REAL OPTIONS AND VALUING STEAM ASSISTED GRAVITY DRAINAGE WELLS IN THE CANADIAN OIL SANDS

by

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Abstract

This paper argues the use of Net Present Value (NPV) does not accurately value Steam Assisted Gravity Drainage (SAGD) wells. Instead, the paper proposes real options to be used in order to capture the decisions and flexibility available to managers in operating a SAGD well. The option to defer, abandon, contract, and expand are estimated using (Trigeorgis, 1991b) log-transformed binomial process. Parameters are estimated using supply cost data from Millington and Murillo (2013). The paper finds that using the DCF or NPV approach recommended by the Economic Evaluation of Oil and Gas Properties Handbook undervalues the SAGD project. Including the set of options increases the value of the SAGD well obtaining a positive NPV. Additionally, the NPV of the project has greater sensitivity to parameters that affect revenues directly than those that affect costs. The sensitivity of the options on the expanded NPV depends on the interaction amongst the different options. However, the paper finds the option to defer and expand are valued the highest and is consistent with what is seen within the industry.

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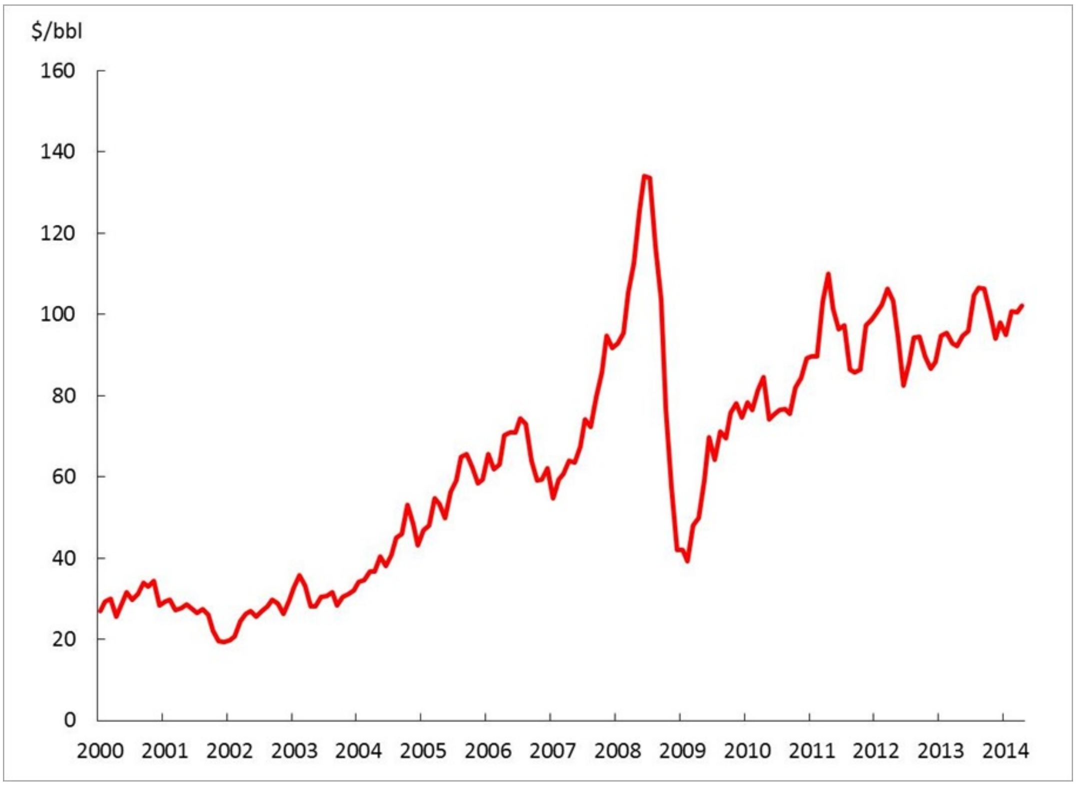
1 Introduction

The importance of crude oil in the Canada has increased significantly over the years, impacting various segments of the Canadian economy. Canadian crude oil production has increased from 1.76 million barrels per day (mmbbl) in 1980 to 3.78 mmbbl in 2012 and is expected to reach 5.1 mmbbl by the end of 2020 (EIA International Energy Outlook, 2012). The majority of production is exported to the US Gulf coast where Canada is expected to become the primary supplier of sour crude by the end of 2014 (Morese et al., 2013). Due to various global factors such as increasing demand of crude from emerging markets, crude oil prices have steadily been on the rise, see Figure 1.

