DEMONSTRATION PROJECT REPORTING SYSTEM UPDATE

Plains CO_2 Reduction Partnership Phase III
Task 1 – Deliverable D10

Prepared for:

Andrea T. McNemar

U.S. Department of Energy
National Energy Technology Laboratory
3610 Collins Ferry Road
PO Box 880
Morgantown, WV 26507-0880

DOE Cooperative Agreement No. DE-FC26-05NT42592

Prepared by:

Wesley D. Peck
Tera D. Buckley
Edward N. Steadman
John A. Harju

Energy & Environmental Research Center
University of North Dakota
15 North 23rd Street, Stop 9018
Grand Forks, ND 58202-9018

March 2011
Approved

2011-EERC-04-01

DOE DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government, nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

NDIC DISCLAIMER

This report was prepared by the Energy & Environmental Research Center (EERC) pursuant to an agreement partially funded by the Industrial Commission of North Dakota, and neither the EERC nor any of its subcontractors nor the North Dakota Industrial Commission nor any person acting on behalf of either:

(A) Makes any warranty or representation, express or implied, with respect to the accuracy, completeness, or usefulness of the information contained in this report or that the use of any information, apparatus, method, or process disclosed in this report may not infringe privately owned rights; or

(B) Assumes any liabilities with respect to the use of, or for damages resulting from the use of, any information, apparatus, method, or process disclosed in this report.

Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the North Dakota Industrial Commission. The views and opinions of authors expressed herein do not necessarily state or reflect those of the North Dakota Industrial Commission

EERC DISCLAIMER

LEGAL NOTICE This research report was prepared by the Energy & Environmental Research Center (EERC), an agency of the University of North Dakota, as an account of work sponsored by the U.S. Department of Energy. Because of the research nature of the work performed, neither the EERC nor any of its employees makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement or recommendation by the EERC.

DEMONSTRATION PROJECT REPORTING SYSTEM UPDATE

INTRODUCTION

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 include two demonstration projects that focus on injecting CO_2 into deep geologic formations for CO_2 sequestration.

The first demonstration will inject CO_2 into the Bell Creek oil field in southeastern Montana for the dual purpose of storage and enhanced oil recovery (EOR). This EOR-based project will be the primary focus of Phase III demonstration activities. The second Phase III demonstration activity (the Fort Nelson Demonstration) will involve monitoring, verification, and accounting (MVA) 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.

The primary research objectives of the Bell Creek project are to demonstrate that 1) CO_2 storage can be safely and permanently achieved on a commercial scale in conjunction with an EOR operation; 2) oil-bearing sandstone formations are viable regional sinks for CO_2; 3) MVA methods can be utilized to effectively monitor commercial-scale CO_2–EOR storage projects and to provide a technical framework for the monetization of carbon credits; and 4) the lessons learned and best practices employed will provide the data, information, and knowledge needed to develop similar CO_2–EOR storage projects across the region.

The Fort Nelson Demonstration activity entails the development of a modeling and MVA 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. 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 storage 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.

In addition to the contractually specified reports that will be submitted to DOE, approved information (e.g., reports, summaries, tables, maps, etc.) generated in conducting the above-mentioned demonstration tests will also be managed and reported to DOE and partners through a

Demonstration Project Reporting System (DPRS). The DPRS will be a Web-based interface designed to provide structured access to data by all demonstration participants and other partners to facilitate communication and interpretation of these data and to allow for efficient replication of additional or related demonstration projects.

Information and products currently developed through the PCOR Partnership are disseminated to DOE and partners through the Decision Support System (DSS, ©2007–2011 EERC Foundation) – a database-driven, password-protected Web site containing both traditional static pages and an interactive geographic information system (GIS). The DPRS will be incorporated into the overall architecture of the DSS.

CONTENT AND ORGANIZATION

The content of the DPRS contained within the DSS will be arranged in the following main categories:

1. **Background and Scope of Work**. This section will describe the objectives of the demonstration project and provide basic information about the effort.

2. **Benefits to the Region**. This section will include materials and discussion on how the individual demonstration projects fit into the broader context of CCS within the PCOR Partnership region.

3. **Characterization Data**. This section includes subsurface information on geological characteristics, overlying seal(s) and formations, and formation storage injectivity and capacity.

4. **Modeling**. Modeling activities will feed into the MVA and risk management components of the project development. Approved results of modeling runs and the input parameters will be provided in this section.

5. **Monitoring, Verification, and Accounting**. Data in this category will include information on the MVA techniques being employed at the sites. As the MVA activities mature, this area will contain summaries of monitoring results and interpretations.

6. **Risk Management**. An integrated risk management concept is central to the PCOR Partnership approach to the demonstration projects. Discussion and products related to this concept will be housed in this section.

7. **Regulations and Permitting**. This section includes discussions on how regulatory and permitting issues were addressed at the two demonstration sites.

8. **Site Operations**. Material pertinent to how the site is operating, including injection rates and cumulative injection data will be included in this section, which will also include information on the transportation of the CO_2 to the site.

9. **Products**. Topical reports, final reports, posters, presentations, and fact sheets directly related to the demonstration project will be accessible in this portion of the DPRS. Programming will allow for a dynamic link to the DSS Products Database, which will house all PCOR Partnership products.

The appendix that follows contains the layout of the initial material compiled for the DPRS. This layout illustrates the organization and basic navigational concept for the Web pages. As the two demonstration sites move toward full operational mode, more information will be compiled and appended to the Web site. Programming of the site will begin as soon as this report is approved.

The DPRS is an important addition to the DSS and will improve the nature and accessibility of the various demonstration project data and ultimately augment the well-established outreach and communication efforts of the PCOR Partnership Program.

APPENDIX A

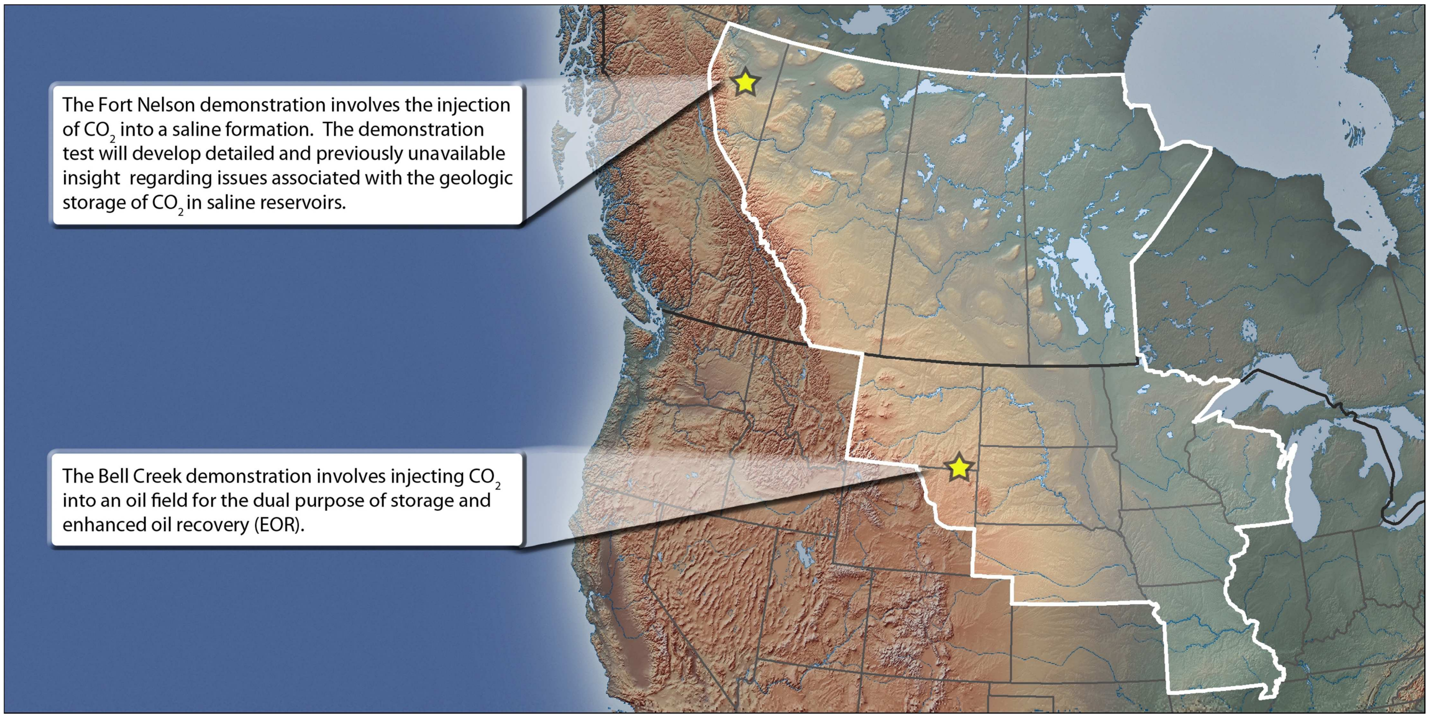
LAYOUT AND INFORMATION FOR THE DPRS

DPRS Navigation

- Demonstration Projects
  - Bell Creek
    - Scope of Work
    - Benefits to the Region
    - Characterization Data
    - Modeling
    - MVA
    - Risk Management
    - Permitting
    - Site Operations
    - Products
  - Fort Nelson
    - Scope of Work
    - Benefits to the Region
    - Characterization Data
    - Modeling
    - MVA
    - Risk Management
    - Permitting
    - Site Operations
    - Products

