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Faculty of Science

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

Bachelor thesis

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Fulltime study

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

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, focusing on using cash flow analysis to evaluate the profitability of oil and gas projects. The study considers the impact of inflation, costs, and revenues on project economics, drawing on data from various sources including industry reports, financial statements, and economic indicators.

The research finds that the petroleum industry in Kurdistan has 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: 9959

Number of pages: 59

I declare that I have prepared the bachelor's thesis myself and all the data I got was from a company they were confidential data so I couldn't name the company and the field.

In Olomouc, May 23, 2024 ……………………………………………

Aihan Ghairi Mohammed

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List of Abbreviations

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
KBPD	Thousand barrels per day

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. Oil companies assess the associated engineering and geological risks to determine the economic viability of a particular petroleum project. 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 is defined as the net amount of cash and cash equivalents transferred into and out of a company. Cash received represents inflows, while money spent represents outflows. Underestimating cash flow may cause a shortfall of cash for other planned activities.

This study focuses on the Kurdistan region's petroleum fiscal regimes and deals with international oil companies (IOCs). We will construct a cash flow for an ideal IOC operating in the Kurdistan Region of Iraq and establish a methodological approach for the economic evaluation of oil and gas projects in the region. We will use parameters like net cash flow, inflation, discounted rate, net present value, internal rate of return, and payback time, in addition to the cash flow chart, to evaluate the profitability of the oil and gas projects for all the stakeholders in the Kurdistan Region of Iraq.

1.1 Research Objective

This undergraduate thesis aims to investigate the financial situation of a specific petroleum project in the Kurdistan Region, analyse its risks, economics, and profits, and evaluate the regulations and rules governing the oil and gas industry in the region. This thesis's findings will serve as an analogue 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 industry regulations and policies.

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. Through a pipeline to Turkey, the region exports both crude oil and natural gas 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 Kurdistan Region of Iraq's petroleum industry generates significant cash flow, which directly influences the region's economic development. Oil and gas sales generate revenue for the KRG, which it uses to fund various development projects and social programmes (Qadir, Mohammed, and Majeed, 2021).

However, various factors such as fluctuations in oil prices, production levels, and transportation costs also affect cash flow in the petroleum industry. A decrease in oil prices, for example, can significantly reduce the revenue generated by oil sales, resulting in a decrease in cash flow. Similarly, production or transportation disruptions can have an impact on 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 strives to utilize revenue efficiently for the benefit of the region's citizens, all while preserving 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. The Kurdistan Region of Iraq (KRG) can use the revenue from the petroleum industry to support the region's growth and development by effectively managing cash flow (Mills, 2016).

2.1 Previous Studies

Studies on the monetary restrictions on oil production and exploration endeavours, such as the one by Al-Attar & Alomair (2005), have found that the structure of the fiscal regime matters more when examining it than the type of contract between the host government and the contractor. Consider the structure of the royalty rate, which can be either fixed or variable.

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

Kaiser and Pulsipher (2004) used a meta-modeling approach to look into different fiscal regimes. They ran simulations to show how statistical indicators (like government takes and contractor takes) change depending on how the system is set up. The construction of a model of the system is the initial stage of meta-modelling. After this step, we generate meta-data for the simulated variables within a specific design space. We then use the meta-data to construct linear models (Iledare & Kaiser, 2006).

2.2 Life cycle of an oil or gas field:

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

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

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

The second phase is a major goal of the exploration phase, which is to gather evidence that there is petroleum within the borders of the given exploration license. Various geological and geophysical studies must be conducted, and their results must be analysed 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 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 fourth phase is development, which is high levels of production of oil or gas that are 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 throughout the entire project's lifecycle (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 reach 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 for 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).

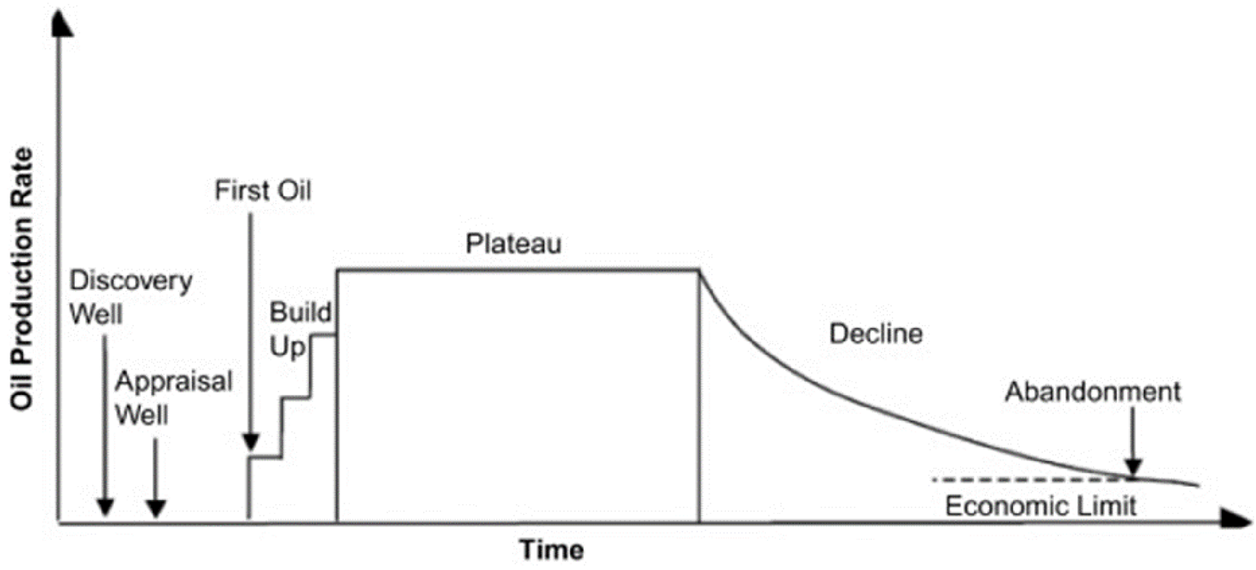


Figure 1 Theoretical production profile of an oilfield (Robelius, 2007).

- 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 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 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 for 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 under 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 royalty. 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 calculation 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 over time.

Taxes: 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.

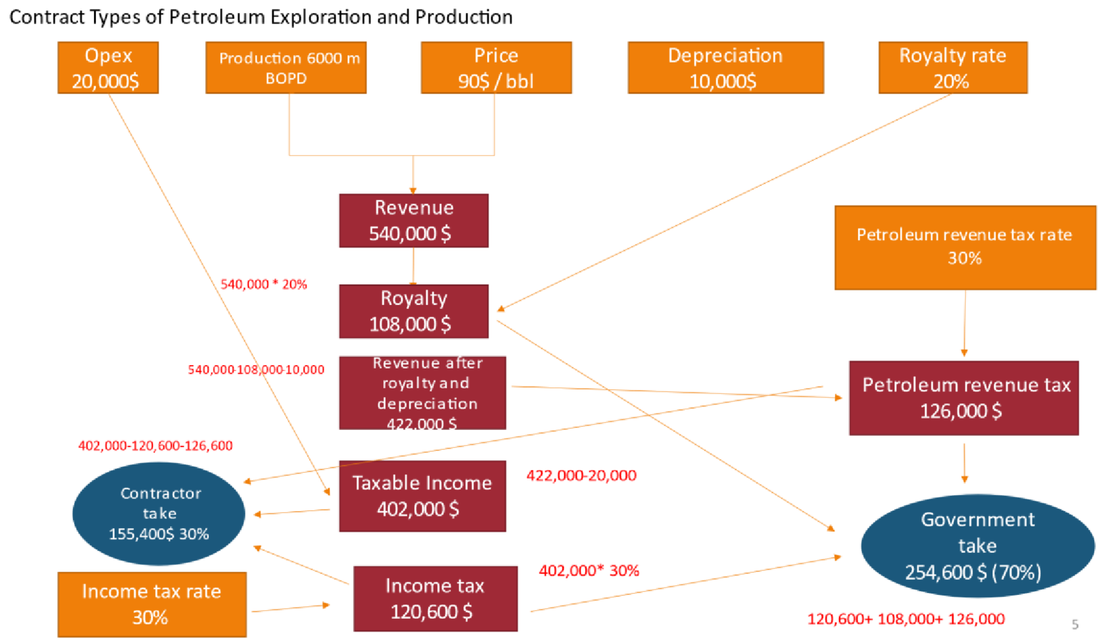


Figure 2 Concessionary Systems based on day production (modified after Agalliu, 2011).

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).

