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Abstract

The U.S. Department of Energy's (DOE) FutureGen 2.0 Program involves two projects: (1) the Oxy-Combustion Power Plant Project and (2) the CO_2 Pipeline and Storage Project. This Final Technical Report is focused on the CO_2 Pipeline and Storage Project.

The FutureGen 2.0 CO_2 Pipeline and Storage Project evolved from an initial siting and project definition effort in Phase I, into the Phase II activity consisting permitting, design development, the acquisition of land rights, facility design, and licensing and regulatory approvals. Phase II also progressed into construction packaging, construction procurement, and targeted early preparatory activities in the field.

The CO_2 Pipeline and Storage Project accomplishments were significant, and in some cases unprecedented. The engineering, permitting, legal, stakeholder, and commercial learnings substantially advance the nation's understanding of commercial-scale CO_2 storage in deep saline aquifers. Voluminous and significant information was obtained from the drilling and the testing program of the subsurface, and sophisticated modeling was performed that held up to a wide range of scrutiny. All designs progressed to the point of securing construction contracts or comfort letters attesting to successful negotiation of all contract terms and willing execution at the appropriate time all major project elements – pipeline, surface facilities, and subsurface – as well as operations.

While the physical installation of the planned facilities did not proceed in part due to insufficient time to complete the project prior to the expiration of federal funding, the project met significant objectives prior to DOE's closeout decision. Had additional time been available, there were no known, insurmountable obstacles that would have precluded successful construction and operation of the project. Due to the suspension of the project, site restoration activities were developed and the work was accomplished. The site restoration efforts are also documented in this report.

All permit applications had been submitted to all agencies for those permits or approvals required prior to the start of project construction. Most of the requisite permits were received during Phase II. This report includes information on each permitting effort.

Successes and lessons learned are included in this report that will add value to the next generation of carbon storage efforts.

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EXECUTIVE SUMMARY

Summary Statement

The U.S. Department of Energy's (DOE) FutureGen 2.0 Program involves two projects: (1) the Oxy-Combustion Power Plant Project and (2) the CO_2 Pipeline and Storage Project. This report is focused on the CO_2 Pipeline and Storage Project, and also addresses interface considerations between the two projects.

The CO_2 Pipeline and Storage Project accomplishments were significant, and in some cases unprecedented. The engineering, permitting, legal, stakeholder, and commercial learnings substantially advance the nation's understanding of commercial-scale CO_2 storage in deep saline aquifers. While ultimately the physical installation of the planned facilities did not proceed due to insufficient time to complete the project prior to the expiration of federal funding, the project delivered on all significant objectives prior to DOE's closeout decision. Had additional time been available, there were no known, insurmountable obstacles that would have precluded successful construction and operation of the project. Among the project's accomplishments were:

- Successfully siting Illinois' first CO_2 pipeline permitted under Illinois Carbon Dioxide Transportation Act proving an approach that can be implemented by future CCS projects.
- Successfully siting and acquiring the land and geologic storage rights for the nation's first commercial-scale CO_2 storage reservoir fully integrated with a coal fired power plant.
- Receiving the first Final US EPA Class VI Underground Injection and Control (UIC) Permits in August 2014. The permits became effective on May 2015 following a successful appeal defense. A second, ongoing appeal does not impact the effectiveness of the permits.
- Designing a complex management and control system to allow the integrated operation of the power plant, pipeline, and storage site.
- Developing, in partnership with the State of Illinois, a long-term approach for CO_2 stewardship and liability management.
- Successfully completing negotiation of all major commercial EPC, operating, and off-take contracts. The CO_2 off-take agreement with the Oxy-Combustion sister project would have provided full cost recovery of the CO_2 transportation and storage operations.
- Successfully negotiating a project labor agreement (PLA) with 17 craft labor unions that would have supplied construction labor for the project.

These accomplishments were realized amidst a constantly changing timeline driven by evolutions in the companion Oxy-Combustion Power Plant Project, and yet the overall CO_2 Pipeline and Storage project remains within DOE and commercial budgetary constraints – a testament to the creative, value-maximizing methods applied in all aspects of the CO_2 Pipeline and Storage Project, inclusive of the pipeline, surface, and sub-surface elements.

Background

The primary objectives of the FutureGen 2.0 CO_2 Pipeline and Storage Project[1] were to site, permit, design, and construct a CO_2 pipeline and CO_2 storage reservoir; to be fully integrated in terms of project management, capacity, capabilities, technical scope, cost, and schedule with the companion FutureGen 2.0 Oxy-Combustion Power Plant Project[2]; and to be capable of safely and permanently accepting, transporting, and sequestering all CO_2 produced by the oxy-combustion power plant in a deep saline geologic formation. Thus, the pipeline and storage site was permitted and designed to transport and store up to 1.1 million metric tons (MMT) per year of CO_2 produced by the oxy-combustion power plant over a twenty year period of operation.

In pursuit of this master objective, a set of performance milestones were stipulated by DOE in the Cooperative Agreements for each of the two projects. Those that fall within the scope of the CO_2 Transport and Storage Project included:

- Completion of Front End Engineering Design (FEED)
- Control of surface and subsurface rights required for 20-years of CO_2 storage
- Submission to DOE of a definitive estimate of project cost
- Issuance of a CO_2 injection permit by U.S. EPA
- Issuance of a final pipeline permit by Illinois Commerce Commission
- Execution of Engineering Procurement and Construction (EPC), and Operating & Management (O&M) contracts
- Achieve financial close

Status as of the Cooperative Agreement Closeout

Summarized below is the status of each major Cooperative Agreement performance milestones as of receipt of the January 28, 2015 notice that the DOE had decided to closeout its financial support of the project due to insufficient time remaining for project completion prior to expiration

[1] The DOE contractual name for the project is the CO2 Regional Storage Project. The phrase CO2 Pipeline and Storage Project is used for general clarity as to the project's scope.
[2] The DOE contractual name for the project is the Oxy-Combustion Large-Scale Test Project. The term Oxy-Combustion Power Plant Project is used for general clarity as to the project's scope.

of the federal funding. The full Cooperative Agreement Closeout Report contains detailed information associated with each milestone as noted:

Completion of Front End Engineering Design (FEED) – The FEED was submitted to DOE on December 12, 2013 – on schedule. The FEED was highly detailed relative to a typical FEED and scored exceedingly well during a formal project development review. Subsequent to the FEED nearly all final design work was completed, which aided substantially in securing competitive EPC contract pricing. The FEED details are found in the pipeline, surface and subsurface chapters' appendices and include:

1. the civil, electrical, instrumentation and mechanical components of the pipeline design,
2. the surface facilities' designs including the site control building (architectural, mechanical, electrical and plumbing), the surface earthwork, and the pad development for the injection and monitoring well installations,
3. the required infrastructure to service the initial construction of the systems, including the road upgrades to accommodate the oversized transport vehicles, and the utility infrastructure to serve the monitoring and operation of the storage systems, including electrical, water and communications, and
4. the subsurface design components of the four injection wells, the two above confinement zone wells, the two single level reservoir wells, the underground source of drinking water well, plus three deep reservoirs remote access tubes.

Control of surface and subsurface rights required for 20-year CO_2 storage – Control of the subsurface rights within the permitted 20-year CO_2 storage area was achieved in September of 2013 – ahead of schedule. This was followed by control of the main injection site surface rights in December of 2013 – on schedule. This required separate agreements from over 100 Landowners to aggregate over 220 parcels of land encompassing more than 10,000 acres of contiguous pore space. This is an extremely unique accomplishment given:

1. the unprecedented nature of deep geological CO_2 storage,
2. the fact that CO_2 is not generally well-understood or familiar to the vast majority of agricultural landowners and residents in central Illinois,
3. the high risk of achieving aggregation amidst a diverse population of "anti-common" landowners (i.e. when multiple parties are each capable of excluding others from a scarce resource—the storage site), and
4. it was accomplished on a compressed timeline based on free-market negotiations (i.e., the Alliance did not have eminent domain, unitization, or legal tools at its disposal).

A number of significant lessons learned were derived from this process as summarized later in this Executive Summary and as fully-described in Appendix 1G of this report.

Submission to DOE of a definitive estimate of Project cost – The Definitive Cost Estimate was delivered to DOE on April 1, 2014 – on schedule. The Definitive Cost Estimate predicted project cost through construction at $471M. This was about 6% greater than the prior estimate, with much of the increase driven by the time impacts, which escalated construction costs, industry price pressure due to the U.S. oil and natural gas boom, and detailed risk and contingency modeling, which led to increased reserves. The Definitive Cost estimate is found in Appendix 1H. Subsequently, during the course of the EPC contract negotiations, the total estimated project cost was reduced and brought into alignment with the DOE budget and commercial financial constraints.

Issuance of a CO_2 injection permit by U.S. EPA – The Class VI Underground Injection and Control (UIC) permits for each of the four injection wells were issued in final form by EPA on August 29, 2014. These were the first final permits issued by EPA. The permitted storage reservoir includes four horizontal injection wells at a depth of approximately 4000 feet in the Mt. Simon sandstone. An array of nine monitoring wells is included in EPA approved measurement, monitoring, and verification plan associated with the permit.

Subsequent to permit issuance, landowners adjacent to the permitted storage site appealed. At the time DOE's issuance of a cooperative agreement close-out notice, the appeal was pending. On April 28, 2015, the EPA Environmental Appeals Board ruled in favor of the FutureGen project on all issues. The final permits became effective as of May 7, 2015. While appeals are never desirable, the case law generated by it will help EPA and future permit applicants on future projects.

On May 20, 2015, the losing appellant appealed to a higher court.. Particularly in light of the strong ruling in the initial appeal, there is a very low risk that the permits will be overturned.

Detailed information on the UIC Permits is found in Chapter 6.

Issuance of a final pipeline permit by the Illinois Commerce Commission – On February 20, 2014, the Illinois Commerce Commission issued a Final Order awarding the Alliance a Certificate of Authority to construct and operate a CO_2 pipeline, and approving the Alliance's preferred route for the CO_2 pipeline. The Commission's approval included the right to exercise condemnation authority (subject to compliance with the Illinois Eminent Domain Act). This was the first CO_2 pipeline certificate issued under Illinois Carbon Dioxide Transportation Act.

Execution of Engineering Procurement and Construction (EPC), and Operating & Management (O&M) Contracts – Contracts or Comfort Letters attesting to successful negotiation of all contract terms and willing execution at the appropriate time, were successfully negotiated for all major project elements – pipeline, surface facilities, and subsurface – as well as operations. These contracts were either executed, or successfully negotiated awaiting execution, with very competitive terms, despite negotiation in a contracting environment that was extremely stressed (the contracting effort was coincident with the U.S. oil and natural gas boom). While taking longer than originally anticipated to negotiate, all contracts were awarded or recommended for award with contractor safety performance as a primary selection criterion. EPC Contracts were successfully completed and ready for execution between May 2014 and early December 2014, and as a result of the competitive pricing, contract structures, terms, and pricing negotiated, the variance vs. budget that was noted at the time of the Definitive Cost Estimate was eliminated. Additional details concerning the EPC and Operations contracts are found in Chapter 1, Section 1.7 of this report.

Achieve Financial Close – The CO_2 Pipeline and Storage Project construction was to be funded on an all cash basis with no debt. Adequate financial resources were available to close on the CO_2 Pipeline and Storage Project; however, financial close on the Oxy-Combustion Power Plant Project needed to occur concurrently for the full program to proceed, while not believed to be insurmountable, there was insufficient time resolve the remaining Oxy-Combustion Power Plant Project closing issues (i.e., appeals, resolution of final EPC contract issues, and final debt/equity commitment which were all interlinked).

At the time of the closeout notice, the Alliance had negotiated a letter of intent to provide full equity to the Oxy-Combustion Power Plant Project contingent upon a final stage of investor due diligence. The equity investors included a major energy company with coal power plant, pipeline, and gas storage operating experience, as well as one of the world's largest energy-focused equity investment funds.

Lessons-Learned

Safety – Successful completion of all construction efforts with zero recordable safety incidents is certainly one of the most important achievements of the FutureGen 2.0 CO_2 Pipeline and Storage Project. The project involved substantial fieldwork associated with site characterization, construction of access roads, and other infrastructure improvement prior to the planned full construction start. During this work there were zero recordable safety incidents, an achievement also met by the companion Oxy-combustion Power Plant Project. Demonstrated emphasis on safety during the early stages of the project, while worker and community trust is being built, is critical to long-term success. Safety started with a strong safety culture created by the Alliance and reinforced with all contractors. As the work progressed, safety priority was further implemented by selecting only contractors who demonstrated an emphasis on safety within their own organizations, and who achieved strong safety performance in their prior projects. All Alliance contracts were awarded with contractor safety performance as a primary selection criterion.

Community Stakeholder Relations – Projects that involve unprecedented characteristics require significant land aggregation or rights-of-way acquisition, are performed within a sensitive labor environment, possess significant political flavor, require a suite of environmental permits, and/or involve construction of a significant public facility demand well planned and extensive stakeholder involvement. The CO_2 Pipeline and Storage project possessed all of these traits in significant magnitude. Ultimately the project succeeded in its siting, and its success is a tribute to both executive commitment, and outstanding, ground-level stakeholder outreach.

At the time of the October 2010 project launch, an aggressive storage site selection milestone of January 2011 was specified. Stakeholder involvement experts advised against such an aggressive date, but a sense of urgency to select the site prevailed. The site selection team proceeded on an accelerated schedule. Following an expedited public meeting in Morgan County, local opposition was strong. Intensive stakeholder outreach followed. Once information demonstrating the substantial benefits and low risk associated with the project was delivered to the local stakeholders, concerns were subsequently allayed and the storage site was successfully sited. The key to this progress was establishing more effective local stakeholder outreach and information dissemination. While the project was ultimately successful, a rapid site selection process nearly resulted in Morgan County withdrawing its proposed site. FutureGen's experience reaffirms that it is imperative that the CO_2 storage siting process not get ahead of local stakeholders.

Acquiring Contiguous Storage Site Subsurface Rights – FutureGen 2.0 was successful beyond expectations in the acquisition of subsurface storage and surface rights which comprised a contiguous storage reservoir. This involved the aggregation of many individual tracts of land and involving many individual landowners. At the outset, partially due to the first-of-a-kind nature of the project, the developing nature of EPA storage regulations, and somewhat limited geologic data in the county due to limited historical oil and gas prospecting, the ultimate storage site was larger than originally anticipated. Some local landowners were motivated to participate due to the project's broad county-wide economic benefits, including construction job creation, the permanent job creation associated with the power plant located in the same county, and inclusion in the project of a local visitor and training center. In FutureGen 2.0's situation, eminent domain, unitization, or other policy tools were not available. It is not believed that such success could be created in nationwide deployment of storage sites absent such tools. Thus, the siting of future storage projects would be benefited by State laws for CO_2 storage site rights acquisition (similar to those already in place in many jurisdictions for oil and gas subsurface rights) that obligate landowners to aggregate tracts by majority participation through unitization, are subject to eminent domain, or by targeting very large contiguous tracts, such as those held by governments, energy companies, or mining companies.

Procurement and Construction (PC) and Operating and Maintenance (O&M) Contracting – While taking longer than originally anticipated, all three EPC contracts and both of the O&M contracts associated with the CO_2 Pipeline and Storage Project were successfully negotiated. Comfort letters were signed in anticipation of financial close when the contract would have gone into full effect.

An important learning is to recognize market conditions when developing contract requirements, and to find win-win strategies when in some cases only one or two viable service providers are available and qualified. Contractors that will build CCS pipelines and storage sites find most of their business in the oil and gas markets, so conditions and contractual expectations in those markets will affect CCS projects. Bearing this in mind, FutureGen 2.0, was able to obtain a high percentage of competitive firm pricing content, while also maximizing joint owner/contractor incentives to meet or beat the budget for content that was not practical to firm price. While the project did not proceed to full construction, all construction contracts were ready for final execution between May 2014 and early December 2014, and as a result of the competitive pricing, contract structures, terms, and pricing negotiated within the project's budget constraints. Additional details concerning the P&C and O&M contracts are found in Chapter 1, Section 1.7 of this report.

Geologic Storage and Permitting Talent – It is abundantly clear that, at this early stage of carbon capture and storage (CCS) deployment, having specialized geologic talent beyond that which might be found in the oil, gas, and mining sector was pivotal. Further, US EPA is proving out the Class VI UIC permitting process, and as EPA Region V is a national leader in their understanding of the issue, FutureGen 2.0 benefited tremendously from being sited in Region V. It is notable that EPA Region V staff commented that FutureGen 2.0's geologic team "spoke their scientific language". That is, the FutureGen 2.0 geologic team (led by Pacific Northwest National Laboratory and Battelle, and supported by Schlumberger) was well up the learning curve on regional geologic and UIC permitting issues. Attention to geologic and scientific detail, as well as complete transparency with EPA speed the permitting activity. Further, the geologic team's ability to communicate with stakeholders clearly profoundly aided community acceptance. Also, quite importantly, they built confidence in power plant equity investors that the storage site would perform as advertised. Engagement of such expertise amidst unprecedented technology implementation should be a requirement for future projects.

Local Engineering Talent – Utilizing a well-qualified, local engineering firm (in this case Patrick Engineering) to provide Project Management, Construction Management, and coordination of certain stakeholder activities was strategically important in several key ways: 1) It delivered the greatest economic value to the project, 2) the skill-set, and more importantly, the individual personnel made available for the project were an outstanding match, and 3) the knowledge of local contractors and labor was invaluable. Such a relationship, at minimum in a strong project consulting role, should be strongly considered in future projects of this character.

1 PROJECT OVERVIEW AND ADMINISTRATION

Under the terms of a Cooperative Agreement (DE-FE0001882) with the U.S. Department of Energy (DOE), the FutureGen Industrial Alliance, Inc. (Alliance) was responsible for locating a suitable site, and executing the design, construction and operation of the FutureGen 2.0 carbon dioxide (CO_2) Pipeline and Storage Project (Pipeline and Storage Project). The Cooperative Agreement is provided in Appendix 1A. The following chapter highlights the background and administration of the CO_2 storage facility programming, inclusive of the associated pipeline required to service the transport of CO_2 from the Oxy-Combustion Power Plant Project (Power Plant Project) that was to have been located in Meredosia, Illinois.

1.1 Introduction

The primary objective of the Pipeline and Storage Project was to site, design, construct, and operate a CO_2 pipeline and CO_2 storage reservoir to be fully integrated in terms of project management, capacity, capabilities, technical scope, cost, and schedule with the Power Plant Project, and to be sufficient to accept, transport, and sequester CO_2 produced by the Power Plant Project in a deep saline geologic formation. The Pipeline and Storage Project was intended to transport and sequester up to 1.1 million metric tons (MMT) per year of CO_2 supplied by the Power Plant Project, which was to have been located in Meredosia, Illinois. Other specific objectives for this project were to:

- Demonstrate operation of the CO_2 pipeline and CO_2 storage reservoir fully integrated with the Power Plant Project at the desired rate for a period of 56 months.
- Execute a monitoring, verification and accounting (MVA) program during the three-year demonstration program and for two years thereafter.
- Demonstrate technologies and protocols for CO_2 MVA necessary to establish the permanence of the sequestered CO_2 and provide an accounting for all captured CO_2.

The purpose of this technical report, in general, is to provide a narrative of the technical results of the work performed through January 2015, and to detail significant new scientific or technical advances as specified in the Statement of Project Objectives (SOPO). This report consolidates nonproprietary information developed by the Alliance as part of the National Environmental Policy Act (NEPA) compliance process, the environmental and cultural resources permitting process, the analysis and design of the pipeline and underground CO_2 injection zone portion of the project, and the construction and testing activities.

The purpose of this chapter is to provide an overview of the project background, administration, management and controls implemented to manage the numerous scopes, budgets and schedules of the Pipeline and Storage Project. The chapter describes the procedural steps taken to site and design the pipeline and storage site, to highlight the successful contracting processes that secured construction-ready contracts, and to highlight the major steps and processes required to progress a project of this magnitude, including stakeholder participation and extremely sensitive land acquisition activities.

1.2 Background

On August 5, 2010, DOE announced the award of American Recovery and Reinvestment Act (ARRA) funding to the Alliance to build the FutureGen 2.0 project. DOE would authorize the expenditure of funds in four phases upon successful completion of objectives associated with each phase. The phases are:

- Phase I – Project Definition
- Phase II – NEPA, Permitting and Design
- Phase III – Construction and Commissioning
- Phase IV – Operations

During Phase I, sites were evaluated and a final site was selected for the CO_2 storage facility, a pipeline route was identified, a conceptual design for the storage facilities was produced, and cost estimates were prepared for the project. The siting process is further described in this chapter, but culminated on February 28, 2011, when the Alliance announced its selection of Morgan County, Illinois as the preferred location for the FutureGen 2.0 CO_2 storage site, the visitors' center, and the research and training facilities. The NEPA process was initiated and a number of subsurface and environmental studies were undertaken during Phase I.

Phase II, which began in February 2013, had five subphases:

- Subphase IIA – Completion of conditions on award specified in the Cooperative Agreement
- Subphase IIB – Submission of power purchase agreements, CO_2 injection permit application, and pipeline permit application
- Subphase IIC – Completion of front-end engineering design and control of surface and subsurface rights required for CO_2 storage
- Subphase IID – Submission of a definitive cost estimate; issuance of a CO_2 injection permit, final pipeline permit, and non-appealable air and water permits; and execution of Engineering, Procurement, and Construction (EPC), Operating and Management (O&M), and commodity contracts
- Subphase IIE – Financial close

In Phase II, environmental studies were conducted and completed, engineering and construction subcontractors were evaluated and selected, and front-end engineering design through advanced design occurred. Definitive Cost Estimates were prepared and numerous permits were obtained for the Pipeline and Storage Project. The timeline depicting the major accomplishments during Phase II is shown in Appendix 1C. Over the course of the project, a number of amendments were made to the Cooperative Agreement. Phase II in Amendment 20, along with the purpose of the amendments and the corresponding budget changes.

Table 1.1 shows the various amendments made to the Cooperative Agreement starting with the authorization to proceed to Phase II in Amendment 20, along with the purpose of the amendments and the corresponding budget changes.

Since the fall of 2013, a set of accelerated activities had been under discussion and evaluation by DOE's National Energy Technology Laboratory (NETL) and the Alliance. The original purpose of the accelerated activities was to increase the amount of time between the project's actual expenditure of ARRA funds and the statutory expiration of ARRA funding on September 30, 2015. In August 2014, DOE signed Amendment 27 that authorized Phase IIE budgets which would bring forward certain Phase III activities. These approved budgets allowed construction of road upgrades, the injection site pad, and the first injection well. By December 2014, construction of the injection well pad was completed, and various road improvements and a water line extension had been constructed. Planning for construction of the first injection well was largely complete.

At the end of January 2015, coinciding with the DOE-directed suspension, Phase I costs totaled $33.3 million and a total of $42.8 million had been spent on Phase II activities, including those moved forward into Phase II from Phase III. The unspent budgets from subcontractors in Phase IIE totaled approximately $5.6 million due to DOE's decision to close out the Cooperative Agreement in Amendment 32. Section 1.8 discusses these costs in more detail.

Table 1.1. Phase II Amendments

Amendment	Effective Date	Authorization Period From/To	Total Phase II Budget ($1000s)	Purpose of Amendment
020	07/1/2013	2/5/2013 - 6/15/2014	$30,658.7	Recognized conditions in Amendment 017 (Phase I) had been met. Authorization to proceed to Phase II.
021	01/6/2014		$30,658.7	Changed the DOE Award Administrator/ Contract Specialist and the DOE Grants/Agreements Officer.
022	02/24/2014		$30,658.7	Changed the DOE Award Administrator/Contract Specialist.
023	06/16/2014		$30,658.7	Changed Subphase IIE end date from June 15, 2014 to November 30, 2014.
024	07/2/2014	2/5/2013 - 7/31/2014	$30,658.7	Revised the amounts in article 30 and No Cost Time Extension (NCTE) through July 31, 2014.
025	07/11/2014		$33,979.8	Updated the amount authorized for Pore Space Purchases.
026	07/23/2014		$33,979.8	Revised amounts for contractor budgets.
027	08/13/2014	2/5/2013 - 11/31/14	$49,283.1	Increased total Phase II budget by $15,303,296, reduced Phase III budget by $15,303,296. Amendment for Phase IIE contained budgets for early construction of the road upgrades, injection site pad and injection well.
028	09/2/2014		$58,432.6	Authorized budget revision. Conditional authorization of the initial installment to the Underground Injection Control Trust Fund for $8.823 million + 3.7% G&A.
029	11/13/2014		$58,432.6	Authorized acquisition of properties along the pipeline right of way (ROW).
030	11/25/2014	2/5/2013 - 1/15/2015	$58,432.6	NCTE of Phase II from November 30, 2014 to January 15, 2015.
031	01/15/2015	2/5/2013 - 1/28/2015	$58,432.6	NCTE of Phase II/Subphase IIE from Jan15, 2015 to Jan 28, 2015.
032	01/28/2015	2/5/2013 - 3/20/2015	$58,432.6	Suspended activities not required for closeout and directed preparation of a closeout plan. The end date for Phase II changed to Mar 20, 2015.
033	03/21/2015	2/5/2013 - 6/30/2015	$58,432.6	End date for Phase II extended to June30, 2015. Closeout Plan approved Reallocated Phase II costs per Article 51.

1.3 Project Management and Project Controls

The Pipeline and Storage Project has been managed with a fully integrated resource-loaded schedule using standard project management scheduling and earned value methodology. Phase I and II project management and controls included budget tracking, scope tracking, and schedule analysis utilizing Primavera P6. The controls staff interfaced with the project's technical staff, financial staff, project managers, and the functional managers on scheduling, cost estimating, risk, and earned value analysis. This process monitored the project's health by utilizing key performance indicators addressing such items as scope change, cost and schedule performance, and critical issues and risks.

The project management process included daily coordination and reviews of numerous project controls data and information. Primavera P6 was used to manage the scopes and schedules. Weekly status meetings were held with all contractors based on their scheduled three-week outlooks.

For the purposes of calculating schedule updates and earned value metric analysis, all level of effort (LOE) activities such as project management, permitting support, drilling planning, etc. were spread over their authorized approval period. All other activities in the schedule were status-based on their percent complete. Each month, the subcontractors submitted schedule updates. The Actual Cost of Work Performed (ACWP) was calculated and presented in the monthly financial tables. Invoices submitted by subcontractors for work performed each month indicated the amounts spent per WBS code, versus the budgeted amounts and expected spending during the period.

The monthly schedule and cost analyses resulted in the representation of schedule variances (SV). A negative SV (when earned value was less than the planned spend rate) most often reflected a hold on the authorization of certain activities that were previously expected to be approved in the period, resulting in select work not being performed and budgets not being consumed or expended. Cost variances (CV) were calculated to indicate whether the work was being executed at the budgeted cost. The variance analyses helped to identify baseline changes or corrective actions required.

1.4 Siting Process

Under the terms of the Cooperative Agreement with DOE, the Alliance was responsible for the siting, design, construction and operation of the FutureGen 2.0 CO_2 Pipeline and Storage Project. This section highlights the major components of the siting process. Additional detail is found in Appendix 1D.

1.4.1 Storage Site

The Alliance was responsible for siting a CO_2 storage facility and associated pipeline network to service the Meredosia power plant. To achieve this goal, the Alliance developed a siting process consisting of guidance to prospective offerors, request for proposals, proposal evaluation, and site selection. On October 6, 2010, the Alliance issued Guidance for Prospective Site Offerors, which outlined the site selection guidelines for Illinois communities that wanted to be considered as the host for the CO_2 storage site. On October 25, 2010, the Alliance issued its Request for Proposals (RFP). The RFP described the surface and subsurface qualifying, scoring, and best value criteria that the Alliance would use to select the CO_2 storage site and the data that site offerors needed to provide. The qualifying, scoring, and best value criteria were developed with the assistance of the Illinois State Geologic Survey and other subject matter experts.

Following the issuance of the RFP, the Alliance sponsored a prospective bidders meeting in Springfield, Illinois, on October 28, 2010. Representatives from 16 prospective bidders attended the meeting. During the meeting, the Alliance provided an overview of FutureGen 2.0, described the requirements of the RFP and data collection needs, and emphasized the due dates for questions, notices of intent to submit a bid, and proposals. The Alliance also answered questions posed during the bidders meeting and posted those questions and answers on its website.

On February 28, 2011, the Alliance announced its selection of Morgan County as the preferred location for the FutureGen 2.0 CO_2 storage site, visitors' center, and research and training facilities. The Alliance noted that among the factors resulting in the selection of the Morgan County site were its high quality geology, which is well suited for safe and secure long-term storage of CO_2, (see Chapter 4 for additional details) and its close proximity to the Meredosia power plant, which simplifies pipeline routing and substantially reduces the project's overall cost. Further, the Alliance recognized that there was a strong show of support from community business and elected leaders, as well as significant support from directly affected landowners. The Alliance identified the Christian and Douglas County sites as alternative sites should concerns arise around the technical, legal, or public acceptability of the preferred Morgan County site.

On July 17, 2012, the Alliance Board of Directors confirmed that the proposed Morgan County site remained its preferred location and directed the Alliance to no longer pursue the other two sites. For that reason, only the Morgan County site was analyzed in DOE's FutureGen 2.0 Environmental Impact Statement that was prepared pursuant to NEPA.

Although one well was originally anticipated, with possibly one backup well, the CO_2 storage site in the end was to consist of four horizontal injection wells located on one pad. In addition, various surface facilities and surrounding smaller footprint sites comprised the monitoring, verification, and accounting system. Between 2011 and 2013, the Alliance worked with local landowners to acquire additional pore space to maximize flexibility for CO_2 injection and to ensure that the CO_2 plume would not affect non-participating landowners. As a result of these efforts, additional acreage was acquired south and west of the original study area boundaries. While the location of the CO_2 plume shifted south slightly as a result of availability of additional pore space and the Alliance's plan to construct and operate four horizontal injection wells of varying lengths, the plume size itself remained as estimated in earlier reports – approximately 4,000 acres, as shown in Figure 1.1.

Figure 1.1. Plume Area, January 2015

1.4.2 Pipeline

For initial cost estimating purposes in the early stages of the Pipeline and Storage Project, the Alliance identified a proposed route between the power plant and the injection site in which to locate the pipeline (referred to as the northern route). Based on subsequent investigations and field work, however, the Alliance identified and ultimately selected a more preferable pipeline route (referred to as the southern route) based on constructability, access to rights-of-way (ROWs) and the desire to avoid, to the extent possible, sensitive environmental resources such as wetlands, cultural resources, forest land, and threatened or endangered species and their habitats. The southern route was submitted to the Illinois Commerce Commission in an application for a Certificate of Authority to construct and operate the pipeline, filed in March 2013. Information regarding the selected pipeline route is contained in Appendix 1G. The approximate length of the pipeline to the Morgan County site is 28 miles.

As discussed in Section 1.6.2 below, the Alliance complied with applicable federal and state law for acquisition of the pipeline ROW. Once the route was selected, notices were sent to the landowners, public meetings with landowners were held, and in some cases, meetings were held with owners who asked to meet at their properties to discuss slight alternatives to the pipeline positioning. The Alliance worked with affected landowners regarding specific alignments and compensation for the required pipeline rights-of-way. Appraisals were completed for all of the parcels just prior to DOE's directive to initiate close-out of the Cooperative Agreement per Amendment 32.

