Palacký University Olomouc

Faculty of Science

Department of Geology

Cash Flow and Economic evaluation of oil and gas projects in the Kurdistan Region of Iraq

Bachelor thesis

Aihan Ghairi Mohammed

Petroleum Engineering (B0724A330002)

Fulltime study

Supervisor: Prof. Howri Mansurbe, Ph.D.

Advisor: Ing. Pavel Spirov, Ph.D.

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Anotace:

Tato práce se zabývá ekonomikou ropného průmyslu v kurdském regionu s důrazem na použití analýzy cash flow při hodnocení ziskovosti projektů v oblasti těžby ropy a plynu. Výzkum zkoumá dopad inflace, nákladů a příjmů na ekonomiku projektu a vychází z dat z různých zdrojů, včetně průmyslových zpráv, finančních výkazů a ekonomických ukazatelů.

Výzkum ukazuje, že ropný průmysl v Kurdistanu se potýká s řadou výzev, včetně politické nestability, regulatorní nejistoty a volatility trhu. Nicméně analýza cash flow může poskytnout cenné informace o ekonomice projektu, umožňující společnostem posoudit životaschopnost investic a učinit informovaná rozhodnutí o alokaci zdrojů.

Studie dospívá k závěru, že pro společnosti působící v Kurdistanu je zásadní mít komplexní porozumění ekonomickým faktorům ropného průmyslu. Použitím analýzy cash flow pro hodnocení ekonomiky projektů mohou společnosti snížit riziko, optimalizovat alokaci zdrojů a maximalizovat výnosy z investic. Tato práce poskytuje cenné poznatky pro praxi v průmyslu, politické rozhodování a výzkumníky zajímající se o ekonomiku ropného sektoru.

Annotation:

This thesis examines the economics of the petroleum industry in the Kurdistan region, with a focus on the use of cash flow analysis in evaluating the profitability of oil and gas projects. The study considers the impact of inflation, costs, and revenues on project economics, drawing on data from a range of sources including industry reports, financial statements, and economic indicators.

The research finds that the petroleum industry in Kurdistan is subject to several challenges, including political instability, regulatory uncertainty, and market volatility. However, cash flow analysis can provide valuable insights into project economics, allowing companies to assess the viability of investments and make informed decisions about resource allocation.

The study concludes that a comprehensive understanding of the economic drivers of the petroleum industry is essential for companies operating in Kurdistan. By using cash flow analysis to evaluate project economics, companies can mitigate risk, optimize resource allocation, and maximize returns on investment. This thesis provides valuable insights for industry practitioners, policymakers, and researchers interested in the economics of the petroleum sector.

Keywords: Cashflow, Revenue, Contract, cost, Production, Oil, Gas, Inflation, Tax

Klíčová slova: 9500

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In Olomouc, May 06, 2023 …………………………………………

Aihan Ghairi Mohammed

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Abbreviations	Definitions
IOC	International Oil Company
PSA	Production-Sharing Arrangement
FOC	foreign oil corporation
NOC	national oil corporation
NCF	Net cash flow
OPEX	Operating expense
CAPEX	Capital Expenditures
DCF	Discounted Cash Flow
NPV	Net present value
IRR	Internal Rate of Return
STOIIP	Stock Tank Oil Initially in Place
MMSTB	Million Stock Tank Barrels
API	American Petroleum Institute
OWC	Oil Water Contact
TVD	True Vertical Depth
MCO	Maximum Capital Outlay
GRV	Gross Rock Volume
bbl/d	Barrel per day
TCS	Terminal cash surplus
P10	Possible or Optimistic
P50	Probable or Most Likely
P90	Proven or Pessimistic

1 Introduction

Petroleum economics offers the instruments for quantifying and assessing the financial risks associated with field exploration, appraisal, and development, and it serves as a consistent foundation for evaluating various investments.

A petroleum economist's job is to assess choices among investment opportunities using economic criteria. To evaluate the economics of a particular petroleum project, oil companies assess its associated engineering and geological risks. Oil and gas companies must consider payout time and rate of cash flow, which are crucial factors and are frequently decisive in evaluating the viability of energy projects. Cash flow can be defined as the net amount of cash and cash equivalents transacted into and out of a corporation. Inflows are represented by cash received, whereas outflows are represented by money spent. Underestimating cash flow may cause a shortfall of cash for other planned activities.

Petroleum Fiscal Regimes in The Kurdistan region and the deals with International Oil Companies (IOCs) are the focus of this study. Efforts will be made to construct a cash flow for an ideal IOC operated in the Kurdistan Region of Iraq and establish a methodological approach for the economic evaluation of oil and gas projects in the region. Apart from the cash flow chart, parameters such as (Net cash flow, inflation, Discounted rate, Net present value, Internal rate of return, and payback time) will be utilized to assess the profitability of the oil and gas projects for all the stakeholders in the Kurdistan Region of Iraq.

1.1Reasearch objective

This undergraduate thesis aims to investigate the financial situation of a specific petroleum project in the Kurdistan Region, analyze its risks, economics, and profits, and evaluate the regulations and rules governing the oil and gas industry in the region. The findings of this thesis will serve as an analog for other petroleum projects in the region and shed light on the financial aspects of the oil industry, contributing to a better understanding of the factors affecting profit distribution between oil companies and the Kurdistan Regional Government (KRG). The thesis will mainly construct a cash flow to understand the healthiness of the project, in addition to developing a petroleum economics project outlining the prerequisites for petroleum projects in the region. By achieving these objectives, this thesis aims to provide valuable insights into the financial aspects of the oil industry in the Kurdistan Region and contribute to the development of more effective regulations and policies in the industry.

Chapter 2 Background

The Kurdistan Region of Iraq is known for its vast oil reserves, which have the potential to contribute significantly to the region's economy. The region produces both crude oil and natural gas, which are exported through a pipeline to Turkey and from there to various markets. The Kurdistan Regional Government (KRG) is responsible for managing the oil and gas sector in the region, including exploration, production, and distribution.

Cash flow is an essential aspect of petroleum economics as it represents the inflow and outflow of funds associated with the production and sale of oil and gas. The cash flow generated by the petroleum industry in the Kurdistan Region of Iraq is significant and has a direct impact on the region's economic development. The KRG receives revenue from the sale of oil and gas, which is used to fund various development projects and social programs (Qadir, Mohammed, and Majeed, 2021).

However, cash flow in the petroleum industry is also affected by various factors, including fluctuations in oil prices, production levels, and transportation costs. For example, a decrease in oil prices can significantly reduce the revenue generated by the sale of oil, leading to a decrease in cash flow. Similarly, disruptions in production or transportation can also impact cash flow by reducing the amount of oil and gas available for sale.

To manage cash flow effectively, the KRG has implemented various measures, including the establishment of the Kurdistan Oil and Gas Revenue Management Law, which outlines the procedures for managing and distributing revenue generated from the sale of oil and gas. The law aims to ensure that revenue is used effectively for the benefit of the region's citizens while also maintaining financial stability.

In summary, cash flow is a critical aspect of petroleum economics in the Kurdistan Region of Iraq, and its management plays a crucial role in the region's economic development. By effectively managing cash flow, the KRG can ensure that revenue generated by the petroleum industry is used to support the region's growth and development (Mills, 2016).

2.1 previous studies

Studies on the monetary restrictions imposed on oil production and exploration endeavors, such as the one presented by Al-Attar & Alomair (2005) have concluded that when it comes to examining the fiscal regime, the structure of the fiscal regime of the contract is significantly more important than the type of contract that exists between the host government and the contractor. Take into consideration the structure of the royalty rate, which can either be fixed or variable.

Tordo (2007) employed a descriptive method to examine the influence that numerous fiscal regimes had on the profitability of petroleum projects and presented a blueprint for constructing a more successful fiscal regime.

Kaiser & Pulsipher (2004) used a meta-modeling approach to investigate different fiscal regimes, in which simulations were carried out to demonstrate how statistical indicators (government takes and contractor takes) fluctuate based on system characteristics. The construction of a model of the system is the initial stage of meta-modeling. Following this step, meta-data is generated for the simulated variables that are included within a certain design space. After that, the meta-data is used in the construction of linear models Iledare & Kaiser (2006).

2.2 Petroleum economic projects

When planning to build any petroleum project it must go through some phases. And those are.

1. Licensing.
2. Exploration.
3. Appraisal.
4. Development.
5. Production.
6. Abandonment.

The first phase is the host country's government grants the oil firm the authority to conduct petroleum exploration within its territory (Tordo, 2007).

The second phase is major goal of the exploration phase is to gather evidence that there is petroleum within the borders of the given exploration license. There are a variety of geological and geophysical studies that must be conducted, and their results analyzed and evaluated to reach this objective. A decision on how many exploration wells to drill will be made based on how likely it is that a commercially viable amount of oil can be found. If the wells don't work out, the whole project is going to be canceled. Exploratory wells are drilled to acquire more particular geological information, such as rock and fluid properties, initial reservoir pressure, and productivity. Seismic data is used to discover locations that may hold oil or gas resources (Kenton, 2022).

After the discovery of a hydrocarbon deposit, more wells are drilled to determine the scope of the find. The collection of core or fluid samples, the performance of various types of analysis, the execution of buildup tests, drill stem tests, top and bottom of formation evaluations, and other activities are typical uses. More drilling needs to be done if there is any hope of improving the accuracy of projections regarding the amount of oil that can be found and the potential profit that can be made from the project (*Glossary: appraisal well* 2013). Whether or not the amount of petroleum found has the potential to be profitable on a commercial scale will determine whether more exploration is carried out

The four-phase is development which is high levels of production well an oil or gas that is drilled after an appraisal well has established that extracting the resource from the field would be profitable. Exploration like this is being conducted so that the field can reach its full potential in terms of the number of hydrocarbons it can produce. After receiving a request from the petroleum industry to do so, the government will change the exploration license into a production license. It is planned that the development plan will be carried out and that producing wells and infrastructure will be built and brought online. Throughout the entirety of a project's lifecycle, the costs associated with the project's development stage will constitute the bulk of those expenses (Rezk, 2006).

