A Real Options Analysis of a GHG Sequestration Project

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Abstract

Several organisations in the upstream petroleum industry have begun to incorporate the cost of dealing with greenhouse gas (GHG) emissions into their project evaluation processes. The risks due to these costs, like many other petroleum project risks, involve long lead times demanding a flexible response. Moreover, the patterns of risks in these costs are complex and different from other more standard petroleum industry risks. Therefore, some organisations want to develop expertise in using, for this purpose, evaluation techniques that are geared to dealing with the management of flexibility in the face of unusual and complex uncertainty.

This paper presents an application of real option analysis (ROA) to the evaluation of a geological GHG sequestration option. ROA combines decision tree analysis (DTA), if needed, to take into account the flexibility considerations, with market-based valuation (MBV) to deal with complex and unusual patterns of uncertainty.

We have examined situations where the key non-diversifiable uncertainties underlying the asset decision are in energy prices and in the prices of GHG emission permits issued under a "cap and trade" system of regulation, focussing on natural gas and CO2. In previous work presented at special sessions in the two IAEE meetings in 2002, we used a combination of expert opinion from various domains to construct a model of these prices for use in the ROA of energy-based industrial projects.

In this paper, we apply this model to a situation where the developer of an offshore gas field can create the opportunity to sequester geologically some or all of its stripped-off CO2 using natural gas as its energy source to do so.

We have also looked, for the sake of comparison, at this opportunity if there is known time-dependent tax on emissions set to the expected price in our "cap and trade" model

We value the sequestration option as an annual series of "sequester vs. vent" choices, where the effective revenue is the cost of the permits or the tax avoided. Then we look at the optimal timing for the creation of the option, if that timing must be specified with certainty now. Finally, we determine the value of a current investment that would decrease the future cost of the sequestration plant.

We have done this analysis using standard single-scenario and probabilistic discounted cash-flow (DCF) analyses with a typical DCF discount rate, as well as using ROA.

The DCF estimates of the value of the sequestration plant once it is constructed are less than the ROA estimate in each situation. The DCF methods also attribute less value to the current investment to decrease future sequestration costs. Finally the DCF analyses suggest that the sequestration plant be constructed later than does ROA. The differences between the ROA and DCF results are greater if the there is the known tax on emissions rather than an uncertain permit price.

In this paper, we explain the reasons for these differences.

Introduction

For over 15 years, the global community has been considering how to manage our reaction to the possibility that, if human-induced net emissions of greenhouse gases (GHGs) to the atmosphere are curtailed enough, GHG concentrations in the atmosphere will remain low enough to decrease, by a worthwhile amount, the probability of climate changes that we would want to avoid. There is a great deal of uncertainty about most aspects of this issue (scientific, technological, economic and political), but it is now clear that the possibilities for different types and degrees of regulation of GHG emissions from petroleum production projects should be factored into the methods used to evaluate such projects.

Independently, for over 25 years, various people have suggested that commercial organisations, particularly in the upstream petroleum industry, should take into account, in their evaluation of decisions about their asset structure and management:

1) the multi-dimensional structure and the time evolution of the uncertainty in the determinants of asset cash-flows; and
2) how asset structure, including the flexibility that asset managers have to change that structure, influences the effect of underlying uncertainties on asset value.

"Real options analysis" (ROA) is the term most commonly used for the methods of doing this that are most soundly grounded in our current knowledge about asset valuation. For a review of this topic, see Laughton, Sagi and Samis (2000), and for a commentary on some recent misunderstandings about ROA in the upstream petroleum industry, see Laughton (2005).

The uncertainties that arise from the potential for GHG emission regulation are complex, multi-dimensional, new and long-term. The management of the impact of these uncertainties on petroleum production projects will require flexible responses. For this reason, the incorporation of GHG considerations into the project evaluation processes of the upstream petroleum industry provides a test-bed for the potential costs and benefits of using ROA in this industry. We have brought together a team with expertise in the science, technology, economics, politics and integrated assessment of the GHG regulation issue, and in ROA and petroleum project evaluation, to form a small research programme to begin to explore this topic.

One key element of a real options analysis is the specification and parameterisation of the model for the probabilistic process by which uncertainties in the underlying variables of the analysis are resolved. Our first task was to create a simple version of such a model for the energy market and GHG regulation, which we did and presented in special sessions at the two meetings in 2002 of the International Association for Energy Economics (IAEE). At the writing of this paper, the details of those sessions have not yet been written up. The presentation materials and other details are available, on request, from the lead author at laughton.david@davidlaughtonconsulting.ca. The structure, but not the detailed justification, of the model is given below.

In this paper, we use that model in the evaluation of a GHG geological sequestration project. We strip out a lot of project detail to focus on the differences between how standard discounted cash-flow (DCF) and ROA methods determine the effects of uncertainty on value. In the concluding section of this paper, we discuss various elaborations of this preliminary analysis.