Demonstration Projects

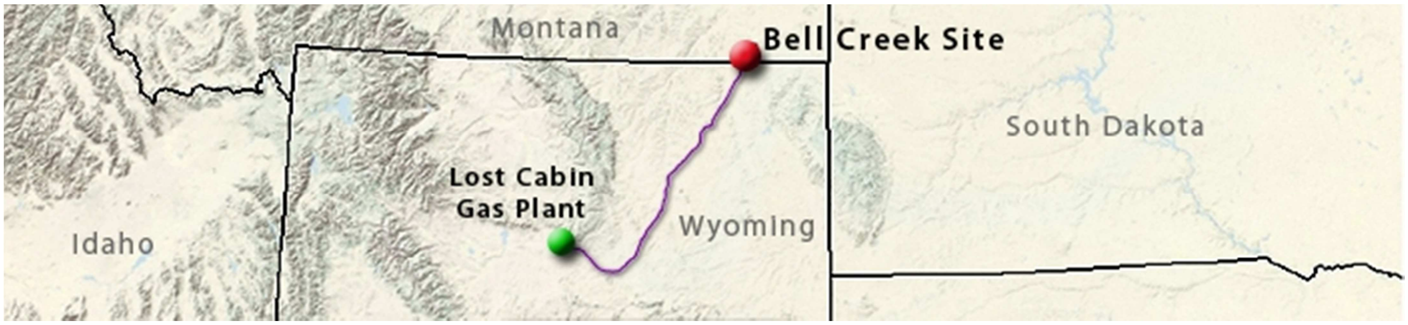
The PCOR Partnership is performing two demonstration projects that focus on injecting CO_2 into deep geologic formations for storage, with an emphasis on designing and conducting monitoring, verification, and accounting (MVA) programs.



Programmer Note: Each text box will be hyperlinked to the demonstration introduction page.

Demonstration Projects > Bell Creek

Bell Creek Demonstration



The Bell Creek carbon capture and storage (CCS) and enhanced oil recovery (EOR) project will demonstrate that commercial EOR operations, with simultaneous CO_2 storage, can safely and cost-effectively store regionally significant amounts of CO_2.

Over the lifespan of the project, at least 14 million tonnes of CO_2 will be transported 232 miles by pipeline from the ConocoPhillips Lost Cabin natural gas-processing plant in central Wyoming to the Bell Creek oil field, where it will be injected into the oil-bearing rock of the Muddy Sandstone Formation at a depth of 4400 feet (1370 m). This project will produce an estimated 30+ million barrels of incremental oil.

Denbury Resources, Inc., a major independent oil and gas exploration and production company, will perform the CO_2 capture, transport, and injection. Within this operation, the PCOR Partnership will design and implement a comprehensive monitoring, verification, and accounting (MVA) program designed to demonstrate the best methods for verifying that the CO_2 injected for EOR ultimately remains in place. The PCOR Partnership's effort will occur during the early part of Denbury's 20 year commercial EOR activity.

Research Partners

Denbury | Baker Hughes | Schlumberger Carbon Services | CMG Computer Modelling Group Ltd.

Regulatory Partners

Wyoming Office of State Lands and Investments

Montana Board of Oil and Gas Conservation

Wyoming Pipeline Authority

Wyoming Oil and Gas Conservation Commission

Programmer Note:
The links above will link to each Web site and open in a separate window:

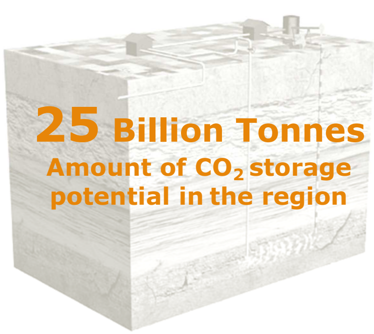
- Denbury: http://www.denbury.com/
- Baker Hughes: http://www.bakerhughes.com/
- Schlumberger: http://www.slb.com/
- Computer Modeling Group: http://www.cmgroup.com/
- Wyoming Office of State Lands and Investments: http://slf-web.state.wy.us/
- Montana Board of Oil and Gas Conservation: http://bogc.dnrc.mt.gov/
- Wyoming Pipeline Authority: http://www.wyopipeline.com/
- Wyoming Oil and Gas Conservation Commission: http://wogcc.state.wy.us/

Scope of Work

<table>
<tr><th>Objectives</th><th>PCOR Partnership Role</th><th>Deliverables</th></tr>
<tr><td>To demonstrate that:
CO_2 storage can be safely and permanently achieved on a commercial scale in conjunction with an EOR operation.
Oil-bearing sandstone formations are viable sinks for CO_2.
MVA methods can be utilized to effectively monitor commercial-scale EOR–CO_2 storage projects and to provide a technical framework for the monetization of carbon credits.
The lessons learned and best practices employed will provide the data, information, and knowledge needed to develop similar EOR–CO_2 storage projects across the region.</td><td>The PCOR Partnership will focus on developing efficient MVA and best practice methods that are transferable to future projects in the region. Technology transfer will be accomplished through published reports, papers in the scientific literature, and presentations.</td><td>Project deliverables will provide information on every aspect of conducting commercial-scale CCS projects, including the following:
Project engineering and economics
Project risk factors
CCS simulation tools
MVA techniques and other technical aspects
Permitting and regulations
Outreach needs and concerns</td></tr>
</table>

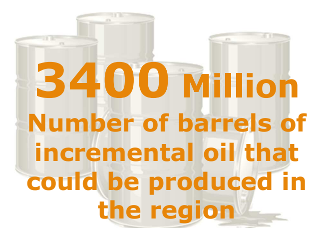
Benefits to the Region

The PCOR Partnership region is home to a broad distribution of oil fields, including many of the largest and most well-understood oil fields in the world. Oil fields may offer the best opportunities to implement large-scale CO_2 storage since they are well characterized, there is already an established legal framework for safe operation, and the sale of the incremental oil will considerably offset the cost of CO_2 capture and transportation. The Bell Creek oil field is one of many oil reservoirs in the PCOR Partnership region that has the potential to store significant amounts of CO_2 through EOR operations.



Reconnaissance-level CO_2 storage resource estimates of PCOR Partnership region oil fields indicate that 25 billion tonnes of CO_2 could be stored during the conduct of CO_2-based EOR operations, which could utilize the emissions from the large point sources for nearly 50 years.

Estimates suggest that the Bell Creek Field will store 14 million tonnes of CO_2 as a result of EOR activities and produce at least 30 million barrels of incremental oil over the next 20 years.



The volume of incremental oil that could be produced from EOR in oil fields in the PCOR Partnership region has been estimated to be approximately 3400 million barrels worth $306 billion.

Demonstrating the technical and economic viability of implementing cost-effective risk management and MVA strategies at a large-scale commercial CO_2 EOR project such as the Bell Creek project will provide stakeholders with the real-world data necessary to move commercial-scale CCS technology deployment forward. The results generated by the Bell Creek project will provide stakeholders, including policy makers, regulators, industry, financiers, and the public, with the knowledge necessary to make informed decisions regarding the real cost and effectiveness of CCS as a carbon management strategy.

Characterization Data

The Bell Creek oil field is located in southeastern Montana in the northeastern portion of the Powder River Basin. The sedimentary succession in the Bell Creek area consists primarily of sandstones and shales.

