

**Managing Risks in Energy Capital Projects –
The Value of Contractual Risk-Sharing in CCS-EOR**

by
Anna Agarwal

B.Tech. Indian Institute of Technology – Delhi, India, 2005
S.M. Massachusetts Institute of Technology, 2008

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Signature of Author.....
Department of Civil and Environmental Engineering
May 9, 2014

Certified by.....
John E. Parsons
Senior Lecturer, Sloan School of Management
Thesis Supervisor

Certified by.....
Ruben Juanes
Associate Professor of Civil and Environmental Engineering
Thesis Reader

Certified by.....
Herbert H. Einstein
Professor of Civil and Environmental Engineering

Certified by.....
Howard J. Herzog
Senior Research Engineer, MIT Energy Initiative

Accepted by.....
Heidi M. Nepf
Chair, Departmental Committee for Graduate Students

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Abstract

This thesis addresses the question of how to maximize the value of energy capital projects in light of the various risks faced by these projects. The risks can be categorized as exogenous risks (not in control of involved entities) and endogenous risks (arising from sub-optimal decisions by involved entities). A dominant reason for poor project performance is the endogenous risks associated with weak incentives to deliver optimal project outcomes. A key objective of this research is to illustrate that risk-sharing through contracts is central to incentivize the involved entities to maximize overall project value.

The thesis presents a risk management framework for energy capital projects that accounts for both exogenous risks and endogenous risks to evaluate the optimal risk management strategies. This work focuses on a carbon capture and storage project (CCS) with enhanced oil recovery (EOR). CCS is projected to play a key role in reducing the global CO₂ emissions. However, the actual deployment of CCS is likely to be lower than projected because of the various risks and uncertainties involved. The analysis of CCS-EOR projects presented in this thesis will help encourage the commercial deployment of CCS by identifying the optimal risk management strategies. This work analyzes the impact of the exogenous risks (market risks, geological uncertainty) on the value of the CCS-EOR project, and evaluates the optimal contingent decisions. Endogenous risks arise from the involvement of multiple entities in the CCS-EOR project; this thesis evaluates alternate CO₂ delivery contracts in terms of incentives offered to the individual entities to make the optimal contingent decisions.

Key findings from this work illustrate that the final project value depends on both the evolution of exogenous risk factors and on the endogenous risks associated with response of the entities to change in the risk factors. The results demonstrate that contractual risk-sharing influences decision-making and thus affects project value. For example, weak risk-sharing such as in fixed price CO₂-EOR contracts leads to a high likelihood of sub-optimal decision-making, and the resulting losses can be large enough to affect investment and project continuity decisions. This work aims to inform decision-makers in capital projects of the importance of considering strong contractual risk-sharing structures as part of the risk management process to maximize project value.

Thesis Supervisor: John E. Parsons
Title: Senior Lecturer, Sloan School of Management

Thesis Reader: Ruben Juanes
Title: Associate Professor of Civil and Environmental Engineering

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Chapter 1 Introduction

1.1 Motivation and Objective

In this thesis we address the question of how to maximize the value of large energy capital projects in light of the various risks faced by these projects. Many of the large energy projects such as upstream oil and gas projects involve large upfront capital investment, and the project cash flows are subject to considerable uncertainty from multiple risk factors. Academic literature evaluating the performance of large capital projects suggests that under-performance is more of a rule than an exception (Flybjerg et al., 2003; Merrow, 2011; Miller and Lessard, 2000; World Bank, 1994; Ostrom et al., 1993). For example, Miller and Lessard (2000) discuss the performance of large-scale capital projects across different sectors including electricity production, oil and gas, urban transportation, and they report that close to 40% of the projects performed very badly.

Large capital projects face multitude of risks throughout their lifetime. Dewatripont and Legros (2005) classify the risks in large projects into two categories: exogenous and endogenous. Exogenous risks refer to the risks that are not under the control of the project owners and operators such as volatility in the market prices. Endogenous risks are associated with inefficient actions by the involved entities, such as poor maintenance leading to reduced economic life.

Studies find that a key reason for poor performance in large capital projects is the endogenous risks associated with poor incentives to deliver efficient project outcomes. Endogenous risks arise from conflict of interest among the entities involved wherein the interests of the individual entities are not aligned with the common interest of the project, resulting in inefficient actions that do not maximize the overall profit of the project. For example, the World Bank report (1994) studied the reasons for poor performance of infrastructure projects in the developing countries.

The report found that inefficient operations and poor maintenance was rampant in the projects, and the basic reason was poor incentives to satisfy the customers or increase the financial returns. The poor incentives arose from the conflicting objectives among the various entities involved, and little accountability on the project outcomes.

Poor incentives facing the involved entities lead to sub-optimal project outcomes, and if the conflict of interest is anticipated then it leads to inefficient investment decisions where the project might not go ahead even if it was efficient to invest. The project losses suffered as a result of these inefficiencies associated with ex post project outcomes and ex ante investment decisions is what we have termed as endogenous risks in capital projects.

Endogenous risks are influenced by the contract terms that link the different entities involved in the project. The contract terms determine how the project cash flows would be distributed among the involved entities, and the value captured by each entity and the resulting risk exposure will determine the incentives for optimal performance. Flyvbjerg et al (2003) and Miller and Lessard (2000) point that traditionally contracts in infrastructure projects (or large capital projects) put negligible risk on the contractor, and thus the contractor has no incentive to reduce costs or reduce risk. Flyvbjerg et al (2003) emphasize that a key challenge in risk management is to change the current contracting approach.

The objective of this thesis is to develop a risk management framework that accounts for both the exogenous risks and the endogenous risks in evaluating risk management strategies for large energy capital projects. In this thesis, we quantitatively illustrate that risks in large energy capital projects are a combination of the exogenous risks and the endogenous contracting risks. The final project value is determined by how the exogenous risk factors evolve during the project and how the project entities respond to the changes in the risk factors.

We illustrate the proposed risk management framework through an application to carbon capture and storage projects (CCS). CCS is a technology to reduce anthropogenic carbon dioxide (CO₂) emissions from fossil fuel power generation and other CO₂ intensive industrial processes. The CCS value chain involves three key components: CO₂ capture, CO₂ transport and CO₂ storage. Firstly CO₂ is captured at CO₂ emitting sources (such as a coal-fired power plant), and then

transported via pipelines to CO₂ storage sites (such as an oil reservoir) where the CO₂ is sequestered for long-term storage.

The CCS projects face various risks throughout the life of the project, and how these risks are managed will determine the final project value. There is a large level of exogenous uncertainty in CCS projects, the sources of the exogenous uncertainty include variations in the market risk factors, uncertainty on the how the CO₂ storage reservoir responds to the CO₂ injection, and uncertainty on the regulatory policies affecting CCS projects. In an integrated CCS project which involves all three components of the CCS value chain: capture, transport, storage, the various risks will be faced by different entities owning and operating the different parts of the value chain. Thus, risk management in CCS projects is not just about evaluating optimal decisions, but the contract structures linking the different involved entities should offer incentives to the individual entities to make those optimal decisions.

In this thesis, we consider a prototype CCS-EOR project wherein the CO₂ is captured at a coal-fired power plant and is transported via a dedicated pipeline to an oil field, where it is injected for enhanced oil recovery (EOR). We model the CCS-EOR project ownership structure such that the power plant and the oil field are owned and operated by separate entities, and the pipeline is jointly owned by the two entities. The operation between the power plant company and the oil field company is integrated through a long-term contract for the delivery of CO₂.

We focus on the risks that are realized during the operational phase of the project, and that would initiate contingent decision-making involving reoptimization of project operations by the project entities to maximize the project value in light of the change in the risk factors. The two sets of risks we analyze in this thesis are: technical risks and market risks in the operational phase of the project. The technical risk we are interested in is the uncertainty on the EOR efficiency, which refers to the uncertainty on the amount of oil recovered per unit of CO₂ injected in the EOR operations. The market risk factors we analyze in this thesis are the wholesale price of electricity, the price of oil recovered, and the CO₂ emission penalty. Both these types of risks: the market risks and the uncertainty on the technical EOR efficiency, might require project operators to readjust the project operations in response to change in the risk factors in order to optimize the project value. The contingent decision we focus on is the decision to adjust the CO₂ capture and injection rate in response to change in the risk factors. For example, if the oil price drops or the

actual realized EOR efficiency is less than predicted then it might be economical to lower the rate of CO₂ injection in the EOR operations.

In this thesis, we analyze the impact of the exogenous technical risks and market risks on the value of the prototype CCS-EOR project, and evaluate the optimal contingent decisions that would maximize the overall project value.

These contingent decisions will be made by independent entities owning and operating the different parts of the CCS-EOR value chain. The CO₂ delivery contracts that link the individual entities of the CCS-EOR value chain will determine the incentives the individual entities have to make optimal decisions in the common interest of the project. We draw insights from the economics literature on contracts and the principal-agent problem (Joskow, 1985, 1988; Grossman and Hart, 1983; Holmstrom, 1979; Mirrlees, 1975) on the different considerations for design of contracts for the CCS-EOR value chain to create strong performance incentives among the involved entities to maximize the total project value.

We evaluate two alternate standard CO₂ delivery contract structures in terms of the risk allocation between the power plant company and the oil field company and the resulting incentives for optimal decision-making. The contract structures analyzed include a fixed price contract where the CO₂ contract price is fixed for the contract term, and an indexed price contract where the CO₂ contract price is indexed to the oil price. For each of the contract structure, we evaluate the decisions made by individual entities in light of the change in the risk factors. We also evaluate the loss in project value from sub-optimal decision-making under the alternate contract structures. The optimal contract structure would be such that the different entities make decisions that maximize the overall integrated project value.

We quantitatively illustrate that the final project value depends both on exogenous risk factors and endogenous risks associated with the response of the project operators to the change in the exogenous risk factors. We show that strong contractual risk-sharing structures minimize the endogenous contractual inefficiencies and can considerably increase the project value.

1.2 Key Contributions

This thesis is expected to make contributions in the following two areas:

Contribution to project risk management

This thesis work aims to inform the decision-makers in large capital projects of the importance of considering strong contractual risk-sharing structures as part of the risk management process to maximize the project value. The thesis will provide a framework for systematic quantitative analysis of the impact of contractual risk-sharing on the decision-making of the involved entities and the resulting project value.

Additionally, this thesis research is an attempt to better understand the reasons for under-performance of large capital projects, and the considerations that should be accounted for to minimize the risks and maximize the project value.

Contribution to CCS

CCS is projected to play a key role in reducing the global CO₂ emissions to meet the global greenhouse gas reduction targets (IEA, 2010; IPCC, 2005). However, the IPCC report notes that the actual deployment of CCS is likely to be lower than the projected economic potential of CCS because of the various risks and uncertainties involved.

In this thesis, we will analyze the risks in the operational phase of CCS projects, and evaluate optimal risk management decisions and strong contractual risk-sharing structures to encourage the commercial deployment of CCS and thus facilitate realization of the true potential of CCS.

1.3 Thesis Structure

This thesis is organized in six chapters, and this section presents a brief overview of each of the chapters.

Chapter 2:

Chapter 2 presents the main motivation behind this thesis work. We will discuss the reasons of poor performance in large capital projects, and argue that a key reason is the weak incentives facing the involved entities to deliver optimal project outcomes.

In Chapter 2, we will also present insights from the contract theory literature on the importance of risk-sharing through contracts to incentivize optimal decision-making by the involved entities such that the overall project value is maximized. This literature also sheds light on how to structure contracts in CCS-EOR projects.

Chapter 3:

Chapter 3 will focus on CCS-EOR projects. We will first present the different risks in CCS projects, and review the industry practices in terms of the existing CO₂-EOR contract provisions. Next in this chapter, we will present the framework used in the thesis to analyze the risks in CCS-EOR projects. This framework is utilized in Chapter 4 and Chapter 5 where we will present the results. Lastly, in this chapter we will describe the technical and economic characteristics of the prototype CCS-EOR project we focus on in this thesis.

Chapter 4:

The objective of Chapter 4 is to analyze the risk exposure of the overall project. We assume that the project is exposed to only the exogenous uncertainty and there is no endogenous contracting risk. In this chapter, we will present how we model the uncertainty in the exogenous risk factors in the prototype CCS-EOR project. We will analyze the impact of the exogenous risks on the value of the integrated project, and will evaluate the optimal contingent decisions that maximize the overall project value.

Chapter 5:

In Chapter 5, we account for the contractual inefficiencies that might arise due to ownership of different parts of the CCS-EOR project value chain by different entities. We analyze alternate CO₂ delivery contract structures in terms of the risk allocation and the resulting incentives provided to individual entities to respond optimally to the change in risk factors, and evaluate the final project value under the alternate contracts.

Chapter 6:

Chapter 6 presents the key conclusions from this thesis work, and discusses the opportunities for future research in this study.

Chapter 2 Risks and Contracts

Many of the large energy capital projects such as upstream oil and gas projects involve large upfront capital investment, and the project cash flows are subject to considerable uncertainty from multiple risk factors. How these risks are managed will determine the project performance. Academic literature on the performance of large capital projects suggests that under-performance is more of a rule than an exception. The key reason for poor performance in capital projects is the weak incentives facing project entities to deliver optimal project outcomes.

The weak incentives arise from the conflict of interests among the various entities involved, wherein the interests of the individual entities is not aligned with the common interest of the project, resulting in sub-optimal performance decisions that do not maximize the overall profit of the project. The performance incentives are influenced by the contract terms that link the different entities involved in the project. The contract terms determine how the project cash flows would be distributed among the involved entities, and the value captured by each entity and the resulting risk exposure will determine their incentives for optimal performance.

The design of incentives through contracts is the subject of literature on the economics of contracts and the principal-agent problem. This literature points to risk-sharing among the involved entities as being at the heart of creating incentives through contracts. Optimal risk-sharing aligns the interests of the entities involved so that they perform in the common interest of the overall project, resulting in maximization of the total project value. We draw insights from this literature on the different considerations for the design of contracts for the CCS-EOR value chain to create strong performance incentives among the involved entities to maximize the total project value.

In this chapter, we will firstly in Section 2.1, discuss the key reasons for poor project performance, and emphasize the importance of contractual incentive structures in improving

project performance. Then, in Section 2.2, we will discuss the economics literature on the design of incentives through contracts.

2.1 Risks and Incentive Issues in Capital Projects

The academic literature on the performance of large capital projects suggests that under-performance is more of a rule than an exception. Miller and Lessard (2000) discuss the performance of sixty large-scale capital projects across different sectors including electricity production, oil and gas, urban transportation, which were studied as part of the IMEC Research Program. The average investment across these projects was \$985 million, and the study found that close to 40% of the projects performed very badly. Flyvbjerg et al (2003) studied large transport infrastructure projects and found that most of the projects had cost overruns of 50%-100%, and lower than expected revenues. Other studies on the performance of capital projects report similar results (Merrow, 2011; World Bank report, 1994; Ostrom et al, 1993). The poor performance of large capital projects is due to the large risks faced by these projects.

Large capital projects face multitude of risks throughout their lifetime. For our purposes, it is helpful to consider the Dewatripont and Legros (2005) classification of risks into two categories: exogenous and endogenous. Exogenous risks refer to the risks that are not under the control of the project owners and operators such as volatility in the market prices. Endogenous risks are associated with inefficient actions by the involved entities, such as poor maintenance leading to reduced economic life. This distinction between exogenous and endogenous risks is also made by Miller and Lessard (2000). They discuss that project performance is negatively linked to turbulence that originates from two sources: exogenous and endogenous; exogenous turbulence is outside the management control and arises from political, macroeconomic, and social events, and the endogenous turbulence arises from within the project organization such as contractual disagreements and breakdown of partnerships.

The aforementioned literature on the performance of capital projects studied the reasons for poor performance of projects across the different sectors, and point out a common basic reason for the poor performance is the endogenous risks associated with poor incentives to deliver efficient project outcomes. For example, Flyvbjerg et al (2003) point out that the reason of cost overruns

in transportation projects was that the firms were eager to get the contract and had incentives to bid below the realistic cost estimates, and the penalty for manipulating and underestimating the costs was negligible.

The World Bank report (1994) studied the reasons for poor performance of infrastructure projects in the developing countries. The report found that inefficient operations and poor maintenance was rampant in these infrastructure projects, and the basic reason was poor incentives to satisfy the customers or increase the financial returns. The poor incentives arose from the conflicting objectives among the various parties involved, and little accountability on the project outcomes. Ostrom et al (1993) also discuss reasons for poor performance in rural infrastructure projects. They point out that major investments in rural infrastructure often deteriorate rapidly soon after construction, and the underlying cause of failure is set of perverse investments facing the project participants that reward the participants for inefficient actions.

Endogenous risks relate to inefficiencies associated with both the ex post project outcomes as well as the ex ante investment decisions. If the entities anticipate inefficient ex post project outcomes then it lowers the ex ante expected returns from the investment, and the entities might decide not make the investment even though the investment might be overall desirable (Williamson, 1971; Klein et al, 1978; Grossman and Hart, 1986; Joskow, 1985). Flyvbjerg et al (2003) point out that if the actual costs of the projects (with the cost overruns) were known ex ante then the decision-makers might not have gone ahead with that particular project, and instead invested in a different project. The project losses suffered as a result of these inefficiencies associated with ex post project outcomes and ex ante investment decisions is what we have termed as endogenous risks in capital projects.

Endogenous risks are influenced by the project contract terms. The contract terms determine how the project cash flows (costs and revenues) and the project risks will be distributed among the involved entities. The resulting value captured by each entity and their risk exposure will determine the incentives they have for efficient performance. Ostrom et al (1993) emphasize “*contracts (or governance arrangements) are necessary to enable a large number of individuals with different preferences, resources, and stakes in the outcome to design, construct, operate, manage, and use (rural) infrastructure facilities.*” Flyvbjerg et al (2003) and Miller and Lessard (2000) point that traditionally in projects contracting has been done by the public sector, and

these contracts tend to be ‘rule-based’ and not ‘performance based’. The contracts specify design specifications and put negligible risk of bad outcomes on the contractor. Thus, the contractor has no incentive to reduce costs or reduce risk. Thus, as Flyvbjerg et al (2003) emphasize, a key challenge in risk management is to change the current contracting approach. Miller and Lessard (2000) also point out that a transformation is required in how projects are managed, quoting: *“Front end engineering of institutional arrangements (or contracts) and strategic systems is a far greater determinant of success or failure of LEPs (large engineering projects) than are the more tangible aspects of project engineering and management.”*

The challenge in designing contracts to deal with the endogenous risks lies in the huge multiplicity of exogenous risks facing the large capital projects. One way to eliminate the endogenous risks would be write completely contingent contracts, which specifies what the responses of each entity should be under each contingency. But, because of the multitude of exogenous risks in capital projects, it is unlikely that the entities involved can foresee all future contingencies, and even if all contingencies could be foreseen it would be cost prohibitive to write all contingencies in a contract because of the high monitoring, verification and enforcement costs. Thus, all contracts are almost always ‘incomplete’ and give rise to a positive probability of endogenous contracting risks. This challenge of dealing with endogenous project risks is summed up very succinctly by Williamson (1971):

“ . . . The contractual dilemma is this: On the one hand, it may be prohibitively costly, if not infeasible, to specify contractually the full range of contingencies and stipulate appropriate responses between stages. On the other hand, if the contract is seriously incomplete in these respects but, once the original negotiations are settled, the contracting parties are locked into a bilateral exchange, the divergent interests between the parties will predictably lead to individually opportunistic behavior and joint losses.”

Another challenge of writing contingent contracts is the presence of asymmetric information related to hidden information (or adverse selection) and hidden actions (or moral hazard). The contractor has the most accurate information on the project costs and risks, and moreover, there is a positive probability that actions of the contractor can affect the probability distribution of the risks and the realized project value. The information and the actions are ‘private’ to the contractor and is ‘hidden’ from the entity offering the contract. Thus, the contracts cannot be

made contingent on the actions of the contractor. Furthermore, due to large exogenous uncertainty, it is difficult to distinguish whether the resulting project outcome is due to exogenous or endogenous factors. Thus, dealing with endogenous risks gets complicated due to presence of asymmetric information and large exogenous uncertainty.

In this section, we discussed how the risks in large capital projects are a combination of exogenous and endogenous risks. The endogenous risks arise from weak contractual incentives are a key reason for poor project performance. The design of incentives through contracts is the subject of the economics literature on contracts and the principal agent problem. Next, we present the key insights from this literature, and discuss the lessons we draw to structure contracts for the CCS-EOR value chain.

2.2 Insights on Design of Incentives through Contracts

Economics literature on the classical principal-agent problem, and the theoretical and applied contracting literature gives us useful insights on structuring contracts in large capital projects and in particular in CCS-EOR projects.

The classical principal-agent theory (Mirrlees, 1975; Holmstrom, 1979; Grossman and Hart, 1983) deals with the design of optimal contracts (with incentives) in presence of exogenous uncertainty and asymmetric information. The principal-agent theory emphasizes the relationship between incentives and risk-sharing in designing optimal contracts.

In a basic principal-agent model, there is a principal who hires an agent to perform a task. The principal enjoys the outcome, and compensates the agent for the effort exerted by the agent. The central idea of the principal-agent model is that the agent will choose the level of effort contingent on the compensation, and the agent's choice of effort will affect the total outcome. The total outcome depends on the actions of the agent and also on the exogenous factors that are not in the agent's control.

The question is what should the optimal compensation/contract look like? The contract cannot be made contingent on the agent's effort due to the presence of exogenous uncertainty and asymmetric information which make it difficult to distinguish whether the project outcome was

because of exogenous risks or low effort by the agent. The solution of the optimal contract involves solving for two optimization problems: the principal's optimization problem of maximizing his total surplus, and embedded in the principal's optimization problem is the second optimization problem – the agent's optimization problem. The optimal contract should be such that it incentivizes the agent to exert the optimal level of effort that maximizes the principal's value.

The solution to this principal-agent problem is a contract that involves sharing the project outcome (and risks) between the principal and the agent. Under this optimal contract, the agent's compensation now depends on the project outcome, and hence exposes him to the project risks. The resulting risk exposure incentivizes the agent to exert effort to reduce risks and increase the project value. Indeed, the solution also shows that if the agent is paid a flat wage, independent of the project outcome, then he exerts no effort. Additionally, if the agent is risk averse, then exposing him to too much risk, i.e., making his compensation highly correlated with the project outcome is also sub-optimal as the outcome also depends on exogenous factors that are not in the agent's control. The optimal level of risk-sharing between the principal and the agent depends on the several factors including agent's cost of effort, agent's degree of risk aversion and degree of exogenous uncertainty.

This solution to the principal-agent model emphasizes that risk-sharing is at the heart of creating incentives through contracts. Optimal risk-sharing aligns the interests of the entities involved such that they perform in the common interest of the overall project resulting in maximization of the total project value.

Next, we discuss the different pricing provisions commonly found in infrastructure project contracts in light of the risk allocation offered and the resulting incentives for efficient performance. These contracts follow the framework of the principal-agent problem wherein the principal is the entity offering the contract and the agent is the contractor, and the principal compensates the agent according to the terms of the contract.

i. Fixed price contracts

Fixed price contracts specify a fixed price that will be paid to the contractor on the completion of the task, and the price is calculated based on the expectation about future project economics.

These contracts put all the project risks on the contractor, for example if the actual costs exceed the contract price then the contractor bears all the risk of the cost overrun and the entity offering the contract bears none of the risk.

The risk allocation offered by the fixed price contracts provides incentives to the contractor for efficient performance as he bears all the risk of poor project outcome and benefits from improved performance. But, as all the risk is borne by the contractor it creates poor incentives in terms of continued performance in face of exogenous project risks. If the actual costs exceed the contract price due to exogenous risks such as market risks or technological risks, then the contractor might have incentives to breach even if it inefficient to do so.

Another issue with fixed price contracts is in determining the ex ante contract price due to information asymmetries. If the entity offering the contract does not have information about the costs and risks involved then it will be difficult to determine the contract price, and this will potentially lead to disputes between the entity offering the contract and the contractor. These disputes will potentially involve high legal expenses and in anticipation lead to inefficient ex ante investment decisions.

ii. Cost plus contracts

Another common contract type used in infrastructure projects is a cost plus contract. In a cost plus contract, the contractor is compensated for the actual costs incurred plus an additional amount to provide for a profit margin. The additional amount is either a fixed lump-sum amount or a fixed percentage of the actual costs incurred.

In terms of risk allocation, cost plus contracts are the exact opposite of the fixed price contracts. In cost plus contracts, all the risks are borne by the entity offering the contract and the contractor faces no risk. Thus, the cost plus contract corrects for the weakness of the fixed price contracts, and eliminates incentives for breach of contract. However, because of the risk allocation, this contract has poor incentives for efficient performance by the contractor. The contractor bears none of the project risks and hence has no incentive to undertake efficiency measures to reduce costs or risks.

The cost plus contracts face the problem of information asymmetries related to private information about ex post project costs. Only the contractor knows the true ex post project costs,

and these costs are not completely known to (or hidden from) the entity offering the contract. The contractor has incentives to report inflated costs, and this will lead to disputes between the contractor and the entity offering the contract.

iii. Indexed price contracts

This third type of contract deals with the weaknesses of both the fixed price contracts and the cost plus contracts. In indexed price contracts, the contract price is escalated over the contract life by indexing the contract price to an appropriate index. The index could be based on exogenous factors such as market prices and technological changes. Thus, the contract price changes with the changes in the exogenous factors and is independent of the actual decisions of the contractor.

The risks are now shared between the contractor and the entity offering the contract. The entity offering the contract bears the exogenous risks that result in changes in the contract price, and the contractor bears the endogenous risks related to his decisions. For example, if the contractor increases efficiency of the operations then the actual costs of the project will fall below the indexed price, and the contractor's revenues will increase. On the other hand, if the contractor performs inefficiently and the actual costs increase more than the indexed price, then the contractor's revenues fall.

Thus, the indexed price contracts provide incentives for efficient performance by the contractor. Also, as the contract price tracks the changes in exogenous risks, this reduces the risks of contract breach. Hart (2009) shows analytically that indexing the contract price to a "verifiable signal related to industry conditions" can increase the likelihood that the ex post contract price is agreeable to involved entities and thus reduces the incentives of a contractual breach.

The problem with the indexed price contract lies in finding an appropriate index to tie the contract price to. In absence of an available market price, an index is chosen that most closely tracks the changes in the value of the contracted commodity or service (from exogenous risk factors). Due to an imperfect index, there is a positive probability that the indexed price might move substantially away from the contract price resulting in a possibility on contract breach. Joskow (1985) points out that while none of the contract types are ideal, the indexed price

contracts dominate over the fixed price contracts and cost plus contracts in terms of incentives for efficient decision-making.

The above discussion on the different contract types offered under the principal-agent framework highlights that the contractual risk-sharing determines the incentives of the involved entities to make efficient project decisions. Inappropriate risk-sharing offered by the fixed price contracts and the cost plus contracts leads to inefficient decision-making, while the risk-sharing offered by the indexed price contracts minimizes the incentives to perform inefficiently.

The principal-agent model provides a framework to design optimal contracts in presence of exogenous uncertainty and information asymmetries. The optimal contract is such that it incentivizes the agent to exert the optimal level of effort that maximizes the principal's value. An important insight we get from the theoretical solution to the principal-agent problem is that the optimal contract involves sharing the project outcome (and risks) between the principal and the agent. Under this optimal contract, the agent's compensation depends on the project outcome and hence exposes him to the project risks. The resulting risk exposure incentivizes the agent to exert effort to reduce risks and increase the project value. The discussion of the different contract types offered in infrastructure projects illustrates how risk-sharing creates incentives or disincentives for the agent to perform in the principal's (or project's) best interests.

In this thesis, we are concerned about the similar issues as in the principal-agent problem, of maximizing total value of the (CCS-EOR) project and incentivizing optimal performance by the involved entities. But, we do not follow the theoretical framework as in the aforementioned economics literature because of two key reasons. Firstly, in the CO₂ delivery contracts for CCS-EOR projects, the issue of information asymmetries is not a constraint unlike in the principal agent problem, and secondly our goal is to illustrate the inefficiencies that result from inappropriate risk-sharing in standard contracts and not to solve for the optimal contract.

Another set of literature useful for our study is the applied contracting literature that studies the contractual provisions employed in actual transactions in projects involving large capital investments. This literature sheds light on how contract provisions have been designed in different types of projects to allocate risk among the various involved entities. A particularly

relevant set of literature for contract design in CCS-EOR projects is the literature studying contract terms in natural gas supply contracts.

In the natural gas industry's early growth period, investments in developing facilities for gas production, transportation and distribution were dedicated to limited (or single) buyers or sellers because of limited transportation alternatives. Because of the large upfront-dedicated investment involved, the parties (gas producer and the pipeline operator) signed long term gas supply contracts. Given the long-term nature of these contracts, it was important that the ex ante negotiated contract terms accounted for the long-term risks facing these projects, and the contracts were designed to allow efficient decision-making when contingences arise.

A key risk facing natural gas projects is the risk of change in the market conditions. For example, the demand for gas could go down or the gas price could fluctuate. Take-or-pay provisions have been historically used in natural gas supply contracts to allocate these market risks among the involved parties. Canes and Norman (1983) describe how take-or-pay provisions distribute the risk of change in gas demand between the gas producer and the pipeline. Take-or-pay provisions contractually specify the minimum quantity of gas that the pipelines need to pay for even if the gas delivery is not taken. This way, the gas producers bear the risk of drop in demand till the take-or-pay level, and the rest of the risk is borne by the pipeline. So small changes in demand are entirely borne by the gas producer, and larger reductions in demand are shared by both the producer and the pipeline. This risk-sharing protects both the gas producer and the pipeline against sharp fluctuations in future cash-flows and thus protects against risk of inefficient contract breach. Furthermore, Masten and Crocker (1985) show that the take-or-pay provisions induce the pipeline to refuse gas delivery only when it is efficient to do so, i.e. when the value of gas in its alternative use is greater than the value of gas to the pipeline.

Another example of design of contracts to ensure efficient performance are the long-term coal supply contracts. Joskow (1985, 1988) studied contract provisions in long-term coal supply contracts between the coal mines and the electricity generating utilities in terms of the incentives provided for efficient decision-making. Joskow points out two considerations in design of contract terms. The contract terms should 'facilitate efficient adaptation to changing market conditions', and the contract terms should minimize inefficient breach of contractual obligations.

We use these contract design criteria pointed out by Joskow (1985, 1988) to evaluate the performance of alternate CO₂ delivery contract structures for the CCS-EOR value chain.

We focus on a prototype CCS-EOR project wherein the CO₂ is captured at a coal-fired power plant and is transported via a dedicated pipeline to an oil field, where it is injected for enhanced oil recovery or EOR. We model the CCS-EOR project ownership structure such that the power plant and the oil field are owned and operated by separate entities, and the pipeline is jointly owned by the two entities. The operation between the power plant company and the oil field company is integrated through a long-term contract for the delivery of CO₂. The joint ownership of the pipeline and a long-term CO₂ delivery contract reduces the risk of ex post opportunistic behavior, which often arises from relation specificity of investments when the investments are dedicated to a specific use and have little alternative use, as is the case in this prototype CCS-EOR project. It is well established in the contract theory literature (Williamson, 1971; Klein et al, 1978; Grossman and Hart, 1986) that in presence of relation-specific investments, the ex ante choice of governance structure and contracting terms needs to be optimized to minimize the endogenous contracting risks.

The CO₂ delivery contracts that link the individual entities in the prototype CCS-EOR project will determine the incentives the individual entities have to make optimal decisions in the common interest of the project. We evaluate two alternate standard CO₂ delivery contract structures in terms of the risk allocation between the power plant company and the oil field company and the resulting incentives for optimal decision-making. The contract structures analyzed include a fixed price contract where the CO₂ contract price is fixed for the contract term, and an indexed price contract where the CO₂ contract price is indexed to the oil price.

We will show that final project value depends not only on the exogenous risk factors, but also on endogenous contracting risks related to the response of the individual entities to changes in the exogenous risk factors. The next chapter, Chapter 3, discusses the different risks in CCS-EOR projects, and presents the framework we use in this thesis to analyze the exogenous risks and the endogenous contracting risks in the prototype CCS-EOR project. The exogenous risks will be analyzed in the Chapter 4, and the endogenous contracting risks under the alternate contract types will be analyzed in Chapter 5.

Chapter 3 CCS-EOR Value Chain

Risks in capital projects are a combination of exogenous risks and endogenous contracting risks. The final project value will be determined by how the exogenous risk factors evolve during the project and how the project entities respond to the changes in the risk factors. In this thesis, we develop a framework that accounts for both the exogenous project risks and the endogenous contracting risks in evaluating risk management strategies for large energy capital projects.

