Potential Sequestration Opportunities in the PCOR Partnership Region

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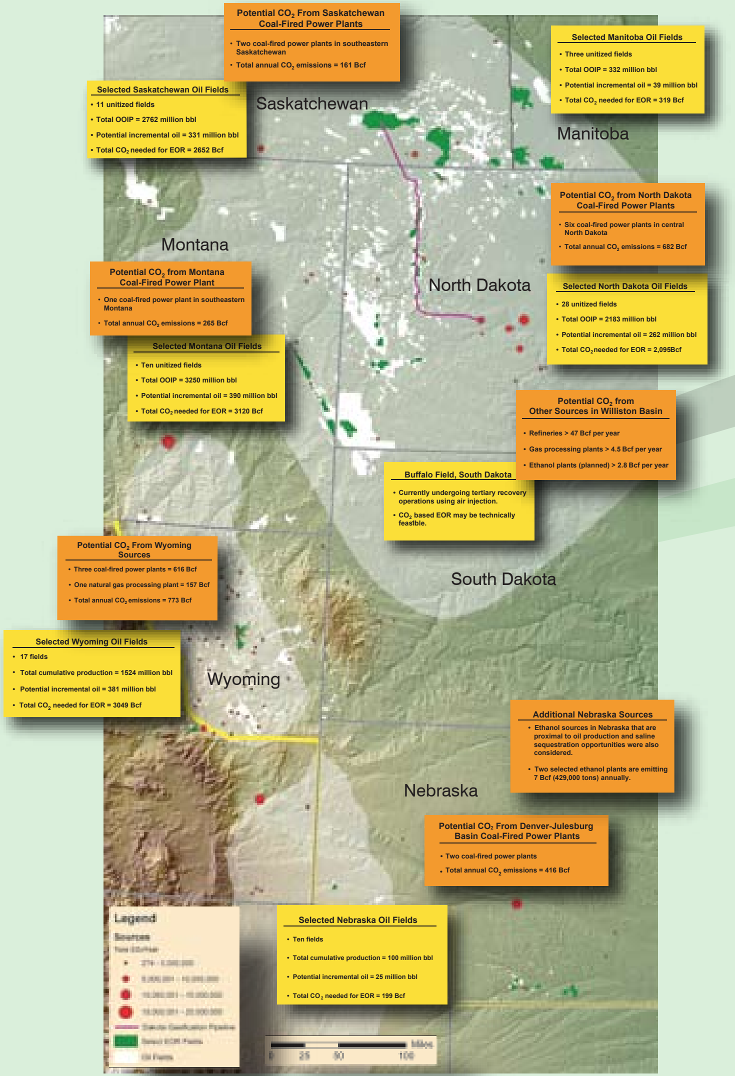
Oil Fields



Storage and Incremental Recovery Through EOR

Basin	Cumulative Incremental Recovery from CO_2 EOR in Selected Units (million stb)	CO_2 Quantity Required* (Bcf)	CO_2 Sequestration Potential Through EOR in Selected Units (Bcf)	CO_2 Sequestration Potential Through EOR in Selected Units (tons)
Williston	1023	8186	8186	501,900,674
Powder River	381	3049	3049	186,949,845
Denver-Julesberg	25	199	199	12,211,839

* CO_2 quantity required is the total purchase amount and does consider recycling of CO_2 from the tertiary recovery operation

Volumetric Storage Totals

Basin	Number of Pools Evaluated	Potential Storage Capacity in Evaluated Fields
Williston	845	> 9 billion tons
Powder River	225	> 1 billion tons
Denver-Julesberg	21	> 14 million tons

Potential CO_2 from Selected Regional Sources

- CO_2 emissions from large stationary sources (greater than 100 Bcf/yr) were evaluated on a sink-to-source proximity basis.
- Total annual emissions are over 2000 Bcf /year.
- At standard conditions, this is approximately equivalent to 120 million tons/year.

Volumetric Methodology

- The estimated capacity represents the sum of each producing interval within a field.
- This calculation yields the maximum storage capacity of an oil-bearing reservoir in pounds (lb) of CO_2; this is then converted to tons.
- The field area considered represents the entire boundary of the oil field. We expect that this figure may be larger than the actual productive areal extent used in detailed reservoir analyses.
- The thickness, porosity, and water saturation figures used represent the reported reservoir thickness as collected from hearing files, reservoir annuals, and published oil field data.
- CO_2 density has been estimated based on reported temperature and pressure values.
- Where temperature and pressure were not available, depth was used to estimate their value.
- Where no data exist, the water saturation was estimated to be 50%.

