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A Risk-Based Monitoring Plan for the Fort Nelson Feasibility Project

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Abstract

The Plains CO_2 Reduction (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 carbon dioxide (CO_2) emissions from SET's Fort Nelson sour gas-processing plant by injecting up to 2 million tonnes of sour CO_2 (approximately 95% CO_2, 4% hydrogen sulfide [H_2S], and 1% methane [CH_4]) a year into a deep mid-Devonian-age 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.

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, and 4) enabling the CCS operator to obtain CCS project closure certification.

Although specific techniques and procedures may change as the project proceeds, this philosophy of integrated characterization, modeling, and risk assessment will ensure that monitoring strategies remain fit for purpose, cost-effective, and efficient throughout the life of the project.

Introduction

The PCOR Partnership, led by the Energy & Environmental Research Center (EERC), and SET are investigating the feasibility of a CCS project to mitigate CO_2 emissions produced by SET's Fort Nelson gas plant (FNGP) as a waste stream from natural gas processing. The gas stream produced by FNGP will include up to 5% H_2S and a small amount of CH_4. As such, it is referred to as a "sour" CO_2 stream. The sour CO_2 gas stream would be injected into a deep saline carbonate formation. A technical team that includes SET, the EERC, and others will conduct a variety of activities to 1) determine the geologic, geochemical, and geomechanical properties of the target injection formation and key sealing formations in the vicinity of the injection site; 2) model the effects that large-scale injection of sour CO_2 may have on those properties as well as wellbore integrity; 3) evaluate the geologic risks of this injection process on local and regional scales based on results of the modeling effort; and 4) implement site-specific, risk-based monitoring, verification, and accounting (MVA) technologies to ensure safe and efficient long-term CO_2 storage. The Fort Nelson demonstration project will be a unique opportunity to develop a set of cost-effective risk-based MVA protocols for large-scale (>1 million metric tons a year) CO_2 storage in a saline formation. The effectiveness of the MVA activities will be dependent on developing a thorough characterization, modeling, and risk assessment effort.

The field demonstration test conducted in the Fort Nelson area of British Columbia, Canada, will evaluate the potential for geologic storage of CO_2 as part of a gas stream that also includes a small quantity of H_2S into a saline carbonate formation. The results of the Fort Nelson activities will provide insight regarding 1) the behavior of dense-phase sour CO_2 in a deep brine-saturated carbonate reservoir environment; 2) the impact of dense-phase sour CO_2 on the integrity of sink and seal rocks in a deep brine-saturated reservoir environment; 3) the effects of large-scale sour CO_2 injection and storage on wellbore integrity, particularly with respect to cements; 4) the effectiveness of selected MVA techniques; and 5) the use of an approach that combines iterative risk assessment, characterization, modeling, and MVA planning to safely and cost-effectively inject and store large volumes of sour CO_2.

The sour CO_2 will be obtained from the Fort Nelson gas-processing plant and injected into a Devonian-age carbonate formation at a depth of approximately 6900 to 7200 feet (2100 to 2200 meters).

Statement of Theory and Definitions

FNGP is the largest sour gas-processing plant in North America and is owned and operated by SET. The plant currently generates about 1.05 million tons of sour CO_2 consisting of approximately 9% H_2S and 91% CO_2. This amounts to a total of about 1.0 million metric tons/year of CO_2 and 50,000 metric tons/year of H_2S. Because of the recent developments with shale gas plays in the Horn River Basin, a large expansion project is currently under way in the Fort Nelson area. Once back at full capacity, FNGP will be the largest single-point CO_2 emission source in British Columbia, generating approximately 3 million metric tons of CO_2 annually. Of that total, approximately 2.2 million metric tons will be CO_2 that is removed from the incoming raw natural gas stream from production operations in the region (referred to as “formation CO_2”), while the other 0.8 million metric tons is generated by combustion of fuel as part of the gas plant operations. The Fort Nelson CCS project is focused on capturing, injecting, and storing only the formation CO_2, and all references to CO_2 in this document are meant to refer to formation CO_2. The Horn River shale gas coming into the plant is 10% to 14% CO_2 by volume. It is anticipated that over the next several years, Horn River shale will be the focus of natural gas exploration and production in northeastern British Columbia, and as more Horn River shale gas is processed at FNGP, the amount of formation CO_2 generated at the plant is expected to increase significantly. These emissions will not go unnoticed by the provincial and federal governments, or the public, and yet, there is still no driver (commercial or regulatory) in place to address the emissions.

Because of the projected emissions from the plant and the growing potential for greenhouse gas regulation by local and/or federal governments, the environmental footprint from this one plant alone could become a significant liability. Thus SET has a strong incentive to find a technology that allows the continued expansion of its gas-processing operations while maintaining an environmentally conscious image.

Therefore, SET is proactively exploring the addition of CCS technology to its Fort Nelson gas-processing plant. The goal of CCS at FNGP is to capture the stream of sour CO_2 that is separated by the current gas-processing operations and store it long term in a deep saline formation. Presently, this sour CO_2 is processed in an existing sulfur plant to recover elemental sulfur, and the residual CO_2 and H_2S is passed through an incinerator and vented to the atmosphere. Several positive outcomes may be achieved by the approval and implementation of the Fort Nelson CCS project, including 1) securing SET’s core business in the long term by demonstrating the ability to process sour gas in an environmentally friendly manner; 2) maintaining SET’s leadership role in acid gas (defined as CO_2 and H_2S removed from raw natural gas) injection and storage technologies in a growing industry; 3) very little change in the cost of operating FNGP as the cost of compression will be about equal to the cost of running the sulfur plant; 4) as a result of shutting down the sulfur plant, less SO_2 released into the local air shed; 5) gaining the potential to earn CO_2 credits (depending on emerging regulation); and 6) enhancing SET’s corporate image based on reliability and responsible environmental stewardship. These attributes are important for both SET’s customers and the public’s perception of the company. The implementation of CCS on a worldwide scale has been slow to happen because of technological, economic, and social challenges as well as lack of a clear regulatory policy and carbon market. However, the Fort Nelson CCS project has several advantages that will facilitate a successful project:

- SET has a long history of safe and effective acid gas injection, with approximately 200,000 metric tons of CO_2 and 300,000 metric tons of H_2S injected annually across eight of its gas-processing plants in western Canada.

