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A STUDY OF PETROLEUM FISCAL SYSTEM FOR UNDEVELOPED RESERVES IN THAILAND

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A Thesis Submitted in Partial Fulfillment of the Requirements
for the Degree of Master of Engineering Program in Petroleum Engineering
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ประเทศไทยมีแหล่งที่ยังไม่ถูกพัฒนาเพิ่มมากขึ้นเนื่องด้วยเหตุผลทางเศรษฐศาสตร์และอีกเหตุผลหนึ่งคือสัดส่วนการแบ่งรายได้ระหว่างภาครัฐบาลและนักลงทุนสำหรับแหล่งขนาดเล็กนั้นเอง โดยทั่วไประบบภาษีปิโตรเลียมแบบถดถอยมักมีผลต่อการตัดสินใจของนักลงทุนโดยเฉพาะอย่างยิ่งกับแหล่งดังกล่าว

วิทยานิพนธ์ฉบับนี้ทำการศึกษาระบบภาษีปิโตรเลียมของประเทศไทยโดยมีการเปรียบเทียบระบบภาษีปัจจุบันและก่อนหน้านี้ นอกจากนั้นยังทำการปรับองค์ประกอบบางอย่างของระบบ เช่น อัตราค่าภาคหลวง, อัตราภาษี, ผลประโยชน์ตอบแทนพิเศษ (SRB) สำหรับกรณีต่างๆ โดยระบุผลกระทบของภาษีแต่ละชนิดนั้นเปรียบเทียบระหว่างรัฐบาลและนักลงทุน มีการเปรียบเทียบความเป็นอัตราก้าวหน้าของระบบภาษีปัจจุบันโดยใช้ตัวชี้วัดที่ได้มาตรฐาน อาทิ ร้อยละที่รัฐบาลได้รับ, ร้อยละที่นักลงทุนได้รับ, มูลค่าปัจจุบันสุทธิ (NPV), อัตราผลตอบแทนภายใน (IRR) เป็นต้น การปรับเปลี่ยนนี้เพื่อให้เกิดประสิทธิภาพ, ความยืดหยุ่น และ การแข่งขันทางเศรษฐศาสตร์ของระบบภาษีเพื่อจูงใจต่อการลงทุนของนักลงทุนสำหรับแหล่งที่ยังไม่ถูกพัฒนาดังกล่าว

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There are many undeveloped petroleum reserves in Thailand that raise the question on the economics of the field development. One reason is the efficiency of the petroleum fiscal regime that governs the share of the petroleum benefit between the investor and the host government particularly in the small petroleum field. Typically, the regressively of the petroleum system creates some bias on the development decision due to the increasing of the government take on the marginal petroleum field.

This thesis studies Thai petroleum fiscal system by compare the current fiscal regime with others. By adjusting some elements of the system such as royalty rate, tax rate and Special Remunerator Benefit (SRB) for various cases to identify the effect of such tax elements to the return on both investor and Government. The progressivity and competitiveness of the proposed fiscal system to the existing system are examined using the standard measures such as Percentages of Government Take, Percentages of Contractor take, Percentages of cost to revenues, Net Present Value (NPV), Internal Rate of Return (IRR) etc. These efficiency, flexibility and economic competitive fiscal system are revised to encourage the investor for the undeveloped field investment.

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LIST OF ABBREVIATIONS

BBL/D	Barrel oil per day
BOE/D	Barrel of oil equivalent per day
BTU/SCF	British thermal unit per standard cubic feet
CAPEX	Capital expenditure
G&A	General and administration costs
IRR	Internal rate of return
K	The geological factor
IRR	Internal rate of return
MMBTU	Million British thermal unit
MTJDA	Malaysia-Thailand joint development area
NCF	Net cash flow
NOC	National oil company
NPV	Net present value
OPEX	Operating expenditure
PS	Price scenario
PSC	Production sharing contract
SA	Service agreement
SR	Special reduction
SRB	Special remunerator benefit

CHAPTER I

INTRODUCTION

1.1 General

Accounting of the world's trend petroleum price is increasing during the past decade. Therefore, the most producers begin to build up the production from their marginal field than return licenses or leave it behind. Although, petroleum price is not all of the reason, the more concessionaires keep on invest than return their concession or license before end of contract, the more government take. But in some case such as marginal reserves is non commercial and also high cost to develop when comparing with the current regime.

Normally, the government can promote the case of marginal field to increase the production by improve or adjust the existing fiscal regime which more appropriate to the marginal or undeveloped field and open the previously unavailable area.

Typically, the fiscal system around the world is divided in to two main systems as follow:

1. Concessionary system
2. Contractual system

The contractual system is separate in Service contract (Service Agreement or SA) that the fee is paid in cash and Production Sharing Contract (PSC) that the fee is paid in kind.

In case of Service contract, the contract can be divided in to pure service contract and risk service contract and the main difference between concessionary and contractual system is the ownership of the hydrocarbon.

1.2 Objectives of thesis

The main objectives of this study are:

1. To study the petroleum fiscal system for Thailand marginal reserves.
2. To compare the profit share between current and new adjustment of petroleum fiscal system on both government and contractor's aspect.

3. To study the suitability of adjusted petroleum fiscal system by using the economic indicator.
4. To maximize the percentages of government take while investor's NPV and IRR are also acceptable.

1.3Statement of purposes

The main purposes of this thesis is to study and improve the marginal field or undeveloped field which located in Thailand by adjust and created some component to applied to those field than leave it by economic reason.

1.4Thesis outline

In this thesis is divided in to six chapters as follow

Chapter I	Introduction
Chapter II	Literature review
Chapter III	Petroleum fiscal system
Chapter IV	Methodology
Chapter V	Study and improvement of Thailand fiscal regime
Chapter VI	Conclusions and recommendations

CHAPTER II

LITERATURE REVIEW

This chapter discusses some related works on petroleum fiscal system. Some works on designed fiscal system and compared fiscal system are also discussed here.

2.1 Literature Review

For design an effective petroleum fiscal system for oil and gas business is no need to be complicated system but it can be simply system if the profit share between host government and contractor can make a deal at optimum point.

Published Petroleum Fiscal System papers can be divided into 4 main groups as design fiscal regime, comparing fiscal by concern some risk or uncertainty, taxation effect and competitiveness comparison of petroleum fiscal in any region

In first group focus on how to design the fiscal system by concern some factors and some scenarios that affect their result such as ROR and price scenario, M.A Mian [1] and Daniel Johnston [2] are obviously explain , J.G. Higgins [3] who exemplify other ways in which Governments modify fiscal terms to account for variations in prospectively include competitive signature bonus bidding, competitive commitment bidding, negotiable tax or profit oil share, different terms(oil or gas developments, onshore and offshore acreage, crude quality, deep water developments), varying the sizes of blocks, grouping blocks for the purpose of ring fence allowances and Charles J. Johnson [4] who concentrated on production sharing contract by including the technical information exchange between government and investor, select some small area to improve the geologic knowledge and also added resource rent tax in the production sharing contract model in order to gain more net present value of benefit to the government.

Next main group is comparing fiscal by concern some risk or uncertainty, PE.Cavoulacos [5] another's who consider on regime by divided fiscal regime in four regimes, Royalty, Production Sharing, Service and RRT which each regime is appropriate for specific situation and show the impact of fiscal risk on the investment, Mark J.Kaisors [6] who develops regression model by using Meta modeling approach which consider market uncertainty while the Golf-Mexico deepwater field development Na Kika is consider as a case study and AndonJ.Blake,MarkC.Roberts [7] compares and investigates the petroleum fiscal regime which based on two criteria by estimate the after-tax net present value under oil price uncertainty and neutral system will allow firm to invest optimally.

Another main group is taxation effect, Michale J. Back [8] who compare two types of fiscal regime, production sharing and concessionary which impact on portfolio selection project where invest in Australia (concessionary) and Malaysia (Production Sharing Contract). The results was presented that standalone project have more favorable than another one, W.G, Alllnson [9] used cash flow analyses that effects of the fiscal regime and investment decisions indicate a preference ranking of Australia, Papua New Guinea and then Indonesia as far as concern on the net after tax return to the companies.

The last group is concerned on competitiveness comparison of petroleum fiscal in any region, Temmy Dharmadji [10] who compares the competitiveness of fiscal regime in Australia, China, India, Indonesia and Malaysia by using Net Present Value was an indicator. Two significant effects on contractor cash flow are both cost recovery limit and contractor profit share. Widjadono Partowidagdo [11] compares of seven difference countries in Asia Pacific which difference petroleum fiscal regime. The results of Thailand III give more profit for small fields than large fields. Sara Zahidi [12] compares the upstream petroleum fiscal systems of Pakistan, Thailand and other countries with medium ranked oil reserves the results is Turkey, Thailand, Congo, Pakistan and Cameroon offering the attractive contractor takes from the highest to the lowest respectively.

CHAPTER III

PETROLEUM FISCAL SYSTEM

This chapter illustrates all about the petroleum fiscal system which composed of the classification of petroleum fiscal system around the world, legal arrangements in the petroleum industry, tax classification, Thailand petroleum fiscal system, classification of marginal fields (undeveloped reserves) then following with investment promotion for marginal fields. Lastly, the economic indicator which included the discounted cash flow methods to measures the profit share between government and contractor are presented.

3.1 Classification of petroleum fiscal system

Normally, there are two main petroleum fiscal systems. Firstly is concessionary system and the last one is contractual system. In concessionary system is known in royalty system and for contractual system is divided in production sharing contract (PSC) and service agreement.

Designing the efficient fiscal system must be composed of many tax components which called hybrid system.

3.2 Legal arrangements in the petroleum industry [13]

The legal basis for hydrocarbon exploration, development and production is normally established in a country's constitution. Normally, the hydrocarbon law, formulated at parliamentary level, sets out the principles of law, while those provisions that do not affect principles of law, or that may need periodic adjustments (such as technical requirements, administrative procedures, and administrative fees), are set in regulations. Governments grant exploration, development and production rights in particular areas or blocks by means of concessions or contracts, depending on their legal systems. Where no hydrocarbon law exists, comprehensive contractual agreements between host governments and investors are used.

Various legal systems have been developed to address the rights and obligations of host government and of private investors. These can be grouped under two families: concessionary systems and contractual systems see Figure 3.1

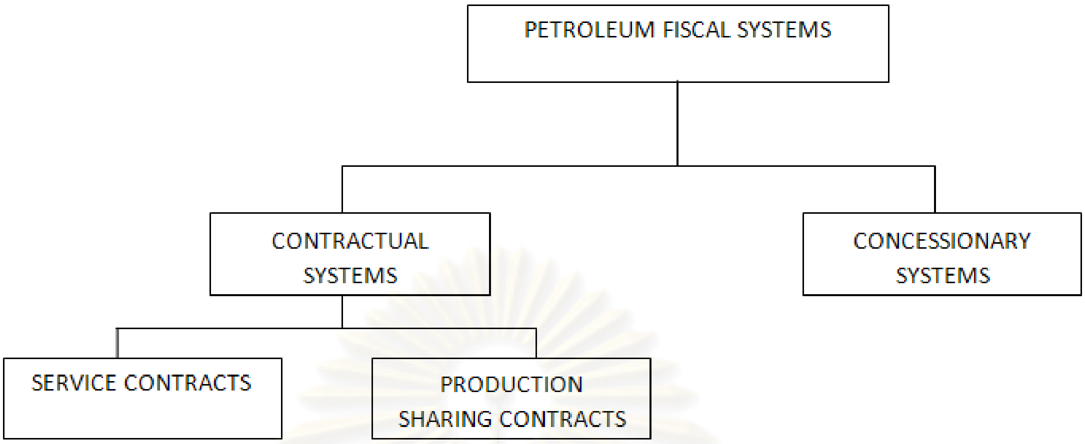

Figure 3.1 Petroleum Legal Arrangements

In both systems, the investor assumes all risks and costs associated with hydrocarbon exploration, development and production, and receive compensation adequate to the risk. Normally, the investment risks are assumed by oil companies rather than the state/owner of the resource. In general terms, the higher the risk of investment activities in a country, the higher the portion of the rent received by the investor.

The fundamental difference between concessionary and contractual systems relates to the ownership of the natural resources:

Under a concessionary system, the title to hydrocarbons passes to the investor at the borehole. The state receives royalties and taxes in compensation for the use of the resource by the investor. Title to and ownership of equipment and installation permanently affixed to the ground and/or destined for exploration and production of hydrocarbons generally passes to the state at the expiry, or termination, of the concession (whichever is earlier). The investor is typically responsible for abandonment.

Under a contractual system, the investor acquires the ownership of its share of production only at the delivery point. Title to and ownership of equipment and installation permanently affixed to the ground and/or destined for exploration and production of hydrocarbons generally passes to the state immediately. Furthermore, unless specific provisions have been included in the contract (or in the relevant legislation) the government (or the national oil company, ―NOC") is typically legally responsible for abandonment.

3.3 Petroleum fiscal system in Thailand

Fiscal regime in Thailand is almost 40 years that Thailand opens for exploration and production business under the concessionary system. Three terms of benefit sharing between the state and investor are Thai I (Petroleum Act1971), Thailand II (since 1982 but now is outdated) and Thai III (since 1989).

In Thai I that start in 1971, Flat royalty and petroleum income tax is 12.5% and 50% respectively. The tax credit is including the royalty of petroleum sales. Outline of Thai I Terms is in Appendix A1.

In 1982 the government has decided to modify the concession that called Thai II, not only the royalty and petroleum income tax but also include the annual benefit and annual bonus. Although Thai II will increase the profit to government in case of increasing the oil and gas price or large reserve but form exploration data since 1982 the petroleum filed in Thailand is marginal fields that have high cost per barrel so Thai II is unfavorable for investment.

Thai II term is divided in to two additional special benefits as Annual Benefit and Annual Bonus.

For annual benefit the expense of concessionaire must limit for deductions which compose of net profits for the payment of petroleum income tax to 20% or less of the petroleum sold during the year. But in the case of concessionaire pay the expense more than 20%, the concessionaire must pay the special benefit to the government as much as exceed of the expense in percentages in agreement.

For annual bonus is calculated in three cases from the amount of crude oil sold during the year. Case one is crude oil sold or disposed of at the daily average of more than 10,000 barrels per year, but not more than the daily average of 20,000 barrels per year will pay 27.5% of the value of petroleum. In case two, crude oil sold or disposed of in excess of the daily average of 20,000 barrels per year, but not more than the daily average of 30,000 barrels per year will pay 37.5% of the value of petroleum. In the last case, crude oil sold or disposed of in excess of a daily average of 30,000 barrels per year will pay 43.5% of the value of petroleum sold.

In both of the annual bonus and annual benefit must be paid in 120 days of the closing date of the accounting year of the Concessionaire.

In 1989 the government has improved the petroleum Act again that called Thai III that more support the marginal filed. However, if more profit than it should be, the concessionaire will share the access profit to the government also. Thai III is modify the royalty from flat rate 12.5%to sliding scale 5-15% (see Table3.1), petroleum income tax is remain the same but Special Remuneratory Benefit (SRB) is set up the first time by progressive rate from 0-75% on ―Windfall Profit" (see Table3.2), SRB is an additional profit that occur in some situation such as the petroleum price increase or very low cost of discoveries so it captures the ―excess" of the profits. In SRB have some constant value that affect the amount of SRB is the geological factor (K) which equal to 150,000 meters. In Thai III have the another constant value which affect to the cash flow, Special Reduction (SR) that equal to 35% of tangible in capital expenditure. The structure and Outline of Thai III are in Appendix A2.

There is one area which called Malaysia-Thailand Joint Development Area (MTJDA). This area uses the Production sharing contract or PSC system. In PSC system have the constant royalty 10%, the cost recovery up to 50 % of annual production, the profit share between Thailand and Malaysia is 50%:50%, the production bonus pay at certain quantity of accumulative production, windfall Profit for Oil is depend on oil price. For taxation, the tax holiday is first eight years, next seven years is 10% and after that 20 % of taxable income. The export duty is 0% of contractor's portion of profit oil exported to third country. For import Duty on Goods and Equipment is exempted if on Master Exemption List.

Table3.1: The sliding scale of royalty: Thai III

bbl per day	**Royalty Rate %**
Up to 2,000	5.00%
2,000-5,000	6.25%
5,000-10,000	10.00%
10,000-20,000	12.50%
over 20,000	15.00%

Table3.2: SRB rate: Thai III

Income per meter of well	**SRB (%)**
Up to Baht 4,800	zero
Baht 4,800 to 14,400	1% per each Baht of 240 increment
Baht 14,400 to 33,600 Baht	1% per each Baht of 960 increment
Over 33,600 Baht	1% per each Baht of 3,840 increment

3.4 Tax [14]

Normally, the governments have to manage their natural resources though the regulation of petroleum rights. Consist of royalty, corporate income taxes, special duties and other taxes which divided in direct tax, indirect tax, non tax and National Resource Stabilization/Savings funds.

1. Direct Tax

Resource rent tax is related to the economic rent generated by the difference between the market price and the cost of extraction (including an acceptable return on investment).

Corporation tax is applicable to all corporate entities irrespective of the sector in which they are operating.

Progressive profit tax is a variant of corporation tax which links the tax rate with various profit indicators, including commodity product prices, production volume, and sales turnover. Progressive tax is depended on the base or reference such as base price base of the volume of production or the base of the cost. If the price is increase than the reference price (market price), the progressive tax must be active in this situation.

The royalty, the sliding scale is the example of the progressive tax.

Regressive tax is should be avoid in undeveloped field or marginal field for example the percentages of government take is decreased while the increase in petroleum price because of constant of the royalty or tax rate.

2. Indirect Tax

Royalties are on production volume, production value, sometimes progressive and linked to market prices.

Windfall profit tax is typically concerned at the beginning of the signing the contract as reference price (market price) and base price. If current price is exceeded the market price the windfall profit tax will active. In Thai III system, the SRB is our example of windfall profit tax

Import duties is applied or exempted for mineral extraction projects.

Value added tax is applied or exempted for mineral extraction projects.

3. Non-tax

Fixed fees and bonus payments

Production sharing arrangements

State equity

4. National Resource Stabilization/Savings funds

In general these instruments are part of ongoing fiscal measures designed to address expected sector characteristics and changing sector and fiscal policy objectives. The burden is also reduced or increased depending upon the level of incentive that the authority wishes to offer. Such changes are typically related to industry life cycle and commodity prices.

Royalty and Tax of Thailand Petroleum Income Tax Act for Thai I and Thai III are in Appendix A1 and Appendix A2

3.5 Classification of marginal fields [15]

Marginal fields are described as:

1. Fields not considered by license holders for development because of assumed marginal economics under prevailing fiscal terms.
2. Fields which have had at least one exploratory well drilled on the structure and have been reported as oil and gas discoveries for more than 10 years.
3. Fields with crude oil characteristics different from current streams which cannot be produced through conventional methods or current technology.
4. Fields with high gas and low oil reserves.
5. Fields that have been abandoned by the leaseholders for upwards of 3 years for economic reasons.

6. Fields which the present leaseholders may consider farming out due to portfolio rationalization.

By the way, different situations mean different conditions which depended on degree of risk. For development project is quite low degree of risk and the focus of negotiation (Negotiation deals) is IRR. However, the strategies that we can use by comingle or grab the advantages of each system and also apply to the individual case. In this thesis, the marginal field is the fields which have the percentages of cost to gross revenue exceed approximately 50% and the IRR lower than 12% or NPV at 12% discounted rate is negative.