The Sequestration Project: Overall Structure

We consider a situation where a broadly held corporation faces a "now or never" decision on whether and how to develop an off-shore natural gas field. The gas contains some CO2, which must be removed before the gas can be sold. The developer must decide what options it wants to put in place to deal with this stream of CO2, if it goes ahead with the field development.

It can do nothing and vent the CO2.

At some point, it can build a compression and transport system so as to have the option to put the CO2 into a reservoir underground. The source of energy for the operation of this sequestration plant will be part of the natural gas stream itself.

The developer can make this sequestration plant cheaper to put in place in the future if it builds its production platform now to accommodate it, rather than forcing a retrofit later.

The Sequestration Project: Simplifications

In this first preliminary analysis, we simplify the details of the situation, so that we might focus on the key aspect of integrating GHG considerations into the project evaluation process: the effect on project value of the resolution of uncertainty jointly about the energy market and GHG regulation.

We ignore project-level uncertainty about the amount of CO2 available for sequestration, and about the capital and operating costs of the sequestration plant. We also ignore systematic uncertainty in the sequestration costs, except for the uncertainty in the price of the natural gas used as the sequestration energy source.

We also presume that there is no other competing use for the sequestration reservoir, so that the opportunity cost of its use for this purpose is zero.

There are no relevant taxes, with the possible exception of the CO2 emission excise tax mentioned below.

Finally, the developer can choose if and when to build the sequestration plant, but this timing decision must be made now. This situation is much simpler to analyse than the situation where the decision to build the plant can be made at any time in the future. By eliminating future flexibility from the problem, we can focus more clearly on the effects on the project valuation, of uncertainty in the model for the energy market and GHG regulation.

The Sequestration Project: Parameters

All monetary parameters are in current (2002) terms.

The stream of CO2 available for sequestration (net of the CO2 emitted during the sequestration process) is 1M tonnes per year for the period from 2006 to 2033.

The sequestration plant will cost US$120M when it put in place, if there is no accommodation made for it when the production platform is built. It will cost US$90M, if US$10M extra is expended, at the time the platform is built, to accommodate it in the future.

The operating costs of the plant, when it is in operation, will be US$0.5M per year and 0.7kcf of gas per net tonne of CO2 sequestered. There are no operating costs when it is not in operation.

There are no incremental decommissioning costs, and no costs to switch the sequestration plant on or off.

GHG Regulation: "Cap and Trade" vs. Excise Tax

The overall structure of future GHG regulation is not known now with certainty. Excise taxes have been put into place on CO2 emissions in some jurisdictions in Europe. Internationally, and internally within Canada and some other jurisdictions, it looks like part of the regulatory regime will be a "cap and trade" system where there will be market prices for permits to emit GHGs to the atmosphere. In the future, there may also be some "best technology command and control" regulation.

For the analysis in this paper, we restrict ourselves to two situations, in which:

1) there will be, with certainty, a market spot price for CO2 emissions arising from a "cap and trade" system; and, for comparison,
2) there will be, with certainty, a regime with a known time-dependent emissions excise tax.

In the second situation, the tax can be considered as an emission price that is known with certainty, and, in the rest of this paper, we shall occasionally abuse precision of terminology, where warranted, to refer to it as the price of CO2 emissions in that situation.

The Underlying Variable Model: Overall Structure

The model of the underlying variables is based on a tree of scenarios for the relevant aspects of the future, where branching on the tree represents the arrival of new information that differentiates among different groups of possible scenarios, and states on the tree are where branching, cash-flows or decisions can occur. The concept of a scenario tree is outlined in detail in Bradley (1998) and references therein. It should be noted that, if there is no uncertainty about the future, and thus only one possible scenario, the scenario tree collapses to a time line, with one state at each time.

The only aspect of the energy market that is directly relevant for the evaluation of the sequestration project is the time series of future natural gas prices. Within the restricted possibilities for GHG regulation that we shall consider, the only aspect of the regulatory framework that is relevant is the price for CO2 emission permits or the tax on emissions.

In the "cap and trade" situation, we have chosen to model directly the uncertain evolution of the joint term structure of the forecasts of the two prices involved. The type of model that we have used is described in detail in Salahor (1998) and Bradley (1998) and references found therein. Any reader who is unfamiliar with any terms used in this description may find more details there.

We presume that:

1) the forecasts follow a joint geometric 2-dimensional diffusion process;
2) the short-term forecast volatilities and the factor correlation coefficient may be time-dependent;
3) the term structure of the forecast volatilities may be exponentially decaying at each time, with a constant decay time for each price;
4) the risk discounting in natural gas and CO2 forward prices is driven by "prices of risk" that are constant; and
5) the real risk-free rate in constant.

