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# CO<sub>2</sub>-EOR Potential in the MGA Region

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# EXECUTIVE SUMMARY

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The Midwestern Governors Association (MGA) region has significant technical and economic potential to arrest the decline, and eventually grow the production of crude oil from its mature oil fields. The analysis of region's petroleum resources suggests that carbon dioxide enhanced oil recovery (CO<sub>2</sub>-EOR) may be an attractive commercial opportunity.

CO<sub>2</sub>-EOR is a thirty year old technology used widely in the Permian Basin of Texas and other geographies to extract significant volumes of incremental oil from mature fields that would have otherwise been left in the ground. Screens used in this assessment to identify EOR candidate fields suggest that an estimated 2 billion barrels of oil could be produced utilizing anthropogenic carbon dioxide for EOR. All four principal MGA oil regions in Michigan, Illinois/Indiana, Kansas, and Ohio were considered.

To produce this oil as much as 1 billion metric tons of anthropogenic CO<sub>2</sub> would be needed over a period of ten to twenty years. The CO<sub>2</sub> emissions from stationary sources in the region are at about 700 million metric tons per annum, significantly more than would be required for regional EOR, with power plants contributing about 80% of the volume. The cost of capturing CO<sub>2</sub> at power plants is still quite high, and may be prohibitive for enhanced oil recovery in the near term if oilfield operators were expected to pay for the full cost of capture from these facilities. However, the region is quite fortunate to have about 35 million metric tons per annum of CO<sub>2</sub> from ethanol fermentation, which can be captured at relatively low cost. ADM is currently capturing approximately 1MMT of CO<sub>2</sub> over three years from their Decatur plant and injecting it into the Mt. Simon saline aquifer in the first of two DOE/ISGS studies, demonstrating the cost and feasibility of CO<sub>2</sub> capture, injection, and geological storage. States such as Iowa and Nebraska, with large volumes of ethanol based CO<sub>2</sub>, can play an important role in supplying the commodity to oilfield operators in neighboring MGA oil states.

Analysis of the potential economics of a CO<sub>2</sub> "flood" in a representative field in each of four principal oil regions suggests that CO<sub>2</sub>-EOR in the MGA could be economically

viable at the reference case assumptions. The reference case uses US EIA oil price projections (about 1% per annum real price increase), CO<sub>2</sub> cost at a current "market" price of about \$32 per metric ton (in the future indexed to oil prices), and best available estimates of production curves and associated investment costs. In addition to the reference case, sensitivities around critical parameters were tested.

Generally, for the reference case, project economics lead to an after-tax IRR of 20% or higher with significant variation across states as described below. The economics of CO<sub>2</sub>-EOR are highly dependent on the operator's projections of oil production response to CO<sub>2</sub> injection, and the capital investment required in wells and surface equipment to upgrade or replace lease assets already in the field. In most cases a CO<sub>2</sub> price of \$80 per metric ton renders projects uneconomic. However a portion of the MGA's emissions sources, such as ethanol and natural gas processing, can supply CO<sub>2</sub> at or below current "market" prices, improving the potential commercial viability of EOR. Furthermore, a broader agenda for the growth and support of CO<sub>2</sub>-EOR activity in the region, with possible investment incentives for operators and emitters, could have a catalyzing effect for the industry.

If CO<sub>2</sub>-EOR were developed on a wide scale, MGA states could add at least 6000 direct new jobs and 3 times as many indirect jobs. Additional benefits would flow through royalties on state mineral interests where they exist, severance taxes on production, and corporate and personal income taxes.

CO<sub>2</sub>-EOR can provide an important balance between the benefits of economic growth from an extractive industry and environmental benefits to society as a whole. As a "new" source of oil, it supports national energy security goals and can improve regional and local economies. As a market for carbon dioxide, it can establish a price signal for carbon, and catalyze, or perhaps even finance, infrastructure for carbon capture and sequestration. In producing more fossil fuels CO<sub>2</sub>-EOR may actually play an important role in the reduction of greenhouse gasses from the atmosphere.

This assessment evaluated the economic potential of select representative fields in each state or basin, with the following conclusions:

## Michigan

The state holds more than 250 million barrels of CO<sub>2</sub>-EOR potential. Our analysis focused on Niagaran Pinnacle Reef trend in the northern lower peninsula, where Core Energy is currently operating the only commercially successful CO<sub>2</sub>-EOR floods in the MGA region. With reference case assumptions, the after-tax project IRR of the representative field could reach more than 40%. However, sourcing of “market price” CO<sub>2</sub> may be problematic, as less than 1 million tons of CO<sub>2</sub> per annum can be supplied by local gas processing. Any additional needs would have to be supported through higher cost capture at power plants. The potential Wolverine Clean Energy Venture project could be an attractive source of CO<sub>2</sub>. The State of Michigan would benefit significantly, through additional royalty revenue from state mineral interests, additional severance tax revenue, and the formation of new jobs.

## Illinois & Indiana

Illinois and Indiana hold more than 500 million barrels of technical CO<sub>2</sub>-EOR potential. A significant volume of “market priced” CO<sub>2</sub> could potentially be sourced and aggregated from ethanol plants both in-state and “imported” from Iowa. This analysis focused on two representative scenarios: the New Harmony field, representing large fields in the Illinois Basin, and the smaller fields of Herald and Concord. The economics suggest an after tax project IRR of about 20% for the larger field and marginal returns of 10% for the smaller fields. The condition of old wells in this area will be critical to operator economics, as much higher capital needs would reduce attractiveness.

## Ohio

The state could be a great commercial success, with about 500 million barrels of incremental CO<sub>2</sub>-EOR potential. However, significant work and further field characterization is needed to confirm this assessment. The East Canton field analysis suggests that a project in this area could deliver an

after tax project IRR of more than 25%, with continuous CO<sub>2</sub> injection, which is likely required for this geology. This approach would require somewhat higher CO<sub>2</sub> utilization rates (0.8mt net CO<sub>2</sub> per barrel of oil produced) than is commonly assumed for a CO<sub>2</sub> flood. While sourcing CO<sub>2</sub> is technically feasible through capture at many local power plants, high capture costs would likely lead to a high cost of CO<sub>2</sub> to the oilfield operator. Sourcing of attractively priced CO<sub>2</sub> is likely to be limited in volume, but enough to test EOR potential. Over time CO<sub>2</sub> availability could increase with the development of shale gas and possible investment incentives.

## Kansas

The state holds more than 750 million barrels of technical CO<sub>2</sub>-EOR potential. Kansas has by far the largest oil resources in the MGA region and shares geological formations with Oklahoma, where commercial CO<sub>2</sub> floods are proven and are serviced by existing and planned CO<sub>2</sub> pipeline infrastructure. The historically prolific Hall Gurney field in central Kansas was chosen for analysis. Economic results utilizing the reference case assumptions suggest an after-tax project IRR of about 20%. However, significant questions remain around geological, performance, and operational assumptions, and need to be examined further. Kansas has a moderate in-state supply of lower cost CO<sub>2</sub> from fertilizer plants and ethanol fermentation, and is currently exporting some of that CO<sub>2</sub> via pipeline for EOR in Oklahoma. The state would have access to the significant volumes of ethanol-based CO<sub>2</sub> in Nebraska, which produces approximately 6 million metric tons per annum.