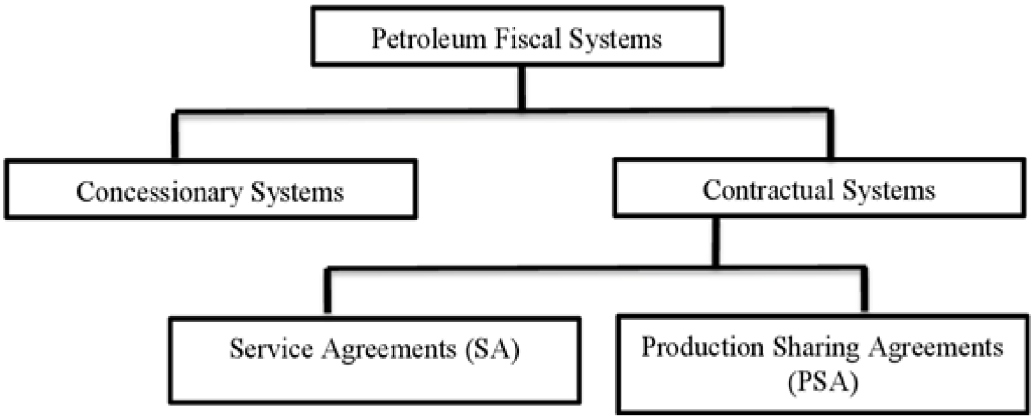


Figure 3 Classification of petroleum fiscal systems (Mazeel, 2010).

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.).

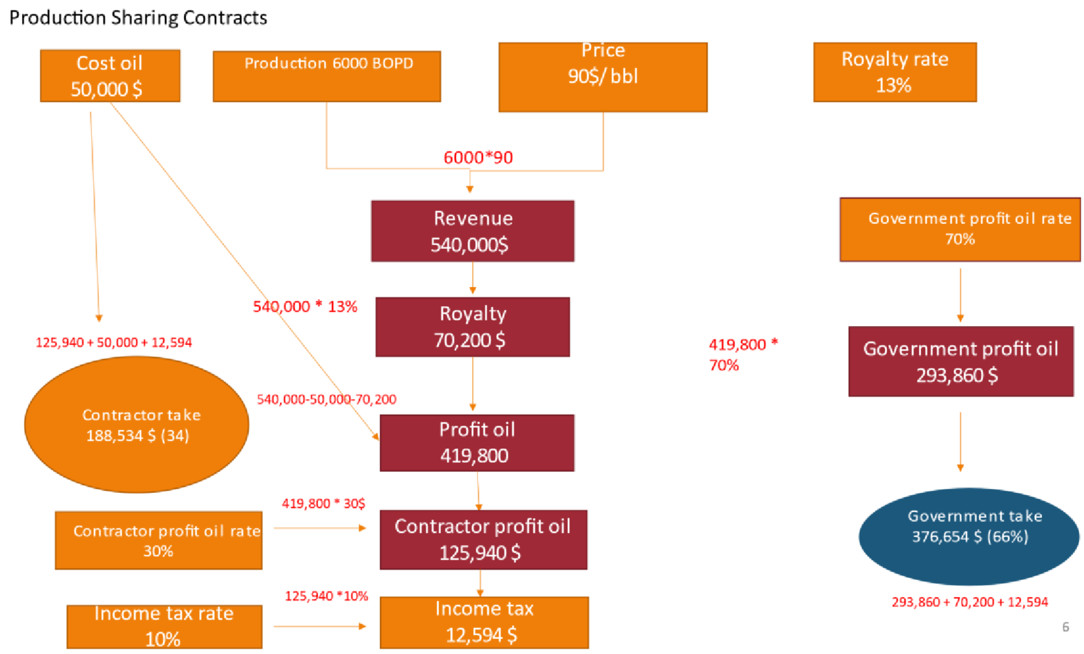


Figure 4 Production sharing on day production (Johnston, 2003).

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.

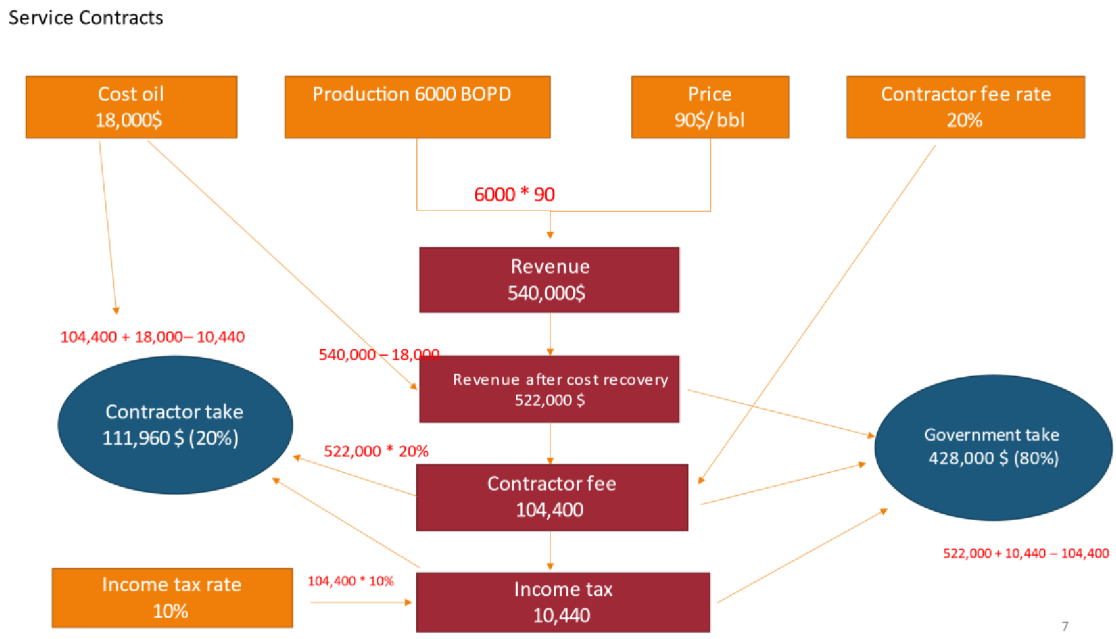


Figure 5 Service contract on day production (Bindemann, 1999).

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.

3.5.1 Reserves and Resources

In recent years, the KRI has been among the most active regions for onshore exploration of oil and gas. A total of 189 exploration and appraisal wells had been drilled by December 2014, with 169 of those wells being drilled during the modern era of exploration in the area (from 2005 onwards). By 2012, the commercial success rate amounted to around 55–60 percent, exceptional by global standards.

The estimated amount of oil and gas resources in Kurdistan is a topic of debate. The Zagros fold belt of Iraq, which extends into the KRI, is estimated to contain untapped resources worth 41 billion barrels of oil and natural gas liquids and 54 trillion cubic feet of gas, according to the US Geological Survey (USGS). While the International Energy Agency (IEA) estimated in 2012 that the Kurdistan Region (KRI) contained 4 billion barrels of proven reserves, the Ministry of Natural Resources (Kurdistan Region) (MNR) estimates oil reserves of 45 billion barrels. Due to the inclusion of potential for exploration and unproven resources in their resource estimates, MNR and USGS estimates are significantly higher. The KRG recently raised its estimate of its oil resources from 45 billion to 70 billion barrels; however, this estimate has not been independently verified and is probably incomplete because it includes resources in disputed areas, especially Kirkuk.

Estimates of proven oil reserves are 7 billion barrels, and of contingent resources found, there are 3.8 billion barrels, for a total of 10.80 billion barrels. The amount of oil in a reservoir before production, both recoverable and non-recoverable, is known as stock tank oil initially in place (STOIIP), and it is roughly 50 billion barrels of oil. Increases in the recovery factor, likely with further development and application of secondary and tertiary recovery methods, could probably achieve ultimate recovery of 20–25 billion barrels of the STOIIP, and possibly more.

For gas reserves, According to the MNR, there are 25 trillion cubic feet (708 billion cubic meters) of proven gas reserves and 99–198 trillion cubic feet (2800–5600 bcm) of unproved gas resources, or roughly 177 Tcf (5000 bcm64). There are, however, 22 Tcf (615 bcm) of contingent resources and 7 Tcf (200 bcm) of proved plus probable reserves in the discovered reserves (Mills, 2016).

Table 1 Reserves of major fields in the KRI (Mills, 2016).

Field	Oil proved + probable reserves and contingent resources (million bbl).	Gas proved + probable reserves and contingent resources (trillion cubic feet).
Khurmala	2726	3.6
Shaikan	1001	1.3
Atrush	854	0.1
Tawke	731	0.1
Taq Taq	579	0.1
Kurdamir	541	2.3
Sheikh Adi	531	0.4
Pulkhana	409	NA
Topkhana	55	1.7
Chemchemal	110	3.4
Khor Mor	138	4.4
Miran	34	3.5

Bina Bawi	45	4.9
Summail	0	1.4

3.5.2 Oil Production, demand, and exports.

In January 2014, Tawke produced 38 kbpd, Shaikan 8.7 kbpd, Taq Taq 84 kbpd, Khor Mor 20 kbpd (condensate and LPG), and Khurmala 84 kbpd. On an estimated basis, average 2014 production came from Tawke (91 kbpd in 2014), Taq Taq (103 kbpd), Khurmala (approximately 100 kbpd), and Shaikan (23 kbpd), with condensate and LPG from Khor Mor (26 kbpd). Smaller amounts have been produced from Sarqala, Barda Rash, Swara Tika, Demir Dagh, Akri Bijeel, and Miran under long-term tests or early production systems, totaling about 50 kbpd in 2014.

