Module 1 – Introduction to Enhanced Oil Recovery (EOR) Methods
Estimated Duration: 2 weeks

Introduction to EOR methods.

Definition of Reserves

Environmental and Economics Aspects of EOR Methods.

Comparative Performance of Different EOR Methods.

Screening Criteria and Technical Constraints.

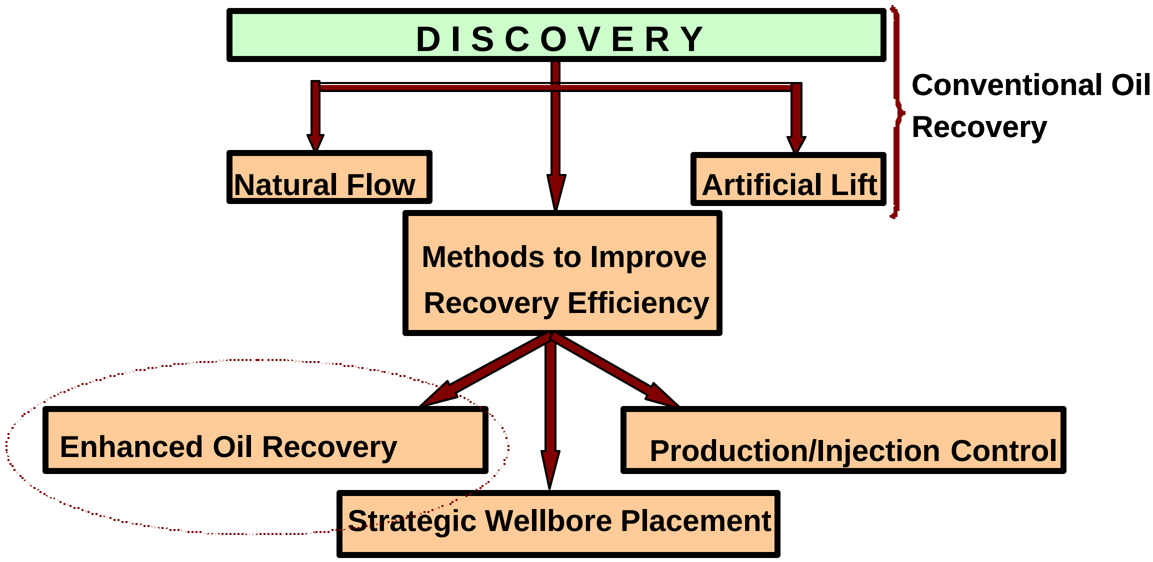
Suggested reading: L, MAB

Learning Objectives

After completing this section you will be able to:

- Describe the three major categories of methods which can be used to improve reservoir recovery efficiency, and explain their differences.
- For each method, state whether it can improve displacement, vertical or areal sweep efficiency and explain how it works.
- Describe screening criteria for enhanced oil recovery methods.
- Use a systematic decision analysis approach for selecting an alternative to improve reservoir recovery efficiency.

Methods to Improve Recovery Efficiency



This course will focus on Enhanced Oil Recovery Methods.

Upon initial discovery, a reservoir generally produces via natural drive mechanisms. If there is not enough natural reservoir energy for wells to flow, some form of artificial lift may be used to provide the energy to lift produced fluids to surface.

In addition to conventional oil recovery processes, there are a variety of methods that are available to improve recovery efficiency. These can be categorized into three fundamental types:

- Enhanced Oil Recovery
- Strategic Wellbore Placement
- Production / Injection Control

There is not a single method which can be considered a "cure all" for recovering additional oil from every reservoir. Each method has its specific application, and a variety of methods may be used in a specific reservoir simultaneously. Before selecting the appropriate methods, a thorough reservoir study should be conducted to properly characterize the reservoir and to analyze historical production characteristics and alternatives.

Enhanced Oil Recovery (EOR) Processes

Enhanced oil recovery (EOR) processes include all methods that use external sources of energy and/or materials to recover oil that cannot be produced, economically by conventional means.

EOR methods include:

- **Waterflooding**
- **Thermal methods**: steam stimulation, steamflooding, hot water drive, and in- situ combustion
- **Chemical methods**: polymer, surfactant, caustic, and micellar/polymer flooding.
- **Miscible methods**: hydrocarbon gas, CO_2, and nitrogen (flue gas and partial miscible/immiscible gas injection may also be considered)

Waterflood	Thermal	Chemical	Miscible gas
Maintains reservoir pressure & physically displaces oil with water moving through the reservoir from injector to producer.	Reduces S_{orw} by steam distillation and reduces oil viscosity.	Reduces S_{orw} by lowering water-oil interfacial tension, and increases volumetric sweep efficiency by reducing the water-oil mobility ratio.	Reduces S_{orw} by developing miscibility with the oil through a vaporizing or condensing gas drive process.

The goal of any enhanced oil recovery process is to mobilize "remaining" oil.

This is achieved by enhancing oil displacement and volumetric sweep efficiencies.

- Oil displacement efficiency is improved by reducing oil viscosity (e.g., thermal floods) or by reducing capillary forces or interfacial tension (e.g., miscible floods).
- Volumetric sweep efficiency is improved by developing a more favorable mobility ratio between the injectant and the remaining oil-in-place (e.g., polymer floods, water-alternating-gas processes).

It is important to identify remaining oil and the mechanisms that are necessary to improve recovery prior to implementing an EOR process.

Waterflooding

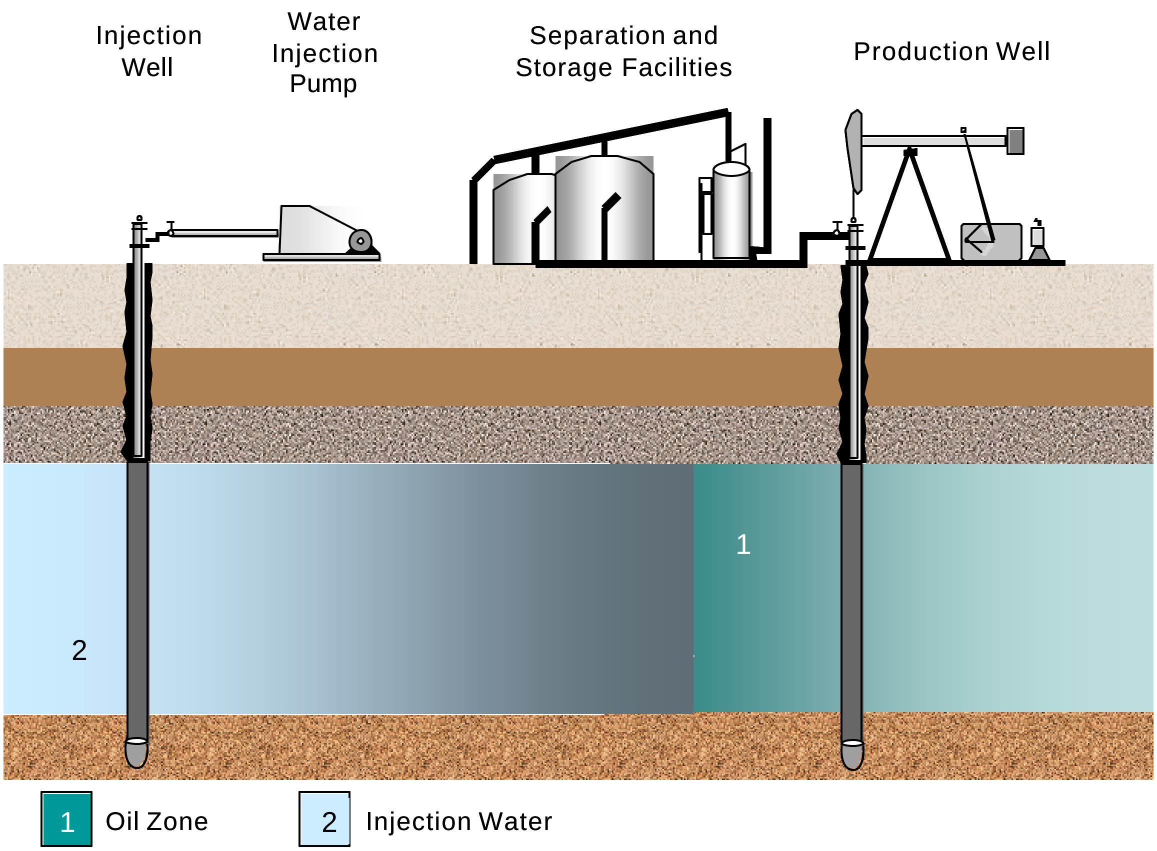


Figure 1 - Waterflooding process.

Description

Waterflooding consists of injecting water into the reservoir. It is the most widely used post-primary recovery method. Water is injected in patterns or along the periphery of the reservoir.

Mechanisms That Improve Recovery Efficiency

Water drive

Increased pressure

Limitations

High oil viscosities result in higher mobility ratios.

Some heterogeneity is acceptable, but avoid extensive fractures.

Challenges

Poor compatibility between the injected water and the reservoir may cause formation damage.

Subsurface fluid control to divert injected water and to shut off undesirable produced fluids.

Screening Parameters

Gravity	>25ºAPI
Viscosity	<30cp
Composition	not critical
Oil saturation	>10% mobile oil
Formation type	sandstone/carbonate
Net thickness	not critical
Average permeability	not critical
Transmissibility	not critical
Depth	not critical
Temperature	not critical

Note: Most EOR screening values are approximations based on successful North American projects. These are not intended to be firm cut-offs, but rather approximate practical limitations. They do not take into account new technology or varying economic situations.

Surfactant/Polymer Flooding

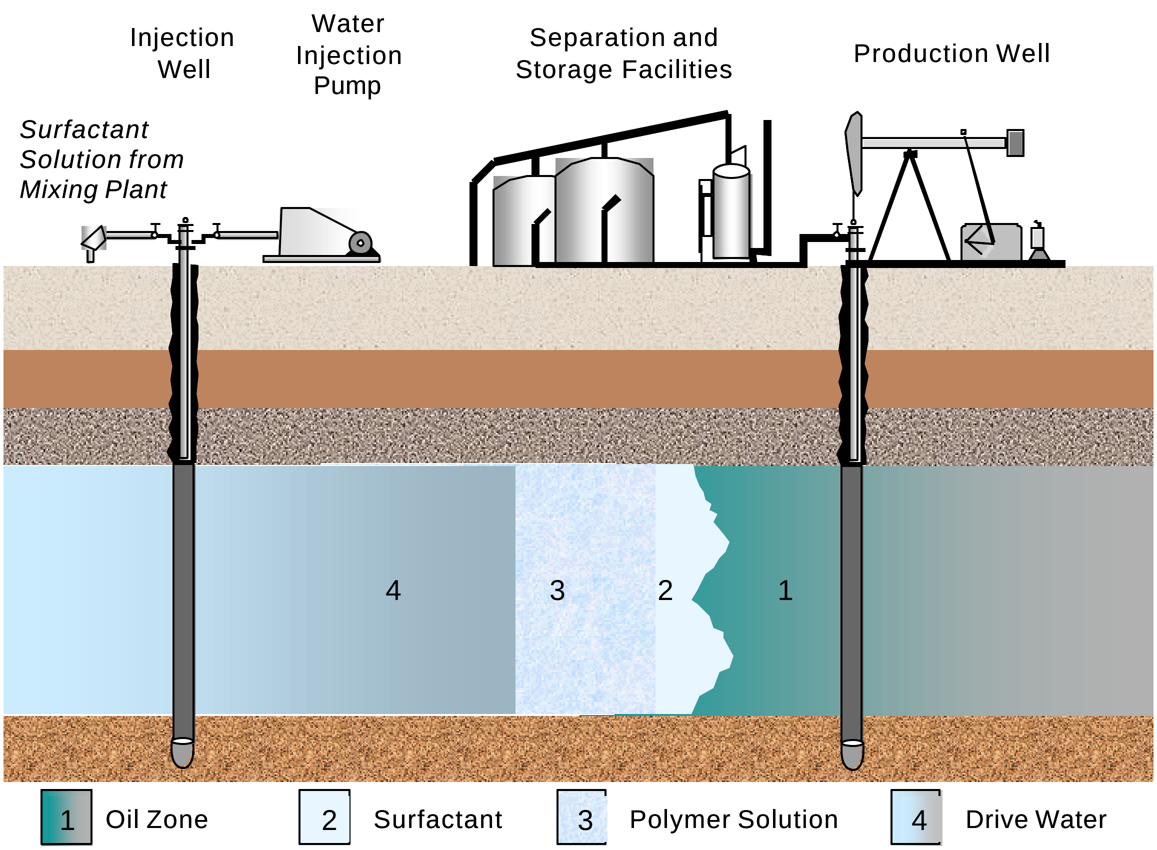


Figure 2 - Surfactant/polymer flooding process.