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# BACKGROUND

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Most oil fields that are classified as economically “depleted” still have significant oil resources remaining in the ground. Traditionally, a field will go through a primary (conventional) and a secondary (water flood) stage of oil recovery before achieving “depletion” when production rates decline to a level no longer considered economic. Primary and secondary production combined typically produce only 30-40% of a reservoir’s original oil in place (OOIP), often leaving over 60%, and at times as much as 90% of the original oil in the ground. A tertiary stage of recovery, also known as enhanced oil recovery can extract some of this remaining oil and extend field life. Specific geologies and oil characteristics determine the type of enhanced recovery technique an operator might use. CO<sub>2</sub>-EOR is a technique particularly appropriate for many MGA region fields, and can yield an additional 10-15% or more of OOIP. Under the right geological conditions carbon dioxide becomes miscible with oil, making it easier to drive out of the reservoir rock. Even when miscibility cannot be achieved, carbon dioxide swells the oil and reduces its viscosity, thereby improving recovery. Some of the carbon dioxide is produced with the oil, and is then recycled and reinjected into the reservoir.

In the United States, CO<sub>2</sub>-EOR is a 30 year old technology that currently accounts for more than 280 thousand barrels of oil per day (mb/d) of production nationwide, predominantly in Texas, Louisiana, Mississippi, Oklahoma, and Wyoming. Historically, CO<sub>2</sub> has been supplied from natural CO<sub>2</sub> deposits, similar to natural gas, found in Colorado and New Mexico (supplying Texas and Oklahoma) and Mississippi (supplying the Gulf Coast). However, natural CO<sub>2</sub> is not very common, and there are no known reserves in the MGA region. In Wyoming CO<sub>2</sub> is supplied from a large natural gas plant that removes the CO<sub>2</sub> as an impurity from the gas. In the traditional CO<sub>2</sub>

markets, demand from operators has begun to outstrip supply of natural CO<sub>2</sub>, and increasingly industry players are turning to anthropogenic supplies of CO<sub>2</sub>. Denbury Resources, a vertically integrated CO<sub>2</sub>-EOR operator, signed MOUs with developers of proposed carbon capture power plant projects in the MGA region to purchase and transport their CO<sub>2</sub> down to the Gulf Coast to use for EOR if enough projects are built to justify a pipeline of that length.

Oil production from successful CO<sub>2</sub>-EOR floods brings the same significant benefits to national energy security and to regional economies as oil production by other means. However, CO<sub>2</sub>-EOR also provides potential environmental benefits by establishing a price signal for carbon, and catalyzing, or perhaps even financing, infrastructure for carbon capture and sequestration. Even in the production of additional fossil fuels, CO<sub>2</sub>-EOR may be an important step towards the reduction of greenhouse gasses from the atmosphere.

As the technical skill set required to implement a CO<sub>2</sub> flood has spread beyond the Permian Basin and Mississippi operators, and as the industry increasingly turns to anthropogenic sources of CO<sub>2</sub>, other oil regions have begun to explore the feasibility and potential of CO<sub>2</sub>-EOR. This report provides a high level assessment of the commercial viability of CO<sub>2</sub>-EOR in the Midwestern Governors Association political region, and is intended to assist MGA stakeholders in outlining a path forward. It was developed by the Clinton Climate Initiative in collaboration with the Great Plains Institute, pursuant to recommendations of the Midwestern Governors Association’s (MGA) CCS Task Force and in advancement of Governor Pat Quinn’s 2011 MGA Chair’s Agenda.

# APPROACH AND ASSUMPTIONS

A set of reference case assumptions were developed for important parameters that would affect project economics (all values are nominal):

## Oil Price

The reference case assumes the current West Texas Intermediate (WTI) average crude oil price for 2011 of approximately \$95/bbl, with future prices projected as per the 2011 EIA US Annual Energy Outlook (about 1% per annum real price increase). The “Low Price” case assumes a \$70/bbl WTI price with future pricing indexed at the same inflation rate as the EIA Outlook.

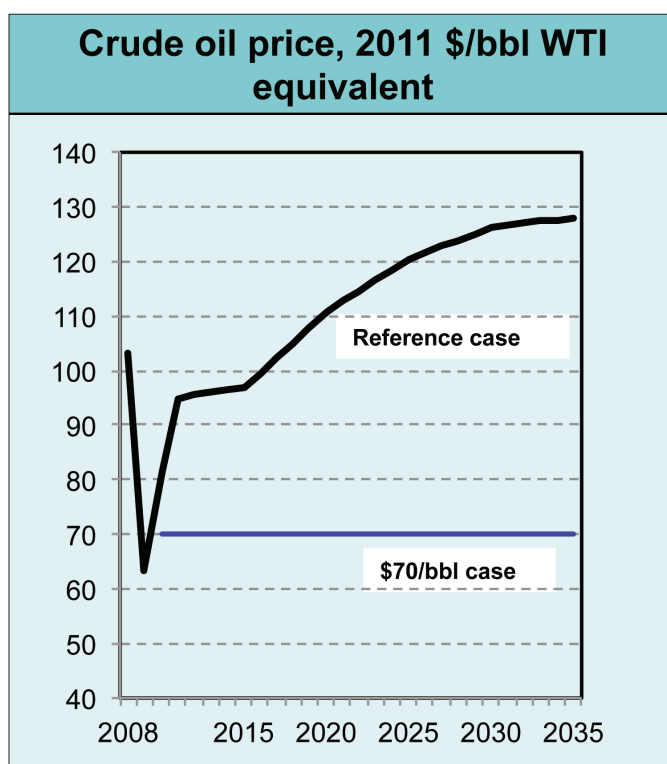


Figure 1: Crude Oil Market Price

## CO<sub>2</sub> Price

The reference case assumes a spot price in the West Texas EOR market of about 2% of the crude oil price in units of million cubic feet (mcf). Therefore at \$95/bbl, the price of CO<sub>2</sub> is \$1.90/mcf, or \$36/MT. Sensitivities assume real prices (indexed to oil inflation) of \$25, \$50, and \$80 per MT reflective of a broad estimate of the cost of capture from industrial sources that produce CO<sub>2</sub> streams at different

purities. Ethanol fermentation, natural gas processing, and ammonia production all produce high purity streams of CO<sub>2</sub>. These sources represent the \$25/MT case. At the opposite end, traditional coal fired power plants require separating the CO<sub>2</sub> from other flue gasses, which is still an expensive technology. This represents the \$80/MT case. Hydrogen plants and other sources represent the middle tier case.

## Field Analysis

Representative fields in each of the MGA oil regions that had passed the screens were selected for analysis based on economic potential and data availability, either in the public domain or via experts. For simplicity, this assessment assumes that an entire field would be unitized or otherwise developed by one operator, and that all capital investments would be made prior to the commencement of operations. Estimates of total and baseline (status quo) production were generated and economics of incremental future production was evaluated using a discounted cash flow analysis. Operations were assumed to end when net cash flows turn negative in the model, and since EOR is assumed to be the last and final phase of recovery prior to field abandonment, no terminal value was assigned.

