Paper #1-5

ONSHORE CONVENTIONAL OIL INCLUDING EOR

Prepared by the Onshore Oil & EOR Subgroup
of the
Resource & Supply Task Group

On September 15, 2011, The National Petroleum Council (NPC) in approving its report, *Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources*, also approved the making available of certain materials used in the study process, including detailed, specific subject matter papers prepared or used by the study's Task Groups and/or Subgroups. These Topic and White Papers were working documents that were part of the analyses that led to development of the summary results presented in the report's Executive Summary and Chapters.

These Topic and White Papers represent the views and conclusions of the authors. The National Petroleum Council has not endorsed or approved the statements and conclusions contained in these documents, but approved the publication of these materials as part of the study process.

The NPC believes that these papers will be of interest to the readers of the report and will help them better understand the results. These materials are being made available in the interest of transparency.

The attached paper is one of 57 such working documents used in the study analyses. Also included is a roster of the Subgroup that developed or submitted this paper. Appendix C of the final NPC report provides a complete list of the 57 Topic and White Papers and an abstract for each. The full papers can be viewed and downloaded from the report section of the NPC website (www.npc.org).

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CONVENTIONAL ONSHORE OIL
INCLUDING ENHANCED OIL RECOVERY

Executive Summary

This topic paper provides background in support of the NPC study on North American natural gas and oil resources in the area of conventional onshore oil and enhanced oil recovery (EOR) for the United States and Canada. For the purpose of this study, "conventional oil" excludes supply from Canadian oil sands/heavy oil, US oil sands/oil shale (kerogen) and tight oil projects utilizing long horizontal wells combined with advanced hydraulic fracturing (the Unconventional Oil Topic Paper of the NPC study covers these resources).

This work reviewed existing studies and references to: 1) identify **key technologies and issues**, 2) describe **potential development pathways**, and 3) summarize common and important topics into major **findings**. Throughout, the goal is to focus on items which will have the most impact on future supply so that the NPC Study Leadership has appropriate context as they respond to the US Secretary of Energy. The topic paper is organized to be consistent with these tasks, describing the results of each.

The findings generally correlate to these key themes:

Essential Segment of Supply – Conventional onshore oil amounts to some 3.5 million b/d of supply, about 42% of total oil produced in the United States and Canada.

Base has been Declining but Recent Trends have Led to Important Improvements - Primary, water-flood, and thermal EOR production are a large part of onshore conventional oil; these sources have been declining. That trend has moderated or even increased as a combination of technology and economics generated significant activity which slowed the decline rate. Small percentage improvements on this large base can add significant volumes.

Growth in Carbon Dioxide EOR - In contrast to the base, miscible carbon dioxide (CO_2) EOR production has been increasing for the last two decades and now makes up 10% of onshore conventional oil volumes. Further increases in this category are likely, and will depend largely on the availability of affordable CO_2 supplies, which range from relatively pure natural sources to generally dilute industrial byproduct streams. A number of legal and regulatory barriers currently exist that may limit the viability of some supply sources. Whether and how these barriers are resolved will impact the CO_2 EOR production frontier. The availability of some CO_2 sources will hinge on state and federal policies regarding carbon capture and storage (CCS). EOR

is compatible with CCS provided an enabling legal, regulatory and economic framework exists*.

Large Resource Targets Still Exist - Many large existing fields have significant volumes of oil located beneath the main producing horizons, in formations holding relatively more water and less oil. Comparable zones also exist in isolation apart from known producing areas. The physical properties of these "residual oil zones" (ROZ) are similar to formations which have been produced using primary or secondary recovery methods. Collectively, these zones are likely to hold several hundred billion barrels of oil-in-place. With diligent delineation and continued technology development, they have the potential to produce significant volumes of incremental oil through the use of miscible CO_2 and other EOR technologies.

Technology Development/Application is Crucial – Technology advances will be vitally important to continually increase the recovery from known oil accumulations. They are also required to realize new volumes from formations that have not been traditionally targeted, such as oil bearing source rocks now being produced with hydraulic fracturing techniques and the ROZ. Technological innovations that leverage improvements in reservoir understanding, advanced well operations and cost reduction will all contribute to the development of incremental opportunities.

This topic paper suggests opportunities to address identified challenges and enable gains in the areas of the key findings. Ultimately, how the industry and policy makers approach these opportunities will determine the level of hydrocarbon supply realized from the onshore conventional oil segment.

*Neither this topic paper nor the sub-group advocates a specific CCS policy direction. Certain CCS issues and the potential impacts to oil supply are discussed to provide context for policy decision makers.

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1. Background

1.1. United States

<u>Historical U.S. Onshore Lower-48 Oil Production</u>

In 2010, the U.S. onshore lower-48 produced 3.1 million barrels of crude oil and condensate per day, or about 56 percent of total U.S. oil production. Crude oil production from the top 12 oil producing states accounts for over 97 percent of total oil production in the onshore lower-48 region (Table B1).

Table B1

2010 U.S. Onshore Lower-48 Crude Oil Production for the Top 12 States

State	2010 Onshore Crude Oil Production, Thousand Barrels Per Day	2010 Percent of Total Onshore Lower-48 Production	2005 – 2010 Change in Oil Production, Thousand Barrels Per Day
Texas	1,138	36.9 %	78
California	522	16.9 %	- 67
North Dakota	307	9.9 %	209
Oklahoma	186	6.0 %	16
New Mexico	171	5.5 %	5
Louisiana	163	5.3 %	- 21
Wyoming	142	4.6 %	1
Kansas	111	3.6 %	18
Colorado	71	2.3 %	8
Utah	67	2.2 %	21
Mississippi	65	2.1 %	17
Montana	65	2.1 %	- 25
Top 12 Subtotal	**3,008**	**97.4 %**	**268**
Total U.S. Onshore Lower-48	**3,087**	**100.0 %**	**485**
Total U.S. Oil Production	**5,512**		**334**

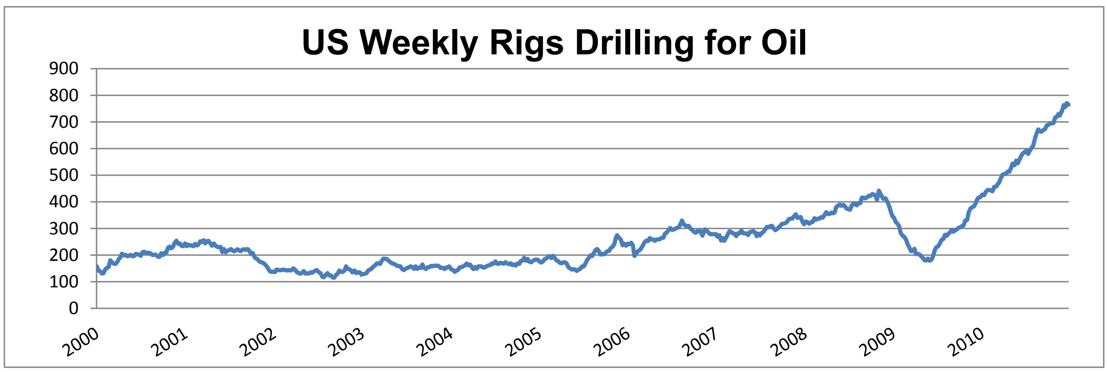
Source: U.S. Energy Information Administration, as of May 20, 2011, preliminary figures subject to revision; includes tight and heavy oil production, excludes oil production in State waters, and excludes natural gas liquids.

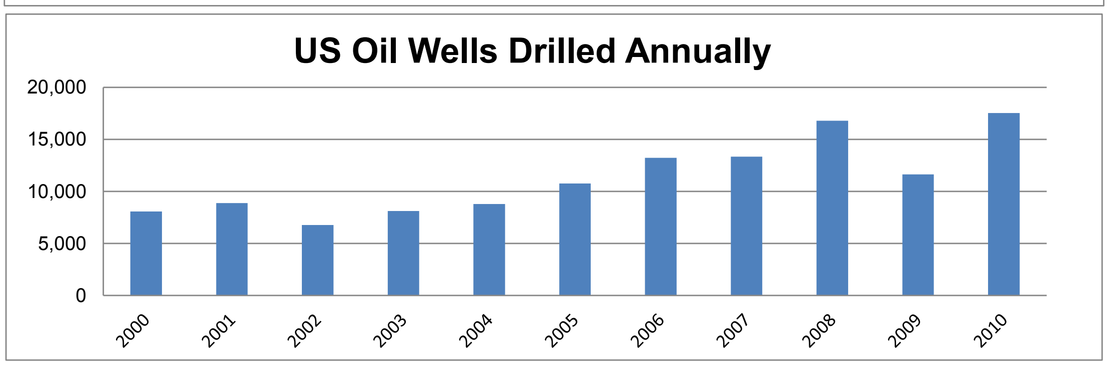
In 2005, onshore lower-48 oil production reached a minimum of 2.6 million barrels per day and has since increased to 3.1 million barrels per day in 2010. North

Dakota experienced the largest state increase in oil production from 2005- 2010, growing by 209,000 barrels per day, with most of the increase coming from the Bakken and Sanish-Three Forks formations. In the past, it was difficult to produce oil in commercial quantities from these formations due to their low permeability. The recent application of horizontal drilling in conjunction with hydraulic fracturing has made these wells profitable to produce at crude oil prices above $70 per barrel.

Higher post-2005 prices also helped stimulate increased drilling activity. Figure B1 below illustrates the increase in drilling rigs targeting oil and the subsequent number of onshore oil wells completed.

Figure B1





Source: Drilling rig data from "North America Rotary Rig Counts" worksheet per Baker Hughes dated July 8th, 2011, http://investor.shareholder.com/bhi/rig_counts/rc_index.cfm
Wells drilled per U.S. Energy Information Administration website, data collected July14, 2011, http://www.eia.gov/dnav/pet/pet_crd_wellend_s1_a.htm

Onshore lower-48 oil production has also been bolstered by the production of condensates produced from shale and low-permeability formations that preponderantly produce natural gas. The best examples of this oil/gas production synergy are the Eagle Ford shale formation located in southeast Texas and the Granite Wash low-permeability sandstone located in the Panhandle of Texas and West Oklahoma.[1] Because oil prices have recently been about 3.9 times higher than natural gas prices on a Btu basis,[2] the production of natural gas liquids (NGL) and condensates from predominantly gas-bearing shale formations significantly improves development economics.

In other regions of the onshore lower-48, such as California, West Texas, Wyoming, and Mississippi enhanced oil recovery technologies (also known as tertiary recovery or "EOR") have been employed. In particular, steam-injection and gas-injection have maintained oil production rates in mature fields well above the natural decline trend.

Consequently, the outlook for future oil production in the onshore lower-48 region is dependent upon both primary[3] and EOR resource development. Expanded production from oil-bearing shales[4] and low permeability formations, especially those not yet under development is critical to mitigating the general decline trend in onshore production. Further, incentivizing the development and application of advanced EOR technologies to mature fields will enable the extension of field economic life with minimal exploration risk, adding additional supply at the margin.

U.S. Onshore Lower-48 Oil Resources

An estimated 113.9 billion barrels of technically recoverable oil resources exist in the onshore, lower-48 (Table B2). The onshore lower-48 regions are shown geographically in Figure B2.

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[1] The Bakken formation in North Dakota, South Dakota, and Montana also produces significant volumes of natural gas even though it is predominantly an oil producing formation.

[2] This ratio is based on a natural gas spot price of $4.38 per million Btu and West Texas Intermediate oil spot price of $99.13 per barrel (5.8 million Btu per barrel) at the close of the trading markets on May 24, 2011.

[3] In this context, primary production refers to oil produced both by the reservoir's inherent pressure and by water-injection. Typically, the industry refers to primary production as being driven by the inherent reservoir pressure, secondary production as being driven by water-injection, and tertiary production (EOR) as being driven by the injection of steam, gases, and/or chemical surfactants.

[4] The oil produced from shale rock is different and distinct from the oil created from "oil shale" rock. Oil shale rock contains solid (non-liquid) kerogen hydrocarbon molecules that must be broken down through the application of heat and/or pressure into the smaller, liquid hydrocarbons associated with conventional oil. In contrast, the oil produced from shale rock is already present in the rock in gaseous and/or liquid form, including natural gas liquids and condensates. See Unconventional Oil Topic Paper for more on this subject.

Although this segment accounts for 56 percent of 2010 U.S. oil production, it accounts for only 52 percent of the traditional U.S. oil resource base due to its advanced maturity. It is estimated to hold only 38 percent of total U.S. undiscovered oil resources and those resources are relatively concentrated, with the Gulf Coast, Rocky Mountains, and West Coast together representing 80 percent.

Even though some of these regions have considerable primary oil resources yet to be discovered, as a whole, the onshore lower-48 resource base has been largely discovered and produced. This conclusion is supported by estimates that 71 percent of the remaining onshore, lower-48 traditional resource base is in the proved and inferred reserve categories that pertain to existing oil fields currently in production. This conclusion is reinforced by the fact that total U.S. oil production peaked in 1970 at 9.6 million barrels per day, sourced primarily at that time from onshore lower-48 fields. It is reasonable to infer that future oil production from the segment will depend heavily on increased recovery from existing and abandoned fields. Further recovery from these fields will largely depend upon the economic viability of EOR and recognition of non-traditional resources, which will be driven by oil price, technology, and regulatory policy.

Table B2

U.S. Technically Recoverable Oil Resources
As of January 1, 2009
(billion barrels)

Region	Proved Reserves	Inferred Reserves	Undiscovered Resources	Total	Percent Undiscovered
Onshore Conventional Oil					
Northeast	0.2	0.2	0.7	1.1	64 %
Gulf Coast	1.5	3.1	6.5	11.0	59 %
Midcontinent	1.2	7.1	5.4	13.6	40 %
Southwest	4.8	23.4	2.6	30.7	8 %
Rocky Mountains	2.5	6.7	2.1	11.3	18 %
West Coast	2.6	7.3	2.3	12.1	19 %
Subtotal	**12.7**	**47.6**	**19.5**	**79.9**	**24 %**
Tight & Shale Oil	NA	2.5	31.6	34.1	93 %
Onshore Lower-48 Subtotal	**12.7**	**50.1**	**51.1**	**113.9**	**45 %**
Alaska & Offshore	7.8	12.4	84.7	105.0	81 %
U.S. Total	**20.6**	**62.5**	**135.8**	**218.9**	**62 %**
Conventional Onshore Lower-48 As a Percent of Total U.S.	**62 %**	**76 %**	**14 %**	**36 %**	

Source: U.S. Energy Information Administration, Annual Energy Outlook 2011 Projections
Notes: NA = Not Available; shale and tight oil proved reserves are included in the regional proved reserve volumes. Crude oil resources include lease condensates but do not include natural gas plant liquids or kerogen. Undiscovered oil resources in areas where drilling is officially prohibited are **not** included. For example, this table does not include the Arctic National Wildlife Refuge undiscovered oil resources of 10.4 billion barrels. Undiscovered resources in this table are "technically recoverable," which is the estimated volume of oil that can be produced with current technology. "Proved reserves" are those reported to the Security and Exchange Commission as financial assets. "Inferred reserves" are expected to be produced from existing fields over their lifetime, but which have not been reported as proved reserves.

Figure B2
U.S. Onshore Lower-48 Oil Resource Regions in Table B2

In Table B2, the onshore lower-48 inferred oil resource estimates by region **include** the oil resources potentially recovered through the use of tertiary and enhanced oil recovery techniques that inject steam, gases, or surfactants. Table B2 estimates do **not** include potentially producible oil resources that exist at or below the oil-water-contact point where the formation goes through a transition to a point where it holds more water and less oil ("residual oil zones"). These "residual oil zones" are known to be large and extensive but are not yet in a status which allows quantification. [5]

Like other emerging hydrocarbon formations, the residual oil zones (ROZ) have not had production-testing on a commercial scale, but could prove to hold many tens of billions of barrels of economically recoverable resources. All oil reservoirs have oil-to-water transition zones, generally of small thicknesses, that owe their origin to capillary forces. These forces cause gradual changes in the oil and water saturations beneath the main oil pay zone. The ROZ is a broader term that can include geologically swept intervals (either laterally or vertically) that can extend several hundred feet below the oil-water-contact point. ROZ can also exist in formations where there is no main pay zone. Current work suggests these situations have the potential to exceed the ROZ resources estimated to reside below existing oil plays. In the Permian Basin, ROZ are being developed using CO_2 EOR technology and one ROZ project is thought to be considering chemical flooding technology.[6]

U.S. Enhanced Oil Recovery Production

Enhanced oil recovery (EOR), also known as tertiary recovery, occurs in an oil field after primary recovery from natural reservoir pressure and secondary recovery from water injection (where applicable[7]) have achieved maximum economic recovery. EOR

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[5] See "Stranded Oil in the Residual Oil Zone," prepared by Meltzer Consulting, Inc., for Advanced International Resources, Inc. and the U.S. Department of Energy, February 2006; and "Assessing Technical and Economic Recovery of Oil Resources in Residual Oil Zones, prepared by Advanced Resources International, Inc. for the U.S. Department of Energy, February 2006.

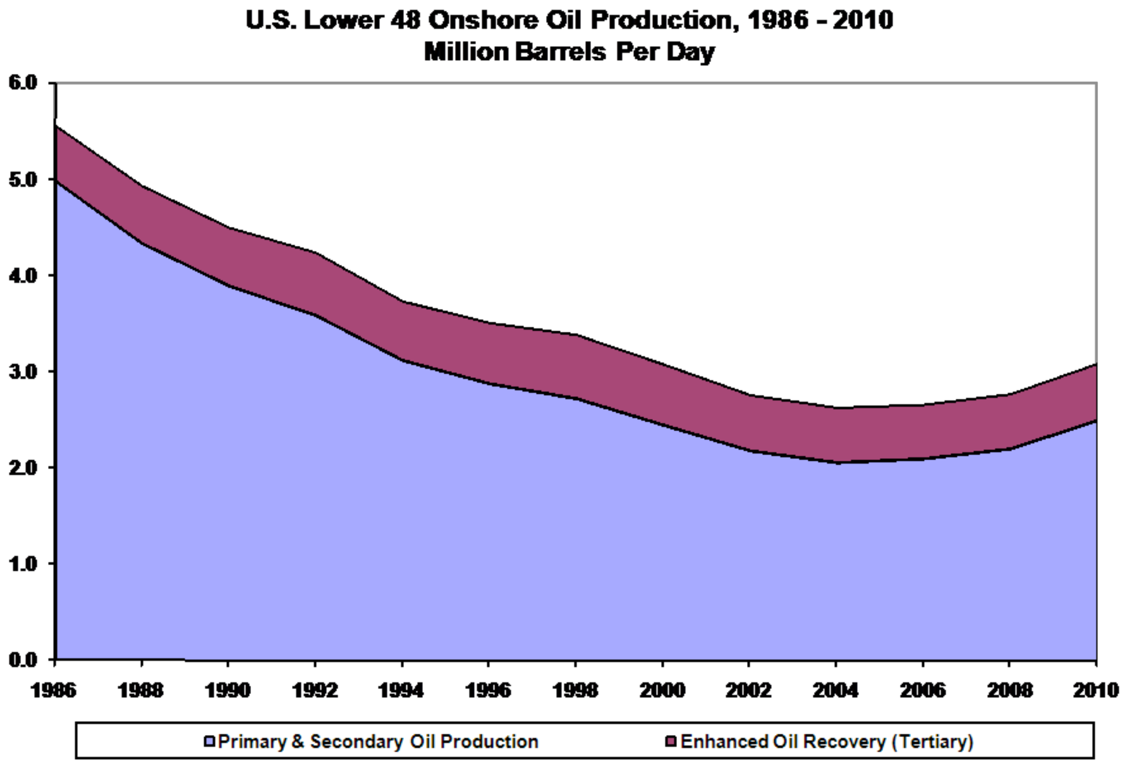
[6] See "CO2 EOR: A Model For Significant Carbon Reductions" by C. M. Ming and L.S. Melzer, presented at the symposium on the Role of Enhanced Oil Recovery in Accelerating the Deployment of Carbon Capture and Sequestration sponsored by MIT Energy Initiative and Bureau of Economic Geology at UT Austin, July 23, 2010

[7] Viscous heavy oil fields generally go directly from primary production to thermal EOR.

uses the injection of steam or hot water, chemical surfactants, or gases such as carbon dioxide (CO_2), nitrogen (N_2), or hydrocarbons (e.g., methane and/or natural gas liquids) to changes the physical properties of the oil. Typically EOR increases production by reducing the viscosity of the oil, which improves its mobility and increases the rate of migration to the production wells. EOR can also induce oil swelling and/or the creation of an immiscible gas cap, both of which force oil movement toward production wells. EOR processes increase near-term rates and allow recovery of reserves not producible with primary and secondary processes.

EOR production has been an increasing proportion of total onshore production as primary and secondary production have declined (Figure B3). In 1986, EOR production accounted for only 10 percent of onshore lower-48 oil production. From 2000 through 2010, EOR accounted for approximately 20 percent of the total (Table B3).

Figure B3



Sources: Oil and Gas Journal Biennial Enhance Oil Recovery Project Surveys and the U.S. Energy Information Administration.