1.4.3 FutureGen Center

The Cooperative Agreement included the development of a visitor, research, and training (VRT) facility, which became known as the FutureGen Center, as a component of the SOPO (see Chapter 5 for additional detail). With input from the local stakeholders and the Alliance's Citizens Board, which had been created by the Alliance to make the FutureGen 2.0 Project more accessible to the community, the Alliance considered both reuse of existing structures in Morgan County as well as new construction. For new construction, the Alliance considered several areas in Jacksonville that were offered for sale.

After numerous discussions with the local stakeholders about the VRT's location, the Jacksonville City Council passed a resolution in July 2013 to allow the Alliance the use of approximately three acres of Community Park in Jacksonville, at the intersection of Main Street and Morton Avenue. The Morgan County Board of Commissioners passed a similar resolution. The design of the FutureGen Center assumed the park location and, as an icon for an environmentally (and energy) conscious future, took into account the need to preserve existing trees and open space. Additional information on the VRT is included in Chapter 5.

1.5 Stakeholder Activity

The objective of the stakeholder involvement effort was to engage the full range of stakeholders in the region to determine what questions and possible concerns they may have had about FutureGen 2.0. The major tasks included:

1. General outreach including interviews and focus groups
2. Coordination with FTI Consulting who had the lead for communication and public relations
3. Development of and management of the Citizens' Board
4. Interactions with the local colleges
5. Create a local presence in Morgan County

Additionally, stakeholder involvement included keeping the federal and state regulatory agencies continually informed of the project plans and progress in order to identify potential issues and address them early in the permitting process.

1.5.1 Stakeholder Involvement

The stakeholder involvement team met with community leaders to identify the network of influential people in the community. Focus groups were held with these leaders to describe the project and to solicit questions. Specific focus groups were held with members of the local farm bureau, the Jacksonville Chamber of Commerce, and landowners in the region proximate to the area where the injection site was to be located. A list of questions was developed based on feedback received in these engagements. Answers to these questions were also developed and provided in meetings and on the Alliance website.

Through the outreach program, community leaders were identified who would act as good conduits to an even broader network of people in the area. The Alliance Citizens' Board was established in March 2011. The member list included the presidents of the three local colleges (MacMurray College, Illinois College, and Lincoln Land Community College), the executive director of the Chamber of Commerce in Jacksonville, the head of the local Farm Bureau, landowners in the area of the storage site, a labor union leader, Morgan County board members, a Jacksonville Regional Economic Development Corporation member, a Jacksonville real estate executive, a Jacksonville banker, the Superintendent of Meredosia-Chambersburg High School, and other community leaders from Morgan County.

Several meetings with the Citizens' Board were held and at each meeting the project team provided a status on the project and solicited questions and comments. One meeting with the Board included a tour of the characterization well site. One suggestion that grew out of the Citizens' Board meetings was to establish a Community Corner article to be posted routinely on the FutureGen Alliance website to keep the community informed. The stakeholder involvement team worked closely with FTI Consulting in developing the Community Corner articles, which went through a DOE approval process before being posted on the website. The stakeholder involvement team also worked closely with FTI on developing the overall content for the website, including Frequently Asked Questions and the Fact Sheets that were used in outreach activities.

Emphasis was placed on coordinating with the local colleges to identify ways to engage faculty and students in the FutureGen 2.0 Project. One professor and one student from Illinois College were granted internships at the Pacific Northwest National Laboratory to work on research directly relating to FutureGen 2.0 for two summers. The local colleges were also involved in providing input on the FutureGen Center. In particular, the colleges were included in a study that was to be conducted by the Alliance in collaboration with the Illinois Department of Natural Resources. The study agreed, as part of an Incidental Take Authorization for the project, to examine the migration of the Illinois chorus frog in the region.

The Alliance opened its Jacksonville office in 2011. Throughout the project, the office was staffed, allowing landowners and members of the community to call or stop by with any questions or concerns regarding the project. Additional detail about the stakeholder activities is included in Appendix 1B.

1.5.2 State, Federal and Local Governments and Railroads

Throughout the FutureGen 2.0 project, all agencies and entities from which permits or approvals were needed to construct and operate the pipeline and injection wells were routinely briefed on the status of the project and provided with all of the information they requested. This included federal, state, and local government agencies and railroads. Chapter 6 (Permits) details all of the agencies and entities contacted for permits, briefly summarizes the permit requirements, lists key interaction dates, and provides points-of-contacts for each agency and entity.

One particularly important achievement was the Alliance's receipt of the first U.S. Environmental Protection Agency (USEPA) Class VI (CO_2 Storage) injection well permits.

1.6 Land Acquisition

The following sections summarize the land acquisition efforts. This included acquisition of pore space (subsurface) rights and surface rights for the pipeline, characterization well, injection well site, and monitoring well locations. A more fully detailed document of the land acquisition is located in Appendix 1G.

1.6.1 Pore Space Acquisition

The core property right required for permanent sequestration of CO_2 is the right to the underground pore space in which it would be stored. The target subsurface location for carbon storage in downstate Illinois was the Mount Simon formation, known to have characteristics very suitable for storage (see Chapter 4 for additional details). During a process of pore space acquisition lasting over three years, the Alliance acquired options on over 10,000 acres of contiguous subsurface pore space from over 100 persons and entities with ownership rights, including all the required pore space in the projected CO_2 plume (final storage footprint) as described in the Class VI injection well permit application. This achievement, though ultimately not realized in the form of a functioning CO_2 storage site, ranks as one of the program's greatest achievements. Repeating this assemblage of rights, among a numerous and diverse group of landowners, in an area not accustomed to the presence of CO_2 transport or storage, is believed by the Alliance project team to have been a very significant challenge that was both met and successfully overcome.

Acquiring options to purchase pore space rights, rather than purchasing those rights directly, minimized financial risk as initial uncertainties could have ultimately caused the Morgan County site to be deemed unsuitable. In addition, having options at early phases of the project provided flexibility to design contingency plume patterns and injection schemes tailored to avoid potential non-essential hold-out properties. This allowed multiple acceptable plume geometries, each covering a slightly different area. Finally, options allowed for declining the future purchase of pore space that may have turned out to be extraneous once the ultimate injection pattern (including potential post injection modifications implemented as a result of monitoring results) was chosen. Utilizing options thus allowed the Alliance to efficiently seek the pore space that seemed most likely to be acquired, maximizing the efficiency of both labor expended and the impact of that labor on assembling the critical rights required to execute the injection site design.

The acquisition of all pore space necessary for injection of CO_2 under the Alliance's Class VI injection well permit was a remarkable feat which will be difficult to duplicate under similar conditions for future developers in this region or other similar regions. Acquiring 100% of any large area of land, involving dozens or even hundreds of landowners is extraordinarily difficult as just one landowner can block the process. The Alliance was assisted by wide local support for the FutureGen 2.0 Project and some flexibility in plume location. Even so, the task required over three years to complete, and was not entirely efficient. Due to optimized CO_2 plume design that was modified to avoid pore space acquisition holdouts, some property rights were acquired which were ultimately not utilized.

1.6.2 Pipeline Acquisition

The Pipeline and Storage Project included the development, engineering, construction, and operation of a CO_2 pipeline from the Meredosia power plant site to the injection site. The planned pipeline was approximately 28 miles in length and required ROW, certain surface facilities, and various railroad and highway crossing agreements. Approximately 115 tracts of land would have been impacted by the final design. The pipeline was to have been constructed pursuant to certificate of authority granted by the Illinois Commerce Commission under the Illinois Carbon Dioxide Transportation and Sequestration Act (the CO_2 Transportation Act), 220 ILCS 75/1 et seq., which granted the Alliance the power of eminent domain. Pipeline ROW acquisitions included permanent easements and temporary construction easements for the pipeline and two block valve locations with access ways for electric and telecommunication lines to them.

Acquisition of the pipeline ROW is also governed by the Illinois Commerce Commission under the CO_2 Transportation Act, as well as the Illinois Eminent Domain Act, 735 ILCS 30/1-1-1 *et seq.*, and, because federal funds were to be used in the acquisition, by the Uniform Relocation Assistance and Real Property Acquisition Policies Act of 1970 ("URA") 42 U.S.C. 4601 *et seq.*, as well as regulations issued under all of those statutes. The URA applies to any acquisition of real estate, including permanent easements, where federal funding is provided. The Alliance pipeline did not result in forced relocation of any homeowner and therefore the relocation aspects of the URA were not applicable.

The CO_2 Transportation Act required notice to all landowners along the route and a public hearing concerning the proposed route. Among other mandates in the CO_2 Transportation Act, the Alliance was required to negotiate an Agricultural Impact Mitigation Agreement, which governs pipeline construction and maintenance impacts on agricultural lands, with the Illinois Department of Agriculture.

As a result of landowner comments and review of technical soil and boring tests, the Alliance made several minor pipeline route modifications, and the final route was determined. All ICC and URA mandated actions prior to landowner contact were completed by the Alliance. Because of funding authority delays, the original appraisals and review appraisals became stale and were repeated. After only five pipeline rights-of-way were fully acquired, the project was suspended.

The form of ROW and an accompanying agreement establishing landowner compensation for soil productivity loss was negotiated by the Alliance and the Illinois Farm Bureau with input from the landowner counsel and the Illinois Department of Agriculture. These documents were modeled after those used for acquisition of ROW for a high-pressure natural gas pipeline recently constructed only a few miles from the proposed Alliance pipeline. The documents were widely acceptable to landowners, so much so that it was anticipated that only a few tracts might have required the use of eminent domain.

1.6.3 Surface Land Acquisition

The Alliance also required several types of surface rights for the Pipeline and Storage Project. In each case, once the need was determined, the Alliance negotiated with the owner of the impacted land. In some instances, the location of a surface facility could be changed if the landowner did not wish to grant the Alliance the necessary right. In other instances, the project required a specific location and the Alliance negotiated the best terms it could for that location. The type of acquisition, for example lease or purchase, was a matter of negotiation. Certain landowners had different goals. So long as the Alliance was able to control the property for its intended use and responsibility (at least 85 years - the length of the planned injection plus a 50-year monitoring period) the Alliance was able to accommodate the landowner's needs.

1.7 Contract Development and Analysis

The following sections describe the four major agreements that were prepared to construct the surface facilities, the subsurface facilities, and the pipeline (Phase III), and the operation of those systems (Phase IV). It is important to note, that for these contract competitions, and for all others across the project and program, that contractor safety was given equal weight to all other evaluation criteria. The reasons for this were as follows: 1) the best way to obtain high safety performance on the job is to hire with safety as a prime performance expectation and cultural facet from the outset, and 2) companies with high safety cultures exhibit a strong correlation with high schedule performance and efficient work practices, making cost and schedule predictability more likely. In addition, the construction contracts were required to include provisions for the use of local union labor as established in the Memorandum of Understanding between the Alliance and the local labor unions. Contractors were required to initiate and establish agreements with the local labor unions for work being performed on the project, and to submit pricing with union labor accounted. For instance, construction of all aboveground site structures, including the Site Control Building, were to be covered by the project labor agreement established between the Alliance and the local labor unions, and the contractors were to be signatories of this agreement.

1.7.1 Introduction and Purpose Statement

The purpose of this section is to provide an overview of the major third party subcontract agreements development utilized for the Pipeline and Storage Project. This section describes the contract development and implementation undertaken to manage the major construction and operation and maintenance related contract scopes, budgets, and schedules. It highlights the successful contracting processes and innovations utilized to secure construction ready companies as well as lessons learned. Appendix 1E contains a more detailed description of the processes used in contract development and analysis.

1.7.2 Procurement Procedures Utilized

The Alliance followed its “Procurement and Contractor Monitoring Policy,” FutureGen Industrial Alliance - Policies and Procedures (Revised June 2013) for all procurements. Appendix 1E provides a copy of the policy. The Alliance also followed a specific checklist of seven parameters for the selected subcontractors to confirm consistency with DOE approval confirmation information stipulated in the Cooperative Agreement. Appendix 1E also provides a more detailed description of the list of these parameters.

1.7.3 Analysis of Subcontract Agreements Awarded or Finalized Negotiations Ready for Award

1.7.3.1 *Site Work and Roadwork Subcontract Agreement*

Overview

RFP SCC-02 was issued to eight pre-qualified sources on February 19, 2014. Prospective bidders submitted requests for clarification and Alliance response clarifications were issued on March 3 and March 10, 2014. Four proposals were received by the proposal due date of March 13, 2014. Additional details are found in Appendix 1E.

Evaluation

Each proposal was carefully evaluated on a predetermined weighted scale (Subcontractor Recommendation Rating Matrix) developed prior to receipt of bids by the members of the Source Selection Panel (SSP). Technical and pricing proposals were considered separately.

The technical proposal was weighted to comprise 50% percent of the total score with 115 points available, and the pricing proposal was likewise worth 50% and allowed for a maximum score of 115 points.

Combined technical and pricing scores were then tabulated. United Contractors Midwest scored well in both categories and had the highest combined score of 200.0 points.

After careful consideration of the technical, schedule, and pricing proposals, and taking into account the responses to follow-up questions and clarifications, the SSP unanimously recommended that a subcontract agreement for the Storage Site Surface Construction Services in support of the Pipeline and Storage Project be awarded to United Contractors Midwest. DOE authorized a subcontract agreement with United Contractors Midwest for a scaled-back release of scope and funding for Phase II services.

Significant or Innovative Contract Provisions

Under the subcontract agreement, the Price and Construction Schedule were subject to renegotiation. Specifically, the Alliance directed bidders to assume a specified period of time to perform the work, and their bids were to be based on that window. In negotiating the final agreement, the parties recognized that tightening that window would affect the construction schedule and the fixed subcontract price. Schedule adjustments were often required as a result of holds on the authorization of certain scheduled performance activities as the financial close date predicted for the Power Plant Project continued move out. This meant that contract schedule milestones were adjusted accordingly, as well as adjustments to the subcontract price.

Initially, all proposals were fixed lump sum proposals to protect the Alliance and ensure the costs could be contained. Since it was imperative to complete construction before the ARRA deadline, liquidated damages were a component of the subcontract, thus the start date and schedule were crucial to the agreement. When the authorized start date slipped, the subcontract terms had to be renegotiated. Accordingly, the subcontract states:

> *If Owner issues [Notice to Proceed] subsequent to June 16, 2014, then the Parties shall adjust the Subcontract Agreement Price, Construction Schedule, Delay [liquidated damages], and other provisions of this Agreement as mutually agreeable to maintain the commercial values originally established herein to the greatest extent possible notwithstanding Owner's delay.*

UCM executed the subcontract agreement on October 23, 2014 and constructed various components of the surface facilities, including road upgrades and the injection well pad under the agreement, without issue, in December 2014.

1.7.3.2 *Subsurface Subcontract Agreement*

Background

RFP DCC-03, was issued to seven pre-qualified sources on February 10, 2014. A pre-bid meeting was held in Jacksonville, Illinois. Subsequent communications and additional documents were submitted to and received from the prospective bidders over the following weeks. The two responsive bidders were Schlumberger Technology Services (Schlumberger) and Baker Hughes Incorporated (Baker Hughes).

The RFP requested a wide range of detailed information, including detailed cost estimates, redlined comments on a fixed price model construction subcontract agreement, safety programs and statistics, union labor relations, company financial conditions and ability to provide parent guarantees, company experience, and employee qualifications.

Two responsive proposals were received by the proposal due date of March 21, 2014. Additional clarification requests were sent and conference calls were conducted with the bidders to clarify their responses.

Neither of the responsive bidders initially provided all of the information, nor the contracting approach that was requested. The Baker Hughes response was a fixed price offer that secured a large portion of the drilling costs (as requested in the RFP), while the Schlumberger bid was a time and materials subcontract agreement that provided activity-based pricing with estimated duration. While it transferred certain risks to the Alliance, the pricing advantage potential was significant.

Evaluation

Each proposal was carefully evaluated by the members of the SSP using a predetermined weighted scale Subcontractor Recommendation Rating Matrix. Technical and non-price as well as commercial pricing and schedule factors were evaluated for both responsive bidders.

The overall combined evaluations of the two competitors were very close, and the final tally of evaluation criteria rated Baker Hughes slightly higher than Schlumberger. Subsequently, Baker Hughes requested to withdraw their proposal (due to high-demand on drilling services during the bid period) and pulled out of the negotiation process. The Alliance decided to initiate final negotiations with Schlumberger. After continued negotiations, the final cost estimate was mutually agreed and was established as the awarded subcontract price.

The Alliance recommended to DOE that a subcontract agreement for the Subsurface Construction Services be awarded to Schlumberger. After DOE approval, Schlumberger executed the subcontract agreement and subsequently performed only authorized drill site planning services prior to project suspension.

Significant or Innovative Contract Provisions

In an effort to reduce the potential for cost creep associated with the Schlumberger time and materials subcontract agreement, an incentive plan was negotiated and included in the drilling agreement. The Alliance negotiated bonus/penalty terms to reward Schlumberger if it performed the work at or under budget. If Schlumberger's performance would be under budget, they would earn an incentive payment of 50% of the reduced spend, subject to a cap. If Schlumberger's actual cost of performance exceeded the estimate by 10%, (110% of original estimate) then Schlumberger would credit the Alliance 50% of the overage. Additionally, Schlumberger required a liability cap of $2,000,000 per well, or $5,000,000 in the aggregate. This was based on the fact that the prime subcontract would account for the substantial majority of

Schlumberger's costs, and Schlumberger management insisted on a limit to its exposure to better reflect its fee. This liability limit term was understood to be consistent with oilfield services industry practices. The liability limit term was a significant improvement on the originally proposed terms, as was the adopted bonus/penalty structure.

1.7.3.3 *Pipeline Construction Services Subcontract Agreement*

Background

RFP PLC-01 was issued to four pre-qualified sources on January 23, 2014. Subsequent communications and additional documents were submitted to and received from the prospective bidders over the following weeks.

The RFP requested a wide range of detailed information, including detailed cost estimates, redlined comments on a fixed price model construction contract, safety programs and statistics, union labor relations, company financial conditions and parent guarantees, company experience and employee qualifications.

Four proposals were received by the proposal due date of March 3, 2014, and subsequent clarifying responses were received by March 19, 2014. Additional clarification requests were sent and received the week of April 14, 2014. Conference calls were also conducted with some bidders to clarify their responses.

No single company initially provided all of the information requested. All provided "unit price" cost estimates (quantities were at risk, unit prices were fixed). Three companies offered to fix a large portion of the pipeline costs, and one declined to bid a fixed price for any portion of the work.

Evaluation

Each proposal was carefully evaluated by the members of the SSP using a predetermined weighted scale Subcontractor Recommendation Rating Matrix.

The non-price (safety, qualifications and experience, contract terms, financial strength) and pricing (commercial) proposals were considered separately. The non-price proposal was worth 50% percent of the total score with 100 total points available to earn. The commercial proposal was worth 50% and also allowed 100 points available to earn in the evaluation. Criteria and weightings were agreed upon prior to receiving the proposals, with safety, qualifications and experience, financial strength, and contract terms each given weightings determined before the evaluation began.

Total non-price scores were derived and assigned to each proposal by the SSP (using the averaging methods described above). Rockford Construction Company (Rockford) scored the highest technical score with 75.4 points out of a possible 100. Michels Corporation (Michels) followed closely with 71.8 points. Once it was apparent that Rockford was leading in point totals but their safety rating was lower than the category leader Michels, follow-up conversations were initiated to ascertain Rockford's latest safety performance record and safety culture assessment directly from three recent clients. The survey indicated that Rockford had, and implemented, a strong safety program and that their marginal safety statistics were driven by unusual events. Therefore, initial concerns over its lower safety rating were addressed.

Technical and commercial scores were then combined. Rockford scored well in both technical and commercial and achieved the highest combined score. Michels scored second place. Based on this scoring system, the SSP ranked the Sheehan Pipe Line Construction Company (Sheehan) and Price Gregory, Inc. (Price Gregory) proposals in third and fourth place. After consideration of the technical, schedule, and cost proposals, and taking into account the responses to follow-up questions/clarifications, the SSP recommended that Rockford be selected as subcontractor for the pipeline construction services.

After successful conclusion of contract negotiations between the Alliance and Rockford, a “comfort letter” was prepared. A subcontract agreement was never approved by DOE or officially executed.

Significant or Innovative Contract Provisions

The majority of the bidders for the pipeline construction would only bid the work on a “cost reimbursable type” contract basis.

The negotiated pipeline construction agreement with Rockford included an innovative hybrid “fixed price-unit price” cost model to maximize the firm fixed price content of the overall contract total. Likewise, a mechanism was incorporated in the price portion of the contract that fixed unit pricing while allowing quantities to “float” with the final design. In addition, weather-related delay costs were capped. In order to accommodate progress payments, the contract included a mechanism to adjust compensation based on fixed unit pricing applied to the actual quantities installed or excess weather delay days during the period of contract performance.

Using this model, the fixed price components of the overall contract accounted for approximately 90% of the value and the variability associated with the unit price component accounted for approximately 10% of the value. Unit price components included cost items such as repair of drain tile, usage of mats, and rain day costs.

1.7.3.4 *Pipeline and Storage Surface Operations Agreement*

Overview

Members of the contract development team began the process of seeking qualified candidate pipeline operation and maintenance contractors for the purpose of providing long-term operation of the pipeline by making inquiries with national and regional firms in January 2014 to determine their interest in submitting a proposal. Contact was made with ten firms including national midstream pipeline operators, carbon services companies, Illinois natural gas suppliers, and a regional pipeline operations company.

The majority of the firms did not express interest in submitting a proposal to operate the pipeline. Ultimately, Utility Safety and Design, Inc. (USDI), a pipeline operations company headquartered in southern Illinois, expressed serious interest and demonstrated competency when contacted by the contract development team. The scarcity of resources willing and able to bid this type of work was a significant concern. This placed pressure on the negotiating team to meet project contracting objectives and economic requirements, while simultaneously dealing with the reality of one responsive and qualified bidder.

Evaluation and Negotiation

After meeting with Alliance representatives to discuss the project, USDI provided a proposal on May 21, 2014 to operate and maintain the pipeline. They updated the proposal on October 3, 2014. USDI subsequently negotiated for schedule terms, and adjusted its lump sum fee structure and time and materials cost proposal to include rates predicated on the power plant commercial operation dates. This arrangement was best suited to the project as the financial close date predicted for the Power Plant Project continued to move out. USDI's proposal provided 100% pipeline operations responsibility and provided full compliance to all applicable federal regulations using union operators. To improve efficiency and cost effectiveness, the agreement terms were revised to include the operations of the surface facilities and various routine maintenance components of the subsurface. USDI also agreed to acceptable commercial terms and conditions.

After successful conclusion of contract negotiations with the Alliance, a "comfort letter" was signed by both USDI and the Alliance. However, an executed subcontract agreement was not approved by DOE.

Significant or Innovative Contract Provisions

The Alliance was able to negotiate an innovative Incentives and Fees Schedule which included performance parameters driven by safety, availability, environmental audit performance, regulatory audit performance, operating efficiency, and annual cost savings.

1.7.4 Conclusion

As discussed above, the Alliance was able to implement a rigorous and defensible contract development process, overcome challenges encountered, and achieve significant progress in negotiating and awarding critical construction and operation contracts.

Several significant innovative elements and lessons-learned were derived from the efforts to hire reliable contractors for the various construction and operation roles required by the project:

1. The firm fixed-price site work and road work subcontract agreement included successfully negotiated schedule liquidated damages to mitigate schedule risk.
2. The time and materials (cost reimbursable) monitoring well and injection well drilling and construction subcontract agreement included successfully negotiated bonus/penalty terms to reward Schlumberger for performing the work at or under budget. A key lesson learned was that drilling contractors are resistant to the cost and schedule risks associated with firm fixed-price contracts due to high risk factors related to the unforeseen underground aspects of their work. This appears to be an oilfield industry standard.

3. The pipeline construction services subcontract agreement was a “hybrid” of a traditional firm fixed-price type contract with certain firm unit rate elements. This maximized the firm fixed-price component of the price, as well as providing a mechanism to adjust the firm unit pricing based on actual quantities installed. The Alliance successfully negotiated schedule liquidated damages to mitigate schedule risk. A key lesson learned was that many pipeline service construction subcontractors are generally resistant to the cost and schedule risks associated with firm fixed-price contracts. Different types of fixed-price and cost-reimbursable bids were received, but the Alliance was able to successfully negotiate the “hybrid” contract described above with Rockford.
4. The pipeline operations agreement was also a “hybrid “contract with certain fixed fees and other time and material rate elements. The Alliance successfully developed and negotiated innovative incentives and fees schedule. A key lesson-learned was that these CO_2 pipeline operators wanted to own the asset that they were managing. Also, CO_2 operations are specialized, and since most pipeline operations in the U.S. relate to natural gas or other commodities, it was difficult to acquire knowledgeable expertise specific to operating a new CO_2 pipeline facility. Therefore, the final operations of a site would require the on-site training of the operator in CO_2 management.

1.8 Cost Summary

The Pipeline and Storage Project budgets established for Phase I through Phase IV totaled $572,340,730 based on Amendment 20 to the Cooperative Agreement effective on July 1, 2013. The estimated budgets shown in Amendment 20 for each phase are shown in Table 1.2.

Table 1.2. Amendment 20 Budget

Phase	Amendment 20 Authorization
I	$33,257,580
II	$30,658,673
III	$380,019,171
IV	$128,405,306
Total	**$572,340,730**

1.8.1 EPC Cost Comparisons: Risk Analysis, Definitive Cost Estimate, and Contractor Agreements

In January 2014, Alliance representatives (Patrick) prepared a risk-based assessment of the construction cost (construction contractor and materials) for the Pipeline and Storage Project elements. The assessment consisted of a collaborative risk identification exercise, a risk assessment for each risk element identified, and a subsequent probability-based risk analysis using a Monte Carlo simulation model (see Appendix 1F). Although both cost and schedule values were captured for each identified risk, the risk-based assessment report focused on cost. The analysis resulted in a base cost estimate for the EPC scope of $165.8 million without contingency and escalation. This compares to the September 2012 Phase II Decision Point Application (DPA) estimate of $233 million for the Phase III pipeline, surface and subsurface costs that were part of the $380 million Cooperative Agreement budget shown in Table 1.2. This analysis was based primarily on the designs of the FEED submitted to DOE in December 2013.

Subsequent to the risk-based assessment of construction costs, on March 31, 2014, a Definitive Cost Estimate (DCE) was prepared by the Alliance and submitted to DOE. This cost estimate was built to a Class 1 AACE International[1] standard and was based on a design that was approximately 90% complete. The DCE included capital, commissioning and caretaking costs.

During the months following the submittal of the DCE, EPC contract development and negotiations took place with selected contractors (see Section 1.7, above). Following the progression of project development and contract development, a comparison can be made between the EPC-related costs from the final negotiated agreements and those EPC-specific costs estimated from the DCE. This comparison is strictly related to the construction of the pipeline (pipe, meters, valve stations, etc.), surface (site control building, drilling pads, roads, etc.), and subsurface (injections wells and monitoring wells) facilities including materials procurement, but excludes the owner's other direct and indirect costs, and excludes the caretaking period from construction completion to the commercial operation date. By stripping the other direct costs, indirect costs, and the caretaking period costs, the EPC cost estimate from the DCE amounted to $184.3 million, as shown in Table 1.3. A more detailed breakdown of the DCE is in Appendix 1H.

1. AACE: While the official name is AACE International, it started as the American Association of Cost Engineering and then became the Association for the Advancement of Cost Engineering before adopting the current official title of AACE International

Table 1.3. EPC Definitive Cost Estimate, March 2014 – Construction Only*

DCE	Pipeline	Surface	Subsurface	Total
Cost of Material & Construction**	$58,913,000	$7,964,000	$99,672,000	$166,549,000
Contingency	$9,426,000	$992,000	$7,372,000	$17,790,000
Total Costs	**$68,339,000**	**$8,956,000**	**$107,044,000**	**$184,339,000**
* Other costs for caretaking period, training and commissioning are not included in these costs. ** Includes other materials to be procured or subcontracted by the Alliance (roads, water line).				

Subsequent to the DCE submittal, contract negotiations occurred with the pipeline, surface and subsurface EPC contractors. Agreements, including contractor pricing, were readied for execution between the Alliance and the EPC contractors, awaiting DOE authorization. Therefore, the EPC-related costs from the final negotiated agreements, shown in the January 29, 2015 final cost estimate, Table 1.4, totaled $159.3 million (utilizing the actual contractor bid prices). A more detailed breakdown of the January 2015 estimate including the owner's other direct, indirect costs, and the caretaking period costs, is in Appendix 1H.

Table 1.4. Received EPC Contractor Costs (January 2015) – Construction Only*

DCE	Pipeline	Surface	Subsurface	Total
Contracted Cost**	$54,686,000	$8,774,000	$87,106,000	$150,566,000
Contingency	$4,360,000	$439,000	$3,915,000	$8,714,000
Total Costs	**$59,046,000**	**$9,213,000**	**$91,021,000**	**$159,280,000**
* Does not include other costs for caretaking period, training and commissioning. **Includes other materials to be procured or subcontracted by the Alliance.				

Table 1.4 shows that the January 2015 analysis of costs is lower than the DCE for the EPC work. One reason for this is that a smaller contingency, $8.7 million for the construction of facilities, was used with the latest estimate, while the DCE for EPC included a contingency of $17.8 million. Since the January 2015 estimate reflects a matured contracting process with written agreements, including negotiated prices, there was a greater confidence level of final construction costs, thus lowering the required contingency percentage.

Another reason for the lower cost estimated in January 2015 as compared to the DCE is that the final negotiated price for the subsurface work was lower than originally estimated. Additionally, while negotiating agreements with contractors, the Alliance team was able to complete certain value engineering exercises, (for example, specifying a different pipe diameter for one subsurface installation), which reduced contractor pricing.

Again, in order to isolate the bare EPC costs for a fair comparison, Table 1.4 excludes the pre-injection period costs, the owner's other direct and indirect costs, as well as escalation. Appendix 1H includes details for both the March 2014 DCE and January 2015 capital cost tables.

In summary, the January 2015 cost estimate for project capital expenditures was $172.3 million, compared to the DCE of $196.5 million and the September 2012 DPA estimate of $233 million. As with the bare EPC cost comparison, the lower cost of the final analysis is attributed to various factors: the two greatest factors are the lower contingency resulting from a greater confidence level of final construction costs (due to written agreements including prices), and a significantly lower final price agreement for the subsurface scope of work.

1.8.2 Comparison of Phase II Cost Expenditure to Original Budget

Upon notice of DOE's January 2015 decision to suspend the SOPO activities, normal project activity was suspended on January 28, 2015. The cost summary of work performed and costs encountered during Phase II (including Phase IIE) through January 28, 2015 are provided in Table 1.5.

Phase II (Subphases A – E) total $42,792,449. Approximately $17.3 million was spent in Phase IIE, including the purchase of the injection site property, accrual of obligated costs for the purchase of certain pipeline easements, accrual of obligated costs for exercising pore space options, construction activities brought forward from Phase III, and G&A. Phase IIE costs also included an $8.8 million payment to the CO_2 Liability Trust Fund. The final Phase II expenditure as of January 29, 2015, (including Phase IIE), is larger than the original Phase II budget because it includes a number of construction and final design-related expenses that were brought forward from Phase III in an effort to maintain the overall project schedule; therefore, careful analysis is needed when comparing the cost summaries of the phases due to the scope of work shifting between phases.

The total spent during Phase IIA - IID, (beginning February 1,2013 and ending July 31, 2014), was $25.5 million and the expenditure for Phase IIE, (beginning August 1, 2014 and ending January 28, 2015) was $17.3 million.

