Storing CO2 with Enhanced Oil Recovery

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Storing CO_2 with Enhanced Oil Recovery

1.0 Introduction

CO2 enhanced oil recovery (CO2-EOR) offers the potential for storing significant volumes of carbon dioxide emissions while increasing domestic oil production. Four notable benefits would accrue from integrating CO2 storage and enhanced oil recovery:

- First, CO2-EOR provides a large, "value added" market for sale of CO2 emissions captured from new coal-fueled power plants. The size of this market is on the order of 7,500 million metric tons between now and 2030. Sales of captured CO2 emissions would help defray some of the costs of installing and operating carbon capture and storage (CCS) technology. These CO2 sales would support "early market entry" of up to 49 (one GW size) installations of CCS technology in the coal-fueled power sector;

- Second, storing CO2 with EOR helps bypass two of today's most serious barriers to using geological storage of CO2 - - establishing mineral (pore space) rights and assigning long-term liability for the injected CO2;

- Third, the oil produced with injection of captured CO2 emissions is 70% "carbon-free", after accounting for the difference between the carbon content in the incremental oil produced by EOR and the volume of CO2 stored in the reservoir . With "next generation" CO2 storage technology and a value for storing CO2, the oil produced by EOR could be 100+% "carbon free";

- Fourth, the 39 to 48 billion barrels of economically recoverable domestic oil economically recoverable from storing CO2 with EOR would help displace imports, supporting a path toward energy independence. It could also help build pipeline infrastructure subsequently usable for storing CO2 in saline formations.

The purpose of this report, which updates and adds to a previously issued series of “basin studies”, is to examine and further quantify the benefits of integrating CO2 storage with enhanced oil recovery. The report also updates the size of the CO2 market available from EOR and how this market could support “early market entry” of CCS technology in the coal-fueled electric power sector.

2.0 Background

2.1. Key Feature of This New Report

In 2004 and 2005, Advanced Resources International, with sponsorship by the U.S. Department of Energy's Office of Fossil Energy, issued a series of ten "basin reports".* These reports examined the domestic CO2 storage and oil recovery potential offered by expanded development and application of CO2-EOR technology. This report entitled, "Storing CO2 with Enhanced Oil Recovery", provides a major update to this past set of data and information. For example, the initial chapter of the report which serves to quantify the size of the CO2 market offered by EOR, contains the following new features:

- A significant number, nearly 500, new oil reservoirs have been added to the data base, including oil reservoirs in the Appalachian Basin. The assessment now includes 2,012 oil reservoirs accounting for nearly three-quarters of the U.S. oil resource base in 27 states, Figure 1. These new oil reservoirs were made available for this study from Advanced Resources proprietary data base;

- Improvements and updates have been made to the well spacing and CO2 injection portions of the model. Oil field cost data have been updated and indexed to year 2006-2007. 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/CO2 cost relationship have been incorporated into the economic analyses, as presented later in this report.

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* The Advanced Resources completed series of ten "basin studies" were the first to comprehensively address CO2 storage capacity from combining CO2 storage and CO2-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.

The later chapters of this report examine how much of the CO_2 emissions captured by the power and industrial sectors could be sold to the EOR industry and how the sale of these captured CO_2 emissions would support the “early market entry” of new coal-fueled power plants equipped with CO_2 capture technologies.

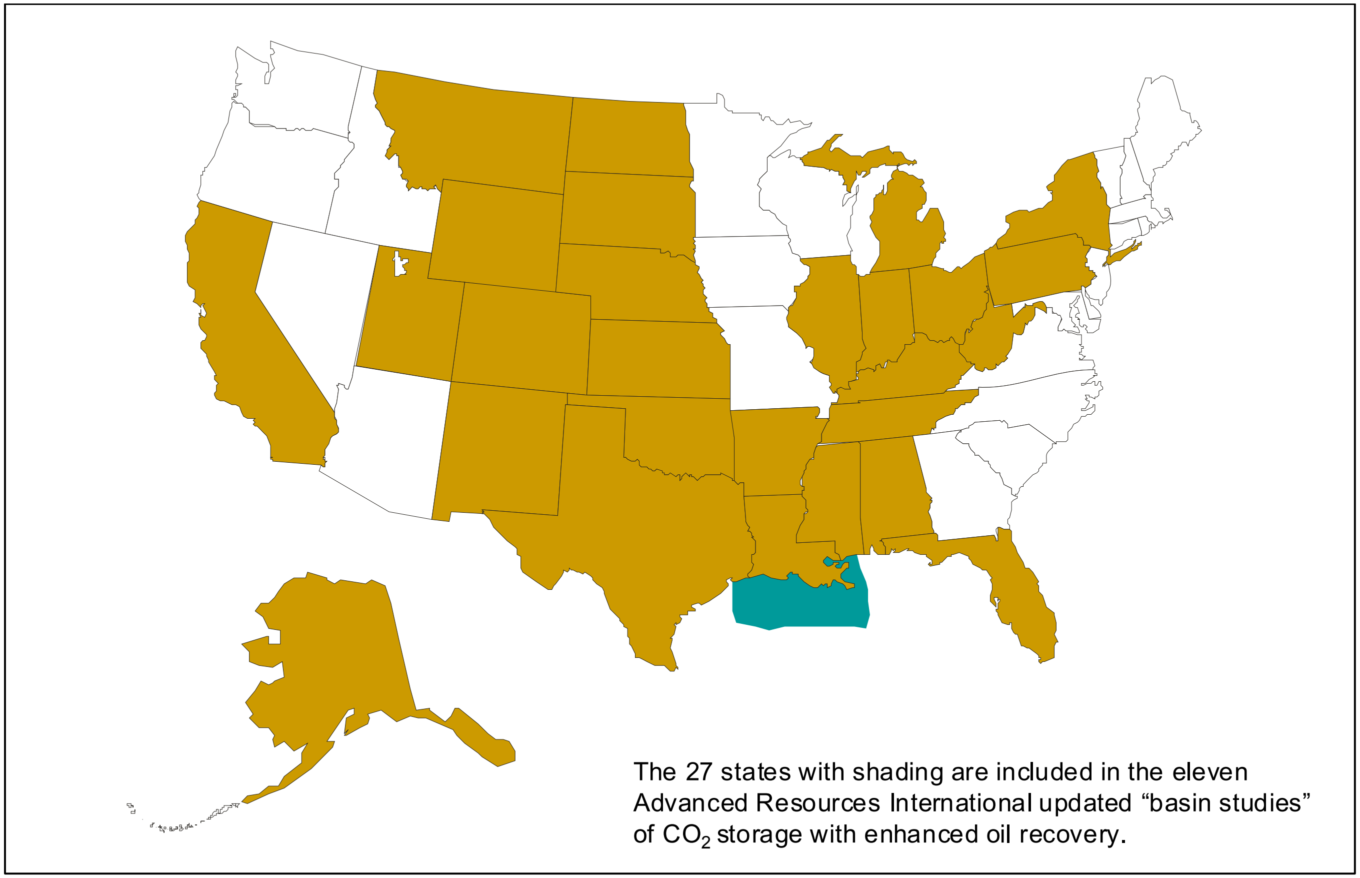

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Figure 1. U.S. Basins/Regions Studied For Future CO2 Storage and Enhanced Oil Recovery

2.2. Addressing Current Misconceptions Surrounding Storing CO2 with EOR

Various analysts and studies have discussed the potential for storing CO2 with enhanced oil recovery but have noted (incorrectly) that this option is quite small or is counter productive to reducing CO2 emissions. For example, the "IPCC Special Report on Carbon Dioxide Capture and Storage", while recognizing that depleted oil fields could provide an attractive, early option for storing CO2 (particularly with CO2-EOR), concluded that oil fields would provide only a relatively small volume of CO2 storage capacity. The report states:

> *"Enhanced oil recovery operations have the lowest capacity of all forms of CO2 geologic storage, estimated globally at 61 to 123 billion tons of CO2 . . . it is important to note that CO2 EOR, as practiced today, is not engineered to maximize CO2 storage. In fact, it is optimized to maximize revenues from oil production, which in many cases requires minimizing the amount of CO2 retained in the reservoir. In the future, if storing CO2 has an economic value, co-optimizing CO2 storage and EOR may increase capacity estimates."*

In a similar vein, the website Climate Progress contains the headline - - "Rule Four of Offsets: No Enhanced Oil Recovery". The website continues by stating:

> *"Capturing CO2 and injecting it into a well to squeeze more oil out of the ground is not real carbon sequestration. . . .CO2 used for enhanced oil recovery (EOR) does not reduce net carbon emissions and should not be sold to the public as a carbon offset."*

Finally, the ERS/IEA Report: "Carbon Dioxide Capture and Storage in the Clean Development Mechanism (CDM)" sets forth two assumptions that shape the report's view of storing CO2 with EOR:

- As CO2-EOR projects reach the end of their life, greater volumes of CO2 will be produced (and emitted); and

- CO2-EOR projects will result in increased carbon emissions from incremental oil production above a No Further Activity (NFA) baseline.

The ERS/IEA report continues by stating that, to be acceptable, a CO2-EOR project would need to provide a full carbon balance across the whole life cycle of the project, including emissions from combustion of the incremental oil produced. The ERS/IEA report recommends that for acceptance by CDM, CO2-EOR would need to demonstrate net emission reductions.

One of the additional purposes of this new report is to address, and hopefully dispel, some of the misconceptions that have arisen around the topic of storing CO2 with enhanced oil recovery by showing that: (1) for the U.S. (and by extension for the world), the CO2 storage capacity offered by CO2-EOR is large, and when innovatively engineered, can be larger still; (2) essentially all the purchased CO2 is reinjected and thus stored in the original (or an adjacent) oil reservoir; and (3) the incremental oil produced is 70% “carbon free”, creating net emission reductions - - and thus additionality - - by displacing conventionally produced oil imports that are 0% “carbon free” or corn-based ethanol, that is only 10 to 15% “carbon free” (and a net contributor of CO2 emissions when coal is used as the process fuel).

2.3. Report Outline

The report begins with a summary presentation of three topics central to establishing the market for CO2 offered by EOR - - what is the size and nature of the domestic oil resource base; how much of this resource base is applicable to and can be recovered with CO2-EOR; and, what portion of this technically recoverable resource would be economic at alternative oil prices and CO2 costs?

The report then examines the market opportunity for selling captured CO2 emissions to the EOR industry and storing these emissions in oil reservoirs using CO2-EOR, giving particular attention to the capture and productive use of CO2 emissions from the nation’s large and growing fleet of coal-fueled power plants.

A series of appendices provide supporting data and technical information for the analytical results discussed in the main report. Additional discussion of key topics such as the oil recovery and cost models and the data bases used in the analyses are available in the previously published set of ten "basin studies" and thus are not repeated in this updated report. The previously prepared "basin study" reports can be accessed at http://www.fe.doe.gov/programs/oilgas/publications/.

3.0 Evaluating the Market for Captured CO_2 Emissions Offered by EOR

The size and value of the market for captured CO_2 emissions offered by enhanced oil recovery rests on three pillars: (1) the size and nature of the domestic crude oil resource base, particularly the large portion of this resource base unrecoverable with existing primary and secondary oil recovery methods; (2) the ability of CO_2-EOR to recovery a portion of this currently unrecoverable ("stranded") domestic oil, while efficiently storing CO_2; and (3) the impact of alternative oil prices and CO_2 costs on the volume of oil that could be economically produced. These three topics are examined, in brief, in this section of the report.

3.1. 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 the Major Oil Reservoirs Data Base; (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.

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

3.2. The Domestic Oil Resource Base

The U.S. has a large, established oil resource base, on the order of 596 billion barrels originally in-place. About one-third of this resource base, nearly 196 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 400 billion barrels of "technically stranded" oil, Figure 2[*].

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[*] 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 recently issued National Petroleum Council report "Hard Truths, Facing the Hard Truths about Energy" July, 2007, http://www.npchardtruthsreport.org/

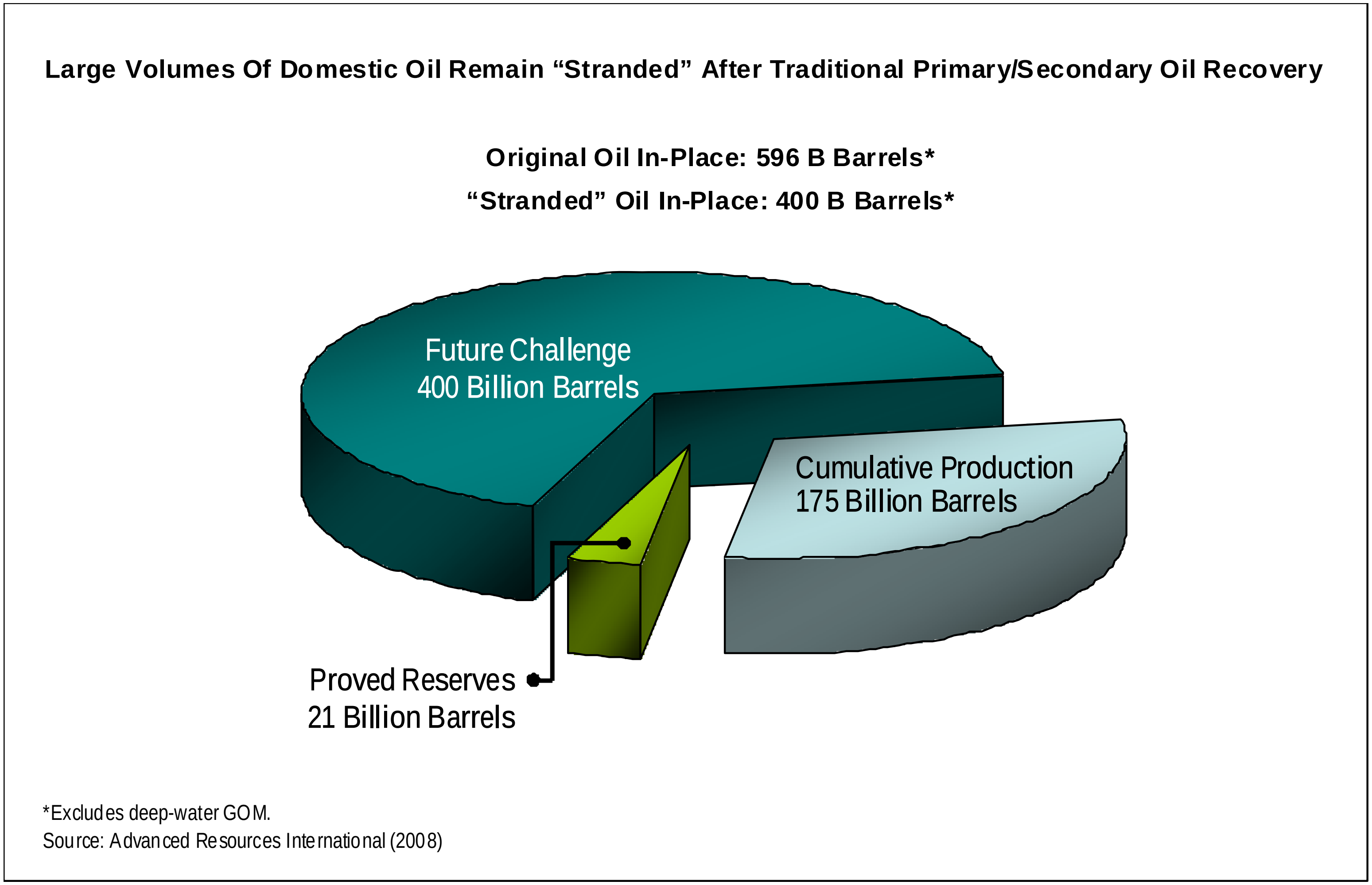

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Figure 2. The Domestic Oil Resource Base

Table 1 provides a tabulation of the national in-place, conventionally recoverable and "stranded" oil in the eleven "basins" addressed by this study. The table shows that 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.