In the "excise tax" situation, the model structure is the same, except that there is no uncertainty in the equivalent of the CO2 price, which is the emission excise tax.

Diffusion processes for price forecast movements result in continuous but "jerky" price paths, much like those observed. A 2-dimensional process allows the CO2 and gas prices to be imperfectly correlated.

Salahor (1998) shows, and Figures 1a,b of this paper confirm, that the decay in the forecast volatilities with respect to the term of the forecast allows for the existence of long-term equilibrating forces in the relevant markets.

A more general model would have more dimensions of fundamental uncertainty (allowing for different sources of uncertainty in climate system response, climate impacts, technology, economic growth, and political considerations). It would also allow for a more general specification of the uncertainty in the price forecast movements, including uncertainty in this uncertainty.

Finally, we have used a very simple model of discounting driven by constant risk-free interest rates and prices of risk. A more general specification would allow uncertainty in these parameters as well.

The Underlying Variable Model: Parameters

There are natural gas spot and forward prices from the past that can be used in an econometric analysis of the parameters in the natural gas price model. However, in the "cap and trade" situation, there is little information about the CO2 market, and we must rely almost totally on expert opinion to determine that part of the model.

In fact, we relied on expert judgement to parameterise the whole model. The detailed rationale behind those judgements were presented during the special sessions at the meetings of the International Association for Energy Economics (IAEE) mentioned above, and the details are available from the lead author at laughton.david@davidlaughtonconsulting.ca. Some comments are given at the end of this section.

The model of the underlying variables in the "cap and trade" situation is parameterised by:

1) the current (2002) term structure of price medians, shown in Figures 1a,b (in current (2002) terms, as are all monetary parameters in this paper);
2) the time series of short-term forecast volatilities for each price:
   a) 20% in annual terms (which is about 1% in daily terms) for gas; and
   b) 25% in annual terms for CO2 for the periods before 2010 and after 2040 inclusive, and linear up and down in the period 2010-2040, with a peak at 2025 of 32.5%;
3) the half-life for the exponential decay in the term-structure of forecast volatilities at any given time:
   a) 3 years for gas; and
   b) 4 years for CO2;
4) the correlation coefficient between gas and CO2 price forecast movements is 0.3 until 2019, -0.2 after 2024, with a linear decline in the period between;
5) the price of risk of each type of price uncertainty:
   a) 0.3 in annual terms for gas (which gives risk discounting of 3% per year four each 10% of annual forecast volatility); and
   b) 0.4 in annual terms for CO2 (which gives risk discounting of 4% per year four each 10% of annual forecast volatility);
6) the real risk-free rate of 3% per year.

The resulting current (2002) term structure of 80% confidence intervals for each price at each time is given Figures 1a,b by the solid lines around the current (2002) term structure of the price medians.

The dashed lines in Figures 1a,b show the term structure of 80% confidence intervals as they would appear at a given future time (2003 for gas, 2020 for CO2), if the realised price at that time were different from the current median forecast (20% above it for gas, 40% above it for CO2). Note that the conditioned future intervals revert back to current intervals. As is shown in Salahor (1998) and the references therein, the time scale, over which this reversion occurs, is determined by the time scale in the decay of the forecast volatility.

Fig. 1a Natural Gas Price Medians, 80% Intervals Current and 20% Shock by 2003

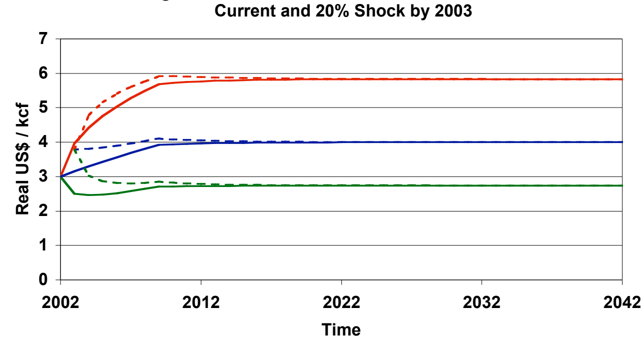
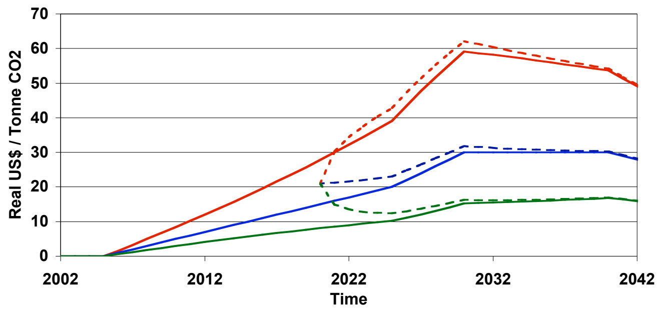


Fig. 1b CO2 Price Medians, 80% Intervals
Current and 40% Shock by 2020



Figures 2a,b show the current (2002) term structure of price expectations and forward prices. As noted in Salahor (1998), the ratio of the forward price and the price expectation is the risk discount factor determined by the relevant prices of risk and the forecast volatilities.

