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Petroleum Production Sharing Contracts in the Middle East: Application of Economic Evaluation and Decision-making Modeling

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ABSTRACT

In this Study, the evolution and history of petroleum contracts is discussed with a focus on the recent major shift witnessed from joint operating agreements (JOA) and Concession contracts to production sharing agreements (PSA) due to the increase in the complexity of operations and funding difficulties especially from the government's side. In addition to that, the fiscal system of PSA's is studied as a legal instrument to allocate risk between the parties, identify ownership of assets, commitments and operational control. This study aims to figure out the application of economic evaluation for PSA's using discounted cash flow analysis (DCF) which is considered to be powerful in evaluating the investment performance by calculating net present value (NPV) of cash flows and the internal rate of return (IRR). The estimated production profile submitted in the PSA of interest was exaggerated. When a Monte-Carlo simulation was run the riskier profile (P10) was the closest to the PSA production forecast. However, in such agreements usually the mid case scenario (P50) is taken into consideration. The NPV for the first 10 years in this project is around $0.45 Billion compared to the total NPV calculated using the economic model $1.26 Billion. However, the recent instability of the oil price in the last 10 years what causes this project in particular not to meet the target so far. The IRR calculated for the 10 years period is almost the hurdle rate 10% and this is again due to the unexpected NPV due to the oil price. To reduce the uncertainty, pilot projects needs to be conducted in the 1st year in smaller spacing to allow for the response to be detected faster and then develop a Field Development Plan (FDP).

Keywords: Petroleum Production Sharing Contracts, Economic Evaluation, Decision-making Modeling, Middle East
JEL Classifications: E23, K12, Q4

1. INTRODUCTION AND BACKGROUND

1.1. Oil and Gas Industry Contracts

According to Boykett et al. (2012) petroleum contracts can be divided into four main types; concessions, joint operating agreements (JOA), service contracts and production sharing agreements (PSA). Concession is the old form of petroleum contracts. It is an agreement in which the investor purchase the exclusive right from the state (land owner) to explore and extract natural resources from an agreed prospect. This right is given to the investor for some type of bonus or license fee. Joint operating agreements are contracts where governments and one or more International Oil Companies (IOC's) agree to undertake a task of exploring or extracting oil from a defined prospect. One of the shareholders with the highest shares is considered to be the "operator" taking the responsibility of managing the field on a day-to-day operations. All parties contribute to the overall investment according to their shares in the venture. The case is different for service contracts where the service company is paid a fee for its operation and the total oil production is owned by the state.

Recently and after many oil producing countries getting their independence, a new type of contracts evolved to re-balance the relationship between oil countries and IOC's. Production sharing agreement (PSA) according to Boykett et al. (2012) is considered to be a mix between JOA and Concession type of contracts. IOC's are not given the ownership of the oil in the ground and only given the right to explore and produce oil. When oil was out of ground then the IOC's will get the operation cost in addition to a profit share from the production. PSA's started in Indonesia in 1960 and now it is heavily used in the Middle East and Central Asia.

1.2. Production Sharing Agreements Fiscal Terms

PSA fiscal terms and conditions slightly differ between countries and continents. It should be stable and dynamic at the same time to attract investors to take risks with reasonable economic returns taking into consideration the volatile oil prices in the international market. In the Middle East, PricewaterCoopers (2015) examined most of the PSA's and it turns out that it has similar fiscal terms which is considered to be the baseline of most contracts such as signature bonus, royalty, cost oil, profit oil and income tax. Fiscal terms for petroleum contracts are defined by PricewaterCoopers (2015). Signature bonus is considered to be a payment to the government once the petroleum contract is signed. Royalty is a payment made to the government based on a fixed percentage from the production without taking the cost into consideration. After production from the field starts, the IOC's will receive a share of the production to recover its costs and this is called cost oil. The remaining share of production is divided between the government and the IOC's and it is called profit oil. In addition to all fiscal terms, a tax on the net income generated by the IOC is paid also to the government according to the taxation regime of the country.

1.3. Field Development Plans

In the beginning of an oil field discovery, the geoscientists run excessive amount of studies and analysis to estimate the original oil in place (OOIP) for each reservoir. This will be the basis for all future development to recover the maximum amount of oil from the OOIP. Therefore, the amount of development should not produce more than the available recoverable amount of oil. This can be calculated by two steps, first by calculating the amount of oil expected to be produced and the remaining amount of oil to be produced.

The amount of oil that is expected to be produced by a reservoir is calculated by multiplying the summation of oil production of all base and development well types for all months by 30.4 which is the average number of days per month. The maximum number of wells to be drilled is determined based on the spacing calculations and an interference test to be conducted between wells.

Before signing any type of agreement, a field development plan (FDP) needs to be prepared by the IOC and submitted to the government or the NOC to be evaluated. FDP's considered to be a document which lists all the activities and process will be implemented to develop the reservoirs within a particular field. It takes into consideration the geology, geophysics, petrophysics, reservoir and production engineering elements of a particular field. In addition to that, the recommended infrastructure, facilities, completions and well designs are identified in such document. Reservoir Management is the process of organizing all appropriate technical, operational and business resources to develop reservoirs until abandonment.

FDP's specifies the number of wells going to be drilled, the type of wells (vertical or horizontal), scheduling of the wells, secondary recovery methods to be applied (gas injection or water flooding), reservoir decline and economic limits. Usually different production schemes and designs are provided in such documents to support the decision-making process of the best development scenario during the contract time period. Shows a field development plan for a particular reservoir. In this study a production sharing agreement of one of the fields in the Middle East is used to analyze the feasibility of developing one of the reservoirs.

1.4. Economic Evaluation and Decision-making Modeling for PSA's

Economic evaluation of PSA's depends heavily on the availability and accuracy of the input parameters to the models such as oil field size, decline rates, oil prices, development and operating costs. The field size is determined from geological and geophysical studies. Oil production rates are estimated using classical decline curve analysis in petroleum reservoir engineering. Then, fiscal terms such as cost recovery methods and profit oil split is added to evaluate best, most likely and worst case scenarios. According to Andor et al. (2015), DCF method is widely used when conducting feasibility analysis to PSA's, It anticipates the annual cash flow of a project discounted to present value. Discount rates are estimated from market surveys, petroleum sales analysis and weighted average cost of capital (WACC). DCF analysis is sensitive to model input assumptions and might lead to inaccurate results. To overcome this limitation, deterministic and stochastic models are built and economic system measures are compared.

1.5. The Research Problem

This study presents solutions to overcome the limitations by having deterministic and stochastic approaches combined in one model. This model is important as it is used to estimate possible outcomes with their occurrence probabilities for one of the reservoirs in a particular field in the Middle East. It is reliable when the outcome certainty is low and well defined. However, if poorly defined inputs are used then the model is subject to garbage-in, garbage-out. Deterministic approach is used here as a reference point to compare with the output from the Monte Carlo simulation.

1.6. Research Objectives

The research objectives are to evaluate the application of an economic comprehensive model for petroleum production sharing contracts in the Middle East. This model will analyze the effectiveness of projects applied to specific reservoirs in terms of oil production and increasing the recovery from the reservoir. It will also identify the advantages and weaknesses of such contracts for the international oil companies and the governments.

1.7. The Research Questions

- What is the impact of applying deterministic and stochastic methods when evaluating reservoir production profiles in PSA's?
- How to identify the uncertain parameters and its effect on the overall decision-making process?

2. LITERATURE REVIEW

The main purpose of this chapter is to gather information and critically evaluation of the research findings on aspects related to the research topic and problems from different secondary data sources such as academic books, technical papers and journal articles. Where the information found will demonstrate the limitations to DCF analysis and the solutions to such limitations using deterministic and stochastic models. Also, the importance of applying sensitivity analysis will be discussed especially for uncertain input model parameters such as oil price.