This production total excludes Kirkuk, which adds another 150 kbpd of exports (and effectively more, since Kirkuk crude is supplying KRG domestic refineries and hence freeing up another crude for export). Kirkuk production could be boosted to a level above 200 kbpd with some remedial work, and the surrounding fields of Bai Hassan, Jambur, and Khabbaz could add another 250 kbpd. However, Kirkuk's capacity will decline without substantial investment and technical assistance, which BP had formerly been providing by agreement with the Ministry of Oil in Baghdad. Kirkuk is thus currently very important for the region's export targets and budget but could become less so as the KRG's fields are expanded. From the mid-2020s, production growth will slow down, and additional developments or extensions of known fields will be required. Figure 6 shows a forecast for KRI oil production (Mills, 2016).

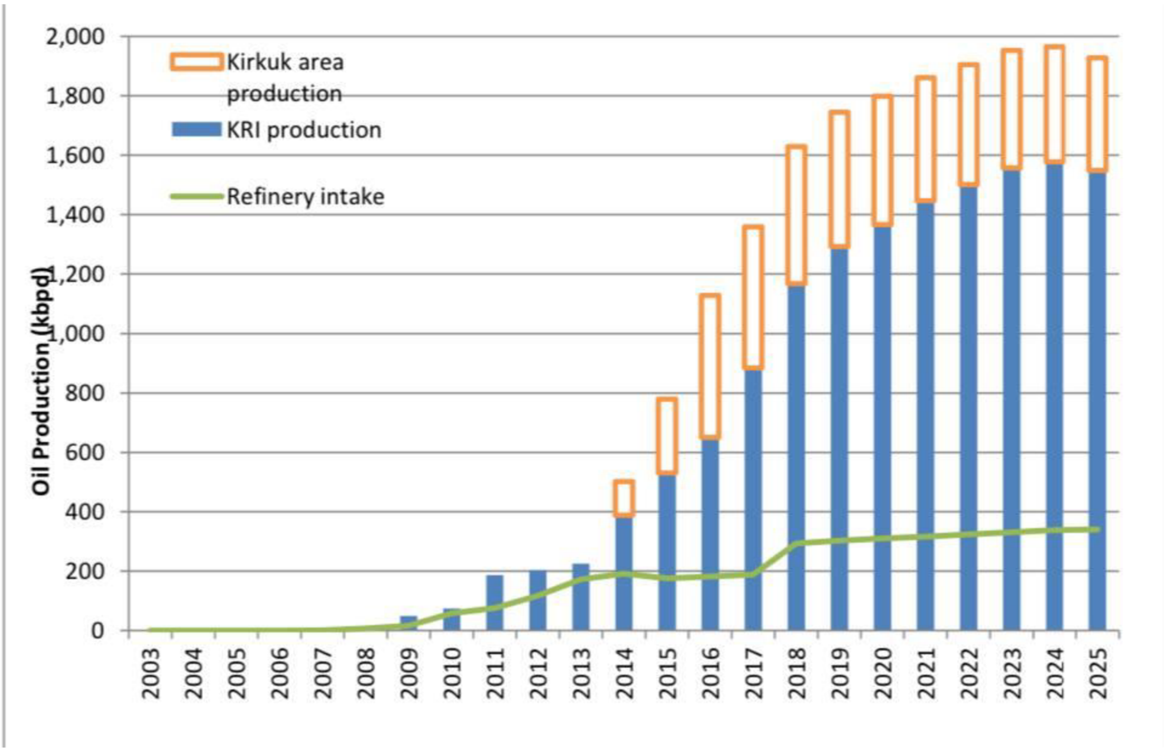


Figure 6 KRI oil production. (Mills, 2016).

Oil exports were initially by truck to Turkey and Iran, and this has continued even with the start of pipeline exports to Turkey. In 2015, about 55 kbpd were reportedly trucked from fields to be injected into the export pipeline, while 10 kbpd of heavy oil (probably from Shaikan) were exported by truck to Turkey. Trucks and pipelines from Khurmala and Taq Taq were used to feed the Kalak and Bazian refineries. Further volumes of both crude oil and products are exported by truck and not reported in this MNR figure.

3.5.3 Gas production, demand, and exports.

Gas production in the KRI stands at around 3–4 bcm annually, and is currently entirely for domestic use; the Khor Mor field supplies power plants at Bazian and Erbil, while the Summail field, which was supplying the Dohuk power plant, has run into production problems.

The addition of Kirkuk to the KRG's control adds about 2.5 bcm annually, which could increase if more currently flared gas is captured. However, most of this gas is required for local power generation. Miran and Bina Bawi could produce about 11 bcm between them, with 5 bcm from an expansion of Khor Mor and 6 bcm from Chemchemal. Figure 7 shows an outlook for KRI gas production and demand.

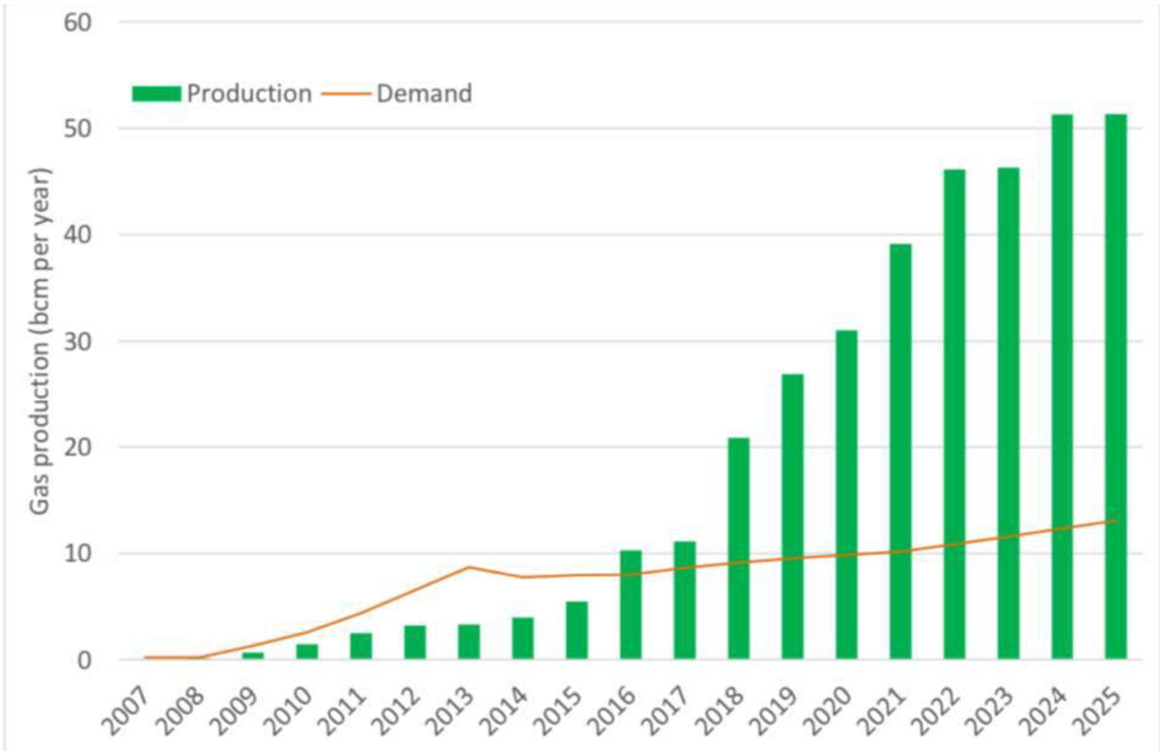


Figure 7 KRI gas production and demand (Mills, 2016).

3.6 Discovery and Development

If drilling Exploration Well leads to a Discovery, the contractor must tell the government within (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 (30) days of being told about Discovery, the contractor must give the Management Committee all available technical data and its opinion on the commercial potential of 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 (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 (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 (Dake, 2013).

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) Preliminary estimate of recoverable reserves.

B. Development Plan

After the contractor has determined that the discovery has commercial potential. Within (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 (M. Rafiqul Islam, 2021).

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.

3.7 KRG gas assets Economics

Data from this part were all taken from the company and they were confidential it shows the data and charts from a company's production.