3.6 Investment promotion for marginal fields [16], [17], [18]

Comprehension of issues relating to investment decisions for marginal field development requires an appreciation of the nature of such fields. That is, it requires an appreciation of the features which render them marginal from the perspective of their commercial viability. A review of existing literature reveals the absence of a unified description of marginal fields. Petroleum Fiscal System is not only the main commitment between Host government and Contractor but also agreement of each others as well. In typically, petroleum fiscal system should be efficiency, flexibility and competition in worldwide.

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In typically, petroleum fiscal system should be efficiency, flexibility and competition in worldwide.

Designing of petroleum fiscal system around the world is difference which depended on the region, acreage opportunities. Mainly, the deal will share the profit (take term) and/or risk. Normally, the government and contractor take in term of percentages.

The ideal regime should:

1) Ensure a stable business environment and minimize sovereign risk.
2) Discourage undue speculation.
3) Provide potential for a reasonable return on both government and contractor.
4) Avoid complexity and limit administrative burden.
5) Allow enough flexibility to accommodate changes in perceived prospective and economic conditions.
6) Promote healthy competition and market efficiency.

The elements that become part of a contract or fiscal system are usually either: Negotiation, Statutory or fixed term and bid term

3.7 Economic indicator [19]

Typically, the economic indicators for oil and gas investment are composed of Net Present Value (NPV), Internal Rate of Return (IRR), percentages of government take and percentages of contractor take. In this thesis, the total cost to gross revenue is recommended.

To evaluate a fiscal system, governments and oil companies use different measures:

Oil companies aim to optimize their portfolio of assets. They use economic measures to compare investment opportunities worldwide and to assess their relative risk-reward profile. During the economic life of an asset, oil companies monitor the revenue generated by it to verify that they have covered the capital investment and expenditures and that the return on capital is consistent with the risk associated with the particular asset and with the strategic objectives of the corporation.

Host governments are interested in evaluating whether a fiscal system responds to its intended objectives. To do so, at a project level host governments use economic and system measures to assess whether the benefits-financial and social-derived from the project are consistent with its risk level and with the objectives of the government's sector policy. At a country level host governments monitor the impact of the revenue flow generated by the oil sector as a whole on the key macro-economic indicators (mainly inflation, balance of payments)

Economic and fiscal systems measures are project-specific quantities that vary with numerous system parameters unique to the project (including, but not limited to, the size and quality of discoveries, the development and operational plan of the operator, the cost structure; the financing costs, discounts for the particular crude oil stream), as well as non-project specific variables (such as crude oil prices, inflation, currency exchange rates, local and global economic conditions, and regulatory changes). Hydrocarbon price, development cost, technological improvements, demand-supply relations, country risk, and the corporate strategy, all impact investment planning. Hence the accurate computation of the economic and fiscal system measures associated with a field largely depends on the reliability of the assumptions. In effect, only at the end of a field's economic life, when all revenue, cost, royalty and tax data are known, can the profitability and the division of profits between the host government and the investors be reliably determined. In practice, due to their commercial sensitivity, cash flow and cost data are very rarely made public.

Various economic indicators are used to assess the performance of a project. The most common are the net present value of the project's cash flow (NPV), the internal rate of return (IRR), and the profitability ratio. The NPV provides an evaluation of the project's net worth to the investor in absolute terms, while the IRR and the profitability ratio are relative measures used to rank projects for capital budgeting. Economic values are not intended to be interpreted on a standalone basis, but should be used in conjunction with other system measures and decision parameters. A combination of indicators is usually necessary to adequately evaluate a contract's economic performance.

One indicator frequently referred to in sector literature is the division of profits between companies and government (the ―take”). The take is a fiscal statistic as opposed to an economic measure. Because the take does not provide a direct indication of the economic performance of a field, it generally matters more to the host government than to the oil companies.

The take is often a negotiated quantity that depends upon the strength, knowledge, experience, and bargaining position of the oil company and host government, the perception of the risk associated with the field development at the time the contract was written, and the availability of opportunities worldwide.

Unlike economic measures, which are generally well-established, general confusion surrounds the application and interpretation of take. The government take is defined as the government’s percentage of pre-tax project net cash flow adjusted to take into account any form of government participation. The government take can be calculated in discounted or undiscounted value.

The take statistics for a given country offer a first frame of reference to assess whether or not the fiscal terms applicable to a contract under negotiation are in line with those that already exist in that country (Johnston 2003), or as benchmark to determine the competitiveness of a country’s fiscal terms. However, comparing the take of different projects and/or different countries is a very difficult and often misleading exercise because:

Calculation the take at project level requires firstly, the ability to forecast the expected cash flow for the project. As noted above, estimating the cash flow of a prospective project is highly uncertain, and even under the best conditions, is based on incomplete and often unobservable information, secondly the availability of information that is normally proprietary and not publicly known;

The same limitations apply to the calculation of the take at country level. In addition, in a given country numerous vintages of contracts are normally in force at any one time; countries typically use more than one arrangement; and a contract are often renegotiated as political and economic conditions change, or as better information becomes available.

In industry statistics the government take is usually determined on the basis of theoretical price and cost assumptions. As noted above, the actual government take can be quite different from the theoretical average.

The take is inconsistent with the economic measures mentioned above, since it is frequently calculated and reported on an undiscounted basis. There can be a significant difference in the level of take depending on the manner in which the cash flow elements are discounted. For example the discounted take is normally much higher than the undiscounted one for regressive front-loaded systems.

As the government take is made up of different elements, more or less regressive, the risk-profile, hence the attractiveness to investors, of two fiscal regimes that present the same percentage government take can be dramatically different.

The government take does not capture the spillover effects of oil and gas projects on the economy at large.

CHAPTER IV

METHODOLOGY

In this chapter, Thailand petroleum fiscal regime is studied which composed of production profile, hydrocarbon price, CAPEX and OPEX. Moreover, the pre study of both Thai I and Thai III are also observed as well.

4.1 Assumption

This is an offshore gas field which located in gulf of Thailand as Figure 4.1.

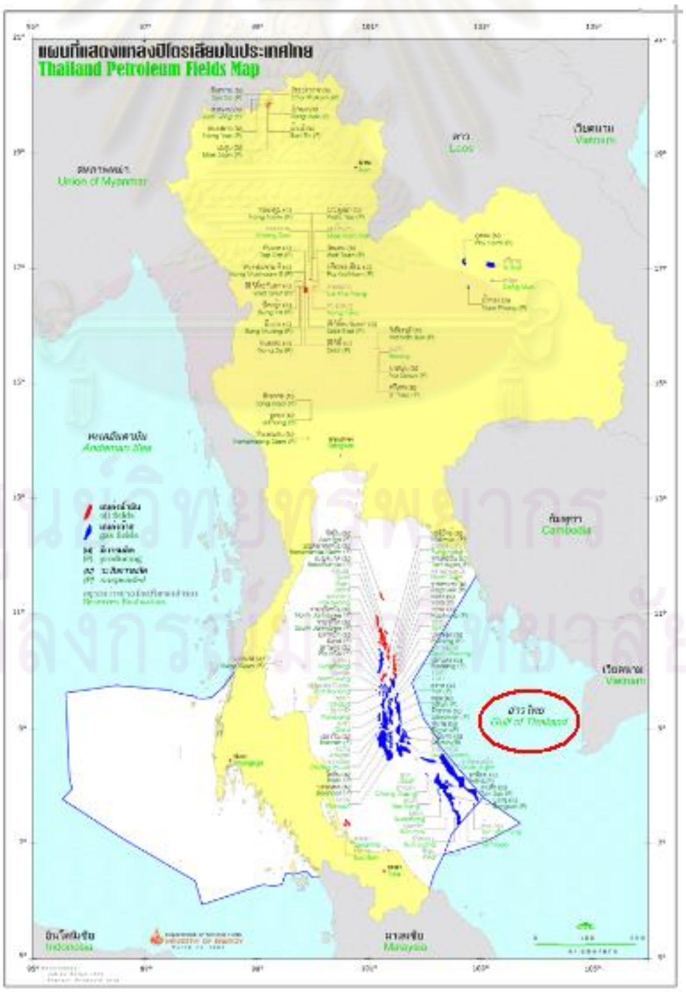

Figure 4.1The offshore gas field in gulf of Thailand (Source: http://www.dmf.go.th/)

The Maximum export gas rate 350 MMscfd at maximum 23 mole% CO_2. Handle 20,000 bbl/d of condensate. Re- inject up to 20,000bbl/p of produced water. Stabilized condensate is transferred via a dedicated 70 km pipeline 8" to condensate export manifold, for export via existing sales infrastructure. Gas export is 70 km 24" sea line to the existing. The facilities are 45 km 30" sea line to the 3rd pipeline. CO_2 removal utilizes ~~"m~~embrane technology". Dew point control utilizes ~~"c~~old process (refrigeration)". Condensate stabilization employs ~~"s~~tabilization column" to achieve a vapors pressure at 12 psia.

4.1.1 Production profile

In order to carry out the comparison study of main character of Thai I and Thai III in undeveloped reserve, the reserve life is approximately 300MMBOE in 14 years is divided in to condensate 19MMBBL and Gas1,694BSCF along the field life as shown in Figure 4.2

The example of production rate calculation shown in Appendix B1

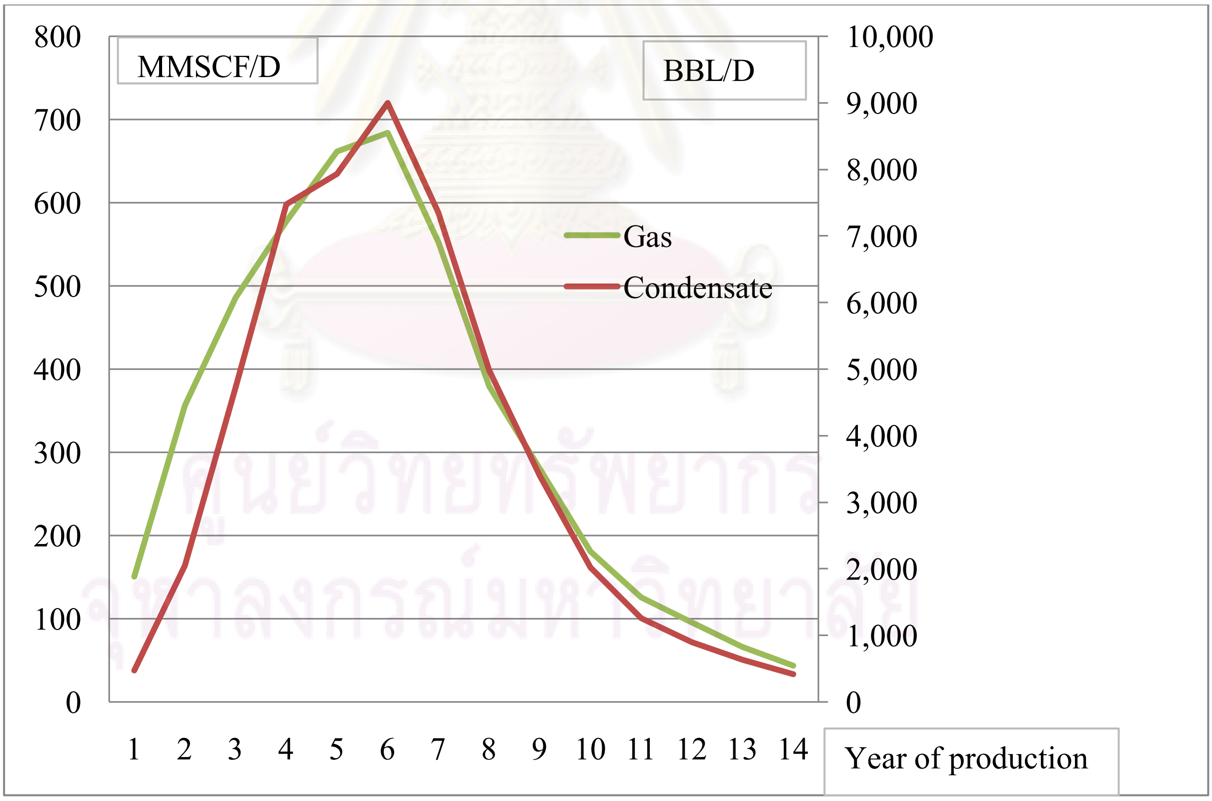

Figure 4.2 Production profile from year 1 to 14

4.1.2 Oil and Condensate price assumption

The production is started from year 1 to year 14. For oil and condensate prices, four price scenarios are generated. Price scenario1 is constant at 70 dollar per barrel. Price scenario2 is constant at 105 dollar per barrel. Price scenario3 is start at 70 dollar per barrel and escalate 5 percents per year. The last oil price scenarios start at 70 dollar per barrel and escalate 7.5 percents in every year (see Figure 4.3).

For gas prices is constant along the production and sale period at 3 US dollar per MMBTU.

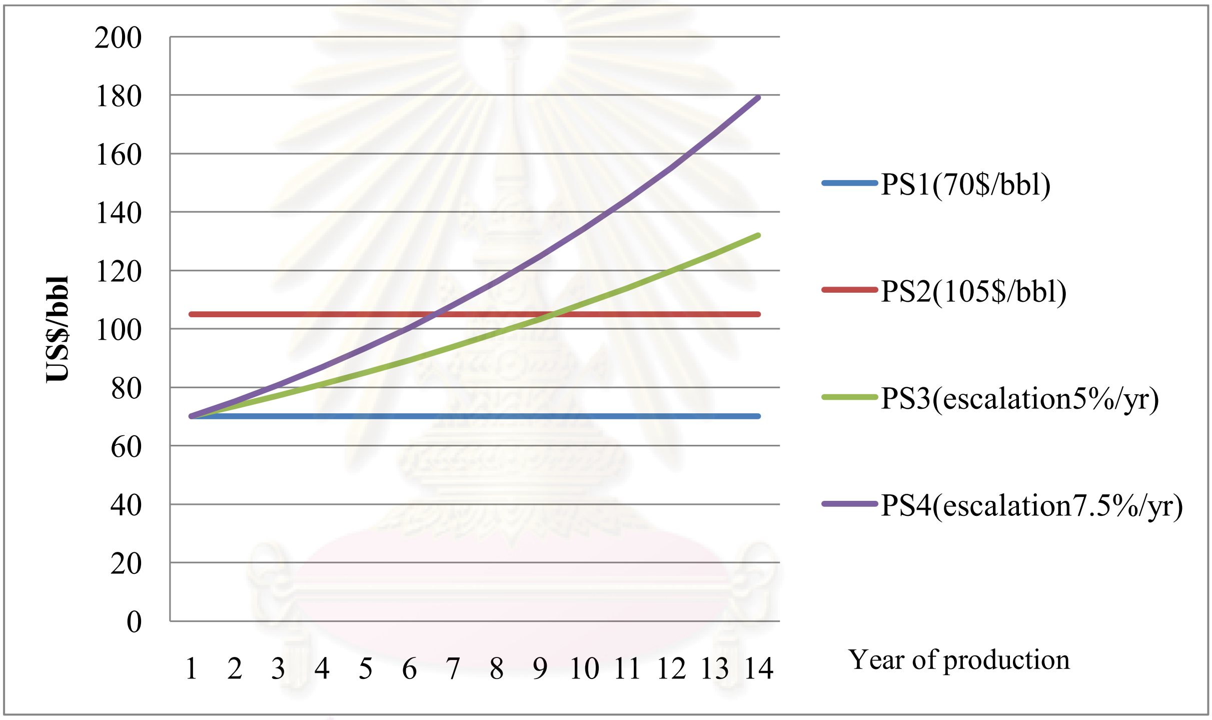

Figure 4.3 Petroleum price scenarios from year 1 to 14

4.1.3 Cost assumption

For Capital Expenditure (CAPEX) which is composed of Acquisition Cost, Exploration Activities and Development Activities and the total of CAPEX is 1,604 million US dollar. Operating Expenditure (OPEX) is consisting of Field OPEX, G&A and Decommissioning. The total OPEX is 1,003 million US dollar (see Table 4.1).

Table 4.1 Cost assumption of CAPEX and OPEX

Capital Expenditure (1,604 MMUS$)	**Cost of Development Drilling**	**Central Processing Platform (CPP)**
	230 MMUS$	1,374 MMUS$
Operating Expenditure	**Field Operating Expenditure**	**Decommissioning**
(1,003 MMUS$)	851 MMUS$	152 MMUS$

For more details of CAPEX, OPEX and cash flow profile are all in the Appendix C1.

4.1.4 Percentages of cost to total gross revenue

Varying the oil and condensate price from 30 US dollar per barrel to 300 US dollar per barrel, the percentages of cost to revenue is decreased from approximately 70 percents to almost 30 percents when increased the petroleum price in Figure 4.4, In this situation can be clearly seen that the oil and condensate price is direct effect to the percentages of cost to revenue as shown in Appendix B2

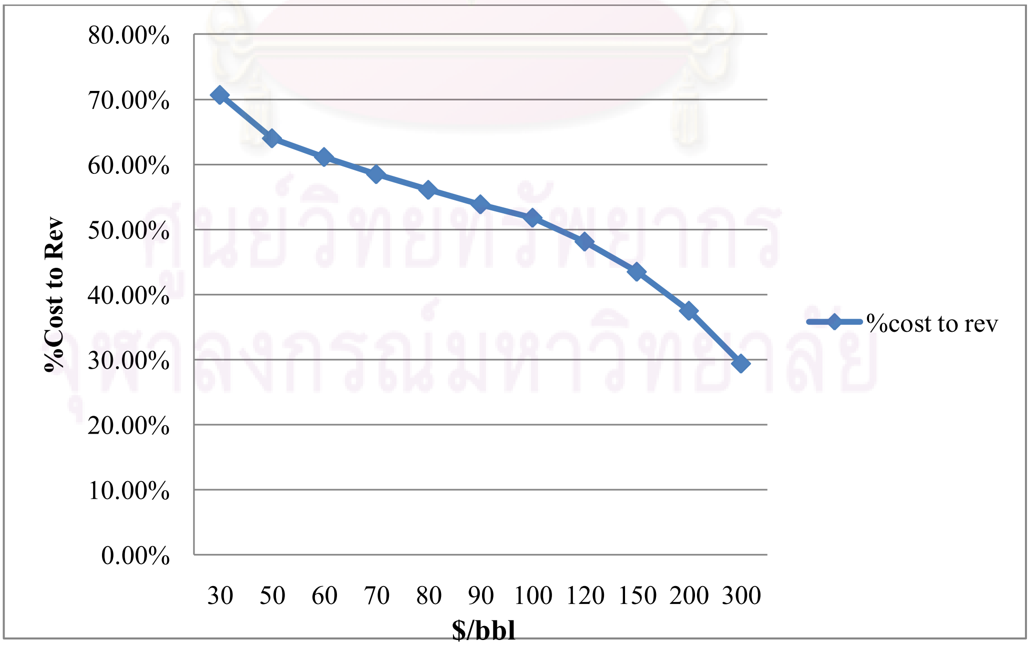

Figure 4.4 Sensitivity of percentages of cost to revenue to petroleum price per barrel

Ranges of cost to gross revenue for four price scenarios are between 50 to 60 percents. It can be clearly seen that price scenario 1 (70\$/bbl) have highest of % cost to gross revenue approximately 58% and lowest approximately 50% in price scenario 2 (105\$/bbl) (see Table 4.2).

