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Real Option Valuation of Offshore Petroleum Field Tie-ins

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Abstract. We value two real options related to offshore petroleum production. We consider expansion of an offshore oil field by tying in a satellite field, and the option of early decommissioning. Even if the satellite field is not profitable to develop at current oil prices, the option to tie in such satellites can have a significant value if the oil price increases. Early decommissioning does not have much value for reasonable cost assumptions. Two sources of uncertainty are considered: oil price risk and production uncertainty. The option valuation is based on the Least-Squares Monte Carlo algorithm.

Keywords: Investment uncertainty, satellite fields, petroleum development, oil fields, energy commodities

1 Introduction

We explore the flexibility related to investment timing in offshore oil exploration and production. Offshore oil production can require large investments in infrastructure, offshore and onshore facilities and well-drilling costs. These costs are to a large degree sunk once the investment has been made. Since 2000, oil prices have been increasingly volatile, thereby creating uncertainty about whether marginal projects can deliver a sufficient return on the investment.

During the financial turmoil in 2008/2009 the development of several smaller fields on the Norwegian Continental Shelf were postponed due to uncertainty related to whether they could deliver a sufficient return, among others the satellite field Alpha connected to the Sleipner field. This should make the problem of optimal investment timing interesting for practitioners assessing investment opportunities and both government and researchers forecasting the future level of investment in petroleum production.

The most critical decisions in a petroleum production project with regards to profitability is when and if the field should be developed and the largest part of the investment is made. Depending on the field and the technology used to produce it, the

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operator might also have choices available after the field has started to produce. Often there are smaller reservoirs surrounding the main field. Generally too small to warrant an independent production unit, these reservoirs can be developed via the production unit at the main field. The operator also has to decide when to abandon the field and decommission the production unit by taking into account future production as well as equipment lifetime and operating cost. Once the field is abandoned, restarting production is in most cases not realistic.

Real options valuation (ROV) has been applied to petroleum projects for a long time as they have many attributes that make them suitable for this valuation. These projects often involve a large initial investment, the output is a risky and easily traded commodity, and management have many choices available related to timing, production technology and size. Siegel, Smith and Paddock [27] assess investing in offshore petroleum leases. Cortazar and Schwartz [7] use a Monte Carlo model to find the optimal timing of investing in a field with a set production rate that declines exponentially and with varying, but known, operating costs. With this predetermined production rate, the value of the field becomes a function of the oil price, which is modeled as a two-factor model where the spot price follows a geometric Brownian motion and the convenience yield follows a mean-reverting process. Smith and McCardle [20] consider the timing of investment, the option to abandon and to vary the production rate by drilling additional wells. Both prices and production rates are modeled as stochastic processes, where the price follows a geometric Brownian motion. Ekern [12] uses a ROV model to value the development of satellite fields and adding incremental capacity using a binomial lattice model. He finds that satellite fields that are currently unprofitable can have an option value. Lund [18] considers an offshore field development by using a case from the North Sea field Heidrun. The model used is a dynamic programming model, and take into account the uncertainty regarding both reservoir size and well rates in addition to the oil price. The paper models the price as a geometric Brownian motion, and use a binomial valuation model to find the optimal size of the production rig and investment timing. Armstrong et al. [2] uses information from production logging and a copula-based Bayesian updating scheme for real options valuation of oil projects. Dias et al. [11] use Monte Carlo simulations together with non-linear optimization to find an optimal development strategy for oil fields when considering three mutually exclusive alternatives. Chorn and Shokor [6] combine dynamic programming and real options valuation to value investment opportunities related to petroleum exploration. Dias [10] provides a more thorough review of ROV related to petroleum exploration and production.

The contribution of our paper is that we consider the decision to add a known (smaller) tie-in field to an existing one, taking into account possible abandonment, price risk and technical risk. We use a real options approach where the valuation and optimal exercise is found using the least-squares Monte Carlo (LSM) algorithm presented by Longstaff and Schwartz [17]. We do not consider the problem of initial investment in the main field, as this problem has been considered both in petroleum production and other industries before, see e.g. Kort et al. [15][3]. Furthermore, the value of deferring an investment is generally low in petroleum production [18]. Instead, we focus on decisions being made as the field is in production, where we model expanding production by tying in surrounding satellite fields as well as the option to abandon the field early and selling the production equipment.

