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PETROLEUM FISCAL REGIME ANALYSIS:
THE CASE OF MYANMAR OFFSHORE EXPLORATION AND PRODUCTION

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A Thesis Submitted in Partial Fulfillment of the Requirements

for the Degree of Master of Engineering Program in Petroleum Engineering

Department of Mining and Petroleum Engineering

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การศึกษาประสิทธิภาพของระบบภาษีปิโตรเลียม ของเมียนมาร์ในปัจจุบัน เพื่อให้คำแนะนำแก่รัฐบาล กรณีศึกษาในการพัฒนาแหล่งปิโตรเลียมนอกชายฝั่ง 4 กรณี ได้นำมาใช้ในการศึกษาโดยใช้วิธีจำลองสถานการณ์แบบมอนติคาร์โล แบบจำลองทางเศรษฐศาสตร์ในกรณีฐานใช้เพื่อหาระดับผลตอบแทนที่รัฐบาล และบริษัทผู้ลงทุนได้รับรวมถึงอัตราค่าภาคหลวงที่แท้จริง นอกจากนี้ได้ทำการปรับปรุงระบบภาษีปิโตรเลียม โดยใช้ระบบสัญญาอัตราผลตอบแทนเพื่อเสนอแก่รัฐบาล ผลจากการวิเคราะห์ตามกรณีศึกษา ช่วยในการสร้างสถานการณ์ ที่ทุกฝ่ายได้รับผลประโยชน์ โดยคำนึงถึงประสิทธิภาพของระบบภาษีปิโตรเลียมของเมียนมาร์ ตามระบบปรับปรุงที่ได้นำเสนอ

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The efficiency of the current Myanmar fiscal regime is in order to provide some recommendation to provide the Government. Four cases field development and production of Myanmar offshore concessionary blocks were studied by using the Monte Carlo simulation methodology. The base case economic model is identified the level of government take and Internal rate of return and Effective Royalty Rate (ERR) .Further more improve fiscal system, Rate of Return Contract system is introduced to the government. .As the results and analysis of case studies, in order to have win-win situations between government and contractor, the efficient Myanmar fiscal regime should be considered as improved fiscal system or rate of return contract .

Department: Mining and Petroleum Engineering.... Student's signature:..................

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CONTENTS

Chapter Page

Chapter Page

Chapter Page

Chapter Page

Chapter Page

LIST OF TABLES

LIST OF FIGURES

Page

Page

Page

NOMENCLATURES

DCF	discounted net cash flow
CF	cash flow
r	discount rate
n	total number of years
NPV	net present value
NCF	net cash flow
i	discount rate
y	year

CHAPTER I

INTRODUCTION

1.1 General

The right set of fiscal system in the petroleum exploration and production business is the balancing between attracting the partners and creating a good deal for the country. Typically a fiscal system might not provide sufficient encouragement to the investor. Analysis on any fiscal system should consider how effective to the government and how efficient to the investors. Obviously, petroleum fiscal system should be set up with suitable boundary conditions.

The economics of upstream petroleum business is complex and dynamic. Typical contract terms of the petroleum fiscal systems have bonus, work commitment, timing, relinquishment rules, guarantees, government participation, ring fencing, contract stability and special incentives etc. Some of the resources, in which host countries used more than one system so that contract terms are often negotiated and renegotiated as political and economic conditions change, or as better information become available.

Generally, there are three main types of petroleum fiscal regimes (M.A Mian, 2002);

1) Concessionary system(royalty and tax system)

2) Production sharing Contracts/Agreement (PSC/PSA)

3) Pure service contracts and risk service contracts.

Above contracts are between host government and international exploration and production company or international national exploration company. Some country's basic petroleum law acts all petroleum operations. Some countries have only petroleum agreement and foreign direct investment law .It means that there is no petroleum law but combination of those two things can work between government and contractor.

According to Myanmar fiscal system, basically the three types of block basis petroleum fiscal systems in Myanmar are as follows (Johnston. D, 1994);

(1) Reactivation of suspended field (RSF) system for marginal field development;

(2) Improve oil recovery (IOR) or performance compensation contract (PCC) and

(3) Production sharing contract (PSC).

Myanmar employs a production sharing contract (PSC-1989) system in oil and gas production licenses for offshore properties. In the traditional PSC system, the contractor pays a royalty, based on production and profitable petroleum, based on after cost recovery and one more taxes, based on taxable income. Normally, the royalty is the percentage of the gross revenues of sale of hydrocarbons and can be paid in cash or in kind. The revenue after deductible royalty, allowable all costs and profitable hydrocarbon to government that remaining revenue is called taxable income. After paid tax, net cash is flowing to the contractor and which is determined by discounted net cash flow.

Myanmar current offshore area has 28 blocks and 14 companies are working (Htoo, 2009). However only two existing production platform have been developed and producing and another two projects are developing in offshore area since fiscal regime started 1989. In this thesis, the focus is only on Myanmar offshore PSC. Current Myanmar offshore and onshore concessionaries block are shown in Figure 1.1 and Table 1.2.

Table 1.1 Current offshore Concessionary Blocks and Available Blocks

Shallow Blocks	Available Blocks
26	6
Deep water Blocks	Available Blocks
18	11

As mentioned above, the purpose of this thesis is based on the design issues of the current Myanmar petroleum fiscal system. The quantitative analysis of the petroleum fiscal regime among the ASEAN countries such as Vietnam, Bangladesh and Thailand has been carried out. By constructing the base case Economics model, cash flow analysis is used to evaluate division of project discounted net cash flow for deterministic analysis. Moreover, probabilistic analyses were performed. Finally, according to the results and analysis, improved fiscal performance method has to introduce to Government.

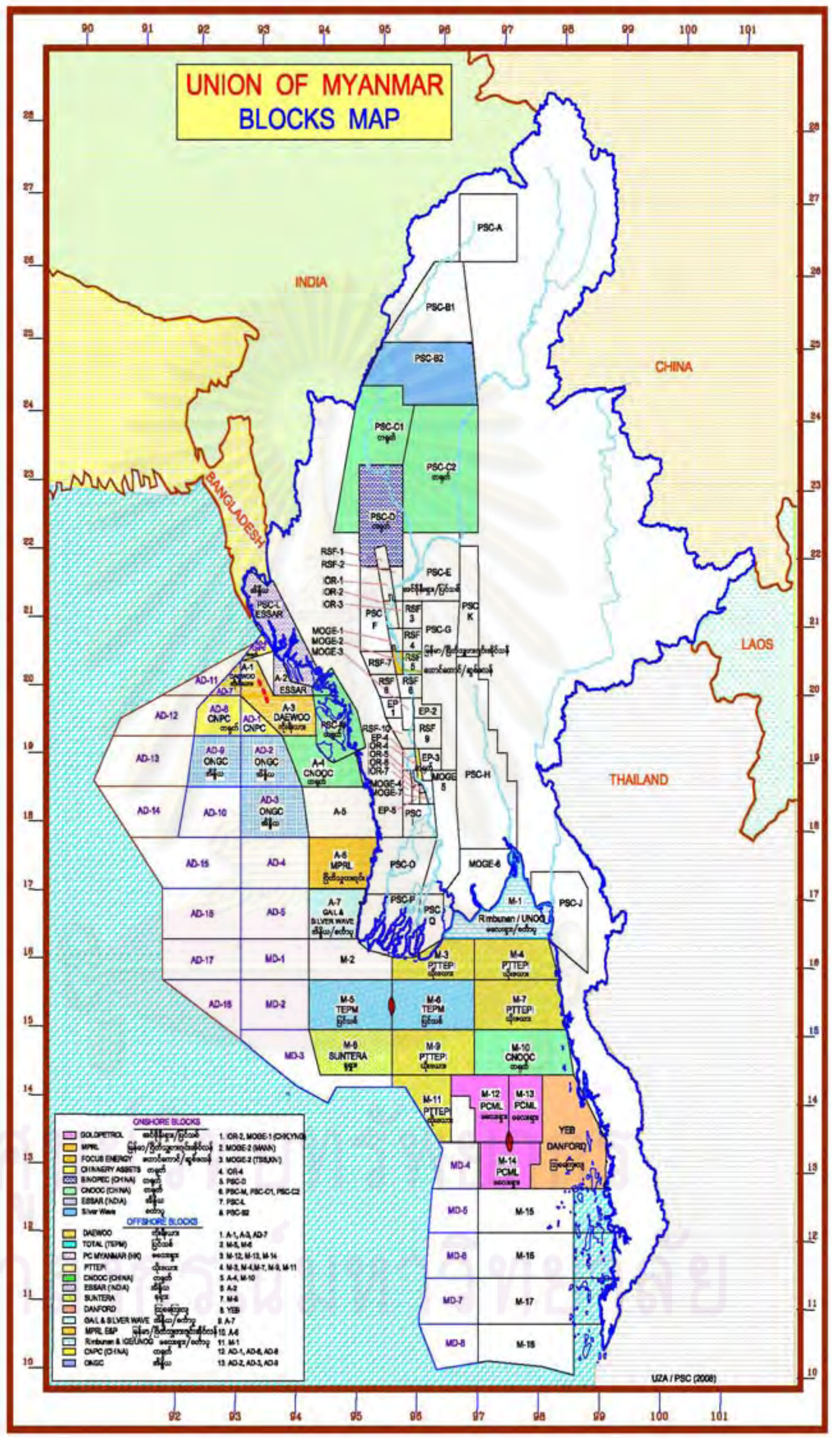

Figure 1.1 Myanmar offshore and onshore concessionary blocks

Table 1.2 Myanmar Current Offshore PSC Contract Blocks

Companies(operator)	Blocks
TOTAL	M-5,M-6(YADANA)
PETRONAS Carigali	M-12.M-13,M-14(YETAGUN)
DAEWOO	A-1(SHWE), A-3, AD-7
PTTEP	M-9,M-7,M-9,M-11
CNOOC	A-4,M-10
ESSAR	A-2
ZERUBEZHNEFT	M-8
DANFORD EQUITIES	YEB
MPRL E & P	A-6
SILVER WAVE ENERGY	A-7
UNOG	M-1
CNPC	AD-1,AD-6,AD-8
ONGC	AD-2,AD-3,AD-9

1.2 Objectives and scopes of study

The objectives and scopes of study are as follows:

1. To study on the description and analysis of current Myanmar Fiscal terms.

2. To investigate the economics analysis of hypothetical, representing exploration and field development possibility in Myanmar off shore.

3. To provide some insights for the policy recommendation to the government for decision making under risk regarding the appropriate fiscal regime.

1.3 Statement of purposes

As the results of deterministic analysis and probabilistic analysis, in order to have win-win situations between government and contractor, the efficient Myanmar fiscal regime should be considered as a new efficient fiscal design in such a way that is simple to apply and provide the contractor with a fair rate of return (ROR) on investment.

1.4 Outline of thesis

In this thesis, the chapter two reviews on all the related fiscal regime analysis literatures, such as fiscal severity and flexibility, cash flow analysis, economic indicators of net present value, internal rate of return. In addition, fiscal regime analysis tools of deterministic and probabilistic analysis related literatures are also reviewed. Moreover, quantitative analyses of fiscal regime among four countries are described. The chapter three presents the methodology for the evaluation of stochastic analysis and probabilistic analysis to complete the processes of fiscal regime analysis. In chapter four, components of Myanmar current fiscal regime are mentioned. The chapter five represents the results and analysis of the case studies of Myanmar offshore exploration and production fields. Improved fiscal system analysis on Myanmar regime is described in chapter six. In this chapter ROR contract model is used for implementation.

The chapter seven describes the recommendation for the new fiscal design and conclusions.

CHAPTER II

LITERATURE REVIEW

This chapter illustrates the literature review of this study. It presents the concept of petroleum fiscal regimes and its characteristics. In addition, it achieves the economics model of cash flow analysis. Furthermore, it introduces the methodology of deterministic analysis and probabilistic analysis. Moreover, quantitative analyses of fiscal regime among four countries are described. Finally, improve methodology of rate of return contract system is introduced to the Myanmar offshore petroleum fiscal regime.

2.1. Literature Review

A petroleum fiscal system or fiscal regime refers to all the payments, including bonus, rentals, royalties, production sharing arrangements, carried interest provisions, corporate income taxes and special taxes, to government required under a petroleum arrangement which was proposed by C.Khelil(1995) and M.A.Mian(2002).

The flexible and enough fiscal regimes were economically encouraged to the contractor. In other words, contractor's NPV before government take rewards the contractor's NPV after its takes efficient fiscal regime .The descriptions and analysis were provided by M.A.Mian(2002) and W.Hou(2009).

In 2008, W.Hou and W.G, Allison analyzed the flexibility of the China fiscal terms and competitive studies of fiscal regime in terms of severity and flexibility as comparison of Asia Pacific Region. Comparison of Asia Pacific Region indicated that China offshore fiscal regime is less insufficient than most of other regimes.

Daniel Johnston (1994) and M.A.Mian(2002) illustrated about the mechanics of the various kinds of fiscal systems that factors driving exploration economics. The analyses are on practical aspects of petroleum taxation and contractor / government relationships.

In 2004, Mark J.Kaiser and Allan G.Pulsipher reported to use a Meta-Modeling Methodology for constructing functional relations that described how the system variables interact and impact the fiscal system measures. The fiscal terms and parameters of a contract impact system measures are complicated. The result showed that a constructive model approach to fiscal system analysis was developed to isolate variable interaction and determine the manner in which private and market uncertainty impact take and the economic measures associated with a field.

Venugopal, S. (2005), Wood, D. (2008) and W.hou (2009) provided the sensitivity analysis of fiscal models .They analyzed the economic performance and fiscal contributions of hypothetical gas and oil fields.

Venugopal, S. (2005) ,Eliana L.Ligero, S., Fernanda V.Alves Risso, SPE, and Denis J. Schiozer, SPE, UNICAMP (2007) and W.hou (2009) presented that the economic indicator of NPV has been carried out by Monte Carlo Simulation. They determined measures of accuracy and precision of NPV and these predictions were compared with deterministic measured values.

D.R.Hallermann(1994), Rovicky Dwi Putrohari, A. K., Heri Suryanto,Ida Marianna Abdul Rashid (2007) ,T. Dharmadji, T. Parlindungan (2002) and W.hou (2008) published the comparative studies of fiscal regimes countries. They analyzed the flexibility and severity of each country.

The poor fiscal system will give more to the contractor at the expense of the host government or vice visa. In order to get win-win situation, fiscal regime should be considered as a new efficient fiscal design in such a way that it is simple to apply and provide the contractor with a fair rate of return (ROR) contract method provided by M.A. Mian(2010).

In the literature review of this study, it can be seen that most of the reviewed fiscal regime flexibility and efficiency. It is necessary to evaluate or analyze the fiscal regime analysis. In the review of deterministic analysis of economics cash flow model, it was evaluated with existing field data. But, it is necessary to evaluate for sensitivity analysis. Then, it will also be improved for its accuracy.

CHAPTER III

METHODOLOGY

3.1Methodology

In this thesis, the objective is to analyze the fiscal regime severity, flexibility and efficiency to the contractor point of view. This thesis presents the two methods of analyses. The first method is deterministic analysis and the second one is probabilistic analysis.

3.2 Petroleum Fiscal Regime Characteristics

As mentioned in chapter one, typically three main types of petroleum fiscal regimes are typically used all over the petroleum resources own countries. Whatever differences in all of systems, the main feature is its simplicity. The complicated fiscal system and its agreements usually disintegrate when unexpected events occur. In other words, the more simple rules are easier to manage and more efficient to implement and audit. Moreover, another feature is flexibility; the negotiate ability of government and contractor. In conclusion, efficient and flexibility features designing of both of fiscal system's financial outcome will be the same.

3.2.1 Government Take/Contractor Take

Government Take is the total amount of government received through signature bonus, production bonus, royalty, petroleum profit sharing and income tax. State participation is not included. Typically, Government Take is the largest component of net cash flow during the productive life of a field. In typical, during the production life, government takes royalty, after cost recovery profit sharing and income tax. In other words, government take is gross revenue less total recoverable project costs and contractor's net cash flow. Government Take as percentage is total government take revenue which is divided by government take and contractor's net cash flow (NCF) before take NPV. It can be seen clearly in mathematical expressions,

Government Take = Royalty +Profit Petroleum+Income Tax

(Or)

Government Take = Gross Revenue-Project Costs-Contractor NCF

$$\text{Government Take as a percentage} = \frac{\text{Government Take}}{(\text{Contractor NCF} + \text{Government Take})}$$

Contractor Take is the total amount of gross revenue after government take and project costs. In mathematical expression,

Contractor Take as a percentage = 1- Government Take as a percentage

3.2.2 Fiscal Severity or efficiency

The term fiscal severity is measured by government take highly profitable with before government take net present value (NPV) of the project over contractor's NPV. Generally, it can be seen clearly in progressive or regressive regime.

3.2.2.1 Progressive Regime (efficient)

The percentage of governments' take of the project is increase as profitability of the project increase.

3.2.2.2 Regressive Regime (inefficient)

The percentage of governments' take of the project is as high as beginning of the small or marginal project which makes a negative NPV to the contractor.

Figure 3.1 shows that the definitions of progressive and regressive regimes of the project NPV. In the figure, the smooth line (progressive) of government take is less in low NPV of the project and the dotted line (regressive) of government take is too much in low NPV of project. This fact can be hurt to contractor.

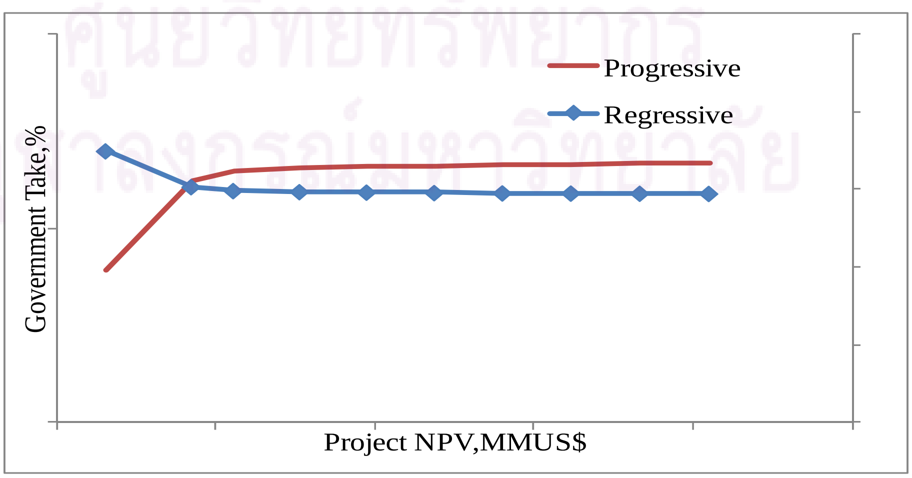

Figure 3.1 Illustration of progressive & regressive

3.3 Economics Indicators

Typical economic model generate cash flow, discount cash flow, net present value (NPV) and internal rate of return (IRR), effective royalty rate (ERR) and project net cash flow.

3.3.1 Gross Revenue

In an Exploration and Production (E&P) project, Gross Revenue is obtained from the sales of petroleum. It is calculated by multiplying the petroleum production in each year and the price for the certain product.

3.3.2 Project costs

Project costs in (E&P) project, usually exploration costs are spent before a development take place. It is referred to capital costs. Development costs are also incurred at the beginning of a project. These are sometimes referred to as capital costs. Operating costs occur periodically and are necessary to maintain production from the field. They are usually small, compared to the initial capital costs. Abandonment costs are a special category of capital expenditure associated with making good or abandoning an oil or gas field at the end of field life once it has become uneconomic to continue producing process.

In general, the first large components of cash flow are the initial capital expenditures spent in the first two or three years of a project life before initial production. After production starts, the company will receive gross revenue from the sales of petroleum. Annual operating costs are usually small compared with capital costs. The largest component of cash flow during the productive life of a field is government take, which is the net cash flow that goes to the government. The remaining costs are abandonment costs. Usually these are incurred at the end of field life when it is no longer economic to continue production. The remaining revenue is the contractor's net cash flow. This cash is free for contractor to spend on other projects or add to monetary reserves. The contractor's net cash flow is the basis on which contractor determines the feasibility of a project and the attractiveness of the investment.

3.3.3 Cash flow (CF)

Cash Flow is the movement of cash into or out of a project. It is usually measured during a specified, certain period of time.

3.3.4 Net cash flow (NCF)

Net cash flow (NCF) is the total cash into a project less than the total cash out of a project during the period. In other words, total amount of gross revenue deducts all costs and all of payable outcome, such as bonus, royalty, profit petroleum and income tax to the government, called net cash flow. The total expenditures include exploration costs, development costs, operating costs, abandonment costs and Government Take.

In general,

Net Cash Flow = total cash received into the project

Less

total cash expended the project

	(Or)	
Net Cash Flow	= Gross revenue of the project	
	Less	
	total cash expended the project	

3.3.5 Discounted cash flow (DCF)

Discounted cash flow (DCF) analysis is a method of valuing a project, using the concepts of the time value of money. All future cash are estimated and discounted to give their present values (PVs) – the sum of all future cash flows, both incoming and outgoing, is the net present value (NPV), which is taken as the value or price of the cash flows in question.

Calculated as:

$$DCF = \frac{CF_1}{(1+r)^1} + \frac{CF_2}{(1+r)^2} + \frac{CFn}{(1+r)^n} \qquad (3.1)$$

Where: CF= Cash Flow

r=Discount rate

3.3.6 Net Present Value (NPV)

Net Present Value (NPV) is traditional economic indicator to determine the results of economic analysis. An NPV is the present value of a net cash flow occurring sometime in the future. It measures how much a project is worth compared with an alternative investment. NPV is calculated by adding together the discounted net cash flow (NCF) in each year of project life. The equation of NPV is shown below.

$$NPV = \sum_{y}^{n} \frac{NCF_y}{(1+i)^y} \tag{3.2}$$

Where: y = Year "y"

n = Total number of years of NCF

i = Discount rate

If NPV indicates a positive, a project is economic, and the higher the NPV value, the more profitable and desirable the project.

3.3.7 IRR

IRR, internal rate of return is defined as the discount rate that makes the net present value of all cash flows from a particular project equal to zero. So, to find the internal rate of return is meaning that to find the discount rate that makes the following equation is equal zero: where NPV=0 and i = IRR or the discount rate that makes NPV=0.The higher the internal rate of return of the project, the more acceptable it is to pledge the project.

3.3.8 Rate of return contract

Rate of return contract is a one kind of petroleum agreement between government and contractor. Typically, it is truly progressive system and base on profitability; include cost, income and time.

3.3.9 Effective Royalty Rate (ERR)

Effective Royalty Rate (ERR) is total amount of government take without adding income tax divided by gross revenue in the giving accounting period. It means that combination of royalty and profit petroleum is divided by gross revenue. It is a measurement of front-end loaded system. In this system there is no government participation in working interest.

3.3.10 Access to gross Revenue (AGR)

Access to gross Revenue (AGR) is the complement of ERR.AGR is maximum share of revenues that can receive by contractor's working interest.

3.4Deterministic Analysis and sensitivity analysis

A quantitative deterministic analysis can perform single-point estimates, or is deterministic in nature. An Exploration and production project has a lot of uncertainties, such as oil and gas prices, capital costs, production profiles and sometimes fiscal regimes. In those of risk and uncertainty have been carried out by sensitivity analysis. Sensitivity analysis is to evaluate the effects of changes in each input variable. Sensitivity analyses involve varying one input variable within a certain range with other variables remain unchanged. The results of a sensitivity analysis illustrate the impact of the uncertainty of each input variable on the profitability of a project. Using this method, an analyst may assign values for discrete scenarios to see what the outcome might be in each. In an economic model, an analyst commonly examines three different outcomes: worst case (lower), best case (higher), and most likely case (base case).

3.4 Probabilistic Analysis

A better way to perform quantitative probabilistic analysis is by using Monte Carlo simulation. In Monte Carlo simulation, uncertain inputs in a model are represented using ranges of possible values known as probability distributions. By using probability distributions, variables can have different probabilities of different outcomes occurring. Probability distributions are a much more realistic way of describing uncertainty in variables of a risk analysis.

In probability distribution, two types of distributions functions are as follows;

3.4.1 Probability Density Function (PDF)

Probability Density Function (PDF) is a continuous random variable (X) which takes on a value in specified interval. It can be seen by determining the corresponding area under its probability density function F(x).The value of F(x) means probability function at x. An example of PDF is as shown in Figure 3.2

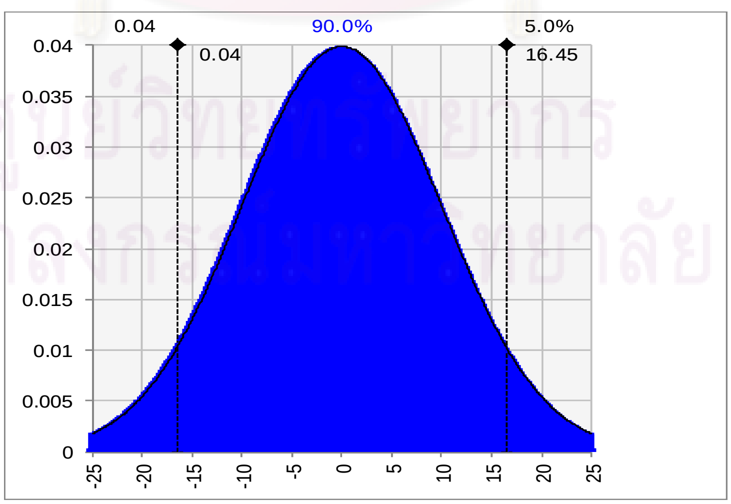

Figure 3.2 Example of PDF

3.4.2 Cumulative Density Function (CDF)

Cumulative Density Function (CDF) is the corresponding curve of probability density function. The function is normally denoted by F(x).The CDF indicates the probability that the outcome of X in a random trial which will be less than or equal to any specified value of x. An example of PDF is as shown in Figure 3.3.

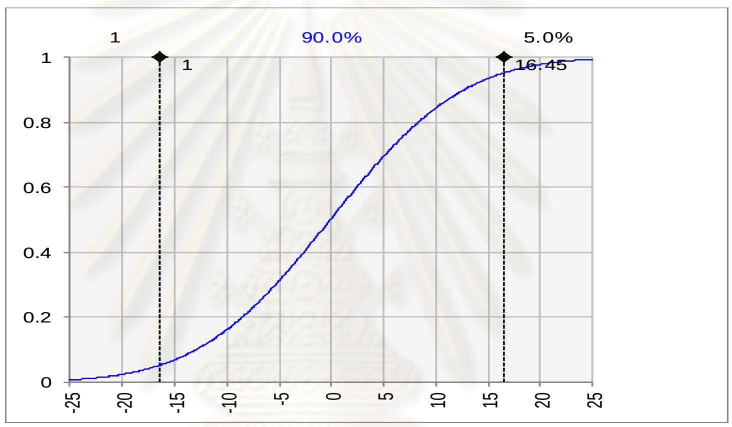

Figure 3.3 Example of CDF

In general, Common probability distributions include:

3.4.3 Normal Distribution

Normal Distribution is the mean or expected value and a standard deviation are to be described the variation about the mean. Values in the middle near the mean are most likely to occur. Examples of variables described by normal distributions include inflation rates and energy prices. An example of normal distribution's PDF and CDF are shown in Figure 3.4.

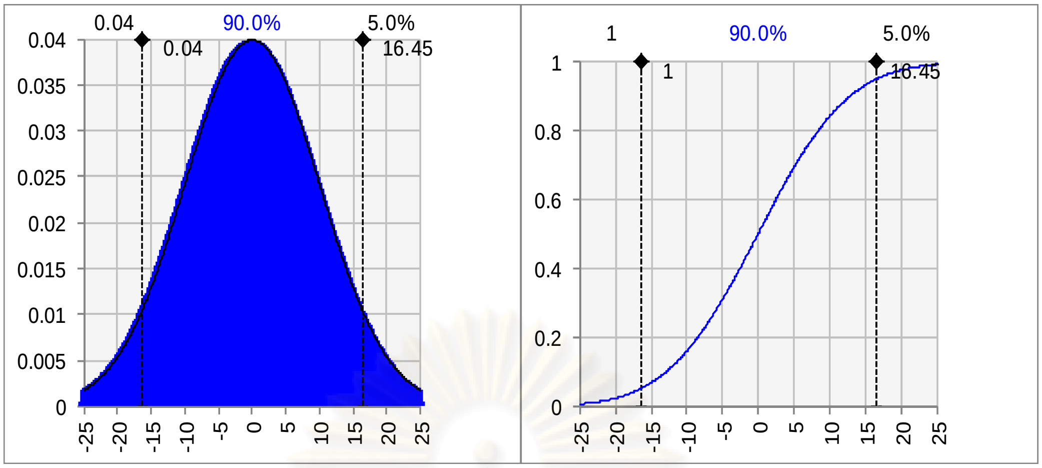

Figure 3.4 PDF (left) and CDF (right) of normal distribution

3.4.4 Lognormal Distribution

Lognormal Distribution values are positively skewed, not symmetric like a normal distribution. It is used to represent values that don't go below zero but have unlimited positive potential. Examples of variables described by lognormal distributions include oil and gas reserves. . An example of lognormal distribution's PDF and CDF is shown in figure 3.5.