Table 4.2 Percentages of cost to total gross revenue for four price scenarios

Price scenario	**Total cost (MMUS\$)**	**Gross revenue (MMUS\$)**	**Cost to revenue (%)**
1 (70\$/bbl)	2,607	4,457	58.49
2 (105\$/bbl)		5,130	50.82
3 (escalation5%/yr)		4,854	53.71
4 (escalation7.5%/yr)		5,097	51.15

4.1.5 Income

Income or revenues is depended on price scenarios and types of fiscal regimes such as Thai I or Thai III.

Thailand Petroleum Income Tax Act (Thai I) have royalty and tax as Table 4.3

Table 4.3 Royalty and Tax of Thailand Petroleum Income Tax Act (Thai I)

Royalty		12.50%			
Tax Calculation	**Tangible/Intangible Expenses Estimation**	Before Production		After Production	
		Tangible	Intangible	Tangible	Intangible
	● Exploration/Delineation Wells	100%	0%	20%	80%
	● Development Wells	100%	0%	50%	50%
	● Production Facilities	100%	0%	100%	0%
	● Other Facilities	100%	0%	100%	0%
	Depreciation Rate				
	● Pre-Production Expenses	10%per year			
	● Tangible Expenses	20%per year			
	Allowable Expenses				
	● Depreciated Pre-Production Expenses				
	● Depreciated Tangible Expenses				
	● Bonuses and Fee				
	● Operating Expenses				
	● Intangible Well Cost				
Petroleum Income Tax Rate		50%of Taxable Income			

Structure of Thailand Petroleum Income Tax Act (Thai I) is included royalty which is constant rate at 12.5% and 50% of taxable income see Figure 4.5

The example of %government takes and %contractor take are shown in Appendix B3 and Appendix B4

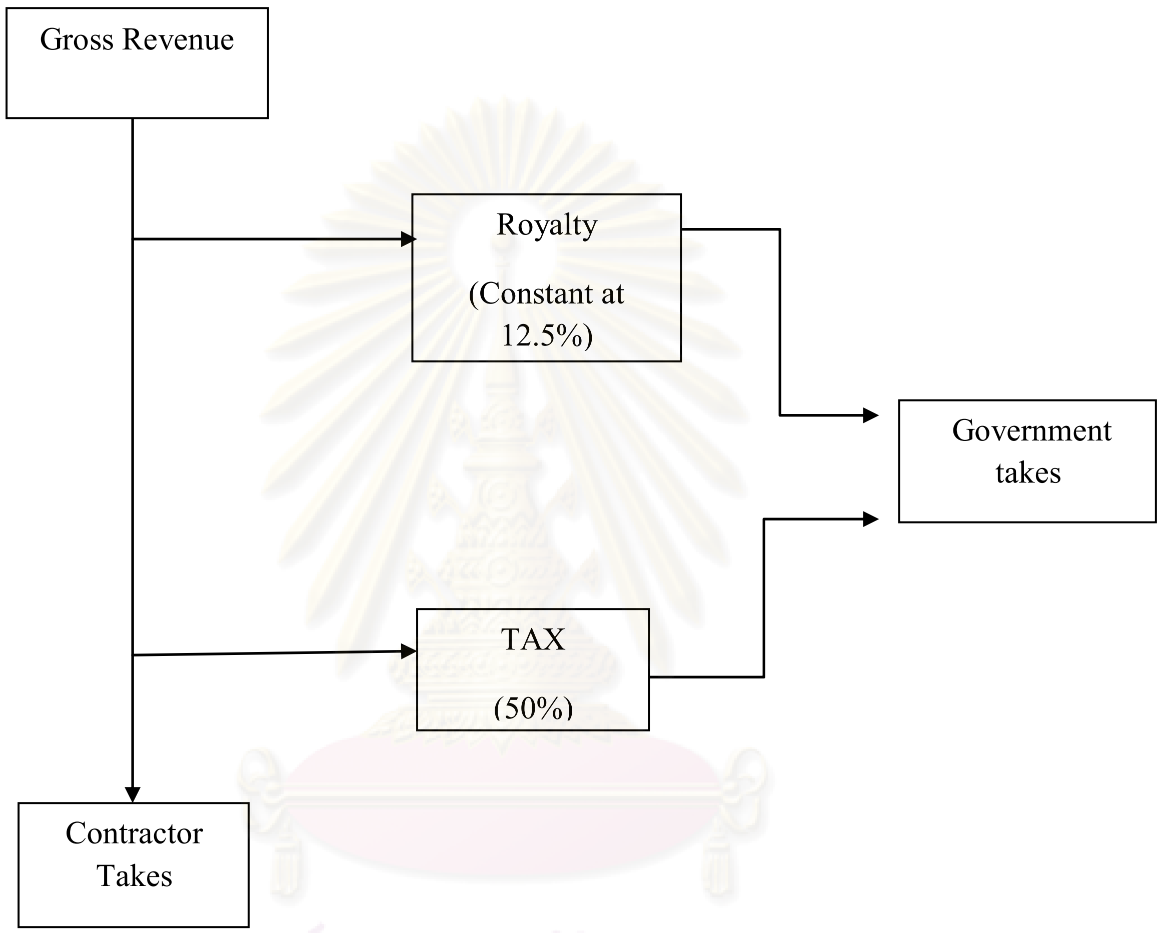

Figure 4.5 Structures of Thai I

Thailand Petroleum Income Tax Act (Thai III) is included not only royalty and tax but also SRB as well see Table 4.4

Table 4.4 Royalty, Tax and SRB of Thailand Petroleum Income Tax Act (Thai III)

Royalty		From	To		**Rate**
		≤	2,000	BOE/D	5.00%
		2,000	5,000	BOE/D	6.25%
		5,000	10,000	BOE/D	10.00%
		10,000	20,000	BOE/D	12.50%
		20,000	≥	BOE/D	15.00%
Special Remuneration Benefit(SRB)					
Geological Constant, K (Meters)		150,000			
Special Reduction (SR)		35.00%			
Annual Revenue per one meter of well drilled(Baht/meter)		From	To	SRB rate	
		≤	4,800	0.00%	
		4,800	14,400	1.00%	
		14,400	33,600	1.00%	
		33,600	≥	1.00%	
Tax Calculation	**Tangible/Intangible Expenses Estimation**	Before Production		After Production	
		Tangible	Intangible	Tangible	Intangible
	● Exploration/Delineation Wells	100%	0%	20%	80%
	● Development Wells	100%	0%	50%	50%
	● Production Facilities	100%	0%	100%	0%
	● Other Facilities	100%	0%	100%	0%
	Depreciation Rate				
	● Pre-Production Expenses (Intangible + OPEX)	10%per year			
	● Tangible Expenses (Both Pre & Post Prod.)	20%per year			
	Allowable Expenses				
	● Depreciated Pre-Production Expenses				
	● Depreciated Tangible Expenses				
	● Bonuses and Fee				
	● Operating Expenses				
	● Intangible Well Cost				
Petroleum Income Tax Rate		50%of Taxable Income			

Structure of Thailand Petroleum Income Tax Act (Thai III) is composed of sliding scale royalty from 0% to 15%, SRB from 0% to 75% and petroleum income tax is 50% see Figure 4.6

The example of SRB calculations is shown in Appendix B5

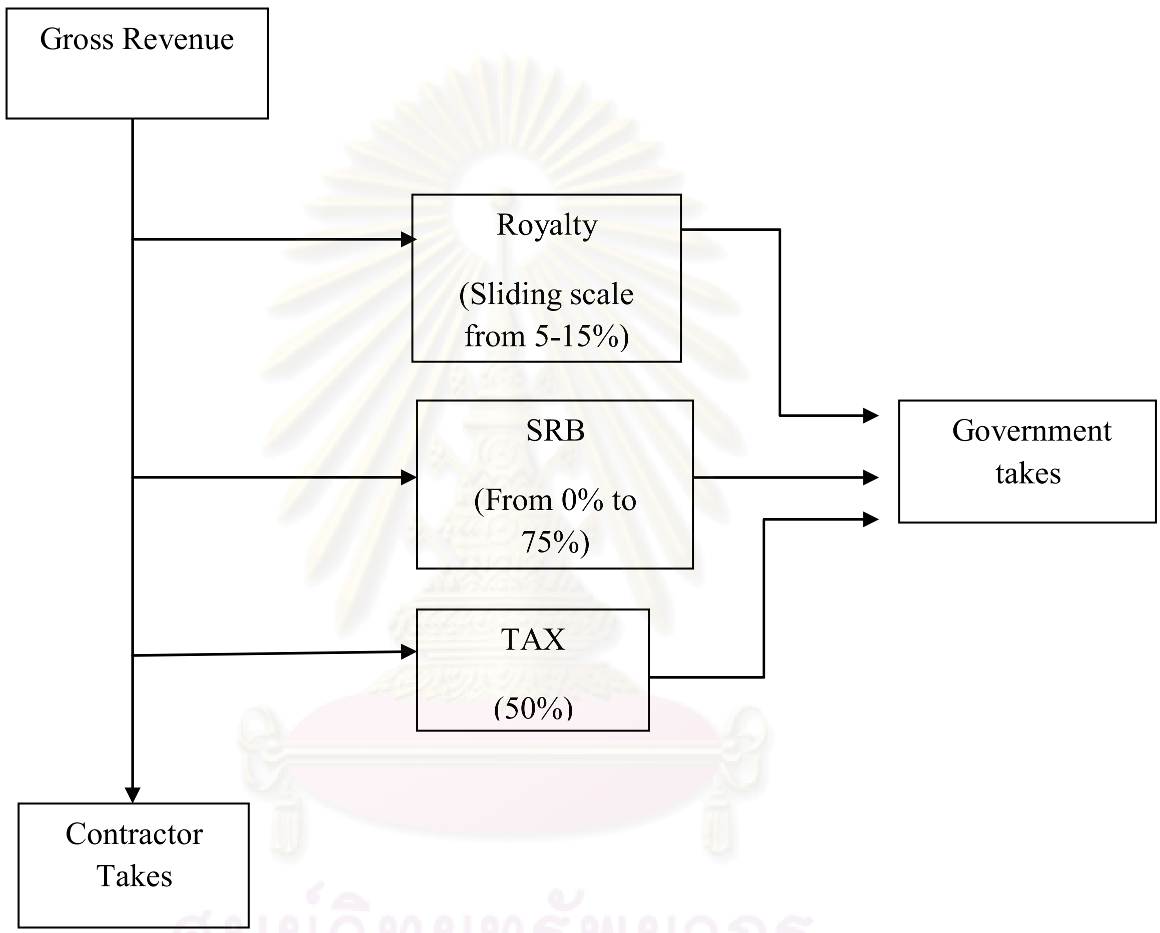

Figure 4.6 Structures of Thai III

4.1.6 Decision criteria

Decision criteria in this thesis are two main components, First is Net Present Value (NPV) at 12% discounted rate and the last one is Internal Rate of Return (IRR) which higher than 12%.

4.2 Pre study the characteristics of Thai I and Thai III

Compare and analyze the characteristic of both Thai I and existing system by observes the trend of percentages of government take together with the price between 50$/bbl to 200$/bbl moreover, the total cost to gross revenue is also observe by varying the oil and condensate price from 30$/bbl to 300$/bbl and analyze the percentages of government take when increased the reserve in every price scenarios up to 40% and also analyze the percentages of government take to total cost to gross revenue from base case of all four price scenarios up to 30% cost increase.

4.2.1 Pre study in Thailand fiscal system

For both of Thai I and Thai III term, analyze the percentages of government take for check general characteristics of both system when assume the petroleum price from 50$/bbl to 200$/bbl.

4.2.2 Total cost to gross revenue

Again for both of Thai I and Thai III term, analyze the total cost to gross revenue by varying the oil and condensate price from 30 US dollar per barrel to 300 US dollar per barrel for check the trend of the total cost to gross revenue together with petroleum price.

4.2.3 Percentages of government take to increased reserve

For all four price scenarios and both of Thai I and Thai III term, analyze the government's take in percentages that based on net revenue when increase the reserves from base case in every price scenarios up to 40%.

4.3 Study the characteristics of Thai III

In this part is concentrated on the Thai III system by start with analyze the sensitivity of NPV at 12%, IRR, without the royalty, tax and SRB calculation, reduce the royalty, reduce the tax rate, adjust of royalty, tax rate and SRB after that compare the three cases of individual component in royalty, tax rate and SRB, for royalty is divided in to five cases as no royalty, half royalty, maximum 12.5%, maximum 14% and royalty holidays. For tax rate is divided in to two cases, tax holidays and royalty as tax credit, For adjust the component of SRB is divided in to four main cases, no SRB, half of the geological factor (K), twice of the geological factor (K) and adjust the Special Reduction (SR) 50% and 20%.

4.3.1 With-out any tax

For all four price scenarios but only for Thai III term, analyze the characteristic of the field when without the royalty, tax and SRB calculation and compare the NPV at 12%, IRR and compare with the percentages of government take in Thai III term.

4.3.2 Adjust the royalty

In this section is divided in four cases as follow:

No royalty
Half royalty
Maximum at 12.5%
Royalty exemption

The royalty holidays is calculate by neglect the royalty first three years, first four years, first five years and first seven years.

Perform in all four price scenarios and compare IRR, NPV at 12% and percentages of government take.

4.3.3 Adjust the tax rate

In this section is divided in to two cases as follow:

With-out any tax
Half tax
Tax holidays

Tax holiday is calculated by neglect the tax rate (Tax rate is normally 50% of petroleum income tax) first year to first three years.

Perform in all four price scenarios and compare IRR, NPV at 12% and percentages of government take.

4.3.4 Tax credit-Royalty as tax credit

For royalty as a tax credits which mean deduct the tax payable to the government by the royalty in each year.

Perform in all four price scenarios and compare IRR, NPV at 12% and percentages of government take.

4.3.5 Adjust the component of SRB

In this section is divided in to three cases as follow:

No SRB

Adjust the Special Reduction (SR)

Normally, the special Reduction (SR) that equal to 35% of tangible in capital expenditure. In this study is divided in to 70% of SR and 100% of SR.

Twice of the geological factor (K)

Geological factor (K) is normally 150,000 meters. In case of adjusting twice of the geological factor (K) equal 300,000 meters.

Perform in all four price scenarios and compare IRR, NPV at 12% and percentages of government take.

CHAPTER V

STUDY AND IMPROVEMENT OF THAILAND PETROLEUM FISCAL REGIME

5.1 Pre study

5.1.1 Percentages of government take

In Figure 5.1, the general characteristics when assume the average the petroleum price from 50$/bbl to 200$/bbl. For Thailand I, percentages of government take is decreased when increase in petroleum price while percentages of government take is increased while increase in petroleum price in Thailand III.

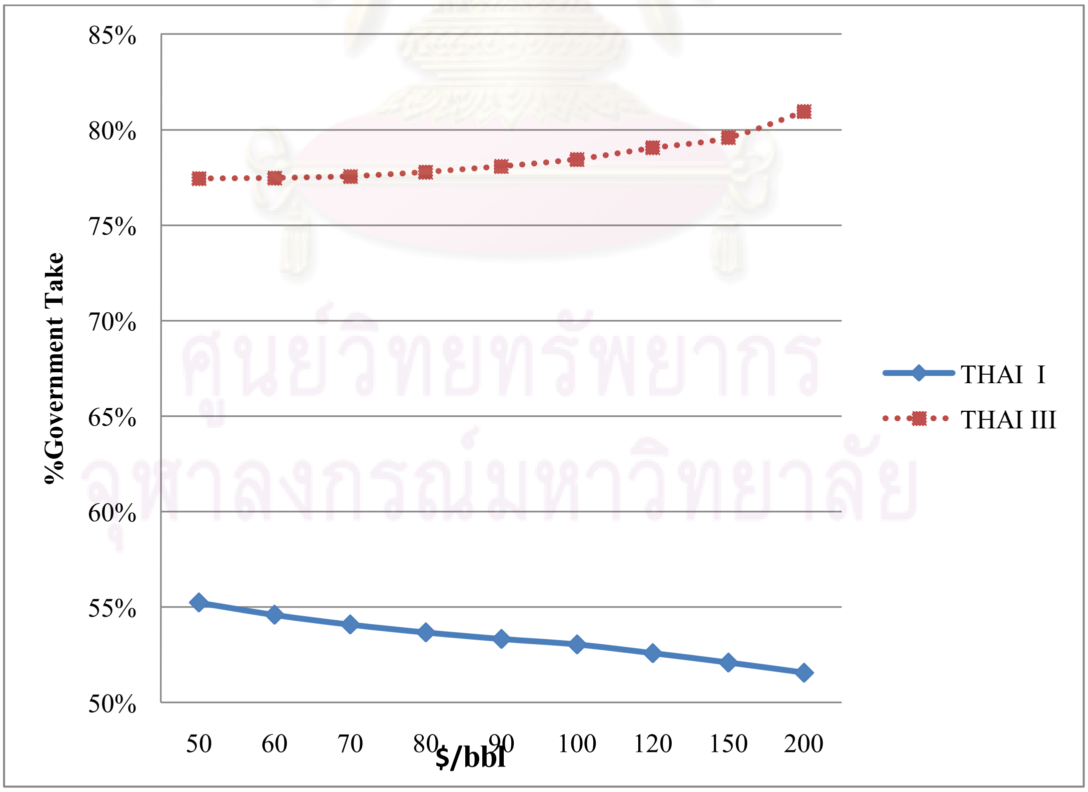

Figure 5.1 Sensitivity of government takes to petroleum price per barrel between Thai I and Thai III

5.1.2 Total Cost to gross revenue

Again, the oil and condensate price varying from 30 US dollar per barrel to 300 US dollar per barrel, the percentages of cost to revenue is decreased from approximately 70 percents to 30 percents when increased the petroleum price in Figure 5.2, In this situation can be clearly seen that the oil and condensate price direct effect to the percentages of cost to revenue.

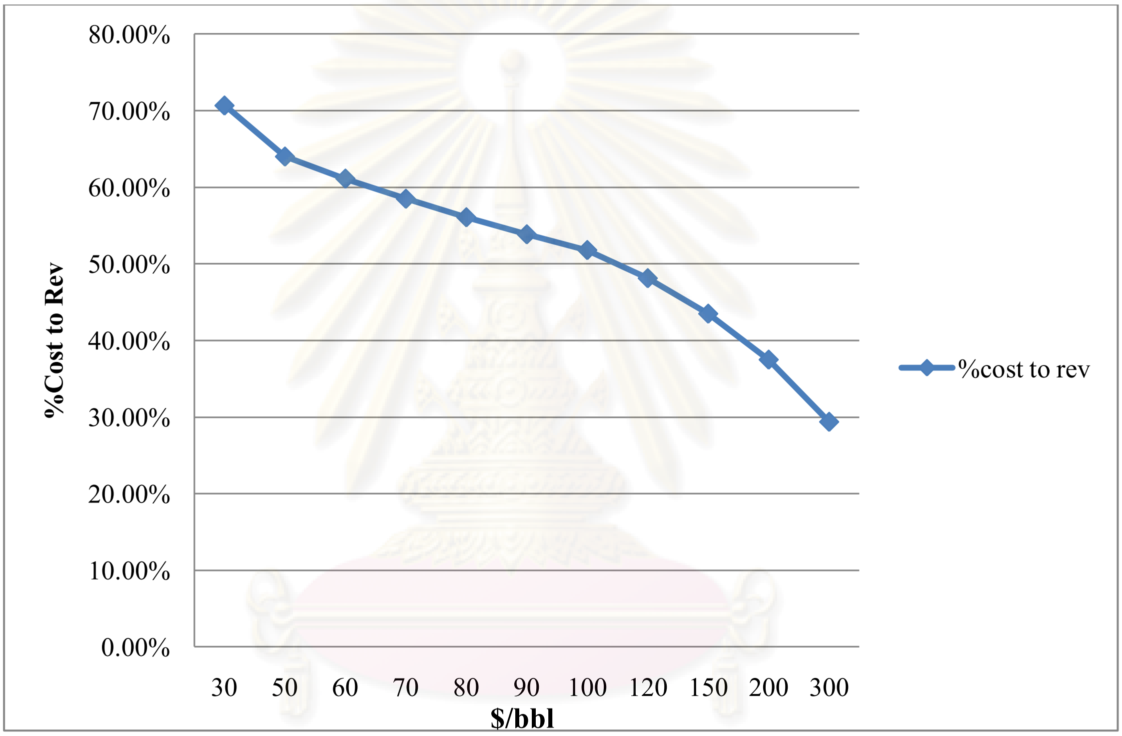

Figure 5.2 Sensitivity of percentages of cost to revenue to petroleum price per barrel

5.1.3 Percentages of government take to increased reserves

In each petroleum price scenarios, the percentages of government take based on net revenue in Thai I is decreased when reserve is increased from 10% to 40% while Thai III the percentages of government take is increased (see Figure 5.3)

It can be clearly seen that Thai I is regressive system while Thai III is progressive system so the reason of Thai III are considered in this study instead of Thai I.

