CHAPTER III

METHOD OF THE STUDY

3.1 Introduction

The geostochastic system for estimation of undiscovered hydrocarbon resources in the Chonnabot prospect is performed using Fast Appraisal System for Petroleum Universal (FASPU) program. A resource appraisal system is designed for play analysis using a reservoir engineering geologic model and an analytic probabilistic methodology. The geological model is a particular type of probability model using reservoir engineering equations. The probabilistic methodology is an analytic method derived from probability theory. The resource estimates of crude oil, non-associated gas, associated-dissolved gas, and total gas are calculated in terms of probability distributions.

3.2 Method of petroleum resource assessment

The FASPU program is a prototype package of programs designed to assess the resource potential of undiscovered oil and gas resources using a play analysis method. The play analysis is a general term for various geologic models and probabilistic methods of analyzing a geologic play for petroleum potential.

The resource assessment is separated to individual groups that have similar geological characteristics and the same type of play attributes. Each play will therefore be analyzed, including hydrocarbon accumulation in forms of oil, oil with dissolved gas and non-associated gas. There are three sets of geologic attributes or random variables involved in this play analysis approach; the play, the prospect, and the hydrocarbon volume attributes. The characteristics of play and prospect are the analyzing of presence or absence of the geological properties at the play and the prospect levels, respectively. The hydrocarbon volume attributes are concerned with the size of the hydrocarbon accumulation.

The play attributes consist of existence of hydrocarbon source, favorable timing for migration of hydrocarbon from source to trap, existence of potential migration path, and existence of potential reservoir facies. The presence of these four characteristics is due to the play favorable for containing petroleum. If lacks of one or more of these are not favorable, every play has no petroleum accumulations. Expert geologists make subjective estimate of the probability of the presence of each play attribution. The product of the probability of these four attributions is equal to the probability of this play is favorable for the existence of petroleum accumulations, and called "Marginal play probability".

The prospect attributes consist of existence of trapping mechanism, effective porosity, and hydrocarbon accumulation. If the prospect attributes are favorable and there are the presence of all three prospect attributes, it suggests that there are petroleum accumulation in the prospect. In the same way as in prospect attribute judgment, the probability of the presence of each prospect attribute will be expected. The product of these three probabilities is the probability that the prospect has a petroleum accumulation, given the play is favorable, and called "Conditional deposit probability".

The hydrocarbon volume attributes consist of area of closure, thickness of reservoir rock, effective porosity, trap fill, depth to reservoir, and hydrocarbon saturation. The hydrocarbon volume attributes jointly determine the volume of the hydrocarbon accumulation within the prospect.

The FASPU program is used to reservoir engineering equations for calculate the in place volumes of oil and non-associated gas, respectively;

Oil in place in MMbbl unit

$$= 7{,}758 \text{ x } 1{,}000 \text{ x A x F x H x P x } \left(\frac{S_h}{B_o}\right) \tag{3.1}$$

Non-associated gas in place in Bcf unit

$$= 1{,}537.7 \text{ x } 1{,}000 \text{ x A x F x H x P x } S_h \text{ x } \left(\frac{P_e}{T}\right) \text{ x } \left(\frac{1}{Z}\right) \tag{3.2}$$

where A = area of closure (1,000 acres)

F = trap fill (decimal fraction)

H = reservoir thickness (feet)

P = effective reservoir porosity (decimal fraction)

S_h = hydrocarbon saturation (decimal fraction)

B_o = oil formation volume factor (no unit)

P_e = original reservoir pressure (psi)

T = reservoir temperature (degree Rankine)

Z = gas compressibility factor (no unit)

To generalize the geologic model, a variety of mathematical functions needs to be available for modeling the five geologic variables original reservoir pressure (P_e), reservoir temperature (T), gas-oil ratio (Rs), oil formation volume factor (B_o), and gas compressibility factor (Z) as functions of depth. Four types of mathematical functions will be established; zoned linear, exponential, power, and logarithmic. Zoned linear means piece-wise linear with as many as four zones, or levels, and three transition depths. Each of the four types of mathematical function has two parameters A and B, except zoned linear which has a set of A and B coefficients for each zone. The four types of mathematical function can be obtained form;

1) Zoned Linear Function : (A x Depth) + B

   Maximum of 4 zones with 3 transition depths (feet)

2) Exponential Function : A x [exp (B x Depth)]
3) Power Function : A x (Depth xx B)
4) Logarithmic Function : A x [Ln (B x Depth)]

When assessing the play, the following procedure is applied: for each of the five geologic variables, one type of function is selected and assigned values for the parameters A and B.

Both equations for oil in place and non-associated gas in place consist of a product of a product of factors that are functions of the hydrocarbon volume attributes. The attributes are treated as continuous independent random variables, with the exception of the effective porosity which displays near perfect positive correlation with hydrocarbon saturation. Expert geologists make subjective judgments determine of the probability distribution for an attribute based on actual geological and geophysical data when available, and on the experience and knowledge of the experts using analog data and geologic extrapolations when data are unavailable. The probability distribution for each attribute is described by a complementary cumulative distribution function determined from seven estimated fractiles (100^{th}, 95^{th}, 75^{th}, 50^{th}, 25^{th}, 5^{th}, and 0^{th}). For example, the 5^{th} fractile is an attribute value such that there is a five percent chance of at least that value. In each play analyzed, the seven fractiles are estimated for all six of the hydrocarbon volume attributes, except hydrocarbon saturation whose seven fractiles are one of the two possible sets of fixed values depending upon the expected reservoir lithology. The hydrocarbon type probabilities are also estimated, which the respective probabilities of a given accumulation being either oil or non-associated gas. However, if the reservoir depth is greater than a specified depth, called oil floor depth, the accumulation is assumed to be non-associated gas. The oil floor depth is assigned, along with recovery factors for oil and gas, in the case of recoverable estimates and is 100 percent for each in the case of in place estimates.

The number of drillable prospects in the play is treated as a discrete random variable, and seven fractiles are estimated.

Probability judgments concerning each of the three sets of attributes are developed by experts familiar with the geology of the area of interest. The experts first review all existing data relevant to the appraisal, identify the major plays within the assessment area, and then assess each identified play. All of the geologic data required by this model for a play are entered on a primary oil and gas appraisal data form (Figure 3.1) and an addendum data form (Figure 3.2). Information from the data forms is entered into computer data files as the input for a computer program based upon an analytic method.

Evaluator : ______________________________ **Play Name :** ______________________

Data Evaluated : _________________________

<table>
<tr><th colspan="4">Attribute</th><th colspan="5">Probability of Favorable or Present</th><th>Comments</th></tr>
<tr><td rowspan="5">Play Attributes</td><td colspan="3">Hydrocarbon Source</td><td colspan="5"></td><td></td></tr>
<tr><td colspan="3">Timing</td><td colspan="5"></td><td></td></tr>
<tr><td colspan="3">Migration</td><td colspan="5"></td><td></td></tr>
<tr><td colspan="3">Potential Reservoir Facies</td><td colspan="5"></td><td></td></tr>
<tr><td colspan="3">Marginal Play Probability</td><td colspan="5"></td><td></td></tr>
<tr><td rowspan="4">Prospect Attributes</td><td colspan="3">Trapping Mechanism</td><td colspan="5"></td><td></td></tr>
<tr><td colspan="3">Effective Porosity (>3%)</td><td colspan="5"></td><td></td></tr>
<tr><td colspan="3">Hydrocarbon Accumulation</td><td colspan="5"></td><td></td></tr>
<tr><td colspan="3">Conditional Deposit Probability</td><td colspan="5"></td><td></td></tr>
<tr><td rowspan="12">Hydrocarbon Volume Parameter</td><td rowspan="2">Reservoir Lithology</td><td colspan="2">Sand</td><td colspan="5"></td><td></td></tr>
<tr><td colspan="2">Carbonate</td><td colspan="5"></td><td></td></tr>
<tr><td rowspan="2">Hydrocarbon</td><td colspan="2">Gas</td><td colspan="5"></td><td></td></tr>
<tr><td colspan="2">Oil</td><td colspan="5"></td><td></td></tr>
<tr><td rowspan="2">Fractiles
Attribute</td><td colspan="7">Probability of equal to or greater than</td><td></td></tr>
<tr><td>100</td><td>95</td><td>75</td><td>50</td><td>25</td><td>5</td><td>0</td><td></td></tr>
<tr><td>Area of Closure
(1,000 acres)</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Reservoir Thickness
(feet)</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Effective Porosity (%)</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Trap Fill (%)</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Reservoir Depth
(1,000 feet)</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>HC Saturation (%)</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td colspan="2">No. of drillable prospects
(a play characteristic)</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
</table>

Figure 3.1 Oil and gas appraisal data form used in the play analysis of the Chonnabot prospect (from Crovelli and Balay, 1994).

ADDENDUM DATA FORM FOR FASPU

Geological Variables

Four Types of Mathematical Functions

1. Zones Linear Functions : A * Depth + B

   Maximum of 4 zones with 3 transition depths (feet)

2. Exponential Function : A *exp (B * Depth)
3. Power Function : A * Depth **B
4. Logarithmic Function : A * Ln (B * Depth)

For each of the five geological variables below, select one type of function and assign values for the parameters A and B.

Pe	Original Reservoir Pressure (Psi)
T	Reservoir Temperature (degree Rankine)
Rs	Gas-Oil Ratio (Thousand CuFt / bbl)
Bo	Oil Formation Volume Factor (no unit)
Z	Gas Compressibility Factor (no unit)

		Parameters										
Variable	**Function**	**A**	**B**	**D**	**A**	**B**	**D**	**A**	**B**	**D**	**A**	**B**
Pe												
T												
Rs												
Bo												
Z												

Oil Floor Depth (feet) : __________

Oil Recovery Factor (percent) : __________

Gas Recovery Factor (percent) : __________

Figure 3.2 Addendum oil and gas appraisal data form used in the play analysis of the Chonnabot prospect (from Crovelli and Balay, 1994).

3.3 Analytical method of play analysis

An analytical method using probability theory is developed as a more efficient alternative to the costly and time-consuming Monte Carlo simulation method for petroleum play analysis (Crovelli, 1987). The analytic method is developed by the application of many laws of expectation and variance in probability theory. The analytical method systematically tracks through the geologic model, computes all of the means and variances of the appropriate random variables, and calculates all of the probabilities of occurrence. The lognormal distribution is used as a model for various unknown distributions in order to arrive at probability fractiles. Oil, non-associated gas, dissolved gas, and gas resources are each assessed in turn. Separate methodologies have been developed for analyzing individual plays. A simplified flowchart of the analytic methodology of play analysis is presented in Figure 3.3 and the basic steps of the analytic method of play analysis are;

1) Select the play.

2) Oil is the first resource to be assessed.

3) The following volume attributes are estimated: (1) area of closure, (2) thickness of reservoir or thickness reservoir rock, (3) effective porosity, (4) trap fill, (5) depth to reservoir, and (6) hydrocarbon saturation. Determine the mean and variance from the estimated seven fractiles, assuming a uniform distribution between fractiles, that is, a piecewise uniform probability density function. Recall that the hydrocarbon saturation distribution depends on whether the estimated reservoir lithology is sandstone or carbonate. Calculate the mean and variance of the product of effective porosity and hydrocarbon saturation, assuming they possess near perfect

positive correlation. Also compute the mean and variance for the reciprocal of the oil formation volume factor, which is a function of reservoir depth.

4) Compute the mean and variance of the accumulation size of oil in place using a reservoir engineering equation. The equation involves the product of a constant, area of closure, reservoir thickness, trap fill, effective porosity, hydrocarbon saturation, and the reciprocal of the oil formation volume factor. Various laws of expectation and variance are involved in the calculations.

5) Model the accumulation size distribution by the lognormal probability distribution with mean and variance from step 4. Calculate various lognormal fractiles of the accumulation size for oil.

6) Compute the probability that a prospect has an oil accumulative, given the play is favorable. This is called the conditional prospect probability of oil. This probability is the product of the conditional deposit probability, the probability that the reservoir depth is less than the oil floor depth, and the hydrocarbon type probability of oil.

7) Compute the mean and variance of the conditional prospect potential for oil, which is the quantity of oil in a prospect, given the play is favorable. They are derived by applying the conditional prospect probability of oil to the mean and variance of the accumulation size of oil.

8) Compute various fractiles of the conditional prospect potential for oil by a transformation to appropriate lognormal fractiles of the accumulation size of oil using the conditional prospect probability of oil.

9) Compute the mean and variance of the number of prospect from the estimated seven fractiles, assuming a uniform distribution between fractiles.

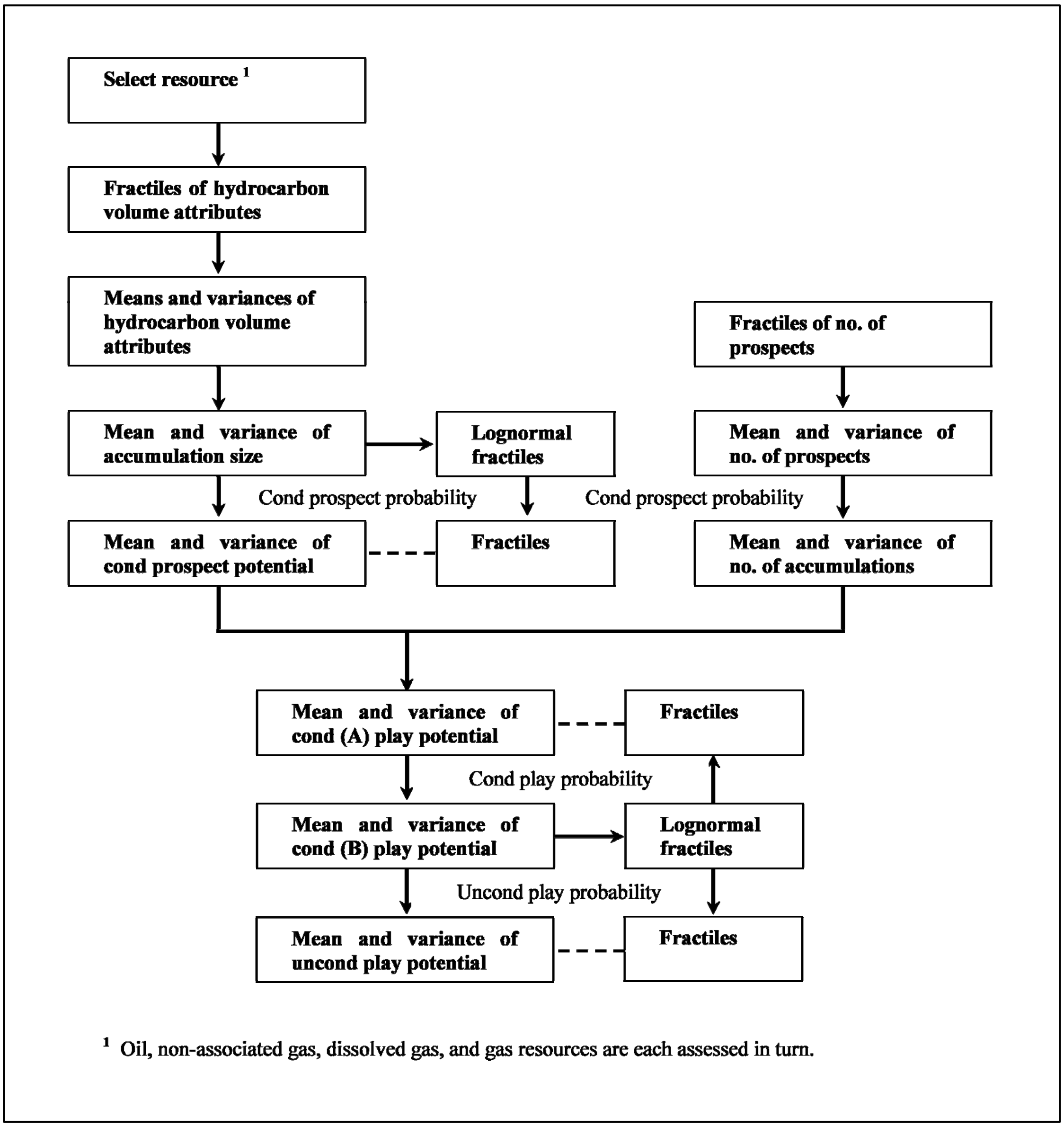

Figure 3.3 Flow chart of the analytic method of the play analysis (from Crovelli and Balay, 1994).

10) Compute the mean and variance of the number of oil accumulations, given the play is favorable. They are derived by applying the conditional prospect probability of oil to the mean and variance of the number of prospects.

11) Compute the mean and variance of the conditional (A) play potential for oil, which is the quantity of oil in the play, given the play is favorable. They are determined from the probability theory of the expectation and variance of a random number (number of prospects) of random variables (conditional prospect potential).

12) Compute the conditional play probability of oil, which is the probability that a favorable play has at least one oil accumulation, and is a function of the conditional prospect probability of oil and the number of prospects distribution.

13) Compute the mean and variance of the conditional (B) play potential for oil, which is the quantity of oil in the play, given the play is favorable and there is at least one oil accumulation within the play. They are obtained by applying the conditional play probability of oil to the mean and variance of the conditional (A) play potential for oil.

14) Compute the unconditional play probability of oil, which is the probability that the play has at least one oil accumulation, and is the product of the conditional play probability of oil and the marginal play probability.

15) Compute the mean and variance of the unconditional play potential for oil, which is the quantity of oil in the play. They are derived by applying the unconditional play probability of oil to the mean and variance of the conditional (B) play potential for oil.

16) Model the probability distribution of the conditional (B) play potential for oil by the lognormal distribution with mean and variance from step 13. Calculate various lognormal fractiles.

17) Compute various fractiles of the conditional (A) play potential for oil by a transformation to appropriate lognormal fractiles of the conditional (B) play potential for oil using the conditional play probability of oil.

18) Compute various fractiles of the unconditional play potential for oil by a transformation to appropriate lognormal fractiles of the conditional (B) play potential for oil using the unconditional play probability of oil.

19) Non-associated gas is the second resource to be assessed. Repeat steps 3 through 18, substituting non-associated gas for oil, with two basic modifications as follows. A different reservoir engineering equation is used to calculate the accumulation size of non-associated gas in place. The conditional prospect probability of non-associated gas is equal to the conditional deposit probability minus the conditional prospect probability of oil.

20) Associated-dissolved gas is the third resource to be assessed. Repeat steps 3 through 18, substituting associated-dissolved gas for oil, with two basic modifications as follows. The reservoir engineering equation for the accumulation size of oil in place is multiplied by a gas-oil ratio, which is a function of reservoir depth. The conditional prospect probability of dissolved gas is the same as the conditional prospect probability of oil.

21) Gas is the fourth resource to be assessed. Repeat steps 4 through 18, substituting gas for oil, with two basic modifications as follows. Replace step 4 to compute the mean and variance of the accumulation size of gas in place by using

conditional probability theory and conditioning on the type of gas. The conditional prospect probability of gas is the same as the conditional deposit probability.

3.4 Petroleum play analysis

Play analysis is a quantitative approach for estimating undiscovered oil and gas resources at a play scale. A play is a group of prospects within a geographically and stratigraphically delimited area where a set of specific geological factors is in place simultaneously, thus making permit the discovery of hydrocarbon. The geological factors are reservoir rocks, traps, mature source rocks, migration path, and timing (CCOP, 1999). Most of the variables used in the model are expressed in a probabilistic form that is either as a probability of occurrence or as a probability distribution. Probabilities are assigned to the geologic attributes of the model necessary for generation and accumulation of hydrocarbons. In this appraisal method, geologists make judgments about the geologic factors necessary for the formation of a hydrocarbon accumulation and quantitatively assess the geologic factors that determine its size.

3.4.1 The probability of favorable play attributes

The play attributes consist of four regional characteristics that describe a given play including hydrocarbon source, timing, migration, and potential facies. These attributes determine whether conditions underlying the play are favorable for occurrence of hydrocarbon within it. For each of these four play attributes one has to assign a value between 0 (not present/not favorable) and 1.0 (certain present/favorable). The definition of the various attributes as follows;

The existence of hydrocarbon source is the probability of occurrence of a rock unit that has generated and expelled oil or gas in sufficient quantity to form one or more accumulation within the play. This probability factor is evaluated based on a set of minimum source rock criteria that includes organic richness (total organic carbon), kerogen type, and thermal maturity. When know hydrocarbon accumulations occur in the play, this play probability is 1.

Timing for migration of hydrocarbon from source to trap is the probability of occurrence of a suitable relationship between the time of trap formation and the time of hydrocarbon movement into or through the play in prospect. This probability factor is dependent on knowledge of the time of trap formation and the time of hydrocarbon generation from source rocks or maturity of source rocks. When know hydrocarbon accumulations occur in the play, this play probability is 1.

The existence of potential migration path is the probability of effective movement of hydrocarbons through conduits that may be permeable clastic or carbonate rocks, fractures or faults. The evaluation of this probability is mostly based on structural and stratigraphic information from which inferences can be drawn concerning the presence of geologically favorable conduits. When know hydrocarbon accumulations occur in the play, this play probability is 1.

The existence of potential reservoir facies is the probability of occurrence of a rock that contain porosity and permeability capable of containing producible hydrocarbon accumulation. This probability factor is evaluated based on reservoir data from the play, projections from adjacent areas, and analog comparisons. In most marine environments the potential reservoir facies probability is 1 because marine gas can form their own reservoir by mechanically displacing sediments. When know hydrocarbon accumulations occur in the play, this play probability is 1.

The marginal play probability which is the product of the hydrocarbon source, timing, migration, and potential facies. This term expresses the probability that all of the first four play attributes are concurrently favorable somewhere in the play but not necessarily everywhere in the play. If oil or natural gas accumulation has been found in the play is an indication that the play attributes are favorable, the marginal play probability is 1. If oil or natural gas accumulation has not been found in the play, the marginal play probability is less than 1.

3.4.2 The probability of favorable prospect attributes

The prospect attributes consist of three local characteristics that determine the nature of prospect within a play including trapping mechanism, effective porosity, and hydrocarbon accumulation. Evaluation of these attributes is accomplished by recording a single value between 0 (total certainty that the attribute is absent) and 1 (total certainty that the attribute is present) for the probability that the attribute is generally favorable in a randomly selected prospect within the play area.

The existence of trapping mechanism is the probability of occurrence of a structural or stratigraphic configuration that provides a trap for migrating hydrocarbons. This probability factor is evaluated based on regional geologic information such as geologic mapping or projection from nearby areas, seismic records, and appropriate analog comparisons.

The effective porosity is the probability of occurrence of significant interconnected void space within the potential reservoir facies capable of holding hydrocarbons. Evaluation of this attribute is recorded with an estimate of the probability that the porosity in the prospect is equal to or greater than 3 percent defined in the effective porosity volume parameter. This probability factor is evaluated based on available core measurements, well log calculations, projections from adjacent areas, and analog comparisons.

The hydrocarbon accumulation is the conditional probability of occurrence in a randomly chosen prospect in the play of the combination of hydrocarbon source, timing, and migration necessary for the formation of hydrocarbon charge equal or larger than the minimum size. This probability factor is evaluated based on the structural, stratigraphic, and thermal history of the play.

The conditional deposit probability which is the product of trapping mechanism, effective porosity, and hydrocarbon accumulation. This term express the probability that a randomly chosen prospect in the play is an accumulation, given that the play is favorable for hydrocarbon accumulation. As a guide, the conditional deposit probability should not exceed the success ratio calculated from the drilling results so far. Usually the drilling starts in the most promising parts of the play. It is necessary to evaluate if the remaining parts of the play is better or worse than the explored part.

The unconditional play probability (the probability of discovery) which is the product of the marginal play probability and conditional deposit probability. The unconditional play probability is the probability that at least one undrilled prospect in the play is hydrocarbon accumulations of minimum size.

3.4.3 Reservoir parameters

The reservoir lithology does not affect the assessments. The hydrocarbon type, probability of gas (hydrocarbon mix) is the probability that an accumulation is a gas accumulation. 1 minus this probability is the probability that the accumulation is an oil accumulation. The basic for the estimation of the hydrocarbon mix is based on thermal maturity, type of organic material, type of hydrocarbon observed in wells and seeps, and seismic observation.

3.4.4 Hydrocarbon volume parameters

When the hydrocarbon volume parameters are being assessed, it is assumed that both the marginal play probability and the conditional deposit probability equal 1.0. The following parameters consist of area of closure, net reservoir thickness, effective porosity, trap fill, depth to the reservoir, and hydrocarbon saturation. They describe the range of probability value of the reservoir characteristics that determine the volume of hydrocarbons present in an individual accumulation within the play. Evaluation of these parameters are accomplished by recording the estimated value at seven fractiles (probability level) ranging from 100 percent (total certainly that at least this estimated value will be attained) to 0 percent (total certainly that the estimated value will not be exceeded). Intermediate fractile values indicate the relative confidence that the potential reservoir volume is at least as great as the recorded fractile values.

These minimum values are used at the 100th fractile unless a higher value is selected. The probabilities that these threshold values are achieved are incorporated in the prospect attribute judgments and the number of drillable prospects distribution. The minimum threshold values are selected to be less any reasonable economic limit in order to prevent economic considerations from influencing the evaluation procedure. An additional parameter, the number of drillable structures, is actually a play attribute, but will be discussed along with the hydrocarbon volume parameters.

The area of closure hydrocarbon volume parameter estimates the possible range for the area of the potential reservoir within a trap above the spill point. A minimum value is 600 acres or 2.40 square kilometers to be used at the 100th fractile. This minimum value is very important for the number of drillable prospects parameter. Data used in the evaluation of this parameter may include seismic mapping, surface geologic mapping, and analog comparison.

The hydrocarbon volume parameter reservoir thickness estimates the possible range for the thickness of the potential reservoir, or the amount of vertical closure in the situation where structural amplitude is less than individual reservoir thickness. The thickness value describes the maximum reservoir thickness for a single reservoir or for stacked multiple reservoirs with effective porosity of 3 percent or a minimum threshold value. A minimum value is 5 feet or 1.60 meters to be used at the 100th fractile. Data used in the evaluation of this parameter may include seismic records, surface and subsurface geological maps, projection from nearby areas, and analog comparison.

The effective porosity hydrocarbon volume parameter is the average value for the amount of interconnected void space in the available reservoir rock. A minimum value is 3 percent to be used at the 100th fractile, and the probability that this minimum value is achieved is incorporated into the effective porosity in the prospect attribute. Data used in the evaluation of this parameter is based on measurement well cores, well log calculations, projection from nearby areas, and analog comparisons.

The hydrocarbon volume parameter trap fill estimates the possible range for trapped hydrocarbon volume as a percentage of the porous volume under closure. A minimum value is 30 percent to be used at the 100^{th} fractile. The probability that this minimum value is achieved is incorporated into the determination of the hydrocarbon accumulation in the prospect attribute. Data used in the evaluation of this parameter is based on source rock richness and thermal maturation, hydrocarbon drainage area, size of structure, porosity and permeability of reservoir rock, and analog comparisons.

The reservoir depth hydrocarbon volume parameter estimates the possible range for the depth that must be drilled to penetrate the potential reservoir. A minimum value is 100 feet or 30 meters to be used at the 100^{th} fractile. Data used in the evaluation of this parameter is based on seismic records, projection from nearby areas, and analog comparisons.

The hydrocarbon volume parameter hydrocarbon saturation estimates the possible volume of hydrocarbon saturation as a percentage of the porous volume within the reservoir for the prospects in the play. The hydrocarbon saturation is 1 minus the water saturation. A minimum value of 60 percent is used at the 100^{th} fractile. The probability that this minimum value is achieved is incorporated into the hydrocarbon accumulation in the prospect attribute.

The number of drillable prospects parameter describes the range of possible values for the number of valid targets that would be considered for drilling if the play were to be fully explored. Only prospects with the minimum accumulation size are considered. The distribution of the number of drillable prospects parameter also takes into account the probability that the reservoir formation nearby may be absent in part of the play area. Seismic records, surface and subsurface mapping, and analogue from better known areas of similar geology should be used in the evaluation of this parameter.

3.4.5 Geological variables as a function of depth

The estimation of the resources within a play requires that a number of reservoir engineering equations are included in the FASPU program. The following depth related parameters are needs as input data;

Pe : original reservoir pressure (psi)

T : reservoir temperature (degree Rankine)

Rs : gas-oil ratio (Thousand cubic feet/bbl)

B_o : oil formation volume factor (no unit)

Z : gas compressibility factor (no unit)

These parameters can be modeled using one of four different mathematical functions (zoned linear, exponential, power, and logarithmic). Each of these four types of mathematical functions has two parameters A and B, except zoned linear, which has a set of A and B coefficients for each zone.

3.4.6 Miscellaneous parameters

The oil floor depth or critical reservoir temperature is the depth below which the reservoir oil has cracked into gas. By using the geothermal gradient in the play area, the equivalent depth can be calculated.

The recovery factor is often the most important and the most difficult parameter to establish with confidence at any stage. The recovery factor is dependent on many aspects which range from reservoir drive mechanisms, fluid viscosity, reservoir thickness, rock permeability, porosity, rock type right down to the abandonment conditions. In the prospect evaluation, the reserves are recoverable using "good oilfield practices". Empirical value of recovery rate as follows;

	Gas pool	Oil pool
Strongly water drive	30%-40%	45%-60%
Partly water drive	40%-50%	30%-45%
Gas top drive	50%-70%	20%-40%
Solution gas drive	50%-70%	10%-20%

3.5 The result of the FASPU program

The FASPU program calculates the mean and variance of number of accumulations and accumulation size of oil (and gas) using the hydrocarbon volume parameters, the geological variable (functions) and a reservoir engineering equation. The number of accumulations is the number of accumulations of the relevant hydrocarbon type and the accumulation size is the amount of in place hydrocarbons in an accumulation. The accumulation size distribution is then modeled by the lognormal probability distribution. The lognormal is assumed to give a fair representation of the real accumulation distribution within a play.

Conditional prospect potential is the risked amount of in place hydrocarbon in a randomly selected accumulation under the assumption that the marginal play probability is 1.