Fig. 2a Natural Gas Expected and Forward Prices

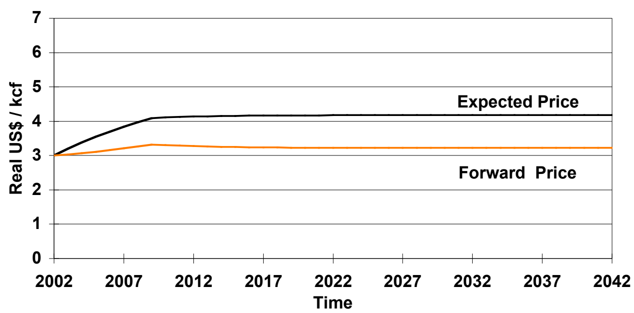
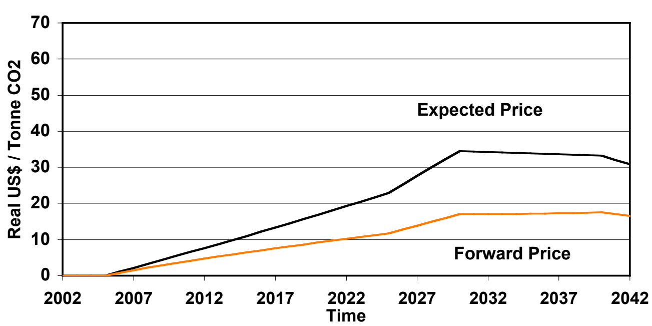


Fig. 2b CO2 Expected and Forward Prices



In the "excise tax" situation, which we use to compare with this "cap and trade" situation, we use the same gas price model and sets the term structure of CO2 emission taxes to be equal to the current (2002) term structure of "cap and trade" CO2 price expectations.

The current gas price forecast is based on a gradual expected price increase until a long-term backstop source of gas is available in a few years with a median price of US$4.00 (in 2002 terms).

The CO2 price forecast is essentially zero for a few years until the first Kyoto commitment period is imminent, and then it increases as the climate system response and climate impacts become more visible, the political system responds to pressure for action, and as GHG emissions increase with economic growth. The price then plateaus and finally decreases as technology arises to decrease the GHG intensity of the economy.

There is greater uncertainty in the CO2 prices than the gas prices, and the uncertainty peaks in the region around 20025, where much of the climate system and technological uncertainty may begin to be resolved. There are more drivers of the CO2 prices with long-term effects. This is reflected in the longer time-scale for the equilibrating forces in the CO2 market.

Natural gas and CO2 price forecast movements are positively correlated until 2025 and then are negatively correlated, reflecting a shift in technology. Right now natural gas is the least carbon intensive fossil fuel. Energy users will tend to shift to natural gas if CO2 price forecasts are shocked upward, and the demand for CO2 credits will increase if gas price forecasts are shocked upward. In the future as technology develops natural gas will be competing with less carbon intensive fuels and the economic forces just noted will reverse. We have approximated the timing of this transition as being known now with certainty. Of course, it is actually uncertain.

Finally, there are more drivers of the CO2 prices, including the political drivers for regulation, that are tightly correlated with overall economic growth. Therefore, the price of risk in CO2 prices, which reflects how much compensation investors demand, through discounting, for bearing a given level of uncertainty, is higher for CO2 prices than gas prices.

Valuation Methods

As part of the evaluation of how to manage this opportunity to sequester the CO2, if the gas field is developed, we focus, in each of the situations under consideration, on the incremental current (2002) value of the opportunity under the different possible management policies, presuming that the gas field development does go ahead. We use the definition of value commonly used in finance, which is found, for example, in the Income Tax Act of Canada: the price obtainable for the asset in an open and unrestricted market between knowledgeable, informed and prudent parties, acting at arm's length, neither party being under any compulsion to transact.

We have used three methods to calculate an estimate of the incremental value of this opportunity to sequester CO2. In each case, we have made the approximation that decisions are made, and cash-flows occur, annually. As noted in Bradley (1998), this time grid can be refined, if greater accuracy is desired, at the expense of more calculation.

First, we determined the value using standard single-scenario DCF methods in the scenario of expected gas and CO2 prices, using a continuously compounded risk-adjusted discount rate of 10% per year.

Second, we determined the expected DCF value. given the probability distribution for the price scenarios that arises from the price model described above.

Third, we determined the value using ROA methods.

The DCF calculations are standard and well known in the petroleum industry, and we shall not describe them here in detail.