Table 1.5. Comparison of Phase Budgets

Phase	**Amendment 20 Authorization** (Beginning of Phase II)	**Amendment 30 Authorization** (At Project Suspension)	**Final Cost Estimate** (Including Actual Cost and Contracted Pricing)
I	$33,257,580	$33,257,580	$33,258,000
II	$30,658,673	$58,432,595 includes IIE	$42,792,000 includes IIE
III	$380,019,171	$352,245,248	$395,972,000
IV	$128,405,306	$128,405,307	$102,351,000
Total	**$572,340,730**	**$572,340,730**	**$574,373,000**

If the Phase III task dollars that were brought forward are removed from the expended Phase II and IIE sums (items such as surface construction, water line extension, land procurement, and construction management estimated at $13.3 million), the expected Phase II spend sum would equal roughly $29.5 million ($42.8 million - $13.3 million), or about $1 million under the original Phase II budget. Although the start-and-stop nature of the project, combined with the unplanned preparation and submittal of numerous spend plans for Phase II and Phase IIE, created production inefficiencies, the actual cost of work performed tracked favorably compared to the work scheduled. In an environment of significant change, the Phase II goal of having construction-ready contracts was achieved within the DOE-authorized budget.

1.8.3 Phase III and IV Cost Projections

Table 1.5 also shows that the expected cost to complete the construction and commissioning (Phases II and III), including other costs such as land payments and UIC trust fund payments, would have cost a total of $439 million ($396 million + $43 million) if the project were allowed to move forward. This compares to the original estimated budget of $411 million for Phases II and III. One factor for the increased cost is that in the final estimate, the Alliance set aside $47.6 million toward the Owners Project Reserve (compared to the assigned reserve in the DCE of $27 million) because the higher reserve would improve the probability that the Power Plant Project would successfully attract private financing. This Owner's reserve is on top of the $8.7 million contingency already carried in the EPC costs. Therefore, in this projected Phase III cost estimate, over $55 million is considered reserve or contingency. An additional $6.5 million of this cost estimate was set aside as working capital. The $439 million value also includes an escalation allowance of $9 million. Thus, leaving aside the increased reserve, working capital, and escalation, the overall Phase II and Phase III project costs would have remained within budget.

The Phase IV cost estimate covers the estimated cost of facility operations for the first 56 months of service, which is the defined time period of operation for Phase IV from the Cooperative Agreement. The most recent financial analysis shows the expected total operating costs would have been roughly $26 million less than the Cooperative Agreement budget during the 56-month initial period of operation, or $102 million versus $128 million.

The operating cost estimate was divided into categories that were estimated separately: 1) the costs to maintain and operate the pipeline and injection wells, as negotiated with the pipeline operator, and Battelle-estimated costs for subsurface MVA of the injected CO_2 as required by the USEPA Class VI UIC permit, and 2) the other direct and indirect Alliance costs, for items such as insurance, trust fund payments, and security. Appendix 1H includes a table with the projected operating costs.

In broad summary, the total DOE budget for all four phases of the project was $572,340,730. At the time of project suspension, the estimated total project cost was $574,373,000, which is within 0.36% of the total authorization, with the primary variance being due to the decision, consistent with project objectives and industry practice, to account for a generous project reserve in order to create an additional level of security for Power Plant Project private investors.

1.9 Discussion, Successes, and Lessons Learned

The following discussion highlights the successes and lessons learned as a result of work completed on the Pipeline and Storage Project. Although the project has been summarized in previous sections, the following sections are designed to highlight the most important project findings and accomplishments.

1.9.1 Safety

All planning, engineering, and construction work was performed without a single safety incident: no first aid cases, recordable incidents, or lost time incidents. Safety was a high priority, starting with designing for safety, continuing with the contractor selection process which made contractor safety performance a dominant selection factor, then following through with meaningful onsite participation in contractor safety meetings, including Alliance-participation in the form of pre-work discussions and conducting real-time safety audits during construction activities.

1.9.2 Permitting

Among other accomplishments, the Pipeline and Storage Project embodied the first attempt to site and design a pipeline from a CO_2 power plant source to a permanent injection site (FutureGen 1.0 included the injection site on the same property as the power plant). As such, one of the project's successes includes issuance of the first ICC Certificate of Authority to construct and operate the pipeline as approved on February 20, 2014. In addition, the Alliance's CO_2 Transportation and Sequestration Plan was approved by the ICC on May 14, 2014.

Perhaps foremost in the project's achievements was the successful application for and receipt of the first Underground Injection Control Class VI Permits (one for each of the four injection wells) in the U.S., approved by the USEPA on August 29, 2014. The permits were challenged by adjacent landowners on October 1, 2014; that challenge was denied on April 28, 2015, and USEPA declared the permits final on May 7, 2015.

In all, permits or approvals were required from DOE, USEPA, the U.S. Army Corps of Engineers (USACE), U.S. Fish and Wildlife Service, U.S. Department of Transportation's Pipeline and Hazardous Materials Administration (PHMSA), U.S. Department of Agriculture, Illinois Environmental Protection Agency, Illinois Historic Preservation Agency, Illinois Department of Natural Resources, ICC, Illinois Department of Agriculture, Illinois Department of Transportation, Coon Run Drainage and Levee District, railroad companies, and local governments.

Members of the Alliance project team briefed all permitting agencies on the scope of the project early in the process and routinely informed the agencies of the project's progress, and, where relevant, solicited agency input in the design and execution of required field studies. Often, the results of field studies were informally shared with agencies before formal permit applications were submitted to confirm the adequacy of the studies and the results, thus eliminating costly delays and iterations in permit approvals once they were formally submitted. Many agencies expressed their appreciation of the regular and timely communications as it facilitated their interactions within and among agencies for this highly visible project. Permits were actively pursued during the entire project, and were steadily received, many in days rather than months, even after the project was suspended. The key lesson learned is to identify and communicate early and often with the regulators (classic stakeholder engagement), to maintain a regular schedule of permit activities and deadlines, and to maintain contact with regulators until the permits are received. Permitting is a potentially fatal issue to any project, and must be treated with the highest priority.

1.9.3 Land Acquisition

The Alliance required a variety of real estate rights to implement the project, including deep subsurface pore space rights, a pipeline right-of-way and a wide variety of other surface rights. The acquisition of all pore space necessary for injection of CO_2 in accordance with the Alliance's Class VI injection well permit was a remarkable feat which will be difficult to duplicate in a diverse landholder environment. Acquiring 100% of any large area of land, involving dozens of landowners, is extraordinarily difficult as only one landowner can block the process, adding to that the fears and concerns associated with introducing a "new" industrial gas being stored under extremely fertile and valuable farm land for the first time. The margin for error in stakeholder engagement and landowner negotiations becomes very narrow. Successful aggregation is attributed first and foremost to consistent and fair treatment of landowners, paired with knowledgeable legal support that specialized in land aggregation, and followed-up by constant on-the-ground presence utilizing local talent and faces where feasible.

The pipeline easement rights acquisition, though not as far along as the pore space acquisition process when the project was suspended, was also successful. The form of ROW and an accompanying agreement that established landowner compensation and terms were widely acceptable to landowners, so much so that it was anticipated that only a few tracts out of 118 parcels might have required the use of eminent domain.

Lessons can be learned from the successful land acquisitions and difficulties resulting from land acquisition. One item that arose was a concern about whether the 80-foot ROW was wide enough for the pipeline construction. Although the width is suitable for the majority of the work for the small-diameter pipe as validated by pipeline contractors, and additional temporary easements could be obtained as needed for special conditions, consideration should be given to obtaining a wider easement to enhance construction flexibility. Specifically, a wider easement is useful and especially desirable in areas that are sloped and those that require boring or directional drilling under roads. Another suggestion is to establish a corridor without identifying the exact pipe location to provide flexibility to adjust the pipe location within the corridor upon discussions with local landowners.

1.9.4 Design and Construction

With any multifaceted design effort where design and planning are occurring simultaneously and by separate entities, compounded in this case where both the Power Plant Project and Pipeline and Storage Project teams were designing systems that relied on the other to some extent, interfacing issues can be a challenge. For example, the temperature, pressure, and maximum flow rate of the CO_2 to be transferred at the power plant battery limits to the CO_2 pipeline must be established early, or at a minimum, a specific range defined, in order to effectively design the pipeline and storage systems. The pipe type and grade, thickness, and diameter are a few of the resulting design parameters that are dependent on this data.

Likewise, the maximum and minimum pressures at the receiving reservoir dictate the allowable wellhead pressure ranges and thus the pipeline pressure. Since routine venting of CO_2 was not an allowable control mechanism on this project, balancing all of these variables was a challenge during the design.

To complicate matters, the design was based on a pipeline with no intermittent booster pumps, which would otherwise have assisted in the control of pressure or flow. Instead, the pipe diameter was selected to allow for the transfer of the CO_2 without booster pumps in the pipeline. Since the pressure drop of the supercritical CO_2 in the pipeline is a function of the pipe diameter and the minor losses in the system, any change in the number and severity of pipe bends caused by a change in route can impact the final pipeline design.

All of these factors, with the addition of CO_2 composition, must in turn be coordinated with CO_2 injection permit parameters. In the end, the system was successfully balanced and integrated to transfer the range of flows at the corresponding temperatures and pressures expected, and with consistent composition characteristics. The key takeaway is early implementation of interface processes to ensure close coordination and mitigation of any specific challenges that may not have been previously anticipated.

Other interface issues that can arise are the understanding of roles and the communication between contractors. The following recommendations are made to manage or minimize complications: 1) identify formal interface management systems and responsibilities early in the project; 2) set up mechanisms to share and protect proprietary information among contractors so that interface designs and planning will not be impacted; and 3) make interface control documents controlled by either the owner or jointly controlled by the subcontractors so that changes cannot be made without approval of the impacted subcontractor(s).

Another recommendation resulting from the project execution effort is to establish the operations and control plan early in the design process. The equipment contracts then need to clearly state the responsibilities for communicating among subsystems. Examples of this include establishing communications protocols and the sharing of critical signals and emergency systems between design contractors.

1.9.4.1 *Surface Facility Successes and Lessons Learned*

The surface design successfully culminated in site preparation and fabrication of long-lead items that were readied for installation of the injection wells. The injection pad (see Appendix 3B for final plans and Appendix 3C for construction photographs) was designed and built to accommodate two simultaneous drilling operations, while the local traffic patterns were planned and prepared to allow for safe one-way construction traffic. Positive comments from the contractor and local residents indicated the pattern successfully protected local farmers, automobiles, and contractors alike. As mentioned previously, all work was performed without any safety incidents.

Although subsurface environmental monitoring and CO_2 tracking operations would have been unseen, visible surface features were required to accommodate system monitoring and maintenance. The site control building and injection facilities were designed to blend in with the character of the surrounding area. The exterior of these structures was designed to resemble typical farm buildings, which was best from both a project aesthetics and economical viewpoint. Monitoring wells that required an atmospheric-controlled environment incorporated a grain-bin style cover design to blend in with the area.

Another project success was the long-term effect that early efforts in project communication and relationship-building made with local stakeholders (local road commissioners, county engineer, principal landowners, and local community leaders). These outreach efforts, and the relationships that resulted from them, proved critical in obtaining approvals for changes that occurred during the design process.

Another overall success of the project was the positive cooperative approach of the team consisting of Alliance personnel and subcontractors including Patrick Engineering and Battelle. These subcontractors and others were able to work together effectively to produce documents on time. One example was the FEED document. Since the pipeline engineer Phase II contract agreement process was not complete until October 2013, this shortened the timeframe available for the FEED development, which was due December 16, 2013. Ultimately the FEED document was built beyond the traditional 30% design level for various aspects of the project, with very good cooperation from all the team members. This deliverable and continued cooperation enhanced the team's ability to produce the definitive cost estimate on time. The subsequently upgraded FEED allowed the team to obtain comprehensive proposals from construction contractors a few months later.

1.9.4.2 *Subsurface Facility Successes and Lessons Learned*

One suggestion to consider when planning an underground storage project includes constructing monitoring sites near existing road systems rather than in more remote areas, such as the middle of fields. This approach will reduce costs required to construct access roads and utilities and additional land procurement. However such sites do need to be located far enough off of the road to minimize impacts due to vehicular traffic passing, such as snow plows throwing snow and rock, and out of sight of curiosity seekers.

Another lesson to consider is that if emergency generators or other emission sources are incorporated into the remote facilities designs, then determine whether they need to be included in any overall project air permit. Another important consideration is to start with, and continually use, the same base drawings and coordinate system for design between the interfacing designers, so that all tie-ins have the same reference points. Additional lessons-learned from a land acquisition perspective can be found in Appendix 1G.

The physical and technical data captured by this project, and identifying the most appropriate processes to obtain that data, are extremely important to the future of sequestration in the Mount Simon reservoir (or other commercial-scale CO_2 sequestration reservoirs).

Acquiring 2D seismic data was demonstrated to be a critical part of the sequestration reservoir siting process. Additionally, understanding the 2D seismic issues at the Morgan County site further required a borehole vertical seismic profile (VSP) program in order to analyze the origins of seismic noise that resulted from the combination of acquisition, processing, and complexity of the subsurface. Overall, the seismic data provided the best means for constructing a robust site-wide velocity model, which is critical for accurately locating and monitoring microseismic events during the operational phase of the project. For geophysical wireline logging, it is important to have a single designated service company petrophysicist as the log analyst, if possible, to provide insight into the proprietary, sometimes "black box" methods of calculating petrophysical properties used in generating log porosities and permeabilities. This was especially important in calculating effective porosity and bulk volume irreducible water, and in integrating rock, fluid, and wireline data to derive estimates of elastic properties, thermal conductivity, and rock-matrix specific heat capacity for input in non-isothermal numerical reservoir simulations.

Another lesson learned is the need for fully adequate, high-quality relative permeability data (derived from analysis of core samples). These data allowed for a better determination of the combination of porosity logs and derived fluid volume data (e.g., ELAN BndWater, UIWater) to use for computing irreducible water saturation and enabled a consistent analysis of the combined log and core data sets. Combining these data with the use of multiple hydrologic test characterization methods (dynamic flowmeter surveys) of varying scales of resolution at the

FutureGen pilot stratigraphic borehole served to quantify the permeability conditions and vertical profile structure within the Mount Simon injection reservoir. This combined characterization approach provided the best opportunity of addressing the upscaling of borehole-derived characterization information for application in modeling of long-term, operational-scale injection performance at the FutureGen sequestration location.

Finally, completion of the Phase I geomechanical field test characterization program was critical to designing injection well orientations to enhance borehole stability conditions, and provided essential data on the state-of-stress within the subsurface, the maximum threshold reservoir injection pressure conditions, and the fracture gradient/depth relationship for the site.

1.9.4.3 *Pipeline Successes and Lessons Learned*

A number of successes resulted from the efforts to plan, engineer, and obtain ROW to accommodate the CO_2 pipeline: 1) when the pipeline was bid for construction, the design had progressed substantially to obtain very accurate and competitive construction bids, and a negotiated agreement with the selected nationally-recognized construction firm included 90% fixed price and 10% unit price terms; 2) the pipeline route was determined and all parcels, excluding one where access was denied, had obtained environmental clearance; 3) all pipeline route easements had been prepared, and the land appraised and appraisals were reviewed by a review appraiser; 4) the public was overwhelmingly supportive of the pipeline; and 5) the pipeline design avoided most environmentally and culturally sensitive areas, and avoided impacts by taking proactive steps such as boring under unavoidable wetlands. Again, these successes are primarily attributed to early and continuous communication, attention to permitting, and pursuit of a very well-developed design.

The summary of lessons learned with regard to the pipeline design include: 1) allow for flexibility for easement widths (see Land Acquisition 1.9.3); 2) establish a setback goal from residences that is greater than the national standard, but allow for special allowances; 3) establish the flexibility to vent CO_2 when managing flows and to control the system; and 4) establish a construction easement to allow for maximum flexibility, especially where slopes exist and where directional drilling or borings may be required to cross under roads, wetlands or streams.

1.9.4.4 *Construction Successes and Lessons Learned*

Two construction successes are noteworthy: 1) construction activities during Phase IIE were completed without any safety incidents, due in part to the prime emphasis given to the issue at each successive step of the project, including contractor selection, contracting, and construction management; and 2) the work was accomplished with successful union participation. Construction contracts included provisions for the use of local union labor as established in the Memorandum of Understanding between the Alliance and local unions. Contractors engaged in pre-job meetings with the local unions to discuss the division of work between the various building trades, and more deeply with regard to each site individual worker’s role, and the potential use of union labor to fill the role. The key to the successful process was to ensure that labor representatives were present during pre-job meetings, and that all effected unions and the contractors were in agreement to the number and role of the union representation on the site, well before the start date.

1.9.5 Budget Compliance

The Pipeline and Storage Project, as of DOE's issuance of the Cooperative Agreement Closeout Amendment on January 28, 2015, was in compliance with the Cooperative Agreement's authorized budget. Well within reasonable accuracy, the total final cost estimate (the total of all Phases) is arguably the same as the final authorized budget (+0.36%) set forth in the Cooperative Agreement and as shown in Table 1.5. Throughout Phase II, amendments to the Cooperative Agreement adjusted the project scope and budget to reflect changes to the project schedule caused by delays. Contracting efforts by the Alliance were able to bring the project to a construction-ready state within the Phase II budget, as supplemented by moving some Phase III activities and costs to Phase II. The projected costs for construction were less than the DPA's estimated costs for Phase III construction of the pipeline, storage and subsurface components of the project, although the Owner's reserve allowances were increased (to meet the anticipated requirements of Power Plant Project investors), resulting in the overall projected Phase III budget being higher than the Cooperative Agreement's Phase III budget.

The Alliance's project management and controls system closely tracked the budgets and schedules, providing excellent feedback to the project management team and thus allowing the greater team to successfully adapt to changing project conditions. The value of basic project controls – intelligent monitoring of scope, cost, and schedule, cannot be over-estimated.

In summary, the total DOE budget for all four phases of the project was $572,340,730. At the time of project termination the estimated final total project cost was $574,373,000, which is within 0.36% of the authorized amount. Given the large amount of owner's reserve included in the $574 million estimate, (over $47 million, a good portion of which was purposely made larger than normal to ease potential investor concerns), there is a high degree of confidence that the project would have been fully executed at or under the authorized budget amount.

1.10 Appendices

Appendix 1A – Cooperative Agreements and Amendments

Appendix 1B – Stakeholder Activity

Appendix 1C – Timeline

Appendix 1D – Siting Process

Appendix 1E – Contract Development

Appendix 1F – Risk Analysis

Appendix 1G – Land Acquisition

Appendix 1H – Project Costs

2 PIPELINE

The purpose of the FutureGen 2.0 CO_2 Pipeline and Storage Project was to demonstrate the capture, transport and storage of CO_2 emissions from a coal-fired power plant. The middle portion of the overall project, the transport of the CO_2 gas, was to be accomplished by a 28-mile underground pipeline running from the power station in Meredosia on the western edge of Morgan County, Illinois to the storage site in the northeastern corner of Morgan County (see Figure 1.1). The pipeline was to utilize proven CO_2 pipeline technology commonly deployed in thousands of miles of installation common to other regions of the United States.

The Morgan County pipeline route was initially selected by the FutureGen Alliance (Alliance) based on topography and to avoid culturally and environmentally sensitive areas. The initial route was presented to all landowners who were then given the opportunity to request route changes on their properties. To the extent possible the Alliance then altered the pipeline route to satisfy landowner requests.

2.1 Introduction

During Phase I, numerous pipeline analyses were prepared by Gulf Interstate Engineering Company (GIE), including but not limited to the pipeline feasibility report, hydraulic analyses, a design basis memo, route mapping, and cost estimates. At the beginning of Phase II, proposals were received from four pipeline designs firms. The Alliance selected and contracted with GIE to complete the design the CO_2 pipeline. An aerial LiDAR topographic survey of the pipeline route was completed in August 2013 by Benton and Associates of Jacksonville, Illinois, and used in the design of the pipeline. GIE submitted a preliminary front-end engineering and design (FEED) design basis memorandum (DBM) in September 2013 and a pipeline design bid package in January 2014. The original version of the FEED document, submitted to the DOE in December 2013, is included in Appendix 2E and the final version of the DBM is included in Appendix 2A.The design package continued to be updated after the bid proposals and pipeline contractor selection. The final version of the design package, the issued-for-contract-closeout design, is included in Appendix 2B. This chapter therefore does not delve into design details that reside in the appendices, but discusses the higher level issues and fundamentals of the design.

2.2 Design Approach

The design of the FutureGen CO_2 Pipeline Project is generally based on federal codes and state codes, engineering standards, and GIE in-house specifications conforming to oil and gas industry practices.

The pipeline begins at the meter station located on the discharge side of the compression and purification unit at the power plant site. From there the pipeline extends across rural farmland in Morgan County to its terminus at the storage site. The storage site, in addition to providing flow apportioning, control, and CO_2 injection, also contains the systems responsible for the CO_2 monitoring, verification and accounting.

The pipeline design was based on the assumed maximum instantaneous flow rate (sizing case) of CO_2 that was to be produced at the power station and injected at the storage site. The maximum allowable injection pressure in the Mount Simon sandstone formation effectively set a maximum allowable pressure at the surface of the injection wells. Given the maximum allowed pressure at the injection wellheads, the pipeline was designed to achieve the required wellhead pressure while accounting for frictional head loss at the maximum instantaneous flow rate and design temperatures, while at the same time ensuring the pipeline pressure did not fall below a minimum threshold pressure required to keep CO_2 in the dense phase. The pipeline was designed to utilize the pressure from the compression at the power plant to drive the CO_2 flow the entire 28 miles without any intermittent pumping or compression station.

The control system for the pipeline was to be housed at a single location, at the storage Site Control Building, and it would include a supervisory control and data acquisition system to manage the inlet at the power station, the pipeline, and the injection operations.

2.2.1 Design Data

The instantaneous CO_2 flow rate from the power plant was assumed to be between 2,659 metric tons (minimum design flow) to 4,137 metric tons per day (maximum design flow) as shown in Table 2.1. In addition to this criterion, the design assumed CO_2 gas parameters and pipeline conditions, such as: other (non-CO_2) constituents, minimum pipeline pressure, metering, valving, and leak-detection technology. The ground elevation profile from the topographic survey was also employed in the analysis. These additional criteria are detailed in Section 4.1 of the DBM in Appendix 2A.

Table 2.1. CO_2 Flow Rate and Conditions Parameters

Feature	Value	Units	Basis / Notes
CO_2 Flow - Design Maximum	4,137	MT/day	Maximum expected flow of CO_2 stream based on variations from design conditions *(maximum instantaneous rate)*.
CO_2 Flow - Design Minimum	2,659	MT/day	Minimum flow from compressor island during startup or ramp down.
Entry Pressure	1500 - 2100	psig	The pipeline will be designed for a receipt pressure of 2100 psig. The actual value may change to a lower value based on the maximum allowable injection pressure at the storage site.

2.2.2 Pipeline Route

The pipeline route was to begin at the Meredosia power station and head eastwardly to the storage site in the northeastern corner of Morgan County.

The majority of the pipeline route was to pass though cultivated farm land at a depth of at least five feet. There were to be thirty underground road crossings, including three highways controlled by the Illinois Department of Transportation, and two underground borings to accommodate railroad crossings. The road and railroad crossings are listed in Appendix 2A.

In order to expedite the permitting of the pipeline, the Alliance made the decision to bore under all wetland features on the pipeline route. This included a horizontal directional drill (HDD) crossing the Coon Run Dike in the Illinois River bottom lands and jack-and-bore crossings of several other wetland locations along the route.

Figure 2.1. CO_2 Pipeline Route

Because the project received federal funding, the pipeline easement purchases were required to conform to the Uniform Relocation Assistance and Real Property Acquisition Act (URA). (See Chapter 1, Section 1.6.2 - Pipeline Acquisition and Appendix 1G – Land Acquisition.)

2.2.3 Basis of Design

Pipelines transporting dense phase (liquid) CO_2 are regulated under federal code Title 49 CFR Part 195 Transportation of Hazardous Liquids by Pipelines. All federal and state regulations were followed in the design of the FutureGen pipeline. Additional design standards were employed, including standards and codes from the American Society of Mechanical Engineers, American Petroleum Institute, American Welding Society, American Institute of Steel Construction, American Concrete Institute, American Society for Testing and Materials, National Association of Corrosion Engineers, Hydraulic Institute, Manufacturers Standardization Society, and the International Building Code.

2.2.4 Reference Codes & Specifications

A list of standards and codes used in the pipeline design is in Appendix 2A Section 4.2.

2.2.5 Pipeline Design

The FutureGen pipeline design called for a 10-inch diameter carbon steel pipe (API 5L, PSL 2, X70) specified to ensure high toughness at low temperatures which can occur during the pipeline pressurization (filling) process or depressurization such as blowdown or a leak. The pipe size was selected based on a hydraulics study by GIE which accounted for the flow volume, pipeline profile, input and output pressure and physical characteristics of dense phase CO_2. The gaseous CO_2 was to be compressed as part of the power station process and received at high pressure in dense phase at the pipeline's power plant inlet station. The inlet station was to include redundant meters for custody transfer and a permanent proving station for meter calibration. There were to be two main line block valve (MLBV) stations at roughly equal spacing along the pipeline route to stop or control the CO_2 flow in order to isolate a section of pipe. A communication system with two redundant fiber optic cables was to connect the inlet station, the MLBV stations, and the outlet meters and wellhead sensors to the Site Control Building at the injection site where the SCADA system controls would reside.

The control room at the Site Control Building was to be manned at all times. The pipeline patrolling and general maintenance work was to be contracted to a third party O&M contractor. The periodic meter proving would be conducted with the permanently installed prover at the inlet station and by a truck-mounted third-party prover at the injection site. The injection site was to have four separate meters, one for each injection well. The leak detection system would have included a computer algorithm to analyze the data from the inlet meters and the outlet meters to assure mass balance and provide detection of leaks. The pipeline design is detailed in Appendix 2A Section 4.3.

Safety in design was the primary objective in the development of the FEED and the advanced design. Several safety features were incorporated in the design to enhance overall project robustness, integrity and on-stream factor. This included constructability reviews, fracture mitigation and control study, material selection investigation, due diligence in equipment specification, and the hazard and operability study (Appendix 2C).

2.3 Results

2.3.1 Design Plans and Specifications

GIE prepared and refined the design as the project proceeded from FEED level to the advanced design level, to the issued-for-bid (IFB) plans and specifications for soliciting construction bids. Appendix 2B contains the advanced design that was prepared and used for the negotiation of the pipeline construction contract with Rockford Company, with revisions to reflect the design status at the time of project suspension.

2.3.2 Pipeline Cost Estimate

Along with the pipeline design, GIE also prepared the definitive cost estimate in March 2014. The estimate was drafted to an Association for the Advancement of Cost Engineering (AACE) International Class 1 level of accuracy (-10%/+15%). The estimated cost of construction was determined by the estimate to be $40.77 million dollars.

In March 2014 the Alliance prepared bid packages and sought bids for the pipeline construction contract. Four firms responded to the request for proposals. After a contractor selection process and negotiations were completed, the Alliance selected Rockford Company to be the pipeline construction contractor. (See Chapter 1, Section 1.7.3.3 Pipeline Construction Services Subcontract Agreement for additional information.) As detailed in Chapter 1 of this report, the firm price offered by Rockford was $36.5 million.

The material costs for the pipeline were estimated to be $16.95 million dollars. The material procurement process was in process when the project was suspended. Actual quotes received before project suspension for the long lead and the major cost equipment and materials such as line pipe, meter skids, analyzer shelter, line valves, and control valves compared favorably with the estimates. Mainline pipe costs were expected to be less than the Definitive Cost Estimate due to the price of steel decreasing significantly between March 2014 and January 2015.

Table 2.2. CO_2 Pipeline Cost Estimate – Direct Costs

Cost Item	Definitive Cost Estimate (March 2014)	Contracted Costs (January 2015)
1.0 Total Materials & Equipment	$16,954,000	$16,954,000*
2.0 Total Construction	$40,767,000	$36,539,959
3.0 Total Commissioning**	-	-
4.0 Duties, Freight, & Taxes	$1,826,000	$1,192,000
Pipeline Direct Costs Total	**$59,547,000**	**$54,685,959**

Notes: *Used the same material estimates as DCE.
**Commissioning costs are included elsewhere.

The duties, freight, and taxes estimate was reduced to account for sales tax exemptions due to the pipeline being in the county's enterprise zone.

2.4 Conclusions

2.4.1 Project Successes

The FutureGen CO_2 pipeline, while never constructed, did achieve several significant milestones during Phase II:

- The pipeline design was sufficiently developed to be successfully employed in contract negotiations with Rockford Corporation, which led to agreed-upon pricing for the pipeline construction which included 90% fixed-price and 10% unit-price terms.
- The agreed upon construction contract of $36.54 million was less than the pipeline construction cost estimate of $40.77 million but within the specified level of accuracy (-10%/+15%).
- While the material purchases were not made prior to project suspension, quotes for materials being received at the time were favorable in comparison with the cost estimate. Thus it can be stated with confidence that the overall pipeline materials and construction would have been accomplished within the Definitive Cost Estimate.
- The pipeline project had support from the local residents as demonstrated by all but one landowner granting permission to conduct environmental and cultural resources surveys on the pipeline parcels.
- All pipeline easements, excluding one where access was denied, had obtained environmental and cultural resources clearance.
- All pipeline easements were prepared and all parcels had first appraisals and review appraisals.
- The pipeline design avoided most environmentally and culturally sensitive areas, and avoided impacts due to proactive steps such as boring under unavoidable wetlands.
- The ICC awarded the first-ever Certificate of Authority to construct and operate a CO_2 pipeline in the State of Illinois.
- The ICC approved the first-ever CO_2 Transportation and Sequestration Plan in the State of Illinois for a clean coal facility.

2.4.2 Lessons Learned

While the pipeline corridor definition and design processes were successful, there were difficulties encountered that could be avoided.

2.4.2.1 *Pipeline Easement Layout*

There was significant revising of the pipeline layout and easement documents throughout the design process. This was partly the result of the URA requirement that landowners be provided with the precise location of pipeline right-of-way on their parcel as a first step in the negotiation with the land owner. This required a “desktop” design of the pipeline before any field surveying for topography, or environmental and cultural resources was completed. Once permission to access the properties was obtained and actual survey data became available, changes to the pipeline design and easement documents were often required.

The Alliance's desire to have as little impact on the agricultural land as possible also contributed to minor changes to the pipeline layout. This objective led to the selection of a standard pipeline easement width of 80-feet which was supported by a study by the Interstate Natural Gas Association of America. Discussions with pipeline construction contractors verified an 80-foot wide easement was generally sufficient for construction of a 10-inch diameter pipeline. However, that width left little flexibility to realign the pipeline when a small deviation was found to be necessary or in cases where sloped topography required more soil to be moved.

While there will always be some revisions to a pipeline layout as the pipeline design progresses, the number of changes can be reduced if a wider initial corridor is selected. This does not necessarily mean the actual construction disturbance area will be wider, rather it would provide additional flexibility during design to adjust to small route changes.

The project successfully sited the pipeline at least 150 feet away from buildings, which is three times the regulatory setback, except in one case. In this case, the pipe was buried a significant depth, which provided additional protection.

The CO_2 Transportation and Storage Act, which requires the ICC to approve an application for any CO_2 pipeline before it may be constructed, allows a pipeline developer to submit an application for a specific route or a 200-foot corridor. The Alliance submitted an application seeking approval for a specific route for the pipeline, in large part because the URA required specific route information to be included in notices to potentially affected landowners. Subsequent minor route deviations required re-filings of the pipeline route with the ICC. Although the URA requires a specific route, the route revision process at the ICC could possibly have been avoided had the Alliance chosen the 200-foot corridor for the pipeline in its original application.