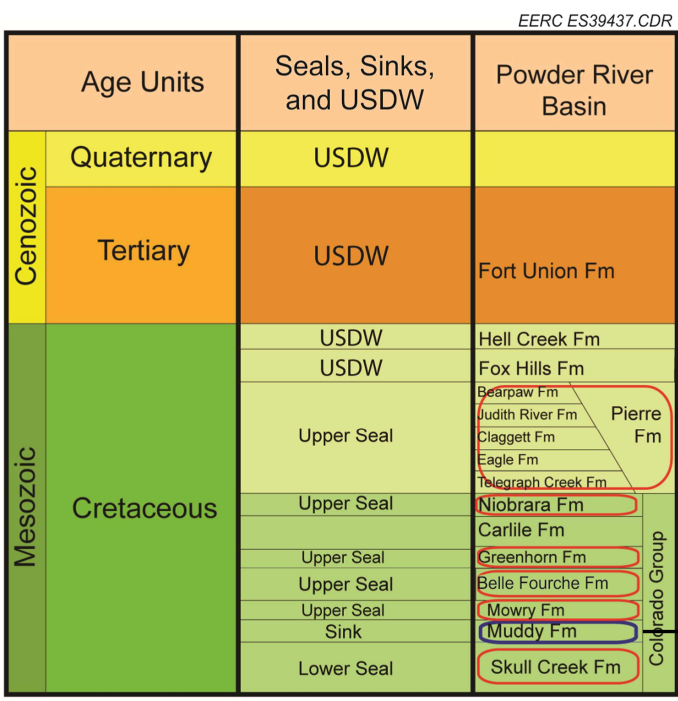
The Bell Creek oil field is an ideal candidate for CO_2 enhanced recovery for a variety of reasons:

- Its depth provides adequate temperature and pressure conditions for maintaining injected CO_2 in a supercritical state and supports the maintenance of miscibility of the CO_2 and oil.
- The high-porosity and permeability conditions of the reservoir allow for high CO_2 injection rates and a fairly rapid production response.
- The Bell Creek oil reservoir is overlain by multiple units of thick, competent shales which will serve as seals to prevent vertical migration of CO_2.

Surface Location

The Bell Creek oil field is located in a rural upland prairie area. The topography is generally rolling hills, with scattered buttes being the primary distinctive features. Surface land use activities in the area include oil production, ranching, and small grain farming. Most of the land surface ownership in the Bell Creek area is private, although the area does include large tracts of land owned and managed by the U.S. federal government. Denbury holds a majority of the mineral rights within the Bell Creek oil field and, as the field operator, has the right to inject CO_2 within the boundaries of the oil field for the purpose of EOR operations. The injection and CO_2 storage project will be designed to ensure that the injected CO_2 remains within the Bell Creek oil field boundaries.

Muddy Formation



Crude oil production in the Bell Creek area is primarily from stratigraphic traps in the Muddy Formation, the uppermost sandstone formation of the Lower Cretaceous-age Colorado Group. The Muddy Formation is dominated by clean sandstones deposited in a near-shore marine environment that have porosity and permeability characteristics that are promising for large-scale CO_2 injection.

Key Characteristics of the Muddy Formation

Depth: 1300–1400 m (4300–4600 ft)
Thickness: 6–10 m
Temperature: 42°C
Range of Average Permeability: 500–1200 mD
Total Dissolved Solids: 6400–7400 ppm
Porosity: 24%

Structure

- Monocline with a 1° dip to the northwest and whose axis trends southwest-to-northeast for a distance of approximately 20 miles.
- Up-dip facies change from sand to shale that serves as a trap. The sand bodies of the reservoir are dissected and, thus, somewhat compartmentalized by intersecting shale-filled channels.
- Available porosity and permeability data suggest that the injectivity and storage capacity of the Muddy Formation in the Bell Creek oil field will be adequate to support long-term, large-scale CO_2 injection at a rate of up to 1 million tonnes per year. This is further supported by historical data from the operation of the oil field, particularly the successful waterflood EOR operations that have been ongoing in the reservoir for the past several decades.

Mowry Formation

The shale formations of the overlying Upper Cretaceous Mowry Formation will provide the primary seal, preventing leakage to overlying underground sources of drinking water (USDW) or the surface. Overlying the Mowry Formation are several low-permeability shale formations, including the Upper Cretaceous-age Belle Fourche, Greenhorn, Niobrara, and Pierre Shales which will provide additional layers of protection from leakage to the surface or USDW.

Faults and Fractures

No areas of faulting or fracturing have yet been identified in the Bell Creek study area. However, the intermontane nature of the Powder River Basin, which is known to have areas of significant faulting and fracturing, suggests that such features may exist in proximity to the planned injection area. As part of the baseline characterization and modeling activities scheduled for 2011, a robust analysis of existing well log and historical seismic survey data will be performed to determine whether or not faults and fractures are present in the Bell Creek area.

Existing Boreholes

A total of 638 existing borehole penetrations, which are associated with oil exploration and production activities, have been identified. The PCOR Partnership and Denbury are developing a plan to evaluate the integrity of these wellbores. A thorough and careful study of well files at the Montana Board of Oil and Gas Conservation (MBOGC) and Denbury Resources, Inc., offices will be undertaken, including evaluation of documents and well logs associated with wellbore drilling, completion, operation, suspension, plugging, and abandonment. That information will be used to develop a wellbore leakage-monitoring and mitigation plan for the Bell Creek project study area.

Existing Data Sources

The geology of the Bell Creek project area is in an advanced stage of characterization. Data regarding reservoir and seal properties are extensive and broadly available to the PCOR Partnership, through Denbury, the MBOGC, and published literature. Specific data sets that the PCOR Partnership has either obtained or is acquiring include:

- Historical geophysical logs from hundreds of wells.
- Core samples and analytical data.
- Reservoir geochemistry data.
- Historical seismic survey data.
- Historical and new production and injection data from the oil field.
- Over a dozen published and unpublished geological and engineering studies.

These data provide a foundation for determining the detailed geometric, petrophysical, and fluid properties of the study area. These data will permit robust interpretations of key properties of the injection target and sealing formations. Activities in 2011 and 2012 will be focused on efficiently and effectively compiling these available data and using them to identify portions of the study area or technical topics that require additional examination.

Modeling

The modeling effort was designed to more accurately understand the long-term fate of the injected CO_2 and to assist Denbury in optimizing oil recovery. The EERC is building a detailed geologic model, which will be followed by a 3-D compositional reservoir simulation study that will include a history match of primary and secondary recovery and prediction and optimization of CO_2 injection for both incremental oil recovery and CO_2 storage.

Geologic and reservoir-modeling techniques include:

- Construction of a geologic framework model that represents a 3-D interpretation of the geology of the Bell Creek Field.
- Advanced reservoir modeling to simulate the performance of CO_2 flooding using the generalized equation-of-state model (GEM) software by Computer Modelling Group, Ltd. (CMG).
- Pressure–volume–temperature (PVT) modeling using CMG's WinProp.
- Correcting equation-of-state (EOS) systems and tuning them to match laboratory data (constant composition expansion, differential liberation, separator, swelling tests, and slim-tube tests) before use in the compositional simulation.

Geologic Reservoir Model

The Bell Creek Field consists of six hydraulically independent and stratigraphically trapped producing units named "A" through "E" and Ranch Creek ("F"). The reservoir under study is a heterogeneous sandstone Muddy Formation composed of two different major reservoir units interpreted as barrier islands (littoral marine bar) and valley fills. Using Schlumberger's Petrel 2010 software, a detailed 3-D geologic reservoir model is currently under construction for Unit D of the Bell Creek Field. This modeling effort will later be expanded to Units A, B, C, E, and F in stages.

The geologic model is being constructed to include:

- The overlying Cretaceous Mowry Formation (shale cap rock).
- The productive sands (oil-bearing, high-permeability).
- Laterally sealing shale of the Cretaceous Muddy Formation and underlying Cretaceous Skull Creek Shale.

A combination of data from well logs, cuttings, cores, well tests, laboratory tests, and field data from the 638 wells that have been drilled in and around the field to date are being used to construct the model. The effect of the water leg of the field will be investigated through history matching to estimate its physical limits and its characteristics.

After each phase of the geologic model is completed, the models will be exported to CMG's GEM compositional simulator. The history match phase will match oil rate, gas-to-oil ratio (GOR), reservoir pressure, and water cut simultaneously to calibrate and validate the model. Several sensitivity runs will be made to improve the CO_2 sweep efficiency and increase the oil recovery. After the history match phase is completed, prediction scenarios will be developed to:

- Investigate the applicability of CO_2 injection in the reservoir.
- Predict future reservoir performance.

- Identify CO_2 migration pathways.
- Assist in validating long-term CO_2 storage.

Initially, 80-acre five-spot pattern simulations will be run to predict oil recovery, which will be expanded to include more patterns until the entire unit can be optimized. Multicomponent EOS modeling will be further improved to match the laboratory test data and to further evaluate existing minimum miscibility pressure (MMP) for the Bell Creek Field.

MVA

The PCOR Partnership is committed to the belief that sustainable MVA strategies must be compatible with commercial operations and practices (i.e., integrate as much of the operational data as possible into the development of the MVA program) as well as site-specific and cost-effective. While the research goals of the project will mean that a very comprehensive suite of MVA technologies will be employed, the ultimate goal will be to determine the MVA technologies that will be employed over the commercial lifetime of the project based on practical and economic considerations. The more comprehensive suite of technologies that will be employed in the research component of the project will provide comparative and collaborative data that will help the PCOR Partnership choose the commercially sustainable MVA technologies that will be employed over the lifetime of the project.

