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November 29, 2007

Ms. Karlene Fine
Executive Director
Attn: Lignite Research Program
North Dakota Industrial Commission
State Capitol – Fourteenth Floor
600 East Boulevard Avenue
Bismarck, ND 58505

Dear Ms. Fine:

Subject: EERC Proposal No. 2008-0119

Enclosed please find an original and seven copies of the proposal entitled "Proposal to North Dakota Lignite Research Council for the Plains $CO_2$ Reduction Partnership Program – Phase III." A special grant round was requested by the Energy & Environmental Research Center (EERC) for submittal of this proposal. This proposal reflects the prior letter of support provided by the North Dakota Industrial Commission (NDIC) Lignite Research Council at the time of submittal of the proposal to the U.S. Department of Energy (DOE) (see Appendix A). The goal of the Plains $CO_2$ Reduction (PCOR) Partnership is to develop market-based solutions to carbon management issues that have the potential to benefit both the region's economy and environment. The EERC looks forward to the opportunity to work with NDIC on this rapidly developing opportunity. Also enclosed is the $100 application fee.

If you have any questions, please contact me by telephone at (701) 777-5279 or by e-mail at esteadman@undeerc.org.

Sincerely,

Ed

Edward N. Steadman
PCOR Partnership Project Manager
Senior Research Advisor

Approved by:

Dr. Barry I. Milavetz, Associate VP for Research
Research Development and Compliance

ENS/jlk
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# PROPOSAL TO NORTH DAKOTA LIGNITE RESEARCH COUNCIL FOR THE PLAINS $CO_2$ REDUCTION PARTNERSHIP PROGRAM – PHASE III

EERC Proposal No. 2008-0119

*Submitted to:*

**Karlene Fine**

**North Dakota Industrial Commission**
**State Capitol – Fourteenth Floor**
**600 East Boulevard Avenue**
**Bismarck, ND 58505**

Proposal Amount: $2,400,000

*Submitted by:*

Edward N. Steadman
John A. Harju
James A. Sorensen
Charles D. Gorecki

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Research Development and Compliance

**November 2007**

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# PLAINS $CO_2$ REDUCTION PARTNERSHIP – PHASE III


## ABSTRACT

The Plains $CO_2$ Reduction (PCOR) Partnership at the Energy & Environmental Research Center (EERC) has been selected as a U.S. Department of Energy (DOE) Phase III Regional Carbon Sequestration Partnership (RCSP) Program. The partnership region covers all or part of nine states and four Canadian provinces, including North Dakota. Phase III efforts of the PCOR Partnership will include two demonstration projects that focus on injecting $CO_2$ into deep geologic formations for $CO_2$ sequestration. Demonstrations will be conducted at two sites, one in North Dakota, where $CO_2$ will be captured at an existing coal-fired power plant and injected into a suitable geologic formation for enhanced oil recovery (EOR) and sequestration, and the other in British Columbia, Canada, where $CO_2$-rich acid-gas will be injected into a deep brine-saturated formation. The primary goals of these activities are to 1) develop economic and technically viable technologies to capture and compress $CO_2$ from existing point sources; 2) develop data sets that verify the ability of targeted geologic formations in the region to store $CO_2$ and, in the case of the EOR project, produce incremental oil; and 3) develop a framework for monetizing carbon credits for $CO_2$ sequestered in geologic formations. Successfully achieving these objectives will lead to the development of new sources of $CO_2$ for tertiary oil recovery, simultaneously mitigating the risks to the region's coal-based power industry and extending the life of the region's productive oil fields by employing a market-based approach to carbon management. The PCOR Partnership Phase III program will be conducted over the course of 10 years. The total value of the project is $136,231,052, of which the North Dakota Industrial Commission (NDIC) Lignite Research Council is being asked to contribute $2,400,000. The requested funding is critical to support the demonstration test in North Dakota. The PCOR Partnership includes over 70 partners, including the EERC; DOE; Basin Electric Power Cooperative; Dakota Gasification Company; Encore Acquisition Company; NDIC Lignite Research Council; NDIC Oil and Gas Research Council; ALLETE; BNI Coal, Ltd.; Great Northern Power Development, LP; Great River Energy; Minnkota Power Cooperative, Inc.; Montana–Dakota Utilities Co.; North American Coal Corporation; Otter Tail Power Company; Westmoreland Coal Company; Xcel Energy; Spectra Energy; and Prairie Public Broadcasting.

# PLAINS $CO_2$ REDUCTION PARTNERSHIP – PHASE III

## PROJECT SUMMARY

The Plains $CO_2$ Reduction (PCOR) Partnership Phase III effort will continue to develop regional solutions to carbon management issues and provide our partners with opportunities for market-based solutions to greenhouse gas (GHG) issues. Phase III efforts include two large commercial-scale demonstration projects that focus on injecting $CO_2$ into deep geologic formations for $CO_2$ sequestration. The first demonstration (the Williston Basin Demonstration) will involve capture and compression of $CO_2$ from an existing coal-fired power plant that will be injected into a deep geologic formation in the Williston Basin for the dual purpose of sequestration and enhanced oil recovery (EOR). This project is similar to the Weyburn project, in which the Dakota Gasification Company (DGC) provides a constant stream of supercritical $CO_2$ to the EnCana Corporation for the dual purpose of sequestration and EOR in the Weyburn Field in Saskatchewan, Canada (1). While the Weyburn project is a well-documented, successful EOR project in the Williston Basin, there are no large-scale EOR projects in the North Dakota portion of the basin. The Williston Basin Demonstration will represent the first $CO_2$ sequestration/EOR project in North Dakota and the first commercial-scale $CO_2$ EOR project anywhere utilizing $CO_2$ captured from a coal-fired power plant. This demonstration represents a great step forward for North Dakota in becoming a global leader in the application of market-driven carbon management solutions.

The second Phase III demonstration (the Fort Nelson Demonstration) will involve monitoring, mitigation, and verification (MMV) support for the injection of $CO_2$-rich acid gas captured from one of the largest North American gas-processing plants. The captured $CO_2$ will be injected into a deep brine-saturated formation in British Columbia, Canada. Sequestration in brine-saturated formations is also compelling because the regional storage capacity of such formations is tremendous (>100 billion tons of $CO_2$). These opportunities may be necessary at some future juncture, should available $CO_2$ supplies exceed EOR demand. The lessons to be learned regarding sink capacities and permanence, MMV, transport, economics, risk, public acceptance, and societal cobenefits that will be provided by the proposed EOR and brine-saturated formation sequestration projects are vital to the long-term opportunities for the lignite energy industry in North Dakota.

The Williston Basin and Fort Nelson Demonstrations are large commercial-scale projects, which will verify the concepts of Phase I and II work. Results from PCOR Partnership Phase II have indicated enormous potential for geologic sequestration of $CO_2$, with applications for EOR. This potential for geologic carbon sequestration provides North Dakota's lignite-based power industry with an enormous sink for managing $CO_2$ emissions. The primary objectives of these demonstrations are 1) to develop value-added strategies for managing $CO_2$ emissions from large stationary sources, 2) to develop infrastructure for transportation of $CO_2$ from the source to the injection sites, 3) to advance the regulatory and permitting framework in North America, 4) to create a test bed for the development of new technologies associated with the sequestration of anthropogenic $CO_2$, 5) to develop a mechanism by which carbon credits can be monetized for $CO_2$ sequestered in geologic formations, and 6) to gather characterization data that will verify the ability of targeted regional formations to store at least 50% of the region's point-source $CO_2$ emissions over the next 100 years. Achieving these objectives will put North Dakota and the PCOR Partnership region at the forefront of $CO_2$ sequestration technology, poised to face the challenges associated with implementing any future $CO_2$ reduction policies that may arise.

## PROJECT DESCRIPTION

### Introduction

In response to the U.S. Department of Energy (DOE) Program Solicitation "Regional Carbon Sequestration Partnerships (RCSPs)," the Energy & Environmental Research Center (EERC) has developed and is coordinating the PCOR Partnership, an international program to identify the major $CO_2$ sequestration opportunities in the central interior of North America and demonstrate the economic deployment of commercial-scale $CO_2$ sequestration technologies.

The PCOR Partnership region, which includes North Dakota, South Dakota, Minnesota, Iowa, Nebraska, Missouri, Wisconsin, and portions of Montana and Wyoming as well as the Canadian provinces of Manitoba, Saskatchewan, Alberta, and British Columbia, was chosen based on a synergy between energy producers (including the petroleum and electric utility industries), geologic sinks, current $CO_2$ activities, terrestrial sinks, and existing industry collaborations. The PCOR Partnership is working to fully realize the United States' vision of reducing carbon intensity, increasing energy efficiency, and achieving carbon sequestration as expressed in the "Carbon Sequestration Technology Road Map and Program Plan" (2).

The PCOR Partnership Phase III Program will apply commercial-scale, market-driven solutions to carbon management issues while also providing our industrial partners with 1) economically feasible techniques to capture and compress $CO_2$ produced by coal-fired power plants, 2) opportunities to increase production in North Dakota oil fields through the use of previously unavailable anthropogenic $CO_2$, and 3) a framework to establish and monetize carbon credits associated with the geological sequestration of $CO_2$. The proposed work involves two commercial-scale field demonstration projects focused on the injection of $CO_2$ into geologic formations. The two field-based injection projects will demonstrate the potential for the expansion of EOR opportunities in the Williston Basin using $CO_2$ from a coal-fired power plant and validate the sequestration of $CO_2$-rich acid gas into a brine-saturated carbonate formation. The field demonstrations will include a full suite of MMV activities and regulatory compliance efforts that will be used to develop protocols for the monetization of carbon credits for both $CO_2$-based EOR projects and projects that sequester $CO_2$ in brine-saturated formations. These activities, along with continued regional characterization and the testing of an innovative ramjet engine-based compression technology, will provide a firm foundation for future large-scale deployments of $CO_2$ capture, transmission, and sequestration technologies. Results will identify potential pathways for $CO_2$ recovery from existing and planned additional coal-based power development in the region, thereby facilitating opportunities for EOR and extending the productive lives of many North Dakota oil fields.

### Objectives

The objectives of the proposed work are to demonstrate that cost-effective capture, transport, and storage of anthropogenic $CO_2$ in the PCOR Partnership region is feasible, particularly with respect to ensuring the safe and economical storage of $CO_2$ in geologic formations. With respect to the North

Dakota lignite industry, the objectives of the PCOR Partnership Phase III efforts are 1) to refine the technical and economic analyses of emerging $CO_2$ capture and compression technologies for implementation in the region's coal-fired power industry; 2) to develop data sets that verify the ability of targeted geologic formations in the region to store $CO_2$ and, in the case of the EOR project, produce incremental oil; and 3) to develop a means by which a carbon credit market for geologic sequestration of $CO_2$ can be established. These goals will simultaneously support the region's coal-fired power industry and extend the economic life of the region's oil fields. A number of complementary PCOR Partnership Phase III activities are not specifically discussed herein. Among them are further regional characterizations; research into safety, regulatory, and permitting issues; and public outreach and education. The goals of this program will be implemented through a management task (Task 13) and twelve technical tasks (Tasks 1–12).

## Methodology

Phase III field-based projects will demonstrate two sequestration scenarios that are of commercial scale (>250,000 tons of $CO_2$ injected per year per project). The projects are designed to verify and validate the proposed concepts for eventual widespread commercial application throughout the region.

The Williston Basin Demonstration will be operated in an oil field in western North Dakota that will be selected in the first 6 months of the project. The objectives of the $CO_2$-flood EOR demonstration will be accomplished through a systematic 2-year design phase and an 8-year injection and monitoring program. The PCOR Partnership intends to conduct activities for this project in cooperation with Encore Acquisition Company. Encore is currently in negotiations with respect to key elements of the EOR project and will not be formally named as a Phase III demonstration partner until such negotiations are concluded. However, Encore has provided the PCOR Partnership with a letter of intent to provide significant cost share to the PCOR Partnership Phase III EOR demonstration efforts. The North Dakota project will inject $CO_2$ from a coal-fired power plant owned and operated by Basin Electric Power Cooperative for sequestration and EOR into strata approximately twice as deep as has been injected previously in North America (3). The high reservoir pressure and temperature conditions ($P > 3000$ psi, T > 250°F) found at such depths may have profound implications on the operational success of a $CO_2$-flood EOR project because the effects of supercritical $CO_2$ on rocks and reservoir fluids under such extreme conditions are poorly understood (4, 5). The potential interaction between the supercritical $CO_2$ and the reservoir rocks and fluids will be examined in both the field and the laboratory. These activities will be conducted under Tasks 4, 5, 6, and 9 of Phase III (see Appendix B for details). Such activities may include, but are not necessarily limited to, geologic and hydrogeologic investigations, reservoir modeling, geochemical evaluations and modeling, and geomechanical testing and modeling. Results from those activities will be broadly applicable because the injection zone conditions are similar to those found in many reservoirs in western North Dakota and could provide opportunities for future EOR projects using lignite-based $CO_2$.

Carbon dioxide for the $CO_2$-flood EOR project will be obtained from the Antelope Valley Station, a coal-fired facility in western North Dakota. The Antelope Valley Station is a pulverized coal-fired power plant located north of Beulah, North Dakota, and is part of a $4 billion energy complex that includes the Great Plains Synfuels Plant. The Antelope Valley Station consists of two 435-$MW_e$ units that fire lignite from the Freedom Mine. The Antelope Valley Plant generates roughly 7.9 million short tons of $CO_2$/year. A slipstream of roughly 16% of the plant's total flue gas output will be processed to separate and capture the $CO_2$, dehydrated, compressed to supercritical conditions, combined with supercritical $CO_2$ from the Great Plains Synfuels Plant, and transported via pipeline to the EOR demonstration site—anticipated to be approximately 150 miles away. It is anticipated that new pipeline will be constructed for at least part of the route from the source to the injection site. The proposed project will also serve as a test case for the utility of the recently created North Dakota Pipeline Authority.

The brine-saturated formation sequestration project involves injection of a $CO_2$-rich acid gas into a porous and permeable carbonate rock system in northeastern British Columbia, Canada, in cooperation with Spectra Energy Transmission. The objectives of the brine-saturated formation injection demonstration will also be accomplished through a systematic 2-year design phase and an 8-year injection and monitoring program. This activity is compelling for two primary reasons: similar carbonate rocks are common in the Williston Basin in western North Dakota, and the injection of acid gas (which is also produced in North Dakota) will provide information about the chemical and geochemical effects of nonpure $CO_2$ injection on carbonate rocks and MMV activities.

The brine-saturated formation demonstration will utilize $CO_2$ from the Fort Nelson natural gas-processing plant in northeastern British Columbia, Canada. To make this natural gas suitable for transmission and sale, acid gases (primarily $CO_2$ and $H_2S$) must be separated from the raw natural gas. The Fort Nelson Plant processes approximately 1.0 billion cubic feet per day (Bcf/d) of raw natural gas, making it one of the largest gas-processing plants in North America. The acid gas removal process generates approximately 1.8 million tons of $CO_2$ per year. Spectra Energy Transmission, the owner/operator of the Fort Nelson gas-processing plant, plans to use the existing amine-based acid gas removal system to capture all of the $CO_2$ generated by the plant and inject it into a nearby brine-saturated carbonate formation. The acid gas stream produced by the gas-processing plant is approximately 85% $CO_2$ and 15% $H_2S$. The acid gas stream will be compressed to a supercritical state for transportation and injection.

Methods of accomplishing the objectives for each demonstration test project include the following:

- Technical and economic analyses of emerging $CO_2$ capture technologies
- Preinjection baseline site characterization
- Development and implementation of appropriate MMV protocols
- Public outreach activities
- Continued regional source and sink matching activities

At each demonstration site, the effective and safe sequestration of the injected $CO_2$ in the intended target reservoir will be verified and validated using a variety of cost-effective MMV techniques. These techniques may include reservoir dynamics monitoring, periodic sampling and analysis of fluids from the target reservoir and overlying formations, and the installation of microseismic and/or tiltmeter arrays (see Appendix B, Task 9, for details on the MMV approaches being considered for Phase III).

## Anticipated Results

The two demonstrations will achieve several key results, including but not limited to 1) the first $CO_2$-flood EOR project utilizing $CO_2$ captured from a coal-fired power plant, 2) the establishment of monetized carbon credits for geological $CO_2$ sequestration, and 3) the development of physically linked regional sources and sinks. Both the Williston Basin and the Fort Nelson Demonstrations have great utility to North Dakota and the PCOR Partnership region, and the results of these demonstrations could be applied to other areas in the region.

There is currently no framework in place to monetize carbon credits for sequestration in geologic formations. The key to the establishment of this framework is 1) a program where the injected $CO_2$ is monitored and verified in a way that is technically accurate and economically feasible and 2) the injection process and storage of the $CO_2$ are safe and well contained. Data generated by the field demonstrations, particularly the MMV data, will support the establishment of a carbon credit-trading market for geologic sequestration of $CO_2$. The development of such a market will facilitate the region's lignite industry's efforts to capture $CO_2$ from coal-fired power plants. Establishing a carbon credit market for geological $CO_2$ sequestration may also enable our lignite industry partners to avoid, or at least be prepared for, future carbon emission regulations and policies.

With respect to matching regional $CO_2$ sources to geologic sinks, the PCOR Partnership will continue working to match lignite-based sources with potential $CO_2$ EOR sinks to facilitate $CO_2$ management in the near term. Another PCOR Partnership Phase III task that will develop valuable information for the North Dakota energy industry focuses on the concept of utilizing the Ramgen Power Systems compression technology, which applies ramjet engine concepts to the compression of gases. Data will be gathered and compiled for an investigation of the Ramgen technology to compress a slipstream of $CO_2$. The Ramgen technology is described in detail in Appendix C.

With respect to $CO_2$-flood EOR, there are a variety of reasons why the proposed EOR project is needed. While the ongoing tertiary recovery project at the Weyburn oil field in Saskatchewan is a well-documented successful example of a $CO_2$-based flood in the Williston Basin (6), there are currently no

$CO_2$-flood EOR operations in the North Dakota portion of the basin. Also, it is anticipated that the Phase III EOR project will be conducted in a reservoir over 10,000 ft deep, and there are no $CO_2$-flood operations in the world that are reported to be in reservoirs that deep (3). The data that will be generated on the effects of deep (depth >10,000 ft) reservoir conditions on $CO_2$-based EOR operations and MMV activities will not only be unique, but also critical to the widespread successful deployment of $CO_2$-based EOR operations in other deep North Dakota reservoirs. Finally, and perhaps most importantly, there are no commercial-scale EOR projects using $CO_2$ generated by a coal-fired power plant. The proposed $CO_2$-flood EOR demonstration project will provide proof-of-concept data with respect to the technical and economic viability of using $CO_2$ from a coal-fired power plant for EOR operations.

**PCOR Partnership Team and EERC Facilities and Capabilities**

The EERC and the members of the PCOR Partnership bring a unique combination of capabilities and facilities to the PCOR Partnership Program. As shown in Table 1, current Phase II partners include utilities, oil and gas companies, coal companies, and industrial groups. Phase III activities will be conducted by a diverse, multipartner team (see Table 2) under EERC leadership that includes the key government, private sector, technical, and outreach groups. The PCOR Partnership Phase III team will include 1) industry sponsors that serve as advisors and provide cost share and technical expertise; 2) research partners that are funded under the PCOR Partnership venture; and 3) collaborators that, in most cases, provide in-kind support. The knowledge base, expertise, and hands-on experience of the PCOR Partnership research team encompass the entire region. The EERC's 245,000 square feet of laboratory, technology demonstration, and office space, located on the University of North Dakota (UND) campus, house state-of-the-art facilities for analysis, fabrication, and laboratory- to pilot-scale testing and verification. All facilities are available for PCOR Partnership Phase III activities. In addition, the EERC has the facilities, equipment, and experienced personnel to undertake 1) relational database design, 2) geographic information system (GIS) programming, 3) database applications and decision support tools, 4) MMV design and implementation, and 5) predictive modeling. The PCOR Partnership's industrial sponsors and collaborative partners have sites and facilities that will be used for the demonstration of $CO_2$ separation, transportation and capture technologies, and injection during Phase III activities.

### Environmental and Economic Impacts While Project Is under Way

The economic and environmental impacts of this project are profound. Because the PCOR Partnership region (and the Williston Basin of North Dakota in particular) is blessed with abundant opportunities for EOR that are located in relatively close proximity to existing and planned coal-fired power production facilities, demonstrating the technical and economic viability of commercial-scale $CO_2$ capture, compression, and transportation from coal-fired power plants may pave the way to the incremental production of hundreds of millions of barrels of oil in North Dakota and, potentially, over 2 billion barrels of oil in the region as a whole (7, 8). Exploitation of this resource through the use of lignite-based $CO_2$ provides a key long-term regional sales market for lignite-generated power, as some rural counties' power demand is dominated by oil and gas operations. Globally, partners in the PCOR Partnership are part of an effort to devise economically viable techniques to avoid the atmospheric emission of millions of tons of $CO_2$ over the lifetime of the project and beyond. Economically, the benefits to North Dakota may be even greater. The additional oil produced as a result of the $CO_2$-based EOR will generate additional primary sector tax revenue. Additionally, many new jobs will be created through the construction of infrastructure and implementation of the project design.

With respect to local impacts from project activities, the $CO_2$-based EOR demonstration in North Dakota will be designed and implemented in accordance with all applicable state and federal regulations ensuring that any environmental impact of the project activities is minimal. MMV activities will be conducted at each technology validation test site to ensure that shallow groundwater resources and the surface environment are not adversely impacted by the injection activities.

### Ultimate Technological and Economic Impacts of Project

The activities in Phase III of the PCOR Partnership will support existing and future opportunities for adding value to carbon management. A vibrant lignite industry is very important to North Dakota, and by developing techniques to capture and compress $CO_2$ affordably and sell the

**Table 1. PCOR Partnership Team, Phase II**

| | | |
|---|---|---|
| UND EERC | Great River Energy | North Dakota Industrial Commission |
| Advanced Geotechnology, | Hess Corporation | Lignite Research, Development and |
| a division of Hycal Energy Research | Interstate Oil and Gas Compact | Marketing Program |
| Laboratories, Ltd. | Commission | North Dakota Industrial Commission |
| Air Products and Chemicals | Iowa Department of Natural Resources | Oil and Gas Research Council |
| Alberta Department of Energy | Lignite Energy Council | North Dakota Natural Resources Trust |
| Alberta Energy and Utilities Board | MEG Energy Corporation | North Dakota Petroleum Council |
| Alberta Geological Survey | Melzer Consulting | North Dakota State University |
| Ameren Corporation | Minnesota Geological Survey – | Otter Tail Power Company |
| American Lignite Energy (ALE) | University of Minnesota | Petroleum Technology Transfer Council |
| Apache Canada Ltd. | Minnesota Power | Prairie Public Television |
| Basin Electric Power Cooperative | Minnkota Power Cooperative, Inc. | Pratt & Whitney Rocketdyne, Inc. |
| Blue Source, LLC | Missouri Department of Natural | Ramgen Power Systems, Inc. |
| British Columbia Ministry of Energy, | Resources | RPS Energy |
| Mines, and Petroleum Resources | Missouri River Energy Services | Saskatchewan Industry and Resources |
| Carbozyme, Inc. | Montana–Dakota Utilities Co. | SaskPower |
| Center for Energy and Economic | Montana Department of Environmental | Schlumberger |
| Development (CEED) | Quality | Shell Canada Energy |
| Dakota Gasification Company | National Commission on Energy Policy | Spectra Energy |
| Ducks Unlimited Canada | Natural Resources Canada | Strategic West Energy Ltd. |
| Ducks Unlimited, Inc. | Nexant, Inc. | Suncor Energy Inc. |
| Eastern Iowa Community College | North American Coal Corporation | U.S. Department of Energy |
| District | North Dakota Department of Commerce | U.S. Geological Survey Northern |
| Enbridge Inc. | Division of Community Services | Prairie Wildlife Research Center |
| Encore Acquisition Company | North Dakota Department of Health | University of Alberta |
| Environment Canada | North Dakota Geological Survey | Western Governors' Association |
| Excelsior Energy Inc. | North Dakota Industrial Commission | Westmoreland Coal Company |
| Fischer Oil and Gas, Inc. | Department of Mineral Resources, Oil | Wisconsin Department of Agriculture, |
| Great Northern Power Development, LP | and Gas Division | Trade and Consumer Protection |
| | | Xcel Energy |

**Table 2. PCOR Partnership Team, Phase III**

| | | |
|---|---|---|
| UND EERC | Lignite Energy Council | North Dakota Industrial |
| ALLETE | Melzer Consulting | Commission Oil and Gas Division |
| Basin Electric Power Cooperative | Minnkota Power Cooperative, Inc. | Otter Tail Power Company Prairie |
| BNI Coal, Ltd. | Montana–Dakota Utilities Co. | Public Television |
| British Columbia Ministry of Energy, | Natural Resources Canada | Ramgen Power Systems, Inc. |
| Mines and Petroleum Resources | North American Coal Corporation | Spectra Energy |
| Encore Acquisition Company | North Dakota Industrial Commission | U.S. Department of Energy |
| Great Northern Power Development, LP | Lignite Research, Development and | Westmoreland Coal Company |
| Great River Energy | Marketing Program | |

produced $CO_2$ to oil producers, lignite will remain a reliable, low-cost energy source. Additionally, future expansion of $CO_2$-based EOR projects in North Dakota will generate millions of dollars in primary sector and tax revenue through the production of millions of barrels of additional oil (potential regional incremental oil resource >2 billion barrels) and extension of the productive life of North Dakota's oil fields. Steps taken to economically capture $CO_2$ from lignite-based power generation will ensure that lignite remains a critical part of North Dakota's economy and help expand the lignite-based power industry in the region.

The lessons to be learned in sink capacities and permanence, MMV, transport, economics, risk, public acceptance, and societal cobenefits that will be provided by the proposed $CO_2$-based EOR projects are vital to the long-term opportunities for the lignite industry in North Dakota. In summary, PCOR Partnership Phase III field demonstrations will provide partners with critical, previously unavailable data on the technical and economic feasibility of capture, compression, and sequestration of $CO_2$ from a coal-fired power plant.

## STANDARDS OF SUCCESS

The overall success of this project will be determined through the successful implementation of the planned Phase III field demonstration tests and their subsequent commercial application within the PCOR Partnership region, including North Dakota. Success will be achieved by identifying suitable candidate opportunities and addressing and solving any economic, technical, environmental, and regulatory hurdles facing those opportunities. Public stakeholders such as regulators and decision makers at the state, county, and municipal levels will be able to use information developed in Phase III to make well-informed plans related to economic growth associated with the region's lignite-related power industry. Regulators and decision makers will also be provided with the tools necessary for developing the regulations, legislation, and public policy associated with the future development of $CO_2$ management projects. Private stakeholders, including the sponsors of PCOR Partnership Phase III, will be able to apply the information and results generated over the course of the Phase III demonstrations to develop their own $CO_2$ capture projects, $CO_2$-flood EOR/sequestration projects and, ultimately, acquire and monetize carbon credits associated with geologic sequestration. The Phase III task devoted to public outreach will ensure that appropriate information is provided to public and private stakeholders.

## BACKGROUND

Phase I of the PCOR Partnership largely focused on characterizing the $CO_2$ sources and sinks in the region. The regional characterization activities conducted under Phase I confirmed that the region's fossil fuel industries embodied in the numerous lignite-fueled power plants and the numerous oil and gas fields in the Williston Basin are critical to our regional economy and that the region also has tremendous capacity for $CO_2$ sequestration through EOR. The deployment of $CO_2$-based EOR projects will provide economic benefits to our industrial partners and enhance the regional economy. In North Dakota, 28 oil fields were identified as being potentially suitable for $CO_2$-flood EOR. These oil fields are estimated to have the potential to produce over 260 million barrels of incremental oil (7, 8). With respect to $CO_2$ sources in North Dakota, large coal-fired power plants were identified as being the most significant $CO_2$ sources (7).

PCOR Partnership Phase II efforts, which are ongoing and scheduled to be completed in the fall of 2009, are primarily focused on smaller-scale field validation tests of $CO_2$ sequestration through injection into oil reservoirs and lignite coal seams for EOR and enhanced coalbed methane (ECBM) recovery and the restoration of Prairie Pothole Region wetlands. A primary goal of the Phase II validation tests is to develop cost-effective MMV strategies that can be broadly applied to commercial-scale $CO_2$ sequestration projects such as those being proposed as part of Phase III. The Phase II validation tests are scheduled to be largely completed before the Phase III injection operations are initiated, and the results of Phase II will be applied toward implementing cost-effective MMV strategies for Phase III activities.

The PCOR Partnership region generates approximately 550 million tons per year of anthropogenic $CO_2$ from stationary industrial sources (9). For the region as a whole, electric utilities contributed a greater share of the emissions than other stationary sources. The PCOR Partnership Phase I evaluations found that coal-fired power plants located in western North Dakota are among the region's largest $CO_2$ sources, approximately 45 million tons of $CO_2$ each year (9). If $CO_2$ storage is shown to be economically feasible, these coal-fired power plants could serve all of the EOR needs for $CO_2$-flood operations in the Williston Basin for several decades. Specifically, PCOR Partnership Phase I evaluations suggest that 79 years' worth of $CO_2$ emissions from those sources could be injected in western North Dakota's petroleum reservoirs as a result of EOR activities alone (9).

## QUALIFICATIONS

The EERC has demonstrated its ability to develop and lead multiyear, multidisciplinary, multiclient programs, including many public–private and stakeholder-based partnerships like the PCOR Partnership. The EERC was established in 1949 as a federal research facility under the U.S. Bureau of Mines and later became the lead laboratory for low-rank coals under DOE. The center was defederalized in 1983 and became a business unit of UND. The EERC currently has 442 active contracts, with 84% from the private sector. Since 1987, the EERC has worked with nearly 1000 clients in 50 countries and all 50 states. The EERC's multidisciplinary staff of more than 300 has maintained its leading role in coal research and has expanded its expertise and partnerships in a broad spectrum of energy and environmental programs. The EERC has successfully completed projects involving geological characterization of subsurface resources, experimental design, analytical methods development, groundwater quality, biomass-based energy, advanced power systems, atmospheric emission controls, reclamation of disturbed lands, disposal and value-added waste management, disposal site characterization, site remediation for oil and gas, cleanup of the federal weapons complex and industry sites, and training activities from a local to international scope.

The EERC's success has been supported by its long-standing partnership with the fossil fuel industry and DOE through the National Energy Technology Laboratory (NETL). The North Dakota Industrial Commission Lignite Research Council has been a particularly strong and valuable partner in Phases I and II of the PCOR Partnership. One mutual goal of the PCOR Partnership and the lignite industry is to continue to ensure the continued supply of reasonably priced North Dakota lignite and lignite based power. The EERC has projects and strong working relationships with the lignite industry operating in North Dakota and other state and federal agencies, including the North Dakota Department of Mineral Resources, the Oil and Gas Division, and the Geological Survey; the U.S. Department of the Interior; and the U.S. Department of Agriculture, among others.

Key personnel for the PCOR Partnership Phase III activities include select administrative and technical staff from all of the PCOR Partnership research partners, representing a broad range of scientific and engineering disciplines and real-world experience. Resumes for key EERC personnel involved with the proposed project are provided in Appendix D. Indeed, the success of Phases I and II was due to the commitment of our industry partners who are even more critical to the success of Phase III. Relevant EERC expertise includes project management; geological characterization and assessment; geological, chemical, and mechanical engineering; reservoir modeling; data management and GIS programming; permitting and regulation compliance; and public outreach. The PCOR Partnership members bring technical expertise in sources, permitting and regulations, transportation, reservoir engineering, and EOR.

## VALUE TO NORTH DAKOTA

The North Dakota lignite industry is essential to the state and regional economy and provides a reliable low-cost energy source. Successful conduct of the PCOR Partnership Phase III activities can provide tremendous economic benefit to the state of North Dakota by facilitating the development of economically viable $CO_2$ capture and compression technologies which will allow $CO_2$ from coal-fired power plants to be utilized in EOR projects. The incentives from these EOR activities are 1) millions of barrels of incremental oil will be recovered; 2) instead of future regulations driving the capture of anthropogenic $CO_2$, additional income associated with the sale of the $CO_2$ could become the driving force; and 3) millions of tons of anthropogenic $CO_2$, that would otherwise be vented into the atmosphere, will be stored safely in geologic formations.

One of the long-term goals of the PCOR Partnership is to develop a market-based approach to carbon management, with the potential to improve both the region's economy and environment. Key to the success of Phase III is monetizing carbon credits for $CO_2$ sequestration in geologic formations. This will provide the framework for safeguarding the lignite industry in North Dakota and will help make $CO_2$-based EOR projects in North Dakota economically feasible. Large-scale commercialization of these activities will result in increased employment opportunities and tax revenues for the citizens of North Dakota, extend the productive life of many of North Dakota's oil fields, and safeguard the lignite industry by continuing to provide lignite-based energy at a low cost.

## MANAGEMENT

Mr. Ed Steadman, EERC Senior Research Advisor, will serve as Project Manager of the Phase III PCOR Partnership. He will have overall responsibility for the contract and will interface regularly with the PCOR Partnership partners, principal investigators, and EERC senior management. He will be responsible for regular reporting to the Lignite Research Council and timely dissemination of information to other project partners. Other members of the project management team will include Mr. John Harju, EERC Associate Director for Research, and Mr. James Sorensen, Senior Research Manager. The project management team will focus on providing timely completion of milestones; timely, high-quality deliverables; and effective communication between the PCOR Partnership and the Lignite Research Council. Regular project review meetings (annual or as otherwise directed) between representatives of the PCOR Partnership and the Lignite Research Council will be scheduled.

## TIMETABLE

Appendix E shows the project schedule for PCOR Partnership Phase III activities over the 10-year time frame. Only Tasks 4–9 are discussed within this proposal. Task 1–13 are described in detail in Appendix B and Appendix C ("Statement of Project Objectives" and "Project Narrative," respectively, provided to DOE as part of the Phase III application process). Specific NDIC reports, including interim reports, special reports, and final reports, will be prepared and submitted to NDIC within the time frame and guidelines specified in the contract between the EERC and the NDIC Lignite Research Council.