In Section 2 we present the data used in this work, and discuss its properties. Further, in Section 3 we study the option to expand the production with a tie-in field as well as abandoning the field early. We then apply these models in a case study of two such real options. Finally, in Section 4 we conclude and offer suggestions for further work.

2 Data

To estimate the long term behavior of the oil price and to find a suitable time-series model, we have used the real price of crude oil denominated in 2008 USD from Reuters EcoWin [24]. The series can be seen in Fig. 1 and consist of the US average price in the years from 1861 to 1944, then Arabian Light posted at Ras Tanura from 1945 to 1985, and Brent spot since 1985 to today. It has 148 annual observations going back to 1860. We could have used more high-frequency data for the latter years, but these are not available prior to 1946 for monthly data and 1977 for daily data. To avoid mixing the different series, only the annual observations have been considered.

To obtain risk-neutral growth and the oil lease rate we use forward prices at time t expiring at time T, $F_{t,T}$, from Wall Street Journal [29] for Light Crude Oil, as seen in Fig. 2. The series have contracts for each month till December 2014 and semiannual contracts expiring as late as December 2017. We find an estimated risk-neutral long term growth of 2.70%. The longest duration for the forward contracts used, T, is eight years, but we assume that the growth indicated by these, $\ln \frac{F_{0,T}}{S_0}$ is a good estimate for the growth in our twenty-year period. We use the expected growth together with an estimate for the risk-free rate, r_f to find the oil lease rate, δ, by using (1). This puts the oil lease rate at 1.6%:

$$\delta = r_f - \frac{1}{T} \ln \frac{F_{0,T}}{S_0} \tag{1}$$

For a market-based estimate for the volatility, we have used implied volatility from options quoted at ICE [14] for Brent oil options. The series have options expiring at 17 different dates with several options set to expire at each date. The longest time to expiry is 3 years. We have used an average value over all strike prices available to find a mean implied volatility for each date. The implied volatility is falling with longer expiration time, implying that the 3-year forecast might not be valid for the long-term real options. Even so, we use the implied volatility for the 3-year option as the oil price long term volatility, with an implied volatility of 29.5%. This is quite a lot higher than the historic

[3] They study what influences the choice of developing the whole project at once versus developing it in gradual steps.

average for the last 148 years, but close to the volatility in the last 40 years of 28.8%. It is also higher than the 20% that Pindyck [21] found when estimating volatility from historical data. Costa Lima and Suslick [8] refer to Pindyck [21] and also argue that the volatility has been stable around 20%. We use the implied volatility as an estimate for the long term volatility. One reason for the difference between the market view and the conclusions of Costa Lima and Suslick [8] and Pindyck [21] could be the increase in oil price volatility in the last years.

To estimate the USD-denominated risk free rate, we have used 20-year US Treasury bonds from [24] as an estimator for the risk free rate. The risk free rate is estimated to be 4.3%.

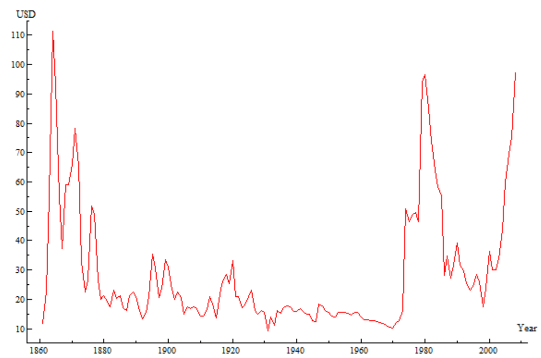


Fig. 1: Real price adjusted Brent spot price, USD 2008

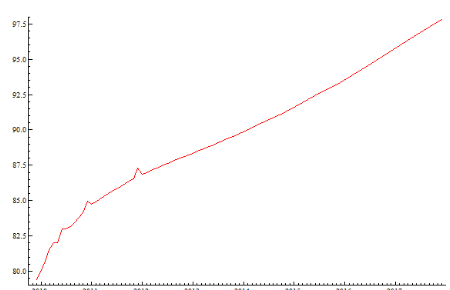


Fig. 2: Light crude oil forward prices with increasing time to maturity. Observation date 2009–09–11