We illustrate the proposed risk management framework through an application to carbon capture and storage (CCS) projects with enhanced oil recovery (EOR). CCS is a technology to reduce anthropogenic carbon dioxide (CO₂) emissions from fossil fuel power generation and other CO₂ intensive industrial processes. The CCS value chain involves three key components: CO₂ capture, CO₂ transport, and CO₂ storage. CO₂ is captured at CO₂ emitting sources (such as a coal-fired power plant), and then transported via pipelines to CO₂ storage sites (such as an oil reservoir) where the CO₂ is sequestered for long-term storage. In an integrated CCS-EOR project, the different parts of the CCS-EOR value chain are likely to be owned and operated by different entities. The power plant operations will be performed by an entity that might differ from the entity responsible for the CO₂ storage operations. The performance of one entity will affect the operations of other entities, ultimately affecting the overall value chain.

Thus, risk management in CCS projects is not just about evaluating optimal strategies and decisions, but the contract structures linking the different involved entities should offer incentives to the individual entities to make those optimal decisions.

We focus on a prototype CCS-EOR project wherein the CO₂ is captured at a coal-fired power plant and is transported via a dedicated pipeline to an oil field, where it is injected for enhanced oil recovery (EOR). We model the CCS-EOR project ownership structure such that the power plant and the oil field are owned and operated by separate entities, and the pipeline is jointly owned by the two entities. The operation between the power plant company and the oil field

company is integrated through a long-term contract for delivery of CO₂. The CO₂ delivery contracts that link the individual entities of the CCS-EOR value chain will determine incentives the individual entities have to make optimal decisions in common interest of the project.

In this chapter we will first present in Section 3.1, the different risks in CCS projects, and discuss the set of risks that we focus on in this thesis. Next, in Section 3.1, we review the industry practices in terms of the existing CO₂-EOR contract provisions. In Section 3.3, we present the framework used in the thesis to analyze the risks in CCS-EOR projects. This framework is utilized in Chapter 4 and Chapter 5 where we will present the results. Finally, in Section 3.4, we present the key technical specifications of the prototype CCS-EOR project analyzed in the thesis, and present the financial valuation of the project in terms of the cash flows and the resulting net present value (NPV) of each of the three components of the value chain.

3.1 Risks and Industry Contract Practices

CCS projects face various risks throughout the life of the project, and how these risks are managed will determine the final value of the project. In this thesis, we focus on the risks that are realized during the operational phase of the project, and that would initiate contingent decision-making involving reoptimization of project operations by the project entities to maximize the project value in light of the change in the risk factors. In this section, we will first present a brief overview of the different types of risks in the CCS projects, and then discuss the two sets of risks during the operational phase of the project we focus on in this thesis.

Later in this section, in Section 3.1.2, we will present a review of the CO₂ contract price provisions that have historically existed in the CO₂-EOR contracts, and discuss the recent changes observed in CO₂ contract prices.

3.1.1 Risks in CCS Projects

We can categorize the different risks in CCS projects into the different phases: pre-construction risks, construction risks, operational risks, and post-operational risks. Next, we briefly discuss the key risks in different phases of a CCS project, and then describe the set of risks in the operational phase we focus on in this thesis. The main literature we draw on in this section is: The Global Status of CCS report (2013), MITEI EOR Symposium report (2010), US EPA report (2008), MIT Future of Coal Report (2007), and the IPCC Special Report on CCS (2005).

‘Pre-construction’ phase risks include uncertainty on public acceptance, and legal issues over the ownership and operating permits for pipelines and pore space. These risks will get resolved in the project feasibility period (pre-construction) before any significant investment is made in a project. The dominant risks in the ‘construction phase’ include construction costs overruns or a time delay. During the ‘operational phase’, the key risks include volatility in the market prices and fuel costs leading to uncertainty in the cash flows, and technical risks associated with geological uncertainty. The ‘post-operational’ phase in CCS project refers to the phase when CO₂ injection has stopped but the CO₂ behavior in the subsurface continues to be monitored to detect migration outside of the injection zone and CO₂ leakage. The risk of CO₂ migration and leakage is largely determined by the geological uncertainty over the subsurface response to CO₂ injection, and is a key concern in CCS projects.

CO₂ migration and leakage could impact ground water and surface water, and adversely impact human and animal health. CO₂ injection could lead to unanticipated pressure changes in subsurface, which could trigger seismic events. The IPCC Special Report on CCS (2005) outlines two scenarios of CO₂ leakage: abrupt leakage and gradual leakage. The abrupt leakage of CO₂ might happen during the operational phase due to well failure or leakage through a abandoned well which was not properly sealed. Such abrupt leakage can be stopped by standard well repair techniques commonly used in the oil and gas industry, and the industry has successfully managed the operational liability issues for decades. The gradual leakage of CO₂ might undermine the success of CCS projects, which require the CO₂ to remain the subsurface for long time periods. The risk of gradual CO₂ leakage can be reduced by proper site selection techniques but cannot be eliminated due to geological uncertainty related to previously unknown

faults and fractures that might serve as CO₂ leakage pathways. The IPCC report points out that if due diligence is done during site selection, design, operation, and closure, there is ‘very likely’ that that 99% of the CO₂ stored will be retained in the sub surface for the first 100 years. The long time frames of CO₂ projects present a unique challenge to be able to model CO₂ migration and leakage risks, and to determine a regulatory framework that defines the long-term liability rules in terms of who is responsible for risks posed by post-injection CO₂ migration and leakage.

As we mentioned, we focus on risks during the operational phase of CCS projects. Risks in other phases of the project lifetime, such as public acceptance (pre-construction phase risk), cost overruns (construction phase risk) and long-term CO₂ leakage and liability (post-operational phase risk), are not analyzed in this thesis. Though, we must add that the decisions in the pre-operational phase will affect the probability distribution of the risks in the operational phase, and the decisions in the operational phase will affect the risks that are realized later in the project.

In Chapter 2, we discussed that risks in capital projects are a combination of exogenous risks and endogenous contracting risks. The final value of the project depends on the evolution of exogenous risk factors during the project, and on the endogenous response of the project entities in response to change in the exogenous risk factors. In this thesis, we focus on the risk factors that would initiate contingent decision-making involving reoptimization of project operations in response to a change in the risk factors. The two sets of risks we analyze in this thesis are: technical risks and market risks in the operational phase of the project. Next we discuss each of these risk categories, and in the next chapter, Chapter 4, we will describe how we model the two sets of risks.

Technical Risks

Technical risks refer to the engineering uncertainty surrounding project operations. For example, unexpected complex geological conditions might be realized, or, alternatively technological efficiency might be less than expected. These risks are specific to each project, and the level of uncertainty depends on the degree of novelty associated with the project. The novelty could in terms of the past experience with the use of technology, the scale at which the technology is deployed, or availability of geological information on the project site, among other factors.

In CCS projects there are technical risks associated with each of the components of the CCS value chain: CO₂ capture, transport, and storage. In my thesis, we will focus on the technical risks in the CO₂ storage operations where the technical risks are considered to be the most significant. The technical risk we are interested in is the uncertainty on the EOR efficiency, which refers to the uncertainty on the amount of oil recovered per unit of CO₂ injected in the EOR operations. The geological uncertainty related to the uncertain response of the subsurface to CO₂ injection leads to difficulty in deterministically predicting the technical EOR efficiency. If the EOR efficiency is less than expected then it would lead to less than expected amount of oil recovery. In response to the reduced EOR efficiency, the project operators might find it economical to operate at a lower CO₂ injection rate.

Market Risks

The volatility in the market risk factors can significantly impact the value of a CCS-EOR project. The market risks are exogenous risk factors, though the impact of these risk factors on the value of the CCS project will depend also on the endogenous contingent decision-making by the project operators in response to the change in the risk factors. For example, in an EOR project, if the price of oil is less than expected, then it would directly affect the project cash flows, and the EOR operator might reduce the rate of CO₂ injection.

The market risk factors we analyze in this thesis are the wholesale price of electricity, the price of oil recovered, and the CO₂ emission penalty.

In Chapter 4, we will analyze the impact of change in the EOR efficiency and the market risk factors on the project value, and evaluate the optimal contingent decisions that would maximize the project value. Contingent decisions such as a change in the amount of CO₂ to be injected has implications on the design of CO₂ delivery contracts between the oil field company and the power plant company. In Chapter 5, we will evaluate how the CO₂ delivery contract terms respond to changes in the EOR efficiency and the market risk factors.

Next, we review the CO₂ contractual provisions that have existed in the U.S. EOR industry.

3.1.2 CO₂ Contracts in the U.S. EOR Industry

The world's first commercial CO₂-EOR project started in 1972, at the Scurry Area Canyon Reef Operators (SACROC) Unit in the Permian Basin in West Texas. Since then 1970s, the EOR projects have continuously increased; in 2010, there were 114 CO₂-EOR projects in the US, which required about 70 million tons of new CO₂ (NETL, 2011). Historically, the CO₂ has been sourced from natural occurring CO₂ deposits such as the McElmo Dome in New Mexico. However, as noted by the Bloomberg report (2012), the supply from natural CO₂ sources is limited and has started showing signs of reduced production rates, thus a market for anthropogenic CO₂ is developing in the Permian Basin. Though most of the CO₂ supply is still from natural CO₂ sources, increasingly more of CO₂ is coming from anthropogenic sources. In 2010, about 25% of the CO₂ supply for EOR came from anthropogenic sources such as gas processing plants (NETL, 2011).

The CO₂ contract provisions that have existed historically in the CO₂-EOR industry can serve as an important precedent for the future CO₂-EOR contracts when more of the CO₂ is expected to come from anthropogenic sources. In this section, we review the contract price provisions that have historically existed in the CO₂-EOR contracts, and discuss the recent changes observed in CO₂ contract prices.

Veld and Phillips (2009) review over 300 CO₂-EOR contracts written in the 1980s and 1990s in the Permian Basin of West Texas. The contracts were of two kinds: short-term and long-term. Short-term contracts were for less than one year, and long-term contracts could be up to fifteen years long. Veld and Phillips (2009) point out that most of the long-term contracts tied the price of CO₂ to the price of oil, while the short-term contracts did not have any such price adjustment. The long-term contracts typically had two components: a floor price, and a linear escalation with the price of oil above the floor price. The paper refers to a sample CO₂-EOR contract, which reads, "*The price to be paid by Buyer for all volumes purchased shall be calculated on a Monthly basis, and shall be (**)% of the average of West Texas Intermediate Crude for such Month.*" The sample contract does not specify the percentage indexed to the price of oil.

Martin and Taber (1992) provide a complete formula of the CO₂ price in the Permian Basin:

$$p_{CO_2}(\$/Mcf) = 0.5 \text{ cents} + X p_{oil} (\$/bbl)$$

where, p_{CO_2} is the CO₂ price in \$/Mcf, p_{oil} is the price of oil in \$/bbl, and X is the linear escalation to price of oil, and is generally 2% to 2.5%.

The above price formula in \$/ton of CO₂ (using conversion of 1 ton CO₂ = 18.9 Mcf):

$$p_{CO_2}(\$/ton) = \$9.45 + X p_{oil} (\$/bbl)$$

where the linear index, X , is 37.8% to 47.25% of the price of oil.

According to this CO₂ price formula, the CO₂ price per ton has a fixed price component of \$9.5 and a linear index of 38% to 47% to the price of oil in \$/barrel. For the price of oil at \$20/bbl, the CO₂ price formula gives CO₂ prices between \$17 to \$19/ton. At \$100/bbl oil price, the CO₂ price will be \$47 to \$57 per ton. Figure 3.1 plots the price of CO₂ as a function of the price of oil using the 47% index to the price of oil.

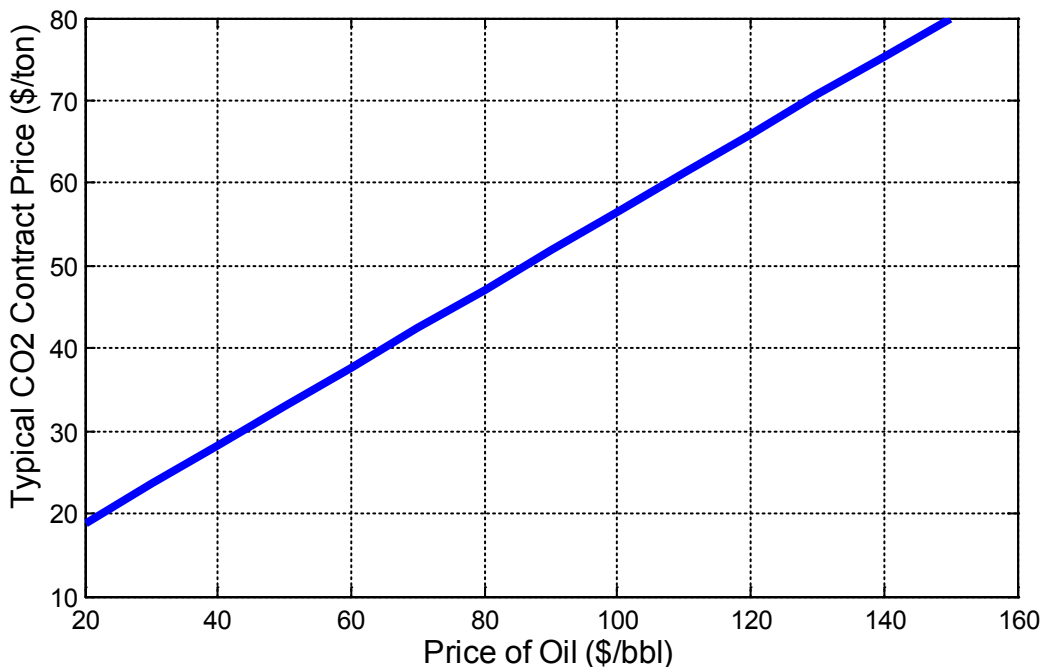


Figure 3.1 CO₂ contract price (\$/ton) given by price formula in Martin and Taber (1992), using 47% linear escalation to oil price (or a 2.5% linear escalation when calculating in \$/Mcf CO₂)

The Bloomberg New Energy Finance report (2012) states that as of March 2011 the contract prices for natural CO₂ were \$15 to \$19 per ton. Natural sources of CO₂ have very low production costs of around \$2.5 to \$ 3.5 per ton (Bloomberg, 2012; MITEI, 2010). In future, as the more expensive anthropogenic sources of CO₂ play an increased role in EOR, the contract prices might go up. In fact, the Bloomberg report points out that the current contracts for anthropogenic CO₂ in Texas have reached \$40 per ton, and are reported to be stay above \$35/ton. This increase in the price of CO₂ is supported by the economic analysis presented by the NETL report (2011) wherein they evaluate the EOR project economics at \$85/bbl price of oil, and use market price of CO₂ as \$40/ton. The increase in CO₂ prices is a reflection of the increased oil prices as well as the higher production costs of anthropogenic CO₂ compared to the natural CO₂.

Next, we present the risk management framework we use to analyze the exogenous risks and the endogenous contracting risks in CCS-EOR projects.

3.2 Proposed Risk Management Framework

In this section, we present the risk management framework proposed to analyze the exogenous risks in CCS-EOR projects, and evaluate the impact of CO₂ contract terms on the decision-making of the entities and the resulting project value.

We model the risk management framework as a two-step analysis:

The first step looks at the overall integrated project, wherein we analyze the impact of exogenous risk factors on the project value, and evaluate the optimal contingent decisions that would maximize the project value. In the second step, we evaluate alternate contract structures for the CCS-EOR value chain in terms of the incentives provided to entities to make the optimal contingent decisions (evaluated in step 1) and thus maximize the overall project value.

These steps of the risk management framework are explained next.

3.2.1 Integrated Project Risk Management – Step 1

In this first step, we focus on the integrated project, and assume that the project is exposed to only the exogenous uncertainty and there is no endogenous contracting risk. This would be the case if the whole project was owned and operated by a single entity who is interested in maximizing the total project value, so there is no endogenous risk from misalignment of interests. We analyze the impact of the exogenous risks on the integrated project, and evaluate the optimal risk management strategies for the integrated project and the resulting project value. The results for this integrated project risk management are presented in Chapter 4.

Firstly, we characterize the evolution of the uncertainty of the different risk factors through the operational life of the project. We focus on the two sets of risk factors identified in the previous section 3.1: technical risks and market risks. The stochastic movement of the market risk factors is modelled using the geometric Brownian motion model, and we use Monte Carlo Simulation to model the future correlated movement of the market risk factors. We construct alternate scenarios of changes in the technical EOR efficiency to illustrate how uncertainty in the EOR efficiency can impact the project. The uncertainty modelling for the market risks and technical risks is presented in Chapter 4, Section 4.1.

We have developed a cash flow model of a prototype CCS-EOR project to calculate the project's costs and revenues for each year, and to calculate the net present value of the project. This cash flow model will be presented later in this chapter, in Section 3.4.

We evaluate the impact of the evolution of the risk factors on the overall project value through a pro forma cash flow analysis, and a more thorough sensitivity analysis.

Pro forma Analysis

A pro forma cash flow analysis is a simplistic measure of the project risk exposure from different risk factors. This method provides a first order project risk analysis, and highlights the key risk factors having the largest impact on the project. The pro forma analysis for the prototype CCS-EOR is presented in Chapter 4, Section 4.2.

But, this method only captures the impact of variation in one risk factor at a time, and does not capture the interrelationships between the risk factors. When there are multiple risk factors that move in correlated fashion, it is important to capture the correlations, as the total exposure might be larger or smaller than simple additions of the exposures from the pro forma analysis. Another limitation of this method is that it does not capture the contingent decisions that might be made to adjust the project operations in response to the change in risk factors.

To evaluate a more complete risk exposure of the project we perform a sensitivity analysis wherein we construct alternate scenarios of changes in the different risk factors.

Sensitivity Analysis

I will evaluate alternate future scenarios of the changes in risk factors in terms of their impact on the project cash flows. Through the scenario analysis we can capture the interrelationship between the movements in the different risk factors. Furthermore, under each of these scenarios, we can evaluate the optimal contingent decisions that can be made in response to change in the risk factors to maximize the project value. The availability of contingent decisions will depend on the technological flexibility and the economics of adjusting the project operations. Optimal contingent decisions are such that they maximize the project value. Optimal contingent decisions and the resulting project value are presented in Chapter 4, Section 4.3.

In this step 1 of integrated project risk management, we assess the impact of the risks on the value of the CCS-EOR project, and evaluate the optimal contingent decisions under different risk scenarios.

3.2.2 Evaluating Contract Structures – Step 2

In the step 2, we introduce endogenous contracting risks. Endogenous risks arise from conflict of interests between the different entities owning and operating different parts of the CCS-EOR value chain. A CCS-EOR project will typically involve different parties owning and operating different parts of the value chain. The power plant operations will be performed by an entity that might be different from the entity responsible for the enhanced oil recovery operations. Thus the performance of one entity will affect the operations of other entities, and thus affecting the

overall value chain. The endogenous risks refer to the inefficient decision-making by the involved entities resulting in increased impact of the risk factors and sub-optimal project outcomes when contingencies arise.

We will analyze alternate contract structures linking the various entities along the different parts of the CCS-EOR value chain. We draw insights from the contract theory literature (discussed in Chapter 2) to develop criteria for optimal contract structures for the CCS-EOR value chain. As discussed in Chapter 2, risk-sharing lies at the heart of creating incentives through contracts. The different contract structures we will evaluate will have different risk allocation structures resulting in different incentives for optimal decision-making. For each of the contract structure, we will evaluate the decisions made by individual entities under the different risk scenarios (defined in Step 1). Weak risk-sharing contractual structures will lead to decisions that are different from the optimal decisions for the overall project. We also evaluate the loss in project value from sub-optimal decision-making under the alternate contract structures. The optimal contract structure would be such that the different entities make decisions that maximize the overall integrated project value.

Chapter 5 presents an evaluation of alternate contract structures for the CCS-EOR value chain in terms of the incentives provided to the individual entities to make optimal decisions, and the resulting project value.

In this thesis, we focus on a prototype CCS-EOR project. Next, we describe the technical specifications and financial valuation of each of the components of the CCS-EOR project.

3.3 Description of Prototype CCS-EOR Project

The prototype CCS-EOR project we focus on is an integrated project with a coal-fired power plant with CO₂ capture, a pipeline that transports the CO₂, and an oil field that injects and subsequently stores the CO₂ for enhanced oil recovery or EOR. This is a dedicated project such that the power plant, the pipeline and the oil field are dependent on each other for the CO₂ capture/transport/injection and there is no alternate source or sink for the CO₂.

This section describes the key technical specifications and the economic parameters of the different components of the prototype CCS-EOR project. The project construction is planned to begin in 2018, the operations will start in 2021 and continue for 25 years till 2045. We evaluate the project net present value (NPV) in 2017 USD as 2017 is the $t = 0$ of the project. The project cash flows are calculated based on the expected values of the project risk factors at $t = 0$. In Chapter 4, we will evaluate how the evolution of project risk factors impacts the project cash flows. In this section we only evaluate the cash flows that are internally generated by the individual components of the CCS-EOR project, and do not consider the contributions of the cash flow transfers between involved entities such as through contractual payments. To evaluate the project cash flows we use a tax rate of 35%, nominal discount rate of 10%, and an inflation rate of 3% for all the components of the CCS-EOR project.

Next, we describe the power plant, then the pipeline, and then the oil field.

3.3.1 Power Plant

The power plant is a 500 MW coal-fired integrated coal gasification combined cycle (IGCC) plant. This is a baseload plant with a capacity factor of 80%. The amount of CO₂ generated is 1 ton/MWh, and the power plant is designed to capture 90% of the CO₂ generated. So, the project is designed to capture 3.2 million tons of CO₂ every year. The heat rate of the power plant with 90% CO₂ capture is 10,000 Btu/kWh resulting in the plant efficiency is 34.1%.

The IGCC power plant in this project is designed to have dynamically adjustable CO₂ capture rate that can be adjusted in response to the evolving project risk factors. The optimal capture rate will be determined by the marginal costs and benefits of CO₂ capture and injection. A significant cost of CO₂ capture is the energy penalty of applying the capture process to the power generation. Depending on how the project risk factors evolve, the CO₂ capture rate can be lowered from the designed 90% to benefit from the increased electricity generation.

Next, we describe how we model the relationship between the CO₂ capture rate and the electricity output of the power plant.

Modeling Flexible CO₂ Capture Rate

A significant cost of CO₂ capture is the energy penalty of applying the capture process to the power generation. MIT's Future of Coal study (2007) reports that adding 90% pre-combustion capture to an IGCC plant leads to a 7.2 percentage point reduction in the generating efficiency compared to a plant without capture. The MIT study gives the breakdown of energy penalty from each of the main processes involved in CO₂ capture: the water gas shift reduces the generating efficiency by 4.2 percentage point, the CO₂ separation reduces efficiency by 0.9 percentage point, and the CO₂ compression reduces efficiency by 2.1 percentage point.

The IGCC power plant in this prototype project is designed to have dynamically adjustable CO₂ capture rate that can be changed in response to the fluctuating risk factors to save on the energy penalty. Keeping the coal feed constant, the total energy penalty of CO₂ capture leads to a 23% decrease in the power output. This implies that if we turn off capture in a 500 MW IGCC power plant capturing 90% CO₂, the net power output will increase to 650 MW.

Figure 3.2 shows how we model the increase in net power output as the CO₂ capture rate is reduced from 90% to 0%.

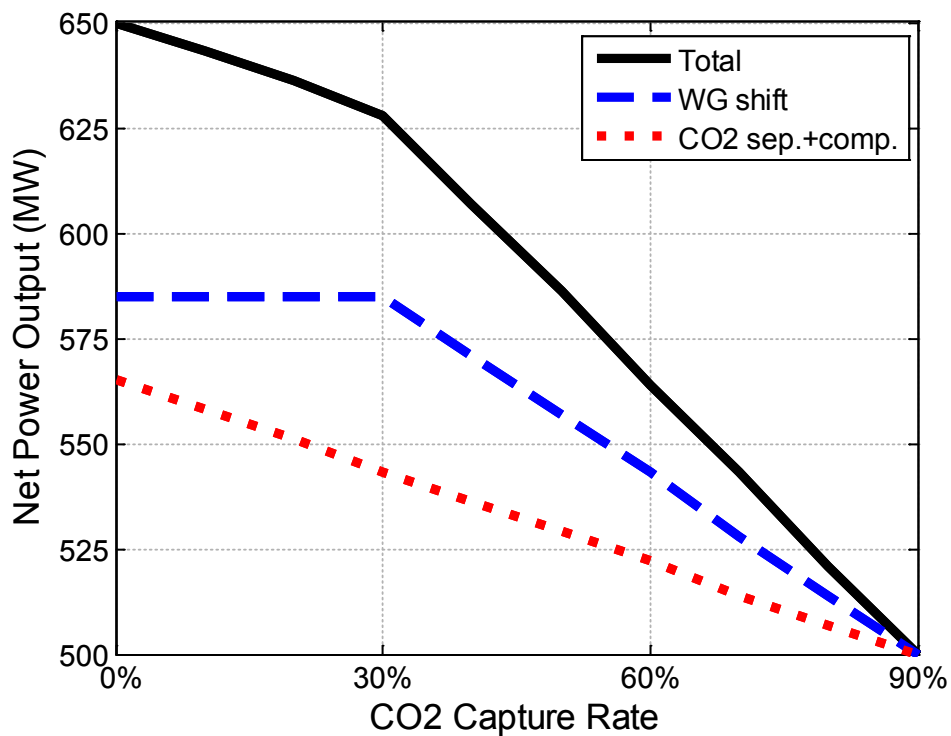


Figure 3.2 Net power output as a function of the CO₂ capture rate

The different lines show the recovery of energy penalty from the different CO₂ capture processes. The dotted line shows the increase in net power output that comes from reduction of energy penalty from CO₂ separation and CO₂ compression processes. The total energy penalty from these two processes is 10% (7% from CO₂ compression and 3% from CO₂ separation), and thus reducing CO₂ capture to 0% leads to an increase of 65 MW in the net power output. The dash line shows the increase in net power output from reducing the energy penalty from the water gas shift reaction. The energy penalty of water gas shift is 13%, leading to an increase of 85 MW in the net power output. Approximately 30% of CO₂ capture can be achieved by “skimming” without the water gas shift (Hildebrand, 2009). We see from Figure 3.2, that all of the energy penalty recovery from water gas shift occurs as the CO₂ capture rate reduces from 90% to 30%, and thereafter no additional increase in net power output is achieved from water gas shift. The solid line shows the total increase in net power output from reducing CO₂ capture from 90% to 0%. We see that the net power output increases from 500 MW to 650 MW, and the increase is mostly linear except for a kink at 30% from the water gas shift.

Next, we present the financial valuation of the power plant by evaluating its cash flows and NPV contribution to the overall integrated project.

Financial Valuation

The costs incurred at the power plant include the capital investment, O&M costs, fuel cost and CO₂ emission penalty. Revenue at the power plant is generated through the electricity sales. Table 3.1 presents the unit costs and prices used to evaluate the cash flows of the power plant. Unless specified all costs are in 2010 USD, and the market commodity prices (coal price, and wholesale price of electricity) are in 2017 USD.

Power Plant		
Overnight Cost	\$/kW	5,000 [1,2]
Fixed O&M Cost	\$/kW/year	80 [1]
Variable O&M Cost	mills/kWh	6 [1]
Price of Coal	\$/MMBtu	3 [3]
Wholesale Price of Electricity	c/kWh	10.3[3]
CO ₂ Emission Penalty	\$/ton	5

References: [1] GCCSI, 2011; [2] GCCSI, 2010; [3] US EIA AEO 2013 (reference case)

Table 3.1 Power Plant: Unit costs and prices

The overnight cost of the power plant is \$5,000/kW. This cost is an average of the overnight costs reported in the literature for a 500 MW IGCC power plant with 90% CO₂ capture. The Global CCS Institute's (GCCSI) Status of CCS: 2010 report estimated the costs of emerging IGCC projects and reported that costs normalized to 500 MW and adjusted to 2010 USD ranged from \$4,204-\$8,101/kW. The GCCSI's economic assessment of CCS technologies in 2011 undertook a detailed analysis of costs of IGCC and evaluated the overnight cost of IGCC plant to be \$3,413/kW in 2010 USD. For the prototype IGCC plant we model the overnight cost to be \$5,000/kW in 2010 USD. The O&M costs at the power plant include a fixed and a variable O&M costs. We model fixed O&M cost to be \$80/kW/year and variable O&M cost to be 6 mills/kWh (GCCSI, 2011).

For the market commodity prices (coal price and wholesale price of electricity) we use the U.S. Energy Information Administration's (EIA) projected 2017 nominal prices given by the 2013 EIA Annual Energy Outlook (reference case). The average price of coal delivered is modeled as \$3/MMBtu. The nominal price of electricity is 10.3 cents/kWh. For the CO₂ emission penalty, we assume that the projected price in 2017 is \$5/ton CO₂. The evolution of market prices through the 25-year project life is simulated by Monte Carlo method assuming zero correlation between the different market prices. The Monte Carlo method is explained in Chapter 4, Section 4.1.1.

Table 3.2 presents a snapshot of the cash flows of the prototype power plant that is operating at 90% CO₂ capture rate.

Power Plant		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	...	2044	2045
		$t = 1$	2	3	4	5	6	7	8	9	10	...	27	28
a1	Construction Schedule	20%	50%	30%										
a2	Overnight Costs	633	1631	1008										
a3	Depreciation	-	-	-	123	236	218	202	187	173	160	...	0	0
a4	O&M Costs	-	-	-	84	87	90	92	95	98	101	...	167	172
a5	Fuel (Coal) Costs	-	-	-	118	122	126	129	133	137	141	...	234	241
a6	CO ₂ Emission Penalty	-	-	-	3.1	3.5	4.0	4.6	5.3	6.1	7.0	...	75.8	87.2
a7	Total Expenses	-	-	-	329	449	438	428	421	414	409	...	476	500
a8	Total Revenue	-	-	-	413	427	442	458	474	491	508	...	914	946
a9	Total Income	-	-	-	84	-21	5	30	53	76	99	...	438	447
a10	Tax	-	-	-	29	-8	2	10	19	27	35	...	153	156
a11	Total Costs	633	1631	1008	235	205	221	237	252	268	284	...	629	656
a12	Net Cash flows	-633	-1631	-1008	177	222	222	221	222	223	224	...	285	290
a13	PV of Net Cash flows	-576	-1348	-757	121	138	125	114	103	94	86	...	22	20
Power Plant NPV		-\$1,074 million												

Table 3.2 Power Plant Cash flows (\$million)

The first investment in the power plant begins in 2018 with the start of power plant construction. The construction schedule and the investment cash flows for the power plant are given in Table 3.2: rows a1, a2. This investment will get depreciated using a 20-year Modified Accelerated Cost Recovery System (MACRS) and the depreciation value is given in row a3. The total O&M costs (fixed and variable costs) are given in row a4. The annual fuel costs are given in row a5. The CO₂ emission penalty incurred for emitting 10% of the CO₂ is given in row a6. The revenue generated from electricity sales are given in row a8. We use a common tax rate of 35% for all the components of the CCS-EOR project. To calculate the tax paid by the power plant we evaluate the total expenses in row a7 as the sum of rows a3:a6, and the total annual income in row a9 as the difference of electricity sales revenue (row a8) and total expenses (row a7). The tax is given in row a10 and is obtained by multiplying the tax rate by the total project income (row a9). The total project cost cash flows (row a11) are calculated as the sum of overnight costs (row a2), O&M costs (row a4), fuel costs (row a5), CO₂ emission penalty (row a6) and the tax (row a10). The project's net cash flows are given in row a12 by subtracting the project costs (row a11) from the project revenue (row a8). The nominal discount rate used to calculate the project NPV is 10%. The discounted net cash flows are presented in row a13. The NPV of the power plant in 2017 is -\$1,074 million.

3.3.2 Pipeline

The CO₂ will be transported via a 50-mile dedicated pipeline to the oil field. The pipeline will have two streams of cash flows: the capital investment in building the pipeline and the O&M costs. The capital costs are modeled as \$1.7 million per mile of the pipeline (Al-Juaid, 2009) and the construction schedule is: 40% in 2018 and 60% in 2019. The capital investment is depreciated using a 15-year MACRS. The O&M costs for the pipeline are \$2.5/ton of CO₂ transported (Al-Juaid, 2009). All cost numbers are in 2010 USD. Table 3.3 below gives a snapshot of the cash flows for the pipeline.