Upstream cash flow

- General assumed to be 100% contractor at both fields.
- Fiscal terms

	Oil	Gas
Although modified separately, the fiscal we have assumed across Miran and Bina Bawi are the same		
Royality	10%	0%
Capacity building payment	0%	0%
Cost recovery celling	80%	100%
R-Factor	mulative revenue/ Cumulative costs(semi-annual basis)	
Profit share	R< or 1: 80% 1<R< or= 2: 80% -(80% - 25%) *(R - 1) / (2-1) R> 2: 25%	R < or 1: 100% 1< R < or = 2: 100% - (100% - 50%) * (R - 1) / (2 - 1) R > 2: 50%

- Pricing
  - Brent Crude: 2016: 40$/bbl, 2017: 60$/bbl, LT: 70$/bbl

Figure 8 Upstream fiscal terms and pricing.

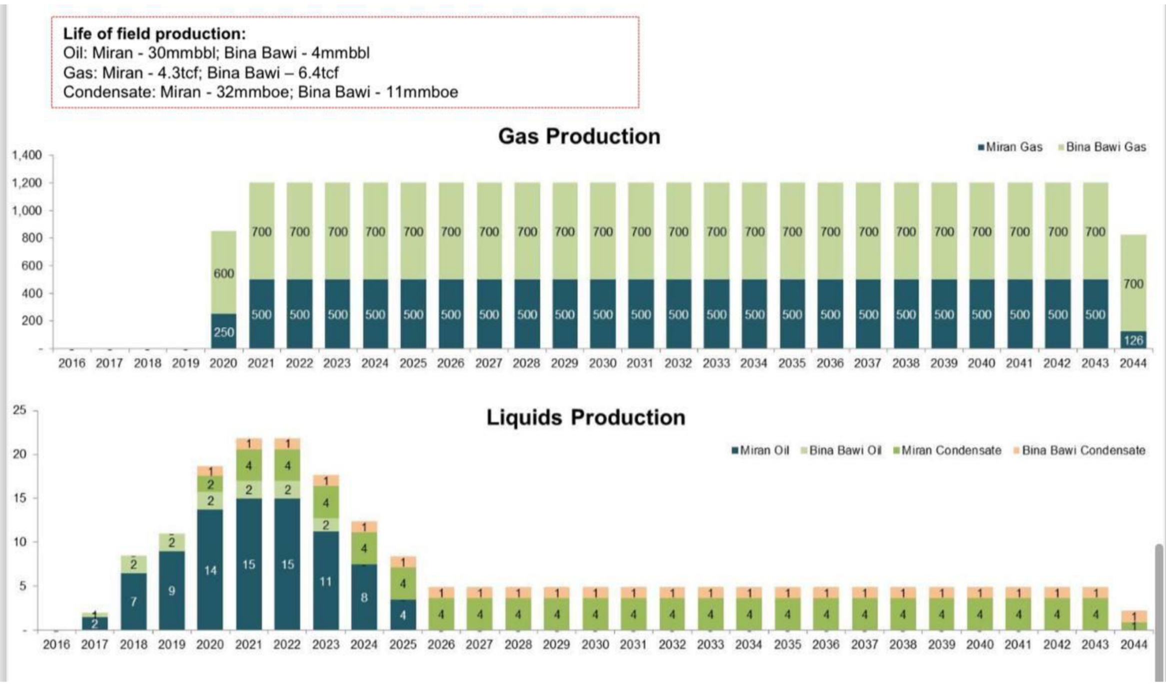


Figure 9 Production profile.

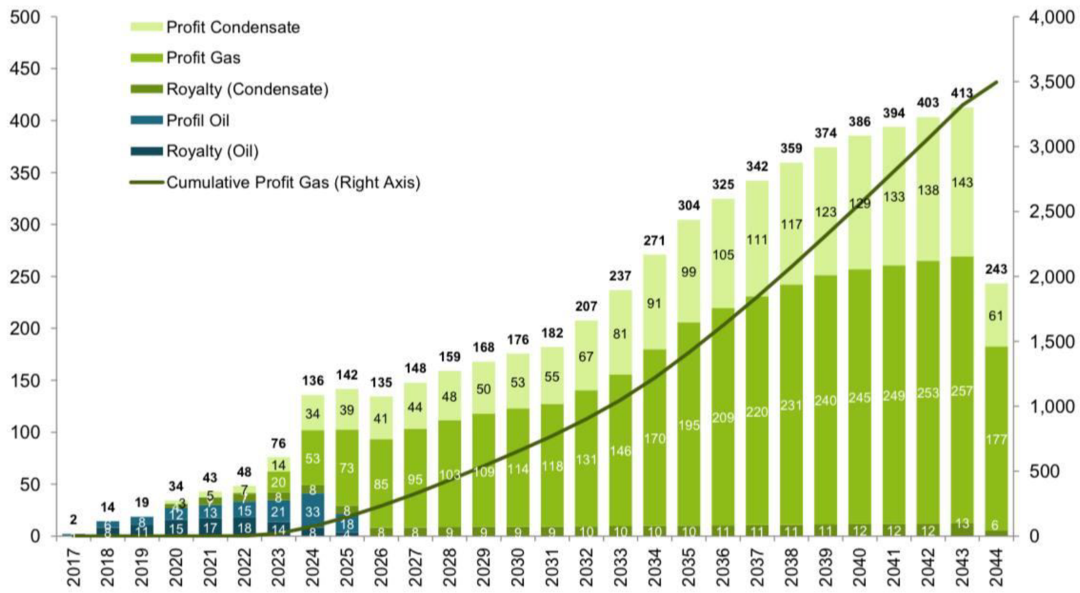
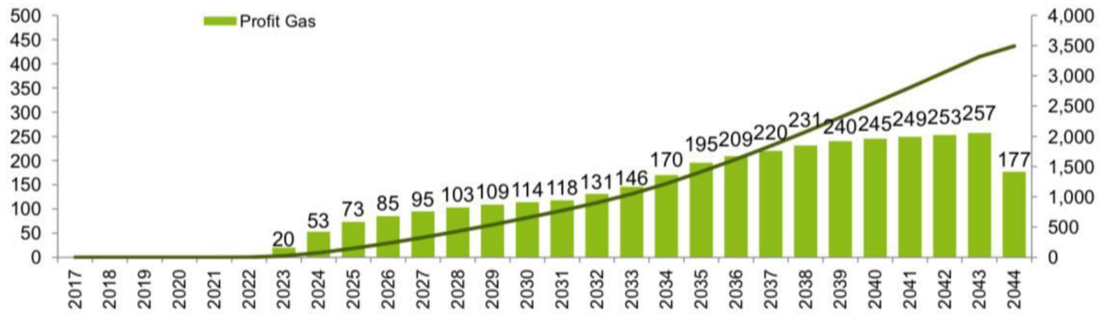


Figure 10 Total KRG upstream cash flows.



(in $m)		LT Brent Price ($/bbl)				
Discount Rate		60	70	80	90	100
	12.5%	360	407	455	502	547
	10.0%	529	592	655	716	774
	7.5%	797	883	969	1,050	1,125
	5.0%	1,235	1,356	1,474	1,584	1,685

Figure 11 Total KRG upstream cash flows.

Midstream cash flows

- **Pricing**
  - **Brent Crude:** 2016: $40/bbl, 2017: $60/bbl, LT: $70/bbl
- **Inflation rate:** 2.5%
- **Construction costs:**
  - $2,750m (turnkey fixed contract)
- **Opex and operations**
  - Fixed opex: USD 40m p.a.
  - Variable opex: 0.1 USD/ Mscf ($44m @ 1,200mscfd)
  - Major maintenance: USD 30m (in 2025, 2030, 2035, 2040)
- **Plateau period assumptions:**
  - Tolling fee: $2.0/mscf, achieves 18% real IRR at ACQ
  - Midstream liquids allocated to KRG
- **Post-Plateau assumptions:**
  - Midstream fixed and variable opex of Midstream paid by KRG
  - No Midstream tolling fee after transfer of the Midstream facilities to KRG
  - Production levels maintained post Plateau Period
- **Finanacing of the project:**
  - Financing by equity: 30%
  - Financing by Senior Debt: 70%
- **Financing assumptions**
  - ECA premium: 20.0%
  - Base rate: 2.0%
  - Margin Pre-Completion: 2.0%
  - Margin Post-Completion: 2.5%
  - Upfront Fee: 2.0%
  - Commitment fee: 0.8%
  - Facility repayment period: 11 years
  - Door-to-Door Tenor: 14 years
  - Maturity date: 31/12/2030
  - Weighted average cost of debt: 9.57%

Figure 12 Assumption Midstream.