3 Real Option Valuation

3.1 Flexibilities in Petroleum Production

In this section we consider two cases where the operator has flexibility, and develop valuation models for this flexibility. We include both input (resource) uncertainty and output price uncertainty, as in Bobtcheff and Villeneuve [3]. Unlike their analysis, we ignore capacity choice issues.

The Value of Including Satellite Fields We assume that the search and exploration phase has been completed; see e.g. Martinelli et al. [19] for a bayesian network analysis of which location to drill a prospect well. In many situations, the operator knows of a smaller and nearby field that can be produced through the main production platform. These smaller fields will often have higher per-barrel costs due to economies of scale and are more interesting to consider in a real option model than ordinary fields since they are not necessarily economical to develop. Typically, such fields will not be large enough to warrant an independent platform, but it can be profitable to tie the fields to existing platforms. Tying in a small field will increase the produceable reserves connected to the platform, but will require an investment. The deterministic NPV of tying in such a satellite field can be calculated by using the reservoir model presented in Sect. 3.2 and valuing the incremental production from the satellite, given the capacity constraints and the time of connection. Given that the increased costs by adding the satellite are fixed, the value of extra production will vary only with the price of oil and the time of connection. If the satellite field is connected before the production declines, then it will not increase the production from the platform until the main field is off its plateau, since the plateau is given by the platform's maximum production rate. Further, if the satellite is connected near the end of the platform's life time, much of the extra fields reserves will be left in the ground unless one extends the lifetime of the platform, which might not be possible depending on the availability of infrastructure etc. Developing a satellite field can require a large initial investment, and it is assumed that any extra operational costs are included in the investment cost. Since these are modeled as deterministic cash flows, the NPV of the future costs are simply added to the investment. Thus, the value of being able to include a satellite field takes the form of a call option to acquire the extra production by paying the investment cost.

The increase in production is the difference between the line and the dotted line in Fig. 3. We can calculate the net present value of increased production when connecting the tie-in at time t by (2):

$$NPV_{S,t} = S\sum_{j=t}^{T} Prod_j^{\Delta} e^{-\delta j} - I \tag{2}$$

S represents the price of oil, $Prod_i^{\Delta}$ the extra production from the satellite in period j, δ the convenience yield and I the present value of the investment and operational costs.

The Timing Dimension of Including a Tie-in Field The process of valuing a project with a fixed end date is different than for an ordinary stock. Even with uncertainty in the output, one is certain that the tie-in will be worthless at the time the main platform is decommissioned. In the case study we have used a production profile from Robinson [25] to calibrate the model of Lund [18] in order to get a representative production profile.

The Value of Early Shut Down Some offshore production units can be moved if the value of the remaining production is low, and the production unit is not near the end of its life. This can be the case if the true field reserves are lower than estimated. To model this, we have used the same price and reservoir model as in the expansion case, but now it is the whole project value that is relevant. Thus, the value of ending the production prematurely can be calculated by using (3):

$$NPV_{S,t} = K_t - S\sum_{i=t}^{T}(Prod_i^{\Delta} e^{-\delta i} - C_i e^{-ri}) \tag{3}$$

This states that the value of decommissioning the field early is the income from selling the production unit, K_t, less the future expected profit, stated as remaining production less the operational costs, C_i. It is assumed that it is possible to sell the unit either to another project or another company for a positive price. We have assumed that the unit depreciates linearly and that the income from a sale follows this value, and that it has a planned lifetime equal to the the field's lifetime. The strike will take the form:

$$K_t = K_0 \frac{T-t}{T} \tag{4}$$

The Effect of Uncertain Production In Sect. 3.2, we model the production uncertainty as a mean-reverting process. Unlike a Brownian motion, the expected value of a mean-reverting process at time t is dependent on both its current value and its equilibrium value.

$$E(\gamma) = \alpha + (\gamma_0 - \alpha)e^{-\lambda t}, \tag{5}$$

where γ represents the production level, α the mean index level, and λ the speed of mean-reversion.

