THE UNIVERSITY OF CALGARY

ENHANCED OIL RECOVERY:
INCORPORATING OPTIMAL TIMING EFFECTS
OF RESERVOIR DEVELOPMENT INTO SUPPLY ANALYSIS

By

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The undersigned certify that they have read, and recommend to the Faculty of Graduate Studies for acceptance, a thesis entitled, "Enhanced Oil Recovery: Incorporating Optimal Timing Effects of Reservoir Development into Supply Analysis" submitted by H. Jack Ruitenbeek in partial fulfillment of the requirements for the degree of Master of Arts.

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ABSTRACT

Enhanced oil recovery (EOR) in Canada is becoming an increasingly important source of oil supply. In 1981, only 40% of Alberta's conventional oil production was derived from pools undergoing primary depletion. Reservoirs under waterflooding and gas flooding schemes accounted for 46% of the production. The remaining 14% can be attributed to reservoirs in which more exotic production methods have been introduced, including solvent flooding, thermal techniques, and polymer flooding.

The timing of petroleum reservoir development can have significant impacts upon the time profile of oil supply, as well as on total recovery from the reservoir. Because of a wide variety of physical mechanisms in the reservoir, incremental recovery from EOR schemes can often be increased by commencing these schemes at higher reservoir pressures and oil saturations. This is referred to as a stock effect of timing, where stock effects are more generally classified as those situations where current production of a resource affects the amount of resource available for future production. Typical cases indicated that, because of stock effects, decreases of 2% to 10% in incremental recovery would occur for every year delay in commencing an EOR scheme in a currently producing field.

Recent historical information shows that operators are reacting to both technical and economic circumstances by commencing waterflooding and EOR schemes earlier in a reservoir's development. The traditional nomenclature of "primary/secondary/tertiary" recovery has thus become obsolete in light of these developments.

Although the existence of stock effects has had impacts on EOR operations, economic supply analyses have not been undertaken which recognize these impacts. As such, analytical techniques have not been developed which incorporate these effects of timing. To some extent this may be attributable to insufficient interdisciplinary work between technical reservoir performance prediction and economic supply analysis. With the growing importance of EOR, however, it is paramount that the petroleum supply analyst informs himself of any stock effects of timing and incorporates them into any modelling work.

A conceptual and analytical partial equilibrium model is developed here which determines the optimal time to commence a contemplated EOR scheme. Elasticities of incremental recovery, timing, and project net worth with respect to prices and costs are calculated with and without stock effects. Through including stock effects, it is found that project recovery and value are significantly more sensitive to the economic environment and fiscal regime than previous studies would indicate. For example, the modelling indicates that when optimal timing is taken into account, supply generally becomes more elastic and a decline in prices or increases in taxes will cause more significant decreases in productivity, longer project delays, and ultimately an overall decline in recovery as a result of stock effects.

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DEDICATION

To my parents,

Tricia

and

Gus

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INTRODUCTION

As the world's conventional oil resources are depleted, both industry and governments are looking to develop new sources of energy supplies. During the 1970s, it appeared in North America that multi-billion dollar mega-projects would be the saviours of Western consumers' energy demands. Infrastructure constraints, long lead times, ever-increasing real cost inflation, and escalating interest rates have coupled with a softened market to cause the demise of many of these projects. Supply availability is, however, still a central concern of energy policy. It now appears that those projects which require little infrastructure, little interim financing, and relatively small capital requirements will come to the forefront during the 1980s. Striking potential exists, on all these grounds, for enhanced oil recovery.

The above developments have caused petroleum supply modelling to become an important concern of the economist. Political decisions of immense importance are being based on such supply analyses, and there is therefore a great deal of pressure to construct accurate and meaningful models. Because of such demands, the state of the art of modelling has progressed in many areas to a very sophisticated stage.

Technological advances in enhanced oil recovery require that the economist familiarize himself well enough with the technology to make knowledgable predictions. Not only has the technology advanced significantly in EOR, but its application is now so widespread that it accounts for a significant portion of Canada's supply potential. Enhanced recovery has thus become a relevant area of study for the supply analyst. Recent studies have contributed significantly to our understanding of enhanced recovery potential and have involved substantial technical research.

One of the characteristics of both waterflood and tertiary recovery, and the one which is the main technical focus of this study, is that the amount of incremental oil recoverable depends on when the project is started. Basically, a flood started at high oil saturations will recover more incremental oil than one started at lower saturations. Since the oil saturation falls as oil is produced from the reservoir, delaying a scheme will tend to yield less oil. Generally a scheme initiated earlier will yield larger ultimate recovery. This is referred to as a stock effect of timing, where stock effects are classified as those situations where current production of resource affects the amount available for future production. Also, the timing of an EOR scheme will have important impacts on project economics, which should be considered in analysing the supply from such schemes.

The basic purpose of this study is to develop a model to address the above factors and to analyse the sensitivity of oil deliverability and ultimate recovery from enhanced recovery schemes to economic factors such as prices, costs and taxation policy.

The contents of the study are organized as follows. The first chapter provides a background description of the technical and historical development of enhanced oil recovery in Canada, as well as a discussion of the impacts of recent regulations. The following two chapters discuss the principle theoretical aspects of supply analysis. Chapter 2 discusses the technical aspects of analysing oil supply from enhanced recovery. Particular attention is given to recent trends in timing EOR schemes and to various types of stock effects. Chapter 3 details the important economic aspects of supply analysis. Apart from some general economic theory, emphasis is placed on the "objective function" and its role in supply analyses. In addition, a review of previous analyses is undertaken which discusses how the important technical and economic issues were addressed in these other studies.

Chapter 4 consolidates the theory in the prior chapters to develop a basis for a partial equilibrium model which addresses the key aspect of optimal timing in an analytical model. Chapter 5 presents some analytical and practical applications of the model. The analytical applications address primarily the general effects on deliverability, ultimate recovery, and net present value of changes in economic and technical factors. Various simulation results are also presented for a reservoir case study. The final chapter, Chapter 6, discusses some of the implications of the model.

CHAPTER 1

EOR POTENTIAL IN CANADA: A BACKGROUND

1.1 INTRODUCTION

The purpose of this chapter is to introduce enhanced oil recovery (EOR) in terms of its major technical features and the role that EOR has played and might play in Canadian oil supply. A description of different oil production mechanisms is outlined, starting with primary production, progressing to the secondary recovery techniques of waterflooding and gas injection, and finally to tertiary recovery. Tertiary recovery is further separated into miscible, chemical, and thermal techniques.

A brief historical description of EOR is given in the context of its development in Canada. This presentation shows the importance of the various techniques in Canada and the contribution of each process to total supply.

The regulation of EOR is discussed to introduce the effects of the evolution of various pricing, taxation and incentive schemes available for EOR in Canada, as initiated by both federal and provincial governments. Governments are introducing substantial incentives for EOR production, in recognition of its growing importance.

Finally, EOR's role as a major future supply source for oil in Canada is examined. A brief qualitative comparative analysis of the benefits of EOR versus some of the other energy alternatives (such as mega-projects, or such as increasing conventional resources by further exploration) is undertaken. Factors discussed in this comparative analysis include the relative costs of each project, the financing ability of each project, the lead times involved, the potential for success given the current technologies (risk), and the degree of infrastructure which will be required to pursue each of the alternatives.

The general conclusion and thrust of this chapter is that EOR potential in Canada is significant, that, on the surface, much of it appears to be an economic alternative, and that current economic conditions are such that many EOR projects would be favoured over the mega-project type of operation which may have been favoured during the 1970s.

1.2 WHAT IS EOR?

Production of petroleum from underground reservoirs is a complex process. The time sequence of events in this process involves a continuous series of adjustments to accommodate the technical changes which occur within a reservoir and the prevailing economic conditions. Because of this nature of petroleum production, it is difficult to define strictly what type of production is taking place. There are, however, some conventions of definition, although the literature is by no means consistent. For these reasons, it is useful background to review some of the principle stages of petroleum production and to identify the areas which are relevant to this study.

1.2.1 Petroleum Production Mechanisms

It is important to understand that the production program for a particular petroleum reservoir depends intimately upon a number of geological factors. A petroleum "reservoir" is a pool of oil in porous rock, surrounded by impermeable strata of rock which prevent its migration. The oil is typically under great pressure from overlying rock or adjacent fluids. Lighter fluids such as natural gas may appear as a gas cap above the oil, or water, which has a higher density, may underlie the oil. The reservoir rock itself is often not homogeneous in that it may contain rock of various porosities and permeabilities. Matters are further complicated by the fact that the oil itself varies substantially in its physical characteristics of density or viscosity and its chemical composition.

While a detailed discussion of petroleum geology is beyond the scope of this study, the above indicates its complex and varied nature. All of the above will influence what exactly will happen when a well is drilled into the reservoir, and hence all will affect production from the reservoir. Production is often classified in three stages: primary, secondary, and tertiary although, as will be discussed later, they need not follow each other in strict order.

Primary production involves the flow of oil up the wellbore under natural pressure. This natural pressure results from factors such as expansion of a gas cap, expansion of dissolved gas in the oil, influx of water from an adjacent water aquifer, or expansion of the oil itself. Strictly speaking, primary production includes only the production resulting under such natural drives, although a number of development techniques have become so commonplace that they are often included as part of primary production.

The two most common techniques are acidizing and hydraulic fracturing. Acidizing involves injection of corrosive fluids to dissolve drilling muds and other materials in the vicinity of the wellbore which may decrease oil flow. Acidizing is particularly effective in carbonate reservoirs, where some of the rock itself can be dissolved. Hydraulic fracturing involves injection of jelly-like fluids down the wellbore at high pressures which crack or fracture the formation and enhance the oil flow.

If a reservoir has no gas cap then, as primary production continues, the pressure in the reservoir will decline until the "bubble point" pressure is reached. Once the reservoir pressure drops below this pressure, dissolved gas will become liberated from the oil and this gas will be produced. This severely depletes the principal drive mechanism (solution gas), and in such cases the recovery factor is seldom in excess of 30% of the original oil in place. The bubble point of a particular reservoir depends on the reservoir temperature and the chemical composition of the oil. Given that production is hindered if the pressure drops below the bubble point, it has become conventional engineering practise to supply energy to the reservoir through injecting gas or water. These processes extend the life of primary production and are referred to as "pressure maintenance." Here again, because it is considered common engineering practise, pressure maintenance is often classified as primary production.

Secondary production is more readily defined than primary production, as it consists essentially only of adding energy to the reservoir to try to displace oil in a piston-like fashion by some other immiscible fluid. Specifically, this includes only waterflooding and lean gas injection. Neither water nor gas will mix with the oil to a significant extent, hence these processes are "immiscible", and the bank of water or gas effectively pushes or displaces the oil towards the producing wells. Ideally, none of the injected fluid will break through to the producing wells until all of the areas in the reservoir have been swept. Practically, however, the immiscible interface between oil and the displacing fluid is not so well-behaved and water or gas can break through before all of the reservoir is swept.

Even after a very successful waterflood, up to 50% of the reservoir volume may still contain oil.[1] This oil is still trapped in the pores in both the swept and unswept regions and can only be produced by further production techniques, usually referred to as tertiary production.

Tertiary production often attempts to correct or prevent one of three principle problems encountered by a waterflood. First, the sweep efficiency of a waterflood seldom attains 100%. One purpose of tertiary recovery is to affect areas which were not reached by a waterflood. Second, even though a waterflood may have swept the entire reservoir, it may not have contacted all of the oil in the reservoir due to faults, barriers, or other nonhomogeneities in the reservoir. Although contact factors can approach 100% in homogeneous sandstone reservoirs, values of 75% are common for carbonate reservoirs.[2] Some tertiary techniques are aimed at improving this contact factor. Finally, because of the immiscibility of oil with water and differential capillary forces,[3] swept regions of the reservoir will still contain residual oil. This residual oil usually accounts for 60 to 90% of all of the oil remaining after a waterflood,[4] and hence many tertiary recovery projects are targeted to recovering this residual oil.

Tertiary production techniques are often divided into three categories:[5] miscible, chemical, and thermal.

Miscible techniques are directed to recovering all of the residual oil in the swept and contacted regions of the reservoir. In principle, these techniques can recover 100% of the residual oil. A miscible flood essentially involves injecting an agent or solvent which can mix with the oil and reduce the forces which trap the oil in the pores. This is followed by water or gas to push the mixture of oil and the solvent to the producing wells. A number of miscible agents have been used commercially or are in the pilot test stages. The miscible process was first conceived using an injected propane slug as a solvent, and since then the hydrocarbon LPG (liquid petroleum gas) slug process has been expanded to use butanes and pentanes-plus.[6] LPG slugs are miscible upon first contact with the oil, but have a disadvantage in their relatively high cost. It is often more economic to initiate a flood which uses either gas enriched with LPG, or simply high pressure lean gas (methane). Both of these latter methods achieve miscibility after multiple sustained contacts with the oil. In the enriched gas process, the gas transfers the light LPG to the oil in the vicinity of the injector well. After multiple contacts, this oil around the injector becomes miscible. Conversely, in the high pressure lean gas process, the light hydrocarbons are leached from the oil such that the gas front eventually becomes miscible. All of the above processes are termed "hydrocarbon miscible" techniques, and the type of technique undertaken will depend upon reservoir conditions and the cost and availability of the alternative injected agents.

A second miscible process which has been used with commercial success, particularly in the United States, is carbon dioxide (CO_2) flooding. CO_2 is gaseous in form under normal reservoir conditions, and operates in a manner similar to the lean gas miscible process, that is, the CO_2 leaches lighter hydrocarbons from the oil. But CO_2 has a number of technical advantages in addition to its miscibility with both water and oil. First, upon dissolving in the oil it substantially swells the oil. This effectively brings the oil closer to its gas-saturated state, causing a greater effective pressure in the oil and enhancing its mobility and flow. Second, CO_2 can also be introduced in the reservoir during a waterflood operation in the form of carbonated water. It has been reported that this practise could increase recovery by as much as 15%.[7]

Chemical processes of tertiary recovery are characterized by their relatively abundant use of chemicals other than hydrocarbons and water. Four general chemical processes are identified: polymer flooding, micellar flooding, microbial enhancement, and alkaline flooding.

Whereas miscible flooding has as its major purpose the recovery of residual oil in swept areas of the reservoir, polymer flooding is initiated to increase the areal or vertical sweep efficiency. When water is injected into a reservoir, it tends to follow a gradient along a line of least resistance. As a result, high permeability areas are swept and low permeability areas are left unswept. Polymers are long chain molecules which, in a water solution, exhibit a viscosity significantly greater than that of water. In effect, a polymer solution is gelatinous, and its injection into a reservoir will inhibit the flow of a flood through the high permeability regions, forcing the flood to sweep the low permeability areas. In practise, such floods involve injection of a slug with a high polymer concentration on the leading edge, tapering to a low concentration on the trailing edge. This slug is then chased by water as a standard waterflood.

A second chemical technique which shows great promise is micellar flooding, also refered to as microemulsion flooding or surfactant/polymer flooding. This process is similar in principle to a polymer augmented waterflood, except that the polymer is preceded by a "microemulsion" slug containing chemicals which effectively make this slug miscible with the oil. The microemulsion slug contains a specially engineered mixture of water, hydrocarbons, brine, and surfactant. The surfactant (surface active agent) is like a detergent in that it washes the oil from the rock into the slug, and hence is responsible for the miscible action of the microemulsion.

One of the problems encountered frequently by chemical injection is that the chemicals plug the face of the formation or are absorbed by the reservoir rock. Tests have therefore been undertaken in an attempt to create these chemicals in situ by injecting cultures of bacteria. Microbes have been isolated which will grow on crude oil and produce CO_2, acting as miscible agents, and others have been found to act as effective surfactants. Although these processes are in their infancy stages and in most cases the actual biochemistry is not understood, they are receiving careful scrutiny by both industry and government institutions.[8]

A chemical scheme which has met with somewhat more success than microbial enhancement is alkaline/polymer flooding, or caustic flooding. The process involves injections of a slug of a caustic substance such as sodium hydroxide, followed by polymer for mobility control. There are basically three mechanisms by which the alkaline flood can increase oil recovery: entrainment, entrapment, and wettability reversal.

In the entrainment process, oil is swept up in an emulsion at the leading edge of the flood, and is produced with the emulsion. Entrapment mechanisms also emulsify residual oil, but here the oil droplets swell to the extent that they become trapped in the smaller pores, diverting the flood to other areas of the reservoir. Although some residual oil is lost in the process, the resulting increased sweep efficiency more than compensates the loss. Finally, wettability reversal is directed to improving the displacement efficiency of a flood. Residual oil which is otherwise trapped by water in the pores becomes physically altered such that it can flow past the water along the rock surface.[9] Although the alkaline process was first patented in 1927,[10] it is still in a developmental stage and has been tested only in a few fields.

Thermal processes operate on the principle that the introduction of heat to the reservoir will decrease the viscosity of the oil, causing it to flow more readily. A number of methods have been tested and implemented, and other exotic methods are in the conceptual stages. Most of the tested methods utilize either hot water or steam injection. Hot water injection involves preheating of the forward portions of the waterflood, increasing the oil mobility near the oil/water interface. Steam injection can be classified either as a steam drive process or a steam stimulation process. Steam drive involves a total sustained increase in the reservoir energy by injecting steam which concurrently displaces oil and reduces its viscosity. Steam stimulation, on the other hand, involves injecting steam and then capping the wellbore for some time to allow the steam to "soak" in and heat a vicinity around the wellbore. The injection well then reverts to a producer and the mobility of the oil flowing through the stimulated zone is increased. Eventually the heat energy is lost and the cycle is repeated. The primary goal of thermal recovery is to increase oil mobility, but the processes exhibit a number of other desireable properties. On occasion, a thermal front will cause lighter fractions of the oil to vapourize, thus creating a miscible flood in advance of the thermal drive.

A more exotic thermal technique is in situ combustion or fire-flooding. In situ combustion involves the injection of air into the reservoir which is spontaneously or artificially ignited, causing some of the oil to burn and to vapourize water in the reservoir. The resultant steam/oil mixture increases oil mobility as well as exhibiting miscible qualities. An important modification of in situ combustion is wet combustion, whereby water is injected alternately with air. This water vapourizes, recapturing the heat from the rock and transfering it through and ahead of the combustion front. The principal advantages of wet combustion are that it requires less air, burns less oil, and achieves a greater efficiency in the use of the heat generated.

The thermal methods discussed above have seen a substantial amount of field and laboratory testing and are well on their way to becoming commercial applications. Two other techniques have received moderate attention recently, although they are still at the experimental states. These techniques are electric heating and the use of underground explosives.

Electric heating is technically effective in very heavy, near solid, crudes where steam injection is impractical. Electrodes are inserted in the wellbores and reservoir connate water is heated by conducting the electricity. After the reservoir is sufficiently heated that the oil is mobile, steam or water drive can be utilized to produce the oil. A successful pilot test of this process was recently completed in the Athabasca tarsands deposit near Fort McMurray.[11]

The use of subsurface explosives to heat oil and fracture reservoirs has received minimal attention in North America, although two successful field tests have been reported in the U.S.S.R.[12] The first explosives ever used were chemical charges placed at the bottom of wellbores. The effects of the charges were limited to enhancing recovery for only a short period, as their primary impact was to create short fractures around the wellbore. Both of the successful tests conducted used small nuclear devices. The charges, when detonated, reduce the viscosity of the oil by heating it, as well as creating an underground cavern in which this oil can accumulate. Radioactive contamination is minimized through proper placement of charges, and acceptable levels of radioactivity can be achieved within a few months. Although this method may currently face problems of unacceptable risk, it is identified as a technique which could eventually yield significant production from heavy oil reserves and watered out reservoirs.

From the preceding discussion, it is clear that a large number of techniques are available for producing oil. A summary of these techniques is presented in Table 1.1. The order and manner in which they are applied depends quite strictly on technical conditions in the reservoir, and prevailing economic conditions. In particular with the tertiary recovery mechanisms, the technical options which are practically available may be limited to only one or two alternatives. For example, miscible floods are not usually technically viable in heavy oil fields. To determine which schemes are theoretically amenable to a particular reservoir, complex screening procedures have been developed which progressively test key physical and chemical parameters of the reservoir and the oil.[13] Often these screening procedures implicitly include some economic considerations. Once the technical alternatives are identified, explicit economic criteria can be utilized to choose the most appropriate development alternative.

1.2.2 EOR Defined

The techniques of interest in this study are broadly classified as "enhanced recovery" techniques. It was previously mentioned that the literature provides a number of definitions of enhanced recovery. The Alberta Energy Resources Conservation Board defines it as:[14]

> Recovery of oil, gas, or natural gas liquids by the implementation of an artificially improved depletion process over a part or the whole of a pool...

This definition potentially includes pressure maintenance, waterflood, and tertiary recovery. A similar definition is presented by Dake,[15] although it excludes pressure maintenance. Finally, there are those who define enhanced oil recovery strictly as tertiary recovery, excluding all schemes of pressure maintenance and secondary recovery.[16]

TABLE 1.1

Summary of Oil Production Techniques

Stage	Process	Mechanism
Primary Production	Natural	Gas-cap Expansion Adjacent Water Aquifer Solution Gas Expansion Oil Expansion
Well Stimulation	Acidizing	Increases Permeability
	Fracturing	Increases Permeability
Pressure Maintenance	Gas or Water Injection above Bubble Point	Prevents Escape of Solution Gas
Secondary Recovery	Waterflood	Immiscible Piston-Like Displacement
	Gas Flood	Immiscible Displacement
Tertiary - Miscible	Hydrocarbon Injection:	
	LPG Slug	Immediate Miscibility
	Enriched Gas	Miscible after Multiple Contacts
	High Pressure Lean Gas	Miscible after Multiple Contacts
	Carbon Dioxide Injection: Gas Carbonated Water	Miscible after Multiple Contacts
Tertiary - Chemical	Polymer Flood	Increases Sweep Efficiency
	Micellar/Polymer Flood	Miscibility via a Surfactant
	Microbial Enhancement	In situ Formation of Miscible Chemicals by Bacteria
	Alkaline/Polymer	Increases Sweep Efficiency via Entrapment; Increase Displacement Efficiency via Entrainment or Wettability Reversal
Tertiary - Thermal	Hot Waterflood	Decreases Viscosity of Crude
	Steam Cycling	Heats Area around Producer
	Steam Drive	Piston-like Displacement
	In situ Combustion:	Injection and Ignition of Air
	Dry	Fireflood Heats and Fractionates Oil
	Wet	Water Improves Heat Transfer
	Electric Heating	Heating of Reservoir Connate Water
	Chemical Explosives	Fractures Rock and Heats Oil in Limited Vicinity
	Nuclear Explosives	Creates Accumulation Cavern and Heats Reservoir Oil

The problem of definition lies not only in categorical classification, but also in timing and degree. For example, the Government of Canada in the National Energy Program defined enhanced oil recovery as tertiary recovery: "the additional crude oil recovery from petroleum reservoirs through the application of third generation methods."[17] This definition is ambiguous in that it does not clearly indicate the role of EOR in reservoir development. Some operators questioned at the time whether they would be required to precede an EOR scheme with a small slug of injected water, just for the purpose of qualifying for the tertiary recovery incentives. Also, the definition does not indicate the "degree of implementation" of a tertiary scheme which must be undertaken. For example, it is becoming more common practise to introduce small quantities of polymer to waterfloods to increase the sweep efficiency in fractured zones. Realistically, however, such an operation would not normally be classified as a polymer flood.

The principal goal of this study is to present a model which takes into account the timing of various events in the process of developing an oil reservoir. In principle, the theoretical discussion is fairly independent of the particular event being considered, as it can be applied to any or all of primary production, pressure maintenance, waterflooding, or tertiary recovery. In fact, any reservoir development model should consider the entire chain of expected events from well completion to reservoir abandonment. The fundamental theory, therefore, is not necessarily restricted to a single process. For the purpose of clarity and practical application, however, it is useful to concentrate on one particular process.

The general process under consideration in this study is enhanced recovery, which is defined for our purposes as those processes which are classified in Table 1.1 as tertiary processes, although they need not be "third generation" processes. The reason for this general scope is that there is currently a great deal of interest in estimating potential supply from these processes, and most of the analyses undertaken to date have assumed that EOR is indeed a "third generation" process. This study, therefore, attempts first to illustrate the necessity of relaxing this assumption and, second, the effects thereof.

1.3 HISTORICAL DEVELOPMENT OF EOR IN CANADA

In historical terms, the Canadian oil industry is relatively young. Although tarsands deposits were discovered by early explorers during the fur trade, and although the first commercial oil production occurred in 1858 in Southern Ontario,[18] the first major oil field (Turner Valley) was not discovered until 1936. Production from Turner Valley wells peaked in 1942 and a second oil boom was not rekindled until 1947 and 1948 with the discoveries of the Leduc, Woodbend, and Redwater fields. Growth in the industry continued thereafter, and Canadian annual oil production eventually peaked at the level of 99.4×10^6 m^3 in 1973. The industry's 1982 production was approximately 79.4×10^6 m^3.[19]

The first pressure maintenance schemes put into operation were not so much explicit attempts to increase recovery as a solution to a disposal problem. When oil is produced, a major by-product is briny water. This water may be harmful to surface vegetation and the most expedient manner to dispose of it is by injecting it back into underground formations. Such disposal wells therefore became quite common, although the water was exclusively injected into water aquifers below the oil-water contact in the reservoir. Eventually, pressure maintenance schemes were introduced to increase oil recovery, with the most advanced system established in the Cardium pool of the Pembina field. This field was discovered in 1953 and by 1959 more than 500 water and gas injection wells were being used, and approximately 45% of the field's area was covered by pressure maintenance schemes.[20]

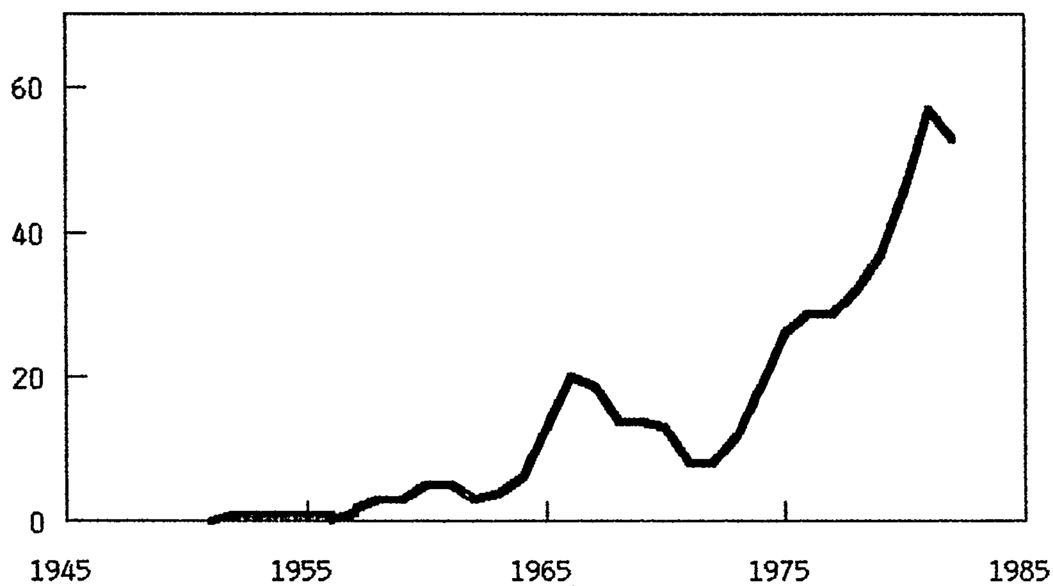
Although pressure maintenance schemes eventually became commonplace, waterflooding as a mechanism of immiscible displacement took some time to develop. The first pilot waterflood was implemented in 1948 in the Turner Valley field, more than a decade after the field's discovery and a full six years after production peaked.[21] Similarly, a pilot waterflood was not considered for the large D-2 pool in the Leduc field until 1959, a full five years after production peaked and also well over a decade after the pool's discovery.[22] The first major commercial waterflood project was implemented in the Viking pool of the Joffre field in 1957. The pool showed its first modest decline from primary recovery in that same year and the waterflood was responsible for continued increases in production into the early 1960s. Since the late 1950s waterflooding schemes have become common and over 500 are now in operation in Alberta.[23]

The early development of pilot EOR techniques in Canada centred on thermal projects. Heavy oil and oilsands account for 97% of Alberta's original oil in place,[24] hence it comes as no surprise that experimental field projects were in place as early as 1952. Activity has grown considerably since that time, as indicated in Figure 1.1. The first technically and commercially successful Canadian enterprise was a series of forward combustion schemes commenced between 1965 and 1967 in the Battrum fields in Saskatchewan.[25] Technical success came earlier in Alberta with Esso's steam soak scheme commenced in 1964 at Cold Lake, although the operator reports that the pilot scheme was not commercially profitable.[26] An indication of the recent contribution of production from thermal techniques is presented in Table 1.2. The table indicates that total production from thermal techniques has stayed relatively fixed over the past three years at an annual production level of approximately 1 million cubic metres.

FIGURE 1.1

History of Activity of Thermal Recovery Techniques in Alberta

(Number of Operating Projects)



Source: Alberta Energy Resources Conservation Board, Oil and Gas Department

TABLE 1.2

Estimated Incremental Production From Thermal Techniques

(10^3 m^3/yr)

	1973	1975	1977	1979	1981
Alberta	negl.*	146.0*	385.0*	621.4	759.5
Saskatchewan	312.0	338.9	341.8	424.1	355.7

*Excludes Esso Cold Lake experimental production.

Sources: Oil and Gas Journal (OGJ) "EOR Surveys" (1976,1978,1980, 1982); 1973 estimated from OGJ (1976) and Alberta ERCB, "Reservoir Performance Charts", (1974).

Of the non-thermal EOR techniques only polymer flooding and hydrocarbon miscible flooding have been implemented at the field level in Canada. The first major solvent flood commenced with injection of natural gas liquids in 1964 into the D3-A pool of the Golden Spike field. Production peaked in 1974 and although the project was deemed to be a commercial success it was a technical failure.[27] Four polymer-augmented waterfloods were operating during the 1970s, the most aggressive being a venture in the Taber Mannville D pool. No polymer is currently being injected in any of these schemes, although some continued pilot work is planned.

An indication of the relative contribution of primary, secondary, and tertiary techniques to total production is shown in Table 1.3. The importance of both secondary and tertiary techniques has grown significantly and this growth has been sustained even during the declines in total production experienced over the past decade. In terms of secondary recovery, waterflooding contributes significantly more than gas flooding. It is important to note that these figures indicate the estimated total annual production from the fields where the particular enhanced recovery schemes are in place. The figures do not indicate the incremental production from these schemes, largely because of lack of estimates of what a particular field would produce had the EOR scheme not been in place. Estimates of incremental recovery would require detailed reservoir simulations which are typically confidential material, if they are undertaken at all.[28]

TABLE 1.3

Source of Alberta Conventional Crude Oil Production, 1981

Mechanism	Production (10^3 m^3)	
Primary Depletion	23,568	(40.8%)
Waterflood (H)[a]	2,878	(5.0%)
Waterflood (L-M)[b]	22,857	(39.6%)
Gas Flood (L-M)	499	(0.9%)
Thermal (H)	760	(1.3%)
Polymer (H)	104	(0.2%)
Solvent (L-M)	7,058	(12.2%)
TOTAL	57,724[c]	(100.0%)

Notes: a) In heavy density crude oil reservoirs.

b) In light and medium density crude oil reservoirs.

c) In addition, 6,446 x 10^3 m^3 of synthetic crude were produced from bitumen mining schemes.

