ECONOMIC EVALUATION OF UNDERGROUND NATURAL GAS STORAGE IN A DEPLETED RESERVOIR IN NIGER DELTA

BY

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CERTIFICATION

This is to certify that this thesis titled, "**Economic Evaluation of Underground Natural Gas Storage in a Depleted Reservoir in Niger Delta**" was carried out by PRINCE MORRIS UDOH with registration number: **FUTO O5/M.TECH/PET/008** in partial fulfillment of the requirements for the award of Master of Technology (M.Tech) in Petroleum Engineering, Federal University of Technology, Owerri.

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DEDICATION

This Research project is dedicated to the Almighty God, my family members, Living Faith Church members (Winners Chapel), Ibeno, Akwa Ibom State, friends and especially to my immediate family Mrs. Juliana P. Udoh, Emmanuel P. Morris, Mary P. Morris, Joseph P. Morris, Ini-abasi P. Morris, my mother Mrs. Comfort M. Udoh and my brothers and sisters.

God bless you all.

PRINCE MORRIS UDOH

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My lovely wife and children are not left behind as they have been the backbone for the success of this work.

This acknowledgement would not be complete if I fail to recognize the expertise of the typist who worked so hard to put this work in one piece.

I also thank everyone that might have contributed in different ways to the success of this work but have not been remembered in this acknowledgement page, it doesn’t mean their influence has been forgotten. May the Almighty God continue to bless and replenish them in all their endeavours.

ABSTRACT

The economic viability of underground natural gas storage in depleted oil reservoir was examined with a depleted oil reservoir located in Niger Delta, Nigeria. The geological information and the production history of the reservoir were gathered, which aided in the computations made. This project took an in-depth look into the economic implications of sub-surface natural gas storage in depleted oil or gas reservoirs, water aquifers and salt caverns. The cost and resultant benefits derivable from the installation and operating the gas discovered to be encouraging. It helps to achieve the target flare out in out oil and gas field and also attract some revenue for the country. From the analysis performed, the total investment cost of the project was got as $96.5million, the gross revenue which was based on the price of natural gas was got as $90.5million. The net present value at a discount rate of 10% was $422million, the internal rate of return was estimated as 79.1% while the pay-out and break-even points stood at 1.14years and $96.5million. The results of the estimated properties and economic analysis show that the reservoir is a good candidate for conversion into storage reservoir.
Keywords: Depleted, oil, natural gas, reservoir, storage, underground, economics, pressure, pay-out, net present value, internal rate of return, break-even.

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CHAPTER ONE

INTRODUCTION

1.1 GENERAL STUDY

The hydrocarbons comprising natural gas range from the most volatile paraffin or alkane compound (such as methane, CH_4, which boils at 258 ^oF or – 161.5^oC) all the way to nonvolatile asphaltic compounds, which are present in road oils. The more volatile constituents are mostly from the alkane family, but naphthenic and aromatic hydrocarbons occur in natural liquids are crude oils. There are also non-hydrocarbons present in natural gas, including nitrogen (N_2), carbon dioxide (CO_2), hydrogen sulfide (H_2S), helium (He), and water vapor. When H_2S exceeds 0.25 grains (1 grain = 0.06479g; 11b = 700 grains) per 100 cubic feet, the gas is considered to be sour, otherwise it is sweet gas.

Natural gases are composed primarily of methane with varying amounts of ethane, propane and butanes. The work of kay made possible the use of the theorem of corresponding states for mixtures in the place of the critical pressures and temperatures used for pure compound. These molal-average properties are called the pseudocritial temperatures for mixtures, and they may be used like true critical for purposes corresponding states.

The pseudocritical point has no physical significance, but it approximates the point of convergence of constant volume lines (isochors) on a pressure-temperature diagram.

Burning of natural gas, compares with other fossil fuels, produces much less carbon dioxide (SO_2), less nitrogen (NOx), and virtually no sulfur dioxide SO_2). Furthermore, it produces neither dust nor soot. Modern gas-fired plant efficiency is in excess of 50%. These considerably reduces the energy consumption, and energy efficiency, gas is likely to become increasingly important in the energy market.

Since 1975, gas has been the primary energy source with the strongest with 3.2% a year on average. All forecast scenarios call for this trend to continue for the next 20 years. This progress will in particular be spurred by strong growth in gas-fired power production. Level of proven gas reserves is comparable to that of the oil reserves. As gas will undoubtedly take on an increasing share in the world wide energy supply. At this current consumption rate, these reserves will cover demand for more than a half century into the future.

Whereas more than 60% of oil reserves are concentrated in the middle East, gas reserves are more evenly distributed, with one-third in Russia (and central-Asia), one-third in the middle East, and the remainder elsewhere. However, the biggest gas reserves are remote from the major consumption areas. To commercialize them, it is necessary to find the right solutions, on a case-by-case basis, to develop, transport, market and even process the gas.

Natural gas, like most other commodities, can be stored for an indefinite period of time. The exploration, production, and transportation of natural gas takes time, and the natural gas that reaches it destination is not always needed right away, so it is injected into underground storage facilities. These storage facilities can be located near market centers that do not have a ready supply of locally produced natural gas.

Traditionally, natural gas has been a seasonal fuel, that is, demand for natural gas is usually higher during the winter, partly because it is used for heat in residential and commercial settings. Stored natural gas plays a vital role in ensuring that any excess supply delivered during the summer months is available to meet the increased demand of the winter months. However, with the recent trend towards natural gas fired electric generation, demand for natural gas during the summer months is now increasing (due to the electricity to power air conditioners and the like). Natural gas in storage also serves as insurance against any unforeseen accidents, natural disasters, or other occurrences that may affect the production or delivery of natural gas. Natural gas is one of the cleanest, and most important of all energy sources. Around three quarters of the natural gas deposit is found separate from crude oil or non-associated gas. The rest is found in association with crude oil or associated gas (Natural Gas Supply Association, 2004).

Wells drilled specifically for natural gas production are referred to as natural gas wells. The composition of these wells contains little or no oil. There are three main types of conventional natural gas wells. (Ikoku, 1984). They are:

(i) Associated gas well in which oil and gas exist,

(ii) Non-associated or dedicated gas well which is drilled specifically for natural gas and contains little or no oil,

(iii) Condensate wells which are wells that contain natural gas, as well as liquid condensate. This condensate is a liquid hydrocarbon mixture that is often separated from the natural gas either at the wellhead, or during the processing of the natural gas. Depending on the type of well-being drilled, completion may differ slightly based on the circumstances associated with the well. Natural gas, being lighter than air, will naturally rise to the surface of a well.

1.2 STORAGE OF NATURAL GAS

Natural gas storage plays a vital role in maintaining the reliability of supply needed to meet the demands of consumers. Historically, when natural gas was a regulated commodity, storage was part of the bundled product sold by the pipelines to distribution utilities.

Storage used to serve, only as a buffer between transportation and distribution, to ensure adequate supplies of natural gas were in place for seasonal demand shifts, and unexpected demand surges. Now, in addition to serving those purposes, natural gas storage is also used by industry participants for commercial reasons; storing gas when prices are low, and withdrawing and selling it when prices are high, for instance. The purpose and use of storage has been closely linked to the regulatory environment of the time.

There are basically two uses for natural gas in storage facilities: meeting base load requirements, and meeting peak load requirements. As mentioned, natural gas storage is required for two reasons: meeting seasonal demand requirements, and as insurance against unforeseen supply disruptions. Base load storage capacity is used to meet seasonal demand increases. Base load facilities are capable of holding enough natural gas to satisfy long term seasonal demand requirements. Typically, the turn-over rate for natural gas in these facilities is a year; natural gas is generally injected during the summer (non-heating season), which usually runs from April through October, and withdrawn during the winter (heating season)), usually from November to March. These reservoirs are larger, but their delivery rates are relatively low, meaning the natural gas that can be extracted each day is limited. Instead, these facilities provide a prolonged, steady supply of natural gas. Depleted gas reservoirs are the most common type of base load storage facility.

Peak load storage facilities, on the other hand, are designed to have high-deliverability for short periods of time, meaning natural gas can be withdraw from storage quickly should the need arise. Peak load facilities are intended to meet sudden, short-term demand increases.

These facilities cannot hold as much natural gas as base load facilities; however, they can deliver smaller amounts of gas more quickly, and can also be replenished in a shorter amount of time, than base load facilities. While base load facilities have long term injection and withdrawal seasons, turning over the natural gas in the facility about once per year, peak load facilities can have turnover rates as short as a few days or weeks. Salt caverns are the most common type of peak load storage facility, although aquifers may be used to meet these demands as well.

Natural gas is usually stored underground, in large storage reservoirs. There are three main types of underground storage: depleted gas reservoirs, aquifers, and salt caverns. In addition to underground storage, however, natural gas can be stored as liquefied natural gas (LNG). LNG allows natural as to be shipped arid stored in liquid form, meaning it takes up much less space than gaseous natural gas.

1.3 TYPES OF UNDERGROUND STORAGE

Underground natural gas storage fields grew in popularity shortly after World War II. At the time, the natural gas industry noted that seasonal demand increases could not feasibly be met by pipeline delivery alone. In order to meet seasonal demand increases, the deliverability of pipelines (and thus their size), would have to increase dramatically. However, the technology required to construct such large pipelines to consuming regions was, at the time, unattainable and unfeasible. In order to be able to meet seasonal demand increases, underground storage fields were the only option.

As mentioned, there are three main types of underground natural gas storage facilities, depleted reservoirs, aquifers, and salt caverns. Essentially, any underground storage facility is reconditioned before injection, to create a sort of storage vessel underground. Natural gas is injected into the formation, building up pressure as more natural gas is added. In this sense, the underground formation becomes a sort of pressurized natural gas container. As with newly drilled wells, the higher the pressure in the storage facility, the more readily gas may be extracted. Once the pressure drops to below that of the wellhead, there is no pressure differential left to push the natural gas out of the storage facility. This means that, in any underground storage facility, there is a certain amount of gas that may never be extracted. This is known as physically unrecoverable gas; it is permanently embedded in the formation.

In addition to this physically unrecoverable gas, underground storage facilities contain what is known as 'base gas' or 'cushion gas'. This is the volume of gas that must remain in the storage facility to provide the required pressurization to extract the remaining gas. In the normal operation of the storage facility, this cushion gas remains underground; however a portion of it may be extracted using specialized compression equipment at the wellhead.

'Working gas' is the volume of natural gas in the storage reservoir that can extract during the normal operation of the storage facility. This is the natural gas that is being stored and withdraw; the capacity of storage facility. This is the natural gas that is being stored and withdrawn; the capacity of storage facilities normally refers to their working gas capacity. At the beginning of a withdrawal cycle, the pressure inside the storage facility is at its highest; meaning working gas can be withdrawn at a high rate.

As the volume of gas inside the storage facility drops, pressure (and thus deliverability in the storage facility also decreases. Periodically, underground storage facility operators may reclassify portions of working gas as base gas after evaluating the operation of their facilities. There are typically three (3) major types of underground natural gas storage as shown in Fig. 1.1 below. They are:

- Depleted reservoirs in oil or gas fields
- Aquifers
- Salt cavern formations

Each of these types possesses distinct physical and economic characteristics which govern the suitability of a particular type of storage type for a given application.

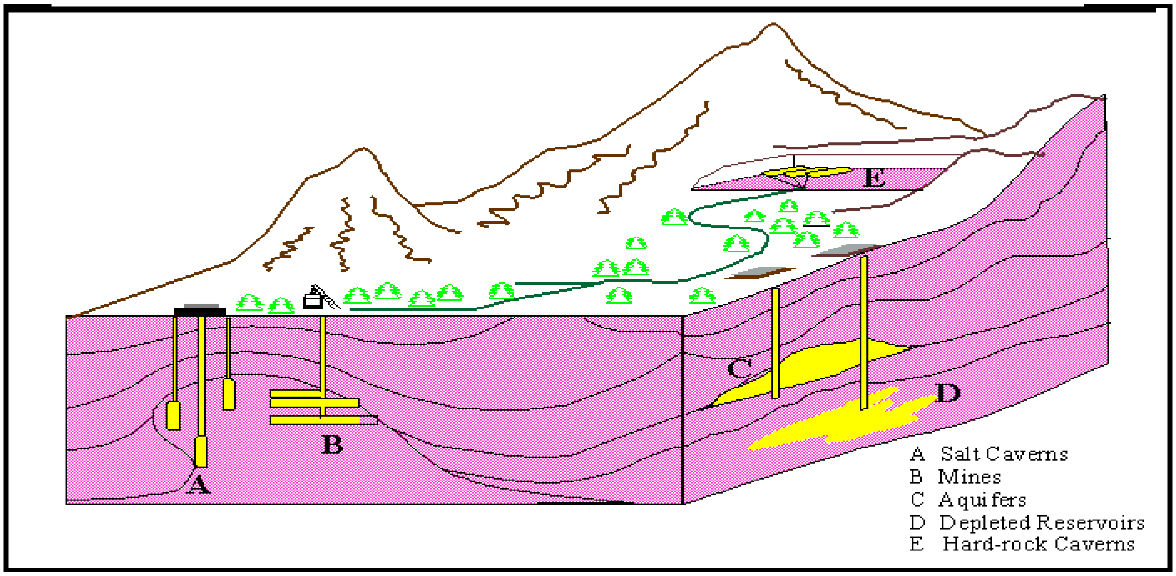


Fig. 1.1: Underground Storage of Natural Gas (A) salt formations, (B) mines (C) aquifer reservoirs (D) depleted reservoirs (E) hard-rock caverns. Source: (United States Department of Energy, 2005).

1.3.1 Depleted Gas Reservoirs

The most prominent and common form of underground storage consists of depleted gas reservoirs. Depleted reservoirs are those formations that have ready been tapped of all their recoverable natural gas. This leaves an underground formation, geologically capable of holding natural gas. In addition, using an already developed reservoir for storage purposes allows the use of the extraction and distribution equipment left over from when the field was productive. Having this extraction network in place reduces the cost of converting a depleted reservoir into a storage facility. Depleted reservoirs are also attractive because their geological characteristics are already well known. Of the three types of underground storage, depleted reservoirs, on average, are the cheapest and easiest to develop, operate, and maintain.

The factors that determine whether or not a depleted reservoir will make a suitable storage facility are both geographic and geologic. Geographically, depleted reservoirs must be relatively close to consuming regions. There must also be close to transportation infrastructure, including trunk pipelines and distribution systems.

Geologically, depleted reservoir formations must have high permeability and porosity. The porosity of the formation determines the amount of natural gas that it may hold, while its permeability determines the rate at which natural gas flows through the formation, which in turn determines the rate of injection and withdrawal of working gas. In certain instances, the formation may be stimulated to increase permeability.