Conditional B play potential is the risked amount of in place hydrocarbon expected to be found in the play under the assumption that the marginal play probability is 1, and that there exists at least one undrilled accumulation of the relevant type in the play. This estimate of play potential therefore ignores that there are a finite number of prospects available for drilling.

Conditional A play potential is the risked amount of in place hydrocarbon expected to be found in the play under the assumption that the marginal play probability is 1. This estimate of play potential should be close to the B potential when there are a large number of prospects in the play.

Unconditional play hydrocarbon potential is the amount of in place oil (and gas) in the accumulation given the estimated value of the unconditional prospect probability. If the marginal play probability is 1, then the unconditional prospect potential and the conditional prospect potential are identical.

CHAPTER IV

UNDISCOVERED RESOURCES ASSESSMENT

4.1 Introduction

Play analysis is a quantitative approach for estimating undiscovered hydrocarbon resource at a play scale. A play is a set of pools or prospects which are conceived as having similar geologic characteristics and sharing common geologic elements (Charpentier et al., 1994). Most of the input variables used in the model are expressed in a probability form that is either as a probability of occurrence or as a probability distribution. This allows the uncertainty about the input variables to be expressed quantitatively. Likewise, the resulting resource estimates are expressed as probability distributions in order to show the uncertainty of the estimates.

The assessment of undiscovered hydrocarbon resource is performed using FASPU program and the play analysis approach. Data in the assessment can be divided into two groups of parameter. In the first group, the evaluation and determining petroleum geology parameters are mode of the favorability for resource in the play as a whole, as well as in a random prospect in the play, and the number of prospects and the size of the possible accumulation. In the second group are the evaluation and determining petroleum engineering parameters. The two groups of parameter are employed and calculated in term of mathematic and probabilistic methods for assessing the hydrocarbon resource of the prospect.

In the first group of parameter, the probability of favorability for resource in the play as a whole (play attribute or marginal play probability) is estimated by judging the probabilities of existence of the subsidiary attributes of hydrocarbon source, timing, migration, and potential reservoir facies. The play can contain resources only if all four of these attributes exist. The play risk, the probability that the play contains no resource, is 1.0 minus the marginal play probability.

The prospect attribute or conditional deposit probability, the probability of occurrence of an accumulation in a random prospect (conditioned on the play attributes being favorable), is estimated by judging the probabilities of existence of the subsidiary attributes of trapping mechanism, effective porosity, and hydrocarbon accumulation. The prospect risk, the probability that a prospect contains no resource (again conditioned on the play attributes being favorable), is 1.0 minus the conditional deposit probability.

The hydrocarbon volume attribute, the estimates are made of the number of prospect and also of various parameters which deal with the size of accumulations. Many of these variables are input as seven fractiles describing a probability distribution. Thus, the uncertainty about number of prospects is expressed by the seven fractiles for number of drillable prospects. The accumulation volumes are analytically calculated from the variables: area of closure, reservoir thickness/vertical closure, effective porosity, trap fill, reservoir depth, and hydrocarbon saturation.

The probabilities determinations are used with the distributions of prospect number and accumulation size to estimate resource amounts. These resource appraisal estimates are estimated using an analytic probabilistic methodology.

In the second group of parameter, used in this assessing are such engineering variables as original reservoir pressure, reservoir temperature, gas-oil ratio, oil formation volume factor, gas compressibility factor, oil floor depth, oil recovery factor, and gas recovery factor.

4.2 Geological model and Petroleum geology parameter

This section studies the geological model and petroleum geology parameters of the Chonnabot prospect. There are three sets of geologic attributes or random parameters involved in this play analysis approach; the play, the prospect, and the hydrocarbon volume. The play and prospect attributes are concerned with the presence or absence of certain geologic characteristics at the play and prospect levels, respectively. The hydrocarbon volume attributes are concerned with the size of the hydrocarbon accumulation.

From the results of the study of geological, geophysical, geochemical, and petroleum reservoir engineering, we can define the attribute and the probability for each attribute, as shown in Table 4.1 to 4.3.

4.2.1 The play attribute

The play attribute determination and analysis is mainly involved with the presence or absence of regional characteristics (Table 4.1). These attribute determine whether conditions underlying the play are favorable for occurrence and accumulation of the hydrocarbon in the play level.

Table 4.1 Assessment the play attribute probability of the Chonnabot prospect.

Attribute		**Probability of Favorable or Present**
Play Attributes	Hydrocarbon Source	1.00
	Timing	1.00
	Migration	0.90
	Potential Reservoir Facies	0.90
	Marginal Play Probability	**0.81**

Play type of the Chonnabot prospect is carbonate reservoir rock of Permian age. There are two production gas fields as prototypes of the exploration and production from limestone and carbonate reservoir rocks, namely Nam Phong and Sinphuhorm gas field, in the Khorat Plateau. As an evidence of previous work of the possible of source rock in the Khorat Plateau, Pha Nok Khao formation of Saraburi Group which has a fair to excellent organic richness and the thermal maturity of source rocks indicated late to overmature stage. This assessment defines the probability of the existence of hydrocarbon source equal to 1.00, and the probability of favorable timing for migration of hydrocarbon from source to reservoir equal to 1.00.

The probability of the existence of potential migration path is 0.90. This is because the reservoir is a fractured carbonate reservoir. Therefore as, the movement of hydrocarbon through conduits fracture porosity and permeability rock is a local migration, and move from the lower level to higher level.

This assessment defines the probability of existence of potential reservoir facies equal to 0.90. Base on the Permian carbonate play the reservoir have low matrix porosity, and permeability that the carbonate facies are comprised of mudstone, wackestone, and fine grained packstone/grainstone. Numerous fractures and microfractures tectonically induced and partly filled with calcite are common and account for the majority of the porosity and permeability and dolomitization of limestone generally provides the best secondary porosity for enhances reservoir quality.

Therefore, the marginal play probability for this prospect equal to 0.81 which is the product of the probability of hydrocarbon source, timing, migration, and the potential reservoir facies.

4.2.2 The prospect attribute

The prospect attribute determination and analysis is mainly involved with the presence or absence of local characteristics (Table 4.2) which determine the nature of prospects within a play. The attribute is generally favorable in a randomly selected prospect within the play area.

Table 4.2 Assessment the prospect attribute probability of the Chonnabot prospect.

Attribute		**Probability of Favorable or Present**
Prospect Attributes	Trapping Mechanism	1.00
	Effective Porosity (>3%)	0.80
	Hydrocarbon Accumulation	1.00
	Conditional Deposit Probability	**0.80**

The probability of existence of trapping mechanism should be 1.0 because the seismic profile shown angular unconformity between the Permian carbonate rock and the Triassic Huai Hin Lat Group.

The probability of effective porosity equal to 0.80 because data from drilled-well in the study area indicated that this carbonate reservoir rock has high average porosity.

The probability of hydrocarbon accumulation is 1.00. Reservoir and source rock is the Permian carbonate. So, the chance of petroleum migration from source rock to trap rock is high.

The conditional deposit probability for the prospect level equals to 0.80 which is the product of the probability of trapping mechanism, effective porosity, and hydrocarbon accumulation.

4.2.3 The hydrocarbon volume attributes

The probability distribution for hydrocarbon volume attribute can consider and calculate from the plot of data and observe a complementary cumulative distribution function and predict the favorable value at the fractile 100^{th}, 95^{th}, 75^{th}, 50^{th}, 25^{th}, 5^{th}, and 0^{th}. In play analyzed, the seven fractiles are estimated for all six of the hydrocarbon volume attributes consist of area of closure, reservoir thickness/vertical closure, effective porosity, trap fill, reservoir depth, and hydrocarbon saturation. The probability for each attribute is shown in Table 4.3.

Table 4.3 Assessment the hydrocarbon volume attribute probability of the Chonnabot prospect.

Attribute			Probability of Favorable or Present						
Hydrocarbon Volume Parameter	**Reservoir Lithology**	Sand	--						
		Carbonate	X						
	Hydrocarbon	Gas	0.95						
		Oil	0.05						
	Attribute / **Fractiles**		**Probability of equal to or greater than**						
			100	**95**	**75**	**50**	**25**	**5**	**0**
	Area of Closure (1,000 acres)		1.01	1.66	4.06	7.07	10.07	12.47	13.07
	Reservoir Thickness (feet)		100	120	205	234	256	323	340
	Effective Porosity (%)		3.00	3.14	3.71	4.61	7.00	13.10	18.00
	Trap Fill (%)		30	35	40	45	50	70	80
	Reservoir Depth (1,000 feet)		11.40	11.65	12.65	13.90	15.15	16.15	16.40
	HC Saturation (%)		60	64	72	82	86	89	90
No. of drillable prospects (a play characteristic)			**5**	**5**	**5**	**6**	**7**	**8**	**9**

The area of closure on top of the Permian carbonate can be taken from the data distribution which is the lognormal distribution type (Table 4.4 and Figure 4.1) because the big or large size prospects usually have the distribution less than the small size prospects.

Table 4.4 Size distributions of area of closure for the Permian carbonate play.

Area of Closure Class (1,000 acres)	Frequency	Cumulative Greater Than Percent
1.50	1	100
2.50	2	93
3.50	1	80
4.50	2	73
5.50	2	60
6.50	1	47
7.50	1	40
8.50	1	33
9.50	0	27
10.50	1	27
11.50	2	20
12.50	1	7

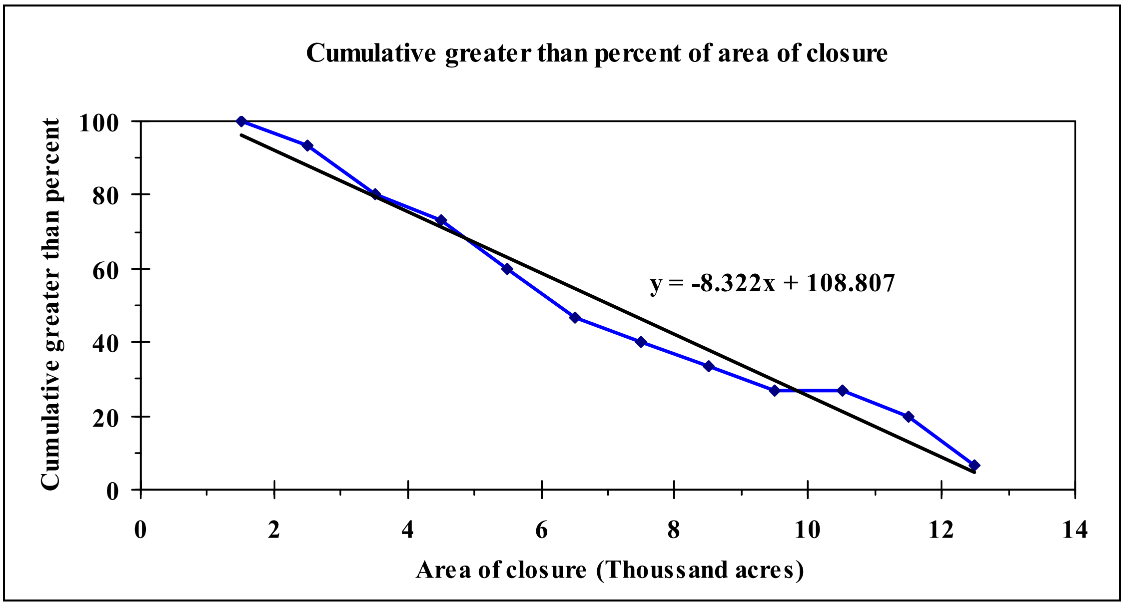

Figure 4.1 Cumulative greater than percent of area of closure for the Permian carbonate play.

The reservoir thickness/vertical closure can be taken from the data distribution which is the lognormal distribution type (Table 4.5 and Figure 4.2).

Table 4.5 Size distributions of reservoir thickness for the Permian carbonate play.

Reservoir Thickness Class (ft)	Frequency	Cumulative Greater Than Percent
100	1	100
120	0	92
140	1	92
160	0	85
180	1	85
200	1	77
220	4	69
240	2	38
260	0	23
280	2	23
300	0	8
320	1	8

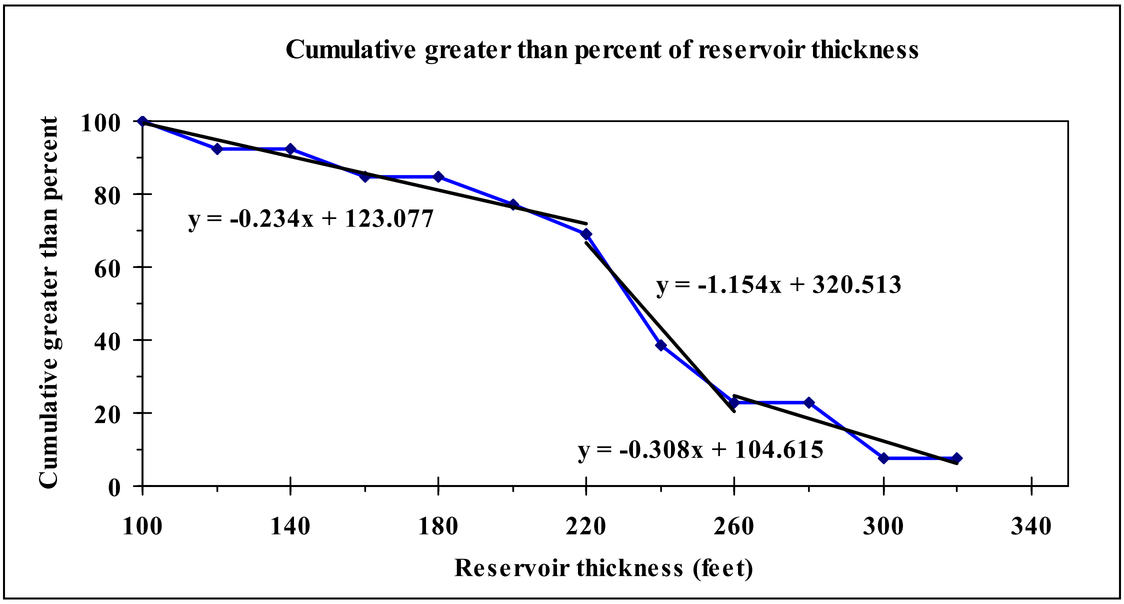

Figure 4.2 Cumulative greater than percent of reservoir thickness for the Permian carbonate play.

The effective porosity can be taken from the data distribution which is the lognormal distribution type (Table 4.6 and Figure 4.3).

Table 4.6 Size distributions of porosity in percent for the Permian carbonate play.

Porosity Class (Percent)	Frequency	Cumulative Greater Than Percent
5	69	100
7	18	41
9	14	25
11	6	13
13	3	8
15	3	5
17	2	3
19	1	1

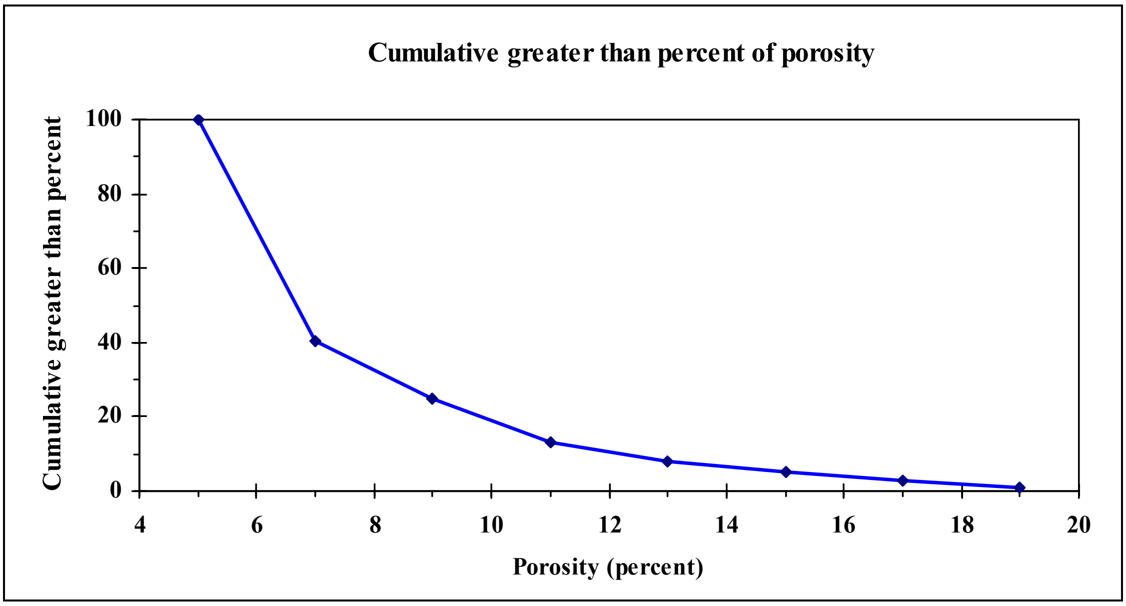

Figure 4.3 Cumulative greater than percent of porosity for the Permian carbonate play.

The percent of trap fill can be considered from the possible range for trapped hydrocarbon volume as a percentage of the porous volume under the closure. The probability that this minimum value is incorporated into the determination of the hydrocarbon accumulation prospect attribute. As discussed earlier a minimum trap fill of 30 percent has been used in this study.

The hydrocarbon saturation can be taken from the data distribution which is the lognormal distribution type (Table 4.7 and Figure 4.4).

Table 4.7 Size distributions of hydrocarbon saturation in percent for the Permian carbonate play.

Hydrocarbon Saturation Class (Percent)	Frequency	Cumulative Greater Than Percent
60	2	100
62	2	97
64	4	95
66	2	90
68	5	87
70	5	81
72	2	75
74	4	72
76	6	67
78	3	59
80	4	56
82	12	51
84	11	35
86	7	22
88	10	13

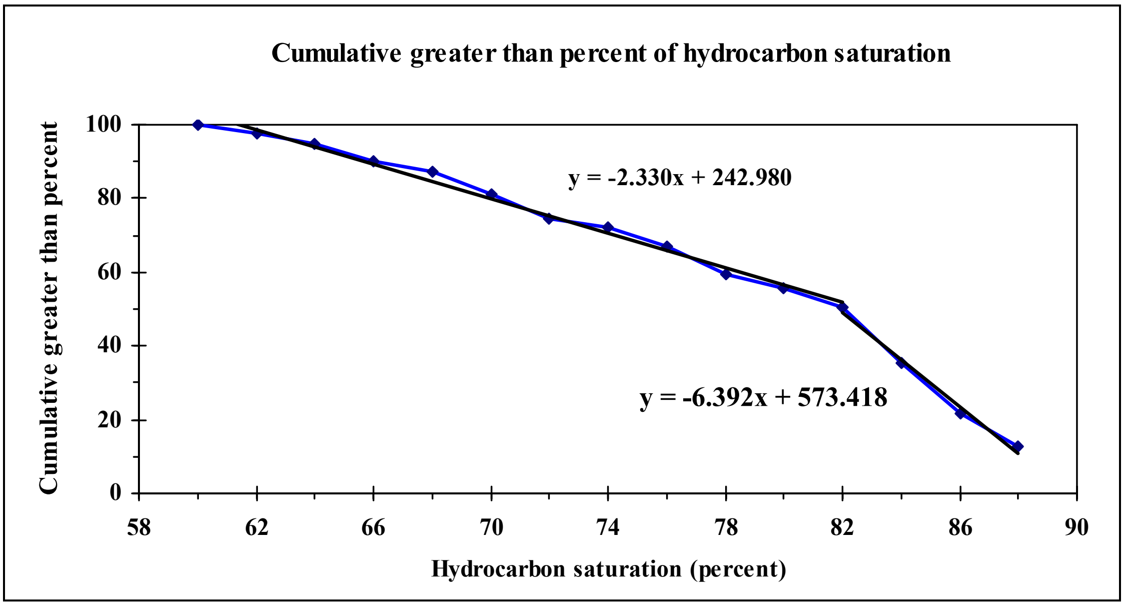

Figure 4.4 Cumulative greater than percent of hydrocarbon saturation for the Permian carbonate play.

4.3 Petroleum reservoir engineering parameter

This section is studied about the reservoir engineering parameters of the Chonnabot prospect, including; original reservoir pressure, reservoir temperature, gas-oil ratio, oil formation volume factor, gas compressibility factor, oil floor depth, and oil and gas recovery factor. Methodology still used the probability theory as in the hydrocarbon approaching.

4.3.1 Original reservoir pressure, P_e

Base on the pressure profile of Chonnabot well, the relationship between the reservoir pressure and depth of reservoir is a linear function (Figure 4.5).

$$Pe = (0.7166 \text{ x Depth}) + 14.5038 \quad (4.1)$$

where : Pe = original reservoir pressure (psi)

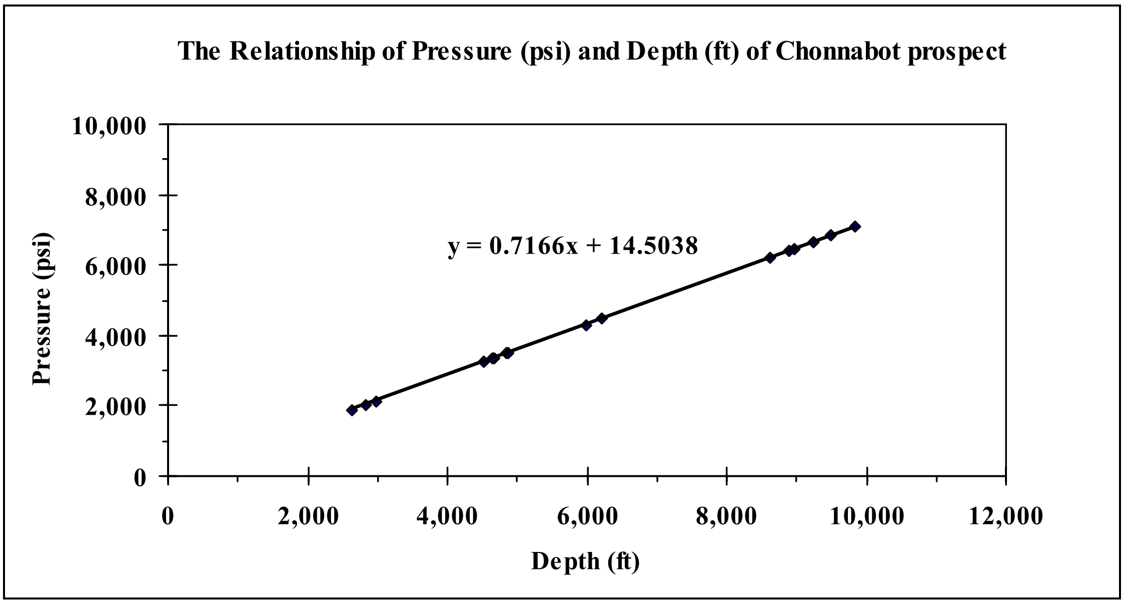

Figure 4.5 Relationship between pressure (psi) and depth (ft) of the Chonnabot prospect.

4.3.2 Reservoir temperature, T

Base on the temperature profile of Chonnabot well, the relationship between the reservoir temperature and depth depicts 3 zones of linear function.

Zone 1) Depth interval 0-2,300 feet; temperature gradient is 2.67 ^{o}F/100 ft

$$T = (0.0267 \text{ x Depth}) + 538.00 \quad (4.2)$$

Zone 2) Depth interval 2,300-5,500 feet; temperature gradient is 0.68 ^{o}F/100 ft

$$T = (0.0068 \text{ x Depth}) + 579.00 \quad (4.3)$$

Zone 3) Depth interval 5,500-10,800 feet; temperature gradient is 1.15 ^{o}F/100 ft

$$T = (0.0115 \text{ x Depth}) + 537.00 \quad (4.4)$$

where : T = reservoir temperature (degree Rankine)

4.3.3 Gas-oil ratio, Rs

Due to there is no any well test data in this area, therefore, this assessment adopted the Rs from the Department of Mineral Fuels (DMF) in the northeastern of Thailand. The study indicated that the relationship between gas-oil ratio and depth of reservoir is a linear function.

$$Rs = (0.00 \text{ x Depth}) + 0.0056146 \quad (4.5)$$

where : Rs = gas-oil ratio (Mcf/bbl)

4.3.4 Oil formation volume factor, B_o

As the gas-oil ratio, there is no any well test data in this area, therefore, this assessment adopted Bo from Department of Mineral Fuels (DMF) in the northeastern of Thailand. The study indicated that the relationship between oil formation volume factor and depth of reservoir is a linear function.

$$Bo = (0.00 \text{ x Depth}) + 1.00 \quad (4.6)$$

where : Bo = oil formation volume factor (no unit)

4.3.5 Gas compressibility factor, Z

Gas compressibility factor analysis from Nam Phong–1 well to Nam Phong–4 well that plot with depth of reservoir, it can generated a linear function (Figure 4.6).

$$Z = (0.00001 \times \text{Depth}) + 1.02384 \tag{4.7}$$

where : Z = gas compressibility factor (no unit)

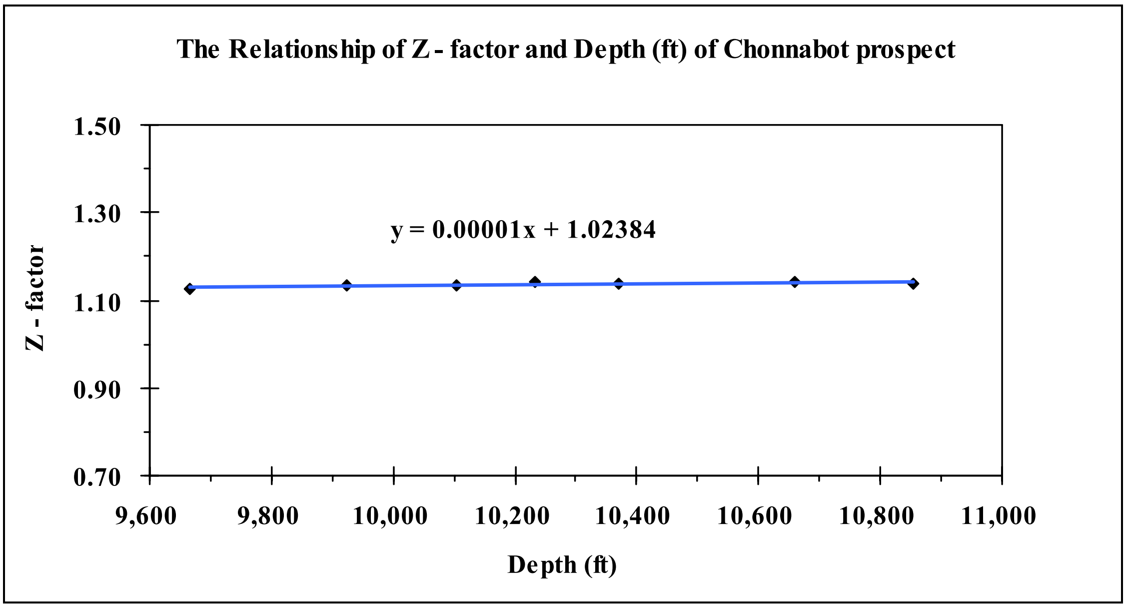

Figure 4.6 Relationship between Z-factor and depth (ft) of the Chonnabot prospect.

4.3.6 Oil floor depth

Oil floor depth is given to be 14,870 feet which is considered from temperature gradient of the Chonnabot well. In assumption of oil will crack and yield gas at above 120 degree Celsius (708 degree Rankine).

4.3.7 Oil and gas recovery factor

Recovery factor is determined to be 90 percent for gas and 5 percent for oil by production history in the northeastern of Thailand is mainly natural gas from Nam Phong and Sinphuhorm gas fields.

4.4 Undiscovered resources of the Chonnabot prospect

The assessments of undiscovered resource of the Chonnabot prospect are presented in the form of complementary cumulative probability distributions. These distributions summarize the range of estimates generated by the FASPU program as a single probability curve in a "greater than" format. The assessments are reported at the mean and the level of confidence to 5 levels as follow;

- Very high confidence at the fractile of 95 (95^{th})
- High confidence at the fractile of 75 (75^{th})
- Medium confidence (most likely) at fractile of 50 (50^{th})
- Low confidence at fractile of 25 (25^{th})
- Very low confidence at fractile of 5 (5^{th})

4.4.1 Oil potential

Oil in place resource within Permian play of the Chonnabot prospect is estimated to 41.1836 MMbbl from 1 oil field at only 5 percent chance of discovery or fractile 5^{th} (Table 4.8, Figure 4.7).

Table 4.8 Estimated oil resource within Permian play of the Chonnabot prospect.

	Mean	**F95**	**F75**	**F50**	**F25**	**F05**
Number of accumulations	0.16101	0	0	0	0	1
Accumulation size (MMbbl)	15.0153	2.81531	6.21216	10.7678	18.6642	41.1836
Unconditional play potential (MMbbl)	1.95824	0	0	0	0	13.8772

4.4.2 Natural gas potential

Non-associated gas in place resource within Permian play of the Chonnabot prospect is estimated to range from 122.433 to 1,807.66 billion cubic feet between 95 percent and 5 percent chance of discovery, respectively (Table 4.9, Figure 4.7).

Table 4.9 Estimated non-associated gas resource within Permian play of the Chonnabot prospect.

