

# **ECONOMIC COMPARISON BETWEEN OIL AND LNG FOR DECISION MAKING TO EVALUATE WHICH PRODUCT TO DEVELOP FROM A DEEPWATER WEST AFRICA FIELD**

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## **1. ABSTRACT**

With the prospective development of a large number of deepwater fields in West Africa containing both economically recoverable amounts of oil and LNG, there is a requirement for a decision tool to evaluate which of these products to produce in the present and future energy markets.

This paper presents information and results that allow for a structured evaluation of a generic deepwater field in West Africa. Cost estimates and Present Value evaluation of the two systems are presented showing the breakdown of the components and comparisons of the field over the total field life from design to abandonment.

This paper provides a mechanism to help owners and operators evaluate which option is the most economical solution in the determination on the decision to produce either oil or LNG before production well drilling starts. There are many deepwater prospects with similar criteria that are presently under consideration.

## **2. INTRODUCTION**

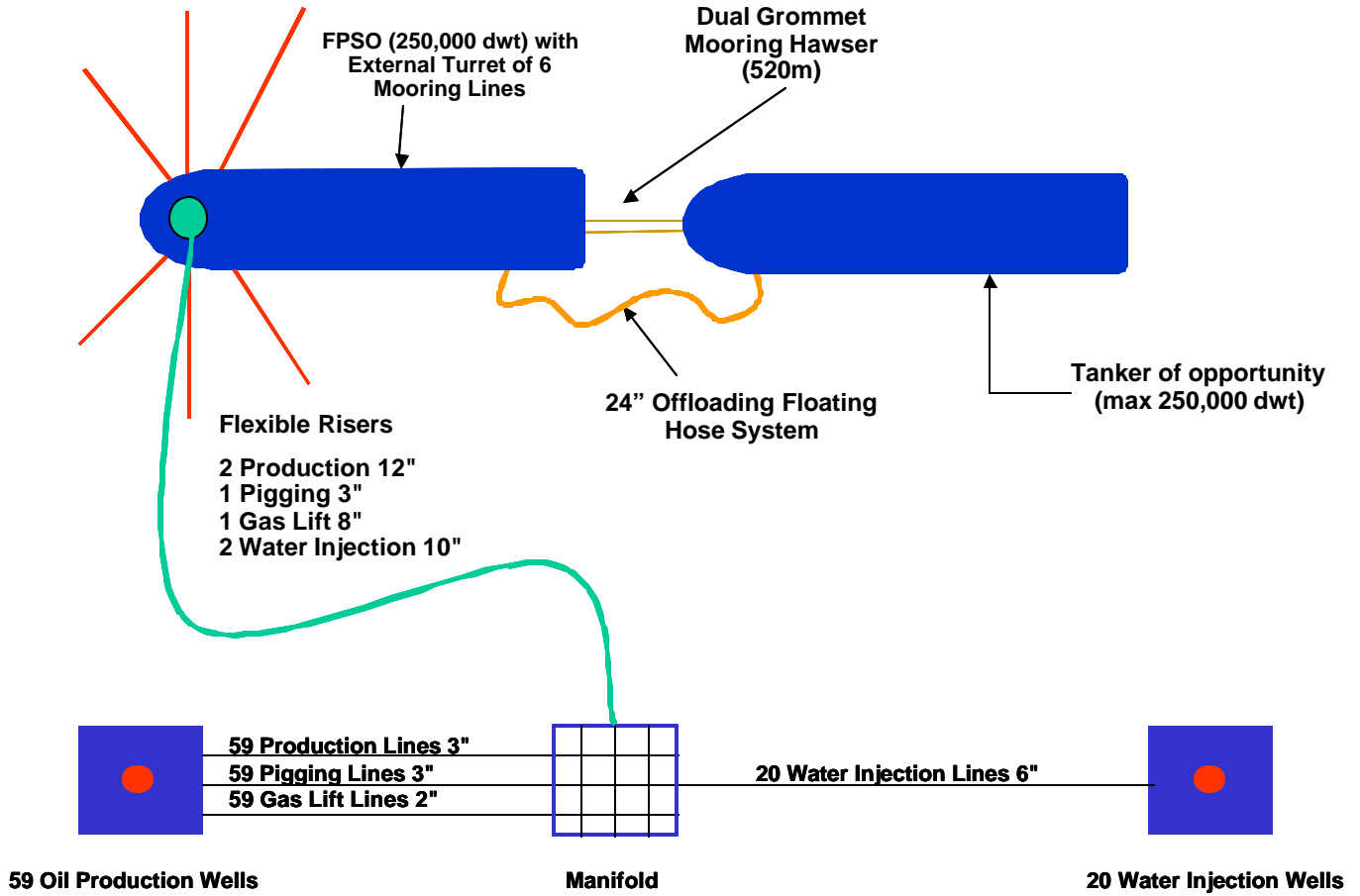
Multitudes of high yield oil and gas reservoirs have been discovered recently in relatively benign environments in deepwater offshore West Africa, which has quickly become the most active area in world market for deepwater offshore field development. This study case is based upon existing field parameters to be developed within the West African Offshore Market Area.

This paper will attempt to guide owners or operators through the process that is involved in making a decision of which production system is best suitable for his application. This is accomplished by comparing the most viable solution based on the economic results.

## **3. DESIGN BASIS**

This paper evaluates the aforementioned two cases using the following parameters for a generic West African field.