Sources: See Footnote 28.

1.4 THE REGULATION OF EOR

One of the most crucial elements of the success and role of EOR as a significant future source of crude oil supply is the extent to which the Federal and Provincial governments are dedicated to the cause. Indeed, the entire economic well-being of Canada's petroleum industry has been at the mercy of government policies over the past decades, and it is possibly one of the most regulated industries in Canada today.

The possible reasons for the governments' involvement in this industry are manyfold. First, oil and gas accumulations occur in areas where governments own the mineral rights. Second, the increased value of the resource since the 1973-74 OPEC price increases has caused the realization of significant economic rents, so oil and gas have become an important tax base. Third, also as a result of the 1973-74 supply disruptions and subsequent price rises, the Federal government has been dedicated to securing domestic supplies. Finally, in an effort to protect consumers from sudden price increases (such as those in 1979 and 1980) the government has intervened in the pricing and distribution of oil and gas. It is not within the scope of this study to discuss the merits of these reasons. It is taken as a given that government regulation of the industry is and will continue to be an important factor in the industry's future.

The regulation of enhanced oil recovery operations arose naturally out of the Government of Alberta's early involvement in the industry. To prevent the wasteful flaring of gas and the wanton depletion of natural reservoir pressure under the "rule of capture," the Oil and Gas Conservation Board was established in 1938 to unitize production and regulate waste. The Board's early mandate to ensure preservation and effective use of the Turner Valley resource base naturally led to the regulation of all development plans which would affect a reservoir's performance. Thus it oversaw all waterflood and pressure maintenance schemes, as well as becoming involved with regulating and monitoring tertiary recovery schemes.

Over the past decade, the regulation of EOR has become more pronounced, and government involvement at both the Provincial and Federal levels has occurred. It is useful to review in somewhat more detail the particular reasons for regulating EOR and for designing programmes which pertain only to EOR.

One reason for the governments' interest in EOR is that production from conventional oil reserves using conventional techniques has been steadily declining. From concerns about increasing domestic sources of energy supply, a number of programmes have been implemented which have attempted to provide incentives for extending Canada's proven reserves base. Since primary and secondary production techniques currently recover less than one-half of the original oil in place, the remaining volumes which serve as a target for EOR represent a major potential source of supply. Further, since many of these resources are in currently producing or abandoned fields, the geological potential of EOR is fairly well established and no costly and risky exploration programmes are required.

Given the existence of this EOR potential, the question then becomes "How and by whom will it be tapped?" In answering this question, one might first more properly address the normative issue of whether it <u>should</u> be tapped. There are a number of factors and criteria which may be applied in addressing this issue, many of which lie in the realm of political decision-making. From an economic perspective, however, one would normally undertake a project or exploit a resource only if some net economic gain could be realized. This net economic gain is easily analysed from a corporation's point of view as expected profit. Simply stated, if a company can realize profits on an EOR project which exceed those profits that might be realized by an alternative investment, then it will be in the company's best interest to undertake that enterprise.

A similar criterion can be applied if the decision is to be made by a society instead of a company. Here, a project will be in society's interests if some net benefits can be realized by that society. Analytically, one would attempt to identify all of the benefits from a project and all of the costs associated with achieving these benefits. If the benefits appear to outweigh the costs, the project is socially beneficial.

In the case of an EOR project, the project would be socially desirable if some net social benefit were generated as a result of producing this oil. Hence, the question of whether the oil should be produced may be addressed by analysing whether net benefits exist. A number of studies have been completed which indicate that the social supply costs of producing oil through EOR techniques are less than the cost of the most likely alternative oil source (which, for Canada, is imported oil).[29] The studies also indicate, however, that although net benefits or rents can be realized, supply prices[30] are much higher than those for conventional techniques. For example, the National Energy Board[31] estimated that production costs for conventional crude oil in Alberta were in the neighbourhood of $\$20/m^3$. By contrast, Prince[32] estimated supply prices for EOR ranging from about $\$50/m^3$ to $\$150/m^3$, depending upon the technique. In summary, although EOR is costly, it is cheaper than the alternative of importing oil, which cost about $\$250/m^3$ in 1982.

It was set out earlier that the oil industry is a highly regulated sector of the Canadian economy. The levels of taxes and royalties which have been applied result in a revenue share to government and consumers well in excess of one half of the value of production. For example, the Government of Canada estimated in its National Energy Program Update 1982 that some 60% of the value of petroleum production from 1981 to 1986 would accrue to governments and consumers.[33] It is evident that, if this same level of taxation were applied to EOR schemes, then the cost to industry of supplying some of the oil would exceed the value of the oil.

In economic terms, the taxation system which is applied to conventional oil is non-neutral when applied to EOR resources.[34] The imposition of such a fiscal regime would cause market distortions which prevent EOR production even though some of this production would create net benefits to Canada. To remove these distortions, federal and provincial governments have implemented special provisions which attempt to create incentives for EOR production without sacrificing economic benefits and government revenues. Because of the changing economic environment and a distinct difficulty in predicting the technical success of EOR schemes, the regulations governing EOR have been the subject of constant review and revision. In addition to pricing provisions, selective tax and royalty reductions, and direct incentive payments, governments are becoming more involved in equity participation in projects and subsidization of EOR research.

It is difficult to assess whether the non-neutrality of EOR regulation is being eliminated by such measures, but a recent study by Prince and Webster[35] gives some indication of the degree of success which certain programs have achieved. They estimated the total incremental recovery from EOR in Alberta under three fiscal (price and tax) regimes: I) Pre - NEP; II) NEP; III) Alberta-Ottawa Price Agreement.

The "Pre-NEP" system features royalties and regulated prices in place in early 1980. Prince and Webster assumed in their analysis that wellhead prices would be $20/bbl. The "NEP" system includes all of the provisions announced in the Government of Canada's National Energy Program of 1980. Major changes were higher wellhead prices for tertiary oil and the introduction of an 8% wellhead tax (PGRT). The Alberta-Ottawa Price Agreement in Fall 1981 saw further price increases and an increase in the PGRT to an effective rate of 12% of operating revenues. For the latter two cases, the fiscal regime was further split into provisions for Canadian and for foreign firms. Canadian firms were assumed to be eligible for a full "Petroleum Incentive Payment" of 20% of development costs, whereas foreign firms do not have this incentive available.[36] The results of this study are summarized in Table 1.4.

The results indicate that the non-neutrality of the taxation system is being slowly eliminated. With the progression of various programs from 1980 to 1982, the estimated cumulative EOR production has risen from 426 x 10^6 m^3 to almost 500 x 10^6 m^3. This is as a result of marginal reserves becoming viable under the new pricing arrangments. (Note that the potential with foreign firms is less than with Canadian firms because of the higher level of PIP payment to Canadian firms.) Whereas in early 1980 the existence of these provisions forced out almost 8% of total potential EOR production, by Fall 1981 the incidence of similar provisions forced out only 3% of potential EOR production. It is hence evident that some progress has been made in the regulation of EOR. As it currently stands, however, many of the firms which are involved in EOR development on a significant scale are the foreign-owned majors. In this respect, the taxation system involves a further distortion which could be reduced through either increased Canadian involvement or further adjustment of the fiscal regime. Although it may not have been the purpose of those regulations to induce further Canadian involvement, the differential may be sufficient to cause shifts of this sort. This effect is not addressed by the Prince and Webster study, and its validity may only be tested given more time for observation.

TABLE 1.4

Effects of Fiscal Regime on Cumulative EOR Production

Fiscal Regime		Cumulative EOR Production (millions of m^3) Estimated[a]	Potential[b]	Lost Production[c]
(I)	Pre-NEP[d]	426	463	7.95%
(II)	NEP			
	- Foreign	463	487	4.99%
	- Canadian	482	488	1.24%
(III)	Price Agreement			
	- Foreign	487	502	3.03%
	- Canadian	496	504	1.58%

Notes: a) Indicates production if all taxes and royalties are included.

b) Indicates production if taxes and royalties are excluded, but PIP payments are maintained.

c) Indicates proportion of production lost as a result of including royalties and taxes.

d) Assumes price of $20/bbl (1978 $).

Source: Prince and Webster (1982), Figure 1.

Adjustments made since the September 1981 pricing agreement represent further steps in encouraging EOR projects. Perhaps the most significant of these steps was the royalty reduction announced by the Government of Alberta in October 1982. The Government estimated[37] that this program alone effectively tripled reserves attributable to EOR in Alberta.

1.5 FUTURE PROSPECTS FOR EOR

Four general areas can be considered for extending domestic crude oil supplies:

a) additional exploration in conventional areas;
b) development of oilsands;
c) exploration and development in frontier areas (offshore);
d) enhanced oil recovery.

Although governments are encouraging development in all of these areas, the most significant near term potential probably lies with EOR. Whereas during the 1970s the industry tended to favour mega-projects in the form of multi-billion dollar tarsands plants and Northern pipelines, we may anticipate that the 1980s will see the rise of less capital intensive or smaller scale projects, such as EOR schemes.

One of the major factors influencing future prospects of EOR when compared to other alternatives is the anticipated return on investment. This is directly related to the supply price and the ultimate value received for the product. Since all oil from the new sources will receive the New Oil Reference Price (NORP), the major consideration governing project economics will be supply price. Estimates of ranges of costs from various sources are presented in

Table 1.5. It is evident that supply prices for EOR are on average considerably less than those for frontier supplies and tarsands development, and that they are comparable to conventional exploration and development costs.

Although supply costs are a key variable in determining a project's viability, the desirability of a project from both a national and commercial viewpoint will also depend on the perceived risk in achieving a certain level of return. Risk exposure is directly linked to such factors as the geological risk of establishing reserves, the engineering risks of producing reserves, the lead times in project development, the total capital requirements and the susceptibility of these capital requirements to cost overruns.

In the case of geological risk and uncertainty, we are dealing with probabilities of successfully finding, delineating, and developing reserves. This risk is highest in unexplored areas such as the frontiers and deep exploration for conventional light oil. The risk is considerably lower for heavy oil deposits, which are quite shallow and the occurrence of which has been fairly well established.[39] The lowest geological risk is associated with tarsands and EOR projects, since the target reserves for both are well established.

The engineering risks associated with producing the reserves tend to be lower for the conventional resources and frontier schemes, where conventional production techniques can be applied. Those techniques using less conventional technology, such as oil sands mining and EOR, are subject to higher risks, although some EOR processes have been developed to a stage where these risks are fairly low. For example, the steam and soak method of thermal recovery has been tested and proven in many applications, and has seen considerable commercial success.

TABLE 1.5

Comparison of Oil Supply Prices

(1982 $; 8% discount rate)

Source of Supply	Range ($/m^3)
Conventional Exploration	
Light - Medium Oil	> 30
Heavy Oil	60 - 125
Tarsands	280 - 350
Beaufort Sea/Mackenzie Delta	
Pipeline Transport	220 - 335
Marine Transport	290 - 415
Enhanced Oil Recovery	
Chemical	65 - 195
Thermal	80 - 130
Miscible	165 - 170

Sources: See Footnote 38.

Large economic risks are associated with projects having long lead times. These lead times tend to be proportional to the scale of a project, so that oilsands plants and frontier development require anywhere from 4 to 10 years of development before the first drop of oil is delivered. Conventional and EOR techniques are not as subject to these long lead-times, hence there is less risk involved in estimating important future economic variables such as prices, interest rates, and operating costs.

Further, risk exposure is related to a project's capital requirements. A recent cost estimate for a tarsands plant is $14 billion for a 150,000 b/d plant.[40] A small oil pipeline through the MacKenzie Delta would cost in the neighbourhood of $500 - $800 million. An onshore production facility in the MacKenzie Delta costs about $500 million, whereas developing a reservoir such as Tarsiut in shallow water in the Beaufort Sea would cost upwards of $7 billion.[41] By contrast, incremental capital costs for EOR schemes are in the neighbourhood of $20 million for a thermal project, about $10 million for miscible processes, and about $2 million for chemical processes.[42] Even compared to conventional exploration, which can cost in excess of $5 million for a deep well in the Alberta foothills, EOR capital requirements are relatively small.

Finally, the social desirability of a project must also consider additional social infrastructure requirements. These tend to be very large for frontier and tarsands development, and hence such projects also have greater potential environmental and socio-economic impacts. EOR development has the smallest incremental infrastructure requirements, since it is undertaken in areas where some development previously occurred and hence where facilities already exist. In fact, where conventional reserves are subject to production decline, incremental output from EOR may involve very low incremental infrastructure costs.

In summary, one might expect EOR to play an important role in supplying some of Canada'a near-term crude oil requirements. Since conventional reserves are declining, non-conventional reserves must be exploited. Although frontier reserves and oilsands ultimately offer the largest resource base, EOR has a number of advantages which make it an important resource. First and foremost, it is, in general, less costly on a per unit output basis to implement an EOR scheme than it is to pursue a mega-project. Second, the mega-projects have such long lead times that they may not contribute significant incremental producibility until the 1990s. Third, in capital markets which have recently reflected very high real interest rates, companies are more likely to opt for less capital intensive projects such as EOR schemes, as opposed to multi-billion dollar mega-projects. Finally, EOR has the additional advantage that, although such schemes may be difficult to engineer, the geological crude oil target is often a part of our proven resource base.

All of the above, when coupled with a favourable regulatory environment, indicate that EOR will be an important prospect for increasing domestic crude oil producibility. In light of this, it is paramount that EOR receives its proper place in any thorough analysis of Canada's oil supply picture. It is the purpose of this study to indicate some of the important technical and economic aspects of EOR development, and to suggest how they may be incorporated in an overall supply analysis.

CHAPTER 2

EOR SUPPLY ANALYSIS: TECHNICAL ASPECTS

2.1 INTRODUCTION

The purpose of this second chapter is to introduce some of the many technical and engineering aspects involved in EOR supply analysis. The central focus will be on stock effects in the reservoir, progressing from a basic discussion of the maximum efficient rate to the final discussion of hysteresis effects in the reservoir. Stock effects arise where the production of oil in any given period will affect the producibility of oil in later periods. Of all the effects discussed, particular emphasis will be placed on the effects of optimal timing in staging reservoir development. This is because the problem of optimal timing is perhaps the most interesting from the economic analyst's point of view in that it involves choosing between two goals often thought to be opposing: maximizing recovery versus maximizing net present value.

The chapter concludes with some evidence of the existence of the stock effects which were discussed only theoretically in the first parts of the chapter.

2.2 TECHNICAL ASPECTS OF EOR

2.2.1 Incremental Recovery

High product prices, low implementation costs, and favourable tax and royalty concessions may all contribute to the commercial profitability of an EOR scheme. Ultimately, however, the success of a particular project will also depend upon the additional oil recovery caused by the EOR scheme. Not only is the total incremental recovery of importance, but, from an economic standpoint, the time profile of production of this incremental oil will also have a bearing on a project's profitability. It is therefore very important to attempt a prediction of incremental total recovery and incremental producibility before undertaking a project. This chapter sets out some of the important technical aspects in predicting such recoveries. Although the discussion will fall far short of a thorough and complete discussion of performance prediction,[1] it is intended to focus on stock effects in the reservoir.

The unique nature of each petroleum reservoir precludes discussing reservoir performance without some caveats. Since all reservoirs are different, it is unlikely that a general theory or a general correlation will be so universal that no exceptions to the rule can be found. In other words, the lessons learned from laboratory and field experience may be useful, but they may not always apply. Only with this disclaimer can one proceed into a discussion of performance prediction.

The first rough estimate which can be used for predicting recovery is to look at the historical record. In Alberta, for example, primary production mechanisms produce about 23% of the original light and medium density oil in place and about 7% of the original heavy oil in place. Incremental waterflood recovery is about 16% of oil in place for light and medium oil and 18% for heavy oil.[2] Hence the average target for incremental recovery via EOR schemes is about 60% of the light and medium oil, and 75% of the heavy oil. The success of various EOR schemes in recovering this residual oil is indicated in Table 2.1. It is clear that the range of recoveries is often quite large, and the actual recovery will depend upon more detailed reservoir characteristics.

TABLE 2.1

Incremental Production from EOR Techniques[a]

EOR Technique	Net Incremental Production (% of ROIP)[b]
Steam Drive	25 - 65
In Situ Combustion	28 - 48
Steam Cycle	23[c]
CO_2 Miscible	15 - 22
Hydrocarbon Miscible	15 - 18
Alkaline	23[c]
Polymer	4 - 6
Sufactant	30 - 43

Notes: a) Figures presented refer to typical conceptual and actual schemes which have been documented in the literature as technically successful.

b) Remaining oil in place.

c) Range not estimated.

Sources: Agbi and Mirkin (1980), Prince (1980), Alberta ERCB (1981), Dafter (1979, 1980, 1981), Heintz, Herbeck and Hastings (1976,1977).

The figures in Table 2.1 refer to over three decades of industry experience. Over this period, the manner in which reservoirs have been developed has changed, since technical expertise increases with experience. The most notable change, apart from the changes in the degrèe of technical sophistication of development techniques, has been in the staging of development.

2.2.2 Staging Reservoir Development

Historically, a typical method of reservoir development was to operate under primary drive for 3 to 7 years, and then to start a waterflood or a gas flood. Once the secondary scheme had gone to completion, a tertiary EOR scheme might be considered; hence the reference to third generation schemes. More recently, however, the industry has been commencing both its waterflood and EOR projects at earlier dates in a reservoir's development.

Hobson and Tiratsoo[3] found that, of 172 EOR projects which were active in the world in 1974, only 65 (38%) were applied after some secondary production had taken place. The remaining 62% were applied immediately following primary recovery operations. The authors comment:[4]

> A number of new methods have been tried in recent years, and the terms tertiary and even quaternary recovery have been used for these. However, apart from being the third or the fourth method applied to a given field, such labels have little merit. Indeed, it has been recognized in some cases, that their application immediately after the primary production stage would have provided a chance of better success.

A more recent survey of 470 terminated, active, and projected EOR projects, completed by Dafter[5], supported this conclusion. The results of his 1981 survey are presented in Table 2.2. It indicates that EOR schemes are often applied as a second stage of reservoir development and even, at times, as a first stage. The author comments:[6]

> ... enhanced oil recovery and tertiary recovery are not synonomous (contrary to quite widespread opinion). Of the 470 projects analysed, only 185 (39.4 per cent) were reported to be truly tertiary recovery schemes. A large number — 258 (54.9 per cent) — involved the recovery of oil during the second phase, that is immediately after production from normal reservoir pressures. Twenty-seven thermal projects (5.7 per cent of the total) involved the primary recovery of heavy oil which could not be produced to any extent using natural reservoir mechanisms.

It is also apparent from these results that the stage of application seems to be correlated to the degree of technical certainty associated with the scheme. Thermal projects are generally started sooner than miscible projects, which are in turn implemented, on average, sooner than chemical schemes. At the extremes, it is seen that for the most proven technology -- steam soak -- 97% of the schemes are implemented at the primary or secondary stage. Conversely, for one of the most experimental technologies -- alkaline or caustic flooding -- only 1 of 15 schemes (7%) was implemented as a secondary recovery project and the rest were implemented after a waterflood or gas flood.

Of the 470 projects surveyed by Dafter in 1981, 70 were located in Canada. A summary of the application stage of these schemes is presented in Table 2.3. There are a number of notable differences between Canada and the rest of the world which indicate that the forward staging of EOR schemes is even more pronounced in Canada, particularly for thermal schemes and hydrocarbon miscible flooding.

TABLE 2.2

Application Stage of EOR Schemes

	Primary	Secondary	Tertiary
Thermal	27	201	74
Steam Soak	13	114	4
Steam Drive	10	45	44
In Situ Combustion	4	42	26
Chemical	0	25	75
Alkaline	0	1	14
Surfactants	0	4	28
Polymers	0	20	33
Miscible	0	32	36
Carbon Dioxide	0	9	24
Hydrocarbon	0	23	12
All Processes	27 (5.7%)	258 (54.9%)	185 (39.4%)

Source: Dafter (1981), Page 125.

TABLE 2.3

Application Stage of EOR Schemes in Canada

	Primary	Secondary	Tertiary
Thermal	17	20	11
Steam Soak	10	5	2
Steam Drive	4	3	3
In Situ Combustion	3	12	6
Chemical	0	4	3
Alkaline[a]	0	0	2
Surfactants[a]	0	1	0
Polymers	0	3	1
Miscible	0	10	5
Carbon Dioxide[b]	0	0	2
Hydrocarbon	0	10	3
All Processes	17 (24.3%)	34 (48.6%)	19 (27.1%)

Notes: a) Proposed.
b) Judy Creek Schemes.

Source: Dafter (1981), Pages F21-F25; F41; F51-F52.

Whereas outside of Canada about 25% of the thermal schemes are applied after some type of secondary recovery, in Canada only 16% can rightfully be called tertiary schemes. More striking, however, is that more than 1/3 of the thermal schemes undertaken or proposed in Canada are being applied before any production from natural drive takes place. This is to be compared to the rest of the world where less than 4% of the thermal schemes are applied as the first method of production. The second major difference lies in hydrocarbon miscible flooding. Of the 13 surveyed in Canada, 10 (77%) are applied after primary production. In contrast, of the 22 surveyed in the rest of the world, 13 (59%) are applied after primary production. The overall result is that, in Canada, almost 3/4 of the EOR projects are commenced as either primary or secondary modes of production.

The above indicates that forward staging is becoming common for EOR techniques. It is also occurring with waterflooding. Perhaps one of the most striking examples is Dome Petroleum's intention for developing its offshore reserves in the Beaufort Sea.[7] All of Dome's estimates of ultimate recovery depend upon early implementation of pressure maintenance and waterflooding schemes. In particular,[8]

> ... a waterflood system will be used at the Kopanoar oilfield in the Beaufort Sea from the outset of production... [This] is not an indication of poor reservoir pressure, simply good engineering practice... [If] the reservoir pressure were allowed to decline at all, it could eventually reduce the amount of oil ultimately recoverable.

Even the regulatory agencies are beginning to insist on some early staging, where feasible. In Alberta, the ERCB is insisting that waterfloods be implemented as quickly as possible.[9] In addition, current practice upon application for a waterflood is to review the potential for a hydrocarbon miscible flood as well. It is encumbent upon the company to demonstrate that either the miscible flood is not technically appropriate or that it will not yield any incremental oil. Especially in the Nisku reefs, the ERCB feels that the potential is so great that it is almost "directing" operators to commence EOR schemes immediately following the commencement of primary production.[10]

It is necessary for oil supply analysts to incorporate this change in behaviour into their supply forecasts. Although economics has a large role to play, one must first understand some of the technical reasons behind changing EOR staging. The following section outlines some of the theoretical aspects of reservoir development which will affect reservoir performance. This section is followed by a presentation of some field and laboratory evidence which supports the theory.

2.3 STOCK EFFECTS

2.3.1 Introduction

Most decisions regarding reservoir development must consider to some degree the existence of "stock effects" in the reservoir. Stock effects can be classified, in general, as a situation where the production of oil in one period will affect the producibility of oil in future periods. Such stock effects exist for all resources which consist of a fixed stock. The degree and complexity of the stock effects depend strictly upon the type of resource under question. Oil is one example of a resource where the stock effects are quite complex.

At the outset, it should be noted that stock effects refer principally to <u>physical</u> effects rather than economic effects. The economic impacts of stock effects are usually referred to in terms of user costs, which are covered in the next chapter. The following sections refer to the physical and technical effects rather than the economic ones. Before looking at some of the detailed stock effects, it is useful to look first at some possible stock effects in general.

The most basic stock effect in a reservoir is depletion. Depletion simply refers to the fact that the production of a unit of oil today precludes producing it at some time in the future. Depletion is a characteristic common to all oil reservoirs. The manner in which depletion is manifested, however, depends upon the reservoir. In general, production of a unit of oil in time $t=0$ will decrease producibility in all future periods $t=1$ to $t=T$, where the last period T refers to the period just preceding total source exhaustion. Depletion in this sense refers to a case where the total amount produced over a reservoir's life is fixed. There is an even tradeoff between the present and future: producing one unit today implies that one unit will be sacrificed tomorrow. These effects will be termed neutral stock effects.

Stock effects are often much more complex than this, as quite often production today may affect the total stock which is recoverable. Here, producing one unit of oil today requires sacrificing more than one unit of oil in the future. Such effects will be termed negative stock effects. The classic example of a negative stock effect is the concept of production at a rate higher than a reservoir's "maximum efficient rate", which will be discussed in detail below.

In contrast to negative stock effects, one can also find examples of positive stock effects. A positive stock effect would arise when the early production of a unit of oil results in some overall net increase in the quantity of oil ultimately produced. There are essentially two situations in which this might occur: one involves externally induced causes and the other involves internally induced causes. External causes refer to some deterioration of the resource base which is related to time and is beyond the control of an individual producer. A striking example of this is production under the "rule of capture."[11] Here, a reservoir is being exploited by more than one producer, each trying to produce the oil before his neighbour does.[12] Internally induced causes are quite different in nature: they refer to a net increase in reserves as a result of a controlled action on the part of the producer. Most of the positive stock effects relate to the staging of reservoir development and the role of timing in implementing certain schemes.

To reiterate, stock effects refer primarily to technical producibility and not profitability. Whether a particular event causes negative or positive stock effects depends only upon its impact on the total reserve base. One could easily find examples where it would make economic sense to implement schemes having negative stock effects or, by contrast, one could find examples of schemes which were uneconomic even though they had positive stock effects.

The following sections discuss some of the stock effects which occur in oil reservoirs and their importance to reservoir development.

2.3.2 Maximum Efficient Rate (MER)

Early discussion of stock effects in the engineering literature centred around the maximum efficient rate of production (MER) from a reservoir. It was originally of interest because, under the rule of capture, multiple operators in a single reservoir found it to their individual advantage to produce at as high a rate as was technically achievable, as long as revenues covered their variable costs of production. There existed, for all intents, a race to produce the oil. At such high rates, it was observed that pressure drawdowns were so substantial that early production of gas and water often occurred.

This loss of natural reservoir drive reduces the ultimate recovery, and is hence a negative stock effect. Such a reservoir is termed "rate sensitive" and the MER represents a limiting rate of production above which there will be a significant reduction in the practical ultimate recovery.[13]

Production at rates above the MER will lead to a decrease in natural drive for a number of possible reasons. Reservoirs with gas caps or underlying water aquifers can be subject to "coning" at high production rates. Coning involves extreme localized pressure drawdowns in and around the vicinity of the well-bore. This pressure drawdown is "felt" by gas and water in other strata and, if these fluids are more mobile than the oil, they will be produced through the oil.[14] At rates of production below the MER, the pressure drawdown is less marked since there is essentially more time available for reservoir pressure to stabilize.

Not all oil reservoirs are rate sensitive during primary production. Craft and Hawkins[15] note that recovery from true solution-gas drive reservoirs and very permeable, uniform reservoirs subject to very active water drives is essentially independent of individual well rates as well as total reservoir production rates. Indeed, a study of a number of typical Alberta pools undertaken by Intercomp showed that:[16]

> ... the reservoirs were not sensitive to production rate insofar as reservoir mechanics were concerned. That is, given reasonable economic parameters and good field operating practice, the ultimate recovery was not adversely affected by increased production rate. In fact, the studies showed that higher ultimate recovery was obtained at higher producing rates.

The results of the Intercomp study are interesting in that they seemed to contradict the "state-of-the-art" in thought regarding MER and production rates. It was, however, an indication that ultimate recovery may be increased by maintaining higher pressures in the reservoir with correspondingly higher production rates.[17] Such positive stock effects are pursued in greater detail in the upcoming sections.

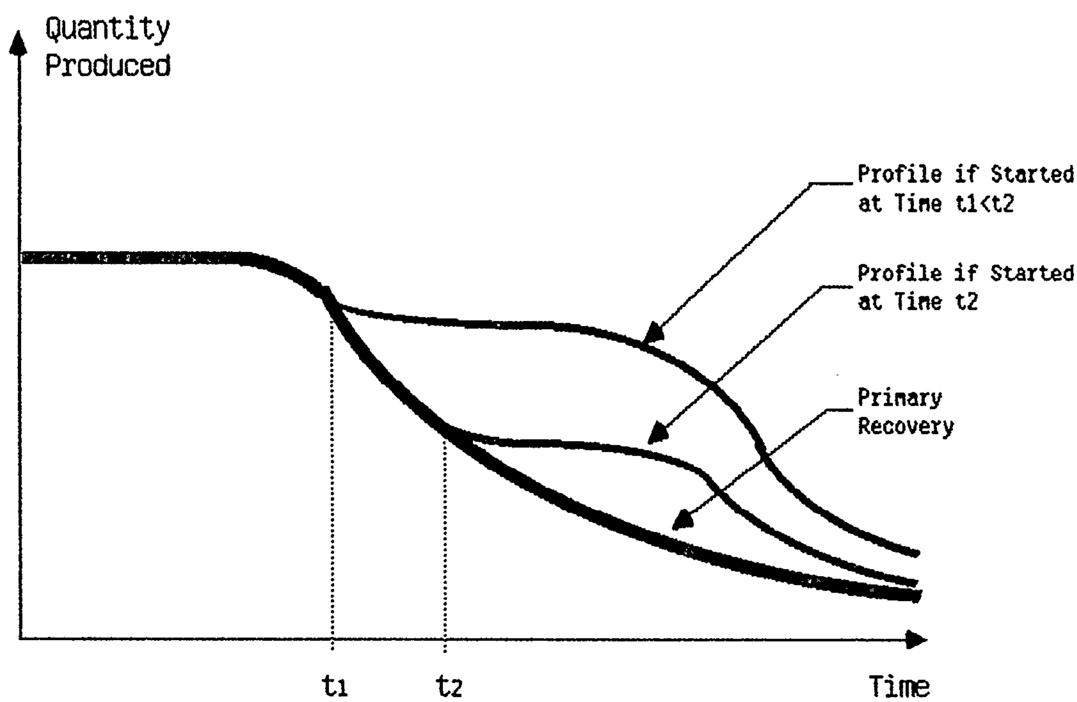
2.3.3 Positive Stock Effects and Staging of Reservoir Development

The record indicates that both waterflooding and EOR schemes are being implemented earlier in a reservoir's production life. A central reason for this is because positive stock effects often occur when a scheme is started at higher reservoir pressures. A graphical example of this is presented in Figure 2.1 for the case of a waterflood. It is seen that a waterflood which is commenced early produces more incremental oil and that, in this example, production is higher in all periods. The same will often apply to certain EOR schemes.

Although time may be an important economic variable, it is not generally the key technical reason for starting a scheme earlier. More useful concepts when discussing stock effects are reservoir pressure and oil saturation (S_o). Reservoir pressure gives a measure of the potential energy within the reservoir and thus yields information important in determining oil flow rates. Oil saturation measures, as a percentage, the volume of the available pore space which is occupied by oil under reservoir conditions. The term "oil saturation" is used in this study as opposed to the more widely used term "residual oil saturation" (ROS). This is because ROS is not used consistently, and can refer to the minimum (irreducible) oil saturation, the average oil saturation at any given time, or the oil saturation in zones previously swept by a waterflood or EOR scheme.