2.1. Discounted Cash Flow Analysis (DCF)

Andor et al. (2015) findings support the appropriateness and common use of DCF methodology to assess whether to start an investment or not. Vikas et al. (1997) examined the decision tree scheme indicated in Figure 1 which represent the decision alternatives to invest or not invest. If the investment is undertaken then there are two possible alternatives: An oil discovery or a dry hole. Expected net present value (ENPV) is calculated at the probabilities (P) of finding oil and drilling a dry hole (1-P). Once a commercial discovery is made, then three different scenarios are investigated (Best, most likely and worst). The research of scientific literature according to Andor et al. (2015), disclosed that DCF analysis is easy to implement and widely used over investment evaluation methodologies. ENPV is calculated using the following equation:

$$ENPV = P\ (PVNCF) – (1\text{-}P)\ (\text{exploration costs}) \quad (1)$$

The present value of net cash flow (PVNCF) is calculated as follows:

$$PVNCF = \sum_{t=0}^{t=n} \frac{NCF(t)}{(1+i)^t} \quad (2)$$

Where (i) is the minimum rate of return and NCF is the after tax net cash flow which is calculated using the following equation:

$$NCF = P(t)\ q(t) – OPEX – CAPEX – GovR(t) \quad (3)$$

Where P(t) is the oil price, q(t) is the oil production rate, OPEX is operating cost, CAPEX is sum of exploration and development cost and GovR(t) is the government revenue which includes the national oil company profit share, royalty and corporate taxes.

After calculating the PVNCF, the internal rate of return (IRR) is determined. It is simply the rate of return that the firm earns of its capital budgeting projects. Once calculated, then it is compared with the required rate of return. If it is greater than the required rate of return then the project is accepted. The same equation for PVNCF is used to calculate IRR but with setting PVNCF equal to zero and solving for (i).

2.1.1. Revenue component

To calculate the revenue part of the NCF equation, two components are required that is the oil price and the amount of oil produced each month.

2.1.2. Oil price forecast

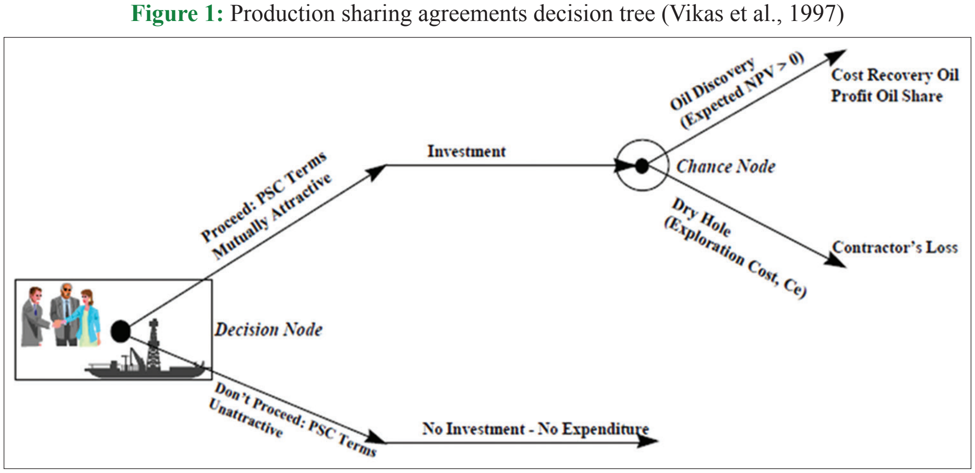
In order to maximize the profit, the oil price is a critical parameter to achieve the goal. Therefore, appropriate oil price forecast model is required. Following researches are found as follow in this respect:

Xie et al. (2006), proposed and built a new method for crude oil forecasting based on support vector machine (SVM) model for time-series forecasting. SVM uses neural network algorithm and based on risk minimization principle. The results of this new method were compared with two existing models (auto-regression integrated moving average and back-propagation neural networks) and found that this model is superior and provides a more accurate oil price forecasting compared to the individual models.

The "Floating Price Model" assumes that the crude prices are inelastic which means that it grows with time regardless the effect of demand. The historical monthly oil price data is plotted as it is shown in Figure 2 and then fitted with a curve. The exponential equation fitting the data is then used to forecast oil prices. Floating Price Model is represented by the equation below:

$$P_o^t = P_o^1 * (1+r)^t \qquad t = 1, 2, \ldots.tt \quad o = 1, 2, \ldots oo \quad (5)$$

Figure 1: Production sharing agreements decision tree (Vikas et al., 1997)



P_o^t - The crude oil price of crude oil at time month (t)
P_o^1 - The crude oil price of crude oil at 1st month
r - Monthly crude oil price growth.

2.1.3. Oil production forecast

Oil production is the other element in calculating the revenue. According to Rahuma et al. (2013), there are different methods used to estimate the oil production forecast and the simplest, most reliable and accurate method for a developed oil field is the decline curve analysis (DCA) using Arps equations (Arps is the developer of the DCA model) developed in 1945.

Obah et al. (2012) use simulation, experimental design (ED) and DCA to build a forecasting model. The model considers all uncertainties in forecasting such as geological, dynamic and operation uncertainties.

Despite the value of these researches, they are not used in this thesis for oil production forecast due to the unavailability of reservoir data, and complexity of implementation. DCA is used in this thesis since it is the bases of most of the studies and researches found on oil production forecast (Figure 3).

Arps equation is applied to define the three decline models and three variables must be known to apply the equations. Those variables are initial production rate (q0), initial exponential decline rate (D) and the degree of curvature or what is known as hyperbolic exponent (b).

Figure 2: Crude oil monthly price – US dollar per barrel

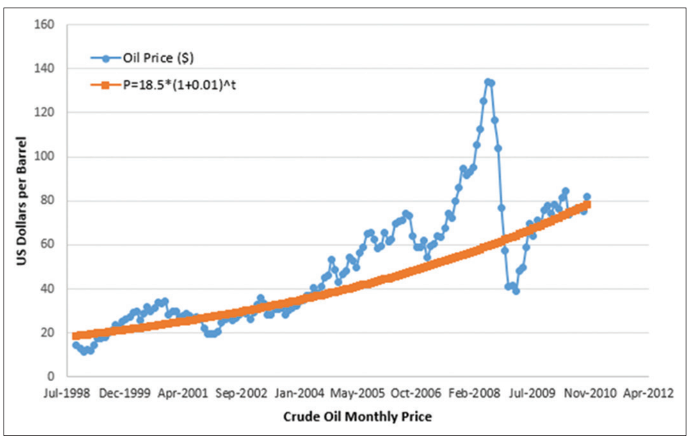
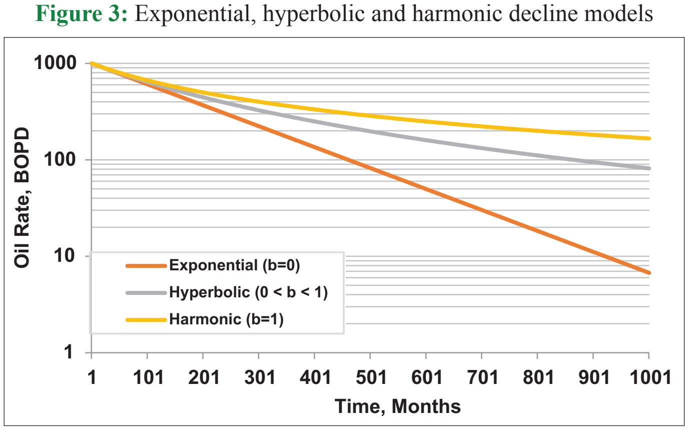


Figure 3: Exponential, hyperbolic and harmonic decline models



2.1.4. Cost component

To calculate the cost part of the objective function, two components are required that is the capital expenditure (CAPEX) and the operating expenditure (OPEX).

2.1.5. Capital expenditure (CAPEX)

CAPEX is a onetime cost paid initially at the time the well is drilled. Capital expenditure consist of three cost components drilling cost, completion cost and site preparation cost and the following is the details on each.

