OPTIMIZATION OF STRATEGIES FOR NATURAL GAS UTILIZATION: CASE STUDY OF THE NIGER DELTA

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OPTIMIZATION OF STRATEGIES FOR NATURAL GAS UTILIZATION: CASE STUDY OF THE NIGER DELTA

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ABSTRACT

Nigeria is endowed with huge proven gas reserves estimated to be 184 trillion cubic feet (Tcf). It ranks as the 7th holder of natural gas reserves in the world, and the largest in Africa. Nigeria also flares more natural gas than any other country; it accounts for 12.5% of the world's annual gas flared and it wastes $2.0 billion annually by flaring gas associated with crude oil extraction. There is crucial need to monetize the gas reserves, reduce gas flaring and its environmental impacts, and to derive he maximum economic benefits from gas production.

The purpose of this research is to identify options for natural gas utilization, evaluate the various strategies and thereupon develop a model for optimizing the natural gas utilization strategies using the Niger Delta as a case study. A Linear Programming model is formulated based on the Transshipment model formulation concept. An objective function is established based on profit derived from the various utilization strategies (represented as nodes on the model) subject to certain constraints. The optimal decision for the model is determined from the solution of the optimization model. Results obtained from this study indicate that the optimal utilization decision involved the continuation of projects (including both current and planned) such as the Liquefied Natural gas project at Bonny (including the sales of both LNG and NGL), supply of gas for domestic use and power generation, transport to West African countries, transport of natural gas to Algeria through the TransSaharan Gas Pipeline (TSGP), and sales of EOR products to market. Upcoming project such as the Olokola LNG was only viable as the gas price increased. Optimal decision is affected by fixed or variable costs and more significantly by changes in market price. Sensitivity analysis is carried out to evaluate impact of changes in the input parameters on the objective function. This research also discusses the impact of gas pricing on the implementation of the Nigerian gas master plan (NGMP).

The model can be used to make optimum decisions in terms of selecting which set of projects would provide maximum benefits from several competing natural gas projects.

DEDICATION

In Loving memory of my DAD,

“LATE MR JOHN OTENE OGBE”.

May his gentle soul rest in peace. Amen.

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CHAPTER ONE

1.0 INTRODUCTION

1.1 PROBLEM DESCRIPTION

Natural gas is a subcategory of petroleum that is a naturally occurring, complex mixture of hydrocarbons, with a minor amount of inorganic compounds. It was once an almost embarrassing and unwanted by-product-or more correctly a co-product- of crude oil production but that notion has since been abandoned because of the huge potential for gas commercialization and utilization *(Wang and Economides, 2009).* .

Nigeria has proven gas reserves estimated to be 184 Tscf, making it the seventh largest reserves in the world (*Oil and Gas Journal (OGJ)*, 2009). A decree was issued by the Nigerian government to stop the flaring of natural gas in hydrocarbon exploration and production (E&P) activities by 2008 all in an effort to realise commercial benefits from the nation's huge gas reserves. However due to several factors mitigating against this investment ideas by the government, this deadline date has far expired but huge volumes of gas are still been flared *(World Energy, 2004).*

The Natural gas available in Nigeria could either be associated or non-associated.Non-associated natural gas is found in reservoirs containing no oil (dry wells). Associated gas, on the other hand, is present in contact with and/or dissolved in crude oil and is coproduced with it and consists primarily of methane. Higher molecular weight paraffinic hydrocarbons (C_2-C_7) are usually present in smaller amounts with the natural gas mixture, and their ratios vary considerably from one gas field to another. Non-associated gas normally contains a higher methane ratio than associated gas, while the latter contains a higher ratio of heavier hydrocarbons*(Matar and Hatch, 1994).*

Nigeria flares more natural gas associated with oil extraction than any other country in the world. Estimate suggests that out of the 3.5 billion cubic feet (Bscf) of associated gas (AG) produced annually, 2.5 billion cubic feet (Bscf), or about 70% is wasted via flaring. This statistical data shows that gas flaring is notoriously unreliable, and Nigeria may waste US $ 2.0 billion per year by flaring associated gas. Flaring is done as it is costly to separate commercially viable associated gas from the oil (*Adewale, 2010*). Companies operating in Nigeria also harvest natural gas for commercial purposes, but prefer to extract it from deposits where it is found in isolation as non-associated gas. Thus associated gas is burned off to decrease costs *(Wikipedia,* 2010*)*. The World Bank estimates Nigeria alone accounts for 12.5% of the world's annual gas flared though the Nigerian government has enacted a policy of "Zero-Gas Flare" by 2008 which has still not been met by the operators. This translates to about 800 Bscf of natural gas flared annually. Hence, energy companies have to develop strategies to utilize the "stranded" gas produced. The Natural gas traded today is strongly driven by long-term and high risk contractual agreements *(Adegoke et al, 2005).*

Major problems in utilizing natural gas worldwide have been predominantly the high transportation costs compared to crude oil. Transportation costs could be as much as four times that of crude. However, the OPEC World Energy Models forecast that world oil demand will rise from 76 MM bbl per day in 2000 to 103 MM bbl/day in 2020 seems to create opportunity for utilization of associated gas (World Energy, 2004). The additional benefits of natural gas utilization such as the reduced green house gas emissions (GHG) would further substantiate the claim for utilization of gas in Nigeria.

Natural gas utilization entails devising a strategy for converting natural gas from the production field to several options for economic benefits in terms of money and the environment. The options for the natural gas utilisation includes : enhanced oil recovery (EOR); conversion of natural gas to gasoline, methanol, CNG, and liquefied natural gas (LNG); transportation of natural gas or its by-products by pipeline, rail and sea; and other in-state utilization options such as use in utility or industry. Most commonly used means of transporting or utilizing natural gas consist primarily of pipelines and LNG. Pipelines account for 75%, with LNG accounting for the rest (EIA, 2004). The properties of LNG (one volume unit of LNG yields 600 units of standard gas volume) allow for its long distance transport by ships across oceans to markets and for its local distribution by truck onshore. Occasionally, liquefaction of natural gas also provides the opportunity to store the fuel for use during high consumption periods close to demand centers, as well as in areas where geologic conditions are not suitable for developing underground storage facilities *(Wang and Economides, 2009).*

Optimization approaches have been adopted over the years in making optimal decisions in terms of selection and cost effectiveness. This concept is applied in this study for optimization of gas utilization. Optimization is the act of obtaining the best result under given circumstances and has featured in the design, construction, and maintenance of any engineering system, where engineers have to take many technological and managerial decisions at several stages. The ultimate goal of all such decisions is either to minimize the effort required or to maximize the desired benefit (Rao, 2009). This involve formulating an objective function and several constraints for constrained optimization (Mathematica tutorials on constrained optimization, 2004).

1.2 OBJECTIVES OF THE STUDY

The objectives of this study are primarily to;

- Review the available options.
- Identify sources and volumes of Natural Gas to be produced.
- Develop a mathematical optimization model for natural gas utilization in the Niger Delta fields (case study) subject to constraints such as economics, environmental factors, etc.
- Solve the optimization problem to identify the natural gas reserve required to meet market demand
- Identify the optimum decision or utilization path that would generate the maximum profits in terms of gas utilization and consumption.

1.3 SCOPE OF THE STUDY

- Utilization options restricted to existing and planned natural gas utilization project in the Niger Delta region of Nigeria
- A transshipment model is developed which is a linear objective function subject to linear constraints.
- Input parameters are obtained from the Niger Delta region. These include Obtaining fixed and operating cost data for the different nodes in the transshipment model scheme, gas composition data for the field, etc.
- The linear optimization problem is solved using a linear optimization software.
- Perform a sensitivity analysis on the base optimum decision by changing the variables affecting the objective function; fixed cost, operating cost, gas and LNG market prices, etc.

1.4 MOTIVATION FOR THE STUDY

- Huge natural gas reserves in the Niger Delta.
- A need to reduce flaring of natural gas and consequently reducing carbon emissions and environmental pollution.
- Economic benefits of natural gas utilization.
- Reduction in Green House Gas (GHG) emissions.

CHAPTER TWO

2.0REVIEW OF LITERATURE

A review of literature is presented to provide the background information for the work. The scope of the review includes the following;

2.1 NIGERIA'S NATURAL GAS

In addition to oil, Nigeria holds the largest natural gas reserves in Africa but has limited infrastructure in place to develop the sector. The Natural gas in Nigeria is found in relatively simple geological structures along the country's coastal Niger River Delta and the offshore blocks. Other prospective hydrocarbon bearing basins include the Benin basin, Anambra basin, Benue trough, etc but these are yet to be fully explored (World Energy, 2004). Figure 2.1 shows the location of the Niger Delta. Associated natural gas production is mostly flared but the development of regional pipelines, the expansion of liquefied natural gas (LNG) infrastructure and policies to ban gas flaring are expected to accelerate growth in the sector, both for export and domestic use in electricity generation. Table 2.1 is a summary of the Nigerian energy profile (Energy Information and Administration (EIA), 2005).

2.1.1 Proven Reserves and Exports

Oil and Gas Journal estimates that Nigeria had 184 trillion cubic feet (Tscf) of proven natural gas reserves as of January 2009, which makes Nigeria the seventh largest natural gas reserve holder in the world and the largest in Africa (Figure 2.2). The majority of the natural gas reserves are located in the Niger Delta *(OGJ, 2009)*.

Approximately 749 Bscf were exported, mostly as liquefied natural gas (LNG). Most of the gas reserve is located offshore. Fifty seven percent of Nigeria's gas production or 2.6 Bscf/d is from offshore fields. In 2007, Nigerian exports of LNG to the US were 95 Bscf, making it the third largest source of LNG imports after Trinidad (447 Bscf) and Egypt (115 Bscf). Nigeria exported close to 500 Bscf of LNG in 2009. Of this total, 2% went to the United State, 66% went to Europe mainly Spain (31%), France (19%) and Portugal (16%). Other export destinations include Asia (15%) and Mexico (16%). (EIA, 2010).

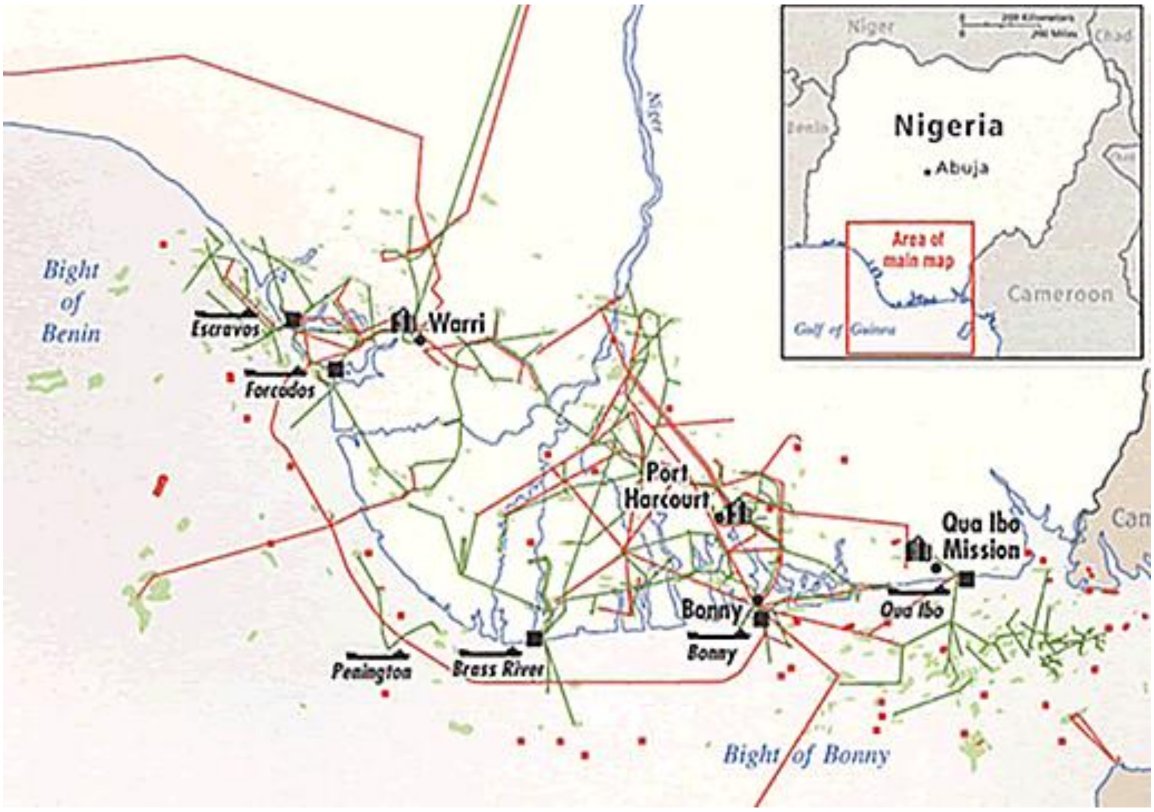


Figure 2.1; The Niger Delta region of Nigeria (EIA, 2010)

2.1.2 Nigerian Energy Consumption

According to the International Energy Agency (IEA), in 2007, total energy consumption was 4 Quadrillion Btu (107,000 kilotons of oil equivalent). Of this, combustible renewables and waste accounted for 80.2 % of total energy consumption. This high percent share represents the use of biomass to meet off-grid heating and cooking needs, mainly in rural areas. IEA data for 2008 indicate that electrification rates for Nigeria were 47 percent for the country as a whole. In urban areas, 69 % of the population had access to electricity compared to rural areas where electrification rates were 26 %. Approximately 81 million people do not have access to electricity in Nigeria. (EIA, 2010).

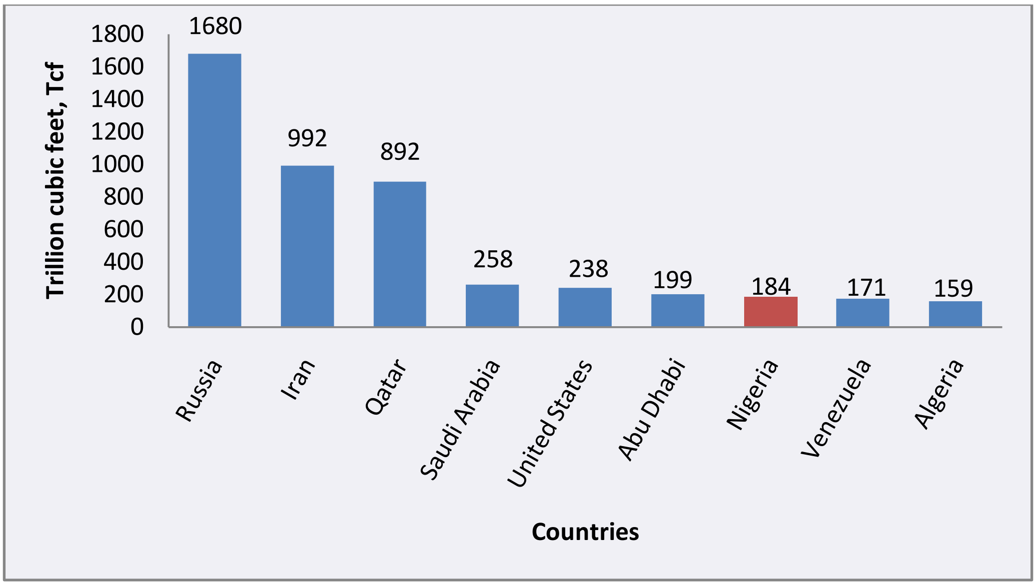


Figure 2.2; Top proven Natural Gas Reserve Holders

Table 2.1: Summary of Nigeria Energy Profile *(EIA, 2010)*

Energy Overview	
Proven Oil Reserves (January 1, 2009E)	36.2 billion barrels
Oil Production (2008E)	2.17 million barrels per dayof which 90% was crude oil (1.94 million).
Oil Consumption (2008E)	286 thousand barrels per day
Net Oil Exports (2008E)	1,883 thousand barrels per day
Proven Natural Gas Reserves (January 1, 2009E)	184 trillion cubic feet
Natural Gas Production (2007E)	1,204 billion cubic feet
Natural Gas Consumption (2007E)	456 billion cubic feet
Net Natural Gas Exports (2007E)	749 billion cubic feet
Recoverable Coal Reserves (2005E)	209 million short tons

Coal Production (2007E)	0.009 million short tons
Coal Consumption (2007E)	0.009 million short tons
Electricity Installed Capacity (2006E)	5.96 GigaWatts
Electricity Production (2006E)	22 billion kilowatt hours
Electricity Consumption (2006E)	16 billion kilowatt hours
Total Energy Consumption (2006E)	1 quadrillion BTU*, of which Oil (53%),
Total Per Capita Energy Consumption (2006E)	Natural Gas (39%), Hydroelectricity (7%), Coal (0%), Nuclear 7.8 million BTU
Energy Intensity (2006E)	5,901 BTU per $2000-PPP**
Environmental Overview	
Energy-Related Carbon Dioxide Emissions (2006E)	101 million metric tons
Per-Capita Energy-Related Carbon Dioxide Emissions (2006E)	0.8 metric tons
Oil and Gas Industry	
Organization	The Nigerian National Petroleum Corporation (NNPC) manages the state-owned oil industry.
Major Refineries	Port Harcourt-Rivers State (150,000), Kaduna (110,000), Warri (125,000), Port Harcourt-Alesa Eleme (120,000)

2.1.3 Flaring of Natural Gas

Nigeria flares its natural gas chiefly because its oil fields lack the infrastructure to produce and market associated natural gas. According to the National Oceanic and Atmospheric Administration (NOAA), Nigeria flared 593 Bscf of natural gas in 2007, which, according to NNPC, cost the country US$ 1.46 billion in lost revenue. Figure 2.3 show the volume of gas flared in 2007 by the top 9 countries in the world. The government of Nigeria has been working to end natural gas flaring for several years but the deadline to implement the policies and fine oil companies has been repeatedly postponed with some analysts pushing the date as far forward as 2012. In 2009, the Nigerian government developed a Gas Master Plan that would promote new gas-fired power plants to help reduce gas flaring and provide much-needed electricity generation. (EIA, 2010).

Gas flaring is generally discouraged as it releases toxic components into the atmosphere and contributes to climate change. The World Bank reported in 2004 that, "Nigeria currently flares 75% of the associated gas it produces. Gas flaring releases large amounts of methane, which has a high global warming potential. Gas flares have potentially harmful effects on the health and livelihood of the communities in their vicinity, as they release a variety of poisonous chemicals. Humans exposed to such substances can suffer from a variety of respiratory problems. The international community, the Nigerian government, and the oil corporations seem in agreement that gas flaring needs to be curtailed but efforts have been limited over the years *(Wikipedia, 2010).*

2.1.4 Security in the Niger Delta

The Nigerian natural gas sector is also affected by the security issues in the Niger Delta. Projects are often delayed or shut-in as a result of sabotage, bunkering, and general insecurity. Most recently, the Escravos Gas to Liquids (GTL) project was delayed until 2012 (from 2010 earlier scheduled).

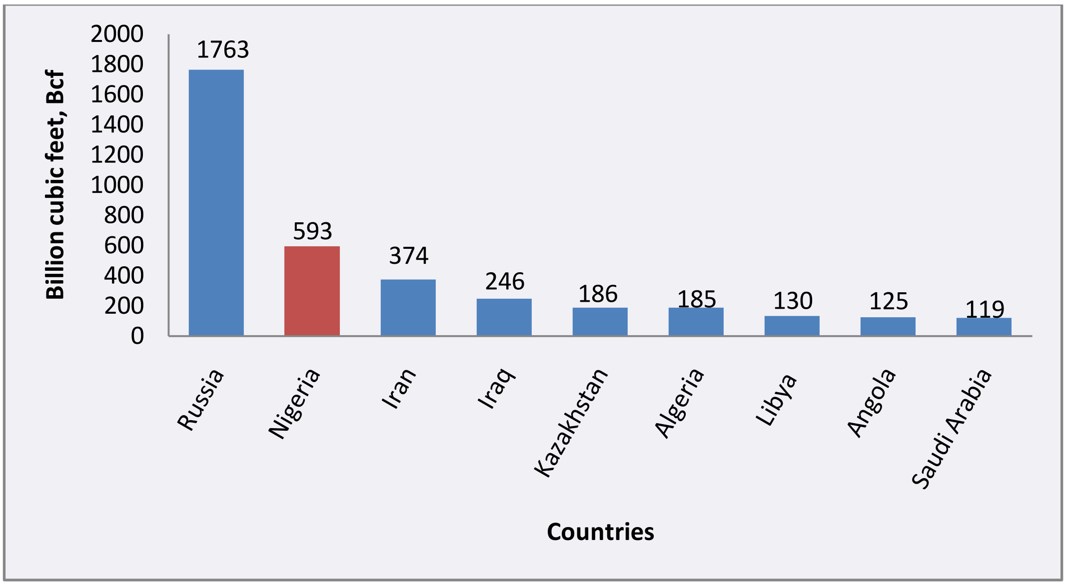


Figure 2.3; Top natural gas flares in the world

2.2 NIGERIA LEGISLATION IN FAVOR OF GAS UTILIZATION

Some legislations have recently come on board to encourage more gas utilization opportunities which would finally bring to an end the era of gas flaring. These legislations are geared towards providing the needed incentives such as tax breaks for the International Oil companies (IOC) , to motivate them in speeding up the natural gas utilization projects. These legislations include the Nigerian Petroleum Industry Bill and the Nigerian Gas Master Plan.

