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Value assessment for reservoir recovery optimization

R. Saito [a], G.N. de Castro [a], C. Mezzomo [b], D.J. Schiozer [b,*]

[a] EAESP/FGV, Av. Nove de Julho, 2029-10° andar, 01313-902, São Paulo SP, Brazil
[b] Fundacao Getúlio Vargas, Avenida Nove de Julho, 2029, 10th floor, 01313-902, São Paulo SP, Brazil

Abstract

This paper analyzes the managerial flexibility embedded in oil and gas exploration and production. The analysis includes the economic impact of using different production techniques on the valuation of oil reserves. Two methodologies are used to evaluate the simulation of engineering techniques: (i) the real option approach; and (ii) the discounted cash flow (DCF) method. Given the external variables (e.g., oil price, interest rate), this paper evaluates the best engineering technique for oil recovery by using a valuation approach. We conclude that by appropriately combining different production techniques, the value of oil reserves can increase under the real option approach and can be higher than the value assessed under the DCF method. Since oil recovery includes many managerial choices, we argue that the real option approach is more appropriate than the DCF method. The paper concludes that concession time and dividend yield are the most sensitive parameters for the valuation of oil reserves.

Keywords: Petroleum; Reservoir engineering; Simulation; Optimization; Real options

1. Introduction

The discounted cash flow (DCF) analysis is the best-known technique among financial analysts to determine a project's feasibility. However, there are situations in which strategic and operational aspects are not taken into consideration in the DCF analysis. For example, an oil company has reserves with a production cost greater than the market price forecast over the next few years. It would certainly not be economically justifiable to begin oil production. However, let us suppose that, for some reason, such production happens to become economically viable due to the volatility of the present scenario (e.g., shortage of supply, a price hike, etc.) or due to a new technology. The exploration of these reserves would then become worthwhile from an economic point of view. The possibilities of interrupting, increasing and/or decreasing production, and initiating production are clearly options that have economic value to managers. The oil and gas exploration, development and production industry presents us with an opportunity to apply the real option theory in evaluating oil reserves.

In the oil and gas industry, it is quite common for managers to wait a year or more before they decide to explore and/or develop a reserve. Some reasons include: (i) greater certainty regarding the international oil market; (ii) better capital costs for project

* Corresponding author.
E-mail addresses: rsaito@finenge.com (R. Saito), denis@cepetro.unicamp.br (D.J. Schiozer).

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financing; (iii) project implementation in two stages to better evaluate the reserve's potential; (iv) new exploration, development and production technologies; and (v) negotiation with more suitable technological and commercial partners. In these cases, the cost of waiting can turn out to be high. An interesting result is that a project with a negative net present value today can become viable tomorrow. This difference illustrates the value of the flexibility option offered to managers.

The literature on real options applied to capital budget problems is vast. Trigeorgis (1997) includes several works applying real options to value flexibility and strategy, in addition to applications of real options in pollution compliance, land development and financial default. We particularly highlight the work of Paddock et al. (1998) for the evaluation of petroleum reserves. The methodology used to evaluate natural reserves is the application of both the real option theory and the DCF. In this paper, we have implemented and adapted the work of Paddock to compare the main practices in the industry.

The timing of this paper is good because it analyzes the economic value of concessions granted by the Brazilian Petroleum agency (ANP) government to the private sector for the exploration, development and production of oil and gas reserves. This concession includes not only the permission to explore such oil reserves,[1] but also their subsequent development and production. This concession to the private sector is the result of Petrobras[i] limited investment capabilities as well as the deregulation of the oil industry in Brazil. In the next 10 years, Petrobras plans to set up partnerships to develop projects worth US$75 billion, in addition to consortium ventures in the oil and gas industry. According to the Brazilian government, as a result of this effort, the country's production should expand from the present 940 million barrels per day (bpd) to more than 1500 million bpd in 2005.