Drilling cost is the cost of drilling a well by a drilling rig and involves the cost of operating the rig equipment, personal, material and chemicals needed and service units. All of these costs gets represented by daily drilling rig rate (RR) which is agreed by a contact between the field development operating company and the rig owner company in case the rig is not owned by the operating company.

Site preparation and hook-up cost is another element of cost spend at the preparation stage prior to drilling the well. It includes the cost of leveling-up the site topography so the drilling rig can rig-up and rig-down safely and constructing the well cellar. In addition to that it involves the cost of constructing necessary road routs that provides a smooth transport of drilling rig and supporting units to the well location. The other part of this cost is the hook-up cost which includes the cost of laying oil and gas lift pipelines from well manifold to the well location. Based on historical cast data, Facility Construction Engineers has an estimated single value that they use as the bases for this cost and it gets reviewed on regular biases. Thus, the well CAPEX is considered to be the sum of the drilling, completion, site preparation and hook up cost. There is a well type cost for each specific well design targeting a specific reservoir.

2.1.6. Operating expenditure (OPEX)

This is usually the cost spent monthly to keep the well operating and reduce the chances of failure and shutting-down the well. This cost highly depends on the well method of operation. For example, beam pump wells costs more than the other methods since it needs generator, and need maintenance more regular than the other types. Therefore, Production Engineers have guideline on the monthly cost based on studying the number of failures and maintenance costs involved with each method of operation.

2.1.7. Deterministic models

The deterministic model is estimated by using equations (2.2) and (2.3) assuming a unique input will lead into a fixed output. Such models are considered to be simple and easy to use. However, it can get very complicated with large number of inputs and outputs. According to Hegar (2015) these models can be used as a first pass to calculate NPV's and IRR's for the best and worst case scenarios of a PSA according to the different assumptions of oil price and input parameters to the reservoir simulation model responsible for providing the oil production forecast. The results from such models considered to be few and high level. However, when uncertainties and assumptions increases it is recommended to use statistical methods to estimate possible outcomes.

The limitation of such models is that it doesn't account for uncertainty. It always assumes that the input parameters are known and therefore the solutions will be unique. Whereas in the oil and gas industry it will be difficult to trust the deterministic models especially when dealing with heterogeneous parameters such as an initial production of a well, annual decline rate, reservoir porosity, reservoir permeability and oil prices. Stochastic models can combine physics, statistics and uncertainty in one trustable framework.

2.1.8. Stochastic models

In order to account for uncertainties in the input parameters and their impact on the economic indicators of a PSA such as NPV and IRR, Mont Carlo Simulation approach is used according to Echendo and Onwuka (2014). Instead of having exact values for the critical input parameters in PSA, probability distributions are generated for every single parameter within a realistic range.

According to Vikas et al. (1997) PSA's critical parameters can be represented by different probability distributions. Oil reserves are usually represented with triangular distributions. It will be skewed to the right when there is higher probability of discovering bigger fields and vice versa. Oil price is also represented with a triangular distribution and if it is expected to drop then the distribution is skewed to the left. Oil production decline rate follows a uniform distribution since only best and worst case estimates are determined from analogs or nearby fields in the region. Cost recovery percentages usually follows a triangular distribution to account for the best, most likely and worst-case scenario based on the history of previous PSA's and the regulations within the country.

2.1.9. Sensitivity analysis and tornado charts

The most likely case is usually used as base case scenario according to Vikas et al. (1997) and sensitivity analysis is run for all input parameters (oil reserves, decline rate, operating cost, development cost, profit oil, cost oil,… etc.) to study the impact of changing such parameters on the overall results (NPV and IRR) and how this change will move the overall results from the most likely case to the best- or worst-case scenarios.

All in all, PSA's needs to be evaluated economically and then decision-making model to be used to select the most profitable scenario with an acceptable risk. Revenues and profitability of the project using PSA's fiscal terms and conditions considered to be the most important results of such feasibility analysis. It shows also how attractive are the fiscal terms for investors. Based on Echendo and Onwuka (2014) results, it is concluded that to minimize uncertainty of input parameters such as oil reserves, more efforts should be done by governments to collect more geophysical and geological data. In addition to that, Tornado Charts are considered a powerful tool to identify the project NPV and IRR sensitivities to key input parameters.

3. RESEARCH METHODOLOGY

In this research, a case study from the Middle East is used. To assess the feasibility of PSA's as studied by Echendo and Onwuka (2014), deterministic and stochastic methods of discounted cash flow analysis are used to evaluate the best, most likely and worse case scenarios which are incorporated into a decision making model.

3.1. Research Design

The research uses both qualitative (reservoir engineering judgment) and quantitative approaches to evaluate the feasibility of a PSA in the Middle East. Sensitivity analysis are used to highlight the most important parameters affecting the final decision making result. In addition to that, the terms and conditions of such agreements are described and explained. The development plan or the depletion plan for one of the reservoirs is studied in this research paper. The proposal of this particular reservoir in the PSA is to have an infill drilling program and a waterflood improved oil recovery development to be implemented during the period of the contract. This recommendation is based on the technical team analysis and results from the reservoir simulation model. In this study, the production profile and well counts from the PSA are analysed. The analysis results in having three possible cases (best, base and worst case scenarios). Total reserves, recovery factor, net present value (NPV) and internal rate of return (IRR) are calculated for each scenario. This will help in identifying where the PSA case falls according to the three different scenarios. All assumptions are listed and then a sensitivity analysis is conducted to determine the major parameters affecting the results. Therefore, more work needs to be done on such parameters to reduce uncertainty. The Deterministic Floating Price Model explained earlier in the literature review is used to forecast oil price. The oil price data for the previous 12 years was used to develop a correlation to forecast oil price in the future.

3.2. Data Types and Sources

The basic source of the research data is the production sharing agreement report for one of the fields in the Middle East. This document has all the numbers and assumptions required to perform the economical evaluation using deterministic and stochastic methods. Inputs from managers involved in this particular production sharing agreement are received by conducting interviews as well. The data types can be divided into two major components.

3.2.1. Revenue component

This section shows the different elements needed to calculate the revenue part of the objective function such as the number of development wells (terminology used for wells drilled in the future), initial production from the new wells followed with the annual decline, number of waterflood patterns and initial production expected from a single pattern followed with the annual decline. The expected production from the development wells in addition to the incremental oil expected from implementing the waterflooding secondary recovery method is multiplied by the oil price to estimate the revenue component. This revenue component takes into account royalties and cost recovery oil as well.

3.2.2. Development wells

This input parameter includes the number of new wells to be drilled scheduled throughout the contract life. Each individual well has a production profile starts with an initial production and an annual decline as it is shown in Figure 4. This production profile is generated using simulation models where all the geologic parameters are included and the history production as well. Although this PSA might consider one production profile for the development well through the life of the PSA, however the reservoir pressure will decline with time and if pressure support is reduced then these rates will be affected and will be reduced as well. According to the PSA, the development of this particular reservoir consists of drilling 150 new wells. The initial oil production is 40 BOPD with annual decline of 12%.

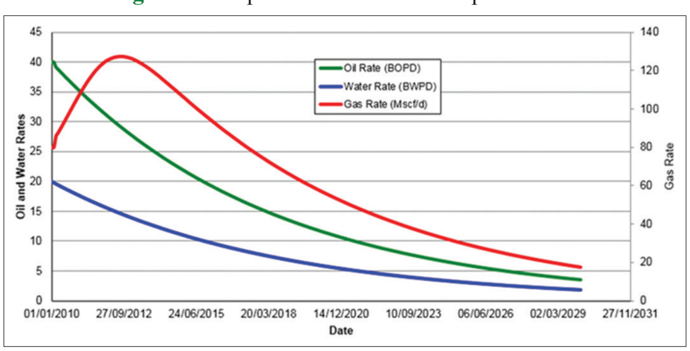
3.2.3. Waterflood patterns

Waterflooding is a secondary recovery process to increase oil production and provide pressure maintenance for the reservoir. According to the PSA, a waterflooding project is going to be implemented by having 57 patterns. A single pattern of waterflood has 4 injectors and one producer. The incremental oil production or response due to waterflooding is usually seen in the producer and in this case it is 90 BOPD with 13% annual decline. The waterflood response of a single pattern is estimated using reservoir simulation model as it is shown in Figure 5.