## BUDGET

The EERC is requesting $2,400,000 from the NDIC Lignite Research Council for the first 2 years of PCOR Partnership Phase III. Additional cost share of $133,831,052 is shown in Table 3. The total project budget is necessary to adequately address the concerns surrounding the use of $CO_2$ for EOR in North Dakota and to establish economically and technically feasible technologies to capture and compress $CO_2$ from coal-fired power plants and other large point sources of $CO_2$ in North Dakota. The level of Lignite Research Council funding is critical to adequately represent the perspective of the North Dakota

**Table 3. PCOR Partnership Cost Share**

| Organization | Year 1–2 | Year 3–8 | Year 9–10 | Total |
|---|---|---|---|---|
| DOE | $ 6,800,000 | $ 49,980,380 | $ 10,219,620 | $ 67,000,000 |
| Oil and Gas Research Council – Cash | $ 500,000 | | | $ 500,000 |
| Lignite Research Council – Cash | $ 2,400,000 | | | $ 2,400,000 |
| Basin Electric Power Cooperative – In-Kind | $ 2,000,000 | | | $ 2,000,000 |
| Encore Acquisition – In-Kind | $ 1,050,000 | | | $ 1,050,000 |
| Lignite Energy Council Members – Cash/In-Kind | $ 400,000 | | | $ 400,000 |
| Spectra Energy Gas Transmissions – In-Kind | $ 2,477,462 | | | $ 2,477,462 |
| Prarie Public Broadcasting, Inc. | $ 49,750 | | | $ 49,750 |
| Cash – In Negotiation | | $ 3,000,000 | $ 1,000,000 | $ 4,000,000 |
| In-Kind – In Negotiation | | $ 47,095,760 | $ 9,258,080 | $ 56,353,840 |
| **Total** | **$ 15,677,212** | **$ 100,076,140** | **$ 20,477,700** | **$ 136,231,052** |

lignite industry in this project. Funding of a lesser amount will not adequately demonstrate a serious commitment to managing $CO_2$ emissions from large $CO_2$ point sources in North Dakota. In funding Phase III of the PCOR Partnership, DOE assumes the Lignite Research Council will monetarily support the program as outlined in a letter from the Lignite Research Council to the EERC (see Appendix A). The scope of work developed for overall project funding assumes funding is received from the Lignite Research Council. A detailed budget is provided in Appendix F.

## MATCHING FUNDS

Matching funds being provided to the PCOR Partnership Phase III program are detailed in Table 3.

## TAX LIABILITY

The EERC—a research organization within UND, which is an institution of higher education within the state of North Dakota—is not a taxable entity.

## CONFIDENTIAL INFORMATION

No confidential information is included in this proposal.

## PATENTS AND RIGHTS TO TECHNICAL DATA

It is not anticipated that any patents will be generated by PCOR Partnership Phase III activities. The rights to the technical data generated by this project will be held jointly by the EERC and the sponsoring partners.

## REFERENCES


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# APPENDIX A

# LETTER OF SUPPORT

# INDUSTRIAL COMMISSION OF NORTH DAKOTA

LIGNITE RESEARCH, DEVELOPMENT AND MARKETING PROGRAM

Governor,
**John Hoeven**
Attorney General,
**Wayne Stenehjem**
Agriculture Commissioner,
**Roger Johnson**

http://www.state.nd.us/ndic

May 29, 2007

Mr. Edward N. Steadman
Senior Research Advisor
Energy & Environmental Research Center
15 North 23rd Street, Stop 9018
Grand Forks, ND 58202-9018

RE: Plains Carbon Dioxide Reduction (PCOR) Partnership – Phase III

Dear Mr. Steadman:

This letter is in response to your request for participation in Phase III of the PCOR Partnership, one of the seven U.S. Department of Energy's National Energy Technology Laboratory Regional Carbon Sequestration Partnerships. The proposed large-scale carbon dioxide sequestration demonstration project in our state is critical to the future of North Dakota lignite industry. The North Dakota Lignite Research, Development and Marketing Program (LRP) is committed to the development and demonstration of this commercial-scale sequestration project in the Williston Basin of North Dakota.

Contingent upon the submission of a grant application to the Lignite Research Council (LRC) that meets program guidelines, matching industry funds, sufficient funds within the LRP, a favorable recommendation from the LRC, and approval from the North Dakota Industrial Commission, the North Dakota Lignite Research, Development and Marketing Program is committed to providing $2.4 million towards the first two years of this 10-year project.

Sincerely,

Jeffrey L Burgess

Jeff Burgess, P.E.
Director and Technical Advisor
Lignite Research, Development and Marketing Program

Cc: Karlene Fine, Executive Director and Secretary, NDIC
John Dwyer, Chairman, Lignite Research Council


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**INDUSTRIAL COMMISSION OF NORTH DAKOTA**

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# APPENDIX B

# STATEMENT OF OBJECTIVES

# STATEMENT OF PROJECT OBJECTIVES

## Plains $CO_2$ Reduction (PCOR) Phase III Renewal Application

## A. OBJECTIVES

The primary objectives of Phase III are 1) to gather characterization data to verify the ability of the target formations to store $CO_2$, 2) to develop the infrastructure required to transport $CO_2$ from the source to the injection site, 3) to facilitate development of the rapidly evolving North American regulatory and permitting framework, and 4) to develop a mechanism by which carbon credits can be monetized for $CO_2$ sequestered in geologic formations.

## B. SCOPE OF WORK

The Plains $CO_2$ Reduction (PCOR) Partnership Phase III objectives will be reached through a series of thirteen tasks performed over 10 years in three budget periods. The project tasks include 1) Regional Characterization, 2) Public Outreach and Education, 3) Permitting and NEPA Compliance, 4) Site Characterization and Modeling, 5) Well Drilling and Completion, 6) Infrastructure Development, 7) $CO_2$ Procurement (capture, purification, or purchase), 8) Transportation and Injection Operations, 9) Operational Monitoring and Modeling, 10) Site Closure, 11) Post Injection Monitoring and Modeling, 12) Project Assessment, and 13) Project Management.

## C. TASKS TO BE PERFORMED

Table 1 illustrates the task structure over the three budget periods.

### Task 1.0 – Regional Characterization

***Subtask 1.1 – Regional Characterization***.

- Subtask 1.1.1 Review and update attribute data for existing sources. Add additional attributes as necessary for characterization. Incorporate new sources as they come on line. Deliverable (D) 1.

- Subtask 1.1.2 Perform detailed characterization of several target areas similar to the demonstration area to develop methodologies for refined capacity estimations (D2, D5, D7).

- Subtask 1.1.3 Refine sequestration analogs for specific geologic horizons within the regional basins.

**Table 1. PCOR Partnership Phase III – Budget Periods and Project Tasks**

- Subtask 1.1.4 Work with the Geologic Surveys/Oil and Gas Divisions of the states and provinces to develop greater detail of the field and reservoir data.

- Subtask 1.1.5 Develop and refine calculations to derive reservoir data, such as water saturation, porosity, permeability, and resistivity.

- Subtask 1.1.6 Review current and emerging terrestrial carbon aggregator programs (i.e., Farmers Union, Ducks Unlimited, etc.) to compile regionwide net carbon storage benefits and assess impacts of expiring conservation reserve program acres during the project period.

- Subtask 1.1.7 Continue to maintain a database of existing and emerging compression technologies applicable to $CO_2$.

- Subtask 1.1.8 Catalog existing pipeline routes and determine possible future routes that could be used to implement $CO_2$ sequestration.

- Subtask 1.1.9 Use models such as the Carnegie–Mellon Integrated Environmental Control Model and the Massachusetts Institute of Technology $CO_2$ Pipeline Transport and cost model to calculate pipeline routes and costs for various source–sink pairings.

- Subtask 1.1.10 Continue to gather information on current and planned $CO_2$ sequestration-related regulations at the state, province, and federal levels and continue to participate in the Interstate Oil and Gas Compact Commission Regulatory Working Group.

- Subtask 1.1.11 Determine anticipated permitting activities for potential projects in all states and provinces of the PCOR Region (D3, D4, D6, and D8).

***Subtask 1.2 – Decision Support System***.

- Subtask 1.2.1 Develop an enhanced 3-D interface to subsurface data.

- Subtask 1.2.2 Develop tools and features appropriate for data analysis and modeling, such as graphical output of select geologic data (i.e., decline curves).

- Subtask 1.2.3 Supplement the DSS (decision support system) with source and sink data that are outside of the PCOR Partnership region but relevant to the regional vision and to PCOR Partnership partners.

- Subtask 1.2.4 Provide access to the data collected through all of the characterization activities through user-friendly Web pages and GIS tools.

An updated DSS will be submitted at the end of BP3 and every 2 years in BP4 (D9).

***Subtask 1.3 – Develop a Demonstration Project Reporting System (DPRS)***. Information specific to the demonstration tests will be maintained, utilized, and reported to the U.S. Department of Energy (DOE) and partners through a Demonstration Project Reporting System (DPRS). The DPRS will be a Web-based interface that will house data from each demonstration activity and facilitate communication and interpretation of these data. The DPRS will be designed to provide structured access to data by all demonstration participants and other partners and to allow for efficient replication of additional or related demonstration projects (D10).

## Task 2.0 – Public Outreach and Education

***Subtask 2.1 – Outreach Planning***. An action plan (D11) for Phase III outreach, addressing both general outreach and specific outreach in the area of the demonstration project, will be developed early in Year 1 with input from the Partners and will be updated at the beginning of each budget period (BP).

***Subtask 2.2 – Data Acquisition and Management***. The outreach data management system, an addition to the DSS, will consist of geographic information system (GIS)-compatible databases containing information needed to plan, track, and assess outreach actions as well as to produce thematic maps and other products to aid in outreach activities, including the Web site, PowerPoint presentations, fact sheets, and video products both at the regional level and for the area of the demonstration project. The details of the information and scheduling will be worked out with DSS managers as part of the outreach planning process.

***Subtask 2.3 – Public Web Site***. The public PCOR Partnership Web site will be updated and expanded in Year 1 to include a section on the Phase III demonstration project and the monetization of carbon credits. Starting in Year 3, the Web site will be updated as appropriate with major updates on a biannual basis (D12 and D13).

***Subtask 2.4 – Fact Sheets***. The set of ten PCOR Partnership fact sheets developed to date in Phase I and Phase II will be expanded by developing fact sheets in Phase III that provide general background information on the PCOR Partnership Phase III program and that profile each of the demonstration programs. These fact sheets will be updated at the midterm and end of the Phase III funding period (D14, D15, and D16).

***Subtask 2.5 – PowerPoints***. A PowerPoint presentation will be developed in Year 1 for the Phase III activities. In Year 2, PowerPoint presentations will be developed for each of the demonstration projects. These PowerPoint presentations will be updated on an annual basis (D17, D18, and D19).

***Subtask 2.6 – Video Materials***. Starting in Year 1, video materials will be developed to aid in portraying the function of the demonstration projects. These materials, including animation, are intended for use in PowerPoint presentations and public Web pages. In Years 4 and 5, 15-minute videos will be developed to profile each of the demonstration sites and be available for use on the public Web site and as DVDs. In Year 9, a 30-minute broadcast-quality video will be produced that provides an updated view of the role of sequestration in carbon management. The video materials will be produced in partnership with Prairie Public Broadcasting (D20, D21, D22, and D23).

***Subtask 2.7 – Posters***. Three posters (D24, D25, and D26), intended for a general audience, will be developed. The first will provide a summary of the sequestration opportunities in the region with an emphasis on geologic sequestration, including the Phase III demonstration projects, the role of the Regional Carbon Sequestration Partnerships (RCSP) program and the PCOR Partnership program to address sequestration needs, and how PCOR Partnership efforts fit into international efforts to manage carbon emissions. The other two posters will provide profiles of the demonstration projects.

***Subtask 2.8 – Environmental Impact Statement Outreach Support***. During Years 1 and 2, the outreach task will support the Environmental Impact Statement process as appropriate, including disseminating site outreach materials and giving presentations.

***Subtask 2.9 – General Outreach***. During the course of the project, the outreach team will identify and act on opportunities to provide outreach both at the regional level and in the vicinity of the demonstrations and address needs with respect to general information on sequestration as well as information on the demonstration projects in the region. Activities will include presentations, assembly of materials for the press and for specific audiences, as well as conducting focus groups to gauge the knowledge of target audiences and the effectiveness of outreach materials.

### Task 3.0 – Permitting and NEPA Compliance

Because both field tests are occurring at ongoing commercial operations, it is expected that there will be minimal additional environmental consequences that occur because of Phase III activities. In addition, it is anticipated that the Energy & Environmental Research Center's (EERC's) partners will be obtaining all necessary permits and approvals that are needed to comply with state and federal requirements. However, should the EERC's direct involvement or assistance become necessary for the Williston Basin demonstration, the text below outlines the procedures that will be followed.

***Subtask 3.1 – Completion of DOE's Environmental Questionnaire***. In order to begin Phase III operations, the EERC will complete the DOE Environmental Questionnaire for both the Williston Basin and Fort Nelson demonstration project (D27 and D28). DOE's NEPA implementation procedures require consideration of the potential environmental consequences of all proposed actions. DOE must determine as early as possible whether such actions require an Environmental Assessment (EA) or an Environmental Impact Statement (EIS), or if they qualify for Categorical Exclusion. DOE has suggested the most intensive NEPA scenario be addressed.

***Subtask 3.2 – Assist in the Development of the Environmental Assessment***. If DOE determines that an EA or EIS is necessary for the Williston Basin demonstration, the Cooperative Agreement will be modified to reduce the award value and subcontract directly with an organization to prepare the appropriate document. However, as Project Managers, we do anticipate a significant amount of effort will be expended in interfacing with the EIS subcontractor, as such we have provided a brief summary of anticipated EIS activities below:

- Notice of intent (NOI). In accordance with CFR 1501.7, a NOI must be published in the *Federal Register* announcing the decision to prepare an EIS, before public scoping begins. This notice will be published in coordination with DOE. The NOI will include a description of the proposed action, scoping activities, and a contact person.

- Public scoping. Once the notice is published, public scoping activities can begin. This will involve soliciting federal and state agency, Tribal, and public comment on the scope of the EIS. At least two informal public meetings will be conducted. Depending on the amount of comments received, a scoping document may be developed. In addition, a newsletter or Web site may be developed to inform the public of the proposed activities. The EERC will follow all DOE NEPA regulations with regard to public involvement. The following outline indicates the minimum level of public involvement:

  - NOI published in the *Federal Register*
  - Scoping activities
  - File draft EIS – availability published in *Federal Register*
  - Draft EIS sent to interested parties and made available via Web site
  - Receive public comments
  - Respond to public comments
  - Complete and file final EIS (FEIS)
  - At least 30-day review period
  - Record of decision (ROD)

- Developing the purpose and need statement and alternatives. The purpose and need statement establishes the reasonable alternatives an EIS must address. The most fundamental objective of the proposed project will be developed (need), and the goals that are to be accomplished while meeting the need for action will be listed (purpose).

- Defining region of influence (ROI). The ROI establishes boundaries for data collection. It is resource-based, and it establishes the context when possible impacts are discussed.

- Affected environment. The resources evaluated in the ROI include the following:

  - Noise
  - Air quality
  - Geology, topography, and soils
  - Surface water
  - Groundwater
  - Transportation
  - Land use
  - Utilities
  - Solid waste
  - Hazardous materials and wastes
  - Biological
    - Vegetation
    - Wildlife
    - Protected species

    - ♦ Wetlands
  - – Cultural
    - ♦ Historical
    - ♦ Archaeological
  - – Socioeconomic (if necessary)

- Impact assessment. The impact assessment will parallel the affected environment section of the document. The effects of the proposed action will be addressed, including the following:

  - – Direct effects
  - – Indirect effects
  - – Short-term effects
  - – Long-term effects
    - ♦ Beneficial vs. adverse
    - ♦ Mitigation
    - ♦ Context
    - ♦ Significance
  - – Unavoidable adverse effects

- Other applicable federal regulations. Other federal regulations that need to be addressed as part of an EIS include the following:

  - – Archaeological and Historic Preservation Act
  - – Clean Air Act
  - – Clean Water Act
  - – Comprehensive Environmental Response, Compensation, and Liability Act
  - – Watershed Protection and Flood Prevention Act
  - – Endangered Species Act
  - – Farmland Protection Policy Act
  - – Wetlands Conservation Act
  - – Fish and Wildlife Coordination Act
  - – National Historic Preservation Act
  - – Noise Control Act
  - – Solid Waste Disposal Act
  - – Occupational Safety and Health Act
  - – Resource Conservation and Recovery Act
  - – Safe Drinking Water Act
  - – Toxic Substances Control Act

- Applicable Executive Orders that need to be addressed as part of an EIS include the following:

  - – Protection and Enhancement of Environmental Quality (EOs 11514 and 11991)
  - – Floodplain Management (EO 11988)
  - – Protection of Wetlands (EO 11990)

- Intergovernmental Review of Federal Programs (EO 12372)
    - Federal Compliance with Pollution Standards (EO 12088)
    - Environmental Justice (EO 12898)

- Assist in the completion of the FEIS. Once the draft EIS has been filed and public comments have been received and addressed, the FEIS can be written and submitted. Following the filing of the FEIS, there is typically at least a 30-day review period before the ROD can be issued. If necessary, the EERC will assist in the ROD completion.

***Subtask 3.3 – General Permitting Assistance***. It is anticipated that EERC partners will obtain all necessary permits and approvals to comply with state and federal requirements. However, the EERC anticipates that it will be directly involved or assisting in meeting the following requirements:

- North Dakota Industrial Commission (NDIC) Requirements. All of the reporting requirements and permit types that are necessary to comply with NDIC regulations will be accomplished in Subtask 3.3.

- North Dakota Public Service Commission (PSC) Requirements. The PSC regulates the construction of pipelines in the state of North Dakota. If a new $CO_2$ pipeline were to be constructed as part of this project, numerous permits may be required. A pipeline route application will be submitted to the PSC.

- Crossing various types of water bodies and wetlands, federal lands, tribal lands, roadways, and railroads may require permits from multiple agencies—local, state, and federal—that have jurisdiction over the mediums crossed. The exact route of the pipeline will dictate what agencies need to be contacted.

- The newly formed North Dakota Pipeline Authority is tasked with facilitating the development of pipeline facilities. This entity will most likely be involved with this subtask, should it become necessary.

***Subtask 3.4 – Development of a Permitting Action Plan***. A permitting action plan (D29) will be designed in accordance with relevant local, state, and federal regulatory requirements for the project, as follows:

- Development of a Gantt chart to schedule permit due dates and anticipated approval dates.

- A listing of the person and/or entities responsible for permit development and filing.

- Preparation and submission of applications for required permits to the appropriate local, state, and federal regulatory agencies.

An updated Permitting Action Plan (D75) will be submitted in BP4.

A Best Practices Manual (D76) for permitting will be developed in BP5.

## Task 4.0 – Site Characterization and Modeling

***Subtask 4.1 – Williston Basin Test Site***. The selection of a host injection site for the Williston Basin enhanced oil recovery (EOR) test has not been finalized and is subject to change based on 1) the outcome of ongoing negotiations between the oil field operating company, the power plant operating company, and the EERC and 2) the collection and evaluation of detailed proprietary data for the selected field that were previously unavailable for characterization under PCOR Partnership Phases I and II. Therefore, the first activity to be conducted under Task 4.0 will be the selection of an oil field to host the large-volume injection test. The final site selection will be determined by the third quarter of Phase III, Year 1 (Budget Period 3).

Detailed subsurface mapping and characterization must be conducted prior to large-scale injection of $CO_2$ for the Williston Basin EOR test. Site characterization activities will be conducted to develop predictive models that address three critical issues to determine the ultimate effectiveness of the target formation: 1) the capacity of the target formation, in this case, an oil reservoir within an established oil field; 2) the mobility and fate of the $CO_2$ at near-, intermediate-, and long-term time frames; and 3) the potential for leakage of the injected $CO_2$ into overlying formations and/or the surface environment. Key site characterization parameters that will be addressed during Years 1 and 2 (Budget Period 3) and Year 3 (Budget Period 4) include properties of the reservoir and seal rocks, properties of the fluids in the reservoir and overlying fluid-bearing formations, and the production and operational history of the target oil reservoir.

The proposed work will be carried out at four different scales:

- Reservoir scale – focused on the oil pool within the selected host oil field and the immediately underlying and overlying confining units (seals).

- Local scale – focused on the area that legally defines the entire oil field and vertically includes the entire sedimentary succession from the basement to the surface within the field.

- Regional or subbasin scale – focused on evaluating relevant data and information over the entire regional structural feature, or subbasin, of which the field is a part. For example, if the injection target is the Red River Formation in a field that is located on or near the Cedar Creek Anticline, then the subsurface environment of the entire anticline will be characterized to address potential long-term fate of the injected $CO_2$.

- Basin scale – to determine the potential movement of $CO_2$ over extremely long periods of time (>10,000 years), the flow regime in key aquifer systems will be examined in the Williston Basin to determine discharge area (if any exists) and flow characteristics.

Once the site selection process is complete, the following specific activities will be conducted under Task 4.0.

*Subtask 4.1.1 – Site Selection.* The PCOR Partnership will work with Encore to select an oil field in the Williston Basin to serve as the host site for the large-scale $CO_2$ injection project. Work conducted under this subtask will include:

- The evaluation of geology and engineering data associated with candidate oil fields in the Williston Basin.

- Site visits to candidate oil fields.

*Subtask 4.1.2 – Williston Basin Test Site Baseline Geology Determination.* Williston Basin test site baseline geology determination will include:

- Development of a Geological Characterization Experimental Design Package (D31) that describes the specific approaches and analytical techniques used to conduct the activities of Subtask 4.1.2.

- Collection, evaluation, and interpretation of historic data sets. Databases from Encore and state regulatory agencies will be mined to gather a variety of data including, but not necessarily limited to, well/reservoir information of the selected oil field and other pertinent areas; drilling, completion, and stimulation/workover records of all wells in the field; digital production/injection history of all wells; and geological and geophysical information on the selected oil field, including maps, cross sections, and geophysical surveys.

- Acquisition, evaluation, and interpretation of new data sets, including data collected from field-based site characterization activities. Field-based site characterization activities may include, but are not necessarily limited to, core collection and analyses, well logging, and the application of selected geophysical survey techniques.

- A report on the specific characterization of the Williston Basin oil field to be used for the injection program (D64) will be prepared. A Best Practices Manual for Characterizing Oil Fields for $CO_2$ Sequestration (D35) will also be prepared.

- Creation of a geological model of the strata at the appropriate scales.

- Reservoir modeling. Attributes such as injectivity, fluid production, and reservoir dynamics will be modeled using software packages that include, but are not necessarily limited to, the Schlumberger ECLIPSE model. The ultimate fate of the $CO_2$ over short-, intermediate-, long- and extremely long-term time frames will be predicted. A report on the specific results of the Williston Basin oil field simulations (D66) will be prepared. A Best Practices Manual for $CO_2$ EOR and Sequestration Modeling Simulations will also be prepared (D69).

*Subtask 4.1.3 – Williston Basin Test Site Baseline Hydrogeology Evaluation.* The following information will be collected:

- Hydrostratigraphic delineation
- Aquifer and aquitard geometry and thickness
- Rock properties relevant to the flow of formation waters and injected acid gas such as porosity and absolute and relative permeability
- Geothermal regime
- Pressure regime
- Direction and strength of formation water flow

A Baseline Hydrogeological Experimental Design Package (D34) describing the specific approaches and analytical techniques that will be used to conduct the activities of Subtask 4.1.3 will be developed in the initial stage of the project.

A model of the flow-driving processes and mechanisms in the site study area and strata of interest will be developed to help in understanding the effect of natural flow on flow paths in the targeted injection formation and, in case of leakage, the effect of injection on the greater subsurface system.

*Subtask 4.1.4 – Geochemical Evaluations and Modeling*. Laboratory tests will be conducted on core samples of the target injection formation and key sealing formations under reservoir conditions to assess the geochemical reactions anticipated to occur between the injected gas and the rocks and fluids of the reservoir and seal. Mineral compositions will be obtained using x-ray diffraction, x-ray fluorescence, and scanning electron microscopy techniques. Samples of fluids from key formations in the selected oil field will be collected and analyzed for major and minor constituents. Laboratory results will be used to refine geochemical models which will be integrated with $CO_2$ fate predictive modeling efforts. A final report describing and discussing the results of the geochemical evaluations and modeling (D33) will be prepared.

Geochemical modeling will include the following:

- The interaction between the injected $CO_2$, the reservoir fluids, and the rocks will be modeled to determine the amount of $CO_2$ that may be stored through dissolution and mineral precipitation.
- An appropriate modeling program will be used to obtain a normative composition of each injection horizon. This composition will be used to perform geochemical modeling to assess the long-term fate of $CO_2$ in the subsurface.

*Subtask 4.1.5 – Geomechanical Rock Properties and Stress Regime Determination for Williston Basin Test Site*. The geomechanical properties of the reservoir and cap rock and stress regime in the area will be determined to assess the mechanical integrity of the system and potential for rock fracturing. An in-depth review of available information on the stress regime and structural features in the area of the reservoir will be conducted to identify structures such as faults or dissolution areas. This information will help to elucidate the geological history of the reservoir and identify possible natural leakage paths like faults. The information will also lead to the development of a Geomechanical Experimental Design Package (D30) describing the specific approaches and analytical techniques that will be used to conduct the activities of Subtask 4.1.5. Activities may include, but are not necessarily limited to, in situ stress orientation and magnitude analysis, log-based analysis of rock mechanical properties, laboratory tests on geomechanical properties of key rocks, and geomechanical modeling. The results of the geomechanical evaluations will be presented in a Geomechanical Final Report (D32).

*Subtask 4.1.6 – Assessment of Wellbore Integrity and Leakage Potential at Williston Basin Test Site*. It is not possible to determine the "exact" state of all wellbores within an oil field; consequently, both "real" field data and analytical or numerical simulations will be combined to quantify processes associated with the hydraulic integrity of the wells. The results of this assessment will be presented in a Wellbore Leakage Final Report (D36). Assessment of wellbore integrity and leakage potential at the Williston Basin test site includes the following:

- Compilation of statistical well geometry and performance data within the pilot and surrounding regions from well databases.

- Evaluation of wellbore integrity issues under the conditions of $CO_2$ injection and long-term buoyancy-driven forces utilizing probabilistic techniques.

***Subtask 4.2 – Fort Nelson Test Site***. The selection of a host injection site for the Fort Nelson test has not been finalized and is subject to change based primarily on the collection and evaluation of detailed proprietary data for the selected brine formation in the Fort Nelson area. Therefore, the first activity to be conducted for the Fort Nelson test under Task 4.0 will be the selection of the specific brine formation target zone and location in the Fort Nelson area to host the large-volume injection test.

Detailed subsurface mapping and characterization must be conducted prior to large-scale injection of $CO_2$ at the Fort Nelson test site. Site characterization activities will be conducted to develop predictive models that address three critical issues to determine the ultimate effectiveness of the Fort Nelson test: 1) the capacity of the target formation; 2) the mobility and fate of the $CO_2$ at near-, intermediate-, and long-term time frames; and 3) the potential for leakage of the injected $CO_2$ into overlying formations and/or the surface environment. Key site characterization parameters that will be addressed during Years 1 and 2 (Budget Period 3) and Year 3 (Budget Period 4) include properties of the injection zone and seal rocks and properties of the fluids in the reservoir and overlying fluid-bearing formations.

The proposed work will be carried out at four different scales:

- Reservoir scale – focused on the specific zone within the selected test location site. This area is defined as the area of the predicted plume and the immediately underlying and overlying confining units (seals).

- Local scale – focused on the area that extends approximately 5 km from the edge of the predicted plume area.

- Regional or subbasin scale – focused on evaluating relevant data and information from the selected brine formation, the immediately underlying and overlying seal formations, and the major secondary seals in the entire regional structural feature, or subbasin, of which the Fort Nelson area is a part.

- Basin scale – to determine the potential movement of $CO_2$ over extremely long periods of time (>10,000 years), the flow regime in key aquifer systems will be examined in the northwestern portion of the Alberta Basin to determine discharge area (if any exists) and flow characteristics.

*Subtask 4.2.1 – Site Selection*. Spectra Energy will select a location and injection zone in the Fort Nelson area to serve as the host site for the Fort Nelson large-scale $CO_2$ injection test. The PCOR Partnership will provide technical assistance to the site selection process. Work conducted under this subtask will include:

- The evaluation of geology and engineering data associated with candidate injection zones in the Fort Nelson area.

- A site visit to the Fort Nelson area.

*Subtask 4.2.2 – Fort Nelson Test Site Baseline Geology Determination*. Fort Nelson test site baseline geology determination will include:

- Development of a Site Geological Characterization Experimental Design Package (D37) describing the specific approaches and analytical techniques that will be used to conduct the activities of Subtask 4.2.2.

- Collection, evaluation, and interpretation of historic data sets. Databases from Spectra and provincial regulatory agencies will be mined to gather a variety of data including, but not necessarily limited to, drilling records of selected oil and gas exploration and production wells in the Fort Nelson area and geological and geophysical information for the Fort Nelson area, including maps, cross sections, and geophysical surveys.

- A Site Characterization Report for the Fort Nelson Site (D65) will be prepared.

- A Best Practices Manual for Characterizing Brine Formation Sites will be developed (D68).

- Acquisition, evaluation, and interpretation of new data sets, including data collected from field-based site characterization activities. Field-based site characterization activities may include, but are not necessarily limited to, core collection and analyses, well logging, and the application of selected geophysical survey techniques.

- Injection zone modeling. Attributes such as injectivity, fluid production, and reservoir dynamics will be modeled using software packages that include, but are not necessarily limited to, the Schlumberger ECLIPSE model. The ultimate capacity of the injection zone and the fate of the $CO_2$ over short-, intermediate-, long-, and extremely long-term time frames will be predicted. A report on the simulation modeling results (D67) will be prepared. A Best Practices Manual for Simulating Injection in Brine Formations will also be prepared (D70).

*Subtask 4.2.3 – Fort Nelson Test Site Geochemical Evaluations and Modeling.* Laboratory tests will be conducted on core samples of the target injection formation and key sealing formations under reservoir conditions to assess the geochemical reactions anticipated to occur between the injected gas and the rocks and fluids of the reservoir and seal. Mineral compositions will be obtained using x-ray diffraction, x-ray fluorescence, and scanning electron microscopy techniques. Samples of fluids from key formations in the selected oil field will be collected and analyzed for major and minor constituents. Laboratory results will be used to refine geochemical models which will be integrated with $CO_2$ fate predictive modeling efforts. The results of these activities will be presented in a Geochemical Final Report for the Fort Nelson Site (D41).

Geochemical modeling will include the following:

- The interaction between the injected $CO_2$, the reservoir fluids, and the rocks will be modeled to determine the amount of $CO_2$ that will be stored through dissolution and mineral precipitation.

- Geochemical modeling will be used to assess the long-term fate of $CO_2$ in the subsurface.

*Subtask 4.2.4 – Geomechanical Rock Properties and Stress Regime Determination for Fort Nelson Test Site.* The geomechanical properties of the reservoir and cap rock and stress regime in the area will be determined to assess the mechanical integrity of the system and potential for rock fracturing. An in-depth review of available information on the stress regime and structural features in the area of the reservoir will be conducted to identify structures such as faults or dissolution areas. This information will help to elucidate the geological history of the reservoir and identify possible natural leakage paths like faults. This information will also lead to the development of a Geotechnical Experimental Design Package (D38) describing the specific approaches and analytical techniques that will be used to conduct the activities of Subtask 4.2.4. Activities may include, but are not necessarily limited to, in situ stress orientation and magnitude analysis, log-based analysis of rock mechanical properties, laboratory tests on geomechanical properties of key rocks, and geomechanical modeling. The results of these activities will be presented in a Geomechanical Final Report for the Fort Nelson Site (D40).

### Task 5.0 – Well Drilling and Completion

The PCOR Partnership will work with the operator of the selected oil field to develop engineering designs for the installation of necessary injection, production, and monitoring wells. The development of operational plans for the injection and recycling of $CO_2$ over the duration of the project will also be conducted. Because the host site for the large-volume $CO_2$ injection test will be an operational oil field already undergoing large-volume water injection activities, it is likely that existing wells may be utilized for $CO_2$ injection, oil production, and monitoring. However, new wells may need to be drilled, and it is likely that existing wells will have to be recompleted, or otherwise worked over, to accommodate the long-term injection of supercritical $CO_2$. The PCOR Partnership will provide technical support to accomplish the objectives of Task 5.0. The actual drilling, completion, and/or reconditioning of wells will be conducted by the commercial operator as part of its cost-share commitment to Phase III. General topic areas for which the PCOR Partnership will provide technical support for the Williston Basin injection test include the following. Under current funding, we will not provide support for the well-drilling and completion task for Fort Nelson.

***Subtask 5.1 – Injection Scheme Design***. Previously unavailable well-logging data will be used to refine knowledge of the key reservoir parameters that control injectivity (i.e., nature of porosity, permeability, and fracture networks) for the Williston Basin test. The injectivity of the target reservoir formation in the area of the selected oil field for the Williston Basin test will be determined in more detail than what is currently available. Reservoir modeling exercises will be used to develop an injection scheme that meets the technical and economic needs for the Williston Basin test project. The injection scheme will include the minimum number of wells needed to achieve the injection goal and the optimal location of wells. Material needs and costs will be determined for the Williston Basin test. An Injection Experimental Design Package (D42) will be prepared and submitted at the end of BP3.

***Subtask 5.2 – Monitoring Scheme Design***. The Williston Basin test site monitoring scheme design (D43) will include the following:

- Existing wells in the oil field will be considered and evaluated with respect to their potential use as monitoring wells for the Williston Basin test.

- If necessary, designs for the reconfiguration of existing wells into monitoring wells for the Williston Basin test will be developed.

- If necessary, locations for new wells will be identified and new monitoring wells designed for the Williston Basin test.

- Material needs and costs will be determined for the Williston Basin test.