A risk-based approach is being used to define the MVA strategy. The MVA plan will be derived from the risk assessment of the storage project and will focus on the early detection of the critical risks and their subsequent mitigation and/or management. Furthermore, it is imperative that the MVA plan be cost-effective and result in minimal disruption of the EOR operations.

Key measurable parameters will be identified for each high-criticality risk, and an appropriate MVA technology will be selected based on its maturity, cost/benefit ratio, and likelihood of success.

Near-surface and subsurface MVA technologies were considered based on several criteria. Additionally, injection site location, field layout, estimated fluid migration patterns, site-specific risk, and the injection programs were utilized to determine the applicability of a variety of technologies. Only technologies that were commercially available and found to have a high applicability to the above criteria are presented in the table below.

MVA Technologies under Consideration

Monitoring Level	Measurement Technique	Measurement Parameters	Application
Atmospheric	NA	NA	We do not plan to engage in atmospheric monitoring.
Near-Surface	Sampling of shallow groundwater wells	CO_2, HCO_3^{1-}, CO_3^{2-}, major ions, heavy metals, trace elements, pH, and salinity	Fluid sampling can be utilized for quantifying solubility and mineral trapping, to determine CO_2–water–rock interactions, to detect leakage into shallow groundwater aquifers.
Near-Surface	Soil gas sampling	Soil gas composition, tracer analysis, and isotopic analysis of CO_2	Soil gas sampling can be utilized to detect potential leakage of CO_2 and its subsequent movement to the surface and for identifying the source and concentrations of CO_2 in soil gas. Provide baseline data to address/confirm/deny future issues.

Subsurface	Flowmeters	Injection rate	Flowmeters will be necessary to quantify injection rates and track injected volumes of CO_2, which is necessary for accounting purposes.
Subsurface	Wellhead pressure and temperature	Pressure and temperature transducers	Wellhead pressure and temperature transducers are expected to be utilized in order to quantify injection parameters that will be necessary for history-matching activities and to immediately identify injectivity issues should they occur.
Subsurface	Fluid sampling	CO_2, HCO_3^{1-}, CO_3^{2-}, major ions, heavy metals, trace elements, pH, tracer analysis, fluid compositional analysis, and salinity	Downhole fluid sampling can be utilized to quantify solubility and mineral trapping, to determine CO_2–water–rock interactions, to detect leakage outside of the storage reservoir, and as an input for history-matching activities. Additionally, fluid sampling has additional applicability in terms of detecting CO_2 breakthrough during the CO_2 flood, calculating and tracking fluid saturations, and tracing the movements of CO_2 in the storage formation.
Subsurface	Downhole pressure and temperature sampling	Formation pressure, annulus pressure, and groundwater aquifer pressure	Downhole pressure and temperature sampling can be utilized as an input for controlling injection pressures so that the formation pressure is maintained below the fracture gradient, to immediately identify a loss of injectivity or containment should it occur, to detect leakage out of the storage formation, to potentially identify fluid migration along the wellbore, and to detect CO_2 breakthrough.
Subsurface	Geophysical well logs	Sonic velocity and pulsed neutron	Geophysical well logs can be utilized to track CO_2 movement in and above the storage formations, to identify or detect CO_2 breakthrough, to monitor for vertical leakage through sealing formations, to track migration of brine, to provide time-lapse near-wellbore fluid saturations, to monitor for CO_2 migration along the wellbore, and for calibration of 2-D and 3-D seismic surveys.
Subsurface	Ultrasonic imaging, multifinger caliper measurements, annular pressure and temperature, and cement bond log	Wellbore integrity	Wellbore integrity-monitoring techniques are used to assess internal and external wellbore integrity and degradation rates, identify pathways for out-of-zone leakage along the wellbore, and/or enhance an operator's ability to proactively remediate engineered well systems.
Subsurface	Multicomponent 3-D surface seismic time-lapse survey	Travel time, energy, and acoustic impedance of compressional and shear waves	Time-lapse 3-D multicomponent surface seismic surveys can monitor the migration and distribution of injected CO_2, provide an estimate of sweep efficiency, monitor for leakage through sealing formations, and provide data for history matching during periodic simulation updates.
Subsurface	Downhole seismic (time-lapse cross well seismic surveys)	Travel time, energy, and acoustic impedance of compressional and shear waves	Downhole seismic can be used to detect the vertical and lateral extent of the injected CO_2 plume within the storage reservoir within a 1000-ft radius of the wellbore; monitor for vertical, out-of-zone CO_2 movement through sealing formations; estimate sweep efficiency; and provide data for history matching during periodic simulation updates.

Subsurface	Microseismic	Induced seismicity	Microseismic monitoring technologies are used to detect potential injection-derived fault activation and/or hydraulic fracturing as well as provide feedback to deploy real-time modifications to injection pressure schemes and programs.
Subsurface	Cross well electrical tomography	Electrical resistivity	Cross well electrical tomography techniques are used to measure sweep efficiency, provide qualitative estimates of CO_2 saturations, and monitor the migration and distribution of injected CO_2.

Source: Intergovernmental Panel on Climate Change Special Report on Carbon Dioxide Capture and Storage.

Risk Management

The risk management strategy for this project was designed to include risk assessment, risk monitoring and, if necessary, risk mitigation and/or management. Additionally, risk communication with both internal and external stakeholders will be an essential part of gaining confidence and trust in the project. As the project moves forward, risk management will move through several phases, e.g., exploratory, preinjection, injection, and postinjection, and the risk management process that is developed will be used to monitor and review the changes to the relevant risks during all phases of the project.

Step 1. Risk Assessment

Risk assessment steps for this project include:

1. **Identification** – Risk identification will involve determining which risks are relevant to the project. This will be done using several methods including functional analysis, utilization of existing risk databases, and expert panel workshops.
2. **Estimation** – The probability (frequency) and severity of each risk will be estimated. The estimations will be placed in a risk register that includes potential project-specific risks. The risk register will be very site-specific and include only those risks that have been validated by experts or project leaders to be relevant to the project. There are general risks that can initially be identified for this type of large-scale CO_2 injection project including:
    - Wellbore integrity and potential leakage.
    - Uncertainty regarding the reservoir pressure regime.
    - Changes in global economic conditions (e.g., a big drop in oil prices).

Step 2. Risk Evaluation

This phase will analyze the identified risks that make up the risk register, and their overall risk to the project will be estimated. A risk's rating, or criticality, will be estimated using a combination of the frequency or probability of occurrence and the potential severity (criticality = frequency + severity). A common challenge of technical risk assessments is linking technical risks, such as CO_2 leakage, to a "strategic" severity (e.g., public perception).

The approach being considered for the Bell Creek project is to use a table of physical consequences that allows a physical rating of the risks along with transfer matrices that connect the physical consequences to the strategic severity levels. The transfer matrices will be developed with project stakeholders. An expert panel will be convened that will use the results of modeling and simulations, along with the risk criteria, to assign a frequency of occurrence and physical consequence rating to each risk. Following expert review, the criticality will be calculated for each risk using the transfer matrices to convert the estimated physical consequences into severity. Lastly, the estimated risks will be evaluated in terms of their acceptability for the project. Questions that will be answered during risk evaluation include, “Is this risk acceptable for the project?” and “Does this risk need to be treated?” The mitigation actions for the high risks will be prioritized based on the criticality of the individual risks.

Step 3. Risk Mitigation

Once the risks have been fully assessed, action will be taken for the risks that require treatment. If a risk is too difficult to reduce or is within scientifically reasonable limits, it may simply be accepted. Often, it is possible to change parameters of the project, e.g., move an injection well, to avoid certain risks, or a risk can be mitigated by either lowering the probability that the risk will occur or reducing the severity of the potential consequences. This will be done by designing and implementing a site-specific risk mitigation plan that contains recommendations for further studies and data acquisition to reduce the uncertainty of the critical risks. Additionally, a preliminary risk-based MVA plan will be developed by identifying available monitoring techniques and analyzing their relevance for monitoring the project-specific high-criticality risks.

Permitting

Because the Bell Creek demonstration project is ongoing at a commercial operation, it is expected that there will be minimal additional environmental consequences that occur because of Phase III activities. It is anticipated that the site owners will obtain all necessary permits and approvals that are needed to comply with state and federal requirements. However, the PCOR Partnership will assist the site owner as necessary in the permitting arena. In this task, the EERC will also identify and track existing and evolving regulations for CO_2 storage and transportation.