This paper will present, implement, compare and evaluate the DCF analysis and the Real Option approach used in pricing oil reserves. Our contribution is to discuss the advantages and disadvantages of each model according to the uncertainties under different production techniques during each production phase. For each of these phases, we present critical variables regarding the uncertainties and thus offer the most appropriate or recommended model to be used. This must be done to reconcile the technological aspects of the Brazilian reserves with financial engineering as well as with reserve engineering. The results show that the value of reserves is highly sensitive to technology and oil price volatility.

Section 2 examines the characteristics of an oil reserve, explaining each phase of the upstream chain and its pricing, using the real option theory and the discounted cash flow (DCF) analysis which are described in Section 3. The results are presented and analyzed in Section 4. Final comments and suggestions for future research are found in Section 5.

2. Oil reserves

The oil and gas industry demands much study because it has many operational options and a vast possibility of decisions in each of its phases. In the particular case of the upstream chain in the oil industry, there are three phases: exploration, development and production.

2.1. The exploration phase

The exploration phase comprises drilling and seismic studies to obtain information on the size of the hydrocarbon reserves as well as the cost and best technologies to extract these reserves. The exploration of a potential oil reserve aims at: (i) determining the relative size of the reserve; (ii) verifying the quality of the hydrocarbon's porous media (e.g., oil viscosity and rock porosity); and (iii) identifying the quality of the oil (e.g., density and hydrocarbon mix). Following the exploration phase, the concessionaire can delineate the oil reservoir so as to have a picture of the wells and the technology necessary to obtain the most oil and gas at the lowest possible cost.

[1] In return for this concession to the private sector, the Brazilian government will receive royalties in addition to the rent for the area granted. The amount of the royalties to be paid by the concessionaire is of great interest to the government. The regulation of the exploration, development and production of oil reserves is the task of the National Petroleum Agency (ANP)[1], an autonomous agency working in coordination with the Ministry of Mines and Energy.

2.2. The development phase

The second phase is the development of the reserve. This means that once the reserve's hydrocarbon potential and the technology necessary to develop has been identified, the concessionaire has now the option to begin drilling and installing production platforms to extract the oil and gas. During this phase, numerical reservoir simulation is extensively used to determine exactly the reserve's development plan.

2.3. The production phase

Finally, during the production phase, the concessionaire can exercise the option to extract the hydrocarbon. In order to exercise this option, the concessionaire must consider such factors as the quality of the oil, future extraction projections and their cost, government taxes and royalties, in addition to the price of hydrocarbon itself. The market related parameters can be ascertained with reasonable latitude. On the other hand, operation and technology aspects are more difficult to determine for reserves in general.

2.4. Reservoir engineering

Gauging the potential of an oil reservoir is painstakingly difficult due to its complexity. The characteristics of multiphase flow in porous media, reservoir heterogeneity, temperature, fluid properties, pressure distribution, and even the geometry and size of the reservoir can deeply influence the behavior of the fluids and indicate whether the reserve has development and exploration potential. Many oil reservoirs are not economically viable in spite of the fact that they hold substantial amounts of oil and gas.

With recent advances in computerized tools, it is now possible to model with great precision a reservoir through numerical simulation. With the aim of improving the yield of oil extraction, a number of techniques are used to increase the pressure that keeps the oil flowing to the surface. These techniques include injection of water, gas, chemical products, steam, etc.

The water injection method consists of placing more water, through strategically located wells, at the bottom of the reservoir or in-between producers to increase the existing pressure, pushing the oil through producing wells. Gas injection wells, which use compressors to push the gas downward, are also used with the same objective.[2] In the present study, given the complexity of the problem, we have used reservoir simulation techniques to model these procedures.

3. Option-pricing and DCF approaches

As an alternative to the traditional DCF approach, we have used the real option theory to determine the value of concession contracts for the exploration of petroleum reserves.

3.1. DCF approach

The traditional DCF approach, the most popular method to evaluate projects or companies, was used to assess the value of the reservoirs studied. This was compared to the real option methodology.

Among the known DCF approaches, the Net Present Value (NPV) is commonly a traditional method used to evaluate the economic feasibility of a petroleum project. It consists of analyzing the cash flow of a company or project.