***Subtask 5.3 – $CO_2$ Injection and Recycling System Design***. The need for specialized equipment necessary for large-volume $CO_2$ injection for the Williston Basin test will be determined. As part of the Williston Basin test, the need for capture and compression equipment for recycling of $CO_2$ for later stages of the EOR operation will be addressed.

***Subtask 5.4 – Installation of Downhole MMV Equipment***. The need for specialized equipment located in the downhole environment will likely be necessary to conduct some monitoring, mitigation, and verification (MMV) activities. Subtask 5.4 will include the following activities:

- Determination of the effects and impact of downhole MMV equipment on oil field operations.

- Development of an installation and operation plan that minimizes impacts to oil field operations.

- Installation of downhole MMV equipment as part of the well completion process.

***Subtask 5.5 – Final Report***. A final report (D44) describing the key aspects associated with the drilling and completion of injection and monitoring wells will be prepared. The issues related to the installation and operation of downhole instrumentation with respect to oil field operations and sequestration activities will also be addressed.

## Task 6.0 – Infrastructure Development

During this task, the infrastructure associated with the capture, dehydration, compression, and pipeline transportation required to move the $CO_2$ from the source to the oil field for EOR in the Williston Basin will be defined and installed. PCOR Partnership personnel will interface with the commercial partners to facilitate a successful sequestration demonstration. The infrastructure development for the Williston Basin Test Site will be performed by the industrial partners, with PCOR Partnership personnel documenting the activities, interfacing with source facility engineers and vendors, and providing assistance as needed. The activities discussed in the following text are required to develop the infrastructure to deliver $CO_2$ to the EOR site.

### *Subtask 6.1 – Williston Basin Test Site Infrastructure Development*

#### *Subtask 6.1.1 – Capture Technology Infrastructure Development*

##### *Characterization of the Flue Gas Stream*

A thorough physical and chemical characterization will be completed of the flue gas from which the $CO_2$ will be taken and used for EOR activities in the Williston Basin test.

##### *Specification of the Capture Technology to Be Used*

The design specifications of the chosen capture technology will be developed for the quantity and composition of the flue gas that will be treated. Basin Electric Power Cooperative is developing a request for proposals from capture technology vendors. The PCOR Partnership will be involved in this process in an advisory capacity.

##### *Capture Technology Integration Design*

A final design for integration of the chosen $CO_2$ capture technology into the existing operations of the Antelope Valley Power Station will be completed. The final design will be developed largely by Basin Electric Power Cooperative personnel, with assistance from the capture technology provider and the EERC.

*Fabrication/Procurement of Capture Technology*

The capture plant will be procured and delivered to the Antelope Valley Power Station. Simultaneously, modifications will be made to the facility to permit slipstream operation of the $CO_2$ capture plant.

*Installation and Shakedown of the Capture Plant at the Source Facility*

The capture plant will be installed at the $CO_2$ source facility and will undergo shakedown testing to ensure that it operates as required.

*Subtask 6.1.2 – Dehydration Infrastructure Development*

*Specification of the Dehydration Technology*

The dehydration requirements of the $CO_2$ stream will be determined based on the moisture content and mass flow rate of the $CO_2$ stream expected from the capture technology.

*Procurement of a Commercial Dehydration Technology*

A commercially available dehydration system will be procured by Basin Electric Power Cooperative.

*Installation and Shakedown of the Dehydration System*

The dehydration system will be installed at the Antelope Valley Power Station following the $CO_2$ capture plant and will be shaken down to ensure that the system produces a dry $CO_2$ stream meeting compressor and pipeline requirements.

*Subtask 6.1.3 – Compression Infrastructure Development*

*Specification of the Compression Technology*

The compression requirements of the pipeline and the EOR field will be used to determine the specifications for a commercially available $CO_2$ compressor.

*Fabrication/Procurement of the $CO_2$ Compressor*

The compressor will be procured and delivered to the Antelope Valley Power Station.

*Installation of the $CO_2$ Compressor*

The $CO_2$ compressor will be installed at the Antelope Valley Power Station following the dehydration system.

*Subtask 6.1.4 – Shakedown of the Integrated Capture Plant*. The integrated capture plant (i.e., the $CO_2$ capture technology, the dehydration system, and the $CO_2$ compressor) will be shaken down to ensure successful operation to produce a constant, consistent $CO_2$ stream for the demonstration activity. A topical report (D45) detailing the various unit operations required to capture, dehydrate, and compress the $CO_2$; describing the technologies selected; and summarizing the efficiency of the integrated plant will be prepared by PCOR Partnership personnel after completion of the shakedown testing.

*Subtask 6.1.5 – Pipeline Infrastructure Development*

*Determination of Pipeline Route*

Working with regulatory agencies, the pipeline company, and other stakeholders, the most appropriate pipeline route will be determined to transport the $CO_2$ from the source to the EOR field.

*Obtaining Necessary Permits and Rights-of-Way for the Pipeline*

The appropriate negotiations and paperwork will be completed to obtain the needed pipeline permits and rights-of-way.

*Specification of the Pipeline*

Many factors will be included when the pipeline is planned, including pipeline length; diameter; materials of construction; wall thickness; inlet and outlet pressures; physical and chemical properties of the soil; potential construction issues such as interconnections with other pipelines, flow rate meters, mainline block valves, and tees; the need for and likely locations of booster stations; and corrosion monitoring, leak detection, and inspection and security systems. Other factors will be considered as appropriate.

*Procurement of Pipeline Materials*

The materials required for the pipeline will be procured.

*Construction of the Pipeline*

The pipeline will be constructed between the Antelope Valley Power Station and the EOR field. Upon completion of pipeline construction, a topical report (D46) summarizing the route selection, pipeline material specification, and construction details will be prepared by PCOR Partnership personnel.

***Subtask 6.2 – Ramgen Compression Technology Slipstream Test***. This task will evaluate the applicability of the Ramgen Power Systems compressor technology to $CO_2$ streams. A subcontract will be set up with Ramgen personnel to perform Subtasks 6.2.1 and 6.2.2. If additional funding can be procured, the activity will continue with Subtasks 6.2.3 through 6.2.5. Ramgen personnel will perform the work, with PCOR Partnership personnel providing assistance and interfacing with Basin Electric Cooperative personnel, particularly those on-site at the Antelope Valley Power Station. A topical report (D47) will be prepared at the end of Subtask 6.2.2 that summarizes the Ramgen activities to that point. Should additional funding be available and the task continue, a final topical report detailing the results of the Ramgen compressor testing will be prepared at the end of the demonstration (i.e., after Subtask 6.2.5).

*Subtask 6.2.1 – Planning Required for Integration into the PCOR Partnership Demonstration*. To effectively integrate the Ramgen technology into the demonstration at the Antelope Valley Power Station, high-level facility and interface issues must be identified and documented. Tours by Ramgen engineers of the $CO_2$ source site will provide data for system-level support planning and cost estimation.

*Subtask 6.2.2 – Preliminary Compressor Design Specific to the Demonstration*. The required compressor configuration will be identified and verified. Power, air supply, instrumentation, system controls, and plumbing requirements of the Ramgen compressor will be established and integrated with the power plant's available facilities to determine what additional construction/installation will be required.

*Subtask 6.2.3 – Final Compressor Design and Fabrication*. The detailed design for the Ramgen compressor will be completed and the system fabricated.

*Subtask 6.2.4 – Installation of the Ramgen Compressor at the Antelope Valley Power Station*. Any facility modifications required at the power plant will be performed and the Ramgen compressor installed and shaken down.

*Subtask 6.2.5 – Testing of the Ramgen Compressor*. Testing of the Ramgen compressor on a slipstream at the Antelope Valley Power Station will be performed and the results evaluated.

**Task 7.0 – $CO_2$ Procurement (capture, purification, or purchase)**
This task will document the procedures that procure $CO_2$ for the EOR activities. During Budget Period 3, PCOR Partnership personnel will interface with our commercial partners with respect to $CO_2$ procurement in the Williston Basin demonstration as a means of documenting critical pathways for future projects.

***Subtask 7.1 – Ongoing Monitoring and Assessment of the Commercial Issues of $CO_2$ Procurement***. Through discussions with Basin Electric Power Cooperative personnel and other industrial partners as well as Internet and other literature searches, PCOR Partnership personnel will be kept abreast of the various commercial issues associated with $CO_2$ procurement, such as the current price of $CO_2$, other potential customers, etc.

***Subtask 7.2 – Procurement Plan and Agreement Report***. A report (D48) will be prepared that documents the business activities used to develop the $CO_2$ procurement plan and agreement for this project.

### Task 8.0 – Transportation and Injection Operations

This task will consist of monitoring and documenting commercial partner activities related to the $CO_2$ pipeline for leaks and corrosion as well as performing inspections and security checks.

***Subtask 8.1 – Ongoing Monitoring and Assessment of Commercial Operations***. $CO_2$ transport and injection will be conducted by our industrial partners as part of a commercial EOR project. The PCOR Partnership will monitor and assess these operations.

***Subtask 8.2 – Transportation and Injection Operations Report***. The results of the $CO_2$ transport injection operations will be summarized in a report (D49).

### Task 9.0 – Operational Monitoring and Modeling

The primary objectives of the PCOR Partnership under Task 9.0 are to develop data sets for the large-volume $CO_2$ injection tests that 1) verify that injection operations do not adversely impact human health or the environment and 2) validate the sequestration of $CO_2$ for the purpose of developing and ultimately monetizing carbon credits.

***Subtask 9.1 – Williston Basin Test Site***. The site for the PCOR Partnership Phase III demonstration will be located within the Williston Basin in the northern Great Plains Region of North America. Injection will be into an oil-bearing reservoir for the simultaneous purpose of EOR and $CO_2$ sequestration.

*Subtask 9.1.1 – Develop Site Characterization, Modeling, and Monitoring*.
The following activities will be evaluated and incorporated into a site characterization modeling and monitoring plan (D50) if suitable. The tests will monitor the $CO_2$ plume, potential for reservoir failure, injection well conditions, and leakage to overlying formations. Possible monitoring activities, based on cost analysis at the onset of Phase III, are to be determined in the preparation process of a site characterization, modeling, and monitoring plan. A Summary of Operations (D71) will be prepared on a quarterly schedule over the course of the characterization, modeling, and monitoring activities conducted during the injection phase of the test. Activities include the following:

- Reservoir pressure monitoring
- Wellhead and formation fluid sampling (oil, water, gas)
- Geochemical changes identified in observation or production wells
- Measurement of surface deformation associated with injection (e.g., tiltmeters, interferometric synthetic aperture radar)
- Microseismic arrays
- Pressure and geochemical monitoring of overlying formations
- Downhole geophysical monitors (passive microseismic arrays and/or tiltmeters)

- Well integrity tests
- Wellbore annulus pressure measurements
- Surface $CO_2$ measured near injector points and high-risk areas
- Major ion chemistry and isotopes
- Monitoring for tracers (perfluorocarbon)
- Seismic surveys
- Aeromagnetic surveys
- Periodic application of innovative downhole logging techniques

*Subtask 9.1.2 – Implementation of Monitoring Plan.* Upon completion of the Williston Basin Test Site Characterization, Modeling, and Monitoring Plan outlined in Subtask 9.1.1, monitoring activities at the site will begin. These activities will follow the guidelines established in the Monitoring Plan and will continue through September 2015.

*Subtask 9.1.3 – Site Characterization, Modeling, and Monitoring Report.* A report outlining specific activities over the course of the project will be compiled into a Monitoring for $CO_2$, EOR, and Sequestration Best Practices Manual (D51). This document will be developed as an effort to validate the $CO_2$ injected throughout the project as being safely stored with little risk of natural release.

***Subtask 9.2 – Fort Nelson Test Site***. The Fort Nelson test site is located in Fort Nelson, British Columbia, Canada. This test will focus on $CO_2$ sequestration through the injection of a large stream of acid gas into a saline formation.

*Subtask 9.2.1 – Develop Site Characterization, Modeling, and Monitoring Plan*. The following list of activities will be evaluated with respect to cost and operational efficiency when the site characterization modeling and monitoring plan (D52) for the Fort Nelson test site are compiled:

- Target injection zone pressure monitoring
- Formation fluid sampling (water, gas)
- Geochemical changes identified in monitoring wells
- Injection well pressure monitoring
- Well integrity tests

- Wellbore annulus pressure measurements
- Overlying formation pressure monitoring
- Monitoring for tracers (perfluorocarbon)
- Measurement of surface deformation associated with injection (e.g., tiltmeters, interferometric synthetic aperture radar)
- Microseismic arrays
- Interferometric synthetic aperture radar

*Subtask 9.2.2 – Implementation of Monitoring Plan*. Upon completion of the Fort Nelson Test Site Characterization, Modeling, and Monitoring Plan outlined in Subtask 9.2.1, monitoring activities at the site will begin. A Summary of Operations for the Fort Nelson Site will be prepared on a quarterly schedule (D72). These activities will follow the guidelines established in the Monitoring Plan and will continue through September 2015.

*Subtask 9.2.3 – Site Characterization, Modeling, and Monitoring Report*. A report outlining specific activities over the course of the project will be compiled into a Monitoring for $CO_2$ Sequestration in a Brine Formation Best Practices Manual (D53). This document will be developed as an effort to validate the $CO_2$ injected throughout the project as being safely stored with little risk of natural release.

**Task 10.0 – Site Closure**. Because both demonstration tests occur at ongoing commercial operations, it is anticipated that site closure will occur beyond the 10-year scope of the Phase III effort. However, research will be conducted with regard to site closure practices that would be applicable for this type of operation.

***Subtask 10.1 – Site Closure Report***. A report (D54) that outlines the procedures that would be necessary to close a site similar to this project will be completed. The report will include post injection monitoring techniques, mitigation summaries, methods to evaluate project effectiveness, and final abandonment procedures.

**Task 11.0 – Post Injection Monitoring and Modeling**

Key long-term goals of the PCOR Partnership in Phase III include establishing and monetizing carbon credits associated with the large-volume injection test. The objectives of Task 11.0 are to use the data generated by the site characterization and monitoring activities to provide the technical basis for 1) the formal establishment of carbon credits that are directly linked to the volume of $CO_2$ injected into the site and 2) a third-party carbon trading entity to validate and ultimately monetize the credits derived from the Phase III test. The Task 11.0 objectives will be accomplished by the following activities.

***Subtask 11.1 – Williston Basin Test Site***

*Subtask 11.1.1 – Interpretation of Phase III Monitoring Results for the Williston Basin Test*. Early modeling results will be compared with actual field data regarding the size, shape, and nature of the injected $CO_2$. A final-stage, holistic modeling effort will be conducted using the tremendous reservoir, hydrogeologic, geochemical, and geomechanical data generated during Phase III to provide technical support for credit monetization efforts.

*Subtask 11.1.2 – Development of Cost-Effective Long-Term Monitoring Strategy for the Williston Basin Test*. To ensure that the $CO_2$ does not migrate outside the designated reservoir, protocols and plans for cost-effective long-term monitoring of the $CO_2$ will be developed. These will be presented in a topical report (D55).

*Subtask 11.1.3 – Testing of Cost-Effective Long-Term Monitoring Strategy for the Williston Basin Test*. The techniques outlined in the Long-Term Monitoring Strategy will be applied for 18 months. The results of the Long-Term Monitoring Strategy tests will be compared to the more robust monitoring techniques applied during Budget Period 4 to determine the technical viability of using the Long-Term Monitoring Strategy techniques to verify and validate the credits associated with the target reservoir. A Progress Report on Monitoring and Modeling the Fate of $CO_2$ at the Williston Test Site (D73) will be prepared.

***Subtask 11.2 – Fort Nelson Test Site***

*Subtask 11.2.1 – Interpretation of Phase III Monitoring Results for the Fort Nelson Test*. Early modeling results will be compared with actual field data regarding the size, shape, and nature of the injected $CO_2$. A final-stage, holistic modeling effort will be conducted using the tremendous reservoir, hydrogeologic, geochemical, and geomechanical data generated during Phase III to provide technical support for credit monetization efforts.

*Subtask 11.2.2 – Development of Cost-Effective Long-Term Monitoring Strategy for the Fort Nelson Test*. To ensure that the $CO_2$ does not migrate outside the designated reservoir, protocols and plans for cost-effective long-term monitoring of the $CO_2$ will be developed. These will be presented in a topical report (D56).

*Subtask 11.2.3 – Testing of Cost-Effective Long-Term Monitoring Strategy for the Fort Nelson Test*. The techniques outlined in the Long-Term Monitoring Strategy will be applied for 18 months. The results of the Long-Term Monitoring Strategy tests will be compared to the more robust monitoring techniques applied during Budget Period 4 to determine the technical viability of using the Long-Term Monitoring Strategy techniques to verify and validate the credits associated with the target reservoir. A Progress Report on Monitoring and Modeling the Fate of $CO_2$ at the Fort Nelson Test Site (D74) will be prepared.

**Task 12.0 – Project Assessment**

***Subtask 12.1 – Annual Assessment Report***. The annual report (D57) will summarize project progress, accomplishments, and progress toward meeting goals.

## Task 13.0 – Project Management

### *Subtask 13.1 – Perform Project Management*

*Subtask 13.1.1 – Earned Value Report*. Earned Value (EV) report principles will be applied to track project budgets and progress. EV reports (D58) will be submitted to the DOE Contracting Officer's Representative (COR) and Contract Specialist (CS) on a quarterly basis.

*Subtask 13.1.2 – Milestone Report*. Quarterly milestone reports (D59) will be provided as required.

*Subtask 13.1.3 – Site Development, Operations, and Closure Plan*. This plan (D60) will describe the details of the site development, operations and plans for project closure. These procedures will include various testing of the entire system to ensure the integrity of the storage project. Literature reviews will be completed to summarize the techniques used under similar conditions.

*Subtask 13.1.4 – Site Commercialization Plan*. The PCOR Partnership will submit a commercialization plan (D61) describing the steps taken by our partners to commercialize the existing site and how those steps might be applicable to similar sinks in the region.

*Subtask 13.1.5 – Provide COR Briefings*. The DOE COR will be provided with progress reports and briefings, as requested.

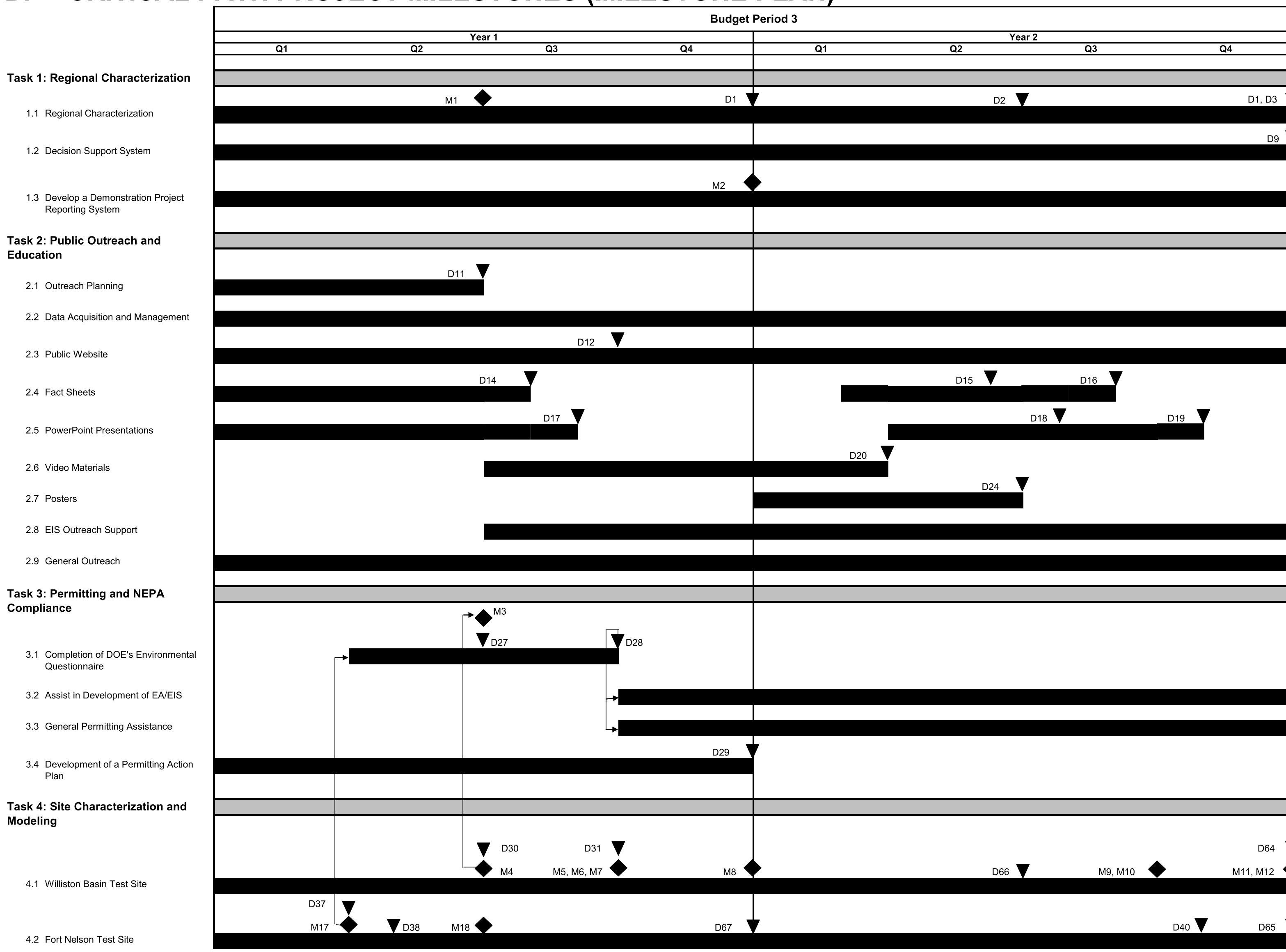
*Subtask 13.1.6 – Prepare Technical Papers for Contractors' Review Meetings*. The PCOR Partnership Phase III subcontractors will be provided with progress reports and briefings, as requested.

*Subtask 13.1.7 – Partnership Project Meetings*. Regular project meetings (annual or as otherwise directed) will be held to ensure that project management and PCOR Partnership partner goals are being met (food will be served in conjunction with these activities, the cost of which may exceed institutional limits).

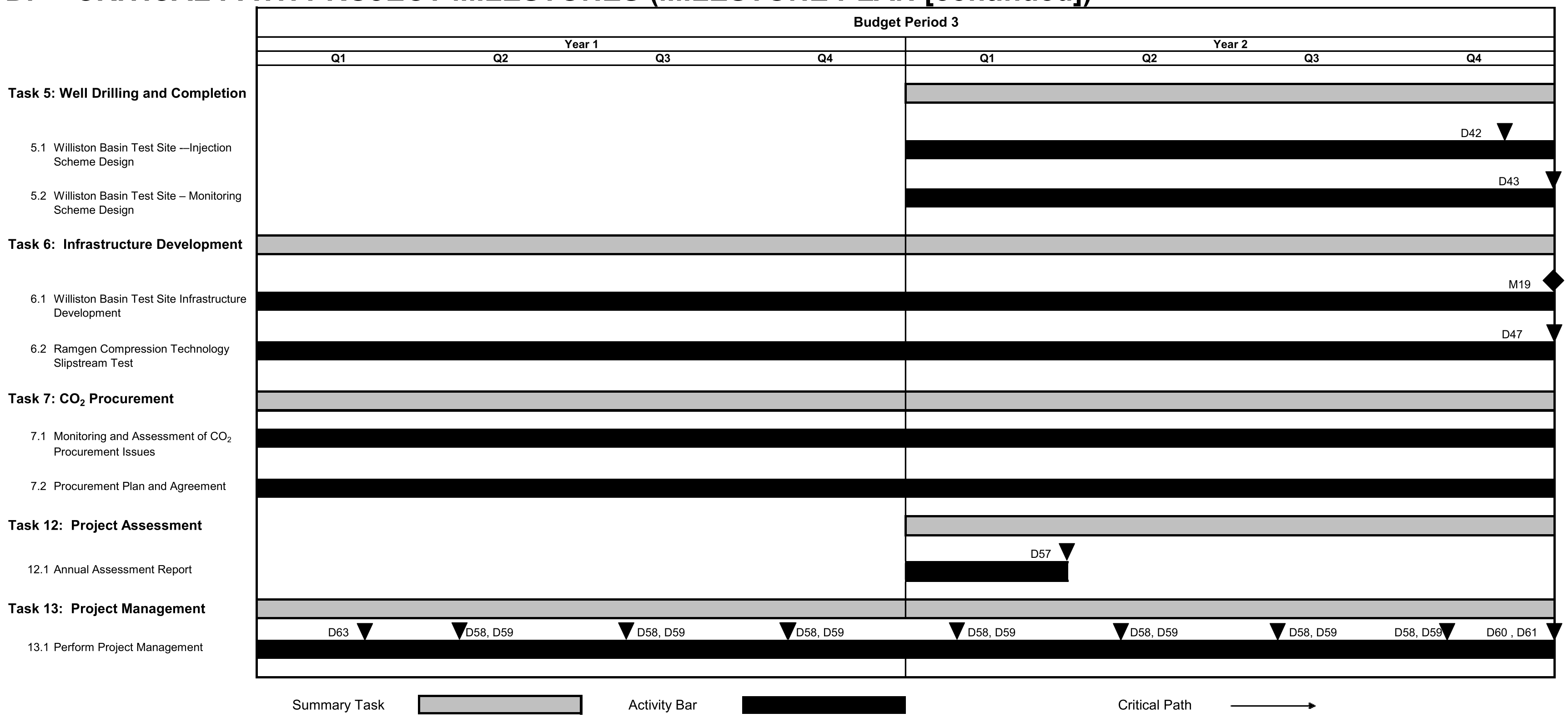
*Subtask 13.1.8 – Project Management Plan*. A project management plan (D63) for Phase III activities will be developed and submitted for DOE approval during the first quarter of Budget Period 3.

*Subtask 13.1.9 – Final Report*. Tasks and subtasks reports will be integrated and compiled into a comprehensive PCOR Partnership Phase III final report (D62).

# D. CRITICAL PATH PROJECT MILESTONES (MILESTONE PLAN)



## D. CRITICAL PATH PROJECT MILESTONES (MILESTONE PLAN [continued])




**D = Deliverables**

D1 Review of Source Attributes
D2 First Target Area Completed
D3 Permitting Review – One State and One Province
D9 Updated DSS
D11 Outreach Plan
D12 Demonstration Web Pages on the Public Site
D14 General Phase III Fact Sheet
D15 Williston Basin (WB) Test Site Fact Sheet
D16 Fort Nelson Test Site Fact Sheet
D17 General Phase III Information PowerPoint Presentation
D18 WB Test Site PowerPoint Presentation
D19 Fort Nelson (FN) Test Site PowerPoint Presentation
D20 Video Support to PowerPoint and Web Site
D24 PCOR Region Sequestration General Poster
D27 FN Test Site – Environmental Questionnaire
D28 WB Test Site – Environmental Questionnaire
D29 Permitting Action Plan
D30 WB Test Site – Geomechanical Experimental Design Package
D31 WB Test Site – Site Geological Characterization Experimental Design Package
D37 FN Test Site – Site Geological Characterization Experimental Design Package
D38 FN Test Site – Geotechnical Experimental Design Package
D40 FN Test Site – Geomechanical Final Report
D42 WB Test Site – Injection Experimental Design Package
D43 WB Test Site – Monitoring Experimental Design Package
D47 Topical Report on the Preliminary Design of Advanced Compression Technology
D57 Project Assessment Annual Report
D58 EVM Quarterly Report
D59 Milestone Quarterly Report
D60 Site Development, Operations, and Closure Plan
D61 Site Commercialization Plan
D63 Project Management Plan
D64 WB Test Site – Site Characterization Report
D65 FN Test Site – Site Characterization Report
D66 WB Test Site – Simulation Report
D67 FN Test Site – Simulation Report

**M = Major Milestone**

M1 Three Target Areas Selected
M2 DPRS Prototype
M3 Start Environmental Questionnaire for WB Test Site
M4 WB Test Site Selected
M5 Data Collection Initiated for WB Test Site
M6 WB Test Site Geochemical Work Initiated
M7 WB Test Site Geological
M8 WB Test Site Wellbore Leakage Data Collection Initiated
M9 WB Test Site B-Version Geological Model Development
M10 WB Test Site Wellbore Leakage Data Collection Completed
M11 WB Test Site Baseline Hydro Data Collection Completed
M12 WB Test Site Geochemical Work Completed
M17 FN Test Site Selected
M18 FN Test Site Geochemical Work Initiated
M19 Capture, Dehydration, and Compression Technology Selected

## E. DELIVERABLES

The PCOR Partnership will provide the following deliverables.

| D = Deliverable M= Milestone | Description | Due | | |
|---|---|---|---|---|
| | | BP3 | BP4 | BP5 |
| **Task 1: Regional Characterization** | | | | |
| D1 | Review of Source Attributes | X | X | X |
| D2 | First Target Area Completed | X | | |
| D3 | Permitting Review – One State and One Province | X | | |
| D4 | Permitting Review – Two Additional States | | X | |
| D5 | Second Target Area Completed | | X | |
| D6 | Permitting Review – Three State and Two Provinces | | X | |
| D7 | Third Target Area Completed | | X | |
| D8 | Permitting Review – Three State and One Province | | X | |
| D9 | Updated DSS | X | X | |
| D10 | DPRS Update | | X | X |
| M1 | Three Target Areas Selected | X | | |
| M2 | DPRS Prototype | X | | |
| **Task 2: Public Outreach and Education** | | | | |
| D11 | Outreach Plan | X | X | X |
| D12 | Demonstration Web Pages on the Public Site | X | | |
| D13 | Public Site Updates | | X | X |
| D14 | General Phase III Fact Sheet | X | X | X |
| D15 | Williston Basin Test Site Fact Sheet | X | X | X |
| D16 | Fort Nelson Test Site Fact Sheet | X | X | X |
| D17 | General Phase III Information PowerPoint Presentation | X | X | X |
| D18 | Williston Basin Test Site PowerPoint Presentation | X | X | X |
| D19 | Fort Nelson Test Site PowerPoint Presentation | X | X | X |
| D20 | Video Support to PowerPoint and Web Site | X | | |
| D21 | Williston Basin Test Site 15-Minute Video | | X | |
| D22 | Fort Nelson Test Site 15-Minute Video | | X | |
| D23 | Sequestration in Carbon Management – 30-Minute Video | | | X |
| D24 | PCOR Region Sequestration General Poster | X | X | |
| D25 | Williston Basin Test Site Poster | | X | |
| D26 | Fort Nelson Test Site Poster | | X | |
| **Task 3: Permitting and NEPA Compliance** | | | | |
| D27 | Environmental Questionnaire – Fort Nelson Test Site | X | | |
| D28 | Environmental Questionnaire – Williston Basin Test Site | X | | |
| D29 | Permitting Action Plan | X | | |
| D75 | Updated Permitting Action Plan | | X | |
| D76 | Best Practices Manual - Permitting | | | X |
| M3 | Start Environmental Questionnaire for Williston Basin Test Site | X | | |
| **Task 4: Site Characterization and Modeling** | | | | |
| D30 | Williston Basin Test Site – Geomechanical Experimental Design Package | X | | |
| D31 | Williston Basin Test Site – Geological Characterization Experimental Design Package | X | | |
| D32 | Williston Basin Test Site – Geomechanical Final Report | | X | |
| D33 | Williston Basin Test Site – Geochemical Final Report | | X | |
| D34 | Williston Basin Test Site – Baseline Hydrogeological Final Report | | X | |
| D35 | Williston Basin Test Site – Best Practices Manual - Site Characterization | | X | |
| D36 | Williston Basin Test Site – Wellbore Leakage Final Report | | X | |
| D64 | Williston Basin Test Site – Site Characterization Report | X | | |
| D66 | Williston Basin Test Site – Simulation Report | X | | |
| D69 | Williston Basin Test Site – Best Practices Manual – Simulation Report | | X | |
| D37 | Fort Nelson Test Site – Site Geological Characterization Experimental Design Package | X | | |
| D38 | Fort Nelson Test Site – Geotechnical Experimental Design Package | X | | |
| D40 | Fort Nelson Test Site – Geomechanical Final Report | X | | |
| D41 | Fort Nelson Test Site – Geochemical Final Report | | X | |
| D65 | Fort Nelson Test Site – Site Characterization Report | X | | |
| D67 | Fort Nelson Test Site – Simulation Report | X | | |
| D68 | Fort Nelson Test Site – Best Practices Manual – Site Characterization | | X | |
| D70 | Fort Nelson Test Site – Best Practices Manual – Simulation Report | | X | |
| M4 | Williston Basin Test Site Selected | X | | |
| M5 | Data Collection Initiated for Williston Basin Test Site | X | | |
| M6 | Williston Basin Test Site Geochemical Work Initiated | X | | |
| M7 | Williston Basin Test Site Geological Characterization Data Collection Initiated | X | | |
| M8 | Williston Basin Test Site Wellbore Leakage Data Collection Initiated | X | | |
| M9 | Williston Basin Test Site B-Version Geological Model Development Initiated | X | | |
| M10 | Williston Basin Test Site Wellbore Leakage Data Collection Completed | X | | |
| M11 | Williston Basin Test Site Baseline Hydro Data Collection Completed | X | | |
| M12 | Williston Basin Test Site Geochemical Work Completed | X | | |
| M13 | Williston Basin Test Site B-Version Geological Model Development Completed | | X | |
| M14 | Williston Basin Test Site Geological Characterization Data Collection Completed | | X | |
| M15 | Williston Basin Test Site Baseline Hydro B-Model Completed | | X | |
| M16 | Williston Basin Test Site Final Geological Model Development Completed | | X | |
| M17 | Fort Nelson Test Site Selected | X | | |
| M18 | Fort Nelson Test Site Geochemical Work Initiated | X | | |

| D = Deliverable M= Milestone | Description | Due | | |
|---|---|---|---|---|
| | | BP3 | BP4 | BP5 |
| **Task 5: Well Drilling and Completion** | | | | |
| D42 | Williston Basin Test Site – Injection Experimental Design Package | X | | |
| D43 | Williston Basin Test Site – Monitoring Experimental Design Package | X | | |
| D44 | Williston Basin Test Site – Drilling and Completion Activities Final Report | | X | |
| **Task 6: Infrastructure Development** | | | | |
| D45 | Topical Report on the Integrated Capture Plant and its Shakedown | | X | |
| D46 | Topical Report on Pipeline Route Selection, Design, and Construction | | X | |
| D47 | Topical Report on the Preliminary Design of Advanced Compression Technology | X | | |
| M19 | Capture, Dehydration, and Compression Technology Selected | X | | |
| M20 | Capture, Dehydration, and Compression Technology Design Completed | | X | |
| **Task 7: $CO_2$ Procurement** | | | | |
| D48 | Procurement Plan and Agreement Report | | X | |
| **Task 8: Transportation and Injection Operations** | | | | |
| D49 | Transportation and Injection Operations Final Report | | X | |
| **Task 9: Operational Monitoring and Modeling** | | | | |
| D50 | Williston Basin Test Site – Site Characterization, Modeling, and Monitoring Plan | | X | |
| D51 | Williston Basin Test Site – Monitoring for $CO_2$, EOR, and Sequestration Best Practices Manual | | X | |
| D71 | Williston Basin Test Site – Quarterly Summary of Operations | | X | |
| D52 | Fort Nelson Test Site – Site Characterization, Modeling, and Monitoring Plan | | X | |
| D53 | Fort Nelson Test Site – Monitoring for $CO_2$ Sequestration in a Brine Formation Best Practices Manual | | X | |
| D72 | Fort Nelson Test Site – Quarterly Summary of Operations | | X | |
| **Task 10: Site Closure** | | | | |
| D54 | Site Closure Report | | | X |
| **Task 11: Post Injection Monitoring and Modeling** | | | | |
| D55 | Report on Cost-Effective Long-Term Monitoring Strategies for the Williston Basin Test Site | | | X |
| D56 | Report on Cost-Effective Long-Term Monitoring Strategies for the Fort Nelson Test Site | | | X |
| D73 | Williston Basin Test Site – Progress Report on Monitoring and Modeling Fate of $CO_2$ | | | X |
| D74 | Fort Nelson Test Site – Progress Report on Monitoring and Modeling Fate of $CO_2$ | | | X |
| **Task 12: Project Assessment** | | | | |
| D57 | Project Assessment Annual Report | X | X | X |
| **Task 13: Project Management** | | | | |
| D58 | EVM Quarterly Report | X | X | X |
| D59 | Milestone Quarterly Report | X | X | X |
| D60 | Site Development, Operations, and Closure Plan | X | | |
| D61 | Site Commercialization Plan | X | | |
| D62 | Final Report | | | X |
| D63 | Project Management Plan | X | | |

## F. BRIEFINGS/TECHNICAL PRESENTATIONS

The EERC will prepare detailed briefings for presentation to the COR at the COR's facility located in Pittsburgh, Pennsylvania, or Morgantown, West Virginia.