	Mean	**F95**	**F75**	**F50**	**F25**	**F05**
Number of accumulations	4.47899	3	4	4	5	7
Accumulation size (Bcf)	657.528	122.433	270.895	470.444	816.987	1,807.7
Unconditional play potential (Bcf)	2,345.50	0	1,250.23	2,232.27	3,337.20	5,644.70

The accumulation size of non-associated gas resource calculated from FASPU program can be summarized as follows;

1) at 95 percent chance of discovery the accumulation size is 122.433 billion cubic feet (from 3 fields)

2) at 75 percent chance of discovery the accumulation size is 270.895 billion cubic feet (from 4 fields)

3) at 50 percent chance of discovery the accumulation size is 470.444 billion cubic feet (from 4 fileds)

4) at 25 percent chance of discovery the accumulation size is 816.987 billion cubic feet (from 5 fields)

5) at 05 percent chance of discovery the accumulation size is 1,807.66 billion cubic feet (from 7 fields)

Based on geochemical study of the Permian carbonate source rock in the study area, it indicates that the possible natural gas generated in the Chonnabot prospect could be only non-associated gas. Therefore, the number of accumulations and accumulation size of associated-dissolved gas is not considered in this study.

```
==========================================================================================
PLAY : PERMIAN CARBONATE                                        PROJECT : PPA CHONNABOT PROSPECT
==========================================================================================

                                       INPUT SUMMARY
------------------------------------------------------------------------------------------

              Play Attribute Probabilities           |       Prospect Attribute Probabilities
-----------------------------------------------------|------------------------------------
 Hydrocarbon                                Potential  |  Trapping      Effective    Hydrocarbon
   Source       Timing       Migration   Res. Facies |  Mechanism      Porosity    Accumulation
------------  ------------  ------------  ------------|  ------------  ------------  ------------
   1.000         1.000         0.900         0.900        1.000          0.800        1.000

Marginal Play     Conditional Deposit     Reservoir      Hydrocarbon Prob.     Recovery Factors %
 Probability          Probability         Lithology       Gas       Oil         Oil     Free Gas
-------------     -------------------     ---------     -------   -------    --------  --------
     0.810               0.800            CARBONATE       0.950     0.050        5.00     90.00

  Geologic Variables        F100      F95       F75       F50       F25       F05       F0
------------------------  --------  --------  --------  --------  --------  --------  --------
Closure (thousand acres)  1.01000   1.66000   4.06000   7.07000   10.0700   12.4700   13.0700
        Thickness (feet)  100.000   120.000   205.000   234.000   256.000   323.000   340.000
      Porosity (percent)  3.00000   3.14000   3.71000   4.61000   7.00000   13.1000   18.0000
     Trap Fill (percent)  30.0000   35.0000   40.0000   45.0000   50.0000   70.0000   80.0000
  Depth (thousand feet)   11.4000   11.6500   12.6500   13.9000   15.1500   16.1500   16.4000
 HC Saturation (percent)  60.0000   64.0000   72.0000   82.0000   86.0000   89.0000   90.0000
     Number of Prospects     5         5         5         6         7         8         9

                       GEOLOGIC VARIABLES and PROBABILITIES OF OCCURRENCE
------------------------------------------------------------------------------------------

                    Mean    Std. Dev.     "Dry Hole" Risk = 0.3520
                  -------   ---------     Prob. ( Depth <= 14870 feet )  =  0.6940
      Closure     7.06500    3.47017
    Thickness     228.600    56.2314                          ------------- RESOURCE -------------
     Porosity     6.11725    3.36151                            Oil      NA Gas     AD Gas      Gas
    Trap Fill     47.3750    10.7328                          ------     ------     ------    ------
        Depth     13.9000    1.44338      Cond. Prob. Prospect has 0.0278  0.7722     0.0278    0.8000
HC Saturation     78.9250    8.34033      Cond. Play Prob.        0.1504     0.9997     0.1504    0.9998
    Prospects     5.80000    0.92736      Uncond. Play Prob.      0.1218     0.8097     0.1218    0.8099
Accumulations     4.64000    1.21589


Variable     Function      A         B       D(feet)      A         B       D(feet)      A         B
--------     --------  --------- --------- --------- --------- --------- --------- --------- ---------
Pe           Linear    0.7166000 14.503800
  (PSI)
T            Linear    0.0267000 538.00000 2300.0000 0.0068000 579.00000 5500.0000 0.0115000 537.00000
  (Deg Rankine)
Rs           Linear        0.000 0.0056146
  (Thousand CuFt/BBL)
Bo           Linear        0.000 1.0000000
  (no units)
Z            Linear    0.0000100 1.0238400
  (no units)

Depth Floor (feet) =  14870.00
```

Figure 4.7 Results of petroleum resource assessment by the FASPU program of the Chonnabot prospect.

PERMIAN CARBONATE ESTIMATED RESOURCES

	Mean	Std. Dev.	F95	F75	F50	F25	F05
OIL (Millions of BBLs)							
Number of Accumulations	0.16101	0.39649	0	0	0	0	1
Accumulation Size	15.0153	14.5930	2.81531	6.21216	10.7678	18.6642	41.1836
Cond. Prospect Potential	0.41683	3.46362	0.0	0.0	0.0	0.0	0.0
Cond. (B) Play Potential	16.0783	15.6238	3.01526	6.65279	11.5309	19.9857	44.0960
Cond. (A) Play Potential	2.41759	8.35046	0.0	0.0	0.0	0.0	16.4316
Uncond. Play Potential	1.95824	7.57502	0.0	0.0	0.0	0.0	13.8772
NON-ASSOCIATED GAS (Billions of CuFt)							
Number of Accumulations	4.47899	1.23814	3	4	4	5	7
Accumulation Size	657.528	642.058	122.433	270.895	470.444	816.987	1807.66
Cond. Prospect Potential	507.770	628.005	0.0	99.4919	345.238	684.789	1628.83
Cond. (B) Play Potential	2946.09	1583.37	1133.10	1847.50	2595.05	3645.06	5943.21
Cond. (A) Play Potential	2945.06	1584.04	1130.44	1846.50	2594.49	3646.77	5950.74
Uncond. Play Potential	2385.50	1835.02	0.0	1250.23	2232.27	3337.20	5644.70
ASSOCIATED-DISSOLVED GAS (Billions of CuFt)							
Number of Accumulations	0.16101	0.39649	0	0	0	0	1
Accumulation Size	0.08431	0.08193	0.01581	0.03488	0.06046	0.10479	0.23123
Cond. Prospect Potential	0.00234	0.01945	0.0	0.0	0.0	0.0	0.0
Cond. (B) Play Potential	0.09027	0.08772	0.01693	0.03735	0.06474	0.11221	0.24758
Cond. (A) Play Potential	0.01357	0.04688	0.0	0.0	0.0	0.0	0.09226
Uncond. Play Potential	0.01099	0.04253	0.0	0.0	0.0	0.0	0.07792
GAS (Billions of CuFt)							
Number of Accumulations	4.64000	1.21589	3	4	5	5	7
Accumulation Size	634.715	642.193	112.120	253.256	446.175	786.052	1775.53
Cond. Prospect Potential	507.772	628.003	0.0	122.981	341.541	672.868	1621.35
Cond. (B) Play Potential	2945.60	1583.69	1132.51	1846.84	2594.40	3644.57	5943.35
Cond. (A) Play Potential	2945.08	1584.04	1130.75	1846.21	2594.12	3646.51	5951.14
Uncond. Play Potential	2385.51	1835.02	0.0	1250.33	2231.92	3336.89	5644.98
YIELD FACTORS							
OIL (Thousand BBL / Acre-Ft)	0.39249	0.24981	0.12686	0.22343	0.33111	0.49069	0.86419
NON-ASSOCIATED GAS (Million CuFt / Acre-Ft)	0.95485	0.61257	0.30594	0.54088	0.80368	1.19417	2.11118
DISSOLVED GAS (Million CuFt / Acre-Ft)	0.00220	0.00140	0.00071	0.00125	0.00186	0.00276	0.00485

Figure 4.7 Results of petroleum resource assessment by the FASPU program of the Chonnabot prospect (Cont.).

4.5 Conclusion and Discussion

The undiscovered petroleum resource in Permian carbonate play of the Chonnabot prospect can be concluded as follows;

4.5.1 Oil potential

Although the result from the FASPU program indicates few quantities of oil (41.1836 MMbbl), the chance of discovery is only 5 percent (fractile 5th). Therefore, it can be concluded that there is a low or no chance to find an oil field within Permian carbonate play of the Chonnabot prospect.

4.5.2 Non-associated gas potential

The result from the FASPU program indicates quantities of non-associated gas accumulation, as follows;

- at very high confidence (95 percent chance of discovery or at fractile 95th), there are three fields with their size 122.433 Bcf.

- at high confidence (75 percent chance of discovery or at fractile 75th), there are four fields with their size 270.895 Bcf.

- at medium confidence (50 percent chance of discovery or at fractile 50th), there are four fields with their size 470.444 Bcf.

- at low confidence (25 percent chance of discovery or at fractile 25th), there are five fields with their size 816.987 Bcf.

- at very low confidence (5 percent chance of discovery or at fractile 5th), there are seven fields with their size 1,807.66 Bcf.

CHAPTER V

PETROLEUM ECONOMICS

5.1 Objective

The most likely undiscovered non-associated gas resource (470.444 Bcf) of the Chonnabot prospect is taken into account to study the economic potential, including the pay back period, net present value, internal rate of return (discounted cash flow rate of return), and profit to investment ratio for analyzing and estimating the investment option.

5.2 The Exploration and production work plan

The period of petroleum exploration under the petroleum acts "Thailand III" is limited to 6 years and can be extended for another 3 years. Production period is limited to 20 years and can be extended for anther 10 years (start at the end of exploration period).

5.2.1 Exploration work plan

The exploration work plan for these non-associated gas field is depended on petroleum accumulation resource size 470.444 Bcf of 4 accumulations. The work plan is scheduled as follows;

1st year @ 2011 : - Concession activities

- Geophysical surveys: 2D seismic survey

2nd year @ 2012 : - Geophysical surveys: 3D seismic survey

- Drill one exploration well

3rd year @ 2013 : - Drill one appraisal well

- Install first phase gas pipeline

4th year @ 2014 : - Drill four development wells

- Install secondary phase gas pipeline

- Install processing production facility

5th year @ 2015 : - Start production

The production will start at the 5th year of the work plan with its initial production rate of 100 MMcfd for 6 years. The production rate will decrease continuously and ended at the 20th year of production work plan. The production rate profile is shown in Table 5.1 and Figure 5.1.

5.3 Assumption of economics study

The petroleum economics evaluation in this study is run under the Petroleum Acts (Thailand III) which has some assumptions and details as follows;

5.3.1 Basic assumptions

- Gas resource size (Bcf) 470.444
- Number of exploration well 1

  Number of appraisal well 1

  Number of production well 4
- Heating value of gas (BTU/cubic feet) 1,000
- Income tax (%) 50
- Escalation factor (%) 2
- Discount rate of money (%) 10

Table 5.1 Petroleum production planning of the undiscovered natural gas resource size 470.444 Bcf.

Year	Gas production rate		
	MMcf/day	MMcf/year	MMBTU/year
2010	0.00	0.00	0.00
2011	0.00	0.00	0.00
2012	0.00	0.00	0.00
2013	0.00	0.00	0.00
2014	100.00	36,500.00	36,500,000
2015	100.00	36,500.00	36,500,000
2016	100.00	36,500.00	36,500,000
2017	100.00	36,500.00	36,500,000
2018	100.00	36,500.00	36,500,000
2019	100.00	36,500.00	36,500,000
2020	92.22	33,658.48	33,658,475
2021	78.01	28,473.65	28,473,650
2022	66.27	24,188.55	24,188,550
2023	56.52	20,629.80	20,629,800
2024	48.39	17,660.53	17,660,525
2025	41.57	15,173.05	15,173,050
2026	35.84	13,081.60	13,081,600
2027	31.00	11,315.00	11,315,000
2028	26.90	9,816.68	9,816,675
2029	23.41	8,542.83	8,542,825
2030	20.43	7,456.95	7,456,950
2031	17.89	6,528.03	6,528,025
2032	15.70	5,728.68	5,728,675
2033	13.81	5,038.83	5,038,825
Total		426,292.63	426,292,625

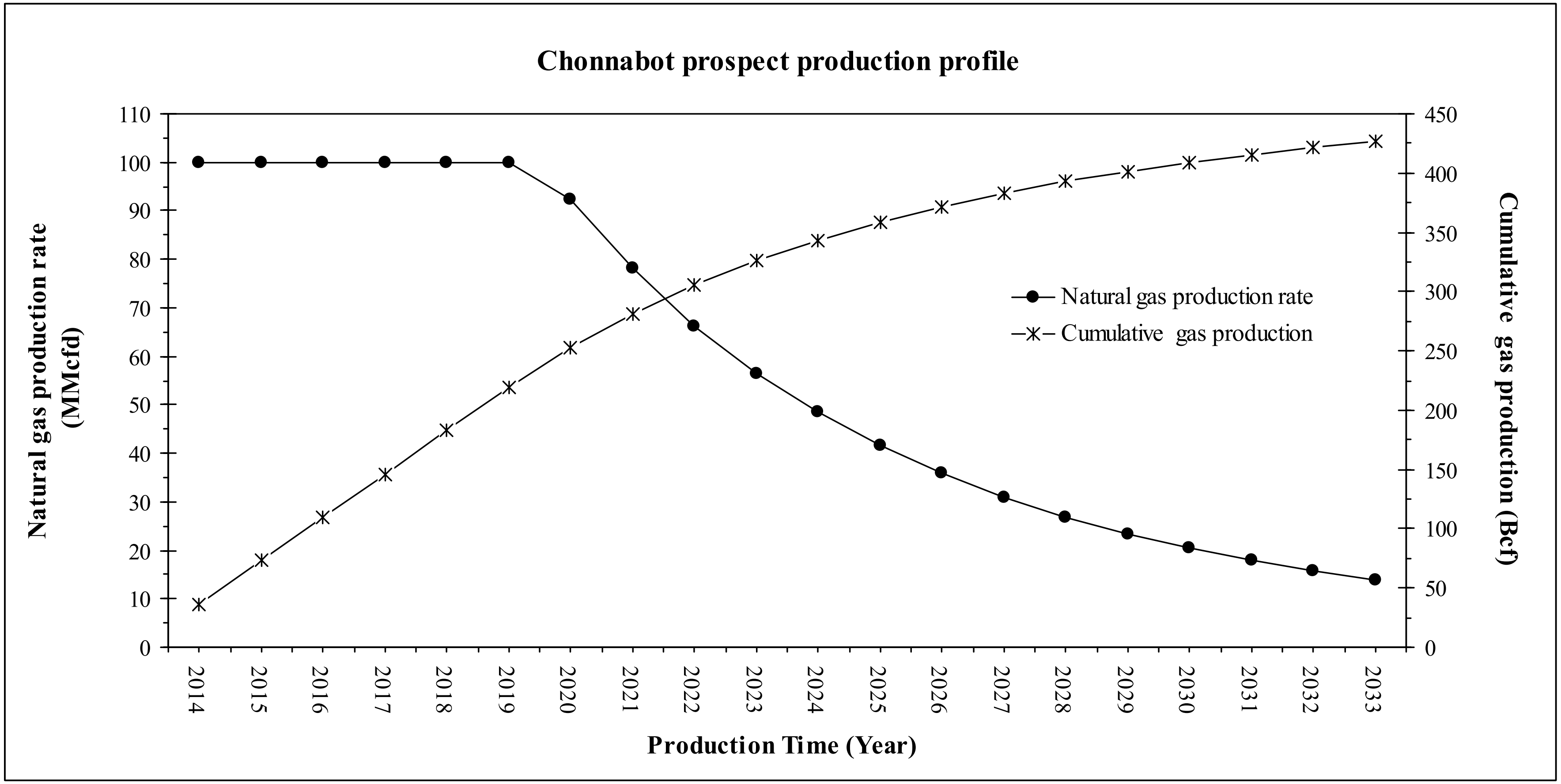

Figure 5.1 The relationship between gas production rate and cumulative gas production with production time for the undiscovered natural gas resource size 470.444 Bcf at the Chonnabot prospect.

• Tangible cost (%)	20
• Intangible cost (%)	80
• Depreciation of tangible cost (%)	20

- Sliding scale royalty (%) for gas production

1) Monthly sale volume (Bcf)	**Rate (%)**
0-600	5.00
600-1,500	6.25
1,500-3,000	10.00
3,000-6,000	12.50
>6,000	15.00

Monthly sale volume levels are calculated from production rate level of oil that relate with block by block basic;

2) Production level (bbl/month)	**Rate (%)**
0-60,000	5.00
60,000-150,000	6.25
150,000-300,0000	10.00
300,000-600,000	12.50
>600,000	15.00

The gas production levels are calculated by using gas and oil heating value condition. In this study it is assumed that one standard cubic foot of gas has heating value equal to 1,000 BTU and a generous conversion factor of 10 million BTU gas to one barrel oil is provide, for example

$$= \left(60{,}000\frac{\text{bbl}}{\text{month}}\right) \text{x} \left(10\text{x}10^6\frac{\text{BTU}}{\text{bbl}}\right) \text{x} \left(\frac{1}{1{,}000}\frac{\text{cubic feet}}{\text{BTU}}\right)$$

$$= 600\text{x}10^6\ \frac{\text{cubic feet}}{\text{month}}$$

5.3.2 Cost assumptions

Expenses and cost used in cash flow analysis are estimated based on 2009 price as follows;

1) Capital cost

• Petroleum concession (MMUS$)	0.50
• Seismic surveys-2D (MMUS$)	3.00
• Seismic surveys-3D (MMUS$)	1.00
• Exploration and Appraisal well (MMUS$/well)	20.00
• Production well (MMUS$/well)	20.00
• Gas pipeline (MMUS$)	7.00
• Processing production facilities (MMUS$)	140.00
2) Operating cost (US$/MMcf)	1,000
3) Petroleum price	
• Gas price (US$/MMBTU)	6.00

5.3.3 Other assumptions

- The gas price is constant over the contract.
- Increasing rate of capital expenditure comes from the price increasing of machineries and other equipments used in petroleum industries, and given to two percent per year.
- The discount rate of money is 10.00 percent.
- Operating cost is escalated 2 percent each year forward.
- The first production is conducted in the fifth year of work plan.
- Signature Bonus, Production Bonus, and Special remuneratory benefit (SRB) are not considered in this study.

5.4 Cash flow table explanations

The cash flow table explanations is shown in Appendix C. Detail of each column in the cash flow table is explained as follows;

A	=	Year
B	=	Gas production per year (MMcf/year)
C	=	Gas production per day (MMcf/day)
D	=	Gas price (US$/MMBTU) constant over the contact
E	=	Gross revenue sale income (MMUS$); (1,000 x B x D) / 1,000,000
F	=	Royalty sliding scale (0.0500, 0.0625, 0.1000, 0.1250, or 0.1500) of gross revenue (MMUS$); E x (0.0500, 0.0625, 0.1000, 0.1250, or 0.1500)

G, H, I		Investment cost is 100 percent of the intangible cost;
G	=	Concession (MMUS$): Investment cost
H	=	Seismic surveys-2D (MMUS$): Investment cost
I	=	Seismic surveys-3D (MMUS$): Investment cost
J, K		Investment cost is divided to intangible cost 80 percent and tangible cost 20 percent;
J	=	Drilling cost of the intangible cost 80 percent: Number of well x well cost x intangible cost 80 percent (MMUS$)
K	=	Drilling cost of the tangible cost 20 percent: Number of well x well cost x tangible cost 20 percent (MMUS$)
L, M		Investment cost is tangible cost 100 percent;
L	=	Pipeline (MMUS$): Investment cost
M	=	Processing production facility (MMUS$): Investment cost
N	=	Operating expenses (OPEX) (MMUS$); (B x 1,000 US$/MMcf / 1,000,000) x Escalation factor 2% for each year
O	=	Total Investing cost (MMUS$); G + H + I + J + K + L + M + N
P	=	Depreciation; Depletion; Amortization rate 20 percent of tangible expenses (straight forward 5 years); (K + L + M) x 0.20
Q	=	Write off (MMUS$); F + G + H + I + J + N

R	=	Total allow expense (MMUS$);	
		sum P + Q	
S	=	Taxable income (MMUS$);	
		Gross revenue sale - Total allow expense	= E – R
T	=	Income tax (50%) (MMUS$)	= S x 0.50
U	=	Year	= A
V	=	Gas production per year (MMcf/year)	= B
W	=	Gas production per day (MMcf/day)	= C
X	=	Gross revenue sale income (MMUS$)	= E
Y	=	Capital expenses (CAPEX) (MMUS$);	
		(G + H + I + J + K+ L + M) x 2% Escalation factor	
Z	=	Operating expenses (OPEX) (MMUS$)	= N
AA	=	Royalty sliding scale (MMUS$)	= F
AB	=	Income tax (50%) (MMUS$)	= T
AC	=	Net cash flow (MMUS$);	
		X – Y – Z – AA – AB	
AD	=	Discounted factor each year	
AE	=	Net present value; NPV@10% (MMUS$)	= AC x AD
AF	=	Cumulative Net present value; NPV@10% (MMUS$)	

Note: - Amortization is 20 percent of tangible cost and it will be accounted for 5 years forward.

- Net present value, profit investment ratio, and interest rate of return are calculated by the equations below;

1) Net present value (NPV)

$$NPV = A \times (1 + i)^{-n} \quad 5.1$$

where A = the net cash flow

n = the amount of year

i = the discount rate.

2) Profit to investment ratio (PIR) is the ratio of sum of net cash flow divided by sum of CAPEX

$$PIR = \frac{\sum(\text{Net cash flow})}{\sum(\text{CAPEX})} \quad 5.2$$

3) Internal rate of return (IRR)

Using trial & error to find I value. I value make the lower equation to be zero when replace I in the equation.

$$0 = (-C) + A\,(1 + I)^{-1} + A\,(1 + I)^{-2} + \ldots + A\,(1 + I)^{-n} \quad 5.3$$

where C = negative net cash flow value

A = net cash flow value

I = the assume value

5.5 Result of cash flow analysis

Cash flow analysis of the undiscovered natural gas resource size 470.444 Bcf at gas price 6.00 US$/MMBTU within 24 years production plan are showed in table 5.2 to 5.3. The result indicated that gross sale revenue is 2,557.76 MMUS$, investment cost is 796.29 MMUS$ (Exploration cost 4.50 MMUS$, Drilling and production facilities cost 267.00 MMUS$, and Operating cost 524.79 MMUS$), government take is 1,013.11 MMUS$ (Royalty cost 264.75 MMUS$, and Income tax @ 50 percent 748.36 MMUS$), cumulative annual cash flow is 733.32 MMUS$, and cumulative net present value at discount rate 10% is 228.88 MMUS$, respectively.

5.6 Economic analysis

From cash flow analysis results, considering the petroleum resource management system under Thailand III fiscal regime, concessionaire can get Net Income, Internal Rate of Return (IRR), and Profit to Investment Ratio (PIR) as follows;

1) Since 1st year until 4th year of the concession (B.C. 2011-2014), cash flow is still negative because this period contains only expenses, including investment, exploration, and development cost.

2) The 5th year (at B.C. 2015) is the first production year that produces 100 MMcfd of natural gas. The gross revenue sale income is 219.00 MMUS$ and cash flow becomes positive at 117.92 MMUS$. The cumulative taxable income is still negative (-19.98 MMUS$).

Table 5.2 Production planning and gross revenue of the undiscovered natural gas resource size 470.444 Bcf at gas price 6.00 US$/MMBTU.

YEAR	GAS PRODUCTION			GROSS REVENUE SALE INCOME	ROYALTY SLIDING SCALE
	MMcf/Y	MMcf/M	MMcfd	US$/MMBTU	US$/MMBTU
2011	0.00	0.00	0.00	0.00	0.00
2012	0.00	0.00	0.00	0.00	0.00
2013	0.00	0.00	0.00	0.00	0.00
2014	0.00	0.00	0.00	0.00	0.00
2015	36,500.00	3,041.67	100.00	219.00	27.38
2016	36,500.00	3,041.67	100.00	219.00	27.38
2017	36,500.00	3,041.67	100.00	219.00	27.38
2018	36,500.00	3,041.67	100.00	219.00	27.38
2019	36,500.00	3,041.67	100.00	219.00	27.38
2020	36,500.00	3,041.67	100.00	219.00	27.38
2021	33,658.48	2,804.87	92.22	201.95	20.20
2022	28,473.65	2,372.80	78.01	170.84	17.08
2023	24,188.55	2,015.71	66.27	145.13	14.51
2024	20,629.80	1,719.15	56.52	123.78	12.38
2025	17,660.53	1,471.71	48.39	105.96	6.62
2026	15,173.05	1,264.42	41.57	91.04	5.69
2027	13,081.60	1,090.13	35.84	78.49	4.91
2028	11,315.00	942.92	31.00	67.89	4.24
2029	9,816.68	818.06	26.90	58.90	3.68
2030	8,542.83	711.90	23.41	51.26	3.20
2031	7,456.95	621.41	20.43	44.74	2.80
2032	6,528.03	544.00	17.89	39.17	1.96
2033	5,728.68	477.39	15.70	34.37	1.72
2034	5,038.83	419.90	13.81	30.23	1.51
TOTAL	426,292.63			2,557.76	264.75

Table 5.3 Cash flow summary of the undiscovered natural gas resource size 470.444 Bcf at gas price 6.00 US$/MMBTU.

YEAR	CASH FLOW SUMMARY						NET PRESENT VALUE (NPV@DCR=10%)
	GROSS REVENUE	CAPEX	OPEX	GOVERNMENT TAKE		NET CASH FLOW	
				ROYALTY	INC.TAX		
	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2011	0.00	3.50	0.00	0.00	0.00	-3.50	-3.50
2012	0.00	21.42	0.00	0.00	0.00	-21.42	-19.47
2013	0.00	24.97	0.00	0.00	0.00	-24.97	-20.64
2014	0.00	236.65	0.00	0.00	0.00	-236.65	-177.80
2015	219.00	0.00	39.51	27.38	0.00	152.12	103.90
2016	219.00	0.00	40.30	27.38	48.57	102.75	63.80
2017	219.00	0.00	41.10	27.38	58.56	91.96	51.91
2018	219.00	0.00	41.93	27.38	58.95	90.75	46.57
2019	219.00	0.00	42.77	27.38	74.43	74.43	34.72
2020	219.00	0.00	43.62	27.38	74.00	74.00	31.38
2021	201.95	0.00	41.03	20.20	70.36	70.36	27.13
2022	170.84	0.00	35.40	17.08	59.18	59.18	20.74
2023	145.13	0.00	30.68	14.51	49.97	49.97	15.92
2024	123.78	0.00	26.69	12.38	42.36	42.36	12.27
2025	105.96	0.00	23.30	6.62	38.02	38.02	10.01
2026	91.04	0.00	20.42	5.69	32.46	32.46	7.77
2027	78.49	0.00	17.96	4.91	27.81	27.81	6.05
2028	67.89	0.00	15.84	4.24	23.90	23.90	4.73
2029	58.90	0.00	14.02	3.68	20.60	20.60	3.70
2030	51.26	0.00	12.45	3.20	17.80	17.80	2.91
2031	44.74	0.00	11.08	2.80	15.43	15.43	2.29
2032	39.17	0.00	9.89	1.96	13.66	13.66	1.85
2033	34.37	0.00	8.86	1.72	11.90	11.90	1.46
2034	30.23	0.00	7.95	1.51	10.39	10.39	1.16
TOTAL	2,557.76	286.54	524.79	264.75	748.36	733.32	228.88
				IRR / DIRR		30.75%	18.86%
				PIR / DPIR		2.56	0.80

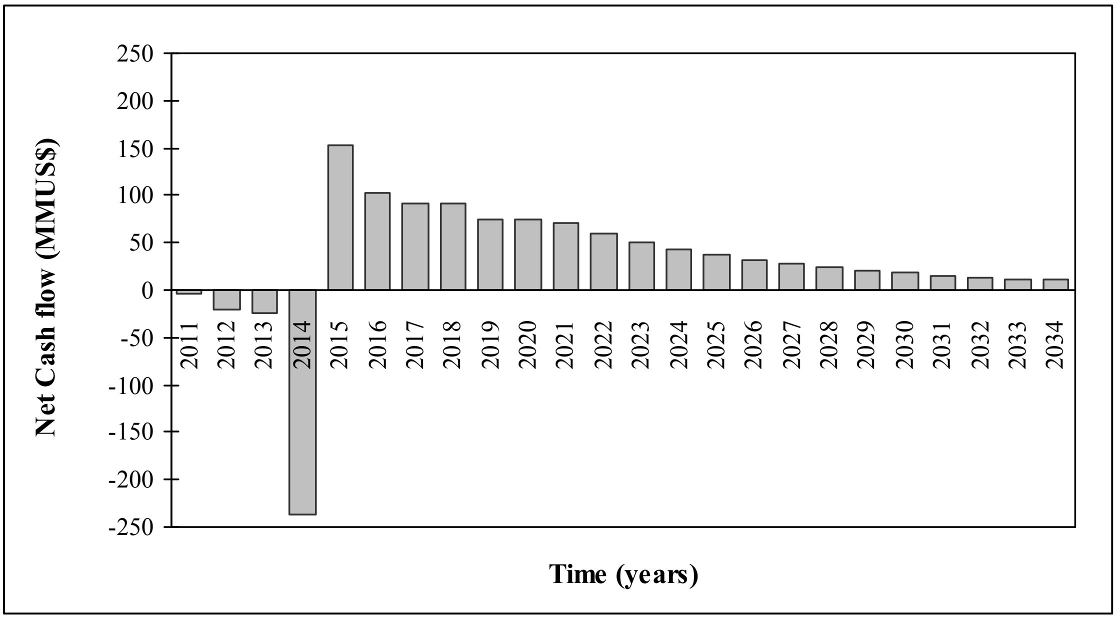

Figure 5.2 Net cash flow (MMUS$) of the undiscovered natural gas resource size 470.444 Bcf at gas price 6.00 US$/MMBTU.