Description

Surfactant/polymer flooding consists of injecting a slug that contains water, surfactant, electrolyte (salt), usually a co-solvent (alcohol), and possibly a hydrocarbon (oil), followed by polymer-thickened water.

Mechanisms That Improve Recovery Efficiency

Interfacial tension reduction (improves displacement sweep efficiency).

Mobility control (improves volumetric sweep efficiency).

Limitations

An areal sweep of more than 50% for waterflood is desired.

Relatively homogeneous formation.

High amounts of anhydrite, gypsum, or clays are undesirable.

Available systems provide optimum behavior within a narrow set of conditions.

With commercially available surfactants, formation water chlorides should be <20,000 ppm and divalent ions (Ca^{++} and Mg^{++}) <500 ppm.

Challenges

Complex and expensive system.

Possibility of chromatographic separation of chemicals.

High adsorption of surfactant.

Interactions between surfactant and polymer.

Degradation of chemicals at high temperature.

Screening Parameters

Gravity	>25ºAPI	
Viscosity	<20cp	
Composition	light intermediates	
Oil saturation	>20% PV	
Formation type	sandstone	
Net thickness	>10 feet	
Average permeability	>20 md	
Transmissibility	not critical	
Depth	<8,000 feet	
Temperature	<225ºF	because at high temperature the chemicals degraded
Salinity of formation brine	<150,000 ppm TDS	

<u>Note</u>: Most EOR screening values are approximations based on successful North American projects. These are not intended to be firm cut-offs, but rather approximate

practical limitations. They do not take into account new technology or varying economic situations.

Polymer Flooding

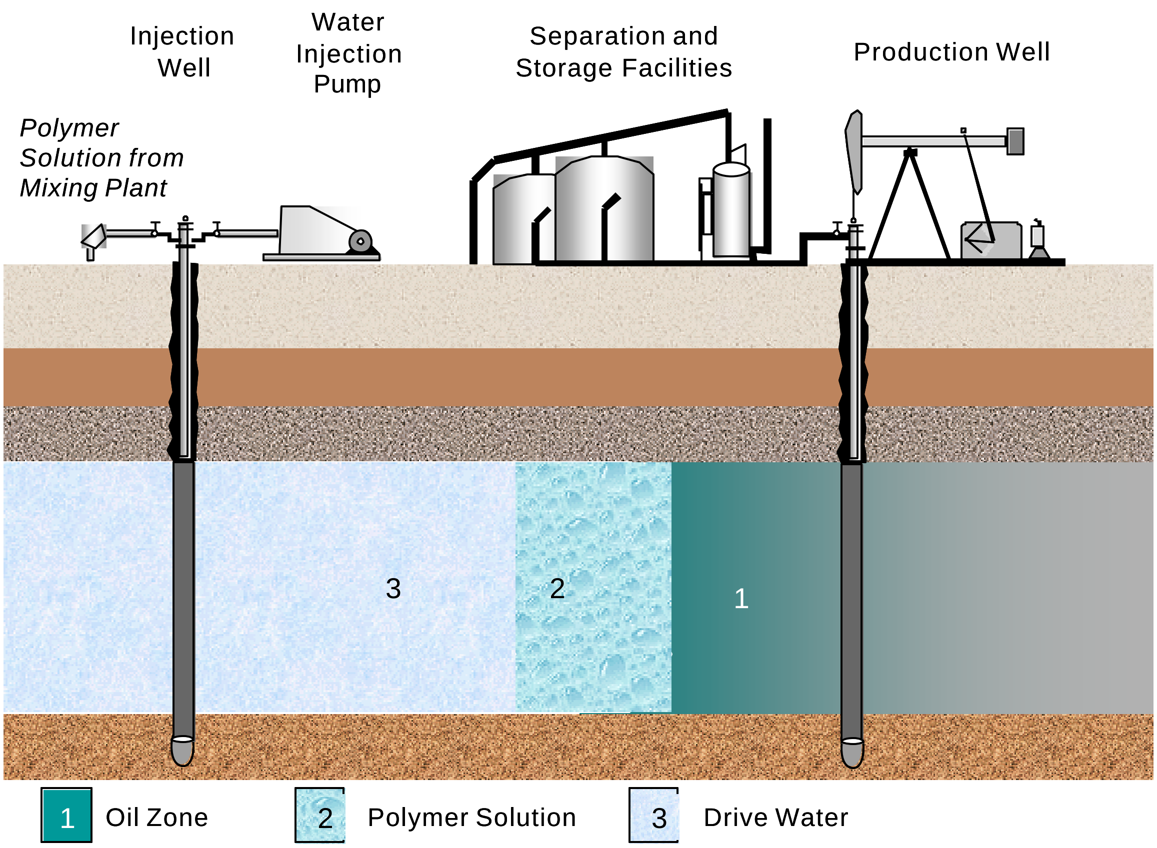


Figure 3 - Polymer flooding process.

Description

Polymer augmented waterflooding consists of adding water soluble polymers to the water before it is injected into the reservoir.

Mechanisms That Improve Recovery Efficiency

Mobility control (improves volumetric sweep efficiency).

Limitations

High oil viscosities require a higher polymer concentration.

Results are normally better if the polymer flood is started before the water-oil ratio becomes excessively high.

Clays increase polymer adsorption.

Some heterogeneity is acceptable, but avoid extensive fractures. If fractures are present, the crosslinked or gelled polymer techniques may be applicable.

Challenges

Lower injectivity than with water can adversely affect oil production rates in the early stages of the polymer flood.

Acrylamide-type polymers loose viscosity due to sheer degradation, or it increases in salinity and divalent ions.

Xanthan gum polymers cost more, are subject to microbial degradation, and have a greater potential for wellbore plugging.

Screening Parameters

Gravity	>18º API
Viscosity	<200 cp
Composition	not critical
Oil saturation	>10% PV mobile oil
Formation type	sandstone/carbonate
Net thickness	not critical
Average permeability	>20 md
Transmissibility	not critical
Depth	<9,000 feet
Temperature	<225ºF

degradation of polymer by high temperature

Note: Most EOR screening values are approximations based on successful North American projects. These are not intended to be firm cut-offs, but rather approximate practical limitations. They do not take into account new technology or varying economic situations.

Miscible Gas Flooding (CO_2 Injection)

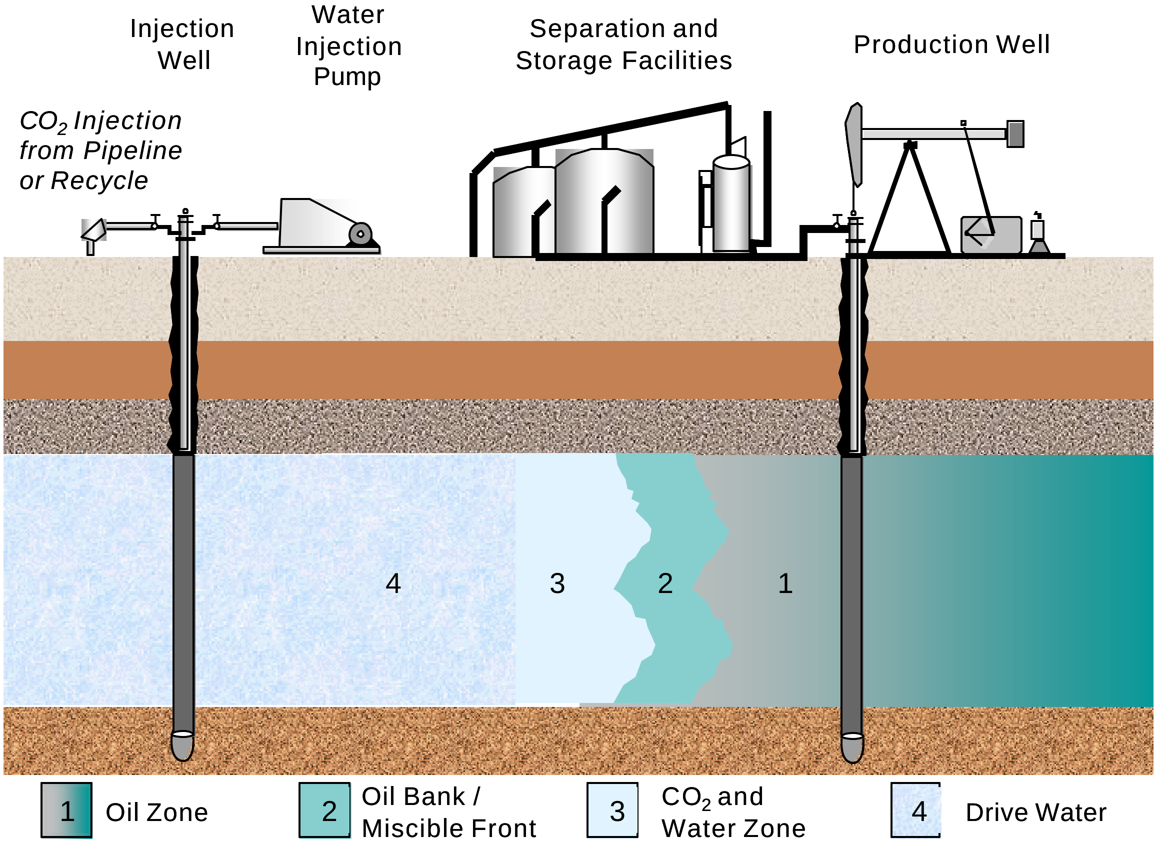


Figure 4 - Miscible gas flooding (CO_2 injection) process.

Description

CO_2 flooding consists of injecting large quantities of CO_2 (15% or more hydrocarbon pore volumes) in the reservoir to form a miscible flood.

Mechanisms That Improve Recovery Efficiency

CO_2 extracts the light-to-intermediate components from the oil, and, if the pressure is high enough, develops miscibility to displace oil from the reservoir (vaporizing gas drive).

Viscosity reduction / oil swelling.

Limitations

Very low Viscosity of CO_2 results in poor mobility control.

Availability of CO_2

Challenges

Early breakthrough of CO_2 causes problems.

Corrosion in producing wells.

The necessity of separating CO_2 from saleable hydrocarbons. Repressuring of CO_2 for recycling.

A large requirement of CO_2 per incremental barrel produced.

Screening Parameters

Gravity	>27º API
Viscosity	<10 cp
Composition	$C_5 – C_{20}$ ($C_5 – C_{12}$) Co2 extract light to intermediate componets from oil in order to miscibility
Oil saturation	>30% PV
Formation type	sandstone/carbonate
Net thickness	relatively thin
Average permeability	not critical
Transmissibility	not critical
Depth	<2,300 feet at higer dept pressure is higer, corrosion is higher
Temperature	<250 ºF

Note: Most EOR screening values are approximations based on successful North American projects. These are not intended to be firm cut-offs, but rather approximate practical limitations. They do not take into account new technology or varying economic situations.