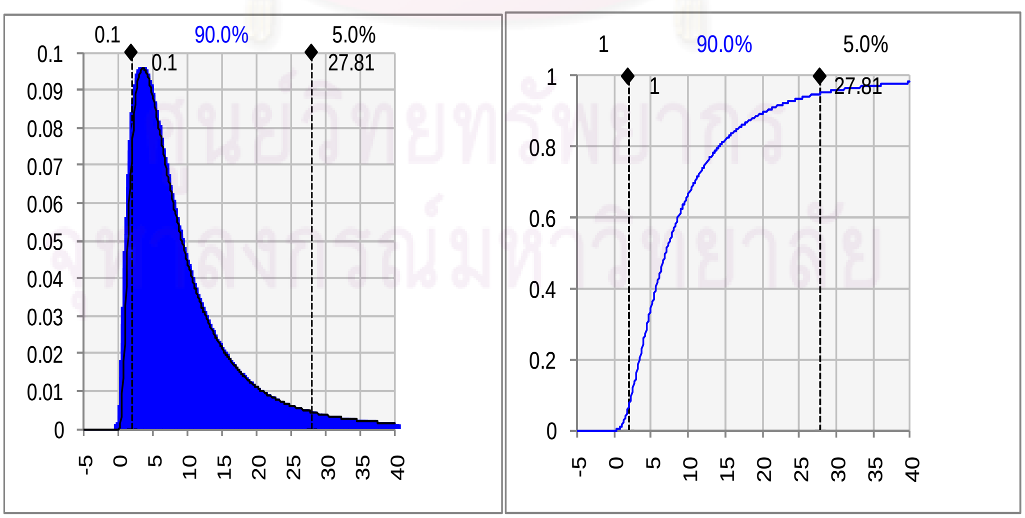

Figure 3.5 PDF (left) and CDF (right) of lognormal distribution

3.4.5 Uniform Distribution

Uniform Distribution defines that all values have an equal chance of occurring, and it can be simply defined the minimum and maximum. . An example of normal distribution's PDF and CDF are shown in figure 3.6.

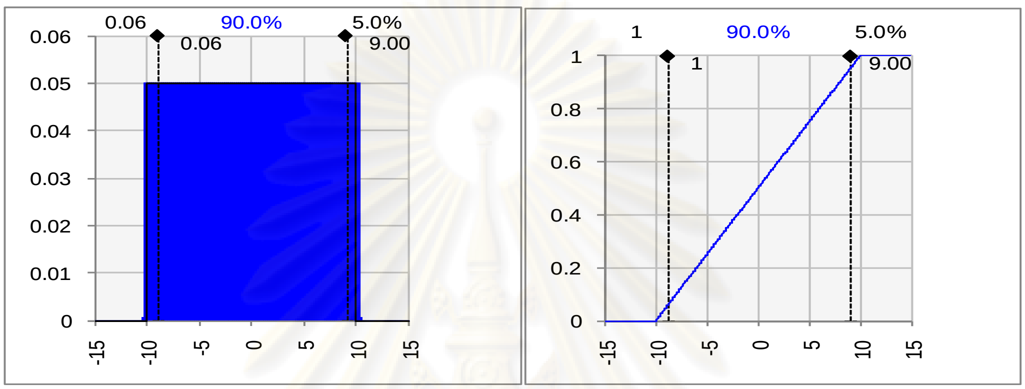

Figure 3.6 PDF (left) and CDF (right) of uniform distribution

3.4.6 Triangular Distribution

Triangular Distribution is the minimum, most likely, and maximum values. Values around the most likely are more likely to occur. If the information of data is not enough, the triangular distribution is used. . An example of normal distribution's PDF and CDF is shown in Figure 3.7.

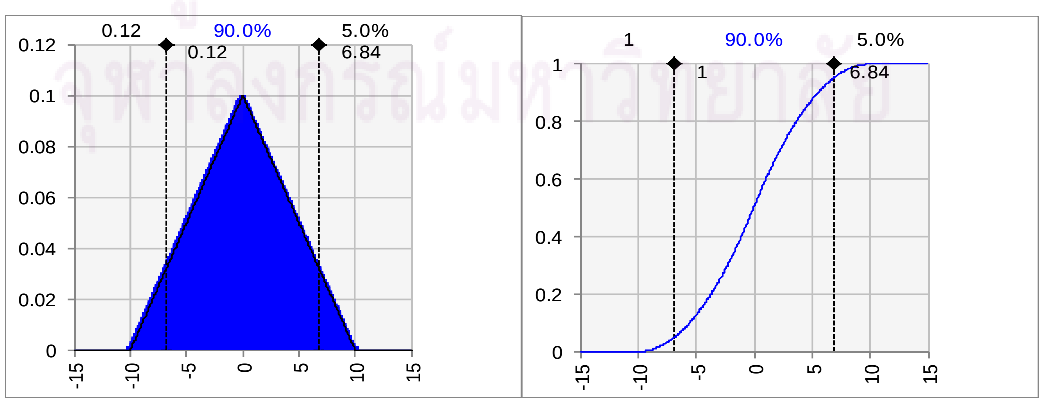

Figure 3.7 PDF (left) and CDF (right) of triangular distribution

3.4.7 Monte Carlo Simulation

The Monte Carlo method has two requirements. The first is a mathematical model. Secondly understands of the CDF's of the variables to be input into the mathematical model. When the CDF's are known, each variable needed in the model is randomly sampled and the model is used to calculate the unknown quantity. This process, known as a trial, is repeated many times until a sufficient number of trials have been made to create a distribution of the unknown quantity. The process of performing an adequate number of trials is called a Monte Carlo simulation.

The software package @Risk will be carried to perform the Monte Carlo calculations after defining the selected input variables by probability distributions and selecting an output, the Monte Carlo Simulation to determine the probability distribution of the output. For each run of simulation, output is NPV and input is selected at random. The result of probability distribution of NPV reflects the probability distribution of the input variables.

3.5 Assumptions

In the economic model, mainly two types of assumptions are used in this thesis analysis. In this study, before going to input in economic model all types of assumptions have to be done by sensitivity analysis. The summaries of assumptions were shown in Table 3.1.

3.5.1 Economics Assumptions

In the analysis, some of necessary assumptions were as follows;

3.5.1.1 Price (Gas/Condensate)

Actually Gas project has been calculated by variable gas price [1] formulae(Appendix A),but in this analyses year one gas price was used by historical gas price of 1998 .In addition, natural gas transportation operation has been omitted in this analyses. Since, Myanmar fiscal regime gas price is based on wellhead price, gas price for fiscal regime analyses was generated only with wellhead price. In the case of Yadana and Yetagun gas fields, base case wellhead gas price for year one was 2 US$/MMBTU in year 1998 and escalation rate 4% per year was starting from year 1999.For sensitivity analysis, 50% higher (3US$/MMBTU) and 50% lower (1US$/MMBTU) price were used. For Zawtika and Shwe gas fields, assuming base case wellhead gas price for year one would be 6 US$/MMBTU in year 2013 and escalation rate 4% per year will be starting from year 2013.For sensitivity analysis, 50% higher (9 US$/MMBTU) and 50% lower (3US$/MMBTU) price have been used. For Yetagun condensate, historical price 25 US$/BBL was used.

3.5.1.2 Escalation and Inflation

Exploration costs, development costs and operating costs escalation rate were 3% per year. Escalation rate 3% was started from the year of exploration phase. The escalated costs were accurate with sensitivity analysis. According to Asian Development Outlook 2009, Myanmar average inflation rate is about 30%/year [2].

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[1] Actual Myanmar current gas price formula is shown in Appendix A.

[2] *Sources*: Myanmar Central Statistical Organization, available: www.csostat.gov.mm, downloaded 27 February 2009;

Whatever the inflation rate is as high as 30%/year, all of oil and gas field machinery and products are imported for oil and gas project. So In this thesis, reasonable escalation rate 3% is used. Myanmar historical inflation rate were shown in Table 3.1.

Table 3.1Myanmar Historical Inflation

Myanmar Historical Inflation	
Year	(%)
2002	58.1
2003	24.9
2004	3.8
2005	10.7
2006	26.3
2007	32.9
2008	26.4

3.5.1.3 Discount rate

10 % discount rate was used for calculating the project NPV and contractor after take net cash flow. Typical oil and gas company used nominal 10% rate.

3.5.2 Costs Assumptions

Explorations costs and development costs were assumed to be used by the cost estimating formula. This information was based on real data and rule of thumb typical oil and gas investor's assumptions.

For hypothetical field analyses, peak production rate and field development costs were related to existing field in the same region. Peak production rate is directly related with field sizes. For details calculating formula as follows;

Project Costs = Known Development costs *(X MMCFD/Known peak rate) ^ 0.7[3]

[3] W.hou (2009) used this formula for hypothetical case analysis of China oil and gas field.

Table 3.2 Summary of Assumption

Items	Assumptions
Water Depth	600 ft <
Gas Price (Yadana,Yetagun)	2 US$/MMBTU
Gas Price(Zawtika,Shwe)	6 US$/MMBTU
Condensate(Yetagun)	25 US$/BBL
Discount Rate	10%
Gas Price Escalation	4%
Exploration, operating, abandonment costs Escalation	3%
Operating Costs	5%/year of Capital costs
Abandonment Costs	5% of Capital costs

CHAPTER IV

COMPONENTS OF CURRENT MYANMAR FISCAL SYSTEM

4.1 Over view of Current Myanmar Production Sharing Contract

This study contains a description and analysis of PSC terms which are believed to be typical of current agreements. A detailed description of the structure and components of these typical PSC (Christie, A, 2000) provisions follows;

Foreign investment in Myanmar oil and gas generally follows the Indonesian model and which is by way of a Production Sharing Contract (PSC).

In addition to the incentives granted under the FIL (Foreign Investment law) and, the following incentives are usually included in the terms of the PSC:

(i) Exemption of duties on the import of petroleum/gas industry-equipment and materials;

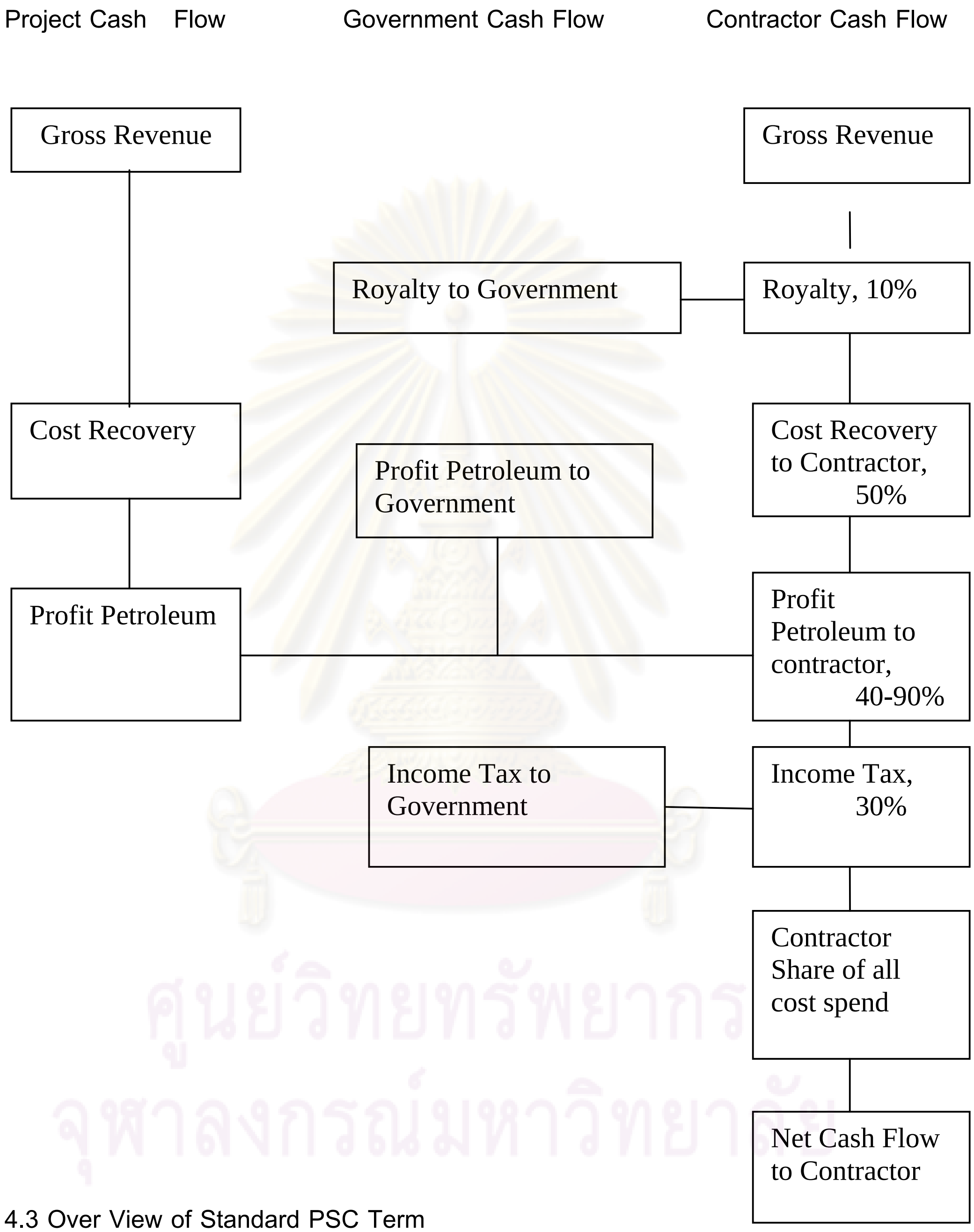
(ii) No export duty is levied on the export of petroleum/gas;

(iii) Negotiated rates of accelerated depreciation;

(iv) Domestic market supply required is satisfied by taking production/priced at not too far below fair international market value; and

(v) A re-negotiation or "stabilization" clause which allows necessary adjustments in the event of situations arising not envisaged in the original contract.

4.2 Structure of Myanmar PSC



4.3 Over View of Standard PSC Term

Some of the major provisions of the standard Off-Shore PSC are highlighted below. However, it should be noted that PSC terms are not rigidly fixed and are generally negotiable.

4.3.1 Commercial Discovery

Commercial Discovery is defined to mean discovery in the contract area of an accumulation or accumulations of Petroleum (which is defined to include both crude oil and natural gas and related condensates) which the Contractor decides to develop and produce.

4.3.2 Term

The exploration period consists of an initial term of up to three years and may be extended by the Contractor for up to two (and possible more) one year extensions, provided that it has fulfilled its obligations under the PSC up until that date.

The development and production period commences on notice of Commercial Discovery and continues for at least twenty years from the date of completion of the development phase.

4.3.3 Relinquishments

If the Contractor elects to enter into the first extension of the Exploration Period, the Contractor must relinquish 25% of the Contract Area (excluding Discovery Areas and Development Areas) at the time of such extension.

4.3.4 Surrender

The Contractor may at any time relinquish all or any part of the Contract Area and any such relinquishment is credited toward any subsequent relinquishment obligations.

4.3.5 Expenditure Commitment

Minimum expenditure commitments for the initial Exploration Period and any extensions (including seismic data collection) are included. These are specific to each PSC and are as negotiated.

4.3.6 Cost Recovery

The Contractor may recover all operating costs and expenses up to and out of a maximum of 50% of all available Petroleum from the Contract Area; provided, however, that costs in respect of any development and production area shall be recovered only from Petroleum, produced from such development and production area as well as costs of exploration shall be recoverable from "Available Petroleum", produced from any development and production area.

4.3.7 Production Sharing/Profit Sharing

Available Petroleum, not taken for payment of royalty of or cost recovery is to be allocated as follows;

Crude Oil	Government	Contractor
Up to 25,000 barrels per day	60%	40%
Between 25,000 and 50,000 barrels per day	70%	30%
Between 20,001 and 100,000 barrels per day	80%	20%
Between 100,101 and 150,000 barrels per day	85%	15%
In excess of 150,000 barrels per day	90%	10%

Natural Gas	Government	Contractor
Up to 300 MMCFD	70%	30%
Between 301 and 600 MMCFD	75%	25%
Between 601 and 900 MMCFD	85%	15%
In excess of 900 MMCFD	90%	10%

4.3.8 Income Tax

The Contractor is required to pay tax, subject to any holiday or concessions granted under the FIL, on the Contractor's net profit attributable to the Petroleum allocated to the Contractor (excluding cost recovery Petroleum).

4.3.9 Royalty

The Contractor must pay a royalty in cash or in kind, at the option of the Government, of 10% of the value of Available Petroleum from the Contract Area. The royalty is not recoverable from the Cost Petroleum.

4.3.10 Data Fee/Signature Bonus

The Contractor must within twenty days after Effective Date, pay a negotiated data fee/signature bonus, which is not recoverable from the Cost Petroleum.

4.3.11 Production Bonus

The Contractor is required to pay the following bonuses:

(a) US$ 1,000,000 upon approval of the Development Plan;

(b) US$ 2,000,000 when average daily production reaches 10,000 barrels per day;

(c) US$ 3,000,000 when average production reaches 30,000 barrels per day;

(d) US$ 4,000,000 when average production reaches 50,000 barrels per day;

(e) US$ 5,000,000 when average production reaches 100,000 barrels per day; and

(f) US$ 10,000,000 when average production reaches 200,000 barrels per day.

Production bonuses paid are not recoverable from the Cost Petroleum.

4.3.12 Domestic Crude Oil Requirement

The Contractor's obligatory share of the domestic market obligation will be in the proportion that the Contractor's entitlement to Crude Oil bears to all crude oil produced in Myanmar, up to 20% of the crude oil allocated to the Contractor. The price Government pays the Contractor for such oil is the equivalent of US$ 1.00 per barrel.

4.3.13 Participation

Government has the right to a 15% undivided interest in the rights and obligations of the Contractor under the PSC, in which right generally lapses unless it is exercised within three months of the discovery of Petroleum.

4.4. Quantitative analyses of Myanmar fiscal regime other than Thailand, Bangladesh and Vietnam

The Natural gas reserves of Thailand, Bangladesh and Vietnam countries are likely the same as Myanmar Natural gas reserves, referring to EIA report (see Table

4.1)[4]..According to the sources of reserves, the newest data of oil and gas journal given by geological nature of Bangladesh has the lowest Natural gas reserves of those countries. Vietnam, Myanmar and Thailand are increasing order of their reserves. Even though, those countries are situated in same region. So, the investment costs are assumed to be the same. So, those countries were selected for comparison analysis.

Table 4.1.The Summary of Natural gas reserves of Myanmar, Thailand, Bangladesh and Vietnam.

Country/Region	Natural Gas (Trillion Cubic Feet) BP Statistical Review Year-End 2007	Natural Gas (Trillion Cubic Feet) CEDIGAZ January 1, 2008	Natural Gas (Trillion Cubic Feet) Oil & Gas Journal January 1, 2009	Natural Gas (Trillion Cubic Feet) World Oil Year-End 2007
Bangladesh	13.77271836	13.20781	5	Not Separately Reported
Burma (Myanmar)	21.189	21.189	10.000	14.960
Thailand	11.654	11.195	11.198	11.198
Vietnam	7.769	7.769	6.800	8.200

For fiscal regime qualitative analysis, fileds size, project life 25 years, production plateau 10years and decline after 10years plateau. Other economics assumption were used to be same as all countries.

In the fiscal regimes, bonus and signature fees are compared to relatively small with other costs .So in this analysis , those parts are omitted. In addition, the effect of state participation were not included in these analyses. The Fiscal regime summary of Vietnam, Thailand and Bangladesh were mentioned in Table 4.3.

[4] For more information about reserves, go to the World Proved Reserves of Oil and Natural Gas and Crude Oil Price, Energy Information Administration (EIA) site http://www.eia.doe.gov/emeu/international/gasreserves.html downloaded 27 February 2010.

4.4.1 Assumptions

In the economics analyses for comparison gas field assumptions, all fields were assumed to be less than 600 ft shallow water gas field and no condensate production. In addition, it is assumed to be contractor holding 100% of the project. Summary of assumption was shown in Table 4.2.

4.4.1.1 Economics Assumptions

(1) Gas Price

Assuming base case wellhead gas price for year one would be 6 US$/MMBTU in year 2013 and escalation rate 4% per year will be starting from year 2013. According to the Myanmar Gas Price formula, the most sensitive part is fuel oil price. So, in this analysis, gas price escalation rate is used as 4%.The sensitivity of Myanmar gas price is shown in Figure 4.1.

(2) Escalation and Inflation

Exploration costs, development costs and operating costs escalation rate were 3% per year starting in 2013.

(3) Discount rate

10 % discount rate was used for calculating the Project NPV and contractor after take net cash flow.

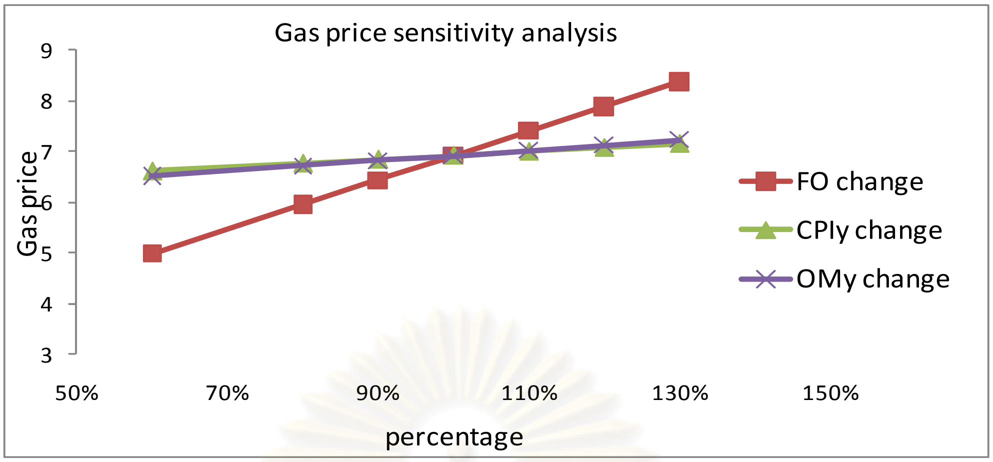


Figure 4.1 Myanmar gas price formula sensitivity analyses

4.4.1.2 Costs Assumptions

Explorations costs and development costs were assumed to be in the 2005 based on real information. Operating costs 5% /year and abandonment costs 5% of development costs. This information was based on real data and rule of thumb typical oil and gas investor's assumptions. For hypothetical field analyses, peak production rate and field development costs were related to existing field in same region. Peak production rate is directly related with field sizes. For details calculating formula as follows;

Project Costs = Known Development costs *(X MMCFD/Known peak rate) ^ 0.7

Table 4.2 Summary of Assumption

Items	Assumptions
Water Depth	600 ft <
Gas Price	6 US$/MMBTU
Discount Rate	10%

Gas Price Escalation	4%
Exploration, operating, abandonment costs Escalation	3%
Operating Costs	5%/year of Capital costs
Abandonment Costs	5% of Capital costs

4.4.2 Results and analysis

Myanmar Fiscal regime (PSC)

Among the four fiscal regimes, the Myanmar fiscal regime is most severity and second most inefficient. Generally, Myanmar government take most severe than other countries. According to the PSC system, Myanmar fiscal regime is used sliding scale in profit petroleum sharing which is avoiding from the regressive regime. Even though, higher rate profit sharing may cause severity and inefficiency to the system.

Thailand (iii) Fiscal regime (Royalty & Tax system)

Thailand fiscal regime is more inefficient than Myanmar and two other countries. But fiscal severity is less than Myanmar and more than in two other countries. The efficiency of Thailand regime is directly reflected on Special Remuneration Benefit (SRB).

Vietnam Fiscal regime (PSC system)

Vietnam Fiscal Regime is second more efficient than Bangladesh. Fiscal severity is also second less severe than Bangladesh. Royalty and Profit sharing is sliding scale .In addition, Vietnam fiscal regime income tax 50% is higher than Bangladesh and Myanmar.

Bangladesh Fiscal regime (PSC system)

The Bangladesh regime is most efficient and less severity than other three countries. There is no royalty and no income tax but only profit sharing sliding scale. In the Figure 4.2, government take highest % is Myanmar and lowest % is Bangladesh. Vietnam government take is lower than Thailand III.

Table4.4. The Gas Fiscal regime summary of Vietnam, Thailand and Bangladesh

	ROYALTY	COST RECOVERY	PROFIT TO GOVERNMENT	INCOME TAX	EXPORT DUTY
THAILAND (Royalty & Tax)	From To Rate ≤ 2000 BOE/D 5% 2000 5000 BOE/D 6% 5000 10000 BOE/D 10% 10000 20000 BOE/D 13% 20000 ≥ BOE/D 15%	NONE	Special Remuneratory Benefit(SRB) payement 0%-75% depentds on annual revenue per meter depth of well	50%	NONE
BANGALADESH (PSC)	NONE	55%	From To Rate ≤ 75 MMCFD 55% 75 150 MMCFD 60% 150 250 MMCFD 65% 400 400 MMCFD 70% 600 600 MMCFD 75% 600 ≥ MMCFD 80%	NONE	NONE
VIETNAM (PSC)	From To Rate ≤ 177 MMCFD 0% 177 354 MMCFD 5% 354 MMCFD 10%	50%	From To Rate ≤ 50000 BOE/D 40% 50000 10,000 BOE/D 60% 10,000 150,000 BOE/D 70% 150,000 BOE/D 80%	50%	NONE
MYANMAR (PSC)	10%	50%	From To > 300 MMCFD 70% 300 600 MMCFD 80% 600 900 MMCFD 85% 900 ≥ MMCFD 90%	30%	NONE

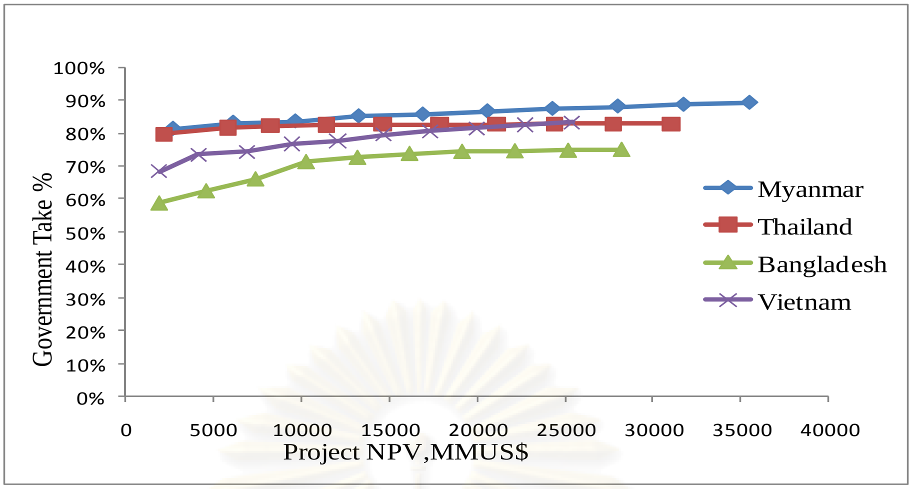


Figure 4.2 Government Take, % against Project before take NPV

CHAPTER V

CASE STUDIES OF THE FISCAL REGIMES AMONG TWO EXISTING PROJECTS AND TWO ONGOING PROJECTS

5.1 Introduction

The Natural gas reserves of Myanmar (2009) from EIA report is 10 Trillion Cubic feet and Myanmar Oil and Gas Enterprise is 10.63 TCF[5] (see Table 5.1).

Table 5.1 Myanmar Offshore Natural Gas Reserves Summary

Natural Gas	Natural Gas	Natural Gas	Natural Gas
(Trillion Cubic Feet)	(Trillion Cubic Feet)	(Trillion Cubic Feet)	(Trillion Cubic Feet)
BP Statistical Review	World Oil	Oil & Gas Journal	Myanmar Oil And Gas Enterprise
Year-End 2007	Year-End 2007	January 1, 2009	January 1, 2009
21.19	14.96	10.00	10.63

5.1.1Background

In the year of between 1972 and 1974 Myanmar National Oil Cooperation (MOC) drilled 12 wells in the Gulf of Martaban. That drilling effort resulted in several uneconomic gas discoveries. In 1974 MOC invited foreign oil companies to bid on offshore blocks. Thirteen offshore blocks were awarded. After numerous dry holes and one gas discovery off the Arakan coast, all of the blocks were relinquished by 1977.

Interest in offshore exploration was backed in 1982, when Yadana gas field was discovered 70 km offshore in the Irrawaddy Delta fan at a water depth of 45 m.

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[5] For more information about reserves, go to the World Proved Reserves of Oil and Natural Gas and Crude Oil Price, Energy Information Administration (EIA) site and Myanmar ministry of energy site http://www.eia.doe.gov/emeu/international / gas res erves.html and http://www.google.com/#hl=en&q=Development+ project+of+ energy+ and+ resources + in+Myan mar%2C2009&aq=f&aqi= &aql= & oq =&gs_rf ai = &fp=9a6ffc70ca3db4ab

Reserves are estimated at more than 5 trillion cubic feet of gas (TCF), with the nearby Sein and Badamyar discoveries adding 0.7 TCF of reserves. Total Myanmar Exploration and Production (TMEP), Unocal, Petroleum Authority of Thailand Exploration and Production International Limited (PTTEP), and Myanma Oil and Gas Enterprise (MOGE), in a joint venture, began development of the field in 1992, and in 1998 Yadana field came on line. Yetagun gas field, with reserves in excess of 3 TCF and 80 million barrels (mmb) of condensate, in the Taninthayi offshore area of the eastern Andaman Sea, was discovered in 1992.