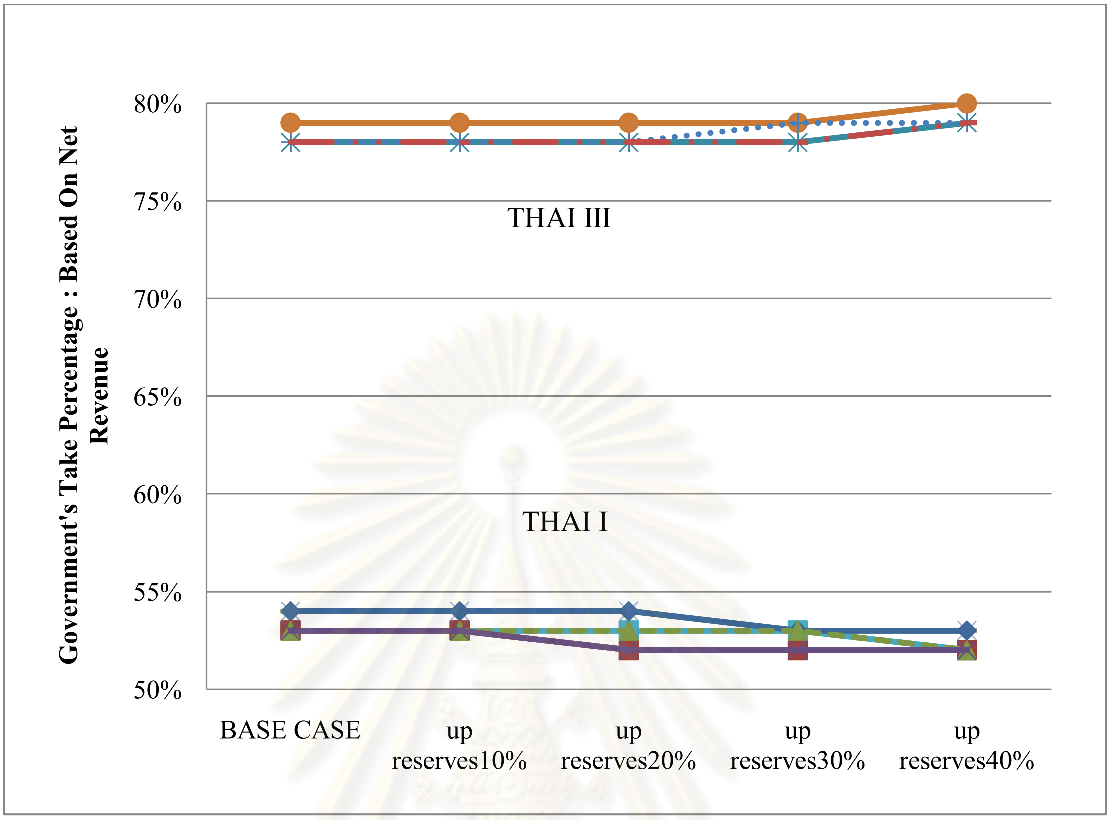

Figure 5.3 Percentages of government take to increased reserve

5.2 Study and improvement of Thai III

In this study, the improvement on tax system is divided into 6 subcategories which are With-out any tax, Adjust the royalty, Adjust the tax rate, Tax credit-Royalty as tax credit, Adjust the component of SRB and Combined cases. The considering criteria is that ~~"~~%IRR more than 12%, NPV at 12% discounted rate is positive and accepted by the investors and selected % government take is highest". These criteria shall be demonstrated in Bar chart in the Appendix D1 to Appendix D18.

5.2.1 With-out any tax

The comparison of %IRR of the four price scenarios from the figure 5.4 demonstrates that the %IRR of all four price scenarios are more than 12% as follow; %IRR of price scenario1 increases from 6.95% to 13.50%, price scenario2 increase from 8.28% to 16.71%, Price scenario3 increase from 7.69% to 15.10% and price scenario4 increase from 8.09% to 15.98%, in which the increasing percentages are 6.55%, 8.43%, 7.41% and 7.89%, respectively. This study shows that the price scenario2 with hydrocarbon 105$/bbl has highest %IRR, while the price scenario1 has the lowest and price scenario4 and price scenario3 are in between. From the above stated data, we now see clearly that this reserve could possibly be developed if we adjust the components of Tax, Royalty or SRB due to the fact that the %IRR is more than 12%, nevertheless, should the government not improve or change any components, the mentioned reserve shall not be developed and this will affect to the decision of investors to choose not to invest in this reserve and the government consequently lose the opportunity to develop this reserve eventually. As a result, in order to create competition among investors and capability to develop reserve, the government has to change the components as earlier suggestion.

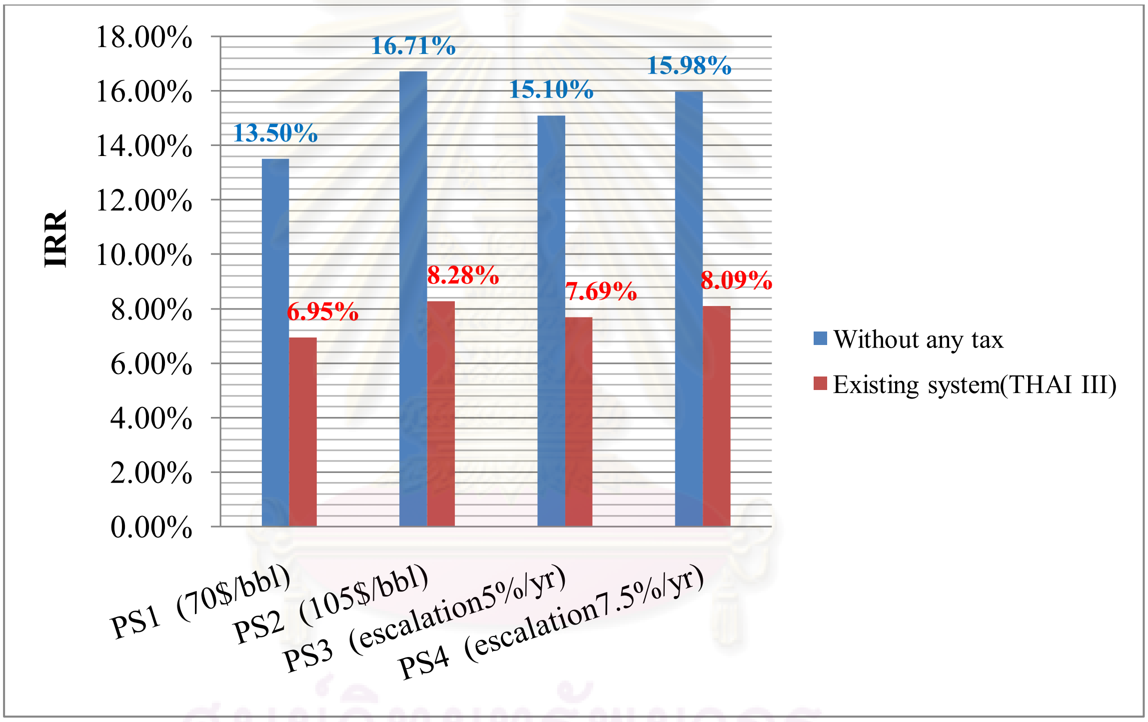

Figure 5.4 %IRR for four price scenarios of without any tax

Alternatively, if the government negotiate adjusting the gas price from 3US$/MMBTU to 6.12US$/MMBTU which is the lowest rate where %IRR of the four price scenarios over 12%. Once the gas price is adjusted, the results shall be 12.01% for price scenario1, 12.71% for price scenario2, 12.34% for price scenario3 and 12.56% for price scenario4. And after adjusting the gas price, the price scenario 2 obtains highest %IRR, while the price scenario1 obtains the lowest as shown in the figure 5.5.

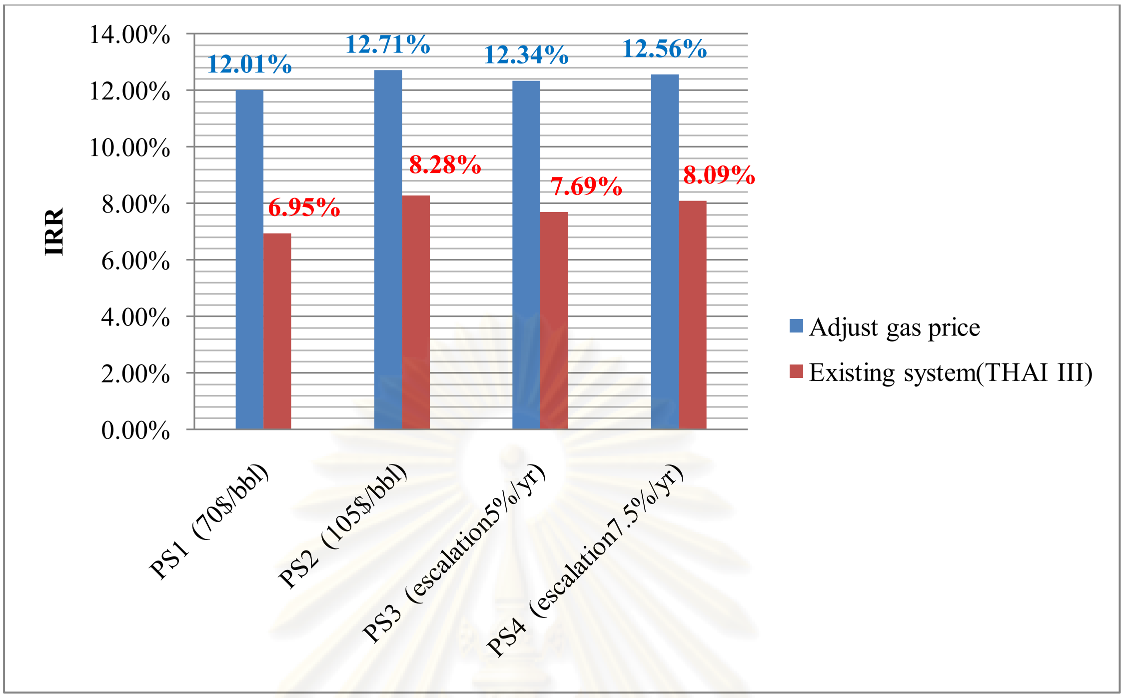

Figure 5.5 %IRR between adjust gas base price and existing system

5.2.2 Adjust the royalty

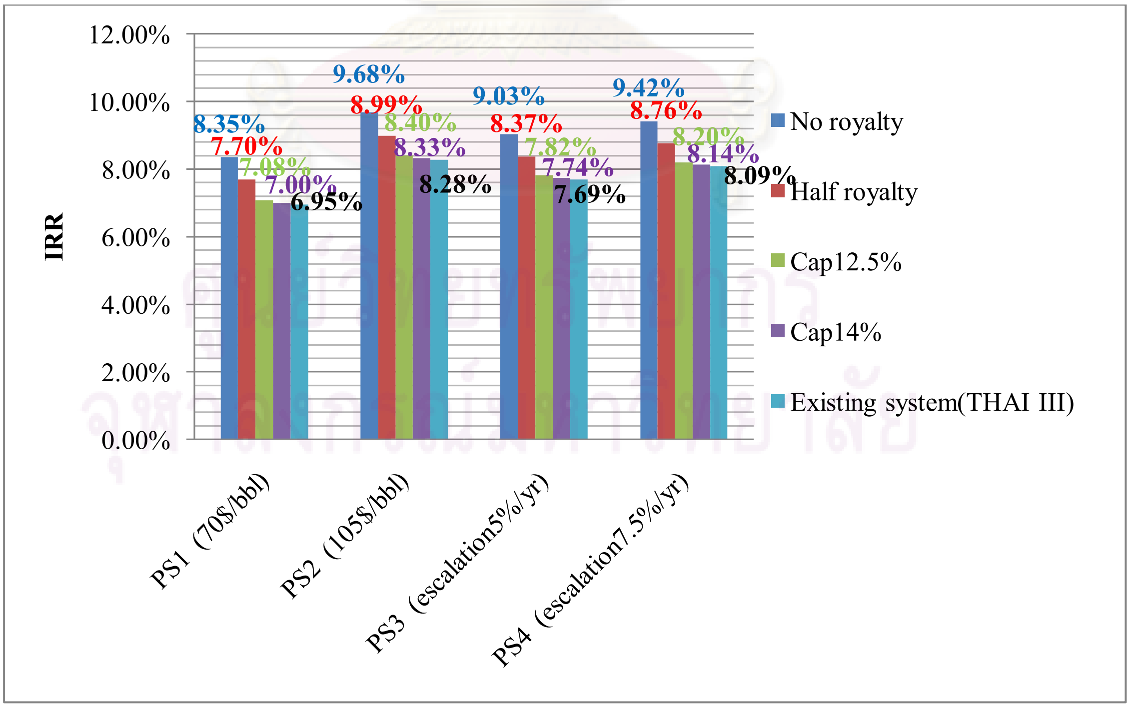

Figure 5.6 Comparison of %IRR between adjusts royalty and existing system for four price scenarios

In addition, apart from adjusting the gas price, in this study also offers an alternative to improve petroleum fiscal system appropriately in order that the undeveloped reserves could be developed starting form royalty. In the figure 5.6, it shows the adjusts on No royalty, half royalty, maximum at 12.5% (sliding scale) and maximum at 14% (sliding scale), by comparison between the existing system, while the price scenario 2 has maximum IRR in all cases; 9.68%, 8.99%, 8.40% and 8.33%, respectively, and NPV at 12% discounted rate are -14MMUSD, -19MMUSD, -22MMUSD and -22MMUSD, respectively. The %IRR and NPV at 12% discounted rate of maximum at 12.5% (sliding scale) and maximum at 14% (sliding scale) are nearly the same due to the fact that the percentage of sliding differs only 1.5% as shown in the figure 5.7.

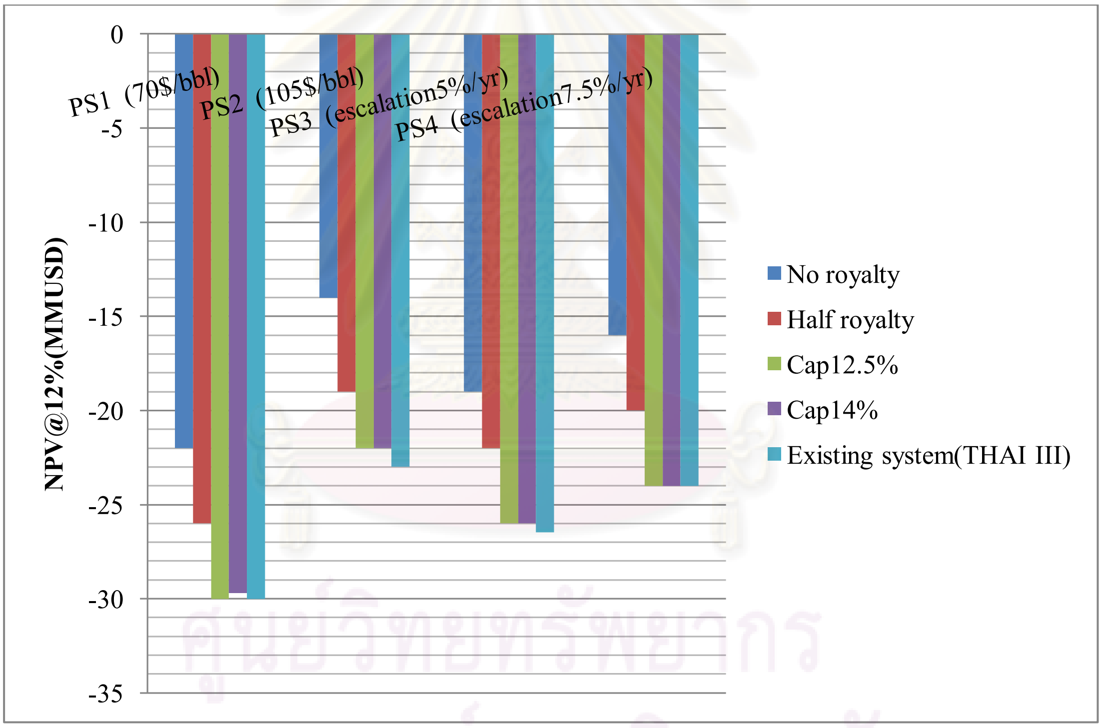

Figure 5.7 Comparison of NPV at 12% discounted rate between adjusts royalty and existing system for four price scenarios

The maximum %government takes goes to the price scenario 2 as well, at maximum at 14% (sliding scale) or 78%, while the lowest with price scenario1 without royalty is 70%. These differ from the existing system 1% and 8%, respectively as shown in the figure 5.8.

From the royalty adjustment for the 4 cases, we will see that even though %IRR is unable to exceed 12%, but with a better trend of the average %IRR which adjust increasingly to almost 2%.