A "production well" is the type of well that is used to produce oil or gas from deposits deep within the ground. When extracting oil or gas from the ground, production wells are drilled to depths of thousands of feet to reach the underlying rock formations rich in these commodities. In the past, oil and gas were extracted using vertical wells, which penetrated deep into the ground to reach a single reservoir. Later, horizontal drilling was developed to allow for the extraction of oil and gas from many reservoirs using a single well that is inclined horizontally into the deposit. Because of this, horizontal drilling became an option. An appraisal well is first drilled to determine whether the reservoir can be developed further. More construction follows, and the start of the buildup period is marked by the first oil production. Eventually, the field will enter a plateau when all the available extraction capacity is used. Once this point is achieved, the field will enter a period of "decline," and eventually be abandoned because of economic reasons. Even though the plateau phase may be brief and resemble a stunning peak for many fields, it may remain for decades at the plateau output level for large fields. this is true for more compact playing areas. Both the productive life of a field and the shape of its production curve are known to be influenced by the specific hydrocarbons extracted from it (Islam, 2022).

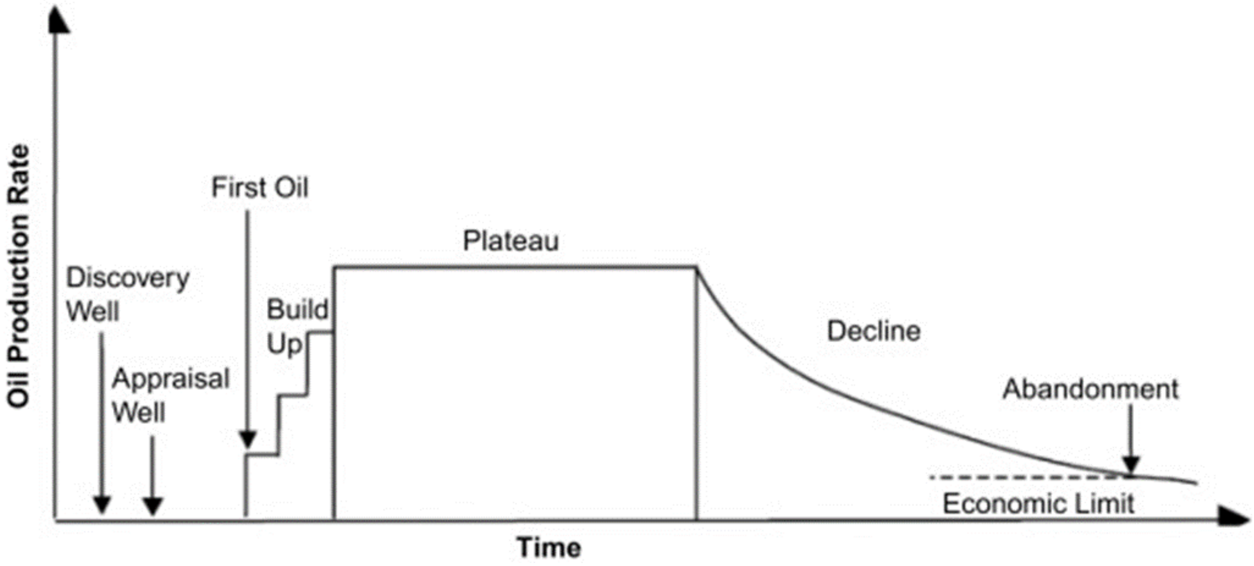

Figure 1 Theoretical production profile of an oilfield Robelius (2007).

- Build up: Production increases at a constant rate during the buildup phase because wells are brought online one by one until they reach the total number expected to be online at the end of the phase.
- Plateau: When the process reaches its plateau, there is little to no variation in the rate of production. For large fields with longer production periods, it may be challenging to calculate the length of the plateau phase.
- Decline: There is a slowdown in output at this phase of the cycle. A lengthier time is spent here than at any other point in the manufacturing process.

The sixth Phase, the final stage of a petroleum project's life cycle is known as "abandonment." To be certain that a project has entered this stage, it must first have reached a point when its operating costs are more than the income it is bringing in. The preparations for the abandonment phase, on the other hand, often start far before the year in which the phase is abandoned (Jahn, Cook, and Graham, 2009).

2.3 Petroleum exploration rights

Rarely do private individuals own petroleum resources, such as in the case of private ownership of petroleum, for example by farmers and landowners in the United States of America. Instead, petroleum resources are typically owned by governments. Private ownership of petroleum resources is more common in developing countries. In most countries, the government will create a national petroleum firm that will be responsible for exploring oil and developing the resource. However, because of the significant risks involved and the high costs associated with investments in petroleum exploration and production, the national oil firm frequently requires assistance from other international oil businesses, which are referred to as contractors. The contractors have the necessary resources and personnel to search for petroleum and to remove it from the ground Tordo (2010).

Two categories can be used to categorize the licensing systems: open-door systems, in which interested contractors are permitted to submit a proposal concerning specific areas at any time (mostly on an annual or bi-annual basis), and licensing rounds, which are held as either an auction or an administrative process and are based on a set of criteria that is provided by the host governments. In every system, the procedure of beginning negotiations between the contractor and the national petroleum corporation is determined by the petroleum law of the country in which the project will be carried out. Petroleum law usually defines the petroleum policy of the host government, the terms of petroleum contracts, and the fiscal tools that the government uses to capture an appropriate reward from the country's petroleum resources. In addition, the petroleum law may also set minimum prices for petroleum products (Babusiaux et al., 2004).

Chapter 3 Fiscal System Classification

3.1 Concessionary Systems

The concessionary system, which is also referred to as the "royalty/tax system," was the first one used in international petroleum contracts. It is still in use by almost half of the world's oil-producing nations, including the United States of America, the United Kingdom of Great Britain and Northern Ireland, France, Norway, and Canada.

According to the terms of the concessionary contract, the government of the host country is required to transfer all its rights to the petroleum resource to the concessionaire. The contractor is responsible for paying all costs involved with exploration, development, and operation. This releases the government from any obligation or liability related to the project. Because of this, a contractor is entitled to collect all of the petroleum output but is required to pay different fees by the laws and regulations imposed by the host government (Barrows, 1994).

In the conventional concessionary system, the company is responsible for paying a royalty that is calculated according to the value of the recoverable mineral resources, in addition to one or more taxes that are calculated according to the company's taxable revenue. In its most fundamental form, a concessionary system is composed of the following three components:

- Royalty
- Tax
- Deduction

Royalty: One of the fiscal tools that is employed all over the world the most frequently is royalties. It denotes a monetary or in-kind payment paid by the contractor to the government that is hosting the contractor. Royalties that are paid to a private entity rather than a host government are referred to as overriding royalties. The only thing that changes is who gets the money, but the principles of calculating remain the same. Royalty fees are determined by the respective host governments and might vary (Johnston, 1997). While some utilize variable rates, others who use a fixed royalty rate are self-explanatory. These variable rates may be established according to annual production, cumulative production, the price of petroleum, or both production and price taken together. Another basis for these rates may be the cumulative production throughout time.

Tax: Taxes are mandatory contributions levied on individuals or corporations by a local, regional, or national government entity. Tax revenues finance government activities,

Deduction: A deduction is an expense that can be subtracted from a taxpayer's gross income to reduce the income subject to taxation.

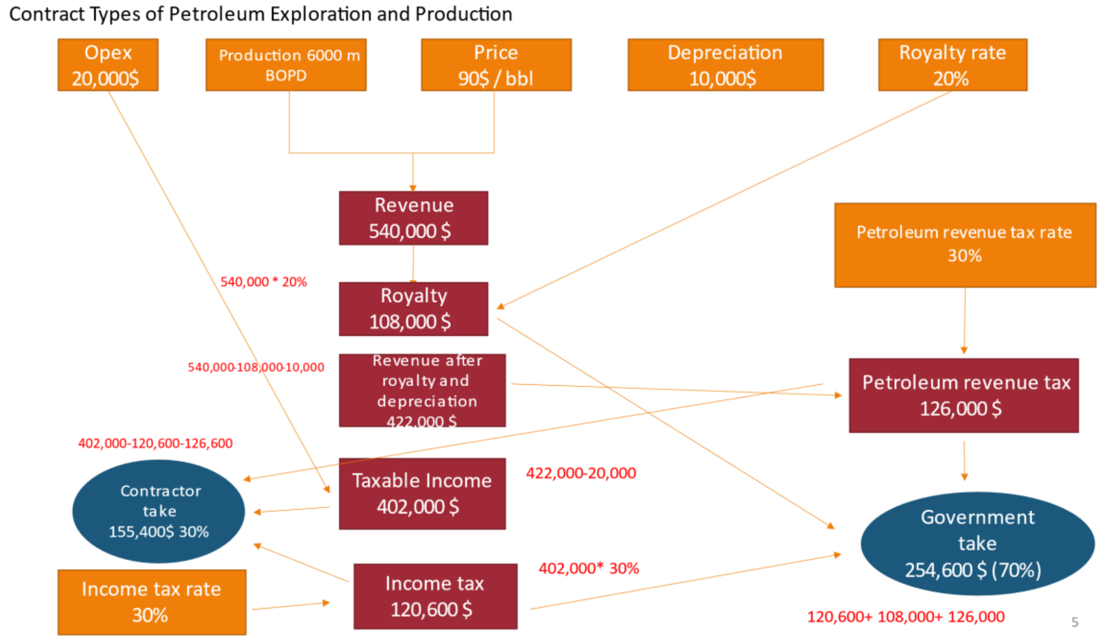

Figure 2 Concessionary Systems based on day production (modified after Agalliu, 2011).