FIGURE 2.1

<u>Effect of Staging on Waterflood Performance</u>



To avoid confusion, S_o is used here to denote oil saturation independent of the type of production mechanism which may have been used, and independent of the length of time any particular mechanism has been in action. S_o simply defines the oil saturation at a given time and place in the reservoir. Both pressure and S_o will generally decline with time as a reservoir is being produced.

In addition to these two factors, an important concept in discussing fluid flow is a fluid's mobility which is defined as the ratio of the effective permeability of that fluid to its viscosity. It gives an expression for the ease with which a fluid flows through a particular environment, encompassing all of the important characteristics of both the fluid and its environment. Clearly, very viscous oils in low permeability areas would have very low mobilities. By contrast, under higher permeabilities or lower viscosities (lighter oils) the mobility of the oil would increase.

In the case of waterflooding and EOR schemes, it is also useful to define "relative mobility" as follows:

$$M = \frac{\text{mobility of displacing fluid}}{\text{mobility of displaced fluid (oil)}}.$$

If $M < 1$, it implies that the oil is capable of moving faster than whatever fluid is displacing it. This is desirable since it means that the displacing fluid will not actually interfere with the movement of the oil. In contrast, if $M > 1$, then the displacing fluid may get ahead of the oil and thus lose its displacing effect and trap some of the oil behind.

Given the preceding definitions, one can now consider how positive stock effects may occur by implementing schemes at higher pressures and oil saturations (i.e., earlier in the production life).

First, consider the simplest case of a typical solution gas reservoir. There are a number of compelling reasons to start a pressure-maintenance scheme, waterflood, or EOR project as soon as the reservoir starts to experience some substantial pressure decline. As the pressure falls, the mobility of the oil also falls and the relative mobility of the solution gas within the oil rises. This causes an increase in the producing gas-oil ratio. If taken to an extreme, most of the gas will have been produced and perhaps only 5 - 15% of the oil will have been produced. If one were to start a pressure maintenance scheme when reservoir pressure begins to decline, more of the natural reservoir energy would be utilized to produce the oil instead of the gas.

Through a similar argument, one can see that EOR schemes which rely on in situ miscibility will recover more incremental oil if they are commenced at higher pressures. In situ miscibility occurs when the injected fluid becomes miscible only after multiple contacts (see Section 1.2.1) through leaching out the light components from the reservoir oil.[18] The high pressure lean gas process relies on this mechanism, and both CO_2 flooding and thermal flooding benefit from it. For such processes to be successful, they require a fair proportion of light components in the oil. Such fractions, however, generally have a higher mobility than the rest of the oil and will be produced more readily if pressure declines sharply. Therefore, at lower reservoir pressures, in situ miscible processes will take longer to achieve miscibility and will have moved through a larger proportion of the reservoir before miscibility is achieved. The effects are enhanced in the case where a producer well is converted to an injector, since the lighter components in the well vicinity would have been produced earlier as a result of the pressure drawdown.

The miscible enriched gas process operates in a converse manner from those above, yet it also depends critically upon reservoir pressure. The mechanism involved here does not require leaching out the light components from the oil; rather it relies on transferring the intermediate components (ethane, propane and butane) from the enriched gas into the oil front to form a miscible front. A certain pressure level is required for this miscibility to occur, and if the pressure falls below the critical level, the enriched gas bank will merely act as an immiscible drive. Hence, miscibility is most easily achieved at high pressures.

One miscible process which is less pressure dependent is the use of alcohol slugs.[19] Alcohol is miscible with both oil and water and hence a slug of alcohol followed by a water drive could work as an effective displacement mechanism. Although miscibility is not so pressure dependent as enriched gas injection is, it is very dependent upon water and oil saturation. When both water and oil are present, most of the alcohol becomes dissolved in the water, a phase separation occurs between oil and water, and what started as an alcohol-oil miscible flood ends up as an alcohol-water immiscible displacement of oil.[20] When very little water is present, miscible displacement is more effective. In terms of staging, this implies that an alcohol flood is more effective if it <u>precedes</u> a waterflood.

The effects discussed above are positive stock effects on a micro scale: they relate to the displacement efficiency of oil in a reservoir. Although these effects can in themselves be substantial, they are more often overshadowed by stock effects relating to sweep and contact efficiencies (first discussed in Section 1.2.1).

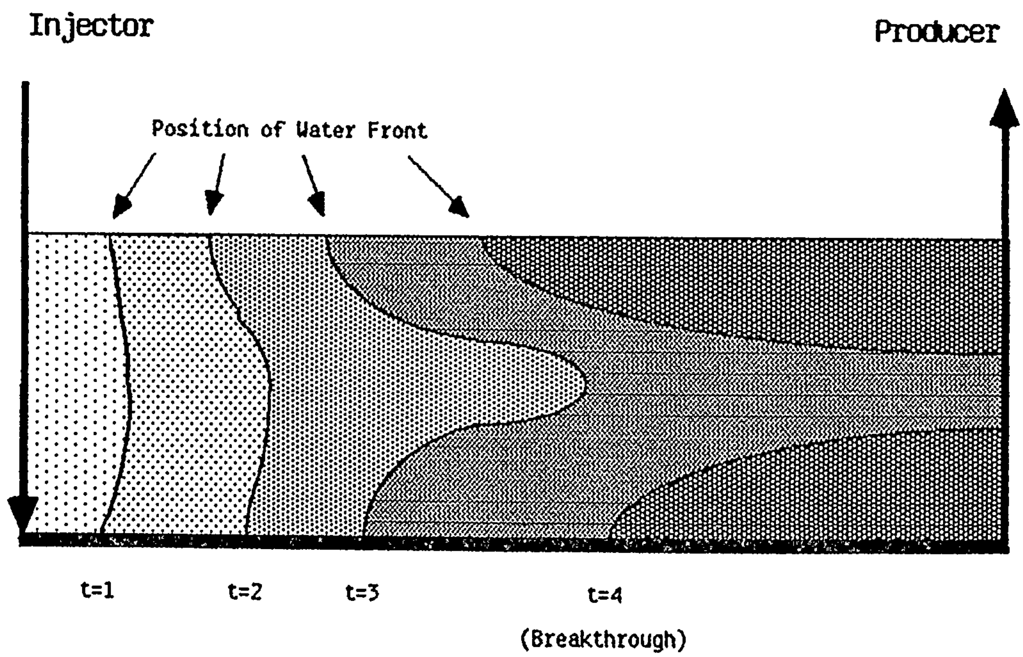
The sweep and contact efficiencies of a waterflood, gas flood, or any EOR flood refer to the proportion of the total reservoir oil affected by the flood. Mobility control is a key factor in attaining high efficiencies. If the mobility of the flood significantly exceeds the oil mobility, fingering of the flood front through the oil can occur (see Figure 2.2). Once the "tip" of the finger reaches the producing well, a channel is established between the injector and the producer through which a great deal of any additionally injected fluid will flow. When a light fluid, such as gas, is injected, it will tend to "ride above" the oil to the producer. Water injection tends to approach the producer from under the oil. Premature breakthrough of any injected fluid can cause a substantial loss of the producible oil. Similarly, once a channel has been established by, for example, a waterflood, it is more difficult to exercise mobility control over the injection of water based tertiary schemes such as polymer floods, alkaline floods, surfactant floods, and most thermal techniques. Any inhomogeneity in a reservoir, such as a water streak, will create similar problems of mobility control for miscible gas floods.

Many of the problems of instability due to insufficient mobility control can be avoided through properly staging the reservoir development. For example, a polymer flood will be more effective as a secondary scheme than as a tertiary scheme since the polymer can block any high permeability streaks in the reservoir. In the case of a miscible flood, the stability of the flood front will be greater if there is a larger volume of oil available for oil-banking.

Although viscous fingering may occur with a waterflood, it is even more likely to occur with gas injection or solvent flooding. Because of this, it was usually common practice to precede a gas flood with a waterflood since there was less risk involved in losing oil from water breakthrough. More recently, however, it has been found that the best of both worlds (mobility control from water and miscibility from solvent) could be achieved by pre-injecting a small volume of water and then alternately injecting solvent and water. This "water alternating gas" (WAG) process again would exhibit better stability characteristics if large volumes of oil are originally present, that is, at high S_o.

FIGURE 2.2

Example of Viscous Fingering



All of the above discussion has pertained to horizontal displacement of reservoir fluids. Indeed, mobility control is most difficult under such conditions since the natural line of phase separation (along a horizontal) is perpendicular to the ideal flood front (which is vertical). But most reservoirs are not perfectly horizontal. Generally, as the angle of dip from the horizontal increases, mobility control does not pose as great a problem, all other things equal. This remains the case provided, however, that lighter fluids such as gas or solvents are injected updip of the producer and that heavier fluids such as water are injected downdip. At the extreme, such as in the case of vertical displacement in a pinnacle reef structure, one could readily inject miscible gas or solvent at the top of the structure and produce from the bottom of the structure near the oil-water contact. This method was profitably applied in some portions of the Leduc zone of the Golden Spike field in Alberta.[21] One feature of vertical displacement which can seriously affect staging is that, unlike a horizontal formation, once a waterflood has been initiated, one cannot commence a miscible scheme until the waterflood has gone to completion. Therefore, an operational decision must be made between waterflooding and miscible flooding which is not readily reversed.[22] Miscible flooding would normally recover more incremental oil but the choice between the two would ultimately depend upon project economics.

2.3.4 Hysteresis Effects

The previous section indicated that ultimate recovery and future producibility from a petroleum reservoir is dependent upon both the reservoir pressure and oil saturation at the time a waterflood or EOR scheme is initiated. Implicitly, it has been assumed that the pressure and oil saturation are uniform and that one might speak of some "average" pressure and S_o. There is, however, one additional stock effect which will have a bearing on future recoveries, which is referred to as a hysteresis effect.

Hysteresis effects refer to physical changes which occur at the pore level in a reservoir as a result of the manner in which oil production from the reservoir took place.[23] Because of hysteresis effects, although current average reservoir conditions are important, the historical path by which those conditions were achieved can also have a bearing on how a reservoir will respond to future development schemes. For example, two initially identical reservoirs might be produced for different periods of time using different development techniques, but in such a way that when both techniques are completed the two reservoirs have the same average oil saturation, average pressure, and volume of remaining oil in place. Although they may appear to be identical at the end, a waterflood or EOR scheme applied at that stage would probably not act the same way in both reservoirs, since some factors are history dependent.

An example of this deals with well spacing during primary production.[24] Suppose two reservoirs are developed, one with 40 acre spacing and the second with 160 acre spacing. Assume further that the total field production rate is the same in both cases. This requires that the per well production in the 160 acre spacing units is higher than in the 40 acre spacing units, and that therefore the pressure drawdown around these wells is also greater. Suppose that this practise continued for two years and that all of the wells were then shut in. At that time, the average pressure and S_o would be identical in the two reservoirs, but they would have strikingly different characteristics. The reservoir with the 40 acre spacing will be more uniformly developed and hence will have a more homogeneous distribution of oil. It is likely, therefore, that a waterflood or

EOR scheme would recover more incremental oil in the evenly developed reservoir, since it is easier to control the mobility and stability of the displacing fluids.

One might argue that if the two reservoirs were left shut in for a sufficient time, then internal pressure would equalize and both would approach homogeneity. However, hysteresis effects at the pore level would prevent the two reservoirs from coming to equilibrium at the same distribution of oil. This is because when pores drain and then refill with fluids, in the presence of two phases (oil and water), the final saturations will depend on the minimum pressure and oil saturation previously experienced in the pore. In the above example, the minimum pressure around the wells would be lower in the case of the 160 acre units, as a result of the greater drawdown to produce at the higher rate. As a result, the minimum pressures experienced in portions of this reservoir are less than in the 40 acre unit spaced reservoir. Hence, even if both are shut in for a long time, they will display different characteristics of oil distribution.

2.4 Neutral Stock Effects and Staging Reservoir Development

Many of the stock effects discussed above might compel an operator to develop a reservoir sooner, since, in so doing, the reserves would be expanded. In some instances, however, forward staging might not yield any incremental oil, but it may still be more economic than waiting because of various cost and technical factors.

The first instance is in the case of a typical "acceleration project," which is undertaken, as Dake describes,[25] for purely economic reasons:

> [Some] methods for stimulating the production of a well ... do not necessarily increase the ultimate oil recovery from the reservoir, but rather, reduce the time in which the recovery is obtained. As such, they are generally regarded as acceleration projects which speed up the production, thus having a favourable effect on the discounted cash flow.

The economic aspects of such a decision are discussed in greater detail in the next chapter. Typical acceleration projects would include acidizing, fracturing, and most thermal techniques.

A second basic technical and economic consideration is the efficient use of energy. Bluntly stated: why expend twice the energy sweeping a reservoir first with a waterflood and then with an EOR flood if you can do the same job with just one sweep? If a reservoir is swept twice, some of the energy from the EOR flood will be used in displacing the water remaining from the waterflood.

Third, there is the question of response time. The shorter the time period between start of injection and start of incremental production, the better the project economics will generally be, all other things equal. If a long delay exists, a project may not even be economic, particularly if large front-end development costs are required. Such is the case with surfactant flooding. The Interstate Oil Compact Commission found that,[26]

> in general, the response time increases when the initial oil saturation decreases... [In a hypothetical example,] the rate of return increases or decreases about 1.5 percent for each 1 percent pore volume change in the ... oil saturation; a small error in the residual oil estimate could change the predicted profitability of a project from a level that would encourage its implementation to one that would discourage any further consideration.

Finally, related to the issue of response time, is the issue of facility requirements. Very often, to implement similar schemes, fewer development facilities are required if a project is commenced early. An example of this relates to the "fill-up" requirements of a reservoir. For oil to be produced effectively by a waterflood or EOR scheme, the pressure in the reservoir must be brought up to a certain level. Before this pressure is achieved, no incremental oil production will occur. The time it takes to bring the reservoir to this pressure is called the "fill-up period."[27] In a reservoir which has been fully depleted under natural drive, it is not uncommon to install injection facilities which have up to three times the capacity of the production facilities.[28] For instance, a field may be waterflooded at a rate of 3,000 m^3/d to speed up the fill-up period, although production may never be more than 1,000 m^3/d. If the waterflood were started earlier, then smaller injection facilities (eg., with a capacity of 1,000 m^3/d) could have been put in place to generate the same ultimate production profile.

2.5 EVIDENCE OF STOCK EFFECTS

There are a large number of theoretical arguments, as noted above, supporting the existence of positive stock effects in a reservoir. This section indicates the recognition of this fact in current literature and briefly presents the findings of a number of group and case studies.

2.5.1 General Literature

Many authors have recognized that waterflooding and EOR techniques are being applied earlier in a reservoir's life.[29] In a recent review of most of the EOR projects being undertaken in the world, Dafter comments:[30]

> The industry is tending to start enhanced recovery much earlier in a field's life than hitherto. This trend arises from an increasing confidence in the techniques and a recognition that enhanced recovery methods are more effective when the target — the amount of residual oil still in place — is larger. Enhanced recovery should no longer be equated with "tertiary recovery" given that a large proportion of the EOR projects are introduced during the primary or secondary phase of production.

In a recent engineering text, Schumacher aptly summarizes the importance of timing and stock effects in contributing to the historical trends noted by Dafter:[31]

> Technically, for some reservoirs the enhanced process works best when used immediately after primary recovery. For other reservoirs, the optimum time may be soon after the waterflood has established the fluid transmissibility characteristics of the reservoir. Ideally, from an economic point of view, tertiary recovery should come along before primary or secondary production reaches its economic limit. This would allow the tertiary oil to share operating costs with ongoing projected production. Thus a ... constraint to be overcome would be the increasing economic and technical burdens imposed by undue delay in the inception of tertiary recovery.

2.5.2 Case Studies

Much of the theoretical reasoning behind the existence of stock effects has either arisen out of or led to laboratory and field studies which support the reasoning. Given the large volume and detail of EOR research which is being undertaken, there are numerous examples of positive stock effects. One can surmise in addition that there are probably more examples where these effects were observed but not reported, since the principal goal was to develop some other theory or the information was used in proprietary applications. The following examples, therefore, only relate a handful of the results of independent experiments which show the existence of stock effects.

One of the earliest laboratory investigations specifically designed to test the role of initial water saturation on the stability and effectiveness of a miscible flood was undertaken in 1956.[32] Using alcohol as a flooding agent, two experiments were conducted on identical cores, one without an initial water saturation and one with an initial water saturation of 40%. These were designed to represent the extreme cases of a reservoir, respectively, before waterflooding and after waterflooding. The effect on ultimate oil recovery was marked. In the "waterflooded" sample, ultimate oil recovery averaged 75.8% of the original oil in place. In the sample with no water, ultimate recovery averaged 94.7% of the OOIP. With respect to the flood's stability, fingering of the flood front was more than twice as pronounced when water was initially present. In summary, the implication of the experiment is that ultimate recovery might be increased by commencing miscible flooding before waterflooding.

Although the above experiment was conducted using alcohol as a miscible agent, similar results were encountered using a miscible slug of liquid petroleum gas (LPG). Koch and Slobod[33] conducted a number of laboratory simulations to investigate the effects of initial pressure and initial water saturation on the effectiveness of the flood. With respect to pressure, it was found that it had no bearing on ultimate recovery of oil <u>as long as</u> a larger slug was injected for low reservoir pressures. If equal size slugs were injected, the ultimate recovery of a flood at high initial reservoir pressures would exceed that of a flood initiated at lower pressures. For example, a 70% ultimate recovery was obtained for a sample at a pressure of 3,300 psi, using a 1.5% pore volume slug. When the pressure was dropped to

2,900 psi, a 4% pore volume slug, using more than twice as much LPG, was required to achieve 70% recovery. They noted that to achieve similar results in the presence of an initial high water saturation (47.8%), slug sizes from 8 - 12% pore volume were required. The final conclusion from the results of these investigations is that, all other things equal, miscible slug processes are more successful at higher reservoir pressures and low water saturation, i.e., early in a reservoir's development. Conversely, a flood started at lower pressures or higher water saturations could achieve technical success, although it could cost from twice to eight times as much for the miscible agent.

It was mentioned previously that one problem with miscible gas processes was mobility and stability. One means of improving mobility was to pre-inject water. It was subsequently found, however, that gas-miscible processes might be even more effective if they are undertaken concurrently with water injection (such as the WAG process). A study by Caudle and Dyes[34] found that gas driven miscible processes applied separately from a waterflood would yield, under an ideally homogeneous reservoir, an ultimate recovery of 60% of the oil. By contrast, they found that recoveries from simultaneous injection approached the ideal limit of 100%. Subsequent investigations by Blackwell, et.al[35] relaxed most of the "ideal reservoir" assumptions of Caudle and Dyes. They found that, even under "non-ideal" conditions, recoveries for simultaneous injection approached 95%.

Apart from hydrocarbons, the most significant miscible agent in use today for EOR is carbon dioxide. Stock effects in CO_2 flooding are also reported to be significant. Agbi and Mirkin[36] estimate that, where primary recoveries are low, a CO_2 flood initiated after primary recovery will yield 50% more incremental oil than one initiated after waterflooding. Comparable results were obtained by Ko[37] in a recent reservoir model study. He found that the total oil recovered over the reservoir's life would increase by about 12% as a result of injecting 19% pore volume of CO_2 when the oil saturation was 0.4 instead of 0.2.[38] Ko also found that, although ultimate recovery was less sensitive to reservoir pressure and CO_2 flooding rate, the incremental EOR production would be produced over a shorter time frame.[39] In summary, it is evident that the ultimate recovery is dependent upon the initial water saturation, and that the producibility profile is dependent upon initial reservoir pressure.

Recent studies also indicate that oil viscosity plays a major role in CO_2 flood efficiency. A number of simulations undertaken by Klins and Farouq-Ali[40] indicate that stock effects are much more significant for heavy oils than for light oils. Results of their experiments are reproduced in Table 2.4. Although positive stock effects existed for all of the oils which were investigated, the most striking effects arose for the very heavy oils (100 - 1,000 cp). Recovery efficiency increased by more than ten-fold through initiating the CO_2 flood when $S_o = 0.7$ instead of when $S_o = 0.4$.

In addition to the miscible flood studies above, a great deal of effort has been directed to controlling mobility through the use of polymers. Polymer banks can be used by themselves, or for mobility control of surfactant and alkaline floods. In an analysis of 56 projects using polymer injection, Sloat observed that "oil efficiencies can be improved from 5% to 15% if polymer is injected when the water/oil ratio is low."[41] The author further comments that:

> polymer, applied at the right time and under the right conditions can improve oil recovery efficiencies. Although reservoir rock characteristics and fluid properties are important, the data accumulated clearly points to timing as an over-riding consideration when it comes to producing 'polymer oil' at a good profit.

TABLE 2.4

Effectiveness of CO_2 Flooding as a Function of Viscosity and Oil Saturation

Viscosity (cp)	Initial Oil Saturation So	Ultimate Recovery % OOIP
1 cp (Light)	0.4	54.66%
	0.6	64.37
	0.7	66.38
10 cp	0.4	30.63
	0.6	47.91
	0.7	48.56
100 cp	0.4	9.62
	0.6	34.75
	0.7	37.05
1,000 cp (Heavy)	0.4	2.65
	0.6	25.47
	0.7	29.35

Source: Klins and Farouq-Ali (1981), Table 3.

The study found that the major improvement as a result of starting at higher oil saturations was an increase in the sweep efficiency. Also, by commencing such floods early, the risk of premature breakthrough was approximately cut in half.

2.6 SUMMARY

This chapter introduced some of the recent trends in initiating waterflooding and EOR schemes, and presented some theoretical and empirical technical evidence for the observed trends. Whereas EOR schemes were traditionally initiated as "third generation" projects, subsequent to primary recovery and waterflooding, they are now being implemented at much earlier stages in a reservoir's development. Most notably, in Canada, the majority of hydrocarbon miscible floods are undertaken before any water or immiscible gas flooding occurs, and more than one-third of the thermal recovery projects have been implemented from the first day of production.

Although this "forward staging" is done to improve the commercial economics of reservoir development, there is compelling evidence which suggests that this forward staging also increases ultimate recovery. Many processes are technically more successful when they are commenced at high reservoir pressures, high oil saturation, or both. This generally corresponds to the early stages of reservoir development. At this time, the additional energy imparted by an EOR scheme to the reservoir is most effectively utilized, and the chance of premature breakthrough of a flood front by viscous fingering is minimized.

Even when the ultimate recovery is not affected by forward staging, some desireable economics may arise as a result of technical factors. Forward staging may decrease the response time, decrease the facility requirements, decrease the material requirements, or simply increase the probability of success. All of these factors would create an incentive for advancing the implementation of an EOR scheme.

Although this chapter suggests that projected recoveries may be increased by forward staging, there are a number of important qualifications to be made. First, both the theoretical and empirical evidence is based on particular assumptions regarding reservoir and oil properties. These assumptions may approximate reality in selected cases, but each reservoir is a unique entity and, as such, may prove to be the "exception to the rule ". Valuable experience may be derived from comparable laboratory and field studies, but these should not be blindly applied to any reservoir. One of the single most problematic areas of engineering an EOR scheme is controlling the mobility and stability of an injected fluid. A fluid's mobility is affected not only by current geological and petrophysical properties in a reservoir, but also by the history of a reservoir's production. Therefore, to properly design a project, some knowledge of the reservoir is required. A second qualifier is that a high pressure miscible gas process generally exhibits very poor mobility behaviour. It has thus become common practise to pre-inject water for mobility control, or to "dilute" the miscible flood by alternately injecting water and gas. Such practises, while somewhat delaying recovery, do improve the ultimate recovery from the reservoir.

The final caveat is that, regardless of what theoretical advantage may exist in forward staging developing, one should never proceed blindly. Some knowledge of a reservoir's primary drive mechanism is essential in designing EOR schemes. For example, if a reservoir has a very active water drive, it would be a waste of good money and materials to start injecting water for a waterflood or for some EOR scheme. In this case, one may wish to wait until the active water drive has run its course. Similarly, a reservoir which is being produced under primary production from an active gas cap will maintain its initial pressure for a long time, and there would be little advantage in supplementing it before the pressure began to decline. Knowledge of a reservoir's natural drive mechanism is not usually known until 5 - 10% of the "primary" oil is produced.[42] This may require anywhere from a few months to a few years of production. Only in certain circumstances, such as when good geological and geophysical data are available, might a reservoir's natural drive mechanism be known from the start. In such a case a reservoir development strategy can be initiated quite early, whereas otherwise one would need to wait until more knowledge is acquired. In any event, once the primary drive mechanism is known, some strategy for developing the reservoir should be devised, and the potential of forward staging should not be overlooked.

In light of recent trends in timing the implementation of EOR schemes, and given that there appear to be compelling technical advantages in commencing such schemes early, these phenomena should be given due consideration by both reservoir engineers and oil supply analysts.

CHAPTER 3

EOR SUPPLY ANALYSIS: ECONOMIC ASPECTS

3.1 INTRODUCTION

The purpose of this chapter is to discuss the various economic aspects which must be considered in supply analysis. The obvious ones are of course prices, costs, interest rates, government taxes and regulations, and future expectations of each of these. Various concepts of "supply" will be investigated, with a particular emphasis on the difference between the engineer's concept of supply "deliverability" and the economist's concept of supply.

The economist's perception of supply will usually be based on some objective function which is to be maximized. The individual company is usually viewed as maximizing the incremental discounted net cash flow. From a social point of view one would usually be maximizing the sum of consumer's and producer's surplus. In discussing the objective function, it should be pointed out that actual practice within the industry may not be to maximize profit or surplus. There is some indication, especially in reservoir engineering, that the initial objective function is to maximize the ultimate recovery, subject to some economic cut-off rate of return. This criteria will not usually be consistent with maximizing profit. Another objective function for certain firms may be to maximize current production for the purpose of generating current cash flow.

A complete EOR supply analysis would include a reservoir by reservoir simulation of each oil pool under prevailing technical and economic conditions. Given the logistical problems of such a task, one is often forced to generalize or aggregate to arrive at a practical type of supply analysis. In addition, because some of the economic assumptions made in supply analysis may not always be applicable, an analyst often finds himself trying to analyze supply within the context of a non-ideal framework. Economic rationale and economic studies usually assume that a company is maximizing profits or that a government is maximizing surplus. Where this is not the case, such analyses may tend to overstate or understate the amount of activity in a certain sector. This study, too, will use as its objective function the maximization of profit and is therefore limited in this regard.

The chapter concludes with a review of some of the previous major EOR supply analyses. The analytical techniques used in these studies are described and evaluated in light of the issues presented in the chapter.

3.2 SUPPLY: A DEFINITION

Over the past decade, the popular press has placed a fair degree of emphasis on "Oil Supply" when discussing conditions in the oil market. The frequent use of this term in these circumstances has led to a certain lack of clarity in what is actually meant by oil supply. Although the term may have certain implicit meanings for the journalist and the layman reader, it means something altogether different to the reservoir and production engineers, and something entirely different again to the petroleum economist. In light of these differences, it is useful to review the principal distinctions between the meanings ascribed to "oil supply" by each of the above disciplines. In particular, one should distinguish between a technical supply function and an economic supply function. It should be realized, however, that the apparent contradictions in definition do not imply that one of the definitions is incorrect. Both definitions have important and valid applications within their individual fields.

Technically speaking, oil supply can mean either deliverability from reserves or the addition of total reserves. Deliverability (sometimes referred to as producibility) typically refers to the quantity of oil which can be produced within a given time period. This time period is quite short with respect to the total life of a reservoir: usually it is expressed in terms of daily production or occasionally in terms of monthly or annual production. Oil reserves are simply the summation of reservoir producibility over the entire field's operating life. At a more general technical level, oil supply refers to the sum total of deliverabilities from all of the individual production units.

Oil supply to a petroleum economist is based on the technical definition of oil supply presented above. In addition, however, the petroleum economist seeks to find a relationship between production and important economic parameters. The economic parameters include such factors as development capital costs, production operating costs, and product prices. Future expectations of costs and prices may also have a bearing on current production. In some cases the economist is interested not in just the production of oil in a short time frame, but rather in the long term availability of oil under certain economic conditions. In such an event, the economist would be evaluating the producible oil reserves under specific economic parameters.

The difference between technical and economic supply of oil is principally a question of where the emphasis is placed. Technical supply analyses emphasize producibility from a reservoir under various production mechanisms. On the other hand, economic analyses emphasize the specific costs involved in undertaking a certain reservoir development plan. Although it is not always explicitly stated, there is usually some implicit assumption behind the technical production profile regarding economic conditions. Furthermore, when one speaks of oil reserves, there exists an explicit assumption of some economic limit beyond which it would not be profitable to produce.

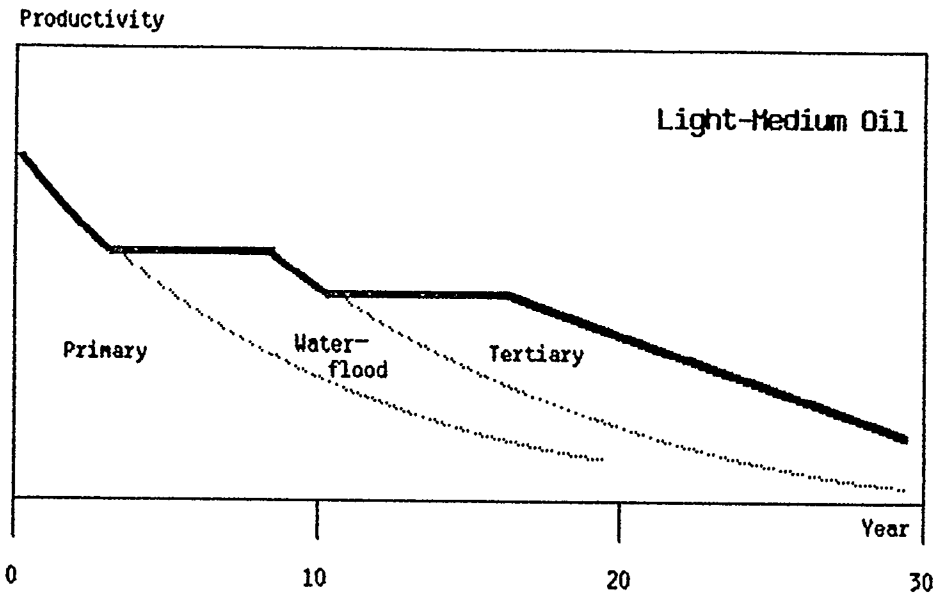
Figures 3.1 and 3.2 indicate some examples of technical oil supply profiles. Figure 3.1 indicates total producibility from typical individual oil reservoirs as estimated by the Alberta Energy Resources Conservation Board (ERCB). The productivity profiles show the amount of oil which can be attributable to various types of production techniques (primary, waterflood, tertiary). The relative proportion of tertiary oil in heavy oil pools tends to be higher than in light and medium density pools because primary recovery mechanisms and waterflooding are not as successful in recovering heavy density oil. Figure 3.2 shows more explicitly the volumes of oil which can be attributable to tertiary recovery mechanisms in a reservoir. Normalized productivity profiles show the time distribution of production from one million cubic metres of reserves.