The Advanced Resources' Major Oil Reservoirs Data Base of 2,012 distinct oil reservoirs contains 74% (437.8 billion barrels of OOIP out of the national total of 595.7 billion barrels of OOIP), of the domestic oil resource, Table 2.

The data base coverage for individual basins/areas ranges from 59% for the Mid-Continent to 97% for Alaska. As such, the Major Oil Reservoir Data Base provides a robust foundation for estimating the national oil recovery potential from CO2-EOR.

Not all of the domestic oil resource is technically amenable to CO2-EOR. Favorable reservoir properties for CO2-EOR include sufficiently deep formations with lighter (higher gravity) oil favorable for miscible CO2-EOR. A portion of the shallower oil reservoirs with heavier (lower gravity) oil may be amenable to immiscible CO2-EOR.

Table 3 provides a basin/area level tabulation of the 2,012 reservoirs in the Major Oil Reservoirs Data Base, showing that only 1,111 reservoirs (containing 319 billion barrels of OOIP) screened as being amenable to miscible and immiscible CO2-EOR. More than half of the oil reservoirs in California, particularly the shallower heavy oil fields, are screened as unfavorable for CO2-EOR while the great bulk (over 80%) of the geologically favorable oil reservoirs in the Permian Basin are screened as favorable for CO2-EOR.

Table 1. National In-Place, Conventionally Recoverable and "Stranded" Crude Oil Resources

Basin/Area	OOIP* (Billion Barrels)	Conventionally Recoverable (Billion Barrels)	ROIP** "Stranded" (Billion Barrels)
1. Alaska	67.3	22.3	45.0
2. California	83.3	26.0	57.3
3. Gulf Coast (AL, FL, MS, LA)	44.4	16.9	27.5
4. Mid-Continent (OK, AR, KS, NE)	89.6	24.0	65.6
5. Illinois/Michigan	17.8	6.3	11.5
6. Permian (W TX, NM)	95.4	33.7	61.7
7. Rockies (CO,UT,WY)	33.6	11.0	22.6
8. Texas, East/Central	109.0	35.4	73.6
9. Williston (MT, ND, SD)	13.2	3.8	9.4
10. Louisiana Offshore	28.1	12.4	15.7
11. Appalachia (WV, OH, KY, PA)	14.0	3.9	10.1
Total	595.7	195.7	400.0

*Original Oil in Place, in all reservoirs in basin/area;
** Remaining Oil in Place, in all reservoirs in basin/area.
Source: Advanced Resources Int'l, 2008.

Table 2. Comparison of National and Data Base Domestic Oil Resource Base

Basin/Area	National OOIP* (Billion Barrels)	Data Base OOIP* (Billion Barrels)	Data Base Coverage (%)
1. Alaska	67.3	65.4	97
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. Louisiana Offshore	28.1	22.2	79
11. Appalachia (WV, OH, KY, PA)	14.0	10.6	76
Total	595.7	437.8	74

*Original Oil In-Place, in all reservoirs in basin/area;
Source: Advanced Resources Int'l, 2008.

Table 3. Major Oil Reservoirs Screened as Favorable for CO2-EOR

Basin/Area	Major Oil Reservoirs Data Base	
	# of Total Reservoirs	# Favorable For CO2-EOR
1. Alaska	42	32
2. California	187	86
3. Gulf Coast (AL,FL, MS, LA)	298	155
4. Mid-Continent (OK, AR, KS, NE)	246	102
5. Illinois/Michigan	172	72
6. Permian (W TX, NM)	228	190
7. Rockies (CO,UT,WY)	187	92
8. Texas, East/Central	213	161
9. Williston (MT, ND, SD)	95	54
10. Louisiana Offshore	156	99
11. Appalachia (WV, OH, KY, PA)	188	68
Total	2,012	1,111

3.3. Technically Recoverable Oil Resources Using CO2-EOR

3.3.1. Using CO2-EOR to Recovery "Stranded" Oil

Numerous scientific as well as practical reasons account for the large volume of "stranded" oil, unrecoverable with primary and secondary methods. These 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.

Injection of CO2 helps lower the oil viscosity and trapping forces in the reservoir. Additional well drilling and pattern realignment for the EOR project helps contact bypassed and occluded oil. These actions enable a portion of this "stranded oil" to become mobile, connected to a wellbore and thus recoverable.

Miscible CO2-EOR is a multiple contact process involving interactions between the injected CO2 and the reservoir's oil. During this multiple contact process, CO2 vaporizes the lighter oil fractions into the injected CO2 phase and CO2 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 CO2-EOR is to remobilize and dramatically reduce the after-waterflooding residual oil saturation in the reservoir's pore space. Figure 3 provides a one-dimensional schematic showing the various fluid phases existing in the reservoir and the dynamics of the CO2 miscible process.

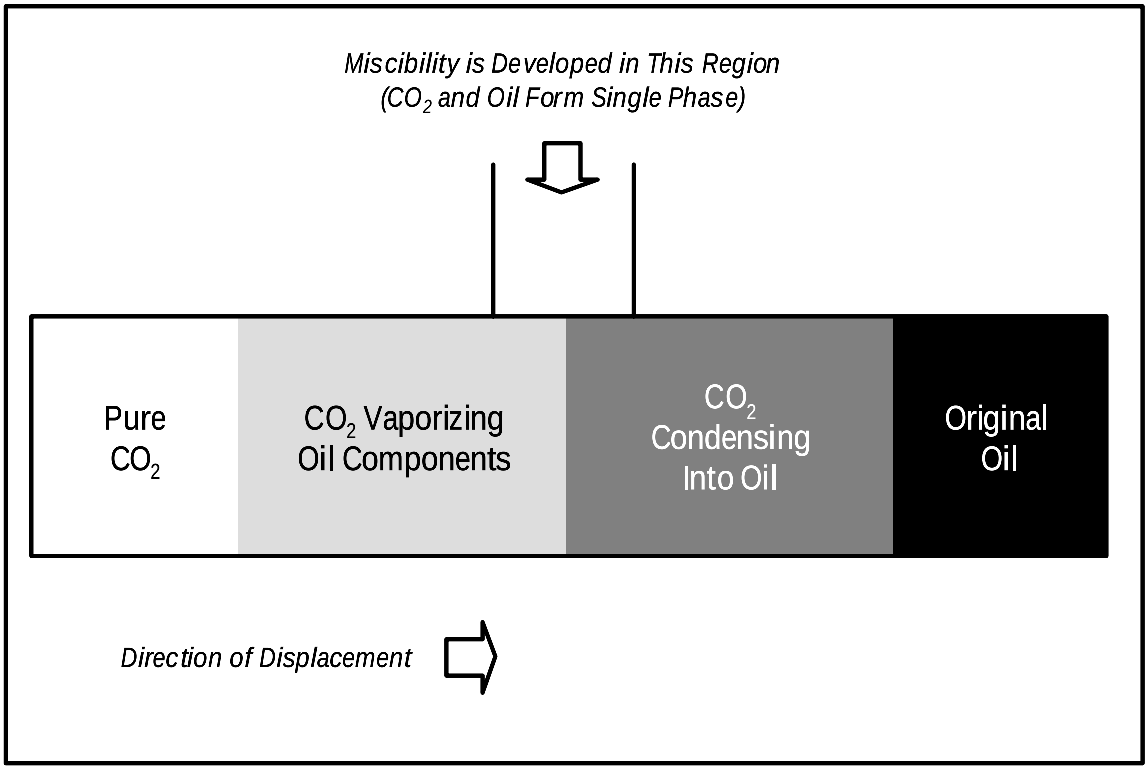

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Figure 3. One-Dimensional Schematic Showing the CO2 Miscible Process.

3.3.2. Current CO2-EOR Activity and Production

According to the latest tabulation of CO2-EOR activity in the U.S., the 2006 EOR Survey published by the Oil and Gas Journal, approximately 237 thousand barrels per day of incremental domestic oil is being produced by 86 CO2-EOR projects, distributed broadly across the U.S.

Figure 4 provides the location of the currently active 86 CO2-EOR projects, noting their CO2 supply sources. Figure 5 tracks the steady growth in CO2-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 CO2-EOR is still being produced from the Permian Basin.

Given the significant number of new and expanded CO2-EOR projects launched in 2006 and 2007, we anticipate that the next EOR Survey, due to be published in the spring of 2008, will show substantial increases in domestic CO2-EOR activity and oil production.

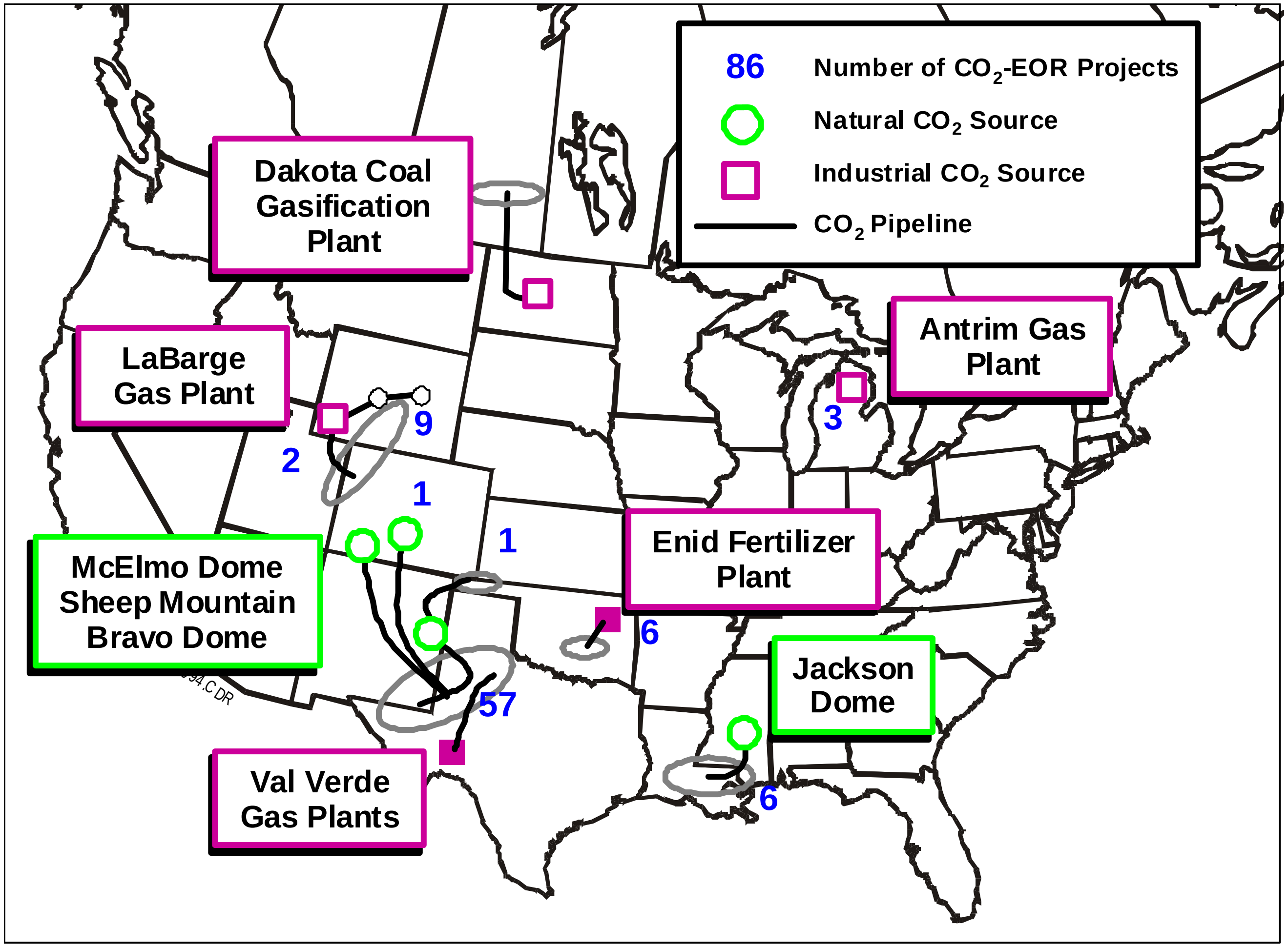

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Figure 4. U.S. CO2-EOR Activity

