CO_2 STORAGE IN DEPLETED OILFIELDS: GLOBAL APPLICATION CRITERIA FOR CARBON DIOXIDE ENHANCED OIL RECOVERY

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OVERVIEW: CO_2 STORAGE IN DEPLETED OILFIELDS: GLOBAL APPLICATION CRITERIA FOR CO_2 ENHANCED OIL RECOVERY

Background to the Study

The IEA Greenhouse Gas R&D Programme (IEA GHG) commissioned Advanced Resources International (ARI), in association with Melzer Consulting, to undertake a study of global CO_2 storage potential associated with enhanced oil recovery (CO2-EOR).

The main aim of the study was to reassess the likely future potential storage capacity for CO_2 in depleted oil fields as part of EOR operations across the world. The study also aimed to identify the key technical, economic and regulatory barriers that may be preventing widespread application of CO2-EOR globally as a means of providing an early opportunity for CO_2 storage.

Previous IEA GHG studies estimated the global storage potential in depleted oil and gas fields as up to 1,000Gt CO_2, 120Gt of which could be stored in association with CO2-EOR operations. Although therefore providing lower potential capacity than both deep saline formations and gas fields, depleted oilfields still constitute a valuable storage resource with extensive repositories of data and knowledge. Storage operations in oil fields would generally be smaller in scale compared to gas fields and aquifers, but the economic and commercial benefits of utilising CO_2 for EOR could in theory provide an immediate driver for implementation of such projects, particularly in a period of high global oil prices. The stimulus of high oil process has led to the increasing development of CO_2 flood operations in recent years, including at the Weyburn oil field in Canada which has extended the profitability of that field for the operator Encana.

IEA GHG thus identified CO2-EOR operations as an early opportunity for CO_2 storage in 2002. However despite developments like those in the Permian Basin, midcontinental and Gulf Coast USA, and at Weyburn, wide scale global development of CO2-EOR has not occurred in spite of current high oil prices. Furthermore, a majority of existing CO2-EOR schemes have not been designed with CO_2 storage as an objective. The aim of this study is to understand why this early opportunity for CO_2 storage has not been realised and when or if this might occur.

Scope of Study

The study took as its starting point, IEA GHG Report on PH3/23 undertaken in 2000 as its base line data set. The study was to assess the data within the report and determine whether there was newer data on issues, (e.g. CO_2 use/bbl oil produced in EOR floods) that could be used to revise global estimates. The study also considered new available data on oil basin reserves and on finds that might also revise the original storage capacity estimation for CO_2 in EOR operations globally. The study was then asked to consider:

1. Identification and characterisation of the main oil fields/basins around the world currently supporting CO2-EOR operations, and those that are planning operations for the future, having already established the feasibility of such development The study would then assess the main drivers/issues (technical, economic, social, political and regulatory) that stimulated the establishment of CO2-EOR operations in these oilfields/basins and, to what

extent CO_2 storage was a consideration. This activity could involve both literature reviews and direct contacts with organisations concerned and could proceed via representative case studies.

2. The study should then characterise the main oilfields/basins where CO2-EOR and/or CO_2 storage was considered but not developed and assess the main issues (technical, economic, social, political and regulatory) that prevented the development of CO2-EOR operations in these oilfields/basins. Like task 1, this activity could involve both literature reviews and direct contacts with organisations concerned and could proceed via representative cases studies.

3. The study should then establish a set of criteria and a screening tool based on the key factors identified in tasks 1 and 2 that can be applied to oil fields around the world that will permit an assessment of their suitability for CO2-EOR, and associated CO_2 storage, in the future.

4. The study would then go on to identify and summarise oilfields/basins that have been identified as potential candidates for CO2-EOR storage activity in the future, when conventional oil production begins to decline and apply the criteria developed in task 3 above.

5. Using the criteria determined in task 3 and information from task 4, predict the provinces in other areas of the world most likely to become suitable for CO2-EOR and storage, and reassess the potential storage capacity for CO_2 as part of EOR operations. Reported storage capacity should if possible be restricted to quantities associated with CO2-EOR operations, rather than storage in fully depleted or abandoned oil fields. Note: Storage capacity should be reported, where possible, in line with the methodology recommended by the Carbon Leadership Sequestration Forum in their recent Phase II and III Task Force reports on storage capacity estimation, and also with regard to findings of the current IEA GHG study on storage capacity coefficients. For all quoted capacity estimates, information sources and underlying assumptions should be clearly stated.

6. The study should consider the impact of both CO_2 price and possible distances CO_2 might have to be transported, on the storage capacity estimate. Other sensitive factors to be examined include oil price versus CO_2 price and the timing of storage availability, which will depend on status both for current and future fields.

7. Finally the consultant should consider whether there is the potential to deploy CO_2 injection earlier in field development, rather than as a tertiary stage production activity and how this might impact on the global storage capacity and in what timeframe.

Current Status of CO2-EOR

CO2-EOR has been deployed extensively in the Permian Basin of West Texas and Eastern New Mexico, and a few other areas in the USA, since the mid-1980's. Today, over 100 CO2-EOR projects produce nearly 250,000 barrels per day of incremental oil from CO2-EOR operations. An extensive CO_2 pipeline network has been developed to deliver the CO_2 required by these projects, primarily from natural sources of CO_2 that are high purity and available at relatively low cost.

CO2-EOR experience in the USA shows that CO2-EOR is successful in fields that:

- Meet the technical criteria for achieving miscibility (primarily depth and oil composition);
- Have sufficient unrecovered oil after primary and secondary recovery (water flooding);
- Have access to reliable sources of CO_2 at affordable costs;
- Are operated during periods with adequate oil prices;
- Have operators with the necessary capital, technical expertise and also corporate culture to accept the inherent uncertainties associated with designing and executing CO2-EOR projects.

In the context of the above factors, it should be noted that where CO2-EOR projects have been abandoned or curtailed, the reasons have generally been economic rather than technical.

Outside of the US, development CO2-EOR has been essentially limited to a much smaller number of schemes in Canada. The main reason that CO2-EOR has not, to date, been implemented elsewhere is due, amongst other factors, to the lack of availability of suitable and affordable CO_2 sources; with the potential increased application of carbon capture and storage (CCS), this situation could change. However, this uptake is only likely to occur when regulatory and financial regimes for CO_2 storage are established. In particular, the requirements for CO2-EOR projects to be 'converted' to storage projects need to be clarified.

Methodology

The main analysis of the report consisted of four principal steps:

- Characterizing world hydrocarbon basins;
- Estimating original oil in place (OOIP);
- Estimating CO2-EOR potential;
- Estimating CO_2 storage potential.

The core data on world basins used in the analysis came from the US Geological Survey (USGS) World Petroleum Assessment (WPA). Last completed in 2000, it provides a comprehensive evaluation of cumulative production, proved reserves, and undiscovered resources in large hydrocarbon reservoirs of the world (outside the US), along with other important geologic characteristics.

The top 40 basins from the USGS assessment were selected, as ranked by volume of oil produced and booked as reserves, for further study as these contain 96% of the "known oil" identified outside the USA. These basins (Figure 1 and Table 1) are spread across every continent, but concentrated in the Middle East and Eastern Europe/Russia. Also included in the analysis were 14 US basins with large volumes of "Known Oil". In total, these 54 basins contain over 95% of global 'known oil'. Appendix D of the ARI report includes a full list of these basin locations.

Figure 1: Principal Hydrocarbon Basins

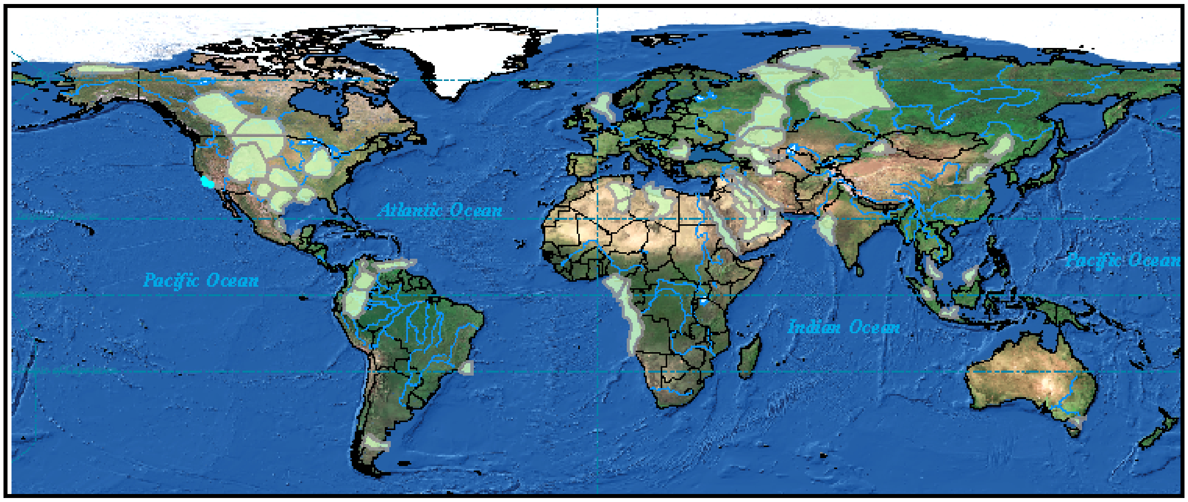


Table 1: Top 52 World Basins by Region

Region Name	Basin Count
Asia Pacific	8
Central and South America	7
Europe	2
Former Soviet Union	6
Middle East and North Africa	11
North America	17
South Asia	1
Sub-Saharan Africa and Antarctica	2

Using data from the USGS and other sources, combined with ARI's previous experience, the OOIP for each basin was estimated, and then further refined to yield the volume of OOIP that could be contacted by CO2-EOR operations

Next, the portion of OOIP in each basin that could be produced using CO2-EOR technology was estimated. Insufficient data was available on world basins to use robust reservoir modeling techniques to estimate EOR performance; instead, statistical analysis was performed on ARI performance and reservoir data (for U.S. miscible CO2-EOR reservoirs only) to develop a relationship between reservoir characteristics and EOR performance. This analysis allowed for estimation of CO2-EOR potential based on limited available data.

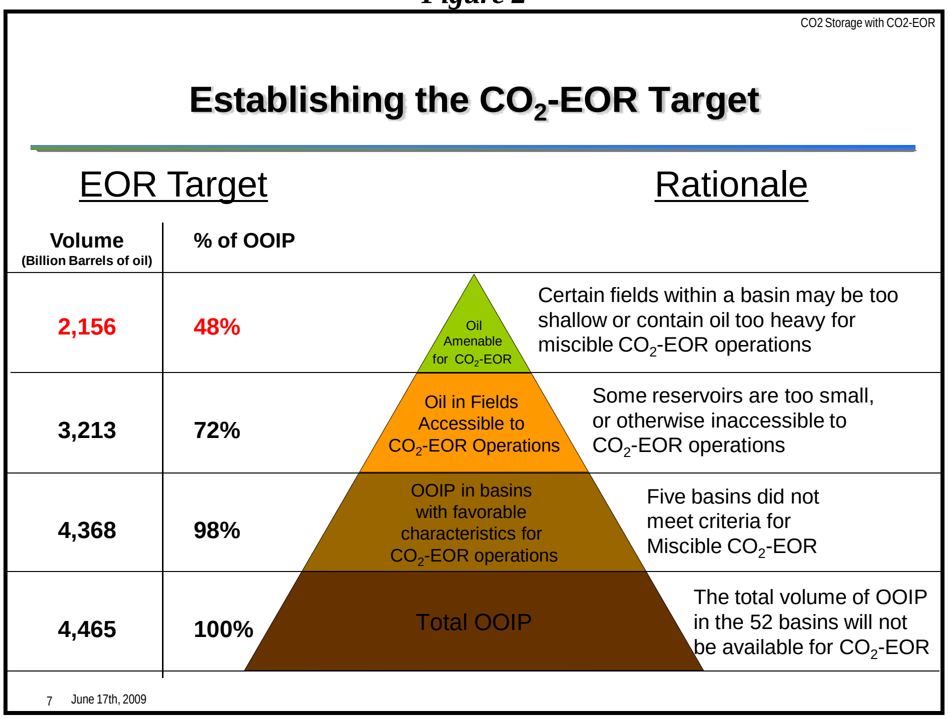
CO_2 storage capacity, assumed to be equivalent to the volume of CO_2 purchased for CO2-EOR, was also estimated based on similar regressions. The basin – scale analysis performed in the study was also tested against over 40 major oil fields and found to be robust.

Results of the Analysis

Establishment of CO2-EOR Potential

A first set of screening criteria applied by the analysis for the top 54 world basins is summarised in Figure 2 below. This initial screening eliminated 5 basins that did not meet the criteria for miscible CO2-EOR, and then catered for inaccessible, prohibitively shallow or undersized reservoirs. These criteria reduced the global OOIP that could be targeted by CO2-EOR from 4,465 to 2,156 billion barrels of oil (BBO).

Figure 2



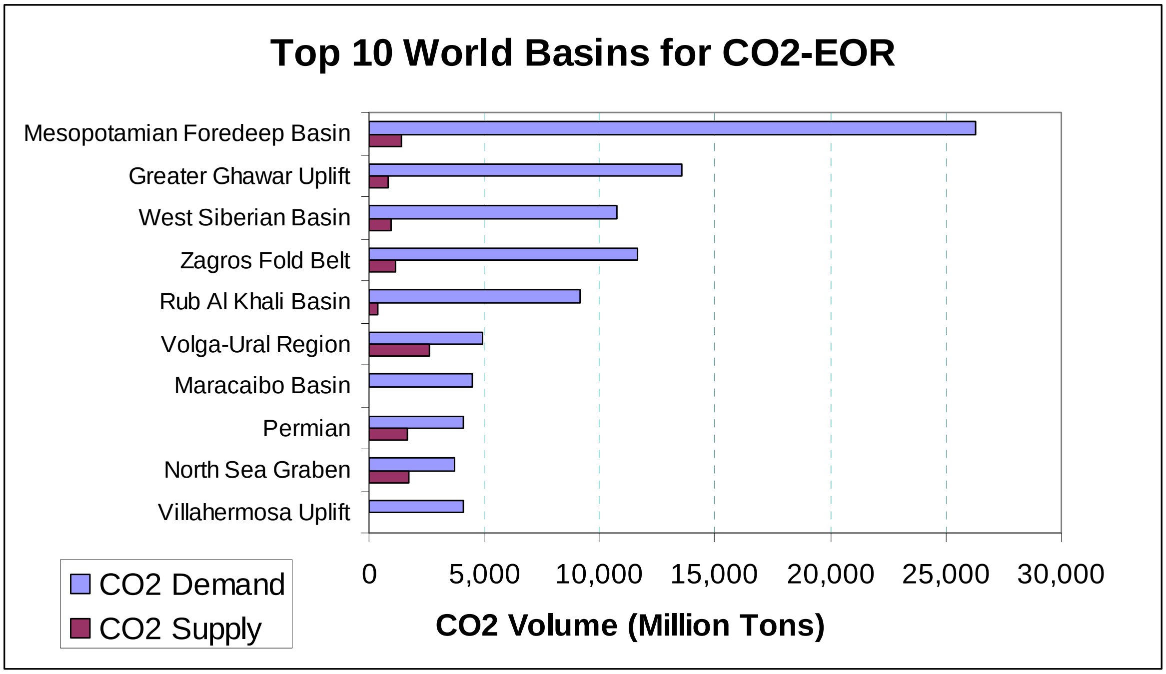
Technically Recoverable Oil from CO2-EOR

World basins contain large volumes of oil that could be incrementally produced through CO2-EOR, especially in the Middle East. In total, 451 BBO are estimated to be technically recoverable, which can then be equated using the ARI analysis to a demand for approximately 140Gt of CO_2. Almost 70% of this potential capacity is contained within the 'top' 10 basins (Figure 3). It should also be noted that application of the same analysis to the 'undiscovered' resource base, global CO_2 capacity could increase to approximately 320Gt.

However, most of the basins with high CO2-EOR potential are not near large volumes of industrial CO_2 supplies and this is also depicted in Figure 3 by comparison of the quantity of CO_2 demanded by CO2-EOR to large-volume industrial CO_2 emission sources over a 30 year period within 195 km of each these top ten basin.

ARI considered that for a realistic estimate of global CO_2 storage capacity relevant to the scale of this study, source-sink matching could be accounted for in a high-level, first order estimate by applying an 800km limit between existing industrial CO_2 sources and major fields. This reduced the global estimate of CO_2 storage potential to 65Gt. However, given the likelihood of new anthropogenic sources, for example large refineries and hydrogen plants in the Middle East, ARI contended that most of the 140Gt to 320Gt global CO_2 storage capacity associated with CO2-EOR is likely to be economic. This latter conclusion was based on an assessment that assumed a CO_2 cost (compression and transportation) to the EOR operator of US$ 15 per tone and a world oil price of US$70 per barrel.

Figure 3



Further Options to Increase Storage Capacity Associated with CO2-EOR

Several developments could increase the CO2-EOR oil recovery potential and associated CO_2 storage potential:

- Earlier application of CO2-EOR in the production life of oil fields;
- Development of improved or ‘next generation’ CO2-EOR technology;
- Targeting additional oil recovery and associated CO_2 storage potential offered by residual oil zones below traditional reservoir formations.

ARI also considered that future source-sink matching of CO2-EOR potential, on a regional or local scale, could also increase overall global potential.

Expert Review Comments

Expert comments on the draft report were received from six reviewers, representing both oil industry sponsors of the IEA GHG programme and technical consultants. These comments included many detailed technical observations; the bullet points below summarise some key observations from the reviewers which required careful consideration and where agreed, appropriate changes to the final report:

- Some of the assumptions and base data used for analyses and tabulated in the report was not clearly explained or sourced, as pointed out by several of the reviewers;
- A key part of the report methodology was the extension of knowledge from the USA and the Permian Basin in particular, to other basins around the world. The reviewers queried how differing conditions across the world, e.g. pressure, temperature, onshore vs offshore, oil composition, lithology, could limit this correlation, with onshore versus offshore considerations being particularly significant;
- Equations used in the study had been derived by regression analysis; most of the reviewers asked for some further details and justification, e.g. R2 value to give the quality of the 'fit', sensitivity analyses for critical parameters etc;
- The draft report referred to 'next generation' technologies; but several reviewers requested more details of exactly what the authors were referring to, and queried whether some of these technologies were already being employed;
- Reference was made in the draft report to CO2-EOR potential determined by previous studies, but reviewers felt there was insufficient assessment of reasons for these different results in relation to the present study. Some reviewers felt that the constraining criteria used in this study were less conservative than assumed by other authors, or suggested some form of sensitivity analyses could be employed;
- The draft report referred to the study methodology as 'theoretically sound', reviewers suggested this phrase might be better replaced with 'based on correlations';
- There was some concern that further thought needed to be given to the distinction between sandstone and carbonate reservoirs, for example separate correlations of recovery factors versus API gravity;
- CO2-Prophet software simulations formed the basis of calculations, reviewers queried whether these could be benchmarked against actual field results;
- Section 8 (early implementation of CO2-EOR in oilfield development) required completion.

On balance, the reviewers provided a positive response to the draft report, but clearly felt that additional work was desirable to sharpen the text and provide further discussion or justification of key assumptions, parameters and calculations employed. The final report included significant changes as a result of the expert comments.

Conclusions

Despite a long and successful record of CO2-EOR activity in the USA, with over 100 schemes currently in operation, implementation of this technology elsewhere in the world has been on a more limited scale and largely confined to Canada. Arguably, the main reason for the concentration of CO2-EOR in North America has been the availability of reliable, affordable and largely natural CO_2 sources. With the anticipated increase of CCS implementation around the world, this situation may change in coming decades. However, regulatory and financial mechanisms for CCS will need to be established and in particular, requirements for the 'conversion' of CO2-EOR schemes into CO_2 storage projects will need to be clear.

Using the USGS World Petroleum Assessment and additional information on US basins, screening criteria were developed and utilised by this study to convert the OOIP in the top 54 hydrocarbon basins around the world, into technically recoverable OOIP using CO2-EOR. These criteria were based on an empirical assessment of relationships between reservoir characteristics and CO2-EOR potential, and application of these statistics to other world basins. This clearly represents a major set of simplifying assumptions, made necessary by the global nature, timescale and resources of the study.

The study estimated global CO_2 storage capacity associated with CO2-EOR as 140Gt, of which over 70% is within the world's 'top ten' basins. Source-sink matching considerations could significantly reduce this potential; for example by applying an 800km limiting distance between current industrial CO_2 sources and major fields, the CO_2 storage capacity associated with CO2-EOR could be reduced to 65Gt. However, new anthropogenic sources are likely to be established in coming decades, including in the Middle East. Consequently, ARI concluded that the majority of the 140Gt storage potential could be economic, assuming a CO_2 cost of US$15 per tonne and a world oil price of US$70 per barrel. The CO_2 storage capacity associated with CO2-EOR could be further increased if CO2-EOR can be applied to 'undiscovered' oil resources and if other steps, such as the earlier deployment of CO2-EOR in oil field production, are undertaken.

Recommendations

The methodology used in this study could be applied in future to more detailed, regional studies of CO2-EOR potential and perhaps with more rigorous statistical correlation of the relationships between oil reservoir properties and CO2-EOR performance.

The results from the study could be considered in conjunction with the recent IEA GHG study of global CO_2 storage potential in depleted gas fields, to create a global perspective on total potential for storage in hydrocarbon fields. This must be considered in the context of an appropriate resource classification scheme.

CO_2 STORAGE IN DEPLETED OILFIELDS: GLOBAL APPLICATION CRITERIA FOR CARBON DIOXIDE ENHANCED OIL RECOVERY

FINAL REPORT

IEA/CON/08/155

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EXECUTIVE SUMMARY

Carbon dioxide (CO_2) capture and storage (CCS) – together with energy efficiency, renewable energy and lower carbon fuels – can lead to deep reductions in global CO_2 emissions. One option for storing the captured CO_2 emissions from use of CCS is to inject the CO_2 into oil fields, using it to produce additional oil. This option, called CO_2 enhanced oil recovery (CO_2-EOR), can provide a "bridge" to a low-carbon energy future. Revenues from CO_2 sales to the EOR industry can offset some of the costs of CO_2 capture, while early implementation of CO_2-EOR can help build transportation and storage infrastructure for the future.

To date, CO_2-EOR has only occurred in a few regions of the U.S. and Canada. Moreover, the large CO_2-EOR projects, except for the "poster child" CO_2-EOR project at Weyburn in Saskatchewan, Canada, do not have CO_2 storage as a co-objective. To better understand the potential and constraints offered by integrated CO_2-EOR and CO_2 storage, this study addressed three questions:

- How large is the world-wide oil resource potential and associated CO_2 storage capacity offered by CO_2-EOR, today and in the future?
- What factors that have facilitated or hindered the wide-scale deployment of CO_2-EOR?
- What set of actions could significantly increase the integrated application of CO_2-EOR and CO_2 storage?

To provide thoughtful answers to these questions, Advanced Resources undertook the following work:

- We reviewed the major CO_2-EOR operations underway around the world to better understand the factors that facilitated or hindered their implementation.
- We built a database of the largest 54 oil basins of the world (that account for approximately 95% of the world's estimated ultimately recoverable (EUR) oil potential*), including major oil fields in these basins.
- We developed a high-level, first-order assessment of the CO_2-EOR oil recovery and CO_2 storage capacity potential in these basins, using the U.S. experience as analogue. We

* Estimated ultimately recoverable (EUR) resource is the sum of cumulative production and booked reserves. In this report, EUR is synonymous with "known oil".

then tested our basin-level estimates with detailed reservoir modeling of 47 large oilfields in 6 of these basins.

- We examined ways that more of the inherent CO_2 storage capacity offered by mature oil fields could be increased, including deploying CO_2-EOR earlier in the life of an oil field, and by applying "next-generation" integrated CO_2-EOR and CO_2 storage technology.

Based on this work, four key findings emerged, as summarized below.

1. CO_2-EOR is Not a New Phenomena: Commercial-Scale, Profitable CO_2-EOR Has Been Underway for Over 30 Years in Geologically Favorable Oil Fields with Access to Affordable CO_2.

CO_2-EOR has been deployed extensively in the Permian Basin of West Texas and Eastern New Mexico, and a few other areas in the U.S., since the mid-1980s. Today, over 100 CO_2-EOR projects in the U.S. produce nearly 250,000 barrels per day of incremental oil. An extensive CO_2 pipeline network has been developed to deliver the CO_2 required by these projects, often over long distances, primarily from natural sources of CO_2 that are high purity and available at sufficiently low cost to allow for profitable CO_2-EOR activity.

The CO_2-EOR experience in the U.S. and elsewhere shows that CO_2-EOR is successful in oil fields that:

- Meet the technical criteria for achieving miscibility (primarily depth and oil composition)
- Have sufficient unrecovered oil after primary and secondary recovery (water flooding)
- Have access to reliable sources of CO_2 at affordable costs.

In addition, two other factors have contributed to successful deployment of CO_2-EOR:

- Operator technical knowledge and commercial interest in pursuing CO_2-EOR technologies
- State and federal financial incentives that promote implementation of CO_2-EOR projects.

2. CO_2-EOR Offers a Large Available Option to Store CO2: The 54 Largest Oil Basins of the World Have the Potential to Produce 470 to 1,070 Billion Barrels of Additional Oil, and Store 140 to 320 Billion Metric Tons of CO_2.

The largest 54 world oil basins have an estimated 4,622 billion barrels of original oil in place (OOIP) in already discovered oil fields. Of this original endowment, these basins have produced 687 billion barrels (as of 2000) and report 845 billion barrels of proved reserves, giving an estimated ultimate recovery of 1,532 billion barrels, for an overall recovery efficiency of 33% (1,532/4,622). This leaves behind a remaining oil target of 3,090 billion barrels for CO_2-EOR.

Additionally, these 54 basins contain an estimated 8,700 billion barrels of undiscovered oil in-place (as of the year 2000), with 2,900 billion barrels of this undiscovered oil resource estimated as recoverable. Thus, an additional 5,800 billion barrels could be a future target for CO_2-EOR. Incorporation of more recent data would significantly increase both the CO_2-EOR and CO_2 storage potential set forth in our report.

- After screening these 54 basins for CO_2-EOR potential and deleting the basins and oil fields that are not technically favorable for miscible CO_2-EOR, we estimate that 470 billion barrels could be recovered from fields favorable for miscible CO_2-EOR, and could facilitate the storage of 140 billion metric tons (Gt) of CO_2.
- Moreover, if CO_2-EOR technology could also be successfully applied to the undiscovered resource base, the world-wide application of CO_2-EOR could recover 1,070 billion barrels of oil, with associated CO_2 storage of 320 Gt.

3. The Lack of Sufficient Volumes of Close-by CO_2 Places Limits on the Portion of this Oil Resource and CO_2 Storage Capacity Can Be Accessed Today.

Currently, approximately half (65 Gt) of the CO_2 demand for CO_2-EOR operations in already discovered fields in the world basins can be met by large, identified anthropogenic CO_2 sources within distances of 800 kilometers (500 miles). Nonetheless, these CO_2 supplies would support the production of 225 billion barrels of incremental oil through CO_2-EOR operations.

However, new anthropogenic sources, such as the large refineries and hydrogen plants being constructed in the Middle East, the development of high CO_2 content natural gas fields in the Far East, the aggregation of smaller CO_2 sources, and the construction of longer, larger capacity, pipelines could significantly close this gap. Our analyses show that by using U.S. $15 per metric ton as the cost for CO_2 (to cover compression and transportation costs), the vast majority of the technical CO_2-EOR potential of 470 to 1,070 billion barrels would be economic to pursue, assuming a $70/barrel world oil price.

4. Numerous Options and Actions Could Increase CO_2-EOR-Based Oil Recovery and Associated CO_2 Storage Capacity.

The primary options for improving the CO_2 storage and oil recovery potential of CO_2-EOR include: (1) early application of CO_2-EOR in the life of an oil field; (2) development and use of “next-generation” CO_2-EOR technology; (3) undertaking more detailed field level assessments of CO_2-EOR potential, including matching of CO_2 sources to high potential oil fields; and (4) addressing the additional CO_2 storage capacity and oil recovery potential offered by residual oil zones below the traditional reservoir formation.

* * * * *

Please note that our assessment of CO_2 storage capacity with CO_2-EOR is merely a "snapshot in time," conducted at a very high level of resource aggregation, using relatively limited data in the public domain. A more robust understanding of this high value option could be gained by:

- Conducting more detailed basin and oil field-specific geologic studies of high potential areas for CO_2-EOR
- Compiling more high-resolution data on CO_2 sources, particularly high quality industrial sources
- Forming partnerships with national stake-holder institutions to further the identification of high-potential CO_2-EOR sites attractive for CO_2 storage.

1. BACKGROUND AND INTRODUCTION

Carbon dioxide (CO_2) capture and storage (CCS); together with the pursuit of renewable energy, use of lower carbon fuels, and accelerated use of nuclear power; represents one critical part of international efforts to achieve deep reductions in global CO_2 emissions, while continuing to allow for the utilization of coal for power generation. In the absence of new policies or supply constraints, energy sector CO_2 emissions are forecast to increase by 130% by 2050 as a result of increased fossil fuel usage.[1] Other than increased efficiency, the only option available to mitigate greenhouse gas (GHG) emissions from large-scale fossil fuel usage is CCS.

Three main types of geological storage options are generally considered for such CCS purposes -- storage in deep saline formations, storage in depleted oil and gas fields, and storage in unmineable coal seams. Of these, storage in deep saline formations holds possibly the greatest potential in terms of overall quantities of CO_2 that could be stored, if this potential can be realized. However, relative to previously exploited oil and gas fields that have benefited from extensive exploration, development, and previous geological investigation, much less is known about the geological characteristics and storage potential of deep saline formations.

Experience from the natural gas storage industry indicates storage opportunities in depleted hydrocarbon fields can have much lower development costs than in deep saline formations because of the generally greater availability of geological data from exploration and production operations, as well as the accessibility of existing oil field infrastructure.[2]

Enhanced oil recovery (EOR) is a generic term for a wide variety of techniques for increasing the amount of crude oil that can be extracted from an oil field. Gas injection (primarily CO_2) is presently the most-commonly used approach to enhanced recovery. With this process, CO_2 is injected into the oil-bearing stratum under high pressure. Oil displacement by CO_2 injection relies on the phase behavior of the mixtures of that gas and the crude, which are strongly dependent on reservoir temperature, pressure and crude oil composition. There are two main types of CO_2-EOR processes:

- *Miscible CO_2-EOR* is a multiple contact process involving interactions between the injected CO_2 and the reservoir's oil. During this multiple contact process, CO_2 vaporizes the lighter oil fractions into the injected CO_2 phase and CO_2 condenses into the reservoir's oil phase. This leads to two reservoir fluids that become miscible (mixing in all parts), with favorable properties of low viscosity, enhanced mobility, and low interfacial tension. The primary objective of miscible CO_2-EOR is to remobilize and dramatically reduce the residual oil saturation in the reservoir's pore space after water flooding. Figure 1 provides a one-dimensional schematic showing the dynamics of the miscible CO_2-EOR process.

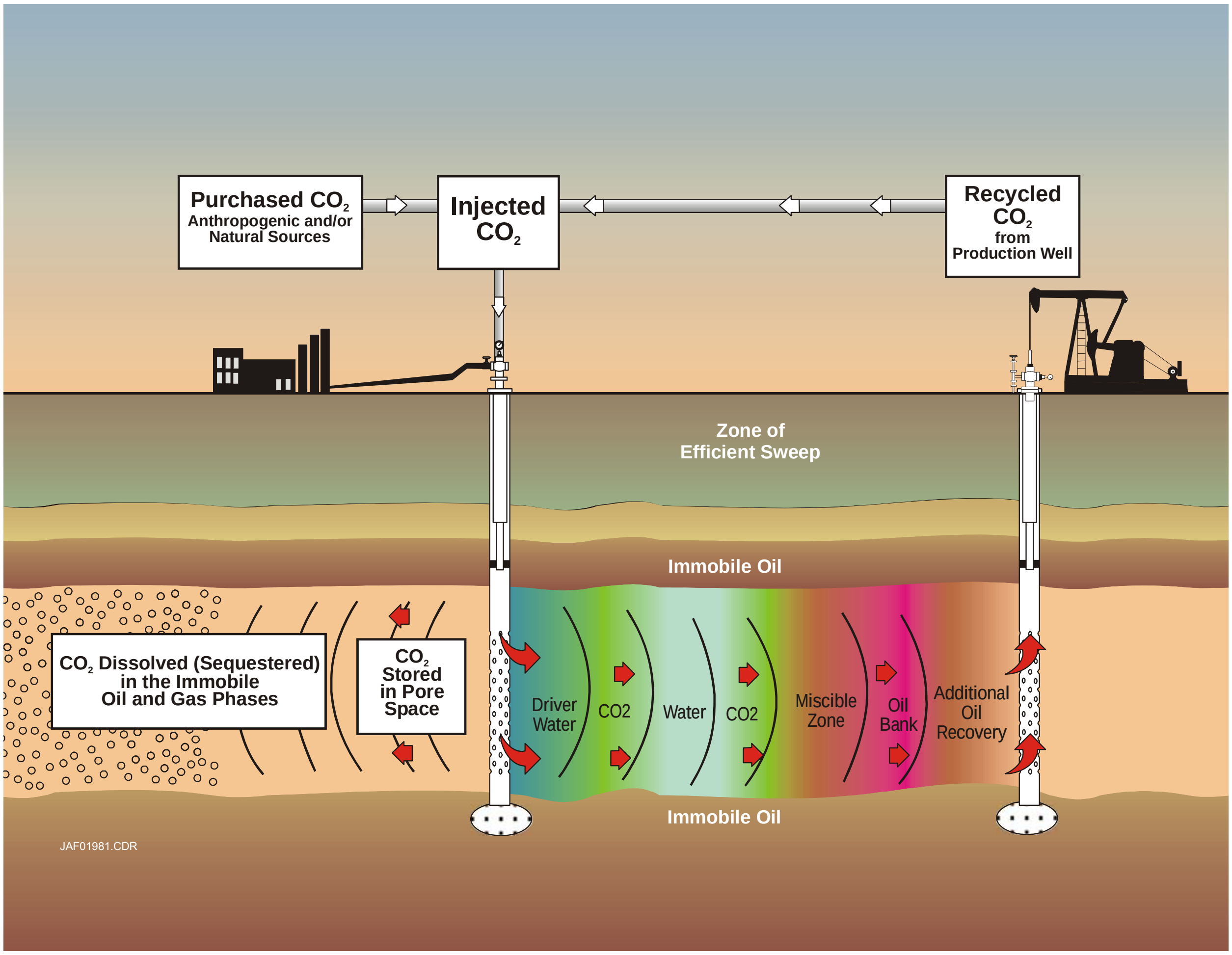
- <u>*Immiscible CO_2-EOR*</u> occurs when insufficient reservoir pressure is available or the reservoir's oil composition is less favorable (heavier). The main mechanisms involved in immiscible CO_2 flooding are: (1) oil phase swelling, as the oil becomes saturated with CO_2; (2) viscosity reduction of the swollen oil and CO_2 mixture; (3) extraction of lighter hydrocarbon into the CO_2 phase; and, (4) fluid drive plus pressure. This combination of mechanisms enables a portion of the reservoir's remaining oil to be mobilized and produced.

Pursuing CCS with enhanced oil recovery using CO_2 injection (CO_2-EOR) offers significant potential to produce more oil from developed fields, while in the process allowing for large quantities of CO_2 to be permanently stored underground rather than emitted to the atmosphere. In previous work, IEA GHG estimated worldwide CO_2 storage capacity *just in oil fields amenable to CO_2-EOR* to be 120 Gt.[3] CO_2 storage in oil fields would generally be smaller in scale relative to deep saline formations, but the potential commercial benefits of utilizing CO_2 for EOR could provide an immediate economic value for implementation of such projects.

Moreover, CO_2-EOR can provide a "bridge" to a low-carbon energy future, characterized, in part, by widespread market penetration of CCS technology. Revenue from CO_2 sales can offset some costs of CO_2 capture from coal-fired power plants. In addition, revenues from incremental oil production from CO_2-EOR operations could help offset some of the costs associated with the development of CO_2 transportation and storage. Finally, early implementation of CCS will drive costs down through "learning by doing."

Nonetheless, wide-scale development of CO_2-EOR has not occurred except for a few regions of the U.S. Furthermore, the majority of the new CO_2-EOR projects that have been pursued have not been designed with CO_2 storage as a co-objective. For CCS projects to be rapidly deployed worldwide, it is imperative to understand why this early opportunity for CO_2 storage as part of CO_2-EOR projects has not been pursued, when and under what conditions might this opportunity be pursed more aggressively in the future, and if it does, what could be the potential for CO_2 storage capacity associated with oil fields conducive to CO_2-EOR.

Figure 1. One-Dimensional Schematic Showing the Miscible CO_2-EOR Process



2. OBJECTIVES AND OVERVIEW OF APPROACH

The success of CO_2-EOR in some regions of the world, but not in others, can be attributable to a set of technical, economic, regulatory, political and social factors. The first objective of this study was to understand the main contributing factors in those areas and circumstances where the implementation of CO_2-EOR has been seriously investigated, whether or not it was eventually deployed. Once these main factors were identified, and their influence on CO_2-EOR deployment understood, the second objective was to identify and characterize those regions of the world that are good candidates for CO_2-EOR operations – and CO_2 storage -- either now or in the future.

Then, given this characterization of potential CO_2-EOR opportunities, the third objective was to develop a revised estimate of global storage capacity in depleted oil fields/basins that are good candidates for the application of CO_2-EOR.

Given these objectives, the overall approach pursued for this project is summarized as follows:

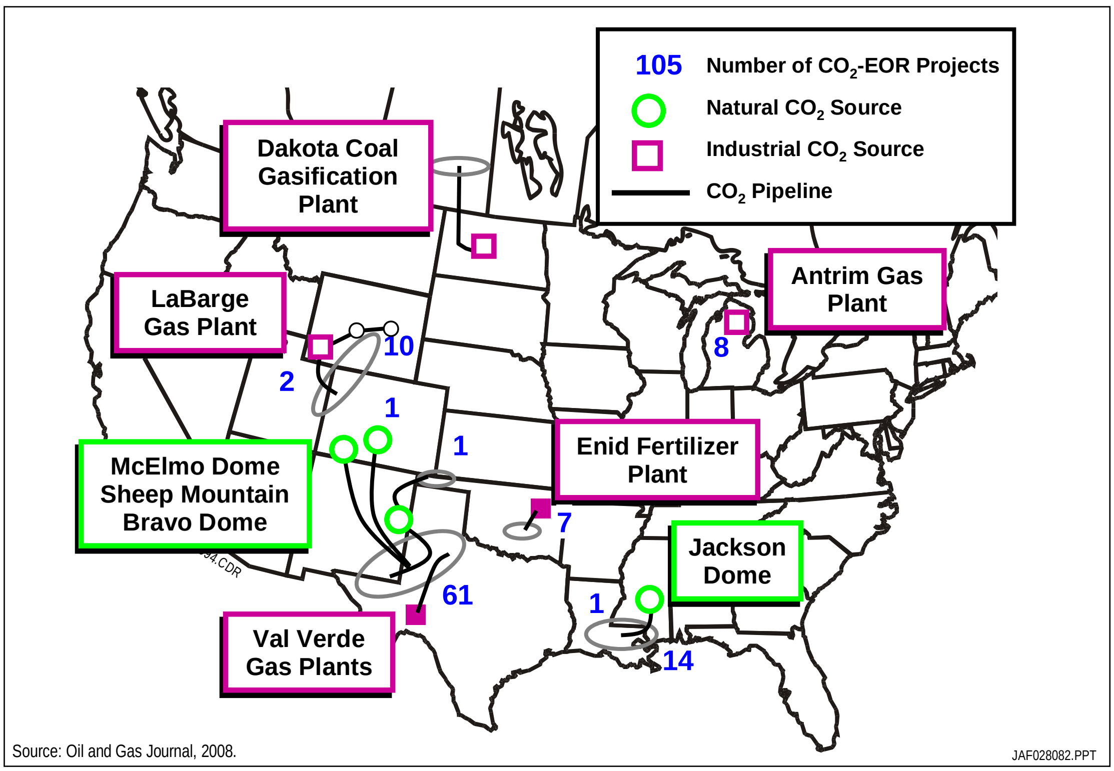
- Identify and characterize the main regions of the world currently supporting or planning CO_2-EOR operations and assess the main drivers that stimulated these operations. Likewise, characterize the main areas where CO_2-EOR was considered but not developed, and assess the main issues that prevented the development.
- Establish a set of screening criteria that can be applied to assess oil field/basin suitability for future CO_2-EOR potential and associated CO_2 storage.
- Identify and characterize the world oil basins that could be potential candidates for CO_2-EOR and associated CO_2 storage activity in the future, applying these criteria.
- Develop a high level, first order estimate of the potential storage capacity for CO_2 as part of EOR operations in these basins, based on the amount of CO_2 required for CO_2-EOR operations.
- Evaluate the potential impact of CO_2 price and transportation costs on the economics of CO_2-EOR and associated storage.
- Evaluate the potential to deploy CO_2 injection earlier in field development, rather than at a tertiary stage of production activity, in terms of oil recovery potential.

3. CRITERIA TO ASSESS SUITABILITY FOR CO_2-EOR

Key Factors of CO_2 Flooding Success – Review and Retrospective

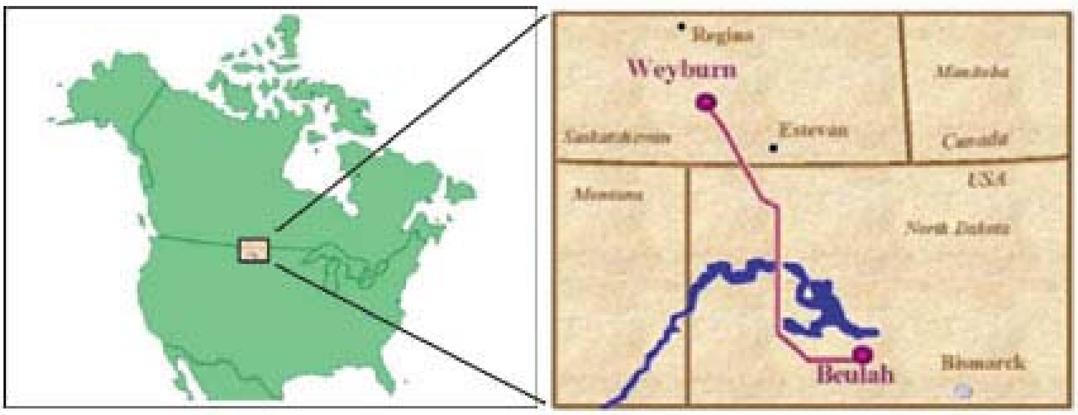
CO_2-EOR has been deployed extensively in the Permian Basin of West Texas and Eastern New Mexico, and a few other areas in the U.S., since the mid-1980s. Today, over 100 CO_2-EOR projects in the U.S. produce nearly 250,000 barrels per day of incremental oil (Figure 2). Of these, the vast majority -- producing 240,000 barrels per day -- are miscible CO_2-EOR projects. Twelve years ago; production from CO_2-EOR was only 170,000 barrels per day from 60 projects.[4] An extensive CO_2 pipeline network has been developed to meet the CO_2 requirements of these projects, primarily obtained from natural sources of CO_2 that are of high purity and are readily available at relatively low cost.

Figure 2. U.S. CO_2-EOR Activity



Despite the many CO_2-EOR projects in the U.S., activity elsewhere in the world is limited. Seven CO_2 miscible projects and one acid gas miscible project are underway in Canada. The "poster child" of a combined CO_2-EOR and geologic sequestration project is EnCana's Weyburn CO_2 flood in Canada (Figure 3) where oil production from CO_2-EOR continues to increase. The Weyburn operation covers 70 square miles and is one of the largest medium-sour crude oil reservoirs in Canada, containing approximately 1.4 billion barrels of original oil in place (OOIP). The Weyburn unit was placed on waterflood injection in 1964, and in 2000, the field began operating on CO_2 miscible flood. The CO_2 flood has been expanded to over 60% of the unit. The implementation of the CO_2-EOR project, along with the continued infill well development program, has resulted in a 65% increase in oil production. EnCana buys anthropogenic CO_2 from the Dakota Gasification Synfuels plant in Beulah, North Dakota.[5]

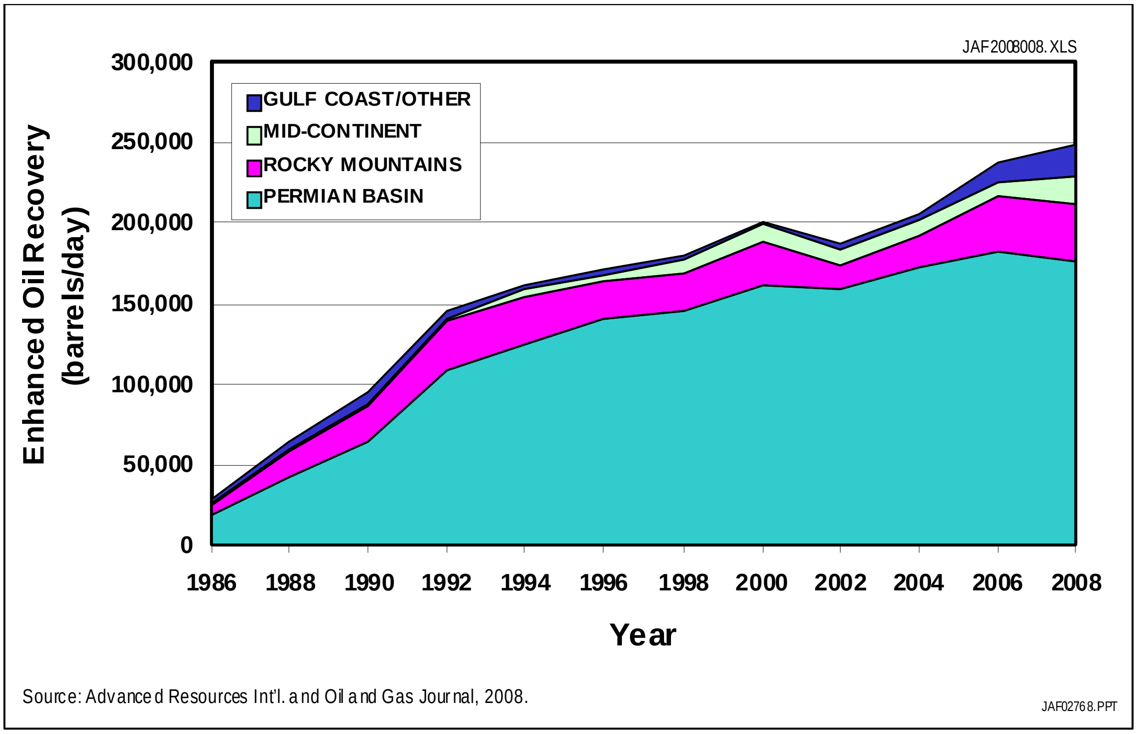
Figure 3. The "Poster Child" – Weyburn Enhanced Oil Recovery Project



A more detailed review of previous and current CO_2-EOR activity and production, along with planned CO_2-EOR projects, including those also considering geologic storage after CO_2-EOR operations have run their course, is provided in Appendix A.

The steady growth of CO_2 flooding in the Permian Basin, as shown in Figure 4, as wells as in other areas, offer a case histories for possible extrapolation to other oil bearing regions. A review of the history of CO_2-EOR shows that it is generally successful in fields that meet the technical criteria for achieving miscibility (defined primarily in terms of reservoir depth and oil viscosity), that have a relatively large volume of unrecovered oil after primary and secondary recovery (water flooding), and where there is a good source of sufficient, predictable, sustainable volumes of pure CO_2 supplies at affordable costs. Over time, other factors that contribute to success are operator knowledge, comfort and willingness to pursue advanced CO_2-EOR technologies; the willingness and ability of the applicable regulatory regime to permit CO_2-EOR projects, and the availability of government financial incentives to promote CO_2-EOR.