The ROA calculation is based on a consistent model of financial markets, which are the markets where value, in the sense defined above, is determined. This model is based on the approximation that transactions costs or barriers are low enough in these markets, that trading quickly drives two assets with the same cash-flow characteristics to have the same price.

The papers in Laughton (1998a) (Laughton (1998b), Salahor (1998), Bradley (1998) and Baker, Mayfield and Parsons (1998)) expand on this, giving references to the original literature on this subject, and show the relationship between the DCF and ROA methods we use. Laughton, Sagi and Samis (2000) and Laughton (2005) also provide relevant comments.

These references show that the computation of asset value in each method can be represented as:

the asset value =
the sum over states on the relevant scenario tree of
(the asset cash-flow in each state
* the unit price for cash-flow in that state).

The scenario tree and the unit prices may be different for the different methods.

For the single-scenario DCF valuation, the scenario tree is the time line for the scenario involved. The unit price for the cash-flow at a given state on the time line is the discount factor for the time of that state, where the discount factors are produced by using the risk-adjusted discount rate for the valuation. For future reference, it will be useful to think of the discount factor as being the product of two discount factors: one for time generated by the risk-free rate (which is 3% per year in our model) and the other for risk generated by the risk premium in the risk-adjusted discount rate (7% per year in this example).

The scenario tree for the probabilistic DCF valuation is a revised version of the scenario tree produced by the diffusion process model for the gas and CO2 price forecasts. In this revised tree, all the branching is presumed to occur at the current time (2002), rather than over time. In this way, we can have multiple versions of the single-scenario DCF valuations. The contribution of these single-scenario values to the expected value is weighted by the probability for the scenario involved. Therefore the unit price for the cash-flow at a given state in the revised scenario tree is the product of the probability of the scenario for that state and the discount factor for the time of that state. The discount factors are the same as for the single-scenario DCF method.

The scenario tree for the ROA valuation is the actual scenario tree produced by the diffusion process model for the gas and CO2 prices. The unit price for the cash-flow at each state in the scenario tree is determined using the Black-Scholes-Merton dynamic replication method outlined in Bradley (1998) and references therein. We find a dynamic trading strategy, involving financial instruments with prices already known or modelled (in this case, claims to risk-free cash, to gas and to CO2 emission permits), that replicates the payoff of a unit of cash in the state being considered. Because of the "no transactions costs" approximation, the unit price for cash-flow in that state is the value of portfolio that begins the trading strategy.

As noted in Laughton (2005), the unit price can be broken down into the product of what may be called the "risk-adjusted probability" of the state and the time discount factor for the time at which the state occurs.

The time discount factor for each time is the unit price for risk-free cash to be received at that time.

While the risk-adjusted probabilities have all of the properties of a probability distribution, if there is any risk discounting, they are not the actual probabilities for the variables being considered. In fact, as Laughton (2005) shows, the risk-adjusted expectation (i.e., the expectation with respect to the risk-adjusted probability distribution) of each of these variables is its true expectation discounted for risk. Salahor (1998) shows that, if the underlying variables are commodity prices, as is the case here, these risk-discounted expectations are the corresponding forward prices.

Bradley (1998) and references therein also show that, in the class of models we are using, where the only uncertainty is in the proportional price forecast movements, the risk-adjusted probabilities have the same proportional uncertainty structure as the true probabilities.

To understand better how risk enters into valuation using DCF and ROA methods, we look at the unit state prices that are relevant for a cash-flow occurring at a particular time, in situations where the cash-flow amount depends only on the gas price at that time. We factor out the discounting for time, and examine the true probability distribution of these gas price states, the risk-adjusted probability distribution, which accounts for risk in ROA, and the risk discounted probability distribution (the product of the true probabilities and the risk discount factor for that time), which accounts for risk in the expected value of probabilistic DCF analysis.

Figure 3a shows the true (solid) and risk-adjusted (dashed) distributions for gas price states 1, 5, and 20 years hence (2002). Figure 3b shows the true (solid) and risk-discounted (dashed) distributions. As Laughton (2005) observes, risk discounting occurs in ROA through a risk adjustment that gives a greater weight in the valuation to lower price states than is warranted by their true probability and a lower weight to high price states. Risk discounting occurs in DCF by giving less weight to all states through the risk discount factor common to all.

Laughton (2005) shows how the ROA treatment of risk is consistent with our basic understanding of the preferences that most people have about uncertainty: They prefer incremental cash more when they are otherwise poor than when they are otherwise rich. If gas prices are correlated with the well-being of most investors, this means that low-price states should have a positive risk adjustment in any valuation and high-price states a negative adjustment, as is the case with ROA. This is what causes the discounting for risk imbedded in gas forward prices and, more generally, in the valuation of any cash-flow claim, where the cash-flows increase with gas prices.