- Unlike most prospective CCS projects in North America, the Fort Nelson CCS project does not have the high costs associated with outfitting a plant with CO_2 capture technology since the sour CO_2 is already separated and captured as part of the sour gas processing; however, the cost of compression, cooling, dehydration, transportation (pipeline), and sequestration remain.

- The prospective injection site is located in a remote area where population density is low and local public support is expected to be strong because of the history of sour gas processing, the economic benefits the plant brings to the local community, and SET's long-standing reputation as a safe and environmentally responsible operator.

- There is no incremental fuel gas requirements with the Fort Nelson CCS project. Most CCS projects require a significant amount of additional fuel gas to be burned in order to drive the new compression required to inject CO_2. In Fort Nelson's case, the fuel gas that would have been burned to perform sulfur recovery becomes available for use as fuel for compression because the sulfur recovery operations will be shut down as a result of the CCS operations.

- A significant amount of high-quality waste heat will be generated from the use of gas turbines to drive the compression required to inject CO_2. This high-quality waste heat will be utilized as steam for the gas-processing plant and to generate up to 9 MW of electrical power that can be used in the gas-processing operations and sold to the local power grid.

- The storage reservoir is far below any usable water and is topped by a very laterally continuous, 1500-ft (500-m)-thick cap rock that preliminary data indicate will successfully contain the injected sour CO_2.

- The British Columbia provincial government considers CCS to be a major component of its greenhouse gas reduction strategy and is supportive of further development of the local natural gas resources.

The federal governments of Canada and the United States, as well as the provincial government of British Columbia, have supported the Fort Nelson CCS project through cash and in-kind contributions.

Description and Application of Equipment and Processes

The EERC plays an important role in the Fort Nelson CCS project by providing three services to SET: reservoir modeling and simulation, development of a risk management methodology for the subsurface technical risks, and the development of a risk-based MVA plan. The involvement of the EERC also demonstrates the international support and implications of the Fort Nelson CCS project.

The philosophy of the EERC is to integrate site characterization, modeling and simulation, risk assessment, and MVA strategies into an iterative process to produce superior-quality results (Figure 1). Elements of any of these activities are crucial for understanding or developing the other activities. For example, as new knowledge is gained from site characterization, it reduces a given amount of uncertainty in geologic assumptions. This reduced uncertainty can then propagate through modeling, risk assessment, and MVA efforts. Although the EERC is not directly involved in site characterization activities, it stands in a strong position to recommend additional activities based on the results of modeling, risk assessment, and MVA evaluations. Data generated by injection operations and MVA activities over the duration of the Fort Nelson CCS project will facilitate refinement of SET's understanding of the geologic setting and risks. This in turn will allow for adjustment of the reservoir model and, if necessary, the MVA plan as a means of further minimizing or mitigating risks. Over time, the operational and MVA data will support the iterative refinement of the reservoir model in such a manner that it becomes a reliable predictor of CCS performance at the Fort Nelson site. This aspect of the project will be critical when issues associated with long-term liability are addressed and oversight of the plume is handed to the provincial government.

The EERC's modeling of the subsurface aids in the understanding and prediction of the behavior of the injected sour CO_2 over the injection and postinjection period. The modeling is also a highly valuable tool for assessing potential scenarios of leakage to the surface, to nearby productive natural gas pools, or into usable water resources. This type of assessment is an essential input to the risk assessment plan and the MVA plan. It lays the foundation for a project-specific, risk-based, goal-oriented MVA plan. The goal of the MVA plan is to effectively monitor the behavior of the sour CO_2 in the subsurface and help ensure that the risks are successfully mitigated.

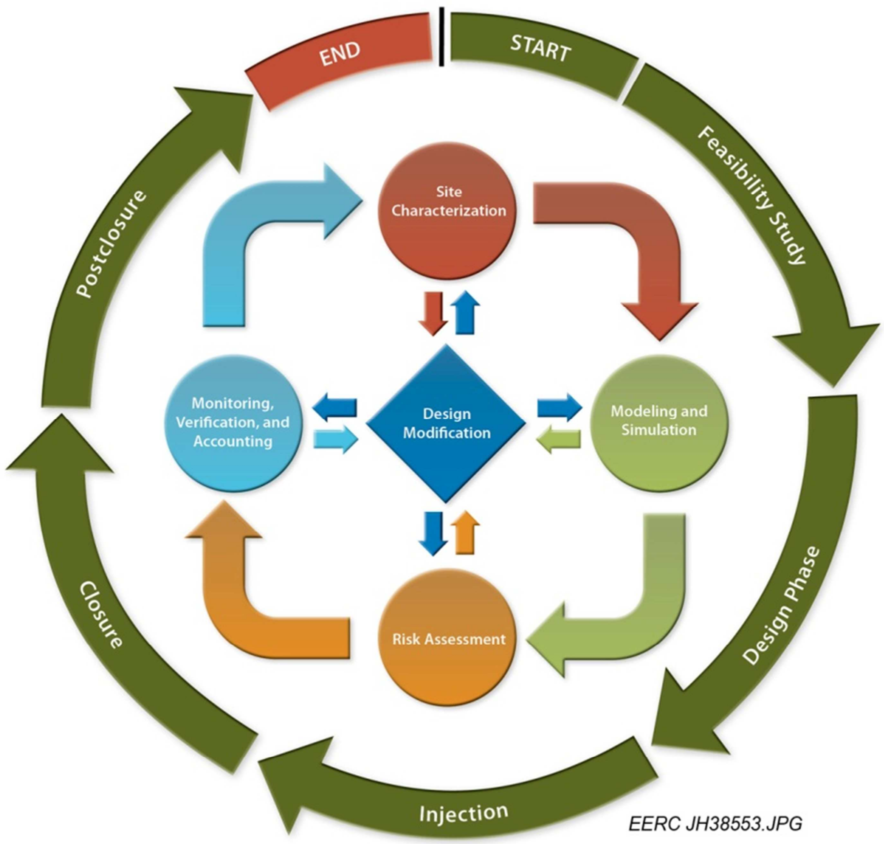

Figure 1. Project elements of the Fort Nelson CCS project. Each of these elements feeds into another, iteratively improving results and efficiency of evaluation.