Miscible Gas Flooding (Hydrocarbon Injection)

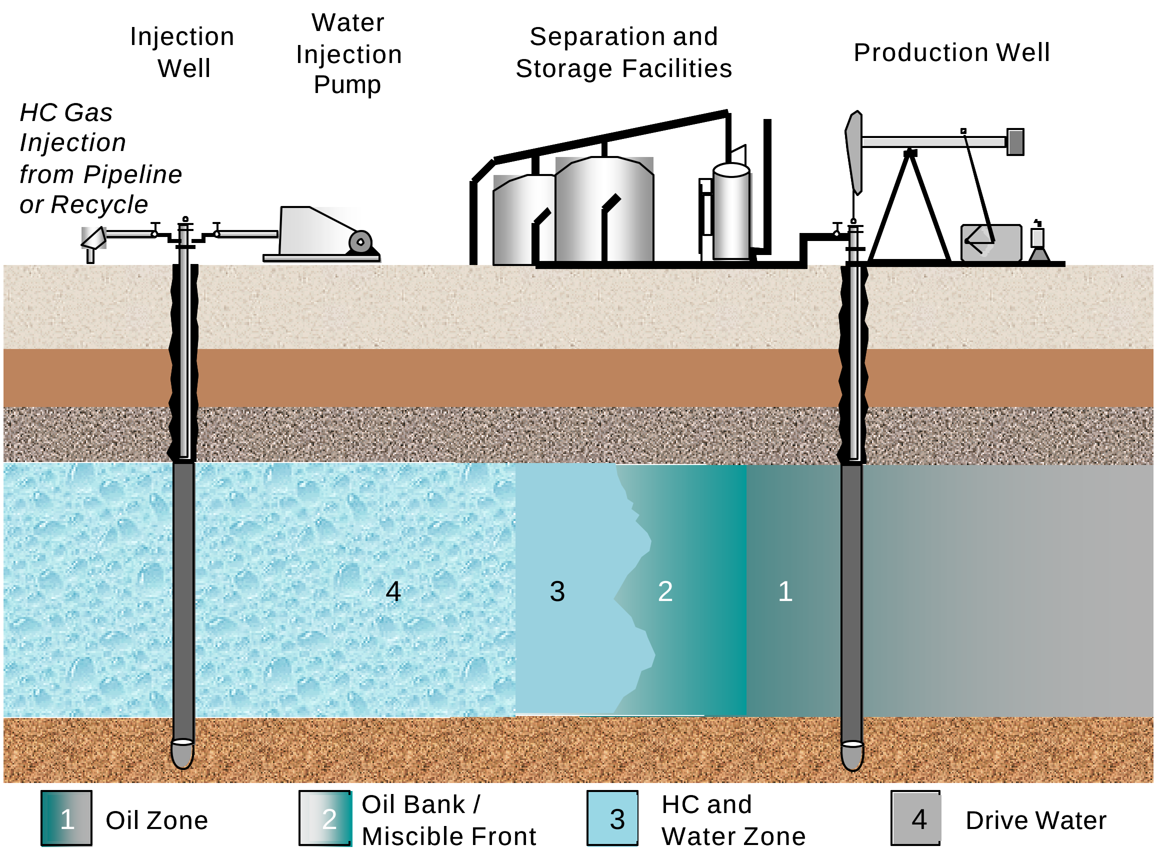


Figure 5 - Miscible gas flooding (hydrocarbon injection) process.

Description

Hydrocarbon gas flooding consists of injecting light hydrocarbons through the reservoir to form a miscible flood.

Mechanisms that Improve Recovery Efficiency

Viscosity reduction / oil swelling / condensing or vaporizing gas drive.

Limitations

Minimum depth is set by the pressure needed to maintain the generated miscibility. The required pressure ranges from about 1,200 psi for the LPG process to 3,000-5,000 psi for the High Pressure Gas Drive, depending on the oil.

A steeply dipping formation is very desirable - pen-nits gravity stabilization of the displacement that normally has an unfavorable mobility ratio.

Challenges

Viscous fingering results in poor vertical and horizontal sweep efficiency.

Large quantities of expensive products are required.

Solvent may be trapped and not recovered.

Screening Parameters

Gravity	>27º API	
Viscosity	<10 cp	
Composition	$C_2 – C_7$	
Oil saturation	>30% PV	
Formation type	sandstone/carbonate	
Net thickness	relatively thin	
Average permeability	not critical	
Transmissibility	not critical	
Depth	>2,000 feet (LPG)	for maitanence the miscibility
	>5,000 feet (lean gas)	
Temperature	<250 ºF	

Note: Most EOR screening values are approximations based on successful North American projects. These are not intended to be firm cut-offs, but rather approximate practical limitations. They do not take into account new technology or varying economic situations.

Nitrogen / Flue Gas Flooding

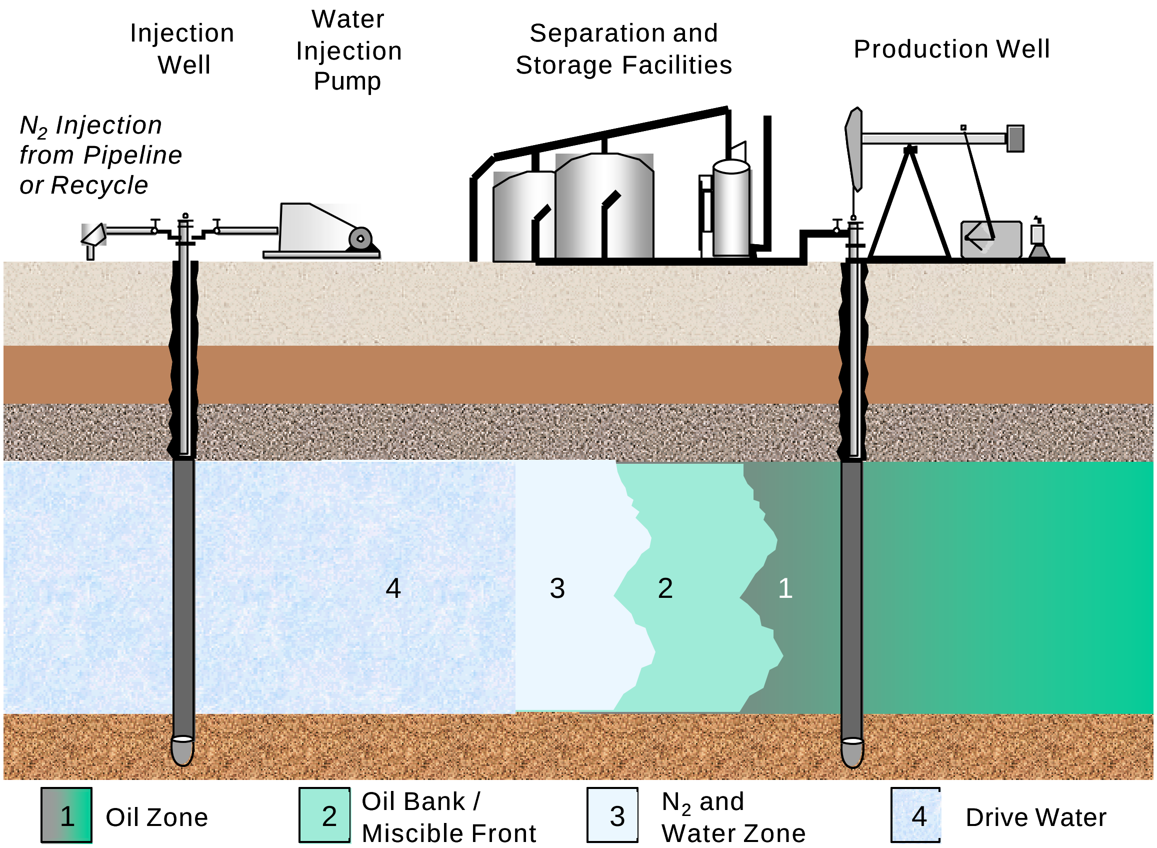


Figure 6 - Nitrogen/flue gas flooding process.

Description

Nitrogen or flue gas injection consists of injecting large quantities of gas that may be miscible or immiscible depending on the pressure and oil composition.

Large volumes may be injected, because of the low cost.

Nitrogen or flue gas are also considered for use as chase gases in hydrocarbon- miscible and CO_2 floods.

Mechanisms that Improve Recovery Efficiency

Vaporizes the lighter components of the crude oil and generates miscibility if the pressure is high enough.

Provides a gas drive where a significant portion of the reservoir volume is filled with low-cost gases.

Limitations

Miscibility can only be achieved with light oils at high pressures; therefore, deep reservoirs are needed.

A steeply dipping reservoir is desired to permit gravity stabilization of the displacement, which has a very unfavorable mobility ratio.

Challenges

Viscous fingering results in poor vertical and horizontal sweep efficiency.

Flue gas injection can cause corrosion.

Nonhydrocarbon gases must be separated from saleable gas.

Screening Parameters

Gravity	>24º API (35 for nitrogen)
Viscosity	<10 cp
Composition	$C_1 - C_7$ to obtain miscibility
Oil saturation	>30% PV
Formation type	sandstone/carbonate
Net thickness	relatively thin (not critical for pressure maintenance)
Average permeability	not critical
Transmissibility	not critical
Depth	>4,500 feet
Temperature	not critical

for miscibility the pressure should be high enough

Note: Most EOR screening values are approximations based on successful North American projects. These are not intended to be firm cut-offs, but rather approximate practical limitations. They do not take into account new technology or varying economic situations.

Thermal (Steamflooding)

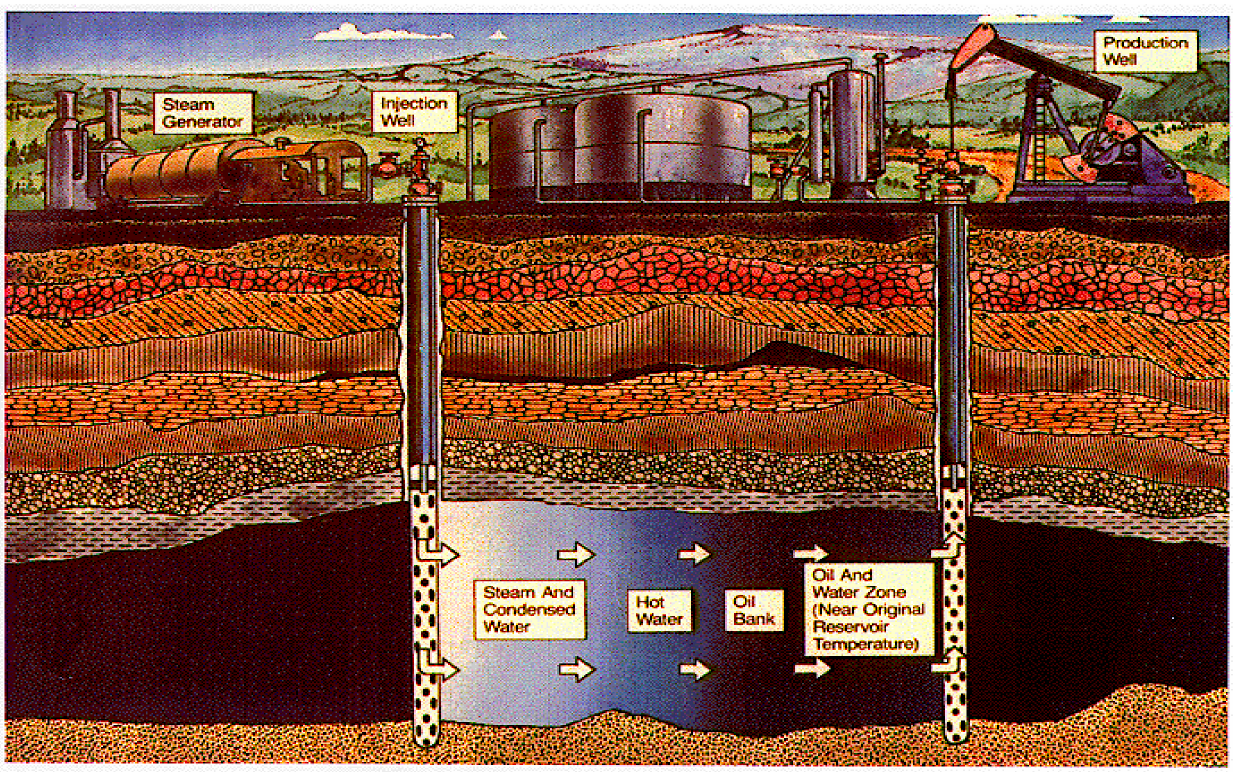


Figure 7 - Thermal steamflooding process.

Description

Steamflooding consists of injecting ±80% quality steam to displace oil.

Normal practice is to precede and accompany the steam drive by a cyclic steam stimulation of the producing wells (called huff and puff).

Mechanisms That Improve Recovery Efficiency

Viscosity reduction / steam distillation.

Supplies pressure to drive oil to the producing well.

Limitations

Applicable to viscous oils in massive, high permeability sandstones or unconsolidated sands.

Oil saturations must be high, and pay zones should be > 20 feet thick to minimize heat losses to adjacent formations.

Less viscous crude oils can be steamflooded if they don't respond to water.

Steamflooded reservoirs should be as shallow as possible, because of excessive wellbore heat losses.

Steamflooding is not normally done in carbonate reservoirs.