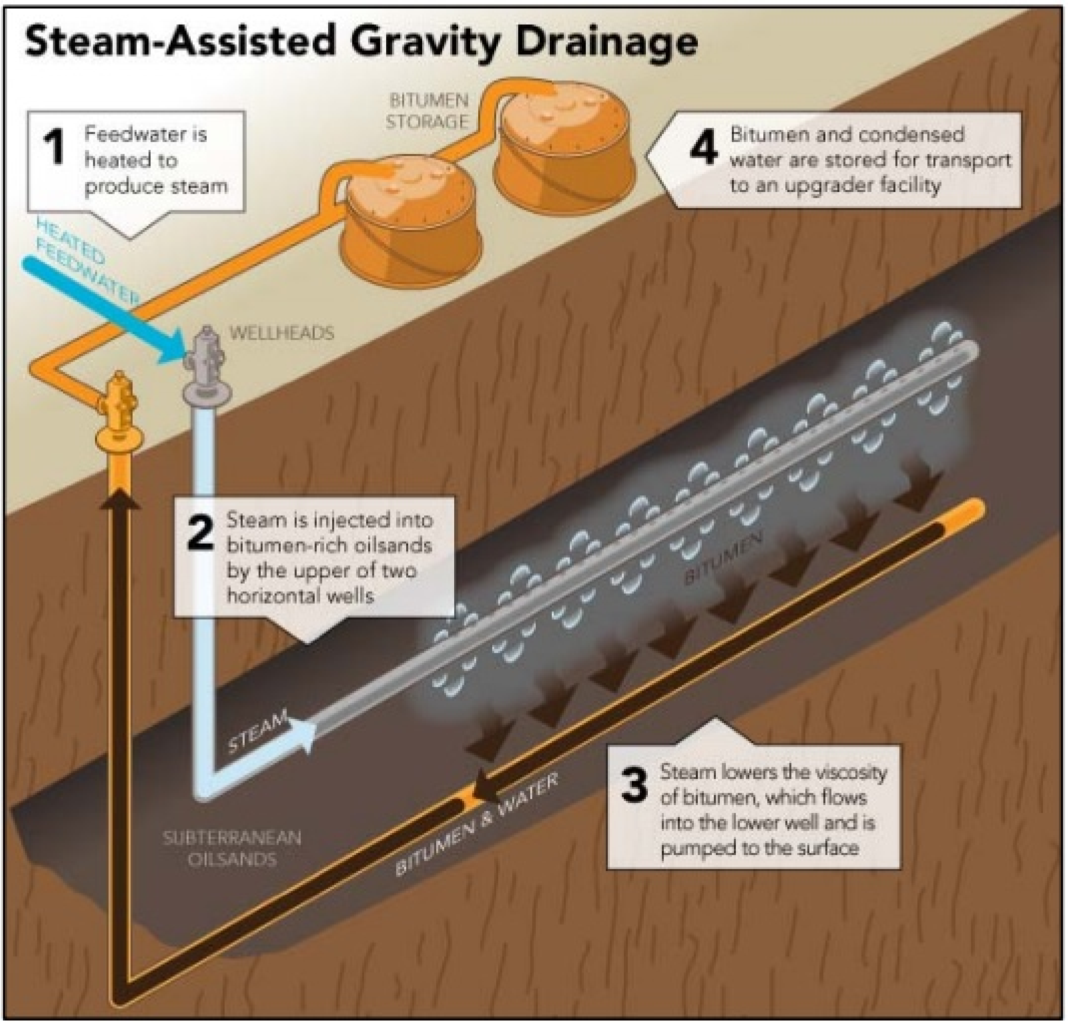
Figure 1: Steady rise of WTI prices



Rising crude oil prices coupled with technology improvements in alternative oil recovery technologies allowed for the increase in crude oil production in both the Canadian oil sands and the United States (Alquist and Guénette, 2014). Oil sands recovery is primarily done using two methods: open pit mining, or

Steam Assisted Gravity Drainage (SAGD). Approximately 80% of the oil sand reserves are buried too deep for open pit mining. Thus, SAGD has become the most popular way of recovering bitumen[1] (Natural Resources Canada, 2013). SAGD wells operate by drilling two horizontal wells into the formation. The upper well (or injection well) continuously injects steam into the ground. As the temperature rises, the bitumen becomes more fluid and flows to the lower well. The crude oil or bitumen and the condensed water is then pumped up and transported to an upgrader facility (Natural Resources Canada, 2013).

Figure 2: Diagram of SAGD well operating



(Alberta Energy, 2014)

[1]Loose sand or partially consolidated sandstone containing a naturally occurring mixture of sand, clay, and water, saturated with a dense and extremely viscous form of petroleum technically referred to as bitumen (Alberta Environment and Sustainable Resource Development, 2008).

However, while conditions had previously favoured the investment and the start up of SAGD wells, the economic environment has slowly shifted. Although, improvements have been made to SAGD technology, SAGD wells still remain high on the cost curve relative to other mining processes (Leaton, 2014; Millington and Murillo, 2013). Furthermore, oil sand wells face various risks including, but not limited to: rising supply and lower US demand resulting in lower crude oil prices, cost inflation due to bottlenecks in transportation, labour shortages, and increases in other operating costs (Munro and Mortlock, 2012). The impact of these risks and uncertainty can already be seen in the industry. This year Total SA, a French integrated oil and gas company announced that it was halting work on its Joslyn North project. The final investment on the project valued at $9 billion was pushed back indefinitely citing cost inflation and shrinking margins as the primary reasons (Dawson, 2014).

As oil prices and demand are determined in a global context, capital and operating costs are one of the few parameters producers can control (Millington and Murillo, 2013). In order to alleviate some of the bottlenecks in transportation some producers have begun using rail. However, transportation using rail is more expensive than pipeline, and there are several limitations including the availability of rail cars, terminals, and storage facilities (Millington and Murillo, 2013). Alternative methods for controlling costs have been to capitalize on economies of scale and producers sharing infrastructure by entering into joint partnerships. Another approach to avoid large cost overruns has been to move away from large "mega" projects and towards managing projects through various development phases (Millington and Murillo, 2013).

Prior to initiating SAGD projects the producer must conduct an economic evaluation of the project to ensure it will be profitable. The Economic Evaluation of Oil and Gas Properties Handbook recommends two methods: (1) comparable sales approach and (2) income approach. The comparable sales approach uses sales of a another well that is similar to impute the value of the new project (US Department of Interior Bureau of Land Managment, 2013). The income approach assigns value to the well based on the present value of expected future cash flows and is also known as the discounted cash flow (DCF) method (US Department of Interior Bureau of Land Managment, 2013). Although DCF techniques seem to be one of the more popular approaches, various critics have emerged dissatisfied with its methodology. Hayes and Abernathy (1980) argue that DCF systematically undervalue projects and propose decisions to be based on executive discretion. Alternatively, Hertz (1964) and Magee (1964) argue that DCF does not capture the managerial flexibility available in a project and recommend using Monte Carlo simulations and decision tree analysis respectively. The importance of accurately pricing managerial flexibility amongst oil producers can be seen through the statement by Canadian Natural Resources (CNR) on their Horizon Oil Sands mine.

> The timing of construction for future expansions is critical for cost control and we remain focused to take advantage of favorable market conditions. We are not driven to production increases at the expense of a higher capital cost. Current expansion and debottlenecking will be very deliberate and flexible to ensure projects can be started or stopped based on market conditions (Canadian Natural Resources, 2013).

The statement by CNR shows how highly the company values the option to choose the timing of its investments and will do so only in favourable economic climate. An alternative to the approaches suggested by Hertz (1964) and Magee (1964) are the use of real options. Real options use financial option pricing theory and applies it to investment and capital budgeting decisions. An option is essentially the right but not the obligation to purchase (or sell) an underlying asset. Thus, real options would then be the right, but not the obligation to undertake or execute a decision. For example, a call option on a stock is the right to purchase a stock at a predetermined price, the exercise price. If at expiration the stock is worth less than the exercise price, the option holder will not exercise the option as it would be cheaper to simply purchase the stock. However, if the stock is worth more than the exercise price the option holder will exercise the option. The payoffs of the call option will be the maximum of zero or the value of the stock minus the exercise price.

Financial options can be written on various underlying assets including, but not limited to stocks, stock indexes, government bonds, currencies, precious metals, and futures contracts (Brach, 2003). Real options deal with capital budgeting, investment, and business transaction decisions. The two share several basic characteristics including, investment under uncertainty, irreversibility, and the choice between several alternatives (Brach, 2003). Table 1 also shows how commonalities in financial options can be used in pricing real options. Therefore, with the use of real options management is better able to capture all the decisions available in valuing and operating a SAGD well.