Presentation of Data and Results

Baseline Geology Discussion. At the reservoir and local scales, the goal of the proposed work is to create a geological model of the strata associated with the Middle Devonian carbonate formations to evaluate reservoir geometry and internal architecture. The overlying/surrounding cap rock will also be evaluated, as well as the underlying aquifer systems that may provide reservoir support in places. Information about the geology of the injection zone and confining strata (e.g., structural setting, stratigraphy, general lithology, thickness, and areal extent) will be collected, processed, and interpreted for the local-scale area. The modeling will also help ascertain the likely nature of pressure dissipation within the reservoir and surrounding reef complex system as well as the movement of displaced brine both within the injection formation and potentially into other proximal brine-saturated formations (i.e., the Keg River and Slave Point Formations).

At the regional scale, the geology, stratigraphy, and lithology will be evaluated, delineated, and described for the entire sedimentary succession from the base of the Middle Devonian Elk Point Group (lower confining unit) to the ground surface (Lower Cretaceous Fort St. John Group and Quaternary drift) for the northwestern Alberta Basin. In addition, the structural elements in the area will be investigated to identify any existing faults and/or fractures that would allow migration of any reservoir and/or injected fluids out of the storage reservoir. On this basis, a geological model will be built, with particular attention given to the Devonian injection interval and overlying and underlying sealing formations.

Geology of the Fort Nelson Area. The Fort Nelson area in northeastern British Columbia lies within the northwestern corner of the Alberta Basin (Figure 2). The sedimentary succession in the Fort Nelson area consists, in ascending order from the Precambrian crystalline basement to the surface, of Middle and Upper Devonian carbonates, evaporates, and shales; Mississippian carbonates; and Lower Cretaceous shales overlain by Quaternary glacial drift unconsolidated sediments (Figures 3 and 4).

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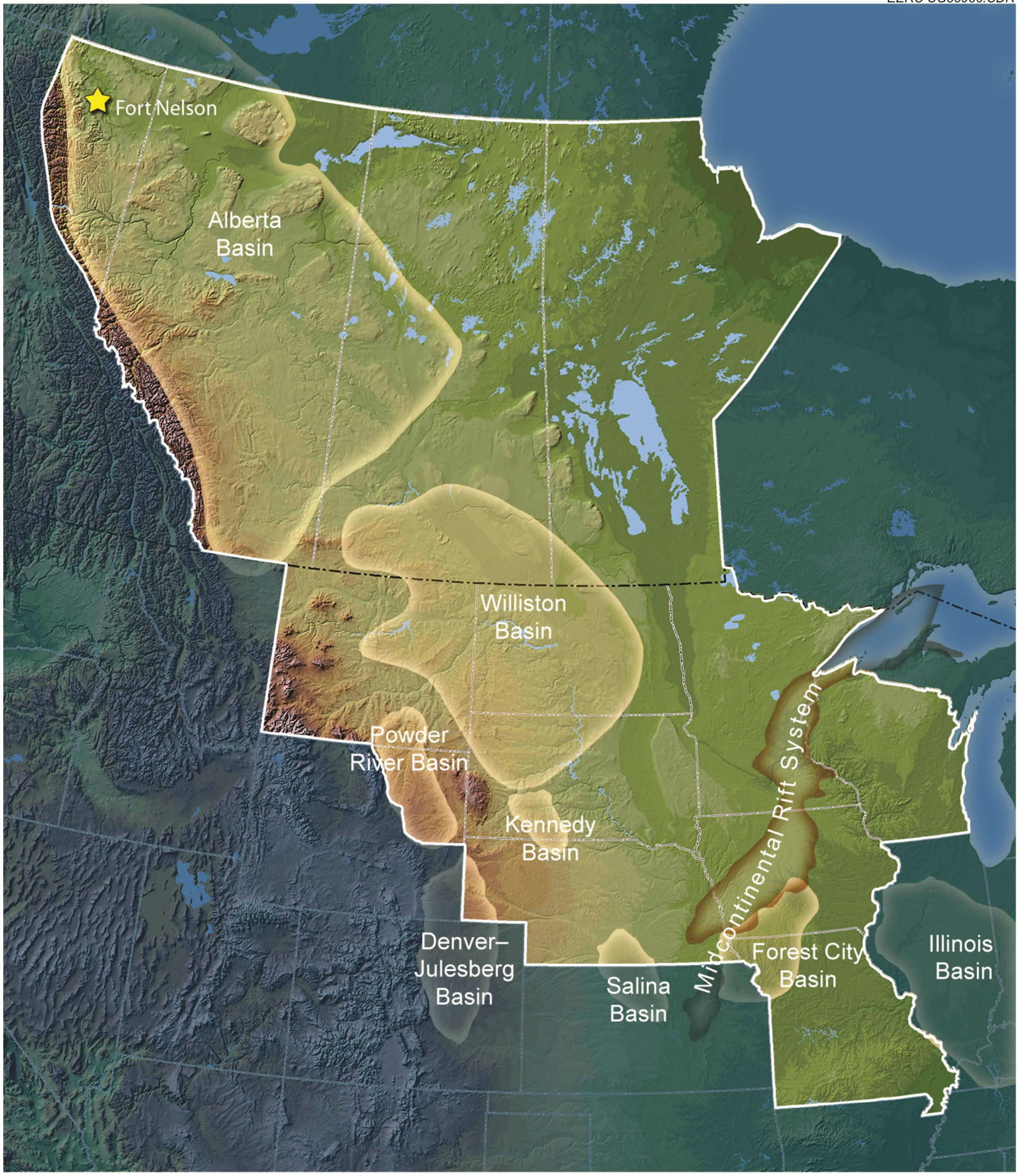

Figure 2. Location of the Fort Nelson demonstration site and sedimentary basins within the PCOR Partnership region.

Exploration activities for mineral and energy resources in the area over the last 50 years have yielded a significant amount of information about the geology of northeastern British Columbia and northwestern Alberta. The carbonate platforms and reefs of the Middle Devonian formations in the northern Alberta Basin are known to contain large quantities 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 (Sorensen and others 2005; Stewart and Bachu 2000). Hydrocarbon production in the Fort Nelson area, in the form of natural gas, is primarily from reservoirs in reefs of the Middle Devonian Slave Point Formation. It is anticipated that saline formations within the underlying Middle Devonian Elk Point Group will be the primary target injection zones for the Fort Nelson CCS project.