Pipeline		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	...	2044	2045
		<i>t = 1</i>	2	3	4	5	6	7	8	9	10	...	27	28
<i>b1</i>	Investment Schedule	-	40%	60%										
<i>b2</i>	Capital Investment	-	44.4	68.5										
<i>b3</i>	Depreciation	-	-	-	5.6	10.7	9.7	8.7	7.8	7.0	6.7	...	0.0	0.0
<i>b4</i>	O&M	-	-	-	10.9	11.2	11.6	11.9	12.3	12.7	13.0	...	21.6	22.2
<i>b5</i>	Total Income	-	-	-	-17	-22	-21	-21	-20	-20	-20	...	-22	-22
<i>b6</i>	Tax	-	-	-	-5.8	-7.7	-7.4	-7.2	-7.0	-6.9	-6.9	...	-7.5	-7.8
<i>b7</i>	Net Cash flows	-	-44.4	-68.5	-5.1	-3.6	-4.2	-4.7	-5.3	-5.8	-6.1	...	-14.0	-14.4
<i>b8</i>	PV of Net Cash flows	-	-36.7	-51.5	-3.5	-2.2	-2.3	-2.4	-2.4	-2.4	-2.4	...	-1.1	-1.0
Pipeline NPV		-\$134 million												

Table 3.3 Pipeline Cash flows (\$million)

The pipeline construction starts in 2019 ($t = 2$), and the construction schedule is presented in row *b1* on Table 3.3. The capital investment is presented in row *b2*. The capital investment is depreciated using a 15 year MACRS, and the depreciation amount is presented in row *b3*. The O&M costs are given in row *b4*. The total project expenses are a sum of depreciation amount and the O&M costs, and as the pipeline has no source of internal revenue, the total income (row *b5*) only includes the expenses. The annual tax amount is given in row *b6*. The net cash flows of the pipeline are given in row *b7*. The present value of cash flows is calculated using a discount rate of 10% and is given in row *b8*. The NPV of the pipeline in 2017 is -\$134 million.

3.3.3 Oil Field

The CO₂ captured at the power plant is injected and stored in the oil field for oil production. This technique of oil production through CO₂ injection is known as enhanced oil recovery or EOR. In this section, we first describe the model for oil production through EOR. Then we present the financial valuation of EOR at the oil field.

Model of Oil Production

Over the 25-year life of the project, it is expected that a total of 140 million barrels of oil will be recovered by injecting 80 million tons of CO₂ from the power plant. At the end of the project, all of the CO₂ injected will be stored in the oil field. In this section, we describe how we model the annual oil production profile for the prototype project. The amount of oil produced depends on the technical EOR efficiency (incremental oil production per unit of CO₂ injected) and the amount of CO₂ injected:

$$\text{Amount Oil Produced (bbl.)} = \text{EOR efficiency (bbl./ton)} * \text{Amount CO}_2 \text{ injected (ton)}$$

Next, we present how we model the annual oil production profile, the annual CO₂ injection profile, and the annual technical EOR efficiency profile for the prototype CCS-EOR project. First, we present how typical oil production profiles look like in current and past EOR projects.

Figure 3.3 presents a generalized oil production profile for typical EOR projects from the Global CCS Institute's Status of CCS report (2012).

We see that the oil production typically starts a few years after the start of CO₂ injection. Thereafter, there is a steep increase in the oil production followed by a decline in oil production.

This generalized oil production profile is reflected in the projected oil production profile in the Weyburn project as seen from Figure 3.4 (the EOR profile is the impact of CO₂ flood).

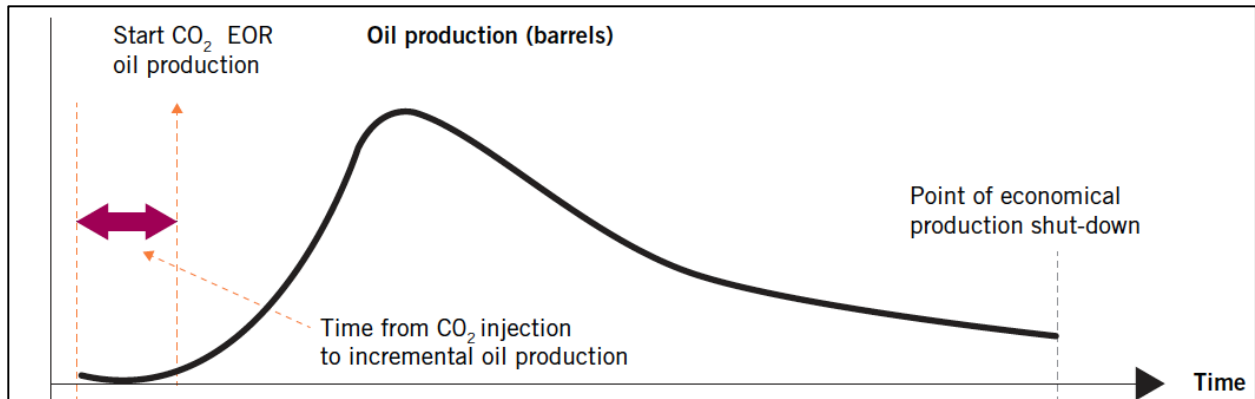


Figure 3.3 Typical Profiles for Oil Production in EOR Projects [Source: Global CCS Institute's Status of CCS report (2012); Original Source: Bellona Foundation Report (2005)]

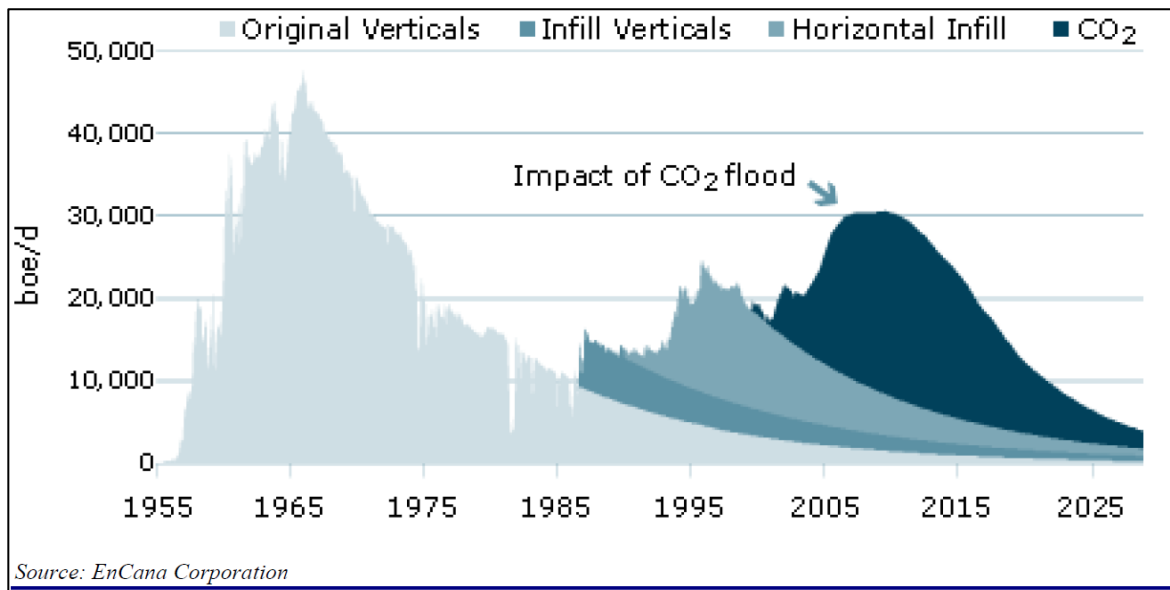


Figure 3.4 Weyburn Project's Oil Production Profile [Source: Bellona Foundation Report (2005)]

We also look at oil production profiles from EOR projects that have long production histories of 25-40 years. Figure 3.5 presents the annual oil production from the CO₂-EOR projects at the Rangely Weber Sand Unit, the Wasson Denver Unit, and the Scurry Area Canyon Reef Operators (SACROC) Unit. The EOR annual oil production data for these projects is from the biennial EOR production surveys by the Oil & Gas Journal (1974 to 2012). Additional project details presented in this section is from the EPRI EOR Scoping Study (1999). The field area in acres reported is from the Oil and Gas Journal EOR Surveys.

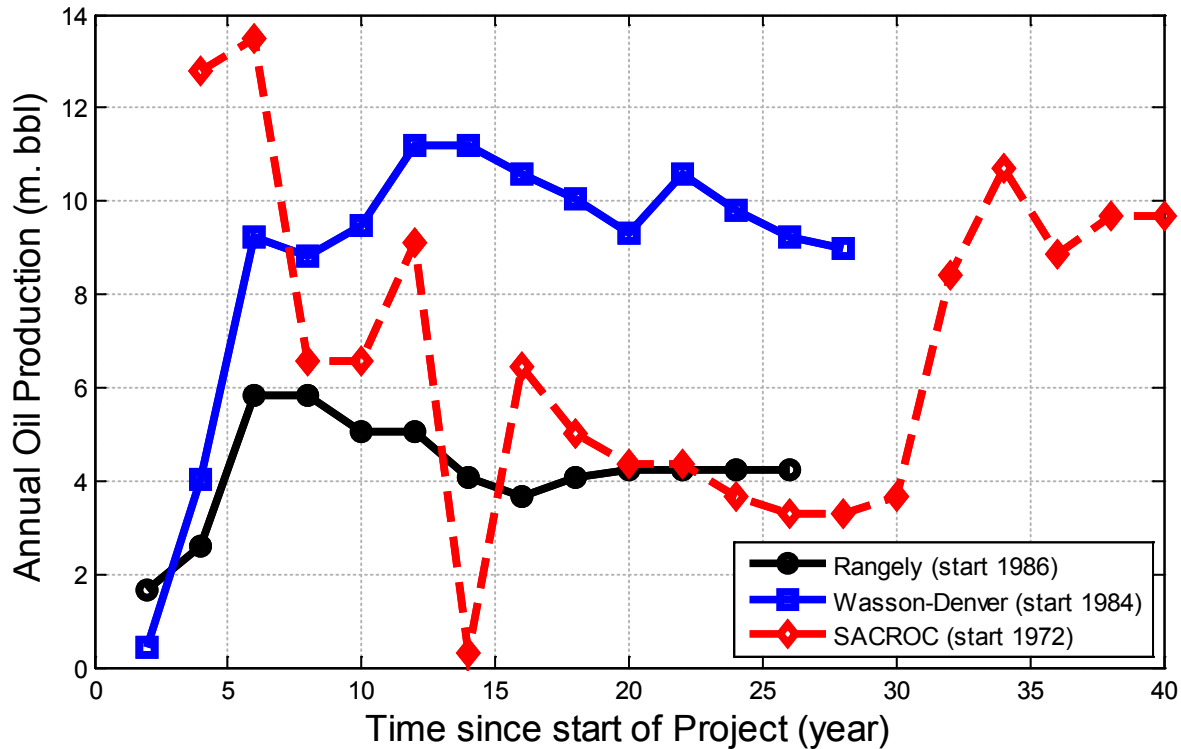


Figure 3.5 EOR Production Profiles for Rangely, Wasson-Denver, and SACROC projects [Source: Oil & Gas Journal EOR Production Surveys: 1974 to 2012]

We see from Figure 3.5 that the Rangely project and the Wasson Denver project initially have a sharp increase in the oil production which is similar to the generalized production profile at EOR projects presented earlier in Figure 3.3.

The Rangely Weber Sand Unit is located in the U.S. Rocky mountain region in northwestern Colorado. The CO₂ flood at the Rangely Unit is operated by Chevron and is reported by the EPRI EOR Scoping Study (1999) as the world’s third largest CO₂ flood. CO₂ injection at Rangely started in 1986, and the CO₂ is anthropogenic sourced from Exxon’s La Barge natural gas processing plant in southwestern Wyoming. The ultimate EOR production is expected to be 136 million barrels or 7.2% of the OOIP (original oil in place). As we see from Figure 3.5 that the EOR production in the Rangely project increases in the initial years until year 6 (1992), then the oil production stays constant for the next two years, and after year 8 the oil production starts to decline. The slight increase in oil production from year 16 to year 20 (2002 - 2006) might be attributable to the field expansion from 15,000 acres to 18,000 acres.

The second project presented in Figure 3.5 is the Wasson-Denver Unit located in the Permian Basin of West Texas. This is one of the world's largest and longest CO₂ flood and is operated by Altura (joint venture between Shell and Amoco). The CO₂ injection at the Wasson-Denver unit is sourced via a 560-mile long pipeline (operated by Shell) from the EcElmo Dome field (naturally occurring CO₂ deposit) in southwestern Colorado. The CO₂ injection started in 1983 but the pipeline was completed only in 1984, and so we consider 1984 as the start year of the project in Figure 3.5. The ultimate EOR production from the Wasson-Denver unit is expected to be 348 million barrels or 16.6% of the OOIP. We see from Figure 3.5 that similar to the Rangely project, in the Wasson-Denver project there is a sharp increase in oil production in the initial six years of CO₂ injection. Thereafter, unlike the Rangely project the oil production does not decrease. A possible reason for why we see that the oil production increase after year 6 is the field expansion into the western half of the Wasson-Denver unit, which increased the field area from 20,000 acres in year 6 (1990) to 28,000 acres.

The third project presented in Figure 3.5 is the CO₂ flood at the Scurry Area Canyon Reef Operators (SACROC) Unit in the Permian Basin in West Texas. The CO₂ injection at this project started in 1972, and this project is the world's first large scale commercial CO₂-EOR project with the longest history of oil production and CO₂ injection in the Permian Basin. We do not have the oil production data from the initial 4 years from 1972 to 1976, and from year 4 to year 6 we see an increase in the oil production to peak production of 14 million barrels in year 6 (1978). After year 6, similar to other projects, we see a decline in oil production. Thereafter the oil production at this project does not follow a generalized trend. Next, we explain the possible explanations for the observed oil production.

We see that in the SACROC project the oil production increases from year 12 to year 14 (1982-1984). The EPRI report (1999) points out that the increase in EOR oil production during this time coincides with increase in water injection rate and so it is not clear if the increased oil production was due to CO₂ injection or water injection. The drop in oil production in year 14 (1986) could be attributed to the oil price collapse in 1986, which might have led to reduced operations. In the 1990s, the SACROC project also saw changes in ownership (Moritis, 2003). Chevron started the project in 1972 and possibly due to the poor economics sold the project to Pennzoil in 1992. Pennzoil was bought by Devon Energy in 1999, and Devon sold its share in

the SACROC project to Kinder Morgan CO2 Company in 2000. Since 2000, Kinder Morgan has made significant investments to redevelop the SACROC project (Moritis, 2003). These investments include enhancing the gas reprocessing capacity and drilling new injection and production wells. Kinder Morgan's infrastructure investments have led to increase in oil production since 2000.

We have presented the generalized oil production profile observed in EOR projects, and compared the generalized profile with the actual oil production profile from real EOR projects. In the prototype CCS-EOR project, we model the annual oil production profile to mimic the generalized oil production profiles observed in EOR projects. Next, we present how we model the annual profiles of the CO₂ injection and the EOR efficiency in the prototype CCS-EOR project such that the resulting annual oil production profiles mimics the typical EOR oil production profiles.

Figure 3.6 presents how we model the CO₂ injection profile in the prototype CCS-EOR project.

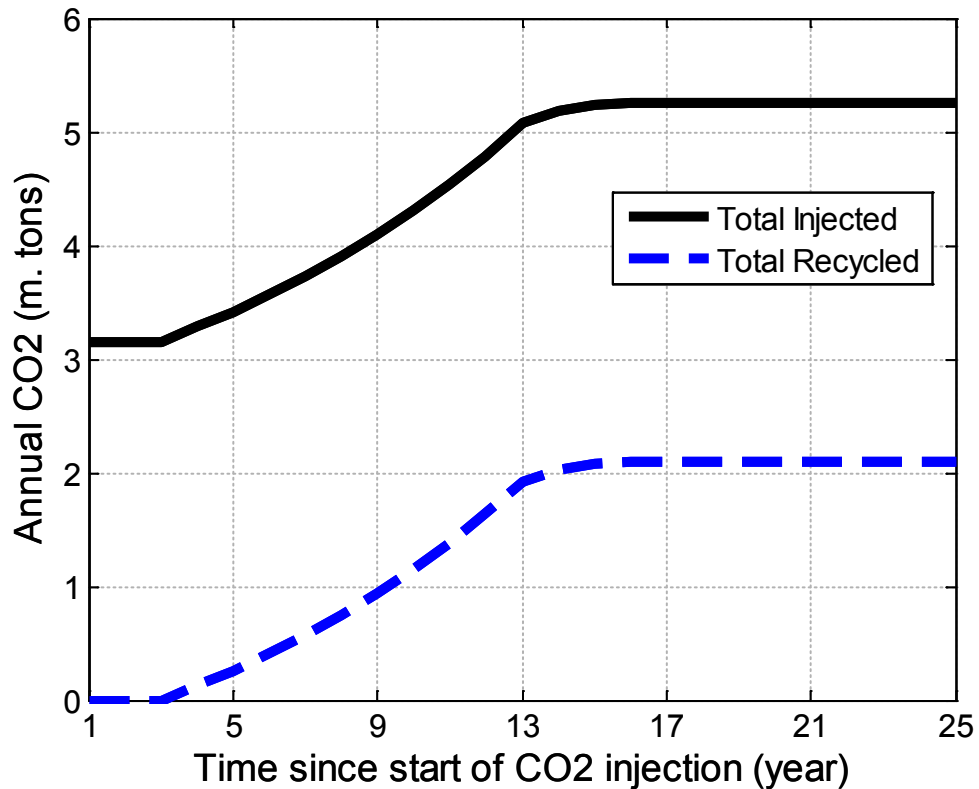


Figure 3.6 CO₂ Injection Profile in Prototype CCS-EOR Project

The total CO₂ injected comprises of the ‘new’ CO₂ from the power plant, and the ‘recycled’ CO₂ that is produced along with the oil and re-injected with the new CO₂. The amount of purchased (or the new) CO₂ is constant through the life of the project and is equal to 90% of the CO₂ captured at the power plant (3.2 million tons/year). The CO₂ recycling rate is expressed as a percentage of the total CO₂ injected in the previous year that comes back to the surface and is injected back in the current year. The CO₂ recycling profile as shown in Figure 3.6 is typical of EOR projects – wherein the CO₂ recycling starts after a gap of a few years from the start of CO₂ injection, thereafter it increases and then plateaus towards the end of life of the project. We model the CO₂ recycling to begin 3 years after the start of CO₂ injection (oil production is assumed to begin 2 years after the start of injection). Then, the CO₂ recycling rate increases linearly for the next 10 years: from 0% in year 3 to 40% in year 13. After year 13, the CO₂ recycling rate plateaus at 40%.

The average recycling rate for the prototype CCS-EOR project is 30%. This recycling rate of 30% is at the lower end of the CO₂ recycling rates observed in traditional EOR projects. In the past and current EOR projects, the recycled CO₂ comprises of 30%-70% of the total CO₂ injected (Martin and Taber, 1992; Brock and Byran, 1989). In some EOR projects as much as 90% of the CO₂ is recycled towards the end of the project (Bloomberg, 2012).

We choose a low recycling rate, as the CCS-EOR projects would be designed for a recycling rate that is lower compared to the recycling rates adopted in traditional EOR projects. This is because, traditionally in EOR projects, there is no value for storing the CO₂, and thus the objective is to maximize the oil production and minimize the amount of ‘new’ or ‘purchased’ CO₂ required. Therefore the traditional EOR projects maximized CO₂ recycling. The choice of CO₂ recycling rates in CCS-EOR projects is discussed by Hovorka (2010) and McCoy (2008). They point out that unlike the traditional EOR projects, the CCS-EOR projects would have financial incentives to store the CO₂ and so the EOR operations would be designed to co-optimize the oil production and the CO₂ storage. Thus, the amount of CO₂ recycled might be much less in CCS-EOR projects compared to the traditional EOR projects. Thus, we model the average recycling rate to be 30% in the prototype CCS-EOR project, which is at the lower end of the observed recycling rate in traditional EOR projects.

Next, we present how we model the technical EOR efficiency curve for the prototype project. The EOR efficiency profile combined with the CO₂ injection profile will give us the oil production profile for the project.

The technical EOR efficiency is expressed in terms of the incremental amount of oil recoverable per unit of CO₂ injected in the oil reservoir. The oil field typically has heterogeneous EOR efficiency, wherein some parts of the field have higher EOR efficiency than rest of the field. The EOR operators account for the field's heterogeneous efficiency in the design of the oil field operations. For example, the operators first develop and start CO₂ injection in the more efficient part of the field, and gradually develop the lesser efficient parts of the field as the amount of CO₂ available increases (with increasing CO₂ recycling rate). Furthermore, when the oil prices drop, often the EOR operations are first halted in the less efficient parts of the field. These decisions by the EOR operators would have important implications on CO₂ delivery contractual obligations with the CO₂ source company, and affect the overall project economics.

We model the oil field in the prototype CCS-EOR project to have heterogeneous EOR efficiency. For simplicity, we model the oil field as two sub-fields with different EOR efficiency. Figure 3.7 presents the expected EOR efficiency curve for the high efficiency sub-field, the low efficiency sub-field, and the average across the overall integrated field.

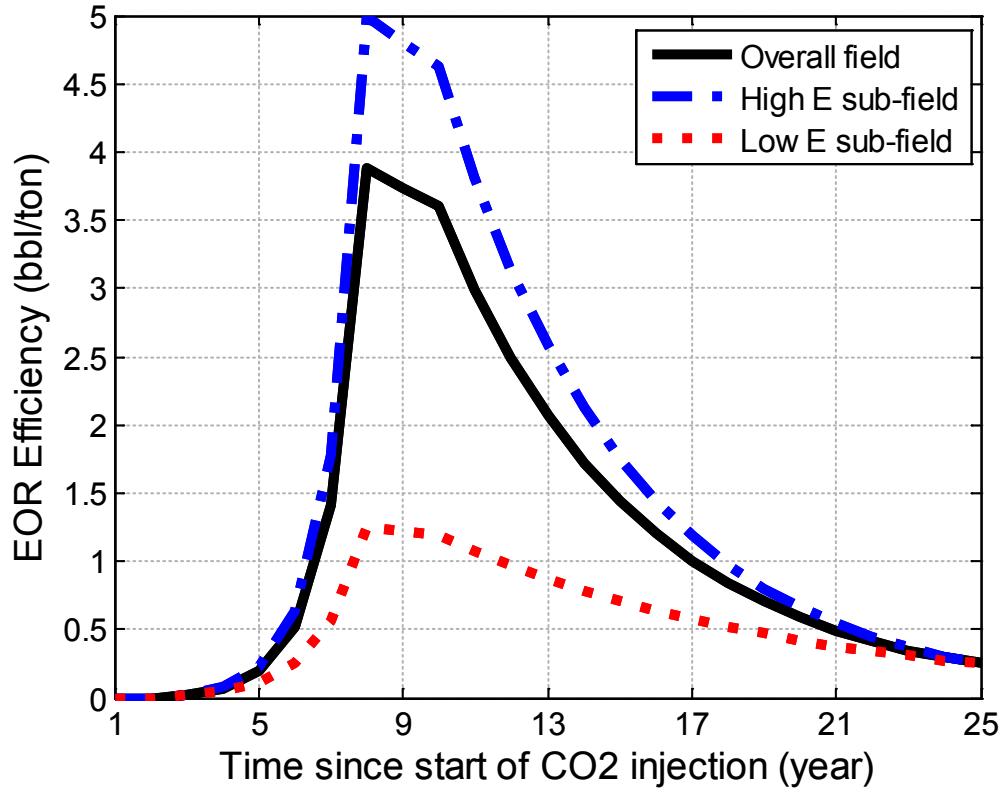


Figure 3.7 EOR efficiency curve in the prototype CCS-EOR project

We model the EOR efficiency profile to reflect the typical oil production profile observed in EOR projects as presented earlier in this section. As we see from Figure 3.7, the EOR efficiency curve has three phases: exponential increase followed by slow decline and thereafter exponential decline. All three phases are modeled as exponential functions.

The initial value of EOR efficiency from $t = 1$ to $t = 2$ is zero as oil production is modeled to begin 2 years after the start of CO₂ injection. Thereafter, EOR efficiency exponentially increases and is modeled to reach the peak value at 8 years from the start of CO₂ injection or 6 years after the start of oil production. This increase in EOR efficiency reflects the initial exponential increase in oil production observed in EOR projects.

After $t = 8$, the EOR efficiency is modeled to slowly decline for next two years ($t = 9$ to $t = 10$). The slow decline in EOR efficiency reflects the plateau phase in oil production, as the slow decline in EOR efficiency with increasing CO₂ injection will result in a plateaued oil production.

Finally, after $t = 10$, there is a steep exponential decline in the EOR efficiency. The steep exponential decline in EOR efficiency reflects the exponential decline in oil production. We model this final exponential decay rate as five times the exponential decay rate in the slow decline period ($t = 9$ to $t = 10$). The EOR efficiency at $t = 25$ years is 0.25 bbl./ton in both the sub-fields and reflects the end of the economic life of the project. A further reduction in the EOR efficiency makes it uneconomical to continue EOR operations beyond the 25 years.

As we see from Figure 3.7, the peak EOR efficiency at $t = 8$ years in the high efficiency sub-field is modeled as 5 bbl./ton, and 1.25 bbl./ton in the low efficiency sub-field. These EOR efficiency profiles lead to an average technical EOR efficiency of 1.23 bbl./ton CO₂ for the overall field over the 25-year life of the project. The average EOR efficiency in the high EOR efficiency sub-field is 1.51 bbl./ton CO₂, and the low EOR efficiency sub-field has an average EOR efficiency of 0.55 bbl./ton CO₂.

The peak EOR efficiency numbers for the high and low efficiency sub-fields have been selected such that the average EOR efficiency over the life of the project reflects the range of average EOR efficiency reported in past EOR projects. EOR literature (Martin and Taber, 1992; Brock and Byran, 1989) that reviews past EOR projects' production and injection histories reports that on an average across the EOR projects the EOR efficiency is 1-2 barrels per ton CO₂ injected. Some projects realized low EOR efficiency numbers around 0.5 bbl./ton.

Figure 3.8 presents the oil production curve calculated from the CO₂ injection curve in Figure 3.6 and the EOR efficiency curve in Figure 3.7.

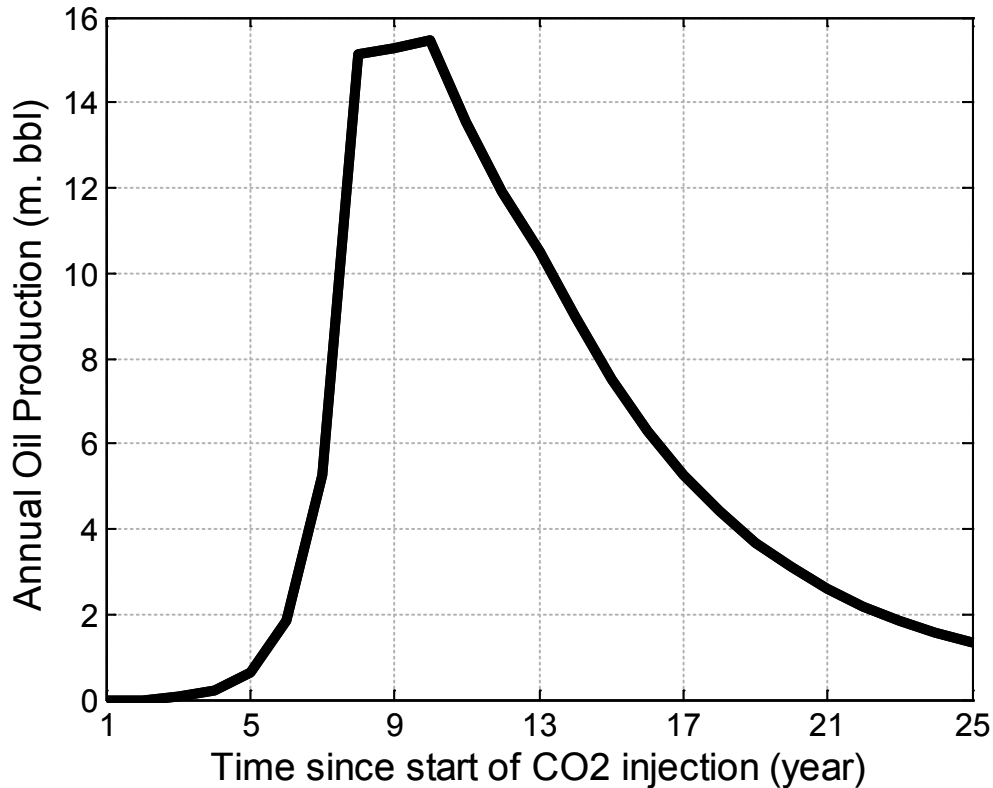


Figure 3.8 Oil production curve in the prototype CCS-EOR project

The oil production starts after a lag of 2 years from the start of CO₂ injection, thereafter the oil production exponentially increases for the next 6 years. The peak oil production in the 8th year is about 15 million barrels. From the 8th year to the 10th year, the annual oil production is almost constant as the decrease in EOR efficiency is offset by the increase in amount of CO₂ recycled. After the 10th year of operations, the annual oil production exponentially declines. Over the 25-year life of the project, it is expected that 140 million barrels of oil will be recovered through EOR. 85% of the expected oil production will be recovered from the high EOR efficiency sub-field, and the remaining 15% will be recovered from the low EOR efficiency sub-field.

These estimates of oil production are based on the expected values of the EOR efficiency. In Chapter 4, we will evaluate how the geological risks involved in EOR operations impact the oil production. Next, we evaluate the cash flows of the oil field.

Financial Valuation

The source of cash flows in an EOR project are costs incurred in the capital investment, O&M costs, and cost of CO₂ recycling. The source of revenue is oil production, and a fraction of the revenue is paid as royalty payments. Table 3.4 presents the unit costs and prices used to evaluate the cash flows. The cost structure is based on NETL EOR report (2008, 2011). The capital investment in EOR project depends on the scale of operations is around \$7.5/barrel of oil produced.). The O&M costs are modeled to be \$12.5/barrel, and the CO₂ recycling costs are \$16 per ton of CO₂ recycled. The EIA’s reference case projection for crude oil (West Texas Intermediate spot price) in 2017 is \$105/barrel in nominal USD (AEO, 2013). The evolution of oil price through the 25-year project life is simulated by Monte Carlo method that is explained in Chapter 4. The oil field pays 17.5% royalty on the revenues from oil production.

Oil Field		
Capital Investment	\$/bbl	7.5 [1]
O&M Cost	\$/bbl	12.5 [1]
CO ₂ Recycle Cost	\$/ton	16 [2]
Price of Oil	\$/bbl	105 [3]
Royalty Payment		17.5% [2]

References: [1] NETL, 2008; [2] NETL, 2011; [3] US EIA AEO 2013 (reference case)

Table 3.4 Oil Field: Unit costs (in 2010 USD) and prices (in 2017 USD)

Table 3.5 presents a snapshot of oil field cash flows.