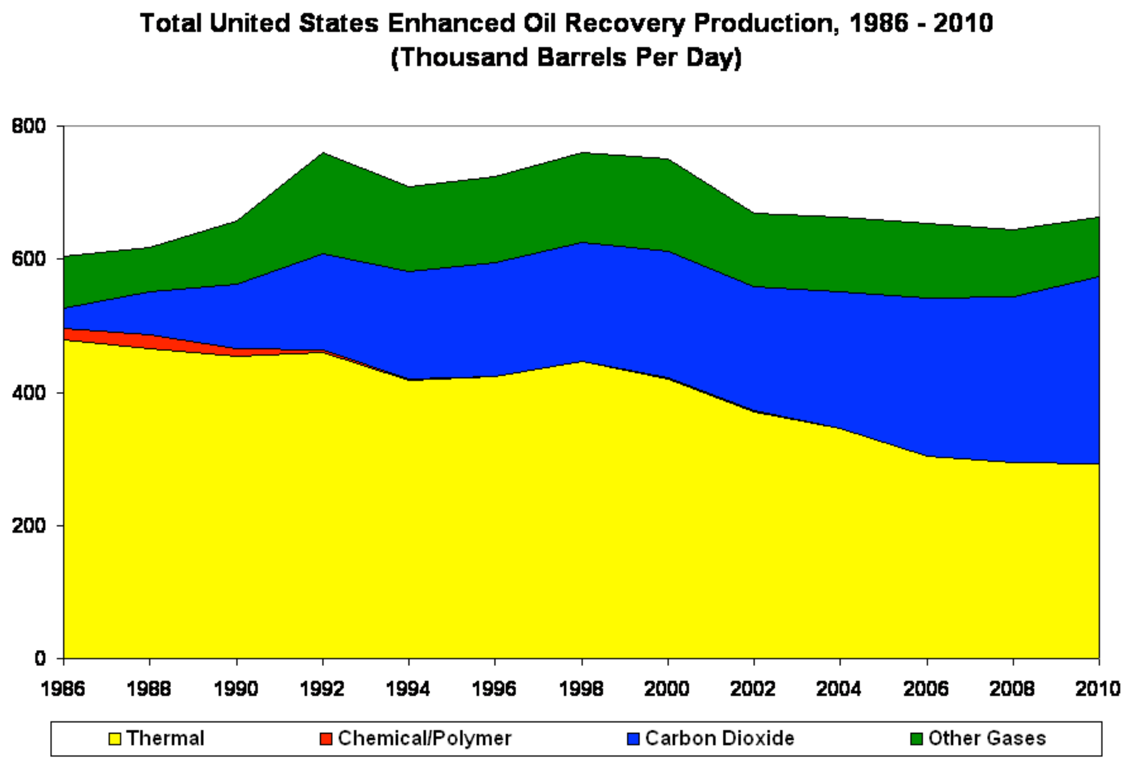
Table B3
U. S. Enhanced Oil Recovery Production, 2000 – 2010
By Technology Category
In Thousand Barrels Per Day

EOR Technology Category	**2000**	**2002**	**2004**	**2006**	**2008**	**2010**
Thermal Injection EOR						
Steam	418	366	340	287	275	273
In-Situ Combustion	3	2	2	13	17	17
Hot Water		3	3	4	2	2
Total Thermal EOR	420	371	346	304	294	292
Chemical Injection EOR						
Polymer/Chemicals	2	0	0	0	0	negligible
Other	negligible	negligible	negligible	0	0	0
Total Chemical EOR	2	negligible	negligible	0	0	negligible
Gas Injection EOR						
Hydrocarbon – Miscible and Immiscible	125	95	97	96	81	81
CO2 Miscible	189	187	206	235	240	272
CO2 Immiscible	negligible	negligible	negligible	3	9	9
Nitrogen	15	15	15	15	20	9
Total Gas EOR	329	297	318	349	350	371
Total U.S. EOR Production	751	669	663	653	644	663
Total Onshore Lower-48 EOR Production 1/	626	574	566	557	563	582
Total Onshore Lower-48 Oil Production	**3,078**	**2,758**	**2,628**	**2,660**	**2,769**	**3,087**
Total Onshore Lower-48 Oil Production, excluding EOR	**2,452**	**2,185**	**2,061**	**2,103**	**2,206**	**2,505**
EOR Percent of Total Onshore Lower-48 Oil Production 2/	20 %	21 %	22 %	21 %	20 %	19 %

Sources: Oil and Gas Journal Biennial Enhance Oil Recovery Project Surveys and the U.S. Energy Information Administration. A table entry of "negligible" indicates that the production volume was less than 0.5 thousand barrels per day. See Appendix A-1 for data from years 1986 through 1998.
1/ All Hydrocarbon – Miscible and Immiscible EOR Production is located either in Alaska or the offshore Gulf of Mexico and were subtracted from U.S. total to calculate onshore lower-48 EOR oil production.
2/ Based on Total Onshore Lower-48 EOR Production, which excludes Hydrocarbon EOR production.

Although total EOR production has been relatively stable during the past decade, CO_2 EOR volumes have increased while volumes from other EOR technologies, notably thermal EOR, have declined significantly (Figure B4).

Figure B4



Source: Oil and Gas Journal, Biennial Enhanced Oil Recovery Project Surveys

Thermal EOR has been applied primarily to the large, heavy oil fields in Southern California since the 1960s, with significant development during the 1970s and 1980s. Despite the very successful application of thermal EOR over the last four decades, thermal production continues to decline as these reservoirs deplete.

Although CO_2 EOR began in the 1970s, many of the projects currently in operation were begun in the mid-1980s with additional projects coming on-line thereafter. By 2010, CO_2 EOR production constituted almost half of total onshore lower-48 EOR production, whereas in 1986 it represented only 5 percent.

Current CO_2 EOR production is primarily limited by access to affordable CO_2 supplies with secondary issues of technical personnel capability, financial strength and the ability to integrate resources by existing owners. Approximately 75 percent of the CO_2 currently supplied to EOR producers comes from natural, relatively pure underground reservoirs. The majority of additional CO_2 supplies come from natural gas processing plants located near EOR production areas. The supply of CO_2 could be increased by developing new natural, pure reservoirs, but more likely, by capturing and transporting more CO_2 from gas processing plants, industrial facilities, refineries, and fossil fuel power plants.

In all cases, new pipelines or other transportation infrastructure will be required to connect these sources to EOR production areas. Emerging greenhouse gas emissions laws and regulations could incentivize CO_2 emitters to work collaboratively with EOR producers to capture and utilize CO_2 for EOR and eventual geologic sequestration[8] in oil and gas reservoirs. This is further discussed in subsequent sections of this topic paper.

In 2010, hydrocarbon-injected EOR accounted for 81,000 barrels per day of oil production, with all of that production occurring either on the Alaska North Slope or in the Gulf of Mexico. Hydrocarbon EOR is primarily associated with the re-injection of methane and natural gas liquids in areas where delivering these products to distant markets is uneconomic. For example, natural gas and light hydrocarbons are re-injected into Alaska North Slope fields due to the lack of a pipeline connection to Canadian and U.S. lower-48 gas markets.

The decline in hydrocarbon EOR production from 2000 to 2010 primarily reflects the depletion of the Alaska North Slope oil fields and is expected to continue. The current price differential between oil and natural gas and limited availability of CO_2 could make the use of methane injection more attractive in some conventional onshore oil reservoirs.

In general, the further application of thermal and hydrocarbon EOR technology is expected to be limited, while the application of CO_2 EOR technology is expected to expand.

Potential from Enhanced from Oil Recovery (EOR)

The potential from EOR production is best illustrated in Table B4 comparing the original oil in place (OOIP), expected oil recovery through primary and secondary production (i.e., reservoir pressure displacement and water flooding), and the volumes of

[8] The term "sequestration" is used here to indicate that the CO2 is intended to be permanently stored in the reservoir.

remaining oil in place (ROIP). For every percentage point increase in recovery of OOIP achieved with EOR, about 5 billion barrels of oil would be produced in the onshore lower-48 region and about 6 billion barrels produced for the entire United States. Although EOR recovery factors vary by field, an incremental 5 to 15 percent recovery of OOIP is reasonable for EOR technologies.[9]

Table B4
Estimated United States Original Oil In Place
And Primary and Secondary Recovery Rates

Region/Basin	Original Oil In Place (OOIP)	Primary and Secondary Production Recoverability		Remaining Oil In Place (ROIP)	
	(billion bbl)	(billion bbl)	% of OOIP	(billion bbl)	% of OOIP
Appalachia (WV,OH,KY,PA)	14.0	3.9	28%	10.1	72%
Illinois/Michigan	17.8	6.3	35%	11.5	65%
Gulf Coast (AL,FL,MS,LA)	44.4	16.9	38%	27.5	62%
Texas (Central & East)	109.0	35.4	32%	73.6	68%
Permian Basin (W. TX, NM)	95.4	33.7	35%	61.7	65%
Mid-Continent (OK,AR,KS,NE)	89.6	24.0	27%	65.6	73%
Williston Basin (MT,ND,SD)	13.2	3.8	29%	9.4	71%
Rocky Mountains (CO,UT,WY)	33.6	11.0	33%	22.6	67%
California	83.3	26.0	31%	57.3	69%
Total Onshore, Lower-48	**500.3**	**161.0**	**32%**	**339.3**	**68%**
Alaska and Offshore	95.4	34.7	36%	60.7	64%
Total United States	**595.7**	**195.7**	**33%**	**400.0**	**67%**

Source: "Storing CO2 with Next Generation CO2-EOR Technology," prepared by Advanced International Resources, Inc. for the National Energy Technology laboratory of the U.S. Department of Energy, DOE/NETL-2009/1350, January 9, 2009, Table 3, page 12.

[9] "Carbon Dioxide Enhanced Oil Recovery", National Energy Technology Laboratory, U.S. Department of Energy, March, 2010, page 9. http://www.netl.doe.gov/technologies/oil-gas/publications/EP/small_CO2_EOR_Primer.pdf

Technically recoverable crude oil volumes under the best of circumstances have been estimated for certain EOR technologies, based on oil reservoir properties. For example, an analysis sponsored by the Department of Energy estimated that between 67 and 100 billion barrels of onshore lower-48 oil is producible through the application of miscible CO_2 EOR technology (Table B5). This would represent a 75 to 115 percent increase relative to the onshore lower-48 resource estimates shown in Table B2.

Table B5
Onshore Lower-48 Estimated Incremental Oil Recovery Volumes for Miscible CO_2 EOR Technically Recoverable Resources

Region/Basin	"Best Practices" Technology (Billion Barrels)	"Next Generation" Technology (Billion Barrels)
Appalachia	1.6	2.6
California	6.3	10.0
Gulf Coast	7.0	7.4
Illinois and Michigan	1.2	3.2
Mid-Continent	10.6	17.0
Permian	15.9	28.0
Rocky Mountains	3.9	7.1
Texas, East/Central	17.6	20.0
Williston	2.5	5.2
Total Onshore Lower-48	**66.6**	**100.5**

Source: Op. Cit. "Storing CO2 with Next Generation CO2-EOR Technology," Table 2, page 5.

These estimates and approximations are not a definitive assessment of the potential for future EOR production. The "economic" potential for incremental oil resources from EOR will be determined by the future price of oil, the future cost of deploying EOR technologies, regulatory policies, and feasibility of applying various EOR technologies to existing and abandoned oil fields.

The application of EOR technologies to abandoned oil fields could prove to be difficult because much of the well and production data for those fields may be missing or incomplete. Detailed wellbore condition and plugging and abandonment information may be difficult to locate. Similarly, there might be little information regarding the oil reservoir's current properties, such as, porosity, permeability, pressure, water saturation, etc. Another hurdle to applying EOR technologies to abandoned fields is the likelihood of having to inject hot water, steam, or gases into the reservoir for an extended period of time prior to realizing the production of incremental oil. The longer the time required to increase field pressure and oil mobility, the lower the rate of return on the EOR investment, all else being equal.

Conversely, new, untraditional resources such as tight, oil source formations or the ROZ can add significant volumes to estimated OOIP. It is possible that some of these formations have properties which make them more amenable to EOR than those already produced. Continued laboratory and field work is necessary to extend recovery potential.

Importantly, even after discounting Table B5 values for technical and commercial concerns, the targets are potentially large enough to make a material contribution to EOR production over the next 25 to 40 years.

Projections of Lower-48 Oil and EOR Production

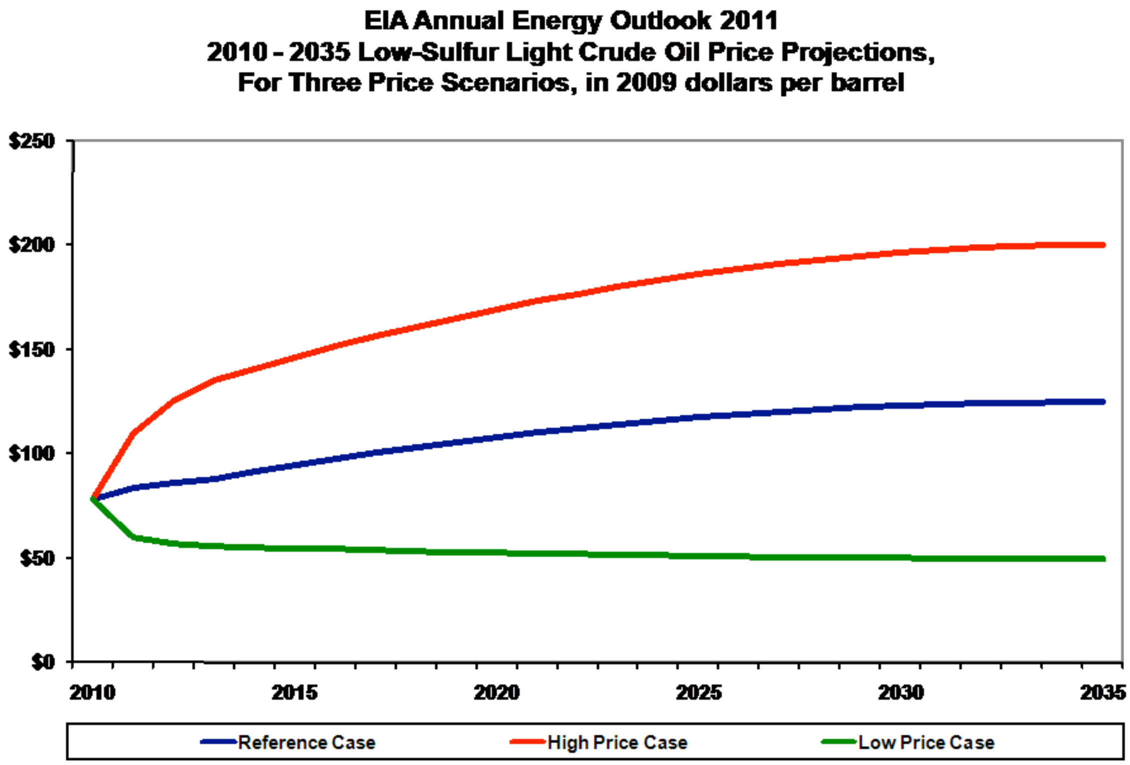
There are relatively few projections publicly available which focus on conventional US lower 48 production potential. By far the most detailed is that provided annually by the U.S. Energy Information Administration (EIA) in its *Annual Energy Outlook 2011* (AEO2011). ARI, as part of studies on CO_2 EOR and carbon storage, has also made projections. As part of the larger NPC study, blinded data was solicited from production and consulting companies. The following discussion will focus primarily on the EIA AEO2011 projections, as they are the most extensive.

The AEO2011 provides projections of onshore lower-48 primary/secondary and tertiary (EOR) oil production. Projections are sensitive to crude oil prices, which are exogenously assumed in the National Energy Modeling System (NEMS) computer runs using three different crude oil price scenarios –Reference, High Price, and Low Price cases.[10] Figure B5 displays the crude oil price trajectories for the three price cases.[11]

[10] World oil prices are difficult to project because world oil production and demand are subject to many forces. Production is directly and indirectly determined by sovereign state energy policy - directly in the form of OPEC oil production limits, and indirectly through taxation, leasing policies, environmental regulations, and through limitations placed on foreign investment. Demand is affected by economic growth rates, currency exchange rates, fuel and investment subsidies and substitution effects.

[11] The AEO2011 price cases do not assume any new and future domestic legislation and/or regulations, particularly the imposition of carbon dioxide emission limits, taxes, or cap-and-trade requirements.

Figure B5



Source: U.S. Energy Information Administration, Annual Energy Outlook 2011 Projections

These price projections are intended to represent the range of oil prices that might occur in the future. In the Reference Case, low-sulfur light crude oil prices rise slowly through 2035, reaching $124.94 per barrel (in 2009 dollars). In the High Price Case, prices increase rapidly to $169.08/bbl in 2020, and thereafter rise more slowly to reach $199.95 in 2035. In the Low Price Case, prices drop below $55 per barrel after 2015, and then very slowly decline to $50.07 per barrel by 2035.

<u>AEO2011 Reference Case Projections</u>

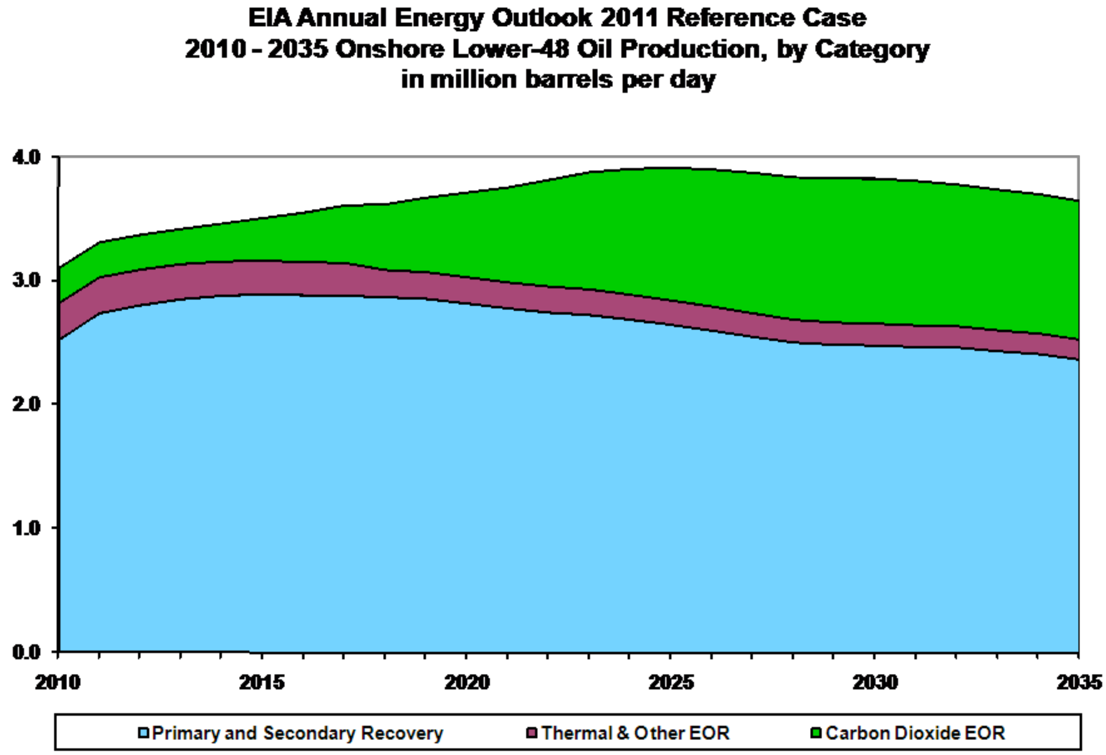
The AEO2011 Reference Case projections assume the indefinite continuation of current State and Federal law and regulation. These projections, for example, do not assume that man-made greenhouse gas emissions will be limited, taxed, or otherwise regulated at some point in the future. Similarly, corporate income tax law is assumed to remain unchanged. Consequently, the development of new oil production capacity, such as CO_2 EOR productive capacity, is determined by future oil prices in relation to the expected future cost of developing new production, based on current law and regulation, and is not predicated by any change in State and Federal law and regulation sometime in the future.

In the Reference Case, total onshore lower-48 oil production is projected to grow slowly from 3.1 million barrels per day in 2010 to a peak of 3.9 million barrels per day in 2025, followed by a decline to 3.7 million barrels per day in 2035 (Figure B6). The growth in oil production is largely attributable to increased CO_2 EOR production, which is projected to increase from 282,000 barrels per day in 2010 to a peak production of 1.2 million barrels per day in 2030, followed by a decline to 1.1 million barrels per day in 2035. The slight decline in CO_2 EOR oil production at the end of the projection is attributable both to the relatively flat oil price projection from 2030 through 2035 and the lack of additional reservoirs for which the application of CO_2 EOR at those oil prices would be economic. Even so, in the longer term, the growth in CO_2 EOR oil production is responsible for the overall rise in onshore lower-48 oil production.

Primary/secondary oil production rises from 2.5 million barrels per day in 2010 to 2.9 million barrels per day in 2015 as tight and shale oil production rapidly grow in the near-term. Without the growth in tight and shale oil production, total primary/secondary oil production would decline much more rapidly. After 2015, primary/secondary oil production is supported by tight and shale oil production, so that total primary/secondary production declines slowly to approximately 2.4 million barrels per day in 2035 as the largest oil fields are depleted. With higher oil prices over time, ever smaller oil fields are developed and produced, but these new fields are insufficient to offset the decline in the largest onshore lower-48 fields without the increased contribution from CO_2 EOR.[12]

[12] Other "new" oil is produced from new ever-smaller reservoirs in existing fields and from ever-smaller pockets of oil in currently producing reservoirs. Regardless of the geologic attributes of the "new" oil production, the diminishing returns of new primary/secondary oil production drilling is insufficient to offset the overall depletion decline in onshore, lower-48 primary/secondary oil production.

Figure B6



Source: U.S. Energy Information Administration, Annual Energy Outlook 2011 Projections
Figure includes tight and shale oil production in the primary and secondary recovery category.

Figure B6 depicts a "Thermal & Other EOR" production component, which is mostly comprised of thermal EOR located in Southern California. This EOR production declines from about 0.3 million barrels per day in 2010 to about 0.2 million barrels per day in 2035. Like primary and secondary production, the slow rise in Reference Case oil prices encourages the incremental development of small thermal EOR projects and prolongs production in existing EOR fields. However, neither the incremental development nor prolonged production is able to offset the overall production decline in Thermal & Other EOR.

The Reference Case EOR production volumes shown in Figure B6 pertain only to the onshore lower-48 region. The application of CO_2 EOR technology is expected to remain mostly an onshore technology. The high cost of applying CO_2 EOR in both the offshore and in Alaska generally precludes its economic viability in these regions. The distance of these areas from affordable CO_2 supplies and the expensive infrastructure required make the application of CO_2 EOR unlikely on a large scale.

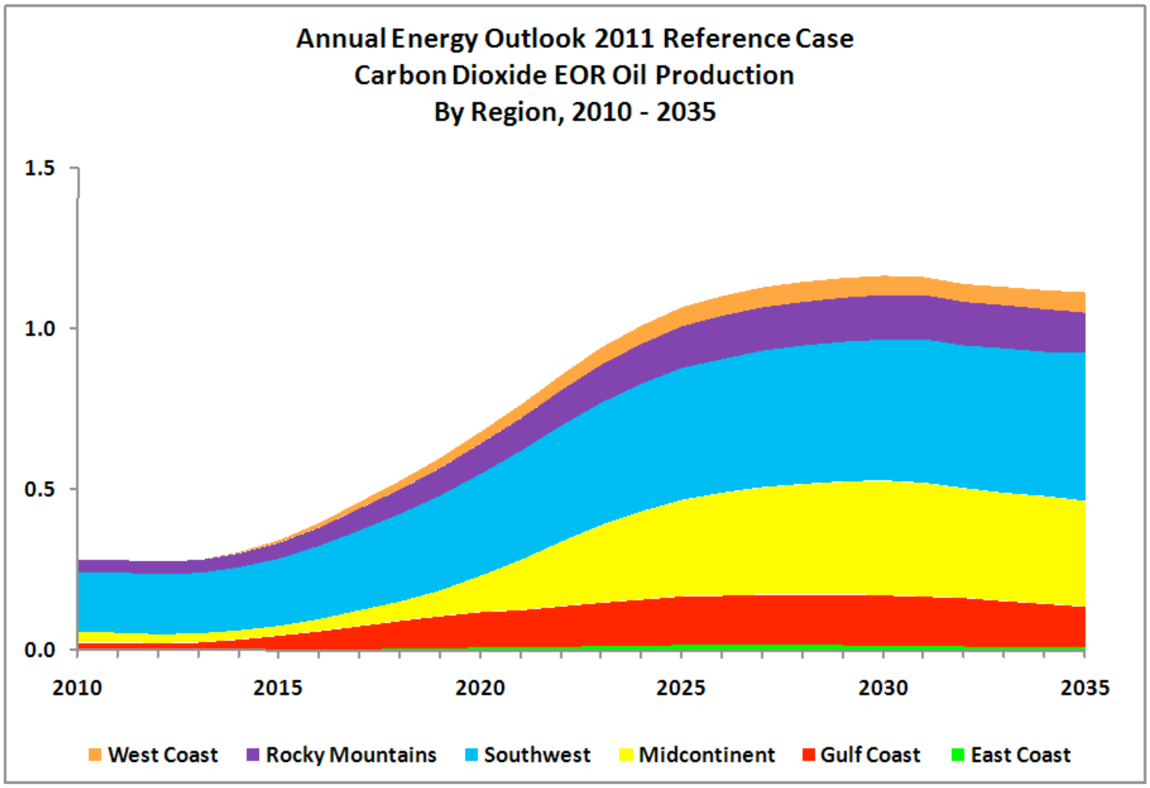
In the AEO2011 projections, other EOR technologies, such as microbial and chemical surfactants, are not expected to contribute material volumes of oil production. Microbial EOR has not been proven to be economically viable in the limited field testing that has been conducted to-date. Chemical surfactant EOR technology is much more promising. [13] Because these surfactants are petrochemical products, however, the cost of application rises with the price of crude oil. In the past, the economic feasibility of surfactant EOR generally seemed to be at an oil price just beyond prevailing levels. Technological advancements could eventually make these EOR technologies economically viable in the future.