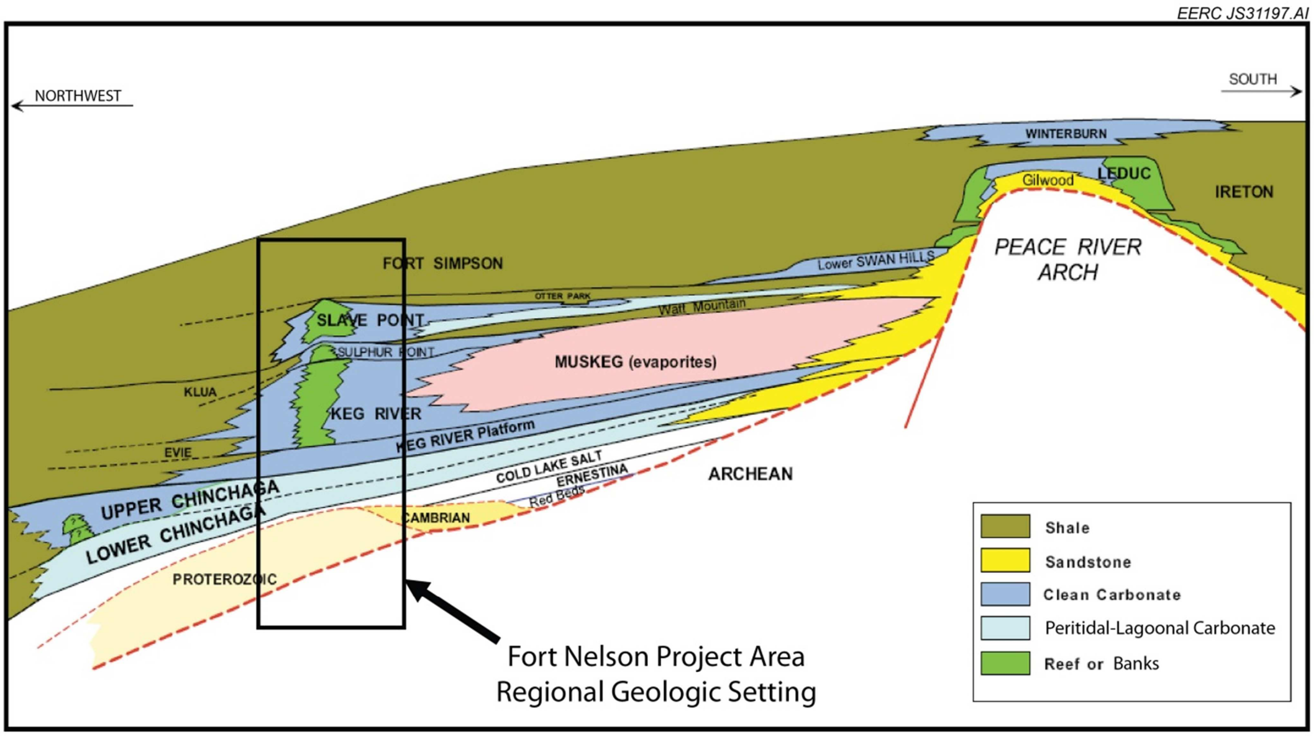

Figure 3. Stratigraphic architecture of Middle Devonian Formations in the Fort Nelson area, northeastern British Columbia (British Columbia Ministry of Energy, Mines, and Petroleum Resources 2007).

The Elk Point Group comprises a succession of shallow-water carbonates, evaporites, and some siliciclastics. In the Fort Nelson area, potential injection strata are dominated by clean carbonate rocks (limestones and dolomites) with prominent reef and/or bank structures that have porosity and permeability characteristics adequate for large-scale CO_2 injection. Only a few wells have been drilled into the Elk Point Group in the vicinity of the proposed injection area because of a lack of hydrocarbon resources in that part of the reef. Therefore, data on the porosity and permeability of those rock formations in the area are sparse. However, although rock property data for the area are limited, the data that do exist suggest that porosity and permeability are likely adequate to support large-scale injection of CO_2. The lack of existing data for the Elk Point Group Formations in the Fort Nelson area means that exploration-level geological characterization activities (e.g., well drilling and testing, seismic data acquisition and processing, etc.) must be conducted to evaluate storage capacity, injectivity, and other containment parameters of the sink-seal system.

With respect to seals that will prevent upward migration of the injected sour CO_2, shale formations of the overlying Middle Devonian Fort Simpson Group will provide the primary seal with respect to preventing leakage to the surface. The Mississippian-age Banff Formation, a carbonate formation that directly overlies the Devonian section in the northern Alberta Basin, is considered regionally to be an aquitard, thereby providing an additional seal between the target injection zones and the surface. Finally, the shales of the Cretaceous-age lower Fort St. John Group provide yet another layer of protection from leakage to the surface.

Site Characterization. Site characterization activities for any CCS project attempt to assess and describe deep geologic formations in terms of their ability to safely and effectively contain injected gas. The first step in site characterization is to define the nature and scope of the industrial source or sources that will be served by the CCS project. Specifically, knowledge of the anticipated gas composition, injection rate, operational period, and total storage volume required will provide guidance on the size of reservoir that will be necessary to support the project. This basic project information can then be used to move forward with the process of site identification and characterization. This process begins with a literature review of all known geological information in a given region in order to gain a broad-based understanding of the geologic systems. Geologic systems that may be suitable targets for large-scale CCS include depleted or depleting hydrocarbon pools, oil fields with enhanced oil recovery opportunities, and deep brine-saturated formations. Next, all relevant data that may assist in describing the current subsurface geologic conditions, in particular, those that relate to storage reservoir injectivity, capacity, and integrity, are acquired. These data are then analyzed and described in order to identify potential areas of interest for additional