3.2.4. Development well discount coefficient

This is a coefficient developed based on the total number of wells to be drilled according to the PSA. According to the available well spacing and interference assessment between the wells (reservoir engineering surveillance assessment) this coefficient could have a wide range instead of a single value.

Figure 4: Oil production for a development well



3.2.5. Waterflood patterns discount coefficient

Similar to the well development discount coefficient, another coefficient is developed for the waterflood patterns based on the reservoir engineering assessment and will help generate a range of the possible number of waterflood patterns in this particular reservoir according to the proposed number in the PSA.

3.3. Cost Component

3.3.1. Capital expenditure (CAPEX)

These are the costs to develop an oil or gas well or the elements that are not a part of the final operating well. This includes drilling the well itself, equipment, piping and facilities. The same costs needs to be captured for developing a waterflood pattern. In our case, a well type cost was estimated to be $870,000 and a pattern cost of $500,000.

3.3.2. Operating expenditure (OPEX)

It is an expense a business incurs through its normal business operations. In other words, these are the costs required to produce a barrel of oil. In our case, the operating cost for a newly drilled well is $25/barrel of oil and $10/barrel oil produced as incremental oil due to implementing waterflooding in the reservoir.

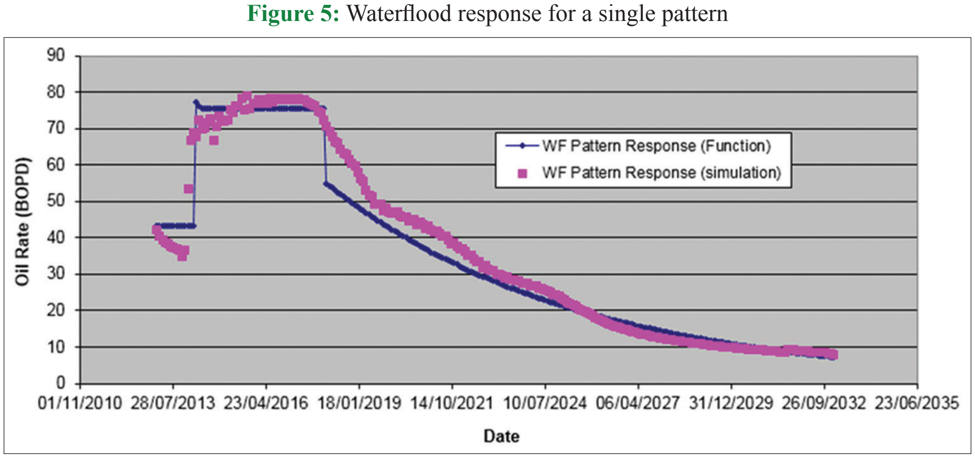
3.4. Data Collection Techniques

The data are collected from the main report and spreadsheets of the Production Sharing Agreement where all the required information is available. Interviews were conducted with managers (in the concerned company) involved in the discussions and signature of the PSA.

3.5. Model Formulation

Excel spreadsheets are used alongside Monte Carlo simulation to perform the deterministic and stochastic calculations and to analyze the decision-making model. Tornado charts are used to identify the effect of the parameters on the final result. The final outcome of the research will be the best, most likely and worse case scenarios for this particular PSA. Since it is a real case study, the model output will be compared with the actual results. In this study, at first three possible cases are investigated. The first two cases, termed as the best and worst cases, are the extreme cases, which are either optimistic or pessimistic about the profitability of the project. In the third case, termed the most likely case, a probability

Figure 5: Waterflood response for a single pattern



distribution for some of the crucial parameters are specified in the model. It is assumed in this third case that uncertainties associated with these crucial parameters are statistically mutually linearly independent. The most likely case which is taken as the mean of the values in the triangular or uniform distribution as defined. The model output is the total reserves for each scenario, recovery factor and production profile throughout the life of the contract.

4. DATA ANALYSIS

This part analyzes the results of the model which help in the decision-making choice for a particular Production Sharing Agreement. Also, the assumptions used for the different scenarios are stated and justified. In addition to that, sensitivity analysis and tornado charts are constructed to determine the critical assumptions and parameters, which needs more attention and work to decrease the range of uncertainty. The aim is to test the profiles submitted in the plan and understand the risk associated with achieving these production profiles. A comprehensive economic sensitivity analysis was carried out for all primary and secondary projects in the particular reservoir. The economic sensitivity analysis for all projects was performed for oil price, reserves, CAPEX, and OPEX variables. Several economic analysis charts and priority matrix indicators (Spider plot and Tornado chart) were used to economically sense check these projects. For each project, a production type curve (TC) was derived from actual data or from simulation data. The assumptions in deriving individual project's TC and cost breakdown were described as well. The assumptions of cost elements were obtained for Facilities, Drilling and Completion. The cost assumption element varies from project to project and subjective to the nature of the project.

4.1. Deterministic Approach

A deterministic model was developed incorporating all the uncertainties in the project as stated in Table 1. The input parameters are in green and based on the best estimate of the reservoir engineers. The results from such models considered to be few and high level. It just gives exact values for the critical output parameters rather than generating probability distributions within realistic ranges.

Figure 6 shows the difference between the production profile submitted by the contractor when bidding for this project (production sharing agreement profile) and the deterministic model profile. The PSA indicates that the contractor will be able to increase the recovery factor of the reservoir up to 17% and total reserves to 93 MMBbls, whereas the deterministic model only gives 15% recovery factor and 84 MMBbls total reserves. Upon the completion of the project, the NPV and IRR indicated in the PSA are $1.7 Billion and 18% respectively. These economic parameters are higher than the outputs of the deterministic model.

One of the major limitations of such models that it doesn't account for uncertainty of the input parameters, which results in giving exact results instead of ranges. In our case, the PSA profile is higher than the calculated profile using the deterministic model. However, it is very difficult to identify if the PSA profile

Table 1: Input and output parameters in the deterministic model

IP development wells =	40
A.D, development wells=	12%
M.D.=	0.01
Res base	8,771,494
Rese base+history	57,969,494
Res new dev.	14,403,737
Res base+history+Res new dev.	72,373,231
Total reserves (base+infill+WF)	84,447,062
OIIP (STB)	565,000,000
Produced up to oct 2010	49,198,000
Recovery factor (base+infill+WF)	0.149
WF res calculated	12,073,831
Development well discount coefficient	1
IP WF =	90
A.D. WF =	13%
WF discount coefficient	1
Well type cost (CAPEX) dev.	870,000
Well type cost (OPEX) dev.	25
Averaqe oil price	70
Pattern cost (CAPEX) WF	500,000
Pattern cost (OPEX) WF	10
NPV	1,378,303,561
IRR	13%

is exaggerating the results or the deterministic model is really pessimistic and the input parameters need to be changed to enhance the project economics and profile. To overcome the limitations and enhance our understanding for the proposed profile deterministic and stochastic approaches will be combined in one model.

4.2. Stochastic Approach

In this approach, probability distributions for the same reservoir input parameters specified in Table 1 are generated to account for uncertainty. Both uniform and triangular distributions are used. Triangular distribution is usually used in situations where the minimum, maximum and most likely values to occur are known. Triangular distributions could be skewed to the left or the right towards the value which is estimated to most likely occur. Uniform distributions are used when the range between the minimum and maximum values is known and all the values in the range are equally likely to occur. Figure 7 shows the different distributions for the reservoir parameters such as original oil in place, initial production for the well, annual decline for a well and development well discount coefficient.

Figure 8 shows the distributions of the parameters used to develop the waterflood profile such as the initial production (waterflood incremental response), annual decline per pattern and waterflood patters discount coefficient.

