NATIONAL ENERGY TECHNOLOGY LABORATORY

Storing CO_2 and Producing Domestic Crude Oil with Next Generation CO_2-EOR Technology: An Update

April 30, 2010

DOE/NETL- 2010/1417

U.S. DEPARTMENT OF ENERGY

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STORING CO_2 AND PRODUCING DOMESTIC CRUDE OIL WITH NEXT GENERATION CO_2-EOR TECHNOLOGY

DOE/NETL- 2010/1417

FINAL REPORT

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1. EXECUTIVE SUMMARY

In order to build on work published in two previous reports - - "*Storing CO_2 with Enhanced Oil Recovery*"[1] and a series of "*Ten Basin-Oriented Reports*" [2], Advanced Resources International (ARI) was sponsored by the U.S. DOE/NETL, Office of Systems, Analysis and Planning to examine both the potential for increased oil recovery as well as CO2 storage which could result from new technologies. CO_2 enhanced oil recovery (CO_2-EOR) offers the potential for storing significant volumes of carbon dioxide emissions while increasing domestic oil production. However, a number of technical challenges limit the full theoretical potential offered by integrated CO_2 storage and CO_2-EOR. In this report, ARI identifies and analyzes four "next generation" CO_2-EOR technology options that address some of these technical challenges.

The four "next generation" CO_2-EOR technology options are: (1) increasing the volume of CO_2 injected into the oil reservoir; (2) optimizing pattern design and orientation, including adding infill wells, to achieve increased contact between injected CO_2 and the oil reservoir; (3) improving the mobility ratio between the injected CO_2/water and the residual oil; and, (4) extending the miscibility range, thus helping more reservoirs achieve higher oil recovery efficiency.

These practices could dramatically increase the performance of CO_2-EOR technology and increase the volume of CO_2 that could be stored in oil reservoirs compared to current practices. Table 1 shows the improvements that "next generation" technology would bring to a sample CO_2-EOR project. In this instance, incremental oil recovery is improved by 57% and CO_2 storage is increased by 18%.

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[1] "*Storing CO_2 with Enhanced Oil Recovery*" report prepared for U.S. DOE/NETL, Office of Systems, Analyses and Planning, DOE/NETL-402/1312/02-07-08, February 7, 2008. http://www.netl.doe.gov/energy-analyses/pubs/Storing%20CO2%20w%20EOR_FINAL.pdf

[2] The Advanced Resources completed 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 plus offshore Louisiana and included 1,581 large (>50 MMBbls OOIP) oil reservoirs, accounting for two thirds of U.S. oil production. These reports are available on the U.S. Department of Energy's web site at: http://www.fe.doe.gov/programs/oilgas/eor/Ten_Basin-Oriented_CO2-EOR_Assessments.html.

Table 1 - Comparison of "Best Practices" and "Next Generation" CO_2-EOR Technologies – Example Light Oil Reservoir

	Current Application of "Best Practices"	"Next Generation" Technology*
Oil Recovery (Million Barrels)	276	433
Oil Recovery (% OOIP)	17%	27%
CO_2 Storage (Bcf)	1,338	1,596
CO_2 Storage (metric tons)	71	84
Project Life (years)	22	32
CapEx ($/Bbl)	$2.20	$3.00
CO_2 Costs ($/Bbl)**	$19.40	$17.00
OpEx ($/Bbl)	$3.10	$5.20

*Includes extra costs for applying "next generation" CO_2-EOR technology.

**Assumes long-term oil price of $70 per barrel and CO_2 cost of $45/metric ton.

At the national level, this analysis suggests three major benefits would accrue from using integrated "next generation" CO_2 storage and enhanced oil recovery:

- Employing "next generation" CO_2-EOR technology would create CO_2 storage capacity in domestic oil fields of over 28 gigatons, equal to captured CO_2 emissions from 151 GWs of coal-fired power plants (for 30 years)[3]. It would also create economic CO_2 demand for 11.5 gigatons to be used in domestic oil fields. (A portion of the economic demand, 2.5 gigatons, can be met by natural CO_2 and already being captured industrial CO_2 emissions.) Importantly, the net economic demand for CO_2 of 9 gigatons is equal to captured CO_2 emissions from 50 GW of coal-fired power (for 30 years). The sale of CO_2 to meet this economic demand for CO_2 by CO_2-EOR can help coal-fired power plants and other industrial facilities offset the costs of CO_2 capture while fully avoiding the costs of CO_2 storage.
- Application of "next generation" technology would provide 126 billion barrels of technically recoverable domestic oil (compared to 81 billion barrels with current "best practices" CO_2 EOR technology). Almost half of this technically recoverable resource,

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[3] Assuming 85% capacity factor and 34% efficiency, a1GW power plant would generate 223 billion kWh of electricity in thirty years (1GW x 85% x 8.76 (conversion between GW and billion kWh/year) * 30 years). With a CO_2 intensity of 0.94 million metric tons CO_2/kWh (thermodynamic equivalency based on efficiency of power plant and emissions profile of average coal) and 90% capture, this power plant would supply 188 million metric tons of CO_2 in 30 years, 6.3 million metric tons per year.

58 billion barrels, would be economically recoverable under the mid-range (Base Case) oil price used in the study, Table 2.[4]

Table 2 - Technically and Economically Recoverable Domestic Oil and CO_2 Storage Capacity from "Next Generation" CO_2-EOR: National Totals*

Basin/Area	Technically Recoverable Oil* (Billion Barrels)		Economically Recoverable Oil** (Billion Barrels)		"Next Generation" CO_2 Storage Capacity (Million Metric Tons)	
	"Best Practices"	"Next Generation"	"Best Practices"	"Next Generation"	Technical Potential	Economic Demand
1. Lower-48 Onshore	66.7	107.1	34.7	49.4	23,990	9,910
2. Offshore GOM	5.7	5.7	0.7	0.7	1,740	200
3. Alaska	8.6	12.7	2.1	7.8	2,670	1,400
Total	81.2	125.6	37.5	57.9	28,400	11,510

*Incremental technically recoverable oil resources after subtracting 2.3 billion barrels already being developed with CO2-EOR.

**Base Case economics uses 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.

- Third, the oil produced with injection of captured CO_2 emissions is to a large extent "carbon-free", after balancing the carbon content in the oil produced and the volume of CO_2 stored with CO_2-EOR in the reservoir. If operators were incentivized to change their CO_2-EOR and storage design (including continuing to inject CO_2 at the end of the project), they could store more CO_2 in the oil reservoir than contained in the produced oil, resulting in over 100% carbon free ("green") oil. A case study of pursuing high capacity CO_2 storage and CO_2-EOR, that helps illustrate this point, is presented in Appendix C.

The results from this study presented in this report are based on using Advanced Resources database of 6,344 large domestic oil reservoirs, screened and evaluated using a streamline reservoir simulation and a detailed cost and cash-flow based economic model.

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[4] In addition to the mid-range oil price case of $70/barrel, the study investigated a low price case of $50/barrel with a CO_2 price of $35/metric ton and a high price case of $100/barrel with a CO_2 price of $60/metric ton.

An additional opportunity for storing CO_2 with CO_2-EOR is in saline aquifers containing residual oil (ROZ) in zones that underlie the primary oil interval (main pay zone). Due to their low oil concentrations, these residual oil zones are not economically feasible to pursue with primary/secondary recovery. However, we believe that the potential CO_2 storage capacity offered by the ROZ is large, on the order of 50 gigatons of CO_2. While needing further study, the ROZ/saline aquifer interval would provide storage for captured CO_2 emissions from over 250 GWs of coal-fired power (30 years). The ability to receive credits for sequestering CO_2 into saline reservoirs containing residual oil would make the ROZ attractive for storing CO_2 and producing additional oil, particularly when operated jointly with a CO_2 flood in the main pay zone. The quantification of the additional CO_2 storage and oil recovery potential offered by ROZs is an important area for further work.

Additionally, advanced drilling and modeling technology have made vertical (“gravity stable”) CO_2 floods more of a possibility. Generally speaking, vertical floods produce crude oil at a slower rate than conventional floods but enable a higher amount of the oil in-place to be recovered. Furthermore, this alternative method would allow a much greater amount of CO_2 to be stored within the oil reservoir, as discussed in Appendix C. Vertical floods are also an important area for future study.

2. BACKGROUND

2.1 UPDATED RESERVOIR AND ECONOMICS DATA

In January 2008, Advanced Resources International, with sponsorship by the U.S. Department of Energy's Office of Fossil Energy, issued a study entitled, "*Storing CO_2 with Enhanced Oil Recovery*." This study examined the domestic oil recovery and CO_2 storage potential offered by widespread application of currently used "best practices" CO_2-EOR technology (In the *Storing CO_2 with CO_2 Enhanced Oil Recovery* report, the term "State of the Art" is synonymous with the term "best practices" used in this report). It also synthesized the analysis previously contained in the series of ten basin reports, noted above.

This report builds on the reservoir data and CO_2-EOR performance provided in the above cited study "*Storing CO_2 with Enhanced Oil Recovery*" and includes an updated cost model and field-by-field reservoir modeling of evaluating and then applying "next generation" CO_2-EOR technology to 1,715 domestic oil reservoirs.

A brief description of the updated data and analytical work contained in this report is set forth below.

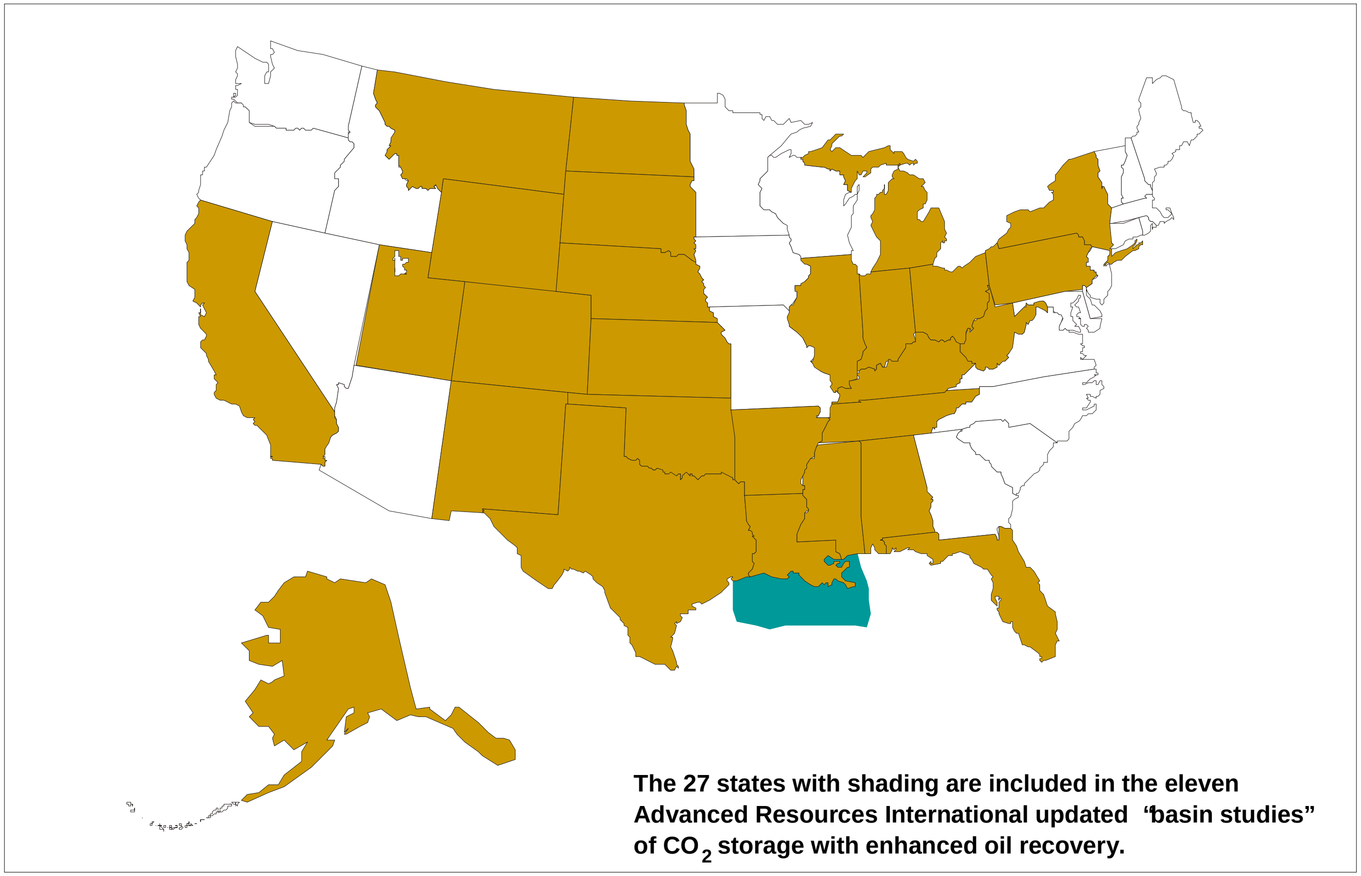
- A significant number, over 4,000 additional oil reservoirs have been added to the database, including oil reservoirs in the Gulf of Mexico, Alaska, and Appalachian Basin. The database now includes 6,344 oil reservoirs accounting for three-quarters of the U.S. oil resource in 27 states, Figure 1. These new oil reservoirs were made available for this study from a proprietary Advanced Resources' database;

- Improvements and updates have been made to the well spacing and CO_2 injection portions of the model. Oil field cost data have been updated and indexed to mid-year 2008. These updates and improvements are based on internal work undertaken by Advanced Resources; and

- An expanded set of oil prices and a revised oil price/CO_2 cost relationship have been incorporated into the economic analyses.

2.2 STUDY METHODOLOGY

A six part methodology was used to assess the CO_2 storage and EOR potential of domestic oil reservoirs. The six steps were: (1) assembling and updating the Major Oil Reservoirs Database; (2) calculating the minimum miscibility pressure for applying CO_2 -EOR; (3) using minimum miscibility pressure and other criteria to screen reservoirs favorable for CO_2-EOR; (4) calculating oil recovery from applying "next generation" CO_2-EOR technology; (5) applying the updated cost and economic model; and, (6) performing economic and sensitivity analyses to understand how the combined effects of technology and oil prices impact the results of applying "next generation" CO_2-EOR and CO_2 storage technology.



The 27 states with shading are included in the eleven Advanced Resources International updated "basin studies" of CO_2 storage with enhanced oil recovery.

Figure 1 - U.S. Basins/Regions Studied For Future CO_2 Storage and Enhanced Oil Recovery

To calculate the incremental oil produced by CO_2-EOR from oil reservoirs, the study utilized the *PROPHET2* model. *PROPHET2* is a stream tube miscible flood predictive model that was first developed by the Texaco Exploration and Production Technology Department under a DOE cost share program and has been further modified by Advanced Resources International.[5]

The *PROPHET2* model was calibrated with an industry standard reservoir simulator, GEM[6], to determine how permeability distributions within a multi-layer reservoir and gravity override, two computational functions absent in *PROPHET2*, might influence the calculation of oil recovery. The models were calibrated by comparing their results from trial runs on an example light oil reservoir.

The GEM model was run at two distributions of reservoir permeability (an upward fining and an upward coarsening permeability structure) plus CO_2 gravity override to establish oil recovery values against which the results from *PROPHET2* would be compared. This work indicated that that oil recovery values from *PROPHET2* were between the oil recoveries from the high and low cases of the GEM model, suggesting that *PROPHET2* is neither over nor under optimistic in its calculations of oil recovery.