Permitting assistance may include:

- Preparation of the U.S. Department of Energy's environmental questionnaire.
- Assistance in the development of the environmental assessment (EA) or environmental impact statement (EIS).
- General permitting assistance which includes all of the reporting requirements and permit types that are necessary to comply with Montana Board of Oil and Gas Conservation (MBOGC) regulations that may be related to MVA activities at Bell Creek.
- Development of a permitting action plan in conjunction with the site owner in accordance with relevant local, state, and federal regulatory requirements for the Bell Creek project. This plan will be updated as necessary. A best practices manual for permitting will be developed.

Site Operations

No injection of CO_2 has occurred in the Bell Creek oil field. The Bell Creek project is currently in the infrastructure development and baseline characterization phase, with the bulk of the PCOR Partnership activities focusing on baseline characterization, modeling, risk assessment, and MVA planning. Denbury is currently in the process of constructing a pipeline from the ConocoPhillips Lost Cabin natural gas-processing plant to the Bell Creek oil field. The project is currently on schedule to begin pipeline construction in December 2010 and start large-scale injection of CO_2 in June 2013.

Demonstration Projects > Bell Creek > Products

Bell Creek Products

Search the DSS Products Database for all PCOR Partnership products. Products directly related to the Bell Creek project include the following:

Title	File Type	Date	Size
Bell Creek Integrated CO_2 EOR and Storage Project	Fact Sheet	March 2011	
Geomechanical Experimental Design Package		November 2010	

Programmer Note:

This list will be automatically populated from the Products Database with the search term "Bell Creek" The list should appear based on publication date with the most recent listed first. When the user clicks on the title, the area should expand and include all of the information that is listed on the Products Database results page for that product and allow the user to download the file.

Fort Nelson Demonstration

The PCOR Partnership and Spectra Energy Transmission (SET) are investigating the feasibility of a carbon capture and storage (CCS) project near Fort Nelson, British Columbia, Canada. The project aims to reduce CO_2 emissions from SET's Fort Nelson sour gas-processing plant by injecting approximately 2.5 million tons of sour CO_2 (approximately 95% CO_2, 4% hydrogen sulfide, and 1% methane) annually into a deep carbonate reef for long-term geologic storage.

The Fort Nelson CCS project provides a unique opportunity to develop a set of cost-effective, risk-based monitoring techniques for large-scale storage of sour CO_2 in deep saline formations. An approach is being developed that integrates characterization, modeling, risk assessment, and monitoring into an iterative process to produce superior-quality results during each phase of the project. Elements of any of these activities are crucial for understanding and developing the other activities. The lessons learned and best practices employed will provide the data, information, and knowledge needed to develop similar CCS projects across the region.

Research Partners

Spectra Energy

HALLIBURTON

CMG Computer Modelling Group Ltd.

RPS Energy

Alberta Innovates Technology Futures

Regulatory Partners

BC Oil & Gas Commission

British Columbia The Best Place on Earth — Ministry of Energy, Mines and Petroleum Resources

Natural Resources Canada

Programmer Note:
The links above will link to each Web site and open in a separate window:

- Spectra Energy: http://www.spectraenergy.com/
- Halliburton: http://www.halliburton.com/
- Computer Modeling Group: http://www.cmgroup.com/
- RPS Energy: http://www.rpsgroup.com/
- Alberta Innovates: http://www.albertatechfutures.ca/
- BC Oil & Gas Commission: http://www.bcogc.ca/
- British Columbia: http://www.gov.bc.ca/ener/
- Natural Resources Canada: http://www.nrcan-rncan.gc.ca/com/index-eng.php

Scope of Work

Objectives	PCOR Partnership Role	Deliverables
To demonstrate that: • CCS can safely and permanently mitigate CO_2 emissions on a commercial scale. • Saline formations are viable regional sinks for CO_2 storage. • MVA methods can be established to effectively monitor commercial-scale CO_2 storage in a saline formation and to provide a technical framework for the monetization of carbon credits. • The lessons learned and best practices employed will provide the data, information, and knowledge needed to develop similar CCS projects across the region.	• Provide SET with reservoir modeling and simulation, risk assessment of subsurface technical risks, and an MVA plan to address risks. • Combine geological characterization, modeling, risk assessment, and monitoring strategies into an iterative process to produce superior-quality results during the project development period.	• **Baseline characterization efforts** are nearly complete and include a site geological characterization and experimental design package (Deliverable 37 [D37]) to determine the capacity of the target formation, the mobility and fate of the CO_2, and the potential for leakage of the injected CO_2. • **A geomechanical experimental design package** (D38) was prepared, and assessment continues on mechanical integrity of the cap and reservoir rock and potential for rock fracturing. • **The baseline geochemical work** (D41) will be completed in December 2011, and laboratory tests continue on samples of the target injection formation and key sealing formations under reservoir conditions to assess the relevant geochemical reactions that will occur upon injection. • **Additional simulation studies** will optimize the injection design. • **Public education and outreach** efforts will take place prior to CO_2 injection (e.g., fact sheets, posters, and presentations). We will also work closely with local, regional, and national regulators to ensure safe and efficient execution of the project.

Benefits to the Region

The carbonate saline reservoir targeted for the Fort Nelson CCS project is a rock type common in the PCOR Partnership region. CO_2 storage capacity estimates (nearly 165 Gt) in regional saline formations show that there is ~340 years worth of storage available in the reservoirs characterized thus far for CO_2 from the PCOR Partnership region.

The activities being conducted by the PCOR Partnership at the Fort Nelson site will provide support to developing effective business models that can ultimately lead to successful widespread implementation of CO_2 storage in brine formations throughout the region. Specifically, demonstrating the technical and economic viability of implementing cost-effective risk management and MVA strategies at a large-scale commercial storage/sequestration project such as the Fort Nelson CCS project will provide stakeholders with the real-world data necessary to make informed decisions regarding the real cost and effectiveness of CCS as a carbon management strategy.

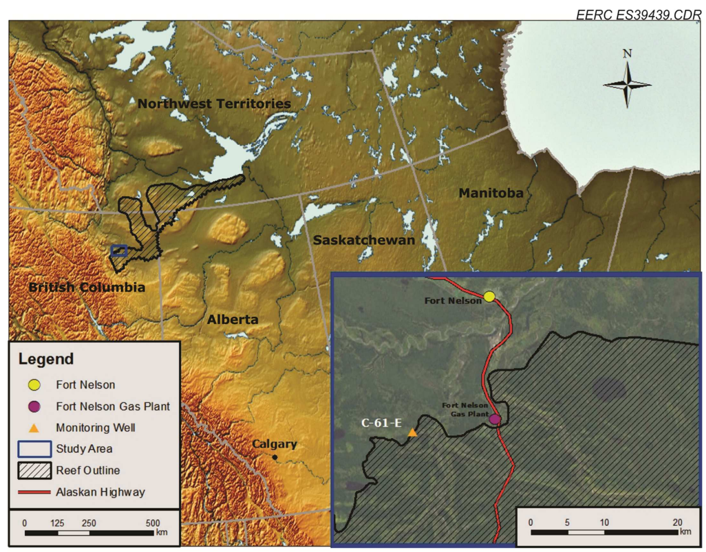
Characterization Data

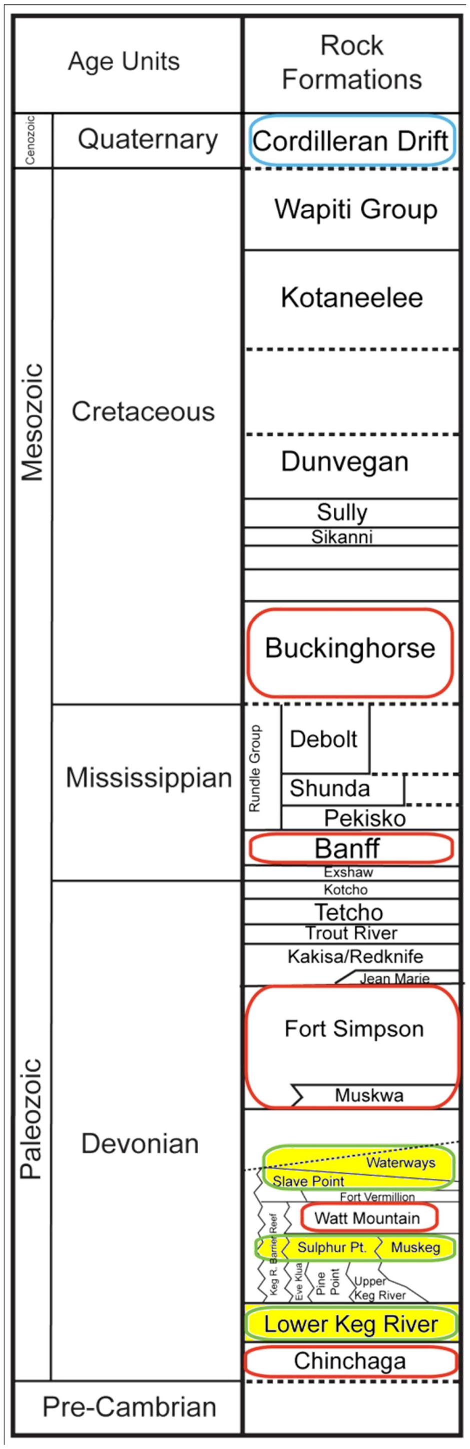
The geology of the Fort Nelson CCS project area should be considered at this time to be at an intermediate stage of characterization. Current knowledge is based on historical and new well logs and core, historical 2-D and 3-D seismic survey data, production and injection data from the gas field operating in the immediate vicinity of the study area, and published and unpublished geological studies.