Table 1: Commonalities between financial and real options

Financial Option	**Variable**	**Investment Project/Real Option**
Exercise Price	Ex	Costs to acquire the asset
Stock Price	V	Present value of future cash flows from the asset
Time to expiration	T	Length of time option is viable
Variance of stock returns	σ^2	Riskiness of the asset, variance of the best and worst case scenario
Risk-free rate of return	r	Risk-free rate of return

The rest of the paper is organized as follows. Section 2 conducts a literature review on option pricing theory used in real options. Section 3 describes the underlying process of the model used and Section 4 describes the assumptions used to calibrate the various parameters of the model. Section 5 presents the results and Section 6 conducts sensitivity analysis. Section 7 presents recommendations for future research and Section 8 concludes.

2 Literature Review

The literature on pricing options and real options is long and extensive, thus the literature review in this paper will be focused on methods that can be used for pricing SAGD wells. For the purposes of pricing SAGD wells the model must meet two criteria: (1) the model must allow for pricing several options. This is important because during the lifetime of the well, management can face several different decisions and real options simultaneously. (2) The model must be relatively simple. The reason for this is that managers often find option pricing theory to be too technical and therefore shy away from its use (Economist, 2000).

McDonald and Siegel (1987) investigate optimal timing of investment under continuous time. The paper finds that the option value to defer investment can be quite significant and the optimal time to invest is when the benefits are twice the costs. Pindyck (1986) extends McDonald and Siegel (1987) model and incorporates capacity decisions in addition to timing decisions. Pindyck finds that for small amounts of uncertainty, the optimal capacity to invest is smaller than if the decision to invest is reversible. Furthermore, a large portion of the firm's value is due to the possibility of future growth and expansion (Pindyck, 1986). Brennan and Schwartz (2004) apply real options in pricing a hypothetical copper mine. In their work the authors use methods suggested by Black and Scholes (1973) and Merton (1973) to value a copper mine that has the option to operate at full capacity, shut down and abandon, or temporarily shutdown. Although, the paper provides insight into the valuation of natural resource investments its methodology is not applicable for the purposes of this paper. This is because Black and Scholes (1973) and Merton (1973) provide an analytical solution to option pricing. Many of the pricing decisions and interactions amongst real options cannot be solved analytically, and therefore a numerical solutions is required.

The three main types of numerical solutions in option pricing theory are: (1) simulation, (2) finite differences, and (3) binomial. Cortazar (2001) uses Monte Carlo simulations to price European options. The price trajectories are approximated from a probability distribution of terminal asset values. The option cash flow is then computed for each simulation and then averaged. The average cash flow is then discounted using the risk free interest rate. However, Cortazar states that simulation methods are considered inadequate in valuing American options. This is because Monte Carlo options really only estimate the option value assuming a given starting point and time. However, for early exercise, the option value at intermediate times needs to be known (Cortazar, 2001). Finite difference approach uses the partial differential equations of the Black-Scholes equation. It then uses discrete estimates of changes in the option value for small changes in time to form difference equations as approximations of the continuous partial derivatives (Geske and Shastri, 1985). Finite difference can be seen as a extension of the trinomial process, where the underlying asset can move up, down, or stay the same. However, instead of a trinomial lattice, the process is extended into a grid (Clewlow and Strickland, 1998). In comparing numerical processes, Geske and Shastri (1985) found that finite differences were generally more accurate when comparing a large number of options (greater than 10). However, the binomial method is generally more accurate when comparing a relatively small number of options. As this paper is currently valuing a SAGD well using only four to nine options, the binomial method will suffice.

One the most cited model using a binomial lattice to price options was proposed by Cox, Ross, and Rubinstein (1979). Binomial lattices or methods in option pricing have the underlying asset move through time in up or down movements. Using this method the option's payoffs are determined at the time of expiry or boundry. The option value today is then calculated through backward induction through time from the boundry. In Cox et al.'s paper, the authors used a multiplicative binomial model, choosing the probabilities to be one half, and valuing options by discounting their terminal expected values in a world using risk neutrality. Alternatively, Jarrow and Rudd (1983) set the jump sizes to be equal, allowing for different probabilities. However, the problem with the above two models is that they are only good over a small time interval as well as one cannot freely choose an arbitrarily large time step (Clewlow and Strickland, 1998). In order to correct for this and allow for a more general framework Trigeorgis (1991b) uses a model in terms of the logarithm of the underlying asset. The process is similar to Cox et al., but probabilities are not set. On average Trigeorgis model has been shown to be more accurate than Cox et al. and Jarrow and Rudd (Clewlow and Strickland, 1998).

Therefore, this paper shall use Trigeorgis (1991b) log binomial model as it will most accurately capture the underlying process of pricing SAGD wells and meets the criteria of pricing multiple options and being relatively simple conceptually.

3 Theoretical Design

Prior to describing the theoretical design of the model, there are several implicit assumptions in the model that need to be addressed. The model assumes markets are both complete and perfectly competitive. If a market is complete, then according to Modigliani and Miller (1958) one can replicate the payoffs of the SAGD well by holding a combination of different assets in a portfolio. Also, in perfectly competitive markets, initiating the will not affect crude oil prices. These assumption may not be applicable for all applications of real options. An example of this could be a pharmaceutical company conducting R&D on a new drug (Loch and Bode-Greuel, 2001). As the drug maybe unique or first to market, there might not be an existing set of assets which can replicate its payoffs. Furthermore, if the pharmaceutical company is the first to market, they obtain a monopoly and have the ability to earn economic rent. However, for the purposes of this paper these assumptions can be tolerated. Given the nature of commodity markets and the various options involved it is not unreasonable to assume a replicating portfolio can be created. Additionally, as crude oil markets are determined in a global context, the introduction of a new well by a single producer will not impact the price of oil.

