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An Early Deployment Strategy for Carbon Capture, Utilization, and Storage (CCUS) Technologies

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Overview

Carbon capture and sequestration (CCS) has been cited by various authorities as an essential element of a global strategy to mitigate climate change. However, current CCS technology is not being deployed, largely due to its high cost. Carbon capture, utilization, and storage (CCUS) can reduce this cost by realizing a revenue stream from the use of captured carbon dioxide (CO2) in enhanced oil recovery (EOR). This paper describes the current use of CO2 for EOR, and discusses potential expansion of EOR using CO2 from power plants. Analysis of potential EOR development in the U.S., where most current CO2-based EOR production takes place, indicates that relatively low cost, traditional sources of CO2 for EOR (CO2 domes and CO2 from natural gas processing plants) are insufficient to exploit the full potential of EOR. To achieve that full potential will require use of CO2 from combustion and gasification systems, such as fossil fuel power plants, where capture of CO2 is more costly.

The benefits of such an expanded EOR production program are significant, and include the economic value of the produced oil, indirect economic activity associated with the oil production, favorable impacts on the producing country's balance of trade, the environmental value of permanently storing CO2 which would otherwise enter the atmosphere, and the energy security value to the producing country of being less reliant on imported oil.

The cost of current CCUS systems, even with the revenue stream for sale of the CO2 for EOR, is too high to result in broad deployment of the technology in the near-term. In the longer term, research and development may be sufficient to reduce CO2 capture costs to a point where CCUS would be broadly deployed. This paper employs a case study of conditions in the U.S. to explore a financial incentive to promote early deployment of CCUS, providing a range of immediate benefits to society, greater likelihood of reducing the long-term cost of CCUS, and greater likelihood of broad deployment of CCUS and CCS in the long-term. Additionally, it may be possible to craft such an incentive in a manner that its cost is more than offset by taxes flowing from increased domestic oil production. An example of such an incentive is included in Box 1 in the body of this paper.

Introduction

Carbon capture and storage (CCS) is a technology which captures carbon dioxide (CO2) from industrial sources, such as power plants, and injects it into geologic formations, typically 1.5 kilometers or more below the earth's surface. CCS has been recognized as an essential element of a multifaceted program to attain global climate goals. For example, in 2008 former UK Prime Minister Tony Blair stated, "… developing carbon capture and storage technology is not optional, it is literally of the essence."[1] More recently, Norway's Prime Minister Stoltenberg remarked, "With nine billion people expected on the planet in 2050, there is no way we can choose between increased energy production and reduced CO_2 – we have to achieve both. Without CCS, we cannot do it."[2]

This report explores a policy mechanism to achieve early deployment of carbon capture, utilization, and storage (CCUS) technology, a type of CCS which makes productive use of the captured CO_2. Economic and energy security benefits would accrue to countries hosting CCUS, and derive from increased domestic oil production which would result from the use of the CO_2 in enhanced oil recovery (EOR). The report provides a general overview of EOR employing CO_2, and discusses the potential for a substantial increase in CO_2-EOR production using CO_2 captured from fossil fuel-based electric power plants. Using a case study based on conditions applicable in the U.S., the report evaluates the implications of providing a limited financial incentive, or subsidy, for the capture of CO_2 and funding the incentive with taxes associated with the increased domestic oil production.

EOR is a method of producing oil that changes the oil's properties to make it more mobile in its geological reservoir. EOR generally follows primary and secondary phases of oil production and hence is sometimes referred to as tertiary oil production.[3] Typically, primary and secondary production technology can produce 20-40% of the "original oil in place" (OOIP).[4,5] If a field is amenable to EOR, and about half of the largest ones in the U.S. are, an additional 5-20% of the OOIP can be recovered.[6,7]

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[1] Speech delivered by Rt Hon Tony Blair regarding Breaking the Climate Deadlock: A Global Deal for our Low Carbon Future, The Climate Group, June 2008, http://www.theclimategroup.org/news_and_events/btcd_blair_speechjun08/ .

[2] Whatever happened to carbon capture in the fight against climate change?, D. Carrington, *The Guardian*, May 9, 2012, http://www.guardian.co.uk/environment/2012/may/09/carbon-capture-storage-climate-change .

[3] Primary oil recovery generally means using natural reservoir pressure or pumping to raise oil from its natural reservoir. Secondary recovery involves injecting fluids (water or gases) into the reservoir to drive additional oil to nearby extraction wells. See definitions of these terms by Schlumberger at: http://www.glossary.oilfield.slb.com/Display.cfm?Term=primary%20recovery and http://www.glossary.oilfield.slb.com/Display.cfm?Term=secondary%20recovery .

[4] Enhanced Oil Recovery Scoping Study, TR-113836, EPRI, 1999, http://www.energy.ca.gov/process/pubs/electrotech_opps_tr113836.pdf

[5] Enhanced Oil Recovery / CO_2 Injection, USDOE/National Energy Technology Laboratory (NETL), http://www.fossil.energy.gov/programs/oilgas/eor/index.html .

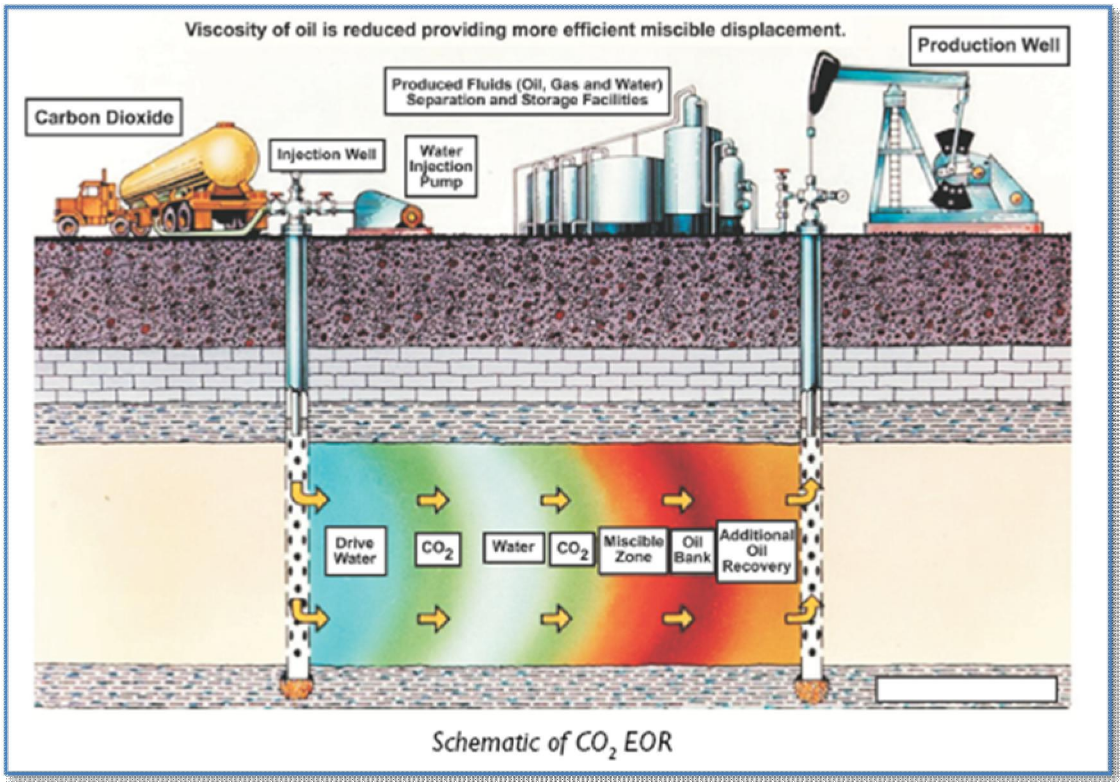
[6] Ibid.

[7] Carbon Dioxide Enhanced Oil Recovery, USDOE/NETL, March 2010, http://www.netl.doe.gov/technologies/oil-gas/publications/EP/small_CO2_EOR_Primer.pdf

EOR is a mature technology. EOR was first used in large scale in Scurry County, Texas, in 1972.[8] In 2012, miscible CO_2-EOR produced 309,000 barrels per day (bpd) of oil, and accounted for about 5% of U.S. crude oil production.[9,10,11] Figure 1[12] presents a characterization of the most common EOR process, which involves successive cycles of CO_2 injection (sometimes supplemented with water injection) and oil production through an advancing front of multiple injection and production wells until the targeted reservoir has been traversed. On every production cycle, some of the CO_2 stays behind in the reservoir, and some returns to the surface with the produced oil. The returned CO_2 is recaptured due to its value, and reinjected, so that ultimately essentially all of the purchased CO_2 is permanently stored underground. The "net" (originally purchased) CO_2 needed varies by field, but typical estimates range from 0.25-0.40 tonnes CO_2 per barrel of oil produced.[13, 14] One U.S. EOR producer, which employs CO_2 injection without an alternating cycle of water injection, reports net CO_2 usage of 0.52-0.68 tonne CO_2 per barrel of produced oil.[15] Most current EOR operations use "natural" CO_2, produced from underground reservoirs in a manner similar to natural gas production. However, natural CO_2 resources are limited so about 24% of the CO_2 used for EOR in the U.S. is obtained from industrial sources.[16] Expansion of EOR using "industrial" CO_2, such as that emitted from fossil fuel-fired power plants, holds the greatest economic and environmental promise for the U.S.[17] According to one report, "The main barrier to reaching higher levels of crude oil production from the application of CO_2-EOR, both in the U.S. and worldwide, is the lack of access to adequate supplies of affordable CO_2."[18]

[8] Summary of Carbon Dioxide Enhanced Oil Recovery Injection Well Technology, J. Meyer, Contek Solutions, report prepared for the American Petroleum Institute (API), 2007.
[9] Survey: Miscible CO_2 now eclipses steam in US EOR production, Oil and Gas Journal, April 2, 2012.
[10] Crude Oil Production, U.S. Energy Information Administration (EIA), data for January 2012, http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_m.htm .
[11] Enhanced Oil Recovery can utilize several approaches, including the injection of steam, chemicals, natural gas, or CO_2. For the remainder of this paper, the terms "Enhanced Oil Recovery" and "EOR" will be used to mean CO_2-EOR.
[12] Carbon Sequestration Through EOR, USDOE/NETL, April 2008.
[13] Op. Cit., API, 2007.
[14] Op. Cit., USDOE/NETL, February 2008.
[15] Denbury Resources, Inc., Spring Analyst Meeting, May23, 2011, (webcast and presentation material available at: http://ir.denbury.com/phoenix.zhtml?c=72374&p=irol-EventDetails&EventId=3970138)
[16] Improving Domestic Energy Security and Lowering CO_2 Emissions with "Next Generation" CO_2-EOR, US DOE, Report No. DOE/NETL-2011/1504, June 20, 2011. Note that about three-fourths of current industrial CO_2 is obtained from natural gas processing plants.
[17] Ibid.
[18] Optimization of CO_2 Storage in CO_2 Enhanced Oil Recovery Projects, Advanced Resources International, Inc., prepared for the UK Department of Energy & Climate Change, Office of Carbon Capture & Storage, November 30, 2010.

