, 2008	₦1,734,000
Cost of lease and well equipment	₦688,000
Production, 2008	80,000bbls
Revenue, 2008	₦1,686,000
Production expenses, 2008	₦614,000
Reserves, 31/12/08 to be produced in	2009 500,000 bbls
2010	400,000 bbls
2011	341,000 bbls
2012	240,000 bbls
2013	160,000 bbls
2014	80,000 bbls

Total 1,721,000 bbls

Price per barrel is ₦56.88 and production cost per barrel is ₦21.34 as at 31/12/09.

Future development cost to be incurred:

Year 2010: IDC ₦666,000

Tangible equipment ₦134,000

₦800,000

Year 2011: Tangible equipment ₦84,000

Income taxes are assumed to be approximately ₦330,000 for each of the six years with 12% as cost of capital.

You are required to determine the discounted present value of its proved reserves as at 31/12/2014.

Suggested Solution 6.04

Mustang Oil Company Discounted Present Value of future revenue from proved reserves

Year	Period	Proved	Revenue	Production	Future	Income	Net	Discount	Present
2015	5	56	28,44	(10)	-	(330,	17,44	0	15,57
2016	4	5	22,	(8,5	((3	13,	0	10,
2017	3	5	19,	(7,2	((3	11,	0	8,3
2018	2	5	13,	(5,1		(3	8,1	0	5,2
2019	1	5	9,1	(3,4		(3	5,3	0	3,0
2020	8	5	4,5	(1,7		(3	2,5	0	1,2
Total	1,	-	97,	(367	((1,	58,	-	43,

Therefore, the discounted present value (NPV) of proved reserves as at 31/12/2014 = **N43,859,386**

6.05 Special Problems in Production Accounting

The special problems faced in production accounting are:-

1. Problem in treatment of well work over
2. Problem in treatment of production cost inventory

1. Problem of Well Work Over

A well work over is the remedial operation on a completed well to restore, maintain or improve the well's production capacity. The following costs may include

- i. Acidizing the well
- ii. Fracturing the well
- iii. Removal of sand
- iv. Paraffin build up
- v. Deepening on existing well or
- vi. Plugging back to produce from a shallower formation

Some companies look at the treatment of work over costs in two ways, either they

- i. Treat it as an expense or
- ii. Capitalized it

Treating it as an expense is predicated on the fact that, the amount involved is greatly immaterial especially for large companies.

Treating as a cost to capitalized and amortized predicated on the fact that recompletion increase the production potential of a reserves, such costs associated with recompletion are capital in nature and therefore should be capitalized as intangible cost and amortized. **Recompletion** refers to well work over costs that

involve drilling to a deeper horizon or plugging back to a shallower producing formation.

2. Problem of Production Costs in Inventory

Production costs are usually allocated to cost of goods sold and inventory. The problem here is that companies rarely value the oil in pipelines and tanks at cost instead they are value at selling prices. If revenues are presumed to be realized, then the realization concept is contravened and also cost is expected to be matched with revenue.

6.06 Gas Sales Contract

Raw natural gas comes primarily from any one of three types of wells: crude oil wells, gas wells, and condensate wells. Natural gas that comes from **crude oil wells** is typically termed associated gas. Natural gas from **gas wells** and from **condensate wells**, in which there is little or no crude oil, is termed non- associated gas.

Gas sale negotiation is essentially a risk management exercise and will require understanding of the ecosystem surrounding the transaction and therefore you must consider issues surrounding the following dramatis personae:

- a) The Government
- b) The Seller
- c) The Buyer
- d) The transporter
- e) The ultimate market
- f) The host community

The Gas Sales Contract or Agreement Should Cover:

- i. The technical issues around the Seller, Buyer, Transporter and the ultimate Consumer
- ii. Commercial issues i.e., pricing and petroleum economics
- iii. Policy and regulatory considerations
- iv. Macroeconomic issues in the jurisdiction
- v. Financing considerations like corporate banking and project financing
- vi. Exogenic events such as geopolitics, natural disasters and global macroeconomics

The Contents of Gas Sale Agreement

- i. Title to the Gas [outright proof + warranty]
- ii. Risk in the goods
- iii. Quantities [Depletion or Supply Contract? DCQs & ACQs]
- iv. Duration and renewal of the contract
- v. Transfer of title and risk in the goods
- vi. Quality and Fitness for purpose
- vii. Force majeure

- viii. Remedies and indemnification

Gas Should Also Capture

- i. Petroleum law
- ii. Tax law
- iii. Arbitration law
- iv. Foreign exchange regime
- v. Special legislation on the subject matter e.g., the Nigerian Gas Master Plan

6.07 Review Questions

- i. Define production costs and explain how to account for such costs.
- ii. Explain the procedures for production accounting.
- iii. Identify special problems in production accounting.
- iv. Critically examine the contents of gas sale contracts and agreements.
- v. Akin's company provided the following information for its 2 properties A and B:

Property cost (acquisition cost)	₦40,000
Drilling cost	200,000
Completion cost	150,000
Selling price per bbl	20
Lifting cost per bbl	4
State severance tax	5%
Working interest share of revenue	90%
Royalty interest	10%

Production

Property A.	750 bbl per month
Property B.	1,200 bbl per month

Required: Determine the viability of the properties assuming the investor wanted 36 months payback period.

MODULE 7

7.00 DEPRECIATION, DEPLETION AND AMORTIZATION

7.01 Learning Outcomes

On successful completion of this Module, Students should be able to:

- i. Elucidate depreciation, depletion and amortization;
- ii. Determine the basis and methods for amortization;
- iii. Evaluate the concept of amortization under Successful Effort and Full Cost methods;
- iv. Determine and apply the right oil and gas reserves to be used in the computation of amortization (DD&A);
- v. Determine and apply the accounting procedures for joint production of oil and gas;
- vi. Explain DD&A under inclusion and exclusion of costs;
- vii. Compute DD&A under revision of reserve estimates, dismantlement, restoration and abandonment costs;
- viii. Explain the concept of ceiling on capitalized costs and its computation.

7.02 Introduction

Depreciation, Depletion and Amortization (DD&A) is an important topic in oil and gas accounting. In financial accounting, depreciation represents an estimate of the portion of the historical cost or revalued amount of a fixed asset chargeable to operations during an accounting period. It means the wear and tear of an asset resulting from use, effluxion of time or obsolescence dictated by changes in technology and Market forces. Fixed or tangible assets are depreciated; natural resources such as gold are depleted while intangible assets such as goodwill and patent rights are amortized.

Statement of Accounting Standard 9 (SAS 9) deals with Accounting for Depreciation, and states the following methods for calculating it as:

- Straight line method
- Reducing balancing method
- Sum of the year digit
- Annuity and Sinking fund.

However, for Oil and Gas Accounting, the practitioners and professionals in the industry commonly refer to depreciation and amortization of proved property and wells and related equipment and facilities as Depreciation, Depletion and Amortization (DD&A). While the regulatory bodies such as Security and Exchange Commission (SEC) of the USA and Financial Accounting Standard board (FASB) of USA used the term Amortization in their written rules. Therefore, in this module, DD&A OR Amortization shall be applied throughout.

7.03 Basis for Amortization

All capitalized expenditure carried within each cost pool should be depreciated on Unit of Production basis. The depreciation charge should be calculated on pool by pool basis, using the ratio of current year oil and gas production, to the estimated quantity of commercial reserves at the end of the year plus the production for the year (SORP 2001).

It is instructive to note that the major method employed for the calculation of DD&A is Unit of Production Method. Also, there is a second Method called Equivalent Formula.

Explanation of the methods is as follows:

1. Unit of Production Method

This is the main method for calculating Depreciation, Depletion and Amortization of Capitalized costs and is used globally. The formula is stated as:

$$\text{DD\&A} = \frac{\text{Net book value at the year-end (31/12)}}{\text{Estimated Reserves at the Beginning of the year (1/1)}} \times \text{Production for the year}$$

***Note that Estimated reserves at the beginning of the year** = Estimated reserves at the year-end plus Production for the year. It is important to state that this must be used always in calculating DD&A. **The Unit of Production formula** stated above shall be used all through for our calculations.

2. Equivalent Formula

The equivalent method is an alternative method of calculating DD&A and it is calculated as follows:

$$\text{DD\&A} = \frac{\text{Production for the year}}{\text{Estimated Reserves at the Beginning of the year (1/1)}} \times \text{NBV at the year-end (31/12)}$$

The two formulas above will always give the same answer. Let us consider example to explain the above explanation.

Illustration 7-01

Governor Nig. Plc has the following information on Lease A.

Capitalized cost at end of the year	₦3,400,000
Accumulated Amortization for prior year	₦200,000
Reserves estimates at the beginning of the year	10,000,000 barrels (bbls)
Production for the year	500,000 bbls
Reserves estimates at the end of the year	8,000,000 bbls

Required:

1. Calculate DD&A Per barrel
2. DD&A for the year

Suggested Solution 7-01

Applying Unit of Production Method

$$\begin{aligned}
 1. \quad \text{DD\&A per barrel} &= \frac{\text{Net book value (NBV) at the year end (31/12)}}{\text{Estimated Reserves at the Beginning of year (1/1)}} \\
 &= \frac{\text{N3,400,000} - \text{N200,000}}{8,000,000\text{bbls} + 500,000\text{bbls}}
 \end{aligned}$$

$$\text{DD\&A per barrel} = \frac{\text{N3,200,000}}{8,500,000 \text{ bbls}} = \text{N0.3765 per barrel}$$

$$2. \text{ DD\&A for the year} = \frac{\text{NBV at the year-end (31/12)}}{\text{Estimated Reserves at the Beginning of year (1/1)}} \times \text{Production for the year}$$

$$\begin{aligned}
 &= \frac{\text{N3,200,000}}{8,500,000 \text{ bbls}} \times 500,000\text{bbls} = \text{N188, 235}
 \end{aligned}$$

A. Amortization under Successful Efforts and Full Cost

SE companies capitalize the exploration and development costs that lead to the discovery of oil and gas reserves by posting such costs into the balance sheet as assets, while all other costs that do not lead to discovery of oil and gas reserves are expensed by taking them to income statement or profit and loss account.

For calculation of DD&A or Amortization for SE companies, acquisition costs of proved properties and the costs of well and related equipment and facilities are amortized to become part of the cost of oil and gas produced (SFAS No. 19, par. 27). This means that the costs cannot be added together when calculating DD&A. The Amortization of acquisition cost must be calculated based on Proved Reserves, while the DD&A for well and related equipment and facilities must be computed over Proved Developed Reserves. The reason for this is that Acquisition costs represent expenditures incurred on behalf of the entire cost center and therefore all proved reserves produced from such cost center should be applied to calculate amortization.

However, Proved Developed Reserves are the reserves that will be produced as a result of the costs already incurred for completed wells and equipment. It is also important to mention that both the acquisition costs and the costs of wells and related equipment and facilities are amortized based on unit of production method. Furthermore, when an oil property is fully developed, proved reserves and proved developed reserves are the same.

For a Full Cost Company, all capitalized costs incurred in a cost center should be amortized on the unit of production basis using PROVED RESERVES. The reason for this is because FC firms capitalize all acquisition cost, exploration, appraisal and development costs. However, in the case of Successful Effort Companies, amortization of exploration and drilling costs incurred within each well, field or property should also be on a unit of production basis using PROVED DEVELOPED RESERVES.

Also, if further appraisal of a concession is planned, cost of exploration and appraisal activities may be carried forward pending determination of proved reserves in commercial quantities for a period of:

- Not more than 3 years following completion of drilling in an offshore area and
- For a maximum of 2 years in an onshore area (SAS 14, par 112)

Illustration 7-02

Ondo Oil Plc drilled the first successful well oil lease A early in 2012. The company plans to develop this lease fully over the next several years. Data for the lease as of Dec 31st 2012 are as follows:

I	Lease hold cost i.e Acquisition cost	₦50,0
I	IDC well and related equipment and facilities	₦90,0
I	Lease and well equipment (Wells and Related E & F)	₦30,0
I	Production during 2012	5,000b
V	Total estimated proved reserves, December 31, 2012	895,00
.	Total estimated proved reserves recoverable from the well,	0bbl
.	December 31, 2012 (i.e., proved developed reserves)	95,000

You are required to calculate:

- DD&A for Acquisition cost
- DD&A for Wells and Related Equipment and facilities.
- To show the proper journal entry to record the above transaction

Suggested Solution 7.02

i. DD&A For Acquisition cost

$$D\&A = \frac{NBV \text{ @ the year end (31/12)}}{\text{Estimated reserves @ the beginning of the year}} \times \text{Production for the year}$$

* Estimated Reserves at the beginning = Estimated proved reserves at the year end + Production for the year.

$$DD\&A \text{ for Acquisition cost} = \frac{₦50,000}{895,000bbl + 5,000bbl} \times 5,000bbl$$

$$= \frac{₦50,000}{900,000bbl} \times 5,000bbl = ₦278$$

ii. DD&A for Wells and Related Equipment and facilities.

* Cost of Wells and Related Equipment and facilities = ₦90,000 + ₦30,000 = ₦120,000

$$\text{DD\&A for (W\&RE\&F)} = \frac{\text{₦120,000}}{95,000\text{bbl}+5,000\text{bbl}} \times 5,000\text{bbl} = \text{₦6,000}$$

* Note that to calculate DD&A for Wells and Related Equipment and facilities, proved developed reserves must be used.

iii. Proper journal entry to record the above DD&A

Dr	Cr		
₦	₦		
DD&A expense – proved property		278	
DD&A expense – wells (W&RE&F)		6,000	
Accumulated DD&A – proved property			278
Accumulated DD&A – wells (W&RE&F)			6,000

Comprehensive Illustration 7-03

Mallam Audu limited has a partially developed lease as of 31/12/2011.

The cost information for the said lease is as follows: Cost Data:

Lease bonus	₦500,000	
Others capitalized acquisition costs	<u>₦40,000</u>	
Total lease cost at year end	<u>₦540,000</u>	
Accumulated DD&A on leasehold costs at beginning of year		₦40,000
IDC at year end		₦650,000
Accumulated DD&A on IDC at beginning of year		₦120,000
Lease and well equipment at year end		₦275,000
Accumulated DD&A on equipment at beginning of year		₦50,000

Reserve and production date:

Estimated proved developed reserves, 12/31/2011	1,750,000bbl
Estimated proved undeveloped reserves 12/31/2011	2,200,000bbl
Production during year	50,000bbl
Required: Calculate the DD&A	

Suggested Solution 7-03

DD&A calculations

a. To calculate DD&A first reserves as of the beginning of the year are determined. Proved reserves equal proved developed reserves plus proved undeveloped reserves.

Proved Reserves (barrels):

Estimated proved developed reserves, 12/31/2011	1,750,000bbl
Add: Estimated proved undeveloped reserves, 12/31/2011	<u>2,200,000bbl</u>
Estimated proved reserves, 12/31/2011	3,950,000bbl
Add: Current year's production	<u>50,000bbl</u>
Estimated proved reserves, 1/1/2012	<u>4,000,000bbl</u>

Proved developed reserves (barrels):

Estimated proved developed reserves, 12/31/2011	1,750,000bbl
Add: Current year's production	<u>50,000bbl</u>
Estimated proved developed reserves, 1/1/2012	<u>1,800,000bbl</u>

b. Second year – end costs are determined.

Proved Property Cost:

	₦
Leasehold costs at year-end	540,000
Less: Accumulated DD&A on lease hold costs	<u>(40,000)</u>
Net leasehold costs	<u>500,000</u>

Wells and Related E&F:

	₦
IDC at year end	650,000
Less: Accumulated DD&A on IDC	<u>(120,000)</u>
Net IDC	<u>₦530,000</u>
Lease and well equipment at year end	275,000
Less: Accumulated DD&A on L&WE	<u>(50,000)</u>
Net lease and well equipment	<u>225,000</u>

c. Third, DD&A is calculated.*

For Proved Property Cost:

$$\frac{\text{Current year production}}{\text{Estimated proved developed reserves, 1/1/2012}} \times \text{Book value at year end}$$

$$= \frac{50,000}{4,000,000} \times \text{₦500,000} = \underline{\underline{\text{₦6,250}}}$$

Wells and Related E&A:

$$\frac{\text{Current year production}}{\text{Estimated proved developed reserves, 1/1/2012}} \times \text{Book value at year end}$$

$$\text{IDC} = \frac{50,000}{1,800,000} \times \text{₦530,000} = \underline{\underline{\text{₦14,722}}}$$

$$\text{L\&WE} = \frac{50,000}{1,800,000} \times \text{₦225,000} = \text{₦6,250}$$

$$\text{Total DD\&A} = \text{₦6,250} + \text{₦14,722} + \text{₦6,250} = \text{₦27,222}$$

Journal Entry to record DD&A

	Dr	Cr
DD&A expense	₦27,222	
Accumulated DD&A – proved property		₦6,250

Accumulated DD&A – IDC
 Accumulated DD&A – L&WE

₦14
 722
 ₦6,
 250

7.04 Joint Production of Oil and Gas

It is expected that most reservoirs contain oil and gas reserves, and the reserves that must be used to calculate DD&A is either oil or gas because both reserves cannot be jointly employed as a base for the calculation of amortization of the capitalized costs. Therefore, if oil and gas reserves are produced jointly, one of three different **amortization methods may be used, assuming the conditions given above are satisfied:**

1. Common unit of measure – converting to common energy unit
2. Same relative proportion – using either oil or gas
3. Dominant mineral – using the dominant mineral

Common unit of measure – converting to common energy unit

Under this method, it is necessary to convert oil and gas reserves produced to a common unit of measure based on relative energy content. Energy content is measured by the British thermal unit (Btu). Most companies use a generally accepted industry average, converting the Btu content of 1 barrel of oil to 6 Mcf of gas in terms of energy content. The calculation can be made by either dividing the Mcf of gas by 6 to get barrels of oil equivalent (BOE), or multiply the barrel of oil by 6 to get equivalent Mcf's. For instance, to convert 35,000 barrel of oil to gas (Mcf), it will be $35,000 \text{ barrel} \times 6 = 210,000 \text{ Mcf}$ of gas. It is also important to note that 1 barrel of oil equal 42 US., gallons or 35 imperial gallons.

Same relative proportion – using either oil or gas

If the oil and gas are expected to be produced in the same ratio or the percentage of oil to gas extracted in the current period from the reservoir is expected to remain the same, then amortization (DD&A) may be computed based on only one of the two minerals – either oil or gas. This is because none of the oil or gas clearly dominates the reservoir.

Dominant mineral – using the dominant mineral

If oil or gas reserve is the dominant mineral i.e. one of the reserves is found in higher ratio or percentage compared to the other in the reservoir, then the reserve with higher ratio should be used in the calculation of DD&A. The dominant mineral is the one with the highest quantities of equivalents after conversion into common unit of measure.

Additionally, measurement and pricing unit other than mcf's may be used for gas. For example, gas may be measured and priced in terms of MMBtu (million British thermal units) rather than Mcf. If a measurement unit other than Mcf is used for gas, the conversion ratio must be calculated based on the unit of measurement being used.

Comprehensive Illustration 7-04

Joint production DD&A

Segun Oil Company has a fully developed producing lease that has both oil and gas reserve. Data for the lease are as follow. (In a fully developed lease the proved reserves and proved developed reserves are the same amount.)

Net capitalized costs, December 31	₦2,200,000
Estimated proved developed reserves December 31:	
Oil	400,000bbl
Gas	1,800,000Mcf
Production during the year:	
Oil	50,000bbl
Gas	240,000Mcf

Required: Calculate DD&A based on

- Common unit of measure – converting to common energy unit.
- Same relative proportion – Using either oil or gas.
- Dominant mineral – Using the dominant mineral.

Suggested Solution 7-04

- I. DD&A based on Common unit of measure.

DD&A = $\frac{\text{Net Book Value @ the year end}}{\text{Estimated Reserve @ the Beginning (1/1)}}$ x Production for the year.

Estimated Reserve @ the Beginning (1/1)

Note: As the question says calculate common unit of measure. It means that we have to calculate both methods i.e. in barrel for oil and Mcf for gas equivalents.

Workings

- a) Calculation of production for the year using oil

Oil			50,000bbl
Gas	$\frac{(240,000\text{mcf})}{6}$	=	$\frac{40,000\text{BOE}}{90,000\text{bbl}}$

- b) Calculation of proved development reserve @ the end of the year,

Oil			400,000bbl
Gas	$\frac{(1,800,000\text{mcf})}{6}$	=	$\frac{300,000\text{BOE}}{700,000\text{bbl}}$

- c) Estimated Reserves at the Beginning 1/1 = Proved Development Reserves @ the end 31/12 + Production for the year

= 700,000bbl + 90,000bbl = 790,000bbl

DD&A = $\frac{\text{Net Book @ the yr end}}{\text{Estimated Reserves @ the Beginning 1/1}}$ x Production for the year.

Estimated Reserves @ the Beginning 1/1

DD&A = $\frac{\text{₦2,200,000}}{790,000\text{bbl}} \times 90,000\text{bbl} = \text{₦250,633}$

(1B). **Common unit of measure using Gas Equivalent**

a. Calculation of Production for the Year.

Gas	240,000Mcf
Oil (6×50,000)	<u>300,000Mcf</u>
	<u>540,000Mcf</u>

b. Estimated Proved Developed Reserve @ the end of the year end (31/12)

Gas	1,800,000Mcf
Oil (400,000 × 6)	<u>2,400,000Mcf</u>
	<u>4,200,000Mcf</u>

c. Estimated Reserves @ the beginning 1/1 = 540,000Mcf + 4,200,000Mcf = 4,740,000Mcf

DD&A = $\frac{\text{Net Book @ the yr end}}{\text{Estimated Reserves @ the Beginning 1/1}} \times \text{Production for the year.}$

$$\text{DD\&A} = \frac{\text{₦2,200,000}}{4,740,000\text{Mcf}} \times 540,000\text{Mcf} = \underline{\underline{\text{₦250,633}}}$$

Accounting entry

	Dr	Cr
DD&A Expense	₦250,633	
Accumulated DD&A		₦250,633

I. DD&A Employing Relative proportion – Using Gas.

DD&A = $\frac{\text{Net Book @ the yr end}}{\text{Estimated Reserves @ the Beginning 1/1}} \times \text{Production for the year.}$

$$\text{DD\&A} = \frac{\text{₦2,200,000}}{180,000\text{Mcf} + 240,000\text{Mcf}} \times 240,000\text{Mcf}$$

$$= \frac{\text{₦2,200,000}}{240,000\text{Mcf}} \times 240,000\text{Mcf} = \underline{\underline{\text{₦258,824}}}$$

Accounting entry	DR	CR
DD&A Expense	₦258,824	
Accumulated DD&A		₦258,824

II. DD&A employing Same Relative Proportion – using Oil

DD&A = $\frac{\text{Net Book @ the yr end}}{\text{Estimated Reserves @ the Beginning 1/1}} \times \text{Production for the year.}$

$$\text{DD\&A} = \frac{\text{₦2,200,000}}{400,000\text{bbl} + 50,000\text{bbl}} \times 50,000\text{bbl}$$

$$= \frac{\text{₦2,200,000}}{450,000\text{bbl}} \times 50,000\text{bbl} = \underline{\underline{244,444}}$$

Accounting entry

	Dr	Cr
DD&A Expense	₦244,444	
Accumulated DD&A		₦244,444

III. DD&A Using dominant mineral – i.e. Oil

DD&A = $\frac{\text{Net Book Value @ the yr end 31st Dec}}{\text{Estimated Reserves @ the Beginning Jan 1st}} \times \text{Production for the year}$

$$\begin{aligned} \text{DD\&A} &= \frac{\text{₦2,200,000}}{400,000\text{bbl} + 50,000\text{bbl}} \times 50,000\text{bbl} \\ &= \frac{\text{₦2,200,000}}{450,000\text{bbl}} \times 50,000\text{bbl} = \underline{\underline{\text{₦244,444}}} \end{aligned}$$

Unit of Revenue Method of Calculating Amortization

This is an alternative method of computing DD&A. If oil and gas are produced jointly, the oil and gas reserves are converted to a common unit of measure based on relative energy content. However, oil and gas prices may be so disproportionate relative to their energy content that the unit-of-production method would result in an improper matching of the costs of oil and gas production against related revenue received.