Figure 4. Growth of CO_2-EOR Production in the U.S. (1986-2008)



Most past CO_2 floods classified as "failures" have generally been abandoned for economic, not technical, reasons. If the economics of CO_2-EOR change due to the value the technology provides as a CO_2 storage enabler, the expansion of CO_2-EOR operations could be dramatic.

A more detailed review of the key factors traditionally contributing to CO_2-EOR success is provided in Appendix B.

Characteristics of Reservoirs/Basins Technically Amenable To CO_2-EOR

Most active CO_2-EOR projects have been conducted in reservoirs below about 750 meters (2,500 feet) in depth and with light oils with gravities above 25^o API. Reservoirs with a wide range of porosities and permeabilities have been successfully flooded.

A variety of reservoir screening criteria for CO_2-EOR have been published over the years, but in general these criteria have been reasonably consistent.[6] In its basin studies in the U.S., Advanced Resources utilized five prominent screening criteria to identify favorable reservoirs in the U.S.: reservoir depth, oil gravity, reservoir pressure, reservoir temperature, and oil composition. These values were used to establish the minimum miscibility pressure (MMP) for conducting miscible CO_2-EOR and for selecting reservoirs that would be amenable to this oil recovery process. Reservoirs not meeting the MMP standard were considered for immiscible CO_2-EOR.

Specifically, the preliminary screening steps involved selecting the deeper oil reservoirs that had sufficiently high oil gravity. A minimum reservoir depth of 3,000 feet at the mid-point of the reservoir was used to ensure the reservoir could accommodate high pressure CO_2 injection. A minimum oil gravity value of 17.5 degrees API was used to ensure the reservoir's oil had sufficient mobility without requiring thermal injection. These criteria are less constraining than most of the criteria reported in the referenced studies. We chose to broaden them under the assumption that operators will be incentivized by future policies designed to limit CO_2 emissions, and perhaps attempt CO_2-EOR operations in reservoirs that were traditionally outside the range of previously-reported criteria.

In this study, reservoir depth and oil gravity were the two key parameters by which world basins are analyzed for CO_2-EOR potential. These were chosen because other data that could be useful for screening amenability to CO_2-EOR (e.g., temperature, pressure, oil composition and/or viscosity, oil saturation, reservoir permeability and porosity) were not available in the public data sets that served as the basis for this study. However, two of the key parameters – reservoir temperature and pressure – can be represented by their relationship to reservoir depth. Another important factor, oil composition, is represented in this study by its relationship to oil gravity.

Nevertheless, it should be noted that, while these technical screening criteria for CO_2-EOR and/or subsequent geologic storage may be applied at the basin level, when actually determining fields and sites within fields for implementing CO_2-EOR and/or subsequent geologic storage projects, additional disaggregated screening will also be necessary. When applied to evaluating currently producing fields or reservoirs, or areas within these fields and reservoirs, these criteria include the previous response to water flooding, and the condition of the existing infrastructure (wells, surface facilities, etc., especially the integrity of the existing wellbores). Factors influencing the relative diversity of geologic conditions, such as the site-specific relative thickness, depth, porosity, permeability, current reservoir temperature and pressure, and oil and water saturation in the target zone, can aid in the selection of the actual locations where CO_2 injection/storage wells should be drilled.

Adequate Price of Oil

CO_2-EOR projects have been successfully pursued when oil prices were as low as $15 per barrel. Nonetheless, as oil prices increase, the economic viability of CO_2-EOR improves. The relationship between the price of oil, the cost of CO_2, and the volume of economically recoverable volumes of oil through the application of CO_2-EOR are discussed later in this report. However, the minimum price necessary for a CO_2-EOR project to be economically viable is very site and situation-specific. Detailed reservoir studies, project plans, and economic assessments are required to determine the economic viability of a specific CO_2-EOR project.

Availability of Reliable, Affordable CO_2

CO_2 costs are equally as important a determinant of project success as oil price. Of particular importance is the relationship between the cost of CO_2 and the price of oil. CO_2 pricing within the Permian Basin can perhaps be considered as the standard for pricing for CO_2-EOR elsewhere. When source fields and associated pipelines were completed in the early 1980s, CO_2 was priced at $19 to $24/tonne. (All costs and prices reported in this study are in current U.S. dollars unless otherwise stated.) At the time, oil price expectations were relatively optimistic. However, this optimism was quickly tempered by the 1986 oil price crash, resulting in much lower CO_2 prices. Due to CO_2 market supply deficiencies in the Permian Basin, index (base) prices have climbed, escalators start at higher levels, and CO_2 prices are not capped, as they were in the past.

Should oil prices be sustained at high levels, new contract terms may emerge. On the other hand, under a market where CO_2 emission reductions have value, “gas-on-gas” competition for new CO_2 sources entering the market may put downward pressure on CO_2 prices. In fact, some may be willing to provide potential CO_2 supplies to CO_2-EOR projects “at cost,”[7] perhaps receiving as compensation a portion of the value of incremental oil production, or the value of any emission reduction credits.

In addition to affordable pricing of CO_2, CO_2-EOR projects’ success also depends upon sufficient and consistent CO_2 supplies. CO_2-EOR projects require a relatively constant supply of CO_2 to maintain optimum reservoir operations. If controls on industrial CO_2 emissions are instituted, then, in many areas of the world, the volumes of CO_2 available for CO_2-EOR projects can be larger than the volumes required by potential CO_2 projects.

Large Remaining Unrecovered Oil Resource -- Best Target for CO_2-EOR

CO_2-EOR tends to be successful in fields that meet the technical criteria for achieving miscibility and that have a relatively large volume of unrecovered oil after primary and secondary recovery (water flooding). Large projects with many patterns are more forgiving. For this reason and others (notably the need for large oil recoveries to justify the infrastructure investments), most CO_2 flooding projects are correspondingly large in size.

The Advanced Resources' series of ten "basin studies" were the first to comprehensively address CO_2 storage capacity from combining CO_2 storage and CO_2-EOR. These ten "basin studies" covered 22 of the oil producing states in the U.S., plus offshore Louisiana, and focused on oil reservoirs larger than 50 million barrels of original oil in place (OOIP). These oil reservoirs in the ten basins considered accounted for two-thirds of U.S. oil production.[8]

In this study, as will be described in more detail below, focus will be given to those oil basins in the world that have the estimated largest volumes of remaining unrecovered oil resources in fields that have already been discovered.

Availability of Government Financial Incentives to Promote CO_2-EOR

Today, investment in CCS will likely only occur if there are suitable financial incentives and/or regulatory mandates. In the current fiscal and regulatory environment, commercial fossil-fuel power and industrial plants are unlikely to capture and store their CO_2 emissions, as CCS reduces efficiency, adds costs, and therefore lowers energy output.[9] Even in places like the European Union (EU), where some constraints on GHG emissions are in place, the benefits of reducing emissions are not yet sufficient to outweigh the costs of CCS.

These barriers can be partially overcome by government support in the form of tax credits, loan guarantees and other incentives. CO_2-EOR can provide an attractive, near-term opportunity to reduce emissions, in that incremental oil production can be used to help offset at least a portion of the increased costs of installing CCS technology. CO_2-EOR is perhaps the only option today where sale of captured CO_2 emissions can generate revenues in the absence of a GHG emissions reduction credit market.[10]

Attractive areas for investment in the deployment of CCS and/or CO_2-EOR with CO_2 storage will be those areas that have in place financial incentives to stimulate investment. The most appropriate package of such measures may vary country by country. Of particular concern are the financing and risk-management required for the critical first round of projects. For rapid implementation, a policy framework that combines near-term technology financing with carbon constraints and/or CCS mandates will most likely provide the largest and nearest term benefits. Financing of the necessary CO_2 transport infrastructure may also be necessary. In addition, governments may need to subsidize or take ownership of CO_2 transport pipelines in some manner.[11]

In addition to financial incentives, considerable levels of direct government investment in technology demonstration will also likely be necessary to stimulate deployment in the near term. A recent IEA analysis estimates that between $30 and $50 billion will need to be invested to achieve the stated G8 goal of launching 20 full-scale CCS demonstration projects in the next few years.[12] Many believe that the normal pace of government spending on R&D and technology demonstration may be too slow to ensure rapid deployment and achieve sufficient emission reductions early enough to impact the global climate before the middle of this millennium. They believe that larger levels of investment than are currently being provided will be necessary, despite the fact that a large number of projects are being pursued.[13] Financial incentives will likely be required to spur investment into CO_2 transportation infrastructure as well.

One option that has been proposed for accelerating deployment of geologic storage in the U.S. involves a federal program that literally pays the incremental costs of installing and operating CCS systems at a defined number of the first such power plants.[14] The costs could be borne by a fee on electricity generation or provided to a "CCS Trust Fund" charged with evaluating and funding appropriate projects. Such a program could be self-financing, have clearly established objectives, avoid the annual federal appropriations process to ensure reliability and predictability of funding, and have a definitive point of completion

In order to facilitate investment in the scaling up of infrastructure necessary to support large scale deployment of geologic storage technologies, governments could also help stimulate investment in going after the "low hanging fruit" – which generally would involve combining CO_2 emissions recovered from relatively pure source streams (such as from H_2 plants, fertilizer plants, and natural gas processing facilities) with viable applications for CO_2-EOR in depleted oil fields. This has been the initial focus of some IEA GHG activities.[15,16]

In May 2009, the U.S. Department of Energy (DOE) took one step in this direction by announcing that $2.4 billion from the American Recovery and Reinvestment Act, one of the major aspects of U.S. economic stimulus activities, will be used to expand and accelerate the commercial deployment of CCS technology.[17]

Operator Knowledge of and Willingness to Pursue CO_2-EOR

Many companies can set unreasonable expectations for a CO_2-EOR project and, when the project underperforms or oil prices drop, management can make a decision to cut losses and abandon CO_2 injection. These companies probably have cultures that are not well-suited for dealing with the uncertainties associated with CO_2-EOR projects. While difficult to objectively evaluate, categorizing the relative attractiveness of alternative oil basins for CO_2-EOR and possible subsequent geologic storage in this study will attempt to consider current local operator knowledge of and willingness to pursue the use of CO_2-EOR technologies. This subject is addressed in more detail in Appendix B.

Policy and Regulatory Regimes for CO_2-EOR and Geologic Storage

Understanding the factors contributing to successful CO_2-EOR projects may be a necessary but non-sufficient condition for the ultimate "conversion" of a CO_2-EOR project to a CO_2 storage project. Numerous regulatory and liability issues and uncertainties are currently associated with CCS that are hindering wide-scale deployment. These uncertainties are also hindering the pursuit of CO_2-EOR, particularly because of the lack of regulatory clarity regarding the process and requirements associated with the transition from EOR operations to permanent geologic storage.[18,19] Determining the viability of eventually "converting" a CO_2-EOR project to a geologic storage project will likely depend on yet additional factors. A variety of organizations such as the IEA,[20] U.S. DOE,[21] Carbon Sequestration Leadership Forum (CSLF),[22] World Resources Institute,[23] U.S. Congressional Research Service,[24] and others have identified the critical factors likely to influence the implementation of CCS projects.

The major barriers to CCS deployment can be summarized as follows:

- In most areas of the world, no current market drivers and/or requirements are currently in place to limit GHG emissions, or alternatively, there is currently no value placed on sequestered GHG emissions.
- Due to CCS's high costs, it is not commercially competitive in today's power generation market.
- CCS has not yet been fully demonstrated in large scale applications, which are critical to establishing its technical, economic and environmental viability to interested stakeholders (potential developers, financers, regulators, and the general public).

- CCS is yet to be defined by appropriate national and international organizations as a certifiable means for reducing emissions of GHGs. This includes both establishing the extent to which geologic storage itself is acceptable, along with the extent to which CO_2-EOR is an acceptable means of geologic storage. This issue is currently unresolved under international mechanisms, as well as regional emissions trading regimes.
- Numerous regulatory and liability issues and uncertainties are currently associated with CCS that are hindering wide-scale deployment. Critical to large scale deployment will be clear establishment of regulatory regimes and standards for such projects.

While little or no existing policy or statutory authority specific to the operational aspects of geologic storage exists in most countries today, a number of countries have existing policies and statutes that may apply to related activities that could be extended to geologic storage. IEA has launched a CCS Regulators Network to help regulators around the world share case studies, challenges and solutions as authorities attempt to develop workable, effective and harmonized regulatory frameworks.[25] Key will be the ability to evolve from the current legal framework for CO_2-EOR (that is largely adequate in places like the United States and Canada to address many, if not most, of the issues that need to be addressed for CCS) in a relatively seamless transition to a framework for geologic storage. That is, it will be critical to minimize unnecessary barriers for a framework for CO_2 storage that is an incidental result of oil production operations to a framework addressing the incremental injection of CO_2 intended solely for permanent storage.

The key issue with determining which, if any, existing regulatory mechanism(s) could be adapted for sequestration could fundamentally boil down to the classification of the injected CO_2. Specifically, this relates to whether the CO_2 is injected for "storage," as a "commodity;" or whether the CO_2 is considered a "waste" ultimately destined for "disposal." Without some legislative intervention, the process for establishing jurisdictional authority and the regulatory requirements for geologic storage could involve a long process of resolving jurisdictional issues, defining the potential applicability of various statutes, understanding the existing judicial precedence, and/or accounting for the existing capability of regulatory bodies to address concerns uniquely associated with geologic storage. Such a process could detrimentally delay wide-scale deployment of geologic storage, and, by implication, CO_2-EOR.

Governments are making important progress in developing suitable geologic storage policy and regulatory frameworks.[26] A number of efforts are underway to develop guidelines for regulating the performance of geologic storage. Some of these efforts include those by the U.S. Environmental Protection Agency,[27] Interstate Oil and Gas Compact Commission (in the U.S.), [28] the World Resources Institute,[29] and the Australia Ministerial Council on Mineral & Petroleum Resources.[30]

Critical to the rapid deployment of geologic storage will be statutes that allow projects to proceed in the absence of established final regulatory frameworks. In fact, the information necessary to provide the basis for the requirements associated with these final frameworks will need to come from these initial storage projects. Therefore, to proceed expeditiously, the process for permitting geologic storage will need to take place within an evolving policy and regulatory environment. Consequently, the regulatory framework appropriate today is likely to change over time. This could very likely require a staged process for regulatory development. Moreover, to facilitate early demonstration projects, those governments that start by adapting existing regulatory frameworks could be those most attractive to early projects, as long as they maintain an eye toward flexibility, as regulations will inevitably need to be adapted based on experience over time.

Deployment of geologic storage will require extensive coordination between various local, national and international authorities claiming some jurisdiction. Importantly, regulators at all levels will need adequate resources to increase their capacity to manage the growing area of geologic storage regulation and project implementation. This will also apply to pipeline regulations. Governments in many countries will need to clarify the property rights associated with CO_2 storage, including access rights and ownership of storage reservoirs.

Finally, and perhaps most importantly, within any established framework for regulating emissions reductions (e.g., the European Emissions Trading Scheme or the Regional Greenhouse Gas Initiative (RGGI) in the U.S. Northeast), in order for geologic storage to achieve wide-scale deployment, it must be established as a certifiable means for reducing GHG emissions. Without such certification, geologic storage projects may not be eligible to receive carbon credits. In addition, CO_2-EOR must be established as a certifiable method for geologic storage. This is essential to ensure that CO_2-EOR projects are pursued such that the storage of CO_2 becomes an important consideration after incremental oil production has run its course. Otherwise, if CO_2-EOR is pursued, operators would look to minimize the volume of CO_2 left in the reservoir, recycling it for use in potential other projects, rather than attempting to permanently store the CO_2 in the reservoir.

In this regard, standards, guidelines, etc. need to be established to provide consistency and market acceptability about the reality of the reductions claimed. The approval of a sequestration project methodology under the Clean Development Mechanism (CDM) is an important first step that will help developing countries to begin mitigating their fossil plant emissions in the near- to medium-term.[31]

Summary

The steady growth of CO_2 flooding in the Permian Basin and elsewhere offers a compelling case history for possible extrapolation to other oil bearing regions of the world, especially if CO_2 emission controls are imposed on industrial operations. Based on this review of the historical application of CO_2-EOR, a set of screening criteria was established that can be applied to oil fields/basins around the world to facilitate an assessment of their suitability for CO_2-EOR and associated CO_2 storage in the future. These criteria can be summarized as follows:

- Meet the technical criteria for achieving miscibility (defined primarily in terms of reservoir depth and oil viscosity)
- Have a relatively large volume of unrecovered oil after primary and secondary recovery (water flooding)
- Have access to sufficient, predictable, sustainable sources of pure CO_2 at affordable costs.

  Over time, other factors contributing to success are:

- Operator knowledge, comfort and willingness to pursue the use CO_2-EOR technologies
- Willingness and ability of the applicable regulatory regime to permit CO_2-EOR projects
- Availability of government financial incentives to promote the implementation of CO_2-EOR projects.

4. CO_2 STORAGE CAPACITY IN BASINS WITH CO_2-EOR POTENTIAL

Overview of Approach

Defined technical criteria were used to identify and characterize world oil basins with potential for CO_2-EOR. However, estimating the actual performance of CO_2-EOR operations is a much more complex and data intensive effort, which can often take months or years to perform on a single candidate field. Moreover, it requires substantial amounts of detailed data, most of which is generally only available to the owner and/or operator of a field. While data access and time constraints prevented the application of this level of rigor to estimating the worldwide performance of potential future CO_2-EOR projects, a methodology was developed which builds upon Advanced Resources' large volume of data on U.S. crude oil reservoirs and on existing CO_2-EOR operations in the United States. This methodology is outlined in brief in Table 1.

Table 1. Overview of Methodology for Screening-Level Assessment of CO_2-EOR Potential and CO_2 Storage in World Oil Basins

Step	Basin-Level Average Data Used	Basis	Result
1. Select World Oil Basins favorable for CO_2-EOR operations	Volume of oil cumulatively produced and booked as reserves	Basins with significant existing development, and corresponding oil and gas production expertise, will likely have the most success with CO_2-EOR.	List of 54 (14 U.S., 40 in other regions) oil basins favorable for CO_2-EOR
2. Estimate the volume of original oil in place (OOIP) in world oil basins	API gravity; ultimately recoverable resource	Correlation between API gravity and oil recovery efficiency from large U.S oil reservoirs.	Volume of total OOIP in world oil basins
3. Characterize oil basins, and the potential fields within these basins, amenable to CO_2-EOR	Reservoir depth in basin, API gravity	Characterization based on results of assessment of U.S. reservoirs amenable to miscible CO_2-EOR	OOIP in basins and fields amendable to the application of miscible CO_2-EOR
4. Estimate CO_2-EOR flood performance/recovery efficiency	API gravity; reservoir depth	Regression analysis performed on large dataset of U.S. miscible CO_2-EOR reservoir candidates	CO_2-EOR recovery efficiency (% of OOIP)
5. Estimate the volume of oil technically recoverable with CO_2-EOR	OOIP; CO_2-EOR recovery efficiency	Regression analysis performed on large dataset of U.S. miscible CO_2-EOR reservoir candidates	Volume of Oil recoverable with CO_2-EOR
6. Estimate volume of CO_2 stored by CO_2-EOR operations	Technically recoverable oil from CO_2-EOR	Ratio between CO_2 stored and oil produced in ARI's database of U.S. reservoirs that are candidates for miscible CO_2-EOR	Volume of CO_2 used and ultimately stored during CO_2-EOR operations

One of the primary features of this methodology is that it uses basin-average data to characterize the future worldwide potential for CO_2-EOR, since, in general, that is the only data that is generally available and in the public domain for all basins in the world. While it is recognized that reservoir and fluid properties within a petroleum basin can vary considerably; and this variability may not necessarily reflect what average properties might otherwise indicate, the availability of only basin-level data limited what could effectively and efficiently be done for this screening level study.

Moreover, this methodology assumes that the characteristics of U.S. reservoirs can be interpreted, by analogy, to correspond to characteristics in other basins in the world. Clearly, this is also not always the case.

The screening level methodology used in this report – intended to provide an overall order of magnitude characterization of the potential of CO_2-EOR if applied worldwide, as well as a comparative characterization of the relative potential of CO_2-EOR between world oil basins -- was determined to be adequate for that purpose. It is no substitute for the detailed geologic characterization, reservoir modeling, and economic evaluation – based on detailed data on the targeted fields and reservoirs -- that would be required before any serious investment in CO_2-EOR be pursued.

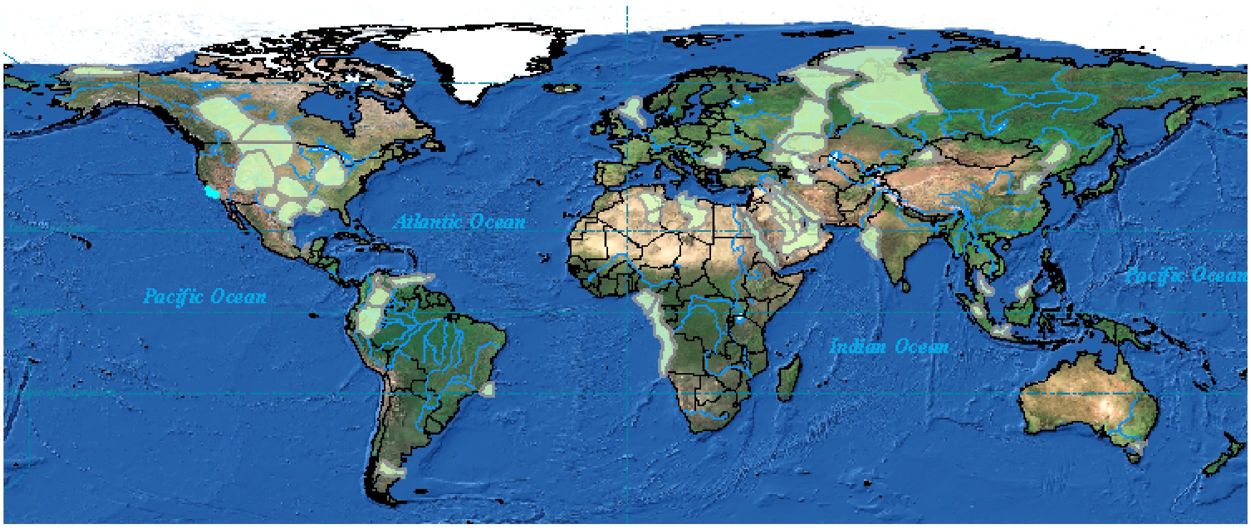
This methodology is described in more detail in the following sections.

Identifying and Characterizing World Oil Basins

The core data on the oil producing basins of the world used in this analysis come from the U.S. Geological Survey (USGS) World Petroleum Assessment.[32] Last completed in 2000, it provides reserves and production data on the large hydrocarbon reservoirs of the world (outside the U.S.), along with other important geologic characteristics. Each basin in the assessment was ranked by the sum of the volume of oil resource that had been produced and booked as reserves, or estimated ultimate recovery (EUR), as of the USGS 2000 study.

For this analysis, the top 40 non-U.S. basins from the USGS assessment, as ranked by the sum of the volume of oil produced and booked as reserves were selected for assessment. These basins, shown in Figure 5, contain 96% of the known oil in the non-U.S. basins characterized in the USGS assessment. They are spread over every continent, but are concentrated in the Middle East, Russia, and Eastern Europe. Of these 40 basins, 13 are predominantly offshore, with the rest predominantly onshore. Additionally, we included 14 U.S. oil producing areas, or basins, of which one is offshore.

Figure 5. World Oil Basins Considered in this Assessment



Region Name	Basin Count
Asia Pacific	8
Central and South America	7
Europe	2
Former Soviet Union	6
Middle East and North Africa	11
North America/Non U.S.	3
United States	14
South Asia	1
Sub-Saharan Africa and Antarctica	2
Total	54

As shown in Table 2, these 54 basins have produced 687 billion barrels, with 845 billion barrels booked as reserves (as of 2000), giving an estimated known oil volume of 1,532 billion barrels.

Appendix D contains a table that cross-references crude oil basins and world regions.

Table 2. Summary of Top 54 World Oil Basins Considered in this Assessment
(Oil volumes in million barrels)

Region Name	Total OOIP (MMBO)	Basin Count	Primary/Secondary Production (MMBO)			
			Cum Production	Reserves	EUR	% of OOIP
Asia Pacific	236,480	8	42,218	35,473	77,691	33%
Central and South America	358,240	7	63,444	48,131	111,575	31%
Europe	145,842	2	26,550	23,252	49,802	34%
Former Soviet Union	751,158	6	109,428	145,342	254,770	34%
Middle East and North Africa	2,205,843	11	215,997	521,987	737,984	33%
North America/Non U.S.	155,718	3	30,157	23,649	53,806	35%
United States	595,700	14	173,500	15,871	189,371	32%
South Asia	22,663	1	3,375	5,065	8,440	37%
Sub-Saharan Africa and Antarctica	150,372	2	22,363	25,877	48,240	32%
Total	**4,622,017**	**54**	**687,032**	**844,647**	**1,531,679**	**33%**

Source: United States Geological Survey, *U.S. Geological Survey World Petroleum Assessment 2000-Description and Results*, Advanced Resources International, Inc.
(EUR = Estimated ultimate recovery)

It should be noted that these USGS-based estimates are most likely somewhat conservative. More recent estimates from BP and the *Oil and Gas Journal* estimate world oil reserves of 1,261 and 1,342, respectively, reflecting better data availability and almost a decade of reserves growth since the USGS 2000 report. Moreover, in the year 2000, the *Oil and Gas Journal* reported world petroleum reserves of 1,016 billion barrels,[33,34] considerably larger than the 2000 USGS assessment. Thus, this assessment of potential CO_2-EOR and associated CO_2 storage capacity based on the year 2000-based data may be understated.

Compiling Data Base of Basin/Field Properties

To accurately estimate basin-level CO_2 storage potential, representative data on reservoir properties was needed for each basin selected for further study. This effort required assembling a large data base with reservoir characteristics of individual fields within the selected basins. Where available, information from the individual fields within a basin was averaged to produce basin level estimates of reservoir properties. Where not, basin average-properties generally reported in these databases were used. The data sources reviewed for this project included the following:

- Data from the USGS World Petroleum Assessment (2000), discussed above, on the world-wide oil resource potential. For some (though not all) basins, the USGS provides some basin-specific information (ranges and means) for field size, depth, gas-oil ratio, and API gravity.[35]

- The data base providing the basis for the previous estimate of potential worldwide sequestration capacity in oil basins that Advanced Resources developed for IEA GHG.[36] In this study, a basin-level data base of CO_2 storage potential was developed that comprised 155 geologic provinces, again using the then-current version of the USGS world assessment as the basis. Basin-level estimates of storage capacity for each province were developed using basin-wide average data on cumulative production, remaining resources, and estimated average geologic properties for reservoir depth, temperature, and oil gravity.
- Data from the annual worldwide oil field production surveys developed by the *Oil and Gas Journal*.[37] For some of the largest oil fields, this production data base contains field-specific information on the number of wells drilled, reservoir depth, cumulative production, API gravity, and estimated conventional reserves.
- A data base of giant oil and gas fields in the world developed by M.K. Horn.[38] Relevant information contained in this data base included location, estimated ultimate recovery of oil and/or gas, lithology, primary trap, and average depth.
- Some specific field data reported in the petroleum geology and engineering literature, such as that of the Society of Petroleum Engineers and American Association of Petroleum Geologists, along with a variety of oil and gas industry publications, such as *World Oil* and *Oil and Gas Journal.*

Estimating Basin Level Original Oil in Place (OOIP)

The volume of OOIP is a key variable in determining the CO_2-EOR potential of a reservoir or basin. Combined with the estimated ultimate recovery of a reservoir, it is used to estimate how much oil remains as a target for the application of CO_2-EOR.

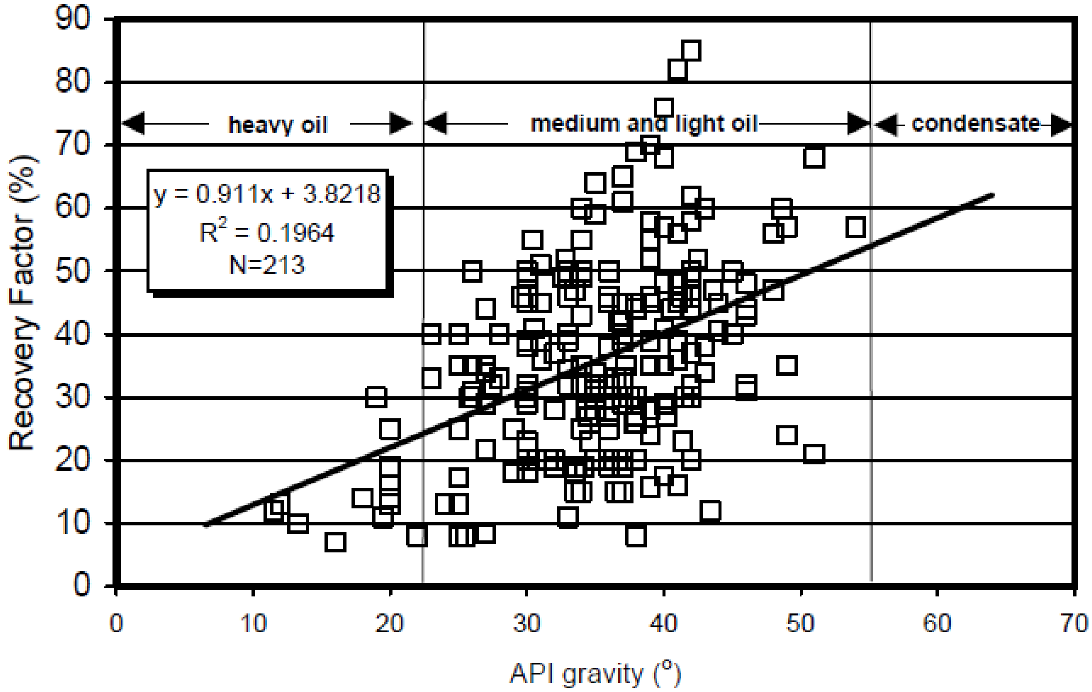
To estimate OOIP in world basins, a relationship was established between the API gravity of the oil in a reservoir and the recovery efficiency of primary and secondary production in that reservoir. This relationship was then used to estimate OOIP of world basins based on their weighted-average API gravity and ultimately recoverable resource.

For predominantly carbonate basins, this report uses a correlation between oil gravity and recovery efficiency developed by S. Qing Sun, et al.[39] For predominantly sandstone basins, a correlation was developed using Advanced Resources' data on U.S. sandstone reservoir oil field performance.

Figures 6a and 6b display the oil gravity/recovery efficiency correlation and data scatter plot for carbonate and sandstone reservoirs respectively.

As shown in Figure 6c, the correlation chosen (Qing Sun et al.) be appears to be somewhat more robust (defined primarily in terms of the r^2 value for the correlation) than a comparable correlation we developed as part of this study for only U.S. reservoirs based on the Advanced Resources' data. We developed a similar correlation just for Permian basin reservoirs in the Advanced Resources' database, where the quality of the reservoir data serving as the basis for the correlation was probably the highest. The correlation chosen is also based on data which include a substantial number of non-U.S. fields.

Figure 6a. API Gravity vs. Primary/Secondary Recovery Efficiency for Carbonate Basin Oil Reservoirs



Source: Sun, Qing. S., SEP, Sloan, Rod, et al., "Quantification of Uncertainty in Recovery Efficiency Predictions: Lessons Learned from 250 Mature Carbonate Fields," Society of Petroleum Engineers Paper No. 84459 presented at the SPE Annual Technical Conference and Exhibition, Denver, Colorado USA, October 5-8, 2003

Figure 6b. API Gravity vs. Primary/Secondary Recovery Efficiency for Sandstone Basin Oil Reservoirs

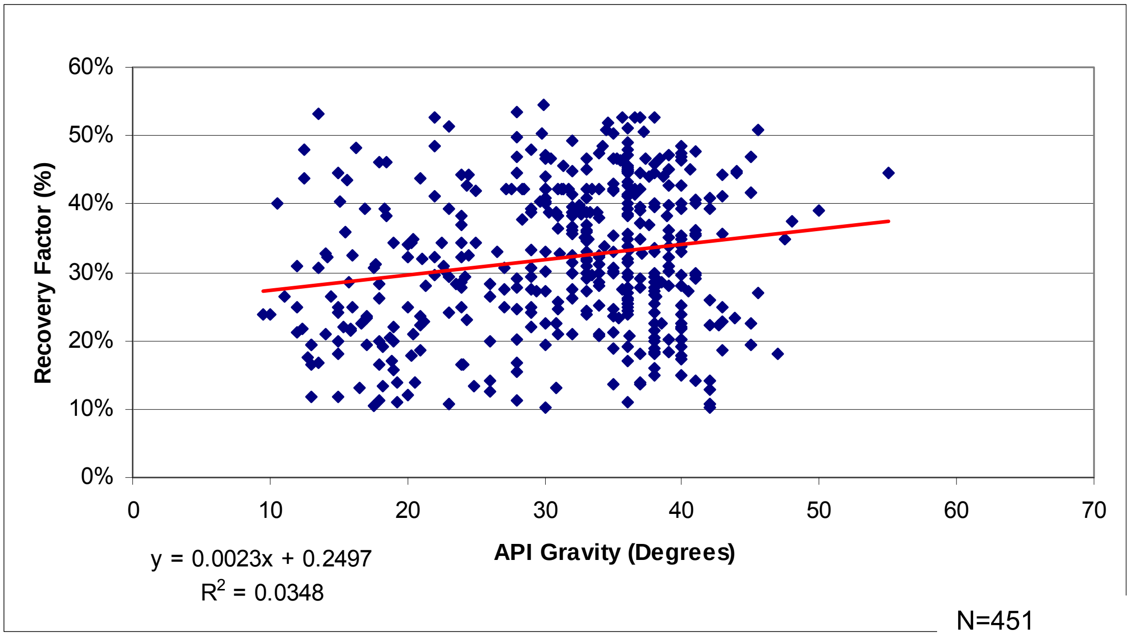
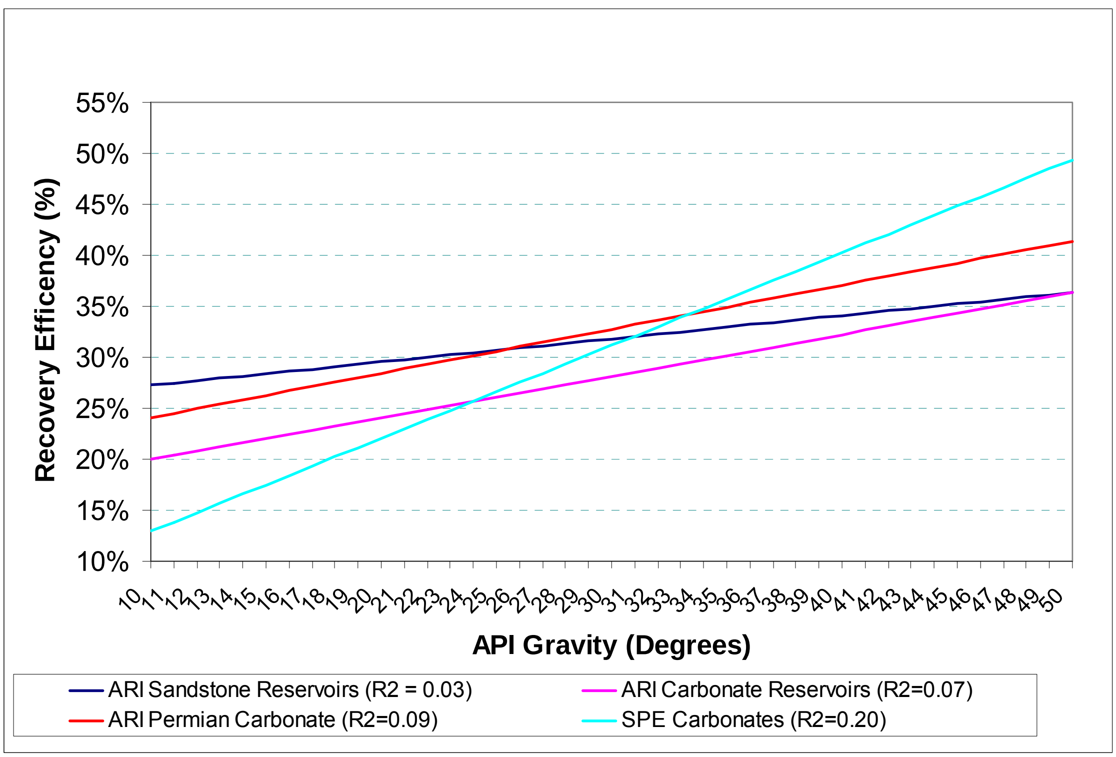


Figure 6c. Comparison of Correlations for Recovery Efficiency vs. API Gravity for Sandstone and Carbonate Reservoirs



Based on the data presented in the figures above, the following correlations were developed and used in this study.

For Carbonate Reservoirs:

REFF = 3.82 + 0.911*API

Where:

REFF = Primary/secondary oil recovery efficiency (% of OOIP)
API = API gravity of reservoir oil.

The r^2 value for this equation is 0.20.

For Sandstone Reservoirs:

REFF = 24.974 + 0.228*API

The r^2 value for this equation is 0.03.

To estimate the OOIP of world basins, these relationships were manipulated to give the following equation:

OOIP = EUR/(REFF/100)

Where:

OOIP = Original Oil in Place (Millions of Barrels)
EUR = Estimated Ultimately Recoverable Resource (Millions of Barrels)
REFF = Primary/secondary oil recovery efficiency (% of OOIP).

The estimated ultimately recoverable resource (EUR) for each basin was defined as the cumulative production plus current proved/booked reserves. This value corresponds to the "known oil" volumes reported for each basin in the USGS World Petroleum Assessment 2000.[40]

Estimates of average API gravity for the world basins were established by primarily averaging field level data in the Giant World Oil Fields database complied by M.K. Horn and the Worldwide Production Summary reports published by the *Oil and Gas Journal*.[41,42]

Using this approach, the 54 world petroleum basins considered in this assessment are estimated to contain 4,622 billion barrels of OOIP, as summarized by region in Table 2. Given the "known oil" volume of 1,532 billion barrels in these 54 basins, the overall recovery efficiency in these basins is 33% (1,532/4,622).

Of the 4,622 billion barrels of OOIP, 3,245 billion barrels (70%) is estimated to be contained in the 43 basins characterized as predominantly sandstone, the other 1,377 billion barrels of OOIP are in the remaining 11 predominantly carbonate basins. The 40 onshore basins analyzed in this report contain 3,716 billion barrels of OOIP (80%), with 906 billion barrels in the 14 predominantly offshore basins.

For details on basin lithology and location, please consult Appendix D.

Screening Basins to Determine Those Technically Amenable to CO_2-EOR

These 54 basins were first screened to establish whether they would be suitable, on average, for the application of miscible CO_2-EOR. To be suitable, it was determined that, on average, a basin must have sufficient pressure for the CO_2 to become miscible with reservoir oil. This required the reservoir depth to be greater than 915 meters (3,000 feet), and required that the crude oil gravity be between 17.5 and 50 degrees API.

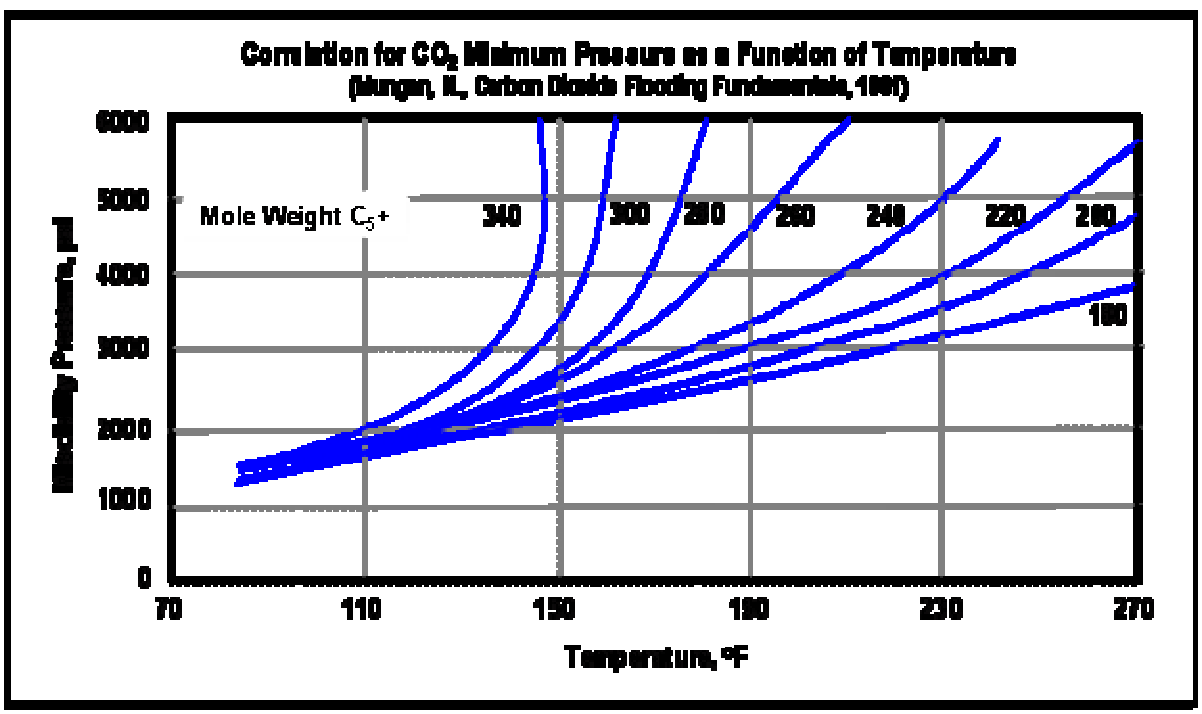
From these data, the basin average minimum miscibility pressure (MMP) is established using the Cronquist correlation, Figure 7:[43]

MMP = 15.988*T (0.744206+0.0011038*MW C5+)

Where

T is Reservoir temperature, in degrees Fahrenheit
MW C5+ is the molecular weight of pentanes & heavier fractions of the oil

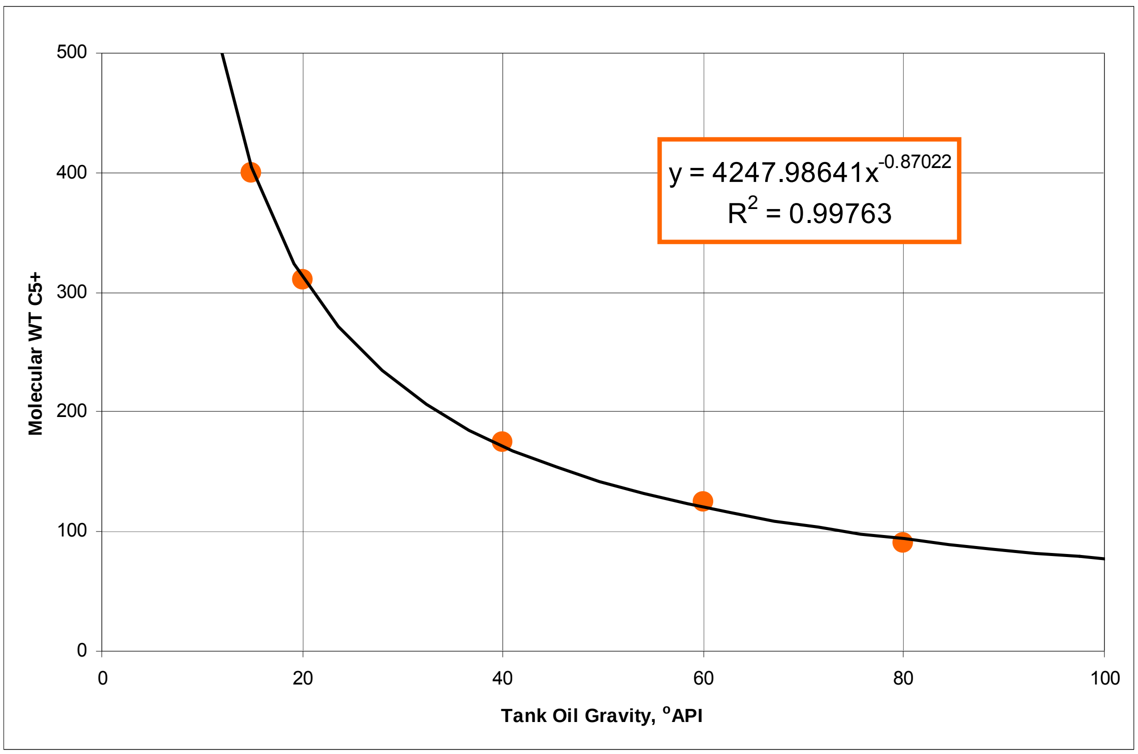
Figure 7. Estimating CO_2 Minimum Miscibility Pressure



The average temperature of the basin was either taken from the database or estimated from the thermal gradient in the basin. The molecular weight of the pentanes and heavier fraction of the oil was estimated from a correlative plot of MW C5+ and oil gravity, shown in Figure 8.

The next step was calculating the MMP for a given reservoir and comparing it to the maximum allowable pressure. The maximum pressure was determined using a pressure gradient of 0.6 psi/foot.

Figure 8. Correlation of MW C5+ to Tank Oil Gravity



Based on these miscibility criteria, three of the top world oil basins (San Jorge Basin, Northwest Java Basin, and the Central Sumatra Basin) were determined to not be amenable to CO_2-EOR because they were, on average, too shallow. One basin (Bombay Basin) was screened out because the oil was too light (API gravity greater than 50 degrees API).

One basin (the Illinois Basin), was determined to be of insufficient reservoir pressure, on average, to achieve miscibility. However, based on our assessments of the CO_2-EOR potential of the U.S., the majority of the individual fields in the basin still have characteristics that allowed for miscibility to be achieved. For this reason, this basin was not excluded from the analysis.

Another basin, the Los Angeles Basin, would also technically screen out as being too shallow, just missing the 915 meter depth cutoff. (The weighted average depth of the reservoirs in the basin was 898 meters.) However, a large volume of OOIP in individual fields within this basin is still suitable for miscible CO_2-EOR, for this reason, the Los Angeles Basin was allowed to remain as one of the basins included in this assessment.

The remaining 50 basins that were considered to be amenable to CO_2-EOR account for 4,538 billion barrels of OOIP. The deletion of the four basins from further consideration in the assessment represented a 2% decrease in the OOIP of the 54 large basins initially considered.

Again, it is important to note that immiscible CO_2-EOR could be viable in some basins, but, for purposes of this assessment, only those basins considered amenable to miscible CO_2-EOR were considered.

Screening for CO_2-EOR Amenable Fields with Basins

Even for basins that, on average, are determined to be amenable to miscible CO_2-EOR, some fields within each basin may not be good miscible CO_2-EOR candidates because they are too shallow, too small, or have values of oil gravity outside of the miscible range. To adjust for the portion of the OOIP contained within each miscible CO_2-EOR amenable basin that would be in fields that were not miscible CO_2-EOR candidates, the results from Advanced Resources' previous analysis of U.S. oil fields were again used as an analogy. Obviously, this proportion will vary considerably from basin to basin; so this estimate is merely intended to adjust the overall OOIP to recognize that some portion of the OOIP in these basins will not be amenable to CO_2-EOR. Clearly, more detailed basin analyses should be performed to better determine this proportion in individual basins.

Nonetheless, as illustrated in Table 3 for the U.S., of the 596 billion barrels of estimated total OOIP in U.S. oil fields, an estimated 438 billion barrels (72% of the total) are in large fields (> 50 million barrels OOIP), and 290 billion barrels (49% of the total) are in large fields amenable to miscible CO_2-EOR.