For ease and consistency, this paper shall use the same notation as presented in Trigeorgis (1991b). First, assume V, is the value the underlying asset. From the firm's perspective this would represent the present value of expected future cash flows from immediately taking on the project. Implicit in this assumption is that the project is perfectly correlated with movements of crude oil prices. V then follows the following diffusion process:

$$\frac{dV}{V} = \alpha dt + \sigma dz \tag{1}$$

Where, α and σ, are the instantaneous expected return and standard deviation respectively and dz follows the standard Wiener process. Then, over any differential time interval dt, $X \equiv logV$ follows the arithmetic Brownian motion (Trigeorgis, 1991b). As the model is in the risk neutral world $\alpha \equiv r$, where r is the risk-free rate. Next, by applying Ito's lemma $V = r - \frac{1}{2}\sigma^2$ and $dX = (r - \frac{1}{2}\sigma^2)dt + \sigma dt$. Then increments of dX are normally and identically distributed with mean $(r - \frac{1}{2}\sigma^2)dt$ and variance of $\sigma^2 dt$. Defining $K \equiv \sigma^2 dt$ and $\mu \equiv r/\sigma^2 - 1/2$, dX is now normally and identically distributed with mean μK and variance K. Continuous time can be approximated in the binomial tree by dividing the project life T into N intervals (Trigeorgis, 1991b). The project is then divided into $\tau \equiv T/N$ periods or intervals. The values of K and μ are then the following:

$$K = \sigma^2 \tau \quad (2) \qquad \mu = \frac{r}{\sigma^2} - \frac{1}{2} \quad (3)$$

Additionally, as X follows a Markov random walk by moving up or down by H and $-H$ with a risk neutral probability of P and $1 - P$ respectively. In discrete time this equates to:

$$\begin{aligned} E(\Delta X) &= PH + (1 - P)H \\ &= PH - H + PH \\ &= 2PH - H \\ \text{and} \\ Var(\Delta X) &= H^2 - [E(\Delta X)]^2 \end{aligned}$$

For discrete time to be consistent with continuous, the mean and variance should be equal.

$$\begin{aligned} 2PH - H &= \mu K \\ 2PH &= \mu K + H \\ P &= \frac{1}{2}\left(1 + \frac{\mu K}{H}\right) \end{aligned} \quad (4)$$

$$\begin{aligned} H^2 - (\mu K)^2 &= K \\ H &= \sqrt{K - (\mu K)^2} \end{aligned} \quad (5)$$

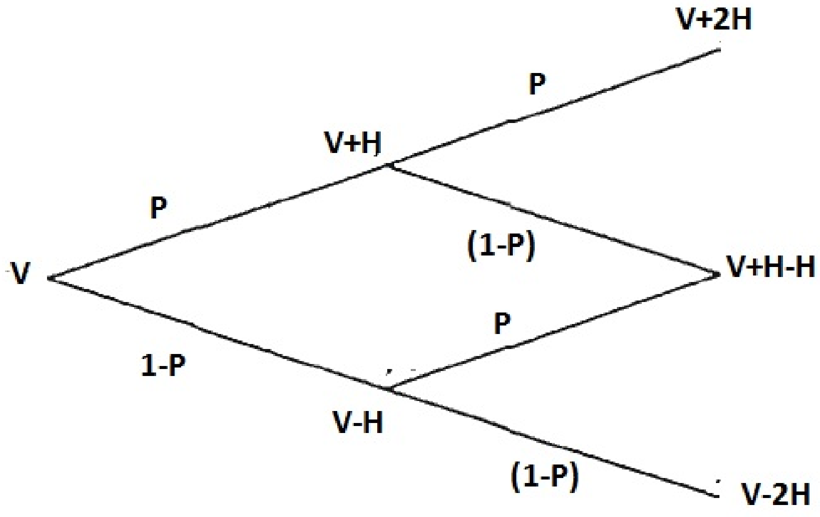
Using the above equations for K, μ, H, and P, the model guarantees stability as well as consistency of discrete to continuous time (Trigeorgis, 1991b).

Implementing the above is a four step process. First the initial parameters (V, r, σ, T, and N) are specified. The method and logic used to specify these parameters is discussed in Section 4. Next, the preliminary values of K, μ, H, and P are calculated using equations (2)-(5) above. In the third step, the value of the option(s) of the overall project at the boundary at time T is determined, where $R(i)$, is the value of the project of option in state i. Finally, in the last step, the algorithm moves in a backward iterative process, making adjustments for cash flows or options at their respective times (Trigeorgis, 1991b). The value of the project in state i is then:

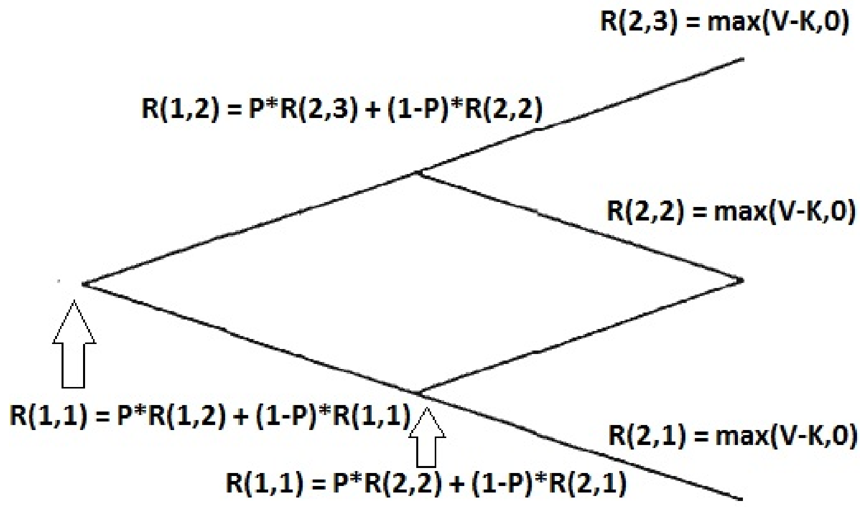
$$R(i) = e^{-r\tau}[PR(i+1)_{t+1} + (1-P)R(i-1)_{t+1}] \tag{6}$$

Where $i+1$ and $i-1$ is the next period's up and down state respectively. Below is an example of the process using an European call where $T = 1$ and $N = 2$. We see that the price moves up by H with a risk-neutral probability P and down by $-H$ with a risk-neutral probability $(1-P)$. Notice that the underlying asset does not explicitly involve the probabilities of moving to an up or down state. Instead the asset is priced in terms of risk-neutral probabilities where the expected values can be discounted at the risk-free rate (Trigeorgis, 1991b).

Figure 3: Movement of underlying asset and value of call



(a) Underlying asset movement



(b) Valuation of call option

4 Valuing the SAGD Well

4.1 Calibration

Having established the theoretical framework of the model, the oil well can now be valued. However, before the various real options associated with the project can be priced, the Net Present Value (NPV) of the cash inflows and expenditures needs to be calculated first. Much of the parameters and variables shall be calibrated using data from a supply cost survey of SAGD wells by Millington and Murillo (2013). Thus, the values used in this paper represent an average SAGD well. However, these parameters can be adjusted with relative ease for any specific well.