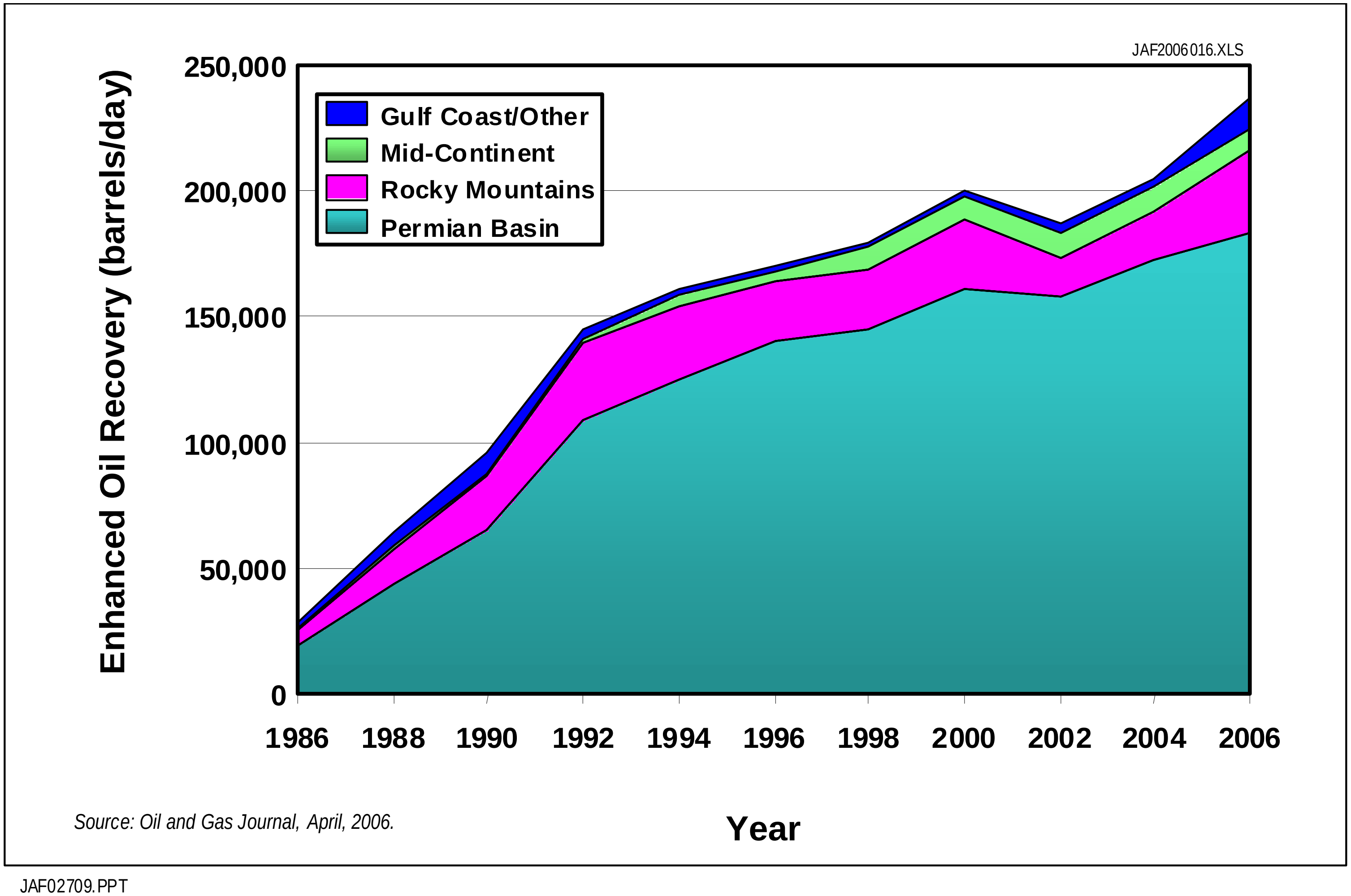


Figure 5. Growth of CO2-EOR Production in the U.S.

3.3.3. 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 much 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 "state-of-the-art" CO_2-EOR projects have steadily improved.

Two key assumptions underlie the oil recovery performance calculated for this study by the ARI/PROPHET model (see Appendix A) for "state-of-the-art" CO_2-EOR:

- First is the injection of much larger volumes of CO_2 (1 HCPV), rather than the smaller (0.4 HCPV) volumes used in the past;

- Second are the rigorous CO_2-EOR monitoring, management and, where required, remediation activities that help assure that the larger volumes of injected CO_2 contact more of the reservoir's pore volume and residual oil rather than merely channel through high permeability streaks in the reservoir.

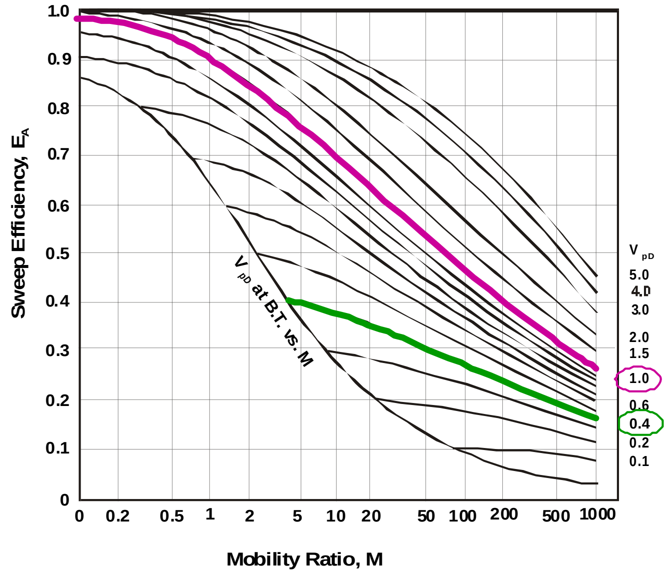
In addition to these two central assumptions, the calculated oil recovery in the ARI/PROPHET model assumes appropriate well spacing (including the drilling of new infill wells), the use of a tapered WAG process, the maintenance of miscibility pressure throughout the reservoir, and the reinjection of CO_2 produced with oil.

Figures 6A and 6B provide the scientific and practical basis for using larger volumes of CO_2 injection. Figure 7 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.

Figure 8, 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").

Petroleum engineering science confirms that using increased volumes of CO_2 leads to increased reservoir sweep efficiency.

Sweep Efficiency in Miscible Flooding



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

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

Oil Recovery Efficiency vs. CO_2 Injection

Injected CO_2 (HCPV)	Sweep Efficiency (RPV)	Incremental Sweep Efficiency (%)
0.40	0.345	
0.60	0.440	+28%
0.80	0.515	+49%
1.00	0.570	+65%

Source: After Claridge (April 1972) (Mobility Ratio of 25)

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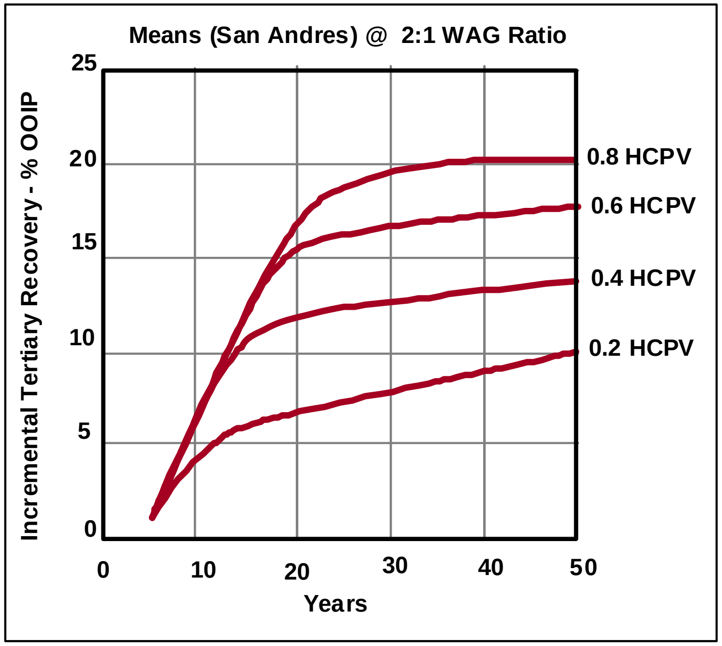
Figure 6A. Science Behind Volume of CO2 Injection and Oil Recovery Efficiency: General Theory

Effect of Solvent Bank Size on 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.

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Figure 6B. Science Behind Volume of CO2 Injection and Oil Recovery Efficiency: Actual Practice

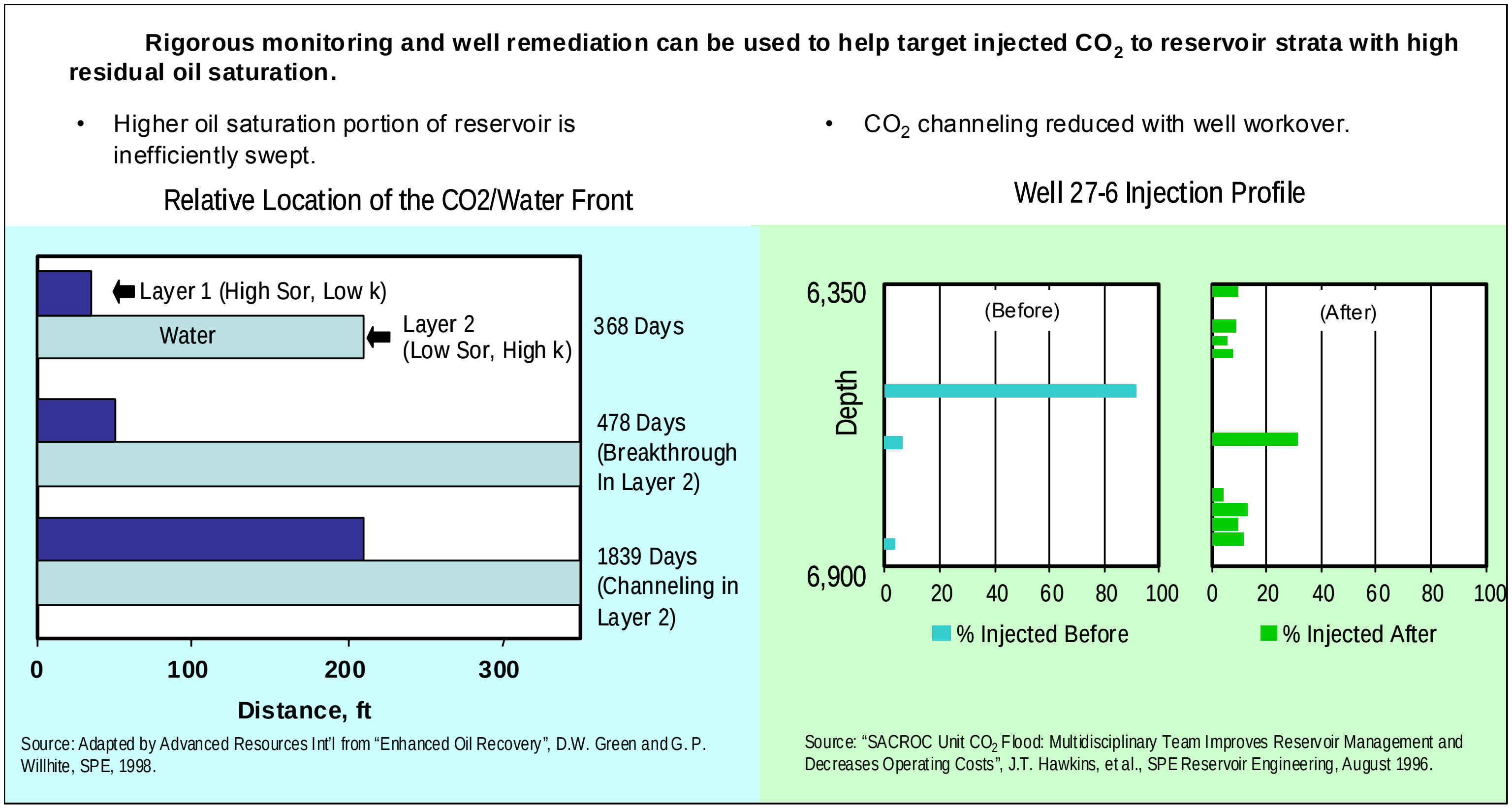

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Figure 7. Overcoming the Effects of Geologic Complexity on CO2-EOR Performance

Eastern Denver Unit (Wasson Oil Field) CO_2-EOR Project	Started
Start of CO_2 injection in EDU with 40% slug size	1984
EDU WAG & start off CO_2 injection in WAC, FIA, B8 FIA	1989
Non performing FIA patterns stopped (~20% slug size)	1992
EDU 40% to 60% CO_2 slug size increase approved	1994
EDU 60% to 80% CO_2 slug size increase approved	1996
EDU 80% to 100% 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 8. Evolution of "Industry Standard" for Volume CO2 Injection ("Slug Size")

The oil recovery calculations contained in this study rely on these “state-of-the-art” practices. As such, the calculated oil recovery efficiencies expected from CO2-EOR are somewhat higher than have been achieved by older CO2-EOR projects. However, they are representative of the “best practices” being employed by technically sophisticated operations and current CO2-EOR projects.

3.3.4. Technically Recoverable Resources

Our reservoir-by-reservoir assessment of the 1,111 large oil reservoirs amenable to CO2-EOR shows that a significant volume, 64 billion barrels, of domestic oil may be recoverable with state-of-the-art application of CO2-EOR. Extrapolating the data base to national-level results indicates that 87.1 billion barrels of domestic oil may become recoverable by applying “state-of-the-art” CO2-EOR, Table 4.

Subtracting the 2.3 billion barrels of oil that has already been produced and proven by CO2-EOR (as of 2004), the application of CO2-EOR would add 84.8 billion barrels of incremental domestic oil supplies, Table 5. For perspective, the current domestic proved crude oil reserves are 21 billion barrels, as of the end of 2006.

Not surprisingly, the Permian Basin of West Texas and New Mexico tops the list with its world class size, favorable geology and carbonate reservoirs. In addition, significant technically recoverable resource potential also exists in East and Central Texas, Alaska and the Mid-Continent as well as the Gulf Coast, California and the Louisiana offshore.

Table 4. Technically Recoverable Resources from Applying "State-of-the-Art" CO2-EOR: Data Base and National Totals

Basin/Area	DATA BASE			NATIONAL	
	OOIP (Billion Barrels)	OOIP Favorable for CO2-EOR (Billion Barrels)	Technically Recoverable (Billion Barrels)	OOIP (Billion Barrels)	Technically Recoverable (Billion Barrels)
1. Alaska	65.4	64.5	12.0	67.3	12.4
2. California	75.2	31.6	5.7	83.3	6.3
3. Gulf Coast (AL, FL, MS, LA)	26.4	20.2	4.2	44.4	7.0
4. Mid-Continent (OK, AR, KS, NE)	53.1	28	6.4	89.6	10.7
5. Illinois/Michigan	12.0	4.6	0.8	17.8	1.2
6. Permian (W TX, NM)	72.4	63.1	13.5	95.4	17.8
7. Rockies (CO,UT,WY)	23.7	18.0	2.9	33.6	4.2
8. Texas, East/Central	67.4	52.4	10.9	109.0	17.6
9. Williston (MT, ND, SD)	9.4	7.2	1.8	13.2	2.5
10. Louisiana Offshore	22.2	22.1	4.6	28.1	5.8
11. Appalachia (WV, OH, KY, PA)	10.6	7.4	1.2	14.0	1.6
Total	437.8	319.1	64	595.7	87.1

Table 5. Technically Recoverable Resources from Applying "State-of-the-Art" CO_2-EOR: National Totals

	Technically Recoverable (Billion Barrels)	Existing CO2-EOR Production/ Reserves	Incremental Technically Recoverable (Billion Barrels)
1. Alaska	12.4	-	12.4
2. California	6.3	-	6.3
3. Gulf Coast (AL, FL, MS, LA)	7	*	7
4. Mid-Continent (OK, AR, KS, NE)	10.7	-0.1	10.6
5. Illinois/Michigan	1.2	-	1.2
6. Permian (W TX, NM)	17.8	-1.9	15.9
7. Rockies (CO,UT,WY)	4.2	-0.3	3.9
8. Texas, East/Central	17.6	-	17.6
9. Williston (MT, ND, SD)	2.5	-	2.5
10. Louisiana Offshore	5.8	-	5.8
11. Appalachia (WV, OH, KY, PA)	1.6	-	1.6
Total	87.1	-2.3	84.8

3.4. Economically Recoverable Resources

3.4.1. Perspective on CO2-EOR Economics

Conducting a CO2-EOR project is capital intensive and costly, entailing the drilling and/or reworking of wells, installing a CO2 recycle plant, and constructing CO2 gathering and transportation pipelines. However, in general, the single largest cost of the project is the purchase of CO2. As such, operators strive to optimize and reduce its purchase and injection, where possible.