3.1 Case 1 – Oil Production



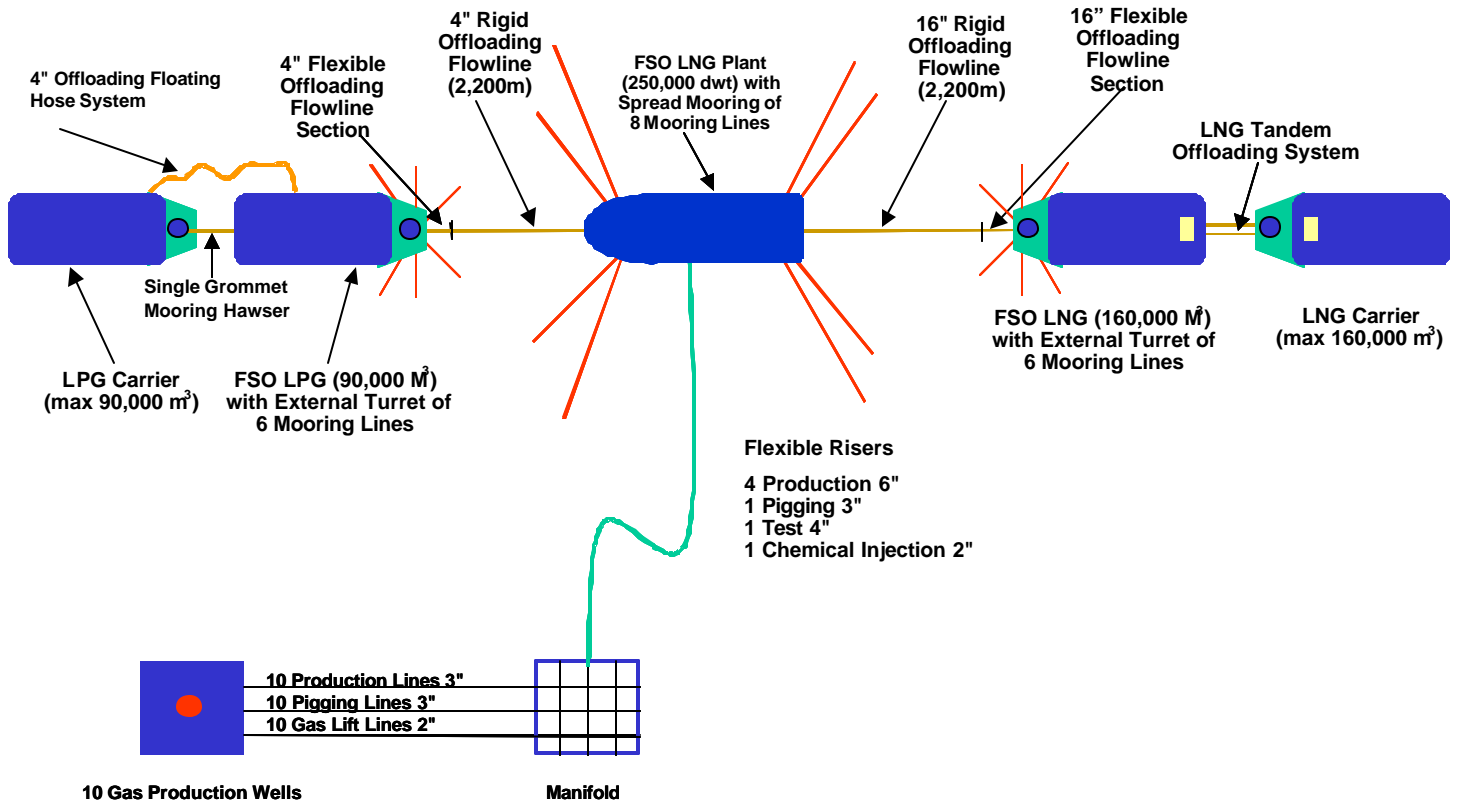
The following parameters were assumed for a generic West African field.

Water depth:	1,000 meters
Service Life:	15.3 Years
Oil Reservoir:	750 MMBBL
Vessel:	250,000 DWT Converted Tanker
Storage:	1,750,000 BBLs
Maximum Offloading Parcel:	1,250,000 BBLs
Production:	250,000 BBL/Day (Single Train)
Offloading Rate:	60,000 BBLs/Hr

Risers:

12" Oil Production	2 Lines
3" Pigging Line	1 Line
8" Gas Lift:	1 Line
10" Water Injection	2 Lines

### 3.2 Case 2 – Gas Production



Water depth:	1,000 meters
Service Life:	25 Years
Gas Reservoir:	6 Trillion Cubic Feet (TCF)
Vessel:	250,000 DWT Converted Tanker
Storage:	160,000 M <sup>3</sup> LNG & 90,000 M <sup>3</sup> LPG
Maximum Offloading Parcel:	135,000 M <sup>3</sup> LNG & 70,000 M <sup>3</sup> LPG
Gas Production to FPSO LNG/LPG Plant:	530 MMCF/Day
LNG Production:	483 MMSCF/Day
LPG/Condensate Production:	3,200 BBL/Day

Offloading Rates:

Methane	8,500 M <sup>3</sup> /Hr
LPG/Condensate:	133 M <sup>3</sup> /Hr

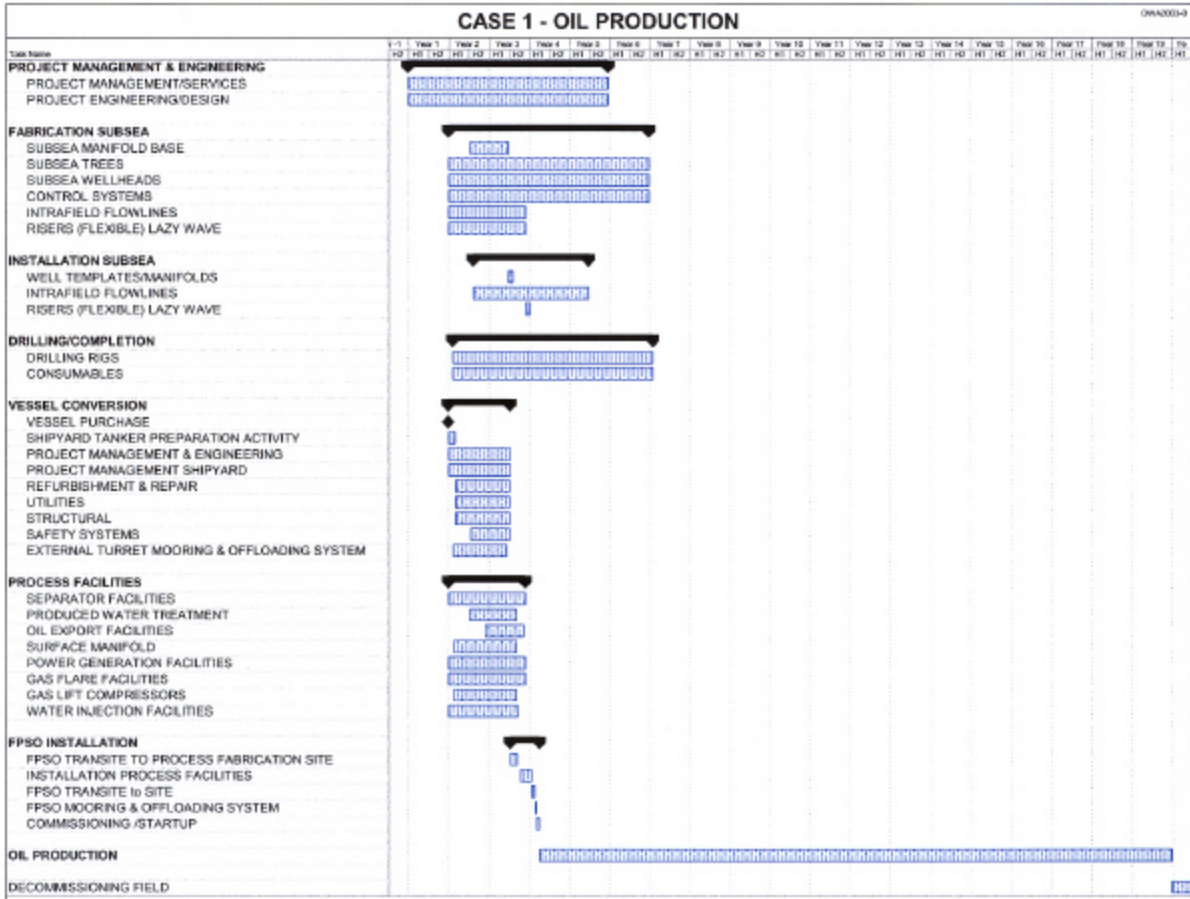
Risers:

6" Gas Production	2 Lines
3" Pigging Line	1 Line
4" Gas Lift:	1 Line
2" Chemical Injection	2 Lines

#### 4. BACKGROUND DATA

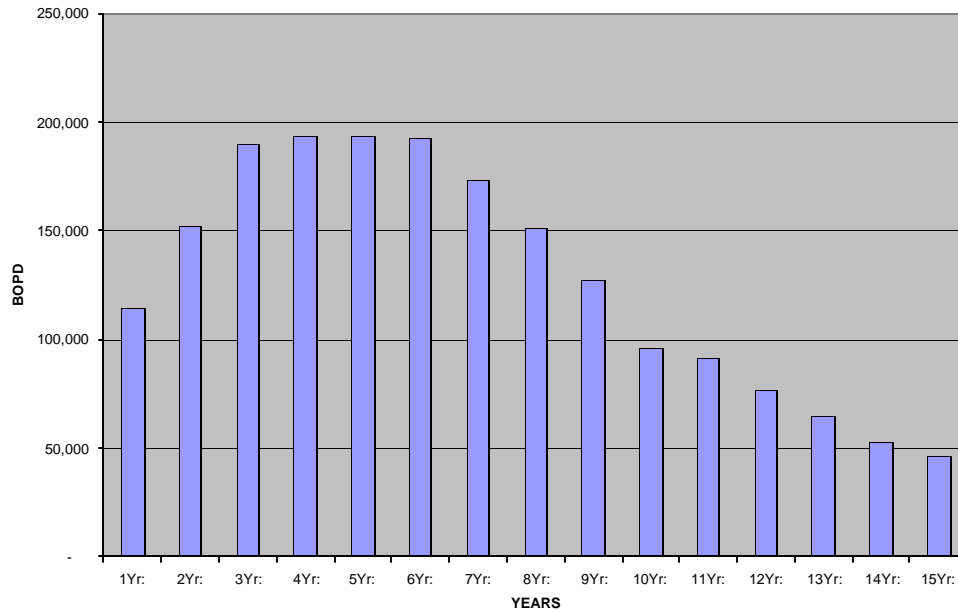
##### 4.1 Case 1 – Oil Production

The overall Oil Production field life schedule from design to abandonment is shown below.



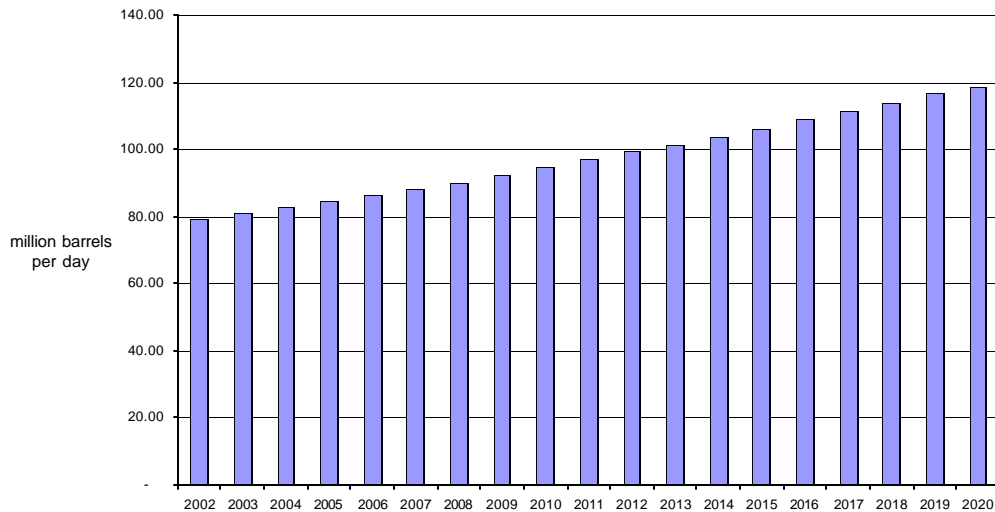
The oil production profile shown below requires a total of 59 production wells with 20 water injection wells producing for 15.3 years at 1,000 meters water depth.

**CASE 1 OIL PRODUCTION - WEST AFRICA  
250,000 BOPD OVER 15 YEARS**



It is assumed that each well takes an average of 70 days to drill and complete. The oil production is 250,000 bbl/day (Single Train) with the disposal gas flared on a converted 250,000 DWT FPSO moored by an external turret mooring system with tandem offloading to a 250,000 DWT maximum tanker of opportunity.