4.1.1 Duration (T), Volatility (σ) and Capacity of the Well

First, the paper assumes the well will operate for 30 years, but will take 3 years to construct. These values were obtained from Millington and Murillo (2013) as well as the database of existing SAGD projects currently under construction (Government of Alberta, 2014). T is set to 43 years to also allow the option to defer (discussed below). The volatility of the project is 33.5%. It was determined by taking the standard deviation of one year WTI returns over the course of the year. The volatility parameter is sensitive to the time period used and can be highly subjective. The period of one year was chosen to be consistent in the parameterization of the other variables below. Furthermore, the literature on estimating volatility is probably as long and extensive as the literature on option pricing. For additional techniques on estimating volatility see Godinho (2006). This paper also makes the same assumption as Millington and Murillo and assumes the well has a capacity of 30,000 barrels per day (bbl/day), but operates at 75 percent of capacity.

4.1.2 Crude Oil Prices

Next, a forecast of crude oil prices is needed during the life time of the well. To achieve this one could use estimates provided by the United States Energy Information Administration (US EIA). The US EIA provides long term forecasts for various energy variables including demand, consumption, supply, and prices in the Annual Energy Outlook publication. However, the issue in using long term energy forecasts is that they fail to capture major energy conversions, primary energy requirements, sectoral needs, exhaustion of energy resources, and energy substitutions (Smil, 2000). Alternatively, one could use market data and WTI futures. However, Alquist et al. (2013) show that while using futures can reduce the predictive error of forecasts, the reduction is relatively modest and highly sensitive to the sample period and forecast horizon. Furthermore, the authors show that oil futures predictive power is on average lower than the a no-change forecast (Alquist et al., 2013). Therefore, the model uses a one year average at the time of writing of the WTI front month futures of $99/bbl.

It is also important to note in Millington and Murillo prices are done using West Texas Intermediate (WTI) equivalent prices. This is done to place the costs of extraction in a market context. Additionally, the Albertan government also calculates royalties based on the Canadian price of WTI. However, crude oil in Canada is usually priced using Western Canada Select (WCS), which is heavier than WTI. As light oil contains low sulphur content, it is less energy intensive to refine than crude oil that is heavier (Millington and Murillo, 2013). It is for this reason the WCS often sells at a discount to the WTI. Although the spread between WTI and WCS fluctuates based on market conditions. Millington and Murillo estimate the long-term differential based on the quality of the two crude oils to be $15/bbl. Therefore, when using WTI prices, the discount of $15/bbl is applied and then converted into Canadian dollars. The final WTI price used after applying the discount and exchange rate is $88.52/bbl.

4.1.3 Exchange and Interest Rates

As WTI and Natural Gas (below) are priced in US dollars an estimate of the exchange rate is needed to have the costs in Canadian dollars. For the same reasons used in determining WTI prices, the paper uses a no change forecast in the exchange rate. An exchange rate of 1.0538 Canadian dollar per US is used and was calculated by taking a one year average of the Canadian-US dollar exchange rate. In order to discount the cash flows of the project this paper follows convention in the literature and discounts the revenue of the project by the risk-adjusted rate and the costs by the risk-free rate (Trigeorgis, 1993). The risk-adjusted rate of 10% is the same used by Millington and Murillo (2013). The risk-free rate of 2.82% was determined by taking the one year average of Canadian long-term government bonds.

4.1.4 Initial Capital and Operating Costs

The capital cost of initiating a SAGD well is estimated to be $32,482 per barrel of capacity or $974 million, while the capital cost of operating is $43.8 million per year (Millington and Murillo, 2013). Once construction has been completed and the well is online, non-energy operating costs excluding royalty, transportation, and abandonment and reclamation costs are estimated to be $79 million per year. The figures were estimated by Millington and Murillo by using financial statements of the respective oil companies and the CanOils database.

4.1.5 Energy Costs

Energy use also plays a significant role in the operation of SAGD wells. An average SAGD well requires 32,100 GJ/day in natural gas and 300 MWh/d in electricity (Millington and Murillo, 2013). As with WTI prices the model assumes a no-change forecast for natural gas and electricity prices. For the price of gas the paper uses a one year average of the Henry Hub Natural Gas contracts, valued at $3.85/mmBTU. The prices are then converted into Canadian dollars using the exchange rate above and into GJ using the conversion rate of 1.054615 MMBtu/GJ[2]. Electricity prices were calculated by using the annual average of the wholesale pool prices provided by the Alberta Electricity System Operator. The price of natural gas and electricity used are $4.066/GJ and $80.19/MWh respectively.

4.1.6 Royalty

Another cost associated with crude oil production are the royalty rates on the gross revenues of oil sand production. Effective January 2011 a firm would pay 1% on the gross revenues if the price of WTI is $55/bbl or lower. Moving up in a linear fashion to 9% if the price of WTI is equal to or greater than $125/bbl (*see Table 2*). As the price of WTI is $88.52/bbl, the royalty rate of 4.69% is applied to gross revenues.

Table 2: Royalty rates on gross revenue

WTI ($CDN/bbl)	%
Below $55	1.00
$55	1.00
$60	1.62
$65	2.23
$70	2.85
$75	3.46
$80	4.08
$85	4.69
$90	5.31
$95	5.92
$100	6.54
$105	7.15
$110	7.77
$115	8.38
$120	9.00
Above $125	9.00

[2] http://www.energy.gov.ab.ca/about_us/1132.asp

4.1.7 Transportation, Emission Taxes, and Abandonment and Reclamation Costs

The remaining costs associated with oil sands production are transportation, taxes on emissions, and abandonment and reclamation costs. The cost of transportation is estimated to be \$4.51/bbl to get the bitumen from the field to Cushing, Oklahoma (Millington and Murillo, 2013). This figure includes the cost of diluent required to meet the pipelines specifications as well as the cost of transportation. An average SAGD well emits 0.06 tonnes of carbon dioxide per barrel (Alberta Energy, 2014) and is taxed at a rate of \$15/tonne (Millington and Murillo, 2013). Currently, this represents a small amount of the total cost of operating a well. However, the Albertan government has expressed interest in increasing the tax on carbon emissions. This would require emitters to pay a \$40/tonne charge if emissions per barrel are not reduce by 40% (Vanderklippe, 2013). Finally, the government of Alberta requires an operator to test abandoned wells to ensure they do not pose any risk to the public or the environment once abandoned (Alberta Energy Regulator, 2014a). Furthermore, the government also requires the operator to pay a security to cover the cost of reclamation in case the operator is unable to complete reclamation. The security can be forfeited if the operator fails to meet the reclamation criteria (Alberta Energy Regulator, 2014b). This paper follows the same assumption of Millington and Murillo and assumes an abandonment and reclamation cost of 2% of total capital expenditures over the course of the well.

4.1.8 NPV

Having all the above variables calibrated the gross value of the cash inflows, V, and the NPV of the project can be calculated. As it is common in the literature, the cash inflows are discounted by the risk adjusted rate of 10% to obtain a value of \$386.75 million. After incorporating the initial investment outlays, the NPV of the project becomes $-607.20 million. Thus, the SAGD well would be rejected if only the NPV criterion were to be used.