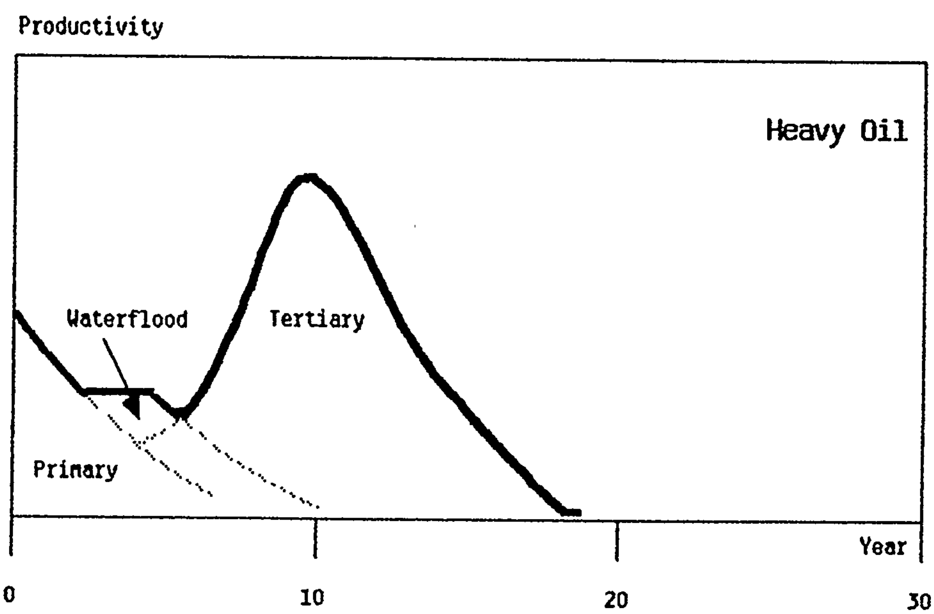
All of the profiles depicted in Figures 3.1 and 3.2 can be classified as technical supply analyses. The emphasis is on the producibility of oil from the reservoir, and there are no explicit assumptions regarding the economics of the particular type of development chosen. There is, of course, some implicit assumption that the incremental economics of both waterflood and tertiary would justify this type of development.

When we add a single economic parameter such as the netback price (after direct taxes) received by a producer, we explicitly recognize that the commercial economics of tertiary recovery will have some bearing on how much oil will be produced. One would expect that with lower netbacks there would be less oil produced, all other things equal. First, lower netbacks may cause some EOR projects to be uneconomic so that they would not be initiated in the first place. Second, lower netbacks imply that fields will be shut-in somewhat

FIGURE 3.1

Schematic of Oil Reservoir Productivity Profiles

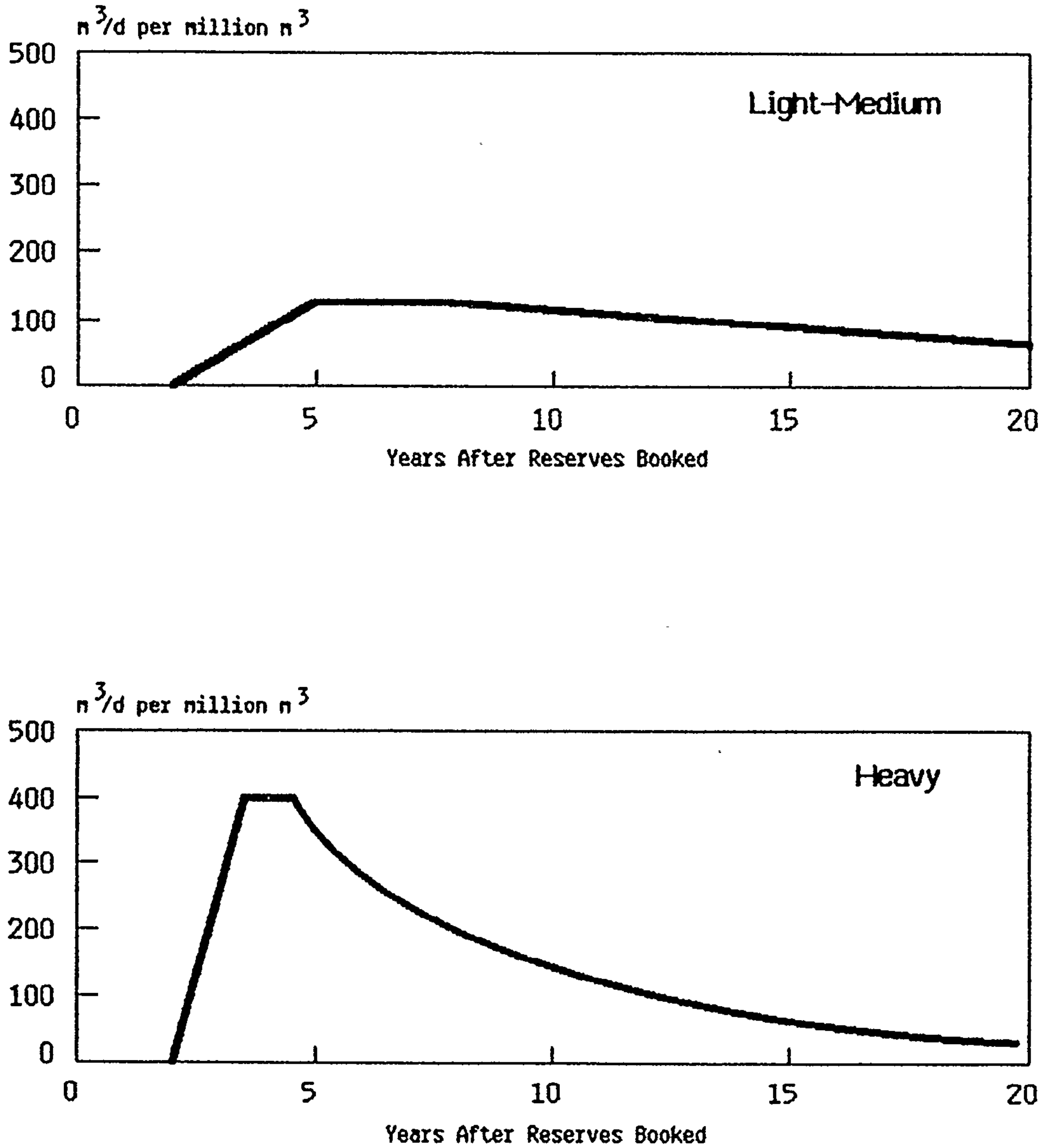




Source: Alberta Energy Resources Conservation Board, "Estimate of Ultimate Potential", (1981), Page 4-2.

FIGURE 3.2

Tertiary Oil Normalized Productivity Profiles



Source: Alberta Energy Resources Conservation Board, "Estimate of Ultimate Potential", (1981), Page 4-3.

sooner than otherwise, as a result of rising per unit operating costs with lower levels of production. Third, they may affect the specific type or scale of any EOR scheme which is applied. The combined effects of these factors would influence the total producibility, as indicated in an analysis conducted by the Independent Petroleum Association of Canada (IPAC).

The results of IPAC's analysis are summarized in Table 3.1, which indicates that incremental EOR producibility in Alberta would be higher in every year at higher producer netbacks. Whereas Table 3.1 shows supply as annual production, one can also derive a measure of incremental EOR reserves as shown in Table 3.2.

3.3 THE OBJECTIVE FUNCTION

In deriving an oil supply curve such as those presented in Tables 3.1 and 3.2, the supply analyst incorporates specific assumptions regarding the principal economic factors. It is not sufficient, however, simply to recognize that costs and product prices may have some impact upon producibility. Some logical link must be established between the economic factors and reservoir producibility. The economist forges this link by assuming that there is some underlying behaviour on the part of the firm developing the reservoir. In other words, it is assumed that a company will have some particular objective in mind when developing an oil reservoir. This objective is formalized by the supply analyst in terms of an objective function.

Although a company's objectives may not always be clear, one can suppose that decisions are being made on some rational basis and that a company's activities are not undertaken at random and without forethought. If, indeed, a company were to make all of its decisions based upon some arbitrary and inconsistent decision rule, then the supply analyst would be faced with a difficult task of forecasting the

TABLE 3.1

EOR Production Supply Curves

Netback ($\$/m^3$)	Producibility (10^3 m^3/day)		
	1990	1995	2000
50	4.5	5.0	1.0
75	30.0	57.5	35.0
100	41.5	65.5	38.5
150	60.0	93.5	57.5
No Limit	67.5	113.0	92.0

Source: Alberta ERCB, "Estimates of Ultimate Potential",(1981), Page 4-18.

TABLE 3.2

EOR Reserve Supply Curve

Netback ($\$/m^3$)	Reserves (10^6 m^3)
50	16
75	253
100	285
150	433
No Limit	610

Source: Alberta ERCB, "Estimates of Ultimate Potential",(1981), Page 4-16.

firm's behaviour under changing circumstances. Analytical techniques which allow the modelling of random decisions do exist, although they require the specification of the statistical distribution of the population of possible outcomes. For simplicity, therefore, it is usually assumed that a company will act in a manner which improves the company's financial position. In short, companies will attempt to maximize their profits. Since profits occur not just in one year but over a period extending many years into the future, the objective may be more generally stated as maximization of the present value of expected future profits. It is important to note that the analyst is interested only in profits and losses which are yet to come, not in the historical profits or losses of the firm. Although historical performances may have some bearing on future expectations and may affect the discount rate, it is still only those future expectations which will form the basis for estimating the expected value of the future profit streams.

Although a petroleum reservoir will be developed by a particular company or group of companies, the operators are often constrained in their behaviour by some form of regulatory body. These constraints are often imposed because the regulatory agency may have objectives which are different from those of the companies operating the reservoir. In supply analysis, therefore, it may be necessary not only to identify the objectives of individual firms, but also to identify the objectives of regulatory bodies.

When evaluating an objective function, the supply analyst must first identify the group of firms or individuals which will be making the decisions that affect a reservoir's development. The objective function in developing reservoirs may differ depending upon whether one takes a private or a social perspective. From a private perspective one would normally expect that companies maximize the expected present value of their after-tax profits whereas socially we might expect some other objective function to apply (such as maximizing total surplus). Although profits are generally easy to quantify, it is a formidable task to develop a social equivalent to private profits. Many attempts have been made at deriving some quantifiable equivalent, and the most widely used is "net social benefit". Evaluating net social benefits involves estimating the social benefit and cost streams which are analogous to private revenue and cost streams. Quantifying externalities is not a simple task, and many ingenious techniques have been devised for estimating the impacts of externalities.[1] Nonetheless, the techniques have often been criticized on the grounds that one cannot under any circumstances quantify in monetary terms what are largely qualitative effects (e.g., pollution, employment impacts, lifestyle impacts, etc.). In view of the difficulties with measuring such qualitative impacts, social benefit analysis often settles for estimating those benefits and costs which are quantifiable and simply listing the degree of non-quantifiable impacts.

In the case of petroleum reservoir development, we are restricted to including in our social objective function only those factors which are estimable in monetary terms. In practise, therefore, a primary difference between a private and a social objective function is that the private firm will attempt to maximize after-tax profits, whereas society would attempt to maximize profits before-taxes and other transfer payments.

Profits before taxes and transfer payments can be construed as social rent, where "rent" is more conventionally defined as "the residual left for the fixed resources of a firm after the variable resources have been paid amounts equal to their opportunity costs."[2] In the case of social rent, society is identified as the "firm" in this definition. In the short run, where a number of costs and resources are fixed, rent is the difference between the revenue received and the amounts paid to the variable inputs. In the long run, however, all costs are variable and only the in situ resource under development is fixed, hence the rent is specifically attributable to the in situ resource.

Chapter 1 showed that a comparison of development under the two assumptions of profit and social rent maximization will indicate the neutrality of a taxation system. A taxation system is neutral where private firms undertake development which maximizes their profits, and in so doing, also maximize the social rent. In other words, a "neutral" tax system corrects externalities and captures rent, but does not otherwise affect behaviour.

Most fiscal regimes, however, are not entirely neutral and therefore one would arrive at different oil supply profiles using the private and social analysis. It is therefore important to identify the relevant decision making group. In the short run, one would probably adopt a private analysis since the firms will be reacting to a particular fiscal regime which is in place. If one believes that the government is striving to establish a neutral regulatory system, then, for a long run analysis, one might adopt a social perspective and set as an objective function the maximization of rent.

3.4 COSTS AND USER COSTS

Whether one is undertaking an analysis from a social perspective or from a private perspective, one will have to consider a number of costs which are directly related to the development of a reservoir. These costs will involve direct expenditures by the operator which are necessary for the technical operation of the particular development scheme chosen. Capital expenditures will include the purchase price of the development capital necessary, as well as the costs of installing this capital. Once this capital is in place and operation of this scheme commences, the firm will incur further costs associated with the production of the oil. In the case of a typical EOR scheme the operator would incur costs for his operating labour, maintenance requirements, injection costs of materials, costs of disposal or recycling of produced by-products, and, finally, fuel requirements for the entire operation.

In analyzing the above costs, one must pay particular attention to their dependence upon production rates. Some costs, such as administrative overhead, are not at all rate dependent. Other costs, particularly the cost of fuel and injected materials, will tend to be higher for greater injection and production rates. Capital requirements are also generally dependent upon the maximum anticipated injection or production rate. This is because the physical capital must be in place to handle the maximum anticipated volumes of injected or produced materials. For example, higher injection rates will require higher compressor capacities as well as higher cost flowlines which are capable of handling the greater throughput. On the other hand, economies of scale may exist at higher capacities, in which case average costs may fall as attainable output rises.

In addition to rate dependence, one should also identify the dependence of costs on the timing of development. Some of this time dependence may arise as a result of the effects of reservoir conditions at start-up on the initial capital requirements for undertaking a scheme. Some examples of these were discussed in Chapter 2. Of particular interest are those cases where implementing a scheme early will involve less physical capital or less injected material to achieve comparable levels of production. Whereas these effects can be said to be endogenous to the reservoir development process, other exogenous timing effects may also have a bearing on development capital and operating costs. The most omnipresent exogenous effect is that of price inflation of the input requirements, be they capital, labour, fuel, or injected materials. Although the historical records have shown that the costs of these inputs have generally been on the increase, in some instances, they have been known to fall in real and sometimes in nominal terms. One striking example of this is the current availability of ethane in Alberta at prices considerably less than two years ago.

All of the above costs will have a bearing on the economic desirability of a particular project. It was mentioned earlier that the supply analyst must consider only the future costs which will be incurred. Any historical or sunk costs must be ignored in the objective function. Similarly, one must realize that in evaluating a particular development alternative, there will usually be some type of development or production which will be undertaken in any event independent of the alternative being evaluated. This implies that the operator can expect, under the status quo, to incur some capital and operating costs and to receive some production revenue. These costs and revenues must be treated the same way that historical costs and revenues are treated. By implication, therefore, one should consider <u>only</u> the incremental costs and revenues which will arise as a result of a particular development scheme. Normally one would expect incremental costs to be positive, but in some years they may also be negative if the costs of the scheme being evaluated were less than the costs which would be incurred under the status quo. Analogously, incremental revenues may be either negative or positive in any given year. It should be noted that the incremental approach need only be taken if one is trying to evaluate a project on a "go/no-go" basis. Where a number of mutually exclusive development schemes are being evaluated, each different from the status quo, it is not necessary to use the incremental approach to identify the best project if the net present values of all of the projects (including the status quo, if it is an option) are determined.

Once all of the expected costs are identified, and given an expected stream of product prices, one can proceed with the problem of choosing the development scheme which will maximize the objective function. In undertaking this optimization procedure, a number of economically significant terms will arise which are referred to as "user costs".

User costs essentially represent the economic equivalent of many of the technical stock effects discussed in Chapter 2. Anthony Scott defines user costs as "... the present value of future profit foregone by a decision to produce a unit of output today."[3] In the context of this discussion, "future profit" refers to future after-tax profits which arise from reservoir development. The most significant neutral stock effect is that of depletion, i.e., the fact that production today of a unit of oil means that that unit of oil will not be available in some future time period for production. The user cost would be the present value of the profit on that unit of production if it were left in the ground to be produced instead in some future year. User costs associated with negative stock effects, i.e., where total recoverable reserves decrease, also include the present value of the future net income which would have been realized by those units of output which are lost as a result of current production. Finally, one can consider the case of the user costs associated with positive stock effects. Positive stock effects arise, as one will recall from Chapter 2, when early production results in a net increase in recoverable reserves from the reservoir. This net increase in recoverable reserves will have associated with it a potential increase in a company's profits. Therefore, profits are not foregone as a result of early production, but rather more profits may be realized as a result of the early production. In other words, in this example, the user costs of production attributable to positive stock effects are negative in that they represent a net benefit due to the earlier production.

In contrast to the costs discussed earlier in this section, user costs need not be explicitly calculated in order to arrive at an optimal development pattern for a reservoir. Rather, user costs fall out as a result of the optimization process; that is, they are directly included in the net present value of profits. They are of interest to the economist in that they indicate the effects of relaxing or applying certain constraints to the optimization problem. Their application will become more apparent in some of the analytical modelling undertaken in the following chapters.

3.5 THE IDEAL SUPPLY ANALYSIS

From the previous discussions, one is led to ask what should be considered in the ideal supply analysis. First, the analysis should address all of the relevant technical concerns of reservoir development. Second, all of the relevant factors in the economic environment should also be included. Finally, it is important that the analysis addresses corporate behaviour in a realistic fashion.

Each of the above qualities of an ideal supply analysis has associated with it a number of problems. The most difficult task is surely to address all of the technical aspects and concerns of reservoir development. In an ideal analysis, this implies undertaking the study on a reservoir by reservoir basis, incorporating the unique characteristics of each reservoir along the way. The technical feasibility of all types of development schemes must be considered for each reservoir, with due attention being given to the dependence of producibility on timing.

The second concern of the supply analyst is to incorporate the economic environment into the analysis. Starting at the stage of direct expenditures, this involves estimating the time stream of expected capital and operating expenditures necessary for every type of development scenario in every reservoir included in the analysis. Once again, these cost estimates may be dependent upon both the type of development being undertaken and the staging of this development. A second major component of the economic environment is the expected value of the oil and any associated by-products being produced from the reservoir. Normally, one would expect prices to be exogenous. In some cases, however, the potential oil supply being evaluated in an analysis may represent a significant portion of the total oil supply availability from all sources. In this event, it is conceivable that the product prices are not entirely exogenous and that they can be affected by the particular development scenario chosen. If this possibility exists, then the ideal supply analysis must also have the means of estimating market prices and establishing the links between these prices and the particular modes of development being pursued. This would be a difficult task, requiring detailed analysis of other supply sources as well as market demand for the product. The final component of the economic environment is the regulatory environment. Where this environment imposes restrictions upon development, or taxes and royalties upon production, the analysis must incorporate the relevant constraints and recognize the role of taxes and transfer payments in evaluating the availability of supply.

The last, all-important step to forging the technical and economic links in the analysis is to incorporate a realistic behavioural framework. As we have seen above, this usually implies the choice of some development scenario which maximizes some objective function. The ideal supply analysis would once again address each reservoir individually and optimize the development pattern for every pool in terms of the types of techniques, the staging of these techniques, and the timing of the overall process. The analysis would then aggregate the supply available from all pools to yield a total supply analysis. It should be noted at this stage that the actual aggregation process should be held suspect. In other words, one should question the assumption as to whether it is possible to realistically aggregate the supply from all pools without creating additional impacts or externalities which will in turn change the economic environment for some of the other pools. If such linkages exist, then they must be identified and incorporated into the ideal supply analysis. The analysis would then require a global optimization subject to the constraints imposed by these linkages.

If all of the technical and economic concerns of reservoir development are identified, and if they are further linked with a realistic behavioural model, then the supply analyst will have a good idea of what the available supply will be from the reservoirs which he is considering. In addition to estimating the incremental EOR reserves, the producibility, and the timing of development, that analyst will have a powerful tool for undertaking sensitivity tests. With the given framework, changes in the technical conditions or economic environment can be readily simulated and the impacts of these changes on oil supply can be measured.

3.6 PROBLEMS OF SUPPLY ANALYSIS

Although the ideal supply analysis discussed above presents a tight theoretical framework for undertaking EOR supply analysis, there are a number of problems which arise in operationalizing such an analysis. Even under the best circumstances where all of the necessary information is available the supply analyst is faced with an immense optimization problem. Even though the number of reservoirs being investigated will always be finite, there are effectively an infinite number of development alternatives for each reservoir. For example, if one were considering a hydrocarbon miscible flood, one is not initially constrained to the amount of miscible fluid being injected nor is one constrained to a particular start-up time or injection rate. The only consoling point to the supply analyst may be that, although one has an effectively infinite choice of timing, slug sizes, and injection rates, each of these variables is limited to a finite range. This suggests that analytical solutions to the optimization problem may exist if it is possible to analytically define the important technical and economic variable within such finite ranges.

Even if analytical solutions can be found after an inordinate amount of analysis, one should question whether the results are indeed meaningful. Although such results would be precise, they are predicated upon what is assumed to be absolutely reliable base-line technical, economic, and behavioural information. As we shall see, such an assumption is misleading at best, and the supply analyst more often than not finds himself operating in an environment of uncertain information and uncertain behaviour.

In addition to the obvious difficulties in projecting geological, technical and economic parameters, a major problem facing the supply analyst concerns the validity of the behavioural assumptions. Very compelling theoretical arguments exist which indicate that individual firms will act in a manner to maximize their profits. One could argue, for example, that if a company were not maximizing its profits, then it would be driven out of business in a perfectly competitive world. This is because, under perfect competition, free flowing knowledge and price competition will ensure that only those operators which use the most cost-effective techniques will survive. In the petroleum industry, however, conditions at the level of reservoir development are not representative of a state of perfect competition. Because government regulations control wellhead prices, price competition between individual producers at the field level cannot exist. Furthermore, the free flow of knowledge is hindered both by the rights to confidentiality of certain information and the fact that some information is so reservoir specific that it would be useless to competitors even if it were to fall in their hands. By implication, therefore, it is possible that decisions are made on a basis other than pure profit maximization, and that such firms might not be driven out of business but, rather, could continue to operate using sub-optimal development methods. The continued application of such methods could lead to the dissipation of economic rents which would have been realized in perfectly competitive circumstances.

Given that there is room for such distortions, the supply analyst is justified in asking what the objective function of industry actually is. Does industry profit maximize? Does it maximize recovery in certain cases without necessarily maximizing profits? Does industry actually do long term planning in developing reservoirs so that the timing of EOR schemes is indeed optimal?

There is some evidence that, indeed, industry may be undertaking development along sub-optimal lines. First, there is the notion that industry attempts to profit maximize but that it utilizes decision rules which will not lead to profit maximizing solutions. A prime example of this is the historical use of "payout time" and "internal rate of return" calculations to justify the relative merit of projects. Using these methods of comparison, projects are often chosen based on early payout or high rates of return. A study prepared by the Canadian Petroleum Association[4] found that "... although there are many other economic criteria such as payout, which are also used, none is relied on quite so heavily in oil industry investment analysis as the D.C.F. [discounted cash flow] rate of return." It is readily shown, however, that both payout time and internal rate of return criteria tend to bias the analysis against projects which are capital intensive in favour of those which have relatively lower capital costs but higher operating costs. Choices made using such decision rules do not necessarily maximize profits.[5]

A second distortion may arise as a result of corporate decision making structures. Particularly in large companies, the profit maximizing decisions are undertaken at a level different from the level at which the detailed engineering and technical analysis is undertaken. For example, of all of the detailed simulations and studies completed by engineering staff, the bottom line of only a handful of such simulations may reach the senior management level. In fact, in some cases it can be seen that the optimization process at a corporate level actually involves two steps. The first step, at the production and reservoir engineering level, is to maximize production or total recovery. The second step is to evaluate the internal rate of return under such a development program. If the internal rate of return exceeds some economic cut-off rate of return as prescribed by the corporation, then the project is undertaken. If the rate of return falls short of this economic cut-off rate, only then will adjustments be considered which may increase the rate of return and decrease the total recovery. Such a decision rule, although perhaps appearing to maximize profits, may not be consistent with an optimal development scenario which maximizes company profits.

A third distortion may arise where companies knowingly attempt to maximize something other than profits. Recently, for example, smaller companies have been very concerned with their cash flow position. In these cases, such companies may attempt to maximize their cash flow using minimal additions to capital. One might argue, of course, that such actions are based on profit maximization in that they are necessary to insure the firm's survival in lean periods. If this were the case, however, then it would imply the existence of distortions in the capital markets which restricted the availability of risk capital for these firms. In either event, a short term distortion is introduced which must be addressed by the supply analyst.

All of the problems discussed above must somehow be confronted by the supply analyst. The analyst must accept that the "ideal" supply analysis is probably unattainable and that compromises will have to be made. One must not overreact and go so far as to say that all supply analyses are useless because of the above problems. Valuable analyses can still be undertaken as will be shown in the next section.

3.7 REVIEW OF PREVIOUS ANALYSES

A number of recent EOR supply analyses are discussed in this section. Although the results of these analyses are of interest, the primary purpose is to evaluate the particular analytical techniques which were used in light of comments in the preceeding sections.

One recent theoretical discussion of reservoir specific petroleum supply modelling appeared in an article by Kuller and Cummings.[6] Although earlier models[7] addressed the problem of supply modelling and the economics of reservoir development, Kuller and Cummings formulated a general analytical model for optimizing investments in petroleum reservoirs. They recognize the existence of stock effects in the reservoir, and that investment requirements and ultimate recovery can be rate dependent. Their optimization process involves maximizing the present value of a stream of discounted profits by choosing an optimal path for both production and investment. The advantages of the model are that it recognizes the petroleum reservoir as the basic unit of analysis, and that it attempts to model supply with due consideration of the relevant economic and technical factors. In addition, although they applied it to primary production, it can potentially be extended to applications in secondary recovery and EOR. A distinct limitation of the model, however, is the manner in which it addresses positive stock effects. First, their discussion concentrates on the effects of the M.E.R. and of the rule of capture. Second, as it deals almost exclusively with primary production, the model does not explicitly address the effects of the optimal staging of secondary and EOR investment as they relate to positive stock effects. Finally, the analytical nature of the model allowed determination only of the direction of changes and not the magnitude of any changes.

A number of quantitative analyses of Canadian EOR supply have been undertaken. One of the earlier studies was that of Watkins,[8] which involved a detailed analysis of 13 enhanced recovery schemes. Of the 13 schemes, however, only 2 were solvent floods and the remainder were waterfloods. Watkins utilized industry cost and performance data to calculate supply prices which ranged from $0.25/bbl ($ 1973) for the least expensive waterflood to $2.35 for the Swan Hills South solvent flood. Although the study did not claim to identify all EOR prospects, it nonetheless contributed significantly to the methodological analysis of EOR schemes. Furthermore, the pools which were included in the analysis represented about 40% of the potential EOR reserves at the time.

Since Watkins' study, more vigourous analyses have been undertaken which use, as a starting point, all of the known petroleum reservoirs in a given region. The general methodology involves a two-step screening process, first employed on a major scale by the National Petroleum Council in the United States.[9] The first step involves a technical screening procedure which selects all of the technically viable schemes for a given reservoir. The second step involves the application of some assumed development costs to determine which of the technically viable procedures is commercially preferable. That scheme is then chosen as optimal for the given reservoir. The process is repeated for every reservoir in the data base to arrive at a more general supply picture.

The above process has been used in a number of studies of Canadian oil supply. The Petroleum Recovery Institute (P.R.I.)[10] examined some 3,000 reservoirs in Alberta using a technical screening process developed by the Institute. Economic screening was based on a "B-factor" calculated to reflect a profitability index for each scheme and reservoir. This index is used to rank the schemes and to arrive at a commercially preferable EOR scheme. The advantage of the P.R.I.'s process is that it recognizes the importance of analyzing supply at the reservoir level, and it attempts to quantify the relevant technical aspects and accommodate the economic concerns. The process does, however, have one serious analytical flaw. The calculation of a "B-factor," as it is undertaken, may not select the profit or rent maximizing scheme. It can be shown[11] that the B-factor is biased in a similar direction as the internal rate of return criterion discussed earlier. Apart from this limitation, the authors also do not optimize the timing of production, although they recognize its importance in the selection process.[12]

> Commencing dates of commercial tertiary operations used in B-factor calculation have an important influence on all economic variables which are incorporated in the effective benefit formula ... The optimization of this parameter is beyond the scope of this work despite its significant role in economic consideration.

The P.R.I. study circumvented this problem by arbitrarily assuming start-up dates for each type of process.

A number of the problems encountered in the P.R.I.'s economic screening were eliminated in a study undertaken by Prince.[13] Prince incorporated P.R.I.'s technical screening procedure, but upgraded the P.R.I. model by including a detailed model of all the Canadian tax provisions and by using "net present value" (NPV) as a selection criterion. The use of NPV is consistent with profit-maximization, and hence insures an optimal choice of technique from the firm's point of view. In addition, the Prince model includes an evaluation of hydrocarbon miscible flooding, which is not included in the P.R.I. study.

The strengths of Prince's model lie in its explicit incorporation of technical factors, economic factors, and the regulatory system. In so doing, the model becomes a powerful tool for simulating the effects of changes in the fiscal regime on EOR supply. This was demonstrated in a recent application of an updated version of the model, wherein Prince and Webster[14] evaluated EOR supply under three different fiscal regimes. The format of the model allowed comparisons of producibility, reserves, and the value of output.

The studies discussed above have all dealt with known reservoirs, yet it is clear that some EOR potential will exist from new discoveries and additions. The problems associated with analyzing this supply source were not addressed in the P.R.I. or Prince studies. Some analyses have, however, been undertaken which attempt to evaluate the supply of oil from future additions. By far the most common methodology employed is that currently used by the Energy Resources Conservation Board.[15] The procedure involves first forecasting new additions, and then forecasting EOR producibility from these additions using historical estimates of incremental recovery. Producibility profiles such as those presented in Figure 3.1 are used as a basis for developing production profiles. A similar approach has been used by the National Energy Board.[16] Although the drawbacks of such an approach are obvious in light of earlier comments regarding ideal analyses, it does give some idea of what EOR from future additions may be.

An inherent limitation of all of the above studies is the manner in which they deal with the staging and timing of reservoir development. The analyses which follow the procedures of the National Petroleum Council study generally assume that EOR schemes will be undertaken in watered-out reservoirs, i.e., those where a waterflood has been completed. This assumption, in fact, ignores the potential stock effects which arise when dealing with project staging. Prince (1980) is one of the few authors who addresses this problem:[17]

> ... we should predict waterflood performance before attempting to apply our tertiary estimating procedure. This leads us to a staging problem in oil production, that is, ultimate effectiveness of a waterflood project depends to some extent on when the project is initiated... In fact, some waterfloods are best started before any primary production has occurred (and this may be true for some tertiary recovery as well).

Prince surmises, however, that this problem is not so relevant when assessing EOR potential in Alberta because "reservoirs that may be intended for but are not yet under waterflood apparently represent an insignificant proportion of existing reserves."[18] Although this may be true for waterflooding, and hence decreases the problems of predicting waterflood performance, it is most certainly not true for EOR schemes. Prince identified some 500 reservoirs where EOR is viable, and there are currently only a handful of schemes in operation.