Based on the results of this screening process for the U.S., of the 4,358 billion barrels of OOIP contained in the miscible-screened world basins, about 2,241 billion barrels (49%) of OOIP were estimated to be in fields amenable to the application of miscible CO_2-EOR. This volume is approximately 48% of the total OOIP in all 54 basins analyzed.

The total screening process for establishing this miscible CO_2-EOR target is illustrated by the resource pyramid in Figure 9, and is summarized in Table 4. This includes screening for basins not considered to be amenable to miscible CO_2-EOR, on average, fields within basins that are too small to be good targets and fields within basins otherwise amenable to CO_2-EOR that would not be miscible CO_2-EOR candidates.

Table 3. Oil Resource Target Amendable to Miscible CO_2-EOR in U.S. Oil Fields

Basin/Area	NATIONAL	ARI DATA BASE			
	Total OOIP	OOIP from Database of Large Reservoirs	OOIP Favorable for CO2-EOR		
			Miscible CO2 Flooding	Immiscible CO2 Flooding	Total
	(Billion Barrels)	(Billion Barrels)	(Billion Barrels)	(Billion Barrels)	(Billion Barrels)
1. Alaska*	67.3	65.4	64.5	0.0	64.5
2. California**	83.3	75.2	21.1	10.5	31.6
3. Gulf Coast (AL, FL, MS, LA)	44.4	26.4	20.0	0.2	20.2
4. Mid-Continent (OK, AR, KS, NE)	89.6	53.1	28.0	0.0	28.0
5. Illinois/Michigan	17.8	12.0	4.4	0.2	4.6
6. Permian (W TX, NM)	95.4	72.4	61.4	1.7	63.1
7. Rockies (CO,UT,WY)	33.6	23.7	13.8	4.2	18.0
8. Texas, East/Central	109	67.4	44.0	8.4	52.4
9. Williston (MT, ND, SD)	13.2	9.4	7.2	0.0	7.2
10. Louisiana Offshore	28.1	22.2	22.1	0.0	22.1
11. Appalachia (WV, OH, KY, PA)	14	10.6	3.9	3.5	7.4
Total	595.7	437.8	290.4	28.7	319.1
% of Total	100%	73%	49%	5%	54%

* The Alaska region shown here contains two distinct basins, the North Slope and Cook Inlet, which are analyzed separatly in this report
** The California Region shown here contains three distinct basins, Coastal, San Joaquin and Los Angeles, analyzed separatly in this report

It is useful to compare the Permian Basin, the only location where industry has extensive experience with CO_2 flooding, with the characterization in Figure 9. According to the data in the Advanced Resources U.S. data base, about 95.4 billion barrels of OOIP exists in Permian basin reservoirs, of which 76% (72.4 billion barrels), exist in large fields. In Figure 9, 73% (3,316/4,538) of the OOIP in all of the world's oil basins that are amenable to CO_2-EOR is in large fields. In the Permian Basin, 64% (61.5 billion barrels) of the OOIP is in large fields amenable to CO_2-EOR, while in the world's oil basins, only 49% (2,241/4538) is assumed to be in this category.

Figure 9. Establishing the Oil Resource Target Amendable to Miscible CO_2-EOR

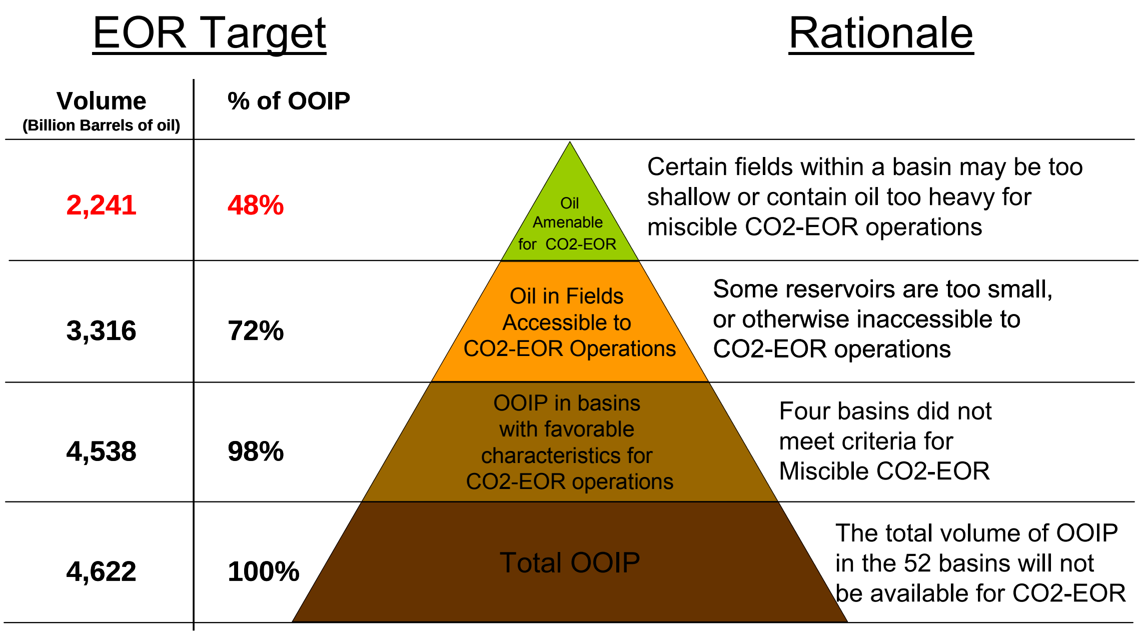


Table 4. Estimated OOIP Amenable to CO_2-EOR in the Basins Considered

Region Name	Total OOIP (MMBO)	Miscible Basin Count	OOIP in Miscible Basins (MMBO)	OOIP in Large Fields (MMBO)	OOIP In Miscible Fields (MMBO)
Asia Pacific	236,480	6	185,552	135,453	91,818
Central and South America	358,240	6	347,336	253,555	171,874
Europe	145,842	2	145,842	106,465	72,168
Former Soviet Union	751,158	6	751,158	548,345	371,700
Middle East and North Africa	2,205,843	11	2,205,843	1,610,265	1,091,531
North America/Non U.S.	155,718	3	155,718	113,674	77,055
United States	595,700	14	595,700	438,782	290,348
South Asia	22,663	0	-	-	-
Antarctica	150,372	2	150,372	109,771	74,409
Total	**4,622,017**	**50**	**4,537,521**	**3,316,311**	**2,240,904**

Advanced Resources International, Inc.

Estimating Technically Recoverable EOR Resources

To estimate the technically recoverable resource from the application of CO_2-EOR processes in the 50 basins, basin-specific reservoir conditions were defined that would be anticipated to affect CO_2-EOR performance. Based on the amount of OOIP in each basin, the incremental volume of oil that could be recoverable from CO_2-EOR operations was then estimated based on these defined basin-average conditions.

It is important to recognize that considerable evolution has occurred in the design and implementation of CO_2-EOR technology since it was first introduced. Notable changes include: (1) injection of much larger volumes of CO_2 over time; (2) incorporation of tapered WAG (water alternating with gas) and other methods for mobility control; and (3) application of advanced well drilling and completion strategies to better contact previously bypassed oil. As a result, the oil recovery efficiencies of today's better designed and operated CO_2-EOR projects have steadily improved. The extent of this improvement has been extensively documented in early work by Advanced Resources for the U.S. Department of Energy. [44]

For purposes of this assessment, the estimated potential EOR performance in world oil basins was based on the "State-of-the-Art" technology characteristics used in this previous study, as well as the result of reservoir modeling from this study. This characterization assumed that 1.0 hydrocarbon pore volumes (HCPV) of CO_2 (which is considerably more than traditional CO_2 floods, which averaged about 0.4 HCPV, due to a combination of high CO_2 costs and low oil prices). It also assumed that CO_2 floods were implemented at the end of water flooding operations using a tapered water-alternating-gas (WAG) process, with the floods developed on an inverted 5-spot pattern (roughly one producer per injector).

In general, these results for U.S. basins show that average technical recovery efficiencies for CO2-EOR range from 15% to 25%, in general, and average about 20%. These recovery efficiencies are somewhat higher than results reported in several previous review studies.[45] However, this study is based on more optimistic assumptions about the potential performance of CO_2-EOR in amenable reservoirs, in particular the amount of cumulative CO_2 injected, which generally leads to higher estimates of technical recovery efficiency than that reflected in historical field performance.

Moreover, recent operational evidence from the Permian basin suggests that CO_2-EOR recovery efficiencies of 20% are feasible. Ongoing CO_2-EOR operations in the 36 Permian basin reservoirs contained in Advanced Resources' database have recovered or booked as reserves 1.9 billion barrels of incremental oil, approximately 15% of these reservoirs' OOIP (12.5 billion barrels). In addition, CO_2 injection is still occurring in the vast majority of these fields, and most have injected less than 1.0 HCPV to date.

To develop a relationship between world basin reservoir characteristics and estimated CO_2-EOR performance, we used U.S. data as a proxy and performed a regression analysis on Advanced Resources' EOR performance and reservoir data for domestic oil reservoirs. For this regression, only those U.S. reservoirs that were determined to be amenable to miscible CO_2-EOR technology were considered. Due to data availability constraints for the world oil basins, the regression focused on the two main reservoir characteristics where basin-level average data were available: oil gravity and reservoir depth. The equations below show the results of this regression analysis of the U.S. reservoirs for the two most common reservoir lithologies.

For Sandstone Reservoirs:

$$EOR\% = 0.06 + 3.2*10^{-3} * API + 4.41*10^{-6} * DEPTH$$

Where:

EOR% = CO_2-EOR recovery efficiency (% of OOIP)
API = API gravity of reservoir oil
DEPTH = Reservoir depth (Feet)

The r^2 value for this equation is: 0.131.

For Carbonate Reservoirs

$$EOR\% = 0.14 + 1.5*10^{-3} * API + 4.0*10^{-6} * DEPTH$$

The r^2 value for this equation is: 0.067.

This basin level methodology based on these correlations was used to predict the CO_2-EOR performance in the set of U.S. basins assessed by Advanced Resources. The results of this basin-level methodology were compared with those produced from the reservoir-specific analyses in the U.S. Table 5 displays the results of this comparison.[46]

Table 5. Comparison of Basin-Level and Field-Level Estimates U.S. CO_2-EOR Recovery Potential

US Basin/Area	EOR Amenable OOIP (MMBO)	API	Depth (Feet)	Temperature Gradient (Degrees F/Foot)	Reservoir Level Assessment		Basin Level Assessment		Difference
					Technically Recoverable EOR (MMBO)	Recovery Efficiency	Technically Recoverable EOR (MMBO)	Recovery Efficiency	
East/Central Texas	44,024	37	4,689	0.033	9,392	21.33%	8,969	20.37%	-4.51%
Permian	61,426	36	5,632	0.021	13,428	21.86%	13,583	22.11%	1.16%
Mid-Continent	28,005	38	5,010	0.028	6,359	22.71%	5,777	20.63%	-9.16%
North Slope	61,434	25	5,009	0.022	11,373	18.51%	10,269	16.71%	-9.71%
Gulf Coast	19,978	35	9,566	0.022	4,131	20.68%	4,316	21.61%	4.49%
San Joaquin	8,792	34	6,074	0.028	2,164	24.61%	1,746	19.86%	-19.30%
Rockies	13,779	35	6,346	0.025	2,625	19.05%	2,811	20.40%	7.11%
Los Angeles	7,563	28	2,947	0.043	1,096	14.49%	1,271	16.81%	15.97%
Coastal California	4,786	30	3,467	0.039	1,179	24.62%	847	17.69%	-28.15%
Williston	7,153	36	8,244	0.025	1,827	25.54%	1,651	23.08%	-9.62%
Cook Inlet	3,026	36	8,647	0.021	670	22.15%	656	21.67%	-2.13%
Total/Average*	**259,966**	**34**	**5,966**	**0.028**	**54,243**	**20.87%**	**51,897**	**19.96%**	**10.12%**

* The average value of the final "Difference" column is the average of the absolute values of the datapoints

Overall, the absolute value of the percent difference between basin-level and field-level results in each of the basins is generally less than 10%, except for basins on the U.S. West Coast. These basins (the San Joaquin, Coastal California, and the Los Angeles Basins) have basin-level predictions based on the regression equation that are substantially less than that obtained by performing field-level analyses. This disparity is due, in part, to the high temperature gradient found in these basins, implying that they would tend to be at a higher than average temperature for a given depth (and therefore lower oil viscosity than typically correlated with oil gravity). This phenomenon influences oil recovery by CO_2-EOR, but was not addressed in the regression methodology (which does not consider temperature), resulting in disparate EOR recovery results.

The presence of these types of disparities, such as a high temperature gradient, suggest the need for more detailed, data intensive analysis once a small number of basins are selected for further study. However, overall, it was determined that, for purposes of this assessment, the basin-level regression gave acceptable results based on the data available for the world basins.

Given this classification, the basin average CO_2-EOR recovery efficiency (defined as a % of OOIP) was estimated based on the equations above. The world basins were classified as predominantly sandstone or carbonate based on field-level data in the Horn database.

The amount of oil recoverable through CO_2-EOR in each basin was estimated by the following equation:

EOROIL = OOIP*AF*EOR%

Where:

EOROIL = Volume of oil recoverable from CO_2-EOR operations (Millions of Barrels)
AF = Adjustment factor, the percentage of OOIP that is in fields amenable to CO_2-EOR (49% in this analysis)
EOR% = CO_2-EOR recovery efficiency (% of OOIP)

The adjustment factor AF is designed to adjust basin-level estimates of total OOIP down to only the OOIP for those reservoirs amenable for CO_2-EOR. In this study, this is based on the findings for U.S. basins, as summarized in Table 3. Importantly, this adjustment factor is applied here as a “top-down” adjustment at the basin level, and is not applicable when each reservoir in a basin is individually assessed.

The results of the application of this methodology are shown in Table 6. Of the 2,241 billion barrels of OOIP that was estimated to be in large fields amenable to the application of miscible CO_2-EOR, 469 billion barrels is estimated to be technically recoverable. This amounts to, on average, 21% of the OOIP in these basins. Of the total 469 billion barrels of CO_2-EOR technically recoverable resource, sandstone reservoirs contain 313 billion barrels (67%) of the CO_2-EOR in the basins analyzed, and the remaining 156 billion barrels reside in carbonate reservoirs. Eighty percent of the 469 billion barrels (374 billion barrels) are contained in predominantly onshore basins.

Table 6. Estimated Incremental Technically Recoverable Oil from the Application of CO_2-EOR in Basins Considered in this Assessment
(Oil volumes in million barrels)

Region Name	Total OOIP	Miscible Basin Count	OOIP in Miscible Basins	OOIP in Large Fields	OOIP In Miscible Fields	Estimated CO_2-EOR Recovery Efficiency	CO_2 EOR Oil Recovery
Asia Pacific	236,480	6	185,552	135,453	91,818	20%	18,376
Central and South America	358,240	6	347,336	253,555	171,874	18%	31,697
Europe	145,842	2	145,842	106,465	72,168	23%	16,312
Former Soviet Union	751,158	6	751,158	548,345	371,700	21%	78,715
Middle East and North Africa	2,205,843	11	2,205,843	1,610,265	1,091,531	21%	230,640
North America/Non-U.S.	155,718	3	155,718	113,674	77,055	23%	18,080
United States*	595,700	14	595,700	438,782	290,348	21%	60,204
South Asia	22,663	0	-	-	-	N/A	-
Sub-Saharan Africa and Antarctica	150,372	2	150,372	109,771	74,409	19%	14,505
Total	**4,622,017**	**50**	**4,537,521**	**3,316,311**	**2,240,904**	**21%**	**468,530**

* Readers familiar with ARI's study "Storing CO_2 with Enhanced Oil Recovery" will note that the volume of technically recoverable oil from CO2-EOR displayed in this table is 4.2 billion barrels less than reported in our study. The discrepancy is caused because we do not include fields that would be subject to immiscible CO_2-EOR in this analysis.

Estimating Purchased CO_2 Volumes Required for CO_2-EOR Operations

The final step was to estimate how much CO_2 would be used, and ultimately stored, as a result of CO_2-EOR operations in each of the 50 CO_2-EOR amenable basins considered. In this assessment, the amount of CO_2 that would need to be purchased for CO_2-EOR operations, as estimated as the result of reservoir simulation, was assumed to be equivalent to the amount of CO_2 that would ultimately be stored in the reservoir. This does not include the volumes of CO_2 recycled during the life cycle of CO_2-EOR operations.

To estimate CO_2 storage potential, an additional regression analysis was performed to establish a relationship between reservoir characteristics and CO_2 use, again based on Advanced Resources past work for the U.S. reservoirs.

The equations below show the results of this regression analysis for the two reservoir lithologies.

For Carbonate Reservoirs:

$$CO_2 \text{ Stored} = 0.27 + (2.82E^{-5} * \text{API}) + (5.24E^{-6} * \text{DEPTH})$$

Where:

CO_2 Stored = "Purchased" CO_2 injected (does not include recycled CO_2)
API = API gravity of reservoir oil
DEPTH = Reservoir depth (Feet)

The r^2 value for this equation is: 0.14.

For Sandstone Reservoirs

$$CO_2 \text{ Stored} = 0.32 + (2.86E^{-3} * \text{API}) + (1.00E^{-5} * \text{DEPTH})$$

The r^2 value for this equation is: 0.20.

As shown in Table 7, based on this data, for this analysis, basin average values range from 0.26 to 0.31 tonnes of CO_2 purchased to produce each barrel of incremental oil produced from CO_2-EOR, with an overall average of 0.29 tonnes CO_2 per barrel of incremental oil produced.

The percent difference between estimated values from the two methodologies is generally less than 7%, with the exception of the North Slope, San Joaquin Basin, and the Williston Basin. Nonetheless, it was determined that, for purposes of this assessment, the basin-level regression gave acceptable results based on the data available for the world basins, the average of absolute errors in the estimates was less than 6%.

Table 7. Comparison of Estimates of CO_2 Storage Potential from the Application of CO_2-EOR in U.S. Basins

US Basin/Area	Reservoir-Level Assessment			Basin-Level Assessment			Difference
	Technically Recoverable EOR (MMBO)	CO2 Stored (Gigatons)	CO2/Oil Ratio (tonnes/Bbl)	Technically Recoverable EOR (MMBO)	CO2 Stored (Bcf)	CO2/Oil Ratio (tonnes/Bbl)	
East/Central Texas	9,392	2.42	0.26	8,969	2.33	0.26	1.1%
Permian	13,428	4.10	0.31	13,583	4.08	0.30	-1.8%
Mid-Continent	6,359	1.61	0.25	5,777	1.51	0.26	3.6%
North Slope	11,373	3.08	0.27	10,269	3.07	0.30	10.2%
Gulf Coast	4,131	1.32	0.32	4,316	1.37	0.32	-0.8%
San Joaquin	2,164	0.54	0.25	1,746	0.50	0.28	14.8%
Rockies	2,625	0.74	0.28	2,811	0.80	0.28	0.1%
Los Angeles	1,096	0.29	0.27	1,271	0.34	0.27	1.0%
Coastal California	1,179	0.34	0.29	847	0.23	0.27	-6.5%
Williston	1,827	0.49	0.27	1,651	0.52	0.31	16.6%
Cook Inlet	670	0.21	0.32	656	0.20	0.30	-5.4%
Total/Average*	54,243	15.1	0.28	51,897	14.9	0.29	5.6%

* The average value of the final "Difference" column is the average of the absolute values of the datapoints

The Illinois Basin was not included in this comparison

Consequently, as shown in Table 8, recovering the 469 billion barrels of technically recoverable incremental oil from the application of CO_2-EOR processes would require the purchase of 139 Gt of CO_2). Given the assumption that, under current economic conditions, the amount of CO_2 that would need to be acquired for conventional CO_2-EOR operations (not CO_2-EOR operations combined with long term storage) is equivalent to the amount of CO_2 that would ultimately be stored, this amounts to a total CO_2 storage potential in the fields in these basins of 139 Gt. Sandstone reservoirs account for 65% (91 Gt) of the total CO_2 storage capacity potential. Onshore basins will provide 80% (110 Gt).

A detailed compilation of the estimates of original oil in place, ultimate primary and secondary oil recovery, incremental technically recoverable oil from CO_2-EOR, and the volume of CO_2 stored in association with CO_2-EOR is provided in Table 9 for the 50 world oil basins with favorable conditions for miscible CO_2-EOR considered in this assessment.

Table 8. Estimated Regional CO_2 Storage Potential from the Application of CO_2-EOR in World Oil Basins

Region Name	CO_2 EOR Oil Recovery (MMBO)	Miscible Basin Count	CO_2 Oil Ratio (tonnes/Bbl)	CO_2 Stored (Gigatonnes)
Asia Pacific	18,376	6	0.27	5.0
Central and South America	31,697	6	0.32	10.1
Europe	16,312	2	0.29	4.7
Former Soviet Union	78,715	6	0.27	21.6
Middle East and North Africa	230,640	11	0.30	70.1
North America/Non-U.S.	18,080	3	0.33	5.9
United States	60,204	14	0.29	17.2
South Asia	-	0	N/A	-
Sub-Saharan Africa and Antarctica	14,505	2	0.30	4.4
Total	**468,530**	**50**	**0.30**	**139.0**

Table 9. Summary of Results for the Basins Considered in this Assessment

Basin Name	Main Country	Location	Known Oil (MMBO)	Recovery Efficency	Discovered Fields OOIP (MMBO)	OOIP in Large Fields for CO2-EOR (MMBO)	Large Field OOIP Favorable for Miscible CO2-EOR (MMBO)	EOR Recovery Efficency	Large Field EOR Oil Technically Recoverable (MMBO)	CO2/Oil Ratio (tonnes /Bbl)	CO2 Stored in Large Fields (Gigatons)
Mesopotamian Foredeep Basin	Saudi Arabia	Onshore	292,442	32%	908,501	663,206	449,559	20%	89,069	0.31	27.2
West Siberian Basin	Russia	Onshore	139,913	34%	412,441	301,082	204,091	21%	43,683	0.27	11.7
Greater Ghawar Uplift	Saudi Arabia	Onshore	141,700	36%	394,328	287,859	195,128	22%	43,348	0.30	13.2
Zagros Fold Belt	Iraq	Onshore	121,601	33%	369,291	269,582	182,739	21%	39,274	0.30	11.8
Rub Al Khali Basin	Emirates	Offshore	89,827	37%	245,615	179,299	121,539	23%	27,977	0.31	8.8
Volga-Ural Region	Russia	Onshore	63,937	33%	193,683	141,388	95,841	20%	19,130	0.27	5.2
North Sea Graben	United Kingdom	Offshore	43,894	34%	127,914	93,377	63,297	23%	14,373	0.28	4.0
Maracaibo Basin	Venezuela	Offshore	49,072	31%	157,328	114,849	77,851	18%	14,307	0.32	4.5
Permian Basin	United States	Onshore	31,131	33%	95,400	72,380	61,426	22%	13,428	0.31	4.1
Villahermosa Uplift	Mexico	Onshore	35,022	34%	104,134	76,018	51,529	24%	12,333	0.34	4.1
Sirte Basin	Libya	Onshore	37,073	34%	110,538	80,693	54,698	22%	11,765	0.29	3.4
North Slope	United States	Onshore	20,848	33%	64,074	62,295	61,434	19%	11,373	0.27	3.1
Niger Delta	Nigeria	Offshore	34,523	32%	106,913	78,047	52,905	20%	10,448	0.30	3.1
East/Central Texas Basins	United States	Onshore	37,287	34%	109,000	67,372	44,024	21%	9,392	0.26	2.4
East Venezuela Basin	Venezuela	Onshore	30,203	31%	96,942	70,767	47,970	18%	8,707	0.31	2.7
Bohaiwan Basin	China	Onshore	24,554	33%	73,998	54,018	36,617	20%	7,443	0.27	2.0
Widyan Basin-Interior Platform	Saudi Arabia	Onshore	17,435	27%	65,553	47,854	32,438	22%	7,068	0.32	2.3
Mid-Continent Basins	United States	Onshore	24,461	27%	89,600	53,133	28,005	23%	6,359	0.25	1.6
South Caspian Basin	Turkmenistan	Offshore	17,439	34%	51,984	37,948	25,723	22%	5,697	0.30	1.7
Trias/Ghadames Basin	Algeria	Onshore	15,203	35%	43,514	31,766	21,533	24%	5,185	0.29	1.5
Alberta Basin	Canada	Onshore	15,279	36%	42,573	31,078	21,067	22%	4,724	0.31	1.4
LA Offshore	United States	Offshore	9,571	34%	28,100	22,251	22,055	21%	4,594	0.35	1.6

Table 9 (Cont'd)
Summary of Results for the Basins Considered in this Assessment

Basin Name	Main Country	Location	Known Oil (MMBO)	Recovery Efficency	Discovered Fields OOIP (MMBO)	OOIP in Large Fields for CO2-EOR (MMBO)	Large Field OOIP Favorable for Miscible CO2-EOR (MMBO)	EOR Recovery Efficency	Large Field EOR Oil Technically Recoverable (MMBO)	CO2/Oil Ratio (tonnes /Bbl)	CO2 Stored in Large Fields (Gigatons)
Songliao Basin	China	Onshore	15,575	33%	47,592	34,742	23,550	19%	4,495	0.26	1.2
Gulf Coast Basins	United States	Onshore	16,950	38%	44,400	26,413	19,978	21%	4,131	0.32	1.3
West-Central Coastal	Gabon	Offshore	13,717	32%	43,459	31,725	21,505	19%	4,057	0.31	1.3
Timan-Pechora Basin	Russia	Onshore	13,120	33%	39,404	28,765	19,498	20%	3,943	0.27	1.1
North Caspian Basin	Kazakhstan	Onshore	10,809	43%	25,140	18,352	12,440	26%	3,226	0.34	1.1
Red Sea Basin	Egypt	Offshore	9,860	32%	30,632	22,362	15,158	20%	3,072	0.32	1.0
Campos Basin	Brazil	Offshore	10,056	31%	32,947	24,051	16,303	19%	3,072	0.36	1.1
Middle Caspian Basin	Turkmenistan	Offshore	9,552	34%	28,507	20,810	14,106	22%	3,036	0.29	0.9
Rockies Basins	United States	Onshore	10,437	31%	33,600	23,662	13,779	19%	2,625	0.28	0.7
San Joaquin Basin	United States	Onshore	15,691	36%	43,861	39,595	8,792	25%	2,164	0.25	0.5
Junggar Basin	China	Onshore	6,810	33%	20,809	15,191	10,297	20%	2,084	0.29	0.6
Putumayo-Oriente-Maranon Basin	Colombia	Onshore	6,601	31%	21,050	15,367	10,416	19%	1,945	0.32	0.6
Carpathian-Balkanian Basin	Romania	Onshore	5,908	33%	17,928	13,087	8,871	22%	1,939	0.32	0.6
Baram Delta/Brunei-Sabah Basin	Brunei	Offshore	6,898	31%	22,213	16,215	10,992	17%	1,895	0.29	0.6
Llanos Basin	Colombia	Onshore	5,403	33%	16,380	11,958	8,106	23%	1,867	0.35	0.6
Williston Basin, US	United States	Onshore	3,739	28%	13,200	9,299	7,153	26%	1,827	0.27	0.5
Tampico-Misantla Basin	Mexico	Onshore	6,895	30%	22,689	16,563	11,227	16%	1,799	0.30	0.5
Interior Homocline-Central Arch	Saudi Arabia	Onshore	4,700	32%	14,616	10,670	7,233	20%	1,421	0.30	0.4
Fahud Salt Basin	Oman	Onshore	4,473	35%	12,645	9,231	6,257	22%	1,346	0.29	0.4
Gippsland Basin	Australia	Offshore	3,861	36%	10,832	7,907	5,360	24%	1,286	0.25	0.3
Coastal California Basin	United States	Onshore	3,535	25%	14,008	12,646	4,786	25%	1,179	0.29	0.3
Malay Basin	Malaysia	Offshore	3,608	36%	10,109	7,380	5,002	23%	1,173	0.24	0.3
Illizi Basin	Algeria	Onshore	3,670	35%	10,608	7,744	5,249	21%	1,114	0.23	0.3
Los Angeles Basin	United States	Onshore	7,019	28%	25,431	22,958	7,563	14%	1,096	0.27	0.3
Williston Basin, Canada	Canada	Onshore	3,505	39%	9,011	6,578	4,459	23%	1,024	0.31	0.3
Appalachia	United States	Onshore	1,144	8%	14,000	11,657	3,905	22%	856	0.34	0.3
Cook Inlet	United States	Onshore	1,388	43%	3,226	3,137	3,026	22%	670	0.32	0.2
Illinois Basin	United States	Onshore	6,170	35%	17,800	11,985	4,422	12%	512	0.27	0.1
Total			**1,503,509**	**33%**	**4,537,521**	**3,316,311**	**2,240,904**	**21%**	**468,530**	**0.30**	**139**

Additional CO_2 Storage Potential beyond that Associated with "State-of-the-Art" CO_2-EOR

Previous studies by Advanced Resources demonstrate that, assuming there is value to storing more CO_2 than that required for the standard application of CO_2-EOR, considerably more CO_2 could be stored in candidate oilfields.[47] Moreover, substantially more incremental oil could be recovered. In this previous work, four "next generation" CO_2-EOR technology options were identified that can address some of the issues faced by current CO_2-EOR practices, and result in more oil production and additional CO_2 utilization and storage. These are:

- Increasing the volume of CO_2 injected into the oil reservoir, which involves increasing CO_2 injection volumes from 1.0 hydrocarbon pore volume (HCPV), currently used in "best practices", to 1.5 HCPV. Higher HCPV's of injected CO_2 enable more of the reservoir's residual oil to be contacted (and even multiply contacted) by the injected CO_2. However, progressively longer CO_2 injection periods, longer overall project length and higher gross CO_2 to oil ratios are involved when greater volumes of CO_2 are injected. In the past, the combination of high CO_2 costs and low oil prices led operators to inject less CO_2 (traditionally about 0.4 HCPV) to maximize profitability. This low volume CO_2 injection strategy was also selected because field operators had very limited capability to observe and then control the sub-surface movement of the injected CO_2 in the reservoir. With adequate volumes of lower cost CO_2 and higher oil prices, CO_2-EOR economics today favor using higher volumes of CO_2. However, these increased CO_2 volumes need to be "managed and controlled" to assure that they contact, displace, and recover additional residual oil rather than merely circulate through a high permeability interval of the reservoir.
- Optimizing well design and placement, including adding infill wells, to achieve increased contact between the injected CO_2 and the oil reservoir. More specifically, the well design and placement objective is to ensure that both the previously highly waterflood-swept (with low residual oil) portions of the oil reservoir and the poorly waterflood-swept (with higher residual oil) portions of the oil reservoir are optimally contacted by the injected CO_2. Examples of such innovative well design and placement options include: (1) isolating the previously poorly-swept reservoir intervals (with higher residual oil) for targeted CO_2 injection; (2) drilling horizontal injection and production wells to target bypassed or poorly produced reservoir areas or intervals; (3) altering the injection and production well pattern alignment; (4) using physical or chemical diversion materials to divert CO_2 into previously poorly-contacted portions of the reservoir; and (5) placing the injection and production wells at closer spacing. To model this, one new vertical production well is assumed to be added to each pattern. This well would produce from previously bypassed or poorly contacted portions of the reservoir. (The "best practices" model assumes that each CO_2 -EOR pattern has one production and one injection well. The "next generation" version of the model adds one well to the pattern that targets the poorly contacted reservoir area in the "best practices" model).
- Improving the mobility ratio between the injected CO_2/water and the residual oil. This assumes an increase in the viscosity of the injected water (as part of the CO_2-WAG process). (The viscosity of the CO_2 itself was left unchanged, although increasing the viscosity of CO_2 with CO_2-philic agents could theoretically further improve performance.) The viscosity of the injected water can be changed by adding polymers or other

viscosity-enhancing materials. This was modeled by assuming the viscosity of injected water is increased to 3 cp,[48] or three times the viscosity of normal water.

- Extending the miscibility range, thus helping more reservoirs achieve higher oil recovery efficiency. This assumes that "miscibility extenders" are added to CO_2-EOR process that reduces minimum miscibility pressure requirements by 500 psi (pounds per square inch). Examples of miscibility enhancing agents would include: addition of liquefied petroleum gases (LPG) to the CO_2, although this would lead to a more costly injection process; addition of H_2S or other sulfur compounds, although this may lead to higher cost operations; and, use of other (to be developed) miscibility pressure or interfacial tension reduction agents. Analytical modeling shows that extending the range of oil reservoirs applicable for miscible CO_2-EOR would significantly increase oil recovery efficiency, particularly when combined with higher volume injection of CO_2.

It is important to note that all of these technologies are currently being deployed, at least at pilot scale, in a few CO_2-EOR projects today.

These technology options could help unlock greater potential to sequester CO_2 and increase domestic oil production. If implemented, these practices could dramatically increase the performance of CO_2-EOR technology and increase the volume of CO_2 that could be stored in the reservoirs when compared to current best practices. Based on an assessment of oil resource potential due to "next generation" CO_2-EOR technologies in the United States, [49] Table 10 shows the improvements that "next generation" technology could increase both technically and economically recoverable incremental oil recoveries due to CO_2-EOR by over 40%. Similarly, CO_2 use and storage associated with the application of CO2-EOR could also increase by 16% to 17%, as summarized in Table 11.

Moreover, CO_2 storage potential could increase several fold, with an even greater volume of potential incremental oil recovery. In addition to the additional CO_2 injected as a part of "next generation" CO_2-EOR, it could also include the result of CO_2-EOR technology applied to the essentially immobile residual oil transition/residual oil zone (TZ/ROZ) underlying the main oil pay zone, as well as the underlying saline reservoir that exists below the TZ/ROZ, as illustrated in Figure 10.

Table 10. Economically Recoverable Domestic Oil Resources from Applying "Next Generation" CO_2-EOR in the United States*

Basin/Area	Incremental Technically Recoverable Oil* (Billion Barrels)		Incremental Economically Recoverable Oil** (Billion Barrels)	
	"Best Practices"	"Next Generation"	"Best Practices"	"Next Generation"
1. Alaska	12.4	12.4	9.5	9.5
2. California	6.3	10.0	5.4	8.1
3. Gulf Coast (AL, FL, MS, LA)	7	7.4	2.2	2.7
4. Mid-Continent (OK, AR, KS, NE)	10.6	17.0	5.6	8.8
5. Illinois/Michigan	1.2	3.2	0.5	1.7
6. Permian (W TX, NM)	15.9	28.0	7.1	15.1
7. Rockies (CO,UT,WY)	3.9	7.1	1.9	3.8
8. Texas, East/Central	17.6	20.0	8.3	9.9
9. Williston (MT, ND, SD)	2.5	5.2	0.5	0.6
10. Louisiana Offshore	5.8	5.8	3.9	3.9
11. Appalachia (WV, OH, KY, PA)	1.6	2.6	0.1	0.1
Total	84.8	118.7	45.0	64.4

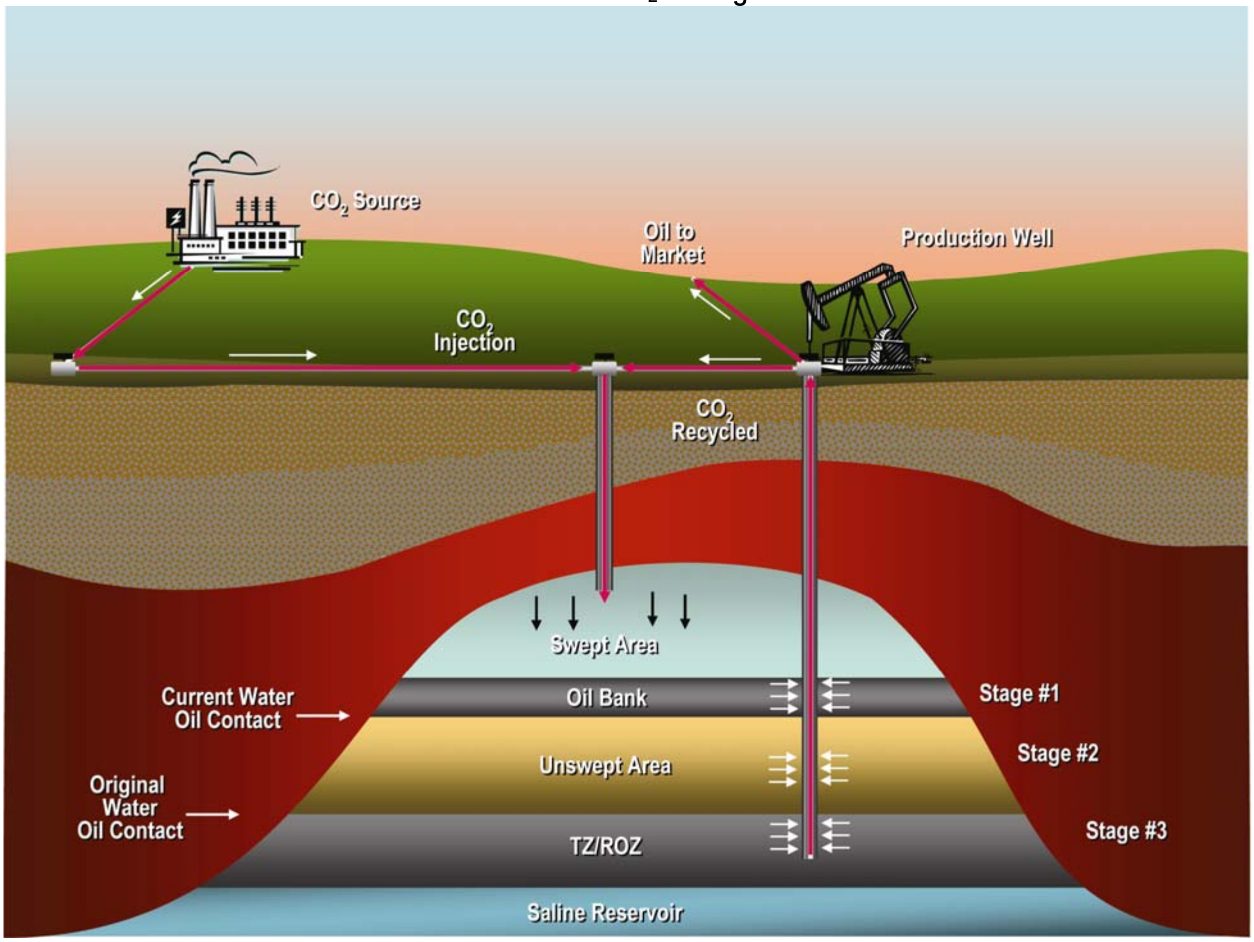
*Incremental technically recoverable oil resources after subtracting 2.3 billion barrels already being developed with CO2-EOR.
**Base Case Economics use an oil price of $70 per barrel (constant, real) and a CO2 cost of $45 per metric ton ($2.38/Mcf), delivered at pressure to the field.
Source: Advanced Resources International, Storing CO2 and Producing Domestic Crude Oil with Next Generation CO2-EOR Technology, Report DOE/NETL-2009/1350 prepared for the U.S. Department of Energy, National Energy Technology Laboratory, January 9, 2009

Table 11. Economically Feasible Market for CO_2 for "Next Generation" CO_2-EOR in the United States

Basin/Area	Gross Market for CO_2 (million metric tons) "Best Practices"	Gross Market for CO_2 (million metric tons) "Next Generation"	CO_2 Already or Scheduled to be Injected (million metric tons)	Net New Market for CO_2 (million metric tons) "Best Practices"	Net New Market for CO_2 (million metric tons) "Next Generation"
1. Alaska	2,094	2,094	-	2,094	2,094
2. California	1,375	1,556	-	1,375	1,556
3. Gulf Coast (AL, FL, MS, LA)	652	691	-	652	691
4. Mid-Continent (OK, AR, KS, NE)	1,443	1,845	20	1,423	1,825
5. Illinois/Michigan	127	329	-	127	329
6. Permian (W TX, NM)	2,712	3,598	570	2,142	3,028
7. Rockies (CO,UT,WY)	574	759	74	500	683
8. Texas, East/Central	1,940	2,099	-	1,940	2,099
9. Williston (MT, ND, SD)	130	122	-	130	122
10. Louisiana Offshore	1,368	1,368	-	1,368	1,368
11. Appalachia (WV, OH, KY, PA)	36	18	-	36	18
Total	12,451	14,477	664	11,787	13,813

*Base Case: Oil price of $70 per barrel; CO_2 cost of $45 per metric ton.
Source: Advanced Resources International, *Storing CO_2 and Producing Domestic Crude Oil with Next Generation CO_2-EOR Technology*, Report DOE/NETL-2009/1350 prepared for the U.S. Department of Energy, National Energy Technology Laboratory, January 9, 2009

Figure 10. Schematic Illustration of Coupling CO_2-EOR with Other Strategies to Maximize Cost-Effective CO_2 Storage



Additional CO_2-EOR and Associated CO_2 Storage Potential from Small Fields and Undiscovered Fields

To this point, we have only assessed the additional CO_2-EOR and associated CO_2 storage potential from large, previously discovered fields. Theoretically, additional CO_2-EOR and associated CO_2 storage potential also exists in smaller fields, in fields that remain to be discovered, and in the anticipated growth of fields that have been discovered. In order to include this "up-side" potential, we extrapolated the results from these large, previously discovered fields to these other resource categories, as described in the paragraphs below.

<u>Extrapolation to Small Fields</u>. Again based on Advanced Resources work in the United States, the resource potential from the known large discovered fields was extrapolated to smaller fields assuming the same ratio of OOIP in small fields to OOIP in large fields as that we estimated, on average, for the U.S. basins. Similarly, it was assumed that the recovery efficiency for CO_2-EOR in the U.S. basins would also apply to the smaller discovered fields in

non-U.S. basins. Under this assumption, CO_2-EOR operations in small fields would increase the technically recoverable CO_2-EOR resource by 174 billion barrels, from 469 to 643 billion barrels. Concurrently, the CO_2 storage potential would increase by 51 Gt, from 139 to 190 Gt (Table 12).

Extrapolation to Undiscovered Fields. Additionally, we included a consideration of the potential for CO_2 EOR operations in oil fields that have yet to be discovered. We calculated the volume of OOIP contained in undiscovered fields using the same methodology employed for discovered fields. In its 2000 World Petroleum Assessment, the USGS provides an estimate of the undiscovered resource potential in world basins.[50] We assumed that this was equivalent to undiscovered estimated ultimate recovery (EUR). These estimates of EUR were used as the basis for estimating undiscovered OOIP based on the primary and secondary production recovery efficiencies developed for the discovered portion of each world basin's resource base. To estimate the oil production and CO_2 storage potential of CO_2-EOR technology in these basins, we assumed the technology would perform with the same oil recovery efficiency and CO_2/oil ratio in the undiscovered portions of the world basins as was calculated in their discovered portions.

Extrapolation to Account for Reserve Growth in Discovered Fields. Experience shows that initial estimates of the size of newly discovered oil fields are usually too low. As years pass, successive estimates of the ultimate recovery of fields tend to increase. The term reserve growth refers to the typical increases in estimated ultimate recovery that occur as oil fields are developed and produced.[51] The USGS world petroleum assessment reports estimates of crude oil reserve growth potential worldwide, but does not break down this potential by basin or country. [52] Nonetheless, similar to the other resource categories, estimates of OOIP were developed based on USGS estimates of reserve growth potential; and the estimation methodologies comparable to those for discovered fields.

Table 13 reports undiscovered resource estimates for the U.S. Of an estimated 706 billion barrels of estimated OOIP in undiscovered fields in the U.S., 473 billion barrels of estimated OOIP (197 billion barrels from reserve growth, 276 billion barrels from undiscovered fields) are contained in areas relevant to this study.

Table 12. Results from Extrapolating World CO_2-EOR and Associated CO_2 Storage Potential to Smaller Fields Based on the United States Analog

Region Name	Miscible Basin Count	OOIP in Miscible Basins (MMBO)	Estimated CO2-EOR Recovery Efficiency	Large Fields				Small Fields			
				OOIP (MMBO)	OOIP In Miscible Fields (MMBO)	CO2 EOR Oil Recovery (MMBO)	CO2 Stored (GT)	OOIP (MMBO)	OOIP In Miscible Fields (MMBO)	CO2 EOR Oil Recovery (MMBO)	CO2 Stored (GT)
Asia Pacific	6	185,552	20%	172,630	91,818	18,376	5	63,850	33,960	6,797	2
Central and South America	6	347,336	18%	261,516	171,874	31,697	10	96,725	63,570	11,724	4
Europe	2	145,842	23%	106,465	72,168	16,312	5	39,377	26,692	6,033	2
Former Soviet Union	6	751,158	21%	548,345	371,700	78,715	22	202,813	137,478	29,114	8
Middle East and North Africa	11	2,205,843	21%	1,610,265	1,091,531	230,640	70	595,578	403,717	85,305	26
North America/Non U.S.	3	155,718	23%	113,674	77,055	18,080	6	42,044	28,500	6,687	2
United States	14	595,700	21%	438,782	290,348	60,204	17	156,918	106,368	22,573	6
South Asia	0	-	N/A	16,544	-	-	-	6,119	-	-	-
Sub-Saharan Africa and Antarctica	2	150,372	19%	109,771	74,409	14,505	4	40,600	27,521	5,365	2
Total	**50**	**4,537,521**	**21%**	**3,377,993**	**2,240,904**	**468,530**	**139**	**1,244,023**	**827,807**	**173,598**	**51**

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Table 13: Comparison of National and Analyzed Undiscovered Resources

US Undiscovered Oil Resources (BBO)	Undiscovered Fields*		Reserve Growth**		Total	
	OOIP	Reserves	OOIP	Reserves	OOIP	Reserves
Onshore						
Conventional Resource	142	48	179	60	321	108
Continious Oil (w/Bakken)					300	6
Residual Oil Zone					100	20
Tar Sands					80	10
Onshore Total	142	48	179	60	428	144
Offshore						
Gulf of Mexico	134	45	18	6	152	51
Other Offshore	123	41	3	1	126	42
Offshore Total	258	86	21	7	278	93
Total	**400**	**134**	**200**	**67**	**706**	**237**
Used in this Study	**276**	**92**	**197**	**66**	**473**	**158**

Indicates Reservoirs Applicable to this study

*Onshore Data is from USGS National Oil & Gas Assessment (NOGA). Offshore data from the Minerals Management Service (MMS). Assumes a 33.5% Recovery Factor

** Source: V.A. Kuuskraa "Undeveloped Domestic Oil Resources: The Foundation for Increasing Oil Production and Viabile Domestic Oil Industry", U.S. DOE/Office of Fossil Fuel, February 2006.

Table 14 shows how U.S. reserve growth data is used to develop a reserve growth estimate for the world basins. We estimate that 1,372 billion barrels of OOIP will be added to U.S. and world basins, of which 916 billion barrels will be available for miscible flooding. Based on average CO_2-EOR performance in these basins, we estimate that 191 billion barrels of this resource will be technically recoverable with CO_2-EOR technology. Recovering this volume of oil would require the purchase of an additional 57 Gt of CO_2

Table 14: Calculation of U.S. and World Reserve Growth Potential

Region	OOIP (BBO)		Reserve Growth (BBO)		CO2-EOR		
	Added due to Field Extensions*	Available for Miscible Flooding	Total Reserves Added*	Due to Field Extensions	Estimated Recovery****	Technically Reocoverable Resource (BBO)	CO2 Stored (Gt)
World	1,175	782	588	394	20.88%	163	49
US***	197	134	99	66	20.71%	28	8
Total	**1,372**	**916**	**686**	**460**	**21%**	**191**	**57**

* In the 2000 WPA, the USGS estimates 613 billion barrels of additional reserves could be added to known reserves in world oil bains. Because only 96% of the world known oil is contained in the basins anayized in this report, we assume only 96% of this is applicable to our analysis. The % of total reserves added in the form of field extentions was estimated based on US data, dicussed in the bullet below.