3.2 Contractual system

The host nation's government will continue to have the legal title to the petroleum, but they will share the profits with the contractor either in kind or monetarily, depending on the provisions of the contract. It is possible to separate the production-sharing contracts from the service contracts that make up the contractual framework. The host government retains the ownership. The contractual system itself could be classified into production-sharing contracts and service contracts. The host government is responsible for the abandonment (Muhammed Abed Mazeel, 2010).

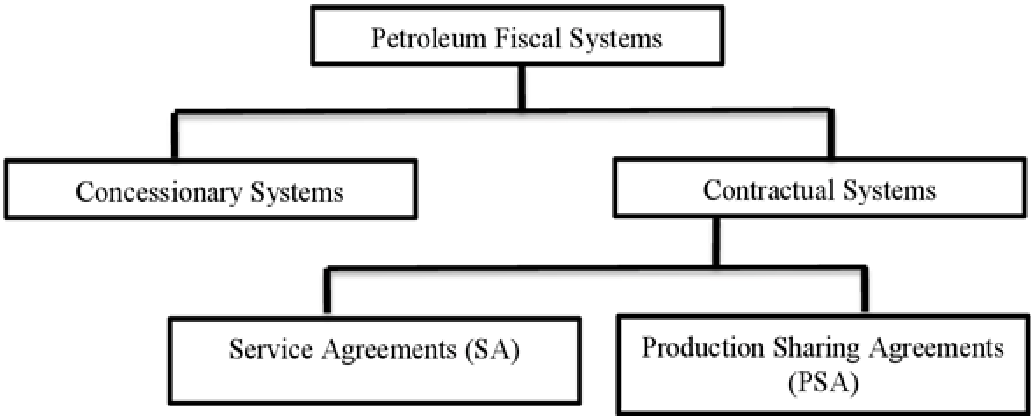

Figure 3 Classification of petroleum fiscal systems (Mazeel, 2010).

3.3 Production sharing contract

In the petroleum sector, including a Production-Sharing Arrangement (PSA) as part of a contractual agreement is common practice. This is the case in almost all cases. In the context of a PSA, a foreign oil corporation (FOC) plays the role of a contractor for the state, which plays the role of the owner of natural resources and provides the state with technical and financial services for exploration and development. Traditionally, the role of the state has been played either by the central government or by an agency such as the national oil corporation (NOC). As recompense for the effort put in and the risks taken, the FOC is entitled to a predetermined share of the oil that is extracted (Duval et al., 2009). The contractor's share is the only thing that is keeping the state from fully owning the petroleum; otherwise, it would be considered state property. There are many stages of oil exploration and development, some of which may include participation from a nation's government or its national oil company (NOC). It is typical for PSAs to include a provision that calls for the formation of a joint committee to oversee the agreement's execution. This committee would be made up of members from both parties (Oxford Institute for Energy Studies, n.d.).

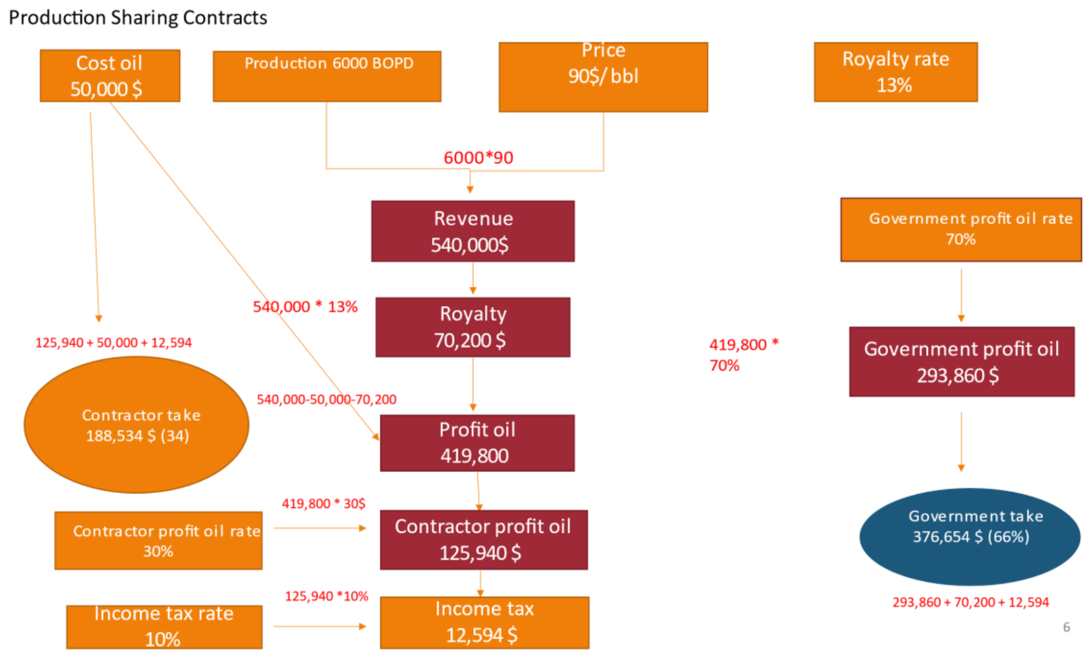

Figure 4 Production sharing on day production (Johnston, 2003).

3.4 service contract

Under the terms of most service contracts, the contractor is responsible for funding and administering various petroleum-related activities in exchange for either a set charge or a portion of the total revenue. This fee is often paid in cash. Cash is the preferred method of payment. Additionally, the contractor deducts his costs from the total money, and in compliance with the tax regulations of the host country, he sends taxes to that country.

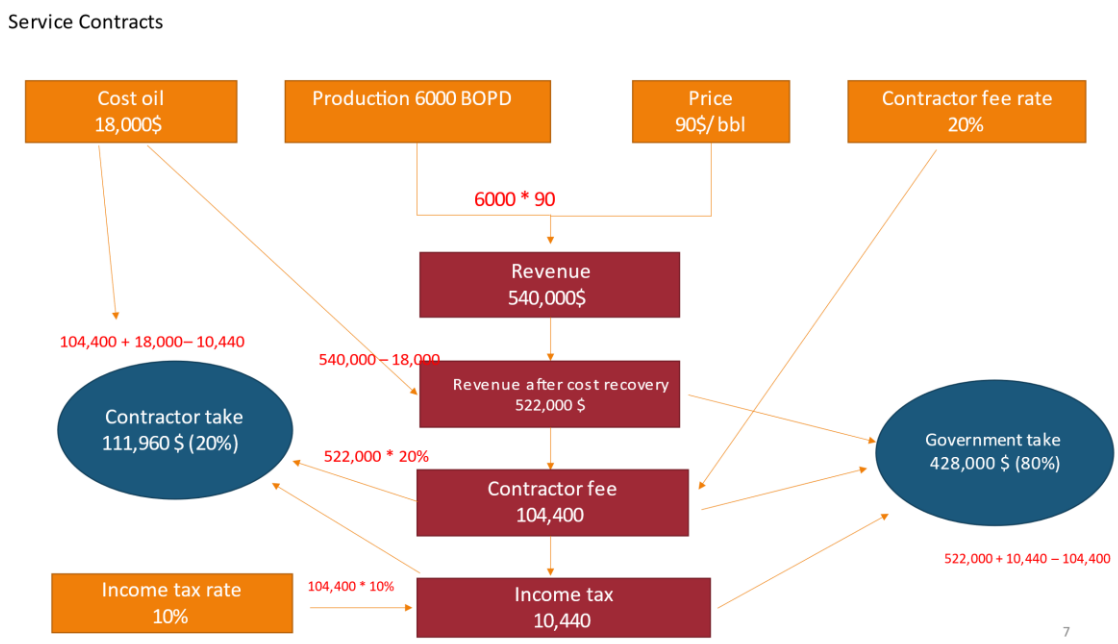

Figure 5 Service contract on day production (Bindemann, 1999).

3.5 Contract System in the Kurdistan Region of Iraq

KRG has production-sharing contracts with companies that work in KRG. Also, there are a lot of steps that will be defined in this article on how the process works in KRG.

Production sharing Contract between KRG and Contractors.

A. The government wants to develop the oil wealth of the Kurdistan Region in a way that helps the people of the Kurdistan Region and all of Iraq the most. It wants to do this by using the most advanced techniques of market principles and encouraging investment, which is all in line with the Constitution of Iraq.

B. The Constitution of Iraq says that the Kurdistan Region Law is the law that applies in the Kurdistan Region, except for things that are the sole responsibility of the Government of Iraq.

C. The KRG government has proposed creating a Ministry of Natural Resources in the Kurdistan Region, which would be responsible for managing the region's natural resources except for water and forests, per an Act of the Parliament of the Kurdistan Region.

D. The government plans to give the Kurdistan Region Parliament the Kurdistan Region Petroleum Act to regulate petroleum operations, including production-sharing contracts.

3.6 Discovery and development

If drilling an Exploration Well leads to a Discovery, the contractor must tell the government within forty-eight (48) hours of tests confirming the presumed existence of such Discovery or within such a long period as the contractor reasonably needs to figure out if there is a Discovery or not. Within thirty (30) days of being told about the Discovery, the contractor must give the Management Committee all available technical data and its opinion on the commercial potential of the Discovery (called the "Discovery Report"). The contractor must give the government any other information about Discovery that it may reasonably ask for promptly.