The other input parameters (CAPEX and OPEX) for well type costs and waterflood project are used as exact values as there is good control of the cost spent based on the historical data. As indicated in chapter 3, the historical oil price data was used to generate a correlation to be used in the model for economical calculations. Also, the baseline production as agreed in the PSA was used to calculate the costs recovered by the contractor when producing oil above it and the profit splits equations indicated

Figure 6: Comparison between the oil profile of the production sharing agreement and the deterministic model

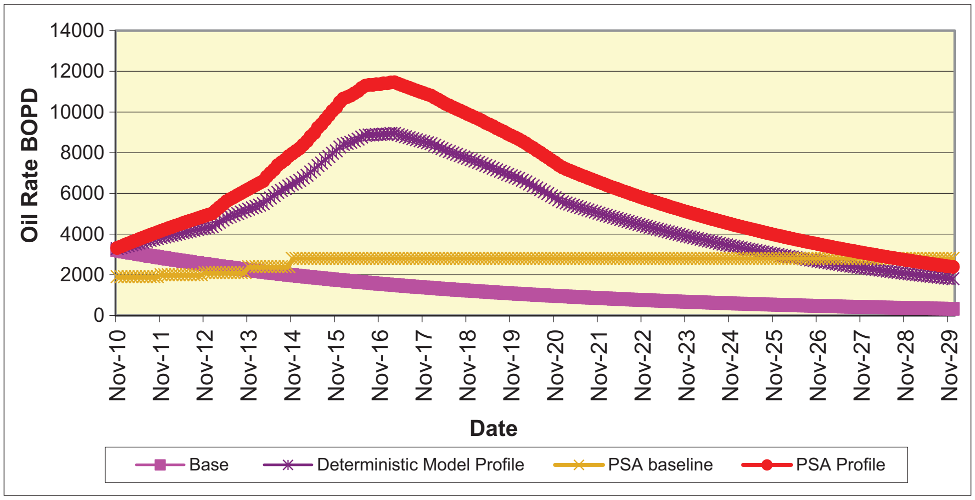


Figure 7: Distributions for reservoir development input parameters

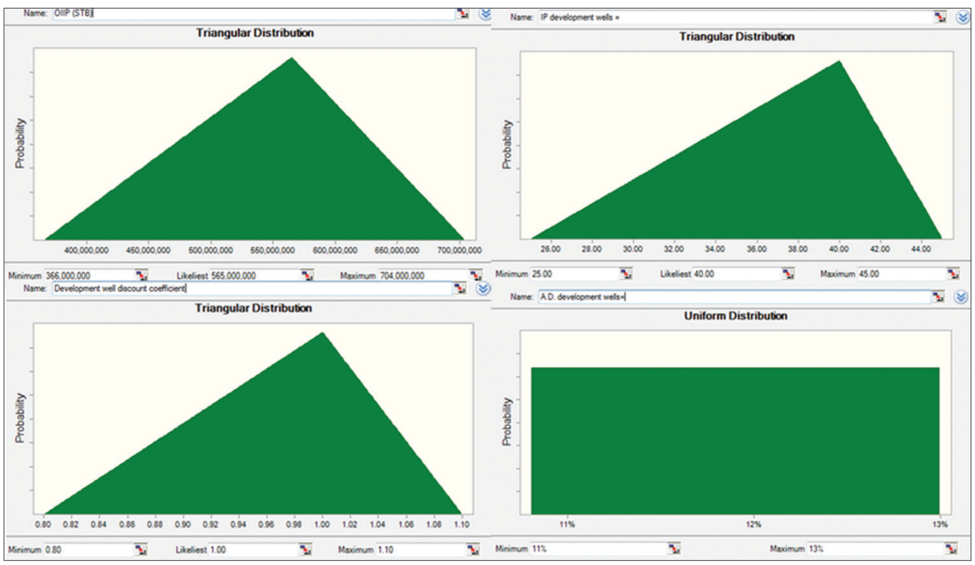
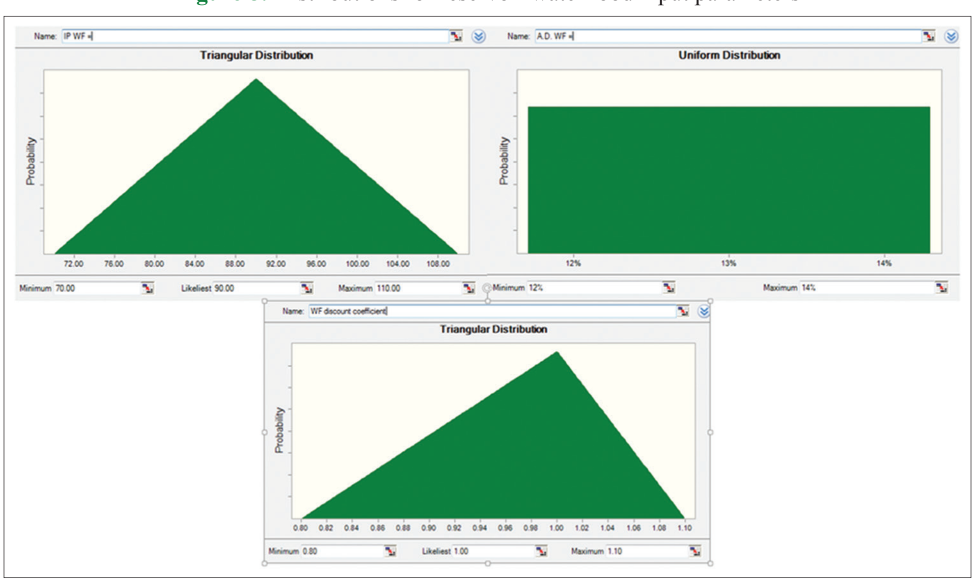


Figure 8: Distributions for reservoir waterflood input parameters



in chapter 3 were used to calculate the generated revenue and therefore calculate NPV and IRR. Monte Carlo simulation approach is used to quantify the impact of input parameters on the investment performance. The principle of Monte Carlo simulation is to define uncertain variables which affects the outcome of a project in terms of probability distributions. Figure 4 shows the oil field production for the best, most likely and worst case scenarios. Now it is clear that the submitted production profile in the PSA represents the riskier scenario (P10), whereas the midcase scenario (P50) is less than the PSA profile.

Now the results from the PSA can be easily compared with the stochastic model results represented in distributions and were the best, most likely and worst-case scenarios help us to confine our expectations from such development plan. When comparing the 17% recovery factor with the output distributions from the stochastic model, we will find that the recovery factor is falling within the calculated range but moving towards the risky scenario (P10) which gives a recovery factor of 18.5%. On the other hand, the total reserves of 93 MMBbls promised in the PSA is even higher than the best case and riskier scenario (P10) which indicates that some input parameters were exaggerated to increase the total reserves recovered. This will lead to better project economics and might lead to a wrong decision to sign this agreement (Figure 9).

In addition to that, when comparing the PSA NPV and IRR results with the distributions as shown in Figure 10, it can be easily seen that the probability of having IRR of 18% is zero. This means that even the input parameters or the oil price used in the calculation is exaggerated to give such high number of IRR. The most likely scenario for IRR is 12% which is close to the result of the deterministic model used earlier. Again the $1.7 Billion NPV stated in the PSA is very risky with 10% probability to happen compared to the $1.26 Billion of the most likely case.