Figure B7 shows the Reference Case CO_2 EOR production projections for the six onshore lower-48 regions identified in Figure B2. CO_2 EOR production grows from about 282,000 barrels per day in 2010 to about 1.2 million barrels per day in 2030 before declining to 1.1 million barrels per day in 2035.[14] The Southwest region (Permian Basin) is the largest EOR producer throughout the projection time frame. Moreover, the Southwest is one of the few regions to show continuous CO_2 EOR production growth through 2035. Southwest CO_2 EOR production grows from 186,000 barrels per day in 2010 to about 460,000 barrels per day in 2035.

[13] This assessment is not based directly on the AEO2011 projections, but rather represents the collective judgment of the NPC Subgroup.

[14] Appendix A-3 shows a "snapshot" of regional CO_2 EOR production for the AEO2011 Reference Case.

Figure B7



Source: U.S. Energy Information Administration, Annual Energy Outlook 2011 Projections

Mid-Continent region CO_2 EOR production grows from 32,000 barrels per day in 2010 to a peak production of about 360,000 barrels per day in 2030, and thereafter declines slightly to about 330,000 barrels per day in 2035. The peak and subsequent production decline results both from relatively constant post-2030 oil prices and from the limited number of potential reservoirs to which CO_2 EOR technology can be applied.

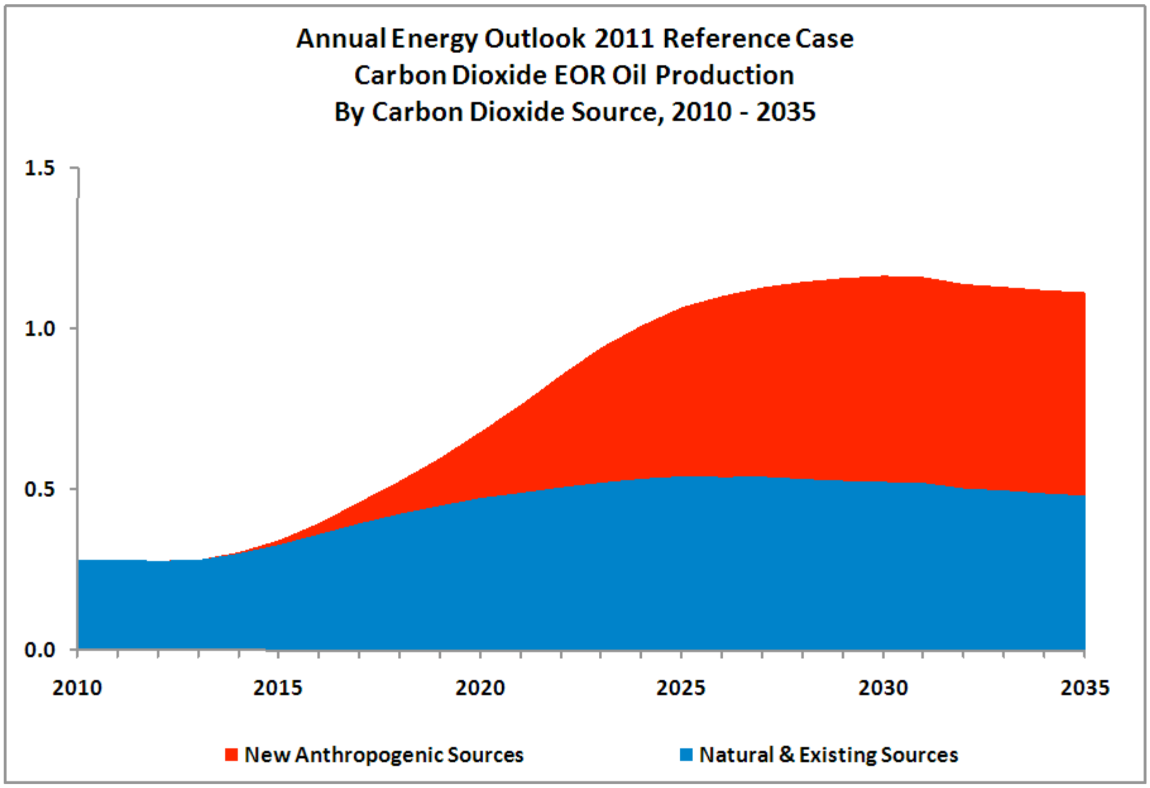
Collectively, the Mid-Continent and Southwest regions account for 70 percent of total onshore lower-48 CO_2 EOR production in 2035. Most of the remaining CO_2 EOR production is projected to occur in the Coastal Gulf of Mexico and Rocky Mountain regions, with each region contributing about 125,000 barrels per day or 11 percent of total CO_2 EOR production in 2035. Both regions are projected to reach peak CO_2 EOR production in the 2030 timeframe, with the Gulf Coast peaking at about 160,000 barrels per day in 2028 and the Rocky Mountain peaking at about 140,000 barrels per day in 2030.

West Coast CO_2 EOR oil production rises to about 60,000 barrels per day in 2025 and remains relative constant through 2035, accounting for 6 percent of total CO_2 EOR oil production in 2035. The East Coast CO_2 EOR oil production is negligible, rising to just under 20,000 barrels per day in 2025, and then falling to about 10,000 barrels per day in 2035.

Future CO_2 EOR production is largely driven by the availability of affordable CO_2 supplies, which is primarily a function of supply location and purity. Generally, natural CO_2 from large underground reservoirs containing trillions of cubic feet of virtually pure CO_2 is the most economic source of supply. Industrial processes that create relatively pure CO_2 such as natural gas processing (typically the next most economic) and hydrogen, ammonia and ethanol plants can usually be cost effective sources. More dilute, cement plant sources may also be viable, but require added cost to remove contaminants.

The most expensive sources of supply are normally dilute anthropogenic CO_2 emissions that result from the atmospheric combustion of fossil fuels, such as coal and natural gas. These sources are expensive because the flue gases are about 80 percent nitrogen (N_2) and less than 20 percent CO_2. Because high amounts of N_2 in the injection stream significantly reduces oil recovery, the purity of CO_2 transported and delivered to an EOR oil field must be high. The cost of separating the CO_2 from the N_2 and other flue gases significantly increases the CO_2 cost from dilute sources. In the AEO2011 Reference Case, incremental EOR production growth to 2015 is served mostly by natural and existing CO_2 sources, with longer term EOR production growth coming mostly from the purer anthropogenic CO_2 sources (Figure B8). With the exception of CO_2 captured from gas processing plants, dilute CO_2 sources are not projected to provide CO_2 supplies to future CO_2 EOR projects. In general, the adoption of regulatory or financial incentives to capture and store anthropogenic CO_2 via EOR would be required to add supply.

Figure B8



Source: U.S. Energy Information Administration, Annual Energy Outlook 2011 Projections

Over the longer term, there is considerable uncertainty regarding the AEO2011 CO_2 EOR production projections. The greatest uncertainty in the AEO2011 CO_2 EOR production projections, aside from future oil prices, is the cost of capturing and purifying anthropogenic CO_2 emissions. Anthropogenic CO_2 sources are projected to account for about 630,000 barrels per day of EOR production in 2035 or 57 percent of total EOR production (Table B6). If pure and dilute anthropogenic CO_2 supply sources are not economic, future CO_2 EOR development would depend solely on natural and existing CO_2 sources. In this situation, CO_2 EOR production would be expected to reach 540,000 barrels per day in 2025 and thereafter decline to about 480,000 barrels per day in 2035.

The absence of affordable anthropogenic CO_2 would significantly reduce EOR across all six regions, with the East Coast, Midcontinent, and West Coast almost 100 percent reliant on anthropogenic sources in 2035 (Table B6). Midcontinent EOR production would be particularly hard hit due to an absence of anthropogenic CO_2, which would reduce its projected 2035 EOR production by about 300,000 barrels per day.

Table B6
Annual Energy Outlook 2011 Reference Case
2035 Regional Carbon Dioxide Enhanced Oil Recovery Production
By CO_2 Supply Source
(in thousand barrels per day)

Region	Natural CO2 Supply	Anthropogenic CO2 Supply	Total	Anthropogenic Percent of Total
East Coast	negligible	11	11	99 %
Gulf Coast	91	35	126	28 %
Midcontinent	23	305	328	93 %
Southwest (Permian)	311	151	462	33 %
Rocky Mountains	57	68	125	55 %
West Coast	-	63	63	100 %
U.S. Total	**482**	**633**	**1,115**	**57 %**

Source: U.S. Energy Information Administration, Annual Energy Outlook 2011 Projections

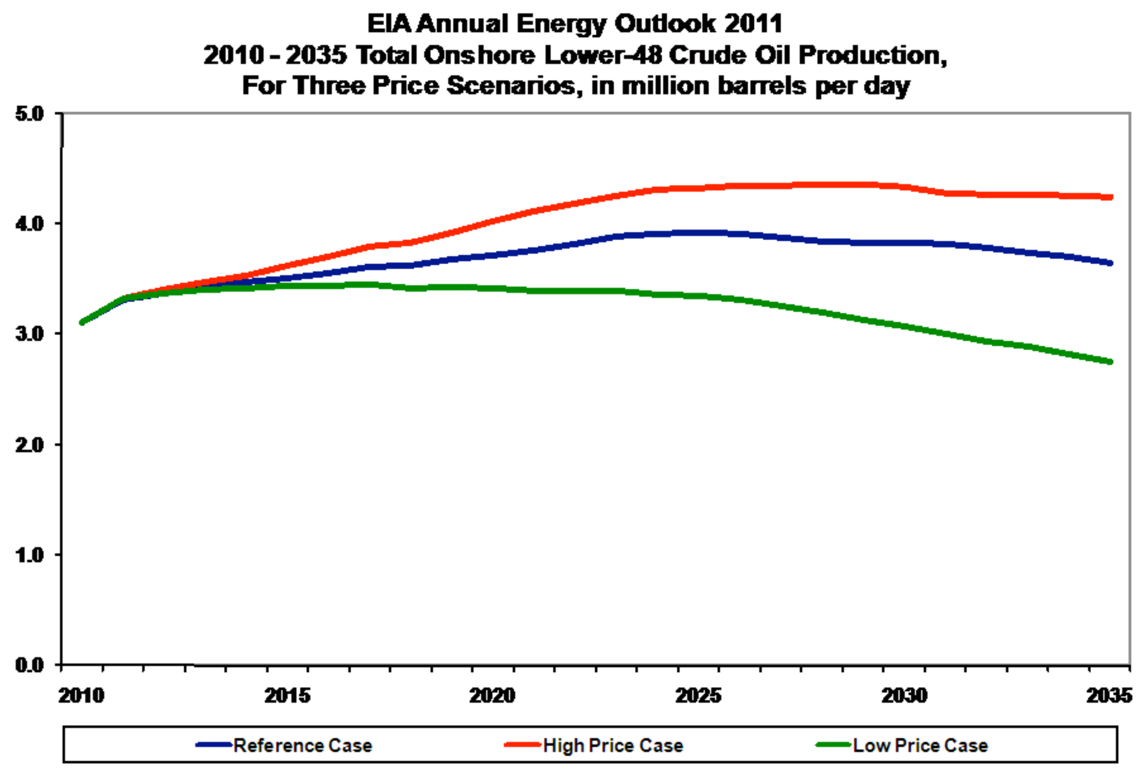
Even those regions that have historically relied on natural CO_2 sources for EOR will rely on anthropogenic sources for a considerable portion of their total CO_2 supply by 2035. For example, the Southwest's (Permian Basin) EOR production would be reduced by about 150,000 barrels per day in 2035 in the absence of anthropogenic sources. Similarly, Rocky Mountain EOR production would be about 70,000 barrels per day less.

Because the future growth in CO_2 EOR production is primarily due to the use of anthropogenic CO_2 for EOR, and because the high level of projected onshore conventional oil production is due to the projected growth in CO_2 EOR production, the absence of affordable anthropogenic CO_2 sources in the future would result in a much more pronounced decline in U.S. onshore conventional oil production than is projected in the AEO2011 Reference Case.

AEO2011 High Price and Low Price Case Projections

Because future oil prices are highly uncertain, it is instructive to consider the onshore lower-48 oil projections for the AEO2011 High and Low Price Cases. Although the AEO2011 oil price cases portray significantly different oil price scenarios (Figure B5), the corresponding production projections (Figure B9) do not show the same degree of variation.[15]

Figure B9



Source: U.S. Energy Information Administration, Annual Energy Outlook 2011 Projections

The smaller variation in production relative to the variation in oil prices results for the following reasons:

1. The steady depletion of large existing oil fields dominates the overall production trend. Although varying prices impact both the length of time that existing fields remain in production and the extent to which new small reservoirs and fields are discovered and developed, both effects exhibit diminishing returns, such that the overall base oil production trend is not greatly affected.
2. The impact of oil prices on projected thermal EOR production is limited because the best prospects in the largest oil fields have likely already been developed. Even though oil price variation impacts existing projects and the extent to which

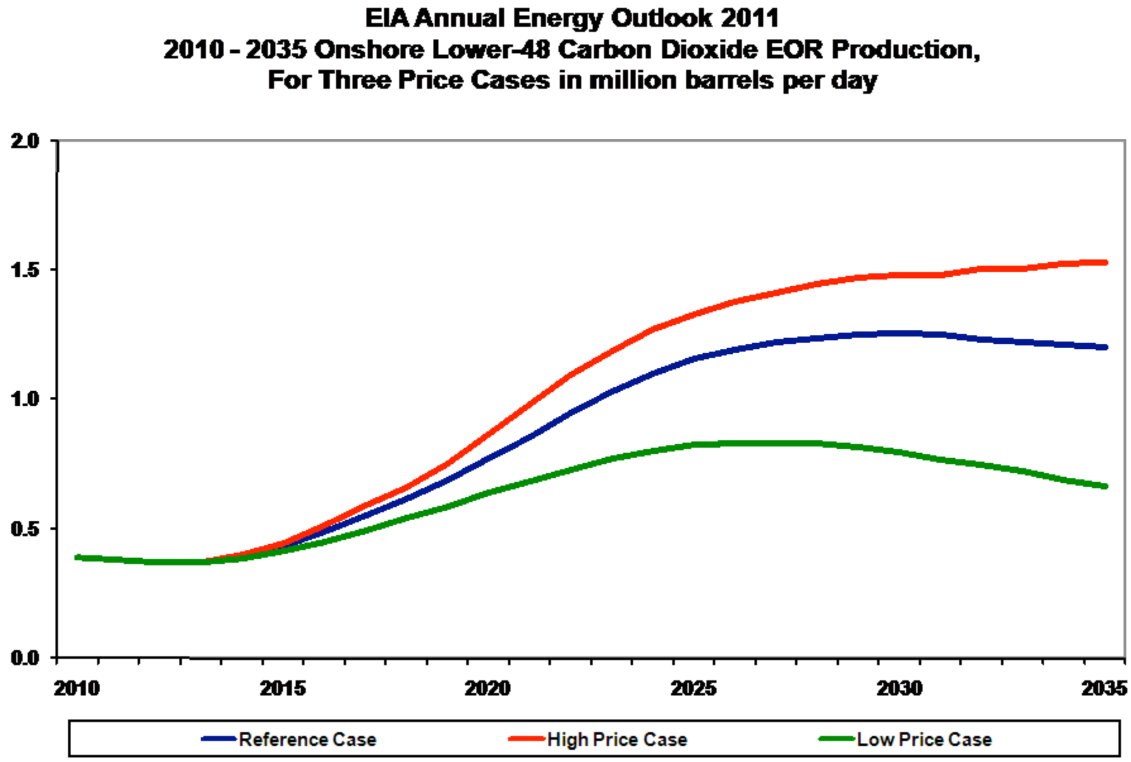
[15] See Appendix A-2 for oil price and production "snapshots" for the AEO2010 Reference, High Price, and Low Price cases for the years 2010, 1015, 2025, and 2035.

new (smaller) projects are initiated, overall impact is limited by diminishing returns. The Steam-Oil-Ratio (SOR) and therefore the extraction costs of the remaining thermal opportunities is higher than for prior development projects.

3. CO_2 EOR production is currently constrained by the availability of affordable CO_2 supplies. As oil prices increase over time, CO_2 EOR production is expected to increase because more CO_2 supply sources become economic, albeit with a time lag.
4. Because the permitting and construction associated with building new CO_2 infrastructure is time consuming (i.e., several years or more), the adoption of CO_2 EOR technology is delayed somewhat relative to the rise in oil prices.
5. As oil prices rise, CO_2 EOR is applied to incrementally smaller oil reservoirs and to reservoirs more distant from CO_2 supply sources or with less than optimal reservoir characteristics. This leads to diminishing returns with the application of the technology.
6. As the least expensive sources of CO_2 are applied to EOR, the incremental cost of CO_2 supply, primarily dilute anthropogenic sources, increases dramatically. Consequently, higher oil prices are matched by higher CO_2 supply costs, including transportation costs to deliver more distant CO_2 supplies to EOR fields. Consequently, there are diminishing returns to CO_2 EOR production as oil prices rise, which also explains why the greatest impact on CO_2 EOR production occurs between the Low and Reference price cases.
7. At higher oil prices, long term CO_2 EOR projects compete for capital and other resources against other onshore oil projects, which go into production more quickly. This results in the increased production from CO_2 EOR lagging behind increases in other oil production as the oil price increases.

The collective impact of the CO_2-related limitations set forth above tempers the positive impact of higher oil prices on CO_2 EOR oil production, as shown in Figure B10.

Figure B10



Source: U.S. Energy Information Administration, Annual Energy Outlook 2011 Projections

1.2. Canada

<u>Canada Historical Onshore Light/Medium Conventional Oil Production</u>

In the NPC study, Canadian oil production is captured in four categories: onshore light/medium oil production, unconventional (includes oil sands and heavy oil), offshore and arctic oil production. This portion of the study will focus exclusively on Canadian onshore light/medium oil production, including pentanes and condensates, and enhanced oil recovery production. Total onshore light/medium oil production peaked in the 1990s at about 1.1 million barrels per day and has subsequently declined to about 0.7 million barrels per day in 2010 (Table C1).

Table C1

1990 – 2010 Canadian Onshore Light/Medium Crude Oil Production Including Enhanced Oil Recovery Production (in million barrels per day)

	1990	1995	2000	2005	2010
Light/Medium Crude Oil	0.94	0.94	0.73	0.58	0.57
Pentanes and Condensates	0.12	0.16	0.19	0.16	0.13
Subtotal	1.06	1.10	0.93	0.74	0.70

Sources: Canadian Association of Petroleum Producers, "Canadian Crude Oil Production and Supply Forecast 2006 – 2020," May 2006, Table 1, Page 3 and "Canadian Crude Oil Forecast, Markets & Pipelines," June 2011, Excel Spreadsheet in Appendix A.

Canada Light/Medium Conventional Oil Resources

Approximately, 8.7 billion barrels of undiscovered light/medium oil resources remain in Canada (Table C2). Of the total, 84 percent of the remaining light/medium oil resources are located onshore, with Alberta and Saskatchewan holding approximately 65 and 13 percent, respectively.

Table C2

Canada Potential Light/Medium Conventional Oil Resources As of 2006, in billion barrels

Region	Light/Medium Crude Oil	Percent of Total
Alberta	5.7	65 %
British Columbia	0.5	6 %
Saskatchewan	1.1	13 %
Subtotal - Onshore	**7.3**	**84 %**
Eastern Offshore	1.4	16 %
Total Canada	**8.7**	**100 %**

Sources: Natural Resources Canada, "Canada's Energy Outlook: The Reference Case 2006," Ottawa, Canada, 2006, page 35. Table US1. Not reproduced in affiliation with the Government of Canada

Canada Enhanced Oil Recovery Production

In the past, Canadian enhanced oil recovery (EOR) production has been a relatively modest contributor to onshore light/medium crude oil production, equal to about 9 percent of total production in 2010 (Table C3). EOR's share of total onshore conventional oil production, however, would grow if EOR production remains constant / grows, or if non-EOR light/medium oil production continues to decline as it has since the mid-1990s (Table C1).

Table C3
Canada Enhanced Oil Recovery Production, 2000 – 2010
By Technology Category
In Thousand Barrels Per Day (unless otherwise noted)

EOR Technology Category	**2000**	**2002**	**2004**	**2006**	**2008**	**2010**
Thermal Injection EOR						
Steam	2.9					
In-Situ Combustion	6.3	6.3	6.3	6.3	4.8	4.8
Hot Water						
Total Thermal EOR	9.2	6.3	6.3	6.3	4.8	4.8
Chemical Injection EOR						
Polymer/Chemicals	0.7				20.0	25.0
Other						
Total Chemical	0.7				20.0	25.0
Gas and Other						
Hydrocarbon - Miscible and Immiscible	51.9	35.0	35.0	25.5	24.2	22.1
CO_2 Miscible	0.3	0.7	7.2	7.2	17.2	11.7
CO_2 Immiscible						
Nitrogen						
Other				1.0	1.0	1.0
Total Gas EOR	52.1	35.7	42.2	33.7	42.4	34.8
Total Onshore Canada EOR Production	**62.0**	**42.0**	**48.5**	**40.0**	**67.2**	**64.6**
Total Onshore Canada Light/Medium Oil Production 1/	**NA**	**NA**	**NA**	**735.9**	**738.2**	**706.8**
EOR as a Percent of Total Onshore Light/Medium Oil Production	NA	NA	NA	5 %	9 %	9 %

Sources: Oil and Gas Journal Biennial Enhanced Oil Recovery Project Surveys and the Canadian Association of Petroleum Producers
1/ Includes condensates.

As of 2009, the volume of onshore Canadian light and medium original oil in place is estimated to be about 80 billion barrels (Table C4). Although the cumulative production of this light/medium oil is not known, a reasonable estimate of primary and secondary recovery would be about 30 percent or about 24 billion barrels, leaving an estimated 56 billion barrels of oil still in the reservoir. Based on these onshore Canadian original-oil-in-place volumes, every 1 percent increase in resource recovery translates into about 800 million barrels of additional production, which again illustrates the potential importance of applying enhanced oil recovery technologies to existing oil fields.