A. Appraisal program

If the contractor believes that the Discovery has commercial potential, it shall submit to the Management Committee an assessment program in respect of the Discovery (the "Appraisal Program") within ninety (90) days of notification to the government of the Discovery. The Management Committee must review the Appraisal Program within thirty (30) days of receiving it. If the government requests any changes to the Appraisal Program, the Management Committee shall convene within sixty (60) days of receiving the proposed Appraisal Program to consider the Appraisal Program and any objections thereto. The contractor shall provide the government with comments on any such objections during the Management Committee meeting or in writing before such meeting.

The contractor shall submit a detailed report relating to Discovery.

The report should include.

a) geological conditions
b) physical properties of any liquids
c) Sulphur, sediment, and water content.
d) type of substances obtained.
e) Natural Gas composition.
f) production forecast per well
g) a preliminary estimate of recoverable reserves.

B. Development Plan

After the contractor has determined that the discovery has commercial potential. Within one hundred eighty (180) days of the said declaration, the contractor shall submit to the Management Committee a suggested Development Plan. The Development Plan must follow industry standards for safety and efficiency in the oil industry worldwide. Unless otherwise approved by the government, such a Development Plan must include the following information:

a) The delimitation of the Production Area, considering the results of the Appraisal Report regarding the importance of the Petroleum Field to be developed within the Appraisal Area.
b) Drilling and completion of Development Wells.
c) Drilling and completion of water or Natural Gas injection wells.
d) Laying of gathering pipelines.
e) Installation of separators, tanks, pumps, and any other associated production and injection facilities for production.

f) Treatment and transportation of Petroleum to the processing and storage facilities onshore or offshore.

g) Laying of export pipelines inside or outside the Contract Area to the storage facility or Delivery Point.

h) Construction of storage facilities for Petroleum.

i) Plan for the utilization of Associated Natural Gas.

Chapter 4 Indicators for Petroleum economic projects

4.1 Net cash flow (NCF)

The net inflow and outflow of cash and other liquid assets is what is meant to be referred to when speaking of a company's "cash flow." The ability of a corporation to sustain positive cash flow is necessary for the corporation to be able to pay off debts, reinvest in the business, distribute earnings to shareholders, meet operating expenses, and plan for economic unpredictability. If a company is experiencing a negative cash flow, this indicates that its cash reserves are being depleted. When determining a company's ability to create positive cash flow, as opposed to net income, which does not consider things like accounts receivable, a business is evaluated based on how well it can pay its bills. The liquidity of a company can be deduced from its cash flow, which, in turn, can serve as a stand-in for the quality of the company's assets also net cashflow can be defined as,

NTC = Cash inflows – Cash outflows

Cash inflows mean (revenue) and Cash outflows mean (Cost)

Here is an example of the net cash flow I made.

Table 1 Net cashflow

Net cash flow	In millions $
Net income	200
Depreciation and Amortization	40
Change in Net Working Capital	-20
Cash flow from operation	220
Capex	110
Issuance of Long-Term Debt	60
Repayment of Long-Term Debt	-40
Issuance of Common Dividends	-10
Cashflow from financing	10
Nat cashflow	120

4.2 Revenue

Revenue is the money a business gets from selling goods or services to customers and clients. The first line of a company's income statement shows the company's revenue, which is often called sales or service revenue. So, revenue is the amount made by customers and clients before the company's costs are considered. (McGill and van Ryzin, 1999).

Revenue is also different from Net income because revenue is the top line of the company and Net income is the bottom. Here is an example of revenue.

Table 2 Revenue and Net Income.

Revenue	Cost of products	Expenses	Net Income

500,000$	300,000$	50,000$	150,000$

4.3 Costs

Cost is the money that needs to be spent to make and sell goods and services or to buy assets. A cost is added to an expense when something is sold or used up. For an asset, the charge to expense could be put off for a long time. The change from assets on the balance sheet to expenses on the income statement is based on the idea of cost. When a cost is labeled as an expense, it can be put toward many kinds of expenses (Csikszentmihalyi, 2000).

Make petroleum, there are two main types of costs: fiscal costs and field costs, which can be broken down into four parts: exploration costs, development costs, operating costs, and abandonment costs. The costs of exploration and development together are called CAPEX, while the costs of running the business are called OPEX. The abandonment cost is in a special category of costs because it has to do with protecting the environment and does not lead to any future profit for the company. It is also a very big part of the cost and could be as much as or more than the development cost (Mian, 2002).

Because petroleum projects are different and have different tax rules, each company has a different way of dividing field costs (CAPEX, OPEX) into their parts.

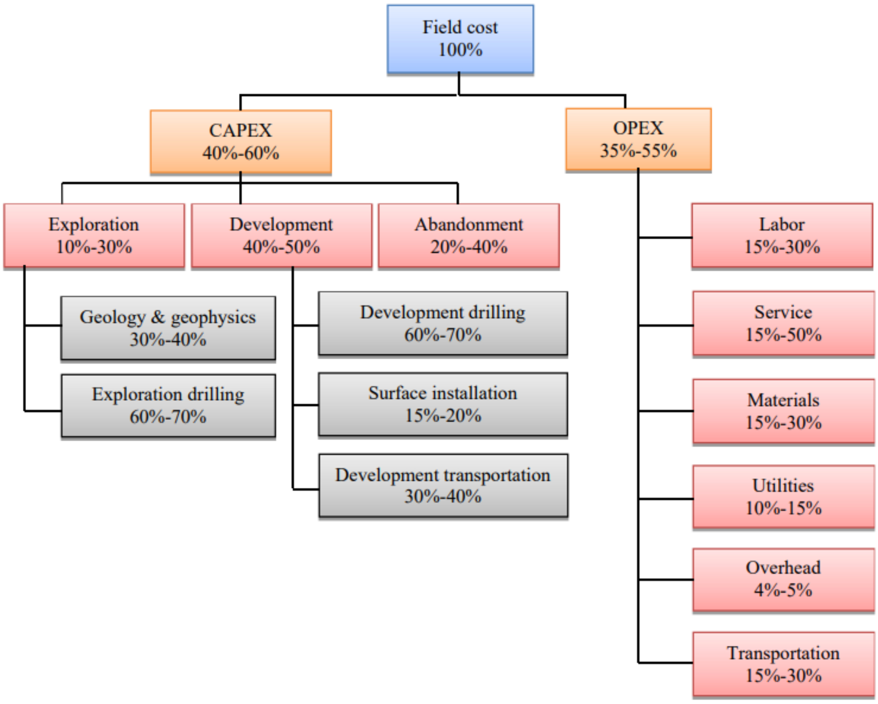

Figure 6 capex and opex difference (modified after Mian, 2002).

4.4 Capital Cost (CAPEX)

Companies must pay a capital cost to acquire the capital assets needed for petroleum production. Capital expenditures (CAPEX) are an upfront cost incurred at the start of a project, while they may also occur later during the project's economic life, such as when new methods and infrastructure are implemented to boost the output of a commodity like petroleum.

We have two types of CAPEX.

1. Exploration cost

Geological and geophysical studies, whether performed in-house or contracted out to a third party such as a service provider, add up to the total cost of exploration. Further, the price tag for drilling exploratory wells is factored in when calculating the overall price tag for exploration. The money spent on exploration is considered a sunk cost if the mission is unsuccessful. Although sunk costs may not be reflected in a project's projected cash flow, they can nonetheless have a significant impact on the project's bottom line (Babusiaux et al., 2004).

2. Development cost

Costs associated with drilling new development wells, installing new production equipment, and building new infrastructure to transport petroleum are the three primary components of the development cost. Many factors—including whether the project is located onshore or offshore, the kind of rock, the size of the oil or gas fields, the availability of specific technology, etc.—lead to a wide range of possible approaches to development (SONG, QU and ZOU, 2021).

4.5 Operating Cost (OPEX)

Expenses incurred while keeping the petroleum project running are reflected in what is known as "operating costs" (OPEX). Many different criteria can be used to categorize operating expenses (Jennings et al., 2000).

1. Operating Service
2. Materials
3. Utilities
4. Overhead
5. Production
6. Transportation

In Figure 7 we can see OPEX spending.

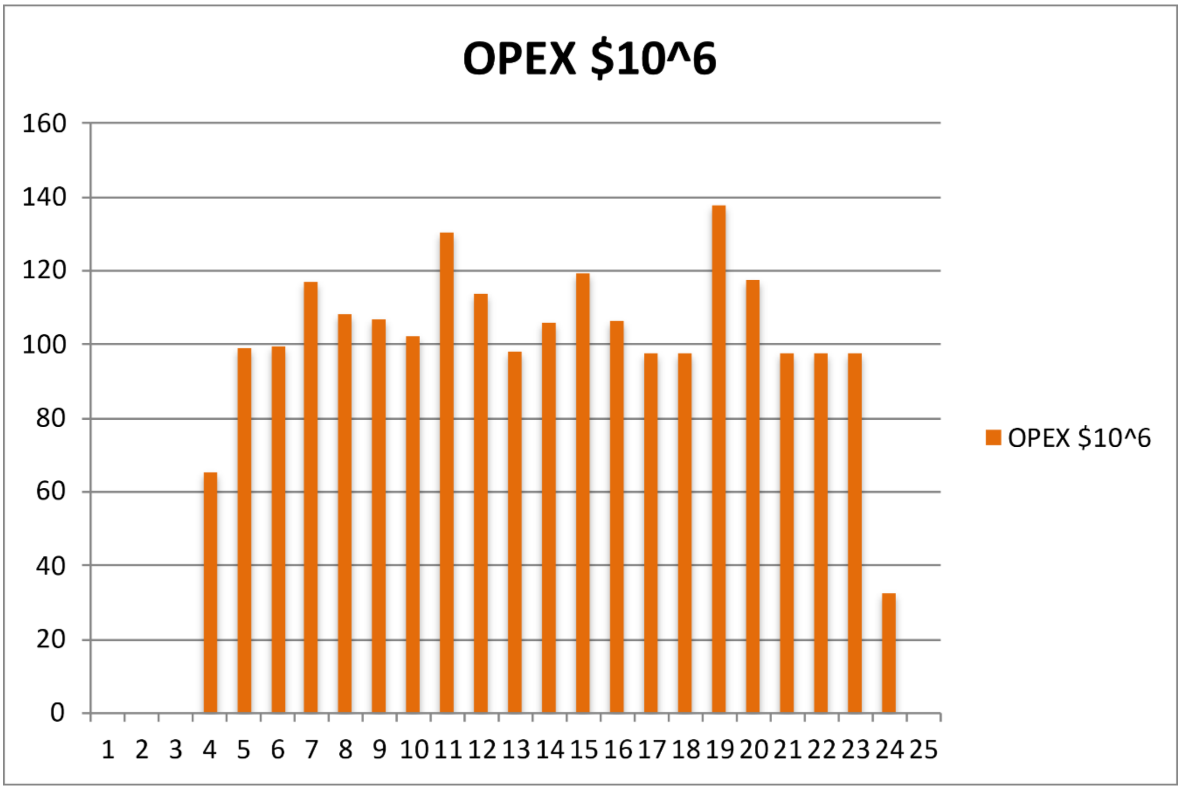

Figure 7 OPEX spending for 20 years x-axis is years and the Y-axis is the amount of spending.