The fiscal analyses in this chapter are mainly based on hypothetically represents in Myanmar offshore exploration and production field developments. The base cases are shown in Table 5.2.

Table 5.2 Summary Base cases of Myanmar offshore gas field

No.	Project	Product	Location
1.	Yadana	Gas	Mottama Offshore
2.	Yetagun	Gas and Condensate	Taninthari Offshore
3.	Zawtika	Gas	Gulf of Mottama
4.	Shwe	Gas	Adaman Sea

Profitability of Contractor's net present value (NPV) of the project after take net cash flow per thousand cubic feet of reserves has been generated in current Myanmar fiscal regime. State participation has been analyzed in each project. Myanmar Oil and gas Enterprise (MOGE) has the right to a 15% undivided interest in the rights and obligations of the Contractor under the PSC, which right generally lapses unless exercised within three months of the discovery of Petroleum.

Upon exercise of this right, MOGE must reimburse the Contractor an amount equal to 15% of the sum of operating costs which the Contractor has incurred. At the option of MOGE, the amount may be reimbursed either in the currency in which the relevant costs have been financed or by "payment out of production" of 50% of MOGE's production.

5.2. Yadana Project

The Yadana gas field contains more than 6.5 trillion cubic feet of natural gas and has an expected field life of over 30 years. In 2009, the output averaged 780 million cubic feet per day. The gas field lays around 1,300 meters (4,300 ft.) beneath the seabed in the water depth around 40 meters (130 ft.). The offshore production complex consists of two well platforms, a production platform, a living quarter's platform, and a manifold compression platform. Produced gas is exported through two pipelines. The first, 409 kilometers (254 mi) long pipeline runs 346 kilometers (215 mi) underwater from Yadana to Daminseik at the coast. From there, a 63-kilometre (39 mi) onshore section runs to the Thailand border. Construction of the pipeline was completed in 1998. The second, 287 kilometers (178 mi) long pipeline from the Yadana to Yangon was inaugurated on 12 June 2010. The 24-inch (610 mm) pipeline has a 151 kilometers

(94 mi) long offshore and 136 kilometers (85 mi) long onshore sections. The pipeline has capacity of 150 million cubic feet per day. Yadana gas field location was shown in Figure 5.1. The summary of Yadana gas production field was as shown in Table 5.3.

Figure 5.1 Location Map of Yadana Gas Field

5.2.1 Assumptions

The economics analyses for Yadana gas field assumptions are shown in Table 5.4.

5.2.1.1 Economics Assumptions

(1) Gas Price

Base case wellhead gas price[6] for year one was 2 US$/MMBTU in year 1998

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[6] For more information about reserves, go to the Historical World Natural Gas and Crude Oil Price, Energy Information Administration (EIA) site http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm.

and escalation rate 4% per year was starting from year 1999(see Table 5.8).

For sensitivity analysis, 50% higher (3US$/MMBTU) and 50% lower (1US$/MMBTU) price were used.

Table 5.3 Yadana Gas Field Summary

ITEMS	DESCRIPTION	REMARKS
Blocks	M5,M6	
Location	Mottama Offshore	
Partners	TOTAL UNOCAL PTTEP MOGE	31.2375 % 28.2625% 25.5% 15%
PSC Signed	1992	
Product	Gas	
Proved Reserves	6.5 TCF	
Production Start up	1998	
Project Cost	650 MMUS$	Exclude transportation costs
Average Water depth	49 meters(130ft)	
Reservoirs	Limestone	

(2) Escalation

Exploration costs, development costs and operating costs escalation rate were 3% per year starting in 1999(see Table 5.8).

(3) Discount rate

10 % discount rate was used for calculating the Project NPV and contractor after take net cash flow. Typically oil and Gas Company used nominal 10% rate.

5.2.1.2 Costs Assumptions

Explorations costs and development costs were assumed to be in the 1995 based on real information: Operating costs 5% /year and abandonment costs 5% of development costs. This information was based on real data and rule of thumb typical oil and gas investor's assumptions.

Table 5.4 Summary of Assumption

Items	Assumptions
Water Depth	600 ft <
Gas Price (Year one)	2 US$/MMBTU
Discount Rate	10%
Gas Price Escalation	4%
Exploration, operating, abandonment costs Escalation	3%
Operating Costs	5%/year of Capital costs
Abandonment Costs	5% of Capital costs

For hypothetical field analyses, peak production rate and field development costs were related to existing field in same region. Peak production rate are directly related with field sizes. For details calculating formula as follows;

According to existing field, peak production rate was constant 5% of initial reserves.

Peak production rates, Field development costs, operating costs and abandonment costs summary were as shown in Table 5.5.

Table 5.5 Peak production rates, Field development costs, operating costs and abandonment costs summary

Reserves	TCF	1	2	3	4	5	6	7	8	9	10
Peak rate	%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Peak production	MMCFD	137	274	411	548	685	822	959	1,096	1,233	1,370
Development cost	MMUS$	189	307	408	499	583	662	738	810	880	947
Operating cost		5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
	MMUS$/year	9	15	20	25	29	33	37	41	44	47
Abandonment cost		5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
	MMUS$	9	15	20	25	29	33	37	41	44	47

Yadana gas field peak production is 800 MMCFD, development cost (exclude transportation costs) was 650MMUS$ and reserves is 6.5 TCF.

Field development planning were 10% for year two and year 5 after that 40% each for year 3 and year 5(see Table 5.6).

Table 5.6 Exploration costs and development costs phasing

Year	Development and Production Plan		
	Exploration costs	%	MMUS$
1	2.1		
2	6.3	10%	65
3	6.3	40%	260
4	6.3	40%	260
5		10%	65

5.2.1.3 Production Profile

Production started up in the year of 1998, peak production rate and decline after 16 year plateau to the field life end of 30 years were shown in Figure 5.2. The estimated production profile, exploration costs, development costs, operating costs and abandonment cost were shown in Table 5.6. Over all capital expenditure, operation costs and abandonment costs were 1679MMUS$ for the project (exclude pipeline transportation costs and pipeline operating costs).

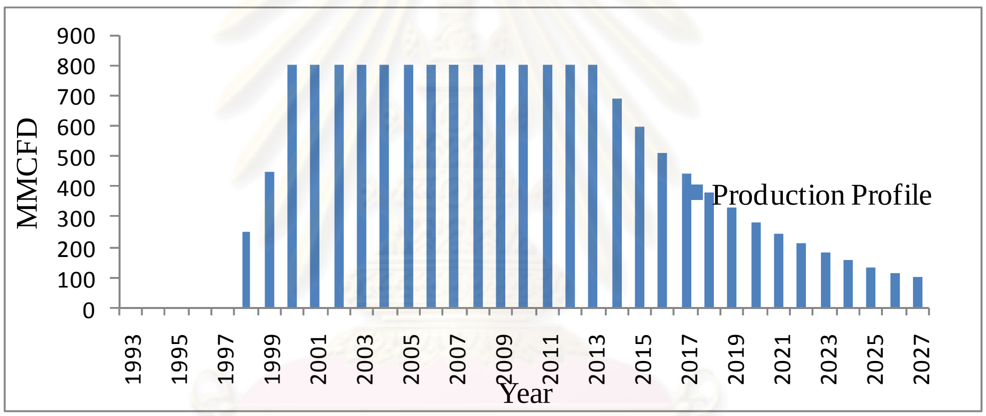


Figure 5.2 Yadana gas field production profile

5.2.1.4 Fiscal Regime Assumptions

Yadana Gas Field production sharing contracts (PSC) was production period 30 years of field life and PSC include to be Royalty 10%, Costs recovery limit 50%, profit gas sharing sliding scale and income tax 30% (include 3year tax holidays) are as shown in (Table 5.9 and Table 5.10).Domestic used about 125 MMCD were assumed to be same price with export sale price.

Table 5.7 Summary of Yadana Gas field costs assumptions

Year	Production				Exploration Cost	CAPX	OPEX	Abandonment Cost	Total cost
	MMCFD	MMCF/Year	MMBTUD	MMBTU/Year	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
							5%		
1993					2.1				-2
1994					6.3	65			-71
1995					6.3	260			-266
1996					6.3	260			-266
1997						65			-65
1998	250	91,250	180,000	65,700,000			33	1.08	-34
1999	447	163,233	321,994	117,527,733			33	1.08	-34
2000	800	292,000	576,000	210,240,000			33	1.08	-34
2001	800	292,000	576,000	210,240,000			33	1.08	-34
2002	800	292,000	576,000	210,240,000			33	1.08	-34
2003	800	292,000	576,000	210,240,000			33	1.08	-34
2004	800	292,000	576,000	210,240,000			33	1.08	-34
2005	800	292,000	576,000	210,240,000			33	1.08	-34
2006	800	292,000	576,000	210,240,000			33	1.08	-34
2007	800	292,000	576,000	210,240,000			33	1.08	-34
2008	800	292,000	576,000	210,240,000			33	1.08	-34
2009	800	292,000	576,000	210,240,000			33	1.08	-34
2010	800	292,000	576,000	210,240,000			33	1.08	-34
2011	800	292,000	576,000	210,240,000			33	1.08	-34
2012	800	292,000	576,000	210,240,000			33	1.08	-34
2013	800	292,000	576,000	210,240,000			33	1.08	-34
2014	690	251,696	496,496	181,221,166			33	1.08	-34
2015	594	216,955	427,966	156,207,720			33	1.08	-34
2016	512	187,009	368,895	134,646,809			33	1.08	-34
2017	442	161,197	317,978	116,061,890			33	1.08	-34
2018	381	138,947	274,088	100,042,194			33	1.08	-34
2019	328	119,769	236,257	86,233,653			33	1.08	-34
2020	283	103,238	203,647	74,331,065			33	1.08	-34
2021	244	88,988	175,538	64,071,358			33	1.08	-34
2022	210	76,705	151,309	55,227,769			33	1.08	-34
2023	181	66,118	130,424	47,604,836			33	1.08	-34
2024	156	56,992	112,422	41,034,075			33	1.08	-34
2025	135	49,125	96,905	35,370,257			33	1.08	-34
2026	116	42,345	83,529	30,488,200			33	1.08	-34
2027	100	36,500	72,000	26,280,000			33	1.08	-34
		5938068			**21**	**650**	**975**		**-1679**

Table 5.8 Escalated costs summary of Yadana Gas Field

Year	Exploration Cost MMUS$		CAPX MMUS$		OPEX MMUS$				Abandonment Cost MMUS$	Cost to be Recovered MMUS$	Price US$/MMBTU	Price US$/MMBTU	
	3%		3%		3%		3%				4%	
1993	1	2.10	1.00	0	1.00	0	1.00	0.00	-2		1.00	0.00
1994	1.03	6.49	1.03	67	1.03	0	1.03	0.00	-73		1.04	0.00
1995	1.06	6.68	1.06	276	1.06	0	1.06	0.00	-283		1.08	0.00
1996	1.09	6.88	1.09	284	1.09	0	1.09	0.00	-291		1.12	0.00
1997	1.13	0.00	1.13	73	1.13	0	1.13	0.00	-73		1.17	0.00
1998	1.16	0.00	1.16	0	1.16	38	1.16	1.26	-38	2.00	1.22	2.43
1999	1.19	0.00	1.19	0	1.19	39	1.19	1.29	-39	2.10	1.27	2.66
2000	1.23		1.23	0	1.23	40	1.23	1.33	-40	2.20	1.32	2.90
2001	1.27		1.27	0	1.27	41	1.27	1.37	-41	2.30	1.37	3.15
2002	1.30		1.30	0	1.30	42	1.30	1.41	-42	2.40	1.42	3.42
2003	1.34		1.34	0	1.34	44	1.34	1.46	-44	2.50	1.48	3.70
2004	1.38		1.38	0	1.38	45	1.38	1.50	-45	2.60	1.54	4.00
2005	1.43		1.43	0	1.43	46	1.43	1.54	-46	2.70	1.60	4.32
2006	1.47		1.47	0	1.47	48	1.47	1.59	-48	2.80	1.67	4.66
2007	1.51		1.51	0	1.51	49	1.51	1.64	-49	2.90	1.73	5.02
2008	1.56		1.56	0	1.56	51	1.56	1.69	-51	3.00	1.80	5.40
2009	1.60		1.60	0	1.60	52	1.60	1.74	-52	3.10	1.87	5.81
2010	1.65		1.65	0	1.65	54	1.65	1.79	-54	3.20	1.95	6.23
2011	1.70		1.70	0	1.70	55	1.70	1.84	-55	3.30	2.03	6.69
2012	1.75		1.75	0	1.75	57	1.75	1.90	-57	3.40	2.11	7.16
2013	1.81		1.81	0	1.81	59	1.81	1.96	-59	3.50	2.19	7.67
2014	1.86		1.86	0	1.86	60	1.86	2.02	-60	3.60	2.28	8.20
2015	1.92		1.92	0	1.92	62	1.92	2.08	-62	3.70	2.37	8.77
2016	1.97		1.97	0	1.97	64	1.97	2.14	-64	3.80	2.46	9.37
2017	2.03		2.03	0	2.03	66	2.03	2.20	-66	3.90	2.56	10.00
2018	2.09		2.09	0	2.09	68	2.09	2.27	-68	4.00	2.67	10.66
2019	2.16		2.16	0	2.16	70	2.16	2.34	-70	4.10	2.77	11.37
2020	2.22		2.22	0	2.22	72	2.22	2.41	-72	4.20	2.88	12.11
2021	2.29		2.29	0	2.29	74	2.29	2.48	-74	4.30	3.00	12.89
2022	2.36		2.36	0	2.36	77	2.36	2.55	-77	4.40	3.12	13.72
2023	2.43		2.43	0	2.43	79	2.43	2.63	-79	4.50	3.24	14.60
2024	2.50		2.50	0	2.50	81	2.50	2.71	-81	4.60	3.37	15.52
2025	2.58		2.58	0	2.58	84	2.58	2.79	-84	4.70	3.51	16.49
2026	2.65		2.65	0	2.65	86	2.65	2.87	-86	4.80	3.65	17.51
2027	2.73		2.73	0	2.73	89	2.73	2.96	-89	4.90	3.79	18.59
		22.16		**700**		**1792**		**60**	**-2515**			

Table 5.9 Fiscal Regime summary of Yadana Gas Field

Year	Revenue MMUS$	Royalty MMUS$	After Royalty MMUS$	Cost Recovery Limit MMUS$	Lost carry forward	Recovered Cost this year MMUS$	After Cost Recovery MMUS$	Profit Petroleum Government %	Profit Petroleum Contractor %	Income Tax	Discount Net Cash Flow
		10%		50%						30%	10%
1993					-2						-2
1994					-76						-67
1995					-358						-233
1996					-649						-219
1997					-722						-50
1998	160	16	144	80	-680	80	64	50	14	3 YearsTax	35
1999	312	31	281	156	-563	156	125	98	27	Holidays	82
2000	609	61	548	304	-298	304	243	191	53	Period	163
2001	662	66	596	331	-9	331	265	207	57	17	154
2002	718	72	646	359		51	595	466	129	39	42
2003	778	78	700	389		44	657	514	142	43	38
2004	842	84	757	421		45	712	558	154	46	38
2005	909	91	818	454		46	772	604	167	50	37
2006	980	98	882	490		48	834	654	181	54	37
2007	1056	106	950	528		49	901	706	195	59	36
2008	1136	114	1022	568		51	972	761	211	63	35
2009	1221	122	1099	610		52	1046	820	227	68	35
2010	1310	131	1179	655		54	1126	882	244	73	34
2011	1405	141	1265	703		55	1210	948	262	79	33
2012	1506	151	1355	753		57	1298	1017	281	84	32
2013	1612	161	1451	806		59	1392	1091	302	91	31
2014	1487	149	1338	743		60	1278	1001	277	83	26
2015	1370	137	1233	685		62	1170	917	254	76	22
2016	1261	126	1135	631		64	1071	839	232	70	18
2017	1160	116	1044	580		66	978	766	212	64	15
2018	1067	107	960	533		68	892	669	223	67	14
2019	980	98	882	490		70	812	609	203	61	12
2020	900	90	810	450		72	738	553	184	55	10
2021	826	83	744	413		74	669	502	167	50	8
2022	758	76	682	379		77	605	454	151	45	7
2023	695	69	625	347		79	546	383	164	49	7
2024	637	64	573	318		81	492	344	148	44	5
2025	583	58	525	292		84	441	309	132	40	4
2026	534	53	481	267		86	394	276	118	35	4
2027	489	49	440	244		89	351	246	105	32	3
	27962	**2796**	**25166**			**2515**	**22651**	**17434**	**5217**	**1537**	**446**

Table 5.10 Fiscal Regime Assumptions

Items		Government	Contractor
Royalty		10%	
Cost Recovery			50%
Profit Sharing	Gas Production MMCFD		
	< 300	70%	30%
	300 600	80%	20%
	600 900	85%	15%
	900 >	90%	10%
Income Tax		30%	

5.2.1.5 Results of Yadana Gas Field

According to above assumptions,Yadana base case results as shown in (Table 5.11).

Table 5.11 Summary Deterministic Results of Yadana Field

Contractor's NPV	MMUS$	388
Contractor's NPV/MCF	US$/MCF	0.060
Project NPV(MMUS$)	MMUS$	4420
Net Cash flow to contractor(MMUS$)	MMUS$	3181
IRR	%	17%
Government Take	%	87%
Contractor Take	%	13%
Effective Royalty rate	%	72%

Figure 5.3 meant that the yearly net cash flows of Yadana Gas field against time. Contractor NCF after government take (the lowest bar) meant that in the year of start producing, according to fiscal regime 3 years tax holiday, contractor take higher than other year.

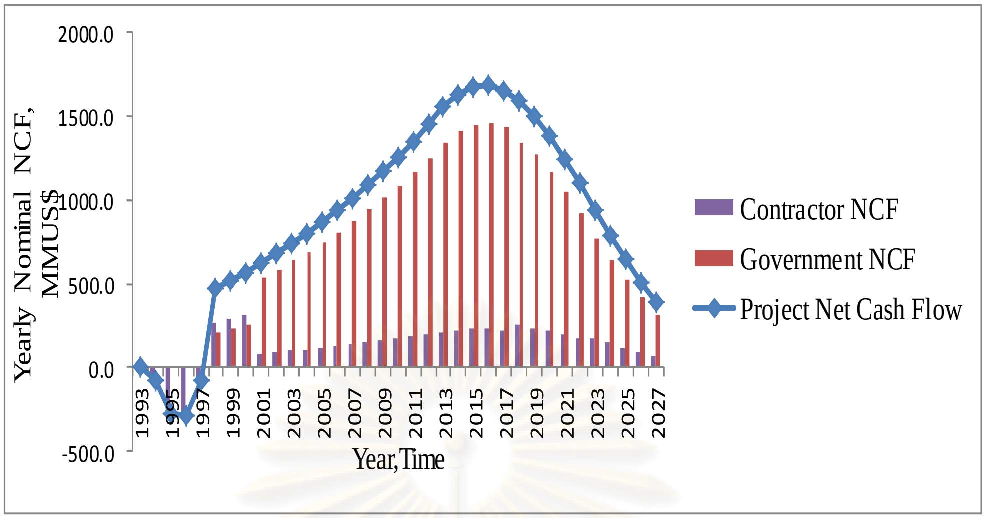


Figure 5.3 Net Cash Flow against time

In the Figure 5.5 stated that government take was progressive as percentage of project NPV increases with the increase in the profitability of the project. The Government Take, Contractor Take % of project NPV meant that Government take progressive as percentage of project NPV was same criteria as effective royalty rate (see Figure 5.4).

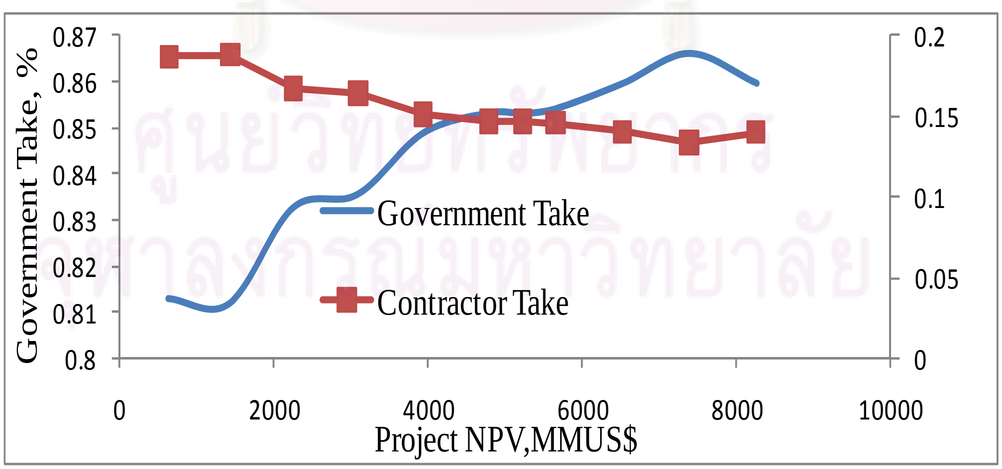


Figure 5.4 Project NPV against Government take and Contractor Take

5.2.2 Sensitivity analysis of Yadana Gas Field

Minimum filed sizes 1 TCF to 10 TCF were used for hypothetically field analyses. In addition, (PSC) production sharing split were same as Table 5.10.

5.2.2.1 Costs Sensitivity

Figure 5.5 (a) shows that base gas price sensitivity varied linearly increased and decreased the value of NPV/MCF starting from 5 TCF to above field sizes. According to profit sliding scale, gas price sensitivity might effect on less than 5 TCF field size, especially in low gas price. In addition, 50 % lower gas price was greatly impacted to small field size, 1 TCF, making a negative NPV. The 50% higher development costs were greatly decreased NPV/MCF in small field and 50% lower development costs were not much as impact as 50 % higher development costs. In addition, lower development costs lesser impact on small and marginal fields and over 6TCF field size was linearly increased and decreased.(shown in Figure 5.5(b).Figure 5.5(c) shown that operating costs changed were very likely linearly increased and decreased overall field sizes.

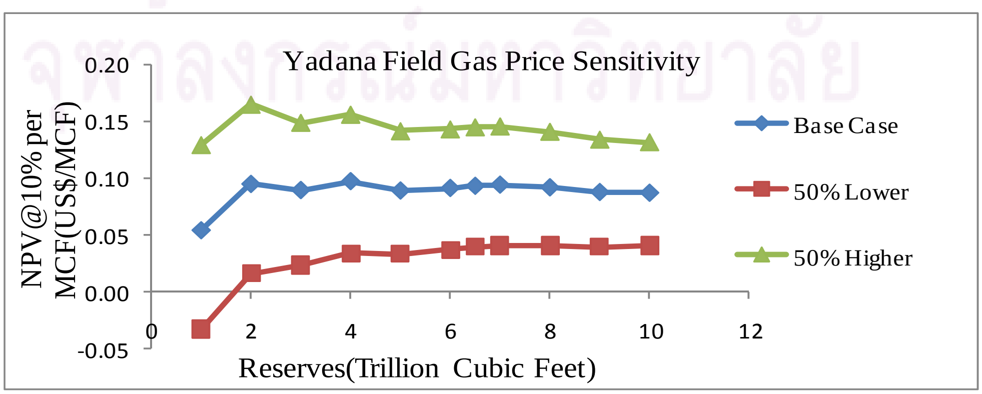


Figure 5.5 (a) Gas Price Sensitivity

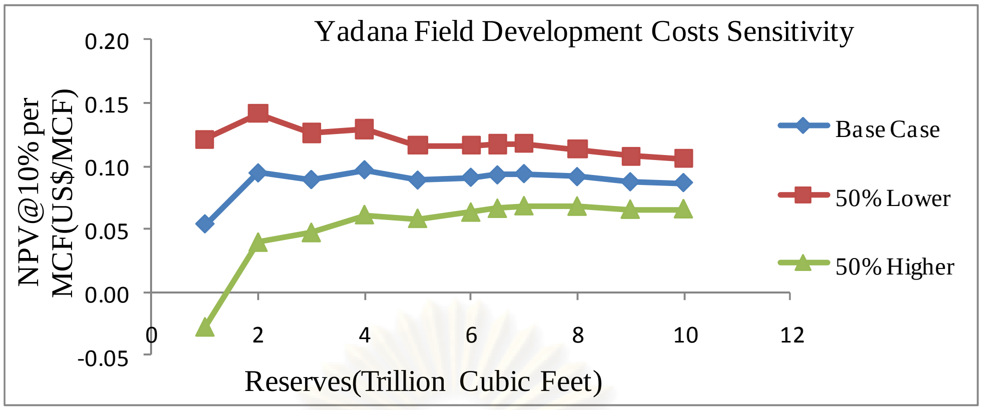


Figure 5.5 (b) Development costs Sensitivity

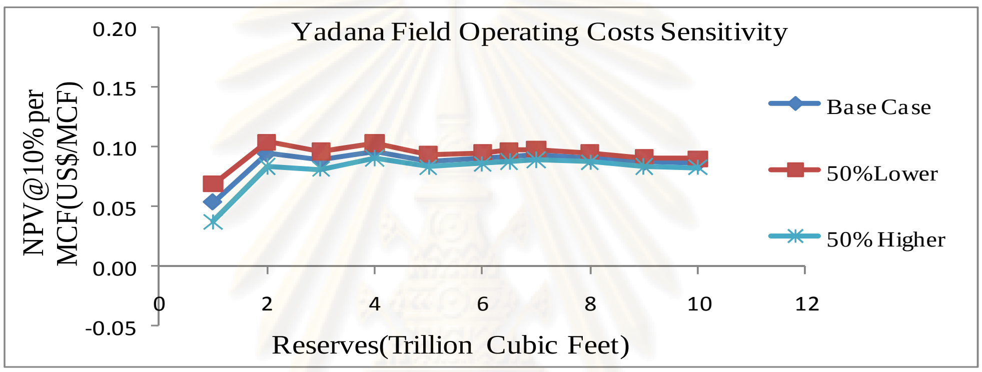


Figure 5.5 (c) Operating costs Sensitivity

5.2.2.2 Peak production rate Sensitivity

Figure 5.6, Peak production rate were rare linearly decreased and increased to the base case. If the peak production rate was decreased to 50% of base case, the size of 1TCF field gave negative NPV.

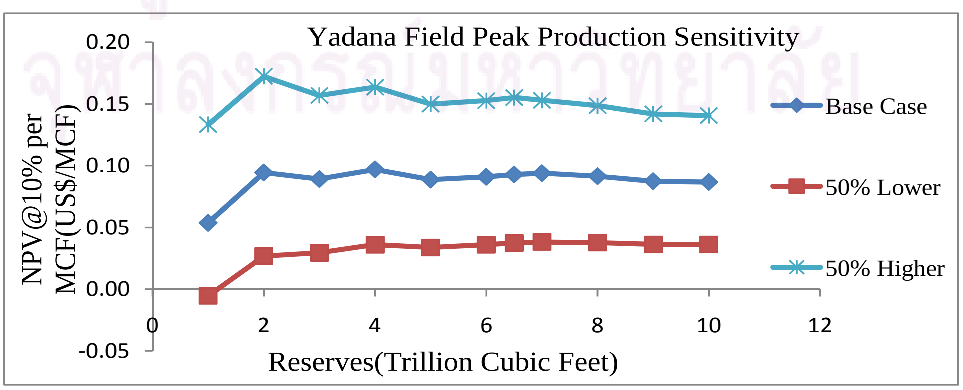


Figure 5.6 Peak Production rate Sensitivity

5.2.2.3 Fiscal Regime (PSC) Sensitivity

Figure 5.7(a), (b), (c) stated that income tax sensitivity was the greatest impact to the fiscal regime. In the Royalty sensitivity changing was linearly and equally different from base case, because royalty is directly deducted from gross revenue. For figure 5.8(b) shown that lower cost recovery limit was greatly impact on less than 6TCF field sizes. Unlimited cost recovery was more efficient to the less than 6 TCF.