Finding a Suitable Model for the Oil Price One of the most significant factors in valuing a potential oil field is the price of oil. Like the price of other tradeable items the oil price is governed by supply and demand. The theoretical ideal model would take into account all the factors that affect supply and demand and produce a forecast of the oil price based on this information [21]. Several such models have been developed, among others the Hubbert model of supply [13] and the LOPEC model [23]. These model the price development by looking at the underlying factors that drive supply and to some extent demand. There are two major obstacles for implementing such a model for generating long term forecasts. First, identifying all of the factors affecting the oil price is in itself a difficult task. Second, producing good forecasts for all of these factors might be just as difficult as producing a forecast for the oil price. A time series model thus seems like an attractive alternative model formulation. Pindyck [21] finds that the oil price can be modeled both as a mean-reverting model and a geometric Brownian motion. Postali and Picchetti [22] shows that a geometric Brownian motion is a good approximation for the oil price movements in the long run. We model the oil price as a geometric Brownian motion because we are interested in the long-term behavior. The geometric Brownian motion is described by (6).

$$\frac{dP}{P} = \alpha dT + \sigma dZ \tag{6}$$

3.2 Reservoir Model

The field production profile is useful when valuing real options, since it provides information on volume and time of production. A realistic model of reservoir performance is challenging to create and to calculate, because of the need to model many parameters in a 3D-setting with many non-linear relations. In this work, a simple zero-dimensional model of Wallace et al. [30] is used. This models the reservoir as a tank with a uniform fluid and with uniform properties in the whole reservoir. Thus, it does not account for differences in permeability in different areas or local differences in pressure caused by the well flow as the areas surrounding the producing wells empties. It is, however, a simple model that has great computational advantages compared to a more complex reservoir model, and it does reflect the form of reservoir production profiles of several types of petroleum fields [18].

Table 1: Reservoir parameters

$P_{w,0}$	- Initial reservoir pressure
$P_{w,t}$	- Reservoir pressure at time t
P_{min}	- Abandonment pressure
R_0	- Initial reservoir volume
R_t	- Reservoir volume at time t
$q_{r,t}$	- Maximum reservoir depletion rate at time t
q_w	- Maximum well rate
q_{max}	- Maximum capacity, or plateau production
$q_{ramp-up,t}$	- Maximum production during field development
N_t	- Number of wells producing at time t

The reservoir pressure follows the following relation:

$$P_{w,t} = P_{w,0} - \frac{R_0 - R_t}{R_0}(P_{w,0} - P_{min}) \tag{7}$$

The reservoir pressure provides the maximum well flow, which decays exponentially with time with continuous production if there are no other constraints on the well flow. The maximum well rate is based on the capacity of the wells installed.

$$q_{r,t} = N_t q_w \gamma_t \frac{P_{w,t} - P_{min}}{P_{w,0} - P_{min}} \tag{8}$$

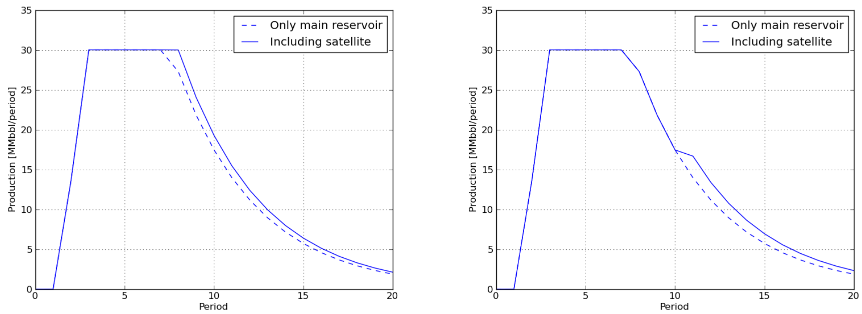
Together, (7) and (8) becomes the simple equation