The EERC will provide and present a technical paper(s) at the DOE NETL Annual Contractor's Review Meeting to be held at the NETL facility in Pittsburgh, Pennsylvania, or Morgantown, West Virginia, and attend the Annual Carbon Sequestration Conference held in Alexandria, Virginia, each May, unless otherwise directed by the COR.

# APPENDIX C

# PROJECT NARRATIVE

# PROJECT NARRATIVE

## U.S. Department of Energy
## Cooperative Agreement No. DE-FC26-05NT42592
## Renewal Application for Large-Volume Sequestration Tests for the Deployment Phase of the Regional Carbon Sequestration Partnerships

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**The Plains $CO_2$ Reduction Partnership Phase III**

**June 5, 2007**

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# PLAINS $CO_2$ REDUCTION (PCOR) PARTNERSHIP PHASE III RENEWAL APPLICATION

## PROJECT NARRATIVE

## PROJECT GOAL

The Plains $CO_2$ Reduction (PCOR) Partnership at the Energy & Environmental Research Center (EERC) has been established as a U.S. Department of Energy (DOE) National Energy Technology Laboratory Regional Carbon Sequestration Partnership (RCSP). The PCOR Partnership region includes all or part of nine states and four provinces. The Phase III efforts of the PCOR Partnership will include two demonstration projects that focus on injecting $CO_2$ into deep saline geologic formations for $CO_2$ sequestration.

The first demonstration will inject $CO_2$ into saline formations in the Williston Basin for the dual purpose of sequestration and enhanced oil recovery (EOR). The Williston Basin project will be the primary focus of Phase III demonstration activities. The second Phase III demonstration activity (the Fort Nelson Demonstration) will involve monitoring, mitigation, and verification (MMV) support for the injection of $CO_2$ captured from one of the largest gas-processing plants in North America into a saline formation in British Columbia, Canada (Figure 1). The PCOR Partnership will be seeking additional funding from a variety of sources with our partners for the Fort Nelson demonstration to allow for a more comprehensive set of deliverables.


Figure 1. Location of Phase III demonstration sites.

The Phase III effort will include injection for $CO_2$ sequestration and EOR in select oil fields in the Williston Basin. The primary objectives of this activity are 1) to gather characterization data that will verify the ability of the target formations to store $CO_2$ and meet the DOE goal of verifying capacity that could store 50% of the region's point-source emissions over the next least 100 years, 2) to develop North America's infrastructure in order to transport $CO_2$ from the source to the injection site, 3) to advance regulatory and permitting framework in North America, 4) to provide a test bed for developing technologies related to sequestration of anthropogenic $CO_2$, and 5) to develop a mechanism by which carbon credits can be monetized for $CO_2$ sequestered in geologic formations. Successful implementation of these activities will put the PCOR Partnership region at the forefront of $CO_2$ sequestration technology and implementation, while adding significant economic value to the region.

In addition to the Williston Basin test, the PCOR Partnership will conduct a modeling and monitoring, mitigation, and verification (MMV) program associated with a project that will inject over 1 million tons of $CO_2$ per year into a brine formation near Fort Nelson, British Columbia, Canada. Key partners with the EERC in this international project will be Spectra Energy, Natural Resources Canada, and the British Columbia Ministry of Energy, Mines, and Petroleum Resources. Several research and development (R&D) issues will be addressed during the PCOR Partnership Phase III Fort Nelson brine formation test. R&D activities will be specifically focused on predictive modeling, monitoring, and injection operations to demonstrate that large-scale sequestration of $CO_2$ into a brine formation is a safe and permanent solution for storing significant amounts of $CO_2$ emissions from the PCOR Partnership region.

## RESEARCH AND DEVELOPMENT TARGETS

### Williston Basin Test

Several R&D issues will be addressed during the PCOR Partnership Phase III Williston Basin test. R&D activities will be specifically focused on predictive modeling, capture, injection, and monitoring operations to demonstrate that large-scale sequestration of $CO_2$ into oil fields is a viable strategy for sequestering significant amounts of $CO_2$ emissions from the PCOR Partnership region.

The Williston Basin project will transport a minimum of 500,000 tons per year of $CO_2$ from the Basin Electric Power Cooperative's Antelope Valley Station (an existing conventional coal-fired power plant in central North Dakota) and inject it into an oil reservoir operated by Encore Acquisition Company located in western North Dakota or eastern Montana. The power plant will be retro-fitted with a system that can capture $CO_2$ from its flue gas stream. The $CO_2$ will be compressed and transported in a supercritical state via pipeline to the target injection location (see Figure 2).

While a specific oil field has not yet been chosen to be the host site for the Williston Basin large-volume $CO_2$ injection test, it is anticipated that the selection will take place in the earliest stages of Phase III. The results of the regional characterization activities conducted under Phases I and II of the PCOR Partnership show that there are at least 40 unitized oil fields in North Dakota and Montana that may be suitable for $CO_2$-based EOR operations. The $CO_2$ storage

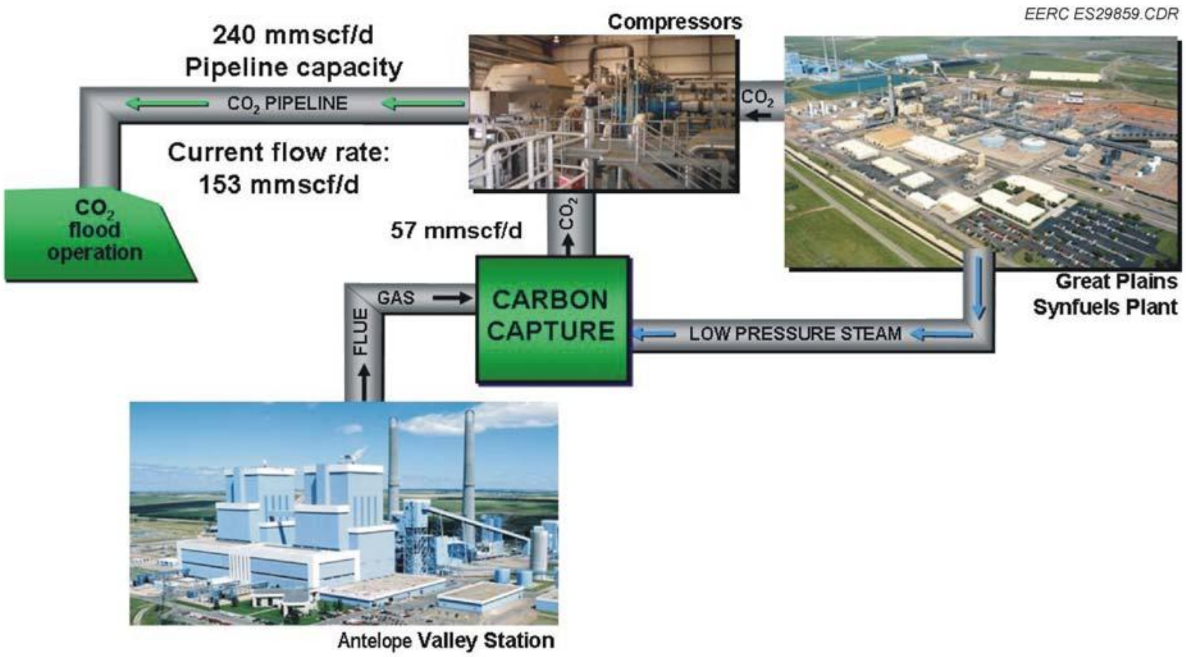


Figure 2. Basin Electric Power Cooperative $CO_2$ optimization project.

capacities of these fields range from several million tons to several hundred million tons. The volume of incremental oil that could be produced from these oil fields has been estimated to be approximately 650 million barrels. Using a recent price for Williston Basin oil of $43/bbl (price quote from Plains Marketing, L.P., May 11, 2007), the value of the incremental oil is nearly $28 billion. From a $CO_2$ source perspective, the ongoing EOR projects at the Weyburn and Midale oil fields in Saskatchewan have established a preliminary value for $CO_2$ in the Williston Basin of approximately $1 per mcf (approximately $17 to $18 per ton). Phase I results indicate that several hundred million tons of $CO_2$ are needed to produce the incremental oil. The magnitude of this financial opportunity for the development of a $CO_2$ market in the Williston Basin has attracted the attention of many oil field operators and the owners of large stationary $CO_2$ sources in the region, including coal-fired power plants. Many of these companies are members of the PCOR Partnership (Phase I and Phase II) and have expressed strong support for a Phase III project that is focused on EOR in the Williston Basin. Based largely on input from the members of the PCOR Partnership, and the tremendous value-added product that can be derived from $CO_2$-based EOR, the PCOR Partnership is compelled to focus the bulk of its Phase III efforts on demonstrating the viability of $CO_2$ sequestration in conjunction with EOR operations.

Basin Electric Power Cooperative is currently engaged in $CO_2$ sales discussions with several oil and gas companies in the Williston Basin; Encore Acquisition Company is emerging as the most likely candidate. Encore Acquisition Company is engaged in the development of onshore North American oil and natural gas reserves. In 1999, Encore purchased the operating leases of major fields on the Cedar Creek Anticline in eastern Montana and southwestern North Dakota (Figure 3). This acquisition quickly made Encore the largest oil producer in

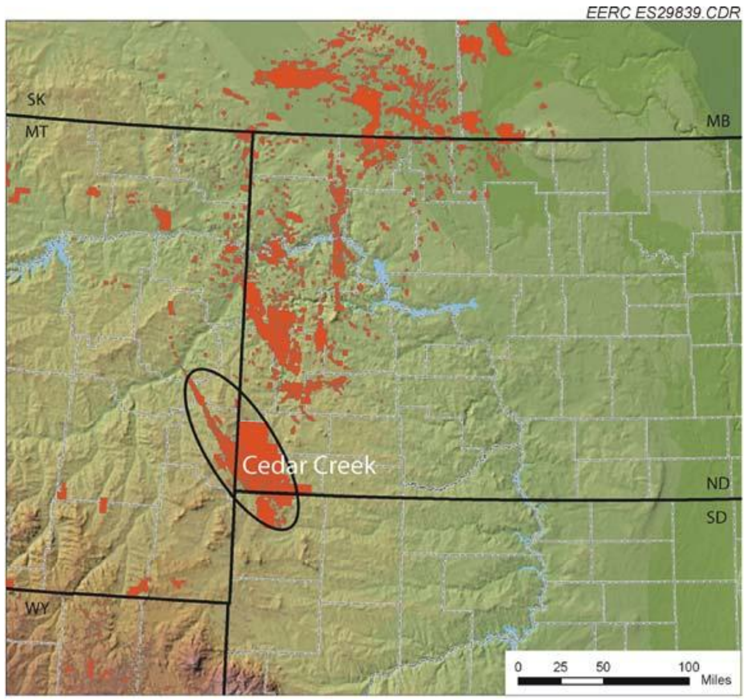


Figure 3. Location of the Cedar Creek Anticline.

Montana and gave Encore a working interest in several fields in North Dakota. In 2007, Encore purchased significant producing assets, including an additional 50 fields in the Williston Basin, which the company plans to enhance through drilling and redevelopment plans. These purchases have total proven reserves of approximately 21 million barrels of oil equivalent and will be 85% operated by Encore. The new purchases, along with Encore's existing properties in the Williston Basin, total nearly 150 million barrels of proven recoverable reserves over the next 10 years. $CO_2$ flooding is expected to play an additional role in Encore's efforts to produce from the Cedar Creek Anticline. Encore estimates that approximately 33 million barrels could be produced from its fields utilizing waterflooding and $CO_2$ flooding techniques. If $CO_2$ flooding is utilized, a minimum of 15 million tons of $CO_2$ would be required for the operation.

The primary objective of the Williston Basin test is to verify and validate the concept of utilizing the region's large number of oil fields for large-scale injection of anthropogenic $CO_2$. Rigorous, robust, and cost-effective programs for baseline site characterization, risk assessment, and MMV will be conducted. The PCOR Partnership is unique among the seven RCSPs in both its vast areal extent and its broad distribution of oil fields, including many of the largest and most well understood oil fields in the world. The results of the proposed Phase III test will be broadly applicable throughout the PCOR Partnership region, as ten of the thirteen state/provincial jurisdictions in the region have oil fields within their boundaries. Oil fields are generally much better characterized than saline formations, are already legally established for the purpose of safe large-scale manipulation of subsurface fluids, and offer a means to offset the considerable costs of $CO_2$ capture and transportation through the sale of incrementally produced oil. Because the $CO_2$ will be purchased by the EOR operating partner, liability issues are much more straightforward than for non-EOR-based sequestration. These attributes make oil fields the most cost-effective choices in the PCOR Partnership region when implementing large-scale $CO_2$ sequestration projects.

The PCOR Partnership Phase III Williston Basin $CO_2$ EOR test program will develop detailed and previously unavailable insight regarding a wide variety of issues associated with the geological sequestration of $CO_2$. The primary research and development targets are summarized below:

- Opportunities for commercialization of carbon management through the use of large-scale $CO_2$ injection operations in oil fields will be established and facilitated. Capture and injection test data and regional characterization data will be used to demonstrate that similar types of geological sinks can provide sufficient storage capacity and commercialization opportunities for large stationary $CO_2$ sources throughout the region.

- Approaches to develop capacity estimates for the thousands of oil fields in the region as part of PCOR Partnership Phases I and II will be field-tested, refined as necessary, verified, and validated. MMV technologies will be deployed in part to substantiate capacity estimates.

- Modeling simulation approaches to predict and estimate $CO_2$ injectivity, plume areal extent, mobility, and fate within the target formation will be field-tested, refined, verified, and validated. Site characterization and MMV activities will support these efforts.

- Approaches to predict the effects of $CO_2$ on the integrity of overlying sealing formations will be verified and validated with field- and laboratory-based data. Testing and modeling of the key geomechanical, geochemical, and hydrogeological parameters of sealing formations that might be affected by large-scale $CO_2$ injection will support these efforts.

- The presence/absence of leakage pathways in the study area will be definitively addressed. Site characterization and MMV activities will provide the basis of this determination.

- A mitigation strategy for potential future leaks through any identified potential pathways will be developed. The goal of the mitigation strategy will be to develop cost-effective means of achieving a state of near-zero leakage throughout the lifetime of the $CO_2$ plume.

- Cost-effective, safe, and broadly applicable $CO_2$ injection well designs and well bore management techniques will be field-tested.

- Risk assessment and management strategies will be examined, evaluated, and applied to ensure large-scale $CO_2$ injection into oil fields is effective and safe.

### Fort Nelson Test

The PCOR Partnership is also proposing to participate in a second large-scale demonstration test. The level of involvement for the Fort Nelson test will be much more limited than for the Williston Basin test. While much of the planning and funding are in place for the Fort Nelson test, several of our Canadian PCOR Partnership partners wanted to ensure that the MMV and carbon credit monetization experience and capabilities developed in the PCOR Partnership could be applied to the Fort Nelson test, and PCOR Partnership participation was requested. The Fort Nelson test represents a very significant Phase III opportunity for the following reasons: 1) a very modest investment (0.5 million a year for Budget Period Three) by DOE will result in an additional large-scale demonstration; 2) since a single commercial partner controls both the source and sink, logistics are simplified and the time line is shortened; and 3) it is in keeping with the regional vision developed by the PCOR Partnership that includes EOR and saline formation injection and is international in scope.

The Fort Nelson project will utilize approximately 1.8 million tons of $CO_2$ per year captured from one of the largest gas-processing plants in North America. The $CO_2$ will be compressed and transported in a supercritical state via pipeline to the target injection location. While a specific brine formation and injection location have not yet been chosen, it is anticipated that the target zone will be a Devonian-age carbonate rock formation located in relatively close proximity to the Fort Nelson gas plant (<50 miles). The results of Phases I and II of the PCOR Partnership show that many areas of the Western Canada Sedimentary Basin, which includes the Fort Nelson area in northeastern British Columbia, have $CO_2$ storage capacities exceeding several million tons per square mile and, as such, represent a very significant long-term sink.

The primary objective of the PCOR Partnership Phase III Fort Nelson test is to verify and validate the concept of utilizing the region's carbonate brine formations for large-scale injection of anthropogenic $CO_2$. Rigorous, robust, and cost-effective programs for baseline site characterization, risk assessment, and MMV will be conducted. The PCOR Partnership is unique among the seven RCSPs in both its vast areal extent and its broad distribution of brine formations, including some of the most studied and well understood carbonate rock systems in the world. The results of the proposed Phase III test will be broadly applicable throughout the PCOR Partnership region, as twelve of the thirteen state/provincial jurisdictions in the region have deep carbonate brine formations within their boundaries.

The PCOR Partnership Phase III Fort Nelson $CO_2$ test program will develop detailed and previously unavailable insight regarding a wide variety of issues associated with the geological sequestration of $CO_2$. The primary research and development targets are summarized below:

- Cost-effective MMV approaches for large-scale $CO_2$ sequestration in brine formations will be suggested for deployment and for evaluation.

- Modeling simulation approaches to predict and estimate $CO_2$ injectivity, plume areal extent, mobility, and fate within the target formation will be recommended for field-testing. Site characterization and MMV activities will be recommended to support these efforts.

- Approaches to predict the effects of $CO_2$ on the integrity of overlying sealing formations will be suggested for verification and validation with field- and laboratory-based data. Testing and modeling of the key geomechanical and geochemical, parameters of sealing formations that might be affected by large-scale $CO_2$ injection will support these efforts.

## PERMITTING

Prior to Phase III field operations, the EERC will complete the DOE Environmental Questionnaire for both the Williston Basin and Fort Nelson demonstration projects. DOE's National Environmental Policy Act (NEPA) implementation procedures require consideration of the potential environmental consequences of all proposed actions. DOE must determine as early as possible whether such actions require an Environmental Assessment (EA) or an Environmental Impact Statement, or if they qualify for Categorical Exclusion.

Categorical Exclusions are granted to activities that are either separately or cumulatively known to have no or only minor environmental effects. Most federal agencies have developed criteria for defining and listing actions that may be Categorical Exclusions. However, these activities are subject to being removed from the listing in particular circumstances; for example, if species listed as threatened or endangered are present. A Categorical Exclusion is anticipated for both demonstrations proposed herein since, in both cases, the federal funding will be applied only to the research and development that augment commercial activities.

If categorical exclusions are not granted, we anticipate conducting an EA. An EA is a midlevel analysis prepared for an activity that is not clearly categorically excluded but does not clearly require an environmental impact statement (EIS). Based on the EA, either an EIS must be prepared or a "Finding of No Significant Impact" is issued. This finding averts further NEPA study.

Generally, an EIS must be prepared for major federal actions that significantly affect the environment. An EIS must review a sufficient assortment of proposed alternatives and the direct, indirect, and cumulative effects or impacts of each alternative. DOE has suggested that resources be allocated to address an EIS scenario.

It is anticipated that the EERC's operating partners will obtain all necessary permits and approvals to comply with state and federal requirements at an ongoing hydrocarbon recovery site. However, in the interest of completeness, Table 1 provides an overview of potential requirements to conduct an EOR/$CO_2$ sequestration project in the Williston Basin.

## PUBLIC OUTREACH

The goals of the PCOR Partnership Outreach and Education in Phase III are to provide: 1) outreach and education mechanisms to raise awareness regarding sequestration opportunities in the region and 2) provide outreach to select target audiences concerned with the demonstration activities.

**Table 1. Major Permit/Report Categories for PCOR Partnership Phase III**

| Regulation | Governance | Agency | Time Frame for Approval or Submittal (maximum) |
|---|---|---|---|
| NEPA | EIS | DOE | 2 years |
| Form 1 | Application for Permit to Drill | NDIC[1] | 2 weeks |
| Form 2 | Organization Report | NDIC | 2 weeks |
| Form 3 | Single Well Bond (2000’ in depth or less) | NDIC | Submit with Form 1, Application to Drill |
| Form 3A | Single Well Bond (in excess of 2000’ in depth) | NDIC | Submit with Form 1, Application to Drill |
| Form 4 | Sundry Notices and Reports on Wells | NDIC | Submit as needed. See NDAC[2] Chapters 43-02-03, 43-02-05, 43-02-09 for full reference |
| Form 5 | Oil Production Report | NDIC | Submit monthly |
| Form 6 | Well Completion or Recompletion Report | NDIC | Submit immediately after the completion of a well in an unspaced pool or reservoir or within 30 days after the completion of a well, or recompletion of a well in a different pool. |
| Form 7 | Plugging Report | NDIC | Submit within 30 days after the plugging of any well. |
| Form 8 | Authorization to Purchase and Transport Oil from Lease | NDIC | 2 weeks |
| Form 8A | Purchaser and Transporter of Dry Gas Report | NDIC | Submit bimonthly |
| Form 9 | Gas–Oil Ratio Report | NDIC | Submittal required by field order, new completion, or recompletion |
| Form 9A | Reservoir Pressure Test | NDIC | Discovery well of any new pool. Submitted within 30 days after the completion of the well. |
| Form 9B | Fluid Level Test | NDIC | Discovery well of any new pool. Submitted within 30 days after the completion of the well. |
| Form 10A | Oil Transporters Monthly Report | NDIC | Submit monthly |
| Form 10B | Oil Transporters and Storers Monthly Report | NDIC | Submit monthly |
| Form 14 | Application for Injection | NDIC | 2 months |
| Form 16 | Saltwater Disposal Report | NDIC | Submit monthly |

Continued. . .

**Table 1. Major Permit/Report Categories for PCOR Partnership Phase III (continued)**

| Regulation | Governance | Agency | Time Frame for Approval or Submittal (maximum) |
|---|---|---|---|
| Form 19 | Well Integrity Report | NDIC | Submit subsequent to any workover conducted on a UIC[3] well, any periodic pressure test conducted on a UIC well, or any pressure test conducted for temporary abandonment purposes |
| Form 17 | Enhanced Recovery Report | NDIC | Submit monthly |
| Form 17A | Enhanced Recovery Source Report | NDIC | Submit with Form 17, Enhanced Recovery Report if there was any injection during the reporting month |
| Form 23 | Tank Bottom Cleaning Report | NDIC | Submit within 30 days after completing a tank cleaning |
| Form 24 | Annual Report of Unit Operations | NDIC | File annually, by April 1, for the preceding calendar year |

[1] North Dakota Industrial Commission.
[2] North Dakota Administrative Code.
[3] Underground injection control.

The approach will be to develop and deliver focused outreach to groups concerned with the demonstration project as well as other key target audiences and, at the same time, develop and deliver outreach designed to raise the awareness of the population across the PCOR Partnership region.

Outreach for the demonstration will provide interested parties with the details of the full-scale geologic $CO_2$ sequestration demonstration project(s) in the context of the evolving national and international carbon management and monetization efforts as well as portraying the role of the RCSP and the PCOR Partnership and its stakeholders in these developments. The outreach task will support the public outreach aspects of the NEPA process for the demonstration projects. Key audiences for the demonstration project outreach include decision makers, opinion leaders in the business community, landowners, students and teachers in community schools, and citizens.

Outreach for the region will focus on sequestration methods, opportunities, and developments, including updates on the demonstration projects. Select audiences, including the media, decision makers, and Grade 6–12 educators, will be a particular focus of outreach.

Outreach will be facilitated by the outreach products developed during Phases I and II as well as by additional tools and capabilities developed during Phase III. Current outreach tools and capabilities include a public Web site (revised annually and updated as products are completed), five fact sheets that describe sequestration issues, five fact sheets that describe the PCOR Partnership's field verification tests, a series of five (one completed, two in production, and two planned) 30-minute broadcast-quality sequestration documentaries coproduced with

Prairie Public Broadcasting, a series of newspaper articles on the basics of sequestration, a 50-page sequestration atlas providing general information on sequestration and detail on regional issues, a public outreach PowerPoint presentation, and an outreach display booth.

## REGIONAL CHARACTERIZATION

The PCOR Partnership will continue to refine the characterization of sources, geologic and terrestrial sinks, infrastructure, and the regulatory framework within the partnership region. The objective is to further refine the assessment of the region's $CO_2$ production and sequestration potential in an effort to optimize source–sink opportunities within the region. This continued regional characterization will be used to refine capacity estimates for the national atlas and to provide context for extrapolating the results of the large-scale demonstrations. The information is disseminated to DOE and partners through the PCOR Partnership Decision Support System© (DSS)– a database-driven Web site containing both traditional static pages and an interactive geographic information system (GIS).

Information specific to the demonstration tests will be maintained, utilized, and reported to DOE and partners through a Demonstration Project Reporting System (DPRS). The DPRS will be a Web-based interface that will house data from each demonstration activity and facilitate communication and interpretation of these data. The DPRS will be designed to provide structured access to data by all demonstration participants and other partners and allow for efficient replication of additional or related demonstration projects. The following types of information will be available through the DPRS:

- Background information regarding the demonstration site
- Project planning and permitting information
- Site characterization
- Modeling output, data, and data analysis
- Maps and cross sections
- Reports
- Photos
- Fact sheets
- Details of the $CO_2$ source and capture
- $CO_2$ transportation-specific information
- Injection data
- Links to a digital media kit

The major stationary $CO_2$ emitting sources that are in operation will have been identified as a result of Phase II activities. Data attributes associated with sources identified in Phase I and Phase II will be updated, and new sources that have come online will be added on an annual basis during Phase III.

During Phase III, saline aquifers, coal fields, and oil/gas fields will continue to be characterized. Capacity estimates will be refined during Phase III. In addition, new data will be collected and analyzed through an emphasis on strengthening our partnerships with geologic survey/oil and gas organizations in states and provinces to leverage the expertise from these organizations.

Terrestrial characterization activities in Phase II focused on the development of sound scientific methods to measure carbon storage and greenhouse gas flux on a variety of land use treatments. During Phase III, assessments will be made with regard to emerging aggregator programs, as well as the effects of expiring Conservation Reserve Program acres and other land use conversions in the PCOR Partnership region.

Implementation of $CO_2$ sequestration relies on knowledge of the infrastructure necessary to carry out the sequestration. Phase II efforts continue to identify sequestration technologies and approaches that are suitable and available for large-scale deployment in the PCOR Partnership region and to estimate their economic viability. Phase III activities will focus on existing and emerging capture and compression technologies and the regional pipeline infrastructure and will continue to evaluate the economic viability of sequestration options.

Pertinent information relating to the current and evolving regulatory framework for $CO_2$ sequestration in the PCOR Partnership region will be collected and provided to DOE and partners through the DSS. The partnership will continue participation with the Interstate Oil and Gas Compact Commission Regulatory Working Group.

Results of the large-scale demonstration tests will provide us with detailed reservoir properties that can be used to model other areas. The knowledge gained through all of the activities involved in the demonstration projects, including the operational parameters, regulatory issues, capture, compression, and transportation activities, and the project economics will be beneficial for evaluating future opportunities in our region.

## $CO_2$ PROCUREMENT

### Williston Basin – $CO_2$ Captured from Basin Electric Power Cooperative's Antelope Valley Station

Carbon dioxide will be obtained from the Antelope Valley Station, a lignite-fired facility in western North Dakota, for the Williston Basin demonstration. A slipstream of roughly 16% of the plant's total flue gas output will be processed to separate and capture the $CO_2$, dehydrated, compressed to supercritical conditions, combined with supercritical $CO_2$ from the Great Plains Synfuels Plant and transported via pipeline to the sequestration site that is anticipated to be approximately 150 miles away.

The Antelope Valley Station is a pc-fired power plant located north of Beulah, North Dakota, and is part of a $4 billion energy complex that includes the Great Plains Synfuels Plant. The Antelope Valley Station consists of two, 435-$MW_e$ units that fire lignite from the Freedom Mine. The boilers are tangentially fired, with low-$NO_x$ burners and overfire air to control $NO_x$ levels. A dry flue gas desulfurization system controls $SO_2$, and fabric filters capture particulate matter. The Antelope Valley Plant generates roughly 7.9 million short tons of $CO_2$/year. For this demonstration, $CO_2$ will be captured from a slipstream consisting of about 32% of the flue gas from one of the Antelope Valley Plant's two units.

The choice of $CO_2$ capture technology has not yet been finalized. Basin Electric Power Cooperative is looking at all options, although it is likely that some type of amine system will be chosen. If the $CO_2$ capture system requires reduction of $SO_2$ to lower levels than the existing flue gas desulfurization system produces, a secondary $SO_2$ scrubber will be added prior to the capture system. A dehydration system will be installed following the $CO_2$ capture system. Low-pressure steam, if required for the capture process, will be available from the Great Plains Synfuels Plant. The dry $CO_2$ stream leaving the capture process and dehydration system will be combined with $CO_2$ from the Great Plains Synfuels Plant and compressed for transport via pipeline.

Pipeline transportation and subsequent EOR require a dry gas stream containing at least 95 wt% $CO_2$ and very low levels of any other corrosive contaminants, such as HCl or $H_2SO_4$. A generic $CO_2$ stream composition representative of what would be produced by the Antelope Valley Station using commercially available monoethanolamine (MEA) and dehydration systems was estimated using the Integrated Environmental Control Model (IECM) developed at Carnegie–Mellon University. (Integrated Environmental Control Model, 2007) The $CO_2$ stream compositions that could be expected following capture and dehydration as estimated by the IECM are shown in Table 2.

**Table 2. Estimated $CO_2$ Stream Compositions Resulting from MEA Scrubbing and Dehydration**

| Component | Freedom Lignite |
|---|---|
| $CO_2$ | 99.44 wt% |
| HCl | 694 ppm |
| $SO_2$ | 0.5 wt% |
| $H_2SO_4$ | 2 ppm |
| $NO_2$ | 21 ppm |

The dehydrated $CO_2$ stream would be compressed to the sequestration field's requirements, estimated at this time to be 2700 psig (equal to the pressure of the $CO_2$ stream delivered by the Great Plains Synfuels Plant with which the Antelope Valley $CO_2$ stream would be combined), and transported as a supercritical fluid via pipeline to the oil field where it would be used for EOR.

Using the IECM, the estimated cost for $CO_2$ procurement from the Antelope Valley Station is $60/short ton (2005 dollars), comprising capture, dehydration, and compression costs to produce a supercritical $CO_2$ stream at 2700 psig. This does not include any replacement power costs to replace the estimated 28% of plant output that would be required to power the capture and compression of the $CO_2$.

The PCOR Partnership regional vision is one of rapid development of infrastructure to take advantage of these situations to become world leaders in sequestration technologies. The PCOR

Partnership Phase III project is teaming with the lignite industry to make this vision a reality. In addition to Basin Electric Power Cooperative, ALLETE, BNI Coal, Dakota Gasification Company, Encore Acquisition Company, Great Northern Power Development, Great River Energy, the Lignite Energy Research Council, MDU Resources Group, Inc., Minnkota Power Cooperative, Inc., Montana–Dakota Utilities, Otter Tail Power Company, the Coteau Properties Company, the Falkirk Mining Company, the North American Coal Corporation, Spectra Energy, and Westmoreland Coal Company have agreed to support the Phase III project efforts. This regional industry team will ensure that the lessons learned in Phase III can be applied throughout the PCOR Partnership region. Several other regional partners have expressed a willingness to participate in the Phase III demonstration by providing $CO_2$. These partners represent both existing and planned coal utilization facilities. Should the Basin Electric Power Cooperative $CO_2$ source prove problematic, $CO_2$ will be secured from one of these sources.