Oil Field		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	...	2044	2045
		<i>t</i> = 1	2	3	4	5	6	7	8	9	10	...	27	28
<i>c1</i>	Investment Schedule	-	30%	30%										
<i>c2</i>	Capital Investment	-	407	419										
<i>c3</i>	Depreciation	-	-	-	41	78	71	64	57	51	49	...	0	0
<i>c4</i>	O&M Costs	-	-	-	-	-	1.5	4.4	12.7	36.9	108.6	...	53.1	46.2
<i>c5</i>	CO ₂ Recycle Costs	-	-	-	-	-	-	3.1	6.5	10.5	15.1	...	92.0	94.7
<i>c6</i>	Drilling Costs	-	-	-	414	-	-	246	0	0	0	...	0	0
<i>c7</i>	Total Expenses	-	-	-	455	78	72	317	76	99	172	...	145	141
<i>c8</i>	Oil Prod. Revenue	-	-	-	-	-	12	35	102	304	915	...	652	580
<i>c9</i>	Royalty	-	-	-	-	-	2	6	18	53	160	...	114	101
<i>c10</i>	Total Revenue	-	-	-	-	-	10	29	84	251	755	...	538	478
<i>c11</i>	Total Income	-	-	-	-455	-78	-62	-289	8	152	582	...	392	337
<i>c12</i>	Tax	-	-	-	-159	-27	-22	-101	3	53	204	...	137	118
<i>c13</i>	Total Costs	-	407	419	254	-27	-20	153	22	101	328	...	282	259
<i>c14</i>	Net Cash Flows	-	-407	-419	-254	27	30	-124	62	150	427	...	255	219
<i>c15</i>	PV of Cash flows	-	-336	-315	-174	17	17	-64	29	64	165	...	19	15
Oil Field NPV		\$2,527 million												

Table 3.5 Oil Field Cash flows (\$million)

Unlike the power plant and the pipeline, only part (60%) of the capital investment for EOR will be done upfront before the start of operations (row *c1* and *c2*). This upfront investment involves the oil field upgrades such as constructing a CO₂ spur-line from the main CO₂ pipeline to the oil field, investment in the surface equipment such as a CO₂ recycle plant. This investment (row *c2*) is depreciated as per a 15-year MACRS and the depreciation amount is given in row *c3*. The remaining 40% capital investment involves drilling of the CO₂ injection wells and the oil production wells, and will be done gradually reflecting the temporal increase in the amount of CO₂ injected and the oil produced. The first investment in drilling wells is done in *t* = 4 (year 2021), the year when CO₂ injection begins and two years before oil production begins. The first investment is 60% of the total drilling investment, and the remaining 40% is made in year 2024 (*t* = 7). This drilling investment is presented in row *c6*, and has no salvage value and is expensed. Other costs incurred during the project involve the O&M costs (row *c4*) and the cost of CO₂ recycling (row *c5*). The total expenses in EOR are presented in row *c7* and is calculated as the sum of depreciation (row *c3*), O&M costs (row *c4*), CO₂ recycling costs (row *c5*), and drilling costs (row *c6*). The revenue from oil production is given in row *c8*, and the royalty payments are

calculated in row c9 as 17.5% of the revenue from oil production. The net revenue is given in row c10 and is the revenue from oil production less the royalty payments. The total EOR project income is given in row c11 (revenue in row c10 less the expenses in row c7), and the tax amount is given in row c12. The total costs are given in row c13 as the sum of capital investments (row c2), O&M costs (row c4), cost of CO₂ recycling (row c5), drilling costs (row c6) and tax (row c12). The net cash flows are presented in row c14 (revenue in row c10 minus the costs in row c12). The present value of net cash flows are evaluated using a discount rate of 10%. The NPV of the EOR project is \$2,527 million.

The overall integrated CCS-EOR project has a positive NPV of \$1,319 million. We see that most of the value of this project is generated in the EOR operations, and the power plant and the pipeline have a negative NPV of -\$1,074 million, and -\$134 million respectively. This uneven distribution of value among the three components of the CCS-EOR project highlight the importance of structuring strong value-sharing contract structures that incentivize each entity to invest in the project. In this thesis, we will analyze alternate contract structures in terms of how they allocate the cash flows between the different involved entities, and evaluate the resulting incentives the entities have to make optimal decisions that maximize the overall project value.

The cash flows of this prototype CCS-EOR project are subject to considerable uncertainty from different risk factors such as volatility in the market risk factors. The final project value will depend on the evolution of the risks during the project life, and the contingent decisions made by the project entities in response to changes in the risk factors. In the next chapter, Chapter 4, we do integrated project risk management (Step 1 of the risk management framework presented earlier in Section 3.2). We will analyze the impact of the change in the different risk factors during the operational phase of the prototype CCS-EOR project on project value, and will evaluate the optimal contingent decisions that would maximize the value in light of the change in the risk factors.

Chapter 4 Integrated Project Risk Management

The final value of large capital projects depends on both the exogenous risk factors and the endogenous contracting risks. The exogenous risks refer to the risks that are not in the control of the project owners and operators such as volatility in the market prices and geological uncertainty. Endogenous risks are associated with inefficient actions by the involved entities and are influenced by the contract terms that link the different entities. In this chapter we focus on the analyzing the exogenous risks, and will present how we model the uncertainty in the exogenous risk factors in a CCS-EOR project and evaluate the impact these risk factors on the financial value of the prototype CCS-EOR project.

As presented earlier in Chapter 3, we focus on risks in the operational phase of CCS-EOR projects, and are particularly interested in analyzing the risk factors that would initiate contingent decision-making wherein the project operators would reoptimize the project operations in response to the change in the risk factors. The two sets of exogenous risks we focus on is the volatility in the market risk factors and the uncertainty on the value of EOR efficiency. The market risk factors analyzed include volatility in the price of oil recovered, the wholesale price of electricity, and the CO₂ emission penalty. The technical project risk we analyze is the uncertainty on the EOR efficiency which refers to the uncertainty on the amount of oil recovered per unit of CO₂ injected in the EOR operations. Both these types of risks: market risks and technical EOR efficiency uncertainty, might require project operators to readjust the project operations in response to change in the risks in order to optimize the project value. For example, if the oil price drops or the actual realized EOR efficiency is less than predicted then it might be economical to lower the rate of CO₂ injection.

The contingent decision we focus on is the decision to adjust the CO₂ capture and injection rate in response to change in the risk factors. We analyze the decision to adjust the CO₂ capture rate at a single point in time during the operational phase of the project: in year 2023 which is 6 years

after the start of the project construction and 3 years after the start of project operations. In reality, the operational decisions might be revised regularly as the risk factor change. But, to model a regular revision in operational decisions would be computationally prohibitive. The amount of calculations needed exponentially increase with the modeling of each additional time step for the adjustment of operating choice because of the multiple risk factors involved. So, to keep it computationally tractable we consider a single time slice of 6 years from the start of project. This choice of time is far along so as to embody a considerable change in the market risk factors to allow for a change in operational decisions, and is not too far along in the project life to not have a financial impact on the project net present value. Furthermore, enough information about the oil reservoir response to the CO₂ injection would be available during the first three years to considerably reduce the uncertainty on the EOR efficiency.

The net present value (NPV) of the project is evaluated as the sum of the ex ante project value which includes the construction phase ($t = 1$ to $t = 3$) and the first three years of project operations ($t = 4$ to $t = 6$), and the ex post project value from $t = 7$ to the end of the project operational phase ($t = 28$). The ex ante project value includes capital investments and value generated during the first three year of operations when the project is operated at the initially planned 90% capture rate. The ex post project value is the value generated from $t = 7$ years and would depend on the contingent decision made by the project operators in response to the change in the exogenous project risks during the first six years of the project.

In this chapter, we evaluate the impact of the contingent decision-making on the ex post project value and the resulting net present value of the prototype project.

In this chapter, we firstly describe in Section 4.1 the modeling of the exogenous risk factors through the life of the project. Section 4.1.1 presents the modeling of stochastic movement of market risk factors and Section 4.1.2 presents the modeling of the uncertainty in the EOR efficiency. In Section 4.2 we evaluate the impact of the exogenous risk factors on the project value through a pro forma cash flow analysis. The pro forma analysis does not capture the impact of contingent decision-making on the value of the project. In Section 4.3, we analyze how the contingent decisions made in response to the change in risk factors affects the project value and evaluate the optimal contingent decisions that would maximize the project value. We consider alternate scenarios of changes in the risk factors: In Section 4.3.1, we evaluate the

optimal contingent decisions for the ‘base case’ which assumes that the market risk factors move in non-correlated fashion and the EOR efficiency does not change. Then, in Section 4.3.2, we do a sensitivity analysis with respect to different assumptions on the correlation coefficients with the market risk factors, and analyze how the optimal decisions change under different correlation assumptions. Section 4.3.3, evaluates the optimal contingent decisions under different scenarios of changes in the EOR efficiency.

4.1 Risk Modeling

In this section we present how we model the exogenous risks in the prototype CCS-EOR project. We focus on two sets of risks that would incentivize the project operators to reoptimize the project operations in response to change in the risk factors – the volatility in three market risk factors: price of oil recovered, wholesale price of electricity, the CO₂ emission penalty, and the uncertainty in the technical EOR efficiency.

Section 4.1.1 describes how we model the market risk factors. The stochastic model of the movement in the market risk factors used is the random walk model and to simulate the temporal evolution in the market risk factors we use the Monte Carlo method. To evaluate the impact of the contingent decision to the project value, we evaluate a representative sample of the three market risk factors at $t = 6$ which mimics the true distribution of the risk factors, and evaluate the ex post project value as the average of the project value across each of the samples. Section 4.1.1 also explains how we generate a sample of three correlated market risk factors at a discrete point of time during the project.

In Section 4.1.2 we present how we model the uncertainty in the EOR efficiency. We evaluate alternate scenarios of changes in the technical EOR efficiency to illustrate how change in the EOR efficiency impacts the project.

4.1.1 Market Risks

We model the impact of three market risk factors on the value of the prototype CCS-EOR project: the price of oil recovered, the wholesale price of electricity, and the CO₂ emission

penalty. In this section, we first describe the random walk model for the stochastic movement in market risk factors. Then we present the Monte Carlo method to simulate the temporal evolution of the market risk factors accounting for the correlations between the three risk factors. Finally in this section, we present how we generate a representative sample of the three correlated market risk factors at a discrete point of time during the life of the project.

Random Walk Model

The model of price movements we use is the one-factor random walk model, where the uncertain parameter is the shock to the price that follows a Brownian motion. We write the random walk process in terms of the log price:

$$d\ln(P_t) = rdt + vdz$$

where, r is the expected rate of growth of spot price, v is the volatility in spot price, and dz and are increments of standard Brownian motion process implying that the shocks to the log spot price are normally distributed. Thus, the spot price is modeled to be log normally distributed.

The discrete time version of the random walk process written in terms of the log spot price is:

$$\ln(P_t) - \ln(P_{t-1}) = \mu + \sigma\varepsilon_t \quad (4.1)$$

where, each time step is 1 year, μ is the annual expected rate of growth of spot price, σ is the annual volatility in spot price. ε_t is a standard normal random variable, implying that the shocks to the log of spot price are normally distributed.

The expected value and variance of the log of spot price is given by:

$$E[\ln(P_t)] = \ln(P_0) + \mu t \quad (4.2)$$

$$Var[\ln(P_t)] = \sigma^2 t \quad (4.3)$$

where, P_0 is the initial value of price at $t = 0$

The spot price is log normally distributed and the expected spot price is given by:

$$E[P_t] = \exp\left(E[\ln(P_t)] + \frac{1}{2}Var[\ln(P_t)]\right) = P_0 \exp\left(\mu t + \frac{\sigma^2 t}{2}\right) \quad (4.4)$$

The confidence bounds on the prices is calculated by exponentiating the confidence bounds for the log price. As an illustration, the equation below gives the 1-sigma upper bound on spot price.

$$1 - \text{sigma UB}[P_t] = \exp(E[\ln(P_t)] + \sqrt{\text{Var}[\ln(P_t)]}) = P_0 \exp(\mu t + \sigma \sqrt{t}) \quad (4.5)$$

As we see, the expected price and the confidence bounds increase with time because in the random walk model all shocks or changes to the price are permanent. In some cases, this assumption of permanent change in prices might not be valid. Market prices can change due to many reasons, such as change in market demand and supply, technological improvements, exhaustion of existing supply sources or discovery of new sources of supply. These different factors affecting price changes can have short-term temporary effects, and/or long-term permanent effects to prices. Simple one-factor models like the random walk model and the mean reversion model can only capture one of the effects of the price changes. There are more complex multi-factor models of price changes (Schwartz and Smith, 2000; Baker et al, 1998) that can increase the accuracy of forecasting price movements but it comes at the cost of increasing computational complexity.

For our analysis, we are interested in the how the long-term changes in spot prices impacts the project and influences the decision-making. In the long-term the contribution of short-term price effects becomes small and we see from the Schwartz and Smith (2000) that at long time horizons the solution from a two-factor model is indistinguishable from a one-factor random walk model. One can mimic the long-term solution from a two-factor model, by using the volatility parameter in the one-factor model as the long-term volatility in the two-factor model and add a small constant term to the variance of the log spot price that accounts for contribution of short-term deviations in the spot price (see equation 6 in Schwartz and Smith, 2000).

In our study we use the random walk model, which is simple and yet reasonably accurate model to capture the long-term trend in spot prices.

We model the impact of three key market risk factors on the prototype CCS-EOR project: price of oil, wholesale price of electricity, and the CO₂ emission penalty. Table 4.1 presents the initial price, the annual expected growth rate, and the annual volatility for the three market risk factors.

	Initial price	μ	σ
Oil price	\$105/bbl	0	21% [1]
Electricity price	10.3 c/kWh	0	10% [2]
CO₂ emission penalty	\$5/ton	0	47% [3]

References: [1] Pindyck, 1999; [2] Niemeyer, 2000; [3] Abadie and Chamorro, 2008

Table 4.1 Initial price, growth rate(μ), and volatility (σ) in the three market risk factors

The prices are in 2017 USD. The oil price and electricity price are from the 2013 Annual Energy Outlook reference case (US EIA AEO 2013); the initial price of oil at $t = 0$ of the project (year 2017) is \$105/bbl, and the initial price of electricity is 10.3 c/kWh. For the CO₂ emission penalty, we assume that the projected price in 2017 is \$5 per ton CO₂. We assume a zero expected growth rate in prices. The source for volatility in market risk factors is listed below the Table 4.1. The volatility parameters include effects of long-term deviations in prices and also some short-term impacts of price changes. So, over the long-term our model will slightly overestimate the volatility and thus the prices compared to forecast from a two-factor model. For example, we find that at $t = 10$ the expected oil price forecast from the one-factor model with 21% volatility is 7% higher compared to if we used the two-factor Schwartz and Smith (2000) model with their volatility estimates.

We use the Monte Carlo method to model the evolution of the market risk factors. The prices paths are evaluated from $t = 0$ to $t = 28$ (end of project), the project construction period is from $t = 1$ to $t = 3$ years, the project operations begin at $t = 4$ and continue for 25 years till $t = 28$.

Monte Carlo Method for Price Movements

Looking forward from time 0, the log value of the spot price at time t is given by:

$$\ln(P_t) = \ln(P_0) + \mu t + \sigma \sum_{i=1}^t \varepsilon_i \quad (4.6)$$

One Monte Carlo simulation involves T random draws of ε_i to generate a complete price path from $t = 0$ to $t = T$. The price paths for the three market risk factors: oil price (P_1), electricity price (P_2), and CO₂ emission penalty (P_3) are given by:

$$\ln(P_{1t}) = \ln(P_{10}) + \mu_1 t + \sigma_1 \sum_{i=1}^t \varepsilon_{1i}$$

$$\ln(P_{2t}) = \ln(P_{20}) + \mu_2 t + \sigma_2 \sum_{i=1}^t \varepsilon_{2i}$$

$$\ln(P_{3t}) = \ln(P_{30}) + \mu_3 t + \sigma_3 \sum_{i=1}^t \varepsilon_{3i}$$

To generate price paths for correlated market risk factors, at each time step (i), we need to generate three correlated samples of standard normal random variables (ε_{1i} , ε_{2i} , and ε_{3i}). This is done using Cholesky decomposition as described in Hull (2011, Chapter 20) where the required samples are:

$$\varepsilon_{1i} = \alpha_{11} x_{1i}$$

$$\varepsilon_{2i} = \alpha_{21} x_{1i} + \alpha_{22} x_{2i}$$

$$\varepsilon_{3i} = \alpha_{31} x_{1i} + \alpha_{32} x_{2i} + \alpha_{33} x_{3i}$$

where, x_{1i} , x_{2i} and x_{3i} are independent random draws from standard normal distribution and α_{jk} are chosen such that the correlations and variances are correct:

$$\alpha_{11} = 1,$$

$$\alpha_{21} = \rho_{21}, \alpha_{22} = \sqrt{1 - \rho_{21}^2},$$

$$\alpha_{31} = \rho_{31}, \alpha_{32} = \frac{\rho_{32} - \rho_{31}\rho_{21}}{\sqrt{1 - \rho_{21}^2}}, \alpha_{33} = \sqrt{1 - \rho_{31}^2 - \frac{(\rho_{32} - \rho_{31}\rho_{21})^2}{1 - \rho_{21}^2}}.$$

where, ρ_{21} is the correlation coefficient between risk factor 1 & 2, similarly the other correlation coefficients are ρ_{32} and ρ_{31} .

One Monte Carlo simulation generates one price path from $t = 0$ to $t = T$ for each of the three risk factors. The expected value and the variance of log value of spot price is the mean and the variance of $\ln(P_t)$ across all the N simulations. As the number of simulations increases, the expected value and variance comes closer to their true value.

$$E[\ln(P_t)] = \frac{\sum_{n=1}^N \ln(P_{tn})}{N}$$

$$VAR[\ln(P_t)] = \frac{\sum_{n=1}^N (\ln(P_{tn}) - E[\ln(P_t)])^2}{N - 1}$$

where, $E[\ln(P_t)]$ and $VAR[\ln(P_t)]$ is the expected value and the variance of $\ln(P_t)$ across all simulations.

To evaluate the correlated price movements of the three risk factors, we model the oil price movement as its independent price movement (since $\alpha_{11} = 1$), and evaluate the distribution of price of electricity conditional on the price of oil, and distribution of the CO₂ emission penalty conditional on the price of oil and wholesale price of electricity. In the literature we did not find relevant estimates of the correlation coefficients between the long run oil price, electricity price and the CO₂ emission penalty. Therefore, we do a sensitivity analysis with respect to different estimates of the correlation coefficients and evaluate how the results change with the values of the correlations. Table 4.2 presents the three scenarios of correlations evaluated in this thesis.

	ρ_{oil_elec}	$\rho_{elec_CO_2}$	$\rho_{oil_CO_2}$
Zero Correlation	0	0	0
Positive Correlation	+0.5	+0.5	+0.5
Negative Correlation	-0.5	-0.5	+0.5

Table 4.2 Alternate scenarios of the correlation coefficients between the market risk factors

We evaluate the impact of change in market risk factors on the prototype CCS-EOR project 1) when the market risk factors are not correlated or have ‘zero’ correlation, 2) when the market risk factors are all ‘positively’ correlated with correlation coefficient of 0.5. This assumption of positive correlation represents a common belief that prices of energy commodities are positively related, so the oil price and the electricity price would go up or go down at the same time. Also, it is generally understood that an increased CO₂ emission penalty might drive up the price of electricity. The final case we evaluate is 3) when the market prices are ‘negatively’ correlated, i.e. the oil price and the electricity price are negatively correlated and the electricity price and the CO₂ emission penalty are also negatively correlated. The absolute value of all the correlation coefficients is assumed as 0.5. We could observe a negative relationship between the oil price and the electricity price if new sources of oil supply are discovered while there is a decrease in the production of fuel for electric power (such as natural gas). A negative correlation between electricity price and CO₂ emission penalty could be associated with high CO₂ emission penalty

which encourages investments in low carbon electricity generation with low variable costs (such as nuclear) which drives the electricity price down in the long-run.

As we would discuss in Section 4.3.2, the ‘positive’ correlation and the ‘negative case give us the range of financial gains that can be achieved by contingent decision-making in response to change in the market risk factors. Lowest financial gains are made when the market risk factors are positively related and a negative correlation leads to higher financial gains.

Figure 4.1 present the expected oil price and 1-sigma confidence bounds on the oil price generated from 5,000 Monte Carlo simulations where the initial price of oil is \$105/bbl.

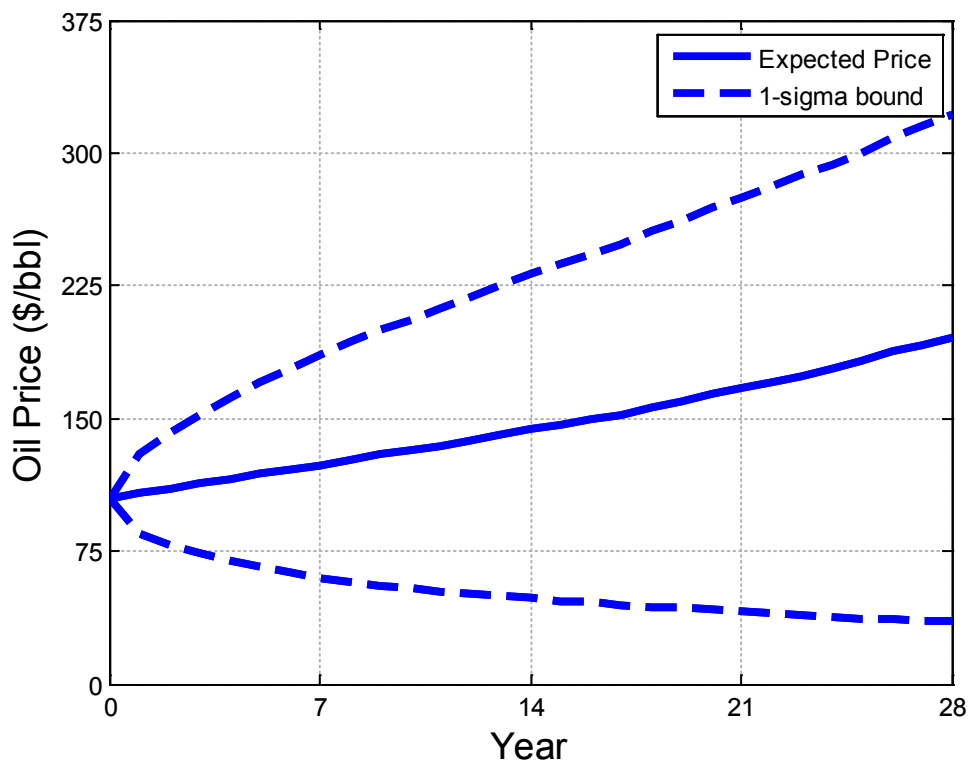


Figure 4.1 Oil price path from Monte Carlo simulations

We see from Figure 4.1 that the expected price of oil increases from \$105/bbl at $t = 0$ to \$189/bbl at $t = 28$. The underlying random walk model of oil price reflects in the increasing confidence bounds on the expected price.

Figure 4.2 and Figure 4.3 present the results Monte Carlo simulations for the wholesale price of electricity and the CO₂ emission penalty. These price paths are generated assuming a ‘positive correlation’ coefficient of 0.5 between all the three risk factors.

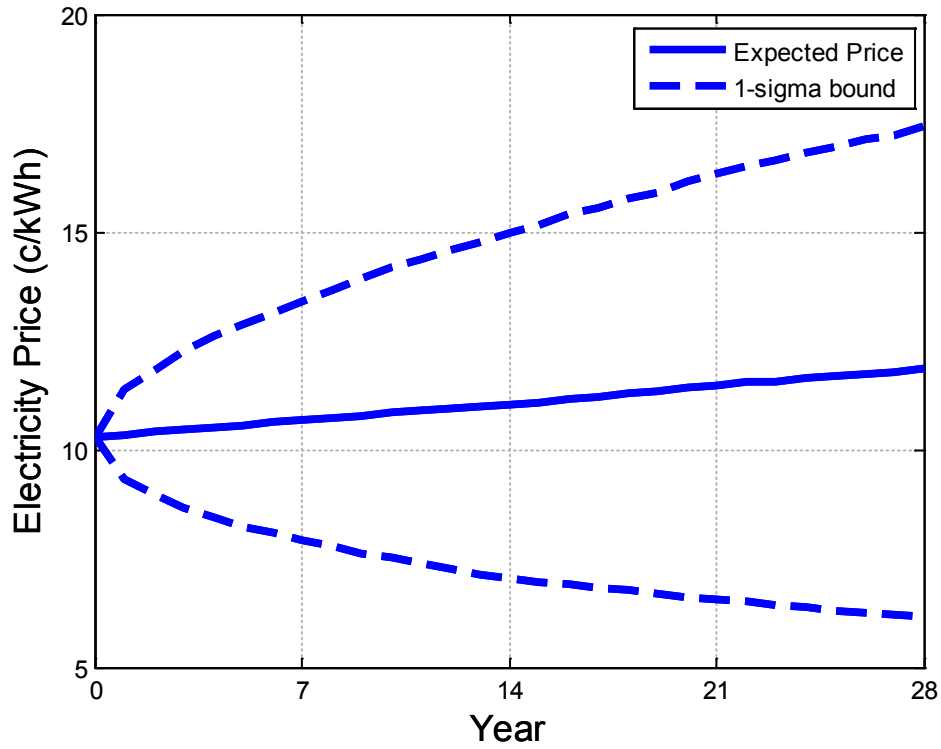


Figure 4.2 Wholesale electricity price path from Monte Carlo simulations

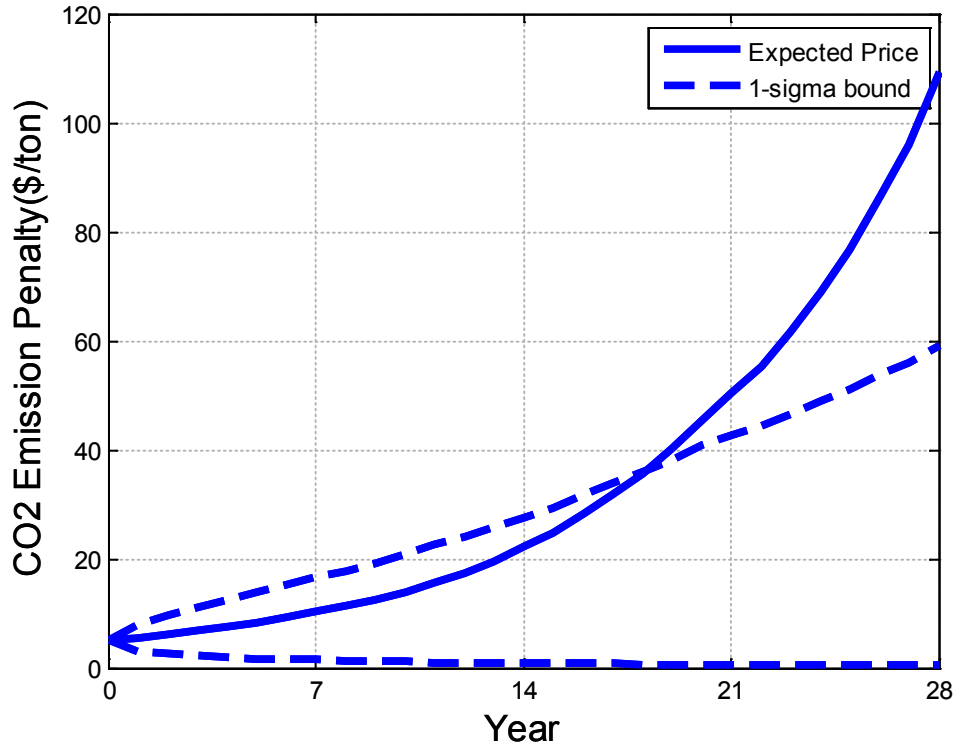


Figure 4.3 CO₂ emission penalty price path from Monte Carlo simulations

The expected wholesale price of electricity increases from 10.3 c/kWh at $t = 0$ to 11.85 c/kWh at $t = 28$. The expected CO₂ emission penalty increases from \$5/ton at $t = 0$ to \$109/ton at $t = 28$. Due to the high annual volatility in the CO₂ emission penalty we see that after $t = 18$, the expected CO₂ emission penalty is higher than the upper bound value on the CO₂ emission penalty.

We have evaluated how the prices of the market risk factors changes during the life of the CCS-EOR project. But, a Monte Carlo simulation is not sufficient to capture the impact of contingent decisions that might be made in response to changes in risk factors. It is these contingent decisions that will shape the final value of the project particularly when risk factors change a lot from their initial expected values. As described earlier, we evaluate the impact of contingent decisions made a single point of time during the project at $t = 6$. The ex ante project value (value from $t = 0$ to $t = 6$) is evaluated based on the expected price paths generated using Monte Carlo method from $t = 0$ to $t = 6$. To calculate the project value as a result of the contingent decision-making at $t = 6$, we generate a representative discrete sample of the three correlated market risk factors at $t = 6$ that mimics the true distribution of the risk factors, and then evaluate the price paths for each of the sample from $t = 6$ to $t = 28$ using Monte Carlo method where price sampled at $t = 6$ serves as the ‘initial’ price for the Monte Carlo simulation. The ex post project value (value from $t = 7$ to $t = 28$) is evaluated as an average across the entire sample set.

Next, we describe how we generate a discrete sample of the three correlated market risk factors.

Discrete Sampling of Correlated Normally Distributed Variables

We use the properties of multivariable normal distribution to sample from the distribution of the log price of the market risk factor that is normally distributed (a property of random walk model as presented earlier in this section). In particular, we use the stratified sampling technique such that each sample point is equally spaced on the probability scale (Hull, 2011: Chapter 20).

The value of the i th sample point is:

$$F\left(\frac{i - 0.5}{n}\right)$$

where n is the number of sample points, and F is the inverse cumulative normal distribution of log spot price.

For $n = 1$, the sampled value is the median of the sample (cdf = 0.5), and for $n = 2$ the sampled values have cdf = 0.25 and 0.75, and so on.

As we see, this sampling creates a sample where the median (also the mean in normal distribution) of the sample is same as the true distribution, the variance of the sample will be equal to the variance of the sample at the limit, and each of the sampled point will have equal probability of $1/n$.

Figure 4.4 shows the cumulative distribution curve from 15 sample points of the oil price at $t = 6$. The mean and variance of log oil price at $t = 6$ used to characterize the normal cumulative distribution are calculated using equation 4.2 and equation 4.3. The initial oil price at $t = 0$ is \$105/bbl. The vertical lines give the expected oil price (solid line) and the 1-sigma confidence bounds (dash lines) on the oil price at $t = 6$.

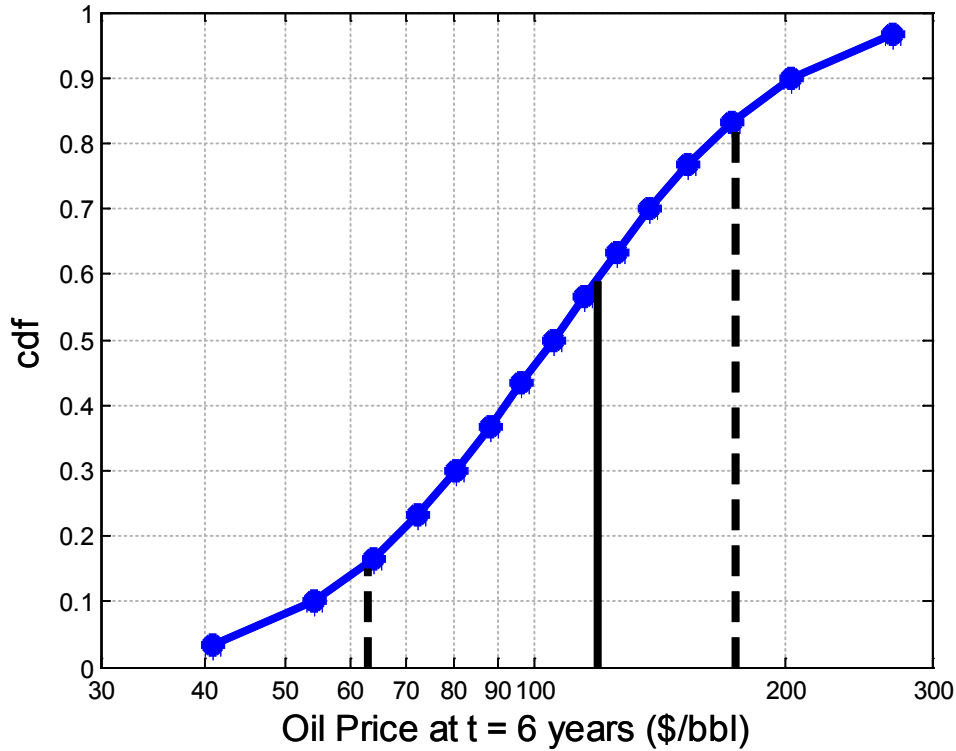


Figure 4.4 Sampling Oil Price at $t = 6$ years

Table 4.3 gives the distribution of the oil price at $t = 6$ years presenting the expected price and the 1-sigma and 2-sigma confidence bounds on the oil price.

	Oil Price (\$/bbl)
Mean	119
+ 1 sigma	173
- 1 sigma	63
+ 2 sigma	289
- 2 sigma	38

Table 4.3 Distribution of Oil Price at $t = 6$ years

Now, we can evaluate the distribution of the electricity price conditional of the price of oil. The log values of the price of oil and the wholesale price of electricity are jointly normally distributed, so to evaluate the conditional distribution of wholesale price of electricity, we use the following property of bivariate normal distribution: In a bivariate normal distribution, the conditional probability distribution function for one of the variables, given a known value for

other variable, is normally distributed. The conditional mean and variance of y_2 (log electricity price) given y_1 (log price of oil) is given by:

$$\mu_{y_2|y_1} = \mu_2 + \rho_{12}\sigma_2 \frac{(y_1 - \mu_1)}{\sigma_1}$$

and, $\sigma_{y_2|y_1} = \sigma_2 \sqrt{1 - \rho_{12}^2}$

where, μ_2 and μ_1 are the mean values of log price of electricity and log oil price respectively from their independent probability distributions as given by equation (4.2), σ_2 and σ_1 are the standard deviation of the log price of electricity and log oil price respectively from their independent probability distributions as given by equation (4.3), and ρ_{12} is the coefficient of correlation between price of oil and electricity.