Figure 1. Typical EOR production alternating injection of CO_2 and water.



Global EOR activity has been monitored by the *Oil & Gas Journal* via voluntary surveys since 1971. The surveys have been conducted every two years since 1974, and the most recent was published in April 2012.[19] The survey covers all types of EOR. In 2012, thermal steam EOR, miscible CO_2 EOR, and immiscible CO_2 EOR contributed 39%, 40%, and 6%, respectively, to the total reported U.S. EOR production of 764,376 barrels per day. The majority of current CO_2 EOR occurs in the U.S., although smaller projects are operating in Brazil, Canada, Trinidad, and Turkey. Many EOR projects are quite large in extent and utilize hundreds of injection and production wells. Selected data from the 2012 survey are presented in Table 1.

Table 1. Characteristics of the 5 largest CO_2-EOR projects in the U.S.[20]

Operator	Field	State	Area, km^2	Production wells, #	Injection wells, #	Formation	Depth, m	Enhanced prod'n, b/d
Kinder Morgan	SACROC	TX	202	390	503	Limestone	2042	26,530
Occidental	Wasson Denver	TX	113	1026	590	Dolomite	1585	24,660
Anadarko	Salt Creek	WY	24	321	279	Sandstone	579	9,500

[19] Op.Cit., Oil and Gas Journal, 2012.
[20] Ibid.

Chevron	Rangely	CO	73	378	262	Sandstone	1829	11,600
Hess	Seminole Main Pay	TX	64	370	110	Dolomite	1615	14,000
			Total production for 5 projects above					86,290
			Total miscible CO_2 EOR in U.S. (112 projects)					308,564

Potential benefits of EOR

Scope of the resource

Estimates of the amount of oil recoverable using EOR have varied over time as economic conditions such as the price of oil have changed, additional reservoir data have been developed, modeling techniques have improved, EOR recovery approaches have evolved, and new types of reservoirs have been evaluated. Globally, ARI reported 469 billion barrels of oil are "technically" recoverable from 50 of the world's largest petroleum basins using "state of the art" EOR.[21] These results were extrapolated to 881 billion barrels when including "resources that remain to be discovered".[22] A separate assessment by ARI, based on "Next Generation" EOR technology, estimated 1,296 billion barrels of technically recoverable oil from 54 basins, including undiscovered fields.[23]

Table 2 presents both "technically" and "economically" recoverable oil estimates for the U.S., for both "state of the art" and "next generation" technologies.[24]

Table 2. U.S. EOR production potential.

Technology	**Technical Potential (billion barrels)**	**Economic Potential (billion barrels)**
State of the art	62	27
Next generation	136	80
- With ROZ "Fairways"*	176	100

*ROZ = Residual oil zone.

The U.S. estimates include both onshore and offshore production, and initial estimates for production from residual oil zones (ROZ). ROZ resources sometimes exist below existing oil fields and may exist in areas lacking a traditional "main pay zone" (MPZ).

[21] Global Technology Roadmap for CCS in Industry, Advanced Resources International, Inc., prepared for United Nations Industrial Development Organization, May 5, 2011.
[22] Ibid.
[23] Using CO_2-EOR to Accelerate the Deployment of CO_2 Capture and Storage, ARI, Inc., prepared for the Coal Industry Advisory Board, February 24, 2011. (Includes potential from discovered and undiscovered fields.)
[24] An Updated Review of U.S. and Worldwide CO_2-EOR Resources, Van Leeuwen, ARI, Inc., presented at the 17th Annual Midland CO_2 Flooding Conference, December 8, 2011.

The potential recovery levels cited in Table 2 dwarf current U.S. EOR production levels (309,000 barrels of oil per day (0.11 billion barrels per year).[25]

Global and U.S. proven oil reserves in 2009 were estimated to total 1,342 billion barrels and 21 billion barrels, respectively.[26]

Types of benefits from EOR production

Several types of benefits can accrue to a nation from production of oil using EOR. The two most direct benefits are domestic production of a valuable commodity, and permanent storage of CO_2, a greenhouse gas. Indirect benefits include the ability to reduce reliance on foreign sources of petroleum, concomitant improvements in the producing country's international trade balance, and increased domestic economic activity. Additionally, if the EOR uses industrial CO_2, additional experience will be obtained with CO_2 capture technologies, potentially reducing the cost of such technologies to future users. Those users could extend well beyond the electric power sector, and include other activities such as cement manufacture, petroleum refining, and chemical manufacturing. A reduction in the cost of CCS technology could be essential to a nation's ability to retain such GHG-intensive industries and the economic benefits they provide in a climate-constrained world.

Focusing on the U.S. as an example, some of these benefits can be quantified. The economically recoverable quantities of oil suggest a program which, when mature, could produce 1-2 billion barrels of oil per year. Using the lower figure, and an oil price of $100 per barrel,[27] suggests that the oil resource itself is worth approximately $100 billion per year. Moreover, for every dollar of revenue generated by domestic oil production in the U.S., another dollar of economic activity results from indirect business activity supporting the oil production, such as manufacture of drilling pipe, and from induced economic activity resulting from purchases made with the salaries flowing from direct and indirect activities.[28] In 2010, crude oil averaged $78 per barrel, the U.S. trade balance was -$498 billion, and oil imports accounted for $324 billion, or 65% of the deficit.[29] Additionally, the stored CO_2 may have a value related to climate management. For CO_2 utilization rates of 0.3 – 0.6 tonnes per barrel of oil produced, an annual storage rate of 300 – 600 million tonnes of CO_2 is possible. These potential annual direct and indirect benefits could reasonably be maintained for a period exceeding 30 years.

[25] Op.Cit., Oil and Gas Journal, 2012.
[26] International Energy Statistics, USDOE/Energy Information Administration, retrieved on-line February 20, 2012, http://www.eia.gov/cfapps/ipdbproject/IEDIndex3.cfm?tid=5&pid=57&aid=6 .
[27] U.S. FOB costs of imported crude oil averaged $102 per barrel for the first 11 months of 2011, USDOE/EIA, http://www.eia.gov/dnav/pet/pet_pri_imc1_k_m.htm

[28] Calculation based on results of RIMS-II Model, maintained by the U.S. Department of Commerce, Bureau of Economic Analysis.
[29] U.S. Census Bureau statistics, http://www.census.gov/indicator/www/ustrade.html .

Barriers to expanded EOR production

The major barrier to an expansion in EOR production using relatively low concentration CO_2 from power plants is the cost of CO_2 capture. In the U.S., additional regulatory barriers also exist.

Economic barrier

The cost of capture is a barrier to the use of power plant CO_2 because this cost generally exceeds the value EOR producers have traditionally been willing to pay for CO_2. The cost of capture of CO_2 from new and retrofit coal-based power plants has been reported by a number of sources and a sample of their results is presented in Appendix 1. In the U.S., the Department of Energy projects that under current policies very little new coal capacity will be built prior to 2035.[30] Hence, the potential for cost-effective retrofit of CO_2 capture systems to existing power plants is also evaluated in the case study included as part of this report. A range of costs for captured CO_2 from power plants was estimated, using sources and assumptions described in Appendix 1, and a value of \$59 per tonne of CO_2 captured was determined for CCS at a new coal-based power plant, and \$71 per tonne CO_2 captured for retrofit power plant CCS systems. These costs include capture and transport to an EOR field. It must be emphasized that these are approximate costs and vary with a number of site-specific characteristics. These site-specific factors increase in importance for retrofitting existing power plants, where costs would vary depending on the difficulty of the retrofit, the capture technology selected, the cost of makeup power to replace energy used for the capture and compression system, the distance from the power plant to the EOR site, and other factors.

These costs are significantly higher than costs currently paid for CO_2 by EOR operators. Several sources provide insight into recent prices paid for CO_2 by EOR operators:

- The EOR Institute[31] examined over 300 contracts for CO_2 purchase by EOR projects in the Permian Basin (West Texas) and reported that: "most contracts indeed have clauses that tie the price of CO_2 to the price of oil. Typically, contracts that are longer than a year have semi-annual or quarterly adjustments to the price of CO_2, and incorporate an agreed price floor combined with linear escalation of the CO_2 price with the oil price above that floor." The contracts were written between 1984 and 1994, a period when U.S. crude oil prices generally ranged between \$12 and \$26 per barrel in nominal dollars, significantly below current prices which recently exceeded \$100 per barrel.[32] The reported linear regression analysis showed a slope of 0.0224 (R-sq = 0.981) for the full data set, and 0.0271 (R-sq = 0.997) for the first 2 of the 10 years (U.S. crude oil prices dropped from \$24.09/barrel to \$12.51/barrel after the second year of the data

[30] The USDOE/EIA projects only 1GW of new coal capacity in the U.S. electric power sector between 2012 and 2035. Annual Energy Outlook, 2012 (Early Release), USDOE/EIA, January 23, 2012, http://www.eia.gov/forecasts/aeo/er/ .

[31] Pegging Input Prices to Output Prices in Long-Term Contracts: CO_2 Purchase Agreements in Enhanced Oil Recovery, Klaas Van't Veld & Owen R. Phillips, EOR Institute, University of Wyoming, July 2009.