4.6 Discounted Cash Flow

Net cash flow needs to be changed to account for the cost of capital needed to carry out the project and develop the field. The discount rate is either the cost of getting more money (like borrowing from a bank) or the return that could be made by investing in something else (for example, if an oil company has all or part of the money it needs to develop a field, it could have used that money to invest in something else).

DCF= NCF / (1 + rD).

4.7 Net present value

The net present value (NPV) value is the algebraic sum of discounted annual cash flows associated with the project NPV is given as:

$$NPV = \sum_{a=0}^{a} \frac{NCFa}{(1+i)^{a}}$$

NCFa = Net cash flow at the end of the year

i: The discount rate

a: Number of the year a = 0,1,2…A

The future profitability of an investment, project, or enterprise can be predicted using net present value. Simply put, the net present value (NPV) of an investment is the discounted sum of all cash flows expected to occur over the investment's lifetime.

While making financial plans, businesses frequently employ the net present value method. Financial experts are better able to make calculated decisions when all investment possibilities and possible projects are reduced to the same level: how much they will be worth in the end (Peymankar, Davari, and Ranjbar, 2021).

4.8 Internal Rate of Return

The project's internal rate of return is the discount rate that makes the project's net present value equal to zero.

$$0 = \sum_{a=0}^{A} \frac{NCFa}{(1+IRR)^{a}}$$

If the IRR is higher than the weighted average cost of capital, the NPV is positive, and if it is lower, the NPV is negative. When the IRR equals the weighted average cost of capital, the NPV equals zero. When a petroleum project has an unusual cash flow (for example, negative, positive, negative), a dual rate of return may happen. In this case, the IRR is a combination of the rate of return and the rate of reinvestment, so other economic indicators must be used to make investment decisions. (Mellichamp, 2017).

4.9 Payback time

The payback of a project shows how many years the company thinks it will take to get its money back from the project. At this point, the total investment is equal to the total net cash flow. The following equation can be used to figure out the payback:

$$\sum_{a=0}^{B} NCFa \geq 0$$

where b represents the payback point at which the cumulative net cash flow is positive for the first time in the project's life. 26 When the project achieves a payback point, in principle it will then be a worthwhile investment. When evaluating mutually exclusive projects, short payback points are preferred over long ones (Tsuchiya, Swai, and Goto, 2020). It is worth mentioning that the payback period alone cannot be used to make investment decisions because it does not take into account the cash flow after the recovery point. However, it is a useful indicator to be used with other indicators to determine if the project is a favorable investment opportunity.

Chapter 5 Methodology

The following report outlines a potential onshore investment in the field x in Kurdistan block WA-418-P. 6 appraisal wells have been drilled across the reservoir giving formation and fluid data used to produce an initial static model and dynamic model of the reservoir. This has been used to produce an overall technical and economic development plan for the reservoir to be screened by (X) company against project criteria. The Reservoir is a Carbonate, holding an estimated STOIIP 400 MMSTB of light crude oil with an API of 32° and an average viscosity of 0.62 centipoises. The reservoir is a laterally extensive layer with variable thicknesses of between 155ft and 234ft, with a diameter of approximately 4km in the SW-NE direction and 5km in the SE-NW direction. The carbonate layer thickens southwards with a crest at 8084 ft TVD and an OWC at 8693ft 3. Further exploration wells have been suggested in the northeastern quadrant of the formation to gain a better understanding with regards to the extent of the sand layer

Appraisal wells have indicated recoverable reserves from carbonates, in the form of undersaturated light crude. Initial good tests indicate an average horizontal permeability of approximately 140 mD with inter-bedded shales resulting in an estimated Kv/Kh ratio of 0.1. Analog fields and dynamic models indicate a recovery of approximately 50% with a deterministic and stochastic reserves range of 88MMstb – 307MMstb and 163MMstb – 251MMstb respectively.

Tanks with a capacity of 82,000 bbl/d will be purchased for an estimated $250m to develop the field. The tanks will contain all topside processing facilities including separators, desalting units, compressors, power generators, and reinjection ability. Oil export will be via tanker to avoid constructing a 200km pipeline to storage. Gas export will be via a 59km pipeline to the nearby X Field and then onto the company X development.

Drilling is estimated to last a total of 4 years, with a total of 6 producers and 8 injectors drilled with the first oil being produced in 2017. Individual drilling time per well is estimated not to exceed 104 days, the total drilling time can therefore be substantially reduced by drilling simultaneous wells using multiple rigs if Company x capital budget allows.

Total oil production is estimated to last 20 years, with an initial plateau of 82,000 bbl/d of oil, followed by a controlled decline due to water cutting.

Water cutting presents a significant challenge in maintaining desirable rates which will be counteracted with the installation of a cemented liner completion with zonal control via the use of inflow control devices or tubing plugs to block unproductive zones. Wire-wrapped screens will also be employed to minimize sand production effects.

The economic analysis was used to model the project cash flow and generate a range of project parameters for use in project screening. After making several assumptions on controlling parameters, a final Project NPV of $ 2.2 billion was calculated. An MCO of $ 715 million corresponds to an investment efficiency of $3.15 profit per $1 invested and an internal rate of return of 50%. Company X will break even after 5 years, making accelerated revenue from a large initial plateau of 82,000 bbl/d. Overall CAPEX equates to $ 1 billion with an OPEX of $ 2.5 billion over 20 years.

5.1 Petro-Physics

The Petro-physical analysis of the W Field was performed using a collection of data sets from 6 appraisal wells: W1, W2, W3, W4, and W5. The data sets consist of wireline logs and core data. The petro-physical evaluation was performed using Techlog software to process and analyze the parameters.

Table 3 Reservoir petro-physical properties.

Well	Liquid	Top reservoir	Base reservoir Pascal	Reservoir height	NTG (%)	Average porosity PU	Avrage water saturation (%)	Average Permeability mD

1	Oil	8180	8370	190	0.52	21	0.25	
2	Oil & Water	8538	8800	262	0.71	22	0.4	182
3	Water	8719	8903	184	0.59	21	1	
4	Oil	8405	8610	283	0.54	21	0.37	
5	Oil	8084	8294	205	0.65	21	0.33	134

A lithology identification process using the Neutron Density plot and M-N plot was performed and confirmed the interpretation of the reservoir structure which is a massive carbonate with shale layers as also shown in the core data. 14 A V-shale was used to distinguish between shale and sand sections within the reservoir to define the Net to Gross. The sand section in the reservoir is compacted, but the shale layers are not consolidated; this is evident from the caliper logs where a large borehole washout occurred in the shale section. The porosity of the reservoir was obtained by Density Porosity measurements which were corrected for light oil hydrocarbon effect. The liquid inside the reservoir was recognized using resistivity and water saturation measurements. Digital Core Permeability data was available for W2 and W5 well and used to calibrate the synthetically generated permeability curve. This calibrated curve was used as data for analysis such as Averages, Variograms, and Lorenz Plots.

5.2 Hydrocarbons in place

Stock Tank Oil Initially in Place (STOIIP) was calculated with both deterministic and stochastic methods. The input parameters were obtained from the petro-physical and fluid property analysis by having a fixed value for the Oil Water Contact and Formation Oil Volume Factor, and various values for the other parameters (Gross Rock Volume, Porosity, and Water Saturations). Tables 4 and 5 show the values of STOIIP and reserves obtained from the deterministic and probabilistic methods.

Table 4 STOIIP from deterministic and stochastic methods (MMbbls).

Method	P90	P50	P10
Deterministic	175	383	614
Probabilistic	327	403	506

The probabilistic method was calculated based on Monte Carlo simulation using Crystal Ball software. The distributions for the variables were mostly triangular for the simulation 15 input. The result of the Probabilistic simulation shows that the estimated STOIIP and reserves are close to the Deterministic method.

Table 5 Reserves from deterministic and stochastic methods (MMbbls).

Method	P90	P50	P10
Deterministic	88	192	307
Probabilistic	163	204	251

5.3 Field development plan

The reservoir will be developed will six producer wells and eight injectors. These wells will produce a plateau rate of 82,000bbl/d, followed by a steady decline as shown in Figure 8, which displays the production profile obtained from the dynamic model. The produced fluids will be processed by tankers with oil exported via tanker to storage and gas exported via a pipeline to X field, 59km away.