When that is the case, the unit-of-revenue is a more appropriate basis of computing amortization because it eliminates the distortion caused by the 6:1 conversion ratio by calculating amortization on the relative value of hydrocarbons. It is instructive to state that the revenue method is not allowed under SE accounting. It is only the FC firms that apply such method.

If the unit of revenue method is used, the actual selling price of the oil and gas should be used to value the production during the year, and current prices (year-end) rather than future prices should generally be used in valuing the proved reserves. Note that, future prices should be used only when provided by contractual arrangement.

The formula for computing amortization using unit-of-revenue is the following:

$$\frac{\text{Capitalized cost at the year end (NBV)}}{\text{Estimated proved reserves at beginning of year valued at year-end prices}} \times \frac{\text{production during year}}{\text{valued at actual selling prices}}$$

Comprehensive Illustration 7-05

The following data belong to Tunde Oil Firm, a full cost company. You are required to compute DD&A for 2001 using:

- I. Equivalent physical unit of production, and
- II. Revenue values of the oil and gas

	₦
Net capitalized costs	3,500,000
Future development costs	1,000,000
Estimated dismantlement and reclamation costs, net of salvage	500,000

End of the year total proved reserves

Oil	950,000 barrels
Gas	900,000 Mcf

2001 Production/Revenue:

Oi	50,000	₦1,5
G	120,00	₦18

End of the year (current) price

Oil	₦1,530/bbl
Gas	₦127.50/MCF

Suggested Solutions 7-05

Equivalent Physical Unit of Production Method

Productions

Oil	50,000bbls
Gas	<u>120,000</u>
6	<u>20,000bbls</u>
	<u>70,000EOB</u>

End of the year total proved reserve:

Oil	950,000bbls
Gas	<u>900,000</u>
6	<u>150,000bbls</u>
	<u>1,100,000BOE</u>

Total capitalized costs or NBV

Net capitalized costs	3,500,0
Future development costs	1,000,0
Estimated dismantlement and reclamation costs, net of	

$$\text{DD\&A} = \frac{5,000,000}{1,100,000 + 70,000} \times 70,000 = \underline{\underline{\text{₦299,145}}}$$

Unit of Revenue Method

Production		₦
O	50,000bbls	× 76,5
G	120,000bbls	× <u>15,3</u>
		<u>91,8</u>

Total proved reserves current value:

O	950,000bbls	×	1,453,50
G	900,000MCF×		
			<u>1,568,25</u>

$$\text{DD\&A} = \frac{5,000,000}{91,800,000 + 1,568,250,000} \times 91,800,000$$

$$= \underline{\underline{\text{N}276,497.50}}$$

Inclusion of additional costs for computation of Amortization

Net capitalized costs, including both leasehold costs and drilling and development costs are amortized over proved reserves under full-cost accounting. **Proved reserves consist of:**

1. Proved developed reserves, which will be produced through existing wells and equipment
2. Proved undeveloped reserves, which will be produced through future wells or through future major recompletions.

Therefore, when the proved reserves are not fully developed, a portion of the proved reserves – which make up the denominator in the DD&A calculation – will be producible only as a result of relatively major future development costs. Consequently, those future development costs must be included in the costs being amortized to avoid a distortion of the DD&A rate, i.e. a mismatching of costs and reserves. Estimate of future development costs should be based on current costs.

In addition, estimated future dismantlement and abandonment costs, net of salvage values, must also be included in the amortization calculation in the same manner as amortization under successful effort accounting.

Illustration 7-06

DD&A: Additional costs

Data for Dickson Company as of December 31, 2012, is as follows: Unrecovered costs (net capitalized costs) N2,000,000

Production during 2012 50,000 bbl

Proved reserves, January 1, 2012 600,000 bbl

Dickson Company estimates that future expenditures to develop partially developed properties (proved properties) will be N300,000. Dickson Company also estimate that future dismantlement and abandonment costs will be N400,000, with salvage of N100,000. Calculate DD&A

Suggested Solution 7-06

DD&A Calculation

Costs to be amortized:

Unrecovered costs	N2,000,000
-------------------	------------

Add: Future development costs	300,000
-------------------------------	---------

Add: Future dismantlement and abandonment costs	400,000
Less: Future salvage	<u>(100,000)</u>
Total costs to amortize	<u><u>₦2,600,000</u></u>

$$\text{DD\&A} = \frac{\text{₦2,600,000}}{600,000 \text{ bbl}} \times 50,000 \text{ bbl} = \text{₦216,667}$$

Exclusion of Significant Development Costs

Amortization for full cost is based on proved reserves: consequently, amortization of unproved properties, which by definition have no proved reserves attributable to them, can seriously distort the amortization rate. Similarly, amortization of major development projects expected to involve significant costs in order to determine the quantities of proved reserves can also seriously distort the amortization rate. In recognition of this problem, the SEC allows unproved properties or development projects entailing significant future development costs to be excluded from the amortization base. Specifically

1. All costs directly associated with the acquisition and evaluation of unproved properties may be excluded until it is determined whether or not proved reserves can be assigned to the properties. However, exploratory dry holes must be included in the amortization base as soon as a well is determined to be dry. Further, any G&G costs that cannot be directly associated with specific unproved properties should be included in the amortization base as incurred.
2. Certain costs associated with major development projects expected to entail significant costs in order to ascertain the quantities of proved reserves attributable to the properties under development may be excluded if they have not previously been included in the amortization base. Excludable costs include both costs already incurred and future costs. The portion of common costs (i.e. costs common to both the known reserves and the reserves yet to be determined) excluded should be based on the ratio of existing proved reserves to total expected proved reserves, or a comparison of the number of wells to which proved reserves have been assigned to the total number of wells expected to be drilled. Both the excluded costs and the related proved reserves should be transferred into the amortization base on a well-by-well or property-by-property basis as proved reserves are established or as impairment is determined.

The above costs may be excluded from the amortization base until proved reserves are established or until impairment (or abandonment) occurs. Any impairment is not expensed but is transferred into the amortization base and recovered, i.e. written off expense, only through DD&A. note that if proved reserves are established, the costs must be included in amortization. Thus, even though production has not yet begun (e.g. construction of a pipeline necessary before any oil or gas is produced), the costs are amortized.

Revision of Reserve Estimate

It is sometimes necessary to revise the estimate of reserves because of new information, changes in technology etc. The effects on amortization rates of such reserve revisions are usually adjusted prospectively. Changes in reserve estimates impact significantly on companies that prepare interim financial statements say on a quarterly or semi-annual basis.

Illustration 7-07

Binutu Exploration Company Plc had total unde depreciated cost of wells and related facilities at 1/1/06 amounting to ₦60,000,000 and estimated proved developed reserves of 15,000,000 barrels. Production and amortization during the first three quarters of 2006 were as follows:-

	Production (barrels)	Amortizati
1st	1,000,000	4,000,000
2nd	500,000	2,000,000
3rd	<u>800,000</u>	<u>3,000,000</u>
	<u>2,300,000</u>	<u>9,200,000</u>

Production for the fourth quarter was 750,000 barrels. On 31 December 2006, the reservoir engineer advised that estimated proved developed reserves were 16 million barrels.

Required:

Compute amortization for the 4th quarter of 2006 using the whole year as a fiscal period

Suggested Solution 7-07

BINUTU EXPLORATION COMPANY PLC CALCULATION OF DD&A FOR 4TH QUARTER-2006

Reserve estimates at 31/12/2006	16,000,000 bbls
Add: Production during 1st to 3rd quarter	2,300,000 bbls
Production during 4th quarter	<u>750,000 bbls</u>
Revised estimate of reserves at 1/1/96	<u>19,050,000 bbls</u>
DD&A for year = $(2,300,000 + 750,000 \text{ bbls}) \times 60,000,000 = 9,606,299$	
	19,050,000 bbls
Total DD&A for the year	₦9,606,299
Less: Depreciation reported in the first 3 quarters	<u>(9,200,000)</u>
Depreciation for fourth quarter	<u>406,299</u>

Each quarter as a fiscal period

An alternative method of calculating DD&A for the fourth quarter is to treat each quarter as a fiscal period. The DD&A figures for the first three quarters are left unchanged and the revised estimate will be used for the fourth quarter calculation only.

$$\begin{aligned}
& \text{DD\&A (4th quarter)} \\
& \frac{750,000 \text{ bbls}}{16,000,000 + 750,000 \text{ bbls}} \times (60,000,000 - 4,000,000 - 2,000,000 - 3,200,000) \\
& = \frac{750,000}{16,750,000} \times 50,800,000 = 2,274,627 \\
& \text{Depreciation for first three quarters} \quad \frac{9,200,000}{\text{DD\&A for the year}} \\
& \quad \quad \quad \underline{\underline{\text{N11,474,627}}}
\end{aligned}$$

Although the results under both methods are significantly different, some oil companies frequently adopt this later approach. Whichever method is adopted consistency of application should be important.

7.05 Dismantlement, Restoration and Abandonment Costs

When oil and gas reserve are fully depleted or production falls to an uneconomically low level and it is no longer feasible to produce minerals even under enhance recovery techniques, equipment are salvaged and operations are abandoned. Oil and gas operations regulations require that wells be plugged all facilities and equipment removed and the terrain restored, as much as possible, to its natural state.

Dismantlement and restoration costs can be quite enormous and sometimes may even exceed the cost of the original illustrations, especially when account is taken of inflation and the time interval between the commencement of production and abandonment of property. Some companies assume that the amount realized from dismantled facilities less salvage cost will offset dismantlement and restoration costs. Accordingly, such company either ignores making any provision for such terminal costs or makes the provision in the year in which abandonment occurs. Clearly, by not making accruals, such companies would not be achieving the matching of revenues with related costs. Sound accounting principles required that estimated dismantlement, restoration and abandonment costs, if material, be included in the cost pool in determining amortization rates.

The amortization relating to dismantlement, salvage and reclamation is usually charged to DD&A (or a profit and loss account titled dismantlement, salvage and reclamation costs) and credited to a liability account. When the company abandons the property and incurred the dismantlement and restoration costs, the costs incurred are charged to the liability account. Any difference between actual dismantlement and restoration costs and the liability is charged or credited to income.

Illustration 7-08

A. Calculate dismantlement, salvage and reclamation costs for 2008 for Co. Y, a successful efforts company assuming the following:

Platform costs	₦180,000,000
Removal and restoration costs	₦35,000,000
Proved reserves at 1/1/08	30,000,000 bbls
2008 production	1,500,000 bbls

B. Pass necessary journal in the books of company Y.

C. Calculate dismantlement, salvage and reclamation costs for 2009 assuming production is 2,000,000 barrels of crude oil.

Suggested Solution 7-08

A. Dismantlement, salvage and reclamation costs for 2008

Removal and restoration cost	₦35,000,000
Proved reserves	30,000,000 bbls
2008 production	1,500,000 bbls
$\frac{1,500,000}{30,000,000} \times 35,000,000$	= ₦1,750,000

B. Journal Entry

	₦	₦
Dismantlement, salvage and reclamation costs (P&L)	1,750,000	
Future liability for salvage and reclamation costs (B/S)		1,750,000
Being provision made for the liabilities to be incurred to dismantle and restore well sites after fully depleted.		

C. Dismantlement, salvage and reclamation costs for 2009

Production in 2009	2,000,000 bbls
Proved reserves at 1/1/2009 (30,000,000 – 1,500,000)	28,500,000 bbls

$$\text{2009 dismantlement costs} = \frac{2,000,000 \text{ bbl}}{28,500,000 \text{ bbl}} \times (35,000,000 - 1,750,000) = \text{₦2,333,333}$$

7.06 Ceiling on Capitalized Cost

A ceiling test is a test to determine whether the recorded capitalized exploration, appraisal and development costs are recovered from proved reserves. It is the test carried out to determine the upper limit of the total amount of costs to be capitalized in each cost centre by taking into cognizance an estimation of the value of underlying reserves.

In oil and gas accounting, acquisition, exploration and development costs are usually capitalized under the full cost method. In addition, full cost method also considers exploratory and development dry holes as asset thereby capitalizing them in the balance sheet. Due to the treatment of dry hole costs, the capitalized cost in a cost center may be more than the underlying value of oil and gas reserves.

Therefore SAS 14 states that cost ceiling must be established for each cost center. The test of this ceiling cost is called the ceiling test.

To minimize this problem A FULL COSTS COMPANY is expected to carry out ceiling test every year.

It is important to note that the excess capitalized cost over ceiling is charged to expense account i.e. debited to P&L account and the amount disclosed separately in the financial statement. In its calculation, the discount rate to use is the CBN minimum rediscount rate. While in USA and Canada 10% is used.

Calculation for ceiling test

Capitalized costs less accumulated amortization and deferred income taxes should not be in excess of estimated fair market value of the reserves.

Format for calculation of ceiling test

A	<u>Calculate the Net Capital Cost</u>	
i	The capitalized cost	
	Less: Accumulated amortization	(
	Less: Deferred income taxes	(
A	Net capitalized costs.	<u>x</u>
	This should not be in excess of ceiling	
B	<u>(i.e. estimated fair market value of reserves)</u>	
	(i) Present value of future net	
	Revenue from estimated production of oil and gas reserves	
	Add: (ii) cost of properties unevaluated or not being	
	Add: (iii) lower of costs or market value of improved	
	included in the cost being amortized	
	Total	<u>x</u>
Total (iii)	xxx	
Less tax basis of asset	<u>(xx)</u>	
	<u>xxx</u>	
Effective tax rate @ y%		<u>(xxx)</u>
Cost ceiling B		<u>yyv</u>
A – B = ceiling		

Illustration 7-09

Ceiling Test

Abdul Oil Company Nig Ltd, which maintains a full cost system of accounting required a calculation of its ceiling test as at 31/12/2005, and the following information to maintain in its calculation had been provided as follows:

<u>CAPITALIZED COST</u>	<u>₦</u>
Unproved property	29,00
Proved property	58,00
Deferred income taxes (recorded)	
Tax basis of assets	50,00
Accumulated DD & A	

Cost related to unevaluated properties		25,00
Discounted present value of proved		30,00
Cost of unproved properties (being amortized)	(N10,000,000)	7,000,000
fair market value		000
Effective tax rate		

Required: Prepare a journal entry to record a write-down of oil and gas assets of Abdul Oil Company Nig Ltd as at 31/12/2005, if any, Prepare the year 2005 income statement of Abdul Oil Company Ltd Showing extra-ordinary item, if any

Suggest Solution 7-11

(a) **Abdul Oil Company Nig. Ltd**

Calculation of ceiling test

Unproved property	N
Proved property	29,0
	<u>58,0</u>
	87,0
Less: Accumulated D & A	<u>(9,00</u>
	78,0
Less: Related deferred income taxes	
Net Book Value	<u>68,8</u>
Note: The N68,800,000 is an after tax figure	<u>00,0</u>
	nn

This should not be in excess of:

Cost ceiling:	N
Disc. Present value of proved reserves	30,000,000
Add: Cost of unevaluated properties	25,000,000
Lower of cost of unproved properties or Fair market	
Value of unproved properties being amortized (10,000,000)	<u>7,000,000</u>
Total	62,000,000
Book Value	62,000,000
Less: Tax basis of assets	<u>50,000,000</u>
	<u>12,000,000</u>
Less: Tax at 70% (12,000,000)	<u>(8,400,000)</u>
Cost ceiling	<u>53,600,000</u>

NOTE: That the capitalized cost should not exceed ceiling, this can be confirmed by the calculation below:

	N
Capitalized costs (a)	68,800,00
Ceiling	<u>53,600,00</u>
Write-down after tax	<u>15,200,00</u>

The ₦15,200,000 write-down is post tax difference and therefore should be grossed up to pre-tax basis, as

$$\frac{15,200,000}{(1 - 0.70)} = \frac{15,200,000}{0.30} = 50,666,667$$

(b) Since there is a write down of ₦50,666,667 after ₦15,200,000 had been grossed up, we can journalized,

JOURNAL ENTRIES

Details	Dr (₦)	Cr (₦)
Profit and loss (Assets write-down)		
Deferred income taxes	15,200,000	
Oil and gas assets	35,466,667	50,666,667
Reduction in assets value		
	140,000	140,000

The deferred tax as arrived at in the journal above is the difference between 50,666,667 and 15,200,000 to give us 35,466,667.

(c) Abdul Oil Company Nig. Ltd Income Statement as at 31/12/2005

Revenue		xx
Less:		
Lifting costs	x	
DD & A	<u>x</u>	x
Net income from operation		x
Less: Extra ordinary items:		
Write down of oil and gas assets	50,666,667	
Less: related deferred income taxes	(35,466,667)	
	<u>15,200,000</u>	
Net revenue	<u><u>x x x</u></u>	

Illustration 7-12

Ceiling test

The following information is in respect of oil & gas operations

Capitalized costs	5,000,000
Accumulated depreciation, depletion and amortized (DDA)	1,000,000
Tax basis of assets	2,000,000
Discount present value of proved reserves	2,724,424
Deferred tax	350,000
Cost of properties not being amortized or evaluated	550,000
Cost of unproved properties (being amortized)	
Fair market value (500,000)	490,000
Tax rate	46%

Required: You are required to compute the ceiling and journalize the entries

SOLUTION

Computation of ceiling test

Capitalized cost		5,000,000
Less: Accumulated DD & A	1,000,000	
Deferred tax	<u>350,000</u>	<u>(1,350,000)</u>
Net Book Value	A	<u>3,650,000</u>
This should not be in excess of (cost ceiling)		
Discounted present value of proved reserves		2,724,424
Add: Cost of value not evaluated		550,000
Lowered of cost unproved properties or fair market value (500,000)		<u>490,000</u>
Total book value		3,764,424
Total book value	3,764,424	
Less: tax basis of assets	<u>2,000,000</u>	
	<u>1,764,424</u>	
Less: Tax at 46% x 1,764,424		<u>(811,635.04)</u>
Cost ceiling:	B	<u>2,952,788.96</u>
The capitalized cost should not exceed ceiling		
Capitalized cost A		3,650,000.00
Less: Ceiling cost B		<u>(2,952,788.96)</u>
Write down (an after tax figure)	A - B	<u><u>697,211.04</u></u>

$$\text{Gross value} = \frac{697,211.04}{(1-0.46)} = 1,291,131.56$$

ii.

Particular	Dr	Cr
Profit & loss A/c (assets write	697,211	
Deferred income taxes	593,920	
Oil and gas assets		<u>1,291,1</u>
	<u>1,291,1</u>	<u>1,291,1</u>

7.07 Review Questions

- i.
 - a. What are the basis and methods for amortization?
 - b. Discuss the accounting procedures for joint production of oil and gas.
 - c. Explain the concept of ceiling on capitalized costs and its computation.
- ii. Alhaji Yahaya Group of company incurred the following cost on its Oil & Gas. Property as at 31st Dec. 2012

	₦
Proved property cost	40,000
Unproved property cost	70,000
Non Drilling Exploration Cost, (Proved Property)	80,000
Non Drilling Exploration Cost, (Unproved Property)	100,000
Drilling costs, proved properties	400,000
WIP, unproved properties	600,000
Dry holes, unproved properties	900,000
Total accumulated DD&A	<u>(490,000)</u>
Total capitalized costs, net of DD&A	<u>1,700,000</u>

Other data	₦
Future development costs	300,0
Future dismantlement costs	400,0
Proved reserves, 12/31/2012, bbl	500,0
Production during year, bbl	100,0

Required

- a. DD&A assuming all possible costs are included in the amortization base.
- b. DD&A assuming all possible cost are excluded from the amortization base.
- iii. Alfa Musa Oil Company was incorporated in early 2010 and has two oil mining lease. Reserves in commercial quantities were discovered in 2012 in one of the OMLs. Expenditure to date was:

<u>OML, 204 (100 years)</u>	₦
Rent and signature bonus	400,000
Exploration costs	2,000,000
Development cost	1,500,000
Estimated future development costs	1,000,000
Estimated future abandonment cost net salvage of value	<u>100,000</u>
	<u>5,000,000</u>

<u>OML 205 (100 years)</u>	₦
Rent and signature bonus	720,000
Exploratory/drilling costs (dry hole costs)	<u>2,220,000</u>
	<u>2,940,000</u>

Reserves and production data of crude oil were:

Proved reserves 31/12/2012

Developed 68,000bbls

Undeveloped 20,000bbls

Production – 2012 8,000bbls

You are required compute DD&A for 2012 and show the figures, which would appear in the balance sheet and profit and loss account for the year under:

1. The full cost method
2. The successful effort method.

MODULE 8

8.00

CONVEYANCES

8.01 Learning Outcomes

On successful completion of this Module, Students should be able to:

- i. Explain conveyance and reasons of conveyance;
- ii. Apply the general principles for accounting and recognition of gains and losses under Successful effort and Full cost methods;
- iii. Explain the factors affecting accounting for conveyance;
- iv. Explain the accounting procedures for sale of partial and entire working interest in Unproved Properties;
- v. Apply the subleases of Unproved Properties and its accounting principles;
- vi. Compute the retirement of Unproved Property and its accounting procedures;
- vii. Explicate more complex forms of conveyances.

8.02 Introduction

A mineral conveyance is a transfer or assignment of any type of ownership interest in minerals from one entity to another. In the initial mineral conveyance, the lessor (owner) conveys to the lessee (tenant) a mineral interest in the property, and the lessor retains a royalty interest such as when the federal government grants a concession to an oil company. The lessee may, in turn, transfer in another conveyance all or part of the mineral interest to a third party.

There are many reasons why owners, especially working interest owners, convey interest in mineral. Some of these include risk sharing, financing, operating efficiency, government regulation, and tax incentives.

This module provides conceptual and theoretical background knowledge about conveyances. The module discussed the reasons for conveyances, general principles for accounting and recognition of gains and losses, factors affecting accounting for conveyances, sale of entire working interest in unproved property, subleases of unproved properties, retirement of proved properties – more complex forms of conveyances, free wells, farm out, carried interest, and utilization.

8.03 Reasons for Conveyances

Petroleum business is a highly risky project and the cost of investment is enormous, therefore transfer of mineral interest especially by the working interest owner to third party is necessary. This initiative will help in reducing costs and risks. Hence, it is a great advantage for oil firm to embark on conveyance.

The reasons for conveyances by petroleum resources industries are as follows:

1. **RISK SHARING-** In oil and gas operations, a lot of capital is invested and this do not give assurance for discovery of oil and gas reserves because at the end, the result of the operation can still be dry hole.

Therefore conveyance of mineral interest to another party is essential in order to reduce and sharing the risk involved.

2. **FINANCING-** The costs of acquisition, exploration, appraisal and development requires huge capital expenditure, which cannot be borne by one oil company and therefore requires invitation of other oil companies to partake in the sharing of exploration and development costs.
3. **OPERATING EFFICIENCY** – Conveyance ensures pooling of resources and experiences together in order to achieve greater effective and efficient operations. For instance, joint venture or unitization brings about economical and efficient means of exploiting an oil well.
4. **GOVERNMENT REGULATION-** Government could, sometimes, use its prerogative to force some oil companies to go into allies or unitization. The Nigerian petroleum drilling and production law of 1969 gives this power to the government.
5. **TAX INCENTIVES** – There is a tax saving in conveyance and hence companies may take that advantage e.g. claims of capital allowances or defer recognition of certain gains.

8.04 General Principles for Accounting and Recognition of Gains and Losses

There are several important issues in respect of accounting for conveyance transaction, among which are:

- Determination of gain or loss, if any; of the parties involved;
- Determination of when revenue and expenses are to be recognized;
- Determination of the exact costs involved; and
- Determination of how to reflect the relevant information in financial statements of the parties concerned.

Sometimes, oil companies in order to secure the supply of oil or gas, make funds available to operators in consideration for a right to purchase oil or gas when discovery is made. In such a situation, conveyance is in essence, a borrowing repayable in cash or its equivalent. Thus, one party to the transaction is treated as a borrower while the other is a lender, especially where cash refund is expected if the oil or gas discovered is insufficient to offset the cash advance received.

When a conveyance is completed with a view to retain the assets in the production of gas or oil, gains or losses are usually recognized in the account of the parties concerned. For example;

- i. A transfer of assets used in oil and gas producing activities exchanged for other assets also used in oil and gas producing activities and
- ii. A pooling of assets in a joint ventures situation for the purpose of finding, developing or producing oil and gas from a joint concession.