For each of the n_1 samples of the log oil price: y_{1i} ($i = 1, 2, \dots, n_1$), we can calculate the conditional distribution of log wholesale price of electricity y_{2i} . For each of the conditional distribution of y_{2i} , we can generate n_2 samples using stratified sampling as described earlier to sample log oil price. Thus, we have n_1 samples of log oil price: y_{1i} ($y_{11}, y_{12}, \dots, y_{1n_1}$), and for each y_{1i} we have n_2 samples of log wholesale electricity price, y_{2ij} ($j = 1, 2, \dots, n_2$) conditional on y_{1i} . The total number of scenarios by sampling oil price and electricity price are $n_1 * n_2$, and from the property of the chosen sampling technique, each of the scenarios (y_{1i}, y_{2ij}) are equal probability with probability = $1/n_1 * 1/n_2$.

Figure 4.5 shows cumulative distribution curves for the wholesale electricity price generated by sampling 15 points ($=n_2$) of wholesale electricity price for each of the sampled oil prices presented earlier in Figure 4.4. Thus, in Figure 4.5, there are 15 ($=n_1$) cumulative distribution curves each of which has 15 ($=n_2$) sample points. We have assumed a positive correlation coefficient = 0.5 with price of oil and thus we see in the figure that as the oil price increases, the conditional distribution of electricity price moves right.

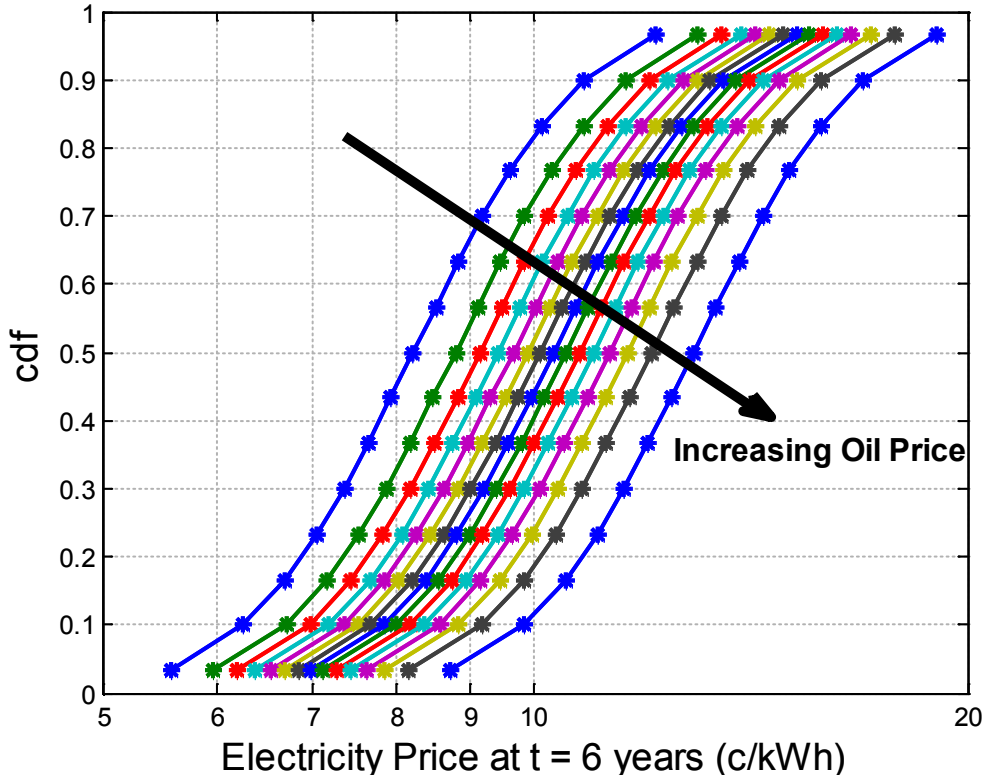


Figure 4.5 Sensitivity of the electricity price distribution to the price of oil assuming positive correlation coefficient of 0.5

Figure 4.6 shows how the distribution of the electricity price changes with the degree of correlation with the price of oil. We present three different scenarios of correlation as given in Table 4.2: zero correlation, positive correlation of 0.5 and negative correlation of -0.5. The electricity price distribution is conditional on the oil price being equal to \$173/bbl which is the 1 sigma upper bound on the oil price at $t = 6$.

We see in Figure 4.6 that if the electricity price and oil price are positively correlated then the electricity price distribution shifts right relative to its distribution at zero correlation. This is because the oil price is higher than its expected value and thus positive correlation results in a higher electricity price compared to when it is not correlated to oil price. Similarly, we see that when electricity price and oil price are negatively correlated then the distribution of the electricity price shifts left compared to when it is positively correlated or not correlated. The expected electricity price is 10.6 c/kWh at zero correlation, the expected electricity price increases to 11.84 c/kWh at positive correlation and reduces to a expected value of 9.34 c/kWh at negative correlation.

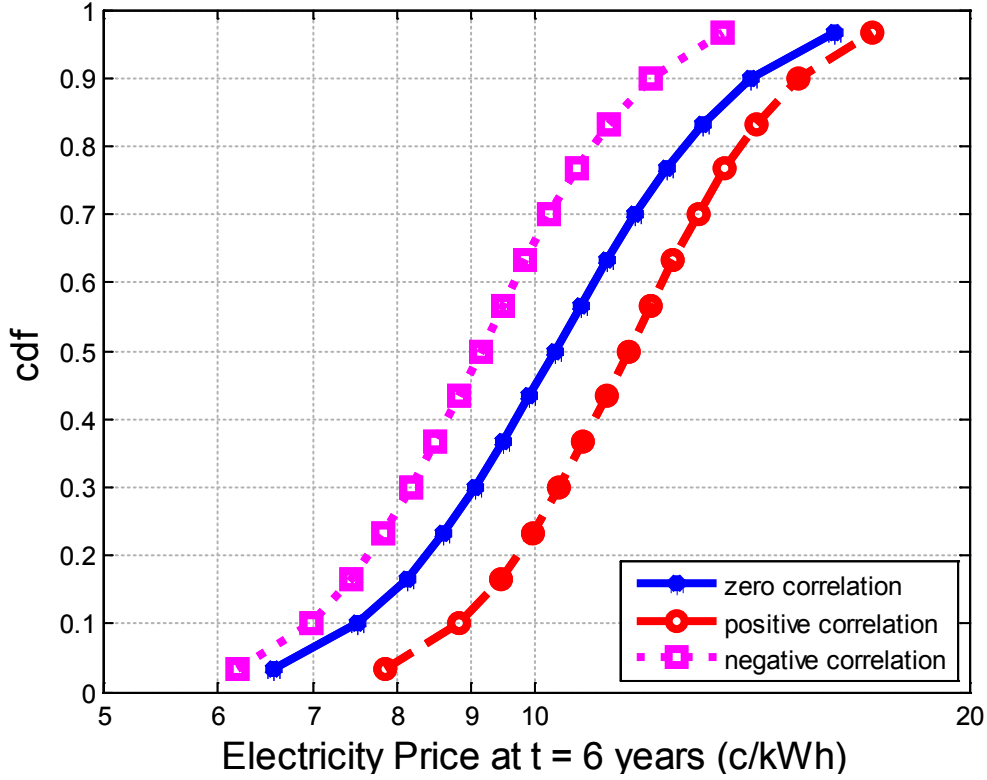


Figure 4.6 Sensitivity of electricity price distribution to the degree of correlation with oil price

We now describe how we evaluate the distribution of the CO₂ emission penalty conditional on the price of oil and the electricity price. Using properties of multivariate normal distribution, the conditional mean and variance of y_3 (log CO₂ emission penalty) given y_1 (log price of oil) and y_2 (log electricity price) is given by:

$$\mu_{y_3|y_2,y_1} = \mu_3 - \frac{1}{k_{33}} \sum_{j=1}^2 k_{3j}(y_j - \mu_j)$$

$$\sigma_{y_3|y_2,y_1} = \sqrt{1/k_{33}} \quad ; \quad K = COV^{-1} = [k_{ij}]$$

where μ_3 , and μ_1 are the mean values of log CO₂ emission penalty, and log of price of oil respectively from their independent probability distributions (equation 4.2) and μ_2 is the conditional mean value of log price of electricity given oil price (evaluated earlier using properties of bivariate conditional distribution). k_{ij} is the matrix elements of the inverse of the covariance matrix of the three market risk factors where the covariance matrix (COV) is:

$$COV = \begin{bmatrix} \sigma_1^2 & \rho_{12} * \sigma_1 * \sigma_2 & \rho_{13} * \sigma_1 * \sigma_3 \\ \rho_{12} * \sigma_1 * \sigma_2 & \sigma_2^2 & \rho_{23} * \sigma_2 * \sigma_3 \\ \rho_{13} * \sigma_1 * \sigma_3 & \rho_{23} * \sigma_2 * \sigma_3 & \sigma_3^2 \end{bmatrix}$$

where, σ_3 and σ_1 are the standard deviation of log CO₂ emission penalty and log oil price respectively from their independent probability distributions (equation 4.3) and σ_2 is the conditional standard deviation of log electricity price given oil price (evaluated earlier). ρ_{12} is the correlation coefficient between price of oil and electricity, ρ_{13} is the correlation coefficient between oil price and CO₂ emission penalty, and ρ_{23} is the correlation coefficient between price of electricity and CO₂ emission penalty.

We will have a unique conditional distribution of CO₂ emission penalty for each of the $n_1 * n_2$ sampled pairs of price of oil and wholesale price of electricity (y_{1i}, y_{2ij}). From each unique distribution of CO₂ emission penalty we will sample n_3 points using the stratified sampling method as described earlier. Thus we will have $n_1 * n_2 * n_3$ number of equal probability scenarios of the three risk factors, each scenario is ($y_{1i}, y_{2ij}, y_{3ijk}$), where $i = 1, 2, \dots, n_1; j = 1, 2, \dots, n_2; k = 1, 2, \dots, n_3$, and has probability = $1/n_1 * 1/n_2 * 1/n_3$.

Figure 4.7 presents the how the distribution of the CO₂ emission penalty changes with the degree of correlation with the price of oil and the electricity price. The three different scenarios of correlation are as given in Table 4.2: the negative and positive correlation refer to how the CO₂ emission penalty is correlated with the price of electricity and in both cases the CO₂ emission penalty is positively correlated with oil price. The zero correlation implies that the CO₂ emission penalty is not correlated with the other two market risk factors. The CO₂ emission penalty distribution in all three correlation cases is calculated conditional on the oil price being equal to \$173/bbl which is the 1 sigma upper bound on the oil price at $t = 6$, and the electricity price is equal to its 1 sigma upper bound value in each of the respective correlation cases.

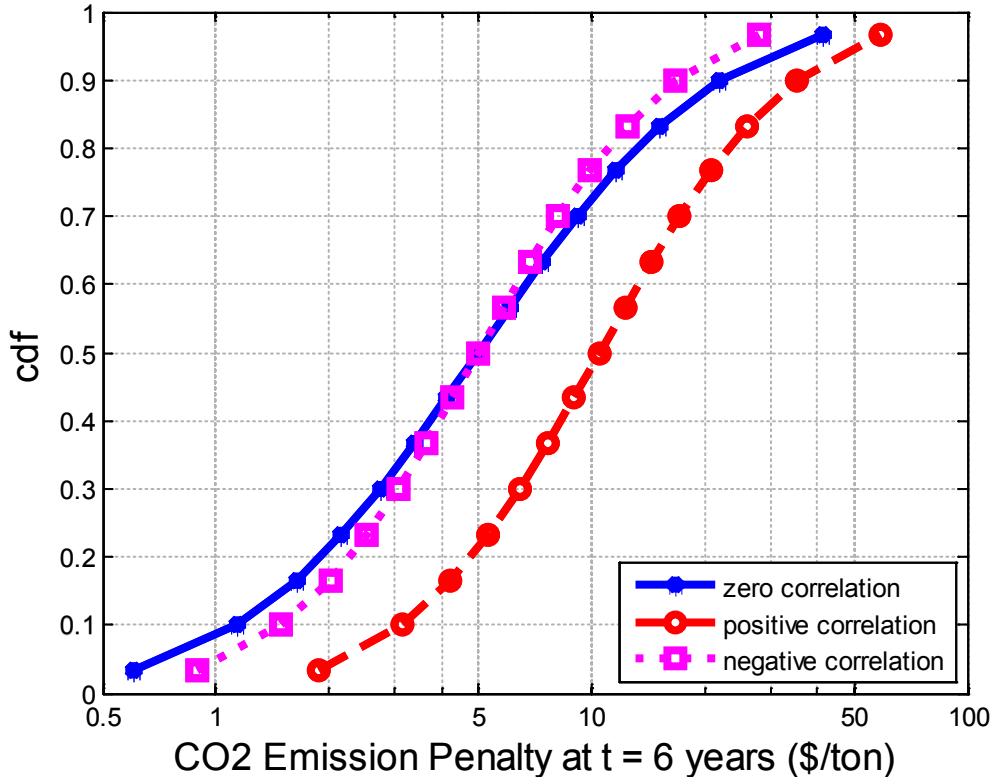


Figure 4.7 Sensitivity of CO₂ emission penalty distribution to the degree of correlation with price of oil and price of electricity

We see from Figure 4.7 that when the CO₂ emission penalty is positively correlated to the two other risk factors, its distribution considerably shifts right compared to when the CO₂ emission penalty is independently distributed. This is because, both the oil price and the electricity price have a value higher than their expected value, and a positive correlation to these two risk factors significantly increases the value of the CO₂ emission penalty compared to when it is not correlated. The distribution of the CO₂ emission penalty in the negative correlation case almost overlaps with the zero correlation case, because the reduction in value of the CO₂ emission penalty due to a negative correlation with the electricity price is being compensated by the increase in CO₂ emission penalty due to a positive correlation with the oil price.

In this section, we presented how we model the volatility in the market risk factors. We firstly presented the random walk model used to characterize the stochastic movement in the market prices. Then, we present the Monte Carlo method to simulate the future evolution in prices accounting for the correlations between the risk factors. Finally, we presented how we generate a representative sample of the three correlated market risk factors at a discrete point of time during

the life of the project, which is useful to evaluate the impact of contingent decisions at a discrete point of time during the project.

Next, we describe how we model the uncertainty in the technical EOR efficiency.

4.1.2 EOR Efficiency Risk

In Chapter 3 we presented the EOR oil production and CO₂ injection model for the prototype CCS-EOR project. The amount of oil produced depends on the technical EOR efficiency (incremental oil production per unit of CO₂ injected) and the amount of CO₂ injected. We are interested in analyzing the geological risks during the operational phase of CCS-EOR projects that would affect the decision of the project operators on the amount of CO₂ to be captured and injected. In particular, we analyze the uncertainty in the technical EOR efficiency. The geological uncertainty related to the uncertain response of the subsurface to CO₂ injection leads to difficulty in deterministically predicting the technical EOR efficiency.

We are interested in evaluating the impact of uncertainty in the EOR efficiency on the financial value of the project. If the EOR efficiency is less than expected then it would lead to less than expected amount of oil recovery. In response to the reduced EOR efficiency, the project operators might find it economical to operate at a lower CO₂ injection rate and this change in the CO₂ requirements has implications on the design of contracts between the oil field company and the power plant company, which will be analyzed in Chapter 5.

We will evaluate alternate scenarios of changes in the technical EOR efficiency to illustrate how change in the EOR efficiency impacts the project. We analyze the scenarios at a single point in time of the project at $t = 6$ years from the project start or 3 years after the start of CO₂ injection. We select the time of 3 years after the start of CO₂ injection as this is the year when CO₂ recycle starts and it is one year after oil production begins, and so enough information should be available to significantly reduce the uncertainty on the EOR efficiency estimates. Furthermore, $t = 6$ is also the same time chosen to evaluate the contingent decisions made in response to change in market risk factors. Thus, at a single point of time we can evaluate the optimal contingent decisions in response to changes in both the market risk factors and the EOR efficiency.

We capture uncertainty in the technical EOR efficiency by focusing on the EOR efficiency in the high efficiency sub-field; the EOR efficiency in the low efficiency sub-field is assumed to be the same as the expected value at the beginning of the project. We analyze three scenarios of changes in the EOR efficiency in the high efficiency sub-field as shown in Figure 4.8.

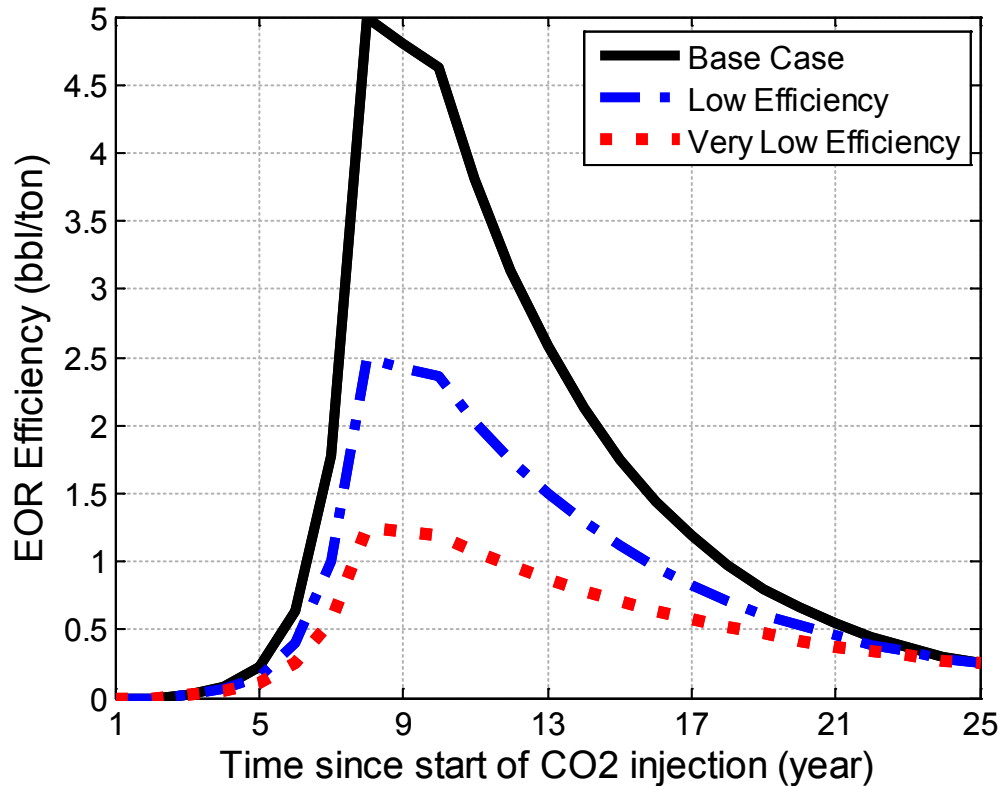


Figure 4.8 Alternate scenarios of changes in the EOR efficiency in the high efficiency sub-field

In the ‘base case’ scenario, the expected annual EOR efficiency 3 years from the start of CO₂ injection is same as the expected value at the beginning of the project with a peak EOR efficiency value of 5 bbl/ton.

In the ‘low’ efficiency scenario the EOR efficiency in the high efficiency sub-field increases at a slower rate compared to the base case and the peak value is 2.5 bbl/ton compared to 5 bbl/ton in the base case. After reaching the peak value, the EOR efficiency decays at a slower rate compared to the base case and has the same terminal value of 0.25 bbl/ton at the 25-year end of project life as the base case.

In the ‘very low’ efficiency scenario the EOR efficiency in the high efficiency sub-field is the same as the low efficiency sub-field. We see that compared to the other two scenarios, in this

scenario the EOR efficiency in the high efficiency sub-field increases at a lower rate and reaches a peak value of 1.25 bbl/ton. This peak EOR efficiency value is the lowest of the three scenarios and is equal to the peak EOR efficiency in the low efficiency sub-field. The EOR efficiency value at the end of project life is the same in all three scenarios and equals 0.25 bbl/ton, which reflects the end of economic life of the EOR project.

Table 4.4 presents the average EOR efficiency over the life of the project in all three scenarios.

	High Efficiency Sub-field	Low Efficiency Sub-field	Overall Field
Base Case	1.51	0.55	1.23
Low Efficiency Scenario	0.90	0.55	0.79
Very Low Efficiency Scenario	0.55	0.55	0.55

Table 4.4 The average EOR efficiency (barrels per ton CO₂) in the alternate scenarios

In the base case scenario, the EOR efficiency is same as the expected value at the beginning of the project. In the ‘low’ efficiency scenario, the average EOR efficiency in the high efficiency sub-field reduces to 0.9 barrels per ton compared to 1.51 bbl/ton in the base case, and the overall oil field efficiency reduces to 0.79 bbl/ton from a value of 1.23 bbl/ton in the base case.

In the ‘very low’ efficiency scenario the EOR efficiency of the high efficiency sub-field is same as the low efficiency sub-field, and the oil field has a homogenous EOR efficiency with an average value of 0.55 bbl/ton.

These EOR efficiency values in the different scenarios reflect the range of EOR efficiency values observed in actual EOR projects. As discussed earlier in Chapter 3, the observed EOR efficiency values in the past EOR projects is between 1-2 bbl/ton on an average, with some projects having low EOR efficiency values up to 0.5 bbl/ton.

Next, we evaluate how uncertainty in the EOR efficiency impacts the amount of oil produced.

Figure 4.9 presents the annual oil production in the three scenarios of different EOR efficiency.

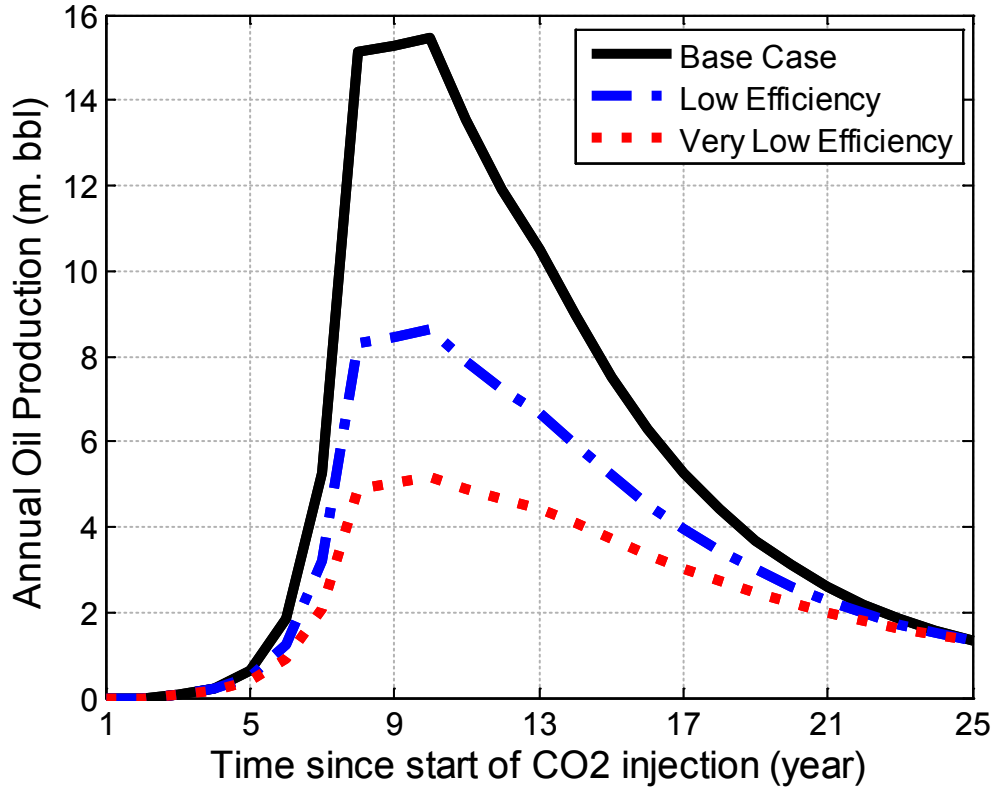


Figure 4.9 Oil production profile in the alternate EOR efficiency scenarios

We see from Figure 4.9 that compared to the base case scenario in the ‘low’ and the ‘very low’ EOR efficiency scenario the amount of oil produced reduces significantly. In the base case, the peak oil production in the 8th year is about 15 million barrels. In the ‘low’ efficiency scenario, the peak oil production reduces to 8.5 million barrels, and further reduces to 5 million barrels in the ‘very low’ efficiency scenario.

The total amount of oil produced is 140 million barrels in the base case scenario. The total oil produced in the ‘low’ efficiency scenario reduces by 35% and is 90 million barrels. In the ‘very low’ efficiency scenario, the total amount of oil produced is 63 million barrels which is 55% less compared to the base case.

These results illustrate the impact of change in the EOR efficiency on the amount of oil produced, but these results assume that no contingent decisions will be made by the project operators in response to change in the EOR efficiency. Often the project operators respond to change in the project risk factors by reoptimizing the project operations which would determine the final amount of oil recovered. In Section 4.3, we analyze how the contingent decisions in

response to change in the EOR efficiency impact the amount of oil produced and the resulting project value.

Next, we present how the change in the project risk factors impacts the financial value of the project through a pro forma analysis.

4.2 Project Risk Exposure – Pro Forma Analysis

In this section, we do a sensitivity analysis to measure the project risk exposure from the different risk factors. This involves a pro forma cash flow analysis where each risk factor is varied one at a time and the impact on the project cash flows is evaluated. This method provides a first order risk exposure of a project and highlights the key risk factors that have the largest impact on the project value. In particular, we evaluate how the overall project value will change if the risk factors changed at the end of three years of the start of operations or six years from the start of the project construction.

Table 4.5 gives the probability distribution of the three market risk factors at $t = 6$. These values are evaluated using the methodology described in Section 4.1.1 and assume zero correlation between the risk factors. The EOR efficiency values in Table 4.5 refer to the three scenarios outlined in Section 4.1.2 and are not the confidence bounds. 1.23 bbl/ton is the expected EOR efficiency at $t = 0$ for the project, and the 0.9 bbl/ton and 0.55 bbl/ton refer to the EOR efficiency values in the ‘low’ and the ‘very low’ scenarios.

		- 2 sigma	- 1 sigma	Mean	+ 1 sigma	+ 2 sigma
Oil price	(\$/bbl.)	38	63	119	173	289
Electricity price	(c/kWh)	6.3	8.1	10.6	13.1	16.7
CO₂ emission penalty	(\$/ton)	0.5	1.6	9.6	15.6	49.3
EOR Efficiency	(bbl./ton)	0.55	0.79	1.23	-	-

Table 4.5 Value of risk factors at $t = 6$ years

Figure 4.10 presents the pro forma risk exposure of the CCS-EOR project. The tornado diagram represents the change in ex post project value when each risk factor is varied one at a time.

The ex post project is \$4,503 million (represented by the vertical line) if the expected value of the risk factors does not change ex post and is equal to the expected value at $t = 0$ as given by the ‘mean’ values in Table 4.5.

The bars in Figure 4.10 represent the different scenarios of changes in the risk factors. The bars for the market risk factors (price of oil, wholesale price of electricity, CO₂ emission penalty) give the ex post project value at $t = 6$ for the 1-sigma and 2-sigma confidence bounds on the values of the risk factors. For example, the ex post value of the project increases to \$6,337 million if the expected value of the oil price at $t = 6$ increases to the 1-sigma upper bound estimate. If the oil price decreases to the 1-sigma lower bound value then the ex post project value decreases to \$2,628 million.

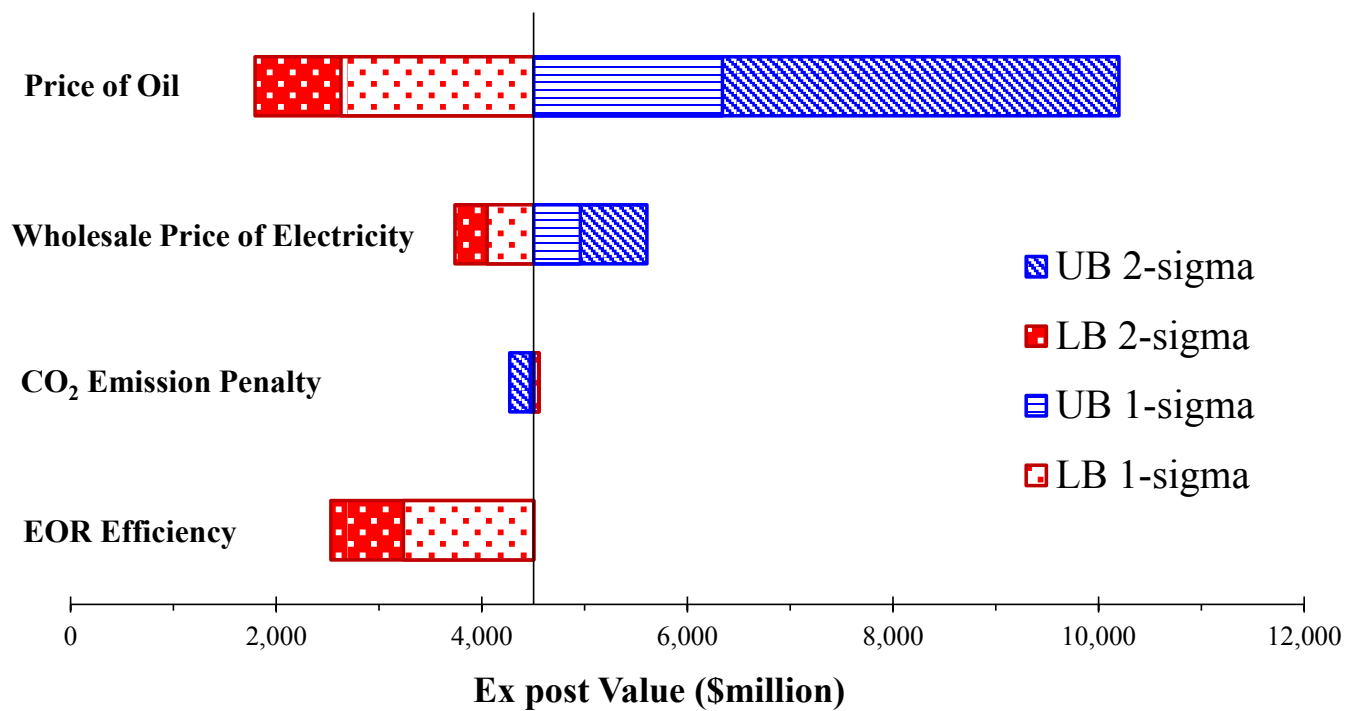


Figure 4.10 Pro forma risk exposure of the prototype CCS-EOR project

We see that the price of oil is the dominant risk factor in the CCS-EOR project and leads to the largest change in the project value. The price of oil affects the project value by having a direct impact on the revenues from EOR oil production.

The uncertainty in the EOR efficiency can also significantly affect the project value. In the ‘low’ efficiency scenario, the project value decreases to \$3,234 and in the ‘very low’ efficiency scenario the project value is \$2,529, which is close to the project value at 1-sigma lower bound on the oil price.

The fluctuation in the wholesale electricity price is also a key risk factor and impacts the revenues from power generation.

The impact of the change in CO₂ emission penalty on the project value is minimal as it only affects the cost of emitting 10% of the CO₂ generated that is not captured. An increase in the CO₂ emission penalty increases the cost of emitting CO₂ and thus negatively impacts the project value and vice versa if the CO₂ emission penalty goes down.

These results provide a first order risk exposure of the CCS-EOR project and highlight the key risk factors of the project. Because of its simplistic approach, the pro forma cash flow method is commonly used to measure the risk exposure of a project. But, there are two key drawbacks of this method. Firstly, this method only captures the impact of variation in one risk factor at a time and does not capture the interrelationships between the risk factors. When there are multiple risk factors that move in correlated fashion it is important to capture the correlations, as the total exposure might be larger or smaller than simple additions of the exposures from the sensitivity analysis. Another limitation of the pro forma method is that it does not capture the contingent decisions that might be made to adjust the project operations in response to the change in risk factors. The project operations are assumed to continue just as planned for the business-as-usual even though the risk factors change ex-post. But, generally the project operators reoptimize the project operations contingent on the change in risk factors, and these contingent decisions can significantly change the project value. The financial gains achieved from contingent decisions are evaluated in the next section.