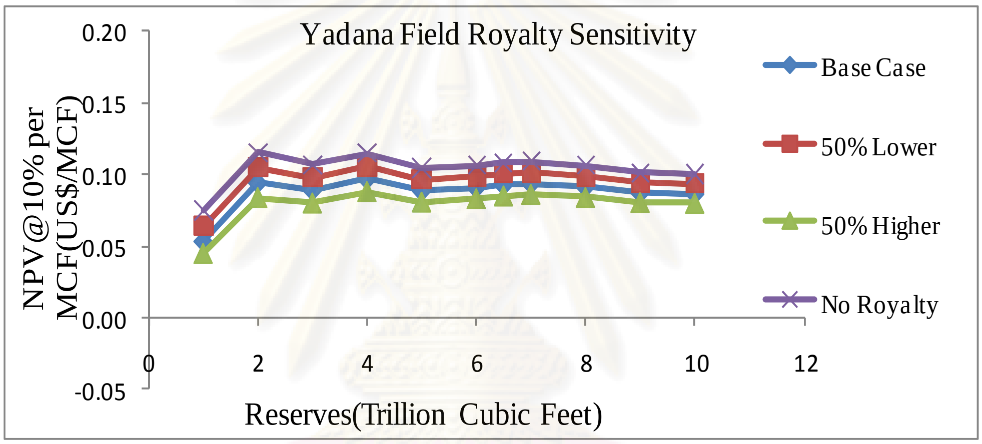


Figure 5.7(a) Royalty rate Sensitivity

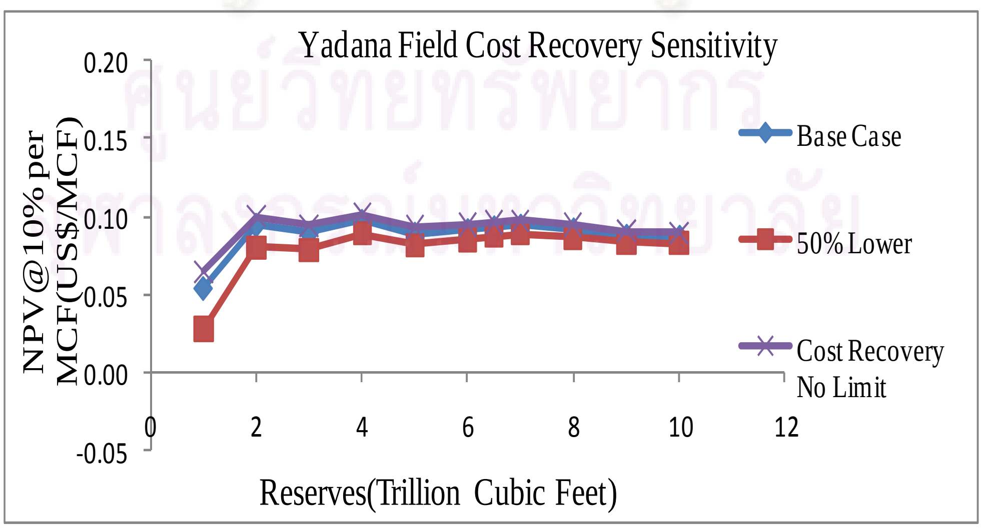


Figure 5.7(b) Costs recovery Sensitivity

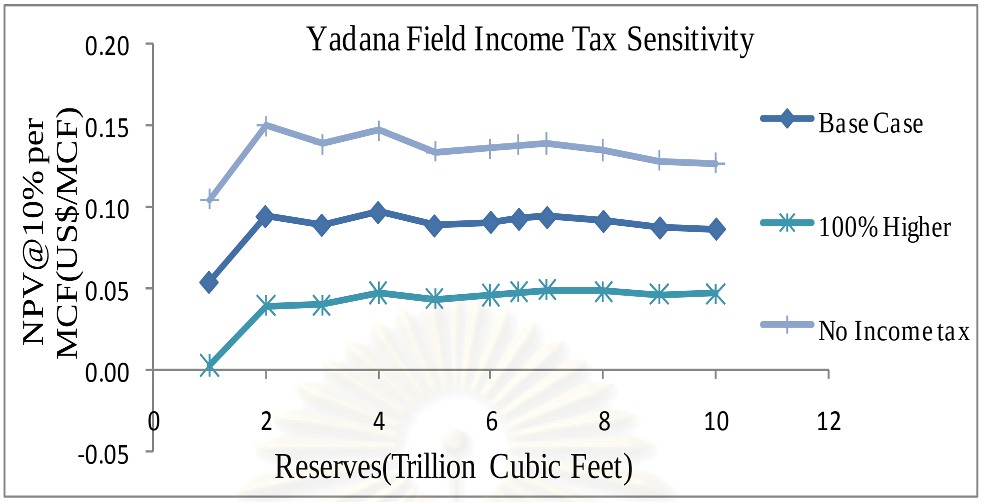


Figure 5.7(c) Income Tax Sensitivity

5.2.3 Probabilistic Analysis

Deterministic analysis gives only one value might not be made a decision to the project; probabilistic analysis can generate several values. The 20000 times iterations of Monte Carlo simulation generated several excepted outcome of the project, Uncertainty value was input and excepted outcome was NPV. According to the limited information of data sources, typically triangular distribution was used. Sensitivity analyses 50% lower and 50% higher of the base case values were used for Monte Carlo simulation input. It can be seen clearly in (Table 5.12).In the table gas price input is year one gas price, operating costs is yearly costs.

In Figure 5.8 deterministic analysis of NPV against the Monte Carlo simulation gave probability of success 50% confident NPV (371 MMUS$) that was nearly the same value of deterministic analysis NPV(388 MMUS$).In addition, probability of success less than 5% confident gave negative NPV and 95% confident was twice of mean value. As a results of Yadana Project, the project NPV were profitable for probability of success more than 5%. (see Table 5.13).

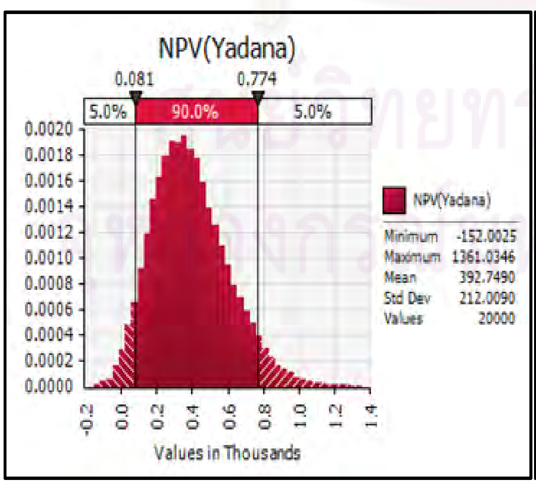
Table 5.12 Input variable parameter of Yadana Gas Field

Yadana			Parameter		
Items	Units	Distribution	Min	Mean	Max
Capital Costs	MMUS$	Triangular	328	651	974
Opetration costS/year	MMUS$/year	Triangular	16	33	49
Abandonment costs	MMUS$	Triangular	11	21	31
Heating Value	BTU/MMSCF	Triangular	362	720	1077
Escalated Gas Price	%	Triangular	2%	4%	6%
Royalty	%	Triangular	5%	10%	15%
Costs Recovery	%	Triangular	25%	50%	75%
Income Tax	%	Triangular	15%	30%	45%
Gas Price(Year 1)	US$	Triangular	1	2	3

Internal Rate of Return outcome was as shown in Figure 5.9, 50 % probability of success 17 percent was likely the same with deterministic analysis. Probability of success 5% confidence IRR value is 5% and 95 % of IRR value is 25 %.(see table 5.13)

Table 5.13 Statistic results Yadana project NPV and Yadana project IRR

Statistics for NPV(Yadana)		Statistics for IRR(Yadana)	
Percentile	**MMUS$**	Percentile	%
5%	81.4	5%	12%
10%	137.5	10%	13%
15%	176.4	15%	13%
20%	209.9	20%	14%
25%	239.4	25%	15%
30%	267.6	30%	15%
35%	294.2	35%	16%
40%	319.6	40%	16%
45%	345.7	45%	17%
50%	371.2	50%	17%
55%	397.4	55%	18%
60%	426.5	60%	18%
65%	455.7	65%	19%
70%	487.9	70%	19%
75%	524.5	75%	20%
80%	566.3	80%	21%
85%	615.6	85%	22%
90%	679.4	90%	23%
95%	774.0	95%	25%



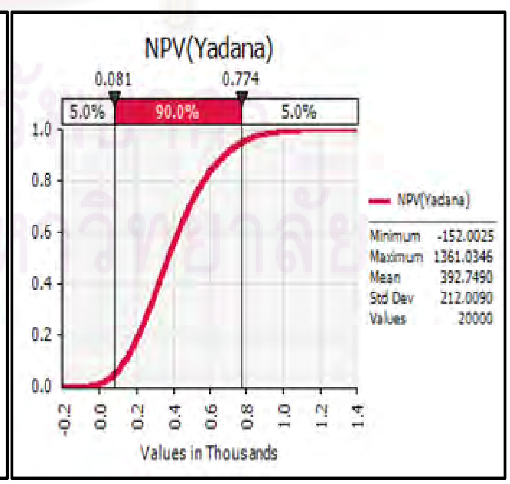


Figure 5.8 PDF of Yadana project NPV and CDF of Yadana project NPV

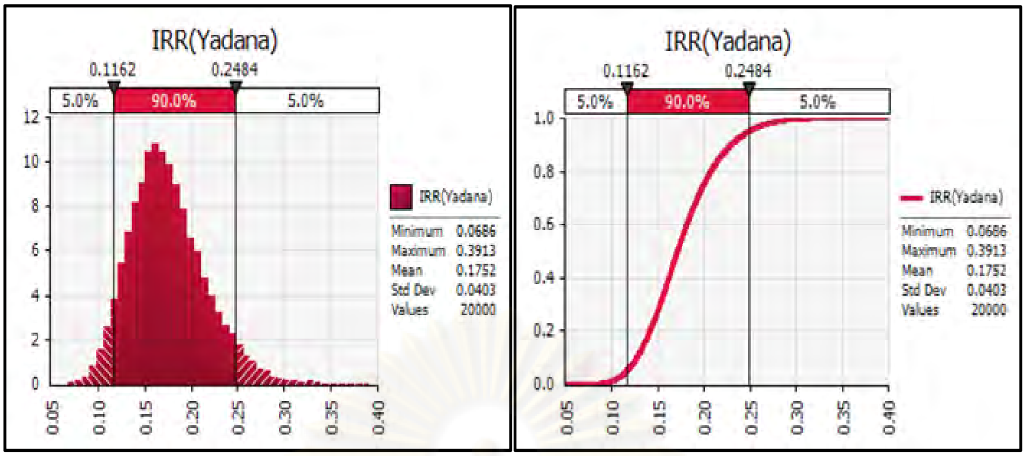


Figure 5.9 PDF of Yadana project IRR and CDF of Yadana project IRR

5.2.4 Conclusions

According the existing data and assumptions, Yadana gas field development project is profitable to the contractor. Moreover, Yadana field PSC used sliding scale in profit sharing is intended to progressive regime. It is efficient regime. As the results of 50 % lower gas price sensitivity and 50 % higher development costs sensitivity showed that the negative NPV is becoming in 1TCF field size. In other words, lower gas price and higher development costs are losing money to the contractor. Even though, Monte Carlo simulation results do not show on those of conditions. Yadana project is profitable.

5.3. Yetagun Project

The Yetagun gas field contains more than 4 Trillion Cubic feet of natural gas and 30 barrel condensate per million cubic feet of natural gas having an expected field life of over 30 years. The gas field lays around 2,286 meters (7,500 ft.) beneath the seabed in the water depth around 100 meters (330 ft.). The offshore production complex consists of one well platform, a production platform combine with a living quarter's platform. Produced gas is exported through 24 inches pipeline and condensate is transferred to Floating storage offloading (FSO). The 270 kilometers (168 mi) long pipeline runs 202 kilometers (126 mi) underwater from Yetagun to Daminseik at the coast. From there, a 68-kilometre (42 mi) onshore section runs to the Thailand border. Construction of the pipeline was completed in 2000.The location of Yetagun gas field is shown in Figure 5.10.

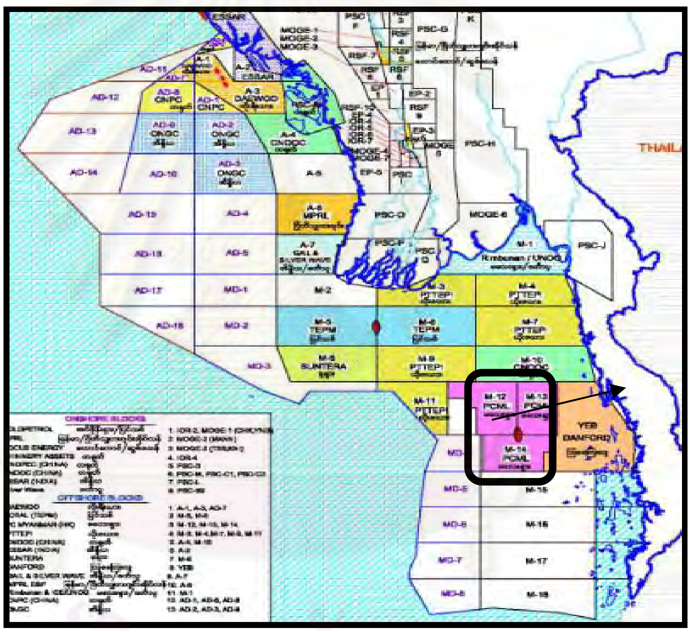


Figure 5.10 Location Map of Yetagun Gas Field

The summary of Yetagun gas production field data was as shown in Table 5.14

Table 5.14 Yetagun Gas Field Summary

ITEMS	DESCRIPTION	REMARKS
Blocks	M12,M13,M14	
Location	Taninthari Offshore	

Partners	PETRONAS	40.75 %
	NIPPON	19.40%
	PTTEP	19.40%
	MOGE	20.45%
PSC Signed	1990	
Product	Gas &Condensate	
Proved Reserves	4.16 TCF	
Production Start up	2000	
Project Cost	640 MMUS$	Exclude transportation costs
Average Water depth	100 meters(330ft)	
Reservoirs	Sandstone	

5.3.1 Assumptions

The economics analyses for Yetagun gas field assumptions summary were shown in Table 5.15.

5.3.1.1 Economics Assumptions

(1) Gas Price

Base case wellhead gas price for year one was 2 US$/MMBTU in year 2000 and escalation rate 4% per year was starting from year 2000.For sensitivity analysis, 50% higher (3US$/MMBTU) and 50% lower (1US$/MMBTU) price were used.

(2) Condensate Price

Base case wellhead condensate price[7] for year one was 25 US$/BBL in year 2000 and escalation rate 4% per year was starting from year 2000.

(3) Escalation

Exploration costs, development costs and operating costs escalation rate were 3% per year starting in 2000.

(4) Discount rate

10 % discount rate was used for calculating the Project NPV and contractor after take net cash flow. Typically oil and Gas Company used nominal 10% rate.

5.3.1.2 Costs Assumptions

Explorations costs and development costs were assumed to be in 2000 based on real information. Operating costs is 5% / year and abandonment cost is 5% of development costs. In addition, condensate production costs were assumed to be 40% of total costs. This information was based on real data and rule of thumb typical oil and gas investor's assumptions.(see Table 5.17)

Table 5.15 Summary of Assumption

Items	Assumptions
Water Depth	600 ft <
Gas Price (Year one)	2 US$/MMBTU

[7]For more information about crude oil price, go to the Historical Indonia Mina Crude Oil Price, Energy Information Administration(EIA)site: http://tonto.eia.doe.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=WEPCMINAS&f= W

Condensate Price (Year One)	25US$/BBL
Discount Rate	10%
Gas Pri ce Escalation	4%
Exploration, operating, abandonment costs Escalation	3%
Operating Costs	5%/year of Capital costs
Abandonment Costs	5% of Capital costs

According to existing field, peak production rate was constant 5.0% of initial reserves. Condensate production was assumed to be 30 BBL condensate /MMCF.(see Table 5.16)

Table 5.16 Peak production rates, Field development costs, operating costs and abandonment costs.

Reserves	TCF	1	2	3	4	5	6	7	8	9	10
Peak rate	%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
Peak production	MMCFD	137	274	411	548	685	822	959	1,096	1,233	1,370
Condensate	BBL CDs/Day	4,110	8,219	12,329	16,438	20,548	24,658	28,767	32,877	36,986	41,096
Development costs	MMUS$	276	448	595	728	851	967	1,077	1,182	1,284	1,382
Operating costs		5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
	MMUS$/year	14	22	30	36	43	48	54	59	64	69
Abandonment costs		5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
	MMUS$	14	22	30	36	43	48	54	59	64	69

Yetagun gas field peak production is 460 MMCFD, development cost (exclude transportation costs) was 640MMUS$ and reserves is 4.16 TCF. Field development planning were 10% for year two and year 5 after that 40% each for year 3 and year 4.

5.3.1.3 Production Profile

Production started up in the year of 2000, 100% of peak production rate is assumed to be after 2 year ramp up and decline after 16 year plateau to the field life end of 30 years were shown in Figure 5.11. The estimated production profile, exploration costs, development costs, operating costs and abandonment cost were shown in Table 5.17. Over all capital expenditure, operation costs and abandonment costs were 1680MMUS$ for the project (exclude pipeline transportation costs and pipeline operating costs).(see Table 5.18).

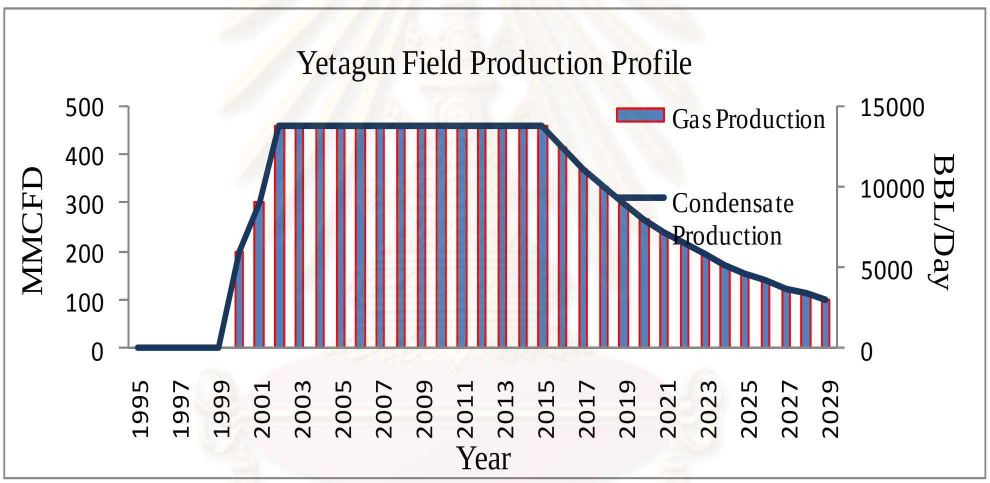


Figure 5.11 Yetagun gas field production profile

5.3.1.4 Fiscal Regime Assumptions

Yetagun Gas Field production sharing contracts (PSC) was production period 30 years of field life and PSC included Royalty 10%,Costs recovery limit 50% ,profit gas and condensate sharing sliding scale(Table 5.20) and income tax 30% (include 3year tax holidays).(see Table 5.19(a,b,c)).

Table 5.17 Summary of Yetagun Gas field costs assumptions

Year	Production				Exploration Cost	CAPX	OPEX	Abandonment Cost	Total cost
	MMCFD	MMCF/Year	MMBTUD	MMBTU/Year	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
							5%		
1995					2.2				-2
1996					6.6	64			-71
1997					6.6	256			-263
1998					6.6	256			-263
1999						64			-64
2000	200	73,000	200,000	73,000,000			32	1.3	-33
2001	303	110,710	303,315	110,709,981			32	1.3	-33
2002	460	167,900	460,000	167,900,000			32	1.3	-33
2003	460	167,900	460,000	167,900,000			32	1.3	-33
2004	460	167,900	460,000	167,900,000			32	1.3	-33
2005	460	167,900	460,000	167,900,000			32	1.3	-33
2006	460	167,900	460,000	167,900,000			32	1.3	-33
2007	460	167,900	460,000	167,900,000			32	1.3	-33
2008	460	167,900	460,000	167,900,000			32	1.3	-33
2009	460	167,900	460,000	167,900,000			32	1.3	-33
2010	460	167,900	460,000	167,900,000			32	1.3	-33
2011	460	167,900	460,000	167,900,000			32	1.3	-33
2012	460	167,900	460,000	167,900,000			32	1.3	-33
2013	460	167,900	460,000	167,900,000			32	1.3	-33
2014	460	167,900	460,000	167,900,000			32	1.3	-33
2015	460	167,900	460,000	167,900,000			32	1.3	-33
2016	412	150,560	412,494	150,560,432			32	1.3	-33
2017	370	135,012	369,895	135,011,576			32	1.3	-33
2018	332	121,068	331,695	121,068,500			32	1.3	-33
2019	297	108,565	297,439	108,565,370			32	1.3	-33
2020	267	97,353	266,722	97,353,478			32	1.3	-33
2021	239	87,299	239,177	87,299,474			32	1.3	-33
2022	214	78,284	214,476	78,283,779			32	1.3	-33
2023	192	70,199	192,326	70,199,163			32	1.3	-33
2024	172	62,949	172,464	62,949,472			32	1.3	-33
2025	155	56,448	154,653	56,448,479			32	1.3	-33
2026	139	50,619	138,682	50,618,865			32	1.3	-33
2027	124	45,391	124,360	45,391,293			32	1.3	-33
2028	112	40,704	111,517	40,703,589			32	1.3	-33
2029	100	36,500	100,000	36,500,000			32	1.3	-33
		3675263			22	640	960		-1660

Table 5.18 Escalated costs summary of Yetagun Gas Field

Year	Exploration Cost		CAPX		OPEX			Abandonment Cost	Cost to be Recovered	Cost to be Recovered Gas	Cost to be Recovered Condensate	Gas Price		Price
	MMUS$		MMUS$		MMUS$			MMUS$	MMUS$	MMUS$	MMUS$	US$/MMB'		US$/MMBTU
	3%		3%		3%		3%			60%	40%		4%	
1995	1	2.2	1.0	0	1	0	1.0	0	-2	-1	-1		1	0.0
1996	1.0	6.798	1.0	66	1	0	1.0	0	-73	-44	-29		1.0	0.0
1997	1.1	7.002	1.1	272	1	0	1.1	0	-279	-167	-111		1.1	0.0
1998	1.1	7.212	1.1	280	1	0	1.1	0	-287	-172	-115		1.1	0.0
1999	1.1	0	1.1	72	1	0	1.1	0	-72	-43	-29		1.2	0.0
2000	1.2	0	1.2	0	1	37	1.2	1.5	-37	-22	-15	2	1.2	2.4
2001	1.2	0	1.2	0	1	38	1.2	1.5	-38	-23	-15	2.1	1.3	2.7
2002	1.2		1.2	0	1	39	1.2	1.6	-39	-24	-16	2.2	1.3	2.9
2003	1.3		1.3	0	1	41	1.3	1.6	-41	-24	-16	2.3	1.4	3.1
2004	1.3		1.3	0	1	42	1.3	1.7	-42	-25	-17	2.4	1.4	3.4
2005	1.3		1.3	0	1	43	1.3	1.7	-43	-26	-17	2.5	1.5	3.7
2006	1.4		1.4	0	1	44	1.4	1.8	-44	-27	-18	2.6	1.5	4.0
2007	1.4		1.4	0	1	46	1.4	1.8	-46	-27	-18	2.7	1.6	4.3
2008	1.5		1.5	0	1	47	1.5	1.9	-47	-28	-19	2.8	1.7	4.7
2009	1.5		1.5	0	2	48	1.5	1.9	-48	-29	-19	2.9	1.7	5.0
2010	1.6		1.6	0	2	50	1.6	2.0	-50	-30	-20	3	1.8	5.4
2011	1.6		1.6	0	2	51	1.6	2.1	-51	-31	-21	3.1	1.9	5.8
2012	1.7		1.7	0	2	53	1.7	2.1	-53	-32	-21	3.2	1.9	6.2
2013	1.7		1.7	0	2	54	1.7	2.2	-54	-33	-22	3.3	2.0	6.7
2014	1.8		1.8	0	2	56	1.8	2.2	-56	-34	-22	3.4	2.1	7.2
2015	1.8		1.8	0	2	58	1.8	2.3	-58	-35	-23	3.5	2.2	7.7
2016	1.9		1.9	0	2	60	1.9	2.4	-60	-36	-24	3.6	2.3	8.2
2017	1.9		1.9	0	2	61	1.9	2.5	-61	-37	-25	3.7	2.4	8.8
2018	2.0		2.0	0	2	63	2.0	2.5	-63	-38	-25	3.8	2.5	9.4
2019	2.0		2.0	0	2	65	2.0	2.6	-65	-39	-26	3.9	2.6	10.0
2020	2.1		2.1	0	2	67	2.1	2.7	-67	-40	-27	4	2.7	10.7
2021	2.2		2.2	0	2	69	2.2	2.8	-69	-41	-28	4.1	2.8	11.4
2022	2.2		2.2	0	2	71	2.2	2.8	-71	-43	-28	4.2	2.9	12.1
2023	2.3		2.3	0	2	73	2.3	2.9	-73	-44	-29	4.3	3.0	12.9
2024	2.4		2.4	0	2	75	2.4	3.0	-75	-45	-30	4.4	3.1	13.7
2025	2.4		2.4	0	2	78	2.4	3.1	-78	-47	-31	4.5	3.2	14.6
2026	2.5		2.5	0	3	80	2.5	3.2	-80	-48	-32	4.6	3.4	15.5
2027	2.6		2.6	0	3	82	2.6	3.3	-82	-49	-33	4.7	3.5	16.5
2028	2.7		2.7	0	3	85	2.7	3.4	-85	-51	-34	4.8	3.6	17.5
2029	2.7		2.7	0	3	87	2.7	3.5	-87	-52	-35	4.9	3.8	18.6
		23		689		1765		71	-2477	-1486	-991			

Table 5.19(a) Fiscal Regime summary of Yetagun Gas Field

Year	Production		Cost to be Recovered	Condensate Price		Condensate Price	Gross Revenue	Royalty	After Royalty
	BBL/Day	BBL/year	MMUS$	US$/BBL		US$/BBL	MMUS$	MMUS$	MMUS$
					4%			10%	
1995			-1		1				
1996			-29		1.0				
1997			-111		1.1				
1998			-115		1.1				
1999			-29		1.2				
2000	6000	2190000	-15	25	1.2	30	67	7	60
2001	9099	3321299	-15	26	1.3	33	109	11	98
2002	13800	5037000	-16	27	1.3	36	179	18	161
2003	13800	5037000	-16	28	1.4	38	193	19	174
2004	13800	5037000	-17	29	1.4	41	208	21	187
2005	13800	5037000	-17	30	1.5	44	224	22	201
2006	13800	5037000	-18	31	1.5	48	240	24	216
2007	13800	5037000	-18	32	1.6	51	258	26	232
2008	13800	5037000	-19	33	1.7	55	277	28	249
2009	13800	5037000	-19	34	1.7	59	297	30	267
2010	13800	5037000	-20	35	1.8	63	317	32	286
2011	13800	5037000	-21	36	1.9	67	340	34	306
2012	13800	5037000	-21	37	1.9	72	363	36	327
2013	13800	5037000	-22	38	2.0	77	388	39	349
2014	13800	5037000	-22	39	2.1	82	414	41	372
2015	13800	5037000	-23	40	2.2	88	441	44	397
2016	12375	4516813	-24	41	2.3	93	422	42	380
2017	11097	4050347	-25	42	2.4	100	403	40	363
2018	9951	3632055	-25	43	2.5	106	385	38	346
2019	8923	3256961	-26	44	2.6	113	367	37	331
2020	8002	2920604	-27	45	2.7	120	350	35	315
2021	7175	2618984	-28	46	2.8	128	334	33	301
2022	6434	2348513	-28	47	2.9	136	318	32	286
2023	5770	2105975	-29	48	3.0	144	303	30	273
2024	5174	1888484	-30	49	3.1	153	289	29	260
2025	4640	1693454	-31	50	3.2	162	275	27	247
2026	4160	1518566	-32	51	3.4	172	261	26	235
2027	3731	1361739	-33	52	3.5	182	248	25	224
2028	3346	1221108	-34	53	3.6	193	236	24	213
2029	3000	1095000	-35	54	3.8	205	224	22	202
	302076.4	110257903.5					8731.0	873.1	7857.9

Table5.19(b)FiscalRegimesummaryofYetagunGasField

Year	Cost Recovery Limit	Lost carry forward	Recovered Cost this year	After Cost Recovery	Profit Petroleum Government	Profit Petroleum Contractor	Income Tax	CDS NCF
	MMUS$		MMUS$	MMUS$	%	%		
	50%				70%	30%	30%	
1995		-1			0			-1
1996		-30	0		0			-29
1997		-141	0		0			-111
1998		-256	0		0			-115
1999		-285	0		0			-29
2000	33	-267	33	27	18.7	8	3 year Tax	26
2001	55	-227	55	44	30.6	13	Holiday	52
2002	89	-153	89	72	50.1	21		95
2003	97	-73	97	77	54.0	23	7	97
2004	104		90	97	68.1	29	9	94
2005	112		17	184	128.9	55	17	39
2006	120		18	199	139.0	60	18	42
2007	129		18	214	149.8	64	19	45
2008	138		19	230	161.2	69	21	48
2009	148		19	248	173.3	74	22	52
2010	159		20	266	186.1	80	24	56
2011	170		21	285	199.6	86	26	60
2012	182		21	306	213.9	92	28	64
2013	194		22	327	229.0	98	29	69
2014	207		22	350	245.0	105	32	74
2015	221		23	374	261.9	112	34	79
2016	211		24	356	249.2	107	32	75
2017	202		25	338	236.8	101	30	71
2018	192		25	321	224.8	96	29	67
2019	184		26	305	213.2	91	27	64
2020	175		27	289	202.0	87	26	61
2021	167		28	273	191.1	82	25	57
2022	159		28	258	180.6	77	23	54
2023	152		29	244	170.5	73	22	51
2024	144		30	230	160.7	69	21	48
2025	137		31	216	151.3	65	19	45
2026	131		32	203	142.2	61	18	43
2027	124		33	191	133.4	57	17	40
2028	118		34	179	125.0	54	16	37
2029	112		35	167	116.9	50	15	35
			991.0	6867.0	4806.9	2060.1	605.3	1453.7

Table 5.19 (c)Fiscal Regime summary of Yetagun Gas Field

Year	GAS NCF	GAS + CDS NCF	Discount Net Cash Flow
			10%
1995	-1.3	-2.2	-2.2
1996	-43.6	-72.7	-66.1
1997	-167.2	-278.6	-230.2
1998	-172.2	-287.0	-215.6
1999	-43.2	-72.0	-49.2
2000	87.9	114.3	71.0
2001	153.6	206.0	116.3
2002	268.0	363.2	186.4
2003	93.3	189.8	88.5
2004	85.9	179.5	76.1
2005	93.3	132.0	50.9
2006	101.2	142.9	50.1
2007	109.5	154.5	49.2
2008	118.4	166.7	48.3
2009	127.7	179.7	47.3
2010	137.6	193.5	46.3
2011	148.1	208.0	45.3
2012	159.3	223.5	44.2
2013	171.1	239.8	43.1
2014	183.5	257.0	42.0
2015	196.7	275.3	40.9
2016	188.3	263.0	35.5
2017	180.0	251.1	30.8
2018	172.0	239.4	26.7
2019	196.9	260.9	26.5
2020	187.8	248.4	22.9
2021	178.9	236.2	19.8
2022	170.2	224.4	17.1
2023	161.9	213.0	14.8
2024	153.8	202.0	12.7
2025	145.9	191.3	11.0
2026	138.4	181.0	9.4
2027	131.1	171.1	8.1
2028	124.0	161.5	7.0
2029	117.2	152.3	6.0
	4054.0	5508.9	731.2

Table 5.20 Fiscal Regime Assumptions

			Government	Contractor
Royalty			10%	
Cost Recovery				50%
Profit to Government	Gas Production MMCFD			
	<	300	70%	30%
	300	600	80%	20%
	600	900	85%	15%
	900	>	90%	10%
	Condensate BBL/Day			
	>	50000	70%	30%
	50001	100000	80%	20%
	100001	150000	85%	15%
	150001	>	90%	10%
Income Tax			30%	

5.3.1.5 Results of Yetagun Gas Field

Yetagun base case results were as shown in Table 5.21.