[32] Annual Energy Review 2010, Table 5.18, U.S. Energy Information Administration, October 19, 2011.

set[33]). The contracts appeared to include transportation costs from the CO_2's point of origin to a commercial pipeline, not to the EOR field. The authors added a coefficient of 0.5 "representing average transportation costs." In other words the delivered cost equation formulated for Permian Basin CO_2 contracts was: $Price_{CO2,\ \$/mcf} = 0.5 + 0.0224 \times Price_{Oil,\ \$/bbl}$.

- The Department of Energy established state-based algorithms relating the price paid for CO_2 to the price of oil in a model used to estimate unconventional oil resources.[34] For most states in the U.S. with active EOR production (TX, WY, CO, MS, UT), the relationship was: $Price_{CO2,\ \$/mcf} = 0.50 + 0.013 \times Price_{Oil,\ \$/bbl}$. For the state of Louisiana, the relationship was: $Price_{CO2,\ \$/mcf} = 0.625 + 0.0163 \times Price_{Oil,\ \$/bbl}$. For any other state, the relationship was: $Price_{CO2,\ \$/mcf} = 1.0 + 0.026 \times Price_{Oil,\ \$/bbl}$.
- In a presentation to a U.S. Department of Energy conference in 2008, a representative of Blue Source stated that CO_2 prices to EOR producers, expressed in terms similar to above, could be estimated at 2% of the price of oil. In other words, $Price_{CO2,\ \$/mcf} = 0.02 \times Price_{Oil,\ \$/bbl}$.[35] This "rule of thumb" was offered at a time when oil prices were relatively high, and was applied to a projected future price of oil of $122/barrel. The author noted that rising costs for engineering, procurement, and construction were placing downward pressure on the 2% rule of thumb.
- A 2011 report published by the U.S. Department of Energy applied a similar approach to above, but used a range of 2% to 3%, with an central estimate of 2.5% of the price of oil.[36]
- Denbury has stated[37] that its CO_2 costs for EOR were $5.05/bbl of oil in 2010, when oil averaged $79.51/barrel. Denbury uses pure CO_2 floods at its Gulf EOR projects, with an injection rate of 10-13 Mcf per barrel. This is about 0.6 tonnes CO_2 per barrel, about twice the rate ARI reports for the Permian Basin. Denbury's reported cost for CO_2 (in $/mcf) equates to about 0.5% of the price of crude oil (in $/barrel). In the format used above, that would be: $Price_{CO2,\ \$/mcf} = 0.005 \times Price_{Oil,\ \$/bbl}$. It is likely that this estimate does not include delivery to the EOR field, since Denbury owns the pipeline between the source of the CO_2 and its EOR fields.

The price data presented above leads to two key conclusions: the price paid for CO_2 is routinely indexed to the price of crude oil, and the price tends to vary significantly by region. For the case study which follows in this report, a CO_2 price equal to 1.5 – 3.0 % of the price of oil will be used (e.g., $Price_{CO2,\ \$/mcf} = 0.025 \times Price_{Oil,\ \$/bbl}$). For crude oil priced at $100 per barrel, this

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[33] Op. Cit., EOR Institute, 2009.

[34] National Strategic Unconventional Resource Model, A Decision Support System, Office of Naval Petroleum and Oil Shale Reserves, U.S. Department of Energy, 2006. (see http://fossil.energy.gov/programs/reserves/npr/NSURM_Documentation.pdf)

[35] An Update on Market Mechanisms for CO_2: Issues and Opportunities, M. Moore, Blue Source, Presented at 2008 SECA Conference, U.S. Department of Energy, http://www.netl.doe.gov/publications/proceedings/08/seca/Presentations/Moore.pdf .

[36] Op. Cit., Improving Domestic Energy Security, DOE/NETL, 2011.

[37] Op. Cit., Denbury Resources, Inc., 2011.

equates to \$1.50 – 3.00 per Mcf, or \$29 - 58 per tonne CO_2. The 1.5 – 3.0% range was selected because it is consistent with estimates provided by others during periods when oil prices were at levels comparable to today; and it is consistent with the analysis of Permian Basin contracts, albeit for periods when oil prices were much lower than today.

Combining the discussion of capture costs (e.g., \$59 or 71/tonne CO_2 captured and delivered, for new and retrofit CCS systems, respectively) with the discussion of price paid for CO_2 by EOR producers (e.g., \$29-58/tonne CO_2 if crude oil is \$100/bbl) shows that there is a general gap between the two prices. Moreover, given historic volatility in the price of oil, the decision to undertake a project would probably be based on a more conservative value for the future price of oil than its most likely price. Absent an additional source of revenue, a large reduction in CO_2 capture cost, or a regulatory mandate to capture CO_2, power plant CO_2 is unlikely to be used for EOR at today's oil price.

<u>Regulatory barriers</u>

In addition to the fundamental economic barrier to use of power plant CO_2 for EOR, there are also potential regulatory barriers for projects which might be considered in the U.S. Injection of fluids underground is regulated by the U.S. EPA's Underground Injection Control (UIC) program.[38] This program establishes requirements for six well categories, or "Classes". Class II wells are oil and gas related injection wells, including those used for EOR, and over 25 years of EOR operations have demonstrated that environmental and industrial goals can both be met under these rules. Class VI well regulations were added in December 2010, and cover geologic sequestration wells. Compliance with Class VI well requirements is clearly more costly that compliance with Class II requirements, and the Class VI rules include an additional provision which maintains liability for possible damages to groundwater for a default period of 50 years after cessation of injection. In the rule established for Class VI wells, EPA identified a general set of criteria under which a Class II EOR operation could become subject to Class VI requirements: "*EPA determined that owners or operators of wells injecting CO_2 in oil and gas reservoirs for GS where there is an increased risk to USDWs* [Underground Sources of Drinking Water] *compared to traditional Class II operations using CO_2 should be required to obtain a Class VI permit, with some special consideration for the fact that they are transitioning from a well not originally designed to meet Class VI requirements. Additionally, EPA recognizes that further clarification is needed to sufficiently characterize the factors that lead to increased risks and warrant conversion from Class II to Class VI. Therefore, today's rule clarifies that Class VI requirements apply to any CO_2 injection project (regardless of formation type) when there is an increased risk to USDWs as compared to traditional Class II operations using CO_2."* The types of factors leading to such redesignation *"include: (1) Increase in reservoir pressure within the injection zone; (2) increase in CO_2 injection rates; (3) decrease in reservoir production rates; (4) the distance between the injection zone and USDWs; (5) the suitability of the Class II AoR* [Area of Review] *delineation; (6) the quality of abandoned well plugs within the AoR; (7) the owner's or operator's plan for recovery of CO_2 at the cessation of injection; (8) the source and properties*

[38] Details on UIC regulations, and the regulations themselves, can be found at the U.S. EPA website for the program: http://water.epa.gov/type/groundwater/uic/ .

of injected CO_2; and (9) any additional site-specific factors as determined by the Director."[39] Despite the listing of criteria to be considered by permitting authorities, uncertainty remains regarding what specific conditions would lead to a change in regulatory class for an EOR operation. This uncertainty applies to any CO_2-EOR operation that differs from "traditional Class II operations."

Another type of regulatory barrier is the accounting of credits for stored CO_2 under regulatory programs which could evolve in the future. To a large degree, these boil down to measurement of CO_2 losses and consideration of the carbon from produced oil. Potential losses could include CO_2 leakage from the EOR reservoir, and CO_2 generated as a result of the energy expended beyond the power plant for CO_2 transport or injection. Some have suggested that the carbon content of the oil produced should be subtracted from the storage credit.[40] These issues can be barriers to use of CO_2 for EOR even in a regulatory framework which does not limit CO_2 emissions, such as the current rules regarding EOR activities in the U.S. The uncertainty regarding how these issues could be resolved discourages investments which have a long-term period for recovery of capital investment. For example, a CO_2 capture facility with a cost exceeding a billion dollars could become a stranded asset if, subsequent to commencement of operation, rules were adopted which reduced the creditable storage by an amount equal to the CO_2 emission potential of produced oil. A comprehensive framework for calculating CO_2 emission reductions from CCS projects has been developed and published by the Center for Climate and Energy Solutions, a non-government organization.[41]

Measurement of stored CO_2 would appear to be a straightforward matter, because commercial markets already have protocols for measuring CO_2 delivery in order to provide appropriate payment to the source. However, for environmental accounting, one must consider the likelihood that multiple capture facilities would feed CO_2 into a common pipeline, which would then feed multiple EOR projects or transport the CO_2 to temporary storage in surge reservoirs. Under those circumstances, it is unclear which party would be responsible for a potential CO_2 leak to the atmosphere. Additionally, within each EOR project much of the purchased CO_2 will be produced with the oil, separated, compressed, and reinjected for additional oil production. Each processing operation involves valves and seals which present opportunities for CO_2 leakage to the atmosphere.

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[39] Preamble to the Final Rule, Underground Injection Control Program for CO_2 Geologic Sequestration Wells, U.S. EPA, 75FR77245, December 10, 2010.

[40] Life Cycle Inventory of CO_2 in an Enhanced Oil Recovery System, P. Jaramillo, et. al., Carnegie Mellon University, *Environmental Science & Technology*, Vol. 43, No. 21, p.8027, 2009.

[41] Greenhouse Gas Accounting Framework for CCS Projects, Center for Climate and Energy Solutions, February 2012, http://www.c2es.org/publications/greenhouse-gas-accounting-framework-carbon-capture-and-storage-projects .

Options for addressing barriers to use of low concentration CO_2 sources EOR

Economic options

There are two paths to overcoming the gap between the cost of capturing CO_2 at power plants, and the cost paid by EOR developers for delivered CO_2. The first can be represented by a direct subsidy for capture via government tax incentive or monetary grant. Such a subsidy would reduce the owner's cost of the subsidized units, but could also reduce the cost of capture at future units if it resulted in a "learn by doing" technology improvement. The second approach would be to conduct research and development on capture technology, with a focus on cost reduction. Both of these approaches are currently being pursued as part of a global effort to improve CCS technology for fossil fuel-based electric power systems.