2.4.2.2 *Field Tile Systems*

Constructing a pipeline in the Midwest presents a unique challenge due to field tile systems commonly employed for subsoil drainage in agricultural fields. In Morgan County, it is common for a field to have underdrain pipes spaced every fifty feet. As a result the construction of a pipeline across a mile-wide field can require cutting and repairing more than 100 field tiles. Of the concerns expressed by landowners, the impact to field tile systems was the most commonly expressed.

Generally it is not possible to avoid crossing field tiles during the construction of a pipeline and the only measure that can be taken is to be diligent in specifying and assuring implementation of the proper repair method of the field tile. However, there are cases where it would be possible to avoid cutting dozens of field tile if the pipeline can be placed closer to a property line than the standard pipeline layout. The layout of a tile system is unique to each parcel but many systems utilize a header tile running parallel to the property line, up to fifty feet away from the parcel's boundary. If the pipeline can be placed parallel to, and between, the property line and the header tile, then only the tile main line exiting the property has to be crossed. The landowner-preferred pipeline location for a typical tile system is shown in Figure 2.2.

At the time the project was suspended negotiations with landowners for pipeline easement acquisition were just beginning. Communications with landowners prior to project suspension revealed at least some were preparing to request efforts be made to avoid crossing multiple tile lines by locating the pipeline closer to the property line.

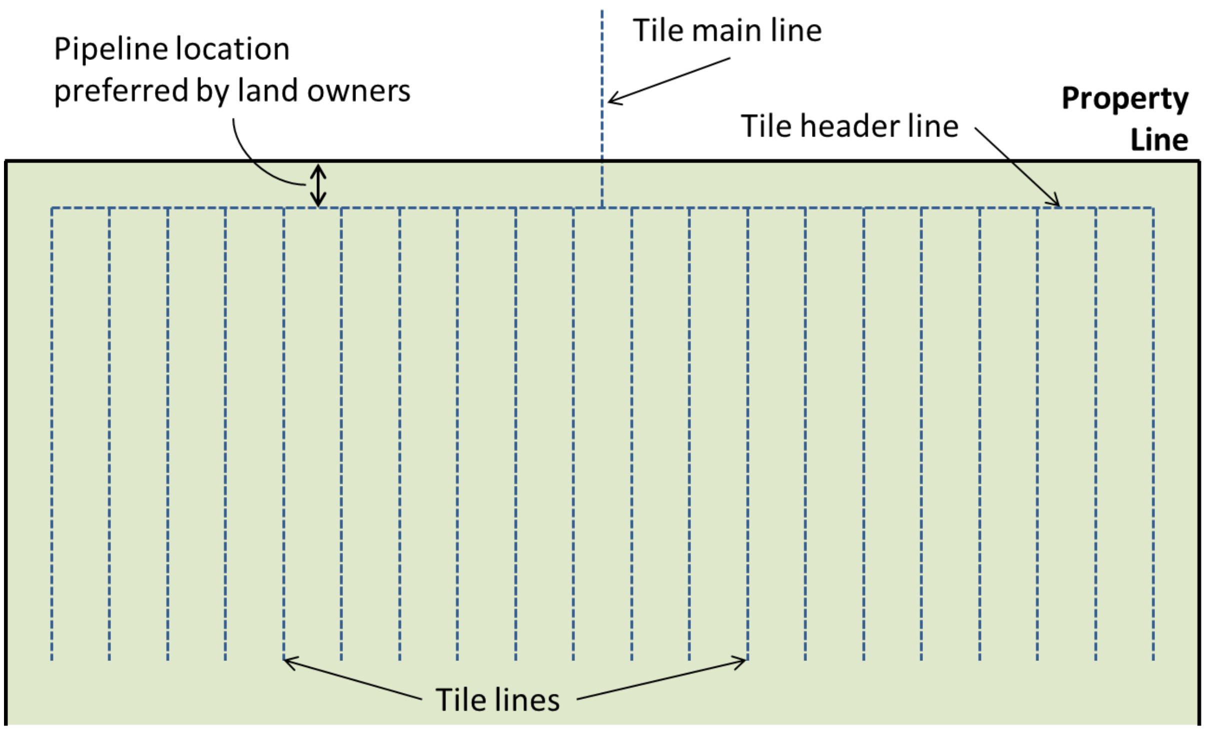


Figure 2.2. Typical Field Tile Layout Showing Land Owner-preferred Pipeline Location

Even in fields currently without a tile system, landowners had expressed concerns because the presence of a pipeline in the field could restrict the design of a tile system in the future. In some of those cases, landowners requested the pipeline be placed deeper than the 5-foot depth requirement contained in the Agricultural Impact Mitigation Agreement between the Alliance and the Illinois Department of Agriculture. However placing the pipeline at a greater depth would have required a right-of-way wider than the standard 80 feet to accommodate for greater amounts of soil resulting from a deeper ditch. The landowners who were presented with this option uniformly preferred to have the pipeline installed at a greater depth, knowing that such an approach would require a wider temporary easement for the pipeline construction.

2.5 References

Interstate Natural Gas Association of America. 1999. Temporary Right-of-Way Width Requirements for Pipeline Construction. http://ingaa.org/cms/514.aspx. Last accessed May 18, 2015.

2.6 Appendices

Appendix 2A – Design Basis Memo

Appendix 2B – Advanced Design

Appendix 2C – Pipeline Technical Studies and Hazard and Operability Study

Appendix 2D – Cost Estimate of Pipeline

Appendix 2E – Pipeline FEED Report

3 STORAGE SITE SURFACE FACILITIES

The purpose of the FutureGen 2.0 CO_2 Pipeline and Storage Project was to demonstrate the capture, transport, and storage of CO_2 produced by a near-zero-emissions coal-fired power plant. This chapter provides information related to the design and construction of surface facilities associated with the storage portion of this project. Located at the eastern end of the transmission pipeline in the northeastern corner of Morgan County, Illinois, surface facilities were to include the injection site (four injection wells and a control facility) and eight monitoring sites within a two-mile radius of the injection site.

3.1 Introduction

The FutureGen Industrial Alliance (Alliance) contracted with Patrick Engineering Inc. (Patrick) in Phase I to prepare the surface design for the Characterization Well pad and associated road upgrades, and subsequently to perform front-end engineering design (FEED) and final engineering design for surface facilities related to the injection site northeast of Jacksonville, Illinois. Hereinafter the term “Storage Site” or “Site,” when used, refers to the region within a two-mile radius of the injection wells intended to store and monitor CO_2 relating to this project, and “Storage Facility” refers to an 8.5-acre parcel injection site purchased by the Alliance that includes the injection wells, the pad, and associated building and pipeline structures located on the parcel. The Phase I Construction Documentation Report submitted in September 2011, and the FEED report submitted in December 2013 by the Alliance, are both included in Chapter 3 Appendix 3C. The design plans and specifications that were issued for construction in August 2014 are included as Appendix 3B.

The Storage Facility was designed to consist of the injection site, including four injection wells planned to inject CO_2 underground for long-term storage, and the injection control building (Site Control Building [SCB]) on the injection site, to be used to monitor and maintain the injection and monitoring wells. The Site also includes various monitoring locations strategically located away from the injection wells, but within a two-mile radius of the injection site. These monitoring locations consisted of deep monitoring wells and shallow monitoring stations, some of which required surface enclosures to accommodate maintenance and inspection, and were designed to blend with the rural landscape. Chapter 4 discusses the subsurface design that comprises the injection wells and monitoring network in more detail.

In addition to the facilities installed at the Storage Facility, local infrastructure improvements (road upgrades, overhead and underground power lines, water lines, and communications cable) were designed to serve the Storage Site facilities and connect the injection and monitoring locations.

Figure 3.1 shows the planned infrastructure facilities that were to be installed and the traffic pattern that was developed for construction purposes.

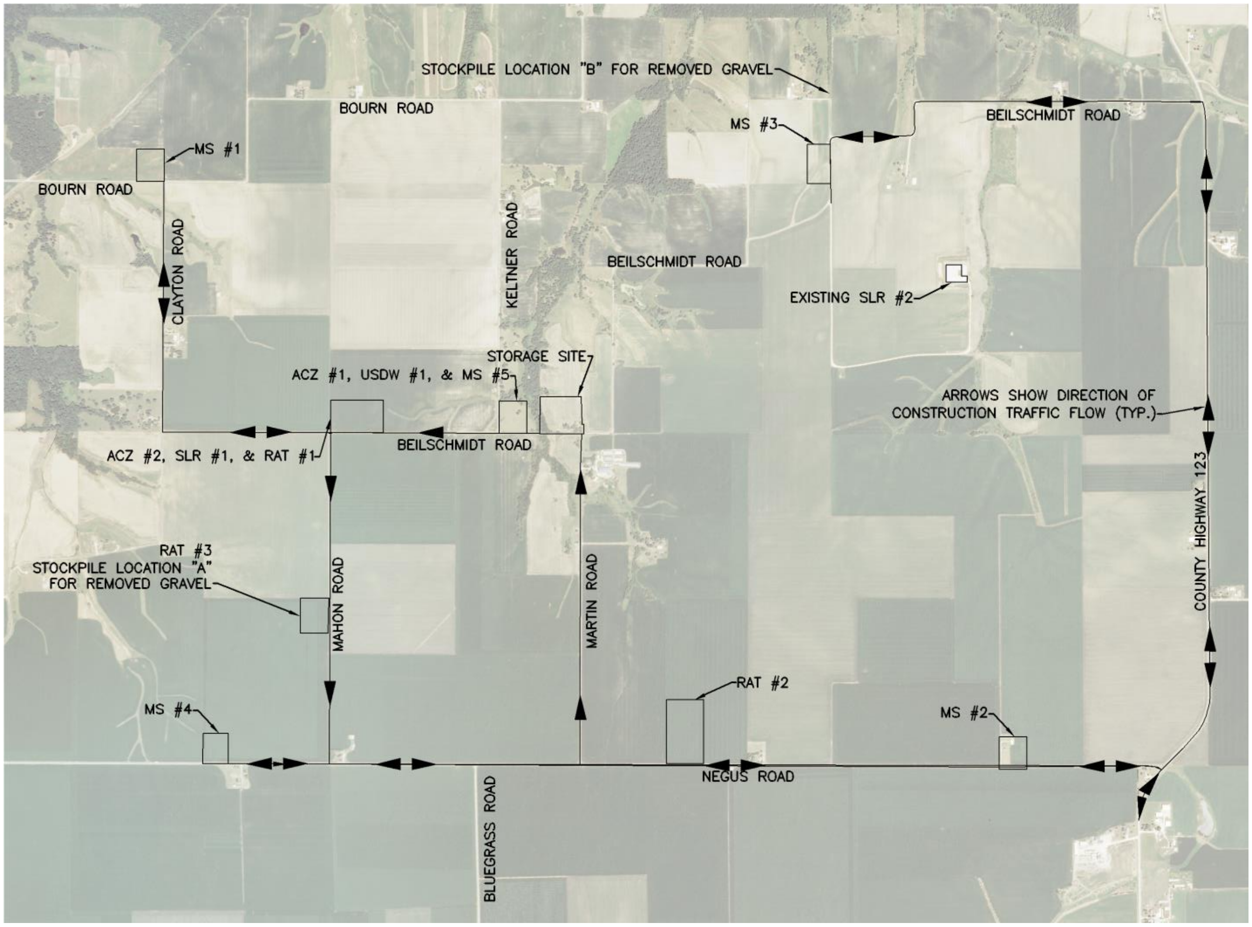


Figure 3.1. Planned Storage Site Infrastructure and Construction Traffic Pattern

3.2 Design Approach

The design the of Storage Site surface facilities was intended to fulfill the Alliance's needs for the construction and establishment of the injection and monitoring systems. The design also included improvements to local infrastructure. The Storage Site surface facilities, in addition to meeting the Alliance's needs, also needed to blend with the local rural landscape and minimize impact to the ongoing agricultural activities. Improvements to the Site were to include structures, roads, and utilities.

The planned structures at the Storage Site included the SCB and associated pipeline and injection well equipment, five well enclosures for deep-well monitoring stations, and five 10x20-foot concrete pads for shallow-well monitoring stations. Road improvements were necessary because the rural roads leading to the Storage Facility were unable to accommodate the size of the vehicles required to mobilize the well drilling equipment. Utility improvements would have extended electricity, water, and fiber optic communications cable to the Storage Facility site, and would have provided water service to deep monitoring well sites for use in drilling activities.

Site improvements are graphically shown in the final construction plan drawings, “CO_2 Storage Site Surface Facilities Project Plans,” contained in Appendix 3B.

Codes and Standards – Patrick and its subcontractors used recognized international, national, state, and/or local codes and standards as applicable for design of surface facilities.

Design Interface Responsibilities – Storage Site facility interfaces with pipeline components and subsurface components of the project were coordinated between Patrick, Gulf Interstate Engineering (GIE), the pipeline design engineer, and Battelle, the subsurface designer and the monitoring, verification, and accounting (MVA) designer. Certain aspects of the design were also coordinated with the upstream Oxy-combustion project (power plant).

Site interfaces with the pipeline components included: (a) civil improvements at the Storage Facility and pipeline laydown area, (b) power and data communications at the Storage Facility and remote main line block valve (MLBV) locations, and (c) hardware for pipeline controls and instrumentation. GIE was responsible for the pipeline design extending from the custody transfer meter at the power plant to the connection with the injection wellheads, including civil improvements at the power plant site and remote MLBV locations. Patrick provided site civil assistance, including surveying services throughout the Storage Site and the project coordinate system maintenance.

Site interfaces with the subsurface and MVA components included: (a) civil improvements, including utilities, at the Storage Facility and at the remote monitoring sites, (b) materials for the MVA lab, the well annular pressure maintenance and monitoring system room, and monitoring sites, and (c) hardware for MVA controls, instrumentation, data acquisition, and storage. Battelle was responsible for the design of the injection wells (including wellheads), monitoring wells, and other MVA stations.

Emergency Response – Site design included consideration of emergency response for fire, tornado/high winds, flooding, power outages, extreme temperatures, toxic atmospheres, and CO_2 blowdown or leakage at the Storage Facility.

Low Impact Design – The Site was designed to have minimal environmental and aesthetic impact to minimize the disturbance of ongoing agricultural activities, local residents, and landowners. Appropriate on-site storage and proper disposal of chemicals and industrial materials were planned. Site design features included minimizing the profile and footprint of the SCB and remote facilities, using “green” principles to blend in with the rural environment, discouraging trespassing through the prudent use of fencing and gates, minimizing Site lighting and noise, modeling above-ground structures to blend with the rural context, and protecting existing landscaping to the extent practicable.

Construction Schedule – Construction of the surface facilities was coordinated to minimize disruptions to pipeline and subsurface construction schedules. At the time project suspension was ordered, in late January 2015, the Project schedule called for surface facility construction to begin on October 29, 2014 and to end on November 30, 2016. Advanced planning and preparation for drilling of the first injection well were underway.

Project Operations and Monitoring – The Site was designed anticipating a 70-year total life: 20 years of active injection followed by up to 50 years of post-injection monitoring as mandated by the Class VI Underground Injection Control Permits.

3.2.1 Storage Facility

The Storage Facility consisted of the site injection location, which included four separate injection wells, the Site Control Building (SCB), and pipeline surface equipment (including metering, valves, monitoring, and the pig receiver) all within the 8.5 acre parcel procured by the Alliance on January 27, 2015.

Refer to Appendix 3A (FEED report) and Appendix 3B (design plans and specifications) for the Storage Facility.

3.2.1.1 *Demolition*

The existing farmhouse at the Storage Facility was demolished. Asbestos abatement and disposal were performed prior to demolition.

3.2.1.2 *Building*

The SCB was designed to include an injection well control room, an attached injection well Annulus Pressure System (APS) room, offices and conference room, and a maintenance garage / shop designed to store a well maintenance vehicle and utility truck. The SCB was designed to incorporate maintenance and energy efficiency measures, to be ADA-accessible, and safe. Further information on the SCB design is provided in Appendices 3A and 3B. The architectural firm of BLDD of Decatur, Illinois accomplished the final building design. Patrick designed the mechanical and electrical systems and civil components of the building site, including the underground chemical storage tank and septic system.

3.2.1.3 *Injection Wells*

Four injection wells were planned at the Storage Facility. Well pad dimensions and clearances were designed in coordination with Battelle and GIE in order to provide adequate space for coincident and sequential drilling and development of the wells. The design incorporated adequate space for two simultaneous drilling operations, which was required to offset lagging authorization to initiate drilling activities and meet the American Reinvestment and Recovery Act (ARRA) spending deadline. Further details regarding Storage Facility design features (e.g., utilities, drainage, landscaping) are provided in Appendices 3A and 3B.

Construction of the injection well pad was completed on December 29, 2014, prior to DOE's decision to suspend Cooperative Agreement cost-sharing of the project and initiate project suspension. Daily construction reports of the construction work performed are provided in Appendix 3C (see Results section).

3.2.2 Storage Site – Site Control Building

The SCB was designed with Leadership in Energy & Environmental Design (LEED) attributes, such as sustainable systems, energy-efficient systems, and LEED-compliant building materials. The structure was intended to be low profile and blend in with the surrounding agricultural environment – it was modeled after the equipment buildings that are common in the surrounding area.

The SCB was planned to be approximately 152 feet by 44 feet (exterior dimensions), with 6,700 square feet of interior space. The building interior was divided into three functional areas with roughly 55% dedicated to control room, office, and conference room space, 25% dedicated to a maintenance garage, and 20% for the APS function.

Figure 3.2. Rendering of Conceptual Site Control Building

Further details regarding the building design are included in the FEED report and design plans and specifications in Appendices 3A and 3B, respectively.

3.2.3 Monitoring Wells – Surface Facilities

Road and utility upgrades, along with monitoring well pad construction, were required for construction and installation of the monitoring network for the Storage Facility. Sheet G1.2 of the construction plans in Appendix 3B shows the overall improvement plan and the monitoring network for the Storage Site (also reference Figure 3.1). Well nomenclature shown on Sheet G1.2 and on Figure 3.1 herein is described in Chapter 4.

Approximately 21 acres would have been required for monitoring site construction: 5 acres leased or purchased for long-term monitoring well sites, and 16 acres leased for monitoring site construction. Well pads were sited to minimize impact to farming. Local road improvements were planned in coordination with the local road district commissioners and the Morgan County Engineer. The road repair and maintenance work was to be completed under the contract with the Alliance civil contractor. This road work was planned to occur both prior to and following the monitoring site construction.

Figure 3.3 shows a rendering of the deep monitoring well enclosures, which had been designed with a corrugated metal silo shell to fit with the rural character of the Site. Other monitoring sites were designed as concrete pads with minimal instrumentation. Further details regarding the design considerations for the monitoring sites may be found in the FEED report in Appendix 3A and in Chapter 4. Design plans for the monitoring sites are provided in Appendix 3B.

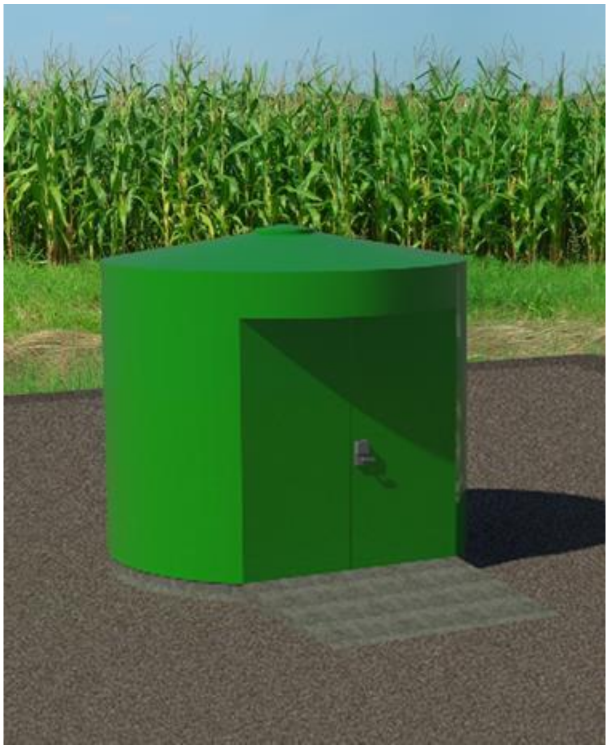


Figure 3.3. Rendering of Conceptual Monitoring Well Enclosure

3.3 Results

3.3.1 Design Plans and Specifications

In December 2013, Patrick developed a Front-End Engineering and Design (FEED package) for use in preparing a capital cost estimate that was later refined for the Project's Definitive Cost Estimate (see Section 3.3.4). The FEED report illustrated the proposed construction locations, civil improvement plans (grading, drainage, paving, and erosion control), and building construction plans (structure, electric, plumbing, mechanical, and architecture). The FEED report is provided in Appendix 3A.

Patrick developed drawings and specifications that were used for Surface Facilities contract bid packages. Design revisions subsequent to the FEED report are incorporated into the final drawings and specifications. The Surface Site construction bid package, which included bid drawings and specifications, was issued for bid on February 19, 2014.

Based on clarifications and changes agreed upon during the bid evaluations and subsequent award to the successful bidder, drawings and specifications were revised to conform to the agreed contract terms. Drawings were subsequently issued for construction on August 22, 2014. These design plans and specifications are provided in Appendix 3B.

3.3.2 Construction

United Contractors Midwest (UCM) was selected by the Alliance to perform surface facility construction activities. After approval delays and a scope reduction from the original contracted scope, (limiting work to construction of the injection well drilling pad, road improvements, and water main extension), the construction contract was issued on October 23, 2014. Construction of Site infrastructure improvements and the Storage Facility injection well pad began on October 29, 2014.

Construction traffic would have led to increased vehicles on local roads; therefore, the Alliance planned to reduce local impacts and to notify all local road users of the construction traffic plans. Adequate signage, restriction of construction traffic to designated roads/routes, and use of flaggers during the construction activities were planned in order to safely address traffic concerns. Sheet G1.2 of the construction plans in Appendix 3B (also illustrated in Figure 3.1) shows the planned traffic flow for the surface construction phase of the project.

3.3.2.1 *Road and Utility Improvements*

Road improvements as described in the final plans and specifications in Appendix 3B were initiated by UCM on October 30, 2014 and were completed on December 17, 2014. Construction reports detailing the work performed are provided in Appendix 3C. The water main extension was constructed by the North Morgan Water Cooperative and completed in December 2014.

3.3.2.2 *Storage Facility*

Initial work at the Storage Facility generally consisted of installing erosion and sediment controls, demolishing the former Martin farmhouse, and constructing the gravel pad required for injection well drilling activities. This work was initiated by UCM on November 13, 2014 and was completed on December 29, 2014. Construction reports detailing the work performed are provided in Appendix 3C.

3.3.2.3 *Safety Performance*

Safety was a top priority during the entire CO_2 Pipeline and Storage project. The emphasis included designing, planning, and contracting for safety, and ensuring that construction was performed under the proper safety provisions. During construction activities, “tailgate” safety meetings were held daily by UCM. During these meetings, work crews, foremen, and Patrick’s resident engineer discussed the day’s activities, potential hazards, changing conditions, and mitigating actions to avoid hazards. Patrick provided the Alliance with weekly Safety Audits to catalogue the safety performance, daily safety meetings, and hours worked.

Safety performance during the 2014 construction season was excellent. No injuries or incidents were recorded during this time period, with a total of 2,630 work hours performed. As a whole, the CO_2 Pipeline and Storage Project included no safety incidents over the 24-month Phase II period, with over 100,000 work hours performed, including office and field hours.

3.3.3 Site Restoration

After notification that DOE had suspended funding of the project on January 28, 2015, steps were taken to return the Storage Site and the characterization well site to their pre-developed condition (i.e., agricultural use). Restoration plans and specifications were produced for the two developed sites: the injection well site and the characterization well site (see design plans and specifications in Appendix 3D). Arrangements were made with local road authorities to store gravel removed from each site at either temporary or permanent stockpiles for the road authorities’ future use. Materials removed from the site were re-used or recycled or, if not possible, disposed.

3.3.4 Costs

Throughout the FEED and final design phases of the project, cost estimates were continually developed and refined to keep the Alliance and DOE abreast of the expected cost of the Storage Site facilities.

Cost estimates were initiated during the FEED phase, and were further refined during the final design phase, culminating in the Definitive Cost Estimate (DCE). The DCE for the storage project was refined during the first quarter of 2014, finally resulting in an estimate of $7.2 million (construction and material costs only) provided by the Alliance to DOE on March 31, 2014.

Cost estimates prepared for the DCE were subsequently used as a basis for evaluating contractor bids during the bidding process.

3.3.4.1 *Bids*

Following an RFP process, bids were received for the Storage Site’s surface facilities, which included the SCB, all well pads and associated infrastructure. The contract development team evaluated bids (as further explained in Chapter 1) and the Alliance’s selection decision was forwarded to DOE on March 28, 2014. The selected construction contractor priced the Surface Facilities construction work at $7.8 million, which included additional roadwork that had been transferred to the contractor. Following the contract development and negotiations of schedule terms, including liquidated damages for schedule delays, the project was delayed until approval was given in October 2014 to move forward with a limited scope of construction activities.

3.3.4.2 *Construction Costs*

Due to concerns over overall program progress timing, instead of approving the full contract scope for construction, DOE authorized a limited amount of construction. This included the injection pad, road improvements, and water system extension in preparation for the drilling of the first injection well, which maintained the critical path to meet the ARRA spending deadline for the CO_2 Pipeline and Storage project. Construction began in late October 2014 and was completed by December 29, 2014 at a cost of $1.28 million.

3.4 Conclusions

3.4.1 Project Successes

The Storage Project, though not fully executed, still achieved several significant milestones during Phase II:

- All planning, engineering, and construction work was performed without a single safety incident: no first aid cases, recordable incidents, or lost time incidents.
- The surface facility cost estimates proved to be highly accurate. The Engineer's estimate for surface facility costs at the time of bidding was within 2% of the selected Contractor's bid.
- The surface facility design process, from FEED to final design, was completed within the allotted timeframes, and successfully adapted to several significant program schedule changes driven by DOE.
- A unique design approach was incorporated to help the facilities blend in with the rural character of the project location. The injection wells would have been visually blocked by the SCB, which was designed to appear to be a standard, rural-looking building. The monitoring wells were to be enclosed in grain bin-type structures that would blend into the agricultural setting. Standard structures would have been incompatible and more likely to draw unwanted attention. The design gained public support from the neighbors.

3.4.2 Lessons Learned

Several lessons were learned during the design and initial construction of the Storage Project surface facilities:

- Close communication through all design phases (initial through final) is critical in identifying design and responsibility interface points. The relationship between the CO_2 pipeline and Storage Site, and the larger relationship to the power plant had to be driven to prevent design and specification disconnects. It is recommended to conduct interface HAZOPs (at a minimum encompassing project element interface points) to identify and properly treat potential issues.
- The design teams could have benefitted from earlier concurrence on formats related to design items, such as a single, agreed-upon base coordinate system and a base topographic map.

- Early project communication and relationship-building with local stakeholders (e.g., local road commissioners, county engineer, and principal landowners) was beneficial in discussing and obtaining approvals for changes that occurred during the final design phase.

3.5 Appendices

Appendix 3A – Storage Site Surface FEED Report

Appendix 3B – Surface Facilities Final Design

Appendix 3C – Surface Facilities Construction and Restoration Report

Appendix 3D – Surface Facilities Costs

4 STORAGE SITE CHARACTERIZATION AND DESIGN

The subsurface storage site was designed to encompass all of the subsurface facilities required for the injection of 22 million metric tonnes (MMT) of carbon dioxide (CO_2) and monitoring of the underground CO_2 plume. The primary components of the storage site system were to be the 4 injection wells and associated control and monitoring infrastructure along with the monitoring network, which was to be made up of several types of monitoring wells and associated environmental monitoring and recording systems. This chapter summarizes the project's subsurface achievements of the FutureGen 2.0 Project, from site characterization to subsurface design, and represent a wealth of data for the broader scientific community; these activities were conducted in support of an application for (and issuance of) the nation's first set of Class VI underground injection control (UIC) permits (see Chapter 6).

4.1 Regional Geologic Setting

The geologic region known as the Illinois Basin covers Illinois and parts of Indiana and Kentucky (Figure 4.1) with a maximum thickness of about 15,000 ft in southeast Illinois (Buschbach and Kolata 1991; McBride and Kolata 1999). However, the thickest part of the important Cambrian Mount Simon Sandstone, selected as the storage reservoir for the FutureGen 2.0 project, is in northeast Illinois, where it exceeds a thickness of 2,600 ft. A post-Cambrian shift in basin subsidence gradually caused the center of the basin to migrate southeast, and the deepest part of the Illinois Basin now lies in extreme southeastern Illinois (Kolata and Nimz 2010).

The FutureGen 2.0 CO_2 storage site is located on the western flank of the Illinois Basin, where an unconformity representing approximately 500 million years of exposure and erosion separates the Precambrian basement rocks from the Cambrian Mount Simon storage reservoir and the younger sedimentary basin fill (Willman et al. 1975).

The lower part of the Mount Simon Sandstone Formation records continental deposition, whereas the uppermost part of the Mount Simon and the overlying Eau Claire Formation record marine transgression. The Eau Claire Formation is dominated by marine sandstones, siltstones, and siliciclastic mudstones, with shale and carbonate in the upper part. Younger Paleozoic rocks in the Illinois Basin record a generally cyclic pattern of sedimentation of sandstones and carbonates, along with important intervals of marine shale deposition. Mississippian and Pennsylvanian rocks in Morgan County have produced scattered but commercial quantities of oil and gas, and the St. Peter Sandstone at the Waverly field, about 20 miles south of the FutureGen 2.0 CO_2 storage site, is a commercial natural-gas storage facility (Buschbach and Bond 1974).

In the Morgan County area, notable unconformities in the Cambrian and Ordovician are associated with regional warping, and those in the Silurian and Devonian units are associated with uplift of the Sangamon Arch (Figure 4.2). Upper Mississippian, lower Pennsylvanian, and upper Pennsylvanian strata are missing due to non-deposition or erosion. Most of the Paleozoic lithostratigraphic units present in Morgan County are widespread across Illinois and adjoining states.

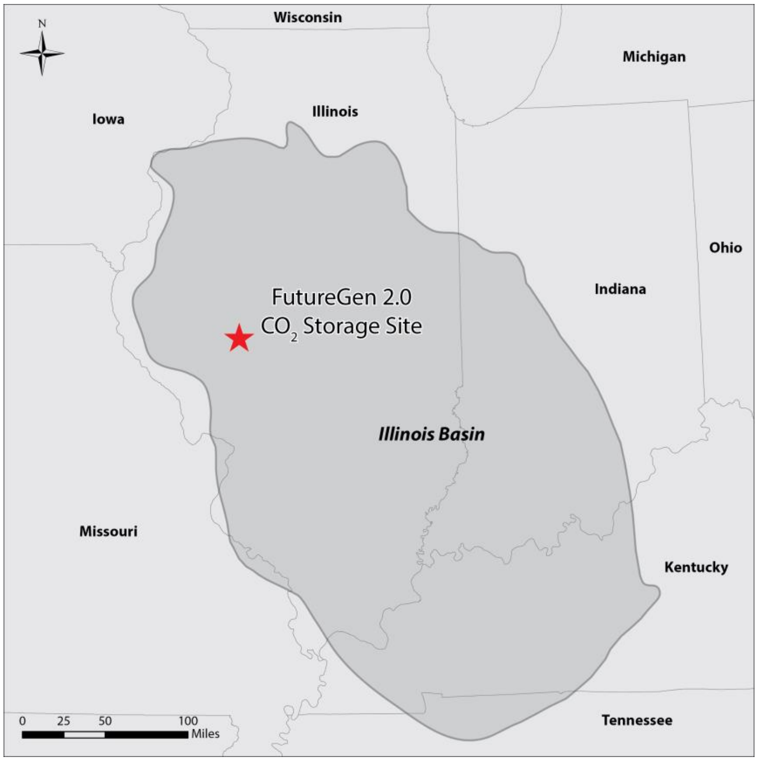


Figure 4.1. Location of the FutureGen 2.0 CO_2 Storage Site within the Illinois Basin (modified from Buschbach and Kolata 1991)

No rock record exists in Morgan County that is representative of the Permian through Tertiary Periods, an interval of more than 210 million years. Dissected Pleistocene Wisconsin glacial outwash, lacustrine, and fluvial deposits form the surface deposits that overlie eroded Pennsylvanian shales (Willman et al. 1975).