** Based on estimates of Reserve growth from Kuuskraa (2006). In this report, 100 billion barrels of reserves are estimated to be added to to reserve growth, of which 67 billion can be attributed to field extentions.

*** Assumes 33.5% recovery efficency, as was assumed in Kuuskraa (2006)

**** Estimated recovery ratios are taken from average CO2-EOR performance in discovered fields

Table 15 combines estimates of CO_2-EOR potential in discovered fields (large and small), undiscovered fields, and reserve additions. Of an estimated 7,710 billion barrels of OOIP, we estimate that 5,137 billion barrels will be amenable to miscible CO_2-EOR technology. Our analysis suggests that CO_2-EOR technology can make 1,072 billion barrels of this resource technically recoverable, and create the potential to store 318 Gt of CO_2.

Comparison to Other Studies of CO_2-EOR and Associated CO_2 Storage Potential

Worldwide Estimates. Not counting the potential from small fields, undiscovered resources, and estimated reserve growth in discovered fields, this study estimates that 469 billion barrels of incremental oil from CO_2-EOR is potentially technically recoverable worldwide, and would be associated with 139 Gt of potential CO_2 storage capacity. This estimate corresponds only to the potential from the application of CO_2-EOR in already discovered fields *as of the year 2000*.

In previous work by Advanced Resources for IEA GHG, CO_2 storage capacity in oil fields with CO_2-EOR potential worldwide was estimated to be 120 Gt, achieved by producing 350 billion barrels, which also included consideration of the potential in fields remaining to be discovered at that time.[53] Another IEA GHG study estimated that potential worldwide oil production from CO_2-EOR could be over 200 billion barrels, requiring from 67 to 72 Gt of CO_2 to achieve this potential.[54]

A study by Shell of the global potential scope for CO_2 flooding reports that 131 billion barrels of incremental recovery potential could be recovered; half of which is in the Middle East.[55] The potential CO_2 storage capacity associated with recovering this incremental oil was not reported.

North Sea Estimates. This study estimates that 14.4 billion barrels of incremental oil recovery could be achievable from the application of CO_2-EOR in the North Sea, potentially storing 4.0 Gt of CO_2. The earlier Advanced Resources study for IEA GHG reported 16.6 billion barrels of incremental oil and 5.3 Gt of corresponding CO_2 storage, but also included the potential in fields that remain to be discovered.

Another study describes a scenario in which, if some of the larger, most mature candidate fields of the North Sea were to adopt CO_2-EOR, they could conservatively produce 2.1 billion barrels of incremental oil over a 25-year “economic” life time, while sequestering 680 million tonnes of CO_2 in recognized secure depositories.[56]

Table 15. Results from Extrapolating World CO_2-EOR and Associated CO_2 Storage Potential to Resources that Remain to be Discovered

Region Name	Discovered Resources	Undiscovered Resources		Total OOIP (MMBO)	Total OOIP Available for Miscible Flooding (MMBO)	Estimated EOR Recovery Efficency	CO2-EOR Oil Technically Recoverable (MMBO)	CO2 Storage Potential (GT)
	OOIP (MMBO)	Reserves (MMBO)	OOIP (MMBO)					
Asia Pacific	236,480	12,486	38,167	274,647	148,404	20%	29,633	8
Central and South America	358,240	44,471	143,181	501,421	331,400	18%	61,071	20
Europe	145,842	14,111	41,244	187,086	126,818	23%	28,660	8
Former Soviet Union	751,158	107,448	303,459	1,054,617	714,881	21%	151,578	42
Middle East and North Africa	2,205,843	217,265	664,218	2,870,061	1,945,494	21%	411,523	125
North America/Non U.S.	155,718	8,408	24,785	180,503	122,356	23%	28,696	9
United States	595,700	92,450	275,970	871,670	580,503	21%	121,126	34
South Asia	22,663	2,091	5,615	28,278	0	N/A		
Sub-Saharan Africa and Antarctica	150,372	70,234	219,628	370,000	250,807	19%	48,881	15
Sub Total	**4,622,017**	**568,964**	**1,716,266**	**6,338,283**	**4,220,662**	**21%**	**881,167**	**261**
World Reserve Growth				1,175,040	782,446	21%	163,370	49
US Reserve Growth				197,015	133,548	21%	27,658	8
Sub Total				**1,372,055**	**915,995**	**21%**	**191,028**	**57**
Grand Total	**4,622,017**	**568,964**	**1,716,266**	**7,710,338**	**5,136,656**	**21%**	**1,072,195**	**318**

One study of selected fields in Norway concluded that EOR could increase ultimate oil recovery by 2 billion barrels, or about 10% of production to date plus remaining reserves.[57] Another recent study provided updated predictions for 18 Norwegian and 30 U.K. North Sea oil fields. From 4 to 6 billion barrels was estimated to be recoverable (incremental oil recovery of 8.5% to 9.0% of the OOIP) from the application of CO_2-EOR, and could result in the storage of about 2.3 Gt of CO_2.[58]

Finally, a study assessing the storage potential for North Sea oil fields off the coast of Scotland determined that from a resource of more than 200 hydrocarbon fields, 14 oil fields were determined to be amenable to CO_2-EOR and can be used for CO_2 storage in conjunction with CO_2-EOR technology. These fields were estimated to provide the potential for as much as 3.0 billion barrels of incremental oil recovery from the application of CO_2-EOR, and could potentially store about 1 Gt of CO_2 associated with its application.[59]

Alberta Basin Estimates. This study estimates that 4.7 billion barrels of incremental oil recovery could be amenable to CO_2-EOR in the Alberta Basin, potentially storing 1.4 Gt of CO_2. Earlier Advanced Resources estimates for IEA GHG reported 4.2 billion barrels of incremental oil and 1.3 Gt of corresponding CO_2 storage. Another study of only selected fields concluded that 1.1 billion barrels of incremental recovery could be obtained from applying CO_2-EOR in oil pools in Southern Alberta only, with potential CO_2 storage capacity of about 1.0 Gt.[60]

Summary. In general, the basin-specific estimates in this study for the potential for CO_2-EOR and associated CO_2 storage are larger than previously-reported results for the following three primary reasons:

- In most cases, this study assesses a larger number of fields than were assessed in the comparable studies.
- This study used screening criteria for determining reservoirs that might be amenable to the application of CO_2-EOR that are less constraining than criteria traditionally used.
- This study is based on more optimistic assumptions about the performance of CO_2-EOR in amenable reservoirs, in particular the amount of cumulative CO_2 injected, which generally leads to higher estimates of recovery efficiency due to the application of CO_2-EOR.

5. COMPARISONS OF BASIN-LEVEL AND FIELD-BASED ANALYSES

The results from the basin-level analyses were compared to more detailed field-based analyses for fields in various non-U.S. basins. These basins included: North Sea Graben Basin (only fields in United Kingdom waters), the Western Siberian Basin, and selected fields in four basins in the Middle East (Mesopotamian Foredeep, Greater Ghawar, Rub Al Khali, and the Fahud Salt Basins). These basins were selected based on the public availability of relatively good field-level data.

These field-level analyses were conducted using the same analytical approach used by Advanced Resources in a series of basin studies performed for DOE, the most recent published in January 2009.[61] This work builds on previous analyses of currently practiced CO_2-EOR technology, as reported in "*Storing CO_2 with Enhanced Oil Recovery*"[62] and a series of "*Ten Basin-Oriented Reports*". [63] This approach is summarized briefly as follows:

1. ***Assemble Oil Fields Data Base.*** This requires the development of up-to-date, volumetrically consistent field-level data that contain essential data, formats and interfaces to: (1) develop an accurate estimate of the size of the original and remaining oil in-place; (2) reliably screen the fields as to their amenability for miscible or immiscible CO_2-EOR; and, (3) provide the essential input data for estimating CO_2 injection requirements and oil recovery.
2. ***Calculate Minimum Miscibility Pressure (MMP).*** The miscibility of a field's oil with injected CO_2 is a function of pressure, temperature and the composition of oil. The study's approach to estimating whether a field's oil will be miscible with CO_2, given fixed temperature and oil composition, was to determine whether it could hold sufficient pressure to attain miscibility. Where oil composition data was missing, a correlation was used for translating the oil gravity to oil composition. The approach for the calculation was described above.
3. ***Screen Fields for CO_2-EOR.*** The fields were screened to determine those that would be amendable for CO_2-EOR. Five prominent screening criteria were used: depth, oil gravity, pressure, temperature, and oil composition. These values were used to establish the MMP, and for selecting fields that would be amenable to this oil recovery process. Fields not meeting the MMP standard were not considered.

   The preliminary screening steps involved selecting the fields that had sufficiently high oil gravity. A minimum depth of 915 meters (3,000 feet), at the mid-point of the field, was used to ensure the field could accommodate high pressure CO_2 injection. A minimum oil gravity of 17.5 ^{o}API was used to ensure the oil had sufficient mobility, without requiring thermal injection.
4. ***Estimate Oil Recovery Potential.*** The study utilized *CO_2-PROPHET* to calculate incremental oil produced using CO_2-EOR. *CO_2-PROPHET* generates streamlines for fluid flow between injection and production wells, and the model performs oil displacement and recovery calculations along the established streamlines. (A finite difference routine is used for oil displacement calculations.) *It is important to note the CO_2-PROPHET is still primarily a "screening-type" model, and lacks some of the key*

features, such as gravity override and compositional changes to fluid phases, available in more sophisticated reservoir simulators.

5. ***Estimate CO_2 Injection Requirements for CO_2-EOR.*** *CO_2-PROPHET* also estimates the amount of CO_2 that would need to be injected to recover the estimated amount of oil to be produced. It estimates both the amount of CO_2 that would need to be purchased, and that which would be recycled as part of recovery operations. For purposes of this study, the amount of CO_2 originally purchased was assumed to be equivalent to the amount of CO_2 ultimately stored after CO_2-EOR operations are completed.

Further documentation of CO2-PROPHET and its benchmarking against actual field results and reservoir simulators is described in Appendix C.

For the purposes of this study, the CO_2-EOR recovery potential (the percentage of OOIP that could be recovered by CO_2-EOR) is compared between the field-level and basin-level analysis.

The results of the field-level analyses for the selected areas are summarized in the paragraphs below, and presented in more detail in Appendix E.

North Sea Graben Basin. In the North Sea Graben Basin, 14 sandstone fields in U.K. waters were selected that were amenable to CO_2-EOR for use in this analysis. These fields are reported to contain 16 billion barrels of OOIP, or 14% of the over 117 billion barrels of OOIP estimated to be contained in all fields in the North Sea Graben Basin using the USGS data.[64,65] In the field level analyses, the average field-specific recovery efficiency from the application of CO_2-EOR was determined to be 17.5%, compared to an estimated value of 22.7% determined from the basin-level analyses. One reason for the lower recovery efficiency in the field level analysis is that many of the North Sea fields have used natural gas injection to increase oil recovery by 3% to 4%, thus reducing the fraction of OOIP available for CO_2-EOR. Adjusting for this condition, the field level and basin level results are reasonably consistent. The CO_2:incremental oil ratio was determined to be about 0.297 tonnes CO_2 per barrel of oil for the field-level and 0.280 for the basin level analyses.

Western Siberian Basin. In the Western Siberian Basin, 19 sandstone fields that were screened to be amenable to CO_2-EOR were selected for more detailed analyses. In the database, it was reported that these fields contained 126 billion barrels of OOIP, or 33% of the 381 billion barrels of OOIP estimated to be contained in all fields in the basin. In the field level analyses, the average field-specific recovery efficiency from the application of CO_2-EOR was determined to be 18.9%, compared to an estimated value of 21.4% determined from the basin-level analyses. The CO_2:incremental oil ratio was determined to be 0.286 tonnes CO_2 per barrel for the field-level analyses compared to 0.267 tonnes CO_2 per barrel of oil for basin-level analyses.

Middle Eastern Basins. In the four Middle Eastern Basins, 14 carbonate fields that were screened to be amenable to CO_2-EOR were selected for more detailed analyses. In summary,

- In the Mesopotamian Foredeep Basin, the two fields assessed contained 55 billion barrels of OOIP, or 6% of the over 878 billion barrels of OOIP estimated to be contained in all fields in the basin.
- In the Greater Ghawar Basin, the three fields assessed contained 8 billion barrels of OOIP, or 2% of the over 400 billion barrels of OOIP estimated to be contained in all fields in the basin.
- In the Rub Al Khali Basin, the eight fields assessed were reported to contain nearly 178 billion barrels of OOIP, or 70% of the 255 billion barrels of OOIP estimated based on the basin level analyses.
- In the Fahud Salt Basin, the one field assessed contained 6.4 billion barrels of OOIP, or 45% of the 14 billion barrels of OOIP estimated in the basin-level analysis.

The field level analyses results for the Middle Eastern Basins is summarized as follows.

- In the Mesopotamian Foredeep Basin, average field-specific recovery efficiency from the application of CO_2-EOR was determined to be 13.5%, compared to an estimated value of 19.8% determined from the basin-level analyses. The CO_2:incremental oil ratio was determined to be 0.363 tonnes CO_2 per barrel for the field-level analyses, compared to 0.306 tonnes CO_2 per barrel of oil for basin-level analyses.
- In the Greater Ghawar Basin, average field-specific recovery efficiency from CO_2-EOR was determined to be 24.7%, compared to an estimated value of 22.2% determined from the basin-level analyses. The CO_2:incremental oil ratio was determined to be 0.303 tonnes CO_2 per barrel for the field-level analyses, compared to 0.286 tonnes CO_2 per barrel of oil for the basin-level analyses.
- In the Rub Al Khali Basin, average field-specific recovery efficiency from CO_2-EOR was determined to be 24.8%, compared to an estimated value of 23.0% determined from the basin-level analyses. The CO_2:incremental oil ratio was determined to be 0.285 tonnes CO_2 per barrel for the field-level analyses, compared to 0.314 tonnes CO_2 per barrel of oil for the basin-level analyses.
- In the Fahud Salt Basin, average field-specific recovery efficiency from CO_2-EOR was determined to be 23.2%, compared to an estimated value of 21.5% determined from the basin-level analyses. The CO_2:incremental oil ratio was determined to be 0.295 tonnes CO_2 per barrel for the field-level analyses, compared to 0.294 tonnes CO_2 per barrel of oil for basin-level analyses.

Summary. The comparison of field and reservoir level estimation techniques above suggests that, though field level results tend to be generally comparable with reservoir level estimations; there is variability in results that cannot be explained at the reservoir level.

The complex nature of these basins cannot be fully captured in the two variable (API gravity and depth) analysis, which due to data availability constraints, was used as the basis of this screening level assessment. In especially complex, heterogeneous basins such as Western Siberia and the North Sea, lack of specific reservoir information can lead to overly optimistic results, as basin complexity would tend to decrease oil recovery that is not accounted for in the current methodology. In the more high-quality, homogeneous Middle-Eastern basins, such as the Rub Al-Khali, Greater Ghawar, and Fahud Salt basins, where basin complexity is less of a factor influencing oil recovery, the basin level and field level results are more comparable.

However, data resolution and availability will be a problem in any evaluation of complex reservoir phenomenon. Considering the lack of data available for world reservoirs, the results of this field-reservoir level comparison suggest that our basin-level estimations are sufficient for the screening-level assessment of the CO_2-EOR potential of world basins that was the objective of this assessment.

6. MATCHING CO_2 SOURCES WITH CO_2-EOR AMENABLE BASINS

Up to this point, this assessment has focused on assessing the oil recovery and associated CO_2 storage potential of CO_2-EOR in world oil basins. The third important criterion discussed in this report is the availability of sufficient, affordable and sustainable volumes of pure CO_2 supplies for use in CO_2-EOR.

In this regard, an assessment was performed of the relative contribution anthropogenic sources of CO_2 could make in facilitating the recovery of the worldwide resource potentially recoverable through the application of CO_2-EOR technologies.

Data Sources

Data on global anthropogenic CO_2 emissions were gathered from the 2008 version of the IEA GHG CO_2 Emissions Database.[66] The database was first developed in 2002, as part of a concurrent IEA GHG study,[67] and has since been continuously revised and expanded. The database contains details on major worldwide sources of CO_2 emissions, including:

- Name of source
- Location (country, latitude and longitude)
- Sector
- Capacity, hours of operation, and annual emissions
- Percentage of CO_2 in flue gases
- Expected growth in emissions.

In its current form, the database contains information on annual CO_2 emissions from 16 types of sources. Table 16 shows which categories of sources were considered high and low CO_2 concentration, respectively, in this study.

Table 16. List of Categories of High and Low CO_2 Concentration Emissions Sources

High CO_2 Concentration Sources	Low CO_2 Concentration Source
Ammonia	Cement
Ethanol	Ethylene
Ethylene Oxide	Iron & Steel
Hydrogen	Biomass Production
Oil and Gas Extraction	Power
Refineries	Aluminum Processing
Fertilizer	Paper Mills
Gas Processing	
Chemicals	

Approximately 9,100 discrete records for CO_2 emissions sources are contained within this database, of which approximately 4,800 contain location information. For purposes of this study, all sources that had associated location information and were classified as operational with annual CO_2 emissions greater than 200,000 tonnes per year were used. Though this volume cutoff may exclude some sources of low-volume, high purity CO_2, such as some ethylene oxide plants, our objective was to identify those anthropogenic sources with the most potential to provide the large volumes of CO_2 needed by CO_2-EOR operations. Even with a 200,000 tonnes/year CO_2 emissions cap, we still included 99% of the anthropogenic CO_2 emissions contained in the IEA database in this analysis.

Spatial/Quantitative Analysis

Data from the IEA GHG CO_2 emissions sources database were projected into a GIS map containing the location and spatial extent of the hydrocarbon basins identified as having CO_2-EOR potential. After screening for distance criteria, each basin's spatial reference information was used to create basin-specific databases of CO_2 emissions. These databases were disaggregated by CO_2 emissions source and used to develop estimates of the volume of high and low concentration CO_2 emissions that could potentially be captured and used for CO_2-EOR operations in each basin.

For the purposes of this study, three scenarios were assumed for identifying viable sources of CO_2 within each oil basin:

- Immediate CO_2 sources. These sources represent those in close proximity to oil fields within the basin, representing specific, individual source-sink pairings. In this scenario, only sources within 15 kilometers of the perimeter of each basin are considered viable to supply CO_2 to the CO_2-EOR prospects.

- Intermediate CO_2 sources. These sources represent those that could be aggregated within a basin to facilitate a network of sources and sinks (oil fields) within a basin. In this scenario, all sources within a 200 kilometer perimeter of each basin are considered.
- Long distance CO_2 sources. These sources represent the scenario where large concentrations of CO2 emission sources are linked with large concentrations of CO2 sinks (oil fields) that are not close to the sources. In this scenario, all sources within 800 kilometers of the basin perimeter are considered viable CO_2 sources.

Figure 11 shows these scenarios as applied to the North Sea Graben basin. All CO_2 sources that fall within the buffer areas shown on the map were considered viable sources under the scenarios discussed above. Though not evaluated in this report, the map also illustrates a 1,600 kilometer radius scenario that represents a region-wide high volume CO_2 transport infrastructure. In this scenario, most of the CO_2 emissions of Western Europe would be within a feasible distance of the North Sea Graben oilfields. In this and the 800 km scenario, all of the basin's CO_2-EOR CO_2 demand can be met by anthropogenic sources, as shown in Table 17.

For concentrations of large-scale CO_2-EOR operations, the long-distance scenario can be quite viable, because it can take advantage of economies of scale in transporting larger volumes of CO_2 through pipelines that connect multiple sources, perhaps to areas that contain multiple fields that can be used for CO_2-EOR and CO_2 storage. In the U.S., there is already precedence for this type of scenario; Denbury Resources is constructing a 320 mile (515 km) pipeline to bring natural and anthropogenic CO_2 to oil fields throughout southern Louisiana and eastern Texas. This line (the so-called "Green Pipeline") is designed to transport up to 13 million tonnes per year (800 MMcfd) of both natural and man-made (anthropogenic) CO_2. Though long itself, this pipeline is but an extension of an already significant pipeline infrastructure Denbury has constructed to bring CO_2 down from the Jackson Dome in Mississippi into Louisiana.

Figure 11. Location of CO_2 Sources near the North Sea Graben Basin

Table 17. Comparison of Potential Anthropogenic CO_2 Supply Sources from North Sea Graben CO_2-EOR Candidates, as a Function of Distance

North Sea Graben	High Concentration CO2 (Million Tons)	Low Concentration CO2 (Million Tons)	Total (Million Tons)
CO2 Supply			
15 Kilometers	206	291	497
200 Kilometers	526	1,196	1,722
800 Kilometers	1,853	22,090	23,943
1,600 Kilometers	1,981	36,197	38,177
CO2 Demand for EOR	--	--	3,691

But Denbury is also looking at bigger plans for moving CO_2 from areas where there are high concentrations of emissions, to areas where there is large potential for CO_2-EOR. In July 2009, Denbury announced that it has initiated a comprehensive feasibility study, in collaboration with the Illinois Department of Commerce and Economic Opportunity, of a possible long-term CO_2 pipeline project which would connect proposed gasification plants in the Midwest to its existing CO_2 pipeline infrastructure in Mississippi or Louisiana (Figure 12).[68] The feasibility study is expected to determine the most likely pipeline route, the estimated costs of constructing such a pipeline, and review regulatory, legal and permitting requirements. Denbury's preliminary internal estimates suggest this would be an 800 to 1,100 kilometer pipeline system with a preliminary cost estimate of approximately $1.0 billion.[69]

Figures 13 and 14 show the effect each distance scenario has on volumes of oil that could be produced from CO_2-EOR and the amount of CO_2 that could be subsequently stored. Under the long distance CO_2 scenario, 34 basins, with 154 billion barrels of oil technically recoverable through CO_2-EOR, would have sufficient sources of CO_2. Additionally, 71 billion barrels of oil could be produced in basins in which CO_2 demand was partially met by anthropogenic supplies. CO_2-EOR operations in these basins could purchase, and store, 65 Gt of CO_2 (of which 44 Gt are in basins with sufficient CO_2 supplies) over 30 years, approximately 19% of the total CO_2 emissions from the basins.[70]

Figure 12. Denbury Resources' Vision for Moving Midwest CO_2 Supplies to the U.S. Gulf Coast CO_2-EOR Market

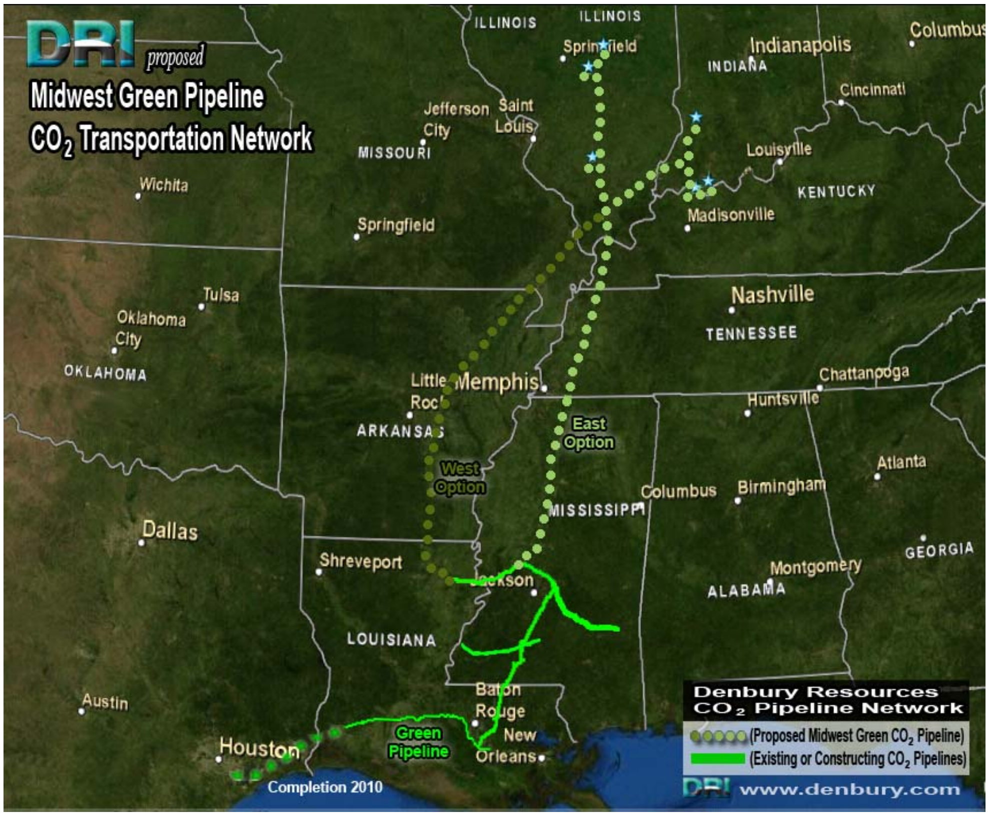


Figure 13. CO_2-EOR Oil Production Potential of Basins with Sufficient CO_2 Supplies

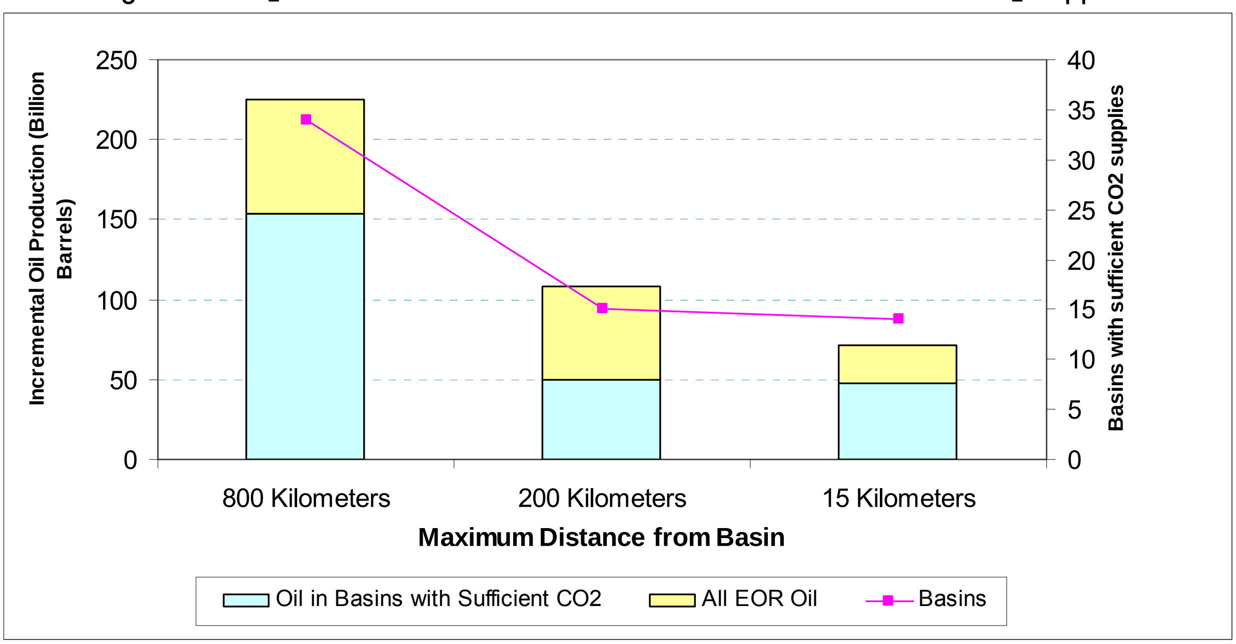
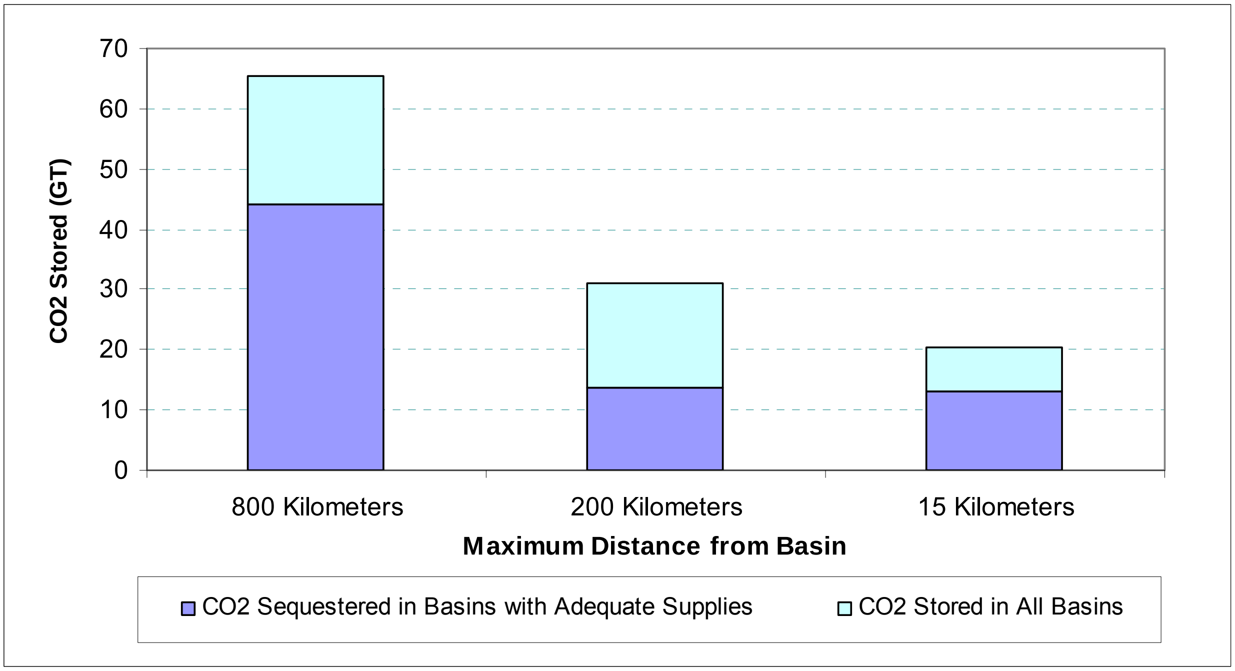


Figure 14. CO_2 Storage Potential Associated with CO_2-EOR Oil Production of Basins with Sufficient CO_2 Supplies



With decreasing distance, the potential for incremental oil recovery and CO_2 storage falls. Under the intermediate CO_2 sources scenario, 15 basins would have access to sufficient supplies of CO_2 for EOR operations. These basins could produce 50 billion barrels of stranded oil and store 14 Gt of captured CO_2 emissions.

The immediate CO_2 sources scenario produces very similar results. If oil fields could only access CO_2 sources within 15 kilometers of their basin perimeter, 13 basins would still have sufficient CO_2 supplies to meet the needs of an EOR market. Under this scenario, CO_2-EOR operations could produce 42 billion barrels of incremental oil and store 12 Gt of captured CO_2 emissions.

More detailed information about each distance scenario is provided in Appendix F.

Application of Other Screening Criteria

In addition to meeting technical criteria for achieving miscibility, having a large potential for CO_2-EOR (and associated CO_2 storage capacity), and a good source CO_2 supplies at affordable costs, the other factors identified for contributing to EOR success were operator knowledge, comfort and willingness to pursue the use CO_2-EOR technologies; willingness and ability of the applicable regulatory regime to permit CO_2-EOR projects; and the availability of government financial incentives to promote the implementation of CO_2-EOR projects. For the basins listed in the tables above, on a relative scale, these factors are arguably most attractive in the U.S., Canadian, West European, and Australian basins, and less attractive in the other basins. However, changes in public policy in any of these countries could change the relative ranking considerably. For example, there have been a number of CO_2-EOR pilots in the Bohaiwan and Songliao basins in China, so operator knowledge, comfort and willingness to pursue the use CO_2-EOR technologies in China is improving, as is the Chinese government's interest in pursuing such projects.

7. IMPACT OF CO_2 TRANSPORT ECONOMIC STORAGE CAPACITY

The estimates of incremental oil recovery potential and associated CO_2 storage capacity from the application of CO_2-EOR processes developed to this point represent technical potential. Clearly, it will be important to understand what portion of this potential is economic under various scenarios of crude oil prices and CO_2 costs and/or emission reduction credits. Thus, there is a need to assess the impact of possible CO_2 transport costs on the overall CO_2-EOR recovery potential of oil basins considered in this assessment.

Estimated Costs of CO_2 Transport

The impact of potential transport distance on economic CO_2-EOR potential can be determined by estimating the impact of these transport distances on the cost of delivered CO_2 to the CO_2-EOR producer. To develop this relationship, we employed Advanced Resources' in-house CO_2 transportation cost model, which can estimate a CO_2 transport "tariff" as a function of the estimated output pressure of the CO_2 source, the volume of CO_2 required for CO_2-EOR operations, and the distance to be transported. This model is discussed in more detail below.

CO_2 transport costs were estimated for each basin by establishing basin-specific project parameters, such as average pipeline distance and CO_2 mass flow rate, and inputting these into the CO_2 transportation cost model.

It is important to note that the focus here is only on transport costs, where the additional costs of transport are represented in terms of the purchase price of CO_2 for the operator of the field. The cost of CO_2 capture is by far the largest cost component of carbon capture, storage and transport. Moreover, some of the costs associated with CCS (net of carbon credits) will be passed on to the operator of the CO_2-EOR project (and subsequent storage) if the market will support the total cost of capture and delivery. Also, for simplicity, the costs represented here are for onshore transportation only. Additional costs will need to be considered for those basins that are predominantly offshore.

Representative Distance of Pipelines. A representative distance of a CO_2 pipeline transport system was defined for three scenarios:

- The first scenario assumes simple source-sink matching of each candidate oil fields and their closest source of CO_2 (the "1 to 1" scenario).
- The second scenario assumes a centralized "trunk line" system in which higher volume CO_2 pipelines link multiple CO_2 sources and serve several CO_2-EOR projects (the "trunk line" scenario) within a basin.

- The third scenario was based on a situation where a long distance (800 kilometer) pipeline would be built to connect a large concentration of CO_2 emission sources to a basin with a large potential for CO_2-EOR (the "long distance" scenario.") This 800 km pipeline is comparable to the length of the Cortez CO_2 pipeline serving Permian Basin CO_2-EOR projects in the U.S., or the CO_2 pipeline Denbury is considered from the Midwest U.S. to the Gulf Coast.

To estimate the average distance of a CO_2 pipeline under the first scenario, the location information for large oil fields contained in the Giant Oil Fields Database by M.K. Horn was used.[71] For CO_2 sources, location information from the IEA GHG CO_2 Emissions Database was used.[72] The minimum distance from each oil field to the nearest viable CO_2 source to it was estimated. A "representative" minimum source-sink distance for all oil fields in a basin was then estimated as the average distance of all the potential source-sink linkages within that basin.

The average distance of a CO_2 pipeline in the second "trunk line" scenario was assumed to be twice the distance of the "representative" pipeline calculated above.

Representative Volume of CO_2 Transported. For the simple source-sink matching scenario, a representative CO_2 volume transported was defined as the average CO_2 emissions from the sources contained inside the perimeter of the basin. Under the "trunk line" scenario, the CO_2 volume transported was assumed to be five times the volume calculated above, constrained by the volume of emissions in each basin.

In the "long distance" scenario, two cases were examined – one where the volume of CO_2 transported was 53,000 tonnes per day (approximately one Bcfd), and another where the volume of CO_2 transported was half that, or 26,500 tonnes per day (or approximately 500 MMcfd). Again, these rates are comparable to the current long distance CO_2 pipelines currently serving the CO2-EOR market in the Permian Basin in the U.S.

Under all scenarios, the pipeline inlet pressure was set at 15 mega pascals (MPa), or approximately 2,175 psi, which corresponds to the default inlet pressure used in a report on the economics of CO_2 transport and storage by McCollum and Ogden[73]. Pipeline outlet pressure was set at 13 MPa, or approximately 1,885 psi, to represent a conservative estimate of pressure requirements for miscible CO_2-EOR operations.

Calculating CO_2 Transportation Costs. To estimate CO_2 transportation costs, the above calculated parameters were input into Advanced Resources' in-house CO_2 transportation model. The model calculates the physical specifications of the pipeline and compression equipment using data given in the McCollum and Ogden report. Project capital and O&M costs are calculated from these specifications based on proprietary costing equations developed by ARI under consultation with representatives from private industry.

In addition to pipeline costs, the model estimates the cost of CO_2 booster stations, which are required to maintain adequate CO_2 pressure inside the pipeline. In the simple source-sink scenario, booster stations are assumed to be required for every 60 miles of pipeline. To account for the larger volumes of CO_2 being transported in the "trunk line" scenario, booster stations were assumed to be needed every 40 miles. These distances were chosen to provide a representative estimate of booster requirements. To calculate exact distance between pipeline booster stations, data on elevation change, exact inlet and outlet pressures, pipeline friction factors, etc., would be required. Unfortunately, such data were not readily available for each basin for this high level screening study.

The model estimates project capital and operating and maintenance (O&M) costs in total and per tonne of CO_2 or kilometer of pipeline. For this study, cost estimates were provided per tonne of CO_2, as these are an approximation of the CO_2 transportation tariff to which EOR project operators could be subject. As in the McCollum & Ogden paper, project costs are annualized assuming an industry-standard 15% annual capital recovery factor. Annualized costs are expressed per tonne of CO_2 transported assuming the pipeline will have a capacity factor of 85%, based on guidance from pipeline operators.

These assumptions were used to develop representative CO_2 transport tariffs for each case discussed above for 14 basins where estimated CO_2 emissions from industrial sources exceed estimated CO_2 storage capacity associated with CO_2-EOR opportunities. Table 18 summarizes the costing assumptions for the "1 to 1" scenario, while Table 19 summarizes the costs for the "trunk line" scenario. The two cases are compared side by side in Table 20.

The transport costs summarized in Table 20 ranges from a low of about $1.16 per tonne to a high of $7.23 per tonne. The costs are somewhat lower for the "trunk line" scenario, primarily based on the higher CO_2 volumes being transported.

For the long distance scenario, the cost assumptions for the two cases are summarized in Tables 21 and 22. For the higher rate (53,000 tonnes per day) case, CO_2 transport costs are estimated to be on the order of $10 per tonne. For the lower rate (26,500 tonnes per day) case, costs are estimated to be on the order of $15 per tonne.

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Table 18. Summary of Costing Assumptions for the "1 to 1" Scenario for 14 Basins where Industrial Emissions Exceed CO_2 Storage Capacity with CO_2-EOR

Basin	Average Distance b/n Sources and Sinks (km)	Average Source CO2 Flow Rate (kt/year)		Pipeline Capital Costs		Booster Station Capital Costs		Total Capital Costs		Annual O&M		Total Costs
		(kt/year)	(tonne/ day)	Total ($/1000)	$/Tonne	Total ($/1000)	$/Tonne	Total ($/1000)	$/Tonne	Total ($/1000)	$/Tonne	$/Tonne
Mid Continent	101.39	2,690	7,370	$ 80,368	$ 5.27	$ 1,378	$ 0.09	$ 81,746	$ 5.36	$ 4,279	$ 1.87	$ 7.23
East Central Texas	44.58	2,099	5,751	$ 30,042	$ 2.53	$ -	$ -	$ 30,042	$ 2.53	$ 1,502	$ 0.84	$ 3.37
Rockies	75.32	3,833	10,501	$ 59,812	$ 2.75	$ 1,963	$ 0.09	$ 61,776	$ 2.84	$ 3,362	$ 1.03	$ 3.88
Bohaiwan Basin	53.11	3,573	9,789	$ 42,302	$ 2.09	$ -	$ -	$ 42,302	$ 2.09	$ 2,115	$ 0.70	$ 2.79
Gulf Coast	53.75	2,393	6,556	$ 36,136	$ 2.66	$ -	$ -	$ 36,136	$ 2.66	$ 1,807	$ 0.89	$ 3.55
Williston Basin (US)	90.03	3,625	9,932	$ 71,416	$ 3.48	$ 1,857	$ 0.09	$ 73,273	$ 3.57	$ 3,922	$ 1.27	$ 4.84
Williston Basin (CA)	56.33	2,959	8,107	$ 44,839	$ 2.67	$ -	$ -	$ 44,839	$ 2.67	$ 2,242	$ 0.89	$ 3.57
Carpathian Basin	48.65	1,066	2,921	$ 29,470	$ 4.88	$ -	$ -	$ 29,470	$ 4.88	$ 1,473	$ 1.63	$ 6.50
Songliao Basin	40.41	3,229	8,847	$ 27,273	$ 1.49	$ -	$ -	$ 27,273	$ 1.49	$ 1,364	$ 0.50	$ 1.99
Gippsland Basin	56.33	6,866	18,811	$ 49,651	$ 1.28	$ -	$ -	$ 49,651	$ 1.28	$ 2,483	$ 0.43	$ 1.70
Coastal Basin	32.33	1,190	3,260	$ 17,658	$ 2.62	$ -	$ -	$ 17,658	$ 2.62	$ 883	$ 0.87	$ 3.49
Los Angeles Basin	16.13	1,052	2,882	$ 9,022	$ 1.51	$ -	$ -	$ 9,022	$ 1.51	$ 451	$ 0.50	$ 2.02
San Joaquin Basin	44.31	1,098	3,008	$ 26,876	$ 4.32	$ -	$ -	$ 26,876	$ 4.32	$ 1,344	$ 1.44	$ 5.76
Alberta Basin	56.33	2,369	6,490	$ 37,847	$ 2.82	$ -	$ -	$ 37,847	$ 2.82	$ 1,892	$ 0.94	$ 3.76

Table 19. Summary of Costing Assumptions for the "Trunk Line" Scenario for 14 Basins where Industrial Emissions Exceed CO_2 Storage Capacity with CO_2-EOR

Basin	Average Distance b/n Sources and Sinks (km)	Average Source CO2 Flow Rate (kt/year)		Pipeline Capital Costs		Booster Station Capital Costs		Total Capital Costs		Annual O&M		Total Costs
		(kt/year)	(tonne/ day)	Total ($/1000)	$/Tonne	Total ($/1000)	$/Tonne	Total ($/1000)	$/Tonne	Total ($/1000)	$/Tonne	$/Tonne
Mid Continent	202.78	13,450	36,849	$ 310,880	$ 4.08	$ 34,450	$ 0.45	$ 345,329	$ 4.53	$ 22,052	$ 1.93	$ 6.46
East Central Texas	89.16	10,495	28,753	$ 104,874	$ 1.76	$ 10,752	$ 0.18	$ 115,626	$ 1.94	$ 7,275	$ 0.82	$ 2.76
Rockies	150.63	19,165	52,507	$ 251,176	$ 2.31	$ 29,452	$ 0.27	$ 280,628	$ 2.58	$ 18,123	$ 1.11	$ 3.70
Bohaiwan Basin	106.22	17,865	48,945	$ 163,046	$ 1.61	$ 18,303	$ 0.18	$ 181,349	$ 1.79	$ 11,610	$ 0.76	$ 2.56
Gulf Coast	107.50	11,965	32,781	$ 138,510	$ 2.04	$ 12,258	$ 0.18	$ 150,768	$ 2.22	$ 9,241	$ 0.91	$ 3.13
Williston Basin (US)	180.07	18,125	49,658	$ 325,471	$ 3.17	$ 37,139	$ 0.36	$ 362,610	$ 3.53	$ 23,290	$ 1.51	$ 5.04
Williston Basin (CA)	112.65	14,795	40,534	$ 158,625	$ 1.89	$ 15,158	$ 0.18	$ 173,783	$ 2.07	$ 10,795	$ 0.86	$ 2.93
Carpathian Basin	97.30	5,330	14,603	$ 85,458	$ 2.83	$ 5,461	$ 0.18	$ 90,918	$ 3.01	$ 5,305	$ 1.17	$ 4.18
Songliao Basin	80.82	16,145	44,233	$ 113,923	$ 1.25	$ 16,541	$ 0.18	$ 130,464	$ 1.43	$ 8,821	$ 0.64	$ 2.07
Gippsland Basin	112.65	15,500	42,466	$ 158,625	$ 1.81	$ 15,880	$ 0.18	$ 174,505	$ 1.99	$ 10,931	$ 0.83	$ 2.82
Coastal Basin	64.66	5,950	16,301	$ 56,936	$ 1.69	$ 3,048	$ 0.09	$ 59,984	$ 1.78	$ 3,423	$ 0.68	$ 2.46
Los Angeles Basin	32.25	5,260	14,411	$ 25,857	$ 0.87	$ -	$ -	$ 25,857	$ 0.87	$ 1,293	$ 0.29	$ 1.16
San Joaquin Basin	88.61	5,490	15,041	$ 77,863	$ 2.50	$ 5,625	$ 0.18	$ 83,488	$ 2.68	$ 4,956	$ 1.06	$ 3.75
Alberta Basin	112.65	11,845	32,452	$ 145,124	$ 2.16	$ 12,135	$ 0.18	$ 157,260	$ 2.34	$ 9,549	$ 0.95	$ 3.29

Table 20. Comparison of Representative CO_2 Transport Costs for the "1 to 1" and "Trunk Line" Scenarios for the 14 Basins where Industrial Emissions Exceed CO_2 Storage Capacity with CO_2-EOR

Basin	Average Distance b/n Sources and Sinks (km)		Average Source CO2 Flow Rate (kilotonne/year)		Total CO2 Transportation Costs ($/Tonne)	
	1 to 1	Trunkline	1 to 1	Trunkline	1 to 1	Trunkline
Mid Continent	163.17	326.34	2,690	13,450	$ 7.23	$ 6.46
East Central Texas	71.74	143.49	2,099	10,495	$ 3.37	$ 2.76
Rockies	121.21	242.42	3,833	19,165	$ 3.88	$ 3.70
Bohaiwan Basin	85.47	170.94	3,573	17,865	$ 2.79	$ 2.56
Gulf Coast	86.51	173.01	2,393	11,965	$ 3.55	$ 3.13
Williston Basin (US)	144.90	289.79	3,625	18,125	$ 4.84	$ 5.04
Williston Basin (CA)	90.65	181.30	2,959	14,795	$ 3.57	$ 2.93
Carpathian Basin	78.30	156.59	1,066	5,330	$ 6.50	$ 4.18
Songliao Basin	65.03	130.07	3,229	16,145	$ 1.99	$ 2.07
Gippsland Basin	90.65	181.30	6,866	11,802	$ 1.70	$ 2.82
Coastal Basin	52.03	104.07	1,190	5,950	$ 3.49	$ 2.46
Los Angeles Basin	25.95	51.90	1,052	5,260	$ 2.02	$ 1.16
San Joaquin Basin	71.30	142.60	1,098	5,490	$ 5.76	$ 3.75
Alberta Basin	90.65	181.30	2,369	11,845	$ 3.76	$ 3.29

Table 21. Summary of Costing Assumptions for the "Long Distance" CO_2 Transportation Scenario – 53,000 tonnes per day

800 Kilometer Pipeline (~ 500 Miles) 53 Kilotonnes of CO_2/Day (~ 1 Bcfd)				
Capital Costs	Total	Annualized	Per Tonne CO_2	Per Mile
Pipeline				
Materials	$176,175,512	$26,426,327	$1.61	$352,351
Labor	$283,558,380	$42,533,757	$2.59	$567,117
Miscellaneous	$124,869,528	$18,730,429	$1.14	$249,739
Right of Way	$58,038,053	$8,705,708	$0.53	$116,076
Total	$642,641,472	$96,396,221	$5.87	$1,285,283
Booster Stations	$98,928,675	$14,839,301	$0.90	
Total	$741,570,148	$111,235,522	$6.78	
O&M Costs				
Pipeline		$32,132,074	$1.96	
Booster Stations		$4,946,434	$0.30	
Booster Electricity		$13,742,965	$0.84	
Total		$50,821,472	$3.10	
Total Pipeline Costs	$741,570,148	$162,056,994	$9.87	

Assumptions:

Pipe Diameter: 61 cm (24 inch)
Capital Recovery Factor: 15%
Capacity Factor: 85%
Booster Stations are needed every 50 miles
Terrain: Grassland
Input Pressure: 15 MPa
Output Pressure: 13 MPa
Price of Electricity ($/kWh): .05

Table 22. Summary of Costing Assumptions for the "Long Distance" CO_2 Transportation Scenario – 26,500 tonnes per day

800 Kilometer Pipeline (~ 500 Miles) 26.5 Kilotonnes CO_2/Day (~ 500 MMcfd)				
Capital Costs	Total	Annualized	Per Tonne CO_2	Per Mile
Pipeline				
Materials	$132,713,468	$19,907,020	$2.43	$265,427
Labor	$237,465,497	$35,619,825	$4.34	$474,931
Miscellaneous	$106,313,368	$15,947,005	$1.94	$212,627
Right of Way	$56,629,250	$8,494,387	$1.03	$113,258
Total	$533,121,583	$79,968,237	$9.74	$1,066,243
Booster Stations	$49,464,338	$7,419,651	$0.90	
Total	$582,585,920	$87,387,888	$10.65	
O&M Costs				
Pipeline		$26,656,079	$3.25	
Booster Stations		$2,473,217	$0.30	
Booster Electricity		$6,871,482	$0.84	
Total		$36,000,778	$4.39	
Total Pipeline Costs	$582,585,920	$123,388,666	$15.03	

Assumptions:

Pipe Diameter: 51 cm (20 inch)
Capital Recovery Factor: 15%
Capacity Factor: 85%
Booster Stations are needed every 50 miles
Terrain: Grassland
Input Pressure: 15 MPa
Output Pressure: 13 MPa
Price of Electricity ($/kWh): .05

The bottom line is that despite potentially long transportation distances, the costs of transporting CO_2, alone, from areas with large concentrations of sources to areas of large CO_2-EOR potential will not likely be prohibitive to economic viability

Economic CO_2-EOR Potential

The characterization of the portion of this technical potential for CO_2-EOR that would be economic at various crude oil prices and CO_2 costs was based on previous Advanced Resources' work on U.S. basins, which were then assumed to apply by analogy to other basins of the world. For purposes of this exercise, a set of curves were developed that represent incremental oil production potential from the application of CO_2-EOR and associated CO_2 requirements as a function of crude oil price and the cost of delivered CO_2, at sufficient pressure to achieve miscibility, paid by the oil producer.