2.2 1 Nigerian Petroleum Industry Bill

In order to remedy some of problems of associated with the utilization of Natural gas and oil, the Nigerian government is currently debating a Petroleum Industry Bill (PIB) that is designed to reform the entire hydrocarbon sector. Parts of the PIB have recently been made into law while the Bill in its entirety continues to be debated by the National Assembly (Thisdayonline, 2010)

2.2.2 Nigeria Gas Master Plan

With estimated reserves of 184Tscf, Nigeria, which the world's 7th largest natural gas producer has flared its gas heavily in the past due to a non-existent domestic gas market and underdeveloped infrastructure. With the emergence of liquefied natural gas and natural gas liquid exports this has been reduced to approximately 30 to 35 percent, or just under 2.5 Bscf/day which is still a fraction of its available huge reserves. Gas exports now contribute billions to government revenues, with the majority coming through the Nigeria Liquefied Natural Gas Limited's project in Bonny Island in the Niger Delta. Nigeria LNG is a joint venture between the Nigerian National Petroleum Corporation, Shell, Total LNG Nigeria Limited and Eni. *(Thisafricaonline, 2010)*.

Efforts to address the issue of infrastructure were put into action when in February 2008 the Nigerian government announced a comprehensive new "Gas Masterplan" that seeks to improve supply to a domestic market that has become a feasible destination for gas in recent years, boost production for exports and provide much needed energy to the power sector. However, progress has been slow due to the issue of pricing and absence of a clear legal and regulatory framework. Part of the new gas policy would oblige oil producers to sell increased amounts of gas to the domestic sector at prices that are a fraction of international export markets. Oil producers are reluctant to comply with such a request, as it would effectively force them to lose money (Onyeukwu, 2010).

2.3 GAS UTILIZATION OPTIONS

Gas utilization entails putting natural gas, which has severally been regarded as a waste in Nigeria, into economic and environment use. The utilization options employed worldwide includes;

- **Pipeline Transportation**; This approach to utilizing gas has been in existence for long and still remains a significant mechanism for gas transportation to markets. Existing routes in Nigeria include the West African Gas Pipeline, WAGP and the Trans Saharan Gas Network, TSGP.
- **HVDC Light**; Gas-to-wire project under which gas is used to generate electricity, then converted to High Voltage Direct Current for long distance transmission to the market (Verghese, 2003).
- **Compressed Natural Gas, CNG**; CNG can be made by compressing natural gas (which

is mainly composed of methane), to less than 1% of the volume it occupies at standard atmospheric pressure. It is stored and distributed in hard containers at a pressure of 200-248 bar, usually in cylindrical or spherical containers (*Wikipedia,2010).*

- **Hydrate Transportation**; A new technology which involves conversion of natural gas to hydrates before transporting to markets (Verghese, 2003).
- **Liquefied Natural Gas, LNG**; LNG is natural gas that has been cooled to the point that it condenses to a liquid, which occurs at a temperature of about -256^{o}F (-161^{o}C) at atmospheric pressure. Liquefaction reduces the volume of gas by as much as 600 times thus making it more economical to store natural gas where other forms of storage do not exist, and to transport gas over long distances for which pipelines are too expensive or other constraints exist (CEE, 2006).
- **Gas to Liquid, GTL**; Gas to liquids (GTL) is a refinery process to convert natural gas or other gaseous hydrocarbons into longer-chain hydrocarbons such as gasoline or diesel fuel *(Wikipedia, 2010)*. GTL technology generally refers to the chemical conversion of natural gas into readily transportable liquids such as methanol or conventional petroleum refinery type distillate fuels *(Chinenye et al, 2007)*. Methane-rich gases are converted into liquid synthetic fuels either via direct conversion or via syngas as an intermediate, for example using the Fischer Tropsch or Mobil processes. It is an emerging technology which involve chemical transformation of natural gas, either into synthetic fuels (syncrude, diesel, kerosene, etc) or chemicals (methanol, DME, etc) *(Balogun and Onyekonwu, 2009).*
- **Enhanced Oil Recovery, EOR**; EOR is the third stage of hydrocarbon production proceeding primary and secondary recovery, during which sophisticated techniques that alter the original properties of the oil are used. Enhanced oil recovery can begin after a secondary recovery process or at any time during the productive life of an oil reservoir. Its purpose is not only to restore formation pressure, but also to improve oil displacement or

fluid flow in the reservoir *(Schlumberger, 2010)*. Some EOR processes utilize natural gas for enhanced recovery of oil, e.g. miscible gas injection.

- **Natural Gas liquids, NGL;** Generally such liquids consist of propane and heavier hydrocarbons and are commonly referred to as lease condensate, natural gasoline, and liquefied petroleum gases.*(EIA, 2010)*.When a wet gas gets to the surface, it forms a liquid which constitute the NGL (Oligney and Economides, 2002).
- **Liquefied Petroleum Gas, LPG;** LPG has long been confused with propane. But it is in fact predominantly a mixture of propane and butane in a liquid state at room temperatures when under moderate pressures of less than 200 psig (CEE, 2006).
- **Underground Storage;** This is another utilization option when natural gas utility is to be deferred for future use by injecting into underground storages. This gas resource can be accessed for later use when it is convenient (Atoyebi, 2010)

2.4 SOURCES OF NATURAL GAS IN NIGERIA

Nigeria has more than 250 oil and gas fields, with about 2,600 producing oil wells and a total oil production of about 2 million barrels per day (MMSTB/d) *(World Energy, 2004)*. In 2007, Nigeria produced 1,204 billion cubic feet (Bscf) of natural gas, while consuming 456 Bscf (*Energy Information Administration, 2010*). All the accumulations of Natural Gas of commercial extent have been proven to exist in the Niger Delta region of Nigeria. The raw gas comes either as associated or non-associated gas. Associated or dissolved gas is found with the crude oil. This gas can exist dissolved in the crude oil (dissolved gas) or as a free gas in contact with the crude oil (sometimes called gas cap gas). Natural gas from gas and condensate wells, in which there is little or no oil, is termed non associated gas (*Naturalgas, 2010)*. All the crude oil reservoirs contain dissolved gas and may or may not contain free gas. Non associated gas is found in a reservoir that contains a minimal quantity of crude oil *(Guo et al, 2005)*. The prominent fields with either associated or non associated natural gas accumulations are described the following section;

2.4.1 Bonga Field; This is located in License block OPL 212 off the Nigerian Coast, which has now been renamed as OML 118 in February 2000. The field covers approximately 60km^2 in an average water depth of 1,000metres (3,300 ft). The field produces both crude oil and natural gas; the crude oil is offloaded to tankers while the gas is piped back to Bonny in Nigeria where it is exported via an LNG plant. The field contains approximately 6,000 MMBOE.

The daily production of oil stands at 202,000 BOPD (2006) and gas production is 150MMscf/d. The estimated oil and gas in place stood at 1470 MMbbl and 965 Bscf *(Shell, 2010).*

2.4.2 Akpo Field; Situated offshore Nigeria in 1400m of water, Akpo field, which is operated by Total with 24% interest, has a daily production of 175,000 B/D of condensate and 320 MMSCF/D of gas for onward shipment to the NLNG plant at Bonny. The recoverable reserve stands at 620 MMbbl of condensate with density of 53 ^{O}API *(Wikipedia, 2010).*

2.4.3 Oso Field; About 89 km south-west of Mobil's Qua Iboe terminal and 67 km from the Bonny island gas processing system, Oso is a giant gas field by African standards now producing 110,000 bbl/d. The field has had enough reserves to recover at least 500m barrels of condensate in a 20-year production period and to still have a deposit of about 3,500 Bscf.

Mobil can recover liquids, including butane, C_4H_{10} and propane,C_3H_8 from the crude oil. As the gas is forced to the surface, it cools and takes the form of condensate, having the qualities of a very light, almost sulphur-free crude oil. Gas associated with condensates is then re-injected into Oso for pressure maintenance *(Online library, 2010).*

2.5 INFRASTRUCTURE AND ACCESSIBILITY

Most of the gas in Nigeria has been referred to as stranded. The current infrastructure for the use of gas inside Nigeria includes a transportation network and some gas utilization projects. The infrastructure in use depends on whether the gas field is located onshore or offshore.

2.5.1 Onshore Location

When the producing oil field is located onshore, whether land or swamp, the producing well is tied to a flow station, which serves as the collection centre for many wells, and the facility is used to separate gas from the remaining hydrocarbon fluid. Much of the separated gas is flared at the flow station while some is sent to the gas gathering system for treatment for domestic or export use. Gas producing fields are connected directly to the processing plants for treatment *(World Energy, 2004)*.

2.5.2 Shallow offshore and Deep offshore

A well located in shallow waters, may be tied to a fixed platform where the gas is partially separated from the remaining hydrocarbon fluid. Offshore wells have been developed with the use of an FPSO, which enable full treatment and storage of the hydrocarbon for immediate export. Associated gas produced in deep offshore via an FPSO can be connected to an offshore gas gathering unit and sent to the nearest LNG facility where it can liquefied and exported *(World Energy, 2004)*.

2.6 STRATEGIES FOR NIGERIAN GAS UTILIZATION

Utilization of natural gas in Nigeria has been a topic of discussion in recent years. There are two potential markets for Nigerian Natural gas: domestic markets and foreign or export markets. Domestic markets include power generation, cement industry, Iron and Steel Industries, Fertilizer Industry, Petrochemicals, etc. Export include Natural gas as LNG, pipeline export, NGL, etc. The National Gas Company (NGC), is responsible for local utilization of natural gas. A large potential market exists for investors in this area. Domestic gas demand is about 400 million cubic feet a day (400 MMscf/d), which is very low compared to the size of Nigeria's population and its gas resources. The domestic market is limited by the low level of industrialization and the inadequacy of the gas transmission and distribution infrastructure. The power sector currently accounts for almost 90% of domestic gas sales *(CEE, 2006).*

NNPC and other major E & P operators are currently embarking on several gas utilization projects for export. The major existing and future expected projects include the Gas liquefaction project, Gas to liquid project, Gas transportation by pipeline project, etc. These utilization strategies, both domestic and foreign are discussed in details below.

2.6.1 Nigerian Liquefied Natural Gas Project (NLNG) Project

The LNG (liquefied natural gas) facility on Bonny Island was completed in September 1999 (Train 1 and 2). The facility processes 252.4 Bscf of LNG annually. Initially, the facility is to be supplied from dedicated non associated gas fields, but within a few years it is anticipated that half of the input gas will consist of associated (currently flared) gas. Construction of a third LNG production train, with an annual capacity of 130.6 Bscf, was completed and operational in December of 2002. The third LNG train increased NLNG's overall LNG processing capacity to 383 Bscf per year. *(CEE, 2006).* Trains 4 and 5, or "NLNGPlus Project", were developed by Halliburton and KBR in 2005 . The plant has an overall production capacity of 16.8 million tons per year (MMT/y) of LNG, 2 MMT/y of LPG, and 1 million tons of condensate processing 1,334 MMscf/d of gas. This will bring the overall capacity of the five trains to 2,810 MMscf/d of gas intake. Additionally, a sixth train has also commenced production *(NLNG, 2010).*

The non-associated producing fields include Obite, Obiafu and Soku fields respectively. It is expected that flaring will be substantially reduced following the immense investment in this project, in addition to the expected huge returns (*NAPIMS*, 2006*).*

2.6.2 Brass LNG

Brass LNG was incorporated in 2004 as a company and four stakeholders in 2006 signed the Shareholders Agreement for the Brass LNG Project. The shareholders were Nigerian National Petroleum Corporation (NNPC), ENI International, Phillips (Brass) Limited (an affiliate of

ConocoPhillips) and Brass Holdings Company Limited - an affiliate of TotalFinaElf (*LNGpedia, 2005)*. The financial investment decision is planned for the first quarter of 2011 with a total capital cost estimate of $15 billion *(LNGWorld, 2005)*.

2.6.3 Escravos Gas Project

Escravos Gas Project (EGP). EGP 1, the first major gas project to gather and process associated natural gas in Nigeria, came on stream in 1997. The project’s second phase – extending capacity to 285 MMscf/d – began operations in 2000. A planned Phase 3 will process up to 400 MMscf/d. The completed project will export 40,000 barrels per day of liquefied petroleum gas and condensate. NGLs are stripped for export and the remaining gas is currently used domestically. The EGP-3 will process an additional 400 MMscf/d of gas from ChevronTexaco's northern offshore fields *(Allafricanews, 2010)*.

Escravos Gas-to-Liquids; Chevron Nigeria Ltd. and the Nigeria National Petroleum Corp. are constructing a 33,000-barrel-per-day gas-to-liquids plant in Escravos, Nigeria, to convert natural gas into clean transportation fuels. Facility construction is under way. The new facility is expected to convert 325 MMscf of natural gas into 33,000 barrels per day of GTL diesel fuels, GTL naphtha and liquefied petroleum gas (Chevron, 2010). The GTL plant is expected to cost $6 billion overall and to become operational by 2012 *(Chevron, 2010)*.

Olokola LNG Project; Chevron is participating in development of the proposed Olokola LNG Project, which includes plans for a 4-train natural gas liquefaction facility and marine terminal located northwest of Escravos. The LNG would be marketed to the Atlantic basin *(Chevron, 2005)*.

The contract was awarded to Delta Afrik – an indigenous company at the cost of $14.6 million by partners, the NNPC, Chevron and recently, Shell. The project will generate foreign exchange through export of LNG; produce 300,000 barrels a day of Liquefied Petroleum Gas (LPG) and condensates, which will be sold as by-products. The initial gas would come from Shell and Chevron operated joint ventures, approximately 1 Bscf/day of gas *(African oil Journal, 2007)*

2.6.4 Oso NGL Project

MOBIL JV NGL plant located at its OSO field in the south-eastern part (Akwa Ibom) of Nigeria started production for export during the third quarter of 1998. The Oso Phase 2 Project is to provide additional gas make-up for the OSO NGL as well as maintain condensate production at the expected plateau (*NAPIMS, 2005).*

Figure 2.4; Map showing the location of LNG plants in the Niger Delta
(Source: EIA, 2006)

2.6.5 Belema Gas Injection project

SHELL JV Belema Gas Injection project is aimed at reducing flares in five flow stations by re-injecting some of the gas, some for gas lifting, and some for use as fuel by local industries and the excess for backing out Non-Associated Gas, NAG, that is currently used to meet various existing contractual obligations. The contracts for the execution of the Engineering, Procurement and Construction (EPC) and gathering pipelines are still in the early stages of execution. About 80 MMscf/d of gas is been utilized (National Petroleum Investment Management Services (*NAPIMS, 2006).*

2.6.6 The West African Gas Pipeline Project (WAGP)

This project run by the parties in The Shell Petroleum Development Company of Nigeria (SPDC) Joint Venture is owned by West African Gas Pipeline Company Limited (WAGPCo), a consortium of Chevron (36.7%), NNPC (25%), Royal Dutch Shell (18%), and the state owned companies in Ghana, Benin and Togo. Shell is expected to supply half of the initially required gas required *(Shell, 2010)*. The $924-million world bank project will traverse 758km (474 mile) both on and offshore to its final planned terminus at Tokoradi in Ghana shown in Figure 2.5. The diameter of the pipeline is 18" with a maximum discharge of 5 Bscm per year (176 Bscf per year) (Wikipedia, 2010). Initial capacity estimate of 200 million cubic feet per day (MMscf/d), would eventually reach full capacity of 450 MMscf/d. *(EIA, 2010)*.

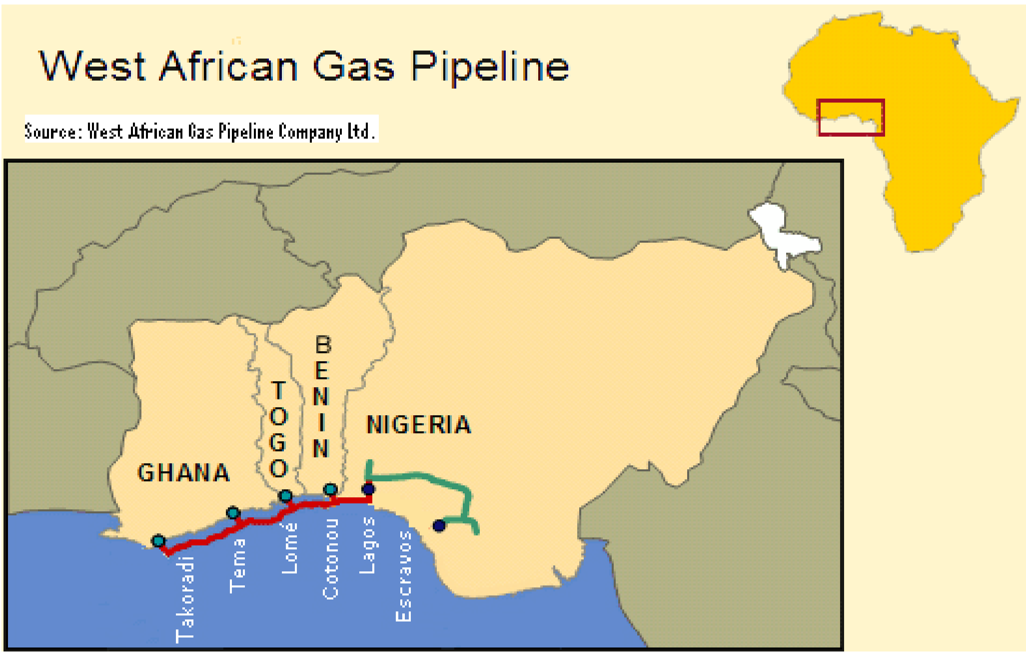


Figure 2.5; Distribution network for the West Africa Gas Pipeline (Source: Wapco, 2006)

2.6.7 Trans-Saharan Gas Pipeline

Nigeria underlined its determination to penetrate the European gas market when it signed preliminary agreements with Algeria on a planned Trans-Saharan Pipeline running through the North African country into Europe. The project would seek to connect the Nigerian gas field with that of Algeria, to the European market. The 2,565-mile (4,128-km) pipeline would carry natural gas from oil fields in Nigeria's Delta region to Algeria's Beni Saf export terminal on the Mediterranean. In 2009 the NNPC signed a memorandum of understanding (MoU) with Sonatrach, the Algerian national oil company. Several national and international companies have shown interest in the $ 12.2 billion project including Total and Gazprom (*EIA, 2010*).

2.6.8 The Gbaran-Ubie Integrated Oil and Power

The Gbaran-Ubie project aims to further develop Nigeria’s oil and gas resources and will ensure government targets to reduce gas flaring. The project which is fully operational will be capable of producing 1 billion standard cubic feet of gas a day (scf/d), equivalent to about a quarter of the gas currently produced for export and domestic use in Nigeria. It will also produce as much as 70,000 barrels of oil per day *(Shell, 2010)*.

2.6.9 The Afam Integrated Gas and Power Project

The Afam integrated gas and power project is owned by Shell Petroleum Development Company (SPDC). It consist of the Afam VI power plant and the Okoloma gas plant in Rivers State, the Niger Delta. When fully operational, this integrated project will increase Nigeria’s power supply by about 20% of current operational capacity and the country’s domestic gas supply by some 20%.

The 650-megawatt (MW) combined-cycle power plant is an advanced design that requires only two thirds of the gas needed by many of Nigeria’s existing power plants to generate each unit of electricity. Afam VI’s gas turbines generate up to 450MW of power. Waste heat from the plant is then used to generate a further 200 MW of very low emission electricity *(Shell, 2010)*.

2.6.10 Expansion of domestic gas distribution network

Several distribution schemes are planned to help promote Nigerian consumption of natural gas. The proposed $745-million Ajaokuta-Abuja-Kaduna pipeline will deliver gas to central and northern Nigeria, while the proposed $552-million, Aba-Enugu-Gboko pipeline will deliver natural gas to portions of eastern Nigeria. The Lagos State government and Gaslink Nigeria Limited (Gaslink), a local gas distribution company, are developing a pilot program to deliver natural gas to nine residential neighbour hoods in the state. Gaslink recently began supplying gas to nearly 30 industrial customers in Lagos Ikeja industrial district *(CEE, 2006)*.

2.7 LINEAR OPTIMIZATION IN NATURAL GAS UTILIZATION

The concept of optimization is an important tool in natural gas transportation problems. Optimization is the act of obtaining the best result under given circumstances. In design, construction, and maintenance of any engineering system, engineers have to take many technological and managerial decisions at several stages. The objective of solving optimization problems is to minimize or maximize some function called the objective function *(Kreyszig, 2006)*. The ultimate goal of all such decisions is either to minimize the effort required or to maximize the desired benefit. Since the effort required or the benefit desired in any practical situation can be expressed as a function of certain decision variables, *optimization* can be defined as the process of finding the conditions that give the maximum or minimum value of a function*(Rao, 2009).*

Linear programming or optimization consists of methods of formulating and solving Linear optimization problems with constraints, i.e., methods of finding a maximum (or minimum) of a linear objective function. Appendix A contains additional discussion on LP.