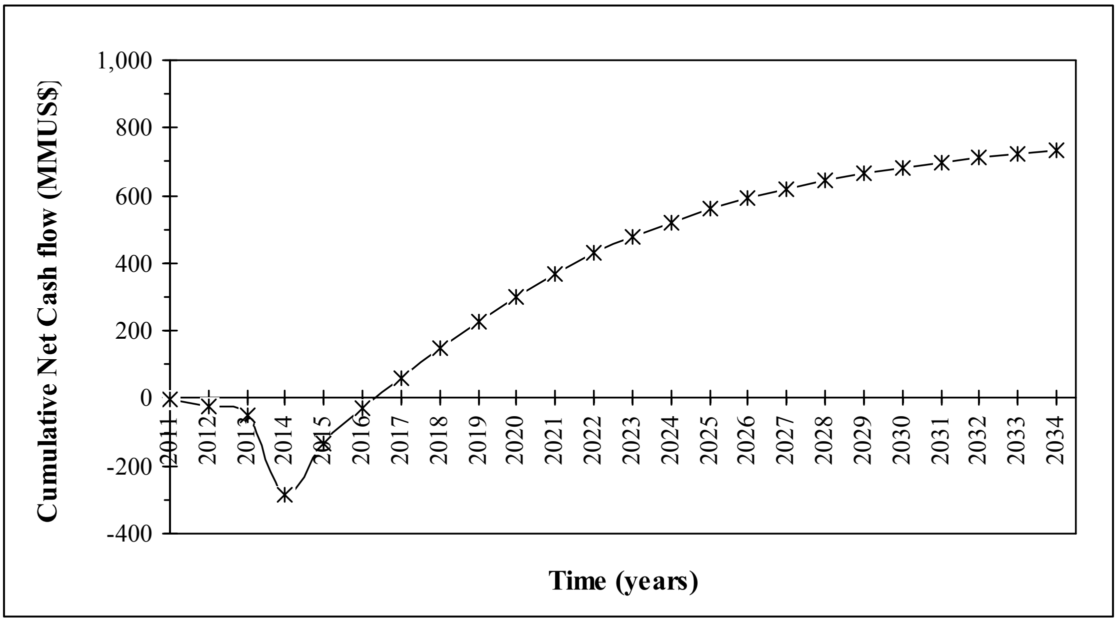

Figure 5.3 The cumulative net cash flow (MMUS$) of the undiscovered natural gas resource size 470.444 Bcf at gas price 6.00 US$/MMBTU.

3) The gas production is continuously produced at a constant rate 100 MMcfd along 6 years from the 5th year production (B.C. 2015) to the 10th year (B.C. 2020). At the 6th year of the production plan this concession earns 438.00 MMUS$ and the cumulative taxable income becomes positive at 97.14 MMUS$.

4) The production rate decrease in the 11th (B.C. 2021) and continue to the 24th year (B.C. 2034). At the last production year, cash flow and cumulative taxable income are still positive value and the cumulative income becomes 1,496.71 MMUS$.

5) The natural gas production has completed paid back at the 3rd year of production (B.C. 2017) when the cumulative net cash flow rise up to positive range.

6) Total net cash flow after concession has succeeded is 733.32 MMUS$ and the net present value is 228.88 MMUS$.

7) Internal rate of return (IRR) is equal to 30.75 percent and discounted internal rate of return (DIRR) is equal to 18.86 percent.

8) The Profit to investment ratio (PIR) is equal to 2.56 and discounted profit to investment ratio (DPIR) is equal to 0.80.

5.7 Sensitivity analysis

From sensitivity analysis, gas price vary between ±50 percent of 6.00 US$/MMBTU and two sizes of the undiscovered natural gas resource (470.444 Bcf for most likely case and 122.433 Bcf for high confidence case) are tested. The results are as follows;

5.7.1 Net income of the concessionaire

For the most likely case at undiscovered natural gas resource size 470.444 Bcf and gas price 6.00 US$/MMBTU, proposal has its profit of 733.32 MMUS$. Consider at minimum gas price 3.00 US$/MMBTU, proposal also has its profit of 160.07 MMUS$. In case of maximum gas price 9.00 US$/MMBTU, proposal has its profit up to 1,306.57 MMUS$ (Table 5.4 and Figure 5.4).

For high confidence case at undiscovered natural gas resource size 122.433 Bcf and gas price 6.00 US$/MMBTU, proposal has its profit of 84.23 MMUS$. Consider at minimum gas price 3.00 US$/MMBTU, profit is negative (-112.58 MMUS$). But at maximum gas price 9.00 US$/MMBTU, the profit is up to 232.27 MMUS$ (Table 5.4 and Figure 5.4).

5.7.2 Internal Rate of Return (IRR) of the concessionaire

For the most likely case at undiscovered natural gas resource size 470.444 Bcf and gas price 6.00 US$/MMBTU, proposal has its internal rate of return (IRR) as 30.75 percent and discounted internal rate of return (DIRR) as 18.86 percent. While at minimum gas price is equal to 3.00 US$/MMBTU, proposal has its IRR 8.51 percent and its DIRR -1.35 percent. In case of maximum gas price 9.00 US$/MMBTU, proposal has its IRR up to 46.91 percent and its DIRR 33.55 percent (Table 5.5 and Figure 5.5).

For high confidence case at undiscovered natural gas resource size 122.433 Bcf and gas price 6.00 US$/MMBTU, proposal has its IRR as 11.12 percent and its DIRR 1.02 percent. While at minimum gas price is equal to 3.00 US$/MMBTU, IRR and DIRR can not be calculated. In case of maximum gas price 9.00 US$/MMBTU, proposal has its IRR up to 27.99 percent and its DIRR 16.35 percent (Table 5.5 and Figure 5.5).

Table 5.4 Net income (MMUS$) of concessionaire under vary gas price and resource size.

Gas price	**Net income (MMUS$)**	
	Most likely case	**High confidence case**
US$/MMBTU	**Resource size 470.444 Bcf**	**Resource size 122.433 Bcf**
3.00	160.07	-112.58
6.00	733.32	84.23
9.00	1,306.57	232.27

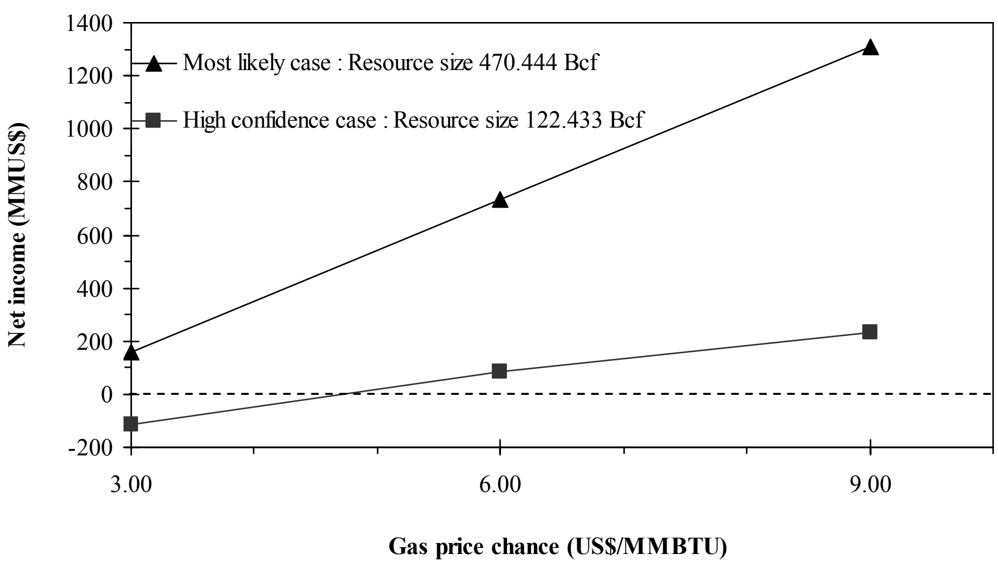

Figure 5.4 Relationship between Net income of concessionaire (MMUS$) and Gas price (US$/MMBTU).

Table 5.5 Internal rate of return of concessionaire under vary gas price and resource size.

Gas price	**IRR**	**DIRR**	**IRR**	**DIRR**
	Most likely case		**High confidence case**	
US$/MMBTU	**Resource size 470.444 Bcf**		**Resource size 122.433 Bcf**	
3.00	8.51	-1.35	N/A	N/A
6.00	30.75	18.86	11.12	1.02
9.00	46.91	33.55	27.99	16.35

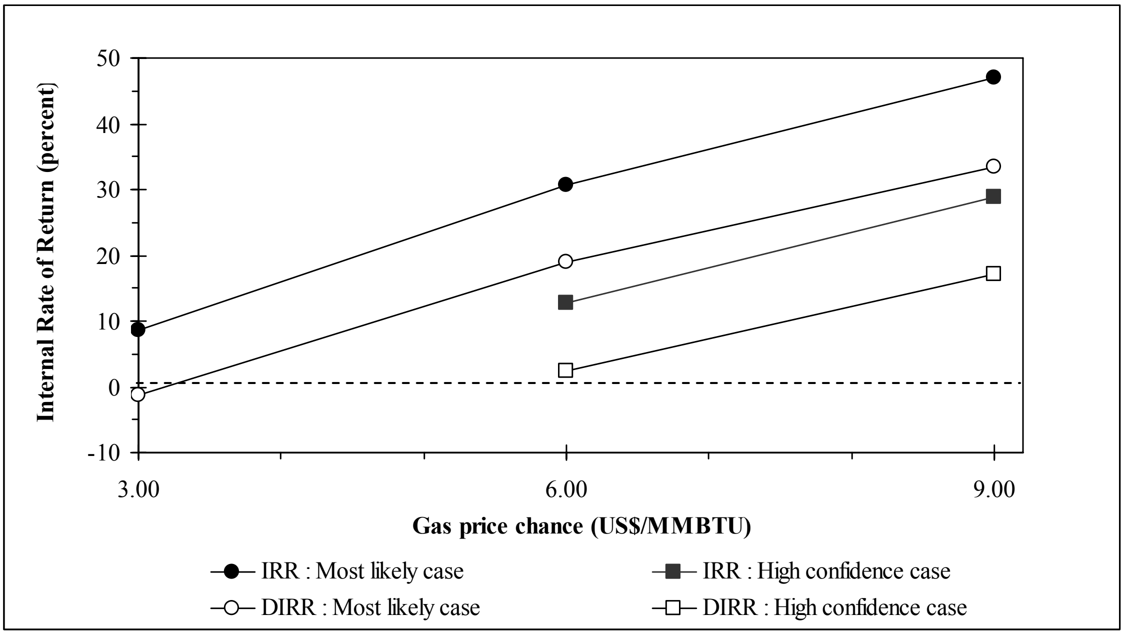

Figure 5.5 Relationship between Internal rate of return of concessionaire (MMUS$) and gas price (US$/MMBTU).

5.7.3 Profit to Investment Ratio (PIR) of the concessionaire

For the most likely case at undiscovered natural gas resource size 470.444 Bcf and gas price 6.00 US$/MMBTU, proposal has profit to investment ratio (PIR) as 2.56 and discounted profit to investment ratio (DPIR) as 0.80. Consider at minimum gas price 3.00 US$/MMBTU, proposal has PIR as 0.56 and DPIR as -0.05. In case of maximum gas price 9.00 US$/MMBTU, proposal has PIR up to 4.56 and DPIR 1.62 (Table 5.6 and Figure 5.6).

For high confidence case at undiscovered natural gas resource size 122.433 Bcf and gas price 6.00 US$/MMBTU, proposal has PIR as 0.29 and DPIR as 0.02. Consider at minimum gas price 3.00 US$/MMBTU, proposal has its PIR as -0.39 and its DPIR as -0.41. In case of maximum gas price 9.00 US$/MMBTU, proposal has its PIR up to 0.81 and its DPIR 0.33 (Table 5.6 and Figure 5.6).

Table 5.6 Profit to investment ratio of concessionaire under vary gas price and resource size.

Gas price	PIR	DPIR	PIR	DPIR
	Most likely case		High confidence case	
US$/MMBTU	Resource size 470.444 Bcf		Resource size 122.433 Bcf	
3.00	0.56	-0.05	-0.39	-0.41
6.00	2.56	0.80	0.29	0.02
9.00	4.56	1.62	0.81	0.33

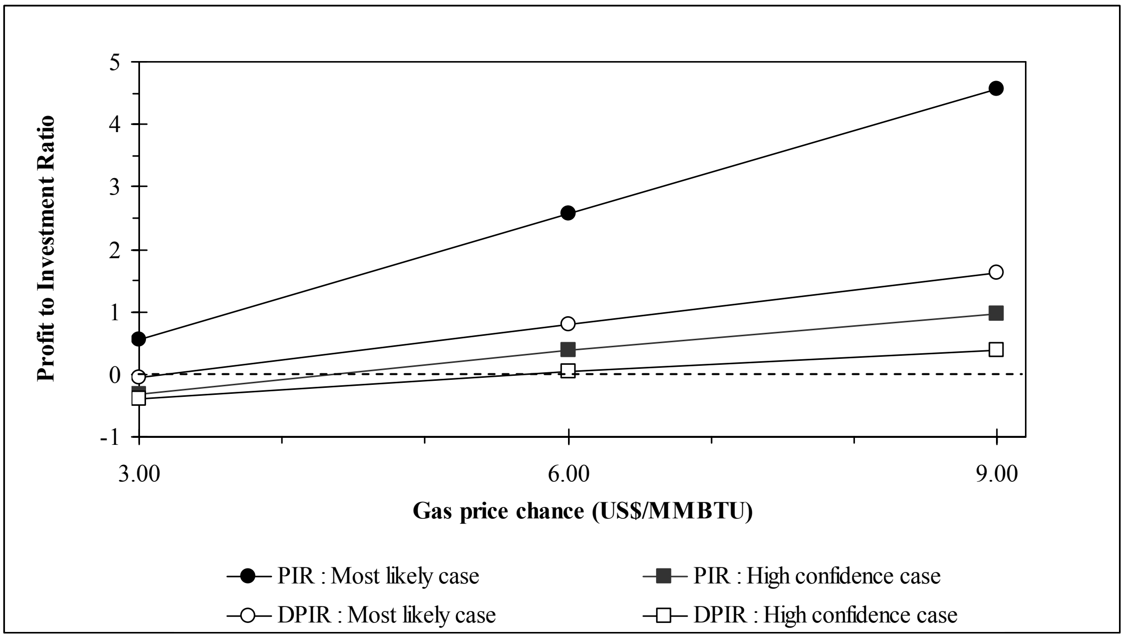

Figure 5.6 Relationship between Profit to investment ratio of concessionaire and gas price (US$/MMBTU).

5.7.4 Host Government Take

The fiscal system set by the government determines the method by which the government claims its entitlement to income from the production and sale of hydrocarbons. The simplest fiscal system is the income tax and royalty scheme. The royalty is normally charged as a percentage of the gross revenues from the sale of hydrocarbons but income tax is only payable once there is a positive taxable income.

For each gas price and undiscovered natural gas resource size, government takes its royalty and income tax at different value as showed in Table 5.7.

Table 5.7 Government takes (Royalty & Income Tax: MMUS$) of concessionaire under vary gas price and resource size.

Gas price	Most likely case		High confidence case	
	Resource size 470.444 Bcf		Resource size 122.433 Bcf	
US$/MMBTU	Royalty	Income Tax	Royalty	Income Tax
3.00	132.38	175.11	32.58	0.00
6.00	264.75	748.36	65.15	99.27
9.00	397.13	1,321.61	97.73	247.31

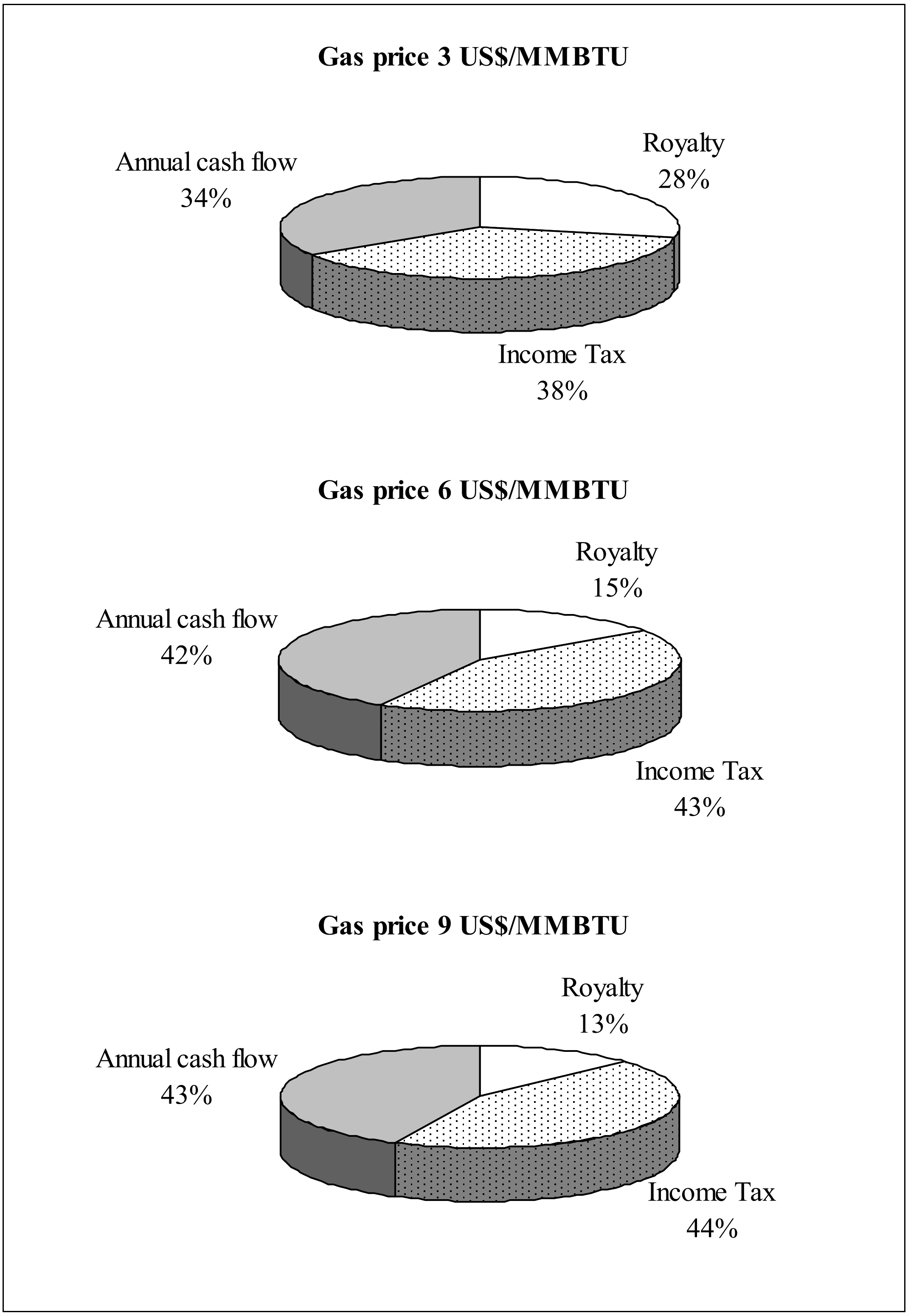

Figure 5.7 Government takes (Royalty & Income Tax: MMUS$) of concessionaire and gas price (US$/MMBTU).

5.7.5 Investment cost

Consider the relationship between undiscovered natural gas resource size and investment cost (Table 5.8), investment cost increases if the undiscovered natural gas resource size is increased. For example, the most likely case at undiscovered natural gas resource size 470.444 Bcf, investment cost is 811.33 MMUS$ while the investment cost of high confidence case at petroleum resource size 122.433 Bcf is only 408.66 MMUS$.

Table 5.8 Investment cost (MMUS$) of concessionaire under vary resource size.

Resource size	Capital cost (MMUS$)	Operation cost (MMUS$)	Investment cost (MMUS$)
Most likely case Resource size 470.444 Bcf	286.54	524.79	811.33
High confidence case Resource size 122.433 Bcf	286.54	122.12	408.66

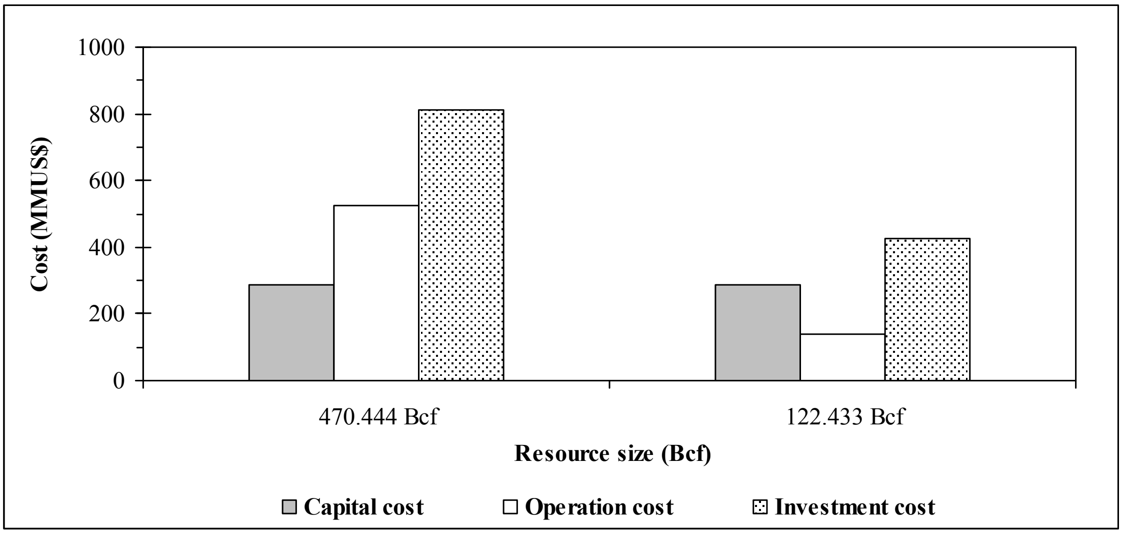

Figure 5.8 Investment cost (MMUS$) of concessionaire and resource size (Bcf).

5.7.6 Expected Value Analysis

Results of FASPU program indicated that there is a probability of 0.3520 (35.20 percent) of dry hold in this petroleum resource assessment, the probability of success equals 0.6480 (64.80 percent). All of geological attributes and reservoir engineering parameters are already assessed and considered under risk assessment.

For most likely case, sensitivity analysis is assumed that 1) petroleum resource size 470.444 Bcf, 2) gas price is 6.00 US$/MMBTU, and 3) 10% discount factor rate. The sensitivity analysis which is made up at gas price vary between ±50% of 6.00 US$/MMBTU which is 3.00, 6.00, and 9.00 US$/MMBTU, respectively. The results are as follows;

The result of the sensitivity analysis is represented in Table 5.9 and Figure 5.9 to 5.10. Figure 5.9 shows a plot of the gas price change against the percentage change in the discounted internal rate of return (DIRR) at 10 percent discount factor rate and Figure 5.10 shows a plot of the gas price change against the value change in the net present value at 10 percent discount factor rate (NPV@DCR=10%).

Table 5.9 Sensitivity of concessionaire under various parameters at most likely case.

Gas price change				
%	**IRR (%)**	**DIRR (%)**	**Net Cash flow**	**NPV@DCR=10%**
-50	8.51	-1.35	160.07	-13.92
0	30.75	18.86	733.32	228.88
+50	46.91	33.55	1,306.57	463.59

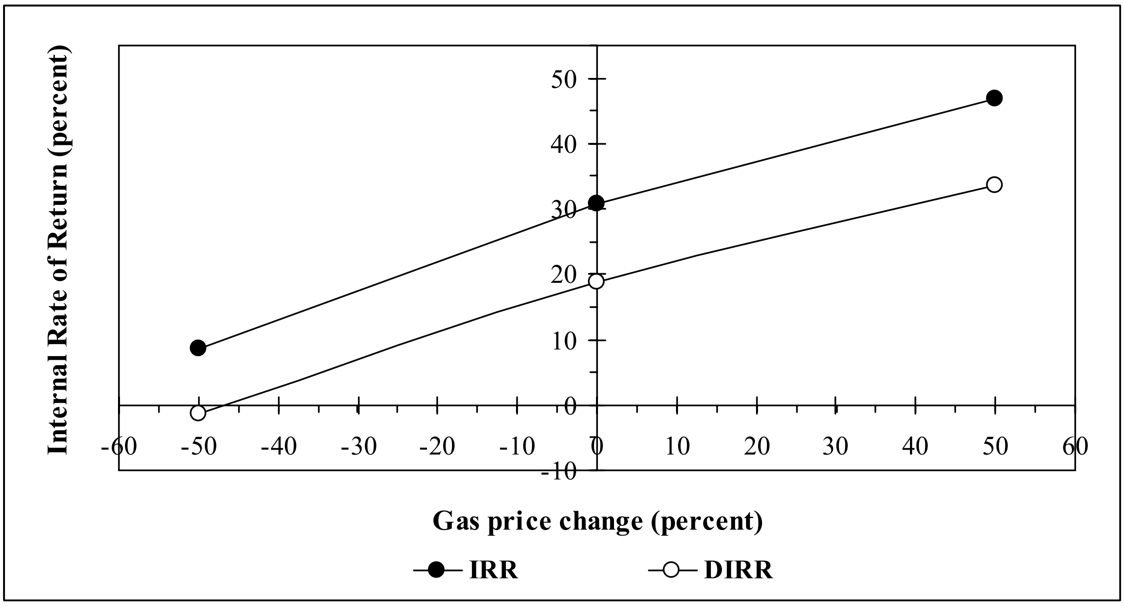

Figure 5.9 Sensitivity diagram of gas price change and internal rate of return for most likely case.

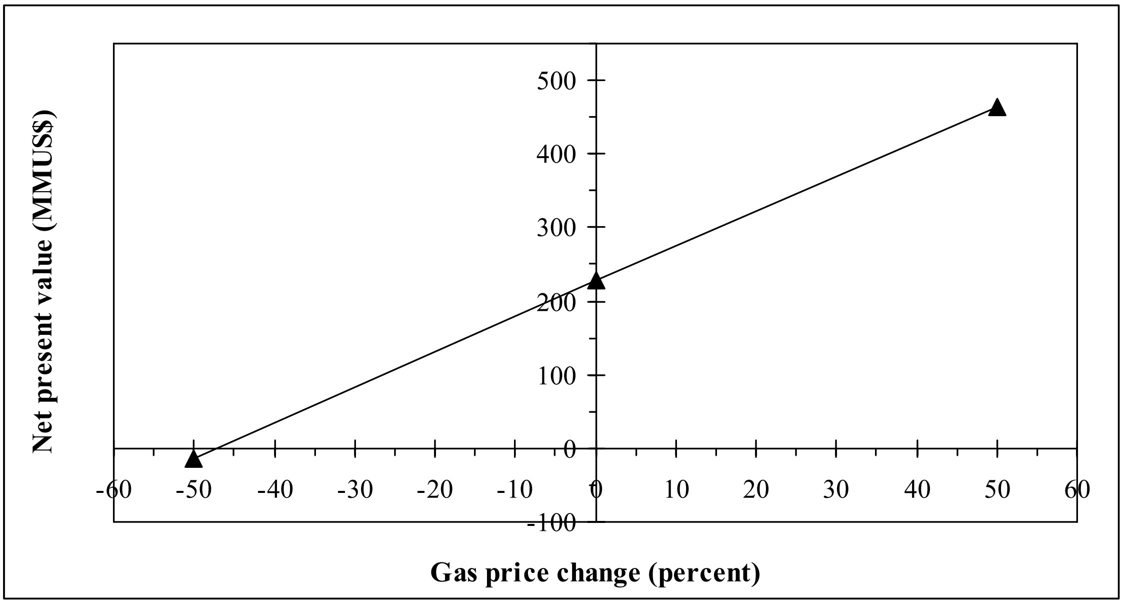

Figure 5.10 Sensitivity diagram of gas price change and net present value (NPV@10%) for most likely case.

Consider the relationship between gas price change and discounted internal rate of return (DIRR) and net present value at 10 percent discount factor rate (NPV@DCR=10%), the gas price varies between -47.31% and +50% and the concessionaire can start having its profit when the gas price is 3.16135 US$/MMBTU.

For high confidence case, sensitivity analysis is assumed that (1) petroleum resource size 122.433 Bcf, (2) gas price is 6.00 US$/MMBTU, and (3) 10% discount factor rate. The sensitivity analysis which is made up at gas price vary between ±50% of 6.00 US$/MMBTU which is 3.00, 6.00, and 9.00 US$/MMBTU, respectively. The results are as follows;

The result of the sensitivity analysis is represented in Table 5.10 and Figure 5.11 to 5.12. Figure 5.11 shows a plot of the gas price change against the percentage change in the discounted internal rate of return (DIRR) at 10 percent discount factor rate and Figure 5.12 shows a plot of the gas price change against the value change in the net present value at 10 percent discount factor rate (NPV@DCR=10%).

Table 5.10 Sensitivity of concessionaire under various parameters at high confidence case.

Gas price change				
%	**IRR (%)**	**DIRR (%)**	**Net Cash flow**	**NPV@DCR=10%**
-50	N/A	N/A	-112.58	-117.41
0	11.12%	1.02%	84.23	5.43
+50	27.99%	16.35%	232.27	94.53

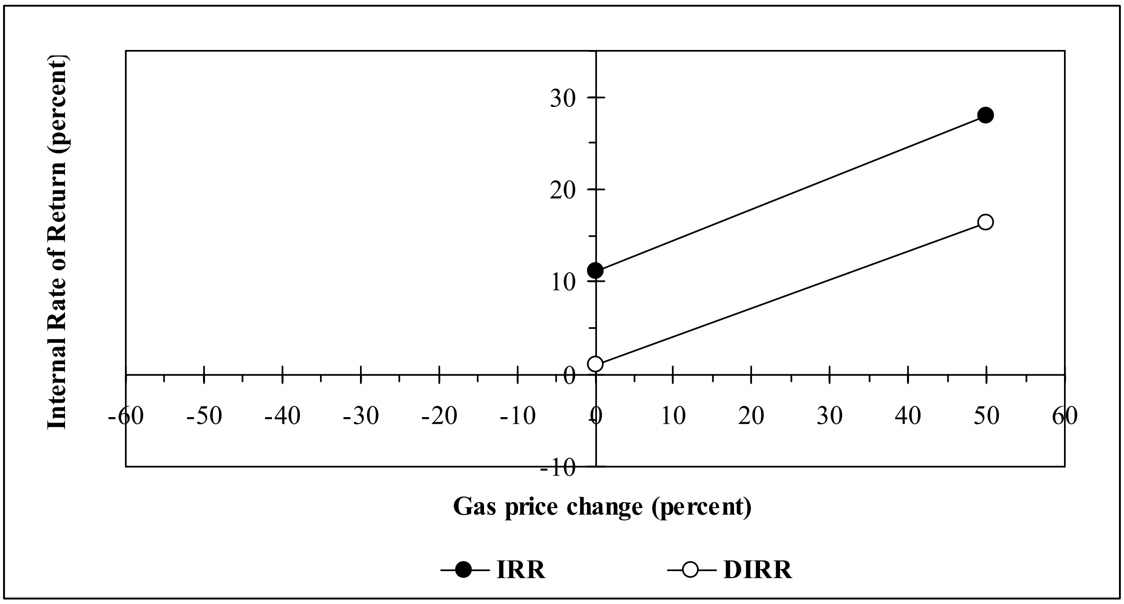

Figure 5.11 Sensitivity diagram of gas price change and internal rate of return for high confidence case.