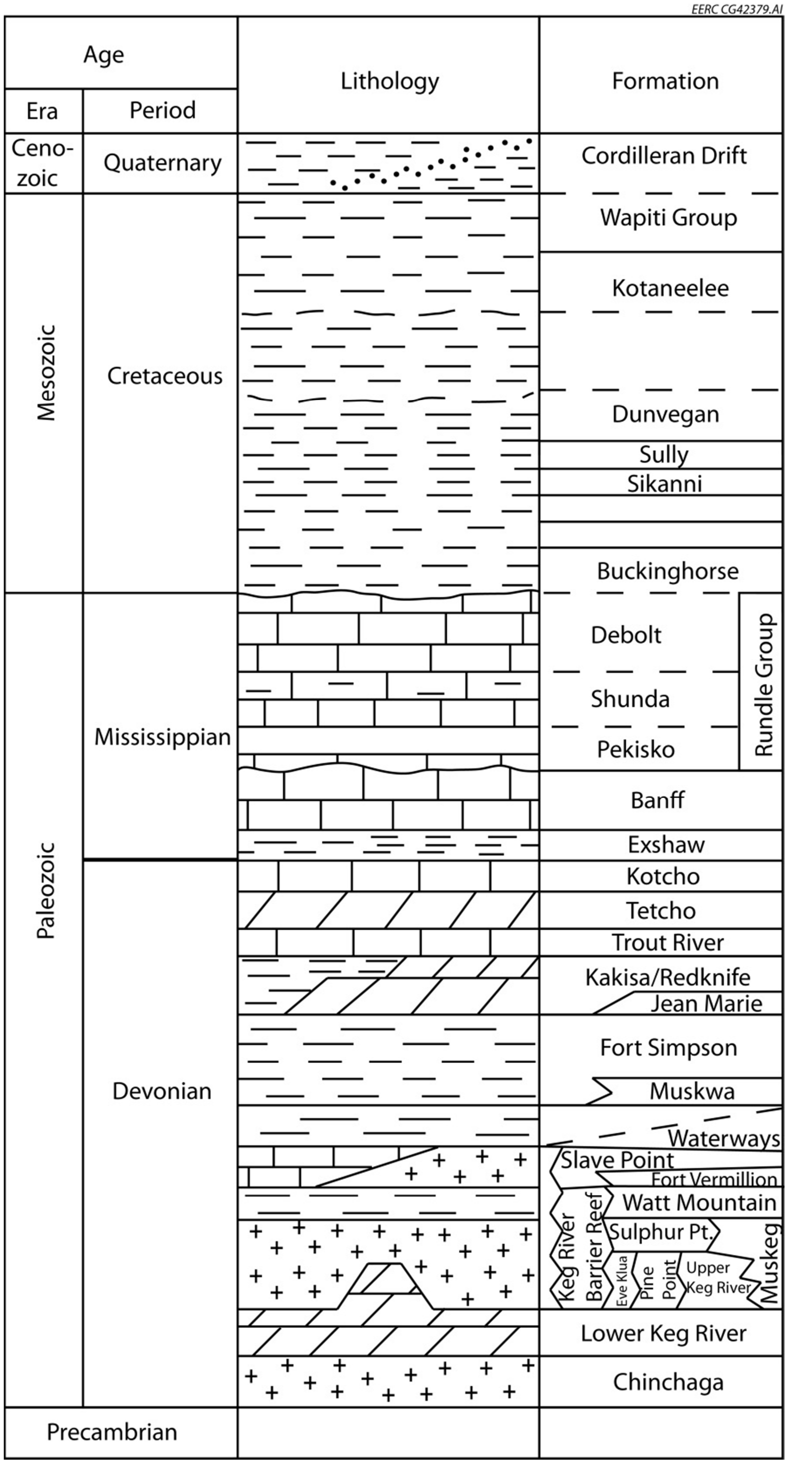

Figure 4. Stratigraphic and hydrostratigraphic delineation and nomenclature as well as general lithology for the northern part of the Alberta Basin, including northeastern British Columbia (modified from British Columbia Ministry of Energy, Mines, and Petroleum Resources 2007).

characterization activities. At this point, modeling projects can be fed information for the initial characterization activities to evaluate the area(s) of interest. Risk assessment and MVA evaluations can then identify which aspects of the program require additional characterization. Finally, the cycle repeats as data are collected from more focused characterization activities such as development of an exploratory well program.

Baseline characterization activities have already been performed, the results of which have been highlighted in this report.

However, further characterization activities will be necessary in order to verify specific conditions and properties in and around the projected injection target zone. These activities may include but are not limited to:

- Drilling of additional exploratory wells for testing, sampling, and evaluation.
- Acquisition and reprocessing of existing seismic data in the area.
- Acquisition of new seismic surveys (likely 3-D seismic surveys).

The drilling of exploratory wells is a critical component necessary to move the Fort Nelson CCS project forward to the implementation stage. Tests that may be conducted in conjunction with drilling additional exploratory wells include the following:

- Collection of a comprehensive suite of downhole geophysical logs
- Drill stem tests
- Well pressure testing
- Collection of core
- Collection of downhole fluid samples
- Application of selected surface-/borehole-deployed geophysical tools (i.e., vertical seismic profile, microseismic arrays, tiltmeters, etc.)
- Water and or CO_2 injection tests

The results of all baseline characterization activities will be subjected to detailed, robust analyses and interpretation by the project technical team. Because data will be generated by a variety of activities and techniques, the comparison, integration, and reconciliation of that information by the technical team is vital to develop interpretations that stay true to the facts. By following this process, the results of the baseline characterization program will provide stakeholders with realistic expectations regarding the design and performance of the CCS project.

The specific location of the test wells will be based on several geological factors, including 2-D and 3-D seismic surveys, structure, orientation of porosity and permeability, the results of the geological modeling and simulation work, first-round risk assessment, and available MVA technology. Specifically, the results of the modeling exercises will help project designers determine 1) locations and spacing of the injection wells, 2) locations and spacing of observation wells, and 3) likely movement and geometry of the sour CO_2 plume. Similarly, sampling programs (core and fluid collection) will be targeted to a specific interval considered for storage. The selection of this interval will be informed by results from baseline characterization (particularly confirmation of the injectivity and storage capacity of the target formation or formations) and subsequent modeling efforts.

2-D and 3-D seismic data within the project area are available and can be purchased and reprocessed for a smaller cost than conducting new surveys. The acquisition and reprocessing of these data (which will be tied to well data as a means of control and comparison) will help increase the resolution of the geological model and result in a better understanding of overall reservoir geometry and local subsurface features, including identification of the following:

- Potential migration pathways such as fractures and faults
- Stratigraphic boundaries
- Formation dip
- Thickness of potential storage and sealing formations
- Changes in lithology
- Presence and geometry of structural features that may serve as traps
- Identification of zones of adequate porosity

The acquisition of new 3-D seismic surveys over the target area would further reduce uncertainties associated with characterization of the injection interval and in prediction simulations. It is important to note that, in order to be effective, seismic survey data must be tied to well data (e.g., geophysical logs, core analyses, and dynamic well testing) as a means of comparison and control. This is critical to support the geologic characterization in terms of understanding the quality of the reservoir with respect to key parameters such as permeability, pressure, and temperature. An initial seismic survey prior to injection would also be necessary if 4-D seismic is determined to be an MVA technology that is technically and economically viable for use at Fort Nelson.