$$q_{r,t} = N_t q_w \frac{R_t \gamma_t}{R_0} \tag{9}$$

This is the maximum production from the field, given that there is no water injection or other types of pressure maintenance performed. It is rarely optimal to construct the production unit so that it can produce at the maximum rate $q_{r,t}$, because of high investment costs. When the field has a maximum processing capacity that is lower than the field maximum production, the production profile will have a flat region where the production is equal to the capacity maximum. This level is called the plateau production. The optimal plateau level is mainly a function of investment cost, production and required rate of return, since it is a trade off between investment cost and the ability to get the oil quickly out of the ground. There might also be technical reasons to limit the capacity. We have included a ramp-up period of three years, which is similar to the case found in Robinson [25]. During this ramp-up period we have assumed that the production grows linearly to capacity maximum over the three year period. The background for such a ramp-up period is among other topics well drilling. It will not be possible to drill all wells at the same time, and connecting the streams to the platform will also require some time. The actual production thus becomes the minimum of $q_{r,t}$, q_{max} and $q_{ramp-up,t}$.

Production Profile with a Tie-in Field To model the increase in production by a tie-in satellite field, the new reserves, R_{new} are added to the initial reserves. This increases both the initial reserves, R_0 and the reserves at the connection time, R_t. The effect of this increase is dependent on when the new field is built. If the satellite is connected before the field goes into decline, then the plateau production will be maintained longer as seen in Fig. 3a.

Uncertainty in Production Production volumes are often uncertain as wells can produce more or less than planned. Lund [18] models this by a changing well capacity. The well capacity is modeled as a simple stochastic function, where the well can either have a high or a low well rate. The probability of one of the wells changing regime from a high rate to a low or opposite is 0.1 per period of 6 months. Each well capacity will be highly random, but with a large number of wells the process resemble a mean-reverting stochastic process. The variance of the field production will be very dependent on the number of wells connected to the field. McCardle and Smith [20] take a different approach by modeling the decline rate as a geometric Brownian motion. This might be appropriate when the field is in decline, but it does not take into account the effect of the production capacity limit and it does not clarify which fundamental property that



(a) t=5 (b) t=10

Fig. 3: Production profiles with tie-in at t=5 and t=10

varies. We consider changing well rates as the main source of uncertainty, as in the the switching model in Lund [18]. We do not model each well individually, however, instead we consider the whole field production by assuming a number of wells. This is implemented as a production factor for the whole field, γ_t, as a mean-reverting process. We believe that this aggregate production factor is more versatile than the model of Lund [18], as operators can create historic production factors from current and previous fields and easily take into account other risk factors like technology development or unscheduled maintenance. The production factor follows:

$$\gamma_t = \gamma_{t-\Delta T} + \lambda(\alpha - \gamma_{t-\Delta T})dT + \sigma dZ \tag{10}$$

where γ_t is the well production factor at time t, and λ, α and σ are mean reversion parameters from the regression. The parameter values can be seen in Table 2. The parameter values are found by Monte Carlo simulations from the model used by Lund [18], and regressing the simulation results to find a mean-reverting model.

Table 2: Production factor mean reversion parameters

Parameter	Value
α	0.665
λ	0.218
σ	0.050

3.3 Valuation Framework

There are mainly two ways of calculating the present value of future cash flows. One solution is using risk-adjusted rates of return and real expected growth rates. The other is risk-neutral pricing.

The rate of return used in the valuation of real options have a significant influence on both optimal exercise policy and option value. Especially with long term valuations, like many real options, a slight change in the rate of return can make a substantial difference due to the compounding effect. Using an appropriate discount rate is thus important to obtain correct results.