**Worldwide Demand for Liquid Oil Products is Expected to Increase  
2.30% Annually Until 2020**

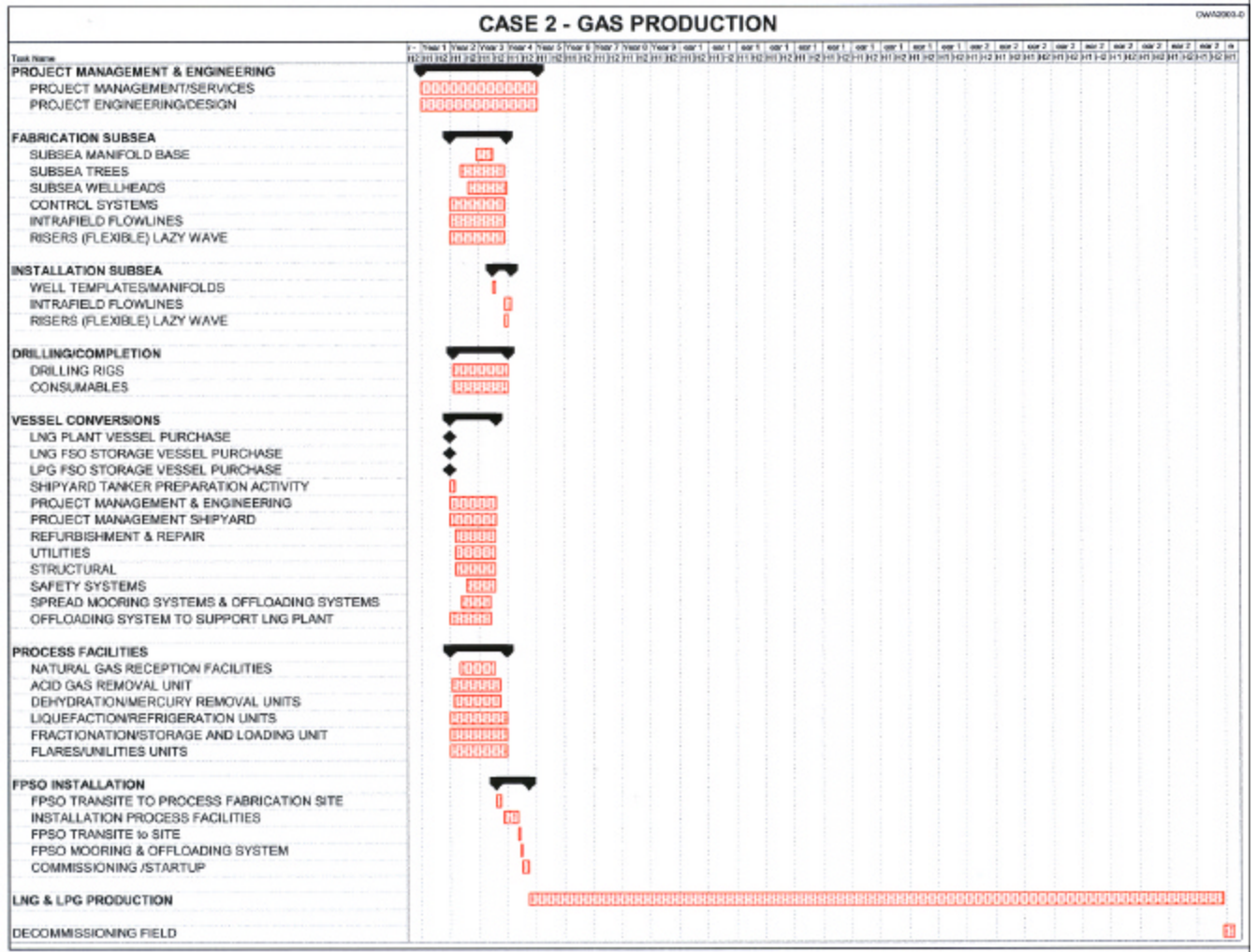


The worldwide demand for Liquid oil Products is expected to increase 2.3% annually until 2020 based on the latest report from the U.S. Department of Energy.

The industrialized nations will be the primary driver of the 2.3% annual increase in consumption with demand in OECD (Organization for Economic Cooperation and Development) countries growing 500,00 bbl/day. Asia's demand is also expected to be a major contributor to growth, with demand increasing 390,000 bbl/day.

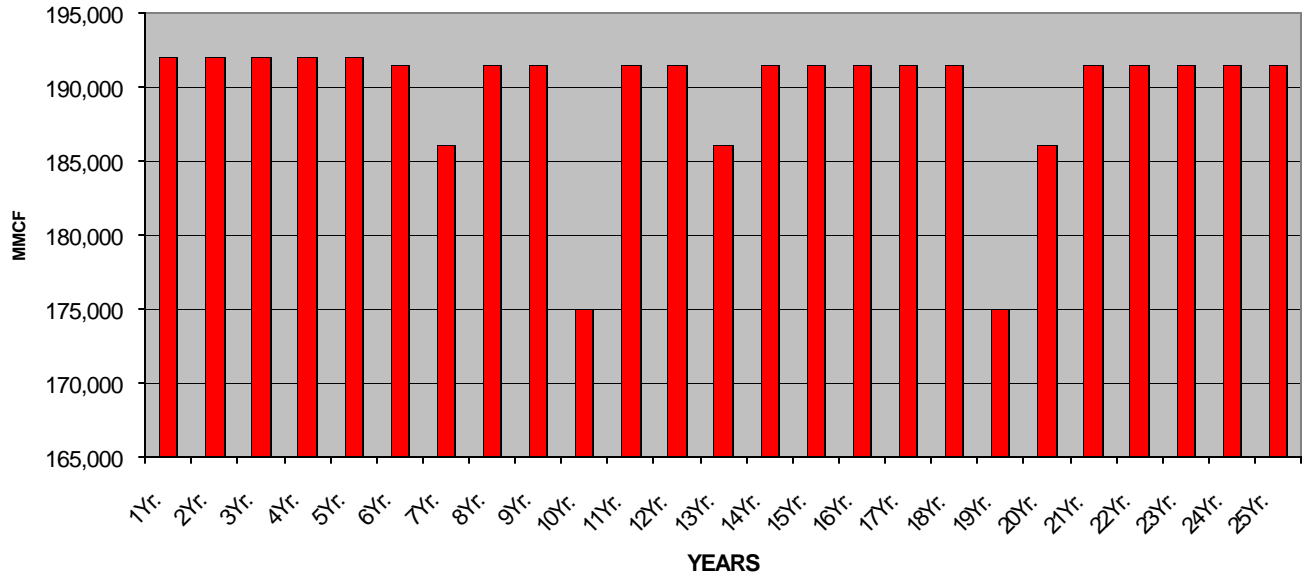
#### 4.2 Case 2 – Gas Production

The overall Gas Production field life schedule from design to abandonment is shown below.

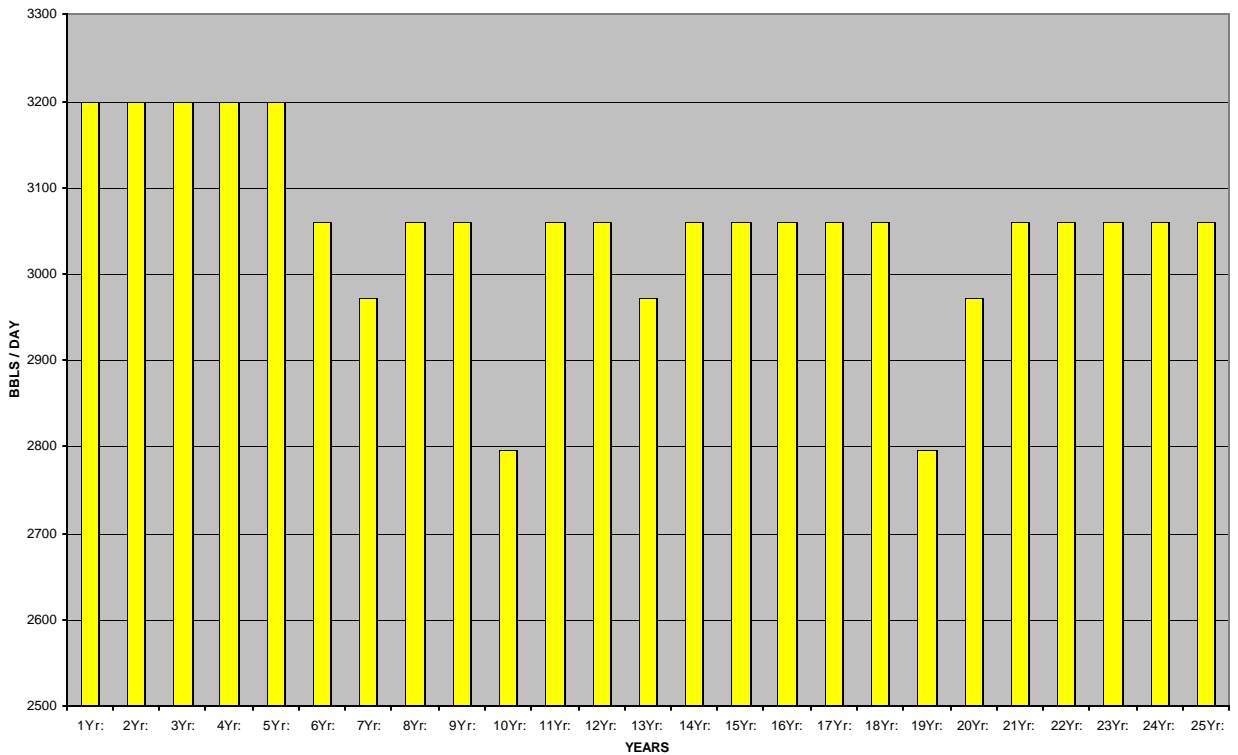


The gas production profile shown below requires a total of 10 gas wells producing for 25 years at 1,000 meters water depth.