The Precambrian rock that directly underlies the Upper Cambrian Mount Simon Sandstone Formation is of particular importance both in relation to the type of Mount Simon sediments that resulted from weathering, and in relation to the thickness of the Mount Simon. Regionally, the Precambrian basement includes silica-rich igneous and metamorphic rock (Bickford et al. 1986; McBride and Kolata 1999); the nature and grain size of sediments that erode from the basement rock are strong controls on the development of reservoir quality. In addition, considerable topographic relief (up to 1,800 ft) has been mapped on the Precambrian basement across the Illinois Basin (Leetaru and McBride 2009). Much of this relief is erosional topography created prior to deposition of Cambrian sediments; the Mount Simon thins or is not present over some paleotopographic highs, such as the Ozark Dome in southeastern Missouri, and localized highs in west-central and southwest Illinois.

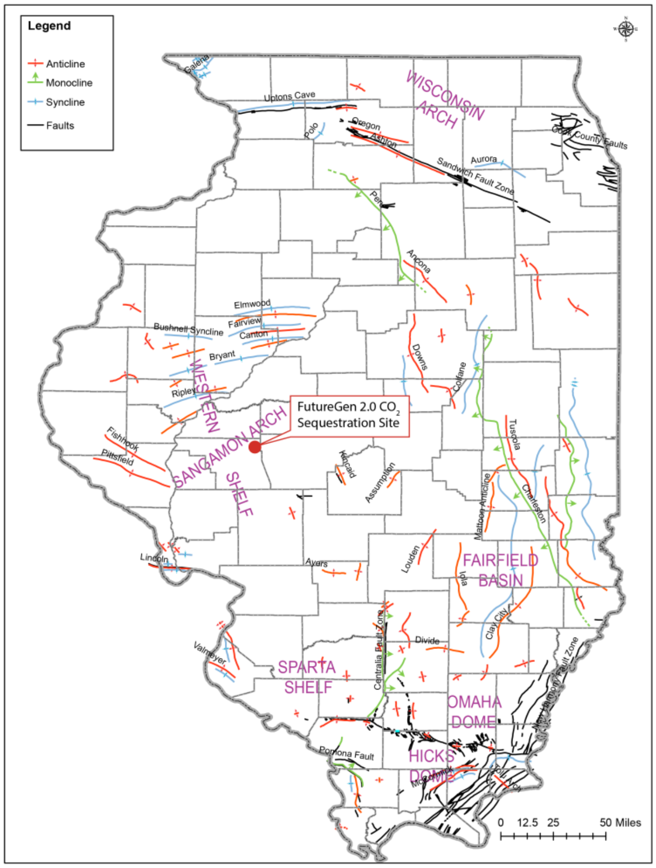


Figure 4.2. Regional Geologic Features (modified from Nelson 1995)

Localized Precambrian highs, penetrated by exploratory wells in Pike County about 40 miles west of the FutureGen 2.0 CO_2 storage site, exhibit apparent relief of 500 to 800 ft (Leetaru and McBride 2009), and at the Decatur CO_2 storage site in Macon County, basement paleotopographic relief exceeds 200 ft and affects Mount Simon reservoir behavior (Finley 2012). This topographic relief can result in the thinning of potential injection intervals.

4.2 Site Surface Geophysical Surveys

4.2.1 Gravity Surveys

4.2.1.1 *Purpose*

Gravity and geodetic surveys were conducted at the FutureGen 2.0 CO_2 storage site in Morgan County, Illinois, to provide subsurface characterization as well as baseline measurements for evaluating the use of geodetic and gravity monitoring of CO_2 injection within the Mount Simon Sandstone reservoir.

4.2.1.2 *Background*

Subsurface density variations produce small differences in the observed gravitational acceleration at the surface. Precise gravity measurements taken at several spatially distributed locations can then be used to both infer the geologic structure and to monitor processes that alter the density, such as the injection of a lower density fluid (e.g., supercritical CO_2 relative to water/brine) into porous media (reservoir).

The gravity survey was designed to obtain 10^{-8} m/s^{-2}(microGal) level accuracy measurements of the Earth's gravitational field that would then be used to give a three-dimensional (3D) estimate of density variations in the subsurface (reservoir and cap rock) and could be integrated into reflection seismic data and well-log interpretations. Also, the baseline gravity survey has been used to evaluate the feasibility of time-lapse surveys at the FutureGen 2.0 CO_2 storage site for monitoring the evolution of the injected CO_2 plume. Several studies from enhanced oil recovery and carbon sequestration projects have shown the ability to observe the variations of density in the subsurface due to CO_2 injection (Chapman et al. 2008; Davis et al. 2008; Ferguson et al. 2007).

In addition to density, gravity measurements are dependent upon a number of variables including the elevation of the measuring device. To correct for this elevation effect, accurate (centimeter-level) position measurements must be made coincident with the gravity survey. Concurrent geodetic measurements and gravity readings at each survey point are necessary for accurate and robust gravity processing and interpretation. The geodetic survey performed for this activity served mainly to provide a reference for gravity measurements, but it also could have served as a baseline to evaluate the method for monitoring surface ground deformation associated with fluid injection of CO_2.

4.2.1.3 *Instruments*

The gravity meter used during the survey was a LaCoste & Romberg Model D that featured a steel “zero length” spring meter mechanism with a worldwide range less prone to drift than quartz meters. The instrument was thermostatically controlled to approximately 50°C throughout the duration of the survey. This was achieved by continuously maintaining electrical connection to the heater circuit either through the externally mounted lithium-ion battery during field operation, or via a wall-mounted, 12-V direct-current charger at night.

A Real-Time Kinematic (RTK) technique was used for the geodetic surveys. The method is based on the use of carrier phase measurements of the Global Positioning System (GPS) signal, where a single reference station provides the real-time corrections, providing centimeter-level or better accuracy. Trimble R8 receivers were used to acquire the GPS signal at both the reference location and the individual gravity stations. A Trimble TSC2 controller running

Trimble's Access software was used for data collection and processing of the GPS signal from the reference and mobile receivers. The system uses an HP450 ultra-high-frequency band radio connecting the reference station to the controller and the mobile receiver (also called the rover).

4.2.1.4 *Field Survey*

The survey was performed from November 6 until November 22, 2011, and consisted of 245 stations (Figure 4.3):

- 230 stations regularly spaced on a 2-mile by 2-mile square grid roughly centered on the injection site,
- 14 stations along two north-south and east-west profiles, which served to extend the survey outside the area that would be affected by the CO_2 plume, and also served as a link with the existing USGS data, and
- 1 station in Jacksonville at the Central Plaza monument, completely outside the survey area to serve as a regional reference for future surveys.

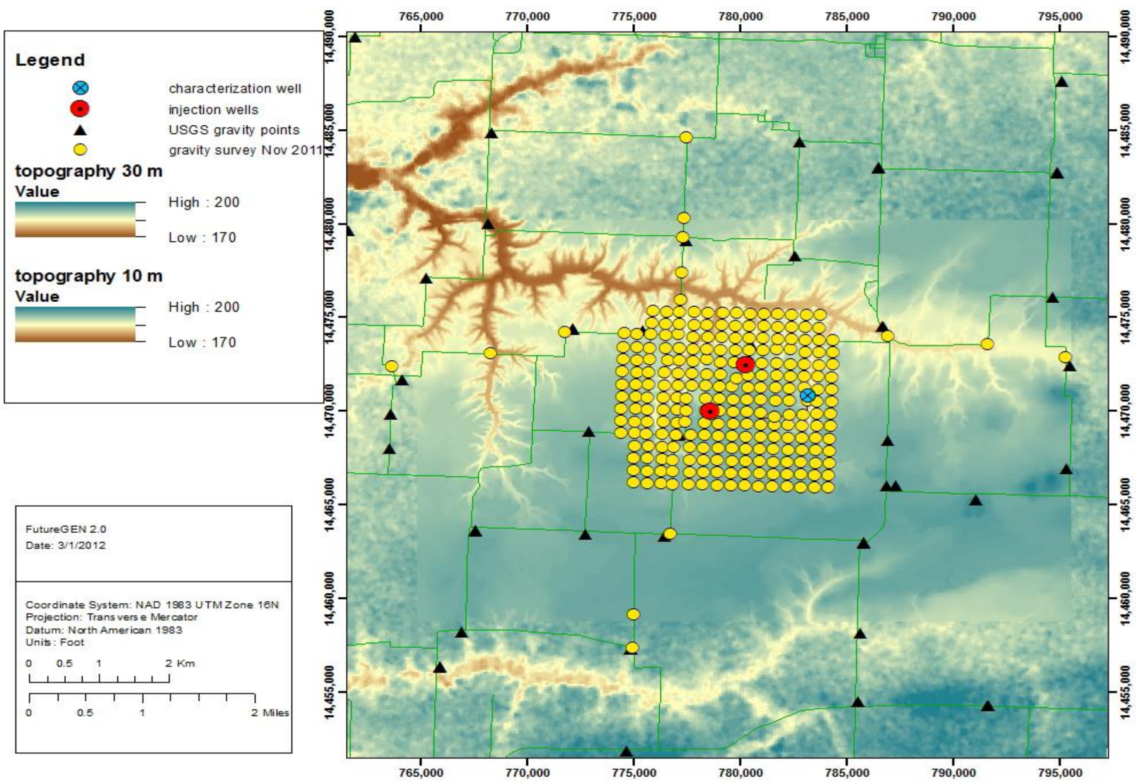


Figure 4.3. Gravity and GPS Stations (yellow circles) Used in the FutureGen 2.0 Baseline Survey along with Existing USGS Gravity Stations (black triangles)

An individual gravity measurement entailed the following steps: removing the instrument from the travel case, placing it on an aluminum base plate, leveling it using the leveling screws, unlocking the arrestment to release the internal beam, and acquiring a series of readings. Depending on the position of the electric beam indicator, the nulling dial was rotated in a direction that would move the crosshair left or right toward the centerline. As the crosshair approached the centerline, the adjustment of the nulling dial was progressively decreased until the two lines converged. The reading was read from the dial counter (to tenths of units) and the nulling dial (hundredths of units). The level and instrument reading was verified and recorded. Five readings were obtained with the requirement that readings agreed to within approximately 10 microGal. Upon collection of five successful readings, the arrestment device was used to lock the gravimeter mechanism, the gravity instrument was returned to the travel case, and the process was repeated at the next measurement station.

To provide centimeter-level accuracy in a GPS survey, differential measurements must be used. This was accomplished by using two or more GPS signals obtained at different locations. There are several sources of error in a GPS signal, such as satellite ephemeris errors and clock errors, and atmospheric distortion effects. An RTK survey determines differential corrections by placing a GPS receiver at a reference location and transmitting the correction in real time using a radio.

The GPS survey used a reference station located roughly at the center of the survey area. The local base was installed by driving an 8-ft copper-coated steel rod into the ground and cementing it in place. This local reference was established by first occupying an existing reference GPS station at the Jacksonville airport and acquiring the coordinates of the local reference from the known reference. With the local reference established, the temporary base station was removed from the airport monument, reassembled at the local reference station, and the survey of the individual local stations commenced. Three GPS measurements were collected at each station using a 30-second occupation time for each measurement. To facilitate longer working time, a 100 Amp-h battery was used to augment the base station’s internal battery and to reduce the amount of time spent returning to the local reference to replace batteries.

The geodetic datum used for the survey was WGS84, because this was the setting the instrument recognized. The post-processed datum used was NAVD88/GEOID09, which was noted in both the geodetic and gravity datasheets.

Because the gravity measurements acquired in this survey were relative, a tie to an absolute gravity station is critical; an absolute station located in Hannibal, Missouri, was selected (Figure 4.4) for the FutureGen 2.0 survey. The absolute gravity measurement was tied to the local reference station (station 137) located roughly in the middle of the survey area and was reoccupied several times each day during the survey. The method for tying the two stations together involved taking triplicate gravity measurements at both the station located in front of Hannibal City Hall and at station 137. The first measurement was obtained at Hannibal City Hall, followed by a measurement at station 137, then completing the loop by returning to Hannibal

City Hall for the final measurement. The following day, station 137 was similarly tied to station 0, a monument located in Central Plaza Park in Jacksonville, Illinois.

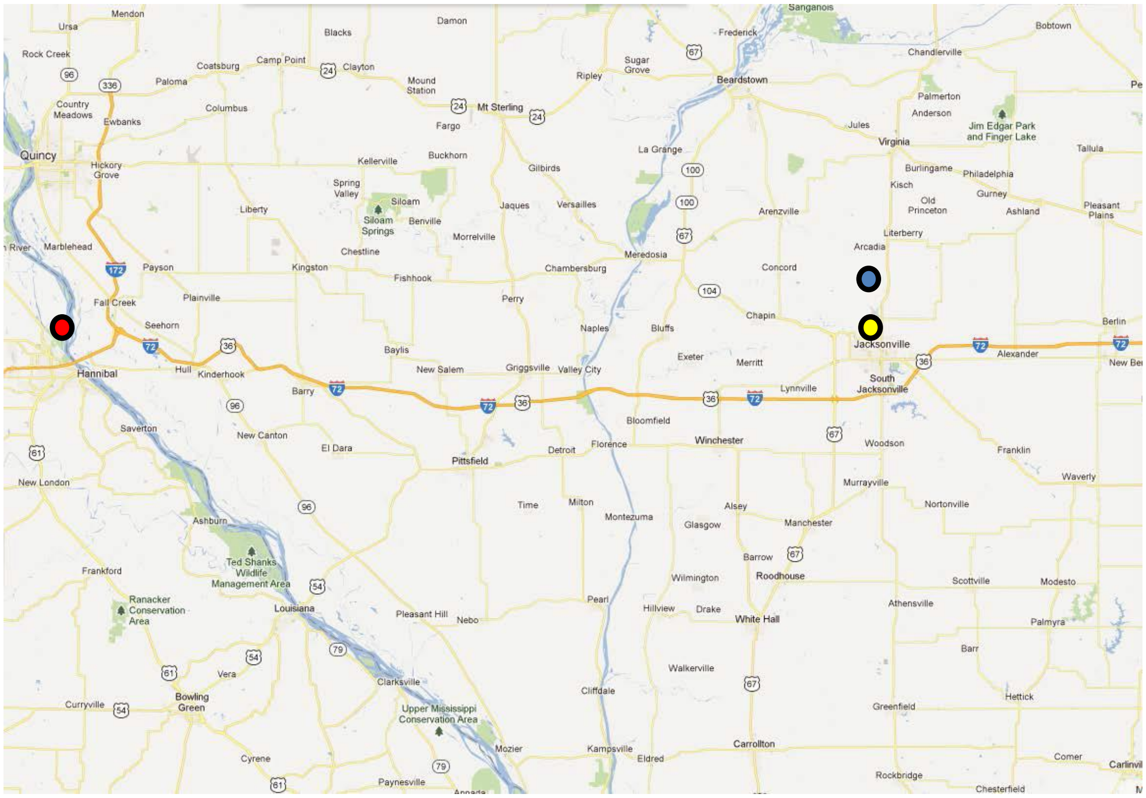


Figure 4.4. Gravity Survey Reference Stations: Hannibal (red circle), Airport (blue circle), and Jacksonville (yellow circle)

The instrumental drift correction for the gravity meter was maintained by taking measurements on a 2-hour cycle at the local reference station (station 137), and at an offsite location twice a day (station 0).

Each measurement record consisted of station location (station ID), latitude, longitude, date, time to the nearest minute, and the dial reading from the instrument.

4.2.1.5 *Interpretation*

The November 2011 measurements have been added to the 128,227 gravity station measurements in and adjacent to the states of Illinois, Indiana, and Ohio (Daniels et al. 2008). The source of the station information is the University of Texas-El Paso (UTEP) research center. Observed gravity measurements relative to the International Gravity Standardization Net 1971 (IGSN71) datum were reduced to the Bouguer anomaly using the 1967 gravity formula and a reduction density of 2.67 g/cm^3. Terrain corrections were calculated radially outward from each station to a distance of 167 km using a method developed by Plouff (1977), which produces the complete Bouguer anomaly. The data were converted to a 500-m grid using minimum curvature techniques. Note that there was a systematic offset of 4 mGal between the two data sets, for both Free Air and Bouguer anomalies, which cannot be explained easily. This kind of offset is quite usual when merging measurements from different origins. The adjustment of the two data sets has been realized by adding 4 mGal to the FG2.0 survey measurements.

The November 2011 survey results have a good correlation with the regional gravity maps. Located at a minimum between two large-scale 15-mGal positive anomalies, the survey measurements complete the regional survey and allow a better definition of the short wavelength content of the gravity signal above the FutureGen 2.0 CO_2 storage site (Figure 4.5). At the scale of the survey, the Bouguer anomaly presents several small undulations (1,000−2,000 m [3,280–6560 ft] in wavelength and 1–2 mGal in amplitude) that can be interpreted as variations in the topography of the Precambrian basement. There is no indication of any major subsurface discontinuities within the site.

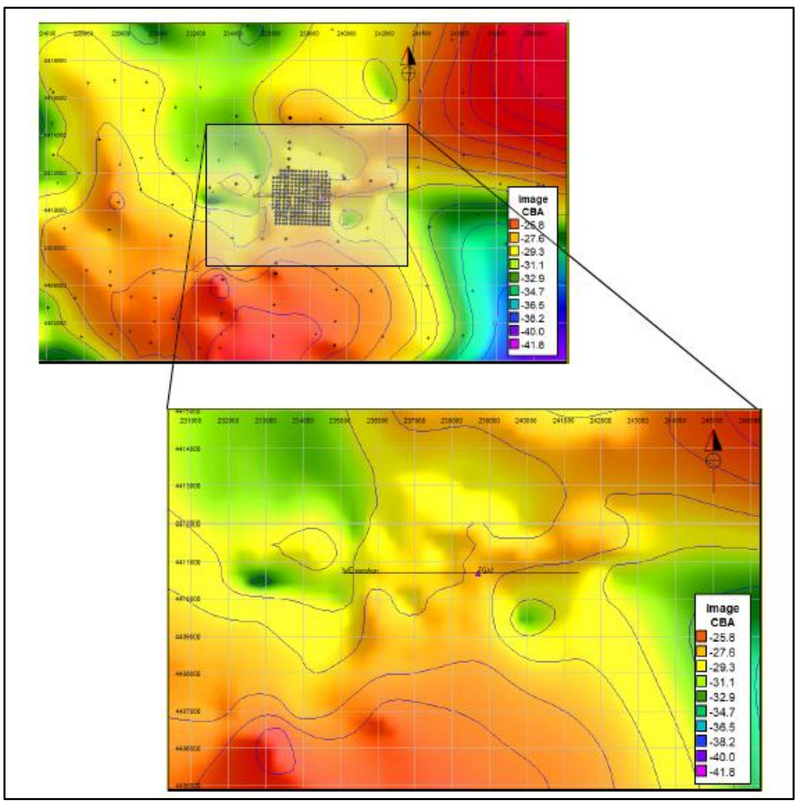


Figure 4.5. Overlay of Local Bouguer Gravity with USGS Regional Survey (regional survey data from Daniels et al. 2008).

At the regional scale, small and large undulations of the Bouguer anomaly are associated with dense intrusive mafic bodies and to basement topography. Figure 4.6 presents forward modeling of the Bouguer anomaly along a 250-km-long southwest-northeast (W-SW to E-NE) profile passing through the deepest wells of the region, the modeling was done using a 3D numerical modeling method (ENcom Model Vision TM 12.0). The observed short wavelength anomalies are well explained by variations in the basement topography (d = 2.67 g/cm^3) overlaid by a less dense Mount Simon Sandstone (d = 2.46 to 2.50 g/cm^3); background density being 2.67 g/cm^3. The depth-to-basement magnetic inversion method (ENcom Automag TM) was first employed to constrain the first interpretation and get a first idea of deep magnetic sources using the following values for magnetic susceptibility (in SI units): 0.001 for sediments, <0.01 for granite (Precambrian basement), and 0.03 to 0.04 for mafic rocks. The long wavelength anomalies are linked to deep denser mafic intrusions (d = 2.82 to 2.85 g/cm^3) in the basement as observed in other parts of the Illinois Basin (McBride et al. 2003) and confirmed by the observed magnetic anomalies (not represented here). Other interpretations could also be valid but this one makes the most of sense, especially when we look at the importance of this phenomenon at the regional scale. Note the thickening of Mount Simon to the east of stratigraphic borehole FGA-1, which is compatible with the growth fault identified on the L100 seismic profile, and with the larger growth faults identified on the regional east-west Illinois State Geological Survey (ISGS) Knox line (ISGS 2013).

Based on forward modeling of Bouguer gravity anomalies, basement topography variations could reach several tens of meters in the vicinity of stratigraphic borehole FGA-1 and hundreds of meters at a larger scale. These variations control the 3D geometry of the Mount Simon reservoir, as already observed by Leetaru and Mc Bride (2009) in Southern Illinois and in the Archer Daniels Midland (ADM) Decatur site (presentations by R. Finley at various conferences).

Highest magnetic (and often gravity) anomalies are related to deep mafic intrusions in the crust and depth-to-magnetic source analysis is a good initial approach, but forward modeling of both gravity and magnetic anomalies must always be achieved.

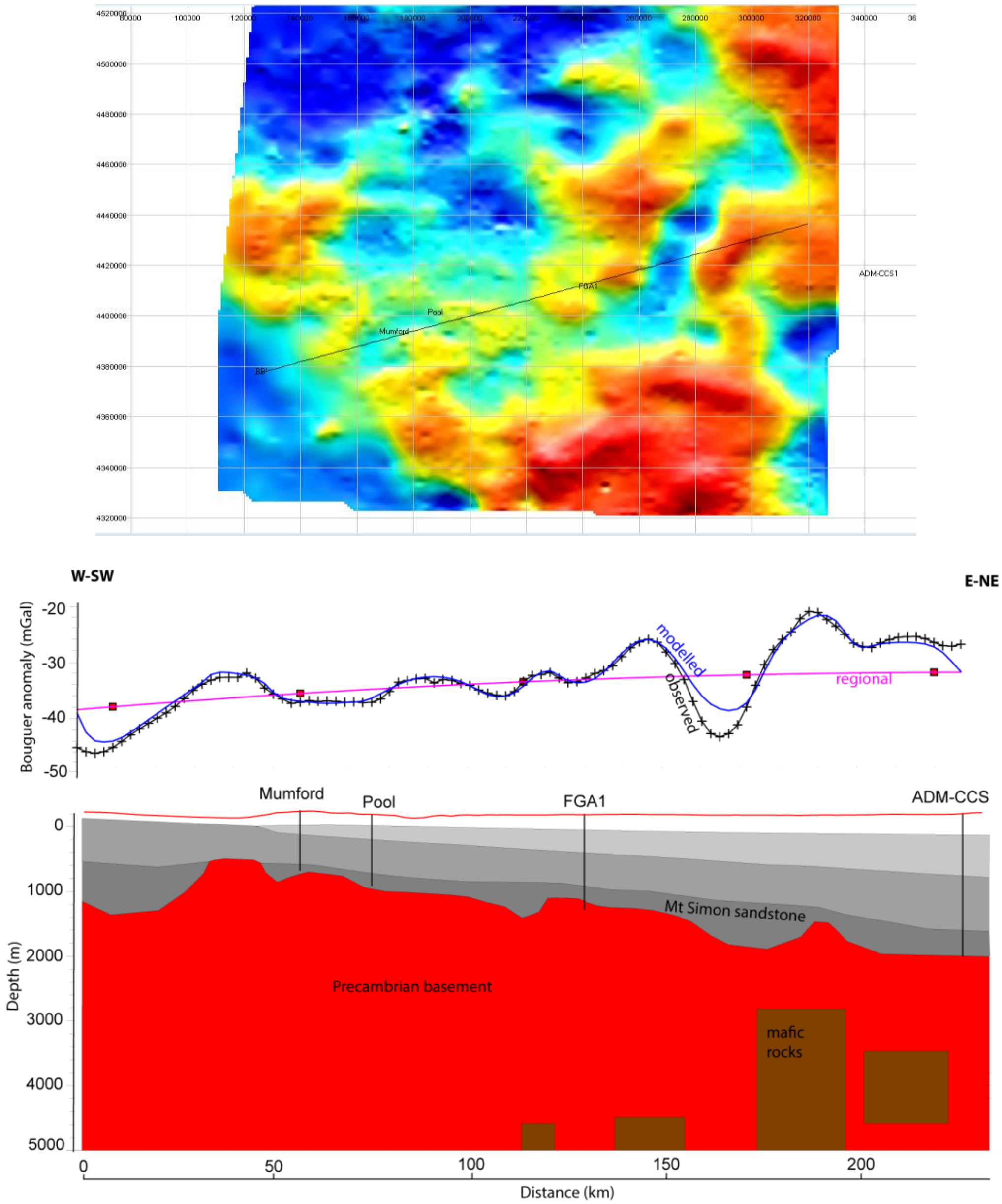


Figure 4.6. Regional WE Bouguer Anomaly Profile. Bottom: modeled depth cross section with Precambrian basement in red and Paleozoic rocks in grays. Middle: Bouguer anomaly in milligals (black line = observed; blue line = modeled; pink = regional). Top: Bouguer anomaly map with location of the profile and of the deepest wells used to constrain the modeling.

4.2.2 2D-Seismic Surveys

Seismic reflection technologies are the most robust method of imaging the subsurface for site characterization and, where conditions permit, for monitoring changes in fluid saturations between and far from wellbores.

This section covers the acquisition, processing, reprocessing (two versions), and interpretation of surface-acquired two-dimensional (2D) seismic data in Morgan County, as well as a few remarks about the initial 2011 site-screening 2D seismic surveys, and remarks about the 2011 ISGS/U.S. Department of Energy (DOE) regional 2D Knox line (ISGS 2013) that passes within 3 miles of the FutureGen 2.0 CO_2 storage site north-south line. The 2013 borehole vertical seismic profiling (VSP) seismic program is reviewed in Section 4.4.5, and has important implications for resolving 2D seismic data challenges.

Conclusions from all of the seismic work is that there are no large-offset faults within the 2D surface seismic lines (Hardage 2013a; McBride in Sullivan 2013), and no observable faults within the 12 high-resolution, short 2D VSP seismic lines that surround the characterization well (Hardage 2013a). Although the existing seismic data cannot rule out the presence of small-displacement, near-vertical faults, nor the presence of low-vertical-displacement strike slip faults within the FutureGen 2.0 projected plume area, a 3D seismic survey (preferably with 3 component receivers that can collect both P-wave and converted S-wave data) is required in order to definitively detect and image any small offset faults that may exist in the site subsurface, away from the borehole.

Although the VSP data are of high quality, the 2D surface seismic data exhibit considerable noise and seismic anomalies. The poorer quality of the 2D surface data at the FutureGen 2.0 CO2 storage site is the result of a combination of factors. These factors include:

- the particular acquisition parameters employed;
- corrections applied to convert crooked acquisition lines to straight-line profiles, and lateral variations in weathered-zone velocities;
- seismic attenuation due to the use of suboptimal processing filters or to low concentrations of methane in formations above the Galena;
- and perhaps most importantly, multiples and energy-mode conversion and scattering due to the abundance of erosional unconformities associated with the Sangamon Arch, complicated by karst/hydrothermal cavernous porosity in the Potosi.

In addition, in 2D seismic lines there are always out-of-plane reflections, and processing/ migration can place these features in their correct position only with 3D acquisition and processing. The interference of “migration smiles,” which result from diffractions of seismic energy, is demonstrated to cause vertical fault-like disruptions in the seismic images. Finally, there is the possibility that low-offset strike-slip features exist at the site, but cannot be resolved on 2D seismic lines. Intermediate processing products of the VSP data (Section 4.4.5) allowed the detection and depth location of generators of multiples, energy attenuation, and seismic mode conversion. The results and parameters generated by the VSP program are critical new input (and insights) for greatly improving 2D and 3D surface seismic acquisition and processing in the western Illinois Basin

In addition to providing parameters for improving surface data acquisition, the VSP program demonstrated that there is a mappable seismic horizon at the base of the proposed injection zone, and that VSP data (particularly converted-wave mode) are viable for detailed mapping of the near-wellbore subsurface at the FutureGen 2.0 CO_2 storage site. Rock physics modeling indicates that neither surface seismic nor VSP data will be able to map saturations of injected CO_2 at this location (Hardage 2014).

Dr. Bob Hardage of the Bureau of Economic Geology, University of Texas at Austin, provided a review of each stage of seismic acquisition and processing, and provided an independent interpretation of all data. Dr. John McBride, University of Utah, also provided a review of the original processed data, as well as both versions of the reprocessed data and the segment of the ISGS line north of the FutureGen 2.0 CO_2 storage site.

4.2.2.1 *2D Seismic Acquisition and Processing*

WesternGeco originally contracted with the FutureGen Industrial Alliance, Inc. (the Alliance) via Schlumberger Carbon Services to conduct short, 5–10 linear mile 2D surveys over three FutureGen 2.0 potential candidate project sites in Douglas, Fayette, and Morgan Counties, Illinois (see WesternGeco, 2011). The entire 2011 FutureGen 2D program was permitted for a total of 43 linear miles; and all acquisition was along state and county roads.

Vibroseis trucks provided the energy source for all surveys, and Tesla-Conquest Inc. provided four Hemi-44 enhanced truck-mounted vibrators each rated at 46,700 pounds hold-down weight. WesternGeco used the Q-Land MAS Point Receiver system in which each geophone string consisted of 12 geophone accelerometers with 10 ft spacing. Data were recorded for each source point with four sweeps at a 12-second sweep and 5 seconds of listening time, sweeping from 6–100 Hz linear with 300 millisecond (ms) start and end tapers, using 90-degree phase rotation between sweeps. Details of acquisition are provided by Jagucki et al. (2011).

The FutureGen 2.0 CO_2 storage site seismic data consist of two 2D lines, totaling15 miles (green and red lines on Figure 4.7). Schlumberger Carbon Services processed and interpreted the 2D seismic data from all three potential sites, with interpretation input by the ISGS (Jagucki et al. 2011). After selection of the Morgan County site, the 2D seismic data provided first-order subsurface characterization and support for the 2011 drilling activities.

Generally, most of the shallow reflectors at the FutureGen 2.0 CO_2 storage site were well imaged. However, at depth, reflector continuity and overall data quality were poor, compared to the Douglas and Fayette County seismic data, even though the Morgan County data were acquired with the same parameters, equipment, and logistical conditions that produced high-quality data at reservoir depths in Douglas and Fayette Counties. A distinct decrease in frequency bandwidth and amplitude occurs below 300 ms two-way-time (TWT) in the Morgan County data. This presented a challenge to the interpretation of the Mount Simon Sandstone and Precambrian basement at the site, and resulted in erroneous prognosis of the thickness of the Mount Simon and depth of the Precambrian basement during drilling of stratigraphic borehole FGA-1.