Table 5.21 Summary Deterministic Results of Yetagun Field

Contractor's NPV(MMUS$)	MMUS$	582
Contractor's NPV/MCF(US$/MCF)	US$/MCF	0.140
Project NPV(MMUS$)	MMUS$	4244
Net Cashflow to contractor(MMUS$)	MMUS$	5509
IRR	%	20%
Government Take	%	86%
Contractor Take	%	14%
Effective Royalty Rate	%	70%

Figure 5.12 meant that the yearly net cash flows of Yetagun Gas field against time. Contractor NCF after government take (the lowest bar) meant that in the year of start producing according to fiscal regime 3 years tax holiday contractor take higher than other year.

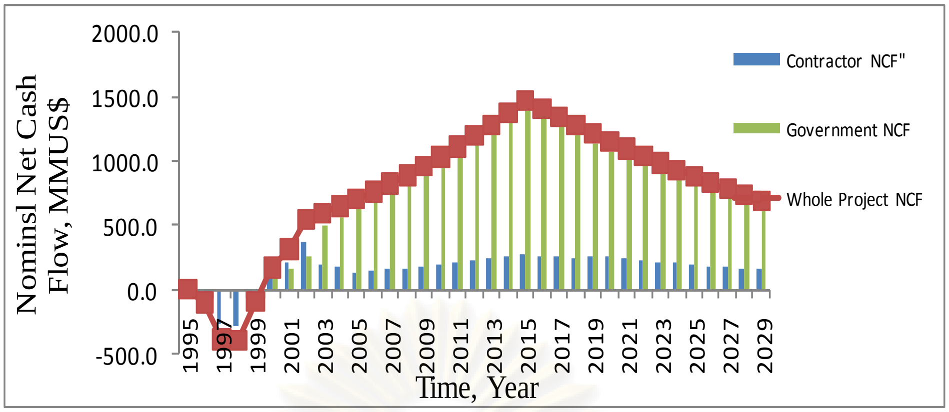


Figure 5.12 Net cash flow against time

The Government Take, Contractor Take % of project NCF meant that Government take progressive as percentage of project NPV was efficient to the contractor as shown in Figure 5.13.

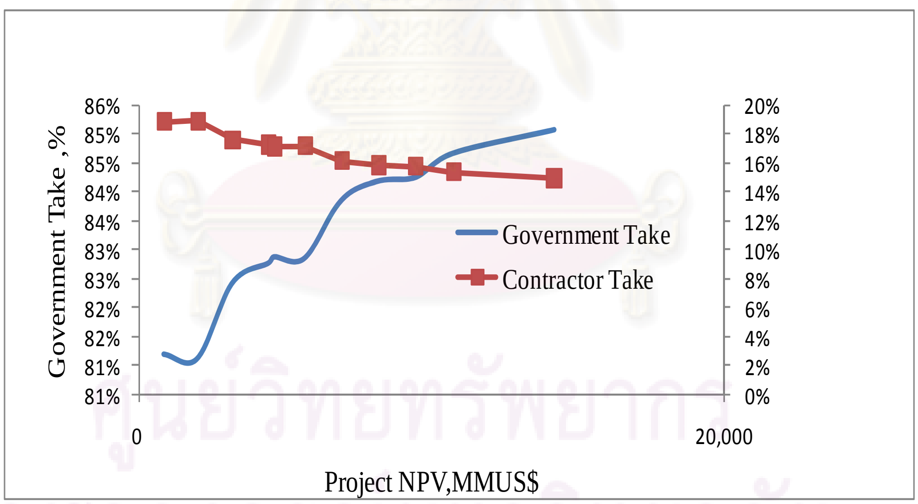


Figure 5.13 Project Net Cash flow against project NPV

5.3.2 Sensitivity analysis of Yetagun Gas Field

Minimum filed sizes 1 TCF to 10 TCF were used for hypothetically field analyses. In addition, (PSC) production sharing split were same as table (5.20).

5.3.2.1 Costs Sensitivity

In the Figure 5.14 (a) shows that base gas/condensate price sensitivity varied linearly increased and decreased the value of NPV/MCF starting from 6 TCF to above field sizes. According to profit sliding scale, gas price sensitivity might effect on less than 6 TCF field size, especially in low gas price. In addition, 50 % lower gas/condensate price was greatly impacted to small field size, 1 TCF, close to a zero NPV. The 50% higher development costs were greatly decreased NPV/MCF in small field and 50% lower development costs were not much as impact as 50 % higher development costs. In addition, lower development costs lesser impact on small and marginal fields and over 6TCF field size was linearly increased and decreased.(shown in Figure 5.14(b).Figure 5.14(c) shown that operating costs changed were very likely linearly increased and decreased overall field sizes.

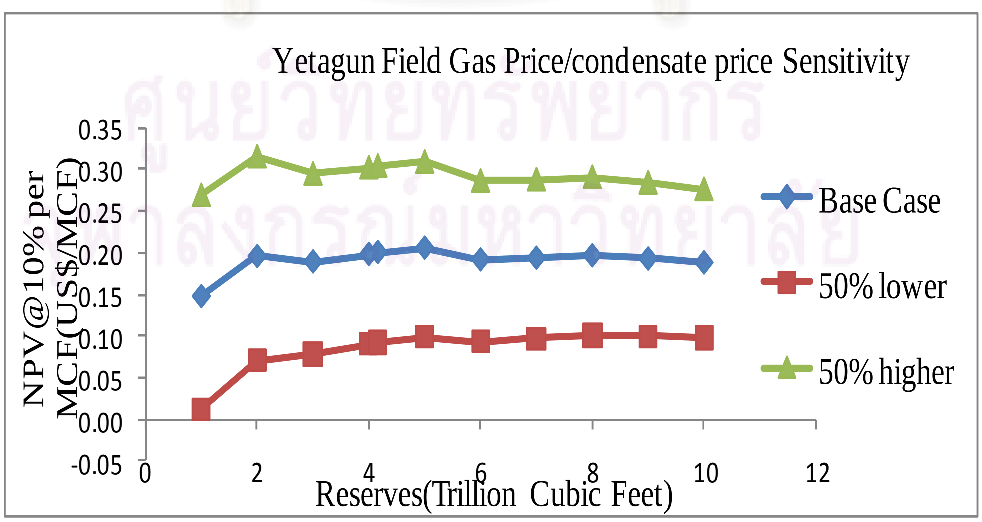


Figure 5.14 (a) Gas & Condensate Price sensitivity

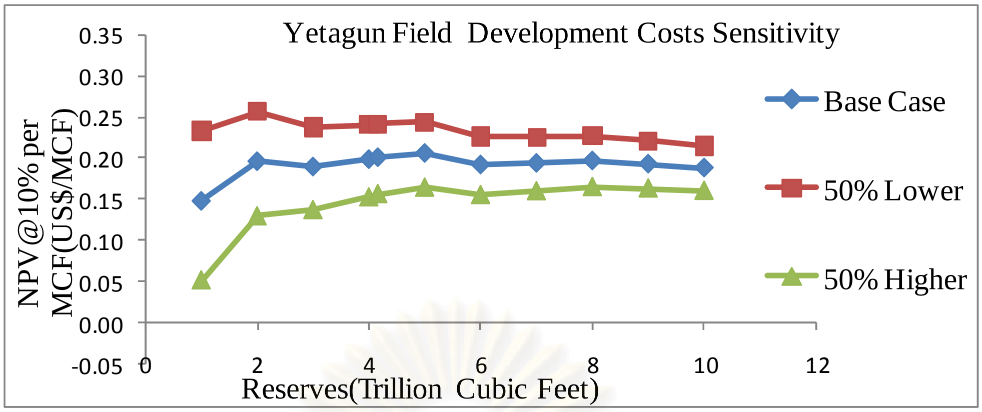


Figure 5.14 (b) Development costs sensitivity

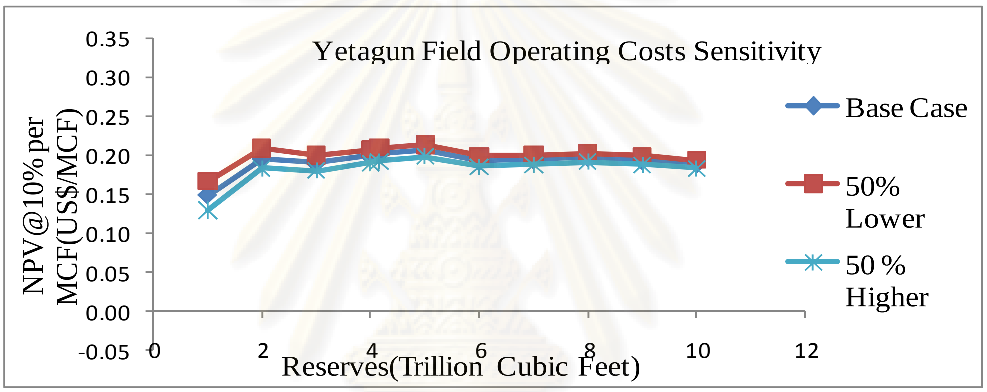


Figure 5.14 (c) Operating costs sensitivity

5.3.2.2 Peak production rate Sensitivity

In the Figure 5.15, Peak production rate were rare linearly decreased and increased to the base case.

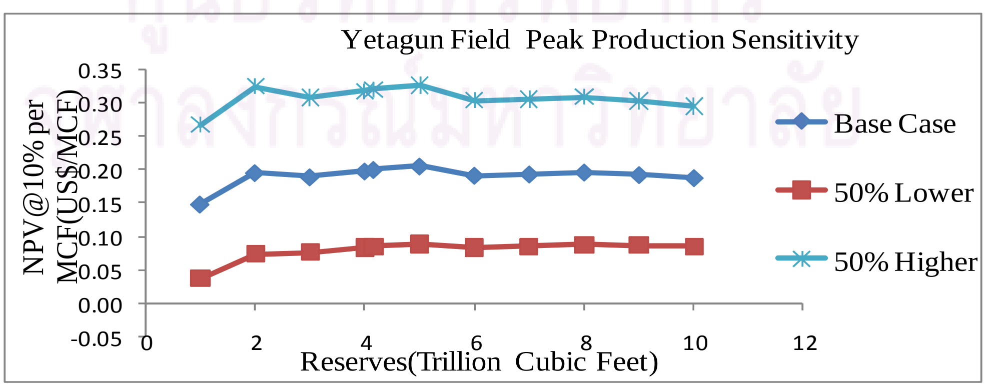


Figure 5.15, Peak production rate sensitivity

5.3.2.3 Fiscal Regime (PSC) Sensitivity

In the Figure 5.16 (a), (b), (c) stated that income tax sensitivity was the greatest impact to the fiscal regime. In the Royalty sensitivity changing was linearly and equally different from base case, because royalty is directly deducted from gross revenue. For Figure 5.16 (b) shown that lower cost recovery limit was greatly impact on less than 4TCF field sizes. Unlimited cost recovery was more efficient to the less than 4 TCF.

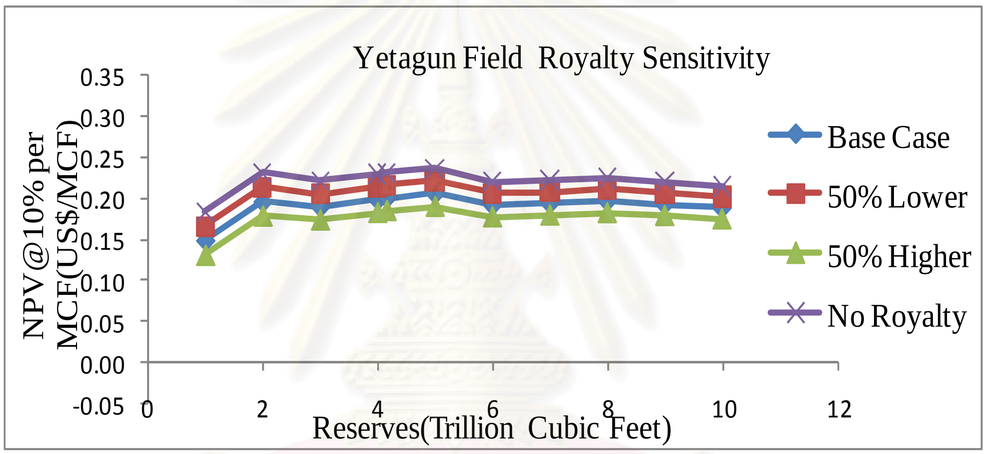


Figure 5.16(a) Royalty sensitivity

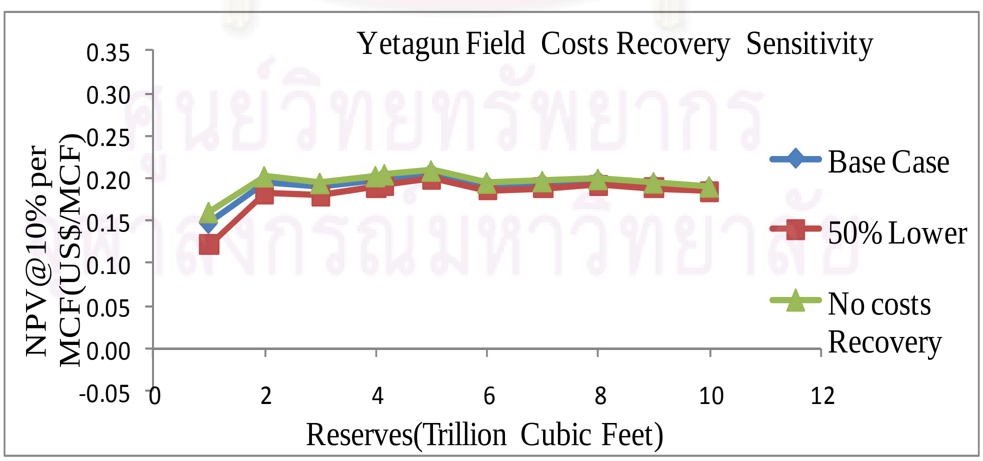


Figure 5.16(b) Costs Recovery sensitivity

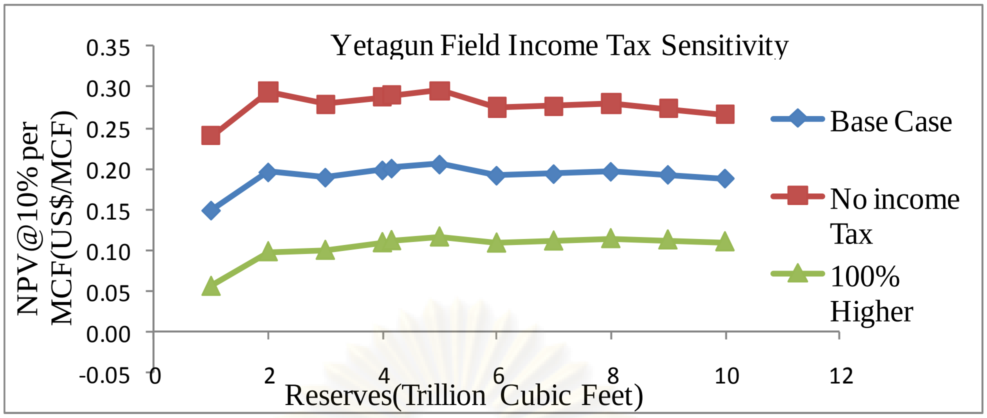


Figure 5.16(c) Income Tax sensitivity

5.3.3 Probabilistic Analysis

Deterministic analysis give only one value might not be made a decision to the project; probabilistic analysis can generate several values.

The 20000 times iterations of Monte Carlo simulation generated several excepted outcome of the project, Uncertainty value was input and excepted outcome was NPV. According to the limited information of data sources, typically triangular distribution was used. Monte Carlo simulation input variable value has been used from the value of sensitivity analyses 50% lower and 50% higher of the base case values.

In Figure 5.17 stated that deterministic analysis of NPV against the Monte Carlo simulation gave probability of success 50% confident NPV (583 MMUS$) was nearly the same with the value of deterministic analysis NPV (582 MMUS$).In addition, probability of success 5% confident NPV was (336 MMUS$) and 95% confident was (881MMUS$).As a results of Yetagun Project, its project NPV was positively for all probability of success 20% percent likely the same with deterministic analysis.

Table 5.22 Input variable parameter of Yetagun Gas Field

Yetgun			Parameter		
Items	Units	Distribution	Min	Mean	Max
Capital Costs	MMUS$	Triangular	321	640	958
Opetration costs/year	MMUS$/year	Triangular	16	33	49
Abandonment costs	MMUS$	Triangular	11	22	33
Heating Value	BTU/MMSCF	Triangular	503	1000	1496
Escalated Gas Price	%	Triangular	2%	4%	6%
Royalty	%	Triangular	5%	10%	15%
Costs Recovery	%	Triangular	25%	50%	75%
Income Tax	%	Triangular	15%	30%	45%
Gas Price(Year 1)	US$	Triangular	1	2	3

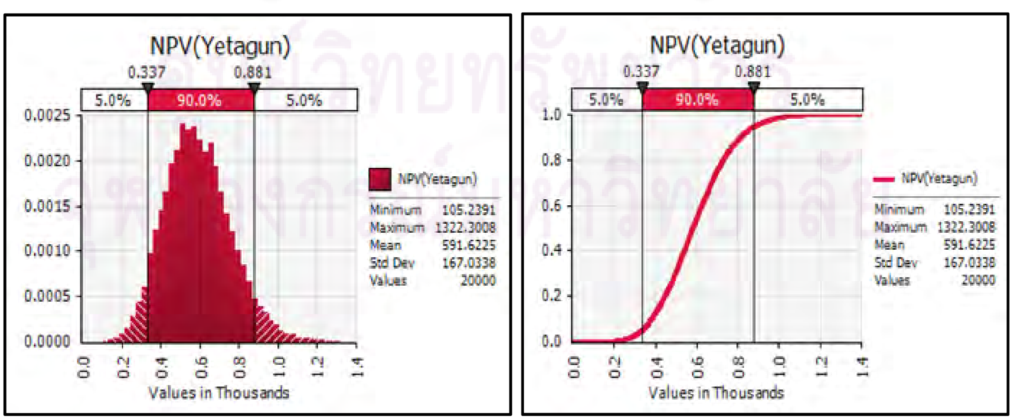


Figure 5.17 PDF of YetagunNPV and CDF of Yetagun NPV

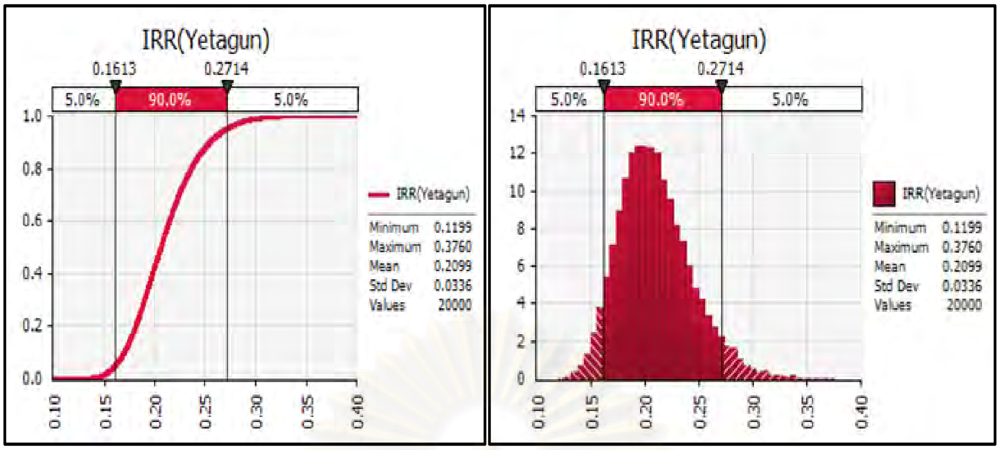


Figure 5.18 PDF of Yetagun IRR and CDF of Yetagun IRR

Statistic results Yadana project NPV and Yadana project IRR was shown in Table5.23.

Table 5.23 Statistic results Yetagun project NPV and Yetagun project IRR

Summary Statistics for NPV(Yetagun)		Summary Statistics for IRR(Yetagun)	
Percentile	MMUS$	Percentile	%
5%	337	5%	16%
10%	382	10%	17%
15%	417	15%	18%
20%	447	20%	18%
25%	473	25%	19%
30%	496	30%	19%
35%	518	35%	19%
40%	540	40%	20%
45%	560	45%	20%
50%	581	50%	21%
55%	604	55%	21%
60%	626	60%	21%
65%	650	65%	22%
70%	673	70%	22%
75%	699	75%	23%
80%	729	80%	24%
85%	765	85%	24%
90%	812	90%	26%
95%	881	95%	27%

5.4. Zawtika Project

The Zawtika gas field contains more than 1.7 Trillion Cubic feet of natural gas and an expected field life of over 25 years. PTT Exploration and Production International (PTTEP) intend to develop and produce gas from the offshore Block M9, owned by Myanmar Oil &Gas Enterprise (MOGE). The M9 block is located in the Bay of Martaban offshore of Myanmar. The field lies approximately 300 km south of Yangon and 240 km west of Tavoy on the Myanmar coast. The water depth is approximately 140 meters. The gas field lays around 1100 meters (3,600 ft.) The offshore production complex from produced gas will be exported through 24 inches pipeline to the Thai border. Construction of the pipeline will be completed in 2012. (see Figure 5.19 and Table 5.24)

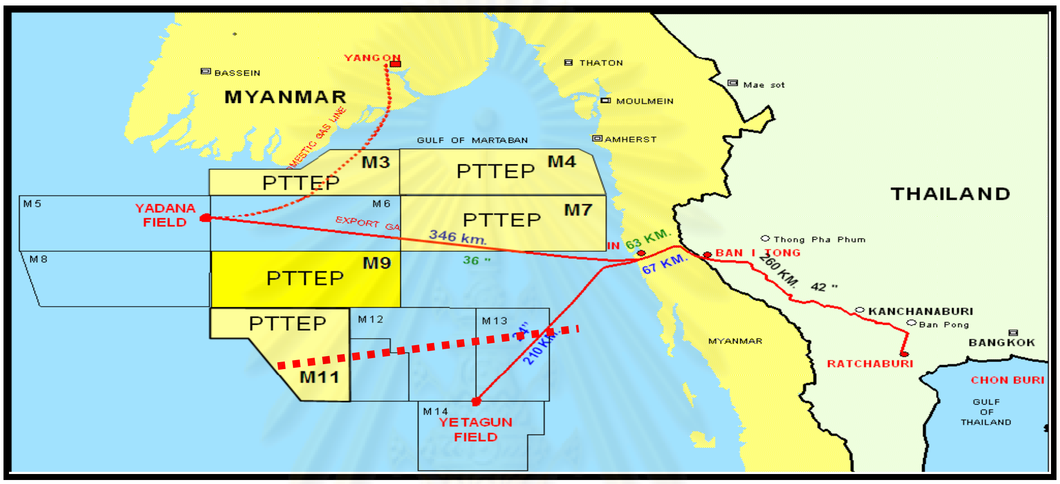


Figure 5.19 Location map of Zawtika Gas Field

Table 5.24 Zawtika Gas Field Summary

ITEMS	DESCRIPTION	REMARKS
Blocks	M-9	
Location	Mottama Offshore	
Partners	PTTEP MOGE	85% 15%
PSC Signed		
Product	Gas	
Proved Reserves	1.7 TCF	
Production Start up	2013	

Project Cost	2100 MMUS$	
Average Water depth	150 meters(492ft)	
Reservoirs	Sandstone	

5.4.1 Assumptions

The economics analyses for Zawtika gas field summary assumptions were shown in Table 5.27.

5.4.1.1 Economics Assumptions

(1) Gas Price

Assuming base case wellhead gas price for year one would be 6 US$/MMBTU in year 2013 and escalation rate 4% per year will be starting from year 2013(see Table 5.30).For sensitivity analysis, 50% higher (9 US$/MMBTU) and 50% lower (3US$/MMBTU) price have been used.

(2) Escalation

Exploration costs, development costs and operating costs escalation rate were 3% per year starting in 2013(Table 5.30).

(3) Discount rate

10 % discount rate was used for calculating the Project NPV and contractor after take net cash flow. Typically oil and gas company used this value.

5.4.1.2 Costs Assumptions

Explorations costs and development costs were assumed to be in the 2005 based on real information. Operating costs 5% /year and abandonment costs 5% of development costs. This information was based on real data and rule of thumb typical oil and gas investor's assumptions.

According to existing field, peak production rate was constant 5% of initial reserves. Peak production rates, Field development costs, operating costs and abandonment costs summary were as shown in Table 5.25.

Table 5.25 Peak production rates, Field development costs, operating costs and abandonment costs summary

Reserves	TCF	1	2	3	4	5	6	7	8	9	10
Peak rate	%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
Peak production	MMCFD	137	274	411	548	685	822	959	1,096	1,233	1,370
Development cost	MMUS$	1,251	1,895	2,418	2,873	3,285	3,664	4,019	4,355	4,673	4,978
Operating cost		5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
	MMUS$/year	63	95	121	144	164	183	201	218	234	249
Abandonment cost		5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
	MMUS$	63	95	121	144	164	183	201	218	234	249

Zawtika gas field peak production is 325 MMCFD, development costs (exclude transportation costs) was 2100MMUS$ and reserves is 1.7 TCF. Field development planning was as shown in (Table 5.26). To maintain the production, additional costs were planned for the year 13th to 17th respectively.

Table 5.26 Exploration costs and development costs phasing

Year	Exploration	Production	Development	
1	14			
2	42			0
3	42		10%	210
4	42		20%	421
5			20%	421
6		Start production	5%	105
7				0
8				0
9				0
10				0
11				0
12				0
13			5%	105
14			5%	105
15			10%	210
16			10%	210
17			15%	316

5.4.1.3 Production Profile

Production going to start up in the year of 2012 and rump up production for 2 years after 100% of peak production rate . After 10 year plateau, production decline will start to the field life end of 25 years were shown in Figure 5.20. The estimated production profile, exploration costs, development costs, operating costs and abandonment cost were shown in Table 5.29.Over all capital expenditure , operation costs and abandonment costs were 2100MMUS$ for the project(exclude pipeline transportation costs and pipeline operating costs).

5.4.1.4 Fiscal Regime Assumptions

Zawtika Gas Field production sharing contracts (PSC) was production period 25 years of field life and PSC include to be Royalty 10%, Costs recovery limit 50%, profit gas sharing sliding scale and income tax 30% (include 3year tax holidays) are shown in Table 5.31.Domestic used about 60 MMCD assumed to be same price with export sale, so in these analysis domestic gas might not be separated.