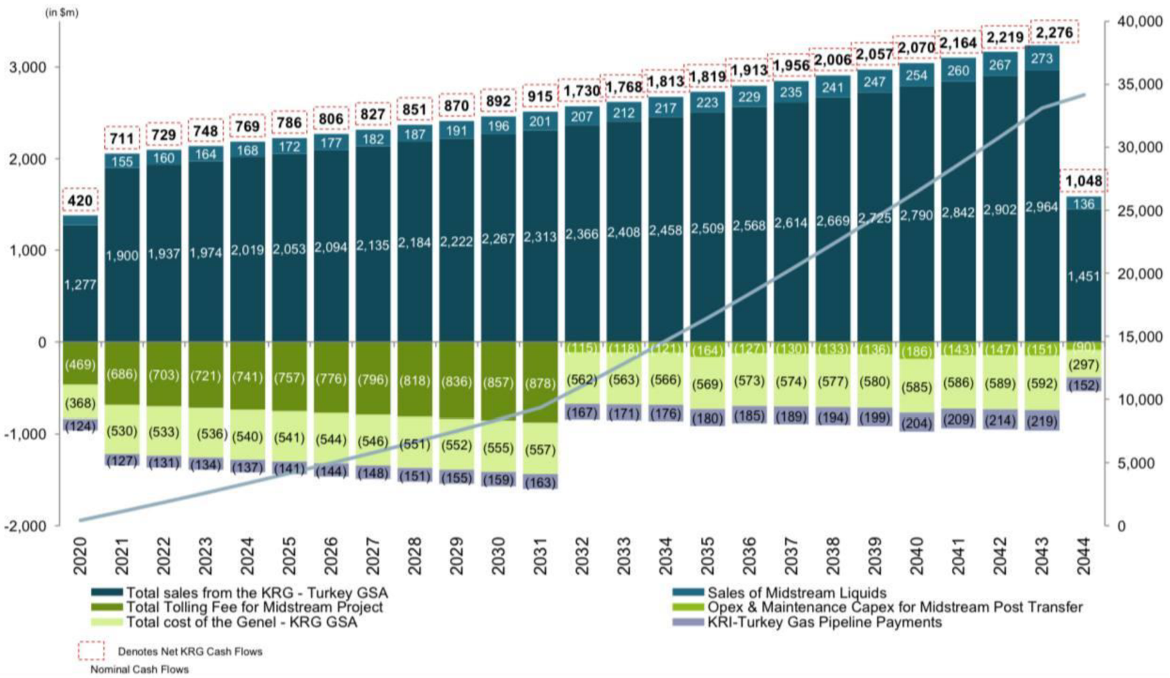
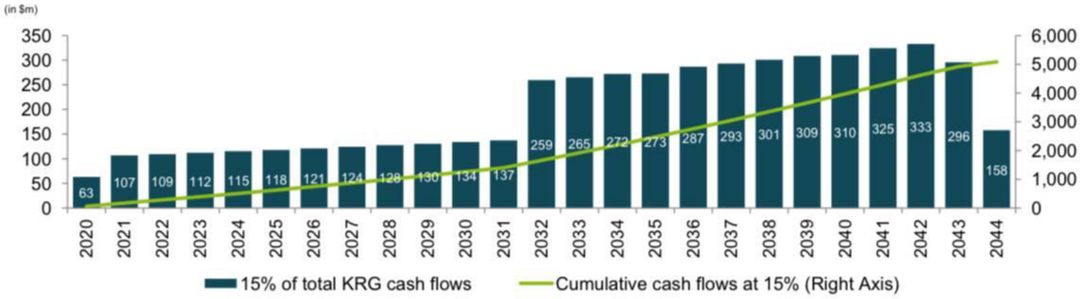


Figure 13 KRG gas cash flows.



(in $m)		LT Brent Price ($/bbl)				
		60	70	80	90	100
Discount Rate	12.5%	626	770	913	1,057	1,200
	10.0%	862	1,051	1,239	1,428	1,616
	7.5%	1,226	1,481	1,736	1,991	2,246
	5.0%	1,804	2,160	2,516	2,872	3,228

Figure 14 KRG gas cash flow - 15% ownership.

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 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 cash flow 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.

cash surplus = gross revenue- expenditure

Cash Surplus = gross revenue - capex - opex - royalty- tax (assuming a tax and royalty fiscal system).

Suppose it is 2020:

Production = 12 MMbbl Capex = $80 m

Oil price = $20/bbl Opex = $15 M

Royalty rate = 16.66%

Tax rate = 70%

To get Capital allowance we will assume the previous Capex was $120 m. With a 25% straight-line capital allowance. So the capital allowance 2020 = 0.25 * $120 m + 0.25 * $80 m = $50 m.

Revenue = production * oil price

= 12 MMbbl x $20/bbl = $240 m

Capex = $80 m

Opex = $15 m

Technical cost = $95 m

Royalty = revenues * royalty rate = $240 m * 0.1666 = $40 m

Fiscal costs = royalty + opex + capital allowance

= $40m+$15m+$50m = $105 m

Taxable income = revenue - fiscal costs

= $240m - $105m = $135m

Tax = rate x taxable income

= 0.70 * $135m = $94.5 m

Cash surplus = revenues - capex - opex - royalty - tax

= $240 – 80 – 15 – 40 - 94.5m = $10.5 m

Host government take = tax + royalty

= $94.5 + 40m = $134.5 m

We calculate the project's cash flow for each year of its life. Figures 15 and 16 present both a typical project cash flow and a cumulative cash flow, which depicts the normal distribution of cumulative revenue among the capex, opex, the investor (in this case, the oil company), and the host government (through taxes and royalty). The cumulative cash surplus, also known as field fife net cash flow, is the total amount of money the business will have after project.

This example was taken from (Jahn, 1998).

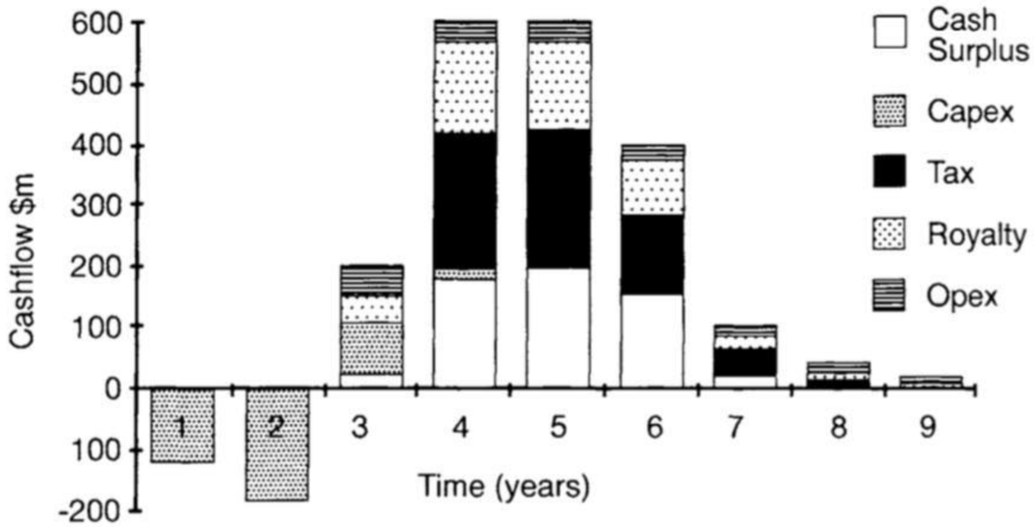


Figure 15 Components of a Project Cashflow (Jahn, 1998).

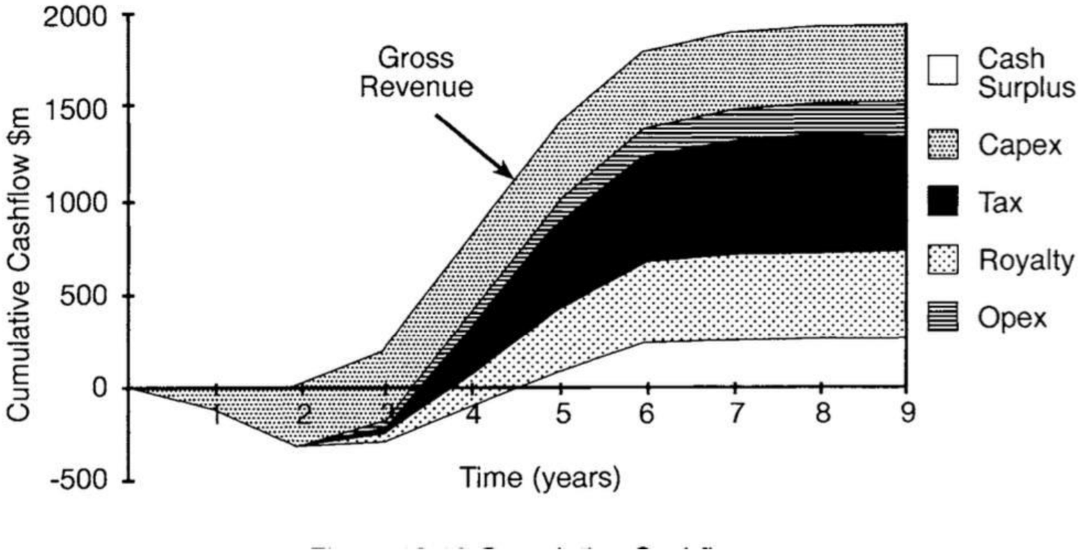


Figure 16 Cumulative Cashflow (Jahn, 1998).