Appendix A provides additional detail on the methodology used in this study.

2.3 REPORT OUTLINE

The report begins with a summary presentation of the three topics central to analyzing the potential of integrated “next generation” CO_2-EOR and CO_2 storage technologies:

1. What is the size and nature of the domestic oil resource base;

2. How much of this resource base is recoverable with “next generation” CO_2-EOR; and,

3. What portion of this technically recoverable oil resource is economic under alternative oil prices and CO_2 costs?

The report then examines the CO_2 storage capacity available in domestic oil fields and the market demand for captured CO_2 emissions offered by the EOR industry.

A series of appendices provide supporting data and technical information for the analytical results discussed in the main report. Appendix A provides information on the study methodology. Appendix B provides detail on our cost and economics model. Appendix C provides a case study of gravity stable CO_2-EOR flooding. Appendix D provides more detailed state-level results of our study.

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[5] “Post Waterflood CO_2 Flood in a Light Oil, Fluvial Dominated Deltaic Reservoir” (DOE Contract No. DE-FC22-93BC14960).

[6] Generalized Equation of State Model Compositional Reservoir Simulator” by Computer Modeling Group LTD.

3. THE DOMESTIC OIL RESOURCE BASE

The U.S. has a large oil resource base, on the order of 597 billion barrels originally in-place. About one-third of this oil resource base, 204 billion barrels, has been recovered or placed into proved reserves with existing primary and secondary oil recovery technologies. This leaves behind a massive target of 393 billion barrels of remaining, "technically stranded", oil, Figure 2.[7]

Table 3 provides a tabulation of the national in-place, conventionally recoverable and "stranded" oil in the lower-48 onshore, offshore Gulf of Mexico (GOM) and Alaska. Much of the "stranded" oil resides in East and Central Texas (74 billion barrels), the Mid-Continent (66 billion barrels), and the Permian Basin of West Texas and New Mexico (62 billion barrels). California, Alaska, the Gulf Coast and the Rockies also have significant volumes of "stranded" oil. Appendix D provides additional details for the "basins" addressed by this study.

The Advanced Resources' Major Oil Reservoirs Database of 6,344 distinct oil reservoirs contains 447 billion barrels of Original Oil in Place (OOIP) out of the national total of 597 billion barrels of OOIP, Table 4. The database values are scaled up to national levels using the state-by-state ratio of cumulative oil production in the Major Oil Reservoir Database and the state-by-state cumulative oil production data from state, EIA, and other sources.

The database coverage for individual basins/areas ranges from 59% for the Mid-Continent to 100% for Alaska and a national coverage of 75%. As such, the Major Oil Reservoir Database provides a solid foundation for estimating the national oil recovery potential from CO_2-EOR.

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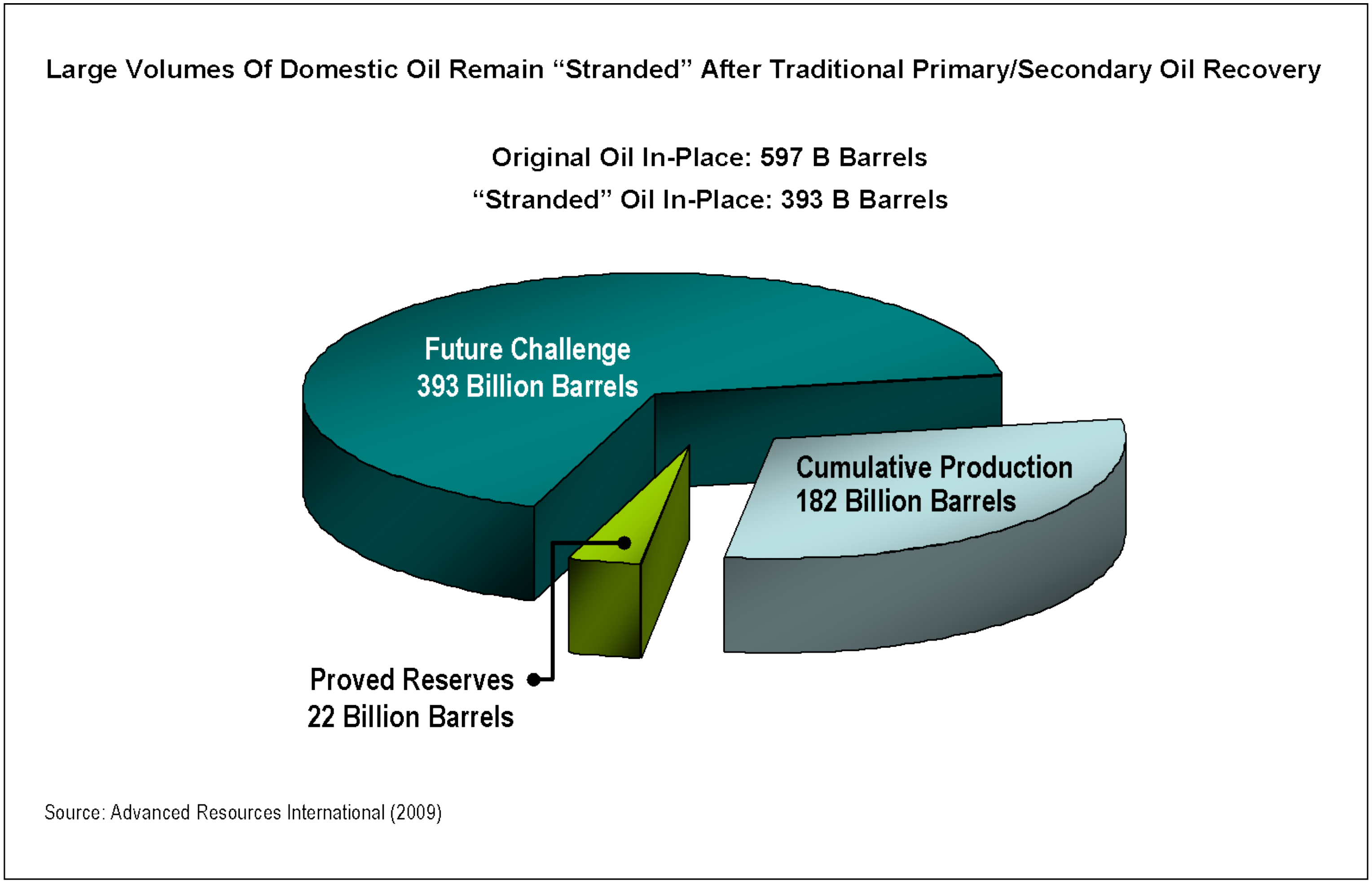
[7] When less established domestic oil resources, such as undiscovered oil, tar sands, and oil trapped in residual oil zones are included, the "stranded" oil resource approaches 1,000 billion barrels. For further information on this topic see Chapter 3 (pages 183 and 184) of the National Petroleum Council report "Hard Truths, Facing the Hard Truths about Energy" July, 2007, http://www.npchardtruthsreport.org/



Source: Advanced Resources International (2009)

Figure 2 - The Domestic Oil Resource Base

Table 3 - National In-Place, Conventionally Recoverable and "Stranded" Crude Oil Resources

Basin/Area	National Data OOIP* (Billion Barrels)	Conventionally Recoverable		ROIP "Stranded"** (Billion Barrels)
		(Billion Barrels)	% of OOIP	
1. Lower-48	500.3	161.0	32%	339.3
2. Offshore GOM	46.1	20.9	45%	25.2
3. Alaska	50.7	21.9	43%	28.8
Total	597.1	203.8	34%	393.3

*Original Oil In-Place **Remaining Oil In-Place

Source: Advanced Resources Int'l, 2009.

Please see Appendix D, Table D-3 for expanded version.

Table 4 - Comparison of Oil Resources of National and Major Oil Reservoirs Databases

Basin/Area	National Data OOIP* (Billion Barrels)	Major Oil Reservoirs Database OOIP* (Billion Barrels)	Coverage
1. Lower-48 Onshore	500.3	350.2	70%
2. Offshore GOM	46.1	46.1	100%
3. Alaska	50.7	50.7	100%
Total	597.1	447.0	75%

*Original Oil In-Place

Source: Advanced Resources Int'l, 2009. Data base figures are from Advanced Resources' internal database of large domestic oil reservoirs.

Please see Appendix D, Table D-4 for expanded version.

Not all of the remaining domestic oil resource is technically amenable to CO_2-EOR. Favorable reservoir properties for miscible CO_2-EOR include sufficiently deep formations with lighter (higher gravity) oil. A portion of the shallower oil reservoirs with heavier (lower gravity) oil may be amenable to immiscible CO_2-EOR.[8]

Table 5 provides a basin/area level tabulation of the 6,344 reservoirs in the Major Oil Reservoirs Database, showing that 1,715 reservoirs (containing 305 billion barrels of OOIP) screened as being amenable to miscible and immiscible CO_2-EOR. More than half of the oil reservoirs in California, particularly the shallower heavy oil fields, screen as unfavorable for CO_2-EOR while the great bulk (over 80%) of the oil reservoirs in the Permian Basin screen as favorable for CO_2-EOR.

Table 5 - Major Oil Reservoirs Screened as Favorable for CO2-EOR

Basin/Area	Major Oil Reservoirs Database	
	# of Total Reservoirs	# Favorable for CO_2-EOR
1. Lower-48 Onshore	1,809	1040
2. Offshore GOM	4,493	642
3. Alaska	42	33
Total	6,344	1,715

Please see Appendix D, Table D-5 for expanded version.

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[8] For readers unfamiliar with the distinction between miscible and immiscible EOR, a more detailed description is given in section 4.1

4. DETAILED DISCUSSION OF CO_2-EOR

4.1 USING CO_2-EOR TO RECOVER "STRANDED" OIL

Large volumes of oil are left unrecovered ("stranded") after completion of primary and secondary oil recovery methods. The reasons for these large volumes of "stranded" oil 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 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 efficient oil recovery.

- Miscible CO2-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, thus remobilizing and dramatically reducing the post-waterflooding residual oil in the reservoir's pore space. Figure 3 provides a one-dimensional schematic showing the fluid dynamics of the CO_2 miscible process.

- Immiscible CO2-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 the oil remaining in the reservoir.

Currently available CO_2-EOR technologies, including both miscible and immiscible CO_2 injection, are in commercial use today. However, today's CO_2-EOR technologies still underperform compared to their theoretical potential as established by laboratory testing, reservoir simulation and a handful of forward-looking, highly instrumented projects. As evidence for underperformance, field data shows that currently practiced CO_2-EOR technology recovers only 5% to 15% of a reservoir's OOIP as opposed to theoretically possible oil recoveries using "next generation" CO_2-EOR technology of over 20% of OOIP.

The "next generation" CO_2-EOR technology options include: (1) increasing the volume of CO_2 injected into the oil reservoir to increase sweep efficiency; (2) optimizing well design and placement, including adding infill wells, to achieve increased contact between the injected CO_2 and the oil reservoir; (3) improving the mobility ratio between the injected CO_2/water and the residual oil; and, (4) extending the miscibility range, thus helping more reservoirs achieve higher oil recovery efficiency.