Together these provide a good foundation for determining the general geometry of the reef complex and allow for reasonable interpretations of key properties of the injection target and sealing formations. However, there are only a few historical wellbores that completely penetrate the Sulphur Point and Keg River Formations, and interpretations of structure, stratigraphy, and petrophysical property distribution within these formations are severely lacking in well control data. Carbonate depositional environments can be notoriously heterogeneous, and the lack of well control in the area means that large error bars must be placed on any interpretations and subsequent predictions based on those interpretations. Further analyses of the area are under way.

Surface Location

The Fort Nelson CCS project is located in northeastern British Columbia within the northwestern portion of the Alberta Basin. The area is largely dominated by rural boreal forest. The topography is generally flat, with rivers and creeks being the only distinctive features. The land is Provincial Crown land, owned by the province of British Columbia, Canada. Because of the remote nature of the Fort Nelson area and lack of permanent roads, surface land use activities are limited to hydrocarbon exploration and production as well as trapping, hunting, and fishing.

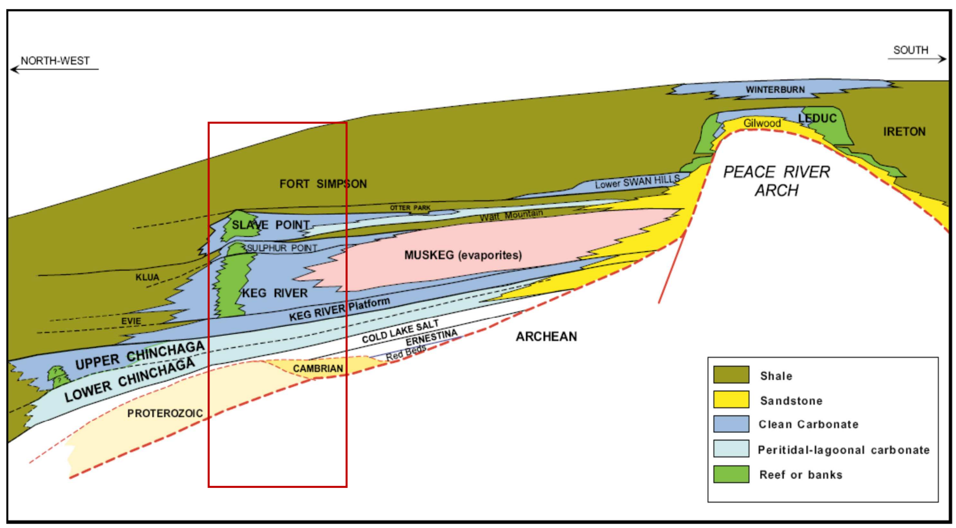


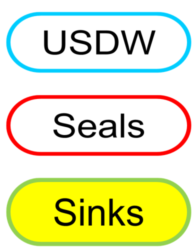


Target Formations

The carbonate platforms and reefs of the Middle Devonian formations in the northern Alberta Basin are known to contain large commercially viable accumulations of hydrocarbons, which suggests that the formations have adequate porosity, permeability, and trapping mechanisms to support the long-term storage of large volumes of CO_2. Natural gas production in the Fort Nelson area is primarily from reservoirs in reefs of the Slave Point Formation.

The primary injection target formation is the Sulphur Point Formation, with the overlying Slave Point and underlying Keg River Formations serving as secondary injection horizons. The injection zones are within an area of the Devonian-age Presqu'ile barrier reef complex, which provides a structural component to the site that will confine the movement of the injected CO_2.





Target Reservoir Properties

In the Fort Nelson area, the Sulphur Point and Keg River Formations are dominated by clean limestones and dolomites with prominent reef and/or bank structures and have porosity and permeability characteristics adequate for large-scale CO_2 injection and storage. Although few wells have been drilled into the Sulphur Point and Keg River Formations in the area being considered for injection because of their lack of hydrocarbon resources, the sparse data available suggest that thickness, porosity, and permeability are also likely adequate to support large-scale injection of CO_2. Preliminary evaluations of existing data conducted by Spectra Energy Transmission indicate that the minimum permeability of either target injection formation in the Fort Nelson area is anticipated to be approximately 60 mD.

Key Characteristics of the Target Injection Formations

Porosity and permeability data support the concept of this being a very promising reservoir for CO_2 storage.

Formation	Depth, m	Thickness, m	Temperature, °C	Range of Permeability, mD	Salinity, ppm	Porosity, %
Sulphur Point	2200	10–20	115–130	60–>1000	30,000–40,000	3–24
Keg River	2215	7–12	115–130	60–>1000	30,000–40,000	6–25

Seals

The Fort Simpson and Muskwa Shale Formations of the overlying Middle Devonian Woodbend Group will provide the primary seals for the injected CO_2, preventing its upward migration. The typical combined thickness of the Fort Simpson and Muskwa Shales in the Fort Nelson area ranges from 450 to 635 m. In addition, low-permeability carbonates of the upper Sulphur Point Formation and, possibly, the Watt Mountain Shale (if present) will also impede migration of the injected CO_2 upward into the currently commercial natural gas reservoirs of the Slave Point Formation. The Mississippian-age Banff Formation, a carbonate formation that directly overlies the Devonian section in the northern Alberta Basin, is a regional aquitard, thereby providing an additional seal between the target injection zones and the surface.

Effective Storage Resource of the 2000-km^2 Study Area (million tonnes CO_2)*

Formations	Pore Volume, million m^3	Pore Volume = 1.00%	Pore Volume = 2.00%	Pore Volume = 1.66% (P10)	Pore Volume = 2.63% (P50)	Pore Volume = 5.13% (P90)
Slave Point	4340	18	36	29.9	47.4	92.4
Sulphur Point	2920	12	24.2	20.1	31.9	62.2
Keg River	22,200	92.1	184.2	153	242	473
Total	29,500	122	244	203	321	628

* A CO_2 reservoir density of 415 kg/m^3 was used to calculate the storage mass (average CO_2 density in the reservoir).

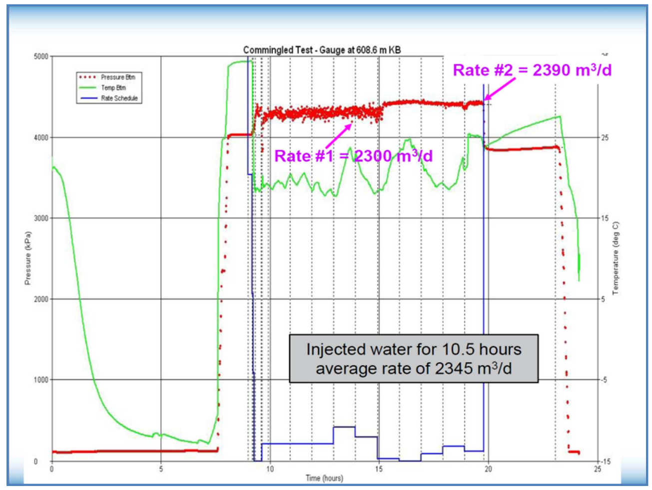
Potential Leakage Points

Approximately 35 existing borehole penetrations that are associated with natural gas exploration and production activities have been identified as potential leakage points. No faults or fractures have been confirmed, but there is evidence to suggest that isolated faults and localized areas of fractures (referred to as "sag" features) may exist in the Fort Nelson project area. Planned further evaluations of existing data sets combined with the collection of new data from future seismic surveys, well-drilling activities, and history-matching exercises will provide additional insight regarding the presence, distribution, and potential role of these features as leakage points. With respect to existing boreholes, the relatively low number of wells in the area limits this potential for leakage and also makes the task of developing a monitoring and mitigation plan for those wells fairly straightforward.

Injection Operation

The planned injection will involve up to 2 million tonnes per year of sour CO_2. The sour CO_2 will consist of roughly 95% CO_2 and 5% H_2S, so up to 1.9 million tonnes per year of CO_2 will be injected. The planned commercial operation will inject for a minimum of 20 years, while this project will monitor the injection for 3 years. It is anticipated that multiple injection wells will be used.