Adjusting these curves to a basis of incremental oil recovery potential as a percentage of OOIP in the oil fields amenable to miscible CO_2-EOR, similar relationships can be developed, again as a function of crude oil price and the cost of delivered CO_2, as shown in Table 23. Important to note in this table is that even when the costs of transporting CO_2 are as high as $15 per tonne, most of the resource that would otherwise be economic if the CO_2 was delivered to the CO_2-EOR project at no cost would <u>still</u> be economic.

Table 23. Economic Incremental Oil Recovery Potential from Miscible CO_2-EOR in the U.S. as a Function of Crude Oil Price and Delivered CO_2 Cost

Incremental Economic Oil Produced (% OOIP)				
CO_2 Lease-Gate Cost		**Oil Price ($ per Barrel)**		
$/tonne	**$/Mcf**	**$30**	**$70**	**$100**
$ -	**$0.00**	13.16%	15.56%	16.07%
$ 15.00	**$0.79**	11.03%	15.22%	15.92%
$ 30.00	**$1.59**	5.51%	14.82%	15.69%
$ 45.00	**$2.38**	2.46%	14.21%	15.50%
$ 60.00	**$3.17**	0.35%	13.48%	15.28%
$ 75.00	**$3.97**	0.14%	11.73%	14.73%

Finally, based on the amount of CO_2 required to be purchased at various oil price and CO_2 cost combinations, estimates of CO_2 requirements per barrel of incremental oil potential were developed, as shown in Table 24.

Table 24. Estimated Purchased CO_2 Requirements for CO_2-EOR as a Function of Crude Oil Price and Delivered CO_2 Cost

CO_2 Purchased (tonnes/bbl)				
CO_2 Lease-Gate Cost		**Oil Price ($ per Barrel)**		
$/tonne	**$/mcf**	**$30**	**$70**	**$100**
$ -	**$0.00**	0.258	0.262	0.264
$ 15.00	**$0.79**	0.248	0.261	0.263
$ 30.00	**$1.59**	0.233	0.259	0.262
$ 45.00	**$2.38**	0.193	0.255	0.260
$ 60.00	**$3.17**	0.143	0.251	0.259
$ 75.00	**$3.97**	0.081	0.247	0.256

Combining the above ratio of 0.261 tonnes of CO_2 per barrel and the price of CO_2 of $15 per tonne, the cost of CO_2 per barrel of incremental produced oil would be on the order of $4 per barrel.

Clearly, CO_2 costs are not the only costs affecting the economics of CO2-EOR projects. Other costs, such as the need to potentially drill new injection and production wells (to reduce pattern spacing), rework and maintain existing wells for CO_2-EOR operations, install small-scale CO_2 (and possibly water) distribution lines, separate and recycle the produced CO_2, as well as operate the CO_2 flood, need to factor into these economics (these costs are included in the economically recoverable estimates reflected in Table 23). However, these costs are comparable to conducting secondary oil recovery operations. In geologically and geographically favorable settings, this cost increase would be relatively modest.

Importantly, should the CO_2 flood be started while secondary oil recovery operations are still underway, there could be the opportunity of sharing some field operating costs and utilizing water injection wells for CO_2 injection, reducing capital costs.

The topic of starting CO_2 flooding earlier in the life of an oil field, and thus potentially achieving a lower cost, higher performance operation, is further discussed in the following section.

8. DEPLOYING CO_2 INJECTION EARLIER IN FIELD DEVELOPMENT

To date, most studies of the potential for CO_2-EOR assume that CO_2 injection begins close to the end of water flood operations in a field. In theory, early initiation of CO_2 injection, at least in some circumstances, may increase the ultimate recovery efficiency of a reservoir, reduce the need for water injection and handling, and accelerate oil production from a field, thus improving overall project economics.[74]

Of considerable value, therefore, is an assessment of the potential impact on CO_2-EOR recoverable resources and estimated CO_2 storage capacity associated with deployment of CO_2 injection earlier, as a second stage in field development, rather than later, as a tertiary stage production activity. Since the potential for early CO_2 injection is highly dependent on reservoir properties and the development history of the field/reservoir, it was not possible, given the limited time and resources available for this study, to perform a detailed assessment of early CO_2 injection on CO_2-EOR potential and associated CO_2 storage capacity worldwide. Instead, a case-study assessment was performed to characterize the potential associated with earlier initiation of CO_2 injection.

This case study builds upon previous work by Advanced Resources.[75] Specifically, as part of a U.S. DOE-funded R&D project (with the goal of demonstrating the application and benefits high-resolution reservoir characterization for better management of CO_2-EOR floods and carbon sequestration projects), Advanced Resources performed three-dimensional reservoir modeling to match historical production performance on a part of the SACROC Unit in the Kelly-Snyder field in the Permian Basin of West Texas.[76]

Discovered in 1948, the Kelly-Snyder field covers an area of about 50,000 acres (20,234 hectares) with an estimated OOIP of 2.8 billion barrels. The field can be divided into three broad regions: the Northern Platform, Central Plain, and the Southwestern. The SACROC Unit was formed in 1952 to facilitate coordinated water flooding of the field. CO_2-EOR began in 1972 and has traditionally been focused in the Central Plain, where reservoir architecture is amenable to pattern flooding. The Northern Platform area contains the thickest interval, however, ranging from 80 feet (24 meters) at the periphery to more than 750 feet (229 meters) at the center, and contains the greatest concentration of oil resource. Geologic and production data from this area suggest it may be a potential candidate for gravity-stable CO_2-EOR. Kinder Morgan, the operator of the unit, is evaluating the feasibility of gravity-stable CO_2-EOR for the SACROC Unit Platform area.

This project took advantage of intense data-collection efforts by Kinder Morgan for the assessment of gravity-stable CO_2-EOR for the SACROC Unit Platform area (Figure 15). These efforts included the collection of core over the entire reservoir interval at three locations in the Platform area, and a foot-by-foot analysis for reservoir properties, including porosity and multi-azimuth permeability, geophysical well logs, and (potentially) cross-well seismic surveys. (A 3-D surface seismic survey already existed over the entire area.) Advanced Resources used these data to develop a high-resolution seismic-to-core transform and applied it to a selected portion of the field for validation. A reservoir simulation model was built based upon this characterization and a good history match was of oil, gas and water production rates, and the average reservoir pressure.

This reservoir model was adapted to the objective of this study. The updated compositional model covers a quarter of a 5-spot injection system of approximately 20 acres, and includes 1 producer and 1 injector (both modeled as quarter wells). Based on core and log data, a geostatistical characterization of porosity and permeability were generated and incorporated in the reservoir model.

An example of permeability geostatistical characterization is shown in Figure 16, and the input data for the model is shown in Table 25. The assumed relative permeability curves are shown in Figure 17.

Figure 15. Map of SACROC Unit Showing Proposed Core Locations in Northern Platform Area

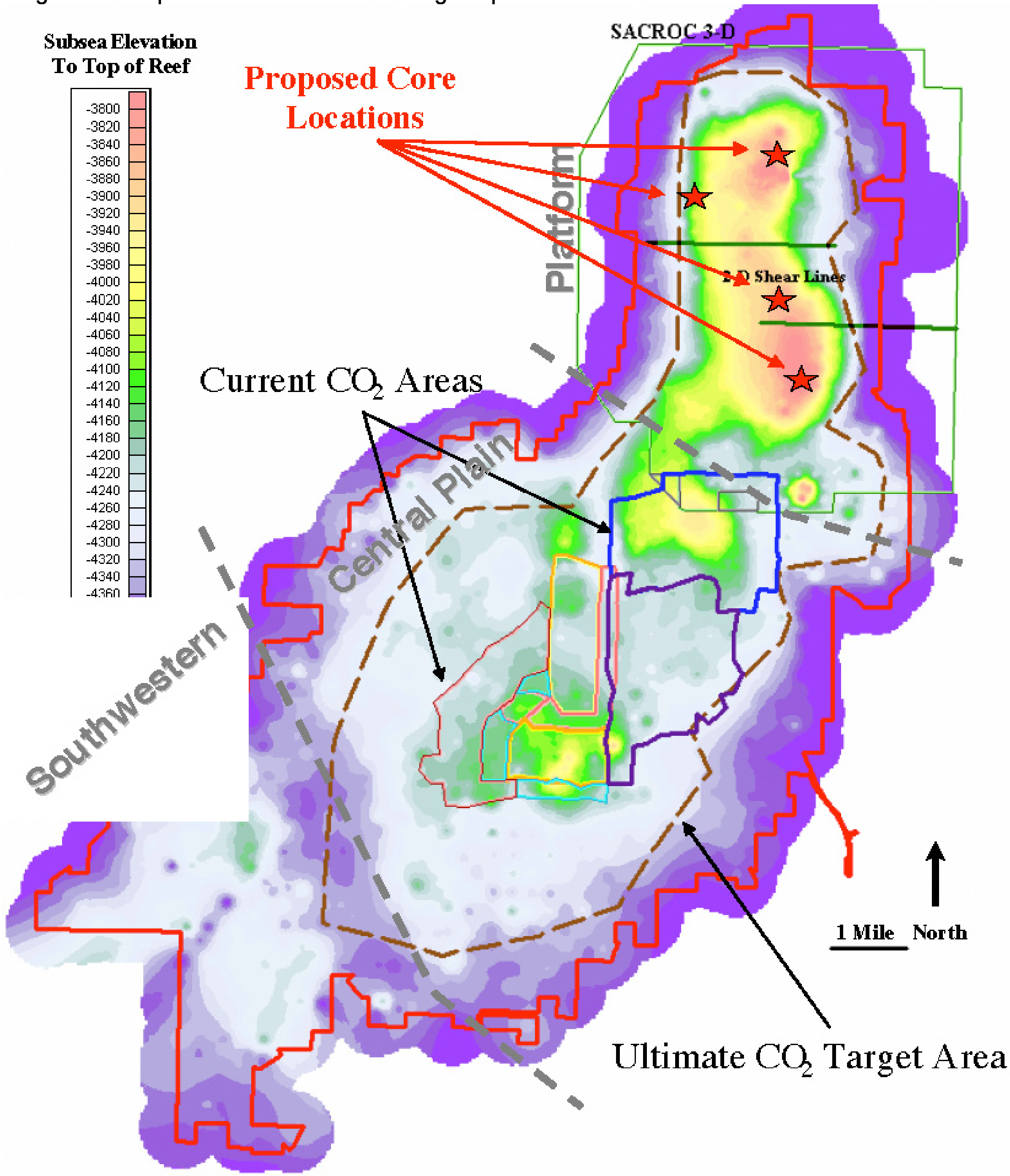


Figure 16. Example of Permeability Geostatistical Characterization used in the SACROC Reservoir Model

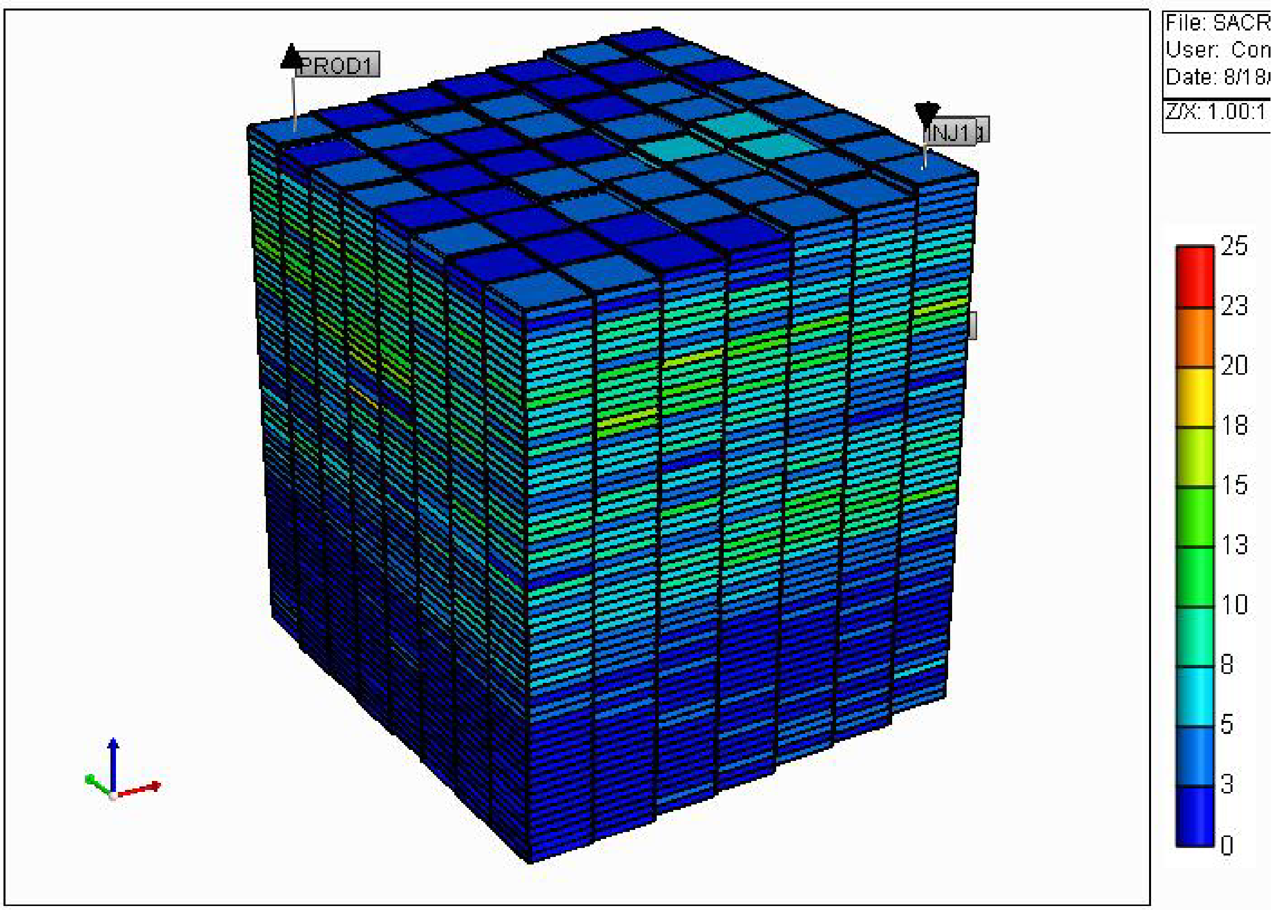
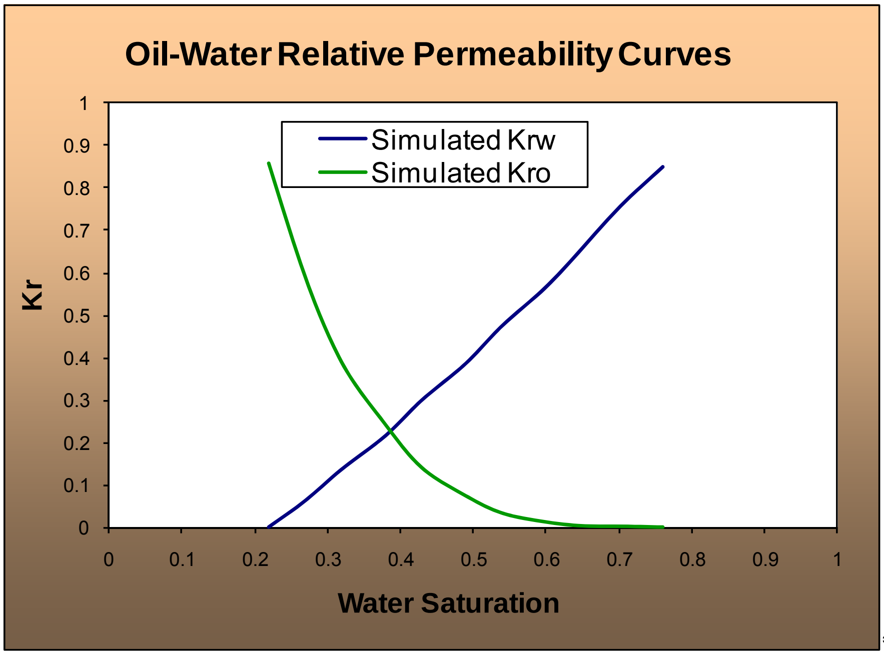


Table 25. Input Data used in the SACROC Reservoir Model

Parameter	Units	Value	Source
Formation Properties			
Average Thickness	ft	900	Geostatistical Realisation[1]
Initial Pressure	psia	3137	at 4300ft TVDSS (actual data)
Initial Temperature	F	132	at 4300ft TVDSS (actual data)
Average Porosity	%	8.3	Geostatistical Realisation[1]
Average Permeability	mD	5	Geostatistical Realisation[1]
Rock Compressibility	1/psi	5.60E-06	Correlation
Fluid Properties			
Oil Compressibility	1/psi	7.00E-05	at 1850 psia (Ramey's correlation)
Oil Density	API	37.2	at STC (actual data and Mc Cain's correlation)
Gas Gravity	-	0.67	at STC (Standing and Katz's correlation)
Water Compressibility	1/psi	2.90E-06	at 1850 psia (Dodson and Standing's correlation)
Water Density	-	62.3	(Earlougher, R.C.)
Water Formation Volume Factor	RB/STB	1.013	(Rowe and Chou's correlation)
Water Viscosity	cp	0.51	(actual data and Matthews and Russell's correlation)

Figure 17. Relative Permeability Relationships used in the SACROC Reservoir Model



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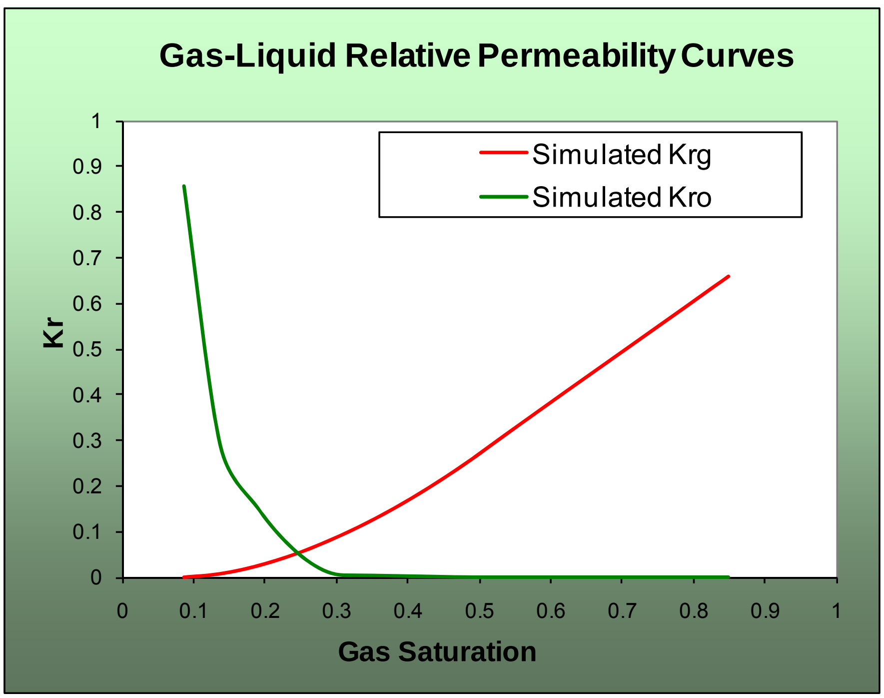


* Residual oil saturation due to water blockage was assumed to be 7%.

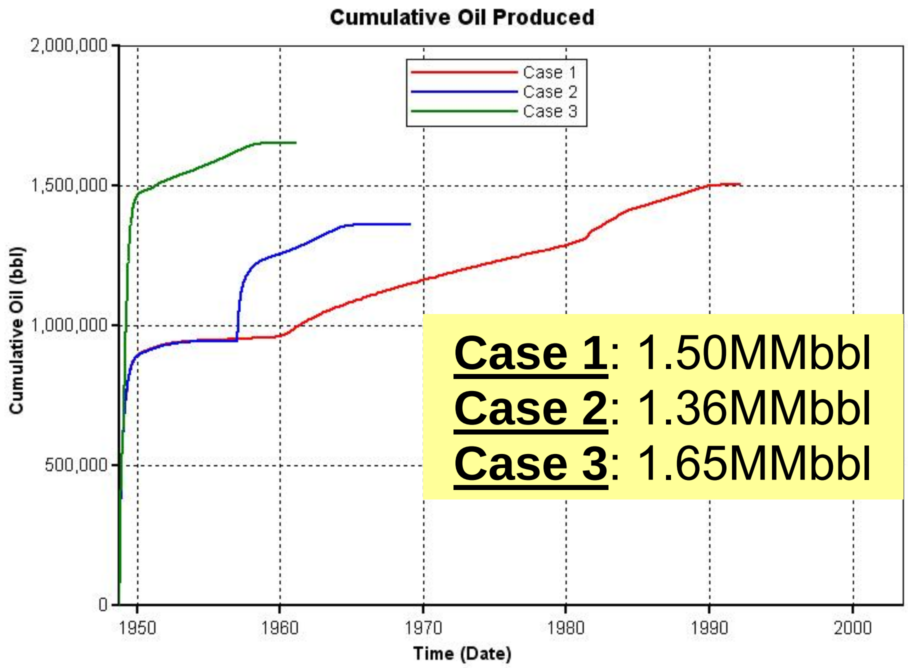
This reservoir characterization and history match was then used to develop several "what if" characterizations to compare what historically took place in the reservoir with regard to water and subsequent CO_2 injection, and what might have occurred had CO_2 injection been initiated earlier. Three alternative cases were considered: (1) modeling the CO2 injection schedule comparable to that actually taking place in the field; (2) beginning CO_2 injection and the end of primary recovery operations, but before the implementation of water flooding, and (3) beginning CO_2 injection at the beginning of field development.

The specific assumptions used for modeling purposes for these characterizations are summarized below:

- **Case 1:** In this case, the reservoir will be on production for 43 years. In the first 6 years, it will undergo primary, natural depletion, oil production with a minimum producing bottom-hole pressure of 350 pounds per square inch (psi). Natural production is followed by 25 years of water injection, at a maximum injection rate of 8,000 barrels per day. After water flooding, a 12 year period of CO_2 water-alternating gas (WAG) process (1-month cycles; first slug CO_2 during 2 months; last slug water for 2 months) is begun. A total of one HCPV will be injected in this case, at a maximum injection rate of 16 million cubic feet per day.
- **Case 2:** In this case, the reservoir will be on production for 20 years. The first 6 years of production will be natural depletion. Afterward, it will proceed into a 2 year CO_2 fill-up period, where CO_2 will be injected continuously at a rate of 16 million cubic feet per day. Finally, the reservoir will undergo 12 years of WAG injection. As in the previous example, a total of one HCVP of CO_2 will be injected into the reservoir in Case 2.
- **Case 3:** In this final case, CO_2 injection starts immediately, in the form of a 12 year WAG, with one equivalent HCPV of CO_2 injected as previous cases.

In all three cases, the total amount of CO_2 injected for CO_2-EOR is the same – 8.8 billion cubic feet (this is with the exception of the CO_2 injected in Case 2 to fill up reservoir to start the CO_2 flood). A summary of oil the production results for the three cases from the SACROC reservoir model are provided in Figure 18 and Table 26. For Cases 1 and 2, the primary recovery factor was 30%, while for Case 3; the secondary recovery factor was 41%.

Figure 18. Summary of Oil Production Results for the Three Cases from the SACROC Reservoir Model



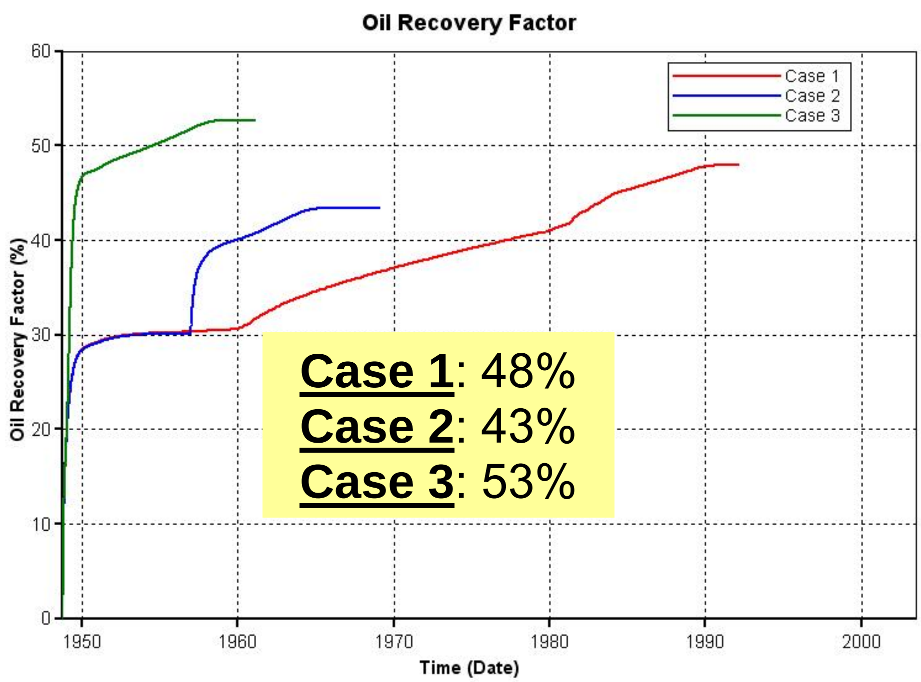


Table 26. Summary of Oil Production Results for the Three Cases from the SACROC Reservoir Model

Case	Cumulative Oil Production (MBbl)		Recovery Factor**		Cumulative CO2 Injected (Bcf)
	Undiscounted	Discounted*	Total Production	Production under WAG	
1	1,500	651	48%	7%	8.8
2	1,358	691	43%	13%	11.7 (8.8 +2.9)
3	1,650	1,020	53%	53%	8.8

* Assumes 15% discount rate. End of year discounting method used
** Pattern OOIP is 3.13 MMbbls

These results show that by starting CO_2 injection early in the field history, enhanced oil recovery is improved, and oil production occurs much more rapidly. For example, in these cases, higher oil recovery is observed for same injected CO_2 volume (1.50 million barrels for Case 1; 1.65 million barrels for Case 3). Moreover, higher oil recovery factor is reached in shorter period of time: 53% recovery efficiency in 12 years for Case 3; compared to a recovery efficiency of 48% in 43 years in Case 1. Assuming a 15% discount rate, Case 3 would produces almost 50% more value (in terms of discounted revenue on the oil produced) than the other two cases. This kind of early oil production response would have a very positive effect on the economics of any CO_2-EOR project.

This also shows that WAG injection initiated early in the field history allows pressure conditions for a miscible flood, resulting in a better sweep efficiency and ultimately higher oil recovery. For example, in Case 2, even after a fill-up period of two years, the reservoir pressure drops below the minimum miscibility pressure very quickly, limiting oil recovery. (This could be improved by optimizing well completions.)

For each of the three cases, for this specific reservoir, oil recovery drops at the end of WAG period. This is related to permeability heterogeneity of the reservoir. Oil saturation in high permeability layers, contributing to most of production, reaches residual oil saturation at the end of 12-year WAG time period (7% in this specific example). Most oil is not displaced in the bottom layers as CO_2 migrates vertically under buoyancy effect. Permeability heterogeneity is a key factor in the sweep efficiency, limiting the benefits of the fill-up and WAG flood to a restricted area of the reservoir in this specific case.

9. CONCLUSIONS AND POSSIBLE NEXT STEPS

Commercial-scale, profitable CO_2-EOR has been ongoing for over 30 years in geologically favorable oil fields with access to affordable CO_2. CO_2-EOR has been deployed extensively in the Permian Basin of West Texas and Eastern New Mexico, and a few other areas in the U.S., since the mid-1980s.

The historical look at the CO_2-EOR experience in the U.S. and elsewhere shows that CO_2-EOR is successful in fields that meet the technical criteria for achieving miscibility (primarily depth and oil composition); have sufficient unrecovered oil after primary and secondary recovery (water flooding); and have access to reliable sources of CO_2 at affordable costs.

Other factors that have contributed to successful deployment of CO_2-EOR include operator technical knowledge and commercial interest in pursuing CO_2-EOR technologies, and state and federal financial incentives that promote implementation of CO_2-EOR projects.

Extrapolating this experience to the 54 largest oil basins of the world indicates that CO_2-EOR could provide 469-1,076 billion barrels of additional oil while storing 139 to 319 Gt of CO_2. However, the lack of readily available of CO_2 places limits on how much of this oil resource and CO_2 storage capacity can be accessed today. Using $10 to $15 per ton as the transportation cost for CO_2 (and thus the delivered cost at the oil field boundary), the vast majority of the technical CO_2-EOR potential could be economic to pursue, assuming mid-range, $70/barrel world oil prices. Moreover, numerous options and actions exist that could increase today's estimates of CO_2-EOR-based oil recovery and CO_2 storage capacity.

Nonetheless, this assessment of CO_2 storage capacity in depleted oil fields potentially amenable to CO_2-EOR is merely a "snapshot in time," conducted at a very high level of disaggregate analysis. A more robust understanding of this high value option could be gained by:

- Detailed, regional or basin-specific geologic studies of high potential areas for CO_2-EOR. While the method of estimating overall CO_2-EOR oil recovery potential used in this analysis is based on correlations, the disparity in basin versus field level results illustrates the importance of additional data to better characterize the CO_2-EOR potential in a basin. The disparity suggests that the complex nature of these basins cannot be fully captured in a two variable analysis. In particular, in especially complex, heterogeneous basins such as Western Siberia and the North Sea, lack of specific reservoir information can lead to overly optimistic results, as basin complexity would tend to decrease oil recovery that is not accounted for in the current methodology.
- Compiling more high-resolution CO_2 source data. Key to matching potential sources of CO_2 emissions and candidate CO_2-EOR prospects is a better understanding of the

volumes, quality, and location of CO_2 sources. The costs of CO_2 capture are a function of the quality of the CO_2, along with, to a much lesser extent, the volumes produced and the distance transported. A more accurate understanding the potential economics of using industrial CO_2 emissions for CO_2-EOR requires a more refined, basin-specific characterization of CO_2 sources.

- Forming partnerships with national stake-holder institutions to further the identification of high-potential CO_2-EOR sites. Successful CO_2-EOR operations require a convergence of interests from a wide variety of industrial entities, many of which have not collaborated before, in addition to oversight from government institutions. The identification, and ultimate pursuit, of such opportunities will require collaboration at a number of levels, involving the public and private sector, as well as non-governmental organizations. IEA GHG has the opportunity to help facilitate the formation of such partnerships.
- Establishing well defined project opportunities. While this study concludes that the worldwide potential for CO_2-EOR is significant, potential projects to pursue were described only in broad terms. A key next step is to begin to narrow down potential project opportunities, and to perform more detailed evaluations of these prospects. For potential CO_2-EOR prospects, appropriate evaluations of technical and economic viability will require access to more detailed information on reservoir properties, development and production history, the extent and condition of existing production infrastructure, and the economic terms.
- Evaluating commercial potential and partnership structures. The value of the oil produced from CO_2-EOR operations will be the key source of revenue, at least for initial projects, and in the absence of a viable market for emission reduction credits. These revenues need to cover the costs of capture, compression, transport, and storage. Mechanisms will need to be established to ensure that every participant along the value chain has the economic incentive to participate. As important as the price of oil to the revenues from, and thus profitability of, a CO_2-EOR project is the cost of CO_2, and, in particular, the relationship between the cost of CO_2 and the price of oil. However, many current CO_2 supply contracts were not written with the more recently experienced historic high levels for oil prices in mind. On the other hand, under a market where CO_2 emission reductions have value, "gas-on-gas" competition for new CO_2 sources entering the market may put downward pressure on CO_2 prices. In fact, some may be willing to provide potential CO_2 supplies to CO_2-EOR projects "at cost*", perhaps receiving as compensation a portion of the value of incremental oil production, or the value of any emission reduction credits.
- Planning for expanding scale of operations. While initial projects may only involve one or a few sources and sinks for CO_2, the opportunities associated with eventual large scale expansion will need to be considered. Commercial structures of linking CO_2 emission sources to oil fields into which it will be injected must consider options for multiple sources and sinks in an integrated network.

APPENDIX A. CURRENT CO_2-EOR ACTIVITY AND PRODUCTION

Throughout the world, numerous scientific and practical reasons account for the large volume of "stranded" oil that has remained unrecovered after the application of traditional

* Most likely accounting for some or all of the costs associated with capture at the source, compression, and transport to the oil field.

primary (pressure depletion) and secondary (water flooding) oil recovery methods. These reasons include: oil that is bypassed due to poor waterflood sweep efficiency; oil that is physically unconnected to a wellbore; and, most importantly, oil that is trapped by viscous, capillary and interfacial tension forces as residual oil in the pore space. The application of CO_2-EOR processes is one means for economically producing some of the oil that is traditionally left stranded.

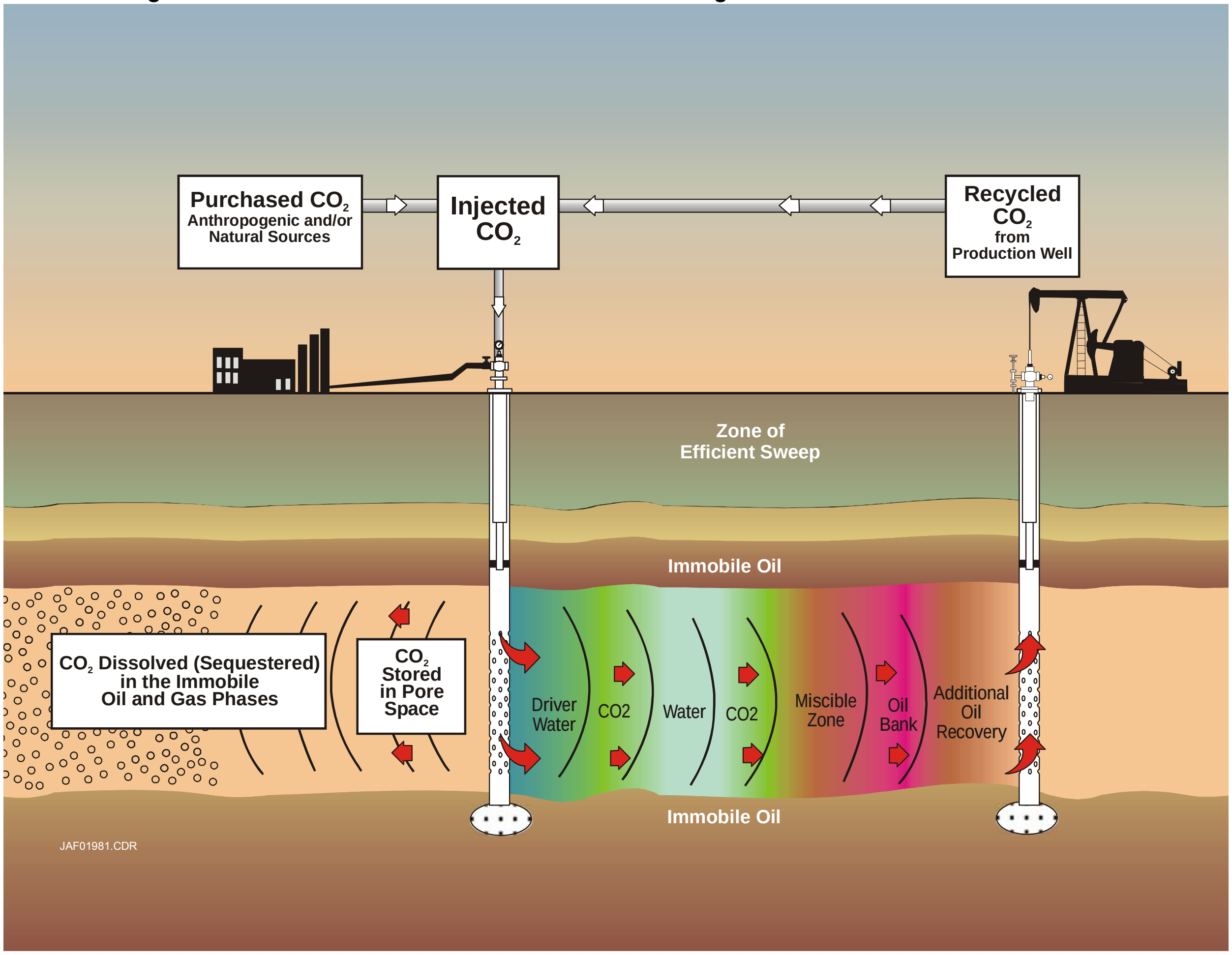
The main mechanism by which CO_2-EOR can recover this trapped oil is by creating, with the assistance of pressure, miscibility between the residual oil and the injected CO_2. Additional mechanisms such as viscosity reduction, oil swelling, and improved reservoir contact further contribute to additional oil recovery.

In this regard, there are two main types of CO_2-EOR processes:

- *Miscible CO_2-EOR* is a multiple contact process involving interactions between the injected CO_2 and the reservoir's oil. During this multiple contact process, CO_2 vaporizes the lighter oil fractions into the injected CO_2 phase and CO_2 condenses into the reservoir's oil phase. This leads to two reservoir fluids that become miscible (mixing in all parts), with favorable properties of low viscosity, enhanced mobility, and low interfacial tension. The primary objective of miscible CO_2-EOR is to remobilize and dramatically reduce the residual oil saturation in the reservoir's pore space after water flooding. Figure A-1 provides a one-dimensional schematic showing the dynamics of the miscible CO_2-EOR process.
- *Immiscible CO_2-EOR* occurs when insufficient reservoir pressure is available or the reservoir's oil composition is less favorable (heavier). The main mechanisms involved in immiscible CO_2 flooding are: (1) oil phase swelling, as the oil becomes saturated with CO_2; (2) viscosity reduction of the swollen oil and CO_2 mixture; (3) extraction of lighter hydrocarbon into the CO_2 phase; and, (4) fluid drive plus pressure. This combination of mechanisms enables a portion of the reservoir's remaining oil to be mobilized and produced.

In general, immiscible CO_2-EOR is much less efficient than miscible CO_2-EOR in recovering oil remaining in a reservoir.

Figure A-1. One-Dimensional Schematic Showing the Miscible CO_2-EOR Process



CO_2-EOR technologies, including both miscible and immiscible CO_2 injection, are in commercial use today. Field data show that currently practiced CO_2-EOR technology generally recovers from 10% to 25% of a reservoir's original oil in place (OOIP). However, today's CO_2-EOR technologies generally still underperform compared to their theoretical potential, as established by laboratory testing, reservoir simulation, and a handful of forward-looking, highly instrumented projects pursing pilot tests of "next generation" technologies.[77]

U.S. -- Overview

In the United States, CO_2-EOR technologies have been demonstrated to be profitable in commercial scale applications for over 30 years. CO_2-EOR has been deployed extensively in the Permian Basin of West Texas and Eastern New Mexico since the mid-1980s; these projects are largely injecting high purity, low cost CO_2 obtained from natural CO_2 reservoirs. An extensive CO_2 pipeline network has been developed in the region to meet the CO_2 requirements of these projects.

The most comprehensive literature review of the status of EOR projects around the world is the biennial EOR survey published by the *Oil and Gas Journal*; the most recent issue of which was published in April 2008.[78] According to this survey, 105 CO_2-EOR projects currently provide nearly 250,000 barrels per day of incremental oil production from EOR in the U.S. Of these, the vast majority, 100 projects producing 240,000 barrels per day, are miscible CO_2-EOR projects. Twelve years ago; production from CO_2-EOR was only 170,000 barrels per day from 60 projects. Since 1986, over 1.3 billion barrels of incremental oil has been estimated to have been recovered using this technology.

In just the last five years, a significant number of new players have entered the CO_2-EOR business in the U.S. In addition, another 12 miscible CO_2-EOR projects and four immiscible EOR projects are listed as planned in the U.S. in the most recent *Oil and Gas Journal* survey.

Figure A-2 provides the location of the currently active CO_2-EOR projects (including the Weyburn project in Canada), including their sources of CO_2 supply.

Figure A-3 tracks the steady growth in CO_2-EOR production for the past 20 years, noting that although new activities are underway in the Gulf Coast and the Rockies, the great bulk of CO_2-EOR is still being produced from the Permian Basin. Notably, this growth was sustained in spite of two oil price crashes, the first in 1986 and the second in 1998, primarily due to the long term nature of project planning and CO_2 flood response. It is significant to note that low oil prices did not deter underlying growth in the CO_2-EOR industry, but only curtailed acceleration of the growth.

Figure A-2. U.S. CO_2-EOR Activity

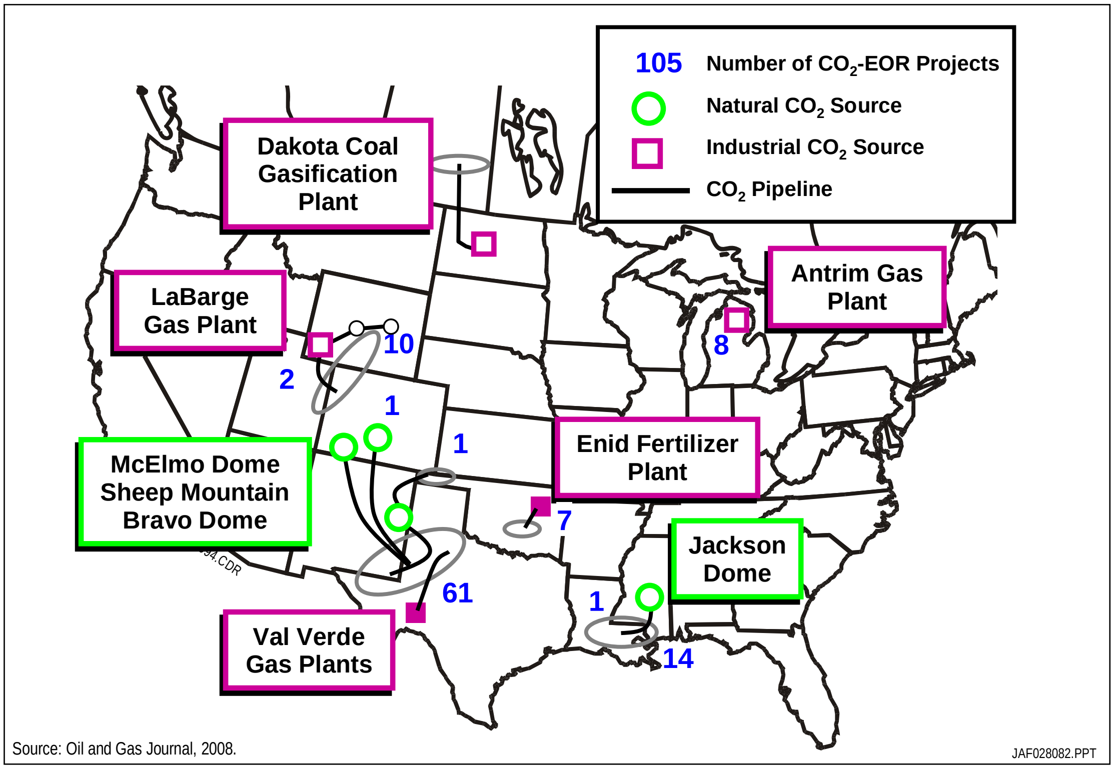
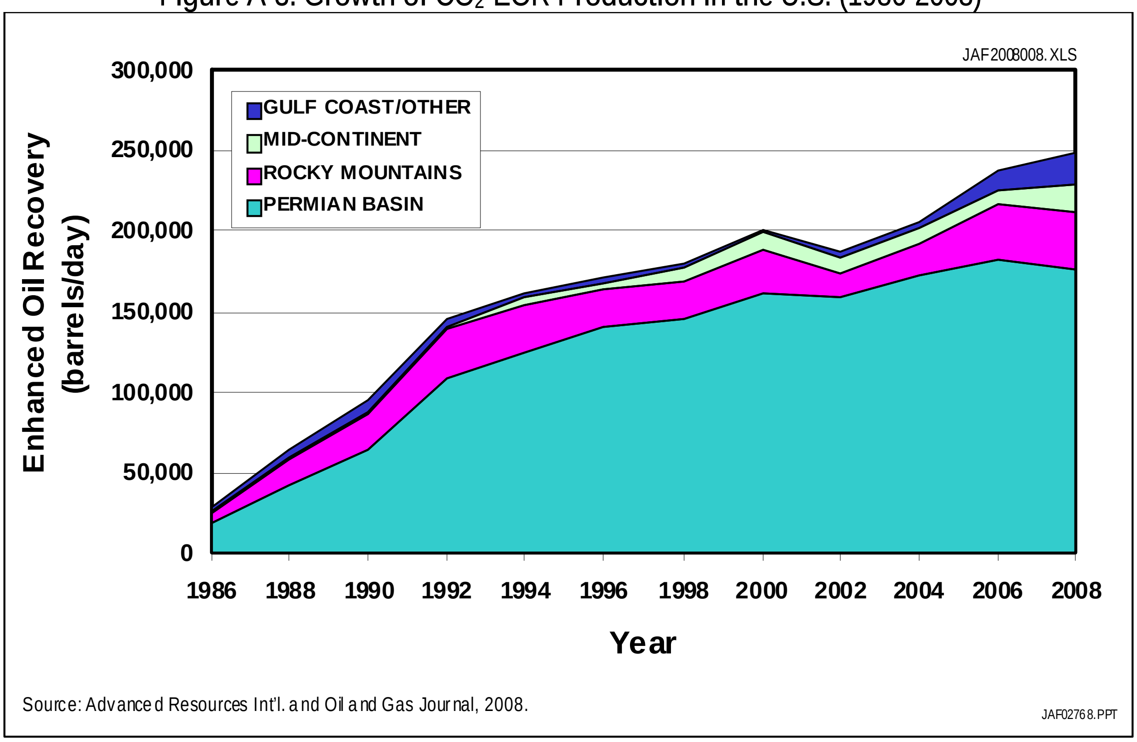


Figure A-3. Growth of CO_2-EOR Production in the U.S. (1986-2008)



Most of the CO_2 used for CO_2-EOR projects in the U.S. (over 80%) comes from natural sources; primarily four large natural CO_2 fields in the Western U.S. shown in Figure 2 – Jackson Dome, Sheep Mountain, McElmo Dome, and Bravo Dome. The rest of the CO_2 used for CO_2-EOR projects comes from gas processing plants, ammonia/fertilizer plants, and one large coal gasification facility. Table A-1 tabulates the volumes of natural and anthropogenic CO_2 used for CO_2-EOR as of the end of 2008.

