Exploration economics: taking opportunities and the risk of double-counting risk

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Exploration Economics; Taking Opportunities and The Risk of Double-Counting Risk

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When investing in projects with uncertain outcomes, most companies use a discount rate that reflects their perception of risk and reward. This rate is used in decision tree models that once again represent opportunities and risks, usually with little attention to what was already included in the discount rates. Besides, capital asset pricing models lead to discount rates as "average measures" that do not often represent individual project's risk. Such inconsistent treatments of risk could distort valuation and ultimately destroy shareholder value. In this paper, we use twelve years of monthly return data for major upstream petroleum companies in the U.S. market, and suggest an industry-wide beta, stripped of the blurring effects of corporate debt and embedded real options. In addition, for each project we separately account for systematic and project-specific risks. This provides a more consistent guideline for valuation of exploration and development projects, particularly in the petroleum and mineral industries.

1. Introduction

Ever since the emergence of capital asset pricing models, corporate finance has provided us with a formal method of translating risk into money. More specifically, we adjust the discount rate used for evaluation of future cash flows to account for time value of money and risk. The adjustment for risk, also called the risk premium, draws on financial theories of Capital Asset Pricing Model (CAPM) after Sharpe (1964) and Lintner (1965), or more sophisticated alternatives of Arbitrage Pricing Theory (APT) proposed by Ross (1976), or even Multifactor Models. Regardless of what method is used, all risk premiums reflect the notion that higher risk should accompany higher rewards. More specifically, greater (systematic) risk implies greater risk premiums.

In an alternative risk-neutral approach to valuation (discussed in Smith and Nau, 1995), we apply risk adjustments to the expected cash flows rather than the discount rates. Risky cash flows will be more heavily modified compared to more certain cash flows, but the discount rate will only reflect the time value of money. These two approaches will essentially yield the same results if they are consistent in treatment of risk. In other words, the risk premium in the discount rate (following CAPM) should have the same effect as risk-adjusting the expected future cash flows. Arnold and Shockley (2010) pointed out that both approaches arise from a unified framework and, in theory, are the same.

Yet, the risk-neutral approach accommodates uncertainties in individual projects while the CAPM approach is a general measure representing all risks in all projects a company undertakes or has undertaken; A broad-brush approach that is correct on "average" but potentially mars individual valuations (Smith and McCardle, 1999). In addition, most oil and gas companies also use diverse sources of capital, including debt, to finance their operations; so besides the risk premium, the discount rate should reflect the cost of borrowed money. This Weighted Average Cost of Capital (WACC) accounts for the aggregate financing and investing the company has made. The problem is, exploration and development opportunities frequently fall outside the range of "average" risk or have risk profiles that change when management later decides to change the course of the projects. Even if a project has average risk, separately modelling market uncertainties (such as variation in prices) in decision trees or scenario analyses, introduces a systematic error to valuations.

To overcome these biases, the solution is a valuation model tailored to each individual project. Laughton et al (2008), suggested a consistent decision tree model combining project specifics with market-based valuation. Smith (2005) further led the discussion in a comment to the binomial tree approach of Brandão et al (2005); for a consistent valuation, we rely on risk-neutral approach and directly model the uncertainties of a problem. For example, in a decision tree model of an exploration well, we should model market uncertainties using risk-neutral time series and private uncertainties using expert probability assessments. Brilliant as this is, the industry did not immediately adopt the framework. Most industries persist in using CAPM perhaps because it is straightforward in calculations and easier to implement in the decision-making process, yet, rendering their practice an inconsistent mixture with excessively high discount rates.[1]

In this paper, we point out the biases and provide a remedy. We discuss that if we use the appropriate beta for discounting outcomes of a decision tree or a binomial tree, as e.g. in Brandão et al (2005) and Brandão and Dyer (2005), we restore much of the consistency. Despite the mounting evidence against plausibility of CAPM[2] and its use in valuations (from early works of Banz, 1981, Basu, 1983 to recent oil and gas study of Willigers et al, 2017), we admit that most firms (73% of CFOs in Graham and Harvey's, 2001, survey) use CAPM to estimate their cost of equity. Our intention in this paper is to provide practical valuation guidelines inspired by the popularity of CAPM. We suggest a discounting method from Bernardo, Chowdhry, and Goyal (2007 and 2012) and Da, Gou, and Jagannathan (2012) where the authors suggest adjusting project beta for the real option potentials of the firm. We combine these learnings with decision analysis principles and devise a more coherent valuation method.

This paper contributes to the practice of project analysis from two aspects: it suggests using a normalized measure of project riskiness across the upstream petroleum industry. We use returns from major firms in the US to calculate this measure of risk. In addition, through an example, we suggest using multiple discount rates in decision-tree models that evaluate project flexibility; separating outcomes of normal risk from those that are more certain. These insights are readily applicable to the exploration of non-fuel minerals, and in a general context, to the process of pharmaceutical drug discovery and R&D project selection.

The next section discusses the deficiencies in explanatory powers of CAPM and implications in practice. Even with such a weakness, we use recent findings in section 3 to calculate the standard measure of project risk. Later in section 4, we apply this measure to valuation of an exploration opportunity and suggest a second refinement to valuation models. Section 5 provides more discussion of the suggested method and concludes.

2. Caveats of Using CAPM

Projects should be accepted only if they increase shareholder value. In other words, we should only invest in those projects that generate a stream of cash flows significantly larger than other competing opportunities. If the risk and return on a company's investments does not surpass other rival

[1] In a recent survey by the Society of Petroleum Evaluation Engineers (SPEE, 2018) on discount rates used in petroleum exploration and development, most respondents reported rates close to 10%. Other studies revealed similarly elevated rates, including the discussion paper released by the International Valuation Standard Council (IVSC, 2015). Several academic analyses, for example Guedes and Santos (2016), have also used discount rates of 10%-15% for valuation of upstream petroleum real options.

[2] More than a quarter of a century has passed since Fama and French (1992) pointed out anomalies in CAPM. They later provided convincing arguments that CAPM beta does not explain the cross-section of stock returns and therefore does not lead to appropriate risk premiums (Fama and French, 1996, 1999, 2004, and 2006).

opportunities[3] in the market, then what keeps the shareholders from investing elsewhere? Using the above arguments, we should design acceptance criteria that measure projects' value from the point of view of shareholders, i.e. the risk and return trade-off as it prevails in a competitive market.