## Production Curves

Oilfield economics are sensitive to field performance. Projections of oil, water, and CO<sub>2</sub> production for this assessment were based on curves of simulated reservoir performance under CO<sub>2</sub> flooding. Performance of the field under evaluation is assumed to replicate the simulation once scaled for differences in original oil in place. Except for East Canton, OH, projections used in this assessment reflect work done by the Illinois State Geological Survey on nine leases in the Illinois Basin for the 2005 MGSC “Phase 1” report. These projections will be most appropriate for Illinois Basin reservoirs, and somewhat less appropriate for Michigan and Kansas. However, industry experience has demonstrated that CO<sub>2</sub>-EOR performance is generally better in carbonate formations, the lithology of the reservoirs in the Michigan and Kansas scenarios in this analysis, than in sandstone formations, the prevalent lithology in the Illinois Basin.

Hence the production curves for Michigan and Kansas in this analysis may be conservative. For the East Canton (OH) field, projections were derived from pilot simulations conducted for that field in 2008-2010.

## Capital and Investment Costs

Large capital investments in the field are required to prepare it for a CO<sub>2</sub> flood. At minimum, wells and surface equipment need to be upgraded to handle carbon dioxide. Larger capital investments may involve drilling new wells either to optimize flood design or to replace wells in poor condition. New wellheads, injection equipment, and changes to central production facilities where oil is separated from water (and CO<sub>2</sub>) may all be necessary.

Well spacing has a significant impact on the scale of these investments, as it generally determines the well count in the flood area. Spacing affects both production volumes and capital costs inversely. Well spacing in a CO<sub>2</sub> flood is driven by operator decisions about the economically optimal design and acreage of “patterns,” the ratio and spatial relationship between injection wells (water or CO<sub>2</sub>) and producing wells that is repeated throughout the field. 40 acre inverted five spot patterns are a traditional water flood and CO<sub>2</sub> flood pattern design. This analysis assumes 20 acre patterns for Illinois and Kansas, with appropriately higher capital costs.

Many fields in the MGA region are quite old and wells are often in poor condition. The reference case assumes that 50% of the wells will need to be drilled new and will require purchases of associated new equipment. Sensitivities assume a 20% increase or decrease in total capital cost requirement including wells.

All new CO<sub>2</sub> floods will require significant investment in CO<sub>2</sub> recycling equipment so that CO<sub>2</sub> produced with oil can be separated, recompressed and dehydrated to prepare it for reinjection into the reservoir. This analysis sized the compression and dehydration equipment capacity in line with projected recycled CO<sub>2</sub> volumes.

## Operating Costs

The operating costs assumptions consist of three components:

- Well maintenance: a fixed cost per incremental well per year inflated nominally was assumed
- Lifting costs: a variable cost of \$0.25/bbl of liquids produced (oil, water, natural gas liquids)
- CO<sub>2</sub> recycle operations: a variable cost per mcf of CO<sub>2</sub> recycled, consisting mostly of the energy required to recompress, dehydrate, and pump the recycled CO<sub>2</sub>. The reference case assumes \$0.35/mcf of recycled CO<sub>2</sub> and hydrocarbon gas. Annual costs increase over time as the volume of recycled CO<sub>2</sub> increases.

## Depth Dependent Costs

Costs for all capital components and fixed operating costs are assigned by depth and regionally dependent cost functions derived from aggregate cost indexes as per McCoy, Rubin 2008 and updated to 2012 dollars via the EIA cost index. The assumed depth is the average depth of EOR candidate reservoirs in the field.

## Other Assumptions

Royalties: 15% (Sensitivities: 12.5%, 17.5%, 20%)

Federal corporate tax 35%; State severance taxes vary widely by state:

- Kansas: 8% with 100% exemption for tertiary production,
- Michigan: 6.6%,
- Ohio: \$0.10/bbl
- Indiana: 1%
- Illinois: 0.1%

Depreciation: straight line for 15 years (this is more conservative than units of production method)

Inflation: oil price escalator (~2% per year)

Discount Rate (nominal) at 20%; sensitivities: 15%, 25%

Federal 45Q tax credits have not been applied.

## Pipeline Costs

Costs of pipeline transport, denominated in \$/MT of CO<sub>2</sub>, are a function of pipeline construction costs, operating costs, and a required rate of return for a presumed pipeline operator.

- Construction costs were determined using an all-in dollar value of \$75,000 per inch-mile (diameter-length) of required pipe, based on a survey of construction cost estimates, particularly as apply to the Midwest. The required diameter is predominantly a function of the volume of CO<sub>2</sub> to be transported, but also of pipeline length.

- Annual operating costs are a function of the length and diameter of the pipe as well as the transported volume of CO<sub>2</sub>. Diameter-length operating costs were derived from MGSC Phase I 2005 and updated to 2012 dollars using the EIA Oil and Gas operating cost index.
- A 15% required rate of return to the transport company and a 20 year project life were assumed.

| Pipeline Transportation Costs (\$/MT CO <sub>2</sub> delivered) |          |                                    |        |        |        |     |
|---|----------|------------------------------------|--------|--------|--------|-----|
| Project Life  | 20-years | IRR :                              |        |        |        | 15% |
| Construction Costs *<br>(\$/inch – mile)                        | \$75,000 | Volume (MMT CO <sub>2</sub> /year) |        |        |        |     |
|   |          | 1                                  | 2      | 5      | 10     |     |
| Distance (mi)   | 50       | \$4.60                             | \$2.90 | \$1.80 | \$1.20 |     |
|   | 100      | \$11.50                            | \$6.90 | \$4.20 | \$2.80 |     |

Figure 2: Pipeline costs are a small component of total CO<sub>2</sub> delivery costs.

\* Construction costs generally include: materials, labor, right-of-way costs, and miscellaneous/other (including overhead).



# REGIONAL OVERVIEW

The MGA has four principal oil and gas regions that are often shared with other non MGA states:

- Michigan Basin – Michigan
- Illinois Basin – Illinois, Indiana, (Kentucky)
- Appalachian Basin – Ohio (Pennsylvania, West Virginia, Kentucky, New York)
- Mid Continent – Kansas (Oklahoma)

The MGA region has rich oil history. To date Illinois, Indiana, Ohio, Kansas, and Michigan together have produced almost 13 billion barrels of crude oil. However, MGA fields are very mature and crude production has been in a long decline. Although Kansas has reversed this trend over the past decade, MGA states are producing at rates much lower than both historical and previous-30 year peaks, and many fields are producing less 5 barrels a day per well. Collectively, the five MGA oil states produced oil at a rate of 175 mb/d in 2010, compared to Texas’ rate of 1,100 mb/d in the same year. Despite this, screens used in this assessment suggest that more than 2 billion barrels of oil could be produced

from CO<sub>2</sub>-EOR in the MGA utilizing a regional supply of anthropogenic CO<sub>2</sub>.