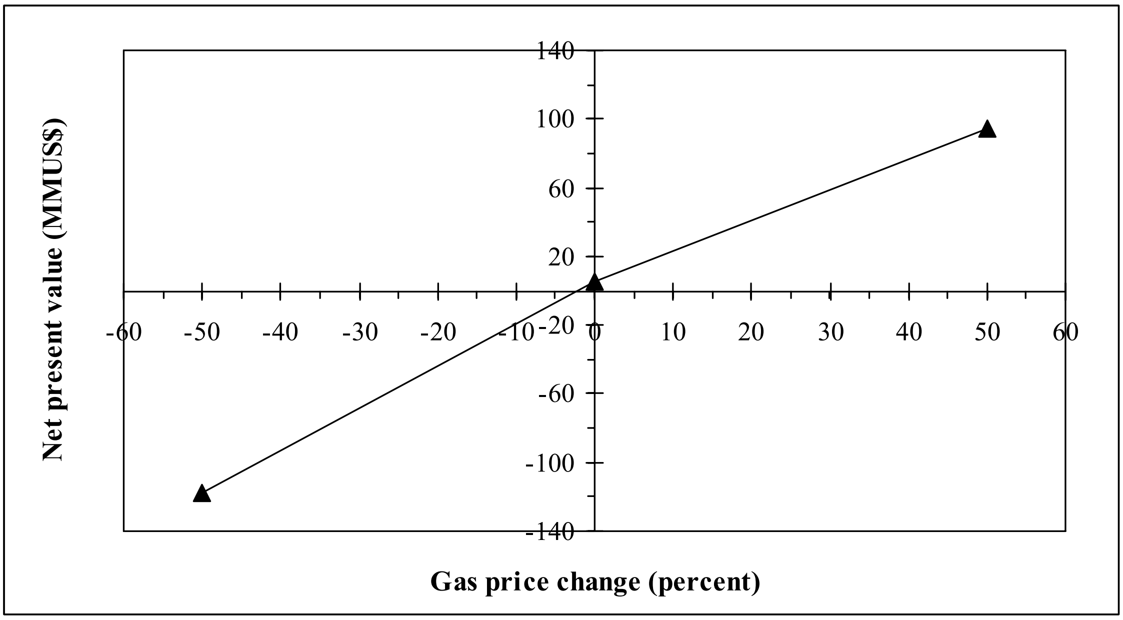

Figure 5.12 Sensitivity diagram of gas price change and net present value (NPV@10%) for high confidence case.

Consider the relationship between gas price change and discounted internal rate of return (DIRR) and net present value at 10 percent discount factor rate (NPV@DCR=10%), the gas price varies between -2.97% and +50% and the concessionaire can start having its profit when the gas price is 5.822 US$/MMBTU.

5.8 Conclusion and Discussion

Petroleum potential of the Chonnabot prospect has enough economics potential for developing evidenced from the results of cash flow and sensitivities analyses when undiscovered natural gas resource size 470.444 Bcf and gas price 6.00 US$/MMBTU. The gas production had started at the 5^{th} year with the production rate of 100 MMcfd. The production rate was constant over 6 years and will be decline in the 11^{th} until ended up at the 24^{th} year. The final production rate at the 24^{th} year is 13.81 MMcfd. The natural gas production has completely paid back at the 3^{rd} year of production. The total net cash flow after concession has succeeded is 733.32 MMUS$ and total net present value at discounted factor 10.00% is 228.88 MMUS$. The government take its royalty 264.75 MMUS$ and its income tax 748.36 MMUS$. The undiscounted internal rate of return (IRR) is 30.75% and discounted internal rate of return (DIRR) is 18.86%. The undiscounted profit to investment ratio (PIR) is 2.56 and discounted profit to investment ratio (DPIR) is 0.80. For this case, this undiscovered natural gas resource can be economically produced because the IRR is 30.75% while the discount rate is only 10.00% (DIRR is equal to 18.86%).

Results from sensitivity analysis performed by changing gas price between ±50% of 6.00 US$/MMBTU and undiscovered natural gas resource size indicate that the minimum gas price should be 3.16 US$/MMBTU for the most likely case consumption and 5.82 US$/MMBTU for the high confidence case.

CHAPTER VI

CONCLUSIONS AND RECOMMENDATIONS

6.1 Conclusions

In summary, this research are to identify, assess, and evaluate the potential and economics of petroleum resource of the Chonnabot prospect. The results of research are divided into four main parts. The first part describes the stratigraphy and sedimentation evolution of this area. The second part describes the petroleum geology and petroleum engineering system of the area. Assessment of the potential of the undiscovered petroleum resource in the area is the third part. The last part deals with economics analysis of the undiscovered petroleum resources.

6.1.1 Stratigraphy of the Khorat Plateau, Thailand

The lithostratigraphy of the Khorat Plateau is established by the integration of the seismic stratigraphy, techno-stratigraphy, well data, previous work, and tectonic history (Chantong, W., 2005). There are six tectono-stratigraphy units.

Basement

These rocks older than the Late Carboniferous are considered to be basement in the Loei-Phetchabun fold belt and the Khorat Plateau area. The Na Mo Group exposed in the Loei provivnce on the northwestern margin of the Khorat Plateau. The low grade metamorphic rocks of the upper greenschist facies is consisted of phylite, chlorite and pelitic schist, metatuff, and quartzite.

The Pak Chom Group mainly is consisted of shallow marine sediments of limestone, greywacke, shale, conglomerate, and tuff. However, radiolarian chert of deep sea facies is also recorded in the sequence, suggested allochthonous content.

Wangsaphung (Si That) and Saraburi Groups

The Si That Group is defined as the pre-rift megasequence. This formation is found only in the subsurface data (underneath the Phu Phan range). The group is consisted of sediments in shallow marine depositional environment (E-Sarn sea) which are deposited during the Late Carboniferous to Late Permian. The Si That Group can be divided into three formations: Si That, Dong Mun, and Lam Pao formations.

The Saraburi Group is defined as the pre-rift megasequence. The group is consisted of sediments of shallow to deep marine depositional environment (Nam Duk sea) which are deposited during the Early to Early Late Permian. This group is widely outcrop along the western edge of the Khorat Plateau, extended from Loei, Petchabun to Saraburi province. The carbonate sequence is consisted mainly of limestone, dolomite, and clastic sediment of shale, sandstone, and siltstone, which represent sediment which deposited in different environment ranging from delta plain, shelf platform, and to deep basin. The Saraburi Group can be divided into three formations: Nam Duk, Pha Nok Khao, and Hua Na Kham formation.

Kuchinarai Group

The Kuchinarai Group is defined as the syn-rift megasequence. The group are consisted of sediment which are deposited in the Triassic half-grabens or graben. This group can be divided into three parts. The upper part is consisted of light to moderate dark grey, buff to tan, red brown to rust brown claystone, and shale. The middle part is consisted of dark lacustrine shale with minor amounts of siltstone, and sandstone. The lower part is made of basal conglomerate. The age of half-grabens filling indicates Late Triassic in age.

Huai Hin Lat Group

The Huai Hin Lat Group is defined as the earliest post-rift megasequence. The group is consisted mainly of claystone, and siltstone interbedded claystone, siltstone, chert, and quartz-conglomerate that deposited during the Late Triassic based on the plant remains, pollen and spores, and a conchostracan. This group is defined as the earliest post-rift megasequence and is separated from the Kuchinarai Group. Although this group is found in the local area, the seismic data show it to be unconformable upon the Kuchinarai Group. Thus, the Hua Hin Lat Group should be separated from the syn-rift megasequence.

Khorat Group

The Khorat Group is defined as the post-rift megasequence. The group is consisted of very high thickness of red clays, siltstone, sandstone, and conglomerates (continental sediments) that deposited during the Jurassic to Cretaceous. This unit is found in both the Loei-Phetchabun fold belt and the Khorat Plateau.

Phon Hong Group

The Phon Hong Group is defined as the post-inversion megasequence. The group is consisted of hypersaline lacustrine and aeolian sediments that deposited the Early Late Cretaceous. This group can be devided into Maha Sarakham and Phu Tok formation.

6.1.2 Hydrocarbon occurrences of the Chonnabot prospect

Source rocks

In this Permian carbonate play type, the Pha Nok Khao formation is considered to be the principles source rocks of the prospect. Analysis of several samples from the two wells shows a content of total organic carbon (TOC) are fair to excellent organic richness for Phu Lop-1 well and fair to very good organic richness for Dao Ruang-1 well.

Maturation studies using a combination of rock-eval Tmax and vitrinite reflectance. The Phu Lop-1 well, Tmax indicate that immature to overmature stage. The Dao Ruang-1 well, Tmax indicate that immature to mature stage and vitrinite reflectance analysis indicate that is thermally mature stage (R_o >1.0% to R_o ~1.4%) for hydrocarbon generation.

Carbonate reservoir rocks

The original rock of the carbonate reservoir was largely dark grey mud supported micritic limestone (wackstone) with minor grain support fossiliferous packstone/grainstone and dolomitic inpart that originated in a low energy, peritidal, restricted marine (lagoon) paleoenvironment with some high energy open marine margin of carbonate platform.

The environment of deposition very much controlled the quality of reservoir rocks. Calcite cements have occluded most porosity in carbonate reservoir. Microfractures are the main porosity for hydrocarbon and intercrystalline porosity is minor in the carbonate section.

From past exploration history, the drilled carbonate rock was found to possess the porosity values ranges from 0 to 18 percent with an average matrix porosity of about 4.0 percent. Well testing results indicate the Permian carbonates at the Dao Ruang-1 well were proved to be low permeability.

Seal and traps

The fine grained sediments of the Permian Upper Clastic and/or Triassic rocks are believed to be seals for Permian carbonate reservoir.

Trap are formed both by geologic structures and stratigraphic associated with the Permian carbonate play. There may be angular unconformity between the Triassic of Huai Hin Lat Group and the Permian of Saraburi Group, traps in the Permian reefal and fore slop reefal limestone, and half graben structures in the Triassic and Permian sediments underlying the Khorat Group.

6.1.3 Hydrocarbon potential estimation of the Chonnabot prospect

The hydrocarbon resource evaluation of the prospect was performed by FASPU program with the established parameters as follows;

The play attribute determination and analysis is mainly involved with the presence or absence of regional characteristics and they are given their probability as follows;

- The probability of hydrocarbon source = 1.00
- The probability of favorable timing = 1.00
- The probability of potential migration path = 0.90
- The probability of potential reservoir facies = 0.90
- The marginal play probability = 0.81

The prospect attribute determination and analysis is mainly involved with the presence or absence of local characteristics which determine the nature of prospects within a play and they are given their probability as follows;

- The probability of trapping mechanism = 1.00
- The probability of effective porosity = 0.80
- The probability of hydrocarbon accumulation = 1.00
- The conditional deposit probability = 0.80

The hydrocarbon volume attributes can be considered and calculated from the plot of data and observe a complementary cumulative distribution function and predict the favorable value at the fractile 100^{th}, 95^{th}, 75^{th}, 50^{th}, 25^{th}, 5^{th}, and 0^{th}. The parameters which affect the petroleum resource quantity are determined. They comprise of area of closure, reservoir thickness/vertical closure, effective porosity, trap fill, reservoir depth, and hydrocarbon saturation.

The reservoir engineering parameters comprise of original reservoir pressure, reservoir temperature, gas-oil ratio, oil formation volume factor, gas compressibility factor, oil floor depth, and oil and gas recovery factor.

Estimation of the total undiscovered oil and gas in the Permian carbonate of the Chonnabot prospect are presented in the form of complementary cumulative probability distribution. These distributions summarize the range of estimates generated by the FASPU program as a single probability curve in a greater than format. The estimates are reported at the mean and at the 95^{th}, 75^{th}, 50^{th}, 25^{th} and 5^{th} fractiles. Results from FASPU program can be summarized as follows;

1) The quantities of oil accumulation is 41.1836 MMbbl but the chance of discovery is only 5 percent (fractile 5^{th}). Therefore, there is a low or no chance to find an oil field within this prospect.

2) The quantities of gas accumulation are vary from 122.433 Bcf at very high confidence (fractile 95^{th}), 270.895 Bcf at high confidence (fractile 75^{th}), 470.444 Bcf at medium confidence (fractile 50^{th}), 816.987 Bcf at low confidence (fractile 25^{th}), and 1,807.66 Bcf at very low confidence (fractile 5^{th}), respectively.

6.1.4 Economics analysis of the undiscovered natural gas resource of the Chonnabot prospect

Petroleum potential of the Chonnabot prospect has enough economics potential for developing evidenced from the results of cash flow and sensitivities analyses when undiscovered natural gas resource size 470.444 Bcf and gas price 6.00 US$/MMBTU. The gas production had started at the 5^{th} year with the production rate of 100 MMcfd. The production rate was constant over 6 years and will be decline in the 11^{th} until ended up at the 24^{th} year. The final production rate at the 24^{th} year is 13.81 MMcfd. The natural gas production has completely paid back at the 3^{rd} year of production. The total net cash flow after concession has succeeded is 733.32 MMUS$ and total net present value at discounted factor 10.00 percent is 228.88 MMUS$. The government take its royalty 264.75 MMUS$ and its income tax 748.36 MMUS$. The undiscounted internal rate of return (IRR) is 30.75 percent and discounted internal rate of return (DIRR) is 18.86 percent. The undiscounted profit to investment ratio (PIR) is 2.56 and discounted profit to investment ratio (DPIR) is 0.80. For this case, this undiscovered natural gas resource can be economically produced because the IRR is

30.75 percent while the discount rate is only 10.00 percent (DIRR is equal to 18.86 percent).

Results from sensitivity analysis performed by changing gas price between ±50 percent of 6.00 US$/MMBTU and undiscovered natural gas resource size indicate that the minimum gas price should be 3.16 US$/MMBTU for the most likely case consumption and 5.82 US$/MMBTU for the high confidence case.

6.2 Recommendations of results for future studies

1) Reliability of petroleum prospect assessment depends on the accuracy of the input parameters and the geological model.

2) The results of this assessment may change as new information on this play type is available from future exploration work in the northeast of Thailand.

3) The undiscovered petroleum resources assessed by FASPU program which can be used for decision making in the investment of petroleum exploration and production in the nearby prospect of northeastern Thailand.

4) The results are useful in the prediction of the future petroleum business in northeastern Thailand.

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APPENDIX A

RAW DATA

Table A.1 The area of closure distribution of the top Permian carbonate play.

Prospect	**Area of closure (acre)**
Prospect 1	2,883.71
Prospect 2	11,621.00
Prospect 3	6,881.86
Prospect 4	7,684.95
Prospect 5	3,212.36
Prospect 6	5,189.19
Prospect 7	5,189.19
Prospect 8	8,648.65
Prospect 9	11,613.91
Prospect 10	1,005.72
Prospect 11	2,110.27
Prospect 12	4,368.81
Prospect 13	4,420.70
Prospect 14	10,244.95
Prospect 15	23,605.88

Table A.2 The reservoir thickness distribution of the Permian carbonate play.

Location	**Reservoir Thickness (feet)**
Location 1	234
Location 2	103
Location 3	144
Location 4	238
Location 5	322
Location 6	238
Location 7	198
Location 8	300
Location 9	300
Location 10	213
Location 11	228
Location 12	244
Location 13	252

Table A.3 The porosity distribution of the Permian carbonate play.

Interval	Porosity	Interval	Porosity	Interval	Porosity
1	0.0200	24	0.0100	47	0.0400
2	0.0000	25	0.0400	48	0.0300
3	0.0300	26	0.0100	49	0.0100
4	0.0100	27	0.0400	50	0.0200
5	0.0300	28	0.0300	51	0.0000
6	0.0500	29	0.0000	52	0.0220
7	0.0100	30	0.0300	53	0.0100
8	0.0400	31	0.0000	54	0.0100
9	0.0300	32	0.0200	55	0.0500
10	0.0100	33	0.0030	56	0.0800
11	0.0500	34	0.0000	57	0.0300
12	0.0700	35	0.0600	58	0.0210
13	0.0300	36	0.0300	59	0.0000
14	0.0200	37	0.0040	60	0.0500
15	0.0100	38	0.0000	61	0.0200
16	0.0030	39	0.0200	62	0.0400
17	0.0200	40	0.0200	63	0.0400
18	0.0200	41	0.0000	64	0.0300
19	0.0100	42	0.0100	65	0.0040
20	0.0100	43	0.0500	66	0.0300
21	0.0300	44	0.0020	67	0.0000
22	0.0200	45	0.0300	68	0.0000
23	0.0300	46	0.0100	69	0.0370

Table A.3 The porosity distribution of the Permian carbonate play (Cont.).

Interval	Porosity	Interval	Porosity	Interval	Porosity
70	0.0300	93	0.0000	116	0.0400
71	0.0000	94	0.0200	117	0.1700
72	0.0700	95	0.0200	118	0.0000
73	0.0010	96	0.0100	119	0.1300
74	0.0100	97	0.0000	120	0.0300
75	0.0000	98	0.0500	121	0.1500
76	0.0000	99	0.0000	122	0.1200
77	0.0000	100	0.0000	123	0.0900
78	0.0900	101	0.0400	124	0.0110
79	0.0000	102	0.0300	125	0.0600
80	0.0040	103	0.0300	126	0.0400
81	0.0000	104	0.1300	127	0.0800
82	0.0200	105	0.0900	128	0.0700
83	0.0500	106	0.0300	129	0.0600
84	0.0500	107	0.0800	130	0.0320
85	0.0200	108	0.0100	131	0.0000
86	0.0000	109	0.0400	132	0.0300
87	0.0000	110	0.0100	133	0.0220
88	0.0300	111	0.0600	134	0.0470
89	0.0000	112	0.0000	135	0.0700
90	0.0100	113	0.0700	136	0.0020
91	0.0300	114	0.0200	137	0.0110
92	0.0000	115	0.1200	138	0.0100

Table A.3 The porosity distribution of the Permian carbonate play (Cont.).

Interval	Porosity	Interval	Porosity	Interval	Porosity
139	0.0000	162	0.0320	185	0.0510
140	0.0200	163	0.0400	186	0.0510
141	0.0000	164	0.0300	187	0.0400
142	0.0300	165	0.0410	188	0.0430
143	0.0200	166	0.0200	189	0.0410
144	0.0330	167	0.0400	190	0.1600
145	0.0100	168	0.0300	191	0.0400
146	0.0100	169	0.0600	192	0.0010
147	0.0100	170	0.0740	193	0.0470
148	0.0300	171	0.0100	194	0.0300
149	0.0120	172	0.0600	195	0.0400
150	0.0000	173	0.0120	196	0.0300
151	0.0420	174	0.0300	197	0.0500
152	0.0020	175	0.0370	198	0.0400
153	0.0000	176	0.0800	199	0.0400
154	0.1100	177	0.0440	200	0.0800
155	0.0900	178	0.0500	201	0.0400
156	0.0100	179	0.0700	202	0.0100
157	0.0300	180	0.0300	203	0.0300
158	0.0300	181	0.0400	204	0.0300
159	0.0300	182	0.0470	205	0.0900
160	0.0700	183	0.1400	206	0.1000
161	0.0360	184	0.0700	207	0.0400

Table A.4 The hydrocarbon saturation distribution of the Permian carbonate play.

Interval	Hydrocarbon saturation	Interval	Hydrocarbon saturation	Interval	Hydrocarbon saturation
1	37.0	24	21.0	47	12.0
2	5.0	25	21.0	48	8.0
3	5.0	26	21.0	49	13.0
4	5.0	27	9.0	50	13.0
5	5.0	28	9.0	51	14.0
6	5.0	29	21.0	52	76.3
7	5.0	30	15.0	53	53.0
8	40.0	31	8.0	54	55.0
9	57.0	32	29.0	55	55.7
10	5.0	33	18.0	56	79.9
11	5.0	34	25.0	57	75.0
12	39.0	35	25.0	58	53.0
13	39.0	36	3.0	59	84.0
14	39.0	37	23.0	60	86.0
15	39.0	38	23.0	61	72.0
16	59.0	39	25.0	62	88.0
17	35.0	40	12.0	63	78.0
18	69.0	41	13.0	64	87.0
19	76.0	42	2.0	65	84.0
20	2.0	43	3.0	66	59.0
21	17.0	44	3.0	67	89.0
22	29.0	45	13.0	68	84.0
23	25.0	46	13.0	69	84.0

Table A.4 The hydrocarbon saturation distribution of the Permian carbonate play (Cont.).

Interval	Hydrocarbon saturation	Interval	Hydrocarbon saturation	Interval	Hydrocarbon saturation
70	72.0	92	62.0	114	66.0
71	85.0	93	87.0	115	26.0
72	38.0	94	84.0	116	23.0
73	86.0	95	74.0	117	29.0
74	85.0	96	78.0	118	31.0
75	46.0	97	90.0	119	20.0
76	81.0	98	31.0	120	59.0
77	49.0	99	89.0	121	4.0
78	73.0	100	69.0	122	9.0
79	30.0	101	85.0	123	8.0
80	88.0	102	65.0	124	35.0
81	87.0	103	53.0	125	27.0
82	85.0	104	85.0	126	30.0
83	90.0	105	69.0	127	48.0
84	89.0	106	65.0	128	48.0
85	71.0	107	86.0	129	47.0
86	65.0	108	32.0	130	75.0
87	17.0	109	82.0	131	67.0
88	78.0	110	84.0	132	42.0
89	86.0	111	68.0	133	54.0
90	80.0	112	69.0	134	45.0
91	86.0	113	39.0	135	34.0

Table A.4 The hydrocarbon saturation distribution of the Permian carbonate play (Cont.).

Interval	Hydrocarbon saturation	Interval	Hydrocarbon saturation	Interval	Hydrocarbon saturation
136	43.0	147	89.0	158	84.0
137	84.0	148	16.0	159	87.0
138	72.0	149	64.0	160	83.0
139	86.0	150	70.0	161	39.0
140	71.0	151	81.0	162	84.0
141	62.0	152	89.0	163	82.0
142	76.0	153	64.0	164	89.0
143	89.0	154	77.0	165	38.0
144	77.0	155	83.0	166	35.0
145	90.0	156	80.0	167	50.0
146	84.0	157	88.0		

APPENDIX B

GUIDELINES FOR RISK ASSESSMENT

3.3.1 Reservoir

PROBABILITY OF EFFECTIVE RESERVOIR

P1 = P1a x P1b

P1a: Probability of existence of reservoir facies with minimum net thickness and net/gross-ratio as applied in the resource assessment, and

P1b: Probability of effectiveness of the reservoir, with respect to minimum porosity, permeability and hydrocarbon saturation

The probability of the presence of an effective reservoir rock with minimum properties as assigned in the volumetric estimate of the prospect, **P1**, comprises two components. The first of these is the probability of the existence of reservoir facies with minimum properties such as net/gross ratio and thickness. The second is the probability that the reservoir parameters will be effective in terms of porosity, permeability and hydrocarbon saturation.

These two components must be considered independently. The second component is most relevant when we are evaluating prospects at significant depths or when we are dealing with special areas of low porosity and permeability.

The following work must be performed in order to evaluate the properties and quality of the prognosed reservoir rock:

- Evaluation of all relevant wells in the area with respect to reservoir depth, diagenesis, porosity, permeability, hydrocarbon saturation, and the interrelationships between these parameters.
- Regional evaluation and facies analysis of the reservoir rock with respect to thickness, N/G ratio, threshold porosity and porosity trends with depth, and hydrocarbon saturation.
- Seismic facies analysis and sequence stratigraphy studies which have a bearing on reservoir prediction (sandstone, carbonate, etc.) and depositional environment.

The establishment of a geological model for the reservoir and its properties is based on the interpretation of geological samples (e.g. from cores), well and seismic data. An accurate prediction of reservoir properties will depend on the number of relevant data points in the area, and on the geographical distribution of these data points with respect to the prospect. In relatively mature areas, the distance to the nearest data point and indications on seismic of facies changes in the direction of the mapped prospect are important factors.

When we are dealing with relatively unknown frontier areas a more general approach must be taken. A regional depositional model for the prognosed reservoir rock must be established. According to Ulmishek (1986), the following three major categories of reservoir rocks can be identified:

1. **Massive reservoir rocks** which usually comprise thick carbonates (including reefs). Reservoir properties are determined to a great extent by cavernous porosity and fracturing, although matrix porosity may be important. Thick sandstone formations with laterally non-persistent shales may also fit this type.
2. **Stratified reservoir rocks** generally comprise one or a few sandstone beds within a relatively confined stratigraphic interval. Intergranular porosity predominates but leaching and fracturing will sometimes play a significant role. “Blanket”, often biostromal, carbonate reservoirs may also fit this type.
3. **Multistrata reservoir rocks** may comprise numerous sandstones within thick clastic formations often of paralic or deltaic origin. Intergranular porosity predominates.

RESERVOIR EVALUATION:

- Continuity/discontinuity of anticipated reservoir facies.
- Is it possible to establish alternative unfavourable models for the reservoir facies?
- Minimum reservoir thickness and net/gross ratio in the volumetric calculations
- What about the prospect location compared to the anticipated distribution of the reservoir facies?
- Data quality and data density must be evaluated. Is the geological model in the prospect location established by interpolation or extrapolation?
- How reliable is the database?

DEPOSITIONAL ENVIRONMENT

- Vertical and lateral facies distribution
- Thickness variations

PARAMETERS TO EVALUATE

- well data
- reservoir depth, diagenesis, etc.
- porosity and permeability plots and maps
- facies related porosity trends
- seismic velocities

Clearly, there exist transitions between the two last categories. Categories one and three are the two that have proved to be the most effective reservoirs in a global context.

3.3.1.1 Presence of reservoir facies

When we are estimating the probability of existence of an effective reservoir we must evaluate the chance that the prognosed reservoir rock possesses at least the minimum values of N/G-ratio and thickness that we applied in the volumetric assessment. It is also important to note that it is *the net reservoir thickness* (thickness x net/gross ratio) which has consequences for our resource estimates.

Prospect evaluation is based on a geological model for reservoir facies. The model must be defined with respect to depositional environment and the lateral distribution of the prognosed facies. When performing risk assessment, the facies model must be evaluated with respect to the questions in the text box on the left.

General guidelines related to reservoir facies are listed in the table in figure 3.9.
The guidelines assume an adequate and reliable database. Note that for clastic reservoirs the sand/shale ratio in the depositional system will determine whether we choose the lower or the higher end of the probability range.

These general guidelines should be adjusted to local conditions, and/or on the reliability of the database.

	Depositional environment \ Data reliability	Direct data, proximal deposits	Direct data, more distal deposits	Limited data, discontinuous deposits	Indirect data, seismic sequence analysis
Marine	Shallow marine, "blanket"	0.9 - 1.0	0.7 - 0.8	0.6 - 0.7	0.4 - 0.6
	Coastal, deltaic, tidal	0.8 - 1.0	0.7 - 0.8	0.6 - 0.7	0.4 - 0.6
	Submarine fan	0.7 - 0.8	0.5 - 0.6	0.3 - 0.5	0.1 - 0.3
	Carbonates	0.8 - 1.0	0.6 - 0.8	0.5 - 0.7	0.3 - 0.5
Continental	Lacustrine deltaic	0.7 - 0.9	0.5 - 0.7	0.4 - 0.6	0.3 - 0.5
	Alluvial fan, braided stream, meand. chan.	0.7 - 0.9	0.5 - 0.7	0.4 - 0.6	0.3 - 0.5
	Eolian	0.8 - 1.0	0.6 - 0.8	0.4 - 0.6	0.4 - 0.6
Others	Fractured basement	0.4 - 0.6	0.3 - 0.5	0.2 - 0.4	0.1 - 0.3
	Fractured, porous lava	0.4 - 0.6	0.3 - 0.5	0.2 - 0.4	0.1 - 0.3

Fig. 3.9 Probability scheme. Presence of effective reservoir facies.

3.3.1.2 Effective pore volume

During prospect evaluation a model for lateral and vertical (depth) distribution of reservoir properties should be established in order to define reasonable cut-off values for effective reservoir permeability and porosity. When performing risk assessment, we are evaluating the probability of porosity and permeability being greater than the minimum value. An analysis of the major factors controlling reservoir effectiveness should be performed as indicated in the text box on the left.

Also during the evaluation of reservoir facies and effectiveness, it is important to have a clear understanding of the extent to which the prognosed models are proven or analogue/theoretical.

FACTORS CONTROLLING RESERVOIR EFFECTIVENESS

- Diagenesis, illitisation, calcite cementation and other processes which may cause deterioration of reservoir quality.
- Secondary porosity.
- Fracturing and its impact on reservoir quality.
- Pressure conditions that may influence the preservation of porosity and/or permeability. High pressure in the reservoir may reduce porosity. Overpressure may maintain high porosity at great depths.
- Early migration may contribute to preservation of porosity and permeability even at great depths.