Table C4
Canada Original Light/Medium Oil in Place
As of 2009

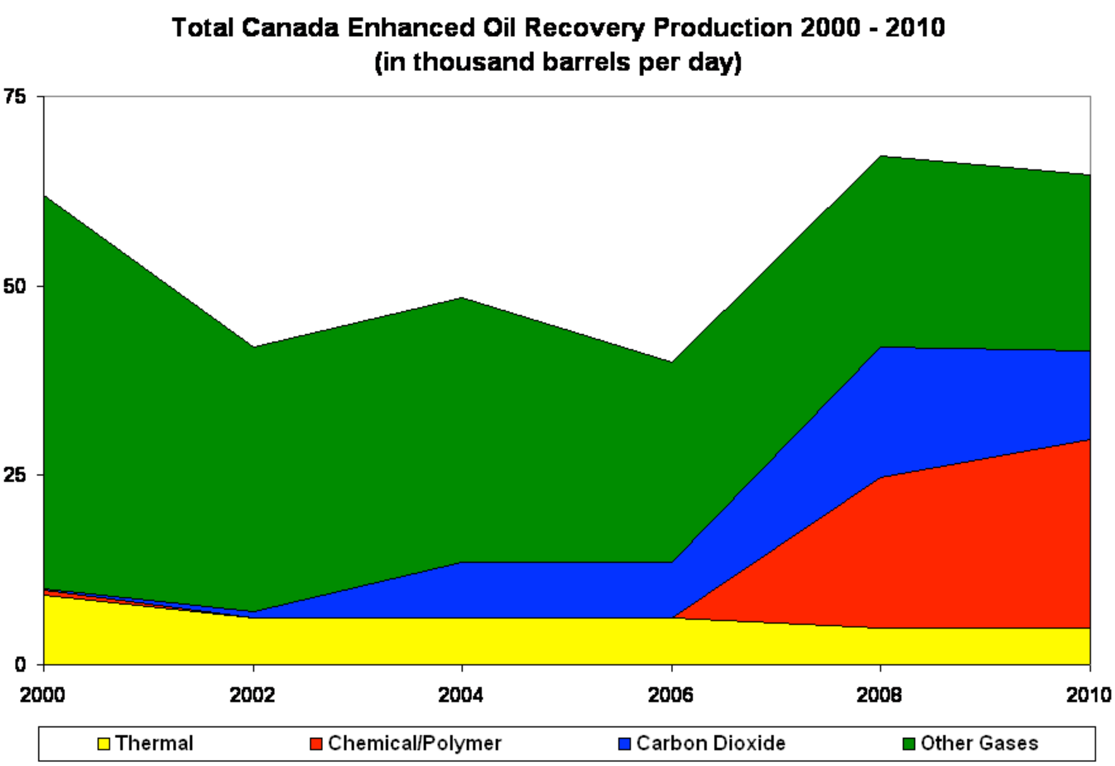
Province/Region	Original Oil in Place (billion barrels)	Percent of Total
Alberta	52.0	59 %
British Columbia	2.9	3 %
Manitoba	1.4	2 %
Ontario	0.6	1 %
Saskatchewan	21.9	25 %
Territories & Other Provinces	0.6	1 %
Total Onshore	**79.3**	**90 %**
Offshore	9.1	10 %
Total Canada	**88.4**	**100 %**

Source: Canadian Association of Petroleum Producers, *Statistical Handbook for Canada's Upstream Petroleum Industry*, May 2011, Table 2.11.1a; thousand cubic meters converted into billion barrels using a conversion factor of equal to (264.2 / (42 x 1E6)).

The EOR technologies employed in Canada have changed over time. Hydrocarbon-injection has declined, while carbon dioxide and chemical-surfactant injection increased (Figure C1). This changing profile of EOR technology over time can be traced to the application of particular EOR technologies in a few select fields. For example, during the early 2000s, hydrocarbon-injection EOR production was primarily from the Pembina and Rainbow Fields in Alberta. Recent polymer-injection EOR production comes from the Pelican Lake Field in Alberta, while CO_2 EOR production is primarily from the Weyburn and Midale Fields in Saskatchewan. Thermal-combustion EOR production is solely attributable to the Battrum Field in Saskatchewan.

CO_2 EOR is more prevalent in the United States than in Canada because large natural underground reservoirs of nearly-pure carbon dioxide exist that are relatively close to candidate U.S. lower-48 oil fields, making development projects economically viable. In Canada, the absence of large natural CO_2 reservoirs limits the use of CO_2 EOR technology and increases reliance on anthropogenic CO_2 sources. The CO_2 injected in the Weyburn and Midale Fields is transported 205 miles by pipeline from the Great Plains Synfuels Plant, located in Beulah, North Dakota. The Great Plains Synfuels Plant converts lignite coal into natural gas, liquids, and sulfur. This conversion process creates sizable volumes of CO_2 emissions of which roughly 50 percent or about 150 MMcf per day (8,000 metric tons per day)[16] is shipped to Saskatchewan oil fields for CO_2 EOR. If, at some time in the future, carbon dioxide capture technology is more extensively deployed at Canadian electric generation and industrial plants, then the application of CO_2 EOR technology might become more widespread in Canada.

Figure C1



Source: Oil and Gas Journal, Biennial Enhanced Oil Recovery Project Surveys

Projected Canada Onshore Conventional Oil Production

Both Canada's National Energy Board (NEB) and the Canadian Association of Petroleum Producers (CAPP) make long-term projections of future oil supply on a national basis. The CAPP projections are discussed here because they were recently updated.

[16] Source: Dakota Gasification Company website. Information collected early 2011.

CAPP projects Canadian onshore conventional light/medium crude oil, pentanes, and condensates production to grow from 706,800 barrels per day in 2010 to about 750,000 barrels per day in 2015, followed by a decline to about 610,000 barrels per day in 2025 (Figure C2).[17] The short-term increase in onshore medium/light oil production is due to the drilling of horizontal wells and the application of hydraulic fracturing in the Canadian portion of the Bakken oil play (Saskatchewan), in Alberta's Cardium formation, and in various Manitoba oil fields.[18]

Between now and 2025, Canadian oil production is primary expected to grow as a result of growing oil sands production that CAPP projects to grow from 1.6 million barrels per day in 2010 to 4.1 million barrels per day in 2025. As oil sands production grows to become 79 percent of total Canadian oil production, production from the other categories will shrink correspondingly. In particular, onshore and offshore conventional oil production levels[19] are projected to be respectively 18 percent and 3 percent of total Canadian oil production by 2025. So over the long-term, Canada's onshore conventional oil production declines both in volume and proportion.

CAPP does not explicitly project future EOR oil production. Thus, it is uncertain what level of future Canada EOR oil production can be expected. In the area of CO_2 EOR, Alberta is pursuing a plan to implement a carbon capture and storage strategy[20]. Carbon dioxide volumes in this plan can be used to infer potential CO_2 EOR production. These are shown in the Potential Development Pathways section of this topic paper.

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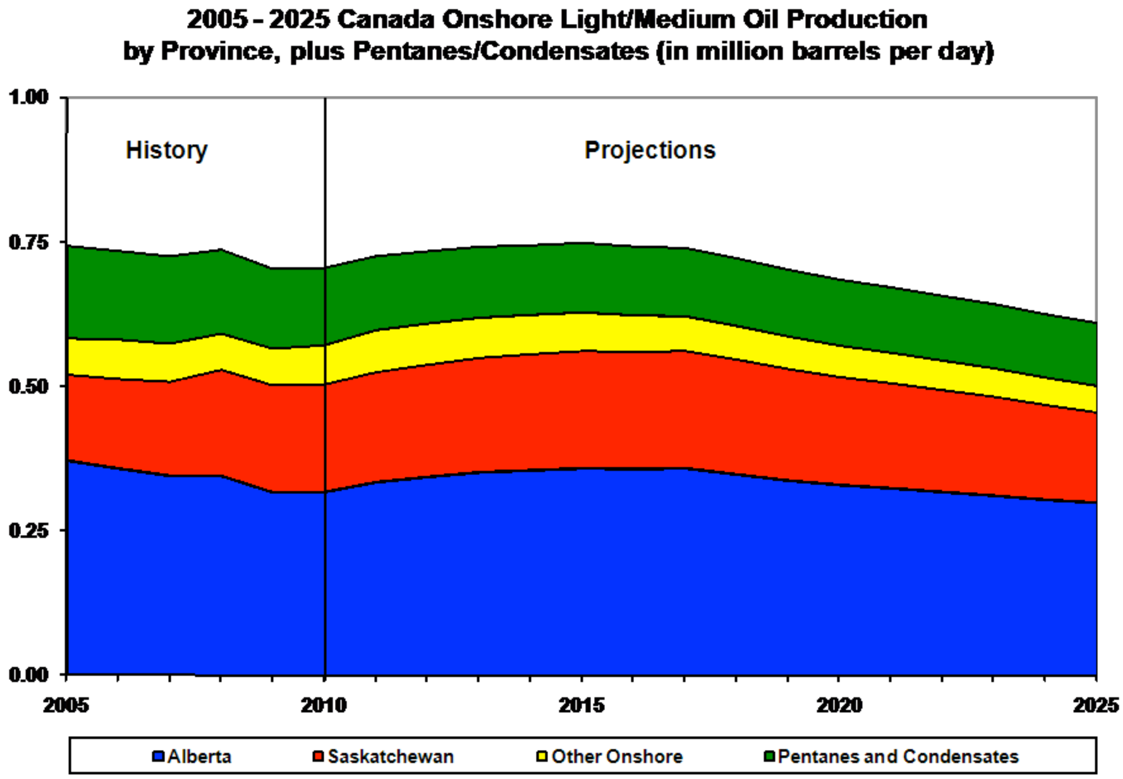
[17] The oil production data includes enhanced oil recovery production volumes. The 2005 through 2025 oil production (including pentanes and condensates) forecast was compiled by the Canadian Association of Petroleum Producers (CAPP) based upon responses from producers who utilized their own proprietary outlooks for crude oil pricing. See "Crude Oil Forecast, Markets & Pipelines," Appendix B.1, June, 2011, page 28 at http://www.capp.ca/forecast/Pages/default.aspx#C2FP2xuyFQqJ
[18] Based on a series of communications between CAPP representatives and Philip Budzik (EIA).
[19] Onshore percentage includes both heavy and tight oil production.
[20] "Accelerating Carbon Capture and Storage Implementation in Alberta", Alberta Carbon Capture and Storage Development Council, March, 2009, http://www.energy.alberta.ca/Org/pdfs/CCS_Implementation.pdf

Figure C2



Source: Canadian Association of Petroleum Producers, Canadian Crude Oil Production Forecast 2011-2025, June 2011, spreadsheet; figure includes "tight" oil production.

The decline in Canada's conventional onshore light/medium crude oil and pentane/condensate production is projected to continue (Figure C2). While it rises from 706,800 barrels per day in 2010 to a peak of about 750,000 barrels per day in 2015, it subsequently declines to about 610,000 barrels per day in 2025. As mentioned earlier, the temporary rise in oil production is primarily due to the increased application of horizontal drilling and hydraulic fracturing in Alberta, Saskatchewan, and Manitoba oil fields. After 2015, the projected decline in production occurs in all the Canadian onshore provinces and occurs for both conventional light/medium oil production and for pentane/condensate production.[21]

[21] The oil forecast by the Canadian Association of Petroleum Producers does not provide pentane and condensate production by Province. However, historically over 90 percent of the pentane/condensate production originated in Alberta.

2. Key Technologies and Issues

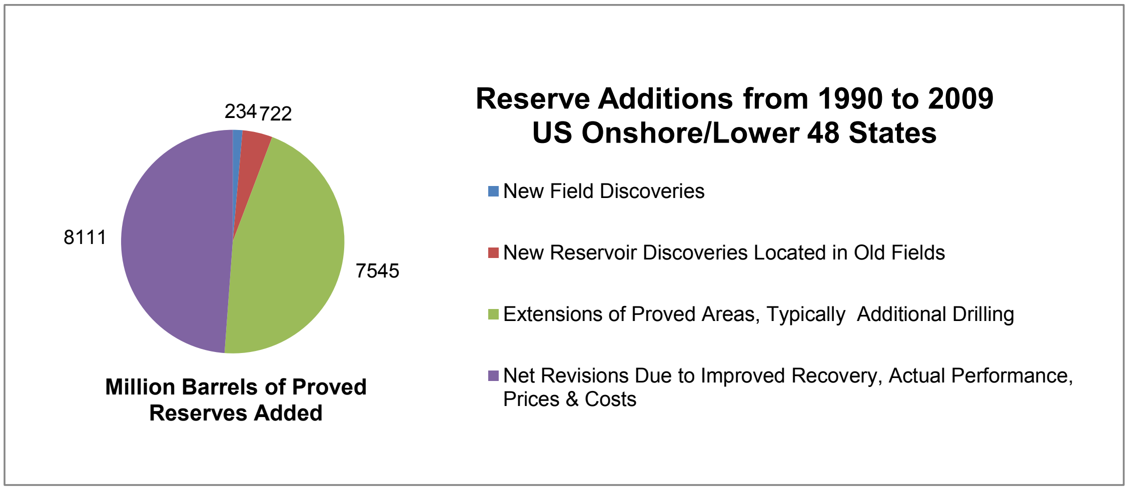
In this section, the sub-group highlights the technologies and issues having the most potential impact on conventional oil supply. For each technology and issue, factors were identified which would either enable or challenge the ability to make a positive impact on supply. These are summarized in tables for each.

2.1. Introduction

In the arena of conventional onshore oil and EOR, the dominant source of supply available over the next 20 years will likely be a combination of three broad categories: 1) Large, mature fields which have been discovered and have been producing over many years; 2) Accumulations which, while known, become economic with a combination of price, applied technology and management practices; 3) Low oil saturation zones, either below the oil/water contact in existing fields or new targets which are geographically separate (sometimes known as "greenfields," with effectively no main pay zone).

This view is supported by recent trends in the conventional onshore arena. As an illustration, Table B2 in the Background section indicates that 75% of future resources estimated by EIA for the US Lower 48 onshore conventional are either proved or inferred reserves. Both of these categories are already discovered. Similarly, the historical data in Figure K1 for the same region indicates that of the 16.6 billion barrels added as proved reserves over a 20 year period, less than 10% were newly discovered reservoirs.

Figure K1



Source: Data from U.S. Energy Information Administration, various worksheets at http://www.eia.gov/dnav/pet/pet_crd_pres_dcu_NUS_a.htm

The largest target of these known accumulations is detailed in Table B4; over 300 billion barrels of Remaining Oil In Place (ROIP) in the US lower 48 alone. This represents the oil estimated to be left behind after application of primary and secondary recovery in known oilfields. Generally, the approach to recover ROIP would be enhanced oil recovery projects. These are typically “brownfield” projects where an existing field has additional infrastructure added to introduce a new substance or process to alter the properties of the oil in order to increase recovery. In other cases, the redevelopment project may simply involve additional drilling using a more modern or efficient technology. Given the size of the targets, incremental recovery of just a few percent can have a material impact on the future magnitude and longevity of this production stream. The baseline technology and issues discussed in this section are focused on oil accumulations which have already been discovered as well as the expanded targets with low oil saturation, including greenfield sites. How these technologies are applied and the way these issues are managed will ultimately impact the pace of development and have the most significant effect on production rates from these resources.

While unlikely to be material to the overall levels of conventional oil production from the onshore, exploration is important incrementally. Besides providing new supply, discoveries often lead to extensions and improvements over time from additional reservoir delineation. Regarding exploration technology, the work presented in the 2007 NPC "Hard Truths" study[22] remains valid. It detailed five core technology areas[23] along with suggestions to accelerate the development and use of these technologies.

The issues facing onshore oil exploration will be very similar to those in gas or unconventional oil operations with the threshold issue being access to new production areas. Several studies have indicated there is onshore oil exploration potential in the US moratoria area. In 2008 ICF authored a study which indicates production potential could range up to 35 thousand bopd in the Rocky Mountain moratoria area in the United States[24]. While important, a volume of this magnitude will not be material to production in the 2 to 4 million bopd range from conventional onshore sources in North America.

2.2. Technology

Oil field development and production are complex operations which involve application of multiple technologies spanning many disciplines. Even an abbreviated list of impact technologies can be a long one. Those lists developed in the 2007 NPC study totaled some 35 technologies for onshore conventional and EOR operations[25].

From this wide range, this sub group chose several technologies which are most likely to influence the supply picture through 2030 due to their potential impact on production from known oil accumulations. These technologies are contained within the following broad processes required to manage oil development and producing operations:

[22] Topic Paper #21, Exploration Technology, Working Document of the NPC Global Oil & Gas Study, July 18, 2007. http://downloadcenter.connectlive.com/events/npc071807/pdf-downloads/Study_Topic_Papers/21-TTG-ExplorationTech.pdf

[23] 1) Seismic; 2) Controlled Source Electromagnetism; 3) Interpretation Technology; 4) Earth-Systems Modeling; 5) Subsurface Measurements.

[24] "Strengthening Our Economy: The Untapped U.S. Oil and Gas Resources", prepared for American Petroleum Institute by ICF International, December 8, 2008, page 53, http://www.api.org/Newsroom/upload/Access_Study_Final_Report_12_8_08.pdf

[25] Topic Paper #19 Conventional Oil and Gas, Working Document of the NPC Global Oil & Gas Study, July 18, 2007. Tables IV.1 & IV.2, http://downloadcenter.connectlive.com/events/npc071807/pdf-downloads/Study_Topic_Papers/19-TTG-Conventional-OG.pdf,

- **Design** – This involves the planning for location, number and type of wells needed to produce and manage the reservoir. It also includes sizing and design of surface facilities to handle produced or injected fluids, plus transportation and disposal of products. Besides project specifications, production expectations must be developed to support investment decisions. R**eservoir characterization, simulation and management** are critical to establishing the initial project feasibility and subsequent management of the producing formations.
- **Implementation** – This includes the actual installation and field operation of wells and equipment, including drilling and well stimulation activities. Here, **advanced well operations** (especially those involving horizontal drilling and hydraulic fracturing) are considered important.
- **Operation & Monitoring** – Because the life of an oilfield can range from several years to more than a century, efficient operating and maintenance practices are important to maximizing recovery and economic benefit. Critical data from operations must be collected and analyzed so that operational improvements and incremental investments can be made to profitably maximize production/reserves. **Downhole monitoring** (especially in complex recovery processes or horizontal wells) is expected to be important to success.
- **Recovery Process Improvement** – At the core, oilfield development relies on one or more recovery processes, be it primary production, water flooding, or some sort of enhanced process like CO_2 flooding. In this area, technology leading to **improved sweep efficiency** will be critical to maximizing production from existing operations and in addressing the multi-hundred billion barrel target of oil remaining in known fields or in low oil saturation targets.
- **Application to New Resources** – Given the natural decline of existing oil production, it is critical to look at new resource targets to maintain or grow production. Within this area, the technologies targeting **low oil saturation zones** can impact supply.

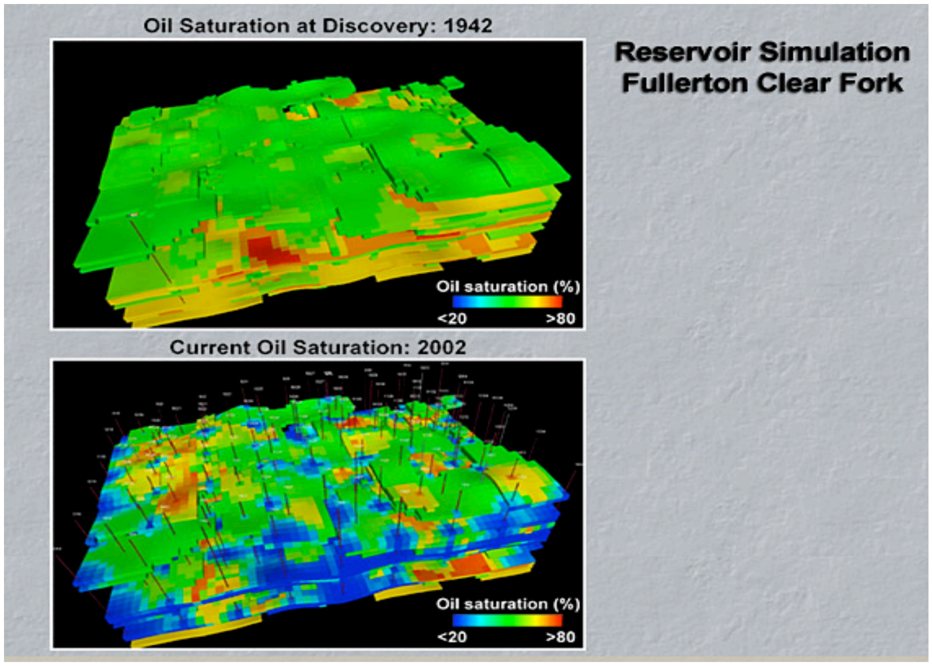
Below is a brief description and discussion of each technology along with a list of challenges and enablers.

Reservoir Characterization, Simulation and Management

Reservoir characterization refers to in-depth study of rock and fluid properties across and surrounding an oil field. It involves the integration of well logs, core samples, geologic descriptions and seismic interpretation in a given area, and may involve hundreds of individual well bores. The work product is a 3-D model which attempts to simplify and describe the reservoir architecture, location of hydrocarbons, flow units and rock properties across the field.

Once a geologic model is developed, mathematical models can be used to integrate historical production, injection and other operating parameters to validate the modeling assumptions and describe the current conditions in the reservoir. The model can then be used to predict the outcome of various development and operating scenarios for the field, such as additional infill drilling, water flooding or more advanced and expensive enhanced recovery processes. Often times, these models are reservoir simulators which utilize large amounts of computational power. However, simpler analytic models are also used. An example result is shown in Figure K2 below:

Figure K2



Source: "Integrated Geological and Engineering Characterization of Fullerton Clear Fork Field in Andrews County, Texas 3-D Reservoir Modeling and Simulation", Fred P. Wang, Bureau of Economic Geology, The University of Texas, July, 2004, Figure 15, http://www.beg.utexas.edu/resprog/fullerton/3dreservoirmod.htm

Robust models can be used for reservoir management in ongoing operations by integrated teams of geologists and engineers. For more complex models, the data is entirely in digital form, allowing more rapid analysis and seamless integration. The most fruitful application of these models occurs when practical experience with a producing field is combined with the theoretical modeling results to identify investment opportunities and optimize current operations.

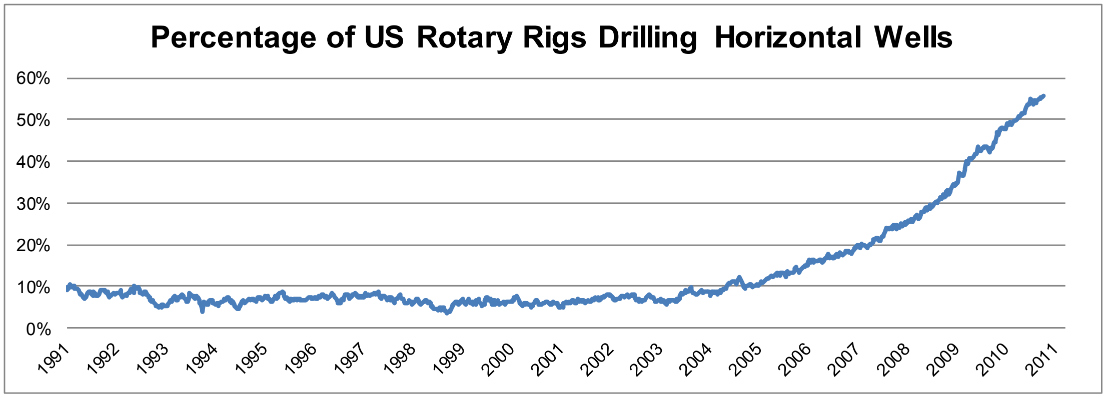
No matter which tools are used, the ultimate goal is identification of activities and investment that can increase production and improve efficiency. The lack of key data in usable form, and a shortage of experienced personnel to analyze that data, represent key challenges to attaining this goal.