Comparing projects with opportunities in the markets is an insightful procedure. Investors in these markets diversify their firm-specific risk and ask for compensation only when they bear systematic risk. Using CAPM, the expected return for a stock $E(R_i)$, is calculated as[4]

$$\mathrm{E}(R_i) = r_f + \beta_i\big(\mathrm{E}(R_M) - r_f\big) \tag{1}$$

Where r_f is the risk-free rate, $\mathrm{E}(.)$ is the expectation operator, $\mathrm{E}(R_M) - r_f$ is the market risk premium, and β_i is the beta of the stock. For most investors, beta is a key factor; it associates the systematic risk of a stock with its expected return. Also, for management of a firm beta is an indicator; it tells them about the collective market notion of risk and return in their existing and future projects. If projects have the same risk as the stock, they can evaluate projects using the same beta.

How do we estimate a stock's beta? The standard approach is to estimate it using historical market returns; i.e. a regression of returns from market portfolio on returns from an individual stock[5]. We followed guidelines of Fama and Macbeth (1973), assumed S&P500 as the market portfolio along with monthly stock returns from the past five years, and calculated beta coefficients, as of January 2017, for sixteen major petroleum exploration and production companies in the US market.

As other authors have previously pointed out, regression beta estimates are noisy and obscured. Our sample of sixteen largest US domiciled companies[6] with important exploration investments (figure 1) shows how dispersed the 95% confidence intervals are. In fact, the beta for a typical mid-sized company could be somewhere between 1 (same systematic risk as the market) to 3 (very risky investment with wild fluctuations). In this figure, we plotted beta estimates against company's market capitalization; showing that for companies with higher market capitalizations and therefore more extensive assets, perhaps the share of risky exploration investments is small and the uncertainty about beta decreases.[7]

[3] Shareholders invest in petroleum or mineral assets to diversify their portfolio and expose themselves to commodity price variations. As such, investments in petroleum or mineral industries do not compete with investments in, for example, the IT industry.

[4] Although because of its practical appeal, we use CAPM to discuss risk, the concepts of firm-specific and systematic risks are more extensive than the choice of asset pricing model. In general, we can divide risk into random firm-specific that reduce by diversification, and systematic, that depend on macroeconomic states of nature.

[5] We rearranged equation (1) to $\mathrm{E}(R_i) = r_f(1 - \beta_i) + \beta_i \mathrm{E}(R_M)$ and used regression to estimate parameters from the equation $\mathrm{E}(R_i) = a + b\mathrm{E}(R_M)$. Here, the slope b estimates beta.

[6] We used monthly returns from COMPUSTAT and financial metrics from EIKON.

[7] Our choice of the horizontal axis is not entirely speculative. Fama and French (1992) show that size (market capitalization) of the stocks can be used along with beta to explain the expected returns. Kaplan and Peterson (1998) also show that firms with larger market capitalization tend to have lower betas.

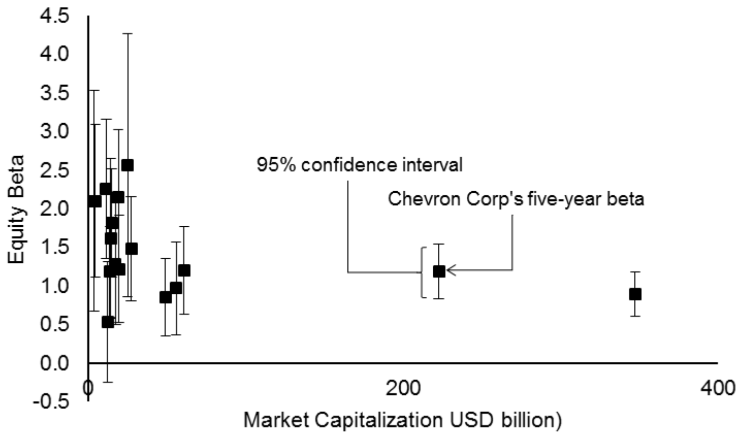

Figure 1 beta estimates for sixteen US domiciled oil and gas companies with significant investments in exploration; five years of monthly returns are used in estimations

The weak explanatory power of beta casts doubts on the applicability of CAPM to project valuation. Some argue that changing the frequency of returns (e.g. using annual returns as suggested by Kothari, Shanken, and Sloan, 1995) could produce a stronger relationship between beta and expected returns, yet Fama and French (1996) assert that the problem with CAPM is more fundamental; beta alone cannot explain the expected returns. Our analysis of twelve years of monthly returns also confirms that although dispersion of beta estimates decreases with larger datasets (figure 2), there remains a wide confidence interval that renders most investment analysis useless[8]. The R^2 in our regressions is also low, ranging from 14% to 38% and suggesting that 60% to 80% of the variations in returns is unsystematic risk and not explained by CAPM beta.

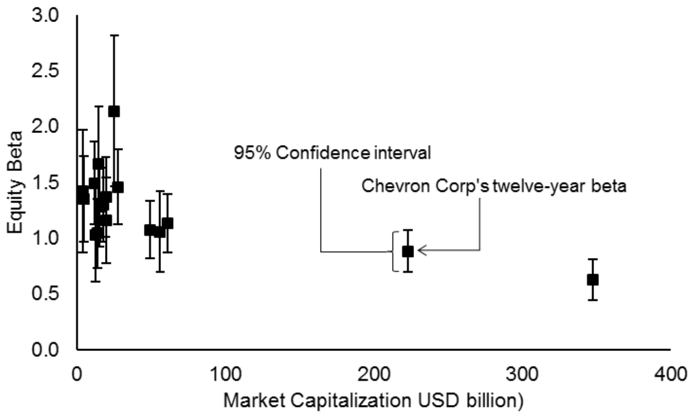

Figure 2 beta estimates for sixteen US domiciled oil and gas companies with significant investments in exploration; twelve years of monthly returns are used in estimations