4.2 Revenue

Revenue is the money a business gets from selling goods or services to customers and clients. Often referred to as sales or service revenue, the first line of a company's income statement displays its revenue. Therefore, revenue represents the earnings from customers and clients before accounting for the company's costs. (McGill and van Ryzin, 1999).

Revenue is also different from net income because revenue is the company's top line, while net income is its bottom line. Here's 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 amount of money required to produce and sell goods and services, or to purchase assets. When we sell or use up an asset, we add a cost to the expense. An asset may delay the charge to expense for an extended period. The transition from assets on the balance sheet to expenses on the income statement is based on the concept of cost. Labeling a cost as an expense allows for its application to various types of expenses (Csikszentmihalyi, 2000).

To 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. We refer to the combined costs of exploration and development as CAPEX and the operational costs as 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 large part of the cost, possibly 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 into their parts (CAPEX, OPEX).

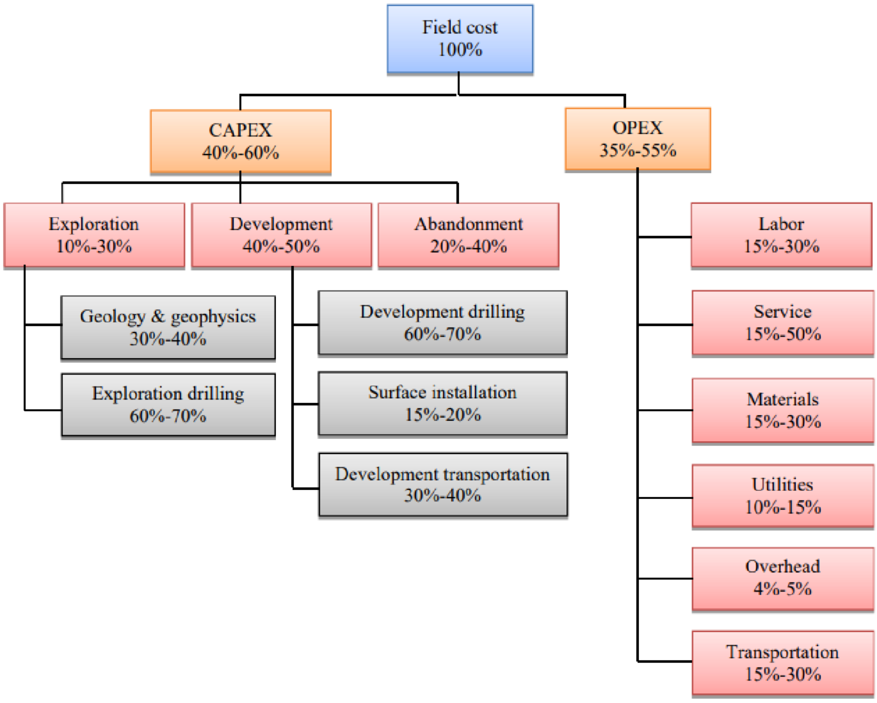


Figure 17 capex and opex difference (modified after Mian, 2002).

Per barrel costs

Per barrel costs (costs per barrel of development production) are useful when production is the constraint on a project, or when making technical comparisons between projects in the same geographical area.

per barrel cost = $\frac{capex + opex}{Production}$ [\$/bbl].

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, contribute to the total cost of exploration. Moreover, the total cost of exploration includes the cost of drilling exploratory wells. The money spent on exploration is considered a sunk cost if the mission is unsuccessful. Despite not appearing in a project's projected cash flow, sunk costs can significantly influence the project's financial performance (Babusiaux et al., 2004).

2. Development cost

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). In Figure 18 we can see OPEX spending.

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

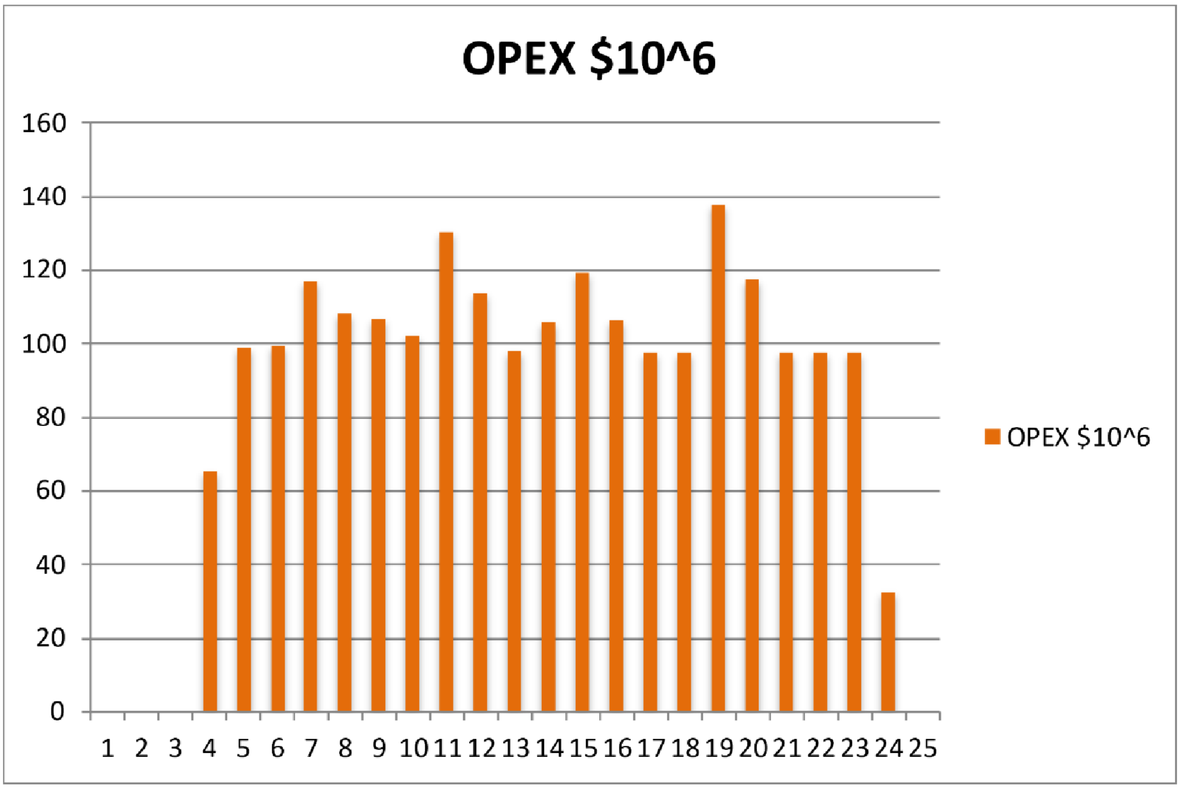


Figure 18 OPEX spending for 20 years x-axis is years and the Y-axis is the amount of spending (Ganat, 2020).

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 in equation 1:

Equation 1 net present value.

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

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 in Equation 2.

Equation 2 Internal rate of return

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

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 3 can be used to figure out the payback:

Equation 3 Payback time.

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

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 consider 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 outlines a potential onshore investment in field x in Kurdistan block WA-418-P. Drilling six appraisal wells across the reservoir has provided formation and fluid data, enabling the production of an initial static and dynamic model of the reservoir. The company (X) has used this information to produce an overall technical and economic development plan, which will screen the reservoir against project criteria. The reservoir is made of carbonate and is thought to hold 400 million barrels 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 155 ft and 234 ft, with a diameter of approximately 4 km in the SW-NE direction and 5 km in the SE-NW direction. The carbonate layer thickens southwards, with a crest at 8084 ft TVD and an OWC at 8693 ft 3. We have proposed further exploration wells in the northeastern quadrant of the formation to enhance our understanding.

Appraisal wells have identified recoverable carbonate reserves in the form of undersaturated light crude. The first good tests show that the interbedded shale has an average horizontal permeability of about 140 mD, which gives us an idea of the Kv/Kh ratio being 0.1. The analogue fields and dynamic models show a recovery of about 50%, with a deterministic reserve range of 88 MMstb–307 MMstb and a stochastic reserve range of 163 MMstb–251 MMstb.

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.

We will install a cemented liner with zonal control, using inflow control devices or tubing plugs to block unproductive zones, to counteract the significant challenge of water cutting and maintain desirable rates. We will also employ wire-wrapped screens to minimise the effects of sand production.

We used the economic analysis to model the project cash flow and generate a range of project parameters for project screening. We calculated a final project NPV of $2.2 billion after making several assumptions on controlling parameters. 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%. After 5 years, Company X will break even, accelerating revenue from a large initial plateau of 82,000 bbl/d. Overall CAPEX amounts to $1 billion, with an OPEX of $2.5 billion over 20 years.

5.1 Field Development Plan

The reservoir will be developed with 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 19, which displays the production profile obtained from the dynamic model.