In order to maintain pressure in depleted reservoirs, about 50 percent of the natural gas in the formation must be dept as cushion gas. However, depleted reservoirs, having already been filled with natural gas and hydrocarbons, do not require the injection of what will become physically unrecoverable gas; that gas already exists in the formation. Gas storage in oil reservoir has benefits over storage in other types of enclosures. Gas can be safely stored to pressures at least as high as the initial reservoir pressure without possible leaks (Tek, 1987).

Advantages associated with Depleted reservoirs:

* Typically, they are near existing regional pipeline infrastructure.

* The fields already have a number of useable wells and field gathering facilities.

* The geology is well known. These fields have previously trapped hydrocarbons which minimizes the risk of reservoir “leaks”.

Disadvantages associated with Depleted reservoirs:

* Because of the nature of the reservoir producing mechanisms, working gas volumes are usually cycled only once per season (extremely high deliverability storage reservoirs are the exceptions).

* Often, these reservoirs are old and require a substantial amount of well maintenance and monitoring to ensure working gas is not being lost via well leaks into other permeable reservoirs.

1.3.2 AQUIFERS

Aquifers are underground porous, permeable rock formations that act as natural water reservoirs. However, in certain situations, these water containing formations may be reconditioned and used as natural gas storage facilities. As they are more expensive to develop than depleted reservoirs, these types of storage facilities are usually used only in areas where there are no nearby depleted reservoirs. Traditionally, these facilities are operated with a single winter withdrawal period, although they may be used to meet peak load requirements as well.

Aquifers are the least desirable and most expensive type of natural gas storage facility for a number of reasons. First, the geological characteristics of aquifer formations are not as thoroughly known, as with depleted reservoirs. A significant amount of time and money goes into discovering the geological characteristics of an aquifer, and determining its suitability as a natural gas storage facility. Seismic testing must be performed, much like is done for the exploration of potential natural gas formations. The area of the formation, the composition and porosity of the formation itself, and the existing formation pressure must all be discovered prior to development of the formation. In addition, the capacity of the reservoir is unknown, and may only be determined once the formation is further developed.

While it is possible to extract cushion gas from depleted reservoirs, doing so from aquifer formations could have negative effects, including formation damage. As such, most of the cushion gas that is injected into any one aquifer formation may remain unrecoverable, even after the storage facility is shut down. Most aquifer storage facilities were developed when the price of natural gas was low, meaning this cushion gas was not very expensive to give up. However, with higher prices, aquifer formations are increasingly expensive to develop. The following requirements must be met for a properly designed aquifer storage; (Katz and Tek, 1980).

- The layer of the water bearing rock should be large enough to accommodate the injected gas.
- The rock should have the porosity that enables water to be forced out by the gas at a reasonable pressure. Also, the rate at which gas can be withdrawn should be reasonable.
- The structure of the reservoir should preferably be dome shaped, and the aquifer should be closed on all sides.
- There should be a suitable layer of completely impermeable rock above the aquifer layer.
- The aquifer should be situated in continuous, unfaulted layer of rock.

Advantage of Aquifer storage reservoirs include:-

* Typically, close to end user market.

* High deliverability from the combination of high quality reservoirs, plus water drive during the withdrawal cycle.

* The high deliverability increase the ability to cycle the working gas volumes more than once per season.

Disadvantages include:-

* A high level of geological risk. These reservoirs have not previously trapped hydrocarbons and as a result, there is a degree of uncertainty concerning the ability to contain injected base and working gas. The risk for substantial reservoir leaks exists.

* Because these reservoirs produce via water drive, water production is often experienced during the withdrawal cycle, increasing operating costs.

* Due to the water drive mechanism during the withdrawal cycle, the base gas requirements are high (80%). A large percentage of base gas is not recoverable after site abandonment. This high base gas requirement likely limits the number of new aquifer storage projects (increases the initial capital cost).

1.3.3 SALT CAVERNS

Underground salt formations offer another option for natural gas storage. These formations are well suited to natural gas storage in that salt caverns, once formed, allow little injected natural gas to escape from the formation unless specifically extracted. The walls of a salt cavern also have the structural strength of steel, which makes it very resilient against reservoir degradation over the life of the storage facility.

Essentially, salt caverns are formed out of existing salt deposits. These underground salt deposits may exist in two possible forms: salt domes, salt beds. Salt domes are thick formations created from natural salt deposits at, over time; leach up through overlying sedimentary layers to form large dome-type structures. They can be as large as a mile in diameter, and 30,000 feet in height. Typically, salt domes used for natural gas storage are between 6,000 and 1,500 feet beneath the surface, although in certain circumstances they can dome much closer to the surface. Salt beds are shallower, thinner formations. These formations are usually no more than 1,000 feet in eight. Because salt beds are wide, thin formations, once a salt cavern is introduced, they are more prone to deterioration, and may also be more expensive to develop than salt domes.

Once a suitable salt dome or salt bed deposit is discovered, and deemed suitable for natural gas storage, it is necessary to develop a 'salt cavern' within the formation. Essentially, this consists of using water to dissolve and extract a certain amount of salt from the drilling a well down into the formation, and cycling large amounts of water through the completed well. This water will dissolve some of the salt in the deposit, and be cycled back up the well, leaving a large empty space that the salt used to occupy. This process is known as 'salt cavern leaching'.

Salt cavern leaching is used to create caverns in both types of salt deposits, and can be quite expensive. However, once created, a salt cavern offers an underground natural gas storage vessel with very high deliverability. In addition, cushion gas requirements are the lowest of all three storage types, with salt caverns only requiring about 33 percent of total gas capacity to be used as cushion gas.

As such, salt caverns cannot hold the volume of gas necessary to meet base load storage requirements. However, deliverability from salt caverns is typically much higher than for either aquifers or depleted reservoirs. Therefore natural gas stored in a salt cavern may be more readily (and quickly) withdrawn, and caverns may be replenished with natural gas more quickly than in either the other types of storage facilities. Moreover, salt caverns can readily begin flowing gas on a little as one hour’s notice, which is useful in emergency situations or during unexpected short term demand surges. Salt caverns may also be replenished more quickly than other types of underground storage facilities. When creating caverns in salt layers, fracturing may be employed to facilitate the cavern construction. Two or more wells may be sunk and connected by fracturing. The bed may then be washed out to provide a large storage area. Fracturing probably cannot be used in salt domes because the general homogeneity of physical properties may not lend itself to controlled horizontal fracturing (Katz et al, 1959).

Advantages of salt cavern storage includes:

- Low base gas requirements of 25%, which can approach 0% in emergencies.
- Ultra-high deliverability (much higher than depleted reservoir and aquifer storage).
- Operating flexibility as those reservoirs can cycle working gas four to five times a year. Their location in the gulf coast allows daily production and nightly injection to help meet peaking natural gas demand during the summer air conditioning season.
- Salt cavern provide excellent seals (i.e. the salt cavern wells are essentially impermeable barriers) and the risk of reservoir gas leaks is small.

Disadvantages include:-

- Typically, located in the south, far away from the winter heating market.
- Costly initial startup 9 disposal of the saturated salt water generated during the solution mining process can be costly and environmentally problematic).

1.4 NATURAL GAS EXPLORATION AND PRODUCTION IN NIGERIA

Natural gas is a major source of energy and Nigeria's gas reserves are estimated at up to ten times as large as its crude oil reserves. Nigeria contains an estimated 124 trillion cubic feet (Tcf) of proven natural gas reserves (10^{th} largest in the world) with upside estimates of associated and non-associated gas being as high as 300 Tcf. Associate gas production is concentrated on fields located onshore and in swampy areas of the Niger River Delta.

1.4.1 Natural Gas Produced in Association with Crude Oil

Nigeria is presently regarded as the 7^{th} most endowed gas nation in the world, with a gas reserve in excess of 165 trillion standard cubic feet (Tcf) and 6^{th} oil producing country in the world. Regrettably however the bulk of these gas resources produced in association with crude oil is flared (Agbor and Onukwu, 2011). The non-associated segment is also relatively undeveloped and unexplored. From this scenario, Nigeria has the unsavory record of being the world leader in gas flaring, with about 25 percent of world's flares amounting to 2 billion scf/d emanating from Nigeria producing fields. A study by the World Bank in 1994 put the total emission of carbon dioxide from gas flaring in the country at an estimated 35 million tons, resulting in more than 12 million tons of methane being released into the atmosphere of the Niger delta. Comparatively, Nigeria's flaring figures are higher than all the other ten OPEC member countries put together. It is instructive that as far back as 1992, some OPEC nations such as Qatar, UAE, Kuwait and Iraq have achieved zero percent flaring, while Great Britain flares 4 percent and Netherlands flare zero percent of its associated gas (Garba, 2007).

Gas flaring is a major contributor to environmental pollution and degradation including global warming.

When utilized as an energy source for industrial, power generation, commercial and residential usages and purposes, natural gas is a relatively benign energy form: clean, non-particulate, non-sulphuric, cheap and environmentally friendly. For instance when burned, natural gas is reputed to emit 45 percent less CO_2 than crude oil on an energy equivalent basis (Anyadiegwu, 2012).

Nigeria, which previously flared over 70 percent of produced gas as at 1996, now flares about 52 percent. Flaring gained ascendancy in Nigeria's oil and gas industry because since 1958 when crude oil production alongside associated gas commenced, most of the producing firms have no local or international market for gas. Earlier attempts by Shell in 1963 to sell gas to industries in Port-Harcourt and Aba and then later to the Afam

Power Plant constituted the most glaring initial attempts then. The failed 1969 take off of the Nigeria Liquefied Natural Gas project also contributed to the growth of flaring and non-monetization of produced gas. Besides, the lack of a definite policy as well as legislation on gas, its development and utilization further worsened matters. The major legislation on gas that tended to set the tone for flare out was the 1979 Associated Gas Re-injection Decree and its 1984, 85,90,94 and 98 amendments (Anyadiegwu, 2012).

1.5 NATURAL GAS UTILIZATION OPTIONS IN NIGERIA

Around 3,000 million standard cubic feet of gas is produced annually. Due to a lack of gas utilization infrastructure; Nigeria flares 75% of the gas it produces and re-injects 12% to enhance oil recovery. Although high, this is significantly below the over 98% flared in 1971. Nigeria has set the year 2010 as its target for achieving flare out of natural gas.

With the aim of increasing gas utilization, the NNPC set up a company, the Nigerian Gas Company Ltd in 1988, with the specific task of developing, harnessing and marketing natural gas from the domestic market. A number of projects are being developed to increase the utilization of gas and to reduce gas flaring, in 1999, the Nigerian government set in place incentives to make the utilization of gas more attractive and to check the waste in the

Nigerian gas sector through flaring. The incentives will include approval of alternative funding for gas projects, a comprehensive energy policy and tax concessions. Other incentives promised to investors in the gas sector were a higher capital allowance, investment tax credits and lower royalty in comparison with oil as well as effective monitoring of oil companies' promised to eliminate gas flaring in the country by 2010.

As a result of these directive and incentives, together with mounting pressure by environmentalists, all the major oil producing companies are executing projects aimed at substantially reducing the amount of gas flared in the course of their operations. Several of the oil JVs have plans for using the gas currently flared and are committed towards utilizing 100% of associated gas for commercial or productive purpose by end of 2010.

The Nigeria Gas Company (NGC) has in place more than 1,000 km of pipeline with seven gas systems and fourteen compressor stations. About 75% of NGC's sales are to four thermal power stations run by the Nigerian Electric Power Authority. The major internationals have set up a number of gas projects.

The most ambitious of these is the **Bonny Island LNG facility** which is estimated to cost $3.8 billion. Nigeria Liquefied National Gas Corporation (NLNG) comprised of the NNPC (49%), Shell (25%) and Agip (10.4%) is developing the, project. Initially the facility will be supplied from dedicated gas fields but NLNG intends to use at least 50% associated gas which currently flared.

The first exports of gas from the facility began in October 1999, with the first shipments to Spain, Italy and Turkey, under long term purchase agreements.

Main Predate of Nat Gas Processing and Their Uses

Product	**Uses**	**Mixtures**
Methanes	Burners, Fuel	-
Ethane	Feedstock for Petrochemicals, Fuel	
Propane	Feedstock, Fuel, Refrigerant	E – P mix
Butane	Fuel; blend with motor spirit (Petrol)	
Pentane	Blend with Motor Spirit and heavier and crude oil	

Debutanized Natural Gasoline components

Ethane - prepare combination is called E.P mixture. Propane – Butane combination is called LPG mixture Pentane + heavier component, = Debutanized Natural Gasoline

1. Production – Processing Schemed

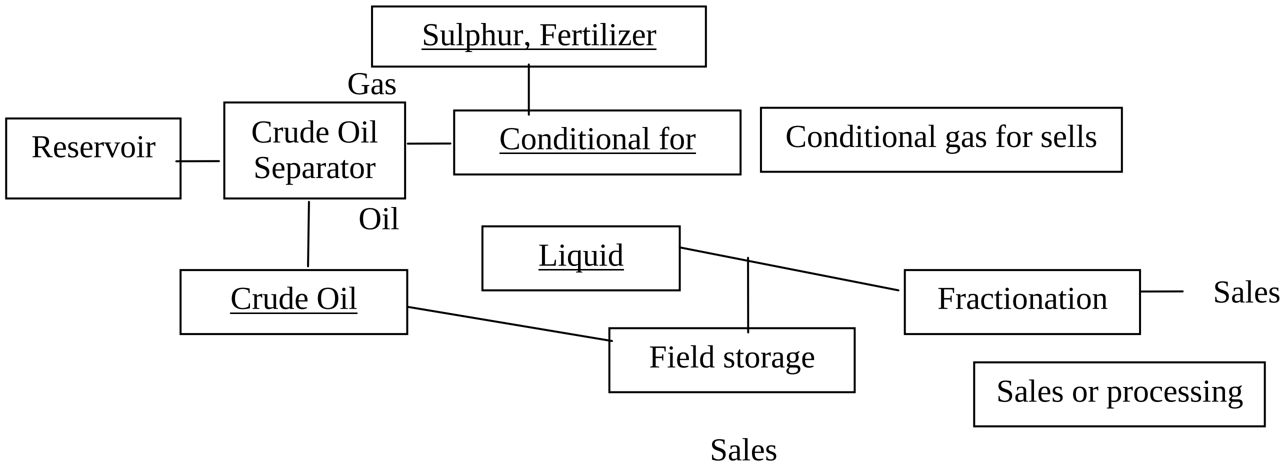


Fig 1.2: Schematic of Production Processing

2. Schematic View of the Present Production Processing Scheme in Nigeria

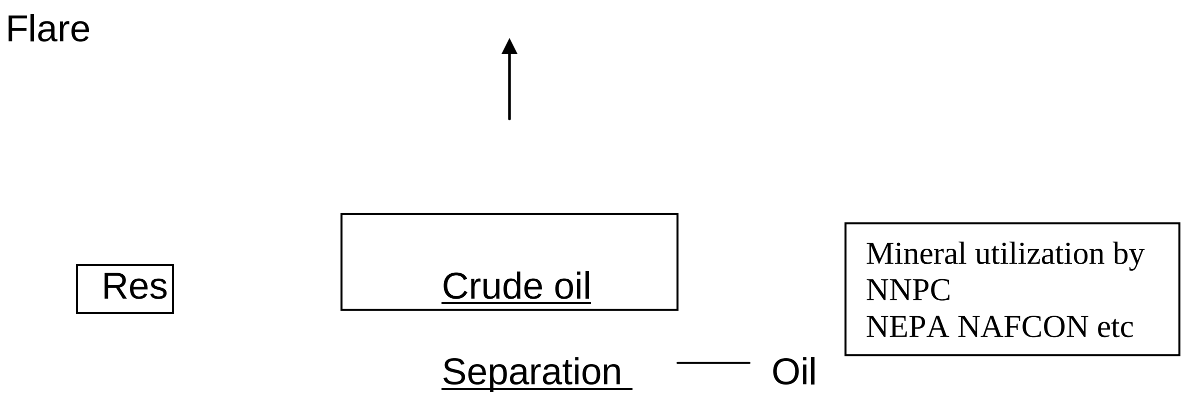


Fig 1.3: Schematic of Present Production Processing Scheme in Nigeria

Fig 1.2 is a fairly competed step for handling natural gas. It encompasses all systems used and each of the rectangles shown reps a calculated module. Within this module is a body of equations and practice which enables one to design it subject to imposed constants. Some major modules have no of sub-modules representing component parts that involve some unique and /or separation operator. For example, the liq. Recovery module may be sub-divided as shown.