From figure 2, it appears that smaller companies have even larger spreads, perhaps because of their less diversified project portfolios. In practice, hydrocarbon accumulations are not distributed evenly; most resources come from large fields that require immense capital commitments and complex operations. It takes years of construction and preparation for these projects to bear fruit, and when in production, they produce for decades. During the span of exploration and development, performance indicators generally decrease, but then with the start of production, positive cash flows arrive. These cycles in companies with diversified project portfolios are perhaps smoothed out, some of the swings

[8] For example, if 95% confidence interval for beta is 0.5 to 1.5, assuming risk–free interest rate 2% and market premium 5%, the cost of equity could be between 4.5% and 9.5%. Many projects will move from positive NPV to negative when we switch from 4.5% cost of equity to 9.5%. Furthermore, some argue that this historical time frame of returns does not represent the changes in the internal portfolio of oil companies over the past decade.

may also be taken by governments' fiscal and regulatory framework, but for others it hits them in full force and redefines their financial standing. The market data we use for beta estimates could come from a short span in a long cycle, with no direct bearing on investment performance. These discontinuities also add to variability of beta estimates.

Despite its apparent shortcomings, CAPM has gained a foothold in practice. Market analysts and companies actively use CAPM beta in their formal investment decision process and financial institutions frequently include beta estimates in their reports. Several authors, including Da, Guo, and Jagannathan (2012) and Levy (2010) argue that CAPM can still provide useful investment apprehension. Our aim in this paper is also to provide support for project appraisal and not to promote the use of CAPM, for a clear and transparent understanding of the ideas behind the discount rate could go a long way in generating investment decision insight.

3. Project Valuation Requires Estimating Project Risk

In any valuation, we need to compare the discounted value of future cash flows with the value of investments. Most companies use a discount rate equal to their WACC, arguing that the benefits from the assets should be enough to cover both costs of debt and capital. But this implies that the risk of a project is the same as the average risk of the company reflected in its beta. Often this is not the case.

First, there is financial leverage. Companies use debt to magnify their investing capabilities. Debt usually has a lower cost, but the commitment to pay its interests escalates the risk (and beta) of company's stock. In the end, a leveraged company is riskier, although the nature of its projects is unchanged.

Using Modigliani and Miller (1958) argumentation, we distinguish between equity and business risks and compensate for the effect of leverage in beta. The asset beta (unlevered beta, β_{Asset}) accounts for the effect of leverage, and is a measure of riskiness in company's assets:

$$\beta_{\text{Asset}} = \frac{\beta}{\left(1 + (1 - Tax\ Rate)\frac{D}{E}\right)} \tag{2}$$

Where D and E are, respectively, the market values for company's debt and equity. Assuming corporate tax rate of 35%, figure 3 shows the asset beta in our sample of petroleum companies.

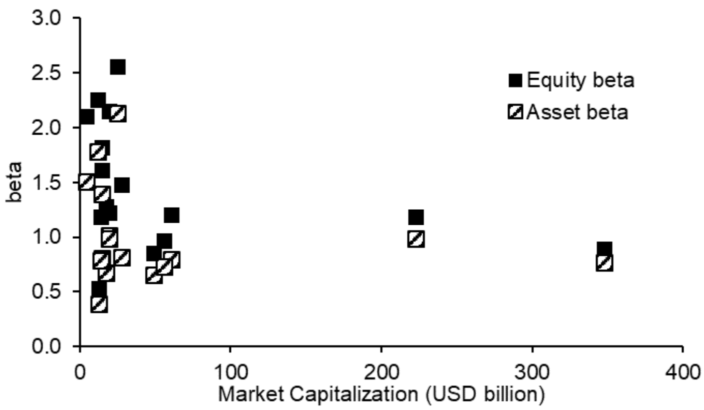

Figure 3 asset and equity beta for our sample of petroleum firms calculated with five years monthly returns. Table 4 shows the data for equity beta and table 5 shows asset beta.

Second, companies enhance project value by creating and exercising real options, by capturing upside opportunities and mitigating risks. Our β_{Asset} still represents the mix of all assets, some with significant real options. Even though we cleared the effect of financial leverage, using β_{Asset} in project valuations means we discount cash flows with a rate that reflects time value of money, projects' systematic risk, *and* some embedded real options. If options are separately represented in a decision tree, using β_{Asset} means double-discounting the options.

We can explain the above point using a simple example: a major oil and gas company considers acquiring the rights to an exploration tract. If they discover oil, their reward will be a conventional mid-sized development project. However, the geological chance of discovery in this tract overshadows all other risks. Normally, the company's β_{Asset} reflects the systematic risk of existing assets and the growth opportunities from all tracts under consideration. For this specific valuation, using β_{Asset} (which already reflects the risk of geologic success or failure) will distort the value.

In general, the equity returns of companies reflect the risk of existing operations together with embedded real options; these include the option to delay investments, contract/expand operations, and value of information. Furthermore, the options, at least from CAPM point of view, are riskier than the existing projects (as observed by Berk, Green, Naik, 1999, Dechow, Sloan, and Soliman, 2004, and Da, Guo, Jagannathan, 2012). Perhaps if we could separate the risk of options and projects, the valuation would be more straightforward. How can we strip the effect of embedded options from β_{Asset}?

If we assume the value of the firm V is composed of the value of its projects A and their embedded growth options G (Bernardo, Chowdhry, and Goyal, 2007) then

$$V = A + G \tag{3}$$

The firm's β_{Asset} is the weighted average of β_{Project} and β_{Option}, with weights corresponding to the ratio of A and G to the total value

$$\beta_{\text{Asset}} = \frac{A}{V}\,\beta_{\text{Project}} + \left(1 - \frac{A}{V}\right)\beta_{\text{Option}} \tag{4}$$

$$\beta_{\text{Asset}} = \beta_{\text{Option}} - \left(\beta_{\text{Option}} - \beta_{\text{Project}}\right)\frac{A}{V} \tag{5}$$

Some authors, including Smith and Watts (1992) and Chen, Novy–Marx, Zhang (2010), argue that proxies such as book-to-market ratio or return on asset (ROA) can be useful in explaining the share of growth options in a firm's value. In other words, even without the knowledge of projects and operations, proxies could provide a rough measure of $\frac{A}{V}$ in equation (5). We assume "share book-to-market" ratio commonly reported by financial services estimates $\frac{A}{V}$. The "book" refers to the accounting valuation of a firm, while "price" is the market perception of the value. As accounting conventions do not recognize intangible assets and growth options (while market prices do), this ratio could reveal the potentials of value creation from embedded real options.