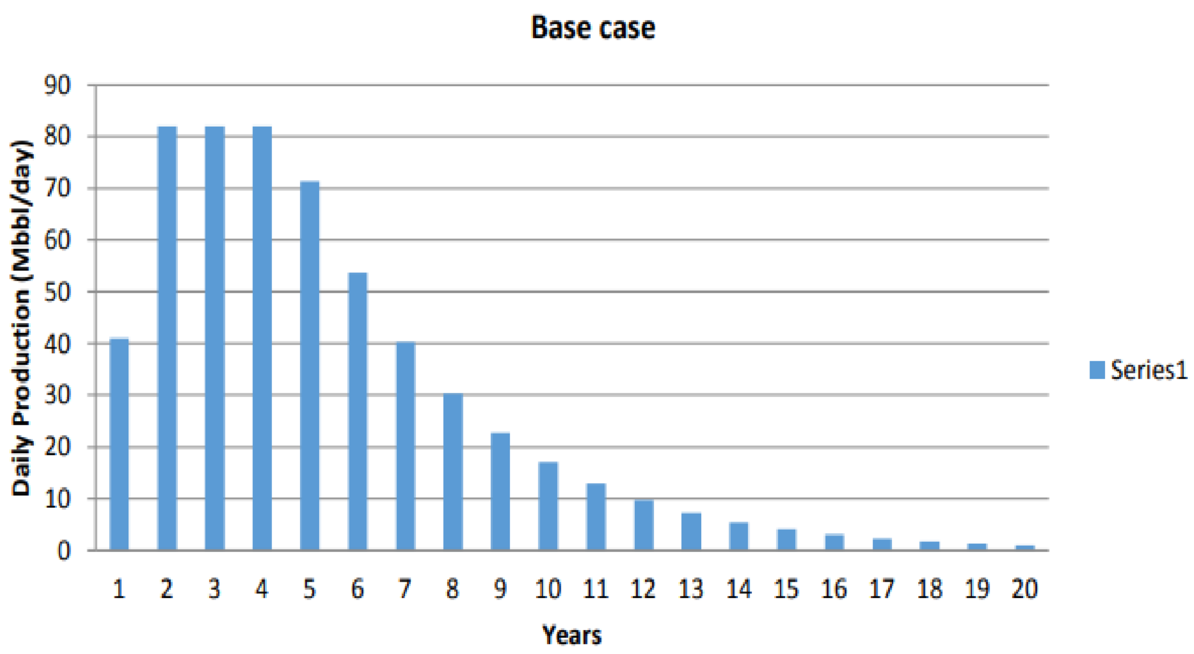


Figure 19 Production Profile.

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.

5.2 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.

5.3 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 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.

5.4 Economics

The selected development case for this project represents the most economically viable approach to this field's development. However, this is based on critical assumptions such as the oil price, tax rate, and discount factor. The development concept was another consideration. The rig development produced a CAPEX of $ 1 billion, compared to a drilling rig development, which produced 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 rig 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 We modelled these assumptions against the expected production profile, resulting in 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%. f 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. Since the company only controls the rig cost, it is crucial to maintain a low price during negotiations. The company revealed the minimum economic oil rate to be $25/bbl, another crucial fact. 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.

5.5 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 2014. 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 likely fluctuate throughout the project's life, having a significant impact on its value. Choosing a single base case value is crucial for uncertainty management, as it provides an end value for the project parameters. Over the last 20 years, the minimum price was around \$25 per barrel, with a maximum price of \$132 per barrel. Taking an average, we get an oil price of \$76 per barrel, which accounts for geopolitical uncertainties. We chose a range of \$50/bbl to \$100/bbl.

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 20 shows the data.

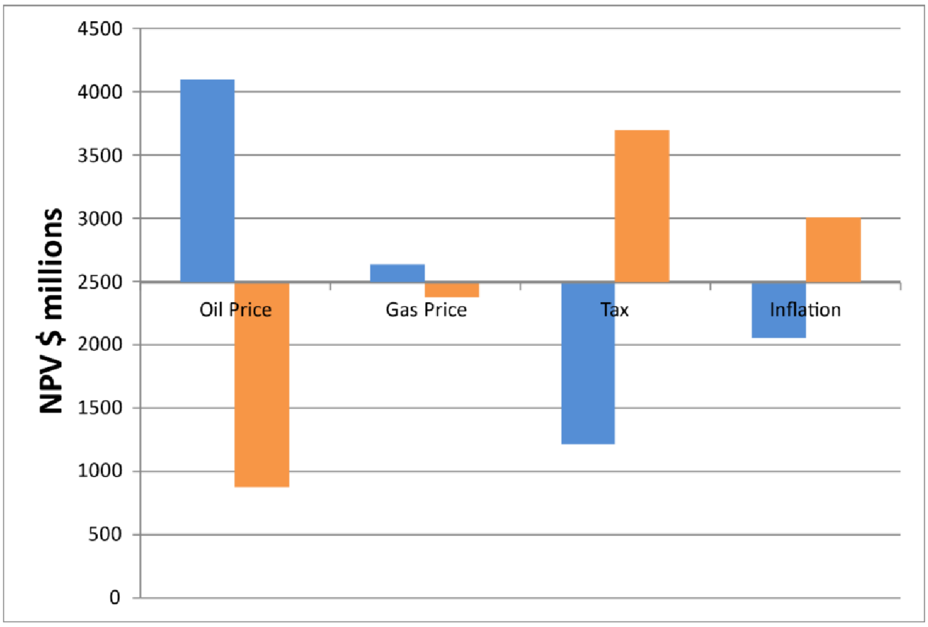


Figure 20 Inflation and tax.

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 Production profile of the field

This is a 20-year company production profile, as we can see in Figure 21. The initial production rate of the field was 12,000 bbl/day and the peak production was 82,200 bbl/ day. The plateau period was three years. Table 3 shows the data on production.

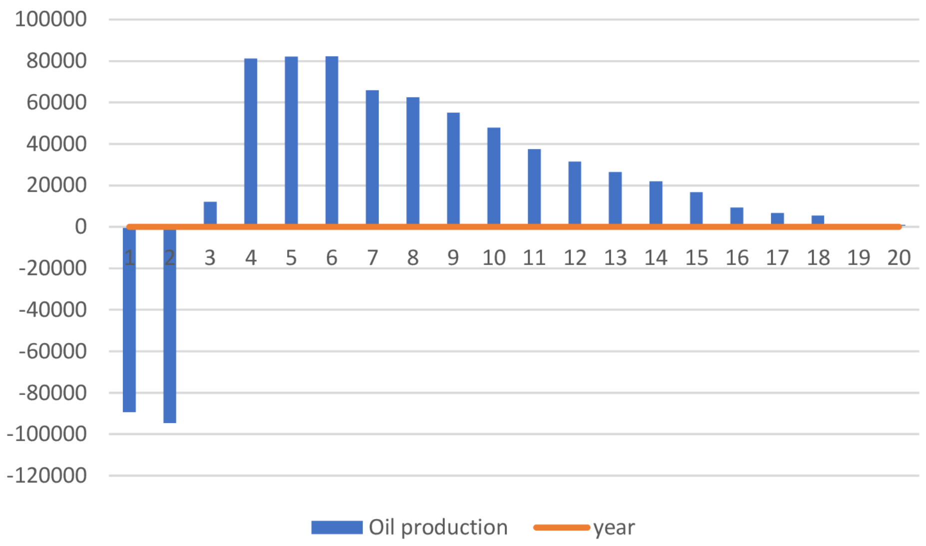


Figure 21 Field oil production.

Table 3 Data of production.

Oil Production bbl/day	Year
-89360	1
-94550	2
12000	3
81140	4
82120	5
82235	6
65890	7
62490	8
55150	9
47830	10

37460	11
31464	12
26460	13
21904	14
16750	15
9325	16
6687	17
5420	18
1100	19
980	20

6.5 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. A full investment profile can be found in the appendix.

6.6 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 22 demonstrates the major uncertainties in the development. The parameters with the greatest impact on NPV are the tax rate, discount rate, oil price, and recovery factor.