EOR, however, presents a unique opportunity for exploiting the option of a tax subsidy. This is because the EOR operation will generate significant tax revenues from oil production royalties and income taxes paid on profits from the oil production. Hence, a subsidy that only rewards CO_2 capture for EOR production which would not occur without the subsidized CO_2 capture would generate additional tax revenues which could offset some or all of the subsidy. From a government budgetary perspective, such a self-funded subsidy could be characterized as "revenue neutral" or "revenue positive." Achieving revenue neutrality would likely enhance the political viability of a capture subsidy in the current economic environment. Hence, it becomes useful to consider two questions:

1. What are the expected tax revenues from the incremental EOR activity, and
2. Can a subsidy be structured which is less than those tax revenues, is sufficient to close the cost gap, and targets only EOR activity which otherwise would not occur?

These questions are addressed in following sections, in the context of potential EOR activity and taxation in the U.S.

Regulatory options

Regulatory barriers could be addressed in two phases. In the first phase, legislation could stipulate that a limited amount of anthropogenic CO_2-EOR capacity would be subject to traditional rules applicable to EOR, with certain adjustments as noted below. In the second phase, knowledge gained in the first phase could be applied to regulatory policies which would apply to the longer term use of power plant CO_2 for EOR. For Phase One, consider a U.S. program targeted for facilitating the capture and use of CO_2 from 10 GW of coal-based power generation[42] by 2025. Such a program would store approximately 2 billion tonnes of CO_2 over the units' 30 year life, while producing about 6.7 billion barrels of oil. This would constitute a small fraction of the 27 – 100 billion barrels of U.S. EOR production identified as economically producible in Table 2. It would imply an incremental annual EOR production of about 220 million barrels per year, or about twice the current EOR production in the U.S. The program to reach this capacity in a decade would require a 12% annual growth rate in EOR capacity (in addition to any growth in EOR capacity occurring outside the incentive program). Because the program would be limited in scope, would advance CO_2 mitigation technology, and because any

[42] 10 GW is 3% of currently installed coal-fired power generating capacity in the U.S.

errors in accounting for CO_2 would almost certainly be a small fraction of the total CO_2 permanently stored via the effort, policy makers might be willing to stipulate protocols which would negate the potential regulatory barriers. For example, legislation creating the needed financial incentives might also stipulate that eligible CO_2 capture facilities:

- Would receive credit in any CO_2 regulatory program for all CO_2 delivered to a pipeline whose sole end users were EOR facilities; and
- Would apply current rules for "Class II" injection wells, without any threat for exposing the project to more stringent "Class VI" rules at some future date.

The CO_2 pipeline owners and EOR project operators would be responsible for providing measurements of CO_2 received and delivered, or injected into EOR projects. These entities would be responsible for any loss of CO_2 to the atmosphere and pay a fee to the U.S. Treasury of $30/tonne for any lost CO_2.[43] Monitoring and measurement protocols might follow existing commercial practices for validating emission reduction credits.[44]

EOR and CCS economics

General considerations

It is useful to examine the general economics of EOR production across a range of possible oil prices in the future. Additionally, given the focus of this paper on CO_2 capture economics, it is also instructive to consider how these general economics apply given alternative prices paid for CO_2. The economics of EOR production in the U.S. have been assessed by reports conducted by Advanced Research, Inc., for the U.S. Department of Energy and others.[45,46,47] These reports identify most cash flows from an EOR project as a function of the price of oil. For example:

- Average royalties are estimated as 17.5% of the price of oil (POO)
- Federal and state income tax is estimated as 35% of net income; production taxes are estimated as 5% of POO (both percentages are based on Financial Reporting System data).[48]
- ARI's 2011 report for DOE assumed that the price paid for CO_2 delivered to an EOR site would range between 2% and 3% of the price of oil.[49] 0.3 tonne of purchased CO_2 was assumed per barrel of produced oil.

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[43] Proceeds from this fee could be used by the Treasury to purchase GHG emission reductions via domestic offset projects, including agricultural or forestry offsets.

[44] Monitoring, reporting, and verification protocols for natural gas processing plant CO_2 used for EOR can be found at the American Carbon Registry website, e.g., http://www.americancarbonregistry.org/carbon-registry/projects/petrosource-eor-carbon-sequestration-project/?searchterm=eor .

[45] Storing CO_2 With EOR, DOE/NETL-402/1312/02-07-08, February 7, 2008.

[46] U.S. Oil Production Potential From Accelerated Deployment of Carbon Capture and Storage, prepared for the Natural Resources Defense Council (NRDC), 2010.

[47] Op. Cit., Improving Domestic Energy Security, DOE/NETL, 2011.

[48] The Financial Reporting System (FRS) was established by the U.S. Government and requires certain energy companies to report financial data to the U.S. DOE, using USDOE/EIA Form EIA-28. Example data for 2009 are presented in Appendix B.

[49] Op. Cit., Improving Domestic Energy Security, DOE/NETL, 2011.

- CO_2 recycling costs were estimated at 1% of POO, and 0.6 tonne of recycled CO_2 was assumed per barrel of produced oil.
- Capital and O&M costs for EOR production were taken from ARI modeling results.

These reports confirm in theory what has been observed in practice: That with relatively low cost CO_2 (e.g., delivered to EOR fields for about $40 per tonne or less) and relatively high priced crude oil (e.g., above $85 per barrel), CO_2-EOR can be a profitable enterprise for conditions existing in several regions of the U.S.

The other half of the financial calculus for power plant CO_2-based EOR is the economic viability of the CO_2 capture facility. In other words, can CO_2 be captured from relatively low concentration industrial sources, such as power plants, and delivered to EOR fields for the price EOR developers have historically paid for CO_2? Appendix 1 provides a brief overview of studies reporting incremental costs for CCS systems applied to new and existing (retrofit) coal fired power plants. In general, the cost of CO_2 capture and delivery is considerably greater than the estimates of CO_2 value to EOR producers. For retrofit systems, it is clear that a key assumption regarding overall costs is the cost of electricity to replace the parasitic power consumption of the capture system. Table 3 presents summary cost data from the discussion in Appendix 1 for new and retrofit CCS systems.

Table 3. Summary CCS cost data.

	New CCS	Retrofit CCS
Incremental capital costs, 2011 $/kW	1,854	2,225
Incremental levelized O&M, F, T, 2011 $/MWh[50]	28.51	29.84

<u>Integrating EOR and CO_2 capture</u>

Drawing from the work by ARI described above, a factored cost analysis of EOR operations was used to calculate the price paid for CO_2 delivered to EOR fields, and federal tax and royalty revenues from a CO_2-EOR operation at crude oil prices ranging from $80 to $120 per barrel. This was combined with CCS cost data in Table 3 to estimate the pre-tax discounted internal rate of return (IRR) for new and retrofit CCS systems capturing CO_2 from a power plant and selling it to an EOR facility. The IRR was then recalculated assuming a subsidy was provided to capture facility for the first 20 years of CO_2 capture at a power plant. The amount of the subsidy was defined as:

- $80 per tonne of CO_2 captured less the price paid for delivered CO_2 by the EOR developer, for CCS installed at a new (greenfield) power plant.
- $85 per tonne of CO_2 captured less the price paid for delivered CO_2 by the EOR developer, for CCS installed at an existing power plant.

For example, if oil were priced at $100 per barrel and the delivered cost of CO_2 were set at 2.5% of the price of oil ($2.50/mcf, or $48/tonne CO_2), then the subsidy for a new power plant would be $32 per tonne of CO_2 ($80-$48). These calculations were repeated for:

[50] O&M, F, T means costs related to operation and maintenance, fuel, and transport of CO_2 to an EOR field.

- Crude oil prices of $80/bbl, $100/bbl, and $120/bbl
- Delivered CO_2 prices of 1.5%, 2%, 2.5%, and 3% of the price of oil, as described above
- New and retrofit CCS facilities.

Results of these calculations are presented in Tables 4 and 5.

As seen in Table 4, for greenfield CCS projects (new power plants), without a subsidy on capture costs, an IRR ranging from negative to 18% is estimated, depending on the price of oil and the price paid by the EOR developer for CO_2. The retrofit cases in Table 5 show somewhat less favorable IRR's, due to the higher incremental cost of retrofit CCS units.

When a 20 year subsidy is included on CO_2 capture costs, however, all of the greenfield cases show a pre-tax IRR of 21 or 22%, and the retrofit cases have a slightly lower 19 or 20% IRR. The volatility of possible returns on investment to the owner of the capture facility is largely eliminated due to the structure of the subsidy.

Table 4. IRR estimates for CCS projects, with and without capture subsidy: Greenfield cases.

	CO2 Price, % of Oil Price*			
	1.5%	2.0%	2.5%	3.0%
Crude Oil Price, $/Bbl	NS / S **	NS / S	NS / S	NS / S
80	- / 21	- / 22	5 / 22	9 / 22
100	- / 22	5 / 22	10 / 22	14 / 22
120	3 / 22	9 / 22	14 / 22	18 / 22

Table 5. IRR estimates for CCS projects, with and without capture subsidy: Retrofit cases.

	CO2 Price, % of Oil Price*			
	1.5%	2.0%	2.5%	3.0%
Crude Oil Price, $/Bbl	NS / S **	NS / S	NS / S	NS / S
80	- / 19	- / 20	3 / 20	7 / 20
100	- / 20	3 / 20	8 / 20	12 / 20
120	1 / 20	7 / 20	12 / 20	15 / 20

* CO_2 price, in $/mcf, expressed as a % of the price of oil, in $/Bbl

** Values in the shaded areas of Tables 4 and 5 are the IRR, in %, for two cases: NS = no subsidy; S = Subsidy on capture of CO_2.

An additional result from the analysis was that the subsidy values in all but three of the twelve scenarios examined were less than the estimated increased federal EOR-related tax revenues over the initial 20 year capture period. The exceptions were the scenarios assuming $80/bbl oil combined with a CO_2 price of 1.5% - 2.5% of the price of oil. For these scenarios, the 20-year tax revenues equaled only 74-99% of the subsidy. However, if the tax revenues were considered over a 30 year CCS project period, they significantly exceeded the subsidy value (which was paid for only 20 years) under all scenarios.