Since about 1/3 of the additional oil recovered is consumed to generate the required steam, the cost per incremental barrel of oil is high.

A low percentage of water-sensitive clays is desired for good injectivity.

Challenges

Adverse mobility ratio and channeling of steam.

Screening Parameters

Gravity	<35º API (10-35º API)	
Viscosity	>20 cp (10-5,000 cp)	
Composition	not critical	
Oil saturation	>500 bbl/acre-ft (>40-50% PV)	
Formation type	sandstone	
Net thickness	>20 feet	in low thickness heat transmitted to adjacent formations.
Average permeability	>200 md	
Transmissibility	>100 md ft / cp	
Depth	>200-5,000 feet	beacause of heat loss in the wellbore the should be as shallow as possible
Temperature	not critical	

Note: Most EOR screening values are approximations based on successful North American projects. These are not intended to be firm cut-offs, but rather approximate practical limitations. They do not take into account new technology or varying economic situations.

Depth Limitations for Enhanced Oil Recovery Methods

This table illustrates the influence of reservoir depth on the technical feasibility of various enhanced oil recovery methods.

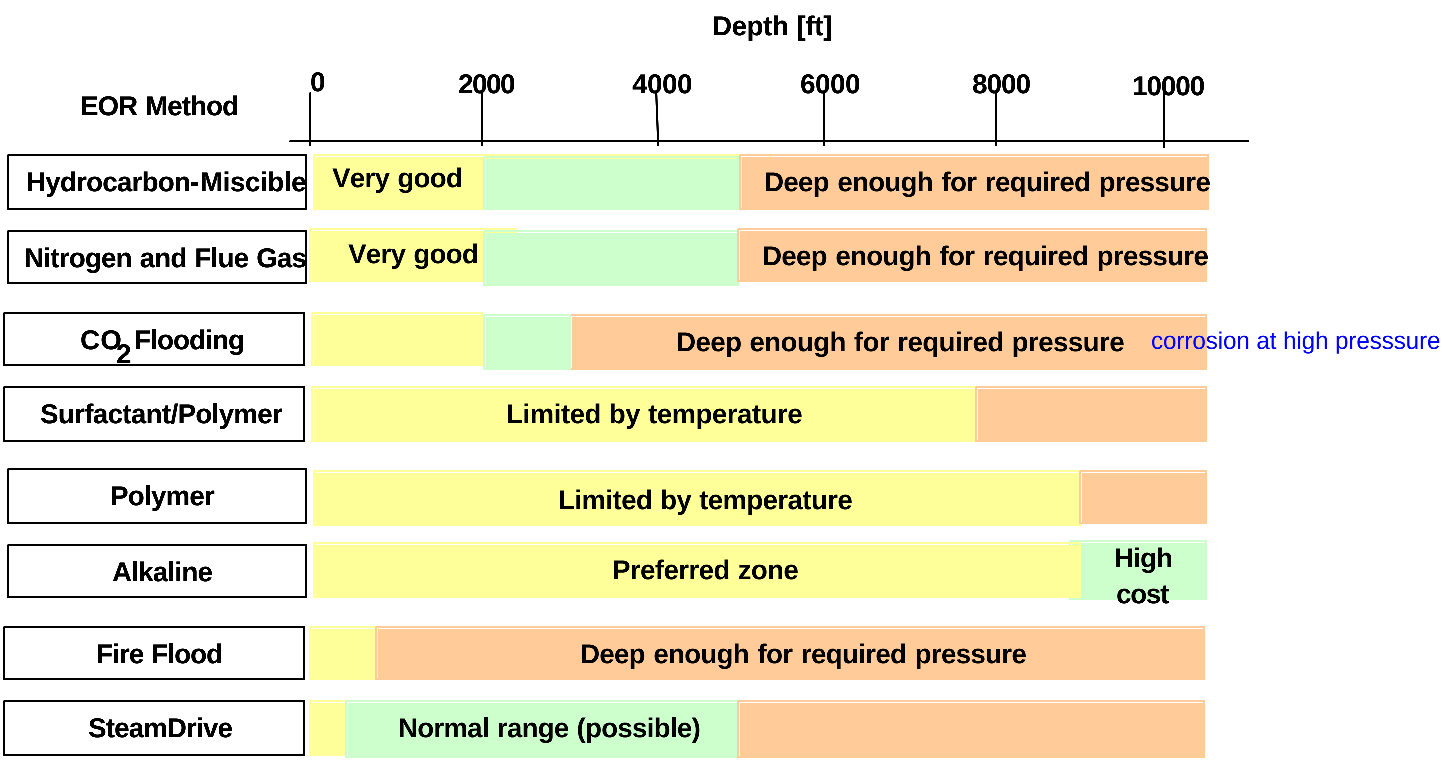


Figure 8 - Depths limitations for EOR methods.

Preferred Oil Viscosity Ranges for Enhanced Oil Recovery Methods

This table illustrates the influence of oil viscosity on the technical feasibility of various enhanced oil recovery methods.

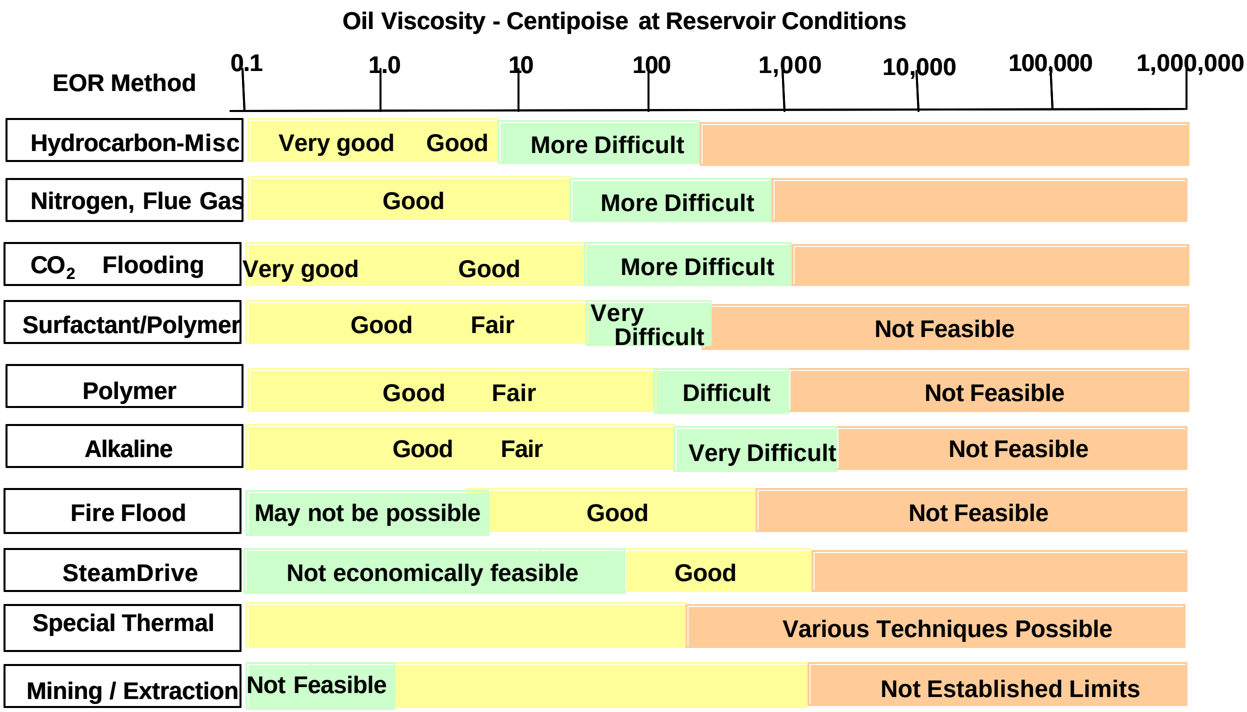


Figure 9 - Oil viscosity incidence for different EOR methods.

Permeability Guides for Enhanced Oil Recovery Methods

This table illustrates the influence of rock permeability on the technical feasibility of various enhanced oil recovery methods.

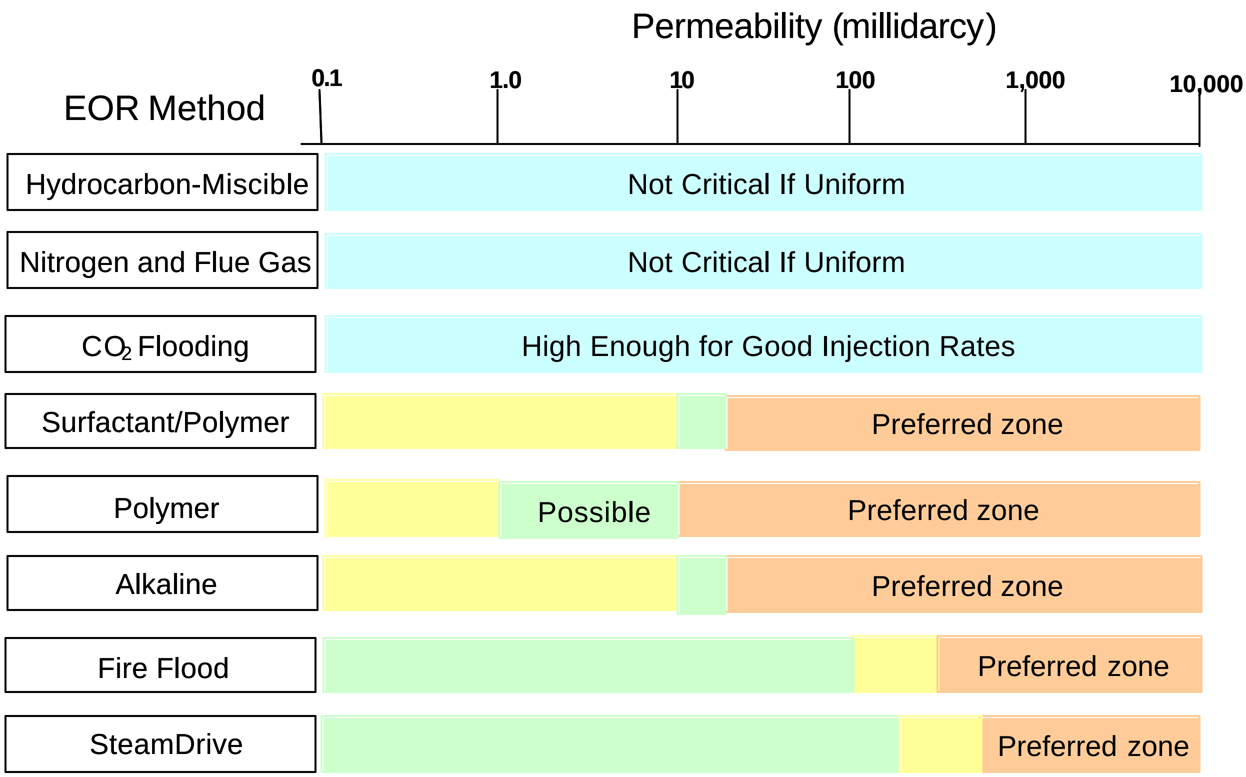


Figure 10 - Reservoir permeability for different EOR methods.

Summary of Screening Criteria for Enhanced Oil Recovery Methods

		Oil Properties				Reservoir Characteristics				
		Gravity ºAPI	Viscosity (cp)	Composition	Oil Saturation	Formation Type	Net Thickness (ft)	Average Permeability (md)	Depth (ft)	Temp (ºF)
	Waterflood	>25	<30	N.C.	>10% mobile oil	Sandstone or carbonate	N.C.	N.C.	N.C.	N.C.
Gas Injection Methods	Hydrocarbon	>35	<10	High % of C_2-C_7	>30% PV	Sandstone or carbonate	Thin unless dipping	N.C.	>2000 (LPG) >5000 (H.P. gas)	N.C.
	Nitrogen & Flue Gas	>24 >35 for N_2	<10	High % of C_1-C_7	>30% PV	Sandstone or carbonate	Thin unless dipping	N.C.	>4500	N.C.
	Carbon Dioxide	>26	<15	High % of C_5-C_{12}	>30% PV	Sandstone or carbonate	Thin unless dipping	N.C.	>2000	N.C.
	Surfactant / Polymer	>25	<30	Light intermediate desired	>30% PV	Sandstone preferred	>10	>20	<8000	<175
Chemical Flooding	Polymer	>25	<150	N.C.	>10% PV	Sandstone preferred; carbonate possible	N.C.	>10 (normally)	<9000	<200
	Alkaline	13-35	<200	Some organic acids	Above waterfloo d residual	Sandstone preferred	N.C.	>20	<9000	<200
Thermal	Combustion	<40 (10-25 normally)	<1000	Some asphaltic components	>40-50% PV	Sand or sandstone with high porosity	>10	>10*	>500	>150 preferred
	Steamflooding	<25	>20	N.C.	>40-50% PV	Sand or sandstone with high porosity	>20	>200**	300-5000	N.C.