The MGA region produces more than 700 MMT of CO<sub>2</sub> annually from stationary sources. This presents a potential supply of anthropogenic CO<sub>2</sub> for EOR uses throughout the region. Coal-fired power plants account for most of the CO<sub>2</sub> emitted, although industrial emissions are significant, including those that emit high purity streams of CO<sub>2</sub> from non-combustion processes, such as ethanol fermentation, gas processing, and ammonia production. Annually, the MGA region produces more than 35 MMT of CO<sub>2</sub> from ethanol fermentation alone. The cost of capturing CO<sub>2</sub> is largely dependent on the purity of the CO<sub>2</sub> stream produced in the flue gas, so high purity sources may present a viable economic option for CO<sub>2</sub> capture for EOR. Conversely, due to the low CO<sub>2</sub> purity of the flue gas from coal fired power plants, the cost of capture at these facilities is significantly more expensive at the moment, although this could change as technology improves.

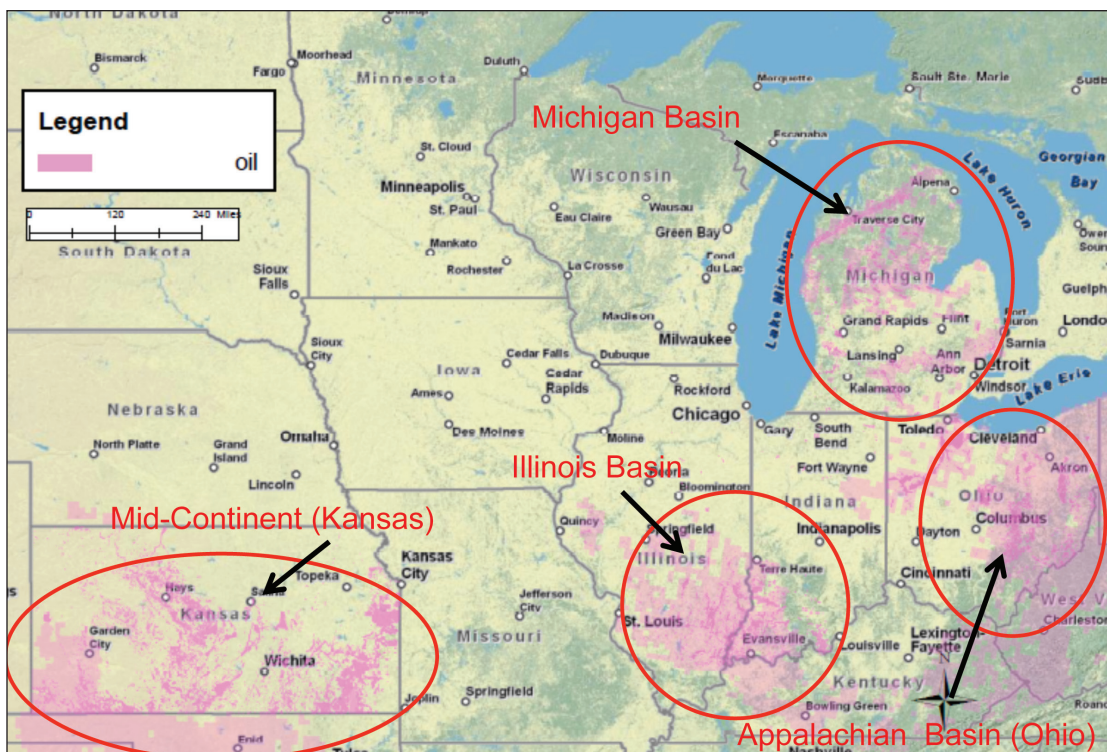


Figure 3: MGA oil and gas basins.

CO<sub>2</sub>-EOR presents an opportunity for renewed growth in oil production throughout the MGA region. If developed on a wide scale, it may result in recovery of more than 2 billion barrels of incremental oil throughout the region. Furthermore, MGA states could add over 6,000 direct new jobs and up to 3 times as many indirect jobs. MGA states would also benefit from additional revenue flowing through state mineral interests, severance taxes, and corporate and personal income taxes. A net CO<sub>2</sub> demand of 670 – 1, 050 MMT CO<sub>2</sub> would be required to recover 2 billion barrels of incremental oil.

CO<sub>2</sub>-EOR is only technically feasible under certain geological conditions. This assessment screened the majority of oil fields in the MGA region for technical CO<sub>2</sub>-EOR potential using public domain information available through the state geological surveys. Carbon dioxide becomes miscible with