Laboratory Activities. A variety of laboratory experiments will be planned to evaluate the effects of sour CO_2 on potential reservoir rock and cap rock samples. Tests will be conducted on well cuttings and core samples from various depth intervals of the potential reservoir and sealing formations.

Selected rock samples will be exposed to supercritical sour CO_2 under average reservoir pressure and temperature for a predetermined period of time, generally from weeks to months in length. A series of experiments will be conducted using combinations of well cuttings, core plugs, and synthetic brines (some composed of 5 mol% NaCl and others composed of a cocktail of compounds based on adjusted formation water analyses provided by SET) in a standard small scintillation vial. Each vial can then be inserted into a temperature-controlled reaction chamber and pressurized with a CO_2 or combined CO_2 and H_2S atmosphere (Hawthorne and others 2010) under pressure and temperature conditions that are consistent with known reservoir conditions. The resulting material from these experiments can, in turn, be analyzed to identify and evaluate the following:

- Potential chemical reactions
  - Changes in mineral phases and/or composition

- Potential physical reactions
  - Surface reactions
  - Dissolution processes

- Changes in saline formation water chemistry
  - Reaction kinetics

- Impacts of these reactions on potential storage operations

Analytical Tools. An x-ray diffraction (XRD) analysis performed on each sample before and after CO_2 and sour gas exposure will aim to determine the mineralogical components of the samples and evaluate any physical or chemical changes. The XRD scans are utilized to identify mineralogical signatures and to qualitatively and semiquantitatively estimate major and minor sample constituents.

QEMSCAN® can be utilized to analyze surface reactions and sample integrity and as an additional source of semiquantitative mineralogical identification. This method will help identify changes that may affect injectivity, storage, and reservoir integrity. Scanning electron microscopy and other optical tools may also be used to gain a more precise understanding of surficial reactions.

Integrative mineralogical analysis is generally performed utilizing linear program normative analysis (LPNORM) to obtain a better overall estimation of mineralogical phases and to integrate data from XRD and QEMSCAN analysis. The LPNORM computer code utilizes linear programming to calculate the overall mineralogical composition of mineral mixtures, such as rock, sediment, or soil samples, by using the mineralogical (or geochemical) composition of individual mineral phases and bulk geochemical composition (de Caritat and others 1994), which is necessary to create accurate geochemical models.

Inductively coupled plasma–mass spectrometry (ICP–MS) and ion chromatography (IC) are used to analyze the resulting brine from these experiments to detect changes in brine composition and to determine the reaction kinetics of the dissolution processes. This analysis will aid in determining the rates at which these changes may occur and help evaluate their potential impact.

Site Characterization Results. The results of each current and future site characterization activity can be fed into all aspects of the modeling, risk assessment, and MVA programs. These activities will aid in the development of more accurate models, aid in the selection of future characterization activities, reduce or mitigate potential risks, and reduce geologic and overall project uncertainty. The integrated site characterization approach outlined here will be used with modeling and risk assessment activities to design the most cost-effective MVA plan possible, specifically tailored to the unique site characteristics of the Fort Nelson project area.

Modeling Plan

Generation of an accurate geological model is an iterative process that involves compiling a wide variety of data collected on local and regional scales through site characterization activities into a complex computational package that attempts to encapsulate the potential variation in physical and chemical parameters identified in the subsurface. Predictive simulations can then be carried out on this package to create a range of potential outcomes that may result from large-scale injection of sour CO_2 into the modeled geology of the Fort Nelson project area. Results of these simulations can then be used, in part, to identify portions of the model that may be responsible for generating results with lower levels of confidence and thus requiring increased data input. As additional data become available (such as data from new exploratory wells), the model can be updated and results improved or validated.

The Fort Nelson model is being created from existing well logs, cores, maps, testing, seismic data, reports and surveys, and other data provided by SET to recreate, as accurately as possible, the geologic regime of the region. Local data, such as well logs and core data, need to be normalized and correlated in order to remove inconsistencies because of a variety of measurement errors. From this, interpretations of geologic structure and lithology can be generated. Other important data can be derived from well logs, core analyses, geophysical surveys, petrographic analysis of cuttings, and thin sections to determine mineralogy and lithology, all of which can be used to determine depositional environments which, in turn, can be compared to depositional analogs typically identified through a literature review. All of this supports the development of a model that accurately represents the true nature of the sink–seal system.

A stochastic approach is generally favored in order to generate a range of potential outcomes in an attempt to encapsulate variability expected within the system. Individual geologic units are modeled first and then stacked into a regional model. Known faults, identified primarily through seismic data, can be applied to the model once the regional model is created. Because of the complex nature of these systems, it is often necessary to compare model results with existing maps and reports to ensure accuracy of results throughout the model development process. In addition, detailed local and regional pressure data and hydrogeological regime data and interpretation of those data are used to further understand reservoir connectivity. Inconsistencies and other numerical artifacts can then be identified by a geologist and removed or altered, if necessary.

Distributions of continuous local-scale properties, such as porosity and permeability, are populated based on the presence of the various lithologic facies identified earlier. Although rock types may be similar across an area, significant variation can exist primarily as a result of changes in the depositional environment. It is this variation that facies modeling attempts to encapsulate. Finally, after the various model elements are combined, regional-scale properties such as head pressure, salinity distribution, and hydrogeologic flow regimes are applied.

Once model construction is completed, dynamic simulations can be carried out to determine the fate of injected sour CO_2 under various conditions. Included in these simulations is an analysis of geochemical interactions. Conducting a vigorous history-matching exercise using historical data from production and injection wells in the Fort Nelson area is essential to calibrate the model. The history-matching exercise will be used to demonstrate to stakeholders that the model reasonably represents the sink–seal system and can used as the basis for predictive simulations. This analysis will further clarify how interactions between the injected gas, the reservoir fluids, and the rocks will influence mineral precipitation and its effects on permeability, injectivity, and ultimate storage capacity. As these results are updated, the expected behavior and influence of injected sour CO_2 will be incorporated into the risk assessment evaluation, guide the collection of additional data, and aid in the design of the MVA plan.