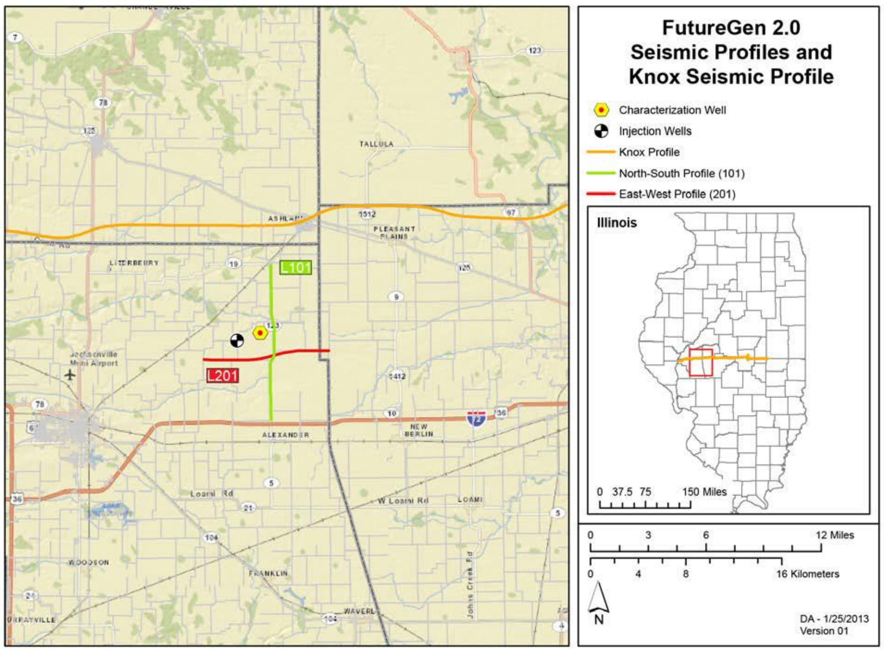


Figure 4.7. Location of the Two 2D Seismic Survey Lines, L101 and L201, at the FutureGen 2.0 CO_2 Storage Site. The north-south line is along Illinois State Highway 123, and the east-west line is along county roads. The western part of the regional Knox seismic profile, published in 2013 by the ISGS and that passes within a few miles of the site, is shown in yellow.

The contrast between seismic images from Douglas and Morgan Counties, as initially processed by WesternGeco/Schlumberger, is shown in Figure 4.8 and Figure 4.9. Both images are displayed in TWT—the time it takes for seismic energy to go down to a reflector and come back to the receiver. Note poorer overall image quality of the Morgan County seismic line, compared with Douglas County data. In addition, note that the pronounced vertical disruption in the Morgan County data near Trace 1246 coincides on the map with a stream and a bend in the seismic line, each of which can cause data anomalies. Upturned horizons at the edge of images are due to normal end-of-line effects.

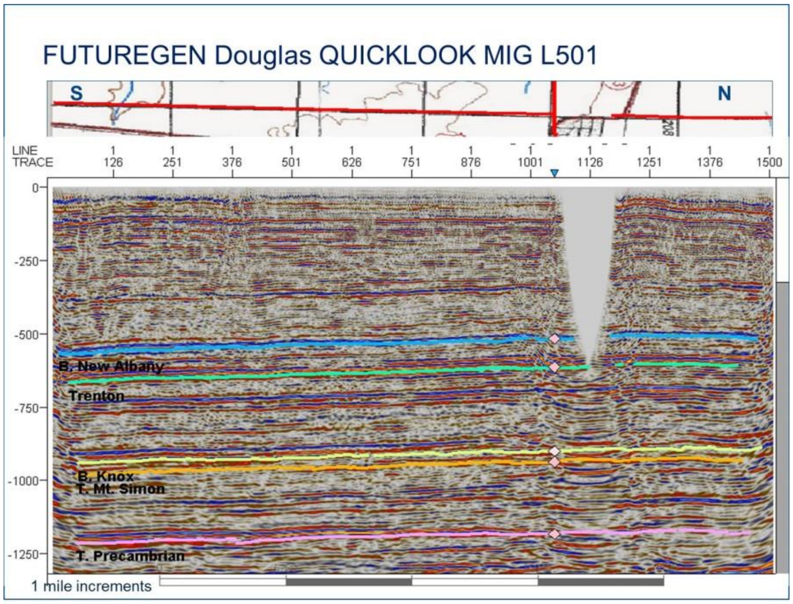


Figure 4.8. Initial Processing Product of the Douglas County North-South FGA 2D Seismic Profile (Jagucki et al. 2011). Gray area between Traces 1001 and 1200 is due to skipped acquisition stations within the town of Arcola, Illinois.

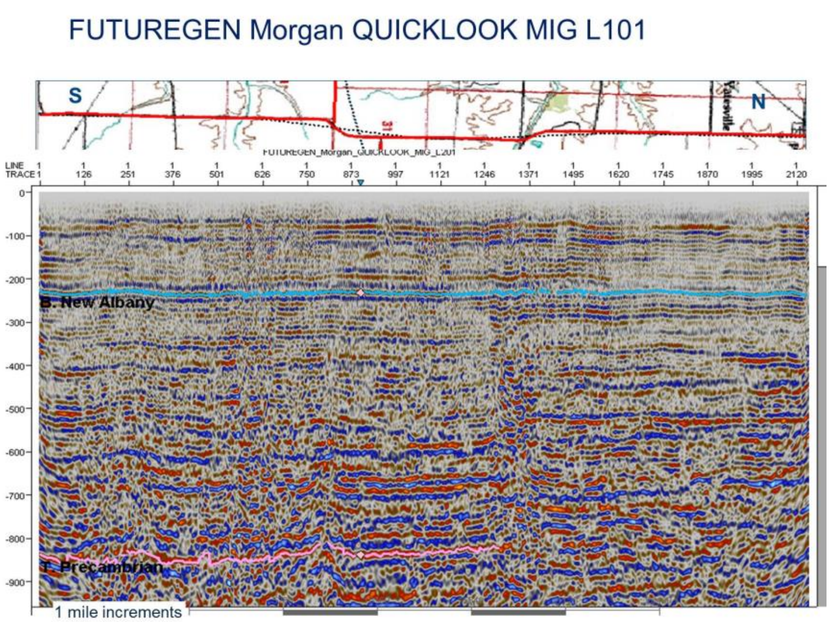


Figure 4.9. Initial Processing Product of the Morgan County North-South FGA 2D Seismic Data (Jagucki et al. 2011). Possible depth of the Precambrian basement, based on projection from the ADM Decatur CCS-1 well is in pink.

The final processing products for the Morgan County data are shown in Figure 4.10 and Figure 4.11.

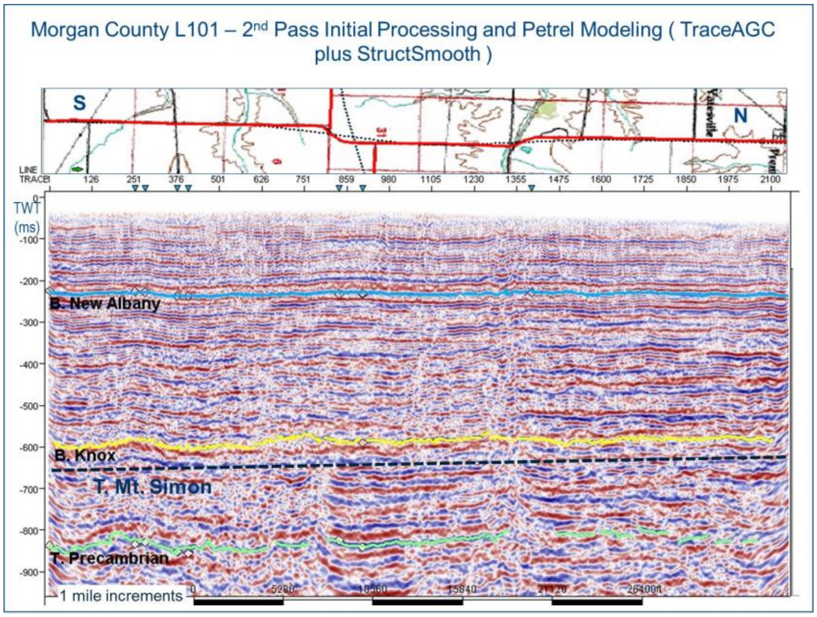


Figure 4.10. Final Processing Product from Schlumberger for the Morgan County North-South 2D Seismic Line (Jagucki et al. 2011).

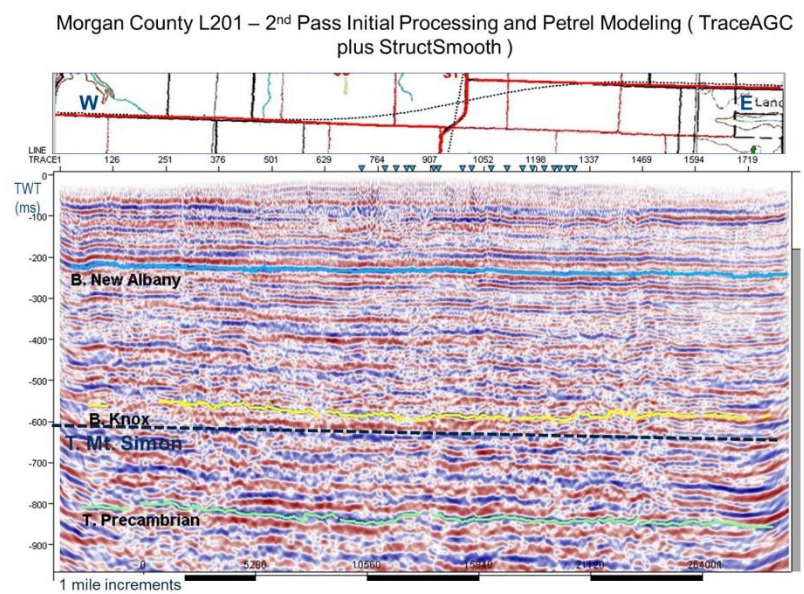


Figure 4.11. Final Processing Product from Schlumberger for the Morgan County East-West 2D Seismic Line (Jagucki et al. 2011).

Dr. Bob Hardage provided an independent interpretation of the original data shot in 2011. His interpretation (Hardage 2011) was that profiles L101 and L201 traversed anomalies that caused vertical disruptions of reflection events along each seismic line. Dr. Hardage's conclusion was that it was not possible to decide if these vertical disruptions in reflector continuity were caused by binning of the data to straighten the crooked seismic lines that result from acquisition along jogs in the roads, or whether the disruptions resulted from subtle faults or from acquisition across shallow karst zones.

Geophysicists use a standard method of identifying faults. A fault can usually be recognized and interpreted in seismic data if it creates a quasi-vertical displacement of 20 ms or more in several successive reflection events. This 20-ms reflector displacement rule represents a reflector discontinuity that most interpreters can see by visual inspection of seismic data. The amount of vertical fault throw that would produce a 20-ms vertical displacement would be (0.01 sec) $\times$ (P-wave interval velocity), for whatever interval velocity is appropriate local to a suspected fault. For the interval from the surface down to the Eau Claire Formation at the FutureGen 2.0 CO_2 storage site in Morgan County, the P-wave interval velocity local to seismic lines L101 and L201 ranges from approximately 7,000 ft/s (shallow) to approximately 12,000 ft/s (deep). Thus, faults having vertical throws of 120 ft at the Eau Claire, and perhaps as little as 70 ft at shallow depths, should have been detected if they traversed either profile.

Figure 4.12 illustrates a gray-scale presentation of migration “smiles” or artifacts in the original processing of north-south Line 101. Some of these migration artifacts are associated with crooked-line effect from acquisition along bends in the road, but many are not. Some may be related to abrupt or irregular changes in seismic velocity, which can occur at erosional unconformities and buried karst features. Note the quasi-vertical trends associated with the uncanceled, upswinging migration surfaces marked in red. Some of these upswinging migration arcs produce fault-like effects where they intersect in the data.

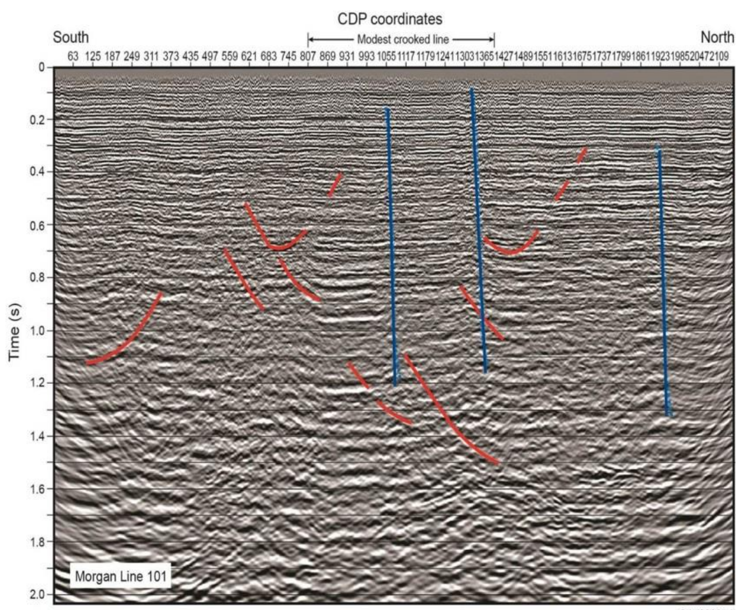


Figure 4.12. The Original “As Processed” North-South Line 101. The top of the Eau Claire Formation is around 0.5 seconds TWT; the top of the Mount Simon Formation

target is around 0.57 S, and the Precambrian basement is around 0.65 S. The vuggy, lost-circulation zones of the karsted Potosi Formation are at a TWT depth of about 0.44 S. Migration artifacts are shown in red, unresolved anomalies in blue (Hardage 2011).

Acquisition of sonic and other geophysical wireline logs collected during drilling of stratigraphic borehole FGA-1 near the end of 2011 allowed the generation of a synthetic seismogram and “ground truth” for the geology imaged by the 2D seismic survey. The stratigraphic borehole FGA-1 location and synthetic seismogram are projected onto the north-south seismic line L101 in Figure 4.13.

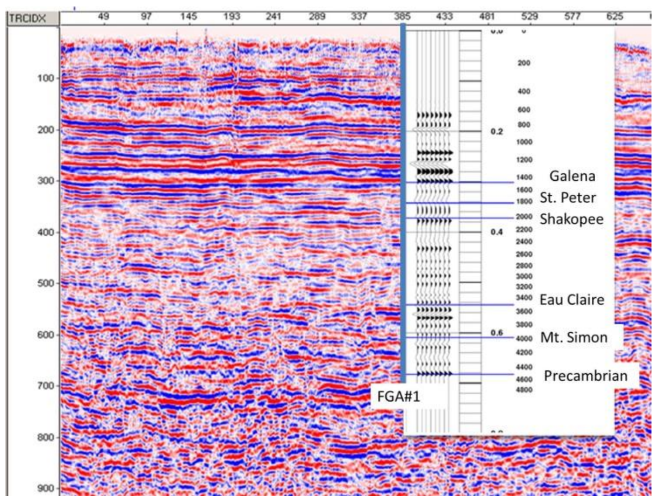


Figure 4.13. Original Processed North-South 2D Surface Seismic Line with Stratigraphic Borehole FGA-1 Synthetic Seismogram and Projected Well Location in Blue.

The two Morgan County seismic profiles were reprocessed by Exploration Development, Inc. (EDI) in August 2012 to reduce the noise, improve the images, and reduce geologic uncertainty. EDI concluded (EDI 2012) that a more conventional acquisition program might provide better signal/noise ratios, and that many of the artifacts in the pre-stack time migration may result from variances in fold (data redundancy) during acquisition. Hardage (2013a) reviewed the EDI reprocessing and concluded that although the images are sharper, the vertical disruptions, which extend far below the sedimentary basin, remain in the reprocessed data, and their regular spatial periodicity is unlikely related to faults. However, additional small offset faults cannot be ruled out without additional seismic data.

EDI conducted an additional abbreviated reprocessing of the two seismic lines in December 2013. McBride (2013) examined both vintages of the reprocessed Morgan County 2D seismic data and concurred that there are no large-scale features in the data that cut into the shallow section, although it could not be definitively determined that no faults are present, given the compressive stress regime at the site and regional studies that demonstrate reactivation of strike-slip faults elsewhere in the Illinois basin. McBride suggested that the original reprocessed lines showed strong travel-time boundaries and concluded that these boundaries may be more related to time-variant filters used during the original processing, rather than geologic attenuation of signal (Figure 4.14). The new reprocessing tended to smooth out discontinuities (Figure 4.15) and homogenize these boundaries; and seismic amplitudes have a more even level, but a close examination of the data reveals the boundaries still exist. McBride suggested working with the processing company on these or on any new data to study the effect of filters, and to avoid filters that degrade the data in this way. Better static corrections may be required to determine if offsets in the shallow (0–400 ms) section are actual small faults or are distortions due to unaccounted-for lateral velocity changes associated with small or buried stream valleys.

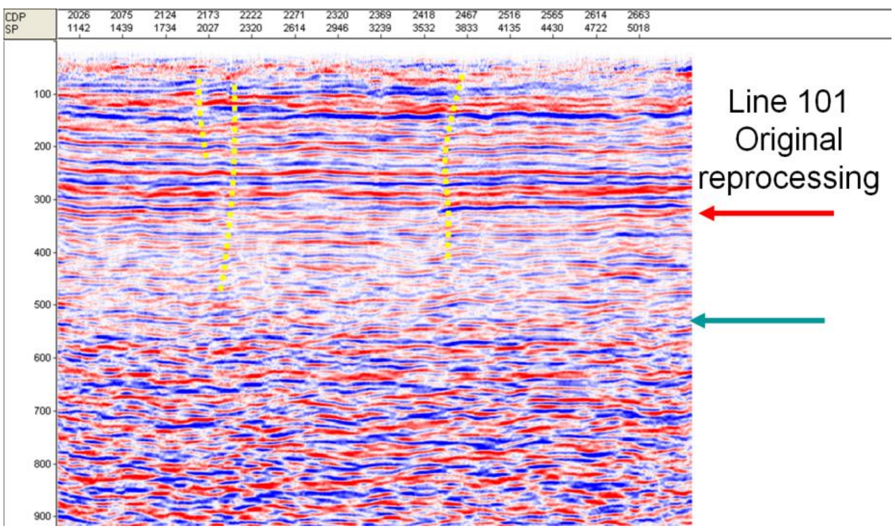


Figure 4.14. Original Reprocessed Line 101. Interval between arrows interpreted by McBride (2013) to result from overly aggressive time-variant filtering during original processing.

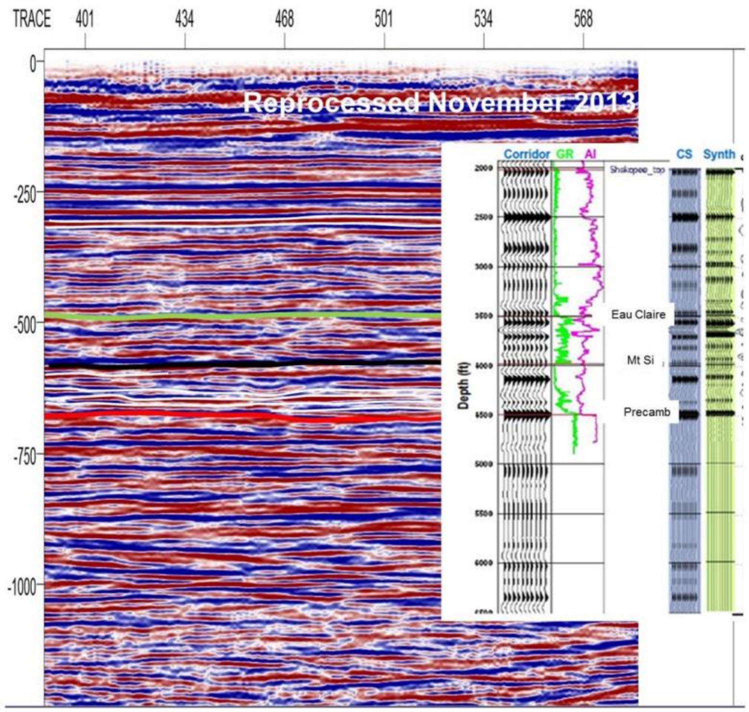


Figure 4.15. Segment of East-West Line 201 after Second Reprocessing. Inset shows tie to VSP data. Seismic horizons appear to be more continuous in this reprocessing product.

Dr. John McBride (Sullivan 2013) examined the western part of the ISGS regional Knox line (shot in 2011 and released to the public in 2013) and found no indication of large faults that might extend into the FutureGen 2.0 CO_2 storage site area. The line does show two growth faults northeast of the storage site area that appear to have largely ceased movement by the end of Mount Simon deposition (Figure 4.16 and Figure 4.17). The faults produced topography on the Precambrian basement and caused thickening and slumping of the Mount Simon. Growth faults are slump-type features that are generally self-healing and not prone to later slippage unless tectonically reactivated. McBride did not recommend additional reprocessing of the western end of Knox line (ISGS had already reprocessed the original data twice).

No faults with large vertical displacement have been identified in any processing of the 2D data; the only apparent fault is the small growth fault that affects Mount Simon and Eau Claire Formation thickness in the eastern part of the L201 profile (Figure 4.18 and Figure 4.19). This interpreted growth fault is more than 1.5 miles down-dip from the outermost edge of the modeled CO_2 plume, but is within the modeled pressure front. It should be noted that the interpreted growth fault does not appear to cut above the Eau Claire, and it may mark the geographic location of initiation of eastward thickening of the Mount Simon into the Cambrian Illinois Basin.

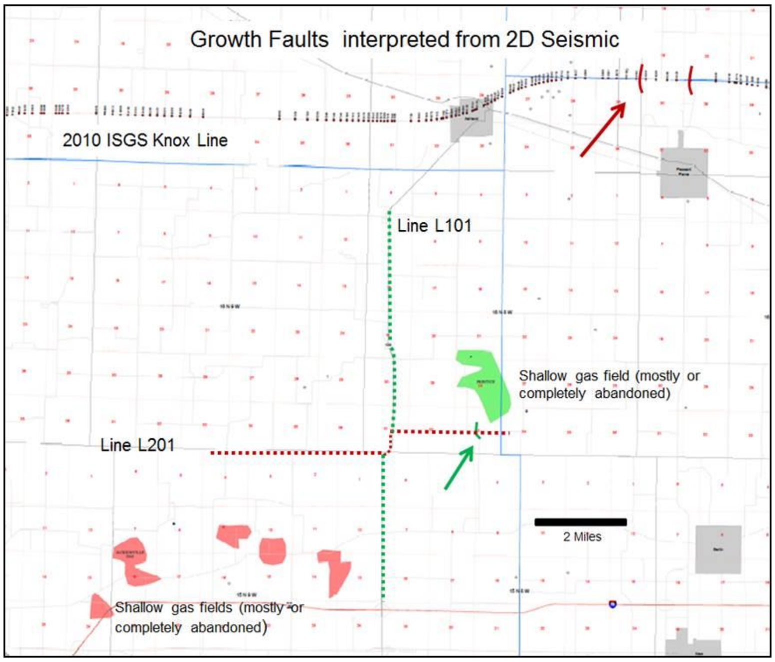


Figure 4.16. Location of Growth Faults Interpreted on 2D Seismic Lines. Red arrow indicates faults on the ISGS Knox line; green arrow indicates location of apparent growth fault on FGA Line L201.

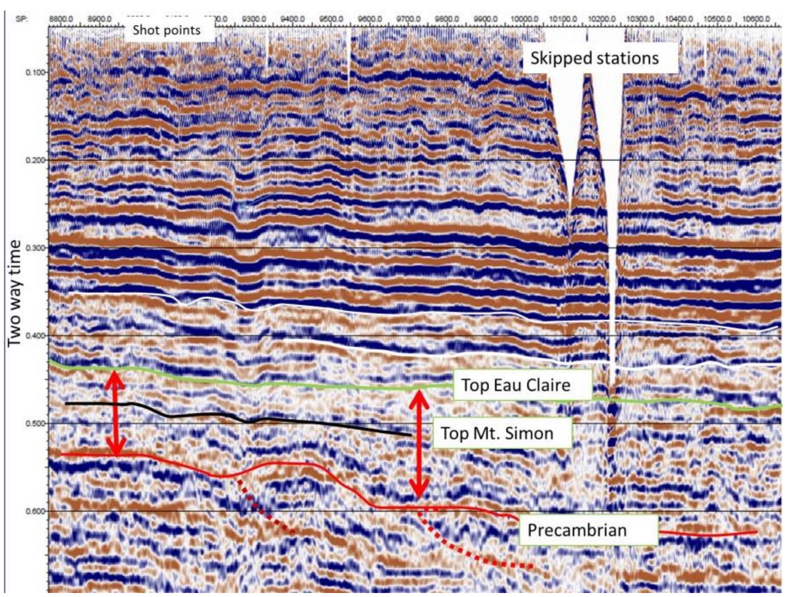


Figure 4.17. Interpreted Basement Faults on the East-West Knox Regional Seismic Line. Faults are located east of Ashland, Illinois.

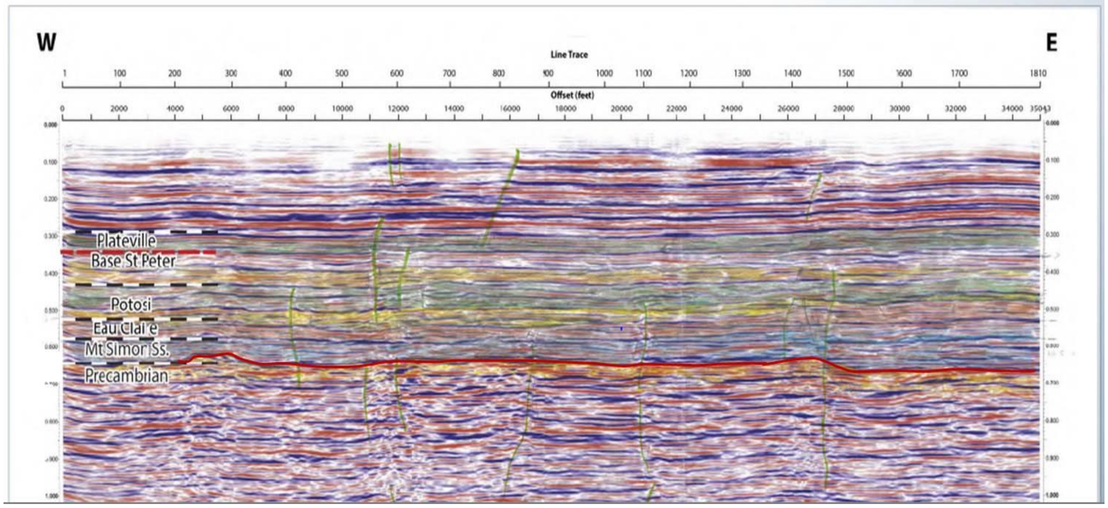


Figure 4.18. Vertical Seismic Anomalies on the East-West FGA 2D Seismic Line L201. Artifacts and anomalies are marked with green lines. Top of the Precambrian surface is marked by the red line. Small growth fault is interpreted between shot points 2500–3000.

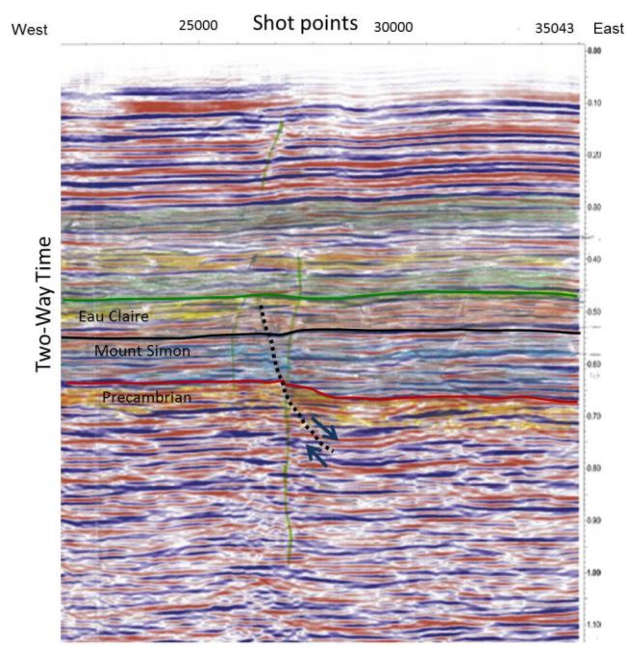


Figure 4.19. Zoom View of Easternmost Segment of Seismic Line L201 with Interpreted Growth Fault. Field of view about 2 miles.

Subsequent short 2D seismic lines generated as part of the VSP program in stratigraphic borehole FGA-1 (see Section 4.4.5) indicated no discernable faults in either the 12 short P-wave 2D seismic lines formed by the 15 offset VSPs nor in the 12 lines formed by the converted (P to

S) wave data (Hardage 2013b). The parameters that were established through intermediate processing products of the VSP program (Sullivan et al. 2014) provide input for greatly improving acquisition and processing of future 2D and 3D surface seismic data in the western-central Illinois Basin. Knowledge gained includes identification and processing solutions for the stratigraphic levels that generate multiples-type static noise and stratigraphic levels that cause signal attenuation. Lessons from the VSP program also include understandings for developing a much more robust velocity model, which strongly controls correct imaging and accurate placement of seismic features in the subsurface.

Finally, in regard to faulting, the field geomechanical testing (see Section 4.4.4) included hydraulic fracturing "minifrac" data and allowed determination that the fault regime at the FutureGen 2.0 CO_2 storage site is strike slip, with slip on undetected faults likely to have this sense of motion. Strike-slip faults may have very small vertical displacement, and could possibly be contributing to the vertical discontinuities. However, most of the observed seismic anomalies cut all the way through the section to the surface, and if regional strike-slip faults cut through the Pennsylvanian bedrock section, they might be expected to be observable in coal mines in the Springfield, Illinois area.

Precambrian topography can profoundly affect reservoir performance in the Mount Simon. None of the seismic geophysical technologies (2D seismic, VSP) indicated a unique signature of substantial basement topography within the field site. However, basement features in both the north-south and the east-west 2D seismic lines suggested possible low-relief erosional features on the Precambrian basement.

4.3 Subsurface Infrastructures Installation

4.3.1 FG-1 Shallow-Borehole Construction

A shallow borehole (API 121372213100) was drilled at the FutureGen 2.0 CO_2 storage site on August 23–25, 2011. The borehole was located in the south-central portion of the drill pad for stratigraphic borehole FGA-1 (N39.80675, W90.05283; elev. = 619.4 ft AMSL), shown in Figure 4.20. The purpose of the borehole was to characterize the Quaternary sediments and upper portion of the Pennsylvanian bedrock. A secondary purpose was to install a shallow groundwater monitoring well if suitably permeable geologic strata were encountered. ISGS personnel drilled, logged, and characterized the well. This included the driller (Jack Aud), well-site geologist (Bill Dey), geophysical logger (Tim Young), and the Battelle-Pacific Northwest Division (PNWD) geologist (Bruce Bjornstad).