The recent increases in domestic oil prices have significantly improved the economics outlook for conducting CO2-EOR. However, oil field costs have also increased sharply, reducing the economic margin essential for justifying this still emerging (and to many operators, novel and risky) oil recovery option.

The cost and economic margins of a representative, reasonably favorable CO2-EOR project are provided, for illustrative purposes, in Table 6 below. (The reader is advised that considerable reservoir-specific variations exist around the cost and economic margin values shown in the illustrative CO2-EOR project.)

Table 6. Illustrative Costs and Economics of a CO2-EOR Project

Assumed Oil Price ($/B)		$70
Less:		
	▪ Gravity/Basis Differentials, Royalties and Production Taxes	($15)
Net Wellhead Revenues ($/B)		$55
Less:		
	▪ Capital Costs	($5 to $10)
	▪ CO2 Costs (@ $2/Mcf for purchase; $0.70/Mcf for recycle)	($15)
	▪ Well/Lease O&M	($10 to $15)
Economic Margin, Pre-Tax ($/B)		$15 to $25

Given the significant front-end investment in wells, recycle equipment and purchase of CO2 (equivalent to $20 to $25 per barrel) and the time delay in reaching peak oil production, pre-tax economic margins on the order of the front-end investment will be required to achieve economically favorable rates of return. Oil reservoirs with higher capital cost requirements and less favorable CO2 to oil ratios would not achieve an economically justifiable return on investment, requiring advanced, more efficient CO2-EOR technology and/or credits for storing CO2.

3.4.2. Economically Recoverable Resources: Base Case

In the Base Case, 45 billion barrels of incremental oil become economically recoverable from applying CO2-EOR. The Base Case evaluates the CO2-EOR potential using an oil price of $70 per barrel (constant, real) and a CO2 cost of $45 per metric ton ($2.38 per Mcf) (delivered at pressure to the field, constant and real).

The $70 per barrel oil price is used as the project investment oil price, established using the average price of crude oil over the past three years, consistent with the investment oil price methodology used in NEMS.

Table 7 presents the basin-by-basin tabulation of economically recoverable resources from applying “state-of-the-art” CO2-EOR technology under Base Case economics.

3.4.3. Economically Recoverable Resources: Sensitivity Cases

To gain insights as to how changes in oil prices would influence the volumes of economically recoverable resources from applying CO2-EOR, the story examined one lower and two higher oil price cases (and their associated CO2 costs).

Table 8 presents the 45 billion barrels of domestic oil recovery potentially available from CO2-EOR at the Base Case oil price and CO2 cost. This increases to 47.9 to 48.3 billion barrels of higher ($90 to $100/B) oil prices and drops to 39.1 billion barrels at lower ($50/B) oil price.

Table 7. Economically Recoverable Resources from Applying "State-of-the-Art" CO2-EOR: National Totals at Base Case Economics*

Basin/Area	Incremental Technically Recoverable (Billion Barrels)	Incremental Economically Recoverable* (Billion Barrels)
1. Alaska	12.4	9.5
2. California	6.3	5.4
3. Gulf Coast (AL, FL, MS, LA)	7.0	2.2
4. Mid-Continent (OK, AR, KS, NE)	10.6	5.6
5. Illinois/Michigan	1.2	0.5
6. Permian (W TX, NM)	15.9	7.1
7. Rockies (CO,UT,WY)	3.9	1.9
8. Texas, East/Central	17.6	8.3
9. Williston (MT, ND, SD)	2.5	0.5
10. Louisiana Offshore	5.8	3.9
11. Appalachia (WV, OH, KY, PA)	1.6	0.1
Total	84.8	45.0

*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.

Table 8. Economically Recoverable Resources from Applying "State-of-the-Art" CO2-EOR: National Totals at Base Case and Alternative Oil Prices/CO2 Costs

Oil Prices ($ per Bbl)	CO2 Costs ($ per metric ton)			
	$35	$45*	$55	$60
Lower Prices				
$50	39.1 BBbls			
Base Case				
$70		45.0 BBbls		
Higher Prices				
$90			47.9 BBbls	
$100				48.3 BBbls

*A CO2 cost of $45 per metric ton (mt) is equal to $2.38 per Mcf

The estimates of economically recoverable domestic oil from applying CO2-EOR have been calculated using a minimum financial hurdle rate of 15% (real, before tax). Higher financial hurdle requirements, appropriate for rapidly installing "state-of-the-art" CO2-EOR technology in new basins and geologic settings, would reduce the above (Table 8) volumes of economically recoverable oil.

To examine the impact of a higher financial return on economically recoverable oil from CO2-EOR, the study applied a higher, 25% (real, before tax) financial hurdle rate. Under this higher hurdle rate, but still at Base Case oil prices and CO2 costs, the economically recoverable oil decreases to 38.2 billion barrels. While the higher financial hurdle rate eliminates a number of economically marginal CO2-EOR prospects, the great bulk of the fields remain economic, supporting the financial robustness of this oil recovery technology.

Figure 6 illustrates the volumes of domestic oil recovery potentially available from applying CO2-EOR technology at alternative oil prices and CO2 costs (using the assumed relationship in the economic model between oil prices and CO2 costs, shown in Table 8).

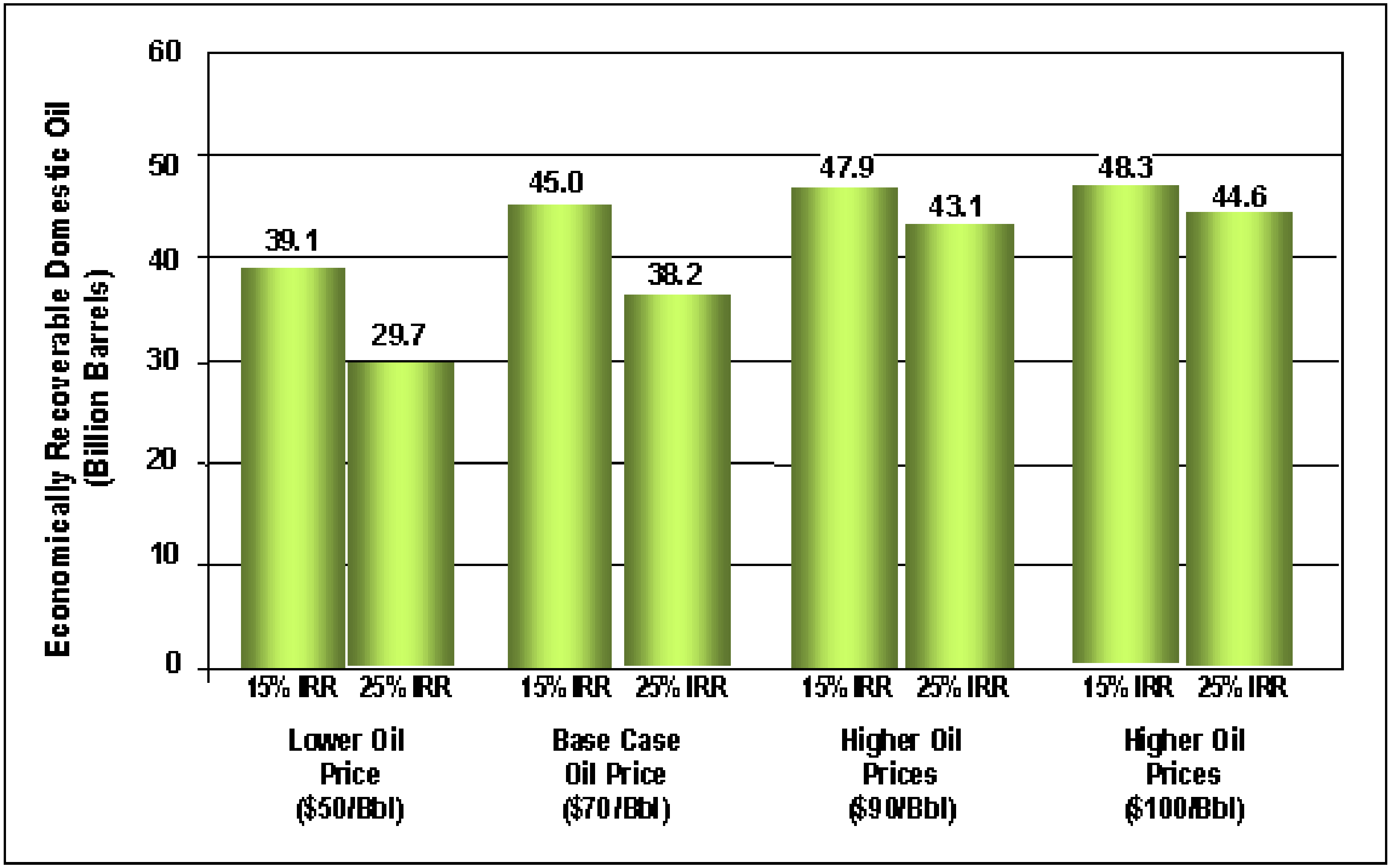

Figure 6. Economically Recoverable Domestic Oil Resources from Applying CO2-EOR

It is instructive to note that the oil recovery potential from CO_2-EOR remains significant, at 39.1 billion barrels, even under the lower, $50 per barrel, oil price case. Equally instructive to note is that higher oil prices, by themselves, will not unlock much more of the large 84.8 billion barrel technically recoverable oil resource available from state-of-the-art CO_2-EOR.

Advances in CO_2-EOR technology, as discussed in the previously published Advanced Resources/DOE report, “Evaluating The Potential For ‘Game Changer’ Improvements In Oil Recovery Efficiency From CO_2 Enhanced Oil Recovery”, will be required to make more of this technically recoverable resource economic.

4.0 The Market for Storing CO_2 with EOR

The primary purpose of this report is to establish how much CO_2, particularly CO_2 emissions captured by power plants, could be stored with enhanced oil recovery.

Chapter 3 established that 39 to 48 billion barrels of economic, incremental domestic oil could be produced by timely application of CO_2-EOR technology. This chapter draws on this oil recovery assessment to estimate how much CO_2, particularly CO_2 emissions captured from new coal-fueled power plants, would be required to produce this volume of economically recoverable oil, helping establish the market for captured CO_2 emissions.

4.1. The CO_2 Injection and Storage Process

The analysis shows that significant volumes of CO_2 (ranging from 10 to 13 billion metric tons depending on oil price) can be stored with enhanced oil recovery. The sequence for doing so is as follows:

- Initially, purchased CO_2, equal to 1 HCPV, is injected along with water for mobility control.

- As oil with CO_2 begins to be produced, the CO_2 is separated from the oil and reinjected. As the produced volumes of CO_2 increase, these larger volumes of CO_2 are 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 injected CO_2, or may inject a large (1 to 2 HCPV) slug of water to recover any remaining mobile oil and CO_2. This CO_2 may then be used in another portion of the reservoir or sold to another oil field.

In general, about 5 to 6 Mcf (0.26 to 0.32 metric tons (mt)) of purchased CO_2 per barrel of oil is used and stored as part of CO_2-EOR. This is augmented with 5 to 10 Mcf (0.26 mt to 0.52 mt) of recycled CO_2 during the latter stages of a CO_2-EOR process.

With incentives for storing CO_2 emissions and "next generation" CO_2 storage technology, considerably larger volumes of CO_2 could be stored. Additional discussion of "next generation" storage of CO_2 with EOR is provided in Appendix C.

4.2. Producing "Carbon Free" Domestic Oil

A typical barrel of crude oil contains 0.42 metric tons (mt) of releasable CO_2 (assuming that 3% of the produced and refined oil barrel remains as asphalt or coke). As such, netting the injection and storage of 0.26 to 0.32 mt of CO_2 emissions against the 0.42 mt of CO_2 in the produced oil, makes the domestic oil produced by CO_2-EOR about 70% (62% to 76%) "carbon free".

Two of the alternatives to using domestic oil produced by CO_2-EOR have a much less favorable net CO_2 balance. Imported oil is 0% "carbon free" (and results in additional CO_2 emissions from ocean transportation). Domestic corn ethanol is only 10 to 15% "carbon free", as significant volumes of energy are required for producing the corn feedstock and final product. When coal is used as the dominant energy source in ethanol production, corn-based ethanol drops to below 0% "carbon free" and becomes a contributor to the CO_2 emissions problem.

4.3. The Market for CO2

The market for CO_2 from power plant and industrial sources is substantial, depending on oil prices and CO_2 costs. (The CO_2 costs used in this study assume that the CO_2 is delivered to the oil field, at pressure.)

Table 9 provides a basin-by-basin tabulation of the volumes of CO_2 that would be required to produce the incremental volumes of economically recoverable domestic oil from applying CO_2-EOR in the Base Case ($70 per barrel oil price and $45 per metric ton CO_2 cost, delivered at pressure).

Table 10 provides the aggregate tabulation of the market for CO_2 for EOR as a function of the Base Case oil price and CO_2 cost, as well as for three alternative oil prices (assuming the relationships between oil prices and CO_2 costs established in the economic model). A review of the past history of CO_2 costs shows that they have been, in general, linked to oil prices.

Table 9. Economically Feasible Market for CO2 for CO2-EOR: Base Case*
(Eleven Basins/Areas)

Basin/Area	Gross Market for CO2 (million metric tons)	CO2 Already or Scheduled to be Injected (million metric tons)	Net New Market for CO2 (million metric tons)
1. Alaska	2,094	-	2,094
2. California	1,375	-	1,375
3. Gulf Coast (AL, FL, MS, LA)	652	**	652
4. Mid-Continent (OK, AR, KS, NE)	1,443	20	1,423
5. Illinois/Michigan	127	-	127
6. Permian (W TX, NM)	2,712	570	2,142
7. Rockies (CO,UT,WY)	574	74	500
8. Texas, East/Central	1,940	-	1,940
9. Williston (MT, ND, SD)	130	-	130
10. Louisiana Offshore	1,368	-	1,368
11. Appalachia (WV, OH, KY, PA)	36	-	36
Total	12,451	664	11,787

*Base Case: Oil price of $70 per barrel; CO2 cost of $45 per metric ton.