We also assumed (following Bernardo, Chowdhry, and Goyal, 2007) that β_{Project} is the same for all upstream "typical" projects; where typical refers to a normal development project without real options. This is a convenient assumption and helps us with determining the parameters of equation (5), but at the same time sacrifices some realism. It implies that any normal project (stripped of its options) has the same risk across all companies within this sector. The variability in the companies' beta is then caused only by their embedded real options. Implicitly, we are assuming the companies have a diverse project portfolio in various phases of development, production, and abandonment, and that none of these phases dominate their portfolio. Otherwise, companies dominated by e.g. mature and declining fields are less risky compared to those in their ramp-up period. We suspect that these cross-company differences are small compared to the benefits of better decision making via an aggregate project beta.[9]

The relationship between β_{Asset} and book-to-market ratio reveals information about embedded growth options. If we assume β_{Asset} is the dependent, and shares' book-to-market ratio is the explanatory variable, then we can use the simple regression equation $Y = a + bX$ to estimate the parameters of equation (5). Here the intercept a estimates β_{Option} and slope b estimates $-\left(\beta_{\text{Option}} - \beta_{\text{Project}}\right)$.

However, book-to-market ratio is a noisy measure of $A/_{V}$ and could distort the regression results. Bernardo et al (2007) suggest an alternative approach; we could split the data into two portfolios based on their market-to-book values. These portfolios represent the (equally weighted) means of β_{Asset} and market-to-book values of the stocks in them. A straight line that connects these two points yields the intercept and slope coefficients for equation (5). We have provided robustness checks of this approach in Appendix B.

Our estimate of β_{Project} is comparable with previous calculations by others. Bernardo, Chowdhry, and Goyal (2007) used data covering the period 1977 to 2004 and (among other industries) calculated β_{Equity} and β_{Project} for the petroleum and natural gas industries. These authors derived similar results when used data covering 1977 to 2009 in a later study (Bernardo, Chowdhry, and Goyal, 2012). The results are summarized in table 1.

Table 1 A comparison of $\beta_{Project}$ for petroleum industry from previous studies. Note that not only the timeframes are different, the oil and gas firms within the studies are probably dissimilar.

Study	Data Covering Period		
	2000-2004	1995-2004	1977-2004
Bernardo, Chowdhry, and Goyal (2007)			
Average β_{Asset}	0.61	0.604	0.734
β_{Option}	0.912	0.972	1.219
β_{Project}	0.451	0.393	0.594
			1977-2009
Bernardo, Chowdhry, and Goyal (2012)			
Average β_{Asset}			0.78
β_{Option}			—
β_{Project}			0.65
This Study		2012-2016	2005-2016
Average β_{Asset}		1.01	0.87
β_{Option}		1.13	0.84
β_{Project}		0.9	0.88

With dissimilarities in historical data and choice of oil and gas firms (Appendix B discusses our choice of firms), our estimate of β_{Project} is slightly higher than previous studies.

4. Multiple Project Outcomes: Petroleum Exploration Valuation

Yet, for a more consistent valuation, estimating project beta is not enough. Common practice in exploration valuation uses a single discount rate across the decision tree model, even though the end-

[9] Also note that development projects commonly have real options later in their lives. Management has the option of using Enhanced Oil Recovery (EOR) techniques to boost production of declining reservoirs, they have flexible abandonment timing, or sometimes can switch between oil or gas production. We assume the value of these further future options is insignificant at the time of exploration decisions.

nodes have disparate, and time varying, risk profiles (Smith and McCardle, 1999). In exploration valuation, the outcome of failure—the cost of dry hole—is much more certain than the outcome of success—the net present value of a large investment with years of income. Using one rate to discount all these cash flows is inherently flawed.

One way to consistent valuation would be to rely on risk-neutral valuation; individually modelling key uncertainties of the project and then discounting all cash flows with a risk-free rate. Discussed in Smith and Nau (1995) and applied to petroleum projects in e.g. Jafarizadeh and Bratvold (2012 and 2015), this scheme is well suited for decision trees and binomial lattices. Still, most companies favour CAPM when evaluating exploration opportunities. In this section we admit industry's reluctance to depart from CAPM and provide a practical compromise; at the cost of departing from risk-neutral valuation, we use the relevant $\beta_{Project}$ for each outcome to inform the appropriate discount rates in a decision tree.

In a pivotal academic interchange of ideas, Brandão et al (2005) suggested combining option pricing methods within decision trees, prompting comments from Smith (2005) who pointed out the inherent inconsistencies and provided alternative solutions. This debate laid out the guideline for an integrated financial and decision analytic approach. We discuss, through an example, that an appropriate use of $\beta_{Project}$ in a decision tree could to some extent restore consistency in the methods like that of Brandão et al (2005) and Brandão and Dyer (2005) and bring them closer to an integrated valuation. We provide details in Appendix D. Our approach is not the ultimate remedy yet is affordable and practical.

4.1 Example: Valuation for an Exploration Decision

We discuss our approach using a project that one of the authors encountered in practice. A company considers drilling an oil prospect next year with 15% chance of success. It costs USD 50 million to drill, and if they find oil, with USD 400 million investment in development, they expect eight years of production revenue. With this level of uncertainty[10], the company considers gathering more information: a nearby production well, scheduled to be drilled this year, can accommodate an optional pilot side–track. With an additional cost of USD 10 million, it can also test the exploration prospect. The test is not perfect, but with 80% accuracy will reveal if the prospect contains oil. If the test results are negative, the company will forgo this exploration opportunity. The question is: should the company invest in the USD 10 million side track?

The value of information from the side-track well depends on two main factors, the probability of success conditional on positive test results (if negative, they will walk away) and its value of future cash flows. With 80% (symmetrical) accuracy of the test and prior probabilities, after application of Bayes rule, the conditional probability of success is 41% and the probability of positive test result is 29%. Figure 4 shows the decisions, uncertainties, and probabilities associated with each outcome. The Net Present Value (NPV) at each end-node is the discounted expected value of future cash flows. These calculations call for consistent use of project beta.