In our case, we are evaluating oil reservoirs, and we use a discount rate to bring the cash flow for the present moment. If the cash generation is higher than the investments, the project creates value. This is in contrast to destroying value.

3.2. Real options

When the subject is options, it is usually associated with call and put options for an asset on the financial market. In the case of real options, the corresponding

[2] In contrast to what may seem logical, water injection is more expensive than gas injection. Water injection happens at very low depths, bringing greater operational costs from energy and maintenance. Gas injection, however, demands extra compressors, so that the pressure above the oil is greater than that below, resulting in higher development costs.

underlying assets are real assets. Real options can be classified as follows[ii]: the option to grow; the option to expand; the option to wait; the option to change the sources of inputs, products or production processes; the option to hire additional scale; and the option to abandon.

In the case of capital intensive industries, such as the oil and gas industry, the option to abandon can be an alternative in the event that the margin of contribution shrinks considerably. Wait options are quite common in the case of reserves, which are not yet fully defined on-stream. The option to reduce or increase scale is a way to follow demand without incurring any unnecessary overheads. The option to change the mix of inputs, products or production processes is seen in the use of land for different crops, workers with different skills, and a power plant that can use either coal or natural gas.

We chose the model of Paddock et al. ("PSS", 1998) to determine the value of the reservoirs. This is reviewed in Section 3.2.1, while Section 3.2.2 shows the parameters employed in the model's use. The PSS method develops an equilibrium model for the underlying asset and integrates it into the model, whose derivation is based on the work of McDonald and Siegel (1983).

3.2.1. The PSS model

The model developed by Paddock et al. (1998) prices concessions for offshore oil reserves or reserves already developed. There are two steps in the development of this model: (1) It demonstrates how to integrate an explicit market-equilibrium model —in this case, developed oil reserves—using the Option Valuation (OV) theory to derive the option's value. This development is important in order to gauge the option's value conducted within a risk-free scenario. (2) Using the example of a concession contract, a problem relating to the assessment of value is set forth in sufficient detail to examine the theoretical and practical issues involving the extension of the theory of financial options evaluation in real cases. Here, the differences between financial options and real options are described, and the way to overcome the obstacles arising from this analogy is also demonstrated.

Including the necessary modifications in the Black–Scholes equation, so that it calculates the value of an American option that pays dividends, we come to the following equation:

$$\frac{\partial X}{\partial t} = rX - (r-\delta)S\frac{\partial X}{\partial S} - \frac{1}{2}\sigma^2 S^2 \frac{\partial^2 X}{\partial S^2} \tag{1}$$

where r is the risk-free rate, S is the value of the reservoir, X is the cost to explore it (or develop it, depending on the phase, and represents our exercise price), σ^2 is the variance of the value of the reservoir, and δ the corresponding payment of dividends (represented by the operational profit of the reserve). The example below shows how this model can be used.

3.2.2. Calculation of the parameters

The main parameters used in the model are:

The value of the developed reserve: Following the study of Gruy et al. (1982), the market uses a parameter wherein the value of the developed reserve is equivalent to one-third (1/3) the market price for crude oil. Therefore, since we used a price of crude oil at \$25.00/barrel, the value of the developed reserve would be approximately \$8.33/barrel.

Standard deviation of the reserve's value: As a proxy for the standard deviation of the reserve's value, we have used the standard deviation of the price of crude oil, given its liquidity, as well as the abundant and reliable information available. The quarterly cash price of crude oil has a standard deviation, σ, equivalent to 5.00% a year.

Exploration and development costs: The exploration and development costs came from simulations and reflect the market values adequate for each case since a higher number of wells indicate higher development costs and also different types of platforms.

Concession time: The contractual concession time according to the new petroleum legislation in Brazil is 30 years. However, in the case studied, we have used a period of 10 years.

Risk-free rate: The risk-free rate used was the average yield of American treasury bonds for a 10-year period. The rate used is equivalent to 6.00%/year.