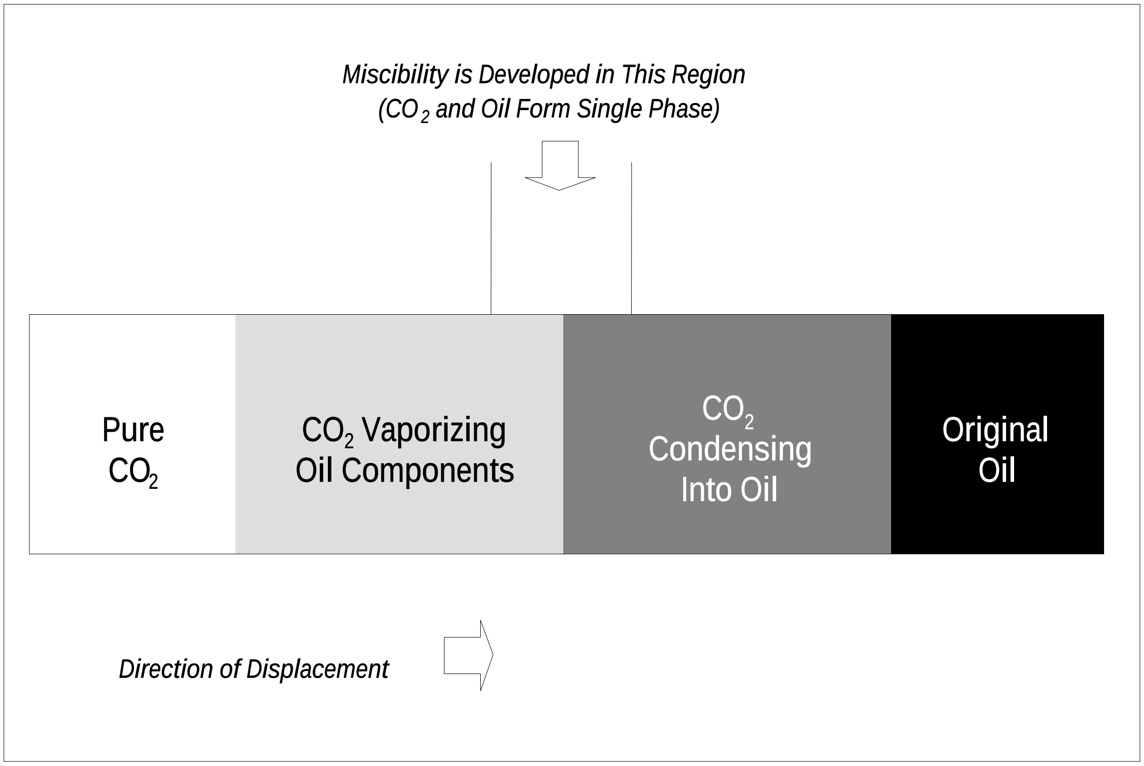


Figure 3 - One-Dimensional Schematic Showing the CO_2 Miscible Process

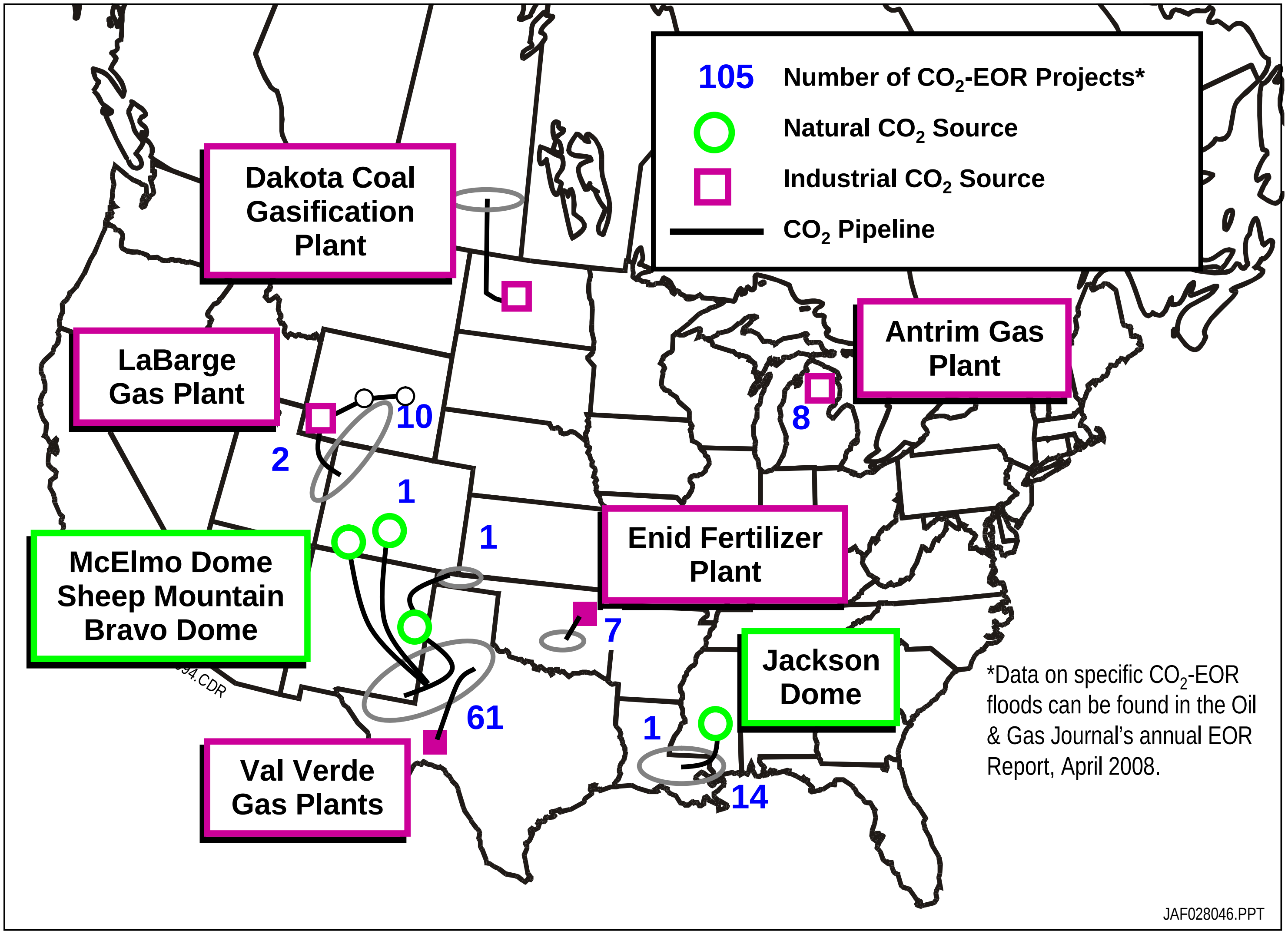
If implemented, these practices could dramatically increase the efficiency of CO_2-EOR-based oil recovery. They would also increase the amount of CO_2 that could be stored in oil reservoirs. Reservoir analysis suggests that the combined application of “next generation” technologies could increase the oil recovery from selected oil reservoirs by about 50% relative to continued application of today’s “best practices” CO_2-EOR technology.

The remainder of this section discusses the performance of today’s “best practices” CO_2-EOR technology, where it is being performed in the U.S., and how “next generation” technology could increase the amount of oil recovered from domestic fields.

4.2 CURRENT CO_2-EOR ACTIVITY AND PRODUCTION

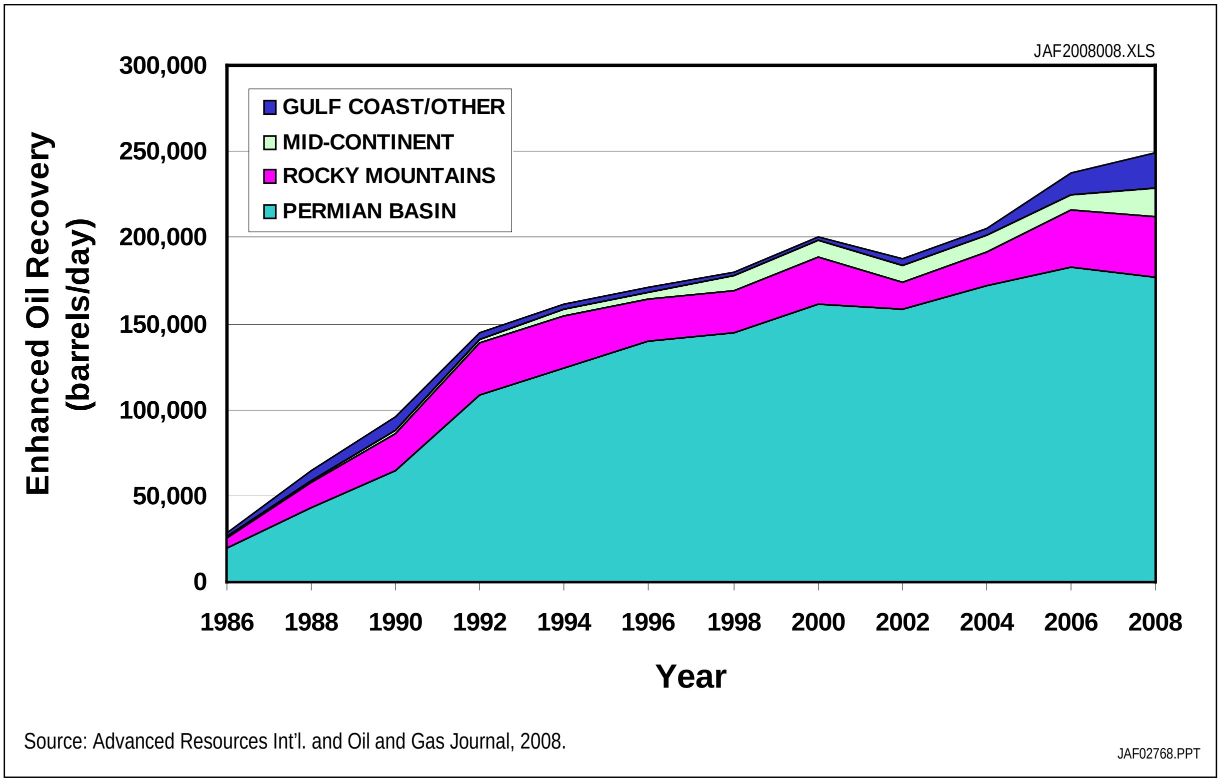
According to the 2008 EOR Survey published by the Oil and Gas Journal, approximately 250,000 barrels per day of incremental domestic oil is being produced by 105 CO_2-EOR projects, distributed broadly across the U.S. Since 1986, when CO_2-EOR was first used in commercial production, over 1.3 billion barrels of incremental oil have been recovered using this technology.

Figure 4 provides the location of the currently active 105 CO_2-EOR projects (including the Weyburn project, in Canada) and illustrates their sources of CO_2 supply. Figure 5 tracks the steady growth in CO_2-EOR based oil 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.



*Data on specific CO_2-EOR floods can be found in the Oil & Gas Journal's annual EOR Report, April 2008.

Figure 4 - U.S. CO_2-EOR Activity



Source: Advanced Resources Int'l. and Oil and Gas Journal, 2008.

Figure 5 - Growth of CO_2-EOR Production in the U.S

4.3 PERFORMANCE OF CURRENT CO_2-EOR TECHNOLOGY

Laboratory tests and reservoir modeling show that very high oil recovery efficiencies are theoretically possible using innovative applications of CO_2 enhanced oil recovery (CO_2-EOR). Under ideal conditions, gravity-stable laboratory core floods using high pressure CO_2 have recovered essentially all of the residual oil. Similarly, reservoir simulation models, using innovative well placement and process designs that facilitate contact of the majority of the reservoir's pore volume with CO_2, also show that high oil recovery efficiencies are possible.

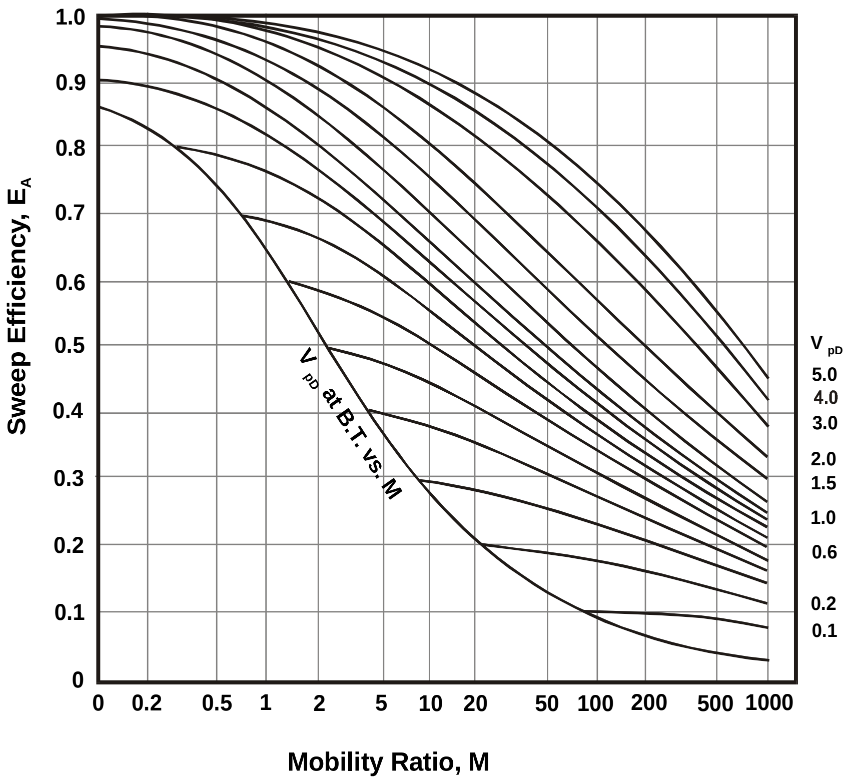
However, the actual field performance of CO_2-EOR projects has not exhibited the high oil recovery efficiency shown in laboratory tests. Geologically complex reservoir settings combined with lack of reliable performance information or process control capability during the CO_2 flood are some of the challenges facing optimum oil recovery using CO_2-EOR.

4.3.1 Barriers to Improved CO_2-EOR Performance

The causes of less-than-optimum past-performance and modest oil recoveries by currently used CO2-EOR technologies include the following:

1. ***Insufficient Injection of CO_2.*** The great majority of past CO_2 floods injected insufficient volumes of CO_2 for optimum oil recovery. This was due in part to high CO_2 costs relative to oil prices and the inability to control CO_2 flow through the reservoir. Figure 6 shows

that low reservoir sweep efficiency results from using small volumes of CO_2 injection, particularly under conditions of high (unfavorable) mobility ratios. Table 6 provides an example of the relationship of CO_2 injection and oil recovery efficiency from an ideal, single layer oil reservoir, where CO_2 is used as the oil secondary recovery process. Table 6 provides a useful methodology for assessing how much CO_2 to inject. It shows that the injection of the final 0.5 HCPV[9] of CO_2 (from 1.0 to 1.5 HCPV), equal to 391,000 Mcf, leads to recovery of 34,000 additional barrels of oil with a CO_2 to oil ratio of 11.5 Mcf per barrel, a CO_2 to oil ratio that is economically favorable at an oil price of \$70 per barrel.



Note: V_{pD} is displaceable fluid pore volumes of CO_2 injected.

Source: Claridge, E.L., "Prediction of Recovery in Unstable Miscible Displacement", SPEJ (April 1972).

Figure 6 - Oil Recovery in Miscible Flooding for Five-Spot Well Patterns

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[9] Hydrocarbon Pore Volume (HCPV) is a measure of the volume of the reservoir originally holding oil.

Table 6 - Example Secondary Oil Recovery Efficiency vs. HCPV of CO_2 Injection*

Injected CO_2 (HCPV)	Injected CO_2 (Mcf)	Reservoir Sweep Efficiency (Fraction)	Oil Recovery (Barrels)	Oil Recovery Efficiency (% OOIP)
0.40	312,800	0.345	117,300	32.2
0.60	469,200	0.440	149,600	41.1
0.80	625,600	0.515	175,100	48.1
1.00	782,000	0.570	193,800	53.2
1.50	1,173,000	0.670	227,800	62.6

*Amount of oil produced by CO2 flood divided by original oil in-place assumed at 364 thousand barrels

Source: Adapted by Advanced Resources Int'l from "Enhanced Oil Recovery", D.W. Green and G. P. Willhite, SPE, 1998.

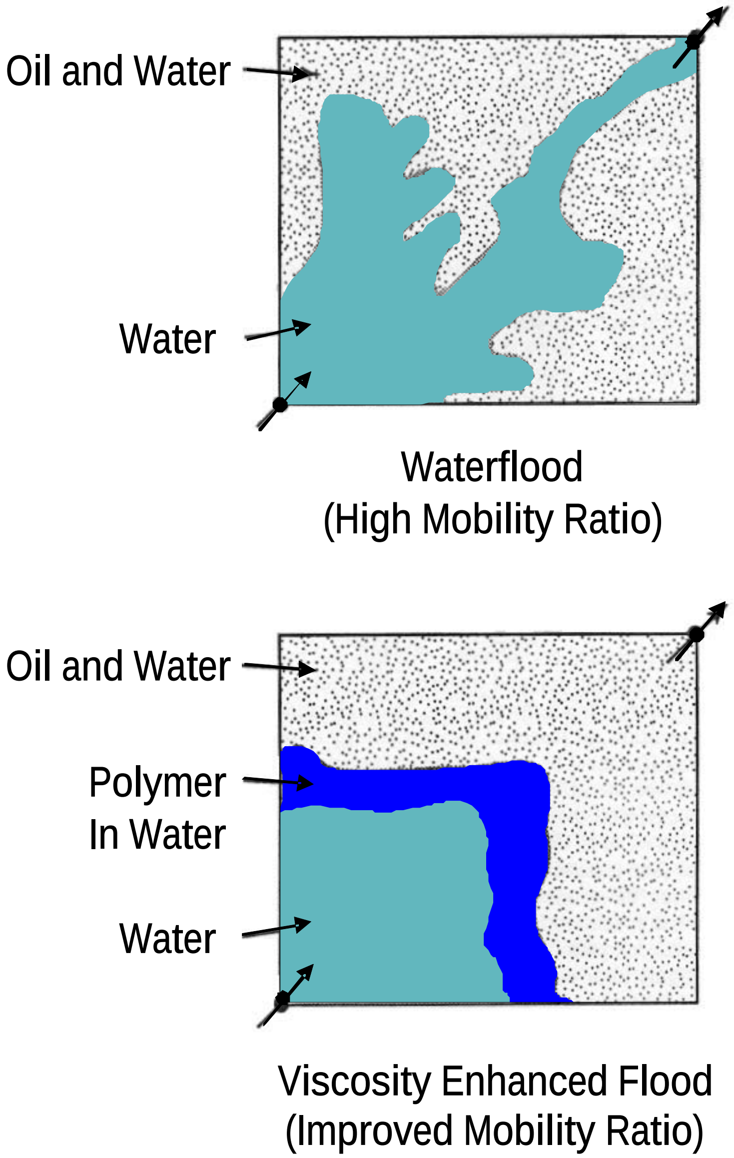
2. ***Poor Sweep Efficiency***. In many of the previous CO_2 floods, the injected CO_2 achieved only limited contact with the residual oil in the reservoir (poor sweep efficiency). This was due to a variety of causes, including: gravity override by the less dense CO_2; viscous fingering of the CO_2 through the reservoir's oil; and channeling of the CO_2 in highly heterogeneous reservoirs. Figure 7 shows how a high mobility ratio for the injected fluid can lead to viscous fingering and how addition of viscosity enhancers would help reduce this problem in a traditional waterflood.