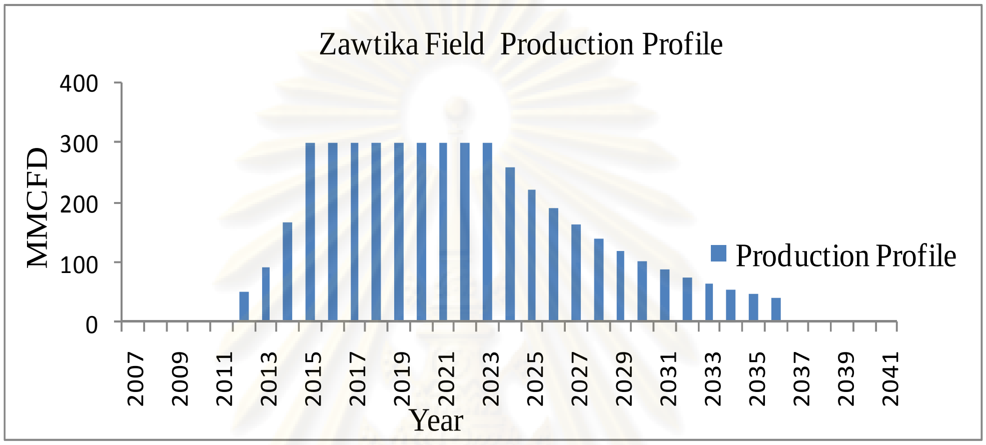


Figure 5.20 Zawtika gas field production profile

Table 5.27 Summary of Assumption

Items	Assumptions
Water Depth	600 ft <
Gas Price (Year one)	6 US$/MMBTU
Discount Rate	10%
Gas Pri ce Escalation	4%
Exploration, operating, abandonment costs Escalation	3%
Operating Costs	5%/year of Capital costs
Abandonment Costs	5% of Capital costs

5.4.1.5 Results of Zawtika Gas Field

Zawtika base case results were as shown in Table 5.28.

Table 5.28 Summary Deterministic Results of Zawtika Field

Contractor's NPV(MMUS$)	MMUS$	118
Contractor's NPV/MCF(US$/MCF)	US$/MCF	0.070
Project NPV(MMUS$)	MMUS$	2829
Net Cashflow to contractor(MMUS$)	MMUS$	2173
IRR	%	12%
Government Take	%	85%
Contractor Take	%	17%
Effective Royalty rate	%	49%

Figure 5.21 meant that the yearly net cash flows of Zawtika Gas field against time. Contractor NCF after government takes (the lowest bar) meant that in the year of start producing according to fiscal regime 3 years tax holiday contractor take higher than other year.

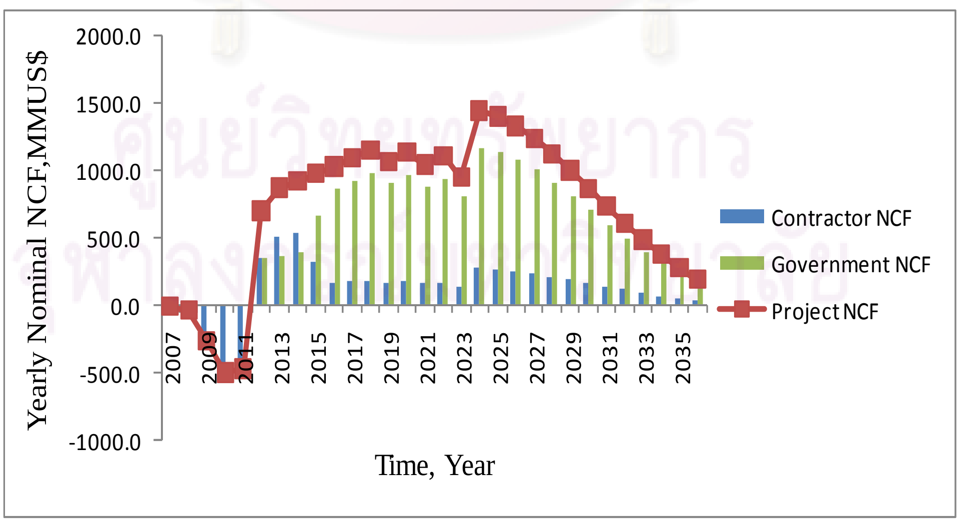


Figure 5.21 Net Cash flow of Zawtika field against time

Table 5.29 Summary of Zawtika Gas field costs assumptions

Year	Production				Exploration Cost	CAPX	OPEX	Abandonment Cost	Total cost
	MMCFD	MMCF/Year	MMBTUD	MMBTU/Year	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
							5%		
2007					14				-14
2008					42	0			-42
2009					42	210			-252
2010					42	420			-462
2011						420			-420
2012	50	18,250	50,000	18,250,000		105	105	4.2	-214
2013	91	33,162	90,856	33,162,451		0	105	4.2	-109
2014	165	60,260	165,096	60,260,172		0	105	4.2	-109
2015	300	109,500	300,000	109,500,000		0	105	4.2	-109
2016	300	109,500	300,000	109,500,000		0	105	4.2	-109
2017	300	109,500	300,000	109,500,000		0	105	4.2	-109
2018	300	109,500	300,000	109,500,000		0	105	4.2	-109
2019	300	109,500	300,000	109,500,000		105	105	4.2	-214
2020	300	109,500	300,000	109,500,000		105	105	4.2	-214
2021	300	109,500	300,000	109,500,000		210	105	4.2	-319
2022	300	109,500	300,000	109,500,000		210	105	4.2	-319
2023	300	109,500	300,000	109,500,000		315	105	4.2	-424
2024	257	93,778	256,926	93,778,162			105	4.2	-109
2025	220	80,314	220,037	80,313,640			105	4.2	-109
2026	188	68,782	188,445	68,782,333			105	4.2	-109
2027	161	58,907	161,388	58,906,674			105	4.2	-109
2028	138	50,449	138,216	50,448,946			105	4.2	-109
2029	118	43,206	118,371	43,205,565			105	4.2	-109
2030	101	37,002	101,376	37,002,178			105	4.2	-109
2031	87	31,689	86,820	31,689,463			105	4.2	-109
2032	74	27,140	74,355	27,139,540			105	4.2	-109
2033	64	23,243	63,679	23,242,887			105	4.2	-109
2034	55	19,906	54,536	19,905,710			105	4.2	-109
2035	47	17,048	46,706	17,047,679			105	4.2	-109
2036	40	14,600	40,000	14,600,000			105	4.2	-109
2037									
2038									
2039									
2040									
2041									
		1663235			140	2100	2625		-4970

Table 5.30 Escalated costs Summary of Zawtika Gas field

Year	Exploration Cost MMUS$		CAPX MMUS$		OPEX MMUS$			Abandonment Cost MMUS$	Cost to be Recovered MMUS$	Price US$/MMBTU	Price US$/MMBTU	
	3%		3%		3%		3%				4%	
2007	1	14	1.0	0	1	0	1.0	0	-14		1	0.0
2008	1.03	43.26	1.0	0	1	0	1.0	0	-43		1.0	0.0
2009	1.06	44.56	1.1	223	1	0	1.1	0	-267		1.1	0.0
2010	1.09	45.89	1.1	459	1	0	1.1	0	-505		1.1	0.0
2011	1.13	0	1.1	473	1	0	1.1	0	-473		1.2	0.0
2012	1.16	0	1.2	122	1	122	1.2	4.9	-243	6	1.2	7.3
2013	1.19	0	1.2	0	1	125	1.2	5.0	-125	6.1	1.3	7.7
2014	1.23		1.2	0	1	129	1.2	5.2	-129	6.2	1.3	8.2
2015	1.27		1.3	0	1	133	1.3	5.3	-133	6.3	1.4	8.6
2016	1.30		1.3	0	1	137	1.3	5.5	-137	6.4	1.4	9.1
2017	1.34		1.3	0	1	141	1.3	5.6	-141	6.5	1.5	9.6
2018	1.38		1.4	0	1	145	1.4	5.8	-145	6.6	1.5	10.2
2019	1.43		1.4	150	1	150	1.4	6.0	-299	6.7	1.6	10.7
2020	1.47		1.5	154	1	154	1.5	6.2	-308	6.8	1.7	11.3
2021	1.51		1.5	318	2	159	1.5	6.4	-476	6.9	1.7	11.9
2022	1.56		1.6	327	2	164	1.6	6.5	-491	7	1.8	12.6
2023	1.60		1.6	505	2	168	1.6	6.7	-674	7.1	1.9	13.3
2024	1.65		1.7	0	2	174	1.7	6.9	-174	7.2	1.9	14.0
2025	1.70		1.7	0	2	179	1.7	7.2	-179	7.3	2.0	14.8
2026	1.75		1.8	0	2	184	1.8	7.4	-184	7.4	2.1	15.6
2027	1.81		1.8	0	2	190	1.8	7.6	-190	7.5	2.2	16.4
2028	1.86		1.9	0	2	195	1.9	7.8	-195	7.6	2.3	17.3
2029	1.92		1.9	0	2	201	1.9	8.0	-201	7.7	2.4	18.2
2030	1.97		2.0	0	2	207	2.0	8.3	-207	7.8	2.5	19.2
2031	2.03		2.0	0	2	213	2.0	8.5	-213	7.9	2.6	20.3
2032	2.09		2.1	0	2	220	2.1	8.8	-220	8	2.7	21.3
2033	2.16		2.2	0	2	226	2.2	9.1	-226	8.1	2.8	22.5
2034	2.22		2.2	0	2	233	2.2	9.3	-233	8.2	2.9	23.6
2035	2.29		2.3	0	2	240	2.3	9.6	-240	8.3	3.0	24.9
2036	2.36		2.4	0	2	247	2.4	9.9	-247	8.4	3.1	26.2
2037												
2038												
2039												
2040												
2041												
		148		2730		4438		178	-7316			

Table 5.31 Fiscal Regime Summary of Zawtika Gas field

Year	Revenue	Royalty	After Royalty	Cost Recovery Limit	Lost carry forward	Recovered Cost this year	After Cost Recovery	Profit Petroleum		Income Tax	Discount Net Cash Flow
								Government	Contractor		
	MMUS$	MMUS$	MMUS$	MMUS$		MMUS$	MMUS$	%	%		
		10%		50%						30%	10%
2007					-14						-14.0
2008					-57						-39.3
2009					-325						-220.9
2010					-829						-379.3
2011					-1302						-322.9
2012	133.2	13	120	67	-1479	67	53	37	16	3 year	-99.9
2013	256.0	26	230	128	-1476	128	102	72	31	Tax	18.8
2014	491.6	49	442	246	-1360	246	197	138	59	Holidays	90.2
2015	944.1	94	850	472	-1021	472	378	264	113	34.0	195.2
2016	997.5	100	898	499	-659	499	399	279	120	35.9	188.9
2017	1053.6	105	948	527		800	148	104	44	13.3	266.0
2018	1112.6	111	1001	556		145	856	599	257	77.0	63.0
2019	1174.6	117	1057	587		299	758	530	227	68.2	50.7
2020	1239.8	124	1116	620		308	807	565	242	72.7	49.1
2021	1308.4	131	1178	654		476	701	491	210	63.1	38.8
2022	1380.4	138	1242	690		491	752	526	225	67.6	37.8
2023	1456.1	146	1311	728		674	637	446	191	57.3	29.1
2024	1315.2	132	1184	658		174	1010	707	303	90.9	42.0
2025	1187.7	119	1069	594		179	890	623	267	80.1	33.6
2026	1072.4	107	965	536		184	781	547	234	70.3	26.8
2027	968.0	97	871	484		190	682	477	204	61.3	21.3
2028	873.7	87	786	437		195	591	414	177	53.2	16.8
2029	788.4	79	710	394		201	508	356	153	45.8	13.1
2030	711.4	71	640	356		207	433	303	130	39.0	10.2
2031	641.7	64	578	321		213	364	255	109	32.8	7.8
2032	578.8	58	521	289		220	301	211	90	27.1	5.8
2033	522.0	52	470	261		226	243	170	73	21.9	4.3
2034	470.6	47	424	235		233	190	133	57	17.1	3.0
2035	424.3	42	382	212		240	142	99	42	12.7	2.1
2036	382.5	38	344	191		247	97	68	29	8.7	1.3
2037											
2038											
2039											
2040											
2041											
	21484.6	2148.5	19336.2			7316.0	12020.1	8414.1	3606.0	1050.1	139.3

The Figure 5.22 stated that Government Take percentage of government take was progressive as percentage of project NPV increases with the increase in the profitability of the project.

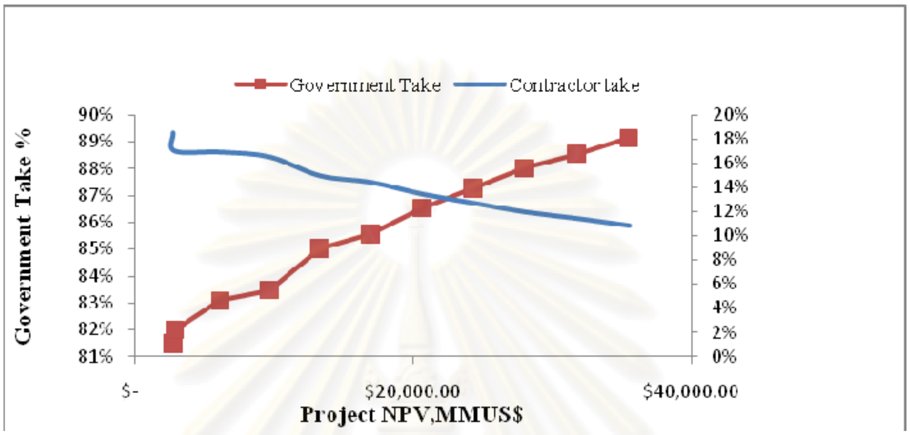


Figure 5.22 Project Net Cash Flow against Government Take, Contractor Take

5.4.2 Sensitivity analysis of Zawtika Gas Field

Minimum filed sizes 1 TCF to 10 TCF were used for hypothetically field analyses. In addition, (PSC) production sharing split were same as Table 5.20.

5.4.2.1 Costs Sensitivity

In the Figure 5.23(a) shows that base gas price sensitivity varied linearly increased and decreased the value of NPV/MCF. According to low gas price sensitivity, it was greatly impacted to small field size, 1 TCF, gave negative NPV. The 50% higher development costs were greatly decreased NPV/MCF in small field and 50% lower development costs were not much as impact as 50 % higher development costs. In addition, lower development costs lesser impact on small and marginal fields and over 6TCF field size was linearly increased and decreased.(shown in Figure 5.23 (b).Figure

5.23 (c) shows that operating costs changed were very likely linearly increased and decreased overall field sizes.

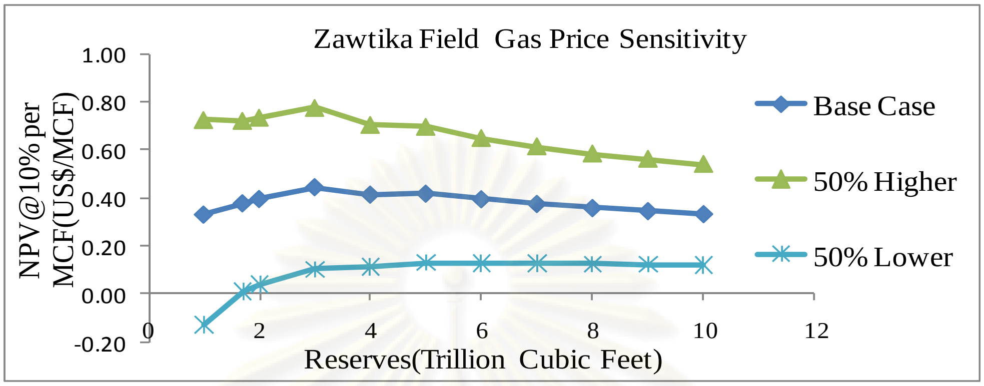


Figure 5.23(a) Gas price Sensitivity

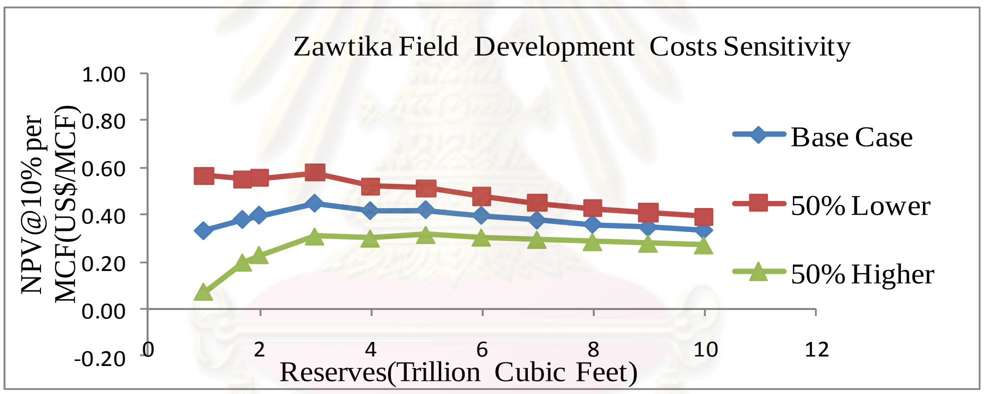


Figure 5.23 (b) Development costs Sensitivity

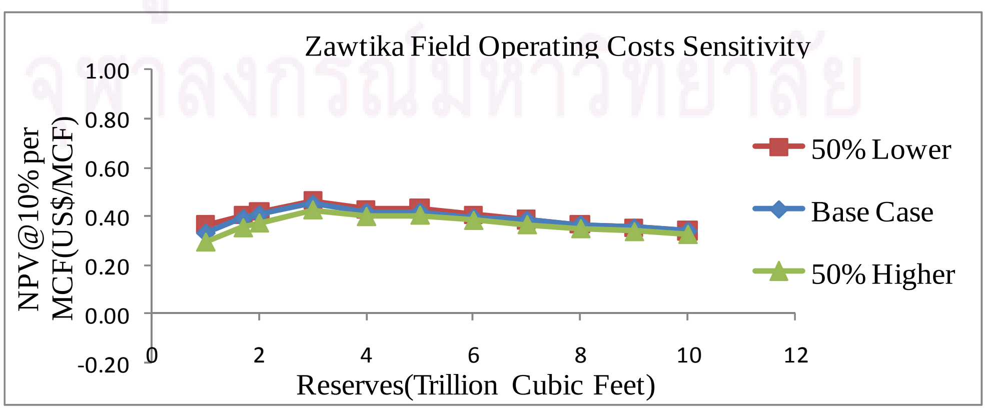


Figure 5.23 (c) operating costs sensitivity

5.4.2.2 Peak production rate Sensitivity

In the Fig 5.24, Peak production rate was rare linearly decreased and increased to the base case.

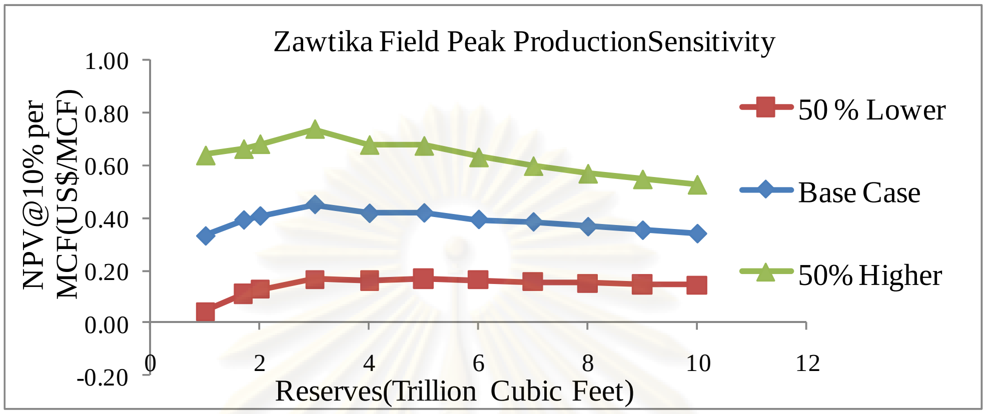


Figure 5.24 Peak production Rate sensitivity

5.4.2.3 Fiscal Regime (PSC) Sensitivity

In the Figure 5.25(a), (b), (c) the income tax sensitivity was the greatest impact to the fiscal regime. In the Royalty sensitivity changing was linearly and equally different from base case, because royalty is directly deducted from gross revenue. For Figure 5.25(b) shows that lower cost recovery limit was greatly impact on less than 2TCF field sizes. Unlimited cost recovery was more efficient to the less than 2 TCF.

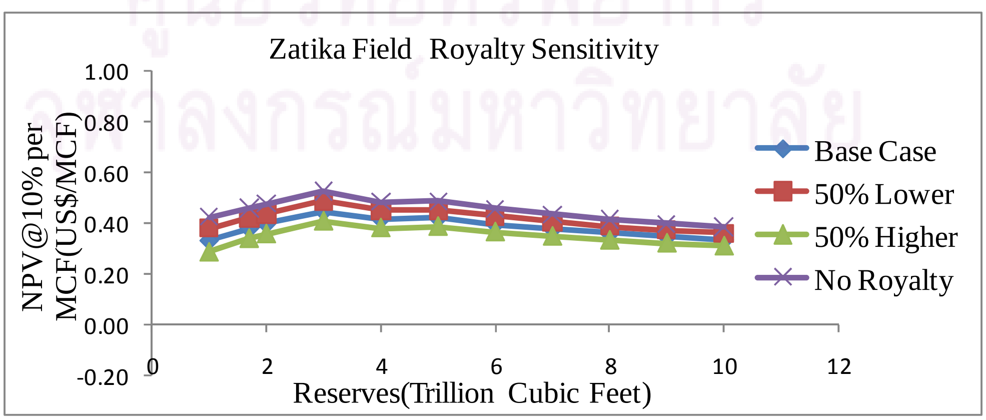


Figure 5.25 (a) Royalty sensitivity

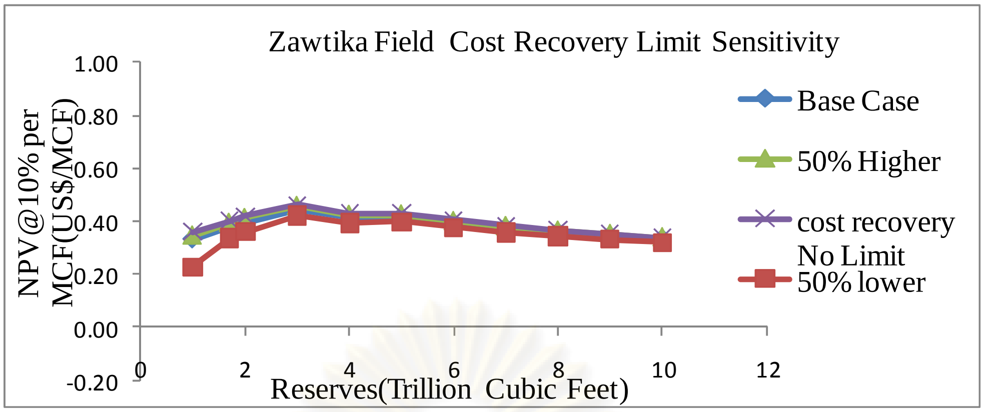


Figure 5.25 (b) Costs recovery sensitivity

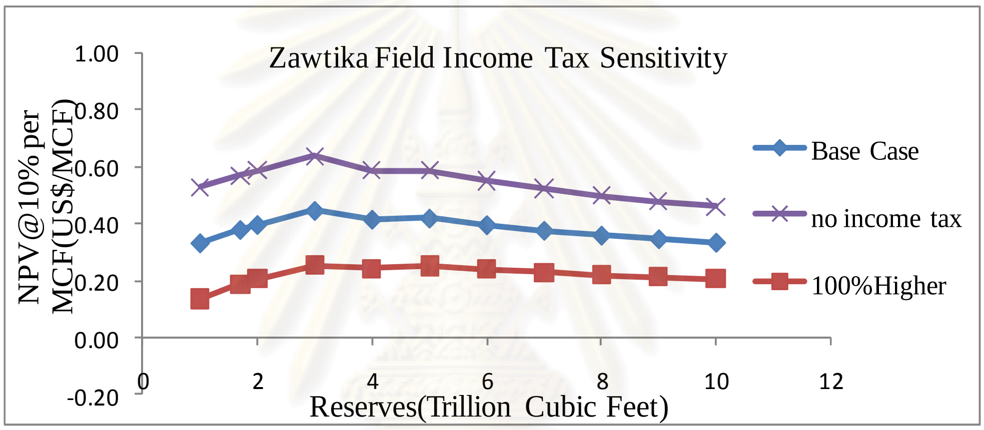


Figure 5.25 (c) Income Tax sensitivity

5.4.3 Probabilistic Analysis

The 20000 times iterations of Monte Carlo simulation generated several excepted outcome of the project, Uncertainty value was input and excepted outcome was NPV. According to the limited information of data sources, typically triangular distribution was used. Monte Carlo simulation input variable value has been used from the value of sensitivity analyses 50% lower and 50% higher of the base case values. For gas price input, lognormal distribution was used. Summary of Input variable are shown in Table 5.32.

In Figure 5.26 stated that deterministic analysis of NPV against the Monte Carlo simulation results fall in between probability of success 25%, NPV (77 MMUS$) and probability of success 30%, (188MMUS$) similarly with the value of deterministic analysis NPV (118 MMUS$).In addition, probability of success less than 25% confident NPV was (77MMUS$) and 95% confident were (1415MMUS$).Probability of less than 20% gave negative NPV. As results Zawtika Project, its project NPV was positively NPV for greater or equal 25% probability. Detail analysis of NPV and IRR value are shown in Table 5.33.In Figure 5.27 shows thePDF and CDF of IRR of Zawtika field.

Table 5.32 Summary of Input variable

Zawtika			Parameter		
Items	Units	Distribution	Min	Mean	Max
Base Gas Price(P1)	US$	Lognormal	-4	5	14
(FO)	US$/BBL	Lognormal	-70	37	124
(OMy)	Index	Lognormal	32	163	304
CPIy	Index	Lognormal	125	193	265
Capital Costs	MMUS$	Triangular	1057	2100	3142
Opetration costs/year	MMUS$/year	Triangular	53	105	157
Abandonment costs	MMUS$	Triangular	70	140	210
Heating Value	BTU/MMSCF	Triangular	502	1000	1496
Escalated Gas Price	%	Triangular	2%	4%	6%
Royalty	%	Triangular	5%	10%	15%
Costs Recovery	%	Triangular	25%	50%	75%
Income Tax	%	Triangular	15%	30%	45%

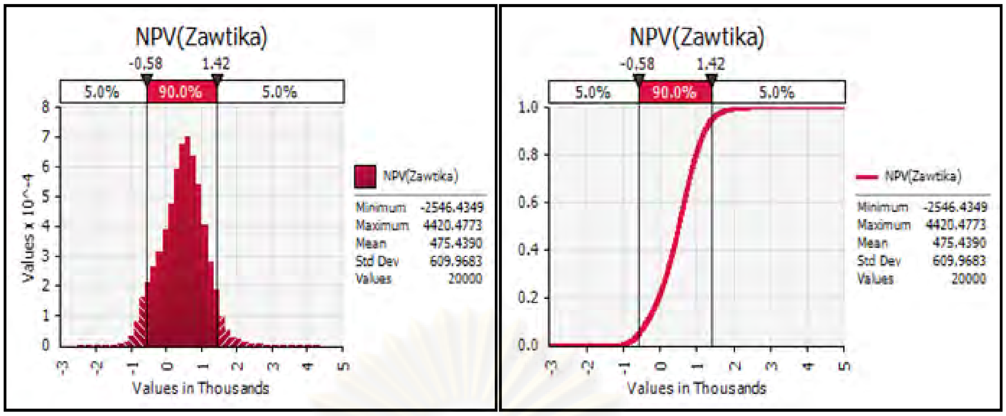


Figure 5.26 PDF of Zawtika project NPV and CDF of Zawtika project NPV

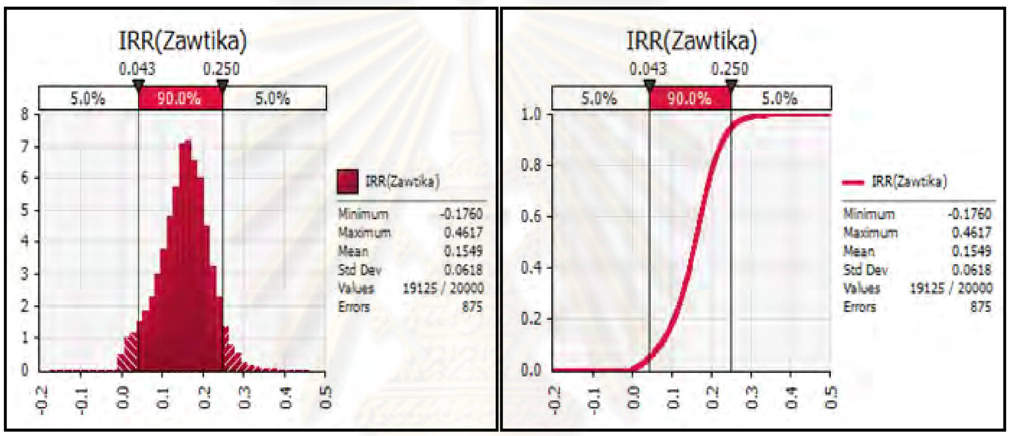


Figure 5.27 PDF of Zawtika project IRR and CDF of Zawtika project IRR

Table 5.33 Stastistic results Zawtika project NPV and Zawtika project IRR

Summary Statistics for NPV(Zawtika)		Summary Statistics for IRR(Zawtika)	
Percentile	NPV	Percentile	%
5%	-580	5%	4%
10%	-359	10%	7%
15%	-183	15%	9%
20%	-44	20%	11%
25%	77	25%	12%
30%	181	30%	13%
35%	274	35%	14%
40%	356	40%	14%
45%	431	45%	15%
50%	505	50%	16%
55%	577	55%	17%
60%	648	60%	17%
65%	719	65%	18%
70%	798	70%	19%
75%	881	75%	20%
80%	976	80%	20%
85%	1074	85%	22%
90%	1218	90%	23%
95%	1415	95%	25%

5.5. Shwe Project

The Shwe gas field contains more than 4.5 Trillion Cubic feet of natural gas and an expected field life of over 30 years. Daewoo international Exploration and Production International intends to develop and produce gas from the offshore Block A-1, owned by Myanmar Oil &Gas Enterprise (MOGE). The A1 block is located in the Adaman Sea offshore of Myanmar. The water depth is approximately 150 meters. The offshore production complex from produced gas will be exported through 32 inches pipeline (110 km) to the shore and 40 inches (870 km) from shore to China Border. Construction of the pipeline will be completed in 2013.(see Figure 5.28 and Table 5.34)

Figure 5.28 Location Map of Shwe Project

Table 5.34 Shwe Gas Field summary

ITEMS	DESCRIPTION	REMARKS
Blocks	A-1, A-3	
Location	Adaman Sea Offshore	
Partners	DAEWOO ONGC KOGAS GAIL MOGE	51 % 17% 8.5% 8.5% 15%
PSC Signed	2000	
Product	Gas	
Proved Reserves	4.5 TCF	
Production Start up	2013	
Project Cost	2970 MMUS$	Exclude transportation costs
Average Water depth	150 meters(492ft)	
Reservoirs	Sandstone	

5.5.1 Assumptions

The economics analyses for Shwe gas field assumptions are as follows;

5.5.1.1 Economics Assumptions

(1) Gas Price

Assuming base case wellhead gas price for year one would be 6 US$/MMBTU in year 2013 and escalation rate 4% per year will be starting from year 2013(Table 5.40).For sensitivity analysis, 50% higher (9 US$/MMBTU) and 50% lower (3US$/MMBTU) price have been used.

