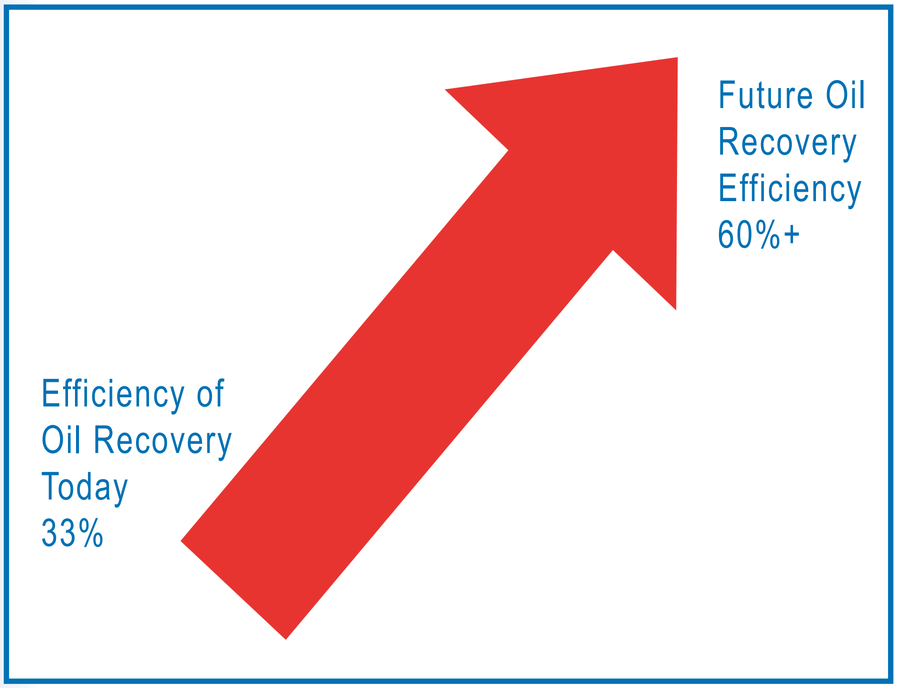
EVALUATING THE POTENTIAL FOR "GAME CHANGER" IMPROVEMENTS IN OIL RECOVERY EFFICIENCY FROM CO_2 ENHANCED OIL RECOVERY



Prepared for

U.S. Department of Energy

Office of Fossil Energy - Office of Oil and Natural Gas

Prepared by

Advanced Resources International

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The domestic oil resource recovery potential outlined in this report is based on six basin-oriented assessments released by the Department of Energy (DOE) in April 2005. These estimates do not include the additional oil resource potential outlined in the ten basin-oriented assessments or recoverable resources from residual oil zones, as discussed in related reports issued by DOE in February 2006. Accounting for these, the future recovery potential from domestic undeveloped oil resources by applying EOR technology is 240 billion barrels, boosting potentially recoverable resources to 430 billion barrels.

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EXECUTIVE SUMMARY

Currently available primary and secondary oil production technologies recover only about one-third of the oil in-place in domestic reservoirs, leaving behind massive volumes of oil in the ground (“stranded oil”). Scientific theory, laboratory tests, and selected field projects show that significant increases in oil recovery efficiency are possible.

This technical report examines the role that “next generation” carbon dioxide enhanced oil recovery (CO_2-EOR) technologies could provide in making “game changer” improvements in domestic oil recovery efficiency and in increasing domestic oil production. Five significant findings emerge from this study:

1. **Traditionally practiced CO_2-EOR technology will raise overall domestic oil recovery efficiency by only a few percent.** This is because: (1) CO_2-EOR is applied in only a few of our domestic oil basins, primarily the Permian Basin; (2) the traditional form of this technology is economic in a relatively small group of geologically favorable oil reservoirs; and, (3) most importantly, traditionally practiced CO_2-EOR designs provide only a modest 10 percent, recovery of the original oil in-place.

2. **Integrated application of the full suite of “next generation” technologies shows that much higher oil recovery efficiencies, two-thirds or more of the oil in-place, are feasible from an expanded group of domestic oil reservoirs.** The analysis shows that a series of “next generation” CO_2-EOR technologies could substantially increase oil recovery efficiency from geologically favorable oil reservoirs. In addition, “next generation” technology could also extend the miscible CO_2-EOR technology to a broader range of domestic oil reservoirs. For example, integrated application of three “next generation” CO_2-EOR technologies (i.e., high volume injection of CO_2, innovative process and well designs, and effective mobility control) in the Field #1oil reservoir would enable

80 percent of the original oil in-place (OOIP) to become recoverable, including 34 percent from primary and secondary recovery.

3. **<u>Successful development and integrated application of "next generation" CO_2-EOR technologies could provide 83.7 billion barrels of technically recoverable domestic oil resource (from the six basins/regions studies so far).</u>** The previously issued six basin-oriented CO_2-EOR studies reported that 43.3 billion barrels of domestic oil could become technically recoverable with "state-of-the-art" CO_2-EOR technology. Successful development and integrated application of "next generation" CO_2-EOR technology could increase this by 40.4 billion barrels, shown in Figure EX-1. This would bring the overall total from application of "next generation" CO_2-EOR technology to 83.7 billion barrels, from the six domestic oil basins/areas studied to date (Table EX-1).

4. **<u>When extrapolated to the total domestic oil resource base, "next generation" CO_2-EOR technology could add 160 billion barrels of domestic oil recovery.</u>** Integrated application of "next generation" CO_2-EOR technologies to the remaining domestic oil basins and regions still to be assessed could bring about "game changer" advances in oil recovery efficiency and domestic oil production. As a first step, we extrapolated the sample of oil reservoirs included in the study to the nation as a whole (using data on original oil in-place, provided in Figure EX-1 and Table EX-1). This extrapolation shows that the application of "state-of-the-art" CO_2-EOR technology would provide 80 billion barrels of technically recoverable resource, primarily from light oil fields. However, "next generation" CO_2-EOR technology could increase this to 160 billion barrels of technically recoverable domestic oil resource.

Figure EX-1. "Stranded" Domestic Oil Resources in Existing Oil Fields

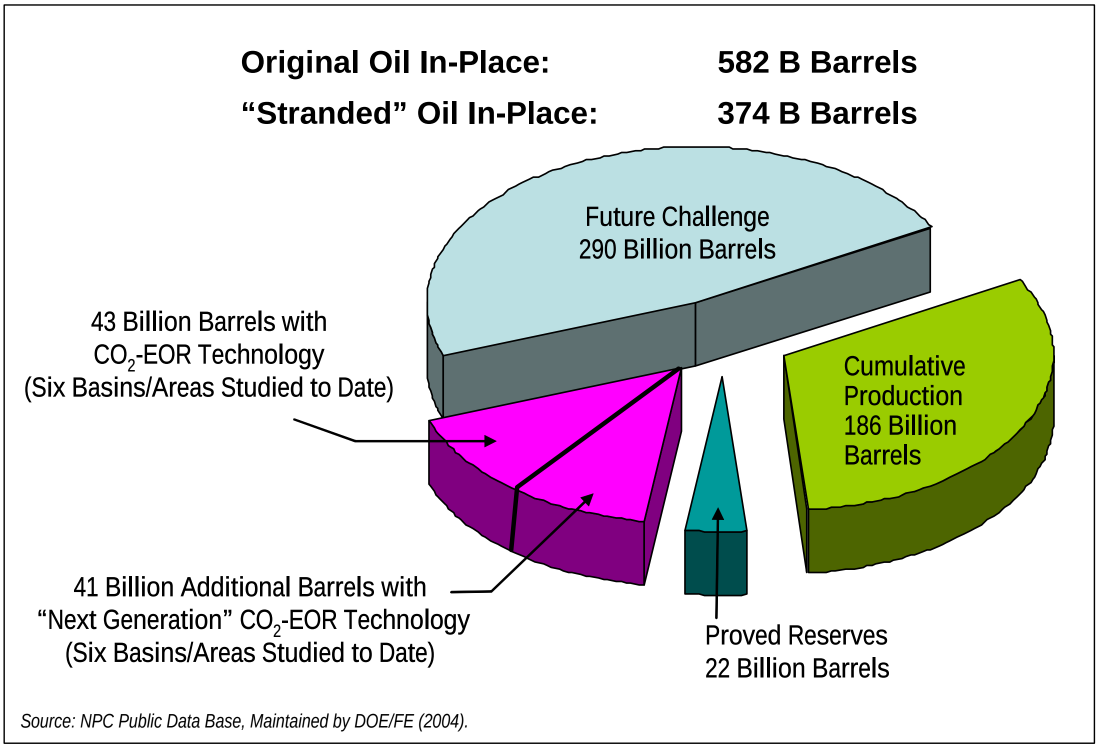


Table EX-1. Technically Recoverable Oil Resource From "Next Generation" CO_2-EOR (Six Basins/Areas Assessed to Date)

Basin/Area	Large Favorable Reservoirs (Six Areas)		All Reservoirs (Six Basins/Areas)		
	Number	Technically Recoverable	OOIP* (Billion Barrels)	ROIP** (Billion Barrels)	Technically Recoverable (Billion Barrels)
California	96	11.9	83.3	57.3	13.3
Gulf Coast	208	11.1	60.8	36.4	19.0
Oklahoma	71	12.1	60.3	45.1	20.1
Illinois	46	1.1	9.4	5.8	1.6
Alaska	33	23.1	67.3	45.0	23.8
Louisiana Offshore (Shelf)	99	4.5	28.1	15.7	5.9
Total	553	63.8	309.2	205.3	83.7

*Original Oil in-Place, in all reservoirs in basin/area; ** Remaining Oil in-Place, in all reservoirs in basin/area.
Source: Advanced Resources International, 2005.

5. **<u>Achieving these higher oil recovery efficiencies would provide tremendous benefits to the domestic economy and for consumers.</u>** These benefits include:

   - The energy trade balance would improve by $3.2 trillion (cumulatively), assuming one-half of the 160 billion barrels of technically recoverable resource becomes economically recoverable and oil prices average $40 per barrel.

   - State and local treasuries would gain $280 billion in revenues from future royalties, severance taxes, and state income taxes on oil production[1]. The federal budget would gain $560 billion in revenues from future royalties from production on federal lands and from corporate income taxes.[2]

   - The decline in domestic oil production would be reversed, creating new well-paying direct and indirect jobs.

[1] Each barrel of domestic oil provides about $7 in revenue to the Federal treasury, at an oil price of $40 per barrel.
[2] Each barrel of domestic oil provides about $3.50 in revenue to state and local treasuries, at an oil price of $40 per barrel.

1. BACKGROUND

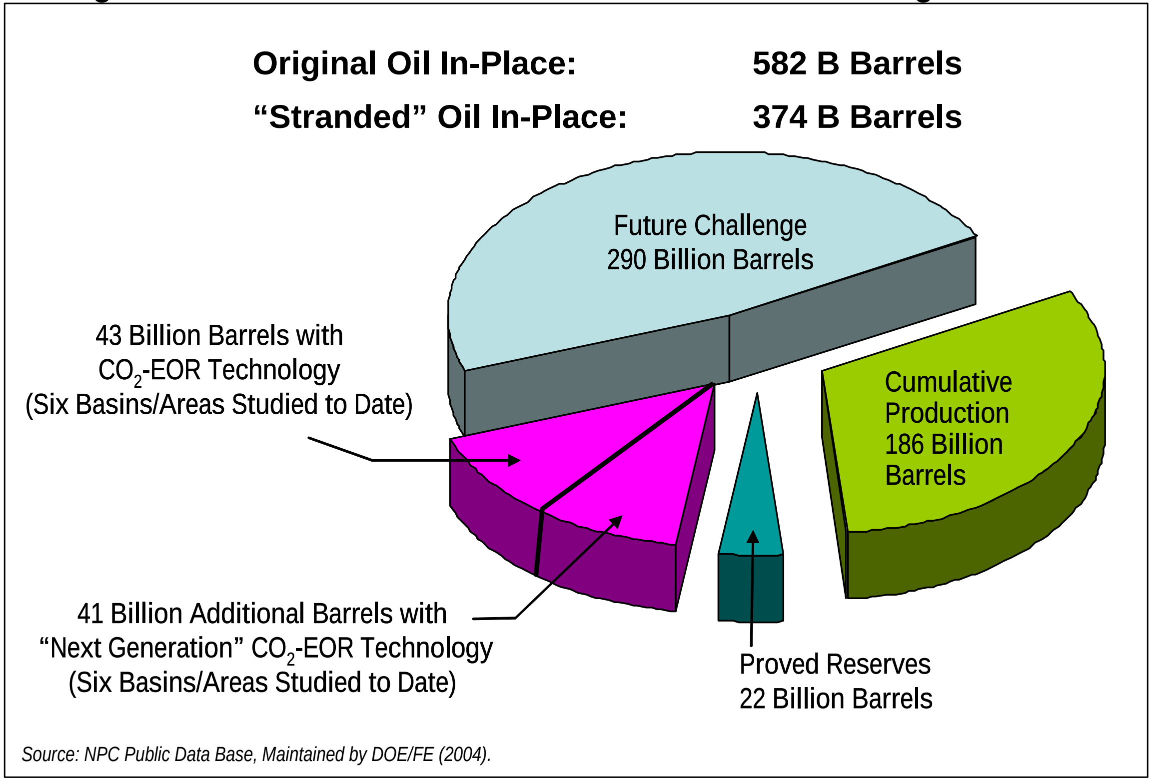
The United States has a large and bountiful storehouse of oil resources, estimated at nearly 600 billion barrels of oil in-place in already discovered oil fields. Currently used primary/secondary oil recovery methods recover only about one-third of this resource, leaving behind ("stranding") a massive target for enhanced oil recovery.

Important steps have been taken by industry to improve the recovery efficiency in domestic oil reservoirs, notably in applying thermal enhanced oil recovery (TEOR) methods to the shallow, heavy oil fields of California and CO_2-EOR to the deeper, light oil fields of West Texas. To date, these improved oil recovery technologies have provided about 14 billion barrels of domestic oil production and reserves, adding about 3 percent to domestic oil recovery efficiency.

Even including the important steps taken so far by industry, the overall domestic oil recovery efficiency remains low. This reflects production and proving of 208 billion barrels out of a resource in-place of 582 billion barrels, in already discovered fields. (See Figure 1). These resource volumes do not include the additional oil resources that exist in domestic oil sands, in the transition zones of oil reservoirs, or in future oil discoveries. Including all these oil resources, truly massive volumes of domestic oil — a trillion barrels — remain "stranded," after application of currently used primary/secondary oil recovery, (see Table 1), as discussed more fully below:

- Approximately 374 billion barrels of "stranded" oil remains in already discovered domestic oil fields, even after application of traditional TEOR and CO_2-EOR technology. (This consists of 582 billion barrels of discovered oil in-place, less past recovery and remaining reserves of 208 billion barrels).

Figure 1. "Stranded" Domestic Oil Resources in Existing Oil Fields



- Undiscovered fields and reserve growth would add 380 billion to the "stranded" oil total. (This consists of 570 billion barrels of "to be discovered" oil in-place, less expected recovery of 190 billion barrels).
- An estimated 100 billion barrels of residual oil is judged to exist in the "transition zone" of discovered oil fields and 80 billion barrels exist in domestic oil sands.

Recent DOE studies have reported that widespread use of improved versions of CO_2-EOR technology could significantly increase the recovery of domestic oil. These reports show that application of "state-of-the-art" CO_2-EOR in six major domestic oil basins (containing 309 billion barrels of original oil in-place and accounting for about one-half of all domestic oil resources, could add 43.3 billion barrels of technically recoverable resource), (see Figure 2 and Table 2). This step alone would improve the oil recovery efficiency in these six basins/regions to nearly 48 percent.

Table 1. Original, Developed and Undeveloped Domestic Oil Resources

	Original Oil In- Place (BBbls)	Developed to Date: Conventional Technology (BBbls)	Developed to Date: EOR Technology (BBbls)	Remaining Oil In-Place (BBbls)	Future Conventional Resources (BBbls)	Target for EOR Technology (BBbls)
I. Crude Oil Resources						
1. Discovered [1]	582	(194)	(14)	374	-	374
• Light Oil	482	(187)	(2)	293	-	293
• Heavy Oil	100	(7)	(12)	81	-	81
2. Undiscovered [2,3]	360	-		360	119	241
3. Reserve Growth [4,5]	210	-		210	71	139
4. Transition Zone [6]	100	-		100	-	100
II. Oil Sands [7]	80	-	*	80	-	80
TOTAL	1,332	(194)	(14)	1,124	190	934

*Less than 0.5 billion barrels

1. Source: DOE/FE Basin Reports, (Advanced Resources, 2005).
2. Source: USGS National Assessment of Oil and Gas Resources Update (USGS; October 2004) Conventional Oil Resources (40.43 billion barrels) and Continuous Oil Resources (2.13 billion barrels). Oil in–place estimated by assuming 33% recovery efficiency.
3. Source: Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Nation's Outer Continental Shelf, 2003 Update (MMS Fact Sheet, December 2004). Oil in-place estimated by assuming 33% recovery efficiency.
4. Source: Estimates of Inferred Reserves for the 1995 USGS National Oil and Gas Resource Assessment (USGS OFP 95-75L, January 1997). Oil in-place estimated by assuming 33% recovery efficiency.
5. Source: Assumptions for the Annual Energy Outlook 2004 (EIA, February 2004).
6. Source: Preliminary Estimates by Advanced Resources Int'l and Melzer Consulting (2005).
7. Source: Major Tar Sand and Heavy Oil Deposits of the United States (Lewin and Associates, Inc., July 1983).

However, "game changer" levels of improvement in oil recovery efficiency are theoretically and scientifically possible. Postulating these "next generation" technology advances and assessing their impacts is the subject of this report, *"Evaluating the Potential for "Game Changer" Improvements in Oil Recovery Efficiency for CO_2 Enhanced Oil Recovery."*

Figure 2. Domestic "Stranded" Oil Resources in Six Basins/Areas Assessed

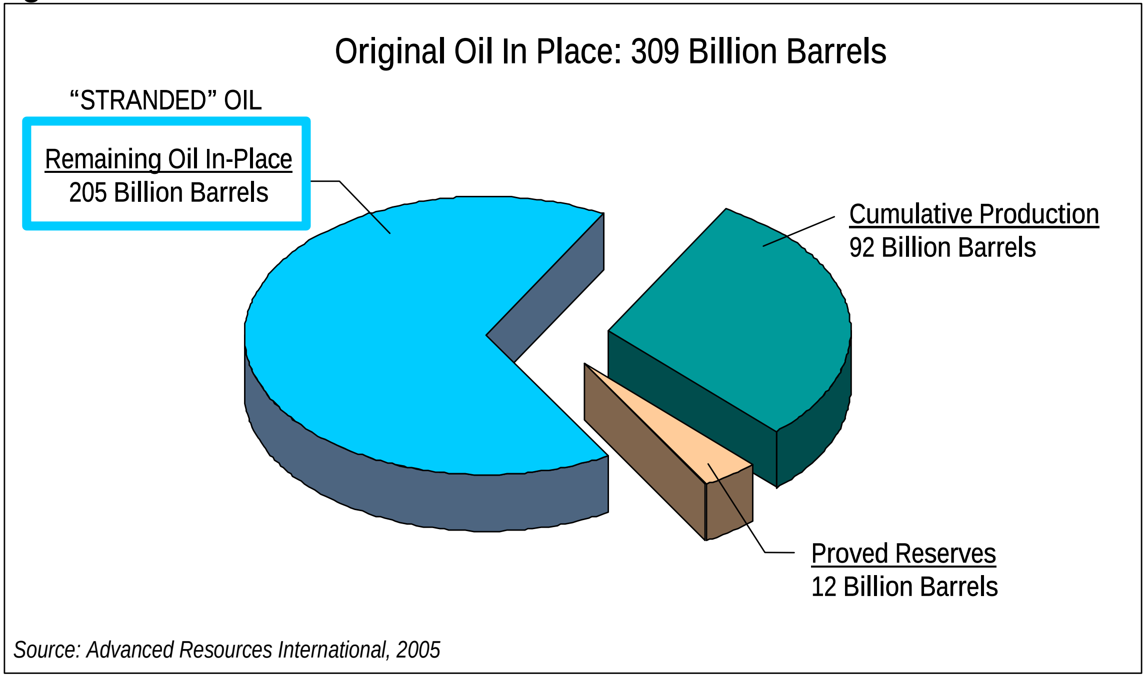


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Table 2. Technically Recoverable Oil Resource From "State-of-the-Art" CO_2-EOR (Six Areas Assessed to Date)

Basin/Area	Large Favorable Reservoirs (Six Areas)		All Reservoirs (Six Areas)		
	Number	Technically Recoverable	OOIP* (Billion Barrels)	ROIP** (Billion Barrels)	Technically Recoverable (Billion Barrels)
California	88	4.6	83.3	57.3	5.2
Gulf Coast	205	5.9	60.8	36.4	10.1
Oklahoma	63	5.4	60.3	45.1	9.0
Illinois	46	0.5	9.4	5.8	0.7
Alaska	32	12.0	67.3	45.0	12.4
Louisiana Offshore (Shelf)	99	4.5	28.1	15.7	5.9
Total	533	32.9	309.2	205.3	43.3

*Original Oil In-Place, in all reservoirs in basin/area; ** Remaining Oil in Place, in all reservoirs in basin/area.
Source: Advanced Resources International, 2005.

2. STUDY OBJECTIVE AND METHODOLOGY

This report summarizes the potential for improving the recovery of domestic oil resources and sets forth a set of "next generation" CO_2-EOR technologies that would enable these resources to be efficiently developed. It has been prepared in response to language set forth in the Congressional Budget for the DOE/Fossil Energy Oil Technology Program.

The study entailed four tasks: (1) assembling an up-to-date data base on domestic oil resources in six domestic basins/areas; (2) reviewing the technical literature on advanced extraction and production technologies; (3) discussing the status of CO_2-EOR technology, particularly "next generation" technologies, with selected companies and individuals; and, (4) modeling the technical and economic oil recovery potential from using these "next generation" technologies.

This eighth report, in a series of assessments of domestic oil resources, extends the six "Basin-Oriented Assessments" released on April 20, 2005[3]. It examines alternative research and technology pathways that could provide "game changer" levels of improvement in domestic oil recovery from applying "next generation" CO_2-EOR technologies in these same six basins/regions.

It is important to note that these scientifically possible "next generation" accomplishments postulated in this report have yet to be comprehensively demonstrated in the field. Significant new investments will need to be made in research and technology development to achieve the most promising results for the domestic energy industry set forth in this report.

[3] U.S. Department of Energy/Fossil Energy: Basin-Oriented Strategies for CO_2 Enhanced Oil Recovery: California, Onshore Gulf Coast, Offshore Louisiana, Oklahoma, Alaska, and Illinois, April 2005.

3. STATUS OF CO_2-EOR TECHNOLOGY

CO_2 injection, under the proper conditions of pressure and temperature, and in the presence of favorable crude oil composition, can become miscible with a reservoir's oil, helping remobilize and produce the oil remaining in the reservoir. The development of miscibility between the injected CO_2 and the reservoir's oil is through in-situ composition changes that occur from multiple fluid contacts and mass transfer between the reservoir's oil and the injected CO_2. Specifically, miscibility is obtained as the injected CO_2 is enriched in composition from the intermediate components in the reservoir's oil that vaporize into the CO_2, and as the injected CO_2 becomes dissolved in the reservoir's oil, ultimately eliminating the interfacial tension between these two fluids.

A review of 12 previously conducted field-scale CO_2 miscible floods shows low (8 to 10 percent) recovery of the OOIP, with a few projects with higher as well as lower recovery efficiencies, (see Table 3). At the same time, a review of 9 smaller scale CO_2 miscible pilots show 13 to 20 percent recovery of OOIP, indicating that alternative practices, such as closer well spacing and higher levels of technical involvement, may lead to higher oil recovery efficiencies (Table 4).[4]

The review of the pilot and field-scale CO_2 miscible floods also provides some insights as to the impacts on oil recovery of injecting larger hydrocarbon pore volumes (HCPVs) of CO_2. For example:

- The 7 CO_2 floods with CO_2 injection of greater than 30 percent HCPV (generally 40 percent to 60 percent HCPV) have an oil recovery efficiency of 15.0 percent.
- The 14 CO_2 floods with CO_2 injection of 30 percent HCPV (or less) have an oil recovery efficiency of only 11.9 percent.

[4] Brock, W.R. and Bryan, L.A., "Summary Results of CO_2 EOR Tests, 1972-1987", SPE Paper No. 18977 presented at the 1990 SPE/DOE Symposium on Enhanced Oil Recovery, Tulsa, OK, April 22-25

Table 3. Summary of Selected CO_2 Miscible Flood Field-Scale Projects

Field	Oil Gravity (°API)	Viscosity (cp)	Amount Injected (% HCPV)	Incremental Recovery (% OOIP)	Gross CO_2 Utilization (Mcf/STB)	Net CO_2 Utilization (Mcf/STB)	Year Initiated
Dollarhide	40	0.4	30	14.0		2.4	1985
East Vacuum	38	1.0	30	8.0	11.1	6.3	1985
Ford Geraldine	40	1.4	30	17.0	9.0	5.0	1981
Means	29	6.0	55	7.1	15.2	11.0	1983
North Cross	44	0.4	40	22.0	18.0	7.8	1972
Northeast Purdy	35	1.5	30	7.5	6.5	4.6	1982
Rangely	32	1.6	30	7.5	9.2	5.0	1986
SACROC (17 pattern)	41	0.4	30	7.5	9.7	6.5	1972
SACROC (4 pattern)	41	0.4	30	9.8	9.5	3.2	1981
South Welch	34	2.3	25	7.6	--	--	--
Twofreds	36	1.4	40	15.6	15.6	8.0	1974
Wertz	35	1.3	60	13.0	13.0	10.0	1986

Source: Brock, W.R. and Bryan, L.A., "Summary Results of CO_2 EOR Tests, 1972-1987", SPE Paper No. 18977 presented at the 1990 SPE/DOE Symposium on Enhanced Oil Recovery, Tulsa, OK, April 22-25.

Table 4. Summary of Selected CO_2 Miscible Flood Producing Pilots

Field	Oil Gravity (°API)	Viscosity (cp)	Amount Injected (% HCPV)	Incremental Recovery (% OOIP)	Gross CO_2 Utilization (Mcf/STB)	Net CO_2 Utilization (Mcf/STB)	Year Initiated
Garber	47	2.1	35	14.0	--	6.0	1981
Little Creek	39	0.4	160	21.0	27.0	12.6	1975
Maljamar #1	36	0.8	30	8.2	11.6	10.7	1983
Maljamar #2	36	0.8	30	17.7	8.1	6.1	1983
North Coles Levee	36	0.5	63	15.0	7.4	--	1981
Quarantine Bay	32	0.9	19	20.0	--	2.4	1981
Slaughter Estate	32	2.0	26	20.0	16.7	3.7	1976
Weeks Island	33	0.3	24	8.7	7.9	3.3	1978
West Sussex	39	1.4	30	12.9	8.9	---	1982

Source: Brock, W.R. and Bryan, L.A., "Summary Results of CO_2 EOR Tests, 1972-1987", SPE Paper No. 18977 presented at the 1990 SPE/DOE Symposium on Enhanced Oil Recovery, Tulsa, OK, April 22-25.

3.1 CO_2-EOR RECOVERY POTENTIAL. In comparison with field projects, 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.[5]

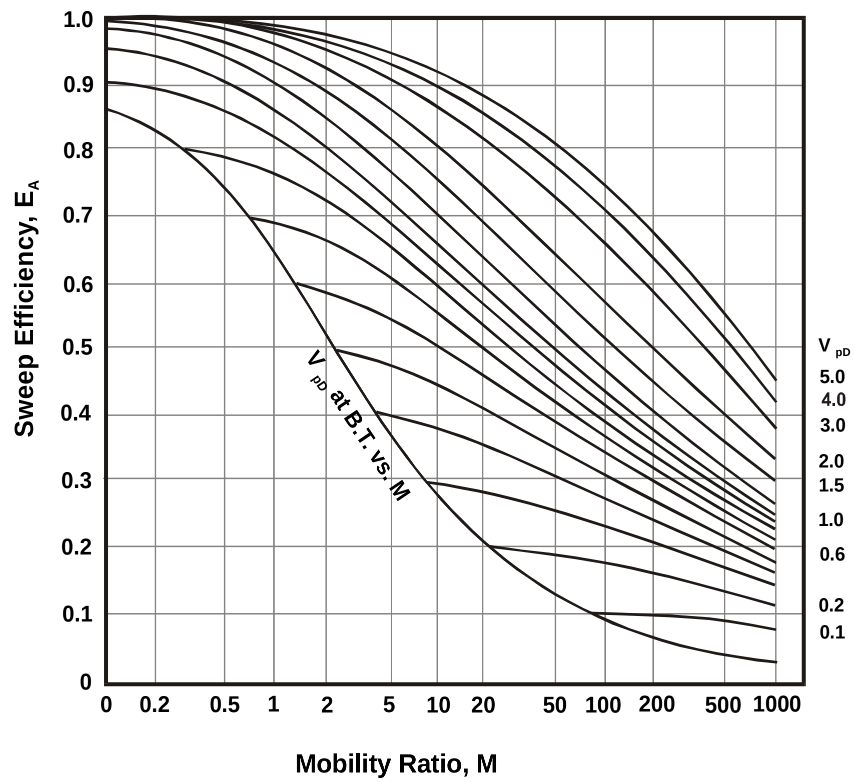
3.2 CO_2-EOR PERFORMANCE. While high oil recoveries are theoretically and scientifically possible, the actual performance of CO_2-EOR in the field, as presented above, has been much less. Geologically complex reservoir settings, combined with lack of reliable performance information or process control capability during the CO_2 flood, place serious barriers and constraints to achieving optimum oil recovery using CO_2-EOR.

The causes of less-than-optimum, past-performance and only modest oil recovery by CO_2-EOR include the following:

- The great majority of past-CO_2 floods used insufficient volumes of CO_2 for optimum oil recovery, due in part to high CO_2 costs relative to oil prices and the inability to control CO_2 flow through the reservoir. Figure 3 shows that low reservoir sweep efficiency results from using small volumes of CO_2 injection, particularly under conditions of high (unfavorable) mobility ratios. Table 5 provides an example of the relationship of CO_2 injection and oil recovery efficiency, where CO_2 is used as the secondary recovery process.

[5]See Appendix A for summary discussion of high oil recovery efficiencies from laboratory and reservoir simulation work in support of gravity stable CO_2-EOR field projects.

Figure 3. Oil Recovery in Miscible Flooding for Five-Spot Well Patterns



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).

Table 5. Example Oil Recovery Efficiency vs. HCPV of CO_2 Injection

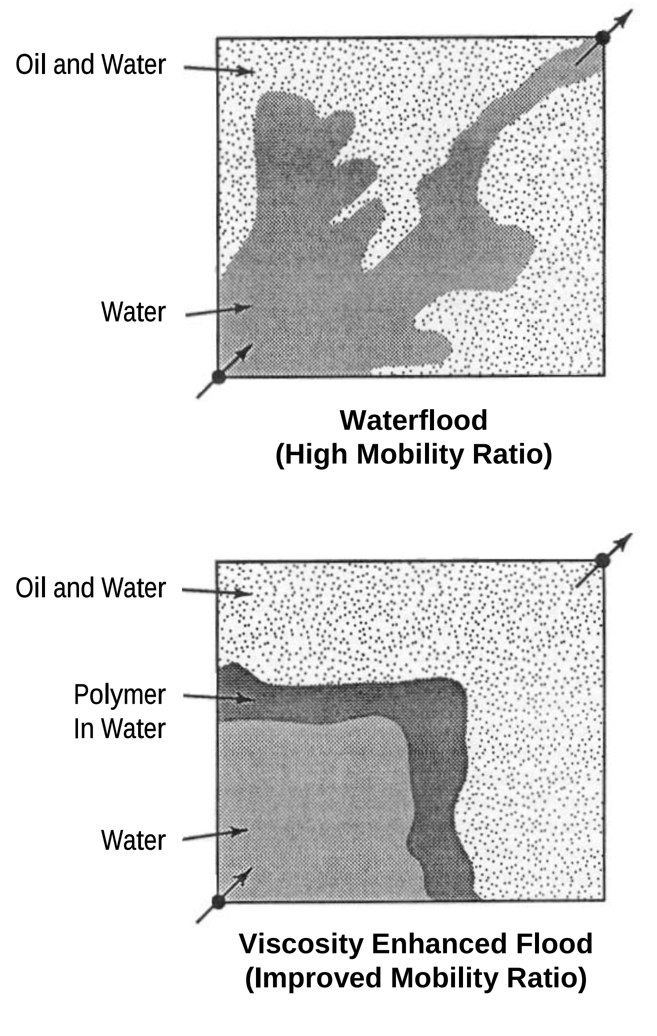
Injected CO_2 (HCPV)	Injected CO_2 (Barrels)	Reservoir Sweep Efficiency (Fraction)	Oil Recovery (Barrels)	Oil Recovery Efficiency (%)
0.40	156,400	0.345	117,300	32.2
0.60	234,600	0.440	149,600	41.1
0.80	312,800	0.515	175,100	48.1
1.00	391,000	0.570	193,800	53.2
1.50	586,500	0.670	227,800	62.6
2.00	782,000	0.725	246,500	67.7

Note: As a "rule of thumb", 2 Mcf of CO_2 at "typical" reservoir pressure and temperature conditions occupies one reservoir barrel of CO_2.

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

- 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), 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 4 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 waterflood.

Figure 4. Schematic of Macroscopic Displacement Efficiency Improvement with Polymer-Augmented Waterflooding (Quarter of a Five-Spot Pattern)



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

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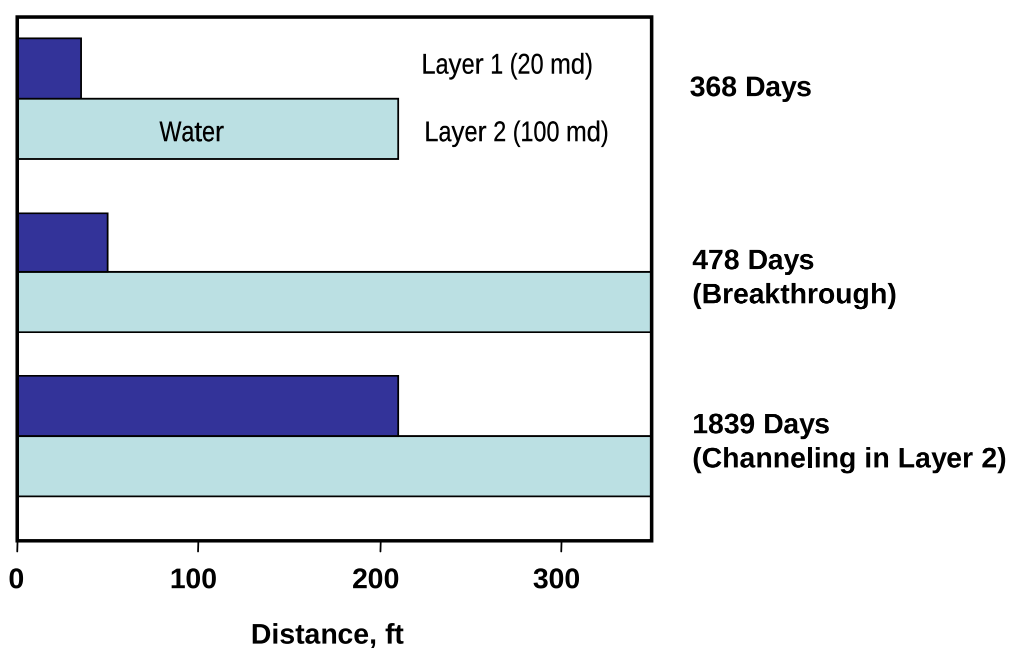
- Analysis of past CO_2 floods also shows that, in many cases, the CO_2-EOR project mobilized only a modest portion of the residual oil (poor displacement efficiency) due to lack of effective miscibility between the injected CO_2 and the reservoir's oil, caused by unexpected pressure declines in portions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

- The final cause of less-than-optimum performance, often overlooked, has been the inability to efficiently target the injected CO_2 to preferred (high residual oil) reservoir strata and then capture and produce the mobilized oil. Figure 5 shows how the lower permeability portion of the reservoir strata is less efficiently swept by a waterflood, leaving behind higher residual oil saturations.

Figure 5. Relative Location of the Water Front in a Layered Reservoir



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

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In addition, a variety of other operating issues have contributed toward less-than-optimum performance, such as loss of CO_2 to reservoir areas outside the pattern area and the inability to "manage and control" the CO_2 flood for lack of real-time performance information.

A number of theoretically sound "research pathways" could be pursued to address these barriers to optimum CO_2-EOR performance. This section sets forth these potential "research pathways". The next sections will examine, using analytical and reservoir modeling, just how much design improvement is possible in CO_2-EOR processes and, importantly, the impact of each of these design improvements or "research pathways" on additional oil recovery efficiency.

3.3 OPPORTUNITIES FOR IMPROVING CO_2-EOR TECHNOLOGY. To examine alternative "research pathways" that could enable the CO_2-EOR process to more closely realize its technical potential, we have set forth five potential "next generation" advances in CO_2-EOR technology, namely:

1. Increasing the volume of injected CO_2 to 1.5 hydrocarbon pore volume (HCPV), considerably beyond what has been traditionally used.

2. Examining innovative flood design and well placement options for contacting and producing the higher oil-saturated (less efficiently waterflood swept) portions of the reservoir, often containing the bulk of the "stranded" oil. This would include adding new horizontal and vertical wells targeting selected reservoir strata and using gravity-stable CO_2-EOR process designs (in steeply dipping and domed oil reservoirs) to increase overall reservoir contact and oil displacement by the injected CO_2.

3. Improving the viscosity of the injected water to reduce the mobility ratio between the injected CO_2/water and the reservoir's oil to reduce viscous fingering of the CO_2 through the mobilized oil bank.

4. Adding “miscibility enhancers” to extend miscible CO_2-EOR to additional oil reservoirs that would otherwise be produced by the less efficient immiscible CO_2-EOR process.

5. Finally, using the full combination of “next generation” CO_2-EOR technologies, which involves injecting higher volumes of CO_2, adopting innovative CO_2 flood and well design, and adding mobility control, to bring about “game changer” increases in oil recovery efficiency from favorable domestic oil reservoirs.

Appendix A provides summary presentations of a series of innovative CO_2-EOR field project and concepts that helped form the “next generation” technologies set forth in this report.

4. ALTERNATIVE RESEARCH PATHWAYS FOR "NEXT GENERATION" CO_2-EOR TECHNOLOGY

4.1 SAMPLE OIL RESERVOIRS. To evaluate the potential of "next generation" CO_2-EOR technologies for increasing oil recovery, we selected and then assembled data on three large, representative domestic oil reservoirs. Next, we applied increasingly sophisticated CO_2-EOR water-alternating-gas (WAG) process designs to examine their potential for improving the recovery efficiency in these three oil reservoirs.

The three oil reservoirs selected are: (1) Field #1 (Reservoir #1), a deep, California light oil reservoir amenable to miscible CO_2-EOR; (2) Field #2 (Reservoir #2), a deep, California heavy oil reservoir currently not amenable to miscible CO_2-EOR; and (3) Field #3 (Reservoir #3), a shallow, Illinois light oil reservoir, also currently not amenable to CO_2-EOR, Table 6. These reservoirs are each reasonably representative of a particular class of domestic oil reservoir examined in the previously cited six basins CO_2-EOR study. As such, the theoretically possible oil recovery improvements established in these three reservoirs could be projected to a substantially larger class of domestic oil reservoirs and their "stranded" oil.