4.3 Contingent Decision-making

The project operators will readjust the project operations in response to the change in the market risk factors and as the uncertainty in the EOR efficiency evolves. These contingent decisions can

significantly affect the project value. In particular, we analyze the decision to adjust the CO₂ capture rate contingent on the value of the risk factors. We analyze the decision to adjust the CO₂ capture rate at a single point in time during the operational phase of the project: in year 2023 which is 6 years after the start of the project construction and 3 years after the start of project operations. The rationale for this choice of time is explained at the beginning of this chapter.

In this section, we will analyze how the optimal CO₂ capture rate changes in response to change in the risk factors at $t = 6$. As discussed earlier in Section 4.1, we model the stochastic movement of market risk factors for three different assumptions on the correlation coefficients, and analyze three scenarios of changes in the EOR efficiency. We will first in Section 4.3.1 evaluate the optimal contingent decisions and the resulting project value for the ‘Base Case’ which assumes that the market risk factors are not correlated and the expected EOR efficiency does not change ex post. In Section 4.3.2, we will analyze the implications of the correlations between the market risk factors on the contingent decision-making and the project economics. Section 4.3.3 will present the impact of reduced EOR efficiency on the economics of contingent decision-making. We model the ‘Base Case’ as no change in EOR efficiency because as we will see a decrease in EOR efficiency improves the economics of contingent decision-making but does not trigger contingent decision-making i.e. if the market risk factors did not change ex post then it would be economical to still continue at 90% CO₂ capture even if the EOR efficiency is ‘very low’.

4.3.1 Optimal Contingent Decisions and Project Value in the ‘Base Case’

In this section, we evaluate the optimal CO₂ capture rate and the financial benefits from reoptimizing the CO₂ capture rate at $t = 6$ of the project. We focus on a ‘Base Case’ that assumes that the movement of the three market risk factors is not correlated and the expected EOR efficiency does not change ex post. The distribution of the market risk factors in this base case is given in Table 4.5. The EOR efficiency value is 1.23 bbl./ton CO₂. Later in this chapter we will present how the results change if the market risk factors are correlated with each other and the EOR efficiency is less than expected.

To evaluate the ex post optimal CO₂ capture rate we evaluate a representative sample of the three market risk factors in year 2023 using stratified sampling technique explained earlier in Section

4.1.1. We sample 15 points each from the probability distribution of oil price, wholesale price of electricity, and CO₂ emission penalty. Thus, we have 3,375 equal-probability triplets of the price of oil, wholesale price of electricity, and CO₂ emission penalty. For each of the 3,375 scenarios, we evaluate what the optimal CO₂ capture rate will be that maximizes the project value in that scenario and the financial gains that can be achieved by the contingent optimization of the CO₂ capture rate.

The results show that in 733 scenarios out of the 3,375 scenarios (implies 22% likelihood) it is financially attractive to reoptimize the CO₂ capture rate. Figure 4.11 presents how the optimal CO₂ capture rate changes with the values of the three market risk factors in these 733 scenarios. Figure 4.12 presents the financial gains (in million 2010 USD) from reoptimizing CO₂ capture rate in the ex post scenarios. In both the figures, the x-axis shows the ex post price of oil (oil price in year 2023), the y-axis shows the ex post price of electricity, and the z-axis shows the ex post CO₂ emission penalty. The dots in Figure 4.11 represents the optimal CO₂ capture rate in each of the 733 ex post equal-probability scenarios where the optimal CO₂ capture rate is less than 90%. The color bar represents the range of ex post optimal CO₂ capture rates. In Figure 4.12, the dots represents the financial gains from adjusting CO₂ capture rate from 90% CO₂ capture rate to the optimal capture rate, and the color bar gives the range of financial gains.

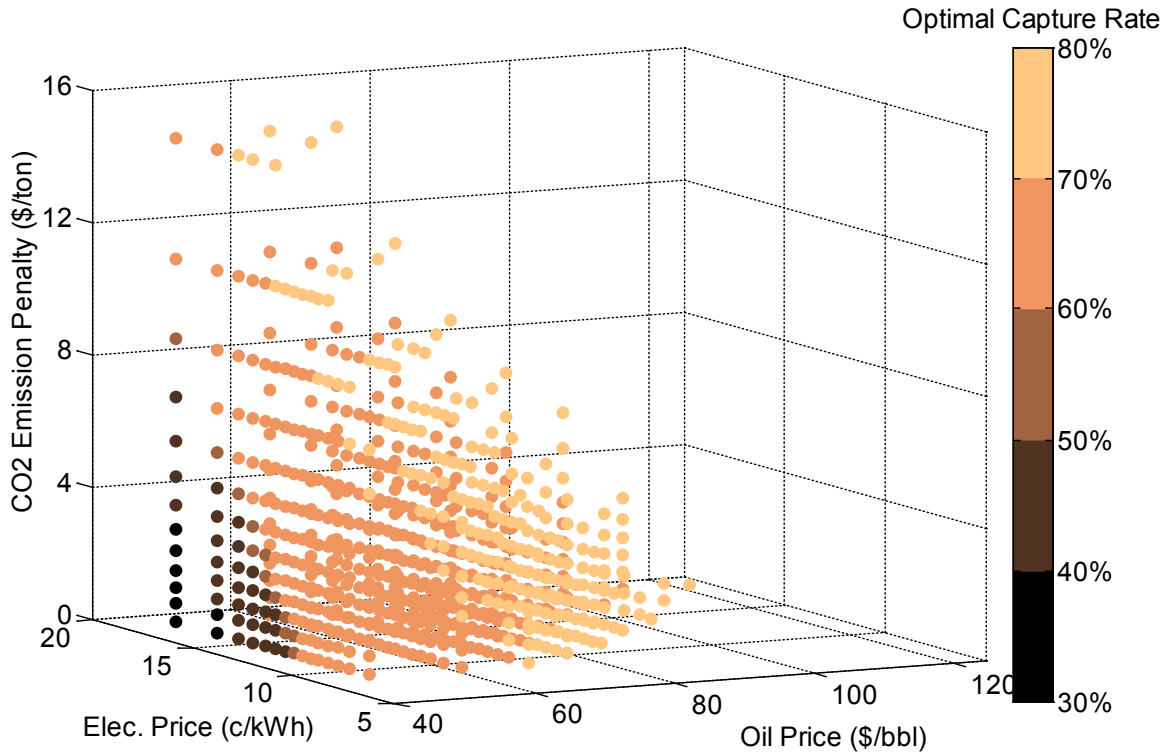


Figure 4.11 Optimal CO₂ capture rate as function of market risk factors (Base Case)

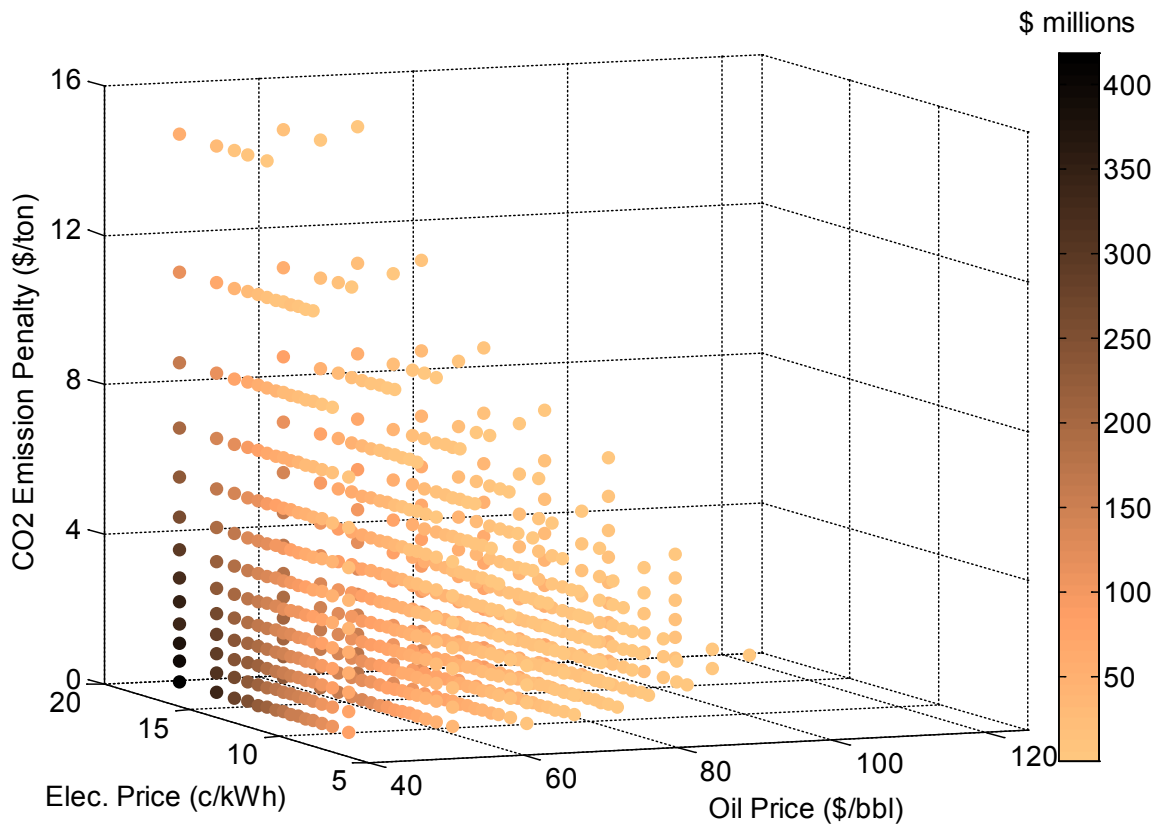


Figure 4.12 Financial gains (\$m) from optimizing CO₂ capture rate (Base Case)

We see from Figure 4.11 and Figure 4.12 that as the oil price drops, electricity price increases, and the CO₂ emission penalty goes down, the optimal CO₂ capture rate decreases from 80% to 30% and the financial gains from optimizing the CO₂ capture rate increase up to \$400 million. This is because at low oil prices, high electricity prices and low CO₂ emission penalty, the marginal costs of CO₂ capture dominate and it becomes increasingly economical to lower the CO₂ capture rate. From these figures, we see that the contingent decision-making is economical when price of oil is less than \$115/barrel (close to expected price, see Table 4.5), and the CO₂ emission penalty is less than \$15/ton CO₂ (close to upper 1sigma confidence bound value). The price of electricity is not a constraint as it is economical to lower CO₂ capture rate even at a low electricity price of 6.6 c/kWh (close to upper 2sigma confidence bound value).

The project NPV is \$1,319 million (in 2017 USD) assuming that the CO₂ capture rate is not optimized in response to change in market risk factors and continued at 90% CO₂ capture rate. Contingent decision-making increases the NPV by \$14 million, which is a 1% increase in the project NPV. If we only consider the 22% of the ex post scenarios where it is economical to adjust the CO₂ capture rate, then the ex post adjustment of CO₂ capture rate leads to average financial gains of \$63 million (2.2% increase in the project value). The maximum financial gain from contingent adjustment of CO₂ capture rate is \$419 million, which is a 14% increase in project value compared to operating at 90% CO₂ capture rate. This scenario corresponds to a low oil price of \$41/bbl, high electricity price of 16 c/kWh, and negligible CO₂ emission penalty (the values of three market risk factors is close to their 2sigma confidence bound values).

Overall, these results show that it is economical to reoptimize the CO₂ capture rate in response to change in the market risk factors. Next, we present how economics of reoptimizing the CO₂ capture rate changes when the movements of market risk factors are correlated and the EOR efficiency is lower than expected.

4.3.2 Impact of Correlation between Market Risk Factors

In the previous section, we see that there is a 22% likelihood that it would be economical to reoptimize and lower the CO₂ capture rate when the market risk factors change ex post assuming that the risk factors are not correlated and there is no change in the EOR efficiency. In this

section, we evaluate how the results of contingent decision-making change with the market risk factors moving in a correlated fashion. We still continue to assume that there is no change in the EOR efficiency and the ex post expected average EOR efficiency is 1.23 bbl/ton.

Figure 4.13 presents how the optimal CO₂ capture rate changes with different assumptions on the correlations between the market risk factors. The three cases of correlations presented here are: zero correlation, position correlation and negative correlation. The values of correlation coefficient for these cases is presented in Table 4.2.

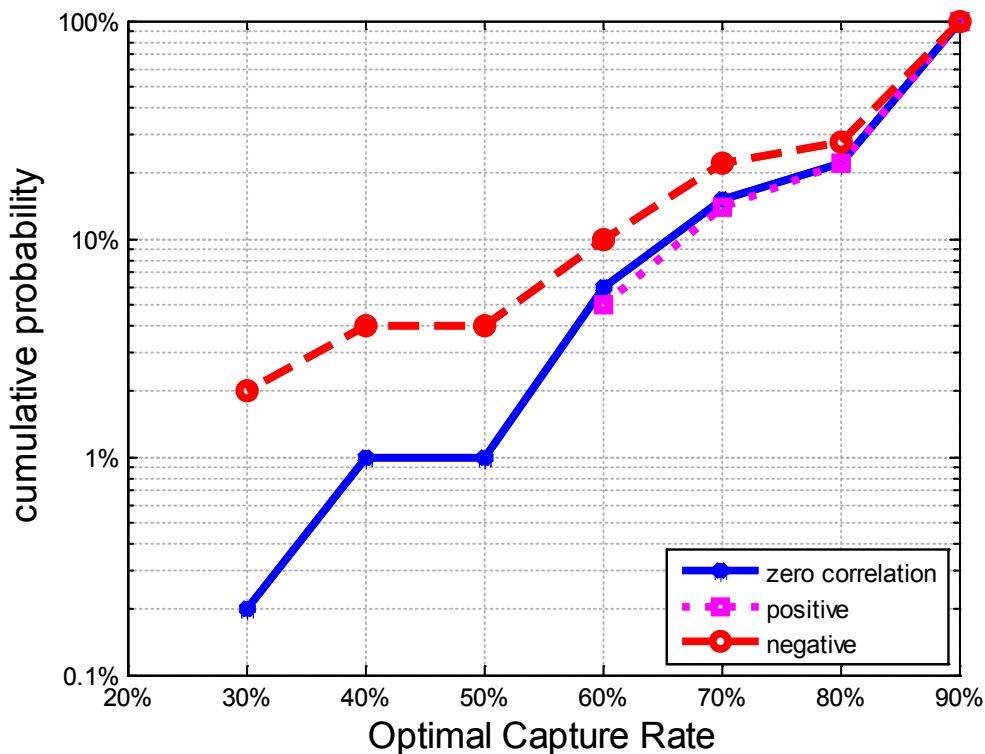


Figure 4.13 Sensitivity of the optimal CO₂ capture rate to correlations between market risk factors

From Figure 4.13 we see that when the market risk factors are negatively correlated there is an increased probability of reoptimizing the CO₂ capture rate and operating at a lower CO₂ capture rate than the initially planned 90% CO₂ capture rate. There is a 22% probability that it will optimal to reoptimize and lower the CO₂ capture rate when the risk factors are not correlated and positively correlated. The probability of reoptimizing the CO₂ capture rate increases to 28% when the risk factors are negatively correlated. When the risk factors are positively correlated it

is never economical to lower the CO₂ capture rate less than 60%. But, if the risk factors are not correlated or negatively correlated it is economical to lower CO₂ capture rate to as low as 30%.

A negative correlation between the risk factors increases the probability of operating at a lower CO₂ capture rate because a negative correlation increases the probability that ex post when the oil price is low the electricity price will be high and the CO₂ emission penalty will be low.

Following the same argument we see that the probability of operating at a low CO₂ capture rate is minimum when the risk factors are positively correlated.

Next, in Figure 4.14 we present how the financial gains from contingent decision-making change with different assumptions on the correlations between the market risk factors.

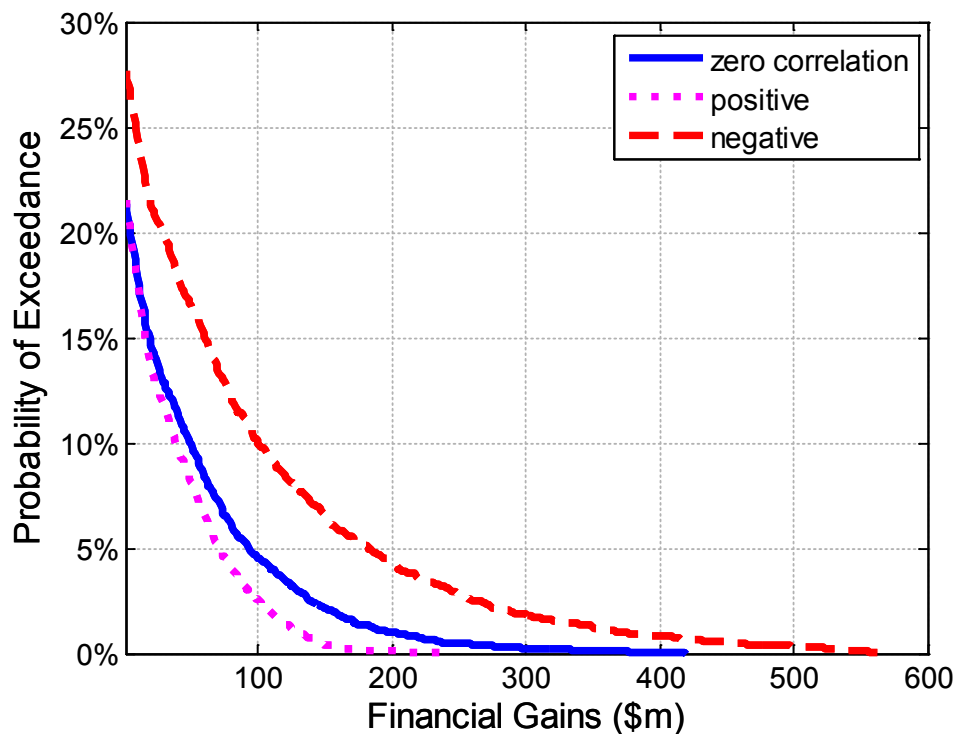


Figure 4.14 Sensitivity of the financial gains from contingent decisions to correlations between market risk factors

Table 4.6 presents the NPV and average ex post value obtained under the different assumptions of correlation coefficients between the market risk factors.

	BAU [1]		First-Best [2]		NPV Gain [3]	Max. Value Gain [4]
	NPV (\$m)	Ex post Value (\$m)	NPV (\$m)	Ex post Value (\$m)		
Zero Correlation	1,319	4,503	1,332	4,516	\$14 m.(1.0%)	\$419 m.(14%)
Positive Correlation	1,322	4,506	1,332	4,516	\$10 m.(0.8%)	\$238 m.(11%)
Negative Correlation	1,323	4,505	1,351	4,534	\$29 m.(2.2%)	\$566 m.(16%)

[1] 'BAU' or Business as Usual refers to continuing at 90% CO₂ capture rate and not reoptimizing in response to change in risk factors

[2] 'First-Best' refers to optimizing the CO₂ capture rate in response to change in risk factors and thus maximizing the project value

[3] 'NPV Gain' refers to difference in the NPV between the first-best and the BAU case in USD and percentage terms

[4] 'Max. Value Gain' refers to the maximum financial gains achieved by reoptimizing the CO₂ capture rate in USD and as a percentage of ex post project value in the BAU case for that scenario

Table 4.6 Sensitivity of the project value to correlations between market risk factors

As expected, we see from Figure 4.14 that the financial gains from contingent optimization of the CO₂ capture rate are the highest when the risk factors are negatively correlated and the least when the risk factors are positively correlated. When the risk factors are negatively correlated, the financial gain from contingent decision-making can exceed \$550 million compared to less than \$250 million when the risk factors are positively correlated. Overall, there is a 28% probability of making positive financial gains when the risk factors are negatively correlated compared to 22% when the risk factors are positively correlated or not correlated.

We see from Table 4.6 that the NPV value in the BAU case (business as usual: when continuing at 90% CO₂ capture rate) is almost the same in all three cases and is about \$1,320 million. The financial gains from contingent decision-making depend on the correlation coefficient between risk factors and are the highest when the risk factors are negatively correlated. When the risk factors are negatively correlated, the contingent optimization of the CO₂ capture rate leads to a 2.2% increase in the NPV compared to about 1% increase when the risk factors are positively correlated or not correlated. The highest NPV value in the first-best case (when CO₂ capture rate is optimized) is achieved in negative correlated case and is equal to \$1,351 million, which is \$29 million more compared to NPV under positive correlation and zero correlation case.

In this section we showed that correlation coefficient between the market risk factors affects the decision to reoptimize the CO₂ capture rate and it is economical to further lower the CO₂ capture rate when the risk factors are negatively correlated. The economics of contingent decision-making also depends on the nature of correlations, and highest financial gains are achieved when

the risk factors are negatively correlated and the gains are minimum when the risk factors are positively correlated.

Next, we discuss how the uncertainty in the EOR efficiency influences contingent decisions.

4.3.3 Impact of Uncertainty in the EOR Efficiency

So far we evaluate the optimal contingent decisions in response to change in the market risk factors assuming no change in the EOR efficiency. In this section we evaluate how the optimal CO₂ capture rate and the economics of contingent decision-making change if the expected EOR efficiency was lower than expected at t = 0. We evaluate and compare three scenarios of changes in the EOR efficiency outlined in Section 4.1.2: Table 4.4 - base case (no change), low EOR efficiency and very low EOR efficiency. In all the cases it is assumed that the market risk factors evolve stochastically in a non-correlated fashion so that we can compare the results to the base case presented in Section 4.3.1. Figure 4.15 presents how the optimal CO₂ capture rate changes with change in the EOR efficiency.

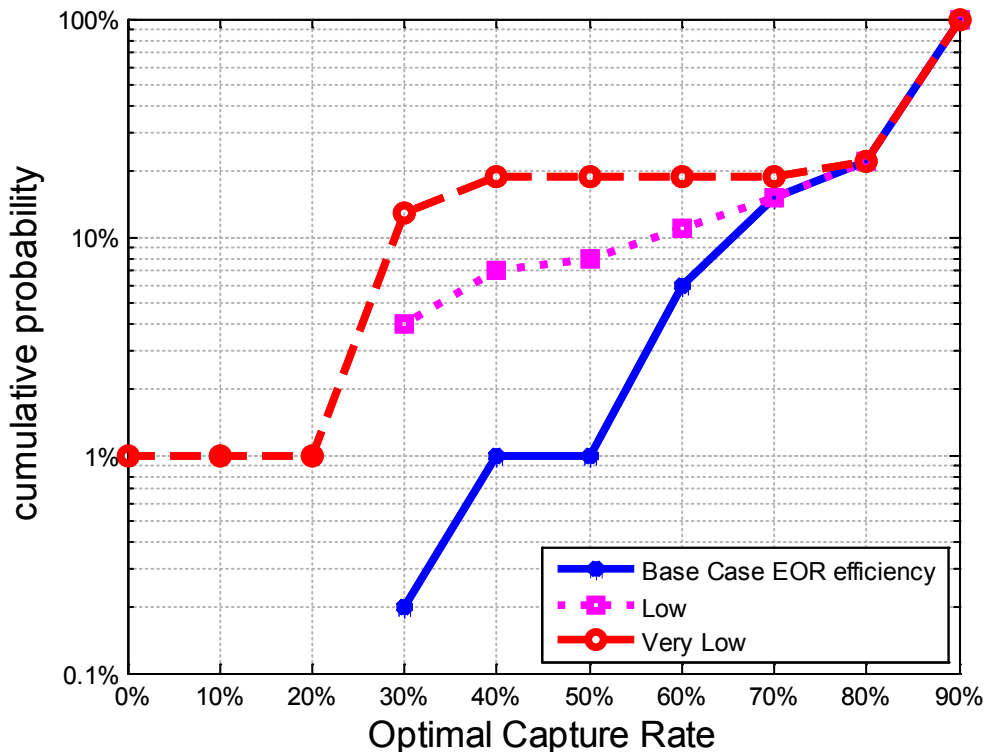


Figure 4.15 Sensitivity of the optimal CO₂ capture rate from contingent decisions to EOR efficiency

We see from Figure 4.15 that as the EOR efficiency goes down, the probability of optimizing to lower levels of CO₂ capture rate increases. When the EOR efficiency does not change (base case: 1.23 bbl/ton) there is a 1% probability that the optimal capture rate would be less than equal to 40%. If the average EOR efficiency is lower and equal to 0.79 bbl/ton (low case) the probability of optimizing to 40% capture rate or lower increases to 7%. This probability increases to 19% if the average EOR efficiency reduces to 0.55 bbl/ton (very low case). Furthermore, at very low EOR efficiency there is a positive probability of 1% that it would be economical to stop the CO₂ capture rate.

One thing to note is that reduced EOR efficiency increases the probability of operating at a lower CO₂ capture rate but does not trigger the contingent decision. The probability of operating at the ex ante optimal CO₂ capture rate of 90% is same in all the scenarios.

Figure 4.16 and Table 4.7 present the financial gains and the project value obtained by reoptimizing the CO₂ capture rate in different EOR efficiency scenarios.

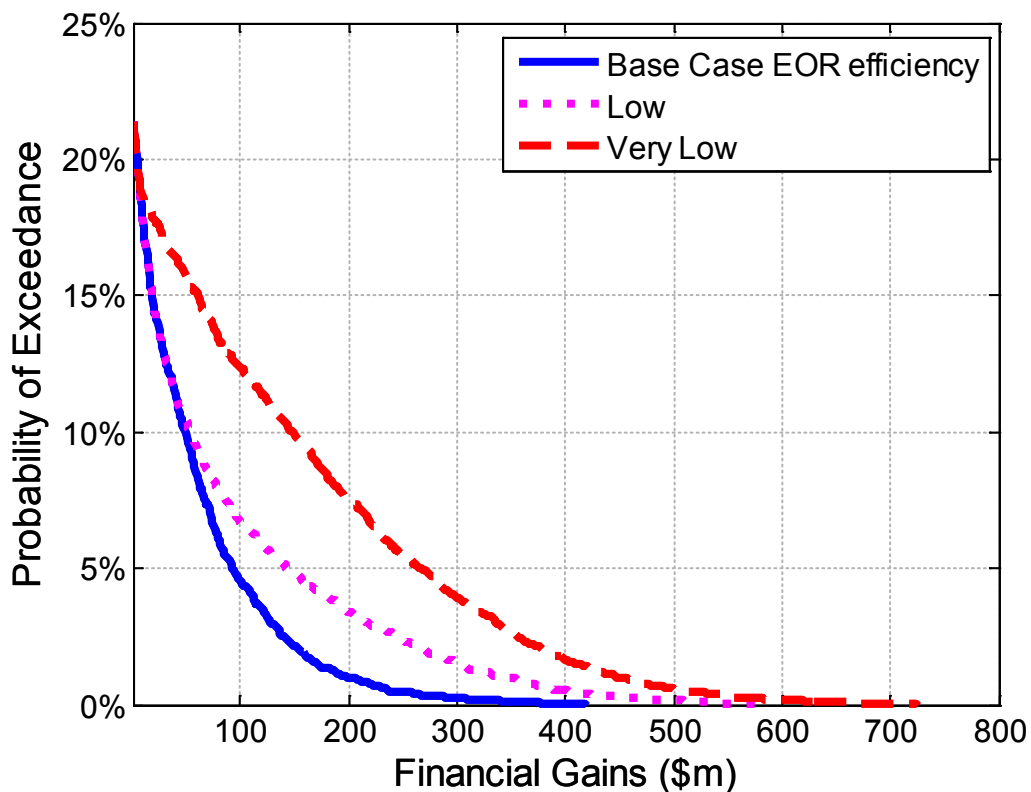


Figure 4.16 Sensitivity of the financial gains from contingent decisions to EOR efficiency

	BAU [1]		First Best [2]		NPV Gain [3]	Max. Value Gain [4]
	NPV (\$m)	Ex post Value (\$m)	NPV (\$m)	Ex post Value (\$m)		
Base Case Efficiency	1,319	4,503	1,332	4,516	\$14 m. (1%)	\$419 m. (14%)
Low Efficiency	52	3,237	72	3,257	\$20 m. (38%)	\$583 m. (22%)
Very Low Efficiency	-652	2,533	-616	2,568	\$35 m.	\$725 m. (29%)

[1] 'BAU' or Business as Usual refers to continuing at 90% CO₂ capture rate and not reoptimizing in response to change in risk factors

[2] 'First-Best' refers to optimizing the CO₂ capture rate in response to change in risk factors and thus maximizing the project value

[3] 'NPV Gain' refers to difference in the NPV between the first-best and the BAU case in USD and percentage terms

[4] 'Max. Value Gain' refers to the maximum financial gains achieved by reoptimizing the CO₂ capture rate in USD and as a percentage of ex post project value in the BAU case for that scenario

Table 4.7 Sensitivity of the project value to EOR efficiency

We see from Figure 4.16 that as the EOR efficiency goes down the financial gains achieved from contingent decision-making increase. While the overall probability of making positive financial gains from reoptimizing CO₂ capture rate is the same in all scenarios of EOR efficiency (22%), there is a higher probability of making larger financial gains as the EOR efficiency goes down. When the EOR efficiency is 'very low' there is a positive probability of exceeding financial gains of \$725 million from contingent optimization of CO₂ capture rate. The maximum financial gains achievable decrease as the expected EOR efficiency increases. This is because with increasing EOR efficiency the marginal benefits of CO₂ capture increase and thus it is less economical to lower the CO₂ capture rate.

The NPV and the average ex post project values in the three scenarios are given in Table 4.7. We see that as the EOR efficiency reduces the project NPV and the ex post value decrease significantly. As expected the financial gains from contingent decision-making increase as the EOR efficiency goes down. In the base case the NPV in the BAU (business as usual: when continuing at 90% CO₂ capture rate) is \$1,319 million, and contingent optimization of CO₂ capture rate increases the NPV by \$14 million or 1%. In the low EOR efficiency scenario the NPV of the project goes down to \$52 million in the BAU case, and contingent decision-making will increase the project value by \$20 million. We see that in the very low EOR efficiency case the project NPV is negative, and thus if the expected EOR efficiency at $t = 0$ is 'very low' then it would not be economical to go ahead with the project. On the other hand, if the expected EOR efficiency at $t = 0$ is the 'base case' value but the ex post expected EOR efficiency decreases to

‘very low’ then it would still be economical to continue operations as the ex post project value is positive even at a ‘very low’ EOR efficiency. Contingent optimization of the CO₂ capture rate in this very low EOR efficiency case will increase the project value by \$35 million.

In this section, we presented that the financial gains from contingent optimization of the CO₂ capture rate increase as the expected EOR efficiency goes down. Furthermore, as the EOR efficiency reduces it is economical to operate at even lower CO₂ capture rates or even stop the CO₂ capture rate. The overall probability of lowering the CO₂ capture below 90% CO₂ capture rate is 22% in all the EOR efficiency scenarios.

4.4 Summary

In this chapter we analyzed the impact of exogenous risks on the financial value of the prototype CCS-EOR project. We focus on two sets of risks: the volatility in the market risk factors (oil price, wholesale price of electricity, and the CO₂ emission penalty), and the uncertainty on the technical EOR efficiency. The stochastic movement of the market risk factors is modeled by the random walk model and the temporal evolution of prices is simulated using the Monte Carlo method. The impact of the change in the EOR efficiency is evaluated by modeling alternate scenarios of changes in the EOR efficiency.

A pro forma cash flow analysis shows that the change in the risk factors can significantly affect the ex post project value, and in particular the results highlight that the oil price risk is the dominant risk factor in the prototype CCS-EOR project followed by the uncertainty in the EOR efficiency.

We evaluate the financial impact of the contingent optimization of the CO₂ capture rate in response to change in the exogenous risks. The results show that the contingent decision-making can lead to considerable financial gains. The gains in project value increase as the oil price decreases, the electricity price increases, the CO₂ emission penalty decreases, and the EOR efficiency decreases.

In the ‘base case’ wherein only the market risk factors evolve (in non-correlated fashion) and the EOR efficiency does not change, there is a 22% probability that it would be economical to

readjust and lower the CO₂ capture rate. This contingent optimization of the CO₂ capture rate leads to \$14 million or 1% increase in the project NPV and the gains in project value can exceed \$400 million.

We find that if the oil price and electricity price were negatively correlated and the electricity price and the CO₂ emission penalty were also negatively correlated, then the likelihood of reoptimizing and lowering the CO₂ capture rate increases to 28% compared to 22% in the base case. The increase in NPV from contingent decision-making when the risk factors are negatively correlated is higher compared to the base case: the NPV increases by \$29 million or 2.2% increase which is higher compared to \$14 million (1%) gains in the base case. There is a positive probability that the financial gains can exceed \$550 million when the market risk factors are negatively correlated.