The borehole was drilled to a total depth of 230 ft below ground surface (bgs). The hole started with an 11-in. auger bit to 9.5-ft depth, beyond which the hole was drilled with a mud-rotary rig and cased to 130 ft using a 5.5-in.-diameter bit (Figure 4.21). An uncased 3.9-in.-diameter hole was drilled from 130 ft to total depth. Continuous core was recovered over the entire borehole, which was sent to the ISGS core facility for archival storage.

Fine-grained Quaternary sediments composed the first 123.5 ft; below this was Pennsylvanian-age argillaceous rocks, mostly shale, siltstone, mudstone, and claystone, with occasional layers of coal, limestone, and sandstone (Figure 4.22). None of these strata appeared to be of sufficient thickness or permeability to justify installing a well screen. Therefore, after drilling, the hole was backfilled with bentonite to 20 ft bgs and a short well screen was installed between 5 and 20 ft to monitor soil-gas within the vadose zone and groundwater within the uppermost surficial aquifer system. The final surface completion for this well is shown in Figure 4.23.

Upon completion of drilling, the ISGS collected a suite of geophysical logs in the borehole including:

- gamma ray
- spectral gamma
- resistivity
- electromagnetic (EM) induction
- full-wave sonic
- acoustic imaging.

Figure 4.20. The FutureGen 2.0 CO_2 Storage Site Shallow Borehole Being Drilled Using a Mud-Rotary Rig. Fenced-off area to the right is the reserve mud pit for stratigraphic well FGA-1.

Only the gamma logs provided useful information about the cased portion of the borehole (0–130 ft). The other logs provided good results for the uncased portion (130–230 ft) of the borehole. Results from these geophysical logging activities are reported by Dey et al. (2012), along with results from an initial groundwater sampling event. Additional aqueous monitoring results from this well, along with continuous measurements of water level and other water-quality parameters will be reported in a separate publically available document.

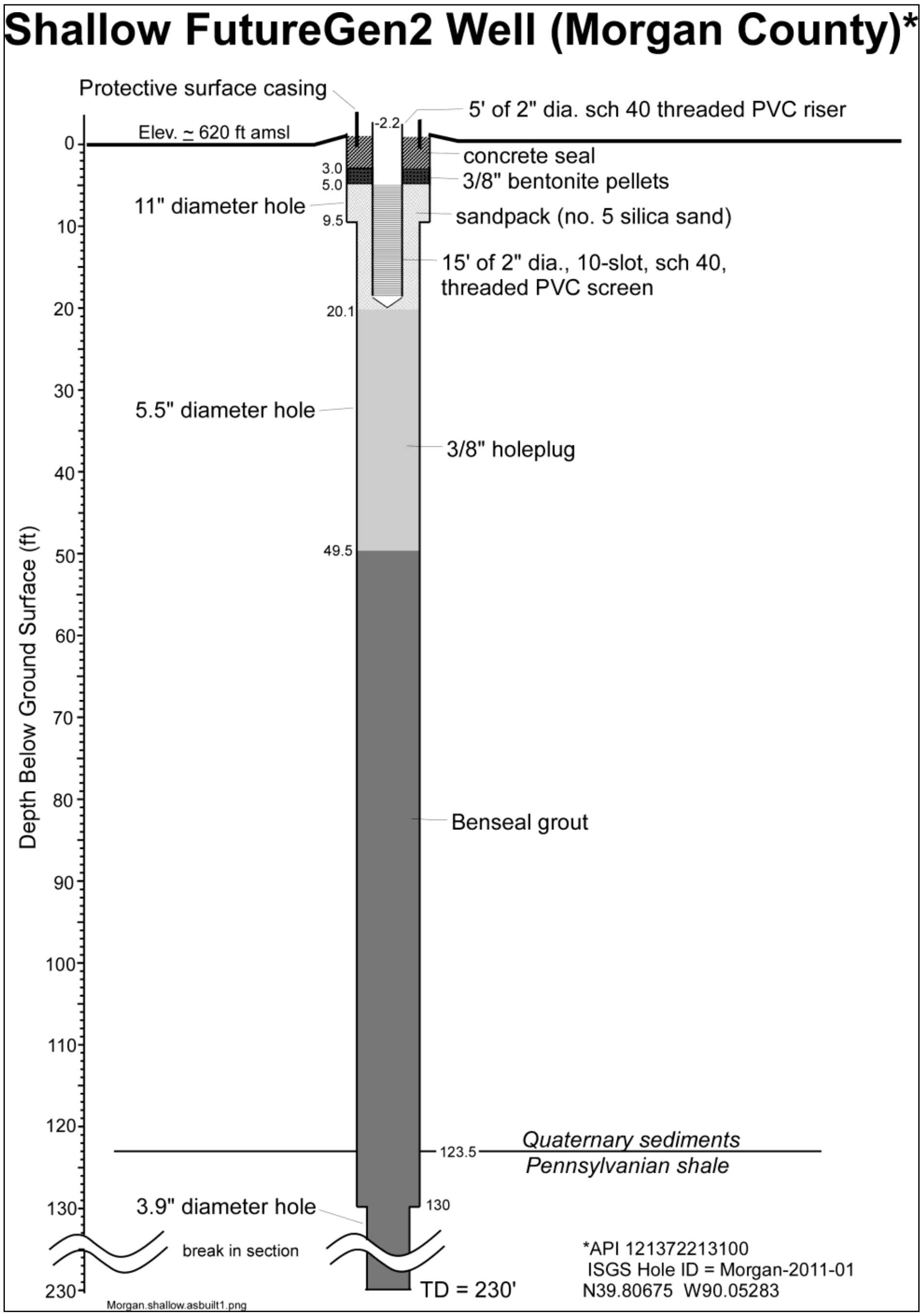


Figure 4.21. As-Built Diagram with Drilling and Well-Completion Details. A 5.5-in.-diameter borehole was originally drilled to 230 ft to collect core, then cemented back to 20 ft before installing the polyvinyl (PVC) well.

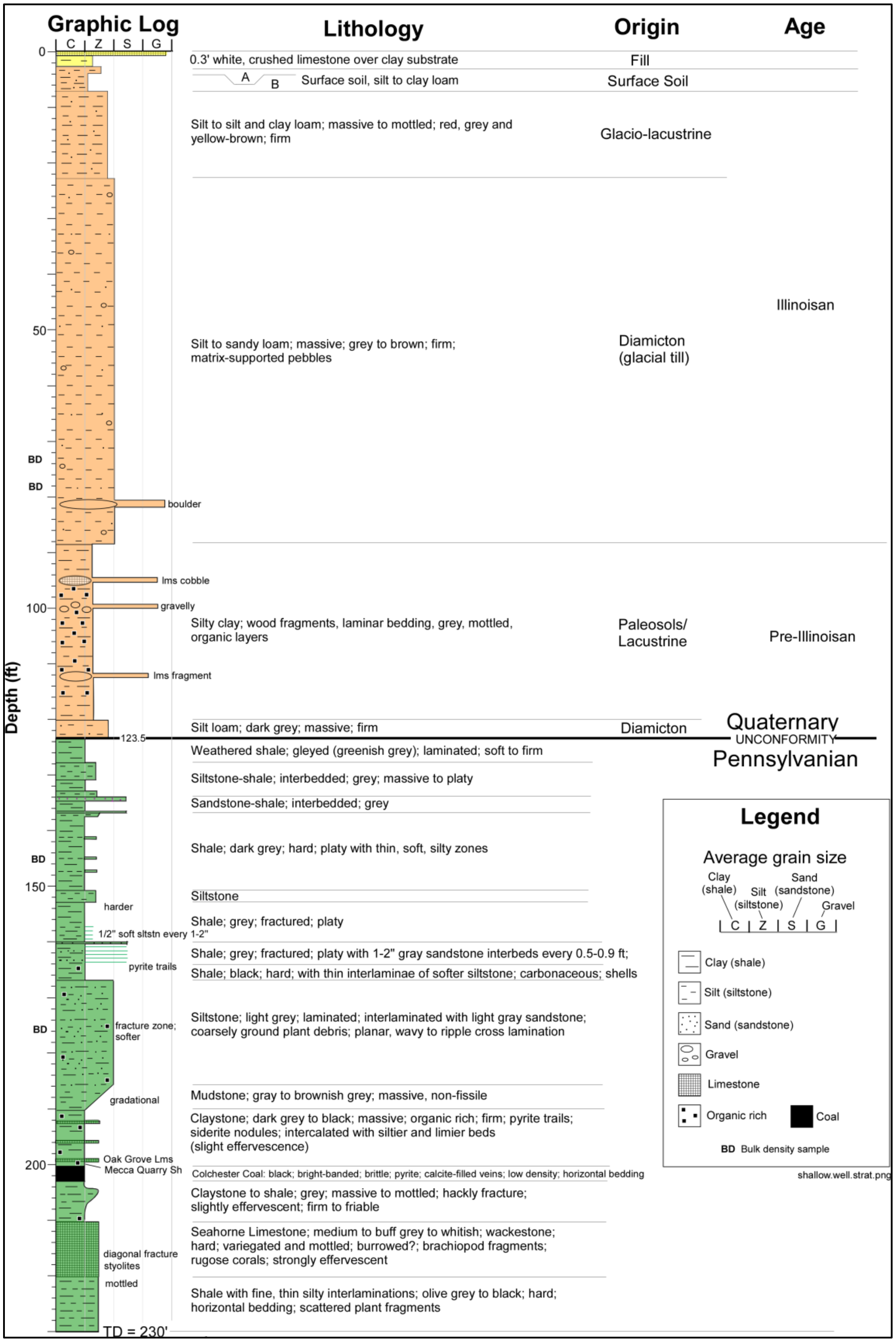


Figure 4.22. Geologic Profile

Figure 4.23. Shallow-Well Surface Completion

4.3.2 Characterization Well Drilling and Testing

This section describes the deep characterization well (referred to as stratigraphic borehole FGA-1) that was drilled at the FutureGen 2.0 CO_2 storage site in Morgan County, Illinois. The characterization well was drilled to collect important geologic and hydrologic data that were used to support UIC permitting and to design the injection and monitoring infrastructure for the CO_2 storage site. The well was to be completed as a Mount Simon monitoring well in anticipation of the site being developed into a storage site; however, given the DOE's decision to discontinue the FutureGen program, the well was plugged in accordance with the Illinois Department of Natural Resources (IDNR) requirements (see Section 4.8 for a description of the well-plugging plan). The information in this section was taken from the companion report *Borehole Completion and Characterization Summary Report for the Stratigraphic Well, Morgan County, Illinois* (Kelley et al. 2012). This section provides only a brief summary of the information presented in that report; therefore, the reader should consult the complete report for more detailed information, including work performed, schedule, data collection methods, and data interpretation.

4.3.2.1 *Well Description*

The stratigraphic borehole FGA-1 (characterization well) was drilled at a location approximately 11 miles northeast of Jacksonville, Illinois, in an area primarily devoted to row crop agriculture (Figure 4.24). Drilling took place from early October through mid-December 2011, followed by a period of open-borehole hydrologic testing from mid-January through late February 2012. Before the well was drilled, an engineered drilling pad, covering an area approximately 350 ft × 300 ft, was constructed to support the drilling operation and to prevent adverse impacts on the surrounding environment (Figure 4.25).

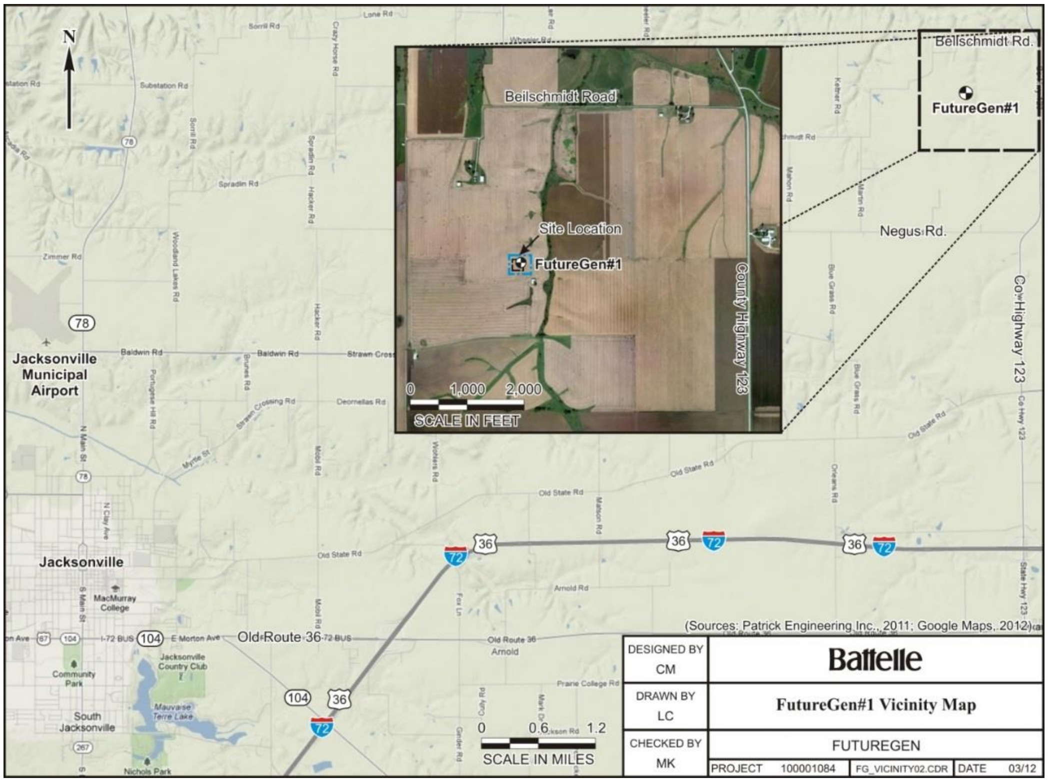


Figure 4.24. Location of the Stratigraphic Borehole FGA-1 Well Site

The well was drilled by Les Wilson, Inc. (LWI) of Carmi, Illinois, under the supervision of Battelle, the company contracted by the Alliance to oversee subsurface aspects of the program. The drilling rig used to drill the well was LWI's rig 22, a 1984 Ideco Rambler mud-rotary drilling rig that was refurbished in 2000. The rig was powered by a Detroit 12.6-L, 600-horsepower (hp) engine. The draw works is an Ideco H-35 and the derrick is an Ideco 105 ft with a hook load of 250,000 lb. Two 800-hp triplex mud pumps and two 300-Bbl steel mud pits with tandem linear shale shakers were used for mixing, pumping, and re-conditioning the drilling mud. In addition to the steel mud pits, a 50-Bbl mixing tank was used for maintaining the mud volume and mixing mud pills to sweep the hole. LWI also furnished a gas/mud separator (gas buster) to separate natural gas from the mud in case natural gas was encountered during the drilling of the well (no gas was encountered).

Figure 4.25. Stratigraphic Borehole FGA-1 Drilling Location (looking south). Lined earthen pit is visible in foreground.

Stratigraphic borehole FGA-1 was drilled to a total depth of 4,826 ft KB[1] (below the Kelly Bushing) and included four discrete sections, as follows:

- a 30-in.-diameter borehole that extended from ground surface to a depth of 163 ft, with a 24-in.-diameter string of conductor casing that was set at 146 ft and cemented to the ground surface;
- a 20-in.-diameter borehole that extended from the base of the conductor hole to a depth of 572 ft, with a 16-in.-diameter string of casing set at 570 ft and cemented to the ground surface;
- a 14 3/4-in.-diameter borehole that extended from the base of the 20-in. borehole to a depth of 4,032 ft, with a 10 3/4-in.-diameter string of casing that was set to a depth of 3,948 ft and is cemented to the ground surface; and
- a 9 1/2-in.-diameter borehole that extended from the base of the 14 3/4-in. borehole to a total depth of 4,826 ft.

[1] All depths in this section are in reference to the drilling rig Kelly Bushing (i.e., ft below the KB) unless otherwise stated. An equivalent depth referenced to below ground surface (i.e., ft bgs) can be obtained by subtracting 14 ft from the KB depth.

Therefore, at the end of the drilling phase, stratigraphic borehole FGA-1 included an upper cased and cemented section extending to the bottom of the intermediate casing string (3,948 ft) and a lower uncased open borehole (3,948 to 4,826 ft). The drilling plan called for installing a 7-in.-diameter string of casing inside the 9 1/2-in. borehole during Phase III of the program to complete the well as a monitoring well. However, instead of completing the well, it was plugged in April 2015 as part of project suspension activities. A well diagram is provided in Figure 4.26.

Except when coring, the entire well was drilled using tri-cone drilling bits. Detailed descriptions of the drilling bits and the other bottomhole assembly components used for each section of the well are provided in the Borehole Completion Report (Kelley et al. 2012). Similarly, the well was drilled entirely on fluid (i.e., air-rotary drilling was not done). The conductor borehole and surface borehole were both drilled using a “freshwater mud,” which was a mixture of freshwater and bentonite gel with other additives. The 9 1/2-in.-diameter borehole, which penetrated the Mount Simon, was drilled with a 3% potassium chloride (KCl) solution with a polymer additive called Flo-Pro™. The Flo-Pro™ system was used because all of the components of the system are 100% acid soluble and thus could be easily removed from the borehole wall after drilling to minimize formation damage that might have resulted from mud invasion if a freshwater-bentonite mud system was used instead. The Borehole Completion Report (Kelley et al. 2012) provides a detailed description of the drilling fluids used to drill each section of stratigraphic borehole FGA-1, including their composition and quantities used.

While drilling the 14 3/4-in. intermediate borehole, a highly porous zone was encountered in the Potosi Formation between depths of 2,937 ft and 3,133 ft, which resulted in a loss of drilling-fluid circulation. Various “lost circulation materials” (LCMs) (walnut hulls, cedar fiber, etc.) were added to the drilling fluid to try to plug the porous zone and restore circulation. However, due to the large pores encountered, this was unsuccessful and the porous zone had to be plugged with cement. After drilling out the cement and restoring circulation, a new mud system was built to drill the remainder of the 14 3/4-in. intermediate hole.

The casing program for stratigraphic borehole FGA-1 was designed to allow for optimum full-hole core acquisition and to allow the borehole to be used as a future monitoring well. A summary of the type of casing run by string is provided in Table 4.1.

All three casing strings were cemented in place by pumping cement from the bottom of the casing to ground surface. Five casing centralizers were installed on the 16-in. casing to keep the casing centered in the borehole while cement was injected in the annular space surrounding it. Twelve bow spring centralizers, three turbo centralizers, and three cement baskets were installed on the 10 3/4-in. casing for the same purpose. A detailed description of the cement used to install each casing string is provided in the Borehole Completion Report (Kelley et al. 2012). The 14 3/4-in. borehole was cemented back to the surface in two stages to avoid breaking down the cement emplaced across the zones of lost circulation in the Potosi Dolomite. A multiple-stage cementing collar was installed at a depth of 2,704 ft (Figure 4.27) in order to complete the two-stage cement job.

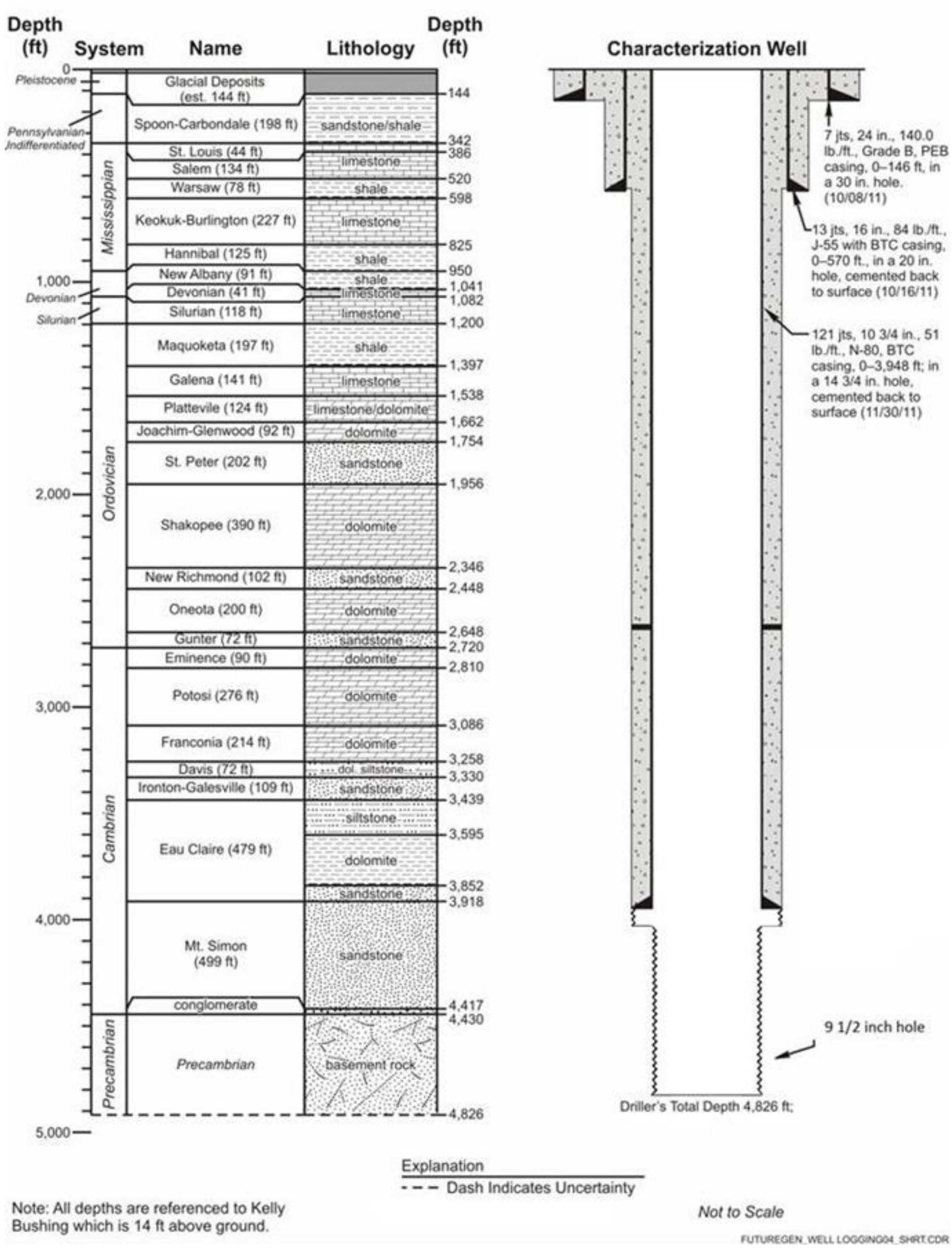


Figure 4.26. Stratigraphic Borehole FGA-1 Well Diagram as Constructed through the Intermediate Casing String with Open-Borehole Section Extending to 4,826 ft

Table 4.1. Summary of Casing Installed

Diameter (in.)	Grade	Weight (lb/ft)	Connection Type	Set Depth (ft KB)
24	J-55	140	PEB (Weld)	146
16	J-55	84	BTC	570
10 3/4	N-80	51	BTC	3,948

PEB = plain-end beveled; BTC = buttress thread; LTC = round long thread; VAM = premium connection.

Figure 4.27. Installation of the 10 3/4-in. Multiple-Stage Cementing Collar

Cement bond logs (CBLs) were run on all casing strings to assess cement quality, except for the conductor casing, which was too large to obtain meaningful data. A conventional sonic CBL and an ultrasonic imaging (Schlumberger USI) log were run on the 16-in. surface casing and the 10 3/4-in. intermediate casing. The CBLs for the 16-in. casing indicated good cement bonding was achieved from 525 ft to 290 ft, the depth interval where Class A tail cement was emplaced. The quality of the cement above this depth was not as good, because of the lighter lead cement emplaced across this interval. The CBLs for the 10 3/4-in. casing indicated a good to excellent bond from the bottom of casing to 2,704 ft (depth of multiple-stage cementing collar), an interval approximately 1,244 ft in length. Above the multi-stage tool, the quality of the cement was not as good, particularly above a depth of 1,960 ft, corresponding to the interval where light lead filler cement was emplaced.

4.3.2.2 *Management of Drilling-Derived Cuttings and Fluids*

The drilling contractor used two steel drilling "pits" (tanks) with a combined volume of 600 Bbl to maintain the drilling fluids used in the drilling process. In addition to the steel pits, a large earthen pit was excavated and lined for the containment of the drill cuttings and waste drilling fluids produced from the steel pits (see Figure 4.25). During the drilling process, drilling fluids were periodically removed from the pit and disposed of. Table 4.2 provides a summary of the drilling fluids generated during drilling and their disposition. At the conclusion of drilling, the remaining fluids were removed from the pit and the cuttings were solidified in place, excavated, and transported to a landfill for final disposal. All cuttings were disposed of at the Clinton Landfill in Clinton, Illinois. Patrick Engineering then backfilled the pit and restored the area above it.

Table 4.2. Disposition of Drilling and Testing Fluids

Disposal Method	Type of Fluid	Quantity (Bbl)
Jacksonville WWTP	Freshwater drilling mud (1,171 Bbl); leftover manufactured brine from borehole conditioning (143 Bbl)[(a)]	1,314
Land spread	Freshwater drilling fluid[(b)]	5,210
Landfill stabilization and disposal	Saline (KCl) drilling fluid[(c)]	2,862
Class II UIC Well	Spent acid (164 Bbl) from borehole conditioning; left over Mount Simon brine water (1,050 Bbl)[(d)]	1,214
	TOTAL	10,600

(a) The Jacksonville WWTP stopped accepting freshwater drilling mud after the initial few loads (1,171 Bbl) due to high suspended solids content and high pH; manufactured brine was 8.9 lb/gal KCl made with potable water and filtered.
(b) A large volume of freshwater mud was used to drill through the lost-circulation zone in the Potosi Formation; therefore, the actual volume of freshwater mud generated was much higher.
(c) Saline drilling fluid primarily includes the Flo-Pro™ drilling fluid used to drill the 9 1/2-in. borehole.
(d) Class II injection well − Barnhill SWD, Permit 216, owned by Earl's Tank Truck Service, Wayne County, Barnhill Township, Illinois.

4.3.2.3 *Characterization Data Collection*

Several types of geologic characterization data and samples were obtained during the drilling process. The following data and or samples were obtained: a mud log, a comprehensive suite of geophysical logs, full-hole core, sidewall core samples, and water samples from the St. Peter Sandstone and the Mount Simon Sandstone. These data collection activities are briefly described below.

In addition, a series of hydrologic tests were conducted in the open-borehole section of the Mount Simon Sandstone after the drilling was completed, including a pumping test, a borehole flowmeter/fluid logging test, and several packer tests. These activities are described in the Borehole Completion Report (Kelley et al. 2012) and in Section 4.4.3 of this report.

4.3.2.3.1 Mud Log

Mud loggers working in conjunction with geologists from Battelle and a geology consultant (Chuck Wiles) inspected and described formation cuttings produced during drilling to identify and track the geologic formations as they were penetrated. A mud log for stratigraphic borehole FGA-1 that describes the mud loggers' interpretations (formation contacts, formation lithology, geologic features, etc.) is included in the Borehole Completion Report (Kelley et al. 2012). Mud logging was provided by Stratagraph NE, Inc. of Marietta, Ohio.

4.3.2.3.2 Geophysical Logs

A comprehensive suite of wireline geophysical logs was run in stratigraphic borehole FGA-1 for the purpose of identifying and characterizing geologic formations penetrated by the well, particularly the Mount Simon Sandstone and overlying Eau Claire confining layer and potential monitoring zones. Four separate logging events (runs) were conducted during the course of drilling the well, as described below.

- Run 1 was conducted after the surface casing was installed and cemented and included two types of CBLs (cement bond logs).
- Run 2 occurred after drilling had advanced through the St. Peter Formation and included open-hole logs to aid in selecting fluid sampling points in the St. Peter Formation.
- Run 3 occurred after the 14 3/4-in.-diameter intermediate borehole was drilled to its total depth (TD) and included open-hole logs.
- Run 4 was completed after the 9 1/2-in.-diameter borehole was drilled to its TD and included the same open-hole logs that were run across the intermediate borehole plus CBLs to evaluate the cement used to emplace the 10 3/4-in.-diameter intermediate casing string.

The logs obtained during each logging run are discussed in Section 4.4.1. All wireline logging was conducted by Schlumberger.

4.3.2.3.3 Sidewall Core Samples

As part of the logging operation, sidewall core samples were collected at various depths below the surface casing, from 698 to 4,796 ft. Section 4.4.2.1 of this report identifies the sidewall core samples that were collected. A more complete summary of the sidewall coring operations and photographs of the core samples are provided in the Borehole Completion Report (Kelley et al. 2012).

4.3.2.3.4 Core

Five core runs were conducted during two separate coring events, resulting in the collection of approximately 205 ft of core. Section 4.4.2.1 describes the cored intervals and core collected.

Coring operations were conducted by Baker Hughes, Inc. Retrieved core was cut into 3-ft-long sections and transported to Core Laboratory in Houston, Texas, for analysis (Figure 4.28). A more complete summary of the coring operations, including photographs of all core sections, is provided in the Borehole Completion Report (Kelley et al. 2012). A summary of core analyses performed by Core Laboratory and a discussion of results is provided in Section 4.4.2 of this report.

Figure 4.28. Cutting Core into Sections for Shipment to the Core Analysis Laboratory (left) and the Shipping Container (right)

4.3.2.3.5 Water Samples

During the process of drilling the borehole, fluid samples were obtained from discrete-depth intervals in the St. Peter Formation and the Mount Simon Formation using a wireline-deployed sampling tool. In addition, after the well had been drilled, additional fluid samples were obtained from the open-borehole section of the Mount Simon Formation by pumping water from the well with a submersible pump. This section discusses the samples collected from the St. Peter Formation and the Mount Simon Formation and the chemical analyses performed on the samples. A more complete discussion of this topic, including interpretation of the chemical analyses performed on the water samples, is provided in the Borehole Completion Report (Kelley et al. 2012) and in Section 4.4.3 of this report.

Sampling was attempted at 20 depths in the St. Peter Formation using the Schlumberger wireline-deployed Modular Dynamic Testing (MDT) tool in the Quicksilver Probe configuration. Pressure and mobility data were obtained at 7 of the 20 attempted sampling points and a water sample was successfully obtained at 1 of the 20 sampling points (Table 4.3).

Table 4.3. Sampling Depths in the St. Peter Formation Where Either a Pressure Measurement or a Fluid Sample Was Obtained Using the Wireline-Deployed Sampling Tool

Sample No.	Sample Depth (ft KB)	Tool	Pressure (psia)	Temp (°F)	Temp (°C)	Mobility (mD/cP)	Fluid Sample Collected?
7	1944.99	MDT-QS	801.6	ND	ND	0.8	No
8	1944.06	MDT-QS	799.04	ND	ND	1.27	No
9	1914.85	MDT-QS	574.06[(a)]	ND	ND	0.33	No
16	1795.99	MDT-QS	732.86	ND	ND	23.82	No
17	1762.96	MDT-QS	718.09	73	22.8	157.73	Yes
19	1148.03	MDT-QS	470.38	ND	ND	4.28	No
20	1148.03	MDT-QS	470.76	ND	ND	5.18	No

Pressure data are discussed in Section 4.4.3.5 of this report along with other fluid-pressure data obtained for the borehole. Laboratory analyses performed on the water samples are described in Table 4.4 and results of the analyses are discussed in Section 4.4.3.4 and by Kelley et al. (2012).