Figure 9: The best, most likely and worst-case scenarios of the stochastic model

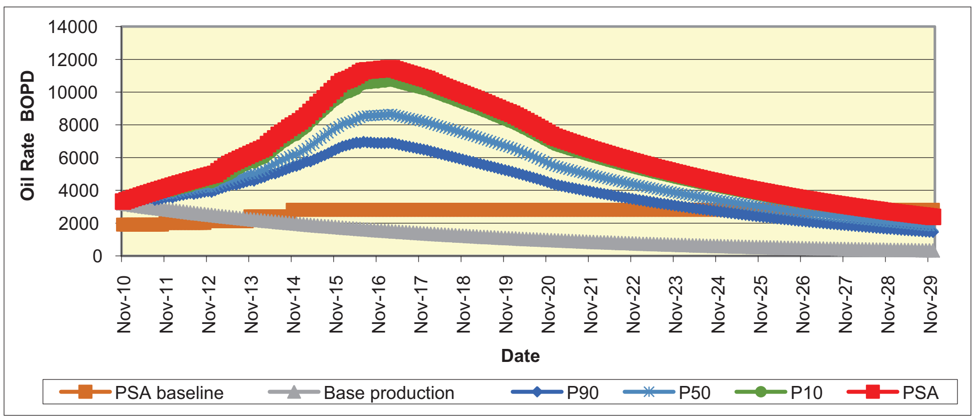
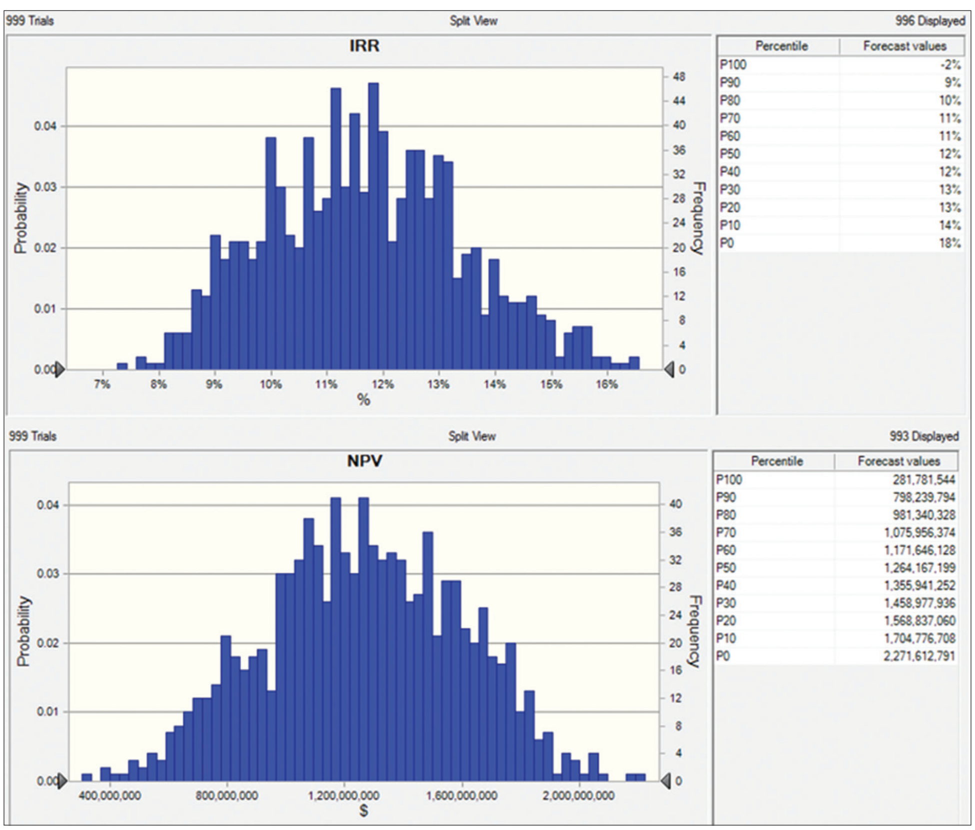


Figure 10: Net present value and internal rate of return stochastic model results



4.3. Sensitivity Analysis

In order to understand the most uncertain parameters and how much weight this effect will have on the overall results for each and every individual parameter, sensitivity analysis is performed. Figure 8 shows that there is a huge uncertainty (45%) in the initial production expected from a waterflood pattern. This uncertainty will play a vital role on the total reserves to be recovered. This huge uncertainty is due to the input type curve used from the simulation model as there is no waterflood history in this reservoir. Also, it is very difficult to simulate the water movement in the reservoir and the sweep efficiency when implementing a waterflood project. This uncertainty can be reduced by conducting a pilot project and assessing the incremental oil due to waterflooding and then use it to modify the type curve used as an input for this model.

The initial production from the development wells comes in the second place in term of the uncertainty. This is due to having a certain type curve for a producing well and with time the reservoir pressure depletes and then this type curve needs to be modified and updated. The model here assumes a single type curve to be used from the start of the project to the end which is not representing reality at all. The initial production for the wells needs to be updated with time to reduce the uncertainty. Also, another reason is the amount of fracture to intersect the well when drilling it. The more fractures intersect the well, the more the production we get. There are several tools used to predict the orientation and location of fractures in the reservoir. However, the conclusions from these tools are not certain.

Oil price uncertainty comes in the third place according to Figure 11. In this paper the deterministic floating price model was used to predict oil price and considered to be the best when compared to the other methods discussed in the literature review in chapter 2. The oil price uncertainty will remain since some fluctuations in the oil price cannot be modeled or predicted and they just follow the political and unrest situations in the whole world generally and the oil producing countries specifically. Also, the supply and demand plays a vital role on the oil prices. However, in this model 12% uncertainty in oil price is acceptable when compared to the initial production from the waterflood project or development wells. Oil price is driving the revenue component and each reservoir in the world has an economic limit to produce the oil from it based on the oil price. The recovery factor results as indicated in Figure 12 affected by several parameters according to the sensitivity analysis performed for the stochastic model. One of the biggest uncertainty when calculating the recovery factor of a reservoir is the original oil in place. The

Figure 11: Total reserves sensitivity analysis

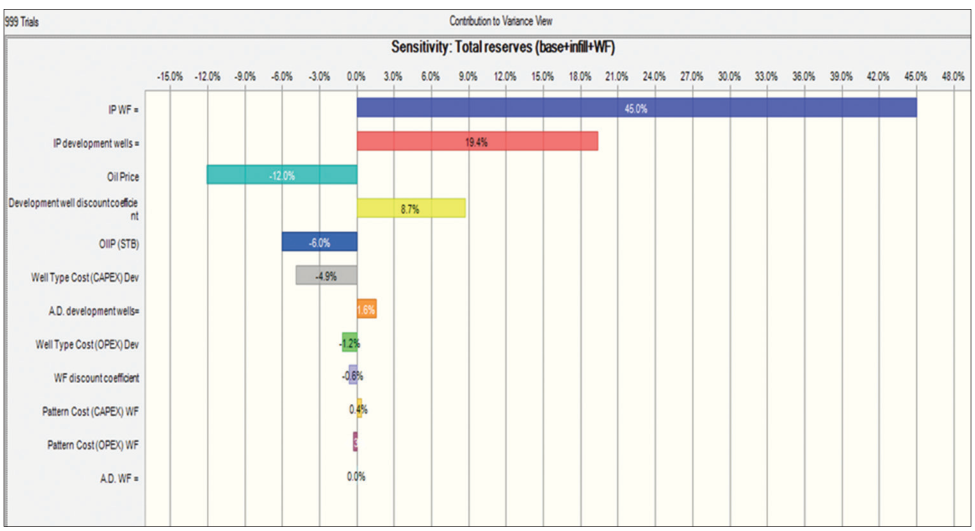
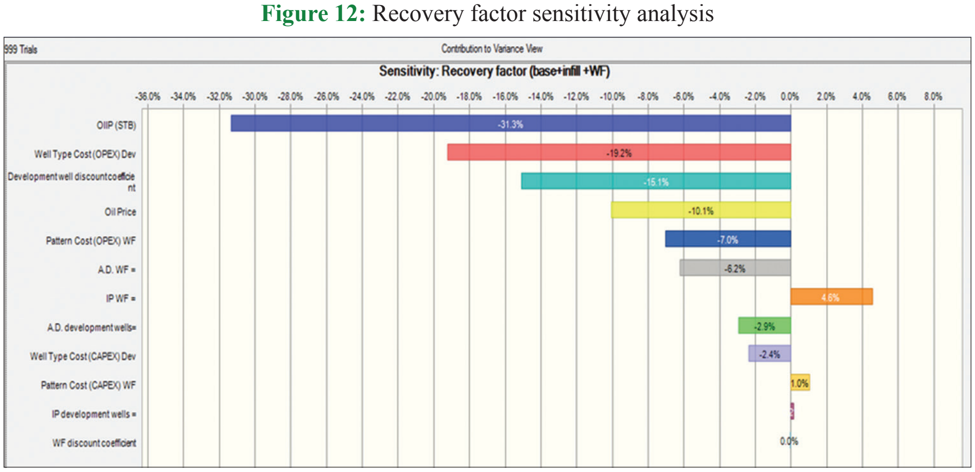


Figure 12: Recovery factor sensitivity analysis



recovery factor is the amount of oil produced from the reservoir divided by the original volume estimated in the reservoir. For a reservoirs with huge areas (14 × 10 km), thickness of 20 feet and heterogeneous permeability and porosity, estimating correct volume originally is a challenge. Another uncertainty is the OPEX for the development wells because as mentioned earlier that there is an economical limit for operating any well, reservoir or field in the world and this cost need to be updated in the model as the wells are becoming old and the oil production decline as well. The number of wells to be drilled will affect the amount of oil to be produced and then will have around 15% uncertainty on the recovery factor. This is based on the spacing (distance between drilled wells). The larger the spacing the lower the number of wells to be drilled.