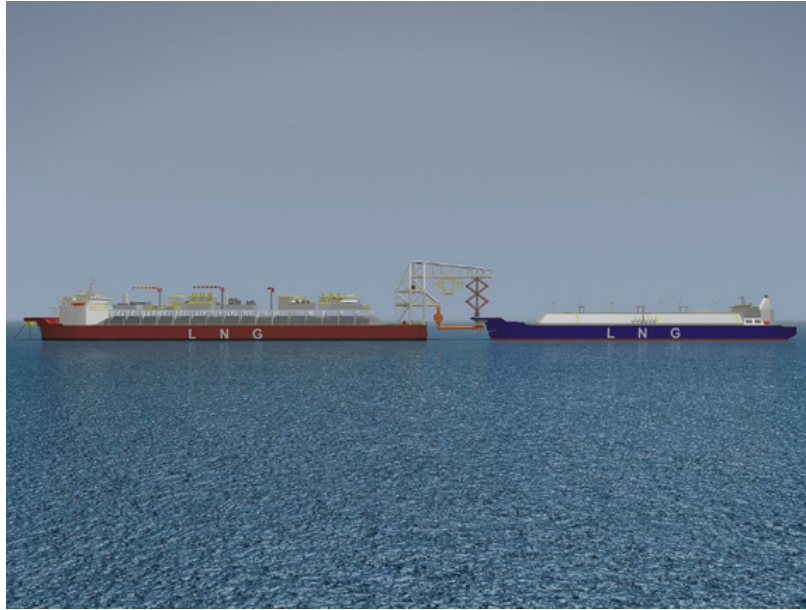
**CASE 2 LNG PRODUCTION - WEST AFRICA  
200,000 MMCF/day OVER 25 YEARS**



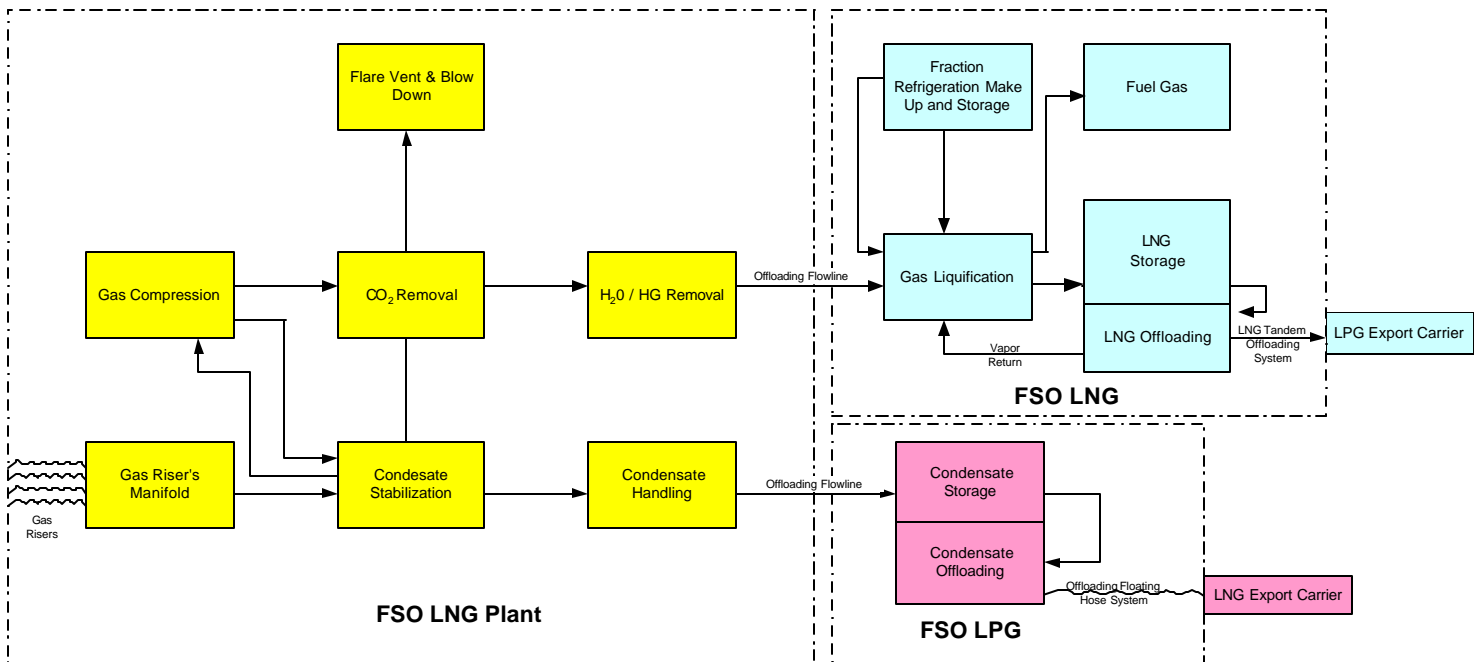
**CASE 2 -CONDENSATE PRODUCTION - WEST AFRICA  
3,200 BBLs / Day over 25 Years**



It is assumed that each well takes an average of 55 days to drill and complete. The LNG production is 483 MMSCF/day (gas equivalent) and condensate production is 3,200 bbl/day on a converted 250,000 DWT tanker with a spread mooring system. The gas is then transferred by a rigid 16' offloading flowline to a 160,000 m<sup>3</sup> LNG FSO (moored by an external turret mooring system) to be liquefied and stored, from which it is offloaded via an LNG tandem offloading system to a 160,000 m<sup>3</sup> maximum LNG carrier.