2.8 RESEARCH FORMULATION

A linear transshipment model (essentially a linear programming model) was formulated based on gas utilization options available in the Niger Delta. The transshipment model consists of a source, process and destination nodes to represent centres of activity. An objective function encompassing all the optimization nodes considered is defined. A set of linear constraints were also defined to restrict the model based on some criteria such as gas composition limit, maximum deliverability at the destination nodes, etc.

The model formulated was solved using optimization software called LINDO (Linear

Discrete Optimizer) because of the large number of variables and equations. The Simplex method of solving linear programming problems embedded in the software was used to solve the model. The solution to the model provides the maximum income realized from the utilization study over a period of 20 years. This basis of 20 years was chosen because typical gas contract agreements period ranges between 20 to 25 years. From the solution of the model, the optimum decision ccan be selected.

2.9 SUMMARY

- The chapter began by reviewing the Nigeria Natural Gas potential and the level of flares that would have otherwise been harnessed to generate huge revenues for the country.
- Gas utilization options worldwide were reviewed.
- The utilization options in Nigeria, both currently projects and planned futures projects, were also reviewed.
- The source of the major oil and gas fields were reviewed.
- A brief aspect to Optimization was introduced with particular emphasis on Linear programming because of its importance in development transshipment problems.

CHAPTER THREE

3.0 METHOLOGY

The optimization model for gas utilization in the Niger Delta region of Nigeria is developed in this section. Methodology used in this study is shown in Figure 3.1. A linear transshipment modelling approach similar to Lannom et al (1996) was adopted. An optimization scheme was constructed with centres of activities represented by nodes. These nodes include source, process and destination (market) nodes. The gas composition data, cost data (fixed and variable costs), gas price, and deliverability requirement are the necessary parameters used to implement the model. The cost data and other relevant data mentioned earlier in Chapter One is input in the model and the model is run to obtain the best solution to the optimization problem. The best solution to the model provides a way of determining the optimal decision strategy. A sensitivity analysis is then carried out on the cost data and market price to ascertain the effect of varying the cost on the optimum decision. Additionally, the effect of considering the gas price for the Nigerian Gas Master Plan was investigated. The different components for the study methodology are presented below;

3.1 MODEL FORMULATION SCHEME

The modeling of natural gas resources in the Niger delta from source to destination is based on the current and future gas utilization projects embarked by the Nigerian Government and International Oil Companies. These projects which were discussed in Chapter Two include options like LNG, GTL, Pipeline transport, Power generation, Enhanced oil Recovery, etc. The modeling scheme follows the approach presented in Figure 3.2. It consists of a source of Natural gas or source node (Niger Delta fields in this case), intermediate processing facilities or intermediate nodes and a final destination or terminal node. A summary of the model formulation is presented on Table 3.1.

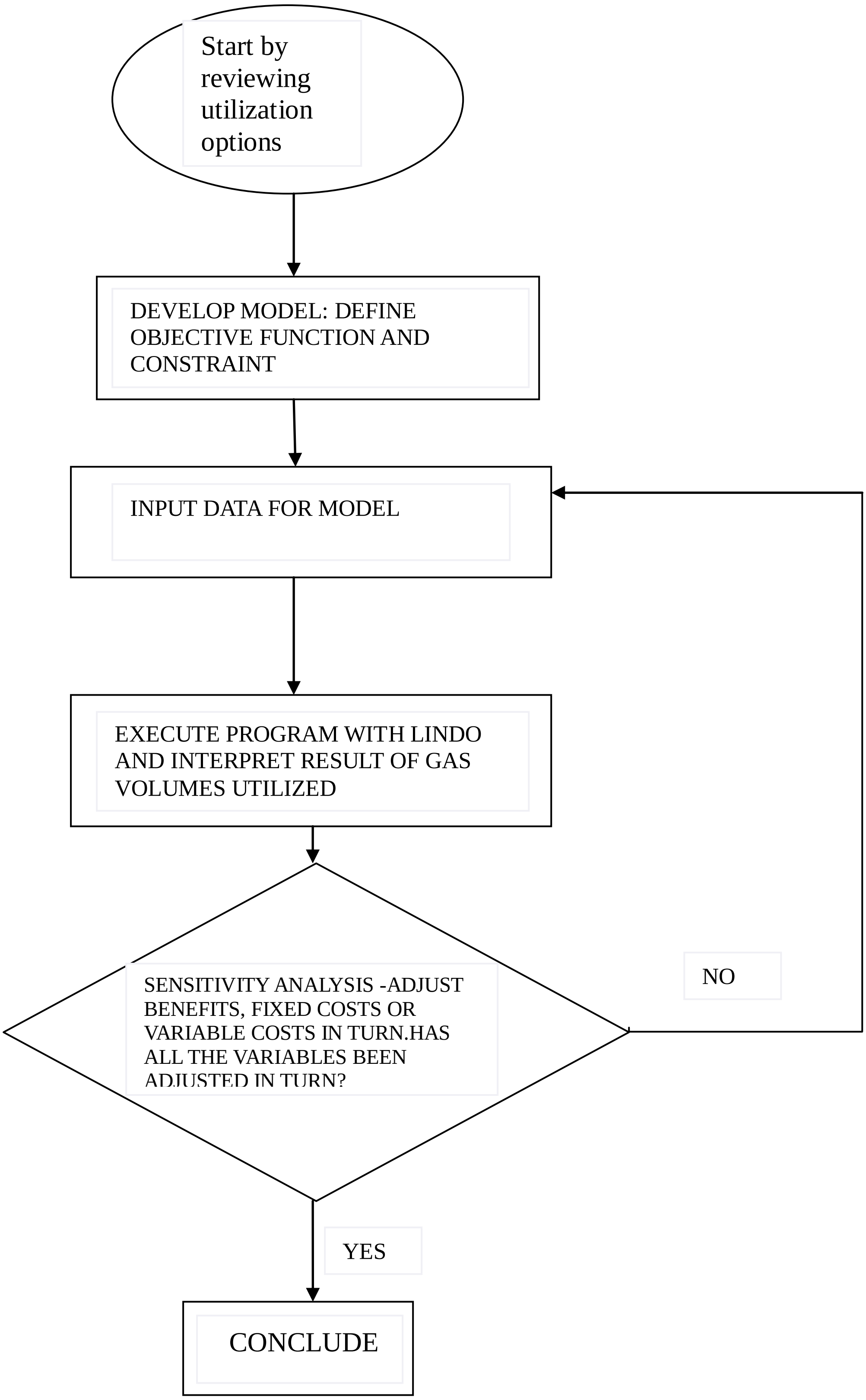


Figure 3.1; Flow chart for the methodology

Table 3.1; Transshipment Model Formulation

Gas Source	Processes	Transportation option	Market
Niger Delta Natural Gas	Conversion to NGL	Marine tankers	Europe
	Conversion to LNG		
	Gas To Liquid		North America
	Conversion to CNG	Pipeline	
	Conditioning for Pipeline		Asia
			West Africa and Algeria
	EOR		Domestic use

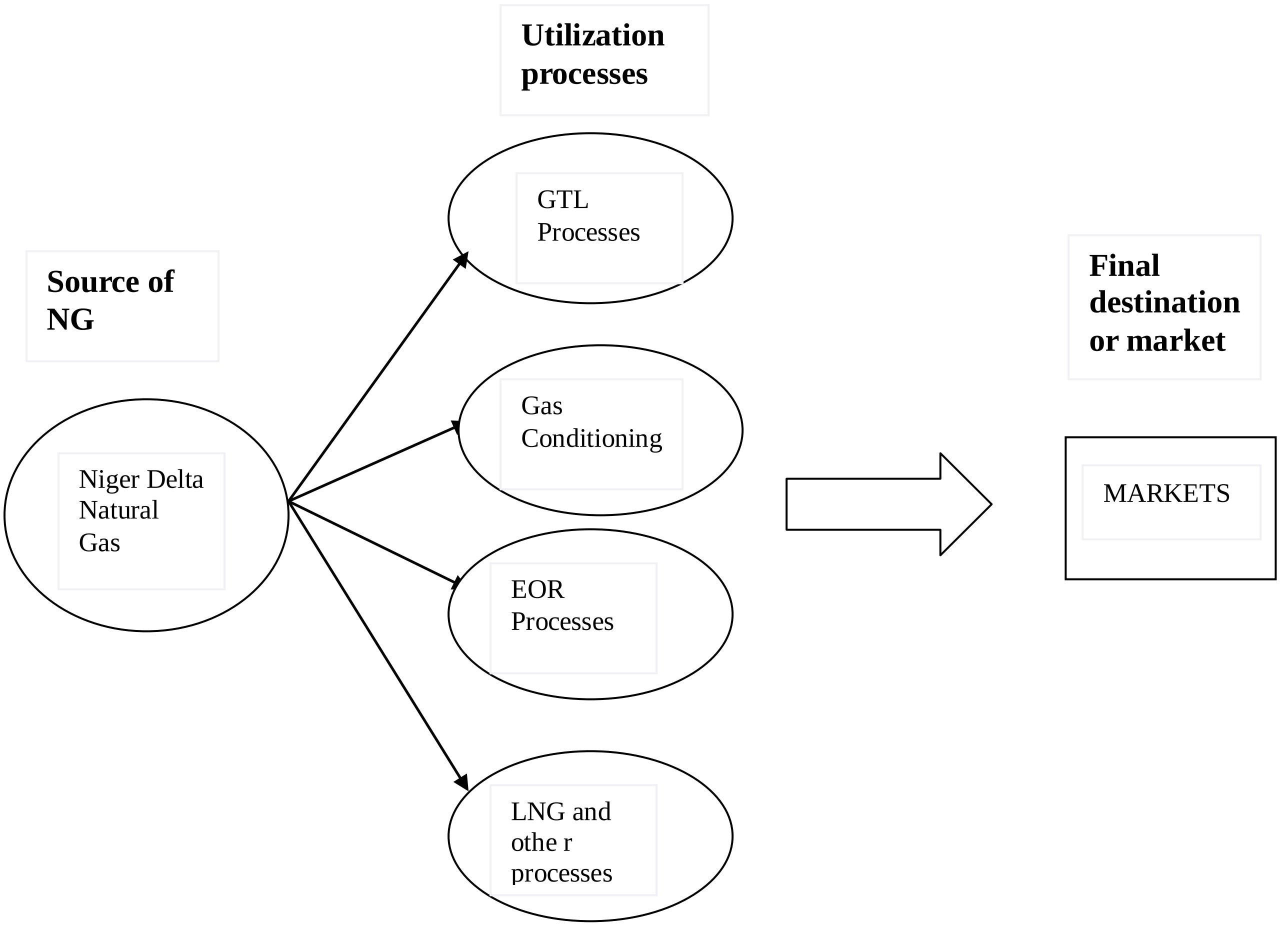


Figure 3.2; Process path for optimization

3.1.1 MODEL ASSUMPTIONS

Some of the assumptions that were made in deriving the model include;

1. Model is derived based on market indices of cost and price. Other factors such as political and social factors are not considered. Thus implying the optimal decision from this model is not influenced by political or social factors.
2. Model is a transshipment model with a single source node feeding series of process and destination nodes. The source description in this case consists of a node with no inflow while a destination has no outflow. However, a process node has both inflow and outflow.
3. All assumptions inherent in a linear programming model such as linearity and proportionality between the constant and the variable in both the objective function and constraints are also applicable.
4. There is no time lag at each of the nodes. The gas transshipped from a particular node just proceeds immediately to the next node.

3.1.2 PROPOSED NATURAL GAS OPTIMIZATION SCHEME

A 20 node natural gas utilization model was developed for the Niger Delta based on data listed in Table 3.1. The Linear programming model proposed is a transshipment model consisting of a source node, intermediate or process node and a destination or termination node. The utilization scheme as proposed for the Niger Delta region of Nigeria is presented in Figure 3.3. This model consists of existing and upcoming utilization options in the Niger Delta region of Nigeria. A summary of the different path in the utilization scheme is presented in Table 3.2

3.2 OPTIMIZATION MODEL APPLIED TO NATURAL GAS UTILIZATION

The natural gas utilization model described in Section 3.1, is a transshipment model. *(Hillier and Lieberman, 2001).* A linear programming approach is therefore adopted in solving the problem *(Lannom et al, 1996)*. Following the general format of LP formulation, both an objective function and sets of constraints are required.

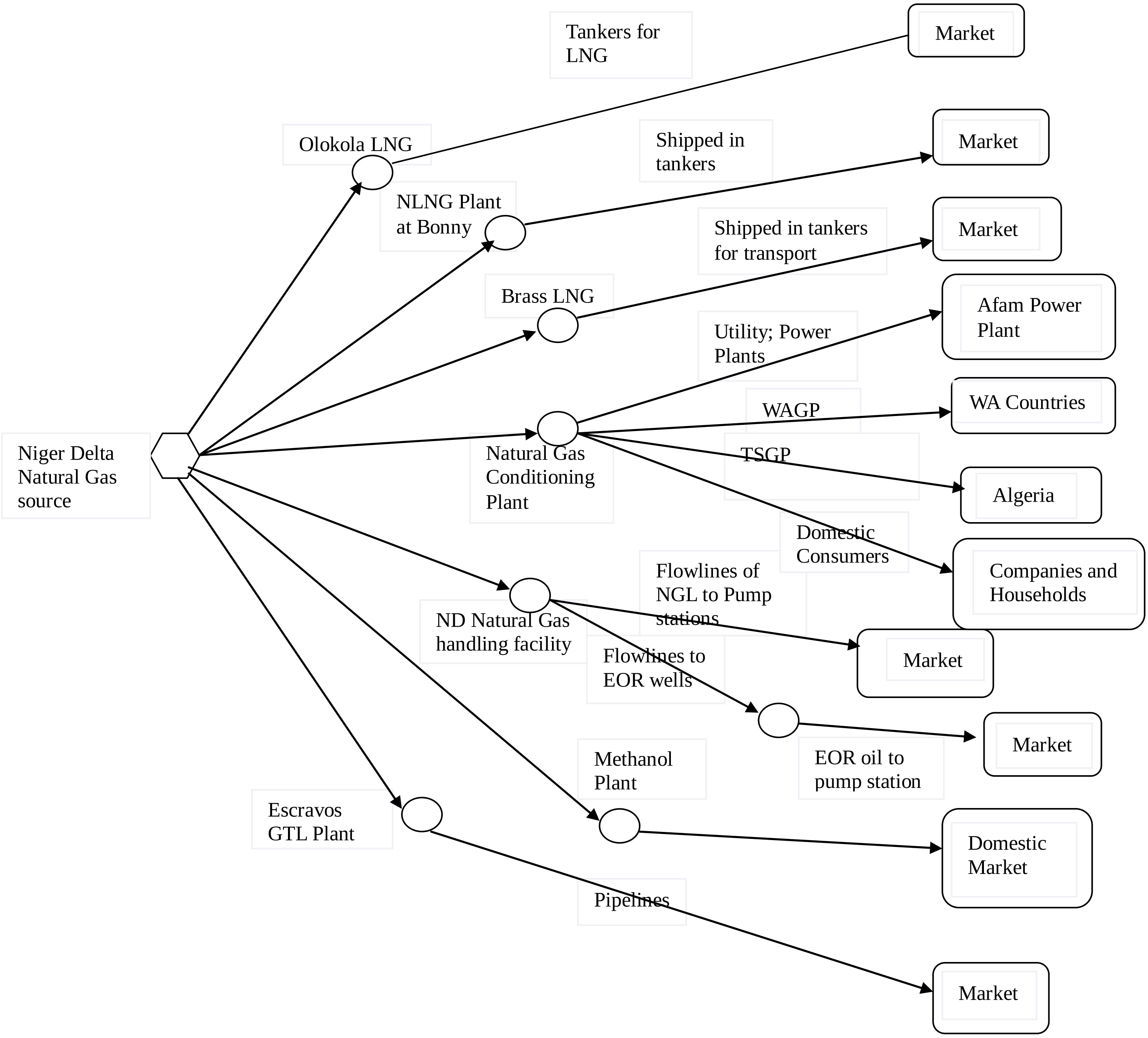
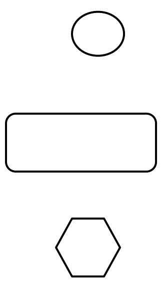


Figure 3.3; Original utilization strategy consisting of 20 nodes for the Niger Delta



Key

◯	**Process Node**	**ND; Niger Delta**
▭	**Terminal or destination node**	**WAGP; West African Gas Pipeline**
⬡	**Source node**	**TSGP; Trans Saharan Gas Pipeline**

Table 3.2; A summary of the different path in the utilization scheme

Destination node Path	Process
0-a-1	Natural Gas from source through Olokola to market
0-b-2	Natural Gas from source through NLNG to market
0-c-3	Natural Gas from source through Brass LNG to market
0-d-4	Conditioning of natural gas at source for utility (Power generation)
0-d-5	Conditioning of natural gas at source for WAGP
0-d-6	Conditioning of natural gas at source for TSGP
0-d-7	Conditioning of natural gas at source for local consumption (Domestic and Industrial)
0-e-8	Conversion of heavier part of Natural Gas for NGL use (Butanes and Pentanes)
0-e-f-9	Use of gas for EOR (miscible injection) and pressure maintenance and subsequent transportation of EOR oil to market
0-g-10	Conversion of NG to Methanol for onward delivery to market
0-h-11	Conversion of NG to GTL (syncrude) at Escravos to market

The LP model type developed is the Mixed Integer LP model due the criteria for some of the variables to be integers.

The objective function is based on the income derived on each natural gas commercialization option. This function is subject to constraints in terms on the source volume capacity, nodal constraints, quality of gas requirement, and deliverability at the destinations.

3.3 MODIFIED NATURAL GAS OPTIMIZATION SCHEME

The natural gas optimization model developed as shown in Figure 3.3 for the Niger Delta considers the options for utilization of the total gas existing in the Niger Delta. The optimization problem suggested for the Niger Delta in Figure 3.3 was found to be very complex and the solution to such a complex model would also be quite challenging. For simplicity, the utilization model was refined based on the following criteria;

1. Gas utilization projects using gas produced by Shell and NNPC because of the enormous

volume of gas they produce in Nigeria.

2. Optimization options must consume large enough gas that can be commercialized.

Based on the above criteria, the original 20 node optimization model was reduced to a 16 node model for detailed study.

The utilization options screened out include: methanol conversion and sales, conversion of gas to GTL, Brass LNG project.

The modified or refined utilization scheme is presented in Figure 3.4 below based on the afore-mentioned criteria. It consists of a simplified 15 node linear optimization model subject to constraints. A summary of the different path in the refined optimization scheme is presented on the Table 3.3.

3.2.1 Objective Function

The objective function is developed to maximize the net income for the Niger Delta. A constrained optimization approach is utilized for the study. The objective function, a profit or net income function, to be maximized with the exclusion of taxes is given by:

J = [Benefits] – [Fixed Costs] – [Variable Costs]...3.1a

This can be translated for the several nodes in the model as;

$$\sum_{i}\sum_{j}\left(B_{ij}x_{ij} - VC_{ij}x_{ij} - FC_{ij}y_{ij}\right) \quad \text{...3.1b}$$

where;

i, j = node indices which indicate the flow through path $i \rightarrow j$ as shown in Figure 3.3.

x_{ij} = amount of gas or by-product processed or/and transported from a node ‘i’ to ‘j’ in Tscf or Bbbl.

y_{ij} = a coefficient switch to determine whether a fixed cost should be applied (y_{ij} = 0 or 1)

B_{ij} = revenues (Benefits) derived at a destination node in \$/Mscf, j is strictly 1, 2,3,4,5,6,7,8, and 9

VC_{ij} = variable costs associated with transportation and/or processing of a given quantity of natural gas at the j-th node in \$/Mscf

FC_{ij} = fixed costs associated with transportation and/or processing of a given quantity of natural gas at the j-th node in $ billion.

3.2.2 Constraints

The optimization model maximizes net income subject to the following constraints

- Gas volume constraints
- Nodal storage constraints
- Fixed cost constraints
- Gas composition constraints

These constraints are further discussed in detail.

- **Gas Volume Constraints;** The amount of gas available for processing, conversion, and

shipment to destination nodes is limited by the following two material balances:

(a) Source node material balance.

$$\sum_i x_{oi} \leq G \qquad 3.2$$

where;

G = amount of gas available at source node, "0", for processing, conversion and transportation.

x_{oi} = amount of gas leaving the source node,"0", to nodes "a" through "c"

(b) Destination node material balance.

$$\sum_j x_{jt} - \sum_i x_{0i} = 0 \qquad 3.3$$

where;

x_{jt} = amount of gas entering terminal or destination nodes " 1" through "11" in the original model .

x_{0i} = amount of gas leaving the source node, " 0 " , to nodes " a " through " c ".