4.2 The Project

The specifications for the SAGD well is as follows. Management has the option to defer construction of the well for up to 10 years. This period was chosen based upon the requirements specified by the Alberta Energy Regulator (AER). AER allows a well to be suspended for up to 10 years. If after 10 years the well is still not operating, the AER requires additional criteria to be met (Alberta Energy Regulator, 2014a). As a simplifying assumption this paper assumes the producer would wish to avoid these additional criteria. Once construction has begun, it will take 3 years to complete before the well becomes operational requiring initial capital outlays of $409.27, $389.41, $248.99 million in years one, two, and three respectively.[3] As it is common in the literature, it is assumed that the investment costs are known and placed in an "escrow account" earing interest of the risk-less rate (2.82%), discounted continuously (Trigeorgis, 1993). In the second year of construction, if the management feels the project is not going to be successful, they have the option to abandon the project by foregoing the second investment outlay. Additionally, it is assumed that the firm is leasing the land, thus there is zero recovery from the project if abandoned. Furthermore, during the third year of construction management also has the option to contract the scale of the project by 25%, paying an investment outlay of only $150 million (versus the $248.99 million originally planned). Finally, if market conditions are favourable the project can be expanded every five years by 10%, incurring a cost of $83 million each time (representing five different expansion options).

[3]Results in present value of $974 million plus 2% reclamation security.

4.3 Determining Option Value and Interaction

The above NPV calculation shows the SAGD well would not be undertaken. However, this calculation does not capture managerial flexibility or collection of real options available in the project. The inclusion of options introduces asymmetry or skewness in the probability distribution of the NPV and expands the opportunity's true value relative to the passive NPV (Trigeorgis, 1993). Thus, the correct valuation of an investment requires an expanded NPV rule which is the sum of the Passive NPV and the combined value of the options:

$$\text{Expanded NPV} = \text{Passive NPV} + \text{Combined Option Value}$$

The various options applicable for a SAGD well are defer, early abandonment, contraction, and expansion. The option to defer the investment is valued as an American call option, where the exercise price is the investment outlay required. Early abandonment is valued as a compound call option. The option to contract and expand are valued as an European put and call respectively. The exercise price for the put is then the potential cost savings, while for the call it is the extra investment required to expand (Trigeorgis, 1993). Table 3 presents how the options adjust the value of the project.

Table 3: Payoff of options

Option	Payoff
Defer	$R' = \max(e^{-r\tau}E(R_{t+1}), R_t)$
Abandon	$R' = \max(R - I_2,\, 0)$
Contract	$R' = \max(R - I_3,\, cR - I'_c)$
Expand	$R' = \max(R,\, eR - I'_e)$

However, managerial flexibility rarely takes the form of a single decision and thus any model using real options must capture the interaction of multiple options (Trigeorgis, 1993). The inclusion of additional options always increases the value of the underlying project. However, this often occurs in an non-additive manner. The reason for this being is that the exercise of an option earlier in the project life will impact the value of any subsequent options (Trigeorgis, 1993). The degree of interaction between options is dependent on the option type and overlap of the exercise region. Options are more additive if they are: (1) of opposite type (ie. call and put) (2) times of exercise are close together. For example two European options which expire at the same time versus varying times (or if they are American options), and (3) options are more out of the money. This means having high exercise price for calls and low exercise price for puts, thus leading to a lower overlap in exercise regions (Trigeorgis, 1993).

Options of different types are optimally exercisable under opposite or negatively correlated circumstances. This implies that the conditional probability of exercising the latter option having a prior option already exercised would be smaller than the marginal probability of exercising the latter option alone (Trigeorgis, 1993). The degree of interaction between the two options would be small and thus the options would be approximately additive. The opposite is true of options of the same type. A pair of puts or calls would have a high conditional probability of exercise and the sign of interaction would depend if they are put (negative) or a call (positive) (Trigeorgis, 1993).

For example, if there existed an option to contract (put) and an option to expand (call), which were both out of the money and expiring at the same time. Their interaction as well as their conditional probabilities would be precisely zero and the marginal probabilities that either option maybe exercised at maturity is positive (Trigeorgis, 1993). Thus, with no interaction the option retains its full undistorted value. Alternatively, it is inappropriate to simply add separate options when they are needed, or in the money.

The option to defer and its interaction with other options is relatively more complex. First, if the cash flows and future options are pushed back, the increased variability may make subsequent options more valuable. However, if the project is delayed because it is currently not profitable, a subsequent call option may become less valuable, though mitigated with the benefit of the option to delay (Trigeorgis, 1993). Additionally, as the option to defer is written on the gross value of the project plus subsequent options, management would be better able to adjust to changing circumstances and increasing the value of early investment compared to a similar situation without the subsequent options. This effect would typically dominate and lead to negative overall interactions between the option to defer and subsequent options (Trigeorgis, 1993).

5 Results

5.1 Value of Individual Options

Computed first are the values of the options individually in Table 4. If the firm had only the option to *defer* the expanded NPV of the project would increase to \$85.82 million. The option is then worth \$693.02 million or 179.19 % of V. Having only the option to *abandon* in year two of construction the project NPV is improved to \$-390.52 million and the option worth \$216.68 million (56% of V). The option to *contract* the project by 25% in the final year of construction is worth \$12.34 million (3.19% of V), expanding the NPV to \$-594.86 million. Finally, the options to *expand* are 6.18%, 5.43%, 4.50%, 3.37%, and 1.97% of V in years $t = 28, 23, 18, 13, 8$ respectively. The options furthest away from the start of the project are worth more. This is because there is greater uncertainty as t increases, causing the option to be worth more the further the date of expiry. Collectively the options are worth 26.71% of V. Notice the non-additivity of the options value, 26.71% versus 21.45%. As mentioned above the interaction amongst the "call" options results in a high conditional probability of exercise and positive interaction.

Table 4: Value of individual options

Option	Expanded NPV	Option Value $ million	% of V
(D) Defer	85.82	693.02	179.19
(A) Abandon	-390.52	216.68	56.03
(C) Contract	-594.86	12.34	3.19
(E) Expand (all)	-503.89	103.31	26.71
Expand (t=28)	-583.30	23.90	6.18
Expand (t=23)	-586.22	20.98	5.43
Expand (t=18)	-589.79	17.41	4.50
Expand (t=13)	-594.19	13.01	3.37
Expand (t=08)	-599.58	7.62	1.97

5.2 Interaction amongst options

Next, the different combination of option values are computed in Table 5. When evaluating the option to expand, all the expansion options shall be considered simultaneously. From the table it can be seen the option to contract or abandon only marginally improves the value of the project when paired with the option to defer. This is unsurprising because if management is given the option to defer the project, they will only initiate the project when the expanded NPV of the project is positive. If this is the case then they are less likely to abandon construction in the second year or contract the operation in the final year of construction. However, the opposite is true when given the option to defer and expand. There exists a relatively strong positive interaction and the value of the options are almost equal the sum of their parts ($789.61 versus $796.33). Given the option to defer the project becomes profitable, and becomes increasingly so if management can expand the project when market conditions become even more favourable.