The same argument applies for predicting recovery from future additions. Methods used by regulatory agencies may be too conservative in that they generally assume that secondary recovery will commence about 3 - 5 years into a reservoir's life and that EOR will commence up to 5 years after (see Figure 3.1). This approach also gives no recognition to the staging and timing problem.

The overall implication of ignoring the optimal timing problem is that supply analyses may underestimate both the ultimate potential and the net present value of production. In general, the studies show that, at higher prices, supply will be inelastic. Prince, for example, calculated a supply elasticity for all EOR processes of 0.8 over the \$20/bbl to \$25/bbl price range.[19] Also, in using this approach, the time at which incremental recovery peaks is almost totally independent of price. For example, Prince estimated that there would be no change in the year of peak output even if prices rose from \$15/bbl to \$25/bbl.[20] This seems counter-intuitive in light of the realities of reservoir development discussed earlier. One would expect that changes in price would also have some impact on the optimal timing of reservoir development, which in turn would affect both the total incremental recovery and the producibility profile.

3.8 SUMMARY

The amount of oil which companies are willing to produce from petroleum reservoirs depends intimately upon the technical characteristics of the reservoir, the development options which are available, the expected costs associated with such development, the expected value of the oil, and finally the general goals of the company. A supply analyst seeking to forecast the amount of oil which will be produced must take into consideration all of these factors when undertaking his analysis. An ideal supply analysis would incorporate all of the technical and economic aspects of reservoir development, and would use these as inputs to arrive at some development scenario which maximizes company profits or government rents.

The problems associated with undertaking such an ideal supply analysis arise principally out of uncertainty. The supply analyst is confronted with incomplete technical and geological information, and an uncertain economic environment. In spite of these problems, a number of sophisticated studies have been undertaken to estimate EOR supply. Certain simplifying assumptions were necessary in undertaking these studies, but they have nonetheless contributed immensely to our understanding of EOR potential. The more involved studies have approached the problem on a pool-by-pool basis. Although this level of disaggregation requires an immense amount of data reduction, it recognizes that the petroleum reservoir is the basic unit of production, and hence, should be the basic unit of analysis. Many of these studies incorporate a technical screening process and optimize the particular type of EOR scheme to be used in each pool. This is a very important and desirable step, and it explicitly recognizes the importance of putting into place the optimal type of development for a reservoir.

The next step which should be taken is to recognize that not only is a particular type of scheme technically and economically optimal for a given reservoir, but the time at which that scheme is started in the reservoir's development is also important. Although many of the studies which have been previously undertaken have recognized this fact, they have not actually incorporated this step into their analysis. It is this step which is the subject of the next section, where a formal model is developed to demonstrate the effects and the importance of optimal timing in EOR supply analysis.

CHAPTER 4

AN OPTIMAL TIMING EOR MODEL

4.1 INTRODUCTION

A partial equilibrium enhanced oil recovery model, which approximates a simulation of the optimal timing problem, is developed which is based on discussions in Chapters 2 and 3. The general purpose of this model is to investigate whether the issue of optimal timing can actually affect the total deliverability, ultimate potential, or net present value of rent generated by EOR projects. The model will therefore be cast in an analytical framework which relies on a number of simplifying assumptions regarding production profiles and economic factors. As a preamble to this analytical formulation, however, a conceptual formulation of the model will be presented which generalizes all of the important aspects in an optimal timing model. These aspects will not all be presented in mathematical form. Simplifying assumptions are made for the purpose of expressing the conceptual framework in a mathematically approachable form.

4.2 PURPOSE OF THE MODEL

The central purpose of the model is to assess the effects of optimal timing on technical and economic parameters of production from EOR schemes. Previous discussions have indicated that there are a number of compelling theoretical grounds for incorporating optimal staging or timing into profit-maximizing models. Because of stock effects in the reservoir, deliverability, ultimate potential, and the net value of production may all be affected by changing project timing. Of primary importance, however, is whether such effects are large enough to cause measurable and significant changes in predicted outcome.

The modelling exercise undertaken here presents a framework which, first, indicates the predicted direction of change and, second, allows one to estimate the magnitude of the changes. The directions of major changes are estimated through analytical computation of elasticities of ultimate recovery with respect to costs, prices, price escalation and discount rate. The magnitudes of these directional changes are addressed in Chapter 5 for a number of case studies.

The basis of the model is an evaluation of production and development economics at the single reservoir level. No provisions are included for simultaneous evaluations of a group of reservoirs although the results for individual reservoirs can be readily aggregated. The model is general enough in its analytical form that the conclusions can be extended to any process where stock effects of timing exist, whether in primary, secondary, or tertiary production.

4.3 CONCEPTUAL FORMULATION

The ideal supply analysis discussed earlier would require a complete description of an industry's behaviour as well as complete information regarding reservoir performance and economic conditions. For various reasons, also described earlier, it is not reasonable to expect that such an analysis can be empirically undertaken. It is, however, possible to focus on individual facets of the optimization problem. The goal of the model presented below is to focus on the aspect of timing. Even within this category there are numerous variables within a scheme, including: the time at which EOR investment commences; the time at which EOR production starts; the rate at which incremental development expenditures are incurred (fluid injection rates, for example), and the time of abandonment. In separating these variables, some of which are exogenously determined, a number of assumptions are required.

Although many specific assumptions will later be made to make the model analytically solvable, the following are the general assumptions, and some of their implications, in defining the model.

First, the model is applicable to a single reservoir unit and it is assumed that the development of this reservoir will have no impacts on the development of other sources of supply. In essence, therefore, any linkages through feedback mechanisms are ignored and development is unitized (i.e., there is no rule of capture). Also, for analytical purposes, this implies that factor prices and product prices are exogenous. The model is therefore a partial equilibrium model.

Second, only one type of development scheme is considered available. Hence, the model cannot be explicitly used to optimize between a comparison or ranking of fundamentally different schemes (such as a polymer flood versus a miscible flood). This assumption should not, however, be construed as a weakness of the model. In the first place, technical screens often eliminate all but one or two technically viable processes. The model can then be applied to two or three processes in parallel to select the one with the best expected economics.

Third, the behavioural assumption is that the operator of the scheme will choose a development scheme so as to maximize the present value of the stream of expected incremental net profits. The present value is defined as zero if no incremental investment is undertaken. For analytical purposes, therefore, unless otherwise stated, the model will consider only incremental costs, revenues, production and reserves. Sunk or historical costs, and those costs which would have to be incurred in future years in any event, are ignored. As such, it is conceivable that costs <u>or</u> production are negative in some years.

Fourth, a number of financial assumptions are made to simplify the analytical treatment of the problem. The project is assumed to be 100% equity financed at a rate commensurate with a company's opportunity cost of capital. Income taxes, royalties, and incentive payments are ignored in the initial formulation and are introduced at a later stage in a qualitative form to illustrate their effects. Also, all prices, costs, escalation rates, and discount rates are expressed in real terms and exclude inflationary effects.

Finally, the time at which enhanced reservoir development commences is assumed to be variable, and capital costs, operating costs, production, and reserves may all be variable and dependent upon the start-up time. It is on this aspect of the problem that the model concentrates. The exact relationships amongst the above variables can be very complex. For this reason, a number of further simplifying assumptions regarding linearity, continuity, and separability are necessary for solving the model analytically. As these assumptions are not required for the conceptual formulation, however, their expression in detail is not addressed until later.

The conceptual problem, therefore, subject to the above assumptions and constraints, is to choose a start-up time for the development scheme which maximizes the net value of the incremental production. Once this start-up time has been determined for one set of exogenous technical and economic conditions, one can vary any one exogenous variable to predict the direction and magnitude of changes in start-up time, present value, and incremental reserves. These changes are expressed in terms of supply elasticities.

4.4 ANALYTICAL MODELLING

4.4.1 Introduction

The conceptual formulation of the problem expressed above can be solved in a number of manners. If all of the technical and economic constraints, linkages, and correlations can be specified, then a simulation environment or an iterative mathematical programming method can be employed to maximize the objective function of net present value. The method utilized here, however, is purely a mathematically analytical approach which is amenable to solution through elementary differential and integral calculus. Although this approach is more limited in terms of its practical application to a specific problem, its major strength lies in the fact that it can be used to test a number of theoretical hypotheses without requiring extensive data from field operations.

The solution method is to describe an economic model which has separable stock effects of timing. The estimation of these stock effects are then addressed at a later stage. Directional results and sensitivities are addressed through calculating various supply elasticities.

4.4.2 Maximizing Project Value

The nomenclature for the model is summarized in Table 4.1. It is important to note that product price, P, should be interpreted as the price received by the producer net of any direct production taxes and royalties. This price is referred to below as a "netback" price. All discounting of revenues and costs is taken to year 0, which can be construed either as the current year or as the start of a reservoir's productive life.

TABLE 4.1

Model Nomenclature

Symbol	Description
t	Time period (current period is $t = 0$)
τ	Period of project startup
T	Length of EOR project
x	Transformation: Time from project start-up
Q	Incremental production
V	Net present value of project
P	Real product price received by producer
C	Real incremental total cost
C^*	Real incremental variable cost
r	Real annual discount rate
π	Real annual product price inflation
κ	Real annual cost inflation
R_τ	Incremental reserves due to project commenced in period τ
f	Term indicating time distribution of incremental reserves
λ	Timing stock effect term: proportion of incremental reserves lost due to a one year delay in project start-up
ε_{12}	Elasticity of parameter "1" with respect to parameter "2"

Notes:

1. Subscript "t", "0", or "x" refers to parameter value in a given year. Subscript "τ" refers to parameter value if project is commenced in year τ .
2. Barred values ($\overline{C}$, $\overline{T}$) refer to τ-independent conditions.
3. Primed values (f', T') refer to conditions where neutral stock effects exist.

Consider an EOR project which is started in year τ , in which the effects of the project will be sustained over a period of T years. Using continuous discounting, the net present value of this scheme is equal to the present value of the incremental revenue less the present value of the incremental costs, or:

$$V_\tau = \int_0^\infty P_t Q_t e^{-rt} dt - \int_0^\infty C_t e^{-rt} dt \qquad \ldots(4\text{-}1)$$

Because, by definition, no incremental production or costs result before year τ or after the scheme's life of T years, Equation (4-1) can be respecified and generalized as:

$$V_\tau = \int_\tau^{\tau+T_\tau} P_t Q_{t,\tau} e^{-rt} dt - \int_\tau^{\tau+T_\tau} C_{t,\tau} e^{-rt} dt \qquad \ldots(4\text{-}2)$$

which now also explicitly shows that the incremental production Q_t, the incremental costs C_t, and the EOR project life T are all generally functions of the start-up year τ. Equation (4-2) is the general objective function for maximization. Start-up time τ is varied until a maximum is attained.

Solution of the general problem is a complex procedure. Because so many of the variables depend upon τ , the optimization process may not be readily solvable. A general solution would require a mathematical programming iterative approach or the application of continuous optimal control techniques. Fortunately, one can make some simplifying assumptions and transformations which will readily generate a solution. The simplifying assumptions allow the problem to be reduced to one in which the objective function contains only one independent variable.

First, it is useful to express the quantity produced as a proportion of the total incremental recovery, R_τ :

$$Q_t = R_\tau \cdot f_{t-\tau} \qquad \ldots(4\text{-}3)$$

where $f_{t-\tau}$ is the proportion of R_τ produced in year t, and the time $t-\tau$ signifies the time from the start of the EOR scheme. Since the sum of the incremental production is equal to the incremental reserves, it is clear that,

$$\int_{\tau}^{\tau+T} f \, dt = 1 \qquad \ldots(4\text{-}4)$$

As before, this distribution function f is generally also dependent upon start-up time τ.

Prince[1] assumed in his study that all EOR schemes had a project length independent of when they started, and that the shape of the incremental production profile was also independent of start-up time. Although these assumptions may not be technically correct, they are adequate as an initial approximation and are hence also adopted here as a base case. These assumptions are relaxed in the discussion presented below in Section 4.6.2. Mathematically, the base case assumptions can be expressed as:

$$\frac{\partial T}{\partial \tau} = 0 \qquad \therefore \; T = \overline{T} \qquad \ldots(4\text{-}5)$$

$$\frac{\partial f}{\partial \tau} = 0 \qquad \therefore \; f_{t-\tau} = \overline{f}_{t-\tau} \qquad \ldots(4\text{-}6)$$

We further assume here that the real project costs are independent of start-up time, and that real oil prices increase exponentially at a rate π from a level P_o at the beginning of the reservoir's life. With respect to costs, it should be realized that the above assumption is a simplification which will be relaxed later in Section 4.6.1. It implies simply that the time profile of costs relative to the start of the EOR scheme is invariant to project start-up time. Hence, similar to Equation (4-6) describing the distribution of production, we have,

$$\frac{\partial C_{t-\tau}}{\partial \tau} = 0 \qquad \therefore \; C_{t-\tau} = \bar{C}_{t-\tau} \qquad \ldots(4\text{-}7)$$

The assumption regarding real prices implies simply that,

$$P_t = P_o e^{\pi t} \qquad \ldots(4\text{-}8)$$

Equation (4-2) can now be rewritten as:

$$V_\tau = \int_{\tau}^{\tau+\bar{T}} P_o e^{\pi t} R_\tau \bar{f}_{t-\tau} e^{-rt} dt - \int_{\tau}^{\tau+\bar{T}} \bar{C}_{t-\tau} e^{-rt} dt \qquad \ldots(4\text{-}9)$$

The above Equation (4-9) can be simplified using the transformation:

$$x \equiv t-\tau \qquad \ldots(4\text{-}10)$$

where x is utilized as a "dummy variable" but can be interpreted as the time from the beginning of the EOR project start. This allows simplification of the integration limits, while also allowing separation of all τ - dependent variables. Applying this transformation, we can define an objective function equivalent to Equation (4-9) as:

$$V_{\tau} = P_o e^{\pi\tau} e^{-r\tau} R_{\tau} \int_0^{\bar{T}} \bar{f}_x e^{(\pi-r)x} dx - e^{-r\tau} \int_0^{\bar{T}} \bar{C}_x e^{-rx} dx \qquad \ldots(4\text{-}11)$$

Note that the two integrals are now independent of project timing. The second integral is simply the value of the project costs discounted to year τ. Interpretation of the first integral is not so straight forward. It is, in a sense, a weighting factor for the price received over the R_{τ} units of incremental production over the EOR project's life. Note that if the price escalates at the same rate as the discount rate ($\pi = r$), then the integral will be equal to unity, indicating that each unit has the same discounted value in year τ (which is $P_{\tau} = P_o e^{\pi\tau}$). Note further that if $\pi > r$ then all later units of production will be valued more than initial production and that the weighting factor will be greater than unity, indicating an average price over the R_{τ} units greater than P_{τ} . Table 4.2 illustrates some typical ranges of this weighting integral for two types of production distribution. Clearly, in addition to a strong dependence on the difference between π and r, the value of the function also depends on the distribution of incremental production.

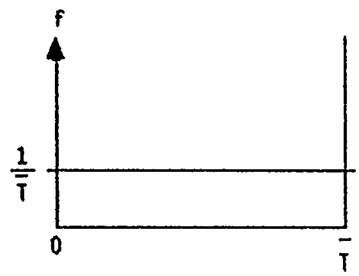
TABLE 4.2

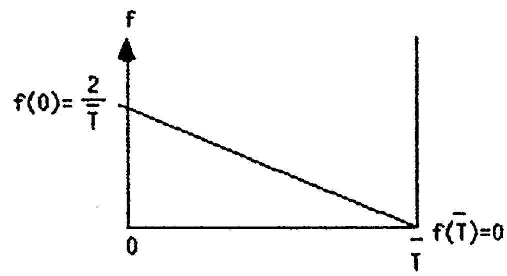
Calculation of Illustrative Weighting Factors

$$F = \int_0^{\bar{T}} f_x \, e^{(\pi-r)x} \, dx$$

f_x	$f_x = \frac{1}{\bar{T}}$	$f_x = \frac{1}{\bar{T}}\left(2 - \frac{2x}{\bar{T}}\right)$

Diagram





General Solution	$F = \frac{e^{(\pi-r)\bar{T}} - 1}{(\pi-r)\bar{T}}$	$F = \frac{-2}{(\pi-r)\bar{T}} + \frac{2[e^{(\pi-r)\bar{T}} - 1]}{(\pi-r)^2 \bar{T}^2}$
Specific Solutions ($\bar{T}$=15)		
$(\pi-r)$= -0.10	F = 0.52	F = 0.64
-0.05	0.70	0.79
0.00	1.00	1.00
+0.05	1.49	1.36
+0.10	2.32	1.76

For ease of notation, the following timing-independent variables are defined:

$$F \equiv \int_0^{\overline{T}} \overline{f}_x e^{(\pi - r)x} dx \qquad \text{...(4-12a)}$$

$$\overline{C} \equiv \int_0^{\overline{T}} \overline{C}_x e^{-rx} dx \qquad \text{...(4-12b)}$$

Our revised objective function therefore becomes:

$$V_\tau = P_o e^{\pi\tau} e^{-r\tau} R_\tau F - e^{-r\tau} \overline{C} \qquad \text{...(4-13)}$$

Because Equation (4-13) is now in a form where there is only one independent variable, τ , the optimization process is straight forward. It is appropriate, under these assumptions, to choose an optimal time for commencing a project such that the following first and second order conditions for maximizing net present value are satisfied:

$$\frac{dV}{d\tau} = 0 \qquad \text{...(4-14a)}$$

$$\frac{d^2V}{d\tau^2} < 0 \qquad \text{...(4-14b)}$$

In the following analysis, we will concentrate first on Condition (4-14a). It is important to note, however, that Condition (4-14a) can be construed as a profit maximum if and only if the second order condition holds true. Derivation of the second order requirements is addressed in detail in Section 4.5.2 below.

If the second order condition is not satisfied, then a "corner" or "boundary" solution will exist. Under these circumstances, the optimal time to commence the scheme would be either immediately or never. On the other hand, if the second order condition is satisfied, then an internal solution might exist (where the optimal startup time is not necessarily immediately but rather at some finite time in the future). One should note that even if both conditions are satisfied, a boundary solution might still apply (such as when $V_\tau < 0$ for all $\tau < \infty$, in which case the scheme will never be economic and should therefore never be undertaken). The analysis which follows shows the implications of optimal timing if the second order condition holds true and internal solutions arise.

Differentiating Equation (4-13) with respect to τ and applying the first order condition of optimization, Equation (4-14a), will yield:

$$P_o e^{\pi\tau} R_\tau F\left(\pi + \frac{1}{R_\tau} \cdot \frac{dR_\tau}{d\tau}\right) = r\left(P_o e^{\pi\tau} R_\tau F - \overline{C}\right) \qquad \text{...(4-15)}$$

We define now the proportionate change in total incremental recovery due to delays in timing as:

$$\lambda_\tau = -\frac{1}{R_\tau} \cdot \frac{dR_\tau}{d\tau} \qquad \text{...(4-16)}$$

Conceptually, λ can be regarded as the proportion of recovery lost due to a one year delay in timing. In general, the actual value of λ will be τ-dependent. Note that $\lambda > 0$ for positive stock effects of timing, i.e., when τ is advanced (shortened), R_τ increases.

Equations (4-15) and (4-16) can now be rearranged to show that, at a profit maximizing choice of τ, and where an internal solution applies, the following condition will hold:

$$-r\overline{C} = (\pi-\lambda-r)P_o e^{\pi\tau} R_\tau F \qquad \text{...(4-17)}$$

This condition is perfectly consistent with what one might expect a profit-maximizing firm to do, since what it states is that an operator will adjust his timing just to the point where the marginal costs of delaying the timing will equal the marginal benefits. To interpret the above condition, consider an operator delaying start-up by one year. This will decrease the present value of his costs by an amount $r\overline{C}$, and decrease the present value of his revenues ($P_o e^{\pi\tau} R_\tau F$) by r% directly because of the delay. In addition, his revenues will increase by π% if he expects prices to rise because the quantity weighted average price of R_τ will go up by that amount. This is a type of user cost of timing which reflects future values of the physical units. Finally, λ represents a stock effect in that a delay of one year will tend to decrease R_τ by λ% and hence decrease revenues in the same proportion. The condition simply states that an operator will delay a project until the benefits from reducing the present value of his costs and increasing prices are outweighed by the costs of delaying revenues and decreasing the incremental recovery.

4.4.3 Incorporating Stock Effects

The above optimizing condition tells us that project timing does, theoretically, depend on stock effects. What is not yet clear is whether λ is significant with respect to π and r. If λ is very small, then one would be justified in neglecting it in supply analysis.

The problem in determining the significance of λ is clearly one of measurement. As was evident from the selection of case studies presented in Chapter 2, lab scale tests and numerical reservoir simulations typically relate ultimate recovery to initial reservoir pressure or to initial oil saturation. The effect of timing on incremental recovery is not usually explicitly determined, and we are using timing here as a proxy for all of the relevant reservoir parameters which enter into the process. For this reason, analytical specification of λ is not usually possible.

It is, however, possible to obtain order of magnitude estimates of λ for any given process. For example, from Agbi and Mirkin,[2] a CO_2 flood initiated after primary recovery will yield 50% more incremental oil than one initiated after waterflooding. As waterfloods can range anywhere from 5 to 20 years in duration, this would suggest an average estimate of λ being from +2%/year to +10%/year. (Actual values in any given year may fall outside of this range, as λ is not necessarily the same for all time periods.) This range is of the same order of magnitude of values of π and r, and hence λ could play as important a role in determining project economics as real price escalation and the real discount rate. Once again, however, the actual impact is not yet clear. To interpret the conditions properly, it is therefore useful to derive a number of impact parameters, similar to supply elasticities.

4.5 IMPACTS OF TIMING

4.5.1 Calculation of Supply Elasticities

To see how timing and, in turn, ultimate recovery, are affected by changes in economic factors, such as prices or taxation, the equilibrium Condition (4-17) must be differentiated with respect to the start-up time τ. The total differential of Condition (4-17) is presented in Appendix A.

It should be noted that, in deriving the following elasticities, it is assumed that λ is τ-independent. This assumption is not, in fact, always valid. Because λ is a proxy for all of the stock effects of timing which occur, and because these stock effects are due to reservoir conditions (such as pressure and oil saturation), λ may vary from one period to the next. As such, the following derivations should be considered as first approximations for an interval of time over which $d\lambda = 0$ is a close approximation. Given these conditions, however, it can be shown that the profit maximizing choice of τ depends upon $\overline{C}$, P_o, π, and r as follows:

$$\frac{\partial \tau}{\partial \overline{C}} = \frac{1}{\overline{C}(\pi-\lambda)} \qquad \text{...(4-18a)}$$

$$\frac{\partial \tau}{\partial P_0} = -\frac{1}{P_o(\pi-\lambda)} \qquad \text{...(4-18b)}$$

$$\frac{\partial \tau}{\partial \pi} = -\frac{\tau}{(\pi-\lambda)} - \frac{1}{(\pi-\lambda-r)(\pi-\lambda)} \qquad \text{...(4-18c)}$$

$$\frac{\partial \tau}{\partial r} = \frac{1}{r\,(\pi-\lambda)} + \frac{1}{(\pi-\lambda-r)(\pi-\lambda)} \qquad \text{...(4-18d)}$$

Elasticities of recoverable reserves to each of the above parameters can be defined and derived, recalling Equation (4-16), as follows:

$$\varepsilon_{RC} = \frac{dR_\tau/R_\tau}{d\bar{C}/\bar{C}} = -\frac{\lambda}{(\pi-\lambda)} \qquad \ldots(4\text{-}19a)$$

$$\varepsilon_{RP} = \frac{dR_\tau/R_\tau}{dP_o/P_o} = \frac{\lambda}{(\pi-\lambda)} \qquad \ldots(4\text{-}19b)$$

$$\varepsilon_{R\pi} = \frac{dR_\tau/R_\tau}{d\pi} = \frac{\lambda}{(\pi-\lambda)}\left\{\tau + \frac{1}{(\pi-\lambda-r)}\right\} \qquad \ldots(4\text{-}19c)$$

$$\varepsilon_{Rr} = \frac{dR_\tau/R_\tau}{dr} = -\frac{\lambda}{(\pi-\lambda)}\left\{\frac{1}{r} + \frac{1}{(\pi-\lambda-r)}\right\} \qquad \ldots(4\text{-}19d)$$

The impacts which any of the above have on the value of the scheme (V_τ) can be evaluated via Equation (4-13). This is most readily done in a simulation environment and will be addressed in Chapter 5.

4.5.2 Interpretation of Results

Equations (4-18) and (4-19) specify directionally the changes in τ and R_τ which will result as project costs and benefits are affected. A number of results immediately fall out of these equations which are of interest to the economist. We shall initially concentrate on the effects of costs and prices.

One notes first some cases where there are no stock effects of timing ($\lambda = 0$), that is, a delay in the project involves no change in the volume of oil recovered by the project. This corresponds to a base case assumption undertaken in most previous supply analyses. It is clear from Equation (4-19) that, under these circumstances, all of the indicated supply elasticities are zero. This is precisely what one would expect under the assumed constraint. From Equation (4-18), however, one sees that timing may be affected even when $\lambda = 0$. In a case, for example, where real price growth of 1%/year is anticipated ($\pi=0.01$), one would expect a 1 year delay for every 1% increase in the costs or 1% decrease in the initial real price.[3]

The parameters $\bar{C}$ and P_0 have important practical applications for policy analysis since they capture the total project costs and the initial per unit revenue expected by a producer. The effects of variations in government policies or in general economic conditions can be simulated through these parameters.

With respect to costs, for example, a major concern is the effect which capital cost increases may have on project economics. Since $\bar{C}$ is already a discounted flow of all capital <u>and</u> operating costs, the share of capital costs must be known to estimate the impacts on $\bar{C}$. Prince[4] estimated that, for all EOR processes, the share of undiscounted capital costs was approximately 15% (hence, normally, the discounted cost share would exceed this). If it were anticipated, for example, that capital costs were going to overrun original estimates by 20%, then $\bar{C}$ would increase by about 3%. In the case of a 1%/year real price escalation, and no stock effects, one would expect a 3 year timing delay to arise (via Equation 4-18a).

Similar simulations can be used to interpret changes in P_0. P_0 is the producer's netback price in the first (or current) period of analysis. Usually, all projections of price escalation are applied to this base price. Any conditions which affect this price can have a bearing on timing. Perhaps the most readily simulated effect is that of a royalty change. Royalties and revenue taxes impact directly the producer's wellhead netback and, therefore, any lump sum changes in such taxes could affect timing. For example, a reduction of one percentage point in the royalty rate would have the effect of increasing P_o by somewhat more than 1% and, if a 1%/year real price escalation is anticipated, projects would commence at least 1 year earlier.[5]

As was discussed previously, however, the assumption of $\lambda = 0$ is not usually valid. The impacts which changes in costs and prices have on timing can be reversed by the presence of stock effects. It is noted that these stock effects generally act in an opposite manner to the effects of real price inflation. If, for example, $\lambda > \pi$, then Equation (4-18) appears to indicate that any increase in costs or decrease in netback will cause an advancement in timing and a subsequent increase in reserves. Intuitively this does not appear logical, and the resolution lies in the second order condition for profit maximization:

$$\frac{\partial^2 V}{\partial \tau^2} < 0 \qquad \text{...(4-14b)}$$

Evaluating Equation (4-13) shows that:

$$\frac{d^2 V}{d\tau^2} = (\pi-\lambda-r)\frac{dV}{d\tau} - r(\pi-\lambda)e^{-r\tau}\,\overline{C} \qquad \text{...(4-20)}$$

which, at a maximum value of V where $dV/d\tau = 0$, yields:

$$\frac{d^2 V}{d\tau^2} = -r(\pi-\lambda)e^{-r\tau}\,\overline{C} \qquad \text{...(4-21)}$$

For Equation (4-21) to satisfy the profit maximizing Condition (4-14b), it is clear that we must have:

$$\pi > \lambda \qquad \text{...(4-22)}$$

The solution yielded by Condition (4-17) if $\pi < \lambda$ is one of a profit maximum occurring at a time approaching infinity (i.e., never). The profit maximizing choice of τ must therefore lie at one of the boundary constraints; these have not been formally defined but require, obviously, that

$$\tau \geqq t_c \qquad \text{...(4-23)}$$

where t_c is the <u>current</u> time period. This suggests that, if $\pi < \lambda$, then a profit maximizing choice, if one exists, occurs at the boundary constraint of $\tau = t_c$, (note that if $V < 0$ at this point, then no such choice exists). In other words, if a profit-maximizing solution exists, τ is determined by Condition (4-17) as long as $\pi > \lambda$ and, otherwise, the scheme should be undertaken as soon as possible. Intuitively, this is logical under the restrictive assumption used here: if neither the costs of the scheme nor the pattern of output are affected by timing, then one would be willing to delay a scheme past t_c only if the rate of price increase more than compensated for any loss of oil volumes.

Returning to Equations (4-18) and (4-19), if $\pi > \lambda$, then any increase in costs will cause a delay in implementation and a decrease in ultimate recovery. In this event, ε_{RC} is usually negative and a 1% cost increase would usually elicit more than a 1% <u>decrease</u> in incremental recovery (unless $\pi > 2\lambda$ in which case the decrease in recovery is less than 1%).

Interpreting the impacts of π and r on timing and on reserves is not so straight forward, and is not pursued in detail here. From Equations (4-18c), (4-18d), (4-19c) and (4-19d) it is clear that the magnitude of changes in R_τ and τ depends intimately upon the relative values of π, λ, and r. As an illustration, a number of values for the function ε_{Rr} are calculated and presented in Table 4.3. The elasticity ε_{Rr} shows the percentage change in incremental recovery arising from a 1% increase in the discount rate.

4.6 RELAXING SOME ASSUMPTIONS

A number of assumptions were required to make the model analytically solvable. Perhaps the most heroic assumptions were those regarding the cost function and the production profiles. In this section, these are relaxed qualitatively and the resulting directions in the results are discussed.

4.6.1 Cost Function

In the above formulation, recall that it was assumed that the profile of real incremental costs ($\bar{\bar{C}}_x$) was independent of start-up time, and hence,

$$\bar{C} = \int_0^T \bar{C}_x e^{-rx} dx \qquad \text{...(4-12b)}$$

is also independent of τ. In reality, however, as was pointed out in Chapter 3, costs are typically dependent upon the expected production profile.

TABLE 4.3

Illustrative Function Values for $E_{R\dot{r}}$

$$E_{R\dot{r}} = -\frac{\lambda}{(\pi - \lambda)} \left[\frac{1}{r} + \frac{1}{(\pi - \lambda - r)} \right]$$

λ	π=0.05, r=0.05	π=0.05, r=0.10	π=0.10, r=0.05	π=0.10, r=0.10
-0.03	20.0	-15.0	7.5	10.0
-0.02	20.0	- 6.7	5.7	10.0
-0.01	20.0	- 2.5	3.3	10.0
0.00	0.0	0.0	0.0	0.0
0.01	20.0	1.7	- 5.0	10.0
0.02	20.0	2.9	-13.3	10.0
0.03	20.0	3.8	-30.0	10.0
0.04	20.0	4.4	-80.0	10.0
0.05		5.0*		10.0
0.06		5.5		10.0
0.07		5.8		10.0
0.08		6.2		10.0
0.09		6.4		10.0

*Limit as $\lambda \to 0.05$

Some proportion of operating costs, for example, are directly related to production. If advancing a scheme causes higher incremental recovery and, hence, greater incremental production, one would expect an almost proportionate increase in production related costs such as those for separation and water treatment. Any such costs, to the extent that they are expressible in terms of $\$/m^3$ production, are readily incorporated as an adjustment to the price received for the product. The model, in this case, would define "price" (P_t) as the market price less the variable per unit operating costs. (Such costs can be treated, essentially, as an additional royalty and analyzed in a similar manner as royalties were above.) As a first approximation, expected price escalation π would remain unchanged as energy costs are typically the most significant cost share in production costs. Analytical results would not differ markedly from those obtained earlier.