<u>Caveats and conclusions on costs</u>

The above analysis is useful in gleaning overall trends of probable outcomes, but must be heavily caveated for any specific project application. EOR is a site-specific technology application, and tax implications are company-specific. Major areas of uncertainty or variability by project include:

- EOR-related
  - Geology, e.g., limestone versus sandstone
  - Depth of oil reservoir
  - Temperature of oil reservoir (generally, a function of depth)
  - Formation permeability, porosity, pore space oil saturation, thickness
  - Condition of existing production wells
  - Lag period between initial CO_2 injection and initial oil production
  - Oil production profile over time, and CO_2 management system[51]
- Financial & CCS-related
  - Tax profile of power producer and EOR developer
  - Type of power producer, e.g., investor owned utility versus merchant power producer, pure electricity producer versus polygeneration
  - Design of the subsidy, e.g., amount, number of years of duration
  - This analysis does not include indirect or induced economic activity associated with the EOR project. Those income streams would produce substantial additional federal tax revenues.[52]

Another consideration which is important for the scenarios which lack a CO_2 capture subsidy is that EOR developers and capture facility owners are likely to use a conservative value when projecting the future price of oil, and resulting prices for delivered CO_2. For example, even though an EOR developer might expect a future oil price of $100 per barrel, he would be prudent to forego a project which would not remain economically viable if the price of oil were only, say, $80 per barrel. Similarly, in the absence of a price subsidy, a prospective CCS owner would likely base his economic feasibility analysis on a conservative estimate for the future price of oil, and the resulting effect of that price on expected revenue from sale of CO_2. In contrast, under a subsidized program, the EOR developer would likely retain a conservative posture regarding the future price of oil, which is fundamental to the profit or loss from EOR, but the prospective CCS system owner would be relatively insulated from changes in oil prices, as they relate to revenues from the capture of CO_2.

Lastly, it is important to remember that the capture of CO_2 from power plants is an immature technology, and both the capture and use of the CO_2 is subject to evolving environmental requirements. These factors are interpreted by the private sector as increasing the risk of an investment, and it is not clear that IRR's in the range of those estimated in this paper are sufficient to result in investments, due to the magnitude and uncertainty of these risks.

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[51] Patterns of EOR oil production and CO_2 utilization over time vary dramatically by project. See, for example, differences between pure CO_2 EOR, traditional WAG-CO_2 EOR, and tapered WAG-CO_2 EOR as presented in Life beyond 80 – A look at Conventional WAG Recovery beyond 80% HCPV Injection in CO_2 Tertiary Floods, SPE-139516-PP, D. Merchant, 2010. Horvaka suggests that EOR projects linked to constant CO_2 production industrial sources might modify traditional "ratio and duration of water alternating with CO_2, well spacing, and injection rates…." EOR as Sequestration – Geoscience Perspective White Paper included in Role of EOR in Accelerating the Deployment of CCS, MIT and UTx Bureau of Economic Geology, July 23, 2010.

[52] Op. Cit., RIMS-II Model, U.S. Department of Commerce.

Given the extent of these site- and company-specific variables, one must approach general conclusions regarding the use of dilute CO_2 streams for EOR with caution. In general, it seems reasonable to conclude that these sources of CO_2 will not be used for EOR under market conditions expected over the near term (e.g., the next 20 years) in the absence of a subsidy or some other financial driver.[53] It also appears that a subsidy could be devised which would make such use of low concentration CO_2 emission streams economically viable, and that the cost of the subsidy could be offset by current tax requirements applied to the increased domestic oil production.

Impacts of lower cost CO_2

About 75% of current CO_2-EOR in the U.S. is performed with "natural" CO_2 produced from geologic deposits, also known as CO_2 "domes". Most of the rest of currently employed CO_2 is captured at industrial facilities with relatively concentrated CO_2 gas streams, such as natural gas processing plants or facilities producing fertilizer from natural gas.[54] CO_2 domes and industrial sources emitting concentrated CO_2 gas streams can produce nearly pure CO_2 for EOR at lower cost than low concentration hydrocarbon conversion sources like power plants. No power plant currently captures CO_2 at commercial scale for any purpose, including EOR. Several commercial scale CO_2 capture projects at low concentration CO_2 emitting facilities, all receiving government subsidies, are underway and are scheduled to begin operation by 2017.[55] Of six such power plant demonstration facilities in the U.S., five are designed to store their CO_2 in EOR projects.

Three questions are central to the question of whether low cost CO_2, such as that provided by CO_2 domes and natural gas processing plants, presents a market barrier to the use of CO_2 from power generation in EOR:

1. How much low cost CO_2 is available?
2. What is the growth rate of the EOR industry and when will this growth exceed the supply of low cost CO_2?
3. Can a subsidy approach for power plant CO_2 be crafted in a way which encourages capture from power plants, facilitates development of improved technology which would no longer require a subsidy, and which does not encumber existing CO_2 markets?

<u>Low cost CO_2</u>

Price data on CO_2 purchases from different sources is generally not publicly available. However, the progression of categories of development for CO_2 began with CO_2 from natural domes, followed by CO_2 separated from methane at natural gas processing plants, followed by collection of CO_2 from other industrial sources which have relatively high concentration streams of CO_2 such as fertilizer plants and ethanol plants. Estimates of capture costs from the Jackson

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[53] A carbon mitigation policy might provide such an economic driver, but it might also lead to closure of carbon emitting industrial facilities.
[54] Op. Cit., <u>Improving Domestic Energy Security</u>, USDOE/NETL, 2011.
[55] The Massachusetts Institute of Technology maintains a data base of CCS projects, estimated project cost, and subsidies at http://sequestration.mit.edu/tools/projects/index_capture.html .

Dome ($4 per tonne) and fertilizer and natural gas processing plants ($24-30 per tonne)[56] are well below the costs presented in Appendix 1 for power plants. Combustion facilities offering relatively low concentration CO_2 gas streams and coal conversion facilities (with the exception of the government subsidized Dakota Gasification / Weyburn project) are only now being developed as sources of CO_2 for EOR projects. In the U.S., most of these more recent anthropogenic CO_2 capture projects are subsidized by the U.S. government. Table 6 presents summary data for CO_2 used in U.S. EOR projects in 2010, with projections for 2012 and 2015.[57] The two projection years assume unchanged production by CO_2 domes over the next three years.

Table 6. Current and projected CO_2 use by EOR in the U.S.

Source Category	CO_2 Used by EOR Projects in the U.S., million tpy		
	2010	2012 estimated	2015 estimated
Domes	50	50	50
Natural gas processing units	9	20	21
Hydrocarbon conversion	1	1	22
Total	60	71	93

Table 6 indicates that a dramatic increase in CO_2 capture is expected for natural gas processing plants between 2010 and 2012, and an even larger increase in CO_2 capture from hydrocarbon conversion facilities is expected between 2012 and 2015. 57% of the additional CO_2 from hydrocarbon conversion facilities projected by 2015 is from projects subsidized by the U.S. government. For purposes of this paper, the CO_2 supplied by domes and natural gas processing plants, which is not subsidized, is considered "low cost." Capture by hydrocarbon conversion facilities is considered "higher cost." Reported reserves in natural domes are estimated to be sufficient for 40 years of production at current rates, and the LaBarge natural gas reservoir in Wyoming (which is about 2/3 CO_2) is estimated to contain more CO_2 than all the currently producing natural domes combined.[58] In Denbury's annual report to the Securities Exchange Commission,[59] the company provided a qualitative characterization of CO_2 production costs, as well as insight into why it is seeking CO_2 from additional anthropogenic sources: "In addition to our natural source of CO_2, we have entered into long-term contracts to purchase man-made CO_2 from nine proposed plants that will emit large volumes of CO_2, four of which are in the Gulf Coast region, four in the Midwest region (Illinois, Indiana, and Kentucky) and one in the Rocky Mountain region." **"**The base price of CO_2 per Mcf from these CO_2 sources varies by plant and location, but is generally higher than our most recent 'all-in' cost of CO_2 from our Jackson Dome

[56] Role of EOR in Accelerating the Deployment of Carbon Capture and Sequestration, MIT Energy Initiative & U TX Bureau of Economic Geology, July 23, 2010 Symposium Report.
[57] Data derived from A Note on Sources of CO_2 Supply for EOR Operations, DiPietro & Balash, DOE/NETL, Presented at CO_2 Conference, December 2011. http://co2conference.net/pdf/1.2_Report_NETL-DiPietro_Sources_of_CO2_Supply_for_EOR_-12-11.pdf . Note the data exclude CO_2 used in the Weyburn EOR project, which is not a U.S. oil production field.
[58] Ibid.
[59] SEC Form 10K filing, Denbury Resources, Inc., p.7, Filed Mar 1, 2011.

using current oil prices. Prices for CO_2 delivered from these projects are expected to be competitive with the cost of our natural CO_2 after adjusting for our share of potential carbon emissions reduction credits using estimated futures prices of carbon emissions reduction credits." It should be noted that most of the projects cited by Denbury convert coal or petcoke to a liquid or gaseous hydrocarbon, not electricity, and some of the identified projects have been awarded federal subsidies. Also, when considering the competitiveness of additional CO_2 resources, the production potential of current sources of CO_2 must be considered along with the location of the CO_2 sources relative to EOR development fields, pipelines linking them, and other factors.

Future growth in EOR production

Figure 2 shows the growth of CO_2-EOR in the U.S. and the price of crude oil from 1988 to 2012.[60] EOR production is more profitable with higher oil prices, and it is interesting to observe that during this period EOR production increased by over 5-fold (7.4%/year), while the price of oil increased over 6-fold (8.2%/year, nominal dollars). The annual growth rate of U.S. EOR production since 2010 has been 16%. The U.S. EIA projects future world oil prices to grow at an average of 4% per year (nominal dollars), roughly doubling in price by 2030, compared to 2011.[61]

Future projections of EOR production are uncertain, as demonstrated by the difference between the growth rate for the past 24 years (7.4%/year) and the growth rate over the past two years (16%/year). Denbury, the second largest EOR producer in the U.S., projects 14-16% annual growth in that company's production between 2011 and 2020.[62] A possible range of future EOR production can be estimated using a range of possible growth rates.