3. Refrigeration system

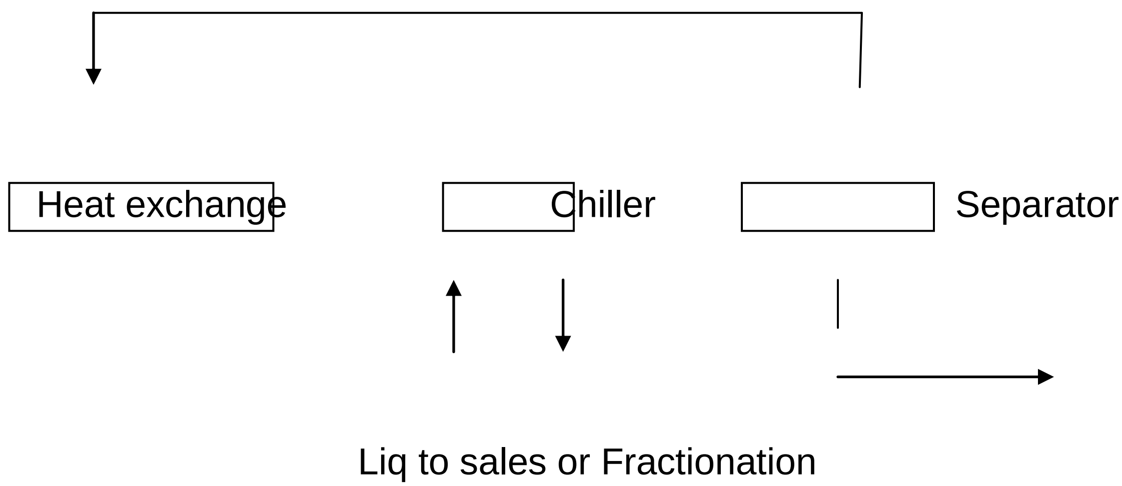


Fig 1.4: The Refrigeration System

Fig 1.4 represents the simplest form of refrigerate system consisting of a well stream exchanger refrigeration chiller and a separation.

The methods used to treat return gas depend on the types of compounds present. A gas with low hydrogen sulphide, H_2S and carbondioxide Co_2 needs little or no treatment, except to adjust the water content. If the gas is dry but sour, it is necessary to remove the Hydrogen sulphide H_2S and carbondioxide CO_2.

1.6 PRESENT NATURAL GAS DISTRIBUTION STATISTICS

A company in the front line of gas utilization in the downstream sector, Gas link Nigeria, has disclosed that customers receiving natural gas from its facilities have increased from 10 to 18 in the last 5 years with a consumption of 5.6 mm cfpd. When the company had only 10 customers receiving natural gas from the company's facilities, average consumption stood at 3 mm cfpd.

The company has also set machinery in motion for the supply of natural gas to Benin city, the Edo state capital, where companies like Guinness, Coca Cola, Bendel Breweries among others, also have indicated their interest.

The number of companies that have expressed commitment for used of natural gas through the signing of a gas sales and purchase agreement (GSPA), has also increased from 21 to 35 within the last one year.

1.7 SCOPE OF STUDY

This research attempts to evaluate the impact of natural gas in the economy of the nation. Nigeria is more or less a gas zone; we have more of gas than oil. Presently, the natural gas associated with production is flared and very little are liquefied and transported. Emphasis would be made on the effect of storage of natural instead of flaring. It will also proffer a better storage facility or method with respect to the prevailing factors. As the 2010 deadline set by the government for zero flaring approaches, underground storage of natural gas could prove to be a great boost to the actualization of this target.

1.8 STATEMENT OF PROBLEMS

The following research problems have been identified in order to direct the study effectively:

- The 2010 target of government to flare out
- Instability of production costs
- Instability of natural gas market prices
- Inequality of demand with supply.
- Improper budgeting

1.9 RESEARCH OBJECTIVES

The objectives of this study include:

- To proffer to meet up with the 2010 deadline for flare out
- Stabilizing of market prices of natural gas
- Marching demand with supply of natural gas
- Attracting revenue for the country
- Enable the operator in the sector to know the ideal cost and type of storage system to suite a particular field.

1.10 METHODOLOGY

The approach to this work is purely analytical. The existing types of storage system will be analyzed and assign cost at different stages of the installation assumptions are to be made during the allocation of cost which if totaled at the end, gives the cost of operating a storage system.

CHAPTER TWO

LITERATURE REVIEW

2.1 OVERVIEW

According to Damrongkijkosol (2006), natural gas was first used as fuel in China during the time of Shu Han Dynasty {A.D. 221 to 263}; the gas was obtained from shallow wells near sea pages, aid distributed located locally through piping made of hollowed-out bamboos. Systematic usage of natural gas was not recorded until the early 17th century, when it provided lighting and heating on a small scale in northern Italy. Natural gas was discovered in New York State in 1821 and oil in Pennsylvania in 1859 {associated reservoir}. The associated gas produced with oil was generally flared. Infact, the development of natural gas industry in United States had to awake the inception of pipeline because reliable pipelines were required to transport the associated gas being produced in increasing volumes with crude oil to areas where it could profitably be used. The early history of natural gas was therefore very largely the history of natural gas in North America (Tiratsoo, 1979).

Natural gas just before the World War II was regarded as a waste/unwanted by-product of crude oil. But due to technological advancement, the uses and need of it has grown so much that it becomes necessary to store it in order to cushion the effect of high seasonal demand. Historical records show that gas storage began by allowing depleted gas reservoir produced in the winter to be recharged in summer by pipeline gas (Katz and Tek 1981).

The first recorded underground gas storage opened in 1915, in Wetland County, Ontario, Canada. In 1956 the four near buffalo, New York, became the first storage project in USA and continue to operate today (Grow, 1970). These projects injected gas produce elsewhere into depleted hydrocarbon reservoir in the summer, and produce the gas for use in winter. In 1916, Deutshe Erdoel AG received a German patent on the solution mining of salt cavities for storing crude oil and distilled (Natural Gas Supply Association, 2004). In 1981, Katz and Tek developed gas reserves as to collect the associated gas which was largely flared and remain one of most difficult and expensive gas to harness. They adopted a system by compressing and treating the gas in purpose-built facilities before it can be used.

Underground storage is usually a good means of meeting peak demands, but it must have a suitable underground structure close to the point of consumption if it is to be an economic proposition (Ikoku, 1984).

2.2 THE NEED FOR GAS STORAGE

Gas storage primarily is used to handle the increased fuel need for space heating in cold weather. It levels the load for the pipeline carrying gas from supply – often a distance of over 1000 miles (1600km) to the market area. For example, offshore gas field in Louisiana supply pipelines to the Detroit area in Michigan. Many gas suppliers now could not provide the fluctuation in gas flow rate needed in winter even if the pipelines could carry the varying load (Katz and Lee, 1976).

Natural gas prices rose dramatically in 2000 and have remained high through the first part of 2001. High prices have raised concerns about the longer term prospects for natural gas prices and their potential impact on consumers and on economic growth. Exacerbating those concerns are the current low level of natural gas supply in storage.

Natural gas represented 24 percent of the energy consumed and 27 percent of the energy produced in the Unites States in 2000. The industrial sector was the largest user of natural gas for cogeneration of electric power and as an industrial feedstock. In additional, natural gas is the largest energy source consumed in the residential sector and the fastest growing energy source for electricity generation.

In recent months, the high prices of natural gas used in the industrial, residential and commercial, and electricity generation sectors have caused exceptional public concern about the present and future operations of the natural gas industry and markets. The recent high prices have also prompted some policymakers to question whether natural gas can play a dominant role in fueling U.S economic growth in the next 20 years.

High natural gas prices, experienced in 2000 and expected to persist at least through 2001 and 2002, were caused by constrained domestic productive capacity that resulted from a sustained period of relatively low oil and natural gas prices, followed by unusually high demand-the result of strong economic growth and an unusually warm summer and cold winter-and a poor storage position heading into the winter season (November 2000 through February 2001).

Low oil and natural gas prices for most of the decade before 2000 contributed to the limited natural gas productive capacity going into 2000. Annual average wellhead natural gas prices (in 1999 dollars) hovered between $1.61 per million Btu ($1.65 per thousand cubic feet) and $2.32 per million Btu ($2.38 per thousand cubic feet) through all of the 1990s, while crude oil prices (the composite refiners’ acquisition cost) ranged from $12.69 to $22.37 per barrel (excluding 1990) (US EIA, 1999).

Oil and gas investments in exploration and production from 1990 through 1996 annually averaged $15 billion in real 1999 dollars, as compared with investments in excess of $30 billion annually (in 1999 dollars) before 1986. From 1986 to 1995, the average return on investment for major oil and gas companies4 ranged from 5.5 percent to 7.3 percent, except for 1990 when the return jumped to 9.5 percent as oil prices rose during the Persian Gulf War. These returns to investment were under the range of 10.4 to 19.2 percent received between 1977 and 1985.

In 1996 and 1997, rising natural gas prices increased investment return to over 10 percent, but in 1998, when natural gas prices fell below $2 per million Btu and oil prices were the lowest they had been in 25 years (in real terms), returns fell to over 10 percent, but in 1998, when natural gas prices fell below $2 per million Btu and oil prices were the lowest they had been in 25 years (in real terms), returns fell to 3.9 percent. Profits and returns on investments were considerably higher in 2000 as a result of the high oil and gas prices, and some of those revenues have been used to increase exploratory and developmental drilling. With the decline in industry investment and drilling during the 1990s, proved natural gas reserves declined from 169 trillion cubic feet at the end of 1990 to 164 trillion cubic feet at the start of 1999. More importantly drilling levels were not sufficient to develop these reserves into increased productive capacity.

Except for 1994, when domestic production increased by 0.72 trillion cubic feet, in response to the higher demand and higher wellhead prices. While this increase was sufficient to meet the major portion of demand growth seen in 2000, a large net drawdown of gas in storage and an increase in imports were also required to meet the remaining demand.

Sustained prices of about $2.25 per million Btu from 1994 to 1999 may have stimulated additional drilling and somewhat mitigated the tightened supply response that led to the jump in sport prices in 2000. for example, in 1996 natural gas prices rose by $0.60 to $2.21 per million Btu and the number of wells drilled increased by more than 10 percent over their 1995 level, and in 1997 prices rose by an additional $0.11 to $2.32 per million Btu and the number of wells increased by 26 percent above 1996.2 Gas drilling declined precipitously in 1991 and 1992, in 1994 and 1995, and again in 1999 as a result of relatively low prices, setting the stage for the tight supply situation that developed in 2000.

Natural gas consumption increased by about 1 trillion cubic feet in 2000 because of strong economic growth and higher heating and cooling loads served by natural gas. As compared with 1.7 – percent average annual growth in demand for natural gas from 1990 to 1999, demand jumped by 4.8 percent in 2000. more importantly, there was virtually no growth in gas consumption between 1996 and 1999, due in part to mild weather. Stronger demand was already evident in the spring, when natural gas demand would normally be expected to abate and prices to moderate significantly. Because natural gas prices began to rise in the spring of 2000, the refill of gas storage was slowed considerably as the industry waited for a possible return to lower prices. Gas storage injections were minimized as demand growth accelerated during the summer and gas acquisition costs escalated. In the 6 weeks ending October 31, 2000, natural gas storage was aggressively filled to 2.7 trillion cubic feet. However, the additional demand for filling storage in the 6 weeks before winter only served to keep natural gas prices high, and the total amount of gas in storage at the start of the 2000-2001 heating season began at a 5-year low for that time of year. The storage situation was even worse for Southern California gas utilities served by E1 Paso pipeline Company because of the rupture on the EI Paso Pipeline in New Mexico) Although interstate natural gas transmission capacity probably was adequate to meet normal peak demand with that pipeline in service, the pipeline rupture constrained California’s gas supply capacity.

California's environmental regulations on electricity generators also added to natural gas demand, because environmental emission allotments for other fuels were exhausted earlier in the year.

Thus, U.S. natural gas market began the winter of 2000-2001 with high prices and a relatively weak storage position. Much colder than normal winter in November and December 2000 reduced gas stocks to such low levels that it raised concerns about possible supply shortfalls during peak periods for the remainder of the winter. The high natural gas demand and rapid gas stock drawdown strained U.S.

Although gas well completions have increased steadily since April 1999, production has not responded sufficiently to satisfy expanding market demand. The industry initially had to overcome the prior drilling slum associated with low natural gas prices. Despite this handicap, domestic production increased by about 0.7 trillion cubic feet in 2000, equivalent to about two-thirds of the increase in consumption from 1999 to 2000 given an industry apparently pressing at the limits of its productive capacity, the higher demand did not bring about increased production, so prices rose higher.