A certain proportion of the operating costs, primarily that associated with injected materials, is independent of timing. In EOR schemes in particular, the planned quantities and rates of injection for flood materials (steam, solvent, chemicals) are production independent. The efficiency and performance of this flooding will, however, have an effect on production and ultimate recovery. As related previously, this efficiency can be dependent upon timing but, for these types of costs in any event, the costs are expected to be timing independent.

Finally, one must consider the capital costs. Here again, they can normally be separated into those which are injection related and those which are production related. In EOR schemes, injection related capital costs, by their nature, are normally timing and production independent. Steam generation, solvent handling, or chemical handling equipment requirements depend upon injected quantities. As argued above, these are production independent. Also, drilling of injection wells typically constitutes a significant cost share but these costs, too, would be production independent. Those capital costs which are dependent upon well production are relatively minor in comparison to the costs of injectant. They would include such possible items as: higher producing well completion costs; larger separating and treatment facilities; higher capacity gathering lines; greater storage capacity. Incremental capital costs in those areas, if incorporated at the design level, would be relatively minor.

In summary, therefore, it is apparent that earlier assumptions regarding the cost function do not limit the model critically. The most significant variable cost component, production related operating costs, can be treated as a royalty which affects the netback price. Operating and capital costs related to injection materials are normally timing independent. Capital costs related to production are usually relatively small.

The generality of the above discussion is not meant to imply that exceptions do not exist. In some cases, as expressed in Chapter 3, capital costs may be lowered by starting a scheme earlier through substantially lowering the injectant requirements. On the other hand, in some cases, incremental capital costs may be lowered simply by delaying a scheme and waiting for excess capacity to arise in existing equipment due to neutral decline effects.

Further, in the event that real cost inflation is expected, project timing would normally be different than where no such increases are anticipated. This can be modelled via simple simulations as in previous sections, or can be undertaken analytically. For example, it can be shown that if real cost inflation of κ%/year is expected, where $\bar{C}$ is now redefined through (compare to Equation (4-12b)):

$$\bar{C} \equiv \bar{C}_o \, e^{\kappa\tau} \qquad \ldots(4\text{-}24a)$$

$$C_o = \int_0^{\bar{T}} \bar{C}_x e^{-rx} dx \qquad \ldots(4\text{-}24b)$$

then timing and ultimate recovery will depend upon costs and prices as follows:

$$\frac{\partial\tau}{\partial\bar{C}_o} = \frac{1}{\bar{C}_o(\pi-\lambda-\kappa)} \qquad \ldots(4\text{-}25a)$$

$$\frac{\partial\tau}{\partial P_o} = -\frac{1}{P_o(\pi-\lambda-\kappa)} \qquad \ldots(4\text{-}25b)$$

$$\varepsilon_{RC} = \frac{dR_T/R_T}{d\bar{C}_o/\bar{C}_o} = -\frac{\lambda}{(\pi-\lambda-\kappa)} \qquad \ldots(4\text{-}26a)$$

$$\varepsilon_{RP} = \frac{dR_T/R_T}{dP_o/P_o} = \frac{\lambda}{(\pi-\lambda-\kappa)} \qquad \ldots(4\text{-}26b)$$

When these are compared to Equations (4-18) and (4-19) (which represent the special case $\kappa = 0$), it is clear that the existence of real cost inflation normally enhances any directional effects on timing and incremental recovery. On the other hand, if κ is significantly large, then it may completely reverse the direction of the effects (eg., if $\pi > \lambda$ but if $\kappa > [\pi - \lambda]$).

4.6.2 Production Profile

In the above formulation, it was assumed that the incremental production profile was independent of start-up time, and hence,

$$F = \int_0^{\bar{T}} \bar{f}_x e^{(\pi - r)x} \, dx \qquad \text{...(4-12a)}$$

is also independent of τ. Realistically, however, neither the shape of the incremental production profile (f_x) nor the length of the project (T) are independent of the conditions at project commencement.

In the case of acceleration projects, where neutral stock effects of timing exist ($\lambda = 0$), the incremental recovery tends to occur over a shorter time period. Hence,

$$f'_x > f_x \qquad \text{for small } x$$

$$f'_x < f_x \qquad \text{for large } x$$

$$T' < T$$

where the primed values refer to the acceleration project. Unless π is very large, this furthermore implies that $F' > F$. The effect that this has is to enhance the acceleration process and, where stock effects exist ($\lambda > 0$), to also enhance these.[6]

There are also instances, however, where the dependence of F on τ is biased in favour of delays. This might be the case where prices are expected to continue to rise in real terms. The duration of any project (T) is dependent on the relationship between the price of the product and the variable operating costs of production. As long as revenues are sufficient to cover such costs, production will continue. Once revenues fall below these costs, however, the producer could cut his losses by shutting in the project. Shutdown occurs at some minimum production rate. Indeed, in the previous formulation it would be found that:

$$P_T Q_T \geq C_T^* \qquad \text{...(4-27a)}$$

$$P_{T+1} Q_{T+1} < C_{T+1}^* \qquad \text{...(4-27b)}$$

where C_T^* represents the variable costs in year T. Year T would hence be the cut-off year.[7] In the face of real price increases, P_t is continually rising and the cut-off rate Q_{T+1} tends to fall. In typical declines, therefore, T can be extended by delaying the project and, in this event, it could happen that: $F' < F$, where F' again refers to the project undertaken at an earlier time. Here, then, we see that the bias favours delaying the project. Note that, for economic reasons, we expect stock effects to be effectively negative ($\lambda < 0$) since delaying the scheme extends its effective life and hence may increase the incremental recovery. This indicates the general complexity of the problem where λ depends upon both the technical efficiency of a scheme as well as countless economic conditions (including P_o, π , C_x^*, Q_x as well as future expectations of all of these).

It is beyond the scope of this discussion to suggest an analytical solution incorporating the general case which will completely relax the assumption that F is τ - independent. In most realistic applications, prediction of the incremental recovery in itself is filled with considerable uncertainty and it would be even more difficult to predict minute changes in the distribution of this incremental recovery. Further, since the output rate is low by the time of abandonment, and the present value of profit becomes small, it seems unlikely to have much of an effect in most cases. Because of these factors, rather than using analytical formulations, it appears more worthwhile to undertake numerical simulation studies such as those in the following chapter.

CHAPTER 5

APPLICATIONS OF THE MODEL

5.1 INTRODUCTION

Whereas the previous chapter discussed mainly the conceptual and analytical framework of the model, this chapter deals with some of the potential applications of the model. First a discussion is presented which shows how the model may be operationalized. For the simple analytical cases, operationalizing the model is no problem since the analysis does provide explicit solutions for all of the interesting variables. In fact, however, the analytical model may not be applicable to all cases, in which case a simulation environment must be established. Both linear and non-linear programming techniques could be applied. It is beyond the scope of this study to undertake any complex mathematical programming, but some simple analytical examples will show the importance of using optimal timing solutions.

Analytical results for a general case are presented to illustrate some of the elasticities mentioned in the previous chapter. To do this, typical reservoir and economic parameters will be chosen and the calculations will be completed using the derived formulae. At this stage, explicit formulae for the impacts on a project's net present value are presented and interpreted.

Numerical simulations will also be undertaken for a CO_2 flood in a hypothetical reservoir. The purpose of these simulations is to illustrate numerically the implications of ignoring or underestimating stock effects.

5.2 OPERATIONALIZING THE MODEL

It is clear from previous chapters that properly timing the stages of reservoir development can have a significant bearing on the profitability of a scheme. The model presented earlier addressed a number of the issues involved in optimizing such development. The strength of the model lies not so much in its analytical formulation as it does in the conceptual framework which it uses to address the problem. As such, there are various means of applying this framework.

The precise manner in which the framework is operationalized depends upon the intended application. For example, analytical solutions are not generally applicable to specific reservoir development problems. They are, however, as illustrated, useful in discussing the overall impacts which may arise out of changes in major economic parameters. In this application, they can indicate biases which might arise out of wholesale changes in fiscal policy. But such analytical solutions will not yield results for specific developments unless the problem is very simple.

Individual reservoir cases will typically break most, if not all, of the assumptions required to model the problem analytically. For instance, in addition to problems with the cost function and production profile discussed in Chapter 4, we can anticipate conditions where expected real prices do not increase monotonically or where the term λ is itself τ- independent.[1] Where such conditions arise, other optimizing techniques are required.

If all of the technical and economic relationships can be expressed as mathematical correlations, then mathematical programming (M-P) techniques may be useful in optimizing timing. Whether linear or non-linear techniques are used, the strength of M-P lies in the completeness of the expressed relationships. As such, a thorough understanding of these relationships is usually required to define the programming problem. A problem with M-P is that, if one requires the optimization of development under a complex set of fiscal and regulatory provisions, it is often a complex matter to incorporate these provisions into the optimizing framework.

The basic core of any M-P problem is an iterative process which maximizes (or minimizes) the objective function subject to specified constraints. It is often, therefore, just as effective to use a less formal iterative "trial and error" procedure to address the optimization problem. In its simplest form, this involves undertaking a number of simulation evaluations using a deterministic model, resetting the relevant technical and economic parameters for every start-up time (τ). It is also less complex to accommodate a deterministic fiscal regime into such a model than it is to accommodate it within an optimizing (M-P) framework. An example of a simulation problem (excluding the regulatory framework) is presented in Section 5.4.

5.3 ANALYTICAL APPLICATION

General solutions can be derived using the analytical equations previously derived. The principle power of such applications is to indicate the possible impacts of incorporating timing effects. They allow the simulation of hypothetical changes in fiscal arrangements or economic variables.

5.3.1 Technical and Economic Assumptions

Although general figures can be derived, it is useful to specify the likely value or range of values for the major variables. It is clear from the derivations that these major variables are the real discount rate (r), the real rate of price escalation (π), and the extent of the stock effects of timing (λ).

Substantial literature and debate has focused on the question of the appropriate discount rate. A 1972 study by G.P. Jenkins found a weighted average private sector pre-tax annual rate of return of about 10%.[2] In addition, it has been recently suggested that, because of the uncertainties involved in EOR, corporations are requiring a 10% real rate of return on such schemes.[3] Finally, major institutional lenders recently indicated that they would require a nominal after-tax rate of return of 22% on EOR projects.[4] This was during a period of double digit inflation, so the real rate of return would have been approximately 10%. All of these indicate that an appropriate discount rate for evaluating such prospects is of the order of 10%/year.[5]

Choosing a value for real oil price increases is less straightforward. The netback price of oil from EOR schemes is subject not only to world oil market conditions, but also to government policies in regulating prices. Forecasts must consider variations in oil prices as well as in royalties. Federal forecasts connected with the National Energy Program indicate that real prices for tertiary recovery oil will, on the average, escalate at between +1%/year and +8%/year over the next decade. Recent trends have seen softening in <u>nominal</u> world prices and hence substantial real declines. On the other hand, political conflicts could just as readily reverse these trends.

It is not the intention here to delve into a detailed analysis of the methods used in oil price forecasting. The uncertainties involved dictate accepting a range of forecasts for sensitivity analysis. There are, however, a number of points which are worthy of note here in establishing such a range. First, since oil is a scarce resource with apparently increasing long-run costs as more marginal methods of exploitation are used, one would expect a long-run trend of real price <u>increases</u>. Second, for the cases in which we are interested, we have seen that for unbounded profit maximization we require that $\pi > \lambda$. Since λ is seldom negative, we are dealing with positive real price increases. In the event that $\pi < \lambda$, we have seen that either the scheme should never be undertaken, or it should be undertaken as early as logistics allow. For these reasons, our analytical discussion concerning satisfaction of the first order profit maximizing condition will concentrate on cases with real price increases. As an extreme, assuming no major variations in royalty rates, we would normally expect $\pi <$ 8%/year, which is the maximum forecast under the NEP.

Further to the arguments favouring real price increases, it is important to note that π represents the expected rate of increase in netback prices of EOR oil and not necessarily the rate of increase in the world price of a specific marker crude oil. Recent Government of Canada forecasts for world oil price increases indicate long term real price increases of approximately 2%/year.[6] There are, however, compelling reasons to believe that netback prices for oil from EOR schemes will increase at higher rates. First, the recent trend of royalty reductions, if continued, will lead to higher netback prices. Second, in heavy oil markets which are currently very soft, increased market demand arising from the availability of upgrading technology and expansion markets in the United States will improve expected netback prices. Further, because of the manner in which free market price differentials between various qualities of crude oil are determined, one normally expects heavy oil prices to increase at higher rates than light oil prices.[7] EOR schemes in general, and thermal EOR schemes in particular (which produce mainly heavy oil), might therefore expect relative real price increases in excess of those usually forecast for world marker crude oil.

The most difficult parameter to estimate is λ. It is not usually possible to measure λ directly, and approximations must therefore suffice. As was pointed out in Section 4.4.3, a CO_2 flood may have values for λ ranging from +2%/year to +10%/year. Prince found in his study of all economically viable hydrocarbon miscible floods that a 25% decrease in oil saturation (S_o) after waterflood would elicit a 12% decline in incremental recovery.[8] The rate at which S_o declines is dependent upon the reservoir drive characteristics and the production decline rate (D) and will lie somewhere between 0% and D%/year.[9] Typical production decline rates can be as high as 10%/year. This suggests that the rate of decline of S_o has a range of 0 - 10%/year, and hence, the 25% decline simulated by Prince would involve a delay of between 2.5 years and (at the mathematical limit) infinity. The limits for λ can be expressed as:

$$\lambda = -\frac{\Delta R_\tau}{R_\tau} \cdot \frac{1}{\Delta \tau} \qquad \ldots(5.1)$$

for discrete measurements. For Prince's simulation, therefore, where $\Delta R/R = -12\%$ and τ could range from 2.5 years to ∞, we determine a range of λ from 0%/year to +4.8%/year.

From the above discussions, we again see that it would be most appropriate to specify a range for λ of 0 - 10%/year, which is essentially the same as that specified for π. In addition, we further require that $\pi > \lambda$.

For discussion purposes, as an illustrative case, we shall assume the following:

$$r = 10\%/\text{year}$$
$$\pi = 3\%/\text{year}$$
$$\lambda = 2\%/\text{year}$$

5.3.2 Impacts on Supply and Timing

As we have seen from Equations (4-18) and (4-19), the impacts on incremental recovery and project timing caused by lump sum changes in a project's real costs or in the real product price are totally independent of r. As such, it is possible to present a general case for any value of π and λ as shown graphically in Figure 5.1.

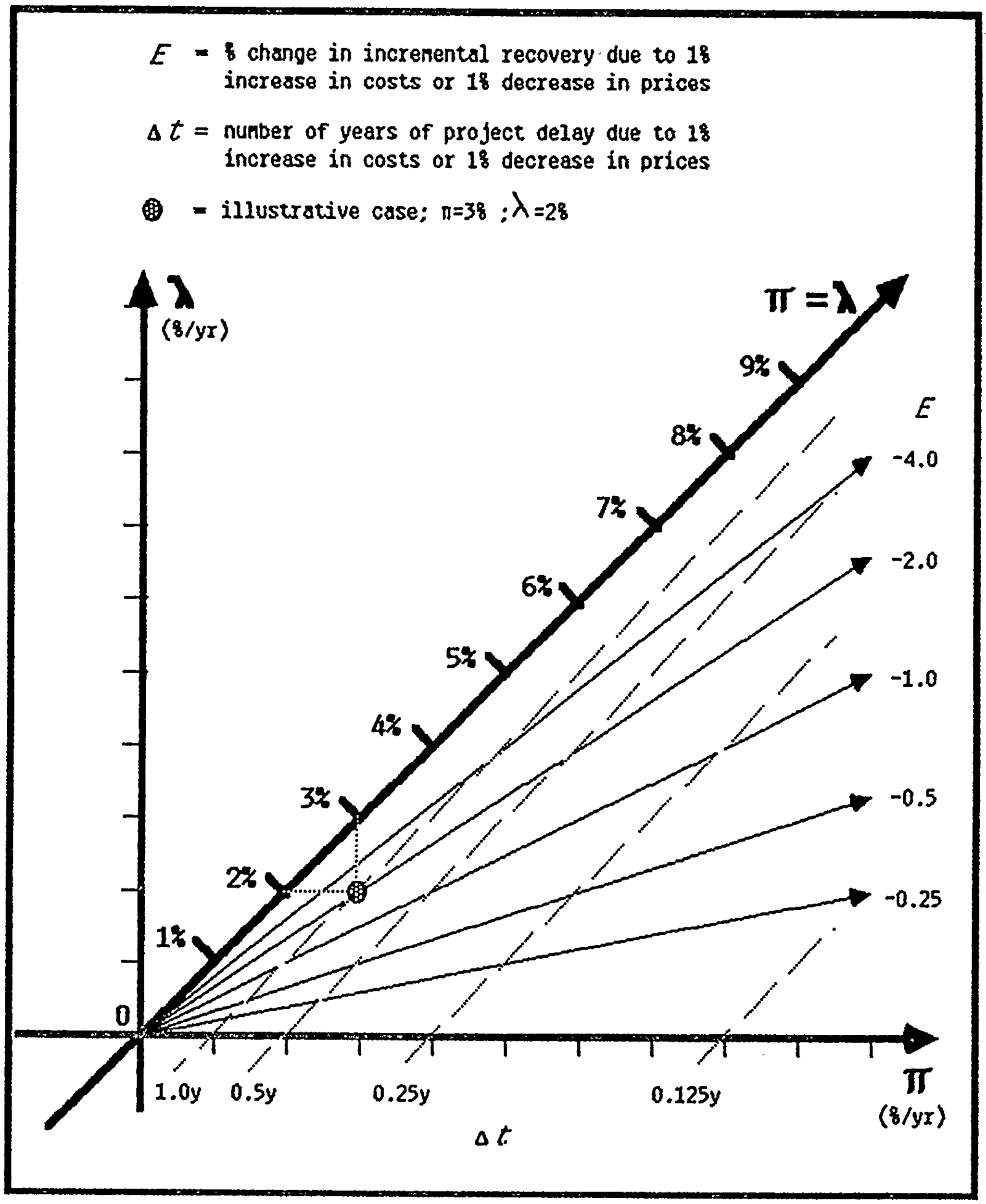
Figure 5.1 illustrates the impacts on incremental recovery and project start-up as a result of increases in costs or decreases in prices. The impacts are shown only for cases where $\pi > \lambda$, which is the second order constraint discussed earlier. The 45^o line labeled "$\pi = \lambda$" shows this cut-off and is used, for notational ease, as a common axis for both π and λ. Any given π is read vertically down from this line and any given value of λ is read horizontally across from the line. The solid rays originating from the origin are points of equal supply elasticity. The parallel broken lines are points of equal impact on timing. The graph can be used to show the impacts on supply and timing for any given value of π and λ.

For example, in our illustrative case at λ = 2% and π = 3%, we can see from the graph that a 1% increase in costs would cause a 1 year project delay and hence a 2% decrease in incremental recovery. It is interesting to note that in the absence of stock effects ($\lambda = 0$), the delay would be considerably less (only 4 months in fact) and there would be no loss in incremental recovery.

Figure 5.1 is also useful to indicate the extent of the impacts if only π or λ changes. For example, both timing delays and recovery losses become more pronounced if λ increases or if π falls.

FIGURE 5.1

Impacts on Supply and Timing



5.3.3 Impacts on Net Present Value

It is evident from previous discussions that stock effects can have significant impacts on the time at which a scheme is started and the incremental recovery from that scheme. We would also, therefore, expect stock effects to have some impacts on the net present value of the scheme.

Unlike timing and incremental recovery, however, the symmetry between an increase in costs and a decrease in price is not as pronounced. Impacts of a 1% price increase are greater than the impacts of a 1% cost decrease because, for an economic scheme, the present value of the revenues exceeds the present value of the costs. This result is reflected in the values of the elasticities of value to price (ε_{vp}) and value to cost (ε_{vc}):

$$\varepsilon_{VP} = \frac{dV/V}{dP_O/P_O} = \frac{r}{\pi-\lambda} \qquad \text{...(5-2a)}$$

$$\varepsilon_{VC} = \frac{dV/V}{d\bar{C}/\bar{C}} = \frac{\pi-\lambda-r}{\pi-\lambda} \qquad \text{...(5-2b)}$$

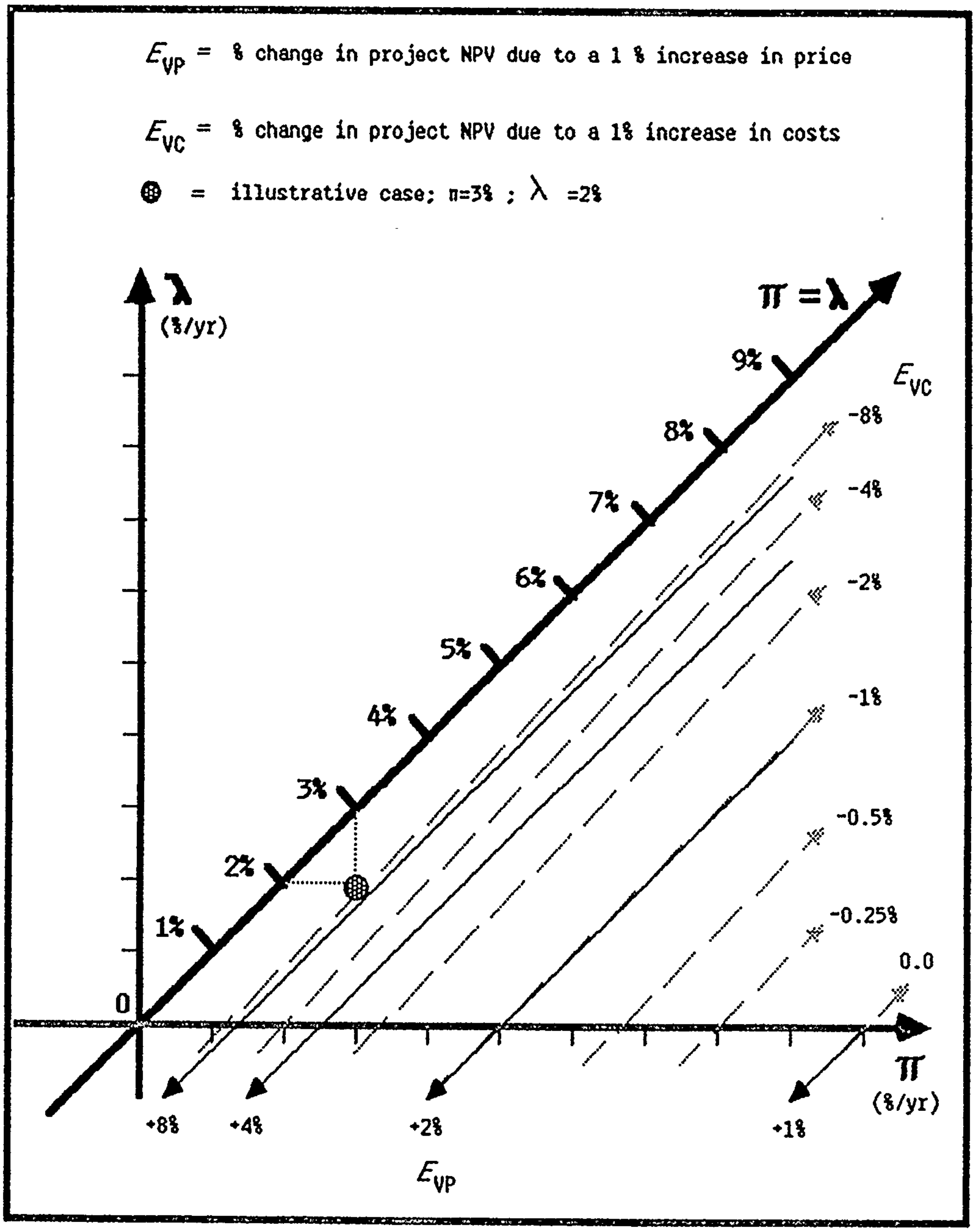
These results are readily derived by differentiating Equation (4-14) with respect to both P_o and $\bar{C}$, and then substituting the impact Conditions (4-18a) and (4-18b) where appropriate.

Equations (5-2a) and (5-2b) can also be graphed in a manner similar to the supply and timing elasticities. Figure 5.2 illustrates these equations for our base case where r = 10%/year. The notational conventions for π and λ in Figure 5.2 are the same as those in Figure 5.1. Note again that we are only interested in those cases where $\pi > \lambda$. The solid lines labeled ε_{vp}, representing the

FIGURE 5.2

<u>Impacts on Project Net Present Value</u>

(r=10%/year)



elasticity of project value to price, correspond to Equation (5-2a). The broken lines labeled ε_{vc} represent the elasticity of project value to costs and correspond to Equation (5-2b).

We note that since $\pi > \lambda$ and $r > 0$ for all of our cases, that an increase in project value will always arise if prices rise, regardless of the extent of stock effects. Also, for all of our "realistic" cases we normally have $\lambda \geqq 0$ and $(\pi - \lambda) < r$, hence a decrease in project value will arise if costs rise. For our illustrative case of $\pi = 3\%$ and $\lambda = 2\%$, we can see from Figure 5.2 that a 1% price decrease would lower the project's value by 10%, but a 1% cost increase would lower it by only 9%. In either case, as we calculated earlier, the project would be delayed by 1 year and incremental recovery would fall by 2%.

From Equation (5-2) or Figure 5.2 we note that the impacts of neglecting stock effects can be significant. If, reverting to our illustration, we still assume that $\pi = 3\%$/year but that $\lambda = 0$, then a 1% decrease in price would lower the project's value by only 3.3% instead of by 10%. Similarly, a 1% increase in cost would lower the project's value by only 2.3% rather than by 9%.

5.3.4 Summary

The above discussion illustrates that if one underestimates the extent of stock effects of timing, then the impacts of cost increases and price decreases on time delays, incremental recovery, and a project's net value will also be underestimated. All of this suggests that EOR supply is significantly more elastic than previous studies have indicated.

5.4 NUMERICAL SIMULATION

5.4.1 Description of Approach

The purpose of this section is to present a simple numerical model of profit maximization which accommodates the inclusion of stock effects of timing. It illustrates, for a hypothetical CO_2 flood in a heavy oil reservoir, how one would choose an optimal time to initiate the scheme. The effects of ignoring stock effects are readily interpreted, and dramatically illustrate the need for incorporating a proper estimate of stock effects into decision analysis. The simulations also serve to confirm a number of the conclusions drawn from the previous analytical formulation.

The nature of the problem to be solved can be expressed as follows. A portion of a heavy oil reservoir is being subjected to a waterflood. This activity can be curtailed at any time and replaced by a carbon dioxide flood using similar equipment at modest incremental cost. The problem, quite simply, involves selection of the year to commence the CO_2 flood in a manner which maximizes the expected net present value of the EOR scheme.

The reservoir conditions and the base case for the technical performance of the scheme are based on reservoir simulations by M.A. Klins and S.M. Farouq-Ali. They arise from the same study which produced the results of stock effects presented in Table 2.4.[10] Economic conditions are, to an extent, based on their work, as well as on work by Prince.

A deterministic computer model was utilized to perform the multiple simulations required to determine the year of first EOR investment. A listing of the FORTRAN source code for the base case is included in Appendix B. The model uses one single year which is user-specified as a base case for flood performance. Performance is internally computed using a range of λ factors if the flood is commenced in years other than the base year. Incremental capital investment, operating and maintenance costs, and CO_2 requirements are used as a cost base and are adjusted according to the first year of the EOR scheme. Price forecasts are user-specified. The incremental recovery and net present value of the scheme are then computed for a range of λ factors and for project start-up years ranging from $\tau = 1$ to $\tau = 30$.

5.4.2 Technical and Economic Assumptions

A carbon dioxide flood in a heavy oil reservoir is modelled.[11] It is assumed that, if investment is commenced in Year 11 of the reservoir's life, then 1,449.3 m^3 of incremental oil will be produced, distributed as indicated in Table 5.1 over the ensuing 10 years. Carbon dioxide is injected at the rate of 1×10^6 m^3/year from Years 11 to 20. Substantial "blowdown" production in Year 21 is realized from continued swelling of the CO_2 in the reservoir even after injection has stopped.

It is assumed that very little incremental equipment would be required beyond that which would be in place for the waterflood. The following items will contribute to the incremental costs:

1) installed compressor in Year 11;

2) compressor operation and maintenance from Years 11 - 20 inclusive;

3) carbon dioxide.

No net salvage value is attributed to the project.

TABLE 5.1

Distribution of Incremental Production from CO_2 Flood

Year	Incremental Production (m^3/year)
11	0.0
12	316.2
13	130.2
14	109.0
15	103.5
16	103.7
17	107.7
18	138.5
19	113.1
20	85.3
21	242.1

Klins and Farouq-Ali estimated compressor costs in 1980 to be \$700/ installed horsepower.[12] No estimates of compressor requirements or separator conditions were specified, although they cite initial reservoir conditions as 600 psia. It is therefore estimated that compressor requirements will be 50 hp.[13] A 1983 cost estimate of \$850/hp is utilized to derive a base year cost of \$42,500. Annual incremental operating and maintenance costs are estimated at 5% of the original equipment cost.[14]

Carbon dioxide values vary considerably depending upon location and whether an operator must buy CO_2 or can recycle it after separating it from the produced oil. Prince estimated that, in Alberta, purchased CO_2 had a minimum value of \$1.10/mcf and that recycled CO_2 had a value of 0.40/mcf (1978 \$).[15] Klins and Farouq-Ali found that, in their simulations, 70% of the CO_2 could be recycled.[16] Assuming a 7%/year average inflation rate, a weighted average price (1983 \$) of CO_2 of \$25 per thousand cubic metres is used here.

The model discounts mid-year values at a real discount rate of 10%/year. All discounted present values are with respect to the beginning of year 1.

The model calculates net present values for a range of λ from $\lambda = 0$ to $\lambda = 5\%$/year. The λ in this case specifies output losses (from the 1449.3 m^3) if delayed after year 11 or output gains if advanced before year 11. It is assumed that real capital costs, operating costs, and injection requirements are independent of project startup. Also, the project length and proportionate distribution of production is independent of τ. That is, as before in the analytical formulation, both $\overline{F}$ and $\overline{C}$ are τ - independent.