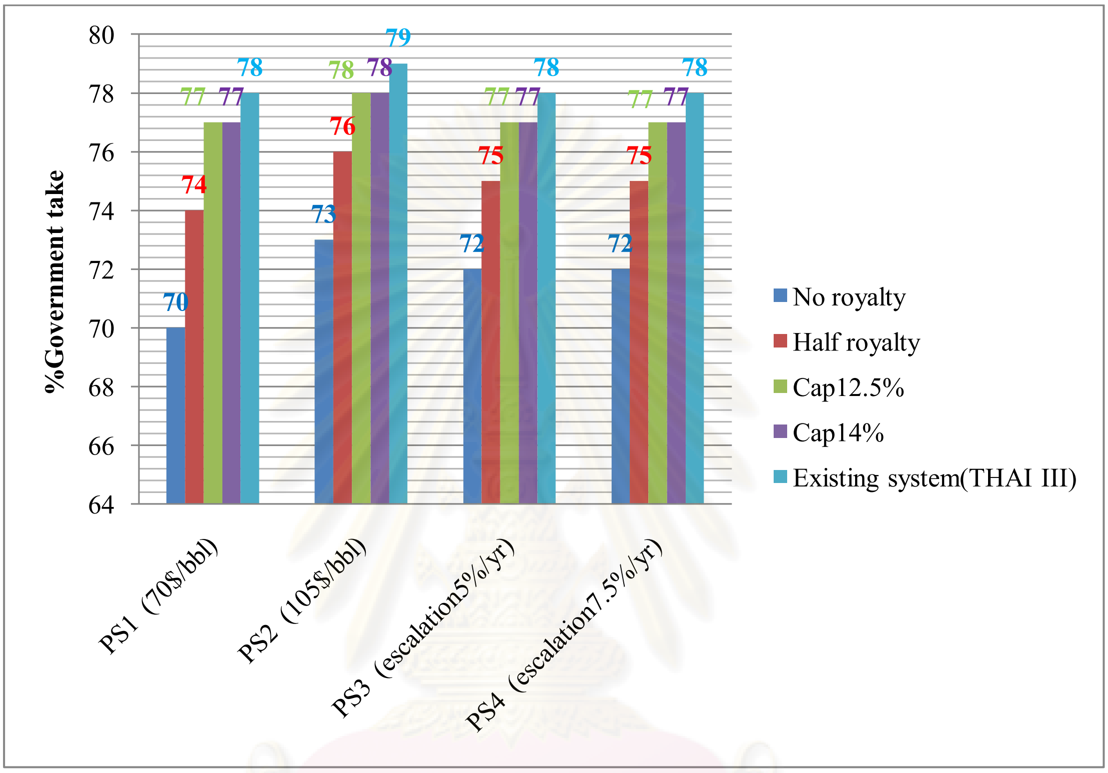

Figure 5.8 Comparison of % government take between adjusts royalty and existing system for four price scenarios

In the case of Royalty exemption from 3 years to 7 years, compared with the existing system, we will see that the royalty exemption 7years has the best %IRR among all price scenarios due to royalty exemption up to 7years; price scenario1 is %IRR 8.05%, price scenario2 is 9.39%, price scenario3 is 8.73% and price scenario4 is 9.12%, respectively. However, if we compare between 3 years, 4 years, 5 years and 7 years of royalty exemption, %IRR of price scenario2 is the highest and price scenario1 is lowest as Figure 5.9.

For NPV at 12% discounted rate at royalty exemption at 7years of all price scenario, we will get as follow; price scenario1 is -24MMUSD, price scenario2 is -16MMUSD, price scenario3 is -20MMUSD and price scenario4 is-18MMUSD, respectively, when compared with the royalty exemption 3 years, 4 years and 5years as Figure 5.10.

In the case of %government takes, the maximum rate goes to at royalty exemption 3years in all price scenarios which is average 77%, while the minimum rate goes to at royalty exemption 7years which is74%, in which these differs from the Existing system by 1% and 4%, respectively as Figure 5.11

When compared Royalty exemption at7 years (the best case) with Adjust royalty, we will see that the %IRR and NPV at 12% discounted rate is less than the case of No royalty, averagely at 0.30% and 2MMUSD, respectively. On the other hand, in the case of Royalty exemption at3 years and maximum at 14% (sliding scale) where obtain highest %government takes are the same rate at 77%.

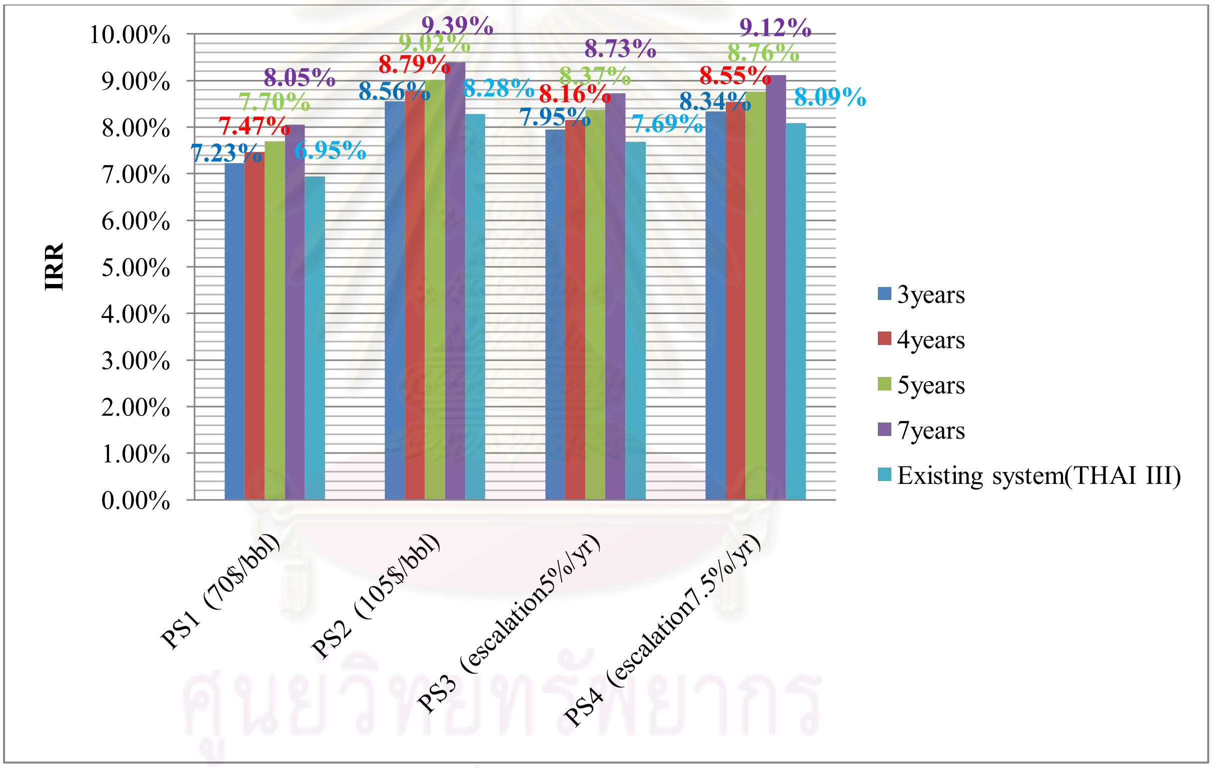

Figure 5.9 %IRR between royalty exemption from 3 to 7 years and existing system for four price scenarios

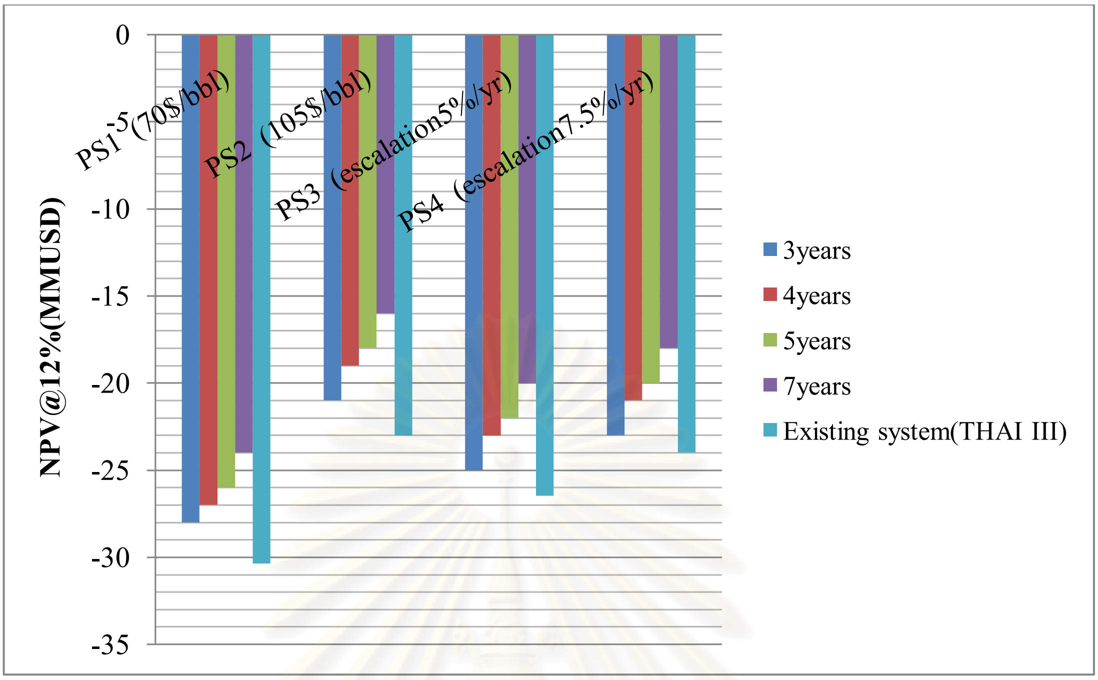

Figure 5.10 NPV at 12% discounted rate between royalty exemption from 3 to 7 years and existing system for four price scenarios

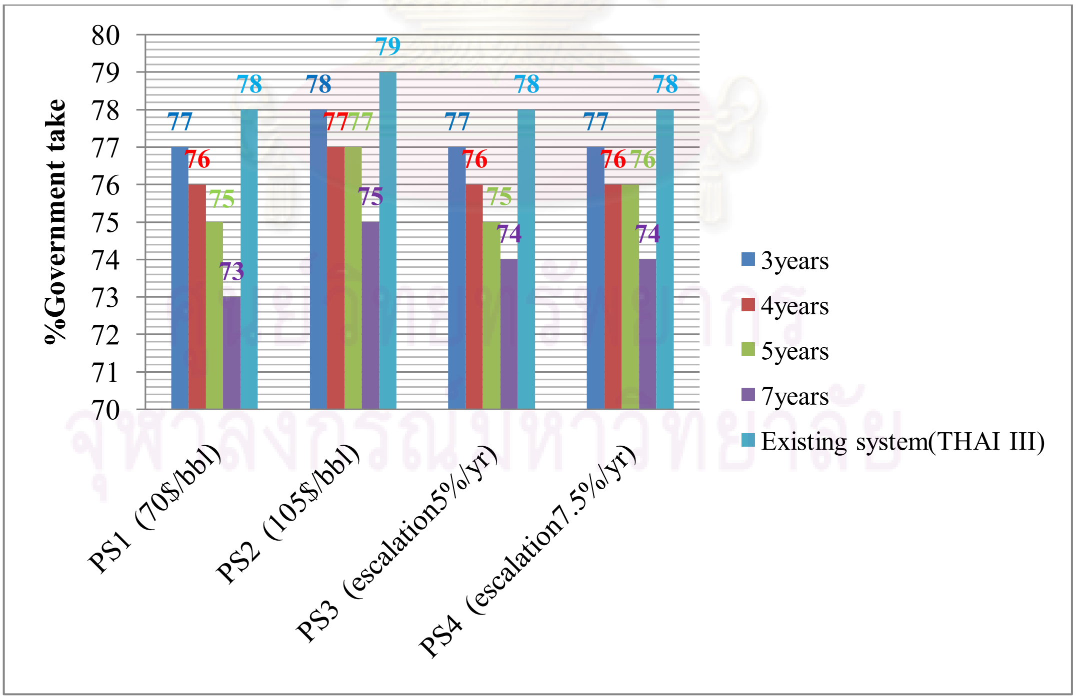

Figure 5.11 % Government take between royalty exemption from 3 to 7 years and existing system for four price scenarios

5.2.3 Adjust the tax rate

In the case of Adjust tax, it is divided into 5 scenarios which are without tax (adjust from 50% of taxable income to 0% of taxable income), Half tax (at 25%of taxable income), Tax exemption 1year (at 0% of taxable income applied only to the first year), Tax exemption 2years (at 0% of taxable income applied only the first 2 years) and Tax exemption 3years (at 0% of taxable income applied only the first 3 years). The results obtained are %IRR is lower than 12% in all price scenarios, except in the case of tax exemption 3 years where obtains %IRR over 12%, however, only the price scenario 1 that the %IRR is almost 12% (11.35%) as Figure 5.12.

When considering NPV at 12% discounted rate, all scenarios are remaining negative, except the case of tax exemption 3 years where obtains positive NPV, however, only price scenario 1 that NPV is negative at -4MMUSD as Figure 5.13

Form the above mention, the results demonstrate that all price scenarios of Tax exemptions (1year) has the maximum %government takes at 76% and the average lowest at 50% when applying 0% of taxable income, please see Figure 5.14

From the Adjust tax rate, we will clearly see that the case of 3 years Tax exemption has high possibility for developed reserves.

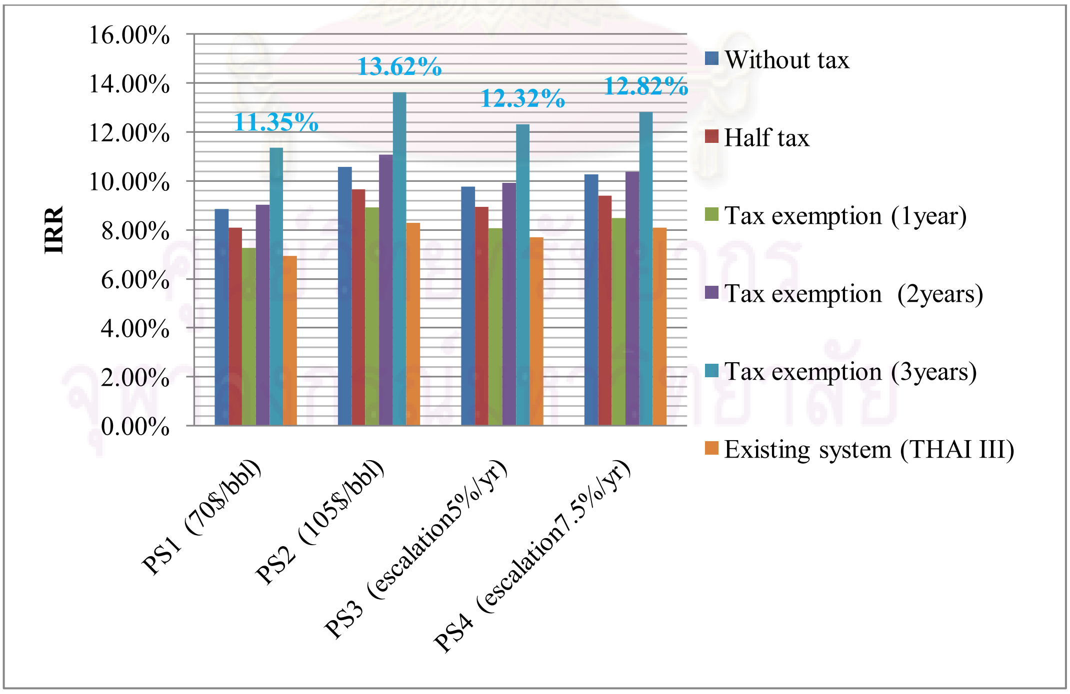

Figure 5.12 Comparison of %IRR between adjusts tax and existing system for four price scenarios

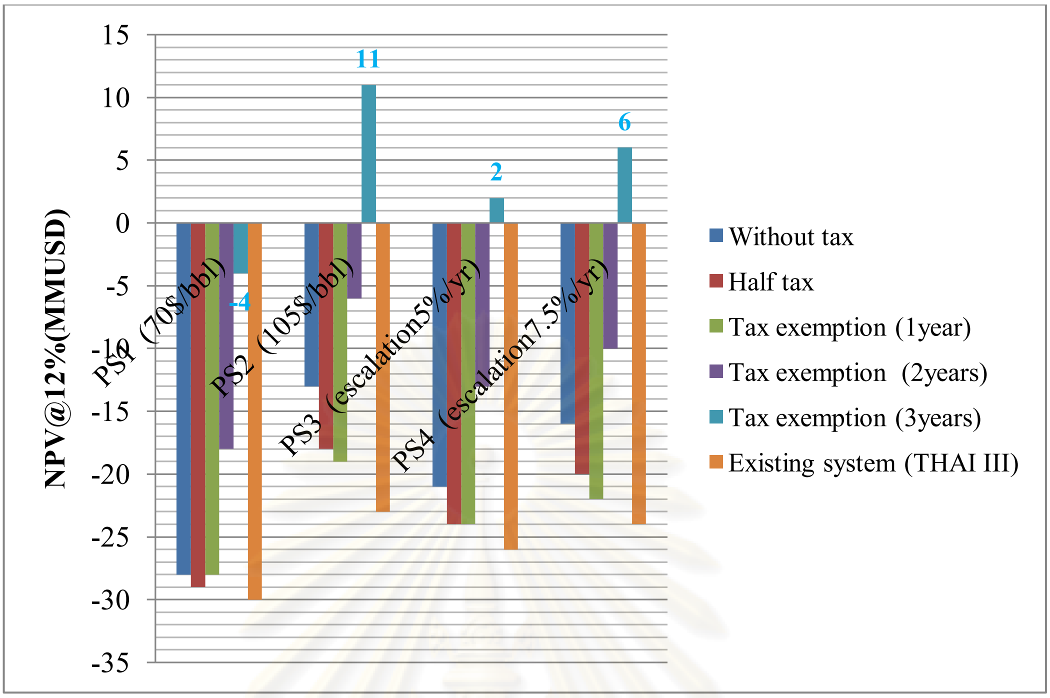

Figure 5.13 Comparison of NPV at 12% discounted rate between adjusts tax and existing system for four price scenarios

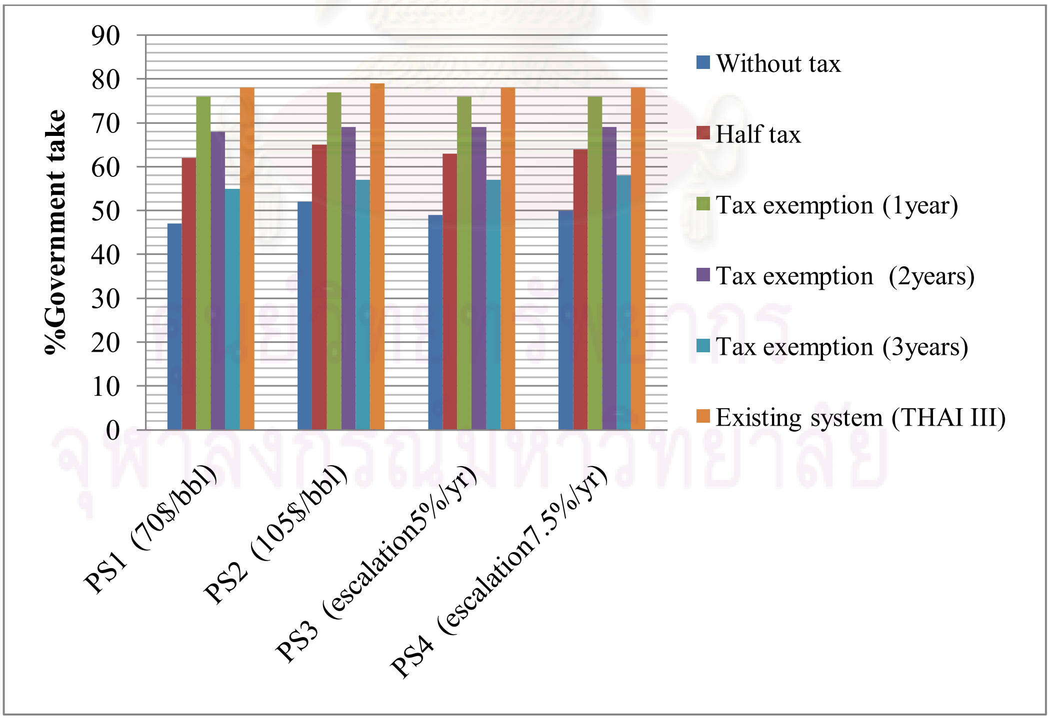

Figure 5.14 Comparison of %government take between adjusts tax and existing system for four price scenarios

5.2.4 Tax credit-Royalty as tax credit

If we apply Royalty as Tax credit from the beginning of the process, we will see that all price scenarios (except price scenario1) have IRR over 12% as follow; 11.79%, 13.54% 12.67% and 13.14%, respectively as shown in the Figure 5.15.