Spot prices at Louisiana's Henry Hub1 were below $3 per million Btu until mid-April 2000, and then broke the $4 barrier in late May as strong demand continued in the electricity generation sector. They remained above $5 per million Btu from September 2000 to February 2001 in response to aggressive filling of storage in the fall and later in response to high heating demand. They average wellhead price for the winter months, November 2000 through February 2001, was roughly 2.7 times higher than during the previous heating season, and the length of time for which sport gas prices have remained elevated is historically unprecedented.

At regional trading centers, average quarterly spot prices displayed unexpected price differentials from the average at the Henry Hub. The Henry Hub average rose from the third to the fourth quarter of 2000 and then changed little in the first quarter of 2001. Although the pattern was similar for the regional trading centers, price differentials from the Henry Hub price varied significantly after the third quarter, especially for the California market. Because natural gas transmission rates are regulated, it appears that the significant variation in spot price differentials among the trading centers originated in the costs of unregulated bundled service (transmission plus fuel) provided by marketers.

2.3 BASIC CHARACTER OF A STORAGE RESERVOIR

The storage container is a porous solid with a caprock overhead to prevent vertical migration. A section and a plan view of a reservoir equipped for storage are shown in the figure below. Water in the storage zone underlies all or part of the gas filled sand or carbonate. Wells designated I/W, for “Input and withdrawal” are completed in the storage zone. Observation wells are completed in the water bearing porous media to permit observation of the pressure and any migrating gas. According to Federal Energy Regulatory Commission, (2004), the storage development cost is capital intensive. Investors usually use the return on investment as financial measure for the viability of such projects. Federal Energy Regulatory Commission, (2004), estimated that the investors require a rate of return of between 12% and 15% for regulated projects and 2years to 20% from unregulated projects. The higher expected return from unregulated projects is due to higher perceived market risk. In addition, significant expenses are accumulated during the planning and location of potential storage sites to determine their suitability, which further increases the risk. The capital expenditure to build the facility mostly depends on the physical characteristics of the reservoir. The development cost of storage facility depends on the type of the storage field (Federal Energy Regulatory Commission, 2004).

2.4 GAS TRANSFER BETWEEN RESERVOIRS

When gas stored at pressures equal to or above the discovery pressure, one must examine the nearby presence of oil and gas reservoirs are at a stage of depletion, there is a driving force between the storage zone and such pressure sinks. A water seal in the production zone of 100 or 200 ft (30.5-61m) represents only a 45-90 psi (310 – 621 kPa) barrier. Over a period of time water can be pushed out of the seal, permitting storage gas to transfer to a producing reservoir. One example is the gas immigration from West Unionville to Ruston in Loiusiana.

When two adjacent gas reservoirs have a differential pressure, the water seal separating them may become displaced and natural gas may transfer from the high pressure to the lower pressure.

2.5 ASSURANCE OF DELIVERABILITY

From gas inventory and or reservoir pressure measurement plus deliverability data, once can predict the field flow at several stages of the storage cycle. The performance of storage reservoirs becomes less predictable during of prolonged high withdrawal rate due to pressure sinks that may develop as a result of heterogeneities.

Another problem of continuing interest is interference by water reaching the well bore. The presence of water not water only reduces the permeability to gas but effectively cuts down the bottom hole pressure drawdown available for gas flow due to increased density of well fluid in the flowing column. For aquifers, water interference problems are likely to subside as the gas bubble thickens. Each reservoir and set of wells must be tested to determine which wells will have water intrusion at a given stage of the withdrawal cycle. Deliverability of storage wells after 20, 30 or 40 years of repetitive use may decrease as result of sand face contamination. Duane, (1967), in his work on Gas storage field development optimization, revealed that it involves consideration of multiple factors, many of which are mutually dependent. According to him, some of the main variables which must be considered in storage field development optimization are (i) potential cyclic capacity and peak-day rate as well as market requirement, (ii) number of wells. (iii) compressor-in let line pressure, (iv) over-pressuring, (v) average well open flow, (vi) casing sizes and (vii) gathering system design. He stated that each of these variables affects the field deliverability performance and each also affects the total project development cost. Duane, (1967), concluded that the optimum method of field development for any given field design conditions is summarized by plotting a graph of the field design parameters (peak day rate and cyclic capacity) versus total cost.

Bomar and Deveniewski, (1997), in their paper on Storage Formation Damage Mechanisms identified some major potential causes for the deliverability decline as: clay problem, particle, clay swelling, salt, deposition at the surface, deposition with the insavour matrix, compressed oil deposition on the sand face, iron scale deposition and bacterial growth. Their conclusions were arrived at after carefully compiling and correlating some existing petrophysical data. The data consist of open hole log evaluation; core data and various special care tests. The data were also evaluated for validity and to determine if all areas and zones of the reservoir were represented. They revealed that the deposition of halite scale on the sand face is the primary cause of decline in deliverability.

The deliverability of wells in Michigan stray sand reservoirs has declined 4.5 percent per year because of fines, salt precipitation, shale sloughing and residues. Early attempt to remove salt gave only a slight increase in deliverability. Recent techniques generally have been successful in increasing deliverability by such as 426 percent. This was achieved by alternatively injecting volumes of (i) Xylene, (ii) 3% and 2% NH_4Cl. Virtually all the wells that were stimulated maintained the increase in the deliverability the following year (Katz and Lee, 1976).

2.6 PROCESSING

Processing is perhaps a less spectacular but nevertheless vital part of the gas industry, and its continued evolution has been and remains a critical factor in the economic exploitation of gas reserves.

In early days in the U.S.A. adequate supplies of sweet (i.e sulphur free) gas were available, much associated gas (i.e. gas produced with oil) was and there was little incentive to treat gas containing sulphur or other undesirable constituents to produce saleable gas. Dehydration of pipeline was practiced but the main emphasis I processing was the recovery of liquid hydrocarbons (natural gasoline).

The piping of untreated gas produced problems due to the effects of condensation of heavier hydrocarbons and “drips” and “traps” were installed into the early lines to draw off the condensed liquids. With the introduction of the motor car, this condensate changed from a waste product to a valuable commodity and by 1908 the first commercial plant for the separation of casing-head or, as it was later to be known, natural gasoline, was on production. By 1911 well over 100 such plant were operating, mainly in the California. The increasing demand for gasoline created by the First World.

2.7 GAS DEVELOPMENT IN NIGERIA

In specific term, Nigeria is more of a gas province than an oil one. Natural gas deposits out-weight oil by far. Nigeria has an estimated 120 trillion cubic feet of gas about three times the size of oil reserves 22 billion. Most of the gas occurs as associated gas i.e. gas occurring along with crude oil in same reservoir. Generally, little exploration for gas is done in Nigeria. Thus, current gas production of about 120,000 million standard cubic feet per daily is associated gas produced during oil production in the Niger Delta. Some of this gas has been used by Shell to generate some electricity in the Niger Delta since the 70s some of it is used by nearly National Electric Power Authority, NEPA, power plants at Ogorade, Afam, and Delta V1 and the 220 Megawatt Egbin power plant, near Lagos. Ogorode, Afam and Delta VI are fed from Sapele, Obigbo and Alakiri gas pipeline, while Egbin is supplied through an extend pipeline to Lagos. In 1991 NEPA power plants consumed 75.5 per cent of the over 109,000 supplied by the Nigerian Gas Company (NGC) (Atiku, 2007). NGC is a subsidiary of the NNPC set-up to market the country's produced gas locally, NGC buys the gas from the oil producing companies at agreed prices and then sells to its consumers. The Nigerian liquefied natural gas, NLNG, is another project that was started to utilize the nation's abundant natural gas reserves, profitably.

Nigerian LNG was first broached in the early 1960s, but remained on drawing board until the late 1980s. The $3.8 billion NLNG sited on Bonny Island, several kilometers off Port Harcourt started production in August 1999. Liquefied Natural gas is a way of compressing large volumes of gas that can be carried to markets thousands of kilometers away, via specially built ships. So NLNG capacity of 4.6 tons per annum has delivered over 60 cargoes to European buyers and sold 4 cargoes on the US spot market. Another plan to utilize Nigerian gas economically is the proposed West Africa Pipeline WAGP', project. The idea is to supply gas home, Nigeria to neighboring West African countries – Benin, Ghana, 'Togo, and later Ivory Coast. Started in the early 1990s, the \VAGP has been dogged by bilateral, multilateral problems between the countries involved and financing problems (OilGasArticles, 2006).

CHAPTER THREE

METHODOLOGY

3.1 DESCRIPTION OF THE CASE STUDY AREA

The hydrocarbons reach belt cuts across the depositional and trends of the delta from southeast to northwest. The Niger delta is world's largest tertiary delta systems and an extremely prolific province. It is situated on the West African continental margin at the apex of the gulf of guinea, which form the site of a triple junction during the continental breakup in the cretaceous. Throughout its history, the delta has been fed by the Niger, Benue, & Cross rivers which between them drain more than 10^6 km^2 of continental lowland Savannah. Its present morphology is that of a wave dominated delta, with a smoothly seaward convex coastline traversed by distributaries channels. From apex to coast, the sub aerial portion stretches more than 300km. Below the Gulf of Guinea, two enormous lobes protrude a further 250km into deeper waters. The Niger Delta basin, in which the oil fields are located, covers an area of some $75000km^{2,}$ and is part of the much larger southern Nigeria Basin. It is separated on the west from the Dahomey {Benin} Basin by the Okitipupa "high" and is bounded on the east by the line of Cameroon volcanic. On the north it transacts the older cretaceous Anambra Basin.

The sedimentary fill consist of a tertiary regressive classic sequence which is some 12000m thick at its maximum. There are five major centers of deposition marking the sites of earlier locate delta systems; they are aligned along an accurate belt which marks a zone of tectonic subsidence in the transition zone from continental to oceanic crust. A major growth – fault trends across the delta from northwest to southeast, dividing it into a number and stratigraphic belts, called Depobelts, which become towards the south.

The deltaic sequence in each of these Depobelts is distinct in age, so that they actually represent successive phase in delta’s history. Individual traps are mainly crescentic growth-fault generated “rollover” anticlines, trending NW-SE. However, there are also a least three types of stratigraphic traps-crystal accumulations below unconformities, canyon-fill accumulations above unconformities, and faces-change traps. Typical of the first type is the Enang field discovered in 1970, with recoverable reserve of 130MMbbl of oil and 20 trillium cubic feet of gas. Here the Biafra and Rubbe bed reservoir sandstones are truncated by the Qua Iboe shale unconformity. The Opuama field is an example of a canyon-filltrap; it lies on shore on the west of the ad produces from the NE-SW trending Opauma channel, which contains a fill consisting of local facies variation of Agbada formation. The

Obiafu-Obrikom field in the central part of the Delta is an example of strategraphic trap in a structural setting. The hydrocarbons in the upper section of the field are trapped by the “rollover” anticline structure, whereas the deeper hydrocarbons are trapped by the eastward thing of the reservoir sediments.

Production from most of the Nigerian fields comes from various porous tertiary sandstones of the Agbada series, which sometimes contain oil and associated gas, and sometimes only non-associated gas. They are usually found in roll-over anticlines in the hanging walls of growth faults, where they may be trapped in either dip or fault closures. The hydrocarbons are found in multiple pay sands with relatively short columns, and adjacent fault blocks usually have independent accumulations. The Agbada beds in which hydrocarbon have been found range in age from Eocene to Pliocene. The Niger delta region of the Republic of Nigeria is Africa’s largest oil producing area. It is clear that Nigeria will continue to contribute significantly to world petroleum production well into the 21st century: with increase in recoverable oil reserves in the Niger delta onshore and offshore; the promising potential of the Niger delta deepwater region; and a lesser but not insignificant contribution from the unexplored onshore Benue trough, part of “the mid-African rift system, which has already proved to hold substantial oil reserves in the Doba basin of neighboring Chad. This is the first part on Nigeria's oil and gas potential.

3.2 NATURAL GAS RESERVE AVAILABILITY

Natural gas is a major source of energy and Nigeria's gas reserves are estimated at up to ten times as large as crude oil reserves. Nigeria contains estimated 124 trillion cubic feet (Tcf) of proven natural gas reserves (10th largest in the world) with upside estimates of associated and non-associated gas being as high as 300 Tcf. Associate gas production is on fields located onshore and in swampy areas of the Niger River Delta

The country national gas reserves/production is estimated to last 109 years.

According to facts and figures on LNG, geologists are insistent that "there is a lot more gas still to be found if companies deliberately explore for gas, as opposed to finding it by chance whilst in search of oil. This is because the Niger Delta is a gas province with oil rims".

Nigeria is regarded as the worst culprit in gas flaring with its associated environmental hazards. It flares about 2 bscf and this is expected to grow especially now that Nigeria's quota in the international market has been by the OPEC, a situation that may see increased oil production. With government setting the year 2008 by which to achieve zero flares, gas plant such as West Delta LNG, Statoil LNG and Agip-Philips-Brass LNG are expected to put off a large percentage of the flares.

3.3 TYPES OF RESERVES

Definitions for three generally recognized reserve categories, “proved”, “probably”, and “possible”, which are used to reflect degrees of uncertainty in the reserve estimates, are listed as follows. The proved reserve definition was developed by a joint committee of the SPE, American Association of petroleum Geologists (AAPG), and American petroleum Inst. (API) and is consistent with current DOE and SEC definitions. The joint committee proved reserve definitions, supporting discussion, and glossary of terms, are quoted as follows. The probable and possible reserve definitions enjoy no such official sanction at the present time but are believed to reflect current industry usage correctly.

3.3.1 Proved Reserves

Proved reserves of crude oil, natural gas, or natural gas liquids are estimated quantities that geological and engineering data demonstrate with reasonable certainty be recoverable in the future from known reservoirs under existing economic conditions.

Discussion: Reservoirs are considered proved if economic reducibility is supported by actual production or formation tests or if core analysis and/or log interpretation demonstrates economic reducibility with reasonable certainty. The area of a reservoir considered proved includes:

(1) That portion delineated by drilling and defined by fluid contacts, if any, and

(2) The adjoining portions not yet drilled that can be reasonably judged as economically productive on the basis of available geological and engineering data.

In the absence of data on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir. Proved reserves are estimates of hydrocarbons to be recovered from a given data forward. They are expected to be revised as hydrocarbons are produced and additional data become available.

Proved natural gas reserves comprise non associated gas and Associated/dissolved gas. An appropriate reduction in gas reserves is required for the expected removal of natural gas liquids and the exclusion of non-hydrocarbon gases if they occur in significant quantities. Reserves that can be produced economically through the application of established improved recovery techniques are included in the proved classification when these qualifications are met:

(1) Successful testing by a pilot project or the operation of an installed program in that reservoir or one with similar rock and fluid properties provides support for the engineering analysis on which the project or program was based, and

(2) It is reasonably certain the project will proceed.