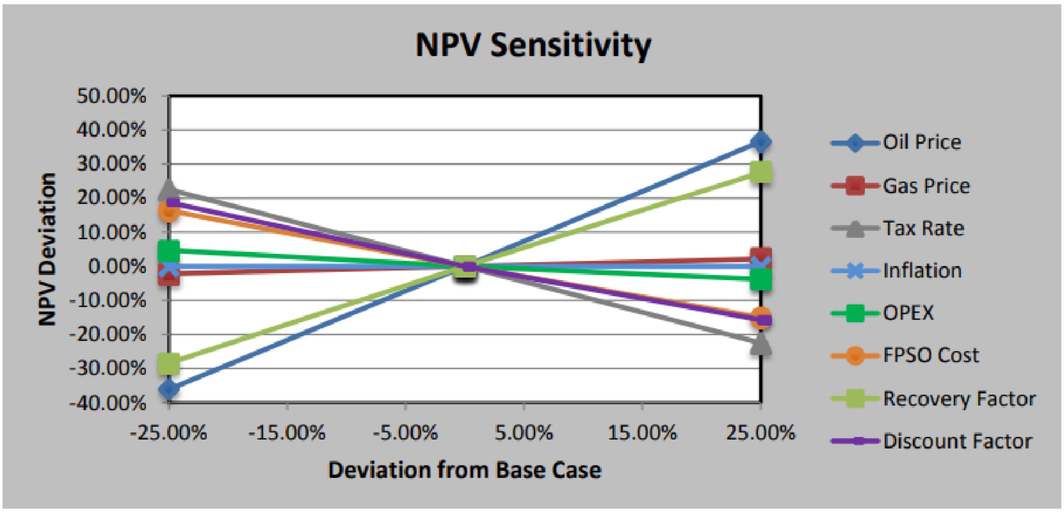


Figure 22 Spider diagram of uncertainties when calculating NPV.

The oil price and tax rate are outside of the company's control; however, the transport cost and recovery factor are within the control of the company. The company needs to pay particular attention to the recovery factor and the transport costs during contract negotiations. Any reduction in transport costs 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 23 shows oil price vs NPV.

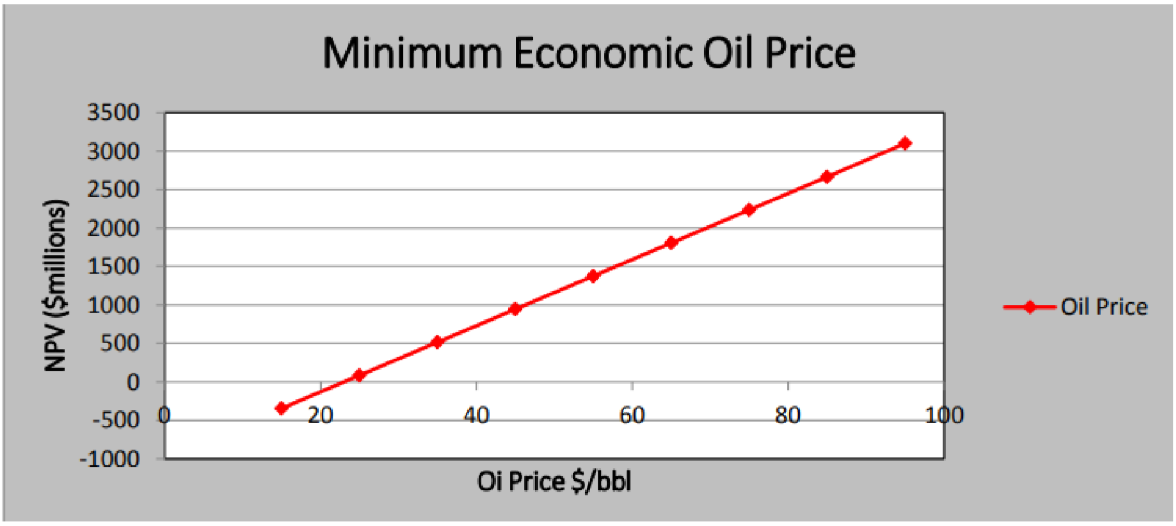


Figure 23 Minimum Economic Oil price.

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.

6.7 Project Parameters

While it is important to evaluate project parameters, it is equally important to assess them 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 minimise risk where possible. The cumulative cash flow curve. Figure 24 illustrates this. We have calculated the NPV using a 10% discount rate.

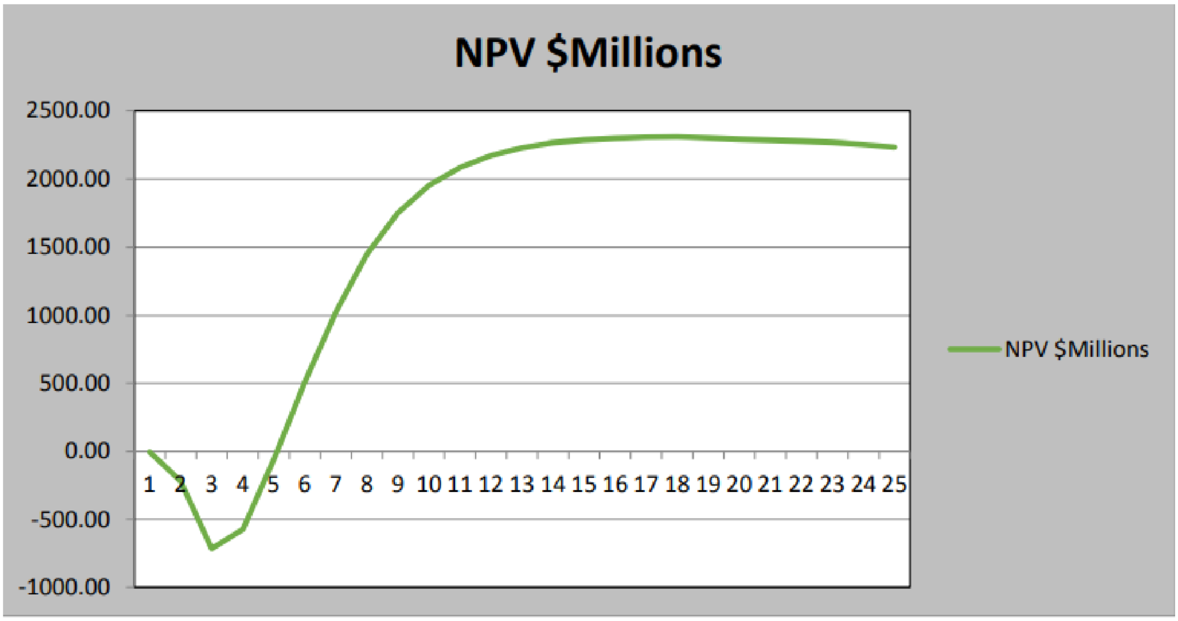


Figure 24 Cumulative cash flow discounted at 10%. The X axis is the year and the Y axis is Spending.

The NPV for this development is $2.2 billion 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 25 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.

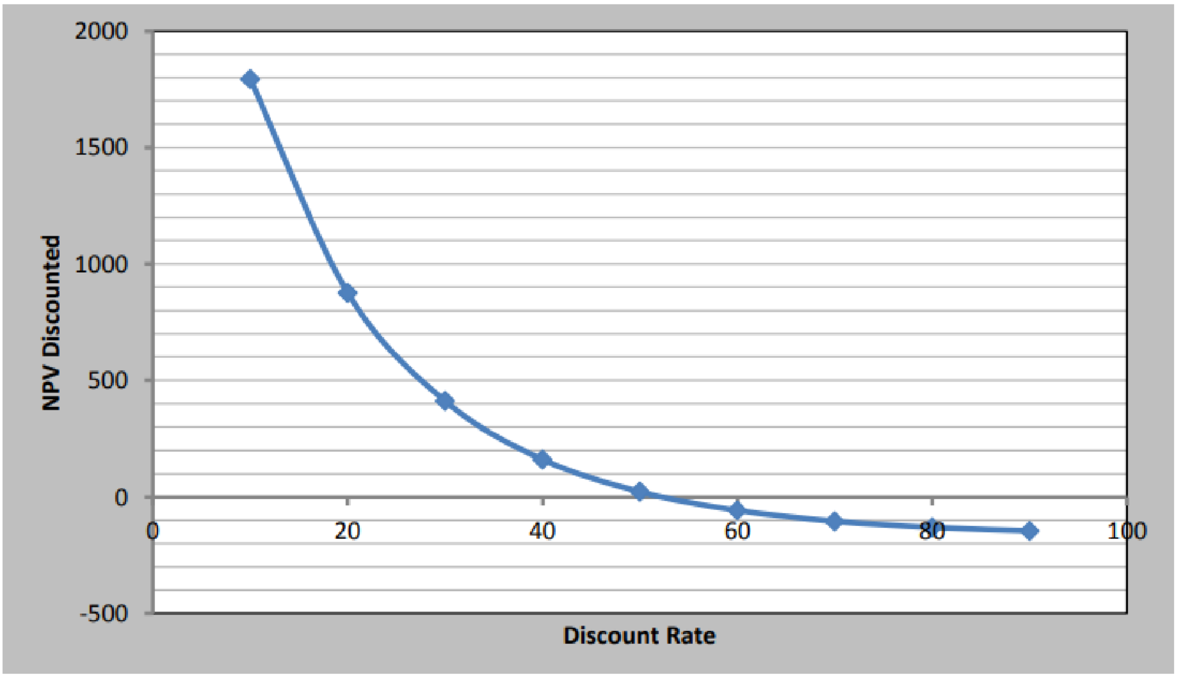


Figure 25 IRR and Discount factor which NPV is zero.

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Appendix 1: Source data for figures 18/20/22/23/24/25

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

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

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				

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