Table 10. 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 Cases**	
	($70/Bbl) (million metric tons)	($50/Bbl) (million metric tons)	($90/Bbl) (million metric tons)	($100/Bbl) (million metric tons)
1. Alaska	2,094	1,740	2,214	2,235
2. California	1,375	1,350	1,405	1,405
3. Gulf Coast (AL, FL, MS, LA)	652	465	805	823
4. Mid-Continent (OK, AR, KS, NE)	1,423	1,403	1,430	1,430
5. Illinois/Michigan	127	112	141	142
6. Permian (W TX, NM)	2,142	1,696	2,384	2,438
7. Rockies (CO,UT,WY)	500	436	512	514
8. Texas, East/Central	1,940	1,810	2,069	2,069
9. Williston (MT, ND, SD)	130	125	148	158
10. Louisiana Offshore	1,368	904	1,599	1,599
11. Appalachia (WV, OH, KY, PA)	36	9	46	46
Total	11,787	10,050	12,753	12,859

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

**Higher Oil Price Cases: Oil price of $90 and $100 per barrel; CO2 costs of $55 and $60 per metric ton.

4.4. Market Demand for CO_2: Power Plant Perspective

So far, the report has examined the market demand for CO2 from the perspective of the enhanced oil recovery industry. In this section of the report, we examine in more detail the market demand for CO2 from the power plant perspective, giving priority to market demand that might be met by capture and sale of CO2 emissions from the coal-fueled power sector.

The overall demand for CO2 by the CO2-EOR industry can be met by three potential sources of CO2 supply, namely:

- Natural CO2 supplies already found and defined in geological structures;
- Industrial, high concentration sources of CO2 that are currently being captured and used by the CO2-EOR industry; and
- The large volumes of power plant and industrial emissions of CO2 that may need to be captured and stored to meet CO2 management goals.

To better align the CO2 market demand information in this report with the power sector, the aggregate demand for CO2 of 11,787 million metric tons (223 Tcf) is presented according to the 14 EIA National Energy Modeling System (NEMS) Electricity Market Module (EMM),Table 11.

Excluding Alaska, which is not projected to build new coal-fueled power plants to any great extent, the demand for CO2 in the lower-48 states offered by the EOR industry is 9,694 million metric tons (183.4 Tcf), Table 11. Figure 7 provides the outline for the 14 EMM regions; Table 12 provides a simplified crosswalk between the 14 EMM regions and their included states.

<u>NEMS Regions</u>: CO2 supply and demand have been organized according to the 14 NEMS regions (13 lower-48 plus Alaska) in the Electricity Market Module

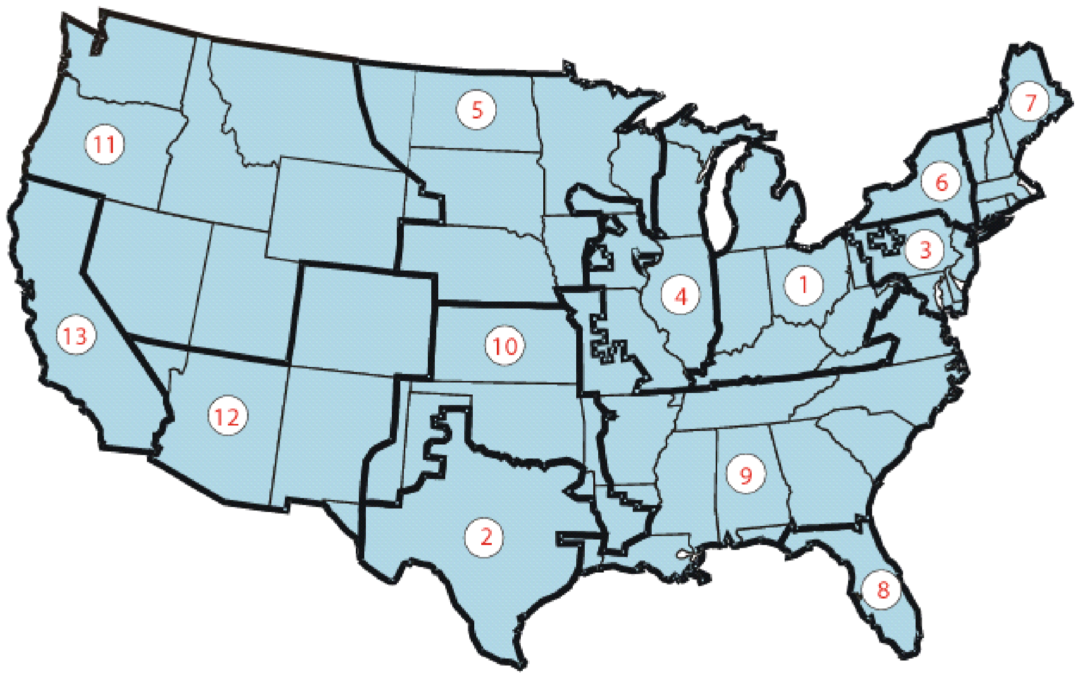

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Figure 7. Geographical Regions in the NEMS Electricity Market Module

Table 11. Economically Feasible Market Demand for CO2 by EOR: NEMS/EMM Power Generation Regions

NEMS EMM Region	Demand for CO2 for EOR	
	Million Metric Tons	Tcf
Region 1 - ECAR	58	1.1
Region 2 – ERCOT	3,820	72.3
Region 3 – PJM (MAAC)	4	0.1
Region 4 – MAIN	100	1.9
Region 5 – MAPP	109	2.1
Region 6 – NY ISO	-	-
Region 7 – NW ISO	-	-
Region 8 – Florida	9	0.2
Region 9 – SERC	2,116	40.0
Region 10 – SWPP	1,570	29.7
Region 11 – WECC/NWPP	411	7.8
Region 12 – WECC/RMPP	120	2.3
Region 13 – WECC/CA	1,376	26.0
Region 14 - Alaska	2,093	39.6
Total U.S.	**11,787**	**223.0**
Lower-48	**9,694**	**183.4**

*Base Case: $70/Bbl oil and $45/mt CO2.

Table 12. Simplified Crosswalk Between the EMM Regions and States

NEMS EMM Region	Associated State(s)
Region 1 - ECAR	Kentucky, West Virginia, Ohio, Indiana, Michigan
Region 2 – ERCOT	Texas
Region 3 – PJM (MAAC)	Pennsylvania, Delaware, New Jersey, Maryland
Region 4 – MAIN	Illinois, Missouri, Iowa, Wisconsin
Region 5 – MAPP	North Dakota, South Dakota, Nebraska, Minnesota
Region 6 – NY ISO	New York
Region 7 – NW ISO	Vermont, New Hampshire, Maine, Massachusetts, Connecticut, Rhode Island
Region 8 – Florida	Florida
Region 9 – SERC	Arkansas, Louisiana, Mississippi, Alabama, Tennessee, Georgia, South Carolina, North Carolina
Region 10 – SWPP	Oklahoma, Kansas and New Mexico
Region 11 – WECC/NWPP	Washington, Oregon, Idaho, Montana, Wyoming, Utah, Nevada
Region 12 – WECC/RMPP	New Mexico, Colorado, Arizona
Region 13 – WECC/CA	California
Region 14 - Alaska	Alaska

Table 13 sets forth the net remaining demand for CO_2 by the EOR industry of 7,470 million metric tons for the lower-48 states, after subtracting the 2,224 million metric tons (42.2 Tcf) of CO_2 available, in the next 30 years, from natural CO_2 deposits and high concentration industrial CO_2 sources (e.g., natural gas processing plants, fertilizer plants) already being captured and used for enhanced oil recovery.

Table 14 tabulates the existing sources of CO_2, both natural and anthropogenic, that are currently injected for EOR.

Table 13. Economically Feasible Market Demand for CO2 by EOR: NEMS/EMM Power Generation Regions*

NEMS EMM Region	Purchased CO2 Requirements	Natural CO2**	Industrial CO2**		Unmet (Net) Demand for CO2	
	(Tcf)	(Tcf)	(MMcfd)	(Tcf)	(Tcf)	(Million mt)
Region 1 - ECAR	1.1	-	15	***	1.1	58
Region 2 – ERCOT	72.2	25	110	1.2	46.0	2,436
Region 3 – PJM (MAAC)	0.1	-	-	-	0.1	4
Region 4 – MAIN	1.9	-	-	-	1.9	100
Region 5 – MAPP	2.1	-	-	-	2.1	109
Region 6 – NY ISO	-	-	-	-	-	-
Region 7 – NW ISO	-	-	-	-	-	-
Region 8 – Florida	0.2	-	-	-	0.2	9
Region 9 – SERC	40.0	8	-	-	32.0	1,695
Region 10 – SWPP	29.7	5	35	0.4	24.3	1,286
Region 11 – WECC/NWPP	7.8	-	175	1.9	5.9	311
Region 12 – WECC/RMPP	2.3	-	65	0.7	1.6	83
Region 13 – WECC/CA	26.0	-	-	-	26.0	1,377
Region 14 - Alaska	39.6	5	-	-	34.6	1,831
TOTAL U.S.	223.0	43	400	4.2	175.8	9,301
TOTAL Lower-48	183.4	38	400	4.2	141.2	7,470

*Base Case: $70/Bbl oil and $45/mt CO2

**Assumed available to be produced and productively used by the CO2-EOR industry in the next 30 years.

***Less than 0.01 Tcf and thus not included in totals.

Table 14. Existing CO2 Supplies

(Volumes of CO2 Injected for EOR*)

State/ Province (storage location)	Source Type (location)	CO2 Supply MMcfd**	
		Natural	Anthropogenic
Texas-Utah-New Mexico-Oklahoma	Geologic (Colorado-New Mexico) Gas Processing (Texas)	1,700	110
Colorado-Wyoming	Gas Processing (Wyoming)	-	240
Mississippi	Geologic (Mississippi)	400	-
Michigan	Ammonia Plant (Michigan)	-	15
Oklahoma	Fertilizer Plant (Oklahoma)	-	35
Saskatchewan	Coal Gasification (North Dakota)	-	145
TOTAL		2,100	545

* Source: 12th Annual CO2 Flooding Conference, Dec. 2006

** MMcfd of CO2 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).

The EIA NEMS Electricity Market Model in AEO 2008 projects that 121 new, one GW size, coal-fueled power plants will come on stream between now and 2030. If these 121 GWs of coal-fueled power generation capacity were equipped with CCS, they would provide 20.5 billion metric tons of captured CO2 emissions, assuming 90% CO2 capture, 38% power plant efficiency, 85% operating capacity, and 30 years of operations. Table 15 sets forth the volumes of CO2 emissions that theoretically would be available in each of the EMM regions (lower-48) from the installation of these new coal-fueled power plants.

A closer look at CO2 demand (net, after subtracting CO2 supplies available from natural and already captured industrial CO2 sources) for EOR shows: (1) there is unmet (net) demand for CO2 in eleven of the EMM regions that could be filled in part or in whole by captured CO2 emissions from power plants; and (2) while the overall supply of CO2 from power plants would more than fulfill the overall (net) CO2 demand from the EOR industry, Region #13 (WECC, CA) appears to be “short” in terms of CO2 supplies, due to the absence of new coal-fueled power plant capacity. (Most likely, installation of

CO2 pipelines crossing EMM regional boundaries would be used to match CO2 demand with available supply.)

The overall conclusion from the analysis is that CO2-EOR may provide a 7,500 million metric ton market for captured CO2 emissions by the coal-fueled power generation industry. While the actual revenues afforded by this market will be established, in the main, by one-on-one negotiations between individual power companies and oil field operators, the potential size of this market could be large.

Using an oil price of $70 per barrel (Base Case), assuming a delivered CO2 cost of $45 per metric ton, and subtracting $10 per metric ton for transportation and handling, the revenue potential offered by the CO2-EOR market could reach $260 billion. In addition, the sale of captured CO2 emissions to the CO2-EOR industry would enable power companies to avoid the costs and challenges of storing CO2.

Table 15. Comparison of Net CO_2 Demand (for EOR) with Potential Captured CO_2 Emissions from Coal-Fueled Power Plants

EMM Region	Region	States	Coal Deployment 2007-2030	Available CO2 From Coal*	Demand for CO2 @ $45/mt & $70/B Oil	Shortfall (Excess) in CO2 Supply
#			(GW)	(MMmt)	(MMmt)	(MMmt)
2	ERCOT	TX	21.0	3,570	2,438	(1,132)
9	SERC	AR, LA, MS, AL, TN, GA, SC, NC	32.7	5,559	1,695	(3,864)
13	WECC/CA	CA	0.0	-	1,377	1,377
10	SWPP	OK, KS, NM	9.3	1,581	1,286	(295)
11	WECC/NWPP	WA, OR, ID, MT, WY, UT, NV	6.4	1,088	311	(777)
5	MAPP	ND, SD, NE, MN	2.5	425	109	(316)
4	MAIN	IL, MO, IA, WI	3.3	561	100	(461)
12	WECC/RMPP	CO, AZ	17.4	2,958	83	(2,875)
1	ECAR	KY, WV, OH, IN, MI	2.5	425	58	(367)
8	Florida	FL	12.5	2,125	9	(2,116)
3	PJM (MAAC)	PA, DE, NJ, MD	8.2	1,394	4	(1,390)
6	NY ISO	NY	5.1	867	-	(867)
7	NE ISO	VT, NH, ME, MA, CT, RI	0.0	-	-	-
U.S. Total			120.9	20,553	7,471	(13,082)

*Assuming all new Coal Plants capture 90% of CO_2, operate at 85% capacity and 38% efficiency (8,876 Btu/kWh); includes 30 years of CO_2 emissions.

5.0 Using Sale of Captured CO2 Emission for “Early Market Entry” of CCS Technology

As discussed in the previous chapter, CO2-EOR may provide a large, “value added” market for sale of captured CO2 emissions from power plants and other industrial sources. Should this market develop in a timely fashion, it would support “early market entry” of carbon capture and storage (CCS) technology, particularly by coal-fueled power plants.

5.1. Economics of CCS

A common feature of EIA carbon management studies is that, in general, CCS is not considered, as of yet, a key part of the solution[1,2,3]. The reason, according to EIA’s EMM cost model, is that using CCS with coal- or gas-fired power is not economically competitive with other options for generating power with low CO2 emissions, as shown on Figure 8.