However, the parties involved generally recognized losses but no gains in conveyance in circumstance such as:

- i. The disposal of party of the interest or if there are doubts concerning the recoverability of the remaining interest in the concession; and

- ii. The disposal of part of the interest, since the seller remains obligated to drill a well or to operate the property if both activities are expected to result in future loss.

Conveyances under Successful Efforts Method

Successful effort companies may recognize gains or losses on other types of conveyances in line with generally accepted accounting principles. In determining the appropriate accounting treatment for a company using the successful effort method, the factors to be considered include whether:

- The property is classified as proved or unproved;
- Impairment of an unproved property is being recorded on an individual basis or on the basis of a geological group; and
- Only partial or entire interest is conveyed.

The general practices for recognition of gains or losses under SE are as follow:

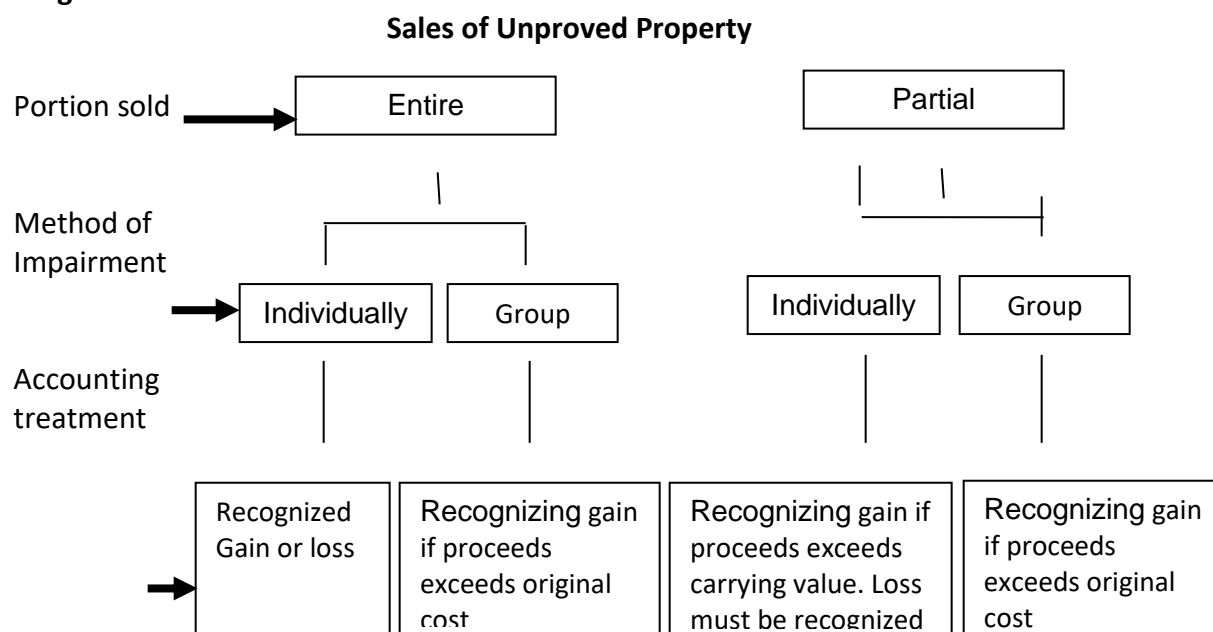
- (a) If the entire interest in an unproved property, for which impairment is recorded on an individual basis, is sold, gain or loss is recognized to the extent of the difference between the proceeds and net book value.
- (b) If entire interest in an unproved property for which impairment is recorded on a group basis is sold, no gain or loss is recognized unless the proceeds exceed the original cost of the lease.
- (c) If a portion of interest in unproved property for which individual impairment is recorded is sold, and the proceeds exceed the total carrying value of the entire property, the excess of proceeds over net book value is recognized as a gain.
- (d) If a portion of interest in unproved property for which group impairment is recorded is sold and the proceeds exceed the total cost of the property, the excess of proceeds over the net book value of the group is recognized as a gain.
- (e) If the entire interest in a proved property on which amortization is individually computed is sold, the difference between the proceeds and the net book value is recognized as a gain or loss.
- (f) If a portion of an interest in a proved property on which amortization is individually computed is sold, the difference between the proceeds and a proportion share of each cost and amortization provision (book value) is recognized as gain or loss.
- (g) If any unproved property on which impairment has been recorded on an individual basis is surrendered or the rights released, the book value of the property is charged to expense.
- (h) If an unproved property on which impairment has been recorded on a group basis is surrendered or the rights released, the book value of the property is charged to the accumulated impairment account and no loss is recognized

Conveyance under Full Cost Method

- (a) Under full cost method, mineral property conveyances, whether or not the properties are currently amortized, do not result in recognition of gain or loss. In other words, under full cost, disposal proceeds are credited to fixed assets and no gain or loss is recorded. Therefore the sale is usually recognized in lower depletion charges in the future.
- (b) If the conveyance would significantly alter the relationship between capitalized cost and proved reserves of oil and gas attributable to the cost centre, then a gain or loss may be recognized in the income statements.
- (c) A significant alteration would not ordinarily be expected to occur for conveyances involving less than 5% of the reserves quantities in the costs centre or when the unit of production amortization rate is altered than less than 25%. A cost value attributable to a significant conveyance may be calculated by multiplying the current depletion rate by the amount of reserves sold.

Accounting for conveyance is summarized in the following

Diagram 8.1



8.05 Factors Affecting Accounting for Conveyances

The nature of accounting treatment would depend on whether:

- i. The method of accounting adopted by a company is full cost or successful effort method.
- ii. The conveyance in respect of a property is partial or entire.
- iii. The conveyance involved proved or unproved property.
- iv. The property is individual or group.
- v. Prudence concept

8.06 Sale of Entire Working Interest in Unproved Property

Where the entire interest in an unproved property is sold, recording gain or loss would depend on whether the property is individual or group impaired.

- (a) Where the property is individually impaired, gain or loss is recognized to the extent of the difference between proceeds received and the net book value (or net carrying amount) of the property.
- (b) Where the property is group impaired, no gain or loss is recognized unless the proceeds received exceed the original cost of the unproved property.

Comprehensive Illustration 8-1

Israel Oil Company Nig Ltd bought the entire leasehold in four leases, each of which was owned by other oil companies. Israel Oil Company Nig. Ltd paid ₦50,000 to each company for the entire interest in each leases. The selling companies had varying cost and different methods of impairments of unproved properties.

Company	Cost value	Basis of impairment (₦)	Net carrying (₦)
Agip oil	Individual	160,000	90,000
Oando oil	Group	100,000	N/A
Total oil	Group	10,000	N/A
Mobile oil	Individual	130,000	40,000

You are required to determine whether gain or loss is to be recognized and raise the necessary journal in each of the selling company's books, if successful effort method of accounting is employed by each of the companies.

Suggested Solution 8-1

AGIP OIL

- (i) A loss of ₦40,000 (₦90,000 - ₦50,000) must be recognized as
 1. The lease was individually impaired
 2. The sales proceed was less than the net carrying value.
- (ii) The necessary journal entry would be:

JOURNAL

	Dr (₦)	Cr (₦)
Cash	50,000	
Provision for impairment	70,000	
Loss on sales of unproved property	40,000	
Unproved property		160,000
	160,000	160,000

OANDO OIL

Oando Oil reports no loss on the sale even though the sales proceed is less than the recognized when property is group impaired. Therefore, the ₦50,000 loss can only be taken into account when the overall impairment provision to be made.

The necessary journal entry is as follows:

	Dr (₦)	Cr (₦)
Cash	50,000	
Unproved property		50,000
	50,000	50,000

TOTAL OIL

Total oil recognizes gain of ₦40,000 (₦50,000 - ₦10,000) because the sales proceed of ₦50,000 exceed the original cost of property (₦10,000) by ₦40,000. It does not matter whether the lease was amortized with other property in group.

The necessary journal entry is as follows:

	Dr (₦)	Cr (₦)
Cash	50,000	
unproved property		9,999
Gain on sale of Unproved property		40,001
	50,000	50,000

NOTE: A balance or a nominal amount of ₦1 must be left in the account to act as a control on the rest of properties in the group. The gain to be recorded therefore would be ₦40,001 i.e. 0.01%

MOBILE OIL

Mobile Oil recognize a gain of ₦10,000 (₦50,000 – 40,000) because the sales proceed of 50,000 exceed the Net carrying cost of ₦40,000.

The necessary journal entry is as below:

Details	Dr (₦)	Cr (₦)
Cash	50,000	
Provision for impairment	90,000	
Unproved property		30,000
Gain or loss on sale of unproved property		10,000
	140,000	140,000

Illustration 8-2

Yakubu Oil Company obtained partial interest in the lease from four oil companies with each company receiving ₦60,000 as compensation for the sale.

Company	Original cost (₦)	Interest sold	Write off method	Net carrying value (₦)
1	100,000	15%	Individual	72,000
2	100,000	20%	Group	N/A
3	22,000	75%	Group	N/A
4	100,000	90%	Individual	80,000

You are required to:

- Determine whether gain or loss is to be recognized by each of the companies
- Make necessary journal entries in the books of companies 1 and 3

Suggested Solution 8-2

- Company 1 recognized no gain because the net carrying value is higher than the sales proceeds. That is, the interest sold is 15% original costs, which is equal to $15\% \times ₦100,000 = ₦15,000$ to receive ₦60,000 compared to net carrying value of ₦72,000 is certainly higher. Hence, the proceed recorded is treated as recovery of cost and the entry is as in (b) below
- Company 2 recognizes no gain since the property is grouped impaired and the original cost is higher than the sales proceeds. The original cost is ₦100,000 while the sales proceed from the interest sold is ₦60,000 i.e. $20\% \times 100,000 = ₦20,000$ is interest sold to receive ₦60,000 and is compared to original cost of ₦100,000.
- Company 3 recognizes a gain of ₦37,000 ($₦60,000 - 23,000$) because the original cost is less than the sales proceeds.
- Company 4 recognizes no gain or loss, even though a loss of ₦20,000 ($₦80,000 - ₦60,000$) was incurred. So we debit cash with ₦20,000 proceeds and credit unproved property account or provision for impairment account by the ₦20,000 proceed.

B. Journal

Details	Dr (₦)	Cr (₦)
Company 1		
Cash	60,000	
Unproved property or provision for impairment		60,000
Company 3		
Cash	60,00	51,999
Unproved property		8,001

Gain on sale of unproved property		
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Illustration 8-3

Kingsley Oil Ltd conveys to SA'A Oil Nig Ltd a 40% interest in unproved Hanya lease for cash consideration of ₦45,000. The cost of this lease was at ₦600,000. Kingsly Oil Ltd is a successful effort company.

You are required to:

- Record the disposal in the book of Kingsley Oil Ltd if there was no impairment record
- If the Kingsley Oil Ltd has been accounting for this property individually and cost of ₦30,000 had been written off as impairment what entry would be done to record the disposal.
- If Kingsley Oil Ltd had been accounting for the Hanya lease as part of a group of properties with total capitalized cost of ₦15,000,000 and allowance for amortization of ₦500,000, enter the necessary record for the disposal.
- If the disposal price was ₦16,000 instead of ₦45,000, show the entry to record the disposal of an undivided 40% share of the working interest under the successful effort method assuming that no impairment had been recorded.

Assuming Kingsley Oil Ltd used full cost method; show the entry to record the disposal of a 40% interest in the lease for ₦18,000

Details	DR (₦)	CR (₦)
i. Cash	45,000	
Unproved leasehold		45,000
ii. Cash	45,000	
Allowance for impairment of unproved property	29,999	
Unproved leasehold		74,999
Note 1 left for control purpose in unproved leasehold account		
	45,000	
iii. Cash	29,000	
Allowance for impairment of unproved property		45,000
Unproved leasehold	16,000	
iv. Cash		16,000
Unproved leasehold		
OR	16,000	
Cash	8,000	
Loss on disposal		24,000
(40% x ₦60,000 – ₦1,600)		
Unproved leasehold		
Note: the remaining 60% interest on the ₦60,000		

would be subject to an impairment test	18,000	
v. Cash		18,000
Unproved leasehold		

8.07 Subleases of Unproved Properties

A working interest owner may sub-lease, instead of outright sale of unproved property, for cash, that is, transferring its operating right to another person for cash or other form of consideration while still retaining the overriding royalty or net profit interest or production payment. This is called sub-lease of unproved property.

Note that sub-leasing transaction is treated the same way as the disposal of part of an interest in unproved property, whether individual impaired or group impaired.

Illustration 8-4

James Oil Ltd, a successful effort company assigns an unproved property whose cost is ₦10,000,000 on which individual provision for impairment of ₦2,000,000 has been recorded for a sum of ₦4,000,000 and retention of overriding royalty on production. You are required to record this transaction in a journal.

Suggested Solution 8-4

DETAILS	DR	CR
Cash	4,000,000	
Provision for impairment Unproved	2,000,000	
overriding royalty Unproved property	4,000,000	
Being recording of sub-lease of unproved property.		10,000,000

Whether the working interest of unproved property is group impaired, i.e. the working interest is part of a group, on which impaired is been recorded, is sub-lease on overriding royalty is retained, the interest retained is also included in unproved overriding royalties account.

Where the disposal proceed is less than the cost of the working interest, the proceed is treated as recovery of cost. On the other hand, if the sales proceed is more than the cost of working interest the gain would be recognized and a nominal amount of ₦1 is assigned to the non-operating interest to act as a control; otherwise the remaining part of the working interest could be looked at as abandoned.

8.08 Retirement of Proved Properties

When there is surrender or abandonment of proved mineral interest, the net book value is either treated as a recovery of cost or charged to accumulated amortization account. No gain or loss is recognized. This is so whether the

surrender or abandonment is partial or entire or whether the property is an individual property or part of a group of properties constituting the amortization base.

Illustration 8-5

Ronaldo Oil Ltd has an oil property with the following cost and depreciation, depletion & amortization (DD&A):

	₦	₦
Proved leasehold	500,000	
Less: Accumulated depletion	<u>(150,000)</u>	350,000
Wells and related facilities – IDC	2,000,000	
Less: Accumulated depreciation	<u>(500,000)</u>	1,500,000
Wells and facilities – equipt.	8,000,000	
Less: Accumulated depreciation	<u>(1,400,000)</u>	<u>6,600,000</u>
		<u>8,450,000</u>

If a lease or property included in the above group with an original cost ₦25,000 for leaseholds, ₦400,000 for IDC and ₦1,000,000 for equipment is abandoned and the salvage proceeds are ₦15,000.

Required:

- Prepare the appropriate journal entries to record the abandonment.
- Assuming the equipment with an original cost of ₦50,000 is salvaged after field operations and returned to the warehouse with an estimated salvage value of ₦1,000, Prepare the journal entry.

Suggested Solution 8-5

(a) Cash

	₦	₦
Accumulated depletion	25,000	
Accumulated depreciation – IDC	400,000	
Accumulated depreciation-equipment	985,000	
Proved leaseholds		25,000
Wells and related facilities-IDC		400,000
Wells and related facilities-equipment		1,000,000
To record abandonment of property Forming part of a group amortization.		

Note that the proceeds of ₦15,000 is adjusted to equipment since neither leasehold cost nor IDC is likely to result in any salvage in the event of an abandonment.

	₦	₦
(b) Inventory	1,000	

Accumulated depreciation-Equipment	49,000	
Wells and related facilities-Equipment		50,000

To record retirement of equipment on lease.

Furthermore, the partial abandonment or retirement of wells and related equipment or facilities may result from a major catastrophic event. In this case, a loss may be recognized but not a gain at the time of abandonment or retirement.

Illustration 8-6

Messi Oil Ltd experienced an earthquake that led to destruction of its oil facility. The original cost of the facility is ₦200,000 and the salvage value is ₦20,000. The capitalized cost of the facility is ₦100,000 and the accumulated depreciation is ₦35,000.

Required: Calculate the gain or loss on the above event and prepare the journal entry.

Suggested Solution 8-6

Cost of facility destroyed		200,000
Less accumulated depreciation:	(<u>35,000</u> x 200,000)	
	100,000	<u>(70,000)</u>
Net Book Value		130,000
Less: Salvage value		<u>(20,000)</u>
Loss		<u><u>110,000</u></u>

Journal entry

	Dr	Cr
Cash		20,000
Accumulated depreciation-Facility	70,000	
Loss	110,000	
Well & related facilities		200,000
Being posting of loss on earthquake		

Complex Form of Conveyance

Conveyance arrangements are consummated with a view to pooling capital and to share the risk and obligations of developing and operating mineral properties. Typically, one party may contribute cash, another party may bring in equipment; and yet another enterprise may supply the required know-how into the arrangement. Another party's contribution may be concession. These contributions are made in return for an ownership interest in a joint or unitized venture. Some of the more commonly encountered conveyance arrangements include:

- i. Free wells arrangement
- ii. Farmouts
- iii. Carried interests
- iv. Utilizations
- v. Production sharing

The accounting for these pooling of interest forms of conveyances are usually complex. They do not involve recognition of gains and losses (since they are considered exchanges of assets) and except for very minor difference discussed later in the chapter, the same rules that apply to successful efforts company apply to full cost companies.

8.09 Free Wells

Under a free well deal, the owner of a concession (assignor) assigns a fractional share of his interest to another party (assignee) in return to the assignee drilling and equipping a well or wells at no cost to the consignor. Each party receives his fractional share of the revenues and his fractional share of the expenses after production commences. In effect, the transaction falls into the pooling of capital concept. Either party records no gain or loss. The assignor records no cost for the obligatory well and the assignee records no cost for the mineral interest acquired but will merely record its cost of drilling and equipping the well and its subsequent share of operating cost incurred.

Illustration 8-7

If a leasehold acquisition costs the assignor ₦50,000 and it assigns a one-third interest to the assignee who drills and equips a successful well after incurring IDC of ₦200,000 and equipment cost of ₦1,000,000 the appropriate entries to record the transactions in the books of the assignor and assignee would be:

Assignors' books

	₦	₦
Proved leasehold	50,000	
Unproved leasehold		50,000
To reclassify cost of a lease to proved leasehold account		

Assignees' books

Wells and related facilities-IDC	200,000
Wells and related facilities-Equipment	1,000,000
Cash	1,200,000

To record cost of free well drilled equipped for one-third interest in lease.

Subsequently the two parties share production costs on the agreed percentages.

8.10 Farm Out

A farmout usually occurs when a company has the mineral rights and concessions to a property but does not have the resources to explore it in the near term. The concession holder (the farmor) assigns the property to another party (the farmee) to explore. The farmee is usually responsible for 100% of the costs of exploration and development, but once production commences, the farmor will earn a specific percentage of the expenses. Like the free well deal, this is considered a pooling of assets in a joint undertaking and no gain or loss is recognized. The farmor's cost of the original interest retained. The interest retained may be an overriding royalty or net profits interest.

8.11 Carried Interest

Under this agreement, the transferee (the carrying party) agrees to pay for a portion or all of the production cost of another party (the carried party) for a share of the working interest. The arrangement is usually adopted when the carried party is either unwilling to bear the risk of exploration or is unable to fund directly the cost of exploration and development.

The transferee is usually reimbursed either in cash, out of the proceeds of the carried party's share of production, or by receiving a disproportionately high share of the production until the carried cost has been recovered. However, if the project is unsuccessful, the carrying party may not be able to recoup all or part of the costs it has incurred on behalf of the carried party.

The accounting treatment given to carry interest arrangement usually depends on the terms of the agreement. Where the carrying party is to be reimbursed in cash, the arrangement is essentially a contingently repayable financing. On the other hand, in the case of reimbursement by increased share of production, the arrangement represents acquisition of additional reserves by the carrying party. The point at which the investment by the carrying party is fully recouped is referred to as payout.

The carried interest arrangement represents perhaps the epitome of confusion in petroleum industry accounting. This is because carried interest contains elements of the other conveyance arrangement such as free well, production payment, joint venture or production sharing. Several difference methods are used to record transactions in carried party's book. These range from recording income to making no entries at all during payout.

A summary of these varying practices may be given as follows:-

- (a) Record a gain or loss at the time the leasehold interest is exchanged for an interest in the drilling and development of the property before payout;
- (b) Record income for the carried party's share of drilling and development costs after payout; and
- (c) Non-recognition of gain or loss but recognition of exchange in the nature of the asset. Total property value remains the same but a fraction of the leasehold cost is allocated to equipment upon completion of development. No entry is made during or at the time of payout.

Illustration 8-8

Assuming company A and B enters into an agreement in which company A, the carrying party, undertake to drill a well to a specific depth on company B's lease. The carried party in return for a 40% interest in the property and the privilege of recovering all of the drilling cost and operating cost until payout out of the first oil produced, if any. The leasehold acquisition cost incurred by company B was ₦80,000. Company A incurred IDC costs of ₦1,250,000 and equipment costs of ₦300,000. The estimated recoverable total reserves are 600,000 barrels from the

first well and 1,500,000 barrels from the lease. Oil is expected to sell for ₦24 per barrel, during the first three years of operating the lease, production and sales 40,000 barrels per year, and lifting costs are ₦90,000 (i.e. ₦2.25 per barrel) per year.