N.C. – Not Critical

The following table contains a set of guidelines regarding typical efficiencies obtained for every major EOR method that will be analyzed in greater depth throughout this course.

Method	Displacement Efficiency	Vertical Sweep Efficiency	Areal Sweep Efficiency
Waterflooding	Maintains reservoir pressure Enhanced water drive displacing oil to producers	Decreases with increased heterogeneity	Affected by barriers, baffles, and boundaries Poor sweep if adverse mobility ratio
Dry HC Gas Injection	Maintains reservoir pressure	Affected by zonal pressure distribution	
Cyclic Steam Injection	Oil viscosity reduction Reduces pressure around the wellbore	Limited to near-wellbore Dissolves plugging deposits around wellbore	Limited to near-wellbore Provides for higher injection rates with subsequent steamflood
Steamflooding	Oil viscosity reduction Steam distillation Pressure drives oil to producers	Steam injection can override because of gravity segregation	Adverse mobility ratio
Water Alternating Steam Process (WASP) Injection	Water injected after steam causes the steam zone to collapse while tending to underrun the reservoir	Reduces gravity override Reduces vertical channeling	Improves areal conformance Reduces channeling
In-situ Combustion	Oil viscosity reduction Pressure gradient drives oil Upgrades crude	Gravity segregation Adverse mobility ratio	Controlling flame front is difficult Adverse mobility ratio
Surfactant Flooding	Reduces interfacial tension Increases water wettability Solubilizes oil Enhances mobility		Improves mobility ratio Improves areal conformance

Polymer Flooding	Augments waterflood Increases viscosity of injected water Decreases mobility of injected water	Provides mobility control Formation plugging	Provides mobility control Viscosity loss from shear degradation
Miscible Gas Flooding – CO2	Viscosity reduction Oil swelling Vaporizing gas Reduces interfacial tension	Adverse mobility ration Gravity segregation Asphaltene deposition near injectors Corosion and scaling	Adverse mobility ratio Early breakthrough and fingering Increases native perm in a carbonate reservoir
Miscible Gas Flooding – HC gas	Viscosity reduction Oil swelling Condensing/vaporizing gas Reduces interfacial tension	Adverse mobility ratio Gravity segregation	Adverse mobility ratio Early breakthrough and fingering
Nitrogen/Flue Gas Injection	Vaporizes light oil components May be miscible but mostly used for pressure maintenance	Adverse mobility ratio Gravity segregation	Adverse mobility ratio Early breakthrough and fingering
Water Alternating Gas (WAG) Injection	Decreases mobility of injected gas Maintains reservoir pressure	Reduced recovery can result from gravity segregation	Improves areal conformance Reduces channeling
Microbial EOR	N/A	Seals reservoir conduits between injectors and producers Seals watered-out and high permeability zones	Seals reservoir conduits between injectors and producers Seals watered-out and high permeability zones

Petroleum Reserves Definitions

Approved by the Board of Directors, Society of Petroleum Engineers (SPE) and the Executive Board, World Petroleum Congresses (WPC), March 1997.

Preamble

Petroleum is the world's major source of energy and is a key factor in the continued development of world economies. It is essential for future planning that governments and industry have a clear assessment of the quantities of petroleum available for production and quantities which are anticipated to become available within a practical time frame through additional field development, technological advances, or exploration. To achieve such an assessment, it is imperative that the industry adopt a consistent nomenclature for assessing the current and future quantities of petroleum expected to be recovered from naturally occurring underground accumulations. Such quantities are defined as reserves, and their assessment is of considerable importance to governments, international agencies, economists, bankers, and the international energy industry.

The terminology used in classifying petroleum substances and the various categories of reserves have been the subject of much study and discussion for many years. Attempts to standardize reserves terminology began in the mid 1930's when the American Petroleum Institute considered classification for petroleum and definitions of various reserves categories. Since then, the evolution of technology has yielded more precise engineering methods to determine reserves and has intensified the need for an improved nomenclature to achieve consistency among professionals working with reserves terminology. Working entirely separately, the Society of Petroleum Engineers (SPE) and the World Petroleum Congresses (WPC) produced strikingly similar sets of petroleum reserve definitions for known accumulations which were introduced in early 1987. These have become the preferred standards for reserves classification across the industry. Soon after, it became apparent to both organizations that these could be combined into a single set of definitions which could be used by the industry worldwide. Contacts between representatives of the two organizations started in 1987, shortly after the publication of the initial sets of definitions. During the World Petroleum Congress in June 1994, it was recognized that while any revisions to the current definitions would require the approval of the respective Boards of Directors, the effort to establish a worldwide nomenclature should be increased.

A common nomenclature would present an enhanced opportunity for acceptance and would signify a common and unique stance on an essential technical and professional issue facing the international petroleum industry.

As a first step in the process, the organizations issued a joint statement which presented a broad set of principles on which reserves estimations and definitions should be based. A task force was established by the Boards of SPE and WPC to develop a common set of definitions based on this statement of principles.

The following joint statement of principles was published in the January 1996 issue of the SPE Journal of Petroleum Technology and in the June 1996 issue of the WPC Newsletter.

There is a growing awareness worldwide of the need for a consistent set of reserves definitions for use by governments and industry in the classification of petroleum reserves. Since their introduction in 1987, the Society of Petroleum Engineers and the World Petroleum Congresses reserves definitions have been standards for reserves classification and evaluation worldwide.

SPE and WPC have begun efforts toward achieving consistency in the classification of reserves. As a first step in this process, SPE and WPC issue the following joint statement of principles.

SPE and WPC recognize that both organizations have developed a widely accepted and simple nomenclature of petroleum reserves.

SPE and WPC emphasize that the definitions are intended as standard, general guidelines for petroleum reserves classification which should allow for the proper comparison of quantities on a worldwide basis.

SPE and WPC emphasize that, although the definition of petroleum reserves should not in any manner be construed to be compulsory or obligatory, countries and organizations should be encouraged to use the core definitions as defined in these principles and also to expand on these definitions according to special local conditions and circumstances.

SPE and WPC recognize that suitable mathematical techniques can be used as required and that it is left to the country to fix the exact criteria for reasonable certainty of existence of petroleum reserves. No methods of calculation are excluded, however, if probabilistic methods are used, the chosen percentages should be unequivocally stated.

SPE and WPC agree that the petroleum nomenclature as proposed applies only to known discovered hydrocarbon accumulations and their associated potential deposits.

SPE and WPC stress that petroleum proved reserves should be based on current economic conditions, including all factors affecting the viability of the projects. SPE and WPC recognize that the term is general and not restricted to costs and price only. Probable and possible reserves could be based on anticipated developments and/or the extrapolation of current economic conditions.

SPE and WPC accept that petroleum reserves definitions are not static and will evolve.

A conscious effort was made to keep the recommended terminology as close to current common usage as possible in order to minimize the impact of previously reported quantities and changes required to bring about wide acceptance. The proposed terminology is not intended as a precise system of definitions and evaluation procedures to satisfy all situations. Due to the many forms of occurrence of petroleum, the wide range of characteristics, the uncertainty associated with the geological environment, and the constant evolution of evaluation technologies, a precise classification system is not practical. Furthermore, the complexity required for a precise system would detract from its understanding by those involved in petroleum matters. As a result, the recommended definitions do not represent a major change from the current SPE and WPC definitions which have become the standards across the industry. It is hoped that the recommended terminology will integrate the two sets of definitions and achieve better consistency in reserves data across the international industry.

Reserves derived under these definitions rely on the integrity, skill, and judgment of the evaluator and are affected by the geological complexity, stage of development, degree of depletion of the reservoirs, and amount of available data. Use of these definitions should sharpen the distinction between the various classifications and provide more consistent reserves reporting.

Definitions

For the purpose of these definitions, the term petroleum refers to naturally occurring liquids and gases which are predominately comprised of hydrocarbon compounds. Petroleum may also contain non-hydrocarbon compounds in which sulfur, oxygen, and/or nitrogen atoms are combined with carbon and hydrogen. Common examples of non-hydrocarbons found in petroleum are nitrogen, carbon dioxide, and hydrogen sulfide.

Reserves are those quantities of petroleum which are anticipated to be commercially recovered from known accumulations from a given date forward. All reserve estimates involve some degree of uncertainty. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. *Unproved reserves* are less certain to be recovered than *proved reserves* and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability.

The intent of SPE and WPC in approving additional classifications beyond proved reserves is to facilitate consistency among professionals using such terms. In presenting these definitions, neither organization is recommending public disclosure of reserves classified as unproved. Public disclosure of the quantities classified as unproved reserves is left to the discretion of the countries or companies involved.

Estimation of reserves is done under conditions of uncertainty. The method of estimation is called *deterministic* if a single best estimate of reserves is made based on known geological, engineering, and economic data. The method of estimation is called *probabilistic* when the known geological, engineering, and economic data are used to generate a range of estimates and their associated probabilities. Identifying reserves as proved, probable, and possible has been the most frequent classification method and gives an indication of the probability of recovery. Because of potential differences in uncertainty, caution should be exercised when aggregating reserves of different classifications.

Reserves estimates will generally be revised as additional geologic or engineering data becomes available or as economic conditions change. Reserves do not include quantities of petroleum being held in inventory, and may be reduced for usage or processing losses if required for financial reporting.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Proved Reserves

Proved reserves are those quantities of petroleum which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods, and government regulations. Proved reserves can be categorized as developed or undeveloped.

If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

Establishment of current economic conditions should include relevant historical petroleum prices and associated costs and may involve an averaging period that is consistent with the purpose of the reserve estimate, appropriate contract obligations, corporate procedures, and government regulations involved in reporting these reserves.

In general, reserves are considered proved if the commercial producibility of the reservoir is supported by actual production or formation tests. In this context, the term proved refers to the actual quantities of petroleum reserves and not just the productivity of the well or reservoir. In certain cases, proved reserves may be assigned on the basis of well logs and/or core analysis that indicate the subject reservoir is hydrocarbon bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

The area of the reservoir considered as proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) the undrilled portions of the reservoir that can reasonably be judged as commercially productive on the basis of available geological and engineering data. In the absence of data on fluid contacts, the lowest known occurrence of hydrocarbons controls the proved limit unless otherwise indicated by definitive geological, engineering or performance data.

Reserves may be classified as proved if facilities to process and transport those reserves to market are operational at the time of the estimate or there is a reasonable expectation that such facilities will be installed. Reserves in undeveloped locations may be classified as proved undeveloped provided (1) the locations are direct offsets to wells that have indicated commercial production in the objective formation, (2) it is reasonably certain such locations are within the known proved productive limits of the objective formation, (3) the locations conform to existing well spacing regulations where applicable, and (4) it is reasonably certain the locations will be developed. Reserves from other locations are categorized as proved undeveloped only where interpretations of geological and engineering data from wells indicate with reasonable certainty that the objective formation is laterally continuous and contains commercially recoverable petroleum at locations beyond direct offsets.

Reserves which are to be produced through the application of established improved recovery methods are included in the proved classification when (1) successful testing by a pilot project or favorable response of an installed program in the same or an analogous reservoir with similar rock and fluid properties provides support for the analysis on which the project was based, and, (2) it is reasonably certain that the project will proceed. Reserves to be recovered by improved recovery methods that have yet to be established through commercially successful applications are included in the proved classification only (1) after a favorable production response from the subject reservoir from either (a) a representative pilot or (b) an installed program where the response provides support for the analysis on which the project is based and (2) it is reasonably certain the project will proceed.

Unproved Reserves

Unproved reserves are based on geologic and/or engineering data similar to that used in estimates of proved reserves; but technical, contractual, economic, or regulatory uncertainties preclude such reserves being classified as proved. Unproved reserves may be further classified as probable reserves and possible reserves.