## LNG & Condensate Production





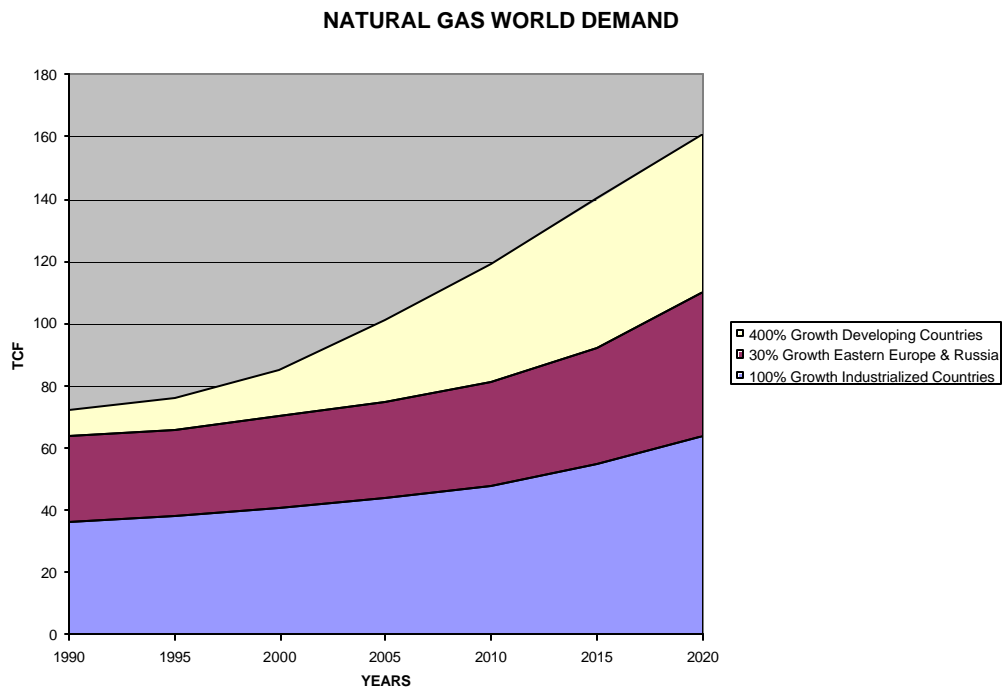
The condensate is transferred by a 4" offloading flowline to a 90,000 m<sup>3</sup> LPG FSO and by tandem offloading system to a maximum 90,000 m<sup>3</sup> LPG carrier.

Demand growth for natural gas over the past ten years has been significant and the growth is projected to continue to be robust over the next 20 years. This demand will drive the requirement for increasing levels of gas supply. The imports are projected to be in the form of LNG. LNG imports could equal two to five percent of the total annual natural gas demand over the next twenty years for North America. Imports range from 0.6 Bcf/day in 2000 to between 3.1 to 3.7 Bcf/day by the year 2020 based on the latest reports from Cambridge Energy Research.

In the year 2000, natural gas imports into Western Europe equaled 45 percent of the total natural gas consumed and these imports consisted of 85% pipeline gas and 15% supplied LNG. Western Europe also anticipates a large demand growth for natural gas over the next twenty years.

Natural gas is anticipated to be the fastest growing primary energy source in the world due to factors such as increasing gas-fired power generation requirements, environmental concerns, fuel diversity, market deregulation and general economic growth.

World consumption of natural gas is expected to increase by 40% in the next ten years from the current level and to almost double to 160 Tcf per annum at the end of twenty years. In the U.S., the 20-year growth is expected to be as follows: 30% growth in the residential sector, 30% in the commercial and industrial sector, and 200% in the power generation sector. In Western Europe, the 20-year growth is expected to be 75% in countries without a LNG terminal and 100% for countries with a LNG terminal.



## 5. FINANCIAL ANALYSIS BASIS AND METHODOLOGY

The financial analysis performed in this paper provides a means of comparing the two cases from design to decommissioning by comparing the development and operation costs and the products selling price.

The CAPEX costs include drilling, engineering, procurement, construction, installation and commissioning of the subsea system and conversion of a tanker to an FPSO. The OPEX costs include the operations and maintenance of the subsea systems, FPSO, Shore Base, helicopter and supply boat, tanker mooring tug, quarter/catering, etc.

The annual selling price of the products is based on the average annual production and present estimated future market prices.

The Net Present Value for each case is estimated using the calculated CAPEX, OPEX and products selling price based on present costs with typical profit and overhead rates to provide a “benchmark” for the relative total profit differential between the cases.

### 5.1 CAPEX Summary

The CAPEX evaluation includes the following:

- Project Engineering/Design
- Project Management/Services
- Drilling Rigs
  - Mobilization Drilling Rigs
  - Drilling Rigs
  - Fuel & Lube
  - Logging & Testing
  - Transportation
  - Diving/ROV
  - Service Personnel
  - Miscellaneous & Overhead
- Drilling Rigs Consumables
  - Mud & Cement
  - Tubulars
  - Hardware
- Subsea Manifold Base
  - Template Structure
  - Template Piles
  - Retrievable Piping Module
  - Manifolds
- Subsea Weldheads

- Subsea Trees
- Control Systems
  - Master Station
  - Software
  - Platform Cabling
  - Surface to Subsea Interface
  - E/H Umilical
  - Hydraulic Power Unit
  - Electrical Power Unit
  - Satellite E/H Umbilical
  - Control Module
  - Subsea Junction Box
  - Subsea Instrumentation
  - Hydraulic Distribution
  - Electrical Distribution
  - Hydraulic Quick Connect Plates
  - Umbilical Termination
  - Stack Testing
  - Installation
  - Commissioning
- Flowlines from Satellite/Cluster
  - Steel
  - Coating
  - Insulation
  - End Terminations
  - Termination Tool
- Risers
- Installation
  - Well Templates/Manifold
  - Flowlines
  - Risers
- Survey
  - Mobilization/Demobilization
  - Survey
- FPSO, LNG Plant Vessel and FSOs
  - Vessel Purchase
  - Mooring & Offloading System
  - Shipyard Tanker Preparation Activity
  - Project Management & Engineering
  - Project Management Shipyard
  - Shipyard Services
  - Refurbishment & Repair

- Utilities
- Structural
- Safety Systems
- Process Facilities

#### Oil

- Separator Facilities
- Produced Water Treatment
- Oil Export Facilities
- Surface Manifold
- Power Generation Facilities
- Gas Flare Facilities
- Gas Lift Compressors

#### Gas

- Natural Gas Reception Facilities
- Acid Gas Removal Unit
- Dehydration/Mercury Removal Unit
- Liquefaction/Refrigeration Units: Located on LNG FSO for this project
- Fraction/Storage and Loading Unit: Located on LNG FSO for this project
- Flares/Utilities Units
- Installation of FPSO, LNG Plant Vessel and FSOs
  - Vessel Transit to Site
  - Vessel Mooring & Offloading System
  - Commissioning/Startup

## 5.2 OPEX Summary

The OPEX evaluation is summarized below. Costs are per year unless otherwise specified.