For future reference, we should note that Figures 2a,b and 3 show the ROA risk adjustment for our gas and CO2 price models saturates as we look further into the future, while the DCF risk discount factor keeps decreasing. Moreover, DCF methods discount all cash-flows at a given time by the same amount for risk, while the risk discounting in ROA depends on the exposure of the cash-flow to the underlying uncertainty. For example, when we use ROA, risk-free cash-flows face no discounting for risk, as should be the case. DCF does discount them for risk, by the same amount as it does every other part of the asset cash-flows.

Fig. 3a Natural Gas Marginal (by Term) Distributions
True (Solid) Risk Adjusted (Dashed)
Term = 2003 2007 2022

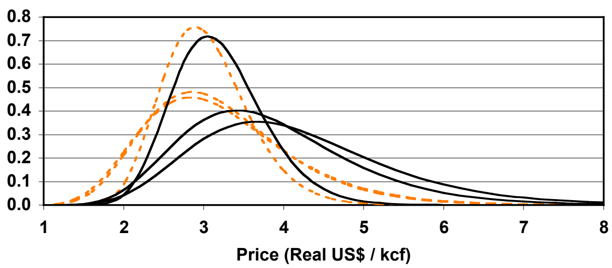
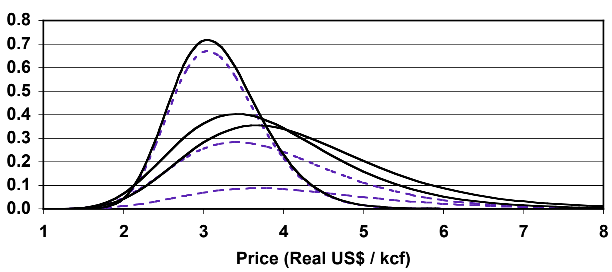


Fig. 3b Natural Gas Marginal (by Term) Distributions
True (Solid) Risk Discounted (Dashed)
Term = 2003 2007 2022



The Valuation of the Operating Cash-flows

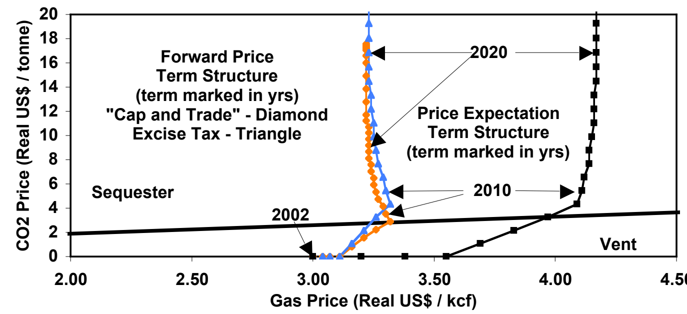
Figure 4 shows the phase diagram for the optimal policy to operate the sequestration plant (sequester vs. vent as a function of the concurrent gas and CO2 prices). This diagram is independent of time, once the plant is built and before the project ends, because the cash-flow dependence on the concurrent CO2 and gas price is independent of time as well, and, in addition, there are no costs of opening or closing the plant..

The optimal policy can be determined without doing any valuation, because, without any intertemporal effects, choosing the higher cash-flow produces the higher value, and the choice that produces the higher cash-flow is a straightforward comparison between the effective revenues and the costs that would result from sequestering the CO2.

Note that if the CO2 price is high enough compared to the gas price, the plant should be run. Otherwise, the CO2 should be vented after emission permits are bought or the excise tax is paid.

Figure 4 also shows the current (2002) term structure of the true and risk-adjusted expectations of the gas and CO2 prices in "cap and trade" and "excise tax" situations. The true expectations show the location of the current (2002) central tendency of the DCF state price distribution for each year in the future, while the risk-adjusted expectations show the central tendency of the ROA distributions. The true expectations are the same in both the "cap and trade" and the "excise tax" situations (by construction, because the level of the CO2 excise tax in each year is set to be the "cap and trade" CO2 price expectation). However, the risk-adjusted expectations are different: The CO2 excise tax is specified with certainty, while the "cap and trade" CO2 prices are risky.

Fig. 4 Annual Sequester vs. Vent Decision



All three term structures are in the "vent" region of the phase diagram in the early years of gas production. This means that only the states in the "tail" of the state price distribution will contribute to the valuation of any early sequestration cash-flows. The price term structures all end up deep in the "sequester" phase, so that the states in the "vent" phase will contribute little to the current (2002) valuation of any sequestration cash-flows that occur late in the project. The transition time is 2008 for the true expectations, and 2009 ("cap and trade") or 2007 ("excise tax") for the risk-adjusted expectations.