Unproved reserves may be estimated assuming future economic conditions different from those prevailing at the time of the estimate. The effect of possible future improvements in economic conditions and technological developments can be expressed by allocating appropriate quantities of reserves to the probable and possible classifications.

Probable Reserves

Probable reserves are those unproved reserves which analysis of geological and engineering data suggests are more likely than not to be recoverable. In this context, when probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable reserves.

In general, probable reserves may include (1) reserves anticipated to be proved by normal step-out drilling where sub-surface control is inadequate to classify these reserves as proved, (2) reserves in formations that appear to be productive based on well log characteristics but lack core data or definitive tests and which are not analogous to producing or proved reservoirs in the area, (3) incremental reserves attributable to infill drilling that could have been classified as proved if closer statutory spacing had been approved at the time of the estimate, (4) reserves attributable to improved recovery methods that have been established by repeated commercially successful applications when (a) a project or pilot is planned but not in operation and (b) rock, fluid, and reservoir characteristics appear favorable for commercial application, (5) reserves in an area of the formation that appears to be separated from the proved area by faulting and the geologic interpretation indicates the subject area is structurally higher than the proved area, (6) reserves attributable to a future workover, treatment, re-treatment, change of equipment, or other mechanical procedures, where such procedure has not been proved successful in wells which exhibit similar behavior in analogous reservoirs, and (7) incremental reserves in proved reservoirs where an alternative interpretation of performance or volumetric data indicates more reserves than can be classified as proved.

Possible Reserves

Possible reserves are those unproved reserves which analysis of geological and engineering data suggests are less likely to be recoverable than probable reserves. In this context, when probabilistic methods are used, there should be at least a 10% probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable plus possible reserves.

In general, possible reserves may include (1) reserves which, based on geological interpretations, could possibly exist beyond areas classified as probable, (2) reserves in formations that appear to be petroleum bearing based on log and core analysis but may not be productive at commercial rates, (3) incremental reserves attributed to infill drilling that are subject to technical uncertainty, (4) reserves attributed to improved recovery methods when (a) a project or pilot is planned but not in operation and (b) rock, fluid, and reservoir characteristics are such that a reasonable doubt exists that the project will be commercial, and (5) reserves in an area of the formation that appears to be separated from the proved area by faulting and geological interpretation indicates the subject area is structurally lower than the proved area.

Reserve Status Categories

Reserve status categories define the development and producing status of wells and reservoirs.

Developed

Developed reserves are expected to be recovered from existing wells including reserves behind pipe. Improved recovery reserves are considered developed only after the necessary equipment has been installed, or when the costs to do so are relatively minor. Developed reserves may be sub-categorized as producing or non-producing.

Producing

Reserves subcategorized as producing are expected to be recovered from completion intervals which are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Non-producing

Reserves subcategorized as non-producing include shut-in and behind-pipe reserves. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe reserves are expected to be recovered from zones in existing wells, which will require additional completion work or future recompletion prior to the start of production.

Undeveloped Reserves

Undeveloped reserves are expected to be recovered: (1) from new wells on undrilled acreage, (2) from deepening existing wells to a different reservoir, or (3) where a relatively large expenditure is required to (a) recomplete an existing well or (b) install production or transportation facilities for primary or improved recovery projects.

URL: http://www.eia.doe.gov/emeu/cabs/venez

Estimated proven world reserves, 1998 versus 1997

(Data compiled by World Oil, with aid of government agencies, industry associations, oil companies and private sources.)

Area and Country	Crude Reserves at Year-End (million barrels)* 1998	1997**	% diff.	Natural Gas Reserves AT Year-End (billion cubic feet) 1998	1997**	% diff.
North America	**56,688.5**	**57,287.2**	**– 1.0**	**261,665.8**	**261,758.8**	**0.0**
Canada	5,581.5	5,655.0	– 1.3	63,555.0	64,197.0	– 1.0
Cuba	178.0	161.2	10.4	38.8	38.8	0.0
Mexico	28,399.0	28,399.0	0.0	30,300.0	30,300.0	0.0
United States	22,013.0	22,546.0	– 2.4	167,772.0	167,223.0	0.3
Others	517.0	526.0	– 1.7	0.0	0.0	...
South America	**62,672.4**	**62,302.5**	**0.6**	**226,055.1**	**221,470.8**	**2.1**
Argentina	2,753.5	2,621.2	5.0	24,246.5	24,148.1	0.4
Bolivia	151.9 •	142.0 •	7.0	5,281.0	4,158.0	27.0
Brazil	7,500.0	7,106.3	5.5	8,740.4	8,039.4	8.7
Chile	77.0	80.0	– 3.8	2,690.0	2,730.0	– 1.5
Colombia	2,600.0	2,600.0	0.0	8,000.0	8,000.0	0.0
Ecuador	2,589.9	2,834.1	– 8.6	3,700.0	3,620.0	2.2
Peru	773.5 •	758.4 •	2.0	7,050.0	6,998.8	0.7
Trinidad & Tobago	600.0	534.0	12.4	19,770.0	18,250.0	8.3
Venezuela	45,500.0	45,500.0	0.0	146,571.0	145,522.0	0.7
Others	126.6	126.5	0.1	6.2	4.5	37.8
Western Europe	**19,270.5**	**19,153.3**	**0.6**	**157,667.9**	**158,538.3**	**– 0.5**
Austria	85.2	87.1	– 2.2	903.7	854.0	5.8
Denmark	881.0	944.0	– 6.7	3,212.3	3,424.1	– 6.2
France	130.4	107.8	21.0	607.2	751.9	– 19.2
Germany	352.9	384.1	– 8.1	12,002.0	12,267.0	– 2.2
Italy	611.2	621.8	– 1.7	7,839.2	8,068.7	– 2.8
Netherlands	106.9	100.6	6.3	62,516.0	64,422.0	– 3.0
Norway	11,901.1	11,665.2	2.0	43,627.4	41,406.9	5.4
United Kingdom	5,153.3	5,190.9	– 0.7	26,651.5	27,004.5	– 1.3
Others	48.5	51.8	– 6.4	308.6	339.2	– 9.0
Eastern Europe	**68,129.4**	**68,024.0**	**0.2**	**1,918,051.0**	**1,916,404.8**	**0.1**
Albania	178.0	132.1	34.7	88.2	56.2	56.9
Croatia	97.2 •	99.2 •	– 2.0	1,235.8	1,299.6	– 4.9
Czech Republic	3.0	3.3	– 9.1	112.3	124.8	– 10.0
FSU-Russian Federation	55,070.0	55,143.0	– 0.1	1,705,000.0	1,705,000.0	0.0
FSU-Kazakhstan	7,000.0	6,800.0	2.9	70,600.0	70,600.0	0.0
FSU-Others	4,571.1	4,582.7	– 0.3	128,750.0	126,482.2	1.8
Hungary	46.4 •	52.9 •	– 12.3	1,397.0	1,588.5	– 12.1
Poland	57.6	59.0	– 2.4	4,944.0	5,097.0	– 3.0
Romania	892.0	931.3	– 4.2	4,146.1	4,328.8	– 4.2
Yugoslavia	132.0	139.1	– 5.1	609.5	638.7	– 4.6
Others	82.1	81.4	0.9	1,168.1	1,189.0	– 1.8

World crude / condensate production and wells actually producing — 1998 versus 1997

(Data complied by World Oil, with aid of government agencies, industry associations, oil cos., and private sources.)

	End of 1998			End of 1997	Daily Average Production (barrels)*		
Area and Country	**Flowing**	**Art. Lift**	**Total**	**Total****	**1998**	**1997****	**% diff.**
North America	**30,939**	**575,234**	**606,173**	**627,865**	**11,160,891**	**11,255,352**	**– 0.8**
Canada	4,815	44,843	49,658	50,901	1,640,109	1,629,260	0.7
Cuba	30	234	264	266	32,500	31,500	3.2
Mexico	1,161	2,251	3,412	3,605	3,165,000	3,119,000	1.5
United States	24,933	527,883	552,816	573,070	6,297,282	6,451,592	– 2.4
Others	0	23	23	23	26,000	24,000	8.3
South America	**2,897**	**47,247**	**50,144**	**50,238**	**6,468,636**	**6,362,391**	**1.7**
Argentina	387	13,984	14,371	14,085	905,279	889,164	1.8
Bolivia	207	128	335	329	34,598 •	30,194 •	14.6
Brazil	378	6,683	7,061	7,058	967,700	841,487	15.0
Chile	15	290	305	338	8,000	8,444	– 5.3
Colombia	170	2,804	2,974	2,924	760,000	652,000	16.6
Ecuador	50	1,272	1,322	1,366	375,482	388,232	– 3.3
Peru	38	3,998	4,036	3,770	115,593 •	118,239 •	– 2.2
Trinidad & Tobago	399	3,723	4,122	4,086	140,023	143,230	– 2.2
Venezuela	1,245	13,845	15,090	15,786	3,150,000	3,280,000	– 4.0
Others	8	520	528	496	11,961	11,401	4.9

Yemen	1,850.0	1,829.0	1.1	17,000.0	17,000.0	0.0
Others	586.0 •	608.1 •	– 3.6	12,000.2	12,098.4	– 0.8
Far East	**54,683.9**	**55,455.4**	**– 1.4**	**309,406.3**	**307,903.2**	**0.5**
Brunei	1,020.0	1,060.0	– 3.8	9,580.0	9,724.0	– 1.5
China	33,520.0	34,030.0	– 1.5	42,360.0	40,860.0	3.7
India	3,026.6	3,437.3	– 11.9	12,884.5	13,343.4	– 3.4
Indonesia	8,637.3	9,091.9	– 5.0	77,065.7	76,171.8	1.2
Malaysia	4,645.0	4,976.0	– 6.7	85,831.0	86,985.0	– 1.3
Myanmar	180.0	150.0	20.0	15,000.0	15,000.0	0.0
Pakistan	208.0	200.0	4.0	21,600.0	22,300.0	– 3.1
Philippines	306.0	308.0	– 0.6	3,500.0	3,500.0	0.0
Thailand	388.4 •	296.4 •	31.0	14,825.1	12,479.0	18.8
Viet Nam	1,997.1	1,246.4	60.2	6,000.0	6,000.0	0.0
Others	755.5 •	659.4 •	14.6	20,760.0	21,540.0	– 3.6
South Pacific	**2,440.0**	**2,137.7**	**14.1**	**44,643.0**	**38,855.8**	**14.9**
Australia	1,772.0	1,692.9	4.7	28,410.0	27,852.7	2.0
New Zealand	110.0 •	119.8 •	– 8.2	2,233.0	2,003.1	11.5
Papua New Guinea	558.0	325.0	71.7	14,000.0	9,000.0	55.6
World Total	**968,511.4**	**963,680.9**	**0.5**	**5,148,977.6**	**5,119,187.0**	**0.6**

* Excludes natural gas liquids

** Revised

• All or a significant portion is condensate.