Summary: Reservoir Characterization, Simulation & Management	
Key Enablers:	Digital & electronic data being available
	Integrated geologic and engineering teams
	Individuals with the ability to manipulate and analyze large volume data sets
Key Challenges:	Old data sets in legacy systems which have difficulty communicating with each other
	Much of available information is only in paper files
	Attracting and retaining sufficient technical staff with the skills to work through detailed data while combining practical field experience

Advanced Well Operations

Advanced well operations refers to improvement in newly drilled wellbore placement and geometry and gains in well stimulation. On the drilling side, the most noteworthy gains of recent years have been in horizontal wells, especially in the low permeability gas and oil plays. Figure K3 illustrates the dramatic increase in the percentage of horizontal wells in the United States over the last five years:

Figure K3



Source: Drilling rig data from "North America Rotary Rig Counts" worksheet per Baker Hughes dated July 8th, 2011, http://investor.shareholder.com/bhi/rig_counts/rc_index.cfm

Horizontal technology can also be applied in conventional oil and EOR reservoirs, where it provides another tool to contact additional oil for less life-cycle cost and reduced surface disturbance. Horizontal wells can be used to increase the areal extent of the producing zone or to target unproduced intervals. Ultimately, one of the keys to improving recovery will be increasing the effective well density in a producing reservoir economically, perhaps using fewer but more costly wells.

Similarly, advances in stimulation and hydraulic fracturing capability provide tools for targeting unproduced oil and enhancing recovery. A series of fractures can increase the effective drainage area of a well by increasing the flow paths around that well. This is particularly important to target large sections of a low permeability formation where hydrocarbons are known to occur. Vertical wells are drilled through these formations and then stimulated using multi-stage fracturing techniques. The Wolfberry area in West Texas is one example[26]. One of the downsides of this approach has been the difficulty of controlling the location of the fractures, but tools are improving to understand and direct the fractures to maximize effectiveness.

For the advanced operations, unit costs should continue to decline as technology deployment continues to become more widespread. Importantly, these techniques have

[26] "Texas 'Playgrounds' Attract Action", The Explorer of the American Association of Petroleum Geologists, D. Brown, July, 2008, http://www.aapg.org/explorer/2008/04apr/basins.cfm

added new reserves previously thought un-producible. However, recent concerns about the environmental impacts of horizontal drilling and hydraulic fracturing could lead to regulatory restrictions that offset any cost and efficiency gains achieved.

Summary: Advanced Well operations	
Key Enablers:	More industry-wide use of this technology, leading to improvements in costs and effectiveness
	Improvements in wellbore integrity allowing selective stimulation and fluid entry
Key Challenges:	Increased regulation around well operations, including fracturing
	In older fields, production rates may be too low to justify costs

<u>Downhole Monitoring</u>

Understanding the fluid paths in an oil reservoir has always been important to maximizing field recovery, and downhole monitoring plays a critical role in achieving this understanding. This area will grow in importance with utilization of new tools (such as horizontal wells) and expensive injection fluids (such as CO_2 or steam). Geologic sequestration of CO_2 may also drive technology advancement. Monitoring, verification and reporting protocols will likely require the use of downhole monitoring to prove trapping and permanence of CO_2 injected for eventual sequestration.

The identification of where and what fluids are entering and exiting the wellbore is critical. The increase in the number of horizontal wells in use tends to increase initial production and per-well reserve numbers. However, this also means that a large amount of reserves are now dependent on these wells functioning efficiently in both conventional fractured reservoirs and EOR projects. Use of horizontal laterals increases the risk that undesirable fluid entry, such as water, gas, CO_2 or other injected fluid, will make operation of the well uneconomic or require expensive remedial work. It is also necessary to determine if the entire lateral is open to hydrocarbon flow, or if stimulation is needed.

To identify intervals for remedial work, the first step is to identify if there is a repairable problem and where the problem is located. Loss of a horizontal lateral because of fluid breakthrough will require the drilling of a replacement well or will leave a major portion of the original hydrocarbons in place unrecovered. This will significantly impact reserves and future production.

Current production logging tools have limited usefulness in long horizontal wells. New tools and methods are needed to obtain fluid entry and exit profiles in the horizontal sections. Permanently installed down hole sensors may be a solution no matter the well geometry. Besides the advantage of operating without shutdown, these sensors have potential to transmit a number of data parameters important to a specific recovery process, such as temperature in a steam flood. Historically, the challenge has been finding a cost-effective technology solution in projects where production rates tend to be lower.

This is also an area in which a shortage of critical materials can slow work or increase expense. An example of this is the recent concern regarding availability of Helium-3[27]. Helium-3 is an inert and non-hazardous gas used to detect neutrons, a key process used in the industry to determine reservoir formation properties. There may be benefit in having a working group from industry and government looking ahead to identify potential shortages of critical materials as well as actions to mitigate impact.

Summary: Downhole Monitoring	
Key Enablers:	Solutions in this area are applicable to a broad range of resources (tight gas, tight oil, conventional, EOR) throughout the industry
	Improvement in electronics and processing speed may aid the solutions
	The technology can be continuous or intermittent
Key Challenges:	Current costs of monitoring appear high in an already high cost business
	Available methods most often require modification to the production equipment which interrupts fluid flow. Improvements would not interrupt flow and would determine the nature and location of fluid entry.
	Limited supplies of critical materials (Helium-3, for example) may limit use of existing tools and techniques

Improved Sweep Efficiency

To improve enhanced recovery from the typical expectation of 35% of oil-in-place into the mid 40% to 60% range, it is essential to improve sweep efficiency[28]. For

[27] Notes from the April 22, 2010, meeting, Subcommittee on Investigations and Oversight Hearing - Helium-3 Supply Crisis, Committee on Science, Space & Technology, U.S. House of Representatives, http://science.house.gov/hearing/subcommittee-investigations-and-oversight-hearing-helium-3-supply-crisis

[28] Topic Paper #19 Conventional Oil and Gas, Working Document of the NPC Global Oil & Gas Study, July 18, 2007. Page 22. http://downloadcenter.connectlive.com/events/npc071807/pdf-downloads/Study_Topic_Papers/19-TTG-Conventional-OG.pdf

example, injected CO_2 will not always contact the entire target oil saturation due to differences in viscosity and the existence of higher permeability flow zones/layers in a given reservoir. The injected fluids will often flow preferentially into zones which have already been swept, a very inefficient use of expensive fluids. The current approach to this issue is alternate injection of water and CO_2 which helps CO_2 to flow more uniformly through the reservoir. This is often combined with various additives (such as polymeric gels) and mechanical modifications to wellbores to provide field specific improvements to sweep efficiency.

Over the years, there have been a number of efforts to use various surfactants to produce "foams" in the reservoir to divert CO_2 to new pathways with higher oil saturation, thereby increasing recovery. These have had limited success over the years for various reasons. However, there are new efforts underway to develop surfactants that are mixed with the injected CO_2 to produce this effect. If these surfactants are proven effective and are commercially available at reasonable cost, this would provide an additional tool to increase recovery and use CO_2 more effectively[29].

Continued improvement in sweep efficiency, while adding a small percentage of recovery for individual wells, can be very beneficial to overall field recovery. With unrecovered oil volumes measured in the hundreds of billion barrels, an improvement of just a few percent in recovery efficiency can add substantial reserves.

Summary: Sweep Efficiency	
Key Enablers:	Low cost chemicals or optimization efforts could add sweep efficiency gains in existing projects
	Well run secondary (waterflood) recovery projects are important stepping stones for new processes
	Focused solutions that involve a variety of tools
Key Challenges:	Solutions are very resource specific and difficult to apply broadly
	Shortage of technical resources to focus on the problem
	Increasing use of horizontal wells will require new tools and techniques

Targeting Low Oil Saturation Zones

[29] Communication from Professor Robert Enick, University of Pittsburgh, to P. Budzik, August 9, 2010

Once a field has been produced and then (often) waterflooded, the reservoir pore space will have less oil remaining. However, this remaining oil can be significant, at over 50% of the total oil originally in place in most fields. These remaining resources are a viable target for EOR.

The targets for EOR go beyond zones that produced oil during primary and secondary processes. Many areas have intervals that are termed "transition" or residual oil zones ("ROZ"), typically low oil saturation zones that occur naturally due to geologic and hydrodynamic factors. These zones were noticed below many producing oil fields but were not developed because they naturally produce water instead of oil. They are also recognized now to exist separately, geographically apart from producing oil fields.

With significant activity and advances in enhanced oil recovery techniques to revitalize production, development of ROZ is being pursued below main production intervals and in lateral expansions. Examples ROZ expansions are evident in the Permian Basin with nine projects underway, including notable fields such as Wasson and Seminole[30]. These are using mostly CO_2 processes, but are just now extending to chemical flooding. The current recovery process with the most application in these zones is CO_2 EOR, with one of the challenges being the limited supply of affordable CO_2.

The magnitude of the ROZ resource is just now coming into focus. Some early estimates of the Permian Basin have indicated at least 89 billion barrels of oil in place. Considering that other basins are also likely to have ROZ resources, previous estimates of 100 billion barrels seem conservative[31].

Ultimately, should affordable CO_2 not be available to develop ROZ resources, a key question will be whether there is another process that can economically target this resource. At this point, there is no clear alternative to CO_2. Injecting a combination of chemicals (surfactants and/or polymers) will likely be considered, but will have its own

[30] See "CO2 EOR: A Model For Significant Carbon Reductions" by C. M. Ming and L.S. Melzer, presented at the symposium on the Role of Enhanced Oil Recovery in Accelerating the Deployment of Carbon Capture and Sequestration sponsored by MIT Energy Initiative and Bureau of Economic Geology at UT Austin, July 23, 2010

[31] "Undeveloped Domestic Oil Resources: The Foundation for Increased Oil Production and a Viable Domestic Oil Industry", Prepared by Advanced Resources International for the U.S. Department of Energy, February, 2006, Table 1.1, http://www.fossil.energy.gov/programs/oilgas/publications/eor_co2/Undeveloped_Oil_Document.pdf,

set of challenges including high cost, environmental and possible detrimental impacts on refinery catalysts. Historically, there have been few commercial demonstrations of surfactant technology in the U.S. However, periods of high sustained oil prices will likely further development in this area.

Summary: Low Oil Saturation Zones	
Key Enablers:	Low oil saturation zones are of significant size to generate interest
	Low oil saturation resources are often close to existing operations and infrastructure
	Topic is getting more attention, for example, with research work at UT Permian Basin
Key Challenges:	Size and extent of the resource is still unknown; traditional government resources to study ROZ are becoming more limited (for example, USGS, USDOE)
	Building sufficient acreage with adequate economic terms considering relatively high upfront capital requirements
	Confidentiality concerns can inhibit technology transfer between operators
	Limited CO_2 supply; priority may be low due to challenging economics
	There appear to be few alternative recovery processes if CO_2 is not an option

2.3. Issues

These are topics other than technology which the sub-group viewed as having the most impact on future supply from the conventional oil and EOR resources. They can be of a financial, legal or regulatory nature.

As described in the background section, the factor which forecasters believe could impact conventional onshore supply the most is the feasibility of CO_2 EOR[32]. The first three issues relate to CO_2 supply and use. While most applicable to dilute anthropogenic supply projects, these issues can impact concentrated sources as well:

- Implementation of policies targeting reduction in greenhouse gas emissions
- Cost of capturing carbon dioxide from point sources

[32] In addition to the background section, some context on CO_2 EOR is included in Appendix A-4

- Legal & regulatory framework around CO_2 storage and/or sequestration in EOR operations

There are also issues that have a more general impact on resource development:

- Economics of new investment and continued operation
- Current ownership mix of onshore oil resources
- Timing of EOR project implementation

There are other topics which are viewed as having potentially significant impacts on future supply from conventional oil resources but are not discussed here due to their generic nature. Examples include:

- Ability to lease or access locations, including conflicts between surface and mineral ownership interests
- Public acceptance of certain operations due to perception of benefits and risks
- Projects slowed by additional and changing permitting requirements
- Difficulty in introducing new technologies due to environmental impact concerns
- Introduction of new laws or regulations at the local/state/federal level

CO_2 Supply Impacts of Policies Targeting Reduction of Greenhouse Gas Emissions

Due to concerns about human contribution to climate change, there may be limitations or reduction goals placed on greenhouse gas emissions (GHG), specifically CO_2. Reductions could be driven by regulatory mandates (mandatory reductions, caps, or fuel mix) and/or financial (some sort of carbon tax or fee). It may be necessary to capture and sequester CO_2 in geologic formations to reduce emissions to meet reduction goals. However, some analysts have concluded that meeting GHG reduction goals through 2050 could be achieved primarily through fuel switching and energy conservation as opposed to large scale carbon capture and storage (CCS)[33]. In light of these competing pathways, policies which incentivize capture or remove uncertainties regarding geologic sequestration will be necessary to increase CO_2 supply for EOR by means of CCS.

California's recent consideration of CO_2 EOR as a possible cap-and-trade compliance mechanism is a policy example that could potentially increase CO_2 supply availability.[34],[35] However, obtaining a verifiable emissions reduction for capturing and storing anthropogenic CO_2 via EOR may not be sufficient to boost CO_2 EOR production. Regulatory and legal certainty and total life-cycle costs will ultimately be the drivers of project viability. If other issues such as new well construction requirements[36] or pore space ownership and long term liability introduce significant uncertainties, potential CO_2 EOR projects may languish despite potential increases in CO_2 supply availability.

Closely related to capture will be the transportation of captured CO_2 to areas where it can be used for EOR. Currently, the most cost-efficient form of transport is via large diameter pipelines, which have been used in the United States for more than 20 years with an excellent safety record[37]. Recently, there have been several examples of CO_2 pipeline projects moving forward[38]. In addition, a task force sponsored by the Interstate Oil and Gas Compact Commission (IOGCC) and others concluded that the state

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[33] See, for example, the Interim Report on "The Future of Natural Gas", MIT Energy Initiative, The Massachusetts Institute of Technology, 2010, page 35, http://web.mit.edu/mitei/research/studies/report-natural-gas.pdf

[34] California Air Resources Board Resolution 10-42, dated December 16, 2010, pp. 13-14,http://www.arb.ca.gov/regact/2010/capandtrade10/res1042.pdf

[35] See also California Air Resources Board July 2011 Cap-And-Trade Discussion Draft at p.84 referencing a yet-to-be-developed Board-approved carbon capture and geological sequestration quantification methodology, http://www.arb.ca.gov/cc/capandtrade/meetings/072011/cap-and-trade-discussion-draft.pdf

[36] See 40 CFR Parts 124, 144, 145, et al. Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO2) Geologic Sequestration (GS) Wells; Final Rule. EOR is generally distinguished from sequestration wells. However, Part 144 identifies nine risk-based factors that could lead to the reclassification of Class II CO2 injection wells to Class VI, including a grant of discretionary power to require re-abandonment of existing wells, http://water.epa.gov/type/groundwater/uic/upload/pre-FR_class6_2010-11-22.pdf

[37] Energy Technology Perspectives 2008, International Energy Agency, 2008,p.271. http://www.iea.org/textbase/nppdf/free/2008/etp2008.pdf

[38] For example, the Greencore pipeline (owned by Denbury Resources, Inc.) as described at http://www.blm.gov/wy/st/en/info/news_room/2011/january/07cfo-greencore.html

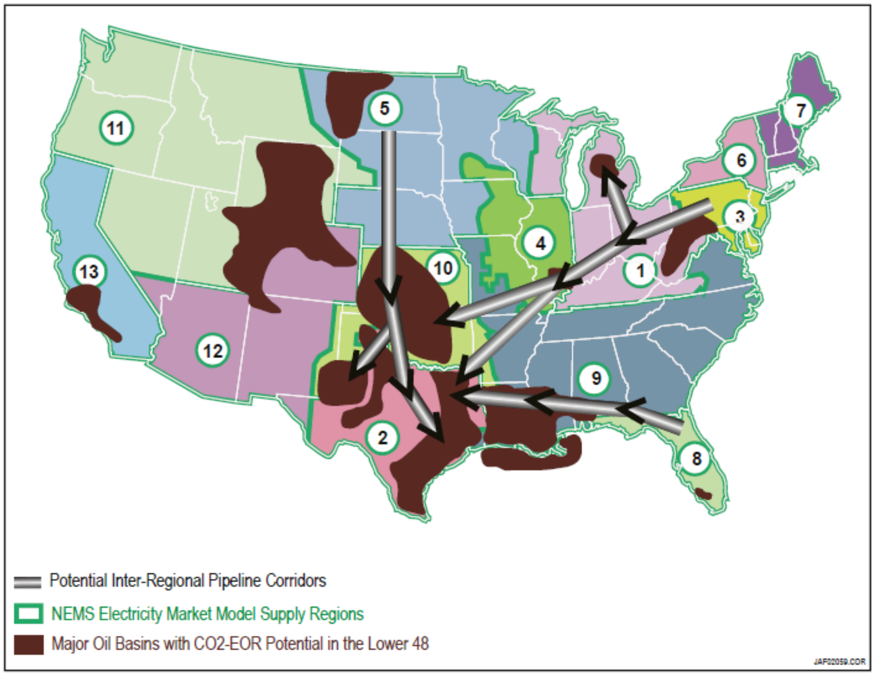
pipeline regulatory system currently in place is adequate for the foreseeable future[39]. Both recent activity and the task force affirm that the existing model is working with regard to CO_2 pipelines in areas under ongoing or planned CO_2 EOR development.

Should significant CCS activity enable expansion of CO_2 EOR investment, a large expansion in the pipeline network would be necessary to link CO_2 producing areas to the basins where additional EOR is most promising. One conceptualization of what a system would look like is illustrated in Figure K4.

[39] "A Policy, Legal, and Regulatory Evaluation of the Feasibility of a National Pipeline Infrastructure for the Transport and Storage of Carbon Dioxide", Multiple authors, September 10, 2010, Page 1, http://www.iogcc.state.ok.us/Websites/iogcc/Images/PTTF%20Final%20Report%202011.pdf

Figure K4

Possible Way that U.S. CO2 Capture/Transport/And Storage Could Evolve (per ARI)



Source: "U.S. Oil Production Potential from Accelerated Deployment of Carbon Capture and Storage", prepared by Advanced Resources International for the National Resources Defense Council, March 10, 2010, Figure 11, Page 37

The price of delivered CO_2 will have to be at a level where investments in EOR projects offer adequate returns. As CO_2 prices are negotiated between sellers and purchasers in various contractual forms, the price can vary widely based on location, contract vintage, etc. In addition, CO_2 prices are heavily influenced by the cost of energy for compression and transportation. Sources[40,41] reference typical prices of less than $1 per mcf ($10 to $15 per metric ton) and maximum prices in the range of $2 to $3 per mcf ($40 to $60 per metric ton). With estimated costs of capture and transport from dilute sources well above this level[42], policies which provide economic incentives to reduce

[40] "Carbon Dioxide Enhanced Oil Recovery", National Energy Technology Laboratory, U.S. Department of Energy, March, 2010, pages 13, 17. http://www.netl.doe.gov/technologies/oil-gas/publications/EP/small_CO2_EOR_Primer.pdf
[41] "The Economics of Enhanced Oil Recovery: Estimating Incremental Oil Supply and CO2 Demand in the Powder River Basin", K. van 't Veld and O. R. Phillips in The Energy Journal, Vol. 31, No. 4, 2010.
[42] "Report of the Interagency Task Force on Carbon Capture and Storage", Various U.S. Agencies, August, 2010, Page 34, http://www.fe.doe.gov/programs/sequestration/ccstf/CCSTaskForceReport2010.pdf

delivered CO_2 pricing and enable long term contracting will be required to make these sources viable.

Summary: CO2 Policies to Reduce GHG Emissions	
Key Enablers:	Policies which incentivize capture and storage of carbon dioxide via EOR
	Policies which recognize delivered price of CO2 to EOR projects must be affordable
	A well-developed pipeline network to provide reliability and security of CO2 supply
	Current regulations allowing for CO2 EOR independent of the GHG reduction policy objectives.
Key Challenges:	Uncertainty surrounding well design, re-abandonment of existing wells, and EOR as geologic sequestration
	Uncertain CO2 price from capture projects
	Policies which impact field operations handling purity CO2
	Awareness in the capture community of the large, secure storage targets in EOR

Cost of CO_2 Capture from Dilute Sources

In the sequence of CO_2 capture and transportation to EOR locations, the largest cost item is the capture of the CO_2, typically from flue gas streams of coal-fired power plants. This is also the area with the least amount of project execution and operating experience[43].

There are basically three technical options to capture CO_2 from power plants, each with their own cost issues

- Pre-Combustion Capture, with high capital investment and IGCC[44] process development costs
- Post-Combustion Capture, with high operating costs + parasitic power losses , and
- Oxy-Fuel Combustion, also with high operating costs + parasitic power losses

Ultimately, reduction in capture costs will be critical to making CO_2 supply from dilute anthropogenic sources viable. Lower costs through technological innovation and scale of deployment could reduce the need for financial subsidies required early in development and lead to a better business model over the longer term.

[43] "Report of the Interagency Task Force on Carbon Capture and Storage", Various U.S. Agencies, August, 2010, Page 27, http://www.fe.doe.gov/programs/sequestration/ccstf/CCSTaskForceReport2010.pdf
[44] Integrated Gasification and Combined Cycle

Summary: Cost of CO2 Capture From Dilute Sources	
Key Enablers:	Future demonstration projects focused on capture, especially at coal plants
	Transport technology and EOR operations are already established
	May be different economics in different regions; that is, CO2 for EOR may have more value in areas where natural supply is not an option
	Activity outside of US may provide experience available for import
Key Challenges:	Estimated costs are high and the question of 'Who will pay?" is unanswered
	Capture projects can be delayed by regulatory uncertainty, including significant concern on transport and injection
	Establishing connection / cooperation between the capture and the injection industries

Legal & Regulatory Framework around CO_2 Storage in EOR

During the life of a CO_2 EOR project, a large percentage of the purchased CO_2 remains trapped in the oil reservoir. The exact amount depends on a number of factors including the local geology, properties of the oil bearing formation and recycle parameters used in a given field. A comprehensive volumetric estimate of oil and gas reservoirs made by the US DOE in 2010[45] indicated a CO_2 storage potential of some 142 Billion metric tons in 29 states and 4 Canadian provinces. Specific to EOR operations, industry rules of thumb indicate that over a project life, 3 to 6 mcf of carbon dioxide will remain in the reservoir for every barrel of oil produced. Importantly, these heuristics were established assuming CO_2 use is minimized due to its cost.