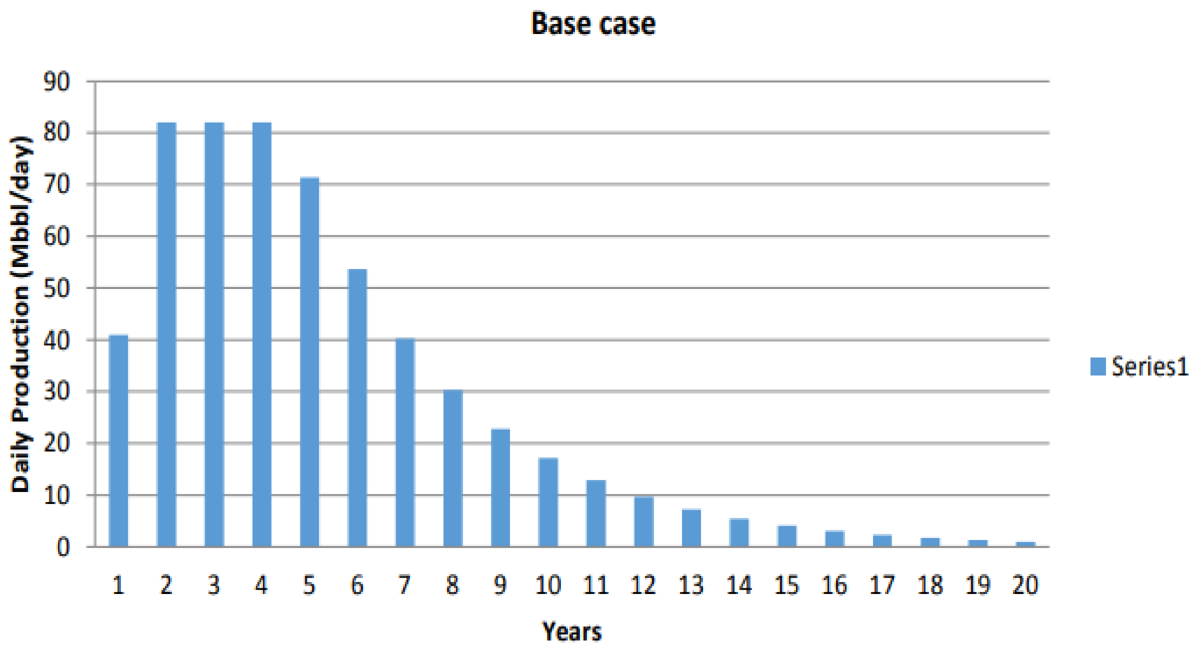

Figure 8 Production Profile obtained from simulation.

The initial plateau period of 82,000 bbl/d is maintained for approximately 3 years until the wells begin to cut water and the production must be chocked back to keep the well online. The reservoir will be allowed to decline for the first year, to analyze the behavior of the bottom hole pressure. The aquifer support is expected to be weak as the contact area for the edge water drive is relatively small. Water injection will therefore be employed to counter this and provide pressure support to the reservoir. Reservoir monitoring is essential throughout this development to remain aware of water cuts, reservoir pressure, sand production, and asphaltenes or wax production.

5.4 Oil and Gas Export

The lack of real oil infrastructure has already been discussed and means the only way of exporting the produced oil is by offloading the oil from tankers onto storage. The gas produced presents a challenge as flaring is not considered an option and gas is very difficult to store and transport economically. The option arises however to utilize the gas for power generation, cutting fuel costs of the project to negligible levels. Any remaining gas will be exported to the X field and then transferred via an existing pipeline to Company X development. To facilitate this, a pipeline shall be constructed from Company X development to the X field. This pipeline will span approximately 59km and is an unavoidable cost considering the decision not to flare and the excess gas after power generation. This capital outlay will be offset by the additional revenue coming from gas sales on the mainland – where there is a very strong gas market.

5.5 Uncertainties

Uncertainties for the project include geopolitical uncertainties, which are minimal in this region of the world. Economic uncertainties regarding GDP, Taxes, and Oil prices are also present and may have a significant impact on project parameters should there be a large deviation from the expected or projected case.

5.6 Production

The X field will be produced by 6 producer wells, with a peak production rate of 82,000 bbl/d. Each well has a maximum production rate of 30,000bbl/d which will be choked back to 13,600bbl/d per well to give the desired plateau rate across all the producer wells. Each well shall be tied back to a central production manifold which will then be fed into the tankers for storage. The presence of inter-bedded shale within the reservoir gives rise to significant geological uncertainties regarding possible sweep profiles during water injection operations. Any early water breakthrough will have a detrimental effect on the well productivity and therefore a cased and perforated liner completion with zonal control has been chosen. This allows the flexibility to close off unproductive zones and maintain the oil rate even after a water breakthrough. Facilities are contained within the completion string to provide essential functions for the completion. These include an SSD for annular/tubing circulation, a retrievable packer for annular isolation, a ported nipple for tubing isolation, and an SSSV for downhole flow containment.

5.7 Economics

The development case chosen for this project represents the most economically viable method of developing this field. This is however based on vital assumptions such as oil price, tax rate, tankers cost, and discount factor. Another consideration was the development concept. The rig development produced a CAPEX of $ 1 billion compared to a drilling rig development which gave a CAPEX of $ 2.4 billion. The NPV for the Rig development was also $ 2.2 billion compared with a much lower NPV of $ 1.8 billion for the Oil rig0 concept. 22 Base assumptions were oil price ($75/bbl), discount rate (10%), tax rate (40% PRRT + 30% Federal), rig cost ($250m), Inflation (3%), and Recovery factor (50%). These assumptions were modeled versus the expected production profile to give an NPV of $ 2.2 billion, an MCO of $ 715 million, an investment efficiency of $3.12 profit per $1 invested, and an internal rate of return of 50%. These project parameters rank very highly alongside Company X's existing assets and should pass project screening criteria. Sensitivities revealed that the major controlling parameters were oil price, discount factor, tax rate, and rig cost. RIG cost is the only parameter within the company's control therefore special attention should be paid to maintaining a low price during negotiations. Another key fact was the minimum economic oil rate, which was revealed to be $25/bbl. It is very unlikely that this value will ever be reached as oil is now being produced from more technically challenging basins and geopolitical instability often tends to inflate oil prices.

5.8 Company Corporate Profile

Company X is a leading international explorer, with 60% of the company's NPV represented by Country X assets. Development Company X's existing plays will raise production to 270,000 boe/d by 2027. The long-term strategy is to focus on exploration growth, represented by an $800m exploration budget in 2019. Current development investment is approximately $25 per barrel, representing a strong level of investment and commitment to long-term production.

Chapter 6 Result and Discussions

6.1 Oil Price

The oil price will most probably fluctuate during the life of the project, having a significant impact on the project's value. While sensitivities form an important part of uncertainty management, a single base case value must be chosen to give an end value for the project parameters. Over the last 20 years, the minimum price was around $25/barrel with a maximum price of $132/barrel. Taking an average gives an oil price of $76/barrel which takes account of geopolitical uncertainties. A range of $50/bbl - $100/bbl was chosen.

6.2 Inflation

inflation has been taken as 3%, in line with fiscal terms in KRG. A range of inflation values will be tested to analyze how a deviation from this value impacts the projected Figure 9 shows the data.

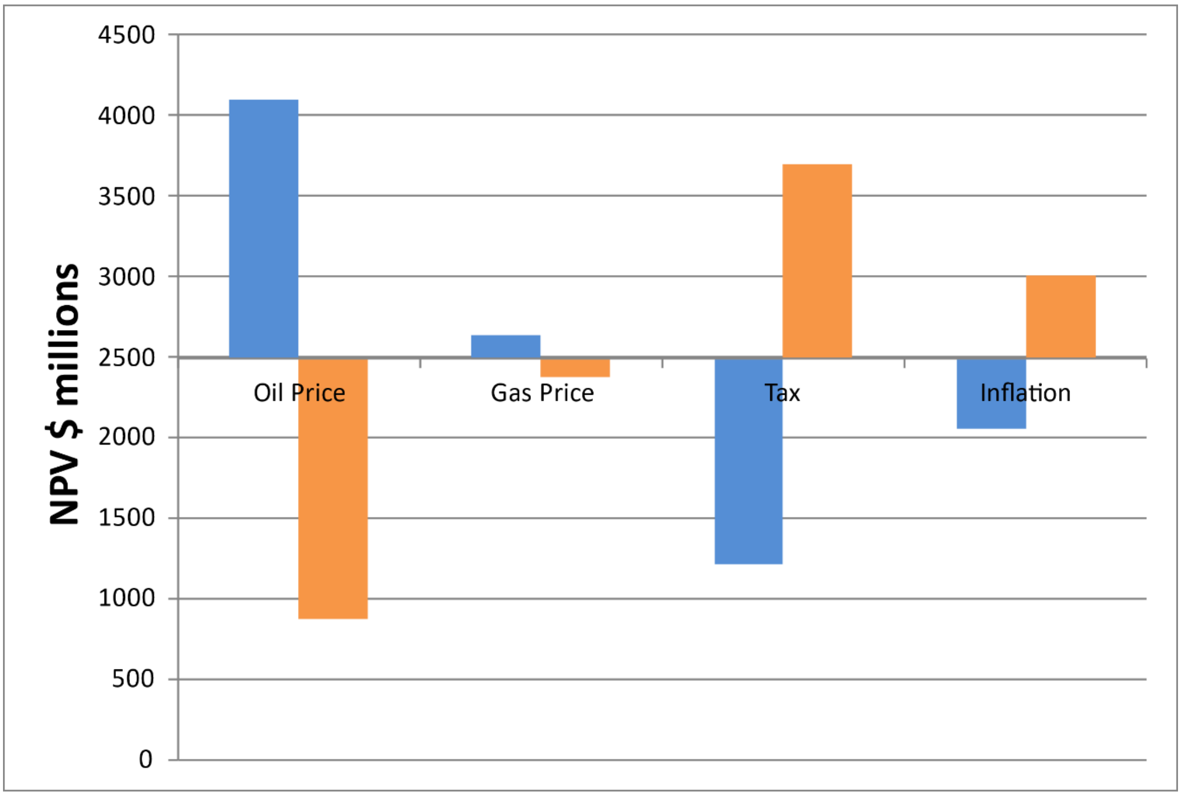

Figure 9 Inflation and tax.