[60] EOR production data taken from Oil & Gas Journal EOR survey articles in 2010, 2012. Survey: Miscible CO_2 now eclipses steam in US EOR production, Oil and Gas Journal, April 2, 2012. Special Report: EOR/Heavy Oil Survey: 2010 worldwide EOR survey, Oil and Gas Journal, April 19, 2010. Crude oil price data taken from U.S. DOE/EIA, http://www.eia.gov/dnav/pet/pet_pri_land1_k_a.htm .

[61] Annual Energy Outlook, U.S. DOE/EIA, 2012.

[62] Denbury financial presentation, Johnson Rice & Company Energy Conference, October 4, 2011, http://phx.corporate-ir.net/phoenix.zhtml?c=72374&p=irol-EventDetails&EventId=4202674 .

Figure 2. U.S. EOR production since 1988.

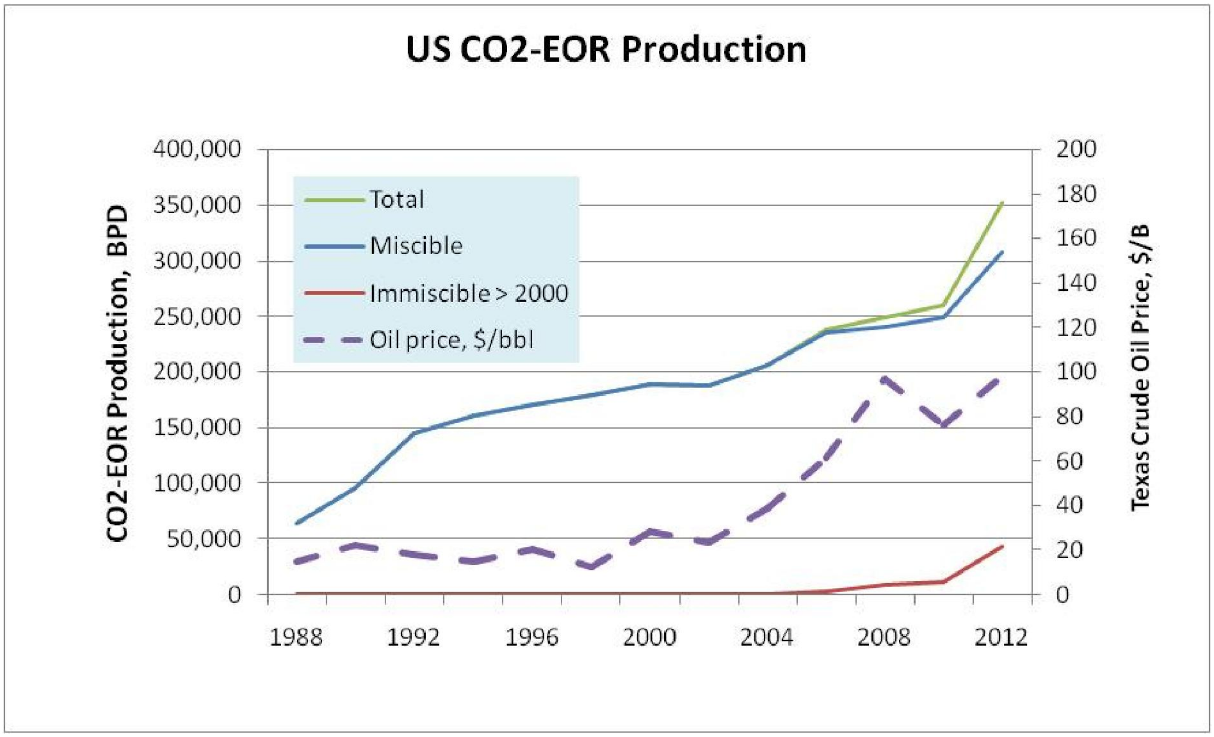
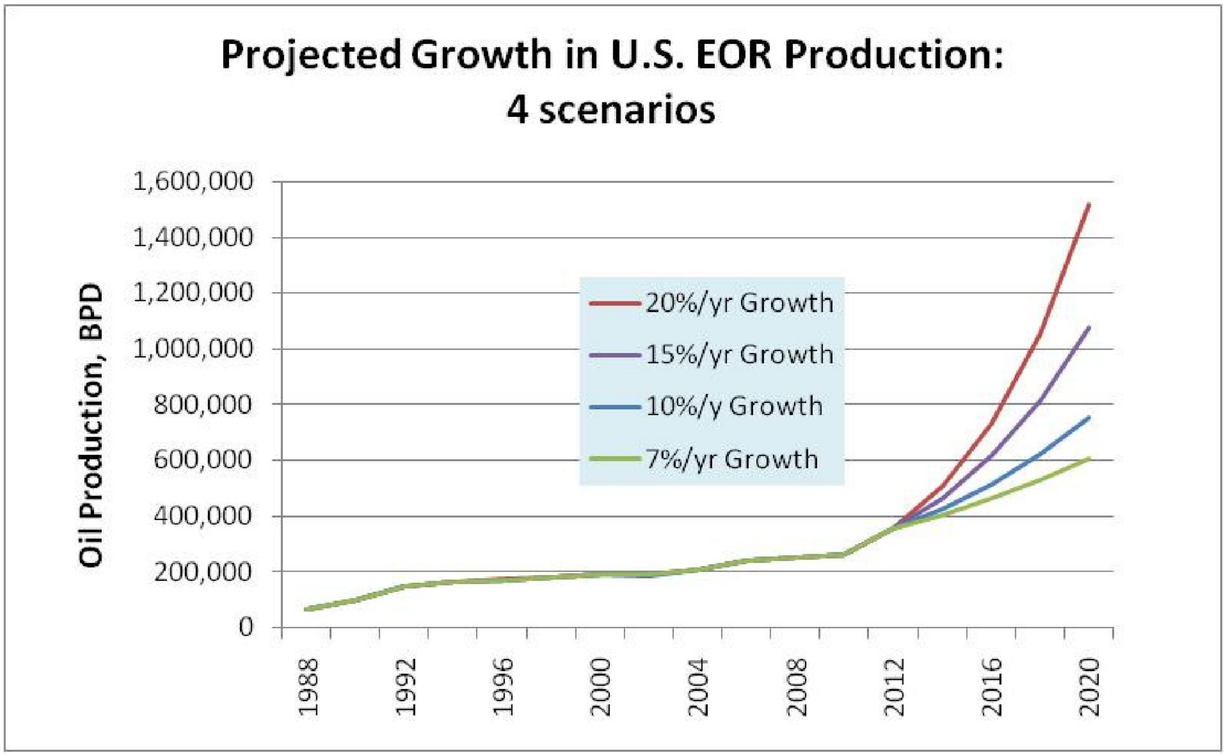


Figure 3 shows the results of such an exercise, using four postulated growth rates for the period 2012-2020. The lowest growth rate (7%/year) is comparable to growth in the sector between 1988 and 2012 (7.4%/year). The 10% and 15% growth rates in Figure 3 are consistent with more recent growth in U.S. EOR production, and with Denbury's projected increase in EOR production by 2020. The 20% growth rate projection might result from an incentive program or discovery of substantial new EOR reserves, such as the emerging ROZ concept for EOR production, which could attract additional industry interest in EOR.

Figure 3. Potential growth in U.S. EOR.



This range of future EOR production implies a range of demand for addition CO_2. Assuming a ratio of 0.3 tonnes of purchased CO_2 per barrel of produced oil, the CO_2 supply needed for the incremental EOR production in 2020 ranges from 28 to 128 million tonnes per year. If the higher annual purchased CO_2 requirements which occur in the early years of an EOR project were assumed, rather than the amount of purchased CO_2 averaged over a field's productive life, then the demand for incremental CO_2 in 2020 could be substantially greater. Nevertheless, assuming the 0.3 tonne/barrel ratio, and a 15% growth rate (comparable to the past two years and to projected growth by Denbury regarding that company's oil production) yields an incremental CO_2 demand of 80 million tpy in 2020, versus today. The 20% growth rate scenario implies an additional demand for 128 million tpy of CO_2. Focusing on "low cost" CO_2 sources (natural domes and natural gas processing plants serving natural gas fields with high CO_2 content), incremental CO_2 demand from even the 15% and 20% growth rates seems small compared to CO_2 reserve estimates (about 5 billion tonnes from known domes and CO_2 produced by natural gas processing plants), but large compared to the current CO_2 production (about 70 million tonnes per year in 2010).[63] An obvious issue for expanded CO_2 production from new natural gas processing plants is that some of the larger CO_2/methane fields are remote from major natural gas markets, and natural gas demand is likely to determine the rate of development of these mixed CO_2/methane fields. For "higher cost" CO_2 from hydrocarbon conversion processes, the available CO_2 is large.

[63] Op. Cit., DiPietro, USDOE/NETL, 2012.

The U.S. Department of Energy has issued a series of reports on EOR over the past several years, all of which look beyond the 2020 time frame discussed above. For example, a June 2011 report[64] estimated that 67 billion barrels of oil are considered economically recoverable via EOR[65], and would require 20 billion tonnes of CO_2. Other estimates of future U.S. EOR production range as high as 100 billion barrels of oil, when possible contributions of ROZ oil are included (see Table 2). This CO_2 demand far exceeds the current reserve estimate by DiPietro[66] for domes and natural gas processing plants (approximately 5.1 billion tonnes). However, the 2010 GHG inventory for the U.S. identifies 2.3 billion tpy of CO_2 emissions from power plants alone.[67] Assuming that 15 billion tonnes of CO_2 were needed to supplement domes and natural gas processing plant supplies of CO_2, and assuming a period of at least 30 years of EOR development, implies a CO_2 demand from other industrial sources averaging about 0.5 billion tpy. Hence, the supply of CO_2 from low-cost resources is inadequate to meet the full potential demand of EOR in the U.S., but the supply of CO_2 from power plants is more than sufficient to meet all of the above levels of demand.