3. ***Poor Displacement Efficiency.*** Analysis of past CO_2 floods also shows that, in many cases, the CO_2-EOR project mobilized only a modest portion of the residual oil (poor displacement efficiency) due to lack of effective miscibility between the injected CO_2 and the reservoir's oil, caused by unexpected pressure declines in portions of the reservoir and less than optimum injection and production well operating practices.

4. ***Lack of CO_2 Contact With Remaining Oil Resources.*** An often overlooked but important cause of poor CO_2-EOR performance is the inability to efficiently target injected CO_2 to preferred (high residual oil) reservoir strata and then capture and produce the mobilized oil. Figure 8 shows how the lower permeability portion of the reservoir strata (Layer 1) is less efficiently swept by a waterflood, leaving behind much higher residual oil saturations in this layer of the oil reservoir. Injection of CO_2 into this type of reservoir, without undertaking selective CO_2 placement, would cause the CO_2 to enter the higher permeability (100 md) Layer 2, bypassing the lower permeability, higher oil saturation Layer 1.

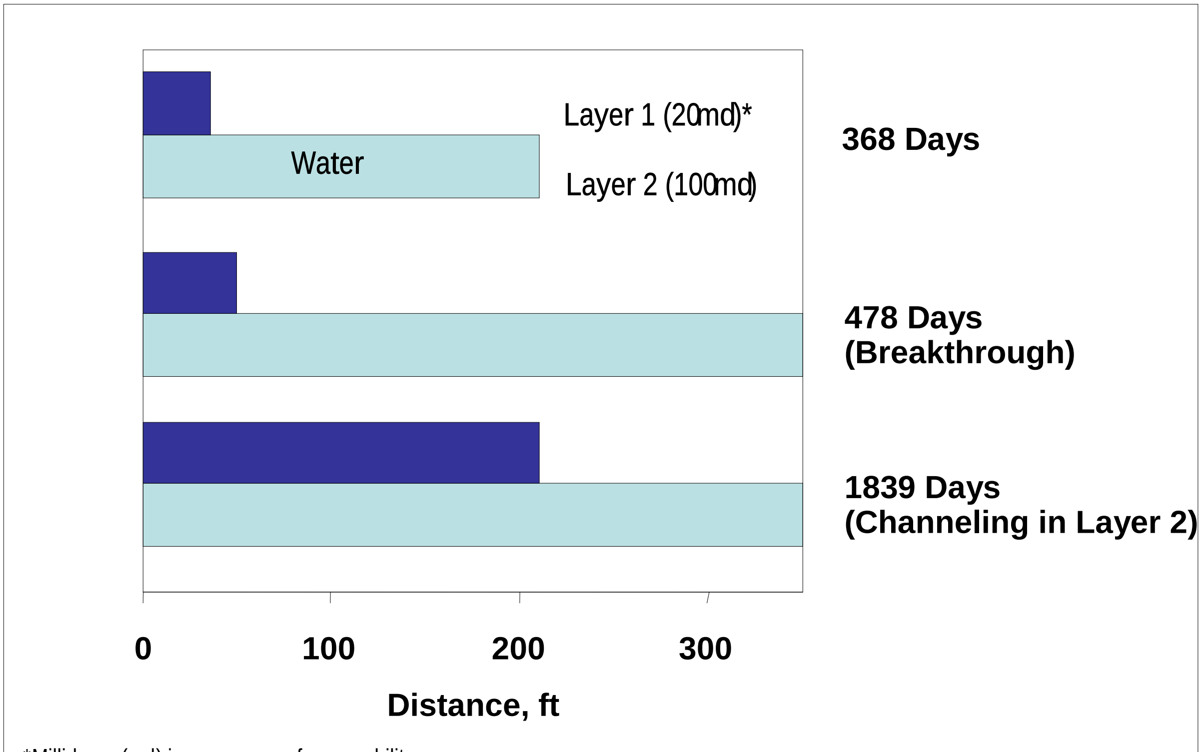
5. ***Inadequate "Management and Control".*** Finally, a variety of other operating issues have contributed toward less-than-optimum performance, including the inability to

"manage and control" the CO_2 flood for lack of real-time process and performance information from within the oil reservoir.



Source: Adapted by Advanced Resources Int'l from "Enhanced Oil Recovery", D.W. Green and G. P. Willhite, SPE, 1998.

Figure 7 - Schematic of Macroscopic Displacement Efficiency Improvement with Polymer-Augmented Waterflooding (Quarter of a Five-Spot Pattern)



*Millidarcy (md) is a measure of permeability.
Source: Adapted by Advanced Resources Int'l from "Enhanced Oil Recovery", D.W. Green and G. P. Willhite, SPE, 1998.

Figure 8 - Relative Location of the Water Front in a Layered Reservoir

4.3.2 Evolution in CO_2 Flooding Practices

Considerable evolution has occurred in the design and implementation of CO_2-EOR technology since it was first introduced. Notable changes include: (1) use of larger (up to 1 HCPV) volumes of CO_2; (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.

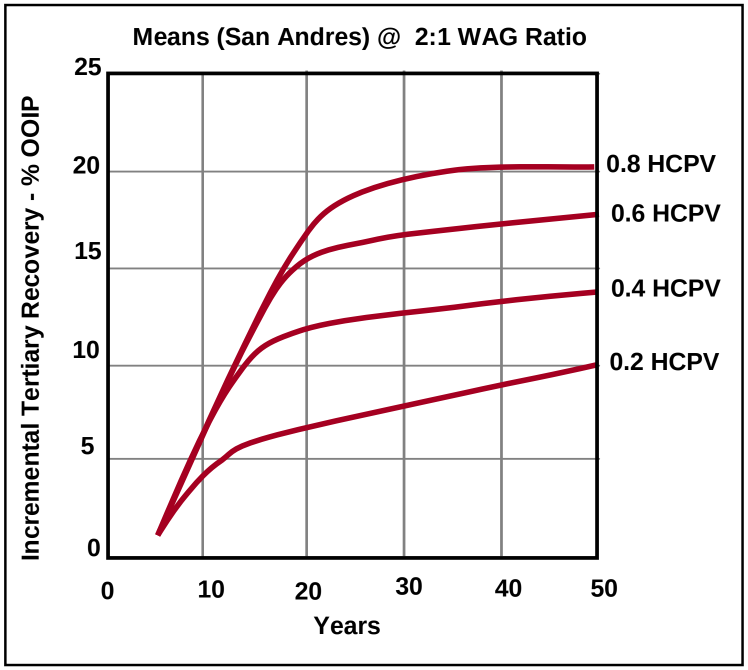
- Figure 9 provides analytical support for using larger volumes of injected CO_2.

- Figure 10, using information from Occidental Petroleum (Oxy Permian), provides a 17 year snapshot of the evolution of the "industry standard" for the most effective volume of CO_2 injection (the optimum "slug size").

- Figure 11, illustrates how rigorous monitoring and well remediation can be used to target injected CO_2 to reservoir strata with high remaining oil saturation, helping reduce ineffective CO_2 channeling.

The "next generation" technology goals analyzed in this report build on the successes of forward thinking firms that have begun to address the challenges for optimizing CO_2-EOR performance.

Actual field projects confirm that injection of higher volumes of CO_2 lead to higher oil recovery.



Source: SPE 24928 (1992)

The CO_2-EOR WAG project at Means (San Andres Unit) was implemented as part of an integrated reservoir development plan and involve the drilling of 205 new producers and 158 new injectors.

Initial objective was to inject 260 Bcf of CO_2, equal to 55% HCPV, (0.4 HCPV purchased; 0.15 HCPV recycled) at a 2:1 WAG ratio.

Latest objective is to inject 480 Bcf (~1 HCPV) of CO_2. Increasing the volume of injected CO_2 can also be achieved by increasing the rate of CO_2 injection (not shown in this chart).

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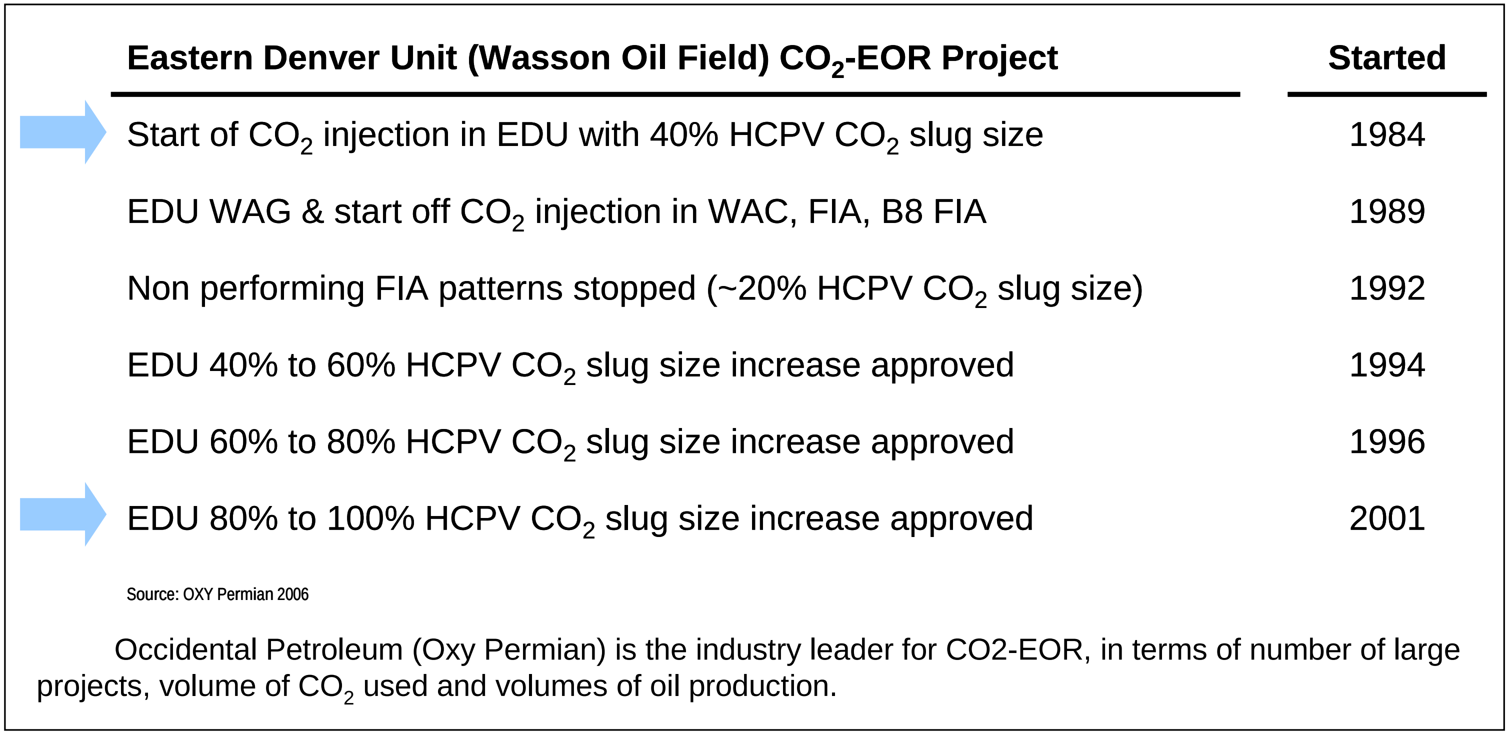
Figure 9 - Science Behind Volume of CO_2 Injection and Oil Recovery Efficiency: Actual Practice



	Eastern Denver Unit (Wasson Oil Field) CO_2-EOR Project	**Started**
➡	Start of CO_2 injection in EDU with 40% HCPV CO_2 slug size	1984
	EDU WAG & start off CO_2 injection in WAC, FIA, B8 FIA	1989
	Non performing FIA patterns stopped (~20% HCPV CO_2 slug size)	1992
	EDU 40% to 60% HCPV CO_2 slug size increase approved	1994
	EDU 60% to 80% HCPV CO_2 slug size increase approved	1996
➡	EDU 80% to 100% HCPV CO_2 slug size increase approved	2001

Source: OXY Permian 2006

Occidental Petroleum (Oxy Permian) is the industry leader for CO2-EOR, in terms of number of large projects, volume of CO_2 used and volumes of oil production.

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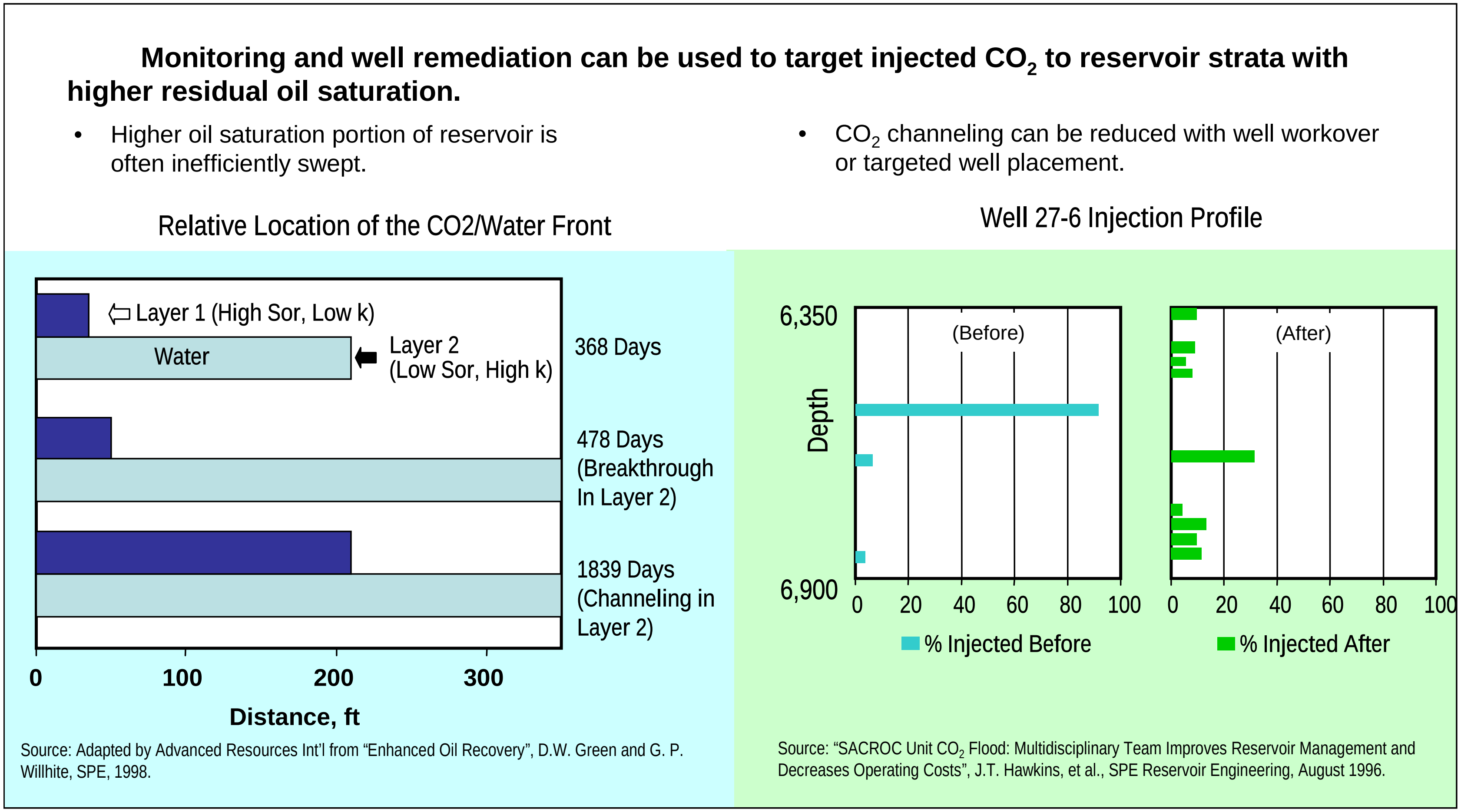
Figure 10 - Evolution of "Industry Standard" for Volume CO_2 Injection ("Slug Size")



Monitoring and well remediation can be used to target injected CO_2 to reservoir strata with higher residual oil saturation.