When pairing the option to contract and abandon, there is little additional benefit of having the option to contract. As both options can be thought of as a put with close expiry dates, they will have strong overlap in exercise regions.

The opposite is true when considering the option to expand and contract, as the two options are of different types, the values are almost additive. The same is true for the option to abandon and expand.

When including the option to defer, adding the option to abandon and contract increases the value of the project marginally. Also, when including all the options, the NPV of the project is only 0.1% greater than only having the options to defer and expand. Thus, when including the option to defer, it becomes unnecessary to include the options to abandon or contract.

Table 5: Interaction amongst multiple options

Two options			
D & A	D & C	D & E	C & E
85.90 (693.11)	85.82 (693.02)	182.41 (789.61)	-495.51 (111.69)
A & C	A & E		
-390.47 (216.73)	-360.60 (246.60)		
Three Options			
D & A & C	D & A & E	A & C & E	C & D & E
85.90 (693.11)	182.60 (789.80)	-360.46 (246.74)	182.42 (789.62)
All Options			
D & A & C & E			
182.61 (789.81)			

Expanded NPV (Option values)

Having determined the expanded NPV of $182.61 million for the SAGD well when including managerial flexibility, the paper shall now sensitivity analysis on the respective parameters.

6 Sensitivity Analysis

6.1 NPV

Sensitivity analysis shall now be conducted on the initial NPV value. This is done by changing individual variables up or down to a maximum of 30%.

The purpose of this is to see which variables when changed slightly, greatly impact NPV.

From Table 6 it can be observed the NPV having the greatest sensitivity to the respective rates. An increase or decrease in the risk-adjusted rate causes a percentage change in NPV of -90% and 105% respectively. The risk-free rate and the exchange rate are similar in their sensitivity, where a 10% change causes a change in NPV of approximately -37%. However, it seems that NPV is more sensitive to greater decreases in the exchange rate where as the opposite is true for the risk-free rate. Where NPV becomes more sensitive to larger values of the risk-free rate.

Changes in the initial and operating capital have similar sensitivities averaging a change in 15% for every 10% increase or decrease from initial values. Alternatively, non-energy operating costs change by approximately 25% for every change in 10%.

NPV changes by -67% for a decrease in WTI by 10% and increases by 61% for a 10% increase from the original value of WTI. Also, WTI seems to be relatively more sensitive to downside changes. Finally, natural gas, electricity prices, emmissions tax, and reclamation security change in a relatively linear pattern, with a 10% change causing a change in NPV of 17%, 2.8%, 2.3%, and 0.6% respectively.

Table 6: Sensitivity of key variables on NPV

Percentage Change	Risk-adjusted rate		Risk free rate		Exchange rate		Initial capital		Operating capital		Non-energy operating costs	
-30	1664.07	(374.05)	-1317.07	(-116.91)	-1429.14	(-135.36)	-309.02	(49.11)	-354.36	(41.64)	-161.01	(73.48)
-20	778.40	(228.19)	-1066.72	(-75.68)	-1149.77	(-89.35)	-408.41	(32.74)	-438.64	(27.76)	-309.74	(48.99)
-10	29.71	(104.89)	-830.39	(-36.76)	-827.61	(-36.3)	-507.81	(16.37)	-522.92	(13.88)	-458.47	(24.49)
0	**-607.20**	(0)	**-607.20**	(0)	**-607.20**	(0)	**-607.20**	(0)	**-607.20**	(0)	**-607.20**	(0)
+10	-1152.43	(-89.79)	-396.32	(34.73)	-420.54	(30.74)	-706.60	(-16.37)	-691.49	(-13.88)	-755.94	(-24.49)
+20	-1622.01	(-167.13)	-196.95	(67.56)	-267.61	(55.93)	-805.99	(-32.74)	-775.77	(-27.76)	-904.67	(-48.99)
+30	-2028.84	(-234.13)	-8.39	(98.62)	-148.41	(75.56)	-905.39	(-49.11)	-860.05	(-41.64)	-1053.40	(-73.48)

Percentage Change	WTI ($US/bbl)		Natural gas prices ($US/mmBTU)		Electricity prices		Emissions tax		Reclamation security	
-30	-1953.96	(-221.8)	-303.59	(50)	-557.07	(8.26)	-565.37	(6.89)	-596.40	(1.78)
-20	-1465.28	(-141.32)	-404.80	(33.33)	-573.78	(5.5)	-579.32	(4.59)	-600.00	(1.19)
-10	-1016.36	(-67.38)	-506.00	(16.67)	-590.49	(2.75)	-593.26	(2.3)	-603.60	(0.59)
0	**-607.20**	(0)	**-607.20**	(0)	**-607.20**	(0)	**-607.20**	(0)	**-607.20**	(0)
+10	-237.81	(60.84)	-708.41	(-16.67)	-623.92	(-2.75)	-621.15	(-2.3)	-610.81	(-0.59)
+20	91.83	(115.12)	-809.61	(-33.33)	-640.63	(-5.5)	-635.09	(-4.59)	-614.41	(-1.19)
+30	381.71	(162.86)	-910.82	(-50)	-657.34	(-8.26)	-649.03	(-6.89)	-618.01	(-1.78)

Expanded NPV (Percentage Change)

Table 6 shows that the variables which impact revenues directly tend to have greater impact on NPV. Furthermore, the change in NPV increases at a relatively exponential rate the greater the percentage change from the original parameterized value. Secondly, variables that only impact costs change NPV at a linear rate. Therefore when parameterizing the variables, one must take special care in the assumptions used regarding the risk-adjusted, risk-free and exchange rates as well as the assumptions on WTI prices.

6.2 Options

First, analysis is conducted on the changes in the risk-free rate and volatility on the impact of the expanded NPV. As shown above, when changing the risk-free rate the values of NPV and V also change. However, as this section is only interested in how the option values change when the risk-free rate and volatility change, the original NPV and V values of \$-607.20 and \$386.75 million shall be used. Changes in both the risk-free rate and volatility change expanded NPV linearly. A 10% change in the risk-free rate and volatility causes an approximate change of 3% and 15% in the expanded NPV.