Two separate price forecasts are simulated. One relates to a constantly escalating base price at a real rate of 3%/year, corresponding to the illustrative analytical example in Section 5.3. The second involves an example of non-constant price escalation, which is the more common case in project evaluations. Specific assumptions are as follows:

<u>Case A</u>:	Yr	1:	P = \$157.50/m^3 (\$25/bbl)
	Yr	2 - 40:	P escalates at 3%/year
<u>Case B</u>:	Yr	1:	P = \$189.00/m^3 (\$30/bbl)
	Yr	2 - 5:	P escalates at 1%/year
	Yr	6 - 10:	P escalates at 3%/year
	Yr	11 - 15:	P escalates at 5%/year
	Yr	16 - 20:	P escalates at 3%/year
	Yr	21 - 40:	P escalates at 2%/year

The assumptions for Case B correspond to circumstances where the operator expects improvements in heavy oil market conditions in 5 years (for example, due to the availability of upgrading). The market adjustment is expected to last about 10 years, after which price escalation tracks more closely a long term forecast for light oil price increases. One notes that Case B is, by its nature, not readily evaluated using the analytical techniques applied earlier, and hence would normally require solution using simulation techniques.

5.4.3 Results

The results of the simulations can be utilized to answer the following questions:

(a) In what year would the operator commence the project if he ignored the presence of stock effects?

(b) What impact would this decision have on the actual incremental recovery and project value if stock effects existed?

(c) In what year should the operator have commenced the project if he had not ignored stock effects?

For the simulation of Case A, these questions can be answered through inspection of Tables 5.2 and 5.3. If an operator ignores stock effects, then he will plan to commence his project in Year 24 and expect to realize a project NPV of $10,810 and an incremental recovery of 1,449 m^3. If however, stock effects of λ = 1%/year actually existed, his realized NPV will be only $6,580 and his realized incremental recovery only 1,273 m^3. If he had been aware of these circumstances, he would have planned to commence investment in Year 23, thereby slightly increasing both project value and incremental production over what was actually realized. The increase is quite minor for λ = 1%, but could be much more substantial if λ is larger.

Table 5.2 indicates our earlier conclusions, that a boundary solution should be chosen if π does not exceed λ. Here we see that if $\pi = \lambda$ = 3%/year, then the project should not be undertaken within the timeframe analyzed. On the other hand, if $\pi < \lambda$, then the project should be commenced as soon as possible (Year 1). Returning

TABLE 5.2

Net Present Value - Case A

($'000)

	Lambda(%)							
Tau	0.0	0.5	1.0	1.5	2.0	3.0	4.0	5.0
1	-57.07	-48.99	-40.54	-31.71	-22.47	-2.73	18.81	42.30
2	-47.57	-40.78	-33.71	-26.36	-18.71	-2.48	15.06	34.00
3	-39.21	-33.58	-27.74	-21.69	-15.43	-2.26	11.85	26.93
4	-31.87	-27.26	-22.51	-17.62	-12.58	-2.05	9.11	20.94
5	-25.44	-21.75	-17.96	-14.09	-10.11	-1.86	6.79	15.88
6	-19.81	-16.94	-14.01	-11.02	-7.97	-1.69	4.83	11.61
7	-14.91	-12.76	-10.58	-8.37	-6.13	-1.54	3.18	8.04
8	-10.65	-9.14	-7.63	-6.09	-4.54	-1.40	1.80	5.07
9	-6.96	-6.02	-5.08	-4.14	-3.19	-1.27	0.66	2.61
10	-3.78	-3.34	-2.91	-2.47	-2.03	-1.16	-0.28	0.59
11	-1.05	-1.05	-1.05	-1.05	-1.05	-1.05	-1.05	-1.05
12	1.28	0.89	0.52	0.14	-0.23	-0.96	-1.67	-2.37
13	3.25	2.54	1.84	1.14	0.46	-0.87	-2.16	-3.42
14	4.91	3.91	2.94	1.98	1.04	-0.79	-2.55	-4.24
15	6.30	5.06	3.84	2.66	1.51	-0.72	-2.84	-4.86
16	7.44	5.99	4.58	3.22	1.89	-0.65	-3.05	-5.31
17	8.37	6.75	5.18	3.66	2.19	-0.59	-3.20	-5.63
18	9.12	7.34	5.64	4.00	2.43	-0.54	-3.29	-5.83
19	9.70	7.81	6.00	4.27	2.61	-0.49	-3.33	-5.94
20	10.14	8.15	6.26	4.45	2.74	-0.45	-3.34	-5.96
21	10.45	8.39	6.43	4.58	2.83	-0.41	-3.31	-5.93
22	10.66	8.54	6.54	4.66	2.88	-0.37	-3.26	-5.84
23	10.77	8.61	6.59	4.69	2.90	-0.34	-3.19	-5.71
24	10.81	8.62	6.58	4.68	2.90	-0.30	-3.10	-5.55
25	10.77	8.57	6.53	4.64	2.88	-0.28	-3.00	-5.37
26	10.68	8.48	6.45	4.57	2.84	-0.25	-2.90	-5.16
27	10.55	8.35	6.34	4.48	2.78	-0.23	-2.78	-4.95
28	10.37	8.19	6.20	4.38	2.71	-0.21	-2.66	-4.73
29	10.15	8.00	6.04	4.26	2.64	-0.19	-2.54	-4.50
30	9.91	7.79	5.87	4.13	2.55	-0.17	-2.42	-4.27

TABLE 5.3

Total Incremental Oil - Cases A & B

(m^3)

	Lambda(%)							
TAU	0.0	0.5	1.0	1.5	2.0	3.0	4.0	5.0
1	1449.30	1523.42	1600.93	1681.97	1766.69	1947.74	2145.32	2360.76
2	1449.30	1515.84	1585.08	1657.12	1732.05	1891.01	2062.81	2248.34
3	1449.30	1508.30	1569.38	1632.63	1698.09	1835.93	1983.47	2141.28
4	1449.30	1500.79	1553.85	1608.50	1664.79	1782.46	1907.18	2039.31
5	1449.30	1493.33	1538.46	1584.73	1632.15	1730.54	1833.83	1942.20
6	1449.30	1485.90	1523.23	1561.31	1600.14	1680.14	1763.30	1849.71
7	1449.30	1478.50	1508.15	1538.23	1568.77	1631.20	1695.48	1761.63
8	1449.30	1471.15	1493.22	1515.50	1538.01	1583.69	1630.27	1677.75
9	1449.30	1463.83	1478.43	1493.11	1507.85	1537.56	1567.56	1597.85
10	1449.30	1456.55	1463.79	1471.04	1478.29	1492.78	1507.27	1521.76
11	1449.30	1449.30	1449.30	1449.30	1449.30	1449.30	1449.30	1449.30
12	1449.30	1442.09	1434.95	1427.88	1420.88	1407.09	1393.56	1380.29
13	1449.30	1434.91	1420.74	1406.78	1393.02	1366.10	1339.96	1314.56
14	1449.30	1427.78	1406.68	1385.99	1365.71	1326.31	1288.42	1251.96
15	1449.30	1420.67	1392.75	1365.51	1338.93	1287.68	1238.87	1192.34
16	1449.30	1413.60	1378.96	1345.33	1312.68	1250.18	1191.22	1135.56
17	1449.30	1406.57	1365.31	1325.45	1286.94	1213.77	1145.40	1081.49
18	1449.30	1399.57	1351.79	1305.86	1261.70	1178.41	1101.35	1029.99
19	1449.30	1392.61	1338.40	1286.56	1236.96	1144.09	1058.99	980.94
20	1449.30	1385.68	1325.15	1267.55	1212.71	1110.77	1018.26	934.23
21	1449.30	1378.79	1312.03	1248.81	1188.93	1078.42	979.10	889.74
22	1449.30	1371.93	1299.04	1230.36	1165.62	1047.01	941.44	847.38
23	1449.30	1365.10	1286.18	1212.18	1142.76	1016.51	905.23	807.02
24	1449.30	1358.31	1273.45	1194.26	1120.36	986.90	870.41	768.59
25	1449.30	1351.55	1260.84	1176.61	1098.39	958.16	836.93	732.00
26	1449.30	1344.83	1248.35	1159.22	1076.85	930.25	804.74	697.14
27	1449.30	1338.14	1235.99	1142.09	1055.74	903.16	773.79	663.94
28	1449.30	1331.48	1223.76	1125.22	1035.04	876.85	744.03	632.32
29	1449.30	1324.86	1211.64	1108.59	1014.74	851.31	715.42	602.21
30	1449.30	1318.27	1199.64	1092.20	994.84	826.52	687.90	573.54

to the earlier discussion, we can therefore see the dire consequences of underestimating λ. If the operator had planned to wait until Year 24 to start the project, and if $\lambda = 5\%/\text{year}$, he would find that the project would lose money at that time if he does decide to initiate it. Presumably, he would have enough presence of mind at that time just to cancel it. In this event, 2,361 m^3 of oil having a net present value of $42,300 would have been lost by ignoring stock effects.

Table 5.4 summarizes the results for Case A. It presents a comparison of the expected outcome if stock effects are ignored, the actual outcome from ignoring stock effects, and the outcome had the optimal time been selected if stock effects had not been ignored. It is apparent that in general, by ignoring stock effects, the actual outcome falls short of expectations and, indeed, fails to maximize the project value.

A similar interpretation can be presented for Case B, which is of interest primarily because it involves a price forecast which does not allow an analytical formulation of the problem using continuously differentiable functions. The results, presented in Tables 5.5 and 5.6, are nonetheless comparable. Impacts on incremental oil recovery for any given delay and value of λ are identical for both Case A and Case B.

Case B is presented here as a base case for comparison of what one would expect to occur in the event of an across the board decrease in all costs. Case B-2, summary results for which are presented in Table 5.7, simulates a 10% decrease in capital costs, operating and maintenance costs, and costs of CO_2 supply. If one were to ignore stock effects, then one would plan to commence 2 years earlier than before, expecting a 31% increase in project value and no change in incremental recovery. If, however, we actually had $\lambda = 2\%$, but

TABLE 5.4

Summary - Case A

Chosen τ = Year 24
Expected NPV = \$10,810
Expected IR = 1,449 m^3

	Actual λ (%/yr)					
	0	1	2	3	4	5
Realized NPV*	10,810	6,580	2,900	-300	-3,100	-5,550
Realized IR*	1,449	1,273	1,120	987	870	769
Optimal τ	24	23	23		1	1
Optimal NPV	10,810	6,590	2,900	0	18,810	42,300
Optimal IR	1,449	1,286	1,143	0	2,143	2,361

*If the operator decides to proceed under any circumstances in Year 24.

TABLE 5.5

Net Present Value - Case B

($'000)

	Lambda(%)							
Tau	0.0	0.5	1.0	1.5	2.0	3.0	4.0	5.0
1	-35.33	-26.14	-16.52	-6.47	4.04	26.49	51.00	77.72
2	-28.27	-20.59	-12.60	-4.29	4.36	22.71	42.53	63.95
3	-21.65	-15.29	-8.71	-1.90	5.15	20.00	35.89	52.89
4	-15.33	-10.13	-4.77	0.74	6.42	18.30	30.89	44.22
5	-8.91	-4.72	-0.42	3.99	8.50	17.87	27.70	38.02
6	-3.49	-0.21	3.14	6.56	10.04	17.22	24.68	32.44
7	1.23	3.70	6.21	8.76	11.34	16.62	22.06	27.66
8	5.32	7.06	8.83	10.60	12.40	16.05	19.77	23.56
9	8.84	9.94	11.04	12.14	13.25	15.49	17.75	20.03
10	12.22	12.73	13.25	13.77	14.28	15.32	16.35	17.39
11	14.82	14.82	14.82	14.82	14.82	14.82	14.82	14.82
12	16.81	16.35	15.90	15.45	15.00	14.13	13.26	12.42
13	18.25	17.39	16.54	15.70	14.88	13.27	11.70	10.18
14	19.15	17.94	16.76	15.59	14.45	12.24	10.11	8.06
15	19.35	17.85	16.39	14.96	13.57	10.88	8.32	5.88
16	19.36	17.62	15.92	14.28	12.68	9.63	6.74	4.02
17	19.20	17.25	15.37	13.56	11.80	8.47	5.36	2.45
18	18.89	16.78	14.76	12.81	10.94	7.41	4.14	1.12
19	18.45	16.22	14.08	12.04	10.08	6.42	3.07	-0.01
20	17.82	15.49	13.28	11.17	9.17	5.44	2.06	-1.01
21	17.16	14.77	12.51	10.36	8.33	4.59	1.22	-1.81
22	16.49	14.06	11.77	9.61	7.58	3.85	0.53	-2.43
23	15.82	13.37	11.07	8.91	6.89	3.21	-0.04	-2.90
24	15.15	12.69	10.40	8.26	6.26	2.65	-0.49	-3.25
25	14.49	12.04	9.76	7.65	5.69	2.18	-0.86	-3.49
26	13.83	11.40	9.16	7.09	5.17	1.77	-1.15	-3.65
27	13.18	10.79	8.59	6.56	4.70	1.42	-1.37	-3.74
28	12.55	10.20	8.05	6.08	4.28	1.12	-1.54	-3.77
29	11.94	9.63	7.54	5.63	3.89	0.86	-1.66	-3.76
30	11.34	9.09	7.05	5.21	3.53	0.64	-1.74	-3.70

TABLE 5.6

Summary - Case B

Chosen τ = Year 16
Expected NPV = \$19,360
Expected IR = 1,449 m^3

	Actual λ (%/yr) 0	1	2	3	4	5
Realized NPV	19,360	15,920	12,680	9,630	6,740	4,020
Realized IR	1,449	1,379	1,313	1,250	1,191	1,136
Optimal τ	16	14	12	1	1	1
Optimal NPV	19,360	16,760	15,000	26,490	51,000	77,720
Optimal IR	1,449	1,407	1,421	1,950	2,145	2,361

TABLE 5.7

Summary - Case B-2

(10% cost decrease)

Chosen τ = Year 14
Expected NPV = \$25,380
Expected IR = 1,449 m^3

	Actual λ (%/yr)					
	0	1	2	3	4	5
Realized NPV	25,380	22,990	20,680	18,470	16,340	14,290
Realized IR	1,449	1,407	1,366	1,326	1,288	1,252
Optimal τ	14	12	1	1	1	1
Optimal NPV	25,380	23,440	25,550	48,000	72,510	99,230
Optimal IR	1,449	1,435	1,767	1,948	2,145	2,361

ignore its effects in choosing a commencement time, then we would actually realize a gain of 63% in project value (from $12,680 to $20,680) and a 4% increase in incremental recovery. Note that in this event the optimal choice would actually have been to commence immediately; the 10% cost decline would have, under conditions of perfect information, caused the project to start 11 years earlier, increased project value by 70%, and increased recovery by 24%.

5.5 SUMMARY

It is clear from both analytical modelling and numerical simulations that stock effects of timing can have a significant impact upon optimal reservoir development. They have an important bearing on project timing, project net present value, and incremental oil recovery. Where these effects exist, their accurate estimation is just as critical as an accurate cost estimate or price forecast, and hence they warrant careful consideration in supply analysis.

CHAPTER 6

CONCLUSIONS AND IMPLICATIONS OF THE MODEL

6.1 INTRODUCTION

This chapter discusses some of the conclusions which may be drawn from the preceding analyses. First, it will indicate whether optimal timing does appear to be an important part of supply analysis. Second, the chapter will discuss what type of regulatory policies would hinder or enhance EOR development. Also, if optimal timing is an important part of EOR analysis, then some important implications for pilot projects and for EOR financing arise. Finally, the implications of the model to oil supply and price forecasting are discussed and some suggestions are forwarded for further research and analysis.

6.2 THE ROLE OF OPTIMAL TIMING IN SUPPLY ANALYSIS

A principal focus of this study has been the extent to which stock effects exist in a petroleum reservoir, and the impacts which these effects have on the optimal development of a reservoir. Optimality has been defined in a manner which ensures maximization of the net economic benefits attainable through reservoir development. Stock effects arise where current production of a resource affects the total resource stock available for future production. Stock effects of timing arise where the total stock available for production is affected by the time at which a development scheme is commenced.

It was found, first, that sound technical grounds frequently exist both in theory and in practise for advancing EOR production to the earlier stages of a reservoir's development. In many such cases, the effect would be to increase the incremental oil attributable to

EOR as well as the ultimate economically recoverable oil. Second, because of these stock effects, an operator of a reservoir is faced with a complex problem of trying to determine not only what type of development should occur, but also when it should be implemented. Simple analytical solutions indicated that both net present value and incremental recovery could be increased if the development is properly staged.

Since timing can influence the profitability of developing individual reservoirs, this study would suggest that any analysis of potential supply should address and incorporate the issues of staging reservoir development. Previous studies, although sometimes recognizing these issues, have not generally integrated them into their analyses. As a result, they tend to conclude that supply from EOR is quite inelastic. This arises from the "on/off" assumptions inherent in their analysis, i.e., the idea that an EOR scheme either goes ahead at full-scale or does not go ahead at all. They do not recognize intermediate scales or development programmes which lie between these extremes. Incorporation of the issues of optimal timing and staging explicitly recognizes that such middle grounds exist.

The implications of ignoring optimal timing are not insignificant. A recent estimate of the ERCB is that there are 4 billion barrels (630×10^6 m^3) of EOR reserves yet untapped in Alberta.[1] Through optimal staging, an increase in this estimate of only 10% would be equivalent to the reserves attributable to a moderately large (10,000 m^3/d) oilsands plant. The potential is even more significant if one considers the development of virgin offshore fields in Canada's arctic and east coast.

A further implication of ignoring optimal timing arises in the question of when EOR production will peak. The National Energy Board's most recent[2] estimate indicated that, in their base case, heavy oil EOR (including waterflooding) would peak in 1993 and lighter oils would peak in about 1996. Optimal timing of EOR could conceivably cause EOR production to peak sooner and hence contribute more as a source of medium-term supply. Conversely, restrictive regulations could have serious adverse effects on the time at which oil production from EOR peaks. By ignoring optimal timing, one finds that any one time decrease in netback prices or increase in costs would decrease oil production from EOR, but that the year of peak production would not be affected. On the other hand, incorporating optimal timing effects under these same conditions would cause delays in project implementation which would in turn cause production to peak at a later date. This implies that the introduction of restrictive regulations could jeopardize the prospects of EOR contributing to medium-term oil supply.

It is clear, therefore, that optimal timing does have a significant role to play in supply analysis. EOR supplies, although they have been previously identified as being more inelastic than conventional supplies,[3] may be much more elastic than previously thought. This has very important implications at the level of EOR regulations, since it implies that EOR can be much more responsive to concessionary prices and taxation systems. On the other hand, restrictive regulations may deter or postpone EOR development more than is socially desirable.

6.3 REGULATION OF EOR

6.3.1 Pricing

Recent trends in price regulation have seen significant price increases for oil produced from EOR schemes. The effects of such increases are, in general, to cause marginal schemes to become economic and economic schemes to be implemented earlier than they otherwise would. Technically, this implies that more incremental oil is being made available much sooner.

Perhaps of greater relevance, however, is the recent real decline in international oil prices. Since the value of EOR production is now much more closely tied to world prices, the current soft market conditions may be having a more significant impact on EOR schemes than was previously anticipated. If, for example, one does not consider the issue of optimal timing, then EOR supply seems quite inelastic above certain critical minimum prices. Any downturn in prices will not elicit a large drop in the quantity supplied. On the other hand, when optimal timing is considered, supply is more elastic and a decline in prices will create a more significant decrease in productivity, will cause project delays, and will cause an overall decline in ultimate recovery as a result of stock effects. The policy implications of this, for planning purposes, are that if prices remain soft then EOR will not contribute as significantly to supply as was previously thought, and any contributions which are made will be delayed.

6.3.2 Taxation

It was noted in this study that the oil and gas industry is very heavily regulated by both Federal and Provincial governments. Enhanced oil recovery has also been subject to substantial regulation, and various incentives and taxes have been introduced through the years. In general, the more recent progression of prices, incentives, and taxes has been directed to establishing a "neutral" environment which still effectively generates revenues for governments. A neutral system is one which will not affect either the timing of production or the ultimate recovery from a particular scheme.

Indeed, in light of the importance of optimal timing in reservoir development, it would seem to be an onerous task to design a neutral taxation system within the current institutional framework. Almost any type of tax, which is not purely a rent tax, will be viewed as a corporate cost and will hence affect both the timing and extent of enhanced recovery. On the other hand, it also implies that the current taxation system is a much more effective lever of government policy than was previously surmised. Any decreases in production taxes or increases in investment incentives would accelerate development and, if stock effects are substantial, could increase both the total output and the value of the output. An important lesson herein is that a decrease in the average tax rate may increase the aggregate tax collected. Similarly, an increase in the average tax rate may decrease the aggregate tax collected.

A second major implication which stock effects and optimal timing have on supply analysis, is that, if one excludes them, one tends to over-estimate the neutrality of a taxation system. Prince and Webster's results, for example, cited in Chapter 1, indicated that approximately 3% of the EOR oil (or 15 x 10^6 m^3) will be lost because of the incidence of the regulatory system. In view of the existence of positive stock effects, this loss is an understatement since it does not consider the volumes lost by delaying schemes. In other words, we are not attaining a neutral taxation system as quickly as recent studies might suggest.

6.4 THE UTILITY OF PILOT PROJECTS

Recent literature and discussions within the industry indicate that a large debate is evolving over the need for pilot testing of EOR schemes.[4] Pilot tests essentially involve the implementation of an EOR process in one portion of a field. The results of the tests are carefully monitored and evaluated in an attempt to generate information which will be useful in designing a process to be applied to the entire reservoir.

Although there are many issues at stake in evaluating the utility of pilot schemes, two arise as pivotal to the arguments put forward. Proponents, on the one hand, generally argue that pilot tests are required to generate important information as to the potential commercial profitability of a larger scale project. Without this information, too much is at risk. Opponents, by contrast, advocate undertaking large scale activities after any necessary laboratory work has been done. They argue that pilots yield little in the way of useful incremental information since it is impossible to extrapolate from a small scale to a large scale.

Both of the above approaches require substantial front-end engineering. A third approach, which requires less detailed engineering, involves concurrent implementation of three or four pilot schemes in different parts of the reservoir.[5] All are monitored and, after a certain amount of time, one is chosen as superior to the rest and is extended to encompass the entire reservoir. The advantage of this approach is that it does not require the initial detailed selection of a <u>single</u> process, and thus can proceed with less investigation. Its drawback is, of course, that front-end costs for the pilot testing are high.

The basic debate, therefore, appears to centre upon the costs and value of information. Proponents of pilot projects judge that the value of the information exceeds the costs of obtaining it. It is not the purpose of this study to comment on the merits of such arguments. The question of optimal timing does, however, add further fuel to the debate. This study indicated that the delays in commencing a project could lead to material reductions in the amount of oil produced or to reductions in the net value of production. Since pilot testing involves such delays, one must consider the costs of delaying the eventual larger-scale project as part of the costs of obtaining information from the pilot. These costs of delay are "hidden" in the sense that they are user costs and represent foregone revenues as opposed to direct investment, yet this study indicates that they can be substantial, and they should not be ignored when contemplating the merits of a pilot project.

The above implies that, before commencing a pilot, one should estimate the delays which the pilot will cause and then evaluate whether these delays may lead to decreased commercial viability of the large-scale project. If the costs are significant, one might consider whether it is more profitable to forego the pilot and commence a full-scale project with less information. Clearly, this will depend on the perceived need for information and the risks involved in proceeding without the information.

6.5 FINANCING EOR SCHEMES

Some advantages which EOR development enjoys over larger scale mega-projects, such as tarsands plants and frontier development, is that EOR requires less new infrastructure as well as less initial investment capital. Some capital is, however, still required, which brings one to the financing of EOR schemes.

At present, potential EOR operations may face a hurdle if they are confronted by a "conservative" capital market. Many lenders still see technically-proven EOR projects as a risky operation, and evaluate the schemes based on this perception. One institutional lender recently indicated[6] that it "would expect an after-tax rate of return of about 22 percent [on EOR], compared to a 12 percent return on an acquisition of proved properties, a 20 percent return on development drilling and a 25 percent return on low-risk exploration". This implies that the financing costs for EOR projects are proportionately higher than those for secondary recovery projects.

A second more formidable problem in financing EOR directly relates to project timing. To reduce risks[7]

> many investors ... like to see primary or secondary production on a property that is to be subject to EOR flooding before committing money. That way, the conventional production acts as insurance against the chance of a flood returning no incremental oil.

In terms of capital availability, this implies that the capital will tend to become "cheaper" as more primary or secondary development is undertaken.

This study indicates, however, that many projects will be both technically and economically more successful if they are started early in a reservoir's life. Indeed, some schemes would be best started as the first method of development. Because of distortions in the capital market, many EOR schemes may be delayed more than they would be in a perfectly uniform capital market. The effects of current practises are to prevent some EOR schemes from being undertaken and to delay others and decrease their value and production.

The net effect of current EOR financing practises is to decrease the ultimate incremental economic recovery from EOR, decrease its value, and cause unwarranted delays. To remedy this involves making some changes in the money markets, these changes relate primarily to providing accurate information regarding EOR and applying that information to investment analysis. Industry must provide the information regarding potential impacts of delays, and capital markets must develop the expertise to interpret and evaluate this information.

6.6 OIL SUPPLY AND PRICE FORECASTING

The model has a number of important implications for the general methods and approaches utilized by the supply analyst. Although careful inspection of the model's assumptions will clarify its limitations, important direction to the supply analyst can also be provided.

A fundamental assertion and assumption of the model was that firms are profit maximizers and that they are aware of the existence and extent of stock effects in the reservoir. It was shown through example that if firms neglect stock effects, their profits will not normally be maximized and any profits which do accrue will fall short of expectations. The model is limited, however, because the conclusions drawn in this study could be quite different if firms did not attempt to maximize profits. In general, therefore, it should be of major concern to the supply analyst whether firms actually profit maximize and whether thay are aware of all of the conditions which might affect their profits.

A second important assumption in the formulation of the analytical model was that firms base their decisions upon exponentially increasing oil prices which can be forecast well into the future. This implies that a firm can rationally choose the precise year in which a particular EOR scheme should be initiated, and further allows the firm to "fine tune" this commencement date as the economic environment changes. If this assumption were invalid, then it would imply that firms are unable to forecast prices and that all decisions would be based upon current conditions rather than future expected conditions. This would place us in a world in which an EOR project would proceed as soon as economic conditions justified it. An operator would not necessarily wait one year for more favourable conditions. Under such conditions, the "on/off" assumptions of other supply analyses are closer to real world conditions than the assumptions made in this study. A supply analyst should therefore be concerned with the extent to which firms forecast prices and the manner in which these forecasts are incorporated in firms' decisions.

Even if firms are found to be profit maximizing entities which are aware of stock effects and which base their decisions upon projections of economic conditions, the supply analyst must be concerned with the expected relationship between price increases and stock effects. The conclusions and implications drawn earlier in this chapter depend critically upon the assumption that the rate of expected price escalation exceeds the rate at which the resource stock declines due to delays in timing (i.e., $\pi > \lambda$). If, in fact, real price escalation is expected to be less than the rate of resource degradation, then we are once again in an "on/off" world in which projects are undertaken either immediately or never. The actual exercise of price forecasting therefore takes on an entirely new light: the result of the price forecast may have a bearing upon the type of supply model which the supply analyst uses. If the forecast indicates that $\pi < \lambda$, then optimal timing effects can be ignored to the extent that lump-sum changes in costs and regulations will only affect whether projects are undertaken now or never. If the price forecast indicates, on the other hand, that $\pi > \lambda$, then the supply forecast should allow for the fine-tuning of project start-up dates and the implications this will have on oil supply.

Price forecasting hence becomes a more important exercise in EOR oil supply forcasting. The supply analyst must be concerned not only with crude oil price escalation in international markets, but also the manner in which netback prices for oil from EOR projects behave . It was argued in Chapter 5 that EOR oil prices can behave quite differently from international oil prices because of quality differentials, the availability of upgrading for heavy oil, the availability of expansion markets for heavy oil, and changes in regulatory structure. As a result, expected prices for oil from EOR schemes can often significantly exceed expected international oil price increases.

6.7 FURTHER RESEARCH AND ANALYSIS

The basic purpose of this study was to identify some of the issues involved in oil reservoir development which have not been adequately incorporated in previous studies of enhanced oil recovery potential. Two central conclusions which arise out of this study serve as a basis for pursuing further research and analysis.

First, analysts must break the habit of thinking of reservoir development in terms of primary, secondary, and tertiary recovery. Although these terms may have been useful in the past, their continued use as a means of categorizing and analyzing oil supply implies that stock effects between these categories and the effects of timing are ignored. The results of ignoring these effects is to underestimate the elasticity of oil supply and to underestimate both the negative and positive impacts which government actions may have on oil producibility.

Second, oil supply analysis involves a complex interaction between both technical and economic factors of reservoir development. This implies that it is important to develop analyses which allow input from the technical disciplines of engineering and geology, as well as economic disciplines.

Although the modelling presented in this study does address issues of timing, and does incorporate some relevant technical constraints, it still falls short of the "ideal" analysis. A number of simplifying assumptions were made to make the general model analytically solvable. This does not, however, invalidate the conclusions which arise as a result of the excercise. The model acts as a first step in what must be a long process of rationalizing oil supply analysis.

This process of arriving at more realistic analyses still requires a large amount of research. First, and foremost, the onus lies on the technical disciplines to better investigate and define the stock effects and timing effects which may exist at the reservoir level. When laboratory testing, field testing, and computer simulations are undertaken this can become a standard parameter for investigation. Second, oil supply analysts must not undertake the studies in a technical vacuum: they must incorporate technical factors and constraints wherever possible in their economic analyses. Finally, the actual analytical process has tremendous potential through the use of mathematical programming solutions using a comprehensive data base of individual reservoirs.

In concluding, one can rightfully ask whether there are any payoffs in promoting the sophistication and complexity of such analytical techniques. To answer this, one must consider what the required incremental effort is vis-a-vis the additional benefits. Perhaps surprisingly, the incremental effort is relatively small. At the technical level, most laboratory, field, and mathematical tests have the ability to vary such parameters as reservoir pressures, oil saturation, and timing. The effort required simply involves undertaking a few more sensitivity tests and reporting the results. At the level of supply analysis, the additional effort is more involved, but not beyond the ability of modern mathematical programming when coupled with the use of high speed computers and advanced data management systems. By contrast, the benefits from such analyses can be profound. First, the technical research will provide important information to project managers regarding optimal reservoir development. Also, results of the supply analysis will give policy planners a better indication of the available oil supply and the impacts which their policies may have on this availability. In summary, although additional benefits are not readily quantified, one can conjecture that they far outweigh the incremental efforts necessary to develop more sophisticated oil supply analyses.

NOTES

CHAPTER 1

1. Prince (1980) found that in Alberta most of the light oil reservoirs had a residual oil saturation of 25 - 40% after waterflooding (p. 56). In heavy oil reservoirs, this percentage can be significantly higher.

2. Herbeck, Heintz and Hastings (January, 1976), p. 42. Contact factor is defined here as the proportion of the reservoir in the swept area which is contacted by flood materials.

3. Where water is displacing oil through a number of rock pores, capillary forces tend to "pull" the water through narrow pores faster than through large pores. If, as is usual, there exist common connecting points on the production side of these pores, then there is a tendency for water to backfill the larger pores, thus trapping some oil in these pores.

4. Herbeck, Heintz and Hastings (January, 1976), p. 44.

5. See, for example, Prince (1980), Herbeck, Heintz, and Hastings (1976,1977).

6. Herbeck, Heintz, and Hastings (February, 1976), p. 58.

7. Sayyough (1982).

8. "Microbes Still Face Formidable Obstacles", Enhanced Recovery Week, (May 24, 1982).