Overall, we see that the economics of contingent decision-making is the highest when the market risk factors are negatively correlated followed by when the risk factors are not correlated and is the least when the market risk factors are positively correlated. This is because a negative correlation increases the likelihood that when the oil price is low, the electricity will be high, and the CO₂ emission penalty will be low, and hence it would be more likely that it would be profitable to lower the CO₂ capture rate. On the other hand, a positively correlation reduces the likelihood that the market risk factors would make it profitable to lower CO₂ capture rate.

Lastly in this chapter, we evaluated the change in the economics of contingent decision-making in response to change in the EOR efficiency. We find that if the market risk factors did not change ex post then a drop in EOR efficiency alone would not trigger readjustment of the CO₂ capture rate, and it would be economical to continue at 90% CO₂ capture rate even if the EOR efficiency reduced. We evaluate different scenarios of changes in the EOR efficiency wherein the market risk factors evolve stochastically in a non-correlated fashion (as in the base case). We find that decrease in the EOR efficiency increases the likelihood of operating at a lower CO₂ capture rate. For example, the probability of operating at 30% CO₂ capture rate or lower increases from 1% in the base case (when the EOR efficiency is 1.23 bbl/ton) to a probability of 19% when the EOR efficiency value drops very low (0.55 bbl/ton). A drop in the EOR efficiency also strengthens the economics of contingent decision-making. The gains in project value from contingent optimization of the CO₂ capture rate increase from \$14 million in the base case to \$35

million in the very low EOR efficiency case. Contingent decision-making can lead to financial gains of more than \$700 million when the EOR efficiency is very low.

In this chapter, we have analyzed the risk factors as purely exogenous risks and evaluate the optimal contingent decisions. But, these contingent decisions will be made by independent entities owning and operating the different parts of the CCS-EOR value chain. Thus, the final project value will depend both on the exogenous change in risk factors and the endogenous response of the project operators to the change in the risk factors. In Chapter 5, we will evaluate alternate contract structures for the CCS-EOR value chain in light of the contractual incentives to the involved entities to optimally adjust the CO₂ capture rate and maximize the overall project value.

Chapter 5 Contracts for the CCS-EOR Value Chain

The contracts linking the different involved entities along the CCS-EOR value chain define how the project value and the project risks are distributed among the different entities. The resulting risk exposure determines the performance incentives of the entities, and ultimately determines the final project value. In the previous chapter, Chapter 4, we showed that significant financial gains are achieved by reoptimizing the CO₂ capture rate in response to change in the risk factors during the operational phase of the prototype CCS-EOR project. This contingent decision of adjusting the CO₂ capture rate will be made by separate entities that own and operate the different parts of the CCS-EOR value chain. The response of the individual entities will depend on the risk-sharing defined by the CO₂ delivery contract terms.

In this chapter, we will evaluate alternate CO₂ delivery contract structures linking the different entities in the CCS-EOR value chain in terms of the incentives provided to the individual entities to make optimal contingent decisions. We will show how the final project value depends not only on the change in the risk factors, but also on how the individual entities respond to changes in the risk factors. We model the CCS-EOR project ownership structure such that the power plant and the oil field are owned and operated by separate entities, and the pipeline is jointly owned by the two entities. The operation between the power plant company and the oil field company is integrated through a long-term contract for the delivery of CO₂. We consider two alternate contract structures for the CCS-EOR value chain: fixed price CO₂ contracts that specify a fixed price per ton CO₂ delivered, and oil-indexed price CO₂ contracts that index the price of CO₂ to the oil price: price of CO₂ (\$/ton) = $x\%$ of oil price (\$/bbl).

In Chapter 2, we had presented the insights from the economics literature for structuring contract terms to incentivize the project entities to deliver efficient project outcomes. In Section 5.1 of this chapter we briefly summarize the literature insights, and describe the criteria we adopt to measure the performance of alternate CO₂ contract structures. The alternate CO₂ contract terms

are evaluated in Section 5.2 in terms of the risk of insolvency, probability of optimal decision-making and the final project value achieved under the alternate contract structures. In Section 5.2, we consider the ‘base case’ change in the risk factors that assumes that the market risk factors evolve in a non-correlated fashion, and the EOR efficiency does not change ex post. In Section 5.3, we evaluate the performance of the alternate contract structures under the other scenarios of changes in the risk factors including different assumptions on the correlations between the market risk factors and changes in the EOR efficiency. Finally, in Section 5.4, we summarize the key findings from this chapter.

5.1 Considerations for Contract Design

The economics literature on contract theory and the principal agent problem deal with design of incentives through contracts to ensure efficient project outcomes. A detailed discussion of this literature is presented in Chapter 2. This literature emphasizes that risk-sharing between the involved entities is key to create incentives for efficient project performance. Optimal risk-sharing aligns the interests of the entities involved such that they perform in the common interest of the overall project resulting in maximization of the total project value.

The CO₂ delivery contracts that link the individual entities of the CCS-EOR value chain will define how the project value and the risks are shared between the entities, and hence determine incentives the individual entities have to make optimal decisions in the common interest of the project. In the prototype CCS-EOR project, we measure the performance of the alternate CO₂ delivery contract structures by adopting the following two contract design objectives pointed out by Joskow (1985, 1988).

Minimize Insolvency Risk

Joskow studies contract provisions in long-term coal supply contracts between the coal mining companies and the electricity generating utilities, and points out that contract terms should *minimize inefficient breach of contractual obligations*. One key reason for inefficient contractual breach would be if either of the involved entities finds it unprofitable to continue operations even though it might be profitable on aggregate terms.

The CO₂ delivery contracts for the CCS-EOR value chain should be such that they *minimize the risk of insolvency and thus prevent contractual breach* when it is not efficient from the overall project perspective. The power plant company and the oil field company will go-ahead with the project only if it is financially attractive for both the entities. Furthermore, as the risk factors evolve during the project, the financial value captured by both entities will also change. The entities will continue with the project ex post only if it is financially attractive to do so. Thus, the contract terms should be such that it is economical for both the entities to go-ahead with the project at $t = 0$, also the contract terms should still be financially attractive ex post as the risk factors evolve. Section 5.2 and Section 5.3 evaluate the insolvency risk under the alternate contract structures under different scenarios of changes in the risk factors.

Incentivize Optimal Contingent Decision-Making

The other key objective of the contract terms, Joskow points out, is that the contract terms should “*facilitate efficient adaptation to changing market conditions*”. This consideration in context of this thesis implies that the contract terms linking the CCS-EOR value chain should be such that they *incentivize the entities to reoptimize the CO₂ capture rate* in response to change in the risk factors.

The individual entities will have incentive to reoptimize the CO₂ capture and injection rate, if the total value captured by the entity at the optimal CO₂ capture rate is greater than the total value captured at the ex ante contractually agreed 90% CO₂ capture rate. We evaluate the likelihood that the alternate contract structures would incentivize the involved entities to reoptimize the CO₂ capture rate. Section 5.2 and 5.3 presents the incentives for optimal decision-making under the alternate contract structures for the different scenarios of changes in the risk factors.

Next, we will evaluate alternate CO₂ delivery contract structures in terms of the risk of ex post insolvency and the incentives provided to the individual entities to reoptimize the CO₂ capture rate. We will also evaluate the final project value achieved under the different contract types.

In the next section, we analyze the alternate contract types in light of the change in market risk factors. This scenario has been termed as the ‘base case’ in Chapter 4. The base case involves a random walk evolution in the market risk factors, and no change in the EOR efficiency. Later, in Section 5.3, we will present a sensitivity analysis with respect to different assumptions of

correlations between the market risk factors and changes in the EOR efficiency, and will evaluate how the contract structures perform in these different scenarios.

5.2 Performance of Alternate Contract Structures (Base Case)

In this section, we will evaluate the performance on alternate CO₂ contract structures: fixed price contracts and oil-indexed price contracts, in light of the change in the risk factors. The fixed price CO₂ contracts specify a fixed price per ton CO₂ delivered, and oil-indexed price CO₂ contracts index the price of CO₂ to the oil price: price of CO₂ (\$/ton) = $x\%$ of oil price (\$/bbl). We focus on the ‘base case’ (defined in Section 4.3.1, Chapter 4, which assumes that the three market risk factors evolve with time following a random walk and their movement is not correlated, and the expected EOR efficiency does not change ex post. The distribution of the market risk factors in this base case is given in Table 4.5, Chapter 4. The average EOR efficiency value for the overall oil field is 1.23 bbl./ton CO₂. The performance of the contract structures under different assumptions on the correlations between the market risk factors and value of the EOR efficiency will be evaluated in Section 5.3.

Next, we evaluate the alternate contracts in terms of the risk of insolvency for the power plant company and the oil field company when the risk factors changes as in the base case. In Section 5.2.2., we will evaluate the risk of sub-optimal contingent decision-making by the involved entities under the alternate contract types. Then, in Section 5.2.3, we will evaluate the final project value achieved under the alternate contract types.

5.2.1 Insolvency Risk

We analyze the two alternate contract types (fixed price and oil-indexed price), and evaluate what are the contract terms that would be financially attractive to both entities at $t = 0$, and also ex post as risk factors evolve. For the ex post analysis, we consider the same set of ‘base case’ ex post scenarios as evaluated in Section 4.3.1, Chapter 4, for evaluating the optimal CO₂ capture rate. These are 3,375 equal-probability scenarios of changes in three market risk factors (oil

price, electricity price, and CO₂ emission penalty) in year 2023 (6 years from the start of project).

Figure 5.1 presents the fixed price contract terms for which both the power plant company and the oil field company have a positive financial value, and Figure 5.2 presents the oil-indexed price contract terms to ensure solvency of the two entities.

The solid lines in Figure 5.1 and Figure 5.2 show the range of contract prices that will result in positive financial value for both entities at $t = 0$ (ex ante). We see that the minimum fixed contract price that makes this project financially attractive to the power plant company is \$57/ton, and the maximum contract price that the oil field company would be willing to pay is \$123/ton. Similarly, the solid lines in Figure 5.2, show the ex ante range of negotiable oil-indexed contract price is between 41% of the oil price to 88% of the oil price.

The stars in Figure 5.1 and Figure 5.2 show the maximum contract price the oil field would be willing to pay ex post at different oil prices. The power plant company would always be solvent ex post as its ex post internal cash flows (not accounting for contractual payments) are always positive. We assume that project always operates at the 90% CO₂ capture rate (contingent CO₂ capture rate is considered next in Section 5.2.2). At a given ex post price of oil, if the contract price is more than shown by the stars, then the oil field company would have a negative ex post value and it would lead to breach in the contract terms by the oil field company.

We see that as the ex post price of oil increases, the maximum contract price that the oil field company can pay and still be solvent also increases. For a given oil price, we see that there is a range of maximum contract prices, this reflects sensitivity of the contract prices to the other risk factors: the price of electricity and the CO₂ emission penalty.

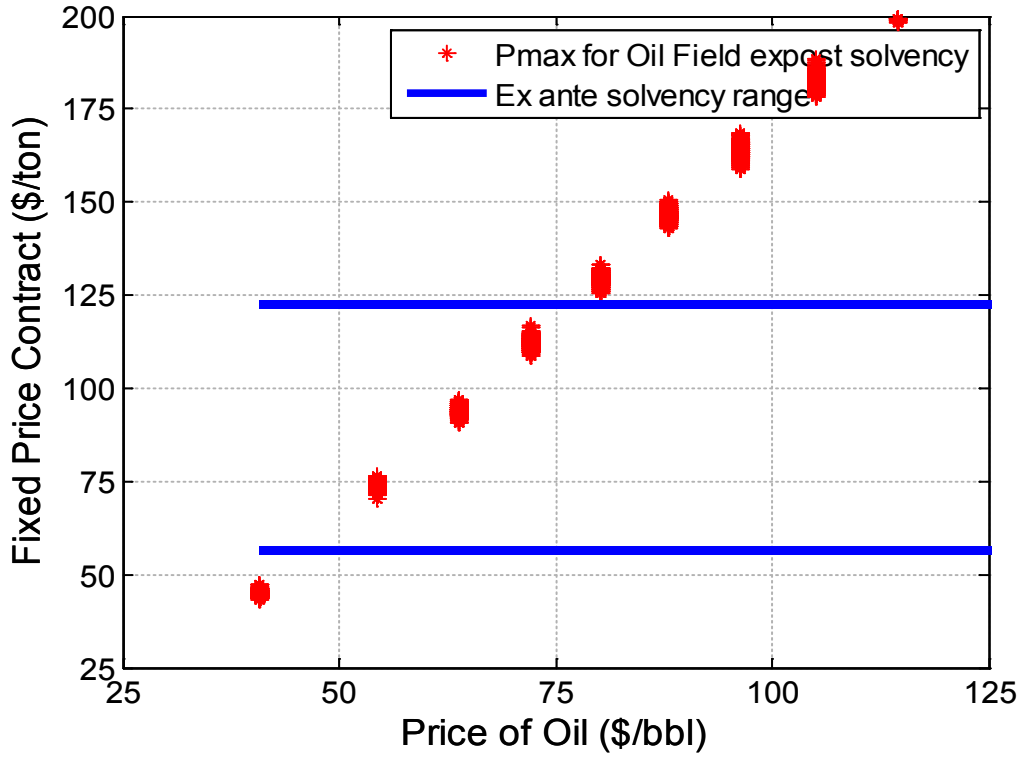


Figure 5.1 Ex post insolvency risk under fixed price contracts (base case)

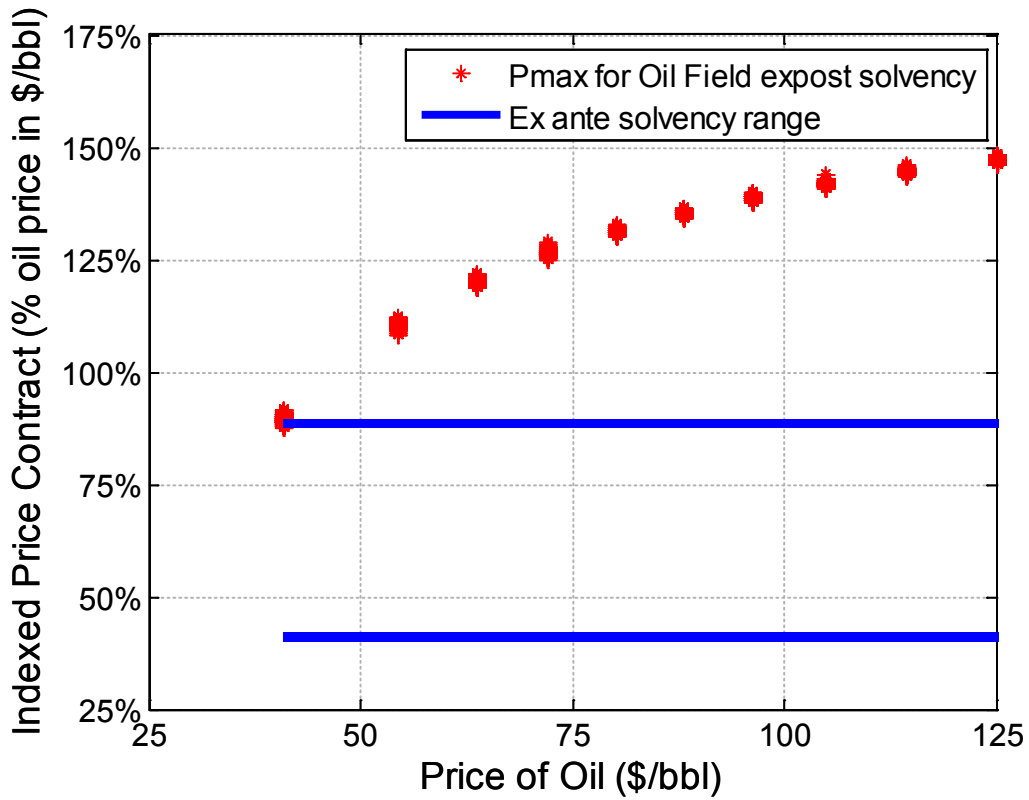


Figure 5.2 Ex post insolvency risk under oil-indexed price contracts (base case)

The key thing to note from Figure 5.1 is that under the fixed price contracts, at an ex post price of oil less than \$50/bbl, the ex post maximum contract price for oil field solvency is less than the ex ante minimum contract price that would make power plant solvent. Thus, in the fixed price contracts we don't find any price of CO₂ that would be financially attractive to both entities ex ante as well as ex post. Thus under all possible ex ante negotiable contract prices, there is a positive probability of ex post insolvency. If the minimum profitable contract price of \$57/ton is negotiated, then there is a 6.7% probability that ex post the oil field company would have a negative project value and will discontinue project operations even though it is overall profitable to continue operations. If the ex ante negotiated price is the maximum negotiable price of \$123/ton, then the ex post insolvency risk increases to 26.7%.

Under the oil-indexed price contracts, we see from Figure 5.2 that if the ex ante negotiated contract prices are in the range of 41% to 87% of the oil price then there is zero risk of ex post insolvency. The risk of insolvency is 0.4% at the ex ante maximum negotiable contract price of 88% of the oil price.

The results show that sharing the oil price risk between power plant company and the oil field company through the oil-indexed price contracts can eliminate the ex post insolvency risk. Under the fixed price contracts the entire oil price risk is borne by the oil field company and thus at low oil prices (below \$50/bbl) there is 100% probability of ex post insolvency. Overall, under the fixed price contracts the risk of ex post insolvency is between 6.7% - 26.7%. Sharing the oil price risk as in oil-indexed contracts can eliminate the insolvency risk and thus prevent inefficient breach of contractual obligations.

In this section, we evaluated the risk of ex post insolvency under the two alternate contract structures. The other key consideration in design of contract terms is that the contract should provide incentives for optimal contingent decision-making. Next, we evaluate the two contract structures in terms of the incentives they provide the power plant company and the oil field company to reoptimize the CO₂ capture rate in response to change in the risk factors as per the base case assumptions.

5.2.2 Incentives for Contingent Decision-making

In Chapter 4, we presented that significant financial gains are achieved by the contingent optimization of the CO₂ capture rate in response to change in the risk factors. This contingent adjustment of the CO₂ capture rate will be made by independent entities owning and operating different parts of the value chain: the power plant company will decide on the CO₂ capture rate, and the oil field company will decide on the CO₂ injection rate. So, an important consideration in determining the contract terms between these involved entities is that the contractual risk allocation should provide incentives to the individual entities to make contingent decisions such that the overall project value is maximized.

In this section, we focus on the base case change in the risk factors, and evaluate the incentives provided to the involved entities to reoptimize the CO₂ capture rate under the two alternate contract types. In Section 4.3.1, Chapter 4, we evaluated the optimal CO₂ capture rate in the different ex post scenarios of changes in risk factors in the base case. We saw that there was a 22% probability that ex post the optimal CO₂ capture rate will be less than the initially planned 90% capture rate, i.e. in 733 out of the 3,375 scenarios it is economical to lower the CO₂ capture rate. In this section, we focus on these 733 scenarios where it is optimal to lower CO₂ capture rate and evaluate the incentives provided under the two alternate contract types to the individual entities to reoptimize the CO₂ capture rate.

Figure 5.3 and Figure 5.4 present the probability of sub-optimal decision-making as a function of the contract price for the fixed price contracts and oil-indexed price contracts respectively. The probability of sub-optimal decision-making accounts for both the risk of operating at a sub-optimal CO₂ capture rate and the risk of ex post insolvency leading to a contractual breach. The probability of sub-optimal decision-making is calculated only for the 22% of the ex post scenarios where it is economical to reoptimize the CO₂ capture rate.

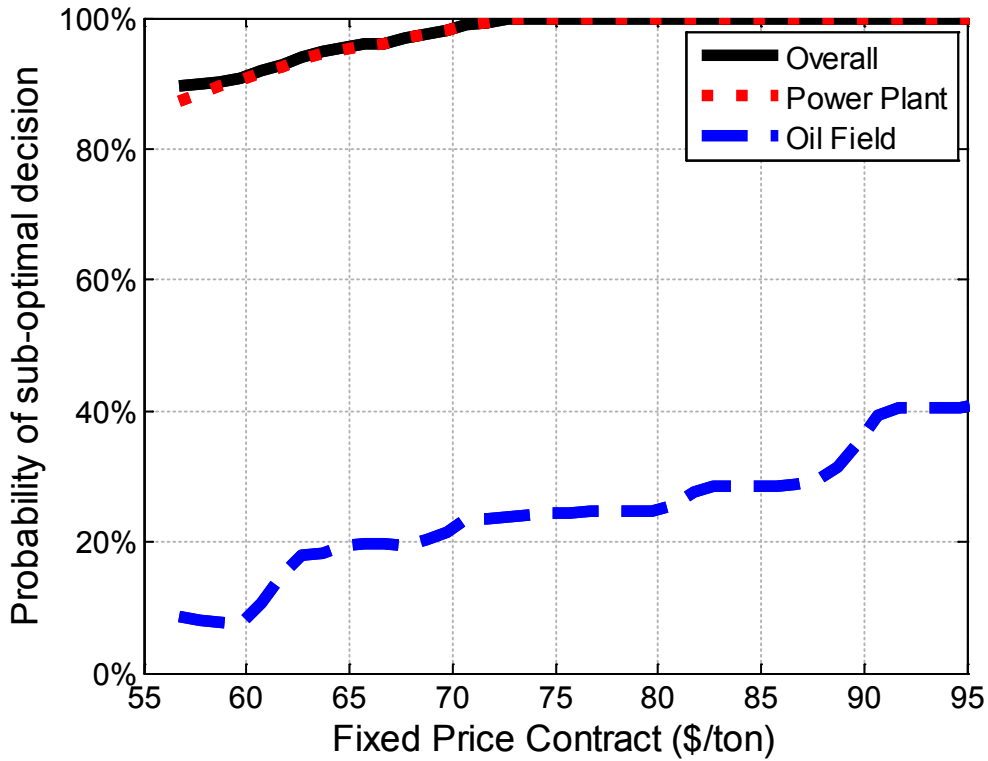


Figure 5.3 Probability of sub-optimal decision-making under fixed price contracts (base case)

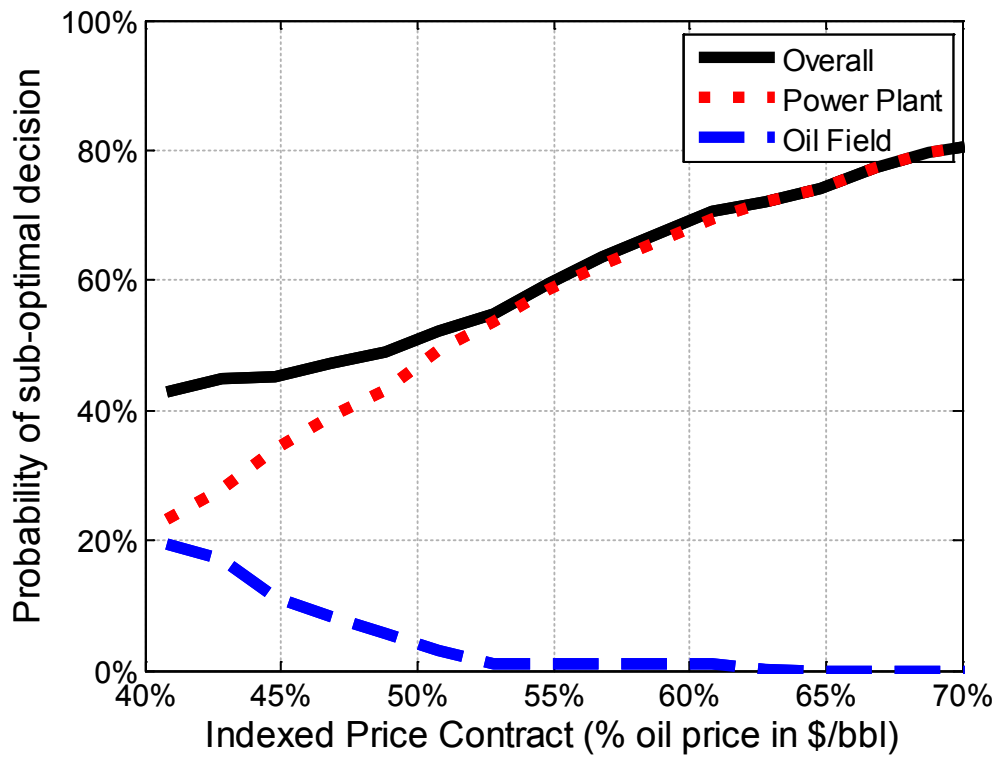


Figure 5.4 Probability of sub-optimal decision-making under oil-indexed price contracts (base case)

From Figure 5.3 we see that overall under the fixed price contracts, there is at least a 89% probability of sub-optimal decision-making, and the contract price that minimizes the risk is the minimum ex ante negotiable contract price of \$57/ton. At this ‘optimal’ fixed contract price there is a 87% probability that the power plant would not have incentives to reoptimize the CO₂ capture rate. The probability of sub-optimal decision-making by the power plant company increases with the contract price, and is 100% if the contract price is greater than \$72/ton. The poor incentives for the power plant company arise from being paid a fixed price and not sharing any oil price risk. Furthermore, there is a 8% probability that the oil field company would make sub-optimal decisions under the optimal fixed price contract. This includes a 6% probability of ex post insolvency of the oil field company leading to a contractual breach, and an additional 2% probability that the oil field company would not have incentives to reoptimize the CO₂ capture rate even if it was solvent. The ex post insolvency risk for the oil field company would increase to 23%, if we also account for those scenarios where the power plant does not have incentives to reoptimize the CO₂ capture rate, and the project operations continued at 90% CO₂ capture rate. As the fixed contract price increases, the ex post insolvency risk increases, resulting in increased probability of sub-optimal decision-making by the oil field company. Even if the oil field company was solvent, there is a positive probability of 2% under the optimal contract price, that the oil field company would not have incentives to reoptimize the CO₂ capture rate. This points to scenarios where the oil price is high (greater than \$95/bbl) and so the oil field company wants to operate at 90% CO₂ capture rate, even though it is overall optimal to lower the CO₂ capture rate as the electricity price is high (greater than 14 c/kWh) and the CO₂ emission penalty is low (less than \$4/ton).

Figure 5.4 presents that the risk of sub-optimal decision-making under oil-indexed price contracts. We see that increasing the oil-indexed CO₂ contract price will reduce the risk of sub-optimal decision-making by the oil field company, but will increase the risk for the power plant company. The optimal oil-indexed contract price is 41% of oil price, which minimizes the overall project risk of sub-optimal decision-making to 43%. At this optimal oil-indexed contract price, there is a 23% probability that the power plant would not have incentives to reoptimize the CO₂ capture rate. We note that since the power plant company now shares the oil price risk with the oil field company, it has increased incentives to lower the CO₂ capture rate when the oil price goes down, compared to the fixed price contracts. The risk-sharing in the indexed price contracts

also eliminates the risk of ex post insolvency of the oil field company. From Figure 5.4, we see that at the optimal oil-indexed contract price, there is a 20% probability that the oil field company would not have incentives to reoptimize the CO₂ capture rate. If the contract price is higher than 65% of oil price, then there is zero risk of sub-optimal contingent decision-making by the oil field company.

So far, in this section, we have evaluated two alternate contract types in terms of the risk of ex post insolvency and the risk of sub-optimal decision-making. We see that fixed price contracts have high risk of ex post insolvency and high probability of operating at a sub-optimal CO₂ capture rate. Aggregating these two contractual risks, we find that the optimal fixed contract price of \$57/ton results in a 20.7% probability of sub-optimal decision-making, which includes contractual breach due to insolvencies and operating at a sub-optimal CO₂ capture rate. Indexed price contracts share the oil price risk between the power plant company and the oil field company, and thus reduce the risk of insolvency and the risk of sub-optimal decision-making. The optimal contract price under the indexed price contract is 41% of the oil price, and under this contract price, there is no risk of ex post insolvency and a 9.3% probability of sub-optimal decision-making. To, further reduce the risk of operating at sub-optimal CO₂ capture, the CO₂ contract terms would need to reflect sharing of other risk factors such as the electricity price and the CO₂ emission penalty. Next, we quantify the impact of choice of contract structures on the financial value of the prototype CCS-EOR project.

5.2.3 Final Project Value

So far, we have evaluated the influence of contractual risk-sharing on the decision-making of the entities, and find that weak risk-sharing in fixed price contracts results in high risk of sub-optimal decision-making. In this section, we evaluate the impact of the sub-optimal decisions on the final project value. We focus on the ‘optimal’ contract price that minimizes the risk of sub-optimal decision-making under the respective contract structures. For the fixed price contracts we consider the ex ante minimum negotiable CO₂ contract price of \$57/ton, and for the indexed price contracts we consider the ex ante minimum negotiable CO₂ contract price of 41% of the oil price. For these two contract types, we evaluate the resulting project value. As we calculated

earlier, the project NPV is \$1,332 million in the ‘first-best’ case when there are no contractual inefficiencies. We find that under the optimal fixed price contract due to high risk of sub-optimal decision-making the NPV decreases by \$128 million to a value of \$1,204 million (9.6% decrease). The NPV under the optimal oil-indexed price contract is \$1,327 million, which implies a loss of \$5 million or 0.4% decrease from the first-best value.

Figure 5.5 presents the probability curve of the ex post project value in the first-best case, and under oil-indexed price and fixed price contracts. Figure 5.6 presents the probability curve of the ex post project value focusing only on ‘select’ 22% of the ex post scenarios where it is economical to reoptimize the CO₂ capture rate.

The maximum average ex post project value when there are no contractual inefficiencies (first-best) is \$4,516 million. Figure 5.5 shows that the cumulative probability curve of the ex post project value for the oil-indexed price contracts almost overlaps with the first-best. The average ex post under the optimal oil-indexed contract drops by \$5 million (0.1% decrease) compared to the first-best value. The ex post value curve for the fixed price contract is shifted lower compared to the project first-best. This reflects the 6.7% probability of ex post insolvency and an overall 20.7% probability of sub-optimal decision-making under fixed price contracts. The optimal fixed price contract reduces the ex post value by \$128 million to \$4,388 million, which is a 2.8% decrease.

Figure 5.6 gives the cumulative probability curve for the ex post project value focusing only on the 22% of the ex post scenarios where it is economical to lower the CO₂ capture rate. The maximum ex post project value in absence of contractual inefficiencies is \$2,864 million on average across the 22% of the scenarios. We see from Figure 5.6 that the ex post project value under the optimal oil-indexed price contract is almost the same as the first-best. Overall, under the optimal indexed price contract, the average ex post project value in the 22% of the scenarios is \$2,839 million, which is \$24 million or 0.8% less than the first-best project value. Fixed price contract leads to a larger financial loss and the average value across the 22% scenarios is \$2,377 million, which is \$487 million or 17% less than the first-best project value. We see from Figure 5.6, that the probability of making positive financial gains in the optimal fixed price contract is only 77% compared to a 100% under the optimal oil-indexed price contract. This is a result of a 23% probability of ex post insolvency for the oil field company under the fixed price contract.