- **Node Storage Constraints**; The second set of constraints applied in the model prohibits

storage of gas or its by-products at a process node. This node material balance constraint can be written as:

[Node inflow] - [Node outflow] = 0 ....3.4a or in terms of the variables,

$$\sum_i x_{ij} - \sum_k x_{jk} = 0 \quad \text{.........} 3.4b$$

where;

x_{ij} = amount of gas entering the j-th node from other nodes, i, (i = source or process nodes)

x_{jk} = amount of gas leaving the j-th node to other nodes, k (k= processor destination nodes).

- **Fixed Cost Constraints**; In the model formulation, a set of constraints is defined to ensure that a fixed cost is applied to any node that involves conversion, processing or transportation of natural gas and/or its by-products. These constraints take the following form:

$$y_{ij} - \frac{x_{ij}}{M} \geq 0 \quad \text{.........} 3.5$$

where;

x_{ij} = amount of gas entering the j-th node from other nodes, i, (i = source or process nodes)

y_{ij} = a coefficient switch to determine whether a fixed cost should be applied (y_{ij} = 0 or 1)

M = a significantly large gas volume that drives the value of y_i to unity in the maximization function if x_{ij} has a positive, non-zero value.

- **Gas Composition Constraints**; The final set of constraints applied limits the amount of Natural gas that can be used for certain processes. The gas composition for the Niger Delta fields will be used to define these constraints. Because these mole percentages limit the amount of convertible gas, the constraint is given by:

$$x_{jt} \leq \left(\frac{Y}{100}\right) G \quad \text{.........} 3.6$$

where;

G = amount of gas available at the source node, "0"

x_{it} = amount of gas leaving any node "i" to a terminal node "t"

Y = mole percent of gas at the destination node.

- **Restriction of the fixed cost coefficient**

The restriction of the fixed cost coefficient switch to only values of 0 and 1 converts the LP model to a Mixed Integer LP.

$$y_{ij} = 0 \; or \; 1 \quad \ldots\ldots 3.7$$

- **Gas Deliverability Constraints;** This constraint limits the amount of gas consumed by each utilization option to the capacity of the project. The constraint is given by;

$$x_{jt} \leq 365Q_{jt}t \ldots\ldots 3.8$$

X_{jt} = amount of gas or byproduct leaving any node "i" to a destination node "t" in Trillion cubic feet, Tscf or billion barrels, Bbbl.

Q_{jt} is the gas deliverability or throughput at the destination node in units of MMscf/d.

t is the time for the utilization or contract time (20 years in this case)

3.3.1 Discussion of the Various Utilization Nodes and Deliverability Requirement

A thorough discussion of the different nodes for the refined model is necessary for better understanding of the condition of the Niger Delta.

Source of Natural Gas - Node '0'; This consists of the producing fields (both associated and non-associated gas fields) operated by Shell. One of the fields include Bonga field with a gas production capacity of 150MMscf/d (www.shell.com). Total production in Nigeria is put at 5.1Bscf/d (NAPIMS, 2005). Shell produces about 50% of the total gas production which is approximately set at 2.5 Bscf/d.

Gas Gathering System (GSS) – Node 'a'; The gas from the source node passes through node 'a' which consist of a complex network of low pressure, small diameter pipeline which transport natural gas from the wellhead at node '1' to the LNG nodes 'd' and 'e' (Naturalgas, 2010).

Approximately 3.5 Bscf/d of gas is expected to be utilized for the NLNG from the source node (www.nlng.com). A total gas requirement for the node is put at 4.5 Bscf/d due to additional gas expected to be provided by Shell to node 'e', the Olokola LNG plant.

Table 3.3; A summary of the different path in the refined utilization scheme

Destination node Path	Process
0-a-d-1	Natural Gas from source through NLNG (as LNG) to Europe
0-a-d-2	Natural Gas from source through NLNG(as LNG) to America
0-a-d-3	Natural Gas from source through NLNG(as NGL) to market
0-a-e-4	Natural Gas from source through Olokola LNG (where it is converted to LNG) to market
0-a-e-5	Natural Gas from source through Olokola LNG (where it is converted to NGL) to market
0-b-6	Conditioning of natural gas at source for utility (Power generation)
0-b-7	Conditioning of natural gas at source for WAGP
0-b-8	Conditioning of natural gas at source for TSGP
0-b-9	Conditioning of natural gas at source for local consumption (Domestic utilization)
0-c-10	Use of gas for EOR (gas injection) and pressure maintenance and subsequent transportation of EOR oil to market

Nigerian LNG Plant- Node 'd'; The gas from node 'a' is split into node d and e. Bulk of the of gas (1Bscf/d) arriving at node 'd' is derived from associated gas producing fields; SPDC-Soku, NAOC-Obiakrom, EPNL-Obite in agreement with the joint venture.

Total gas capacity including the fourth and fifth trains is estimated at 2.9Bscf/d. Shell is expected to provide 53% of the gas needs of the JV (E-Technical, 2005). Total gas to node 'd' is 3.5 Bscf/day at maximum capacity.

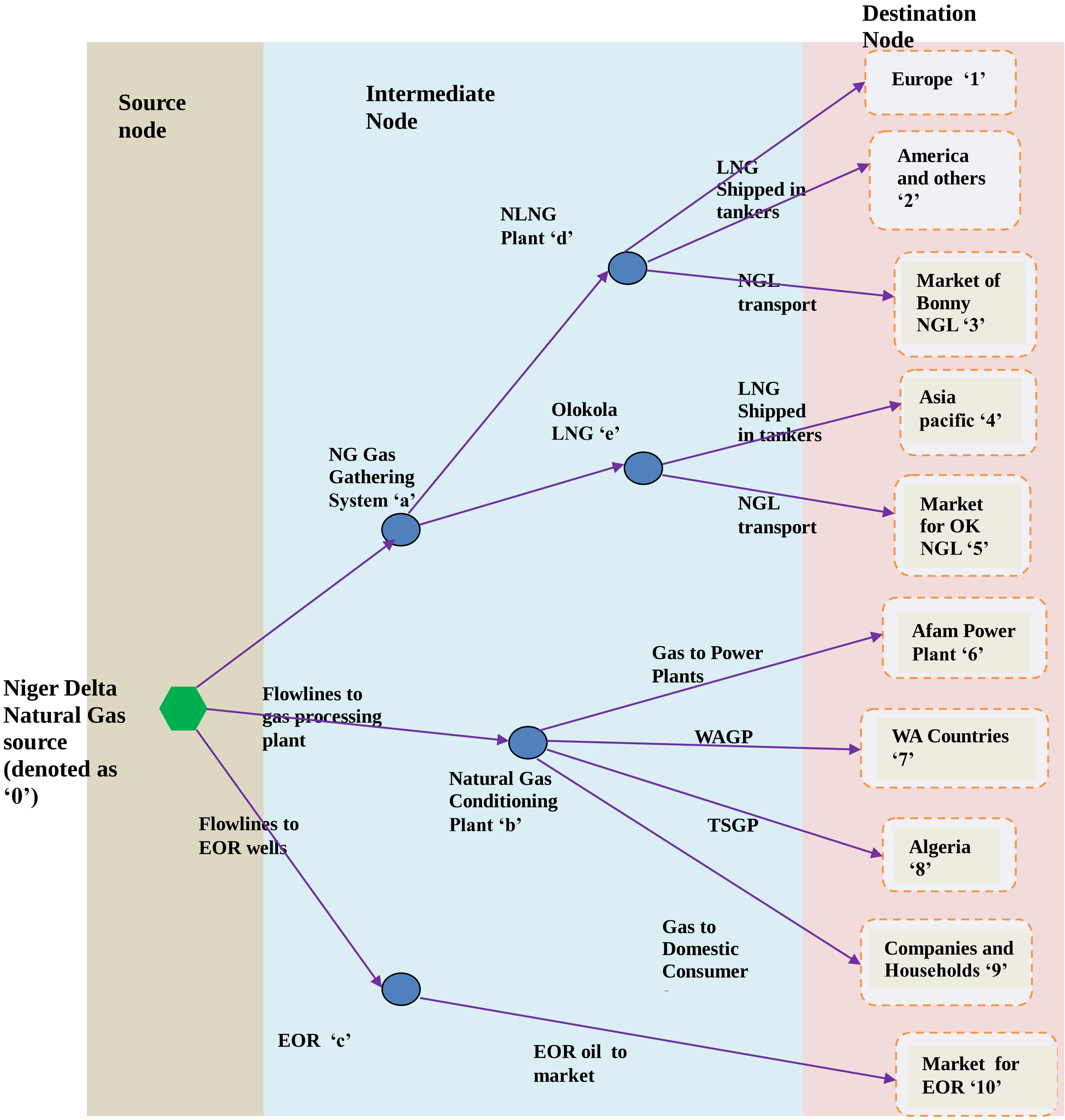


Figure 3.4; Modified (refined) Optimization scheme consisting of 15 nodes for the Niger Delta

Key

Process Node	ND; Niger Delta
Terminal or destination node	WAGP; West African Gas Pipeline
Source node	TSGP; Trans Saharan Gas Pipeline

Olokola LNG Node 'e': This is the project operated by Chevron with BP and recently Shell as partners in the Joint Venture. Shell is providing half of the gas requirement to the Olokola LNG through node 'a' as part of the joint venture agreement. The total plant capacity is put at 22 MMT/y requiring over 3Bscf of natural gas from the joint venture partners.

Node 1 and 2: The Liquefied natural gas (LNG) from node 'a', about 16.8MMT/y goes to destination node '1' and '2' comprising of market dominated by America and Europe. The by-product including 3MMT/y of LPG and 1MMT/y of condensate (that is 4 MMT/y of NGL) terminates at destination node '3'. It is also shipped for export in tankers to market dominated by North America and Europe.

Node '3': This node receives heavier component preferably known as Natural Gas Liquids (NGLs) from the Natural gas handling facility in the Niger Delta and distributes it to foreign market. The NGLs (sometimes called Butanes) are sometimes the preferred mode of transportation because it is easier to transport over long distances in tankers. Revenues are generated at this node from the sales of NGLs.

Node 3 and 4: Node '3' denotes expected destination of the LNG from node 'e'. The destination node '4' is initially going to receive 10MMT/y of LNG while the node '5' is initially receiving 3.5MMT/y of NGL. Total initial gas supply would be 1Bscf from the joint venture partners. North America and Europe are among the key consumers of the LNG and by-products. The product has several petrochemical applications. Again, with the increasing huge energy demand in China and the rest of Asia, demand for the Olokola LNG is expected to be very high.

Gas conditioning Plant- Node 'b': The gas from the source node '0' passes through node 'b' to destination nodes '6', '7', '8' and '9'. Over 2 Bscf/d is expected to be utilized and distributed to the four destination nodes; nodes 5 and 6 consisting of the WAGP and the TSGP while nodes 4 and 7 include gas for Power generation and domestic consumption. Owing to the large demand at node 8 (put at 2 Bscf/d), the source gas production has to be increased before the start up of the TSGP project in order to meet this huge market demand. The destination nodes ‘6’ and ‘9’ currently consume some volume of gas, a total of about 1.3 Bscf/d, which is expected to rise.

West African Gas Pipeline (WAGP): The gas pipeline covering both onshore, in some parts of Nigeria, and offshore consists of a 30” diameter pipeline in the onshore section and 20” diameter pipeline in the offshore section. The total length of the pipeline is 678km. The maximum capacity of the pipeline is put at 13.7 MM m^3 (483.4 MMscf) (Wikipedia, 2010). About 200MMscf/d of natural gas is expected to be utilized in this route (EIA, 2009).Start up of the project was set at December, 2009 but has since been postponed to a later date due to moisture found in the gas.

TransSaharan Gas Pipeline (TSGP): The 48” pipeline covering three countries including the Sahara desert has an estimated length of 4128km. It is expected to utilize a whopping 2 Bscf/d of natural gas from node ‘b’ and is consequently a very huge project with a maximum discharge capacity of 82 MM m^3/d (2.9Bscf/d) (Wikipedia, 2010). Pipeline agreement was signed in 2009 and first gas is expected in 2015/2016 with cost estimate put at $10 billion (Sonatrach Conference, 2008). Total pipeline length traversing the three countries includes 1037 km in Nigeria, 841km in Niger and 2310km in Algeria.

Power Supply Node ‘6’: Node ‘6’ is aimed at putting gas to use in generating electric power. Shell is currently generating Power through the Afam Power Plant Project. The Afam VI project (main focus of this utilization) came on stream in 2009 and is expected to boost Nigeria’s power output. Additionally, Afam VI is not considered as a domestic utilization option.

Node ‘7’: The gas transported through the WAGP, which crosses both on and offshore destinations terminates in node ‘7’. This node coincides with the natural gas receiving countries; Ghana, Benin and Togo. The 200MMscf/d gas supply via the WAGP is expected to be used by these countries for power generation.

Node '8'; The gas from node 'b' through the TSGP terminates at this node '8' which coincides with Algeria in the Northern part of Africa. The gas is expected to be transported from Algeria through the Mediterranean to final destination in Europe (especially Spain and Italy). The approximately 2Bscf/d of gas transported from the source is expected to reach node '8'.

Industrial and household utilization Node '9': Several domestic utilization options include; cement industry expected to gulp about 300MMscf/d, fertilizer manufacturing gas utilization expected at 200MMscf/d, steel sector also expected to consume about 130MMscf/d of natural gas. Other domestic utilization option such as households is expected to further utilize 100MMscf/d of natural gas bringing the total gas required for the node to 730MMscf/d. The expanded model for domestic gas consumption is shown in Figure 3.5.

Enhanced Oil Recovery Project (EOR) Node 'c': 80MMscf/d of natural gas from the producing fields on the source node is expected to be utilized for EOR (CEE, 2005). The Shell Belema gas injection project is part this EOR project. The natural gas consisting mainly of methane is used for gas injection at node 'c'. The EOR product (oil) goes to destination node '10'.

Node '10': The gas injection/EOR at node 'c' traps the gas and aids the enhanced recovery of trapped oil that cannot be produced due primarily to the low natural reservoir energy. This is one technology for EOR. There is also a possibility of converting the natural gas to carbon dioxide through the so called 'shift reaction'. The shift reaction splits the natural gas to its components; hydrogen and carbon dioxide. The hydrogen is used to generate clean electricity while the carbon dioxide is utilized for EOR. This technology came about due to attempts by government and companies to reduce CO_2 from natural gas and consequently reduce the risks of global warming. Furthermore, the EOR oil provides additional revenue to the gas utilization scheme.

3.4 SUMMARY OF THE NATURAL GAS OPTIMIZATION MODEL

Recall that in section 3.2, the equations 3.1 – 3.8 provide a summary of the Linear

Programming model; including both the objective function and constraints as applied to the problem of gas utilization. Additionally, the model contains a total of 30 variables. This set of equations transformed to a computer code for LINDO (LINDO, 2010) to represent each node in the utilization scheme. Table 3.4 shows the transformation of equations used in formulating the LP model into a form coded into LINDO.

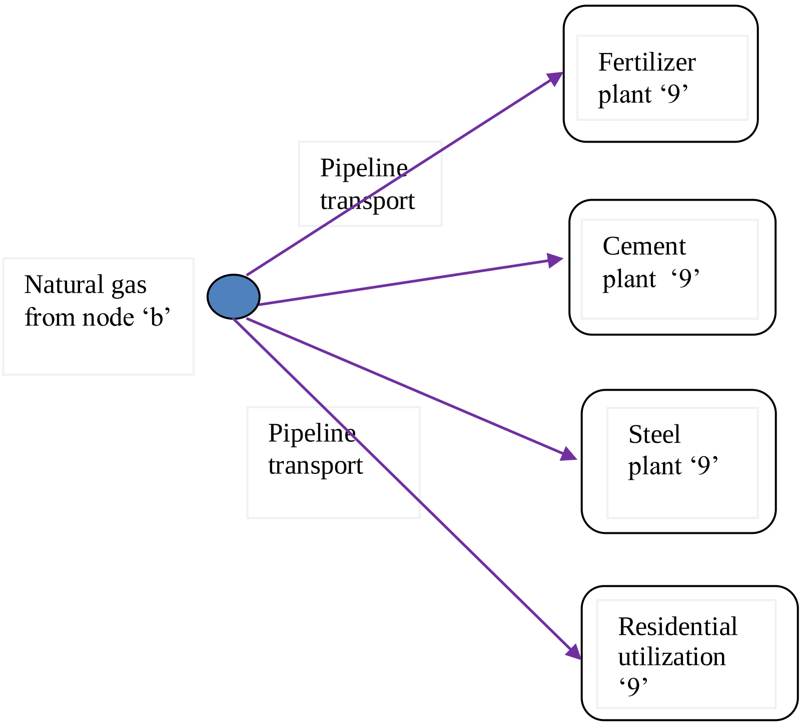


Figure 3.5; The Expanded domestic utilization

There is also the fixed cost coefficient restriction to either 0 or 1 (equation 3.7). This is represented for each of the fixed cost coefficient variable. These optimization equations, as applicable to the utilization scheme in Figure 3.3 are shown below. The mixed integer linear transshipment model equations derived for the Niger Delta is summarized for the all the nodes below.

Table 3.4: Summary of model equations coded in LINDO

Equations used in LP Model Formulation	Expanded set of Equations coded in LINDO
One objective function; Equation 3.1	Equation 3.9
Two gas volume constraints; Equation 3.2 – 3.3	Equations 3.10 – 3.11
Five Node storage constraints; Equations 3.4a and 3.4b	Equations 3.12 – 3.16
Fifteen fixed cost constraints; Equation 3.5	Equations 3.17 – 3.31
Ten gas composition constraints; Equation 3.6	Equations 3.32 – 3.41
Gas deliverability constraints; Equation 3.8	Equation 3.42 – 3.51
Fixed cost coefficient restriction; Equation 3.7	Equation 3.52

OBJECTIVE FUNCTION

MAXIMIZE

$(B_{0a} – VC_{0a})\ X0a + (B_{ob} – VC_{0b})\ X0b + (B_{0c} – VC_{0c})\ X0c + (B_{ad} – VC_{ad})\ Xad + (B_{ae} – VC_{ae}) Xae + (B_{d1} – VC_{d1})\ Xd1 + (B_{d2} - VC_{d2})\ Xd2 + (B_{d3} - VC_{d3})\ Xd3 + (B_{e4} - VC_{e4})\ Xd4 + (B_{e5} - VC_{e5})\ Xb5 + (B_{b6} – VC_{b6})\ Xb6 + (B_{b7} – VC_{b7})\ Xb7 + (B_{b8} – VC_{b8})\ Xb8 + (B_{b9} – VC_{b9})\ Xb9 + (B_{c10} – VC_{c10})\ Xc10 – FC_{0a}\ y0a – FC_{0b}\ y0b – FC_{0c}\ y0c – FC_{ad}\ yad – FC_{ae}\ yae – FC_{d1}\ yd1 – FC_{d2}\ yd2 – FC_{d3}\ yd3 – FC_{e4}\ ye4 – FC_{e5}\ ye5 – FC_{b6}\ yb6 – FC_{b7}\ yb7 – FC_{b8}\ yb8 – FC_{b9}\ Xb9 – FC_{c10}\ yc10$ 3.9

CONSTRAINTS

Gas Volume Constraint

X0a + X0b + X0c <= 30 ....3.10

Xd1 + Xd2+ Xd3+ Xe4 + Xb5 + Xb6 + Xb7 + Xb8 + Xb9 + Xc10 - X0a - X0b - X0c =

0...3.11

Node Storage Constraints

X0a – Xad – Xae= 0 ....3.12

Xad – Xd1 – Xd2 – Xd3= 0 ....3.13

Xae – Xe4 –Xe5 = 0 ....3.14

X0b – Xb6 – Xb7 – Xb8 – Xb9 = 0 ....3.15

X0c - Xc10 = 0 ....3.16

Fixed Cost Constraints

10000 y0a – X0a >= 0 ....3.17

10000 y0b – X0b>= 0 ....3.18

10000 y0c – X0c >= 0 ....3.19

10000 yad – Xad >= 0 ....3.20

10000 yae – Xae >= 0 ....3.21

10000 yd1 – Xd1 >= 0 ....3.22

10000 yd2 – Xd2 >= 0 ....3.23

10000 yd3 – Xd3 >= 0 ....3.24

10000 ye4 – Xe4 >= 0 ....3.25

10000 ye5 – Xe5 >= 0 ....3.26

10000 yb6 – Xb6 >= 0 ....3.27

10000 yb7 – Xb7 >= 0 ....3.28

10000 yb8 – Xb8 >= 0 ....3.29

10000 yb9 – Xb9 >= 0 ....3.30

10000 yc10 – Xc10 >= 0 ....3.31

Gas Composition Constraints

Xd1 <= $\frac{Yd1}{100}$ *G 3.32

$Xd2 <= \frac{Yd2}{100} *G$ 3.33

$Xd3 <= \frac{Yd3}{100} *G$ 3.34

$Xe4 <= \frac{Ye4}{100} *G$ 3.35

$Xe5 <= \frac{Ye5}{100} *G$ 3.36

$Xb6 <= \frac{Yb6}{100} *G$ 3.37

$Xb7 <= \frac{Yb7}{100} *G$ 3.38

$Xb8 <= \frac{Yb8}{100} *G$ 3.39

$Xb9 <= \frac{Yb9}{100} *G$ 3.40

$Xc10 <= \frac{Yc10}{100} *G$ 3.41

Gas Deliverability constraint

$Xd1 <= Q_{d1}t$ 3.42

$Xd2 <= Q_{d2}t$ 3.43

$Xd3 <= Q_{d3}t$ 3.44

$Xe4 <= Q_{e4}t$ 3.45

$Xe5 <= Q_{e5}t$ 3.46

$Xb6 <= Q_{b6}t$ 3.47

$Xb7 <= Q_{b7}t$ 3.48

$Xb8 <= Q_{b8}t$ 3.49

$Xb9 <= Q_{b9}t$ 3.50

$Xc10 <= Q_{c10}t$ 3.51

$y_{ij} = 0 \text{ or } 1$ 3.52

3.5 DATA REQUIRED FOR THE STUDY

The model represented by the equations in section 3.4 requires some set of data for each node in order to run to obtain the optimum of the objective function. These data include the total gas available at the source, the gas composition analysis, fixed and variable costs for each node in the model. The key to building a successful model is to obtain good estimate of the input data from reliable sources for the base case run to produce meaning results. The estimates of input data used to validate the Niger Delta optimization model are discussed in the following section.