Required

Calculate the lease net income for companies A and B for year 1,2, and 3 and make necessary entries in the books of A and B for the period, assuming that the companies adopt the successful efforts method of accounting. (Assuming that there are no changes in reserves estimate over the three years)

Suggested Solution 8-8

Journal Entries

A. Company A – Year 1	₦	₦
Wells and related facilities – IDC	1,250,000	
Wells and related facilities – equipment	300,000	
Accounts payable		1,550,000
To record the costs incurred on IDC and equipment		
Account receivable (40,000 bbls @ ₦24)	960,000	
Crude oil revenues		960,000
To record crude oil sales		
Lease operating expenses (40,000 bbls @ ₦2.25)	90,000	
Account payable		90,000
To record lease operating expenses		
Amortization of wells & related facilities – IDC	176,830	
Amortization of wells & related facilities – Equipt.	42,439	
Allowance of amortization – IDC		176,830
Allowance for amortization – Equipment		42,439
To record DD&A for year 1		

Workings – Total production required to payout:-

$$\frac{1,550,000}{24 - 2.25} = \frac{1,550,000}{\text{₦21.75}} = 71,264 \text{ bbls}$$

Calculation of amortization

$$\frac{40,000}{282,758} \times \text{₦1,250,000} = \text{₦176,830}$$

$$\frac{40,000}{282,758} \times \text{₦300,000} = \text{₦42,439}$$

Company A

Year 2

	₦	₦
Account receivable	834,202	
Crude oil revenues		834,202
To record crude oil sales		
31,264 bbls @ ₦24.000 =	750,336	
40% of 8,736 bbls @ ₦24.00 =	<u>83,866</u>	
	<u>834,202</u>	
Lease operating expenses	78,206	
Account payable 34,758 @ ₦2.25		78,206
To record lease operating expenses		
Amortization of wells & related facilities – IDC	153,656	
Amortization of wells & related facilities – Equipment	36,877	
Allowance for amortization – IDC		153,656
Allowance for amortization – Equipment		36,877
To record DD&A for year 2		

Working – calculation for amortization

$$\frac{34,758}{242,758} \times (\text{₦}1,250,000 - \text{₦}176,830) = \frac{34,758}{242,758} \times \text{₦}1,073,170 = \text{₦}153,656$$

$$\frac{34,758}{242,758} \times (\text{₦}300,000 - \text{₦}42,439) = \frac{34,758}{242,758} \times \text{₦}257,561 = \text{₦}36,877$$

Company A
Year 3

	₦	
Account receivable	384,000	
Crude oil revenues		
384,000		
To record crude oil sales (40% of 40,000 bbls @ ₦24)		
Lease operating expenses	36,000	
Account payable		
36,000		
To record lease operating expenses (40% of 40,000 bbls @ ₦2.25)		
Amortization well & related facilities-IDC	70,732	
Amortization well & related facilities-Equipment	16,976	
Allowance for amortization-IDC		
70,732		
Allowance for amortization-Equipment		
16,976		
To record DD&A for year 3		

Workings – Calculation for amortization

$$\frac{16,000}{70,732} \times (1,250,000 - 176,830 - 153,656) = \frac{16,000}{208,000} \times 919,514 =$$

$$\frac{16,000}{208,000} \times (300,000 - 42,430 - 36,877) = \frac{16,000}{208,000} \times 220,684 = 16,976$$

Workings – Allocation of reserves

First Year

Estimated remaining reserves after payout $600,000 - 71,264 = 526,736$ bbls

Share of Co. A 40% of 528,786 = 211,494

Add: Reserves to payout 71,264

Co.A reserves 282,758 bbls

Share of Co. B 60% of 528,736 = 317,242

600,000 bbls

Second year

Reserves at end of the year $(600,000 \text{ bbls} - 40,000 \text{ bbl} - 40,000 \text{ bbl}) = 520,000$ bbls

Share of Company A (40% of 520,000 bbls) 208,000

Reserves to Co. A during the year (31,264 to payout and 40% of 8,730) 34,758

242,758

bbls

Notes

$80,000 - 72,264 = 8,736$ bbls

$71,264 - 40,000 = 31,264$ bbls

$528,736 - 520,000 = 8,736$ bbls

Share of Co. B

60% of 520,000 bbls 312,000

Reserves to Co. B during the year

60% of 8,736 bbls 5,242

317,242

$242,758 + 317,242 = 560,000$ bbls

Third year

Reserves at the end of the year

$(600,000 - 40,000 - 40,000 - 40,000) = 480,000$ bbls

Share of Co. A (40% of 480,000) = 192,000

Add: reserves to Co. A during the year (40% of 40,000 bbls) 16,000

208,000

Share Co. B 60% of 480,000 288,000

Add: Share of production during the year 60% of 40,000 bbls 24,000

	<u>312,000</u>
(208,000 + 312,000 = 520,000)	<u>520,000</u>

Company B – Year 1

	₦	₦
Proved leaseholds	80,000	
Unproved leaseholds		80,000
To transfer from unproved property to proved property on discovery of oil		

Company B – Year 2

Account receivable	125,798	
Crude oil revenue		125,798
To record share of crude oil sold (60% of 8,736 bbls produced after payout @ ₦24/bbl)		
Lease operating expenses	11,794	
Account payable		11,794
To record share of lease operating expenses (60% of 8,736 bbls produced after payout @ ₦2.25/bbl)		

	₦	₦
Amortization of proved leaseholds	1,322	
Accumulated amortization of proved leaseholds property		1,322
To record DD&A for year 2		
Working – calculation of amortization		
<u>5,242</u> x 80,000 = ₦1,322		
317,242		

Company B – Year 3

	₦	₦
Accounts receivable	576,000	
Crude oil revenues		576,000
To record share of crude oil sold (60% of 40,000 bbls produced and sold @ ₦24/bbl)		
Lease operating expenses	54,000	
Accounting payable		54,000
To record share of lease operating expenses (60% of 40,000 bbls @ ₦2.25/bbl)		
Amortization of proved leaseholds	6,052	
Accumulated amortizationOf proved leasehold		6,052
To record DD&A for year 3		

Workings – Calculation of amortization

<u>24,000</u> x (₦80,000 - ₦1,322) =	<u>24,000</u> x 78,678 = ₦6,052
312,000	312,000

Company A – Lease Net Income

Year 1 Year 2 Year 3

		Ye	Ye	Ye
A	Revenues	96	83	38
B	Lease operating	90,	78,	36,
C	DD&A – IDC	17	15	70,
D	DD&A – Equipment	42,	38,	16,
E (A-	Lease Net Income	65	56	26

Company B Lease Net Income

A		Y	Y	Y
B	Revenues	0	1	5
C	Lease operating	0	1	5
E (A-	DD&A – IDC	0	1,	6,
	Lease Net Income	0	1	5

Note: The following key points should be observed

- The carried party does not report any income or amortization of leasehold costs until payout.
- The carrying party report all revenues and expenses until payout. The carrying party's books reflect no leasehold costs and the carrying party's book holds no drilling and development costs.
- Both the carrying and carried parties report reserves quantities from the inception. These reserves estimates are made by calculating the reserves quantity that will be lifted before payout occurs. Production to that point is allocated entirely to the carrying party. Subsequent production is shared between the two parties in the agreed ratio.
- Under the successful effort method, the carried party should reclassify the leasehold costs from an unproved to a proved category once discovery is made and should not report any amortization of the proved property until payout is achieved.

8.12 Unitization

Unitization is a form of joint undertaking whereby concession holders pool their interest together to form a single unit in return for a participating interest in the combined unit of reservoir. Among the reasons for undertaking unitization are to increase operational efficiency, achieve tax advantages and minimize risks.

Unitization is governed by a unit operating agreement which usually includes the list of the parties and their fractional interests referred to as participation factors. The participation factors form the basis of the equalization of individual investment, joint costs distribution and sharing of production and/or production proceeds. Since the original factors are determined using limited data about the reservoir, agreements usually provide for one or more redetermination. Revision of participation factors may lead to adjustment of the unit members' share of

production and costs. Such redetermination adjustments are usually accounted for on a prospective basis rather than by way of prior period restatement.

Equalization of cost at time of unitization

Participation factors do not always give weight to the stage of development of properties, as these are usually based on reserves estimate and other factors. Frequently, the properties are in different phases of development, some partially drilled and developed and others fully drilled and equipped. Consequently, it may be necessary for the parties who contributed underdeveloped properties to pay cash to those parties who contributed, developed or partially developed properties in order to “equalize” the capital contribution. Occasionally equalization may also be achieved by adjusting the share of future production or revenues or future costs rather than through cash settlements.

The value of the property that each party contributes to the unit is usually separately determined and proper credit given to the party. Equipment are usually valued at fair market value, condition value or even cost whereas intangibles such as wells are usually valued at a certain amount per foot, at flat amounts or in rare cases at cost. Balance due to or due from a unit subscriber is settled in production payments with respects to intangible and in cash with respect to equipment.

Where production payments are used to equalize capital contribution, the party with an unfavorable balance may not receive any revenue from the unitized operation until the balance is liquidated from his participating percentage of production. The party with a favorable balance will receive will receive it participating percentage of production proceeds plus an amount to apply towards liquidation of the balance due to it. More often, however, an accord is reached to equalize over a set number of years or months.

In recording the adjustment, the exchange theory is sometimes applied. In such a case, a gain or loss is recognized to the extent of the difference between the net book value of the properties contributed and the fair market value of the consideration received. A more common method of recording adjustment which accords more with generally accepted accounting practice is to consider unitization as a pooling of interest in which neither gain nor loss should be recognized. In rare situation, gain is recognized and that is when cash received exceeds the amount of investment. A party making cash equalization payment will increase its investment in wells and related equipment while the party receiving cash will decrease its investment in wells and related equipment.

Adjustment of participating factors

As earlier mentioned, unit operating agreements frequently provide that participation factors may be revised after the reservoir or fields has been more clearly defined and the contribution of each party has been more accurately ascertained. The following illustration explains better.

Illustration 8-9

Four oil companies, A, B, C and D have recently signed an agreement to unitize their respective properties in order to more efficiently exploit a field using tertiary recovery technique. Based on estimated reserves in each of the properties, participation factors were assigned as follows:

Company	Participant interest
A	25%
B	30%
C	20%
D	25%

The agreement further stipulates that a separate exchange of wells and lease equipment will be made between the parties to give each party proper credit for IDC equipment.

The net book value and the value ascribed to the IDC and equipment contributed by each of the parties are stated below:

	Company	Net Book Value (₦)	Value Contributed (₦)
IDC	A	4,000,000	6,000,000
	B	3,000,000	4,500,000
	C	2,500,000	3,000,000
	D	4,800,000	5,200,000
Equipment	A	10,000,000	8,000,000
	B	7,000,000	4,900,000
	C	2,000,000	3,500,000
	D	4,000,000	4,800,000

Required:

- Calculate cash payment or receipts required to equalize the capital contributions
- Make necessary entries to reflect the unitization in the books of company A and B.

Suggested Solution 8-9

PART (a)

IDC

Co	Net Book Value	Value	Value	Cash
A	4,000	6,000	4,675	1,325

B	3,000	4,500	5,610	-1,110
C	2,500	3,000	3,740	-740
D	500	5,200	4,675	525
Tot	10,000	18,700	18,700	-

Equipment

C	Net Book	Value	Value	Cash
A	10,000	8,000	6,050	1,950
B	7,000	7,900	7,260	640
C	2,000	3,500	4,840	- 1,340
D	4,000	4,800	6,050	- 1,250
T	23,000	24,200	24,200	-

Company A

	₦	₦
Cash	1,325,000	
Wells and related facilities – IDC		1,325,000
To record receipt of cash on IDC equalization		
Cash	1,950,000	
Wells and related facilities – Equipment		1,950,000
To record receipt of cash on equipment equalization		

Company B

Wells and related facilities – IDC	1,110,000	
Cash		1,110,000
TO record cash payment made on IDC equalization		
Cash	640,000	
Wells and related facilities – Equipment		640,000
To record cash received on equipment equalization.		

Company C

Wells and related facilities – IDC	740,000	
Cash		740,000
To record cash payment made on IDC equalization.		
Wells and related facilities – Equipment	1,340,000	
Cash		1,340,000
To record cash payment made on equipment equalization.		

Company D

Cash	825,000	
Wells and related facilities – IDC		500,000

Gain on exchange of unitized properties	25,000
To record cash receipt on IDC equalization and gain recognized.	
Wells and related facilities – Equipment	1,250,000
Cash	1,250,000
To record cash payment made on equipment equalization.	

Note:

- (1) Cash receipts and payment are reflected as decreases and increases in investment respectively.
- (2) Gains or losses are not recognized at the time of equalization except in the case of Company D's.

IDC where a gain of ₦25,000 is recognized. This is because the cash received exceeds the net book value of the development property contributing. Some companies will not recognize the gain of ₦25,000 on the rationale that if the IDC and equipment had been treated as a single fundable asset, no gain would result. There is some merit to this argument.

8.13 Review Questions

Four oil companies, W, X, Y and Z have recently signed an agreement to unitize their respective properties in order to more efficiently exploit a field using tertiary recovery technique. Based on estimated reserves in each of the properties, participation factors were assigned as follows:

Company	Participant interest
W	25%
X	30%
Y	20%
Z	25%

The agreement further stipulates that a separate exchange of wells and lease equipment will be made between the parties to give each party proper credit for IDC equipment.

The net book value and the value ascribed to the IDC and equipments contributed by each of the parties are stated below:

	Company	Net Book Value (₦)	Value Contributed (₦)
IDC	W	8,000,000	12,000,000
	X	6,000,000	9,000,000
	Y	5,000,000	6,000,000
	Z	9,600,000	10,400,000
Equipment			
	W	20,000,000	16,000,000
	X	14,000,000	9,800,000
	W	4,000,000	7,000,000

Z	8,000,000	9,600,000
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Required:

- (a) Calculate cash payment or receipts required to equalize the capital contributions
- (b) Make necessary entries to reflect the unitization in the books of company W and X

MODULE 9

9.00 ACCOUNTING FOR JOINT INTEREST ARRANGEMENT

9.01 LEARNING OUTCOMES

On successful completion of this Module, Students should be able to:

- i. Elucidate the reasons for joint venture arrangement.
- ii. Explain the formation of joint ventures.
- iii. Explain the legal forms of joint venture.
- iv. Evaluate joint operating Arrangement.
- v. Apply accounting process for joint venture arraignment.
- vi. Solve practical problems in joint venture Accounting.

9.02 General Overview

Joint ventures and other similar arrangements (joint arrangements) are frequently used by oil and gas companies as a way to share the higher risks and costs associated with the industry or as a way of bringing in specialist skilled to a particular project. The legal basis for a joint arrangement may take various forms; establishing a joint venture might be achieved through a formal joint venture contract, or the governance arrangements set out in a company's formation documents might provide the framework for a joint arrangement. The feature that distinguishes a joint arrangement from other forms of corporation between parties is the presence of joint control. An arrangement without control is not a joint arrangement.

The IASB Published IFRS 11 joint Arrangements in May 2011. The standard introduces a number of significant changes in the accounting for joint arrangement which includes;

- "Joint arrangement" replaces "joint venture" as the new umbrella term to describe all arrangements where two or more parties have joint control.
- There are two types of joint arrangement, being "joint operations" and "joint ventures".
- Contractual rights and obligations drive the categorization of a joint arrangement as a joint operation or a joint venture;
- The policy choice of proportionate consolidation for joint venture is eliminated; and
- An "investor in a joint venture" is defined as being a party who does not participate in joint control, with guidance on the appropriate accounting.

When you decide to create a joint venture, you should set out the terms and conditions in a written agreement. This will help prevent any misunderstandings once the joint venture is up and running.

A written agreement should cover;

- The structure of the joint venture, e.g. whether it will be separate business in its own right,
- The objectives of the joint venture.
- The financial contributions each makes.

- Whether you will transfer any assets or employees in the joint venture.
- Ownership of intellectual property created by the joint venture.
- Management and control.e.g. respective responsibilities and processes to be followed.
- How liabilities, profits and losses are shared.
- How any disputes between the parties will be resolved?
- An exit strategy.

According to Uche and Adebisi (2002), Joint venture is defined as “an act of development of resources on a property by two or more parties”. This implies that in a joint venture arrangement resources in form of capital are pooled together in an effort to achieve the desire objectives.

Abegunde (2006) - Joint venture is a contractual agreement between two or more parties undertaking an economic activity which is subject to contractually agreed basis of sharing control and operations.

According to SAS 14, paragraph 91; a joint venture or unit of operation of an oil and gas pool is the cooperative effort of two or more mineral interest owners, usually called joint venture partners. The partners accomplish, through their combined effort and knowledge, the maximum amount, if then, is recovered from a common concession or license. Paragraph 92 defines joint venture operation as the practice of consolidating under a single operational responsibility, the separate concessions whereby each concession holder receives the amount of production from the entire pool that is attributable to his separate ownership.

A joint control is the contractually agreed sharing of control over an economic activity. An identified group of ventures must unanimously agree on all key financial and operating decisions. Each of the parties that share joint control has a veto right: they can block key decisions if they do not agree.

Not all parties to the joint venture need to share joint control. Some participants may share joint control and other investors participate in the activity but not in the joint control. Those investors participate in the activity but not in the joint control. Those investors account for their interest in its share of assets and liabilities, an investment in an associate (if they have significant influence) or as an available for sale financial asset in accordance with IAS 39.

Similarly, joint control may not be present even if an arrangement is described as a joint venture. Decisions over financial and operating decisions that are made by “simple majority” rather than by unanimous consent could mean that joint control is not present even in situations where there are only two shareholders but each has appointed a number of directors to the Board or relevant decision main body.

Joint control will only exist if decisions require the unanimous consent of the parties sharing control. If decisions are made by simple majority, the following factors may undermine the joint control assertion;

- The directors are not agents or employees of the shareholders.
- The shareholders have not retained veto rights.
- There are no side agreements requiring directives vote together.
- A quorum of Board members can be achieved without all members being in attendance.

If it is possible that a number of combinations of the directors would be able to reach a decision; it may be that joint control does not exist. This is a complex area which will require careful analysis of the facts and circumstances. If joint control does not exist, the arrangement would not be a joint venture.

A key test when identifying if joint control exists is to identify how disputes between ventures are resolved. If joint control exists, resolution of disputes will usually require eventual agreement between the venturer, independent arbitration, or dissolution of the joint venture.

One of the venturers acting as operator of the joint venture does not prevent joint control. The operator's powers are usually limited to day-to-day operational decisions; key strategic financial and operating decisions remain with the joint venture partners collectively.

9.03 Reasons for Joint Venture Arrangement

- i. It brings about minimization of risk on the part of oil companies.
- ii. It leads to operational efficiency, since each of the oil companies will have to be involved in the core areas of operations.
- iii. It enables the companies in sharing huge capital outlay and political consideration and operational cost, etc.
- iv. A joint venture is always in a long term basis depending on the nature of operational agreement. A conventional joint venture agreement and production sharing is always in the long run, while unitization is usually for the short run.

Classification of Joint Venture

Joint ventures are analyzed into three classes under the current standards, jointly controlled operations, jointly controlled assets and jointly controlled entities.

Jointly controlled assets are common in the upstream industry and jointly controlled entities in the downstream sector. Jointly controlled asset exist when the venturers jointly own and control the assets used in the joint venture. Jointly controlled assets are likely to meet the definition of joint operations when companies adopt IFRS 11.

Jointly controlled operations:- Jointly controlled operations are arrangement where each venture uses their own property, plant and equipment, raise their own finance and incur their own expenses and liabilities. An example would be an arrangement where one party owns an oil refinery and another party owns transportation facilities (such as a pipeline or tankers). The second party will

market and deliver the oil produced. Each party will bear its own costs and take a share of the revenue generated by the sale of the oil to third party customers.

Entity A controls mineral rights and operates an oil sands mine. Entity B has processing capacity in the form of a refinery. The refinery is located next to the oil sands operation and processes bitumen extracted from the mine. Entity A and B have a contractual agreement according to which they share the revenue of the refined product. Entity A retains title and control of the oil sands operation and entity B retains the same for the refinery.

Entities A and B considers the oil sands mine and the refinery to be jointly controlled operation. They recognized the assets that they control, the liabilities that they incur, an expense and their share of the income that earn the sale of the refined products, respectively.

Jointly Controlled Entities:- Jointly controlled entities exist when the venturers jointly control an entity which, in turn owns the assets and liabilities of the joint venture. A jointly controlled entity is usually, but not necessarily, a large entity, such as a company. The key to identifying an entity is to determine whether the joint venture can perform the function associated with an entity. Such as entering into contracts in its own name, incurring and setting its own liabilities and holding a bank account in its own right.

Joint Controlled Assets: A venturer in a jointly controlled assets arrangement recognizes;

- Its share of the jointly controlled assets, classified according to the nature of the assets;
- Any liabilities the venturer has incurred;
- Its proportionate share of any liabilities that arises from the jointly controlled assets;
- Its share of expenses from the operation of the assets; and
- Its share of any income arising from the operation of the assets.

For example, entity A, B and C together owns and operate an offshore loading platform close to producing fields which they own and operate independently from each other. They own 45%, 40% and 15%, respectively of the platform and have agreed to share services and costs accordingly. Decisions regarding the platform require the unanimous agreement of the three parties. The platform is neither a jointly controlled entity nor a jointly controlled operation. It is the platform of jointly controlled assets.

9.04 Formation of Joint Ventures

The following are some of the common ways in which joint ventures are formed:

- A farming/farmout agreement is reached whereby a leaseholder allows a second party to drill on his property. In return for drilling, the party that pays for the well acquires an interest in the lease.
- A concession holder assigns an undivided fractional share of the property to another operator under a carried interest arrangement.
- A working interest owner assigns an undivided fractional share of the property to another operator under a free-well arrangement.
- Two or more parties acquire a concession as joint leases with undivided interest.
- Owners of concessions in two or more separate properties or blocks cross-assign undivided shares of their concession.
- An oil company with a concession sells an undivided fractional interest to another oil company for cash.
- Several leaseholders pool their property interest into one unit through unitization or other pooling of interest arrangement.

1 LEGAL FORMS OF JOINT VENTURE

Joint operation may be undertaken in three legal forms;

- Joint venture of undivided interests.
- Legal partnership.
- Jointly owned corporation.

2 JOINT OPERATING AGREEMENT

Joint venture of undivided interests is by far the most common form of joint operation. In an undivided interest, parties share the interest in an entire lease. For example, a company having a 50% undivided interest in a 1000 acres lease owns a 50% interest in the entire lease of 1000 acres. This differs from a situation where a company owns a 100% interest in 500 acres carved out 1000 acres lease. The former is an undivided interest and the latter is a divided interest. In a joint venture of undivided interests, companies may acquire an undivided interest in a property when the property is initially acquired. Alternatively, an undivided interest may be created at a later date if the companies' pool, unitize, or otherwise join their properties together in such a manner that all the parties have an undivided interest in the entire property.

Legal partnership

Legal partnerships are much less common than joint ventures. When companies join together to form a legal partnership they normally do so under the laws of a particular state. Typically, companies join together in a partnership formed for the exploration and production of a particular project.

Legal partnerships are frequently utilized to achieve certain income tax or legal objective.

Jointly owned corporation

Jointly owned corporation are very rare domestically. Internationally, most operations are conducted as joint ventures; however, there may be some instances where jointly owned corporations are formed. The laws of certain foreign countries may call for oil and gas operations to be carried out only by locally incorporated companies. In order to comply with the local laws; two or more companies may find it necessary to set up a company in that country. The companies establishing the foreign company usually own all of the stock in the new corporation.

Joint Operating Arrangement

The joint operation arrangement or agreement (JOA) spells out how the property is to be operated. One important part of the joint operating arrangement is the accounting procedures. Both joint operating arrangement and the accounting procedures are of significant importance to the accountant. It is important to remember that, as with any negotiated contract, the parties are free to include any provisions and language they believe to be important.

The Joint Operating Arrangement (JOA) delineates the duties and responsibilities of the operator and non operators. The joint operating Arrangement typically covers all phases (i.e., exploration, development, and production) of operation of the joint property. The major subsections that may be included in a standard joint operating arrangement are as follows;

- **Definition:-** Defines basic terms used in the agreement. Example includes operators, non operators, contracted area, Authority for Expenditure (AFE), oil and gas lease, drill site, etc.
- **Exhibits:-** Contains a list of all the exhibits that form the appendices of the agreement. For example, exhibit "A" contains the legal description of the properties, the parties to the agreement and the percentage or fractional ownership interest of each owner. Exhibit "C" in the accounting procedure. Other exhibits that may be included are exhibits containing the gas balancing agreement, information about instances and information about the lease agreement.
- **Interests of Parties:-** Defines how specific revenues, cost, and liabilities will be distributed according to the ownership interests specified in the exhibits.
- **Titles: -** Describes title examination requirement for drill sites, how the costs of the title process will be distributed, and how loss of title would be handed.
- **Operator:-** Designates the operator and the general rights and duties of the operator. It describes the process for the resignation or removal of the operator and the process for appointment of a successor. All records and reports including the accounting records to be maintained by the operator and provided to the non operators and governmental units are listed.

Right and duties of operator

Specific responsibilities of the operator that are normally set out include:-

- Consulting freely with the parties concerning the joint venture operations and keeping them currently advised of all matters of importance arising in connection there with.
- Selecting employees for the purpose of the joint venture operations and determining their number, qualifications and conditions of employment.
- Entering into agreements with third parties for use by the third parties of facilities of the joint venture, provided that no right or enjoyment of the other partners in the joint venture is diminished in any material respect.
- Entering into contracts for the performance of services or the provision of facilities, equipment, materials or supplies by third parties provided that such third parties shall be competent and capable both technically and financially to perform their obligation under such contracts, it being the intent of the parties that procedures customary in the oil industry for securing competitive prices shall prevail unless compelling reasons to be contrary exists.
 - Preparation and implementation of initial and annual work programmed, budgets, and Authority for Expenditure (AFE) in allowance with the accounting procedures.
 - Ensuring that subcontractors and agents comply with the applicable regulations in force in the oil and gas industry.
 - Keeping accurate record and books of accounts with respect to the joint venture operations, using accounting procedures commonly in use in the petroleum industry. Such records and books should provide sufficient information to comply with the reasonable accounting requirements of the joint venture parties.
 - Circuiting each joint venture partner access to the joint venture operations and all facilities to observe the joint venture operations conducted to the extend that such operations are not unduly affected or disrupted.
 - Promptly notifying the operating committee of material claims and litigation relating to the joint venture operations and, unless otherwise advised by the operating committee prosecute, defend, or settle such claims and litigation.

Drilling and Development:- Specifies procedures to be followed in drilling and development activities and termination operations include the specific date and location for the drilling of the initial well. Participation in the initial well is typically obligation for all parties. It describes the procedures that must be followed in undertaking subsequent drilling and operations, including a section providing for “operations by less than all parties”.

This section provides the process by which carried working interests are created and allows penalties in non-lowest situations related to drilling, deepening, rework, and abandonment of wells.

Expenditure and liabilities:- Specifies that any liabilities are to be several and not joint (i.e. each party is individually responsible only for its own obligations and liabilities, and only its own proportionate share of development and operating costs). Gives the operator the right to demand and receive cash advances from the other working interest owners. Spells out the remedies that exist in the event that any owner fails to discharge its financial obligation related to the property. It provides for the payment of shut-in royalties, minimum royalties, delay rentals and valorem taxes.

Acquisition, maintenance, or transfer of interest:- Specifies procedures to follow when surrendering or renewing a lease or assigning interests. Also gives preferential rights of purchase to other working interest owners when one working interest owner wishes to sell part or all of its interest.