[10] A myriad of other sources of uncertainty, from extent of discovered oil to prices and interest rates, influence the value; yet to keep the problem simple, we assumed the cash flows are expected values and there are no real options other than those modelled in the decision tree.

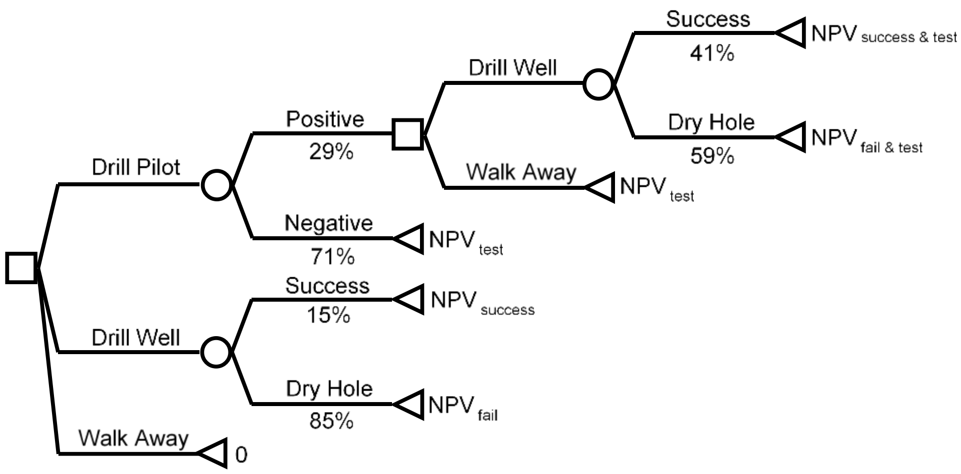

Figure 4 A decision tree model for the problem of value of side-track well

If we assume industry-wide project beta is 0.9, then with risk-free interest rate of 2% and market risk premium of 5% (Fama and French, 1997), the cost of equity using equation (1) will be 6.5%. If this specific company uses 50% debt financing with 4% interest[11], then its weighted average cost of capital will be slightly over 5%. This rate is applicable to cash flows from end-nodes in the decision tree marked as NPV_{success} and $NPV_{\text{success \& test}}$ as they are "typical" upstream development projects. We admit that these projects may not be completely devoid of real options, but for simplicity we assume the options are insignificant within the context of decisions today. The other outcomes in the decision tree (NPV_{fail}, NPV_{test}, and $NPV_{\text{test \& fail}}$) refer to the present value of the cost of dry hole and side-track well that are generally constant. They do not vary with markets and their project beta is zero. Using equation (1) and assumptions above, the discounting rate for these "certain" outcomes is 3%.

We modelled the geological uncertainty in the decision tree, a technical risk that does not require discounting or risk adjustment because it is not correlated with the market. We also discounted all cash flows to time zero for an even-handed comparison. Figure 5 shows that the optimal action is to first drill the pilot well. If the results came out positive, then they should proceed with drilling the exploration well. If we had followed the industry convention and used a single discount rate across the decision tree, the recommended decision could have been different. Using any single discount rate higher than 8% in this decision tree would show the optimal decision as "walk away" (the lower branch in the first decision node).

[11] In the current U.S. market, companies have debt financing at rates as low as 3% or as high as 10%.

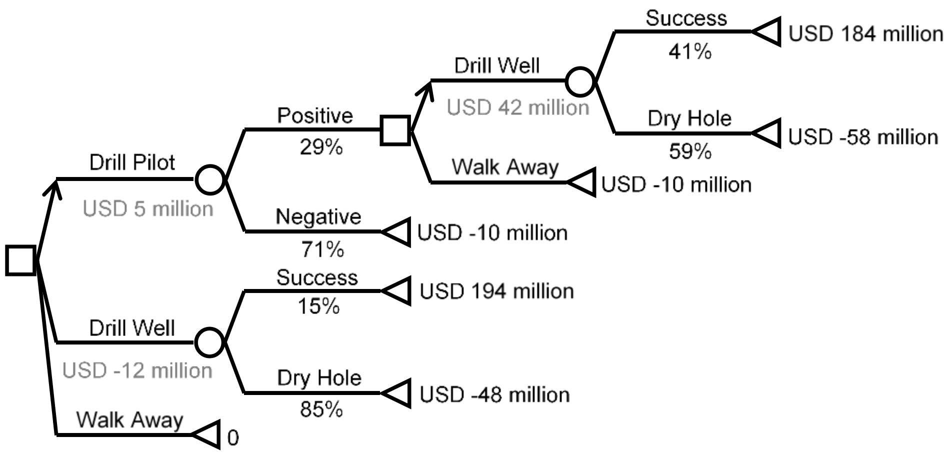

Figure 5 arrows showing the optimal course of action for the exploration problem. The numbers at the end-nodes represent the net present value of the cash flows, discounted at associated rates (5% for development projects and 3% for certain outcomes such as dry hole). Numbers in grey font represent expected net present value for each alternative.

To clarify how our approach leads to different decision recommendation, table 2 also shows the results from other traditional and biased analyses. In those approaches, the combined effect of two biases leads to misleading results; 1) excessively high discount rates, and 2) use of the same discount rate for all end-nodes in the decision tree. The accompanying spreadsheet also allows readers to dynamically change the discount rates and see for themselves the effect on recommended decision.

Table 2 Using different discount rates across the decision tree of figure 5 results in different decision recommendations

Approach	Discount rate	Value of Drilling Pilot	Value of Drilling Well	Recommended Decision
This paper: $\beta_{Project}$ for typical end-nodes and zero beta for certain nodes of the tree	6% for typical and 3% for certain nodes	USD 5 Million	USD -12 Million	Drill Pilot
Traditional Oil and Gas: One discount rate for all outcomes	8% for all nodes	USD -1 Million	USD -18 Million	Walk Away
Traditional Oil and Gas: One discount rate for all outcomes	10% for all nodes	USD -4 Million	USD -22 Million	Walk Away

This method is generally applicable to a variety of real options. We model key technical uncertainties and identify outcomes, then categorize outcomes based on their inherent risks. Some outcomes would be of typical risk level, others might be nearly certain. The key to consistency is, as discussed in Appendix D, in valuation of risky cash flows.