When compared NPV at 12% discounted rate in all price scenario from price scenario 2 to price scenario 4, except the price scenario1 where NPV is -1MMUSD, they are 11MMUSD, 5MMUSD and 8MMUSD, respectively as Figure 5.16

We will see that the average %government takes is at 52% which differs from the Existing system where the averages of 78% is at 26%. As a result, the adjustment of Royalty into Tax credit has a capable trend to develop reserves, however, the %government take shall decrease over 20% and when compared with the case of Tax exemption 3years, it will give similar %IRR, while the NPV at 12% discounted rate of turning in Royalty to Tax credit will give the higher rate than the case of Tax exemption 3years in all price scenarios as shown in Figure 5.17.

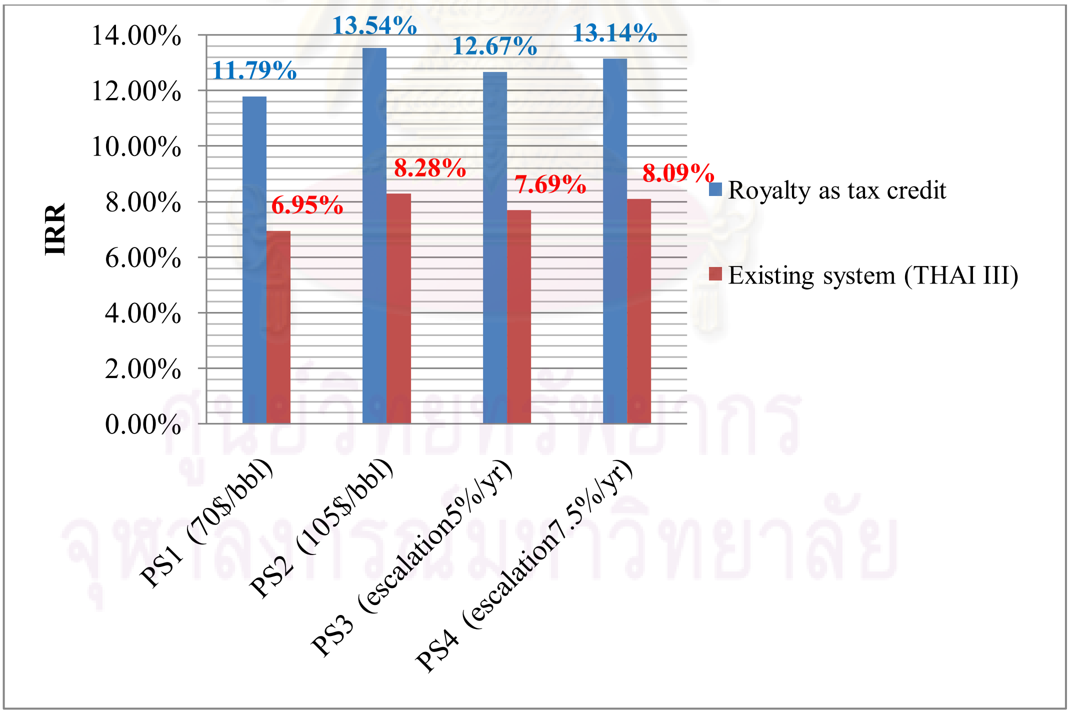

Figure 5.15 Comparison of %IRR between royalty as tax credit and existing system for four price scenarios

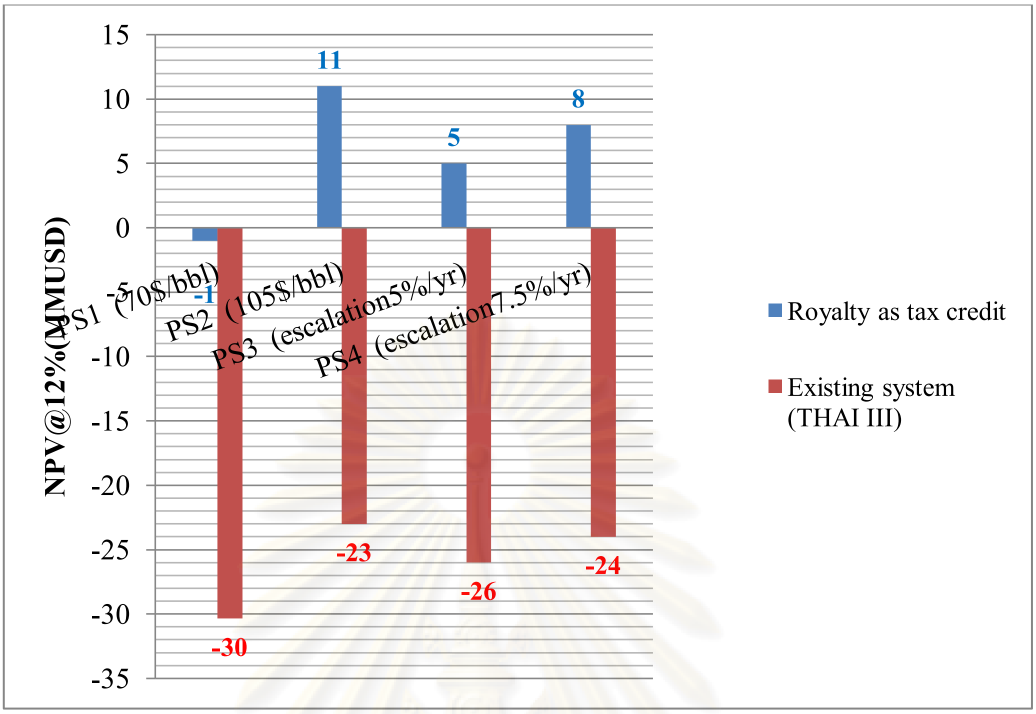

Figure 5.16 Comparison of NPV at 12% discounted rate between royalty as tax credit and existing system for four price scenarios

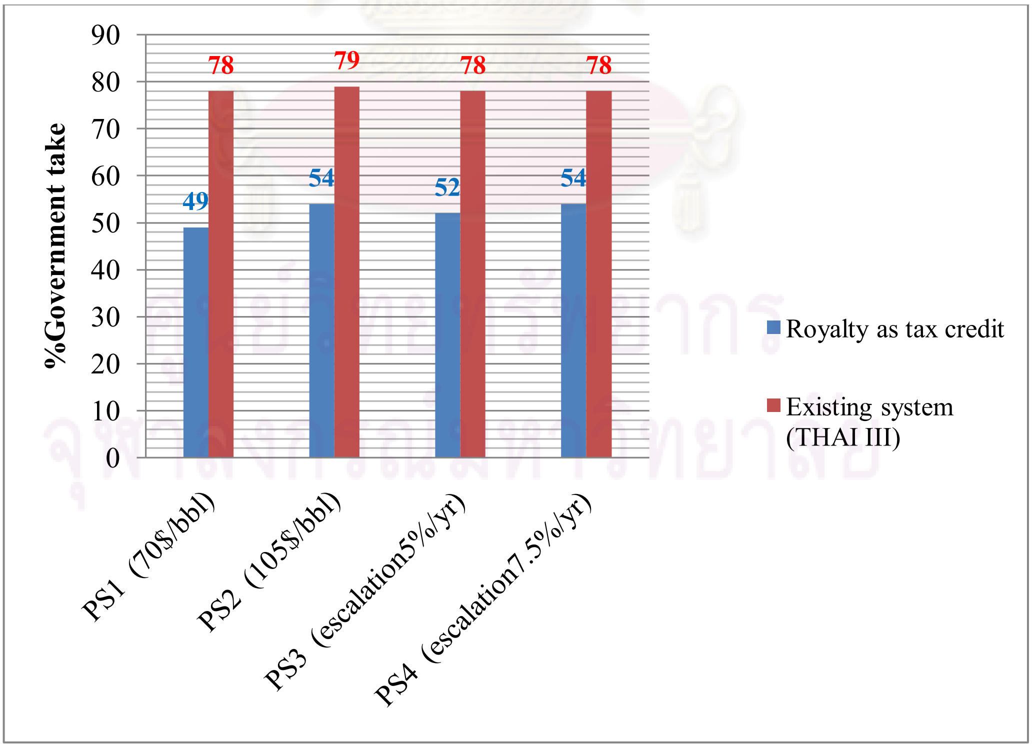

Figure 5.17 Comparison of %government takes between royalty as tax credit and existing system for four price scenarios

5.2.5 Adjust the component of SRB

The scenario of adjust the component of SRB consists of no SRB, special reduction (SR) from 35% to 100%, special reduction from 35% to 70% (2 times), 2 times Geological factor (K) from 150,000m to 300,000m. We will see that in the case of no SRB has maximum %IRR in all price scenarios which are 8.40%, 10.95%, 9.75% and 10.50%, respectively, on the other hand, it the case of 2 times Geological factor (K) from 150,000m to 300, 000m has minimum percentages which are 7.26%, 8.76%, 8.11% and 8.57%, respectively as shown in Figure5.18

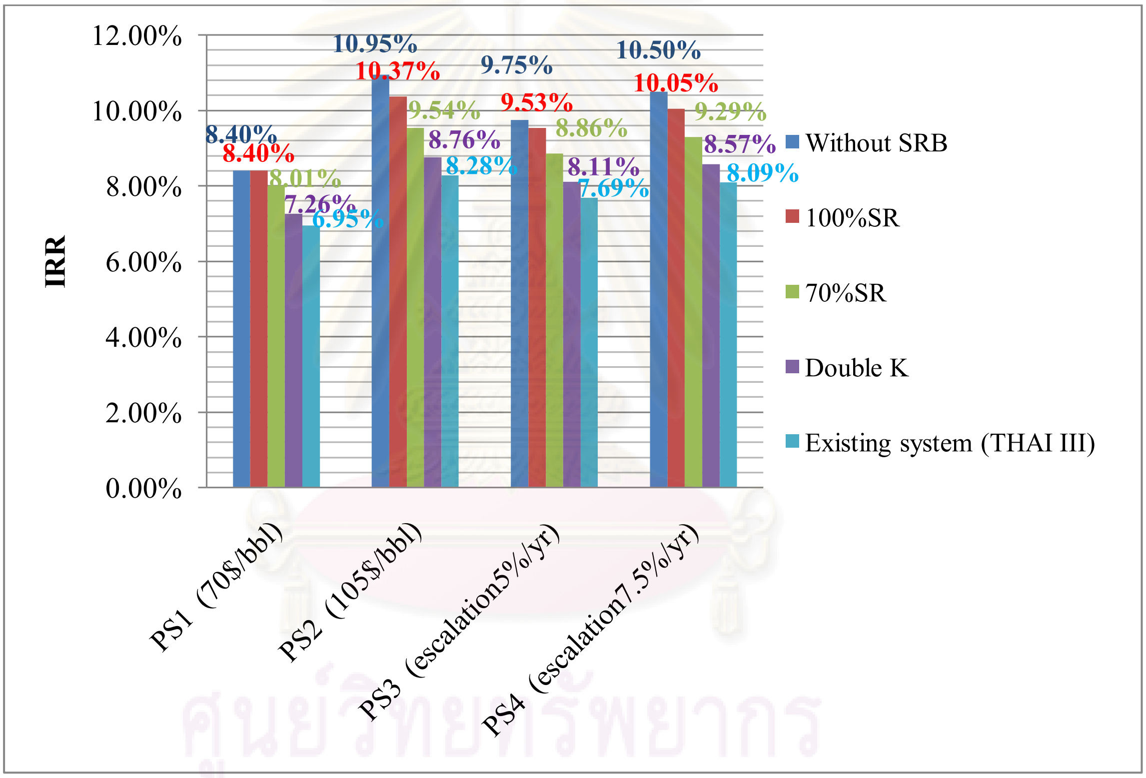

Figure 5.18 Comparison of %IRR between adjust SRB and existing system for four price scenarios

5.2.6 Combined cases

In this study we have found that in the cases of Tax exemption (3 years) and Royalty as tax credit, there are highest possibilities to develop reserves due to the fact that %IRR of all price scenarios are over 12%, except for the price scenario1 where both scenarios are almost 12% as follow; 1.35% and 11.79%, respectively. As a result, we've decided to select 2 following scenarios which are double K and Tax exemption 1 year as base because double K and Tax exemption 1 year have the same lowest %IRR at 7.26%

After we group the 2 scenarios together (Royalty as tax credit& double K), only the royalty as tax credit& tax exemption 1 year have %IRR over 12% which are 12.01% and 12.09%, respectively as demonstrated in Figure 5.19

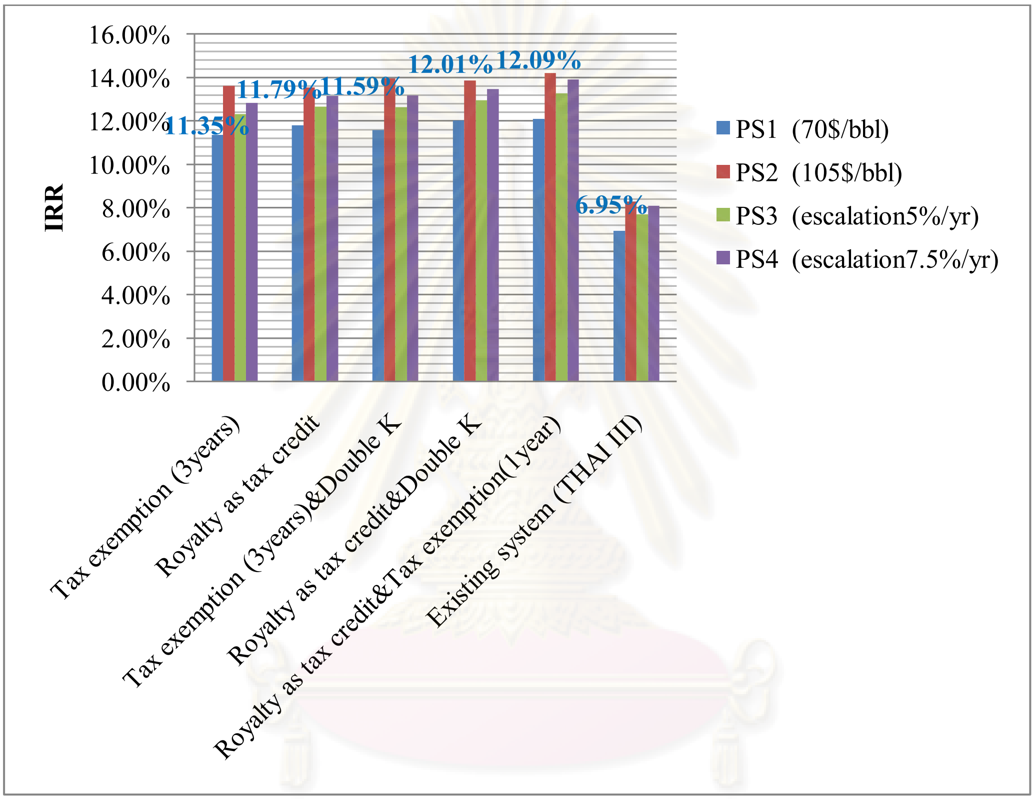

Figure 5.19 Comparison of %IRR between combined cases and existing system for four price scenarios

However, when compared NPV at 12% discounted rate, we have found that in the case of investors obtain the acceptable lowest %IRR which is 12% and the government shall receive the maximum beneficial share if it's the case of Royalty as tax credit& double K where obtain 0.1MMUSD, 13MMUSD, 7MMUSD and 11MMUSD, respectively as demonstrated in Figure 5.20

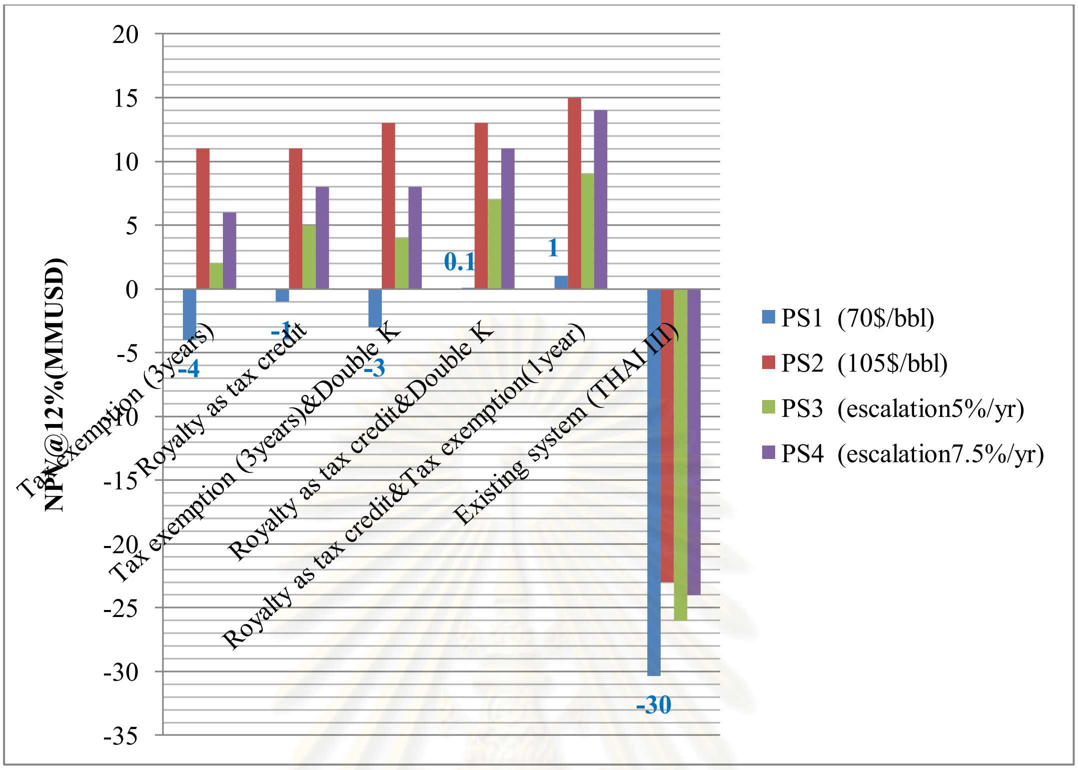

Figure 5.20 Comparison of NPV at 12% discounted rate between combined cases and existing system for four price scenarios

The average of comparison of the percentage of the governments takes regarding Royalty as tax credit & double K case is 50%, in which the Price scenario from 1 to 4 are 47%, 52%, 50% and 51%, respectively. However, when compared with the existing system with the mean of 78%, we have found that the percentage of the Government takes decreases by almost 30% as Figure 5.21.