The timing of when higher cost CO_2 from power plants might contribute significantly to overall CO_2 supply for EOR is difficult to predict. Major uncertainties in the U.S. include the ability to expand CO_2 infrastructure, regulatory policy – particularly policy toward existing lower cost sources of CO_2, the potential for ongoing and future capture R&D to reduce the cost of CO_2 capture from power plants, and potential subsidies which could offset a portion of the cost of CO_2 capture at power plants. Texas, for example, provides a 75% reduction of its standard petroleum severance tax for eligible EOR projects using anthropogenic CO_2. [68]

<u>A possible incentive design</u>

Three desirable features of a program to provide incentives for CO_2 capture facilities are:

1. The incentive must be adequate to encourage the desired activity; i.e., the construction and operation of CO_2 capture facilities linked to EOR projects.
2. The incentive should have a clear end date, after which future capture facilities could compete without subsidy.
3. The incentive should not displace other legitimate economic activity of a similar nature. In other words, the incentive for higher-cost capture facilities should not displace low-cost capture facilities.[69]

The CCS economics presented earlier concluded that the revenue from sale of CO_2 to EOR facilities is generally insufficient to justify an investment in currently available CCS technologies

[64] Op. Cit., <u>Improving Domestic Energy Security</u>, DOE/NETL, 2011.
[65] The report assumes use of "next generation" EOR technologies, a crude oil price of $85/bbl, CO_2 availability for $40/tonne, and an acceptable pre-tax IRR of 20%.
[66] Op. Cit., DiPietro, USDOE/NETL, 2012.
[67] <u>Inventory of US GHG Emissions and Sinks: 1990-2010</u>, U.S. EPA, January 2012, http://epa.gov/climatechange/emissions/ghgdata/index.html .

[68] Texas Administrative Code, Enhanced Oil Recovery Projects – Approval and Certification for Tax Incentive, Title 16, Part1, Chapter 3, Rule Sec.3.50(k).
[69] This third goal may not be absolute. For example, policy makers may determine that it is preferable to displace dome CO_2 with industrial CO_2 because the latter provides a climate change mitigation benefit.

without some form of financial incentive or subsidy. However, the same analysis showed that a complementary subsidy, reflecting the difference between a posited cost of capture and the payment for CO_2 by the EOR developer would provide a return which may be commensurate with perceived risks. This finding is consistent with an earlier report on EOR-based financial incentives for CCS[70], and an extensive investigation led by the Center for Climate & Energy Solutions and the Great Plains Institute.[71]

A reasonable end date for the subsidy and transition to market economics, the second feature listed above, can be addressed with an eligibility factor. The incentive system should be available only to facilities which begin capturing CO_2 within a defined time period, e.g., before 2025. Once determined to be eligible, however, those facilities would continue to be subsidized for the full 20 year term of the subsidy. The viability of CCS to supply CO_2 for EOR production after the subsidy program expires would likely require the following elements: a) reductions in cost via the "learn-by-doing" experience with the subsidized capture projects, and other CCS projects globally; b) continued progress in CCS R&D activities; and c) continued high prices for crude oil.

A subsidy could be prevented from displacing other legitimate EOR projects using lower cost CO_2 by requiring any source receiving the subsidy to secure a relatively high payment for CO_2 by the EOR developer. For example, a criterion for eligibility for the subsidy might be a price floor in the CO_2 contract between the CO_2 provider and EOR project owner. Using the traditional oil price index, such a rate might be 1.5% of the price of crude oil.[72] If an EOR developer had access to lower cost CO_2, such as from a dome or natural gas processing plant, then that source of CO_2 would be exploited because it would be less costly to the EOR developer than the subsidized CO_2. Subsidies for CO_2 capture would flow only to markets where less costly CO_2 could not be developed. In addition to reducing interference with existing markets, this approach increases the likelihood that the tax revenue from EOR production using subsidized CO_2 would be "additive" and would therefore offset the subsidy cost.

Box 1 presents the key features of an example subsidy program which could meet most of the requirements described above. This example is targeted for conditions relevant to markets in the U.S., and presumes that the source of CO_2 would be a coal-based power plant. However, subsidies following similar designs but with different subsidy values could be crafted for other source categories, such as natural gas power plants, or other industrial facilities which would otherwise emit CO_2.

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[70] Enhanced Oil Recovery & CCS, L. Carter, US Carbon Sequestration Council, January 2011, http://www.uscsc.org/educational_papers.asp .

[71] See National Enhanced Oil Recovery Initiative, Convened by the Center for Climate & Energy Solutions and Great Plains Institute, 2012, http://neori.org/ .

[72] I.e., CO_2 price, in \$/mcf = 1.5% x the price of oil, in \$/bbl. For \$100/bbl oil, this would equate to \$1.50/mcf, or \$29/tonne CO_2.

Box 1.

Example Subsidy Structure –

Amount:

- The subsidy rate, in $/tonne of CO2 captured, would be
  - $80 per tonne of CO2 captured less the price paid per tonne for delivered CO2 by the EOR developer, for CCS installed at a new (greenfield) power plant.
  - $85 per tonne of CO2 captured less the price paid per tonne for delivered CO2 by the EOR developer, for CCS installed at an existing power plant.
- The subsidy applies for the first 20 years of CO2 capture.
- The subsidy would be awarded as an income tax credit, and adjusted annually based on the price of oil during the previous year.

Eligibility:

- The capture system must be at a facility converting fossil energy to other forms of energy.
- At least 50% of total input energy must be used to produce electricity
- Capture must begin by 2025.
- The facility must have a contract from an EOR developer providing a purchase price for delivered CO2, in $/tonne of CO2, equal to at least 29% x the price of crude oil, in $/bbl. The contract must apply for the first 20 years of CO2 production. Multiple contracts are acceptable.

Conclusions

CO_2-based EOR is a mature technology, having become commercial in 1972. Most current EOR activity is in the U.S., where it contributes 5% of total domestic oil production. After a decade of relatively low growth in the U.S. (3%/year), EOR grew at 16%/year from 2010 to 2012. The vast majority of CO_2 currently used for EOR comes from natural geologic resources (domes) or natural gas processing plants (facilities that remove excess CO_2 from raw natural gas prior to transmission of the natural gas to markets). Global oil resources amenable to production using EOR are large, with estimates of technically recoverable reserves of 880 – 1300 billion barrels. In the U.S., technically recoverable resources are estimated at 176 billion barrels, and economically recoverable resources are estimated to be as large as 100 billion barrels with “next generation” EOR techniques. For perspective, global liquid fuel production totaled 31 billion barrels in 2007. World and U.S. proved reserves were estimated to be 1340 billion barrels and 21 billion barrels, respectively, in 2009.

Production of oil using EOR provides a range of economic and environmental benefits, as well as the opportunity for the producing country to reduce reliance on foreign sources of crude oil.

Known U.S. sources of relatively low cost CO_2 (domes and natural gas processing plants) lack the capacity to produce the majority of U.S. oil thought to be amenable to CO_2-EOR. Much greater quantities of CO_2 are currently emitted from industrial sources in combustion flue gases having relatively low concentrations of CO_2. This CO_2 can be separated, compressed, and piped to EOR fields, but at a cost which may be greater than EOR producers can afford to pay. In addition to this economic barrier, there are additional regulatory policies which could pose barriers to use of these CO_2 resources for EOR in the U.S.

It may be possible to craft a program to provide a subsidy for the capture of CO_2 from low concentration gas streams, such as the flue gases from coal-based power plants, and to recover the cost of that subsidy from taxes which would flow from the production of additional domestic oil. Features of this hypothetical subsidy are described in Box 1. This subsidy could provide the financial incentive necessary for early deployment of CCUS technology. It is important to understand that the offsetting taxes would not derive from an increase in current tax rates, but rather from application of current tax rates to increased domestic oil production. A temporary subsidy program, combined with continued research and development on CO_2 capture technologies, could lead to cost reductions in capture technology which would make the capture and use of unsubsidized power plant CO_2 economically viable for projects initiated after 2025.

Appendix 1. Cost of CO_2 capture and transport

Recent reports on capture costs

A number of recent reports offer costs for coal-based power plants equipped with Carbon Capture and Storage (CCS) systems. However each report uses its own assumptions regarding when the units would be placed in service, whether the costs are "1st of a kind" or "Nth of a kind", and other key parameters such as the cost of capital and cost of fuel. Table A.1, below, offers a sampling of calculated costs of CO_2 avoided and cost of CO_2 captured, from 5 such reports. All of these reports project costs for current CCS technology; the ZAP report provides most of its cost data for an "OPTI" or optimized future version of CCS.

In Table A.1 the following definitions apply:

- "Cost Avoided" is the [levelized cost of electricity (LCOE) with CCS – LCOE without CCS], in $/MWh, divided by the [emission rate without CCS – emission rate with CCS], in Tonnes CO_2/MWh.
- "Cost Captured" is the [LCOE with CCS – LCOE without CCS], in $/MWh, divided by the CO_2 captured at the system with CCS, in Tonnes CO_2/MWh.

Additionally, columns 3 and 4 in Table A.1 provide data for a power system with CCS relative to the same power system without CCS (e.g., IGCC with CCS versus IGCC without CCS). Columns 5 and 6 provide similar data, but relative to a single technology without CCS, a supercritical pulverized coal (SCPC) system (e.g., IGCC with CCS versus SCPC without CCS).

Adjustments to published values

CCS cost estimates in the WorleyParsons report were taken as representative of the cost of current CCS technology for a new coal-based power plant and applied with the following factors or changes deemed representative of current market conditions in the U.S.:

- A capital charge rate of 15.4% was applied to the report's capital costs, consistent with a methodology described in a report by the U.S. National Research Council.[73,74]
- The cost of coal was assumed to be $3.00 per mmBtu, the average delivered cost of Bituminous coal to U.S. power plants in 2010, as reported by USDOE/EIA, Form 423.
- The carbon content of coal was assumed to be equivalent to 205 #CO_2/mmBtu, the average content of bituminous coal in the U.S., as reported by USDOE/EIA in 2011.[75]

[73] America's Energy Future, National Research Council, 2009. (See Box 7.2, p.374, for an explanation of factors used to annualize the capital cost for CCS-equipped power plants).
[74] This annualization factor reflects a financial structure and risk assumptions consistent those used with traditional power plant technologies in the U.S. These assumptions may not reflect the increased economic, technical, and regulatory risk associated with early deployment of CCS associated with EOR production.
[75] Electric Power Annual, 2010, Table A.3., USDOE/EIA, November 2011.