Table 6. Domestic Oil Reservoirs Used to Evaluate "Next Generation" CO_2-EOR Technologies

Field	Field #1	Field #2	Field #3
Reservoir	Reservoir #1	Reservoir #2	Reservoir #3
Location	San Joaquin Basin	Los Angeles Basin	Illinois Basin
OOIP (MMBbls)	2,365	157	251
Depth (ft.)	5,500	4,500	2,940
Oil Gravity (^{o}API)	35	23	38
Oil Viscosity (cp)	3	13	6
Dykstra-Parsons	0.75	0.75	0.75

4.2 "NEXT GENERATION" CO_2-EOR TECHNOLOGIES. Four specific "next generation" CO_2-EOR technologies were evaluated with reservoir simulation, using the above three oil reservoirs. In each case, we posited an "achievable level of process performance", such as: increased injection of CO_2; an ability to contact more of the reservoir's pore volume using innovative flood and well design (including conducting a gravity-stable CO_2 flood); increasing the viscosity of the injected water used in the CO_2-WAG process; and, reducing the minimum miscibility pressure for deep, heavy oil and shallow, light oil reservoirs.

In this section, we examine how much each of these advances in CO_2-EOR technology would add to theoretically possible oil recovery efficiency when applied individually. In the next chapter we examine the integrated application of the combined set of "next generation" CO_2-EOR technologies to achieve "game changer" levels of improvement in oil recovery efficiency.

While we describe alternative ways that these advances in technology might be achieved, each of these improved levels of process design and field performance represents a topic for substantial future R&D in CO_2-EOR.

Research Pathway #1. Increasing CO_2 Injection. The giant Field #1 oil reservoir, described above, serves as the setting for examining the impact of the "increasing CO_2 injection" research pathway for "next generation" CO_2-EOR technology.

To examine improvement in oil recovery efficiency possible from this "research pathway", we progressively increased the volume of CO_2 injection (using reservoir simulation) from 0.4 HCPV (hydrocarbon pore volume) in the "traditional practices" case to 2.0 HCPV in the "next generation" CO_2-EOR technology cases. Higher HCPV's of injected CO_2 enable more of the reservoir's residual oil to be contacted (and even multiply contacted) by the injected CO_2. However, progressively longer CO_2 injection periods, longer overall project length and higher gross CO_2 to oil ratios are involved in the higher volume CO_2 injection cases.

In the past, the combination of high CO_2 costs and low oil prices led operators to use small-volume injections of CO_2 to maximize profitability. This 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 would 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, high CO_2-saturated interval of the reservoir.

Modeling of the Field #1 oil reservoir (using *PROPHET*) shows that "increasing CO_2 injection" can significantly increase oil recovery efficiency. Increasing the volume of CO_2 injection would provide 258 million (at 1 HCPV) to 539 million (at 2 HCPV) additional barrels of oil recovery (beyond traditional CO_2-EOR practices of 0.4 HCPV) from Field #1, raising overall oil recovery efficiency to a range of 55–67 percent, Table 7. (Analysis of the costs and economics of increasing CO_2 injection is provided in a subsequent chapter of this report.)

Table 7. Comparison of Traditional Practices vs. Increasing CO_2 Injection

	Traditional Practices	Increasing CO_2 Injection		
	0.4 HCPV CO_2	1.0 HCPV CO_2	1.5 HCPV CO_2	2.0 HCPV CO_2
	(10^6 Bbls/%OOIP)	(10^6 Bbls/%OOIP)	(10^6 Bbls/%OOIP)	(10^6Bbls/%OOIP)
OOIP*	2,365	2,365	2,365	2,365
Primary/Secondary Recovery	808 (34%)	808 (34%)	808 (34%)	808 (34%)
"Stranded" Oil	1,557	1,557	1,557	1,557
CO_2-EOR Oil Recovery	234 (10%)	492 (21%)	727 (31%)	773 (33%)
Total Oil Recovery	1,042 (44%)	1,300 (55%)	1,535 (65%)	1,581 (67%)

* OOIP = Original Oil In-Place

Research Pathway #2. Innovative Flood Design and Well Placement. The giant Field #1 oil reservoir (discussed above) also serves as the geologic setting for examining the impact of the "innovative CO_2 flood design and well placement" research pathway for "next generation" CO_2-EOR technology.

To examine the level of improvement in oil recovery efficiency possible from this "research pathway", we set forth an alternative well design and placement configuration (using reservoir simulation). This well design and placement configuration ensured 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 were equally contacted by the injected CO_2.

Examples of such innovative well design and placement options include: (1) isolating the previously poorly-swept reservoir intervals (with higher residual oil) for targeted CO_2 injection; (2) drilling horizontal injection and production wells to target bypassed or poorly produced reservoir areas or intervals; (3) altering the injection and production well pattern alignment; (4) using physical or chemical diversion materials to divert CO_2 into previously poorly-contacted portions of the reservoir; and (5) placing the injection and production wells at closer spacings.

Analytical modeling of the Field #1 oil reservoir (using *PROPHET*) shows that the use of innovative flood design and well placement can significantly increase oil production, particularly when combined with the higher volume (1 HCPV) injection of CO_2. Application of "innovative flood design and well placement" with higher volume (1 HCPV) injection of CO_2 could provide an additional 426 million barrels of oil recovery (beyond traditional CO_2-EOR practices) from the Field #1 oil reservoir, raising overall oil recovery efficiency to 62 percent of OOIP, Table 8.

Table 8. Comparison of Traditional Practices vs. Innovative Wells

	Traditional Practices	Innovative Flood Design and Well Placement
	(10^6Bbls/ %OOIP)	(10^6Bbls/ %OOIP)
OOIP*	2,365	2,365
Primary/Secondary Recovery	808 (34%)	808 (34%)
"Stranded" Oil	1,557	1,557
CO_2-EOR Oil Recovery	234 (10%)	660 (28)
Total Oil Recovery	1,042 (44%)	1,467 (62%)

* OOIP = Original Oil In-Place

Research Pathway #3. Improving the Mobility Ratio. The giant Field #1 oil reservoir serves as the setting for examining the impact of "improving the mobility ratio" research pathway for "next generation" CO_2-EOR technology.

To examine the level of improvement in oil recovery efficiency possible for this "research pathway", we assumed an increase in the viscosity of the injected water (as part of the CO_2-WAG process) to 3 cp, equal to the viscosity of the Field #1 reservoir oil. (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, could theoretically further improve performance.) Examples of ways to increase the viscosity of the injected water would be to add polymers or other viscosity-enhancing materials.

Analytic modeling of the Field #1 oil reservoir (using *PROPHET*) shows that the use of viscosifiers for improving the mobility ratio of the CO_2-EOR process can provide an important addition to oil recovery efficiency. Application of an improved mobility ratio CO_2-EOR design with higher volume (1 HCPV) injection of CO_2 could provide an additional 356 million barrels of oil recovery (beyond traditional CO_2-EOR practices) from Field #1 oil reservoir, raising overall recovery efficiency to 59 percent of OOIP, Table 9.

Table 9. Comparison of Traditional Practices vs. Improving Mobility Ratio

	Traditional Practices	Improving Mobility Ratio
	(10^6Bbls/ %OOIP)	(10^6Bbls/ %OOIP)
OOIP*	2,365	2,365
Primary/Secondary Recovery	808 (34%)	808 (34%)
“Stranded” Oil	1,557	1,557
CO_2-EOR Oil Recovery	234 (10%)	590 (25%)
Total Oil Recovery	1,442 (44%)	1,398 (59%)

* OOIP = Original Oil In-Place

Research Pathway #4. Extending Miscibility*.* Two distinctly different oil reservoirs, the deep, heavy oil Field #2 (Reservoir #2) and the shallow, light oil Field #3 (Reservoir #3) (both previously described) serve as the setting for examining the impact of the “extending miscibility” research pathway for “next generation” CO_2-EOR technology.

To examine the level of improvement in oil recovery efficiency possible from this “research pathway”, we added “miscibility extenders” to the CO_2-EOR process such that the minimum miscibility pressure requirements were reduced by 500 (pounds per square inch (psi). This enabled the above two oil reservoirs, which had previously been processed using immiscible CO_2-EOR, to attain higher oil recovery by using miscible CO_2-EOR.

Examples of miscibility enhancing agents would include: addition of 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 defined) miscibility pressure or interfacial tension reduction agents.

Analytical modeling (using *PROPHET)* shows that extending the range of oil reservoirs applicable for miscible CO_2-EOR would significantly increase oil recovery efficiency, particularly when combined with higher volume (1 HCPV) injection of CO_2.

Application of “miscibility extenders” with higher volume injection of CO_2 (1 HCPV) would provide an additional 12 million barrels of oil recovery (beyond traditional immiscible application of CO_2-EOR) from the Field #2 (Reservoir #2), raising overall oil recovery efficiency to 48 percent, Table 10. Similarly, this research pathway would provide an additional 11 million barrels of oil recovery (beyond traditional immiscible application of CO_2-EOR) from the Field #3 (Reservoir #3), raising overall oil recovery efficiency to 63 percent, Table 10.

Table 10. Comparison of Traditional Practices vs. Extending Miscibility

	Field #2 (Deep Heavy Oil)		Field #3 (Shallow Light Oil)	
	Immiscible CO_2-EOR	Extending Miscibility	Immiscible CO_2-EOR	Extending Miscibility
	(10^6Bbls/%OOIP)	(10^6Bbls/%OOIP)	(10^6Bbls/%OOIP)	(10^6Bbls/%OOIP)
OOIP*	157	157	251	251
Primary/Secondary Recovery	49 (31%)	49 (31%)	112 (44%)	112 (44%)
“Stranded” Oil	108	108	139	139
CO_2-EOR Oil Recovery	15 (10%)	27 (17%)	35 (14%)	46 (19%)
Total Oil Recovery	64 (41%)	76 (48%)	147 (58%)	158 (63%)

* OOIP = Original Oil In-Place

5. ACHIEVING “GAME CHANGER” RESULTS

The previous chapter showed that each of the “next generation” CO_2-EOR technologies could provide increased oil recovery and improved oil recovery efficiency over “traditional practices”. This chapter discusses how optimum oil recovery efficiency from CO_2-EOR technology could result from applying these “next generation” technologies in an integrated, combined fashion. As shown below, and further reported in the following sections, using an optimum combination of “next generation” CO_2-EOR technologies could provide “game changer” levels of improvement in domestic oil recovery efficiency.

The same three sample oil fields—Field #1, Field #2, and Field #3—were selected to evaluate the impact of using the combination of “next generation” technologies research pathways for radically improving oil recovery efficiency with CO_2-EOR technology.

5.1 APPLYING THE COMBINATION OF “NEXT GENERATION” TECHNOLOGIES: CASE #1. To examine the upside level of improvement in oil recovery efficiency theoretically possible for CO_2-EOR technology, we examined the integrated application of a combination of three “next-generation” technologies—(1) higher volume CO_2 injection (1.5 HCPV); (2) innovative CO_2 flood and well placement design; and, (3) improved mobility control. These three “next generation” technologies were applied to the Field #1 oil reservoir. (The performance specifications of these three “next generation” technologies, when applied individually, were discussed previously.)

Analytic modeling of the Field #1 oil reservoir (using *PROPHET*) shows that the use of this combination set of technologies could provide an additional 973 million barrels of oil recovery (beyond traditional CO_2-EOR practices) from the Field #1 oil reservoir. This would raise the overall oil recovery efficiency from this reservoir to 81 percent of OOIP, (see Table 11).

Table 11. Comparison of Traditional Practices vs. Combination of "Next Generation" Technologies (Field #1)

	Traditional Practices	Combination of "Next Generation" Technologies
	(10^6Bbls/ %OOIP)	(10^6Bbls/ %OOIP)
OOIP*	2,365	2,365
Primary/Secondary Recovery	808 (34%)	808 (34%)
"Stranded" Oil	1,557	1,557
CO_2-EOR Oil Recovery	234 (10%)	1,107 (47%)
Total Oil Recovery	1,042 (44%)	1,915 (81%)

* OOIP = Original Oil In-place

5.2 APPLYING THE COMBINATION OF "NEXT GENERATION" TECHNOLOGIES: CASE #2. Next, we examined applying the same combination of three next generation CO_2-EOR technologies plus "miscibility enhancement" to Field #2 (Reservoir #2) and Field #3 (Reservoir #3).

Analytic modeling (using *PROPHET*) shows that the use of this combination of "next generation" technologies could provide an additional 51 million barrels of oil recovery (beyond "traditional" immiscible CO_2-EOR) from the Field #2 reservoir, raising overall oil recovery efficiency to 73 percent of OOIP, (see Table 12).

Similarly, the application of this combination of "next generation" CO_2-EOR technologies to the Field #3 reservoir could provide an additional 56 million barrels of oil recovery (beyond "traditional" immiscible CO_2-EOR), raising overall oil recovery efficiency to 81 percent of OOIP, (see Table 13).

Table 12. “Traditional” vs. Combination of “Next Generation” Technologies (Field #2)

	Traditional Immiscible CO_2-EOR	Combination of “Next Generation” Technologies
	(10^6Bbls/ %OOIP)	(10^6Bbls/ %OOIP)
OOIP*	157	157
Primary/Secondary Recovery	49 (31%)	49 (31%)
“Stranded” Oil	108	108
CO_2-EOR Oil Recovery	15 (10%)	66 (42%)
Total Oil Recovery	64 (41%)	115 (73%)

* OOIP = Original Oil-In-place

Table 13. “Traditional” vs. Combination of “Next Generation” Technologies (Field #3)

	Traditional Immiscible CO_2-EOR	Combination of “Next Generation” Technologies
	(10^6Bbls/ %OOIP)	(10^6Bbls/ %OOIP)
OOIP*	251	251
Primary/Secondary Recovery	112 (44%)	112 (44%)
“Stranded” Oil	139	139
CO_2-EOR Oil Recovery	35 (14%)	91 (36%)
Total Oil Recovery	147 (58%)	203 (81%)

* OOIP = Original Oil-In-place

6. ECONOMICS OF "NEXT GENERATION" CO_2-EOR TECHNOLOGY

In the previous sections of this report, we presented the additional technically recoverable oil resources that could be gained from the application of "next generation" CO_2-EOR technology. In this section, we examine, using the three oil reservoirs previously introduced—Field #1, Field #2, and Field #3—how "next generation" in CO_2-EOR technology could impact economically recoverable oil resources.

6.1 BASIC ECONOMIC MODEL. The economic model used in the analysis draws on the previously published economic models in the six state/region reports. 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 *PROPHET*. This involved assembling the reservoir properties for each of the three oil reservoirs and then placing them into the *PROPHET* stream-tube reservoir model to calculate CO_2 injection and oil and water production versus time. In each case, the project life of the "next generation" CO_2-EOR flood increased substantially beyond the project life in the "traditional practices" case.

- **CO_2 Injection.** The costs of injecting CO_2 were estimated using the same pricing formula assumed in the six basins/region reports:
  - Cost of Purchased CO_2 (per Mcf): 5 percent of oil price ($/Bbl)
  - Cost of Recycled CO_2 (per Mcf): 1 percent of oil price ($/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 Advanced CO_2-EOR Technology.** Five additional modifications were made to the cost and economics model to account for the higher 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, using the cost formulas set forth above.

  - *Innovative Flood Design and Well Placement.* The "next generation" economic model assumes that one additional new horizontal production well and one new vertical CO_2 injection well would be added to each pattern. These wells would enable CO_2 to contact and capture residual oil 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.

– *Extending Miscibility.* The economic model assumes that the costs of purchased and recycled CO_2 are increased by $0.25 per Mcf for additives to extend miscibility, for reservoirs requiring this option.

– *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.

6.2 "NEXT GENERATION" CO_2-EOR TECHNOLOGY COSTS. Insights on the costs and benefits of conducting a "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 "traditional practices" and using the combination of "next generation" technologies in Field #1, Table 14A.

- **<u>Oil Recovery.</u>** Oil recovery from the example Field #1 (Reservoir #1) oil field (with 2,365 million barrels of original oil in-place) is estimated at 1,106 million barrels in 37 years under combination "next generation" technology versus 234 million barrels in 19 years under "traditional practices".

Table 14A. Economic Comparison of Alternative CO_2-EOR Technologies Applied to the Field #1 (Reservoir #1)

	"Traditional Practices"	Combination Application of "Next Generation" CO_2-EOR Technologies
Oil Recovery (10^6 Bbls)	234	1,107
% OOIP	10%	47%
Project Life (years)	19	37
Capital Investment (10^6\$)		
Basic Cap Ex	\$553	\$553
Additional Wells	-	\$1,002
Larger CO_2 Recycle Plant	-	\$318
Information	-	\$187
Total	\$553	\$2,060
CO_2 Costs (10^6\$)		
Purchased CO_2	\$1,561	\$2,626
Recycled	\$362	\$2,003
Total	\$1,923	\$4,629
Operating and Maintenance Costs (10^6\$)		
Basic Op Ex	\$1,930	\$1,930
Additional Wells and Fluid Lifting	-	\$3,000
Viscosity Enhancement	-	\$944
"Management and Control"	-	\$1,060
Total	\$1,930	\$6,934

- **Capital Investment.** Capital investment in the example Field #1 oil field is four-fold higher, at \$2,060 million dollars under combination application of "next generation" technologies versus \$553 million dollars under "traditional practices". The extra costs are due to:

- An extra \$1,002 million for drilling, completing, and equipping additional horizontal and vertical wells,
- A larger CO_2 recycle plan, adding \$318 million, and
- An allocation of \$187 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.

- **CO_2 Costs**. CO_2 costs for the example Field #1 oil field are more than twice as high, at \$4,629 million under combination application of “next generation” technologies versus \$1,923 million under “traditional practices”. The extra costs are due to:
  - Somewhat larger volumes of higher cost purchased CO_2 of 2,101 Bcf under combination “next generation” technology versus 1,249 Bcf under “traditional practices”.
  - Significantly larger volumes of lower cost recycled CO_2 of 8,011 Bcf under combination “next generation” technology versus 1,448 Bcf under “traditional practices”.

- **Operating and Maintenance Costs (O&M)**. O&M costs in the example Field #1 oil field are more than three times higher, at \$6,934 million (for 37 years) under combination application of “next generation” technologies versus \$1,930 million for (19 years) under “traditional practices”. The extra costs are due to:
  - An extra \$3,000 million for operating a larger number of wells for 18 additional years and lifting volumes of additional oil and water,
  - An extra \$944 million for purchase and injection of viscosity enhancing materials, and
  - An additional allocation of \$1,060 million (about \$29 million per year) for “managing and controlling” the “next generation” CO_2 flood.

6.3 EXAMPLE ECONOMIC RESULTS.

The economic comparison of using "traditional practices" CO_2-EOR (0.4 HCPV of CO_2) and a combination of "next generation" CO_2-EOR technologies (with 1.5 HCPV of CO_2) are provided below for the Field #1 reservoir, Table 14B.

Appendix B-1 provides the detailed economic model runs that underlie the summary performance cost information presented in Tables 14A and 14B.

Table 14B. Economic Comparison of Alternative CO_2-EOR Technologies – Applied to Field #1 (Reservoir #1)

	Traditional Practices	Combination Application of "Next Generation" CO_2-EOR Technologies*
Oil Recovery (10^6 Bbls)	234	1,107
% OOIP	10%	47%
Project Life (years)	19	37
CapEx ($/Bbl)	$2.36	$1.86
CO_2 Costs ($/Bbl)	$8.22	$4.18
OpEx ($/Bbl)	$8.25	$6.26
Rate of Return (%)**	Below Minimum Threshold	Above Minimum Threshold

*Includes extra costs for applying "next generation" CO_2-EOR technology.
**Assumes long-term oil price of $25 per barrel, adjusted for gravity and location differentials; minimum threshold rate of return of 15% (real), before tax.

A similar economic comparison is made for the deep, heavy oil Field #2 (Reservoir #2) that was previously produced with "traditional" immiscible CO_2–EOR technology, Table 15. The final economic comparison is made for Field #3 (Reservoir #3) shallow, light oil reservoir that was also previously produced with "traditional" immiscible CO_2-EOR technology, Table 16.

Appendices B-2 and B-3 provide the detailed economic model runs that underlie the summary information presented in Tables 15 and 16.

Table 15. Economic Comparison of Alternative CO_2-EOR Technologies Applied to Field #2 (Reservoir #2)

	"Traditional" Immiscible CO_2-EOR Technology	Combination Application of "Next Generation" CO_2-EOR Technologies*
Oil Recovery (10^6 bbls)	15	66
% OOIP	10%	42%
Project Life (years)	23	29
CapEx ($/Bbl)	$2.76	$2.06
CO_2 Costs ($/Bbl)	$5.41	$5.58
OpEx ($/Bbl)	$10.69	$6.17
Rate of Return (%)**	Negative	Above Minimum Threshold

*Includes extra costs for applying "next generation" CO_2-EOR technology.
**Assumes long-term oil price of $25 per barrel, adjusted for gravity and location differentials; minimum threshold rate of return of 15% (real), before tax.

Table 16. Economic Comparison of Alternative CO_2-EOR Technologies Applied to Field #3 (Reservoir #3)

	"Traditional" Immiscible CO_2-EOR Technology	Combination Application of "Next Generation" CO_2-EOR Technologies*
Oil Recovery (10^6 bbls)	35	91
% OOIP	14%	36%
Project Life (years)	18	39
CapEx ($/Bbl)	$2.65	$1.71
CO_2 Costs ($/Bbl)	$3.96	$7.09
OpEx ($/Bbl)	$9.34	$7.90
Rate of Return (%)**	Above Minimum Threshold	Above Minimum Threshold

*Includes extra costs for applying "next generation" CO_2-EOR technology.
**Assumes long-term oil price of $25 per barrel, adjusted for gravity and location differentials; minimum threshold rate of return of 15% (real), before tax.

7. STATE-BY-STATE RESULTS

Examining the application of the combination of “next generation” CO_2-EOR technologies to the six basins/regions previously assessed -- California, Gulf Coast, Oklahoma, Illinois, Alaska, and Louisiana Offshore (Shelf) -- shows that significant improvements are possible in domestic oil recovery and oil recovery efficiency.

7.1 CALIFORNIA. Because of its geologically complex reservoirs and large volumes of deep heavy oil, the overall oil recovery efficiency in the California on-shore oil fields is low, at 31 percent of the original oil in-place (OOIP), Table 17. (This relatively low oil recovery efficiency includes the successful application of steam-based enhanced oil recovery in California’s large, shallow heavy oil fields.)

Table 17. California: Original Oil In-Place, Cumulative Production, Proved Reservoirs and Recovery Efficiency (Currently Used Oil Recovery Methods)

	OOIP (B Bbls)	Cumulative Recovery (B Bbls)	Proved Reserves (B Bbls)	Total Recovery (B Bbls)	Recovery Efficiency %
Data Base	74.8	21.3	2.2	23.5	31
State Total	83.3	23.1	2.9	26.0	31

Screening the California large oil fields data base identified 96 reservoirs that would be favorable for miscible or immiscible CO_2-EOR. Application of the combination of “next generation” CO_2-EOR technologies to these reservoirs shows that oil recovery efficiency could be significantly improved, raising recovery efficiency in oil reservoirs favorable for CO_2-EOR by 32 percent and raising the overall oil recovery efficiency in California oil fields by 16 percent, Table 18.

Table 18. California: Original Oil In-Place, Recoverable Resources and Recovery Efficiency – ("State-of-the-Art" and "Next Generation" CO_2-EOR Technology)

	OOIP	Oil Recovery from Applying CO_2-EOR Technology			
		"State-of-the-Art"	Incremental from "Next Generation"	Total	Recovery Efficiency
	(B Bbls)	(B Bbls)	(B Bbls)	(B Bbls)	(%)
Data Base					
• Favorable Reservoirs	37.5	4.6	7.3	11.9	32
• Unfavorable Reservoirs	37.3	--	--	--	--
Total	74.8	4.6	7.3	11.9	16
State Total	83.3	5.2	8.1	13.3	16

The use of the combination of "next generation" CO_2-EOR technologies would add 11.9 billion barrels of technically recoverable resource (13.3 billion barrels when extrapolated to the state as a whole). Combining the oil recovery from currently used (primary, secondary and thermal) recovery methods and the additional oil recovery from applying the combination "next generation" CO_2-EOR technologies would raise the overall recovery efficiency in California oil fields to 47 percent, Table 19.

Table 19. California: Original Oil In-Place, Recoverable Resources and Recovery Efficiency – (Currently Used Oil Recovery Methods and "Next Generation" CO_2-EOR Technology)

	OOIP	Past and Future Oil Recovery			
		Current Methods	"Next Generation" CO_2-EOR	Total	State-Wide Oil Recovery Efficiency
	(B Bbls)	(B Bbls)	(B Bbls)	(B Bbls)	(%)
Data Base	74.8	23.5	11.9	35.4	47
State Total	83.3	26.0	13.3	39.3	47

7.2 GULF COAST. The great bulk of the onshore oil reservoirs in the Gulf Coast region (Louisiana on-shore, Mississippi, and East Texas RR#3) have light oil, are moderately deep and often have a favorable bottom water drive. As such, the overall oil recovery efficiency in the Gulf Coast oil fields is high, at 40 percent, Table 20. (A limited number of new CO_2-EOR floods, primarily in Mississippi, are included in the totals.)

Table 20. Gulf Coast: Original Oil In-Place, Cumulative Production, Proved Reservoirs and Recovery Efficiency (Currently Used Oil Recovery Methods)

	OOIP (B Bbls)	Cumulative Recovery (B Bbls)	Proved Reserves (B Bbls)	Total Recovery (B Bbls)	Recovery Efficiency (%)
Data Base	35.1	14.0	0.3	14.3	40
State Total	60.8	23.7	0.8	24.5	40

Screening the Gulf Coast large oil fields data base identified 208 reservoirs that would be favorable for miscible or immiscible CO_2-EOR. Application of the combination of "next generation" CO_2-EOR technologies to these reservoirs shows that oil recovery efficiency could be significantly improved, raising recovery efficiency in oil reservoirs favorable for CO_2-EOR by 35 percent and the overall oil recovery efficiency in Gulf Coast onshore oil fields by 32 percent, Table 21.

Table 21. Gulf Coast: Original Oil In-Place, Recoverable Resources, and Recovery Efficiency – ("State-of-the-Art" and "Next Generation" CO_2-EOR Technology)

	OOIP	Oil Recovery from Applying CO_2-EOR Technology			
		"State-of-the-Art"	Incremental from "Next Generation"	Total	Recovery Efficiency
	(B Bbls)	(B Bbls)	(B Bbls)	(B Bbls)	(%)
Data Base					
• Favorable Reservoirs	32.2	5.9	5.2	11.1	35
• Unfavorable Reservoirs	2.9	--	--	--	--
Total	35.1	5.9	5.2	11.1	32
State Total	60.8	10.1	8.9	19.0	32

The use of the combination of "next generation" CO_2-EOR technologies would add 11.1 billion barrels of technically recoverable resource (19.0 billion barrels when extrapolated to the state or as a whole). Combining the oil recovery from currently used (primary and secondary) recovery methods and the additional oil recovery from applying the combination "next generation" CO_2-EOR technologies would raise the overall recovery efficiency in Gulf Coast oil fields to 72 percent, Table 22.

Table 22. Gulf Coast: Original Oil In-Place, Recoverable Resources and Recovery Efficiency – (Currently Used Oil Recovery Methods and "Next Generation" CO_2-EOR Technology)

	OOIP	Past and Future Oil Recovery			
		Current Methods	"Next Generation" CO_2-EOR	Total	State-Wide Oil Recovery Efficiency
	(B Bbls)	(B Bbls)	(B Bbls)	(B Bbls)	(%)
Data Base	35.1	14.3	11.1	25.4	72
State Total	60.8	24.5	19.0	43.5	72

7.3 OKLAHOMA. Many of the Oklahoma oil fields were discovered and produced before modern reservoir engineering practices began to be routinely applied. In addition, a large number of the older Oklahoma oil fields depleted their reservoir drive and have yet to undertake comprehensive secondary oil recovery. As a result, the overall oil recovery efficiency in the Oklahoma oil fields is low, at 25 percent, Table 23. (A small number of CO_2-EOR and polymer floods are included in the totals.)

Table 23. Oklahoma: Original Oil In-Place, Cumulative Production, Proved Reservoirs and Recovery Efficiency (Currently Used Oil Recovery Methods)

	OOIP (B Bbls)	Cumulative Recovery (B Bbls)	Proved Reserves (B Bbls)	Total Recovery (B Bbls)	Recovery Efficiency %
Data Base	36.5	8.9	0.3	9.2	25
State Total	60.3	14.5	0.7	15.2	25

Screening the Oklahoma large oil fields data base identified 71 reservoirs that would be favorable for miscible or immiscible CO_2-EOR. Application of the combination of “next generation” CO_2-EOR technologies to these reservoirs shows that oil recovery efficiency could be significantly improved, raising recovery efficiency in oil reservoirs favorable for CO_2-EOR by 44 percent and the overall oil recovery efficiency in Oklahoma oil fields by 33 percent, Table 24.

Table 24. Oklahoma: Original Oil In-Place, Recoverable Resources, and Recovery Efficiency – ("State–of-the-Art" and "Next Generation" CO_2-EOR Technology)

	OOIP	Oil Recovery from Applying CO_2-EOR Technology			
		"State-of-the-Art"	Incremental from "Next Generation"	Total	Recovery Efficiency
	(B Bbls)	(B Bbls)	(B Bbls)	(B Bbls)	(%)
Data Base					
• Favorable Reservoirs	27.3	5.4	6.7	12.1	44
• Unfavorable Reservoirs	--	--	--	--	--
Total	36.5	5.4	6.7	12.1	33
State Total	60.3	9.0	11.1	20.1	33

The use of the combination of "next generation" CO_2-EOR technologies would add 12.1 billion barrels of technically recoverable resource (20.1 billion barrels when extrapolated to the state or as a whole). Combining the oil recovery from currently used (primary and secondary) recovery methods and the additional oil recovery from applying the combination "next generation" CO_2-EOR technologies would raise the overall recovery efficiency in Oklahoma oil fields to 58 percent, Table 25.

Table 25. Oklahoma: Original Oil In-Place, Recoverable Resources and Recovery Efficiency – (Currently Used Oil Recovery Methods and "Next Generation" CO_2-EOR Technology)

	OOIP (B Bbls)	Past and Future Oil Recovery			
		Current Methods	"Next Generation" CO_2-EOR	Total	State-Wide Oil Recovery Efficiency
		(B Bbls)	(B Bbls)	(B Bbls)	(%)
Data Base	36.5	9.2	12.1	21.3	58
State Total	60.3	15.2	20.1	35.3	58

7.4 ILLINOIS. The Illinois Basin has a large number of relatively shallow, light oil reservoirs that have been successfully produced with primary and secondary oil recovery methods. As a result, the recovery efficiency in Illinois oil fields is moderately high, at 39 percent of the original oil in-place (OOIP), Table 26.

Table 26. Illinois: Original Oil In-Place, Cumulative Production, Proved Reservoirs and Recovery – Efficiency (Currently Used Oil Recovery Methods)

	OOIP (B Bbls)	Cumulative Recovery (B Bbls)	Proved Reserves (B Bbls)	Total Recovery (B Bbls)	Recovery Efficiency %
Data Base	6.5	2.4	0.1	2.5	39
State Total	9.4	3.6	0.1	3.7	39

Screening the Illinois large oil fields data base identified 46 reservoirs that would be favorable for miscible or immiscible CO_2-EOR. Application of the combination of "next generation" CO_2-EOR technologies to these reservoirs shows that oil recovery efficiency could be significantly improved, raising recovery efficiency in oil reservoirs favorable for CO_2-EOR by 35 percent and raising the overall oil recovery efficiency in Illinois oil fields by 17 percent, Table 27.

Table 27. Illinois: Original Oil In-Place, Recoverable Resources, and Recovery Efficiency – ("State–of-the-Art" and "Next Generation" CO_2-EOR Technology)

		Oil Recovery from Applying CO_2-EOR Technology			
	OOIP	"State-of-the-Art"	Incremental from "Next Generation"	Total	Recovery Efficiency
	(B Bbls)	(B Bbls)	(B Bbls)	(B Bbls)	(%)
Data Base					
• Favorable Reservoirs	3.1	0.5	0.6	1.1	35
• Unfavorable Reservoirs	3.4	--	--	--	--
Total	6.5	0.5	0.6	1.1	17
State Total	9.4	0.7	0.9	1.6	17

The use of the combination of “next generation” CO_2-EOR technologies would add 1.1 billion barrels of technically recoverable resource (1.6 billion barrels when extrapolated to the state as a whole). Combining the oil recovery from currently used (primary and secondary) recovery methods and the additional oil recovery from applying the combination “next generation” CO_2-EOR technologies would raise the overall oil recovery efficiency in Illinois oil fields to 56 percent, Table 28.

Table 28. Illinois: Original Oil In-Place, Recoverable Resources and Recovery Efficiency – (Currently Used Oil Recovery Methods and “Next Generation” CO_2-EOR Technology)

		Past and Future Oil Recovery			
	OOIP	Current Methods	“Next Generation” CO_2-EOR	Total	State-Wide Oil Recovery Efficiency
	(B Bbls)	(B Bbls)	(B Bbls)	(B Bbls)	(%)
Data Base	6.5	2.5	1.1	3.6	56
State Total	9.4	3.7	1.6	5.3	56

7.5 ALASKA. Oil recovery efficiency in Alaska is dominated by performance in a small number of very large oil fields, such as Prudhoe Bay and Kuparuk River. An aggressive program of water injection, reinjection of the produced natural gas (which contains a significant percent of CO_2), and hydrocarbon miscible CO_2-EOR has led to an overall oil recovery efficiency in the Alaska oil fields of 33 percent of the original oil in-place (OOIP), Table 29.

Table 29. Alaska: Original Oil In-Place, Cumulative Production, Proved Reservoirs and Recovery Efficiency (Currently Used Oil Recovery Methods)

	OOIP (B Bbls)	Cumulative Recovery (B Bbls)	Proved Reserves (B Bbls)	Total Recovery (B Bbls)	Recovery Efficiency %
Data Base	65.3	14.9	6.7	21.6	33
State Total	67.3	15.3	6.9	22.2	33

Screening the Alaska large oil fields data base identified 33 reservoirs that would be favorable for miscible or immiscible CO_2-EOR. Application of the combination of "next generation" CO_2-EOR technologies to these reservoirs shows that oil recovery efficiency could be significantly improved, raising recovery efficiency in oil reservoirs favorable for CO_2-EOR by 36 percent and raising the overall oil recovery efficiency in Alaska oil fields by 35 percent, Table 30.

Table 30. Alaska: Original Oil In-Place, Recoverable Resources, and Recovery Efficiency – ("State–of-the-Art" and "Next Generation" CO_2-EOR Technology)

	OOIP	Oil Recovery from Applying CO_2-EOR Technology			
		"State-of-the-Art"	Incremental from "Next Generation"	Total	Recovery Efficiency
	(B Bbls)	(B Bbls)	(B Bbls)	(B Bbls)	(%)
Data Base					
• Favorable Reservoirs	64.5	12.0	11.1	23.1	36
• Unfavorable Reservoirs	0.8	--	--	--	--
Total	65.3	12.0	11.1	23.1	35
State Total	67.3	12.4	11.4	23.8	36

The use of the combination of "next generation" CO_2-EOR technologies would add 11.1 billion barrels of technically recoverable resource (11.4 billion barrels when extrapolated to the state or as a whole). Combining the oil recovery from currently used (primary, secondary and hydrocarbon miscible) recovery methods and the additional oil recovery from applying the combination "next generation" CO_2-EOR technologies would rase the overall recovery efficiency in Alaska oil fields to 68 percent, Table 31.

Table 31. Alaska: Original Oil In-Place, Recoverable Resources and Recovery Efficiency – (Currently Used Oil Recovery Methods and "Next Generation" CO_2-EOR Technology)

	OOIP	Past and Future Oil Recovery			
		Current Methods	"Next Generation" CO_2-EOR	Total	State-Wide Oil Recovery Efficiency
	(B Bbls)	(B Bbls)	(B Bbls)	(B Bbls)	(%)
Data Base	65.3	21.6	23.1	44.7	68
State Total	67.3	22.2	23.8	46.0	68

7.6 LOUISIANA OFFSHORE (SHELF). Conducting CO_2-EOR in offshore areas, even with the best of currently available technology, will encounter barriers and constraints beyond those experienced in onshore operations. Given the very limited past experience in operating CO_2-EOR in the offshore, the already favorable primary/ secondary oil recoveries from these high permeability, strong water drive reservoirs, and expectations of nearly 6 billion barrels of technically recoverable oil resource from application of “state-of-the-art” CO_2-EOR technology to the Louisiana Offshore (Shelf) reservoirs, the application of “next generation” CO_2-EOR technology may not be feasible for this basin/region. As such, no further analysis of increasing oil recovery or oil recovery efficiency has been conducted for the Louisiana Offshore (Shelf) oil fields.

8. SUMMARY

The results from this study indicate that domestic oil recovery efficiency could be improved significantly with “next generation” CO_2-EOR technology. Domestic oil recovery (in the six basins/regions examined so far) could be increased by 83.7 billion barrels of technically recoverable resource (over current primary/secondary methods) and overall oil recovery efficiency (in these six basins/regions) would be increased to 61 percent of original oil in-place.

However, the reader should note that significant new investments are required in research and technology development for CO_2-EOR to provide the increased domestic oil resources and to realize the higher oil recovery efficiencies set forth in this report.

The four major findings from this study are as follows:

1. **Demonstration of “state-of-the-art” CO_2-EOR practices and development of “next generation” CO_2-EOR technologies could greatly increase the recovery efficiency from domestic oil reserves.** Domestic oil recovery efficiency, even including “traditionally practiced” thermal and CO_2-EOR technologies, is low – less than 36 percent of the original oil in-place. “State-of-the-art” CO_2-EOR technology can raise this to nearly 48 percent. Development and successful application of “next generation” CO_2-EOR technologies can further increase domestic oil recovery efficiency, raising this critical value to 61 percent overall (and in geologically favorable reservoirs to over 80 percent) in the six basins/regions addressed by this study.

2. **With "state-of-the-art" CO_2 enhanced oil recovery technology, an estimated 43.3 billion barrels of "stranded" oil (in the six basins and areas studied to date) could become technically recoverable.** Of the 895 oil reservoirs in the data base, 533 large reservoirs screen favorably for "state-of-the-art" CO_2-EOR, providing 32.9 billion barrels of technically recoverable resource. When the CO_2-EOR potential in these 533 large favorable oil reservoirs is extrapolated to the "stranded" oil resources in each of the six basins/areas, the CO_2-EOR potential becomes 43.3 billion barrels of technically recoverable resource, as reported in previous DOE/FE studies[6], Table 32. Extrapolated to all domestic light oil reservoirs, "state-of-the-art" CO_2-EOR technology could provide 80 billion barrels of technically recoverable domestic oil resource, as reported in the DOE/FE study, *Undeveloped Oil Resources: The Foundation for Increased Oil Production and a Viable Domestic Oil Industry*.[7]

Table 32. Technically Recoverable Oil Resource From "State-of-the-Art" CO_2-EOR (Six Basins/Areas Assessed to Date)

Basin/Area	Large Favorable Reservoirs (Six Areas)		All Reservoirs (Six Basins/Areas)		
	Number	Technically Recoverable	OOIP* (Billion Barrels)	ROIP** (Billion Barrels)	Technically Recoverable (Billion Barrels)
California	88	4.6	83.3	57.3	5.2
Gulf Coast	205	5.9	60.8	36.4	10.1
Oklahoma	63	5.4	60.3	45.1	9.0
Illinois	46	0.5	9.4	5.8	0.7
Alaska	32	12.0	67.3	45.0	12.4
Louisiana Offshore (Shelf)	99	4.5	28.1	15.7	5.9
Total	533	32.9	309.2	205.3	43.3

*Original Oil In-Place, in all reservoirs in basin/area; ** Remaining Oil In-Place, in all reservoirs in basin/area.
Source: Advanced Resources International, 2005.