3.5.1 Gas Composition Data

The gas composition to be used in this optimization model is that derived from the gas composition data obtained from literature *(Enyi and Appah, 2005)*.It is a typical gas composition for a Nigerian gas field - (Ughelli). The Table 3.5 shows different natural gas composition from different fields in the world including the Nigerian field as reported by Enyi and Appah.

For the Niger Delta case study, the data on column 7 of Table 3.5 is converted into destination node requirement, the component requirement for each node to satisfy the gas composition constraints. The conversion is summarized in Table 3.6.

Table 3.5; Composition of some commercial natural gases by volume % *(Enyi, and Appah, 2005)*

Component	North Sea	Netherlands	Brunei	Libya	Algeria	Nigeria(Ughelli)
Methane	94.8	81.7	88.0	71.4	86.5	88.1
Ethane	3.0	2.7	5.1	16.0	9.4	6.3
Propane	0.6	0.4	4.8	7.9	2.6	2.1
Butanes	0.2	0.1	1.8	3.4	1.1	0.3
Pentanes +	0.2	1.1	0.2	1.3	0.1	1.1
Nitrogen	1.2	14.0	0.1	0.0	0.3	-
Carbondioxide	-	-	-	-	-	2.1
Helium	-	-	-	-	-	-
Total	100.0	100.0	100.0	100.0	100.0	100.0

Table 3.6; Data for Gas composition constraint

Process	Component used	Mole %
Pipeline	C1,C2,C3	96.5%
NGL conversion	C3,C4,C5+	3.5%
EOR processes (equivalent to the composition of recovered oil)	50% C1,C2,C3,C4,C5+,CO2	55.95%
LNG conversion	C1,C2	94.4%
Methanol conversion	C1	88.1%

3.5.2 Fixed Cost Data for Different Utilization Option

The fixed cost for each of the nodes (including both source, process and destination nodes) is obtained from the individual project costs. These individual project costs are presented below;

NLNG project; The total cost for this node is $9.38 billion in 2006. The present cost is obtained by inflating this cost using an inflation rate from the accounting formula:

$$Present\ cost = cost * (1 + inflation\ rate)^n \quad \text{.......} 3.53$$

Applying equation 3.53, using an average inflation rate of 10.25% gives a fixed cost of $13.86 billion.

Olokola LNG: This is a similar LNG project with an estimated fixed cost of $14.6 billion (Reuters, 2010). The plant capacity is estimated at 22MMT/y of LNG with associated by-products.

The West African Gas Pipeline, WAGP; The fixed cost of the 678 km pipeline is estimated at $924 million (Wikipedia, 2010).

The Trans Saharan Gas Pipeline, TSGP; This is much larger project with a pipeline length of 4128km passing through Algeria en-route Europe. Its estimated fixed cost was $12.2 billion based on 2010 dollar (NGC, 2010). This huge cost difference between the TSGP and the WAGP is due to the difficult Sahara desert terrain in Niger and Algeria that would be traversed by the pipeline and of course the length of the pipeline.

Gas Gathering System (GSS): Three gas gathering networks known as the Gas Transmission

System (GTS) will transport predominantly associated gas to the LNG complex;

a) GTS-1 is an onshore system with its main trunkline extending some 149 km to the Northwest of the plant and terminates in a 150 m^3 slug-catcher.

b) GTS-2 is a second onshore system with a 90 km trunkline also extending to the Northwest but to the south of GTS-1. It terminates with a slug-catcher.

c) The Offshore Gas Gathering System (OGGS), also known as GTS-3, is a 320 km offshore line. It terminates in a 1250 m^3 slug catcher *(www.nlng.com)*

The total length of the GGS is 559 km. The basis for the fixed cost estimation is the WAGP which consist of a 678 km pipeline valued at $924 million.

Using proportion,

678 km is valued at $924 million, therefore,

559 km will give a cost of (559/678)*$924 million,

The fixed cost is then obtained as $762 million. The overall cost of the GGS including other accessories like the slug-catcher is estimated at $800 million.

Natural Gas Conditioning: The natural gas produced and fed into the mainline gas pipeline system must meet the specified quality standard for the pipeline grid to operate properly. This is achieved by the gas conditioning system aimed at removing water vapour, sulphur deposits, acid gas, mercury, which have devastating effect on the pipelines and the final consumers *(EIA, 2010.)*

For treating 300MMscf/d of natural gas, $510 million is required as fixed capital cost for gas conditioning. Therefore, by proportion, 3Bscf/d of natural gas at this node would have a fixed cost of $5.0 billion.

Gas injection/EOR: The overall fixed cost for drilling an injection well is valued at $5.85 million. Assuming a total of 10 wells, the fixed cost is put at $58.5 million.

Transportation of LNG to market (Europe and America): LNG shipping costs are determined by the daily charter rate and re-gasification, which is a function of the price of the ship, the cost of financing, and operating costs. The shipping cost is presented below (NLNG, 2010);

- The total cost of the Bonny Gas Transport (BGT) ships for the base trains (1 & 2) is $132 million.
- Shipping cost for Train 3 cost a total of $160 million.
- Train 4 and 5 (NLNGPlus) cost $210 million.
- Train 6 costs an additional $957 million. This puts the total shipping cost at $2.98 billion (nlng.com).
- A re-gasification cost is $0.5 billion *(Rajnauth et al, 2008).*

Therefore the total cost is $3.48 billion. Of the total LNG export, Europe consumes 66% and the rest goes to America and recently Asia (EIA, 2010).

Transportation to Power Plant: Afam VI Power Plant is Shell's biggest and latest investment in generating electric power utilizing gas from Olokola gas plant. The plant which came into full operation in 2009 has an installed capacity of 650MW of electricity and utilizes some 240 MMscf/d of natural gas. Fixed cost for transporting natural gas to the power plant in Afam is virtually zero because of the situation of the Power Plant in location of the natural gas producing fields.

Transportation to Domestic Consumers: The total cost of laying pipeline for domestic utilization for proposed projects linking the Niger Delta, North and Western Nigeria, according to NNPC, amount to a sum of $ 4 billion.

Transportation of NGL to market: The transport of NGL to market is obtained from the cost of LNG less the re-gasification costs. The fixed cost obtained considering the ratio of NGL to LNG produced by the plant is $ 0.83 billion.

Transportation of EOR oil to market: The cost associated in transporting EOR oil to market basically operating cost because the facilities for this node are already in place from the sales of crude oil. This implies there is no fixed cost associated with the transport of EOR to market.

3.5.3 Variable cost (Operating cost)

Gas conditioning: The annual operating cost is estimated at $ 127 million. Converting this cost to

$/Mscf using the fact that the 300MMscf/d was utilized,

$$\frac{\$210\ \text{MM}}{\text{year}} \left| \frac{\text{year}}{300\ \text{MMscf}} \right| \frac{}{365\ \text{days}}$$

(Note: MM in this case signify 10^6)

The result obtained from multiplying the above values is of $1.92/Mscf.

NLNG project: As reported in the World Energy bulletin, the operating cost of liquefying natural gas is put between $0.8/Mscf and $1.0/Mscf with an average of $0.90/Mscf (World Energy, 2004). Adopting the average operating cost for liquefaction and translating it to the present using an average inflation rate of 10.25% over 5 years gives $1.77/Mscf.

Olokola LNG: The operating cost of the plant is typical of LNG plants which are presented above as $0.9/Mscf since similar volume of gas is been utilized. Similarly, the current cost of $1.77/Mscf is used using the same inflation rate.

TSGP: The operating (variable) cost of this project is estimated at $0.75/Mscf as at 2004 (World Energy, 2004). Using an average inflation rate for 6 years of 11.9%, the operating cost at present is $1.44/Mscf. Major challenge is the difficult logistical and political conditions especially the length of pipeline traversing the Sahara desert.

WAGP: Based on the variable cost of the TSGP, by proportion, the cost of the WAGP is obtained as $0.24 /Mscf.

Gas Gathering System, GSS: For the Gas gathering system, the average operating cost was presented to be $0.26/Mscf (Yousfi, 2007). Using an inflation rate of 11.5%, the present cost is $0.36/Mscf

EOR/Miscible gas injection: The operating cost associated with 10 injection wells used for EOR is estimated at $3.15 million per annum. Using a value of 80MMscf/d of gas for EOR, the operating cost associated with EOR is $0.609/Mscf.

Transportation of LNG to Sale's point: The transport cost for LNG to Europe is obtained as $0.852/Mscf using the Zeebrugge terminal in Belgium. Additional, for transport to America, the operating cost is $1.15/Mscf. Operating cost for this transport node to the Far East country of Japan cost $2.022/Mscf. The total cost has an average of $1.34/Mscf.

Transportation of NGL to market: The operating cost of transporting Bonny NGL to market is roughly based on the cost of LNG using export volume equivalent. Converting the cost gives the operating cost to be $1.81/bbl.

Transportation of NGL to market: The operating cost of transporting Olokola NGL to market is roughly based on the cost of LNG on export volume equivalent. Calculating the cost gives the operating cost of $1.78/bbl.

Transportation of Natural Gas to Power Plant and Domestic Consumers: The operating cost for transport of gas to a Power Plant or for domestic utilization has a standard Nigerian cost given as $0.30/Mscf.

Transportation of EOR oil to market: The variable cost in transporting EOR oil to market from West Africa to Houston is given as $2.27/bbl (EIA, 2009). In 2010, the operating cost using an inflation rate of 11.6% is $2.53/ bbl.

3.6.3 Total Volume of Gas at the Source

The total volume of gas at the source is kept as a variable in this study. From the study therefore, the total volume of gas can be obtained. Additionally, a total of 20 years was taken as the project life because most gas sales contract are signed for a period between 20-25 years.

3.6.4 SUMMARY OF COST DATA

The fixed cost and operating cost associated with the Niger Delta Natural gas development options were presented in the previous section for a specific volume of as available at the source node. This cost data is applied to all the nodes in the optimization model. A summary of these data refined optimization model, the following costs are associated is presented in Table 3.7a and b.

3.7 MARKET PRICE OF NATURAL GAS

The price of natural gas in the international market was obtained from the open literature varies very significantly with time. Market price today is not expected to be the same tomorrow. The discussion below gives the recent values for natural gas and by product prices used in this study.

3.7.1 Market price Analysis

LNG prices: The price of LNG based on the Japan CIF (cost, insurance and freight) as at July, 2010 was $10.80/MMBTU (BP statistics, 2010).

Natural Gas

EU CIF: The price as at July, 2010 was $ 8.10/MMBTU (BP statistics, 2010).

UK Heren NBP Index: The price quoted for July, 2010 was $ 5.47/MMBTU (BP statistics, 2010). Note that NBP Index is National Business Perception Index.

- US Henry Hub; The price as at December, 2010 was $ 4.4/MMBTU (Baker Hughes, 2010).
- NGL (Predominantly butanes); The price of NGL in the United states according to Conoco Philips October release is $1.25/gal (Conoco Philips, 2010).

Table 3.8 thereafter summarizes the recent prices of oil and Natural gas relevant to the model.

3.8 IMPLEMENTING THE OPTIMIZATION CODE

The model was implemented using the optimization software, called LINDO. LINDO is a comprehensive tool designed to make building and solving Linear, Quadratic, Stochastic, and Integer programming models faster, easier and more efficient. LINDO provides a completely integrated package that includes a powerful language for expressing optimization models, a full featured environment for building and editing problems, and a set of fast built-in solvers *(www.lindo.com).*

Table 3.7a; Conversion and Transportation costs (fixed costs)

Node	Process/Destination	Fixed costs(billions $)	Source of Fixed Cost
a	Gas Gathering System, GSS	0.8	(NLNG, 2010). Data obtained from the NLNG website.
b	Conditioning of Natural Gas	5.0	(Enyi and Appah, 2005).
c	Enhanced oil Recovery, EOR	0.585	*(Business News and Articles, 2007)*
d	Liquefaction to LNG at Bonny	13.86	NLNG website.
e	Liquefaction of NG at Olokola	14.6	(Reuters, 2010).
1	Market Sales of Bonny LNG to Europe	2.3	(NLNG, 2010)
2	Market Sales of Bonny LNG to America	1.18	(NLNG, 2010)
3	Market Sales of Bonny NGL to Market	0.83	Based on volume ratio of NGL to LNG produced.
4	Market Sales of Olokola LNG	3.48	(NLNG, 2010)
5	Market Sales of Olokola NGL	0.83	Based on volume ratio of NGL to LNG produced.
6	Power generation at Afam	0	Proximity to producing fields
7	Pipeline transport of Natural Gas to WA countries	0.924	(NGC, 2010). Very reliable cost data.
8	Pipeline transport of Natural Gas to Algeria	12.2	(NGC, 2010).
9	Domestic utilization of Natural Gas	4	(NNPC, 2010)
10	Transport of EOR oil to market	0	(based on NGL transport: volume equivalent)

Table 3.7b; Conversion and Transportation costs (variable costs)

Node	Process/Destination	Variable cost($/Mscf)	Source of VC
a	Gas Gathering System, GSS	0.36	(Rajnauth,2008)
b	Conditioning of Natural Gas	1.92	*(Enyi and Appah, 2005)*
c	Enhanced oil Recovery, EOR	0.609	Based on volume of EOR oil produced to that of an NGL.
d	Liquefaction to LNG at Bonny	1.77	(World Energy, 2004)
e	Liquefaction of NG at Olokola	1.77	(World Energy, 2004)
1	Market Sales of Bonny LNG to Europe	0.852	NLNG website.
2	Market Sales of Bonny LNG to America	1.15	NLNG website.
3	Market Sales of Bonny NGL to Market	1.81	Based on Bonny LNG on volume basis. However, cost is per barrel.
4	Market Sales of Olokola LNG	0.852	NLNG website.
5	Market Sales of Olokola NGL	1.78	Based on volume of Olokola LNG produced. However, cost is per barrel.
6	Power generation at Afam	0.3	Typical cost for transmitting gas through pipeline.
7	Pipeline transport of Natural Gas to WA countries	0.24	(World Energy, 2004).
8	Pipeline transport of Natural Gas to Algeria	1.47	(World Energy, 2004).
9	Domestic utilization of Natural Gas	0.3	NNPC, 2010
10	Transport of EOR oil to market	2.53	(Based on NGL sales). Also cost is per barrel.

=

Table 3.8; Price of Oil and Natural Gas

Commodity	**Market price (June, 2010)**
Bonny Light	$ 90/bbl (Baker Hughes, December-2010)
Natural Gas	$ 4.4/Mscf (Baker Hughes, December-2010)
NGL(Butanes)	$1.25/gal *(Conoco Philips, 2010)* equivalent to $52.5/bbl
LNG	$ 4.4/Mscf (Baker Hughes, December-2010)
Domestic prices	Power; $1/Mscf Industries and others; $1/Mscf

The objective function with the associated constraints for each of the nodes was presented previously. These sets of equations are coded in LINDO software. The solution to the model equations is provided by LINDO using the ‘branch and bound’ algorithm for integer programming. The model for the natural gas utilization is a mixed integer linear programming model. The branch and bound algorithm employs a Linear programming relaxation of the Integer Programming problem and solving iteratively until the solution outputs an integer (0 or 1 in the case of a BLP).

The model was executed for the case of a base study and thereafter the executions were repeated at some increase or decrease in the parameters such the gas price and the costs input parameters. The equations including the parameters for fixed cost, variable costs and market price for natural gas for the base case as run in LINDO is shown in Appendix B.

CHAPTER FOUR

4.0 RESULTS AND DISCUSSION

The results for the optimization model for the Niger Delta are presented in this chapter. From the results, the optimal decision, in terms of the viable projects, is obtained. The results also present the gas volume necessary to satisfy market demand for the gas utilization projects. Profitable projects are those projects where the profit is greater than zero. A base case study is presented by incorporating all the available data (gas composition data, fixed and variable data, gas price, and deliverability data) into the natural gas utilization model. The model is subsequently run using LINDO optimization software and results obtained are analyzed. A sensitivity analysis is performed to determine how parameters like the variable/operating costs, fixed cost and market/spot price of natural gas and by-product affect the optimal decision.

Criteria for Selecting the Optimal utilization

The optimal decision (utilization) in this case is defined as the route (in terms of nodes) where there is gas to meet the demand; $X_{ij} > 0$, which also imply that the path is profitable (project can break even). Those nodes (making up the route) where there is no gas are viewed as non optimal path or route; $X_{ij} = 0$ (since X_{ij} cannot be less than 0). The sensitivity involves increasing the fixed cost, variable cost and markets price since these are the most uncertain parameters in the future by ±10%, ±20%, ±30%, ±40% and ±50%, respectively. The nodal results for gas distribution for each of the node are given in the Appendix D. The effect of these changes on the objective function (maximum income function) is then investigated.

4.1 BASE CASE

The results for the base case run referred to as run A (shown on Table 4.2) in this study are presented in this section. The result obtained from the base case indicates that the gas reserves necessary to satisfy the demand at the various destination nodes for the cost data and gas price as specified on Table 3.3 and Table 3.4 is 41.29 Tscf. The optimum revenue for the base case for a period of 20 years (this is the total period of time required for the utilization project) is $28.96 billion. For the base case, this model has predicted the following projects to be profitable because of the non-zero values of the quantity of gas from those nodes. They include gas utilization projects comprising the Nigerian Liquefied natural gas plant at Bonny and subsequent sale of product and by-product (LNG and NGL) from the plant, Power Project at Afam, the WAGP, the TSGP, domestic (Industrial/Residential) uses and the EOR product sales. However, the optimization model result show that project such as the Olokola LNG plant, where both LNG and NGL are recovered, are not profitable for this base case study. For the study, the price of gas for the domestic utilization was kept at export level for the base run A. Subsequently, the cost was reduced to the gas to domestic use price in Nigeria to present a better picture of the Nigerian domestic gas market. The issue of natural gas pricing in the domestic market has been a problem in Nigeria. The IOCs cannot make any significant profit from the ventures because the low gas prices required for local market subsidy. This has led the IOCs to focus more attention to exports like the LNG. This study has proved that the low prices in Nigeria cannot compensate for the huge investments in the venture. Therefore depressed prices for domestic gas renders make the domestic utilization non profitable.

4.2 SENSITIVITY ANALYSIS (POST OPTIMALITY ANALYSIS)

The objective function defined in Chapter Three is a function of the variable cost, fixed cost and the market price of natural gas. It is important to note that the study of the effect of discrete parameter changes on the optimal solution is called sensitivity analysis (Rao, 2009). Sensitivity analysis is carried out by adjusting these parameters by a certain percentage and analyzing the effect of these changes on the objective function. For the purpose of this study, an increment of ±10%, ±20%, ±30%, ±40% and ±50% in parameters from the base case, were implemented.

4.2.1 Fixed Cost Analysis

The optimal gas utilization options and reserves necessary to meet the demand have been obtained from the base optimization run (run A) and were presented previously. Table 4.1 illustrates the sensitivity in the fixed cost for ±10% sensitivity in fixed cost from the base case. Detailed results from the sensitivity analysis for ±20%, ±30%, ±40% and ±50% of fixed cost from the base case are shown in Appendix C.