Internal revenue code election:- States whether the joint venture is to be operated or be taxed as a partnership.

Claims and lawsuit:- Defines the procedures to be followed in case of legal action relating to operation of the venture, and authorizes the operator to settle claims for un-insured damages up to maximum amount.

Force majeure:- Provides that if any party is unable to meet its non monetary obligations, such as the operator's obligation to proceed with drilling activities, because of circumstances beyond that party's control- act of God, war, fire etc the party's obligations will be temporarily suspended.

Notes:- States that all notes between parties will be in writing.

Terms of agreement:- States that the agreement will remain in effect so long as the underlying lease is in effect whether through production, extension, renewal, or otherwise.

Compliance with laws and regulations:- States that the agreement is subject to all applicable laws, and states that the operator cannot wait or release non operators from any rights, privileges or obligations arising from governmental regulations.

Miscellaneous:- Other provisions including those concerning successors severability, and the signature page.

9.05 Accounting for Joint Venture Arrangement

The accounting procedure is an integral part of any jointly operating arrangement (JOA). The accounting procedure specifically addresses Issues related to the maintenance of the joint account; specifically the determination of appropriate changes and audits applicable to joint operations.

SECTION I: GENERAL SECTION

The General provisions section deals with a variety of issues as follows:

- **Definitions:** This section lists terms used in the contract that are frequently subject to question or interpretation. Examples include first level supervision, technical employee, and controllable material.
- **Joint account reloads and currency exchange:** In international operations it is necessary to indicate which language and in which currency the joint account will be maintained.
- **Statements and billings:** The operator is to provide a monthly statement to all of the non operators. The statement should include a listing of all costs and expenditures incurred during the preceding month, and the amount of advances received from the parties, each party shares of the costs and expenses, and the respective cash balances or deficits. The costs and expenditures incurred during the month should be identified as;
 - (a) Costs and expenditures under the single expenditure limit and thus not requiring and Authority for Expenditure (AFE) (Categorized as either investment or expense).
 - (b) Costs and expenditure relating to specific AFEs.
 - (c) Costs and expenditures relating to appropriations (authorized expenditures over the single expenditures limit but not related to a well).
- **Payment aid advances:** The operator is given the right to require the non operators to prepay or advance the next month's estimated cash outlays—referred to as a cash call. Cash calls are common in international oil and gas operations. In domestic operations, they are often encountered when there are a number of wells being drilled and cash outlays are large. In the event that the cash call for any given month exceed the actual amount of cash required for that month, each party's share of the balance should be carried forward to reduce that party's cash call for next month. If cash calls are not used, the operator will send a billing to the non operators itemizing costs for the month. The non operators must remit their proportionate share to the operator in a timely manner typically within 10 days.
- **Adjustments:** Payments of a billing or cash advance does not indicate that the non-operator agrees with the correctness of a billing or statement. The non-operator has 24 months from the end of the current year to raise exceptions to any change. After that period, the statements are deemed to be true and correct.
- **Audits:** All non-operators have the right to audit the joint account and other records of the operator pertaining to the joint operation. The non- operators have 24 months from the end of the year in which the disputed change occurred to raise an exception or make a claim to the operator.
- **Allocation:** In the course of joint operation, it frequently becomes necessary to allocate joint and/or common cost between the joint operation and other operations. For example, the operator may have solely-owned

equipment that is used on jointly owned properties. The costs associated with the equipment may be allocated to all the properties that it serves.

SECTION II: DIRECT CHARGES

All the working interest owners in a jointly owned property have an obligation to pay their proportionate share of the costs and expenses in return for a share of production. Joint account refers to costs that have been identified with or allocated to a particular jointly owned property and therefore is the responsibility of that particular group of working interest owners. It does not necessarily refer to a separate account. Two specific types of costs are recognized and separated for the purpose of making changes to the joint account, direct and indirect. The example of general activities typically charged directly to the joint account are; Exploration drilling, development drilling, installation of production equipments, and rentals. While the examples of general activities charged to indirect costs are; home office administration, data processing, office services, human resources, human resources and legal support.

The following is a more detailed explanation of the cost that would be charged direct or indirect costs;

- Licenses, permit etc; generally all costs incurred by the operator in relation to the acquisition, maintenance, renewal or relinquishment of licenses, permits or surface right acquired by the joint operations are direct charges.
- **Salaries, wages and related costs:-** The salaries, wages and related costs of employees of the operator engaged in the joint operations whether temporarily or permanently assigned are direct charges.
- **Employee benefits:-** Employee benefits are generally considered to be part of the employer's total labour cost. Most operating agreements allow the operator to charge the joint account with the current cost of established employee benefit plans as long as they are made available to all employees on a regular basis. This charge is usually expressed as a percentage of the total labour chargeable to the joint account. Another method of charging employee benefits to the joint account is on a when and as paid basis. Costs that can be included in the percentage calculation include; bonus, medical and dental insurance, business travel insurance, pensions, profit sharing plans, life insurance, tuition assistance, long-term disability insurance, and vision care plans. Among the costs not included are personal leaves, car pool subsidies, company car use, employee stock ownership plans, lay off benefits, and parking.
- **Services:-** The cost of service is generally broken down between those services provided by a third party and those provided by an affiliate of the operator. The cost of services performed by third parties for the

benefit of the joint operation is direct charges, provided the transactions that resulted in the changes are derived pursuant to an arm's length transaction. The cost of professional administrative, scientific, or technical personnel services provided by an affiliate of the operator in lieu of services provided by the operator's own personnel are direct charges, if provided for the direct benefit of the joint operations. The rates charged must be equal to the actual cost of the services, must exclude any element of profit, and should not be higher than charges of the third parties for comparable services performed under comparable conditions.

- **Office, camps and miscellaneous facilities:-** The cost of maintaining any office, sub-offices, camps, warehouses, housing, shore-based facilities or other facilities of the operator and/or affiliates of the operator that are directly serving the joint operations are directly chargeable to the joint account. If any such facilities serve other operations in addition to the particular joint operation in question, or any business other than the petroleum operations, the net costs are to be allocated to the operations served on an equitable and consistent basis.
- **Communication:** The costs of acquiring, leasing, installing, operating, repairing, or otherwise utilizing communication systems are direct charges if the equipment is necessary for the joint operations. Such equipment may include satellite, radio, and microwave facilities.
- **Exclusively owned equipment and facilities of the operator:-** The operator may use equipment and facilities if exclusively owned on a joint property. In that case, the operator is allowed to charge the joint account mental rates based on the actual cost incurred by the operator including factors relating to the cost of ownership. However, the rates charged may not exceed the average prevailing commercial rates of non affiliated third parties for like equipment and facilities used in the same area.
- **Ecological and environmental costs:-** Ecological and Environmental costs incurred in relation to a particular operation are generally considered to be costs of operating jointly owned property and are directly chargeable to the joint account.
- **Materials and supplies:-** The costs of materials and supplies net of any discounts purchased or furnished by the operator for the joint operations are direct charges. The costs include but not limited to, export brokers' fees, transportation charges, loading and unloading, export and import duties, licenses fees, and in-transit losses not covered by insurance.
- **Damages and losses:-** Costs that can be associated with losses by casualty or theft are directly chargeable to the joint account. Any settlement received from an insurance carrier should be credited to the parties participating in any joint property insurance coverage.

SECTION III: OVERHEAD.

Overhead for joint purposes is defined as "those costs attendant to executive and administrative functions incurred by the operator at the home, division, area,

regional or similar administrative office serving indirectly, the development and producing operation. Overhead costs include, offsite function costs attributable to the staffing, maintaining, and operating foregoing offices, as well as those costs incurred for the prime benefit to the operator and the total scope of his operations, except where specifically provided for in the accounting procedure or where approval is obtained from the non-operators to charge directly". It is common practice in the industry to negotiate an agreed rate to reimburse the operator for overhead costs applicable to the joint operation. Such rates may either be on combined fixed rate basis or percentages rate basis.

The combined fixed rate basis is the most commonly used method of computing overhead in domestic production and drilling operations. The rate is referred to as combined because it is meant to cover an operator's expenses at all levels and fixed because it does not vary in proportion to actual expenses.

SECTION IV: PRICING OF JOINT ACCOUNT MATERIAL PURCHASES, TRANSFER, AND DISPOSITIONS.

- **Purchases:** Material that is purchased from a third party should be charged to the joint Account at the price paid by the operator after the deduction of all discounts received.
- **Material transfer pricing:-** Material owned by one of the parties that is moved to the joint property, and material transferred from the joint property or disposed of by the operator, should be priced on the following basis exclusive of cash discounts (unless otherwise agreed to by the parties).
 - i. **New material (condition A):** New material should be priced at the current new price in effect at the date of movement, as listed by a reliable supply store near the joint property or near the manufacturer.
 - ii. **Good used material (condition B):** Condition B material is material in sound and serviceable condition, condition that is suitable for reuse without reconditioning.
 - iii. **Used material (condition C):** Condition C material is not sound and serviceable condition, and is not suitable for its original function until after reconditioning.
 - iv. **Condition D:** Material, excluding junk, no longer suitable for its original purpose, but usable for some other purposes should be priced on a basis commensurate with its use.
 - v. **Condition E:** Junk should be priced at prevailing junk prices.
- **Disposition of material:** The disposition of surplus material can occur by any of the three following methods: -
 - i. Material purchased by operator or non-operator.
 - ii. Division in kind
 - iii. Sales to outsiders.

SECTION V: INVENTORIES

The Accounting procedure requires the operator to maintain detailed records of condition controllable materials and to conduct regular physical inventories. The operator is responsible for maintaining an accurate record of controllable materials. The listing of controllable materials should be compared with a physical examination of existing assets at reasonable intervals, and appropriate action taken when discrepancies are identified.

Any expenses incurred by the operator in conducting periodic inventories should be charged to the joint account. If non-operators elect to have a representative present they do so at their own cost and expense. Special inventories are generally required whenever there is change in the operator. The expenses related to conducting special inventories resulting from a change of operator are normally charged to the joint Account.

9.06 Practical Problems in Joint Venture Accounting

As earlier mentioned two methods are involved, combined fixed rate basis and percentages basis.

Illustration 1: Fixed Rate Basis

A Well was spaded on 6th September, 2013 and the rig was released on October 15, 2013. Other contract information was as following; Date of agreement July 7, 2013.

Drilling overhead rate ₦300,000 Per month Producing well rate ₦180,000 per month

Drilling overhead shall be prorated for less than a full month. Calculate the drilling overhead to be charged to the joint Account.

SOLUTION 1:

Drilling overhead to be charged to the joint Account is calculated as follow:-

$$\begin{array}{rcl} \text{September 2013} - 24/30 \times 300,000 & = & \text{₦ } 240,000 \\ \text{October 2013} - 16/31 \times \text{₦ } 300,000 & = & \underline{\text{₦ } 154,839} \\ & & \text{₦ } 394,839 \end{array}$$

Illustration 2: Using the same data in illustration 1, calculate the producing overheads chargeable to the joint Account.

SOLUTION 2:

Producing overhead to be charged to the joint Account is calculated as follows:-September 2013 – $24/30 \times 180,000$ = ₦144,000

$$\begin{array}{rcl} \text{October 2013} - 16/31 \times \text{₦ } 180,000 & = & \underline{\text{₦ } 92,903} \\ \text{Total overhead chargeable} & & \underline{\text{₦ } 236,903} \end{array}$$

Illustration 3

A well was spaded on July 6, 2012 and the drilling rig was released on September 7, 2012 with continuous drilling during this period. A completion rig was moved on location on September 15, 2012 and released on October 12, 2012. The well is placed on production from October 15, 2012 and continues producing through December 2013.

Other contract information is as follows:-

Date of agreement	May 8, 2012
Drilling overhead rate	N 400,000 per month
Producing overhead rate	N 220,000 per month

Escalated rates do not become effective until year 2014 calculate drilling and producing overheads chargeable to the joint Account.

Solution 3:

Drilling overhead chargeable to the joint Account is calculated as follows:-

July 2012	26/31 x N 400,000	= N 335,484
August 2012	30/30 x N 400,000	= N 400,000
September 2012	7/31 x N 400,000	= N 93,333
September 2012(completion)	15/30 x N 400,000	= N 200,000
October 2012(completion)	12/31 x N 400,000	= N 154,839
Total overhead chargeable		<u>N1,183,656</u>

Producing overhead chargeable to the joint account is calculated as follows:

October – December 2012	2.5 Months at N 220,000 per month	= N 550,000
January – December 2013	12 months at N 220,000 per month	= <u>N2,640,000</u>
Total overhead chargeable		<u>N3,190,000</u>

PERCENTAGE BASIS OVERHEAD

Illustration 4

Assume ANAN Limited, an operator of a joint venture, engaged a drilling contractor on day rate and a well is spaded on March 3, 2012. A completion rig moves to location on May 25, 2012, and is released on June 3, 2012. Production is continuous up to March 15, 2013 at which time production ceased. On March 20, 2013 a drilling rig and crew capable of drilling to the producing interval on the joint property are moved to location and begin work over operations to restore production. The work-over operations last seven days, production recommenced on a March 28, 2013 and continued to 31st December, 2013. Expenses incurred for the period March 3, 2012 to 31st December 2013 include the following:

	N
Intangible drilling costs	5,000,000
Intangible Completion costs	66,000
Intangible work-over costs	312,000

Tangible work-over costs	215,000
Surface equipment	520,000

Drilling contractor day rate is ~~N~~24,000 while the completion and work-over rig is ~~N~~22,000 per day. Producing well rate is ~~N~~85,000 per Month. Assume development and operating overhead rates of 5% and 25% respectively are stipulated in the Accounting procedure.

Solution 4

	Development N	Operating N
Cost of day rate drilling contractor 3/3/2012- 1/5/2012 84 days @ 24,000	2,016,000	
Completion rig:-		
7 days – May 2012 @ 22,000	154,000	
3 Days – June 2012 @ 22,000	66,000	
Intangible drilling costs	5,000,000	
Intangible completion costs	66,000	
Surface equipment	520,000	
Producing:		
June – December 2012	– 7 months	59
5,000		
January – March 2013 – 3 months		
Work-over:		255,000
March – 7 days @ 22,000		
Work-over tangible costs	215,000	
Work-over intangible costs	312,000	
Producing:		
April – December 2013 – 9months		
	8,503,000	
X 5%		1,525,000
Overhead chargeable	425150	381000

ACCUMULATION OF JOINT COSTS IN REGULAR ACCOUNTS

Most joint ventures are accounted for using the proportionate consolidation method. Under the proportionate consolidation method, each owner, accounts for its pro-rata portion of the assets, liabilities, revenue, and expenses of the venture.

The most common method of booking joint costs is to initially record all costs in the operator's regular accounts. The costs are associated with specific properties via a system of property identification numbers. The operator identifies all costs that have been charged to the jointly owned properties it operates at the end of each month. The operator then recognizes a receivable for the non-operators' share of those costs and credits or cuts back its regular accounts for the non-operators' portion of the costs. The operators' own portion of the costs incurred during the month is thus left in its regular accounts.

Illustration 5

Total company owns 60%, mobile company owns 10%, and Oando company owns 30% of the joint working interest property 2004. Total company is the operator. Total company incurs the following costs during October 2013, in connection with lease number 2004.

	₦
Salaries and wages, field employees	10,000
Contract service, reacidizing	5,000
Purchase and installation of compressor unit	1,800
Property taxes paid	1,000
Equipment from operator's inventory installed on lease	1,200
Allowed overhead charge (2 wells at ₦2400 per well)	4,800

Solution 5

Entries during month by operator (Total Company)

	₦	₦
Lease operating expenses – joint lease	10,000	
Wages payable		10,0
Lease operating expenses – joint lease	5,000	
Account payable		5,00
Wells and related equipment – joint lease	1,800	
Account payable		
Lease operating expenses – joint lease	1,000	
Property taxes payable		1,000
Wells and related equipment – joint lease	1,200	
Materials and supplies		1,200

Entries at end of month (Total Company):

Lease operating expenses – joint lease	4,800
Overhead expenses – control account**	4,800
Account receivable – Mobile company (10% x 23800)	2,380
Account receivable – Oando company (30% x 23800)	7,140
Lease operating expenses – joint lease (40% x 20800)	8,230
Well and related equipments- joint lease (40%x3000)	1,200

Mobil Company:

Lease operating expenses	,2,080	
Wells and related equipments	300	
Account payable – Total company		2,380

Oando Company:

Lease operating expenses	6,240	
Wells and related equipments	900	
Account payable – Total company		7,140

*The actual overhead costs were charged to the overhead expense–control account when incurred, with allowed overhead charges billed to the lease at the end of the month.

DISTRIBUTION OF JOINT COSTS AS INCURRED

Another method that might be used by the operator is to record the distribution of joint costs as incurred. The operator changes its regular (non- joint interest) accounts and recognizes a receivable from the non-operators for their portion of the costs as each transaction occurs. The operator, however, actually bills the non-operators for their portion of the costs only once a month.

Illustration 6

Assume the same ownership and operator as in illustration 5. Total company incurs minor work-over costs of ₦20,000.

Solution 6**Entry:**

	₦	₦
Lease operating expenses (60% of ₦20,000)	12,000	
Accounts receivable – Mobile (10% x ₦20,000)	2,000	
Accounts receivable – Oando (30% x ₦20,000)	6,000	
Cash		20,000

NON- CONSENT OPERATIONS

A situation that frequently occurs requiring considerable accounting effort is a non-consent operation. Non-consent operations arise when one or more of the working interest owners do not consent to the drilling, deepening, reworking, or abandonment of a well. Non-consent operations related to deepening, reworking or abandonment are similar to drilling operation.

The party wishing to drill – usually the operator – must give written notice to all of the working interest owners of the proposed drilling operations. The parties have a period of time, typically 30 days, to reply. If one or more of the parties elect not to participate, the consenting parties are re-notified and given the election to pay only their proportionate share of the costs, or in addition to their proportionate

share, to pay all or part of the non-consenting party's share. The party electing not to participate is referred to as a carried working interest or carried party. The working interests' owners who agree to pay the carried party's share of the costs are referred to as the carrying parties. If none of the working interest owners agree to participate in drilling the well, the operator can either drill the well or carry all of the other owners himself or not drill the well. When the carrying parties have recovered the cost they paid on behalf of the carried party plus the penalty, the carried party is said to have reached payout.

Illustration 7

Carried working Interest

Total company, Mobil Company, and Oando Company each own 33.33% of the joint working interest property 2004. The royalty interest is 1/8. Total company, the operator, notified Mobil company and Oando Company of its plan to drill well No 4 at an anticipated cost of ₦200,000 Mobil company elects to go non-consent. Total company and Oando Company agree to carry their proportionate share of mobile company's costs. If the Well is successful, they will be allowed to recover from mobile company's share of production, the costs they carried plus a penalty of 300% upon payout; Mobil Company will resume participation at 33.33%. Total company and Oando Company determine their proportionate share of Mobil company's costs and revenue in the following manner:

	Interest of Consenting parties	Proportion of mobile costs and revenue.
Total company	33.333%	33.333/66.666=50%
Oando company	33.333%	33.333/66.666=50%
	<u>66.666%</u>	

Assume that the well is drilled at a cost of ₦200,000.

Total company and Oando company each pay ₦100,000 of which ₦66,666 is their own share and ₦33,334 is their portion of Mobil company's (i.e. ₦200,000 x 33.333 x 50%).

On July 25, 2013, Well No 4 is completed. Production and operating costs for the first three months of production are (no severance tax).

Month	Sales	Sales price	Total operating expenses
August	10,000bbl	60/bbl	400,000
September	18,000bbl	60/bbl	650,000
October	12,000bbl	60/bbl	450,016

Calculate the payout made by Total company.

Solution 7

	Aug.	Sep.	Oct.
Sales volume	10,000	18,000	12,000
Price/bbl	<u>₦60</u>	<u>₦60</u>	<u>₦60</u>

Cross sale (₦)	600,000	1,080,000	720,000
Net of royalty	7/8	7/8	7/8
Net sales (₦)	525,000	945,000	630,000
Operating expenses (₦)	400,000	650,000	450,016
Net revenue (₦)	<u>125,000</u>	<u>295,000</u>	<u>179,984</u>

REVENUE TO TOTAL COMPANY:

Total revenue to total company (50%) ₦ 62,500

Total company portion (33.333%) (₦)	41,666	98,332	59,994
Mobiles portion (16.667%) (₦)	20,834	49,168	29,998

LAYOUT:

Mobile company's share of Well	₦66.666
Total's revenue proportion of mobile's cost	50%
Amount paid by total company	33,334
Penalty	300%
Recoverable by total company	<u>₦100,000</u>
Amount to be recovered	<u>₦100,000</u>
Recovered in August	<u>(20,834)</u>
Balance to be recovered	<u>79166</u>
Recovered in September	<u>(49,168)</u>
Balance to be recovered	<u>29,998</u>
Recovered in October	<u>29,998</u>
Balance to be recovered	<u>0</u>

In November, Mobil company would be treated as a 33.33% working interest owner, paying its proportionate share of operating costs and receiving its proportionate share of revenue.

Entry for total company for July, August

	₦	₦
Wells and related equipments (50% of 200,000)	100,000	
Account receivable –Oando Company (50% of 200,000)	100,000	
Account payable		200,000
August;		
Lease operating expenses (50% x ₦400, 000)		200,000

Account receivable-Oando Company (50% x ₦ 400, 000)	200,000
Cash	400,000
Cash	200,000
Royalty Payable Company (₦ 200,000 X 1/8)	25,000
Account payable – Ondo Company	
(50% x ₦ 200, 000 X ₦ 200,000 X 7/8)	87500
Oil revenue (50% X ₦ 200,000 X 7/8)	87,500

Note: Total Company does not set up a recoverable from Mobil company for Mobil's carried interest. Also Total Company recognizes its share of revenue retained from Mobil company's interest as revenue-not as a reduction in its capitalized costs.

ACCOUNTING FOR MATERIALS

One of the most difficult and challenging problems facing a joint interest operator is the pricing of materials transferred to and from the property being operated. Material to be used on a joint property can be purchased directly for the specific property, moved to or from the operators' warehouse, or transferred from another property. Material purchased directly for a property is charged to that property at the cost of the material, less all discounts received. Any transportation charges are also charged to the property.

Illustration 8: Purchase of New Materials

The total company purchased casing for a joint property at a net price of ~~₦~~200,000. Loading, hauling and unloading costs from the railway railhead to the website were ~~₦~~ 20,000. Total company is the operator on the lease and has a 60% working interest.

Solution 8

Entry	₦	₦
Account receivable –non operator (40% x ₦ 220,000)	88000	
Warehouse property (casing) (60% x 200,000)	120,000	
Warehouse property (freight) (60% x 20,000)	12,000	
Cash		
220,000		

Illustration 9: Transfer from Warehouse – Condition A.

Assume that Total Company has a submersible pump in its warehouse with a cost of ~~₦~~ 9,000, including shipping and handling to the warehouse. The pump is new and is to be installed in a newly drilled well. The current market value is ~~₦~~9,000. The pump

is transferred from Total Company's warehouse to a jointly owned property in which Total company has a 60% working interest. Transportation costs from the warehouse to the property total ₦ 200

Solution 9

Entry to record transfer of pump:	₦	₦
Account receivable –non-operators (₦ 900 x 40%)	3	
	6	
Warehouse property (pump) (9000 x 60%)		
Warehouse inventory		
Entry to record transportation costs:		9
Account receivable – non-operators (₦ 200 x 40%)		0
		0
		n
Warehouse property (transportation) (₦ 200 x 60%)		
Account payment fright company	1	
	2	
	0	

Illustration 10: Transfer from warehouse to joint property-condition B.

Assume the pump in the previous example (illustration 9) that was carried on the books of Total warehouse at ₦9,000 has a current market price of ₦10, 000. Also assume that the pump is used, is in sound condition, and is being installed in a newly drilled well. Transportation cost is ignored.

Solution 10

The condition B value of the pump would be ₦10,000 x 75% = ₦ 7,500.