9. Wettability refers to the preference of one phase in a two-phase medium to adhere to the bounds of a medium. For example, in a water wet reservoir, reservoir rock is coated with water and oil is trapped, surrounded by water. In an oil-wet reservoir, the residual oil clings to the rock. Wettability reversal reverses this preference and, under a pressure gradient, mobilizes the oil.

10. Schumacher (1978), p. 61.

11. "Petro-Canada Encouraged by Electrical Pre-steam Pilot", Enhanced Recovery Week, (June 21, 1982).

12. Schumacher (1980), p. 165.

13. Prince (1980), Agbi and Mirkin (1980), and Schumacher (1978) all utilize such screening procedures. For example, in Agbi and Mirkin's screening guide (p. 6), the existence of fractures and faults precludes any EOR activity, and the existence of bottom water automatically eliminates most non-thermal techniques.

14. Alberta ERCB, "Alberta's Reserves" (1981), p. 1-8.

15. Dake (1980), pp. 124 - 130, refers to such schemes as "supplemental recovery".

16. Prince (1980) and Agbi and Mirkin (1980), are examples of authors who exclude secondary recovery from their definitions.

17. Government of Canada (1980), p. 28.

18. Smith (1978), p. 15.

19. "Oil Reserves Fall Slightly While Gas Climbs", Oilweek, (July 25, 1983), p. 11.

20. White (1960), p. 175.

21. Ibid., p. 209.

22. Ibid., p. 155.

23. In 1981, there were 449 waterfloods in Alberta light/medium oil reservoirs and 60 in heavy oil fields. Alberta ERCB, "Alberta Oil and Gas Conservation Schemes" (1982).

24. Alberta ERCB, "Alberta's Reserves" (1981).

25. Oil and Gas Journal, "EOR Survey" (1976).

26. Oil and Gas Journal, "EOR Survey" (1982).

27. This particular case is a textbook example of what can go wrong with a solvent flood. It was subsequently discovered that there was a high permeability streak in the centre of the pool which broke up the flood front. The scheme is currently operating as a gas flood.

28. A difficulty arises in estimating incremental production attributable to a specific process because, to estimate this production accurately, one would require estimates of production in the absence of that process. Such estimates require, in most cases, some type of reservoir simulation study. In many instances detailed studies of this sort are never undertaken, and the results from those cases where reservoir simulations have been

done are typically confidential. The figures presented Table 1.3 are the best estimates available from public data. The principal data sources for the information consist of the "1982 EOR Survey" of the Oil and Gas Journal and statistics compiled by the Alberta ERCB as presented in "Alberta Oil and Gas Conservation Schemes". Where these sources were in conflict, reference was made to reservoir performance statistics maintained by the ERCB for major pools ("Reservoir Performance Charts: Oil Pools"). Some discretionary judgement was exercised at times in excluding or including particular schemes. For example, polymer flood production was included even after polymer injection had ceased. Further, all of the Pembina Cardium EOR schemes were excluded because, according to ERCB reservoir studies, no incremental oil was ever recovered and, in some instances, reservoir production mechanisms were damaged because of implementation of the schemes. Primary recovery and synthetic crude production were derived from ERCB statistics contained in "Conservation in Alberta".

29. See, for example, Agbi and Mirkin (1980), Prince (1980), Prince and Webster (1982), Dafter (1980). It also bears mentioning here that it is difficult to calculate "the" cost of EOR schemes since the marginal cost curve for the oil is sloping upward. The incremental cost of EOR at the margin may be significantly higher than the "average costs" reported in most studies.

30. The supply price, or levelized cost, of oil from a given project is the constant price which must be received for every unit of output if the project is to have a net present value of zero at a given discount rate. Equivalently, it can be thought of as a break-even price which must be received for the project to achieve an internal rate of return equal to the discount rate. Mathematically, it is equal to the present value of the entire cost stream (operating and capital costs) divided by the present value of the produced volumes, where both of these streams are discounted at the same discount rate.

31. National Energy Board (1981), Appendix L.

32. Prince (1980), pp. 106 - 110.

33. Government of Canada (1982), p. 91. The breakdown is as follows: operating costs = 10%; industry net cashflow = 30%; producing provinces = 21%; Government of Canada = 15%; consumer price protection = 24%.

34. This same taxation system may also be non-neutral when applied to higher cost conventional oil.

35. Prince and Webster (1982).

36. These payments were formulated in the NEP as the Petroleum Incentive Program (PIP), and their level would be determined by the type of activity, the location of the activity, and the level of foreign ownership and control of the corporation undertaking the activity.

The major feature of PIP payments is that they are direct grants and they do not have to be "earned" in the sense that the previous system of depletion allowances could only be deducted from resource income. These grants are in the form of a percentage of qualifying expenditures, and are strongly linked to Canadian ownership. For all conventional oil and gas development after 1981, including EOR projects, the PIP grants are as follows: [Government of Canada (1980),p.40]

a) 0-50% Canadian Ownership: Nil;
b) 50-75% Canadian Ownership: 10%;
c) 75-100% Canadian Ownership: 20%.

The PIP payments offer substantial incentives to Canadian companies for undertaking EOR schemes. In addition to reducing some of the financial requirements in pursuing these projects, they also contribute to the commercial profitability of the projects. Prince and Webster (1982) estimate that for a typical steam flood, project profits would increase by 6% for a firm qualifying for the maximum PIP grant.

37. In Alberta ERCB, "Conservation in Alberta" (1982), it is estimated that reserves from non-waterflood EOR projects are 0.9 billion barrels (150 x 10^6 m^3), whereas with the announcement of the incentive the Government estimated that "this incentive could lead to more than two billion extra barrels [300 x 10^6 m^3] being produced". Government of Alberta (1982).

38. Supply prices were derived from a variety of sources and, although they are expressed consistently in 1982 $ at an 8% discount rate, they should be regarded as order of magnitude estimates because cost estimates may be inconsistent from one source to the next. Where costs were expressed in other than 1982 $, they were escalated at an annual nominal rate of 15%. Estimates for the various sources of supply are as follows.

Finding and development costs for conventional exploration in new oil plays is difficult to estimate for a number of reasons. First, exploration activity can have relatively long lead times and, even after reserves are booked, extensions and revisions of the reserve estimates will often add significantly to the originally estimated reserves. Because of this, one should not simply attribute the full range of exploration costs to just the year-of-discovery reserve estimate. Second, exploratory drilling may result in either oil discoveries or gas discoveries. As such, only a portion of total exploratory costs should be attributed to the "oil finding" activity. The estimate for light-medium crude oil included in Table 1.5 deals with these issues as follows. A ten year average of "equivalent oil reserves/well drilled" was calculated for Alberta where gas reserves were converted to oil reserves at the rate of 1000 m^3 of gas per 1.0 m^3 of oil, and wells drilled included both exploratory and development wells. As reported in Oilweek ("Oil Reserves Fall Slightly While Gas Climbs", July 25, 1983; "Frontier Outlays Push Up Drilling Expenditures", December 5, 1983), over the period 1973-1982 in Alberta, 51,665 wells were drilled to add 126 x 10^6 m^3 of oil reserves and 983 x 10^9 m^3 of natural gas. Drilling costs in 1982 averaged $390,000/well. The average cost of reserve additions is therefore approximately $18.20/$m^3$. Since these reserves are not all produced in the year in which they are booked, the supply price will be greater than this. To calculate this supply price it is assumed that if oil reserves are booked in year 0, then 10% of the reserves will be produced in each of the years 2-11. Under these assumptions, the present value of 1 cubic metre of oil at 8%/year is 0.6213 cubic metres. Hence, the supply price of the exploratory and development costs would total $29/$m^3$ of oil or about three cents per cubic metre of gas. This should be considered as a lower estimate because: a) it excludes operating costs, b) average costs are less than marginal costs, and c) current marginal success rates for reserve additions are likely less than the 10 year average. On the other hand, more recent finds may not, as noted earlier, be fully appreciated and not all development costs necessarily relate to discoveries since 1973.

Estimates for heavy oil costs were obtained from discussions with Saskatchewan Energy and Mines. Tarsands mining, extraction and upgrading costs were derived from discussions with the Alberta ERCB. Costs of Beaufort Sea oil are documented in a study by the Beaufort Sea Alliance (1983). EOR supply prices were obtained from Prince (1980).

39. The Government of Saskatchewan Department of Energy and Mines estimates an exploratory success rate of 80%.

40. Alberta ERCB, Oil Sands Department, with respect to Alsands plant.

41. Dome Petroleum Limited (1982).

42. Prince (1980), pp. 132, 134, 144, 145 and 149 - 153.

CHAPTER 2

1. For a thorough discussion the reader is referred to texts by Latil (1980), Interstate Oil Compact Commission (1978), Agbi and Mirkin (1980), and Schumacher (1978).

2. Alberta ERCB, "Alberta's Reserves" (1981), p. 2-113.

3. Hobson and Tiratsoo (1981).

4. Quoted in Dafter (1980), p. 127.

5. Ibid., pp. 118 - 127.

6. Ibid., p. 127

7. "Pressure Maintenance for Oil Production from Beaufort", Oilweek, September 30, 1982.

8. Hatter (1981).

9. Ibid.

10. Discussions with Alberta ERCB, Oil and Gas Department.

11. For a complete discussion on the history and implications of the rule of capture, see McDonald (1971).

12. From an individual producer's perspective, therefore, the total accessible stock declines even if he does not produce it, because others are producing it.

13. Craft and Hawkins (1959), pp. 197ff.

14. Dake (1980), p. 120.

15. Craft and Hawkins (1959), p. 198.

16. Intercomp Resource Development and Engineering Ltd. (1974).

17. There is some question as to what should normally be included in "good field operating practice." There is presumably some limit to which Intercomp's conclusions can be driven before the reservoir drive mechanisms are damaged.

18. Latil (1980), p. 105.

19. Ibid., pp. 113f.

20. Sievert and Dew (1957).

21. Dafter (1980), p. F52.

22. Discussions with D&S Engineering.

23. For a detailed discussion of hysteresis effects at the pore level, see Dake's (1980) description of imbibition and drainage in Chapter 10, pp. 343 - 346.

24. Discussions with D&S Engineering.

25. Dake (1980), p. 121.

26. Interstate Oil Compact Commission (1978), pp. 10 - 11.

27. Latil (1980), pp. 37 - 39.

28. Discussions with D&S Engineering.

29. See, for example, Latil (1980), Dafter (1980), Interstate Oil Compact Commission (1978), Schumacher (1978), and Prince (1980).

30. Dafter (1980), p. 152.

31. Ibid., p. 181.

32. Sievert, Dew and Conley (1958).

33. Koch and Slobod (1956).

34. Caudle and Dyes (1958).

35. Blackwell, et.al (1960).

36. Agbi and Mirkin (1980), p. 27.

37. Ko (1982).

38. Ko's results indicated a decrease from 43.0% to 32.7% in tertiary recovery by commencing at So=0.4 instead of So=0.2 if the total CO_2 volume was held constant. Other simulations indicated, however, that there existed a large dependence of ultimate recovery on the relationship between the volume of injected CO_2 and the remaining oil in place (ROIP). If the relative volume of CO_2 to ROIP (defined as the hydrocarbon pore volume of carbon dioxide) was cut in half, then recovery typically fell by 32%. In going from So=0.2 to So=0.4 with a constant absolute volume of injected CO_2, the actual pore volume of CO_2 is effectively cut in half and one would have expected recovery to fall to 29.2% (43% multiplied by 0.68). The observed recovery of 32.7% indicated that 12% more oil was recovered than would have been expected by

commencing at So=0.4. This additional recovery is attributed to stock effects.

39. In doubling the injection rate, incremental recovery remained constant at 16% of the original oil in place (OOIP), but the production period decreased from 12.0 to 5.7 years. Similarly, in halving the injection rate, the recovery period increased to 22.5 years.

40. Klins and Farouq-Ali (1981).

41. Sloat (1970).

42. Discussions with D&S Engineering.

CHAPTER 3

1. See, for example, Sen, Marglin and Dasgupta (1972).

2. Leftwich (1979), p. 478.

3. Scott, A. (1967), p. 34. Howe (1979), p. 78, provides a similar definition of user costs in natural resource economics as follows: "the present value of all future sacrifices (including foregone use, higher extraction costs, increased environmental costs) associated with the use of a particular unit of an in situ resource." For more detailed discussions on user costs and how they relate to stock effects, see Bradley (1979) or McDonald (1971).

   User costs in natural resource economics, as outlined above, should not be confused with user costs in capital theory. In the latter case, the user cost of a unit of capital is typically defined as a "[rental price which] covers the opportunity cost of lending the funds used to buy it <u>plus</u> the economic depreciation or decay per unit <u>less</u> the expected rate of capital gains per period due to a rise in the unit price of capital goods." (Ott, Ott, and Yoo [1975], p. 99.)

   Although it is not the intent here to describe in great detail all of the similarities and differences of the above definitions, some clarification is appropriate. A number of similarities between the two types of user costs exist. For example, if real price escalation of the natural resource and of the capital unit is expected, then both the user cost of current production and the user cost of capital rise. Also, resource depletion and capital depreciation are somewhat similar concepts to the extent that both imply that current utilization will decrease the availability of future output or services. On the other hand, important differences also exist. For example, in the case of natural resources, current production can affect (via stock effects) the entire resource base, whereas in capital theory the current use of a unit of capital affects only the future services derived from that unit.

4. Canadian Petroleum Association (1975), p. 8.

5. This is illustrated by the following example. Consider two projects with the following cashflows:

	Project A		Project B	
Year	Costs	Revenues	Costs	Revenues
0	60	0	100	0
1	25	50	10	50
2	25	50	10	50
3	25	50	10	50
4	25	50	10	50

It can be shown that the following profitibility indicators apply to these projects:

	Project A	Project B
N.P.V. (at 10%)	$19.3	$26.9
Payout Time	2.4 yr	2.5 yr
IRR	24.10%	21.86%

At a 10% cost of funds, Project B is the best project, yet decision rules based on payout time and internal rate of return would choose Project A.

6. Kuller and Cummings (1974).

7. McKie and McDonald (1962), Smith (1968).

8. Watkins (1977).

9. National Petroleum Council (1976).

10. Agbi and Mirkin (1980).

11. Ibid., pp. 21 - 23. The bias in the B-factor is not always critical for the application in which it was used. The authors used it often simply as a means to reject or accept schemes. As such, it is consistent with the NPV criterion.

12. Ibid., p. 49.

13. Prince (1980).

14. Prince and Webster (1982).

15. Alberta ERCB, "Estimates of Ultimate Potential" (1981).

16. National Energy Board (1981).

17. Prince (1980), p. 61.

18. Ibid., p. 61.

19. Ibid., p. 118.

20. Ibid., p. 119.

CHAPTER 4

1. Prince (1980), Appendix D.

2. Agbi and Mirkin (1980), p. 27.

3. Under these circumstances, since $\lambda=0$, we have Equation (4-18) simplified to:

$$\frac{\partial\bar{C}}{\partial\tau}\cdot\frac{1}{\bar{C}} = -\frac{\partial P_O}{\partial\tau}\cdot\frac{1}{P_O} = \pi$$

4. Prince (1980), p. 89.

5. For example, with a gross price of $\$200/m^3$ and a royalty of 25%, we have Po=\$150. A reduction of the royalty to 24% would increase Po to \$152, which represents an increase of 1.33% in the netback price.

6. It can be shown that Equation (4-17) becomes:

$$-r\bar{C} = (\pi-\lambda-r-\sigma)P_O e^{\pi\tau}F$$

where:

$$\sigma \equiv -\frac{1}{F}\cdot\frac{dF}{d\tau}$$

and hence:

$$\frac{\partial\tau}{\partial\bar{C}} = \frac{1}{\bar{C}(\pi-\lambda-\sigma)}$$

such that σ enhances the effects of the stock effect term λ.

7. This ignores the fact that it may at times be profitable to operate at a loss if shutting down the project implies sacrificing expected future net gains.

CHAPTER 5

1. As an example, we might expect a real decline in price for a few years until a floor price is reached and sustained for some time, after which prices may rise. Similarly, with respect to λ, there are technical constraints which apply near the limits of both delayed schemes and schemes which are initiated earlier.

2. G.P. Jenkins (1972), pp. 211 - 245.

3. "Tertiary Recovery: Oil Industry Finds NEP Lacking", Canadian Petroleum, (March, 1981), p. 5.

4. "Prudential Outlines EOR Financing Considerations", Enhanced Recovery Week, (June 28, 1982).

5. Note that the variety of sources differs as to whether a 10% real after-tax or before-tax return is required. In normal manufacturing at a marginal tax rate of 50%, a 10% before tax return translates into roughly a 5% after-tax rate of return. In the case of EOR projects, however, the relationship is not so clear cut. Because of accelerated write-offs on oilfield equipment and various other incentives for EOR, the after-tax and before-tax rates of return may differ very little. In fact, particularily where heavy oil upgrading is concerned, the after-tax rate of return may well exceed the before-tax rate of return because of the accelerated write-offs allowed on development and process capital.

6. Government of Canada (1982), p. 12.

7. Price differentials reflect the differences in market prices between crude oil types of differing quality. Heavy oil prices are typically less than light oil prices because the products which can be refined from light oils have a higher market value. Light oils will produce high proportions of high valued products such as aviation fuel, motor gasoline, kerosene, and naphtha, whereas heavy oils produce a preponderance of lower valued products such as heavy fuel oil and asphalt. Although the price differentials which arise in a free market are a function of many complex factors, a major determinant is the cost of converting the heavy oil into an oil which will produce a product slate comparable to that produced by lighter oils. The means of conversion can involve either conventional refining technologies (such as hydrotreating) or more innovative upgrading technologies. Since the conversion technologies involve typical

manufacturing inputs such as process equipment, process energy, and common labour, the real costs of conversion (in the absence of technological innovations) are not expected to increase at rates much different from general manufacturing cost inflation in all sectors. As such one expects that, although real world oil prices may increase or decrease, price differentials will remain relatively constant in real terms.

Under these conditions, one expects that heavy oil prices would increase at rates in excess of light oil price increases. By way of example, consider that mid-1983 field prices were approximately $\$250/m^3$ for light (marker crude) oil and $\$180/m^3$ for heavy oil. (Alberta Petroleum Marketing Commission) If one expects a 2%/year real increase in the light oil price and no real increase in the price differential of $\$70/m^3$, then mid-1984 prices would be projected to be $\$255/m^3$ for light oil and $\$185/m^3$ for heavy oil. This would represent a 2.8% real increase in the price of heavy oil over the course of one year. It should be noted that, by the same token, relative real declines in heavy oil prices would normally be expected to be more pronounced than real declines in light oil prices.

8. Prince (1980), p. 60.

9. Dake (1978), pp. 121ff.

10. Klins and Farouq-Ali (1981). Unfortunately, the authors documented the incremental EOR recovery over waterflooding for only one of their cases, which is that used here. Figures in Table 2.4 include waterflood volumes, hence no estimate of λ can be derived for just the CO_2 flood.

11. Ibid.

12. Ibid.

13. To calculate energy requirements, it is assumed that the compressor must handle 1×10^6 m^3 of CO_2 per year, compressing from atmospheric pressure of 100 kPa to a reservoir pressure of 4,134 kPa (600 psia). At standard conditions, CO_2 has a specific volume of 0.5373 m^3/kg (Gas Processors Suppliers Association [GPSA], p. 16-3). Energy requirements to compress CO_2 to 4,100 kPa are approximately 300 kJ/kg (GPSA, pp. 17 - 26) and hence, at a rate of 1×10^6 m^3/year, the power required is 18.3 kJ/s. Assuming a 50% cycle efficiency for the compressor, the installed power must be 36.6 kJ/s, or 49 hp.

14. The major compressor operating cost is fuel. As it uses 36.6 kJ/s, this translates to 1,150 GJ annually. The mid-1983 natural gas price at the Alberta border was $2.40/GJ (Alberta Petroleum Marketing Commission), hence the cost would be $2,760 annually, or 6.5% of the equipment cost. As industrial base load energy is commonly available at a discount, a cost of 5%/year is assumed.

15. Prince (1980), p. 209.

16. Klins and Farouq-Ali (1981).

CHAPTER 6

1. Alberta ERCB, "Conservation in Alberta", (1982).

2. National Energy Board (1981), p. 136.

3. Prince (1980), p. 121.

4. "Pilot Floods Criticized as Unnecessary", Enhanced Recovery Week, (June 28, 1982).

5. This approach was taken for Esso's early pilots in the Cold Lake area.

6. "Prudential Outlines EOR Financing Considerations", Enhanced Recovery Week, (June 28, 1982).

7. Ibid.

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APPENDIX A

DERIVATION OF SUPPLY ELASTICITIES

The following is presented to supplement the derivation of Equations (4-18) and (4-19) in the text. The nomenclature used here is that defined in Table 4.1.

Recall that, from Condition (4-17), the profit maximizing choice of τ if R depends on τ will be such that:

$$-r\overline{C} = (\pi-\lambda-r)P_o e^{\pi\tau} R_\tau F \qquad \text{...(4-17)}$$

The total differential of this is as follows:

$$\begin{aligned}
-rd\overline{C}-\overline{C}dr = \; & (\pi-\lambda-r)e^{\pi\tau}R_\tau F\ dP_o \\
& +(\pi-\lambda-r)P_o\pi e^{\pi\tau}R_\tau F\ d\tau \\
& +(\pi-\lambda-r)P_o\tau e^{\pi\tau}R_\tau F\ d\pi \\
& +(\pi-\lambda-r)P_o e^{\pi\tau}F\frac{\partial R_\tau}{\partial\tau}\ d\tau \\
& +(\pi-\lambda-r)P_o e^{\pi\tau}R_\tau\ dF \\
& +P_o e^{\pi\tau}R_\tau F\ d\pi \\
& -P_o e^{\pi\tau}R_\tau F\ d\lambda \\
& -P_o e^{\pi\tau}R_\tau F\ dr
\end{aligned}$$

Since λ and F can be assumed to be τ - independent, we know that $d\lambda = dF = 0$, and hence the above can be simplified to:

$$
\begin{aligned}
0 \quad = \quad & (r) \; d\overline{C} \\
& + (\overline{C} - P_O e^{\pi\tau} R_\tau F) \; dr \\
& + ((\pi-\lambda-r) e^{\pi\tau} R_\tau F) \; dP_O \\
& + ((\pi-\lambda-r) P_O \pi e^{\pi\tau} R_\tau F + (\pi-\lambda-r) P_O e^{\pi\tau} F \frac{\partial R_\tau}{\partial \tau}) \; d\tau \\
& + ((\pi-\lambda-r) P_O \tau e^{\pi\tau} R_\tau F + P_O e^{\pi\tau} R_\tau F) \; d\pi
\end{aligned}
$$

Since,

$$\lambda \quad = \quad - \frac{1}{R_\tau} \cdot \frac{dR_\tau}{d\tau}$$

and therefore,

$$\frac{\partial R_\tau}{\partial \tau} \quad = \quad - \lambda R_\tau$$

the coefficient for $d\tau$ can be re-expressed as:

$$((\pi-\lambda-r)(\pi-\lambda) \; P_O e^{\pi\tau} R_\tau F) \quad d\tau$$

From the above, all of the supply elasticities in Equations (4-18) and (4-19) are readily derived. As one illustration, an analysis of the impacts of a change in costs ($\overline{C}$) on τ and R is presented.

The impacts on timing are as follows:

$$\frac{\partial \tau}{\partial \overline{C}} = \frac{-r}{(\pi-\lambda-r)(\pi-\lambda)P_o e^{\pi\tau} R_\tau F}$$

$$= \frac{-r}{(\pi-\lambda)(-r\overline{C})}$$

$$= \frac{1}{\overline{C}(\pi-\lambda)}$$

Hence the impacts on incremental recovery are:

$$\varepsilon_{RC} = \frac{dR_\tau}{d\overline{C}} \cdot \frac{\overline{C}}{R_\tau}$$

$$= \frac{dR_\tau}{d\tau} \cdot \frac{\partial \tau}{\partial \overline{C}} \cdot \frac{\overline{C}}{R_\tau}$$

$$= (-\lambda R_\tau) \cdot \frac{1}{\overline{C}(\pi-\lambda)} \cdot \frac{\overline{C}}{R_\tau}$$

$$= -\frac{\lambda}{(\pi-\lambda)}$$

APPENDIX B

SIMULATION MODEL

The following is a listing of the FORTRAN source code of the program used to model the numerical simulations contained in Chapter 5. All variables are documented and internally defined. The listing which follows corresponds to Case A as described in the text.

```
C PROGRAM            **** FLOOD ****
C
C Flood is  a  discounting cash flow  model which simulates
C a carbon dioxide flood in a heavy oil reservoir. A timing
C variable  'Lambda'  is  defined  to  accomodate potential
C stock effects of timing.
C
C ***********************************************************
C
C DEFINITION AND DECLARATION OF VARIABLES
C
C PRESENT VALUE OF REVENUES FOR 8 LAMBDAS AND 30 START TIMES
      REAL PVR(8,30)
C
C NET PRESENT VALUE ARRAY
      REAL NPV(8,30)
C
C TOTAL INCREMENTAL OIL ARRAY
      REAL ROIL(8,30)
C
C PRESENT VALUE OF COSTS FOR 30 START YEARS
      REAL PVC(30)
C
C REAL PRICE AND PRICE ESCALATION FOR YEARS 1 TO 40
      REAL P(40),PESC(40)
C
C DISCOUNT FACTOR FOR YEARS 1 TO 40 AT 10%/YEAR
      REAL DISCF(40)
C
C SINGLE ITERATION COST VECTOR
      REAL C(40)
C
C ARRAY VALUE FOR RANGE OF STOCK EFFECT FACTORS (LAMBDAS)
      REAL L(8)
C
C BASE YEAR INPUT PRODUCTION PROFILE FOR 10 YEARS
      REAL QB(10)
C
C COMPUTED NORMALIZED PRODUCTION PROFILE (PROPORTIONATE)
      REAL QFAC(10)
C
C TOTAL BASE YEAR INCREMENTAL RESERVES
      REAL RINC
C
C OIL AND CO2 PRICES IN BASE YEAR
      REAL PBASE,CO2P
C
C ANNUAL CO2 INJECTION
      REAL CO2
C
C COMPRESSOR COST
      REAL KBASE
C
C TOTAL COST MULTIPLIER
      REAL CFAC
C
C BASE YEAR FOR INPUT PRODUCTION PROFILE
      INTEGER TAUBASE
C
C LOOPING VARIABLES
      INTEGER J,JL,JY,TAU
```

```
      DATA L/0.0,0.005,0.01,0.015,0.02,0.03,0.04,0.05/
      DATA QB/316.2,130.2,109.0,103.5,103.7,107.7,138.5,113.1,
     * 85.3,242.1/
C
      PBASE=25.0*6.3
      CO2=1000.0
      CO2P=25.00
      CFAC=1.000
      TAUBASE=11
      KBASE=42500.
C
C FOR MID-YEAR DISCOUNTING AT 10%/YEAR
C
      DISCF(1)=1./1.05
      DO 100 J=2,40
      DISCF(J)=DISCF(J-1)/1.1
  100 CONTINUE
C
      P(1)=PBASE
      DO 102 J=2,5
  102 P(J)=P(J-1)*1.03
      DO 103 J=6,10
  103 P(J)=P(J-1)*1.03
      DO 104 J=11,15
  104 P(J)=P(J-1)*1.03
      DO 105 J=16,20
  105 P(J)=P(J-1)*1.03
      DO 106 J=21,25
  106 P(J)=P(J-1)*1.03
      DO 107 J=26,30
  107 P(J)=P(J-1)*1.03
      DO 108 J=31,35
  108 P(J)=P(J-1)*1.03
      DO 109 J=36,40
  109 P(J)=P(J-1)*1.03
C
      PESC(1)=1.000
      DO 110 J=2,40
  110 PESC(J)=P(J)/P(J-1)
C
      DO 210 TAU=1,30
      PVC(TAU)=0.0
       DO 200 J=1,40
  200  C(J)=0.0
        DO 201 J=TAU,TAU+9
  201   C(J)=(0.05*KBASE+CO2*CO2P)*CFAC
         C(TAU)=C(TAU)+KBASE*CFAC
        DO 202 J=TAU,TAU+9
  202   PVC(TAU)=PVC(TAU)+C(J)*DISCF(J)
  210 CONTINUE
```

```
      DO 300 JY=1,30
      DO 300 JL=1,8
  300 PVR(JL,JY)=0.0
      RINC=0.0
      DO 310 J=1,10
  310 RINC=RINC+QB(J)
      DO 320 J=1,10
  320 QFAC(J)=QB(J)/RINC
C
      DO 360 JL=1,8
      DO 360 JY=1,30
      ROIL(JL,JY)=RINC*(1.0+L(JL))**(FLOAT(TAUBASE-JY))
      DO 350 J=JY+1,JY+10
      PVR(JL,JY)=PVR(JL,JY) + ROIL(JL,JY)*QFAC(J-JY)*P(J)*
     *                                    DISCF(J)
  350 CONTINUE
C
      WRITE(8,399)
      WRITE(8,400) 1000.*CO2,CO2P,KBASE,CFAC
      WRITE(8,401) (J,P(J),PESC(J),PVC(J)/1000.,J=1,30)
      WRITE(8,402)
      WRITE(8,403) (L(J)*100.,J=1,8)
      WRITE(8,413) (JY,(ROIL(JL,JY),JL=1,8),JY=1,30)
      WRITE(8,404)
      WRITE(8,403) (L(J)*100.,J=1,8)
      WRITE(8,413) (JY,(PVR(JL,JY)/1000.,JL=1,8),JY=1,30)
      WRITE(8,405)
      WRITE(8,403) (L(J)*100.,J=1,8)
      WRITE(8,413) (JY,(NPV(JL,JY)/1000.,JL=1,8),JY=1,30)
C
  399 FORMAT(///80("*")/" Results for CO2 Flood Evaluation."/
     * 80("*")//////)
  400 FORMAT(" CO2 Injection (m**3/year)          = ",F10.2//
     *       " CO2 Price ($/10**3 m**3)           = ",F10.2//
     *       " Capital Cost Base ($)              = ",F10.2//
     *       " Cost Multiplier                    = ",F11.3//
     *       " Mid-year Discount Rate             =      10%"//
     * 80("*")/////)
  401 FORMAT("  Year          Price          P-Esc          PV(C)"/
     *       "                ($/m3)                        ($'000)"/
     *       "  ====          =======        =====          ======="/
     */30(1X,I4,9X,F7.2,10X,F5.3,9X,F7.2/)/80("*")////)
  403 FORMAT(20X,"Lambda(%)"/1X,"TAU",5X,8F8.1/)
  413 FORMAT(30(1X,I2,6X,8F8.2/)//1X,80("*")/////)
  402 FORMAT(" TOTAL INCREMENTAL OIL (m**3)"/
     *       " ============================"//)
  404 FORMAT(" PRESENT VALUE OF REVENUES ($'000)"/
     *       " =================================="//)
  405 FORMAT(" NET PRESENT VALUE ($'000)"/
     *       " ========================="//)
      STOP
      END
```