Africa	**77,234.7**	**76,042.5**	**1.6**	**377,935.9**	**360,990.9**	**4.7**
Algeria	13,000.0 •	13,290.0 •	– 2.2	137,500.0	139,500.0	– 1.4
Angola	4,030.0	3,900.0	3.3	1,660.0	1,680.0	– 1.2
Cameroon	660.0	645.5	2.2	3,900.0	3,800.0	2.6
Congo	1,700.0	1,615.0	5.3	4,300.0	4,300.0	0.0
Cote d'Ivoire	135.0	117.1	15.3	1,040.3	1,040.3	0.0
Egypt	3,710.0	3,719.0	– 0.2	37,205.0	32,749.0	13.6
Gabon	2,565.0	2,672.3	– 4.0	3,503.0	3,578.9	– 2.1
Libya	26,900.0	26,900.0	0.0	46,300.0	45,500.0	1.8
Nigeria	22,500.0	21,225.3	6.0	124,000.0	109,200.0	13.6
Tunisia	290.0	313.9	– 7.6	2,295.5	2,210.0	3.9
Others	1,744.7	1,644.4	6.1	16,232.1	17,432.7	– 6.9
Middle East	**627,392.0**	**623,278.3**	**0.7**	**1,853,552.6**	**1,853,264.4**	**0.0**
Iran	92,870.0	89,700.0	3.5	812,238.1	812,239.0	0.0
Iraq	98,975.0	99,665.0	– 0.7	112,600.0	112,600.0	0.0
Kuwait	92,355.0	91,180.0	1.3	52,350.0	52,725.0	– 0.7
Neutral Zone	4,650.0	4,600.0	1.1	8,000.0	8,000.0	0.0
Oman	5,564.0	5,399.0	3.1	29,100.0	28,500.0	2.1
Qatar	5,338.0	4,805.0	11.1	395,000.0	395,000.0	0.0
Saudi Arabia	259,100.0	259,000.0	0.0	204,000.0	204,000.0	0.0
Syria	2,300.0	2,345.0	– 1.9	8,400.0	8,400.0	0.0
Turkey	299.0	312.2	– 4.2	314.3	332.0	– 5.3
UAE-Abu Dhabi	62,500.0	62,820.0	– 0.5	198,500.0	198,320.0	0.1
UAE-Dubai	1,005.0	1,015.0	– 1.0	4,050.0	4,050.0	0.0

Western Europe	**1,364**	**3,343**	**4,707**	**4,831**	**6,189,256**	**6,236,358**	**– 0.8**
Austria	44	879	923	970	20,008	19,944	0.3
Denmark	17	166	183	180	230,000	238,500	– 3.6
France	12	432	444	474	38,952	41,191	– 5.4
Germany	21	1,275	1,296	1,369	57,494	56,024	2.6
Italy	104	127	231	234	112,454	119,156	– 5.6
Netherlands	------------------------- Not available -------------------------				59,650	61,262	– 2.6
Norway	542	0	542	550	2,923,960	3,043,691	– 3.0
United Kingdom	610	440	1,050	1,011	2,733,013	2,638,202	3.6
Others	14	24	38	43	13,725	18,388	– 25.4
Eastern Europe	**8,345**	**114,293**	**123,258**	**126,816**	**7,391,132**	**7,425,471**	**– 0.5**
Albania	0	1,500	1,500	N/A	6,300	9,215	– 31.6
Croatia	38	692	730	758	31,160 •	29,367 •	6.1
Czech Republic	22	138	160	171	3,612	3,280	10.1
FSU-Russian Federation	6,870	91,130	98,000	101,918	6,039,000	6,087,702	– 0.8
FSU-Kazakhstan	693	6,599	7,292	8,064	520,622	518,007	
FSU-Others	------------------------- Not available -------------------------				599,503	577,265	3.9
Hungary	235	695	930	1,000	32,975 •	35,457 •	– 7.0
Poland	69	1,753	1,822	1,951	7,518	8,939	– 15.9
Romania	418	11,786	12,204	12,274	130,436	134,470	– 3.0
Yugoslavia (Serbia)	------ Not available -------		620	680	18,000	19,722	– 8.7
Others	------------------------- Not available -------------------------				2,006	2,047	– 2.0

Africa	**4,540**	**3,531**	**8,071**	**8,135**	**7,343,345**	**7,513,000**	**– 2.3**
Algeria	865	310	1,175	1,214	1,248,000 •	1,278,500 •	– 2.4
Angola	289	316	605	581	735,000	708,951	3.7
Cameroon	221	77	298	291	120,500	118,500	1.7
Congo	87	343	430	395	279,675	238,550	17.2
Cote d'Ivoire	23	0	23	17	21,000	16,000	31.3
Egypt	190	1,060	1,250	1,272	833,600	852,600	– 2.2
Gabon	118	252	370	280	357,000	367,000	– 2.7
Libya	912	513	1,425	1,470	1,390,000	1,446,000	– 3.9
Nigeria	1,760	365	2,125	2,251	2,125,000	2,300,000	– 7.6
Tunisia	32	159	191	186	81,995	79,820	2.7
Others	43	136	179	178	151,575	107,079	41.6
Middle East	**5,498**	**4,214**	**10,519**	**10,283**	**21,354,947**	**20,364,462**	**4.9**
Iran	1,152	0	1,152	1,121	3,657,000	3,626,000	0.9
Iraq	------------------------- Not available -------------------------				2,110,000	1,150,000	83.5
Kuwait	810	0	810	788	1,777,230	1,742,060	2.0
Neutral Zone	182	273	455	439	529,101	516,616	2.4
Oman	150	2,227	2,377	2,230	899,000	902,800	– 0.4
Qatar	348	64	412	385	793,000	665,000	19.2
Saudi Arabia	1,430	105	1,535	1,565	8,114,000	8,297,000	– 2.2
Syria	------ Not available -------		807	832	550,000	570,000	– 3.5
Turkey	3	820	823	793	61,741	66,175	– 6.7
UAE-Abu Dhabi	1,058	172	1,230	1,210	2,145,000	2,119,800	1.2
UAE-Dubai	11	210	221	216	270,000	284,210	– 5.0
Yemen	195	91	286	276	387,800	366,988	5.7
Others	159	252	411	428	61,075 •	57,813 •	5.6
Far East	**77,048**	**14,166**	**91,214**	**89,467**	**6,556,039**	**6,557,849**	**0.0**
Brunei	85	539	624	636	157,400	163,000	– 3.4
China	74,190	1,900	76,090	74,600	3,199,000	3,199,500	0.0
India	644	2,481	3,125	3,150	534,887	572,775	– 6.6
Indonesia	1,184	7,653	8,837	8,686	1,527,573	1,550,781	– 1.5
Malaysia	543	433	976	886	725,000	714,000	1.5
Myanmar	30	810	840	828	11,000	11,500	– 4.3
Pakistan	90	75	165	140	61,000	57,000	7.0
Philippines	7	0	7	7	790	817	– 3.3
Thailand	46	102	148	123	75,610 •	70,950 •	6.6
Viet Nam	102	36	138	122	245,745	194,755	26.2
Others	127	137	264	289	18,034 •	22,771 •	– 20.8
South Pacific	**210**	**1,058**	**1,268**	**1,261**	**706,418**	**683,538**	**3.3**
Australia	141	1,034	1,175	1,191	534,790	567,020	– 5.7
New Zealand	34	11	45	35	44,535 •	39,964 •	11.4
Papua New Guinea	35	13	48	35	127,093	76,554	66.0
World Total	**130,841**	**763,086**	**895,354**	**918,896**	**67,170,664**	**66,398,421**	**1.2**

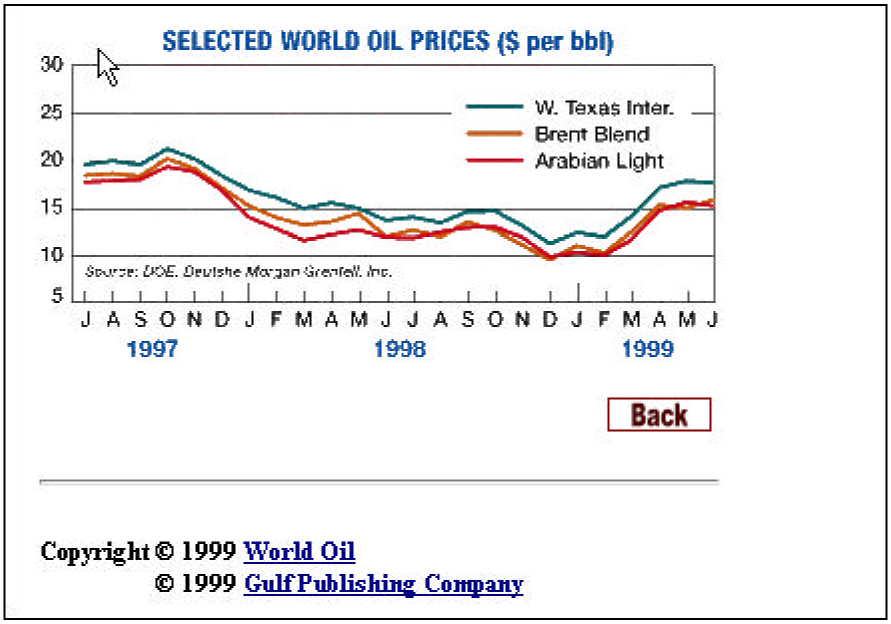
* Totals do not include natural gas liquids or oil from unconventional sources.

** Revised N/A: Not available

• All or a significant portion is condensate.

Note: 1998 producing well total will not equal sum of breakdown categories due to lack of data in some countries.

Oil prices may determine the feasibility of an EOR project. Sources of information in the internet world oil.



Environmental and Economic Aspects of EOR Processes

Learning objective

Examine the relationships among oil and gas prices, EOR production and environmental considerations in some EOR operations.

Challenges

- Tougher environmental restraints,
- Uncertainty in the prediction of oil/gas prices,
- Technological difficulties,
- Reservoir description and characterization.

Facts

- The number of new EOR processes will go down as the oil price goes down
- EOR environmental record has been good. Most of EOR injectants are not very toxic.
- Cogeneration of steam and electricity improves the economics.
- Gas fired boilers reduce emissions and improve the efficiency.

Profitability of EOR projects in the USA.

Method	Percentage reported as profitable in		
	1982	1988	1990
Steam	86	95	96
Combustion	65	78	88
Hot Water	-	89	78
CO_2	21	66	81
Hydrocarbon	50	100	100
Nitrogen	100	100	100
Flue Gas	100	100	100
Polymer	72	92	86
Micellar/Polymer	0	0	0
Alkaline	40	100	successful
Surfactant	-	-	100 (1 project)

Method	**Number of Discontinued Projects**	**Number of listed as 'Successful' or 'Promising'**	**Number listed as 'Discouraging'**	**Percent reported as 'Profitable'**
Steam	32	14	8	62
Combustion	6	4	2	50
CO2 Miscible	5	1	1	50
CO2 Immiscible	20	8	12	100
Hydrocarbon	4	1	1	0
Nitrogen	1	0	1	100
Polymer	53	16	29	63
Micellar/Polymer	10	4	4	33
Alkaline	3	0	3	0
Totals	134	48	61	-

Evaluations of completed or terminated EOR projects in the USA (most were discontinued in 1986-1988).

Sources Additional Reading

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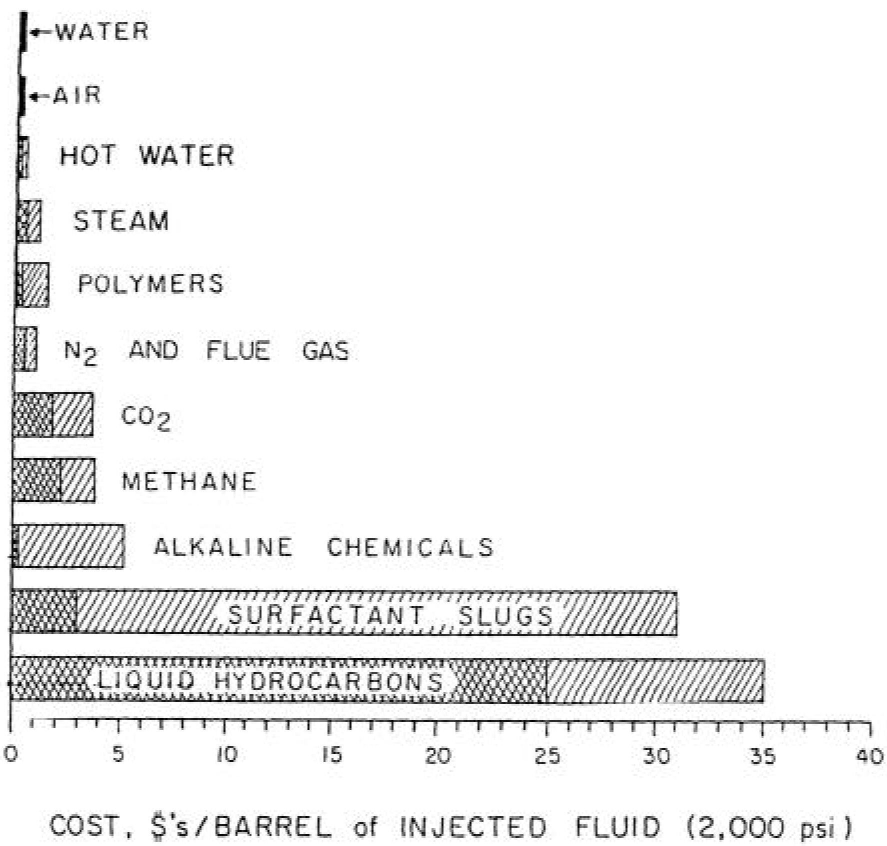
Moritis, G. Oil & Gas J. (April 23, 1990) 49-82