- Vessel
  - Operating Personnel
  - Maintenance/Repair
  - Personnel Consumables
  - Annual Inspection
- Vessel 5 Year Underwater Cleaning and Inspection
- Process Facilities
  - Operating Personnel
  - Maintenance/Repair
  - Personnel Consumables
- Subsea Well Equipment Operation
  - Operating Personnel

- Maintenance/Repair
- Subsea Well Equipment Replacement Cost (Every 10 Years)
- Subsea Well Workover
  - Minor Workover
  - Workover of Remote Wells
- Template/Manifold Inspection & Maintenance
- Flowline/Pipeline Inspection & Maintenance
- Production Risers Inspection & Maintenance
- Production System Mooring Inspection & Maintenance
- Tanker Export System Inspection & Maintenance
- Shore Base
- Helicopter, Supply Boat & Mooring Tug(s)
- Quarters/Catering
- Insurance
- Field Decommissioning

## **6. CASE STUDY COST COMPARISON**

### **6.1 CAPEX**

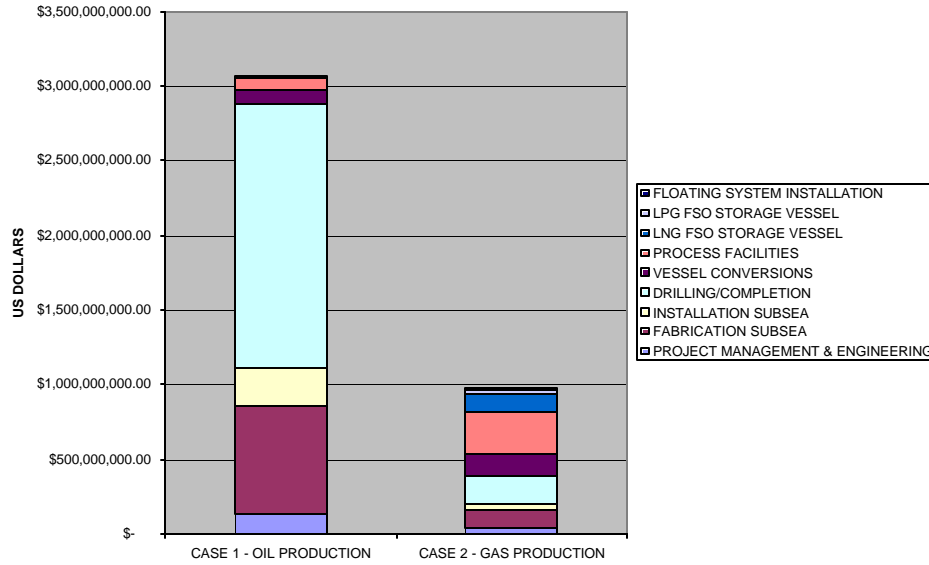
The financial analysis performed for this study provides a comparison between the two cases and is considered to be accurate within +/- 10% using today's prices.

The CAPEX summary shows that the subsea costs for Oil Production are over seven times higher than those for Gas Production due to the difference in the number of wells (79 for Oil versus 10 for Gas).

The costs for the LNG and condensate topsides / process modules are about three times more than those for the oil production.

As shown in the graph, the total CAPEX investment for Case 1 – Oil Production at US\$3 billion is approximately three times higher than that for Case 2 – LNG and Condensate Production.

## OIL & GAS PRODUCTION WEST AFRICA CAPEX



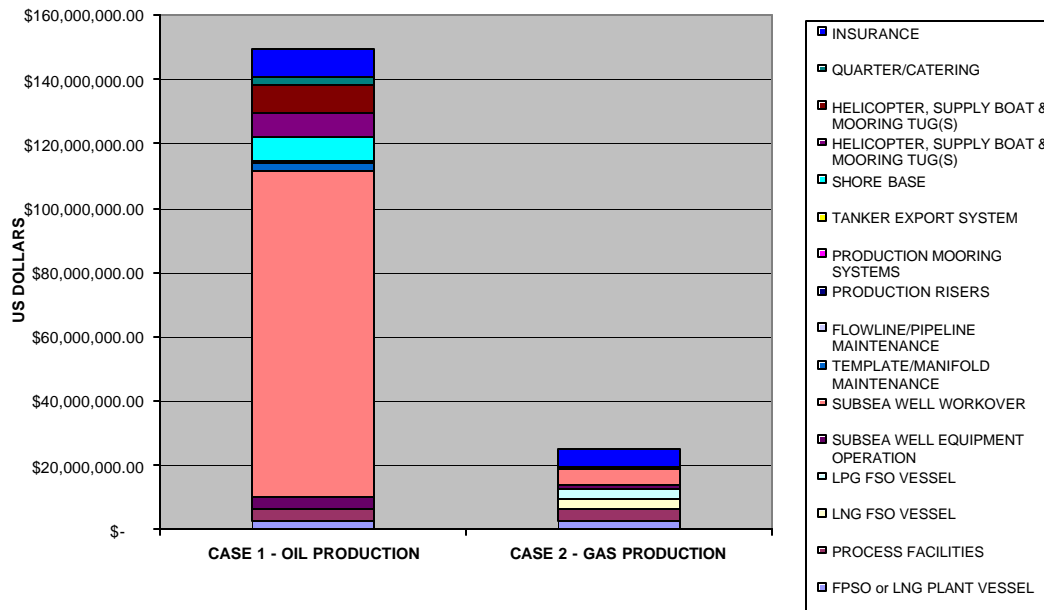
### 6.2 OPEX

The operational costs of the two cases are also estimated within +/- 10% accuracy using today's prices.

The OPEX graph shows the costs for the first year of operations. The OPEX costs were increased by 2% a year for inflation and are estimated over the course of 15.3 years for Oil Production and 25 years for the LNG and Condensate Production. Field decommissioning costs are included at the end of production for both cases.

The annual OPEX cost is higher for the Oil Production mainly due to the difference in the number of wells (79 for Oil versus 10 for Gas).