Table A-1. Volumes of CO_2 Supplying EOR Projects in 2008

State/Province (Storage location)	Source Type (location)	CO_2 Supply (million tonnes/year)		CO_2 Supply (MMcfd)	
		Natural	Anthropogenic	Natural	Anthropogenic
Texas-Utah-New Mexico-Oklahoma	Geologic (Colorado-New Mexico) Gas Processing (Texas)	28	2	1,455	80
Colorado-Wyoming	Gas Processing (Wyoming)		4		230
Mississippi	Geologic (Mississippi)	15		800	
Oklahoma	Fertilizer Plant (Oklahoma)		1		35
Michigan	Gas Processing (Michigan)		<1		15
Saskatchewan	Coal Gasification (N. Dakota)		3		150
TOTAL		**44**	**10**	**2,255**	**510**

Source: Brian Hargrove, L. Stephen Melzer, and Lon Whitman, "A Status Report on North American CO_2-EOR Production and CO_2 Supply, presented at the 14th Annual CO_2 Flooding Conference, Midland, TX, December 11-12, 2008

U.S. – Permian Basin

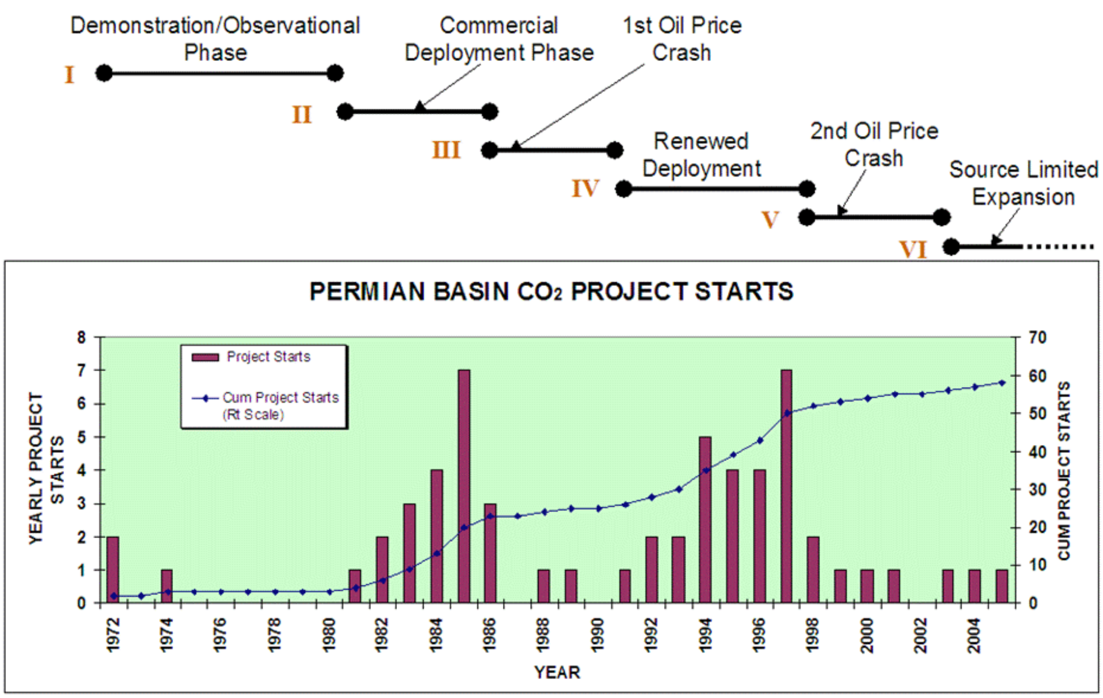
The CO_2-EOR industry began with two large-scale projects in the Permian Basin in the early 1970s. Shell and Gulf effectively converted a waste stream of by-product CO_2 from natural gas processing facilities in the southern portion of the Permian Basin into a useful commodity by capturing, compressing and routing it to the North Cross unit near McCamey, Texas, and then on to Snyder, Texas and the SACROC unit in Scurry County. The response of the reservoirs to the CO_2, especially in the four pattern area of SACROC, convinced several other major oil companies of the viability of CO_2 injection.

Based on these results, plans were conceived to bring several large underground sources of natural CO_2 to the region. These supplies of CO_2 came from Bravo Dome in northeastern New Mexico, Sheep Mountain in south central Colorado, and McElmo Dome in southwestern Colorado. Locations of these supplies are shown in Figure A-2.

With these new supplies, the next phase of activity witnessed several key fields deployed into CO_2-EOR operations. Most notable of these were the Wasson, Seminole and Slaughter fields, all San Andres formation fields; each with billions of barrels of original oil in place (OOIP). Flooding is continuing on these projects today, some twenty plus years after original implementation.

Figure A-4 categorizes the phases of CO_2-EOR deployment in the Permian Basin. This is also representative of Wyoming and Mississippi, except that both effectively avoided the necessity of (and skipped) Phase I.

Figure A-4. The Phases of CO_2 Enhanced Oil Recovery



Today, of the 105 CO_2-EOR projects (both miscible and immiscible) in the United States, 61 projects, producing over 182,000 barrels per day, are in the Permian Basin, Table A-2. Many of these fields have been producing oil using CO_2-EOR for over 30 years. The projects in these fields purchased approximately 30 million tonnes (1,535 million cubic feet per day (MMcfd)) of CO_2 for EOR in 2008. To date, companies have injected 500 million tonnes (10.8 trillion cubic feet (Tcf)) of CO_2 into these fields.[79]

U.S. – Non-Permian Basin

The remaining 44 CO_2-EOR projects in the U.S. produce approximately 68,000 barrels per day. These projects are geographically widespread; with several projects each in Michigan, Mississippi, Oklahoma, and Wyoming, and one or two projects each in Colorado, Kansas, Louisiana, and Utah. These projects are listed with some key characteristics in Table A-3.

The single largest CO_2-EOR project in the U.S. outside the Permian Basin is the Rangely project in Colorado. Currently owned and operated by Chevron, the field was under waterflood until 1986, when CO_2 injection was initiated. CO_2 is transported to the field from Exxon's Shute Creek natural gas processing plant near LaBarge, Wyoming (from the LaBarge field). Well over 45 million tonnes (1 Tcf of CO_2) has been injected into the field's Weber reservoir since start of CO_2-EOR in 1986. Currently CO_2 is being injected via 262 injection wells at a rate of 3 million tonnes per year (160 MMcfd), producing 11,600 barrels per day of incremental oil from 378 production wells. Chevron is expecting to recover an additional 114 million barrels of oil from using CO_2-EOR, or 6% of OOIP.

One large concentration of CO_2-EOR activity is in Wyoming, where Anadarko and Merit Energy produce over 20,000 barrels per day from ten projects. These projects consist of both deeper miscible CO_2-EOR projects and shallower immiscible CO_2-EOR projects. Moreover, a large number of additional CO_2-EOR candidate reservoirs have been identified in Wyoming, as well as relatively nearby in Montana and North Dakota, estimated to contain substantial incremental oil recovery potential.[80]

Another concentration of projects is in Mississippi, where Denbury Resources has 14 projects producing over 20,000 barrels per day of incremental oil due to CO_2-EOR. All of their fields produce from high gravity oil reservoirs at depths exceeding 3,000 meters (over 10,000 feet), with the exception of one shallower field that is implementing an immiscible CO_2-EOR project. Denbury estimates that over 125 million barrels of incremental reserves due to CO_2-EOR exist in these projects, and they have significant expansions to existing CO_2-EOR projects, along with major new projects, in their plans.[81] As noted in recent investor presentations, and as discussed in more detail below, Denbury is aggressively pursuing anthropogenic sources of CO_2 to offset its declining natural CO_2 reserves in Jackson Dome. By 2015, over half of the CO_2 they inject is expected to be from anthropogenic sources.[82]

Other concentrations of activity exist in Oklahoma, where Chaparral,[83] Merit Energy, and Whiting also produce over 10,000 barrels per day from seven projects; and in Michigan, where Core Energy operates eight small projects that together produce about 650 barrels per day.[84]

A number of CO_2-EOR projects have been attempted in the past. As part of a series of basin studies conducted under sponsorship of the U.S. Department of Energy (DOE),[85] Advanced Resources reviewed the status of these historical projects. A summary of these reviews, for both ongoing projects and discontinued projects outside of the Permian Basin of West Texas and Eastern New Mexico, is provided in Table A-4. This review demonstrated that many projects were technical successes, but were determined not to be economically viable, primarily because of the lack of affordable, dependable supplies of CO_2.

Several hydrocarbon miscible floods (rather than CO_2) are underway in Alaska, enhancing production from some of the largest producing oil fields in the U.S (Table A-5). Facilitating this operation is a very large gas processing plant which processes more than (160 million tonnes per year (8 billion cubic feet per day (Bcfd)) of natural gas that is reinjected into the reservoir. This gas stream also contains a large concentration (approximately 11-12%) of CO_2, technically making this project the largest CO_2 injection project in the world.

Finally, since 1981, ExxonMobil has been operating a N_2 miscible WAG flood in the Jay/Little Escambia oil field that may also be applicable to CO_2-EOR. Reservoir simulation studies indicate potential recovery of about 20% OOIP from CO_2-EOR, about twice the volume currently expected from N_2-EOR.

Table A-2. Producing CO_2-EOR Projects in US - Permian Basin Only
As published in Oil & Gas Journal, April 21, 2008

Type	Operator	Field	State	County	Start date	Area, acres	No. wells prod.	No. wells inj.	Tot. prod., b/d	Enh. prod., b/d
CO_2 miscible										
	Apache	Slaughter	Tex.	Hockley & Terry	5/85	569	24	11	600	580
	Apache	Slaughter	Tex.	Hockley & Cochran	6/89	8,559	228	154	5,800	4,000
	Chaparral Energy	North Perryton	Tex.	Ochiltree	12/07	2,500	6	3	200	170
	Chevron	Mabee	Tex.	Andrews-Martin	1/92	3,600	220	85	3,100	2,000
	Chevron	Slaughter Sundown	Tex.	Hockley Co	1/94	5,500	155	144	5,950	4,747
	Chevron	Vacuum	NM	Lea Co.	7/97	1,084	48	24	4,500	2,950
	ConocoPhillips	South Cowden	Tex.	Lea	2/81	4,900	43	22	450	250
	ConocoPhillips	Vacuum	NM	Lea	2/81	4,900	192	103	6,200	5,200
	Energen Resources	East Penwell (SA) Unit	Tex.	Ector	5/96	1,020	47	22	766	450
	ExxonMobil	Means (San Andres)	Tex.	Andrews	11/83	8,500	484	284	10,000	8,700
	Fasken	Hanford	Tex.	Gaines	7/86	1,120	23	26	300	300
	Fasken	Hanford East	Tex.	Gaines	3/97	340	7	4	45	45
	Gr. Western Drilling	Twofreds	Tex.	Loving,Ward,Reeves	1/74	4,392	32	9	170	170
	George R. Brown	Garza	Tex.		5/06	650				
	Hess	Adair San Andres Unit	Tex.	Gaines	11/97	1,100	19	18	2,300	900
	Hess	Seminole Unit-Main Zone	Tex.	Gaines	7/83	15,699	408	160	19,500	19,500
	Hess	Seminole Unit-ROZ Phase 1	Tex.	Gaines	7/96	500	15	10	1,200	1,200
	Hess	Seminole Unit-ROZ Phase 2	Tex.	Gaines	4/04	480	16	9	1,800	1,800
	Hess	Seminole Unit-ROZ Phase 1	Tex.	Gaines	4/04	480	16	9	1,800	1,800
	Hess	Seminole Unit-ROZ Stage 1	Tex.	Gaines	12/07		6	2	50	50
	Kinder Morgan	SACROC	Tex.	Scurry	1/72	49,900	391	444	24,980	24,227
	Orla Petco	East Ford	Tex.	Reeves	7/95	1,953	8	4	128	128

Table A-2 (continued)
Producing CO_2-EOR Projects in US - Permian Basin Only
As published in Oil & Gas Journal, April 21, 2008

Type	Operator	Field	State	County	Start date	Area, acres	No. wells prod.	No. wells inj.	Tot. prod., b/d	Enh. prod., b/d
CO_2 miscible										
	Occidental	Alex Slaughter Estate	Tex.	Hockley	8/00	246	21	14	370	300
	Occidental	Anton Irish	Tex.	Hale	4/97	4,437	112	94	5,100	4,000
	Occidental	Cedar Lake	Tex.	Gaines	8/94	2,870	159	98	4,950	2,860
	Occidental	Central Mallet Unit	Tex.	Hockley	1984	6,412	182	136	2,900	2,100
	Occidental	Cogdell	Tex.	Scurry/Kent	10/01	2,684	93	55	6,460	5,900
	Occidental	El Mar	Tex.	Loving	4/94	6,000	64	32	350	270
	Occidental	Frazier Unit	Tex.	Hockley	12/84	1,600	67	52	1,250	925
	Occidental	GMK South	Tex.	Gaines	1982	1,143	16	7	610	375
	Occidental	Igoe Smith	Tex.	Cochran	9/05	1,235	61	27	700	440
	Occidental	Levelland	Tex.	Hockley	9/04	1,179	84	51	1,800	950
	Occidental	Mid Cross - Devonian Unit	Tex.	Crane, Upton & Crockett	7/97	1,326	13	5	320	296
	Occidental	N. Cross - Devonian Unit	Tex.	Crane & Upton	4/72	1,155	26	13	1,045	835
	Occidental	North Cowden Demo.	Tex.	Ector	2/95	200	10	3	230	80
	Occidental	North Dollarhide	Tex.	Andrews	11/97	1,280	28	20	1,950	1,000
	Occidental	North Hobbs	NM	Lea	3/03	3,100	125	75	8,560	6,300
	Occidental	S. Cross - Devonian Unit	Tex.	Crockett	6/88	2,090	73	30	5,875	5,790
	Occidental	Salt Creek	Tex.	Kent	10/93	12,000	174	135	7,700	6,600
	Occidental	Sharon Ridge	Tex.	Scrurry	2/99	1,400	31	18	900	400
	Occidental	Slaughter (H T Boyd Lease)	Tex.	Cochran	8/01	1,240	37	24	1,080	1,040
	Occidental	Slaughter Estate Unit	Tex.	Hockley	12/84	5,700	194	150	4,100	2,430
	Occidental	Slaughter North West Mallet	Tex.	Cochran & Hockley	2008	1,048	39	24	950	0
	Occidental	Slaughter West RKM Unit	Tex.	Hockley	2006	1,204	51	33	1,560	30
	Occidental	South Welch	Tex.	Dawson	9/93	1,160	89	70	1,180	865
	Occidental	T-Star (Slaughter Consol.)	Tex.	Hockley	7/99	1,700	51	35	2,100	2,100
	Occidental	Wasson Bennett Ranch	Tex.	Yoakum	6/95	1,780	115	89	4,320	3,510
	Occidental	Wasson Denver Unit	Tex.	Yoakum & Gaines	4/83	27,848	1,010	575	31,500	26,850
	Occidental	Wasson ODC Unit	Tex.	Yoakum	11/84	7,800	325	270	9,900	9,200
	Occidental	Wasson Willard Unit	Tex.	Yoakum	1/86	8,500	275	228	4,965	4,765
	Occidental	West Welch	Tex.	Gaines	10/97	240	0	0	1,790	0
	Pure Resources	Dollarhide (Devonian) Unit	Tex.	Andrews	5/85	6,183	83	66	2,420	1,970
	Pure Resources	Dollarhide (Clearfork "AB")	Tex.	Andrews	11/95	160	21	4	230	124
	Pure Resources	Reinecke	Tex.	Borden	1/98	700	32	8	977	830
	Stanberry Oil	Hansford Marmaton	Tex.	Hansford	6/80	2,010	5	6	102	102
	Whiting Petroleum	North Ward Estes	Tex.	Ward/Winkler	5/07	16,300	816	816	4,225	700
	XTO Energy, Inc.	Goldsmith	Tex.	Ector	12/96	330	16	9	120	20
	XTO Energy, Inc.	Cordona Lake	Tex.	Crane	12/85	2,084	64	26	1,350	400
	XTO Energy, Inc.	Wasson (Cornell Unit)	Tex.	Yoakum	7/85	1,923	90	62	1,675	800
	XTO Energy, Inc.	Wasson (Mahoney)	Tex.	Yoakum	10/85	640	45	30	1,875	1,450
CO_2 immiscible										
	Kinder Morgan	Yates	Tex.	Pecos	3/04	26,000	551	121	27,940	6,280
TOTAL		**61**					**7,636**	**4,950**	**245,268**	**182,054**

Table A-3. Producing CO_2-EOR Projects in Non - Permian Basin Only

As published in Oil & Gas Journal, April 21, 2008

Operator	Field	State	County	Start date	Area, acres	No. wells prod.	No. wells inj.	Tot. prod., b/d	Enh. prod., b/d
Chevron	Rangely Weber Sand	Colo.	Rio Blanco	10/86	18,000	378	262	15,300	11,600
Murfin Drilling	Hall-Gurney	Kan.	Russell	12/03	10	2	3	3.3	3.3
Denbury Resources	Lockhart Crossing	La.	Livingston	12/07	3,398	11	3		
Core Energy	Charlton 6	Mich.	Otsego	2006	60	1	1	10	10
Core Energy	Charlton 30-31	Mich.	Otsego	2005	285	2	1	75	75
Core Energy	Dover 33	Mich.	Otsego	1996	120	2	1		75
Core Energy	Dover 33	Mich.	Otsego	1996	85	2	1	0	0
Core Energy	Dover 35	Mich.	Otsego	2004	80	2	2		76
Core Energy	Dover 35	Mich.	Otsego	2004	70	3	2	210	210
Core Energy	Dover 36	Mich.	Otsego	1997	200	1	2		125
Core Energy	Dover 36	Mich.	Otsego	1997	190	1	2	70	70
						14	**12**	**365**	**641**
Denbury Resources	Lazy Creek	Miss.	Pike	12/01	840	5	6	250	250
Denbury Resources	Little Creek	Miss.	Lincoln & Pike	1985	6,200	30	34	1,650	1,650
Denbury Resources	West Mallalieu	Miss.	Lincoln	1986	8,240	42	31	6,200	6,200
Denbury Resources	Martinville	Miss.	Simpson	3/06	280	5	1	600	650
Denbury Resources	Martinville	Miss.	Simpson	3/06	212	2	2	180	180
Denbury Resources	McComb	Miss.	Pike	11/03	12,600	37	21	1,650	1,650
Denbury Resources	Smithdale	Miss.	Amite	3/05	4,100	5	3	600	600
Denbury Resources	Soso	Miss.	Jones/Jasper/Smith	4/06	2,600	37	17	1,350	1,350
Denbury Resources	Soso	Miss.	Jones/Jasper/Smith	4/06	1,800	16	8	350	350
Denbury Resources	Brookhaven	Miss.	Lincoln	1/05	10,800	31	23	3,100	3,100
Denbury Resources	East Mallalieu	Miss.	Lincoln	12/03	880	11	8	1,800	1,800
Denbury Resources	Tinsley	Miss.	Yazoo	9/07	10,104		6	440	
Denbury	Eucutta	Miss.	Wayne	4/06	2,100	25	29	3,000	3,000
Denbury	Martinville	Miss.	Simpson	3/06	180	3	1	270	0
						249	**190**	**21,440**	**20,780**

Table A-3 (continued)
Producing CO_2-EOR Projects in NON - Permian Basin Only
As published in Oil & Gas Journal, April 21, 2008

Operator	Field	State	County	Start date	Area, acres	No. wells prod.	No. wells inj.	Tot. prod., b/d	Enh. prod., b/d
Chaparral Energy	Sho-Vel-Tum	Okla.	Stephens	9/82	1,100	60	40	1,100	1,100
Chaparral Energy	Camrick	Okla.	Beaver	4/01	2,320	32	19	1,275	1,175
Merit Energy	Northeast Purdy	Okla.	Garvin	9/82	3,400	85	49	1,800	1,800
Merit Energy	Bradley Unit	Okla.	Garvin/Gardy	2/97	700	29	12	800	600
Whiting Petroleum	Postle	Okla.	Texas	11/95	11,000	92	82	4,500	4,500
Whiting Petroleum	Postle Expansion	Okla.	Texas	1/07-1/09	7,000	72	62	1,700	1,700
Chaparral Energy	Sho-Vel-Tum	Okla.	Stephens	11/98	98	6	1	72	70
						376	**265**	**11,247**	**10,945**
ExxonMobil	Greater Aneth Area	Utah	San Juan	2/85	13,440	143	120	6,000	3,000
Resolute Natural Resources	Greater Aneth	Utah	San Juan	10/98	1,200	12	10	1,200	400
						155	**130**	**7,200**	**3,400**
Anadarko	Patrick Draw Monell	Wyo.	Sweetwater	9/03	3,500	56	47	3,000	3,000
Anadarko	Salt Creek	Wyo.	Natrona	1/04	3,500	174	153	5,000	6,000
Anadarko	Salt Creek	Wyo.	Natrona	5/07	5	1	1		
Anadarko	Sussex	Wyo.	Johnson	12/04	25	4	1		
Merit Energy	Lost Soldier	Wyo.	Sweetwater	5/89	1,345	33	39	4,672	4,545
Merit Energy	Lost Soldier	Wyo.	Sweetwater	5/89	790	16	17	2,232	1,661
Merit Energy	Lost Soldier	Wyo.	Sweetwater	6/96	120	11	7	1,740	1,015
Merit Energy	Wertz	Wyo.	Carbon, Sweetwater	10/86	1,400	12	22	3,912	2,986
Merit Energy	Wertz	Wyo.	Carbon, Sweetwater	9/00	810	12	18	1,685	1,033
Anadarko	Salt Creek	Wyo.	Natrona	10/05	5	4	1	-	-
						323	**306**	**22,241**	**20,240**
			TOTAL			**1,508**	**1,171**	**77,796**	**67,609**

Table A-4. Summary of Selected U.S. CO_2-EOR Projects outside the Permian Basin

Field Name	State	Type of EOR	Comments
Lick Creek	AR	CO2 immiscible	Initiated in 1976 by Phillips to demonstrate the viability of the immiscible CO2/wateflood process as a secondary recovery option for thin, heavy oil sands like the Meakin Sandstone. Through 1981, 0.755 MMBbls of incremental oil had been produced . The projected total production was estimated at 3.66 MMBbls total oil with 3.09 MMBbls incremental in the 15 years of production.
North Coles Levee (San Joaquin Basin	CA	CO2 miscible	ARCO (now BP) initiated CO2 injection in the Stevens Sand from 1981 through 1984. CO2 injection involved two adjacent 10 acre patterns and one 10 acre line drive pattern. CO2 was from a H2 plant at ARCO's refinery. 1.7 Bcf of CO2 was injected before loss of CO2 supply due to refinery closure. Reported to have successfully mobilized oil in the CO2 swept area, in the range of 15% - 20% HCPV. Problems with pattern balance and CO2 injection design led to high CO2-to-oil ratios. Reservoir simulation indicated that a larger, more balanced CO2 slug of 62% to 82% HCPV would have provided a considerably higher oil recovery.
Lost Hills (San Joaquin Basin)	CA	CO2 miscible	In 2000, ChevronTexaco initiated a pilot WAG CO2 injection project. 1.9 Bcf of CO2 was injected into the Etchegoin oil reservoir. The project was suspended in 2002, after a two year assessment period.
Wilmington (LA Basin)	CA	CO2 immiscible	Long Beach Oil Development initiated an immiscible CO2 project in a shallow, heavy oil (2,300 feet) from 1982 through 1987. The 330 acre project involved 42 producing wells and 8 injection wells in a line drive pattern. CO2 was obtained from the stack gas of the hydrogen units at Texaco's Wilmington refinery (85% CO2 and 15% N2). 8.2 Bcf of gas (7 Bcf of CO2) was injected in 4 years. Project recovered an estimated 488,000 barrels of oil. According to a technical report, this iproject injected only about one third of the "ideal" volume of CO2. Reservoir analysis indicated that a larger volume of CO2, additional injection wells, and a modified WAG ratio would have significantly improved results
East Coyote, Huadle Dome Unit (LA Basin)	CA	CO2 miscible	CO_2 WAG project started in 1982 and stopped in 1984, with 183 MMcf CO_2 injected
Huntington Beach, Onshore Area A-37 (LA Basin)	CA	CO2 miscible	Cyclic CO_2 project started in 1981 and stopped in 1982, with 183 MMcf CO_2 injected
Wilmington, Fault Block I Ranger (LA Basin)	CA	CO2 miscible	CO_2 WAG project started in 1983 and stopped in 1986, with 2,330 MMcf CO_2 injected
Wilmington, Fault Block III Tar (LA Basin)	CA	CO2 miscible	CO_2 WAG project started in 1981 and stopped in 1996, with 3,490 MMcf CO_2 injected
Ventura (Coastal Basin)	CA	CO2 miscible	Pilot CO_2 injection project initiated in D-6 (c) reservoir in 1988, with 215 MMcf of CO_2 injected. No further results are publicly reported.
Rangely	CO	CO2 miscible	Currently owned and operated by Chevron, the field was under waterflood until 1986, when CO2 injection was initiated. CO2 is transported to the field from Exxon's Shute Creek gas processing plant near LaBarge, Wyoming (from the Labarge field). Well over 1 trillion cubic feet of CO2 has been injected into the Weber reservoir since start of CO2-EOR in 1986. Currently CO2 is being injected via 262 injection wells at a rate of 166 MMcf/d, producing 11,600 Bbls./day of incremental oil from 378 production wells.Chevron is expecting to recover an additional 114 million barrels of oil from using CO2-EOR, 6% of OOIP.
Forsyth	IL	CO2 miscible	A small pilot was initiatedutilizing CO2 from the Archer-Daniels-Midland Ethanol Processing Facility in Decatur, IL
Mattoon	IL	CO2 miscible	In the early 1990s, a single-well "huff-and-puff" CO2 pilot was initiated, involving a well that was drilled to a depth of 1,800 feet in the Cypress reservoir. CO2 was again supplied from ADM's ethanol plant. After several months of operation, the pilot was shut down due to high CO2 costs compared to the oil recovery rate.
Hall-Gurney	KS	CO2 miscible	Joint DOE-industry (Muffin Drilling) CO2-EOR pilot underway to demonstrate the potential for EOR. The 10 acre project was initiated in 2000 using one CO2 injector and two producing wells on a half five spot pattern, with field production beginning in 2003. Today the pilot is producing about 3 barrels per day.
Big Andy	KY	CO2 Miscible	N2/CO2 huff and puff project current operating; N2 flood began in 1986
Weeks Island	LA	Gfravity stable CO2 miscible	Beginning in 1978, Shell and the U.S. DOE began a CO2 gravity stable pilot project at the "S" Sand Reservoir B. Initial gas injection of 853 MMcf of CO2 (24% HCPV) and 55 MMcf of natural gas lasted from October 1978 until February 1980; followed by re-injection of the produced CO2 and natural gas (at 761 Mcf/d) through 1987. Early production testing revealed an oil bank was being mobilized in the watered out sand. Oil production began in early 1981. By 1987, 261,000 barrels of oil, or 64% of ROIP, had been recovered. Project mobilized 205,000 barrels of residual oil, equal to 60% of the oil left after water displacement. Pilot was considered a success; but full field development was not successful due to inability of the CO2 injection design to displace the strong bottom water drive.

Table A- 4 (continued)
Summary of Selected U.S. CO_2-EOR Projects outside the Permian Basin

Bay St. Elane	LA	Gravity stable CO2 miscible	Initiated in 1981, in a steeply dipping (36º), low residual oil (20%) sandstone reservoir. Approximately 433 MMcf of CO2 solvent was injected into an up-dip well over a 9-month period, resulting in a 0.33 PV CO2 (plus methane/butane) injection. Approximately 300 MMcf of nitrogen was then injected as the drive gas. Project expected to recover 75,000 barrels of incremental oil. Operator reports that while an oil bank was mobilized and one of the producing wells flowed at 92% oil cut (previously 100% water cut), there was difficulty in producing the oil bank with the existing well placements. Final performance results for this innovative CO2-EOR project are not available.
Paradis	LA	CO2 immiscible	Small scale "huff and puff" test conducted in 1984/1985; involved injecting two cycles of CO2 into a producing well. A total of 39 MMcf of CO2 was injected resulting in reported incremental oil recovery of 20,700 barrels. Post project analysis showed that higher CO2 injection rates would have enabled the CO2 to contact more of the reservoir's oil
Lockhart Crossing	LA	CO2 miscible	Denbury resources intiated project in 2007. To early to determine results.
Charlton/Dover	MI	CO2 miscible	A series of small floods have been initiated by Core Energy for the past 10 years, using CO2 from an Antrim shale gas processing plant. The targets are a number of small Niagran pinnacle reef field reservoirs. Today, 8 distinct projects are producing a total of 550 barrels per day. Each project is characterized by 1-2 production wells and 1-2 injectors.
Lazy Creek	MS	CO2 miscible	Project initiated in late 2001, which is today producing 250 Bbl/day from 5 producers and 6 injectors.
Little Creek	MS	CO2 miscible	Experimental CO2 pilot conducted by Shell Oil from 1974 to 1977. Large volume of CO2 equal to 1.6 HCPV was first injected and then followed by 1 PV of water. Produced 124,000 barrels of oil (through March 1978), 21% of OOIP (and 45% of ROIP). In 1999, Denbury acquired the Little Creek Field and expanded the field-scale CO2 flood. Today, the project is producing nearly 1,700 Bbl/day from 30 producers and 34 injectors.
West Mallalieu	MS	CO2 miscible	The field has experienced three phases of CO2-EOR: 1) Initial CO2-EOR pilot initiated by Shell in 1986; involving 4 inverted 5-spot patterns surrounded by water injection barrier wells. At end of 1997, field was shut-in, produced 2.1 MMBbls due to CO2-EOR. 2) DOE-sponsored cyclic CO2 Pilot started in August 2000 by J.P. Oil Company; involved injection of 63 MMcf of CO2 into one producing well. All of the injected CO2 was produced back in the next three months, with only negligible volumes of liquid production. 3) Denbury initiated expanded CO2-EOR Project in mid-2001 by adding four patterns in 2001, four patterns in 2002, three patterns in 2003 and three patterns in 2004. By the end of 2004, Denbury had booked 14.9 MMBbls of proved reserves. Today, the project is producing 6,200 Bbl/day from 42 producers and 31 injectors
Martinville	MS	CO2 miscible & immiscible	Initiated in 2006, the project now produces 830 Bbl/day from 7 producers and 3 injectors. Also contains small CO2 immiscible project intiated in 2006
McComb	MS	CO2 miscible	Initiated in 2003, now produces 1,650 Bbl/day from 37 producers and 21 injectors.
Smithdale	MS	CO2 miscible	Initiated in 2005, now produces 600 Bbl/day from 5 producers and 3 injectors.
Soso	MS	CO2 miscible	Initiated in 2007, now produces 1,700 Bbl/day from 53 producers and 25 injectors.
Brookhaven	MS	CO2 miscible	Initiated in 2005, now produces 3,100 Bbl/day from 31 producers and 23 injectors.
East Mallalieu	MS	CO2 miscible	Initiated in 2003, now produces 1,800 Bbl/day from 11 producers and 8 injectors.
Tinsley	MS	CO2 miscible	Initiatied in 2007 -- too early to evaluate
Eucutta	MS	CO2 immiscible	Initiated in 2009, now produces 3,000 Bbl/day from 25 producers and 29 injectors.
South Pine	MT	CO2 miscible	In 1984, a CO2 injectivity mini-test (non-producing) was conducted in the Red River Unit, consisting of an injection well and two observation wells. Brine was injected to flush all mobile oil from the reservoir; followed by a CO2 flood during which 48 MMScf was injected, then again followed by a brine flood. Results of the flood were encouraging; analysis of pressure cores showed a post-flood oil saturation of 21%, a 23% decrease from the 44% pre-flood oil saturation. However, the lack of a nearby CO2 sources and low oil prices in the mid -1980's spelled the end of CO2-EOR research in the region.
Little Knife	ND	CO2 miscible	From 1980 to 1981, a joint DOE-Gulf Oil Corporation mini test of a CO2 miscible WAG flood was conducted, where one injection and three observation wells were drilled on the structural high. Water was first injected to increase the reservoir pressure, then 1:1 CO2- WAG injection was conducted. It was determined that the waterflood sweep had displaced 37% of the OOIP.
Postle	OK	CO2 miscible	Beginning in 1995, ExxonMobil began CO2 injection a rate of 35 MMcf/d, after construction of a $25 million, 120-mile pipleline to carry CO2 from Bravo Dome, New Mexico. In 1998, was injecting 90 MMcf/d of CO2. Significant response occurred after 10% pore volume of CO2 had been injected. Production had risen to 6,500 Bbls/day in late 1999 and 2,000 Bbls/day in 2003 with 6,000 Bbls/day of enhanced oil production due to the CO2 flood. Today operated by Whiting, 164 producers and 144 injectors produce 6,200 Bbl/day.
Northeast Purdy and Bradley Unit	OK	CO2 miscible	Now operated by Merit (acquired from Anadarko), these two CO2 floods are fed by a 120-mile pipeline, transporting CO2 from a large fertilizer complex. EOR production in the Northeast Purdy Field is 1,800 Bbls/day and in theBradley Unit is 600 Bbls/day. The CO2-EOR project in the Bradley Unit is expected to expand to a field-wide flood update

Table A-4 (continued)
Summary of Selected U.S. CO_2-EOR Projects outside the Permian Basin

Sho-Vel-Tum	OK	CO2 miscible	Chaparrel Energy is operating two CO2-EOR projects; a miscible CO2 flood was started in 1982 in the light oil Sims reservoir. This 1,100 acre project involves 60 production and 40 injections wells, and is producing 1,100 Bbl/day. An immiscible CO2 flood was started in late 1998 in a heavier oil (19 °API) Aldridge reservoir; involving 6 production and injection wells, and is producing about 3,000 Bbls/day due to CO2-EOR
Camrick	OK	CO2 miscible	Chaparrel Energy's miscible CO2 flood was started in 1991. This 2,320 acre project in the Morrow reservoir has 32 production and 19 injection wells, and is producing 1,175 Bbl/day.
Fort Neches Unit (Gulf Coast)	TX	CO2 miscible	A notable CO2-EOR project, although no longer active, combined CO2-EOR with horizontal drilling. Texaco and DOE initiated a CO2 injection project in the Marginulina Sand, planning to recover 19% of OOIP or 2 MMBbl of by-passed oil. Actual performance of the CO2-EOR was reasonably in line with the forecast, at 14% of OOIP or 1.5 MMBbl.
Spraberry Field (Central Texas)	TX	CO2 miscible	CO2 injection into the E.T.O'Daniel Pilot Area began in February 2001, and initial results indicated that large volumes of CO2 were being retained in the reservoir, as would be expected in order to push oil into production wells. However, as of early 2004, very little CO2 was being injected into the Spraberry Trend Area, due to the success of waterflooding in the pilot area.
Greater Aneth	UT	CO2 miscible	A CO2 flood was initiated in the McElmo Creek Unit in 1985 using a 5 spot pattern on 40-acre spacing. By the early 1990's, the flood was considered a technical success but marginal economic due in large part to low CO2 injectivity into the low permeability formation. In the mid 1990s a horizontal drilling program was started, and the horizontal well, 5-spot, line-drive pattern outperformed the vertical pattern by 2.2 to 2.5 times in terms of oil production. Recently, two CO2 floods were begun in the Ratherford and Aneth Units of this field using horizontal wells. In general, the horizontal multi-lateral completions are expected to recover 15% of OOIP, with CO2-EOR expected to add 10% of OOIP. Today, the field is producing 3,400 Bbl/day from 155 producers and 132 injectors.
Granny Creek-Stockly	WV	CO2 miscible	CO2 flood, north half, waterflood, south half
Blue Creek	WV	CO2 miscible	Injection test; CO2 pilot, Gary Energy, 1980
Griffithsville	WV	CO2 miscible	Irregular; pilot CO2 flood
Walton	WV	CO2 miscible	Irregular; 1 5-spot; modified 5-spot; inverted 5-spot; 1 steam flood attempted CO2 pilot, 2 10-acre 5 -spots with 13 water injection wells
Hilly Upland	WV	CO2 miscible	10 acre pilot; 1 injection well
Lost Soldier	WY	CO2 miscible	Beginning 1989 in the Tensleep formation, the project has since been expanded to the Darwin-Madison and Cambrian formations. The three floods combined produce over 7,000 barrels per day from 60 producers and 66 injectors.
Wertz	WY	CO2 miscible	Began in 1986 in the Tensleep formation and has since been expanded to the Darwin-Madison formation. The two floods currently produce at a rate of 4,000 barrels per day from 24 producers and 40 injectors.
Salt Creek	WY	CO2 miscible & immiscible	Following a successful CO2-EOR pilot, a full scale CO2-EOR project was started in 2004. Approximately 130 MMcf/d of CO2 is being injected into the formation. Today, Anadarko has both miscible and miscible projects underway. Today, the miscible project is producing 6,000 Bbl/day from 174 producers and 153 injectors; while the immiscible project is producing 70 Bbl/day from 4 producers and 1 injector.
Patrick Draw Monell	WY	CO2 miscible	Initiated in 2003, the project is producing 3,000 Bbl/day from 56 producers and 47 injectors;
Sources:			
2008 Oil and Gas Journal EOR Survey (April 21, 2008)			
DOE CO2-EOR basin studies (http://www.fossil.energy.gov/programs/oilgas/eor/Ten_Basin-Oriented_CO2-EOR_Assessments.html)			
West Virginia information courtesy of Katherine Lee Avary at WVGES			
Kentucky project courtesy of Brandon Nuttall, Kentucky Geological Survey			
Rangeley (http://emfi.mines.edu/emfi2005/ChevronTexaco.pdf)			

Table A-5. Summary of Selected U.S. Hydrocarbon and N2 Injection EOR Projects

Field Name	State	Type of EOR	Comments
Prudhoe Bay (along w/ smaller nearby units Eileen West End, Aurora, Borealis, Orion, Polaris, & Pt. McIntyre)	AK	HC miscible	Began in 1982 following waterflooding operations, and progressed in stages to a field-wide flood by 1987, and later other nearby units. BP Alaska injects CO2-rich hydrocarbon gas utilizing a total of 535 production wells and 257 injection wells covering a total of 100,000 acres. the source of gas in the gas processing facility on the Alaska North Slope, where there is currently a minimal accessible market for the produced gas. The project has been termed a success and is currently producing about over 42,500 Bb/day of incremental oil.
Kuparuk River	AK	HC miscible	In mid-1988, a CO2-rich hydrocarbon miscible flooding operation (from the same gas source as above) began at Kuparak River and responded in stages through the end of 1996. Today, ConocoPhillips' utilizes 350 production wells and 260 injection wells covering 110,000 acres. This project has also been termed a success; and is currently producing about 33,000 Bbl/day of incremental oil.
Jay/Little Escambia Field	FL	N2 miscible	ExxonMobil initiated a N2 miscible WAG flood in 1981 following seven years of waterflooding. Evaluation of applying CO2-EOR to the Jay/Little Escambia oil field indicates potential recovery of about 20% OOIP, about twice the volume currently expected from N2-EOR. Today, the field is still producing 10,700 Bbl/day of incremental oil 100 production wells and 90 injectors.
South Pass Block 89	LA offshore	HC miscible	Started in 1983, this project produces about 2,300 Bbl/day from 8 injection wells and 9 producers.

CO_2-EOR Projects Outside of the United States

Despite the many CO_2-EOR projects in the U.S., activity elsewhere in the world is limited. Seven CO_2 miscible projects and one acid gas miscible project are underway in Canada. The “poster child” of a CO_2-EOR eventually converting into a geologic storage project is EnCana’s Weyburn CO_2 flood in Canada, where oil production from CO_2-EOR continues to increase. The Weyburn operation covers 70 square miles and is one of the largest medium-sour crude oil reservoirs in Canada, containing approximately 1.4 billion barrels of original oil in place. The Weyburn unit was placed on waterflood injection in 1964, and in 2000, the field began operating on CO_2 miscible flood. The CO_2 flood has been expanded to over 60% of the unit. The implementation of the CO_2-EOR project, along with the continued infill well development program, has resulted in a 65% increase in oil production. EnCana buys anthropogenic CO_2 from the Dakota Gasification Synfuels plant in Beulah, North Dakota.

Apart from giving new life to an old field, the use of CO_2 as an injectant makes EnCana's Weyburn site the world's largest CO_2 storage project. From 2000 to 2004, the Weyburn project was the site of a world-scale research initiative operated under the auspices of the IEA GHG, which concluded that Weyburn is a suitable reservoir for long-term storage of CO_2. The project currently injects 2.4 million tonnes per year, and is expected to inject, and ultimately store, 23 million tonnes as part of CO_2-EOR operations. Currently, plans are to continue to inject CO_2 into the field after EOR operations have ceased, with the ultimate expectation of storing 55 million tonnes.[86]

Another CO_2-EOR project has been in operation by Apache Canada since 2005 in the nearby Midale field, using the same source for CO_2 as Weyburn.[87] In addition, a small CO_2-EOR project has been in operation at the Joffre in Alberta since 1984, operated by Penn West, using CO_2 from a nearby petrochemical plant.

Only a few (mostly immiscible) CO_2-EOR projects are underway elsewhere in the world (in Brazil, Turkey, and Trinidad and Tobago). A number of immiscible displacement projects were also pursued in Hungary in the 1980s and 1990s, taking advantage of a natural CO_2 reserve in the area. In this case, EOR was achieved by creating an artificial gas cap which forced oil towards the production wells. Finally, numerous reports mention the fact that a large number of CO_2-EOR and or gas injection pilots have been attempted or are underway in China, though very little information is provided on the details of these pilots. In some cases, the injection stream is a flue gas stream or other waste stream, often with a relatively low concentration of CO_2. Reportedly, CO_2-EOR pilots have been implemented in the Liaohe, Jilin, Dagang, Shengli, Zhongyuan, Daqing, Jiangsu, Songliao, Changqing, Huebei, and Xinli fields.[88,89]

Acid gas, a concentrated stream of hydrogen sulfide (H_2S) and CO_2, is a new type of injectant seeing applications in EOR in several places around the world. Apache Canada has a pilot in the Zama field in northwestern Alberta that produces about 1,000 barrels of oil per day. Chevron injects sour gas as part of its second-generation project in the Tengiz field in Kazakhstan. This expansion has increased production by 250,000 barrels of oil per day. Finally, Petroleum Development Oman also has under development the $1 billion Harweel sour-gas injection project in southern Oman, and expects to produce about 60,000 barrels of oil per day by 2010, with a potential in the next decade of production increasing to 100,000 barrels of oil per day from the ten fields in the cluster.[90]

However, unlike the U.S. experience, especially in the Permian basin, there is not yet a sufficient history of experience from which to draw general conclusions about these projects outside the U.S.

Planned CO_2-EOR/Geologic Storage Projects in the U.S.

As of April 2008, 15 CO_2-EOR projects were in various degrees of planning, according to the *Oil and Gas Journal,* as summarized in Table A-6.[91] Most of these projects plan to only inject CO_2 for CO_2-EOR operations, and are not currently being designed to continue to sequester CO_2 after oil production ceases.

Table A-6. Planned EOR Projects Worldwide
(As published in Oil & Gas Journal, April 21, 2008)

Type	Operator	Field	Location	Pay zone	Size acres	Depth, ft.	Gravity °API	Start date
CO_2 immiscible								
	Anadarko	Sussex	Johnson Co., Wyo.	Tensleep	2,544	9,000	29	2010
	ARC Energy Trust	Redwater	Redwater, Alta., T58 R21 W4M	Leduc D-3	160	3,000	36	7/08
	Denbury	Cranfield	Adams Co., Miss.	Lower Tuscaloosa	7,754	10,250	39	5/08
	Denbury	Heidelberg West	Jones & Jasper Co., Miss.	Eutaw	915	5,000	22	10/08
CO_2 miscible								
	Core Energy	Chester 6	Otsego, Mich.	A1 Carbonate	100	5,700	43	6/09
	Core Energy	Niagaran "A"	Otsego, Mich.	Brown Niagaran	120	5,700	43	12/09
	Core Energy	Niagaran "B"	Otsego, Mich.	Brown Niagaran	140	5,700	43	12/10
	Denbury	Delhi	Richland, Madison, Franklin Parishes, l	Holt-Bryant	8,000	3,300	42	1/09
	Denbury	W. Lazy Creek	Pike Co., Miss.	Lower Tuscaloosa	600	10,250	39	10/09
	Fasken	Abell	Crane Co., Tex. Blk 1C, H&TC RR Sur	Devonian	769	5,200	40	1/09
	Fasken	River Bend	Crane Co., Tex. Blk 1C, H&TC RR Sur	Devonian	470	5,300	40	1/09
	Fasken	Hanford ROZ	Gaines, Tex.	San Andres	340	5,700	32	1/09
	Kinder Morgan	Katz	Stonewall County, Tex.	Strawn	5,483	4,800	40	5/09
	Occidental	North Dollarhide	Andrews Co., Tex.	Clearfork	270	6,500	40	2008
	Ridgeway Arizona Oil	Milnesand	Roosevelt County, NM	San Andres	40	4,600	27	2008

One project in the planning and permitting stages is being pursued as a joint CCS/CO_2-EOR project. On July 31, 2008, Hydrogen Energy International filed an Application for Certification for an integrated gasification combined cycle (IGCC) power generating facility in Kern County, California. The project would gasify petroleum coke (or blends of petroleum coke and coal, as needed) to produce hydrogen to fuel a combustion turbine operating in combined cycle mode. The gasification component would produce hydrogen to feed a 390 megawatt (MW) combined cycle plant, providing approximately 100 MW of peaking power. The gasification component would also capture approximately 90% of its CO_2 emissions, or two million tonnes per year (130 MMcfd) of CO_2, which would be transported and used for EOR and storage in the Elk Hills Oil Field.[92]

A number of other joint CCS/CO_2-EOR projects are under consideration in the U.S. For example, Baard Energy, in their Ohio River Clean Fuels project, is planning to develop a 53,000 barrels per day coal- and biomass-to-liquids project, which has announced plans to market the plant's CO_2 for EOR.[93] Rentech is developing a 29,600 barrel per day coal- and biomass-to-liquids plant in Natchez, Mississippi, which will market the plant's CO_2 for EOR. The first phase of the project is expected in 2011. DKRW Energy is developing a 15,000-20,000 barrel per day coal-to-liquids plant in Medicine Bow, Wyoming, which may also market its CO_2 for EOR. The project is expected to begin operation in 2013.[94] And Alter NRG has recently announced

Canada's first proposed coal-to-liquids project that will capture CO_2 for use in CO_2-EOR projects.[95]

Finally, several oil field injection tests are being or have recently been conducted as part of the Phase II validation stage of the DOE Regional Carbon Sequestration Partnership Program.[96] These tests ultimately could lead to larger scale projects.

Planned CO_2-EOR/Geologic Storage Projects outside the U.S.