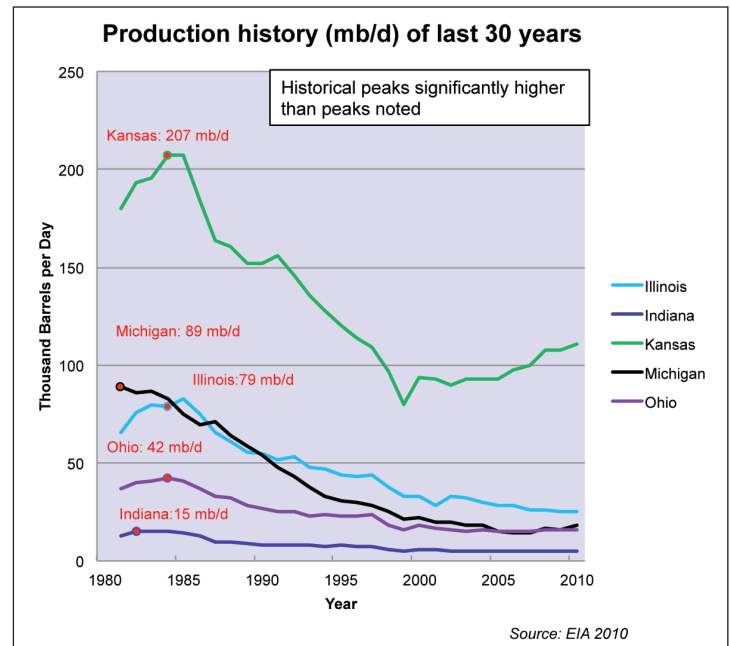


Figure 4: MGA 30 year production

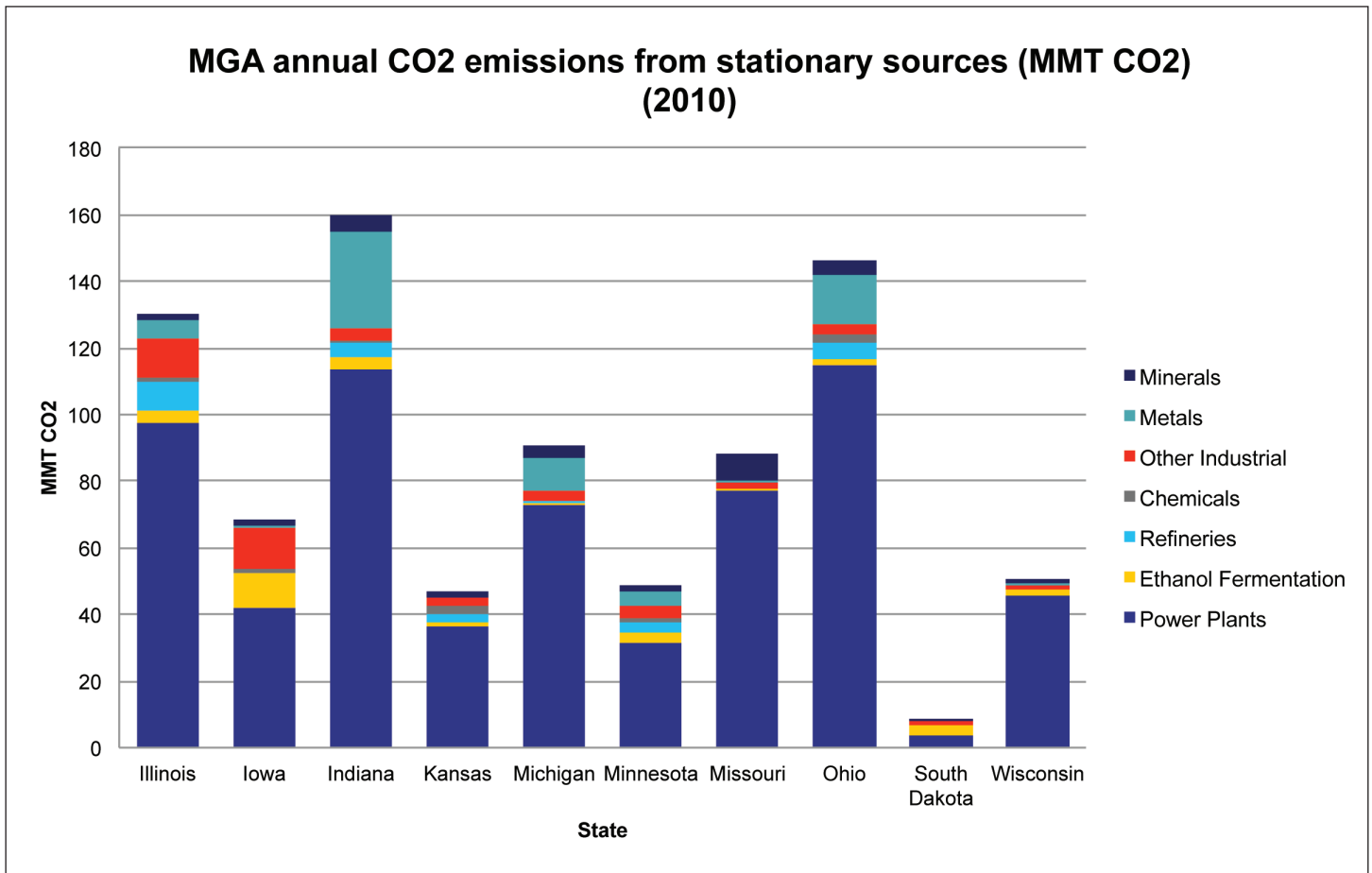


Figure 5: MGA region emits approximately 700 MMT CO<sub>2</sub> annually

oil only under pressure. An operator assessing technical viability in a particular lease, would calculate the minimum pressure required to achieve miscibility, and then determine whether that pressure violated the naturally or legally allowed pressure in the target reservoir. Where possible, average minimum miscibility pressure (MMP) values were calculated for field-reservoir combinations and compared against assumed initial or fracture pressure values to screen

for candidate fields. When sufficient data was not available, other parameters were used to approximate miscibility. In general, reservoirs with average depth below 2500 feet and oil gravities with API values between 30 and 50 were classified as miscible. For fields with multiple producing reservoirs, only the reservoirs that passed the screens would count for incremental oil recovery values.

| Basin            | EOR potential (Mil bbl) | Net CO <sub>2</sub> Demand (MMT) | Direct Jobs Created   |
|------------------|-------------------------|----------------------------------|-----------------------|
| Illinois/Indiana | 500                     | 160 – 250                        | 1,550 – 3,100         |
| Ohio             | 500                     | 190 – 300                        | 1,550 – 3,100         |
| Michigan         | 250                     | 80 – 130                         | 800 – 1,800           |
| Kansas           | 750                     | 240 – 370                        | 2,300 – 4,600         |
| <b>TOTALS</b>    | <b>2,000</b>            | <b>670 – 1,050</b>               | <b>6,200 – 12,400</b> |

## Michigan

Summary: CO<sub>2</sub>-EOR could be commercially viable in Michigan.

- Analysis focused on fields in Niagaran Pinnacle Reef trend in the northern lower peninsula
- Representative field suggests strong operator economics
- Sourcing of “market price” CO<sub>2</sub> may be problematic
- State would benefit through additional revenue and jobs

Michigan has a long oil industry tradition, and to date has produced approximately 1.2 billion barrels of oil. This analysis focuses on the Niagaran-Silurian pinnacle reef trend in the northern lower peninsula, a long series of small, deep fields that were discovered in the 1960s and 1970s and reached peak production in the early 1980s. The trend stretches across most of the peninsula and overlaps the Antrim gas fields in the east. The trend’s relatively recent discovery and exploitation suggest the infrastructure should be in far better condition than older fields elsewhere in Michigan, reducing capital cost requirements. Importantly, it contains the only commercial CO<sub>2</sub> floods in Michigan and the MGA region, demonstrating the technology’s feasibility and potential. CORE Energy produces oil from five fields using a carbon dioxide stream from a natural gas processing plant. In aggregate, this assessment suggests that the Niagaran trend has over 125MM bbls of

incremental oil potential which would require 40-60MMT of CO<sub>2</sub> to produce.

One potential development strategy assumes that larger central production facilities (CPFs) that serve multiple fields or wells could serve as locations for initial CO<sub>2</sub> recycling plants, and the fields they serve would serve as anchor demand for a CO<sub>2</sub> pipeline. CPFs in the trend, and their associated fields, were ranked by gross sales and the largest were identified and mapped together with their fields. Incremental oil potential from these anchor fields is more than 50 million barrels.

Chester 18 field was chosen as a representative field for the economic analysis, as data for the field was available in the public domain. Our reference case assumptions lead to a pre-tax project IRR of 70% and after-tax of 49%. Local experience suggests that oil production may be better than the underlying Illinois based production curves used in the cash flow model, suggesting stronger economic potential. Worst case capital investment sensitivities still realize after-tax IRR values of over 20%. In summary, although Chester 18 is one of the larger fields in the trend, results suggest that there is commercial potential in the smaller fields.