Monitoring, reporting and verification rules around CO_2 migration and permanence will be important for EOR projects that require or claim geologic storage. These projects would likely require some form of certification to qualify for tax credits, reduction/trading credits or other financial support. A clear understanding of liability allocation among the parties (CO_2 supplier, EOR operator and public institutions) and consensus on operational and post-closure stewardship requirements will be necessary. If the legal and regulatory framework adds unreasonable costs or uncertain liabilities, then EOR projects are likely to proceed slowly, if at all. The Interstate Oil & Gas Compact Commission (IOGCC) has done some excellent work to outline existing regulations as

[45] "2010 Carbon Sequestration Atlas of the United States and Canada – Third Edition (Atlas III), National Energy Technology Laboratory, U.S. Department of Energy, Pages 28, 156. http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlasIII/2010atlasIII.pdf

well as provide guidance for jurisdictions which must develop new rules[46]. The EPA's recent issuance of new Class VI wells standards for sequestration projects[47] provide additional guidance and maintain the distinction between EOR wells and sequestration wells. However, the potential for significant regulatory discretion regarding re-abandonment of existing wells may increase uncertainty for prospective EOR project sponsors.

To date, these issues have not been significant barriers for projects which use CO2 from natural or anthropogenic sources which are economically viable in today's environment. These typically operate under existing regulations without issue. However, new regulations could impact existing operations and should be reviewed for adverse consequences.

Summary: Legal and Regulatory Framework for Storage	
Key Enablers:	Jurisdictions where regulators define well designs and requirements with clear guidelines and quick feedback, providing operators the certainty required to move forward
	IOGCC efforts to develop a framework and a common approach and provide workable solutions to many of these issues
Key Challenges:	Post closure liability often undefined, no clear delineation as to who has what liability
	Timelines discussed for sequestration can be very long, meaning liabilities are open ended and uncertain
	Establishing a certification process for storage volumes concurrent with oil production
	Potential re-abandonment of existing wells.

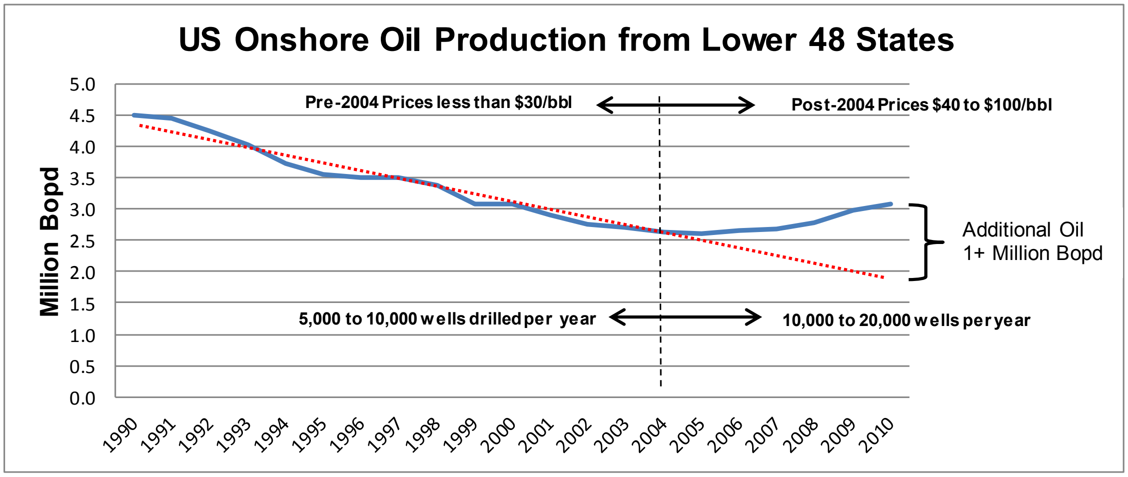
Economics of Investment and Continued Operation

Conventional oil production from the onshore/EOR arena tends to be mature and high cost. Data from the last 20 years indicates that, without sufficient economic incentive, the pace of development is unlikely to overcome natural decline. For example, onshore production from the US lower 48 states was on a relatively steady decline for the 15 years prior to 2004, with modest development activity. At that point, higher prices led to increased drilling activity, contributing to flat production year over year. Figure K5

[46]"Storage of Carbon Dioxide in Geologic Structures, A Legal and Regulatory Guide for States and Provinces, Interstate Oil and Gas Compact Commission, Task Force on Carbon Capture and Geologic Storage, September 25, 2007. http://iogcc.publishpath.com/Websites/iogcc/PDFS/2008-CO2-Storage-Legal-and-Regulatory-Guide-for-States-Full-Report.pdf
[47] See http://water.epa.gov/type/groundwater/uic/upload/pre-FR_class6_2010-11-22.pdf

indicates that by 2010, the production from this area was close to 1 million barrels per day higher than it would have been on the historic decline trend. While production from new unconventional resources and technologies certainly helped, it is clear that economics and resulting drilling activity had a large bearing on the outcome:

Figure K5



Source: Production data, wells drilled and oil prices from various data downloaded from U.S. Energy Information Administration website, data collected early 2011, www.eia.gov

Costs are particularly high for enhanced oil recovery projects. This is due to added wells, surface facilities, injectant costs and processing used in the more complex recovery methods. The International Energy Agency routinely publishes cost estimates for various fossil energy sources. In 2008[48], it estimated costs for the various types of EOR projects to range from $40 to $80 per barrel, while price expectations were in the $60 to $80 per barrel range at the time. Estimates from earlier years yield similar results, with estimated EOR costs very near or above prevailing oil prices.

Costs are also higher for wells which have low production rates due to reduced economies of scale. The IOGCC estimates that low rate (less than 10 Bopd) wells contributed some 700,000 Bopd in 2008[49], over 20% of onshore US production.

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[48] World Energy Outlook 2008, International Energy Agency, 2008, Figure 9.10, page 218
[49] "Marginal Wells: Fuel for Economic Growth", Interstate Oil and Gas Compact Commission, 2009, Page 5

Because of high costs, future investment in these types of operations is very sensitive to tax treatment. There are a number of tax incentives in place for both EOR and low-rate wells, typically reduction in certain state taxes. There are also federal tax credits, but these are not currently available because market prices exceed benchmark price levels predetermined in the original federal legislation.

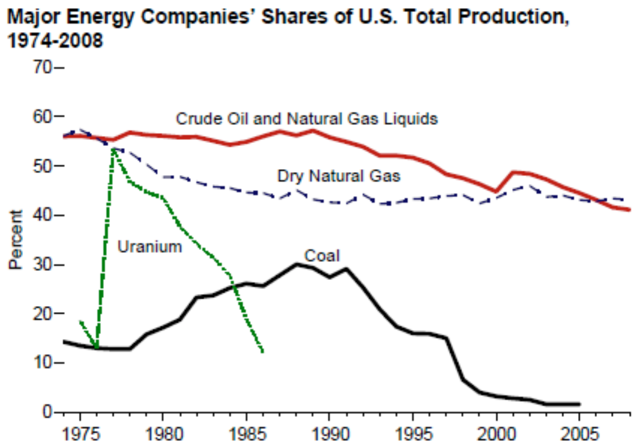
For conventional onshore production levels to grow or even stay flat, strong economic incentives will be required to keep investment spending at an adequate level.

Summary: Economic Issues	
Key Enablers:	Sustained higher price environment
	The existing federal tax credit does provide an economic floor if prices drop
	Various states have incentives in the form of reduced severance taxes for both EOR and low rate wells
	Technology and improved management practices can lower costs
	Organizations which disseminate improved practices (for example, Stripper Well Consortium, Petroleum Technology Transfer Council)
Key Challenges:	Threshold pricing for tax credits is currently exceeded, no tax incentive for incremental investment in an escalating cost environment
	Administration of the some credits can be complex
	Proposals to increase taxes or eliminate existing benefits to meet various policy goals

Ownership Mix of Onshore Oil Resources

Over the last decade, the ownership of the onshore oil properties in North America has continued to move from large, integrated companies to smaller, independent operators. Figure K6 illustrates the total US oil production held by the largest energy companies as tracked by the EIA:

Figure K6



"Major U.S. Energy Companies" are the top publicly-owned, U.S.-based crude oil and natural gas producers and petroleum refiners that form the EIA Financial Reporting System.

In 2008, there were 27 companies included on the list.

Source: "Annual Energy Review 2009", U.S. Energy Information Administration, August, 2010, pages 86, 91. http://www.eia.gov/emeu/aer/pdf/aer.pdf

Note this data is for all US oil production, including offshore and Alaska, where larger companies dominate. Therefore, for the onshore lower-48, the larger firms actually owned less than the approximate 40% indicated for 2008 in Figure K6.

There are many advantages to having smaller firms in control of these properties. With smaller and less integrated asset portfolios, they can react quickly to market conditions and opportunities. In addition, these companies are well positioned to operate properties late in life, where a strong focus on reducing overhead costs allows production to continue for a longer time period.

However, many of the smaller companies, while aggressive to develop economic opportunities, often prioritize drilling programs over investment in improving recovery. Drilling usually produces more immediate production increases and shorter economic payouts. EOR projects are slower to build production and thus produce economic returns over a longer period. Also, in general, the technical capability to design and operate improved recovery projects has decreased throughout the industry as the major companies have shifted away from this activity. The oil field service industry, often the source of technical support to smaller companies, has excellent resources to support projects which are focused on exploration or drilling. However, it has not developed as much capability in the design, operation and monitoring of EOR projects.

For production to grow in the EOR arena, project economics must be competitive; both internal and external design and implementation resources will have to be available.

Summary: Ownership mix of Onshore Oil	
Key Enablers:	Improved financial incentives for EOR projects will increase activity
	Technology transfer and training programs in the EOR arena could increase likelihood of implementation
Key Challenges:	With a relatively long economic payouts and less immediate production impact, the priority to install EOR projects may be lower with some property owners
	The technology and skills necessary to design and operate improved recovery projects is not always available from service companies or consultants
	Fragmented ownership making it difficult to put together a project of sufficient critical mass
	Public funding (e.g. DOE) not always available to assist in overcoming barriers

Timing of EOR Project Implementation

In general, timing of the initiation of EOR projects is critical to allow economically attractive returns. The investment is more likely to be economic where a significant portion of the needed wells are currently active and producing oil. In this situation, project operating expenses are limited to those incremental expenses resulting from increased production rates and costs added by the EOR process itself. Lower unit costs may also be possible for well and facility additions due to existing infrastructure and procurement relationships.

Conversely, waiting to initiate EOR projects until late in the life of the field often requires replacement of wells and facilities which were previously plugged or temporarily abandoned. It will also increase per barrel expenses as base well and facility costs are no longer supported by remaining primary and secondary oil production. In total, an EOR project slated for development later in field life will be more expensive and have higher investment risk, meaning it is less likely to be implemented.

Projected increases in oil rates from future EOR projects for 2020 forward are likely to be optimistic. At that point, assuming a typical field decline rate of 8%, production will be about half of today's rate in a given situation. This will make a significant number (likely greater than 25%) of the new conventional EOR projects marginal and most of the new brownfield low oil saturation EOR projects uneconomic, without a major change in oil prices, EOR technology or CO_2 costs.

The key will be maintaining production from EOR candidate fields over time while bringing the resources (raw materials, technical know-how and capital) to new project development.

Summary: Timing of EOR Project Implementation	
Key Enablers:	Continued production of low volume wells which delay abandonment
	State regulations which recognize potential future use and allow for temporary abandonment (where the environment and safety conditions permit) rather than permanent abandonment
	Sequestration options along with a CO2 capture program has potential to increase pace
Key Challenges:	Current production decline in EOR candidate fields.
	Demand for EOR injectant and personnel are substantial challenges.
	There are few people with EOR project implementation experience and many are likely to retire within the next 10 years. Keeping this experience and passing it down to the new crew is going to be a challenge.

3. Potential Development Pathways

3.1. Approach

In order to develop the boundaries of a supply fairway for conventional onshore oil and enhanced oil recovery, similar topics from the Key Technologies and Issues section above were grouped into categories. For each of these categories, narratives for constrained and unconstrained cases were developed. A production profile for each pathway was developed qualitatively to provide a directional view of the trajectory over the next 25 years. Numerical rates were added for illustrative purposes, not as a result of rigorous modeling. For the United States, production categories of primary + secondary, CO_2 EOR and other EOR were considered separately and then summed. For Canada, conventional light oil was considered as a total production stream made up of existing (virtually all primary + secondary) and new CO_2 EOR.

For context, these profiles were overlain on production projections based on those discussed in the Background section of this report. Note that this onshore sub-group study specifically excludes "unconventional" or "tight" oil. Both the EIA and CAPP include those categories in their projections but neither provides an explicit breakdown for the contribution of unconventional oil. To adjust for this incongruence, the projections were reduced by an estimate of unconventional oil which grew from 0.5 to 1.0 million bopd annually across the projection period[50].

The sub-group did not consider specific price cases or supply cost curves. Historically, supply cost estimates can be quite dynamic[51], so assuming a single cost curve can be misleading. However, the sub-group felt that the unconstrained path is consistent with a scenario ranging between the EIA Reference and High Price cases

[50] For recent history, the growth of production in North Dakota and Montana, dominated by the Bakken play, was used as a proxy for unconventional oil. The change in year over year projections (as unconventional oil became more recognized) was used as a base for future estimates. Neither the EIA nor CAPP has reviewed or endorsed these adjustments.

[51] See, for example, World Energy Outlook 2008, International Energy Agency, 2008, Figure 9.10, page 218, 303 and 311.

where oil prices eventually go to levels of $125 to $200 per barrel in real (2009) dollars. These price levels indicate an environment of relatively tight supplies and market pricing sufficient to stimulate technological innovation as well as policies to encourage production. Conversely, the constrained path is consistent with a lower price environment, quite similar to the $50 per barrel case the EIA runs as a Low Price Case. Given that the hydrocarbon resources to be developed in the conventional onshore arena are largely already known, the actual amount and pace of development (especially EOR) will depend heavily on the intersection of price with technology within the regulatory and policy environment prevailing at the time.

3.2. Unconstrained Pathway

Technology or Issue	Description
Technology Category #1 • Reservoir Characterization, Simulation and Management • Sweep Efficiency Gains • Downhole monitoring and horizontal well diagnosis • Technology transfer enabled • Impacts both primary/secondary and EOR	Existing tools around reservoir characterization, simulation and overall management practices continue to be implemented, increasing project inventory in existing fields. There is continued improvement in sweep efficiency, translating to higher oil recovery and better use of injectants such as carbon dioxide, steam and chemicals. Gains in downhole monitoring are made, allowing better data acquisition which adds to recovery process improvement. Importantly, continuous downhole monitoring of horizontal well performance improves, allowing those wells to produce to their ultimate potential. Public/private partnerships grow, enabling technologies to develop and be shared among operators and resource owners. There is widespread movement to digital formats for public data, improving cycle time for project screening and development. Institutions at all levels encourage job market entrants to consider technical careers in the industry.
Technology Category #2 Advanced Well Operations	Advanced well operations of horizontal drilling and fracturing continue their growth throughout the US with minimal regulatory intervention or local opposition. Incremental technology improvements are developed which allow additional resource plays to be exploited economically. High amount of synergy with Technology Category #1.
Low Oil Saturation Zones	Low/residual oil zones are widely recognized by industry and government as potential targets for both hydrocarbon production and carbon storage. State / federal geological agencies undertake systematic assessments of low oil saturation zones which have been drilled but largely

	overlooked in the past. Results from projects currently underway in the Permian Basin become models for other areas. Focused efforts (either public and/or private) to develop new technologies which are alternatives to CO2 flooding in these zones progress. Mechanisms to share these throughout the industry are in place.
Carbon Dioxide Includes GHG policies, capture costs and legal/regulatory framework	An aggressive CCS effort develops, in which worldwide and US policies are implemented which incent capture and storage of large CO2 volumes. CO2 EOR is qualified as sequestration within a clear legal and regulatory framework. Transportation issues are resolved and a pipeline infrastructure develops; CO2 price to oil producers is affordable as capture costs come down. EOR is seen as one piece of a near term bridge to large scale capture and storage throughout the US.
Economics & Policy • Impacts to profitability, • Ability of smaller operators or smaller fields to implement EOR/infill	Oil prices remain strong relative to gas prices, driving operators to focus on oil opportunities. Power, steam and CO2 prices remain reasonable due to lower underlying natural gas prices. Tax policy to encourage higher risk/cost activities is implemented to maintain activity through price cycles. These include a revamp of the EOR tax credit and allowances for marginal or low rate wells. Regulators in Alberta remain cognizant of royalty rate impacts and adjust as needed to maintain activity. Flexible plugging regulations become widespread to avoid premature abandonment and loss of incremental oil projects. Solid economics drive operators to implement projects which require more engineering work. The IOGCC work on CO2 transportation, storage and other regulatory items are widely adopted, providing operators more certainty. Institutions which provide support and knowledge to all operators continue their growth, enabling application to a wide variety of fields and reservoirs throughout the US.

Expected production characteristics for the Unconstrained Pathway are discussed below along with numerical results in Table P1. Graphical representations are in the Combined Results section and individual graphs are in Appendix A-5.

Primary/Secondary – In this area, maintaining United States production flat in the face of underlying decline would be a significant accomplishment especially when unconventional oil reservoirs are not considered. Areas of contribution will be growth of plays where multiple formations can be commingled, additional infill wells can be drilled in existing fields, and increments to secondary recovery projects are achievable. Essentially, this path extends the results of the last few years when production in the onshore was flat and slightly growing. Both price and technology improvement will play important roles by adding investment projects as targets become smaller or of lower quality. While still in decline, Canada's primary/secondary production flattens more than anticipated, similar to results of the 2008 to 2010 time frame.

CO_2 Enhanced Oil Recovery – For the Unconstrained Pathway, the sub-group had a wide range of views on the shape of the path. All views had significant growth over time as CO_2 supply becomes more abundant and EOR becomes an accepted solution to carbon storage. The views diverged regarding the rate of growth and generally depended on the perception of key factors including competition with alternative investments and the time required for the technology to gain wider deployment in the industry, for project design/piloting and for infrastructure build-out. One of the largest influencing factors is the size of future CCS activities and the portion of captured CO_2 which is ultimately supplied to EOR. Some forecasts have indicated CO_2 enhanced recovery could contribute over 2 million barrels per day of oil by 2030[52]. The sub-group generally saw a more step-wise development of CCS and diverse storage options for CO_2, even in an unconstrained case, especially when considering the technical personnel limitations expected within the industry.

The Pathway shown has a slightly higher growth rate than history for the first 5 to 7 years, reflecting recent investment activity as well as continuous growth of incremental CO_2 supplies from natural sources, gas processing and new anthropogenic sources (e.g. relatively pure sources or proposed CCS demonstration projects). During this period, the positive environment spurs project and infrastructure development which results in a

[52] These projections typically envision rapid investment in significant new electrical generation capacity with CO2 capture. Importantly, virtually all the CO2 capture volumes are targeted for EOR in these forecasts. See, for example, "Preliminary Analysis of the Practical Energy Plan Act of 2011", Climate Works Foundation, page 4.
http://www.climateworks.org/news/item/?pl=Practical_Energy_Plan_Act_of_2011_could_result_in_12_percent_reduction_in_US_GHG_emissions_in_2030

much high oil growth rate over the following 6 to 8 years. After that, the growth rate slows somewhat to reflect the large base that must be maintained. The rates in later years reflect the large target of unrecovered oil available and significantly increased availability of large, affordable CO_2 volumes not included in EIA projections. Canadian volumes increase with the implementation of the Alberta CCS plan over the next several years, including some delay for technology application and infrastructure development.

US Other EOR – This category, largely thermal in past years, showed limited growth even with the higher oil prices of the last few years. Maintaining a flat level (Table P1 above) reflects some incremental thermal work as well as limited gains in alternative recovery processes such as chemical flooding.

Table P1
Unconstrained Case Production Characteristics

Mmbopd By Year	US Primary + Secondary	US CO2 EOR	US Other EOR	Canadian Light	Total
2015	2.1	0.4	0.3	0.7	3.4
2025	2.1	1.0	0.3	0.7	4.1
2035	2.1	1.4	0.3	0.7	4.4

The Unconstrained Pathway represents a "goldilocks" scenario where everything comes together in a synergistic manner to stem historical production declines and usher in the next significant leg-up in onshore North American production. To provide a balanced view of the production fairway, the sub-group developed a much less optimistic counterpart, the Constrained Pathway.

3.3. Constrained Pathway

Technology or Issue	Description
Technology Category #1 • Reservoir Characterization, Simulation and Management • Sweep Efficiency Gains • Downhole monitoring and horizontal well diagnosis • Technology transfer enabled • Impacts both primary/secondary and EOR	There is limited use of existing reservoir management applications combined with few new tools, meaning investment opportunities are slow to be developed. Sweep efficiency continues at status quo, so unit costs go up, causing additional wells to be shut in. Little movement in downhole monitoring means data analysis remains spotty; lack of understanding of flow characteristics in horizontal wells cause abandonment prior to full exploitation of initially established reserves. Existing public data remains in paper or legacy formats, causing long cycle times and loss of projects. There is limited technology transfer activity; it takes longer for new techniques to permeate industry operations. Limited new personnel enter the industry with fewer growth opportunities.
Technology Category #2 Advanced Well Operations	Increased regulation around hydraulic fracturing substantially increases costs and delays, decreasing use. Technology development slows with less activity and only the most prolific opportunities can afford the technology.
Low Oil Saturation Zones	There is limited recognition of the potential of low oil saturation zones and information on them is spotty and tightly held. No alternatives to CO2 flooding are pursued and carbon storage in these reservoirs is not considered by policy makers.
Carbon Dioxide Includes GHG policies, capture costs and legal/regulatory framework	The use and generation of CO2 is seen as a clear and present danger. Worldwide and U.S. policies are implemented which discourage hydrocarbon production and use of CO2 injectant; existing incentives are removed and regulations around operations (production, plant processing and pipeline) are increased significantly; fees and taxes are also increased substantially. Canadian CCS plans are shelved. This results in new investment drying up; existing operations move to a decline mode. Only projects located close to natural sources remain viable.
Economics & Policy • Impacts to profitability, • Ability of smaller operators or smaller fields to implement EOR/infill	Oil prices are weak relative to gas prices, driving focus away from oil production. Existing tax incentives are phased out and no new incentives are added. Additional or punitive taxes are enacted; higher risk and cost activities are avoided by operators. Regulations requiring accelerated abandonment come into play so numerous fields are abandoned and future advanced recovery projects in these locations are limited.

	Operators and resource owners have little incentive to pursue projects involving higher amounts of engineering, instead funding a smaller number of opportunities which are drilling based.

Discussion of the expected production characteristics for the Constrained Pathway is presented below along with numerical results in Table P2. Graphical representations are included in the Combined Results section and individual graphs are in Appendix A-5.

Primary/Secondary – In this area, production drops with a falloff in drilling and recompletion activity. The reduction in the first few years reflects a 15% drop, similar to that estimated in one study examining the elimination of hydraulic fracturing[53]. Thereafter, a simple decline similar to that experienced in the 1990 to 2005 time frame was applied. Similarly, Canadian production declines at higher rates.

CO_2 Enhanced Oil Recovery – Development in the United States quickly stagnates and production growth stops as infrastructure build-out all but stops. New Canadian projects never really get off the ground. In the out years, production declines slowly as projects are wound down.