Volumetric Variables Used

$$Q = (A) * (T) * (\varphi) * (\rho_{co2}) * (1-S_w)$$

Where:

Q = Storage capacity of the oil reservoir (lb CO_2)

A = Field area (ft^2)

T = Producing interval thickness (ft)

Φ = Average reservoir porosity (%)

ρ_{co2} = Density of CO_2 (lb/ft^3)

(1-Sw) = Saturation of oil, where Sw is the initial reservoir water saturation (%)

EOR Methodology

In trying to determine the sequestration capacity of the unitized pools, some assumptions had to be made. The first major assumption was to simplify the oil recovery potential from injection of CO_2. Shaw and Bachu (2002) noted that oil production could be increased from 7% to 23% of the original oil in place (OOIP) through successful miscible flooding techniques, while Nelms and Burke (2004) suggested a value of 7% to 11%. This spreadsheet uses an average value of 12% recovery of the OOIP. Where OOIP was not available, 25% of the cumulative production is used to estimate recovery (PTTC, 1999). Next, the quantity of CO_2 necessary to recover incremental oil was estimated. Based on Nelms and Burke (2004), this evaluation assumed 8 thousand standard cubic feet (Mcf) of CO_2 was required for every incremental barrel of oil recovered.

OOIP(stb) * 12% recovery factor = incremental oil recovered (stb)

Incremental oil recovered (stb) * 8 Mcf/stb = CO_2 required (Mcf)

CO_2 required is roughly equivalent to the amount stored when no blowdown phase occurs

stb = stock tank barrel

Reservoir Data Obtained from:

- Alberta Energy and Utilities Board
- Manitoba Industry, Economic Development and Mines – Petroleum Branch
- Montana Board of Oil and Gas Conservation
- Nebraska Oil and Gas Conservation Commission
- North Dakota Industrial Commission Oil and Gas Division
- Saskatchewan Industry and Resources – Exploration and Geological Services
- South Dakota Department of Natural Resources – Oil and Gas Section
- Wyoming Geological Association – Powder River Basin Oil and Gas Fields Volume I

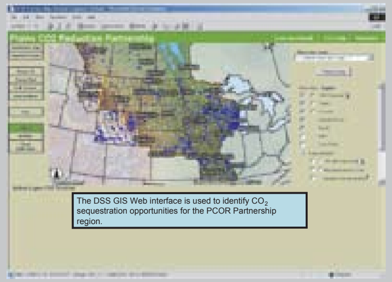
Estimates of CO_2 Storage Capacity in Oil Fields of the PCOR Partnership Region

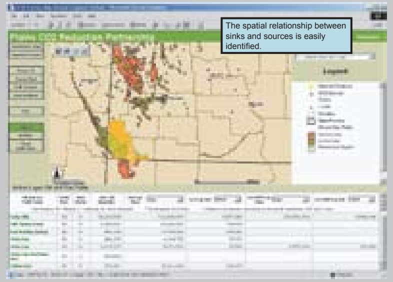
The potential CO_2 sequestration capacities of selected oil fields in the Williston Basin, Powder River Basin, and part of the Denver–Julesberg Basin were estimated as part of Phase I of the Plains CO_2 Reduction (PCOR) Partnership regional characterization. Reconnaissance-level sequestration capacities were calculated using two methods, depending on the nature of the available reservoir characterization data for each field. The estimates were developed using reservoir characterization data that were obtained from the petroleum regulatory agencies and/or geological surveys from the oil-producing states and provinces of the PCOR Partnership region. The data and sequestration capacity estimates for each field are stored in a Web-based decision support system for the purpose of matching CO_2 sources to sinks. Initial reconnaissance-level estimates for evaluated fields (using a volumetric method) in the three basins indicate a storage capacity of over 10 billion tons of CO_2.

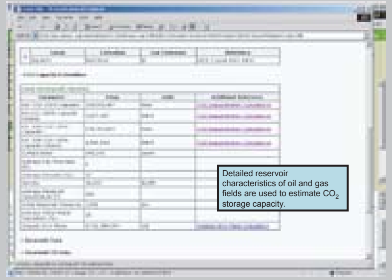
Estimates of CO_2 Storage Capacity in Saline Aquifers of the PCOR Partnership Region