[6] U.S. Department of Energy/Fossil Energy: "Basin-Oriented Strategies for CO2 Enhanced Oil Recovery: California, Onshore Gulf Coast, Offshore Louisiana, Oklahoma, Alaska and Illinois", April 2005.
[7] U.S. Department of Energy/Fossil Energy: "Undeveloped Oil Resources: The Foundation for Increased Oil Production and a Viable Domestic Oil Industry" February 2006.

3. **With integrated application of the full set of "next generation" CO_2 enhanced oil recovery technologies, 83.7 billion barrels of "stranded" oil (in the six basins and areas studied to date) could become technically recoverable.** Of the 895 oil reservoirs in the data base, 553 large reservoirs screen favorably for CO_2-EOR, with 63.8 billion barrels of technically recoverable resource when using the full set of "next generation" CO_2-EOR technologies. When the CO_2-EOR potential in these 553 large favorable oil reservoirs is extrapolated to the "stranded" oil resources in each of the six state/areas, the CO_2-EOR potential becomes 83.7 billion barrels of technically recoverable resource, Table 33.

Table 33. Technically Recoverable Oil Resource From "Next Generation" CO_2-EOR (Six Basins/Areas Assessed to Date)

Basin/Area	Large Favorable Reservoirs (Six Areas)		All Reservoirs (Six Basins/Areas)		
	Number	Technically Recoverable	OOIP* (Billion Barrels)	ROIP** (Billion Barrels)	Technically Recoverable (Billion Barrels)
California	96	11.9	83.3	57.3	13.3
Gulf Coast	208	11.1	60.8	36.4	19.0
Oklahoma	63	12.1	60.3	45.1	20.1
Illinois	46	1.1	9.4	5.8	1.6
Alaska	32	23.1	67.3	45.0	23.8
Louisiana Offshore (Shelf)	99	4.5	28.1	15.7	5.9
Total	553	63.8	309.2	205.3	83.7

*Original Oil In-Place, in all reservoirs in basin/area; ** Remaining Oil In-Place, in all reservoirs in basin/area.
Source: Advanced Resources International, 2005.

4. **When extrapolated to all domestic oil fields, the integrated application of "next generation" CO_2-EOR technologies could provide 160 billion barrels of technically recoverable resource.** Integrated application of "next generation" CO_2-EOR technologies to the remaining domestic oil basins and regions still to be assessed could bring about truly "game changer" advances in oil recovery efficiency and domestic oil production. Extrapolating the sample of oil reservoirs included in the study to the

nation as a whole (using data on original oil in-place, provided in Figures EX-1 and Table EX-1) shows that the integrated application of “next generation” CO_2-EOR technologies could provide 160 billion barrels of technically recoverable resource from domestic oil fields.

APPENDIX A

SELECTED SUMMARIES OF INNOVATIVE CO_2-EOR FLOODING DESIGNS, RESEARCH PILOTS AND FIELD-SCALE PROJECTS

A. WEEKS ISLAND

Production History. The Weeks Island Field, discovered in 1945, is located in Iberia Parish, Louisiana, in the Gulf Coast Basin. The Weeks Island "S" Sand Reservoir B is one of 55 Pliocene and Miocene-age sands within this field.

Reservoir B was first produced in 1968 by gas-cap expansion and later by water injection. During primary recovery, 0.79 MMbbls of oil, equivalent to 55 feet of the original oil column and 24% of the OOIP, were produced via gas cap expansion from the State Unit A-16 production well. During secondary recovery, fresh water was injected into the State Unit G-2 injection well, which penetrated the west flank of the oil column below the oil-water contact. The waterflood recovered 1.77 MMbbls of incremental oil, equal to 54% of the OOIP. This provided an overall oil recovery of 2.56 MMbbls of oil (79% of OOIP). Ultimate oil recovery was projected to reach 2.61 MMbbls (80% of OOIP) at the field's economic limit.

Reservoir Properties. The Weeks Island "S" Sand Reservoir B contains a light oil and has an average porosity of 26% and an average permeability of 1,200 md. The reservoir is at depth of 13,000 feet, and had an original pressure of 6,013 psia and a temperature of 225ºF.

Reservoir B is relatively small and is sealed against the north flank of a piercement salt dome by radial and peripheral faults. It dips fairly steeply, at an angle of 26º. The initial oil column was 353 feet thick between a gas-oil contact located initially at 12,705 feet below sea level and a water-oil contact of 13,058 feet below sea level.

CO_2 Flood Design. The State Unit A-17 well was drilled to evaluate reservoir parameters through the analysis of core and geophysical logs. Residual oil saturation at the start of the tertiary CO_2 flood was low at 0.22 with a FVF of 1.545 (giving a stock tank residual oil saturation of about 14% and an oil content of about 288 STB/AF).

The project operator, Shell, used a multi-component, multiphase simulator to model fluid behavior in the reservoir. The model showed that water coning would be a problem when injecting CO_2 into Reservoir B.

CO_2-EOR Results. Gravity stable flooding was conducted from October 4, 1978 to February 27, 1980, and 908 MMcf of gas, containing 94% (858 MMcf) CO_2 and 6% (55 MMcf) methane, was injected into the State Unit A-16 well, just above the gas-oil contact.

Oil production began in January 1981 when the water-oil interval reached the producing interval in the State Unit A-17 well. One month later, downdip water production was terminated to forestall CO_2 breakthrough.

Produced gas recycling was initiated in 1983 and continued through 1987. Figure A-1 provides an illustration of the progressive displacement of the oil column from start of CO_2 injection to the end of the project.

Both State Unit A-17 and A-18 wells produced at high watercut and continuously increasing GOR until late 1987 when the reservoir was essentially depleted. Despite severe water coning, over 90% of the waterflood residual oil was mobilized and over was 80% was recovered. Through 1987, cumulative tertiary oil production was 261,500 barrels (8.3% OOIP) with 23 Mcf of gas injected per barrel of oil recovered. Post tertiary oil saturations were reduced to an average of 2% as confirmed by State Unit A-18, drilled in late 1982, to evaluate the CO_2-swept portion of the reservoir.

Observations. Including primary, secondary and tertiary recovery, oil production in this reservoir totaled 2.88 MMBbls, or 89% recovery of the OOIP. Although the tertiary recovery in the Weeks Island "S" Sand Reservoir B was very efficient, the low remaining oil saturation after primary and secondary recovery and the extensive water coning significantly impacted the economics of this tertiary oil recovery project. The operator noted the need to implement this type of tertiary oil recovery process early in the production history to help reduce costs and accelerate overall oil recovery.

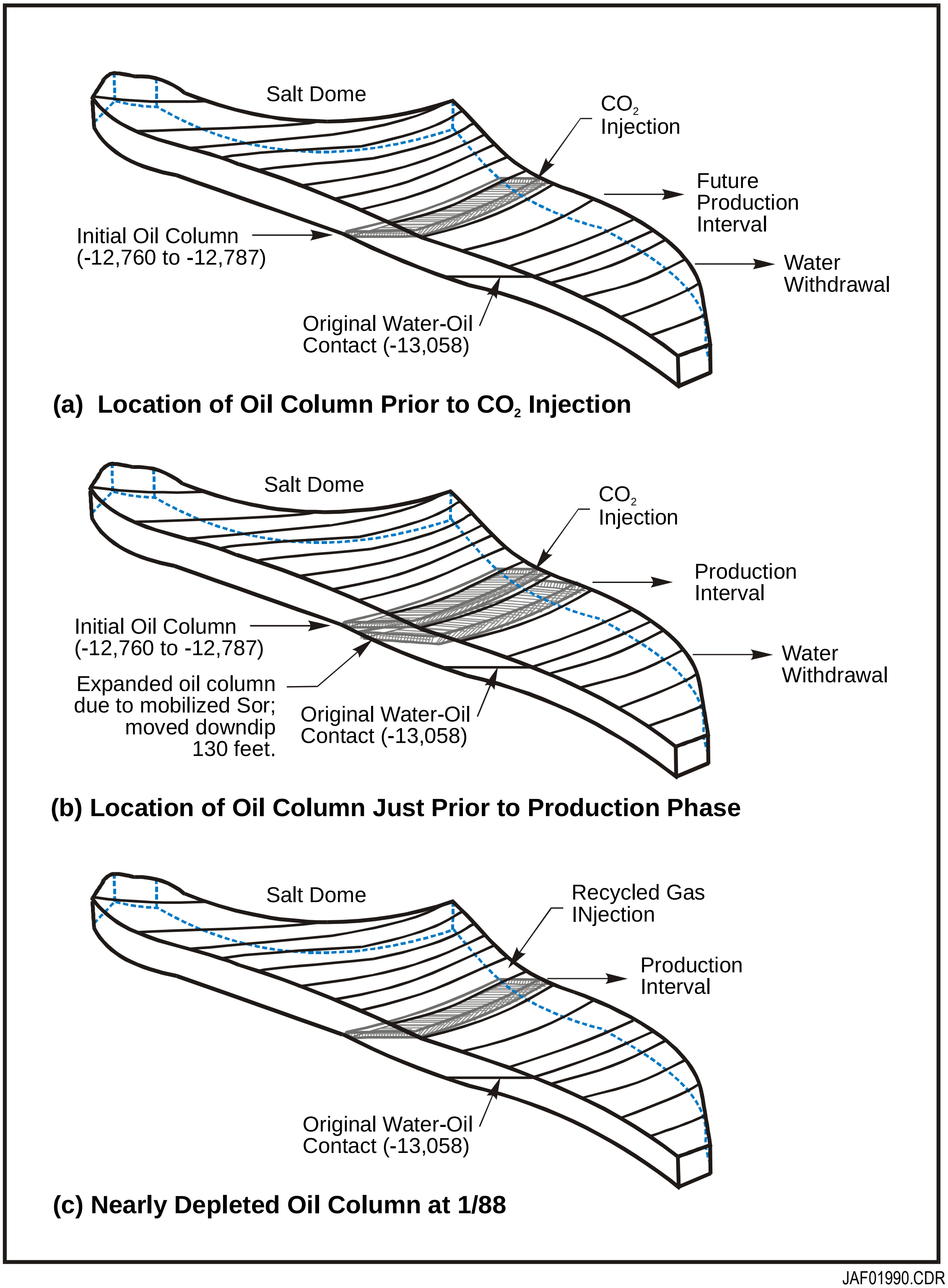

Figure A-1. Progressive Oil Column Displacement (contour interval 100 ft.)

B. BAY ST. ELAINE

Reservoir Properties. The Bay St. Elaine Field is located in southern Louisiana, Figure B-1. The 8,000 foot Reservoir E Unit overlies a salt dome in the coastal marshes of Louisiana. The reservoir dips at an average angle of 36° as result of the upward migration of a salt dome. The reservoir contains a light oil and has a high porosity of 32.9% and a high permeability of 1,480 md. The gross thickness varies from 30 ft near the updip unconformity to 102 ft in the downdip section of the reservoir providing an average net sand of 35 feet. Table B-1 provides additional data on reservoir properties.

The average residual oil saturation in the 8,000' Reservoir E Unit at the start of the gravity-stable flood was estimated at 20% pore volume.

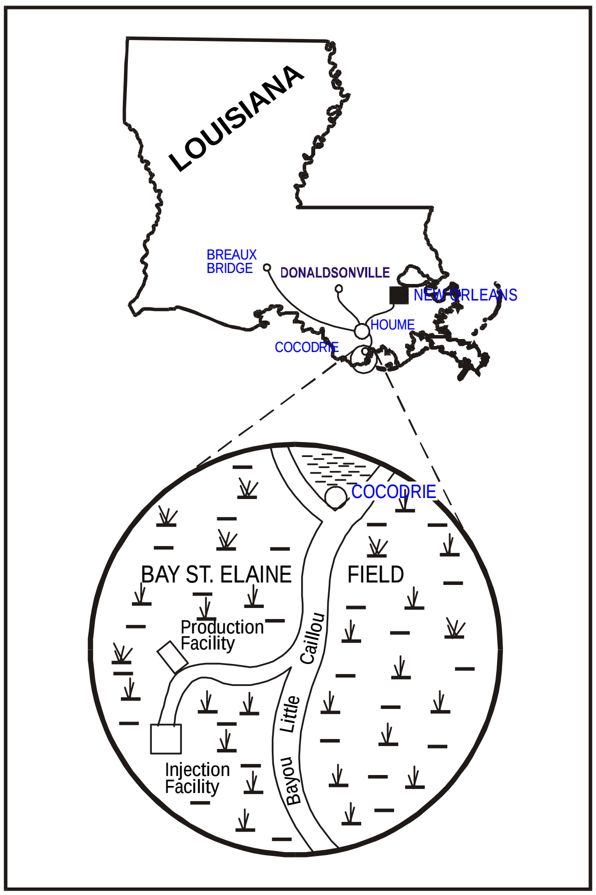

Figure B-1. Bay St. Elaine Field Location

Production History. The 8,000' Reservoir E Unit was produced under strong natural water drive during primary production. All the wells in Reservoir E were producing at nearly a 100% water cut when the gravity-stable CO_2 injection began. Primary oil recovery at the time of CO_2 injection was approximately 9.4 MMBbls.

Table B-1. Key Reservoir Parameters

Temperature, °F	164
Current reservoir pressure, psia	3,334
Datum depth, ft	7,400
Porosity, %	32.9
Permeability, md	1,480
Dip, degrees	36
Average net sand, ft	35
Residual oil saturation, % PV	20
Connate water saturation, % PV	15
Oil gravity, °API	36
Live oil viscosity, cp	0.667
FVF, RB/STB	1.28

CO_2 Flood Design. A total of 22,825 Mcf of CO_2 was injected into the 8,000' Reservoir E Unit when CO_2 injection was completed in November 1981.

CO_2-EOR Results. In June 1981, Well 22-5 began to produce oil at a cut of 5%. Although the oil cut in the production wells continued to increase, overall tertiary recovery remained low due to problems with CO_2 and/or water coning. This problem had been expected since the 8,000' Reservoir E Unit had a thin oil column underlain by a strong water drive and overlain by a high mobility CO_2-solvent slug.

Final results showed that a multi-contact CO_2 miscible process did occur between injection Well 22-26 and production Well 22-5. Estimated tertiary recovery from the 8,000 foot Reservoir E Unit was 75,000 barrels of oil.

C. TIMBALIER BAY

Production History. Timbalier Bay Field is located in the coastal waters of Louisiana, approximately 60 miles south of the city of New Orleans. Timbalier Bay, discovered in 1937, contains over 400 different oil reservoirs and 435 wells. Overall field production peaked in 1969 at 58,000 BOPD and had declined to a rate of less than 4,000 BOPD in 1984.

Production from the S-2B(RA)SU reservoir began in January 1952. The OOIP in the reservoir was determined to be 20.7 MMBbls. Approximately 60% of the OOIP, or 12 MMBbls, had been recovered at the time of the CO_2 pilot flood, based on a strong water drive and 33 years of primary production.

Reservoir Properties. The S-2B(RA)SU reservoir has a light, 39° API oil. The reservoir net sand is approximately 67 feet thick, with 30% porosity, a high permeability and a reservoir dip of 7.5 to 14 °. At the time of CO_2 flooding, 29 wells had been drilled into this reservoir at an average depth of 7,400 ft.

CO_2 Flood Design. After most of the wells in the S-2B(RA)SU reservoir, especially the down-dip wells, had watered out and been shut-in, a gravity-stable CO_2 pilot project was initiated in April 1984, lasting through June 1985. Six S-2B(RA)SU wells were used in the project, including one injector, three producers, and two monitoring wells. The project encompassed 37 acres and was designed for a 30% HCPV slug of CO_2. The goal was to vertically displace oil through a 60 ft watered out section of the S-2B(RA)SU sand.

CO_2-EOR Results. The Timablier Bay Field gravity-stable CO_2 pilot flood was expected to recover 463 MBbls of tertiary oil, or approximately 23% of OOIP in the project area. The displaced oil bank was expected to reach the perforated intervals after 30 months of injection. (No further information is publically available.)

Table C-1. Key Reservoir Parameters

Temperature, °F	180
Current reservoir pressure, psia	3,397
Datum depth, ft	7,400
Porosity, %	30.0
Permeability, md	9,244
Dip, degrees	7.5 to 14.0
Average net sand, ft	67
Residual oil saturation, % PV	29.0
Connate water saturation, % PV	11.0
Oil gravity, °API	39.0
Live oil viscosity, cp	0.39
FVF, RB/STB	1.392

D. WELLMAN FIELD

Production History. The Wolfcamp Reef Reservoir of the Wellman Field, discovered in 1950, is located in Terry County, Texas, in the western Midland Basin. The Wolfcamp reservoir is a limestone reef accumulation of Permian age. From 1958-1965, field production was 1,800 BOPD. In 1966, after allowables were raised, production began to increase, and by 1972, the Wellman Field was producing 8,000 BOPD.

Primary production, lasting until 1979, produced 41.8 MMBbls, or 33.2% of OOIP. During this time the oil/water contact rose 220 ft. from its original subsea depth. Wells producing high volumes of water were recompleted upward to minimize water production.

After, the Wellman Field was unitized in 1978, secondary oil recovery began in 1979. Water was injected above and below the original oil/water contact depth of 6,680 ft, although not above the oil/water contact that existed in 1979. In the early 1980s, Wellman field produced 9,000 BOPD, ending with a cumulative oil production of 55 MMBbls (43.7% of OOIP). The oil/water contact rose another 160 ft during secondary recovery, now to a total of 380 ft. above the original oil/water contact. Figure D-1 depicts the migration of the oil/water zone through the primary, secondary, and tertiary recovery phases.

Reservoir Properties. The Wolfcamp reservoir has a thickness of 824 ft above the original oil/water contact zone, at a depth of 6,680 ft. Average porosity in the reef structure is approximately 8.5% and permeability is 110 md. Original oil in-place for the Wolfcamp Reservoir of Wellman Field is estimated to be 126 MMBbls

CO_2-EOR Design and Results. Gravity-stable CO_2 injection was initiated in late 1983. A boost in production was immediately noticed and by 1989, oil production had increased to 2,400 BOPD. This rate was stabilized in mid-1990, signifying that a miscible oil bank had formed. Tertiary oil recovered by May 1991 was approximately 3.5 MMBbls (2.8% of OOIP), corresponding to CO_2 utilization ratio of 6.5 Mscf/bbls. The tertiary oil project was terminated in 1991 due to problems with access to CO_2. By this time, the Wellman Unit had recovered a total of 69.2 MMBbls of which 65.7 MMBbls came from primary and secondary production. The operator estimates that if the CO_2 flood had continued past 1991, ultimate recovery from the tertiary flood would have been 21 MMBbls, or 16.7% of OOIP.

Observations. If the wells in this field had been deepened to fully produce the oil bank, an additional 7.5 million barrels could have been produced, raising the projected tertiary oil recovery to 28.5 MMBbls or 22.7% OOIP. As of 2002, the Wellman Unit had recovered an additional 5.4 MMBbls of oil from continuation of secondary oil recovery for a cumulative recovery of nearly 75 MMBbls.

Table D-1. Wolfcamp Key Reservoir Parameters

Lithology	Limestone
Reservoir interval, ft	9,156 to 9,980
Average porosity, %	8.5
Average permeability, md	110
Connate-water saturation	0.20
ROS after waterfood	0.35
Initial reservoir pressure, psig	4,105
Current reservoir pressure, psig	2,000
Reservoir temperature, °F	151
Depth to original OWC, ft	9,980
Depth to original OWC, ft subsea	6,680
Depth to current OWC, ft subsea	6,230

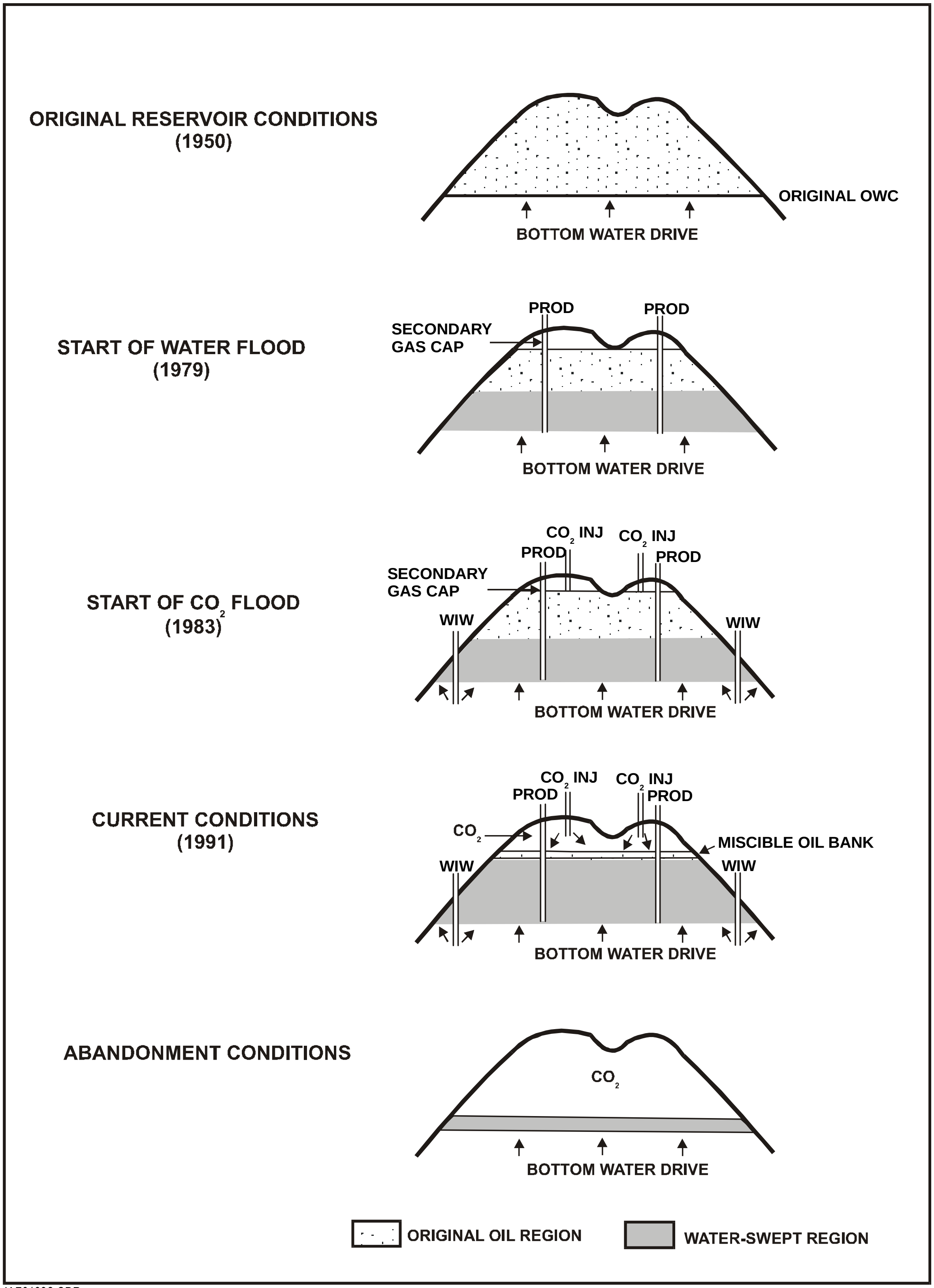

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Figure D-1. Depletion Stages

E. WHITE TIGER FIELD (VIETNAM)

Reservoir Properties. The Bach Ho (White Tiger) field is located approximately 120 kilometers southeast of the coastal city of Vung Tau, in the Cuu Long basin off the southern coast of Vietnam. The primary reservoir in the field, the Basement reservoir, has an estimated original oil in-place (OOIP) of 3.3 billion barrels.

The Basement reservoir is a Tertiary-age massive granite that occurs at a depth of 3,000 meters and is approximately 1,700 meters thick. It consists of three domes, North, Central and South, primarily defined by granite composition. It is a highly complex, faulted reservoir containing both micro- and macro-fractures. Being an extensional basin, most faults are open and not sealing. (It is believed that oil migrated into the granite along these faults and fractures from adjoining shales.)

CO_2-EOR Design and Expected Results. Reservoir studies showed that 700 MMbbls of incremental oil, about 20% of OOIP, could be recovered using a combination of bottom-up and top-down CO_2 flooding. The purchased CO_2 utilization factor for this flooding design is 8.3 Mcf/bbl. Approximately 550 million tons of CO_2 would be injected (340 million tons of purchased CO_2) throughout project life.

Table D-1.
Summary of Incremental Oil Recovery

	Oil (MMbbls)
Phase 1	210
Phase 2	490
Total	700

Observations. The simulation results provide numerous conclusions and insights into the potential for gravity-stable CO_2-EOR for the White Tiger Basement reservoir:

- Due to the thick nature of the reservoir, and high vertical permeability via natural fractures, regardless of injection strategy, a gravity-stable flood is the most likely outcome.

- Bottom-up injection appears to provide superior recovery results (+/- 20% OOIP) over top-down injection due to the early displacement of oil in the deeper, above MMP, portions of the reservoir to the producing wells. Bottom-up injection may also have the advantage of utilizing existing water injection wells.

- CO_2 utilization factors for gravity-stable floods are higher than for lateral-displacement CO_2-EOR schemes (8-12 Mcf/bbl vs. 3-5 for a typical lateral displacement flood). These factors may be improved with further optimization.

F. SPRAYBERRY TREND AREA

Background. Discovered in 1949, the Sprayberry Trend Area is located in West Texas, encompassing an area of over 2,500 square miles. Over 7,500 wells have been drilled in the different reservoirs of the Sprayberry Trend Area, and oil recovery has been primarily from imbibition. The Sprayberry Trend reservoirs have an original oil in-place of almost 10 billion barrels, of which only about 10% has been recovered to date. Part of this low oil recovery is because the Sprayberry Trend Area remains one of the most complicated naturally fractured reservoirs to understand and to model.

Reservoir Properties. Core samples were taken for this simulation study in order to assess the affects of critical reservoir parameters (temperature, pressure, permeability, and water saturation) on applying a CO_2 gravity drainage tertiary oil recovery project. Porosity in the samples averaged about 10.6%, permeability ranged from 0.01 md to 0.38 md, and water saturation ranged from 38% to 45%.

Project Design. Waterflooding was initiated in October 1999 in the E.T. O'Daniel CO_2 Pilot area of the Sprayberry Trend. The 67 acre site was selected as a result of high oil recovery that had occurred in the area during primary and secondary recovery phases. The pilot area consists of 15 wells, including 4 proposed CO_2 injection wells, 3 central production wells, and 2 monitoring wells. The 3 central producing wells are lined along the major fault trend in the Sprayberry Area, flanked on each side by the 4 proposed CO_2 injectors and surrounded by 6 water injectors, creating a hexagonal pattern and providing confinement for the injected CO_2. Water injection began before CO_2 injection to raise the reservoir pressure above MMP for CO_2. By establishing a waterflood baseline, all produced oil as a result of CO_2 injection could be quantified.

Project Results. CO_2 injection in the E.T. O'Daniel Pilot Area began in February 2001, but was short-lived. Initial results indicated that large volumes of CO_2 were being retained in the reservoir, as would be expected, to push oil into production wells. As of early 2004, cumulative oil production during the 2.5 years of waterflooding was over 150,000 barrels of oil. Pioneer Natural Resources is currently expanding waterflooding in the pilot area, and waterflooding production is expected to recover an additional 15% of the OOIP in the Sprayberry Trend Area over the next 20 years.

Observations. Although CO2 flooding shows promise in the Sprayberry Trend, the pilot was short-lived due to the success of oil recovery from waterflooding.

G. YATES FIELD

Background. The Yates Field, discovered in 1926, is located in Pecos and Crockett Counties, Texas, in the Central Basin Platform of the Permian Basin. Original oil in-place for the Yates Field is approximately 5 billion barrels. Oil production peaked in the late 1970s, following field unitization, at 125,000 BOPD. A gravity-stable CO_2 flood pilot study was initiated in the Yates Field in early 2004. Although oil production has increased slightly, it is still too early to judge the degree of success for this pilot project.

Reservoir Properties. The Yates Field is composed primarily of highly fractured carbonates, including packstones and grainstones, and is the structural highpoint of the Central Basin Platform. Core derived permeability and porosity values at Yates are 210 md and 29%, respectively.

Production History. Primary production in the Yates Field began in 1926 and lasted until 1979, when water flooding was initiated in the west side of the field. Polymer injection occurred in the west side of the Yates Field from 1983-1989, and in-field drilling of the east side of the field continued into the mid-1980s. From 1985-1991 CO_2 was injected into the east side of the Yates Field in an effort to maintain pressure and increase production. Nitrogen injection began in 1993 at 30 MMcfd to maintain pressure and in 1996, nitrogen injection was increased to 60 MMcfd. Finally, the WALRUS program (Wettability Alteration of Reservoirs Using Surfactant) was initiated, involving the addition of surfactant to injected water in an effort to increase oil mobility. Figure G-1 depicts the migration of the oil column through the various recovery phases.

CO_2 Flood Design. Gravity drainage CO_2 injection began on March 1, 2004 in the Yates Field at a rate of 42.5 MMcfd. Gassed-out horizontal producing wells were reworked and converted into CO_2 injectors within 50 ft. of the oil/gas contact. As of December 2004, CO_2 injection rate had been increased to 60 MMcfd.

CO_2-EOR Results. Current oil production has increased slightly, and contains a high CO_2 percentage since gravity-stable CO_2 injection began. However, it is yet to be determined whether this is a result of CO_2 or some other mechanism. Within the CO_2 area, 41 wells show a CO_2 production percentage of greater than 20%, however, only 7 of these wells show increasing production.

Observations. Interpretation of the initial early oil production is underway. Oil response could be a result of movement of the GOC, and historical injection in the Yates Field has typically been followed by temporary increases in oil production. The oil production response was much earlier than predicted by through modeling. Production response in Phase 1 of the project has been positive and injection is expected to expand into the southeastern portion of the field in the future.

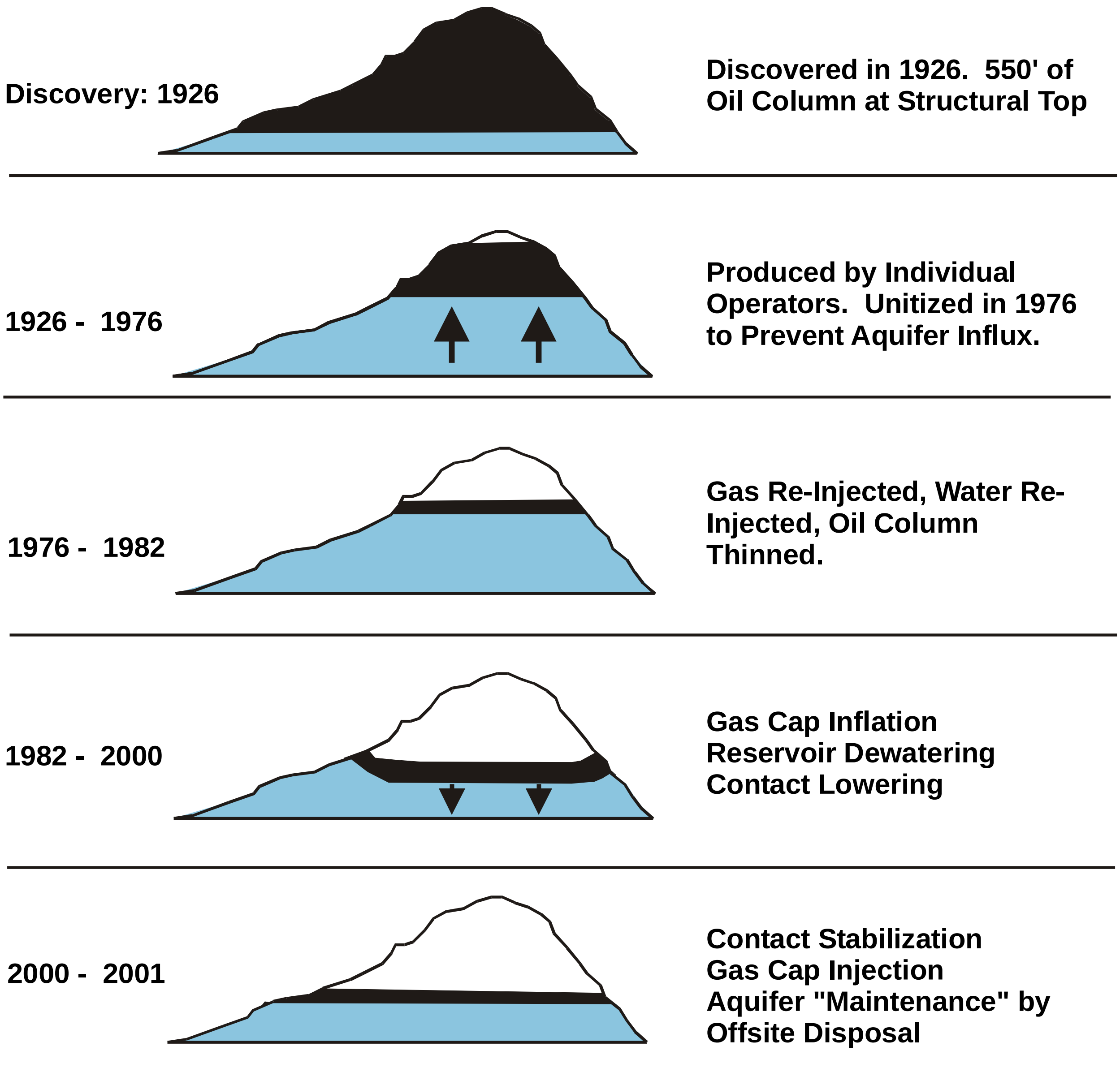

Figure G-1. Migration of the Oil Column

H. SACROC

Background. Discovered in 1948, the Kelly-Snyder field of West Texas covers an area of approximately 50,000 acres with an estimated OOIP of 2.8 billion barrels. The field is divided into three broad regions -The Northern Platform, Central Plain, and the Southwestern Region. The SACROC Unit was formed in 1952 to facilitate coordinated waterflooding of the field and an earlier CO_2 flood was conducted in the Central Plain area.

Reservoir Description. The Northern Platform area contains the thickest reservoir interval, ranging from 80 feet at the periphery to more than 750 feet at the center. It also contains the greatest concentration of the oil resource.

CO_2-Flood Design. Geologic and production data suggest the Kelly-Snyder Field may be a potential candidate for gravity-stable CO_2-EOR. Kinder Morgan, the operator of the Unit, is evaluating the feasibility of gravity-stable CO_2-EOR for the SACROC Unit Northern Platform area. This design project will take advantage of intense reservoir characterization data-collection efforts planned by Kinder Morgan. This will include the collection of core over the entire reservoir interval at four locations in the Northern Platform area, its foot-by-foot analysis for reservoir properties including porosity and multi-azimuth permeability, geophysical well logs, and crosswell seismic surveys. (A 3D surface seismic survey already exists over the entire area.) Advanced Resources International will use these data to develop a high-resolution seismic-to-core transform, and apply it to a selected portion of the Northern Platform Area.

No further information is currently available concerning well placement, gas injection volumes, and operation of the planned flood, as the project is still in a preliminary design phase.

I. LOST HILLS

Reservoir Description. The Lost Hills Field, discovered in 1910, is located in Kern County in the San Joaquin Basin of central California. Productive intervals include Middle to Upper Miocene-age siliceous shale, chert, and diatomite, as well as Plio-Pleistocene-age sands. Productive reservoirs are located at the crest of the anticline and along its southeast-plunge. The field is cross-cut by several normal faults, which rarely exceed 40 feet in offset. In 1999, the Belridge Diatomite was targeted by Chevron for a pilot study using CO_2 injection for enhanced oil recovery.

The field is approximately 8 miles long and 1 mile wide and situated on the crest of a NW-SE trending anticline. The Belridge Diatomite is approximately 600 feet thick and averages 1,900 feet in depth. Oil gravity varies widely along the field, ranging from 34º API in the southeast to 18º API in the northwest. Additional reservoir characteristics are listed in Table I-1.

Production History. Primary recovery is estimated at 135 million barrels of oil through 1999. The use of large hydraulic fracturing treatments have improved oil production. However, reservoir characteristics have limited primary recovery to 3-5% of original oil in-place. Waterflooding operations, beginning in 1992, have increased oil production from 6,400 BOPD to 10,400 BOPD, raising the overall recovery to 9-10% of OOIP.

CO_2 Flood Design. Chevron's goals were to 1) test the technical and economic viability of CO_2-EOR in the low-permeability Belridge Diatomite, 2) obtain results in under 3 years, and 3) gather data that will aid in turning the pilot to a full-field project. As such, the pilot consisted of 4 injectors covering 2.5 acres each. The pilot lasted for 2 ½ years and a total of 375 MMcf CO_2 was injected. Oil production response was witnessed in one well as a result of CO_2 injection.

Table I-1. Reservoir Rock and Fluid Properties	
Lithology, %	Diatomite
Porosity, %	50.0
Permeability, md	0.1 – 10
Initial Water Saturation	35-60
Oil Gravity, °API	18-34
Initial Oil Viscosity, cp	4-40
Initial Oil FVF, rb/STB	1.09
Original Reservoir Pressure, psia	1228
Current Reservoir Pressure, psia	850
Minimum Miscibility Pressure, psia	5000
Reservoir Temperature, °F	110-120
Net Thickness, ft	600
Average Depth, ft	1900

CO_2 –EOR Results. While initial results from the 4-pattern Lost Hills CO_2 pilot were favorable, longer-term results were not as promising. Although the larger spacing of the 4-pattern CO_2 injection pilot in Lost Hill field was meant to lower the chances of early CO_2 breakthrough to producing wells, early breakthrough occurred. Monitoring has confirmed that some of the CO_2 did indeed enter the diatomite matrix. But it has also suggested that fast CO_2 migration along faults and fractures caused early breakthrough.

J. WILMINGTON

Reservoir Description. The Wilmington field, discovered in 1932, is located in Los Angeles County, California. The field is a broad asymmetrical anticline, cut by a series of transverse faults into ten fault blocks. In Fault Block V, the shallowest productive zone, named the Tar Zone for its heavy oil, was the target of a CO_2-EOR Pilot in 1982.

Wilmington's Fault Block V covers 330 acres, with the Tar Zone containing an estimated 208 million barrels original oil in-place (OOIP). The Fault Block V Tar Zone is approximately 300 feet thick in the project area and is divided into three subzones – the S, T, and F_1. The Tar Zone units dip to the south at an angle of 9.5°. Porosity averages 27% and oil gravity is 14° API. Table J-1 provides additional reservoir parameters.

Production History. At project initiation (1982), the Tar Zone had recovered 31.2 million barrels through primary and secondary means. Production in the project area was about 1,200 barrels per day from 38 wells and declining by 10% annually. The water cut was 95%. Although secondary recovery efforts began in 1961, it is unclear how much incremental recovery is due to waterflooding.

CO_2 Flood Design. The CO_2 injection project was designed to cover all of the southern area of Fault Block V as well as half the central area. The project consisted of 42 producing wells and 8 injectors. The injectors were arranged in two east-west lines in the southern half of the project area. The initial plans called for the purchase of 7.5 Bcf of injection gas (85% CO_2 / 15% N_2) from the hydrogen plant at Texaco's Wilmington Refinery. It was understood that this volume was much less (by nearly 25%) than the ideal volume to be injected. The project was to run for 5 years.