The risk analysis of porosity is closely related to the interpretation and choice of porosity data as input to the volumetric calculation. In general, available well data are used to establish regional porosity-versus-depth trends from which the scatter in data points is used to define the minimum, most likely and maximum values for the average porosity for a given depth interval (fig. 3.10).

In most cases we take account of the uncertainty in the porosity values by using the minimum average porosity value in the input parameters for the volumetric calculation. However, the probability of effective porosity may be a critical parameter when we are evaluating prospects at great depths, or if we are dealing with special areas of generally low porosity (i.e. lower than the threshold value for porosity). When we are evaluating prospects at great depths, we should estimate the minimum threshold porosity for efficient production of hydrocarbons. This value should be used as the minimum value in the volumetric calculation.

Other regional factors (i.e. reservoir facies, tectonic uplift, regional erosion, and diagenesis) may also influence porosity values.

We should also be aware that there is a substantial difference between porosity data measured on cores and data calculated from electric logs. The difference may be as high as 10 to 15%.

Res. depth, *(pressure, temp.)* / Data reliability		Direct data, proximal deposits	Direct, but less data, more distal deposits	Limited data, uncertain correlation	Indirect data
1 - 3 km	Homogeneous, clean reservoir	0.9 - 1.0	0.8 - 0.9	0.7 - 0.8	0.6 - 0.7
	Mixed, unclean reservoir	0.8 - 1.0	0.7 - 0.8	0.6 - 0.7	0.4 - 0.6
3 - 4 km	Homogeneous, clean reservoir	0.8 - 0.9	0.7 - 0.8	0.5 - 0.7	0.4 - 0.5
	Mixed, unclean reservoir	0.7 - 0.9	0.6 - 0.7	0.5 - 0.6	0.3 - 0.5
> 4 km	Homogeneous, clean reservoir	0.7 - 0.9	0.5 - 0.7	0.4 - 0.6	0.3 - 0.5
	Mixed, unclean reservoir	0.6 - 0.9	0.3 - 0.5	0.2 - 0.4	0.1 - 0.3

Late uplift	Take **maximum burial** into consideration
Calcite cementation	Consider **regional studies**
Illitisation	**Regional studies, clay content**
Dolomitisation	Consider **regional studies**
Early migration	May **preserve** reservoir porosity
Secondary porosity	Pressure/solution studies, etc.
ADJUST DEPTH BOUNDARIES ABOVE TO FIT BASIN PROPERTIES	
ADJUST MINIMUM POROSITY VALUE IN VOLUME CALCULATIONS	

Fig. 3.10 Reservoir depth vs. data

PROBABILITY OF EFFECTIVE TRAP

***P2 = P2a x P2b**, where:*

P2a: Probability of presence of the mapped structure with a minimum rock volume as prognosed in the volume calculation.

P2b: Probability of effective seal mechanism for the mapped structure.

3.3.2 Trap mechanism

The trap is a sealed structural closure or geometrical body. The probability of the presence of an effective trap, **P2**, is the product of the probability of the existence of the mapped structure as a valid geometrical closure, and of a sealing mechanism which acts in such a way that the trap's bounding surfaces enclose the minimum rock volume as defined in the volumetric calculation.

For this probability factor we must assess the probability of the existence of the minimum gross rock volume of the mapped structure. Furthermore, we must evaluate the probability of effective sealing of the structure. The sealing mechanism incorporates both the surrounding rocks and faults.

It is also important to note that the point in time of trap formation relative to the time of onset of migration will be considered as part of the evaluation of probability factor P3 (*probability of effective petroleum charge*). Issues related to tectonic and/or isostatic reactivation after accumulation of hydrocarbons will be assessed as part of the evaluation of probability factor P4 (*probability of effective retention after accumulation)*.

It is recommended that the following work be carried out before we assess the probability of an effective trap:

- Ideally, all surfaces enclosing the reservoir volume (both top and base) should be mapped. If the reservoir model indicates a geometrically uniform reservoir body (i.e. parallel top- and bottom surfaces), it will be sufficient to map the top surface.
- Establishing a geological model for our definition of the mapped structure and sealing mechanism (i.e. sealing rocks and faults must be identified).
- Spill-point relations must be defined and carefully mapped.
- Time-depth relations (depth conversion) of the sealing surfaces must be established (with associated uncertainties).
- Seismic profiles should be examined with respect to potential seismic anomalies such as hydrocarbon and lithology indicators.

When we are dealing with poorly known frontier areas a more general approach must be adopted. A regional model for prognosed trapping mechanisms must be established. According to Ulmishek (1986) the two following major categories of trap types can be identified on a global basis:

1. **Intensely deformed structural style,** where structural (including salt- and clay diapirs) and combined structural/stratigraphic traps are abundant.

2. **Slightly deformed structural style,** where structural traps are rare; stratigraphic (including paleogeomorphic) traps predominate.

In addition, Ulmishek (1986) defined two different seal types as follows:

1. **Perfect seals** are comprised of effectively impermeable rocks such as anhydrites, over-pressured shales, or other thick (hundreds of metres) plastic shale formations, and permafrost.

2. **Imperfect seals** comprise partly permeable rocks such as differentially compacted shales, dense carbonates, marls, etc., and are more common in areas of tectonic faulting and fracturing.

The evaluation of probability of existence of the mapped trap as a geometrical body must take the following issues into consideration.

- seismic data quality
- seismic coverage
- seismic interpretation
- identification of top/bottom surfaces of the reservoir
- reliability of the trap definition
- depth conversion

3.3.2.1 Presence of the mapped structure

In general, prospect mapping includes three major processes; interpretation of the seismic profiles, construction of time maps of the top (and bottom) surface, and conversion of the time maps to depth maps. The probability of correct delineation of the minimum rock volume by mapping of the top and base reservoir, calculation of areal closure and depth conversion, etc.), together with placement of the trap at the correct location have to be assessed. Risk analysis requires a careful evaluation of each step in this process.

Regarding seismic data quality, we must evaluate the possibility that the mapped geometrical body does not exist (or that the bounding surfaces enclose less than the minimum estimated reservoir rock volume). Uncertainty will arise if resolution of these surfaces on seismic profiles is poor. The seismic coverage must also be assessed. The density of seismic profiles (fig. 3.11) must be adequate to ensure that we can delineate a measurable rock volume and the spill-points of the prognosed trap. If this is not possible, our prospect should be redefined as a "lead", and we should consider the possibility of acquiring new data in order to reduce this uncertainty in the mapping. It is important to assess whether the space between the profiles is so great that the acquisition of new data is necessary in order to confirm that the reservoir rock volume is greater than the minimum as defined in the volumetric calculation.

The process of seismic interpretation includes the picking of seismic reflectors, correlation across fault boundaries, tie between crossing profiles, etc. The structural and/or stratigraphic complexity of the prospect (fig. 3.11) must be evaluated with respect to its influence on the uncertainty in determining the minimum rock volume. In addition, the identification of the bounding reservoir surfaces (top and bottom) must be assessed. If we have not been able to identify the seismic reflectors representing the relevant bounding surfaces, we must evaluate the uncertainty of the seismic interpretation and its impact on the minimum rock volume.

The impact of depth conversion is a critical factor when we are assessing low-relief structures. Uncertainty in time-depth conversion algorithms which determine the structural apex (and thereby the top of the prognosed hydrocarbon column) will influence our estimate of the minimum rock volume. Both vertical and lateral velocity variations must be assessed. Note that seismic velocities derived from 2D-processing data have a tendency to be in the range 5-10% higher than geological average velocities. If possible, seismic velocities should be calibrated with velocities derived from nearby wells.

Seismic correlation and mapping / Data reliability		3D-seismic	2D-seismic: Dense grid size	2D-seismic: Open grid size	2D-seismic: Very open grid
Good corr., nearby wells	Low structural complexity	0.9 - 1.0	0.9 - 1.0	0.8 - 1.0	0.7 - 0.9
	High structural complexity	0.7 - 1.0	0.6 - 0.9	0.5 - 0.8	0.4 - 0.7
	Low relief, uncertain depth conversion	0.6 - 0.9	0.5 - 0.8	0.4 - 0.7	0.3 - 0.6
Uncertain corr, distant wells	Low structural complexity	0.9 - 1.0	0.8 - 1.0	0.7 - 0.9	0.5 - 0.8
	High structural complexity	0.7 - 0.9	0.6 - 0.9	0.4 - 0.8	0.3 - 0.7
	Low relief, uncertain depth conversion	0.5 - 0.8	0.4 - 0.7	0.3 - 0.6	0.2 - 0.5
Unreliable corr. analogue model	Low structural complexity	0.9 - 1.0	0.7 - 1.0	0.6 - 0.8	0.4 - 0.7
	High structural complexity	0.4 - 0.7	0.3 - 0.6	0.2 - 0.5	0.1 - 0.4
	Low relief, uncertain depth conversion	0.3 - 0.7	0.2 - 0.6	0.1 - 0.5	0.1 - 0.4

Interpretation of top surface not based on seismic reflector:	
Parallel reflectors	In general, middle to high end of range
Non-parallel reflectors	Low end of range

Area of closure/grid size:	
> 5 times	Dense grid size
2 - 5 times	Open grid size
< 2 times	Very open grid size

Fig. 3.11 Probability scheme. Presence of efficient structural closure.

3.3.2.2 Effective seal mechanism

The surrounding rocks in contact with the prognosed reservoir volume of any prospect will determine its sealing mechanism. The enclosing surfaces of the reservoir volume may be classified into three different groups (Milton and Bertram, 1992), *depositional surfaces*, *tectonic surfaces*, *and facies change-related surfaces.*

When we are assessing this factor we must evaluate the permeability of the surface (or surfaces) which define and enclose the reservoir volume. The sealing capacity of the trap will depend on the lithologies along the surfaces that enclose the reservoir rock. Only surfaces that are necessary to enclose the reservoir volume should be included. Top-, bottom- and lateral seals must be regarded as equally important. All traps can be classified into two major groups; those that depend on a *simple seal mechanism,* and those that depend on *a combined seal mechanism* as shown in table, (fig.3.12).

Seal mechanism	Top surface	Bottom, side	Structural style	Very good	Good	Accept-able	Poor
Simple seal	Con-form	N/A.	Anticline, buried highs, build-ups, faulted str.	0.9 - 1.0	0.8 - 1.0	0.6 - 0.8	0.4 - 0.6
Simple seal	Uncon-form	N/A.	Faulted structures	0.8 - 0.9	0.7 - 0.8	0.5 - 0.7	0.3 - 0.5
Combined seal	Con-form	Uncon-form	Onlap, low-stand wedge	0.5 - 0.7	0.4 - 0.5	0.3 - 0.4	0.1 - 0.3
Combined seal	Con-form	Faults	Downfaulted structures	0.6 - 0.8	0.5 - 0.6	0.3 - 0.5	0.1 - 0.3
Combined seal	Con-form	Facies shift	"shale out"	0.6 - 0.8	0.5 - 0.7	0.4 - 0.6	0.1 - 0.3
Combined seal	Uncon-form	Con-form	Subcrop structures	0.4 - 0.5	0.3 - 0.5	0.2 - 0.4	0.1 - 0.3

Salt, anhydrite, carbonates	**Very good** sealing properties
Thick shales	**Good** sealing properties
Thin shales	**Poor to acceptable** sealing properties
Basalt	**Acceptable to good** sealing properties
Faults cutting top surface	**Poor to acceptable** sealing properties
Juxtaposition; fault planes	Depends on sand/shale or sand/sand contact

Fig. 3.12 Probability scheme.
The probability of an effective of seal mechanism.

All traps defined by a sealing top surface with a 4-way closure exhibit a *simple sealing mechanism*. The distribution of the reservoir within this closure affects the pore volume, but not the sealing mechanism of the trap. Structures such as anticlines, sedimentary build-up structures (submarine fans, reefs, barrier banks, etc.), together with buried topographic highs and erosion remnants may be included in this group. Fault-dependant structures where the fault plane is part of the sealing top surface (rotated fault blocks, horst blocks, etc.) are also included in this group. The only seal risk associated with traps of this type is that related to the sealing properties of the overlying lithology (i.e. caprock). Hydrocarbon spill from these structures will generally only occur from a saddle point at the top surface.

Traps with *combined seal mechanism* include those that require either lateral and/or bottom seal mechanisms in addition to top seal, in order to define the trap. The structural map at the top reservoir surface is not sufficient to define the reservoir volume for this type of trap. Traps formed by pinch-out or the shaling out of sand-bodies, and down-faulted structures (down-thrown fault blocks) belong to this group. The seal risk associated with this group of traps is related as much to lateral and bottom surfaces as to the top surface. Spill from these structures may occur either from a saddle point in the top surface or from the deepest point where the top and lateral/bottom surfaces meet.

When we are assessing the risk of sand to sand contact across fault planes, we must also consider the potential "shale smearing" in the fault plane, and the dip of the sand layer that is anticipated to be in direct contact with the reservoir rock. Different trap mechanisms are shown in fig.3.13.

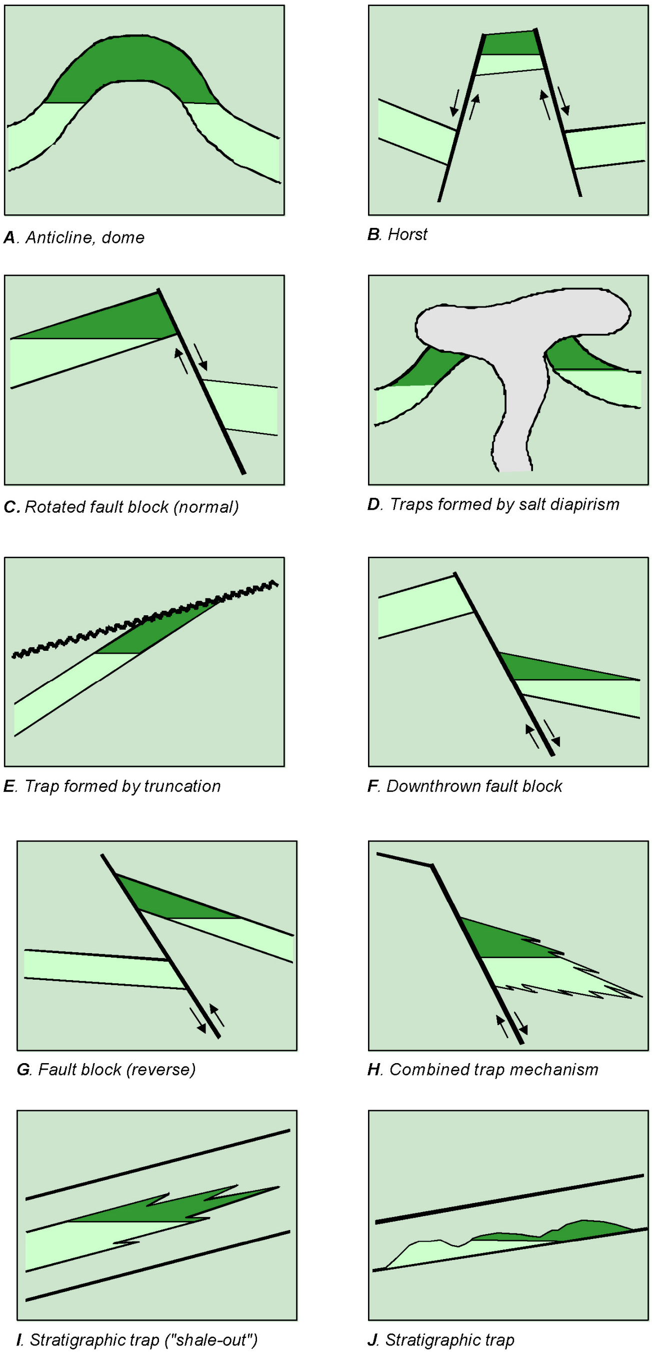


Fig. 3.13 Examples of trap mechanisms.

PROBABILITY OF EFFECTIVE PETROLEUM CHARGE

P3 = P3a x P3b, where:

P3a: Probability of effective source rock in terms of the existence of sufficient volume of mature source rock of adequate quality located in the drainage area of the mapped structure.

P3b: Probability of effective migration of hydrocarbons from the source rock to the mapped structure.

FACTORS TO BE EVALUATED:

- quality and maturity of the potential source rock(s),
- what type of hydrocarbons are generated,
- volume of mature source rock within the drainage area,
- points in time for onset and end of oil migration,
- points in time for onset and end of gas migration,
- mapping of drainage area and migration routes,
- mapping of "fill-spill" relationships

3.3.3 Petroleum Charge

The petroleum charge system comprises an effective source rock (in terms of its quality, volume and maturity), and a migration mechanism for hydrocarbons from the source rock(s) to the sealed trap. The probability factor for the petroleum charge system, **P3**, is a product of the probability of effective source rock, **P3a**, and the probability of effective migration, **P3b**. Each component of the petroleum charge system, P3a and P3b, must be considered independently.

The determination of this factor requires an evaluation of source rock potential before we carry out the volumetric calculation for the prospect. We must examine the following factors.

When performing the volumetric assessment of the prospect, the potential hydrocarbon charge can be estimated by the following formula:

> *Petroleum charge = Effective drainage area x Average thickness x TOC x Transformation factor x Expulsion factor (primary migration) x Secondary migration factor*

The purpose of this calculation is to justify the trap-fill in terms of the volume of available hydrocarbons. In most areas, lack of sufficient data will introduce considerable uncertainty to these estimates. A Monte-Carlo simulation tool could therefore be very useful. The other factor relevant to the trap-fill is the sealing capacity of the structure. If the calculated charge is not sufficient to fill the prospect, the trap fill (or hydrocarbon column) must be reduced accordingly.

In unknown frontier areas a more general approach must be taken, and regional models for the predicted source rocks must be established. According to Ulmishek (1986) the following three major categories of organic matter can be identified within potential source rocks:

Humic organic matter, which is mainly terrestrial. Coal-bearing rocks are included here. Dry gas is the major hydrocarbon product.

Dispersed sapropelic organic matter is found in marine and lacustrine rocks. The content of organic matter is usually close to the Clarke level and seldom reaches 2-3% in discrete samples. Significant mixing of humic organic matter is common.

Concentrated sapropelic organic matter is found in marine and lacustrine rocks, sometimes in relatively thin formations. Average concentration of exclusive sapropelic organic matter commonly exceeds 4-5% and reaches 20% or more in individual samples.

3.3.3.1 Presence of sufficient volume mature source rock

The presence of an effective source rock is evaluated on the basis of source rock analysis, discoveries in the area and from oil/source rock correlation. The number of data points and the distance from the mapped structure to relevant data points are critical factors. A model describing the depositional environment of the source rock is necessary in order to predict its lateral extension and possible organic facies changes.

The presence of sufficient volume of mature source rock is evaluated using maturity maps that also include potential drainage areas. A simulation of the source rock maturity is necessary, and commercial basin modelling programs should be employed for such simulations.

Quality/effectiveness of the source rock
- kerogen type (I, II, III or IV)
- TOC-content
- Transformation of organic matter to oil and/or gas
- Lateral variations, distance to data points

Maturity of source rock
- "overcooked"
- gas window
- transition gas/oil window
- peak oil window
- marginal mature/onset of oil window

Volume of mature source rock within drainage area
- more than sufficient volume
- marginal volume
- inadequate volume

This probability factor is evaluated by considering the following three factors;

- the probability of adequate **quality and effectiveness** of the predicted source rock with respect to hydrocarbon generation,
- the probability of the presence of **mature** source rock within the drainage area of the prospect
- the probability of the presence of sufficient **volume** mature source rock within the drainage area

Figure 3.14 shows how quality, maturity and volume of source rock can be taken into consideration. Even though most of these parameters can be measured in the laboratory, there remains much uncertainty related to these measurements. Samples are in most cases from wells and/or geological outcrops at a given distance from the source area under consideration for our prospect. An assessment of data relevance and quality are therefore crucial factors in the risk assessment of source rock properties.

Data reliability / Depositional environment		Restricted marine or lacustrine environment with conc sapropelic organic matter	Mixed marine or lacustrine environment with dispersed sapropelic organic matter	Deltaic environment with mostly humic organic matter (terrestrial; mainly gas)
Proven source rock	Sufficient volume	0.9 - 1.0	0.8 - 1.0	0.8 - 1.0
	Marginal volume	0.5 - 0.8	0.4 - 0.7	0.4 - 0.7
	Marginal mature	0.3 - 0.6	0.2 - 0.5	0.2 - 0.5
Quality reduced source rock	Sufficient volume	0.7 - 0.9	0.6 - 0.8	0.6 - 0.8
	Marginal volume	0.4 - 0.6	0.3 - 0.6	0.3 - 0.6
	Marginal mature	0.2 - 0.5	0.1 - 0.4	0.1 - 0.4
Hypothetical source rock	Sufficient volume	0.5 - 0.8	0.4 - 0.7	0.4 - 0.7
	Marginal volume	0.3 - 0.7	0.3 - 0.6	0.3 - 0.6
	Marginal mature	0.1 - 0.4	0.1 - 0.4	0.1 - 0.4
Speculative source rock	Sufficient volume	0.4 - 0.7	0.3 - 0.7	0.3 - 0.7
	Marginal volume	0.2 - 0.6	0.2 - 0.5	0.2 - 0.5
	Marginal mature	0.1 - 0.4	0.1 - 0.3	0.1 - 0.3

Fig. 3.14 Probability scheme. The probability of effective source rock with respect to volume and maturity.

During risk assessment of potential source rocks, we must be aware that we perform risking on the basis of average values and not extremes. When we estimate the probability of sufficient volume mature source rock in the drainage area, we must also evaluate uncertainties in the definition and mapping of the drainage area. Large uncertainties in the mapping can have both positive and negative consequences for the anticipated hydrocarbon charge.

3.3.3.2 Effective migration

A critical factor that we must consider carefully is the relationship between the timing of migration and of trap formation. Here we must evaluate the probability of the trap being formed in due time to allow the accumulation of migrated hydrocarbons. We must assume that the trap is effective in terms of its sealing properties (with respect to both faults and cap rocks). It must be assumed that the trap has existed continuously from time of its

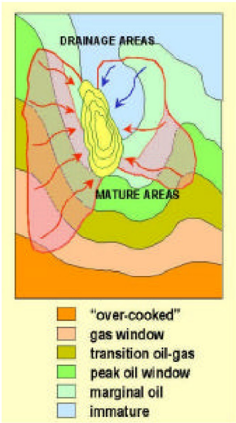


Fig. 3.15 Example of a maturity map with drainage areas and migration paths.

formation (i.e. P1 = 1.0 and P2b = 1.0). If seismic data alone does not provide an adequate basis to determine the time of trap formation, backstripping may be a useful approach.

It is important to note that evaluation of the petroleum charge system ends at the point in time of hydrocarbon accumulation in the sealed trap. This ensures that we avoid double risking of the probability factor related to retention after accumulation, P4.

Timing / Migration	The trap is formed before onset of hydrocarbon migration	Time of trap formation and time of migration are overlapping	The trap is formed when the source rock is supposed to be "overcooked"
Local migration	0.9 - 1.0	0.4 - 0.8	0.1 - 0.4
Lateral migration without barriers	0.8 - 0.9	0.4 - 0.7	0.1 - 0.3
Lateral migration with barriers	0.5 - 0.8	0.2 - 0.5	0.1 - 0.3
Vertical migration without barriers	0.7 - 0.9	0.3 - 0.6	0.1 - 0.3
Vertical migration with barriers	0.4 - 0.6	0.2 - 0.4	0.1 - 0.2
Long-distance "fill-spill" migration	0.4 - 0.6	0.2 - 0.4	0.1 - 0.2
The trap is in the "shadow" of migration	0.2 - 0.4	0.1 - 0.3	0.1

Fig. 3.16 Probability scheme. The probability of effective migration and timing.

Under normal pressure regimes hydrocarbons migrate upwards, and the migration mechanism can therefore be evaluated from maps (preferably depth maps) on which the direction of migration along the top of the carrier formation is perpendicular to the depth contours (fig. 3.15). Ideally, we should use paleomaps for this purpose, but such maps are not available in most cases. Migration may also occur along permeable fault zones and vertically by pressure equalisation. When evaluating potential migration mechanisms, we must also consider structural complexity, the dip of potential carrier formations, their lithologies, and the seal integrity at the upper surface of the carrier bed along the migration route. In general, gas exhibits a greater tendency than oil to exploit vertical migration routes (fig. 3.16).

Even in cases where we anticipate that the prognosed source rock is "overcooked" at the present day, we cannot eliminate the possibility that the trap is filled. Later tectonic movements may have caused the spillage of hydrocarbons from other traps into the trap under consideration ("fill-spill"). Uncertainties related to the possible presence of another source rock and our modelling must also be taken into consideration.

3.3.4 Retention after accumulation

The probability of effective retention of hydrocarbons in the prospect after accumulation, **P4**, is evaluated given the assumption that the sealed trap was filled with hydrocarbons at a given point in time. In order to evaluate this factor, we shall examine the course of events from the time of hydrocarbon accumulation to the present day.

We must assume that the caprocks at the time of accumulation had adequate sealing capacity to hold the minimum hydrocarbon column, and that all faults that delineate the trap are sealing. These factors have already been analysed as part of the risk evaluation of the trapping mechanism (P2).

Geological processes after accumulation / Data control		Positive unambiguous data (seismic, wells, etc.)	Data control and interpretation is poor to fair	Negative unambiguous data (seismic, wells, etc.)
No late activity	No tectonic activity after accumulation	0.9 - 1.0	0.8 - 1.0	0.7 - 1.0
	Shallow traps, possible biodegradation	0.8 - 0.9	0.4 - 0.7	0.1 - 0.3
Erosion	Trap in connection to generating source	0.7 - 0.9	0.3 - 0.6	0.1 - 0.3
	Trap not connected to generating source	0.5 - 0.8	0.2 - 0.5	0.1 - 0.2
Uplift and tilting	Form, volume, top-point not changed	0.7 - 0.9	0.4 - 0.7	0.2 - 0.4
	Form, volume, top-point changed	0.5 - 0.6	0.3 - 0.4	0.1 - 0.2
Reactivated faults	Compression and/or transpression	0.5 - 0.7	0.4 - 0.5	0.3 - 0.4
	Tension	0.4 - 0.6	0.3 - 0.4	0.1 - 0.3

Fig. 3.17 Probability scheme. The probability of effective retention.

CAUTION

In order to avoid "double-risking", we have to distinguish carefully between which factors affect the sealing mechanism and which affect retention after accumulation.

In considering the probability of effective retention, we must evaluate potential fault reactivation, regional uplift (and subsequent erosion), together with tectonic and/or isostatic tilting of the trap after accumulation. The guidelines are given in fig. 3.17.

A reconstruction of the post-accumulation history of the trap is an important factor in determining the hydrocarbon column and the anticipated hydrocarbon phase (oil or gas) in the prospect. It is therefore desirable to establish this history at an early stage in the risk assessment process, especially if post-accumulation events are anticipated to have had a significant influence on the prospect under evaluation.

Local or regional factors may significantly influence the assignment of this factor (i.e. fracturing of the cap rock, limited overburden). The pressure tolerance of the cap rock with respect to relative pressure differences between the cap rock and the reservoir rock may also be an important factor.

3.3.5 Hydrocarbon indicators

Certain anomalies identified on seismic reflection data can be caused by hydrocarbon-filled reservoirs. It may be useful to investigate such anomalies if we have reason to believe that they may provide direct evidence for the presence of hydrocarbons in our prospect. However, seismic anomalies may have many causes, both geological and geophysical, and some of the latter may be the result purely of acquisition and processing methods. A direct hydrocarbon indicator (DHI) on seismic data may be defined as follows:

> *A direct hydrocarbon indicator (DHI) is defined as a change in seismic reflection character (seismic anomaly) which is the direct result of the reservoir's fluid content changing from water to hydrocarbons.*

Depending on the cause of the seismic anomaly, it may be characterised as **real** or **false** in terms of its being a direct indicator of hydrocarbons (DHI). An anomaly resulting from an artefact caused by geophysical acquisition or processing is by definition a false DHI, while an anomaly resulting from geological causes may be either real or false.

Seismic anomalies should always be evaluated carefully with respect to their repeatability on adjacent 2D profiles. Various detailed studies of amplitude (e.g., amplitude versus offset, AVO) and phase may be useful in reducing uncertainty associated with seismic anomalies. We must also investigate whether the anomaly defines a trap, and whether other geological or geophysical causes other than the presence of hydrocarbons can explain the anomaly.

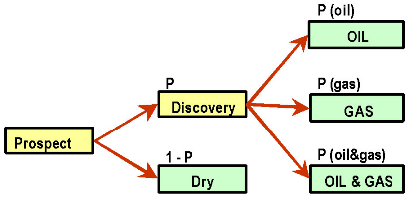
If we believe during the prospect interpretation and mapping process that we have identified a reliable hydrocarbon indicator, we may use information from the phenomenon as a basis for definition of some or all of the prospect parameters (rock volume, reservoir thickness, hydrocarbon column and phase, etc.). When performing the geological risk analysis, the DHI will be an important factor when considering the probability of effective trap (P2) and petroleum charge (P3).

Oil seepage, pockmarks at sea-bottom, gas anomalies in seismic data etc., are all indicators of hydrocarbons being present. Thus, this will skew the probability of having petroleum in the system towards the higher end. On the contrary, the probability of retention will be skewed towards the lower end.

3.3.6 Probabilities of oil or gas

When using modern prospect evaluation tools, such as GeoX, the proportion of oil and gas in our prospect is usually one of the input parameters in the volumetric calculation. However, in some cases we wish to evaluate different cases (oil-case, gas-case or a combination case). In these situations we must assess the risk associated with each case. In order to perform a correct risk assessment it is useful to draw up a "decision tree" as illustrated on the following page.

For any given prospect, the four possible outcomes (dry, oil, gas, oil & gas) are independent. The sum of their probabilities of occurrence is therefore equal to 1.0.