- Step 1: Calculate net present value of all outcomes; use project beta to inform the discount rate for typical risk outcomes. Use zero beta for certain outcomes.
- Step 2: Model technical uncertainties in the decision tree and select the alternative with the highest expected value.

With these steps, we could extend our approach to, e.g., valuation of mining projects as in Topal (2008), or drug exploration in pharmaceutical projects. Using decision trees to model key technical uncertainties and individual risk assessment of outcomes, we could extend valuations to a wider context.

4.2 Discussions

Our method of exploration valuation differs in two aspects from the conventional methods. First, we suggest using project beta when discounting cash flows of "typical" projects—those nearly free from embedded real options. Second, not all end-nodes in the decision trees should be discounted with this same rate. The “failure” end-nodes are less uncertain than full blown development projects, so they should be discounted with a rate that reflect zero beta. This method of project valuation, compared with traditional methods, sometimes leads to different decision recommendations.

In addition to compensating for the effect of financial leverage and growth options, we could also adjust betas for operating leverage. Other things equal, companies with higher operating leverage expect to have higher risk in their project values. For example, a company with fixed long-term drilling rig contract has a high operating leverage. In any future scenario, high or low oil prices, large or small discovery, etc, they should pay the same fixed drilling rate. Compared with companies that use floating rig rates, this company experiences more variability. We discuss in Appendix C, that adjusting project beta for this effect is not straightforward. We avoided this problem by collecting beta information from firms with similar operating leverage as the company in our example.

As Lund (2014) and Davis and Lund (2018) show, the tax regime also affects project risks. Exploration wells in two distinctively different tax regimes, say Norway and Russia, entail different government takes due to tax and depreciation deductions. With different risk levels, a consistent valuation also calls for adjustment to beta due to differences in tax systems. In our sample of project betas, we tried to limit these effects by considering companies predominantly with US exploration licenses, however in practice, it is beneficial to consider further refinements to betas and improve consistency.

Above all, calculating beta for companies with less diversified project portfolios means our estimates will be coloured by the most prominent projects. Hydrocarbon accumulations are not evenly distributed and large discoveries require immense resources for development. Those smaller companies aiming to develop large discoveries experience intense financial swings as projects go through completion phases; with this also varies their beta. For economic analysis of exploration projects, we encourage practitioners to judge what lies ahead and be aware of limitations in beta.

Aside from the considerations about market data, companies deal with internal subjective assessments. They claim that excessive discount rates include an extra margin for such unforeseeable biases. For example, most companies argue that the chance of exploration success is often optimistically estimated; in other words, fewer exploration wells lead to discoveries than expected. Furthermore, as Merrow (2012) reports, a large subset of oil and gas projects experience cost overrun and slippage. Because of these biases, projects tend to underperform their “advertised” economics. Companies know this and compensate by applying higher than WACC discount rates. In practice, discount rates as high as 10-15% are common.

Given the state of practice, our method seems to go on the opposite direction; we recommend using generally lower discount rates and differentiating typical-risk from certain outcomes. While the estimation biases in project analyses are real, we tend to take a prescriptive position and recommend consistent valuation with reduced estimation biases. We believe a black-box approach to any valuation is harmful, and for our method to be useful, it should become a fully inclusive practice. Those engineers and geologists who provide inputs to the valuation process should be aware of the impact of their estimation biases. Aside from this, our approach makes a more consistent method by leaving project specific risks out of the discount rate. When we separately model risks in decision trees or other valuation models, we tend to appreciate their individual effects and consider measures to avoid biases.

Finally, our approach is related with the bottom-up and fundamental beta estimation method discussed, e.g., in Brealey et al. (2012) and Damodaran (2012). Here, individual project risks are assessed by looking into market peers in the same business and then aggregated up to form a project beta, keeping in mind the differences in operating leverage, debt, and mix of projects within firm’s internal portfolios. The project beta calculated in this approach could replace step 1 in our methodology and used for project appraisals. Still, we should consider the issues raised earlier about consistency of the assumptions, including the additional challenge of finding direct peers in the market and obtaining hard-to-find information about their business characteristics.

5. Conclusions

In this paper, we discuss that project risk should inform the discount rate. Furthermore, the traditional WACC valuation fails when managers have the flexibility to change course after some uncertainty is resolved. We suggest two main modifications to the conventional valuation practice: first, following Bernardo, Chowdhry, and Goyal (2007) use project beta—disentangle beta from the effect of financial leverage and growth options—to calculate the discount rate. We used monthly return data for major upstream companies in the U.S. market and calculated an industry-wide project beta. Second, use this rate for “typical risk” outcomes in a decision tree that explicitly models technical risks. For other “fixed” outcomes in the tree, use zero-beta rate.

This method is simple and practical, and at least when we agree on an industry-wide project beta, leads to consistent valuations. It may be too broad for some applications, and perhaps will not replace the detailed approach of fundamental beta estimates (Brealey et al. 2012 and Damodaran, 2012) or the risk-neutral approach of Smith and Nau (1995), but its simplicity supports practical procedures and could ease the valuation process. Furthermore, most upstream companies use hurdle rates that far exceed the theoretical WACC to cover the unaccounted uncertainties and nonlinearities. Our method provides insight on the extent of these implicit assumptions. Above all, we offer a valuation model, and as statistician George Box noted, all models are wrong, but some are useful.

The supplementary material and historical data used in this paper are available at:

https://www.dropbox.com/s/bptx0owcjd82v50/Example_EXP%20Valuation.xlsx?dl=0

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Appendix A the Cash Flow Model

We used the model in table 2 to calculate cash flows for end-nodes in the decision tree. If they discover oil, the end-node representing success is shown at the upper part of the table. They expect to discover 20 MMbbl of oil and each year produce 20% of the remaining oil in place. This requires USD 400 million upfront investment and yearly operating cost of USD 50 million. Oil prices are expected spot prices predicted for the next 10 years.