Table J-1. Rock and Fluid Properties for Project Area	
Zone	Tar
Porosity, %	27
Permeability, md	
Subzone S	1,000
Subzone T	500
Subzone F_1	400
Depth, ft	2,300
Reservoir temperature, ^{0}F	120
Oil gravity, °API	14
Oil compressibility, psi^{-1}	$3.8\text{x}10^{-6}$
Oil viscosity for oil containing 50 scf/STB at 1,000 psi and 120^0 F, cp	180 to 410
Molecular weight of stock-tank oil	383
Initial oil saturation, %	0.75
Oil saturation at start of gas injection, %	0.57
Average gross oil pay, ft	300
Average net oil pay, ft	141
Initial pressure, psi	1,000
Initial solution GOR, scf/STB	87
Initial FVF, RB/STB	1.05
Oil FVF at start of gas injection, RB/STB	1.04
Project surface area, acres	330
Project net oil sand volume, acre-ft	46,428
Project water sand volume, acre-ft	6,600
Initial OIP in oil zone in project area, STB	69,465,000
OIP at start of gas injection, STB	53,301,000

CO_2 –EOR Results. Gas breakthrough occurred soon after WAG injection began in March 1982. Oil production increased after CO_2 injection but soon returned to the 10% decline predicted for the waterflood. This decline in oil production continued for two years. Oil rates began to climb in early 1984, due to modification of the WAG ratio. In 1985, the flood was shifted to focus on the low-permeability, higher oil saturated, subzone F_1 (although not exclusively). Wells in this area experienced an increase in production of 400 barrels per day over the course of a year. When gas purchases were stopped in early 1986, a drop in production of 200 barrels per day was experienced. At the termination of the project, incremental recovery due to CO_2 injection was estimated at nearly 490,000 barrels, which was less than anticipated.

K. HALFMOON

Reservoir Properties. The Halfmoon Field is located in Park County, northwestern Wyoming within the Big Horn Basin. The field contains two producing intervals, the shallower, Permian-age Phosphoria limestone/dolomite and the Pennsylvanian-age deeper, Tensleep sandstone. Each of the producing intervals are anticlinal structures with natural fracturing at their crests. For additional reservoir properties refer to Table K-1.

CO_2 Flood Design. Detailed laboratory and reservoir modeling work indicated that a 9-fold reduction in oil viscosity and associated 4.5% increase in production could be gained as a result of cyclic CO_2 injection. Overall, three types of CO_2 experiments were performed for the respective formations; 1) a continuous flood with no water chase; 2) two or three huff 'n' puff cycles with water influx; and 3) cyclic injection with pressure depletion and a follow-up waterflood.

The laboratory experiments indicated that cumulative oil recoveries of 26.6% of OOIP for the Phosphoria and 51.9% of OOIP for the Tensleep formation could be recovered utilizing immiscible CO_2 injection. Response in the Tensleep formation was superior with CO_2 injection while a single huff 'n' puff cycle was superior in the Phosphoria formation.

CO_2-EOR Results. The laboratory work on the design of the oil recovery project at the Halfmoon field project indicated that immiscible CO_2 recovery of incremental heavy oil was technically feasible using either cyclic or drive injection modes. The influence of conformance on gas confinement dominated the response to cyclic injection.

Table L-1. Halfmoon Reservoir Rock and Fluid Properties	
Reservoir	
temperature (ºF)	135 to 141
pressure (psig)	450 to 900
Phosphoria Producing Interval	
depth (ft)	about 3,400
net pay (ft)	about 40
average porosity (%)	14
average permeability (md)	17
Tensleep Producing Interval	
depth (ft)	about 3,600
net pay (ft)	about 98
average porosity (%)	15
average permeability (md)	95
Oil	
gravity (ºAPI)	about 17
viscosity at 140ºF (cp)	118
C_{44+} Content (wt%)	about 42
Asphaltene Content (wt%)	5.5
Water Content (wt%)	7.6 (prior to dewatering)
Gas	
Composition (mol %)	94.1 CO_2, 1.7 N_2, 1.2 H_2S, 3.0 C_{1+}

L. FORREST RESERVE

Reservoir Description. The Forrest Reserve Field is located in the southwestern peninsula of the island of Trinidad, on the southern flank of the east-northeast trending Fyzabad Anticline. The reservoir dips at an angle of 30º towards the south, Figure L-1. Bottom water exists in most pay zones in the deepest, southern edge of the reservoir. Faults, shale outs and water contacts bound the reservoirs within the field. The field contains three sandstone reservoirs: Upper Forrest Hills, Lower Forrest Hills and Upper Cruse.

The OOIP for these reservoirs was estimated at 1.9 MMbbls for the Upper Forest Sands, 16.2 MMbbls for the Lower Forest Sands, and 36.4 MMbbls for the Upper Cruse Sands, for a total of 54.5 MMbls of oil. The reservoir properties of the Upper and Lower Forest Hills and Upper Cruse Formations are listed in Table L-1.

Production History. The primary drive mechanism for all three reservoirs of the Forest Reserve Field is solution gas drive with minor contributions from gravity and water influx.

In the Lower Forest Sands, 4.9% OOIP (92 MBO) was recovered through primary production. No secondary production was done in this reservoir and the CO_2 injection pilot was began at the end of primary recovery.

In the Upper Forest Sand, primary recovery was followed by gas injection in 1961 through 1972 and a less than a year of waterflooding in 1976. A total of 17.4% OOIP (2,818 MBO) was recovered through primary and secondary production in this reservoir.

In the Upper Cruse Sand reservoir, 21.3% of OOIP (7,753 MBO) was recovered during primary production between 1933 and 1960. Secondary recovery through natural gas injection contributed an addition 20% of OOIP (7,280 MBO) between 1956 and 1977. Waterflooding was initiated in 1974 but was ceased in 1980 due to early water breakthrough and poor mechanical condition of wells, contributing only 0.4% of OOIP (1,456 MBO).

CO_2 Flood Design and Results (EOR26). The first pilot (EOR 26) in the Forest Reserve Field, injecting CO_2 into the Upper Forest Formation, was started in 1974. Between 1979 and 1989 about 4% of OOIP was recovered using very low CO_2 injection rates. After 1989, the CO_2 injection rate was increased but oil production declined, as it was concluded that the injection rates were too high. Addition of more production wells did not improve results and the pilot was shut down. A total of 7.6% of OOIP (142 MBO) was recovered through CO_2 injection.

CO_2 Flood Design and Results (EOR33). The Lower Forest Sand pilot (EOR 33) began in 1976 after primary and secondary (waterflooding) production. CO_2 injection has been intermittent in this reservoir. Prior to 1985, operations were relatively inefficient due to excessive CO_2 injection rates. With reduced CO_2 injection, oil production significantly improved from 1991 to 1997. After 1997, efficiency decreased once more when the five of the eight production wells went offline. In 2000, more rigorous reservoir pressure monitoring let to an improvement in oil recovery performance. CO_2 injection in the Lower Forest Sand recovered 5.8% of OOIP (941 MBO) through August 2003 at a CO_2 utilization of 9 Mcf/bbl. Ultimate recovery is estimated at 8.7% of OOIP.

CO_2 Flood Design and Results (EOR4). The Upper Cruse Sand CO_2 injection pilot project (EOR 4) was began in January 1986 utilizing one injection well. Positive response was noted with the addition of three new production wells and a lowering of injection rates between 1995 and 2001. Approximately 2.2% of OOIP was recovered (814 MBO) through August 2003 at a CO_2 utilization of 6 Mcf/bbl. Ultimate recovery through CO_2 injection for the Upper Cruse Sand is estimated at 4.7% of OOIP.

Observations. Excessive injection rates lead to significant CO_2 channeling in all three Forest Reserve Field pilots. It is speculated that the high injection rates led to seriously harming the stability of the immiscible, gravity stable nature of the CO_2 flood.

Figure L-1. Location of Trinidad's CO_2 Projects.

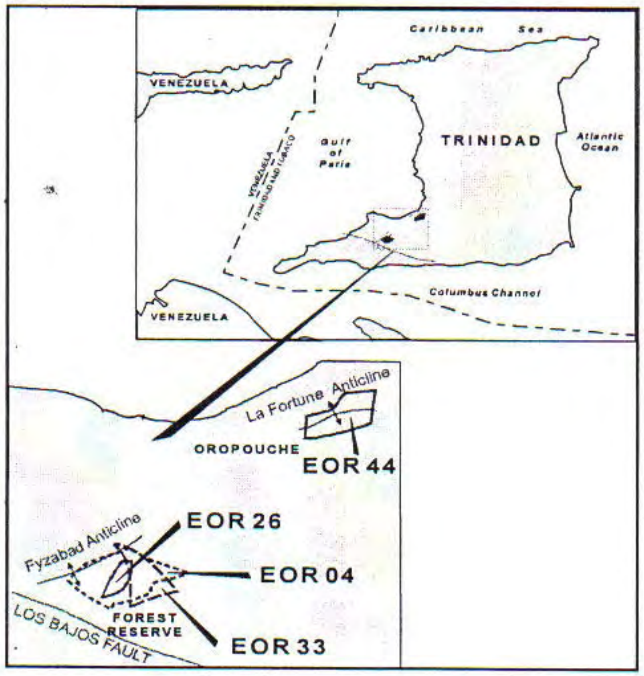

Table L-1. Reserve Data—Forest Reserve and Oropouche CO_2 Projects			
	EOR 4	EOR 33	EOR 26
ROCK PROPERTIES			
Area, acres	120	67	21
Pay Zone	U. Cruse	L. Forest	U. Forest
Depth, ft	4200	3000	2600
Thickness, ft	196	144	58
Porosity, %	31	32	30
Permeability, md	334	125	150
Oil Saturation, %	73	75	70
Temperature, °F	130	120	120
Transmissibility, md/ft-cp	5036	538	189
FLUID PROPERTIES			
Initial Conditions			
Reservoir Pressure, psi	2200	1410	1300
Solution Gas Ratio, scf/bbl	400	193	150
Oil Formation Volume Factor, bbl/bbl	1.16	1.1	1.07
Oil Gravity, °API	25	19	17
Oil Viscosity, cp	6	16	32
At CO2-Flood Start			
Reservoir Pressure, psi	650	500	600
Solution Gas Ratio, scf/bbl	70	50	80
Oil Formation Volume Factor, bbl/bbl	1.07	1.04	1.04
Oil Viscosity, cp	13	32	46

M. OROPOUCHE FIELD

Reservoir Properties. The Oropouche Field is located in the southwest peninsula of the island of Trinidad, straddling the east-northeast trending La Fortune Anticline. The AO-8 fault block reservoir is a deepwater continental slope deposit. The reservoir consists of two sand units the thickness of which varies greatly between the north and south edges of the fault block where small water legs also exist. Shale outs and faults bound the reservoir which dips at a 30º angle on either side of the La Fortune Anticline. The original oil in-place (OOIP) for the AO-8 reservoir was estimated at 8.73 MMbbls of oil. For further reservoir properties refer to Table M-1.

Production History. Prior to the initiation of the CO_2 injection pilot, 17.9% of OOIP (1.56 MMbbls of oil) was recovered from the Oropouche Field during primary production. The main drive mechanism during primary production was solution gas drive.

CO_2 Flood Design. The Oropouche Field Immiscible CO_2 pilot (EOR 44 in Figure L-1) was implemented in 1990 by the Petroleum Company of Trinidad and Tabago (Petrotrin). Utilizing three wells, CO_2 was injected into the AO-8 reservoir's secondary gas cap at the crest of the anticlinal structure. A positive response was observed in two wells. The incremental oil production rate over the first 6 years was 70 bbl/day at a utilization of 25 Mcf/bbl. The project had high CO_2 injection rates between 1990 and 1996 resulting in high degree of injected gas channeling promoted by the low transmissibility of the reservoir

CO_2 EOR Results. During the ten year pilot, 3.1% of OOIP (263 MMbbls of incremental oil) was recovered from immiscible CO_2 injection at EOR 44.

Observations. The CO_2 EOR pilot (EOR 44), conducted in the Oropouche Field was found to be uneconomical due to low oil production compared to CO_2 injection and was terminated after ten years. The lack of positive response was, most likely, the result of excessive CO_2 injection rates leading to an instable CO_2 front in a gravity-stable CO_2 flood.

Table M-1. Orapouche Field Rock and Fluid Properties

Rock Properties	
Area (ac)	175
Pay Zone	AO-8
Depth (ft)	2,160
Thickness (ft)	35
Porosity (%)	30
Permeability (md)	2-36
Oil Saturation (%)	70
Temperature (ºF)	120
Transmissibility (md-ft/cp)	111
FLUID PROPERTIES	
Initial Conditions	
Reservoir Pressure (psi)	1,584
Solution Gas Oil Ratio (scf/bbl)	260
Oil Formation Volume Factor (bbl/bbl)	1.13
Oil Gravity (ºAPI)	29
Oil Viscosity (cp)	5
At CO_2 Flood Start	
Reservoir Pressure (psi)	375
Solution Gas Oil Ratio (scf/bbl)	50
Oil Formation Volume Factor (bbl/bbl)	1.04
Oil Viscosity (cp)	6

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APPENDIX B.1

EXAMPLE APPLICATION OF CO_2-EOR ECONOMICS MODEL: FIELD #1 (RESERVOIR #1)

1. "Traditional Practices" Miscible CO_2-EOR Technology (0.4 HCPV of CO_2)
2. Integrated Application of the Combination of "Next Generation" CO_2-EOR Technologies (1.5 HCPV of CO_2)

Basin	San Joaquin	
Field	Field 1	
Formation	Reservoir 1	
Technology Case	Traditional Practices	
Depth (ft)	5,500	
OOIP (MMBls)	2,365.0	
Cum Primary Recovery (MMbls)	691.3	
Primary EUR (MMbls)	808.0	
Miscibility	Miscible	
API Gravity	37.0	
Patterns	502	
Existing Injectors Used	0	
Convertible Producers Used	244	
New Injectors Drilled	258	
Existing Producers Used	548	
New Producers Drilled	0	

Pattern Detail

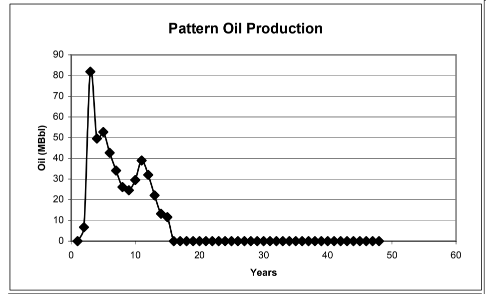
Cum Oil (Mbbl)	466		
Cum H2O (Mbw)	6,150	13.20	Bw/Bbl
Gross CO2 (MMcf)	5,372	11.53	Mcf/Bbl
Purchased CO2 (MMcf)	2,617	5.62	Mcf/Bbl
Recycled CO2 (MMcf)	2,755	5.91	Mcf/Bbl

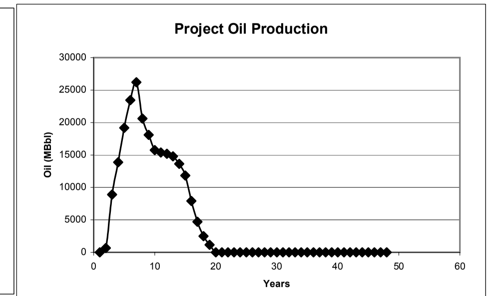
Field Detail

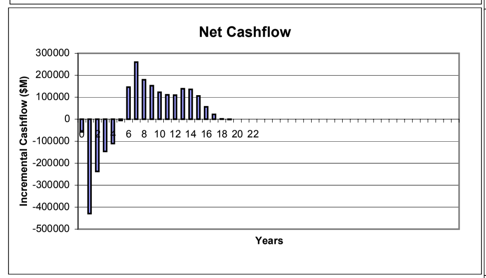
Cum Oil (MMbbl)	233.83	
% OOIP Recovered	9.9%	
Cum H2O (MMbw)	3,087	
Gross CO2 (MMcf)	2,696,543	
Purchased CO2 (MMcf)	1,249,026	
Recycled CO2 (MMcf)	1,447,517	
Payback Period (per pattern)	10	years
Project Length	18	years

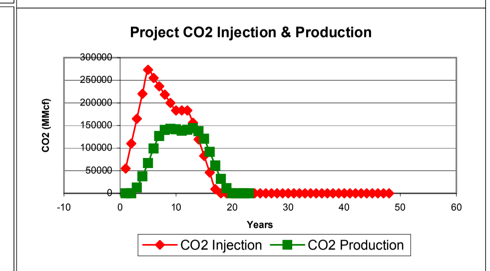
				$/BBl
Total Net Revenue ($M)	$	9,884		
Total Capital Investment ($M)	$	(1,101)	$	2.36
CAPEX G&A	$	-	$	-
Total CO2 Cost ($M)	$	(3,960)	$	8.50
Total O&M Costs ($M)	$	(3,845)	$	8.25
	$	(8,905)	$	19.12

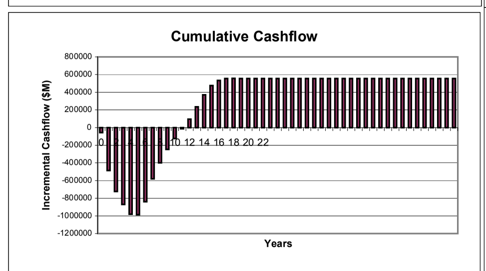
Pattern IRR (BTx)	5.5%
Project IRR (BTx)	5.6%

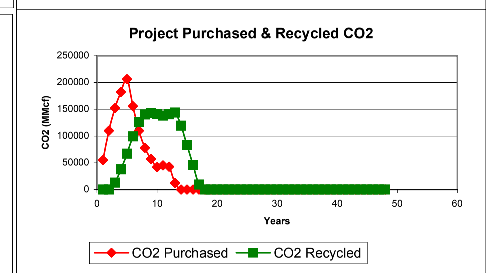


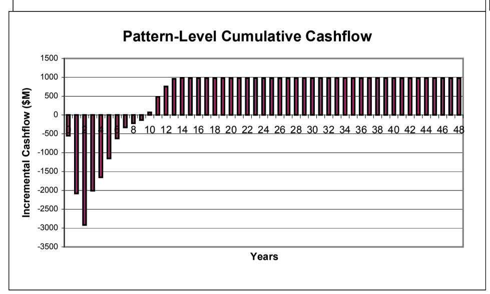












Assumptions:

Economic Case:	Traditional
Oil Price	$ 25.00
CO2 Purchase Cost	5% of oil price
CO2 Recycle Cost	1% of oil price
Recycling Plant Costs	1 Year before Breakthru
Well O&M	Prod Wells Only
Minimum IRR	**25.0%**

Pattern-Level Cashflow Model

Traditional Practices

State	**CA**	**San Joaquin**	New Injectors	0.51
Field	**Field 1**		Existing Injectors	0.00
Formation	**Reservoir 1**		Convertable Producers	0.49
Depth	**5,500**		New Producers	0.00
Distance from Trunkline (mi)	**10**		Existing Producers	1.09
# of Patterns	**502**		Disposal Wells	0.00
Miscibility:	**Miscible**			

1

Year		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14
CO2 Injection (MMcf)			548	548	548	548	530	365	365	365	365	365	365	365	93	-
H2O Injection (Mbw)			274	274	274	274	283	365	365	365	365	365	365	365	501	548
Oil Production (Mbbl)			-	7	82	50	53	43	34	26	25	30	39	32	22	13
H2O Production (MBw)			571	564	419	387	359	346	380	394	392	383	367	369	369	423
CO2 Production (MMcf)			-	1	128	246	292	322	273	264	271	278	290	298	296	206
CO2 Purchased (MMcf)			548	547	420	302	238	44	92	101	95	87	75	68	-	-
CO2 Recycled (MMcf)			-	1	128	246	292	322	273	264	271	278	290	298	93	-
Oil Price ($/Bbl)	$ 25.00		25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00
Gravity Adjustment	37 Deg		24.25	24.25	24.25	24.25	24.25	24.25	24.25	24.25	24.25	24.25	24.25	24.25	24.25	24.25
Gross Revenues ($M)			-	162	1,986	1,203	1,278	1,035	827	633	597	715	946	776	536	320
Royalty ($M)	-12.5%		-	(20)	(248)	(150)	(160)	(129)	(103)	(79)	(75)	(89)	(118)	(97)	(67)	(40)
Severance Taxes ($M)	0.0%		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Ad Valorum ($M)	0.0%		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Revenue($M)			-	142	1,738	1,052	1,118	906	724	554	522	626	828	679	469	280
Capital Costs ($M)																
New Well - D&C		(274)														
Reworks - Producers to Producers		(169)														
Reworks - Producers to Injectors		(23)														
Reworks - Injectors to Injectors		-														
Surface Equipment (new wells only)		(81)														
CO2 Recycling Plant		-	(549)	-	-	-	-	-	-	-	-	-	-	-	-	-
Water Injection Plant		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Trunkline Construction		(4)														
Total Capital Costs		(552)	(549)	-	-	-	-	-	-	-	-	-	-	-	-	-
	0%	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CO2 Costs ($M)																
Total CO2 Cost ($M)			(684.9)	(684)	(557)	(439)	(371)	(135)	(183)	(192)	(186)	(178)	(167)	(159)	(23)	-
O&M Costs																
Operating & Maintenance ($M)			(103)	(103)	(103)	(103)	(103)	(103)	(103)	(103)	(103)	(103)	(103)	(103)	(103)	(103)
H2O Inj O&M ($M)			-	-	-	-	-	-	-	-	-	-	-	-	-	-
Lifting Costs ($/bbl)	$ 0.25		(143)	(143)	(125)	(109)	(103)	(97)	(104)	(105)	(104)	(103)	(101)	(100)	(98)	(109)
G&A	20%		(49)	(49)	(46)	(43)	(41)	(40)	(41)	(42)	(41)	(41)	(41)	(41)	(40)	(42)
Total O&M Costs			(295)	(295)	(274)	(255)	(247)	(240)	(248)	(250)	(249)	(248)	(246)	(244)	(241)	(255)
Net Cash Flow ($M)		(552)	(1,530)	(837)	907	359	500	531	292	112	87	200	415	276	204	25
Cum. Cash Flow		(552)	(2,081)	(2,919)	(2,012)	(1,653)	(1,154)	(623)	(331)	(219)	(132)	68	483	759	963	988
Discount Factor	15%	1.00	0.87	0.76	0.66	0.57	0.50	0.43	0.38	0.33	0.28	0.25	0.21	0.19	0.16	0.14
Disc. Net Cash Flow		(552)	(1,330)	(633)	596	205	249	229	110	36	25	49	89	52	33	4
Disc. Cum Cash Flow		(552)	(1,882)	(2,515)	(1,919)	(1,714)	(1,465)	(1,236)	(1,126)	(1,090)	(1,065)	(1,015)	(926)	(875)	(841)	(838)

Rate	25%	20%	15%	10%
NPV (BTx)	($1,218)	$ (1,068)	$ (839)	$ (485)
IRR (BTx)	5.53%			

Pattern-Level Cashflow Model

State	**CA**
Field	**Field 1**
Formation	**Reservoir 1**
Depth	**5,500**
Distance from Trunkline (mi)	**10**
# of Patterns	**502**
Miscibility:	**Miscible**

			15	Totals
	Year			
CO2 Injection (MMcf)			-	5,372
H2O Injection (Mbw)			502	5,486
Oil Production (Mbbl)			12	466
H2O Production (MBw)			429	6,150
CO2 Production (MMcf)			113	3,276
CO2 Purchased (MMcf)			-	2,617
CO2 Recycled (MMcf)			-	2,755
Oil Price ($/Bbl)	**$**	**25.00**	$ 25.00	
Gravity Adjustment		**37**	$ 24.25	
Gross Revenues ($M)			$ 281	$ 11,296
Royalty ($M)	**-12.5%**		$ (35)	$ (1,412)
Severance Taxes ($M)	**0.0%**		$ -	$ -
Ad Valorum ($M)	**0.0%**		$ -	$ -
Net Revenue($M)			$ 246	$ 9,884
Capital Costs ($M)				
New Well - D&C				$ (274)
Reworks - Producers to Producers				$ (169)
Reworks - Producers to Injectors				$ (23)
Reworks - Injectors to Injectors				$ -
Surface Equipment (new wells only)				$ (81)
CO2 Recycling Plant			$ -	$ (549)
Water Injection Plant			$ -	$ -
Trunkline Construction				$ (4)
Total Capital Costs			$ -	$ (1,101)
		0%	$ -	$ -
CO2 Costs ($M)				
Total CO2 Cost ($M)			$ -	$ (3,960)
O&M Costs				
Operating & Maintenance ($M)			$ (103)	$ (1,550)
H2O Inj O&M ($M)			$ -	$ -
Lifting Costs ($/bbl)	**$**	**0.25**	$ (110)	$ (1,654)
G&A		**20%**	(43)	$ (641)
Total O&M Costs			$ (256)	$ (3,845)
Net Cash Flow ($M)			$ (10)	$ 978
Cum. Cash Flow			$ 978	
Discount Factor	**15%**		0.12	
Disc. Net Cash Flow			$ (1)	$ (839)
Disc. Cum Cash Flow			$ (839)	

Rate	25%
NPV (BTx)	($1,218)
IRR (BTx)	5.53%

Field Cashflow Model

State	CA	**Traditional Practices**	San Joaquin
Field	Field 1		
Formation	Reservoir 1		
Depth	5500		
Distance from Trunkline	10 miles		
# of Patterns	502.00		
Miscibility:	Miscible		

	Pattern	**Field**
Existing Injectors Used	0.00	0
Convertable Producers Used	0.49	244
New Injectors Needed	0.51	258
New Producers Needed	0.00	0
Existing Producers Used	1.09	548

Total Injectors Required	502
Total Producers Required	548

Existing Injectors

Existing Producers

		0	1	2	3	4	5	6	7	8	9	10	11
CO_2 Injection (MMcf)			55,009	110,018	165,027	220,027	273,249	254,906	236,573	218,229	199,906	183,350	183,361
H_2O Injection (Mbw)			27,500	55,009	82,509	110,018	138,411	147,588	156,755	165,921	175,088	183,361	183,361
Oil Production (Mbbl)			-	673	8,895	13,875	19,166	23,453	26,204	20,602	18,092	15,763	15,391
H_2O Production (MBw)			57,348	113,994	156,022	194,917	230,920	208,270	189,816	187,306	187,728	190,127	192,226
CO_2 Production (MMcf)			-	50	12,901	37,590	66,876	99,175	126,564	140,229	142,709	141,353	138,160
CO_2 Purchased (MMcf)			55,009	109,968	152,126	182,437	206,372	155,730	110,008	78,001	57,198	41,997	45,200
CO_2 Recycled (MMcf)			-	50	12,901	37,590	66,876	99,175	126,564	140,229	142,709	141,353	138,160
Oil Price ($/Bbl)	$ 25.00		$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00
Gravity Adjustment	37		$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25
Gross Revenues ($M)			$ -	$ 16,312	$ 215,714	$ 336,476	$ 464,784	$ 568,746	$ 635,457	$ 499,600	$ 438,733	$ 382,248	$ 373,240
Royalty ($M)	-12.5%		$ -	$ (2,039)	$ (26,964)	$ (42,059)	$ (58,098)	$ (71,093)	$ (79,432)	$ (62,450)	$ (54,842)	$ (47,781)	$ (46,655)
Severance Taxes ($M)	0.0%		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ad Valorum ($M)	0.0%		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Revenue($M)			$ -	$ 14,273	$ 188,750	$ 294,416	$ 406,686	$ 497,653	$ 556,025	$ 437,150	$ 383,891	$ 334,467	$ 326,585
Capital Costs ($M)													
New Well - D&C		$ (27,509)	$ (27,509)	$ (27,509)	$ (27,509)	$ (27,509)	$ -	$ -	$ -	$ -	$ -		
Reworks - Producers to Producers		$ (16,994)	$ (16,994)	$ (16,994)	$ (16,994)	$ (16,994)	$ -	$ -	$ -	$ -	$ -		
Reworks - Producers to Injectors		$ (2,299)	$ (2,299)	$ (2,299)	$ (2,299)	$ (2,299)	$ -	$ -	$ -	$ -	$ -		
Reworks - Injectors to Injectors		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
Surface Equipment (new wells only)		$ (8,159)	$ (8,159)	$ (8,159)	$ (8,159)	$ (8,159)	$ -	$ -	$ -	$ -	$ -		
CO_2 Recycling Plant	2	$ -	$ (275,806)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Water Injection Plant	1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction		$ (2,150)											
Total Capital Costs		$ (57,111)	$ (330,767)	$ (54,961)	$ (54,961)	$ (54,961)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CO_2 Costs ($M)													
Total CO_2 Cost ($M)			$ (68,761)	$ (137,473)	$ (193,383)	$ (237,443)	$ (274,684)	$ (219,457)	$ (169,151)	$ (132,558)	$ (107,174)	$ (87,835)	$ (91,040)
O&M Costs ($M)													
Operating & Maintenance ($M)	1		$ (10,374)	$ (20,748)	$ (31,121)	$ (41,495)	$ (51,869)	$ (51,869)	$ (51,869)	$ (51,869)	$ (51,869)	$ (51,869)	$ (51,869)
H_2O Inj O&M ($M)			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Lifting Costs ($M)			$ (14,337)	$ (28,667)	$ (41,229)	$ (52,198)	$ (62,522)	$ (57,931)	$ (54,005)	$ (51,977)	$ (51,455)	$ (51,473)	$ (51,904)
G&A	20%		(4,942)	(9,883)	(14,470)	(18,739)	(22,878)	(21,960)	(21,175)	(20,769)	(20,665)	(20,668)	(20,755)
Total O&M Costs			$ (29,653)	$ (59,297)	$ (86,821)	$ (112,432)	$ (137,269)	$ (131,760)	$ (127,049)	$ (124,615)	$ (123,989)	$ (124,010)	$ (124,528)
Net Cash Flow ($M)		$ (57,111)	$ (429,181)	$ (237,457)	$ (146,414)	$ (110,420)	$ (5,267)	$ 146,436	$ 259,824	$ 179,977	$ 152,728	$ 122,622	$ 111,017
Cum. Cash Flow		$ (57,111)	$ (486,292)	$ (723,749)	$ (870,164)	$ (980,584)	$ (985,850)	$ (839,414)	$ (579,590)	$ (399,613)	$ (246,885)	$ (124,263)	$ (13,246)
Discount Factor	15%	1.00	0.87	0.76	0.66	0.57	0.50	0.43	0.38	0.33	0.28	0.25	0.21
Disc. Net Cash Flow		$ (57,111)	$ (373,201)	$ (179,552)	$ (96,270)	$ (63,133)	$ (2,619)	$ 63,308	$ 97,678	$ 58,835	$ 43,415	$ 30,310	$ 23,862
Disc. Cum Cash Flow		$ (57,111)	$ (430,312)	$ (609,864)	$ (706,134)	$ (769,267)	$ (771,885)	$ (708,577)	$ (610,899)	$ (552,064)	$ (508,649)	$ (478,339)	$ (454,477)

Rate	25%	20%	15%	10%
NPV (BTx)	($481,123)	$ (445,232)	$ (371,118)	$ (228,353)
IRR (BTx)	5.59%			

Field Cashflow Model

State	CA	
Field	Field 1	
Formation	Reservoir 1	0
Depth	5500	
Distance from Trunkline	10	792
# of Patterns	502.00	
Miscibility:	Miscible	

		12	13	14	15	16	17	18	19	Totals
CO2 Injection (MMcf)		183,350	156,052	119,376	82,710	46,033	9,367	-	-	2,696,543
H2O Injection (Mbw)		183,350	197,015	215,348	229,043	192,366	155,700	105,370	50,361	2,754,072
Oil Production (Mbbl)		15,180	14,779	13,634	11,837	7,922	4,709	2,490	1,165	233,832
H2O Production (MBw)		191,121	188,632	191,774	196,402	159,606	122,518	85,491	43,031	3,087,250
CO2 Production (MMcf)		140,610	143,813	137,287	120,691	91,585	61,696	31,977	11,335	1,644,602
CO2 Purchased (MMcf)		42,740	12,239	-	-	-	-	-	-	1,249,026
CO2 Recycled (MMcf)		140,610	143,813	119,376	82,710	46,033	9,367	-	-	1,447,517
Oil Price ($/Bbl)	**$ 25.00**	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	
Gravity Adjustment	**37**	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	
Gross Revenues ($M)		$ 368,127	$ 358,388	$ 330,632	$ 287,051	$ 192,098	$ 114,187	$ 60,381	$ 28,243	$ 5,670,416
Royalty ($M)	**-12.5%**	$ (46,016)	$ (44,798)	$ (41,329)	$ (35,881)	$ (24,012)	$ (14,273)	$ (7,548)	$ (3,530)	$ (708,802)
Severance Taxes ($M)	**0.0%**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ad Valorum ($M)	**0.0%**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Revenue($M)		$ 322,111	$ 313,589	$ 289,303	$ 251,170	$ 168,086	$ 99,914	$ 52,833	$ 24,712	$ 4,961,614
Capital Costs ($M)										
New Well - D&C										$ (137,545)
Reworks - Producers to Producers										$ (84,972)
Reworks - Producers to Injectors										$ (11,493)
Reworks - Injectors to Injectors										$ -
Surface Equipment (new wells only)										$ (40,794)
CO2 Recycling Plant	**2**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (275,806)
Water Injection Plant	**1**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction										$ (2,150)
Total Capital Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (552,760)
	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CO2 Costs ($M)										
Total CO2 Cost ($M)		$ (88,578)	$ (51,252)	$ (29,844)	$ (20,677)	$ (11,508)	$ (2,342)	$ -	$ -	$ (1,923,162)
O&M Costs ($M)										
Operating & Maintenance ($M)	**1**	$ (51,869)	$ (51,869)	$ (51,869)	$ (51,869)	$ (41,495)	$ (31,121)	$ (20,748)	$ (10,374)	$ (778,034)
H2O Inj O&M ($M)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Lifting Costs ($M)		$ (51,575)	$ (50,853)	$ (51,352)	$ (52,060)	$ (41,882)	$ (31,807)	$ (21,995)	$ (11,049)	$ (830,270)
G&A	**20%**	(20,689)	(20,544)	(20,644)	(20,786)	(16,675)	(12,586)	(8,549)	(4,285)	$ (321,661)
Total O&M Costs		$ (124,133)	$ (123,266)	$ (123,865)	$ (124,715)	$ (100,052)	$ (75,514)	$ (51,291)	$ (25,707)	$ (1,929,965)
Net Cash Flow ($M)		$ 109,400	$ 139,072	$ 135,594	$ 105,778	$ 56,525	$ 22,058	$ 1,542	$ (995)	$ 555,727
Cum. Cash Flow		$ 96,154	$ 235,225	$ 370,820	$ 476,597	$ 533,122	$ 555,181	$ 556,723	$ 555,727	
Discount Factor	**15%**	0.19	0.16	0.14	0.12	0.11	0.09	0.08	0.07	
Disc. Net Cash Flow		$ 20,448	$ 22,603	$ 19,163	$ 13,000	$ 6,041	$ 2,050	$ 125	$ (70)	$ (371,118)
Disc. Cum Cash Flow		$ (434,029)	$ (411,426)	$ (392,263)	$ (379,263)	$ (373,223)	$ (371,173)	$ (371,048)	$ (371,118)	

Rate	25%
NPV (BTx)	($481,123)
IRR (BTx)	5.59%

Basin	**San Joaquin**	
Field	**Field 1**	
Formation	**Reservoir 1**	
Technology Case	**Next Generation**	
Depth (ft)	5,500	
OOIP (MMBls)	2,365.0	
Cum Primary Recovery (MMbls)	691.3	
Primary EUR (MMbls)	808.0	
Miscibility	Miscible	
API Gravity	37.0	
Patterns	502	
Existing Injectors Used	0	
Convertible Producers Used	244	
New Injectors Drilled	760	
Existing Producers Used	548	
New Producers Drilled	548	

Pattern Detail

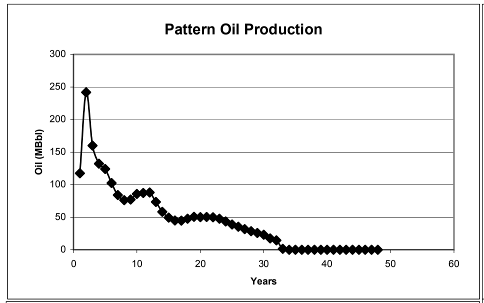
Cum Oil (Mbbl)	2,204		
Cum H2O (Mbw)	7,232	3.28	Bw/Bbl
Gross CO2 (MMcf)	20,144	9.14	Mcf/Bbl
Purchased CO2 (MMcf)	4,255	1.93	Mcf/Bbl
Recycled CO2 (MMcf)	15,889	7.21	Mcf/Bbl

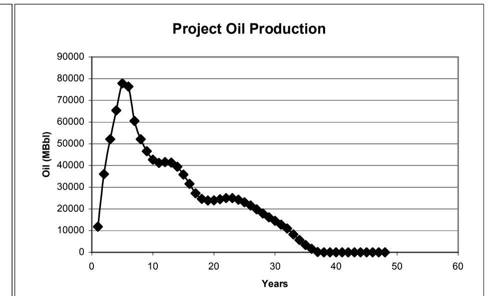
Field Detail

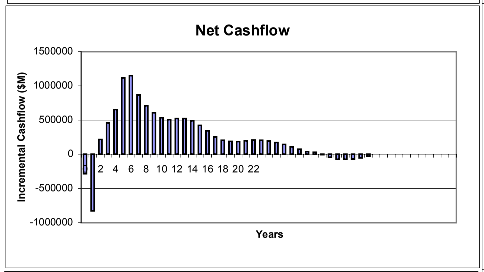
Cum Oil (MMbbl)	1,106.46	
% OOIP Recovered	46.8%	
Cum H2O (MMbw)	3,630	
Gross CO2 (MMcf)	10,112,087	
Purchased CO2 (MMcf)	2,100,724	
Recycled CO2 (MMcf)	8,011,363	
Payback Period (per pattern)	2	years
Project Length	37	years

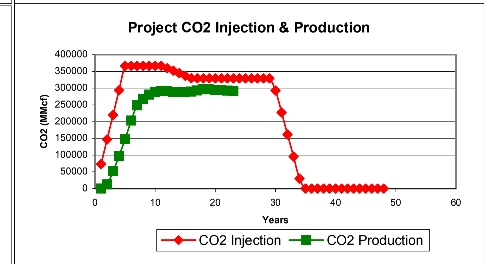
			$/BBl	
Total Net Revenue ($M)	$	46,768		
Total Capital Investment ($M)	$	(3,731)	$	1.69
CAPEX G&A	$	(373)	$	0.17
Total CO2 Cost ($M)	$	(9,291)	$	4.22
Total O&M Costs ($M)	$	(14,066)	$	6.38
	$	(27,461)	$	12.46

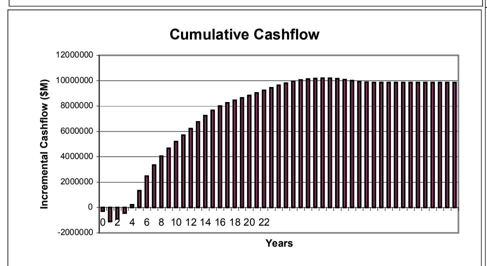
Pattern IRR (BTx)	56.4%
Project IRR (BTx)	45.2%

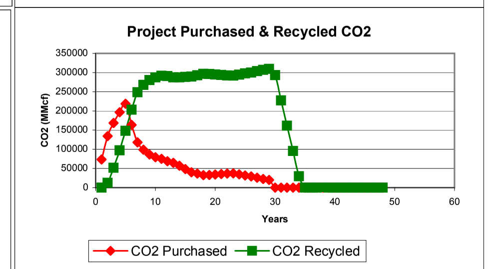


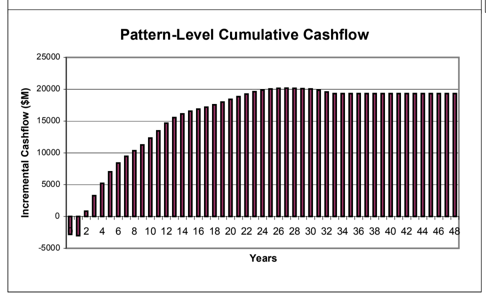












Assumptions:

Economic Case:	Traditional	
Oil Price	$	25.00
CO2 Purchase Cost	5% of oil price	
CO2 Recycle Cost	1% of oil price	
Recycling Plant Costs	1 Year before Breakthru	
Well O&M	Prod Wells Only	
Minimum IRR	**25.0%**	

Pattern-Level Cashflow Model

State	**CA**	**San Joaquin**	New Injectors	1.51
Field	**Field 1**		Existing Injectors	0.00
Formation	**Reservoir 1**		Convertable Producers	0.49
Depth	**5,500**		New Producers	1.09
Distance from Trunkline (mi)	**10**		Existing Producers	1.09
# of Patterns	**502**		Disposal Wells	0.00
Miscibility:	**Miscible**			

Next Generation

3

	Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13
CO2 Injection (MMcf)			731	731	731	731	731	731	731	731	731	731	731	658	656
H2O Injection (Mbw)			183	183	183	183	183	183	183	183	183	183	183	219	220
Oil Production (Mbbl)			118	242	160	132	124	102	84	76	77	86	87	88	73
H2O Production (MBw)			460	267	204	199	177	178	181	185	187	178	171	180	201
CO2 Production (MMcf)			-	123	391	452	509	547	576	585	578	579	589	565	554
CO2 Purchased (MMcf)			731	607	339	278	222	183	155	146	153	151	142	94	103
CO2 Recycled (MMcf)			-	123	391	452	509	547	576	585	578	579	589	565	554
Oil Price ($/Bbl)	$ 25.00		$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00
Gravity Adjustment	37 Deg		$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25
Gross Revenues ($M)			$ 2,851	$ 5,862	$ 3,879	$ 3,208	$ 3,008	$ 2,482	$ 2,036	$ 1,844	$ 1,873	$ 2,078	$ 2,113	$ 2,135	$ 1,780
Royalty ($M)	-12.5%		$ (356)	$ (733)	$ (485)	$ (401)	$ (376)	$ (310)	$ (254)	$ (231)	$ (234)	$ (260)	$ (264)	$ (267)	$ (222)
Severance Taxes ($M)	0.0%		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ad Valorum ($M)	0.0%		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Revenue($M)			$ 2,494	$ 5,130	$ 3,394	$ 2,807	$ 2,632	$ 2,172	$ 1,781	$ 1,614	$ 1,639	$ 1,818	$ 1,849	$ 1,868	$ 1,557
Capital Costs ($M)															
New Well - D&C		$ (1,972)													
Reworks - Producers to Producers		$ (169)													
Reworks - Producers to Injectors		$ (23)													
Reworks - Injectors to Injectors		$ -													
Surface Equipment (new wells only)		$ (380)													
CO2 Recycling Plant		$ -	$ (1,183)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Water Injection Plant		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction		$ (4)													
Total Capital Costs		$ (2,548)	$ (1,183)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital G&A	10%	$ (255)	$ (118)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CO2 Costs ($M)															
Total CO2 Cost ($M)			$ (913.1)	$ (790)	$ (522)	$ (461)	$ (405)	$ (366)	$ (337)	$ (328)	$ (335)	$ (334)	$ (324)	$ (258)	$ (267)
O&M Costs															
Operating & Maintenance ($M)			$ (207)	$ (207)	$ (207)	$ (207)	$ (207)	$ (207)	$ (207)	$ (207)	$ (207)	$ (207)	$ (207)	$ (207)	$ (207)
H2O Inj O&M ($M)			$ (46)	$ (46)	$ (46)	$ (46)	$ (46)	$ (46)	$ (46)	$ (46)	$ (46)	$ (46)	$ (46)	$ (55)	$ (55)
Lifting Costs ($/bbl)	$ 0.25		$ (144)	$ (127)	$ (91)	$ (83)	$ (75)	$ (70)	$ (66)	$ (65)	$ (66)	$ (66)	$ (65)	$ (67)	$ (69)
G&A	30%		(105)	(100)	(89)	(87)	(85)	(83)	(82)	(82)	(82)	(82)	(81)	(82)	(83)
Total O&M Costs			$ (502)	$ (480)	$ (433)	$ (422)	$ (412)	$ (405)	$ (400)	$ (399)	$ (400)	$ (400)	$ (398)	$ (410)	$ (413)
Net Cash Flow ($M)		$ (2,803)	$ (222)	$ 3,860	$ 2,440	$ 1,924	$ 1,816	$ 1,400	$ 1,044	$ 886	$ 903	$ 1,085	$ 1,127	$ 1,199	$ 878
Cum. Cash Flow		$ (2,803)	$ (3,025)	$ 835	$ 3,274	$ 5,199	$ 7,014	$ 8,415	$ 9,458	$ 10,344	$ 11,248	$ 12,333	$ 13,459	$ 14,659	$ 15,537
Discount Factor	15%	1.00	0.87	0.76	0.66	0.57	0.50	0.43	0.38	0.33	0.28	0.25	0.21	0.19	0.16
Disc. Net Cash Flow		$ (2,803)	$ (193)	$ 2,919	$ 1,604	$ 1,100	$ 903	$ 605	$ 392	$ 290	$ 257	$ 268	$ 242	$ 224	$ 143
Disc. Cum Cash Flow		$ (2,803)	$ (2,996)	$ (78)	$ 1,527	$ 2,627	$ 3,529	$ 4,135	$ 4,527	$ 4,817	$ 5,074	$ 5,342	$ 5,584	$ 5,808	$ 5,951

Rate	25%	20%	15%	10%
NPV (BTx)	$3,407	$ 4,615	$ 6,299	$ 8,779
IRR (BTx)	56.39%			

Pattern-Level Cashflow Model

State	**CA**
Field	**Field 1**
Formation	**Reservoir 1**
Depth	**5,500**
Distance from Trunkline (mi)	**10**
# of Patterns	**502**
Miscibility:	**Miscible**

	Year	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**	**27**	**28**
CO2 Injection (MMcf)		656	656	656	656	656	656	656	656	656	656	656	656	656	656	656
H2O Injection (Mbw)		220	220	220	220	220	220	220	220	220	220	220	220	220	220	220
Oil Production (Mbbl)		58	50	45	45	48	51	50	50	50	48	44	39	36	32	29
H2O Production (MBw)		203	205	206	207	206	212	211	207	209	208	206	206	209	208	210
CO2 Production (MMcf)		578	591	598	595	592	576	578	586	582	588	600	609	609	618	621
CO2 Purchased (MMcf)		78	65	58	61	64	81	78	71	74	68	56	47	47	38	35
CO2 Recycled (MMcf)		578	591	598	595	592	576	578	586	582	588	600	609	609	618	621
Oil Price ($/Bbl)	**$ 25.00**	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00
Gravity Adjustment	**37**	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25
Gross Revenues ($M)		$ 1,415	$ 1,200	$ 1,091	$ 1,085	$ 1,157	$ 1,229	$ 1,216	$ 1,222	$ 1,208	$ 1,154	$ 1,055	$ 941	$ 861	$ 771	$ 691
Royalty ($M)	**-12.5%**	$ (177)	$ (150)	$ (136)	$ (136)	$ (145)	$ (154)	$ (152)	$ (153)	$ (151)	$ (144)	$ (132)	$ (118)	$ (108)	$ (96)	$ (86)
Severance Taxes ($M)	**0.0%**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ad Valorum ($M)	**0.0%**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Revenue($M)		$ 1,238	$ 1,050	$ 955	$ 950	$ 1,012	$ 1,076	$ 1,064	$ 1,069	$ 1,057	$ 1,010	$ 923	$ 823	$ 753	$ 675	$ 605
Capital Costs ($M)																
New Well - D&C																
Reworks - Producers to Producers																
Reworks - Producers to Injectors																
Reworks - Injectors to Injectors																
Surface Equipment (new wells only)																
CO2 Recycling Plant		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Water Injection Plant		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction																
Total Capital Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital G&A	**10%**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CO2 Costs ($M)																
Total CO2 Cost ($M)		$ (242)	$ (229)	$ (222)	$ (225)	$ (228)	$ (245)	$ (242)	$ (235)	$ (238)	$ (232)	$ (220)	$ (211)	$ (211)	$ (202)	$ (199)
O&M Costs																
Operating & Maintenance ($M)		$ (207)	$ (207)	$ (207)	$ (207)	$ (207)	$ (207)	$ (207)	$ (207)	$ (207)	$ (207)	$ (207)	$ (207)	$ (207)	$ (207)	$ (207)
H2O Inj O&M ($M)		$ (55)	$ (55)	$ (55)	$ (55)	$ (55)	$ (55)	$ (55)	$ (55)	$ (55)	$ (55)	$ (55)	$ (55)	$ (55)	$ (55)	$ (55)
Lifting Costs ($/bbl)	**$ 0.25**	$ (65)	$ (64)	$ (63)	$ (63)	$ (63)	$ (66)	$ (65)	$ (64)	$ (65)	$ (64)	$ (95)	$ (90)	$ (88)	$ (84)	$ (81)
G&A	**30%**	(82)	(81)	(81)	(81)	(81)	(82)	(82)	(81)	(81)	(81)	(90)	(89)	(88)	(87)	(86)
Total O&M Costs		$ (408)	$ (406)	$ (405)	$ (406)	$ (406)	$ (409)	$ (409)	$ (407)	$ (408)	$ (407)	$ (447)	$ (441)	$ (438)	$ (433)	$ (429)
Net Cash Flow ($M)		$ 588	$ 415	$ 327	$ 319	$ 378	$ 422	$ 414	$ 427	$ 411	$ 371	$ 256	$ 171	$ 104	$ 40	$ (23)
Cum. Cash Flow		$ 16,124	$ 16,540	$ 16,867	$ 17,186	$ 17,564	$ 17,986	$ 18,400	$ 18,827	$ 19,238	$ 19,609	$ 19,865	$ 20,036	$ 20,140	$ 20,180	$ 20,157
Discount Factor	**15%**	0.14	0.12	0.11	0.09	0.08	0.07	0.06	0.05	0.05	0.04	0.03	0.03	0.03	0.02	0.02
Disc. Net Cash Flow		$ 83	$ 51	$ 35	$ 30	$ 31	$ 30	$ 25	$ 23	$ 19	$ 15	$ 9	$ 5	$ 3	$ 1	$ (0)
Disc. Cum Cash Flow		$ 6,034	$ 6,085	$ 6,120	$ 6,150	$ 6,180	$ 6,210	$ 6,235	$ 6,258	$ 6,277	$ 6,292	$ 6,301	$ 6,306	$ 6,309	$ 6,309	$ 6,309

Rate	25%
NPV (BTx)	$3,407
IRR (BTx)	56.39%

Pattern-Level Cashflow Model

State	**CA**
Field	**Field 1**
Formation	**Reservoir 1**
Depth	**5,500**
Distance from Trunkline (mi)	**10**
# of Patterns	**502**
Miscibility:	**Miscible**

	Year	29	30	31	32	33	Totals
CO2 Injection (MMcf)		656	295	-	-	-	20,144
H2O Injection (Mbw)		220	400	548	548	60	7,521
Oil Production (Mbbl)		26	23	18	15	1	2,204
H2O Production (MBw)		210	206	395	486	55	7,232
CO2 Production (MMcf)		626	611	250	87	7	16,548
CO2 Purchased (MMcf)		30	-	-	-	-	4,255
CO2 Recycled (MMcf)		626	295	-	-	-	15,889
Oil Price ($/Bbl)	$ **25.00**	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	
Gravity Adjustment	**37**	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	
Gross Revenues ($M)		$ 628	$ 560	$ 424	$ 354	$ 35	$ 53,449
Royalty ($M)	**-12.5%**	$ (79)	$ (70)	$ (53)	$ (44)	$ (4)	$ (6,681)
Severance Taxes ($M)	**0.0%**	$ -	$ -	$ -	$ -	$ -	$ -
Ad Valorum ($M)	**0.0%**	$ -	$ -	$ -	$ -	$ -	$ -
Net Revenue($M)		$ 550	$ 490	$ 371	$ 310	$ 31	$ 46,768
Capital Costs ($M)							
New Well - D&C							$ (1,972)
Reworks - Producers to Producers							$ (169)
Reworks - Producers to Injectors							$ (23)
Reworks - Injectors to Injectors							$ -
Surface Equipment (new wells only)							$ (380)
CO2 Recycling Plant		$ -	$ -	$ -	$ -	$ -	$ (1,183)
Water Injection Plant		$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction							$ (4)
Total Capital Costs		$ -	$ -	$ -	$ -	$ -	$ (3,731)
Capital G&A	**10%**	$ -	$ -	$ -	$ -	$ -	$ (373)
CO2 Costs ($M)							
Total CO2 Cost ($M)		$ (194)	$ (74)	$ -	$ -	$ -	$ (9,291)
O&M Costs							
Operating & Maintenance ($M)		$ (207)	$ (207)	$ (207)	$ (207)	$ (207)	$ (6,819)
H2O Inj O&M ($M)		$ (55)	$ (100)	$ (137)	$ (137)	$ (15)	$ (1,880)
Lifting Costs ($/bbl)	$ **0.25**	$ (78)	$ (75)	$ (116)	$ (136)	$ (15)	$ (2,554)
G&A	**30%**	(86)	(84)	(97)	(103)	(67)	$ (2,812)
Total O&M Costs		$ (425)	$ (466)	$ (557)	$ (583)	$ (304)	$ (14,066)
Net Cash Flow ($M)		$ (70)	$ (49)	$ (185)	$ (273)	$ (273)	$ 19,307
Cum. Cash Flow		$ 20,087	$ 20,038	$ 19,852	$ 19,580	$ 19,307	
Discount Factor	**15%**	0.02	0.02	0.01	0.01	0.01	
Disc. Net Cash Flow		$ (1)	$ (1)	$ (2)	$ (3)	$ (3)	$ 6,299
Disc. Cum Cash Flow		$ 6,308	$ 6,307	$ 6,305	$ 6,301	$ 6,299	

Rate	25%
NPV (BTx)	$3,407
IRR (BTx)	56.39%

Field Cashflow Model		Next Generation	Pattern		Field			
State	CA	San Joaquin	Existing Injectors Used	0.00	Existing Injectors Used	0		
Field	Field 1		Convertable Producers Used	0.49	Convertable Producers Used	244	Total Injectors Required	
Formation	Reservoir 1		New Injectors Needed	1.51	New Injectors Needed	760	502	Ex
Depth	5500		New Producers Needed	1.09	New Producers Needed	548	Total Producers Required	
Distance from Trunkline	10 miles		Existing Producers Used	1.09	Existing Producers Used	548	548	Exis
# of Patterns	502.00							
Miscibility:	Miscible							

		0	1	2	3	4	5	6	7	8	9	10
CO2 Injection (MMcf)			73,342	146,684	220,027	293,379	366,721	366,721	366,721	366,721	366,711	366,711
H2O Injection (Mbw)			18,333	36,676	55,009	73,342	91,675	91,685	91,675	91,675	91,685	91,685
Oil Production (Mbbl)			11,802	36,074	52,133	65,416	77,870	76,344	60,501	52,077	46,550	42,700
H2O Production (MBw)			46,144	72,900	93,377	113,372	131,137	102,875	94,311	92,358	91,143	91,198
CO2 Production (MMcf)			-	12,359	51,661	97,072	148,135	203,064	248,520	267,927	280,513	287,611
CO2 Purchased (MMcf)			73,342	134,325	168,366	196,307	218,586	163,657	118,201	98,794	86,198	79,100
CO2 Recycled (MMcf)			-	12,359	51,661	97,072	148,135	203,064	248,520	267,927	280,513	287,611
Oil Price ($/Bbl)	$ 25.00		$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00
Gravity Adjustment	37		$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25
Gross Revenues ($M)			$ 286,199	$ 874,788	$ 1,264,218	$ 1,586,329	$ 1,888,353	$ 1,851,346	$ 1,467,150	$ 1,262,879	$ 1,128,849	$ 1,035,478
Royalty ($M)	-12.5%		$ (35,775)	$ (109,348)	$ (158,027)	$ (198,291)	$ (236,044)	$ (231,418)	$ (183,394)	$ (157,860)	$ (141,106)	$ (129,435)
Severance Taxes ($M)	0.0%		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ad Valorum ($M)	0.0%		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Revenue($M)			$ 250,424	$ 765,439	$ 1,106,191	$ 1,388,038	$ 1,652,309	$ 1,619,928	$ 1,283,756	$ 1,105,019	$ 987,743	$ 906,043
Capital Costs ($M)												
New Well - D&C		$ (197,979)	$ (197,979)	$ (197,979)	$ (197,979)	$ (197,979)	$ -	$ -	$ -	$ -	$ -	
Reworks - Producers to Producers		$ (16,994)	$ (16,994)	$ (16,994)	$ (16,994)	$ (16,994)	$ -	$ -	$ -	$ -	$ -	
Reworks - Producers to Injectors		$ (2,299)	$ (2,299)	$ (2,299)	$ (2,299)	$ (2,299)	$ -	$ -	$ -	$ -	$ -	
Reworks - Injectors to Injectors		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Surface Equipment (new wells only)		$ (38,161)	$ (38,161)	$ (38,161)	$ (38,161)	$ (38,161)	$ -	$ -	$ -	$ -	$ -	
CO2 Recycling Plant	2	$ -	$ (593,895)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Water Injection Plant	1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction		$ (2,150)										
Total Capital Costs		$ (257,583)	$ (849,328)	$ (255,433)	$ (255,433)	$ (255,433)	$ -	$ -	$ -	$ -	$ -	$ -
Capital G&A	10%	$ (25,758)	$ (84,933)	$ (25,543)	$ (25,543)	$ (25,543)	$ -	$ -	$ -	$ -	$ -	$ -
CO2 Costs ($M)												
Total CO2 Cost ($M)			$ (91,678)	$ (170,996)	$ (223,372)	$ (269,652)	$ (310,266)	$ (255,337)	$ (209,881)	$ (190,474)	$ (177,876)	$ (170,778)
O&M Costs ($M)												
Operating & Maintenance ($M)	1		$ (20,748)	$ (41,495)	$ (62,243)	$ (82,990)	$ (103,738)	$ (103,738)	$ (103,738)	$ (103,738)	$ (103,738)	$ (103,738)
H2O Inj O&M ($M)			$ (4,583)	$ (9,169)	$ (13,752)	$ (18,336)	$ (22,919)	$ (22,921)	$ (22,919)	$ (22,919)	$ (22,921)	$ (22,921)
Lifting Costs ($M)			$ (14,486)	$ (27,244)	$ (36,377)	$ (44,697)	$ (52,252)	$ (44,805)	$ (38,703)	$ (36,109)	$ (34,423)	$ (33,475)
G&A	30%		(10,570)	(20,622)	(29,586)	(38,306)	(46,797)	(44,563)	(42,732)	(41,954)	(41,448)	(41,164)
Total O&M Costs			$ (50,387)	$ (98,529)	$ (141,958)	$ (184,329)	$ (225,705)	$ (216,027)	$ (208,092)	$ (204,719)	$ (202,531)	$ (201,297)
Net Cash Flow ($M)		$ (283,341)	$ (825,902)	$ 214,938	$ 459,884	$ 653,081	$ 1,116,338	$ 1,148,564	$ 865,783	$ 709,826	$ 607,336	$ 533,968
Cum. Cash Flow		$ (283,341)	$ (1,109,243)	$ (894,305)	$ (434,421)	$ 218,660	$ 1,334,998	$ 2,483,561	$ 3,349,345	$ 4,059,170	$ 4,666,506	$ 5,200,474
Discount Factor	15%	1.00	0.87	0.76	0.66	0.57	0.50	0.43	0.38	0.33	0.28	0.25
Disc. Net Cash Flow		$ (283,341)	$ (718,175)	$ 162,524	$ 302,381	$ 373,401	$ 555,017	$ 496,556	$ 325,480	$ 232,043	$ 172,643	$ 131,989
Disc. Cum Cash Flow		$ (283,341)	$ (1,001,516)	$ (838,993)	$ (536,611)	$ (163,210)	$ 391,807	$ 888,363	$ 1,213,843	$ 1,445,886	$ 1,618,529	$ 1,750,517

Rate	25%	20%	15%	10%
NPV (BTx)	$978,025	$ 1,509,449	$ 2,310,026	$ 3,586,324
IRR (BTx)	45.23%			

Field Cashflow Model

State	CA		
Field	Field 1		
Formation	Reservoir 1	:isting Injectors	0
Depth	5500		
Distance from Trunkline	10:ting Producers		792
# of Patterns	502.00		
Miscibility:	Miscible		

		11	12	13	14	15	16	17	18	19	20	21	22	23
CO2 Injection (MMcf)		366,711	359,472	352,012	344,543	337,083	329,613	329,392	329,382	329,392	329,382	329,392	329,382	329,392
H2O Injection (Mbw)		91,675	95,300	99,035	102,759	106,494	110,229	110,350	110,350	110,350	110,350	110,350	110,340	110,340
Oil Production (Mbbl)		41,174	41,586	41,320	39,422	35,788	31,556	27,208	24,628	23,860	23,925	24,467	24,975	24,964
H2O Production (MBw)		90,480	90,375	92,012	93,598	96,334	99,823	102,554	103,076	104,004	104,642	104,767	104,958	105,204
CO2 Production (MMcf)		291,798	290,663	287,536	287,581	288,776	289,674	292,766	296,642	296,386	295,076	293,851	292,541	292,104
CO2 Purchased (MMcf)		74,913	68,809	64,477	56,962	48,307	39,939	36,626	32,740	33,007	34,307	35,542	36,842	37,289
CO2 Recycled (MMcf)		291,798	290,663	287,536	287,581	288,776	289,674	292,766	296,642	296,386	295,076	293,851	292,541	292,104
Oil Price ($/Bbl)	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00
Gravity Adjustment	37	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25
Gross Revenues ($M)		$ 998,470	$ 1,008,453	$ 1,002,001	$ 955,985	$ 867,849	$ 765,226	$ 659,804	$ 597,232	$ 578,606	$ 580,189	$ 593,336	$ 605,632	$ 605,388
Royalty ($M)	-12.5%	$ (124,809)	$ (126,057)	$ (125,250)	$ (119,498)	$ (108,481)	$ (95,653)	$ (82,475)	$ (74,654)	$ (72,326)	$ (72,524)	$ (74,167)	$ (75,704)	$ (75,674)
Severance Taxes ($M)	0.0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ad Valorum ($M)	0.0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Revenue($M)		$ 873,662	$ 882,396	$ 876,751	$ 836,487	$ 759,368	$ 669,573	$ 577,328	$ 522,578	$ 506,281	$ 507,665	$ 519,169	$ 529,928	$ 529,715
Capital Costs ($M)														
New Well - D&C														
Reworks - Producers to Producers														
Reworks - Producers to Injectors														
Reworks - Injectors to Injectors														
Surface Equipment (new wells only)														
CO2 Recycling Plant	2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Water Injection Plant	1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction														
Total Capital Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital G&A	10%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CO2 Costs ($M)														
Total CO2 Cost ($M)		$ (166,591)	$ (158,677)	$ (152,480)	$ (143,098)	$ (132,578)	$ (122,342)	$ (118,974)	$ (115,086)	$ (115,355)	$ (116,652)	$ (117,890)	$ (119,187)	$ (119,637)
O&M Costs ($M)														
Operating & Maintenance ($M)	1	$ (103,738)	$ (103,738)	$ (103,738)	$ (103,738)	$ (103,738)	$ (103,738)	$ (103,738)	$ (103,738)	$ (103,738)	$ (103,738)	$ (103,738)	$ (103,738)	$ (103,738)
H2O Inj O&M ($M)		$ (22,919)	$ (23,825)	$ (24,759)	$ (25,690)	$ (26,624)	$ (27,557)	$ (27,587)	$ (27,587)	$ (27,587)	$ (27,587)	$ (27,587)	$ (27,585)	$ (27,585)
Lifting Costs ($M)		$ (32,914)	$ (32,990)	$ (33,333)	$ (33,255)	$ (33,030)	$ (32,845)	$ (32,440)	$ (31,926)	$ (31,966)	$ (32,142)	$ (32,309)	$ (32,483)	$ (32,542)
G&A	30%	(40,995)	(41,018)	(41,121)	(41,098)	(41,030)	(40,975)	(40,853)	(40,699)	(40,711)	(40,764)	(40,814)	(40,866)	(40,884)
Total O&M Costs		$ (200,566)	$ (201,571)	$ (202,950)	$ (203,781)	$ (204,422)	$ (205,114)	$ (204,619)	$ (203,950)	$ (204,003)	$ (204,231)	$ (204,448)	$ (204,672)	$ (204,749)
Net Cash Flow ($M)		$ 506,505	$ 522,148	$ 521,320	$ 489,609	$ 422,367	$ 342,116	$ 253,735	$ 203,542	$ 186,924	$ 186,782	$ 196,832	$ 206,068	$ 205,329
Cum. Cash Flow		$ 5,706,978	$ 6,229,126	$ 6,750,446	$7,240,055	$7,662,422	$8,004,539	$8,258,274	$8,461,815	$8,648,739	$8,835,521	$9,032,353	$9,238,421	$ 9,443,750
Discount Factor	15%	0.21	0.19	0.16	0.14	0.12	0.11	0.09	0.08	0.07	0.06	0.05	0.05	0.04
Disc. Net Cash Flow		$ 108,870	$ 97,593	$ 84,729	$ 69,196	$ 51,907	$ 36,560	$ 23,579	$ 16,447	$ 13,134	$ 11,412	$ 10,458	$ 9,520	$ 8,249
Disc. Cum Cash Flow		$ 1,859,387	$ 1,956,980	$ 2,041,709	$2,110,905	$2,162,812	$2,199,372	$2,222,950	$2,239,398	$2,252,532	$2,263,944	$2,274,402	$2,283,923	$ 2,292,172

Rate	25%
NPV (BTx)	$978,025
IRR (BTx)	45.23%

Field Cashflow Model

State	CA
Field	Field 1
Formation	Reservoir 1
Depth	5500
Distance from Trunkline	10
# of Patterns	502.00
Miscibility:	Miscible

		24	25	26	27	28	29	30	31	32	33	34	35
CO2 Injection (MMcf)		329,382	329,392	329,382	329,392	329,382	329,382	293,128	227,255	161,373	95,500	29,628	-
H2O Injection (Mbw)		110,340	110,340	110,350	110,350	110,350	110,350	128,472	161,403	194,344	178,320	156,253	116,062
Oil Production (Mbbl)		24,242	23,102	21,606	19,799	17,881	16,114	14,538	12,731	11,004	8,288	5,688	3,368
H2O Production (MBw)		104,592	104,075	104,321	104,230	104,361	104,752	104,717	123,316	151,187	135,666	114,592	93,949
CO2 Production (MMcf)		294,564	297,666	300,000	303,564	306,918	309,513	309,674	273,610	220,303	158,587	95,746	34,437
CO2 Purchased (MMcf)		34,819	31,726	29,382	25,828	22,465	19,869	-	-	-	-	-	-
CO2 Recycled (MMcf)		294,564	297,666	300,000	303,564	306,918	309,513	293,128	227,255	161,373	95,500	29,628	-
Oil Price ($/Bbl)	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00
Gravity Adjustment	37	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25	$ 24.25
Gross Revenues ($M)		$ 587,858	$ 560,224	$ 523,947	$ 480,123	$ 433,620	$ 390,769	$ 352,545	$ 308,720	$ 266,843	$ 200,984	$ 137,926	$ 81,684
Royalty ($M)	-12.5%	$ (73,482)	$ (70,028)	$ (65,493)	$ (60,015)	$ (54,203)	$ (48,846)	$ (44,068)	$ (38,590)	$ (33,355)	$ (25,123)	$ (17,241)	$ (10,211)
Severance Taxes ($M)	0.0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ad Valorum ($M)	0.0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Revenue($M)		$ 514,376	$ 490,196	$ 458,454	$ 420,107	$ 379,418	$ 341,923	$ 308,476	$ 270,130	$ 233,488	$ 175,861	$ 120,685	$ 71,474
Capital Costs ($M)													
New Well - D&C													
Reworks - Producers to Producers													
Reworks - Producers to Injectors													
Reworks - Injectors to Injectors													
Surface Equipment (new wells only)													
CO2 Recycling Plant	2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Water Injection Plant	1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction													
Total Capital Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital G&A	10%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CO2 Costs ($M)													
Total CO2 Cost ($M)		$ (117,164)	$ (114,074)	$ (111,728)	$ (108,176)	$ (104,810)	$ (102,215)	$ (73,282)	$ (56,814)	$ (40,343)	$ (23,875)	$ (7,407)	$ -
O&M Costs ($M)													
Operating & Maintenance ($M)	1	$ (103,738)	$ (103,738)	$ (103,738)	$ (103,738)	$ (103,738)	$ (103,738)	$ (103,738)	$ (103,738)	$ (103,738)	$ (103,738)	$ (82,990)	$ (62,243)
H2O Inj O&M ($M)		$ (27,585)	$ (27,585)	$ (27,587)	$ (27,587)	$ (27,587)	$ (27,587)	$ (32,118)	$ (40,351)	$ (48,586)	$ (44,580)	$ (39,063)	$ (29,016)
Lifting Costs ($M)		$ (32,208)	$ (31,794)	$ (31,482)	$ (31,007)	$ (30,561)	$ (30,217)	$ (29,814)	$ (34,012)	$ (40,548)	$ (35,988)	$ (30,070)	$ (24,329)
G&A	30%	(40,784)	(40,660)	(40,566)	(40,424)	(40,289)	(40,186)	(40,065)	(41,325)	(43,286)	(41,918)	(33,918)	(25,972)
Total O&M Costs		$ (204,315)	$ (203,776)	$ (203,373)	$ (202,756)	$ (202,175)	$ (201,728)	$ (205,735)	$ (219,425)	$ (236,157)	$ (226,224)	$ (186,041)	$ (141,559)
Net Cash Flow ($M)		$ 192,897	$ 172,345	$ 143,354	$ 109,175	$ 72,432	$ 37,980	$ 29,459	$ (6,109)	$ (43,013)	$ (74,238)	$ (72,763)	$ (70,086)
Cum. Cash Flow		$ 9,636,647	$ 9,808,992	$ 9,952,346	$ 10,061,521	$ 10,133,954	$ 10,171,934	$ 10,201,393	$ 10,195,284	$ 10,152,271	$ 10,078,033	$ 10,005,270	$ 9,935,185
Discount Factor	15%	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01
Disc. Net Cash Flow		$ 6,739	$ 5,235	$ 3,787	$ 2,508	$ 1,447	$ 660	$ 445	$ (80)	$ (491)	$ (737)	$ (628)	$ (526)
Disc. Cum Cash Flow		$ 2,298,910	$ 2,304,146	$ 2,307,932	$ 2,310,440	$ 2,311,887	$ 2,312,547	$ 2,312,992	$ 2,312,911	$ 2,312,420	$ 2,311,683	$ 2,311,055	$ 2,310,528

Rate	25%
NPV (BTx)	$978,025
IRR (BTx)	45.23%

Field Cashflow Model

State	CA
Field	Field 1
Formation	Reservoir 1
Depth	5500
Distance from Trunkline	10
# of Patterns	502.00
Miscibility:	Miscible

			36	37	Totals
CO2 Injection (MMcf)			-	-	10,112,087
H2O Injection (Mbw)			61,053	6,044	3,775,391
Oil Production (Mbbl)			1,611	146	1,106,458
H2O Production (MBw)			54,326	5,537	3,630,263
CO2 Production (MMcf)			9,377	658	8,306,870
CO2 Purchased (MMcf)			-	-	2,100,724
CO2 Recycled (MMcf)			-	-	8,011,363
Oil Price ($/Bbl)	$	**25.00**	$ 25.00	$ 25.00	
Gravity Adjustment		**37**	$ 24.25	$ 24.25	
Gross Revenues ($M)			$ 39,077	$ 3,530	$ 26,831,611
Royalty ($M)	**-12.5%**		$ (4,885)	$ (441)	$ (3,353,951)
Severance Taxes ($M)	**0.0%**		$ -	$ -	$ -
Ad Valorum ($M)	**0.0%**		$ -	$ -	$ -
Net Revenue($M)			$ 34,192	$ 3,089	$ 23,477,660
Capital Costs ($M)					
New Well - D&C					$ (989,894)
Reworks - Producers to Producers					$ (84,972)
Reworks - Producers to Injectors					$ (11,493)
Reworks - Injectors to Injectors					$ -
Surface Equipment (new wells only)					$ (190,804)
CO2 Recycling Plant	**2**		$ -	$ -	$ (593,895)
Water Injection Plant	**1**		$ -	$ -	$ -
Trunkline Construction					$ (2,150)
Total Capital Costs			$ -	$ -	$ (1,873,209)
Capital G&A		**10%**	$ -	$ -	$ (187,321)
CO2 Costs ($M)					
Total CO2 Cost ($M)			$ -	$ -	$ (4,628,746)
O&M Costs ($M)					
Operating & Maintenance ($M)	**1**		$ (41,495)	$ (20,748)	$ (3,423,348)
H2O Inj O&M ($M)			$ (15,263)	$ (1,511)	$ (943,848)
Lifting Costs ($M)			$ (13,984)	$ (1,421)	$ (1,184,180)
G&A		**30%**	(16,644)	(6,650)	$ (1,382,259)
Total O&M Costs			$ (87,387)	$ (30,330)	$ (6,933,635)
Net Cash Flow ($M)			$ (53,194)	$ (27,241)	$ 9,854,749
Cum. Cash Flow			$ 9,881,990	$ 9,854,749	
Discount Factor	**15%**		0.01	0.01	
Disc. Net Cash Flow			$ (347)	$ (155)	$ 2,310,026
Disc. Cum Cash Flow			$ 2,310,181	$ 2,310,026	

Rate	25%
NPV (BTx)	$978,025
IRR (BTx)	45.23%

APPENDIX B.2

EXAMPLE APPLICATION OF CO_2-EOR ECONOMICS MODEL: FIELD #2 (RESERVOIR #2)

1. Traditional Immiscible CO_2-EOR Technology (0.4 HCPV of CO_2)
2. Integrated Application of the Combination of “Next Generation” CO_2-EOR Technologies (1.5 HCPV of CO_2)

Basin	**LA**
Field	**Field 2**
Formation	**Reservoir 2**
Technology Case	**Traditional Practices**
Depth (ft)	4,500
OOIP (MMBls)	156.6
Cum Primary Recovery (MMbls)	48.0
Primary EUR (MMbls)	48.6
Miscibility	Immiscible
API Gravity	23.0
Patterns	32
Existing Injectors Used	0
Convertible Producers Used	0
New Injectors Drilled	32
Existing Producers Used	40
New Producers Drilled	4

Pattern Detail

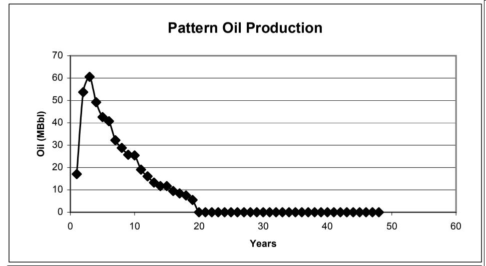
Cum Oil (Mbbl)	479		
Cum H2O (Mbw)	8,133	16.99	Bw/Bbl
Gross CO2 (MMcf)	4,108	8.58	Mcf/Bbl
Purchased CO2 (MMcf)	1,565	3.27	Mcf/Bbl
Recycled CO2 (MMcf)	2,543	5.31	Mcf/Bbl

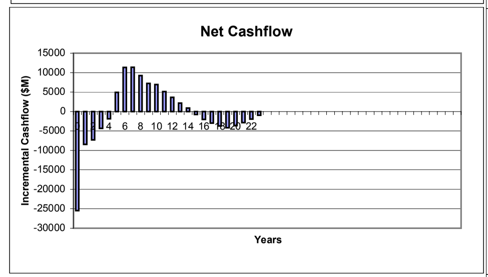
Field Detail

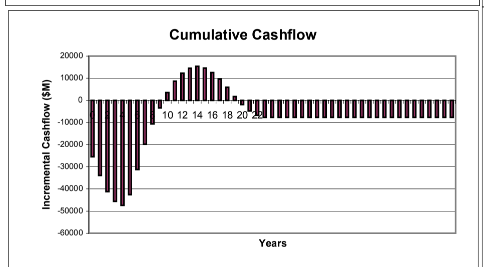
Cum Oil (MMbbl)	15.32	
% OOIP Recovered	9.8%	
Cum H2O (MMbw)	260	
Gross CO2 (MMcf)	131,450	
Purchased CO2 (MMcf)	46,906	
Recycled CO2 (MMcf)	84,543	
Payback Period (per pattern)	67	years
Project Length	23	years

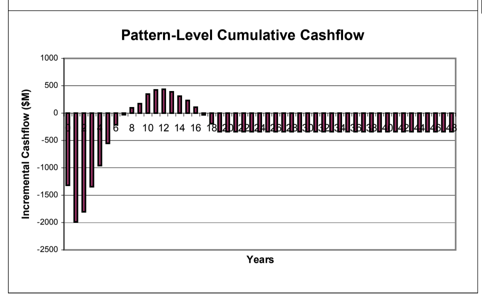
				$/BBl
Total Net Revenue ($M)	$	8,693		
Total Capital Investment ($M)	$	(1,320)	$	2.76
CAPEX G&A	$	-	$	-
Total CO2 Cost ($M)	$	(2,592)	$	5.41
Total O&M Costs ($M)	$	(5,121)	$	10.69
	$	(9,032)	$	18.86

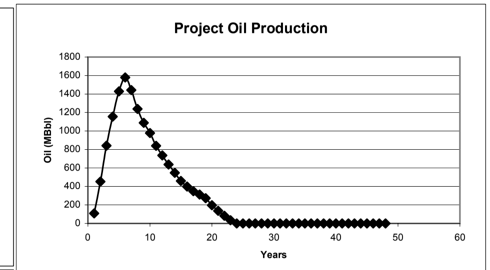
Pattern IRR (BTx)	#NUM!
Project IRR (BTx)	#DIV/0!