As set forth in EIA’s cost model, incorporation of CCS with new advanced coal-fueled power plant currently adds over $20 per MWh of costs, making this a higher cost option than advanced nuclear power and subsidized wind- or biomass-based electricity generation. Even by 2020, assuming modest technology progress for advanced coal and CCS, adding CCS to a coal-fueled power plant would increase electricity generation and transmission costs by nearly $19 per MWh, keeping this a high cost option.

Figure 8 shows that, according to EIA’ Reference Case for 2020, Advanced Coal with CCS would entail costs of $81 per MWh of electricity compared to $60 per MWh for Pulverized Coal without CCS and $66 per MWh for Advanced Nuclear.

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[1] Energy Market and Economic Impacts of a Proposal to Reduce Greenhouse Gas Intensity with a Cap and Trade Systems, U.S. DOE, Energy Information Administration, January, 2007.

[2] Energy Market Impacts of Alternative Greenhouse Gas Intensity Reduction Goals, U.S. DOE, Energy Information Administration, March, 2006.

[3] Energy Market Impacts of a Clean Energy Portfolio Standard - Follow-up, U.S. DOE, Energy Information Administration, February, 2007.

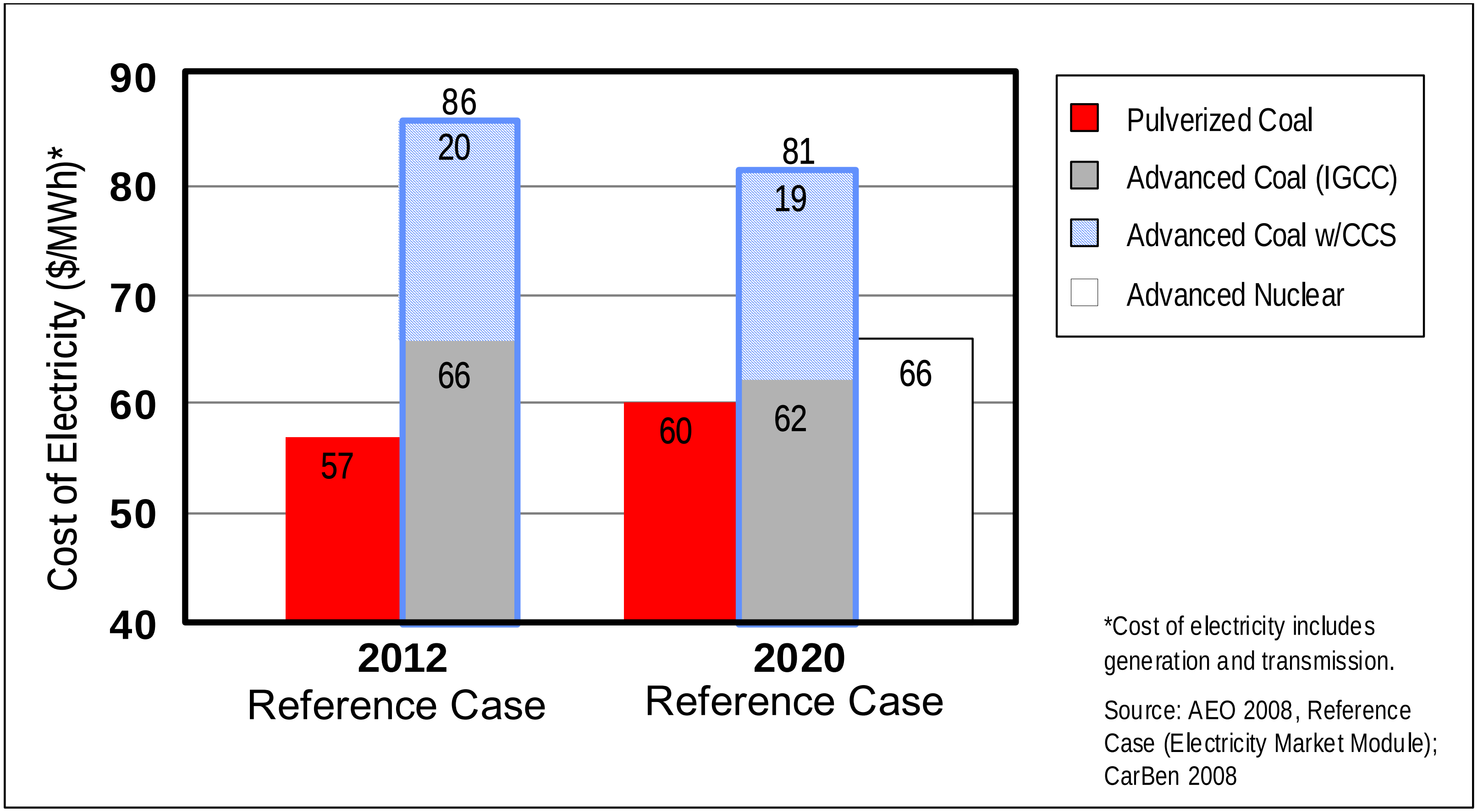

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Figure 8. Advanced Coal Plants w/CCS Are Currently Uncompetitive in 2012 and 2020 (EIA's AEO 2008 Reference Case)

However, revenues from selling captured CO2 emissions into the CO2-EOR market can change the competitive outlook. For example, as shown in Table 16, the sale of captured CO2 emissions at $25 to $35 per metric ton can reduce the costs of power generation with CCS by $17 to $24 per MWh, significantly offsetting the costs of installing CCS with new coal-fueled power plants.

Table 16. Relationship of CO2 Sales Price to Cost Offsets in the Coal-Fueled Power Sector (Year 2020)

Sale of CO2	**Sale of CO2**
@ $25/mt CO2	@ $35/mt CO2
7,920 btu/kWh x	7,920 btu/kWh x
94 MMmt CO2/QBtu x	94 MMmt CO2/QBtu x
90% Capture	90% Capture
Cost Offset: $16.80/MWh	Cost Offset: $23.50/MWh

5.2. Supporting "Early Market Entry" of CCS Technology

To examine just how much contribution to "early market entry" of CCS may be possible from sale of captured CO2 emissions into the EOR market, the study integrated the previously presented CO2 demand information into the CarBen Model's version of the DOE/EIA NEMS Electricity Market Module.

The CarBen and EIA EMM Models provide the year 2012 and year 2020 cost and competitive positions for three coal-fueled power generation options, Table 17.

Table 17. EIA Reference Case Year 2012 and Year 2020 Costs of Electricity

	Cost of Electricity $/MWh*	
Power Generation Option	Year 2012	Year 2020
1. Pulverized Coal without CCS	$56.60	$59.70
2. Advanced Coal without CCS	$65.70	$62.00
3. Advanced Nuclear	-	$66.00
4. Advanced Coal with CCS	$86.30	$80.80

*Costs include generation and transmission

Sale of captured CO2 emissions at $35 per metric ton ($1.85/Mcf) at the plant gate, equal to $45 per mt ($2.38/Mcf) at the oil field lease line (assuming $10 per mt ($0.53/Mcf) for transportation), would provide a cost offset of $23.50/MWh.

In 2012, the revenue offset of $23.50/MWh from sale of captured CO2 emissions is not sufficient to make CCS cost competitive. By 2020, however, with assured, long-term sale of captured CO2 emissions at $35 per metric ton (at the plant gate) providing $23.80/MWh of revenue offsets, new advanced coal plans with CCS would become cost competitive with alternative, non-CCS coal based power generation options, as shown in Table 18 and in Figure 9.

Table 18. Cost of Electricity in Year 2020 with Sale of CO2

Power Generation Option	Cost of Electricity (2020)		
	Initial* Cost	CO2 Sale Offset	Final* Cost
	($/MWh)	($/MWh)	($/MWh)
1. Pulverized Coal without CCS	$59.70	-	$59.70
2. Advanced Coal without CCS	$62.00	-	$62.00
3. Advanced Nuclear	$66.00	-	$66.00
4. Advanced Coal with CCS	$80.80	($23.50)	$57.30

*Costs are for 2020 and include transmission

The CarBen and EIA EMM models project that 29 new coal-fueled power plants would be placed into operation between 2013 and 2020 in the lower-48. Assuming that half of these power plants are favorably located with respect to oil fields attractive for CO2-EOR and are able to sell CO2 at $35/mt at the plant gate, the integration of CO2 storage and EOR would support the construction of 15 new advanced coal w/CCS power plants, each with 1 GW of capacity. (A 1 GW advanced coal-fueled power plant built by 2020 is estimated to be able to sell about 5.1 million metric tons of captured CO2 emissions per year; 15 plants would be able to provide 2,300 million metric tons in 30 years). Additional sales of captured CO2 emissions by power plants built after 2020 would support additional installations of CCS, as discussed below.

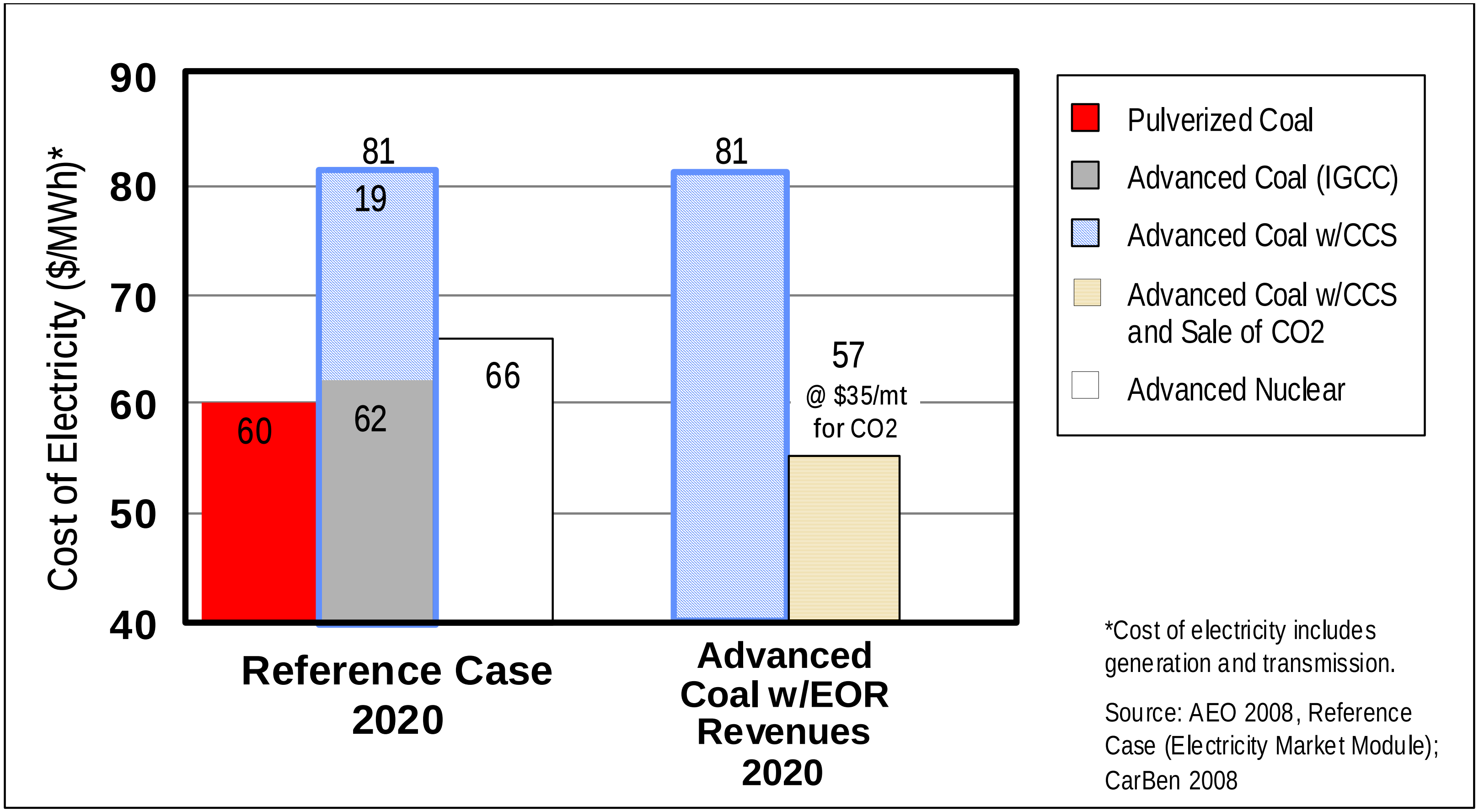

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Figure 9. Sale of Captured CO2 Emissions Can Help Make Coal Plants w/CCS Competitive

5.3. Adding “Learning” to the “Early Market Entry” Opportunity

The CarBen and EIA EMM models contain a “learning” function which reduces the costs of installing new technology as a function of the number of CCS installations. As such, the costs of producing advanced coal-fueled electricity with CCS decline.

The “early market entry” of 15 CCS installations, made possible by the sale of captured CO2 emissions into the EOR market, helps accelerate the “learning” process. As such, the costs of producing electricity using advanced coal with CCS are expected to decline to $74.50/MWh by 2020, as shown in Table 19.

Table 19. Year 2020 Costs of Electricity with Accelerated “Learning” Based Cost Reductions

Power Generation Option	Cost of Electricity $/MWh* Year 2020
1. Pulverized Coal without CCS	$59.70
2. Advanced Coal without CCS	$62.00
3. Advanced Nuclear	$66.00
4. Advanced Coal with CCS**	$74.50

*Costs include transmission

**Accelerated “learning” only applied to Advanced Coal with CCS

The significance of the “learning” based cost reductions for advanced coal-fueled power w/CCS is that now a lower sales price for captured CO2 emissions, at $25/mt ($1.32/Mcf) at the plant gate, equal to $35/mt ($1.85/Mcf) at the oil field lease line, (assuming $10/mt ($0.53/Mcf) for transportation), would provide sufficient cost offsets of $16.80/MWh to make advanced coal w/CCS cost competitive.

With assured, long-term sale of captured CO2 at $25 per metric ton at the plant gate, and assuming cost reductions due to “learning”, new advanced coal plants with CCS providing electricity at a cost of $58 per MWh would be the preferred economic choice for the post-2020 time period, as shown in Table 20 and Figure 10.

Table 20. Year 2020 Cost of Electricity with "Learning" and CO2 Sale Offset

Power Generation Option	Cost of Electricity (2020) Initial* Cost	CO2 Sale Offset	Final* Cost
	($/MWh)	($/MWh)	($/MWh)
1. Pulverized Coal without CCS	$59.70	-	$59.70
2. Advanced Coal without CCS	$62.00	-	$62.00
3. Advanced Nuclear	$66.00	-	$66.00
4. Advanced Coal with CCS	$74.50	($16.80)**	$57.70

*Costs include transmission

**CO2 sale for a plant with EIA Reference Case efficiency and $25/mt CO2 price, at the plant gate.

An additional 80 new (1 GW size) coal-fueled power plants are expected in the lower-48 between 2020 and 2030. Subtracting the purchase of 2,300 million metric tons of captured CO2 emissions from 15 plants, the lower-48 EOR market has a remaining demand for an additional 5,170 million metric tons of CO2. Assuming that a sufficient number of these plants are favorably located, the unmet demand for CO2 by the EOR market would support the installation of 34 advanced coal power plants with CCS between years 2020 and 2030, bringing the total to 49 new power plants with CCS.