To the extent possible, the PCOR Partnership would like to provide access to a portion of the $CO_2$ source slipstream to test emerging technologies that coordinate with the goals of the demonstration, specifically the Carbozyme biomimetic $CO_2$ capture technology, while Pratt & Whitney Rocketdyne's compact reformer for industrial hydrogen may act as an additional source of $CO_2$. While tests of these technologies would be complimentary to the PCOR Partnership's efforts, they will be funded by their respective development programs rather than the RCSP Phase III program.

### Fort Nelson Test – $CO_2$ Captured from a Natural Gas-Processing Plant

The Fort Nelson demonstration will utilize $CO_2$ from the Fort Nelson natural gas-processing plant in northwestern British Columbia, Canada. The Fort Nelson Plant processes approximately 1.0 billion cubic feet per day (Bcf/d) of raw natural gas, making it one of the largest gas-processing plants in North America. To make this natural gas suitable for transmission and sale, acid gases (primarily $CO_2$ and $H_2S$) must be separated from the raw natural gas. The acid gas removal process generates approximately 1.8 million tons of $CO_2$ per year. Spectra Energy, the owner/operator of the Fort Nelson gas-processing plant, plans to use the existing amine-based acid gas removal system to capture all of the $CO_2$ generated by the plant and inject it into a nearby saline formation. The acid gas stream produced by the gas-processing plant is approximately 85% $CO_2$ and 15% $H_2S$. The acid gas stream will be compressed to a supercritical state. Figure 4 summarizes some of the key elements of the planned Fort Nelson $CO_2$ injection project.

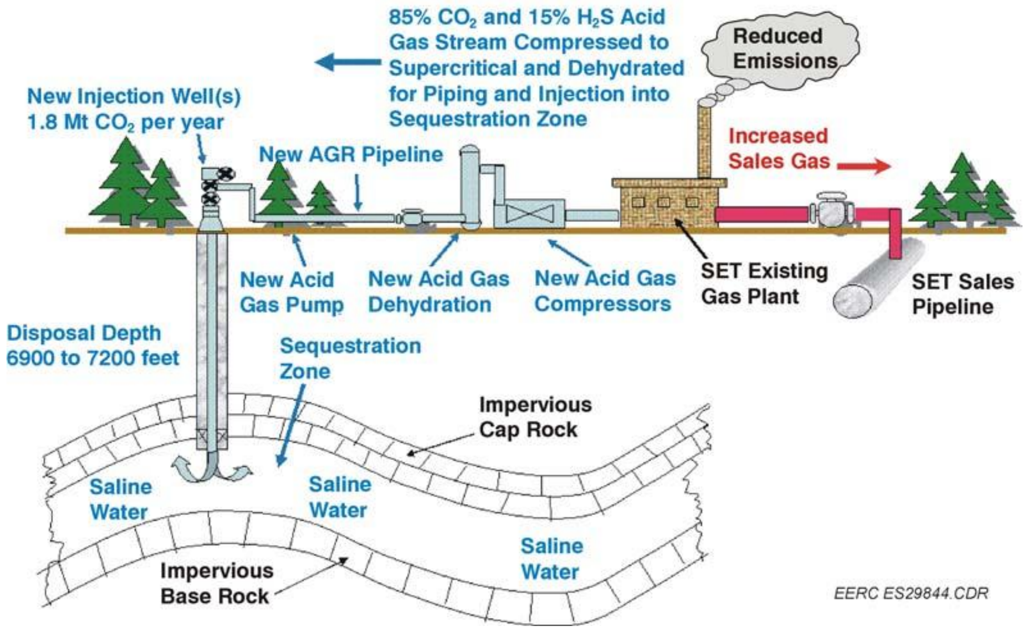


Figure 4. Diagram summarizing key elements of the Fort Nelson test.

## TRANSPORTATION AND INJECTION OF $CO_2$

### Infrastructure Required for Transportation of the $CO_2$ for the Williston Basin Project

Transportation of the $CO_2$ to the sink will be performed by pipeline. The PCOR Partnership vision for our region includes the potential for a major network of $CO_2$ pipelines that connect major sources and sinks. It is anticipated that the initial legs of the pipeline system will be developed for EOR projects such as this one and that they will be used for saline formation injection after the EOR opportunities have been exhausted. For this project, a pipeline will be constructed between the Antelope Valley Station/Great Plains Synfuels Plant complex near Beulah, North Dakota, and the Cedar Creek Anticline in southwestern North Dakota. The Massachusetts Institute of Technology (MIT) $CO_2$ Pipeline Transport and Cost Model (MIT, 2007) was used to estimate the least expensive route for the pipeline. Estimates obtained using the model show that a 150-mi, 8-in.-diameter pipeline would be required to move up to 1.2 million short tons of $CO_2$ per year from Beulah, North Dakota, to the Cedar Creek Anticline. The pipeline could be constructed for roughly \$26.5 million. Annual O&M (operating and maintenance) costs for the pipeline would be \$0.76 million. The total pipeline cost would be roughly \$4.30 per short ton $CO_2$/yr. Because the distance between the source and the sink is more than 100 miles, a booster station might be required along the route to maintain the $CO_2$ stream at a supercritical state.

The injection strategy will be developed in cooperation with our commercial EOR partner. Injection equipment will be provided by our EOR partner, and the costs of the equipment will provide a basis for in-kind cost share. Since the fields being considered have already undergone secondary recovery, they already have established injection strategies which should facilitate more rapid engineering and permitting process for $CO_2$ injection.

### Ramgen Slipstream Test

Current plans call for a possible demonstration of the Ramgen Power Systems shock compression technology on a portion of the $CO_2$ stream to evaluate its ability to reduce cost while increasing compression efficiency. Initial engineering and planning for a slipstream demonstration of the Ramgen Power Systems compression technology is included in Phase III efforts. The Ramgen compression technology applies ramjet engine concepts to the compression of gases. The technology features a rotating disk that operates at high peripheral speeds, achieving a supersonic effect in a stationary environment. The efficiency of this compression process is very high because the compressor has very few aerodynamic leading edges and minimal drag. Besides being more efficient than existing compressor technologies (i.e., centrifugal and axial designs), shock compression can produce high single-stage compression ratios; results in smaller and simpler compressors, which are less expensive to manufacture; and offers a more viable opportunity to recover waste heat.

Centrifugal compressors are typically applied at compression ratios of 1.8 to 2.8 per stage with adiabatic efficiencies that typically range from 82% to 85%. Axial compressors are typically designed to develop pressure ratios of 1.2 to 1.4 per stage and require four to ten stages to achieve usable industrial pressure ratios. Although single-stage axial efficiencies can be greater than 90%, the integrated overall compressor efficiency is in the range of 82–90%. In contrast, Ramgen's shock compression has the potential to develop compression ratios from 2.0 to 15.0 per stage with an associated adiabatic efficiency of 85%–90%.

$CO_2$ compressors represent a significant fraction of the capital and operating costs of a carbon capture system. The $CO_2$ compressor power required for a pc-fired power plant can range from 2% to 10% the net plant output (Ramezan, 2006). In a plant performance comparison performed for the U.S. DOE, a 430-MW pc plant was estimated to require 25 MW to capture 90% of the $CO_2$ produced. (Ramezan, 2006) At an estimated cost of $82/kW (Ciferno et al., 2006), the compressors alone would cost $20.5 million.

Ramgen’s compression technology is especially well-suited to the compression of $CO_2$ because sonic velocity is inversely proportional to the square root of the molecular weight of the gas. A heavier gas has a lower Mach number, or sonic velocity. The strength of the shock wave, hence the amount of compression, increases exponentially with the Mach number. Because $CO_2$ has a heavier molecular weight than air, it can go supersonic at a lower velocity, effectively achieving a higher compression ratio for a slower rate of spin.

### Infrastructure Requirements for the Fort Nelson Test

The existing acid gas removal system at the gas-processing plant is sufficient to capture 1.8 million tons of $CO_2$ per year for the Fort Nelson test. Spectra Energy will install significant infrastructure to transport the supercritical $CO_2$ to the injection site. New systems that Spectra Energy will construct at Fort Nelson include acid gas compressors, a dehydration system, a pipeline for the acid gas stream, and an acid gas pump. The length of the new acid gas pipeline has not been determined because the selection of an injection location has not yet been finalized.

It is anticipated that the pipeline will not exceed 50 miles in length and that Spectra Energy will have the necessary surface rights needed to construct and operate the pipeline.

## GENERAL SITE INFORMATION

### Williston Basin Test

The specific host site for the injection wells needed for the Williston Basin test will be determined during the first year of Phase III. Discussions with likely partners (still ongoing) during the development of the Phase III proposal indicate that several western North Dakota and eastern Montana oil fields may be appropriate locations to host the PCOR Partnership Phase III large-volume sequestration test. Figure 5 is a map showing the locations of the Williston Basin oil fields being considered as host sites for $CO_2$ injection and MMV activities under Phase III. The selection of a host injection site has not been finalized and is subject to change based on 1) the outcome of ongoing negotiations between the oil field operating company, the power plant operating company, and the EERC and 2) the collection and evaluation of detailed proprietary data for the selected field that was previously unavailable for characterization under PCOR Partnership Phases I and II.

The likely host company for the injection activities is Encore Operating, L.P. (Encore), but Hess Corporation (Hess) and Conoco-Phillips are also possible EOR partners for the test. Encore, headquartered in Fort Worth, Texas, has been a member of the PCOR Partnership since Phase I and is consistently one of the top three oil-producing companies in North Dakota. Hess, a vertically integrated oil company with global operations, is one of the largest oil producers in North Dakota and has maintained a presence in the Williston Basin for over 50 years. Conoco-Phillips is the operator for many of the largest oil fields in the Cedar Creek Anticline area of southeastern Montana and southwestern North Dakota. Regardless of which oil field is selected for the Phase III demonstration, unencumbered access to the site will be provided by a network of state- and county-maintained roads as well as oil field service roads maintained by the oil field operating company. Any physical impediments that may impact the project will be identified and evaluated as part of the site-selection process. All oil fields being considered have been unitized, which means that the operating company has been given regulatory approval by the North Dakota Department of Mineral Resources or the Montana Board of Oil and Gas Conservation to conduct large-scale fluid injection activities (including $CO_2$) as part of the reservoir's operation. The fact that the selected oil field is already an established injection-oriented oil field will provide the project with flexibility regarding the selection of well sites and the construction of $CO_2$ injection wells and attendant infrastructure. It will also significantly streamline the permitting process because environmental impact studies have already been conducted as part of the establishment of oil fields.

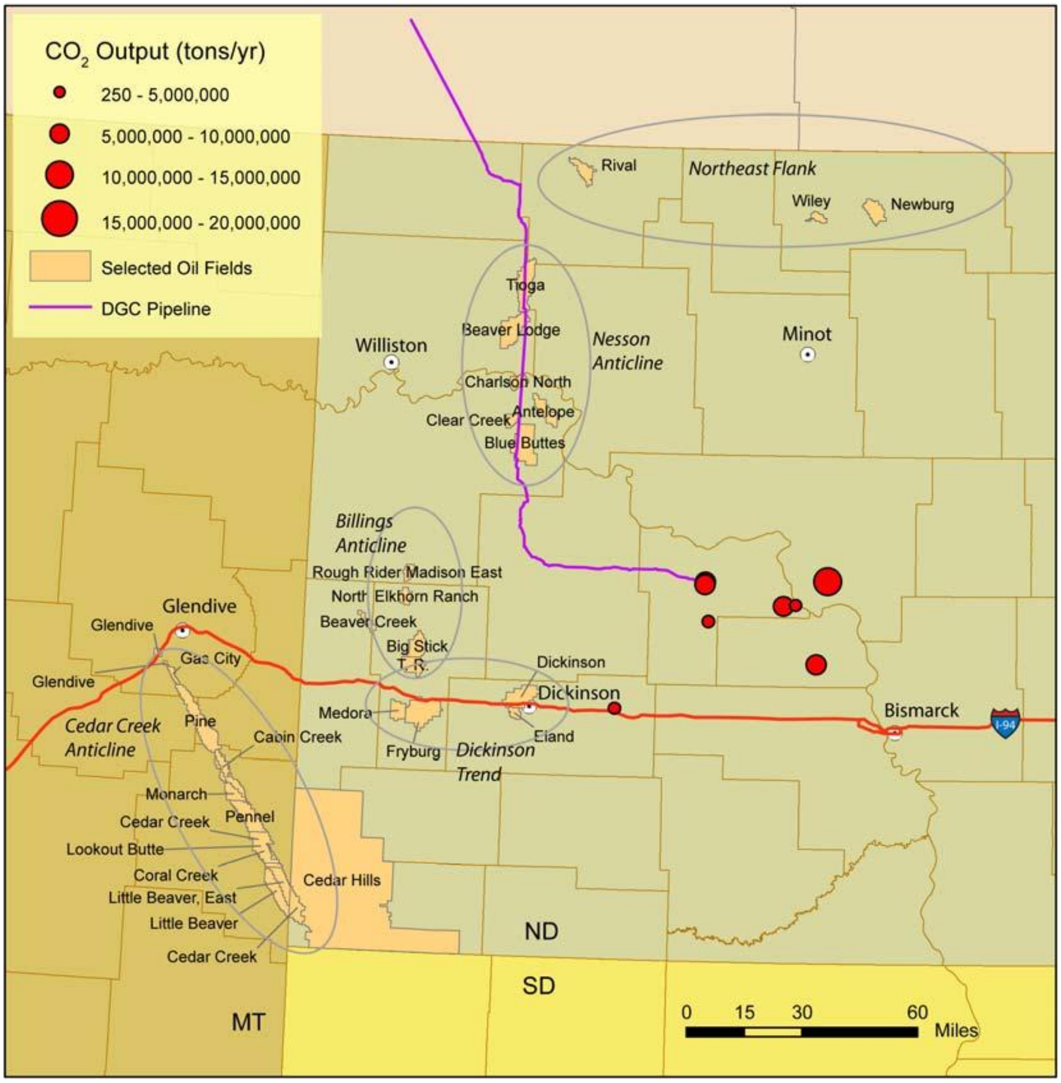


Figure 5. Key potential locations for Phase III demonstration project in the Williston Basin.

### Fort Nelson Test

The specific host site for the injection wells needed for the Fort Nelson Phase III test has not yet been determined, but will likely be located within about 50 miles of the Fort Nelson gas-processing plant. The target injection formation will be at a depth of between 6500 and 7500 feet. Formations in this depth range will be at the temperature and pressure that ensure the injected $CO_2$ remains in a supercritical state. The precise location will be determined early in Phase III and will be based on geological characteristics and logistical considerations associated with the development of transportation infrastructure. Figure 6 is a map showing the location of the Fort Nelson gas-processing plant.

Spectra Energy will be the host company for the $CO_2$ capture, transportation, and injection activities. Spectra Energy currently owns the gas-processing plant and plans on obtaining the rights to the pore space of the target injection zone by the end of 2007. Headquartered in

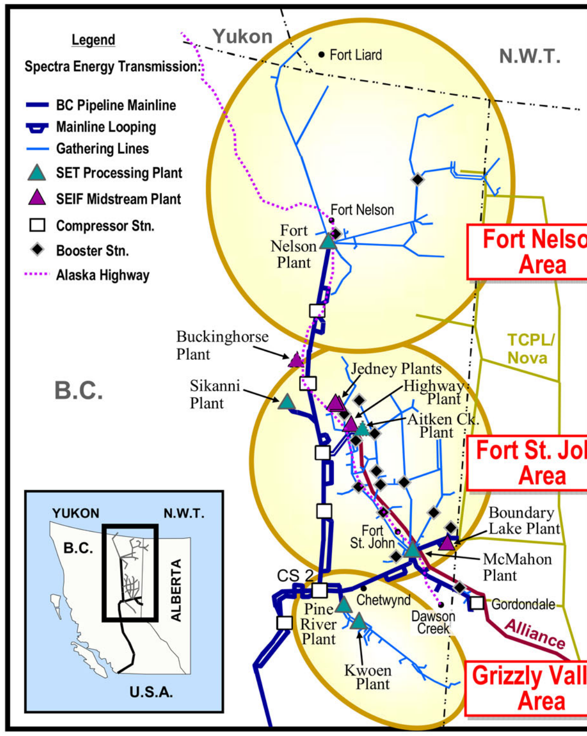


Figure 6. Major gas-producing areas of northeastern British Columbia, including the Fort Nelson area.

Houston, Texas Spectra Energy, is a member of the PCOR Partnership and is the owner/operator of one of the largest pure-play midstream natural gas companies in North America. The Fort Nelson area is home to many oil and gas production areas, and unencumbered access to the site will be provided by a network of oil field service roads maintained by the operating companies, as well as by roads maintained by the province of British Columbia. Any physical impediments that may impact the project will be identified and evaluated as part of the site-selection process. Spectra Energy is working closely with the British Columbia Ministry of Energy, Mines, and Petroleum Resources (BCMEMPR) to obtain the necessary permits and regulatory approval to conduct large-scale $CO_2$ injection activities in the area. Preliminary meetings with the BCMEMPR indicate that the province is supportive of the Fort Nelson $CO_2$ injection project and will work with Spectra Energy and the PCOR Partnership to ensure that the permitting and regulatory approval process is conducted in a timely and effective manner. The fact that depleted gas fields in the Fort Nelson are currently being used for large-scale disposal of acid gas ($H_2S$ and $CO_2$) will significantly streamline the permitting process because environmental impact studies have already been conducted as part of the approval process for acid gas disposal projects.

## SUBSURFACE INFORMATION

### Description of Target Formations

***Assessment of Formation Characterization***. Hundreds of oil fields in North Dakota and Montana have been thoroughly characterized since the discovery of oil in the Williston Basin in the early 1950s. Thousands of wells have been drilled into a variety of zones throughout the basin. Depths of the wells range from a few thousand feet to over 14,000 feet in the basin center. Formation fluid production and water injection data from many of these wells provide insight into formation injectivity and permeability, as well as the integrity of overlying seals. At the oil field and reservoir levels, a significant amount of historical data exists for each field, including well logging data for the reservoir and seals, fluid analyses, fluid production and water injection data, and other key reservoir dynamics data. Geophysical surveys for many areas exist, but the availability, precise nature, and applicability of the survey data with respect to the proposed Phase III project have yet to be determined. It is anticipated that additional, more detailed data will be provided to the PCOR Partnership by the oil field operator partner upon initiation of Phase III.

***Description of Geological Characteristics of the Williston Basin***. The Williston Basin is a relatively large, roughly circular, intracratonic basin with a thick sedimentary cover in excess of 16,000 ft. It covers several hundred thousand square miles across parts of North Dakota, South Dakota, Montana, and the Canadian provinces of Manitoba and Saskatchewan (Figure 7). Deposition in the Williston Basin occurred during all periods of the Phanerozoic. The Williston Basin is considered by many to be tectonically stable, with only a subtle structural character. The stratigraphy of the area is well studied, especially in those intervals that are oil-productive. Figure 8 shows a west–east cross section of the geologic strata in North Dakota. The geometry of the Williston Basin is fairly symmetrical with gently dipping slopes. Figure 9 shows the stratigraphic nomenclature of the basin. Thus, in the absence of a structural and/or hydrodynamic trapping mechanism, the migration of a low-gravity fluid like $CO_2$ will be expected to occur up-dip along the stratigraphic trap, toward the flanks of the basin. However, accumulation of hydrocarbons in the hundreds of oil fields scattered throughout the basin provides evidence of the presence of structural and/or hydrodynamic trapping mechanisms in the area in addition to the prevailing stratigraphic traps. The oil fields that will most likely be considered for the Phase III test are located in four general structurally and/or stratigraphically defined areas of the Williston Basin: 1) the Cedar Creek Anticline, 2) the Billings Anticline, 3) the Nesson Anticline, and 4) the Northeast Flank. These areas, and the key unitized fields within them, are outlined in Figure 2. Traps in these areas are generally controlled by structure or a combination of structure and stratigraphically derived porosity changes. While general information on the structural geology, lithostratigraphy, hydrostratigraphy, and petroleum geology of the Williston Basin is readily available, additional characterization data for specific candidate sinks will be necessary before their utilization as $CO_2$ storage sites. Detailed maps of critical elements such as formation thickness, porosity, permeability, and water salinity will need to be developed, and the competency of regional traps will have to be determined based on further evaluations.

Production and injection history, as well as core analysis, provide a relatively detailed understanding of the petrographic properties of nearly all of the formations that occur in the

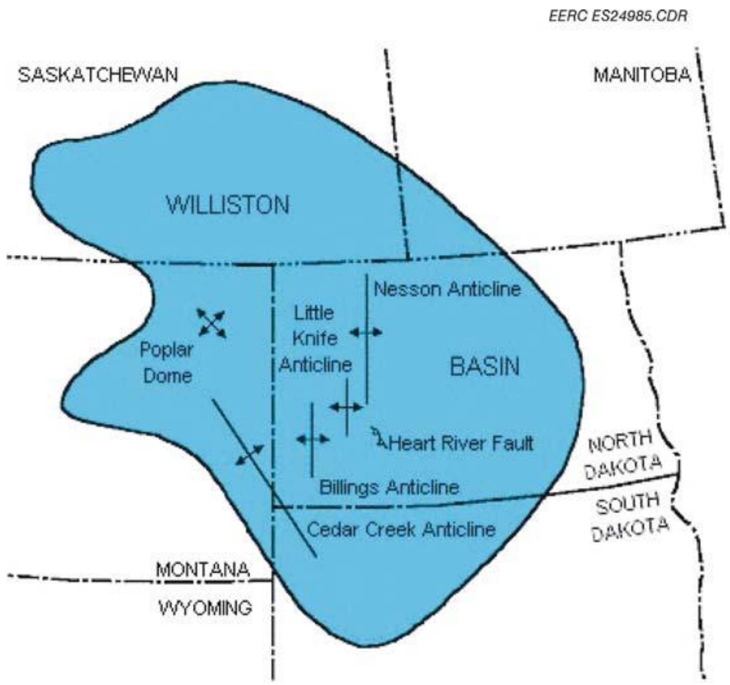


Figure 7. Index map of the Williston Basin with some major structures (modified from Gerhard et al., 1982).

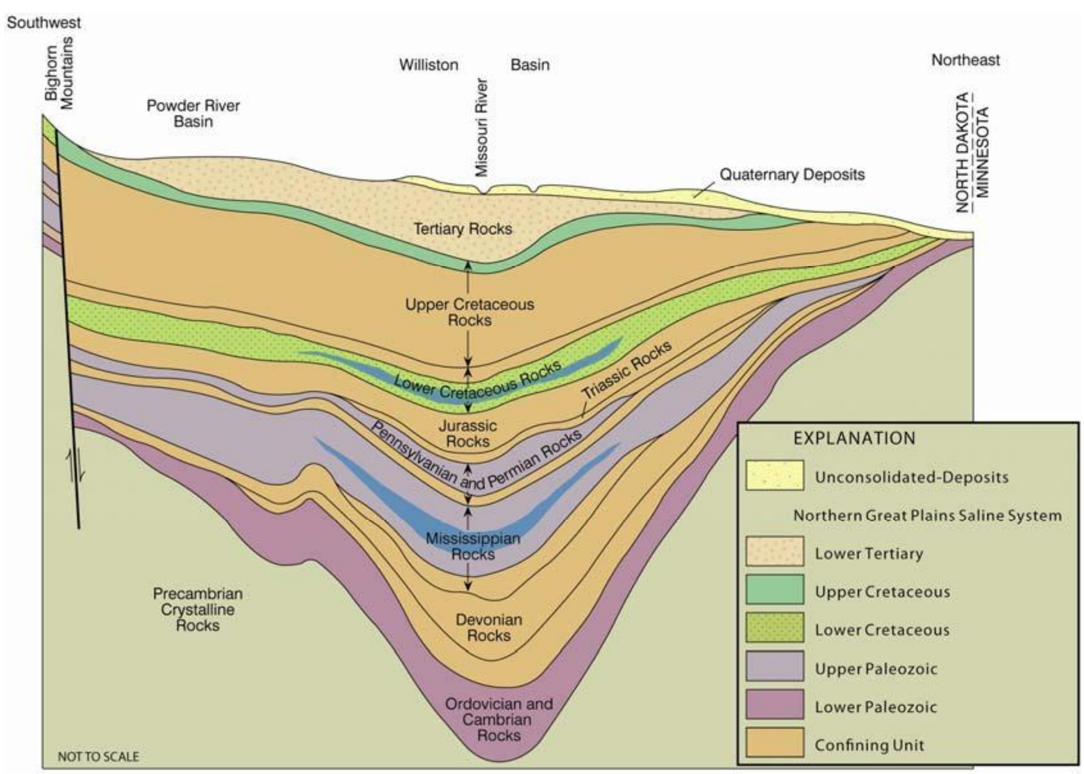


Figure 8. West–east cross section of the geologic strata in North Dakota.

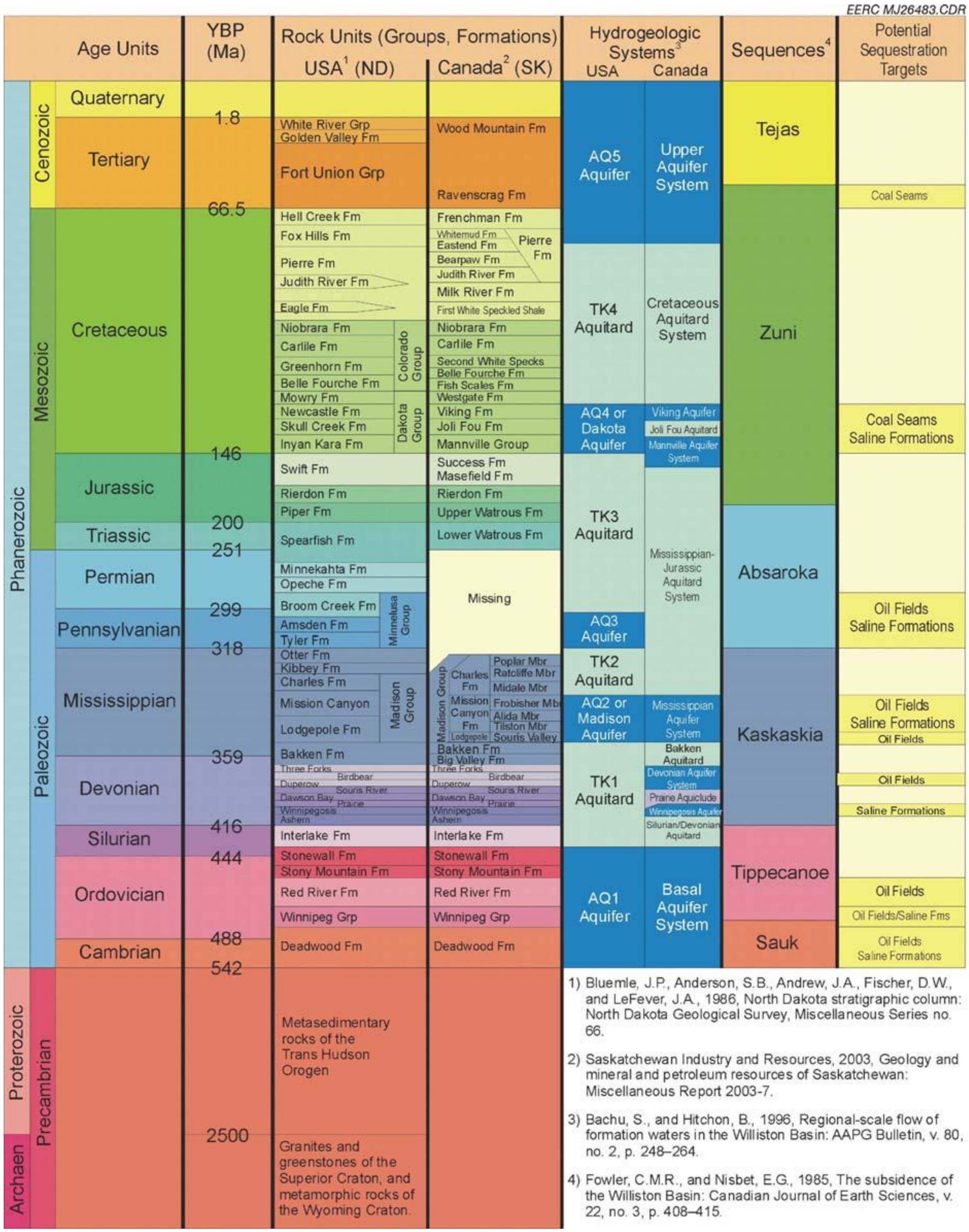


Figure 9. Chart illustrating the stratigraphic nomenclature and relevance to storage and sealing capabilities of formations in the Williston Basin.

Williston Basin. Table 3 includes a summary of key reservoir characteristics for selected fields that exhibit characteristics common to some of the formations that may be considered as injection targets.

## Regional Storage Capacity

Phase I characterization activities showed that the PCOR Partnership region emits approximately 550 million tons of $CO_2$ from large stationary sources each year in the region. Over the course of 100 years it is assumed that approximately 55 to 60 billion tons of $CO_2$ will be generated by large stationary sources. The results of regional sink characterization activities conducted under Phases I and II of the PCOR Partnership shown in Table 4 indicate that oil fields in the region have the capacity to store nearly 31 billion tons of $CO_2$, which is greater than 50% of the anticipated regional emissions over the next 100 years assuming a static emissions profile. The estimated capacity is likely lower than the actual storage capacity of all the oil fields in the region because the Phase I and II characterization activities only evaluated oil fields for which data were readily available. Many oil fields in Wyoming, Nebraska, Montana, and British Columbia did not have readily available data necessary for the regional characterization. It is also important to note that the Williston Basin and Alberta Basin are still being actively explored and new oil fields will likely be discovered, which will further increase the $CO_2$ storage capacity of oil fields in the region. Because of the large capacities and numerous opportunities for $CO_2$ sequestration in oil fields throughout the region, the Phase III large-volume $CO_2$ injection test into a paleozoic oil reservoir in the Williston Basin is highly representative of the geological sinks that are available to the states and provinces of the PCOR Partnership region.

With respect to the storage capacity of brine formations in the PCOR Partnership region (which will be represented by the Fort Nelson test), the results of regional sink characterization activities conducted under Phases I and II of the PCOR Partnership indicate that brine formations in the region have the theoretical capacity to store over 500 billion tons of $CO_2$. These results suggest that there is more than enough capacity to store all of the region's large stationary source $CO_2$ in the region's brine formations for the next century.

**Table 3. Reservoir Characteristics for Selected Fields That May Be Analogs for $CO_2$-Injection Target Reservoirs**

| Field – Formation | Depth, ft | Pressure, psi | Temperature, °F | Porosity, % | Injectivity, Mt/yr/well | Est. $CO_2$ Capacity, Mt |
|---|---|---|---|---|---|---|
| Bear Creek – Duperow | 11250 | 4500 | 249 | 12–20 | 0.46 | 2–5 |
| Beaver Lodge – Duperow | 10000 | 3942 | 249 | 13–14 | 0.5 | 170 |
| Cedar Creek – Red River | 8200 | 3500 | 192 | 10–15 | 0.13 | 33–78 |
| T.R. – Mission Canyon | 9300 | 4200 | 211 | 10–13 | 0.26 | 6–19 |
| Eland – Lodgepole | 9800 | 4600 | 231 | 5–10 | 0.26 | 6–15 |

**Table 4. Estimated $CO_2$ Storage Capacities of Oil Fields in PCOR Partnership Region States and Provinces**

| State/Province | $CO_2$ Storage Capacity, million tons |
|---|---|
| NE | 26 |
| SD | 171 |
| WY | 952 |
| MT | 2398 |
| MB | 859 |
| SK | 10,294 |
| AB | 11,126 |
| ND | 4959 |
| Total | 30,785 |

## Description of Overlying Seal(s) and Formations – Williston Basin Test

The thickest, most comprehensive seal for most of the oil fields under consideration will be provided by the Mississippian-age Charles Formation. The Charles Formation in western North Dakota and eastern Montana is dominated by thick evaporites (anhydrite and halite) characterized by extremely low permeability and high geomechanical strength. A study of chemical composition of oils from different horizons in the Williston Basin (Jarvie et al., 1997) indicates that no mixing of oils from below the Charles Formation occurs with oils from overlying horizons. This is strong evidence that seals provided by evaporite beds of the Charles Formation are competent enough to prevent vertical migration.

Figure 10 illustrates the lateral extent of anhydrites and other evaporites within the Charles Formation. Based on the very low permeability and high mechanical strength of anhydrite (among the lowest permeability and highest mechanical strength observed among sedimentary rocks), this cap provides a very competent seal for underlying reservoirs. The cumulative average thickness of the Charles Formation is 250 ft. In some areas, the thickness can be in excess of 300 ft. The Charles Formation is laterally extensive, covering thousands of square miles (Hoda, 1977; Downey, 1986). Several additional secondary seals also exist above the Charles Formation in the areas being considered (Carlson, 1979; Downey, 1986). The most competent and massive of these secondary seals in ascending order are 1) Opeche Shale; 2) Spearfish Formation (shales and evaporites); 3) Upper Colorado Group, consisting of shales of the Mowry, Belle Fourche, Greenhorn, Carlile, and Niobrara Formations; 4) shale of the Pierre Formation; and 5) shales and mudstones of the Hell Creek Formation. All of the mentioned secondary seals demonstrate substantial lateral extent throughout western North Dakota and eastern Montana, and thicknesses of not less than 100 ft.