Another procedure of obtaining a valuation is to price the cash flows using other securities with similar risk profiles that are traded in the market. By replacing the real price growth with the risk-neutral price growth obtained from traded forward-contracts, one can use the risk-free rate to obtain the value of the project and connected options. This treats risk in a consistent manner compared to the market, avoiding biases that can occur otherwise (Laughton [16]). This is commonly called risk-neutral valuation. Since all parameters are estimated from financial markets, which are assumed to be efficient, this leads to an accurate valuation of the project.

Using risk-adjusted rates has the advantage of being familiar to decision-makers in most firms today, and is perhaps the most intuitive of the two approaches. We do however choose to use risk-neutral pricing, since this ties the valuation of the risky cash flows directly to observed prices of this risk. The risk-neutral method is also the most common approach when valuing options. One issue with using risk-neutral pricing is that the risk-neutral method can underestimate capital costs when risk of default is present (Almeida and Philippon [1]). This can lead to inaccurate valuations when the cost of distress is high. This was the case during the financial crisis in 2008/2009, when the risk-free rates went down but the cost of capital for firms increased. Thus, the risk neutral valuation would advice firms to invest more in a time where firms' capital costs increased, which is clearly the wrong advice. However, in more stable conditions the distortions related to the risk of default should be low, specially when considering large petroleum companies.

3.4 Case Study

For valuing finite-maturity American call options one must use numerical methods. Common approaches include lattice methods, a la Cox et al. [9], or finite difference methods, see Brennan and Schwartz [4]. However, these methods are cumbersome when there are multiple and possibly heterogeneous sources of uncertainty. In such situations, approaches based on Monte Carlo simulation come to the fore; see [5,28,17].

Input Data In this section, we use the model developed in previous sections to value two real options connected to an offshore oil project with the Least Squares Monte Carlo algorithm developed in Longstaff and Schwartz [17]. First and second degree monomials of the forward price of the underlying asset as presented in (2) and (3) are used as regressors in the LSM calculation. We use risk neutral pricing.

Table 3: Financial parameters

S_0	- Current oil price	- USD 60
r_f	- Risk free rate of return	- 4.3%
δ	- Lease rate	- 1.6%
σ	- Annual volatility oil price	- 29.5%
K_E	- Expansion option strike/Total cost tie-in field	- MUSD 600
K_A	- Early decommissioning option strike/Initial production unit sales price	- MUSD 500

Table 4: Reservoir parameters

R_0	- Initial reservoir reserves	- 300 MMbbl
R_{tie-in}	- Initial tie-in reserves	- 15 MMbbl
q_w	- Maximum well production	- 66 MMbbl/yr
q_p	- Platform production capacity	- 33.17 MMbbl/yr
T	- Field life time	- 20 Years
I_{Tot}	- Total Investments	- MUSD 2,228
$T_{Ramp-up}$	- Production Ramp-up time	- 3 Years

Expansion Option The option to invest in a tie-in field takes the form of a call option, as discussed in Sect. 3.1. To acquire this option the operator might have to invest in extra deck-space or other forms of extra capacity today, denoted C_{tie-in}. This will be the cost of obtaining the real option, and should not be confused with K_E which is the investment needed when the tie-in is connected. Using the input data in the previous section and taking the price growth into account, we find that the maximum static NPV is obtained at $T = 8$ which is the last year of plateau production. However, after deducting investment costs the NPV is MUSD -176 at the optimal investment time discounted back to $t = 0$. In a deterministic setting, it does not pay off to produce the satellite and based on this the operator should not invest in excess capacity in order to have the opportunity.

When we add price uncertainty the answer changes. By valuing the investment opportunity as an American call option on the incremental production, the option to invest is estimated to be worth MUSD 150. This implies that if the investment needed today, C_{tie-in}, is less than MUSD 150, the operator should invest in order to have the option. This helps explain why operators frequently invest in extra capacity, since having the opportunity of producing nearby satellite fields creates valuable real options.

Adding further uncertainty by introducing uncertainty in production, the option value is still in the same range as before with an option value of MUSD 161. The lower contribution is not surprising, as the variation in production is lower compared to price variation and the production follows a mean-reverting process rather than a Brownian motion.