- CO_2 transport costs were adjusted above those levels assumed for transport to local saline reservoirs estimated in the WorleyParsons report, and no charge was applied for storage itself.
- Costs were adjusted to 2011 $s using a GDP price deflator.[76]

Table A.1. Estimated costs of CO_2 capture, transport, and storage.

Source	Type of emitter	Cost versus same technology without CCS, $/tonne		Cost versus SCPC without CCS, $/tonne	
		Avoided	Captured	Avoided	Captured
1. NETL Baseline rev.2, 2010, 2007 $s, 1^{st} year costs.[77]	GE IGCC SubCPC SupCPC NGCC	43 68 69 84		66 75 69 36	
2. NETL Baseline 2007, 2007 $s[78]	GE IGCC SubCPC SupCPC NGCC	32 68 68 83	27 44 45 70		
3. WorleyParsons 2011, 2010 $s[79]	IGCC SupCPC USupPC	47 77 72	38 51 52	63 77 58	55 51 48
4. ZAP GCCSI, adj for Base (current) Technology, 2009 $s[80]	USupPC	82	65		
5. EPA IPM cost for new advanced coal, 2007$s[81]	IGCC			68	60
6. EPA IPM cost for existing unit retrofits, 2007 $s[82]	SubCPC	96	92		
7. NETL CCS retrofit report, 2006 $s[83]	SubCPC, retrofit		59-65		

IGCC = Integrated gasification combined cycle

SubCPC = Subcritical pulverized coal

[76] GDP Implicit Price Deflator, U.S. Federal Reserve Economic Data, Federal Reserve Bank of St. Louis, http://research.stlouisfed.org/fred2/graph/?s[1][id]=GDPDEF .

[77] Cost and Performance Baseline For Fossil Energy Plants, Rev2, NETL, p.20, Nov2010. Units are "1^{st} year CO_2 avoided cost, $/tonne, 2007$s"

[78] Cost and Performance Baseline for Fossil Energy Plants, original version, NETL, May 2007.

[79] Economic Assessment of Carbon Capture and Storage Technologies, 2011 update, Worley Parsons for GCCSI, 2011 [Nth-of-a-kind technologies].

[80] The Costs of CO_2 Capture, Transport and Storage, ZAP, GCCSI, July 2011. Table values converted reported "OPTI" costs to "BASE" costs to reflect costs for current generation technology (pre-2025). Costs are scaled to 2x700MWnet system.

[81] IPM v. 4.10 Documentation, Chapter 6, ICF for EPA, 2010. (Table A.1 costs reflect $10/t CO_2 for transportation and storage).

[82] Ibid.

[83] Carbon Dioxide Capture from Existing Coal-Fired Power Plants, DOE/NETL-401/110907, November 2007.

SupCPC = Supercritical pulverized coal

USupPC = Ultra supercritical pulverized coal

NGCC = Natural gas combined cycle

Using the above factors, the adjusted value for CO_2 capture and transport from a new SCPC power plant with CCS was $90/tonne of CO_2 avoided. The cost per tonne captured was $59/tonne.

Because of relatively low forecasted growth in electricity demand in the U.S.,[84] it is also useful to consider CO_2 capture costs from existing power plants retrofit with CCS. One approach would be to apply a "retrofit factor" to the above new plant costs. Factors of 20% have been used for other technologies, such as SO_2 flue gas desulfurization systems, in order to reflect the space constraints and limitations on design freedom at an existing facility versus a new facility. Such a factor should be applied to capital costs, fixed O&M, and variable O&M, but not to incremental fuel use attributable to CCS or cost of CO_2 transport[85]. Given the large size of CCS capture systems, and significant new demands on cooling water, a 20% factor may be too conservative for CCS.[86] Nevertheless, application of such a factor to the above new facility costs would change them to $108/tonne CO_2 avoided, and $71/tonne CO_2 captured.

An alternative approach to estimate retrofit costs would be to use the studies in Table A.1 which considered retrofits explicitly (reports number 6 and 7 in the table). The NETL costs, with an adjustment for pipeline transport and conversion to 2011 dollars, range from 75 to 81 $/tonne CO_2 captured for two hypothetical costs of replacement power: $64/MWh and $80/MWh. [87] The EPA retrofit costs were based on the DOE/NETL retrofit report in Table A.1. Neither is used because they are based on expected costs at a specific existing power plant, and it is not clear that the unit is representative of most existing units which might be good CCS retrofit candidates.

This report uses data from the GCCSI/WorleyParsons report, with adjustments specified above, to represent costs for greenfield CCS facilities, and applies the same costs, with a 20% retrofit factor on capital and O&M, for retrofit units. Table A.2, below, summarizes the incremental capital and operating costs for CCS units.

[84] The USDOE/EIA projects only 1GW of new coal capacity in the U.S. between 2012 and 2035. Annual Energy Outlook, 2012 (Early Release), USDOE/EIA, January 23, 2012, http://www.eia.gov/forecasts/aeo/er/ .

[85] For example, a 20% retrofit factor would mean the capital cost of retrofitting an existing unit would be 120% x the capital cost of a new unit of equivalent capacity; and O&M of the existing unit would cost 120% x the O&M cost of a new unit of equivalent generation.

[86] For example, the NETL retrofit study cited in Table A.1 found that an amine-based capture system, and association compression and cooling systems, would require about 1 acre (4047 square meters) of land per 100 MW of retrofit capacity.

[87] These capture costs include pressurization to supercritical levels, but do not include pipeline transport or CO_2 injection costs, which were outside the scope of report.

Table A.2. Summary CCS cost data.

	New CCS	Retrofit CCS
Incremental capital costs, 2011 \$/kW	1,854	2,225
Incremental levelized O&M, F, T, 2011 \$/MWh[88]	28.51	29.84

The reports cited above provide a reasonable sampling of published estimates of CCS costs, and an appreciation of the range of values in such estimates. However, this review of reported costs is not intended to be exhaustive in its scope nor assess the differences between studies.

CO_2 Delivery cost

Most CCS cost studies do not apply a rigorous analysis to the cost of transporting and injecting the captured CO_2, which tends to be a small fraction of overall carbon capture and storage costs. For example, the GCCSI/WorleyParsons study estimated transport and storage costs to be \$7/MWh CO_2, or about 5% of overall CCS costs. Of this amount, \$1/MWh was for transport and \$6/MWh was for storage. Hence, transport alone was less than 1% of the total CCS cost. However, most CCS cost studies assume storage in nearby saline storage sites, and do not consider the case of EOR.[89] In order to serve attractive EOR sites, CO_2 may require transport over a longer distance, e.g., 500-750 miles (800-1200 km), which would entail greater transport costs. The transport cost estimate becomes somewhat complicated by the facts that while transport costs are nearly proportional to distance, they are also greatly influenced by mass flow rates and resulting pipeline diameter (providing substantial economies of scale to larger diameter pipelines).[90] Hence, it is possible that for EOR storage of CO_2 a relatively long pipeline would service several CO_2 capture facilities and several EOR projects, and that each supplier and user would have a relatively shorter and smaller diameter connecting line to the larger system.[91] Local sources of CO_2 could probably satisfy a modest expansion of the U.S. EOR industry, but a major expansion would likely involve multi-state pipelines. Resulting pipeline costs might be about \$4 per tonne CO_2 for regional systems, and \$10-15 per tonne for pipelines crossing several states.[92,93] As noted above, for purposes of this report a single transport cost

[88] O&M, F, T means costs related to operation and maintenance, fuel, and transport of CO_2 to an EOR field.

[89] For example, DOE/NETL assumes a transport distance of 50 miles (80km). Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity, USDOE/NETL, Nov. 2010. GCCSI/WorleyParsons used an assumption of 250 km in its 2009 reference case (resulting in a cost of transport and storage of \$4/MWh and \$6/MWh respectively), but reduced this to 100km in its 2011 update report. Strategic Analysis if the Global Status of Carbon Capture and Storage, Report 2: Economic Assessment of CCS Technologies, WorleyParsons, et. al., for GCCSI, 2009. Economic Assessment of CCS Technologies – 2011 Update, GCCSI/WorleyParsons.

[90] The Costs of CO_2 Transport, Zero Emissions Platform, July 15, 2011, http://www.zeroemissionsplatform.eu/library/publication/167-zep-cost-report-transport.html .

[91] See A Policy, Legal, and Regulatory Evaluation of the Feasibility of a National Pipeline Infrastructure for the Transport and Storage of Carbon Dioxide, Topical Report, Interstate Oil and Gas Compact Commission, prepared for the Southern States Energy Board, September 10, 2010.

[92] Op. Cit., Zero Emissions Platform, 2011.

of $10 per tonne CO_2 was used. No charge was applied for CO_2 storage because this was assumed to be part of the economic analysis of the EOR project.

[93] Documentation for EPA Base Case v.4.10, Chapter 6: Carbon Capture, Transport, and Storage, U.S.EPA, http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html .

Appendix 2. Example financial data for U.S. oil companies.

Income Statement Items	U.S. Petroleum Activities	
	Petroleum Production	Refining & Marketing
Operating Revenues		
Raw Material Sales	90,117	97,525
Refined Products Sales	-	521,497
Transportation Revenues	262	489
Hedging/Derivatives	8,769	1,154
Management and Processing Fees	525	3,149
Other	3,039	12,687
Total Operating Revenues	102,712	636,501
Operating Expenses		
General Operating Expenses	35,480	635,296
Depreciation, Depletion, & Allowance	52,838	8,327
General & Administrative	3,391	4,773
Total Operating Expenses	91,709	648,396
Operating Income	11,003	(11,895)
Other Revenue & (Expense)		
Earnings of Unconsolidated Affiliates	2,351	683
Gain(Loss) on Disposition of Property, Plant, & Equipment	1,068	502
Total Other Revenue & (Expense)	3,419	1,185
Pretax Income	14,422	(10,710)
Income Tax Expense	3,794	(2,903)
Contribution to Net Income	10,628	(9,396)

Source: US DOE/EIA, http://www.eia.gov/cfapps/frs/frstables.cfm?tableNumber=5 .