The sale of captured CO2 emissions could enable 40% (49 out of 121) of the new coal-fueled power plants expected to be built between now and 2030 to install CCS, providing significant assistance toward addressing CO2 emissions in this sector and helping further drive down the costs of CCS technology.

Additional information on the incorporation of sales of captured CO2 emissions by power plant into the Electricity Generation Module of the CarBen Model (a simplified component of the EIA NEMS EMM) is provided in Appendix B.

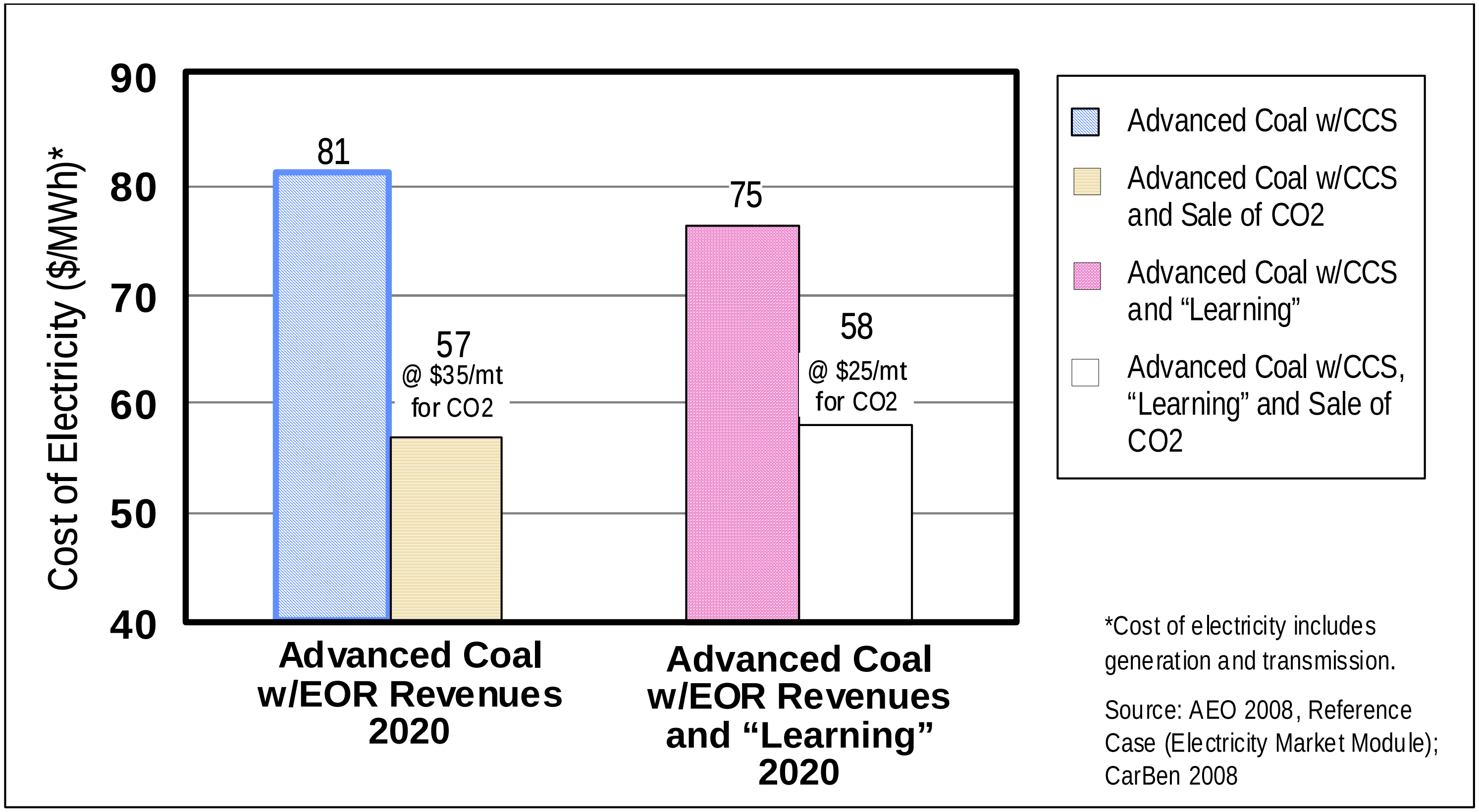

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Figure 10. Sale of Captured CO2 Emissions Can Help Make Coal Plants w/CCS Competitive.

Appendix A

Study Methodology

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 Data Base; (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 data base used in the previous set of “basins studies”. The study updated and augmented this data base by incorporating the internally prepared Appalachian Basin Data Base and by incorporating other improvements to this data base previously performed by Advanced Resources.

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 Data Base 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.

Table A-1. Reservoir Data Format: Major Oil Reservoirs Data Base

Basin Name	
Field Name	
Reservoir	

Print Sheets

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)	

Considerable effort was required to construct an up-to-date, volumetrically consistent data base 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.

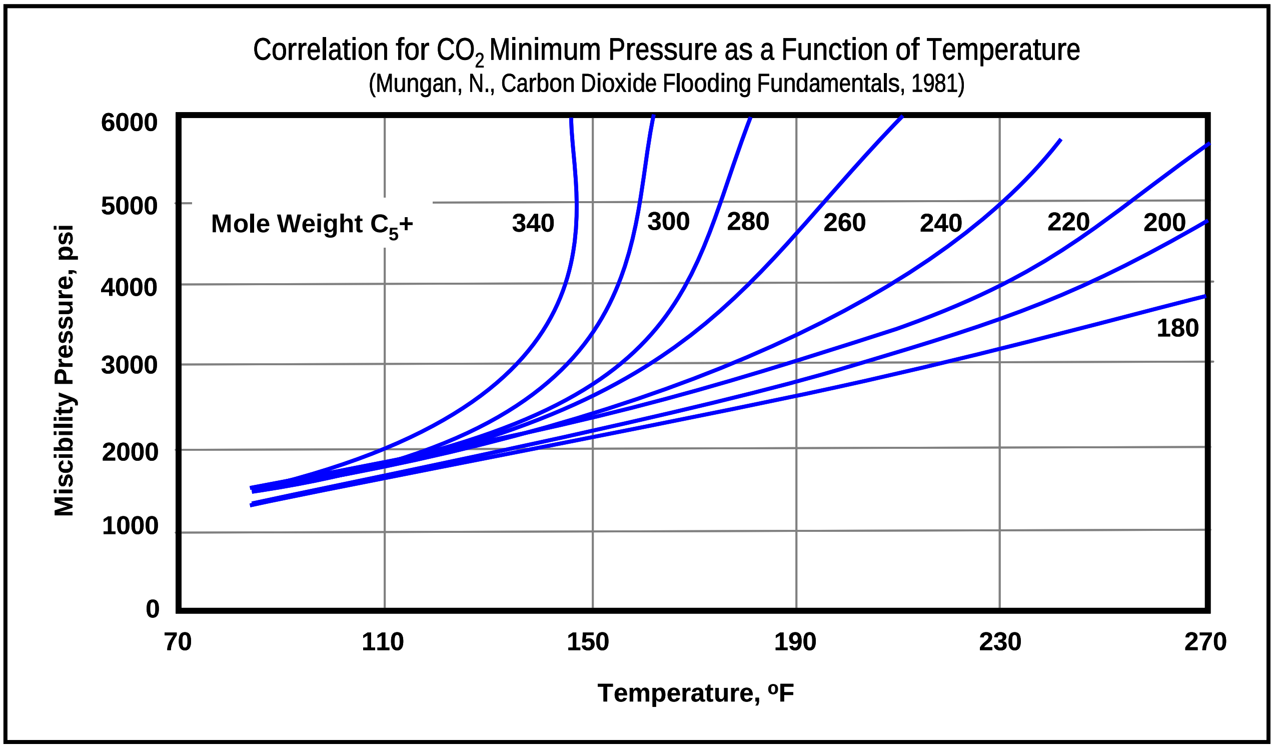
A.3 CALCULATING MINIMUM MISCIBILITY PRESSURE. The miscibility of a reservoir's oil with injected CO_2 is a function of pressure, temperature and the composition of the reservoir's oil. The study's approach to estimating whether a reservoir's oil will be miscible with CO_2, given fixed temperature and 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:

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

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

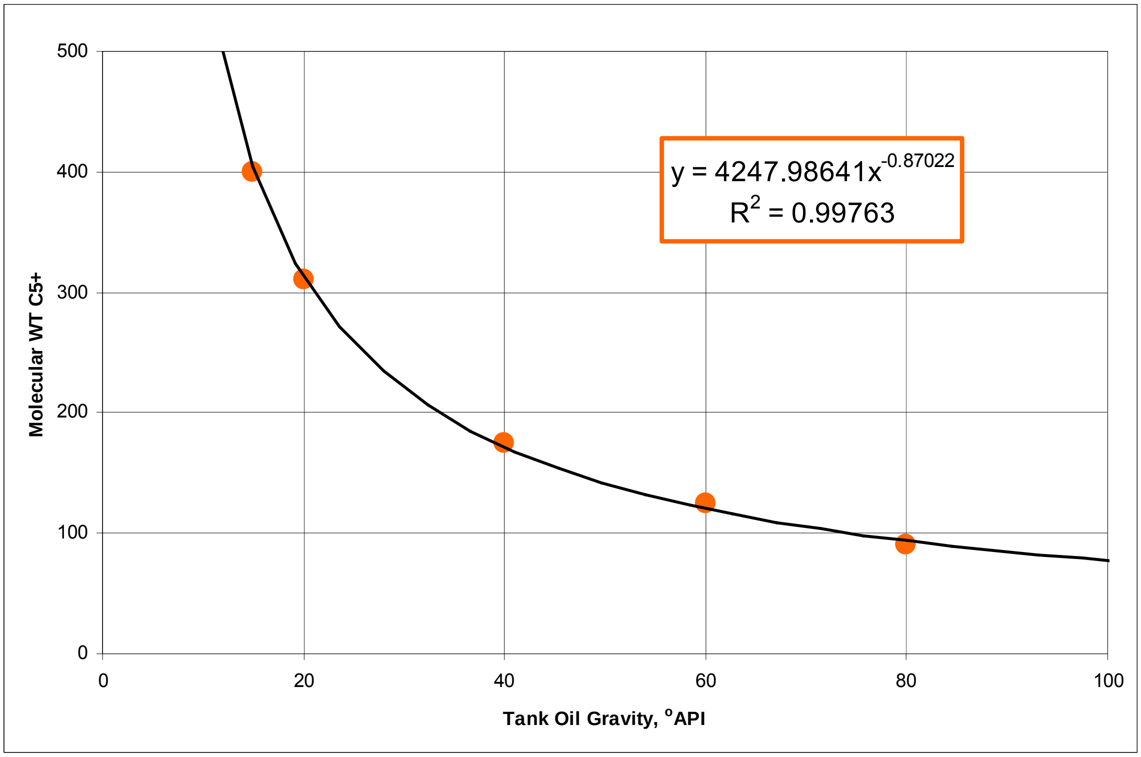
Figure A-1. Estimating CO2 Minimum Miscibility Pressure



The temperature of the reservoir was taken from the data base 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 data base 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-2. Correlation of MW C5+ to Tank Oil Gravity



A.4 SCREENING RESERVOIRS FOR CO_2-EOR. The data base 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 °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* was developed as an alternative to the DOE's CO_2 miscible flood predictive model, *CO_2PM*. According to the developers of the model, *CO_2-PROPHET* has more capabilities and fewer limitations than

CO_2PM. For example, according to the above cited report, *CO_2-PROPHET* performs two main operations that provide a more robust calculation of oil recovery than available from *CO_2PM*:

- *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

Incorporation of Economically Feasible CO2 Demand for EOR into the CarBen Model and the Electricity Market Module

Enabling “Early Market Entry” of CCS Technology in the Electric Power Sector

The following three tables in Appendix B provide a synopsis of CarBen’s Electricity Market Model (that emulates the EIA NEMS Electricity Market Module) and how revenues from sale of CO2 into the EOR industry could help stimulate “early market entry” of CO2 capture and storage (CCS) by the coal-fueled power sector.

- Table B-1 illustrates how the cost of generating and transmitting electricity, from advanced coal plants (IGCC) and pulverized coal (PC) plants (with and without CCS) changes with time, from 2012 through 2030. Table B-1 then illustrates how the cost offsets from sale of captured CO2 would help reduce the cost of electricity and help make the Advanced Coal with CCS option competitive with coal generated power without CCS.

- Table B-2 illustrates the same changes in costs of electricity now with “accelerated” learning included, from the installation of 49 new advanced coal plants with CCS.