A water injection test was conducted at the Slave Point and Sulphur Point saline-filled reservoirs. The reservoirs took 950 m^3 (6000 bbl) of drilling fluid (water) during drilling, and an additional 1025 m^3 of water was injected during the test. There was no reservoir pressure buildup and no boundaries. Results indicate that 1.1 million m^3/d (2100 tonnes/d) of sour CO_2 can be injected into a single borehole.



Modeling

During the preinjection phase of the project, the characterization activities are used as input to the modeling effort. The results of the modeling and characterization activities are used as input to the first-round risk assessment, which helps identify knowledge gaps and project risks. The output from the risk assessment is then used to guide further characterization efforts and develop the monitoring plan. Once injection begins, the monitoring program results will be compared to the modeling predictions. The models will be adjusted as necessary, and new simulations will be run to predict the movement of the injected sour CO_2 in the reservoir. Predictions that closely match the monitoring data will strengthen the project by:

1. Demonstrating that the modeling can be used to accurately aid in risk identification.
2. Providing insight into long-term stability of the CCS system.
3. Helping to ascertain when closure conditions have been met in the postinjection phase.
4. Enabling the CCS operator to obtain CCS project closure certification.

The modeling and simulation for the Fort Nelson CCS project covered approximately 2000 km^2, which includes a large portion of the Devonian Presqu'ile barrier reef. The potential injection horizons are the permeable Slave Point, Sulphur Point, and Keg River Formations in the reef complex. All versions of the model contain, from top to bottom:

- Fort Simpson and Muskwa Shales (upper seal).
- Slave Point (permeable carbonate, gas-bearing, secondary injection target).
- Watt Mountain (noncontinuous shale baffle).
- Sulphur Point (permeable carbonate, primary injection target).
- Keg River (permeable carbonate, secondary injection target).
- Chinchaga (evaporite, lower seal).

The reef complex is also confined laterally by the Otter Park Shale and the tight back reef carbonates of the Slave Point, Sulphur Point, and Keg River Formations, all of which have been incorporated into the geologic models.

Modeling Versions

To date, there have been three iterations, or "versions," of the Fort Nelson modeling.

Version 1	Version 2	Version 3

Programmer Note:

When the user clicks on one of the orange version buttons, the next will appear below the button. When they hover over the button, the button should change to blue (like it does on the Atlas page).

Version 1

Referred to as the "Scoping Model," Version 1 was developed using Computer Modelling Group, Ltd. (CMG), simulators. The model was developed just after Exploratory Well C-61-E was drilled in 2009 and relied heavily on the preliminary data acquired from the logging, testing, and coring of this well.

The stratigraphic and structural model was developed using a rudimentary geologic understanding and only included the formation brine and injected CO_2, with no in situ gas pools present. Generic and homogeneous properties were distributed by zone and layer, and the outlines of two nearby gas pools (Clark Lake "A" and "B") were included in the model to determine when and if the injected CO_2 would potentially contact them over a 100-year time frame. Predictive injection simulations were run using C-61-E and a second generic well located about 5 km to the west as injection wells, each injecting 1 million tonnes/yr of sour CO_2 for a duration of 100 years, to determine if pressures exceeded 80% of the estimated fracture pressure gradient (17 kPa/m) or if the injected CO_2 contacted the Clark Lake "A" gas pool.

The results of these simulations were favorable as they predicted that neither of these situations would occur over the time frames that were evaluated. These predictions were considered as representing worst-case scenarios for migration since only structural CO_2 trapping was considered (capillary, aqueous dissolution, and mineral trapping were not included).

Version 2

Version 2 was developed by Spectra Energy's Geologic Characterization Team and the EERC immediately after the scoping model in 2009.

Both Version 1 and the preliminary results of Version 2 were used as the basis for the first-round risk assessment. Version 2 included a more rigorous understanding of the structure, reef edge, facies, or zones and a more detailed understanding of the reservoir and cap rock properties. Version 2 also allowed for reasonable variations on many of the reservoir parameters, including the level of communication between different formations or horizons and the influence of the production and injection activities in the nearby gas pools.

The geologic model was developed using Schlumberger's Petrel seismic-to-simulation software, and these models were then imported into CMG's generalized equation-of-state model (GEM) simulator for predictive simulations. Version 2 included formation brine, in situ natural gas (methane, CO_2, and H_2S), and injected sour CO_2 (composition ranging from 85% CO_2 and 15% H_2S to 95% CO_2 and 5% H_2S). The models were imported into CMG's GEM simulators for predictive simulation. The following processes were utilized for predictive simulations in Version 2:

- Multiphase flow water (brine) and gas (methane, CO_2, and H_2S)
- Mass transfer between water and gas phases (special focus on CO_2 and H_2S dissolution into formation brine)
- Uncoupled geochemical modeling

Many different injection scenarios were tested in Version 2, both in location and in the number of injectors. Typically, three to six injectors were utilized, including C-61-E, and in all cases, 2 million tonnes/yr of sour CO_2 was injected for a duration of 50 years (100 million tonnes over the life of the project), without exceeding 80% of the fracture gradient (17 kPa/m). During the winter of 2009–2010, additional 2-D and 3-D seismic data were purchased and reprocessed, and the C-61-E well was reentered and subjected to leak off and water injection testing. These data all fed into the next round of modeling.

Version 3

Version 3 was developed using more detailed log analyses and the newly reprocessed 2-D and 3-D seismic data. In Version 3, the structural model was updated to include a better definition of the reef edge, formation boundaries, and features that created a structural trap. Heterogeneous properties (porosity, permeability, etc.) were populated using a more detailed understanding of their distribution, not only vertically (from well logs), but also laterally from the seismic data. Three injection wells were utilized in these simulations, and all are located to the west, more than 5 km from C-61-E. In addition to running predictive simulations, a history-matching process is being performed on Version 3. This includes matching the production and injection of more than 80 producing wells and seven water injectors from the two neighboring gas pools, which have been in production since the 1960s. This history match will help validate the geologic properties of both the injection horizon and the adjacent formations and help develop a better understanding of the pressure profile laterally and vertically across the reef front. Once this history match is completed, predictive simulations will again be run and used as a basis for a second-round risk assessment.

The results from the second-round risk assessment and Version 3 of the model will be used to:

- Identify additional data needs.
- Determine the location of the next test well (expected winter 2011–2012).
- Integrate both existing and new 3-D seismic data.

MVA

A risk-based approach to define the monitory verification and accounting (MVA) strategy is being used. The MVA plan will be derived from the risk assessment of the storage/sequestration project and will focus on the early detection of the occurrence of the most critical risks and their subsequent management. It is also imperative that the MVA plan be cost-effective and result in minimal disruption of the storage/sequestration operations at Fort Nelson.

MVA Technologies under Consideration

Monitoring Level	Measurement Technique	Measurement Parameters and Frequency*	Application
Atmospheric	NA	NA	Atmospheric monitoring is not planned.
Near-Surface	Sampling of shallow groundwater wells and local rivers and streams	CO_2, HCO_3^{1-}, CO_3^{2-}, major ions, heavy metals, trace elements, pH, and salinity *Quarterly*	Fluid sampling can be utilized for quantifying solubility and mineral trapping, to determine CO_2–water–rock interactions, and to detect leakage into shallow groundwater aquifers.
Near-Surface	Soil gas sampling	Soil gas composition, tracer analysis, and isotopic analysis of CO_2 *Quarterly*	Soil gas sampling can be utilized to detect potential leakage of CO_2 and its subsequent movement to the surface and for identifying the source and concentrations of CO_2 in soil gas.
Subsurface	Flowmeters	Injection rate *Continuous*	Flowmeters will be necessary to quantify injection rates and track injected volumes of CO_2, which is necessary for accounting purposes.
Subsurface	Wellhead pressure and temperature	Pressure and temperature transducers *Continuous*	Wellhead pressure and temperature transducers are expected to be utilized in order to quantify injection parameters which will be necessary for history-matching activities and to immediately identify injectivity issues should they occur.
Subsurface	Fluid sampling	CO_2, HCO_3^{1-}, CO_3^{2-}, major ions, heavy metals, trace elements, pH, tracer analysis, fluid compositional analysis, and salinity *Quarterly*	Downhole fluid sampling can be utilized to quantify solubility and mineral trapping, to determine CO_2–water–rock interactions, to detect leakage outside of the storage reservoir, and as an input for history-matching activities. Additionally, fluid sampling has applicability in terms of determining the location of the gas–oil and oil–water contacts, calculating and tracking fluid saturations, and tracing the movements of CO_2 in the storage formation.
Subsurface	Downhole pressure and temperature	Formation pressure, annulus pressure, and potable groundwater	Downhole pressure and temperature sampling can be utilized as an input for controlling injection pressures so that the formation pressure is maintained below