Risk Assessment

There are several components to an effective risk management framework, including risk assessment, risk treatment, communication, and monitoring. Risk assessment consists of identifying the relevant site-specific risks; estimating the criticality, which is the overall risk to the project (using a combination of probability of occurrence and severity of potential consequences); and evaluating the need to treat the risk based on its rating. The assessment must include the acquisition and evaluation of data to confirm key site characteristics such as capacity, injectivity, and containment as described in previous sections of this document. Once assessed, the risks that have been evaluated as critical must be treated using one of four options: accepting, transferring, avoiding, or mitigating. Finally, the risks must be monitored to ensure that they are successfully controlled. A MVA plan based on the results of the risk assessment helps ensure the project is safe by focusing on and monitoring the site-specific risks. This also helps to limit project costs by ensuring that funding is not spent on monitoring for risks that may not be relevant to the project. Additionally, communication with both internal and external stakeholders about risk is an essential part of gaining confidence and trust in the project.

An essential first step in setting up a risk management system for a project is establishing the context of the project. Several questions should be answered during this stage, such as “What is the scope of the risk management framework that is being established?” and “How is the system defined?” During this stage of the risk management framework, the risk management policy can be developed. The risk management policy establishes the guidelines and boundaries that will be used throughout the lifetime of the project. Another key component of this phase is the definition of the risk criteria. The main components of the risk criteria include the frequency and severity tables used during the risk assessment.

The risk criteria can be based on information established for use in other risk assessments by the project operator or they may need to be developed for a specific project. The operator's risk tolerance level should also begin to develop during this stage. The risk assessment must also take into account the needs and perspective of key stakeholders other than the project operator, including regulators, proximal mineral and surface rights owners, local and regional populations that may be affected by the project, and funding providers. The objectives for this phase of risk management can be accomplished through interviews with various project stakeholders.

Assessment Steps. Risk assessment consists of three steps: identifying the risks to the project, estimating the magnitude of each risk, and evaluating the necessity of treatment.

Risk identification involves determining which risks are relevant to the project. It can be done using several methods, e.g., functional analysis, utilizing existing databases of risks, and expert panel workshops. The end result of this phase is a risk registry that includes potential project-specific risks. The risk registry should be very specific and include only those risks that have been validated by experts or project leaders to be relevant to the project. Ideally, all of the risks in the registry should be defined in a way that they can each be evaluated based on quantitative data, such as can be provided by in situ or laboratory testing. This will ensure that the evaluation of risk can be defended using objective concrete data as opposed to expert opinion, which can be subjective and more easily open to criticism. While this ideal may not always be possible (for instance, it is difficult to quantify political uncertainties that may or may not drive the development of new CCS regulations), the risk registry should aim to minimize reliance on expert opinion. Making reference to established standards is another way to reduce subjectivity in the assessment of technical risks, and such references should be included wherever appropriate. If it is recognized that something is irrelevant for a particular project, it can be discarded from the list; however, the reasons it was removed should be documented for communication and reporting purposes. Some risks that will be of major import to the local citizens (i.e., what the local population sees as important to them) should be retained regardless of whether the risk has been weighed as low probability or impact (e.g., potential impacts to drinking water and potential for induced seismic activity).

The risk estimation phase is where the identified risks that make up the risk registry are analyzed and their overall risk to the project estimated. A risk's rating is usually estimated using a combination of the probability of occurrence and the potential severity. The risk criteria developed at the beginning of the risk management process are key components during this step.

Following the risk assessment, a risk map can be created. A risk map is a way to visually present the risks so that they can be easily compared. It allows users to quickly tell how significant a risk is for the project and compare it to the other risks that were evaluated. When a risk map is read, it is very important to understand the difference between the maximum and most probable values in any assessment. The maximum rating is far less likely to be seen in reality; however, it represents the rating that cannot be ruled out as a possibility.

The results of risk assessment activities directly influence the choices made when an MVA plan is developed. Identified site-specific risks can drive the choices of potential monitoring and mitigation strategies. This helps to ensure that MVA resources are applied efficiently and effectively at the storage facility. Furthermore, the risk assessment can be regularly updated during the project's lifetime to help refine future MVA efforts as additional data become available.

MVA Plan

CCS technology is still at an early stage of development and, therefore, must demonstrate its capability to permanently and safely remove CO_2 from the atmosphere. As a result, monitoring technologies are needed to keep track of the changes occurring in the subsurface as a result of CO_2 injection over long periods of time. Furthermore, the integration of these technologies in a coherent and site-specific MVA plan will ensure that the collected information allows the operator to apply the appropriate mitigation actions should a deviation from the injection plan occur.

In the U.S. Department of Energy National Energy Technology Laboratory's report on best MVA practices, the following objectives are assigned to the MVA plan associated to CO_2 storage operations (U.S. Department of Energy National Energy Technology Laboratory, 2009):

- Improve the understanding of storage processes and confirm their effectiveness.
- Evaluate the interactions of CO_2 with formation solids and fluids.

- Assess environmental, safety, and health.

- Evaluate and monitor any required remediation efforts should a leak occur.

- Provide a technical basis to assist in legal disputes resulting from any impact of storage technology (groundwater impacts, seismic events, crop losses, etc.).

The Fort Nelson CCS project is being evaluated and planned under the assumption that the regulatory authorities of British Columbia will require that a proper site-specific MVA plan be implemented at the Fort Nelson CCS site. SET and the EERC are using a risk-based approach to define the MVA strategy. This means that the MVA plan will stem from the risk assessment of the storage project and be primarily focused on the early detection of the occurrence of the most critical risks and their mitigation.

Furthermore, additional objectives for the Fort Nelson CCS project's MVA plan include:

- Cost-effectiveness: Fort Nelson is not a research and development project but a commercial-scale demonstration project. Therefore, it requires the use of cost-effective and proven technologies.

- Minimal disruption of operations: The MVA plan should by no means impede storage operations. Rather, it should enable effective and high confidence monitoring of the injected plume.

Once key measurable parameters are identified for each high-criticality risk, relevant MVA technologies can be proposed. The technical applicability of each MVA technology will be evaluated in terms of its maturity/applicability, cost/benefit ratio, and likelihood of success. The following is a short list of relevant MVA technologies that may be considered for monitoring the deep subsurface based on initial assessments:

- Multicomponent surface seismic
- Microseismic (well-based)
- Vertical seismic profiling (VSP)
- Surface (wellhead) injection rate measurements (mandatory by regulation)
- Downhole fluid chemistry/geochemistry
- pH measurements
- Tracers
- Annulus pressure measurements
- Geophysical and well integrity logs
- Downhole and surface pressure/temperature measurements (mandatory by regulation)

Periodic surface wellhead injection rate measurements, surface pressure and temperature, and downhole pressure and temperature measurements are mandatory and required by British Columbia regulatory agencies as part of the license to operate an injection scheme.