Fig. 5 Probability of Sequestration

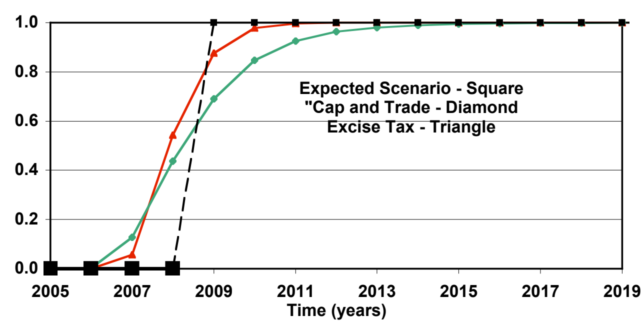


Figure 5 shows the current (2002) probability for each time in the future that sequestration, if it is possible, will be better than venting. The sharp transition at 2008 is for the single scenario DCF analysis, which effectively presumes that there is no uncertainty around the expected price scenario. The transition in the "excise tax" situation is sharper than "cap and trade" transition, because there is more uncertainty in the "cap and trade" cash-flows, due to the uncertainty in the "cap and trade" emission price (even though it is correlated with the gas price in the relevant period of time).

Figure 6a shows the current (2002) value of the claim to the sequestration cash-flow at each time in the future, once the sequestration plant is in place. These results demonstrate the effect on value of of the different approaches by ROA and DCF methods to the treatment of risk. (Note the probabilistic and single-scenario DCF values in both the "cap and trade and "excise tax" situations are very similar. Figure 6b, which we discuss below, shows the differences.) The constant 7% per year risk premium in the DCF valuation, when compared to the ROA, undervalues the long-term sequestration cash-flows. The long-term equilibrium that we have modelled for the GHG regulation process in the "cap and trade" situation, and the certainty we have modelled in the "excise tax" situation, make much lower risk premia more appropriate. Moreover the use of the same discount rate in the DCF analysis of the two situations misses the effect on the valuation of the two very different structures of the uncertainty in the effective sequestration revenues. The 7% per year risk premium produces a greater undervaluation in the "excise tax" situation where the effective revenues are known with certainty than in the "cap and trade" situation where the revenues are discounted somewhat for risk.

Fig. 6a Current Sequester vs. Vent Option Payoff Value

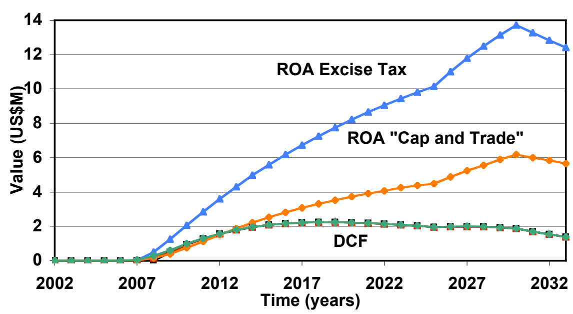


Fig. 6b Current Sequester vs. Vent Option Payoff Value

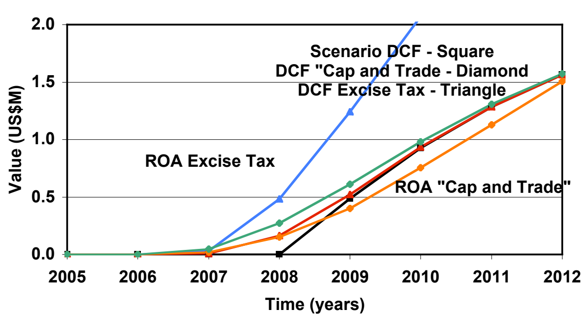


Figure 6b shows these values for the years from 2005 to 2012, allowing us to focus on the valuation of cash-flows that may occur in the transition period. We can see the sharp transition in scenario DCF values compared to the more gradual transition in the expected DCF values, reflecting the term structure of sequestration probabilities in Figure 5.

Building the Sequestration Plant

Deciding now when to plan to build the sequestration plant in the future depends on the trade-off, for each possible year in which it might be built, between two sources of value:

1) the decrease, by delaying construction for a year, in the current (2002) value of the cost of building the plant; and
2) the current (2002) value of the claim to the cash-flow from operating the plant in that year.

This trade-off will also depend on whether that cost is US$90M (if an initial US$10M investment has made a platform retrofit unnecessary) or US$120M (if a platform retrofit is necessary).

Table 1 shows the highest incremental value of this sequestration option, and the current pre-investment and investment timing choice that produces that value, as determined by each method we have used for estimating value, in both the "cap and trade" and "excise tax" situations.

Table 1
Sequestation Option Value (US$M)
and Management (Preinvest, Invest Time)

	"Cap and Trade"	"Excise Tax"
ROA		
Manage	Yes, 2014	Yes, 2010
Value	5.69	115.91
Scenario DCF		
Manage	No, 2019	No, 2019
Value	4.25	4.25
Probabilistic DCF		
Manage	No, 2019	No, 2019
Value	4.23	4.25
ROA Value	-7.15	78.59
ROA Value Loss	12.84	37.32

The scenario DCF valuation is the same in both the "cap and trade" and "excise tax" situation by construction of the excise tax. The current (2002) value is US$4.25M if the plant is built in 2019 without the upfront investment to accommodate it.