When examining the net presernt value for the project it can be shown from Figure 13 that oil price, annual decline of the development wells, the initial production of the development wells and the waterflood patterns are considered the major parameters contibuting to the varience in NPV. More work as indicated eairler need to be done on these parameters and more data need to be gathered to reduce the uncertainity range on them and consequently reduce the varience on the NPV. Having a consolidated numbers for the NPV is really improtant for all projects and it affects the decision making process.

The duration of the PSA is 20 years, the oil price prediction for this long period of time will be difficult and as it was mentioned before that the oil price is controled by other unpredictible political factors. However, drilling more wells and gathering data from the reservoir help in enhancing the forecast of the oil production and hence the NPV.

On the other hand, the controlable parameters such as cost weather it is CAPEX or OPEX can be reduced and improved with time. Applying new technologies bring down the cost of drilling and completing the wells. In this particular reservoir, the cost of drilling new wells used to be $1.2 million and now it become $870,000 in 2009 when conducting this study to evaluate the PSA. Also, the OPEX can be reduced by using the proper method of production for the wells and it used to be $40 per barrel and it was reduced to $25 per barrel.

The revenue and cost components are the main factors in the NCF eqution and then the discount factor (10% used in this case) used to bring all cash flows into present time is also improtant.

The last economical indicator to be used in parralel with the net present value is the internal rate of return. It is simply the rate of return that the firm earns of its capital budgeting projects. Once calculated, then it is compared with the required rate of return.

Figure 13: Net present value sensitivity analysis

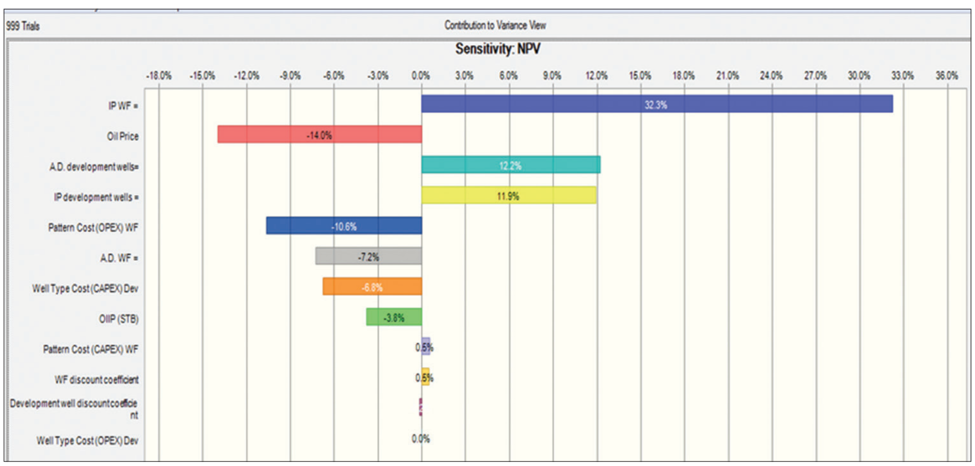


Figure 14: Internal rate of return sensitivity analysis

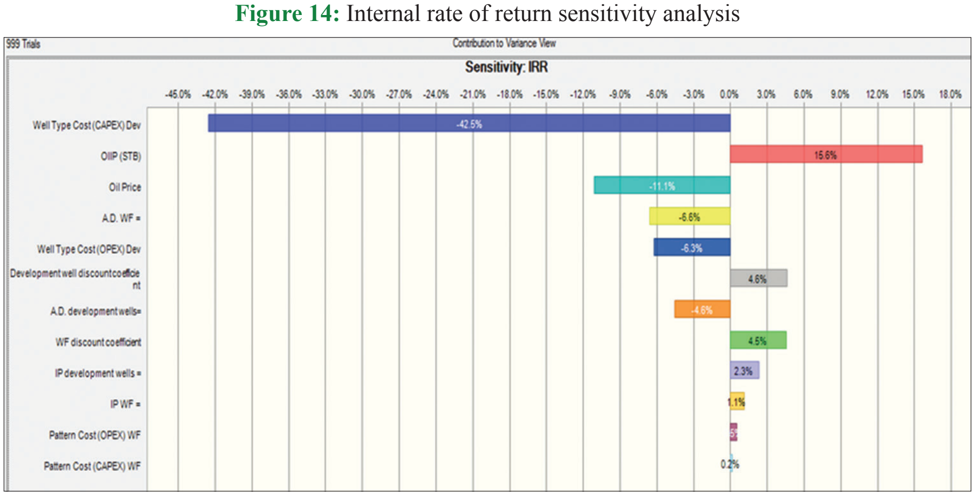


Figure 15: The best, most likely and worst-case scenarios of the stochastic model