Net income less depletion: The net income used, less depletion, was found using four basic premises: (i) the per barrel value of a developed reserve is equivalent to one third (1/3) the crude oil's market value; (ii) the operational costs are \$10.00/barrel; (iii) depreciation accounts for twenty percent (20%) of the market price of crude oil; (iv) the annual production rate is 10% a year, since it covers a 10-year period. The calculated value is 1.28% a year (equivalent to the dividend yield concept).

4. Applications

To show an example of how this model can be used practically, we have used a real Brazilian offshore reservoir. We have organized this example of the application in the following way. Section 4.1 shows the reservoir's description. The values of the parameters are those described in Section 3.2.2. The results are shown in Section 4.2 and finally, in Section 4.3, we determine the sensitivity of the reservoir's value in relation to the changes in oil barrel price.

4.1. Reservoir description

A real reservoir was used to make the simulations where we are interested in the benefits of reservoir engineering techniques to increase its value. The numeric model for the field simulation is a finite-differences model.

Three cases were analyzed to compare the Real Option methodology and the DCF approach to draw some conclusions about the best practices. In the simulations, we used the following procedure. In the first case studied, we only used the natural forces existing in the reservoir for the production of oil, and we looked for the optimum number of wells in the reservoir. We started with a large number of wells to evaluate the potential of each reservoir region, and we excluded the wells that presented the worst NPV. In the second case, after finding the optimum number of wells, we analyzed the best location for each well. We looked for the setting that gave the highest NPV. Finally, in the third case, in addition to natural forces, water was injected to see whether additional development and operational costs were compensated by higher oil recovery. The results were then compared with the theory described in this paper.

4.2. Results

The results are explained below. Since the partial differential equations have no analytical solution, they have been solved numerically, using the explicit finite-differences method[iii].

The procedure to calculate the results is as follows:

(i) Calculate the present value of a developed reserve. As already mentioned, this has been done and the value arrived at is $S = \$8.33$/barrel;
(ii) Calculate the development costs and consequently the ratio of S/X (see Table 1 below for an example);
(iii) Calculate the value of the reserve to be developed. This can be done by multiplying the option value by the development costs and oil production. For 60 wells, we have: (i) the value of the reservoir equivalent to $0.154105 \times 12.21 \times 27.1$ million barrels, which results in an economic value of US\$51 million.

Using the procedure described above, we found the Real Option methodology results and compared them with the NPV approach. The comparison is shown in Fig. 1 presented below.

It can be seen from Fig. 1 that when we used seven wells to simulate the oil recovery, the reservoir value was maximized for both methods. Analyzing the results, we concluded that there is a tradeoff between development costs and the value of the option. When there are more wells, the option value increases but it does not compensate for the additional development costs. In other words, the flexibility to increase or

Table 1
Development costs for different number of wells

Value per development costs			
Value	Number of wells	Development costs per barrel (US\$)	S/X
8.33	6	1.46	5.72
8.33	7	1.51	5.51
8.33	8	1.84	4.53
8.33	9	2.04	4.08
8.33	21	4.51	1.85
8.33	33	6.92	1.20
8.33	45	9.27	0.90
8.33	60	12.21	0.68

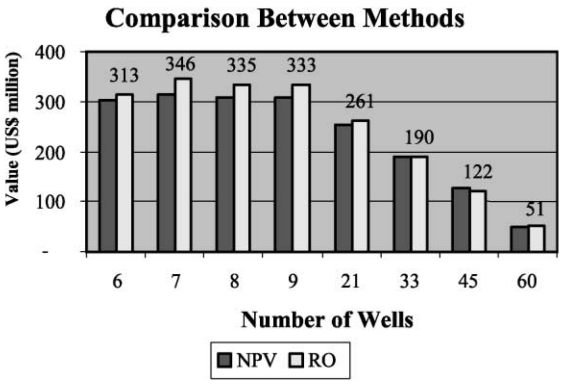

Fig. 1. Number of wells simulation.

diminish the oil recovery, for a certain level of price, can (not) be compensated by higher costs.

After running numerical simulations, the optimum number for the reservoir was seven wells, we studied the influence of the location of the wells in the reservoir's value. The results show that the revenues can increase a little in relative terms (about 0.2% maximum), but in this case, it represents a substantial amount of money: US$5 million. Fig. 2 below shows the results.