	sampling	formation pressure *Continuous*	the fracture gradient, to immediately identify a loss of injectivity or containment should it occur, to detect leakage out of the storage formation, and to potentially identify fluid migration along the wellbore.
Subsurface	Geophysical well logs	Sonic velocity and pulsed neutron *Staged (frequency diminishes with project life)*	Geophysical well logs can be utilized to track CO_2 movement in and above the storage formations, detect changes in fluid saturation, identify gas–oil and oil–water contacts, monitor for vertical CO_2 migration along the wellbore, provide time-lapse near-wellbore CO_2 saturations, and for calibration of 2-D and 3-D seismic surveys.
Subsurface	Ultrasonic imaging, multifinger caliper measurements, annular pressure and temperature, cement bond log	Wellbore integrity *Staged (frequency diminishes with project life)*	Wellbore integrity-monitoring techniques are used to assess wellbore integrity and degradation rates, identify pathways for out-of-zone leakage along the wellbore, and/or enhance an operator's ability to proactively remediate engineered well systems.
Subsurface	Multicomponent 3-D surface seismic time-lapse survey	Travel time, energy, and acoustic impedance of compressional and shear waves *Staged (frequency diminishes with project life)*	Time-lapse 3-D multicomponent surface seismic surveys can monitor the migration and distribution of injected CO_2, monitor for leakage through sealing formations, identify changes in fluid saturation, and provide data for history matching during periodic simulation updates.
Subsurface	Downhole seismic (time-lapse vertical seismic profile [VSP] seismic surveys)	Travel time, energy, and acoustic impedance of compressional and shear waves *One baseline and one time-lapse*	Downhole seismic can be used to detect the vertical and lateral extent of the injected CO_2 plume within the storage reservoir within a 1000-ft radius of the wellbore; estimate changes in oil–water and gas–oil contacts; monitor for vertical, out-of-zone CO_2 movement through sealing formations; and provide history-matching data for periodic simulation updates.
Subsurface	Microseismic	Induced seismicity *Continuous*	Microseismic monitoring technologies are used to detect potential injection-derived fault activation and hydraulic fracturing and provide feedback to deploy real-time modifications to injection pressure schemes and programs.

* Precise measurement frequencies and durations will be influenced by and determined upon completion of the site characterization, modeling and simulation updates, risk assessment, and permit and regulatory constraints.

Source: Intergovernmental Panel on Climate Change Special Report on Carbon Dioxide Capture and Storage.

Risk Management

Step 1. Risk Assessment

1. **Identification** – A risk register of 32 identified project risks was developed using existing risk databases and expert panel workshops.
2. **Estimation** – A unique method was used to relate a measureable physical consequence resulting from subsurface technical risk to a strategic impact. This method involved the development of a series of transfer matrices, where the value for the physical consequence was entered into the transfer matrix and converted into a value for the level of a strategic consequence, or severity.
3. **Evaluation** – The probability (frequency) of occurrence for each risk was determined, and each risk was assessed a criticality score (criticality = frequency + severity), which was used to evaluate all project risks using Simeo™-ERM.

Step 2. Risk Evaluation

There are two critical risks to be considered:

1. The project economics and regulatory climate are deemed untenable by Spectra Energy and funding is withdrawn.
2. The technical evaluation deems the site technically unsuitable for safe and economical injection.

The results of the first-round risk assessment indicated 14 critical technical risks that could significantly impact the project. Many of the risks are considered by Spectra to be business-sensitive and cannot be disclosed in this document. Generally speaking, the serious risks fall into four general categories:

1. Contamination (with sour CO_2) of two currently producing gas pools.
2. Pressure changes that could affect nearby natural gas production and water disposal operations.
3. Loss of injectivity.
4. Insufficient storage volume in the target reservoir.

As this first-round assessment is based on early, limited, baseline characterization data, it is important to note that the majority of these risks will likely be downgraded as additional, more detailed, site-specific information becomes available.

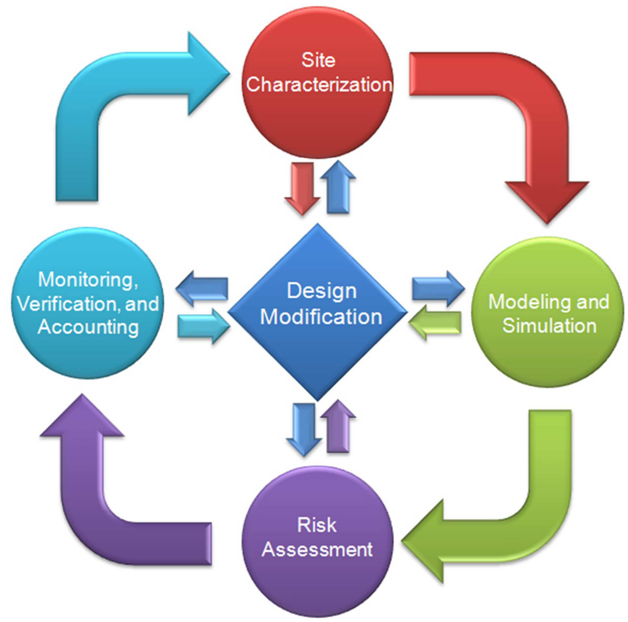
Step 3. Risk Mitigation

The results of the risk assessment were used to make MVA recommendations. First, the 14 critical risks were each broken down into causes, failure modes, and consequences. This allowed for the identification of the individual parameters related to that risk that could be monitored, e.g., pressure and temperature. Next, available technologies that could monitor these parameters were examined. Lastly, taking into account the site-specific characteristics of the Fort Nelson project, a list of recommended technologies to monitor the critical risks was created. As is typical of the exploratory nature of evaluating noncommercial deep saline formations, the risk mitigation plan contained recommendations for further studies and data acquisition to reduce the uncertainty of the critical risks.

A complete second-round risk assessment will be completed by June 2011.

Interrelated Process

Risk management, modeling, and MVA are all interrelated processes, where the results of one become the inputs of the others. This creates a dynamic iterative process that allows the risks to be assessed and controlled throughout the life of the project. As the project moves forward, it will move through several phases, e.g., exploratory, preinjection, injection, and postinjection, and the risk management process that is developed will be used to monitor and review the changes to the relevant risks during all phases of the project.



ISO 31000

The risk management process used for managing the subsurface technical risks of the Fort Nelson CCS project complies with International Organization for Standardization (ISO) 31000, an international standard for risk management. The risk management methodology integrated the ISO 31000 framework with existing Spectra Energy risk management processes, practices, and risk tolerance standards. Additionally, a risk-reporting tool (Simeo™-ERM) was used, which allowed the risks to be mapped and documented.

Two reference periods (0–50 years and 50–100 years) were chosen, corresponding to the injection and postinjection periods, respectively. Although these were chosen for the purposes of the risk assessment, they are simply estimates as Spectra Energy has not officially committed to injecting for 50 years.

Permitting

Because the Fort Nelson CCS project is occurring at a commercial operation, it is expected that there will be minimal additional environmental consequences that occur because of Phase III activities. It is anticipated that the site owners will obtain all necessary permits and approvals that are needed to comply with state and federal requirements. However, the PCOR Partnership will assist the site owner as necessary in the permitting arena. In this task, the EERC will also identify and track existing and evolving regulations for CO_2 storage and transportation.

To date, the PCOR Partnership assisted in the preparation of DOE’s Environmental Questionnaire. Additional permitting assistance may include:

- Assistance in the development of the environmental assessment.
- General permitting assistance including all reporting requirements and permit types that are necessary to comply with British Columbia Oil and Gas Commission (BCOGC) regulations that may be related to MVA activities at Fort Nelson.

Site Operations

No injection of CO_2 has occurred in the Fort Nelson area. An effective business model for successful commercial implementation of CO_2 storage in brine formations is also currently under development. The project is currently on schedule to begin large-scale injection of CO_2 by April 2014.

Demonstration Projects > Fort Nelson > Products

Fort Nelson Products

Search the DSS Products Database (link to http://www2.undeerc.org/website/pcorp/ProductsDB/Default.aspx. Don't open a separate window.) for all PCOR Partnership products. Products directly related to the Fort Nelson project include the following:

Title	File Type	Date
Fort Nelson Carbon Capture and Storage Feasibility Project Update	Presentation	October 21, 2010
PCOR Partnership, Fort Nelson Demonstration Test	Fact Sheet	October 2008

Programmer Note:

This list will be automatically populated from the Products Database with the search term "Fort Nelson". The list should appear based on publication date with the most recent listed first. When the user clicks on the title, the area should expand and include all of the information that is listed on the Products Database results page for that product and allow the user to download the file