(2) Escalation

Exploration costs, development costs and operating costs each escalation rate will be 3% per year starting in 2013(Table 5.40).

(3) Discount rate

10 % discount rate was used for calculating the Project NPV and contractor after take net cash flow. Typically oil and Gas Company used this value.

5.5.1.2 Costs Assumptions

Explorations costs and development costs were assumed to be in the 2004 based on real information. Operating costs is 5% /year and abandonment costs are 5% of development costs. This information was based on real data and rule of thumb typical oil and gas investor's assumptions.

For hypothetical field analyses, peak production rate and field development costs were related to existing field in same region. According to existing field, peak production rate was constant 5.0% of initial reserves. Peak production rates, Field development costs, operating costs and abandonment costs summary were as shown in Table 5.35.

Table 5.35Summary of peak production rates and development costs and abandonment costs

Reserves	TCF	1	2	3	4	5	6	7	8	9	10
Peak rate	%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
Peak production	MMCFD	137	274	411	548	685	822	959	1,096	1,233	1,370
Development costs	MMUS$	1,366	2,070	2,640	3,138	3,587	4,002	4,390	4,756	5,104	5,437
Operating costs		5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
	MMUS$/year	68	104	132	157	179	200	219	238	255	272
Abandonment costs		5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
	MMUS$	68	104	132	157	179	200	219	238	255	272

Shwe gas field peak production is 500 MMCFD, development costs (exclude transportation costs) was 2970MMUS$ and reserves is 4.5 TCF.

Field development planning was as shown in (Table 5.36). To maintain the production additional costs were planned for the year 13th to 17th respectively.

5.5.1.3 Production Profile

Production going to start up in the year of 2013, 100% of peak production rate will start after two year rump up. After 16 year plateau, start to decline .The field life will be 30 years.(see in Figure 5.29). The estimated production profile, exploration costs, development costs, operating costs and abandonment costs were shown in Table 5.39.Over all capital expenditure , operation costs and abandonment costs were 2970MMUS$ for the project(exclude pipeline transportation costs and pipeline operating costs)

Table 5.36 Exploration costs and development costs phasing

Development and Production Plan				
Year	Exploration cost	Production	Development	
1	14			
2	42			0
3	42		10%	279
4	42		20%	558
5			20%	558
6	140	Start	5%	139
7				0
8				0
9				0
10				0
11				0
12				0
13			5%	139
14			5%	139
15			10%	279
16			10%	279
17			15%	418

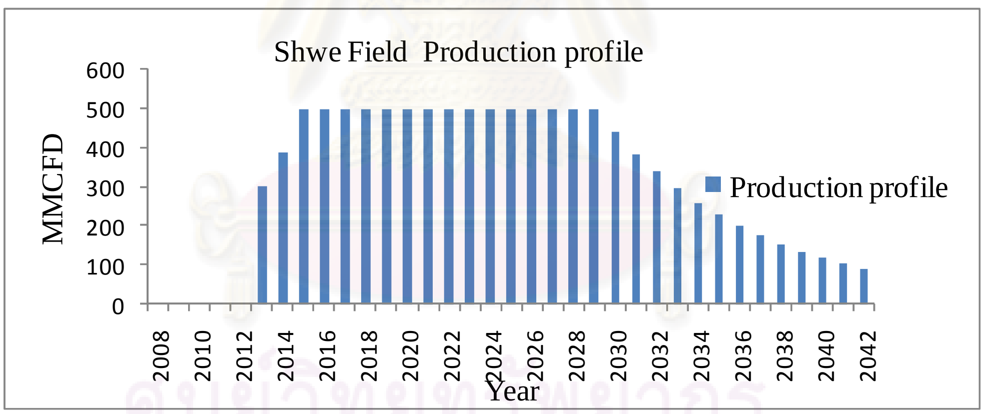


Figure 5.29 Shwe gas field production profile

Table 5.37 Summary of Assumption

Items	Assumptions
Water Depth	600 ft <
Gas Price (Year one)	6 US$/MMBTU
Discount Rate	10%
Gas Pri ce Escalation	4%

Exploration, operating, abandonment costs Escalation	3%
Operating Costs	5%/year of Capital costs
Abandonment Costs	5% of Capital costs

5.5.1.4 Fiscal Regime Assumptions

Shwe Gas Field production sharing contracts (PSC) was production period 30 years of field life and PSC include to be Royalty 10%, Costs recovery limit 50%, profit gas sharing sliding scale and income tax 30% (include 3year tax holidays) are as shown in (Table 5.25).Domestic used about 100 MMCD was assumed to be same price with export sale, so in these analysis domestic gas might not be separated.

5.5.1.5Results of Shwe Gas Field

Figure 5.30 meant that the yearly net cash flows of Zawtika Gas field against time. Contractor NCF after government take (the lowest bar) meant that in the year of start producing according to fiscal regime 3 years tax holiday contractor take higher than other year. Summary results of Shwe project is shown in Table 5.38.

Table 5.38. Summary results of Shwe Gas Field

Contractor's NPV(MMUS$)	MMUS$	900
Contractor's NPV/MCF(US$/MCF)	US$/MCF	0.200
Project NPV(MMUS$)	MMUS$	8658
Net Cashflow to contractor(MMUS$)	MMUS$	6713
IRR	%	19%
Government Take	%	86%
Contractor Take	%	14%
Effective Royalty rate	%	62%

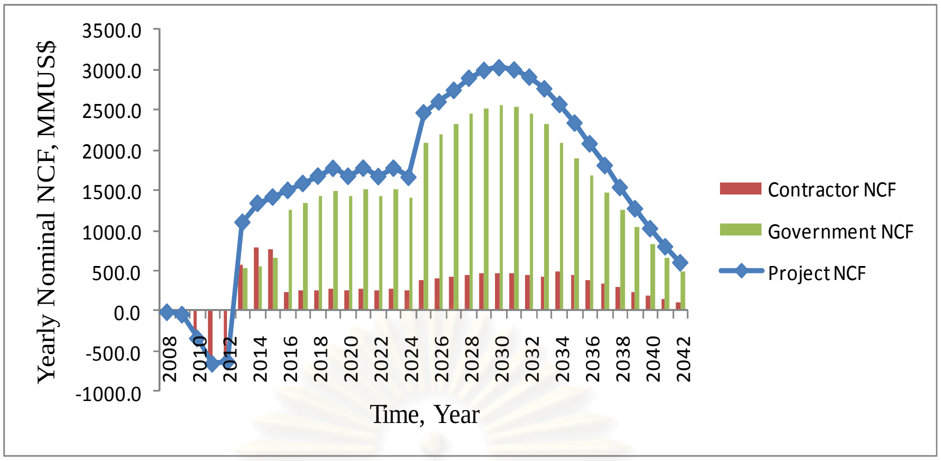


Figure 5.30 Net Cash flow of Shwe gas field against time

In the Figure 5.32, Government Take, Contractor Take % of project NCF meant that Government take progressive as percentage of project NPV .(see Figure 5.31).

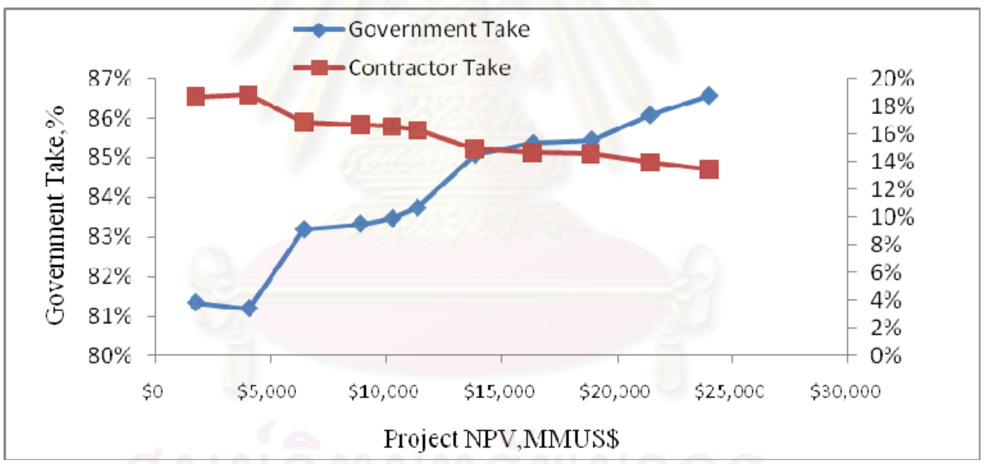


Figure 5. 31 Government Take % against project NPV.

5.5.2 Sensitivity analysis of Shwe Gas Field

Minimum filed sizes 1 TCF to 10 TCF were used for hypothetically field analyses. In addition, (PSC) production sharing split were same as Table (5.20).

5.5.2.1 Costs Sensitivity

In the figure 5.32 (a) shows that base gas price sensitivity varied linearly

Table 5.39 Summary of Shwe Gas Field costs Assumption

Year	Production				Exploration Cost	CAPX	OPEX	Abandonment Cost	Total cost
	MMCFD	MMCF/Year	MMBTUD	MMBTU/Year	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
							5%		
2008					14				-14
2009					42	0			-42
2010					42	279			-321
2011					42	558			-600
2012						558			-558
2013	300	109,500	300,000	109,500,000		140	140	5.6	-285
2014	387	141,364	387,298	141,363,892		0	140	5.6	-145
2015	500	182,500	500,000	182,500,000		0	140	5.6	-145
2016	500	182,500	500,000	182,500,000		0	140	5.6	-145
2017	500	182,500	500,000	182,500,000		0	140	5.6	-145
2018	500	182,500	500,000	182,500,000		0	140	5.6	-145
2019	500	182,500	500,000	182,500,000		0	140	5.6	-145
2020	500	182,500	500,000	182,500,000		140	140	5.6	-285
2021	500	182,500	500,000	182,500,000		140	140	5.6	-285
2022	500	182,500	500,000	182,500,000		279	140	5.6	-424
2023	500	182,500	500,000	182,500,000		279	140	5.6	-424
2024	500	182,500	500,000	182,500,000		419	140	5.6	-564
2025	500	182,500	500,000	182,500,000			140	5.6	-145
2026	500	182,500	500,000	182,500,000			140	5.6	-145
2027	500	182,500	500,000	182,500,000			140	5.6	-145
2028	500	182,500	500,000	182,500,000			140	5.6	-145
2029	500	182,500	500,000	182,500,000			140	5.6	-145
2030	439	160,108	438,653	160,108,466			140	5.6	-145
2031	385	140,464	384,833	140,464,224			140	5.6	-145
2032	338	123,230	337,617	123,230,199			140	5.6	-145
2033	296	108,111	296,194	108,110,675			140	5.6	-145
2034	260	94,846	259,853	94,846,215			140	5.6	-145
2035	228	83,209	227,970	83,209,217			140	5.6	-145
2036	200	73,000	200,000	73,000,000			140	5.6	-145
2037	175	64,043	175,461	64,043,386			140	5.6	-145
2038	154	56,186	153,933	56,185,689			140	5.6	-145
2039	135	49,292	135,047	49,292,080			140	5.6	-145
2040	118	43,244	118,477	43,244,270			140	5.6	-145
2041	104	37,938	103,941	37,938,486			140	5.6	-145
2042	91	33,284	91,188	33,283,687			140	5.6	-145
		4055320	11110467	4055320486	140	2790	4185	167	-7282

Table 5.40 Escalated costs Summary of Shwe Gas field

Year	Exploration Cost MMUS$		CAPX MMUS$		OPEX MMUS$			Abandonment Cost MMUS$	Cost to be Recovered MMUS$	Price US$/MMBTU		Price US$/MMBTU
	3%		3%		3%		3%				4%	
2008	1	14	1.0	0	1	0	1.0	0	-14		1	0.0
2009	1.03	43.26	1.0	0	1	0	1.0	0	-43		1.0	0.0
2010	1.06	44.56	1.1	296	1	0	1.1	0	-341		1.1	0.0
2011	1.09	45.89	1.1	610	1	0	1.1	0	-656		1.1	0.0
2012	1.13	0	1.1	628	1	0	1.1	0	-628		1.2	0.0
2013	1.16	0	1.2	162	1	162	1.2	6.5	-323	6	1.2	7.3
2014	1.19	0	1.2	0	1	167	1.2	6.7	-167	6.1	1.3	7.7
2015	1.23		1.2	0	1	172	1.2	6.9	-172	6.2	1.3	8.2
2016	1.27		1.3	0	1	177	1.3	7.1	-177	6.3	1.4	8.6
2017	1.30		1.3	0	1	182	1.3	7.3	-182	6.4	1.4	9.1
2018	1.34		1.3	0	1	187	1.3	7.5	-187	6.5	1.5	9.6
2019	1.38		1.4	0	1	193	1.4	7.7	-193	6.6	1.5	10.2
2020	1.43		1.4	199	1	199	1.4	8.0	-398	6.7	1.6	10.7
2021	1.47		1.5	205	1	205	1.5	8.2	-410	6.8	1.7	11.3
2022	1.51		1.5	422	2	211	1.5	8.4	-633	6.9	1.7	11.9
2023	1.56		1.6	435	2	217	1.6	8.7	-652	7	1.8	12.6
2024	1.60		1.6	672	2	224	1.6	9.0	-895	7.1	1.9	13.3
2025	1.65		1.7	0	2	231	1.7	9.2	-231	7.2	1.9	14.0
2026	1.70		1.7	0	2	237	1.7	9.5	-237	7.3	2.0	14.8
2027	1.75		1.8	0	2	245	1.8	9.8	-245	7.4	2.1	15.6
2028	1.81		1.8	0	2	252	1.8	10.1	-252	7.5	2.2	16.4
2029	1.86		1.9	0	2	260	1.9	10.4	-260	7.6	2.3	17.3
2030	1.92		1.9	0	2	267	1.9	10.7	-267	7.7	2.4	18.2
2031	1.97		2.0	0	2	275	2.0	11.0	-275	7.8	2.5	19.2
2032	2.03		2.0	0	2	284	2.0	11.3	-284	7.9	2.6	20.3
2033	2.09		2.1	0	2	292	2.1	11.7	-292	8	2.7	21.3
2034	2.16		2.2	0	2	301	2.2	12.0	-301	8.1	2.8	22.5
2035	2.22		2.2	0	2	310	2.2	12.4	-310	8.2	2.9	23.6
2036	2.29		2.3	0	2	319	2.3	12.8	-319	8.3	3.0	24.9
2037	2.36		2.4	0	2	329	2.4	13.1	-329	8.4	3.1	26.2
2038	2.43		2.4	0	2	339	2.4	13.5	-339	8.5	3.2	27.6
2039	2.50		2.5	0	3	349	2.5	14.0	-349	8.6	3.4	29.0
2040	2.58		2.6	0	3	359	2.6	14.4	-359	8.7	3.5	30.5
2041	2.65		2.7	0	3	370	2.7	14.8	-370	8.8	3.6	32.1
2042	2.73		2.7	0	3	381	2.7	15.2	-381	8.9	3.8	33.8
		148		3627		7694		308	-11469			

Table 5.41 Fiscal Regime Summary of Shwe Gas field

Year	Revenue MMUS$	Royalty MMUS$	After Royalty MMUS$	Cost Recovery Limit MMUS$	Lost carry forward After CR	Recovered Cost this year MMUS$	After Cost Recovery MMUS$	Profit Petroleum Government %	Profit Petroleum Contractor %	Income Tax	Discount Net Cash Flow
		10%		50%						30%	10%
2008					-14						-14.0
2009					-57						-39.3
2010					-398						-281.4
2011					-1053						-492.6
2012					-1681						-429.0
2013	799.3	80	719	400	-1605	400	320	240	80	3 year	97.0
2014	1091.1	109	982	546	-1226	546	436	327	109	Tax	275.5
2015	1489.0	149	1340	744	-653	744	596	447	149	Holidays	370.4
2016	1573.5	157	1416	787		830	586	440	147	44.0	352.6
2017	1662.4	166	1496	831		182	1314	986	329	98.6	97.5
2018	1755.9	176	1580	878		187	1393	1045	348	104.5	94.0
2019	1854.3	185	1669	927		193	1476	1107	369	110.7	90.5
2020	1957.7	196	1762	979		398	1364	1023	341	102.3	76.1
2021	2066.4	207	1860	1033		410	1450	1087	362	108.7	73.5
2022	2180.6	218	1963	1090		633	1330	997	332	99.7	61.3
2023	2300.7	230	2071	1150		652	1419	1064	355	106.4	59.4
2024	2426.9	243	2184	1213		895	1289	967	322	96.7	49.1
2025	2559.5	256	2304	1280		231	2073	1555	518	155.5	71.8
2026	2698.9	270	2429	1349		237	2192	1644	548	164.4	69.0
2027	2845.3	285	2561	1423		245	2316	1737	579	173.7	66.3
2028	2999.1	300	2699	1500		252	2447	1835	612	183.5	63.7
2029	3160.7	316	2845	1580		260	2585	1939	646	193.9	61.1
2030	2921.7	292	2630	1461		267	2362	1772	591	177.2	50.8
2031	2700.4	270	2430	1350		275	2155	1616	539	161.6	42.1
2032	2495.4	250	2246	1248		284	1962	1472	491	147.2	34.9
2033	2305.6	231	2075	1153		292	1783	1337	446	133.7	28.8
2034	2130.0	213	1917	1065		301	1616	1131	485	145.5	28.5
2035	1967.4	197	1771	984		310	1461	1023	438	131.5	23.4
2036	1816.9	182	1635	908		319	1316	921	395	118.4	19.2
2037	1677.7	168	1510	839		329	1181	827	354	106.3	15.6
2038	1549.0	155	1394	774		339	1055	739	317	95.0	12.7
2039	1429.9	143	1287	715		349	938	657	281	84.4	10.3
2040	1319.8	132	1188	660		359	829	580	249	74.6	8.2
2041	1218.0	122	1096	609		370	726	508	218	65.4	6.6
2042	1124.0	112	1012	562		381	630	441	189	56.7	5.2
	60077.2	6007.7	54069.5			11469.0	42600.4	31462.7	11137.8	3239.9	1058.6

increased and decreased the value of NPV/MCF. According to low gas price sensitivity, it was greatly impacted to small field size, 2 TCF, gave negative NPV. The 50% higher development costs were greatly decreased NPV/MCF in small field and 50% lower development costs were not much as impact as 50 % higher development costs. In addition, lower development costs lesser impact on small and marginal fields and over 6TCF field size was linearly increased and decreased.(shown in Figure 5.32(b).5.32(c) shown that operating costs changed were linearly increased and decreased overall field sizes.

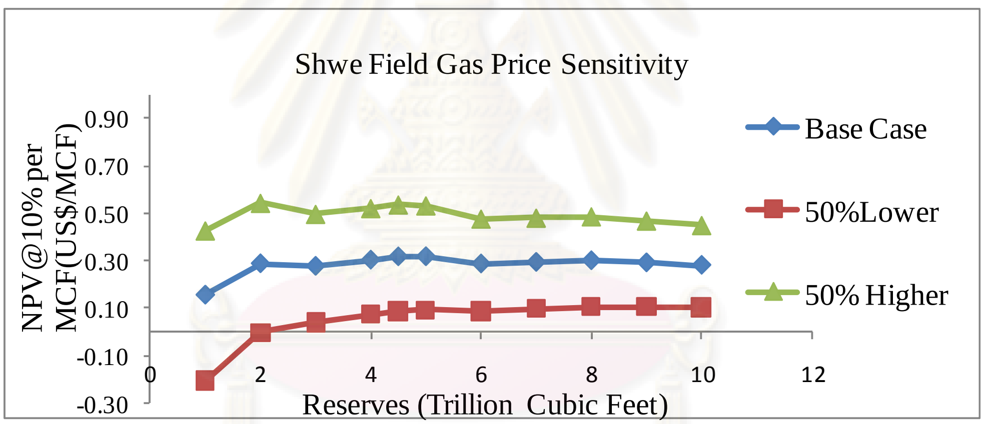


Figure 5.32(a) Gas Price sensitivity

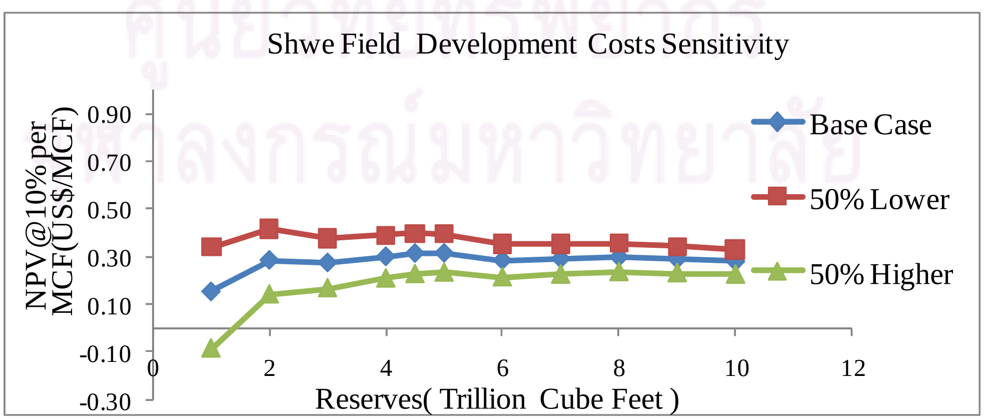


Figure 5.32 (b) Development costs sensitivity

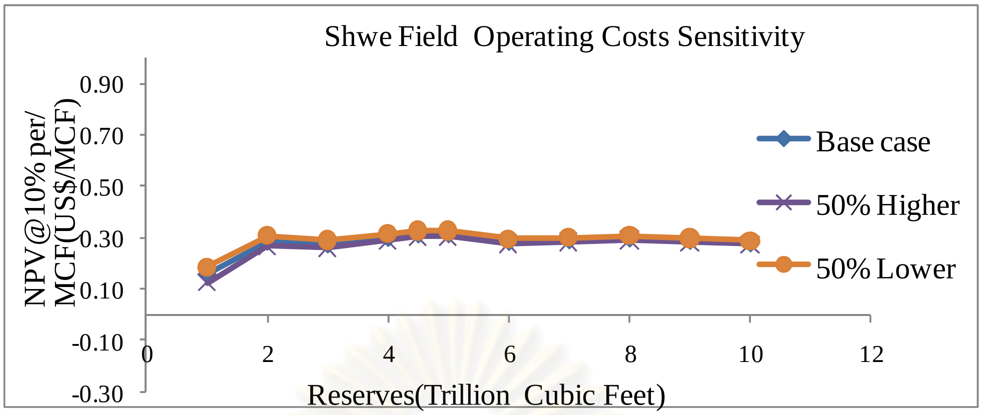


Figure 5.32 (c)Operating costs sensitivity

5.5.2.2 Peak production Sensitivity

In the Figure 5.33 stated that 50% lower peak production rate greatly effect to the 1 TCF field size and making a negative NPV.50% higher rate gave positive NPV to the whole field sizes. In addition, higher and lower rate linearly increased or decreased to the project.

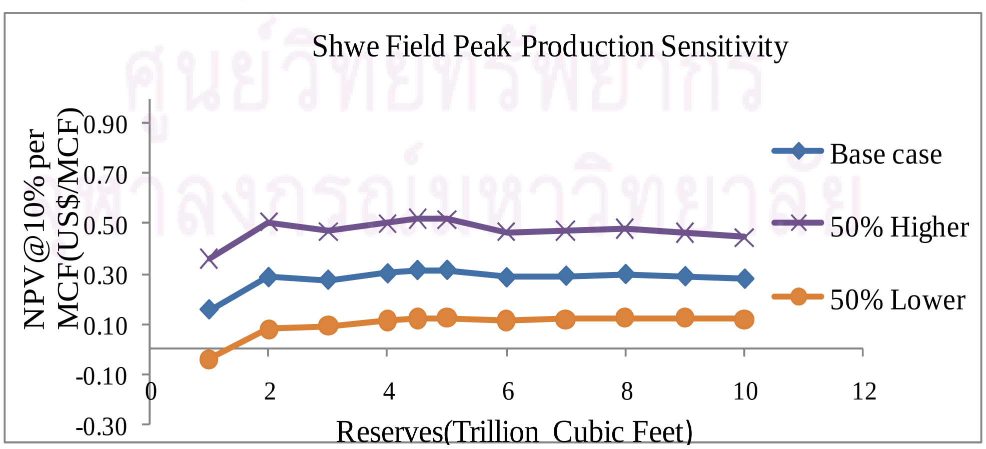


Figure 5.33 Peak production sensitivity

5.5.2.3 Fiscal Regime (PSC) Sensitivity

In the figure 5.34(a), (b), (c) stated that income tax sensitivity was the greatest impact to the fiscal regime. In the Royalty sensitivity changing was linearly and equally different from base case, because royalty is directly deducted from gross revenue. For figure 5.34(b) shows that lower cost recovery limit was a slightly impact on less than 5TCF field sizes. Unlimited cost recovery was more efficient to the less than 5 TCF.

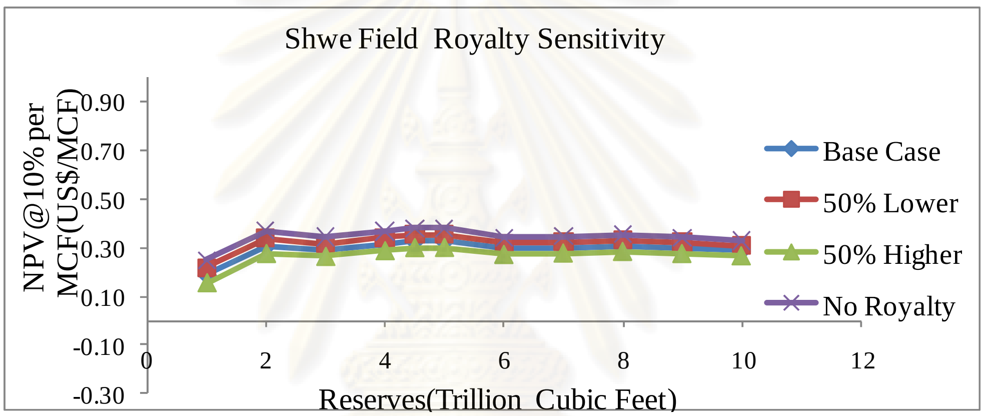


Figure 5.34 (a) Royalty Sensitivity

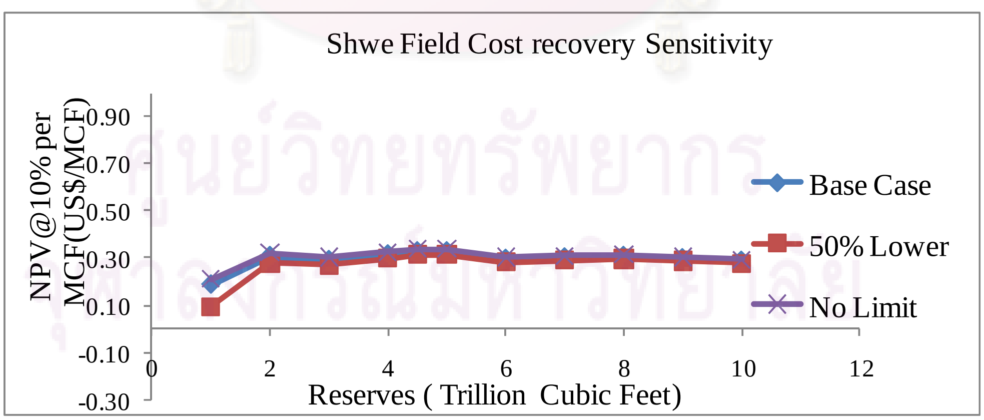


Figure 5.34 (b) Costs recovery sensitivity

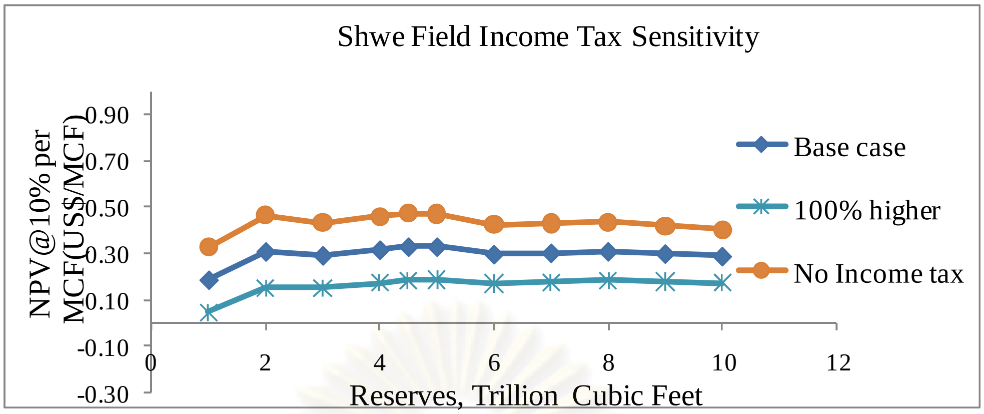


Figure 5.34 (c) Income Tax sensitivity

5.5.3 Probabilistic Analysis

Deterministic analysis gives only one value might not be made a decision to the project; probabilistic analysis can generate several values.