Table 3 cash flow model for success (top) and failure (bottom)

	Discount rate	5%										
	Rservoir volume (MM bbl)	20										
	Decline rate	20%										
Success	Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
	Oil price (USD/bbl)	65	67	68	69	70	70	70	70	70	70	70
	Production (MMbbl)	0	0	0	4	3.2	2.6	2.0	1.6	1.3	1.0	0.8
	Revenue (USD million)	0	0	0	276	224	179	143	115	92	73	59
	Cost (USD million)	0	50	400	50	50	50	50	50	50	50	50
	Cash Flow (USD million)	0	-50	-400	226	174	129	93	65	42	23	9
	NPV (USD million)	194										

	Discount rate	2%		
Failure	Year	2018	2019	2020
	Cost (USD million)	0	50	0
	Cash Flow (USD million)	0	-50	0
	NPV (USD million)	-49		

In addition to the cash flow model, the companion spreadsheet also shows the Bayesian update, and the calculations behind the decision tree.

Appendix B: Market Data and Robustness Check

We used monthly returns (in COPUSTAT database) from 2005 to 2016 to calculate beta and estimate cost of capital. There are numerous firms under COMPUSTAT's oil and gas category, but we decided to limit our study to the sixteen major players in the U.S. upstream petroleum market because they make up the bulk of market capitalization and have significant investments in exploration assets. While the complete dataset is available in the companion file, table 3 shows the key figures used in figures 1 and 2.

Table 4 Equity beta estimates used in figures 1 and 2. We used historical monthly returns for each company in a regression against S&P returns

	Using Twelve Years Monthly Return			Using Five Years Monthly Return		
	Equity β	Standard Error	R^2	Equity β	Standard Error	R^2
ExxonMobil Corp.	0.628	0.090	0.254	0.895	0.142	0.407
ConocoPhillips	1.133	0.129	0.352	1.204	0.285	0.235
Chevron Corp.	0.884	0.095	0.381	1.186	0.176	0.438
Marathon Oil Corp.	1.493	0.187	0.311	2.258	0.454	0.299
Murphy Oil Corp	1.352	0.193	0.256	2.101	0.496	0.236
Hess Corp.	1.279	0.180	0.263	1.819	0.349	0.319
Occidental Petroleum Corp.	1.076	0.130	0.327	0.854	0.252	0.166
Apache Corp.	1.296	0.166	0.301	1.282	0.395	0.154
Anadarko Petroleum Corp.	1.458	0.168	0.347	1.482	0.340	0.247
Devon Energy Corp.	1.367	0.179	0.292	2.152	0.434	0.298
Continental Resources Corp.	1.665	0.258	0.269	1.616	0.520	0.143
Pioneer Natural Resources Corp.	2.139	0.339	0.219	2.562	0.851	0.135
Concho Resources Inc.	1.158	0.193	0.247	1.220	0.349	0.174
EOG Resources Inc.	1.058	0.180	0.196	0.969	0.299	0.153
Noble Energy Inc.	1.041	0.153	0.246	1.182	0.292	0.220
Cabot Oil & Gas Corp.	1.024	0.209	0.144	0.535	0.391	0.031

We used EIKON database to obtain the additional information we required to calculate asset beta in figure 4. The first four columns of table 5 show the firms' names, their market capitalization, debt to equity ratio, and Price to Book value. Then in the fifth column, we used equation (2) and calculated asset betas from equity betas of the five-year period. The last column of the table also shows the "service beta." This is a figure that estimation services provide as their assessment of future beta; usually starting with regression of historical data and then arbitrarily adjusted to reflect the risk in the future. We can observe that the service betas from EIKON are close to our equity beta from regression of five years monthly return (shown in table 4).

Table 5 information used to estimate asset beta in figures 4

	Market Capitalization (USD billion)	Debt to Equity Ratio	Price to Book Value	Asset β	Service Equity β
ExxonMobil Corp.	347.36	0.256	1.939	0.767	0.810
ConocoPhillips	60.91	0.780	2.011	0.799	1.170
Chevron Corp.	222.66	0.317	1.523	0.983	1.230
Marathon Oil Corp.	11.52	0.414	0.929	1.779	2.300
Murphy Oil Corp	4.58	0.609	0.921	1.506	2.160
Hess Corp.	14.90	0.468	1.082	1.394	1.770
Occidental Petroleum Corp.	49.09	0.457	2.334	0.659	0.690
Apache Corp.	17.45	1.370	2.529	0.678	1.090
Anadarko Petroleum Corp.	27.37	1.255	2.353	0.816	1.380
Devon Energy Corp.	19.29	1.713	2.799	1.018	2.210
Continental Resources Corp.	14.49	1.530	3.405	0.810	1.409
Pioneer Natural Resources Corp.	25.10	0.309	2.368	2.133	0.941
Concho Resources Inc.	19.59	0.360	2.202	0.989	1.139
EOG Resources Inc.	55.86	0.500	4.018	0.731	0.939
Noble Energy Inc.	13.80	0.762	1.442	0.790	1.124
Cabot Oil & Gas Corp.	12.37	0.592	4.683	0.386	0.468

To calculate project beta, we followed the methodology of Bernardo et al (2007) and used information in the fourth and fifth columns of table 4. Market-to-book ratio is generally a noisy measure of $A/_V$, therefore, a regression line may not reveal the relationship between data. Instead, we constructed two portfolios, a high- and a low-market-to-book ratio portfolio, representing two points on a line.

To check the robustness of this approach, we repeated the experiment with finer details. Instead of two portfolios each with eight firms, we used four (each containing four firms) as well as all individual firms in a linear regression. As we expected, the slope representing $-(\beta_{\text{Option}} - \beta_{\text{Project}})$ changes with more disaggregation, yet our results are robust with respect to β_{Project}. In other words, as table 5 shows, the conclusions in this paper are also valid even if we use a regression with all individual betas.

Table 6 Results of robustness check

Robustness Check	β_{Asset}	β_{Option}	β_{Project}
Two Portfolios	1.01	1.13	0.90
Four Portfolios	1.01	1.30	0.78
Regression of all betas	1.01	1.38	0.61

Furthermore, if there is a correlation between the independent variable, book-to-market ratio, and the error terms, then the ordinary regressions above give biased results. To see if such a correlation exists, Bernardo et al (2007) perform instrumental variable (IV) regression. In this approach we look for instruments such that their slope of regression is a consistent estimator of the true slope. Bernardo et al (2007) suggest instruments like earning-to-price ratio, cashflow-to-price ratio, and the dividend yield. In our data set of petroleum stocks, we have data on price-to-cash flow per share and dividend yield. We performed ordinary regression along with IV regression for each of these instruments and compared results.