Entry	₦	₦
Account receivable-non operators (40% x ₦7500)	3,000	
Warehouse property (₦ 7500 x 60%)	4,500	
Other revenue/expenses (₦ 10,000 - ₦ 7500) X 60%)	1,500	
Warehouse inventory	9,000	

Illustration 11: Transfer from property to another property-condition B

A pump originally costing ₦42,000 is transferred from Oando lease, a joint property on which Total company serves as operator and has a 60% interest to Mobil lease, another joint property operated by Total company in which Total company has a 90% interest. At the time of transfer, the current market price of the pump is ₦ 50,000. The pump is condition B and was condition A material when first charged to the property. Ignore transportation charges. Assume that the pump is being installed in a newly drilled well.

Solution 11

The condition value of the equipment is ₦ 50000 x 75% = ₦37,500

Entry	₦	₦
Account receivable –Mobil lease non-operators (37,500 x 10%)		3,750
Warehouse property – Mobil lease (₦ 37,500x90%)		33,750

Accumulated Depreciation, Depletion and Amortization
 (DD&A)- Alpha lease (42,000-37,500)x 60% 2,700
 Account receivable *-Alpha lease non operators
 (~~N~~37,500X 40%)
 15000

Warehouse property- Alpha lease (~~N~~ 42,000x60%)
 25,200

*When material is transferred off a lease, the customary accounting treatment is to credit the account receivable from the non operators rather than to credit an account payable.

Illustration 12: Transfer from joint property to another joint property- Condition C

Total company is the operator on both lease A and leases B, and has a 40% working interest in lease A and an 80% working interest in lease B. A piece of equipment originally costing ~~N~~ 40000 is transferred from lease A to lease B. The current market price of the equipment is ~~N~~46000 and the equipment is transferred at condition C. The working interest owners of lease B will pay all costs of reconditioning.

Solution 12

The condition value of the equipment is ~~N~~ 46000X50% =~~N~~ 2300

Entry	N	N
Account Receivable-non operators-lease B (20%X N 2300)	4600	
Wells and related equipment (80%x 23000)	18400	
Accumulated DD&A- lease A (40%x(40000-23000))	6800	
Account receivable-non operators- lease A(60%X23000)	13800	
Wells and related equipment- lease A (40%X40000)	16000	

Assume that the cost of reconditioning the equipment is ~~N~~ 10000. This entire amount would be charged to lease B.

Account Receivable- non operators- lease B (20%X10000)	2000
Wells and related equipment- lease B (80%X 10000)	8000
Account payable vendor	10000

OFF SHORE OPERATION

Off shore operations are commonly joint working interest ventures because of the large dollar amounts and large amount of risk involved. Domestically, these operations are conducted in either federal or state owned waters. Bidding on lease from either the state or the federal government is normally required to obtain a lease. Bidding on offshore federal lease is done by sealed bids, with generally a separated bid for each tract.

Some different types of costs are income for offshore operations in comparison to onshore operations. These include the costs of using mobile rigs, fixed platforms, helicopter costs, and special safety equipment designed for offshore use.

9.07 Review Questions

(1). Pagih oil operates the Dajo lease. The accounting procedure attached to the Joint Operating Arrangement (JOA) allows Pagih to recoup its overhead by the use of combined fixed rate-well basis of ₦2,000 per producing Well and ₦20,000 per drilling Well.

Required:

- (a). How much total overhead would Pagih oil bill the joint account if the Dajo lease had four Wells that produced every day the previous month?
 - (b). What if three Wells produced everyday and only one produced for five days?
 - (c). What if the only operation on the lease the previous month was the drilling of a Well?
Drilling operations commenced on the first of the month, operations were suspended for four days on the 20th, and operations commenced again on the 24th and continued to be 30 days.
- (2). Pagih oil owns 70%, Dejo oil owns 20% and Oando oil owns 10% of the working interest, property 1002, assumed Pagih oil is the operator and incurs the following costs during the month of July 2013, in connection with the property.

	₦
Salaries and wages, field employees	60,000
Salaries and wages, first-level field supervisor	20,000
Operator's cost of holiday, vacation, sickness and disability	
Benefit, 8% of above	6,400
Social security tax 7.5% of above	6,000
Employee benefits, group life insurance	19,200
Material installed on property from Pagih's inventory	3,000
Transportation of material and employee 12,000 miles @ ₦0.25 per mile	3,000
Contract service, re-acidizing (work-over)	25,000
Purchase and installation of compressor unit	15,000
Repair of Christmas tree	5,000
Property taxes paid	5,000
Insurance premium paid	8,000
Overhead, 2 Wells @ ₦7,000 per Well	14,000

Required:

- (1). Give the entries to record and distribute the costs, assuming regular accounts are used.
- (2). Why do partners normally enter into an operating agreement?
- (3). What distinguish the duties of operators from non-operators?

MODULE TEN

10.00 ACCOUNTING FOR PRODUCTION SHARING AND SERVICE CONTRACT AGREEMENTS

10.01 Learning Outcomes

On successful completion of this Module, Students should be able to:

- i. Elucidate the concept of production sharing and service contract Agreements.
- ii. Practically demonstrate the procedure for Accounting in production sharing contracts.
- iii. Explain the general principles of Accounting for production sharing contracts agreements.
- iv. Apply service contracts Agreements.

10.02 Accounting in Production Sharing Contracts

A Production Sharing Agreement (PSA) is the method where by government facilitates the exploration of their country's hydrocarbon resources by taking advantage of the expertise of a commercial oil and gas entity. Governments try to provide a stable regulatory and tax regime to create sufficient certainty for commercial entities to invest in an expensive and long-lived development process. There are as many forms of production sharing arrangement (PSA) and royalty agreements as there are combinations of national, regional and municipal governments in oil producing areas. The term carrying party and carried party are used. The carrying party is the contractor while the carried party is the government or national oil company.

As oil and gas entity in a typical production sharing arrangements will undertake exploration, supply the capital, develop the resources found, build the infrastructure and lift the natural resources. The oil and gas entity (usually referred to as the operator or carrying party) will have the right to extract resources over a period of time; this is typically the full production life of the field such that there would be minimal residual value of the asset at the end of the production sharing arrangement. The oil and gas entity will be entitled to a share of the oil produced which will allow the recovery of specified cost (cost oil) plus an agreed profit margin (profit oil). The government will retain title to all of the hydrocarbon resources and often the legal title to all fixed assets constructed to exploit the resources.

The residual value of the fixed assets in most cases would be minimal and the operator would decommission them under the terms of the production sharing arrangement. The company is viewed as having acquired the right to extract the oil in the future when it performs the development work under the production sharing arrangement. The development expenditure is capitalized according to the requirements of IFRS 6 and IAS 16.

The government will take a substantial proportion of the output in production sharing arrangements. The oil may be delivered in product or paid in cash under an agreed pricing formula. An entity should consider its overall risk profile in determining whether it has a service agreement or working interest. Certain PSA may be more like service arrangements whereby the government compensates the entity for exploration, development and construction activities. These are arrangements where the PSA, is substantially shorter than the expected useful life of the production asset or are explicit cost plus arrangements. The entity thus bears the risks of performing this contract rather than traditional exploration and development risks. Expenditure incurred on the exploration and development plus a profit margin is usually capitalized as receivable from the government rather than an interest in the future production of the field.

The production sharing arrangements contain a right of renewal with no significant incremental cost. The government may have a policy or practice with regard to renewal that should be considered when estimating the life of the agreement.

At the production of oil, the carrying party or the oil and gas entity will first recoup its costs of investment and pay other commitments, and any excess will become the profit which would be shared between the carried party and the carrying party at an agreed ratio.

Some key terms are defined in a typical production sharing contracts as follows:-

- **Profit Oil:** - This is the quantity of oil earmarked after royalty and tax oil, to be shared between the carried party and the carrying party, in an agreed sharing ratio or scale. The accountant should ensure that accurate profit oil quantity is established, schedules showing sharing ratio is prepared and correct records of proceeds from scales or profit oil and remittances to the carried party are kept.
- **Royalty Oil:-** The quantity of oil available or allocated to the national oil company which will generate an amount of proceeds equal to the actual payment of royalty and concession rentals.
- **Cost Oil:** - Cost oil is the quantity of oil earmarked to recover the cost of investment in exploring, developing and drilling an oil well by the carrying party or contractor or oil and gas entity.
- **Tax Oil:** - Tax oil is the quantum of available crude oil allocated to the national oil company which will generate an amount of proceeds equal to the actual payment of petroleum profit tax.

In summary, the key terms in a production sharing contracts are contractor (carrying party) or oil and gas entity and national oil company or government (carried party).

Contractor (Carrying party)

- Pays royalty and tax to the government.

- Provides all financing, technology and bears all risks and cost of exploration and development.
- Recovers cost out of production revenues.
- Required to pay a signature bonus.
- Cost recovery as well as allocation of royalty oil, tax oil, and profit oil, occurs after first oil production.
- Required to pay production bonuses when production reaches specified levels.
- Required to submit annual work programmes and budget for the secreting and approval of the national oil company (the carried party)
- Has an exploration work commitment expressed in annual dollar expenditure over the exploration period.

National Oil Company (the carried party)

- Retains the ownership of concession and hydrocarbons
- Audits and approves all operating costs.
- Title to all equipment purchased reverts to it upon termination or expiration of the contract.
- Shares profit oil with the oil company in agreed ratios.

1. Accounting in Production Sharing Contracts Arrangements

There are two ways of accounting in production sharing contracts namely:

- The book of the contractor (carrying party).
- The book of the concession holder (carried party).

THE BOOK OF THE CONTRACTOR

The contractor is the key player in accounting for production sharing contracts. The responsibility here is:-

- Recording and accumulation of costs for reimbursement
- Oil revenue appropriation accounting; and
- Financial accounting for oil and gas operations.

Recording and accumulation of cost for reimbursement

When oil production begins and oil revenues are appropriated to reimburse parts of the accumulated costs, the accountant should maintain an up date base on cost recovery, oil production reserve quantities and payout status that is accurate at all times. The database should be used to generate cost recovery reports with which to inform the concession holder on the status of cost recovery an regular basis:

The main accounting work before first oil is to record accurately those cost that will be recoupable as “cost oil” in future. The cost may include operating and capital cost. All costs are subjected to audit and approval by the carried party.

OPERATIONG COSTS: These are non-capital cost incurred that are changeable to the current years operations and is recoupable in the same year. The costs includes:-

- Geological and geophysical costs.
- Cost of exploration and appraisal drilling
- Provision for abandonment.
- Field operating expenses
- Intangible drilling cost

All classes of revenue expenditure whose benefits do not extend beyond the current year. Example, general office expenses, labour and related costs, employees relocations costs, costs of services provided by third parties, legal expenses, service provided by affiliates of the contractor, head office overhead charge, interest expenses, insurance premiums and settlement, duties and etc.

CAPITAL COSTS: Are costs with the potential to provide benefit to the business beyond one year. Example, plant expenditure, pipeline and storage expenditures, building expenditures, drilling expenditures, wells and related equipment. It includes all pre-production expenditures not included in non –capital costs.

In most contract, capital costs must be amortized and recouped over say, five years, while non-capital costs can be recouped in the year of operations. Cost recovery accounting must be detailed as follows:

- Basic data of reimbursement costs:-
- Detailed calculation of amounts recouped in oil.
- Capital expenditure incurred after the date of commencement of commercial production.
- Details of production costs.
- Total amount recouped in oil.
- Total un-recovered costs carried forward.

ACCOUNTING TREATMENT

- Before proved reserves are discovered, costs incurred are recorded in appropriate ledger accounts as temporary assets accounts.
- If production results in a dry hole or the lease period expire without commercial discovery, the treatment will depend on whether the contract allows such costs to be recovered from any future lease.
- If future recoupment is possible, the contractor will transfer the costs in the ledger accounts to a cost recoverable account and close all the ledger account.
- If future recoupment is not possible, the treatment will depend on whether the company uses the successful efforts or full cost method.
- If exploration results in proved reserves, the company will simply consolidate all the cost ledger account in a cost recoverable account and close all ledger accounts.

Oil Revenue appropriation accounting

One of the unique characteristics of production sharing contracts is that oil sales proceeds are not credited directly to the profit and loss account in order to determine income. They are appropriated as tax oil, cost oil, royalty oil and profit oil.

The appropriation of oil revenue begins at first oil and covers all accounting duties relating to the division, disposition, allocation and appropriation of crude oil produced under the contract. The contract stipulates that actual quantities of crude oil should be allocated to these four categories. In practice, the contractor sells the total quantity of oil produced and appropriates the proceeds in accordance with the terms of the contract.

Tax and Royalty oil; - The quantity of oil earmarked to take care of petroleum profit tax and royalties. The contractor pays the value in money to the government. The accountant has the responsibility to ensure that:

- Adequate quantity of oil is appropriated.
- Payment is made correctly and appropriately to designated government agency; and
- The payments are recorded and reflected in the accounts and records.

The accounting entry must be zero as the contractor is only carrying out the transaction on behalf of the government.

Profit Oil: This is the residual oil to be shared by the concession holder and contractor in agreed ratio. The accountant responsibility here is to prepare schedule of accurate quantity of oil available as profit oil, schedule showing sharing formula and keep correct records of proceeds from sales of profit oil and remittances to the carried party. In most cases, the contractor sells the oil on behalf of the concession holder, remits the proceeds and effects necessary entries in its books.

Cost oil – This is the quantity of oil meant to recover the cost of investment in exploration, developing and drilling an oil well by the carrying party or contractor. Revenue from crude oil allocated for cost oil is to be applied to reduce the balance on the cost recoverable account as follows:

When oil proceeds are received, CR. Cost oil proceeds; DR. Bank to record cost oil proceeds received.

Also DR Cost oil proceeds; CR Cost recoverable account to write down the balance on the recoverable account with the proceeds from cost oil.

Accounting treatment

Profit oil is the only oil allocation that properly classifies as oil “income oil” and its proceeds can therefore be recorded as revenue in the income statement in order to determine the income for the period. The argument here is that whether the contractor should record only its equity shares of proceeds from profit oil or include the portion of the concession holder.

However, in practice most oil and gas accounting standards recommends that the contracts, as the focal point of accounting production sharing contracts, should account for the gross revenue and net off the share of the concession holder.

Note here that oil allocations are basically guided by the terms of the operating contract. Oil appropriations must therefore be in accordance with the contract and the approval of the concession holder.

Financial accounting for oil and gas operations

The main purpose of accounting for oil and gas operations is to determine the periodic income and ascertain the financial position of the enterprise. The financial statements must be guided by the terms of the production sharing contracts and the provision of the accounting standards. Statement of Accounting Standard (SAS) 14, paragraph 80 stipulates that the contractor can treat the costs incurred either as direct exploration costs or as a loan, in accordance with the terms of the contracts and the possibility of repayment. However, most production shearing contractors adopts the direct exploration costs approach and treatment of costs incurred as a loan is now rarely encountered in practice.

TREATMENT OF COSTS AS DIRECT EXPLORATION OR CONCESSION COSTS:

Statement of Accounting Standard (SAS) 14, paragraph 82 states that where the contractor treats the costs incurred as direct explanation or concession cost, it should account for such costs in accordance with its accounting policy –using either the successful efforts or the full cost method.

The following must be included in production sharing contracts.

- High level accounting summary and notes on the status of reimbursement cost.
- High level of accounting summary and notes on appropriation oil revenue.
- The payout status of the account.
- The accounting policies of the organization in respect of matters such as:
 - i. Dry hole expenses.
 - ii. Depreciation, Depletion and abandonment.
 - iii. Conveyances.
 - iv. Ceiling tests.
- Financial disclosures required of oil company in respect of :
 - i. Methods of accounting.
 - ii. Capitalized costs.
 - iii. Costs incurred
 - iv. Disclosures of results of operations
 - v. Reserves quantity information.
 - vi. Standardized measures of discounted future net cashless.

TREATMENT OF COST INCURRED AS LOAN

Statement of Accounting Standards (SAS) 14, Paragraph 81 states that “where costs under a production sharing contract are treated as a loan, and before establishing commercial reserves, a provision equivalent to exploration cost is usually made if the effort is determined to be unsuccessful under the successful efforts methods or impaired under the full cost method. Where commercial reserves are found, the provisions against all costs incurred are reserved to income subject to the limit of the loan being recovered from the reserves. Future exploration costs in the contract area usually carried as exploration costs if the costs will be recoverable from future production. The balance outstanding at the end of each year is usually written down to the outstanding balance of recoverable costs at the time.

THE BOOKS OF THE CONCESSION HOLDER

In the books of the concession holder, the contractor accounts for 100% of the costs and revenues, the carried party should not account for carried costs or the related revenues, oil and gas reserves or production from which such costs are recovered. The concession owner has responsibility for paying all concession rentals while the lease is still active. Depending on the facts available, the concession holder may make allowances for impairment of unproved property as necessary. It is important to know that:

- The concession holder should not report any income or any amortization of leaseholder until payment.
- Should reclassify from unproved property account to proved property account when oil is discovered.

The monitoring of production sharing contract operations requires the concession holder to review and approve work programs, budgets and actual pay force, when commercial production is reached, the concession holder must ensure that oil allocations are made in line with the terms of agreement. Most cases, the concession holder will have to verify the costs with the actual performances signed both during the pre-production years after commercial production began.

When the share of profit oil revenue is received, the concession holder will Debit the bank and credit oil revenue from concession.

10.03 General Principles of Accounting for Production Sharing

The key player in production sharing contracts is the contractor. As the contractor account for 100% of oil produced and appropriates it to cost oil, royalty oil, tax oil, tax oil and profit oil, the contractor must also report for the aggregate production revenue attributable to royalty payment, cost recovery, payment of taxes and sharing of profit oil. Therefore, the contractor should draw no distinction between the costs and revenues attributable to its own and carried interests. The contractor should also report all exploration, drilling and development costs till payout. In addition, the contractor must report all reserve quantities. Obviously the contractor must not record any leasehold cost or allowance for impairments.

Accounting Standards Board of the United Kingdom recommends the following principles for accounting in production sharing contracts arrangements:

- The carrying party should combine costs, revenues, oil and gas reserves and production attributable to the carried interest with those associated with its own equity interests.
- Its turnover and cost of sales should include revenue and operating cost, respectively, associated with the carried interest.
- Unit of production calculations should include the expenditures and oil and gas reserves and production associated with the carried interest, as well as the equity interest.
- Capitalized costs related to the carried interest should be amortized over the field as a whole, rather than just over the period during which reimbursement occurs.

10.04 Service Contract Agreements

The second type of agreement prevalent in a contractual system is service agreement. Service agreements can be classified as being either risks service contract or non risk service contracts. In non risk service agreements, the contractor provides services in the form of such activities as exploration, development, and production and is paid a fee by the government that covers all the costs. In practice non risk service agreements are rare. Risk service contracts are much more common. In a risk service contract, the contractor bears all of the cost, and risks related to exploration, development and production activities. In return, if production is achieved, the contractor is allowed to recover his cost as production is sold. In addition, the government pays the contractor a fee for its “services”. The fee is typically based on production. The terms and features of the risk service contracts are similar to those appearing in production sharing contracts (PSCs), so therefore the accounting requirements are basically the same.

Illustration

Mobil Company enters into a risk service agreement with the Nigeria government. Mobil company pays the government in Naira, a ₦1,000,000 signing bonus and bears all of the costs associated with exploration, development, and production. The contract defines cost incurred in the exploration and development phase of each project area as being capital costs (CAPEX) and all costs incurred in the production phase as being operating costs (OPEX).

Each year in which production occurs the government agrees to pay Mobil Company a fee comprised of the following:

- All OPEX incurred in the current year.
- 1/10th of all un-recovered CAPEX.

- N 0.50 per barrel on production from 0 to 4000 barrels per day.
- N 0.75 per barrel on production from 4001 to 10000 barrels per day.
- N1.00 per barrel on production above 10000 barrels per day.

The maximum total fee that will be paid in any year is N1.35 per barrel times the total number of barrels produced. Any un-recovered OPEX or CAPEX (unrecovered due to the maximum fee) can be carried forward for future years. In 2012, production begins on field No. 1 to date Mobil Company has spent N10,000,000 on CAPEX and during 2012 spends N2,000,000 in OPEX. Production during 2012 equals 4,000,000 barrels or $4,000,000/365 = 10,959$ barrels per day.

Required: Determine the fee of Mobil Company for 2012.

Solution

The fee that Mobil Company would receive for 2012 would be determined as follows:

	N
OPEX	2,000,000
CAPEX N1,000,000/10	1,000,000
4,000 x 365 days x N0.50	730,000
6,000 x 365 days x N0.75	1,642,500
959 x 365 days x N1 (10,959 – 10,000)	<u>350,035</u>
	<u><u>5,722,535</u></u>

The total fee per barrel is computed as follows;

~~N~~5,722,535/4,000,000 barrels = ~~N~~1.4306 per barrel.

The N1.4306 fee per barrel is greater than the maximum of N1.35; therefore, the actual fee paid to Mobil Oil Company is;

$N1.35 \times 4,000,000 = \text{N}5,400,000$ The difference between the calculated of N5,722,535 and the maximum fee of N5,400,000 is N322,535 that is considered to be un-recovered CAPEX and is carried forward to the next year. Mobil Oil Company will also be liable for income tax on all oil and gas operation determined in accordance with the Nigerian Income Tax Laws.

10.05 Review Questions

- (1). What are the differences and similarities between Production Sharing Contract (PSCs) and risk service contract?
- (2). What are the various methods that governments utilize to generate revenues and other benefits from minerals resources?
- (3). Assume that Mobil oil, a U.S company, is involved in petroleum operations in Nigeria. Mobil oil has a 49% Working Interest (WI) while Pagih Oil Company has a 51% Working Interest (WI). Annual gross production is to split in the following order;
 - (a). Royalty is 15% of annual gross production and is to be paid in-kind.
 - (b). VAT is equal to 5% of annual gross production and is to be paid in-kind.
 - (c). Cost oil is limited to 50% of gross production with costs to be recovered in the following order:
 - I. Operating expenses paid 80% by Mobil company and 20% by Pagih oil company.
 - II. Exploration costs (paid entirely by Mobil company).
 - III. Development costs:- after completion of exploration Pagih oil company opted to participate at 20%; therefore, development and operating costs were paid 80% by Mobil Oil Company and 20% by Pagih Oil.
 - IV. Any excess remaining after cost recovery become profit oil: (1). 10% of profit oil goes to the government

The remainder is split between Mobil and Pagih Oil Company based on their Working Interest.

For 2013 assume that;

- Recoverable operating costs total N10,000,000
- Exploration costs un-recovered to date total N1,000,000,000
- Development costs uncovered to date N500,000,000
- The annual gross production for the years is 1,000,000,000 barrels of oil
- The agreed upon price is N250/barrel

Required: Allocate the production between parties.

MODULE 11

11.00 FINDING COSTS

11.01 Learning Outcomes

On successful completion of this Module, Students should be able to:

- i. Elucidate the concept of finding costs.
- ii. Compute finding costs.

11.02 Introduction

Finding cost is one of the most common, but difficult to define, performance measures used in evaluating oil and gas operations. Findings costs is the most frequently cited ratio utilized in evaluating the efficiency of a company in adding new reserves. The basic ratio consists of the finding costs of adding new reserves divided by the new reserves added. Finding costs are simply the costs incurred in finding any particular reserves within a specific period. For example, if the costs incurred were N5,000,000 and the reserves added were 500,000 barrels, then the finding cost would be N10 per barrel.

Finding costs attempt to establish a relationship between finding rate and the cost of finding. The physical measure of the productivity of exploration and development drilling i.e. oil Wells drilled and completed is matched with the total drilling expenditures and other exploration and development expenditures.

This module has been divided into two major parts. The first part deals with conceptual issues in relation to finding costs while the second part dwells on the theoretical and practical problems involved in the calculation of finding costs.

11.03 Meaning and Purpose of Finding Costs

Purpose of Finding Costs

The following are the purposes of finding costs:

- a) To determine oil price.
- b) To serve as an important indices for evaluating the exploration and drilling efficiency of a company.
- c) To help investors make investment decision.
- d) To evaluate returns on oil and gas investment.
- e) To help Government use funding costs to evolve and guide their oil and gas policy.

Critical variables in computing finding cost:

The difficulty with finding cost is not the calculation but determining the details to be included in the calculation. Although the calculation of finding costs is relatively simple, interpreting them and giving proper meaning to them can be a problem. Their interpretation in most cases can be misleading.

The variables range from the costs to be included (or excluded), the reserve data to be used, the impact of accounting methods to the timing difference between the accounting recognition of expenditure and reserves estimation. These factors include costs, reserve data, accounting method and time period.