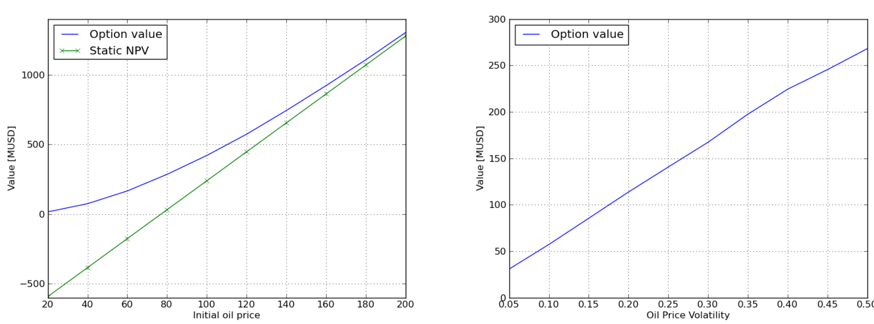
Sensitivity Analysis As we can see from Fig. 4a, the option value increase with increasing initial oil price. Unlike a static NPV calculation the option value increases nonlinearly with low initial oil prices, but the growth becomes linear at higher prices.

Table 5: Monte Carlo parameters

N	-	Number of realizations	-	100 000
M	-	Number of time points	-	100

This is natural, as the tie-in is almost certain to be developed at high prices, and the extra value from the option is low. In this case, the option value is almost equal to a static NPV. However, unlike the static NPV the option value is never negative. Because the operator has the choice but not the obligation to develop the tie-in, it will never be developed if it has a negative NPV.

Another important variable is oil price volatility, and the option sensitivity to this variable can be seen in Fig. 4b. The option does not have any significant value for volatilities below 5% per year, and this confirms the conclusion that the project would not have positive NPV in a static valuation method. That the value of a project should increase with larger volatility is contrary to common intuition. The crucial difference between real option valuation and a discounted cash flow approach is that the project owner has the option to not exercise the option. Thus the owner is protected from the case where the price falls, since the satellite field will not be developed in this case. High volatility increases the value because it increases the probability of a very high payoff, without increasing the probability of a large loss. However, higher volatility will increase the optimal exercise price and delay the investment time as seen in Fig. 5b. This is because one needs to have a price high above the break-even price to be certain that the price will not drop to a level where the project has a negative NPV when the volatility is high. Also, we observe that the volatility has less effect on the option value than the initial oil price.

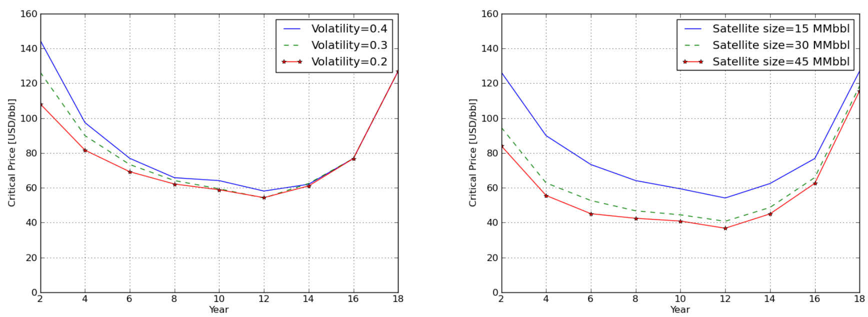


(a) Initial oil price

(b) Oil price volatility

Fig. 4: Expansion option value sensitivities

Another important output from a ROV is the optimal oil trigger price that triggers the investment. For the option to develop the satellite field, the development of the trigger price can be seen in Fig. 5. The trigger price is defined as the smallest price that triggers investment in the LSM-algorithm. As expected, the trigger price increases with increasing volatility and with decreasing satellite size.