- Table B-3 compares the EIA Reference Case of new coal-fueled power plant builds (with and without CCS) with the Alternative Case involving capture and sale of CO2 by the power industry to the CO2-EOR industry. Table B-2 then summarizes how cost offsets from sale of CO2 (plus “learning”) in the Alternative Case would enable a significant number of “early market entries” of power plants with CCS (cumulative):

- 2020 - - 15 GW size plants w/CCS

- 2030 - - 48 GW size plants w/CCS

Table B-1

Economic Implications of Sale of CO2 Without Accelerated "Learning" for Advanced Coal w/CCS in the CarBen Electricity Market Model

- Revenues (cost offsets) from sale of CO2, even without "learning", can make Advanced Coal plants w/CCS more economic than Pulverized Coal or Advanced Coal w/o CCS

Offset Revenue from Sale of CO_2 (\$/MWh)	2012	2020	2030
CO2-EOR Revenue Offset \$35/mt		\$ 23.50	\$ 23.50
CO2-EOR Revenue Offset \$25/mt		\$ 16.80	\$ 16.80

Competition Among Coal-Fueled Power Generation Options			
	2012	2020	2030
Price of Electricity w/o and w/CCS (\$/MWh)			
Pulverized Coal	\$ 56.60*	\$ 59.70	\$ 59.10
Advanced Coal	\$ 65.70	\$ 62.00	\$ 59.30
Advanced Coal w/CCS	\$ 86.30	\$ 80.80	\$ 75.50
Price of Electricity w/CCS and Sale of CO2 (\$/MWh)			
Advanced Coal w/CCS & Sale of CO2 at \$35/mt	\$ 59.60	\$ 57.30*	\$ 52.00*
Advanced Coal w/CCS & Sale of CO2 at \$25/mt		\$ 64.00	\$ 58.70*

*Least-cost, competitive preferred power generation option

Table B-2

Economic Implications of Sale of CO_2 and With Accelerated "Learning" for Advanced Coal w/CCS in the CarBen Electricity Market Model

- Revenues (cost offsets) from sale of CO_2, plus "learning", can make Advanced Coal plants w/CCS more economic than Pulverized Coal or Advanced Coal w/o CCS

Offset Revenue from Sale of CO2 ($/MWh)	2012	2020	2030
CO2-EOR Revenue Offset $35/mt		$ 23.50	$ 23.80
CO2-EOR Revenue Offset $25/mt		$ 16.80	$ 16.80

Competition Among Coal-Fueled Power Generation Options			
	2012	2020	2030
Price of Electricity w/o and w/CCS ($/MWh)			
Pulverized Coal	$ 56.60*	$ 59.70	$ 59.10
Advanced Coal	$ 65.70	$ 62.00	$ 59.30
Advanced Coal w/CCS	$ 86.30	$ 74.50	$ 71.60
Price of Electricity w/CCS and Sale of CO2 ($/MWh)			
Advanced Coal w/CCS & Sale of CO2 at $35/mt	$ 59.60	$ 51.00*	$ 48.10*
Advanced Coal w/CCS & Sale of CO2 at $25/mt		$ 57.70*	$ 54.80*

*Least-cost, competitive preferred power generation option

Table B-3

Incorporation of CO2 Sales into the CarBen Electricity Market Model

Reference Case: Coal Power Plant Builds

Reference Case	2012	Δ 2013-20	2020	Δ 2021-30	2030
Cumulative Coal Additions (GW)	12	29	41	80	121
Pulverized Coal	12	22	34	41	75
Advanced Coal (IGCC)	-	7	7	39	46
Advanced Coal (IGCC) w/CCS	-	-	-	-	-

Alternative Case: Coal Power Plant Builds with Sales of CO2 to EOR

After CO2-Sale	2012	Δ 2013-20	2020	Δ 2021-30	2030
Cumulative Coal Additions (GW)	12	29	41	80	121
Pulverized Coal	12	11	23	24	47
Advanced Coal (IGCC)	-	3	3	22	25
Advanced Coal (IGCC) w/CCS	-	15	15	34	49

Appendix C

“Next Generation” CO_2 Storage and EOR Technology

"Next Generation" CO_2 Storage and EOR Technology

"Next generation" CO_2 storage and enhanced oil recovery technology offers the potential for storing significantly larger volumes of CO_2 than possible using current practices. Four key technology advances form the heart of "next generation" technology:

- Innovative flood design and well placement, including the application of vertical (gravity stable) CO_2 floods, where geologically feasible, as shown on Figure C-1;

- Extensive use of mobility control techniques, to improve the CO_2 flood mobility ratio and reservoir contact, in both horizontal and vertical CO_2 floods, as illustrated in Figure C-2;

- Even higher volumes of CO_2 injection, beyond the 1 HCPV "standard" used in "state-of-the-art" CO_2 floods, Figure C-3. This would also entail injecting CO_2 into the transition/residual oil zone (TZ/ROZ) and the saline water zone below the main reservoir section, as shown on Figure C-1;

- Making significant investments in "real-time" flood performance diagnostics and control, as illustrated in Figure C-2, using:

  - 4-D seismic;
  - Instrumented observation wells;
  - Zone-by-zone performance information; and
  - Inter-disciplinary technical teams.

To provide an example of how much more CO_2 could be stored with EOR, the study used reservoir simulation to examine the application of CO_2 storage and EOR in an example for Gulf Coast oil reservoir, geologically favorable for either horizontal ("state-of-the-art") or gravity stable ("next generation") CO_2-EOR. Table C-1 provides background information on this example oil reservoir. Table C-2 shows that over six times as much CO_2 could be stored in this reservoir using "next generation" technology, enabling the operator to store 1.6 times as much CO_2 in the oil reservoir as the CO_2 content in the recovered oil.

Figure C-1. Illustration of "Next Generation" Integration of CO2 Storage and EOR

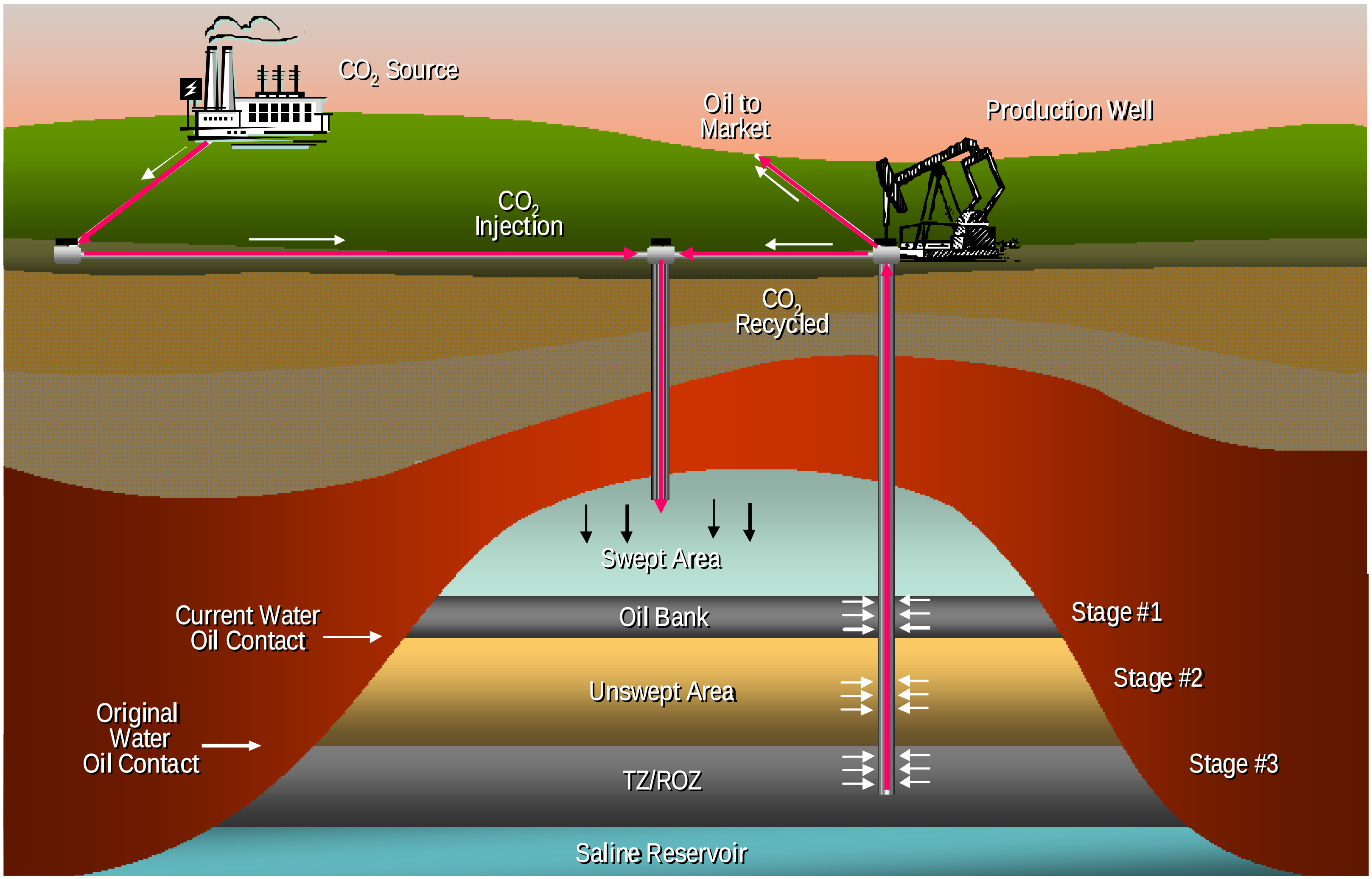
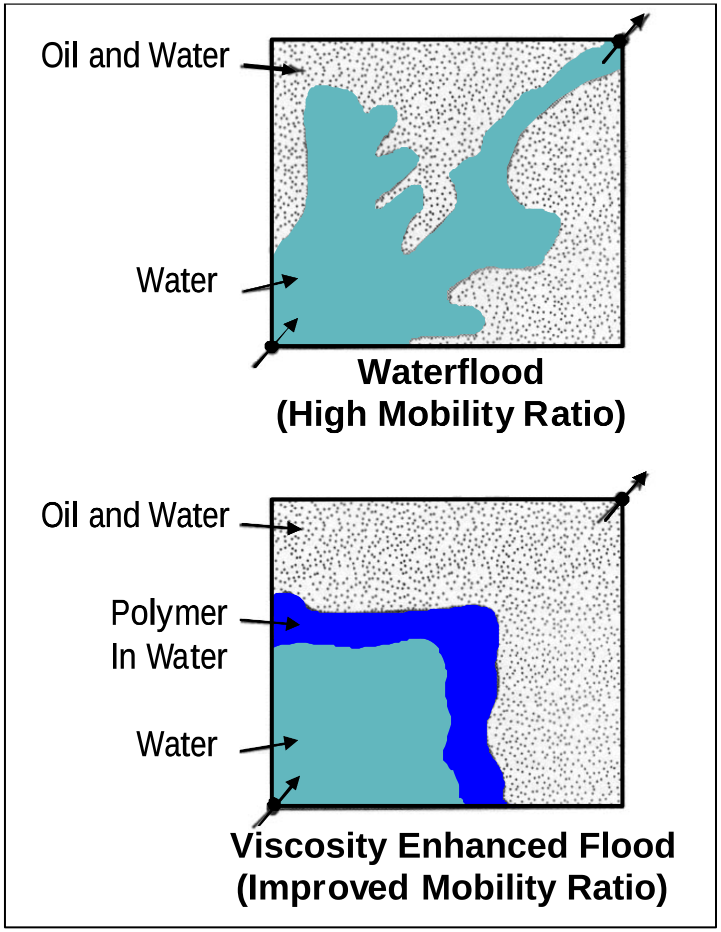


Figure C-2. Impact Of Advanced Mobility Control On CO2-EOR Performance



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Injected CO_2 achieves only limited contact with the reservoir due to:

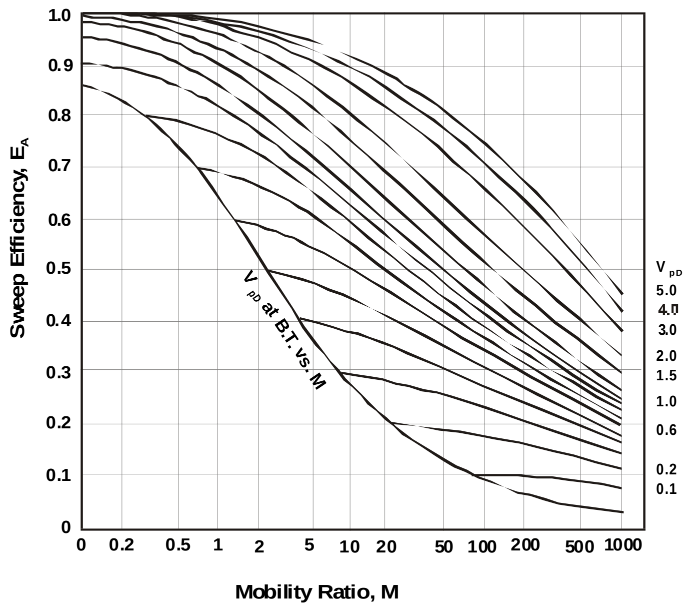
- Viscous fingering
- Gravity override

Addition of viscosity enhancers would improve mobility ratio and reservoir contact.

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

Figure C-3. Impact Of Increased CO2 Injection On CO2-EOR Performance

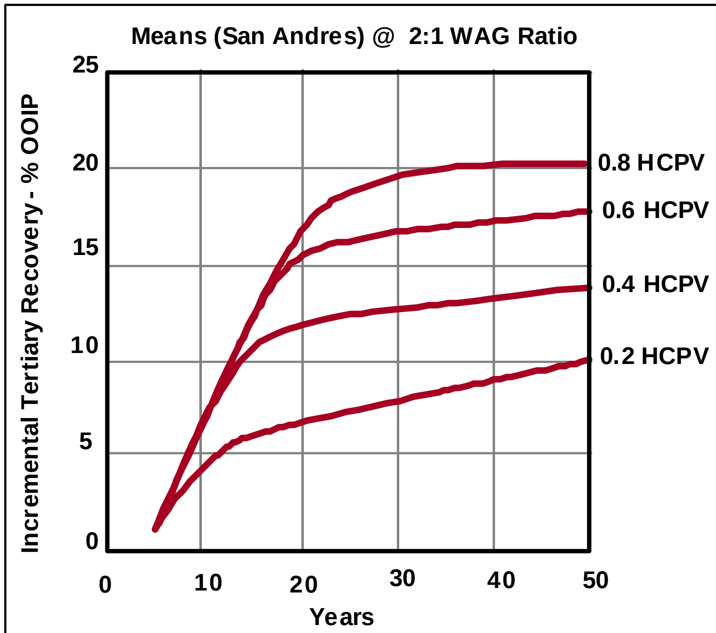
Sweep Efficiency in Miscible Flooding



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

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

Injected CO_2 vs Oil Recovery



Source: SPE 24928 (1992)

Table C-1. Case Study: Integration of “Next Generation” CO_2 Storage with EOR

Case Study: Large Gulf Coast oil reservoir with 340 million barrels (OOIP) in the main pay zone has been selected as the “case study”.

- The primary/secondary oil recovery in this oil reservoir is favorable at 153 million barrels, equal to 45% of OOIP. Even with this favorable oil recovery using conventional practices, 187 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 CO_2 storage capacity of this oil reservoir and structural closure is 2,710 Bcf (143 million tonnes).

Table C-2. Case Study: Integration of "Next Generation" CO2 Storage with EOR

<u>Producing "Green Oil": Integrating CO2-EOR and CO2 Storage.</u> **With alternative CO2 storage and EOR design, much more CO2 can be stored and more oil becomes potentially recoverable.**

The additional oil produced is "GREEN OIL"*.

	"State of the Art"	"Next Generation"
	(millions)	(millions)
CO_2 Storage (tonnes)	19	109
Storage Capacity Utilization	13%	76%
Oil Recovery (barrels)	64	180
% Carbon Neutral ("Green Oil")	80%	160%

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*"Green Oil" means that more CO_2 is injected and stored underground than the volume of CO_2 contained in the produced oil, once burned.