- (a) **Costs:-** The costs that should be included in finding costs incurred can be difficult to determine whether acquisition costs, exploration costs, and or development costs. Where more than one exploration activities are carried on at the same time, deciding on the basis of allocation can be a little difficult.
- (b) **Reserve Data:-** The first question is deciding on the reserve data, which should be used in the calculation of finding cost-period reserves, probable, possible or potential reserves. Specific decisions have to be taken on whether the following reserves classification should be included in the reserve data;
 - Reserves added by discovery
 - Reserves added by revisions of prior year's estimate
 - Reserves added from new discoveries and extensions
 - Reserves added by enhanced recovery techniques
 - Reserves added by acquisition – proved reserves purchased in place.
 - What conversion factor is to be used to convert oil to gas and gas to oil.

Note here that reserves element is more complicated because it can be highly subjective, inaccurate and uncertain.

- (c) **Accounting Method:-** Oil and gas companies can adopt either the full cost method or the successful efforts method of accounting. These two methods are based on different assumptions and can produce different results even using the same financial data. The question that arises in calculating finding costs is whether measuring the impact using full cost or successful efforts method on the figures obtained.
- (d) **Time Period:-** The reconciliation of the time interval between the time exploration expenditures are incurred and when reserves are generated becomes difficult in most cases. Accounting reports are usually based on regular 12 months periods but reserves estimation is project oriented and do not occur in definite, regular time schedules.

Limitations in Calculating Finding Costs

The limitation inherent in calculating finding costs is that the expenditures and the reserves additions recognized in a particular time interval do not necessarily correspond with each other. For example, reserves added from a successful Well drilled late in this year might not be recognized in the company's account until the following year while the expenditures may be recognized this current year. Costs

incurred in the current year can produce reserves in much later years. The issue centre on:

- Whether the time period should be when the costs are incurred or reserves are added or when they are recorded or recognized in the books; and
- Whether to use the same period of time or differing time periods.

11.04 Problems in Calculating Finding Costs

- i. There is no consensus regarding which costs should be included as finding costs.
- ii. Companies use different methods of accounting for oil and gas exploration and development operations i.e. Full cost and successful efforts. Consequently, even if there were a specific definition of finding costs, the amounts would likely still differ since the various accounting methods treat the costs differently in terms of expenses and capitalization.
- iii. There is typically a timing difference between the period(s) when the finding costs were actually expended and when the new reserves are actually reported in the financial statements. The timing difference poses a difficulty in interpreting the finding costs.
- iv. There is some debate as to which reserve estimates should actually be used in the calculation. Two methods of accounting for exploration and development cost are currently accepted in practice, the successful efforts method and full cost method. In general, under the successful efforts method, Geological and Geophysical (G&G) exploration costs are written off as incurred. The costs of dry exploratory wells are written off when the determination is made that the Well is dry. The costs of successful exploratory wells and successful and dry development Wells are capitalized and amortized over production. Under full costs method all costs incurred in exploration, drilling and development are capitalized and harmonized. Clearly, any attempt to calculate finding costs for a sample of both full-cost and successful efforts companies would require a detailed evaluation of all of the reported costs to ensure that equivalent costs, whether expensed or capitalized are used.
- v. In computing finding costs, there should be correspondence or matching between the costs in the numerator and the reserves in the denominator. The difficulty is determining which reserves should be used to correspond to the costs in the numerator.
- vi. The finding cost for a company that is developing proved reserves or drilling development wells would be significantly lower than for a company engaged in an aggressive exploration. Comparisons between the two companies can be sometimes misleading.
- vii. Finding cost as a measure of operating efficiency does not reflect the quality of the reserves added. For example, a company may record a low finding cost but discovers sour or low quality oil or natural gas. High finding costs that find high quality reserves can result in better economics than low finding cost that finds low quality reserves.

Approaches to Calculating Finding Costs

The generic term “finding cost” has now been redefined with expenditures and reserves not directly related to or arising from exploration activity being excluded from finding cost.

The exclusion of development cost is based on the logic that finding costs per barrel is used to measure the exploration efficiency of a company. As development costs do not in any way affect exploration, there is no basis for including them. Proved property acquisition costs and reserves arising from them are excluded for a similar reason. Although purchased reserves, like discovered reserves added to the reserves base of the company, such additions are not as a result of any direct exploration effort by the company. The inclusion of the cost and reserves arising from purchases of proved reserves in place in calculating finding cost cannot be justified on these bases. Calculations that include purchased reserves should be more appropriately termed. “Replacement costs”.

Three related concepts have now arisen from the finding costs concept these are finding cost, finding and development costs and replacement costs.

1. **Finding Costs:-** Finding cost is the cost of unproved property acquisition and exploration divided by reserve additions and extensions.
2. **Finding and Development Costs:-** The total cost incurred for unproved property acquisitions, exploration and development divided by the reserves resulting from new additions, revisions of prior years, estimates and enhanced recovery techniques.
3. **Replacement Costs:-** When the portion of acquisition cost incurred to acquire proved reserves and the proved reserves acquired are included in the calculation, the ratio is now described as replacement cost. Replacement cost is the total unproved and proved leases, acquisition costs, explorations costs and development costs divided by the sum of proved reserve additions revisions, extensions and purchases in place.

The three concepts, finding costs, finding and development and replacement costs are expressed mathematically as follows:

1. Finding cost =
$$\frac{\text{Unproved leasehold cost} + \text{exploration costs}}{\text{Reserves additions and extensions}}$$
2. Finding and development cost =
$$\frac{\text{Unproved leased hold cost} + \text{exploration cost} + \text{development costs}}{\text{Reserves additions and extension} + \text{improved recovery} + \text{revisions}}$$
3. Replacement costs =
$$\frac{\text{Unproved lease hold cost} + \text{exploration cost} + \text{development cost} + \text{proved property acquisition}}{\text{Reserves additions and extension} + \text{improved recovery} + \text{revisions}}$$

Reserves additions and extensions + improved recovery + reserves + proved property acquisitions reserves.

If reserves added through extensions and discoveries are to be used then finding costs should be calculated as:-

Formula I:- Without Revisions

Finding Costs =
$$\frac{\text{Geological and geophysical costs + all exploratory drilling costs}}{\text{Reserves extensions and discoveries (excluding revisions)}}$$

Or

Formula I:- With Revisions

Find Costs =
$$\frac{\text{Geological and geophysical cost + all exploratory drilling costs}}{\text{Reserves extensions and discoveries (including revisions)}}$$

The next issue is whether to include reserves purchased in-place, proved properties must be included in the numerator so that cost and reserves correspond.

Formula II: Without Revisions

Finding Costs =
$$\frac{\text{Geological and geophysical cost + exploratory drilling costs + proved properties}}{\text{Reserves extensions and discoveries + purchased reserves in place}}$$

Or

Formula 2: With Revisions

Finding Costs =
$$\frac{\text{Geological and geophysical exploration cost + exploratory drilling costs + proved properties.}}{\text{Reserves extensions and discoveries + purchased reserves in place (including revisions)}}$$

Finally, sometimes finding costs is computed by attempting to include all costs, necessary to replace reserves.

Formula III: With Revisions

Finding Costs =
$$\frac{\text{Geological and geophysical cost + all exploratory and development drilling costs + proved and unproved properties acquisition costs}}{\text{All Reserves additions (including revisions)}}$$

11.05 Practical Problems in Finding Costs

Illustration I

The following results were computed using a five year period (2009-2013) Company

	Method A	Method B	Method C
	₦	₦	₦
Pagih Oil	6.59	3.20	6.15
Diato Oil	4.19	2.93	4.46
Dejo Oil	8.75	2.90	5.23
Oando Oil	5.58	3.27	6.69

Total Oil	4.53	3.18	9.27
Mobil Oil	2.68	2.38	5.68
Chevron Oil	5.97	2.34	3.54
Shell Oil	3.53	1.61	2.74
Adamu Oil	4.71	1.81	4.04
Asta Oil	2.04	1.93	4.43
Average	4.86	2.56	5.22

Illustration II

Using the reserves disclosure data presented below for mobile company calculate finding costs using the various formulae.

	2011	2012	2013
	N	N	N
Unproved property acquisition	25	45	80
Proved property acquisition	50	50	50
G & G	300	350	325
Exploratory drilling (including dry hole)	321	400	450
Development drilling	150	90	200
Revisions of previous estimate	60	130	221
Improved recovery	210	132	115
Purchase of reserves in place	50	15	10
Extensions and discoveries	53	73	65

Solution 2

Formula 1 without revisions:

$$\text{2011: } \frac{N300 + N321}{53} = N11.717$$

$$\text{2012: } \frac{N350 + N400}{73} = N10.274$$

$$\text{2013: } \frac{N325 + N450}{65} = N11.923$$

Formula 1 with revisions

$$\text{2011: } \frac{N300 + N321}{53+60} = N5.496$$

$$\text{2012: } \frac{N350 + N400}{73+130} = N3.695$$

$$\text{2013: } \frac{N325 + N450}{65+221} = N2.710$$

Formula 2 without revisions

$$\text{2011: } \frac{N300 + N321 + N50}{53+50} = N6.515$$

$$\text{2012: } \frac{N350 + N400 + N50}{73+15} = N9.091$$

$$\text{2013: } \frac{N325 + N450 + N50}{65+10} = N11.000$$

Formula 2 with revisions

$$\text{2011: } \frac{N300 + N321 + N50}{53+50+60} = N4.117$$

$$\text{2012: } \frac{N350 + N400 + N50}{73+15+130} = N3.670$$

$$\text{2013: } \frac{N325 + N450 + N50}{65+10+221} = N2.787$$

Formula 2 with revisions

$$\text{2011: } \frac{N300 + N321 + N150 + N50 + N25}{53+50+60+210} = N2.268$$

$$\text{2012: } \frac{N350 + N400 + N90 + N50 + N45}{73+15+130+132} = N2.671$$

$$\text{2013: } \frac{N325 + N450 + N200 + N50 + N80}{65+10+221+115} = N2.689$$

Illustration 3

Calculate average finding cost for three years for mobile oil company assuming the following:

	2011	2012	2013
	N	N	N
Development costs	20m	15m	25m
Production costs	2m	3m	5m
Exploration costs	10m	5m	15m
Proved property	5m	5m	5m
Unproved property acquisition	4m	4m	3m
Proved developed oil reserves	8mbbls	7mbbls	6mbbls
Proved oil reserves	10mbbls	9mbbls	6mbbls
Proved developed gas reserves	1.0bcf	1.0bcf	1.0bcf
Proved gas reserves	1.5bcf	1.5bcf	1.5bcf

Solution 3

	Nm	Nm	Nm
Finding Costs:			
Exploration Costs	10	5	15
Unproved property	<u>4</u>	<u>4</u>	<u>3</u>
	<u>14</u>	<u>9</u>	<u>18</u>
Proved reserves (bbls)			
Oil	10	9	6
Gas	<u>250</u>	<u>250</u>	<u>250</u>

Reserves “found”	<u>260</u>	<u>259</u>	<u>256</u>
Finding cost-yearly average (bbl)	0.05	0.03	0.07
Average finding cost = 0.05/bbl			

11.06. Review Questions

- How do you interpret finding cost ratio? Why are they so popular in financial statement analysis?
- What are the difficulties with computing and applying finding costs ratios
- Calculate average finding cost for three years for mobile oil company assuming the following:

	2011	2012	2013
	N	N	N
Development costs	30m	25m	35m
Production costs	3m	4m	6m
Exploration costs	20m	6m	25m
Proved property	6m	6m	6m
Unproved property acquisition	5m	5m	4m
Proved developed oil reserves	9mbbls	8mbbls	7mbbls
Proved oil reserves	20mbbls	10mbbls	7mbbls
Proved developed gas reserves	2.0bcf	2.0bcf	2.0bcf
Proved gas reserves	2.5bcf	2.5bcf	2.5bcf

MODULE 12

12.00 FINANCIAL STATEMENTS DISCLOSURES

12.01 LEARNING OUTCOMES

On successful completion of this Module, Students should be able to:

- i. Discuss and apply the method of Accounting for oil and gas.
- ii. Determine and apply capitalized costs.
- iii. Compute costs incurred and results of operations.
- iv. Explain reserve quantity information.
- v. Determine and apply standardized measures of discounting net cash flows.
- vi. Explain the disclosures specific to full cost companies.

12.02 Introduction

The oil and gas companies differs from other companies in one significant way, the most important economic assets, oil and gas reserves are not recorded in the statement of financial positions, but rather they are disclosed as foot notes to the financial statement. This posed a major challenge when trying to measure the performance of an organization by investors, analysts etc. in an attempt to make up for this limitation and meet the financial reporting requirements of investors, the Nigerian Accounting Standard Board and some other International Accounting Standard Boards, like the United Kingdom and United State of America Financial Accounting Standards Board issued some guidelines on disclosure requirement which are highlighted as follows and are considered to be supplementary information:-

- i. Method of accounting
- ii. Proved oil and gas reserves quantity
- iii. Capitalized costs relating to oil and gas producing activities
- iv. Cost incurred for property acquisitions, exploration and development activities.
- v. Results of operations for oil and gas producing activities
- vi. A standardized measure of discounted future net cash flows relating to proved oil and gas reserved quantities.

Broadly, the standard or disclosure rules apply to quote companies with significant oil and gas activities. A company is deemed to have significant oil and gas producing activities if it meets any or more of the following tests. The test shall be applied separately for each year of which a complete set of annual financial statements is presented.

- (a) Revenue from oil and gas producing activities, (including both sales to unaffiliated customers and sales or transfers to the enterprise's other operations), are 10 percent or more of the combined revenues of all of the enterprise's industry segments.
- (b) Results of operations for oil and gas producing activities, excluding the effect of income taxes, are 10 percent or more of the great of:

- i. The combined operating profit of all industry segments that did not incur an operating loss.
- ii. The combined operating loss of all industry segments that did incur an operating loss.
- (c) The identifiable assets of oil and gas producing activities (tangible and intangible enterprise assets that are used by oil and gas producing activities including an allocation portion of assets used jointly with other operations) are 10 percent or more of the assets of the enterprise, excluding assets used exclusively for general corporation purposes.

In this module, the general financial accounting disclosures for oil and gas activities will be discussed. First, the module begins with a discussion on the disclosure requirements that relate to method of accounting for oil and gas activities. The module then examined the accounting disclosure requirements in relation to proved oil and gas reserves quantity; capitalized costs in respect of oil and gas producing activities; cost incurred for property acquisitions, exploration and development activities; results of operations for oil and gas activities; standardized measure of discounted future net cash flows relating to prove oil and gas reserve quantities; and disclosures that are specific to full cost companies.

12.03 Method of Accounting

This is the section that oil and gas companies normally state whether they use successful effort or full cost method of accounting. In addition, the company's method of accounting for costs incurred and the manner of disposing of such costs is also dealt with in this section.

Proved Oil and Gas reserves Quality

This schedule provides information regarding quantities of companies' estimated proved and proved developed oil and gas reserves. Specifically, the purpose of the disclosure is to explain changes quantities of proved

Format: Reserve Quality information for the year Ended December 31....

T o t a l o i l A n d g a s	Uni ted Stat e stat e oil and gas	Foreig n geogra phic Area A Oil and gas	Foreig n geogra phic Area B Oil and gas	Other Foreign geograp hic Area A Oil and gas
--	---	---	---	--

Proved developed reserves:	X	X	X	X	X
Beginning of the year					
End of the year	X	X	X	X	X
Oil and Gas applicable to Long-term supply agreements with Governments or authorization which the enterprise acts as provider:					
Proved reserves – end of year	X	X	X	X	X
Reserved during the year	X	X	X	X	X
Enterprise's proportional Interest in reserves of investees accounted for by the equity Method					
End of year	<u>X</u>	<u>XX</u>	<u>XX</u>	<u>XX</u>	<u>XX</u>

Note: Oil reserves are stated in barrels; gas reserves stated in cubic feet.

Guidelines for disclosure of reserves quantity information:

Net quantities of an enterprise's interest in proved reserves and proved developed reserves of (a) crude oil (including condensate and natural gas liquids) and (b) natural gas shall be disclosed as of the beginning and the end of the year. "Net" Quantities of reserves include those relating to the enterprises' operating and non-operating interests in properties. Quantities of reserves relating to royalty interests owned shall be included in "Net" Quantities if the necessary information is available to the enterprise; if reserves relating to royalty interest owned are not included because of the information unavailability, the fact and the enterprise's share of oil and gas produced for those royalty interest shall be disclosed for the year. "Net" Quantities shall not include reserves relating to interest of others in properties owned by the enterprise. Changes in the net quantities of an enterprise's proved reserves of oil and gas during the year shall be disclosed. Changes resulting from each of the following shall be shown separately with appropriate explanation of significant changes.

- (a) **Revisions of Previous Estimates:-** Revisions represent changes in previous estimate of proved reserves, either upward or downward, resulting from new information (except for an increase in proved acreage) normally obtained from development drilling and production history or resulting from a change in economic factors.

- (b) **Improved Recovery:-** Changes in reserves estimate resulting from, application of improved recovery techniques shall be shown separately, if significant, if not significant, such changes shall be included in revisions of previous estimates.
- (c) Purchases of minerals in place
- (d) **Extensions and Discoveries:-** Additions to proved reserves that result from (1) extension of the proved acreage of previously discovered (old) reservoirs through additional drilling in periods subsequent to discovery and (2) discovery of new fields with proved reserves or of new reservoirs of proved reserves in old fields.
- (e) Production
- (f) Sales of minerals in place

If an enterprise's proved reserves of oil and gas are located entirely with its home country, that fact shall be disclosed. If some or all of its reserves are located in foreign countries, the disclosure of Net Qualities of reserves of oil and gas and changes in them shall be separately disclosed for (a) the enterprise's home country (if significant reserves are located there) and (b) each foreign geographic area in which significant reserves are located. Foreign geographic areas are individual countries or groups of countries as appropriate for meaningful disclosures in the circumstances.

Net Qualities disclosed in conformity with reserves located in foreign countries disclosure shall not include oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts, including such agreements with foreign governments or authorities. However, quantities of oil and gas subject to such agreement with foreign government or authorities as of the end of the year, and the net quantity of oil and gas received under the agreements during the year shall be separately disclosed if the enterprise participate in the operation of the properties in which the oil and gas is located or otherwise serves as the "producer" of those reserves, as opposed, for example to being an independent purchase, broker, dealer or importer.

In determining the reserve quantities to be disclosed, the following shall be considered:-

- (a). If the enterprise issues consolidated financial statement, 100 percent of the net reserve quantities attributable to the parent company and 100 percent of the net reserve quantities attributable to its consolidated subsidiaries (whether or not wholly owned) shall be included. If a significant portion of those reserve quantities at the end of the year is attributable to a consolidated subsidiary (ies) in which there is a significant minority interest, that fact and the approximate portion shall be disclosed.
- (b). If the enterprise's financial statement include investments that are proportionally consolidated, the enterprise's reserve quantities shall include its proportionate share of the investees net oil and gas reserves.

- (c). If the enterprise's financial statements include investments that are accounted for by the entity method, the investors net oil and gas reserves quantities shall not be disclosed. However, the enterprise's (investor's) shall of the investees' net oil and gas reserves shall be separately disclosed as of the end of the year.

12.04 Capitalized Costs

Total value of capitalized costs and their respective accumulated depreciation, depletion, and amortization, and valuation allowances, if significant shall be separately disclosed or included, as appropriate, with capitalized costs of proved and unproved properties. One purpose of this disclosure is to aid in the comparison of companies with both upstream and downstream operations to those of companies with solely upstream operations. This disclosure will be different depending on whether the company is a full cost company or successful efforts company.

Format

Capitalized Cost relating to oil and gas producing activities at December 31.....

Total

Unproved oil and gas properties		x
Proved oil and gas properties	<u>x</u>	
Accumulated depreciation, depletion and amortization and		
Valuation allowance	x	<u> </u>
Net capitalized costs	x	<u> </u>
Enterprise's share of equity method investees net		<u> </u>
Capitalized costs		<u> </u> <u> </u>

12.05 Costs Incurred for Property Acquisition, Exploration and Development Activities

This disclosure reports all of the property acquisition, exploration and development costs incurred during the current year regardless of whether the costs were capitalized or charged to expense. As a result this disclosure should be equivalent whether the company uses the successful efforts method or the full cost method and thus aids in the comparison of firms regardless of the method of accounting being used. Each of the following types of costs for the year shall be disclosed whether those costs are capitalized or charged to expenses at the time they are incurred.

- (a). Property acquisition costs
- (b). Exploration costs
- (c). Development costs

If significant costs have been incurred to acquire proved properties with proved reserves, those costs must be disclosed separately from the costs of acquiring unproved properties.

Format:**Cost incurred in Oil and Gas property Acquisition, Exploration and Development activities for the year ended December 31.....**

	T o t a l	Ni ge ri a	Foreig n Geogr aphic Area A	Foreig n Geogr aphic Area B	Other foreign Geogra phic Areas
Acquisition of properties					
○ Proved					
○ Unproved	X	X	X	X	X
Exploration cost	X	X	X	X	X
Development costs	X	X	X	X	X
Proportionate share of equity					
Method	X	X	X	X	X
Investees costs of property	X	X	X	X	X
Acquisition, exploration and development	X	X	X	X	X

12.06 Results of Operations

The disclosure of the results of operations for oil and gas producing activities is an income statement-type report that includes only the costs associated with upstream oil and gas exploration and production activities. As such, this disclosure should aid in the comparison of companies with only upstream activities to companies with both upstream and downstream activities. The report will differ depending on whether the company uses full cost or the successful effort method. The results of operations for oil and gas producing activities shall be disclosed for the year. That information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed. The following information relating to those activities shall be present;

- (a). Revenue
- (b). Production (lifting) cost
- (c). Exploration expenses
- (d). Depreciation, depletion and amortization and valuation provisions
- (e). Income tax expenses
- (f). Results of operations for oil and gas producing activities (excluding corporate overhead and interest costs).

Format: Results of operations for producing activities for the year ended December 31.....

	T o t a l	U n i t e d	Foreign Geograp hic Area A	Foreign Geogra phic Area B	Other foreign Geograp hic Areas
Revenue	X	X	X	X	X
Production costs	((x	(x)	(x)	(x)
Exploration cost	((x	(x)	(x)	(x)
Depreciation, depletion and Amortization and valuation provision	((x	(x)	(x)	(x)
Method	X	X	XX	XX	XX
Income tax expense	((x	(x)	(x)	(x)
Results of operations for producing Activities (excluding corporate Overhead and financing costs)	X	X	X	X	X
Enterprise's share of equity method Investees results of operations for producing activities (excluding corporate overhead and financing costs)	X	X	X	X	X

12.07 Standardized Measures of Discounted Future Net Cash Flows

A standardized measure of discounted future net cash flow relating to an enterprise's interest in (a) proved oil and gas reserves and (b) oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the participants in the operation of the properties on which the oil and gas is located or otherwise serves as the producer of those reserves shall be disclosed as of the end of the year. The standardized measure of discounted future net cash flows relating to those two types of interest in reserves may be combined for reporting purposes.

The following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed;

(a). Future Cash Inflow:- These shall be computed by applying year end prices of oil and gas relating to the enterprise proved reserves to the year end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.

(b). Future Development and Production Costs:- These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant; they shall be presented separately from estimated production costs.

(c). Future Income Tax Expenses:- These expenses shall be computed by applying the appropriate year-end statutory tax rate, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the enterprise's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to permanent differences and tax credit and allowances' relating to the enterprise's proved oil and gas reserves.

(d). Future Net Cash Flow:- These amounts are the results of subtracting future development and production costs and future income tax expenses from future cash inflows.

(e). Discount:- This amount shall be derived from using a discounted rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.

(f). Standardized Measure of Discounted Future Net Cash Flow:- This amount is the future net cash flows less the computed discount.