The Real Option methodology presents higher values than the NPV approach and this difference averages around 4.8%. An important point in this case is that we found the highest value for the Real Option. This case presents the lowest value for the NPV approach. A possible reason for this fact is that the Real Option approach is not very sensitive to oil recovery rates. The oil production in this case is higher compared with other cases, but the recovery is slower.

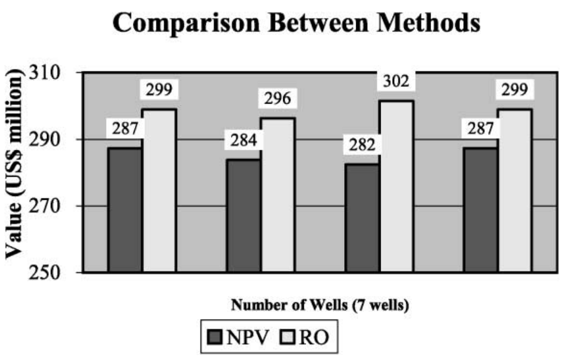

Fig. 2. Well locating simulation.

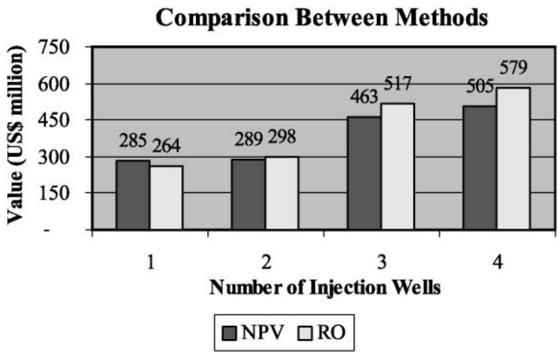

Fig. 3. Injection techniques.

Finally, we simulated additional wells by injecting water. We concluded that in this particular case, the injection technique is very important for the feasibility of the project. It increased the reservoir value substantially. The results are shown in Fig. 3.

The reservoir value has a tremendous increase due to the water injection technique. There is a 77% increase according to the NPV approach (going from

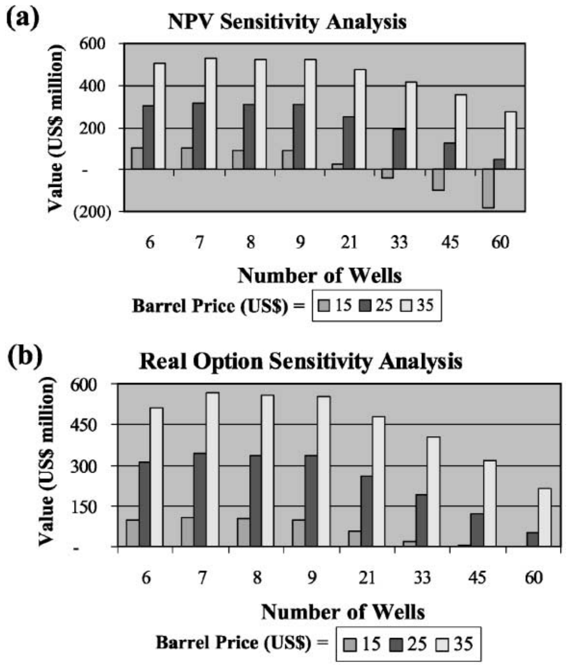

Fig. 4. The value of the reservoir for NPV and real option approaches.

US$285 million to US$505 million) when we simulated the oil recovery using one or four injection wells. In the case of the Real Option method, the increase was higher, going from US$264 million to US$579 million (a 120% increase). It can be observed that when we used one injection well, the NPV approach presents a higher value than Real Option methodology. It reinforces the fact that the Real Option method captures the impact of the oil production rate less than the NPV approach.

4.3. Sensitivity analysis

We made a sensitivity analysis of the oil barrel price to verify if we could find different outcomes according to its level. The values used in this case varied from US$15 to US$35. The analysis was made for the two different approaches, which we are using to evaluate the value of the reservoir: DCF and Real Option. The results are shown in Fig. 4.