Other EOR – This category would be expected to continue to decline, albeit at a higher rate than historical due primarily to relatively high gas prices and increasing per-barrel fixed costs. No improvements or alternative recovery processes are expected to fill the gap.

Table P2
Constrained Case Production Characteristics

Mmbopd By Year	US Primary + Secondary	US CO2 EOR	US Other EOR	Canadian Light	Total
2015	1.7	0.3	0.2	0.6	2.8
2025	1.1	0.2	0.2	0.4	1.9

[53] "Measuring the Economic and Energy Impacts of Proposals to Regulate Hydraulic Fracturing", prepared for the American Petroleum Institute by IHS Global Insight, 2009, http://www.api.org/Newsroom/upload/IHS_GI_Hydraulic_Fracturing_Task1.pdf

2035	0..8	0.2	0.1	0.3	1.3

3.4. Combined Results

Figures P1, P2 and P3 illustrate the perceived range of the supply fairway for onshore conventional oil for North America, the US and Canada, respectively. The Unconstrained Pathway would suggest an annual growth rate of 1% to 2% over the next 25 years. While not a step change in contribution, it does indicate a steady stream of production from a diverse resource base.

The Constrained Pathway indicates a steady decline in the range of 4% annually over the next 25 years. Not dissimilar to the decline realized for much of the past 25 years, this suggests an environment of relatively low oil prices and significant development and production costs relative to those prices.

The mid-point within the Figure P1 fairway is close to the reference production case, suggesting the potential for this resource to continue supplying an important portion of the oil supply for the continent while alternative hydrocarbon resources grow, be it unconventional liquids or natural gas.

Figure P1

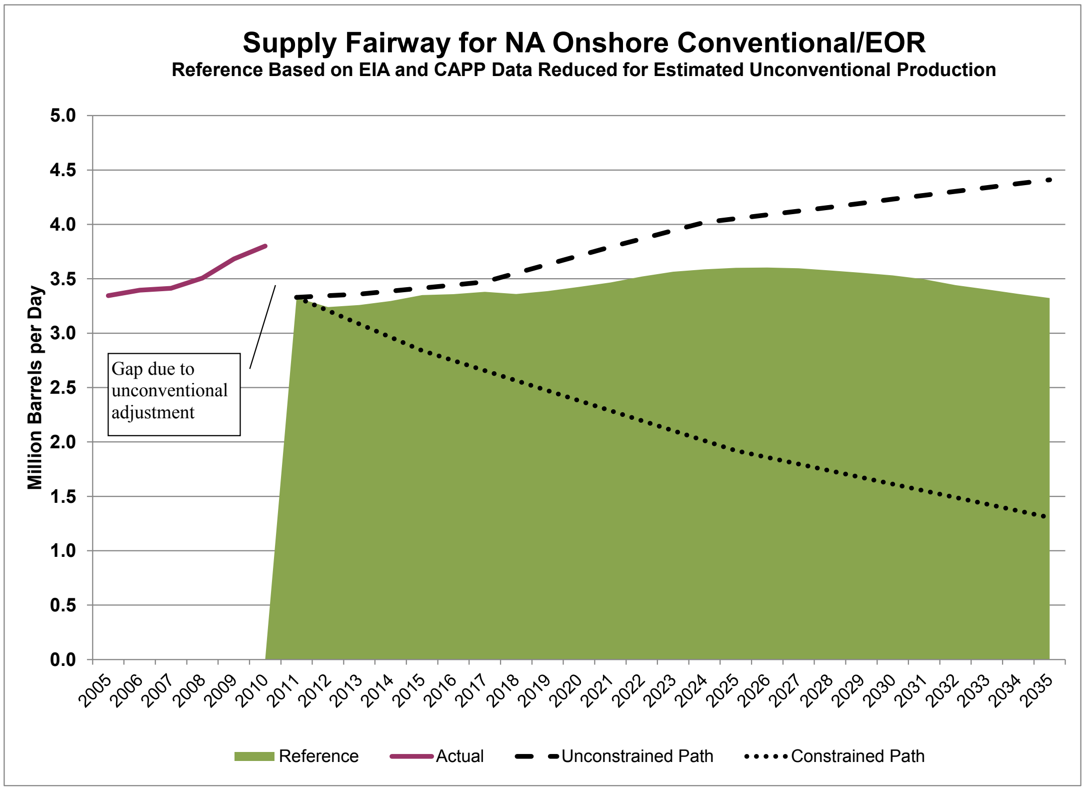

Supply Fairway for NA Onshore Conventional/EOR
Reference Based on EIA and CAPP Data Reduced for Estimated Unconventional Production
Million Barrels per Day
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
Gap due to unconventional adjustment
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
Reference
Actual
Unconstrained Path
Constrained Path

Figure P2

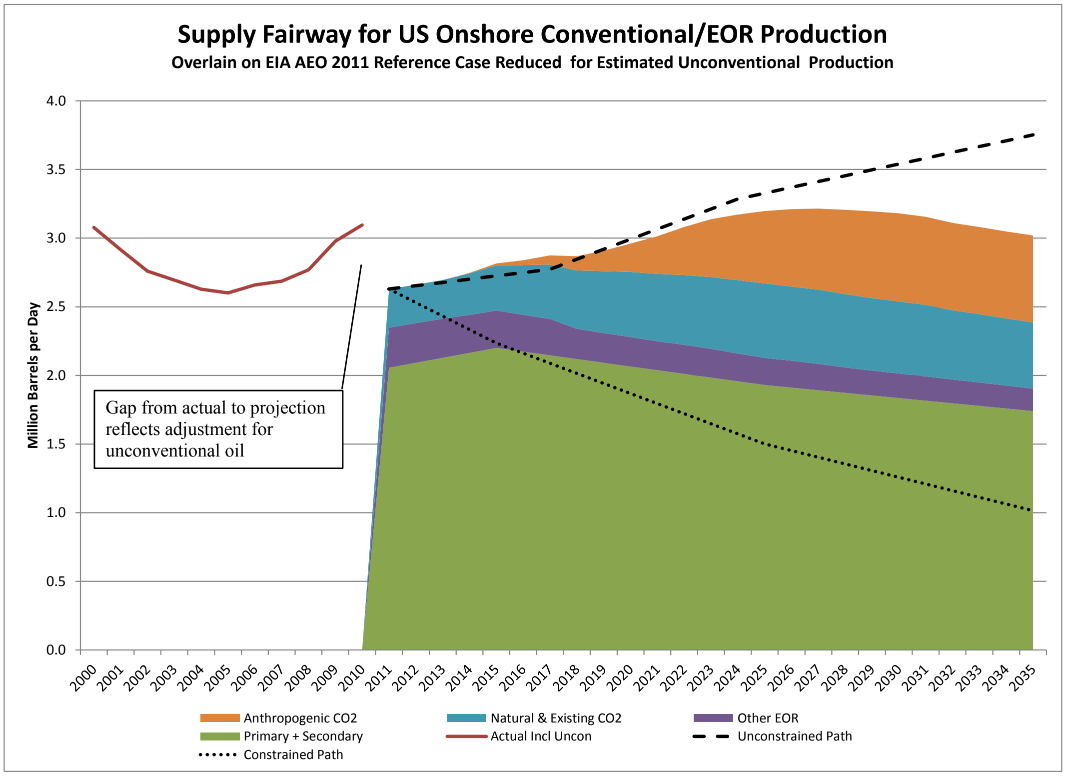
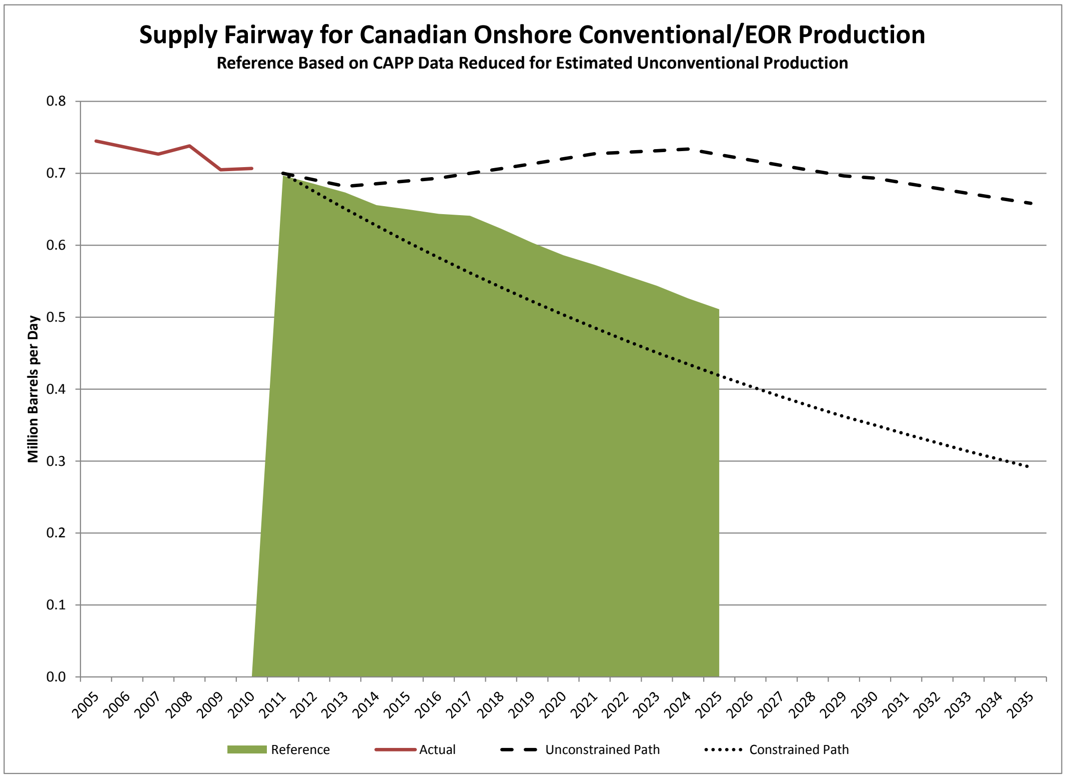


Figure P3


Supply Fairway for Canadian Onshore Conventional/EOR Production
Reference Based on CAPP Data Reduced for Estimated Unconventional Production
Million Barrels per Day
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0.0
2005 2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035
Reference
Actual
Unconstrained Path
Constrained Path

4. Findings

Findings were developed after review of the technologies, issues, enablers and challenges that the conventional onshore oil/EOR area faces. A few comments to further support and describe the findings are included as well. They are combined where appropriate and opportunity areas are listed which can be considered for action. The opportunities are generally classified as follows: 1) pro-active regulation, 2) affirmation of current practices, 3) direct financial support, and 4) institutional and/or technology support*.

Although not a finding, it is important to recognize that continued exploration, development and production from the conventional onshore area are consistent with objectives spelled out by Energy Secretary Chu in his commission of this study:

Environmental Protection – Much of the future work in the onshore area will be in locations where development has already taken place and operations are established, thus minimizing the new footprint required. In addition, the use of carbon dioxide in certain EOR processes can provide a sequestration option for captured CO_2 should public policy move in that direction.

Economic Growth – Development in the onshore is by definition internal to the continental United States and Canada, with both materials and required services typically sourced domestically. The economic benefits of investment, jobs, and tax revenues accrue at local, state/provincial and national levels.

Energy Security – The supply from this resource category is among the most secure as it is sourced from hundreds of thousands of wells in multiple regions. With this vast and diverse infrastructure, material supply disruptions are fewer and less likely to be affected by natural or man-made events.

** It is not the intention of this topic paper or sub-group to advocate that specific policies be implemented in regard to these opportunities. They are discussed to provide context for decision makers as they discuss issues which can impact oil supply.*

Finding #1: SUPPLY RESPONDS TO INCENTIVES AND CERTAINTY

Investment activity in the conventional onshore/EOR industry reacts quickly to viable economic returns, and production increases follow with some lag. Importantly, this response requires a consistent and stable regulatory policy environment. Longer term investments requiring large capital infrastructure are especially sensitive to stable policy. Sustained, incremental activity can stem the historical decline and contribute large volumes over time as gains compound year over year.

Supporting Comments

- In the mid-2000's, higher activity resulted in some 1.0 million Bopd of increased production in the onshore US. It was triggered by strong prices, incremental technology advances, and regulatory certainty. The production resulted largely from projects targeting known resources.
- This represents the activity of thousands of operators over several hundred thousand producing wells. They primarily operate in areas with existing infrastructure. As such, activity increases or decreases quickly with price signals and profitability measures and is enabled by a high level of regulatory predictability and certainty.
- The timing of the production impact varies depending upon the type of activity. Development drilling or well enhancement can add volumes within a few months; development of an EOR project may not add volumes until several years after project initiation. In uncertain policy or price environments, shorter term resource investments will generally be favored over long term projects such as EOR.

Opportunity Areas for Consideration	
Proactive Regulation	
Current Practices Affirmed	
Direct Financial Support or Investment	Review or enhance tax credit program for low volume wells
	Review/enhance the federal EOR tax credit to make it more relevant in the current price environment; consider simplification of calculations as well as alternative minimum tax impacts on capital investments
Support, Technology or Institutional Programs	Support of organizations which disseminate best practices or technology applications (e.g. Research Partnership to Secure Energy for America (RPSEA) and the Petroleum Technology Transfer Council)

Finding #2: EOR IS A CRITICAL FUTURE SUPPLY COMPONENT

Production from enhanced oil recovery projects, specifically those relying on carbon dioxide (CO_2) injection, is a critical source of long term, stable future production from lower 48 onshore conventional resources. The approach taken on various policies at both state and federal levels will determine whether this supply stream declines, has healthy incremental growth or reaches new plateaus.

Supporting Comments

- The production wedge from CO_2 EOR is one of the largest variables in conventional oil production projections, with estimates ranging from 0.3 to over 2.0 million Bopd by 2030.
- In an age when new field discoveries are smaller and generally decline faster, EOR projects provide very stable, long term sources of oil reserves.
- The resource target for all EOR is estimated at several hundred billion barrels, though this number is very dependent on oil price, CO_2 price / availability and specific field / wellbore conditions.
- EOR projects typically have high fixed and variable costs, making EOR production the "marginal barrel" in many markets, often just below prevailing oil price expectations.
- The key determinant of the size of the future EOR wedge will be a reliable, affordable and growing supply of carbon dioxide.
- Skills needed to design and operate EOR projects are not always readily available; in addition, operators of many candidate fields do not have experience in EOR.
- For some fields, there is a limited window of opportunity to implement EOR projects due to aging infrastructure and rapidly declining production volumes over which to spread fixed costs. Delays in development could mean loss of potential reserves, with ultimate impact dependent on the regulatory environment, available technology and economics. Progressive abandonment policies could allow flexibility in management of mature fields, providing opportunities to mitigate a portion of these reserve losses.

- There are a number of areas where additional regulation and/or policy actions could have significant negative consequences for EOR production.

Opportunity Areas for Consideration	
Proactive Regulation	Ensure flexible well plugging rules exist to avoid premature abandonment of candidate oil fields
	Provide regulatory certainty for well design/construction standards, re-abandonment of existing wells, CO2 capture/sequestration credits, and CO2 pipeline permitting. Maintain class II well design where CO2 is injected for EOR or concurrent EOR/storage purposes.
	Develop a clear regulatory framework for converting an initial EOR project into a CCS project which can claim financial or emission allowance incentives.
	Codify long-term liability rules for CO2 stored in reservoir after EOR
Current Practices Affirmed	New regulations around the handling and use of carbon dioxide are limited (example: new rules from EPA regarding CO2 as "hazardous")
	The regulatory framework in states with existing CO2 operations are exported to new areas without addition of onerous changes. Example: CO2 pipelines - no need to reinvent the wheel.
	Projects which incidentally store CO2 not be harmed by new regulations targeting storage projects pursued for financial purposes.
Direct Financial Support or Investment	Support conversion of public oil & gas data from paper/film legacy systems to digital format to improve project development capability and efficiencies.
	Tax policy to incentivize new computer hardware/software.
	Rapid amortization for site characterization or other front end costs.
	Review/enhance the federal EOR tax credit to make it more relevant in the current price environment; consider simplification of calculations and negative AMT impacts.
Support, Technology or Institutional Programs	Support of research in the areas of reservoir characterization, reservoir modeling and sweep efficiency improvement. Consider public/private partnerships (e.g. RPSEA) to provide appropriate prioritization of topics.

Finding #3: NEW LARGE-SCALE CO_2 SUPPLIES ARE REQUIRED FOR UPSIDE EOR SUPPLY PROJECTIONS

A large increase in CO_2 supply from dilute anthropogenic sources will be required over the next 10 to 15 years to extend the production levels attributable to EOR. The keys to this supply will be complex, linked to carbon storage/sequestration and involve substantial government fiscal and policy action.

Supporting Comments

- Estimates of oil supply resulting from capture projects using dilute CO_2 sources range to over 2 million Bopd.
- The cost of dilute CO_2 is dominated by high capture costs; support will be required to build demonstration projects for supply and as test sites for technology evolution.
- Lack of growth in this area appears to be due to economics as opposed to a market failure.
- EOR is compatible with CCS should it move forward; EOR projects are seen as a win-win for those advocating early adoption of CCS.
- Permanent carbon sequestration during EOR will be part of the justification of these projects; the legal framework to delineate post-closure liability must be put in place. Additional considerations include pore space ownership, well design standards and potential re-abandonment of existing wells.
- These issues are already well-discussed among various government agencies and industry groups (CRS, US EPA, IOGCC, IEA, etc.)
- State support can be important even if financial incentives are small; it helps to provide greater regulatory certainty and remove barriers that arise in any new project development.
- Canada may be ahead of the US in this area with a combination of policy and funding.

Opportunity Areas for Consideration	
Proactive Regulation	A program is implemented which incentivizes emission reductions while recognizing CO2 EOR as a CCS option.
	Framework and regulations are developed which allow operators to understand and manage post-closure liability from the outset of project conceptualization.
	States without clear processes regarding CO2 EOR use IOGCC guidance or another source to develop needed regulations; don't reinvent the wheel.
	CERCLA/RCRA exemptions for storage in qualified sites
	Price premium for low-carbon power, akin to "renewable" pricing, or, "credit" for CO2 sequestered via EOR. Ability to generate offsets for CO2 captured from sources outside regulatory jurisdiction.
Current Practices Affirmed	Adoption of any new rules do not hinder projects that are operating or in the permitting phase
	CO2 transportation regulations, currently under discussion for CCS, are not onerous for EOR users
	Maintain a flexible approach which allows both common-carrier and private CO2 pipeline models
	Avoid considering CO2 a pollutant; reinforce with regulators that CO2 is not hazardous, and is not corrosive in the absence of free water or with proper metallurgy.
Direct Financial Support or Investment	Direct investment or funding of carbon capture and EOR + Sequestration projects for demonstration purposes
	Express backstop of long term liabilities arising from sequestration may be necessary, including trust fund models as recently adopted by several states.
	Enhanced tax credits for CO2 EOR + Sequestration projects with exemptions from liability under Alternative Minimum Tax provisions
Support, Technology or Institutional Programs	Increased funding for NETL Carbon Sequestration Partnerships

Finding #4 RESIDUAL OIL ZONES HAVE PROMISE

There are substantial petroleum resources in low-oil saturation zones, which occur naturally or are remaining after primary and secondary recovery. The natural zones are now known to be a significant resource as well. Increased understanding of these zones will ultimately be necessary for extensive development, whether via carbon dioxide flooding or another EOR technology.

Supporting Comments

- A sizable portion of the 300+ billion barrels expected to remain unrecovered in existing oil fields are in zones of low oil saturation.
- There are additional low oil saturation zones (often called residual oil zones or ROZ) which occur naturally. These are not well characterized, but have been conservatively estimated to hold at least 80 billion barrels. These provide a new set of targets in addition to already produced fields. Evaluation of additional areas between existing fields is likely to add significantly to these estimates.
- Carbon dioxide flooding is the only applicable process which is currently deployed on a commercial scale to recover these resources. As such, the new target zones offer large storage potential should CCS advance.
- Technology development and demonstration in these zones will be focused in areas with existing infrastructure and CO_2 supply options.
- At this point, no non- CO_2 alternative EOR process has been developed that appears to be capable of substantial commercial development. Waterfloods which include chemical additives seem to have the most application and promise.

Opportunity Areas for Consideration	
Proactive Regulation	Ensure flexible well plugging rules exist to avoid premature abandonment of candidate oil fields or sectors within fields
Current Practices Affirmed	
Direct Financial Support or Investment	Consider separate tax credit to incent ROZ development
Support, Technology or Institutional Programs	Support work to describe the ROZ resources at various levels, including state agencies, universities, USDOE, RPSEA and the USGS.
	Support open access research in alternative recovery processes, focusing on chemical flooding. Need both basic and applied research.

Finding #5 TECHNOLOGY DEVELOPMENT OFFERS TOOLS FOR RESERVES GROWTH

Much like in the unconventional oil and onshore gas arenas, the technologies of horizontal drilling and advanced hydraulic fracturing are important to developing opportunities in the conventional oil area. Techniques to monitor and understand horizontal well performance will grow in importance as the use of these types of wells continues to grow.

Supporting Comments

- These technologies, when combined with price, offer new tools to profitably develop conventional oil and EOR reservoirs. In many situations, these allow new hydrocarbon targets, previously thought un-producible, to be developed.
- Horizontal wells accounted for over 50% of wells drilled in the US during 2010.
- Given the increasing reliance on horizontal wells for reserve development, it will be critical to understand fluid flow in a given well to optimize production and maximize reserves and recovery efficiencies.
- These technologies can depend on materials which may be in short supply or are used extensively in other industries.

Opportunity Areas for Consideration	
Proactive Regulation	
Current Practices Affirmed	New regulation on hydraulic fracturing should endeavor to maintain current effectiveness to avoid loss of opportunities
	Maintain ability to comingle multiple formations where conservation principles are not compromised
Direct Financial Support or Investment	
Support, Technology or Institutional Programs	Support research in the areas of downhole monitoring of wells, especially horizontals and those used in EOR.
	Working group of industry and government to identify potential material shortages and actions to mitigate impact

Appendices

Appendix A-1

United States Enhanced Oil Recovery Production, 1986 – 1998
By Technology Category
In Thousand Barrels Per Day

EOR Technology Category	**1986**	**1988**	**1990**	**1992**	**1994**	**1996**	**1998**
Thermal Injection EOR							
Steam	469	455	444	454	416	419	439
In-Situ Combustion	10	7	6	5	3	4	5
Hot Water	1	3	4	2	negligible	negligible	2
Total Thermal EOR	480	465	454	461	419	424	446
Chemical Injection EOR							
Polymer/Chemicals	15	21	11	2	2	negligible	negligible
Other	1	2	1	negligible	negligible		
Total Chemical EOR	17	23	12	2	2	negligible	negligible
Gas Injection EOR							
Hydrocarbon – Miscible and Immiscible	34	26	55	113	100	96	102
CO2 Miscible	28	64	96	145	161	171	179
CO2 Immiscible	1	negligible	negligible	negligible			
Nitrogen	19	19	22	23	23	28	28
Flue Gas/Other	26	21	17	17	4	4	4
Total Gas EOR	108	131	191	298	289	299	314
Total U.S. EOR Production	605	618	657	761	709	724	760
Total Onshore Lower-48 EOR Production 1/	571	592	601	648	609	627	658
Total Onshore Lower-48 Oil Production	5,560	4,932	4,500	4,239	3,733	3,509	3,385
Total Onshore Lower-48 Conventional Oil Production	4,989	4,313	3,843	3,478	3,024	2,785	2,625
EOR Percent of Total Onshore Lower-48 Oil Production 2/	10.3%	12.0%	13.4%	15.3%	16.3%	17.9%	19.4%

Sources: Oil and Gas Journal Biennial EOR Survey and U.S. Energy Information Administration
A table entry of "negligible" indicates that the production volume was less than 0.5 thousand barrels per day.
1/ All Hydrocarbon – Miscible and Immiscible EOR Production is located either in Alaska or the offshore Gulf of Mexico. So, the EOR production volumes in this category were subtracted from U.S. total to calculate onshore lower-48 EOR oil production.
2/ Based on Total Onshore Lower-48 EOR Production, which excludes Hydrocarbon EOR production.