No seismically active faults are present in North Dakota (von Hake, 1975). No historically known earthquakes have occurred in the vicinity of any of the oil fields being considered (Figure 11). Data from the National Earthquake Hazards Reduction Program (NEHRP, 2006) indicate no quaternary faults in the study areas. Location of known faults, folds, and lineaments in parts of North Dakota, South Dakota and Montana are shown in Figure 12a, b. It is worth noting that none of the faults indicated in Figure 12a intersects any of the fields under consideration and, consequently, the Charles Formation seal. Lineaments, shown in Figure 12b,

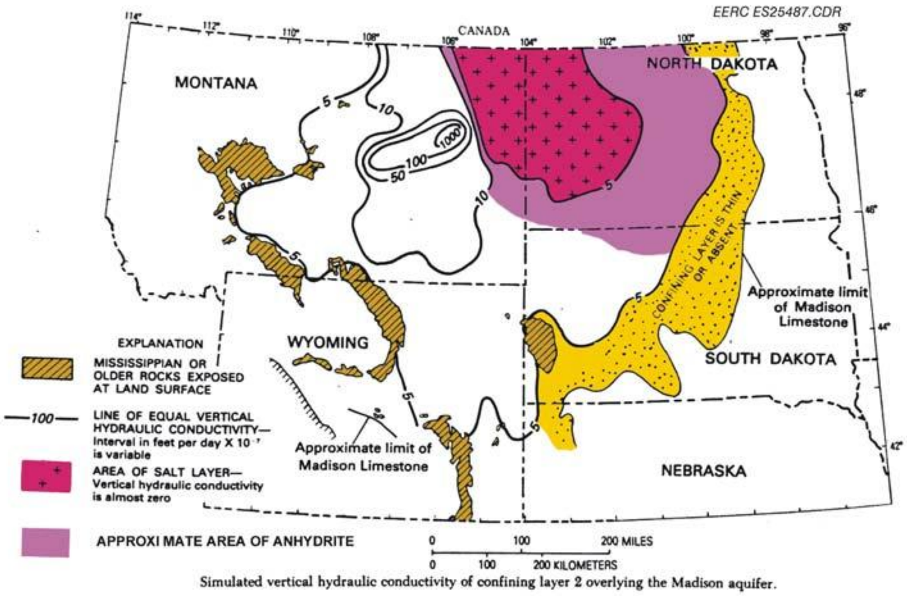


Figure 10. Distribution of salts and anhydrites within the Charles Formation in the Williston Basin.

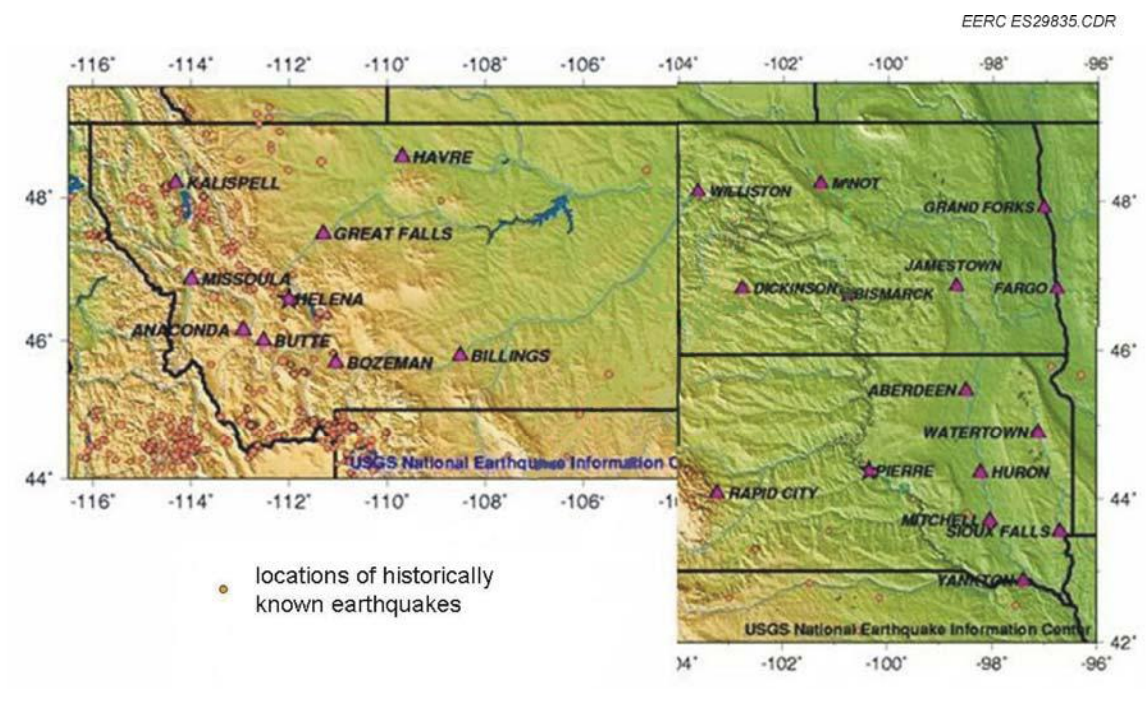


Figure 11. Locations of historically known earthquakes.

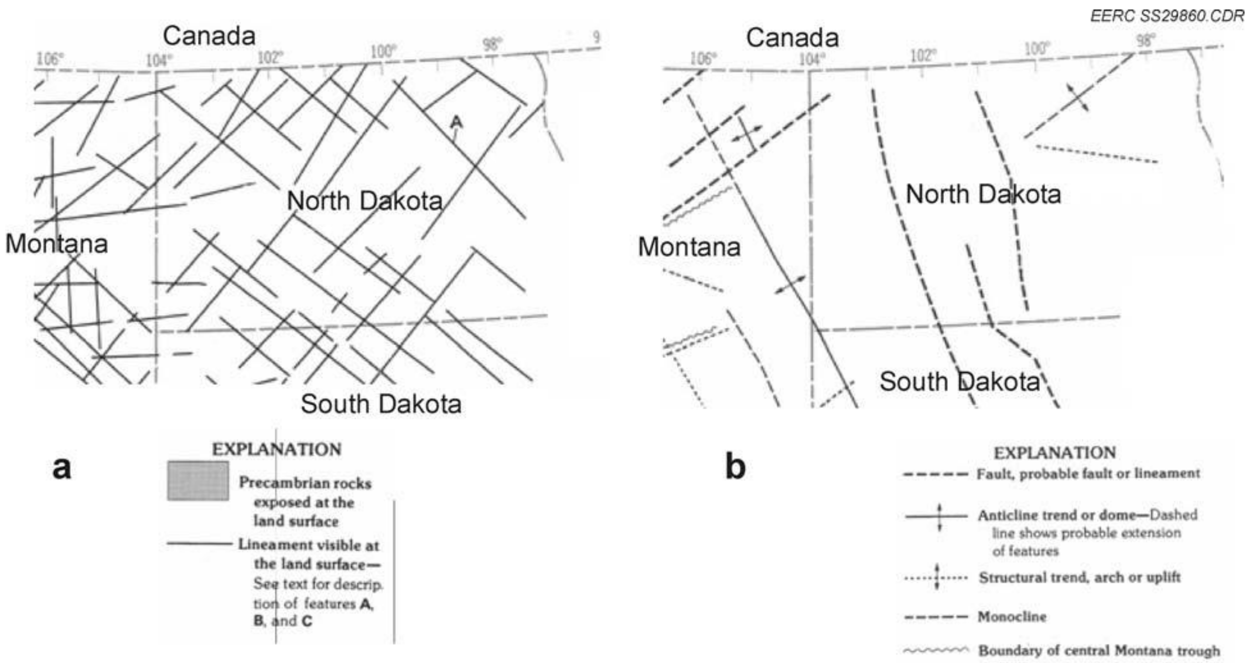


Figure 12. Shown on left (a): location of known faults and folds and shown on right (b): documented and suspected lineaments in the Williston Basin (Downey and Dinwiddie, 1986).

indicate possible planes of weakness which could provide potential paths for fluid migration. However, analysis of hydrologeological data indicates there is no evidence of vertical fluid migration along these possible pathways. Maps of hydraulic head for the aquifers in different horizons (Hoda, 1977; Downey, 1986) demonstrate uniform head distribution in all of the aquifer systems without any sudden changes that would be indicative of recharge areas caused by fluid movement through fractures in the seals. Analysis of the salinity distribution in the aquifers also supports the conclusion that no fluid exchange between deeper and shallower aquifers occurs. Salinity maps of the deep saline aquifer systems (Hoda, 1977) illustrate uniform salinity distribution, while brine inflow from deeper, more saline aquifer systems (such as those that include oil reservoirs that are being considered for Phase III injection) would result in the formation of zones of increased salinity in the overlying systems. Finally, thorough numerical modeling (Downey, 1986) of the Mississippian Madison aquifer system (which includes the Charles Formation as an aquitard, or seal) in North Dakota and adjoining areas did not reveal any zones of increased permeability within Charles Formation which would correspond to the location of fracture networks.

### Description of Overlying Seal(s) and Formations – Fort Nelson Test

For the Fort Nelson project, the thickest, most comprehensive seal for the Devonian carbonate rock formations under consideration will be provided by the massive and extensive shales of the Fort Simpson Formation. The Fort Simpson Formation in northeastern British Columbia and northwestern Alberta is characterized by low permeability and high geomechanical strength.

Based on the very low permeability and high mechanical strength of the shale, this cap provides a very competent seal for underlying brine formation reservoirs. The cumulative average thickness of the Fort Simpson Formation is approximately 500 m, and in some areas the thickness can be in excess of 1000 m. The Fort Simpson Formation is laterally extensive, covering thousands of square miles. Secondary seals also exist above the Fort Simpson Formation in the areas being considered. The most competent and massive of these secondary seals is the Banff Formation, which is predominantly shale and not less than 100 feet thick in the Fort Nelson area.

### Formation Storage Injectivity and Capacity – Williston Basin Test

Injection activities in the Williston Basin test will most likely be conducted in an oil field that has already been unitized. The oil field unitization process is the regulatory process by which an oil field operator or group of operators are granted permission by the state to conduct large-scale injection operations for the purpose of EOR within a specified oil field. Unitized oil fields are generally considered the best near-term option for $CO_2$-based EOR for several reasons, including:

- Unitized oil fields have gone through a public legal/regulatory process that enables coordinated injection and removal of fluids for the purpose of EOR.

- Volumes of oil produced through the primary recovery phase have proven significant enough to undertake a secondary phase of production (i.e., waterflooding).

- Unit operators must provide extensive reservoir dynamics and production data to the regulatory authority (i.e., the North Dakota Industrial Commission Department of Mineral Resources, Oil and Gas Division) for the evaluation of secondary recovery activities.

- The injectivity of these reservoirs has already been demonstrated and quantified by the extensive water injection activities that are conducted as part of secondary recovery operations. Preliminary estimates of $CO_2$ injectivity for several unitized oil fields in North Dakota indicate that $CO_2$ injectivity can range from 100,000 to 500,000 tons per year per well.

- Unit data can provide the basis for determining the potential of utilizing $CO_2$ for EOR.

Within the PCOR Partnership region, there are bountiful opportunities for $CO_2$-based EOR in unitized oil fields. The host field will be selected from one of the four primary oil-producing areas in the Williston Basin. These include the Cedar Creek region of southwestern North Dakota and eastern Montana, the Billings Anticline–Dickinson area fields located in western North Dakota, the Nesson Anticline area in northwestern North Dakota, and the Northeast Flank area of north-central North Dakota. The potential incremental oil resource and the corresponding volumes of $CO_2$ needed for EOR are listed for each region in Table 5.

The location of the Cedar Creek Anticline is shown in Figure 3. It contains at least ten pools potentially suitable for EOR with a total potential incremental oil resource of 628 million barrels (stb). The volume of $CO_2$ necessary to recover this oil is estimated at 4860 Bcf (298 Mt).

**Table 5. Summary of Potential Incremental Oil Recovery from $CO_2$ Injection for Selected Cedar Creek Anticline Unitized Oil Fields**

| Unit Name | Pool Unitized | Potential Oil Recovery at 12% OOIP,* million stb | $CO_2$ Needed Using 8 mcf/bbl Oil Recovered, Bcf |
|---|---|---|---|
| Cedar Hills North (ND) | Red River | 33 | 267 |
| Cedar Hills South (ND) | Red River | 43 | 346 |
| Pennel (MT) | Interlake | 36 | 288 |
| Pennel (MT) | Madison | 12 | 95 |
| Pennel (MT) | Red River | 28 | 223 |
| Cabin Creek (MT) | Interlake | 85 | 680 |
| Cabin Creek (MT) | Madison | 55 | 437 |
| Cabin Creek (MT) | Red River | 44 | 351 |
| Pine (MT) | Red River | 106 | 846 |
| Pine (MT) | Interlake | 186 | 1327 |
| Total | | 628 | 4860 |

* Original oil in place.

Table 5 lists the locations of the key unitized oil fields within the Cedar Creek Anticline, the potential oil recovery volume using $CO_2$ EOR for each field, and the volume of $CO_2$ required.

The location of the unitized oil fields in the Billings County–Dickinson area are shown in Figure 13. This region contains at least eight unitized pools potentially suitable for EOR with a total potential incremental oil resource of 67 million barrels (stb). The volume of $CO_2$ necessary to recover this oil is estimated at 533 Bcf (32 Mt). Table 6 lists the locations of the key unitized oil fields within the Billings–Dickinson region, the potential oil recovery volume using $CO_2$ EOR for each field, and the volume of $CO_2$ required.

The location of the Nesson Anticline is shown in Figure 14. This region contains at least eight pools potentially suitable for EOR with a total potential incremental oil resource of 122 million barrels (stb). The volume of $CO_2$ necessary to recover this oil is estimated at 970 Bcf (58 Mt). Table 7 lists the key unitized oil fields within the Nesson Anticline, the potential oil recovery volume using $CO_2$ EOR for each field, and the volume of $CO_2$ required.

The location of the Northeast Flank oil fields are shown Figure 15. This region contains three pools potentially suitable for EOR with a total potential incremental oil resource of 33 million barrels (stb). The volume of $CO_2$ necessary to recover this oil is estimated at 260 Bcf (15 Mt). Table 8 lists the key unitized oil fields within the Northeast Flank region, the potential oil recovery volume using $CO_2$ EOR for each field, and the volume of $CO_2$ required.

It is important to keep in mind that the $CO_2$ storage capacity and incremental oil production estimated for unitized oil fields in Phase I are reconnaissance-level estimates.

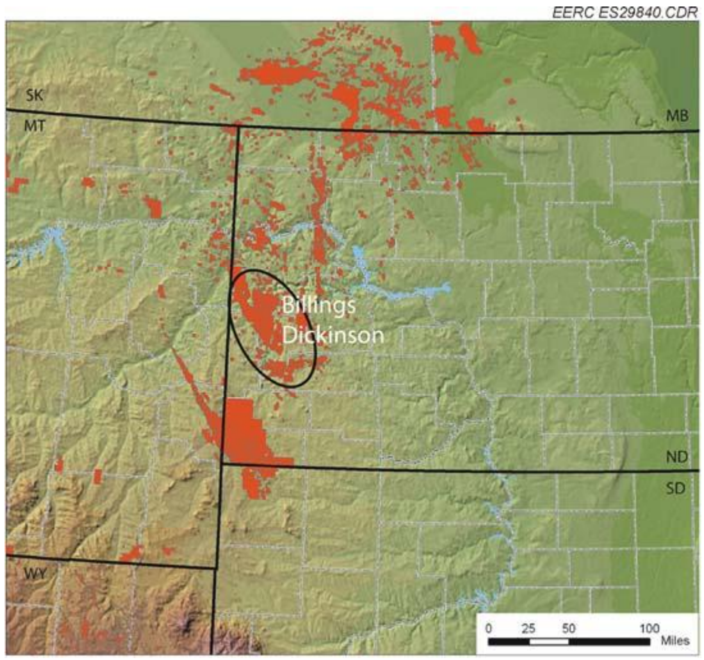


Figure 13. Location of the Billings–Dickinson area.

**Table 6. Summary of Potential Incremental Oil Recovery from $CO_2$ Injection for Selected Billings–Dickinson Region Unitized Oil Fields**

| Unit Name | Pool Unitized | Potential Oil Recovery at 12% OOIP*, million stb | $CO_2$ Needed Using 8 mcf/bbl Oil Recovered, Bcf |
|---|---|---|---|
| Big Stick | Madison | 20 | 159 |
| Fryburg | Heath–Madison | 19 | 149 |
| Dickinson | Heath | 7 | 59 |
| Medora | Heath–Madison | 7 | 56 |
| North Elkhorn Ranch | Madison | 7 | 53 |
| Rough Rider East | Madison | 4 | 30 |
| Eland | Lodgepole | 12 | 96 |
| T.R. | Madison | 14 | 146 |
| Total | | 90 | 748 |

*Original oil in place

Ultimately, to achieve a more accurate evaluation, particularly with respect to injectivity of the target reservoir, the following are needed:

- Detailed geologic characterization
- Updated OOIP statistics
- Production history data
- Reservoir dynamics data
- Modeling efforts
- Injection tests

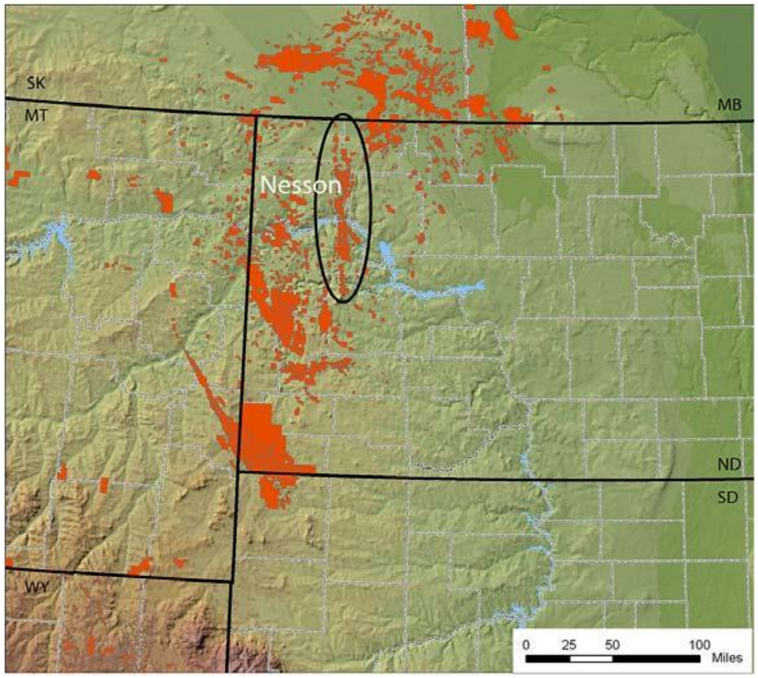


Figure 14. Location of the Nesson Anticline.

**Table 7. Summary of Potential Incremental Oil Recovery from $CO_2$ Injection for Selected Nesson Anticline Unitized Oil Fields**

| Unit Name | Pool Unitized | Potential Oil Recovery at 12% OOIP, million bbl | $CO_2$ Needed, Bcf |
|---|---|---|---|
| Beaver Lodge | Duperow | 28 | 224 |
| Tioga | Madison | 26 | 207 |
| Beaver Lodge | Madison, Silurian, Ordovician | 27 | 165 |
| Antelope | Madison | 12 | 96 |
| Blue Buttes | Madison | 11 | 89 |
| Charlson North | Madison | 10 | 77 |
| Clear Creek | Madison | 3 | 26 |
| Antelope | Devonian | 2 | 16 |
| Bear Creek | Duperow | 2 | 13 |
| Charlson South | Madison | 1 | 9 |
| Total | | 122 | 922 |

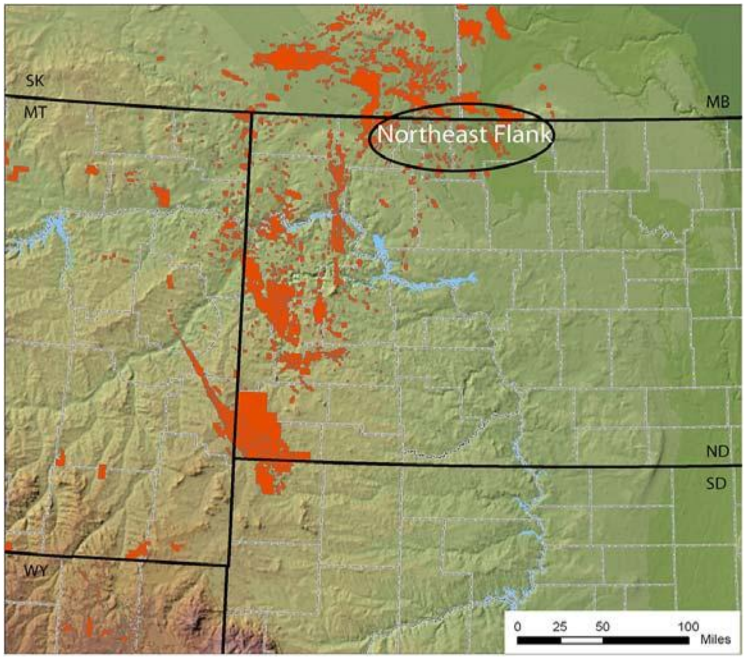


Figure 15. Location of the Northeast Flank.

**Table 8. Summary of Potential Incremental Oil Recovery from $CO_2$ Injection for Selected Northeast Flank Oil Fields**

| Field Name | Pool Unitized | Potential $CO_2$ Oil Recovery at 12% OOIP, million bbl | $CO_2$ Needed, Bcf |
|---|---|---|---|
| Newburg | Spearfish–Charles | 12 | 92 |
| Wiley | Glenburn | 12 | 92 |
| Rival | Madison | 9 | 76 |
| Total | | 33 | 260 |

### Formation Storage Injectivity and Capacity for Fort Nelson Test

The injectivity and storage capacity of the formation into which $CO_2$ will be injected as part of the Fort Nelson test has not yet been determined. As mentioned above, Spectra Energy has not finalized the selection of either the surface location of the injection site, nor the specific vertical zone of the brine formation into which the acid gas will be injected, which makes estimates of injectivity and capacity purely speculative at this time. The historical and ongoing operation of large-volume acid gas disposal operations into depleted gas fields in geologically similar areas near the Fort Nelson area indicates that the injectivity and storage capacity of the formations being considered by Spectra Energy for the Phase III test are likely to be adequate to accommodate the planned injection rate of over 1 million tons of $CO_2$ per year.

### Water Rights/Impacts

***Williston Basin Test***. Because this project is part of an enhanced resource recovery project, it can be assumed that all appropriate rights have been attributed to the partners of the project. EOR activities will have gone through the unitization process; therefore, requisite rights for injection will have been acquired. The unitization process has been completed in accordance with the North Dakota Century Code and corresponding rules contained in the NDAC.

***Fort Nelson Test***. In British Columbia, individuals typically do not own subsurface rights, including water rights; those rights are owned by the Crown and are managed and administered by the province. The EERC's partner is currently negotiating with the BCMEMPR, the provincial agency which administers mineral rights leases, to obtain the necessary rights to the pore space. Pore space includes mineral and water rights. It is anticipated that the acquisition of the necessary subsurface rights will be completed no later than the end of 2008.

### Liability

***Williston Basin Test***. Because this project is part of an enhanced resource oil project, liability for the project will be addressed through the regular course of business. EOR activities will have to comply with existing oil and gas rules; therefore, liability concerns are addressed through the issuance of surety or cash bonds. In addition, the injection formation will have completed the unitization process in accordance with North Dakota Century Code and corresponding rules contained in the NDAC. These codes and rules also address liability issues at ongoing hydrocarbon recovery sites.

***Fort Nelson Test***. It is anticipated that liability will be assigned according to the same rules that are applied to acid gas disposal into depleted gas reservoirs. This would indicate that the EERC's partner will assume liability for the project in accordance with the Oil and Gas Commission Act and the Petroleum and Natural Gas Act. These issues are addressed in part through comprehensive general liability insurance.

## SITE CHARACTERIZATION

### Williston Basin Test

The capacity estimates and predictions of plume size for the Williston Basin project described previously are based on a limited data set and should therefore be considered to be reconnaissance-level only. They are meant to illustrate the potential order-of-magnitude value of the target formation with respect to its injectivity and potential ultimate $CO_2$ storage capacity. The inherent heterogeneity found in nearly all geologic formations means that detailed subsurface mapping and characterization must be conducted in any area prior to large-scale injection of $CO_2$, particularly with respect to seal formations. The target formation and its overlying sealing formation at any site that is considered as the location for large-scale $CO_2$ injection operations must be thoroughly characterized at local, intermediate, and large scales in the early stages of the planning process. These early characterization activities are necessary to develop accurate predictions with respect to storage capacity and the ultimate fate of $CO_2$ within the target formation. The data from early characterization, in part, provide the baseline information necessary to design and conduct cost-effective MMV strategies.

Site characterization activities will be conducted to develop predictive models that address three critical issues to determine the ultimate effectiveness of the target formation: 1) the capacity of the target formation, in this case a unitized oil-producing reservoir within an established oil field; 2) the mobility and fate of the $CO_2$ at near-, intermediate-, and long-term time frames; and 3) the potential for leakage of the injected $CO_2$ into overlying formations and/or the surface environment. Key elements of the reservoir and seals that will be characterized are listed in Table 9.

Baseline site characterization will be accomplished using a wide variety of data sets. Previously conducted oil field exploration and operational activities are expected to provide significant baseline characterization data, but it is anticipated that new data sets will also have to be gathered to fill data gaps not adequately covered by the historical oil field data sets. The types of data that the PCOR Partnership anticipates will provide the basis for site characterization may include but are not necessarily limited to those shown in Table 10.

While it is anticipated that existing wells in the oil field will be available to serve as monitoring wells for the $CO_2$ injection test, it may be necessary to drill additional wells. The need to drill additional wells will be determined early in Year 1 of Phase III.

Data obtained and compiled as part of the baseline characterization will provide the basis for a variety of modeling activities. The primary components of the modeling will be the development of 1) a geological model that incorporates local (oil field), subregional (i.e., Cedar Creek, Nesson, or Billings Anticlines), and regional (Williston Basin) scale stratigraphy and

**Table 9. Key Site Characterization Parameters That Will Be Addressed During Phase III**

| Properties of Reservoir and Seal Rocks | Properties of Reservoir Fluids | Production and Operational History of the Oil Reservoir |
|---|---|---|
| Mineralogy | Oil | Oil production |
| Porosity | • Composition | Gas production |
| Permeability | • API gravity | Water production |
| Transmissivity | • Viscosity | Water injection |
| Geomechanical Properties | Water | Pressure and temperature |
| Geochemical Properties | • Salinity | Well stimulation activities |
| Oil/Water Saturation | • Geochemical properties | |
| | Gas | |
| | • Bulk and trace composition | |

**Table 10. Historical and New Data Sets Anticipated to Be Applied to Phase III Site Characterization**

| Anticipated Historic Data Sets | Anticipated New Data Sets |
|---|---|
| Core and Core Analyses | Advanced well logging |
| Well Logs | Reservoir fluid analyses |
| Reservoir Fluid Analyses | Fluid analyses from overlying formations |
| Fluid Analyses from Overlying Formations | Downhole tiltmeters |
| Seismic Surveys | Microseismic arrays |
| Other Geophysical Surveys | Cross-well geophysical |
| Aeromagnetic Surveys | Reservoir modeling |
| Reservoir Modeling | Aeromagnetic surveys |
| Aerial Photo Interpretation | Core and core analyses |
| | Airborne Interferometric Synthetic Aperture Radar (InSAR) |

architecture; 2) a hydrogeological model that operates at the local, subregional, and regional scales; and 3) a reservoir dynamics model for the selected reservoir. These models will provide the basis for developing MMV plans and conducting risk assessments that consider short-, intermediate-, and long-term effects of large-scale $CO_2$ injection.

## Fort Nelson Test

The inherent heterogeneity found in nearly all geologic formations means that detailed subsurface mapping and characterization must be conducted in any area where large-scale injection of $CO_2$ will take place, particularly with respect to seal formations. The target formation and its overlying sealing formation at the Fort Nelson site will be thoroughly characterized at local, intermediate, and large scales in the early stages of the planning process. These early characterization activities are necessary to develop accurate predictions with respect to storage capacity and the ultimate fate of $CO_2$ within the target formation. The data from early characterization also provide the baseline information necessary to design and conduct cost-effective MMV strategies.

The costs of baseline characterization will be influenced greatly by site-specific factors, including availability of historical data from previous oil and gas exploration activities and the costs of acquiring new data (i.e., geophysical surveys, drilling rigs for collecting new core), which typically vary from region to region. This makes it difficult to estimate the likely costs of thoroughly characterizing a location. However, some guidance with respect to the general magnitude of such costs are available in a published case study of the saline formation injection activities at Sleipner in Norway's North Sea. Specifically, it has been estimated that the total characterization costs incurred in the late 1990s prior to injection at Sleipner were approximately \$1.9 million. These costs included the gathering of existing data, a series of 3-D seismic surveys, collection and analysis of rock cores, well logging, and reservoir simulation modeling. It is important to note that northeastern British Columbia is one of the most remote regions of North America and is characterized by an extreme climate that limits the number of days available annually to conducted field-based data collection activities. It is, therefore, highly likely that the cost of conducting baseline characterization in the Fort Nelson area at a similar level to that which was applied at Sleipner will be considerably greater. A more detailed evaluation of the costs of geological characterization will be determined in Year 1 of Phase III. The finalization of a site characterization plan will be determined largely on the identified costs of applying characterization technologies into the Fort Nelson test.

## SITE DEVELOPMENT

### Williston Basin Test

Since our Williston Basin demonstration will be conducted as part of a commercial EOR operation, our commercial partners will be primarily responsible for the site development. The estimated injectivity of the various reservoirs summarized above suggests that two to eight vertical injection wells will be sufficient for meeting the injection target of 1 MMt $CO_2$ a year. If it is determined that a smaller volume of $CO_2$ will be injected annually (not to be less than 500,000 tons per year), then it is likely that a minimum of two injection wells will be employed to provide redundancy in the event one of the injectors experiences problems. Site development may include conducting a small-scale pilot test if feasible. It is anticipated that currently existing wells in the oil field will be used as injectors, producers, and monitoring wells, but the need for drilling new wells has not been dismissed. If existing wells are used for $CO_2$ injection, it is likely they will need to be reconfigured and possibly recompleted to accommodate supercritical $CO_2$.

Currently, there is no way to deliver supercritical $CO_2$ via pipeline to any fields that are not along the Nesson Anticline, which is served by the Great Plains Synfuels Plant pipeline. Therefore, for the purposes of planning and budgeting, it is anticipated that new pipeline and infrastructure will have to be constructed for the Phase III test. Because the operation will include an EOR component, it is also likely that, at some point in the operation (likely in the later years of Phase III), a considerable volume of $CO_2$ will be produced with the oil, requiring infrastructure and equipment for capturing, recompressing, and reinjecting the recycled $CO_2$. Thus site design may include capture and compression equipment for $CO_2$ processing, pumps for $CO_2$ injection and equipment for monitoring (e.g., pressure, temperature and strain gauges, and fluid sampling equipment). It is expected that both borehole and surface monitoring tools will be used along with wireline logging techniques. Use of tracers, fluid sampling, pressure, and deformation monitoring along with numerical modeling will be applied to definitively determine the subsurface area that will be affected by the injection.

### Fort Nelson

The injectivities of the reservoirs within the specific brine formations being considered for the Fort Nelson project are not publicly available, but the presence of large-scale acid gas disposal operations in the Fort Nelson area suggest that an injection rate goal of 1.8 million tons per year is attainable. It is likely that a minimum of two injection wells will be employed to provide redundancy in the event one of the injectors experiences problems. Site development may include conducting a small-scale pilot test if feasible. It is anticipated that new wells will have to be drilled for use as injectors and monitoring wells. It is anticipated that new pipeline and infrastructure will have to be constructed for the Fort Nelson $CO_2$ injection project. Site design may include compression and pumps for $CO_2$ injection and equipment for monitoring (e.g., pressure, temperature and strain gauges, and fluid sampling equipment). It is expected that both borehole and surface monitoring tools will be used along with the application of wireline logging techniques during the drilling of injection and monitoring wells. Use of tracers, fluid sampling, pressure, and deformation monitoring along with numerical modeling will be applied to definitively determine the subsurface area that will be affected by the injection.

## RISK ASSESSMENT AND MITIGATION STRATEGY

Table 11 briefly lists the risks associated with the different stages of the $CO_2$ sequestration process in any Williston Basin oil field. No attempt is made to list all the consequences of the events presented in the table (e.g., leakage can affect potable water quality; reactivation of faults can entail seismic activity, etc.). The strategies to quantify and mitigate the risks are also described in the table.

The PCOR Partnership has significant experience with monitoring and mitigating risks in its ongoing $CO_2$ sequestration demonstration projects in the Zama oil field in northwestern Alberta, Canada. The Zama demonstration project, which is primarily focused on the use of cost-effective baseline characterization and MMV for the purpose of monetizing carbon credits associated with geological storage, has recently been officially recognized by the Carbon Sequestration Leadership Forum for its effectiveness and merit. The philosophy behind the baseline characterization and MMV approach at Zama that has been recognized internationally will be applied to developing a cost-effective and technically rewarding strategy for risk assessment and mitigation.

It is anticipated that for large-scale demonstrations, a database of features, events, and processes distinct in the considered environment will be created. A numerical model of the reservoir will be created, and a sensitivity analysis will be performed with respect to the factors listed in the database. The analysis will allow for the quantification of the risks associated with the factors. The numerical model will be constantly updated basing on the results of the monitoring program. As the model is updated, risks will be reassessed to ensure safety of the operations and storage.