- Higher oil saturation portion of reservoir is often inefficiently swept.
- CO_2 channeling can be reduced with well workover or targeted well placement.

Relative Location of the CO2/Water Front

Source: Adapted by Advanced Resources Int'l from "Enhanced Oil Recovery", D.W. Green and G. P. Willhite, SPE, 1998.

Well 27-6 Injection Profile

Source: "SACROC Unit CO_2 Flood: Multidisciplinary Team Improves Reservoir Management and Decreases Operating Costs", J.T. Hawkins, et al., SPE Reservoir Engineering, August 1996.

JAF02772.PPT

Figure 11 - Overcoming the Effects of Geologic Complexity on CO_2-EOR Performance

4.4 "NEXT GENERATION" CO_2-EOR TECHNOLOGY

For this report, we examine four specific "next generation" CO_2-EOR technology options. These options involve: 1) increasing the volume of CO_2 injected, 2) optimizing well design and placement, 3) improving the mobility ratio, and 4) extending miscibility. Below, we discuss each technology application in detail and investigate how these options would increase the performance of currently used CO_2-EOR technologies. Importantly, each of these is a topic for future R&D.

4.4.1 Overview of Next Generation Technology Performance

Technology Option #1. Increasing CO_2 Injection

The first "next generation" technology option involves increasing CO_2 injection volumes to 1.5 HCPV. Higher HCPVs 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, higher volumes of CO_2 injection lead to longer overall project length and higher gross CO_2 to oil ratios. Field operators will need to carefully consider this option to evaluate its cost effectiveness.

In the past, the combination of high CO_2 costs and low oil prices led operators to use small-volume injections of CO_2 (traditional 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 would 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.

Technology Option #2. Innovative Flood Design and Well Placement

Technology Option # 2 assumes that through optimized well design and placement more of the residual oil in a reservoir would be contacted. 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 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/or production) wells to target bypassed or poorly produced reservoir areas or intervals; (3) modifying 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 spacings.

To model Technology Option #2, we assume that one new vertical injection or production well would be added to each pattern targeting previously bypassed or poorly contacted portions of the reservoir. (The model assumes that each CO_2-EOR pattern has one production and one injection well).

Technology Option #3. Improving the Mobility Ratio

Technology Option # 3 assumes that an increase in the viscosity of the injected water (as part of the CO_2-WAG process) is achieved using polymers or other agents. (The viscosity of the CO_2 itself was left unchanged, although increasing the viscosity of CO_2 with CO_2-philic agents, such as those being pursued in the joint DOE/University of Pittsburgh research program[10], could theoretically further improve performance.) To model Technology Option # 3, we assume the viscosity of injected water is increased to 3cps[11], or three times the viscosity of water.

Technology Option #4. Extending Miscibility

Technology Option # 4 assumes that "miscibility extenders" are added to the CO_2-EOR process to reduce minimum miscibility pressure requirements by 500psi   (pounds per square inch). Examples of miscibility enhancing agents would include: addition of Liquefied Petroleum Gasses (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. Successful application of Technology Option # 4 could allow 21 previously immiscible fields to become suitable for miscible CO_2-EOR operations.

Technology Option # 5. Integrating Application of "Next Generation" Technology Options

The maximum benefits, in terms of increased oil recovery, accrue when these four individual "next generation" technology options are applied jointly, and as part of a highly instrumented and process-controlled field operations strategy.

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[10] DOE Program Reference Number: DE-FC26-01BC15315.

[11] A centipoise (cp) is the unit of measure for dynamic viscosity. Water has cp value of 1 at 20 degrees Celsius.

4.5 EXAMINING THE COSTS AND BENEFITS OF USING “NEXT GENERATION” EOR CO_2 TECHNOLOGY

Insights on the costs and benefits of conducting an integrated “next generation” CO_2-EOR flood may be gained by examining the changes in oil production, capital investment, CO_2 requirements and operating costs between using today’s “best practices” and using, in an integrated fashion, “next generation” CO_2-EOR technologies. The example set forth is representative light oil field, Table 7 and Table 8.

Appendix B provides additional discussion of the “next generation” cost and economic model.

Table 7 - Economic Comparison of Alternative CO_2-EOR Technologies – Example Light Oil Reservoir

	Current Application of “Best Practices”	“Next Generation” Technology*
Oil Recovery (Million Barrels)	276	433
Oil Recovery (% OOIP)	17%	27%
Project Life (years)	22	32
CapEx ($/Bbl)	$2.20	$3.00
CO_2 Costs ($/Bbl)**	$19.40	$17.00
OpEx ($/Bbl)	$3.10	$5.20

*Includes extra costs for applying “next generation” CO_2-EOR technology.

**Assumes long-term oil price of $70 per barrel, adjusted for gravity and location differentials, and $45/metric ton of CO_2 .

<u>Oil Recovery</u> Oil recovery from the example light oil field (with 1,596 million barrels of original oil in-place) is estimated at 433 million barrels in 32 years under “next generation” CO_2-EOR technology versus 276 million barrels in 22 years under “best practices” CO_2-EOR technology.

Table 8 - Economic Comparison of Alternative CO2-EOR Technologies - Example Light Oil Reservoir*

	Currently Used "Best Practices"	Application of "Next Generation" CO_2-EOR Technologies
OIL RECOVERY (Million Barrels)	276	433
% OOIP	17%	27%
Project Life (years)	22	32
CAPITAL INVESTMENT (Million $)		
Basic Cap Ex	$615	$615
Additional Wells	-	$583
Larger CO_2 Recycle Plant	-	$8
Process Control Measurements and Feedback	-	$99
Total	**$615**	**$1,305**
CO_2 COSTS (Million $)		
Purchased CO_2	$3,184	$3,799
Recycled CO_2	$2,174	$3,546
Total	**$5,358**	**$7,345**
OPERATING AND MAINTENANCE (Million $)		
Basic OpEx	$855	$855
Additional OpEx and Fluid Lifting	-	$970
Viscosity Enhancement and Mobility Control	-	$358
Real-Time Project Information and Management	-	$88
Total	**$855**	**$2,271**

* Figures in millions of 2007 dollars, unless otherwise noted

Capital Investment Capital investment in this sample oil field under "next generation" CO2-EOR technology is $1,305 million versus $615 million with currently used "best practices". The extra costs are due to:

- An extra $583 million for drilling, completing, and equipping additional wells
- A larger CO_2 recycle plant, adding $8 million, and
- An allocation of $99 million for instrumented observation wells, 4-D seismic and downhole testing to provide real-time information with which to "manage and control" the "next generation" CO_2 flood.

On dollars of capital investment per recovered barrel of oil basis, the CapEx costs of "next generation" technologies are about $0.80 per barrel higher.

CO_2 Costs CO_2 injection and supply costs for the example oil field are higher, at $7,345 million under "next generation" CO_2-EOR technology (with its 1.5 HCPV of CO_2 versus $5,358 million under "best practices". The extra costs are due to:

- Larger volumes of purchased CO_2 under "next generation" technology of 1,596 Bcf of purchased CO_2, compared to 1,338 Bcf under "best practices".
- Significantly larger volumes of recycled CO_2 are used under "next generation" technology than "best practices" technology. In this example, "next generation" technology uses 5,066 Bcf of recycled $CO_{2;}$ "best practices" technology uses only 3,103 Bcf of recycled CO_2.

On a cost of CO_2 per barrel of oil recovered basis, CO_2 costs are $2.40 per barrel lower with "next generation" technology.

Operating and Maintenance Costs (O&M) O&M costs in the sample oil field are higher, at $2,271 million (for 32 years of operation) under "next generation" CO_2-EOR technology versus $855 million (for 22 years) under "best practices". The extra costs are due to:

- An extra $970 million for operating a larger number of wells for 10 additional years and lifting additional volumes of produced oil and water,
- An extra $358 million for purchase and injection of viscosity enhancing and mobility control materials aspects, and
- An allocation of $88 million for helping "manage and control" the "next generation" CO_2 flood.

5. TECHNICALLY RECOVERABLE RESOURCES FROM "NEXT GENERATION" CO_2-EOR OPERATIONS

Our reservoir-by-reservoir assessment of the 1,715 large oil reservoirs amenable to CO_2-EOR (extrapolated to national totals) shows that a significant volume, 128 billion barrels, of domestic oil may be recoverable with the application of "next generation" CO_2-EOR technologies, Table 9. Subtracting the 2.3 billion barrels of oil that has already been produced or placed into proved reserves by CO_2-EOR (as of 2006), "next generation" CO_2-EOR would add 126 billion barrels of technically recoverable oil to domestic supplies, Figure 12. For perspective, the current domestic proved crude oil reserves are 22 billion barrels, as of the end of 2007.

The Permian Basin of West Texas and New Mexico, with its world class size, favorable geology and carbonate reservoirs, offers the largest volume of technically recoverable oil resource from CO_2-EOR. In addition, significant potential exists in East and Central Texas, the Mid-Continent, the Gulf Coast and California.

Geologically complex oil reservoirs with large volumes of residual oil (due to low primary and secondary recovery sweep efficiencies) will be most benefitted by "next generation" technology. The more homogeneous sandstone reservoirs, such as those in the Gulf Coast which achieve high oil recovery efficiencies using current CO_2-EOR practices, may not be favorable settings for "next generation" technology.

Table 9 - Technically Recoverable Resources from Applying "Next Generation" CO_2-EOR:Totals from Extrapolating Advanced Resources' Database to National Level

Basin/Area	OOIP (Billion Barrels)	OOIP Favorable for CO_2-EOR (Billion Barrels)	Technically Recoverable (Billion Barrels)	
			"Best Practices" Technology	"Next Generation" Technology
1. Lower-48 Onshore	500.3	345.4	69	109.4
2. Offshore GOM	46.1	29.6	5.7	5.7
3. Alaska	50.7	42.5	8.6	12.7
Total	597.1	417.5	83.4	127.9

Please see Appendix D, Table D-9 for expanded version.

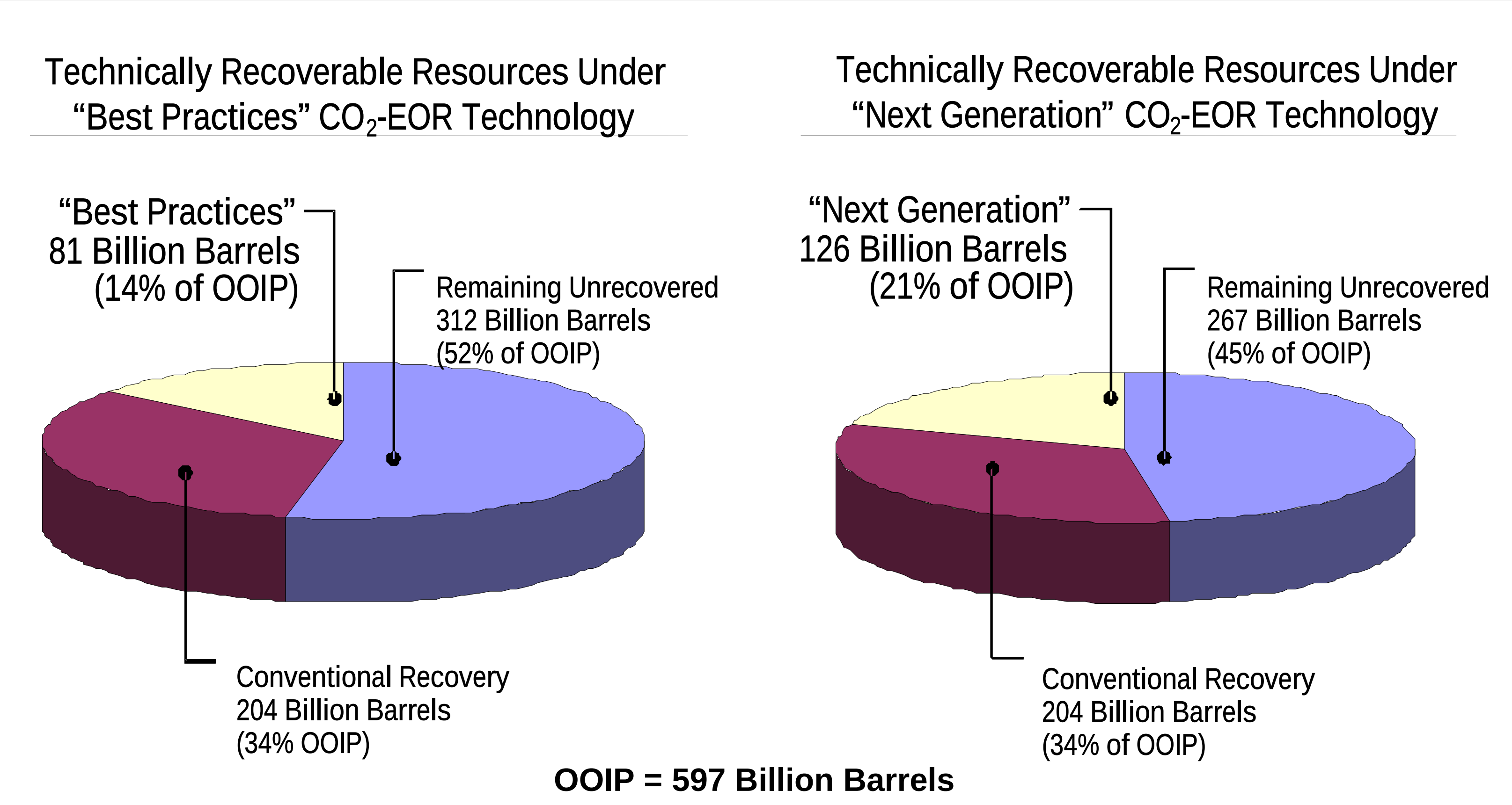

Figure 12 - Comparison of Technically Recoverable Resource between State of the Art and Next Generation CO_2-EOR Technologies

6. ECONOMICALLY RECOVERABLE RESOURCES

6.1 PERSPECTIVE ON CO_2-EOR ECONOMICS

Given the significant front-end investment in wells, recycle equipment and purchase of CO_2 and the time delay in reaching peak oil production, significant economic margins will be required to achieve economically favorable rates of return. Oil reservoirs with higher capital cost requirements and less favorable CO_2 to oil ratios would not achieve sufficient return on investment, requiring credits for storing CO_2 to make an integrated CO_2-EOR and CO_2 storage project economic.

6.2 ECONOMICALLY RECOVERABLE RESOURCES: BASE CASE

The Base Case evaluates the "next generation" CO_2-EOR potential using an oil price of $70 per barrel (constant, real) and a CO_2 cost of $45 per metric ton ($2.38 per Mcf) (constant and real, delivered at pressure to the field). In the Base Case, 57.9 billion barrels of incremental oil become economically recoverable from applying "next generation" CO_2-EOR technology, after subtracting the 2.3 billion barrels of oil already produced through existing CO_2-EOR operations, Table 10.