The results mainly show that the OLS regression (and associated simplified two-point line) is appropriate for estimating beta project. Specifically, a Hausman specification test rejects the hypothesis that independent variable is correlated with regression error at 5% significance level. Like Bernardo et al (2007) who reported that slope estimates from IV regression are larger than OLS and closer to two-point aggregation of portfolios, we also use beta projects 0.9 from table 6 in our calculations.

Appendix C Operating Leverage and Project Risk

Exploration projects have a mixture of fixed and variable costs. The fixed costs do not vary with oil prices, market index, or the size of discovery while the variable costs do. Companies usually decide the proportion of fixed and variable costs. For example, an exploration company can enter a long-term contract with a third party for fixed drilling rates or can even buy its own drilling rig. This is a large upfront fixed cost. If oil prices suddenly drop, the company must still pay the fixed costs, facing possibly large losses. On the other hand, in case of high prices, they will realize large profits. Compare this company with a second company that uses floating rig rates in the market. With fluctuations in oil prices, rig rates also fluctuate (usually with a lag time), leaving the company with almost the same expected profit. In other words, the first company compared to the second company had large fixed costs, higher operating leverage, and more risk. If we could measure operating leverage in companies across industry, then perhaps we could further fine-tune project beta used in exploration valuation.

Information about operating leverage of companies is usually not in public domain. Still, we could use proxies to indirectly measure it. Companies routinely publish their Earnings Before Interest, Tax, Depreciation, and Amortization (EBITDA); a measure of their operating performance. A reasonable measure of operating leverage in most industries is the ratio of EBITDA to Net Sales. However, this may not be appropriate for petroleum exploration business as first oil usually is produced and sold years after the exploration well is drilled. In other words, EBITDA and Net Sales in a specific year may be completely unrelated.

Also, operating leverage is correlated with book-to-market ratio; the proxy that we used earlier to disentangle project and growth beta. For a set of companies with distinctively different levels of operating leverage, our method will produce betas that mix the effect of growth options and operating leverage. Bernardo et al (2007) also point this out in their robustness tests and conclude that their results are not driven by differences in operating leverage across firms. To avoid these difficulties and ensure a consistent valuation methodology, we used a group of upstream petroleum companies with almost similar operating leverage.

Appendix D Real Options Valuation

Business projects are rarely stationary. Some like exploration drilling show dramatic dynamics, for them the outcome of drilling is the ultimate revelation, it opens new doors into further decisions with risks and opportunities. Other projects show less sizable, but still important, dynamics as in, for example, the option to switch between oil or gas production. However, the common feature of all these projects is that their outcomes change as the conditions change and as new information arrives. Their value depends on the later decisions that management takes.

A good valuation model shows the dynamics of a project and the decisions that could change its course. As firms operate in the market, the model should also associate projects with their value in the marketplace. While several existing approaches to real option valuation agree on these principles, there are differences in style and perception. Some approaches are less consistent and others, while more effortful, provide a comprehensive and coherent valuation model. In this appendix, we briefly discuss major approaches to real option valuation and their relationship with our method.

Brandão et al (2005) used binomial decision trees (a version of decision trees with binary outcomes for uncertain nodes) within the notion of Marketed Asset Disclaimer (MAD), discussed in Copeland and Antikarov (2001), to evaluate real options. Their approach, like ours, is a mix of decision analysis and Discounting Cash Flow (DCF) methods. As Smith (2005) pointed out, this method had some fundamental inconsistencies. Among others, there is the question of discount rate. If the value of project without options is taken as the underlying parameter, as MAD approach requires, then what is the appropriate discount rate? Brandão et al (2005) use the WACC. Specifically, they use WACC to calculate net present value of a project without option, estimate its volatility in a Monte Carlo simulation that models the uncertainties, and build a binomial decision tree by assuming that project without option is the underlying asset. As we discussed earlier in this paper, WACC already includes the effect of real option, therefore MAD approach double-counts this effect.

If we assume the correct discount rate is μ, then it should include the market risk premium $\lambda = \mu - r_f$, where r_f is the risk-free rate. In other words, μ reflects the time value of money and riskiness with respect to market. In a risk-neutral valuation scheme, we deduct risk premiums from the sources of uncertainty such as prices and discount the resulting cash flows with risk-free rate. For example, if our project only produces one barrel of oil next year, in today's value it will be

$$V = \frac{1 \times (S - \lambda^*)}{\left(1 + r_f\right)} \tag{6}$$

Where S is the expected price of oil next year and λ^* is the price risk premium. In traditional discounted cash flow approach, we use expected prices, but we discount using a risk adjusted rate $\mu = \lambda + r_f$

$$V = \frac{1 \times S}{\left(1 + \lambda + r_f\right)} \tag{7}$$

For consistent valuations, both approaches should result in the same valuation. In other words, the risk-premiums for discount rate and prices, λ and λ^*, are of the same nature. They both reflect the premium of market risk.

In this paper, we generalized this notion when we followed CAPM and set $\lambda = \beta_{\text{project}}\left(\mathrm{E}(R_M) - r_f\right)$. We assumed λ is applicable to typical petroleum projects with many years of production. We also implicitly assumed that β_{project} reflects the systematic risk for end-nodes of the decision tree, is applicable to all elements of the cash flows, and remains constant over the years of a project. Our approach is a step towards consistency because we removed the effect of financial leverage and real options from beta.

It is useful to think of the underlying assumptions when we use this model. In exploration valuation, we model technical uncertainty in a decision tree with end-nodes calculated using β_{project}. There is no double-counting of risk here as project beta accounts for systematic risk and probability of finding oil accounts for unsystematic risk. On the other hand, if our decision tree included both technical and market uncertainties, then using project beta for discounting perhaps distorts the valuation. For such problems, we prefer a fully risk-neutral approach.