We will use an example of a prospect with a probability of discovery of 0.4. If, given discovery, there is 40% chance for oil, 30% for gas and 30% for oil and gas in combination, we can calculate the probability of any one of these events by multiplying by the probability of discovery. The result will be; P(oil) = 0.16, P(gas) = 0.12, P(oil&gas) = 0.12 and P(dry) = 0.60.

APPENDIX C

CASH FLOW TABLE EXPLANATION

Table C.1 The cash flow table explanation.

A	B	C	D	E	F	G	H	I	J	K
YEAR	GAS PRODUCTION		GAS PRICE	GROSS SALE INCOME	ROYALTY SLIDING SCALE	INVESTMENT COST / CAPITAL EXPRESS (CAPEX)				
						CONCESSION	SEISMICSURVEYS 2D	SEISMICSURVEYS 3D	DRILLING	
									INTANGIBLE	TANGIBLE
	MMcf/year	MMcf/day	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2011	0.00	0.00	6.00	0.00	0.00	0.50	3.00		0.00	0.00
2012	0.00	0.00		0.00	0.00			1.00	16.00	4.00
2013	0.00	0.00		0.00	0.00				16.00	4.00
2014	0.00	0.00		0.00	0.00				64.00	16.00
2015	36,500.00	100.00		219.00	27.38					
2016	36,500.00	100.00		219.00	27.38					
2017	36,500.00	100.00		219.00	27.38					
2018	36,500.00	100.00		219.00	27.38					
2019	36,500.00	100.00		219.00	27.38					
2020	36,500.00	100.00		219.00	27.38					
2021	33,658.48	92.22		201.95	20.20					
2022	28,473.65	78.01		170.84	17.08					
2023	24,188.55	66.27		145.13	14.51					
2024	20,629.80	56.52		123.78	12.38					
2025	17,660.53	48.39		105.96	6.62					
2026	15,173.05	41.57		91.04	5.69					
2027	13,081.60	35.84		78.49	4.91					
2028	11,315.00	31.00		67.89	4.24					
2029	9,816.68	26.90		58.90	3.68					
2030	8,542.83	23.41		51.26	3.20					
2031	7,456.95	20.43		44.74	2.80					
2032	6,528.03	17.89		39.17	1.96					
2033	5,728.68	15.70		34.37	1.72					
2034	5,038.83	13.81		30.23	1.51					
TOTAL	426,292.63			2,557.76	264.75	0.50	3.00	1.00	96.00	24.00

Table C.1 The cash flow table explanation (Cont.).

L	M	N	O	P									Q	R	S	T
		OPERATING EXPENSES	TOTAL	DEPRICIATION ; DEPLETION ; AMORTIZATION (20%) TANGIBLE EXPENSES (MMUS$)									WRITE	TOTAL	TAXABLE	INCOME
PIPELINE	FACILITY	(OPEX)	COST										OFF	ALLOW EXPENSE	INCOME	TAX (50%)
MMUS$	MMUS$	MMUS$	MMUS$	2011	2012	2013	2014	2015	2016	2017	2018	2019	MMUS$	MMUS$	MMUS$	MMUS$
		0.00	3.50	0.00									3.50	3.50	-3.50	0.00
		0.00	21.00		0.80								17.00	17.80	-17.80	0.00
4.00		0.00	24.00			2.40							16.00	18.40	-18.40	0.00
3.00	140.00	0.00	223.00				34.20						64.00	98.20	-98.20	0.00
		39.51	39.51					34.20					66.88	101.08	117.92	0.00
		40.30	40.30						34.20				67.67	101.87	117.13	48.57
		41.10	41.10							33.40			68.48	101.88	117.12	58.56
		41.93	41.93								31.80		69.30	101.10	117.90	58.95
		42.77	42.77									0.00	70.14	70.14	148.86	74.43
		43.62	43.62										71.00	71.00	148.00	74.00
		41.03	41.03										61.22	61.22	140.73	70.36
		35.40	35.40										52.49	52.49	118.35	59.18
		30.68	30.68										45.19	45.19	99.94	49.97
		26.69	26.69										39.06	39.06	84.71	42.36
		23.30	23.30										29.93	29.93	76.04	38.02
		20.42	20.42										26.11	26.11	64.93	32.46
		17.96	17.96										22.86	22.86	55.63	27.81
		15.84	15.84										20.09	20.09	47.80	23.90
		14.02	14.02										17.70	17.70	41.20	20.60
		12.45	12.45										15.65	15.65	35.61	17.80
		11.08	11.08										13.88	13.88	30.86	15.43
		9.89	9.89										11.85	11.85	27.32	13.66
		8.86	8.86										10.58	10.58	23.80	11.90
		7.95	7.95										9.46	9.46	20.78	10.39
7.00	140.00	524.79	796.29										890.04	1061.04	1,496.71	748.36

Table C.1 The cash flow table explanation (Cont.).

U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF
YEAR	GAS PRODUCTION		CASH FLOW SUMMARY						DISCOUNTED FACTOR	NET VALUE NPV@10%	CUMULATIVE NET PRESENT VALUE NPV@10%
			GROSS REVENUE SALE INCOME	CAPEX	OPEX	GOVERNMENT TAKE		NET CASH FLOW			
						ROYALTY	INC. TAX				
	MMcf/year	MMcf/day	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	10.00	MMUS$	MMUS$
2011	0.00	0.00	0.00	3.50	0.00	0.00	0.00	-3.50	1.0000	-3.50	-3.50
2012	0.00	0.00	0.00	21.42	0.00	0.00	0.00	-21.42	0.9091	-19.47	-22.97
2013	0.00	0.00	0.00	24.97	0.00	0.00	0.00	-24.97	0.8264	-20.64	-43.61
2014	0.00	0.00	0.00	236.65	0.00	0.00	0.00	-236.65	0.7513	-177.80	-221.41
2015	36,500.00	100.00	219.00	0.00	39.51	27.38	0.00	152.12	0.6830	103.90	-117.51
2016	36,500.00	100.00	219.00	0.00	40.30	27.38	48.57	102.75	0.6209	63.80	-53.71
2017	36,500.00	100.00	219.00	0.00	41.10	27.38	58.56	91.96	0.5645	51.91	-1.80
2018	36,500.00	100.00	219.00	0.00	41.93	27.38	58.95	90.75	0.5132	46.57	44.77
2019	36,500.00	100.00	219.00	0.00	42.77	27.38	74.43	74.43	0.4665	34.72	79.49
2020	36,500.00	100.00	219.00	0.00	43.62	27.38	74.00	74.00	0.4241	31.38	110.88
2021	33,658.48	92.22	201.95	0.00	41.03	20.20	70.36	70.36	0.3855	27.13	138.00
2022	28,473.65	78.01	170.84	0.00	35.40	17.08	59.18	59.18	0.3505	20.74	158.75
2023	24,188.55	66.27	145.13	0.00	30.68	14.51	49.97	49.97	0.3186	15.92	174.67
2024	20,629.80	56.52	123.78	0.00	26.69	12.38	42.36	42.36	0.2897	12.27	186.94
2025	17,660.53	48.39	105.96	0.00	23.30	6.62	38.02	38.02	0.2633	10.01	196.95
2026	15,173.05	41.57	91.04	0.00	20.42	5.69	32.46	32.46	0.2394	7.77	204.72
2027	13,081.60	35.84	78.49	0.00	17.96	4.91	27.81	27.81	0.2176	6.05	210.77
2028	11,315.00	31.00	67.89	0.00	15.84	4.24	23.90	23.90	0.1978	4.73	215.50
2029	9,816.68	26.90	58.90	0.00	14.02	3.68	20.60	20.60	0.1799	3.70	219.21
2030	8,542.83	23.41	51.26	0.00	12.45	3.20	17.80	17.80	0.1635	2.91	222.12
2031	7,456.95	20.43	44.74	0.00	11.08	2.80	15.43	15.43	0.1486	2.29	224.41
2032	6,528.03	17.89	39.17	0.00	9.89	1.96	13.66	13.66	0.1351	1.85	226.26
2033	5,728.68	15.70	34.37	0.00	8.86	1.72	11.90	11.90	0.1228	1.46	227.72
2034	5,038.83	13.81	30.23	0.00	7.95	1.51	10.39	10.39	0.1117	1.16	228.88
TOTAL	426,292.63		2,557.76	286.54	524.79	264.75	748.36	733.32		228.88	

IRR	30.75%	DIRR	18.86%
PIR	2.56	DPIR	0.80

APPENDIX D

CASH FLOW TABLE ANALYSIS

Table D.1 Economic analysis for petroleum resource size 122.433 Bcf and gas price 3.00 US$/MMBTU.

YEAR	GAS PRODUCTION		GAS PRICE	GROSS SALE INCOME	ROYALTY SLIDING SCALE	INVESTMENT COST / CAPITAL EXPRESS (CAPEX)				
						CONCESSION	SEISMICSURVEYS 2D	SEISMICSURVEYS 3D	DRILLING	
									INTANGIBLE	TANGIBLE
	MMcf/year	MMcf/day	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2011	0.00	0.00	3.000	0.00	0.00	0.50	3.00		0.00	0.00
2012	0.00	0.00		0.00	0.00			1.00	16.00	4.00
2013	0.00	0.00		0.00	0.00				16.00	4.00
2014	0.00	0.00		0.00	0.00				64.00	16.00
2015	36,500.00	100.00		109.50	13.69					
2016	29,504.78	80.84		88.51	8.85					
2017	18,430.68	50.50		55.29	5.53					
2018	11,884.40	32.56		35.65	2.23					
2019	7,878.53	21.59		23.64	1.48					
2020	5,352.73	14.67		16.06	0.80					
TOTAL	109,551.10			328.65	32.58	0.50	3.00	1.00	96.00	24.00

Table D.1 Economic analysis for petroleum resource size 122.433 Bcf and gas price 3.00 US$/MMBTU (Cont.).

PIPELINE	FACILITY	OPERATING EXPENSES (OPEX)	TOTAL COST	DEPRICIATION ; DEPLETION ; AMORTIZATION (20%) TANGIBLE EXPENSES (MM US$)									WRITE OFF	TOTAL ALLOW EXPENSE	TAXABLE INCOME	INCOME TAX (50%)
MMUS$	MMUS$	MMUS$	MMUS$	2011	2012	2013	2014	2015	2016	2017	2018	2019	MMUS$	MMUS$	MMUS$	MMUS$
		0.00	3.50	0.00									3.50	3.50	-3.50	0.00
		0.00	21.00		0.80								17.00	17.80	-17.80	0.00
4.00		0.00	24.00			2.40							16.00	18.40	-18.40	0.00
3.00	140.00	0.00	223.00				34.20						64.00	98.20	-98.20	0.00
		39.51	39.51					34.20					53.20	87.40	22.10	0.00
		32.58	32.58						34.20				41.43	75.63	12.89	0.00
		20.76	20.76							33.40			26.29	59.69	-4.39	0.00
		13.65	13.65								31.80		15.88	47.68	-12.03	0.00
		9.23	9.23									0.00	10.71	10.71	12.93	0.00
		6.40	6.40										7.20	7.20	8.86	0.00
7.00	140.00	122.12	393.62										255.20	426.20	-97.54	0.00

Table D.1 Economic analysis for petroleum resource size 122.433 Bcf and gas price 3.00 US$/MMBTU (Cont.).

YEAR	GAS PRODUCTION		CASH FLOW SUMMARY						DISCOUNTED FACTOR	NET VALUE NPV@10%	CUMULATIVE NET PRESENT VALUE NPV@10%
			GROSS REVENUE SALE INCOME	CAPEX	OPEX	GOVERNMENT TAKE		ANNUAL CASH FLOW			
						ROYALTY	INC. TAX				
	MMcf/year	MMcf/day	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	10.00	MMUS$	MMUS$
2011	0.00	0.00	0.00	3.50	0.00	0.00	0.00	-3.50	1.0000	-3.50	-3.50
2012	0.00	0.00	0.00	21.42	0.00	0.00	0.00	-21.42	0.9091	-19.47	-22.97
2013	0.00	0.00	0.00	24.97	0.00	0.00	0.00	-24.97	0.8264	-20.64	-43.61
2014	0.00	0.00	0.00	236.65	0.00	0.00	0.00	-236.65	0.7513	-177.80	-221.41
2015	36,500.00	100.00	109.50	0.00	39.51	13.69	0.00	56.30	0.6830	38.46	-182.95
2016	29,504.78	80.84	88.51	0.00	32.58	8.85	0.00	47.09	0.6209	29.24	-153.71
2017	18,430.68	50.50	55.29	0.00	20.76	5.53	0.00	29.01	0.5645	16.37	-137.34
2018	11,884.40	32.56	35.65	0.00	13.65	2.23	0.00	19.77	0.5132	10.15	-127.19
2019	7,878.53	21.59	23.64	0.00	9.23	1.48	0.00	12.93	0.4665	6.03	-121.16
2020	5,352.73	14.67	16.06	0.00	6.40	0.80	0.00	8.86	0.4241	3.76	-117.41
TOTAL	109,551.10		328.65	286.54	122.12	32.58	0.00	-112.58		-117.41	

IRR	#DIV/0!	DIRR	#DIV/0!
PIR	-0.39	DPIR	-0.41

Table D.2 Economic analysis for petroleum resource size 122.433 Bcf and gas price 5.822 US$/MMBTU.

YEAR	GAS PRODUCTION		GAS PRICE	GROSS SALE INCOME	ROYALTY SLIDING SCALE	INVESTMENT COST / CAPITAL EXPRESS (CAPEX)				
						CONCESSION	SEISMICSURVEYS 2D	SEISMICSURVEYS 3D	DRILLING	
									INTANGIBLE	TANGIBLE
	MMcf/year	MMcf/day	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2011	0.00	0.00	5.822	0.00	0.00	0.50	3.00		0.00	0.00
2012	0.00	0.00		0.00	0.00			1.00	16.00	4.00
2013	0.00	0.00		0.00	0.00				16.00	4.00
2014	0.00	0.00		0.00	0.00				64.00	16.00
2015	36,500.00	100.00		212.50	26.56					
2016	29,504.78	80.84		171.78	17.18					
2017	18,430.68	50.50		107.30	10.73					
2018	11,884.40	32.56		69.19	4.32					
2019	7,878.53	21.59		45.87	2.87					
2020	5,352.73	14.67		31.16	1.56					
TOTAL	109,551.10			637.81	63.22	0.50	3.00	1.00	96.00	24.00

Table D.2 Economic analysis for petroleum resource size 122.433 Bcf and gas price 5.822 US$/MMBTU (Cont.).

PIPELINE	FACILITY	OPERATING EXPENSES (OPEX)	TOTAL COST	DEPRICIATION ; DEPLETION ; AMORTIZATION (20%) TANGIBLE EXPENSES (MM US$)									WRITE OFF	TOTAL ALLOW EXPENSE	TAXABLE INCOME	INCOME TAX (50%)
MMUS$	MMUS$	MMUS$	MMUS$	2011	2012	2013	2014	2015	2016	2017	2018	2019	MMUS$	MMUS$	MMUS$	MMUS$
		0.00	3.50	0.00									3.50	3.50	-3.50	0.00
		0.00	21.00		0.80								17.00	17.80	-17.80	0.00
4.00		0.00	24.00			2.40							16.00	18.40	-18.40	0.00
3.00	140.00	0.00	223.00				34.20						64.00	98.20	-98.20	0.00
		39.51	39.51					34.20					66.07	100.27	112.23	0.00
		32.58	32.58						34.20				49.75	83.95	87.82	31.08
		20.76	20.76							33.40			31.49	64.89	42.42	21.21
		13.65	13.65								31.80		17.98	49.78	19.42	9.71
		9.23	9.23									0.00	12.10	12.10	33.77	16.89
		6.40	6.40										7.96	7.96	23.21	11.60
7.00	140.00	122.12	393.62										285.84	456.84	180.97	90.48

Table D.2 Economic analysis for petroleum resource size 122.433 Bcf and gas price 5.822 US$/MMBTU (Cont.).

YEAR	GAS PRODUCTION		CASH FLOW SUMMARY						DISCOUNTED FACTOR	NET VALUE NPV@10%	CUMULATIVE NET PRESENT VALUE NPV@10%
			GROSS REVENUE SALE INCOME	CAPEX	OPEX	GOVERNMENT TAKE		ANNUAL CASH FLOW			
						ROYALTY	INC. TAX				
	MMcf/year	MMcf/day	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	10.00	MMUS$	MMUS$
2011	0.00	0.00	0.00	3.50	0.00	0.00	0.00	-3.50	1.0000	-3.50	-3.50
2012	0.00	0.00	0.00	21.42	0.00	0.00	0.00	-21.42	0.9091	-19.47	-22.97
2013	0.00	0.00	0.00	24.97	0.00	0.00	0.00	-24.97	0.8264	-20.64	-43.61
2014	0.00	0.00	0.00	236.65	0.00	0.00	0.00	-236.65	0.7513	-177.80	-221.41
2015	36,500.00	100.00	212.50	0.00	39.51	26.56	0.00	146.43	0.6830	100.01	-121.39
2016	29,504.78	80.84	171.78	0.00	32.58	17.18	31.08	90.95	0.6209	56.47	-64.92
2017	18,430.68	50.50	107.30	0.00	20.76	10.73	21.21	54.61	0.5645	30.83	-34.10
2018	11,884.40	32.56	69.19	0.00	13.65	4.32	9.71	41.51	0.5132	21.30	-12.80
2019	7,878.53	21.59	45.87	0.00	9.23	2.87	16.89	16.89	0.4665	7.88	-4.92
2020	5,352.73	14.67	31.16	0.00	6.40	1.56	11.60	11.60	0.4241	4.92	0.00
TOTAL	109,551.10		637.81	286.54	122.12	63.22	90.48	75.44		0.00	

IRR	10.00%	DIRR	0.00%
PIR	0.26	DPIR	0.00

Table D.3 Economic analysis for petroleum resource size 122.433 Bcf and gas price 6.00 US$/MMBTU.

YEAR	GAS PRODUCTION		GAS PRICE	GROSS SALE INCOME	ROYALTY SLIDING SCALE	INVESTMENT COST / CAPITAL EXPRESS (CAPEX)				
						CONCESSION	SEISMICSURVEYS 2D	SEISMICSURVEYS 3D	DRILLING	
									INTANGIBLE	TANGIBLE
	MMcf/year	MMcf/day	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2011	0.00	0.00	6.000	0.00	0.00	0.50	3.00		0.00	0.00
2012	0.00	0.00		0.00	0.00			1.00	16.00	4.00
2013	0.00	0.00		0.00	0.00				16.00	4.00
2014	0.00	0.00		0.00	0.00				64.00	16.00
2015	36,500.00	100.00		219.00	27.38					
2016	29,504.78	80.84		177.03	17.70					
2017	18,430.68	50.50		110.58	11.06					
2018	11,884.40	32.56		71.31	4.46					
2019	7,878.53	21.59		47.27	2.95					
2020	5,352.73	14.67		32.12	1.61					
TOTAL	109,551.10			657.31	65.15	0.50	3.00	1.00	96.00	24.00

Table D.3 Economic analysis for petroleum resource size 122.433 Bcf and gas price 6.00 US$/MMBTU (Cont.).

		OPERATING EXPENSES	TOTAL	DEPRICIATION ; DEPLETION ; AMORTIZATION (20%) TANGIBLE EXPENSES (MM US$)									WRITE	TOTAL	TAXABLE	INCOME
PIPELINE	FACILITY	(OPEX)	COST										OFF	ALLOW EXPENSE	INCOME	TAX (50%)
MMUS$	MMUS$	MMUS$	MMUS$	2011	2012	2013	2014	2015	2016	2017	2018	2019	MMUS$	MMUS$	MMUS$	MMUS$
		0.00	3.50	0.00									3.50	3.50	-3.50	0.00
		0.00	21.00		0.80								17.00	17.80	-17.80	0.00
4.00		0.00	24.00			2.40							16.00	18.40	-18.40	0.00
3.00	140.00	0.00	223.00				34.20						64.00	98.20	-98.20	0.00
		39.51	39.51					34.20					66.88	101.08	117.92	0.00
		32.58	32.58						34.20				50.28	84.48	92.55	36.28
		20.76	20.76							33.40			31.81	65.21	45.37	22.68
		13.65	13.65								31.80		18.11	49.91	21.40	10.70
		9.23	9.23									0.00	12.19	12.19	35.09	17.54
		6.40	6.40										8.00	8.00	24.11	12.06
7.00	140.00	122.12	393.62										287.77	458.77	198.53	99.27

Table D.3 Economic analysis for petroleum resource size 122.433 Bcf and gas price 6.00 US$/MMBTU (Cont.).

YEAR	GAS PRODUCTION		CASH FLOW SUMMARY						DISCOUNTED FACTOR	NET VALUE NPV@10%	CUMULATIVE NET PRESENT VALUE NPV@10%
			GROSS REVENUE SALE INCOME	CAPEX	OPEX	GOVERNMENT TAKE		ANNUAL CASH FLOW			
						ROYALTY	INC. TAX				
	MMcf/year	MMcf/day	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	10.00	MMUS$	MMUS$
2011	0.00	0.00	0.00	3.50	0.00	0.00	0.00	-3.50	1.0000	-3.50	-3.50
2012	0.00	0.00	0.00	21.42	0.00	0.00	0.00	-21.42	0.9091	-19.47	-22.97
2013	0.00	0.00	0.00	24.97	0.00	0.00	0.00	-24.97	0.8264	-20.64	-43.61
2014	0.00	0.00	0.00	236.65	0.00	0.00	0.00	-236.65	0.7513	-177.80	-221.41
2015	36,500.00	100.00	219.00	0.00	39.51	27.38	0.00	152.12	0.6830	103.90	-117.51
2016	29,504.78	80.84	177.03	0.00	32.58	17.70	36.28	90.47	0.6209	56.17	-61.34
2017	18,430.68	50.50	110.58	0.00	20.76	11.06	22.68	56.08	0.5645	31.66	-29.68
2018	11,884.40	32.56	71.31	0.00	13.65	4.46	10.70	42.50	0.5132	21.81	-7.87
2019	7,878.53	21.59	47.27	0.00	9.23	2.95	17.54	17.54	0.4665	8.18	0.31
2020	5,352.73	14.67	32.12	0.00	6.40	1.61	12.06	12.06	0.4241	5.11	5.43
TOTAL	109,551.10		657.31	286.54	122.12	65.15	99.27	84.23		5.43	

IRR	**11.12%**	DIRR	**1.02%**
PIR	**0.29**	DPIR	**0.02**

Table D.4 Economic analysis for petroleum resource size 122.433 Bcf and gas price 9.00 US$/MMBTU.

YEAR	GAS PRODUCTION		GAS PRICE	GROSS SALE INCOME	ROYALTY SLIDING SCALE	INVESTMENT COST / CAPITAL EXPRESS (CAPEX)				
						CONCESSION	SEISMICSURVEYS 2D	SEISMICSURVEYS 3D	DRILLING	
									INTANGIBLE	TANGIBLE
	MMcf/year	MMcf/day	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2011	0.00	0.00	9.000	0.00	0.00	0.50	3.00		0.00	0.00
2012	0.00	0.00		0.00	0.00			1.00	16.00	4.00
2013	0.00	0.00		0.00	0.00				16.00	4.00
2014	0.00	0.00		0.00	0.00				64.00	16.00
2015	36,500.00	100.00		328.50	41.06					
2016	29,504.78	80.84		265.54	26.55					
2017	18,430.68	50.50		165.88	16.59					
2018	11,884.40	32.56		106.96	6.68					
2019	7,878.53	21.59		70.91	4.43					
2020	5,352.73	14.67		48.17	2.41					
TOTAL	109,551.10			985.96	97.73	0.50	3.00	1.00	96.00	24.00

Table D.4 Economic analysis for petroleum resource size 122.433 Bcf and gas price 9.00 US$/MMBTU (Cont.).

PIPELINE	FACILITY	OPERATING EXPENSES (OPEX)	TOTAL COST	DEPRICIATION ; DEPLETION ; AMORTIZATION (20%) TANGIBLE EXPENSES (MM US$)									WRITE OFF	TOTAL ALLOW EXPENSE	TAXABLE INCOME	INCOME TAX (50%)
MMUS$	MMUS$	MMUS$	MMUS$	2011	2012	2013	2014	2015	2016	2017	2018	2019	MMUS$	MMUS$	MMUS$	MMUS$
		0.00	3.50	0.00									3.50	3.50	-3.50	0.00
		0.00	21.00		0.80								17.00	17.80	-17.80	0.00
4.00		0.00	24.00			2.40							16.00	18.40	-18.40	0.00
3.00	140.00	0.00	223.00				34.20						64.00	98.20	-98.20	0.00
		39.51	39.51					34.20					80.57	114.77	213.73	37.91
		32.58	32.58						34.20				59.13	93.33	172.21	86.11
		20.76	20.76							33.40			37.34	70.74	95.13	47.57
		13.65	13.65								31.80		20.34	52.14	54.82	27.41
		9.23	9.23									0.00	13.66	13.66	57.24	28.62
		6.40	6.40										8.81	8.81	39.37	19.68
7.00	140.00	122.12	393.62										320.35	491.35	494.61	247.31

Table D.4 Economic analysis for petroleum resource size 122.433 Bcf and gas price 9.00 US$/MMBTU (Cont.).

YEAR	GAS PRODUCTION		CASH FLOW SUMMARY						DISCOUNTED FACTOR	NET VALUE NPV@10%	CUMULATIVE NET PRESENT VALUE NPV@10%
			GROSS REVENUE SALE INCOME	CAPEX	OPEX	GOVERNMENT TAKE		ANNUAL CASH FLOW			
						ROYALTY	INC. TAX				
	MMcf/year	MMcf/day	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	10.00	MMUS$	MMUS$
2011	0.00	0.00	0.00	3.50	0.00	0.00	0.00	-3.50	1.0000	-3.50	-3.50
2012	0.00	0.00	0.00	21.42	0.00	0.00	0.00	-21.42	0.9091	-19.47	-22.97
2013	0.00	0.00	0.00	24.97	0.00	0.00	0.00	-24.97	0.8264	-20.64	-43.61
2014	0.00	0.00	0.00	236.65	0.00	0.00	0.00	-236.65	0.7513	-177.80	-221.41
2015	36,500.00	100.00	328.50	0.00	39.51	41.06	37.91	210.01	0.6830	143.44	-77.96
2016	29,504.78	80.84	265.54	0.00	32.58	26.55	86.11	120.31	0.6209	74.70	-3.26
2017	18,430.68	50.50	165.88	0.00	20.76	16.59	47.57	80.97	0.5645	45.70	42.44
2018	11,884.40	32.56	106.96	0.00	13.65	6.68	27.41	59.21	0.5132	30.38	72.82
2019	7,878.53	21.59	70.91	0.00	9.23	4.43	28.62	28.62	0.4665	13.35	86.18
2020	5,352.73	14.67	48.17	0.00	6.40	2.41	19.68	19.68	0.4241	8.35	94.53
TOTAL	109,551.10		985.96	286.54	122.12	97.73	247.31	232.27		94.53	

IRR	27.99%	DIRR	16.35%
PIR	0.81	DPIR	0.33

Table D.5 Economic analysis for petroleum resource size 470.444 Bcf and gas price 3.00 US$/MMBTU.

YEAR	GAS PRODUCTION		GAS PRICE	GROSS SALE INCOME	ROYALTY SLIDING SCALE	INVESTMENT COST / CAPITAL EXPRESS (CAPEX)				
						CONCESSION	SEISMICSURVEYS 2D	SEISMICSURVEYS 3D	DRILLING	
									INTANGIBLE	TANGIBLE
	MMcf/year	MMcf/day	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2011	0.00	0.00	3.00	0.00	0.00	0.50	3.00		0.00	0.00
2012	0.00	0.00		0.00	0.00			1.00	16.00	4.00
2013	0.00	0.00		0.00	0.00				16.00	4.00
2014	0.00	0.00		0.00	0.00				64.00	16.00
2015	36,500.00	100.00		109.50	13.69					
2016	36,500.00	100.00		109.50	13.69					
2017	36,500.00	100.00		109.50	13.69					
2018	36,500.00	100.00		109.50	13.69					
2019	36,500.00	100.00		109.50	13.69					
2020	36,500.00	100.00		109.50	13.69					
2021	33,658.48	92.22		100.98	10.10					
2022	28,473.65	78.01		85.42	8.54					
2023	24,188.55	66.27		72.57	7.26					
2024	20,629.80	56.52		61.89	6.19					
2025	17,660.53	48.39		52.98	3.31					
2026	15,173.05	41.57		45.52	2.84					
2027	13,081.60	35.84		39.24	2.45					
2028	11,315.00	31.00		33.95	2.12					
2029	9,816.68	26.90		29.45	1.84					
2030	8,542.83	23.41		25.63	1.60					
2031	7,456.95	20.43		22.37	1.40					
2032	6,528.03	17.89		19.58	0.98					
2033	5,728.68	15.70		17.19	0.86					
2034	5,038.83	13.81		15.12	0.76					
TOTAL	426,292.63			1,278.88	132.38	0.50	3.00	1.00	96.00	24.00

Table D.5 Economic analysis for petroleum resource size 470.444 Bcf and gas price 3.00 US$/MMBTU (Cont.).