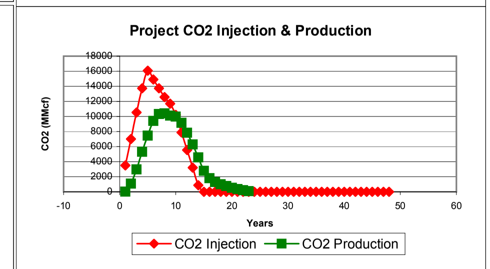


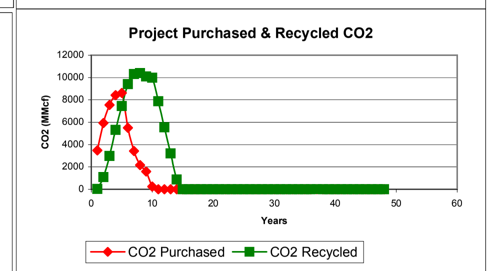












Assumptions:

Economic Case:	Traditional	
Oil Price	$	25.00
CO2 Purchase Cost	5% of oil price	
CO2 Recycle Cost	1% of oil price	
Recycling Plant Costs	1 Year before Breakthru	
Well O&M	Prod Wells Only	
Minimum IRR	**25.0%**	

Pattern-Level Cashflow Model **Traditional Practices**

State	**CA**	**LA**	New Injectors	1.00
Field	**Field 2**		Existing Injectors	0.00
Formation	**Reservoir 2**		Convertable Producers	0.00
Depth	**4,500**		New Producers	0.13
Distance from Trunkline (mi)	**10**		Existing Producers	1.25
# of Patterns	**32**		Disposal Wells	0.00
Miscibility:	**Immiscible**			

	Year	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
CO2 Injection (MMcf)			548	548	548	502	365	365	365	365	365	136	-	-	-
H2O Injection (Mbw)			274	274	274	297	365	365	365	365	365	480	548	548	548
Oil Production (Mbbl)			17	54	61	49	43	41	32	29	26	25	19	16	13
H2O Production (MBw)			527	409	337	315	337	351	360	364	363	364	439	479	501
CO2 Production (MMcf)			4	166	296	364	335	309	309	309	317	316	179	105	67
CO2 Purchased (MMcf)			544	382	252	138	30	56	57	56	49	-	-	-	-
CO2 Recycled (MMcf)			4	166	296	364	335	309	309	309	317	136	-	-	-
Oil Price ($/Bbl)	$ 25.00		$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00
Gravity Adjustment	23 Deg		$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75
Gross Revenues ($M)			$ 355	$ 1,114	$ 1,257	$ 1,021	$ 884	$ 845	$ 668	$ 598	$ 533	$ 527	$ 396	$ 334	$ 276
Royalty ($M)	-12.5%		$ (44)	$ (139)	$ (157)	$ (128)	$ (110)	$ (106)	$ (84)	$ (75)	$ (67)	$ (66)	$ (50)	$ (42)	$ (34)
Severance Taxes ($M)	0.0%		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ad Valorum ($M)	0.0%		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Revenue($M)			$ 310	$ 975	$ 1,100	$ 893	$ 773	$ 739	$ 585	$ 523	$ 467	$ 461	$ 347	$ 292	$ 241
Capital Costs ($M)															
New Well - D&C		$ (348)													
Reworks - Producers to Producers		$ (159)													
Reworks - Producers to Injectors		$ -													
Reworks - Injectors to Injectors		$ -													
Surface Equipment (new wells only)		$ (148)													
CO2 Recycling Plant		$ (623)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Water Injection Plant		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction		$ (42)													
Total Capital Costs		$ (1,320)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital G&A	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CO2 Costs ($M)															
Total CO2 Cost ($M)			$ (681.3)	$ (519)	$ (389)	$ (263)	$ (122)	$ (148)	$ (148)	$ (148)	$ (140)	$ (34)	$ -	$ -	$ -
O&M Costs															
Operating & Maintenance ($M)			$ (111)	$ (111)	$ (111)	$ (111)	$ (111)	$ (111)	$ (111)	$ (111)	$ (111)	$ (111)	$ (111)	$ (111)	$ (111)
H2O Inj O&M ($M)			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Lifting Costs ($/bbl)	$ 0.25		$ (136)	$ (116)	$ (99)	$ (91)	$ (95)	$ (98)	$ (98)	$ (98)	$ (97)	$ (97)	$ (115)	$ (124)	$ (129)
G&A	20%		(49)	(45)	(42)	(40)	(41)	(42)	(42)	(42)	(42)	(42)	(45)	(47)	(48)
Total O&M Costs			$ (297)	$ (272)	$ (253)	$ (243)	$ (247)	$ (251)	$ (251)	$ (251)	$ (250)	$ (250)	$ (271)	$ (282)	$ (288)
Net Cash Flow ($M)		$ (1,320)	$ (668)	$ 184	$ 458	$ 387	$ 404	$ 340	$ 185	$ 124	$ 76	$ 177	$ 76	$ 10	$ (46)
Cum. Cash Flow		$ (1,320)	$ (1,988)	$ (1,804)	$ (1,346)	$ (958)	$ (554)	$ (214)	$ (29)	$ 95	$ 172	$ 349	$ 424	$ 435	$ 388
Discount Factor	15%	1.00	0.87	0.76	0.66	0.57	0.50	0.43	0.38	0.33	0.28	0.25	0.21	0.19	0.16
Disc. Net Cash Flow		$ (1,320)	$ (581)	$ 139	$ 301	$ 221	$ 201	$ 147	$ 70	$ 41	$ 22	$ 44	$ 16	$ 2	$ (8)
Disc. Cum Cash Flow		$ (1,320)	$ (1,900)	$ (1,761)	$ (1,460)	$ (1,239)	$ (1,038)	$ (891)	$ (821)	$ (781)	$ (759)	$ (715)	$ (699)	$ (697)	$ (704)

Rate	25%	20%	15%	10%
NPV (BTx)	($1,046)	$ (924)	$ (775)	$ (600)
IRR (BTx)	#NUM!			

Pattern-Level Cashflow Model

State	**CA**
Field	**Field 2**
Formation	**Reservoir 2**
Depth	**4,500**
Distance from Trunkline (mi)	**10**
# of Patterns	**32**
Miscibility:	**Immiscible**

	Year	14	15	16	17	18	19	Totals
CO2 Injection (MMcf)		-	-	-	-	-	-	4,108
H2O Injection (Mbw)		548	548	548	548	548	386	8,194
Oil Production (Mbbl)		12	12	10	8	8	6	479
H2O Production (MBw)		512	518	524	528	530	374	8,133
CO2 Production (MMcf)		47	36	29	24	20	12	3,240
CO2 Purchased (MMcf)		-	-	-	-	-	-	1,565
CO2 Recycled (MMcf)		-	-	-	-	-	-	2,543
Oil Price ($/Bbl)	**$ 25.00**	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	
Gravity Adjustment	**23**	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	
Gross Revenues ($M)		$ 243	$ 243	$ 197	$ 174	$ 156	$ 114	$ 9,935
Royalty ($M)	**-12.5%**	$ (30)	$ (30)	$ (25)	$ (22)	$ (19)	$ (14)	$ (1,242)
Severance Taxes ($M)	**0.0%**	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ad Valorum ($M)	**0.0%**	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Revenue($M)		$ 212	$ 212	$ 172	$ 153	$ 136	$ 100	$ 8,693
Capital Costs ($M)								
New Well - D&C								$ (348)
Reworks - Producers to Producers								$ (159)
Reworks - Producers to Injectors								$ -
Reworks - Injectors to Injectors								$ -
Surface Equipment (new wells only)								$ (148)
CO2 Recycling Plant		$ -	$ -	$ -	$ -	$ -	$ -	$ (623)
Water Injection Plant		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction								$ (42)
Total Capital Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ (1,320)
Capital G&A	**0%**	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CO2 Costs ($M)								
Total CO2 Cost ($M)		$ -	$ -	$ -	$ -	$ -	$ -	$ (2,592)
O&M Costs								
Operating & Maintenance ($M)		$ (111)	$ (111)	$ (111)	$ (111)	$ (111)	$ (111)	$ (2,114)
H2O Inj O&M ($M)		$ -	$ -	$ -	$ -	$ -	$ -	$ -
Lifting Costs ($/bbl)	**$ 0.25**	$ (131)	$ (132)	$ (133)	$ (134)	$ (134)	$ (95)	$ (2,153)
G&A	**20%**	(48)	(49)	(49)	(49)	(49)	(41)	$ (853)
Total O&M Costs		$ (291)	$ (293)	$ (293)	$ (294)	$ (295)	$ (247)	$ (5,121)
Net Cash Flow ($M)		$ (78)	$ (80)	$ (121)	$ (142)	$ (159)	$ (148)	$ (339)
Cum. Cash Flow		$ 310	$ 230	$ 109	$ (33)	$ (192)	$ (339)	
Discount Factor	**15%**	0.14	0.12	0.11	0.09	0.08	0.07	
Disc. Net Cash Flow		$ (11)	$ (10)	$ (13)	$ (13)	$ (13)	$ (10)	$ (775)
Disc. Cum Cash Flow		$ (716)	$ (725)	$ (738)	$ (751)	$ (764)	$ (775)	

Rate	25%
NPV (BTx)	($1,046)
IRR (BTx)	#NUM!

Field Cashflow Model

		Traditional Practices	Pattern		Field			
State	CA	LA	Existing Injectors Used	0.00	Existing Injectors Used	0		
Field	Field 2		Convertable Producers Used	0.00	Convertable Producers Used	0	Total Injectors Required	
Formation	Reservoir 2		New Injectors Needed	1.00	New Injectors Needed	32	32	Ex
Depth	4500		New Producers Needed	0.13	New Producers Needed	4	Total Producers Required	
Distance from Trunkline	10 miles		Existing Producers Used	1.25	Existing Producers Used	40	44	Exis
# of Patterns	32.00							
Miscibility:	Immiscible							

		0	1	2	3	4	5	6	7	8	9	10
CO2 Injection (MMcf)			3,507	7,013	10,520	13,732	16,070	14,901	13,732	12,563	11,688	10,220
H2O Injection (Mbw)			1,753	3,507	5,260	7,160	9,498	10,082	10,666	11,251	11,688	12,422
Oil Production (Mbbl)			109	453	841	1,156	1,428	1,580	1,442	1,238	1,088	978
H2O Production (MBw)			3,375	5,991	8,148	10,164	12,318	11,192	10,883	11,052	11,360	11,535
CO2 Production (MMcf)			23	1,085	2,977	5,308	7,450	9,404	10,316	10,401	10,097	9,978
CO2 Purchased (MMcf)			3,484	5,928	7,542	8,425	8,620	5,497	3,416	2,162	1,591	243
CO2 Recycled (MMcf)			23	1,085	2,977	5,308	7,450	9,404	10,316	10,401	10,097	9,978
Oil Price ($/Bbl)	$ 25.00		$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00
Gravity Adjustment	23		$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75
Gross Revenues ($M)			$ 2,271	$ 9,402	$ 17,450	$ 23,984	$ 29,641	$ 32,775	$ 29,920	$ 25,697	$ 22,576	$ 20,292
Royalty ($M)	-12.5%		$ (284)	$ (1,175)	$ (2,181)	$ (2,998)	$ (3,705)	$ (4,097)	$ (3,740)	$ (3,212)	$ (2,822)	$ (2,536)
Severance Taxes ($M)	0.0%		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ad Valorum ($M)	0.0%		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Revenue($M)			$ 1,987	$ 8,227	$ 15,269	$ 20,986	$ 25,936	$ 28,678	$ 26,180	$ 22,485	$ 19,754	$ 17,755
Capital Costs ($M)												
New Well - D&C		$ (2,227)	$ (2,227)	$ (2,227)	$ (2,227)	$ (2,227)	$ -	$ -	$ -	$ -	$ -	
Reworks - Producers to Producers		$ (1,015)	$ (1,015)	$ (1,015)	$ (1,015)	$ (1,015)	$ -	$ -	$ -	$ -	$ -	
Reworks - Producers to Injectors		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Reworks - Injectors to Injectors		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Surface Equipment (new wells only)		$ (945)	$ (945)	$ (945)	$ (945)	$ (945)	$ -	$ -	$ -	$ -	$ -	
CO2 Recycling Plant	2	$ (19,948)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Water Injection Plant	1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction		$ (1,350)										
Total Capital Costs		$ (25,485)	$ (4,188)	$ (4,188)	$ (4,188)	$ (4,188)	$ -	$ -	$ -	$ -	$ -	$ -
Capital G&A	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CO2 Costs ($M)												
Total CO2 Cost ($M)			$ (4,360)	$ (7,681)	$ (10,172)	$ (11,858)	$ (12,637)	$ (9,222)	$ (6,849)	$ (5,303)	$ (4,513)	$ (2,798)
O&M Costs ($M)												
Operating & Maintenance ($M)	1		$ (712)	$ (1,424)	$ (2,137)	$ (2,849)	$ (3,561)	$ (3,561)	$ (3,561)	$ (3,561)	$ (3,561)	$ (3,561)
H2O Inj O&M ($M)			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Lifting Costs ($M)			$ (871)	$ (1,611)	$ (2,247)	$ (2,830)	$ (3,437)	$ (3,193)	$ (3,081)	$ (3,073)	$ (3,112)	$ (3,128)
G&A	20%		(317)	(607)	(877)	(1,136)	(1,400)	(1,351)	(1,328)	(1,327)	(1,335)	(1,338)
Total O&M Costs			$ (1,900)	$ (3,642)	$ (5,261)	$ (6,814)	$ (8,397)	$ (8,104)	$ (7,970)	$ (7,960)	$ (8,007)	$ (8,027)
Net Cash Flow ($M)		$ (25,485)	$ (8,461)	$ (7,284)	$ (4,352)	$ (1,874)	$ 4,902	$ 11,352	$ 11,361	$ 9,222	$ 7,234	$ 6,931
Cum. Cash Flow		$ (25,485)	$ (33,946)	$ (41,231)	$ (45,583)	$ (47,457)	$ (42,555)	$ (31,204)	$ (19,843)	$ (10,621)	$ (3,388)	$ 3,543
Discount Factor	15%	1.00	0.87	0.76	0.66	0.57	0.50	0.43	0.38	0.33	0.28	0.25
Disc. Net Cash Flow		$ (25,485)	$ (7,357)	$ (5,508)	$ (2,862)	$ (1,072)	$ 2,437	$ 4,908	$ 4,271	$ 3,015	$ 2,056	$ 1,713
Disc. Cum Cash Flow		$ (25,485)	$ (32,843)	$ (38,351)	$ (41,212)	$ (42,284)	$ (39,847)	$ (34,939)	$ (30,668)	$ (27,654)	$ (25,598)	$ (23,884)

Rate	25%	20%	15%	10%
NPV (BTx)	($29,203)	$ (26,809)	$ (23,306)	$ (18,440)
IRR (BTx)	#DIV/0!			

Field Cashflow Model

State	CA			
Field	Field 2			
Formation	Reservoir 2		‹isting Injectors	0
Depth		4500		
Distance from Trunkline		10	›ting Producers	40
# of Patterns		32.00		
Miscibility:	Immiscible			

		11	12	13	14	15	16	17	18	19	20	21	22	23	Totals
CO2 Injection (MMcf)		7,882	5,545	3,207	870	-	-	-	-	-	-	-	-	-	131,450
H2O Injection (Mbw)		13,591	14,760	15,929	17,098	17,533	17,533	17,532	17,532	16,493	12,987	9,480	5,974	2,468	262,195
Oil Production (Mbbl)		840	737	637	548	460	399	349	312	273	198	137	83	35	15,322
H2O Production (MBw)		12,098	12,858	13,736	14,692	15,679	16,220	16,530	16,718	15,832	12,516	9,164	5,788	2,394	260,243
CO2 Production (MMcf)		9,145	7,842	6,292	4,568	2,772	1,811	1,291	991	764	537	353	202	76	103,683
CO2 Purchased (MMcf)		-	-	-	-	-	-	-	-	-	-	-	-	-	46,906
CO2 Recycled (MMcf)		7,882	5,545	3,207	870	-	-	-	-	-	-	-	-	-	84,543
Oil Price ($/Bbl)	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	
Gravity Adjustment	23	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	
Gross Revenues ($M)		$ 17,423	$ 15,285	$ 13,227	$ 11,368	$ 9,548	$ 8,273	$ 7,251	$ 6,481	$ 5,657	$ 4,104	$ 2,842	$ 1,726	$ 730	$ 317,923
Royalty ($M)	-12.5%	$ (2,178)	$ (1,911)	$ (1,653)	$ (1,421)	$ (1,194)	$ (1,034)	$ (906)	$ (810)	$ (707)	$ (513)	$ (355)	$ (216)	$ (91)	$ (39,740)
Severance Taxes ($M)	0.0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ad Valorum ($M)	0.0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Revenue($M)		$ 15,245	$ 13,375	$ 11,574	$ 9,947	$ 8,355	$ 7,239	$ 6,345	$ 5,671	$ 4,950	$ 3,591	$ 2,487	$ 1,511	$ 639	$ 278,183
Capital Costs ($M)															
New Well - D&C															$ (11,137)
Reworks - Producers to Producers															$ (5,076)
Reworks - Producers to Injectors															$ -
Reworks - Injectors to Injectors															$ -
Surface Equipment (new wells only)															$ (4,725)
CO2 Recycling Plant	2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (19,948)
Water Injection Plant	1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction															$ (1,350)
Total Capital Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (42,237)
Capital G&A	0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CO2 Costs ($M)															
Total CO2 Cost ($M)		$ (1,971)	$ (1,386)	$ (802)	$ (217)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (79,769)
O&M Costs ($M)															
Operating & Maintenance ($M)	1	$ (3,561)	$ (3,561)	$ (3,561)	$ (3,561)	$ (3,561)	$ (3,561)	$ (3,561)	$ (3,561)	$ (3,561)	$ (2,849)	$ (2,137)	$ (1,424)	$ (712)	$ (67,657)
H2O Inj O&M ($M)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Lifting Costs ($M)		$ (3,234)	$ (3,399)	$ (3,593)	$ (3,810)	$ (4,035)	$ (4,155)	$ (4,220)	$ (4,258)	$ (4,026)	$ (3,178)	$ (2,325)	$ (1,468)	$ (607)	$ (68,891)
G&A	20%	(1,359)	(1,392)	(1,431)	(1,474)	(1,519)	(1,543)	(1,556)	(1,564)	(1,517)	(1,205)	(892)	(578)	(264)	$ (27,310)
Total O&M Costs		$ (8,154)	$ (8,351)	$ (8,585)	$ (8,845)	$ (9,115)	$ (9,259)	$ (9,337)	$ (9,382)	$ (9,105)	$ (7,233)	$ (5,354)	$ (3,470)	$ (1,583)	$ (163,857)
Net Cash Flow ($M)		$ 5,121	$ 3,637	$ 2,187	$ 884	$ (760)	$ (2,019)	$ (2,992)	$ (3,712)	$ (4,154)	$ (3,642)	$ (2,867)	$ (1,960)	$ (944)	$ (7,680)
Cum. Cash Flow		$ 8,664	$ 12,301	$ 14,487	$ 15,371	$ 14,611	$ 12,592	$ 9,600	$ 5,888	$ 1,734	$ (1,908)	$ (4,776)	$ (6,736)	$ (7,680)	
Discount Factor	15%	0.21	0.19	0.16	0.14	0.12	0.11	0.09	0.08	0.07	0.06	0.05	0.05	0.04	
Disc. Net Cash Flow		$ 1,101	$ 680	$ 355	$ 125	$ (93)	$ (216)	$ (278)	$ (300)	$ (292)	$ (223)	$ (152)	$ (91)	$ (38)	$ (23,306)
Disc. Cum Cash Flow		$ (22,784)	$ (22,104)	$ (21,749)	$ (21,624)	$ (21,717)	$ (21,933)	$ (22,211)	$ (22,511)	$ (22,803)	$ (23,025)	$ (23,178)	$ (23,268)	$ (23,306)	

Rate	25%
NPV (BTx)	($29,203)
IRR (BTx)	#DIV/0!

Basin	**LA**	
Field	**Field 2**	
Formation	**Reservoir 2**	
Technology Case	**Next Generation**	
Depth (ft)	4,500	
OOIP (MMBls)	156.6	
Cum Primary Recovery (MMbls)	48.0	
Primary EUR (MMbls)	48.6	
Miscibility	Miscible	
API Gravity	23.0	
Patterns	32	
Existing Injectors Used	0	
Convertible Producers Used	0	
New Injectors Drilled	64	
Existing Producers Used	40	
New Producers Drilled	68	

Pattern Detail

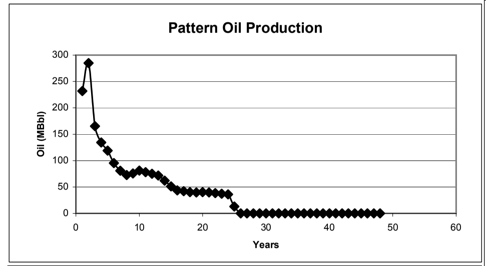
Cum Oil (Mbbl)	2,049		
Cum H2O (Mbw)	5,144	2.51	Bw/Bbl
Gross CO2 (MMcf)	15,404	7.52	Mcf/Bbl
Purchased CO2 (MMcf)	3,739	1.82	Mcf/Bbl
Recycled CO2 (MMcf)	11,665	5.69	Mcf/Bbl

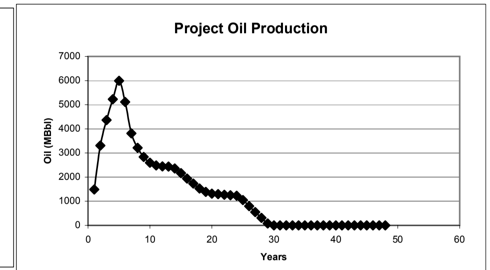
Field Detail

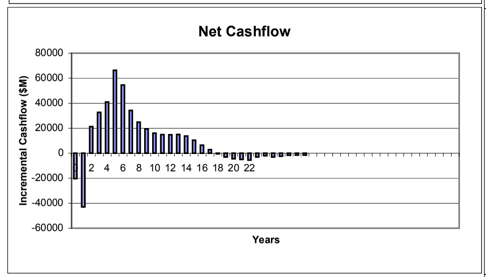
Cum Oil (MMbbl)	65.57	
% OOIP Recovered	41.9%	
Cum H2O (MMbw)	165	
Gross CO2 (MMcf)	492,938	
Purchased CO2 (MMcf)	115,263	
Recycled CO2 (MMcf)	377,675	
Payback Period (per pattern)	2	years
Project Length	29	years

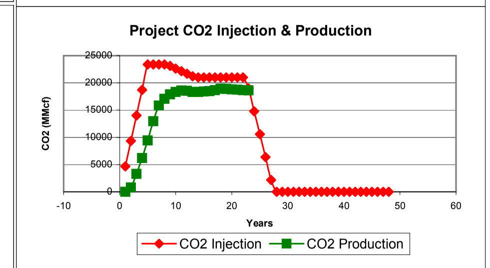
			$/BBl	
Total Net Revenue ($M)	$	37,201		
Total Capital Investment ($M)	$	(3,826)	$	1.87
CAPEX G&A	$	(383)	$	0.19
Total CO2 Cost ($M)	$	(11,441)	$	5.58
Total O&M Costs ($M)	$	(12,640)	$	6.17
	$	(28,289)	$	13.81

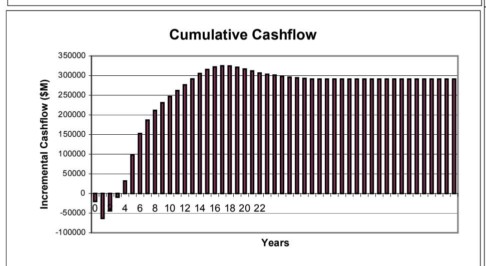
Pattern IRR (BTx)	62.5%
Project IRR (BTx)	46.5%

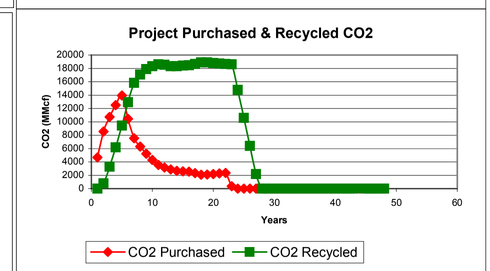


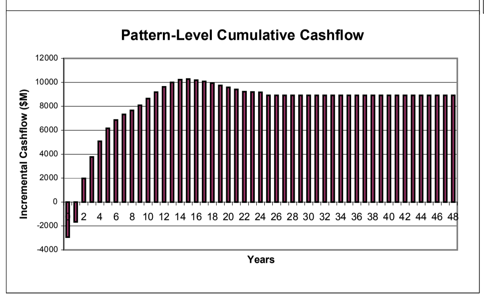












Assumptions:

Economic Case:	Traditional
Oil Price	$ 25.00
CO2 Purchase Cost	5% of oil price
CO2 Recycle Cost	1% of oil price
Recycling Plant Costs	1 Year before Breakthru
Well O&M	Prod Wells Only
Minimum IRR	**25.0%**

Pattern-Level Cashflow Model

Next Generation

State	**CA**	**LA**	New Injectors	2.00
Field	**Field 2**		Existing Injectors	0.00
Formation	**Reservoir 2**		Convertable Producers	0.00
Depth	**4,500**		New Producers	2.13
Distance from Trunkline (mi)	**10**		Existing Producers	1.25
# of Patterns	**32**		Disposal Wells	0.00
Miscibility:	**Miscible**			

3

	Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13
CO2 Injection (MMcf)			731	731	731	731	731	731	731	731	689	656	656	656	656
H2O Injection (Mbw)			183	183	183	183	183	183	183	183	204	220	220	220	220
Oil Production (Mbbl)			232	285	165	135	119	95	81	73	76	81	78	75	72
H2O Production (MBw)			308	184	168	167	158	167	169	171	170	196	195	194	195
CO2 Production (MMcf)			-	123	391	452	509	547	576	585	578	579	589	565	554
CO2 Purchased (MMcf)			731	607	339	278	222	183	155	146	111	77	67	92	103
CO2 Recycled (MMcf)			-	123	391	452	509	547	576	585	578	579	589	565	554
Oil Price ($/Bbl)	$ 25.00		$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00
Gravity Adjustment	23	Deg	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75
Gross Revenues ($M)			$ 4,813	$ 5,909	$ 3,430	$ 2,792	$ 2,471	$ 1,977	$ 1,680	$ 1,506	$ 1,568	$ 1,681	$ 1,619	$ 1,560	$ 1,486
Royalty ($M)	-12.5%		$ (602)	$ (739)	$ (429)	$ (349)	$ (309)	$ (247)	$ (210)	$ (188)	$ (196)	$ (210)	$ (202)	$ (195)	$ (186)
Severance Taxes ($M)	0.0%		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ad Valorum ($M)	0.0%		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Revenue($M)			$ 4,211	$ 5,170	$ 3,001	$ 2,443	$ 2,162	$ 1,730	$ 1,470	$ 1,318	$ 1,372	$ 1,471	$ 1,416	$ 1,365	$ 1,300
Capital Costs ($M)															
New Well - D&C		$ (1,923)													
Reworks - Producers to Producers		$ (159)													
Reworks - Producers to Injectors		$ -													
Reworks - Injectors to Injectors		$ -													
Surface Equipment (new wells only)		$ (530)													
CO2 Recycling Plant		$ -	$ (1,160)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Water Injection Plant		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction		$ (55)													
Total Capital Costs		$ (2,666)	$ (1,160)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital G&A	10%	$ (267)	$ (116)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CO2 Costs ($M)															
Total CO2 Cost ($M)	$ 0.25	misc extender	$ (1,095.8)	$ (973)	$ (704)	$ (644)	$ (587)	$ (549)	$ (520)	$ (511)	$ (455)	$ (405)	$ (396)	$ (420)	$ (431)
O&M Costs															
Operating & Maintenance ($M)			$ (272)	$ (272)	$ (272)	$ (272)	$ (272)	$ (272)	$ (272)	$ (272)	$ (272)	$ (272)	$ (272)	$ (272)	$ (272)
H2O Inj O&M ($M)			$ (46)	$ (46)	$ (46)	$ (46)	$ (46)	$ (46)	$ (46)	$ (46)	$ (51)	$ (55)	$ (55)	$ (55)	$ (55)
Lifting Costs ($/bbl)	$ 0.25		$ (135)	$ (117)	$ (83)	$ (75)	$ (69)	$ (66)	$ (62)	$ (61)	$ (61)	$ (69)	$ (68)	$ (67)	$ (67)
G&A	30%		(122)	(117)	(107)	(104)	(102)	(101)	(100)	(100)	(100)	(102)	(102)	(102)	(102)
Total O&M Costs			$ (575)	$ (552)	$ (507)	$ (497)	$ (489)	$ (484)	$ (480)	$ (478)	$ (484)	$ (499)	$ (497)	$ (496)	$ (495)
Net Cash Flow ($M)		$ (2,932)	$ 1,265	$ 3,646	$ 1,789	$ 1,302	$ 1,086	$ 697	$ 470	$ 329	$ 432	$ 567	$ 523	$ 450	$ 374
Cum. Cash Flow		$ (2,932)	$ (1,667)	$ 1,979	$ 3,768	$ 5,070	$ 6,156	$ 6,854	$ 7,323	$ 7,652	$ 8,084	$ 8,651	$ 9,175	$ 9,624	$ 9,999
Discount Factor	15%	1.00	0.87	0.76	0.66	0.57	0.50	0.43	0.38	0.33	0.28	0.25	0.21	0.19	0.16
Disc. Net Cash Flow		$ (2,932)	$ 1,100	$ 2,757	$ 1,177	$ 745	$ 540	$ 301	$ 177	$ 108	$ 123	$ 140	$ 112	$ 84	$ 61
Disc. Cum Cash Flow		$ (2,932)	$ (1,832)	$ 925	$ 2,101	$ 2,846	$ 3,386	$ 3,687	$ 3,864	$ 3,971	$ 4,094	$ 4,234	$ 4,347	$ 4,431	$ 4,492

Rate	25%	20%	15%	10%
NPV (BTx)	$2,766	$ 3,511	$ 4,448	$ 5,638
IRR (BTx)	62.54%			

Pattern-Level Cashflow Model

State	**CA**
Field	**Field 2**
Formation	**Reservoir 2**
Depth	**4,500**
Distance from Trunkline (mi)	**10**
# of Patterns	**32**
Miscibility:	**Miscible**

	Year	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28
CO2 Injection (MMcf)		656	656	656	656	656	656	656	656	656	342	-	-	-	-	-
H2O Injection (Mbw)		220	220	220	220	220	220	220	220	220	377	548	212	-	-	-
Oil Production (Mbbl)		62	51	43	42	40	40	40	40	38	37	36	13	-	-	-
H2O Production (MBw)		196	199	206	204	208	206	207	208	207	209	460	195	-	-	-
CO2 Production (MMcf)		578	591	598	595	592	576	578	586	582	588	600	609	609	618	621
CO2 Purchased (MMcf)		78	65	58	61	64	81	78	71	74	-	-	-	-	-	-
CO2 Recycled (MMcf)		578	591	598	595	592	576	578	586	582	342	-	-	-	-	-
Oil Price ($/Bbl)	**$ 25.00**	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ -	$ -	$ -
Gravity Adjustment	**23**	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ -	$ -	$ -
Gross Revenues ($M)		$ 1,290	$ 1,060	$ 902	$ 874	$ 834	$ 823	$ 837	$ 821	$ 797	$ 773	$ 746	$ 269	$ -	$ -	$ -
Royalty ($M)	**-12.5%**	$ (161)	$ (133)	$ (113)	$ (109)	$ (104)	$ (103)	$ (105)	$ (103)	$ (100)	$ (97)	$ (93)	$ (34)	$ -	$ -	$ -
Severance Taxes ($M)	**0.0%**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ad Valorum ($M)	**0.0%**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Revenue($M)		$ 1,128	$ 928	$ 789	$ 764	$ 730	$ 720	$ 733	$ 718	$ 697	$ 676	$ 653	$ 235	$ -	$ -	$ -
Capital Costs ($M)																
New Well - D&C																
Reworks - Producers to Producers																
Reworks - Producers to Injectors																
Reworks - Injectors to Injectors																
Surface Equipment (new wells only)																
CO2 Recycling Plant		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Water Injection Plant		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction																
Total Capital Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital G&A	**10%**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CO2 Costs ($M)																
Total CO2 Cost ($M)	**$ 0.25**	$ (406)	$ (393)	$ (386)	$ (389)	$ (392)	$ (409)	$ (406)	$ (399)	$ (402)	$ (171)	$ -	$ -	$ -	$ -	$ -
O&M Costs																
Operating & Maintenance ($M)		$ (272)	$ (272)	$ (272)	$ (272)	$ (272)	$ (272)	$ (272)	$ (272)	$ (272)	$ (272)	$ (272)	$ (272)	$ -	$ -	$ -
H2O Inj O&M ($M)		$ (55)	$ (55)	$ (55)	$ (55)	$ (55)	$ (55)	$ (55)	$ (55)	$ (55)	$ (94)	$ (137)	$ (53)	$ -	$ -	$ -
Lifting Costs ($/bbl)	**$ 0.25**	$ (64)	$ (63)	$ (62)	$ (62)	$ (62)	$ (61)	$ (62)	$ (62)	$ (61)	$ (62)	$ (151)	$ (62)	$ -	$ -	$ -
G&A	**30%**	(101)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(127)	(100)	-	-	-
Total O&M Costs		$ (492)	$ (490)	$ (489)	$ (489)	$ (489)	$ (488)	$ (489)	$ (489)	$ (488)	$ (528)	$ (687)	$ (487)	$ -	$ -	$ -
Net Cash Flow ($M)		$ 230	$ 45	$ (87)	$ (113)	$ (151)	$ (177)	$ (162)	$ (170)	$ (193)	$ (23)	$ (34)	$ (252)	$ -	$ -	$ -
Cum. Cash Flow		$ 10,229	$ 10,273	$ 10,186	$ 10,073	$ 9,922	$ 9,745	$ 9,583	$ 9,413	$ 9,220	$ 9,198	$ 9,164	$ 8,912	$ 8,912	$ 8,912	$ 8,912
Discount Factor	**15%**	0.14	0.12	0.11	0.09	0.08	0.07	0.06	0.05	0.05	0.04	0.03	0.03	0.03	0.02	0.02
Disc. Net Cash Flow		$ 33	$ 6	$ (9)	$ (11)	$ (12)	$ (12)	$ (10)	$ (9)	$ (9)	$ (1)	$ (1)	$ (8)	$ -	$ -	$ -
Disc. Cum Cash Flow		$ 4,524	$ 4,530	$ 4,520	$ 4,510	$ 4,498	$ 4,485	$ 4,475	$ 4,466	$ 4,457	$ 4,456	$ 4,455	$ 4,448	$ 4,448	$ 4,448	$ 4,448

Rate	25%
NPV (BTx)	$2,766
IRR (BTx)	62.54%

Pattern-Level Cashflow Model

State	**CA**
Field	**Field 2**
Formation	**Reservoir 2**
Depth	**4,500**
Distance from Trunkline (mi)	**10**
# of Patterns	**32**
Miscibility:	**Miscible**

	Year	**29**	**30**	**31**	**32**	**33**	**Totals**
CO_2 Injection (MMcf)		-	-	-	-	-	15,404
H_2O Injection (Mbw)		-	-	-	-	-	5,659
Oil Production (Mbbl)		-	-	-	-	-	2,049
H_2O Production (MBw)		-	-	-	-	-	5,144
CO_2 Production (MMcf)		626	611	250	87	7	16,548
CO_2 Purchased (MMcf)		-	-	-	-	-	3,739
CO_2 Recycled (MMcf)		-	-	-	-	-	11,665
Oil Price ($/Bbl)	**$ 25.00**	$ -	$ -	$ -	$ -	$ -	
Gravity Adjustment	**23**	$ -	$ -	$ -	$ -	$ -	
Gross Revenues ($M)		$ -	$ -	$ -	$ -	$ -	$ 42,516
Royalty ($M)	**-12.5%**	$ -	$ -	$ -	$ -	$ -	$ (5,314)
Severance Taxes ($M)	**0.0%**	$ -	$ -	$ -	$ -	$ -	$ -
Ad Valorum ($M)	**0.0%**	$ -	$ -	$ -	$ -	$ -	$ -
Net Revenue($M)		$ -	$ -	$ -	$ -	$ -	$ 37,201
Capital Costs ($M)							
New Well - D&C							$ (1,923)
Reworks - Producers to Producers							$ (159)
Reworks - Producers to Injectors							$ -
Reworks - Injectors to Injectors							$ -
Surface Equipment (new wells only)							$ (530)
CO_2 Recycling Plant		$ -	$ -	$ -	$ -	$ -	$ (1,160)
Water Injection Plant		$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction							$ (55)
Total Capital Costs		$ -	$ -	$ -	$ -	$ -	$ (3,826)
Capital G&A	**10%**	$ -	$ -	$ -	$ -	$ -	$ (383)
CO_2 Costs ($M)							
Total CO_2 Cost ($M)	**$ 0.25**	$ -	$ -	$ -	$ -	$ -	$ (11,441)
O&M Costs							
Operating & Maintenance ($M)		$ -	$ -	$ -	$ -	$ -	$ (6,800)
H_2O Inj O&M ($M)		$ -	$ -	$ -	$ -	$ -	$ (1,415)
Lifting Costs ($/bbl)	**$ 0.25**	$ -	$ -	$ -	$ -	$ -	$ (1,835)
G&A	**30%**	-	-	-	-	-	$ (2,590)
Total O&M Costs		$ -	$ -	$ -	$ -	$ -	$ (12,640)
Net Cash Flow ($M)		$ -	$ -	$ -	$ -	$ -	$ 8,912
Cum. Cash Flow		$ 8,912	$ 8,912	$ 8,912	$ 8,912	$ 8,912	
Discount Factor	**15%**	0.02	0.02	0.01	0.01	0.01	
Disc. Net Cash Flow		$ -	$ -	$ -	$ -	$ -	$ 4,448
Disc. Cum Cash Flow		$ 4,448	$ 4,448	$ 4,448	$ 4,448	$ 4,448	

Rate	25%
NPV (BTx)	$2,766
IRR (BTx)	62.54%

Field Cashflow Model			Next Generation	Pattern		Field			
State	CA		LA	Existing Injectors Used	0.00	Existing Injectors Used	0		
Field	Field 2			Convertable Producers Used	0.00	Convertable Producers Used	0	Total Injectors Required	
Formation	Reservoir 2			New Injectors Needed	2.00	New Injectors Needed	64	32	Ex
Depth		4500		New Producers Needed	2.13	New Producers Needed	68	Total Producers Required	
Distance from Trunkline		10	miles	Existing Producers Used	1.25	Existing Producers Used	40	44	Exis
# of Patterns		32.00							
Miscibility:	Miscible								