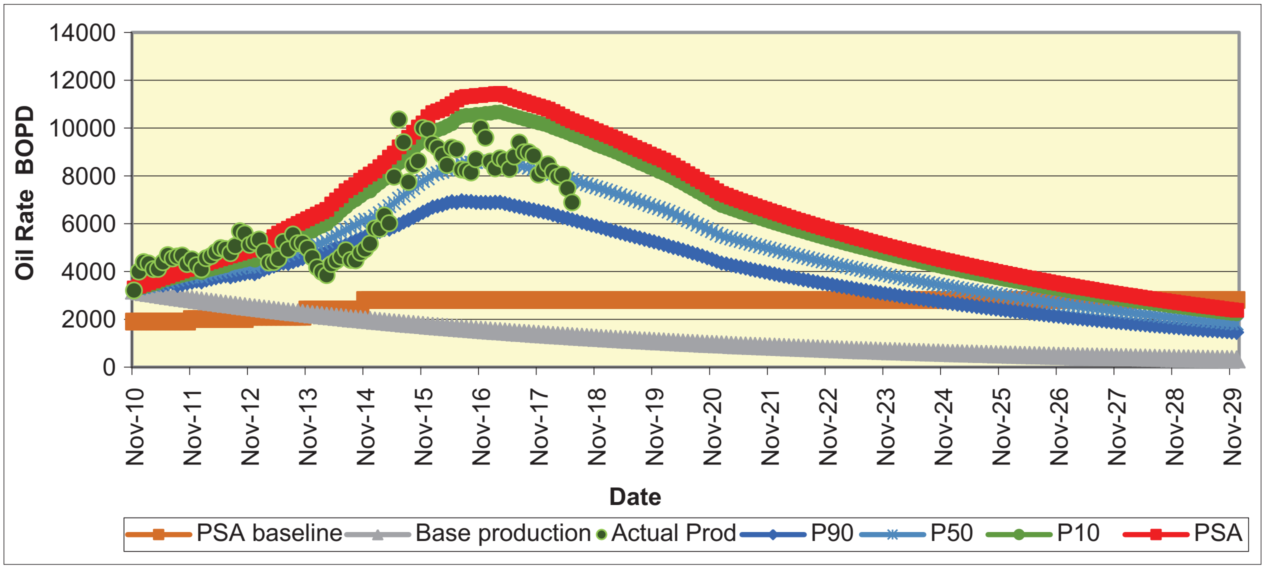
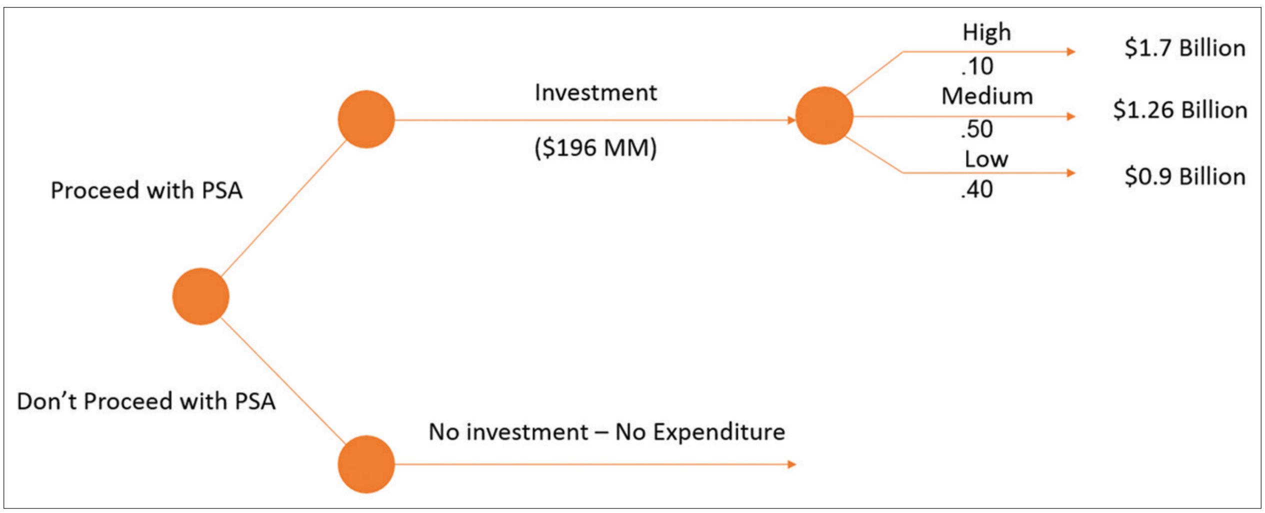


Figure 16: Production sharing agreement decision tree



If it is greater than the required rate of return then the project is accepted. In this case the required IRR for this project is 12% and the mid case scenario (P50) shows that the project will achieve the required IRR. However, this can be easily improved when looking at the sensitivity analysis conducted for the IRR in Figure 14. It shows that the biggest contributor to variance in IRR is the development well type cost (CAPEX). As mentioned earlier in this study that this parameter can be controlled with the implementation of new technologies which increases the operation efficiency and reduces cost.

5. CONCLUSION AND RECOMMENDATION

5.1. Conclusions

In this study, an economic model, which consists of a combined deterministic and stochastic approach, was used to evaluate a production sharing agreement (PSA) for one of the fields in the Middle East. This field consists of many reservoirs and the study was conducted only on one of the reservoirs taking into consideration the field development plan (FDP) for this particular reservoir. As discussed in details in chapter 4, the estimated production profile submitted in the PSA was exaggerated. When a Monte-Carlo simulation was run the riskier profile (P10) was the closest to the PSA production forecast. However, in such agreements usually the mid case scenario (P50) is taken into consideration. When running economics, the oil production profile is considered to be a major parameter to increase or decrease revenue of the project. In 2009, this PSA was submitted and negotiations took place between different parties based on the results of the economic model presented in this study. It was agreed to modify the production profile in the PSA to use the mid case scenario (P50) and the agreement was signed. From that day the program of developing wells and conducting the waterflood project was followed with some modifications.

Figure 15 shows the real actual production from 2009 until 2019 which really matches the mid case scenario submitted in the PSA. The NPV for the first 10 years in this project is around

\$0.45 Billion compared to the total NPV calculated using the economic model \$1.26 Billion. This is only around 36% of the total NPV although 50% of the time of the contract has gone already. As it is shown in Figure 15 the production was almost matching the mid case scenario. However, the recent instability of the oil price in the last 10 years what causes this project in particular not to meet the target so far. The IRR calculated for the 10 years period is almost the hurdle rate 10% and this is again due to the unexpected NPV due to the oil price. A decision-making process was developed to evaluate such agreements and try to identify the key uncertainties in such a project. This tree was presented to management to decide on whether to sign this agreement or not. It is a huge amount of investment (around \$190 million) and for 20 years. As it was discussed earlier that there are so many uncertainties in the model itself and controlling the economics of the project. However, the NPV shows positive values even on the low reward case as it is shown in Figure 16. The probability of achieving the medium and low case is close but the difference in reward in terms of NPV is huge (around \$0.36 Billion).

All in all, the economics of the project at that time (2009) looked very attractive and promising. The technical uncertainties did not affect the project economics and could be controlled and adjusted. However, the trigger of most of the PSAs is the oil price which can kill the project in any time, especially if the contractor is investing in so many projects at the same time. Usually all companies have a specific range of NPV and IRR to invest or not in any project. In addition to the hurdle rate and economics, sometimes there are strategic reasons of why a company might sign a PSA even if it does not meet the needed criteria.

When oil prices drop usually the contractors go back to the government and try to renegotiate the terms and conditions of the PSA. If these negotiations were successful then the PSA will continue with a modified version, otherwise contractors usually pull out of contracts when these negotiations just reach to a deS

5.2. Recommendations

When looking at the sensitivity analysis conducted in chapter 4, the largest uncertainties when it comes to economics were the initial production from the waterflood project, well type cost for development wells, annual decline from wells and oil price. To reduce the uncertainty, pilot projects needs to be conducted in the 1st year in smaller spacing to allow for the response to be detected faster. These pilot projects need to be mentioned in the PSA. In addition to that it is recommended to increase the risk on any production coming from the waterflood project and consider it as a contingent production based on the pilot results. During this pilot project, it is recommended to use several surveillance methods such as Tracers and sunning production logging tools to assess the performance of the project as quick as possible. Again, these tools might help in assessing the technical performance of the project and not necessary the economic performance of it.

To optimize and reduce uncertainty on the well cost, a bench marking technique in the market will help to understand the different ranges of different equipment's to be used in the well construction phase. Also, the understanding of such prices will help to get discounted rates which will improve the economics as well.

"Floating Price Model" used in this study to predict oil prices considered to be accurate enough since results show that the optimum production that achieves the maximum net present value (NPV) is the same regardless of the model used (when compared to other models available for predicting oil prices). However incorporating different models for predicting oil prices and having an input from the experts in the market to even risk this model more will help in reducing the uncertainty of such parameter in the model. As for reducing the uncertainty on the original oil in place (OOIP) which will affect the recovery factor assigned in the PSA, it is recommended to have a data gathering program set in the 1st year of the contract. The objective of this program is to get better estimates for the porosity and oil saturation in the reservoir and hence increase the confidence on the OOIP. Other parameters such as the areal extent of the reservoir and thickness usually estimated with higher confidence.

5.3. Research Limitations

Although the model developed has reached its aims in analyzing the production sharing agreement, risking the production profiles, running sensitivities to understand the uncertainties of the input parameters and developing a comprehensive decision making model. However, sometimes there are strategic objectives hidden or not announced and cannot be measured such as the technical and economical justifications for a decision. These strategic justifications were not mentioned or discussed in this research and it is usually limited only to top-level manager. In addition to that it is not always the case that the decision taken on such agreements is based on strong economical/technical justification. Another limitation of the model that it doesn't take into consideration the reduction of the reservoir pressure and its effect on the wells type curves when it comes to development drilling. Also, the developed model is basic and cannot capture the reduction in well type cost due to increasing the learning curve year after year.

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