The *Oil and Gas Journal* reported only one planned pilot CO_2-EOR project outside the U.S. in 2008; a project by Petrobras in the Miranga field in Brazil.[97]

In addition to its planned project in California, Hydrogen Energy is also planning a project in Abu Dhabi that will convert natural gas to hydrogen and CO_2. The hydrogen power plant will generate approximately 400 MW of low-carbon electricity, and would provide more than 5% of all Abu Dhabi's current power generation capacity. Up to 1.7 million tonnes of CO_2 per year will be transported to a producing oil field and used to replace natural gas that is currently being injected to maintain pressure. The CO_2 injected into the field will also enable previously unrecoverable oil to be produced. If this technology is widely deployed it could boost Abu Dhabi oil production an estimated 1 to 3 billion barrels.[98]

This project in Abu Dhabi was modeled after a similar project in Scotland. The so-called "Peterhead site" offered great potential to be the world's first hydrogen power plant with CCS. A considerable amount of needed infrastructure was already in place, and land was available next to an existing, conventional gas fired power plant. Pipelines were in place to transport the CO_2 and a North Sea oil field, BP's Miller field, had been identified as a suitable storage site. This project would have provided sufficient CO_2 for EOR to extend the life of the Miller oilfield for 15 to 20 years with the production of more than an additional 50 million barrels of oil. Unfortunately, financial incentives adequate to make such a first-of-its-kind CCS project economically viable were not available in the time frame necessary to enable this project to proceed. By the time work stopped on the project, it had been fully permitted.[99]

In March 2006, Statoil and Shell launched a plan for a project to utilize CO_2 captured from a large natural gas-fired power plant and methanol production facility at Tjeldbergodden in Norway to be used in an offshore CO_2-EOR project at the Shell-operated Draugen field, and later at the Statoil-operated Heidrun field. A proposed capture facility plans to remove up to 2.5 million tonnes of CO_2 per year (including a possible 0.3 million tonnes from an existing methanol plant). This amount is equivalent to about 5% of Norwegian emissions. Offshore oil and gas installations with energy supplies from land will reduce their CO_2 and nitrogen oxides (NO_x) emissions to almost zero.

Finally, the North Sea was identified by IEA GHG in an earlier study to have significant opportunity for CO_2-EOR.[100] Interest has been expressed in the idea of establishing a 'backbone' CO_2 supply system for North Sea oil fields (the CENS (CO_2 for EOR in the North Sea) project.[101]

In fact, a considerable amount of work has been done identifying the best CO_2-EOR prospects in the North Sea. Oil majors like BP, Shell, ConocoPhillips, and Statoil have investigated CO_2-EOR potential at fields like Forties, Miller, Draügen and Gullfaks; but have not pursued these opportunities. However, initial evaluation of these prospects concluded that CO_2-EOR oil yields are disappointing, and together with escalating capital costs for the conversion of offshore installations, including facilities and wells for CO_2 injection, these prospects were determined unlikely to be economic. Further studies by Herriot Watt University and the Norwegian Petroleum Directorate have deemed CO_2-EOR development in the North Sea area uneconomic without financial incentives.[102] The authors cite as causes, a lack of regulatory guidance, poor sweep efficiency (and hence oil recovery) high oil recovery rates from secondary recovery techniques (compared to onshore fields), high costs of offshore platform retrofits, the availability of sufficient and cheap volumes of CO_2, and the costs to establish a region-wide CO_2 supply infrastructure.

APPENDIX B. KEY FACTORS OF CO_2 FLOODING SUCCESS: REVIEW AND RETROSPECTIVE

The steady growth of CO_2 flooding in the Permian Basin and elsewhere offers a case history for possible extrapolation to other oil bearing regions. A review of the history of CO_2-EOR shows that CO_2-EOR generally tends to be successful in fields that meet the technical criteria for achieving miscibility (defined primarily in terms of reservoir depth and oil viscosity), that have a relatively large volume of unrecovered oil after primary and secondary recovery (water flooding), and where there is a good source of sufficient, predictable, sustainable volumes of pure CO_2 supplies at affordable costs. Over time, other factors contributing to success are operator knowledge, comfort and willingness to pursue advanced CO_2-EOR technologies; the willingness and ability of the applicable regulatory regime to permit CO_2-EOR projects and, the availability of government financial incentives to promote CO_2-EOR projects.

Most past CO_2 floods classified as "failures" have generally been abandoned for economic reasons, not technical ones. If the economics of CO_2-EOR change due to the value the technology provides as a CO_2 storage enabler, the expansion of CO_2-EOR operations could be dramatic.

This section attempts to describe those key characteristics which have led to the continued expansion of CO_2 floods in areas where they have proven successful.

Influence of Reservoir Characteristics on CO_2-EOR Performance

The unique properties of CO_2 create some exciting commercial uses in oil reservoirs but, in turn, also offer some substantial challenges that must be overcome. The miscible conditions of CO_2 with oil allow a large number of potential projects to classify as miscible projects. Most projects are conducted in reservoirs below about 750 meters (2,500 feet) in depth and with light oils with gravities above 25^o API. Projects encompassing a wide range of reservoir lithologies, porosities and permeabilities have been successfully flooded.

Sweep efficiency of the reservoir is both critical and difficult to quantify without a previous phase of water flooding to provide a basis. Fracturing and channeling in the reservoir can cause inefficient sweep and result in flood failure. Neither will preclude implementation of a CO_2 project, but will require preventative design and/or remediation in the form of conformance control.

Moreover, achieving miscibility is not an absolute criterion of success for a CO_2-EOR project, but miscibility certainly enhances recovery. Operating above minimum miscible pressure (MMP) in a reservoir is often stated as a requirement for implementation of a successful CO_2-EOR project. However, it should be noted that several successful CO_2-EOR projects are immiscible floods, and several new projects are exploring the realm of the near-miscible region (Anadarko's Salt Creek and Denbury's Eucutta and Martinville projects).

Of the currently producing miscible CO_2-EOR projects in the U.S., about 60% are in carbonate reservoirs, with the rest in sandstone reservoirs. These projects report reservoir porosities ranging from 3% to 26%, with an average of about 14%. Reservoir depths range from 460 to 3,700 meters (1,500 to nearly 12,000 feet), with a mean of about 1,850 meters (6,080 feet), and a median of about 1,550 meters (5,540 feet). Nearly all, however, are deeper than 915 meters (3,000 feet), so the injected CO_2 will be in a dense phase, supercritical state, and thus able to achieve miscibility with the oil in the formation. Oil gravities range from 28^o to 45^o API, with a mean and median of about 37^o API.

Histograms of key reservoir characteristics for active CO_2-EOR projects are provided in Figure B-1.

Another important factor behind CO_2 flood sweep efficiency, not shown in Figure B-1, is the lateral and, for vertical floods, vertical continuity of the reservoir. More continuous reservoirs allow for more efficient flood front movement from injector to producer wells. Some types of reservoirs are more advantaged in this respect than others, and it relates both to their depositional and diagenetic histories.

Reliable and Affordable CO_2

Perhaps the single largest deterrent for expanding CO_2 flooding today is the lack of substantial volumes of reliable and affordable CO_2. The establishment of CO_2 sources and the resulting growth of CO_2 flooding in the Permian Basin, Wyoming, and Mississippi provide three independent case histories and testament to that observation. All three of these areas are constrained by CO_2 supply, and CO_2 source production remains fully committed today. For example, after nearly a decade where CO_2 supplies in the Permian Basin outpaced demand in CO_2-EOR projects, since 2004 there has been a shortfall of CO_2 supply (Figure B-2). Even in regions of the U.S. where CO_2 activity is currently taking place, most CO_2-EOR operators in these regions are of the opinion that the availability of CO_2 limits industry's ability to expand the application of CO_2-EOR.

Figure B-1. Histograms of Reservoir Properties of Active CO_2-EOR Projects

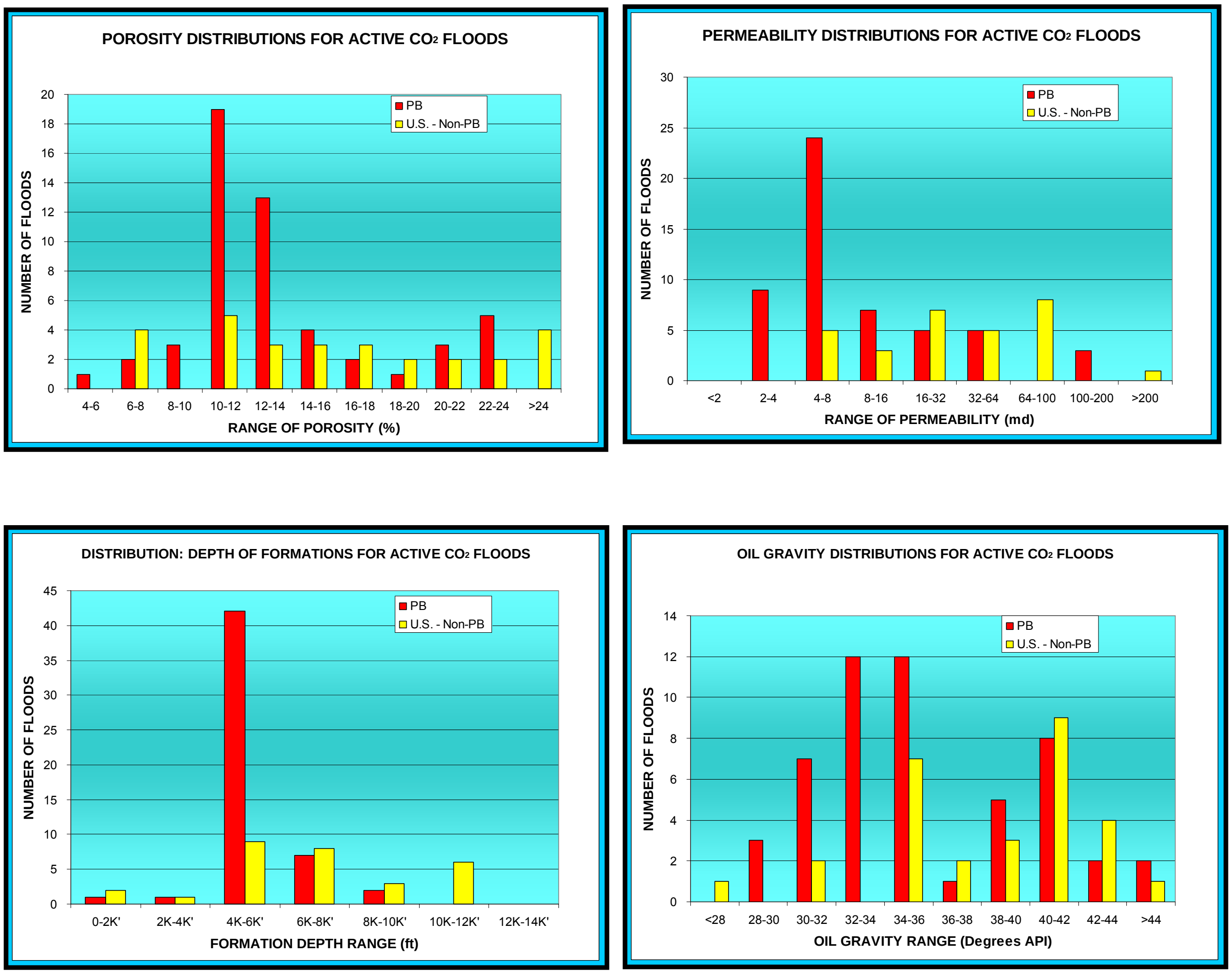
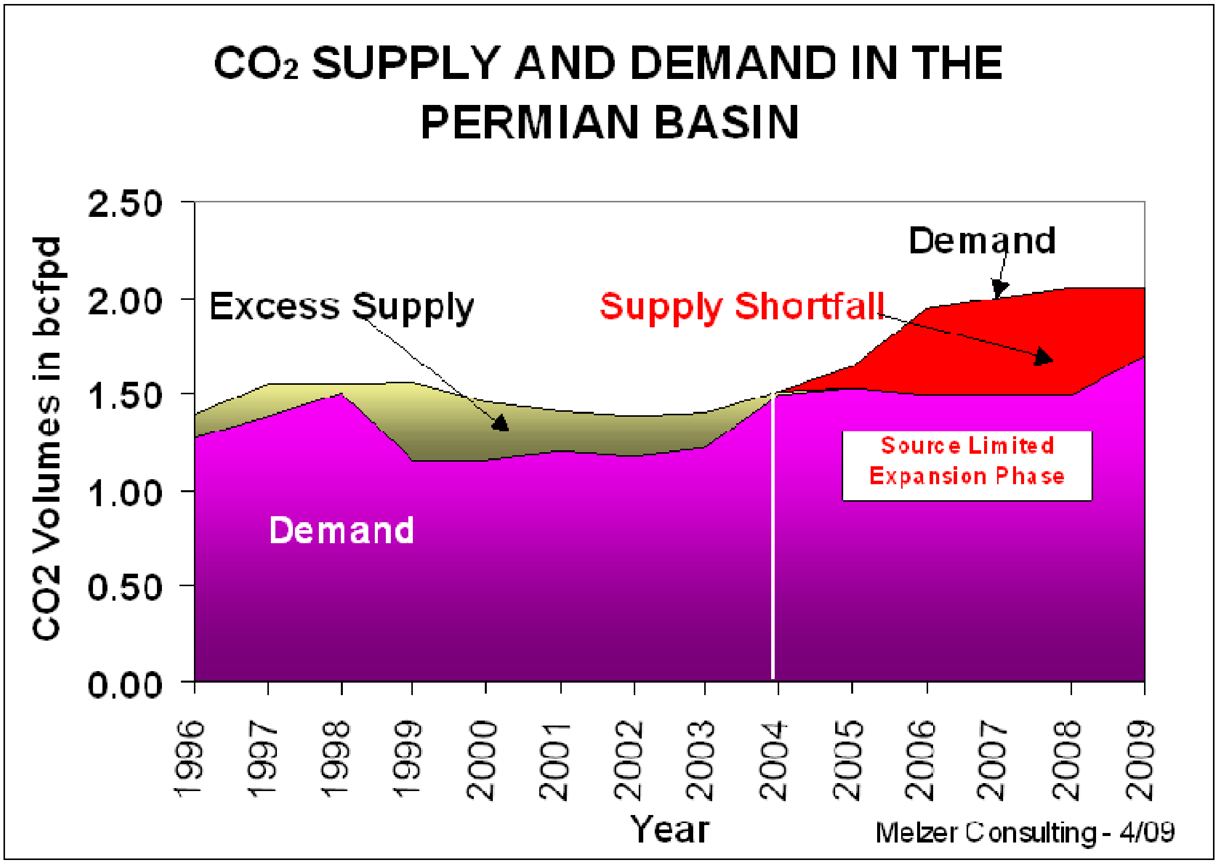


Figure B-2. CO_2 Supply and Demand in the Permian Basin



In the Permian Basin alone, there could be an additional 5 to 9 million tonnes per year (300 to 500 MMcfd) of incremental CO_2 demand, from the combination of current CO_2-EOR project expansions, the conversion of several old waterfloods to CO_2 injection, and several projects looking at pursuing a residual oil zone (ROZ), should those supplies be available.[103]

There are signs, however, that at least some of the CO_2 supply shortfall is being proactively addressed:

- Kinder Morgan completed its Doe Canyon gas plant in southwestern Colorado in late 2008, adding 2 million tonnes per year (110 MMcfd) of CO_2 supply availability to the Permian basin of West Texas and New Mexico. This was supplemented by expansion in McElmo dome, also in Colorado, that added another 3.5 million tonnes per year (200 MMcfd) of CO_2 production capacity. The additional CO_2 from McElmo Dome and Doe Canyon had been already sold to existing projects and to the North Ward Estes EOR project, which is the anchor field for deliveries from Doe Canyon.[104]
- Enhanced Oil Resources Inc. (EOR Inc.) recently announced a memorandum of understanding (MOU) for developing a pipeline with SunCoast Energy Corp. to carry

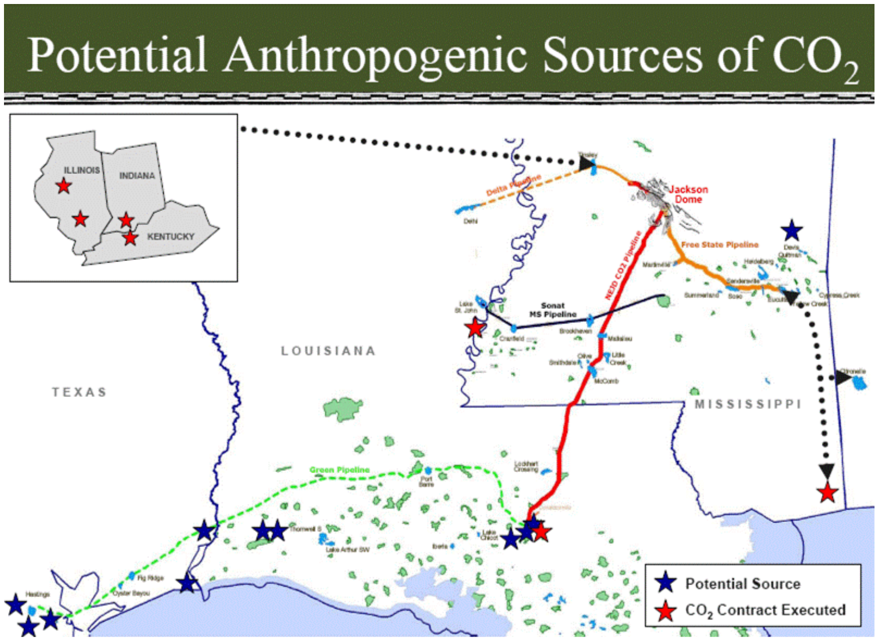
CO_2 560 kilometers (350 miles) from its St. Johns, Arizona helium and CO_2 field to the Permian basin. The company's initial plans are to transport 6 million tonnes per year (350 MMcfd) of CO_2 into the Permian basin. The pipeline design capacity will be 9 million tonnes per year (500 MMcfd). EOR Inc. has reserved the right to the first 3 million tonnes per year (175 MMcfd) of capacity for its own oil field in the basin and for some other targeted fields. If both companies meet their obligations, EOR Inc. expects the pipeline to be built by late 2010.[105,106]

- SandRidge Energy entered into an agreement with Occidental in June 2008 to build a CO_2 treatment plant (Century Plant) and associated CO_2 compression and pipeline facilities in Pecos and Terrell Counties in Texas. SandRidge will provide high-CO_2 natural gas to the plant under a 30-year agreement, providing Occidental with a dedicated CO_2 stream to use in its CO_2-EOR projects in the basin. Inlet plant capacity will start at about 5 million tonnes per year (300 MMcfd), but could ramp up to over 20 million tonnes per year (1,000 MMcfd) by 2011, resulting in nearly 8 million tonnes per year (450 MMcfd) of CO_2 for use in CO_2-EOR.[107]

Similarly, in Wyoming, Anadarko Corp. has plans to extend its 200 kilometer (125 mile) pipeline that currently transports CO_2 to the Salt Creek and Monell fields. The ExxonMobil La Barge gas plant is the source for this CO_2.[108] ExxonMobil is spending $70 million to expand the plant's capacity by 50% to capture CO_2. Currently, its capacity is about 4 million tonnes of CO_2 per year; the plant's expansion, scheduled to be completed in 2010, will augment this volume to 6 million tonnes per year.[109] Moreover, several other projects are being considered that could further expand CO_2 supply in the region. These include a coal-to-liquids facility (Medicine Bow Fuel and Power, at 3.5 million tonnes per year), several gas processing plants (Refined Energy Holdings at as much as 3 million tonnes per year; ConocoPhillips at 0.8 million tonnes per year), and an underground coal gasification project (Gas Tech at about 2 million tonnes per year).[110]

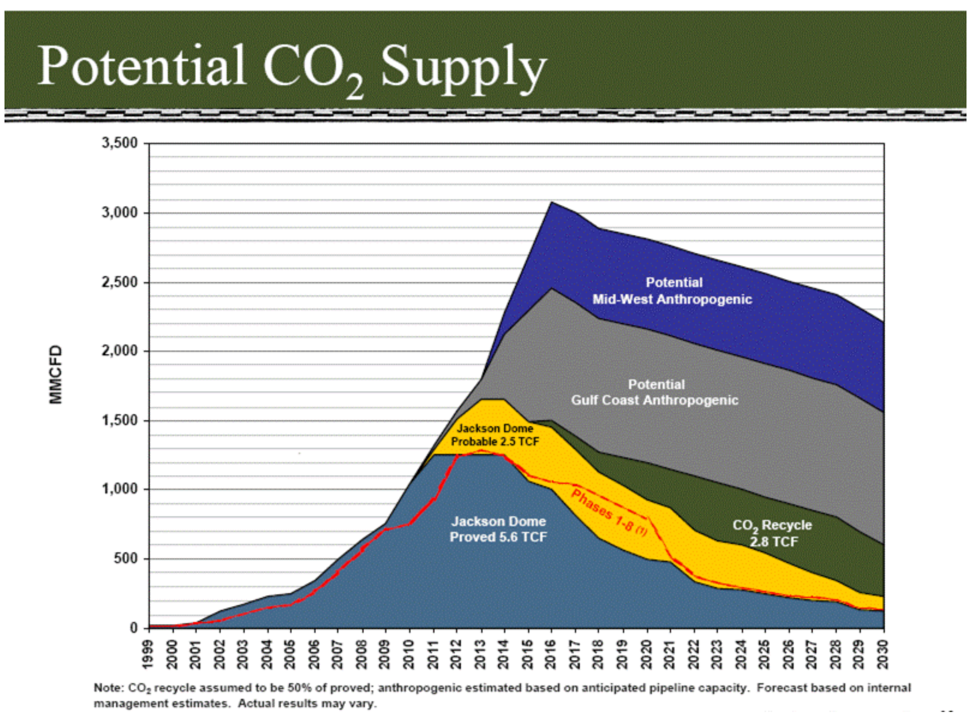
Denbury Resources is going beyond just incremental increases in capacity by taking a more strategic, long-term approach to pursuing CO_2-EOR projects, and to secure the CO_2 to supply these projects, in Mississippi, Louisiana, and the Texas Gulf Coast.[111] Denbury plans to expand its existing infrastructure to bring additional captured CO_2 to the CO_2-EOR market that already exists. The company has signed CO_2 purchase contracts with three planned chemical plants for a portion of its anthropogenic CO_2 supplies,[112] and is actively pursuing additional anthropogenic sources of CO_2 to supplement its natural reserves (Figure B-3); supplies which are projected to decline beginning around 2015 (Figure B-4) . They have identified seven potential anthropogenic sources that could provide 30 to 36 million tonnes per year (1,550 to 1,880 MMcfd) of CO_2 starting in 2013-2014.

Figure B-3. U.S Gulf Coast



Source: Denbury Resources Inc., June 2009 Corporate Presentation

Figure B-4. Denbury Resources' Strategic Vision for Supplying U.S. Gulf Coast CO_2-EOR Market



Source: Denbury Resources Inc., June 2009 Corporate Presentation

Denbury also has plans to increase its CO_2 pipeline capacity by adding a possible pipeline transporting CO_2 into East Texas. The approximately 510 kilometer (320 mile) "Green Pipeline" is designed to transport up to 13 million tonnes per year (800 MMcfd) of both natural and man-made (anthropogenic) CO_2.

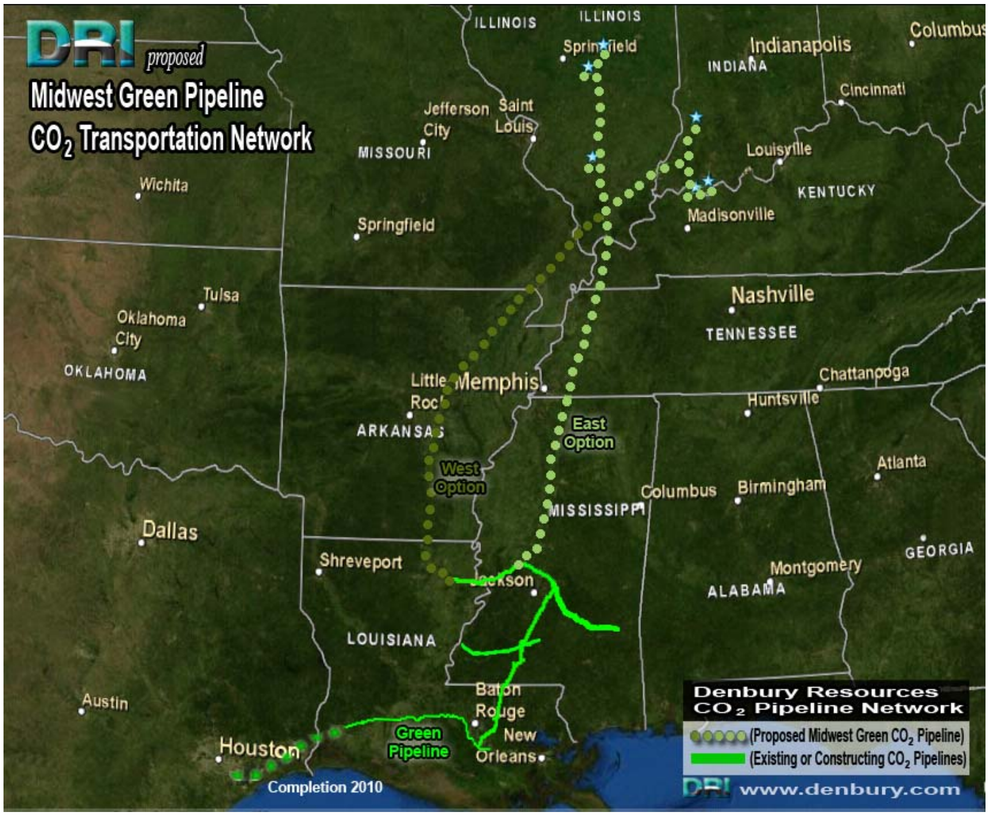
Finally, Denbury is also looking at bigger plans for moving CO_2 from areas where there are high concentrations of emissions, to areas where there is large potential for CO_2-EOR. In July 2009, Denbury announced that it has initiated a comprehensive feasibility study, in collaboration with the Illinois Department of Commerce and Economic Opportunity, of a possible CO_2 pipeline project connecting proposed gasification plants in the Midwest to its existing CO_2 pipeline infrastructure in Mississippi and/or Louisiana (Figure B-5).[113] The study is expected to determine the most likely pipeline route, the estimated costs of constructing such a pipeline, and review regulatory, legal and permitting requirements. Denbury's preliminary internal estimates suggest this would be a 500 to 700 mile pipeline system with a preliminary cost estimate of approximately $1.0 billion. In addition to the feasibility study, Denbury has entered into contingent CO_2 purchase contracts with four planned Midwest facilities.[114]

Oil Prices, Government Incentives and Demonstration Projects

One clear lesson for the emergence of CO_2 flooding as both a technical and economic success in the early 1970s was the presence of governmental financial incentives to 'kick start' the building of infrastructure and to facilitate commercial scale project deployment. The first of two chief incentives in the U.S. related to removal of proration[115] of production at SACROC by implementation of an EOR process. At that time, CO_2-EOR was only a process tested in the laboratory and in small scale field tests, but the promise of producing 30 days per month, instead of the allowable one day, was sufficient to allow the operators to feel compelled to give EOR a try. The Texas Railroad Commission, as the state regulator of oil and gas activity, offered this incentive, and the SACROC operators and other unit holders selected CO_2-EOR as the chosen EOR technique for this field.

The emerging market acceptance of CO_2-EOR as a viable recovery process led to the building of a pipeline to connect by-product CO_2 from four natural gas plants located as far as 360 kilometers (225 miles) away (Canyon Reef Carriers). The capture facilities, the pipeline, and the field investments allowed demonstration at a scale of the infrastructure required to facilitate CO_2-EOR.

Figure B-5. Denbury Resources' Strategic Vision for Moving Midwest CO_2 Supplies to the U.S. Gulf Coast CO_2-EOR Market



Source: Denbury Resources Inc.

The second key incentive came later (late 1970s) during U.S. oil price controls. At that time, the price of crude oil in the U.S. was heavily regulated, as it had been throughout much of the 20th century. Government price controls defined "oil tiers" which limited the price of "old oil" (that already discovered) while allowing newly discovered oil ("new oil") to be sold at a higher price. "Old oil" projects could "re-qualify" their production to get the "new oil" prices by initiating EOR projects. Under the Tertiary Incentive Program in the early 1980s, oil producers were eligible for this financial benefit if they engaged in projects using methods such as thermal, chemical, or miscible gas processes to recover crude oil that could not be recovered by conventional means or through secondary recovery techniques. The benefit to the oil producers included the right to sell at market crude oil prices, rather than at controlled prices, that are than sufficient to recover the expenses of these EOR projects.

In addition, the recognition of the potentially successful role of government financial incentives to encourage EOR projects also encouraged the federal government and a number of state governments to offer further incentives. The U.S. Congress codified a general EOR tax credit in 1990. [See Section 43 of the U.S. Internal Revenue Code].[116] Where applicable, it provides a 15% credit against income taxes at the front end for qualified EOR costs, including amounts paid for depreciable tangible property (instead of cost recovery through depreciation deductions over the tax life of the assets), intangible drilling and development expenses, and injectant expenses (this includes the costs of purchased CO_2). The incentive phases out as oil prices rise above $28 per barrel (adjusted for inflation since 1991).

Finally, a number of states, including Texas, also offer severance tax reductions and other tax incentives to encourage EOR.

Coupled with the demonstrated success at SACROC at the time, along with government sponsorship of CO_2–EOR research and demonstrations projects in late 1970s by the U.S. Department of Energy and its predecessor organizations, these incentives helped to convince industry of the potential viability of CO_2-EOR and facilitate the build-out of source and pipeline infrastructure in the Permian Basin.

Business-Related CO_2-EOR Project Failures

CO_2-EOR requires large up front investments and is relatively slow in returning financial returns on those investments. As a result, internal rates of returns are traditionally not robust. The advantage of CO_2-EOR is that it has lower risks than exploration projects and large reserves associated with its application can be booked. Most oil companies are exploration-oriented and can be misled by the “unrisked” rates of return present in exploration projects. Consequently, companies can set unreasonable expectations on a CO_2-EOR project and, when the project underperforms, management can make a decision to cut losses and abandon CO_2 injection. History also tells us that, usually, these abandonments coincide with oil price collapses, such as was the case in 1986 and 1998.

Some company cultures are not well-suited for dealing with the vagaries and uncertainties associated with developing and understanding the characteristics of reservoirs over time. The best CO_2-EOR companies have been those that realize that perfect planning is not possible when dealing with deep oil reservoirs. They recognize that adjustments to a CO_2-EOR operational plan will be necessary, and therefore encourage the acquisition and analysis of data to make such adaptations. Correspondingly, there are other organizations that expect an operational plan for CO_2 flooding to be perfect. This latter group includes the companies that have not had a history of CO_2-EOR success.

Technical CO_2-EOR Failures

As mentioned earlier, some reservoirs are not conducive for moving injected fluids from injector wells to producer wells. This "reservoir sweep" is truly fundamental to flooding success. Natural fracturing and compartmentalization are two examples of reservoir characteristics that can challenge sweep efficiency and lead to low recoveries. It should be noted, however, that all reservoirs have fractures and all are compartmentalized to some degree. As a result, these challenges are present in all reservoirs. Large projects will have some well patterns that underperform due to these effects. If the project is small in size, a few underperforming patterns can jeopardize the success of a project. Large projects with many patterns are more forgiving. For this reason and others (notably the need for large oil recoveries to justify the infrastructure investments), most CO_2 flooding projects are therefore large in size.

The "fingering" of the CO_2 through a reservoir also presents a technical challenge that has sometime led to "technical" failures. Challenges with reservoir sweep can be viewed from both vertical and horizontal perspectives. Figure B-6 illustrates a sweep challenge due to fracturing. In this case, an open fracture intersects a producing well and, when the flood front intersects the fracture, short-circuiting can occur. The miscible front breaks down as the pressure is relieved.

Figure B-7 illustrates a more common problem with the varying vertical permeabilities or processing rates of the flooded section. The high permeability intervals, often referred to as "thief zones," can quickly cause break though of CO_2 at the producing well, thereby increasing the volumes and costs of processing the recycle stream with little added production value.

Both of these problems can be addressed with techniques the industry calls conformance control. Many formulations of chemicals, including actual cement, have been used in an attempt to inject into and plug the offending channel(s). The techniques have a mixed record of success, likely due to the complexity of geology within the reservoir. As a testament to the success, however, several businesses continue to make a living conducting chemical squeezes and conformance treatment.

Small projects also have challenges with such thief zones. It is effectively impossible to contain all the CO_2 within the flooded area, as some CO_2 will leak off to pressure sinks beyond the lease lines. The losses are typically within the flooded zone, but several projects have found that vertical losses, say, to a gas cap, have resulted in poor utilization of CO_2 and can lead to an economic failure.

Figure B-6. Example of "Shortcutting" Sweep due to Natural Fractures

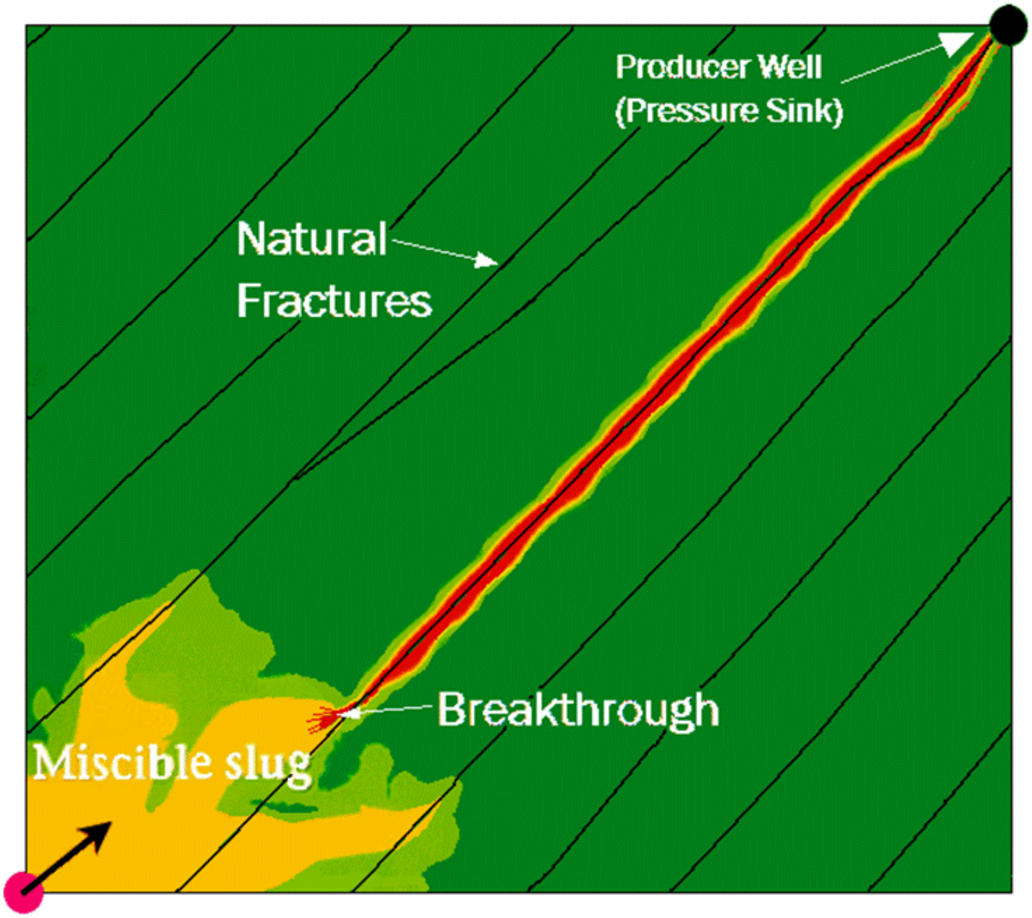
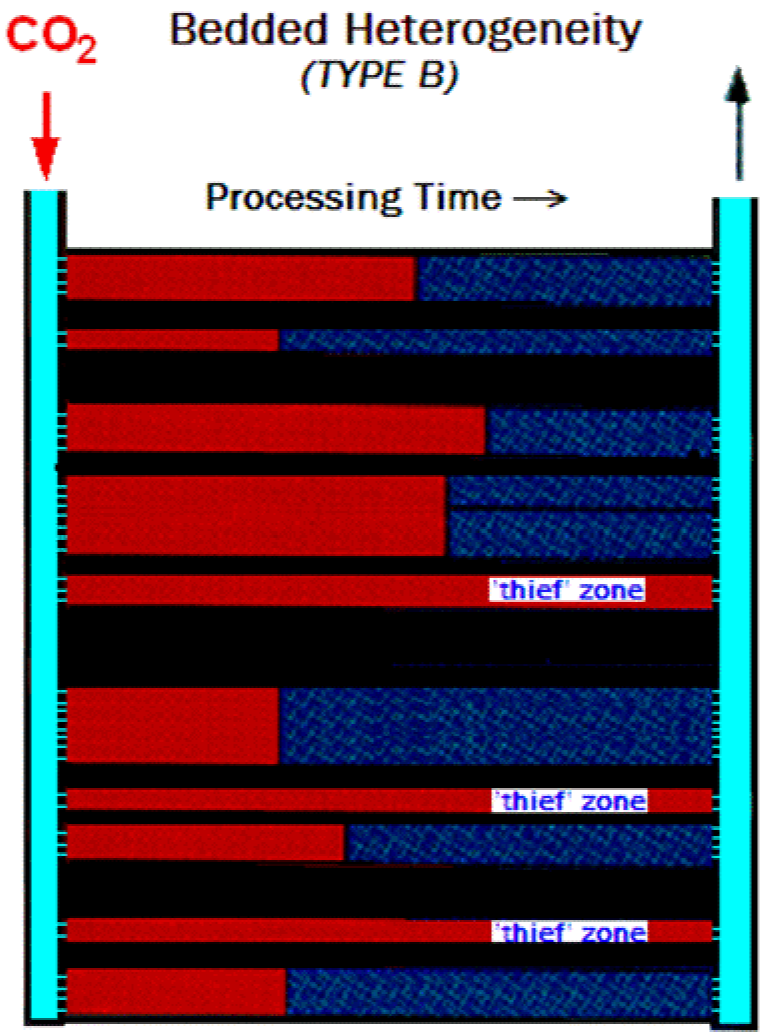

Producer Well
(Pressure Sink)
Natural
Fractures
Breakthrough
Miscible slug

Figure B-7. Example of “Thief Zones” due to Vertical Permeability Variation



Most other field results, however, have determined that this problem is not common due to bedding (often thin) in which vertical permeabilities are less than horizontal permeabilities. As a result, the ratio of vertical to horizontal permeability estimated based on well cores is not often representative of actual reservoir characteristics. It is, however, a technical concern and should be addressed in the CO_2 flood planning stage.

Another mistake than can be made is overstating the target oil available to be mobilized by the contacting CO_2. Some waterfloods and natural water drives are so efficient that residual oil saturations to water flooding are not sufficient to allow recovery of the necessary volumes of oil to make an economically successful CO_2 flood. However, most residual oil saturation values lie above 20-30%, making the target oil values sufficiently large to make the economics work.

Operational challenges can also make projects unsuccessful. A commonly quoted example has to do with carbonic acid and its corrosive effect on tubulars. Water is necessary to make carbonic acid. When water is present in low concentrations, conventional steel is used without providing any degree of incremental risk in CO_2 flooding. However, production streams often have sufficient water concentrations included with the CO_2 such that production well tubing and casing can find incremental corrosion risk. Lined tubing and chemical inhibition programs successfully manage these risks in almost all cases. Those operators and their personnel that have had experience with sour oil production do not typically have corrosion surprises. This is due to the fact that personnel are trained to look for signs of corrosion and have developed inhibition programs even during the primary phase of production. The incremental issues with corrosion due to the addition of CO_2 to injection streams are therefore not new to their operational planning.

One last area of operational challenges in CO_2 flooding is often simply a nuisance but can lead to a sense of being overwhelmed at the field level. There are two issues here; the first is intermittent/marginal flow and pumping of wells. CO_2 lightens the fluid column, can create gas locking in the downhole pump, and cause a need to move from one lifting mechanism to another at various times during the well's producing life. The second relates to CO_2 expansion, which can create a potential for freezing of the flow stream just downstream of the choke point in flowing wells. Where conditions are susceptible, line heaters are used and are generally successful in alleviating this problem.

* * * * *

In conclusion, the first stages of CO_2 flooding in both the U.S. and elsewhere have been limited by the availability of reliable and affordable CO_2. However, the need for carbon capture and storage could alleviate that obstacle to a large extent. While other operational challenges exist in pursuing CO_2-EOR operations, these are largely within the realm of experience of oil and gas operators, and have not created systemic difficulties for forward-thinking, enlightened operators. Taken with the growing need for humankind to remove increasing concentrations of CO_2 from the atmosphere, the growth of CO_2-EOR is likely to accelerate. It should also offer the opportunity to convert maturing and abandoned oil projects into CO_2-EOR opportunities in areas that have never witnessed CO_2 flooding before.

APPENDIX C. BENCHMARKING CO_2-PROPHET

The *CO2-PROPHET* model was compared and calibrated by Advanced Resources with an industry-standard compositional reservoir simulator.[117]

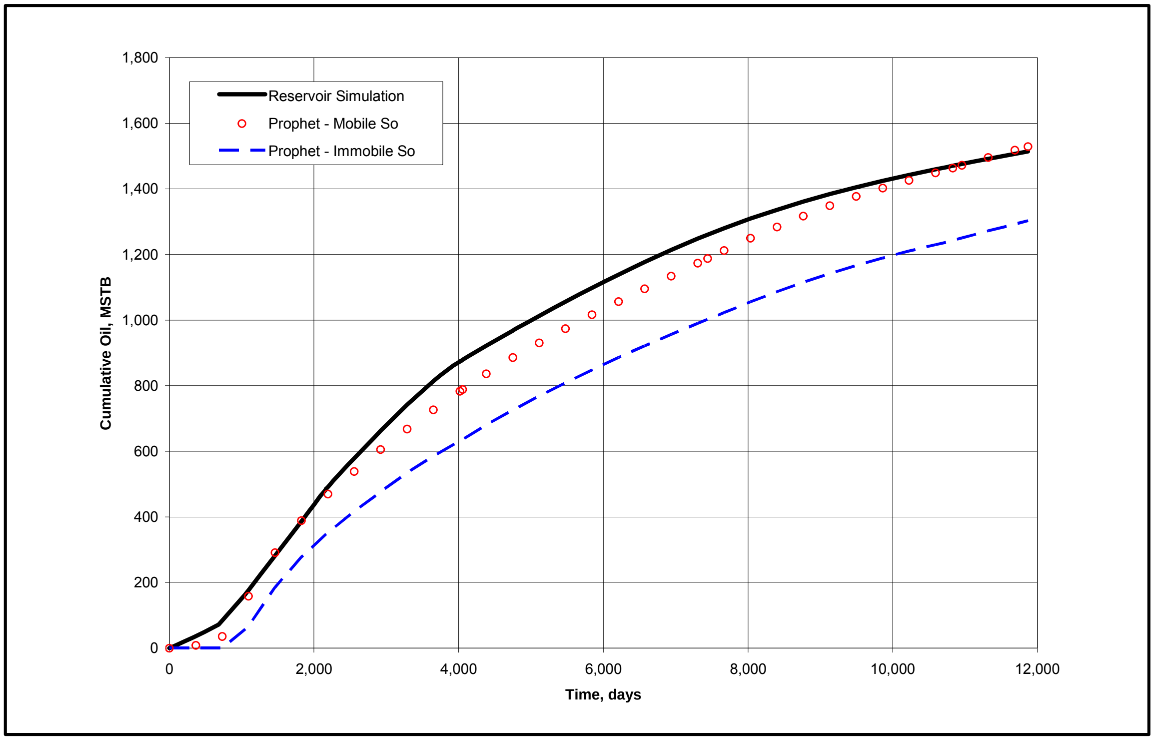
As a first step, the Wasson Denver Unit (San Andres) reservoir data set was used as the input file for modeling a simultaneous main pay zone (MPZ) and the transition zone/residual oil zone (TZ/ROZ) CO_2 flood using a full-scale simulator. An analogous data set was placed into *CO2-PROPHET* to replicate the MPZ and TZ/ROZ simultaneous flood. First, for simplicity, all oil saturations in the input database for the *CO2-PROPHET* model were set at residual oil. Under this simplified condition, *CO2-PROPHET* had lower oil recoveries than the full-scale simulator.

A closer review of the two input data sets enabled us to understand the reasons for the divergence. No mobile oil saturations were initially included in the input file for *CO2-PROPHET*; however, the input data file for the full-scale reservoir simulator had higher (and mobile) oil saturation in the TZ interval. Using simple weight-averaging, a small mobile oil saturation (~3%) was added to the reservoir intervals in the *CO2-PROPHET* input file to account for the mobile oil in the TZ. An excellent match for projected Wasson cumulative oil recovery was obtained between *CO2-PROPHET* and the full-scale simulator, after making this adjustment. This two step comparison and match is shown on Figure C-1.

Similar *CO2-PROPHET* and full-scale simulator comparisons were completed for three additional oil fields - - Seminole (San Andres Unit), Wasson (Bennett Ranch Unit), and Vacuum (San Andres/Grayburg) (Figures C-2 through C-4) - - again showing an excellent match between the two models when the oil saturation modification (discussed above) was included in the *CO2-PROPHET* input data set.

Table C-1 provides the model comparisons, with the ultimate oil recovery from these four oil fields scaled to field level. While oil recovery calculations for individual fields vary somewhat, overall the two models provide an excellent match of the aggregate oil production from the four sample oil fields.

Figure C-1 Analysis of Simultaneous MPZ and TZ/ROZ Oil Recovery: Simulation Comparison Results, Wasson Denver Unit.



Advanced Resources International, Inc.