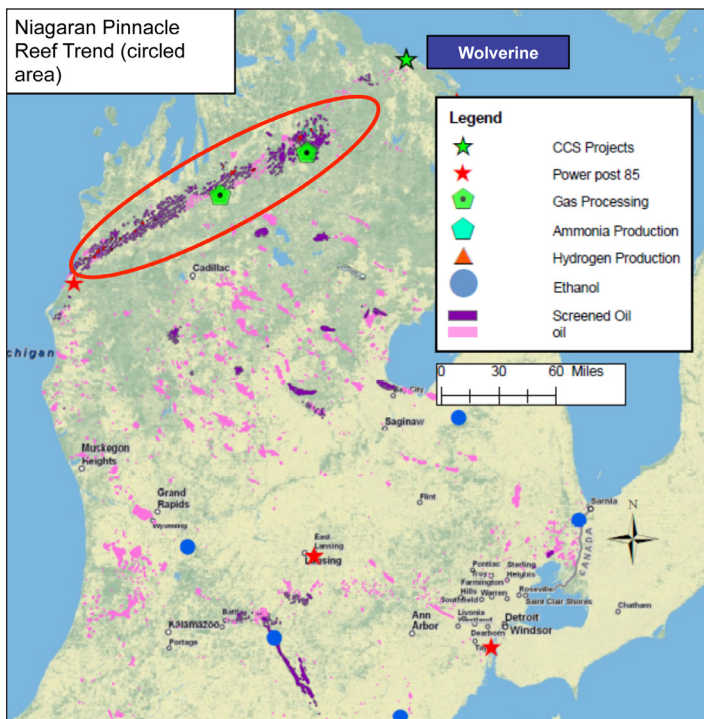


Figure 6: Niagaran Pinnacle Reef trend

The largest obstacle to further CO<sub>2</sub>-EOR development in the Niagaran reef trend is lack of carbon dioxide in the area. The region is thinly populated and there are limited sources of industrial emissions. Local gas processing plants can supply approximately 1MMT per year in aggregate, but capacity is spread very unevenly across a number of plants scattered across the trend. The processing plants remove CO<sub>2</sub> as an impurity from the natural gas. Significantly larger volumes of CO<sub>2</sub> would be required to develop the trend: there are 225 fields that meet an economic size criterion of 500,000 barrels of cumulative production. At various points

over the last several years proposals for carbon capture at either end of the trend have been made: a 180MW IGCC upgrade to the Tes Filer City Station plant in Manistee, and a capture component to the proposed 600MW Wolverine Clean Energy Venture power plant in Rogers. Both plants had their air permits denied under the previous governor’s administration. Wolverine legally contested the decision and received the air permit for the Rogers project in June 2011 and is now considering moving forward with the plant, but may do so without the capture component. The Tes Filer proposal seems to have been abandoned.

The state could earn over \$1 billion in revenues over 10 or more years (once CO<sub>2</sub> is available via pipeline) if the entire trend were developed in that time frame. An analysis of state mineral interests in the trend indicate a potential revenue of approximately \$220 million in royalties and an additional \$750 million in state severance taxes from incremental CO<sub>2</sub>-EOR production over that timeframe.

This analysis suggests that in the northern pinnacle reef trend operator economics seem very favorable and the largest obstacle is CO<sub>2</sub> supply. Incentives to operators common to traditional CO<sub>2</sub>-EOR markets, such as severance tax credits, may not be effective in catalyzing the industry without first addressing the CO<sub>2</sub> supply challenge. The state might consider incentives for installing carbon capture equipment at the Wolverine Clean Energy Venture.

## Illinois and Indiana

Summary: Illinois and Indiana are likely to have economically viable CO<sub>2</sub>-EOR opportunities.

- Our screening process suggests that the region has 500M+ bbls of miscible EOR potential
- The region has an abundance of low cost CO<sub>2</sub>
- Representative field economics suggest reasonable profitability for larger fields and potentially marginal results for smaller fields
- State economy would benefit, adding 1,550-3,100 direct jobs.

Illinois, Indiana, and Kentucky (which is not in the MGA) share the Illinois Basin. Many of the fields were discovered in the mid to late 1930s and Illinois’ historical production peaked in the early 1940s. Together, Illinois and Indiana

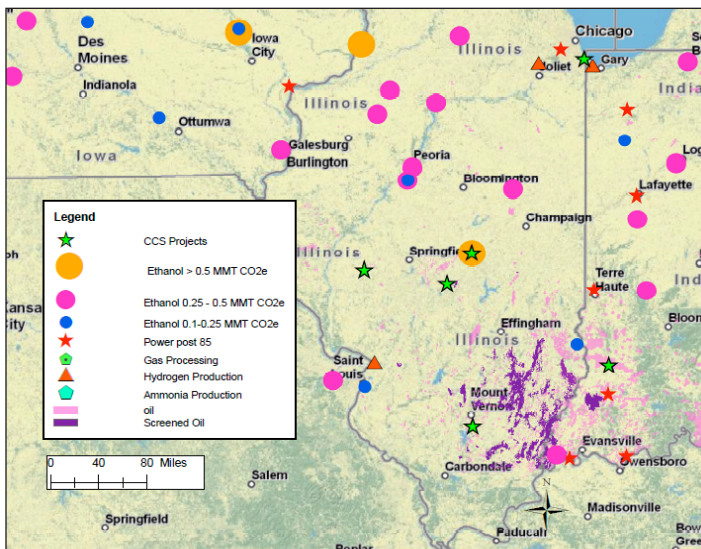


Figure 7: Illinois Basin and Iowa

have produced 4 billion barrels of oil, most of it out of the Basin. The screen used in this analysis to identify EOR candidate fields suggests that more than 500 million barrels of oil could be recoverable through CO<sub>2</sub>-EOR (using an alternative methodology, the Midwest Geological Sequestration Consortium MGSC estimated 800 – 1300 million barrels including Kentucky). If fully developed, this would require a net CO<sub>2</sub> requirement of 160 – 250 MMT.

Illinois and Indiana emit about 300MMT of CO<sub>2</sub> per annum, predominantly from old coal-based power plants. Ethanol fermentation emissions constitute approximately 7MMT of that total. At present, the Illinois State Geological Survey/ADM/DOE Illinois Basin – Decatur Project (IBDP) is capturing and injecting 1 MMT of ethanol derived CO<sub>2</sub> over the next three years to test geological storage in the Mt. Simon saline aquifer. IBDP will overlap with a commercial scale pilot with the same stakeholders slated to begin injecting into the Mt. Simon at approximately 2000MT/day in Q3 2013 for 2 – 3 years. Separately, several coal gasification projects in the region at different stages of development offer an additional source of potential CO<sub>2</sub> for EOR use. Denbury Resources has signed MOUs with several of these projects to purchase and transport their CO<sub>2</sub> down to the Gulf Coast for EOR, if a sufficient number get built to justify a pipeline of that length.

These sources suggest the possibility of single source or hybrid source CO<sub>2</sub> supply scenarios. Ethanol fermentation

emissions might be aggregated with larger plants, such as ADM Decatur, serving as anchors. A pipeline running northwest to southeast through Illinois could also extend into Iowa to aggregate some of the substantial ethanol fermentation emissions in that state. With Iowa included, there are 17MMT of ethanol fermentation emissions available in the three states. If the Taylorville Energy Center project is approved, it lies close to the ADM Decatur facility, and could link to an “ethanol CO<sub>2</sub>” pipeline. For the prospective gasification plants, Denbury’s proposed “Midwest Pipeline” could serve as a “sink” that can accept the large, constant emissions volumes they would produce and allow the Illinois Basin’s variable demand to be “fed” by spurs from the main pipeline.