Recommendations for a Risk-Based MVA Program. A functional analysis performed during the first-round risk assessment was used to identify failure modes and possible causes and effects for each component of the subsurface storage system for the high-criticality risks for different phases of the project. It is important to note that no specific high-criticality risk was found that relates to the surface or shallow subsurface. Therefore, no monitoring technique associated with these two zones was initially evaluated. Nevertheless, current and pending federal and provincial legislation could impose surface and/or shallow subsurface monitoring in order to prove the efficiency and safety of the storage related to health and safety and public acceptance. Also, experiences at other CCS locations suggest that proactively establishing background data regarding standard water quality parameters and levels of CO_2 in the surface/shallow subsurface environment can be a valuable tool for addressing questions that may arise in the future regarding the potential impact of CO_2 injection on the surface/near-surface environment. With this in mind, surface/shallow subsurface monitoring will need to be evaluated as part of the next iteration.

Two types of MVA plans are recommended:

- Primary monitoring plan: Continuous monitoring to confirm that the models are in accordance with the observed system behavior. Continuous monitoring provides key information on the response of the downhole reservoir environment to the injection. These data help the reservoir engineers understand what is going on in the sink–seal system and provide early notification if the reservoir, seal, or wellbore begin to experience problems. The data are also used in the model to help forward-match and identify areas where changes to the geologic description of the underlying model may be necessary. Over time the model's predicted performance will closely match the observed performance, at which point the predictive model can be considered to be reliable. These data can also be used in understanding long-term liability and facilitate project closure with the province.

- Contingent monitoring plan: Should continuous monitoring detect a system deviation, a risk-based decision tree is implemented. This decision tree defines the response plan for proper mitigation of the risk as early as possible through complementary measurements or modification of the injection strategy. In practice, it is anticipated that the regulator will require at minimum an annual report showing all observed/measured data, the reconciliation/explanation of results, and notice of any significant deviation from the model predictions or deviation from the operating permit. It will be important that for any deviation of note the operator provide a mitigation plan and description of responses that will be taken to address the deviation. A report of the results of any such mitigation/management steps taken by the operator must be provided to the regulator upon completion of those steps. Failure to comply with the process will result in the issue going up the regulatory enforcement ladders, which may ultimately include revocation of the license to operate and mandated operation closure/cleanup.

Spatial definition of MVA applications is not yet possible. Therefore, the MVA program will either have to be refined, taking into account the spatial dimension once the modeling and simulation work are completed, or site selection will need to be guided by MVA criteria. The two different strategies that could be adopted follow:

- The MVA plan is not taken into account in the injection strategy optimization criteria. The injection strategy will define the locations of the injection and monitoring wells on the site through injection simulation combined with geologic factors and evidence. The current MVA plan will be refined by determining where the emitters and receptors associated with different techniques will be placed. At this point in time, the project is still in an exploration phase with respect to understanding the key parameters of the reservoir (i.e., injectivity, capacity, and containment). The collection, integration, and interpretation of previously unavailable core analysis, well logging, and seismic survey data during the summer of 2011 will significantly improve the knowledge base for the sink–seal system at Fort Nelson. This, in turn, will support the iterative development of an effective MVA plan as that knowledge base is improved. The specificity of the MVA plan will be further refined as more subsurface data become available as a result of the exploratory well drilling and testing activities that are planned for the winter of 2011–2012.

- Alternatively, this first-round risk-based MVA protocol for the Fort Nelson CCS project can serve as a criterion for the injection strategy optimization, which will, in turn, guide MVA plan refinement.

While both strategies are feasible, the most commercially viable option (and the proactive approach) would be to optimize the injection strategy based on the geology and hydrogeology of the area and on economics. In this way, the injection strategy can be tailored to minimize risk rather than simply mitigate it.

It will be necessary to review and update this initial MVA plan once the current model update and subsequent risk assessment have been completed. Specific MVA components pertaining to the frequency of acquisition, overall plan effectiveness, and a cost assessment will be necessary once an injection strategy is finalized to ensure overall project success. Regulatory permitting and accounting requirements will also need to be reviewed in terms of compliance.

Proposed Path Forward

To properly implement an effective, economical, and optimized commercial-scale CCS project at the Fort Nelson site, an iterative update process between site characterization, modeling and simulation, risk assessment, and MVA must be used so as to ensure regulatory compliance and project safety in an economical manner. Currently, a first-round evaluation has been performed and is being used to identify additional characterization activities that are beneficial to the project and update simulation work in order to help guide the selection of a site-specific injection strategy. Upon completion of the current site characterization and modeling update work, specific injection scenarios can be evaluated in terms of criteria set forth by SET.

Once a final injection strategy has been defined, the risk assessment will be updated to include risk criticality rankings for the specific selected injection strategy based on simulation results, which will, in turn, be used to guide a specific MVA strategy. The updated MVA plan will include specific technologies, spacial locations of measurements, acquisition frequencies, and baseline data necessary to address critical project risk and regulatory requirements and identify potential deviations from expected conditions in a timely manner. Once the updated assessment has been completed, the injection program can begin. However, periodic updates will be necessary throughout the injection phase of the project in order to confirm system behavior and agreement between the physical injection, simulation results, anticipated risks, and successful deployment of MVA strategies.

Conclusions

SET's FNGP is the largest sour gas-producing plant in North America. Because of recent developments in the Horn River shale plays, it is expected that the plant will return to its full processing capacity, making the plant the largest point source for CO_2 emissions in British Columbia. To reduce this potential liability, SET is currently investigating technical and commercial CCS options that may be able to mitigate the effects of a return to full capacity.

The geology and hydrogeology in the vicinity of FNGP is amenable to geologic storage of CO_2. Ongoing work involves site characterization to fully define the geologic system, modeling, and simulation work to predict reservoir response to injected gas, risk assessments to identify and mitigate site security issues, and an MVA program designed to verify or detect deviations in system behavior in accordance with expectations. This process requires multiple iterations to ensure an effective, optimized, safe, and economical injection program. Currently, an initial assessment has been completed, and work is ongoing that will ultimately lead to a finalized injection strategy and affiliated risk-based MVA program.

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