Reserves to be recovered by improved recovery techniques that have yet to be established through repeated economically successful applications will be included in the proved category only after successful testing by a pilot project or after-the operation of an installed-program in the reservoir provides support for the engineering analysis on which the project or program was based. Estimates of proved reserves do not include crude oil, or natural gas liquids being held in underground storage.

3.3.1.1 Proved Developed Reserves

Proved developed reserves are a subcategory of proved reserves. They are those reserves that can be expected to be recovered through existing wells (including reserves behind pipe) with proved equipment and operating methods. Improved recovery reserves can be considered developed only after improved recovery project has been installed.

3.3.1.2 Proved Undeveloped Reserves

Proved undeveloped reserves are a subcategory of proved reserves. They are those additional proved reserves that are expected to be recovered from (1) future drilling of wells, (2) deepening of existing wells to a different reservoir, or (3) the installation of an improved recovery project.

3.3.2 Probable Reserves

Probable reserves of crude oil, natural gas, or natural gas liquids are estimated quantities that geological and engineering data indicate are reasonably probable to be recovered in the future from known reservoirs under existing economic conditions. Probable reserves have a higher degree of uncertainty with regard to extent, recoverability, or economic viability than do proved reserves.

3.3.3 Possible Reserves

Possible reserves of crude oil, natural gas, or natural gas liquids are estimated quantities that geological and engineering data indicate are reasonably to be recovered in the future from known reservoirs under existing economic conditions. Possible reserves have a higher degree than do proved or probable reserves.

3.4 NATURAL GAS PRODUCTION CAPACITY IN THE CASE STUDY AREA

The federal government of Nigeria is set to raise natural gas production capacity to 7.1bn cfpd in 2010. This represents an increase of 29.09 % over the 5.5 bn cfpd achieved this year. The target expected on attainment of oil reserves of 40 bn bbl and productivity of 4 bn bbl would boost the drive for earning equal amount of income from natural gas as in crude oil.

Nigeria produces an average of 5.5 bn cfpd of gas out of which about 2.6 bn cfpd, representing about 60% is utilized. This implies that the remaining 40%, which is flared, is available for commercialization.

Government is aware that the volume of gas being flared amounts to huge loss of revenue that could otherwise be better utilized for the provision of social amenities to improve the lot of her people and arrest the attendant in degradation associated with gas flaring.

It has been estimated that the quantum of gas flared yearly in the country is enough to generate about 6 GW of electricity that is capable of catering for energy needs of all sub-Saharan Africa. The money value of the flared gas per year is put at $2.5 bn.

3.5 HYDROCARBON PRODUCING AREAS OF THE CASE STUDY AREA

*ALO	*DELTA
*IGBARIAM	*OKAN
*OBEN	*MEJI
*POLOGBENE	*FORCADOS
*OBE	*EREMOR
*ISAN	*PENNINGTON
*PARABE	*MIDDLETON
*MEREN	*APOI
*TAPA	*TENNE
*EKPE	*ORUBIRI
*ADUA	*ALAKIRI
*ASABO	*SOKU
*ENANG	*EKULAMA
*USARI	*OLOIBIRI
*ETIM	*TEBIDABA
*INIM	*DIEBU CREEK
*UBIT	*NUN RIVER
*UTAPATE	*OPUKUSHI

*BONNY	*ETELEBOU
*CHAN	*UBIE
*CAWTHRONNE	*OSHI
*YORLA	*OTAMINI
*BOMU	*UMUECHEM
* AFAM	* IMO RIVER
* AHIA	* UTOROGU
* OBAGI	* UGHELLI
* IDU	* AFISHIERE
* UZENE	* KOKORI
* OKPOKONOU	* ODIDI
* OLOMORO	* EGWA
* OBRIKOM	* JONES
* MBEDE	* SAPELE
* OGUTA	

3.6 INDUSTRIAL STRENGTH

Nigeria is a country rich in natural resources; consequently most industry activity revolves around these. Agriculture is an important industry involving a large percentage of the country's workforce. Oil is the country's most important natural resource and generates up to 95% of Nigeria's revenues.

The country is a member of OPEC and is the largest oil-producer in Africa. The continued increase in crude oil means continued growth in this sector.

Scattered throughout Nigeria are small family businesses producing traditional craft goods-pottery, carvings, ornamental cloth, and leather goods,-and more modern consumer goods, such as bricks and other building materials, milled grain, and beverages. In the 1970s large-scale enterprises were established, mostly in the south. They include motor-vehicle assembly plants, oil refineries, and factories producing textile, fertilizers, rubber goods, pharmaceuticals, foodstuffs, pulp and paper, cigarettes, aluminum, iron and steel, and petrochemicals.

Nigeria offers the interested investor Africa's largest domestic market as well as the additional attractions of a low-cost labour pool and abundant natural resources.

The Foreign Exchange Decree of 1995 re-established the foreign exchange market. Foreign companies can source foreign exchange at the parallel market rate. Companies are allowed to hold domiciliary accounts in private Banks. Foreign investors are allow to bring capital into the country without requiring prior government approval.

The degree of foreign investment in the country is relatively small considering the abundant natural resources. The legislation passed the government has helped to improve this situation slightly. Economic liberalization is also a government priority.

Nigeria’s main export products are petroleum and related products as well as cocoa and rubber, the country’s main trading partners include the US, India, Spain Brazil and France.

Nigeria’s main imports include machinery, chemicals, transport equipment, manufactured goods, food and live animals. The UK, France, Germany, China and the US are the country’s most significant import partners.

Nigeria has signed various trade agreements with various countries.

CHAPTER FOUR

RESULTS

4.1 STORAGE FIELD DEVELOPMENT OF DEPLETED FIELD

4.1.1 Technical Flow Chart for Natural Gas Storage

The technical flow chart for gas storage in reservoirs is shown in Fig 4.1.

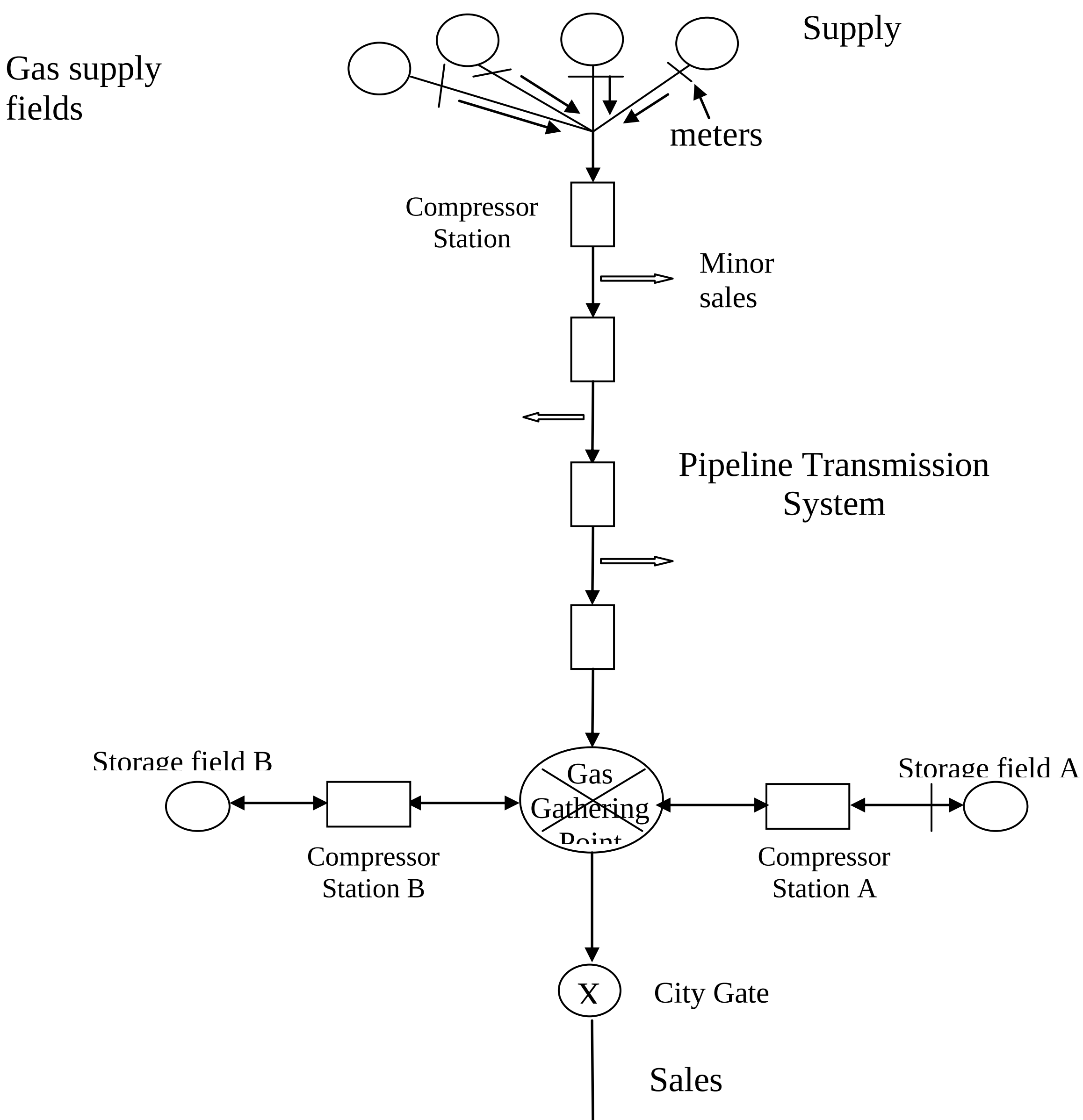
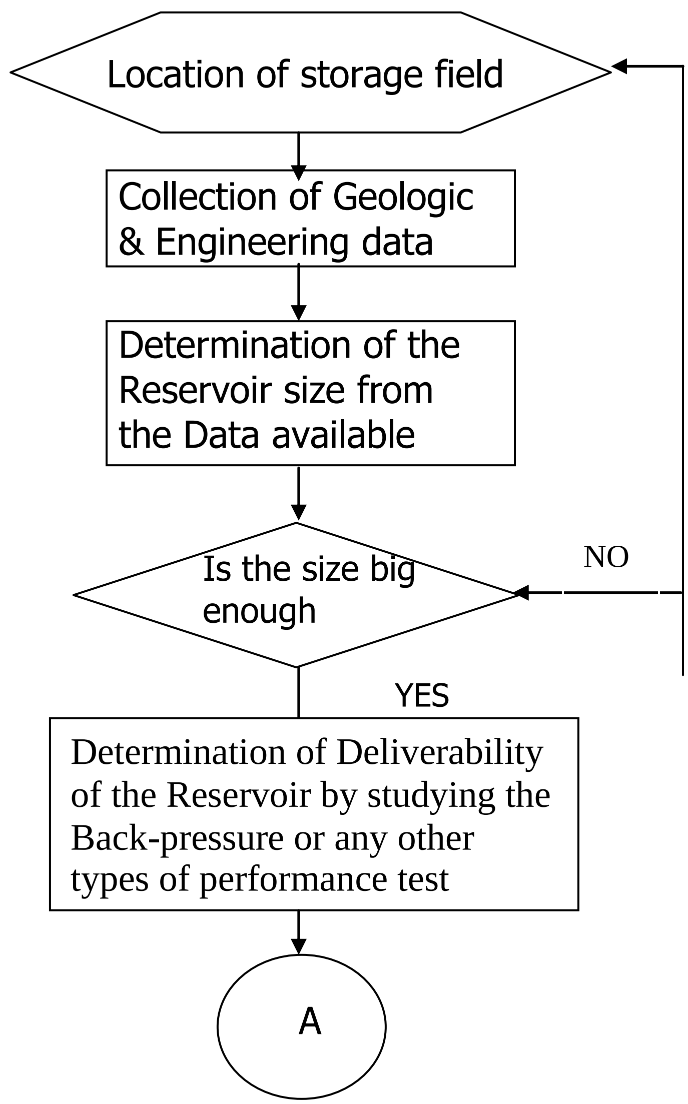
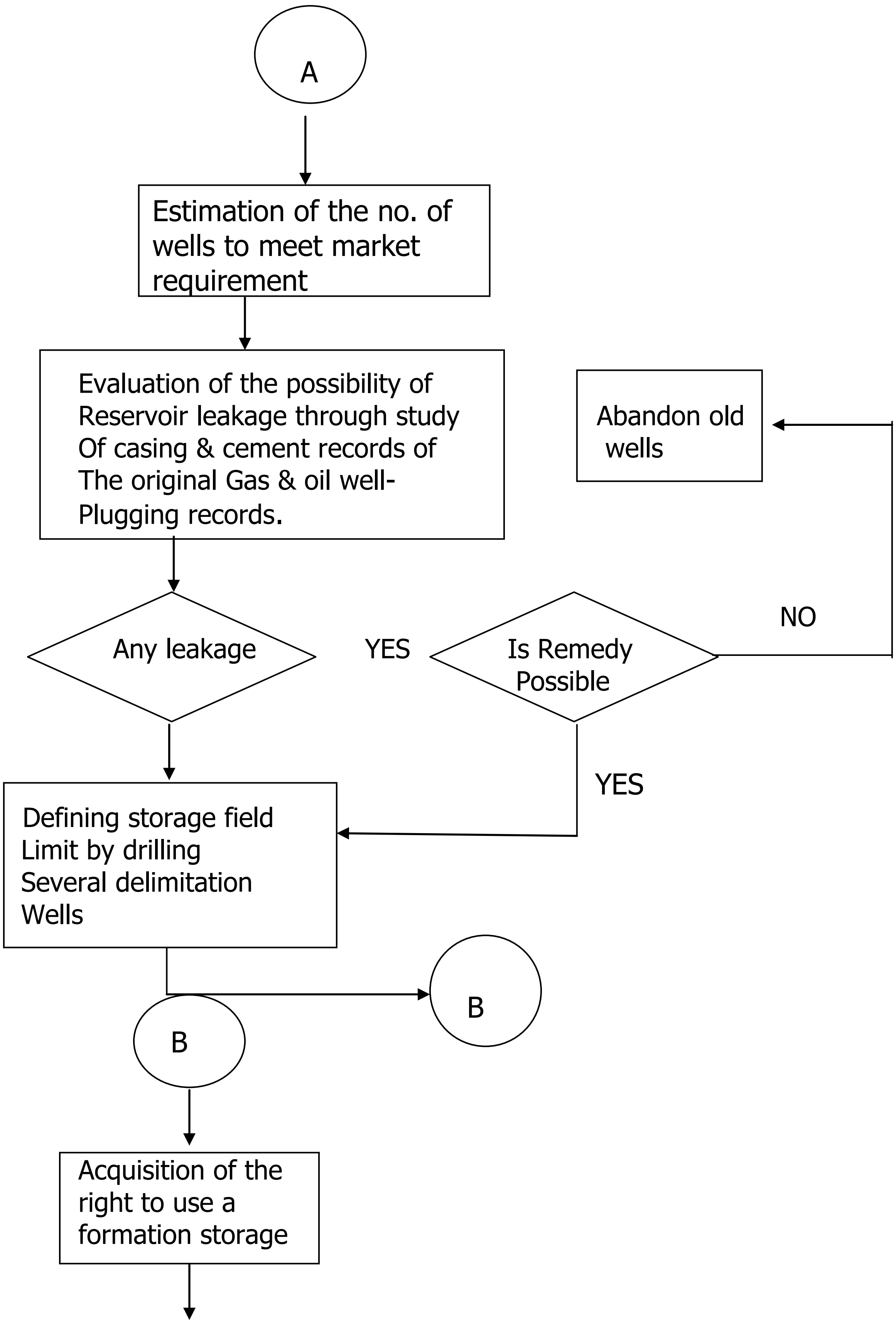


Fig 4.1: Technical Flow Chart for Underground Gas Storage

4.1.2 Flow Chart for the Conversion of a Depleted Gas or Oil Reservoir for Natural Gas Storage

The flow chart for the conversion of a depleted gas or oil reservoir for natural gas storage is as shown in Fig 4.2.