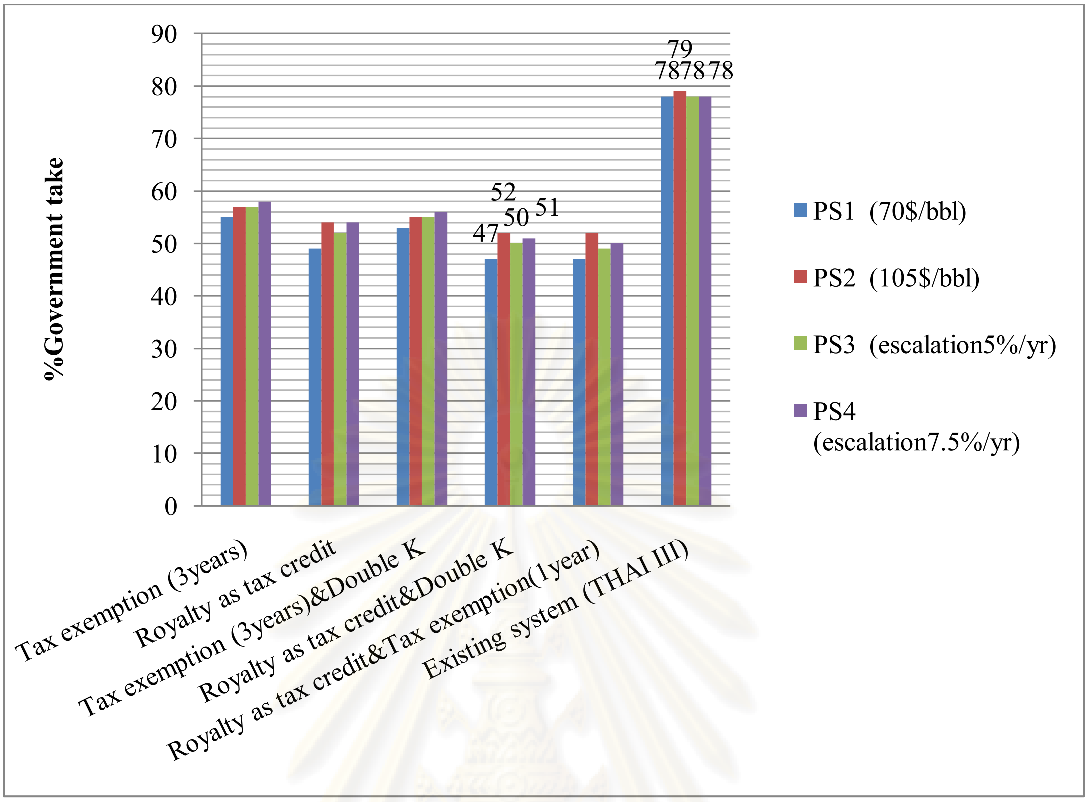

Figure 5.21 Comparison of %government take between combined cases and existing system for four price scenarios

CHAPTER VI

CONCLUSIONS AND RECOMMENDATIONS

6.1 Conclusions

Undeveloped reserved have %cost to gross revenue between 50-60% due to high CO_2 gas field as well as offshore. These factors cause high %cost to gross revenue. Besides, current petroleum fiscal system (THAI III) is quite high as well and it is one of the factors that make such reserves cannot be developed due to the fact that %IRR is lower than 12% and not accepted by investors.

From the study, we have experimented under the 4 situations of changing gas price with the 6 price scenarios on tax systems which are no tax, adjustment on royalty rate, adjustment on tax rate, adjust royalty as tax credit, adjust the component of SRB and combined cases, and the result shows that the best scenario goes to Royalty as tax credit & double K where increase capability for investors to obtain %IRR over 12%, while the government shall receive maximum beneficial share. Nevertheless, new technologies occur in the future may decrease the cost of production which somehow improves undeveloped reserves as well.

While in the case of adjustment on gas price from 3 US$/MMBTU to 6.12 US$/MMBTU, undeveloped reserves can obtain over 12% on %IRR and the NPV at 12% discounted rate can be positive, however, the adjustment on gas price not only affects on increasing gas price specially, but to increase other utility prices also, for example, electricity price in which people can suffer from the consequences so considering to increase the gas price is not the proper solution. As a result, the government is supposed to adjust some components of taxation in order to improve undeveloped reserves; otherwise, it will lose the opportunity for investment and beneficial share.

Nonetheless, in the situation of increasing gas price, the government still receive beneficial share from Progressive system as the rate of SRB is the same with an adjustment on 2 times Geological factor (K), hence the new SRB ratio shall slightly decrease under 0.5% when compared with the existing system.

6.2 Recommendations for further study

This study is Deterministic study which does not include risk or opportunity consideration of each parameter used in the studied model and may convey from most likely. As a result, the further studies should include any kind of risk that may affect parameters or use stochastic analysis method.

Further studies should compare the results to other undeveloped reserves in other countries as well, in terms of the size of reserves, production or %cost to gross revenue, etc, and also compare different %IRR and NPV in order to obtain the data on minimum acceptable rate by investors as well as compare them with Thai III system and other taxation systems, such as, PSC system, SA system, etc.

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APPENDICES

APPENDIX A

A1 Outline of Thailand I Terms

Table A1 Outline of Thai I Terms

Nature of right:	Concession agreement signed with Ministry of Industry (formerly Ministry of National Development).
Management responsibility:	Company, subject to plans approved by Department of Mineral Resources.
Area of blocks, onshore:	10,000sq.km. maximum 5 blocks.
Duration:	
Exploration Period	8 years + 4-year renewal period.
Production Period	30 years + 10 from end of exploration period.
Relinquishment:	50% after 5 years (35% in deep water)
	25% after 8 years (40% in deep water)
Financial and fiscal obligations:	
1. Work expenditure	• Work and financial obligations are fixed for first 3 years, and second 5 years.
2. Operating costs	• Company’s responsibility.
3. Bonuses	• According to application for concession, referred to as ―special benefits”.
4. Royalties	• Royalty 1/8 or 12.5% in cash (8.75% in deep water), and 1/7 in kind.
5. Income tax	• Income tax on profits 50% to 60% (presently 50%); or 35% on profits plus 23.08% remittance tax under 1979 Royal Decree.
Capital cost recovery:	Amortized over 5 to 10 years.
Operating cost recovery:	Expensed.
Pricing:	
Crude Oil	• No restrictions in law, but royalties and income taxes on exported oil geared to ―posted prices”, with discounts.
Natural gas	• Negotiable
Disposition of petroleum:	
1. Local market supply	• Government may require supply to local market; Special pricing if crude exported exceeds 10 x domestic demand.
2. Exports	• Subject to ban or restriction.

Additional cost factors:	• Office in Thailand.
	• ~~"~~Special benefits" agreed in concession, e.g. scholarships, grants to universities, libraries and lab equipment, etc.
	• Employment and training of Thai
	• Approval of employment of aliens.
	• Equipment becomes property of Thai government.
Arbitration:	Zurich, Switzerland, if not otherwise agreed. Rules of International Court of Justice of 6 May 1946.

A2 Outline of Thai III Terms, including SRB

Table A2 Outline of Thai III Terms, including SRB

Nature of rights	Concession agreement signed with Ministry of Energy (formerly Ministry of Industry).
Management responsibility	Company, subject to plans approved by Department of Mineral Fuels (formerly DMR).
Eligibility	Concessionaire must be a Thai limited company with registered capital of at least 100 million Baht.
Area of blocks	Not exceeding 4,000 sq. km., maximum 5 blocks or 20,000 sq. km. (except deep water blocks). Special concessions not exceeding 200 sq. km., with relaxed royalty rates, may be issued for high-cost onshore fields.
Duration	
Exploration period	6 years + 3-year renewal.
Production period	20 years from end of exploration period + 10-year renewal. Commercial field test. Production plans and reports and government approval of amendments to plans required. Obligation to produce within 4 years, with possible deferrals of 2 years each. Government sole risk option: Exercisable after a 12-month negotiation period. If government does not proceed within 2 years, concessionaire may request return of the area.

	If government proceeds and realizes profits, concessionaire will be reimbursed its costs. Concessionaire may elect to co-venture with government for a period of 3 years.
Relinquishments	50% after 4 years (35% in deep water block). 25% after 6 years (40%in deep water block)
Reserved exploration area	12.5% of initial area, up to 5 years after end of exploration period.
1. Work expenditure	Fixed for each of first 3 years, and, later, for each of second 3 years. Excess may be carried forward. Modification possible with consent of Minister. Government may require deposit of paid-up registered capital with commercial bank in Thailand.
2. “Special benefits”	As proposed in concession application (e.g .bonuses, scholarships, grants to educational institutions, study tours, et.)
3. “Special remuneratory benefit”	SRB is “windfall profits” tax, payable only in years concessionaire has “petroleum profit”. In calculating such profit or loss, capital expenditure, operating costs and a special reduction (an expense “uplift”) for the year and petroleum loss carried forward indefinitely from prior years may be deducted. The “special reduction” was specified as 0%. SRB is calculated by exploration block at following rates, subject to a ceiling of 75% of petroleum profit: <u>Income per meter of well</u> <u>SRB</u> Up to Baht 4,800 — zero Baht 4,800 to 14,400 increment — 1% per each Baht 240 Baht 14,400 to 33,600 increment — 1% per each Baht 960 Over 33,600 Baht increment — 1% per each Baht 3,840 To determine “income per meter of well”, first calculate annual petroleum profit and adjust for inflation and exchange rates; then calculate accumulated total meters of all wells drilled during concession period. Income per meter of well equals adjusted annual petroleum profit divided by total depth of all wells + GSF. “GSF” means “geological stability factor”, which is fixed for each

	geological region and is at least 150,000 meters, higher in difficult drilling areas.
4. Royalty	Imposed at progressive rates: Up to 2,000 barrels per day 5.0% 2,000-5,000 barrels per day 6.25% 5,000-10,000 barrels per day 10.0% 10,000-20,000 barrels per day 12.5% over 20,000 barrels per day 15.0% In deep water blocks, royalty is 70% of the above rates. Government has authority to fix lower rates in special situations. Royalty in cash based on posted, realized or market price .Royalty in kind is volume equivalent in value to royalty paid in cash. Payable monthly .Royalty disputes to be settled by court, not international arbitration.
5. Income tax	50% on profits (or 35% on profits plus 23.08% remittance tax, under Royal Decree). Payable semi-annually. Revenues, deductions and taxes for all ―Thailand III" blocks of the same concessionaire may be consolidated. Other blocks of the same concessionaire must be consolidated separately. Capital costs generally amortized over 5 to 10 years (accelerated depreciation permitted). Operating costs, royalties and SRB expensed. Revenues on crude oil sales based on realized price or, for exports, on the higher of realized or ―tax reference" price, the latter being the posted price with a discount. Ten-year loss carry forward, no losses carry back.
Pricing	

Crude oil	Export sales on f.o.b. posted price fixed by concessionaire and agreed by government. Domestic sales, in absence of regular exports, on price not exceeding that of imported crude oil; otherwise, on average realized price of exports by all concessionaires.
Natural gas	Negotiable
Disposition of crude oil	
Local market supply	Government may require supply to local market at domestic sales prices. First priority must be given to government at a domestic oil refinery.
Exports	May be subject to ban or restriction under PA Section 61. (Currently not.)
Disposition of natural gas	In practice, must be sold to PTT at negotiated price, as it has a monopoly on the internal transportation of natural gas.
Additional factors	Office in Thailand. Employment and training of Thai nationals. Preference to local goods and services, including ships. Approval of employment of foreign nationals. Equipment becomes property of Thai government at end of production period. Exemption from customs duty and VAT on imports required for petroleum operations. No surface rentals, except for reserved exploration areas. No mandatory government participation.
Disputes	Bangkok, unless otherwise agreed. Rules of International Court of Justice of 6 May 1946, as amended. Royalty disputes to be settled by Thai court.
Transfers	Qualifications of affiliated company transferees now to be scrutinized.
Confidentiality	Confidentiality period for reports submitted by concessionaire ends 1 year after date of receipt.
Application to prior concessions	Upon application and consent if concessionaire not yet in production.

APPENDIX B

B1 Production rate calculations

The heating value is 970 BTU/SCF and percentage of carbon dioxide content is 23 along the reserve life.

Example of calculation

Gas	= 151 MMSCF/D
Condensate	= 474 BBL/D
Heating value	= 970 BTU/SCF

Solution = 151 MMSCF/D x 970 BTU/SCF x 1BBL/6MMBTU + 474BBL/D
=24,884BOE/D

B2 Total cost to gross revenue

Example of calculation

CAPEX	= 1,604 MM US dollar
OPEX	= 1,003 MM US dollar
Gross revenues	= 4,553 MM US dollar

Solution = [(1,604+1,003)/ 4,553] x100 = 57.26%

B3 Percentages of government take

[Government's NCF/ (Government's NCF+ Contractor's NCF)] x 100

B4 Percentages of contractors take

1- Government's take

B5 SRB calculations

Table B5.1 Assumption of SRB calculation

Revenue	2,500 MMBAHT
Royalty	250 MMBAHT
Capital cost	300 MMBAHT
Operation cost	200 MMBAHT
Lost carry forward	-
Net profit	1,500 MMBAHT

Table B5.2 Abbreviations of SRB calculation

Rev	Gross revenue	2,500 MMBAHT
I	Exchange rate (Concession's year)	26 Baht/US$
Ia	Exchange rate (Fiscal Year)	28 Baht/US$
C	Consumer price index (Concession's year)	124
Ca	Consumer price index (Fiscal year)	157
W	Whole sale price index (Concession's year)	117
Wa	Whole sale price index (Fiscal year)	143

$$A = \frac{\text{Rev adjust}}{K+M}$$

$$\text{Rev adjust} = \text{Rev} \times \frac{I}{Ia} \times 0.5 \left[\frac{C}{Ca} + \frac{W}{Wa} \right]$$

$$\text{Rev adjust} = 2{,}500 \times \frac{26}{28} \times 0.5 \left[\frac{124}{157} + \frac{117}{143} \right]$$

Rev adjust = 1,864.10 MMBAHT

K (Geological factor) = 150,000 Meters
M (Cumulative meter of drilling) = 80,547 Meters

$$A = \frac{1{,}864.10 \text{ MMBAHT}}{150{,}000+100{,}000 \text{ Meters}}$$

$$= 7{,}456.40 \text{ Baht/Meter}$$

Table B5.3 SRB rate: Thailand III

Income per meter of well	**SRB (%)**
Up to Baht 4,800	zero
Baht 4,800 to 14,400	1% per each Baht of 240 increment
Baht 14,400 to 33,600 Baht	1% per each Baht of 960 increment
Over 33,600 Baht	1% per each Baht of 3,840 increment

$$\% \text{ SRB} = \frac{7{,}456.40-4{,}800}{240}$$

$$= 11\%$$

$$\text{SRB} = 0.11 \times 1{,}500$$

$$= 165 \text{ MMBAHT}$$

APPENDIX C

C Cash flow model with CAPEX and OPEX

Table C1 Cash flow model with CAPEX and OPEX

DESCRIPTION	UNIT	F-TOTA	C-TOTA	Before 3Yr	Before 2Yr	Before 1Yr	1	2	3	4	5	6	7	8	9	10	11	12	13	14
1.0 REVENUE																				
1.1 Production Rate	**BOE/D**	**293**	**293**	**0**	**0**	**0**	**24,884**	**59,637**	**83,288**	**100,846**	**114,894**	**119,606**	**96,694**	**66,311**	**48,660**	**31,287**	**21,623**	**16,378**	**11,354**	**7,509**
• Oil	BBL/D	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
• Gas	MMSCF/D	1,694	1,694	0	0	0	151	356	486	578	662	684	553	379	280	181	126	96	66	44
• Condensate	BBL/D	19	19	0	0	0	474	2,054	4,730	7,478	7,929	8,999	7,347	4,982	3,400	2,017	1,255	900	637	417
1.2 Cumulative Production Volume	**MMBOE**			**0.00**	**0.00**	**0.00**	**9.08**	**30.85**	**61.25**	**98.06**	**140.00**	**183.65**	**218.94**	**243.15**	**260.91**	**272.33**	**280.22**	**286.20**	**290.34**	**293.08**
• Oil	MMBBL			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
• Gas	BSCF			0	0	0	55	185	362	573	815	1,065	1,266	1,405	1,507	1,573	1,619	1,654	1,678	1,694
• Condensate	MMBBL			0.00	0.00	0.00	0.17	0.92	2.65	5.38	8.27	11.56	14.24	16.06	17.30	18.03	18.49	18.82	19.05	19.21
1.3 Sales Rate	**BBL/D**	**192**	**192**	**0**	**0**	**0**	**1,549**	**28,259**	**50,525**	**67,202**	**80,485**	**87,609**	**70,203**	**48,764**	**34,739**	**21,233**	**13,977**	**10,325**	**7,070**	**4,505**
• Oil	BBL/D	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
• Gas	MMSCF/D	1,070	1,070	0	0	0	7	162	283	369	449	486	389	271	194	119	79	58	40	25
• Condensate	BBL/D	19	19	0	0	0	474	2,054	4,730	7,478	7,929	8,999	7,347	4,982	3,400	2,017	1,255	900	637	417
1.4 Cumulative Sales Volume	**MMBOE**			**0.00**	**0.00**	**0.00**	**0.57**	**10.88**	**29.32**	**53.85**	**83.23**	**115.20**	**140.83**	**158.63**	**171.31**	**179.06**	**184.16**	**187.93**	**190.51**	**192.15**
• Oil	MMBBL			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
• Gas	BSCF			0	0	0	2	62	165	300	464	641	783	882	953	996	1,025	1,046	1,061	1,070
• Condensate	MMBBL			0.00	0.00	0.00	0.17	0.92	2.65	5.38	8.27	11.56	14.24	16.06	17.30	18.03	18.49	18.82	19.05	19.21
1.5 Heating Value	**BTU/SCF**			**0**	**0**	**0**	**970**	**970**	**970**	**970**	**970**	**970**	**970**	**970**	**970**	**970**	**970**	**970**	**970**	**970**
1.6 Prices	**US$/BOE**			**0.00**	**0.00**	**0.00**	**2.11**	**10.44**	**14.28**	**16.67**	**17.24**	**18.55**	**18.83**	**19.28**	**18.82**	**18.06**	**17.21**	**16.94**	**17.25**	**17.13**
• Oil	US$/BBL			70.00	70.00	70.00	70.00	73.50	77.18	81.03	85.09	89.34	93.81	98.50	103.42	108.59	114.02	119.72	125.71	132.00
• Gas	US$/MMBTU			3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
• Condensate	US$/BBL			70.00	70.00	70.00	70.00	73.50	77.18	81.03	85.09	89.34	93.81	98.50	103.42	108.59	114.02	119.72	125.71	132.00
1.7 Gross Revenue	**MMUS$**	**4,854**	**4,854**	**0.00**	**0.00**	**0.00**	**19.17**	**227.26**	**434.11**	**613.56**	**722.95**	**809.92**	**664.52**	**466.76**	**334.25**	**206.20**	**135.82**	**101.27**	**71.50**	**46.95**
• Oil		0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
• Gas		3,113	3,113	0.00	0.00	0.00	7.06	172.17	300.88	392.39	476.69	516.47	412.96	287.65	205.89	126.25	83.58	61.92	42.26	26.86
• Condensate		1,741	1,741	0.00	0.00	0.00	12.11	55.09	133.23	221.17	246.26	293.45	251.56	179.11	128.36	79.95	52.24	39.35	29.24	20.09
1.8 Royalty	**MMUS$**	**576**	**576**	**0.00**	**0.00**	**0.00**	**0.96**	**22.50**	**52.14**	**78.40**	**94.92**	**107.61**	**85.48**	**55.64**	**35.65**	**18.74**	**10.33**	**6.84**	**4.07**	**2.53**
• Oil		0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
• Gas		518	518	0.00	0.00	0.00	0.67	20.86	47.26	69.68	85.57	96.55	76.54	49.95	32.16	16.96	9.41	6.25	3.70	2.29
• Condensate		58	58	0.00	0.00	0.00	0.29	1.63	4.88	8.72	9.35	11.05	8.95	5.68	3.49	1.78	0.93	0.60	0.37	0.23