The estimates of economically recoverable domestic oil from applying CO_2-EOR have been calculated using a minimum financial hurdle rate of 15% (real, before tax). Higher financial hurdle requirements, appropriate for rapidly installing "next generation" CO_2-EOR technology in new basins and geologic settings, would reduce the volumes of economically recoverable oil.

Table 10 - Economically Recoverable Resources from Applying "Next Generation" CO_2-EOR: National Totals at Base Case Economics*

Basin/Area	Technically Recoverable (Billion Barrels)	CO_2-EOR Currently Underway (Billion Barrels)	Incremental Technically Recoverable (Billion Barrels)	Incremental Economically Recoverable** (Billion Barrels)
1. Lower-48 Onshore	109.4	-2.3	107.1	49.4
2. Offshore GOM	5.7		5.7	0.7
3. Alaska	12.7	Note 1	12.7	7.8
Total	127.9	-2.3	125.6	57.9

Note 1: The hydrocarbon miscible floods underway on the North Slope of Alaska contain 24% CO_2 in the injected gas.

*Incremental technically recoverable resources after subtracting 2.3 billion barrels already produced or proven with CO_2-EOR.

**Base Case Economics use an oil price of $70 per barrel (constant, real) and a CO_2 cost of $45 per metric ton ($2.38/Mcf), delivered at pressure to the field. Economically recoverable resources form the database of large oil reservoirs are not further extrapolated to national totals. We assume that all the reservoirs with economic potential are already included in this database.

Please see Appendix D, Table D-10 for expanded version.

6.3 ECONOMICALLY RECOVERABLE RESOURCES: SENSITIVITY CASES

To gain insights as to how changes in oil prices would affect "next generation" CO_2-EOR projects, the report examined one lower and one higher oil price case (and their associated CO_2 costs). Table 11 presents the 57.9 billion barrels of domestic oil recovery potentially available from CO_2-EOR at the Base Case oil price and CO_2 costs. The economically recoverable resource increases to 67.6 billion barrels at a higher ($100/Bbl) oil price and drops to 46.6 billion barrels at a lower ($50/Bbl) oil price.

Table 11 - Economically Recoverable Resource from "Next Generation" CO_2-EOR : National Totals at Alternative Economic Cases

Basin/Area	Base Case	Lower Oil Price Case	Higher Oil Price Cases
	($70/Bbl)	($50/Bbl)	($100/Bbl)
	(Billion Barrels)	(Billion Barrels)	(Billion Barrels)
1. Lower-48 Onshore	49.4	43.1	54.9
2. Offshore GOM	0.7	0.5	2.4
3. Alaska	7.8	3.0	10.3
Total Demand	57.9	46.6	67.6

Please see Appendix D, Table D-11 for expanded version.

7. THE MARKET FOR STORING CO_2 WITH EOR

The previous chapters established that 126 billion barrels of additional domestic oil could be technically produced with “next generation” CO_2-EOR technology. In addition, they established that 47 to 68 billion barrels could be economically produced with “next generation” technology. This chapter discusses first how much CO_2 could be technically stored in domestic oil fields (storage capacity) and second how much CO_2 would be required to be purchased (and stored) to produce the economically recoverable oil.

7.1 THE CO_2 INJECTION AND STORAGE PROCESS OF CO_2-EOR

The sequence for injecting and storing CO_2 as part of CO_2-EOR is as follows:

- Initially, purchased or captured CO_2 emissions would be injected into the oil field along with water for mobility control.
- As oil and CO_2 begins to be produced, the CO_2 is separated from the oil and reinjected, continuing the life of the CO_2-EOR project.
- Near the end of the CO_2-EOR project, the operator may choose to close the field at pressure, storing essentially all of the purchased CO_2, or may inject a large (1 to 2 HCPV) slug of water to recover any remaining mobile oil and CO_2. This produced CO_2 may then be used in another portion of the reservoir or sold to another oil field.

7.2 CO_2 STORAGE CAPACITY

The analysis shows that significant volumes of captured CO_2 emissions could be injected and stored with “next generation” CO_2 EOR, creating 28.4 billion metric tons of technical CO_2 storage capacity, Table 12. This number is only a fraction of the 138 million metric tons mentioned in the NETL Carbon Sequestration Atlas[12] as potentially available storage in oil and gas reservoirs. These numbers are not comparable as the CO_2 stored in this report is determined analytically by a stream tube predictive model and represents the amount of CO2 sequestered in active pursuit of enhanced oil recovery. Storage only occurs in oil reservoirs which screen as being acceptable candidates for EOR. The maximum CO_2 injected in this process is defined as part of the technology being modeled. In Contrast, the number in the Sequestration Atlas is the result of a calculation in which all producible oil and gas originally found in geologic formations is replaced with an equivalent volume of CO_2.

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[12] “2008 Carbon Sequestration Atlas of the United States and Canada, Second Addition”, U.S. Dept. of Energy, Office of Fossil Energy, National Energy Technology Laboratory, 2008 http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlasII

Table 12 - Technical CO2 Storage Capacity using "Next Generation" CO2-EOR: Totals from Extrapolating Advanced Resources' Database to National Level (Eleven Basins/Areas)

Basin/Area	Gross Technical CO_2 Storage Capacity (Million Metric Tons)	CO_2 Already Scheduled to be Injected (Million Metric Tons)	Net Technical Storage Capacity for CO_2 (Million Metric Tons)
1. Lower-48 Onshore	24,647	660	23,987
2. Offshore GOM	1,742	-	1,742
3. Alaska	2,668	-	2,668
Total	**29,058**	**660**	**28,398**

Please see Appendix, Table D-12 for expanded version.

7.3 THE MARKET FOR CO_2

A subset of the technical CO_2 storage capacity offered by domestic oil fields is the volume of CO_2 that oil producers may be willing to purchase (and then store) for use in economically feasible CO_2-EOR projects. Table 13 and Table 14 tabulate the economic CO_2 demand for EOR as a function of oil price and CO_2 cost. Table 14 also subtracts out CO_2 from natural and anthropogenic sources and the CO_2 demand in Alaska to provide a net demand for CO_2 in the lower 48 states.

Table 13 – Economically Feasible Market for CO2 for "Next Generation" CO2-EOR: Base case* (Eleven Basins/Areas)

Basin/Area	Gross Market for CO_2 (Million Metric Tons)		CO_2 Already or Scheduled to be Injected (Million Metric Tons)	Net New Market for CO_2 (Million Metric Tons)	
	"Best Practices"	"Next Generation"		"Best Practices"	"Next Generation"
1. Lower-48 Onshore	9,061	10,752	660	8,401	9,912
2. Offshore GOM	200	200	-	200	200
3. Alaska	440	1,399	-	440	1,399
Total	9,701	12,171	660	9,041	11,511

*Base Case: Oil price of $70 per barrel; CO_2 cost of $45 per metric ton.

Please see Appendix D, Table D-13 for expanded version.

In the Base Case, net economic CO_2 demand is approximately 9.0 billion metric tons, equal to the amount of CO_2 that could be captured from 48 GWs of coal fired power plant capacity over 30 years[13]. (A major portion of this CO_2 demand is from lower-48 oil fields and equals 7.7 billion metric tons, Table 14.) As such, "next generation" technology creates a significantly larger demand for CO_2 than created by "best practice" CO_2-EOR technologies, where the net CO_2 demand was 6.5 gigatons, equal to the emissions from 35 GWs of coal-fired power capacity (in the "best practices" case, Lower-48 oil field CO_2 demand is 6.2 gigatons).

The demand for CO_2 from the EOR market can be an important source of revenue for the initial set of power plants that invest in CO_2 capture.

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[13] Assuming 85% capacity factor and 34% efficiency. A 1GW powerplant with these specifications would generate 223 billion kWh of electricity in thirty years (1GW * 85% * 8.76 (conversion between GW and billion kWh/year) * 30 years). With a CO_2 intensity of .94 million tons CO_2/kWh (thermodynamic equivalency based on efficiency of power plant and emissions profile of coal) and 90% capture, this power plant could supply 188 million tons of CO_2 in 30 years.

Table 14 - Economically Feasible Market Demand for CO_2 by CO_2-EOR: Alternative Cases (Eleven Basins/Areas)

Basin/Area	Base Case	Lower Oil Price Case*	Higher Oil Price Case**
	($70/Bbl) (Million Metric Tons)	($50/Bbl) (Million Metric Tons)	($100/Bbl) (Million Metric Tons)
1. Lower-48 Onshore	9,912	8,475	11,318
2. Offshore GOM	200	150	660
3. Alaska	1,399	466	2,020
Total Demand	11,511	9,091	13,998
Less: Natural CO_2 Sources	2,280	2,280	2,280
Less: Industrial Sources	220	220	220
Total US	9,011	6,591	11,498
Total Lower-48***	7,672	6,235	9,078

*Lower Oil Price Case: Oil price of $50 per barrel; CO_2 cost of $35 per metric ton.

**Higher Oil Price Case: Oil price of $100 per barrel; CO_2 costs of $60 per metric ton.

*** 260 MMmt of Natural CO_2 Supplies were from Alaska.

Please see Appendix D, Table D-14 for expanded version.

Table 15 tabulates the volumes of natural and anthropogenic CO_2 currently being used for CO_2-EOR, with the coal gasification plant in North Dakota serving as the “poster child” for linking capture of industrial CO_2 emissions with CO_2-EOR.

Table 15 - Existing CO2 Supplies – volumes of CO2 injected for EOR

State/ Province (storage location)	Source Type (location)	CO_2 Supply MMcfd**	
		Natural	Anthropogenic
Texas-Utah-New Mexico-Oklahoma	Geologic (Colorado-New Mexico) Gas Processing (Texas)	1,820	105
Colorado-Wyoming	Gas Processing (Wyoming)	-	230
Mississippi	Geologic (Mississippi)	700	-
Michigan	Ammonia Plant (Michigan)	-	15
Oklahoma	Fertilizer Plant (Oklahoma)	-	30
Saskatchewan	Coal Gasification (North Dakota)	-	150
TOTAL		2,520	530

* Source: Advanced Resources, 2009

** MMcfd of CO_2 can be converted to million metric tons per year by first multiplying by 365 (days per year) and then dividing by $18.9 * 10^3$ (Mcf per metric ton).

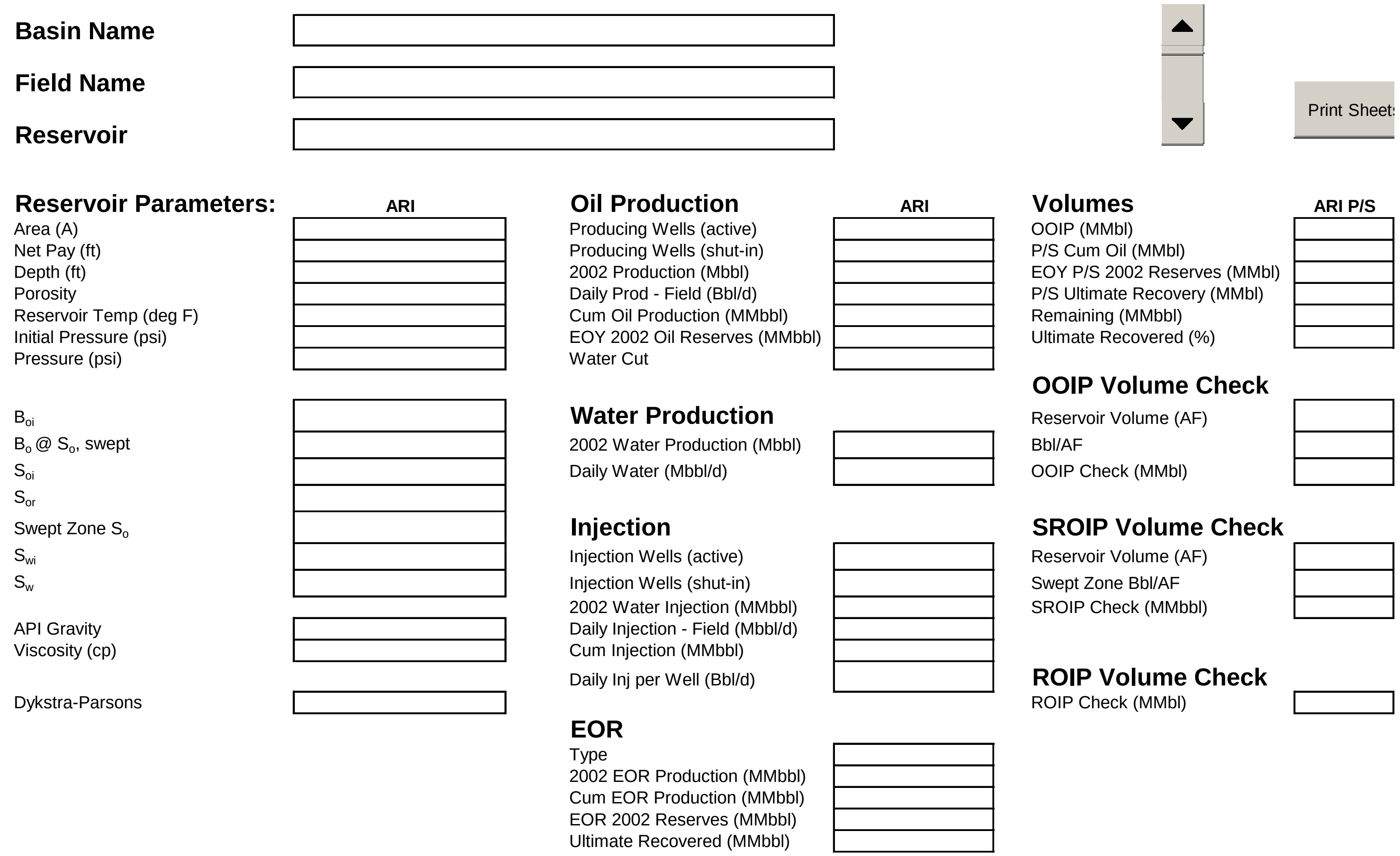
APPENDIX A: STUDY METHODOLOGY

A.1 OVERVIEW A six part methodology was used to assess the CO_2 storage and EOR potential of domestic oil reservoirs. The six steps were: (1) assembling the Major Oil Reservoirs Database; (2) calculating the minimum miscibility pressure; (3) screening reservoirs for CO_2-EOR; (4) calculating oil recovery; (5) assembling the cost and economic model; and, (6) performing economic and sensitivity analyses.

A.2 ASSEMBLING THE MAJOR OIL RESERVOIRS DATA BASE The study started with the database used in the previous set of “basins studies”. The study updated and augmented this database by incorporating the internally prepared Appalachian Basin Database and by making other improvements to this database.

Table A-1 illustrates the oil reservoir data recording format developed by the study. The data format readily integrates with the input data required by the CO_2-EOR screening and oil recovery models, discussed below. Overall, the Major Oil Reservoirs Database contains 2,012 reservoirs, accounting for 74% of the oil expected to be ultimately produced in the U.S. by primary and secondary oil recovery processes.

Considerable effort was required to construct an up-to-date, volumetrically consistent database that contained all of the essential data, formats and interfaces to enable the study to: (1) develop an accurate estimate of the size of the original and remaining oil in-place; (2) reliably screen the reservoirs as to their amenability for miscible and immiscible CO_2-EOR; and, (3) provide the *CO_2-PROPHET* Model the essential input data for calculating CO_2 injection requirements and oil recovery.