A
Estimation of the no. of wells to meet market requirement
Evaluation of the possibility of Reservoir leakage through study Of casing & cement records of The original Gas & oil well-Plugging records.
Abandon old wells
NO
Any leakage
YES
Is Remedy Possible
YES
Defining storage field Limit by drilling Several delimitation Wells
B
B
Acquisition of the right to use a formation storage

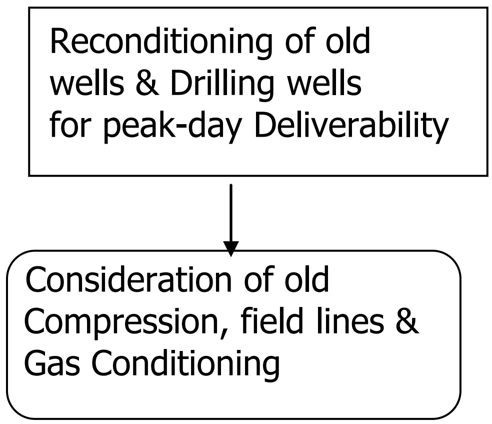


Fig 4.2: Flow Chart for the Conversion of a Depleted Gas or Oil Reservoir for Natural Gas Storage

A. Location of storage field (whether) close to market).

B. Collection of Geological and Engineering data.

C. Thorough study of the Geological and Engineering data available about the field.

D. Production and pressure history of the individual gas wells should be obtained. Any core data showing porosity, permeability and laboratory determinations of interstitial water are valuable.

E. These data, combined with geological data, are necessary to determine the size of the reservoir.

F. Back-pressure or any other type of individual well performance tests must be studied to determine the deliverability of a reservoir and from this, the estimation of the number of storage wells necessary to meet market requirement is done.

G. Casing and cement records of the original gas or oil wells and well-plugging records must be studied careful to evaluate the possibility of reservoir leakage through improperly plugged well or behind the casing of remaining active wells with poor cement jobs or insufficient cement.

H. A study must be made of all wells drilled within the field limits that have penetrated the storage permanently plug certain old wells or set new casing on some wells. The results of such a study and report will determine whether it is advisable to processed with the acquisition for storage of a given depleted or partially depleted gas or oil field.

I. Acquisition of the right to use a formation for storage. Defining the field limits, if the original field was not well delimited when it was being developed, it may be necessary to drill several delimitation well before major storage operation commences. This helps so as not to acquire storage right on acreage that will eventually prove to be well outside the field limits. These wells will be drilled primarily for structural information. They can also enable one to detect any storage gas that has migrated out to these wells.

J. Reconditioning of wells.

Drilling of additional wells for peak-day deliverability. The number will depend upon the thickness and permeability of the formation, the maximum safe daily, production rate per well, the maximum wellhead pressure drawdown during withdrawal, etc.

4.2 COST EVALUATION

Several items enter into the total investment necessary to put an underground storage field into operation. These items includes:-

- Cost of acquisition
- Cost of development
- Cost of base or cushion gas
- Cost of compression

* Cost of transmission

Acquisition cost (will involve purchase of all physical equipment in the field such as:

- Acquisition cost
- Cost of remaining gas or oil wells
- Cost of gathering lines
- Cost of process equipment
- Cost of compressor station
- Cost remaining recoverable gas or oil in the formation.

* Cost of acquiring the right to use the formation for storage.

Note: Physical equipment call often is purchased for its depreciated value, while remaining minerals can usually be acquired at same rate as the rate paid during production.

* Development cost
* Cost of drilling storage wells
* Cost of drilling observation wells
* Cost of structural – Control wells
* Cost of wellhead structures
* Cost of gathering system.

Complete drilling costs including drilling, well casing, cement, logging, cording, and testing that is done. A shallow storage well less than 2,000ft in depth could be drilled and completed for no more than $5,000 per well.

Wellhead structures includes equipment to enable the operator to test and service the well in normal operations without special equipment or delay; which includes.

* Pressure tap so situated that wellhead shut-in pressures can be taken with a dead weight gauge.
* Horizontal meter run with orifice fittings, a value at the gathering system –end of the meter run for controlling flow rate to or from the well.
* A meter or manometer for measuring deferential across the orifice plate.

* A blow-off valve for cleaning the well and for running instruments into the well, which is an integral part of a wellhead structure.

* A well-house to enclose and protect wellhead equipment from weather.

* Depending on the depth of the storage reservoirs, reservoir temperature and surface weather conditions, it may be necessary to install a heater at the wellhead to prevent hydrate formation and free + zinc off of the gathering lines.

Gathering-system costs will depend upon the capacity of the wells and well-spacing patterns, but should not cost more than $10,000 per well. In the average underground storage field, the total reservoir capacity is divided approximately into 50 percent cushion gas and 50 per cent working gas.

The cost of cushion gas could fluctuate from 25 to 50 cents per Mcf, depending upon the locality. In any instance, it should be equal to the pipeline company's off-peak or interruptible sales price.

Compression, transmission, dehydration, and other gas-treating costs are entirely dependent upon individual situations.

Compressor stations could be built for $250 to $300 per installed horsepower.

Transmission-line costs vary widely. A rule of thumb that would prove satisfactory for approximate costs would be 50 to 60 cents per inch bf diameter per foot of length of transmission line.

Gas-treating cost would depend upon what treatment is necessary. Separators and gas cleaners would be included in the compressor station costs. Douglas ball states that for the highest investment cost for underground storage capacity has been slightly under $1 per Mcf of working storage capacity. The economic flow chart for natural gas storage in depleted reservoir is as shown in Fig 4.3.

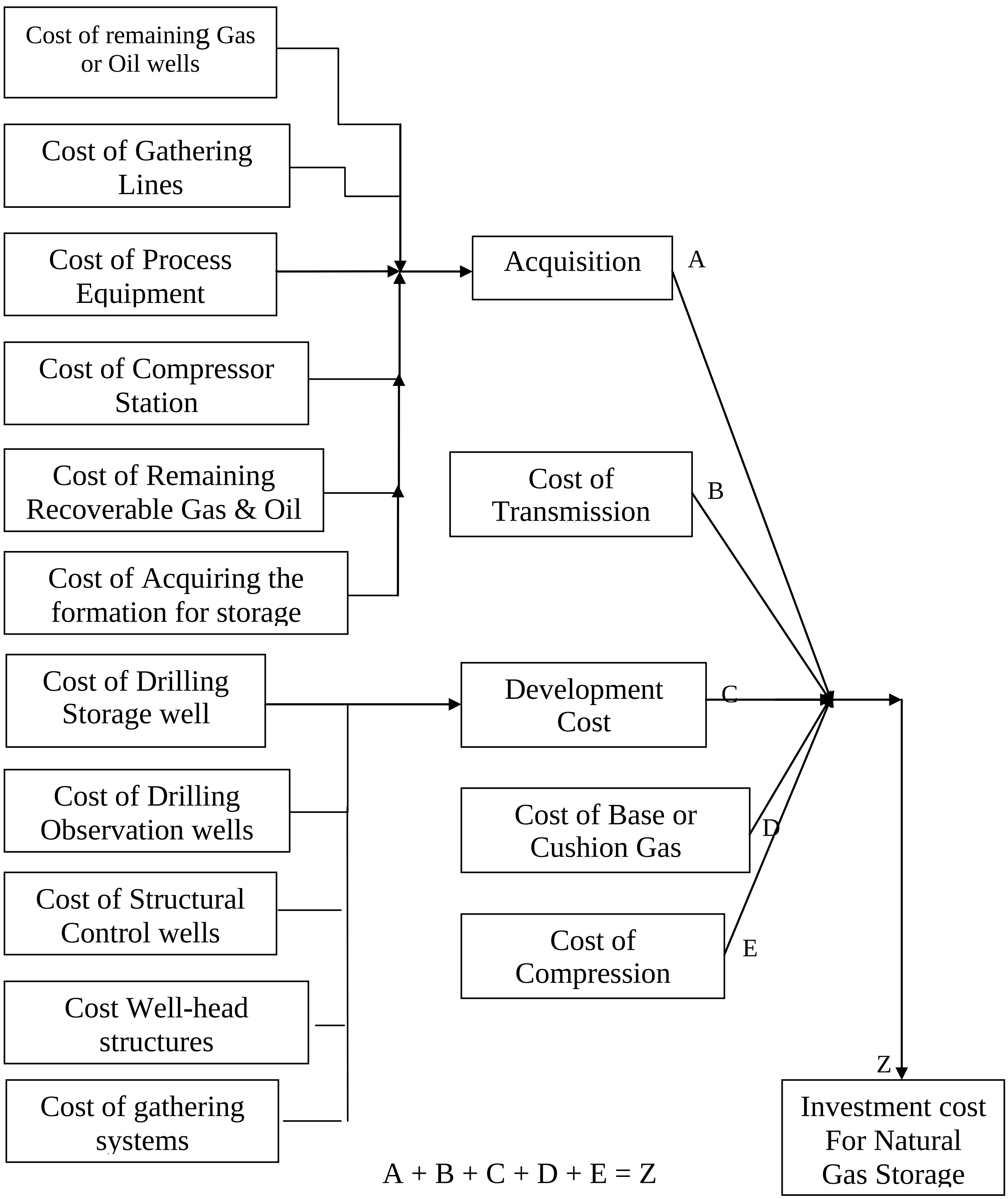


Fig 4.3: Economic Flow Chart for Natural Gas Storage in Depleted Reservoir

4.2.1 Economics of Storage

The Apoil field: An example

The Apoil field is located in the Niger delta province in southern Nigeria. For Onshore installations (considering well depth = 2,600ft and natural gas price $7.28/MMBtu)

Working storage = top storage capacity (14.4Bcf) – base gas (2.bBcf)

= 14.4Bcf - 2.3Bcf = 12.1Bcf

Horsepower requirements = 9460 hp

Acquisition

(a) Cost of remaining gas or oil wells = salvage value of 20% of initial well cost

Initial well cost = $50/ft x 2600fi = $130,000

Salvage value of remaining gas well = 20% of $1 30,000 = **$26,000**

(b) Cost of gathering lines

- Average distance = 34.607 miles
- Material = $4,270,412.3
- Labour $43,038,043.4
- Miscellaneous = $1,182,035.2
- ROW & damages = $308,250.1
- Cost = $283,143.324/mile

- Total cost of gathering lines = **$9,798,74**

(c) Cost of metering facilities

- Material = $866,160
- Labour $58,142.86
- Miscellaneous = $23,231.429
- Land & improvements = $3,428.57
- Total cost of metering facility = **$950,962.86**

(d) Cost of compression station

- Horsepower = $9460 lip
- Equipment & material = **$2,634,205.333**
- Labour = $795,427,333
- Land=$20300
- Miscellaneous = $424,588
- Cost $409.57
- Total cost of compressor station = $3,874,520.666

(e) Cost of remaining recoverable gas or oil information:

* Amount of remaining recoverable gas information is 10.72Bcf,

* Gas price is $7.28/MMBtu or $7476.6/Mcf

COST = $7476.6 x 1000 x 10.72 = $80.15 million

Acquisition Cost TOTAL = $94.4.8 million (N14.410 Trillion)

Development Cost:

Considering well depth = 260ft, number structural control wells = 4

Number of well structures =7, number of gathering systems = 10

(a) Cost of drilling storage wells = $100/ft = $260,000

(b) Cost of drilling observatory wells = 100/ft. = $260,000

© Cost of structural control wells = $100/ft x 4 wells

= $100/ft x 2600ft x 4

= $ 1,040,000

(d) Cost of wellhead structures $5000 / well x 7 = $35,000

(e) Cost of gathering system = $10,000/well x 10 = 1000,000

Development cost TOTAL = $1,695,000 (N2.5.80.billion)

Cost of cushion gas:

(50 cent/Mcf working storage gas, working gas volume 12.1 Bcf) =

$0.5 x 12.1x = $6050 (N919,600.00 billion)

Total investment cost = Acquisition Cost + Development Cost + Cost

cushion gas = **$96,501050 (N14.67.00 Trillion).**

4.3 FINANCIAL ANALYSIS

Based on the Energy Information administration (EIA) standards, 1027Btu of average heat content is equivalent to 1 cubic foot.

Average gas price is currently fixed at $7,28/MMBtu. In an attempt to convert to $ / MMBtu,

1027 Btu 1 scf

Thus 12.IBcf working gas = **12426700 MMBtu**

Table 4.1: Average Reservoir Storage Cost per MMBTU

Cost Item	Amount
Annual demand Charge {fixed}	$ 0.40 / MMBtu
Injection fee {variable}	$ 0.02 / MMBtu
Withdrawal fee {variable}	$ 0.02 / MMBtu
Fuel {variable}	$ 0.04 / MMBtu
Total cost	$ 0.48 / MMBtu

Thus, considering a reservoir of 12.1 Bcf working gas =

12426700MMBtu, the total cost would then be:

0.48* 1246700 = $59,64816 (N90,665.00 million)

Evaluating the Revenue, we have price at a rate of $7.28/MMBtu,

The price of 12426700 MMBtu = $90.5 million (N13,756.00 million) One dollar equivalent One Hundred and Fifty Two Naira as use as exchange rate.