		OPERATING EXPENSES (OPEX)	TOTAL COST	DEPRICIATION ; DEPLETION ; AMORTIZATION (20%) TANGIBLE EXPENSES (MMUS$)									WRITE OFF	TOTAL ALLOW EXPENSE	TAXABLE INCOME	INCOME TAX (50%)
PIPELINE	FACILITY															
MMUS$	MMUS$	MMUS$	MMUS$	2011	2012	2013	2014	2015	2016	2017	2018	2019	MMUS$	MMUS$	MMUS$	MMUS$
		0.00	3.50	0.00									3.50	3.50	-3.50	0.00
		0.00	21.00		0.80								17.00	17.80	-17.80	0.00
4.00		0.00	24.00			2.40							16.00	18.40	-18.40	0.00
3.00	140.00	0.00	223.00				34.20						64.00	98.20	-98.20	0.00
		39.51	39.51					34.20					53.20	87.40	22.10	0.00
		40.30	40.30						34.20				53.99	88.19	21.31	0.00
		41.10	41.10							33.40			54.79	88.19	21.31	0.00
		41.93	41.93								31.80		55.61	87.41	22.09	0.00
		42.77	42.77									0.00	56.45	56.45	53.05	0.98
		43.62	43.62										57.31	57.31	52.19	26.10
		41.03	41.03										51.13	51.13	49.85	24.92
		35.40	35.40										43.95	43.95	41.48	20.74
		30.68	30.68										37.93	37.93	34.63	17.32
		26.69	26.69										32.88	32.88	29.01	14.51
		23.30	23.30										26.61	26.61	26.37	13.18
		20.42	20.42										23.27	23.27	22.25	11.13
		17.96	17.96										20.41	20.41	18.83	9.42
		15.84	15.84										17.97	17.97	15.98	7.99
		14.02	14.02										15.86	15.86	13.59	6.79
		12.45	12.45										14.05	14.05	11.58	5.79
		11.08	11.08										12.48	12.48	9.89	4.95
		9.89	9.89										10.87	10.87	8.71	4.36
		8.86	8.86										9.72	9.72	7.47	3.74
		7.95	7.95										8.70	8.70	6.41	3.21
7.00	140.00	524.79	796.29										757.67	928.67	350.21	175.11

Table D.5 Economic analysis for petroleum resource size 470.444 Bcf and gas price 3.00 US$/MMBTU (Cont.).

YEAR	GAS PRODUCTION		CASH FLOW SUMMARY						DISCOUNTED FACTOR	NET VALUE NPV@10%	CUMULATIVE NET PRESENT VALUE NPV@10%
			GROSS REVENUE SALE INCOME	CAPEX	OPEX	GOVERNMENT TAKE ROYALTY	GOVERNMENT TAKE INC. TAX	NET CASH FLOW			
	MMcf/year	MMcf/day	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	10.00	MMUS$	MMUS$
2011	0.00	0.00	0.00	3.50	0.00	0.00	0.00	-3.50	1.0000	-3.50	-3.50
2012	0.00	0.00	0.00	21.42	0.00	0.00	0.00	-21.42	0.9091	-19.47	-22.97
2013	0.00	0.00	0.00	24.97	0.00	0.00	0.00	-24.97	0.8264	-20.64	-43.61
2014	0.00	0.00	0.00	236.65	0.00	0.00	0.00	-236.65	0.7513	-177.80	-221.41
2015	36,500.00	100.00	109.50	0.00	39.51	13.69	0.00	56.30	0.6830	38.46	-182.95
2016	36,500.00	100.00	109.50	0.00	40.30	13.69	0.00	55.51	0.6209	34.47	-148.48
2017	36,500.00	100.00	109.50	0.00	41.10	13.69	0.00	54.71	0.5645	30.88	-117.60
2018	36,500.00	100.00	109.50	0.00	41.93	13.69	0.00	53.89	0.5132	27.65	-89.95
2019	36,500.00	100.00	109.50	0.00	42.77	13.69	0.98	52.07	0.4665	24.29	-65.66
2020	36,500.00	100.00	109.50	0.00	43.62	13.69	26.10	26.10	0.4241	11.07	-54.59
2021	33,658.48	92.22	100.98	0.00	41.03	10.10	24.92	24.92	0.3855	9.61	-44.98
2022	28,473.65	78.01	85.42	0.00	35.40	8.54	20.74	20.74	0.3505	7.27	-37.71
2023	24,188.55	66.27	72.57	0.00	30.68	7.26	17.32	17.32	0.3186	5.52	-32.20
2024	20,629.80	56.52	61.89	0.00	26.69	6.19	14.51	14.51	0.2897	4.20	-27.99
2025	17,660.53	48.39	52.98	0.00	23.30	3.31	13.18	13.18	0.2633	3.47	-24.52
2026	15,173.05	41.57	45.52	0.00	20.42	2.84	11.13	11.13	0.2394	2.66	-21.86
2027	13,081.60	35.84	39.24	0.00	17.96	2.45	9.42	9.42	0.2176	2.05	-19.81
2028	11,315.00	31.00	33.95	0.00	15.84	2.12	7.99	7.99	0.1978	1.58	-18.23
2029	9,816.68	26.90	29.45	0.00	14.02	1.84	6.79	6.79	0.1799	1.22	-17.01
2030	8,542.83	23.41	25.63	0.00	12.45	1.60	5.79	5.79	0.1635	0.95	-16.06
2031	7,456.95	20.43	22.37	0.00	11.08	1.40	4.95	4.95	0.1486	0.74	-15.32
2032	6,528.03	17.89	19.58	0.00	9.89	0.98	4.36	4.36	0.1351	0.59	-14.74
2033	5,728.68	15.70	17.19	0.00	8.86	0.86	3.74	3.74	0.1228	0.46	-14.28
2034	5,038.83	13.81	15.12	0.00	7.95	0.76	3.21	3.21	0.1117	0.36	-13.92
TOTAL	426,292.63		1,278.88	286.54	524.79	132.38	175.11	160.07		-13.92	

IRR	8.51%	DIRR	-1.35%
PIR	0.56	DPIR	-0.05

Table D.6 Economic analysis for petroleum resource size 470.444 Bcf and gas price 3.16 US$/MMBTU.

YEAR	GAS PRODUCTION		GAS PRICE	GROSS SALE INCOME	ROYALTY SLIDING SCALE	INVESTMENT COST / CAPITAL EXPRESS (CAPEX)				
						CONCESSION	SEISMICSURVEYS 2D	SEISMICSURVEYS 3D	DRILLING	
									INTANGIBLE	TANGIBLE
	MMcf/year	MMcf/day	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2011	0.00	0.00	3.16	0.00	0.00	0.50	3.00		0.00	0.00
2012	0.00	0.00		0.00	0.00			1.00	16.00	4.00
2013	0.00	0.00		0.00	0.00				16.00	4.00
2014	0.00	0.00		0.00	0.00				64.00	16.00
2015	36,500.00	100.00		115.39	14.42					
2016	36,500.00	100.00		115.39	14.42					
2017	36,500.00	100.00		115.39	14.42					
2018	36,500.00	100.00		115.39	14.42					
2019	36,500.00	100.00		115.39	14.42					
2020	36,500.00	100.00		115.39	14.42					
2021	33,658.48	92.22		106.41	10.64					
2022	28,473.65	78.01		90.02	9.00					
2023	24,188.55	66.27		76.47	7.65					
2024	20,629.80	56.52		65.22	6.52					
2025	17,660.53	48.39		55.83	3.49					
2026	15,173.05	41.57		47.97	3.00					
2027	13,081.60	35.84		41.36	2.58					
2028	11,315.00	31.00		35.77	2.24					
2029	9,816.68	26.90		31.03	1.94					
2030	8,542.83	23.41		27.01	1.69					
2031	7,456.95	20.43		23.57	1.47					
2032	6,528.03	17.89		20.64	1.03					
2033	5,728.68	15.70		18.11	0.91					
2034	5,038.83	13.81		15.93	0.80					
TOTAL	426,292.63			1,347.66	139.50	0.50	3.00	1.00	96.00	24.00

Table D.6 Economic analysis for petroleum resource size 470.444 Bcf and gas price 3.16 US$/MMBTU (Cont.).

		OPERATING EXPENSES (OPEX)	TOTAL COST	DEPRICIATION ; DEPLETION ; AMORTIZATION (20%) TANGIBLE EXPENSES (MMUS$)									WRITE OFF	TOTAL ALLOW EXPENSE	TAXABLE INCOME	INCOME TAX (50%)
PIPELINE	FACILITY															
MMUS$	MMUS$	MMUS$	MMUS$	2011	2012	2013	2014	2015	2016	2017	2018	2019	MMUS$	MMUS$	MMUS$	MMUS$
		0.00	3.50	0.00									3.50	3.50	-3.50	0.00
		0.00	21.00		0.80								17.00	17.80	-17.80	0.00
4.00		0.00	24.00			2.40							16.00	18.40	-18.40	0.00
3.00	140.00	0.00	223.00				34.20						64.00	98.20	-98.20	0.00
		39.51	39.51					34.20					53.93	88.13	27.26	0.00
		40.30	40.30						34.20				54.72	88.92	26.47	0.00
		41.10	41.10							33.40			55.53	88.93	26.46	0.00
		41.93	41.93								31.80		56.35	88.15	27.24	0.00
		42.77	42.77									0.00	57.19	57.19	58.20	13.86
		43.62	43.62										58.04	58.04	57.34	28.67
		41.03	41.03										51.67	51.67	54.74	27.37
		35.40	35.40										44.40	44.40	45.61	22.81
		30.68	30.68										38.32	38.32	38.14	19.07
		26.69	26.69										33.21	33.21	32.01	16.00
		23.30	23.30										26.79	26.79	29.04	14.52
		20.42	20.42										23.42	23.42	24.55	12.27
		17.96	17.96										20.54	20.54	20.81	10.41
		15.84	15.84										18.08	18.08	17.69	8.85
		14.02	14.02										15.96	15.96	15.07	7.54
		12.45	12.45										14.13	14.13	12.87	6.44
		11.08	11.08										12.55	12.55	11.02	5.51
		9.89	9.89										10.93	10.93	9.71	4.86
		8.86	8.86										9.76	9.76	8.35	4.17
		7.95	7.95										8.74	8.74	7.19	3.59
7.00	140.00	524.79	796.29										764.79	935.79	411.87	205.94

Table D.6 Economic analysis for petroleum resource size 470.444 Bcf and gas price 3.16 US$/MMBTU (Cont.).

YEAR	GAS PRODUCTION		CASH FLOW SUMMARY						DISCOUNTED FACTOR	NET VALUE NPV@10%	CUMULATIVE NET PRESENT VALUE NPV@10%
			GROSS REVENUE SALE INCOME	CAPEX	OPEX	GOVERNMENT TAKE		NET CASH FLOW			
						ROYALTY	INC. TAX				
	MMcf/year	MMcf/day	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	10.00	MMUS$	MMUS$
2011	0.00	0.00	0.00	3.50	0.00	0.00	0.00	-3.50	1.0000	-3.50	-3.50
2012	0.00	0.00	0.00	21.42	0.00	0.00	0.00	-21.42	0.9091	-19.47	-22.97
2013	0.00	0.00	0.00	24.97	0.00	0.00	0.00	-24.97	0.8264	-20.64	-43.61
2014	0.00	0.00	0.00	236.65	0.00	0.00	0.00	-236.65	0.7513	-177.80	-221.41
2015	36,500.00	100.00	115.39	0.00	39.51	14.42	0.00	61.46	0.6830	41.98	-179.43
2016	36,500.00	100.00	115.39	0.00	40.30	14.42	0.00	60.67	0.6209	37.67	-141.76
2017	36,500.00	100.00	115.39	0.00	41.10	14.42	0.00	59.86	0.5645	33.79	-107.97
2018	36,500.00	100.00	115.39	0.00	41.93	14.42	0.00	59.04	0.5132	30.30	-77.68
2019	36,500.00	100.00	115.39	0.00	42.77	14.42	13.86	44.34	0.4665	20.68	-56.99
2020	36,500.00	100.00	115.39	0.00	43.62	14.42	28.67	28.67	0.4241	12.16	-44.83
2021	33,658.48	92.22	106.41	0.00	41.03	10.64	27.37	27.37	0.3855	10.55	-34.28
2022	28,473.65	78.01	90.02	0.00	35.40	9.00	22.81	22.81	0.3505	7.99	-26.29
2023	24,188.55	66.27	76.47	0.00	30.68	7.65	19.07	19.07	0.3186	6.08	-20.21
2024	20,629.80	56.52	65.22	0.00	26.69	6.52	16.00	16.00	0.2897	4.64	-15.57
2025	17,660.53	48.39	55.83	0.00	23.30	3.49	14.52	14.52	0.2633	3.82	-11.75
2026	15,173.05	41.57	47.97	0.00	20.42	3.00	12.27	12.27	0.2394	2.94	-8.81
2027	13,081.60	35.84	41.36	0.00	17.96	2.58	10.41	10.41	0.2176	2.26	-6.55
2028	11,315.00	31.00	35.77	0.00	15.84	2.24	8.85	8.85	0.1978	1.75	-4.80
2029	9,816.68	26.90	31.03	0.00	14.02	1.94	7.54	7.54	0.1799	1.36	-3.44
2030	8,542.83	23.41	27.01	0.00	12.45	1.69	6.44	6.44	0.1635	1.05	-2.39
2031	7,456.95	20.43	23.57	0.00	11.08	1.47	5.51	5.51	0.1486	0.82	-1.57
2032	6,528.03	17.89	20.64	0.00	9.89	1.03	4.86	4.86	0.1351	0.66	-0.91
2033	5,728.68	15.70	18.11	0.00	8.86	0.91	4.17	4.17	0.1228	0.51	-0.40
2034	5,038.83	13.81	15.93	0.00	7.95	0.80	3.59	3.59	0.1117	0.40	0.00
TOTAL	426,292.63		1,347.66	286.54	524.79	139.50	205.94	190.90		0.00	

IRR	10.00%	DIRR	0.00%
PIR	0.67	DPIR	0.00

Table D.7 Economic analysis for petroleum resource size 470.444 Bcf and gas price 6.00 US$/MMBTU.

YEAR	GAS PRODUCTION		GAS PRICE	GROSS SALE INCOME	ROYALTY SLIDING SCALE	INVESTMENT COST / CAPITAL EXPRESS (CAPEX)				
						CONCESSION	SEISMICSURVEYS 2D	SEISMICSURVEYS 3D	DRILLING	
									INTANGIBLE	TANGIBLE
	MMcf/year	MMcf/day	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2011	0.00	0.00	6.00	0.00	0.00	0.50	3.00		0.00	0.00
2012	0.00	0.00		0.00	0.00			1.00	16.00	4.00
2013	0.00	0.00		0.00	0.00				16.00	4.00
2014	0.00	0.00		0.00	0.00				64.00	16.00
2015	36,500.00	100.00		219.00	27.38					
2016	36,500.00	100.00		219.00	27.38					
2017	36,500.00	100.00		219.00	27.38					
2018	36,500.00	100.00		219.00	27.38					
2019	36,500.00	100.00		219.00	27.38					
2020	36,500.00	100.00		219.00	27.38					
2021	33,658.48	92.22		201.95	20.20					
2022	28,473.65	78.01		170.84	17.08					
2023	24,188.55	66.27		145.13	14.51					
2024	20,629.80	56.52		123.78	12.38					
2025	17,660.53	48.39		105.96	6.62					
2026	15,173.05	41.57		91.04	5.69					
2027	13,081.60	35.84		78.49	4.91					
2028	11,315.00	31.00		67.89	4.24					
2029	9,816.68	26.90		58.90	3.68					
2030	8,542.83	23.41		51.26	3.20					
2031	7,456.95	20.43		44.74	2.80					
2032	6,528.03	17.89		39.17	1.96					
2033	5,728.68	15.70		34.37	1.72					
2034	5,038.83	13.81		30.23	1.51					
TOTAL	426,292.63			2,557.76	264.75	0.50	3.00	1.00	96.00	24.00

Table D.7 Economic analysis for petroleum resource size 470.444 Bcf and gas price 6.00 US$/MMBTU (Cont.).

PIPELINE	FACILITY	OPERATING EXPENSES (OPEX)	TOTAL COST	DEPRICIATION ; DEPLETION ; AMORTIZATION (20%) TANGIBLE EXPENSES (MMUS$)									WRITE OFF	TOTAL ALLOW EXPENSE	TAXABLE INCOME	INCOME TAX (50%)
MMUS$	MMUS$	MMUS$	MMUS$	2011	2012	2013	2014	2015	2016	2017	2018	2019	MMUS$	MMUS$	MMUS$	MMUS$
		0.00	3.50	0.00									3.50	3.50	-3.50	0.00
		0.00	21.00		0.80								17.00	17.80	-17.80	0.00
4.00		0.00	24.00			2.40							16.00	18.40	-18.40	0.00
3.00	140.00	0.00	223.00				34.20						64.00	98.20	-98.20	0.00
		39.51	39.51					34.20					66.88	101.08	117.92	0.00
		40.30	40.30						34.20				67.67	101.87	117.13	48.57
		41.10	41.10							33.40			68.48	101.88	117.12	58.56
		41.93	41.93								31.80		69.30	101.10	117.90	58.95
		42.77	42.77									0.00	70.14	70.14	148.86	74.43
		43.62	43.62										71.00	71.00	148.00	74.00
		41.03	41.03										61.22	61.22	140.73	70.36
		35.40	35.40										52.49	52.49	118.35	59.18
		30.68	30.68										45.19	45.19	99.94	49.97
		26.69	26.69										39.06	39.06	84.71	42.36
		23.30	23.30										29.93	29.93	76.04	38.02
		20.42	20.42										26.11	26.11	64.93	32.46
		17.96	17.96										22.86	22.86	55.63	27.81
		15.84	15.84										20.09	20.09	47.80	23.90
		14.02	14.02										17.70	17.70	41.20	20.60
		12.45	12.45										15.65	15.65	35.61	17.80
		11.08	11.08										13.88	13.88	30.86	15.43
		9.89	9.89										11.85	11.85	27.32	13.66
		8.86	8.86										10.58	10.58	23.80	11.90
		7.95	7.95										9.46	9.46	20.78	10.39
7.00	140.00	524.79	796.29										890.04	1061.04	1,496.71	748.36

Table D.7 Economic analysis for petroleum resource size 470.444 Bcf and gas price 6.00 US$/MMBTU (Cont.).

YEAR	GAS PRODUCTION		CASH FLOW SUMMARY						DISCOUNTED FACTOR	NET VALUE NPV@10%	CUMULATIVE NET PRESENT VALUE NPV@10%
			GROSS REVENUE SALE INCOME	CAPEX	OPEX	GOVERNMENT TAKE		NET CASH FLOW			
						ROYALTY	INC. TAX				
	MMcf/year	MMcf/day	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	10.00	MMUS$	MMUS$
2011	0.00	0.00	0.00	3.50	0.00	0.00	0.00	-3.50	1.0000	-3.50	-3.50
2012	0.00	0.00	0.00	21.42	0.00	0.00	0.00	-21.42	0.9091	-19.47	-22.97
2013	0.00	0.00	0.00	24.97	0.00	0.00	0.00	-24.97	0.8264	-20.64	-43.61
2014	0.00	0.00	0.00	236.65	0.00	0.00	0.00	-236.65	0.7513	-177.80	-221.41
2015	36,500.00	100.00	219.00	0.00	39.51	27.38	0.00	152.12	0.6830	103.90	-117.51
2016	36,500.00	100.00	219.00	0.00	40.30	27.38	48.57	102.75	0.6209	63.80	-53.71
2017	36,500.00	100.00	219.00	0.00	41.10	27.38	58.56	91.96	0.5645	51.91	-1.80
2018	36,500.00	100.00	219.00	0.00	41.93	27.38	58.95	90.75	0.5132	46.57	44.77
2019	36,500.00	100.00	219.00	0.00	42.77	27.38	74.43	74.43	0.4665	34.72	79.49
2020	36,500.00	100.00	219.00	0.00	43.62	27.38	74.00	74.00	0.4241	31.38	110.88
2021	33,658.48	92.22	201.95	0.00	41.03	20.20	70.36	70.36	0.3855	27.13	138.00
2022	28,473.65	78.01	170.84	0.00	35.40	17.08	59.18	59.18	0.3505	20.74	158.75
2023	24,188.55	66.27	145.13	0.00	30.68	14.51	49.97	49.97	0.3186	15.92	174.67
2024	20,629.80	56.52	123.78	0.00	26.69	12.38	42.36	42.36	0.2897	12.27	186.94
2025	17,660.53	48.39	105.96	0.00	23.30	6.62	38.02	38.02	0.2633	10.01	196.95
2026	15,173.05	41.57	91.04	0.00	20.42	5.69	32.46	32.46	0.2394	7.77	204.72
2027	13,081.60	35.84	78.49	0.00	17.96	4.91	27.81	27.81	0.2176	6.05	210.77
2028	11,315.00	31.00	67.89	0.00	15.84	4.24	23.90	23.90	0.1978	4.73	215.50
2029	9,816.68	26.90	58.90	0.00	14.02	3.68	20.60	20.60	0.1799	3.70	219.21
2030	8,542.83	23.41	51.26	0.00	12.45	3.20	17.80	17.80	0.1635	2.91	222.12
2031	7,456.95	20.43	44.74	0.00	11.08	2.80	15.43	15.43	0.1486	2.29	224.41
2032	6,528.03	17.89	39.17	0.00	9.89	1.96	13.66	13.66	0.1351	1.85	226.26
2033	5,728.68	15.70	34.37	0.00	8.86	1.72	11.90	11.90	0.1228	1.46	227.72
2034	5,038.83	13.81	30.23	0.00	7.95	1.51	10.39	10.39	0.1117	1.16	228.88
TOTAL	426,292.63		2,557.76	286.54	524.79	264.75	748.36	733.32		228.88	

IRR	**30.75%**	DIRR	**18.86%**
PIR	**2.56**	DPIR	**0.80**

Table D.8 Economic analysis for petroleum resource size 470.444 Bcf and gas price 9.00 US$/MMBTU.

YEAR	GAS PRODUCTION		GAS PRICE	GROSS SALE INCOME	ROYALTY SLIDING SCALE	INVESTMENT COST / CAPITAL EXPRESS (CAPEX)				
						CONCESSION	SEISMICSURVEYS 2D	SEISMICSURVEYS 3D	DRILLING	
									INTANGIBLE	TANGIBLE
	MMcf/year	MMcf/day	US$/MMBTU	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$
2011	0.00	0.00	9.00	0.00	0.00	0.50	3.00		0.00	0.00
2012	0.00	0.00		0.00	0.00			1.00	16.00	4.00
2013	0.00	0.00		0.00	0.00				16.00	4.00
2014	0.00	0.00		0.00	0.00				64.00	16.00
2015	36,500.00	100.00		328.50	41.06					
2016	36,500.00	100.00		328.50	41.06					
2017	36,500.00	100.00		328.50	41.06					
2018	36,500.00	100.00		328.50	41.06					
2019	36,500.00	100.00		328.50	41.06					
2020	36,500.00	100.00		328.50	41.06					
2021	33,658.48	92.22		302.93	30.29					
2022	28,473.65	78.01		256.26	25.63					
2023	24,188.55	66.27		217.70	21.77					
2024	20,629.80	56.52		185.67	18.57					
2025	17,660.53	48.39		158.94	9.93					
2026	15,173.05	41.57		136.56	8.53					
2027	13,081.60	35.84		117.73	7.36					
2028	11,315.00	31.00		101.84	6.36					
2029	9,816.68	26.90		88.35	5.52					
2030	8,542.83	23.41		76.89	4.81					
2031	7,456.95	20.43		67.11	4.19					
2032	6,528.03	17.89		58.75	2.94					
2033	5,728.68	15.70		51.56	2.58					
2034	5,038.83	13.81		45.35	2.27					
TOTAL	426,292.63			3,836.63	397.13	0.50	3.00	1.00	96.00	24.00

Table D.8 Economic analysis for petroleum resource size 470.444 Bcf and gas price 9.00 US$/MMBTU (Cont.).

PIPELINE	FACILITY	OPERATING EXPENSES (OPEX)	TOTAL COST	DEPRICIATION ; DEPLETION ; AMORTIZATION (20%) TANGIBLE EXPENSES (MMUS$)									WRITE OFF	TOTAL ALLOW EXPENSE	TAXABLE INCOME	INCOME TAX (50%)
MMUS$	MMUS$	MMUS$	MMUS$	2011	2012	2013	2014	2015	2016	2017	2018	2019	MMUS$	MMUS$	MMUS$	MMUS$
		0.00	3.50	0.00									3.50	3.50	-3.50	0.00
		0.00	21.00		0.80								17.00	17.80	-17.80	0.00
4.00		0.00	24.00			2.40							16.00	18.40	-18.40	0.00
3.00	140.00	0.00	223.00				34.20						64.00	98.20	-98.20	0.00
		39.51	39.51					34.20					80.57	114.77	213.73	37.91
		40.30	40.30						34.20				81.36	115.56	212.94	106.47
		41.10	41.10							33.40			82.17	115.57	212.93	106.47
		41.93	41.93								31.80		82.99	114.79	213.71	106.86
		42.77	42.77									0.00	83.83	83.83	244.67	122.34
		43.62	43.62										84.68	84.68	243.82	121.91
		41.03	41.03										71.32	71.32	231.60	115.80
		35.40	35.40										61.03	61.03	195.23	97.62
		30.68	30.68										52.45	52.45	165.25	82.63
		26.69	26.69										45.25	45.25	140.41	70.21
		23.30	23.30										33.24	33.24	125.71	62.85
		20.42	20.42										28.96	28.96	107.60	53.80
		17.96	17.96										25.32	25.32	92.42	46.21
		15.84	15.84										22.21	22.21	79.63	39.81
		14.02	14.02										19.54	19.54	68.81	34.40
		12.45	12.45										17.25	17.25	59.63	29.82
		11.08	11.08										15.28	15.28	51.84	25.92
		9.89	9.89										12.83	12.83	45.92	22.96
		8.86	8.86										11.43	11.43	40.12	20.06
		7.95	7.95										10.21	10.21	35.14	17.57
7.00	140.00	524.79	796.29										1022.42	1193.42	2,643.22	1,321.61

Table D.8 Economic analysis for petroleum resource size 470.444 Bcf and gas price 9.00 US$/MMBTU (Cont.).

YEAR	GAS PRODUCTION		CASH FLOW SUMMARY						DISCOUNTED FACTOR	NET VALUE NPV@10%	CUMULATIVE NET PRESENT VALUE NPV@10%
			GROSS REVENUE SALE INCOME	CAPEX	OPEX	GOVERNMENT TAKE		NET CASH FLOW			
						ROYALTY	INC. TAX				
	MMcf/year	MMcf/day	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	MMUS$	10.00	MMUS$	MMUS$
2011	0.00	0.00	0.00	3.50	0.00	0.00	0.00	-3.50	1.0000	-3.50	-3.50
2012	0.00	0.00	0.00	21.42	0.00	0.00	0.00	-21.42	0.9091	-19.47	-22.97
2013	0.00	0.00	0.00	24.97	0.00	0.00	0.00	-24.97	0.8264	-20.64	-43.61
2014	0.00	0.00	0.00	236.65	0.00	0.00	0.00	-236.65	0.7513	-177.80	-221.41
2015	36,500.00	100.00	328.50	0.00	39.51	41.06	37.91	210.01	0.6830	143.44	-77.96
2016	36,500.00	100.00	328.50	0.00	40.30	41.06	106.47	140.67	0.6209	87.34	9.38
2017	36,500.00	100.00	328.50	0.00	41.10	41.06	106.47	139.87	0.5645	78.95	88.33
2018	36,500.00	100.00	328.50	0.00	41.93	41.06	106.86	138.66	0.5132	71.15	159.48
2019	36,500.00	100.00	328.50	0.00	42.77	41.06	122.34	122.34	0.4665	57.07	216.55
2020	36,500.00	100.00	328.50	0.00	43.62	41.06	121.91	121.91	0.4241	51.70	268.25
2021	33,658.48	92.22	302.93	0.00	41.03	30.29	115.80	115.80	0.3855	44.65	312.90
2022	28,473.65	78.01	256.26	0.00	35.40	25.63	97.62	97.62	0.3505	34.21	347.12
2023	24,188.55	66.27	217.70	0.00	30.68	21.77	82.63	82.63	0.3186	26.33	373.44
2024	20,629.80	56.52	185.67	0.00	26.69	18.57	70.21	70.21	0.2897	20.34	393.78
2025	17,660.53	48.39	158.94	0.00	23.30	9.93	62.85	62.85	0.2633	16.55	410.33
2026	15,173.05	41.57	136.56	0.00	20.42	8.53	53.80	53.80	0.2394	12.88	423.21
2027	13,081.60	35.84	117.73	0.00	17.96	7.36	46.21	46.21	0.2176	10.06	433.27
2028	11,315.00	31.00	101.84	0.00	15.84	6.36	39.81	39.81	0.1978	7.88	441.14
2029	9,816.68	26.90	88.35	0.00	14.02	5.52	34.40	34.40	0.1799	6.19	447.33
2030	8,542.83	23.41	76.89	0.00	12.45	4.81	29.82	29.82	0.1635	4.88	452.21
2031	7,456.95	20.43	67.11	0.00	11.08	4.19	25.92	25.92	0.1486	3.85	456.06
2032	6,528.03	17.89	58.75	0.00	9.89	2.94	22.96	22.96	0.1351	3.10	459.16
2033	5,728.68	15.70	51.56	0.00	8.86	2.58	20.06	20.06	0.1228	2.46	461.63
2034	5,038.83	13.81	45.35	0.00	7.95	2.27	17.57	17.57	0.1117	1.96	463.59
TOTAL	426,292.63		3,836.63	286.54	524.79	397.13	1,321.61	1,306.57		463.59	

IRR	46.91%	DIRR	33.55%
PIR	4.56	DPIR	1.62

BIOGRAPHY

Mr. Sakchai Glumglomjit was born on October 1, 1979 in Prachuapkhirikhan province, Thailand. He received his Bachelor's Degree in Engineering (Geotechnology) from Suranaree University of Technology (SUT) in 2002. After graduation, he has been employed under the position of geologist by the office of Groundwater Exploration and Evaluation, Department of Ground Water Resources, Ministry of Natural Resources and Environment. From 2004 to 2006, he has been employed under the position of geologist by O.P. Exploration & Drilling Ltd., Part, Thailand. From 2006 to 2010, he studied for his Master's Degree of Engineering at School of Geotechnology, Institute of Engineering at SUT with the major in Petroleum Engineering. During graduation 2006-2010, he was a part time worker in position of teaching assistant and research assistant at SUT. For his work, he is a good knowledge in petroleum geology and petroleum prospect assessment.