It can be seen from Fig. 4 that the optimum number of wells does not differ between the two methods. It can occur in some cases, as we observed in other studies. An interesting point that can be observed from the figure is that, according to Real Option assessment, the reservoir always has a positive value. As mentioned before, the value exists due to the possibility of a change in the environment that can make the reservoir development feasible. Fig. 5 below shows the comparison of the two approaches for different price levels.

It can be observed from Fig. 5 that the Real Option methodology is more volatile than the NPV approach. For high values of development costs, the NPV evaluates the reservoir by a higher value than Real Option. The result changes for lower development costs.

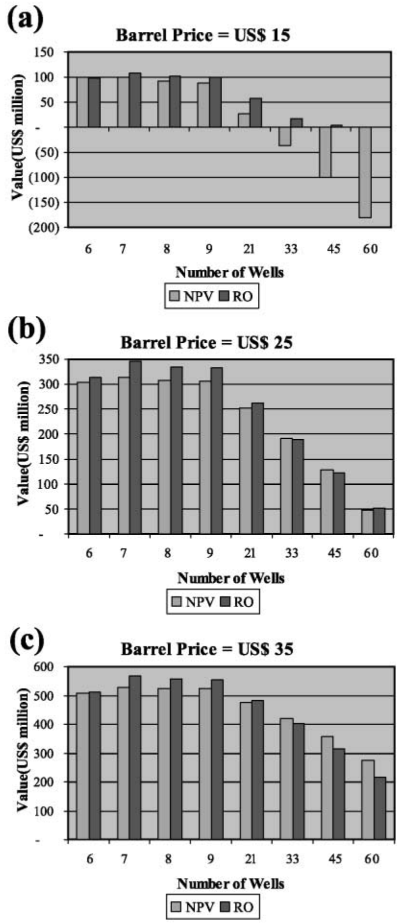

Fig. 5. The value of the reservoir for different prices.

5. Conclusions

The emphasis of this study is on the development phase, where the location of wells and the injection techniques are to be defined. Moreover, the conclusions derived here can be applied to the production phase, where managers have to make decisions that will influence the company's value. The main contribution of this study is its ability to integrate the recent techniques of reservoir simulation engineering with the pricing techniques of the DCF approach and the real option approach. This is particularly useful because, in the last few years, petroleum extraction techniques have evolved towards a combined use of water and gas injection.

The objective of this paper was to include managerial flexibility (such as water injection and/or well location) in the valuation of reservoirs. We have concluded that these techniques can increase the value of reservoirs and that capital allocation can be optimized by doing exhaustive simulations. The main advantage of the real option methodology compared to the traditional discounted cash flow technique is that the former takes into consideration the operational issues of the petroleum industry. In other words, the turbulent scenario of the sector is better evaluated by the real option methodology because it uses the volatility of the price instead of the absolute price in the model.

When we implemented the real option theory, we used a classic model for the pricing of oil reserves and applied a sensitivity analysis to determine which factors are most relevant in their economic value. The concession time, as well as the dividend yield, were important factors in the analysis. This shows the importance of the country's regulation laws. The evaluation of the reservoir engineering techniques with injection in different periods during the initial phase of production would be valuable in obtaining better estimates.

As discussed previously, the approximation of the parameters is the greatest weakness of the Real Option model. A better model of volatility could perhaps be an important point to be studied, and the consideration of mean reverted price techniques or mean reversible with Poisson jumps, instead of the Brownian stochastic method, could also be analyzed to improve the results of this method.

When the analysis of the optimal number of wells was made, it could be seen that there are cases in which the best choice is a greater number of wells when the value is analyzed. However, since companies have budget constraints, we concluded that a smaller number of wells could be the best choice because other projects can be implemented, which will increase the value of the company.

Another important point to be emphasized is the fact that a cost monitoring value during the production phase is very important because the implementation of some additional wells can increase the value of the reservoir. The tasks of the manager are not finished when there is a reservoir producing oil. In contrast, his work increases because there are additional operational decisions that he will have to make.

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