Figure C-2. Analysis of Simultaneous MPZ and TZ/ROZ Oil Recovery: Simulation Comparison Results, Seminole San Andres Unit

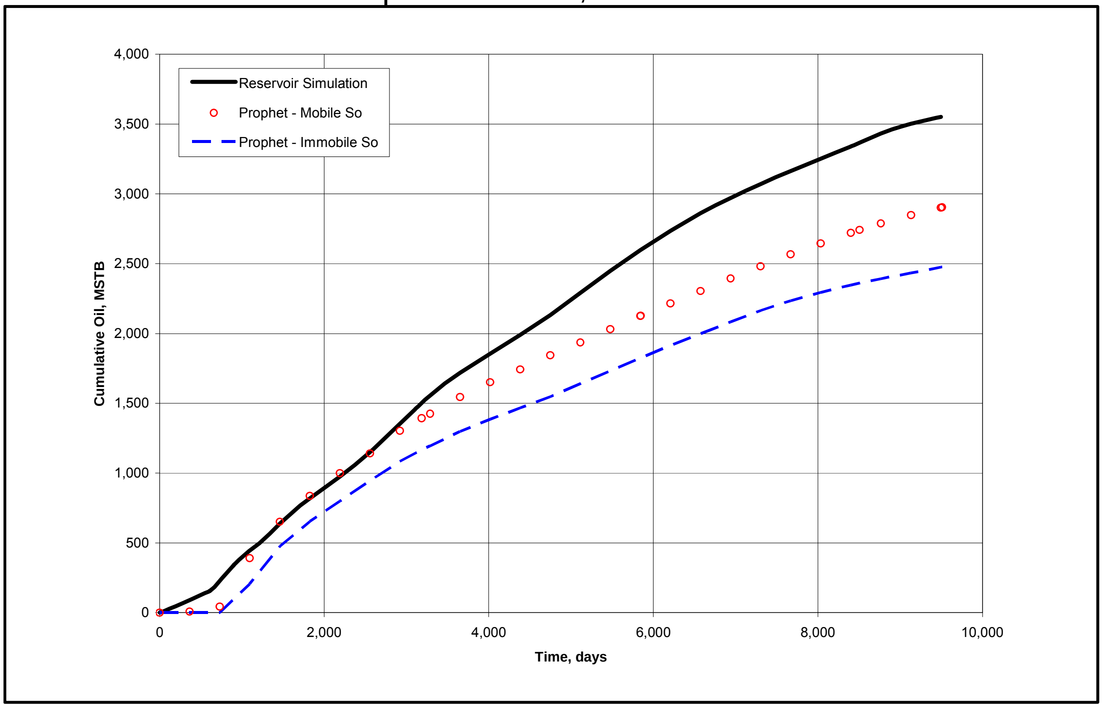


Figure C-3. Analysis of Simultaneous MPZ and TZ/ROZ Oil Recovery: Simulation Comparison Results, Wasson Bennett Ranch Unit

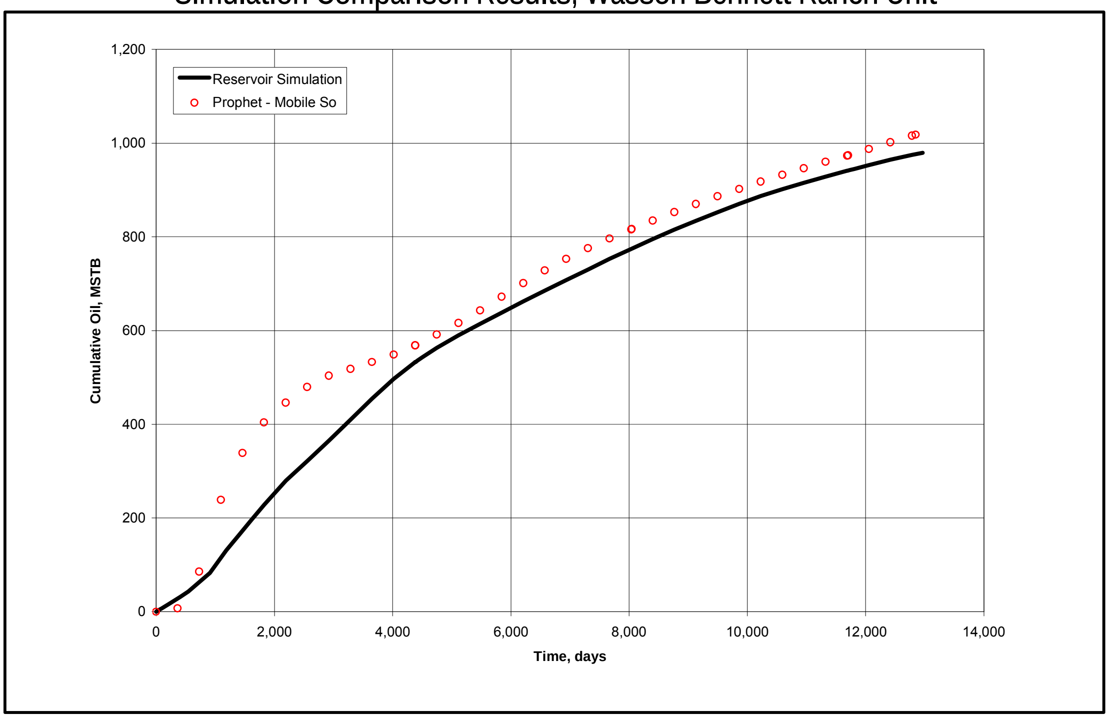


Figure C-4. Analysis of Simultaneous MPZ and TZ/ROZ Oil Recovery:

Simulation Comparison Results, Vacuum (San Andres/Grayburg)

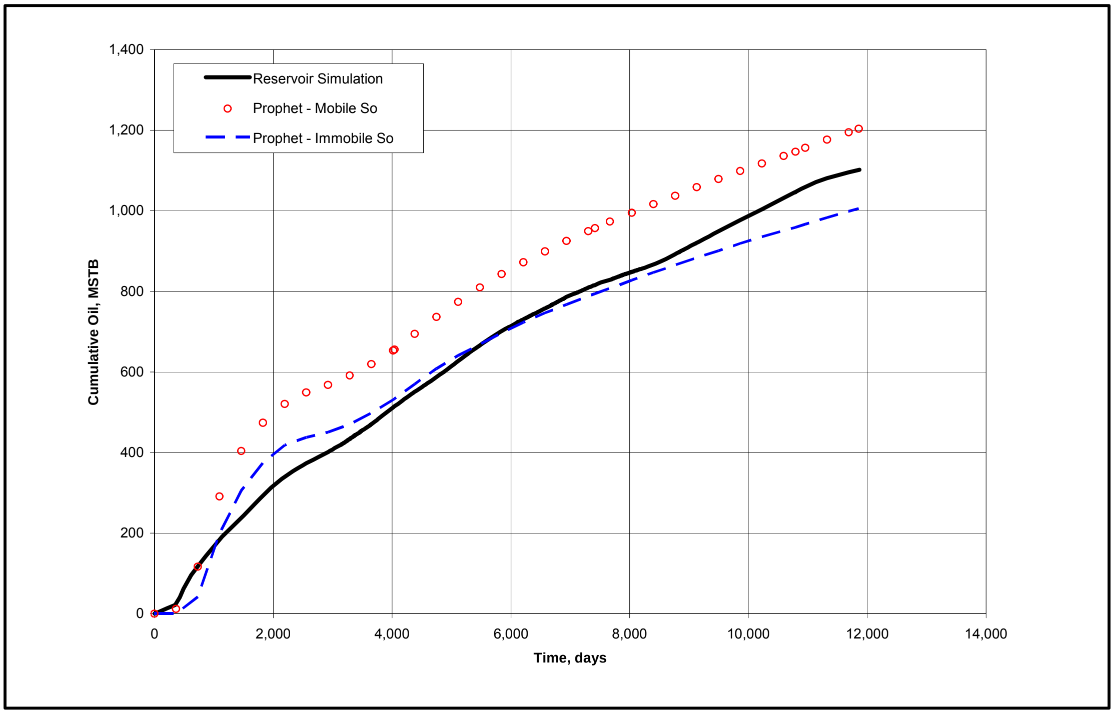


Table C-1. Comparison of Compositional Model Simulation and *CO2-PROPHET* Model Simulation

Field/Unit	Compositional Model Simulation Field Level Oil Recovery (MMB)	*CO2-PROPHET* Model Simulation Field Level Oil Recovery (MMB)	% Difference Between Models
Seminole (San Andres Unit)	696	569	(18%)
Wasson (Denver Unit)	1,054	1,064	1%
Wasson (Bennett Ranch Unit)	172	179	4%
Vacuum (Grayburg/San Andres)	529	577	9%
Total	**2,451**	**2,389**	**(2%)**

APPENDIX D. WORLD BASIN/REGION CROSS REFERENCE

USGS Region	Basin	Overlain Countries
Asia Pacific	Baram Delta/Brunei-Sabah Basin	Brunei
		Malaysia
	Bohaiwan Basin	China
	Central Sumatra Basin	Indonesia
	Gippsland Basin	Australia
	Junggar Basin	China
	Malay Basin	Malaysia
	Northwest Java Basin	Indonesia
	Songliao Basin	China
Central and South America	Campos Basin	Brazil
	East Venezuela Basin	Trinidad and Tobago
		Venezuela
		Guyana
	Llanos Basin	Venezuela
		Colombia
	Maracaibo Basin	Venezuela
		Colombia
	Putumayo-Oriente-Maranon Basin	Brazil
		Colombia
		Ecuador
		Peru
	San Jorge Basin	Chile
		Argentina
	Tampico-Misantla Basin	Mexico
Europe	Carpathian-Balkanian Basin	Ukraine
		Moldova
		Bulgaria
		Turkey
		Serbia
		Romania
	North Sea Graben	Norway
		United Kingdom

USGS Region	Basin	Overlain Countries
Former Soviet Union	Middle Caspian Basin	Turkmenistan
		Uzbekistan
		Russia
		Kazakhstan
		Georgia
		Azerbaijan
	North Caspian Basin	Kazakhstan
		Russia
	South Caspian Basin	Iran
		Turkmenistan
		Azerbaijan
	Timan-Pechora Basin	Russia
	Volga-Ural Region	Kazakhstan
		Russia
	West Siberian Basin	Kazakhstan
		Russia
Middle East and North Africa	*Fahud Salt Basin*	Oman
	Greater Ghawar Uplift	Bahrain
		Qatar
		Saudi Arabia
	Illizi Basin	Libya
		Algeria
	Interior Homocline-Central Arch	Saudi Arabia
	Mesopotamian Foredeep Basin	Iran
		Iraq
		Kuwait
		Saudi Arabia
	Red Sea Basin	Egypt
		Eritrea
		Israel
		Jordan
		Sudan
		Yemen
		Saudi Arabia
		Djibouti
	Rub Al Khali Basin	Oman
		Yemen
		United Arab Emirates
		Saudi Arabia
	Sirte Basin	Libya
	Trias/Ghadames Basin	Tunisia
		Algeria
		Libya
	Widyan Basin-Interior Platform	Iraq
		Syria
		Saudi Arabia
		Kuwait
	Zagros Fold Belt	Turkey
		Syria
		Iraq
		Iran

USGS Region	Basin	Overlain Countries
North America	*Alberta Basin*	Canada
	Villahermosa Uplift	Mexico
	Williston Basin, Canada	Canada
North America/United States	East/Central Texas Basins	United States
	Permian Basin	United States
	Mid-Continent Basins	United States
	North Slope	United States
	Gulf Coast Basins	United States
	San Joaquin Basin	United States
	Rockies Basins	United States
	LA Offshore	United States
	Los Angeles Basin	United States
	Illinois Basin	United States
	Williston Basin, US	United States
	Coastal California Basin	United States
	Cook Inlet	United States
	Appalachia	United States
South Asia	Bombay	India
		Pakistan
Sub-Saharan Africa and Antarctica	Niger Delta	Cameroon
		Nigeria
		Equatorial Guinea
	West-Central Coastal	Namibia
		Sao Tome and Principe
		Gabon
		Angola
		Equatorial Guinea
		Cameroon
		Zaire
		Congo

(shaded)	**Offshore Basin**
Italicized Basin Name	**Carbonate Basin**

APPENDIX E. COMPARISONS OF BASIN-LEVEL AND FIELD-BASED ANALYSES

To test the validity of the basin-level analyses, the results from the basin-level analyses were compared to more detailed field-based analyses for fields in various non-U.S. basins: North Sea Graben Basin (only fields in United Kingdom waters), the Western Siberian Basin, and selected fields in four basins in the Middle East (Mesopotamian Foredeep, Greater Ghawar, Rub Al Khali, and the Fahud Salt Basins). These basins were selected based on the public availability of relatively good field-level data.

These field-level analyses were conducted using the same analytical approach used by Advanced Resources in a series of basin studies performed for DOE, the most recent published in January 2009.[118] This work builds on previous analyses of currently practiced CO_2-EOR technology, as reported in "*Storing CO_2 with Enhanced Oil Recovery*"[119] and a series of "*Ten Basin-Oriented Reports*". [120] This approach is summarized briefly as follows:

7. ***Assemble Oil Fields Data Base.*** This requires the development of up-to-date, volumetrically consistent field-level data that contain essential data, formats and interfaces to: (1) develop an accurate estimate of the size of the original and remaining oil in-place; (2) reliably screen the fields as to their amenability for miscible or immiscible CO_2-EOR; and, (3) provide the essential input data for estimating CO_2 injection requirements and oil recovery.
8. ***Calculate Minimum Miscibility Pressure (MMP).*** The miscibility of a field's oil with injected CO_2 is a function of pressure, temperature and the composition of oil. The study's approach to estimating whether a field's oil will be miscible with CO_2, given fixed temperature and oil composition, was to determine whether it could hold sufficient pressure to attain miscibility. Where oil composition data was missing, a correlation was used for translating the oil gravity to oil composition. The approach for the calculation was described above.
9. ***Screen Fields for CO_2-EOR.*** The fields were screened to determine those that would be amendable for CO_2-EOR. Five prominent screening criteria were used: depth, oil gravity, pressure, temperature, and oil composition. These values were used to establish the MMP, and for selecting fields that would be amenable to this oil recovery process. Fields not meeting the MMP standard were not considered.

   The preliminary screening steps involved selecting the fields that had sufficiently high oil gravity. A minimum depth of 915 meters (3,000 feet), at the mid-point of the field, was used to ensure the field could accommodate high pressure CO_2 injection. A minimum oil gravity of 17.5 ^{o}API was used to ensure the oil had sufficient mobility, without requiring thermal injection.
10. ***Estimate Oil Recovery Potential.*** The study utilized *CO_2-PROPHET* to calculate incremental oil produced using CO_2-EOR. *CO_2-PROPHET* generates streamlines for fluid flow between injection and production wells, and the model performs oil displacement and recovery calculations along the established streamlines. (A finite difference routine is used for oil displacement calculations.) *It is important to note the*

CO_2-PROPHET is still primarily a “screening-type” model, and lacks some of the key features, such as gravity override and compositional changes to fluid phases, available in more sophisticated reservoir simulators.

11. ***Estimate CO_2 Injection Requirements for CO_2-EOR.*** *CO_2-PROPHET* also estimates the amount of CO_2 that would need to be injected to recover the estimated amount of oil to be produced. It estimates both the amount of CO_2 that would need to be purchased, and that which would be recycled as part of recovery operations. For purposes of this study, the amount of CO_2 originally purchased was assumed to be equivalent to the amount of CO_2 ultimately stored after CO_2-EOR operations are completed.

Further documentation of CO2-PROPHET and its benchmarking against actual field results and reservoir simulators is described in Appendix C.

The results of the field-level analyses for the selected areas are summarized in the paragraphs below.

North Sea Graben Basin. In the North Sea Graben Basin, 14 sandstone fields in U.K. waters were selected that were amenable to CO_2-EOR for use in this analysis. These fields are reported to contain 16 billion barrels of OOIP, or 14% of the over 117 billion barrels of OOIP estimated to be contained in all fields in the North Sea Graben Basin using the USGS data.[121,122] These results are summarized in Table E1.

For the purposes of this study, the CO_2-EOR recovery potential (the percentage of OOIP that could be recovered by CO_2-EOR) is compared between the field-level and basin-level analysis.

In the field level analyses, the average field-specific recovery efficiency from the application of CO_2-EOR was determined to be 17.5%, compared to an estimated value of 22.7% determined from the basin-level analyses. One reason for the lower recovery efficiency in the field level analysis is that many of the North Sea fields have used natural gas injection to increase oil recovery by 3% to 4%, thus reducing the fraction of OOIP available for CO_2-EOR. Adjusting for this condition, the field level and basin level results are reasonably consistent. The CO_2:incremental oil ratio was determined to be about 0.297 tonnes CO_2 per barrel of oil for the field-level and 0.280 for the basin level analyses, as shown in Table E-2.

Table E-1. Field-Level Results for North Sea Graben Basin (UK Fields Only)

Field	% of Calculated OOIP	CO_2:Oil Ratio (tonne /Bbl)
Arbroath	16.5%	0.247
Auk	18.9%	0.272
Brae / East	13.4%	0.310
Forties	15.4%	0.349
Fulmar	18.6%	0.256
Heather	19.1%	0.281
Kimmeridge	20.4%	0.278
Lennox	20.5%	0.288
MacCulloch	15.4%	0.263
Maureen	16.1%	0.255
Montrose	19.5%	0.233
Scott	20.6%	0.287
Statfjord	19.4%	0.275
Thistle	14.3%	0.292
Total/Average	**17.5%**	**0.297**

Table E-2. Comparison of the Basin- and Field-Level Results for North Sea Graben Basin

North Sea	Recovery Efficiency	CO_2 Oil Ratio (tonne/Bbl)
Field Data	17.5%	0.297
Basin Data	22.7%	0.280
Difference	-5.25%	negligible

Western Siberian Basin. In the Western Siberian Basin, 19 fields that were screened to be amenable to CO_2-EOR were selected for more detailed analyses. In the database, it was reported that these fields contained 126 billion barrels of OOIP, or 33% of the 381 billion barrels of OOIP estimated to be contained in all fields in the basin. These field-level results are summarized in Table E-3.

Table E-3. Field-Level Results for the Western Siberian Basin

Field	Formation	% of Calculated OOIP	CO_2 Oil Ratio (tonne /Bbl)
Samotlor	BV18-19	17.3%	0.291
Barsukov	PK19-20	26.1%	0.296
Olkhovskoye (Tyumen)	AS3	16.9%	0.312
Povkhovskoye	BV8ab	19.6%	0.284
Priobskoye	AS11	20.9%	0.242
Rogozhnikovskoye	YU2-3	18.1%	0.315
Russkoye, West Block	PK1-2	10.5%	0.491
Samotlor	1BV10	17.9%	0.261
Samotlor	2BV11	18.4%	0.254
Samotlor	AV1	22.3%	0.255
Samotlor	AV2-3	20.6%	0.259
Samotlor	AV4-5	20.3%	0.270
Samotlor	BV8	19.6%	0.274
Sovetskoye	AV1	17.1%	0.289
Sovetskoye	Yu1a	23.6%	0.304
Sugmutskoye	BS9b	17.8%	0.290
Surgut Yuzhnny	1BS10	17.0%	0.313
Tarasovskoye (Ayvasedopurskoye)	BP13-14	27.3%	0.275
Vat'yegan	BV20	17.4%	0.305
Total/Average		**18.9%**	**0.286**

In the field level analyses, the average field-specific recovery efficiency from the application of CO_2-EOR was determined to be 18.9%, compared to an estimated value of 21.4% determined from the basin-level analyses. The CO_2:incremental oil ratio was determined to be 0.286 tonnes CO_2 per barrel for the field-level analyses compared to 0.267 tonnes CO_2 per barrel of oil for basin-level analyses, as summarized in Table E-4.

Table E-4. Comparison of the Basin- and Field-Level Results for the Western Siberian Basin

Western Siberia	Recovery Efficiency	CO_2:Oil Ratio (tonne/Bbl)
Field Data	18.9%	0.286
Basin Data	21.4%	0.267
Over (Under) Estimation	-2.5%	0.019

Middle Eastern Basins. In the four Middle Eastern Basins, 14 fields that were screened to be amenable to CO_2-EOR were selected for more detailed analyses. In summary,

- In the Mesopotamian Foredeep Basin, the two fields assessed contained 55 billion barrels of OOIP, or 6% of the over 878 billion barrels of OOIP estimated to be contained in all fields in the basin.
- In the Greater Ghawar Basin, the three fields assessed contained 8 billion barrels of OOIP, or 2% of the over 400 billion barrels of OOIP estimated to be contained in all fields in the basin.
- In the Rub Al Khali Basin, the eight fields assessed were reported to contain nearly 178 billion barrels of OOIP, or 70% of the 255 billion barrels of OOIP estimated based on the basin level analyses.
- In the Fahud Salt Basin, the one field assessed contained 6.4 billion barrels of OOIP, or 45% of the 14 billion barrels of OOIP estimated in the basin-level analysis.

The field-level results for the Middle Eastern Basins are summarized in Table E-5.

Table E-5. Field-Level Results for the Fields Assessed in the Middle Eastern Basins

Basin	Field	Formation	% of Calculated OOIP	CO_2 Oil Ratio (tonne /Bbl)
Fahud Salt	**Yibal**	1	23.2%	0.295
Greater Ghawar Uplift	**Dukhan**	1	21.8%	0.296
Greater Ghawar Uplift	**Dukhan**	2	27.6%	0.278
Greater Ghawar Uplift	**Dukhan**	3	27.3%	0.277
Mesopotamian Foredeep	**Khafji**	1	12.8%	0.361
Mesopotamian Foredeep	**Umm Gudar**	1	15.8%	0.367
Rub Al Khali	**Asab**	1	25.5%	0.304
Rub Al Khali	**Bab**	1	27.3%	0.252
Rub Al Khali	**Bu Hasa**	1	26.4%	0.232
Rub Al Khali	**Bu Hasa**	2	24.7%	0.235
Rub Al Khali	**Bul Hanine**	1	24.8%	0.311
Rub Al Khali	**Fateh**	2	21.6%	0.327
Rub Al Khali	**Umm Shaif**	1	27.2%	0.310
Rub Al Khali	**Zakum**	1	18.1%	0.325

The field level analyses results for the Middle Eastern Basins is summarized as follows.

- In the Mesopotamian Foredeep Basin, average field-specific recovery efficiency from the application of CO_2-EOR was determined to be 13.5%, compared to an estimated value of 19.8% determined from the basin-level analyses. The CO_2:incremental oil ratio was determined to be 0.363 tonnes CO_2 per barrel for the field-level analyses, compared to 0.306 tonnes CO_2 per barrel of oil for basin-level analyses.
- In the Greater Ghawar Basin, average field-specific recovery efficiency from CO_2-EOR was determined to be 24.7%, compared to an estimated value of 22.2% determined from the basin-level analyses. The CO_2:incremental oil ratio was determined to be 0.303 tonnes CO_2 per barrel for the field-level analyses, compared to 0.286 tonnes CO_2 per barrel of oil for the basin-level analyses.
- In the Rub Al Khali Basin, average field-specific recovery efficiency from CO_2-EOR was determined to be 24.8%, compared to an estimated value of 23.0% determined from the basin-level analyses. The CO_2:incremental oil ratio was determined to be 0.285 tonnes CO_2 per barrel for the field-level analyses, compared to 0.314 tonnes CO_2 per barrel of oil for the basin-level analyses.
- In the Fahud Salt Basin, average field-specific recovery efficiency from CO_2-EOR was determined to be 23.2%, compared to an estimated value of 21.5% determined from the basin-level analyses. The CO_2:incremental oil ratio was determined to be 0.295 tonnes CO_2 per barrel for the field-level analyses, compared to 0.294 tonnes CO_2 per barrel of oil for basin-level analyses.

These results summarized in Table E-6 shows that, while variable within individual fields; overall, the basin level and field level results are comparable.

Table E-6. Comparison of the Basin- and Field-Level Results for the Middle Eastern Basins

Mesopotamian Foredeep	Recovery Efficiency	CO_2:Oil Ratio (tonne/Bbl)
Field Data	13.5%	0.363
Basin Data	19.8%	0.306
Over (Under) Estimation	6.3%	-0.057

Greater Ghawar	Recovery Efficiency	CO_2:Oil Ratio (tonne/Bbl)
Field Data	24.7%	0.286
Basin Data	22.2%	0.303
Over (Under) Estimation	-2.5%	0.017

Rub Al Khali	Recovery Efficiency	CO_2:Oil Ratio (tonne/Bbl)
Field Data	24.8%	0.285
Basin Data	23.0%	0.314
Over (Under) Estimation	-1.8%	0.029

Fahud Salt	Recovery Efficiency	CO_2:Oil Ratio (tonne/Bbl)
Field Data	23.2%	0.295
Basin Data	21.5%	0.294
Over (Under) Estimation	-1.7%	-0.002

Summary. While the method of estimating overall CO_2-EOR oil recovery potential used in this analysis is based on correlations, the disparity in basin versus field level results illustrates the importance of additional data to better characterize the CO_2-EOR potential in a basin.

The disparity suggests that the complex nature of these basins cannot be fully captured in a two variable (API gravity and depth) analysis. In especially complex, heterogeneous basins such as Western Siberia and the North Sea, lack of specific reservoir information can lead to overly optimistic results, as basin complexity would tend to decrease oil recovery that is not accounted for in the current methodology. In the more high-quality, homogeneous Middle-

Eastern basins, such as the Rub Al-Khali, Greater Ghawar, and Fahuld Salt basins, where basin complexity is less of a factor influencing oil recovery, the basin level and field level results are more comparable.

APPENDIX F. MATCHING CO_2 SOURCES WITH CO_2-EOR AMENABLE BASINS

For the purposes of this study, three scenarios were assumed for identifying viable sources of CO_2 within each oil basin:

- Immediate CO_2 sources. These sources represent those in close proximity to oil fields within the basin, representing specific, individual source-sink pairings. In this scenario, only sources within 15 kilometers of the perimeter of each basin are considered viable to supply CO_2 to the CO_2-EOR prospects.
- Intermediate CO_2 sources. These sources represent those that could be aggregated within a basin to facilitate a network of sources and sinks (oil fields) within a basin. In this scenario, all sources within a 200 kilometer perimeter of each basin are considered.
- Long distance CO_2 sources. These sources represent the scenario where large concentrations of CO_2 emission sources are linked with large concentrations of CO2 sinks (oil fields) that are not close to the sources. In this scenario, all sources within 800 kilometers of the basin perimeter are considered viable CO_2 sources.

Long Distance CO_2 Scenario

This scenario includes all CO_2 sources within 800 kilometers of the basin perimeter as viable supplies for CO_2-EOR operations. Figures F-1 and F-2 display oil production and CO_2 demand and supply data for the top 10 ten basins (as ranked by volumes of technically recoverable oil) in this scenario. Under this scenario, 34 basins, with 154 billion barrels of oil technically recoverable through CO_2-EOR, would have sufficient sources of CO_2. CO_2-EOR operations in these basins could purchase, and store, 44 Gt of CO_2 over 30 years. In this scenario, 14 basins have enough CO_2 supplies to produce a portion of their OOIP amenable to miscible CO_2-EOR. Using the available CO_2 in this scenario, these 14 basins could produce 71 billion barrels of oil, thereby storing 21 Gt of CO_2. Table F-1 shows oil production and CO_2 storage results for all 34 basins with sufficient CO_2 sources in this scenario.

Figure F-1. Top 10 World Basins for CO_2-EOR with Sufficient CO_2 Supplies within 800 Kilometers

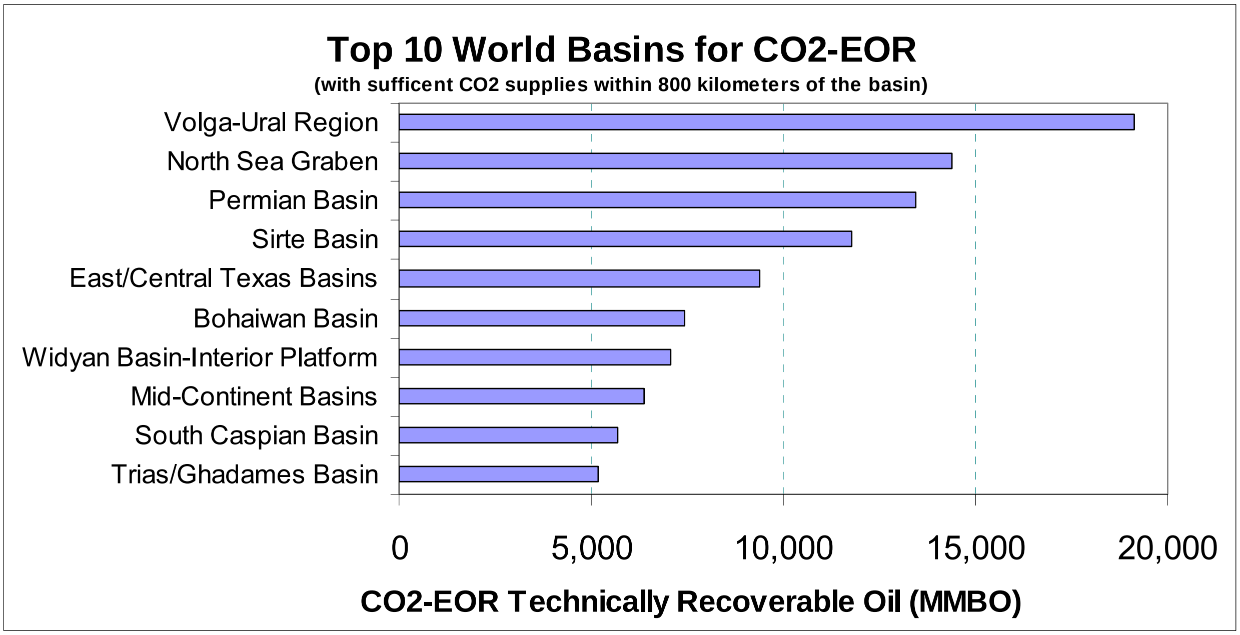


Figure F-2. Relationship of CO_2 Supply and Demand for the Top 10 World Basins for CO_2-EOR with Sufficient CO_2 Supplies within 800 Kilometers

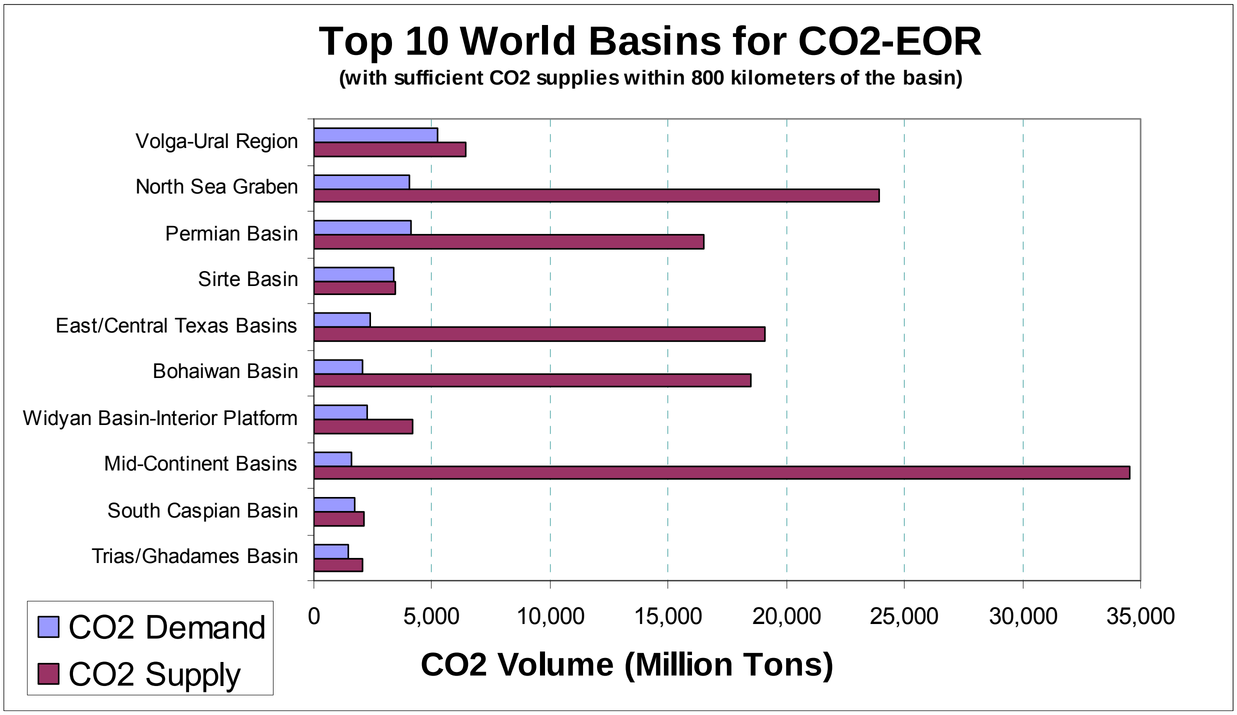


Table F-1. Technically Recoverable Oil Resource and CO_2 Storage Potential of Basins with Sufficient CO_2 Supplies within 800 Kilometers

Basin	EOR Recoverable Oil (MMBO)	CO2 Demand (Million Tons)	Available CO2 Emissions within 800 Kilometer Radius (Million Tons)
Volga-Ural Region	19,130	5,219	6,454
North Sea Graben	14,373	4,031	23,943
Permian Basin	13,428	4,103	16,514
Sirte Basin	11,765	3,368	3,467
East/Central Texas Basins	9,392	2,415	19,098
Bohaiwan Basin	7,443	2,039	18,502
Widyan Basin-Interior Platform	7,068	2,276	4,152
Mid-Continent Basins	6,359	1,609	34,533
South Caspian Basin	5,697	1,715	2,135
Trias/Ghadames Basin	5,185	1,481	2,076
Alberta Basin	4,724	1,449	2,850
Songliao Basin	4,495	1,189	8,563
Gulf Coast Basins	4,131	1,319	34,962
Timan-Pechora Basin	3,943	1,051	1,983
North Caspian Basin	3,226	1,100	4,854
Red Sea Basin	3,072	973	2,501
Campos Basin	3,072	1,095	1,991
Middle Caspian Basin	3,036	874	3,726
Rockies Basins	2,625	742	16,822
San Joaquin Basin	2,164	536	2,342
Junggar Basin	2,084	609	769
Carpathian-Balkanian Basin	1,939	621	10,342
Llanos Basin	1,867	648	890
Williston Basin, US	1,827	492	5,954
Tampico-Misantla Basin	1,799	531	5,232
Interior Homocline-Central Arch	1,421	431	2,322
Fahud Salt Basin	1,346	396	923
Gippsland Basin	1,286	324	3,141
Coastal California Basin	1,179	338	2,355
Malay Basin	1,173	278	1,898
Illizi Basin	1,114	259	443
Los Angeles Basin	1,096	292	4,101
Williston Basin, Canada	1,024	314	15,594
Illinois Basin	512	141	52,282
Total	153,993	44,258	317,713

Intermediate CO_2 Sources Scenario

In this scenario, only CO_2 sources inside or within 200 kilometers of each basin perimeter are considered viable supplies for CO_2-EOR operations. Under this scenario, 15 basins would have access to sufficient supplies of CO_2 for EOR operations, and could produce 50 billion barrels of oil and store 14 Gt of captured CO_2 emissions. Additional CO_2-EOR potential is present in 31 basins for which there are partial supplies of anthropogenic CO_2. These basins could produce an additional 60 billion barrels of oil and store 17 Gt of CO_2 through CO_2-EOR operations. Figures F-3 and F-4 display the amount of technically recoverable oil resource and CO_2 storage potential that exists in the top 10 basins with sufficient CO_2 supplies in this scenario. More detailed information is shown for these basins in Table F-2.

Figure F-3. Top 10 World Basins for CO_2-EOR with Sufficient CO_2 Supplies within 200 Kilometers

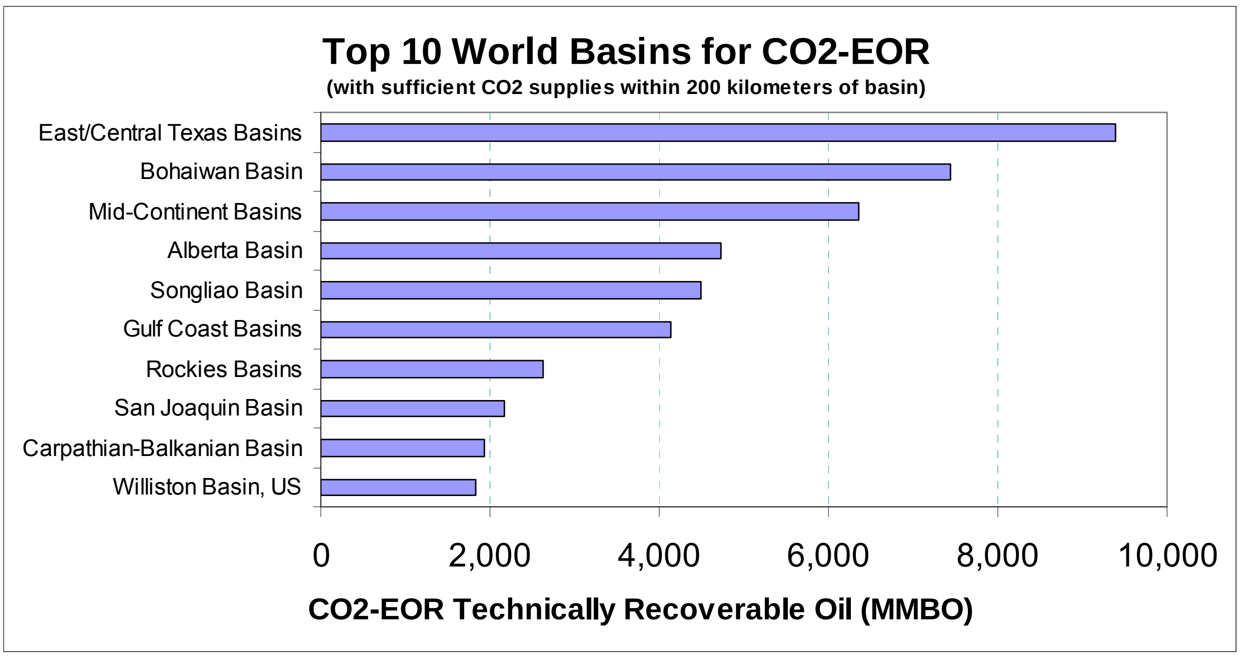


Figure F-4. Relationship of CO_2 Supply and Demand for the Top 10 World Basins for CO_2-EOR with Sufficient CO_2 Supplies within 195 Kilometers

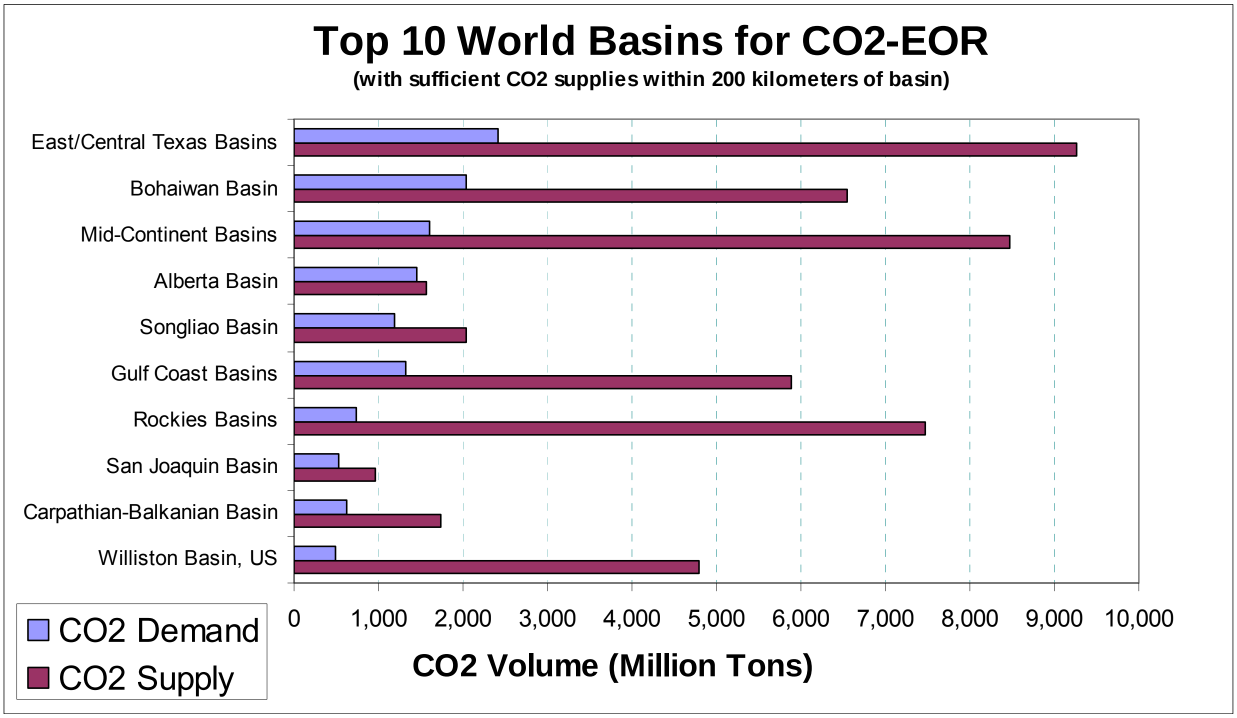


Table F-2. Technically Recoverable Oil Resource and CO_2 Storage Potential of Basins with Sufficient CO_2 Supplies within 200 Kilometers

Basin	EOR Recoverable Oil (MMBO)	CO2 Demand (Million Tons)	Available CO2 Emissions within 200 Kilometer Radius (Million Tons)
East/Central Texas Basins	9,392	2,415	9,260
Bohaiwan Basin	7,443	2,039	6,540
Mid-Continent Basins	6,359	1,609	8,474
Alberta Basin	4,724	1,449	1,564
Songliao Basin	4,495	1,189	2,035
Gulf Coast Basins	4,131	1,319	5,889
Rockies Basins	2,625	742	7,476
San Joaquin Basin	2,164	536	956
Carpathian-Balkanian Basin	1,939	621	1,728
Williston Basin, US	1,827	492	4,800
Coastal California Basin	1,179	338	1,036
Gippsland Basin	1,286	324	1,030
Los Angeles Basin	1,096	292	884
Williston Basin, Canada	1,024	314	1,598
Illinois Basin	512	141	26,803
Total	**50,195**	**13,821**	**80,072**

Immediate CO_2 Sources Scenario

In this scenario, CO_2 sources are only considered as viable supplies to the CO_2-EOR market in each basin if they are within 15 kilometers of the basin's perimeter. Under this scenario, CO_2-EOR operations could produce 48 billion barrels of incremental oil and store 14 Gt of captured CO_2 emissions. There are an additional 26 basins for which a partial supply of anthropogenic CO_2 would be available to CO_2-EOR operations. These basins could produce 24 billion barrels of oil and store 7 Gt of CO_2 through CO_2-EOR operations. Figures F-5 and F-6 display the technically recoverable oil resource and CO_2 storage potential of the top 10 basins with sufficient CO_2 supplies in this scenario. Table F-3 shows more detailed information by basin.

These basins would be good candidates for initial demonstration projects, because of the close proximately of large CO_2 sources to fields with significant CO_2-EOR potential. However, these basins should not be considered the only areas where CO_2 storage in association with CO_2-EOR could or should be pursued.

Figure F-5. Top 10 World Basins for CO_2-EOR with Sufficient CO_2 Supplies within 15 Kilometers

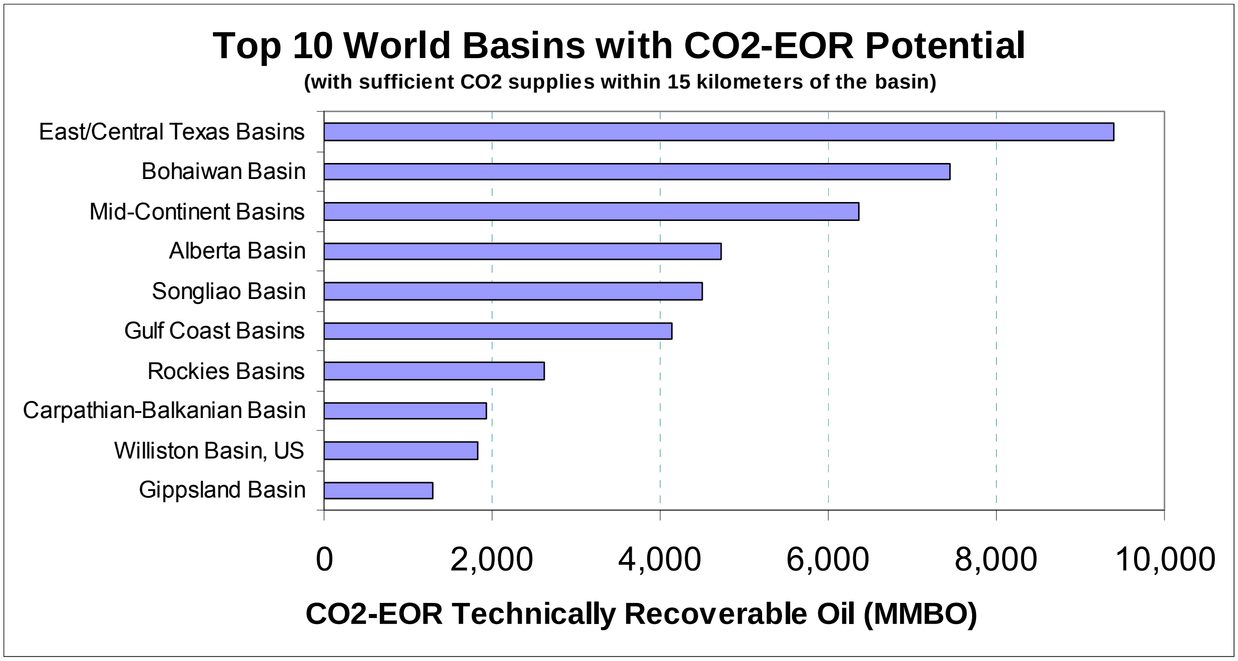


Figure F-6. Relationship of CO_2 Supply and Demand for the Top 10 World Basins for CO_2-EOR with Sufficient CO_2 Supplies within 15 Kilometers

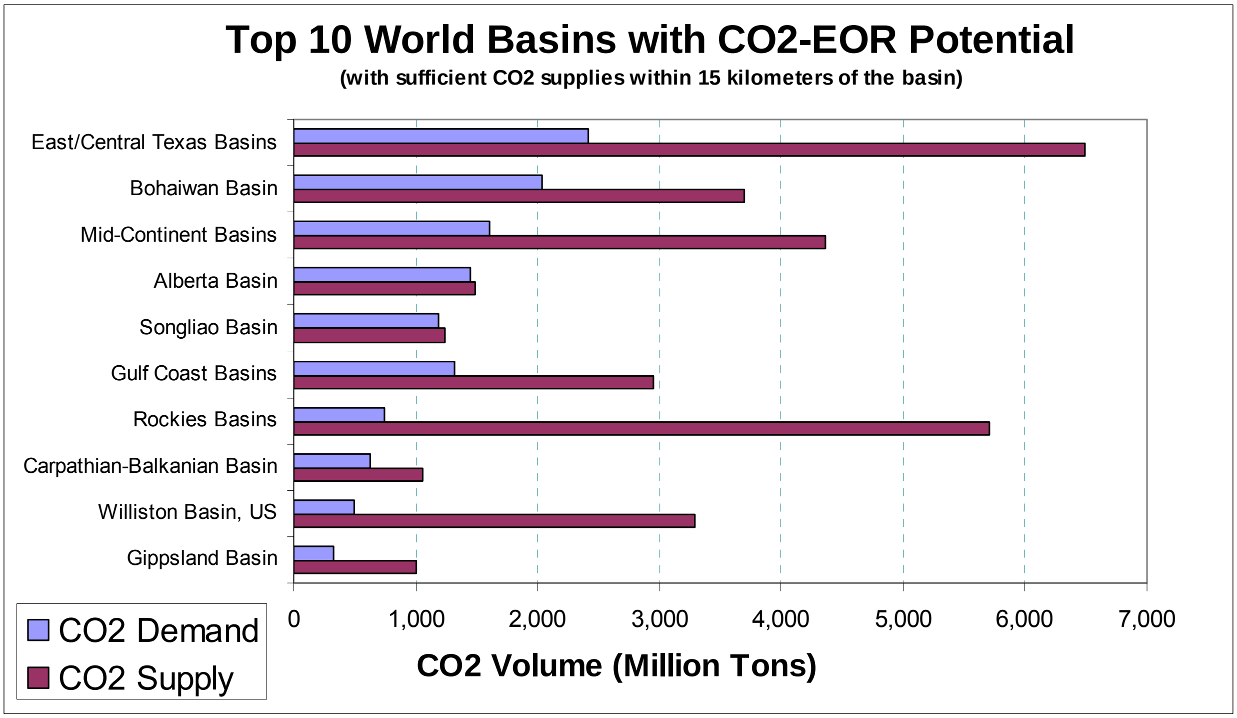


Table F-3. Technically Recoverable Oil Resource and CO_2 Storage Potential of Basins with Sufficient CO_2 Supplies within 15 Kilometers

Basin	EOR Recoverable Oil (MMBO)	CO2 Demand (Million Tons)	Available CO2 Supplies within 15 Kilometer Radius (Million Tons)
East/Central Texas Basins	9,392	2,415	6,487
Bohaiwan Basin	7,443	2,039	3,690
Mid-Continent Basins	6,359	1,609	4,361
Alberta Basin	4,724	1,449	1,486
Songliao Basin	4,495	1,189	1,247
Gulf Coast Basins	4,131	1,319	2,954
Rockies Basins	2,625	742	5,710
Carpathian-Balkanian Basin	1,939	621	1,057
Williston Basin, US	1,827	492	3,294
Gippsland Basin	1,286	324	1,011
Coastal California Basin	1,179	338	387
Los Angeles Basin	1,096	292	449
Williston Basin, Canada	1,024	314	458
Illinois Basin	512	141	19,137
Total	**48,031**	**13,285**	**51,728**

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