The probabilistic DCF valuation is essentially the same as the single scenario analysis, because it is optimal to build the plant at a time when there is negligible probability that the manager will choose to vent the CO2. Without this venting option, the cash-flow model would be linear in the underlying price variables and the expected DCF values would be the same as the DCF values in the expected price scenario.

The ROA analysis gives very different results. It suggests that the upfront investment be made and that the plant be built much earlier (2014 in the "cap and trade" situation and 2010 in the "excise tax" situation). As noted above, the value estimation is much more sensitive to the actual uncertainty in the underlying variables: The project is much more valuable if the CO2 price is known with certainty, as in the "excise tax" situation (US$115.91M vs. US$5.69M).

ROA suggests that the plant be built earlier for two reasons. The ROA value of the operating cash-flows is greater than the DCF value, so the value lost by delay is greater. Also, the ROA value of the future cost of building the sequestration plant decreases, if delayed, at the risk-free rate of 3% per year, while the DCF value decreases at the risk-adjusted rate of 10% per year used in the DCF analysis to value all cash-flows. Given these rates, the DCF value lost by delaying a risk-free cash-flow exceeds the ROA value lost until 2019, which, coincidentally, is the latest time suggested by any of the analyses for building the plant.

The decision whether to make the upfront investment of US$10M now to save US$30M later, is a straight tradeoff between the two costs. The current (2002) DCF value of the extra US$30M in future costs is less than the ROA value in part because DCF suggests that the plant be built later. More importantly, the DCF analysis discounts this future cost, as it discounts all cash-flows, at the risk-adjusted DCF rate of 10% per year. ROA recognises that this future cost is modelled to be risk-free and discounts it at the risk-free rate of 3% per year.

As we see from Table 1, the undervaluation of the future cost saving by the DCF analysis is enough to change the recommendation about whether to undertake the initial investment. Salahor (1998) observed a similar problem with DCF analysis in a choice about outsourcing gathering and processing for a gas field, where a current investment to save future low risk costs was undervalued enough to suggest the wrong course of action.

If ROA gives correct valuations, then the current (2002) value lost from following management policy suggested by DCF management directive would be US$12.84M (US$5.69M to -US$7.15M) in the "cap and trade" situation and US$37.32M (US$115.91M to US$78.59M) in the "excise tax" situation.

Conclusions

We have used a preliminary model of energy markets and GHG regulation (the "cap and trade" model), and a foil for that model (the "excise tax" model), to explore how organisations in the upstream petroleum industry might begin to integrate the effects of GHG regulation into their project evaluation process. We used a simplified model of an option to sequester geologically part of a pure stream of CO2 to show that how the risks associated GHG regulation might be modelled, and how these risks are valued, can have a big impact on the decision-making about such options, which can in turn have a big impact on their value. This provides another example of how simple DCF analyses can give misleading results because they do not take in account the complex effects of risk on value.

We have not looked at how going beyond the determination of the expected DCF value, but staying within the single discount rate DCF paradigm, might mitigate the differences between the two methods of estimating value. We leave this to others.

Any commercial organisation that uses ROA to analyse the effects of GHG regulation on asset design and value would need to expand upon what we have done.

Our model of energy markets and GHG regulation is just a preliminary effort. We may do some work in the future to expand on this model by looking beyond the price variables to the determinants of the prices as underlying variables. In particular, the structure of long-term equilibrium needs more careful analysis.

We purposefully simplified the project model for the analysis presented in this paper.

The simplest generalisations would be to include tax considerations and to allow the choices about investing in the sequestration plant to be made in the future.

It would also be important to consider the evolution of project-level uncertainty in the amounts of CO2 available for sequestration and the costs involved, and the implications the resolution of this uncertainty would have for future design choices, such as plant technology and capacity.

However, the most difficult issue that needs to be addressed is the evolution in the systematic uncertainties in the costs, other than the direct uncertainty in the energy cost due to the gas price, which we have already taken into account. This is particularly important because uncertainties in the cost of sequestration technology will be a key driver of the uncertain development of GHG regulation, while such regulation remains an issue. Moreover, there may be an opportunity cost for using a given reservoir to sequester a given stream of CO2, and this cost would be driven by emission permit prices among other factors. Therefore, a more complete joint model of the uncertainty in GHG regulation, energy markets and sequestration technology will be required to address this type of sequestration decision fully. The modelling, for use in ROA, of these types of linkages is in its infancy (Laughton 2005).

This brings up one final consideration. The type of project analysis that we have considered here, if it is developed further, may be able to contribute usefully to bottom-up assessments of the future of GHG regulation.

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