Appendix A-2
EIA Annual Energy Outlook 2011
Crude Oil Production for Three Oil Price Cases

2010	Reference Case	High Price Case	Low Price Case
Low-Sulfur Light Oil Price (2009 $/bbl)	$78.03	$78.03	$78.03
Oil Production (MMB/D)			
Onshore Lower - 48	3.11	3.11	3.11
Primary & Secondary	2.53	2.53	2.53
Carbon Dioxide EOR	0.28	0.28	0.28
Thermal & Other EOR	0.30	0.30	0.30
Offshore & Alaska	2.40	2.40	2.40
Total United States	5.51	5.51	5.51
2015	Reference Case	High Price Case	Low Price Case
Low-Sulfur Light Oil Price (2009 $/bbl)	$94.58	$146.10	$50.00
Oil Production (MMB/D)			
Onshore Lower - 48	3.51	3.62	3.44
Primary & Secondary	2.90	3.00	2.84
Carbon Dioxide EOR	0.34	0.35	0.32
Thermal & Other EOR	0.27	0.27	0.27
Offshore & Alaska	2.30	2.31	2.30
Total United States	5.81	5.93	5.74
2025	Reference Case	High Price Case	Low Price Case
Low-Sulfur Light Oil Price (2009 $/bbl)	$117.54	$185.87	$51.28
Oil Production (MMB/D)			
Onshore Lower - 48	3.92	4.32	3.35
Primary & Secondary	2.65	2.88	2.42
Carbon Dioxide EOR	1.07	1.24	0.74
Thermal & Other EOR	0.20	0.20	0.20
Offshore & Alaska	1.96	2.74	1.85
Total United States	5.88	7.06	5.20
2035	Reference Case	High Price Case	Low Price Case
Low-Sulfur Light Oil Price (2009 $/bbl)	$124.94	$199.95	$50.07
Oil Production (MMB/D)			
Onshore Lower - 48	3.65	4.24	2.75
Primary & Secondary	2.37	2.63	2.01
Carbon Dioxide EOR	1.12	1.44	0.57
Thermal & Other EOR	0.16	0.16	0.16
Offshore & Alaska	2.30	2.89	1.58
Total United States	5.95	7.13	4.33

Appendix A-3
EIA Annual Energy Outlook 2011 Reference Case
Onshore Lower-48
Carbon Dioxide Enhanced Oil Recovery Production by Region
In thousand barrels per day

Thousand Barrels Per Day	2010	2015	2025	2035
East Coast	0	2	18	11
Gulf Coast	25	45	151	126
Mid-Continent	32	29	299	328
Southwest	186	212	412	462
Rocky Mountain	40	48	130	125
West Coast	0	8	60	63
Total Onshore Lower-48	282	343	1,070	1,115
Percent of Total				
East Coast	0 %	0 %	2 %	1 %
Gulf Coast	9 %	13 %	14 %	11 %
Mid-Continent	11 %	8 %	28 %	29 %
Southwest	66 %	62 %	38 %	41 %
Rocky Mountain	14 %	14 %	12 %	11 %
West Coast	0 %	2 %	6 %	6 %
Total Onshore Lower-48	100 %	100 %	100 %	100 %

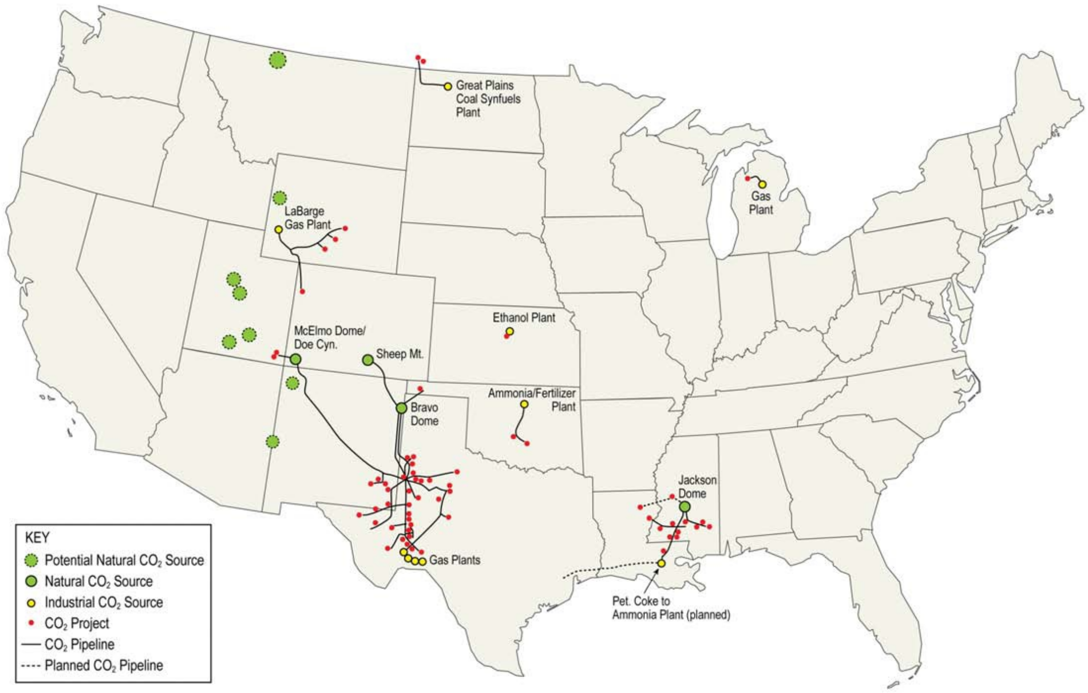
Appendix A-4
Some Additional Context on Carbon Dioxide

Enhanced oil recovery using carbon dioxide is an established technology which has been used in the United States since the 1970's. The roughly 280 MBopd estimated to be produced using this process comes from about 110 projects in the Gulf Coast, Southwest and Rocky Mountain regions[54].

A key requirement for the projects is a dependable source of high purity CO_2 which is available at a reasonable cost. For EOR, relatively pure CO_2 is important as impurities increase the cost of CO_2 handling and reduce effective oil recovery. The bulk of the of CO_2 EOR development to date has been in areas of west Texas and southeast New Mexico, where candidate oil fields and naturally occurring source fields are close enough to provide CO_2 at a reasonable cost. CO_2 EOR activity in the southern Mississippi region is also increasing for the same reason. In other locations, projects have been implemented where candidate oil fields are close to a relatively pure industrial source, where CO_2 is economically captured for EOR use. Figure A4-1 is a map illustrating the location of major CO_2 EOR developments.

[54] "2010 Worldwide EOR Survey", Oil & Gas Journal, April 19, 2010, page 41.

Figure A4-1



Source: "Carbon Dioxide Enhanced Oil Recovery", National Energy Technology Laboratory, U.S. Department of Energy, March, 2010, pages 10. http://www.netl.doe.gov/technologies/oil-gas/publications/EP/small_CO2_EOR_Primer.pdf

Although there are some incremental development activities to produce naturally occurring CO2 (see, for example Denbury Resources[55] and Kinder Morgan[56]), most natural CO2 supply sources have been fully developed. Future CO_2 supply growth is expected to come from new anthropogenic sources. The most likely near term projects are those where a relatively pure source exists, making capture and transport cost effective. Recent examples include separation of CO_2 from natural gas (for example, Denbury Resources[57] , ExxonMobil[58], and Oxy/Sandridge[59]). Certain industries,

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[55] Denbury Resources Inc., Fall Analyst Meeting, November 18, 2010, slide 10
[56] Kinder Morgan CO2 Supply web page, Kinder Morgan Inc., http://www.kne.com/business/co2/supply_mcelmo.cfm
[57] Press Release, Denbury Resources, Inc., June 28, 2011, http://phx.corporate-ir.net/phoenix.zhtml?c=72374&p=irol-newsArticle&ID=1580286&highlight=
[58]LaBarge Field & Shute Creek Facility", presentation by ExxonMobil at the 3rd Annual Wyoming CO2 Conference, The Wyoming Enhanced Oil Recovery Institute, June, 2009. http://www.uwyo.edu/eori/_files/co2conference09/ExxonMobil%20EORI%20Presentation_June%202009,EORI%20website%20posting%20.pdf

including hydrogen, ethanol, cement, ammonia, lime, iron and steel produce carbon dioxide streams as a by-product. Over time, a portion of this CO_2 production could be pulled towards EOR by market demand. As the price of oil has increased, this has increased the demand for CO_2 and its value. Future CO_2 supply growth will depend to a large degree on oil pricing, perceptions about its future and advances in capture technology.

Dilute anthropogenic CO_2 sources are numerous and widespread, but are also the most challenging to develop. The technology to capture and purify CO_2 from large point sources such as power plant flue gas is still developing and will likely require substantial fiscal and regulatory support to demonstrate at a large scale and achieve economic viability. Likewise, CO_2 production from coal or biomass to liquid projects will also require incentives.

A recent U.S. government task force illustrates that EOR projects could play an important role in carbon capture and storage (CCS).[60] To overcome barriers to CCS development, 5 to 10 commercial scale demonstration projects are suggested. The majority of these projects include EOR as part of the geologic storage component. In this context, EOR projects are seen as win-win by proponents of early CCS adoption.

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[59] Press release, Occidental Petroleum, Inc., June 30, 2008. "Occidental to Develop Major New Texas Enhanced Oil Recovery Assets, Increasing U.S. Production"

[60] "Report of the Interagency Task Force on Carbon Capture and Storage", Various U.S. Agencies, August, 2010, Page 32, http://www.fe.doe.gov/programs/sequestration/ccstf/CCSTaskForceReport2010.pdf

Appendix A-5

Figure A5-1

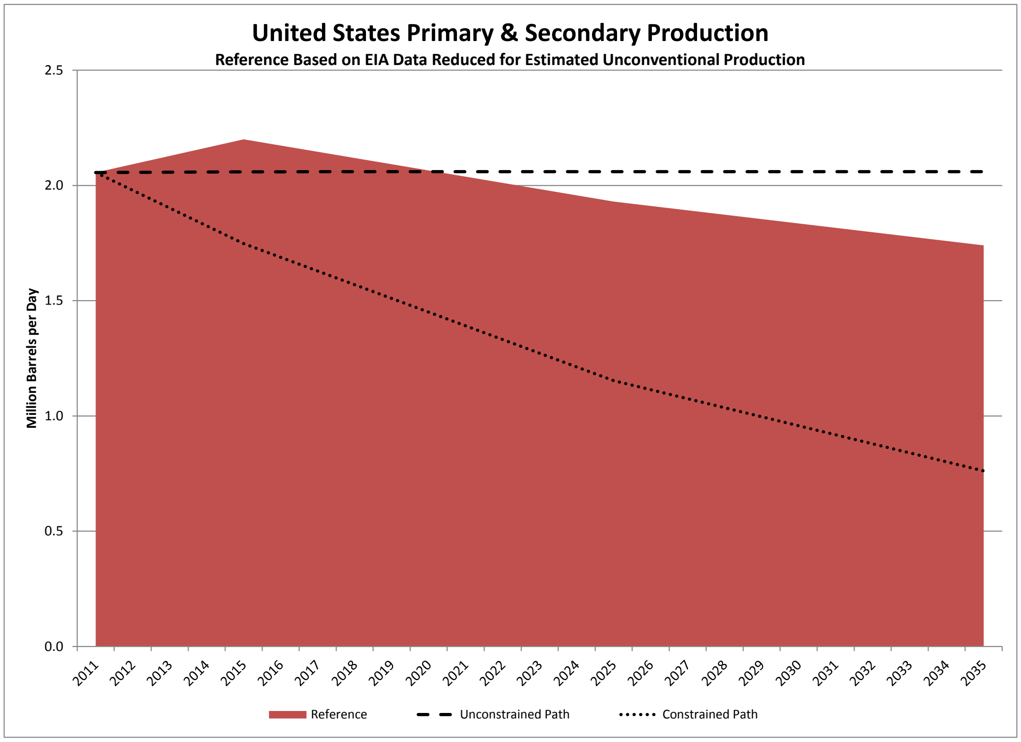


Figure A5-2

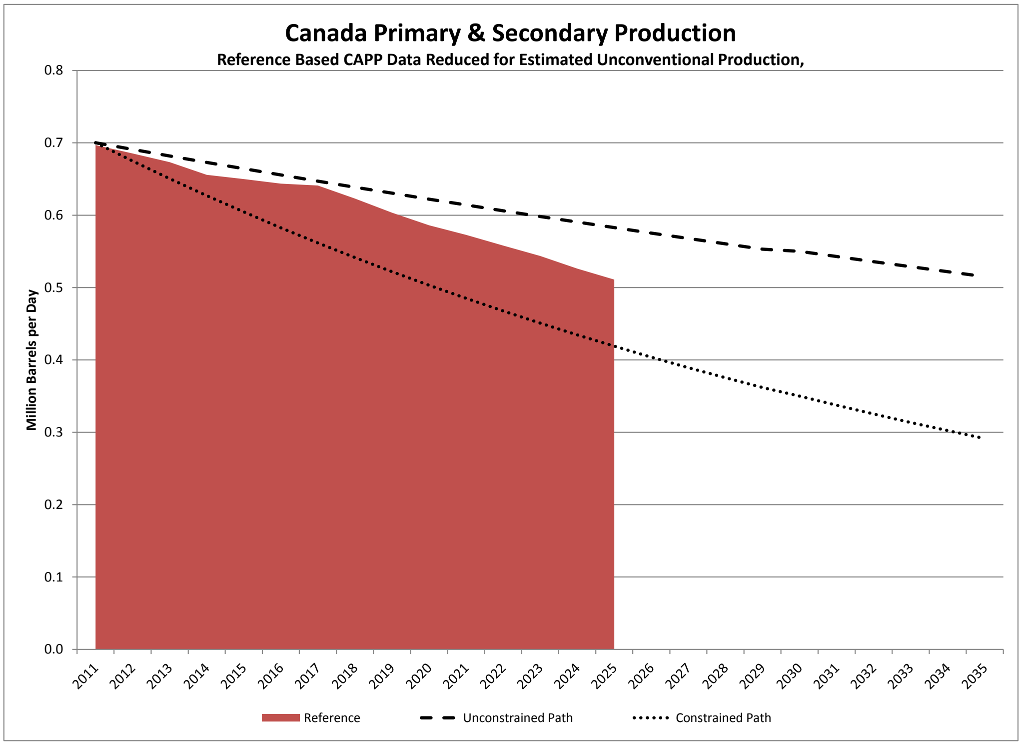


Figure A5-3

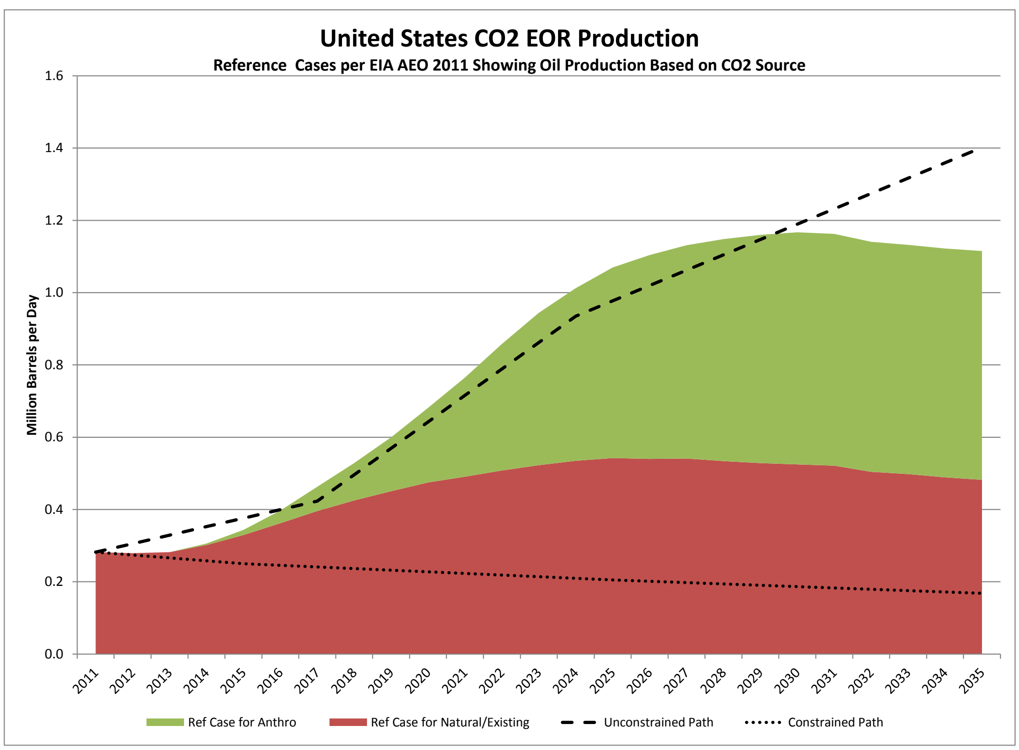


Figure A5-4

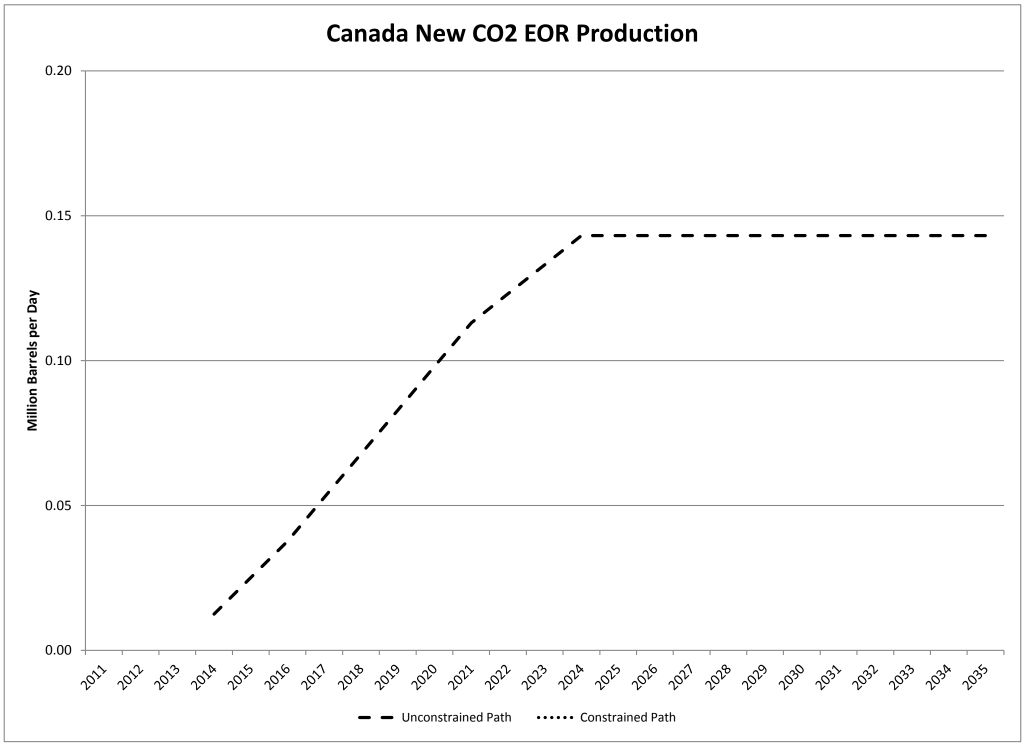
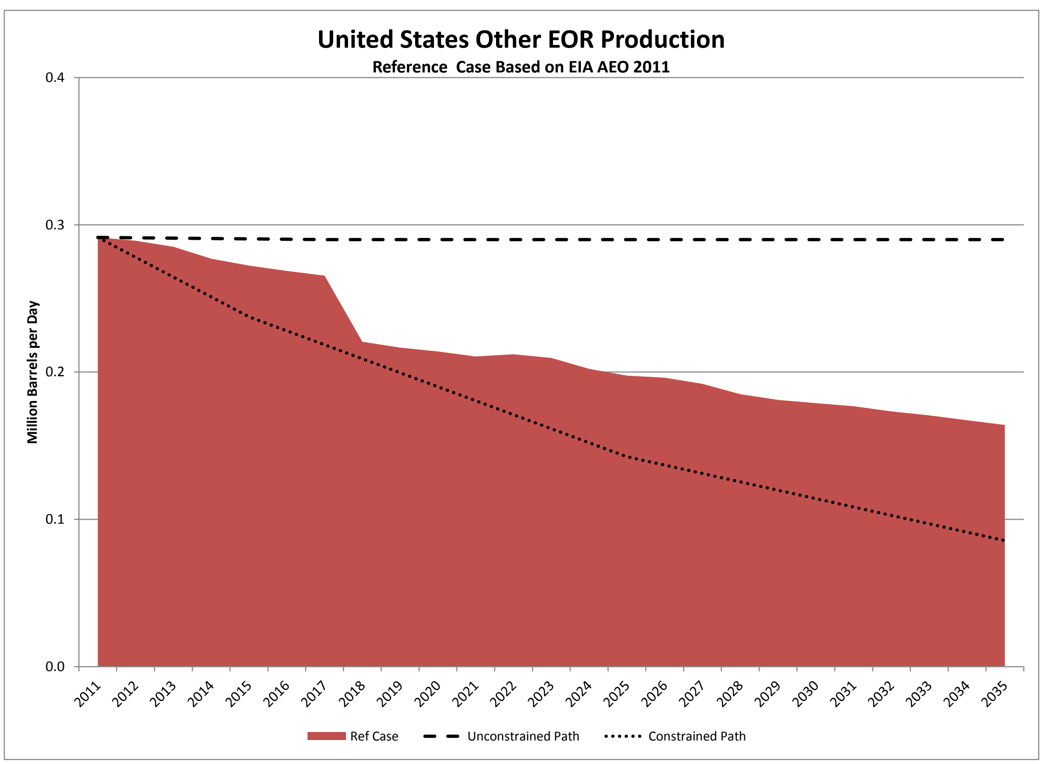

Canada New CO2 EOR Production
Million Barrels per Day
0.20
0.15
0.10
0.05
0.00
2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035
Unconstrained Path
Constrained Path

Figure A5-5


United States Other EOR Production
Reference Case Based on EIA AEO 2011
Million Barrels per Day
0.4
0.3
0.2
0.1
0.0
2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035
Ref Case
Unconstrained Path
Constrained Path