Table 4.1; 10% change in fixed cost (Conversion and Transportation costs)

Node	Fixed costs(billions $)	10% increase Fixed costs(billions $)	10% decrease Fixed costs(billions $)
a	0.8	0.88	0.72
b	5	5.5	4.5
c	0.0585	0.06435	0.05265
d	13.86	15.246	12.474
e	14.6	16.06	13.14
1	2.3	2.53	2.07
2	1.18	1.298	1.062
2	0.83	0.913	0.747
4	3.48	3.828	3.132
5	0.83	0.913	0.747
6	0	0	0
7	0.924	1.0164	0.8316
8	12.2	13.42	10.98
9	4	4.4	3.6
10	0	0	0

The optimal income from the optimization model for a 10% increase in fixed cost referred to as run B was $ 24.85 billion and the optimum gas reserves required is 41.29 Tscf from the source node.

These runs are repeated for 20%, 30%, 40% and 50% increase in the fixed cost (referred to as run C, D, E, and F). The results show a corresponding income decrease in net income of $20.73, $16.62, $12.50 and $8.98 billion respectively. The gas reserves required to meet the utilization options remained constant at 41.29 Tscf but changed to 8.89 Tscf at 50% increase in fixed cost. Thus, increasing the fixed cost by 10% does not affect the optimal decision obtained for the base study but reduces the net income to $24.85 billion from $28.96 billion obtained for the base case**.** The optimum decision is affected as the fixed cost increases to 50% (which is the maximum considered for the study). Liquefaction and the TSGP were no longer profitable. However, the optimum income realised decreases progressively as indicated above.

A similar sensitivity analysis is carried out by decreasing the fixed cost. A decrease by 10%, 20%, 30%, 40% and 50% in the fixed cost (also known as run G, H, I, J, K) from the base case resulted in a corresponding net income increase of $33.08, $37.20, $41.31, $46.75 and $55.06 billion respectively. Figure 4.1 shows the results obtained for fixed cost sensitivity. The gas volumes requirement in this case goes to 57.24 Tscf for 50% decrease. Decreasing the fixed cost by 10% does not affect the optimal decision but increases the net income to $42.83 billion**.** The optimum decision is affected as the fixed cost increment goes to 50%. At 50% decrease in fixed cost from the base, all the projects considered for the study become profitable because gas gets supplied to all the nodes and options like the Olokola LNG, which were otherwise non profitable, becomes commercially attractive. Table 4.2 provides a concise summary of the above discussion.

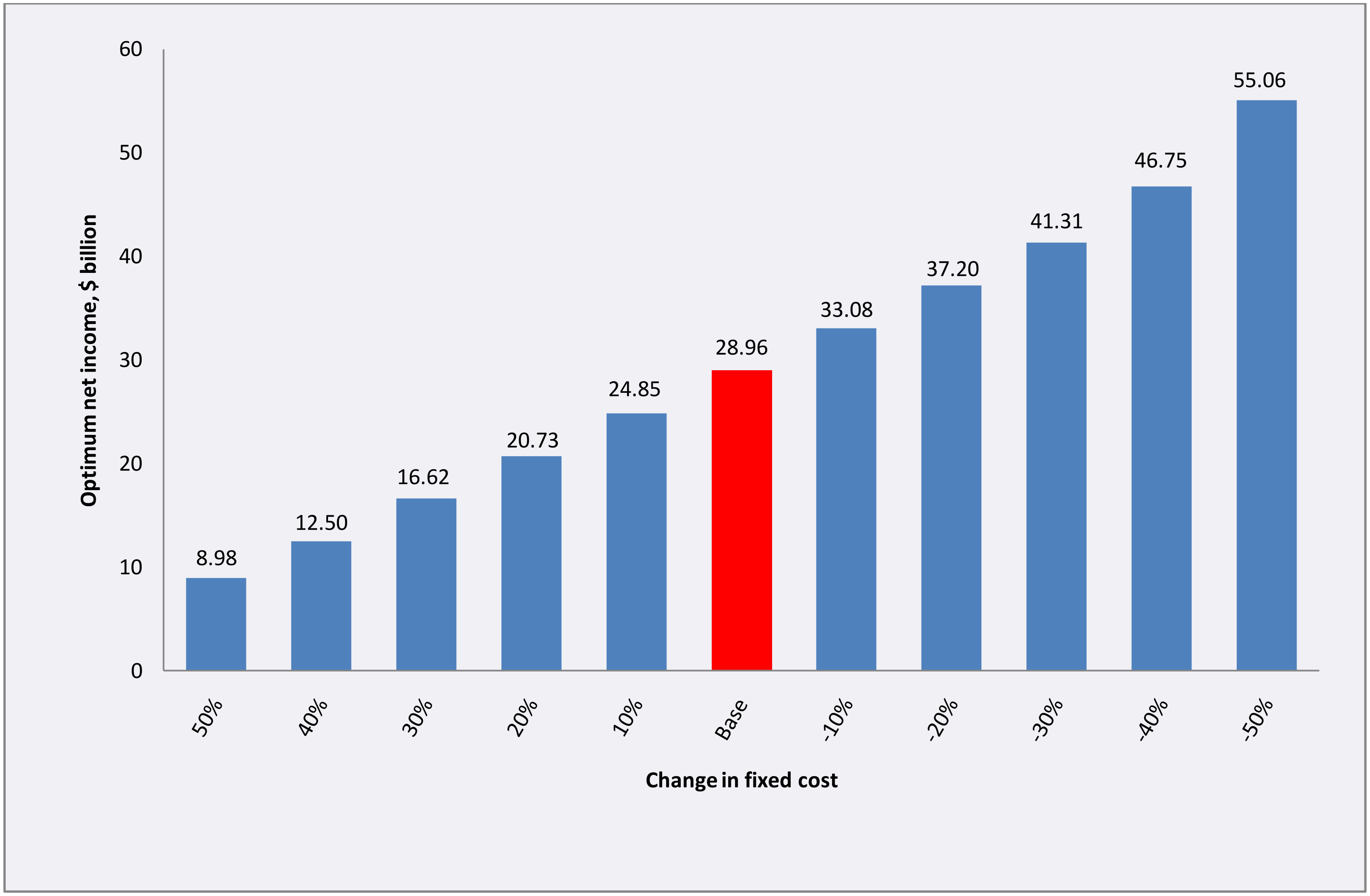


Figure 4.1; Fixed cost sensitivity

Table 4.2; Summary of sensitivity of optimal decision to fixed cost variation

Runs	Parameter varied	Resulting optimum decision	Gas volume utilized, Tscf	Optimum Income $billion
A	Base case	All options except Olokola LNG plant project.	41.29	28.96
B	Fixed cost increased by 10%	All options except Olokola LNG plant project.	41.29	24.85
C	Fixed cost increased by 20%	All options except Olokola LNG plant project.	41.29	20.73
D	Fixed cost increased by 30%	All options except Olokola LNG plant project.	41.29	16.62
E	Fixed cost increased by 40%	All options except Olokola LNG plant project.	41.29	12.50
F	Fixed cost increased by 50%	All options except Liquefaction and TSGP.	8.89	8.98
G	Fixed cost decreased by 10%	All options except Olokola LNG plant project.	41.29	33.08
H	Fixed cost decreased by 20%	All options except Olokola LNG plant project.	41.29	37.20
I	Fixed cost decreased by 30%	All options except Olokola LNG product sales.	42.84	41.31
J	Fixed cost decreased by 40%	All options except Olokola LNG product sales.	42.84	46.75
K	Fixed cost decreased by 50%	All utilization options considered.	57.24	55.06

4.2.2 Variable Cost Analysis

A sensitivity analysis on the objective function by varying the variable cost for each node is also shown. This involves increasing and decreasing the variable cost by 10%. Table 4.3 below illustrates 10% sensitivity in variable cost from the base case. Detailed results showing the sensitivities for 20%, 30%, 40% and 50% for both increasing and decreasing variable cost are shown in Appendix A.

Table 4.3; 10% change in variable costs

Node	Variable costs (billions $)	10% increase Variable costs (billions $)	10% decrease Variable costs (billions $)
a	0.36	0.396	0.324
b	1.92	2.112	1.728
c	0.609	0.6699	0.5481
d	1.77	1.947	1.593
e	1.77	1.947	1.593
1	0.852	0.9372	0.7668
2	1.15	1.265	1.035
3	1.81	1.991	1.629
4	0.852	0.9372	0.7668
5	1.78	1.958	1.602
6	0.3	0.33	0.27
7	0.22	0.242	0.198
8	1.47	1.617	1.323
9	0.3	0.33	0.27
10	2.53	2.783	2.277

For a 10% increment in variable costs, the optimal income from the optimization model was $16.70 billion and the optimum gas reserves are 41.29 Tscf.

The runs were repeated for 20%, 30%, 40% and 50% increase in the variable cost used in natural gas transshipment problem. The results obtained show a similar trend as that of the fixed cost since the optimum income reduces as the variable costs increases. The net income decrease from $16.70 billion to $10.12, $8.20, $6.28 and $4.36 billion respectively as the variable cost is increased in the above stated order. The gas reserves requirement is a minimum of 8.89 Tscf at 20% increase in variable cost. Now, increasing the variable cost by 10% does not affect the optimal decision but reduces the net income to $16.70 billion**.** The optimum decision is affected as the variable cost increment goes above 20%. Liquefaction of Natural gas becomes non profitable above 20% increase in variable cost. Only the Power project, Domestic supply, EOR product recovery sales were found to be profitable at this high percent (≥ 40%) increment in variable costs.

A similar sensitivity is carried out by decreasing the variable costs. The results obtained follow the same trend as the fixed costs. A decrease by 10%, 20%, 30%, 40% and 50% in the variable cost resulted in a corresponding increase in net income of $41.23, $53.50, $65.77, $78.03 and $90.30 billion respectively. This result for sensitivity in variable cost from the base case is shown in Figure 4.2. The gas reserves remained by and large unchanged at 41.29 Tscf. Increasing the variable cost to as high as 50% does affect the optimal decision. However, the maximum income realised from the utilization increases as shown above. Table 4.4 provides a summary of the above discussion.

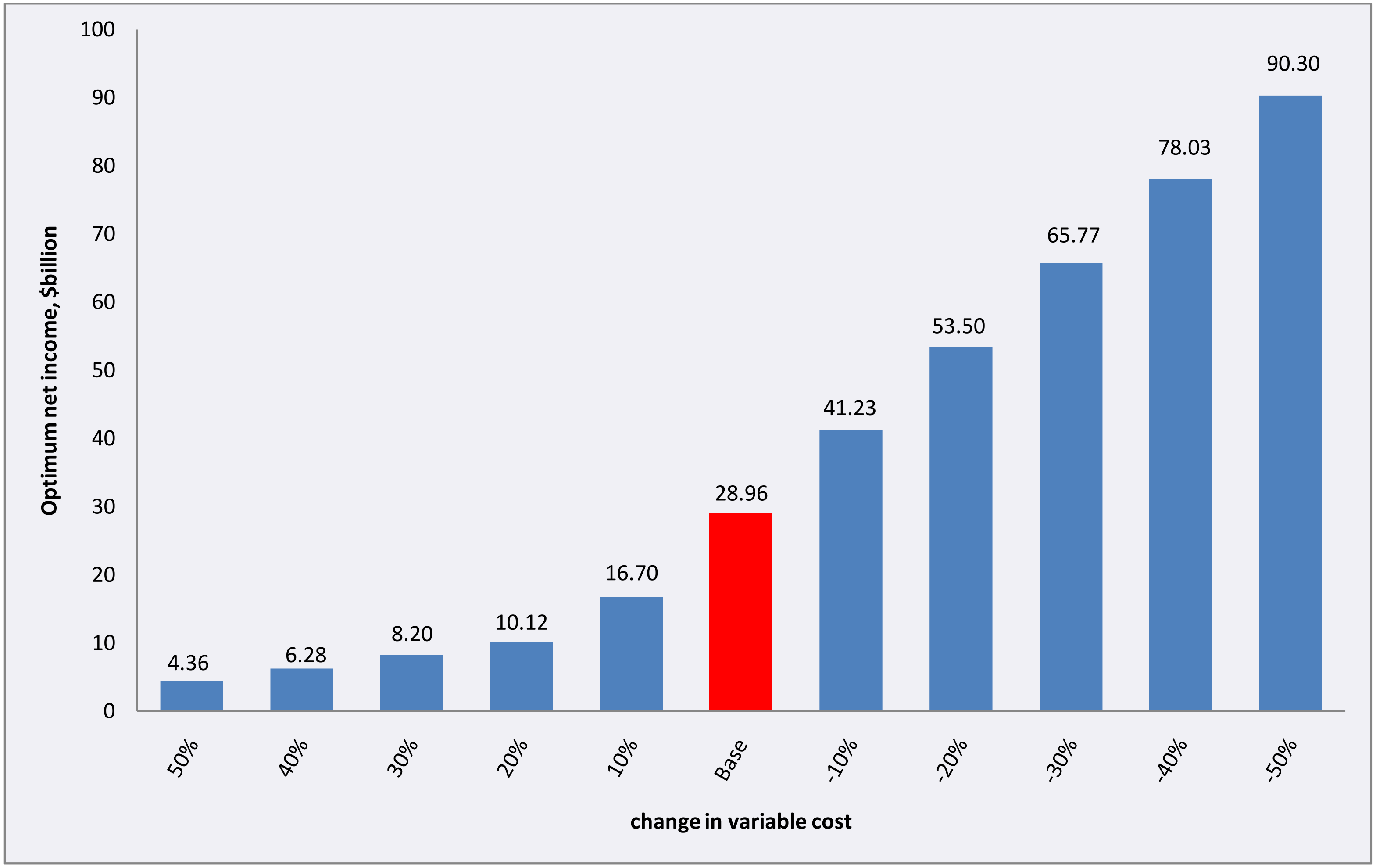


Figure 4.2; Variable cost sensitivity

Table 4.4; Summary of sensitivity of optimal decision to variable cost variation

Runs	Parameter varied	Resulting optimum decision	Gas volume utilized, Tscf	Optimum Income $billion
A	Base case	All options except Olokola LNG plant project.	41.29	28.96
B	Variable cost increased by 10%	All options except Olokola LNG plant project.	41.29	16.70
C	Variable cost increased by 20%	Only projects such as liquefaction anf NLNG	8.89	10.12
D	Variable cost increased by 30%	All options except Olokola LNG plant project.	8.89	8.20
E	Variable cost increased by 40%	Only the Afam Power project, WAGP, Domestic use and EOR.	8.89	6.28
F	Variable cost increased by 50%	Only the Afam Power project, WAGP, Domestic use and EOR.	8.89	4.36
G	Variable cost decreased by 10%	All options except Olokola LNG plant project.	41.29	41.23
H	Variable cost decreased by 20%	All options except Olokola LNG plant project.	41.29	53.50
I	Variable cost decreased by 30%	All options except Olokola LNG plant project.	41.29	65.77
J	Variable cost decreased by 40%	All options except Olokola LNG plant project.	41.29	78.03
K	Variable cost decreased by 50%	All options except Olokola LNG plant project.	41.29	90.30

4.2.3 Market Price Analysis

This section presents the effect of fluctuation in the price of Natural gas or its by-products. A ±10% change in the price of natural gas was investigated as was done for the fixed and variable cost. Table 4.5 below shows the values obtained after increasing and decreasing the market price of natural gas. A detailed Table of results for 20%, 30%, 40%, and 50% is shown in Appendix A. This sensitivity in the market price of natural gas realistic due to the larger fluctuation in oil and commodity prices caused by factors ranging from environmental, political, etc.

Table 4.5; 5% change in market price of hydrocarbon

Commodity	Market price (June, 2010)	10% increase in price	10% decrease in Price of Natural Gas
Bonny Light	$ 90/bbl	$99/bbl	$81/bbl
Natural Gas	$ 4.4/Mscf	$4.84/Mscf	$3.96Mscf
NGL	$1.25/gal or $52.5/bbl	57.75/bbl	$47.25/bbl
LNG	$ 4.4/Mscf	$4.84/Mscf	$3.96Mscf
Natural Gas	$ 1.0/Mscf	$ 1.1/Mscf	$ 0.9/Mscf

The base case result was presented earlier in the section. For a 10% increment (run B) in market price, the optimal income from the optimization model was $48.24 billion and the optimum gas reserves required to meet the market demand is 41.29.

The runs labelled C, D, E, and F were repeated for 20%, 30%, 40% and 50% increase in the market price of natural gas and its by products involved in natural gas transshipment problem. Interestingly, the model is more sensitive to the market price as seen from the results. The results show a corresponding income increase of $67.52, $86.80, $113.68 and $141.23 billion respectively in response to 20%, 30%, 40% and 50%. The required gas reserves increased to 57.24 Tscf in response to

30% increase in market price Furthermore, increasing the market price by 10% does not affect the optimal decision**.** The optimal decision changes as the market price increase exceeds 30%. All the utilization options become profitable for 30% increment in market price.

A similar sensitivity is carried out by decreasing the market price of natural gas. A decrease by 10%, 20%, and 30% in the market price resulted in a corresponding decrease of $10.43, $5.33, and $1.02 billion in the maximum profit realized from the utilization respectively. Beyond 30% decrease, the net income is zero. The result for market price sensitivity is shown in Figure 4.3. Decreasing the market price by 10% does not affect the optimal decision but it decreases the net income to $10.43 billion as expected**.** The TSGP project and the entire LNG project become commercially unattractive as the market price is decreased by 20% or higher from the base case. As the market price decrease exceeds 30%, no option is profitable. Table 4.6 provides a summary of the sensitivity analysis for market price of gas.

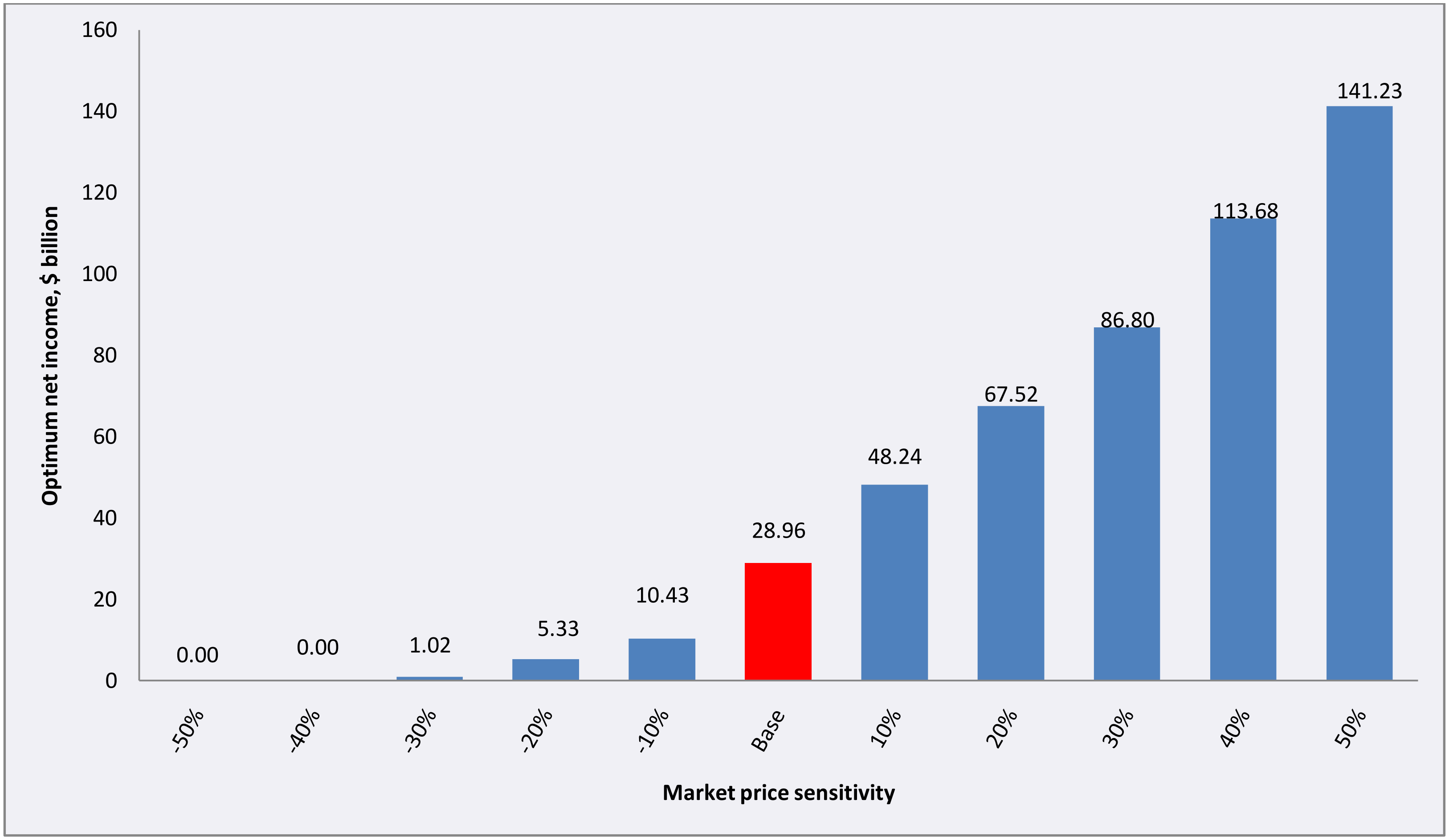


Figure 4.3; Market Price sensitivity

Table 4.6; Summary of sensitivity of optimal decision to market price variation

Runs	**Parameter varied**	**Resulting optimum decision**	**Gas volume utilized, Tscf**	**Optimum Income $billion**
A	Base case	All options except Olokola LNG and TSGP	41.29	28.96
B	Market price cost increased by 10%	All options except Olokola LNG plant.	41.29	48.24
C	Market price cost increased by 20%	All options except Olokola LNG plant.	41.29	67.52
D	Market price cost increased by 30%	All options considered.	57.24	86.80
E	Market price cost increased by 40%	All options considered in the utilization.	57.24	113.68
F	Market price cost increased by 50%	All options considered in the utilization.	57.24	141.23
G	Market price cost decreased by 10%	All options except Olokola LNG and TSGP.	26.16	10.43
H	Market price cost decreased by 20%	All options except Liquefaction and TSGP.	8.89	5.33
I	Market price cost decreased by 30%	All options except Liquefaction and TSGP.	8.89	1.02
J	Market price cost decreased by 40%	No optimal option	0	0.0
K	Market price cost decreased by 50%	No optimal option	0	0.0

4.2.4 Effect of Nigerian Gas Master Plan on Model

The above discussion assumes that the natural gas at the exit nodes is sold based on international export prices. However, as a result of the new gas master plan, this is not the case. The domestic supply obligation (DSO) imposed on IOCs ensures that gas is sold for domestic use (power generation and domestic utilization) at a reduced price. Beginning from December 2010, the price is $1/Mscf. This would increase by 50% annually in the next 3 years and from 2014, the price would be governed by inflation rate.