Cost of EOR Fluids per Barrel

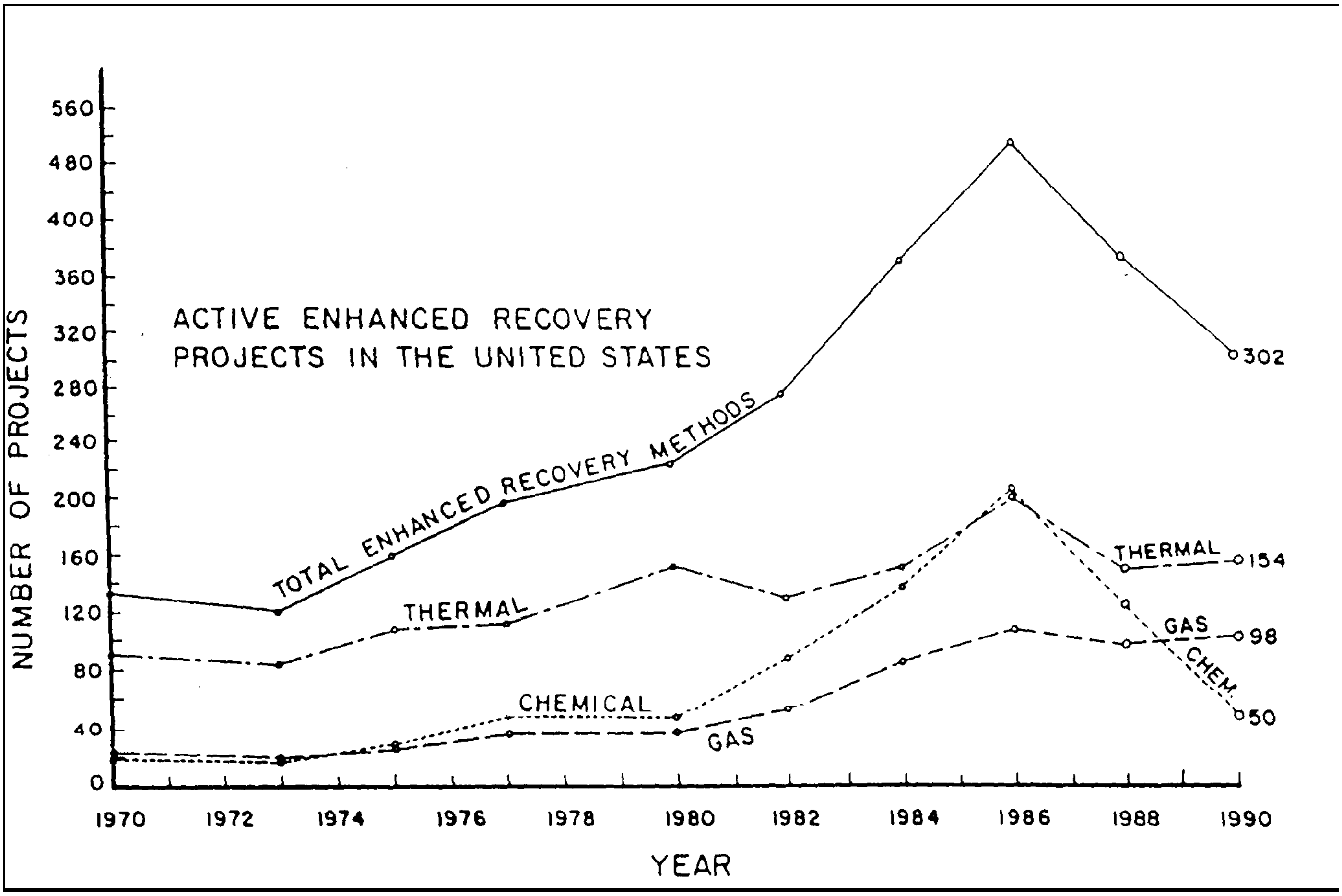
Facts:



Estimated cost of a barrel of EOR injectant at reservoir conditions. The range of costs (shown by the lighter crosshatching) can result from different prices of concentrations of the materials used for the injection fluid.

Source

Taber, J. J. – IOCC Bull. 26 Dec, 1984 (5-13)

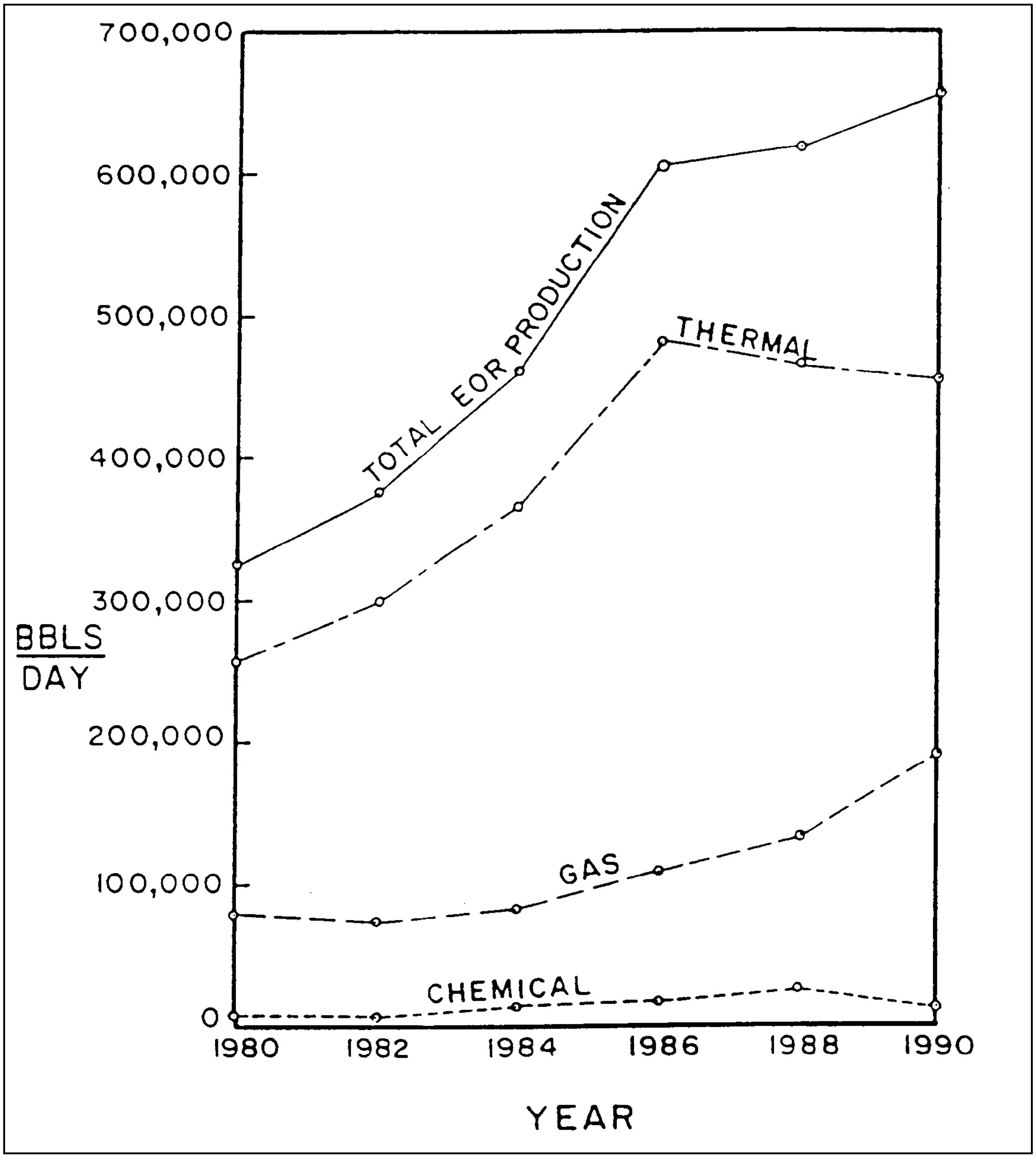


EOR trends in the USA since 1970.

Sources

Moritis, G., Oil and Gas J. April 23, 1990, 49-82 (CO2)

Taber J. J. , IN SITU, 14(4), 1990, 345-405



Oil production from EOR projects in the USA since 1980.

Source

Moritis, G., Oil and Gas J. April 23, 1990, 49-82 (CO2)

Constraints for EOR technologies

The following list summarizes the constraints to some of the advanced recovery technologies identified in this study.

Gas EOR

(1) Reservoir heterogeneity

(2) Mobility control and reservoir conformance

(3) Incomplete mixing

(4) Lack of predictive capability

(5) Poor injectivity

(6) Corrosion problems with C02

Surfactant Flooding

(1) Reservoir heterogeneity

(2) Excessive chemical loss

(3) Coherence, stability and cost-effectiveness of surfactant slugs

(4) Limited to reservoir salinity <20% NaCI

(5) Limited to reservoir temperature <200^{o}F

(6) Limited to permeability> 100 md

(7) Polymer propagation

Alkaline Flooding

(1) Limited range of applicable salinity

(2) High chemical consumption

(3) Brine incompatibility - precipitation

Microbial Enhanced Oil Recovery

(1) Nutrients for field application

(2) Lack of well documented field tests

(3) Limited to reservoir temperature < 170^{o}F

(4) Limited to reservoir salinity.< 10% NaCl

(5) Insufficient basic understanding of the mechanisms of microbial technologies

Reservoir Characterization

(1) The complexity of the rock and fluid distributions even in the "simplest "reservoirs

(2) The inadequate amount of detailed information from even the most ambitiously sampled reservoir

(3) Scaling of properties from core or smaller scale to interwell scale

(4) Difficulties in interpreting seismic data in terms of rock and fluid properties

Thermal EOR

(1) Lower crude oil prices due to gravity, sulfur and heavy metal content

(2) Large front end investments and delayed responses

(3) Absence of cost-effective technology to upgrade low-quality, low-gravity crude into salable products

(4) Absence of cost effective technology that permits the use of low-grade fuel such as coal, petroleum coke, high sulfur crude oil and brackish water to generate steam without violating the environmental regulations.

CLASSIFICATION OF EOR CONSTRAINTS (I - DOE NIPER - 527)

CLASSIFICATION	**EXPLANATION**
Chemical Loss	Loss of injected fluid due to chemical, mechanical, or microbial degradation; chemical loss due to adsorption, ion exchange, or entrapment.
Downhole Completion	Completion techniques; equipment; production problems unrelated to corrosion, scale, or artificial lift.
Facility Design	Surface injection or production facilities.
Gravity Segregation	Gravity override in Steam; potential may exist for override in Situ or gas injection projects.
Injectivity	Process specific to gas injection projects. Low polymer injectivity in chemical projects was considered inherent to the polymer process.
Injection Control	Formation pressure parting; injected fluid flow out of intended zone; inadequate monitoring of injection.
Injectant Quality	Steam quality at sandface; injection well plugging related to poor mixing (polymer) or injection system contaminants (rust, lubricants).
Mobility Control	Gas channeling related to mobilitv rather than heterogeneity; breakdown of polymer bank due to bacterial degradation.
Operations	Problems with oil treating, corrosion, scale, artificial lift, compression, formation plugging unrelated to injectant quality
Reservoir Conditions	Refers to reservoir fluid conditions such as oil saturation, thickness of oil column, reservoir drive mechanism, etc. As defined, reservoir conditions are a subset of reservoir description
Reservoir Description	Refers to rock related description such as depositional environment, rock composition, faulting, heterogeneity, continuity, etc

Reservoir Heterogeneity	Areal or vertical permeability variations, faults, directional flow trends, depositional environments, etc
Process Design	Inadequate or incomplete investigation of different areas known to be important in the EOR processes

References

The following list of references include fundamental principles and field applications for all recovery techniques seen in this course:

Miscible, Polymer, Alkaline, and Thermal flooding Processes.

They are in alphabetical order and are mostly SPE papers.

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Team Exercise:

Let's work in groups such that at least two different EOR techniques are covered per group. What do we need to find out?

- *Locations (worldwide) where a particular EOR technique (thermal, chemical, miscible, etc.) is currently being conducted.*
- *Current costs of chemicals/CO_2/steam/etc.*

Rules

- *Send and share information by e-mail. This will avoid duplicate efforts. This could be:*
- *Internet addresses,*
- *Reference and summary of a particular recent paper. Note: Oil & Gas Journal has current information (www.ogj.org)*
- *Perspectives of the company you work/worked for in the summer.*