Basin Name

Field Name

Reservoir

Reservoir Parameters:	ARI
Area (A)	
Net Pay (ft)	
Depth (ft)	
Porosity	
Reservoir Temp (deg F)	
Initial Pressure (psi)	
Pressure (psi)	
B_{oi}	
B_o @ S_o, swept	
S_{oi}	
S_{or}	
Swept Zone S_o	
S_{wi}	
S_w	
API Gravity	
Viscosity (cp)	
Dykstra-Parsons	

Oil Production	ARI
Producing Wells (active)	
Producing Wells (shut-in)	
2002 Production (Mbbl)	
Daily Prod - Field (Bbl/d)	
Cum Oil Production (MMbbl)	
EOY 2002 Oil Reserves (MMbbl)	
Water Cut	

Water Production	
2002 Water Production (Mbbl)	
Daily Water (Mbbl/d)	

Injection	
Injection Wells (active)	
Injection Wells (shut-in)	
2002 Water Injection (MMbbl)	
Daily Injection - Field (Mbbl/d)	
Cum Injection (MMbbl)	
Daily Inj per Well (Bbl/d)	

EOR	
Type	
2002 EOR Production (MMbbl)	
Cum EOR Production (MMbbl)	
EOR 2002 Reserves (MMbbl)	
Ultimate Recovered (MMbbl)	

Volumes	ARI P/S
OOIP (MMbl)	
P/S Cum Oil (MMbl)	
EOY P/S 2002 Reserves (MMbl)	
P/S Ultimate Recovery (MMbl)	
Remaining (MMbbl)	
Ultimate Recovered (%)	

OOIP Volume Check	
Reservoir Volume (AF)	
Bbl/AF	
OOIP Check (MMbl)	

SROIP Volume Check	
Reservoir Volume (AF)	
Swept Zone Bbl/AF	
SROIP Check (MMbbl)	

ROIP Volume Check	
ROIP Check (MMbl)	

Table A-1 - Reservoir Data Format: Major Oil Reservoirs Database

A.3 CALCULATING MINIMUM MISCIBILITY PRESSURE The miscibility of a reservoir's oil with injected CO_2 is a function of pressure, temperature and the composition of the reservoir's oil. The study's approach to estimating whether a reservoir's oil will be miscible with CO_2, given fixed temperature and oil composition, was to determine whether the reservoir would hold sufficient pressure to attain miscibility. Where oil composition data was missing, a correlation was used for translating the reservoir's oil gravity to oil composition.

To determine the minimum miscibility pressure (MMP) for any given reservoir, the study used the Cronquist correlation, Figure A-1. This formulation determines MMP based on reservoir temperature and the molecular weight (MW) of the pentanes and heavier fractions of the reservoir oil, without considering the mole percent of methane. (Most Gulf Coast oil reservoirs have produced the bulk of their methane during primary and secondary recovery.) The Cronquist correlation is set forth below:

$$\text{MMP} = 15.988 * T^{(0.744206+0.0011038*\text{MW C5+})}$$

Where: T is Temperature in °F, and MW C5+ is the molecular weight of pentanes and heavier fractions in the reservoir's oil.

The temperature of the reservoir was 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 obtained from the database or was estimated from a correlative plot of MW C5+ and oil gravity, shown in Figure A-2.

The next step was calculating the minimum miscibility pressure (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. If the minimum miscibility pressure was below the maximum injection pressure, the reservoir was classified as a miscible flood candidate. Oil reservoirs that did not screen positively for miscible CO_2-EOR were selected for consideration by immiscible CO_2-EOR.

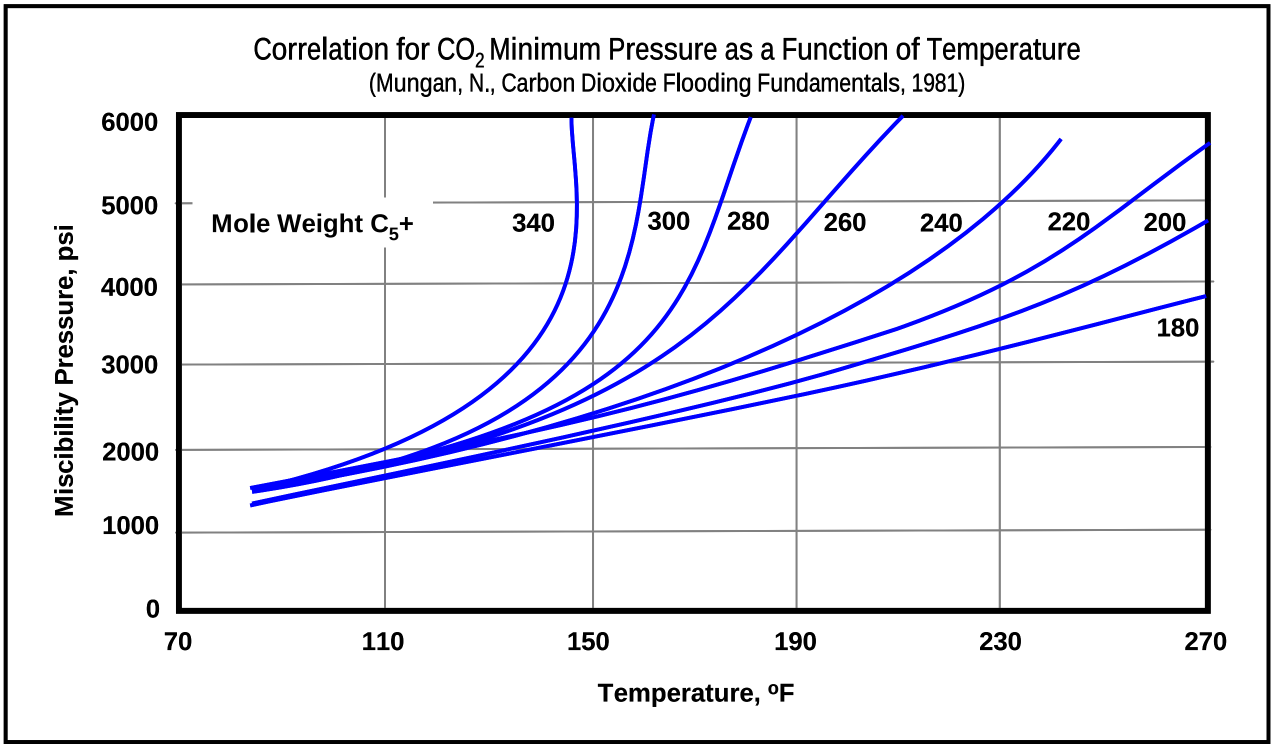


Figure A-1 - Estimating CO_2 Minimum Miscibility Pressure

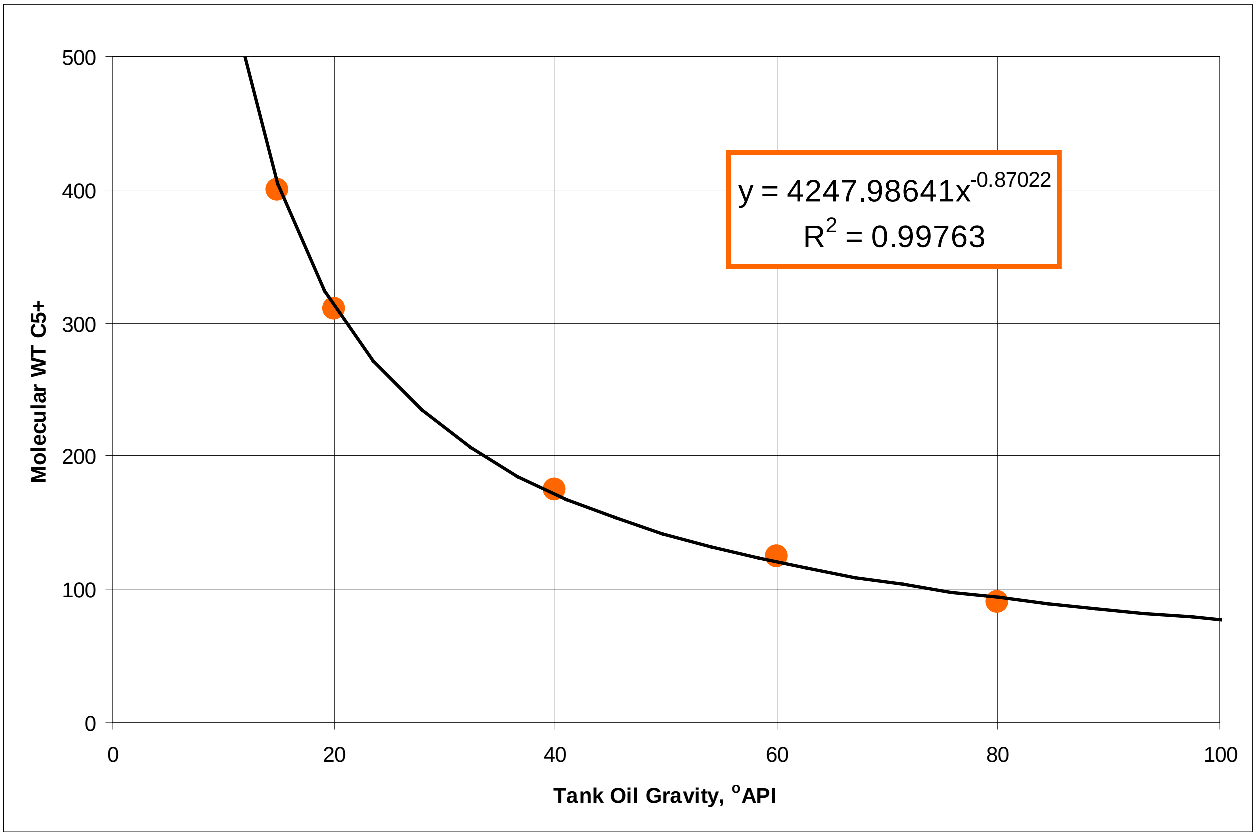


Figure A-2 - Correlation of MW C5+ to Tank Oil Gravity

A.4 SCREENING RESERVOIRS FOR CO_2-EOR The database was screened for reservoirs that would be applicable for CO_2-EOR. Five prominent screening criteria were used to identify favorable reservoirs. These were: reservoir depth, oil gravity, reservoir pressure, reservoir temperature, and oil composition. These values were used to establish the minimum miscibility pressure for conducting miscible CO_2-EOR and for selecting reservoirs that would be amenable to this oil recovery process. Reservoirs not meeting the miscibility pressure standard were considered for immiscible CO_2-EOR.

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 of 17.5 ^{o}API was used to ensure the reservoir's oil had sufficient mobility, without requiring thermal injection.

A.5 CALCULATING OIL RECOVERY 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.)

Even with these improvements, 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.

A.6 ASSEMBLING THE COST MODEL A detailed, up-to-date CO_2-EOR Cost Model was developed by the study. The model includes costs for: (1) drilling new wells or reworking existing wells; (2) providing surface equipment for new wells; (3) installing the CO_2 recycle plant; (4) constructing a CO_2 spur-line from the main CO_2 trunkline to the oil field; and, (5) various miscellaneous costs.

The cost model also accounts for normal well operation and maintenance (O&M), for lifting costs of the produced fluids, and for costs of capturing, separating and reinjecting the produced CO_2. A variety of CO_2 purchase and reinjection costs options are available to the model user.

A.7 CONSTRUCTING AN ECONOMICS MODEL The economic model used by the study is an industry standard cash flow model that can be run on either a pattern or a field-wide basis. The economic model accounts for royalties, severance and ad valorem taxes, as well as any oil gravity and market location discounts (or premiums) from the "marker" oil price. A variety of oil prices are available to the model user.

APPENDIX B: ECONOMICS OF "NEXT GENERATION" CO_2-EOR TECHNOLOGY

B1. BASIC ECONOMIC MODEL. The economic model used in the analysis draws on the previously published economic models in the above mentioned "Storing CO_2 with Enhanced Oil Recovery" report. This basic economic model was modified to incorporate the additional costs associated with applying "next generation" CO_2-EOR technology in the field. The specific process and cost changes incorporated into the "next generation" CO_2-EOR version of the economic model are set forth below.

- **Oil and Water Production.** The oil production and CO_2 injection rates from applying "next generation" CO_2-EOR technology and the increase in the life of the CO_2-EOR project were estimated using *PROPHET2*. This involved assembling the reservoir properties for each of the reservoirs and then placing them into the *PROPHET2* stream-tube reservoir model to calculate CO_2 injection and oil and water production versus time.

- **CO_2 Injection.** The costs of injecting CO_2 were estimated using the same pricing formula assumed in the "Storing CO_2 with Enhanced Oil recovery" report of $45/mt CO_2 ($2.38/Mcf) @ $70/BBl Oil. The cost of recycled CO_2 (per Mcf) is 1 percent of oil price ($/Bbl).

  The capital investment costs for the CO_2 recycle plant were scaled to reflect the higher peak recycled CO_2 volumes in the "next generation" technology cases.

- **Additional Costs for Applying "Next Generation" CO_2-EOR Technology.** Four additional modifications were made to the cost and economics model to account for the costs of applying each of the "next generation" CO_2-EOR technologies, as set forth below:
  - *Increased Volume of CO_2 Injection.* The costs for purchasing, recycling, and injecting 1.5 HCPV of CO_2 are included in the "next generation" economic model.

  - *Innovative Flood Design and Well Placement.* The "next generation" economic model assumes that one additional new vertical production well would be added to each pattern. This well would produce from previously bypassed or poorly contacted portions of the reservoir. (The model assumes that each pattern already has or drills one production and one injection well.)

  - *Viscosity Enhancement.* The economic model assumes that the water injection costs for the CO_2-WAG process are increased by $0.25 per barrel of injected water to account for the addition of viscosity enhancers and other mobility control agents or actions.

  - *Flood Performance Diagnostics and Control.* The economic model assumes that the "next generation" CO_2-EOR project is supported by a fully staffed technical team (geologists, reservoir engineers, and economic analysts), uses a series of observation wells and downhole sensors to monitor the progress of the flood, and conducts periodic 4-D seismic plus pressure and residual oil saturation measurements to "optimize, manage, and control" the CO_2 flood. The "next generation" economic model adds 10 percent to the initial capital investment and

10 percent to the annual operating costs of the CO_2 flood to cover these extra costs.

APPENDIX C: CO_2-EOR USING GRAVITY STABLE CO_2 INJECTION AND OIL DISPLACEMENT

A large Gulf Coast oil reservoir with 329 million barrels (OOIP) in the main pay zone has been selected as the "case study" for this analysis. The gravity stable CO_2-EOR flood design is shown in Figure C-1, below. The starting conditions of the sample Gulf Coast reservoir are as follows:

- The primary/secondary oil recovery in this oil reservoir is favorable at 148 million barrels, equal to 45% of OOIP. Even with this favorable oil recovery using conventional practices, 181 million barrels is left behind ("stranded").
- In addition, another 100 million barrels of essentially immobile residual oil exists in the underlying 130 feet of the transition/residual oil zone (TZ/ROZ).
- Below the TZ/ROZ is an underlying saline reservoir with 195 feet of thickness, holding considerable CO_2 storage capacity.

Based on the above, the theoretical CO2 storage capacity of this oil reservoir and structural closure is 2,710 Bcf (143 million metric tons). One purpose of the gravity stable design is to utilize as much of the safe and secure CO2 storage capacity as possible.