This necessitated the need to investigate the effect of changing domestic gas price on the profit obtained if the gas master plan pricing scenario is to be used, assuming other export destination prices remain constant. For the purpose of this work, the base case for this study is taken as $1/Mscf. Detailed gas pricing data as specified by the NGMP is provided in Appendix B. The optimum net income attained from the optimization incorporating the base domestic gas is $15.77 billion. This price is increased by 50%, 100%, 150%, 200% and 250% in consecutive order. The benefit realised from the optimization are correspondingly $15.77, $15.82, $16.70, $17.57 and $20.73 billion. Figure 4.4 provides a summary of the sensitivity analysis for a change in market price of natural gas.

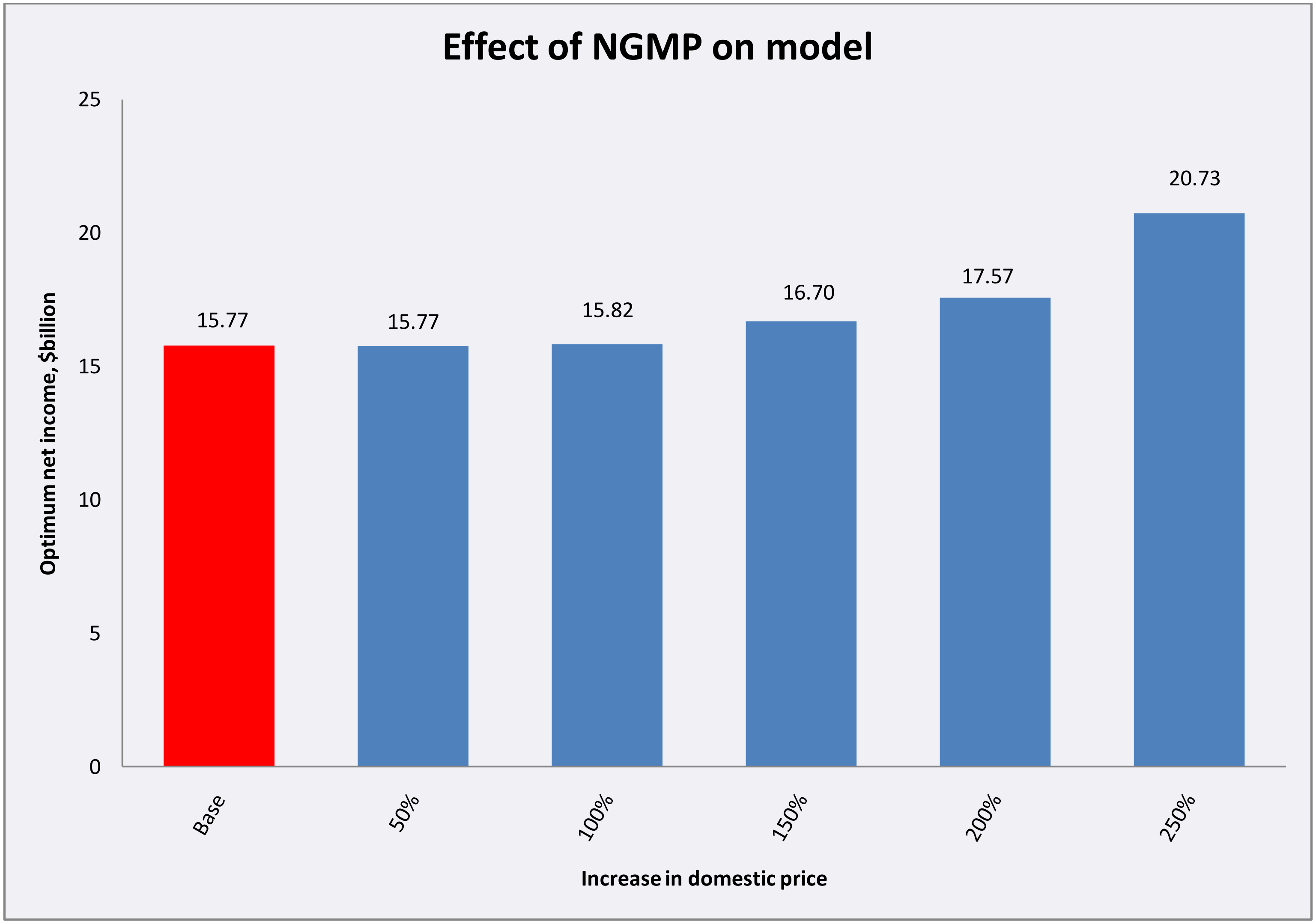


Figure 4.4; Domestic price sensitivity

4.3 DISCUSSION OF RESULTS

The detailed LINDO output solution of the optimization model for the base run is presented in the Appendix D. This result suggests an optimum (in this case maximum) income for a base period of 20 years is $28.96 billion and the required gas volume to accomplish this project was calculated as 41.29 Tscf. The base case study indicate that the most profitable projects include the Nigerian LNG project, use of gas for power generation, transport of gas to West African Countries for power generation through the West African Gas Pipeline (WAGP), the TransSaharan gas pipeline and sales of EOR products (EOR oil). Based on this optimization study, the Olokola LNG plant project was found to be non profitable. The reason for the non profitability of the Olokola LNG is that the cost does not compensate for the demand for gas by the competing projects at those destination nodes. The volume of gas at the exit node for Olokola LNG becomes zero.

Effect of changing fixed cost

Increasing the fixed cost by as far as 50% (with a 10% interval increment) from the base case results in a corresponding decrease in the maximum income. The income decreases essentially from the base value of $28.96 billion to a minimum of $8.98 billion. Furthermore, the gas reserves required to meet market demand essentially remained constant at 41.29 Tscf. The results therefore indicate that the optimum decision is affected as the fixed cost increment gets to 50%. The optimum utilization options changed and in this case, liquefaction and TSGP were not optimally profitable. This model therefore provides a basis for evaluating investment in the listed projects. The sub optimality of the Olokola LNG plant demonstrated by this research may be the reason why the financial investment decision (FID) in the project has still not been reached at this point.

On the other hand, as the fixed cost is decreased to a minimum of 50%, the income increased from $28.96 billion to a maximum of $56.06 billion whereas the gas volume increased from a base case of 41.29 Tscf to a maximum of 57.24 Tscf. This increase in gas volume required to meet market demand can be achieved by increase in gas production from the producing fields. Also as the gas production increases, option such as Olokola LNG which is otherwise considered non optimal in this study, becomes profitable. This implies that as the fixed cost reduces, which is highly unlikely, the Olokola project can attract more investment which would lead to an early start-up of the plant. From the fixed cost sensitivity, the range of profit and the gas reserve necessary to meet the market demands for this study are $8.98 to $55.06 billion and 8.89 to 57.24 Tscf.

Effect of changing variable cost

The result for the sensitivity in the variable cost suggests a similar trend as that of the fixed cost. Increasing from the base case to 50% increment in variable cost, results in a decrease in optimum net income from $28.96 billion to $4.36 billion. There is also a corresponding decrease in required gas reserves from 41.29 Tscf to 8.89 Tscf. These results indicate that the optimum income derived from the utilization is more sensitive to variable cost than the fixed costs. Upon increasing variable costs by 20% from the base, it is observed that projects such as Olokola LNG and the TSGP were found to be non profitable. This is because of the low gas volume supply from the source (8.89 Tscf) at these higher variable costs.

Furthermore, decreasing the variable costs produces an increase in the maximum income for the project to be as high as $90.30 billion for a decrease of 50%. Surprisingly, the gas reserve remained essentially unchanged at 41.29 Tscf. This is because the large enough volume of gas (approximately 5.6 Bscf/d) is adequate to satisfy the demand at the exit nodes. The maximum gas utilization income ranges from $4.36 to $90.30 billion for a required gas volume range of 8.89 to 57.24 Tscf. To supply higher gas volumes (e.g. 57.24 Tscf) drilling of new wells to meet market demand. Also high gas volume encourages projects such as the Olokola LNG project which were found to be profitable.

Effect of changing market price

Sensitivity analysis of the model function to the market price of natural gas and it's by products shows some interesting results. Increasing from base value to 50% of the market price, leads to an increase in the optimum net income from $28.96 billion to $141.23 billion. The interesting thing about the results is the significant effect the market price of natural gas has on the maximum net income from the utilization study. Gas volumes required also increased from the base case of 41.29 Tscf to 57.24 Tscf to meet the market demand. Gas has to be supplied from the producer's associated and non-associated gas fields to meet this increase. It can also be noticed that all the utilization options become economically attractive at high market prices. This may be the reason why investors are still optimistic about the Olokola LNG despite the high cost of the project. The attraction to invest is based on the investors' optimism about increases in natural gas prices in the coming years. The recent advances in renewable energy technologies and the call for reduction in carbon emission means that natural gas prices would, in the near future be competing with crude oil prices. This is obviously a positive sign for LNG investors.

On the other hand, for a decrease in the market price of natural gas by 30% renders all the utilization projects considered to be non profitable because of the zero net income realizable. The optimization study suggest therefore shows that as the market price decreases by 30% of its original price, all other things been equal, no project is optimally profitable. The range of net income generated was $0.0 to $126.64 billion for a gas reserves range of 0 to 57.24 Tscf. It is worth mentioning at this point that the minimum gas volume required as a result of decrease in market price of natural gas (as from 20%) rendered some of the projects like the TSGP and, of course, the Olokola LNG, non profitable options. Under the depressed gas price scenario, production would be reduced by shutting down some of the non- associated gas wells and flaring in some cases especially for associated gas wells will become necessary. As the gas price decreases by 30%, no option is profitable.

Effect of Gas Pricing by the NGMP

The result of this study indicate that the optimum decision for gas utilization when the gas master plan is in effect. In this case, optimum utilization is a combination of projects ranging from Liquefaction at Bonny, the WAGP, the TSGP, Power generation at Afam, and EOR process. The domestic gas utilization was essentially non profitable at a gas to power price of $1/Mscf and a gas to industry price of $0.9/Mscf. Increasing the domestic gas price by 100% ($2/Mscf), improves the profitability of the Power utilization option. Additionally, the domestic utilization companies only become profitable for a price increase of 250% of the base. The net income increases to a maximum of $20.73 billion for 50% increment in domestic market price (both power and gas-based industries) upon invoking the gas master plan gas pricing scheme. The result from this study essentially provide an insight to why the IOCs in Nigeria have long not been interested in selling gas to domestic consumers but prefer to export it for more economic benefit.

Summary of the discussion of results is presented for optimal decision path on Table 4.7.

Table 4.7; Summary of results from the gas Utilization Study

Results	Range in Max income, $billion	Range in Gas Reserve, Tscf	Comment on Optimum gas utilization
Base Scenario	28.96	41.29	All options are commercially viable with the exception of the Olokola LNG project.
Fixed cost	8.98– 55.06	8.89 – 57.24	Sensitivity of the model is low. Olokola LNG project not commercially viable for fixed costs higher than the base.
Variable costs Sensitivity	4.36 – 90.30	8.89 – 57.24	Model is more sensitive to variable costs. However, Olokola LNG project still not commercially viable options for variable costs higher than the base.
Market price Sensitivity	0.0 – 141.23	0 – 57.24	Model objective maximization function extremely sensitive to market price. Olokola LNG project not commercially viable for market price of natural gas lower than the base price.
Domestic Gas Price with gas master plan	15.77 – 20.73	33.95 - 41.29	The Power utilization option was not profitable for $1/Mscf but becomes profitable at increment of 10% of the base. Gas fired industries option only become at 50% increase in gas price.

CHAPTER FIVE

5.0 CONCLUSIONS AND RECOMMENDATIONS

5.1 SUMMARY AND CONCLUSIONS

Nigeria has huge reserves of both associated and non-associated natural gas available. Increasing production of associated gas may lead to an increase in oil production, a situation that is constrained by the OPEC quota for Nigeria since Nigeria is a member country. In summary, the following are the thought from the study:

- An optimization model for utilization of natural gas was developed for the Niger Delta region of Nigeria consisting of an objective function and several constraints.
- The model was solved using LINDO software for the optimum value of the objective function and the quantity of gas at the several nodes.
- The optimum decision for gas utilization, obtained from the solution of the model, consist of projects (both ongoing and planned) such as liquefaction of Natural gas at Bonny, supply of gas for power generation at Afam, Transport of gas to West African countries, Transport of gas to Algeria through the TSGP, Domestic utilization of natural gas, and sales of EOR product.
- The change in the value of economic parameters such as the fixed costs, variable costs and price of natural gas were found to significantly affect the optimum net income from the gas utilization.

The following conclusions can be drawn based on this study.

- A natural gas optimization model was derived for the Niger Delta and several constraints such as deliverability and source availability imposed on the model. The profitable projects from the base case involve continuing of projects in the Niger Delta which consist of liquefaction of Natural gas at Bonny for transport to Europe and America, supply of gas for power generation at Afam, transport of gas to West African countries, Transport of gas to Algeria through the TSGP, Domestic utilization of natural gas, and the sales and EOR product.

- Planned Projects such as the Olokola LNG have been found to be non viable based on its high costs and current gas prices. However, high gas prices were found to ultimately favour the take-off of this project.
- Interest and attraction shared by investors for the Olokola LNG project may be based upon the investors' optimism that higher market prices are in the horizon, and these can lift the project into profitability.
- Net income derived from the model for the base case study (BS) with the above utilization options was $ 28.96 billion and the gas required to meet the market demand is 41.29 Tscf (an average of 5.6 Bscf/d) over a period of 20 years.
- As the gas supply goes below 8.89 Tscf, liquefaction of natural gas and the TSGP are no longer profitable options for consideration. The low gas supply scenario implies that some of the producing wells have to be shut in to prevent excess supply of gas. More so, all the projects become non profitable at very low market prices (i.e. prices decrease by 50% of the base case) as indicated previously.
- Additionally, as the gas volumes reaches 57.24 Tscf (the ultimate gas volume scenario), all the utilization options considered now become profitable. Also, the maximum net income derived from the utilization is $141.23 billion.
- Upon considering the Nigerian Gas Master plan in the utilization (using domestic price of gas), it can be concluded from this study that as the price of gas for domestic utilization remain at $1/Mscf, the domestic utilization options (both Power and local industries) becomes non profitable.
- Analysis of the impact of domestic price specified in the Nigerian Gas Master Plan, shows that

at gas price of $1/Mscf, the domestic utilization option becomes economically non profitable. An increase of 100% from the base domestic price, i.e. $2.0/Mscf renders the Power option profitable. The domestic companies' options only become profitable for a gas price of $3.15/Mscf.

5.2 RECOMMENDATION

The following recommendations can be considered for future study;

- The input to the optimization model should be refined as more information becomes available. Data required include fixed costs and variable costs for all the nodes, demand parameters at each destination nodes since these parameters strongly affect the optimal decision from the gas utilization.
- More realistic stochastic variations should be carried out on the fixed, variable and market price of natural gas at each node. This would call for stochastic programming to solve the equations from the optimization model.
- Other gas utilization projects (both current and planned) like the Escravos Gas and GTL projects, Delta State gas utilization project, etc should be investigated by carrying out judicious modifications to this model.
- Model can be employed to evaluate options for gas utilization in a single field whereby a decision can be taken on how to optimize the profit from that field.
- Further studies should incorporate several source nodes to emphasize the presence of several producing wells.

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NOMENCLATURE

Xoa amount of gas or by-product transported from the source node ‘0’ to process node ‘a’ in Tscf

Xob amount of gas or by-product transported from the source node ‘0’ to process node ‘b’ in Tscf

Xoc amount of gas or by-product transported from the source node ‘0’ to process node ‘c’ in Tscf

Xad amount of gas or by-product transported from node ‘a’ to process node ‘d’ in Tscf

Xae amount of gas or by-product transported from node ‘a’ to process node ‘e’ in Tscf

Xd1 amount of gas or by-product transported from node ‘d’ to market node ‘1’ in Tscf

Xd2 amount of gas or by-product transported from node ‘d’ to market node ‘2’ in Tscf

Xd3 amount of gas or by-product transported from node ‘d’ to market node ‘3’ in Tscf

Xe4 amount of gas or by-product transported from node ‘e’ to market node ‘4’ in Tscf

Xe5 amount of gas or by-product transported from node ‘e’ to market node ‘5’ in Tscf

Xb6 amount of gas or by-product transported from node ‘b’ to market node ‘6’ in Tscf

Xb7 amount of gas or by-product transported from node ‘b’ to market node ‘7’ in Tscf

Xb8 amount of gas or by-product transported from node ‘b’ to market node ‘8’ in Tscf

Xb9 amount of gas or by-product transported from node ‘b’ to market node ‘9’ in Tscf

Xc10 amount of gas or by-product transported from node ‘c’ to market node ‘10’ in Tscf

yoa coefficient switch to determine whether a fixed cost should be applied at node ‘a’

yob coefficient switch to determine whether a fixed cost should be applied at node ‘b’

yoc coefficient switch to determine whether a fixed cost should be applied at node ‘c’

yad coefficient switch to determine whether a fixed cost should be applied at node ‘d’

yae coefficient switch to determine whether a fixed cost should be applied at node ‘e’

yd1 coefficient switch to determine whether a fixed cost should be applied at node ‘1’

yd2 coefficient switch to determine whether a fixed cost should be applied at node ‘2’ yd3 coefficient switch to determine whether a fixed cost should be applied at node ‘3’

ye4 coefficient switch to determine whether a fixed cost should be applied at node ‘4’

ye5 coefficient switch to determine whether a fixed cost should be applied at node ‘5’

yb6 coefficient switch to determine whether a fixed cost should be applied at node ‘6’

yb7 coefficient switch to determine whether a fixed cost should be applied at node ‘7’

yb8 coefficient switch to determine whether a fixed cost should be applied at node ‘8’

yb9 coefficient switch to determine whether a fixed cost should be applied at node ‘9’

yc10 coefficient switch to determine whether a fixed cost should be applied at node ‘10’

BOPD barrel of oil per day

BS Base case Study

Bscf Billion standard cubic feet per day

CNG Compressed Natural Gas

EIA Energy Information and Administration

EOR Enhanced Oil Recovery

G Total gas volumes at the source in Tscf

GHG Green House Gases

GTL Gas to liquid

IOCs International Oil Companies

LINDO Linear Interactive Discreet Optimizer

LNG Liquefied Natural Gas

LPG Liquefied Petroleum Gas

M a significantly large volume of gas used to calculate the switching coefficient y.

MMBTU Million British thermal unit

MMscf/d Million standard cubic feet per day

NGL Natural Gas Liquid

NGMP Nigerian Gas Master Plan

OML Oil Mining Lease

OPEC Organization of petroleum Exporting Countries

OPL Oil Prospecting License

Q Deliverability at the destination nodes, MMscf/d

Tscf Trillion standard cubic feet per day

TSGP: Transsaharan Gas Pipeline Project

WAGP: West African Gas Pipeline Project

Y mole fraction of gas or by-product at the destination node

Subscript

0 index for source node

a, b, c, d, e indices for process nodes

i, j and k nodal indices

t index for terminal nodes, "1" through "9"

APPENDIX A

A.1 Formulating the LP

The general linear programming problem can be stated in the following standard forms *(Rao, 2009):*

Scalar Form

Minimize $f(x_1, x_2, \ldots, x_n) = c_1x_1 + c_2x_2 + \cdots + c_nx_n$ A.1

subject to the constraints

$a_{11}x_1 + a_{12}x_2 + \cdots + a_{1n}x_n = b_1$ A.2a

$a_{21}x_1 + a_{22}x_2 + \cdots + a_{2n}x_n = b_2$ A.2b

...