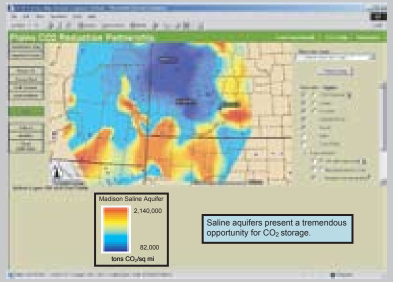
Saline aquifers within the PCOR Partnership region have the potential to store vast quantities of anthropogenic carbon dioxide. Two saline aquifer systems have been evaluated for their regional continuity, hydrodynamic characteristics, fluid properties, and ultimate storage capacities using published data: the Mississippian Madison and the Lower Cretaceous. The unique lateral extent of these aquifers, the current understanding of their storage potential gained through produced fluid disposal, and the geographic proximity to major CO_2 sources suggest they may be suitable sinks for future storage needs. For example, reconnaissance-level calculations on the Mississippian System in the Williston Basin and Powder River Basin suggest the potential to store upwards of 60 billion tons of CO_2 over the evaluated region, while the Cretaceous System has the potential to store over 160 billion tons. Results of the evaluation are stored in an interactive Web-based decision support system for future integration into a national carbon sequestration database.

Decision Support System









Acknowledgments

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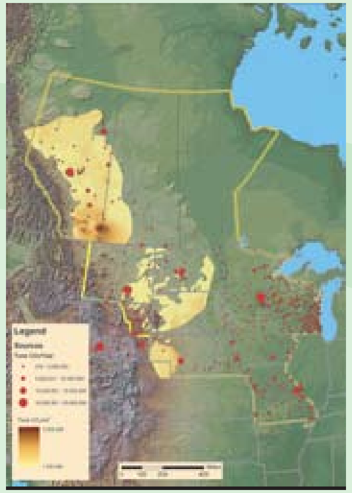
Saline Aquifers

Lower Cretaceous Aquifer System

- Regional evaluation of the Lower Cretaceous aquifer system using existing data sets
  - Formations evaluated include the following:
  - Newcastle Formation
  - Viking Formation
  - Maha Formation
- The system has the potential to store over 160 billion tons of CO_2.

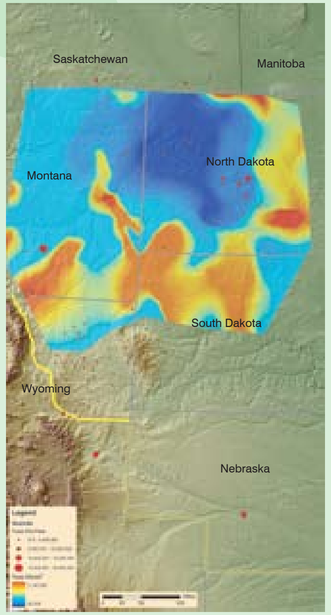


Aquifer System Summary

Aquifer System Evaluated	Basin	Estimated CO_2 Capacity (billion tons)
Lower Cretaceous System		
Newcastle Formation	Williston and Powder River	42
Viking Formation	Alberta	100
Maha Formation	Denver-Julesberg	19
Mississippian System		
Madison Formation	Williston and Powder River	60

Mississippian Aquifer System

- A regional evaluation of the Mississippian Madison Formation was completed in the Williston and Powder River Basins.
- The system has the potential to store over 60 billion tons of CO_2.



Saline Aquifer Storage Calculation

$$Q = 7758 * (A) * (T) * (\varphi) * (CO_2s)$$

Where:

Q = CO_2 remaining in the aquifer after injection (ft^3)

7758 = (43,560 ft^2/acre) X (.178 bbl/ft^3)

A = Area (acres)

T = Producing interval thickness (ft)

Φ = Average reservoir porosity (%)

CO_2s = Solubility of CO_2 (ft^3/bbl)

Saline Aquifer Storage Methodology

In order to calculate storage potentials for the evaluated saline aquifer systems, a model was developed to produce a continuous gridded surface representing the volume of CO_2 that could be sequestered per square mile. In general, the model is based on existing data relating to hydrological studies of regional aquifer systems, oil, gas, water well data, and existing GIS (geographic information system) map data.

The calculation used is a straightforward estimate that relates the pore volume in the reservoir (area × thickness × porosity) and the solubility of NaCl, in the reservoir water, at spatially varying pressures and temperatures. Solubility factors for temperatures and concentrations in excess of 200°F and 200,000 ppm NaCl, respectively, were not readily available at the time of this study (temperatures and concentration values are routinely above these values in the Powder River and Williston Basins). As such, data were extrapolated to above 500°F and 300,000 ppm from tables provided through personal communication with the Indiana Geological Survey (April 2004) in order to attain the necessary solubility correction factors. This methodology modified the MIDCARB CO_2 sequestration tool by extrapolating the solubility parameters of CO_2 in water to account for the higher temperature and salinity present in the study area.