Next, sensitivity analysis is conducted on the options themselves to further tease out their interactions. Table 7 shows that as the expiry date to defer decreases, so does the value of the expanded NPV. This occurs because the closer the expiry date, the less uncertainty there is regarding the value of the well.

Table 7: Sensitivity of key variables on Expanded NPV

Percentage Change	Risk-free Rate		Volatility		Defer Expiry	
-30	164.75	(-9.78)	98.73	(-45.94)	126.15	(-30.92)
-20	170.64	(-6.55)	126.65	(-30.64)	146.09	(-20)
-10	176.58	(-3.3)	154.88	(-15.19)	164.25	(-10.05)
0	182.61	(0)	182.61	(0)	182.61	(0)
+10	188.82	(3.4)	210.79	(15.43)	199.97	(9.51)
+20	195.07	(6.82)	237.35	(29.98)	215.83	(18.19)
+30	201.35	(10.26)	263.97	(44.55)	231.83	(26.95)

Expanded NPV (Percentage Change)

When considering all the options, Table 5 showed that including the option to contract provided no additional value. As stated above this was because of its proximity to the option to abandon and defer. However, if the option to contract is moved further out the negative interaction should lessen. Instead of having the option to contract in the third year of construction, the well now has the option to contract in the sixth year of operation. Note that conceptually the option to contract is not on the final capital outlay, which will now be paid in full, but on the operation of the well. Table 8 presents the interaction amongst the different options. Immediately it can be seen that the value of the option individually has already increased from $12.34 million to $20.54 million. There still exists strong negative interaction amongst deferment and abandonment with the option to contract. However, it is less than what it was before. The opposite is true of the option to contract and expand. The values are almost additive as they are of different types and the time of expiry are now closer together. Including all the options the SAGD well's expanded NPV increased to $187.26 million from $182.61 million.

Table 8: Interaction with adjusted option to contract

C		D & C		A & C		C & E	
-586.66	(20.54)	86.08	(693.28)	-389.63	(217.57)	-484.37	(122.83)
D & A & C		**A & C & E**		**C & D & E**		**D & A & C & E**	
86.148	(693.35)	-357	(250.2)	186.94	(794.14)	187.26	(794.46)

Expanded NPV (Option values)

From the above analysis it can be seen that the option to defer and expand have the highest values. This is also consistent to what is observed in practice. Firms would rather to defer operations indefinitely than proceed and contract later in the future. Also as shown by CNR's statement, firms plan phases for expansion, expanding only when market conditions become favourable.

7 Future Research

This paper assumed a no-change forecast for various variables including WTI, natural gas, electricity prices, interest rates, and volatility. For WTI, natural gas, electricity prices, and interest rates this was done as it was shown to be more accurate than using alternative forecasts or methods. Alternatively, having non-stochastic volatility was done as a simplifying assumption. Given the sensitivity of NPV calculations to different interest rate values and volatility of WTI, it would be beneficial to include these variables stochastically.

Ingersoll Jr and Ross (1992) determine the optimal timing to invest under stochastic interest rates, but with constant cash flows. The authors use the Cox-Rox-Ingersoll model for stochastic interest rates to value a simple project with one capital outlay and a single cash inflow. The authors determine that investment should not be taken until the project's rate of return is in excess of its break-even rate (Ingersoll Jr and Ross, 1992). Ho et al. (1997) price American options with stochastic interest rates using the Geske-Johnson (GJ) approach. The GJ approach uses an analytical formula to satisfy the partial differential equation and boundary conditions that characterize an American option. Then the value of the option is considered as though it could only be exercised at a few discrete dates. Next, using the option prices at the respective dates, the price of the option is extrapolated such that it can be exercised at any date (Geske and Johnson, 1984). Ho et al. use GJ's approach including both stochastic interest rates and varying cash flows by using a multivariate binomial approximation of the underlying asset and zero coupon bond. The authors find the addition of stochastic interest rates have a significant impact on the option prices especially if the option has low volatility or is out of the money (Ho et al., 1997). Miltersen (2000) value a natural resource investment project with varying interest rates. However, the author assumes management decisions are independent of each other and can be valued as a sum of the European options. However, this is not ideal in valuing SAGD wells, because management decisions often interact and do so in a non-additive manner.

Clewlow and Strickland (1998) show how a binomial model can be adjusted for time varying volatility by fixing the state-step and varying the probabilities and time step. However, varying the time step is not ideal for the purpose of valuing SAGD wells because the timing of intermediate options would not be constant if the time step is allowed to change. Another method for mimicking the process of stochastic volatility is to include a jump in the asset prices. Amin (1993) would build upon Cox et al. (1979) allowing for jumps in the binomial process. The movement is similar except the asset can jump to nodes further down in the lattice. Hilliard and Schwartz (2005) suggest a method using the same log binomial approach as Trigeorgis (1991b), but incorporating a jump process that is Poisson distributed. Additionally, they determine probabilities and jump sizes by matching higher order moments and requires 5 to 9 nodes per time step. The model also allows for multiple interacting options, an ideal characteristic for real options pricing. However, although the model can be adjusted for multiple jumps, it uses a high number of nodes per time step and would become computationally taxing. Building upon his own work Trigeorgis (1991a) improves his model incorporating a binomial with a jump process. However, the jump diffusion process is incorporated by using a dividend yield type parameter. The project value including a jump parameter is then estimated by taking the weighted average over the Poisson distribution (Trigeorgis, 1991a). Chang and Fu (2001) incorporate both stochastic volatility and a jump diffusion process in pricing American and European options. However, further research needs to be conducted whether their process can be applied to valuing multiple options simultaneously.

The above has cited various methods and models which attempt to address stochastic interest rates or volatility. However, future work will need to be conducted to incorporate both in pricing real options. As these two variables have the greatest impact on the value of the project, one must be careful in the methodology chosen.

8 Conclusion

This paper has shown the application of real options in valuing a SAGD well using Trigeorgis (1991b) log binomial model and cost data from Millington and Murillo (2013). The paper finds that using the DCF or NPV approach recommended by the Economic Evaluation of Oil and Gas Properties Handbook undervalues the SAGD project. When including real options in the evaluation process, the expanded NPV now becomes positive. Additionally, the paper finds the gross value of cash flows and naive NPV to be sensitive to the risk-adjusted and risk-free rates. Thus, one must pay special attention when parameterizing these values. In general, the NPV is more sensitive to variables that affect revenues versus those that affect costs. When determining expanded NPV, the options to defer and expand were valued the highest. This is consistent with what is observed in practice as firms tend to defer construction and plan expansion projects in multiple phases. Therefore, by incorporating managerial flexibility through real options this paper shows one can better estimate the value of an SAGD well.

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