$a_{m1}x_1 + a_{m2}x_2 + \cdots + a_{mn}x_n = b_m$ A.2c

$x_1 \geq 0$ A.3

$x_2 \geq 0$ A.4

...

$x_n \geq 0$ A.5

where c_j, b_j, and a_{ij} ($i = 1, 2, \ldots, m$; $j = 1, 2, \ldots, n$) are known constants, and x_j are the decision variables.

Matrix Form

Minimize $f(\mathbf{X}) = \mathbf{c}^T\mathbf{X}$ A.6

subject to the constraints

$\mathbf{aX} = \mathbf{b}$ A.7

$\mathbf{X} \geq \mathbf{0}$ A.8

Where;

$$X = \begin{cases} x1 \\ x2 \\ x3 \\ \cdot \\ xn \end{cases} \qquad b = \begin{cases} b1 \\ b2 \\ b3 \\ \cdot \\ bn \end{cases} \qquad c = \begin{cases} c1 \\ c2 \\ c3 \\ \cdot \\ cn \end{cases}$$

and

$$a = \begin{cases} a11 & a12 & a1n \\ a21 & a22 & a2n \\ a31 & a32 & a3n \\ & \cdot & \\ & \cdot & \end{cases}$$

A.2 Solution to LP

The solution to the LP can be obtained graphically for two variable systems. However, for multi-variable system, which is a more practical problem, a computer algorithm is usually employed. The simplex method is one of the oldest methods developed by Dantzig for solving LP problems. More new methods of solving LP include the interior point method. These algorithms (especially the simplex method) have been built in software like LINDO (Linear Interactive Discrete Optimizer).

APPENDIX B

B.1 NIGER DELTA CASE STUDY

For the Niger Delta region of Nigeria using Shell Nigeria associated and non-associated natural gas fields, the optimization model, which is a constrained multi-variable MILP, was developed. Applying the data discussed in section 3.6, 3.7 and 3.8 into the model equations developed in section 3.4 generate the sets of equations provided below. The series of equations shown below describe the optimization model equations as proposed for the Niger Delta. It consists of the objective function and the set of constraints discussed previously.

B.1.1 Base Case Study

For the base case optimization run, the series of equations below were solved using LINDO optimization software employing the branch and bound algorithm for mixed integer linear programming. The detailed solution to the problem is provided in the appendix.

```
!*******************************************************************************
!The objective function is a maximization problem
!The X variables are volume in Tscf
!The y variables are the fixed coefficient switch which can either be either zero or 1
!and is important in specifying whether a fixed
!cost is applicable at a particular node
!*******************************************************************************
!OBJECTIVE FUNCTION
 MAX  - 0.36 X0a - 1.92 X0b - 0.609 X0c - 1.77 Xad - 1.77 Xae
 + 4.4 Xd1 + 4.4 Xd2 + 52.5 Xd3 + 4.4 Xe4 + 52.5 Xe5 + 4.4 Xb6 + 4.4 Xb7 + 4.4 Xb8
 + 4.4 Xb9 + 90 Xc10 - 0.852 Xd1 - 1.15 Xd2 - 1.81 Xd3 - 0.852 Xe4 - 1.78 Xe5 - 0.3 Xb6 - 0.22 Xb7
```

- 1.47 Xb8 - 0.30 Xb9 - 2.53 Xc10 - 0.8 y0a - 5 y0b - 0.0585 y0c - 13.86 yad - 14.6 yae - 2.3 yd1 - 1.18 yd2 - 0.83 yd3 - 3.48 Xe4 - 0.83 ye5 - 0.0 yb6 - 0.924 yb7 - 12.2 yb8 - 4.00 yb9 - 0.0 yc10

! CONSTRAINTS

SUBJECT TO

!Gas Volume Constraint

2) X0a + X0b + X0c - G = 0 !This makes sure that the gas going out of the source node must not be greater than the source volume

3) Xd1 + Xd2 + 5.648 Xd3 + Xe4 + 5.648 Xe5 + Xb6 + Xb7 + Xb8 + Xb9 + 5.648 Xc10 - X0a - X0b - X0c = 0 !This is a material balance constraint

! Node Storage Constraints

4) X0a - Xad - Xae = 0 !Nodal balance for node a

5) Xad - Xd1 - Xd2 - 5.648 Xd3 = 0 !Nodal balance for node d

6) Xae - Xe4 - 5.648 Xe5 = 0 ! Nodal balance for node c

7) X0b - Xb6 - Xb7 - Xb8 - Xb9 = 0 !Node balance for node b

8) X0c - 5.648 Xc10 = 0 !Nodal balance for node f

! Fixed Cost Constraints

9) 100y0a - X0a >= 0

10) 100y0b - X0b >= 0

11) 100y0c - X0c >= 0

12) 100yad - Xad >= 0

13) 100yae - Xae >= 0

14) 100yd1 - Xd1 >= 0

15) 100yd2 - Xd2 >= 0

16) 100yd3 - Xd3 >= 0

17) 100ye4 - Xe4 >= 0

18) 100ye5 - Xe5 >= 0

19) 100yb6 - Xb6 >= 0

20) 100yb7 - Xb7 >= 0

21) 100yb8 - Xb8 >= 0

22) 100yb9 - Xb9 >= 0

23) 100yc10 - Xc10 >= 0

!Gas Composition constraint

24) Xd1 - 0.944 G < 0

25) Xd2 - 0.944 G < 0

26) 5.648 Xd3 - 0.035 G < 0

27) Xe4 - 0.944 G < 0

28) 5.648 Xe5 - 0.035 G < 0

29) Xb6 - 0.965 G < 0

30) Xb7 - 0.965 G < 0

31) Xb8 - 0.965 G < 0

32) Xb9 - 0.965 G < 0

33) 5.648 Xc10 - 0.5595 G < 0

!Deliverability Constraint

34) Xd1 < 10.792

35) Xd2 < 5.560

36) 5.648 Xd3 < 4.24

37) Xe4 < 13.393

38) 5.648 Xe5 < 6.493

39) Xb6 < 1.752

40) Xb7 < 1.460

41) Xb8 < 14.60

42) Xb9 < 5.329

43) 5.648 Xc10 < 0.3504

END

!Restriction of fixed cost coefficient to 0 or 1

!

INTEGER y0a

INTEGER y0b

INTEGER y0c

INTEGER yad

INTEGER yae

INTEGER yd1

INTEGER yd2

INTEGER yd3

INTEGER ye4

INTEGER ye5

INTEGER yb6

INTEGER yb7

INTEGER yb8

INTEGER yb9

INTEGER yc10

B.2. DOMESTIC GAS PRICE BY THE NGMP

B.2.1 Power ($/Mscf)

2010	2011	2012	2013	2014+
1.0	1.5	1.5	2.0	2.0*(1.0 + Inflation Rate)

B.2.2 Gas fired industries

Floor Price ($/Mscf)	0.9
Cap Price ($/Mscf)	3.0

B.2.3 Local Distribution company

$3.0/Mscf

APPENDIX C

C.1 SENSITIVITY ANALYSIS

C.1.1 Fixed Cost Analysis

Values obtained for sensitivity in fixed cost for the following runs 10%, 20%, 30% and 40% and 50% increase are shown in Table C1 to C5.

Table C1: Conversion and Transportation costs for 10% change in fixed cost

Node	Fixed costs(billions $)	10% increase Fixed costs(billions $)	10% decrease Fixed costs(billions $)
a	0.8	0.88	0.72
b	5	5.5	4.5
c	0.0585	0.06435	0.05265
d	13.86	15.246	12.474
e	14.6	16.06	13.14
1	2.3	2.53	2.07
2	1.18	1.298	1.062
2	0.83	0.913	0.747
4	3.48	3.828	3.132
5	0.83	0.913	0.747
6	0	0	0
7	0.924	1.0164	0.8316
8	12.2	13.42	10.98
9	4	4.4	3.6
10	0	0	0

Table C2: Conversion and Transportation costs for 20% change in fixed cost

Node	Fixed costs(billions $)	20% increase Fixed costs(billions $)	20% decrease Fixed costs(billions $)
a	0.8	0.96	0.64
b	5	6	4
c	0.0585	0.0702	0.0468
d	13.86	16.632	11.088
e	14.6	17.52	11.68
1	2.3	2.76	1.84
2	1.18	1.416	0.944
3	0.83	0.996	0.664
4	3.48	4.176	2.784
5	0.83	0.996	0.664
6	0	0	0
7	0.924	1.1088	0.7392
8	12.2	14.64	9.76
9	4	4.8	3.2
10	0	0	0

Table C3: Conversion and Transportation costs for 30% change in fixed cost

Node	Fixed costs(billions $)	30% increase Fixed costs(billions $)	30% decrease Fixed costs(billions $)
a	0.8	1.04	0.56
b	5	6.5	3.5
c	0.0585	0.07605	0.04095
d	13.86	18.018	9.702
e	14.6	18.98	10.22
1	2.3	2.99	1.61

2	1.18	1.534	0.826
3	0.83	1.079	0.581
4	3.48	4.524	2.436
5	0.83	1.079	0.581
6	0	0	0
7	0.924	1.2012	0.6468
8	12.2	15.86	8.54
9	4	5.2	2.8
10	0	0	0

Table C4: Conversion and Transportation costs for 40% change in fixed cost

Node	Fixed costs (billions $)	40% increase Fixed costs (billions $)	40% decrease Fixed costs (billions $)
a	0.8	1.12	0.48
b	5	7	3
c	0.0585	0.0819	0.0351
d	13.86	19.404	8.316
e	14.6	20.44	8.76
1	2.3	3.22	1.38
2	1.18	1.652	0.708
3	0.83	1.162	0.498
4	3.48	4.872	2.088
5	0.83	1.162	0.498
6	0	0	0
7	0.924	1.2936	0.5544
8	12.2	17.08	7.32
9	4	5.6	2.4
10	0	0	0

Table C5: Conversion and Transportation costs for 50% change in fixed cost

Node	Fixed costs(billions $)	50% increase Fixed costs(billions $)	50% decrease Fixed costs(billions $)
a	0.8	1.2	0.4
b	5	7.5	2.5
c	0.0585	0.08775	0.02925
d	13.86	20.79	6.93
e	14.6	21.9	7.3
1	2.3	3.45	1.15
2	1.18	1.77	0.59
3	0.83	1.245	0.415
4	3.48	5.22	1.74
5	0.83	1.245	0.415
6	0	0	0
7	0.924	1.386	0.462
8	12.2	18.3	6.1
9	4	6	2
10	0	0	0

C.1.2 Variable Cost Analysis

The full variable cost sensitivity for 10%, 15%, 20% and 25% for both increasing and decreasing variable cost is shown in Table C6 to C10.

Table C6: Conversion and Transportation costs for 10% change in variable cost

Node	Variable costs (billions $)	10% increase Variable costs (billions $)	10% decrease Variable costs (billions $)
a	0.36	0.396	0.324
b	1.92	2.112	1.728
c	0.609	0.6699	0.5481
d	1.77	1.947	1.593
e	1.77	1.947	1.593
1	0.852	0.9372	0.7668
2	1.15	1.265	1.035
3	1.81	1.991	1.629
4	0.852	0.9372	0.7668
5	1.78	1.958	1.602
6	0.3	0.33	0.27
7	0.22	0.242	0.198
8	1.47	1.617	1.323
9	0.3	0.33	0.27
10	2.53	2.783	2.277

Table C7: Conversion and Transportation costs for 20% change in variable cost

Node	Variable costs(billions $)	20% increase variable costs(billions $)	20% decrease variable costs(billions $)
a	0.36	0.432	0.288
b	1.92	2.304	1.536
c	0.609	0.7308	0.4872
d	1.77	2.124	1.416
e	1.77	2.124	1.416
1	0.852	1.0224	0.6816
2	1.15	1.38	0.92

3	1.81	2.172	1.448
4	0.852	1.0224	0.6816
5	1.78	2.136	1.424
6	0.3	0.36	0.24
7	0.22	0.264	0.176
8	1.47	1.764	1.176
9	0.3	0.36	0.24
10	2.53	3.036	2.024

Table C8: Conversion and Transportation costs for 30% change in variable cost

Node	Variable costs(billions $)	30% increase variable costs(billions $)	30% decrease variable costs(billions $)
a	0.36	0.468	0.252
b	1.92	2.496	1.344
c	0.609	0.7917	0.4263
d	1.77	2.301	1.239
e	1.77	2.301	1.239
1	0.852	1.1076	0.5964
2	1.15	1.495	0.805
3	1.81	2.353	1.267
4	0.852	1.1076	0.5964
5	1.78	2.314	1.246
6	0.3	0.39	0.21
7	0.22	0.286	0.154
8	1.47	1.911	1.029
9	0.3	0.39	0.21
10	2.53	3.289	1.771

Table C9: Conversion and Transportation costs 40% change in variable cost

Node	variable costs(billions $)	40% increase variable costs(billions $)	40% decrease variable costs(billions $)
a	0.36	0.504	0.216
b	1.92	2.688	1.152
c	0.609	0.8526	0.3654
d	1.77	2.478	1.062
e	1.77	2.478	1.062
1	0.852	1.1928	0.5112
2	1.15	1.61	0.69
3	1.81	2.534	1.086
4	0.852	1.1928	0.5112
5	1.78	2.492	1.068
6	0.3	0.42	0.18
7	0.22	0.308	0.132
8	1.47	2.058	0.882
9	0.3	0.42	0.18
10	2.53	3.542	1.518

Table C10: Conversion and Transportation costs for 50% change in variable cost

Node	Variable costs(billions $)	50% increase variable costs(billions $)	50% decrease variable costs(billions $)
a	0.36	0.54	0.18
b	1.92	2.88	0.96
c	0.609	0.9135	0.3045
d	1.77	2.655	0.885
e	1.77	2.655	0.885
1	0.852	1.278	0.426

2	1.15	1.725	0.575
3	1.81	2.715	0.905
4	0.852	1.278	0.426
5	1.78	2.67	0.89
6	0.3	0.45	0.15
7	0.22	0.33	0.11
8	1.47	2.205	0.735
9	0.3	0.45	0.15
10	2.53	3.795	1.265

C.1.3 Market Price Analysis

The full table of results for 10%, 20%, 30%, 40%, and 50% is shown on Table C11 to C15.

Table C11: Market Price by 10%

Commodity	**Market price (June, 2010)**	**10% increase in price**	**10% decrease in Price of Natural Gas**
Bonny Light	$ 90 /bbl	99	81
Natural Gas	$ 4.4/Mscf	4.84	3.96
NGL	$ 52.5/bbl	57.75	47.25
LNG	$ 4.4/Mscf	4.84	3.96

Table C12: Market Price by 20%

Commodity	**Market price (June, 2010)**	**20% increase in price**	**20% decrease in Price of Natural Gas**
Bonny Light	$ 90 /bbl	108	72
Natural Gas	$ 4.4/Mscf	5.28	3.52
NGL	$ 52.5/bbl	63	42

LNG	$ 4.4/Mscf	5.28	3.52

Table C13: Market Price by 30%

Commodity	**Market price (June, 2010)**	**30% increase in price**	**30% decrease in Price of Natural Gas**
Bonny Light	$ 90 /bbl	117	63
Natural Gas	$ 4.4/Mscf	5.72	3.08
NGL	$ 52.5/bbl	68.25	36.75
LNG	$ 4.4/Mscf	5.72	3.08

Table C14: Market Price by 40%

Commodity	**Market price (June, 2010)**	**40% increase in price**	**40% decrease in Price of Natural Gas**
Bonny Light	$ 90 /bbl	126	54
Natural Gas	$ 4.4/Mscf	6.16	2.64
NGL	$ 52.5/bbl	73.5	31.5
LNG	$ 4.4/Mscf	6.16	2.64

Table C15: Market Price by 50%

Commodity	**Market price (June, 2010)**	**50% increase in price**	**50% decrease in Price of Natural Gas**
Bonny Light	$ 90 /bbl	135	45
Natural Gas	$ 4.4/Mscf	6.6	2.2
NGL	$ 52.5/bbl	78.75	26.25
LNG	$ 4.4/Mscf	6.6	2.2

APPENDIX D

The detailed result for the base case optimization run is shown below. This consists of the optimum value of the objective function, the total volume of gas at the source node and the quantity of gas at each of the various nodes.

```
LP OPTIMUM FOUND AT STEP    360
 OBJECTIVE VALUE =   74.4298325


 SET      Y0A TO >=     1 AT    1, BND=   38.99    TWIN=  17.12       396
 SET      YE5 TO >=     1 AT    2, BND=   38.78    TWIN=  30.35       399
 SET      YD3 TO >=     1 AT    3, BND=   38.56    TWIN=  29.88       402
 SET      YAE TO <=     0 AT    4, BND=   29.29    TWIN=  25.29       405
 SET      YAD TO >=     1 AT    5, BND=   28.13    TWIN=  14.66       415

 NEW INTEGER SOLUTION OF    28.1346722     AT BRANCH     10 PIVOT     415
 BOUND ON OPTIMUM:  30.35469
 DELETE      YAD AT LEVEL     5
 DELETE      YAE AT LEVEL     4
 FLIP      YD3 TO <=        0 AT    3 WITH BND=    29.875614
 SET      YAE TO <=     0 AT    4, BND=   21.87    TWIN=  16.56       419
 DELETE      YAE AT LEVEL     4
 DELETE      YD3 AT LEVEL     3
 FLIP      YE5 TO <=        0 AT    2 WITH BND=    30.354692
 SET      YD3 TO >=     1 AT    3, BND=   30.12    TWIN=  22.70       424
```

SET YAD TO >= 1 AT 4, BND= 28.96 TWIN= 15.49 437

NEW INTEGER SOLUTION OF 28.9646721 AT BRANCH 13 PIVOT 437

BOUND ON OPTIMUM: 28.96467

DELETE YAD AT LEVEL 4

DELETE YD3 AT LEVEL 3

DELETE YE5 AT LEVEL 2

DELETE Y0A AT LEVEL 1

ENUMERATION COMPLETE. BRANCHES= 13 PIVOTS= 437

LAST INTEGER SOLUTION IS THE BEST FOUND

RE-INSTALLING BEST SOLUTION...

OBJECTIVE FUNCTION VALUE

1) 28.96464

VARIABLE	VALUE	REDUCED COST
Y0A	1.000000	0.800000
Y0B	1.000000	5.000000
Y0C	1.000000	0.058500
YAD	1.000000	13.860000
YAE	0.000000	-695.242920
YD1	1.000000	2.300000

YD2	1.000000	1.180000
YD3	1.000000	0.830000
YE4	0.000000	0.000000
YE5	0.000000	0.830000
YB6	1.000000	0.000000
YB7	1.000000	0.924000
YB8	1.000000	12.200000
YB9	1.000000	4.000000
YC10	1.000000	0.000000
X0A	17.797098	0.000000
X0B	23.141001	0.000000
X0C	0.350400	0.000000
XAD	17.797098	0.000000
XAE	0.000000	0.000000
XD1	10.792000	0.000000
XD2	5.560000	0.000000
XD3	0.255860	0.000000
XE4	0.000000	8.912170
XE5	0.000000	0.000000
XB6	1.752000	0.000000
XB7	1.460000	0.000000
XB8	14.600000	0.000000
XB9	5.329000	0.000000
XC10	0.062040	0.000000

G	41.288498	0.000000

ROW	SLACK OR SURPLUS	DUAL PRICES
2)	0.000000	-0.248259
3)	0.000000	0.000000
4)	0.000000	-0.111741
5)	0.000000	-1.881741
6)	0.000000	-8.980170
7)	0.000000	-1.671741
8)	0.000000	-0.360741
9)	82.202904	0.000000
10)	76.859001	0.000000
11)	99.649597	0.000000
12)	82.202904	0.000000
13)	0.000000	-7.098430
14)	89.208000	0.000000
15)	94.440002	0.000000
16)	99.744141	0.000000
17)	0.000000	0.000000
18)	0.000000	0.000000
19)	98.248001	0.000000
20)	98.540001	0.000000
21)	85.400002	0.000000

22)	94.670998	0.000000
23)	99.937958	0.000000
24)	28.184341	0.000000
25)	33.416340	0.000000
26)	0.000000	7.093118
27)	38.976341	0.000000
28)	1.445097	0.000000
29)	38.091400	0.000000
30)	38.383400	0.000000
31)	25.243399	0.000000
32)	34.514400	0.000000
33)	22.750513	0.000000
34)	0.000000	1.666259
35)	0.000000	1.368259
36)	2.794903	0.000000
37)	13.393000	0.000000
38)	6.493000	0.000000
39)	0.000000	2.428259
40)	0.000000	2.508259
41)	0.000000	1.258259
42)	0.000000	2.428259
43)	0.000000	15.126158

NO. ITERATIONS= 455

BRANCHES= 13 DETERM.= 1.000E 0