Format: Standardized Measure of Discounted Future Net Cash Flows

	T o t a l	U n i t e d	Foreign Geograp hic Area A	Foreign Geogra phic Area B	Other foreign Geograp hic Areas
Future Cash Inflows*			X	x	x
Future Production and Development costs*	(x	(x	(x)	(x)	(x)
Future income tax expenses	(x	(x	(x)	(x)	(x)
Future net cash flow	x	x	Xx	Xx	Xx
10% annual discount for estimated Timing of cash flow	x <u>X</u>	x <u>x</u>	 <u>X</u>	 <u>x</u>	 <u>x</u>

Standardized measure of discounted Future net cash flow		x	X	x	x
	x				
Enterprise's share of equity method					
Investees standardized measure of discounted future net cash	<u>x</u>	<u>x</u>	<u>X</u>	<u>x</u>	<u>x</u>

* Future net cash flow were computed using year-end price and costs, and year-end statutory tax rates (adjusted for permanent differences) that relates to existing proved oil and gas reserves in which the enterprise has mineral interests, including those mineral interests related to long-term supply agreements with governments for which the enterprise serves as the producer of the reserves. Including x attributable to a consolidated subsidiary in which there is an x-percent minority interest. **Changes in the standardized measure of discounted future net cash flows relating to proved oil and gas reserves Quantities**

The aggregate change in the standardized measures of discounted future net cash flows shall be disclosed for the year. If individually significant, the following sources of change shall be presented separately:

- (a). Net change in sales and transfer prices and in production (lifting) costs related to future production.
- (b). Changes in estimated future development costs
- (c). Sales and transfers of oil and gas produced during the period
- (d). Net change due to extensions, discoveries and improved recovery.
- (e). Net change due to purchases and sales of minerals in place.
- (f). Net change due to revisions in quantity estimates.
- (g). Previously estimated development costs incurred during the period.
- (h). Accretion of discount
- (i). Other – unspecified
- (j). Net changes in income tax.

In computing the amounts under each of the above categories, the effects of changes in prices and costs shall be compound before the effects of changes in Quantities. As a result, changes in Quantities shall be stated at year – end prices and costs. The change in computed income taxes shall reflect the effect of income taxes incurred during the period as well as the change in future income tax expenses. Therefore all changes except income taxes shall be reported pretax.

Format:**Year ended December 31.....**

	2011	2012	
	2013		
Sales and transfers of oil and gas			
Produced net of production costs	(x)	(x)	
(x)			
Development costs incurred during the year	(x)	(x)	
(x)			
Extensions, discoveries and improved			
Recovery, less related costs	x	x	x
Net changes in price and production costs	x	x	x
Revisions of previous reserves estimates	x	x	x
Net changes in taxation	x	x	x
Future development costs	x	x	x
Net changes in purchase and sales of reserves In - place	x	x	x
Additional 10% annual discount	<u>x</u>	<u>x</u>	<u>x</u>
Total change in the standardized measure during the year	<u>xx</u>	<u>xx</u>	<u>xx</u>

12.08 Disclosures Specific to Full Cost Companies

The full cost companies specifically make the following disclosures;

- (a). For each cost centre for each year that an income statement is required, disclose the total amount of amortization expenses (per equivalent physical unit of production if amortizations computed on the basis of physical units or per dollars of gross revenue).
- (b). State separately on the face of the balance sheet the aggregate of the capitalized costs of unproved properties and major development projects that are excluded from the capitalized costs being amortized..
- (c). Provide a description in the note to the financial statements of the current status of the significant properties or projects involved, including the anticipated timing of the inclusion of the costs in the amortization computation.
- (d). Present a table that shows, by category of cost (a) the total costs excluded as of the most recent fiscal year; and (b) the amount of such excluded costs incurred (1) in each of the three most recent fiscal years and (2) in the aggregate for any earlier fiscal years in which the costs were incurred.
- (e). Categories costs in case of significant development projects and capitalized interest.

12.09 Review Questions

1. Discuss the methods of Accounting for oil and gas.
2. Explain reserve quantity information.
3. Enumerate the standardized measures of discounting net cash flows.
4. Highlight the disclosures specific to full cost companies.

MODULE 13

13.00 ACCOUNTING FOR REFINING AND PETROCHEMICAL OPERATION

13.01 Learning Outcomes

On successful completion of this Module, Students should be able to:

- i. Explain petroleum refining process
- ii. Apply accounting principles for refinery operations
- iii. Explain the accounting process for petrochemicals operations
- iv. Determine and apply their financial statement disclosures

13.02 Introduction

The activities in the oil and gas industries are divided into two main categories, namely upstream and downstream.

Upstream activities comprise the exploration for and discoveries of hydrocarbons; crude oil and natural gas. They also include the development of these hydrocarbons reserves and resources and their subsequent extraction or production. Downstream activities in the oil and gas industry include the transportation of crude oil and gas, the refining of crude oil and the sales of the refined products. Crude oil is liquid petroleum after being produced but before being refined. Crude oil is the major raw materials of a refinery, a mixture of organic chemical compounds made up of hydrogen and carbon in various proportions called hydrocarbons.

The refining and petrochemical operations are twin activities found in the upstream activities of the oil and gas industry.

This module has been divided into four parts. The first part of the module describes the various processes of refining petroleum. The second and third parts of the module explain the accounting treatment of refinery, and petrochemical operations respectively. The last part discusses the financial statement disclosures relating to refining and petrochemical operations.

13.03 Petroleum Refining Processes

Refining is the process of producing fuels, lubricants, greases and road surfacing materials with the emphasis on fuels.

Basically it involves vapourizing crude oil by heating it to high temperature, collecting the resulting gases and condensing them back to a liquid state. Crude oil refining comprises of a series of interrelated processes, all involving heating, and each producing several products. Some of these products can be put to end use without further processing while others have to undergo considerable post-

production refining, further cracking, reforming, synthesis and molecular arrangement.

The unique feature of oil refining at all its stages is its flexibility. Crude oil distillation units are designed to cope with a variety of crude and to tailor the yields, within limits, in response to market demands.

Basically, refining processes are grouped into four:

- i. Primary process or physical separation process.
- ii. Secondary or conversion process
- iii. Treating processes
- iv. Blending

Primary Process or Physical Separation: The principle underlying this process is the fact that different liquids vapourize at different temperatures (called boiling points).

The separation of low and high boiling points materials in this way is called fractional distillation (fractionation) and the distillation column in this context is called a fractionation column.

The process is accomplished by running the crude oil through a number of pipes lining a brick furnace. The crude oil is heated to a temperature of approximately 800°F after which it rises to the top of the furnace as vapour and is then transferred to the fractionation tower. The different boiling points give a distillation curve and are peculiar to particular types of crude. The two temperatures between which hydrocarbons boil are called cut points and those in the same cut points are called factions. The points at which they start to boil are called Initial Boiling Point (IBP) and where they stop boiling is called End Boiling Point (EBP) at the EBP, the product would have been completely vapourized.

Crude oil distillation normally has two stages fractionating towers namely; atmospheric tower and vacuum towers.

Atmosphere Tower: This is where the initial distillation of crude oil is conducted. The fractions produced from this atmospheric tower can either be used in their new state or blended with other substances or further processed to make useful products. The maximum temperature at which hydrocarbons can be separated in the atmospheric tower is 900°F.

Vacuum Tower: This operates at less than atmospheric pressure heated hydrocarbons of 900°F and above, and piped from the atmospheric tower to vacuum tower. Steam keeps the oil hot and low pressure allows the hydrocarbons to vapourize at temperature below their cracking points enabling them to be separated into fractions. The light and heavy gas oils are separated from the

heaviest residue called bottoms. The vacuum distillation process is otherwise known as flashing and it enables more gasoline to be obtained from the residue.

The major products in order to increase boiling range are as follows:

- **Fuel Gas:** To refinery fuel gas – below 100°F.
- **Light Straight Run Gasoline:** To sweetening and then to gasoline blending (Boiling range 100°F – 200°F).
- **Heavy Straight:** Run gasoline to hydrogenation, to catalytic reforming and then to gasoline blending (Boiling range 200°F – 400°F).
- **Middle Distillates:** To kerosene, jet fuel, furnace oils, diesel fuels (Boiling range 350°F – 600°F).
- **Catalytic Cracking Charge:** To fluid catalytic unit charge (Boiling range 450°F – 750°F).
- **Fuel Residue:** Vacuum distillation unit (Boiling range about 700°F).

The primary process separates the various fractions, which may serve as inputs for the secondary process. These inputs are otherwise known as “changing stocks”. The term “changing stock” refers to unfinished products that are to be further processed in some secondary refining operation. The secondary processes either result in new products or bring primary products to required quality standards.

- **Secondary or Conversion Processing:** In the secondary processing, units are designed so that feedstock and operating conditions can be varied. Such a high degree of flexibility inevitably leads to considerable complexity in refining process or operations. The net result is that there is no unique manufacturing route to any single finished product. Secondary or conversion processing consists of cracking and non-cracking processes.
- **Treating Process:** The sulphur, which is present in varying degrees in all crude oil, distributed throughout the range of straight-run distillation cuts. De-sulphurization is the generic name given to those processes used to remove or reduce the sulphur that is present in varying degrees in petroleum products. The type of process varies with the product being treated.

Processes that improve the smell only are known as sweetening processes, whereas those that actually remove sulphur compound are called de-sulphurization process. There is a tendency for sulphur compounds to increase in complexity in the higher boiling ranges, and the type of the process required therefore varies according to the fraction being treated.

- **Blending:** Most finished products are not single substances but are blends of several compounds. The final stage of refining therefore is an integral part of the whole processes that involves the selective mixing of basic components to give a wide range of individual grades of the same product.

ACCOUNTING FOR REFINERY OPERATIONS

Accounting for refinery operations begins with the costs incurred from the receipts of crude oil, to the costs incurred in various refining processes, the cost of additives, investments in plant machinery and other operating costs. The accounting treatment of cost incurred in a refinery operatives are discussed below as follows:

Basis of Capitalization:

Costs incurred in improving performance of refining plants or machinery are capitalized while cost incurred in improving the revenue bases of the refined products is expensed with.

Crude Oil Purchasing and Exchanges:

Exchange of crude oil between refining company, due to mismatch should be recorded in a temporary memorandum books; crude oil purchase are recorded as cost of sales while sales of crude oil recorded as income.

Transfer Pricing:

Refinery is an integral part of a whole company, it follows that there could be inter-departmental transfer of crude oil. Therefore determination should be in respect of transfer prices of crude oil from upstream activities division of the company or subsidiaries of the company and transfer price of gasoline and other products of the refinery.

Processing of Crude Oil:

Where the refinery receives crude for processing on behalf of third parties, only memorandum records are to be kept to control the quantity. The consideration received in form of processing fees should however be treated as a deduction from operating costs.

Cost of Catalysts:

The accounting treatment of the cost of acquisition of expense catalysts in refinery operations is to capitalize the costs of the initial supply and depreciate them in accordance with normal accounting practices. The cost of reprocessing and replenishing them is however charged to the operations of the period.

Cost of Periodic Turn-around Maintenance:

Costs incurred in the periodic maintenance of the refinery are initially capitalized. A provision for turn-around costs is then made by a monthly charge to operating expenses.

Depreciation:

Depreciation is calculated on a straight line basis for the whole refinery plant. Total sum of the depreciation is distributed to production and other units on the basis of investments in the units.

Stand by Equipments:

Refineries have a considerable investment in standby equipment which may be used in case of emergencies or when production operations increase. There are many ways of treating depreciation on these equipments. The most acceptable way of treating depreciation is to make periodic provision for standby wear and tear (depreciation) of standby equipments and excludes them from the composite depreciation base.

Inventory Valuation:

In accordance with normal accounting practice, inventories are valued at lower of cost or net realizable value. Unrealized profit must be eliminated.

Sales of Refined Products:

Sales of refined products include transfers to other divisions at appropriate transfer prices and sales to outsiders.

Sundry Income:

Outright crude oil sales and other incomes are included in Sundry income.

Cost Classification and Allocation:

Costs generally are classified by object and function.

Costs are classified by object based on the object itself e.g. salaries, wages, transportation etc. while cost classified by functions are based on areas of managerial responsibilities, except cost of crude oil that are changed to purchases and eventual transfer to manufacturing account as cost of production.

Under allocation cost, total production cost must be determined and spread over unit produced in order to determine unit production costs and selling prices. Costs of service units must be spread over production units before unit production costs are determined. Costs also have to be allocated to joint products.

Service Department Cost Allocation:

Three methods are used to allocate service department costs to production costs and subsequently to production units. They are;

- Direct method
- Step method
- Simultaneous method

Illustration 1

The following data were extracted from the cost records of ANAN Offshore Refinery Company Limited for the month of July 2014.

Department Receiving Services	Original cost	% of Service Rendered		
		Maintenance	Power	Stea
Distillation	5	30	1	3
Cracking	1	25	2	3
Treatment	1	20	2	1
Maintenance	8	-	20	1
Power	4	10	-	0
Steam	1	15	2	-
	9	100%	10	1

Required: Assume no other costs are incurred; allocate the service department costs over the producing departments of ANAN Offshore Refinery Company using the Direct Method.

Solution

Allocation of Costs using Direct Method: Workings:

Distillation

Total % of Maintenance = 30% + 25% + 20% = 75%

Maintenance Cost = N80

Therefore allocation as follows:

$$\begin{array}{lcl}
 \text{Maintenance: } \frac{30}{75} \times 80 = & & 32 \\
 \text{Power: } \frac{25}{75} \times 80 = & & 26.67 \\
 \text{Steam: } \frac{20}{75} \times 80 = & & 21.33 \\
 & & \underline{80.00}
 \end{array}$$

Cracking

Total % of Maintenance = 15% + 20% + 25% = 60%

Power cost = N40

Therefore, allocation as follows;

$$\begin{array}{lcl}
 \text{Maintenance: } \frac{15}{60} \times 40 = & & 10 \\
 \text{Power: } \frac{20}{60} \times 40 = & & 13.33 \\
 \text{Steam: } \frac{25}{60} \times 40 = & & 16.67 \\
 & & \underline{40.00}
 \end{array}$$

Treatment

Total % of steam 30% + 35% + 15% = 80%

Maintenance: $\frac{30}{80} \times 10 = 3.75$

Power: $\frac{35}{80} \times 10 = 4.38$

Steam: $\frac{15}{80} \times 10 = 1.87$

10.00

	Distillation N	Cracking N	Treatment N	Total N
Direct Costs	500	150	120	770
Allocation of Costs: Maintenance	32	10	3.75	45.75
Power	26.67	13.33	4.38	44.38
Steam	21.33	16.67	1.87	39.87
				900

Allocation of Cost to Joint Products

Another task of allocating costs is the allocation of costs to joint products. The following methods are available:

- Physical method
- Market method

- **Physical Method**

This method allocates joint costs to the joint products based upon some physical basis such as:

- Number of units of each product
- Quantity (weight or volume) of each product
- Combination of these factors

In most cases, these physical methods do not reflect the difficulty in processing or the type and amount of labour input required for them. A variation of the physical method that takes care of this deficiency is the barrel gravity method. The method uses API gravity, which is a measure of product weight

$$\text{API} = \frac{141.5 - 131.5}{\text{Specific gravity (in grams)}}$$

Specific gravity is the weight of an object in relation to one gram of water

$$\text{Specific Gravity} = \frac{\text{Total barrel gravity of product in inventory} \times \text{Total Cost of Product}}{\text{The barrel gravity of total production}}$$

- **Market Methods**

This method allocates joint costs to joint products based on their relative market values at the split-off point.

Relative Sales Value Method:

Here, joint costs are allocated on the base of sales value or net realizable value of the products.

Illustration 2

The total production costs incurred by ANAN Refinery Company limited for the year ended 31st December 2013 amounted to N5,000,000. The total market value of the product refined along with the market value of each unit of product and volume of each are as follows:

Product	Volume	Market Value
Gasoline	6,000,000	8,000,000
Dual Purpose Kerosene (DPK)	900,000	850,000
High Pour Fuel Oil (HPFO)	600,000	400,000
Low Pour Fuel Oil (LPFO)	500,000	200,000
	8,000,000	9,450,000

Required: Determine allocation of the production costs to the product using

(a). Physical Method (b). Market Method

Solution 2

(a). Allocation of costs using physical method

Product	Volume allocation (litres)	%	Cost allocation	Cost per unit ₦
Gasoline	6,000,000	75	3,750,000	0.625
Dual Purpose Kerosene (DPK)	900,000	11.25	562,500	0.625
High Pour Fuel Oil (HPFO)	600,000	7.5	375,000	0.625
Low Pour Fuel Oil (LPFO)	500,000	6.25	312,500	0.625
Total	8,000,000	100	5,000,000	

(b). Allocation of costs using market method

Product	Volume allocation (litres)	Market Value N	Market value per unit N	Cost alloc. N	Unit Cost N
Gasoline	6,000,000	8,000,000	1.33	4,232,805	0.705
Dual Purpose Kerosene (DPK)	900,000	850,000	0.94	449,735	0.500
High Pour Fuel Oil (HPFO)	600,000	400,000	0.67	211,640	0.353
Low Pour Fuel Oil (LPFO)	500,000	200,000	0.40	105,820	0.212
Total	8,000,000	9,450,000		5,000,000	

Workings:**(a). Ratios for physical method**

Gasoline =	$\frac{6,000,000}{8,000,000}$	= 0.75
DPK =	$\frac{9,000,000}{8,000,000}$	= 0.1125
HPFO =	$\frac{600,000}{8,000,000}$	= 0.0750
LPFO =	$\frac{500,000}{8,000,000}$	= 0.0625

Allocation - Total cost (5000000)

$0.75 \times 5,000,000 = 3,750,000$
$0.1125 \times 5,000,000 = 562,5000$
$0.0750 \times 5,000,000 = 375,000$
$0.0625 \times 5,000,000 = 312,500$

(b). Market Value/Unit

Gasoline =	$\frac{8,000,000}{6,000,000}$	= 1.33
DPK =	$\frac{850,000}{900,000}$	= 0.94
HPFO =	$\frac{400,000}{600,000}$	= 0.67
LPFO =	$\frac{200,000}{500,000}$	= 0.40

Cost/Unit

$\frac{4,232,805}{6,000,000}$	=	0.705
$\frac{449,735}{900,000}$	=	0.500
$\frac{211,640}{600,000}$	=	0.353
$\frac{105,820}{500,000}$	=	0.212

13.04 Petrochemicals

Petrochemical is a chemical substance produced commercially from, feedstock derived from crude oil or natural gas. Petrochemical plants are usually integral part of large refining complexes and often subsidiaries of major oil companies. Petrochemical function is to turn outputs of the refining process either in form

of crude oil fraction or their crack and or processed derivatives into feedstock that will ultimately be used in the manufacturing of host of other product e.g. plastics and detergents.

Classification of Petrochemicals:

Three main classes of petrochemicals are as follows;

- (a). Aliphatic compounds
- (b). Aromatic compounds
- (c). Inorganic compounds

- (a). **Aliphatic Compounds:-** These are straight chain hydrocarbons saturated (paraffin) or unsaturated (olefin) with hydrogen. They are produced from thermal and hydro cracking process. Products of aliphatic compounds are plastics, solvent etc.
- (b). **Aromatic Compounds:-** These are unsaturated hydrocarbons with six carbon atoms in a ring. Major aromatic feed stock includes benzene, toluene and the xylene. Aromatic compounds are used to make plastic, resins etc.
- (c). **Inorganic Compounds:-** These substances do not contain carbon compounds and are produced from non-hydrocarbon sources. They include carbon black, sulphur and ammonia. They are used in the manufacture of synthetic rubbers, printing ink, paints, acid, fertilizers etc.

Petrochemical Manufacturing Processes

Petrochemical manufacturing processes involve;

- (a). **Ammonia Synthesis:-** The feedstock is natural gas (methane) or any other hydrocarbon. The major outputs of this process are different types of fertilizers.
- (b). **Polyethylene Production:-** The feedstock is ethylene and the major output of this process is plastics.
- (c). **Phthalic Anhydride Production:-** The feedstock used is orthoxylene or naphthalene and the major outputs are plastics, insecticides.
- (d). **Sulphur Recovery:-** The feedstock is natural gas, refinery gas containing at least two percent of hydrogen sulphide.

Petrochemical Plant Units

There are basically two petrochemical plant units namely: Olefin units and polymer units.

- (a). **Olefin Units:-** It provides ethylene and propylene for use in polymer units.
- (b). **Polymer Units:-** These units combine propylene and ethylene into large molecules to make polypropylene and polyethylene.

13.05 Accounting for Petrochemical Operations

Accounting for petrochemical activities operates in the same manner as that of refinery operations. Petrochemical activities can be done separately or jointly with refinery operations to the extent of sharing common administration, general services and utilities. The accounting treatments of various aspects of accounting for petrochemical operations are discussed below;

- (1) **Purchase of Feedstock:** This can be purchased internally or by other companies. Two set of books are maintained. One for those purchased internally and another for those obtained from outsiders.
- (2) **Depreciation:** This is done on straight line basis which is the same with accounting for refinery operation.
- (3) **Research and Development:** The provision of IAS 9 regarding whether these expenditure are to be capitalized or charged to the operations at the period in which the expenditure was incurred is particularly applicable here, IAS 9 states “development costs of a project may be deferred to the future periods if the following conditions are satisfied”:
 - (a). The product or process is clearly defined and the costs attributable to the product or process can be separately identified.
 - (b). The technical feasibility of the product or process has been demonstrated.
 - (c). The management of the enterprise has indicated its intention to produce and market, or use, the product or process.
 - (d). There is a clear indication of a future market for the product or process or, if it is to be used internally rather than sold, its usefulness to the enterprise can be demonstrated, and
 - (e). Adequate resources exists, or are reasonably expected to be available, to complete the project or market the product or process.
- (4). **Standby Equipment:** They are specialized equipments and are depreciated in accordance with normal accounting principles.
- (5). **Allocation of Operating Costs:** Separate cost allocation is made for each product and its related by-products. Process cost accounting methods are easily applicable in the petrochemical industry.
- (6). **Allocation of Costs to Joint Products:** Cumulative costs of joint products are allocated between products on a relative sales value basis.
- (7). **Work in Progress:** Work in Progress value is assumed to be zero
- (8). **Valuation of Production Inventories:** Perpetual and periodic inventory records are maintained for productions inventory. Intra- company profits must be eliminated from inventory.
- (9). **Sales of Petrochemical Product:** Sales are based on cost or market price. Sales include transfer to other departments and sales to outsiders.

13.06 Financial Statements Disclosures

In line with SAS 17, paragraph 55 issued by the defunct Nigerian Accounting Standards Board, refining and petrochemical companies should disclose the following as they relate to their activities;

- Processing fees from third parties
- Any amount of turnaround maintenance capitalized and or expensed split into material costs or labour costs, and where capitalized, the rate amortization.
- The cost of research and development
- For an integrated plant, revenue earned for each class of activities.
- Basis of valuation of product and intermediates.
- De-bottlenecking, major plant rehabilitation and replacement of major components cost incurred, capitalized or expensed and where capitalized, the rate of amortization.

All companies engaged in downstream operation should disclose the following;

- **Packaging and non-core business:-** SAS 17, paragraph 56 prescribes that operating results of packaging and other non-core businesses owned by companies operating in the downstream sector of the petroleum industry should separately be disclosed.
- **Transfer Pricing:-** SAS 17, paragraph 57 prescribed that transfer pricing methods adopted should be disclosed.

13.07 Review Questions

(1) The following data were extracted from the cost records of ANAN Offshore Refinery Company Limited for the month of July 2014.

Department Receiving Services	Original Cost	% of Service Rendered		
		N	Maintenance	Power Steam
Distillation	1,000	15	30	30
Cracking	300	20	35	25
Treatment	240	25	15	20
Maintenance	160	-	15	15
Power	80	20	-	10
Steam	20	20	05	-
	1,800	100%	100%	100%

Required: Assume no other costs are incurred, allocate the service department costs over the producing departments of ANAN Offshore Refinery Company using:

- (a) The Direct Method
- (b) The Step Method

(2). The total production costs incurred by ANAN Refinery Company limited for the year ended 31st December 2013 amounted to N10,000,000. The total market value of the product refined along with the market value of each unit of product and volume of each are as follows:

Product	Volume (Litres)	Market Value N
Gasoline	12,000,000	16,000,000
Dual Purpose Kerosene (DPK)	1,800,000	1,700,000
High Pour Fuel Oil (HPFO)	1,200,000	800,000
Low Pour Fuel Oil (LPFO)	1,000,000	400,000
	<u>16,000,000</u>	<u>18,900,000</u>

Required: Determine allocation of the production costs to the product using

- (a). Physical Method
- (b). Market Method

RECOMMENDED FURTHER READINGS

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