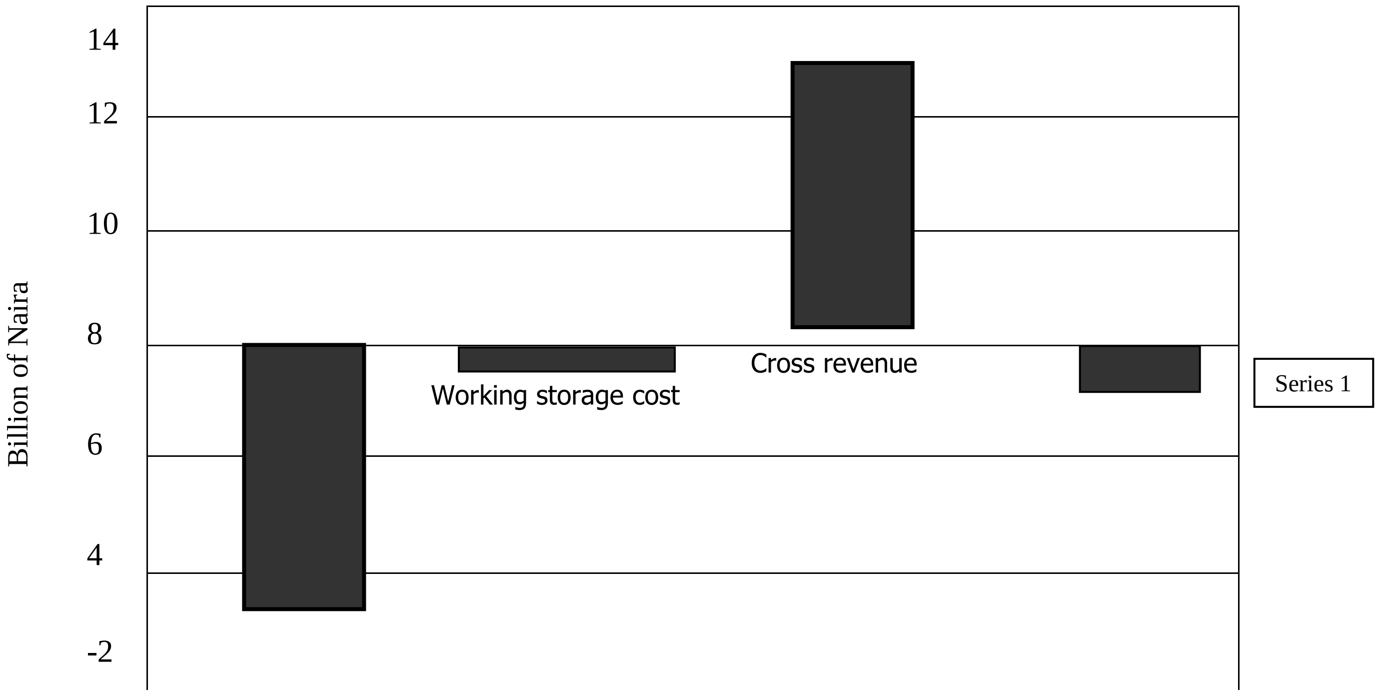


Fig 4.4: Gross Revenue, Net Revenue and Storage Cost Chart for the first year

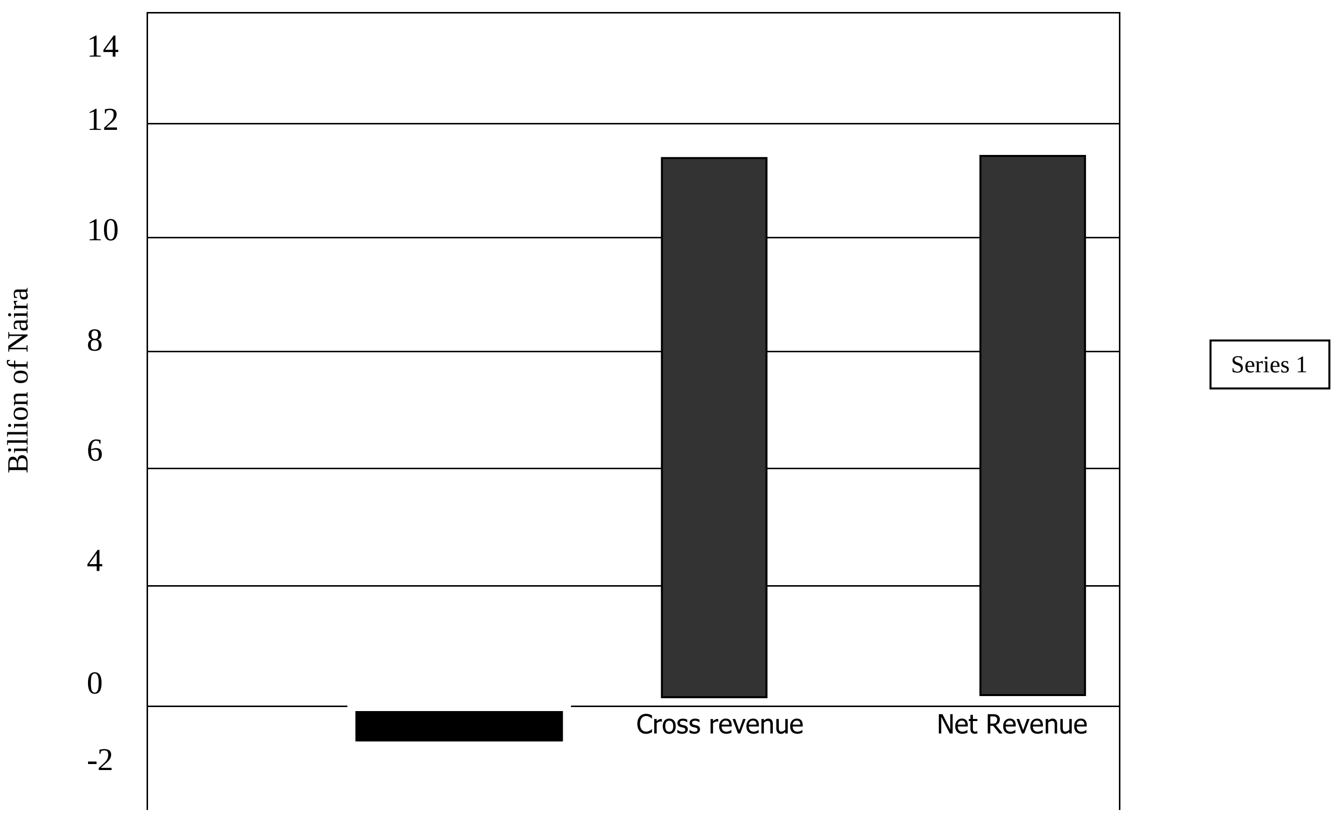


Fig 4.5: Gross Revenue, Net Revenue and Storage Cost Chart for subsequent Year of operation (with one cycle operation annually)

This figure represents the amount of revenue that would have otherwise been realized with the installation of storage facilities.

At present, though, barely 50 percent of the natural gas produced in the country is utilized with other half flared. This constitutes a huge loss of income, which when analyzed based on the working gas of 12.1 bcf gotten for this analysis each well will be having about:

0.5 x \$90.5 million = \$45.25 million (N6,8,78.billon) worth of gas been fared.

On behalf of the operation company which pays penalty of N20 for every million cubic feet of gas flared, an estimated additional penalty of about:

(N 20 x 0.5 x 12.1 x 10^3) = N 121,000 would be incurred just for a lack of a storage facility.

4.4 ECONOMIC INDICATORS

4.4.1 Net Present Value

Net Present Value, NPV is a measure of profitability of any project. The net present value (NPV) or net present worth (NPW) of a time series of cash flows, both incoming and outgoing, is defined as the sum of the present values (PVs) of the individual cash flows. NPV compares the value of a dollar today to the value of that same dollar in the future, taking inflation and returns into account. If the NPV of a prospective project is positive, it should be accepted. However, if NPV is negative, the project should be rejected because cash flows will also be negative.

Table 4.2: Summary of the cash flows for the project

Time (yr)	CAPEX ($MM)	OPEX ($MM)	GROSS REV ($MM)	NCR ($MM)	CUM NCR ($MM)	PV @ 5% ($MM)	PV @ 10% ($MM)
0	96.5	0	0	(96.5)	(96.5)	(96.5)	(96.5)
1	0	5.96	90.5	84.54	(11.96)	80.51	76.85
2	0	5.96	90.5	84.54	72.58	76.68	69.87
3	0	5.96	90.5	84.54	157.12	73.03	63.52
4	0	5.96	90.5	84.54	241.66	69.55	57.74
5	0	5.96	90.5	84.54	326.20	66.24	52.49
6	0	5.96	90.5	84.54	410.74	63.09	47.72
7	0	5.96	90.5	84.54	495.28	60.08	43.38
8	0	5.96	90.5	84.54	579.82	57.22	39.44
9	0	5.96	90.5	84.54	664.36	54.50	35.85
10	0	5.96	90.5	84.54	748.90	51.90	32.59

From Table 2, the Net Present Value, NPV at an expected rate of return/discount rate of 10% which is the sum of all the Present Values in that column = $422.96MM

4.4.2 Internal Rate of Return

The internal rate of return (IRR) on investment for a project is the rate of return that makes the net present value of all cash flows from a particular investment equal to zero. The higher the IRR of a project, the more desirable it is to undertake the project. Table 3 is a table of the net present values at various discount rates, which was used in generating a plot of

NPV against discount rate as shown in Fig 2 for the determination of the IRR which is 79.17%. This value is the discount rate at which the NPV equals zero.

Table 4.3: NPV at various discount rates

Discount Rate (%)	NPV ($MM)
30	86.63399
40	59.83386
50	39.18148
60	22.90037
70	9.811421
80	(0.89159)
90	(9.77451)
100	(17.2438)

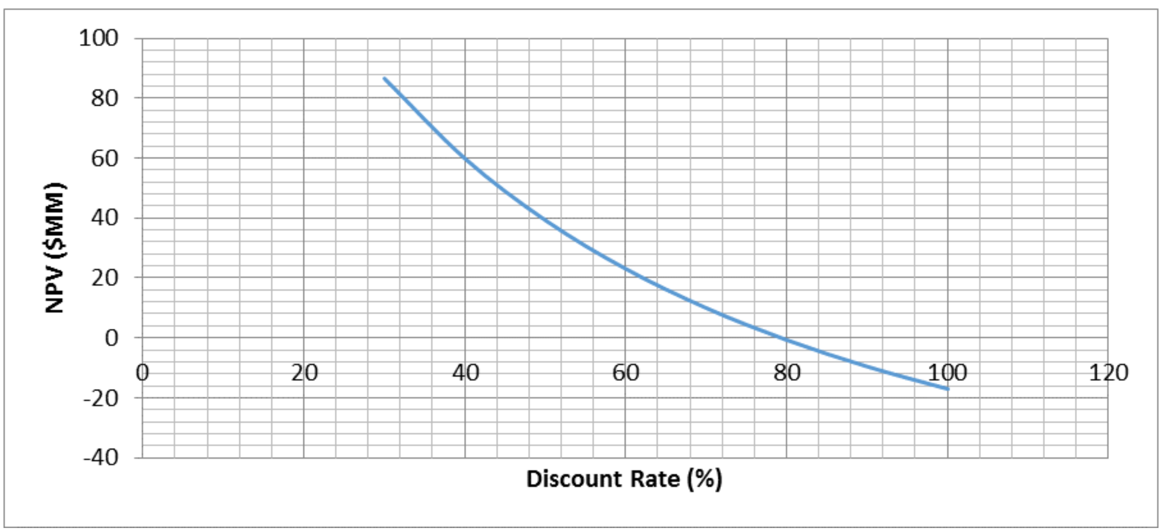


Fig 4.6: Plot of NPV against Discount rate

4.4.3 Pay-out, PO

The pay-out for a project refers to the time (years) at which the initial investment on the project is just recovered. It is the time at which cumulative NCR becomes zero. From Table 2, cumulative NCR becomes zero between the 1st and 2nd year. In this project work, 1 and 2 years were used as the initial point (IP) and final point, (FP) respectively.

Applying interpolation:

(PO – IP) / (FP – IP) = (0 – CUM NCR at IP) / (CUM NCR at FP – CUM NCR at IP)

(PO – 1yr) / (2yrs – 1yr) = (0 – (- 11.96)) / (72.58 – (- 11.96))

PO = 1.14yrs which is also shown in Fig 3 below.

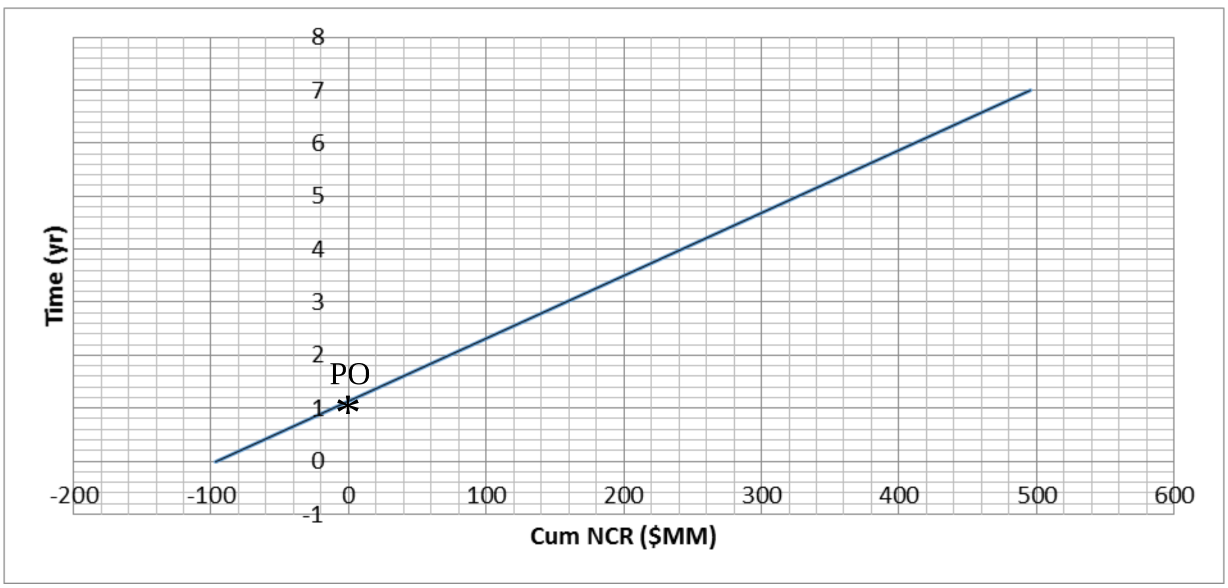


Fig 4.7: Plot of Time (yrs) against Cum-NCR ($MM)

4.4.4 Break-even Point

Break-even point of a project refers to the point at which the initial and all other investments in terms of money is just fully recovered. It is the amount of money just recovered at pay-out. The break-even point of running the reservoir storage facility is $96.5 million as indicated in fig 4.17.