The 20000 times iterations of Monte Carlo simulation generated several excepted outcome of the project, Uncertainty value was input and excepted outcome was NPV. According to the limited information of data sources, typically triangular distribution was used. Monte Carlo simulation input variable value has been used from the value of sensitivity analyses 50% lower and 50% higher of the base case values. Summary of Input variable are shown in Table 5. 42.

In Figure 5.35 stated that deterministic analysis of NPV against the Monte Carlo simulation gave probability of success 40% confident NPV (1436 MMUS$) was very likely with the value of deterministic analysis NPV(900 MMUS$).In addition, probability of success 10% confident NPV was (161 MMUS$)positive and 95% confident was (7023MMUS$).Probability of less than 5% gave negative NPV. As a results of Shwe Project, its project NPV were positively NPV for greater than 5% probability.

Table 5.42 Summary of Input variable

Shwe			Parameter		
Items	Units	Distribution	Min	Mean	Max
Base Gas Price(P1)	US$	Lognormal	-4	5	14
(FO)	US$/BBL	Lognormal	-70	37	124
(OMy)	Index	Lognormal	32	163	304
CPIy	Index	Lognormal	125	193	265
Capital Costs	MMUS$	Triangular	1405	2790	4174
Opetration costs/year	MMUS$/year	Triangular	70	140	209
Abandonment costs	MMUS$	Triangular	70	140	210
Heating Value	BTU/MMSCF	Triangular	502	1000	1496
Escalated Gas Price	%	Triangular	2%	4%	6%
Royalty	%	Triangular	5%	10%	15%
Costs Recovery	%	Triangular	25%	50%	75%
Income Tax	%	Triangular	15%	30%	45%

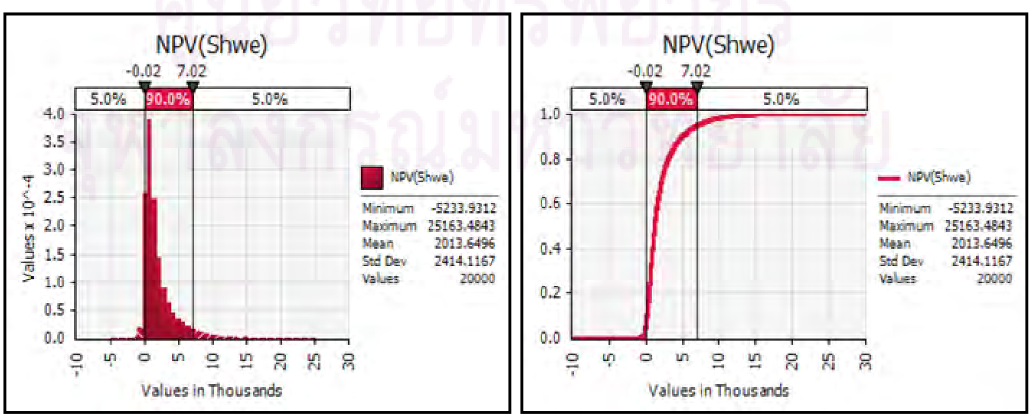


Figure 5.35 PDF of Shwe project NPV and CDF of Shwe project NPV

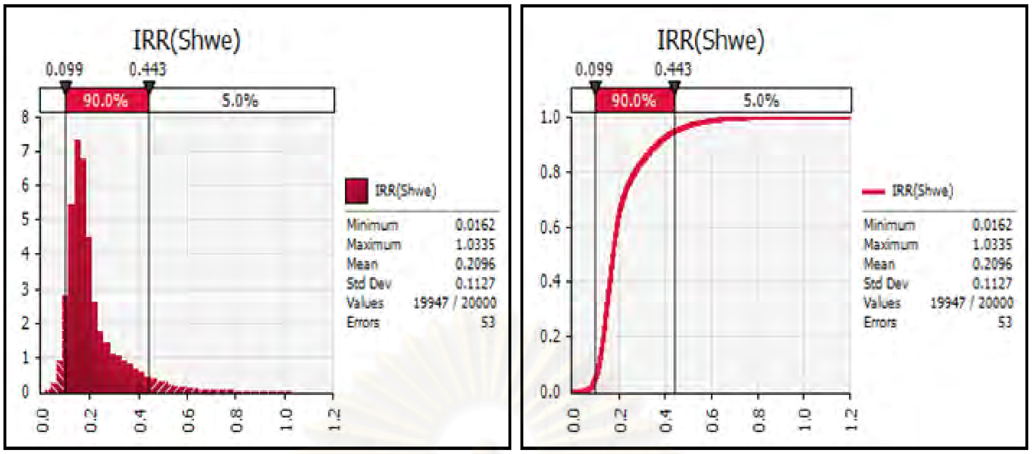


Figure 5.36 PDF of Shwe project IRR and CDF of Shwe project IRR

Table 5.43 Stastistic results Shwe project NPV and Shwe project IRR

Summary Statistics for IRR(Shwe)		Summary Statistics for NPV(Shwe)	
Percentile	IRR	Percentile	NPV
5%	10%	5%	-21.1
10%	11%	10%	161.2
15%	12%	15%	305.6
20%	13%	20%	428.6
25%	14%	25%	546.4
30%	15%	30%	665.4
35%	15%	35%	785.8
40%	16%	40%	919.5
45%	17%	45%	1060.8
50%	17%	50%	1211.5
55%	18%	55%	1386.3
60%	19%	60%	1592.7
65%	20%	65%	1843.7
70%	22%	70%	2137.0
75%	24%	75%	2536.5
80%	27%	80%	3079.1
85%	31%	85%	3841.0
90%	36%	90%	4986.0
95%	44%	95%	7023.8

CHAPTER VI

IMPROVE FISCAL SYSTEM ANALYSIS

6.1 Rate of Return contract system

Flexible fiscal system has many advantages for government and contractor. Typical method used for creating a flexible is with sliding scale terms. Most sliding scale systems are based on royalty, profit sharing and income tax.

Some countries have developed progressive taxes or profit sharing agreements based on project rate of return. As the project ROR increases, effective government take increases. Genuine progressive regime is based on project profitability and not on production rate.

M.A, Mian(2010) introduced ROR contract fiscal design used for new fiscal design. In the ROR contract system, the most key factor is ROR or IRR. In these system, there are three main parts; Progressive Royalty, Corporate Tax and Excess Profit Tax (EPT).

Progressive Royalty is started with contractor's pre-EPT ROR. The royalty rate is between the ROR of 5% and 12 %.(Royalty =2.1429 x ROR -0.0571).The minimum royalty is 5% when ROR is less than or equal 5% and the maximum royalty is 20% when ROR is greater or equal 12%.

Corporate Tax is subject to progressive corporate tax. The tax rate is between the ROR of 10% and 20 %.(Tax=5.5 x ROR -0.25).The minimum tax is 30 % when ROR is less than or equal 10 % and 85% when ROR is greater than 20 %.

Excess Profit Tax (EPT) is related to progressive corporate tax. The tax rate is between the ROR of 15% and 20 %.(EPT=14.0 x ROR -2.1) .The minimum tax is 0 % when ROR is less than or equal 15 % and 70% when ROR is greater than 20 %.The summary of Rate of return contract system are show in Table 6.1

Table 6.1 Summary of Rate of Return Contract

Progressive Royalty	5%<Royalty<20%	ROR<=5% ,ROR>12%
Corporate Tax	30%<Tax<85%	ROR<=10%,ROR>20%
Excess Profit Tax (EPT)	0%<EPT<70%	ROR<=15%,ROR>20%

A rate of return contract is another version of PSC. It is started from Year one ROR =0% and Royalty, Profit petroleum and Income Tax are based on year one ROR/IRR As shown in Table.6.1 ROR contract system New fiscal regime meant that sliding scale has been used for all of government to avoid from boundary conditions.

6.1.1Assumptions

All assumptions are same as Yadana Gas field base case.

Economics model of ROR fiscal system is shown in Table 6.2.

Table.6.2(a) Economic cash flow model using ROR system formula for New fiscal regime

Revenue	Royalty		After Royalty	Cost To be Recovered	Profitable Petroleum	Profit to Petroleum	
MMUS$	%	MMUS$	MMUS$	MMUS$	MMUS$	%	MMUS$
					0		
					0		
					0		
					0		
					0		
512.5	5%	25.6	487	116	371	30%	111
559.6	5%	28.0	532	117	414	30%	124
609.7	5%	30.5	579	118	461	30%	138
662.9	17%	115.2	548	119	428	34%	147
719.4	20%	143.9	576	121	455	73%	332
779.3	20%	155.9	623	122	501	84%	420
842.9	20%	168.6	674	123	551	85%	468
910.4	20%	182.1	728	125	604	85%	513
981.9	20%	196.4	785	126	659	85%	561
1057.6	20%	211.5	846	127	719	85%	611
1137.8	20%	227.6	910	51	860	85%	731
1222.8	20%	244.6	978	52	926	85%	787
1312.7	20%	262.5	1050	54	996	85%	847
1407.9	20%	281.6	1126	55	1071	85%	910
1508.6	20%	301.7	1207	57	1150	85%	977
1615.1	20%	323.0	1292	59	1233	85%	1048
1693.5	20%	338.7	1355	61	1294	85%	1100
1739.1	20%	347.8	1391	62	1329	85%	1130
1749.4	20%	349.9	1400	64	1335	85%	1135
1723.7	20%	344.7	1379	66	1313	85%	1116
1663.7	20%	332.7	1331	68	1263	85%	1073
1572.9	20%	314.6	1258	70	1188	85%	1010
1456.8	20%	291.4	1165	72	1093	85%	929
1321.8	20%	264.4	1057	74	983	85%	836
1174.9	20%	235.0	940	77	863	85%	734
1023.2	20%	204.6	819	79	740	85%	629
872.9	20%	174.6	698	81	617	85%	524
729.7	20%	145.9	584	84	500	85%	425
597.6	20%	119.5	478	86	392	85%	333
479.5	20%	95.9	384	89	295	85%	250
33639.8	5.5	6458.3	27181.4	2577.0	24604.4		19950.8

Table.6.2 (b) Economic cash flow model using ROR system formula for New fiscal regime

Taxable income	Income tax		Contractor NCF	Contractor NCF	Government Take		Net Cash Flow Contractor
MMUS$	%	MMUS$	MMUS$	MMUS$	NCF	%	
			0	-2			
			0	-74			
			0	-283			
			0	-291			
			0	-73			
260	0%	0	260	278	137	35%	260
290	0%	0.0	290	368	152	34%	290
323	0%	0.0	323	401	169	34%	323
281	0%	0.0	281	360	262	48%	281
123	39%	48.4	74	153	524	88%	74
81	67%	54.3	27	105	631	96%	27
83	70%	57.9	25	103	695	97%	25
91	70%	63.4	27	105	759	97%	27
99	70%	69.2	30	108	826	97%	30
108	70%	75.5	32	111	898	97%	32
129	70%	90.3	39	39	1048	96%	39
139	70%	97.2	42	42	1129	96%	42
149	70%	104.6	45	45	1214	96%	45
161	70%	112.4	48	48	1304	96%	48
172	70%	120.7	52	52	1400	96%	52
185	70%	129.5	55	55	1501	96%	55
194	70%	135.9	58	58	1575	96%	58
199	70%	139.5	60	60	1617	96%	60
200	70%	140.2	60	60	1625	96%	60
197	70%	137.8	59	59	1598	96%	59
189	70%	132.6	57	57	1539	96%	57
178	70%	124.8	53	53	1449	96%	53
164	70%	114.8	49	49	1335	96%	49
147	70%	103.2	44	44	1203	96%	44
129	70%	90.6	39	39	1059	96%	39
111	70%	77.7	33	33	911	96%	33
93	70%	64.8	28	28	764	96%	28
75	70%	52.5	22	22	623	97%	22
59	70%	41.1	18	18	494	97%	18
44	70%	30.9	13	13	377	97%	13
4653.6	17.9		2243.6	2243.6	28819.1		2243.6

6.1.2 Results and analysis

In Figure 6.1, new improve system of ROR gives positive NPV for all value of reserves when gas price is lower. Moreover it gives all higher NPV in small and marginal field .So ROR system is prevented losing money to contractor when high risk small or marginal field in low gas price.

Figure 6.2 of existing PSC system gave negative NPV to the contractor when gas price is low for small field. On the other hand existing system is not avoided boundary condition. In addition, contractor NPV of existing Yadana is 388 MMUS$ and new model of ROR contract gave 510 MMUS$. On the other hand, GT of existing PSC is 86%. and new model is 520MMUS$.

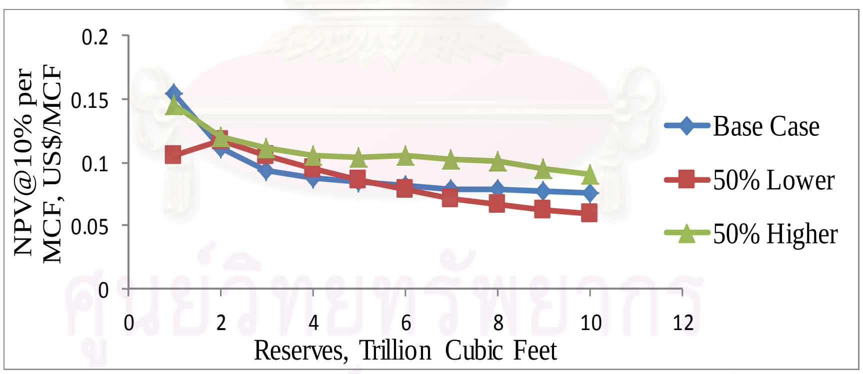


Figure 6.1 Gas price sensitivity analyses for ROR contract system

In the Figure 6.3, in the new system gas price changing is effected to the government .When the gas price is low, government share is low in small field and when gas price is high government take is as high as profitable. It is flexibility.

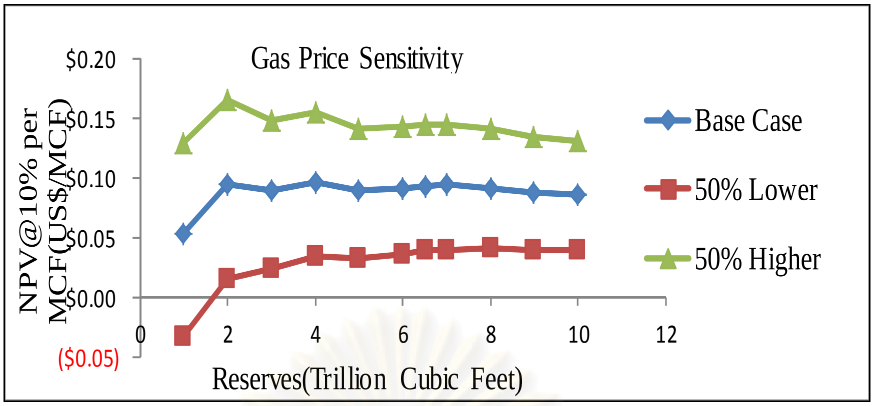


Figure 6.2 Gas price sensitivity analyses for PSC existing system

In the Figure 6.4, in the existing system gas price changing is not significantly affected to the government.

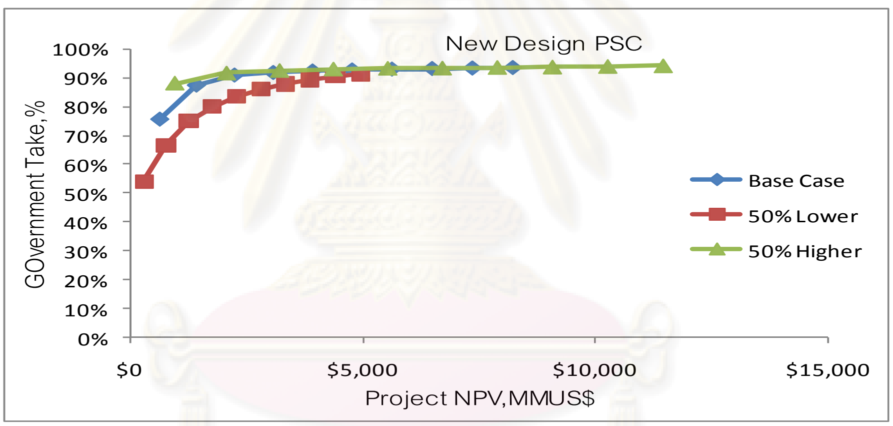


Figure 6.3. government take against the project NPV of New design PSC

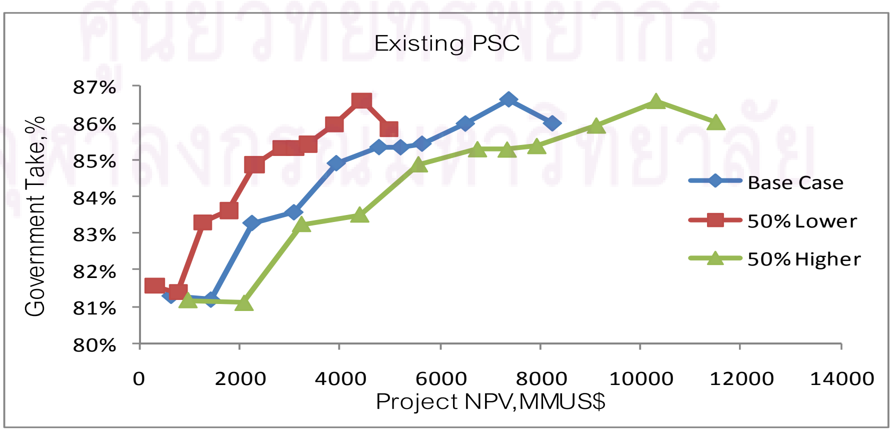
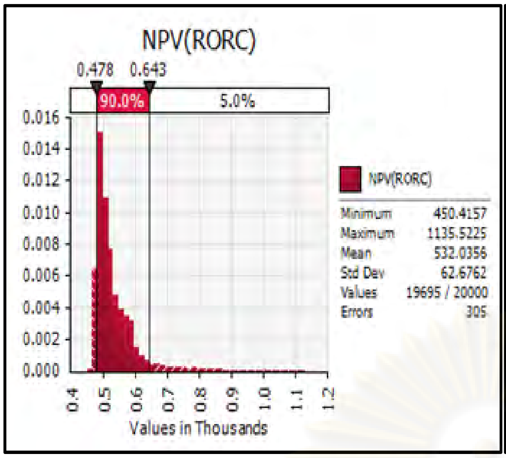


Figure 6.4 government take against the project NPV of New design PSC

Table 6.3 Input variable parameter of Yadana Gas Field

Yadana			Parameter		
Items	Units	Distribution	Min	Mean	Max
Capital Costs	MMUS$	Triangular	328	651	974
Opetration costS/year	MMUS$/year	Triangular	16	33	49
Abandonment costs	MMUS$	Triangular	11	21	31
Heating Value	BTU/MMSCF	Triangular	362	720	1077
Escalated Gas Price	%	Triangular	2%	4%	6%
Royalty	%	Triangular	5%	10%	15%
Costs Recovery	%	Triangular	25%	50%	75%
Income Tax	%	Triangular	15%	30%	45%
Gas Price(Year 1)	US$	Triangular	1	2	3

In the Figure 6.5, Monte Carlo simulation results of improve fiscal system give positively all of probability success. Probability of success 60% value is most likely the same with existing system NPV. Minimum Probability of success 5% give 478 MMUS$ and probability of success 50% is 512 MMUS$. Probability of success 95% is 643 MMUS$. Deterministic analysis gave NPY 510 MMU$ is likely with probabilistic analysis. So this project is profitable. Overall, new improve fiscal system for Myanmar fiscal is flexible and efficient to the contractor and profitable for both sides.



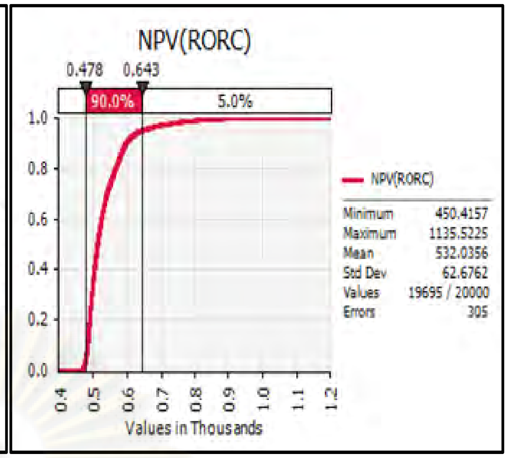


Figure 6.5 PDF of Yadana project NPV (RORC)and CDF of Yadana project NPV (RORC)

Table 6.4 Input variable parameter of Yadana Gas Field

Summary Statistics for NPV(RORC)		Summary Statistics for IRR (RORC)	
Percentile	MMUS$	Percentile	%
5%	478	5%	19%
10%	483	10%	19%
15%	486	15%	19%
20%	489	20%	20%
25%	492	25%	20%
30%	496	30%	20%
35%	499	35%	20%
40%	503	40%	21%
45%	507	45%	21%
50%	512	50%	21%
55%	518	55%	21%
60%	524	60%	22%
65%	531	65%	22%
70%	541	70%	22%
75%	552	75%	23%
80%	566	80%	23%
85%	581	85%	23%
90%	596	90%	24%
95%	643	95%	25%

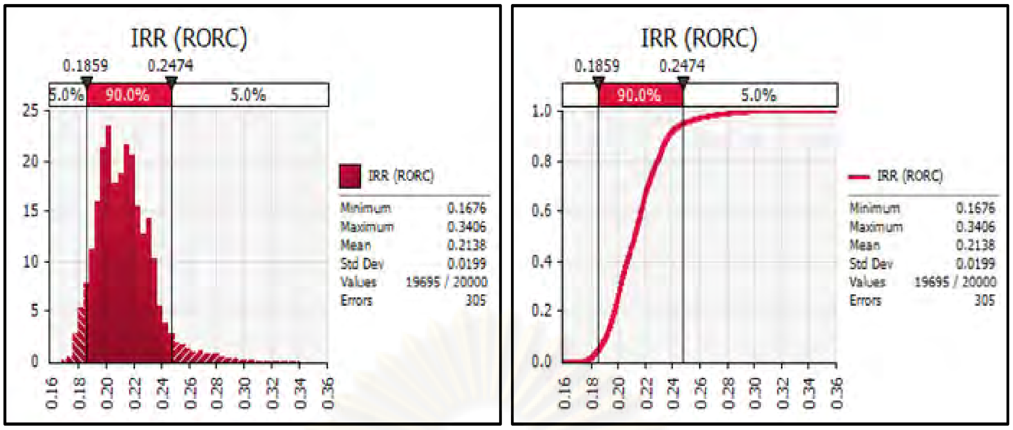


Figure 6.6 PDF of Yadana project IRR (RORC)and CDF of Yadana project IRR (RORC)

CHAPTER VII

CONCLUSION AND RECOMMANDATION

7.1 Conclusions

This thesis started by constructing the economics model using the current Myanmar offshore (shallow) model PSC, which provides fiscal severity and flexibilities. Most severe condition and less efficient could hinder petroleum exploration and production in Myanmar.

As the results of deterministic analysis and probabilistic analysis, in order to have win-win situations between government and contractor, the efficient Myanmar fiscal regime should be considered as a new efficient fiscal design in such a way that is simple to apply and provide the contractor with a fair rate of return (ROR) on investment method.

According to the qualitative analysis of Myanmar offshore (PSC) Fiscal Regime is most severity and less efficiency to the contractor than other countries. Using of profit sharing sliding scale is avoided from regressive regime, in other words Myanmar Fiscal Regime is progressive regime, typically, it cannot hurt to contractor. But, the results of sensitivity analysis meant that when gas price is as low as 50% of Base case gave negative NPV to the contractor.

Overall, deterministic analysis of cash flow model of the Yadana,Yetagun , Zawtika and Shwe Project gave the value of NPV was likely the same as Monte Carlo simulation results .Table 7.1 shows that summary of case studies by deterministic and probabilistic analysis. Furthermore, sensitivity analysis and scenario analyses stated that investment costs and gas price were more sensitive than fiscal regime .In addition; Costs and geological nature have a lot of uncertainty and fiscal regime could be negotiable.

Table 7.1 Summary of Case studies by deterministic and probabilistic analysis

Fields	Yadana	Yetagun	Zawtika	Shwe
Economic Indicators	Deterministic Results			
NPV(MMUS$)	388	582	118	900
IRR(%)	17	20	12	19
GT(%)	87	86	85	86
Probabilistic Results	P-50%	P-50%	P-25%	P-40%
NPV(MMUS$)	371	581	77	919
IRR(%)	17	21	12	16
Probabilistic Results	P-5%	P-5%	P-5%	P-5%
NPV(MMUS$)	81	337	-580	-21

7.2Recommandation

Nowadays, several of petroleum property own countries in the world used as ROR contract systems components in their fiscal system. One is Australia Petroleum resource Rent Tax Regime. Another is Malaysia and India.

Feature of efficient regimes based on ROR system is that government might not be getting their share when contractor receive a certain level of rate of return. Relying on discounted net cash flow, which is affected the NPV of government share. If the government discount rate is low, the government NPV will be delayed and small field will be developed. Since in this these, discount rate is the same as contractor and government.

According to the comparison of the new propose fiscal regime ROR contract model and existing PSC model (Yadana Project), NPV of ROR contract system gives higher NPV value than existing PSC. Typically, existing model shows lesser percentage of government take than ROR contract model, but existing model gives lesser NPV to the contractor. The government take percentage is greater in ROR contract but it gives higher NPV to the contractor. Comparison of new propose fiscal regime ROR contract model and existing one PSC results is shown in Table 7.2.

As the results of deterministic analysis and probabilistic analysis Myanmar offshore two existing project and ongoing project, all of project give positive NPV and profitable to the contractor. But quantitative analysis of fiscal regime results show greatest percentage of government take percentage.

Finally, ROR contract model is propose to use in Myanmar Fiscal Regime. It can be get win-win situations between government and contractor. This new system is simply and flexibility for both of government and contractor.

Table 7.2 Comparison of new propose fiscal regime ROR contract model and existing PSC Results

	NPV(MMUS$)(P-5%)	IRR(%)(P-5%)
Yadana (Existing PSC)	81	17
Yadana (ROR contract)	478	19
	NPV(MMUS$)(P-50%)	IRR(%)(P-50%)
Yadana (Existing PSC)	371	17
Yadana (ROR contract)	512	21

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Appendix A

Myanmar offshore gas price formula,

Normal Price; $P1*(k1*(CPIy/CPI)+k2*(OMy/OM)+k3*(Fy/F)+k4)$

- P1= Base Price (US$/MMBTU)
- k1= weighted constant factor for Consumer price Index in the USA
- k2= weighted constant factor for Producer price Index for Oil tools Machinery
- k3= weighted constant factor for Fuel Oil price(FO)
- k4= weighted constant
- CPI= Consumer Price Index-Urban CPIy= Consumer Price Index-Urban(base Price)
- OM= Oil field and Gas field Machinery Index
- OMy= Oil field and Gas field Machinery Index(base Price)
- F= Fuel oil price (base Price) S'pore Quotation 180 cst 2%grade
- Fy= Fuel oil price S'pore Quotation 180 cst 2%grade

Ceiling Price; % of fuel oil price

Floor Price; (Initial Base Price–Discount Price)adjusted by Economic Index, Fuel Oil

Special Floor Price; Average Ceiling price and Floor Price

Vitae

Kyaw Zin Hpyo was born on June 3, 1974 in Yangon, Myanmar, son of Than Maung and Aye Aye Myint. He was awarded a Bachelor of Petroleum Engineering from The Yangon Technological University in 2002. He has worked in Myanmar Oil and Gas Enterprise as Production Engineer since 2002.He has been a graduate student in the Master's Degree Program in Petroleum Engineering of the Department of Mining and Petroleum Engineering, Chulalongkorn University since 2008.

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