This economic analysis focused on two representative CO<sub>2</sub>-EOR scenarios in the Illinois basin – the first, a ‘large field’ case and the second, a ‘small field’ network. The first case examined the New Harmony field which straddles the Illinois/Indiana border. Typical of other large fields in the basin, New Harmony has a stacked reservoir system which includes the more prolific and extensive reservoirs in the Basin. The field has potential for 50-80 million barrels of incremental oil production which might require a net CO<sub>2</sub> demand of 15 - 40 MMT. Our reference case assumptions lead to a pre-tax project IRR of 33% and an after tax project IRR of 21%. The analysis assumes that wells will produce from multiple stacked reservoirs in the field, but only OOIP estimates for reservoirs that screened miscible were included in the model. The availability of CO<sub>2</sub> at a real value of \$25/MT would improve project economics significantly. However, the condition of old wells (many pre-1942) and equipment is an inhibiting factor. The reference case assumes 50% of wells will require re-drilling, but if that requirement is understated and much larger capital investments are required, the economics for operators may prove unattractive. A 20% increase in total capital cost delivered marginal economic results with an after tax project IRR of 16%.

The second case examined a smaller field network in the southern region of the Illinois portion of the basin. Two fields, Herald and Concord, were selected due to their age,

favorable reservoir characteristics and production history, and their proximity to the Aventine and Abengoa ethanol plants in southwest Indiana, potential CO<sub>2</sub> sources. This could be illustrative of direct source-eor networks smaller than the Basin wide networks envisioned above. Combined, it is believed that these fields could produce 9-13 million barrels of incremental oil with CO<sub>2</sub>-EOR. Our reference case assumptions lead to marginal results: a pre tax project IRR of 18% and an after tax IRR of 10%. However, sensitivities appropriate for this scenario, namely a lower CO<sub>2</sub> cost and a

reduced total capital cost of 20% less than reference lead to a much improved after tax project IRR of 21%.

Indiana and Illinois have minimal state severance taxes of 1% and 0.1% respectively, and these therefore do not represent a potential meaningful increase in state revenue for either state. If CO<sub>2</sub>-EOR were developed on a wide scale in the Illinois Basin, an additional 1,550 direct jobs could be added to the economy.

## Ohio

Summary: Ohio’s large resource potential could be commercially viable.

- Ohio could be a great commercial success although much work and characterization is needed in order to confirm these assessments
- East Canton field economics suggest strong commercial potential
- While sourcing of CO<sub>2</sub> is technically feasible through capture in many local power plants – high capture costs would likely lead to high cost CO<sub>2</sub>
- EOR could directly support 1550 – 3100 new jobs in the state of Ohio

Ohio’s oil history dates back to beginnings of the oil industry in the US. Some of the production history of Ohio oil fields dates back to the late 1800s, and the state has contributed over

1 billion barrels of oil to the US economy. Due to geology and history, and unlike Pennsylvania and other Appalachian Basin neighbors, there has been very little water flooding—secondary recovery—in Ohio’s oil fields. All of the oil has been produced from primary recovery (the largest 30 fields, representing 80% of total OOIP, have produced less than 7% of their respective OOIPs) leaving significant volumes of oil in the ground that would have normally been extracted at this stage in a field’s maturity. Therefore the incremental oil potential for CO<sub>2</sub> flooding may be significantly greater than it would have been if water flooding had been widespread throughout the state. There are about 500 million barrels of incremental EOR potential in the state, which might require 190 – 300 million metric tons of carbon dioxide.

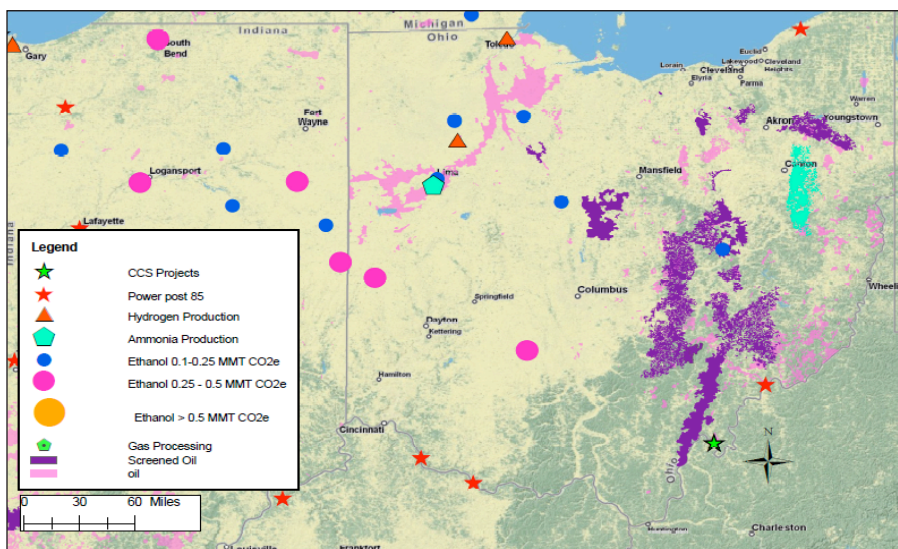


Figure 8: Ohio and Appalachian Basin

However, meaningful technical and structural obstacles exist to deploying CO<sub>2</sub>-EOR on a wide scale in Ohio. The lack of water flood history means there is little data about performance or reservoir characteristics that operators can use to predict response to the injection of carbon dioxide, a critical requirement to evaluate economic feasibility. The long history of Ohio’s industry means that many wells were drilled prior to modern standards and may be unsuitable for conversion to use in

CO<sub>2</sub> flooding. Abandoned wells that once produced from a reservoir that would be flooded need to first be located—a difficult task—and then replugged to modern standards. Field remediation costs may be significant. Most wells are stripper wells, producing less than 5 barrels of oil per day, and there are many very small operators who may not have the capital to redevelop their leases for CO<sub>2</sub> flooding.

The East Canton field was selected for analysis in part due to its structural advantages relative to other Ohio fields, which diminish some of the obstacles to CO<sub>2</sub>-EOR listed above. East Canton was discovered in 1953, and therefore wells and field equipment are relatively modern, and abandoned wells are in known locations and plugged to modern standards. Furthermore, there is high degree of operator concentration in the field, as approximately 2/3 of the wells are owned by two companies.

The Ohio Department of Natural Resources, Division of Geological Survey (OGS) conducted a CO<sub>2</sub>-EOR study in East Canton in 2008-2010 including a one well cyclic (“huff and puff”) CO<sub>2</sub> flood pilot, a geological reservoir characterization of the Clinton Sandstone reservoir underlying the field, and simulation of CO<sub>2</sub>-EOR performance over a pilot area. The simulation generated low, base, and high cases of incremental oil recovery of 8%, 14%, and 20% of OOIP. This assessment assumed the 14% recovery base case for its reference case analysis.