## MONITORING ACTIVITIES

The development and execution of effective MMV operations are a critical element in conducting large-scale injection projects. Successful MMV activities will result in data sets that verify that injection operations do not adversely impact human health or the environment and validate the sequestration of $CO_2$ for the purpose of developing and ultimately monetizing carbon credits. There is a broad range of technologies and approaches that have been applied to $CO_2$ sequestration projects of various scales around the world. Early geological sequestration research and demonstration projects focused on testing a wide variety of MMV strategies. The absence of experience required early projects to gather as much data as possible using a wide variety of techniques. In particular, a desire to visually represent the plume of injected $CO_2$ led to a strong emphasis on the use of geophysical data, especially 3-D and 4-D seismic, to monitor the plume. While geophysical-based approaches and techniques yielded valuable results in early projects that are essential to the development of geological sequestration as a $CO_2$ mitigation strategy, their high costs of deployment and often limited ability to identify $CO_2$ in many

**Table 11. Summary of Potential Risks Associated with Large-Scale Injection of $CO_2$**

| Project Phase | Associated Risks | Quantification and Mitigation Strategy |
|---|---|---|
| Site Development | | |
| | Problems with licensing and permitting | The program for site development will be reconsidered in the event of failure to obtain licenses and permits. The changes to the design can include but are not limited to revising the injection rates, the number of injection wells, and zonal isolation. |
| | Poor condition of the existing wellbores | All wells located in the vicinity of the injection site will be tested for well integrity and recompleted as necessary. |
| | Lower-than-expected injection rates | Basing on the results of the initial injection or a pilot test, reasonable injection rates will be determined. If actual injection rates do not meet the target, additional wells and/or pools will be added. |
| Operations | | |
| | Significant rates of vertical $CO_2$ migration<br>Activation of the preexisting faults and/or fractures<br>Substantial damage to the formation and/or caprock<br>Failure of the wellbores<br>Lower-than-expected injection rates<br>Damage to the adjacent oil fields and/or producing horizons | The monitoring program will allow for early warning regarding vertical migration, fault reactivation, and damage to the target or adjacent formations. If a warning is received, the injection program will be reconfigured. |
| | Failure of the wellbores | In the event of wellbore failure, the well will be recompleted or shut off. |
| | Lower-than-expected injection rates | Additional wells and/or pools will be included in the injection program. |
| Long-Term Storage | | |
| | Leakage through preexisting faults or fractures | The strategy of mitigating leakage through faults will be chosen depending on measured and/or anticipated rates of leakage. It can include but is not limited to decreasing formation pressure and treating the fractures with cement. |
| | Leakage through the wellbores | All wells in the vicinity of the injection site will be periodically tested. In case of leakage, wells will be recompleted and/or plugged. |

geologic settings will likely render them the exception rather than the rule when it comes to developing MMV plans for future projects.

If the deployment of large-scale $CO_2$ injection for geological sequestration is to become widespread, then MMV activities must be cost-effective. In many geological settings, expensive geophysical surveys are not viable centerpieces of MMV strategies. The use of existing data sets to develop background and baseline conditions should be maximized wherever possible. The use of invasive or disruptive technologies should be minimized to not only reduce costs, but also to limit the inadvertent development of leakage pathways through new boreholes.

Where sequestration is associated with EOR operations, it is also important that MMV activities have minimal impact on commercial injection and production operations. MMV activities need to be coordinated and integrated as much as possible with ongoing and planned oil field operations. An emphasis on the collection of reservoir dynamics and monitoring well data (including the use of tracers) in conjunction with routine well operation and maintenance activities can, in some geological settings, be an appropriate and cost-effective strategy for MMV. An emphasis on cost-effectiveness and integration with routine oil field activities is the driving philosophical basis for developing the MMV plan that will be implemented as part of the Phase III test.

At a minimum, the following techniques will be employed to monitor the effects of $CO_2$ injection at the Phase III site. The preinjection state of each of these parameters will be determined by site characterization activities, either through the evaluation of historical data or focused field activities to acquire new data:

- To monitor the $CO_2$ plume:
  - Reservoir pressure monitoring
  - Wellhead and formation fluid sampling (oil, water, gas)
  - Geochemical changes identified in observation or production wells

- To provide early warning of storage reservoir failure:
  - Injection well and reservoir pressure monitoring
  - Pressure and geochemical monitoring of overlying formations
  - Downhole geophysical monitors (passive microseismic and/or tiltmeters)

- To monitor injection well condition, flow rates, and pressures:
  - Wellhead pressure gauges
  - Well integrity tests
  - Wellbore annulus pressure measurements
  - Surface $CO_2$ measured near injector points and high-risk areas

- To monitor solubility and mineral trapping:
  - Formation fluid sampling using wellhead or deep well concentrations of $CO_2$
  - Major ion chemistry and isotopes

- To monitor for leakage into overlying formations through faults or fractures:
  - Reservoir and overlying formation pressure monitoring
  - Monitoring for tracers (e.g., perfluorocarbons)

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# APPENDIX D

# RESUMES OF KEY PERSONNEL

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Senior Research Advisor
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***Principal Areas of Expertise***
Mr. Steadman's principal areas of interest and expertise include environmental management, carbon sequestration, watersheds, sustainable development, chemical transformations during coal combustion, and materials science.

***Qualifications***
M.A., Geology, Summa Cum Laude, University of North Dakota, 1985.
B.S., Geology, Cum Laude, State University of Pennsylvania-Edinboro, 1982.

***Professional Experience***
**2003–Present:** Senior Research Advisor, EERC, UND. Mr Steadman's responsibilities include directing a multidisciplinary team of researchers on a carbon sequestration project in which detailed inventories of $CO_2$ sources, geologic and terrestrial sinks, and sequestration infrastructure were made; $CO_2$ capture and separation technologies were identified; monitoring, mitigation, and verification technologies and permitting requirements were investigated; and the most promising opportunities for carbon sequestration in nine states and four Canadian provinces were defined. Successfully increased sponsor participation in the program. Other responsibilities as Senior Research Advisor include development, marketing, management, and dissemination of market-oriented research; development of programs focused on the environmental and health effects of power and natural resource production, contaminant cleanup, water management, and analytical techniques; publication and presentation of results; client interactions; and advising EERC staff.

**1994–2002:** Associate Director for Research, EERC, UND. Mr. Steadman's responsibilities included developing and administering environmental programs involving water management and contamination cleanup and building industry–government– academic teams to carry out research, development, demonstration, and commercialization of environmental products and technologies.

**1988–1994:** Research Manager, EERC, UND. Mr. Steadman's responsibilities included research project management, coordination of research activities, inorganic analytical methods development, and preparation and presentation of research publications, reports, and proposals.

**1987–1988:** Instructor, Valley City State University. Mr. Steadman's responsibilities included teaching earth science, physical and historical geology, geomorphology, astronomy, and geography and supervising work-study students.

**1986–1987:** Research Associate, Energy and Mineral Research Center, UND. Mr. Steadman's responsibilities included conducting research into the chemical and physical mechanisms of coal combustion and the characterization of coal and coal ash, experimental design, and preparation of research publications, reports, and proposals.

**1985–1986:** Associated Western Universities Postgraduate Fellow. Mr. Steadman's responsibilities included writing research proposals and reports, mine sampling, and chemical analysis of coals and related strata throughout the western United States.

***Publications and Presentations***

Has authored or coauthored over 100 publications and professional presentations

**JOHN A. HARJU**
Associate Director for Research
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***Principal Areas of Expertise***
Mr. Harju's principal areas of interest and expertise include water management, waste management, environmental geochemistry, technology development, hydrology, and analytical chemistry, especially as applied to the upstream oil and gas industry.

***Qualifications***
B.S., Geology, University of North Dakota, 1986.
Postgraduate course work in Management, Economics, Marketing, Education, Climatology, Weathering and Soils, Geochemistry, Geochemical Modeling, Hydrogeochemistry, Hydrogeology, Contaminant Hydrogeology, Advanced Physical Hydrogeology, and Geostatistics.

***Professional Experience***
**2003–Present:** Associate Director for Research, EERC, UND. Mr. Harju's responsibilities include developing and administering environmental programs involving water management and contamination cleanup and building industry–government–academic teams to carry out research, development, demonstration, and commercialization of environmental products and technologies. In this capacity, he oversees the EERC's Red River Water Management Consortium (RRWMC®), a program to develop a long-term watershed management strategy for the Red River Basin focused on water quantity and quality, and the Plains $CO_2$ Reduction (PCOR) Partnership, a collaborative effort of public and private sector stakeholders working toward a better understanding of the technical and economic feasibility of capturing and storing anthropogenic $CO_2$ emissions from stationary sources in the central interior of North America.

**2002–2003**: Senior Research Advisor, EERC, UND. Mr. Harju's responsibilities included development, marketing, management, and dissemination of market-oriented research; development of programs focused on the environmental and health effects of power and natural resource production, contaminant cleanup, water management, and analytical techniques; publication and presentation of results; client interactions; and advisor to internal staff.

**1999–2002**: Vice President, Crystal Solutions, LLC, Laramie, Wyoming. Mr. Harju's firm was involved in commercial E&P produced water management, regulatory permitting and compliance, and environmental impact monitoring and analysis.

**2000–2002:** Principal Scientist, Produced Water Management, Gas Research Institute (GRI) (now Gas Technology Institute [GTI]), Chicago, Illinois. Mr. Harju's responsibilities included development and deployment of produced water management technologies and methodologies for cost-effective and environmentally responsible management of oil and gas produced water.

**1998–2000:** Program Team Leader, Soil, Water, and Waste, GRI/GTI, Chicago, Illinois. Mr. Harju's responsibilities included project and program management related to the development of environmental technologies and informational products related to the North American oil and gas industry; formulation of RFPs, proposal review, and contract formulation; technology transfer activities; and staff and contractor supervision. Mr. Harju served as Manager of the Environmentally Acceptable Endpoints project, a multiyear, $8MM effort focused on a rigorous determination of appropriate cleanup levels for hydrocarbons and other energy-derived contaminants in soils. He also led GRI/GTI involvement with numerous industry environmental consortia and organizations, including PERF, SPE, AGA, IPEC, and API.

**1997–1998:** Principal Technology Manager, Soil and Water Quality, GRI/GTI, Chicago, Illinois.

**1997:** Associate Technology Manager, Soil and Water Quality, GRI/GTI, Chicago, Illinois.

**1994–1996:** Senior Research Manager, Oil and Gas Group, EERC, UND. Mr. Harju's responsibilities included the following:
– Program Manager for program to assess the environmental transport and fate of oil- and gas-derived contaminants, focused on mercury and sweetening and dehydration processes.
– Project Manager for field demonstration of innovative produced water treatment technology using freeze crystallization and evaporation at oil and gas industry site.
– Program Manager for environmental transport and fate assessment of MEA and its degradation compounds at Canadian sour gas-processing site.
– Program Manager for demonstration of unique design for oil and gas surface impoundments.
– Director, National Mine Land Reclamation Center - Western Region.
– Co-Principal Investigator on project exploring feasibility of underground coal gasification in southern Thailand.
– Consultant to International Atomic Energy Agency for program entitled "Solid Wastes and Disposal Methods Associated with Electricity Generation Fuel Chains."

**1994:** Research Manager, EERC, UND.

**1990–1994:** Hydrogeologist, EERC, UND.

**1989–1990:** Research Specialist, EERC, UND.

**1988–1989:** Laboratory Technician, EERC, UND.

***Professional Memberships***
Rocky Mountain Association of Geologists

***Publications and Presentations***
Has authored and coauthored numerous publications

**JAMES A. SORENSEN**
Senior Research Manager
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***Principal Areas of Expertise***
Mr. Sorensen's principal areas of interest and expertise include research program management, subsurface transport and fate of organic and inorganic contaminants associated with the natural gas industry, hydrogeologic data reduction and interpretation, technical report writing and presentations, and hydrogeology-related fieldwork.

***Education***
B.S., Geology, University of North Dakota, 1991.
Postgraduate course work in Hydrogeology, Advanced Geomorphology, Groundwater Monitoring and Remediation, Geochemistry, and Contaminant Hydrogeology, 1993–1995
NGWA workshop on Risk-Based Corrective Action, 1995
40-Hour OSHA Training for Hazardous Waste Site Personnel, 1998 (refresher course, 1999)

***Professional Experience***
**1999–Present:** Senior Research Manager, EERC, UND. Mr. Sorensen currently serves as manager and coprincipal investigator for several research programs, including a 3-year, $1.2 million program focused on the subsurface environmental fate and remediation of natural gas processing wastes. Responsibilities include supervision of research personnel, preparing and executing work plans, budget preparation and management, writing technical reports and papers, presentation of work plans and results at conferences and client meetings, interacting with clients and industrial contacts, and proposal writing and presentation.

**1997–1999:** Program Manager, EERC, UND. Mr. Sorensen managed projects on topics that included treatment of produced water, environmental fate of mercury, and gas methane hydrates. He cochaired the Workshop on Environmental Issues Related to Gas Sweetening Alkanolamines, sponsored by Gas Research Institute and the U.S. Department of Energy, in Calgary, Alberta, Canada, April 28–29, 1998.

**1993–1997:** Geologist, EERC, UND. Mr. Sorensen conducted a variety of field-based hydrogeologic investigations throughout the United States and Canada. Activities were primarily focused on evaluating the subsurface transport and fate of mercury associated with natural gas production sites. Other research topics included the subsurface transport and fate of natural gas processing wastes and agricultural chemicals.

**1991–1993:** Research Specialist, EERC, UND. Mr. Sorensen assembled and maintained comprehensive databases related to oil and gas drilling, production, and waste management.

***Professional Memberships***
Society of Petroleum Engineers

***Publications and Presentations***
Has coauthored numerous publications

**STEVEN A. SMITH**
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***Principal Areas of Expertise***
Petroleum drilling and production, sequestration of carbon dioxide in geologic reservoirs, evaluation of geologic provinces with respect to $CO_2$ sequestration.

***Qualifications***
B.S., Geology, University of North Dakota, 2001

***Professional Experience***
**2004–Present:** Research Scientist, EERC, UND. Mr. Smith's responsibilities include developing and maintaining a database of oil-bearing geologic reservoir characteristics as they pertain to $CO_2$ sequestration in nine states and four Canadian provinces; evaluating geologic formations and determining their potential for $CO_2$ sequestration; determining and reevaluating the $CO_2$ storage capacity within oil bearing and saline strata; planning and designing methods to interact with a Web-enabled geographic information system interface for the analysis of research data; oversee the development of deliverable products for U.S. Department of Energy carbon sequestration project; and assisting in the preparation of proposals and topical reports.

**2001–2003:** Well Site Geologist, Subcontractor, Baker, Montana. Mr. Smith's responsibilities included overseeing all of the oil company's interests, with respect to the geologic decisions on location; preparing morning report and geologic strip logs to summarize well progression; directing interaction with oil company upper management; evaluating sample cuttings, gas, and drill times while project well was drilling; performing structural geologic correlation with offset wells; and working in close communication with directional driller and rig crew to maintain accuracy in completion of well.

**1994:** Staff Geologist Intern, R.E. Wight Associates, Inc., Middletown, Pennsylvania. Mr. Smith's responsibilities included system checks and operation at groundwater remediation sites, hazardous materials sampling and preparation, well purging, sampling, and recharge calculations.

***Publications and Presentations***
Has coauthored several publications

**TERRY BAILEY**
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***Principal Areas of Expertise***
Mr. Bailey has over 30 years of industry experience in oil and gas exploration and development activities.

***Qualifications***
M.S., Geology, University of Colorado, 1977.
B.S., Geology, University of North Dakota, 1970.

***Professional Experience***
**July 2007–Present:** Research Scientist, EERC, UND, Grand Forks, North Dakota. Mr. Bailey is currently working with the Plains $CO_2$ Reduction (PCOR) Partnership at the EERC developing petrophysical models of the subsurface to determine geologic geometries, formation parameters, and storage volumes and their relationship to $CO_2$ sequestration.

**February–June 2007:** Earth Science Adviser, PPI Technology Services Nigeria Ltd., Mr. Bailey was contracted to Chevron Oil Company's Nigeria Mid-Africa Business Unit, Lagos, Nigeria, where he estimated original gas in place (OGIP) and created a depletion plan for the Awodi Field, one of several gas fields comprising the Nigerian Olakola liquefied natural gas (LNG) project. His work included 3D seismic interpretation, structure and isopach mapping, risk assessment, determining optimum development well locations, and selecting the logging (wire-line or MWD), coring, and testing programs for these wells.

**March–June 2006:** Geologist, Swift Technical Services LLC. Mr. Bailey was contracted to Chevron Oil Company's Nigeria Mid-Africa Business Unit, Houston, Texas, where he determined optimum development plans for several Chevron gas fields making up the Nigerian Olakola LNG project. Olakola is one of the largest LNG projects in the world, and Chevron's project design calls for delivering 2.3 billion cu ft of gas a day to the LNG plants. The development plans included determining the number and locations of wells required to optimally drain reserves and selecting the logging (wire-line or MWD), coring, and testing programs for these wells.

**January–March 2006:** Consultant Geologist, Syntroleum Corporation – Houston, Texas. Mr. Bailey provided geologic evaluation and risk assessment of development options for two relinquished lease concessions in Nigeria, Africa (Ibigywe and Ajapa discoveries). His work included seismic interpretation, construction of structure (top and base of sand), net sand isopach and net oil isopach maps, and volumetric estimation of original oil in place (OOIP) and OGIP.

**2002–2005:** Geologist, Reservoir Management Team, Chevron Nigeria Mid-Africa Business Unit, Houston, Texas. Mr. Bailey completed geological studies of Chevron's major oil and gas reservoirs in onshore ("swamp" area) and offshore Nigeria. These studies were conducted to determine primary development and infill drilling locations, assess field deepening opportunities, and evaluate secondary recovery potential. Reservoirs studied are located in the Makaraba, Abiteye, Okan, Meji, and Sonam Fields. The studies included:

- Geological evaluation (well to well correlations, 3D seismic interpretation, structure, and isopach mapping) utilizing Landmark (primarily SeisWorks and StratWorks), VoxelGeo, and proprietary Chevron geological and geophysical applications.
- Construction of earth models using GOCAD software.
- Determination of OOIP and OGIP (reservoir reserve size 10 MM to 140 MM OEG).
- Identification of drill locations.
- Documentation and presentation of results.

Mr. Bailey also provided geologic exhibits of studied reservoirs (primarily structure and isopach maps) to auditors for reserve certification and mentored other earth scientists in the construction of GOCAD faulted S grids.

**1998–2002:** Senior Staff Earth Scientist, CalTex Petroleum Corporation, Duri, Indonesia.

- Mr. Bailey completed integrated geological interpretations of Central Sumatra Basin oil fields (reserve size 10 MMBO to 750 MMBO OOIP) under the jurisdiction of the Petani Asset Management Team (AMT) and utilized Geoframe (including IESX, Stratlog, and CPS3) and Voxel Geo interpretation workstation applications.
- He constructed geologic models of major assets using GOCAD software applications and assisted in reservoir simulation studies. He utilized GOCAD and "real time" LWD data from horizontal wells to "steer" well paths to optimum target reservoir locations.
- Mr. Bailey identified areas of bypassed oil opportunities in mature assets and proposed development drill locations (including high angle slant, horizontal, and vertical wells) to maximize reserve recovery and provided well site duty on critical wells. Petani AMT Earth science champion for horizontal wells. Number of horizontal wells drilled by Petani AMT increased from one in 1998 to 11 in 2000. Production from these horizontal wells averages three times that of typical vertical well.
- He used Geolog for formation evaluation of electric logs, recommended initial completion intervals and identified workover opportunities.
- Mr. Bailey mentored national earth scientists in sequence stratigraphic concepts, structure mapping, application of horizontal well technology, and use of quality control techniques to verify geologic interpretations. He used strong teamwork skills to become a valued member of all national AMT.

**1988–1998:** Staff Geologist and Senior Development Geologist, Chevron Production Company, Lafayette, Louisiana.

- Mr. Bailey utilized subsurface geological and geophysical data to optimize Gulf of Mexico oil and gas fields (High Island, West Cameron, East Cameron and Vermilion Areas) economics by recommending successful drill locations and well work-over potential. He used Landmark (including Seisworks 2D and 3D, Seiscube, Syntool, Stratworks), Voxel Geo, and Coherency Cube software to generate comprehensive and accurate maps. Mr. Bailey also incorporated sequence and parasequence stratigraphy concepts into interpretations and applied his knowledge of geochemistry, Allan mapping, and smear/gouge ratios to assess fault seal capacities.

- He supervised electric logging operations offshore GOM.
- Mr. Bailey served as lead trajectory analysts on Chevron's West Cameron Profit Center's Oil Spill Response Team. This position required proficient use of World Wide Oil Spill computer model and Hazwoper (Hazardous Waste Operations) certification.
- He evaluated farm-in/farm-out opportunities and monitored offset lease activity.
- Mr. Bailey was also involved with field sales and alternate funding efforts

**1982–1988:** Senior Geologist, Tenneco Oil Company, Lafayette, Louisiana. Mr. Bailey used geological and geophysical data to generate interpretations necessary for the development (new drills/workovers/re-completions) of oil and gas fields in the South Pass and Ship Shoal areas of the GOM. He supervised offshore electric logging operations and evaluated well logs in assigned areas. Mr. Bailey also evaluated and made recommendations for leasing of acreage offsetting assigned fields and evaluated "transition zone" acreage in the South Pass and Main Pass areas for lease acquisitions.

**1981–1982:** Consultant Geologist, Rego Associates, Williston, North Dakota. Mr. Bailey represented clients as well the site geologist; examined well cuttings, prepared sample lithology description logs, recorded and reported shows, recommended core and DST intervals, described cores, and evaluated electric well logs. He evaluated acreage for acquisition/drill/farm-in.

**1980–1981:** Development Geologist, Amerada Hess Corporation, Williston, North Dakota. Mr. Bailey worked in well site geology. He examined and described well cuttings, reported shows, recommended core and DST zones, described cores, and recommended drill locations.

**1976–1980:** Geological Engineer, Shell Oil Company, New Orleans, Louisiana. Mr. Bailey proposed over 30 development drill locations in several offshore GOM gas fields (High Island, Sabine, & East Cameron areas) with cumulative recoverable reserves of 550 BCF. His success rate was 94% from these drills. Mr. Bailey also represented Shell at field unitization determinations.

***Professional Memberships***

- American Association of Petroleum Geologists, Certified Petroleum Geologist
- Lafayette Geological Society Second Vice President 1997–1998

**CHARLES D. GORECKI**
Research Scientist
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***Principal Areas of Expertise***
Mr. Gorecki's principal areas of interest and expertise are reservoir engineering and $CO_2$ sequestration.

***Qualifications***
B.S., Geological Engineering, University of North Dakota, 2007.
**Relevant Course Work**
Reservoir Engineering
– Worked with the Eclipse Simulators and gained a basic knowledge of the software.
– Gained a general understanding of oil and gas reservoir characteristics.
Senior Design
– Modeled the Shell Golden 34X-34 pinnacle reef in North Dakota to determine the potential for $CO_2$ sequestration and enhanced oil recovery.
Geological Engineering Field Camp
– Gained valuable experience characterizing and mapping rock units in the field.
– Analyzed field data and interpreted the results in technical reports.
Geomechanics
– Determined in situ stresses in rock units for underground excavations.
– Worked with equipment used to determine compressive strength, point load index, slake durability, permeability, and porosity.
Geophysics
– Used a gravimeter to determine variations in local gravity fields.
– Measured local variations in the magnetic field using a Proton-Procession Magnetometer.
– Used seismic readings to determine the orientation and density of underlying rock materials.

***Professional Experience***
**2007–Present:** Research Scientist, EERC, UND. Mr. Gorecki is currently working with the Plains $CO_2$ Reduction (PCOR) Partnership at the EERC on developing models to describe the behavior of $CO_2$ prior to injection into saline aquifers and oil fields.

***Military Experience***
**2003–2006:** Specialist, North Dakota Army National Guard. Mr. Gorecki was deployed as a Combat Engineer to Iraq from February 2004 to March 2005.
– Served as Combat Lifesaver, Gunner, and Team Leader.
– Operated specialized equipment to find and destroy Improvised Explosive Devices.
– Received the Bronze Star and Army Commendation Medal for actions taken during combat operations in Iraq.

– Acted as Team Leader for 2 months on Base Reaction Force; duties included responding to and coordinating responses to immediate threats.
– Honorably discharged on June 22, 2006.

**1997–2003:** Minnesota Army National Guard
– Promoted to Corporal and Team Leader in 2000.
– While Team Leader, commanded an armored personnel carrier.
– Conducted marksmanship training.
– Received Army Achievement Medal during annual training in 2002 for exceptional performance.

***Professional Memberships***
Delta Waterfowl, Committee Member Kelly's Slough Chapter

**DR. ANASTASIA A. DOBROSKOK**
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***Principal Areas of Expertise***
Dr. Dobroskok's principal areas of interest and expertise include rock mechanics, reservoir engineering, numerical modeling, computational fracture mechanics, and fluid mechanics.

***Qualifications***
Ph.D., Mechanical Engineering, Institute for Problems of Mechanical Engineering (IPME), St. Petersburg, Russia, 2003.
M.S., Mechanical Engineering, St. Petersburg State Technical University, Russia, 1996.

***Professional Experience***
**2005–Present:** Research Engineer, EERC, UND. Dr. Dobroskok's responsibilities include providing technical support, performing literature research, conducting research in the area of computational mechanics applied to reservoir engineering; preparing proposals; reporting results, and publishing and presenting findings.

**2003–2005:** Research Scholar, UND. Dr. Dobroskok's responsibilities included conducting research in the area of fracture and solid mechanics; creating methods and computer codes supporting the research program; reporting results to funding agencies; publishing papers; and presenting findings at conferences.

**1999–2003:** Research Scientist, IPME. Dr. Dobroskok's responsibilities included conducting research in the area of solid and fracture mechanics and material science; providing teaching assistance for material science and numerical methods classes); writing proposals and preparing cost estimates for submission; reporting results to funding agencies; publishing papers; and presenting findings at conferences.

**1996–1999:** Software Engineer, Rante Ltd. St. Petersburg, Russia. Dr. Dobroskok's responsibilities included adapting existing software package to meet accounting needs; developing reporting systems in MS Access; and training staff in utilizing computer software.

**1993–1994:** Software Developer, Institute for Rock Mechanics and Mining. St. Petersburg, Russia. Dr. Dobroskok's responsibilities included creating a computer code to conduct numerical simulations of rock behavior and creating an interface to simplify procedures.

***Publications and Presentations***
Has authored and coauthored numerous publications.

**ERIN M. O'LEARY**
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***Principal Areas of Expertise***
Ms. O'Leary's principal areas of interest and expertise include management of projects that involve building databases and PC- and Web-based programs for engineering and scientific applications and information systems, including business analysis, data modeling, application design, and software development.

***Qualifications***
B.A., Business Administration, University of North Dakota, 1988.

***Professional Experience***
**2002–Present:** Senior Research Manager, Research Information Systems, EERC, UND. Ms. O'Leary is responsible for developing proposals, securing clients, conducting research, managing research projects with multidisciplinary technical staff, building databases and PC- and Web-based software applications for engineering and scientific projects, writing technical reports, and managing the Research Information Systems Group, a team of programmers and database administrators developing PC and Web-based databases and applications for research projects and for internal business functions of the EERC.

**1996–2002:** Manager, Information Systems, EERC, UND. Ms. O'Leary's responsibilities included management of the Information Systems Group and the Resource Management Group. These groups are responsible for developing and implementing database management systems, providing mainframe computer services, providing project management support for principal investigators, and providing personnel planning and financial projections.

**1994–1996:** Information Technology Manager, EERC, UND. Ms. O'Leary's responsibilities included evaluating, designing, implementing, and maintaining database management systems in support of research projects. In addition, duties included program development and demonstration of the database management capabilities to potential clients.

**1989–1993:** Research Specialist, Combustion Studies, EERC, UND. Ms. O'Leary's responsibilities included information management, network administration, project budget planning and tracking, database development and maintenance, advanced data transfer, and manipulation programming.

**1988–1989:** Research Technician, Combustion Studies, EERC, UND. Ms. O'Leary's responsibilities included assisting with budget monitoring, maintaining a database for sample tracking, assisting in data reduction, and performing literature searches.

**1983–1988:** Intake Technician, Northeast Human Service Center, Grand Forks, North Dakota. Ms. O'Leary's responsibilities included maintaining the ARIS computer system, tracking client information and staff time, assisting in budget preparation, and developing computer format and procedures for statistical reporting.

**1988:** Internship, Records and Forms Administration, 3M Center, St. Paul, Minnesota. Ms. O'Leary's responsibilities included training in records administration, micrographics, forms administration, records center archiving and retrieval systems, and corporate archiving.

***Publications and Presentations***
Has authored or coauthored numerous publications and presentations.

**MELANIE D. JENSEN**
Research Engineer
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***Principal Areas of Expertise***

Ms. Jensen's principal areas of interest and expertise include high-pressure/high-temperature processes; production of fuels from renewables; carbon sequestration; environmental/waste cleanup technologies; adsorption system design and operation; low-temperature plasma technologies; photocatalytic processes; statistical experimental design, evaluation, and subsequent modeling; development of quality assurance/quality control (QA/QC) programs; and technical communication.

***Education***

B.S., Chemical Engineering, University of North Dakota, 1983.
B.A., Anthropology, University of North Dakota, 1978.

***Professional Experience***

**1985–Present:** Ms. Jensen performs research in the areas of reaction engineering, coal combustion, reburning, carbon sequestration, hazardous waste treatment, gas-phase particulate and mercury collection, photocatalytic processes, fuel production from biomass, contaminated water cleanup, and phytoremediation. She designs, develops, operates, and/or evaluates complex processes and equipment, including high-pressure/high-temperature coal conversion systems, low-temperature plasma systems, and multicolumn sorption systems. She evaluates and compares various characterization, remediation, and decontamination technologies for application to waste treatment and cleanup programs. She identifies promising carbon sequestration opportunities by matching major sources with applicable $CO_2$ separation and capture technologies and nearby geologic and/or terrestrial sinks. Ms. Jensen tracks, reduces, and interprets data generated during research projects. She develops statistically designed experimental matrices, analyzes the results, and derives models describing system behavior. Ms. Jensen also develops integrated, multiproject programs to meet both the immediate and long-term needs of clients; prepares or assists with the preparation of proposals and supporting documentation; develops comprehensive QA/QC plans; and prepares patent applications. Her project management activities include detailed program planning; scheduling of equipment and personnel, budget monitoring, maintenance of project schedules, preparation of reports, papers, and presentations; and communicating with clients. Ms. Jensen disseminates results to a variety of audiences through the preparation of technical reports, peer-reviewed papers/journal articles, and posters and slide presentations.

***Publications and Presentations***

Has authored or coauthored numerous publications

***Patents***

Rindt, J.R.; Hetland (Jensen), M.D. Direct Coal Liquefaction Process. U.S. Patent No. 5256278, October 26, 1993.

**DANIEL J. DALY**
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***Principal Areas of Expertise***
Mr. Daly's principal areas of interest and expertise include energy and environmental education, sustainable development, the evolution of energy and environmental policy, waste management for the energy industry and the nuclear defense complex, and the geology and hydrogeology of the northern Great Plains.

***Qualifications***
M.S., Geology, University of North Dakota, 1984.
B.A., Earth Science, New Mexico Highlands University, 1974.

***Professional Experience***
**1985–Present:** Research Manager/Geologist, EERC, UND.
- Fall 2003 – Present: Manager for outreach and education task under the Plains CO2 Reduction Partnership (Clients: U.S. Department of Energy and more than 30 government and industry stakeholders in the United States and Canda).
- Fall 1999 – Present: Management and program building as Coordinator of the Red River Valley Clean Cities (RRVCC) Coalition (Clients: U.S. Department of Agriculture, U.S. Department of Energy [DOE] and regional stakeholders).
- 1995–2003: Part of the management team for the Cooperative Agreement providing technical support for the development of innovative technologies to aid in nuclear complex cleanup under the DOE Environmental Management Program (Client: DOE).
- 1992–1995: Management of national-level assessment of waste generation and shallow subsurface environmental issues related to gas industry exploration and production. (Clients: GTI and DOE).
- 1989–1998: Tracking and assessment of government policy and regulatory actions in support of strategic planning.

**1975–1984:** Project-based appointments with the North Dakota Geological Survey, UND's North Dakota Mining and Mineral Resources Research Institute, and UND's Engineering Experiment Station on investigations of 1) environmental issues related to coal mining and coal conversion waste management and 2) geology and hydrology of the northern Great Plains Williston Basin region.