		0	1	2	3	4	5	6	7	8	9	10
CO2 Injection (MMcf)			4,675	9,350	14,026	18,701	23,377	23,377	23,377	23,377	23,107	22,631
H2O Injection (Mbw)			1,169	2,338	3,507	4,675	5,844	5,844	5,844	5,844	5,979	6,217
Oil Production (Mbbl)			1,484	3,307	4,365	5,226	5,988	5,114	3,809	3,216	2,838	2,595
H2O Production (MBw)			1,968	3,145	4,219	5,284	6,296	5,396	5,298	5,315	5,337	5,583
CO2 Production (MMcf)			-	788	3,293	6,188	9,443	12,944	15,842	17,079	17,881	18,334
CO2 Purchased (MMcf)			4,675	8,563	10,732	12,514	13,934	10,432	7,535	6,298	5,226	4,297
CO2 Recycled (MMcf)			-	788	3,293	6,188	9,443	12,944	15,842	17,079	17,881	18,334
Oil Price ($/Bbl)	$ 25.00		$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00
Gravity Adjustment	23		$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75
Gross Revenues ($M)			$ 30,803	$ 68,618	$ 90,570	$ 108,438	$ 124,254	$ 106,107	$ 79,043	$ 66,732	$ 58,897	$ 53,837
Royalty ($M)	-12.5%		$ (3,850)	$ (8,577)	$ (11,321)	$ (13,555)	$ (15,532)	$ (13,263)	$ (9,880)	$ (8,342)	$ (7,362)	$ (6,730)
Severance Taxes ($M)	0.0%		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ad Valorum ($M)	0.0%		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Revenue($M)			$ 26,953	$ 60,041	$ 79,248	$ 94,883	$ 108,723	$ 92,844	$ 69,162	$ 58,391	$ 51,535	$ 47,107
Capital Costs ($M)												
New Well - D&C		$ (12,306)	$ (12,306)	$ (12,306)	$ (12,306)	$ (12,306)	$ -	$ -	$ -	$ -	$ -	
Reworks - Producers to Producers		$ (1,015)	$ (1,015)	$ (1,015)	$ (1,015)	$ (1,015)	$ -	$ -	$ -	$ -	$ -	
Reworks - Producers to Injectors		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Reworks - Injectors to Injectors		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Surface Equipment (new wells only)		$ (3,390)	$ (3,390)	$ (3,390)	$ (3,390)	$ (3,390)	$ -	$ -	$ -	$ -	$ -	
CO2 Recycling Plant	2	$ -	$ (37,111)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Water Injection Plant	1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction		$ (1,750)										
Total Capital Costs		$ (18,461)	$ (53,822)	$ (16,711)	$ (16,711)	$ (16,711)	$ -	$ -	$ -	$ -	$ -	$ -
	10%	$ (1,846)	$ (5,382)	$ (1,671)	$ (1,671)	$ (1,671)	$ -	$ -	$ -	$ -	$ -	$ -
CO2 Costs ($M)												
Total CO2 Cost ($M)	-0.25		$ (7,013)	$ (13,238)	$ (17,745)	$ (21,864)	$ (25,622)	$ (22,121)	$ (19,223)	$ (17,986)	$ (16,780)	$ (15,613)
O&M Costs ($M)												
Operating & Maintenance ($M)	1		$ (1,741)	$ (3,481)	$ (5,222)	$ (6,963)	$ (8,704)	$ (8,704)	$ (8,704)	$ (8,704)	$ (8,704)	$ (8,704)
H2O Inj O&M ($M)			$ (292)	$ (584)	$ (877)	$ (1,169)	$ (1,461)	$ (1,461)	$ (1,461)	$ (1,461)	$ (1,495)	$ (1,554)
Lifting Costs ($M)			$ (863)	$ (1,613)	$ (2,146)	$ (2,628)	$ (3,071)	$ (2,627)	$ (2,277)	$ (2,133)	$ (2,044)	$ (2,044)
G&A	30%		(781)	(1,528)	(2,210)	(2,877)	(3,532)	(3,399)	(3,294)	(3,251)	(3,224)	(3,224)
Total O&M Costs			$ (3,677)	$ (7,207)	$ (10,455)	$ (13,636)	$ (16,768)	$ (16,191)	$ (15,735)	$ (15,548)	$ (15,466)	$ (15,527)
Net Cash Flow ($M)		$ (20,307)	$ (42,942)	$ 21,213	$ 32,666	$ 41,000	$ 66,332	$ 54,532	$ 34,204	$ 24,856	$ 19,289	$ 15,968
Cum. Cash Flow		$ (20,307)	$ (63,249)	$ (42,035)	$ (9,369)	$ 31,631	$ 97,963	$ 152,495	$ 186,699	$ 211,555	$ 230,844	$ 246,812
Discount Factor	15%	1.00	0.87	0.76	0.66	0.57	0.50	0.43	0.38	0.33	0.28	0.25
Disc. Net Cash Flow		$ (20,307)	$ (37,341)	$ 16,040	$ 21,478	$ 23,442	$ 32,979	$ 23,576	$ 12,858	$ 8,126	$ 5,483	$ 3,947
Disc. Cum Cash Flow		$ (20,307)	$ (57,648)	$ (41,607)	$ (20,129)	$ 3,313	$ 36,292	$ 59,868	$ 72,726	$ 80,852	$ 86,335	$ 90,282

NPV (BTx)	25%	20%	15%	10%
NPV (BTx)	$48,196	$ 70,565	$ 101,352	$ 144,553
IRR (BTx)	46.49%			

Field Cashflow Model

State	CA		
Field	Field 2		
Formation	Reservoir 2	xisting Injectors	0
Depth	4500		
Distance from Trunkline	10	:ting Producers	40
# of Patterns	32.00		
Miscibility:	Miscible		

			11	12	13	14	15	16	17	18	19	20	21	22
CO2 Injection (MMcf)			22,156	21,679	21,204	20,996	20,997	20,996	20,997	20,996	20,997	20,996	20,997	20,996
H2O Injection (Mbw)			6,454	6,692	6,931	7,034	7,034	7,034	7,034	7,034	7,034	7,034	7,034	7,034
Oil Production (Mbbl)			2,484	2,447	2,441	2,355	2,164	1,942	1,731	1,530	1,386	1,317	1,292	1,268
H2O Production (MBw)			5,766	5,928	6,085	6,249	6,266	6,330	6,397	6,480	6,545	6,594	6,608	6,622
CO2 Production (MMcf)			18,601	18,528	18,329	18,332	18,408	18,465	18,662	18,909	18,893	18,810	18,732	18,648
CO2 Purchased (MMcf)			3,555	3,151	2,875	2,665	2,589	2,531	2,335	2,087	2,104	2,187	2,266	2,348
CO2 Recycled (MMcf)			18,601	18,528	18,329	18,332	18,408	18,465	18,662	18,909	18,893	18,810	18,732	18,648
Oil Price ($/Bbl)	$	**25.00**	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00
Gravity Adjustment		**23**	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75
Gross Revenues ($M)			$ 51,540	$ 50,776	$ 50,643	$ 48,864	$ 44,893	$ 40,305	$ 35,909	$ 31,739	$ 28,751	$ 27,324	$ 26,806	$ 26,314
Royalty ($M)	**-12.5%**		$ (6,442)	$ (6,347)	$ (6,330)	$ (6,108)	$ (5,612)	$ (5,038)	$ (4,489)	$ (3,967)	$ (3,594)	$ (3,415)	$ (3,351)	$ (3,289)
Severance Taxes ($M)	**0.0%**		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ad Valorum ($M)	**0.0%**		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Revenue($M)			$ 45,097	$ 44,429	$ 44,313	$ 42,756	$ 39,281	$ 35,267	$ 31,420	$ 27,772	$ 25,157	$ 23,908	$ 23,455	$ 23,025
Capital Costs ($M)														
New Well - D&C														
Reworks - Producers to Producers														
Reworks - Producers to Injectors														
Reworks - Injectors to Injectors														
Surface Equipment (new wells only)														
CO2 Recycling Plant	**2**		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Water Injection Plant	**1**		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction														
Total Capital Costs			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		10%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CO2 Costs ($M)														
Total CO2 Cost ($M)		-0.25	$ (14,633)	$ (13,991)	$ (13,477)	$ (13,163)	$ (13,088)	$ (13,029)	$ (12,833)	$ (12,585)	$ (12,603)	$ (12,685)	$ (12,764)	$ (12,847)
O&M Costs ($M)														
Operating & Maintenance ($M)	**1**		$ (8,704)	$ (8,704)	$ (8,704)	$ (8,704)	$ (8,704)	$ (8,704)	$ (8,704)	$ (8,704)	$ (8,704)	$ (8,704)	$ (8,704)	$ (8,704)
H2O Inj O&M ($M)			$ (1,614)	$ (1,673)	$ (1,733)	$ (1,758)	$ (1,758)	$ (1,758)	$ (1,759)	$ (1,759)	$ (1,759)	$ (1,759)	$ (1,759)	$ (1,758)
Lifting Costs ($M)			$ (2,062)	$ (2,094)	$ (2,131)	$ (2,151)	$ (2,107)	$ (2,068)	$ (2,032)	$ (2,002)	$ (1,983)	$ (1,978)	$ (1,975)	$ (1,973)
G&A		**30%**	(3,230)	(3,239)	(3,251)	(3,256)	(3,243)	(3,232)	(3,221)	(3,212)	(3,206)	(3,204)	(3,204)	(3,203)
Total O&M Costs			$ (15,609)	$ (15,710)	$ (15,818)	$ (15,869)	$ (15,813)	$ (15,762)	$ (15,715)	$ (15,677)	$ (15,651)	$ (15,644)	$ (15,641)	$ (15,637)
Net Cash Flow ($M)			$ 14,855	$ 14,729	$ 15,018	$ 13,724	$ 10,381	$ 6,475	$ 2,872	$ (490)	$ (3,096)	$ (4,421)	$ (4,950)	$ (5,459)
Cum. Cash Flow			$ 261,667	$ 276,395	$ 291,413	$ 305,137	$ 315,518	$ 321,993	$ 324,866	$ 324,376	$ 321,280	$ 316,858	$ 311,908	$ 306,449
Discount Factor	**15%**		0.21	0.19	0.16	0.14	0.12	0.11	0.09	0.08	0.07	0.06	0.05	0.05
Disc. Net Cash Flow			$ 3,193	$ 2,753	$ 2,441	$ 1,940	$ 1,276	$ 692	$ 267	$ (40)	$ (218)	$ (270)	$ (263)	$ (252)
Disc. Cum Cash Flow			$ 93,475	$ 96,228	$ 98,668	$ 100,608	$ 101,884	$ 102,576	$ 102,843	$ 102,803	$ 102,585	$ 102,315	$ 102,052	$ 101,800

NPV (BTx)	25%
NPV (BTx)	$48,196
IRR (BTx)	46.49%

Field Cashflow Model

State	CA
Field	Field 2
Formation	Reservoir 2
Depth	4500
Distance from Trunkline	10
# of Patterns	32.00
Miscibility:	Miscible

		23	24	25	26	27	28	29	30	31	32	33	34
CO_2 Injection (MMcf)		18,985	14,785	10,586	6,387	2,188	-	-	-	-	-	-	-
H_2O Injection (Mbw)		8,040	10,140	10,090	8,684	7,277	4,864	1,357	-	-	-	-	-
Oil Production (Mbbl)		1,249	1,226	1,050	797	551	313	83	-	-	-	-	-
H_2O Production (MBw)		6,629	8,256	8,184	6,854	5,532	4,193	1,251	-	-	-	-	-
CO_2 Production (MMcf)		18,620	18,777	18,975	19,124	19,351	19,564	19,730	19,740	17,441	14,043	10,109	6,103
CO_2 Purchased (MMcf)		365	-	-	-	-	-	-	-	-	-	-	-
CO_2 Recycled (MMcf)		18,620	14,785	10,586	6,387	2,188	-	-	-	-	-	-	-
Oil Price ($/Bbl)	**$ 25.00**	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ -	$ -	$ -	$ -	$ -
Gravity Adjustment	**23**	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ 20.75	$ -	$ -	$ -	$ -	$ -
Gross Revenues ($M)		$ 25,923	$ 25,431	$ 21,792	$ 16,540	$ 11,441	$ 6,494	$ 1,720	$ -	$ -	$ -	$ -	$ -
Royalty ($M)	**-12.5%**	$ (3,240)	$ (3,179)	$ (2,724)	$ (2,068)	$ (1,430)	$ (812)	$ (215)	$ -	$ -	$ -	$ -	$ -
Severance Taxes ($M)	**0.0%**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ad Valorum ($M)	**0.0%**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Revenue($M)		$ 22,682	$ 22,252	$ 19,068	$ 14,473	$ 10,011	$ 5,682	$ 1,505	$ -	$ -	$ -	$ -	$ -
Capital Costs ($M)													
New Well - D&C													
Reworks - Producers to Producers													
Reworks - Producers to Injectors													
Reworks - Injectors to Injectors													
Surface Equipment (new wells only)													
CO_2 Recycling Plant	**2**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Water Injection Plant	**1**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction													
Total Capital Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	10%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CO_2 Costs ($M)													
Total CO_2 Cost ($M)	-0.25	$ (9,857)	$ (7,393)	$ (5,293)	$ (3,193)	$ (1,094)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M Costs ($M)													
Operating & Maintenance ($M)	**1**	$ (8,704)	$ (8,704)	$ (8,704)	$ (6,963)	$ (5,222)	$ (3,481)	$ (1,741)	$ -	$ -	$ -	$ -	$ -
H_2O Inj O&M ($M)		$ (2,010)	$ (2,535)	$ (2,523)	$ (2,171)	$ (1,819)	$ (1,216)	$ (339)	$ -	$ -	$ -	$ -	$ -
Lifting Costs ($M)		$ (1,970)	$ (2,370)	$ (2,308)	$ (1,913)	$ (1,521)	$ (1,127)	$ (333)	$ -	$ -	$ -	$ -	$ -
G&A	**30%**	(3,202)	(3,322)	(3,304)	(2,663)	(2,023)	(1,382)	(622)	-	-	-	-	-
Total O&M Costs		$ (15,885)	$ (16,931)	$ (16,838)	$ (13,709)	$ (10,585)	$ (7,206)	$ (3,036)	$ -	$ -	$ -	$ -	$ -
Net Cash Flow ($M)		$ (3,060)	$ (2,071)	$ (3,063)	$ (2,430)	$ (1,668)	$ (1,524)	$ (1,531)	$ -	$ -	$ -	$ -	$ -
Cum. Cash Flow		$ 303,389	$ 301,317	$ 298,254	$ 295,825	$ 294,156	$ 292,632	$ 291,101	$ 291,101	$ 291,101	$ 291,101	$ 291,101	$ 291,101
Discount Factor	**15%**	0.04	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01
Disc. Net Cash Flow		$ (123)	$ (72)	$ (93)	$ (64)	$ (38)	$ (30)	$ (27)	$ -	$ -	$ -	$ -	$ -
Disc. Cum Cash Flow		$ 101,677	$ 101,605	$ 101,512	$ 101,448	$ 101,409	$ 101,379	$ 101,352	$ 101,352	$ 101,352	$ 101,352	$ 101,352	$ 101,352

NPV (BTx)	25%
NPV (BTx)	$48,196
IRR (BTx)	46.49%

Field Cashflow Model

State	CA
Field	Field 2
Formation	Reservoir 2
Depth	4500
Distance from Trunkline	10
# of Patterns	32.00
Miscibility:	Miscible

			35	36	37	Totals
CO2 Injection (MMcf)			-	-	-	492,938
H2O Injection (Mbw)			-	-	-	181,094
Oil Production (Mbbl)			-	-	-	65,566
H2O Production (MBw)			-	-	-	164,610
CO2 Production (MMcf)			2,195	598	42	529,522
CO2 Purchased (MMcf)			-	-	-	115,263
CO2 Recycled (MMcf)			-	-	-	377,675
Oil Price ($/Bbl)	$	**25.00**	$ -	$ -	$ -	
Gravity Adjustment		**23**	$ -	$ -	$ -	
Gross Revenues ($M)			$ -	$ -	$ -	$ 1,360,503
Royalty ($M)	**-12.5%**		$ -	$ -	$ -	$ (170,063)
Severance Taxes ($M)	**0.0%**		$ -	$ -	$ -	$ -
Ad Valorum ($M)	**0.0%**		$ -	$ -	$ -	$ -
Net Revenue($M)			$ -	$ -	$ -	$ 1,190,440
Capital Costs ($M)						
New Well - D&C						$ (61,530)
Reworks - Producers to Producers						$ (5,076)
Reworks - Producers to Injectors						$ -
Reworks - Injectors to Injectors						$ -
Surface Equipment (new wells only)						$ (16,948)
CO2 Recycling Plant	**2**		$ -	$ -	$ -	$ (37,111)
Water Injection Plant	**1**		$ -	$ -	$ -	$ -
Trunkline Construction						$ (1,750)
Total Capital Costs			$ -	$ -	$ -	$ (122,416)
		10%	$ -	$ -	$ -	$ (12,242)
CO2 Costs ($M)						
Total CO2 Cost ($M)		-0.25	$ -	$ -	$ -	$ (361,732)
O&M Costs ($M)						
Operating & Maintenance ($M)	**1**		$ -	$ -	$ -	$ (217,591)
H2O Inj O&M ($M)			$ -	$ -	$ -	$ (45,274)
Lifting Costs ($M)			$ -	$ -	$ -	$ (57,544)
G&A		**30%**	-	-	-	$ (82,541)
Total O&M Costs			$ -	$ -	$ -	$ (402,950)
Net Cash Flow ($M)			$ -	$ -	$ -	$ 291,101
Cum. Cash Flow			$ 291,101	$ 291,101	$ 291,101	
Discount Factor	**15%**		0.01	0.01	0.01	
Disc. Net Cash Flow			$ -	$ -	$ -	$ 101,352
Disc. Cum Cash Flow			$ 101,352	$ 101,352	$ 101,352	

NPV (BTx)	25%
NPV (BTx)	$48,196
IRR (BTx)	46.49%

APPENDIX B.3

EXAMPLE APPLICATION OF CO_2-EOR ECONOMICS MODEL: FIELD #3 (RESERVOIR #3)

3. Traditional Immiscible CO_2-EOR Technology (0.4 HCPV of CO_2)
4. Integrated Application of the Combination of “Next Generation” CO_2-EOR Technologies (1.5 HCPV of CO_2)

Basin	**IL**
Field	**Field 3**
Formation	**Reservoir 3**
Technology Case	**Traditional Practices**
Depth (ft)	2,940
OOIP (MMBls)	250.7
Cum Primary Recovery (MMbls)	108.0
Primary EUR (MMbls)	111.5
Miscibility	Immiscible
API Gravity	38.0
Patterns	124
Existing Injectors Used	124
Convertible Producers Used	0
New Injectors Drilled	0
Existing Producers Used	147
New Producers Drilled	0

Pattern Detail

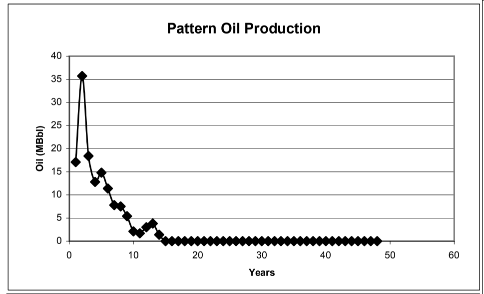
Cum Oil (Mbbl)	143		
Cum H2O (Mbw)	1,872	13.10	Bw/Bbl
Gross CO2 (MMcf)	973	6.81	Mcf/Bbl
Purchased CO2 (MMcf)	323	2.26	Mcf/Bbl
Recycled CO2 (MMcf)	650	4.55	Mcf/Bbl

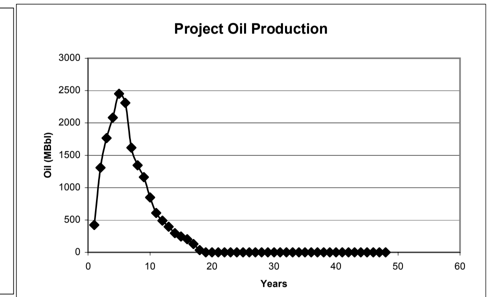
Field Detail

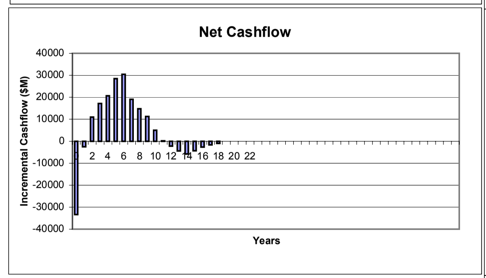
Cum Oil (MMbbl)	17.72	
% OOIP Recovered	7.1%	
Cum H2O (MMbw)	232	
Gross CO2 (MMcf)	120,602	
Purchased CO2 (MMcf)	37,307	
Recycled CO2 (MMcf)	83,296	
Payback Period (per pattern)	2	years
Project Length	18	years

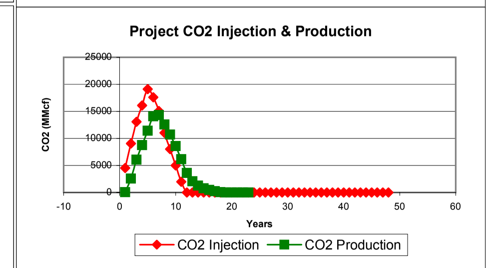
				$/BBl
Total Net Revenue ($M)	$	3,063		
Total Capital Investment ($M)	$	(378)	$	2.65
Total CO2 Cost ($M)	$	(566)	$	3.96
Total O&M Costs ($M)	$	(1,334)	$	9.34
	$	(2,279)	$	15.95

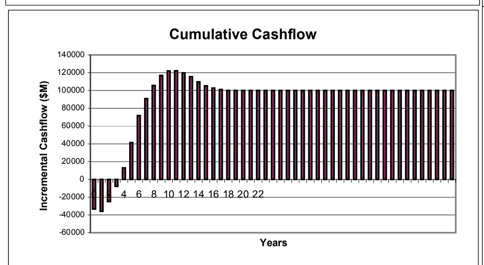
Pattern IRR (BTx)	53.9%
Project IRR (BTx)	34.8%

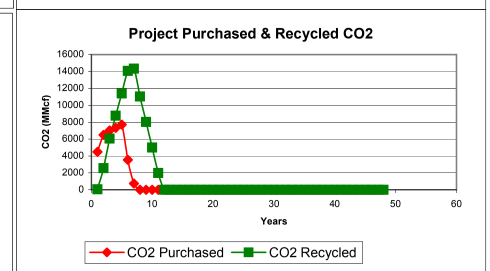


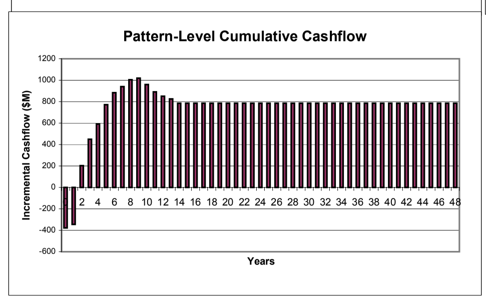












Assumptions:

Economic Case:	Traditional
Oil Price	$ 25.00
CO2 Purchase Cost	5% of oil price
CO2 Recycle Cost	1% of oil price
Recycling Plant Costs	1 Year before Breakthru
Well O&M	Prod Wells Only
Minimum IRR	**25.0%**

Pattern-Level Cashflow Model

State	**IL**	**IL**	New Injectors	0.00	
Field	**Field 3**		Existing Injectors	1.00	1
Formation	**Reservoir 3**		Convertable Producers	0.00	
Depth	**2,940**		New Producers	0.00	
Distance from Trunkline (mi)	**10**		Existing Producers	1.19	
# of Patterns	**124**		Disposal Wells	0.00	
Miscibility:	**Immiscible**				

Traditional Practices

	Year	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**
CO_2 Injection (MMcf)			183	183	162	122	122	122	80	-	-	-	-	-	-
H_2O Injection (Mbw)			91	91	102	122	122	122	143	183	183	183	183	183	183
Oil Production (Mbbl)			17	36	18	13	15	11	8	8	5	2	2	3	4
H_2O Production (MBw)			164	95	93	115	114	116	119	140	160	171	175	175	175
CO_2 Production (MMcf)			2	101	141	109	107	110	111	70	35	20	12	9	7
CO_2 Purchased (MMcf)			181	82	21	13	15	12	-	-	-	-	-	-	-
CO_2 Recycled (MMcf)			2	101	141	109	107	110	80	-	-	-	-	-	-
Oil Price ($/Bbl)	**$ 25.00**		$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00
Gravity Adjustment	**38** Deg		$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50
Gross Revenues ($M)			$ 419	$ 875	$ 451	$ 314	$ 363	$ 279	$ 191	$ 184	$ 132	$ 51	$ 42	$ 74	$ 93
Royalty ($M)	**-12.5%**		$ (52)	$ (109)	$ (56)	$ (39)	$ (45)	$ (35)	$ (24)	$ (23)	$ (17)	$ (6)	$ (5)	$ (9)	$ (12)
Severance Taxes ($M)	**0.0%**		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ad Valorum ($M)	**0.0%**		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Revenue($M)			$ 367	$ 765	$ 394	$ 274	$ 317	$ 244	$ 167	$ 161	$ 116	$ 45	$ 36	$ 64	$ 81
Capital Costs ($M)															
New Well - D&C		$ -													
Reworks - Producers to Producers		$ (19)													
Reworks - Producers to Injectors		$ -													
Reworks - Injectors to Injectors		$ (118)													
Surface Equipment (new wells only)		$ -													
CO_2 Recycling Plant		$ (222)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Water Injection Plant		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction		$ (20)													
Total Capital Costs		$ (378)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital G&A	**0%**														
CO_2 Costs ($M)															
Total CO_2 Cost ($M)			$ (226.3)	$ (127)	$ (61)	$ (43)	$ (46)	$ (43)	$ (20)	$ -	$ -	$ -	$ -	$ -	$ -
O&M Costs															
Operating & Maintenance ($M)			$ (43)	$ (43)	$ (43)	$ (43)	$ (43)	$ (43)	$ (43)	$ (43)	$ (43)	$ (43)	$ (43)	$ (43)	$ (43)
H_2O Inj O&M ($M)			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Lifting Costs ($/bbl)	**$ 0.25**		$ (45)	$ (33)	$ (28)	$ (32)	$ (32)	$ (32)	$ (32)	$ (37)	$ (41)	$ (43)	$ (44)	$ (45)	$ (45)
G&A	**20%**		(18)	(15)	(14)	(15)	(15)	(15)	(15)	(16)	(17)	(17)	(18)	(18)	(18)
Total O&M Costs			$ (107)	$ (91)	$ (86)	$ (90)	$ (91)	$ (90)	$ (90)	$ (96)	$ (102)	$ (104)	$ (105)	$ (106)	$ (106)
Net Cash Flow ($M)		$ (378)	$ 34	$ 547	$ 248	$ 141	$ 181	$ 111	$ 57	$ 64	$ 14	$ (59)	$ (69)	$ (41)	$ (24)
Cum. Cash Flow		$ (378)	$ (344)	$ 202	$ 450	$ 591	$ 771	$ 883	$ 940	$ 1,005	$ 1,019	$ 960	$ 891	$ 850	$ 826
Discount Factor	**15%**	1.00	0.87	0.76	0.66	0.57	0.50	0.43	0.38	0.33	0.28	0.25	0.21	0.19	0.16
Disc. Net Cash Flow		$ (378)	$ 29	$ 413	$ 163	$ 80	$ 90	$ 48	$ 21	$ 21	$ 4	$ (15)	$ (15)	$ (8)	$ (4)
Disc. Cum Cash Flow		$ (378)	$ (349)	$ 65	$ 227	$ 308	$ 398	$ 446	$ 467	$ 489	$ 493	$ 478	$ 463	$ 456	$ 452

Rate	25%	20%	15%	10%
NPV (BTx)	$278	$ 356	$ 446	$ 549
IRR (BTx)	53.94%			

Pattern-Level Cashflow Model

State	**IL**
Field	**Field 3**
Formation	**Reservoir 3**
Depth	**2,940**
Distance from Trunkline (mi)	**10**
# of Patterns	**124**
Miscibility:	**Immiscible**

	Year	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	Totals
CO2 Injection (MMcf)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	973
H2O Injection (Mbw)		64	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,952
Oil Production (Mbbl)		1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	143
H2O Production (MBw)		62	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,872
CO2 Production (MMcf)		3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	837
CO2 Purchased (MMcf)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	323
CO2 Recycled (MMcf)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	650
Oil Price ($/Bbl)	**$ 25.00**	$ 25.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Gravity Adjustment	**38**	$ 24.50	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Gross Revenues ($M)		$ 34	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,501
Royalty ($M)	**-12.5%**	$ (4)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (438)
Severance Taxes ($M)	**0.0%**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ad Valorum ($M)	**0.0%**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Revenue($M)		$ 30	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,063
Capital Costs ($M)																						
New Well - D&C																						$ -
Reworks - Producers to Producers																						$ (19)
Reworks - Producers to Injectors																						$ -
Reworks - Injectors to Injectors																						$ (118)
Surface Equipment (new wells only)																						$ -
CO2 Recycling Plant		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (222)
Water Injection Plant		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction																						$ (20)
Total Capital Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (378)
Capital G&A	**0%**																					
CO2 Costs ($M)																						
Total CO2 Cost ($M)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (566)
O&M Costs																						
Operating & Maintenance ($M)		$ (43)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (608)
H2O Inj O&M ($M)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Lifting Costs ($/bbl)	**$ 0.25**	$ (16)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (504)
G&A	**20%**	(12)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	$ (222)
Total O&M Costs		$ (71)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,334)
Net Cash Flow ($M)		$ (41)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 785
Cum. Cash Flow		$ 785	$ 785	$ 785	$ 785	$ 785	$ 785	$ 785	$ 785	$ 785	$ 785	$ 785	$ 785	$ 785	$ 785	$ 785	$ 785	$ 785	$ 785	$ 785	$ 785	
Discount Factor	**15%**	0.14	0.12	0.11	0.09	0.08	0.07	0.06	0.05	0.05	0.04	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.01	0.01	0.01	
Disc. Net Cash Flow		$ (6)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 446
Disc. Cum Cash Flow		$ 446	$ 446	$ 446	$ 446	$ 446	$ 446	$ 446	$ 446	$ 446	$ 446	$ 446	$ 446	$ 446	$ 446	$ 446	$ 446	$ 446	$ 446	$ 446	$ 446	

Rate	25%
NPV (BTx)	$278
IRR (BTx)	53.94%

Field Cashflow Model | **Traditional Practices**

State	IL	IL	**Pattern**		**Field**		
Field	Field 3		Existing Injectors Used	1.00	Existing Injectors Used	124	
Formation	Reservoir 3		Convertable Producers Used	0.00	Convertable Producers Used	0	Total Injectors Required
Depth	2940		New Injectors Needed	0.00	New Injectors Needed	0	124
Distance from Trunkline	10 miles		New Producers Needed	0.00	New Producers Needed	0	Total Producers Required
# of Patterns	124.00		Existing Producers Used	1.19	Existing Producers Used	147	147
Miscibility:	Immiscible						

Ex

Exis

		0	1	2	3	4	5	6	7	8	9	10
CO2 Injection (MMcf)			4,528	9,059	13,080	16,098	19,118	17,608	15,061	11,041	8,023	5,002
H2O Injection (Mbw)			2,264	4,528	7,048	10,069	13,087	13,843	15,116	17,124	18,632	20,145
Oil Production (Mbbl)			424	1,309	1,766	2,083	2,450	2,309	1,617	1,347	1,163	848
H2O Production (MBw)			4,075	6,441	8,744	11,596	14,424	13,228	13,806	14,967	16,070	17,472
CO2 Production (MMcf)			50	2,559	6,061	8,762	11,408	14,076	14,329	12,561	10,724	8,571
CO2 Purchased (MMcf)			4,479	6,500	7,018	7,336	7,710	3,532	732	-	-	-
CO2 Recycled (MMcf)			50	2,559	6,061	8,762	11,408	14,076	14,329	11,041	8,023	5,002
Oil Price ($/Bbl)	$ 25.00		$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00
Gravity Adjustment	38		$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50
Gross Revenues ($M)			$ 10,390	$ 32,081	$ 43,261	$ 51,038	$ 60,031	$ 56,568	$ 39,616	$ 32,993	$ 28,496	$ 20,780
Royalty ($M)	-12.5%		$ (1,299)	$ (4,010)	$ (5,408)	$ (6,380)	$ (7,504)	$ (7,071)	$ (4,952)	$ (4,124)	$ (3,562)	$ (2,597)
Severance Taxes ($M)	0.0%		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ad Valorum ($M)	0.0%		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Revenue($M)			$ 9,091	$ 28,071	$ 37,853	$ 44,659	$ 52,527	$ 49,497	$ 34,664	$ 28,869	$ 24,934	$ 18,182
Capital Costs ($M)												
New Well - D&C		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Reworks - Producers to Producers		$ (468)	$ (468)	$ (468)	$ (468)	$ (468)	$ -	$ -	$ -	$ -	$ -	
Reworks - Producers to Injectors		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Reworks - Injectors to Injectors		$ (2,917)	$ (2,917)	$ (2,917)	$ (2,917)	$ (2,917)	$ -	$ -	$ -	$ -	$ -	
Surface Equipment (new wells only)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
CO2 Recycling Plant	2	$ (27,481)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Water Injection Plant	1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction		$ (2,487)										
Total Capital Costs		$ (33,353)	$ (3,385)	$ (3,385)	$ (3,385)	$ (3,385)	$ -	$ -	$ -	$ -	$ -	$ -
Capital G&A	0%											
CO2 Costs ($M)												
Total CO2 Cost ($M)			$ (5,611)	$ (8,765)	$ (10,288)	$ (11,360)	$ (12,490)	$ (7,934)	$ (4,497)	$ (2,760)	$ (2,006)	$ (1,251)
O&M Costs ($M)												
Operating & Maintenance ($M)	1		$ (1,077)	$ (2,154)	$ (3,232)	$ (4,309)	$ (5,386)	$ (5,386)	$ (5,386)	$ (5,386)	$ (5,386)	$ (5,386)
H2O Inj O&M ($M)			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Lifting Costs ($M)			$ (1,125)	$ (1,938)	$ (2,628)	$ (3,420)	$ (4,218)	$ (3,884)	$ (3,856)	$ (4,078)	$ (4,308)	$ (4,580)
G&A	20%		(440)	(818)	(1,172)	(1,546)	(1,921)	(1,854)	(1,848)	(1,893)	(1,939)	(1,993)
Total O&M Costs			$ (2,642)	$ (4,910)	$ (7,031)	$ (9,275)	$ (11,525)	$ (11,124)	$ (11,090)	$ (11,357)	$ (11,633)	$ (11,959)
Net Cash Flow ($M)		$ (33,353)	$ (2,547)	$ 11,010	$ 17,149	$ 20,638	$ 28,512	$ 30,439	$ 19,077	$ 14,751	$ 11,295	$ 4,973
Cum. Cash Flow		$ (33,353)	$ (35,901)	$ (24,890)	$ (7,742)	$ 12,897	$ 41,409	$ 71,847	$ 90,924	$ 105,675	$ 116,970	$ 121,943
Discount Factor	15%	1.00	0.87	0.76	0.66	0.57	0.50	0.43	0.38	0.33	0.28	0.25
Disc. Net Cash Flow		$ (33,353)	$ (2,215)	$ 8,325	$ 11,276	$ 11,800	$ 14,175	$ 13,159	$ 7,172	$ 4,822	$ 3,211	$ 1,229
Disc. Cum Cash Flow		$ (33,353)	$ (35,568)	$ (27,243)	$ (15,967)	$ (4,167)	$ 10,008	$ 23,167	$ 30,339	$ 35,161	$ 38,372	$ 39,601

Rate	25%	20%	15%	10%
NPV (BTx)	$13,820	$ 23,821	$ 36,639	$ 53,106
IRR (BTx)	34.76%			

Field Cashflow Model

State	IL
Field	Field 3
Formation	Reservoir 3
Depth	2940
Distance from Trunkline	10
# of Patterns	124.00
Miscibility:	Immiscible

‹isting Injectors	376
1‹ting Producers	854

		11	12	13	14	15	16	17	18	19	20	21	22	23
CO2 Injection (MMcf)		1,984	-	-	-	-	-	-	-	-	-	-	-	-
H2O Injection (Mbw)		21,653	22,645	22,647	19,711	15,180	10,652	6,123	1,592	-	-	-	-	-
Oil Production (Mbbl)		608	489	397	298	246	203	129	35	-	-	-	-	-
H2O Production (MBw)		18,922	20,321	21,197	18,766	14,538	10,208	5,865	1,525	-	-	-	-	-
CO2 Production (MMcf)		6,158	3,616	2,066	1,265	771	466	246	62	-	-	-	-	-
CO2 Purchased (MMcf)		-	-	-	-	-	-	-	-	-	-	-	-	-
CO2 Recycled (MMcf)		1,984	-	-	-	-	-	-	-	-	-	-	-	-
Oil Price ($/Bbl)	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ -	$ -	$ -	$ -	$ -
Gravity Adjustment	38	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ -	$ -	$ -	$ -	$ -
Gross Revenues ($M)		$ 14,886	$ 11,970	$ 9,722	$ 7,291	$ 6,015	$ 4,982	$ 3,160	$ 851	$ -	$ -	$ -	$ -	$ -
Royalty ($M)	-12.5%	$ (1,861)	$ (1,496)	$ (1,215)	$ (911)	$ (752)	$ (623)	$ (395)	$ (106)	$ -	$ -	$ -	$ -	$ -
Severance Taxes ($M)	0.0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ad Valorum ($M)	0.0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Revenue($M)		$ 13,025	$ 10,474	$ 8,506	$ 6,380	$ 5,263	$ 4,360	$ 2,765	$ 744	$ -	$ -	$ -	$ -	$ -
Capital Costs ($M)														
New Well - D&C														
Reworks - Producers to Producers														
Reworks - Producers to Injectors														
Reworks - Injectors to Injectors														
Surface Equipment (new wells only)														
CO2 Recycling Plant	2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Water Injection Plant	1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction														
Total Capital Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital G&A	0%													
CO2 Costs ($M)														
Total CO2 Cost ($M)		$ (496)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M Costs ($M)														
Operating & Maintenance ($M)	1	$ (5,386)	$ (5,386)	$ (5,386)	$ (5,386)	$ (4,309)	$ (3,232)	$ (2,154)	$ (1,077)	$ -	$ -	$ -	$ -	$ -
H2O Inj O&M ($M)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Lifting Costs ($M)		$ (4,883)	$ (5,202)	$ (5,398)	$ (4,766)	$ (3,696)	$ (2,603)	$ (1,499)	$ (390)	$ -	$ -	$ -	$ -	$ -
G&A	20%	(2,054)	(2,118)	(2,157)	(2,030)	(1,601)	(1,167)	(731)	(293)	-	-	-	-	-
Total O&M Costs		$ (12,322)	$ (12,706)	$ (12,941)	$ (12,182)	$ (9,606)	$ (7,001)	$ (4,384)	$ (1,761)	$ -	$ -	$ -	$ -	$ -
Net Cash Flow ($M)		$ 207	$ (2,233)	$ (4,435)	$ (5,803)	$ (4,342)	$ (2,642)	$ (1,619)	$ (1,016)	$ -	$ -	$ -	$ -	$ -
Cum. Cash Flow		$ 122,150	$ 119,917	$ 115,483	$ 109,680	$ 105,338	$ 102,696	$ 101,077	$ 100,061	$ 100,061	$ 100,061	$ 100,061	$ 100,061	$ 100,061
Discount Factor	15%	0.21	0.19	0.16	0.14	0.12	0.11	0.09	0.08	0.07	0.06	0.05	0.05	0.04
Disc. Net Cash Flow		$ 45	$ (417)	$ (721)	$ (820)	$ (534)	$ (282)	$ (150)	$ (82)	$ -	$ -	$ -	$ -	$ -
Disc. Cum Cash Flow		$ 39,646	$ 39,228	$ 38,508	$ 37,688	$ 37,154	$ 36,872	$ 36,721	$ 36,639	$ 36,639	$ 36,639	$ 36,639	$ 36,639	$ 36,639

Rate	25%
NPV (BTx)	$13,820
IRR (BTx)	34.76%

Field Cashflow Model

State	IL
Field	Field 3
Formation	Reservoir 3
Depth	2940
Distance from Trunkline	10
# of Patterns	124.00
Miscibility:	Immiscible

		24	25	26	27	28	29	30	31	32	33	34	35	Totals
CO_2 Injection (MMcf)		-	-	-	-	-	-	-	-	-	-	-	-	120,602
H_2O Injection (Mbw)		-	-	-	-	-	-	-	-	-	-	-	-	242,060
Oil Production (Mbbl)		-	-	-	-	-	-	-	-	-	-	-	-	17,720
H_2O Production (MBw)		-	-	-	-	-	-	-	-	-	-	-	-	232,165
CO_2 Production (MMcf)		-	-	-	-	-	-	-	-	-	-	-	-	103,751
CO_2 Purchased (MMcf)		-	-	-	-	-	-	-	-	-	-	-	-	37,307
CO_2 Recycled (MMcf)		-	-	-	-	-	-	-	-	-	-	-	-	83,296
Oil Price ($/Bbl)	$ 25.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Gravity Adjustment	38	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Gross Revenues ($M)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 434,130
Royalty ($M)	-12.5%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (54,266)
Severance Taxes ($M)	0.0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ad Valorum ($M)	0.0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Revenue($M)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 379,864
Capital Costs ($M)														
New Well - D&C														$ -
Reworks - Producers to Producers														$ (2,342)
Reworks - Producers to Injectors														$ -
Reworks - Injectors to Injectors														$ (14,585)
Surface Equipment (new wells only)														$ -
CO_2 Recycling Plant	2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (27,481)
Water Injection Plant	1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction														$ (2,487)
Total Capital Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (46,895)
Capital G&A	0%													
CO_2 Costs ($M)														
Total CO_2 Cost ($M)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (67,457)
O&M Costs ($M)														
Operating & Maintenance ($M)	1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (75,405)
H_2O Inj O&M ($M)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Lifting Costs ($M)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (62,471)
G&A	20%	-	-	-	-	-	-	-	-	-	-	-	-	$ (27,575)
Total O&M Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (165,451)
Net Cash Flow ($M)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 100,061
Cum. Cash Flow		$ 100,061	$ 100,061	$ 100,061	$ 100,061	$ 100,061	$ 100,061	$ 100,061	$ 100,061	$ 100,061	$ 100,061	$ 100,061	$ 100,061	
Discount Factor	15%	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	
Disc. Net Cash Flow		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 36,639
Disc. Cum Cash Flow		$ 36,639	$ 36,639	$ 36,639	$ 36,639	$ 36,639	$ 36,639	$ 36,639	$ 36,639	$ 36,639	$ 36,639	$ 36,639	$ 36,639	