## OIL & GAS PRODUCTION WEST AFRICA OPEX FIRST YEAR



### 6.3 Production Price

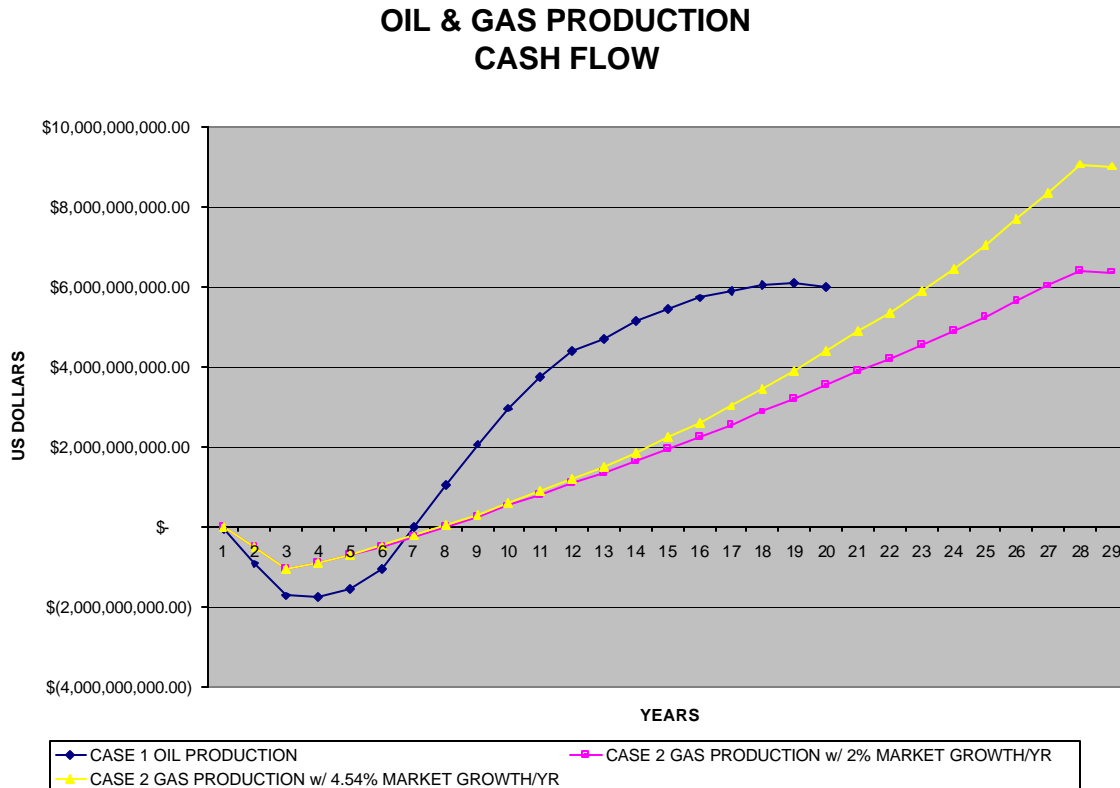
The price per barrel for oil (Case 1) was between \$22.50 to \$28.50 based on an assumption of 2% inflation over the 15.3-year production life.

The price per MMBTU for natural gas (Case 2) was between \$3.50 to \$6.50 based on an assumption of 2% inflation over the 25 year production life and between \$3.50 to \$6.75 based on an assumption of 4.54% inflation.

The price per barrel for condensate (Case2) was between \$20.00 to \$28.00 based on an assumption of 2% inflation over the 25 year production life.

## 6.4 Cash Flow Analysis

The following graph shows the comparison of the field life cash flow between the two cases with the LNG options of 2% to 4.54% inflation in price annually.

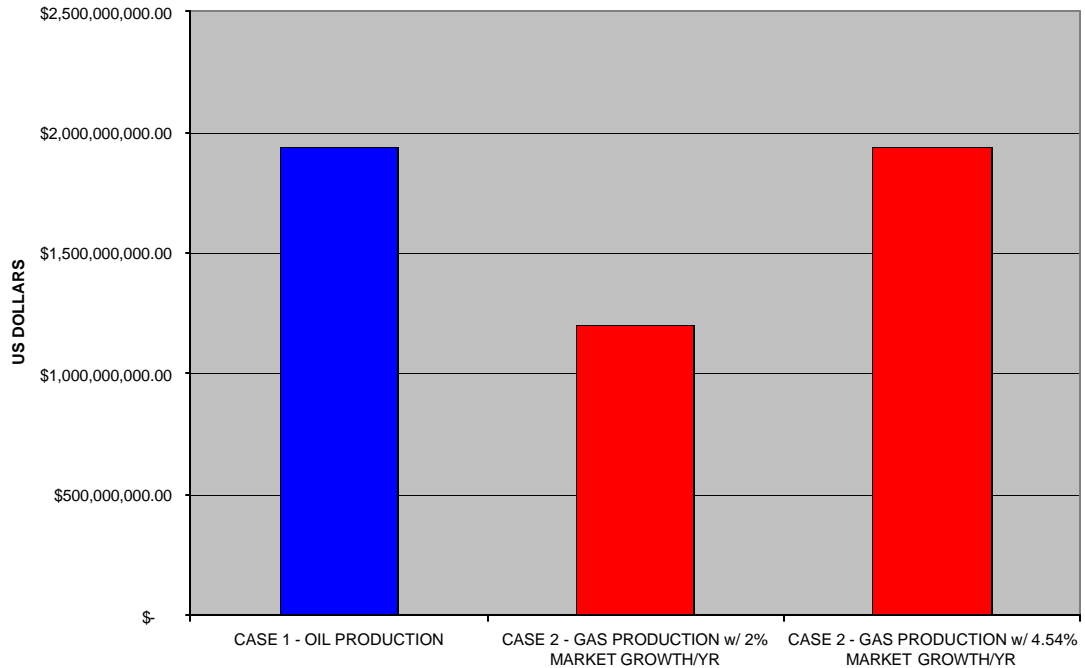


## 6.5 Net Present Value (NPV)

As mentioned previously, the Net Present Value (NPV) for each case is estimated using the calculated CAPEX, OPEX and products selling price based on present costs with typical profit and overhead rates to provide a “benchmark” for the relative total profit differential between the cases. The NPV serves as a tool for comparing the total economic performance based on the same time reference, accounting for inflation and the present value of future expenses. The NPV for each case study is based on a 10.5% discount rate computed from the first field production milestone.



## NET PRESENT VALUE AT FIRST PRODUCT



The results show that oil production presents the best economic choice with low risk if LNG price increase is only about 2% to 4.54% annually over 25 years. If LNG price increase is about 4.54% annually, the economic choice is equal. If LNG price inflation is above this figure, LNG production is preferred.

It is worth noting that the likelihood of significant annual increase in LNG price is quite strong based on present conditions. While oil is an industry that presently has over-production capacity that will probably not change in the future, natural gas is expected to have a large demand growth, particularly for power generation. However, current LNG shipping capacity, as well as terminal capacity in North America and Western Europe, is very limited. Until the existing infrastructure for LNG delivery is fully upgraded to keep up with the growth in demand, LNG price will keep on increasing for a while.

## 7. CONCLUSIONS

The results of the two cases demonstrate that when making an economic evaluation comparison, one must exhaustively account for CAPEX, OPEX, and production future market selling price over the life of the field.

The results of this case study indicate that, for a deepwater field with economic potential for either oil or gas, the decision would favor Case 1 – Oil Production based on low risk and quick return criteria. But if potentially higher profits with lower capital investment are desired and the

anticipated gas market price forecasts are favorable, Case 2 – Gas Production would be the preferred choice.

The United States and Western Europe are projected to continue to utilize over eighty percent of gas consumed in the industrialized regions. Imported LNG is viewed primarily as an alternate supply source to meet the forecast demand for natural gas in the U.S. Should domestic production levels be lower than forecasted for technical, commercial or economic reasons, the level of natural gas imports would be expected to increase to meet the U.S. market demand requirements.

With LNG as an alternate source of gas supply, pipeline gas will establish for LNG the pricing, delivery and quality criteria that would be associated with its use as a supply source to meet the forecasted U.S. gas demand.

In the future, LNG imports are anticipated to become an increasingly important potential source of supply to the U.S., and many large energy companies have announced initiatives in the LNG area that would require substantial capital investments.