6.3 Petroleum Resource Rent Tax (PRRT)

The PRRT tax regime is imposed as a 40% profits-related tax after past development, operating, and exploration costs are recovered with interest. It is also considered that the KRG fiscal regime is relatively developed therefore the level of uncertainty is relatively small.

6.4 Costs

Development costs equate to \$ 1 billion spread over the first 5 years. Production commences in year 4 with operational costs of \$ 2.4 billion spread over 20 years. Abandonment costs were estimated at \$ 300 million to be paid over the final 2 years of the project. These Figures were all estimated using analog field developments and QUE$TOR. A full investment profile can be found in the appendix.

6.5 Sensitivity Analysis

To quantify and understand the uncertainties present in the economic model, it was necessary to create a spider diagram comparing the project impact of different parameters. Figure 10 demonstrates the major uncertainties in the development. The parameters with the greatest impact on NPV are the tax rate, discount rate, Tanker’s cost, the oil price, and the recovery factor.

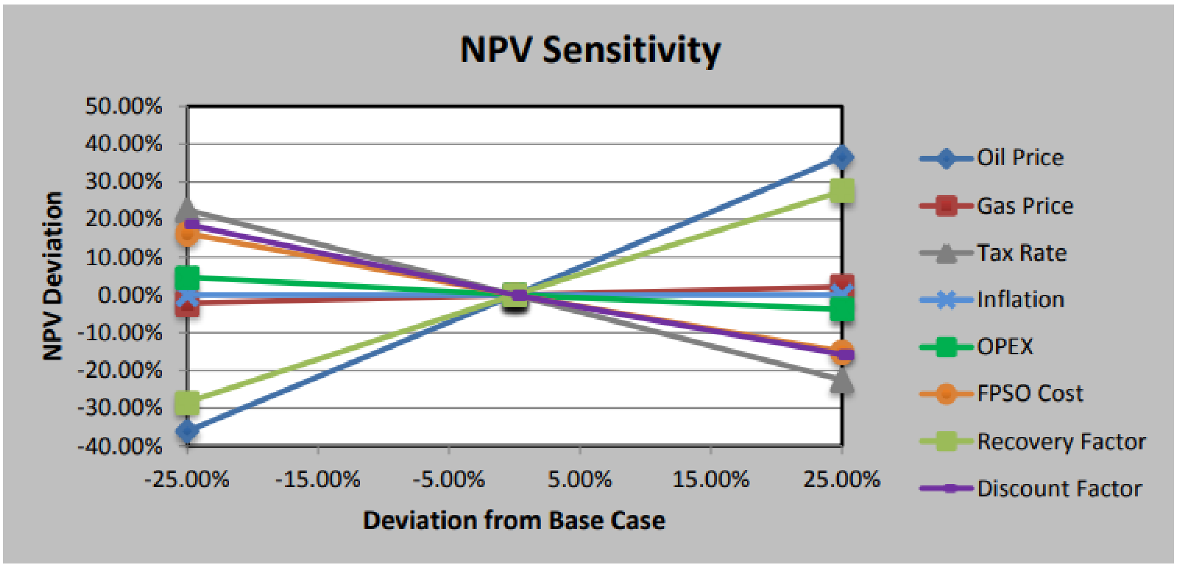

Figure 10 Spider diagram of uncertainties when calculating NPV.

The oil price and tax rate are outside of the company’s control, however, the tankers cost, and recovery factor are within the control of the company. The company needs to pay particular attention to the recovery factor and the Tanker’s costs during contract negotiations. Any reduction in tanker cost will have a significant impact on the project NPV and therefore the end profitability of the project. It is important to analyze at what point the project becomes uneconomical. The oil price corresponding to a zero NPV is the breakeven oil price, assuming all other variables remain constant. Figure 11 shows oil price vs NPV.

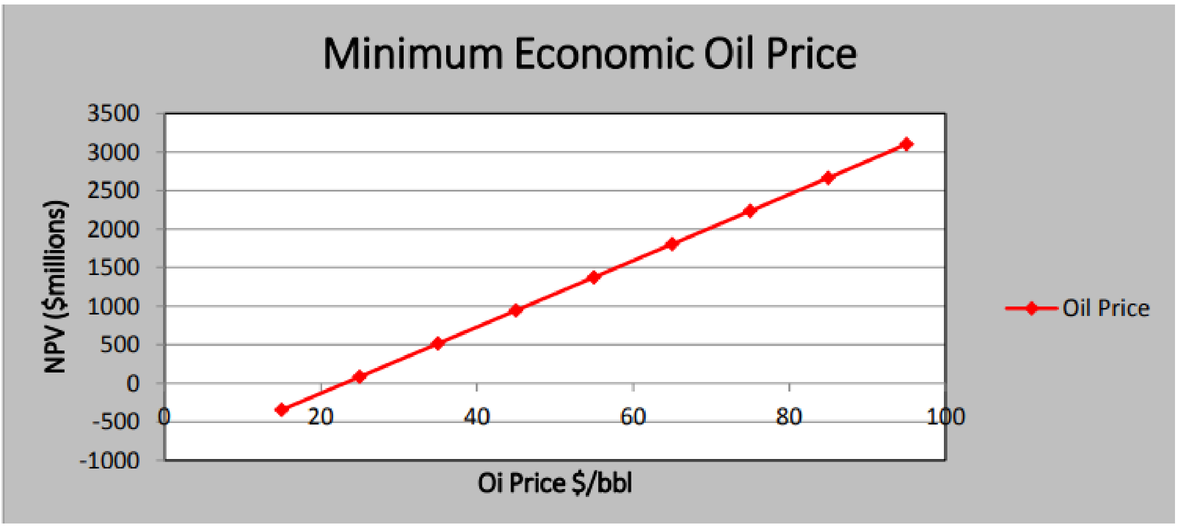

Figure 11 Minimum Economic Oil price.

It can be seen the minimum economic oil price is $25 per barrel, which is far lower than would be reasonably expected even in geopolitical conditions. This is therefore considered a very unlikely scenario.

6.6 Project Parameters

While it is important to evaluate project parameters, it is equally important to assess these in the context of the company, also known as project screening. Company X is an emerging player in the exploration industry and must rely on highly efficient investments with relatively low MCOs to reduce exposure and minimize risk where possible. The cumulative cash flow curve allows us to analyze these project parameters. This is shown in Figure 12 the NPV has been calculated with a 10% discount rate.

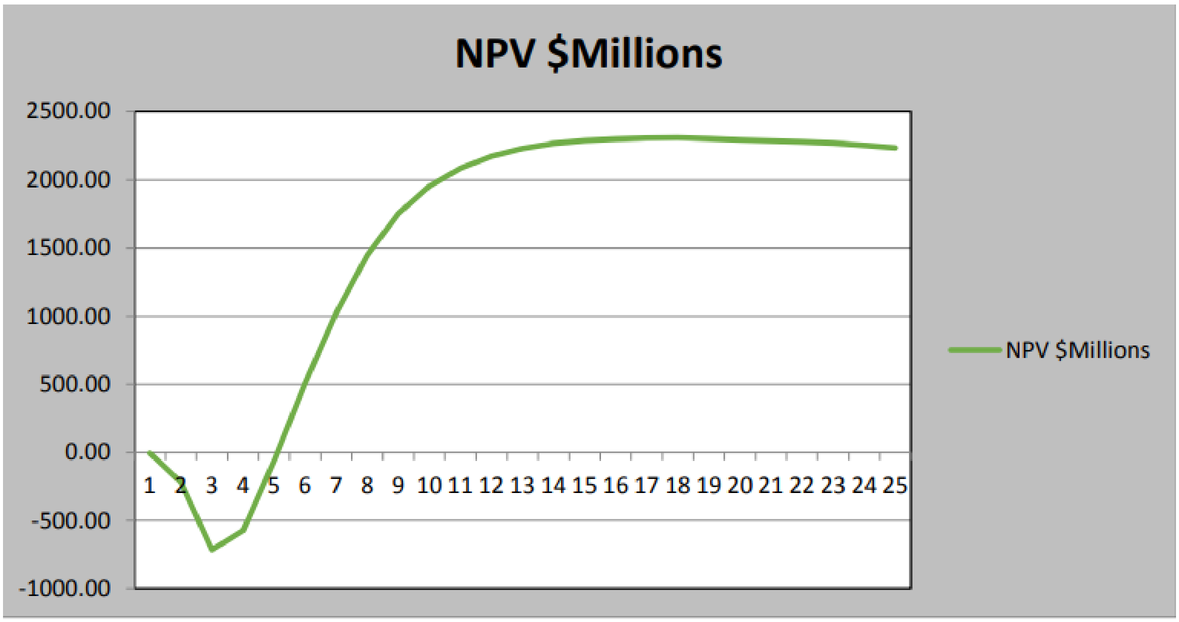

Figure 12 Cumulative cash flow discounted at 10%.

The NPV for this development is $2.2billion with an MCO of $715million and a payback period of 5 years, which is attractive for Company X as it provides a highly liquid project with an accelerated payback period and high initial revenues, important for a company focusing on exploration and growth. The terminal cash surplus (TCS) is the end point of the NPV curve and dividing this by the MCO gives a Profit to Investment Ratio for the development of $3.13 per $1 invested. The total capital investment is approximately $5 per barrel, which is well below Company X's current rate of $25 per barrel. Figure 13 below shows the Internal Rate of Return, the Discount Factor at which the NPV of the project reaches zero. The IRR is approximately 50%, which ranks highly among the other assets in the Company X portfolio.