Table C1 Cash flow model with CAPEX and OPEX (continue)

DESCRIPTION	UNIT	F-TOTA	C-TOTA	Before 3Yr	Before 2Yr	Before 1Yr	1	2	3	4	5	6	7	8	9	10	11	12	13	14
2.0 PETROLEUM OPERATION COSTS																				
2.1 Capital Expenditure (Today's US$)	**MMUS$**	**1,514**	**1,514**	**255.59**	**656.01**	**483.88**	**80.51**	**38.08**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
• Acquisition Cost		0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
• Exploration Activities		0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
- G&G		0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
- G&A		0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
- Number of Exploration & Delineation Drilling	*wells*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
- Cost of Exploration & Delineation Drilling		0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
• Development Activities		1,514	1,514	255.59	656.01	483.88	80.51	38.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
- Engineering Study		0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
- Number of Development Drilling	*wells*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
- Cost of Development Drilling		214	214	0.00	75.44	100.28	0.00	38.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
- Number of Wellhead Platform (WP)	*WPs*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
- Cost of Wellhead Platform (WP)		0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
- Sealines		0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
- Central Processing Platform (CPP)		1,300	1,300	255.59	580.57	383.60	80.51	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.2 Operating Expenditure (Today's US$)	**MMUS$**	**771**	**771**	**0.00**	**0.00**	**0.00**	**31.07**	**44.43**	**64.43**	**69.55**	**74.01**	**74.17**	**66.38**	**61.99**	**53.33**	**53.67**	**24.00**	**18.00**	**18.00**	**118.00**
• Field Opex		671	671	0.00	0.00	0.00	31.07	44.43	64.43	69.55	74.01	74.17	66.38	61.99	53.33	53.67	24.00	18.00	18.00	18.00
• G&A		0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
• Decommissioning		100	100	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	100.00
2.3 Total Expenditure (Today's US$)	**MMUS$**	**2,285**	**2,285**	**255.59**	**656.01**	**483.88**	**111.58**	**82.51**	**64.43**	**69.55**	**74.01**	**74.17**	**66.38**	**61.99**	**53.33**	**53.67**	**24.00**	**18.00**	**18.00**	**118.00**
2.4 Capital Expenditure (Escalated)	**MMUS$**	**1,604**	**1,604**	**261.98**	**689.22**	**521.09**	**88.87**	**43.08**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
• Acquisition Cost		0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
• Exploration Activities		0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
- G&G		0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
- G&A		0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
- Number of Exploration & Delineation Drilling	*wells*	*0*	*0*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*
- Cost of Exploration & Delineation Drilling		0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
• Development Activities		1,604	1,604	261.98	689.22	521.09	88.87	43.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
- Engineering Study		0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
- Number of Development Drilling	*wells*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
- Cost of Development Drilling		230	230	0.00	79.26	107.99	0.00	43.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
- Number of Wellhead Platform (WP)	*WPs*	*0*	*0*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*
- Cost of Wellhead Platform (WP)		0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
- Sealines		0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
- Central Processing Platform (CPP)		1,374	1,374	261.98	609.97	413.10	88.87	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2.5 Operating Expenditure (Escalated)		**1,003**	**1,003**	**0.00**	**0.00**	**0.00**	**34.29**	**50.27**	**74.72**	**82.68**	**90.18**	**92.63**	**84.97**	**81.33**	**71.72**	**73.98**	**33.91**	**26.07**	**26.72**	**179.55**
• Field Operating Expenditure		851	851	0.00	0.00	0.00	34.29	50.27	74.72	82.68	90.18	92.63	84.97	81.33	71.72	73.98	33.91	26.07	26.72	27.39
• G&A		0	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
• Decommissioning		152	152	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	152.16
2.6 Total Expenditure (Escalated)		**2,607**	**2,607**	**261.98**	**689.22**	**521.09**	**123.16**	**93.35**	**74.72**	**82.68**	**90.18**	**92.63**	**84.97**	**81.33**	**71.72**	**73.98**	**33.91**	**26.07**	**26.72**	**179.55**

Table C1 Cash flow model with CAPEX and OPEX (continue)

DESCRIPTION	UNIT	F-TOTAL	C-TOTAL	Before 3Yr	Before 2Yr	Before 1Yr	1	2	3	4	5	6	7	8	9	10	11	12	13	14
3.0 TAX CALCULATION FOR THAILAND																				
3.1 Revenue (Subject to Petroleum Income Tax)		**4,854**	**4,854**	**0.00**	**0.00**	**0.00**	**19.17**	**227.26**	**434.11**	**613.56**	**722.95**	**809.92**	**664.52**	**466.76**	**334.25**	**206.20**	**135.82**	**101.27**	**71.50**	**46.95**
3.2 Allowable Expenses		**3,183**	**3,183**	**52.40**	**221.94**	**329.73**	**328.76**	**392.12**	**372.28**	**276.58**	**207.18**	**204.55**	**170.45**	**136.97**	**107.37**	**92.72**	**44.25**	**32.91**	**30.79**	**182.08**
• Royalty		576	576				0.96	22.50	52.14	78.40	94.92	107.61	85.48	55.64	35.65	18.74	10.33	6.84	4.07	2.53
• Pre-Production Intangible Expenses & OPEX		0	0																	
- Depreciated Pre-production Expenditur		0	0																	
• Tangible Capital Expenditure		1,489	1,489	261.98	649.59	467.09	88.87	21.54	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
- Depreciated Tangible Expenditure		1,489	1,489	52.40	182.32	275.73	293.51	297.82	245.42	115.50	22.08	4.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
• Intangible Capital Expenditure		115	115	0.00	39.63	54.00	0.00	21.54	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
• Operation and G&A		1,003	1,003	0.00	0.00	0.00	34.29	50.27	74.72	82.68	90.18	92.63	84.97	81.33	71.72	73.98	33.91	26.07	26.72	179.55
• Bonuses and Fees		**0**	**0**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
3.3 Loss Carry Forward											**0.00**	**0.00**								
3.4 Taxable Income		**1,671**	**1,671**	**-52.40**	**-221.94**	**-329.73**	**-309.59**	**-164.86**	**61.83**	**336.98**	**515.77**	**605.37**	**494.07**	**329.79**	**226.89**	**113.48**	**91.57**	**68.35**	**40.71**	**-135.13**
3.5 Taxable Income After SRB		**1,141**	**1,141**	**-52.40**	**-221.94**	**-329.73**	**-309.59**	**-164.86**	**61.83**	**336.98**	**515.77**	**605.37**	**234.93**	**174.79**	**133.86**	**94.19**	**87.91**	**68.35**	**40.71**	**-135.13**
3.6Tax Rate				**50%**	**50%**	**50%**	**50%**	**50%**	**50%**	**50%**	**50%**	**50%**	**50%**	**50%**	**50%**	**50%**	**50%**	**50%**	**50%**	**50%**
3.7Income Tax		**571**	**571**	**-26.20**	**-110.97**	**-164.87**	**-154.79**	**-82.43**	**30.91**	**168.49**	**257.88**	**302.69**	**117.47**	**87.39**	**66.93**	**47.10**	**43.96**	**34.18**	**20.35**	**-67.56**
3.8 Tax Payable to THAILAND		**638**	**638**	**-26.20**	**-110.97**	**-164.87**	**-154.79**	**-82.43**	**30.91**	**168.49**	**257.88**	**302.69**	**117.47**	**87.39**	**66.93**	**47.10**	**43.96**	**34.18**	**20.35**	**0.00**
4.0 SPECIAL REMUNERATION BENEFIT																				
4.1 Revenue (For SRB)		**4,854**	**4,854**	**0.00**	**0.00**	**0.00**	**19.17**	**227.26**	**434.11**	**613.56**	**722.95**	**809.92**	**664.52**	**466.76**	**334.25**	**206.20**	**135.82**	**101.27**	**71.50**	**46.95**
4.2 Allowable Expenses		**3,664**	**3,664**	**353.68**	**902.71**	**665.67**	**155.23**	**115.85**	**126.86**	**161.08**	**185.10**	**200.24**	**170.45**	**136.97**	**107.37**	**92.72**	**44.25**	**32.91**	**30.79**	**182.08**
• Royalty		576	576	0.00	0.00	0.00	0.96	22.50	52.14	78.40	94.92	107.61	85.48	55.64	35.65	18.74	10.33	6.84	4.07	2.53
• Costs		2,607	2,607	261.98	689.22	521.09	123.16	93.35	74.72	82.68	90.18	92.63	84.97	81.33	71.72	73.98	33.91	26.07	26.72	179.55
• SR		481	481	91.69	213.49	144.58	31.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
- Tangible for SR				261.98	609.97	413.10	88.87	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4.3 Loss Carry Forward				**-353.68**	**-1,256.39**	**-1,922.06**	**-2,058.12**	**-1,946.70**	**-1,639.45**	**-1,186.97**	**-649.12**	**-39.44**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**-135.13**
4.4 Income for SRB		**1,325**	**1,325**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**454.63**	**329.79**	**226.89**	**113.48**	**91.57**	**68.35**	**40.71**	**0.00**
4.5 Total Depth of Drilled Wells																				
• Number of Meters Drilled		278,303	278,303	0	0	181,406	0	32,508	0	64,389	0	0	0	0	0	0	0	0	0	0
• Cumulative Meters Drilled		0	0	0	0	181,406	181,406	213,914	213,914	278,303	278,303	278,303	278,303	278,303	278,303	278,303	278,303	278,303	278,303	278,303
4.6 SRB Rate																				
• Adjusted Revenue	Million Baht			0	0	0	434	5,022	9,358	12,904	28,918	16,213	12,978	8,893	6,213	3,740	2,403	1,748	1,204	771
• Annual Revenue per 1 Meter Drilled	Baht/Meter			0	0	0	1,310	13,799	25,716	30,129	67,518	37,854	30,301	20,764	14,507	8,731	5,611	4,081	2,811	1,801
• SRB Rate				0%	0%	0%	0%	38%	52%	57%	69%	62%	57%	47%	41%	17%	4%	0%	0%	0%
4.7 SRB		530	530							**0.00**	**0.00**	**0.00**	**259.14**	**155.00**	**93.02**	**19.29**	**3.66**	**0.00**	**0.00**	**0.00**

APPENDIX D

D Study and improvement of Thai III

Table D1 %IRR for four price scenarios of without any tax

%IRR	Without any tax	Existing system
PS1 (70$/bbl)	13.50%	6.95%
PS2 (105$/bbl)	16.71%	8.28%
PS3 (escalation5%/yr)	15.10%	7.69%
PS4 (escalation7.5%/yr)	15.98%	8.09%

Table D2 %IRR between adjusts gas base price and existing system

%IRR	Adjust gas base price	Existing system
PS1 (70$/bbl)	12.01%	6.95%
PS2 (105$/bbl)	12.71%	8.28%
PS3 (escalation5%/yr)	12.34%	7.69%
PS4 (escalation7.5%/yr)	12.56%	8.09%

Table D3 Comparison of %IRR between adjusts royalty and existing system for four price scenarios

%IRR	No royalty	Half royalty	Cap12.5%	cap14%	Existing system
PS1 (70$/bbl)	8.35%	7.70%	7.08%	7.00%	6.95%
PS2 (105$/bbl)	9.68%	8.99%	8.40%	8.33%	8.28%
PS3 (escalation5%/yr)	9.03%	8.37%	7.82%	7.74%	7.69%
PS4 (escalation7.5%/yr)	9.42%	8.76%	8.20%	8.14%	8.09%

Table D4 Comparison of NPV at 12% discounted rate between adjusts royalty and existing system for four price scenarios

NPV@12%discounted rate	No royalty	Half royalty	Cap12.5%	cap14%	Existing system
PS1 (70$/bbl)	-22	-26	-30	-30	-30
PS2 (105$/bbl)	-14	-19	-22	-22	-23
PS3 (escalation5%/yr)	-19	-22	-26	-26	-26
PS4 (escalation7.5%/yr)	-16	-20	-24	-24	-24

Table D5 Comparison of % government take between adjusts royalty and existing system for four price scenarios

%Government take	No royalty	Half royalty	Cap12.5 %	cap14%	Existing system
PS1 (70$/bbl)	70	74	77	77	78
PS2 (105$/bbl)	73	76	78	78	79
PS3 (escalation5%/yr)	72	75	77	77	78
PS4 (escalation7.5%/yr)	72	75	77	77	78

Table D6 %IRR between royalty exemption from 3 to 7 years and existing system for four price scenarios

	Royalty exemption				
%IRR	3years	4years	5years	7years	Existing system
PS1 (70$/bbl)	7.23%	7.47%	7.70%	8.05%	6.95%
PS2 (105$/bbl)	8.56%	8.79%	9.02%	9.39%	8.28%
PS3 (escalation5%/yr)	7.95%	8.16%	8.37%	8.73%	7.69%
PS4 (escalation7.5%/yr)	8.34%	8.55%	8.76%	9.12%	8.09%

Table D7 NPV at 12% discounted rate between royalty exemption from 3 to 7 years and existing system for four price scenarios

	Royalty exemption				
NPV@12%discounted rate	3years	4years	5years	7years	Existing system
PS1 (70$/bbl)	-28	-27	-26	-24	-30
PS2 (105$/bbl)	-21	-19	-18	-16	-23
PS3 (escalation5%/yr)	-25	-23	-22	-20	-26
PS4 (escalation7.5%/yr)	-23	-21	-20	-18	-24

Table D8 % Government take between royalty exemption from 3 to 7 years and existing system for four price scenarios

	Royalty exemption				
%Government take	3years	4years	5years	7years	Existing system
PS1 (70$/bbl)	77	76	75	73	78
PS2 (105$/bbl)	78	77	77	75	79
PS3 (escalation5%/yr)	77	76	75	74	78
PS4 (escalation7.5%/yr)	77	76	76	74	78

Table D9 Comparison of %IRR between adjusts tax and existing system for four price scenarios

%IRR	Without tax	Half tax	Tax exemption			Existing system
			Tax exemption (1year)	Tax exemption (2years)	Tax exemption (3years)	
PS1 (70$/bbl)	8.85%	8.09%	7.26%	9.03%	11.35%	6.95%
PS2 (105$/bbl)	10.57%	9.66%	8.92%	11.07%	13.62%	8.28%
PS3 (escalation5%/yr)	9.77%	8.94%	8.06%	9.92%	12.32%	7.69%
PS4 (escalation7.5%/yr)	10.26%	9.40%	8.49%	10.39%	12.82%	8.09%

Table D10 Comparison of NPV at 12% discounted rate between adjusts tax and existing system for four price scenarios

NPV12%@discounted rate	Without tax	Half tax	Tax exemption			Existing system
			Tax exemption (1year)	Tax exemption (2years)	Tax exemption (3years)	
PS1 (70$/bbl)	-28	-29	-28	-18	-4	-30
PS2 (105$/bbl)	-13	-18	-19	-6	11	-23
PS3 (escalation5%/yr)	-21	-24	-24	-13	2	-26
PS4 (escalation7.5%/yr)	-16	-20	-22	-10	6	-24

Table D11 Comparison of %government take between adjusts tax and existing system for four price scenarios

%Government take	Without tax	Half tax	Tax exemption			Existing system
			Tax exemption (1year)	Tax exemption (2years)	Tax exemption (3years)	
PS1 (70$/bbl)	47	62	76	68	55	78
PS2 (105$/bbl)	52	65	77	69	57	79
PS3 (escalation5%/yr)	49	63	76	69	57	78
PS4 (escalation7.5%/yr)	50	64	76	69	58	78

Table D12 Comparison of %IRR between royalty as tax credit and existing system for four price scenarios

%IRR	Royalty as tax credit	Existing system
PS1 (70$/bbl)	11.79%	6.95%
PS2 (105$/bbl)	13.54%	8.28%
PS3 (escalation5%/yr)	12.67%	7.69%
PS4 (escalation7.5%/yr)	13.14%	8.09%

Table D13 Comparison of NPV at 12% discounted rate between royalty as tax credit and existing system for four price scenarios

NPV@12%discounted rate	Royalty as tax credit	Existing system
PS1 (70$/bbl)	-1	-30
PS2 (105$/bbl)	11	-23
PS3 (escalation5%/yr)	5	-26
PS4 (escalation7.5%/yr)	8	-24

Table D14 Comparison of %government takes between royalty as tax credit and existing system for four price scenarios

%Government take	Royalty as tax credit	Existing system
PS1 (70$/bbl)	49	78
PS2 (105$/bbl)	54	79
PS3 (escalation5%/yr)	52	78
PS4 (escalation7.5%/yr)	54	78

Table D15 Comparison of %IRR between adjust SRB and existing system for four price scenarios

%IRR	Without SRB	100%SR	70%SR	Double K	Existing system
PS1 (70$/bbl)	8.40%	8.40%	8.01%	7.26%	6.95%
PS2 (105$/bbl)	10.95%	10.37%	9.54%	8.76%	8.28%
PS3 (escalation5%/yr)	9.75%	9.53%	8.86%	8.11%	7.69%
PS4 (escalation7.5%/yr)	10.50%	10.05%	9.29%	8.57%	8.09%

Table D16 Comparison of %IRR between combined cases and existing system for four price scenarios

IRR	Tax exemption (3years)	Royalty as tax credit	Tax exemption (3years)& Double K	Royalty as tax credit &Double K	Royalty as tax credit & Tax exemption(1year)	Existing system
PS1 (70$/bbl)	11.35%	11.79%	11.59%	12.01%	12.09%	6.95%
PS2 (105$/bbl)	13.62%	13.54%	13.97%	13.87%	14.20%	8.28%
PS3 (escalation5%/yr)	12.32%	12.67%	12.63%	12.96%	13.28%	7.69%
PS4 (escalation7.5%/yr)	12.82%	13.14%	13.18%	13.48%	13.92%	8.09%

Table D17 Comparison of NPV at 12% discounted rate between combined cases and existing system for four price scenarios

NPV@12%discounted rate	Tax exemption (3years)	Royalty as tax credit	Tax exemption (3years)& Double K	Royalty as tax credit &Double K	Royalty as tax credit & Tax exemption(1year)	Existing system
PS1 (70$/bbl)	-4	-1	-3	0.1	1	-30
PS2 (105$/bbl)	11	11	13	13	15	-23
PS3 (escalation5%/yr)	2	5	4	7	9	-26
PS4 (escalation7.5%/yr)	6	8	8	11	14	-24

Table D18 Comparison of %government take between combined cases and existing system for four price scenarios

%Government take	Tax exemption (3years)	Royalty as tax credit	Tax exemption (3years)& Double K	Royalty as tax credit &Double K	Royalty as tax credit & Tax exemption(1year)	Existing system
PS1 (70$/bbl)	55	49	53	47	47	78
PS2 (105$/bbl)	57	54	55	52	52	79
PS3 (escalation5%/yr)	57	52	55	50	49	78
PS4 (escalation7.5%/yr)	58	54	56	51	50	78

VITAE

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