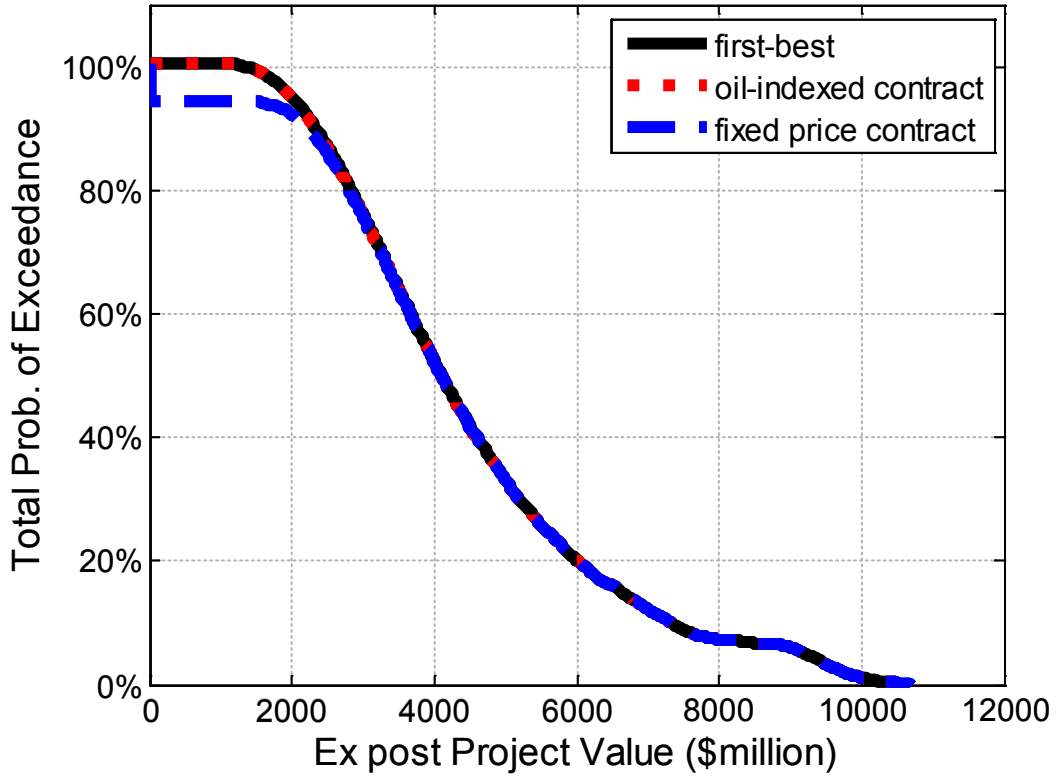


Figure 5.5 Impact of contract structure on the ex post project value

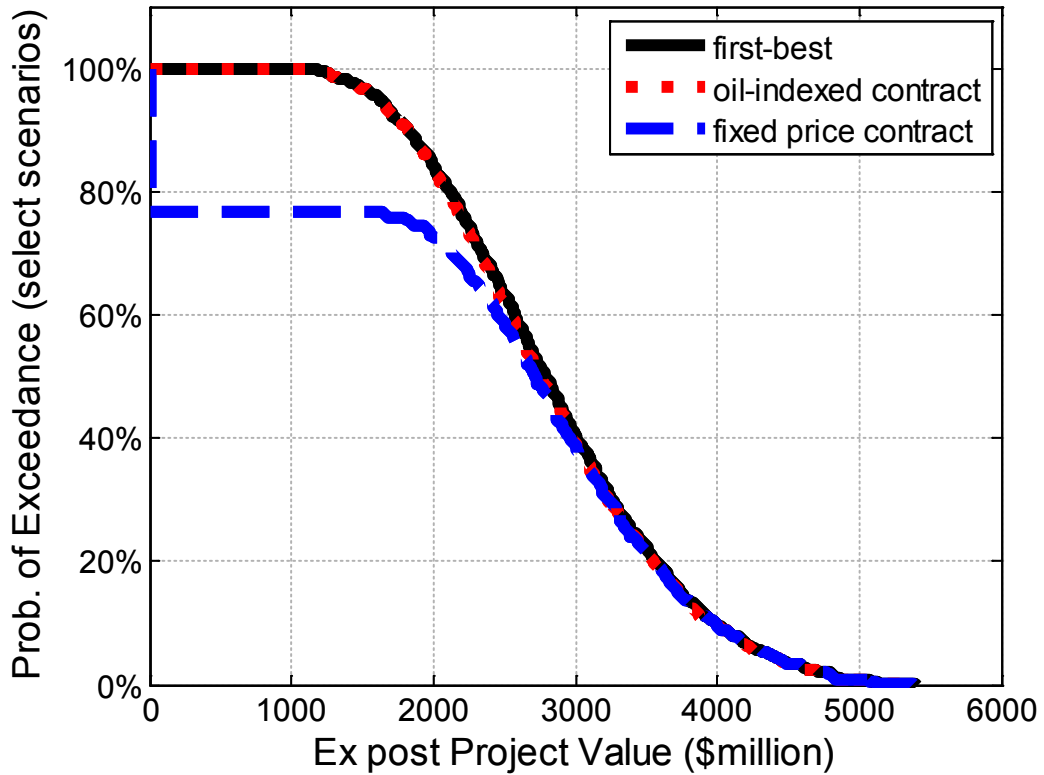


Figure 5.6 Impact of contract structure on the ex post project value in 'select' scenarios

These results show that the fixed price CO₂ contracts result in a much larger financial loss compared to the oil-indexed price contracts. Overall, the optimal fixed price contract leads to a 9.6% decrease in the project NPV and a high probability of ex post insolvencies. Indexed price contracts eliminate the risk of ex post insolvencies leading to 100% probability of positive ex post project value and result in a 0.4% loss in the project NPV.

So far, we evaluated how the fixed price and the oil-indexed price contracts perform when the risk factors change according to the ‘base case’ assumptions, which include non-correlated movement of market risk factors and no change in expected EOR efficiency. Next, we consider other scenarios of changes in risk factors where the market risk factors move in a correlated fashion and the expected EOR efficiency is reduced. We will evaluate how the alternate contract structures perform under these different assumptions on the changes in the risk factors.

5.3 Sensitivity Analysis of the Contractual Performance

In this section, we evaluate how the two alternate CO₂ delivery contract structures: fixed price and oil-indexed price contract structures perform when the market risk factors move in a correlated fashion or if the expected EOR efficiency decreases. These different scenarios of correlated movements of market risk factors and drop in the EOR efficiency were evaluated earlier in Chapter 4, Section 4.3.2 and Section 4.3.3.

In Chapter 4, Section 4.3.2, we had evaluated the optimal contingent CO₂ capture rate and the financial gains from contingent decision-making when the risk factors are positively correlated, negatively correlated or not correlated with correlation coefficients as given in Table 4.2. The EOR efficiency was assumed to not change ex post. The results show that when the market risk factors are negatively correlated there is an increased probability of reoptimizing the CO₂ capture rate and operating at a lower CO₂ capture rate than the initially planned 90% CO₂ capture rate. The increase in NPV from contingent decision-making is the highest when the risk factors are negatively correlated, followed by base case (no correlation), and is the least when the market risk factors are positively correlated.

The optimal contingent CO₂ capture rate and the change in NPV for different assumptions on the value of the EOR efficiency were evaluated in Chapter 4, Section 4.3.3, with the EOR efficiency values as given in Table 4.4. In these scenarios, the market risk factors were assumed to evolve stochastically in a non-correlated fashion. We find that a decrease in EOR efficiency increases the likelihood of operating at a lower CO₂ capture rate, and the financial gains from adjusting the CO₂ capture rate also increase as the EOR efficiency reduces.

As we have discussed, these financial gains from contingent optimization of the CO₂ capture rate will depend on the contractual incentives each of the involved entity has to respond to changes in the risk factors. Next, we evaluate the two alternate CO₂ delivery contract structures under the alternate scenarios of correlated movement of the market risk factors and changes in the EOR efficiency. Doing this sensitivity analysis of the performance of CO₂ contract structures under the different assumptions on changes in risk factors gives us a bound on the performance of the contract structures. For each of the risk scenario, we focus on the ‘optimal’ contract price that minimizes the contractual risks and maximizes the project value under the respective contract type.

Figure 5.7 presents the risk of insolvency of the oil field company under the different assumptions of changes in the risk factors for the two alternate ‘optimal’ contract price terms. Figure 5.8 presents the probability of sub-optimal decision-making by the power plant company and oil field company in each of the risk scenarios for the ‘optimal’ contract prices under the fixed price and the oil-indexed price CO₂ contracts. Note that the probability of sub-optimal decision-making includes sub-optimal decisions related to both the contractual breach due to insolvencies and operating at a sub-optimal CO₂ capture rate.

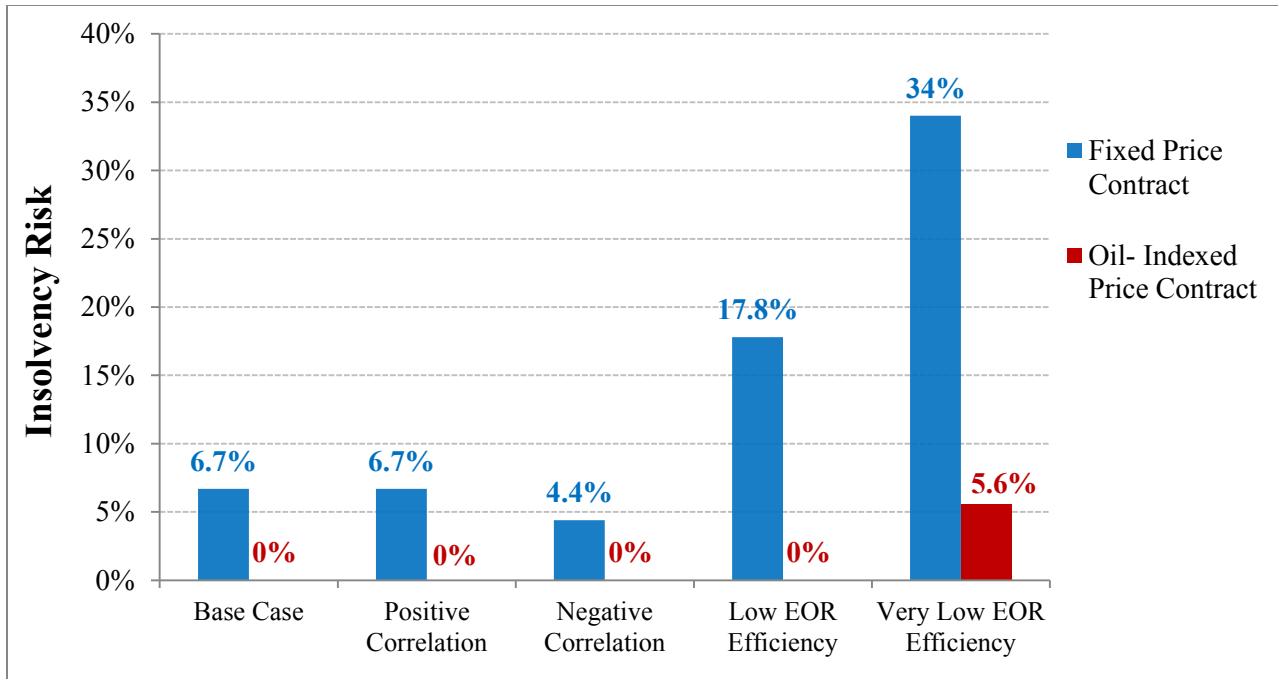


Figure 5.7 Sensitivity analysis of the contractual insolvency risk

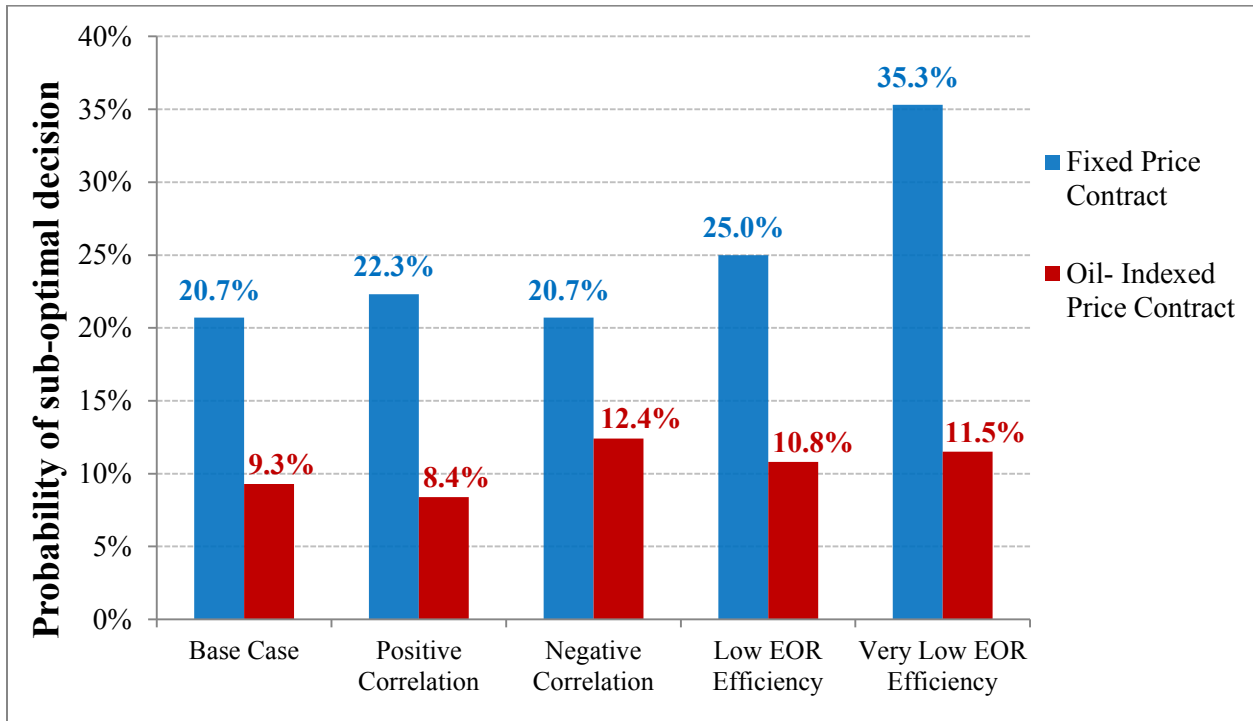


Figure 5.8 Sensitivity analysis of the incentives for optimal contingent decision-making

From Figure 5.7, we see that the insolvency risk is always higher under the fixed price CO₂ contracts compared to the oil-indexed price contracts irrespective of how the risk factors evolve. Furthermore, if ex post only the market risk factors evolved (in correlated or non-correlated fashion) and the EOR efficiency value was same as the base case value, then there is zero insolvency risk under the optimal oil-indexed price contract. If the expected EOR efficiency reduced to 0.8 bbl/ton (low EOR efficiency scenario) from the base case value of 1.23 bbl/ton, the risk of insolvency under the oil-indexed price contract would still be zero compared to a 18% probability of insolvency under the fixed price contract. Under the very low EOR efficiency case (corresponds to EOR efficiency of 0.6 bbl/ton), the risk of insolvency under the fixed price contract increases to 34%, and is relatively smaller under the indexed price contracts: 6%.

Similar to Figure 5.7, in Figure 5.8 we see that the probability of sub-optimal decision-making is the highest in the fixed price contracts in all the risk scenarios. If we look at the first three scenarios of different assumptions of correlation coefficients between market risk factors: base case (no correlation), positive correlation, negative correlation – we see that overall the performance of the two contract types does not change much. The probability of sub-optimal decision-making under the optimal fixed contract price is about 20%, and under the oil-indexed price contract it is about 10%.

Note, that under the assumption of negative correlation between the market risk factors, we see slight improvement in the performance of the fixed price contracts relative to the oil-indexed price contracts. This could be because when the market prices are negatively correlated there is an increased probability that when the oil price is low, the electricity price will be high and the CO₂ emission penalty will be low. Thus, the power plant company would have increased incentives to lower the CO₂ capture rate even though it does not share the low oil price risk.

The fixed price contract's performance significantly deteriorates when the EOR efficiency drops. From Figure 5.8, we see that in the low EOR efficiency case, the probability of sub-optimal decision-making under the fixed price contract increases to 25% from 21% under base case. When the EOR efficiency drops even lower (very low EOR efficiency scenario), the probability of sub-optimal decision-making increases to 35% under the fixed price contract, which is very close the risk of insolvency under this scenario. The performance of the fixed price contract worsens when the EOR efficiency drops, because with reduced EOR efficiency there is higher

probability that it would be economical to lower the CO₂ capture rate when the oil price drops, and since the power plant company does not share the oil price risk it has no incentive to adjust the CO₂ capture rate. The performance of the oil-indexed price contract when the EOR efficiency drops is almost similar to the base case when EOR efficiency does not change, and is close to 10% probability of sub-optimal decision-making.

Table 5.1 presents the project NPV under the two alternate optimal contract price structures, and compares the loss in value under each of the contract type with the first-best project NPV (the NPV achieved when there are no contractual risks). The different risk scenarios presented are the base case change of risk factors, under the different assumptions of correlations between market risk factors, and different assumptions on the value of the EOR efficiency. The first-best NPV under the different scenarios was evaluated in Chapter 4, Section 4.3, Table 4.6 and Table 4.7.

	First-Best	Fixed Price		Indexed Price	
	NPV \$m	NPV \$m	Difference \$m (%)	NPV \$m	Difference \$m (%)
Base Case	\$1,332	\$1,204	- \$128 (-9.6%)	\$1,327	- \$5 (-0.4%)
<i>Correlations</i>					
Positive Correlation	\$1,332	\$1,219	- \$113 (-8.5%)	\$1,330	- \$2 (-0.1%)
Negative Correlation	\$1,351	\$1,244	- \$108 (-8.0%)	\$1,337	- \$15 (-1.1%)
<i>EOR Efficiency</i>					
Low Efficiency	\$72	- \$264	- \$337	\$67	- \$6 (-8.1%)
Very Low Efficiency	- \$616	- \$1,235	- \$619	- \$694	- \$78

Table 5.1 Sensitivity analysis of the project's net present value obtained under the alternate CO₂ delivery contract structures.

The high risk of insolvency and poor incentives for contingent decision-making under the fixed price contracts is reflected in the final project value achieved under this contract type. We see from Table 5.1 that in scenarios where the EOR efficiency does not change: base case, and different assumptions of correlation coefficients, the loss in project NPV under the fixed price contracts is about 10%. The loss in value under the oil-indexed price contracts is much less and is about 1% or less. The significance of financial loss under the fixed price contracts is evident

from the scenarios where the EOR efficiency is lower than the base case value. The first-best project value under the low EOR efficiency scenario is \$72 million. The value drops to a negative of \$267 million under the fixed price contract. The value under the oil-indexed price contract continues to stay positive at \$67 million. This low EOR efficiency case clearly illustrates how the choice of contract structures affects the project. Even though the project has an overall positive NPV in the low EOR efficiency case and it is economical to go ahead with this project, inappropriate risk-sharing under the fixed price contract would lead to inefficient decision wherein it would not be economical to go ahead with this project if the expected EOR efficiency is 'low'. The loss in project value goes up if the EOR efficiency drops even lower (very low EOR efficiency scenario). In the fixed price contract, the loss in project value is \$619 million, compared to a much smaller loss of \$78 million under the oil-indexed price contract.

In this section, we presented how the alternate CO₂ delivery contract structures perform under the different risk scenarios, which represented different assumptions on the correlations between the market risk factors and the expected EOR efficiency.

Next, we summarize the key findings from the results presented in this chapter.

5.4 Summary

In this chapter, we evaluated two alternate CO₂ delivery contract price structures: fixed price and oil-indexed price, in terms how these contract structures respond to changes in the market risk factors and changes in the EOR efficiency. The performance of the contract structures was evaluated in terms of the risk of ex post insolvency, probability of sub-optimal decision-making, and the final project value achieved under the respective contract types.

In the 'base case' where we assumed that the market risk factors stochastically evolve in a non-correlated fashion and the EOR efficiency does not change ex post, we find that there is larger loss in project value under the fixed price contracts compared to the oil-indexed price contracts. The larger loss in project value under the fixed price CO₂ contracts is because of the weak risk-sharing which results in high risk of insolvency and poor incentives for contingent optimization of the CO₂ capture rate. While, the sharing the oil price risk under oil-indexed price CO₂

contracts can eliminate the risk of insolvency and align the incentives of the involved entities to optimize the CO₂ capture rate. Under the optimal fixed price contract (that minimizes the contractual risks), there is a 20.7% probability of sub-optimal decision-making including inefficient breach of contractual obligations due to insolvency and operating at a sub-optimal CO₂ capture rate. The optimal oil-indexed price contract reduces this probability of sub-optimal decision-making to 9.3%. The resultant project net present value under the optimal fixed price contract is \$1,204 million, which is \$128 million less or 9.6% lower than the first best project value. The loss in project value under the optimal oil-indexed price contract is only \$5 million or 0.4% less than the first best project value.

In this chapter, we compared how the performance of the two alternate contract types changes under different assumptions of changes in the risk factors. We consider different correlation coefficient between the market risk factors, and evaluate how the contract types would perform if the market risk factors were positively correlated or negatively correlated. We also look at two scenarios of reduced EOR efficiency, and analyze the performance of contract structures under reduced EOR efficiency. These scenarios of reduced EOR efficiency assumed that market risk factors evolved stochastically in a non-correlated fashion.

Overall in all these scenarios, we find that the oil-indexed price contracts always outperform the fixed price contracts. The relative performance of the two contract types changes depending on the assumptions of changes in the risk factors. The stark difference in the relative contractual performance comes out when we consider a drop in EOR efficiency along with a stochastic evolution in the market risk factors. When the EOR efficiency drops, we find that the performance of the fixed price contract deteriorates. For the optimal fixed contract price (that minimizes the contractual risks), there is a 25% probability of sub-optimal project outcomes under the low EOR efficiency scenario, and a 35% probability of sub-optimal project outcomes when the EOR efficiency is very low. Comparatively, the probability of sub-optimal project outcomes under the optimal oil-indexed price contract is about 10% and does not change much with change in the EOR efficiency. If we compare the financial performance of the two contract types in these different risk scenarios, we find that the fixed price contract leads to a much larger loss in value compared to the oil indexed price contract. The loss in value under the fixed price

contract can be so large that it could result in a negative project value that could otherwise be net positive if the contractual inefficiencies were minimized.

The results in this chapter emphasize how contractual risk-sharing influences the decision made by the project entities, and determines the project value. We see that weak risk-sharing as in the fixed price contracts leads to inefficiencies related to insolvencies and sub-optimal contingent decisions. These sub-optimal project outcomes result in financial loss that could be large enough to affect investment and operational continuity decisions. The oil-indexed price contracts offer risk-sharing between entities and significantly lower the contractual inefficiencies and increase the financial performance of the project.

Chapter 6 Conclusions

This thesis presents a risk management framework for energy capital projects that accounts for both the exogenous risk factors and the endogenous contracting risks to evaluate the optimal risk management strategies that maximize the overall project value. The risk management strategies include contingent decisions in response to change in the exogenous risk factors, and contractual risk-sharing to incentivize the entities to make the optimal contingent decisions. We illustrate the proposed risk management framework through an application to carbon capture and storage projects (CCS) with enhanced oil recovery (EOR). We focus on a prototype CCS-EOR project wherein the CO₂ is captured at a coal-fired power plant and is transported via a dedicated pipeline to an oil field, where it is injected for EOR.

In this chapter, we will first present the conclusions from the thesis work, and then give suggestions on the opportunities for future work.

6.1 Summary and Conclusions

This thesis work emphasizes the financial significance of contingent decision-making in response to change in the risk factors, and quantifies the impact of contractual risk-sharing on the decision-making of the involved entities and the resulting project value. A key objective of this thesis is to illustrate that the value of the energy capital projects depends on both the exogenous risks and the endogenous contracting risks. Next, we summarize the key results from the thesis, and discuss the main takeaways from the results.

We analyze the impact of the exogenous risks on the value of the prototype CCS-EOR project during the operational phase of the project. The two sets of exogenous risks we analyze in this thesis are: the volatility in the market risk factors (oil price, wholesale price of electricity, and CO₂ emission penalty), and the uncertainty on the technical EOR efficiency. The results from a

pro forma cash flow analysis show that the change in the risk factors can significantly affect the ex post project value, and highlight that the oil price risk is the dominant risk factor in the prototype CCS-EOR project followed by the uncertainty in the EOR efficiency.

We evaluate the optimal contingent decisions that would maximize the project value in light of the change in the risk factors. The contingent decision we focus on is the decision to adjust the CO₂ capture and injection rate in response to change in the risk factors.

Significance of Contingent Decision-making

We find that the optimal contingent decision-making can lead to significant financial gains. Overall, the financial gains from contingent decisions increase as the oil price decreases, the electricity price increases, the CO₂ emission penalty decreases, and the EOR efficiency decreases. In the ‘base case’ wherein only the market risk factors evolve (in non-correlated fashion) and the EOR efficiency does not change, there is a 22% probability that it would be economical to readjust and lower the CO₂ capture rate. This contingent optimization of the CO₂ capture rate leads to \$14 million increase in the project NPV (1% increase in NPV), and there is a positive probability that the gains in project value can exceed \$400 million.

We also evaluate the financial impact of the contingent optimization of the CO₂ capture rate for different assumptions on the changes in the risk factors including different assumptions on the correlations between the movement of the market risk factors and different expected EOR efficiency values. We find that the economics of contingent decision-making is the highest when the market risk factors are negatively correlated followed by when the risk factors are not correlated and is the least when the market risk factors are positively correlated. This is because a negative correlation increases the likelihood that when the oil price is low, the electricity will be high, and the CO₂ emission penalty will be low, and hence it would be more likely that it would be profitable to lower the CO₂ capture rate. On the other hand, a positive correlation reduces the likelihood that the market risk factors would make it profitable to lower the CO₂ capture rate. There is a positive probability that the financial gains can exceed \$550 million when the market risk factors are negatively correlated. Furthermore, we find that a decrease in the EOR efficiency increases the likelihood of operating at a lower CO₂ capture rate, and strengthens the economics of contingent decision-making. If the EOR efficiency is ‘very low’ (compared to

the base case), then the contingent optimization of the CO₂ capture rate can lead to financial gains of more than \$700 million.

The contingent decision of adjusting the CO₂ capture rate will be made by separate entities that own and operate the different parts of the CCS-EOR value chain. We model the CCS-EOR project ownership structure such that the power plant and the oil field are owned and operated by separate entities, and the pipeline is jointly owned by the two entities. The operation between the power plant company and the oil field company is integrated through a long-term contract for the delivery of CO₂.

We show that the incentives the individual involved entities have to make the optimal contingent decisions and maximize the overall project value depend on the risk allocation defined by the CO₂ delivery contract terms.

Impact of Contractual Risk-sharing on the Decisions and the Project Value

We evaluate two alternate standard CO₂ delivery contract structures in terms how these contract structures respond to changes in the market risk factors and changes in the EOR efficiency. The contract structures analyzed include a fixed price contract where the CO₂ contract price is fixed for the contract term, and an indexed price contract where the CO₂ contract price is indexed to the oil price. The performance of the contract structures is evaluated in terms of the risk of ex post insolvency of the involved entities, probability of sub-optimal decision-making by the involved entities, and the final project value achieved under the respective contract types.

We see that weak risk-sharing in the fixed price CO₂ contracts leads to inefficiencies related to ex post insolvencies and sub-optimal contingent decisions by the involved entities, resulting in significant loss in the project value. The risk-sharing offered by the oil-indexed price CO₂ contracts can eliminate the risk of insolvency and align the incentives of the involved entities, and thus oil-indexed price contracts significantly lower the contractual inefficiencies and increase the financial performance of the project.

In the ‘base case’ where we assumed that the market risk factors stochastically evolve in a non-correlated fashion and the EOR efficiency does not change, we find that under the optimal fixed price contract (that minimizes the contractual risks), there is a 20.7% probability of sub-optimal

decision-making including inefficient breach of contractual obligations due to insolvency and operating at a sub-optimal CO₂ capture rate. The optimal oil-indexed price contract reduces this probability of sub-optimal decision-making to 9.3%. The resultant project net present value under the optimal fixed price contract is \$1,204 million, which is \$128 million less or 9.6% lower than the first best project value (value when no contractual inefficiencies). The loss in project value under the optimal oil-indexed price contract is only \$5 million or 0.4% less than the first best project value.

We find that the oil-indexed price contracts always outperform the fixed price contracts under the different assumptions on the correlations between the movements of the market risk factors and different value of the EOR efficiency. The relative performance of the two contract types changes depending on the assumptions of changes in the risk factors. The stark difference in the relative contractual performance comes out when we consider a drop in the EOR efficiency along with a stochastic evolution in the market risk factors. When the EOR efficiency drops, we find that the fixed price contract results in a much higher probability of sub optimal decision-making compared to the oil indexed price contract. The high likelihood of sub-optimal project outcomes under fixed price contracts results in financial loss that can be so large that it could result in a negative project value that could otherwise be net positive if the contractual inefficiencies were minimized. The performance of the fixed price contract worsens when the EOR efficiency drops, because with reduced EOR efficiency there is higher probability that it would be economical to lower the CO₂ capture rate when the oil price drops, and since the power plant company does not share the oil price risk it has no incentive to adjust the CO₂ capture rate. Furthermore, as the EOR efficiency reduces, the insolvency risk faced by the oil field company also increases under fixed price contracts. The risk-sharing offered by the oil-indexed price contracts assures that the performance of the oil-indexed price contract does not change with a drop in the EOR efficiency and is very close to the first-best project value.

These results emphasize how contractual risk-sharing influences the decisions made by the project entities, and determines the final project value. The results highlight the importance of structuring strong contractual risk-sharing in order to maximize the value of energy capital projects. Risk allocation through contracts incentivizes the involved entities to work in the

common interest of the project and thus make optimal decisions that maximize the overall project value.

A key takeaway from the thesis is that the risks in large capital projects are a combination of exogenous risks and endogenous risks.

Project Risks are Combination of Exogenous Risks and Endogenous Risks

The thesis results illustrate that the final project value depends on both the exogenous change in risk factors and the endogenous risks associated with the response of the project operators to the change in the risk factors. We see that in the prototype CCS-EOR project, a change in the exogenous risk factors such as a drop in the oil price, drop in EOR efficiency, leads to a considerable loss in the project value. Strong contractual risk-sharing structures incentivize the involved entities to reoptimize the project operations in response to change in the risk factors, and thus significantly increase the project value. On the other hand, inappropriate contractual risk-sharing will lead to inefficiencies such as insolvencies and conflict of interests, resulting in sub-optimal project outcomes which could be large enough to affect investment and project continuity decisions.

The risk management in energy capital projects involves evaluating the optimal risk management decisions, and structuring strong risk-sharing structures that incentivize the involved entities to work in the common interest of the project and maximize the overall project value.

6.2 Future Work

In this section, we discuss the opportunities for future research on this thesis work that would further contribute to the knowledge and understanding of managing risks in large capital projects, and in specific to CCS projects. We have identified three key areas of future work: analyze risks in other phases of CCS projects such as post closure CO₂ leakage, analyze alternate commercial arrangements such as spot contracts and joint ventures, and analyze the interaction with project finance structures such as through public-private partnerships.

Risks in Other Phases of CCS Projects

In this thesis we have focused on the risks during the operational phase of CCS-EOR projects. An extension to this research would be to analyze the risks in other phases of CCS projects. For example, post closure CO₂ leakage is a key risk and can undermine the very purpose of CCS. Post closure CO₂ leakage depends both on the exogenous risk factors such as geological uncertainty and endogenous performance incentives. Future work would involve analyzing the impact of exogenous risk factors, and evaluating the commercial structures that would incentivize the involved entities in CO₂ sequestration to conduct due diligence to efficiently mitigate and manage the CO₂ leakage risk. Structuring commercial structures for managing post closure CO₂ leakage is challenging given the long time frame over which the CO₂ is required to stay in the sub-surface.

Alternate Commercial Arrangements

In this thesis, we have focused on the long-term delivery contracts that distribute the project value and projects risks between the involved entities, and we show how the value-sharing and the risk-sharing influences the decision-making by the individual entities and ultimately affects the project value.

Apart from long-term contracts, there are other types of commercial structures that exist in capital projects such as short-term/spot contracts and joint ventures. It will be useful to also look at the other types of commercial structures, and analyze how they distribute the project value and risks between entities. CCS projects might involve spot or short-term contracts once there is a dense enough network of CO₂ pipelines such that there is insignificant probability of ex post opportunistic behavior. It will be interesting to study how the duration of contracts would change as the pipeline network evolves, and to analyze the price and quantity provisions that might exist in spot CO₂ contracts. One can also evaluate other types of commercial value-sharing arrangements such joint ventures between the involved entities in terms of how these arrangements can be structured to incentivize optimal decision-making.

We have focused on the CO₂ delivery contracts, and we evaluate how the contract terms can be structured to benefit from the economics of dynamically adjustable CO₂ capture and injection rate. The flexibility in adjusting the CO₂ capture and injection rate would also depend on the

terms of other off-take contracts such as the power purchase agreements (PPAs) and oil supply contracts. In this thesis, we assume that the other off-take contracts are completely flexible and do not pose a constraint on the CO₂ capture rate, and the amount of oil and electricity to be produced. A future area of work may consider some standard off-take commercial arrangements that exist in the industry, and evaluate how these arrangements would interact with the CO₂ delivery contracts.

Project Financing and Public Sector Participation

Project financing is an important aspect of the investments in capital projects involving multiple lenders and sponsors that jointly finance the project, and depend on the project performance to earn financial returns on their investments. It will be useful to study how risk allocation works in the framework of project financing, and influences the project outcomes.

The capital projects particularly for the provision of ‘public’ good and services such as transportation, electricity, typically involve the government or the public sector. A lot of such capital projects are being jointly financed by the public sector/government and the private sector, and these arrangements are commonly known as public-private partnerships (PPPs). As expected, the public and private sector might have different objectives with the private sector seeking to maximize the commercial profits, and the government seeking to also maximize the social welfare. In this thesis, we study how to structure commercial risk-sharing arrangements between entities who are all trying to maximize their individual commercial profits. Future research on how to structure the commercial arrangements and the risk-sharing in public-private investments to co-optimize the commercial and social benefits would be very useful in determining the success of the public infrastructure projects.

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