Assuming there is value to storing CO_2 with gravity stable CO_2-EOR and sequestration technology, much more CO_2 can be stored relative to "next generation" technology and more oil becomes potentially recoverable:

- CO_2 storage increases by 3 to 4 fold to 109 million tons with 76% of the theoretical storage capacity utilized.
- Oil recovery is increased by two fold, to 180 million barrels, containing 72 million tons of CO_2 (when combusted). Importantly, 109 billion tons of CO_2 is injected and stored during the EOR flood. As such. more CO_2 is stored than contained in the produced oil, making the produced oil "green."

Table C-1 - Case Study: Integration of "Next Generation" CO2 Storage with EOR

	"Next Generation"	"Second Generation" CO_2-EOR & Storage		
	CO_2-EOR	CO_2-EOR	Seq.	Total
CO_2 Storage (tonnes)	32	76	33	109
Storage Capacity Utilization	22%	53%	23%	76%
Oil Recovery (barrels)	92	180	-	180
% Carbon Neutral ("Green Oil")	87%	106%	-	151%

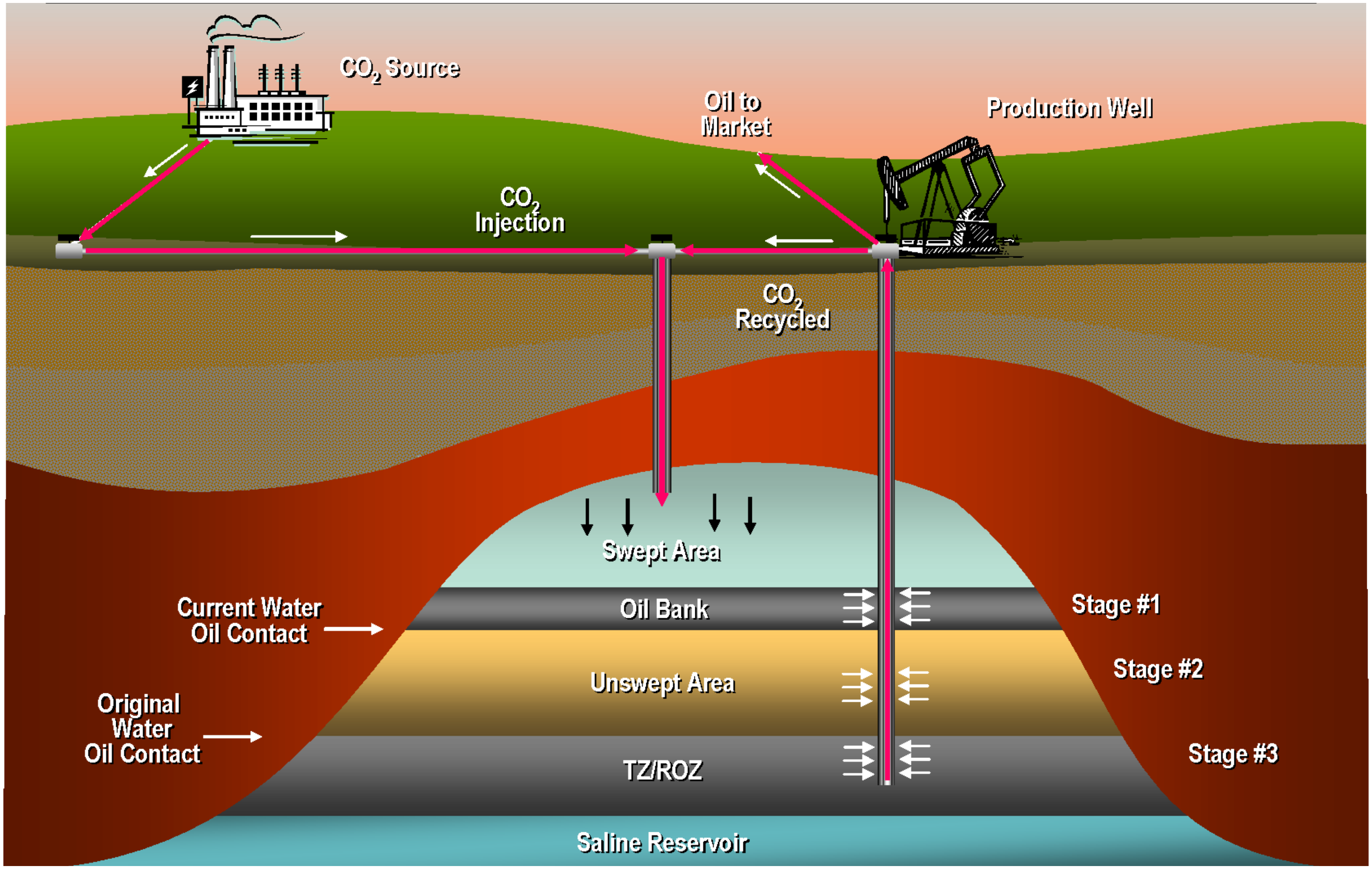


Figure C-1 - Illustration of Gravity Stable Integration of CO2 Storage and EOR

APPENDIX D: DETAILED REGION-LEVEL TABLES

Table D-3 - National In-Place, Conventionally Recoverable and "Stranded" Crude Oil Resources

Basin/Area	OOIP (Billion Barrels)	Conventionally Recoverable		ROIP "Stranded"
		(Billion Barrels)	% of OOIP	(Billion Barrels)
1. Alaska	50.7	21.9	43%	28.8
2. California	83.3	26.0	31%	57.3
3. Gulf Coast (AL, FL, MS, LA)	44.4	16.9	38%	27.5
4. Mid-Continent (OK, AR, KS, NE)	89.6	24.0	27%	65.6
5. Illinois/Michigan	17.8	6.3	35%	11.5
6. Permian (W TX, NM)	95.4	33.7	35%	61.7
7. Rockies (CO,UT,WY)	33.6	11.0	33%	22.6
8. Texas, East/Central	109.0	35.4	32%	73.6
9. Williston (MT, ND, SD)	13.2	3.8	29%	9.4
10. Offshore GOM	46.1	20.9	45%	25.2
11. Appalachia (WV, OH, KY, PA)	14.0	3.9	28%	10.1
Total	597.1	203.8	34%	393.3

Table D-4 – Comparison of National and Database Domestic Oil Resource Base

Basin/Area	National Data OOIP* (Billion Barrels)	Major Oil Reservoirs Database OOIP* (Billion Barrels)	Database Coverage (%)
1. Alaska	50.7	50.7	100
2. California	83.3	75.2	90
3. Gulf Coast (AL, FL, MS, LA)	44.4	26.4	60
4. Mid-Continent (OK, AR, KS, NE)	89.6	53.1	59
5. Illinois/Michigan	17.8	12.0	67
6. Permian (W TX, NM)	95.4	72.4	76
7. Rockies (CO,UT,WY)	33.6	23.7	70
8. Texas, East/Central	109.0	67.4	62
9. Williston (MT, ND, SD)	13.2	9.4	71
10. Offshore GOM	46.1	46.1	100
11. Appalachia (WV, OH, KY, PA)	14.0	10.6	76
Total	597.1	447.0	75

*Original Oil In-Place

Table D-5 – Major Oil Reservoirs Screened as Favorable for CO2-EOR

Basin/Area	Major Oil Reservoirs Database	
	# of Total Reservoirs	# Favorable for CO_2-EOR
1. Alaska	42	33
2. California	187	89
3. Gulf Coast (AL,FL, MS, LA)	290	159
4. Mid-Continent (OK, AR, KS, NE)	246	108
5. Illinois/Michigan	172	111
6. Permian (W TX, NM)	228	191
7. Rockies (CO,UT,WY)	189	99
8. Texas, East/Central	213	161
9. Williston (MT, ND, SD)	95	54
10. Offshore GOM	4,493	642
11. Appalachia (WV, OH, KY, PA)	188	68
Total	6,344	1,715

Table D-9 – Technically Recoverable Resources from Applying "Next Generation" CO2-EOR: Totals from Extrapolating Advanced Resources' Database to National Level

Basin/Area	OOIP (Billion Barrels)	OOIP Favorable for CO_2-EOR (Billion Barrels)	Technically Recoverable (Billion Barrels)	
			"Best Practices" Technology	"Next Generation" Technology
1. Alaska	50.7	42.5	8.6	12.7
2. California	83.3	34.8	6.0	9.7
3. Gulf Coast (AL, FL, MS, LA)	44.4	34.1	7.1	9.9
4. Mid-Continent (OK, AR, KS, NE)	89.6	49.1	10.5	17.8
5. Illinois/Michigan	17.8	10.3	1.4	2.5
6. Permian (W TX, NM)	95.4	83.5	18.4	27.2
7. Rockies (CO,UT,WY)	33.6	29.0	4.1	8.6
8. Texas, East/Central	109.0	84.8	17.4	27.3
9. Williston (MT, ND, SD)	13.2	10.2	2.5	3.9
10. Offshore GOM	46.1	29.6	5.7	5.7
11. Appalachia (WV, OH, KY, PA)	14.0	9.7	1.6	2.6
Total	597.1	417.5	83.4	127.9

Table D-10 – Economically Recoverable Resources from Applying "Next Generation" CO2-EOR: National Totals at Base Case Economics*

Basin/Area	Technically Recoverable (Billion Barrels)	CO_2-EOR Currently Underway (Billion Barrels)	Incremental Technically Recoverable (Billion Barrels)	Incremental Economically Recoverable** (Billion Barrels)
1. Alaska	12.7	Note 1	12.7	7.8
2. California	9.7		9.7	7.7
3. Gulf Coast (AL, FL, MS, LA)	9.9		9.9	2.5
4. Mid-Continent (OK, AR, KS, NE)	17.8	-0.1	17.7	9.1
5. Illinois/Michigan	2.5		.5	1.1
6. Permian (W TX, NM)	27.2	-1.9	25.3	12.1
7. Rockies (CO,UT,WY)	8.6	-0.3	8.3	4.3
8. Texas, East/Central	27.3		27.3	11.8
9. Williston (MT, ND, SD)	3.9		3.9	0.7
10. Offshore GOM	5.7		5.7	0.7
11. Appalachia (WV, OH, KY, PA)	2.6		2.6	0.1
Total	**127.9**	**-2.3**	**125.6**	**57.9**

Note 1: The hydrocarbon miscible floods underway on the North Slope of Alaska contain 24% CO_2 in the injected gas.

*Incremental technically recoverable resources after subtracting 2.3 billion barrels already produced or proven with CO_2-EOR.

**Base Case Economics use an oil price of $70 per barrel (constant, real) and a CO_2 cost of $45 per metric ton ($2.38/Mcf), delivered at pressure to the field. Economically recoverable resources form the database of large oil reservoirs are not further extrapolated to national totals. We assume that all the reservoirs with economic potential are already included in this database.

Table D-11 – Economically Recoverable Resource from "Next Generation" CO2-EOR: National Totals at Alternative Economic Cases

Basin/Area	Base Case	Lower Oil Price Case	Higher Oil Price Cases
	($70/Bbl) (Billion Barrels)	($50/Bbl) (Billion Barrels)	($100/Bbl) (Billion Barrels)
1. Alaska	7.8	3.0	10.3
2. California	7.7	7.4	8.2
3. Gulf Coast (AL, FL, MS, LA)	2.5	1.7	3.1
4. Mid-Continent (OK, AR, KS, NE)	9.1	8.5	9.2
5. Illinois/Michigan	1.1	0.5	1.3
6. Permian (W TX, NM)	12.1	9.5	13.9
7. Rockies (CO,UT,WY)	4.3	3.6	4.8
8. Texas, East/Central	11.8	11.2	13.3
9. Williston (MT, ND, SD)	0.7	0.7	0.9
10. Offshore GOM	0.7	0.5	2.4
11. Appalachia (WV, OH, KY, PA)	0.1	0.1	0.3
Total Demand	57.9	46.6	67.6

Table D-12 – Technical CO2 Storage Capacity using "Next Generation" CO2-EOR: Totals from Extrapolating Advanced Resources' Database to National Level (Eleven Basins/Areas)

Basin/Area	Gross Technical CO_2 Storage Capacity (Million Metric Tons)	CO_2 Already or Scheduled to be Injected (Million Metric Tons)	Net Technical Storage Capacity for CO_2 (Million Metric Tons)
1. Alaska	2,668	-	2,668
2. California	1,963	-	1,963
3. Gulf Coast (AL, FL, MS, LA)	2,665	-	2,665
4. Mid-Continent (OK, AR, KS, NE)	3,709	20	3,689
5. Illinois/Michigan	551	-	551
6. Permian (W TX, NM)	7,016	570	6,446
7. Rockies (CO,UT,WY)	1,768	70	1,698
8. Texas, East/Central	5,513	-	5,513
9. Williston (MT, ND, SD)	849	-	849
10. Offshore GOM	1,742	-	1,742
11. Appalachia (WV, OH, KY, PA)	614	-	614
Total	29,058	660	28,398

Table D-13 – Economically Feasible Market for CO2 for "Next Generation" CO2-EOR: Base Case* (Eleven Basins/Areas)

Basin/Area	Gross Market for CO_2 (Million Metric Tons)		CO_2 Already or Scheduled to be Injected (Million Metric Tons)	Net New Market for CO_2 (Million Metric Tons)	
	"Best Practices"	"Next Generation"		"Best Practices"	"Next Generation"
1. Alaska	440	1,399	-	440	1,400
2. California	1,355	1,427	-	1,355	1,427
3. Gulf Coast (AL, FL, MS, LA)	576	612	-	576	612
4. Mid-Continent (OK, AR, KS, NE)	1,337	1,802	20	1,317	1,782
5. Illinois/Michigan	194	245	-	194	245
6. Permian (W TX, NM)	2,939	3,358	570	2,369	2,788
7. Rockies (CO,UT,WY)	546	866	70	476	796
8. Texas, East/Central	1,975	2,090	-	1,975	2,090
9. Williston (MT, ND, SD)	124	148	-	124	148
10. Offshore GOM	200	200	-	200	200
11. Appalachia (WV, OH, KY, PA)	14	25	-	14	25
Total	9,701	12,171	660	9,041	11,511

*Base Case: Oil price of \$70 per barrel; CO_2 cost of \$45 per metric ton.

Table D-14 – Economically Feasible Market Demand for CO2 by CO2-EOR: Alternative Cases (Eleven Basins/Areas)

Basin/Area	Base Case	Lower Oil Price Case*	Higher Oil Price Case**
	($70/Bbl) (Million Metric Tons)	($50/Bbl) (Million Metric Tons)	($100/Bbl) (Million Metric Tons)
1. Alaska	1,400	466	2,023
2. California	1,427	1,355	1,574
3. Gulf Coast (AL, FL, MS, LA)	612	404	789
4. Mid-Continent (OK, AR, KS, NE)	1,782	1,576	1,712
5. Illinois/Michigan	245	92	273
6. Permian (W TX, NM)	2,788	2,279	3,340
7. Rockies (CO,UT,WY)	796	689	905
8. Texas, East/Central	2,090	1,929	2,481
9. Williston (MT, ND, SD)	148	139	176
10. Offshore GOM	200	150	657
11. Appalachia (WV, OH, KY, PA)	25	13	66
Total Demand	11,511	9,091	13,998
Less: Natural CO2 Sources	2,280	2,280	2,280
Less: Industrial Sources	220	220	220
Total US	9,011	6,591	11,498
Total Lower 48***	7,642	6,235	9,078

*Lower Oil Price Case: Oil price of $50 per barrel; CO2 cost of $35 per metric ton.

**High Oil Price Case: Oil price of $100 per barrel; CO2 costs of $60 per metric ton.

*** 260 MMmt of Natural CO2 Supplies were from Alaska.