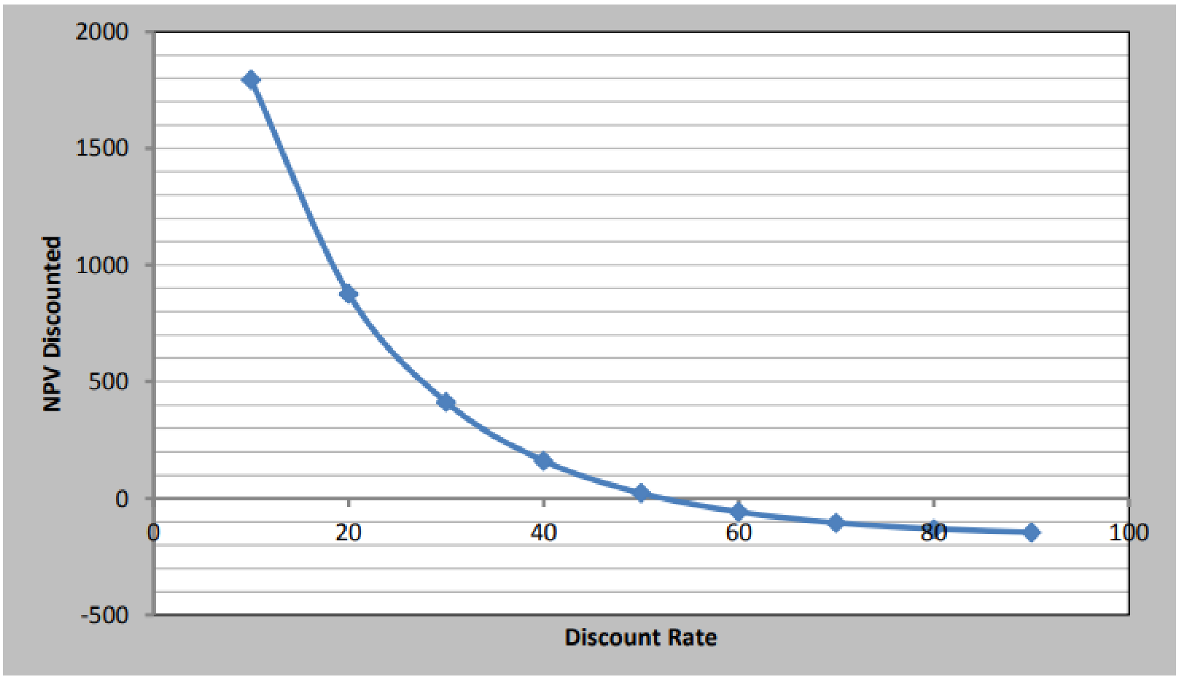

Figure 13 IRR and Discount factor which NPV is zero.

6.6 Commercial Summary

This development offers a significant addition to Company X’s portfolio with high investment efficiency and a large NPV. The IRR of 50% indicates a project with a low-risk factor and strong growth. The location of the development in KRG acts to diversify Company X’s current portfolio, which is mainly Asia-dominated, with 60% of the current NPV represented. An accelerated revenue stream acts to provide a large cash surplus early in the project, which can be reinvested in further exploration activities. Company X’s goal is to raise production to 270,000 bbl/d by 2027. This project offers the opportunity to improve production by approximately 80,000 bbl/d in the first 3 years followed by a steady and controlled decline. The long field life also gives Company X a stable source of cash flow which differs from current projects that are short-term and high-value. Figure 22 shows us all the data that I used for a 20-year project.

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Appendix 1:

Year	Production		Revenues		CAPEX	OPEX	Profit	Profit	Tax		NCF	NCF	NPV	NPV	NCFD	NPVD
	Oil	Gas	Oil	Gas			$2014	MOD	PRRT (40%)	Federal (30%)	mod	$2014	mod	$2014	Discounted	
	10^6 boe/y	10^9 SCF/y	$10^6		$10^6	$10^6	$10^6		$10^6	$10^6	$10^6	$10^6		$10^6	$10^6	£10^6
2014	0	0	0	0	4.83	0	-4.83	-4.83	0.00	0.00	-4.83	-4.83	-4.83	-4.83	-4.83	-4.83
2015	0	0	0	0	235.21	0	-235.21	-258.73	0.00	0.00	-258.73	-235.21	-263.56	-240.04	-213.83	-218.66
2016	0	0	0	0	600.86	0	-600.86	-727.04	0.00	0.00	-727.04	-600.86	-990.60	-840.90	-496.58	-715.24
2017	9.57	5.3592	717.75	42.8736	245.22	65.30	450.10	599.09	239.64	107.84	251.62	189.04	-738.98	-651.86	142.03	-573.20
2018	23.92	13.3952	1794	107.1616	8.63	98.81	1793.72	2626.19	1050.48	472.71	1103.00	753.36	364.01	101.51	514.56	-58.65
2019	28.70	16.072	2152.5	128.576	0	99.23	2181.85	3513.88	1405.55	632.50	1475.83	916.38	1839.85	1017.88	569.00	510.35
2020	28.70	16.072	2152.5	128.576	0	117.22	2163.86	3833.40	1533.36	690.01	1610.03	908.82	3449.88	1926.70	513.00	1023.35
2021	26.21	14.6776	1965.75	117.4208	0	108.26	1974.91	3848.54	1539.42	692.74	1616.39	829.46	5066.26	2756.16	425.65	1449.00
2022	20.84	11.6704	1563	93.3632	0	106.73	1549.63	3321.78	1328.71	597.92	1395.15	650.85	6461.41	3407.01	303.62	1752.62
2023	15.67	8.7752	1175.25	70.2016	0	102.23	1143.22	2695.66	1078.26	485.22	1132.18	480.15	7593.58	3887.16	203.63	1956.26
2024	11.78	6.5968	883.5	52.7744	0	130.32	805.95	2090.44	836.18	376.28	877.98	338.50	8471.57	4225.66	130.51	2086.76
2025	8.85	4.956	663.75	39.648	0	113.97	589.43	1681.71	672.68	302.71	706.32	247.56	9177.89	4473.22	86.77	2173.53
2026	6.66	3.7296	499.5	29.8368	0	97.92	431.42	1353.97	541.59	243.71	568.67	181.20	9746.55	4654.42	57.73	2231.27
2027	5.00	2.8	375	22.4	0	105.73	291.67	1006.92	402.77	181.25	422.91	122.50	10169.46	4776.92	35.48	2266.75
2028	3.76	2.1056	282	16.8448	0	119.52	179.32	680.99	272.39	122.58	286.01	75.32	10455.48	4852.24	19.83	2286.58
2029	2.83	1.5848	212.25	12.6784	0	106.48	118.45	494.79	197.92	89.06	207.81	49.75	10663.29	4901.98	11.91	2298.49
2030	2.13	1.1928	159.75	9.5424	0	97.45	71.84	330.11	132.05	59.42	138.65	30.17	10801.93	4932.16	6.57	2305.06
2031	1.60	0.896	120	7.168	0	97.67	29.50	149.10	59.64	26.84	62.62	12.39	10864.55	4944.55	2.45	2307.51
2032	1.20	0.672	90	5.376	0	137.92	-42.54	-236.54	0.00	0.00	-236.54	-42.54	10628.01	4902.00	-7.65	2299.86
2033	0.90	0.504	67.5	4.032	0	117.59	-46.06	-281.69	0.00	0.00	-281.69	-46.06	10346.33	4855.95	-7.53	2292.33
2034	0.68	0.3808	51	3.0464	0	97.39	-43.34	-291.59	0.00	0.00	-291.59	-43.34	10054.73	4812.60	-6.44	2285.88
2035	0.51	0.2856	38.25	2.2848	0	97.38	-56.85	-420.67	0.00	0.00	-420.67	-56.85	9634.06	4755.76	-7.68	2278.20
2036	0.38	0.2128	28.5	1.7024	0	97.38	-67.18	-546.84	0.00	0.00	-546.84	-67.18	9087.22	4688.58	-8.25	2269.95
2037	0.12	0.0672	9	0.5376	133.86	32.46	-156.78	-1403.88	0.00	0.00	-1403.88	-156.78	7683.34	4531.80	-17.51	2252.44
2038	0	0	0	0	167.33	0	-167.33	-1648.16	0.00	0.00	-1648.16	-167.33	6035.19	4364.47	-16.99	2235.45

Key Figures	Value	C/D Factor	f(time)
Inflation	10	1.1	(1+i)^n
Discount Factor	10	1.1	(1+i)^-n
Oil Price	$65/b	75	
Gas Price	$8/10^3SCF	8	
Tax	0.4	0.4	

	NPV		
Sensitivity	**High**	**Expected**	**Low**
Oil Price	4102	2488	873
Gas Price	2633	2488	2379
Tax	1217	2488	3700
Inflation	2057	2488	3004

Lever	High	Low	High	Low				
Oil Price	64.87%	-64.91%	4102	873		64	0	-64
Gas Price	5.83%	-4.38%	2633	2379		20	0	-20
Tax	-51.09%	48.71%	1217	3700				
Inflation	-17.32%	20.74%	2057	3004				

Variable	High	Expected	Low
Oil Price	90	65	40
Gas Price	12	8	5
Tax	0.6	0.4	0.2
Inflation	5	3	1

Discount	0	10	20	30	40	50	60	70	80	90
NPV ($ millions	3679	1794	876	411	162	23	-57	-104	-130	-145