Rate	25%
NPV (BTx)	$13,820
IRR (BTx)	34.76%

Basin	**IL**
Field	**Field 3**
Formation	**Reservoir 3**
Technology Case	**Next Generation**
Depth (ft)	2,940
OOIP (MMBls)	250.7
Cum Primary Recovery (MMbls)	108.0
Primary EUR (MMbls)	111.5
Miscibility	Miscible
API Gravity	38.0
Patterns	124
Existing Injectors Used	124
Convertible Producers Used	0
New Injectors Drilled	124
Existing Producers Used	147
New Producers Drilled	147

Pattern Detail

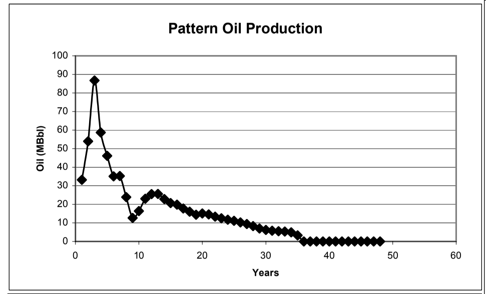
Cum Oil (Mbbl)	732		
Cum H2O (Mbw)	2,572	3.51	Bw/Bbl
Gross CO2 (MMcf)	7,295	9.96	Mcf/Bbl
Purchased CO2 (MMcf)	1,542	2.11	Mcf/Bbl
Recycled CO2 (MMcf)	5,753	7.86	Mcf/Bbl

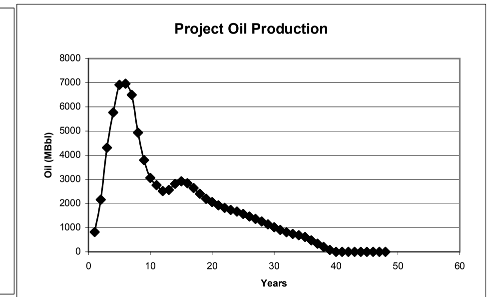
Field Detail

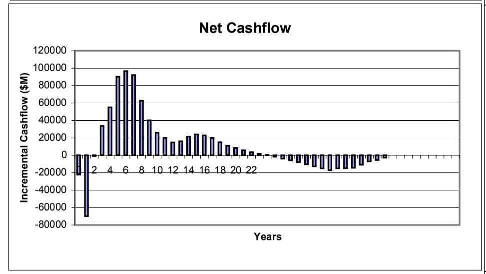
Cum Oil (MMbbl)	90.78	
% OOIP Recovered	36.2%	
Cum H2O (MMbw)	319	
Gross CO2 (MMcf)	904,530	
Purchased CO2 (MMcf)	188,579	
Recycled CO2 (MMcf)	715,951	
Payback Period (per pattern)	3	years
Project Length	39	years

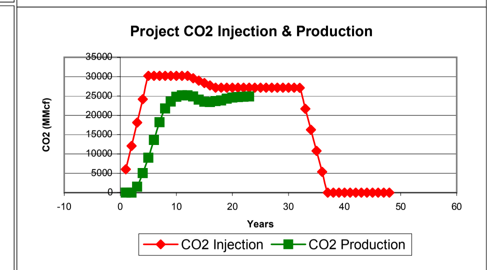
				$/BBl
Total Net Revenue ($M)	$	15,694		
Total Capital Investment ($M)	$	(1,137)	$	1.55
CAP EX G&A ($M)	$	(114)	$	0.16
Total CO2 Cost ($M)	$	(5,189)	$	7.09
Total O&M Costs ($M)	$	(5,784)	$	7.90
	$	(12,224)	$	16.70

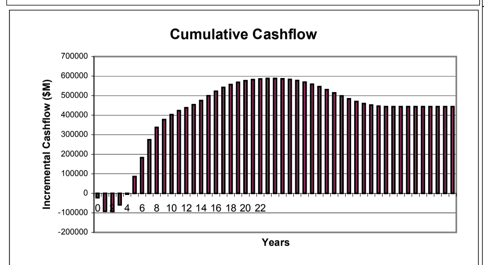
Pattern IRR (BTx)	50.3%
Project IRR (BTx)	40.4%

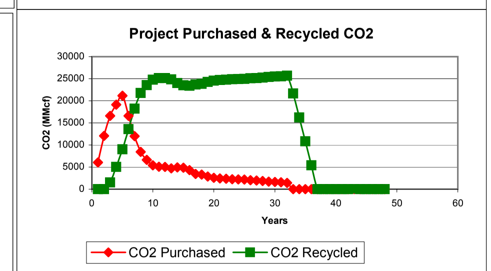


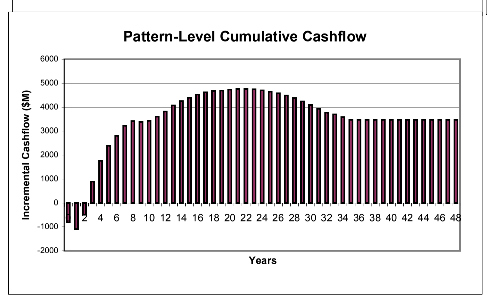












Assumptions:

Economic Case:	Traditional
Oil Price	$ 25.00
CO2 Purchase Cost	5% of oil price
CO2 Recycle Cost	1% of oil price
Recycling Plant Costs	1 Year before Breakthru
Well O&M	Prod Wells Only
Minimum IRR	**25.0%**

Pattern-Level Cashflow Model **Next Generation**

State	**IL**	**IL**	New Injectors	1.00
Field	**Field 3**		Existing Injectors	1.00
Formation	**Reservoir 3**		Convertable Producers	0.00
Depth	**2,940**		New Producers	1.19
Distance from Trunkline (mi)	**10**		Existing Producers	1.19
# of Patterns	**124**		Disposal Wells	0.00
Miscibility:	**Miscible**			

Year			0	1	2	3	4	5	6	7	8	9	10	11	12	13	14
CO2 Injection (MMcf)				244	244	244	244	244	244	244	244	244	244	244	243	219	219
H2O Injection (Mbw)				61	61	61	61	61	61	61	61	61	61	61	61	73	73
Oil Production (Mbbl)				33	54	87	59	46	35	35	24	13	16	23	26	26	23
H2O Production (MBw)				149	127	63	51	55	54	53	56	63	60	60	63	60	68
CO2 Production (MMcf)				-	0	61	142	161	184	186	204	214	211	198	187	192	181
CO2 Purchased (MMcf)				244	243	183	102	83	59	58	39	29	33	45	56	27	38
CO2 Recycled (MMcf)				-	0	61	142	161	184	186	204	214	211	198	187	192	181
Oil Price ($/Bbl)	$ 25.00			$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00
Gravity Adjustment	38	Deg		$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50
Gross Revenues ($M)				$ 812	$ 1,323	$ 2,125	$ 1,438	$ 1,131	$ 859	$ 865	$ 584	$ 310	$ 402	$ 565	$ 626	$ 627	$ 560
Royalty ($M)	-12.5%			$ (102)	$ (165)	$ (266)	$ (180)	$ (141)	$ (107)	$ (108)	$ (73)	$ (39)	$ (50)	$ (71)	$ (78)	$ (78)	$ (70)
Severance Taxes ($M)	0.0%			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ad Valorum ($M)	0.0%			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Revenue($M)				$ 711	$ 1,158	$ 1,860	$ 1,258	$ 989	$ 751	$ 757	$ 511	$ 271	$ 352	$ 494	$ 548	$ 549	$ 490
Capital Costs ($M)																	
New Well - D&C			$ (419)														
Reworks - Producers to Producers			$ (19)														
Reworks - Producers to Injectors			$ -														
Reworks - Injectors to Injectors			$ (118)														
Surface Equipment (new wells only)			$ (166)														
CO2 Recycling Plant			$ -	$ (397)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Water Injection Plant			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction			$ (18)														
Total Capital Costs			$ (740)	$ (397)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	10%		$ (74)	$ (40)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CO2 Costs ($M)																	
Total CO2 Cost ($M)	$ 0.25	misc extender		$ (365.3)	$ (365)	$ (304)	$ (223)	$ (204)	$ (181)	$ (179)	$ (161)	$ (151)	$ (155)	$ (167)	$ (178)	$ (136)	$ (147)
O&M Costs																	
Operating & Maintenance ($M)				$ (87)	$ (87)	$ (87)	$ (87)	$ (87)	$ (87)	$ (87)	$ (87)	$ (87)	$ (87)	$ (87)	$ (87)	$ (87)	$ (87)
H2O Inj O&M ($M)				$ (15)	$ (15)	$ (15)	$ (15)	$ (15)	$ (15)	$ (15)	$ (15)	$ (15)	$ (15)	$ (15)	$ (15)	$ (18)	$ (18)
Lifting Costs ($/bbl)	$ 0.25			$ (46)	$ (45)	$ (37)	$ (27)	$ (25)	$ (22)	$ (22)	$ (20)	$ (19)	$ (19)	$ (21)	$ (22)	$ (21)	$ (23)
G&A	30%			(40)	(40)	(37)	(34)	(34)	(33)	(33)	(32)	(32)	(32)	(32)	(33)	(32)	(33)
Total O&M Costs				$ (187)	$ (187)	$ (177)	$ (164)	$ (161)	$ (157)	$ (157)	$ (154)	$ (153)	$ (153)	$ (155)	$ (157)	$ (159)	$ (161)
Net Cash Flow ($M)			$ (814)	$ (279)	$ 605	$ 1,379	$ 871	$ 624	$ 413	$ 421	$ 196	$ (32)	$ 44	$ 172	$ 213	$ 254	$ 182
Cum. Cash Flow			$ (814)	$ (1,093)	$ (488)	$ 891	$ 1,762	$ 2,387	$ 2,800	$ 3,220	$ 3,417	$ 3,384	$ 3,428	$ 3,600	$ 3,814	$ 4,067	$ 4,249
Discount Factor	15%		1.00	0.87	0.76	0.66	0.57	0.50	0.43	0.38	0.33	0.28	0.25	0.21	0.19	0.16	0.14
Disc. Net Cash Flow			$ (814)	$ (243)	$ 458	$ 907	$ 498	$ 310	$ 179	$ 158	$ 64	$ (9)	$ 11	$ 37	$ 40	$ 41	$ 26
Disc. Cum Cash Flow			$ (814)	$ (1,057)	$ (599)	$ 308	$ 806	$ 1,116	$ 1,295	$ 1,453	$ 1,517	$ 1,508	$ 1,519	$ 1,556	$ 1,596	$ 1,637	$ 1,663

Rate	25%	20%	15%	10%
NPV (BTx)	$910	$ 1,249	$ 1,692	$ 2,273
IRR (BTx)	50.31%			

Pattern-Level Cashflow Model

State	**IL**
Field	**Field 3**
Formation	**Reservoir 3**
Depth	**2,940**
Distance from Trunkline (mi)	**10**
# of Patterns	**124**
Miscibility:	**Miscible**

	Year	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32
CO_2 Injection (MMcf)		219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	219	217
H_2O Injection (Mbw)		73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	73	74
Oil Production (Mbbl)		21	20	18	16	14	15	15	13	13	12	11	10	9	8	7	6	6	6
H_2O Production (MBw)		67	65	65	67	68	67	68	68	69	70	70	69	71	71	72	73	73	73
CO_2 Production (MMcf)		189	194	198	198	199	201	200	201	202	200	203	206	204	207	206	206	208	209
CO_2 Purchased (MMcf)		30	24	21	21	20	18	19	18	16	18	16	13	15	12	13	12	11	9
CO_2 Recycled (MMcf)		189	194	198	198	199	201	200	201	202	200	203	206	204	207	206	206	208	209
Oil Price ($/Bbl)	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00
Gravity Adjustment	38	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50
Gross Revenues ($M)		$ 506	$ 485	$ 435	$ 392	$ 353	$ 369	$ 358	$ 328	$ 306	$ 288	$ 272	$ 251	$ 230	$ 202	$ 172	$ 153	$ 142	$ 135
Royalty ($M)	-12.5%	$ (63)	$ (61)	$ (54)	$ (49)	$ (44)	$ (46)	$ (45)	$ (41)	$ (38)	$ (36)	$ (34)	$ (31)	$ (29)	$ (25)	$ (21)	$ (19)	$ (18)	$ (17)
Severance Taxes ($M)	0.0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ad Valorum ($M)	0.0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Revenue($M)		$ 443	$ 424	$ 381	$ 343	$ 309	$ 323	$ 313	$ 287	$ 268	$ 252	$ 238	$ 220	$ 202	$ 177	$ 150	$ 134	$ 124	$ 118
Capital Costs ($M)																			
New Well - D&C																			
Reworks - Producers to Producers																			
Reworks - Producers to Injectors																			
Reworks - Injectors to Injectors																			
Surface Equipment (new wells only)																			
CO_2 Recycling Plant		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Water Injection Plant		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction																			
Total Capital Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	10%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CO_2 Costs ($M)																			
Total CO_2 Cost ($M)	$ 0.25	$ (139)	$ (134)	$ (130)	$ (130)	$ (129)	$ (127)	$ (128)	$ (127)	$ (126)	$ (128)	$ (125)	$ (122)	$ (125)	$ (121)	$ (122)	$ (122)	$ (120)	$ (117)
O&M Costs																			
Operating & Maintenance ($M)		$ (87)	$ (87)	$ (87)	$ (87)	$ (87)	$ (87)	$ (87)	$ (87)	$ (87)	$ (87)	$ (87)	$ (87)	$ (87)	$ (87)	$ (87)	$ (87)	$ (87)	$ (87)
H_2O Inj O&M ($M)		$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)	$ (18)
Lifting Costs ($/bbl)	$ 0.25	$ (22)	$ (21)	$ (21)	$ (21)	$ (21)	$ (20)	$ (21)	$ (20)	$ (20)	$ (29)	$ (29)	$ (28)	$ (27)	$ (26)	$ (25)	$ (25)	$ (24)	$ (24)
G&A	30%	(33)	(32)	(32)	(32)	(32)	(32)	(32)	(32)	(32)	(35)	(35)	(34)	(34)	(34)	(34)	(33)	(33)	(33)
Total O&M Costs		$ (160)	$ (159)	$ (158)	$ (158)	$ (158)	$ (158)	$ (158)	$ (158)	$ (158)	$ (169)	$ (168)	$ (167)	$ (167)	$ (165)	$ (164)	$ (163)	$ (162)	$ (162)
Net Cash Flow ($M)		$ 144	$ 132	$ 92	$ 55	$ 21	$ 38	$ 27	$ 2	$ (15)	$ (45)	$ (56)	$ (70)	$ (90)	$ (109)	$ (136)	$ (151)	$ (158)	$ (162)
Cum. Cash Flow		$ 4,393	$ 4,525	$ 4,618	$ 4,672	$ 4,694	$ 4,731	$ 4,758	$ 4,761	$ 4,745	$ 4,700	$ 4,644	$ 4,575	$ 4,485	$ 4,375	$ 4,240	$ 4,089	$ 3,931	$ 3,769
Discount Factor	15%	0.12	0.11	0.09	0.08	0.07	0.06	0.05	0.05	0.04	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.01	0.01
Disc. Net Cash Flow		$ 18	$ 14	$ 9	$ 4	$ 1	$ 2	$ 1	$ 0	$ (1)	$ (2)	$ (2)	$ (2)	$ (2)	$ (2)	$ (2)	$ (2)	$ (2)	$ (2)
Disc. Cum Cash Flow		$ 1,680	$ 1,694	$ 1,703	$ 1,707	$ 1,709	$ 1,711	$ 1,713	$ 1,713	$ 1,712	$ 1,711	$ 1,709	$ 1,707	$ 1,705	$ 1,703	$ 1,700	$ 1,698	$ 1,696	$ 1,694

Rate	25%
NPV (BTx)	$910
IRR (BTx)	50.31%

Pattern-Level Cashflow Model

State	**IL**
Field	**Field 3**
Formation	**Reservoir 3**
Depth	**2,940**
Distance from Trunkline (mi)	**10**
# of Patterns	**124**
Miscibility:	**Miscible**

		Year 33	34	35	Totals
CO2 Injection (MMcf)		-	-	-	7,295
H2O Injection (Mbw)		183	183	123	2,685
Oil Production (Mbbl)		5	5	3	732
H2O Production (MBw)		73	158	113	2,572
CO2 Production (MMcf)		207	38	11	6,010
CO2 Purchased (MMcf)		-	-	-	1,542
CO2 Recycled (MMcf)		-	-	-	5,753
Oil Price ($/Bbl)	**$ 25.00**	$ 25.00	$ 25.00	$ 25.00	
Gravity Adjustment	**38**	$ 24.50	$ 24.50	$ 24.50	
Gross Revenues ($M)		$ 131	$ 121	$ 81	$ 17,936
Royalty ($M)	**-12.5%**	$ (16)	$ (15)	$ (10)	$ (2,242)
Severance Taxes ($M)	**0.0%**	$ -	$ -	$ -	$ -
Ad Valorum ($M)	**0.0%**	$ -	$ -	$ -	$ -
Net Revenue($M)		$ 115	$ 106	$ 71	$ 15,694
Capital Costs ($M)					
New Well - D&C					$ (419)
Reworks - Producers to Producers					$ (19)
Reworks - Producers to Injectors					$ -
Reworks - Injectors to Injectors					$ (118)
Surface Equipment (new wells only)					$ (166)
CO2 Recycling Plant		$ -	$ -	$ -	$ (397)
Water Injection Plant		$ -	$ -	$ -	$ -
Trunkline Construction					$ (18)
Total Capital Costs		$ -	$ -	$ -	$ (1,137)
	10%	$ -	$ -	$ -	$ (114)
CO2 Costs ($M)					
Total CO2 Cost ($M)	**$ 0.25**	$ -	$ -	$ -	$ (5,189)
O&M Costs					
Operating & Maintenance ($M)		$ (87)	$ (87)	$ (87)	$ (3,041)
H2O Inj O&M ($M)		$ (46)	$ (46)	$ (31)	$ (671)
Lifting Costs ($/bbl)	**$ 0.25**	$ (24)	$ (45)	$ (32)	$ (893)
G&A	**30%**	(33)	(39)	(36)	$ (1,180)
Total O&M Costs		$ (189)	$ (216)	$ (185)	$ (5,784)
Net Cash Flow ($M)		$ (75)	$ (110)	$ (114)	$ 3,470
Cum. Cash Flow		$ 3,695	$ 3,584	$ 3,470	
Discount Factor	**15%**	0.01	0.01	0.01	
Disc. Net Cash Flow		$ (1)	$ (1)	$ (1)	$ 1,692
Disc. Cum Cash Flow		$ 1,693	$ 1,693	$ 1,692	

Rate	25%
NPV (BTx)	$910
IRR (BTx)	50.31%

Field Cashflow Model

State	IL				
Field	Field 3				
Formation	Reservoir 3				
Depth	2940				
Distance from Trunkline	10 miles				
# of Patterns	124.00				
Miscibility:	Miscible				

Next Generation
IL

Pattern		**Field**	
Existing Injectors Used	1.00	Existing Injectors Used	124
Convertable Producers Used	0.00	Convertable Producers Used	0
New Injectors Needed	1.00	New Injectors Needed	124
New Producers Needed	1.19	New Producers Needed	147
Existing Producers Used	1.19	Existing Producers Used	147

Total Injectors Required
124
Total Producers Required
147

Ex
Exis

		0	1	2	3	4	5	6	7	8	9	10
CO2 Injection (MMcf)			6,039	12,078	18,116	24,155	30,194	30,194	30,194	30,194	30,194	30,194
H2O Injection (Mbw)			1,510	3,021	4,528	6,039	7,549	7,549	7,547	7,549	7,549	7,549
Oil Production (Mbbl)			822	2,161	4,313	5,768	6,913	6,960	6,496	4,936	3,794	3,057
H2O Production (MBw)			3,693	6,851	8,406	9,674	11,026	8,679	6,839	6,671	6,953	7,098
CO2 Production (MMcf)			-	2	1,514	5,034	9,026	13,599	18,209	21,763	23,558	24,789
CO2 Purchased (MMcf)			6,039	12,075	16,602	19,121	21,168	16,595	11,985	8,431	6,636	5,405
CO2 Recycled (MMcf)			-	2	1,514	5,034	9,026	13,599	18,209	21,763	23,558	24,789
Oil Price ($/Bbl)	$ 25.00		$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00
Gravity Adjustment	38		$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50
Gross Revenues ($M)			$ 20,142	$ 52,952	$ 105,662	$ 141,328	$ 169,369	$ 170,523	$ 159,161	$ 120,943	$ 92,963	$ 74,887
Royalty ($M)	-12.5%		$ (2,518)	$ (6,619)	$ (13,208)	$ (17,666)	$ (21,171)	$ (21,315)	$ (19,895)	$ (15,118)	$ (11,620)	$ (9,361)
Severance Taxes ($M)	0.0%		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ad Valorum ($M)	0.0%		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Revenue($M)			$ 17,624	$ 46,333	$ 92,454	$ 123,662	$ 148,197	$ 149,208	$ 139,266	$ 105,825	$ 81,342	$ 65,526
Capital Costs ($M)												
New Well - D&C		$ (10,393)	$ (10,393)	$ (10,393)	$ (10,393)	$ (10,393)	$ -	$ -	$ -	$ -	$ -	
Reworks - Producers to Producers		$ (468)	$ (468)	$ (468)	$ (468)	$ (468)	$ -	$ -	$ -	$ -	$ -	
Reworks - Producers to Injectors		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Reworks - Injectors to Injectors		$ (2,917)	$ (2,917)	$ (2,917)	$ (2,917)	$ (2,917)	$ -	$ -	$ -	$ -	$ -	
Surface Equipment (new wells only)		$ (4,118)	$ (4,118)	$ (4,118)	$ (4,118)	$ (4,118)	$ -	$ -	$ -	$ -	$ -	
CO2 Recycling Plant	2	$ -	$ (49,276)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Water Injection Plant	1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction		$ (2,268)										
Total Capital Costs		$ (20,164)	$ (67,172)	$ (17,896)	$ (17,896)	$ (17,896)	$ -	$ -	$ -	$ -	$ -	$ -
Capital G&A	10%	$ (2,016)	$ (6,717)	$ (1,790)	$ (1,790)	$ (1,790)	$ -	$ -	$ -	$ -	$ -	$ -
CO2 Costs ($M)												
Total CO2 Cost ($M)	$ 0.25	misc extender	$ (9,058)	$ (18,114)	$ (25,661)	$ (31,198)	$ (36,265)	$ (31,692)	$ (27,082)	$ (23,528)	$ (21,733)	$ (20,502)
O&M Costs ($M)												
Operating & Maintenance ($M)	1		$ (2,154)	$ (4,309)	$ (6,463)	$ (8,618)	$ (10,772)	$ (10,772)	$ (10,772)	$ (10,772)	$ (10,772)	$ (10,772)
H2O Inj O&M ($M)			$ (378)	$ (755)	$ (1,132)	$ (1,510)	$ (1,887)	$ (1,887)	$ (1,887)	$ (1,887)	$ (1,887)	$ (1,887)
Lifting Costs ($M)			$ (1,129)	$ (2,253)	$ (3,180)	$ (3,861)	$ (4,485)	$ (3,910)	$ (3,334)	$ (2,902)	$ (2,687)	$ (2,539)
G&A	30%		(985)	(1,969)	(2,893)	(3,744)	(4,577)	(4,405)	(4,232)	(4,102)	(4,038)	(3,993)
Total O&M Costs			$ (4,646)	$ (9,286)	$ (13,668)	$ (17,732)	$ (21,721)	$ (20,974)	$ (20,224)	$ (19,663)	$ (19,384)	$ (19,191)
Net Cash Flow ($M)		$ (22,181)	$ (69,969)	$ (752)	$ 33,440	$ 55,046	$ 90,211	$ 96,542	$ 91,960	$ 62,634	$ 40,225	$ 25,833
Cum. Cash Flow		$ (22,181)	$ (92,150)	$ (92,901)	$ (59,461)	$ (4,415)	$ 85,796	$ 182,338	$ 274,298	$ 336,932	$ 377,157	$ 402,989
Discount Factor	15%	1.00	0.87	0.76	0.66	0.57	0.50	0.43	0.38	0.33	0.28	0.25
Disc. Net Cash Flow		$ (22,181)	$ (60,843)	$ (568)	$ 21,987	$ 31,473	$ 44,851	$ 41,738	$ 34,571	$ 20,475	$ 11,435	$ 6,385
Disc. Cum Cash Flow		$ (22,181)	$ (83,023)	$ (83,592)	$ (61,604)	$ (30,131)	$ 14,719	$ 56,457	$ 91,028	$ 111,503	$ 122,938	$ 129,323

Rate	25%	20%	15%	10%
NPV (BTx)	$60,830	$ 97,744	$ 150,559	$ 227,162
IRR (BTx)	40.37%			

Field Cashflow Model

State	IL		
Field	Field 3		
Formation	Reservoir 3	‹isting Injectors	376
Depth	2940		
Distance from Trunkline	10	:ting Producers	854
# of Patterns	124.00		
Miscibility:	Miscible		

			11	12	13	14	15	16	17	18	19	20	21	22
CO2 Injection (MMcf)			30,194	30,184	29,569	28,956	28,341	27,726	27,121	27,121	27,119	27,121	27,121	27,121
H2O Injection (Mbw)			7,547	7,554	7,862	8,169	8,474	8,784	9,087	9,084	9,084	9,087	9,087	9,084
Oil Production (Mbbl)			2,759	2,517	2,561	2,814	2,919	2,838	2,645	2,407	2,197	2,058	1,929	1,822
H2O Production (MBw)			7,232	7,471	7,576	7,724	7,881	8,013	8,074	8,245	8,244	8,240	8,303	8,377
CO2 Production (MMcf)			25,137	25,160	24,853	24,034	23,503	23,404	23,682	23,834	24,267	24,558	24,700	24,771
CO2 Purchased (MMcf)			5,057	5,024	4,716	4,923	4,838	4,323	3,440	3,287	2,852	2,563	2,422	2,350
CO2 Recycled (MMcf)			25,137	25,160	24,853	24,034	23,503	23,404	23,682	23,834	24,267	24,558	24,700	24,771
Oil Price ($/Bbl)	$	**25.00**	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00
Gravity Adjustment		**38**	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50
Gross Revenues ($M)			$ 67,596	$ 61,671	$ 62,735	$ 68,932	$ 71,515	$ 69,540	$ 64,801	$ 58,968	$ 53,833	$ 50,431	$ 47,271	$ 44,628
Royalty ($M)	**-12.5%**		$ (8,449)	$ (7,709)	$ (7,842)	$ (8,617)	$ (8,939)	$ (8,692)	$ (8,100)	$ (7,371)	$ (6,729)	$ (6,304)	$ (5,909)	$ (5,579)
Severance Taxes ($M)	**0.0%**		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ad Valorum ($M)	**0.0%**		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Revenue($M)			$ 59,146	$ 53,962	$ 54,893	$ 60,316	$ 62,575	$ 60,847	$ 56,700	$ 51,597	$ 47,104	$ 44,127	$ 41,362	$ 39,050
Capital Costs ($M)														
New Well - D&C														
Reworks - Producers to Producers														
Reworks - Producers to Injectors														
Reworks - Injectors to Injectors														
Surface Equipment (new wells only)														
CO2 Recycling Plant	**2**		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Water Injection Plant	**1**		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction														
Total Capital Costs			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital G&A		**10%**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CO2 Costs ($M)														
Total CO2 Cost ($M)	$	**0.25**	$ (20,154)	$ (20,117)	$ (19,500)	$ (19,401)	$ (19,009)	$ (18,186)	$ (17,000)	$ (16,848)	$ (16,411)	$ (16,124)	$ (15,982)	$ (15,910)
O&M Costs ($M)														
Operating & Maintenance ($M)	**1**		$ (10,772)	$ (10,772)	$ (10,772)	$ (10,772)	$ (10,772)	$ (10,772)	$ (10,772)	$ (10,772)	$ (10,772)	$ (10,772)	$ (10,772)	$ (10,772)
H2O Inj O&M ($M)			$ (1,887)	$ (1,889)	$ (1,965)	$ (2,042)	$ (2,119)	$ (2,196)	$ (2,272)	$ (2,271)	$ (2,271)	$ (2,272)	$ (2,272)	$ (2,271)
Lifting Costs ($M)			$ (2,498)	$ (2,497)	$ (2,534)	$ (2,634)	$ (2,700)	$ (2,713)	$ (2,680)	$ (2,663)	$ (2,610)	$ (2,575)	$ (2,558)	$ (2,550)
G&A		**30%**	(3,981)	(3,981)	(3,992)	(4,022)	(4,042)	(4,045)	(4,036)	(4,030)	(4,015)	(4,004)	(3,999)	(3,997)
Total O&M Costs			$ (19,137)	$ (19,138)	$ (19,264)	$ (19,471)	$ (19,632)	$ (19,726)	$ (19,759)	$ (19,737)	$ (19,668)	$ (19,622)	$ (19,601)	$ (19,589)
Net Cash Flow ($M)			$ 19,855	$ 14,708	$ 16,129	$ 21,444	$ 23,934	$ 22,935	$ 19,941	$ 15,012	$ 11,025	$ 8,381	$ 5,779	$ 3,550
Cum. Cash Flow			$ 422,844	$ 437,552	$ 453,681	$ 475,125	$ 499,059	$ 521,994	$ 541,935	$ 556,947	$ 567,972	$ 576,353	$ 582,132	$ 585,681
Discount Factor	**15%**		0.21	0.19	0.16	0.14	0.12	0.11	0.09	0.08	0.07	0.06	0.05	0.05
Disc. Net Cash Flow			$ 4,268	$ 2,749	$ 2,621	$ 3,031	$ 2,941	$ 2,451	$ 1,853	$ 1,213	$ 775	$ 512	$ 307	$ 164
Disc. Cum Cash Flow			$ 133,591	$ 136,340	$ 138,961	$ 141,992	$ 144,933	$ 147,384	$ 149,237	$ 150,450	$ 151,225	$ 151,737	$ 152,044	$ 152,208

Rate	25%
NPV (BTx)	$60,830
IRR (BTx)	40.37%

Field Cashflow Model

State	IL
Field	Field 3
Formation	Reservoir 3
Depth	2940
Distance from Trunkline	10
# of Patterns	124.00
Miscibility:	Miscible

		23	24	25	26	27	28	29	30	31	32	33	34
CO2 Injection (MMcf)		27,121	27,121	27,119	27,121	27,121	27,121	27,121	27,121	27,119	27,087	21,663	16,239
H2O Injection (Mbw)		9,087	9,087	9,084	9,084	9,087	9,084	9,084	9,087	9,087	9,102	11,815	14,528
Oil Production (Mbbl)		1,735	1,669	1,571	1,463	1,364	1,259	1,141	1,021	910	813	742	691
H2O Production (MBw)		8,413	8,462	8,546	8,587	8,658	8,713	8,762	8,839	8,924	8,961	9,017	11,149
CO2 Production (MMcf)		24,877	24,915	24,956	25,098	25,160	25,269	25,415	25,506	25,560	25,690	25,694	21,530
CO2 Purchased (MMcf)		2,244	2,206	2,163	2,024	1,962	1,853	1,706	1,616	1,559	1,396	-	-
CO2 Recycled (MMcf)		24,877	24,915	24,956	25,098	25,160	25,269	25,415	25,506	25,560	25,690	21,663	16,239
Oil Price ($/Bbl)	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00
Gravity Adjustment	38	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50
Gross Revenues ($M)		$ 42,502	$ 40,891	$ 38,491	$ 35,848	$ 33,418	$ 30,836	$ 27,950	$ 25,003	$ 22,299	$ 19,929	$ 18,167	$ 16,922
Royalty ($M)	-12.5%	$ (5,313)	$ (5,111)	$ (4,811)	$ (4,481)	$ (4,177)	$ (3,854)	$ (3,494)	$ (3,125)	$ (2,787)	$ (2,491)	$ (2,271)	$ (2,115)
Severance Taxes ($M)	0.0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ad Valorum ($M)	0.0%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Revenue($M)		$ 37,189	$ 35,780	$ 33,680	$ 31,367	$ 29,241	$ 26,981	$ 24,456	$ 21,877	$ 19,512	$ 17,438	$ 15,896	$ 14,806
Capital Costs ($M)													
New Well - D&C													
Reworks - Producers to Producers													
Reworks - Producers to Injectors													
Reworks - Injectors to Injectors													
Surface Equipment (new wells only)													
CO2 Recycling Plant	2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Water Injection Plant	1	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction													
Total Capital Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Capital G&A	10%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CO2 Costs ($M)													
Total CO2 Cost ($M)	$ 0.25	$ (15,805)	$ (15,767)	$ (15,722)	$ (15,584)	$ (15,522)	$ (15,413)	$ (15,267)	$ (15,176)	$ (15,118)	$ (14,940)	$ (10,831)	$ (8,120)
O&M Costs ($M)													
Operating & Maintenance ($M)	1	$ (10,772)	$ (10,772)	$ (10,772)	$ (10,772)	$ (10,772)	$ (10,772)	$ (10,772)	$ (10,772)	$ (10,772)	$ (10,772)	$ (10,772)	$ (10,772)
H2O Inj O&M ($M)		$ (2,272)	$ (2,272)	$ (2,271)	$ (2,271)	$ (2,272)	$ (2,271)	$ (2,271)	$ (2,272)	$ (2,272)	$ (2,275)	$ (2,954)	$ (3,632)
Lifting Costs ($M)		$ (2,537)	$ (2,533)	$ (2,529)	$ (2,513)	$ (2,505)	$ (2,493)	$ (2,476)	$ (2,465)	$ (2,459)	$ (2,444)	$ (2,440)	$ (2,960)
G&A	30%	(3,993)	(3,991)	(3,990)	(3,985)	(3,983)	(3,980)	(3,974)	(3,971)	(3,969)	(3,965)	(3,964)	(4,120)
Total O&M Costs		$ (19,574)	$ (19,568)	$ (19,563)	$ (19,541)	$ (19,532)	$ (19,516)	$ (19,493)	$ (19,480)	$ (19,472)	$ (19,456)	$ (20,129)	$ (21,484)
Net Cash Flow ($M)		$ 1,810	$ 446	$ (1,605)	$ (3,758)	$ (5,814)	$ (7,948)	$ (10,304)	$ (12,779)	$ (15,078)	$ (16,957)	$ (15,064)	$ (14,797)
Cum. Cash Flow		$ 587,492	$ 587,937	$ 586,333	$ 582,574	$ 576,760	$ 568,813	$ 558,509	$ 545,730	$ 530,652	$ 513,695	$ 498,630	$ 483,834
Discount Factor	15%	0.04	0.03	0.03	0.03	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01
Disc. Net Cash Flow		$ 73	$ 16	$ (49)	$ (99)	$ (134)	$ (159)	$ (179)	$ (193)	$ (198)	$ (194)	$ (150)	$ (128)
Disc. Cum Cash Flow		$ 152,281	$ 152,296	$ 152,248	$ 152,148	$ 152,015	$ 151,856	$ 151,677	$ 151,484	$ 151,286	$ 151,093	$ 150,943	$ 150,815

Rate	25%
NPV (BTx)	$60,830
IRR (BTx)	40.37%

Field Cashflow Model

State	IL
Field	Field 3
Formation	Reservoir 3
Depth	2940
Distance from Trunkline	10
# of Patterns	124.00
Miscibility:	Miscible

			35	36	37	38	39	Totals
CO2 Injection (MMcf)			10,815	5,392	-	-	-	904,530
H2O Injection (Mbw)			15,750	13,933	12,100	7,571	3,040	332,903
Oil Production (Mbbl)			618	474	337	205	82	90,780
H2O Production (MBw)			12,151	10,350	8,550	6,738	2,814	318,903
CO2 Production (MMcf)			16,699	11,539	6,362	1,233	284	745,184
CO2 Purchased (MMcf)			-	-	-	-	-	188,579
CO2 Recycled (MMcf)			10,815	5,392	-	-	-	715,951
Oil Price ($/Bbl)	$	**25.00**	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	
Gravity Adjustment		**38**	$ 24.50	$ 24.50	$ 24.50	$ 24.50	$ 24.50	
Gross Revenues ($M)			$ 15,129	$ 11,605	$ 8,263	$ 5,013	$ 2,005	$ 2,224,120
Royalty ($M)	**-12.5%**		$ (1,891)	$ (1,451)	$ (1,033)	$ (627)	$ (251)	$ (278,015)
Severance Taxes ($M)	**0.0%**		$ -	$ -	$ -	$ -	$ -	$ -
Ad Valorum ($M)	**0.0%**		$ -	$ -	$ -	$ -	$ -	$ -
Net Revenue($M)			$ 13,238	$ 10,155	$ 7,230	$ 4,386	$ 1,754	$ 1,946,105
Capital Costs ($M)								
New Well - D&C								$ (51,964)
Reworks - Producers to Producers								$ (2,342)
Reworks - Producers to Injectors								$ -
Reworks - Injectors to Injectors								$ (14,585)
Surface Equipment (new wells only)								$ (20,588)
CO2 Recycling Plant	**2**		$ -	$ -	$ -	$ -	$ -	$ (49,276)
Water Injection Plant	**1**		$ -	$ -	$ -	$ -	$ -	$ -
Trunkline Construction								$ (2,268)
Total Capital Costs			$ -	$ -	$ -	$ -	$ -	$ (141,024)
Capital G&A		**10%**	$ -	$ -	$ -	$ -	$ -	$ (14,102)
CO2 Costs ($M)								
Total CO2 Cost ($M)	$	**0.25**	$ (5,408)	$ (2,696)	$ -	$ -	$ -	$ (640,844)
O&M Costs ($M)								
Operating & Maintenance ($M)	**1**		$ (10,772)	$ (8,618)	$ (6,463)	$ (4,309)	$ (2,154)	$ (377,023)
H2O Inj O&M ($M)			$ (3,938)	$ (3,483)	$ (3,025)	$ (1,893)	$ (760)	$ (83,226)
Lifting Costs ($M)			$ (3,192)	$ (2,706)	$ (2,222)	$ (1,736)	$ (724)	$ (102,421)
G&A		**30%**	(4,189)	(3,397)	(2,606)	(1,813)	(863)	$ (143,833)
Total O&M Costs			$ (22,091)	$ (18,204)	$ (14,316)	$ (9,751)	$ (4,502)	$ (706,503)
Net Cash Flow ($M)			$ (14,261)	$ (10,745)	$ (7,085)	$ (5,365)	$ (2,747)	$ 443,631
Cum. Cash Flow			$ 469,573	$ 458,828	$ 451,743	$446,378	$443,631	
Discount Factor	**15%**		0.01	0.01	0.01	0.00	0.00	
Disc. Net Cash Flow			$ (107)	$ (70)	$ (40)	$ (26)	$ (12)	$ 150,559
Disc. Cum Cash Flow			$ 150,708	$ 150,638	$ 150,598	$150,571	$150,559	

Rate	25%
NPV (BTx)	$60,830
IRR (BTx)	40.37%