(a) Volatility (b) Satellite size

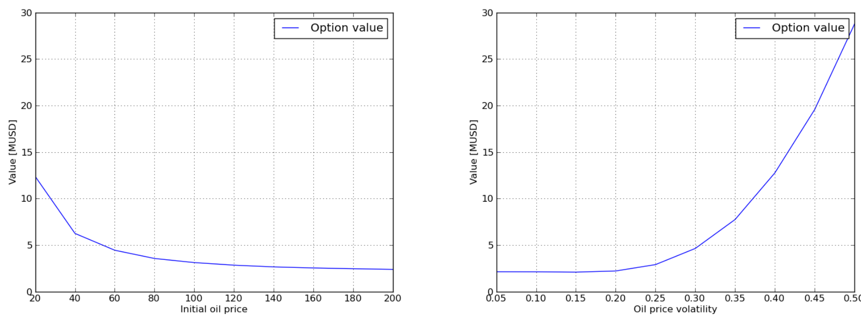
Fig. 5: Trigger price sensitivities

Early Decommissioning Option The opportunity of decommissioning the field prematurely could be a response to lower production volume than expected, or very low oil prices. The operational costs of an oil project are often low compared to the investment cost, and the value of being able to prematurely abandon the field is believed to be low.

When disregarding uncertainty in reservoir reserves, making price risk the only source of uncertainty, the option value is MUSD 4.4. Adding uncertainty in the reservoir reserves, we obtain an option value of MUSD 4.5. We conclude that the option of abandoning the field prematurely is not very valuable, and that the flexibility related to being able to sell the production unit can be disregarded when choosing production technology.

Sensitivity Analysis Since the decommissioning option is similar to a put option, we expect the option value to decrease with rising oil prices. This is also the case, as can be seen in Fig. 6a. Unlike a regular put, the option is worth more than the strike price as the oil price approaches zero. This is because as the project is abandoned the operator also avoids the operating costs. The option value of abandoning is high when the oil price is low, but since the project as a whole will have a negative NPV it will not be built in the first place. Also, we have assumed that the value of the production unit is deterministic.

A more realistic assumption would be that the sales price is positively correlated with the oil price, as few new projects will be initiated if the price is low. This will further reduce the value of early decommissioning. For initial prices close to todays price the option value is negligible compared to the investment. The option value is sensitive to the price volatility, as seen in Fig. 6b. If the price volatility should continue to increase in the future, decommissioning options could become valuable.



(a) Initial oil price

(b) Oil price volatility

Fig. 6: Abandonment option value sensitivities

When considering the trigger prices, we find that the oil price will have to fall below 40 USD per barrel if early decommissioning is to be considered. Compared to historical oil prices this is not an unrealistic situation. Early exercise is however most likely at the end of the production unit's lifetime when the expected sales price is low. We also note that the oil price volatility does not have a large impact on the exercise trigger price.

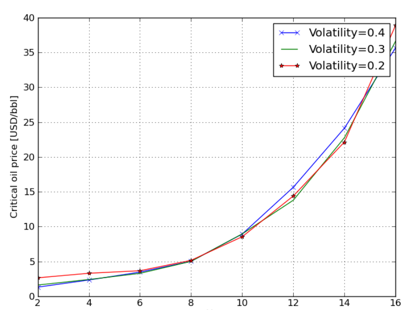


Fig. 7: Abandonment option trigger price

4 Conclusion

In this paper we study the flexibility related to investment timing in offshore oil exploration and production. The oil price is the main source of risk that influence the value of real options related to the project. It is shown that the option to abandon by moving the production unit is not significant compared to the cost of developing the field. The option to expand the production by adding new fields adds value and the value of making initial investments in order to be able to connect such satellite fields in the future can be large even when the current NPV from the satellite fields are negative. As expected, both options increase in value when faced with increased volatility.

For further work, exploring if other price models, e.g. the two-factor model presented by Schwartz and Smith [26], leads to different option valuations would be an interesting extension. Another extension related to the option value framework would be to introduce a stochastic process governing when and if a tie-in field is found. This would be more general than our assumption that the operator knows from the start if there is a nearby field.

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