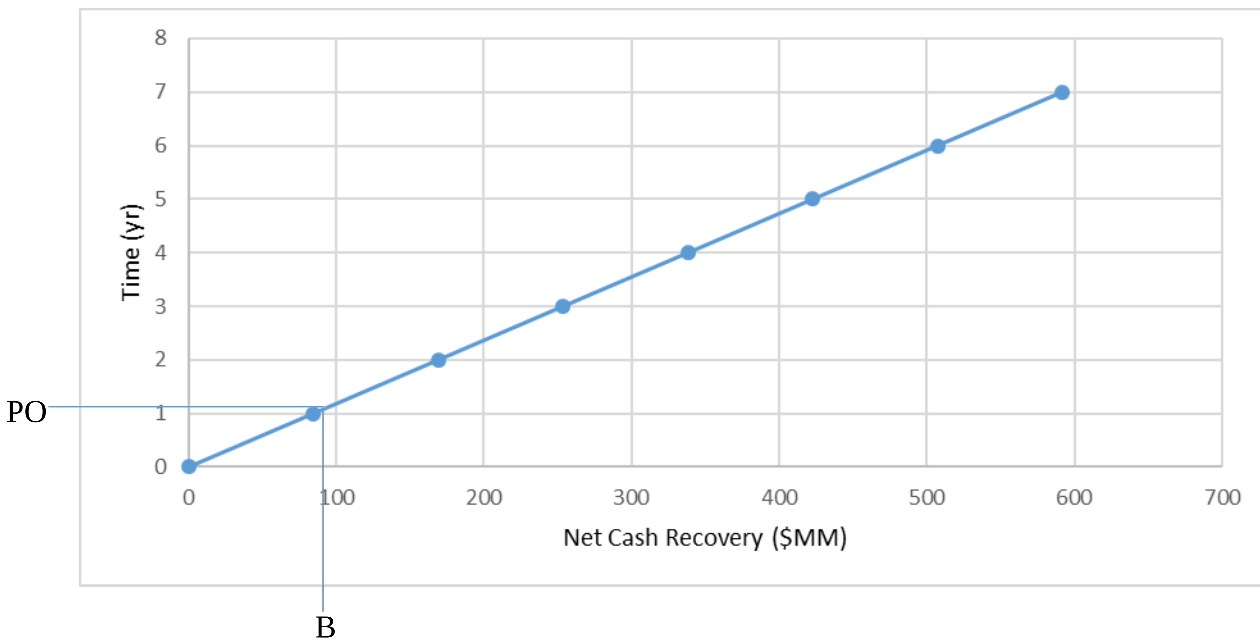


Fig 4: Plot of Time (yrs) against NCR ($MM)

4.5 BENEFITS

4.5.1 Economic benefits

Increase annual revenue derived from the storage and utilization of natural gas is the key advantage to underground storage. It also results to a rise in the production capacity and provides support for dependent industries, which need additional energy for sustenance and growth. A storage resource would also aid in the stabilization of natural gas prices, as fluctuations that arise from irregular production rates would be greatly reduced.

Gas storage primarily aids in heating in cold weather. It levels the load from pipelines carrying gas from the gas supply. Often a distance of 1000 miles (1600 km) to the market area.

A high level of import substitution will be attained in addition to improved foreign exchange earnings. Most of the natural gas exports are made to developed countries and so enhanced bilateral relations which translate to the attraction of foreign investors into the country. Production and storage at a cost-effective rate and the subsequent sale at a higher price creates and additional profit margin in the business. Underground natural gas storage acts as the swing capacity due to seasonal variation in demand. Natural gas is injected into underground storage reservoirs during the second and third quarters when supply exceeds demand. The injected gas is withdrawn from these reservoirs during the fourth and first quarters when space hearting demands peaks and demand exceeds supply. For instance, the French consume five times more gas in January than August.

Storage reservoirs have high-deliverability and are often closer to the end user compared to the reservoirs from which the natural gas is original produced, hence saving transmission cost.

Storage reservoirs provide the only significant supply and demand cushion. Inventories or the amount of working gas in underground storage, provide an indication of the current natural gas supply and demand balance.

4.5.2 Social Benefits

No doubt, storing the vast amounts of natural gas that would otherwise have been flared contributes to diversity in the energy industry. In line with this, more jobs are made available for a portion of the populace that would be an art of the manpower needs.

4.5.3 Industrial Benefits

Natural gas in storage also serves as insurance against any unforeseen accidents, natural disasters, or other occurrences that may affect the production or delivery of natural gas.

The intermittent production of natural gas from wells, as in the case of a lack of storage, poses some difficulty in machinery maintenance.

4.5.4 Environmental Considerations

Abandoned oil and gas fields distributed over the southern region would be effectively utilized, which will not only save the wastage of these huge capital wastage but will also aid in lessening the quantity of gas prone to flaring.

The issue of underground storage will also contribute largely to the realization of the year 2010 ultimatum for a zero-flare industry. The hazards that spring from the flaring process would be also checked, thereby making neighbouring inhabitants, biotic life and the natural environment safe and preserved.

4.6 ENVIRONMENTAL IMPACT ASSESSEMENT

In assessing the interaction of fuels with the environment, the selection and application of entirely objective criteria is often inhibited by traditional impressions, which may be true only in part. Thus the winning of coal is recognized as dangerous and dirty and also disfiguring to the countryside; with combustion of coal are associated various forms of pollution. While these criticisms are true, new technology has gone some way towards ameliorating these problems. In the case of electricity, a refined form of fuel, it is clean in use and has the advantage of flexibility in application. Under further examination it is less attractive in that it is costly, presents a hazard to persons and to property; pollution produced at generating stations must also be considered. In considering gas as a fuel assessment, one may well commence from impressions of the odour of the old type of gas works or concentrate upon the danger of explosions.

The availability of natural gas at high pressure and at a relatively high degree of purity is factors strongly in its favour. Manufacturing plant is not necessary and the problems associated with mining are absent. Lots of natural gas supplies come from offshore wells. Operational difficulties arise there from, but interaction with the environment is minimal.

The effect on the environment arises from the sitting of the terminals, the favoured choices for which are near the coast and remote from conurbations.

Once the gas has been brought to the surface, purification must be undertaken; the processing will vary according to the source of the gas. Gases from different sources contain different quantities of sulphur compound (hydrogen sulphide, mercaptans and carbonyl sulphide), and processing is required both to dry and to sweeten the gas; the former is necessary, among other reasons, to avoid the formation of hydrocarbon hydrates. The impact of natural gas at the personal and domestic level goes somewhat deeper than the trivialities of conversion. The carbon monoxide hazard prior to combustion is removed by conversion from town gas to natural gas. The hazard of the fuel is usually inseparable from the effects of inadequate apparatus and the occurrence of fault conditions.

The effect of natural gas on the environment at the local level relates in the main to terminals and storage. Power stations and gas terminals may be deemed equally offensive to view for those who visit their neighbourhood or are resident near them. Equally, they have little impact on those who never see them. This level of consideration merges into the large-scale and national. Power and energy have to be distributed, and the large the power consumption the greater is the investment in the transmission system. The economics of underground storage cables are unfavourable as compared with pylons and overhead transmission lines. The disfigurement by them and by transformer stations is considerable and the hazard from overhead lines is not negligible. The majority of natural gas pipelines are buried, as are the control point; offence to the environment is thus minimized. Further, the amount of above-ground storage as compared with the period when town gas was in use has decreased. In view of the fact that natural gas is consumed at a multitude of locations and is sulphur-free, the effect on the atmosphere, as compared with the emissions from tall chimneys and cooling towers of the power station, is small. One way in which natural gas may impinge on the local environment is in the matter of LNG tankers in port. The LNG will continue to evaporate so that it must be re-liquefied, burnt or dispersed. Fire and explosion could then only be avoided by imposing restrictions on access and movement more so than for petroleum tankers and stores. The whole issue of designated areas and the installation of flame proof switch gear come up for consideration. On balance, it appears that natural gas offers no insuperable problems prior to combustion and those problems that it does pose are not new. Equally clearly, it helps in endeavors to protect and preserve the environment as compared with the effect of other fuels. It is to be hope that every effort will be made fully to quantify energy every aspect of its impact on the environment so that its advantages may be exploited to the full.

In further consideration of the effects of natural gas on the environment after combustion, it should be observed that, as marketed for fuel purposes, it is virtually free of adventitious solids and sulphur. In properly designed appliances, the products of its combustion are free from smoke and sulphur oxides. Their contribution to atmospheric pollution, therefore, is minimal as compared with that of the flue gases arising from the combustion of commercially available solid and liquid fuels.

Social and other pressures are establishing environmental control standards aimed at limiting either:

a.) The sulphur content of fuels at the point of combustion and

b.) The sulphur content of the resultant flue gases.

These standards will be met only in the casers of solid and liquid fuels by the investment of further capital in flue gas cleaning processes or fuel do sulphurizations plants. Natural gas, therefore, is in a special class as a premium fuel in pollution control. Its ability fully to discharge its role may be restricted by its limited availability in relation to the total fuel market, and the marketing policies of individual gas distributors who should aim to market the gas at a price which reflects its special advantages.

Whereas the products of combustion of solid and liquid fuels cannot be entirely freed from solid particulate matter nor (without considerable investment) be freed even partially from sulphur oxides, flue gases arising from the combustion of commercially-distributed natural gas may be considered to be free of both of these potential pollutants. These important differences confer considerable advantages on fuel users who choose a gaseous form of energy.

4.7 SAFETY

A consideration of safety must always put the total system in perspective. No one expects our highways to be perfectly safe, and although people work hard at reducing accidents, they are also forced to admit that accidents cannot be prevented altogether. All technology carries some degree of hazard, which should be minimized while at the same time making use of the technology. After an incident, the investigation of the causes often leads to corrections, preventing it from happening again in the future. Good safety practice includes as thorough an anticipation of such happenings as possible and making of the necessary corrections prior to the incident contemplated.

In long-range perspective, workmen or the public involved in the technology find that certain social costs are born by them when appropriate corrective measures have not been taken. Not all hazards are contemplated and there can well be social costs or penalties found after the facts. It behooves each company or organization to do their best in minimizing such unforeseen events.

4.7.1 Odorization of Gas – A Safety Measure

Natural gas serving as a domestic fuel must be odorized so that leaking gas may be detected by its odor. The requirement is that a gas of 20% of the lower combustion limit will indicate its presence by smell, a safety factor or 5. This requirement applies to a fuel gas in a gas distribution system, but may not apply to high-pressure transcontinental pipelines or distribution lines.

Odorants are organic compounds containing sulphur, usually mercaptans, disulfides, thloethers, or carbon sulphur ring compounds. They are marketed as liquids with densities of 0.8 to 1.0 g/ml, initial boiling points of 120-230^{0}f {49-110^{0}c}, Reid vapor pressures from 1 to 8 psia {6.89-55.ikpa}, and molecular weight around 85. The odorization rate is in the range of 0.25 to 0.75 lb/mmcf of gas. Odorants increase the sulphur content by 0.07 grains/100ft^3 for the 0.251b/mmcf of gas.

Odorization stations often are situated at distribution pipelines' delivery points to towns - usually with pressure controls. Two methods are employed, injection or bypass odorizers. Since the gas flow being odorized is variable with time, the injection pump rate must be connected to the flow rate. The bypass system involves a side stream of the fuel gas passing over liquid odorant to carry the vaporized odorant to the main fuel supply. The bypass rate is controlled by the fuel gas flow rate.

LP gas (propane) is marketed as liquid, often in cylinders. Here the odorant is placed in the liquid, which in turn gives off vapor fuel with the proper odorant concentration. Ethyl mercaptan (C2H5SH) is used for this service at 1.51b per 10,000 gallons of propane. This concentration is 25 ppm by volume in the liquid and diminishes to 4.5 ppm at 32^{0}f (0^{0}c) and 5.8 ppm at 90^{0}f (30^{0}c) for the gas.

CHAPTER FIVE

CONCLUSION AND RECOMMENDATIONS

5.1 CONCLUSION

At the end of this research work, it was found out that it is economically viable to store natural gas in Nigeria, due to the following facts;

1. Enormous economic merit in terms of revenue realizable from the project as compared to the current prevailing operation which the country stands a chance to gain.

2. The underground storage of natural gas will unavoidably aid in achieving the government 2010 target of flare down which will go a long way in ameliorating the hazards posed by gas flaring.

3. There is need to convert the abandon depleted reservoirs to storage facilities in order to put into further use the existing wells which have gulped huge capital.

4. The intermittent production of natural gas from wells on demand at different periods contributes to facility breakdown which could be averted with gas storage.

5. Production and storage at low economic rate could be capitalize on to and additional profit margin, when the natural gas is subsequently sold at a higher prevailing price.

6. It will aid in stabilizing the energy sector of the country which will adversely aid in the rapid growth of the industrial sector.

5.2 RECOMMENDATIONS

1) Since there is increased gas utilization, efforts should be made to provide adequate storage facilities so as to satisfy peak load requirements.

2) Efforts should be made to obtain storage sites close to the consumption site in order to reduce the transportation costs of the quantity of gas consumed during a peak day.`

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NOMENCLATURE

AAPG = American Association of Petroleum Geologists

API = American Petroleum Institute

B = break-even point

Bcf = billion cubic feet

Bn = billion

Bscf = billion standard cubic feet

CAPEX = capital expenditure

CH_4 = methane

CO_2 = carbon dioxide

CUM = cumulative

DOE = Department of Energy

EIA = Energy Information Administration

FP = final point

Ft = foot

GSPA = gas sales and purchase agreement

He = helium

H_2S = hydrogen sulphide

IP = initial point

IRR = internal rate of return

I/W = input and withdrawal

Km = kilometre

kPa = kilopascal

lb = pounds

LNG = liquefied natural gas

LPG = liquefied petroleum gas

MMbbl = million barrel

MMBtu = million British thermal unit

mmcf = million cubic feet

mm cfpd = million cubic feet per day

N_2 = nitrogen

NCR = net cash recovery

NGC = Nigeria Gas Company

NE = northeast

NH_4Cl = ammonium chloride

NLNG = Nigerian Liquefied Natural Gas

NNPC = Nigerian National Petroleum Corporation

NPV = net present value

NPW = net present worth

NW = northwest

OPEC = Organisation of Petroleum Exporting Countries

OPEX = operating expenditure

PO = pay-out

Psia = pounds per square inch absolute

PV = present value

REV = revenue

scf/d = standard cubic feet per day

SE = southeast

SO_2 = sulphur dioxide

SPE = Society of Petroleum Engineers

SW = southwest

Tcf = trillion cubic feet

US = United States of America

^oC = Degree Celsius

^oF = Degree Fahrenheit

$ = dollar

$MM = million dollars