The East Canton field can potentially produce 75 - 280 million incremental barrels of oil through CO<sub>2</sub>-EOR. The reference case for this study suggests a pre tax project IRR of 47% and after tax of 28%, despite relatively high operating costs for CO<sub>2</sub> floods and significant capital costs. The analysis generated positive net present values at an assumed required rate of return of 20% under almost all sensitivities except the “high price CO<sub>2</sub>” case (\$80/MT). The East Canton has never been water flooded due to the very low permeability of the Clinton Sandstone. The pilot simulation, and this analysis, assumed a continuous injection of CO<sub>2</sub> instead of a more traditional water-alternating-gas (WAG) method, where water is injected after CO<sub>2</sub> to drive the CO<sub>2</sub>-oil mix to the well. End-of-life net utilization of CO<sub>2</sub> is higher than traditional

rule of thumb factors (0.8mt/bbl vs. 0.25 - 0.5mt/bbl) would suggest, and therefore CO<sub>2</sub> purchase costs over the project life are significantly higher than in the other fields analyzed in this study. The analysis assumed no producing wells would need to be re-drilled given the young age of the field, but since there has never been a water flood, all injection wells would need to be drilled new (and related surface equipment would be required) to complete flood patterns. Despite the high operating cost and significant capital investment, this analysis suggests strong commercial potential if CO<sub>2</sub> were available.

Ohio is not lacking for CO<sub>2</sub> emissions from its significant asset base of coal fired power plants. However, the capture cost from this source is high, as highlighted by recent developments with the AEP Mountaineer carbon capture project. CO<sub>2</sub> sources with lower costs of supply, such as ethanol and ammonia plants, are currently limited in the region. Shale gas production from the Marcellus or Utica shales might spur the construction of fertilizer plants which in turn would provide lower cost carbon dioxide.

Ohio severance taxes are minimal at \$0.10/barrel of oil, and therefore do not represent a potential meaningful increase in state revenue. If CO<sub>2</sub>-EOR were developed on a wide scale in Ohio, it could support 1,550 – 3,100 new direct jobs in the state.

The OGS 2010 East Canton study produced meaningful new data, but more reservoir characterization is necessary and a commercial scale pilot is required to generate the type of data that would allow operators to make lease scale performance projections and capital investment decisions.

# Kansas

Summary: CO<sub>2</sub>-EOR should have commercial potential in Kansas.

- Screens used in this study indicate 750 million barrels of technical CO<sub>2</sub>-EOR potential
- Kansas has access to high volume of region's ethanol-based CO<sub>2</sub>
- Modeling suggests positive economics, but requires further analysis
- State economy would benefit from additional 2,300 – 4,600 direct jobs if CO<sub>2</sub>-EOR deployed widely

Kansas' oil history dates back to the 1860's though production did not accelerate until the discovery of the El Dorado field in 1915. The statewide production rate peaked in the 1950's and has since declined significantly, despite a recent turnaround. The state has cumulatively produced more than 6 billion barrels of oil. The three most prolific producing horizons, the Arbuckle, Lansing-Kansas City, and Mississippian formations, are responsible for approximately 70% of this amount. The 10 county Central Kansas Uplift area, which includes large portions of the Arbuckle and Lansing-Kansas City formations, is responsible for approximately 40% of the state's historical production, although "stripper" wells producing under 5 barrels/day are now typical and representative of the statewide decline.

The screens used in this study suggest 750 million barrels of technical CO<sub>2</sub>-EOR potential. Kansas has the largest oil resources in the MGA region and shares geological formations with Oklahoma, where commercial CO<sub>2</sub> floods are proven and are serviced by existing and planned CO<sub>2</sub> pipeline infrastructure. If adopted on a wide scale CO<sub>2</sub>-EOR would require 240 – 370 MMT of CO<sub>2</sub>. However, the full EOR potential of the Arbuckle, Kansas' largest formation, is still uncertain due to geology that makes miscibility difficult to achieve. However near-miscible flooding techniques may be feasible and a DOE-sponsored University of Kansas Center for Research Tertiary Oil Recover Project (TORP) study to examine these techniques in the Arbuckle is currently underway.

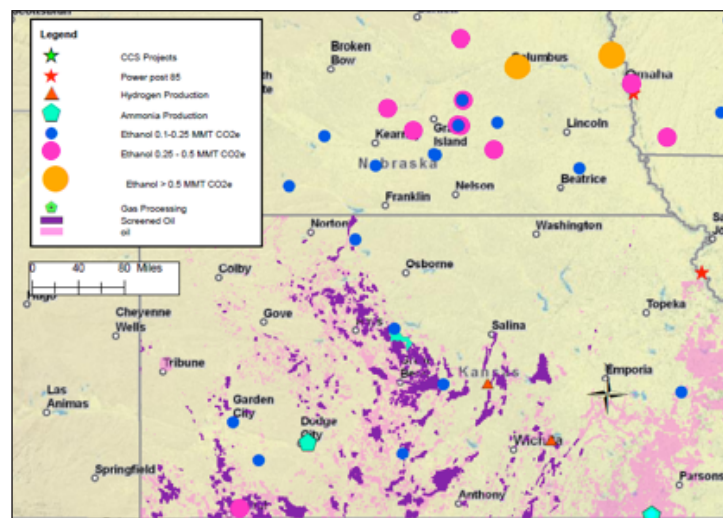


Figure 9: Kansas and Nebraska.

Kansas has a moderate supply of in-state relatively low cost CO<sub>2</sub> from ethanol and fertilizer plants, and has previously used ethanol CO<sub>2</sub> for CO<sub>2</sub>-EOR pilots in Russell and Liberal. The state is currently "exporting" ethanol based CO<sub>2</sub> from Liberal (and will be exporting ammonia based CO<sub>2</sub> from Coffeyville) via pipeline for EOR in Oklahoma. Chaparral Energy, an Oklahoma operator, is shipping the CO<sub>2</sub> to its fields via a growing Oklahoma CO<sub>2</sub> pipeline network. In Kansas, an independent operator, Petrosantander, may purchase all of the CO<sub>2</sub> from the Bonanza Energy ethanol plant in Garden City for EOR in the Stewart field nearby. Sunflower Energy has previously expressed interest in EOR for a proposed CO<sub>2</sub> capture component at its 800 MW coal fired power plant in Holcolmb, although the status of the project is uncertain, and the capture cost would be significantly higher than for ethanol. Kansas could have access to the significant volumes of ethanol-based CO<sub>2</sub> in Nebraska, which produces approximately 6MMT per annum.

Our financial modeling suggests positive economics, but with significant uncertainty and a need for further analysis. The Hall Gurney field was selected for analysis as there was field-reservoir data available in the public domain. The field was also the site of a Kansas Geological Survey (KGS) CO<sub>2</sub>-EOR



pilot in a lease near Russell, although results were mixed. The reference case economics suggest an after-tax project IRR of 22%; however significant questions remain around modeling assumptions including: OOIP, a more representative production profile than the Illinois simulations, and better definition of operator strategy. Changes in these variables can lead to significantly different outcomes.

Kansas has a state severance tax of 8%, but tertiary oil production is given a full exemption, so no incremental severance tax revenues were assumed. If developed on a wide scale, the state economy could benefit from an additional 2,300 – 4,600 of direct jobs.

This analysis suggests a large commercial potential for CO<sub>2</sub>-EOR in Kansas but with significant uncertainty. More characterizations and pilot tests are required to validate the resource base and commercial production potential in the state. Three KGS studies are in progress in fields that overlay typical producing formations: Lansing-Kansas City, Mississippian, and Arbuckle. Characterizations and recovery models from these studies can be used as analogs for appropriate fields elsewhere in the state to develop scoping models of CO<sub>2</sub>-EOR potential.