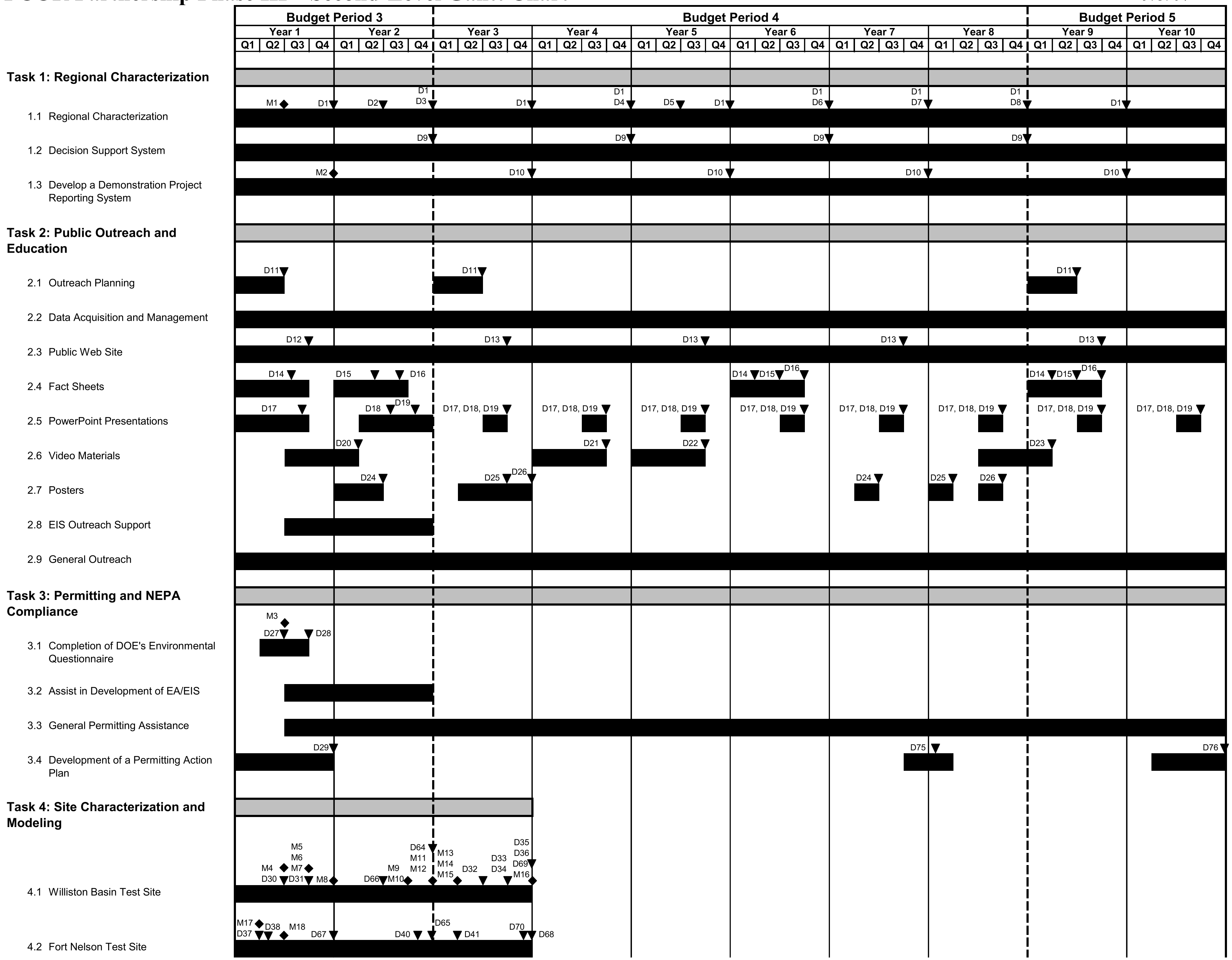
***Publications and Presentations***
Has authored or coauthored over 80 publications

# APPENDIX E

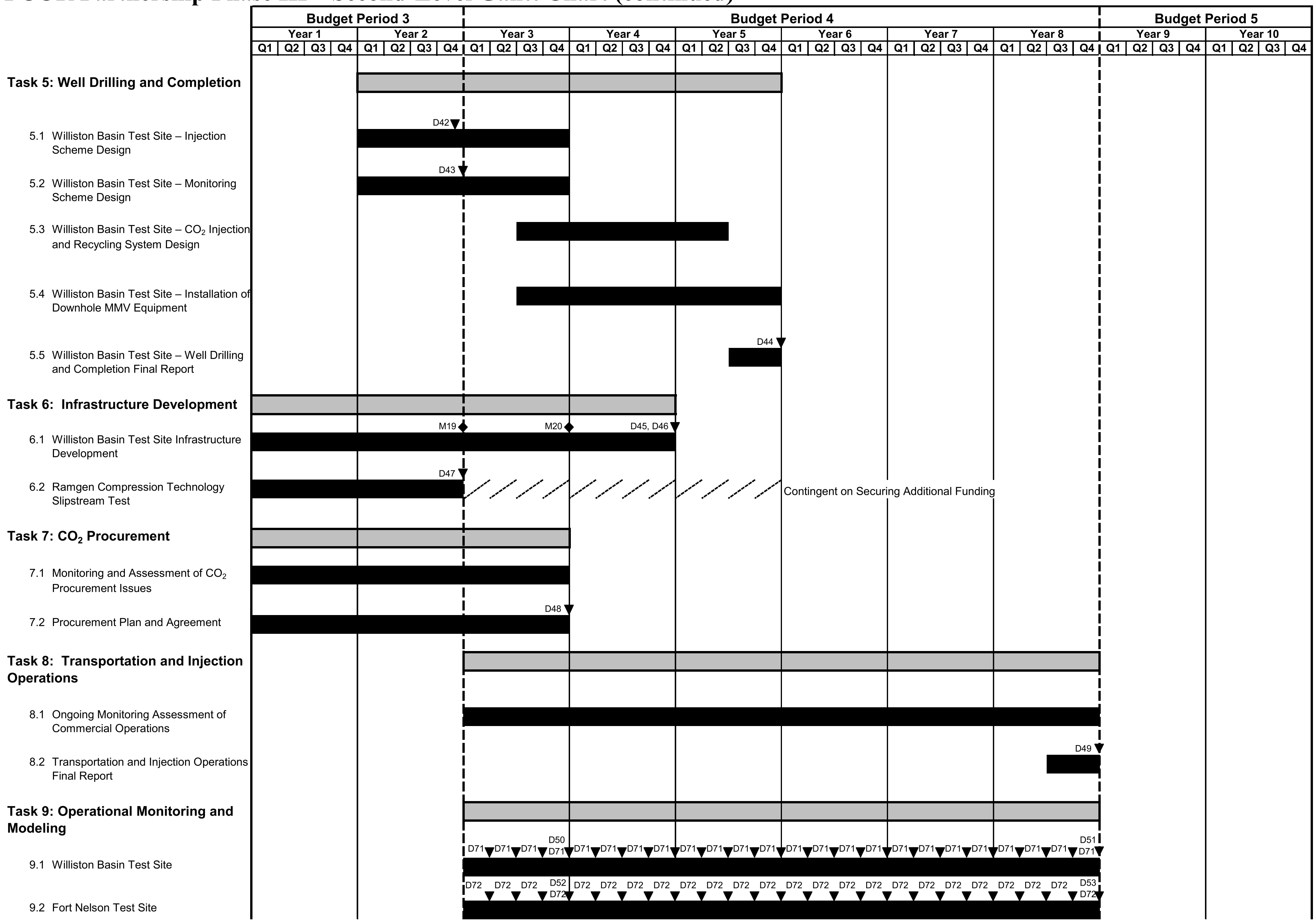
# TIMETABLE

# PCOR Partnership Phase III – Second-Level Gantt Chart

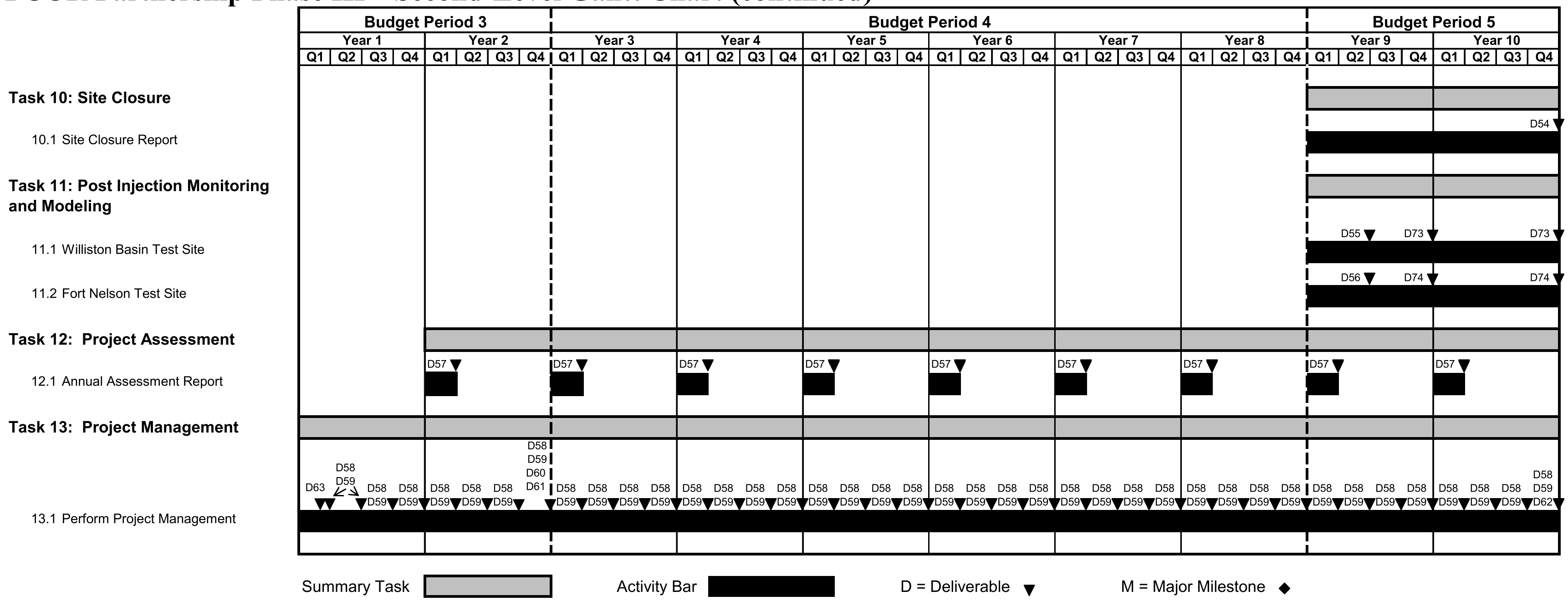
9/5/07



# PCOR Partnership Phase III – Second-Level Gantt Chart (continued)



# PCOR Partnership Phase III – Second-Level Gantt Chart (continued)




**Key for Deliverables**

D1 Review of Source Attributes
D2 First Target Area Completed
D3 Permitting Review – One State and One Province
D4 Permitting Review – Two Additional States
D5 Second Target Area Completed
D6 Permitting Review – Three State and Two Provinces
D7 Third Target Area Completed
D8 Permitting Review – Three State and One Province
D9 Updated DSS
D10 DPRS Update
D11 Outreach Plan
D12 Demonstration Web Pages on the Public Site
D13 Public Site Updates
D14 General Phase III Fact Sheet
D15 Williston Basin Test Site Fact Sheet
D16 Fort Nelson Test Site Fact Sheet
D17 General Phase III Information PowerPoint Presentation
D18 Williston Basin Test Site PowerPoint Presentation
D19 Fort Nelson Test Site PowerPoint Presentation
D20 Video Support to PowerPoint and Website
D21 Williston Basin Test Site 15-Minute Video
D22 Fort Nelson Test Site 15-Minute Video
D23 Sequestration in Carbon Management – 30-Minute Video
D24 PCOR Region Sequestration General Poster
D25 Williston Basin Test Site Poster
D26 Fort Nelson Test Site Poster
D27 Environmental Questionnaire – Fort Nelson Test Site
D28 Environmental Questionnaire – Williston Basin Test Site
D29 Permitting Action Plan
D30 Williston Basin Test Site – Geomechanical Experimental Design Package
D31 Experimental Design Package Williston Basin Test Site Geological Characterization
D32 Williston Basin Test Site – Geomechanical Final Report
D33 Williston Basin Test Site – Geochemical Final Report
D34 Williston Basin Test Site – Baseline Hydrogeological Final Report
D35 Williston Basin Test Site – Best Practices Manual - Site Characterization
D36 Williston Basin Test Site – Wellbore Leakage Final Report
D37 Fort Nelson Test Site – Site Geological Characterization Experimental Design Package
D38 Fort Nelson Test Site – Geotechnical Experimental Design Package
D40 Fort Nelson Test Site – Geomechanical Final Report
D41 Fort Nelson Test Site – Geochemical Final Report
D42 Williston Basin Test Site – Injection Experimental Design Package
D43 Williston Basin Test Site – Monitoring Experimental Design Package
D44 Williston Basin Test Site – Drilling and Completion Activities Final Report
D45 Topical Report on the Integrated Capture Plant and its Shakedown
D46 Topical Report on Pipeline Route Selection, Design, and Construction
D47 Topical Report on the Preliminary Design of Advanced Compression Technology
D48 Procurement Plan and Agreement Report
D49 Transportation and Injection Operations Final Report
D50 Williston Basin Test Site – Site Characterization, Modeling, and Monitoring Plan
D51 Williston Basin Test Site – Monitoring for $CO_2$, EOR, and Sequestration Best Practices Manual
D52 Fort Nelson Test Site – Site Characterization, Modeling, and Monitoring Plan
D53 Fort Nelson Test Site – Monitoring for $CO_2$ Sequestration in a Brine Formation Best Practices Manual
D54 Site Closure Report
D55 Report on Cost-Effective Long-Term Monitoring Strategies for the Williston Basin Test Site
D56 Report on Cost-Effective Long-Term Monitoring Strategies for the Fort Nelson Test Site
D57 Project Assessment Annual Report
D58 EVM Quarterly Report
D59 Milestone Quarterly Report
D60 Site Development, Operations, and Closure Plan
D61 Site Commercialization Plan
D62 Final Report
D63 Project Management Plan
D64 Williston Basin Test Site – Site Characterization Report
D65 Fort Nelson Test Site – Site Characterization Report
D66 Williston Basin Test Site – Simulation Report
D67 Fort Nelson Test Site – Simulation Report
D68 Fort Nelson Test Site – Best Practices Manual – Site Characterization
D69 Williston Basin Test Site – Best Practices Manual – Simulation Report
D70 Fort Nelson Test Site – Best Practices Manual – Simulation Report
D71 Williston Basin Test Site – Quarterly Summary of Operations
D72 Fort Nelson Test Site – Quarterly Summary of Operations
D73 Williston Basin Test Site – Progress Report on Monitoring and Modeling Fate of $CO_2$
D74 Fort Nelson Test Site – Progress Report on Monitoring and Modeling Fate of $CO_2$
D75 Updated Permitting Action Plan
D76 Best Practices Manual - Permitting

**Key for Milestones**

M1 Three Target Areas Selected
M2 DPRS Prototype
M3 Start Environmental Questionnaire for Williston Basin Test Site
M4 Williston Basin Test Site Selected
M5 Data Collection Initiated for Williston Basin Test Site
M6 Williston Basin Test Site Geochemical Work Initiated
M7 Williston Basin Test Site Geological Characterization Data Collection Initiated
M8 Williston Basin Test Site Wellbore Leakage Data Collection Initiated
M9 Williston Basin Test Site B-Version Geological Model Development Initiated
M10 Williston Basin Test Site Wellbore Leakage Data Collection Completed
M11 Williston Basin Test Site Baseline Hydro Data Collection Completed
M12 Williston Basin Test Site Geochemical Work Completed
M13 Williston Basin Test Site B-Version Geological Model Development Completed
M14 Williston Basin Test Site Geological Characterization Data Collection Completed
M15 Williston Basin Test Site Baseline Hydro B-Model Completed
M16 Williston Basin Test Site Final Geological Model Development Completed
M17 Fort Nelson Test Site Selected
M18 Fort Nelson Test Site Geochemical Work Initiated
M19 Capture, Dehydration, and Compression Technology Selected
M20 Capture, Dehydration, and Compression Technology Design Completed

# APPENDIX F

# BUDGET AND BUDGET NOTES

PCOR PARTNERSHIP PHASE III
EERC PROPOSAL #2008-0119

**BUDGET - YEAR ONE**

| CATEGORY | | TOTAL | | OTHER COST SHARE | | NDIC LIGNITE SHARE | | DOE SHARE |
|---|---|---|---|---|---|---|---|---|
| **TOTAL DIRECT HRS/SALARIES** | 40,144 | 1,147,148 | 5,144 | 104,000 | 10,497 | 277,913 | 24,503 | 765,235 |
| **TOTAL FRINGE BENEFITS** | | 542,769 | | 35,922 | | 123,799 | | 383,048 |
| **TOTAL LABOR** | | 1,689,917 | | 139,922 | | 401,712 | | 1,148,283 |
| **TRAVEL** | | 120,567 | | 13,184 | | 21,946 | | 85,437 |
| **EQUIPMENT > $5000** | | 6,000 | | - | | - | | 6,000 |
| **SUPPLIES** | | 46,034 | | 6,534 | | 14,800 | | 24,700 |
| **SUBCONTRACT - (Unspecified) Geological Survey #1** | | 40,000 | | - | | - | | 40,000 |
| **SUBCONTRACT - (Unspecified) Geological Survey #2** | | 40,000 | | - | | - | | 40,000 |
| **SUBCONTRACT - PRAIRIE PUBLIC TELEVISION** | | 35,000 | | - | | - | | 35,000 |
| **SUBCONTRACT - (Unspecified) Acquisition of Baseline Data** | | 160,000 | | - | | 160,000 | | - |
| **SUBCONTRACT - (Unspecified) Core Collection** | | 100,000 | | - | | - | | 100,000 |
| **SUBCONTRACT - (Unspecified) Hydrogeological Eval** | | 80,000 | | - | | 80,000 | | - |
| **SUBCONTRACT - MELZER CONSULTING** | | 50,000 | | - | | - | | 50,000 |
| **SUBCONTRACT - RAMGEN** | | 100,000 | | - | | - | | 100,000 |
| **FEE - EIS (TO DOE - NO FNA)** | | 1,500,000 | | - | | - | | 1,500,000 |
| **COMMUNICATION - PHONES & POSTAGE** | | 5,828 | | 216 | | 849 | | 4,763 |
| **OFFICE (PROJECT SPECIFIC SUPPLIES)** | | 10,756 | | 400 | | 926 | | 9,430 |
| **FOOD** | | 3,000 | | - | | 500 | | 2,500 |
| **OPERATING FEES & SVCS** | | | | | | | | |
| Natural Materials Analytical Res. Lab. | | 12,524 | | - | | 12,524 | | - |
| GC/MS Lab. | | 66,579 | | - | | 66,579 | | - |
| Graphics Support | | 38,386 | | - | | 2,500 | | 35,886 |
| Outside Lab. | | 70,000 | | - | | 70,000 | | - |
| Freight | | 5,100 | | - | | 5,100 | | - |
| **TOTAL DIRECT COST** | | 4,179,691 | | 160,256 | | 837,436 | | 3,181,999 |
| **FACILITIES & ADMIN. RATE - % OF MTDC** | VAR | $ 1,157,809 | 56% | $ 89,744 | 56% | $ 362,564 | 50% | $ 705,501 |
| **TOTAL** | | $ 5,337,500 | | $ 250,000 | | $ 1,200,000 | | $ 3,887,500 |
| **IN-KIND SUPPORT** | | 2,988,606 | | 2,988,606 | | - | | - |
| **TOTAL PROJECT** | | $ 8,326,106 | | $ 3,238,606 | | $ 1,200,000 | | $ 3,887,500 |

Due to limitations within the University's accounting system, bolded budget line items represent how the University proposes, reports and accounts for expenses.
Supplementary budget information, if provided, is for proposal evaluation.

PCOR PARTNERSHIP PHASE III
EERC PROPOSAL #2008-0119

**BUDGET - YEAR TWO**

| CATEGORY | | TOTAL | | OTHER COST SHARE | | NDIC LIGNITE SHARE | | DOE SHARE |
|---|---|---|---|---|---|---|---|---|
| **TOTAL DIRECT HRS/SALARIES** | 41,778 | 1,285,696 | 5,006 | 104,193 | 8,456 | 247,108 | 28,316 | 934,395 |
| **TOTAL FRINGE BENEFITS** | | 616,374 | | 35,123 | | 112,481 | | 468,770 |
| **TOTAL LABOR** | | 1,902,070 | | 139,316 | | 359,589 | | 1,403,165 |
| **TRAVEL** | | 139,897 | | 13,184 | | 21,946 | | 104,767 |
| **SUPPLIES** | | 41,700 | | 4,500 | | 6,500 | | 30,700 |
| **SUBCONTRACT - (Unspecified) Geological Survey #1** | | 60,000 | | - | | - | | 60,000 |
| **SUBCONTRACT - (Unspecified) Geological Survey #2** | | 60,000 | | - | | - | | 60,000 |
| **SUBCONTRACT - PRAIRIE PUBLIC TELEVISION** | | 15,000 | | - | | - | | 15,000 |
| **SUBCONTRACT - (Unspecified) Educator** | | 25,000 | | - | | - | | 25,000 |
| **SUBCONTRACT - (Unspecified) Acquisition of Baseline Data** | | 240,000 | | - | | 240,000 | | - |
| **SUBCONTRACT - (Unspecified) Core Collection** | | 200,000 | | - | | - | | 200,000 |
| **SUBCONTRACT - (Unspecified) Hydrogeological Eval** | | 100,000 | | - | | 100,000 | | - |
| **SUBCONTRACT - MELZER CONSULTING** | | 50,000 | | - | | - | | 50,000 |
| **SUBCONTRACT - RAMGEN** | | 100,000 | | - | | - | | 100,000 |
| **COMMUNICATION - PHONES & POSTAGE** | | 5,906 | | 200 | | 603 | | 5,103 |
| **OFFICE (PROJECT SPECIFIC SUPPLIES)** | | 12,155 | | 556 | | 1,160 | | 10,439 |
| **FOOD** | | 2,600 | | - | | 500 | | 2,100 |
| **OPERATING FEES & SVCS** | | | | | | | | |
| Natural Materials Analytical Res. Lab. | | 13,144 | | - | | 13,144 | | - |
| GC/MS Lab. | | 67,840 | | - | | 67,840 | | - |
| Graphics Support | | 46,057 | | 2,500 | | 6,500 | | 37,057 |
| Outside Lab. | | 70,000 | | - | | 70,000 | | - |
| Freight | | 3,500 | | - | | 3,500 | | - |
| **TOTAL DIRECT COST** | | 3,154,869 | | 160,256 | | 891,282 | | 2,103,331 |
| **FACILITIES & ADMIN. RATE - % OF MTDC** | VAR | $ 1,207,631 | 56% | $ 89,744 | 56% | $ 308,718 | 50% | $ 809,169 |
| **TOTAL** | | $ 4,362,500 | | 250,000 | | 1,200,000 | | 2,912,500 |
| **IN-KIND SUPPORT** | | 2,988,606 | | 2,988,606 | | - | | - |
| **TOTAL PROJECT** | | $ 7,351,106 | | $ 3,238,606 | | $ 1,200,000 | | $ 2,912,500 |

Due to limitations within the University's accounting system, bolded budget line items represent how the University proposes, reports and accounts for expenses. Supplementary budget information, if provided, is for proposal evaluation.

PCOR PARTNERSHIP PHASE III
EERC PROPOSAL #2008-0119

**BUDGET TOTAL - YEARS 1 & 2**

| CATEGORY | | TOTAL | | OTHER COST SHARE | | NDIC Lignite SHARE | | DOE SHARE |
|---|---|---|---|---|---|---|---|---|
| **TOTAL DIRECT HRS/SALARIES** | 81,922 | $ 2,432,844 | 10,150 | $ 208,193 | 18,953 | $ 525,021 | 52,819 | $ 1,699,630 |
| **TOTAL FRINGE BENEFITS** | | $ 1,159,143 | | $ 71,045 | | $ 236,280 | | $ 851,818 |
| **TOTAL LABOR** | | $ 3,591,987 | | $ 279,238 | | $ 761,301 | | $ 2,551,448 |
| **TRAVEL** | | $ 260,464 | | $ 26,368 | | $ 43,892 | | $ 190,204 |
| **EQUIPMENT > $5000** | | $ 6,000 | | $ - | | $ - | | $ 6,000 |
| **SUPPLIES** | | $ 87,734 | | $ 11,034 | | $ 21,300 | | $ 55,400 |
| **SUBCONTRACT - (Unspecified) Geological Survey #1** | | $ 100,000 | | $ - | | $ - | | $ 100,000 |
| **SUBCONTRACT - (Unspecified) Geological Survey #2** | | $ 100,000 | | $ - | | $ - | | $ 100,000 |
| **SUBCONTRACT - PRAIRIE PUBLIC TELEVISION** | | $ 50,000 | | $ - | | $ - | | $ 50,000 |
| **SUBCONTRACT - (Unspecified) Educator** | | $ 25,000 | | $ - | | $ - | | $ 25,000 |
| **SUBCONTRACT - (Unspecified) Acquisition of Baseline Data** | | $ 400,000 | | $ - | | $ 400,000 | | $ - |
| **SUBCONTRACT - (Unspecified) Core Collection** | | $ 300,000 | | $ - | | $ - | | $ 300,000 |
| **SUBCONTRACT - (Unspecified) Hydrogeological Eval** | | $ 180,000 | | $ - | | $ 180,000 | | $ - |
| **SUBCONTRACT - MELZER CONSULTING** | | $ 100,000 | | $ - | | $ - | | $ 100,000 |
| **SUBCONTRACT - RAMGEN** | | $ 200,000 | | $ - | | $ - | | $ 200,000 |
| **FEE - EIS (TO DOE - NO FNA)** | | $ 1,500,000 | | $ - | | $ - | | $ 1,500,000 |
| **COMMUNICATION - PHONES & POSTAGE** | | $ 11,734 | | $ 416 | | $ 1,452 | | $ 9,866 |
| **OFFICE (PROJECT SPECIFIC SUPPLIES)** | | $ 22,911 | | $ 956 | | $ 2,086 | | $ 19,869 |
| **FOOD** | | $ 5,600 | | $ - | | $ 1,000 | | $ 4,600 |
| **OPERATING FEES & SVCS** | | | | | | | | |
| Natural Materials Analytical Res. Lab. | | $ 25,668 | | $ - | | $ 25,668 | | $ - |
| GC/MS Lab. | | $ 134,419 | | $ - | | $ 134,419 | | $ - |
| Graphics Support | | $ 84,443 | | $ 2,500 | | $ 9,000 | | $ 72,943 |
| Outside Lab. | | $ 140,000 | | $ - | | $ 140,000 | | $ - |
| Freight | | $ 8,600 | | $ - | | $ 8,600 | | $ - |
| **TOTAL DIRECT COST** | | $ 7,334,560 | | $ 320,512 | | $ 1,728,718 | | $ 5,285,330 |
| **FACILITIES & ADMIN. RATE - % OF MTDC** | VAR | $ 2,365,440 | 56% | $ 179,488 | 56% | $ 671,282 | 50% | $ 1,514,670 |
| **TOTAL** | | $ 9,700,000 | | $ 500,000 | | $ 2,400,000 | | $ 6,800,000 |
| **IN-KIND SUPPORT** | | 5,977,212 | | 5,977,212 | | - | | - |
| **TOTAL PROJECT** | | $ 15,677,212 | | $ 6,477,212 | | $ 2,400,000 | | $ 6,800,000 |

Due to limitations within the University's accounting system, bolded budget line items represent how the University proposes, reports and accounts for expenses. Supplementary budget information, if provided, is for proposal evaluation.

**BUDGET NOTES**

**ENERGY & ENVIRONMENTAL RESEARCH CENTER (EERC)**

## BACKGROUND

The EERC is an independently organized multidisciplinary research center within the University of North Dakota (UND). The EERC receives no appropriated funding from the state of North Dakota and is funded through federal and nonfederal grants, contracts, and other agreements. Although the EERC is not affiliated with any one academic department, university faculty may participate in a project, depending on the scope of work and expertise required to perform the project.

## INTELLECTUAL PROPERTY

If federal funding is proposed as part of this project, the applicable federal intellectual property (IP) regulations may govern any resulting research agreement. In addition, in the event that IP with the potential to generate revenue to which the EERC is entitled is developed under this agreement, such IP, including rights, title, interest, and obligations, may be transferred to the EERC Foundation, a separate legal entity.

## BUDGET INFORMATION

The proposed work will be done on a cost-reimbursable basis. The distribution of costs between budget categories (labor, travel, supplies, equipment, etc.) is for planning purposes only. The project manager may, as dictated by the needs of the work, incur costs in accordance with Office of Management and Budget (OMB) Circular A-21 found at www.whitehouse.gov/omb/circulars. Escalation of labor and EERC recharge center rates is incorporated in to the budget when a project's duration extends beyond the current fiscal year. Escalation is calculated by prorating an average annual increase over the anticipated life of the project. The cost of this project is based on a specific start date indicated at the top of the EERC budget. Any delay in the start of this project may result in a budget increase. Financial reporting will be at the total agreement level. Budget category descriptions presented below are for informational purposes; some categories may not appear in the budget.

**Salaries:** The EERC employs administrative staff to provide required services for various direct and indirect support functions. Salary estimates are based on the scope of work and prior experience on projects of similar scope. The labor rate used for specifically identified personnel is the current hourly rate for that individual. The labor category rate is the current average rate of a personnel group with a similar job description. Salary costs incurred are based on direct hourly effort on the project. Faculty who work on this project will be paid an amount over their normal base salary, creating an overload which is subject to limitation in accordance with university policy. Costs for general support services such as contracts and intellectual property, accounting, human resources, purchasing, shipping/receiving, and clerical support of these functions are included in the EERC facilities and administrative cost rate.

**Fringe Benefits:** Fringe benefits consist of two components which are budgeted as a percentage of direct labor. The first component is a fixed percentage approved annually by the UND cognizant audit agency, the Department of Health and Human Services, and covers vacation, holiday, and sick leave (VSL). This percentage is applied to direct labor for permanent staff eligible for VSL benefits. The second component is estimated on the basis of historical data and is charged as actual expenses for items such as health, life, and unemployment insurance; social security; worker's compensation; and UND retirement contributions.

**Travel:** Travel is estimated on the basis of UND travel policies which can be found at www.und.edu/dept/accounts/policiesandprocedures.html. Estimates include General Services Administration (GSA) daily meal rates. Travel includes many scheduled meetings with partners and numerous site visits as indicated in the scope of work. Other planned travel includes conference participation along with U.S. Department of Energy (DOE) briefings and meetings.

**Equipment:** The equipment to be purchased is a point-load tester. This device is used to determine the point load strength of intact rock, which can be further related to the uniaxial strength of rock. The test provides a basis for a) a mechanical classification of the rock and b) an estimate of the uniaxial compressive strength of intact rock. These parameters are required to understand the mechanical strength of target formation and cap rock and are needed to ensure the safety of $CO_2$ injection.

**Supplies – Professional, Information Technology, and Miscellaneous:** Supply and material estimates are based on prior experience and may include geographic information system (GIS) and other software, pressure transducers, thermocouples, pH meters, resistivity meters, microseismic monitors, and data loggers. Computer supplies may include disks, paper, memory, software, and toner cartridges. Maps, sample containers, minor equipment, signage, and safety supplies may be necessary as well as other organizational materials such as subscriptions, books, and reference materials.

**Subcontracts:**

**Unspecified – Geologic Surveys 1 and 2:** The Geologic Surveys (or appropriate counterpart in states and provinces) will characterize the sequestration potential for their state or province for geologic settings which they feel have the greatest potential for sequestering carbon dioxide. These groups have geologists and hydrogeologists that are very familiar with the data that is required for this characterization.

**Prairie Public Broadcasting:** Prairie Public Broadcasting will develop video materials, including animation, that will be used in PowerPoint presentations and in public Web pages to help portray the sequestration activities of the demonstration projects. In addition, 30-second to 2-minute video segments will be developed to supplement regional outreach on other sequestration issues through the public Web site.

**Unspecified – Educator:** This subcontractor is intended to support the services of a recognized educator in the region to facilitate with the planning and dissemination of outreach materials to schools.

**Unspecified – Acquisition of Baseline Data:** The subcontractor will provide assistance in the following areas: 1) collection and interpretation of historical geological and geophysical data; 2) deployment and operation of field-based data acquisition equipment; and 3) interpretation of field-based data gathered over the course of Task 4. Subcontractor will provide quarterly and final reports describing the activities conducted over the course of the project and the results of those activities.

**Unspecified – Core Collection:** The subcontractor will conduct field-based activities to collect core samples from the rock formations of interest to the project. Subcontractor will also conduct initial analyses of the collected core samples and will provide a report summarizing the results of the core collection activities.

**Unspecified – Hydrogeological Evaluation:** The subcontractor will provide assistance in the following areas: 1) collection and interpretation of historical data related to the hydrogeological conditions of the study area; 2) collection, analyses, and interpretation of new data, including formation fluid sample collection and analyses; 3) development of hydrogeological databases and integration of databases into a hydrogeological model of the study area. Subcontractor will provide quarterly and final reports describing the activities conducted over the course of the project and the results of those activities.

**Melzer Consulting:** Melzer Consulting will assist the Plains $CO_2$ Reduction Partnership (PCOR) by providing expertise in the assessment of carbon separation, capture and storage opportunities within the PCOR Partnership region especially as they relate to enhanced oil recovery (EOR). Melzer Consulting will also provide technical support for the development of experimental design and interpretation of results for the Williston Basin demonstration project.

**Ramgen:** During Year 1, an initial high-level planning effort will determine the requirements and success criteria for the demonstration at Antelope Valley Power Station. Ramgen will coordinate these criteria with the PCOR Partnership and will provide input based on commercialization needs. High-level facility and interface issues will be identified and documented. Tours of the Antelope Valley site will provide firsthand information that will be valuable to support planning and cost estimation at the system level.

The planning will continue in Year 2 at a more detailed level. The demonstration unit's conceptual configuration will be identified and the requirements developed for all subsystems. The subsystem requirements will be assessed to establish facility requirements including power budget, air supply instrumentation, controls, and plumbing connections.

If additional funding can be procured, design of the demonstration unit will begin late in the second year. This effort will include more detailed configuration studies and the start of the conceptual design phase. A procurement plan will be developed based on the conceptual configuration and the initial design work.

**Professional Fees/Services (consultants):** Not applicable.

**Other Direct Costs**

**Communications and Postage:** Telephone, cell phone, and fax line charges are generally included in the facilities and administrative cost. Direct project costs may include line charges at remote locations, long-distance telephone, postage, and other data or document transportation costs.

**Office (project-specific supplies) and Printing:** General purpose office supplies (pencils, pens, paper clips, staples, Post-it notes, etc.) are generally included in the facilities and administrative cost. Budgeted project office supplies include items specifically related to the project such as copies and printing.

**Food:** Food expenditures for project meetings, workshops, and conferences where the primary purpose is dissemination of technical information may include costs of food, some of which may exceed the institutional limit.

**Professional Development:** Fees are for memberships in technical areas directly related to work on this project. Technical journals and newsletters received as a result of a membership are used throughout development and execution of the project by the research team.

**Operating Fees and Services – EERC Recharge Centers, Outside Labs, Freight:** EERC recharge center rates for laboratory, analytical, graphics, and shop/operation fees are established and approved at the beginning of the university's fiscal year.

Laboratory and analytical fees are charged on a per sample, hourly, or daily rate, depending on the analytical services performed. Additionally, laboratory analyses may be performed outside the university when necessary.

Graphics fees are based on an established per hour rate for production of such items as report figures, posters, and/or PowerPoint images for presentations, maps, schematics, Web site design, professional brochures, and photographs.

Shop and operation fees are for expenses directly associated with the operation of the pilot plant facility. These fees cover such items as training, personal safety (protective eyeglasses, boots, gloves), and physicals for pilot plant and shop personnel.

Freight expenditures generally occur for outgoing items and field sample shipments.

**Facilities and Administrative Cost:** The facilities and administrative rate (indirect cost rate) included in this proposal became effective July 1, 2005. Facilities and administrative cost is calculated on modified total direct costs (MTDC). MTDC is defined as total direct costs less individual items of equipment in excess of $5000 and subawards in excess of the first $25,000 for each award.