Sampling was attempted at 22 discrete depths in the Mount Simon Formation using the MDT tool in the Quicksilver Probe configuration and from one location using the conventional (dual-packer) configuration. Pressure and mobility data were obtained at 7 of the 23 attempted sampling points (Table 4.5). A fluid sample was successfully obtained at 1 of the 22 sampling points attempted using the Quicksilver Probe (depth 4,048 ft KB) and from the 1 location where the dual-packer configuration was used (depth 4,263 ft KB) (Table 4.5). However, the fluid sample obtained using the MDT in the dual-packer configuration (depth 4,263 ft) was visibly affected by drilling fluids; therefore, the analytical results for this sample may not be representative of native Mount Simon Formation fluid.

Table 4.4. Summary of Laboratory Analyses Performed on Fluid Samples

Analysis	Method	Sample Volume (L)	Preservative	Hold Time	Laboratory
Cations/metals[(a)]	EPA 200.7, EPA 200.8[(b)]	1.500[(c)]	0.45 µm filtration; HNO_3; 4°C	6 months	CAS[(d)]
Selenium	EPA 7742	1.500[(c)]	0.45 µm filtration; HNO_3; 4°C	28 days	CAS[(d)]
Mercury	EPA 1631	0.500	0.45 µm filtration; HCl; 4°C	28 days	CAS[(d)]
Anions[(e)]	EPA 300.0	1.000[(f)]	4°C	48 hours	CAS[(d)]
pH	SM 4500-H	1.000[(f)]	4°C	15 min	CAS[(d)]
Conductivity	EPA 120.1	1.000[(f)]	4°C	28 days	CAS[(d)]
Salinity	SM 2520B	1.000[(f)]	4°C	28 days	CAS[(d)]
Alkalinity[(g)]	SM 2320	1.000[(f)]	4°C	14 days	CAS[(d)]
TDS	SM 2540	1.000[(f)]	4°C	7 days	CAS[(d)]

Table 4.4. (contd)

Analysis	Method	Sample Volume (L)	Preservative	Hold Time	Laboratory
Specific gravity	SM 2710F	1.000(f)	4°C	None	CAS(d)
Silica	SM 4500-SiO_2	1.000(f)	4°C	28 days	CAS(d)
TOC	SM 5310	0.250	H_2SO_4; 4°C	28 days	CAS(d)
TIC	SM 5310	0.250	H_2SO_4; 4°C	28 days	CAS(d)
DOC	SM 5310	0.250	0.45 µm filtration; H_2SO_4; 4°C	28 days	CAS(d)
DIC	SM 5310	0.250	0.45 µm filtration; H_2SO_4; 4°C	28 days	CAS(d)
Dissolved CO_2	RSK 175(h)	3 × 0.040	4°C	14 days	CAS(d)
δD of Water	CRDS	1.000(i)	4°C	None	IsoTech(j)
δ^{18}O of water		1.000(i)	4°C	None	IsoTech(j)
Tritium	LSC	1.000(i)	BAK; 4°C	None	IsoTech(j)
δ^{13}C of DIC	TGB	1.000(i)	BAK; 4°C	1 week	IsoTech(j)
^{14}C of DIC	AMS	1.000(i)	BAK; 4°C	1 week	IsoTech(j)

(a) Cations include Ag (silver), Al (aluminum), As (arsenic), B (boron), Ba (barium), Be (beryllium), Ca (calcium), Cd (cadmium), Co (cobalt), Cr (chromium), Cu (copper), Fe (iron), K (potassium), Li (lithium), Mg (magnesium), Mn (manganese), Na (sodium), Ni (nickel), Pb (lead), Sb (antimony), Sr (strontium), Th (thorium), Ti (titanium), and Zn (zinc).
(b) Specific method used is concentration dependent.
(c) Cations and selenium measured from the same 1.5-L sample
(d) Columbia Analytical Services, 1317 S. 13th Ave, Kelso, WA 98626
(e) Anions include Br (bromide), Cl (chloride), F (fluoride), NO_2 (nitrite), NO_3 (nitrate), and SO_4 (sulfate)
(f) Anions, pH, conductivity, salinity, alkalinity, TDS, specific gravity, and silica measured from the same 1.000-L sample
(g) Includes total alkalinity, carbonate alkalinity, bicarbonate alkalinity, and hydroxide alkalinity
(h) Sample preparation as per EPA 3810
(i) All isotopic analysis measured from the same 1-L sample
(j) IsoTech Laboratories, Inc., 1308 Parkland Court, Champaign, IL 61821

EPA = U.S. Environmental Protection Agency; AMS = accelerator mass spectrometer; BAK = benzalkonium chloride (alkyldimethylbenzylammonium chloride); CRDS = cavity ringdown spectroscopy; DIC = dissolved inorganic carbon; DOC = dissolved organic carbon; LSC = liquid scintillation counter; RSK = Robert S. Kerr Laboratory; SM = standard methods; TDS = total dissolved solids; TGB = trace gas biogeochemistry; TIC = total inorganic carbon; TOC = total organic carbon

Pressure data for the Mount Simon Formation are discussed in Section 4.4.3.5 of this report along with other fluid-pressure data obtained for the borehole. Laboratory analyses performed on the water samples are described in Table 4.4 and results of the analyses are discussed in Section 4.4.3.4 and by Kelley et al. (2012).

After the 9 1/2-in. borehole was drilled to TD and the drilling rig was demobilized from the site, additional fluid samples for field and laboratory analysis were obtained from the Mount Simon Formation by pumping water from the well with an electric submersible pump (ESP). Prior to installing the ESP, the borehole was “conditioned” by displacing drilling mud left over from the drilling process with clean manufactured sodium-chloride (NaCl) brine having a weight of approximately 8.8 lb/gal and conducting an acid wash to help remove any accumulation of mud that might have formed on the borehole wall during drilling. In addition, approximately 660 Bbl of fluid were removed from the well by swabbing prior to pumping with the ESP.

Table 4.5. Sampling Depths in the Mount Simon Formation Where Either a Pressure Measurement or a Fluid Sample was Obtained Using the Wireline-Deployed Sampling Tool

Sample No.	Sample Depth (ft)	Tool	P (psia)	T (°F)	T (°C)	Mobility (mD/cP)	Fluid Sample Collected?
7	4,130	MDT - QS	1828.0	97.1	36.2	7.5	NO
8	4,131	MDT - QS	1827.7	97.3	36.3	19.5	NO
9	4,110.5	MDT - QS	1818.3	97.3	36.3	99	NO
11	4,048	MDT - QS	1790.2	97.1	36.2	176	YES
17	4,048 (Repeat)	MDT - QS	1790.3	--		109	NO
21	4,248.5	MDT - QS	1889.2	ND		5.5	NO
22	4,246	MDT - QS	1908.8	ND		28.2	NO
23	4,263	MDT - DP	1896.5	ND		0.9	YES

The ESP (Figure 4.29) was provided by Baker Hughes Centralift Division and was a 33-stage pump with a variable-speed drive designed to yield a 125-gpm flowrate from a depth of 1,500 ft. With the support of a service rig, the pump was installed in the well (inside the 10 3/4-in. casing) at a depth of 1,501.6 ft (end of tubing) to 1,546.4 ft (bottom of pump assembly) on 3.5-in.-OD tubing. Unlike with the wireline-deployed sampling tools, packers were not used to isolate a specific fluid sampling interval while the well was pumped with the ESP; therefore, water samples obtained with the ESP pumping method were collected from the entire open borehole (i.e., from the bottom of the 10 3/4-in. casing [depth 3,948 ft] to the TD of the borehole [depth 4,826 ft]). Approximately 2,200 Bbl of fluid were pumped from the well and stored in water storage tanks onsite for later use in the well's hydrologic reservoir tests. While pumping, samples of the pumped water were periodically collected and analyzed in the field for water-quality parameters, including pH, electrical conductivity, total dissolved solids (TDS), salinity, and turbidity. Three samples of the pumped fluid were collected for further chemical analysis.

Figure 4.29. Installing the Submersible Pump (left); Water Storage Tanks (right)

All water samples from the St. Peter and the Mount Simon Formations were analyzed in the field for water-quality parameters, including pH, electrical conductivity, TDS, salinity, and turbidity, using a field meter (Horiba U-50 Multi-Parameter Water Quality Meter). Water samples were also submitted to Columbia Analytical Services (CAS) (Kelso, Washington) and Isotech Laboratory, Inc. (Champaign, Illinois) for detailed hydrochemical and isotopic analysis, respectively. Table 4.6 identifies the samples that were collected and submitted for laboratory analysis; Table 4.4 summarizes the laboratory analyses performed on each sample. Results of the field and laboratory analyses performed on the samples and a discussion of the results are provided by Kelley et al. (2012) and Section 4.4.3.4 of this report.

Table 4.6. Fluid Samples Submitted for Laboratory Analysis

Sample Name	Formation	Depth (ft KB)	Sample Date	Collection Method
Source Water 10/28/11	NA	Surface	10/28/11	Bucket
Drilling Fluids 10/28/11	NA	Surface	10/28/11	Bucket
St. Peter 1,763 ft	St. Peter	1,763	10/27/11	MDT-QS
Mount Simon 4,048 ft	Mt. Simon	4,048	12/14/12	MDT-QS
Mount Simon 4,048 ft – DUP	Mt. Simon	4,048	12/14/12	MDT-QS
Mount Simon 4,263 ft	Mt. Simon	4,263	12/14/12	MDT-DP
Mount Simon 4,263 ft – DUP	Mt. Simon	4,263	12/14/12	MDT-DP
Drilling Fluids 12/14/11	NA	Surface	12/14/11	Bucket
Drilling Fluids 12/14/11 – DUP	NA	Surface	12/14/11	Bucket
020812001 (2/8/12 1104)	Mt. Simon	3,948–4,826	2/8/12	ESP
020812002 (2/8/12 1104 – DUP)	Mt. Simon	3,948–4,826	2/8/12	ESP
020812003 (2/8/12 1259)	Mt. Simon	3,948–4,826	2/8/12	ESP
020812004 (2/8/12 1259 – DUP)	Mt. Simon	3,948–4,826	2/8/12	ESP
020812005 (2/8/12 1502)	Mt. Simon	3,948–4,826	2/8/12	ESP
020812006 (2/8/12 1502 – DUP)	Mt. Simon	3,948–4,826	2/8/12	ESP

ESP = electric submersible pump
DUP = duplicate sample
MDT-QS = Schlumberger Modular Dynamic Tester, Quick Silver Tool
MDT-DP = Schlumberger Modular Dynamic Tester configured with two full borehole packers
NA = not applicable

4.3.2.4 *Geology Summary*

The geologic formations encountered while drilling the characterization well and their depths and thickness are identified in Table 4.7. A description of the geologic formations encountered in the well is presented in the Borehole Completion Report (Kelley et al. 2012) and in Section 4.5 of this report.

The target CO_2 storage reservoir, the Mount Simon Sandstone, was encountered between depths of 3,918 ft and 4,417 ft, a thickness of 499 ft. Overlying the Mount Simon Sandstone is 479 ft of the Eau Claire Formation, of which the uppermost 413 ft consists primarily of siltstones, shales, and dolomites of the Eau Claire Proviso and Lombard Members; importantly, these strata appear to have the necessary properties of a primary confining zone. The lowermost 66 ft of the Eau Claire Formation (Elmhurst Member) was found to be similar to the underlying Mount Simon Sandstone and therefore may provide CO_2 storage capacity in addition to that provided by the Mount Simon Sandstone. Underlying the Mount Simon Sandstone at this location is Precambrian bedrock. The Precambrian bedrock was encountered at a depth that was several hundred feet shallower than anticipated based on projections from a 2D seismic survey and a small number of wells in the Morgan County area of Illinois that penetrate the Mount Simon Sandstone. Above the Eau Claire and Mount Simon Formations are several other geologic formations of sedimentary origin, including formations that may be suitable for supporting monitoring wells and others that may serve as barriers in addition to the Eau Claire Formation to prevent the upward migration of CO_2.

Table 4.7. Summary of Geologic Formation Encountered in the Stratigraphic Borehole FGA-1

Formation Name	Age	Thickness (ft)	Top Depth (ft bgs)	Top Depth (ft KB)
Pennsylvanian Undifferentiated	Pennsylvanian	198	130	144
St. Louis Limestone	Mississippian	44	328	342
Salem Limestone	Mississippian	134	372	386
Warsaw (Borden) Siltstone/Shale	Mississippian	78	506	520
Keokuk/Burlington Siltstone	Mississippian	227	584	598
Hannibal (Osage) Limestone	Mississippian	125	811	825
New Albany Shale	Devonian	91	936	950
Devonian Limestone	Devonian	41	1,027	1,041
Silurian Limestone	Silurian	118	1,068	1,082
Maquoketa Shale	Ordovician	197	1,186	1,200
Trenton/Galena Limestone	Ordovician	141	1,383	1,397
Platteville Limestone	Ordovician	124	1,524	1,538
Joachim Limestone	Ordovician	69	1,648	1,662
Glenwood Dolomite	Ordovician	23	1,717	1,731
St. Peter Sandstone	Ordovician	202	1,740	1,754
Shakopee Dolomite (Knox)	Ordovician	390	1,942	1,956
New Richmond Sandstone	Ordovician	102	2,332	2,346
Oneota Dolomite	Ordovician	200	2,434	2,448
Gunter Dolomite/Sandstone	Ordovician	72	2,634	2,648
Eminence Dolomite	Cambrian	90	2,706	2,720
Potosi Dolomite	Cambrian	276	2,796	2,810
Franconia Dolomite	Cambrian	172	3,072	3,086
Davis Dolomite	Cambrian	72	3,244	3,258
Ironton Sandstone/Dolomite	Cambrian	109	3,386	3,330
Eau Claire Carbonate/Siltstone (Proviso)	Cambrian	156	3,425	3,439
Eau Claire Siltstone/Shale (Lombard)	Cambrian	257	3,581	3,595
Eau Claire (Elmhurst)	Cambrian	66	3,838	3,852
Mount. Simon Sandstone	Cambrian	499	3,904	3,918
Conglomerate	Cambrian	13	4,403	4,417
Basement	Precambrian	396	4,416	4,430
Total Drill Depth			4,812	4,826

4.3.2.5 *Health and Safety Summary*

Health, Safety, and Environment (HSE) statistics were monitored during the drilling and subsequent reservoir-testing activities. These results are summarized in Table 4.8. During the

83 days of drilling, a total of 20,129 man-hours were worked. Numerous Job Safety Analyses (JSAs), Tool BOX Safety meetings, and Shift Safety meetings were completed as part of the safety program. Only one incident was recorded; it was a twisted ankle that was treated onsite without incurring a loss of time worked. No recordable safety or environmental incidents occurred throughout drilling operations. These statistics demonstrate the effectiveness of the safety program that was implemented for this project. During the reservoir-testing phase following drilling, an additional 5,167.5 man-hours were worked without a single safety or environmental incident. A complete set of daily safety reports for the project is provided in the Borehole Completion Report (Kelley et al. 2012).

Table 4.8. Safety Statistics during Drilling and Field Testing

Drilling Phase		Reservoir-Testing Phase	
Statistic	Occurrences	Statistic	Occurrences
OSHA Recordable:	0	OSHA Recordable:	0
Medical Attention:	0	Medical Attention:	0
Spill:	0	Spill:	0
Equipment Damage:	0	Equipment Damage:	0
Safety Meeting:	223	Safety Meeting:	36
Days on Job	83	Days on Job	37
Lost Time Accident:	0	Lost Time Accident:	0
Near Miss:	0	Near Miss:	0
Environmental Act:	0	Environmental Act:	0
JSAs:	586	JSAs:	233
Tool BOX meeting:	39	Tool BOX meeting:	23
Observation cards:	111	Observation cards:	151
First Aid:	1	First Aid:	0
Dropped Object:	0	Dropped Object:	0
HSE Audit/Checklist:	136	HSE Audit/Checklist:	31
STOP Work:	0	STOP Work:	0
Total Staff Hours:	20,129	Total Staff Hours:	5,167.5
Total Recordable Incident Rate:	0	Total Recordable Incident Rate:	0

4.4 Stratigraphic Borehole FGA-1 Characterization Program

An integrated characterization program was designed for pilot stratigraphic borehole FGA-1 to provide initial hydrogeologic characterization property information that would address the injection, storage, and permanent sequestration potential within the targeted Mount Simon Formation, as it related to establishment of a long-term CO_2 sequestration project at the FutureGen location. To accomplish the initial characterization program objectives, hydrogeologic information was derived from extensive geophysical wireline well-logging surveys, standard and sidewall core analyses, hydrogeologic field testing results, and geomechanical in situ stress measurements. These characterization program elements were conducted during and following drilling of stratigraphic borehole FGA-1, and initially reported by Kelley et al. (2012). Results from each of the identified characterization elements are presented in the following report subsections.

4.4.1 Geophysical Wireline Well-Logging Surveys

A summary of the open-hole wireline geophysical log acquisition, used for geologic characterization is shown in Table 4.9. The wireline logging tools consisted of 1) a basic open-hole Schlumberger Triple Combo suite; 2) enhanced logs including dipole sonic, resistivity and acoustic image logs, the elemental capture log, and the nuclear magnetic resonance log; and 3) a suite of CBLs.

The combination of the elemental capture log, Triple Combo, spectral gamma log, and sonic response are input parameters to solve for ELAN (ELemental ANalysis) mineral composition, fluid saturations, porosity, permeability, and other petrophysical properties. This is an extremely useful log for characterization, and was reprocessed to incorporate sidewall core and core plug data. Geomechanical logs included the Anisotropic Elastic Properties and the Stoneley Permeability logs, and were calculated from the dipole sonic, which records compressional, shear, and Stoneley wave data. These logs address wellbore stability and both intrinsic and drilling-induced anisotropy, as well as provide input for generation of synthetic seismograms. Additional information about geomechanical aspects of the stratigraphic borehole FGA-1 are provided in Section 4.4.4.

Schlumberger's interpretation of the stratigraphic borehole FGA-1 resistivity and acoustic image logs produced rose diagrams of structural and stratigraphic dip magnitude and azimuth, as well as azimuth of maximum and minimum horizontal stress. The computer-generated StrucView graphically displays stratigraphic and structural data for the entire logged interval of stratigraphic borehole FGA-1, including depth of unconformities, changes in dip, and "microfaults." An example of the StrucView log is given in Section 4.5.2, along with examples of rose diagrams of natural and induced fracture data.

Because of tool failure, the magnetic resonance log was acquired only over the deep, Mount Simon/ Precambrian open borehole. This log was processed for permeability and other petrophysical properties. The Ultrasonic Borehole Imager (UBI) acoustic imaging tool was also run only over the deep borehole section.

Table 4.9. Summary of the Stratigraphic Borehole FGA-1 Wireline Logging Program

Log Type	Run #	Log Interval Top (ft bgs)	Log Interval Bottom (ft bgs)
Triple Combo	1	31	2,036
Resistivity	1	31	2,036
Triple Combo (Gamma, Neutron, Density) plus Photoelectric Cross-Section Log	2	553	4,015
Sonic Dipole	2	566	3,962
Resistivity Image	2	564	4,013
Spectral Gamma Ray	2	372	3,978
Elemental Capture Log	2	91	4,014
Rotary Sidewall Cores	2	Top Sample 684	Bottom Sample 3,968
Triple Combo (Gamma, Neutron, Density) plus Photoelectric Cross-Section Log	3	3,932	4,806
Sonic Dipole	3	3,932	4,806
Resistivity Image	3	3,966	4,810
Ultrasonic Image	3	3,922	4,886
Spectral Gamma Ray	3	3,932	4,806
Elemental Capture Log	3	81	4,024
Nuclear Magnetic Resonance	3	3,932	4,806
Rotary Sidewall Cores	3	Top Sample 4,020	Bottom Sample 4,782
Cement bond logs (CBL-VDL), (USIT)	4	3,946	4,820
Platform Express[(a)] (PEX), Sonic, Resistivity image (FMI), Spectral gamma ray (HNGS), Elemental capture spectroscopy (ECS)	2, 3	567	4,029
Cement bond logs (CBL-VDL), (USIT)	4	3,946	4,820

(a) Platform Express includes gamma ray, one-arm caliper, spontaneous potential, photoelectric, temperature, resistivity, neutron density, and porosity.

30-in. Conductor Hole – Drilling of the conductor hole occurred from October 5–6, 2011. The 30-in. conductor hole was drilled to a depth of 163 ft KB. This section of the well was not logged, because of the large diameter of the hole and casing.

20-in. Surface Hole – Drilling to a TD of 572 ft KB and setting casing in the surface section of the well occurred between October 10–20, 2011. Prior to drilling this section, a mud logging unit from Stratagraph NE, Inc. of Marietta, Ohio, was set up to collect and describe rock cuttings for the remaining entirety of the borehole, and a hydrogen sulfide (H_2S) monitoring unit was set up to monitor drilling the Pennsylvanian and Mississippian hydrocarbon-bearing formations. No open-hole logs were collected on this section, but two types of CBLs were run by Schlumberger after the casing cement had achieved sufficient compressive strength. No H_2S and only extremely minor hydrocarbon shows were encountered while drilling this section of hole.

Both a conventional sonic CBL and an ultrasonic imaging (USI) log were run by Schlumberger on the 16-in. surface casing from the logger's TD of 525 ft KB to the ground surface. The logs indicated a good bond from 525 ft KB to 290 ft KB (which corresponds to the Class A tail cement) and a fair bond from 290 ft KB to the surface (which corresponds to the 65/35 Pozmix lead cement).

14 3/4-in. Intermediate Hole – Drilling this section (572−4,032 ft KB) of the borehole began on October 20; work continued through December 3. Drilling was paused at the base of the St. Peter Formation (1,960 ft KB) to run a suite of open-borehole geophysical logs and obtain a fluid sample from the St. Peter with a Schlumberger wireline-deployed sampling tool. One sample was successfully obtained from a depth of 1,763 ft KB. On November 27–28, Schlumberger ran a comprehensive suite of basic plus enhanced open-hole geophysical logs across the intermediate section of the borehole (to 4,032 ft KB), and successfully retrieved 71 rotary sidewall cores. The magnetic resonance tool failed on this run, and the rotary sidewall coring tool jammed on each of two runs; 13 attempted sidewall cores (SWCs) were lost or damaged. The acoustic UBI log was not run in either the shallow or intermediate borehole sections. Casing was run to a depth of 3,948 ft KB and cemented back to the surface.

9 1/2-in. Deep Hole – Drilling the deep section of the well began on December 5, 2011. On December 7, drilling reached the "middle Mount Simon" coring point at a depth of 4,400 ft KB. Approximately 34 ft of full-hole core was collected between depths of 4,400 and 4,442 ft KB. Upon retrieval of the core, it was confirmed what was suspected from the cuttings: that this core section had crossed the contact between the Mount Simon Formation and the underlying Precambrian basement rock at 4,430 ft KB. Details on all coring acquisition and analysis are in Section 4.4.2.

Drilling continued in the 9-1/2-in. hole until a depth of 4,826 ft KB (396 ft into the Precambrian rock, providing an unprecedented evaluation of the basement in this part of the Illinois Basin); subsequent logging activities included open-borehole geophysical logs across the entire section of 9-1/2-in. hole; and collection of 68 SWC samples (60 from the Mount Simon Formation, 8 from the Precambrian meta-rhyolite). The Schlumberger Formation Micro-Imager (FMI) resistivity-based image log and the acoustic imaging tool (UBI) were run across the deep section. Two types of CBLs were run for the 10 3/4-in. casing, along with collection of fluid samples from two depths in the Mount Simon Formation (4,048 and 4,263 ft KB) and pressure measurements from several additional depths. Fluid and pressure sampling is covered in detail in Section 4.4.3.

A CBL and a USI log were run on the 10-3/4-in. intermediate casing while logging the 9-1/2-in. open hole at TD. The CBL/USI logs were run from the base of the 10-3/4-in. casing at 3,948 ft KB to the ground surface. The log indicated a good to excellent bond from 3,940 ft KB (bottom of logged interval) to 2,704 ft KB (depth of multiple-stage cementing collar). The interval from 2,704 ft KB to 1,960 ft KB (corresponding to the 14.4 lb/gal tail cement in the second stage of the cement job) exhibited a fair to poor bond and the interval from 1,960 ft KB to the surface (corresponding to the 11.2 lb/gal lead filler cement in the second stage of the cement job) exhibited a poor to no bond. Comparison of the correlated CBL and USI logs and the open hole logs indicate that the zone from 1,960 ft to 1,980 ft KB “thieved” the cement. The thief zone coincides with the Knox unconformity between the base of the St. Petersburg Sandstone and the top of the Shakopee Dolomite. The logs suggest the presence of vugular porosity in this section of the Shakopee Dolomite that may have been the cause of the lost cement.

4.4.2 Laboratory Core Analysis

The primary objective of the stratigraphic borehole FGA-1 core collection program was to obtain representative core samples from which laboratory-scale measurements could be made for determining critical formation parameters needed to support the development of a site-specific conceptual model and subsequent numerical modeling simulations. During the drilling of stratigraphic borehole FGA-1, conventional, full-hole core samples were collected from the reservoir (Mount Simon Formation) and the primary confining unit (Eau Claire Formation). Rotary SWC samples were also collected from these and several other formations penetrated by stratigraphic borehole FGA-1 (Kelley et al. 2012).

Routine and special core analysis of stratigraphic borehole FGA-1 samples were conducted at Core Laboratories (Core Lab), in Houston, Texas. In addition to petrophysical analysis performed at Core Lab, a series of laboratory studies were performed at PNWD to investigate biogeochemical processes in the reservoir and caprock interactions with suprercritical carbon dioxide (sc-CO_2; Vermeul et al. 2014 – Monitoring, Verification, and Accounting report).

This section describes the core collection, the analysis performed on the samples (at a contract laboratory, at PNWD, and used by researchers on other projects), and the final disposition of the remaining core samples.

4.4.2.1 *Core Collection*

Five core runs were conducted during two separate coring events, resulting in the collection of approximately 205 ft of core out of 225 ft attempted. All whole-core coring operations were conducted by Baker Hughes, Inc. using its Jam Buster™ coring system. Runs 1 and 2 collected samples from the 14-3/4-in.-diameter intermediate borehole, while runs 3 and 4 collected samples from the 9-1/2-in.-diameter deep borehole. A summary of each core run is provided in Table 4.10, including the cored intervals and core collected. Retrieved core was cut into 3-ft-long sections and transported to Core Lab in Houston, Texas, for analysis.

Sidewall core samples were collected by Schlumberger at various depths from 698 to 4,796 ft KB in four separate runs. A total of 139 rotary SWC samples were successfully collected out of

154 attempted. Of the four total sidewall coring runs, three runs used a 1-in.-diameter coring tool and one run used a larger diameter 1.5-in. coring tool. A summary of rotary SWCs is provided in Appendix 4F-1.

A complete description of the core collection process is provided in the Borehole Completion Report (Kelley et al. 2012).

Table 4.10. Full-Hole Coring Summary

Core #	Core Diameter (in.)	Interval Top – Bottom (ft KB)	Number of Feet Cored/Recovered	Formation Name
1	3.5	3,772 – 3,882	110/107.8	Eau Claire (Lombard), Eau Claire (Elmhurst)
2	3.5	3,882 – 3,922	40/30.0	Eau Claire (Elmhurst)
3	3.5	3,924 – 3,957	33/33.0	Mount Simon
4	4.5	4,400 – 4,434	34/25.9	Mount Simon and Precambrian
5	4.5	4,434 – 4,442	8/8.5	Precambrian
		Total cored/recovered	225/205.2	

Kelley et al. 2012

4.4.2.2 *Laboratory Core Analysis*

Analysis of selected core samples was conducted at Core Lab in Houston, Texas, and included routine petrophysical property analysis (porosity, permeability, grain density), petrographic analysis (thin section description and general core description), and a series of special core analyses. Special core analyses were conducted on a limited number of selected core samples and included geomechanical property analysis (hydraulic fracture design, triaxial compressive strength, acoustic velocities, and uniaxial pore volume compressibility), multiphase fluid flow properties (steady-state gas-brine relative permeability, measurements for threshold entry pressure, and imbibition), formation resistivity factor, and high-pressure mercury injection. Details of the laboratory procedures, selected core samples, and analytical results are presented in the final core analysis report (Appendix 4F-3; Core Laboratories 2012), and a summary table of all core analysis performed at the lab is presented in Appendix 4F-1.

4.4.2.3 *Additional Core Studies*

Laboratory studies of biogeochemical processes were conducted at PNWD using Mount Simon Sandstone and Eau Claire Formation cores obtained from stratigraphic borehole FGA-1. These experiments and results are summarized in Section 4.5.1 and discussed more fully by Vermeul et al. (2014).

Stratigraphic borehole FGA-1 core samples were also provided to researchers working on the National Risk Assessment Partnership (NRAP) project in the DOE's Office of Fossil Energy's

Crosscutting and Carbon Sequestration research programs. These studies included a series of experiments designed to examine the effects and flow of CO_2-saturated brine moving through samples from rock formations that are seals for geologic sequestration (GS) (Crandall and Bromhal 2014). The core sample provided for this research was an Eau Claire mudstone from a depth of 3,854 ft. The sample did not contain any visible fractures; therefore, sub-cores used in the experiment needed to have a fracture mechanically induced to provide a flow path. Experiments were performed over multiple weeks by injecting CO_2-saturated brine through fractured samples while the samples were imaged with a computed tomography (CT) scanner at regular intervals during the course of the experiment. Representative reservoir pressures were maintained on the samples during the experiments. The goal was to evaluate the change in the fracture flow that would result from a CO_2 leak. The study found that little reactivity would be expected in the Eau Claire Formation and it appears to have excellent rock properties to serve as a non-reactive, sealing formation for geologic CO_2 sequestration or storage (although the authors noted that longer experiments at elevated temperatures were needed to confirm the result).

Additional NRAP studies included investigation of the potential mobilization of metals in the Eau Claire Formation siltstone (depth of 3,809 ft) where oxygen (O_2) was a major impurity in the injected CO_2 (Shao et al. 2014). Batch experiments were conducted under GS conditions. The results suggest that the potential for mobilization of environmentally important metals needs to be considered for an integrated risk assessment using brines and known impurities in the sc-CO_2 source. Another study (Shao et al. 2013) using Eau Claire sandstone (depth 3,866 ft) and Eau Claire siltstone (depth of 3,809 ft) investigated the pH impacts of rock–brine–CO_2 systems under geologic CO_2 sequestration conditions. Through comparison of in situ spectrophotometric pH_m measurements with model calculations, Shao et al. (2013) demonstrated that the accuracy of calculated pH_m values for rock–brine–CO_2 systems under GS conditions is rock-dependent. For rocks mainly consisting of carbonates, siltstones, and sandstones, calculated pH_m values agreed well with experimentally measured values.

4.4.2.4 *Disposition of Cores*

The Alliance has been directed by DOE to transfer all cores and cuttings obtained at the Morgan County, Illinois, stratigraphic borehole FGA-1 site to the National Energy Technology Laboratory at the Morgantown, WV campus.

4.4.3 Hydrogeologic Field Testing Program

The focus of the stratigraphic borehole FGA-1 hydrogeologic field testing program was three-fold: 1) to provide detailed hydraulic property information for the targeted Mount Simon reservoir; 2) to determine in situ hydrochemical and isotopic characteristics of formation fluid within the Mount Simon Formation and in the more shallow St. Peter Sandstone (which represents the regionally recognized lowermost underground source of drinking water [USDW]); and 3) to establish the existing static pressure/depth profile for the site. The following report subsections provide summary information pertaining to these three test characterization program elements for stratigraphic borehole FGA-1: hydraulic property characteristics (Sections 4.4.3.1 to 4.4.3.3; hydrochemical and isotopic information (Section 4.4.3.4); and the static pressure/depth profile relationship (Section 4.4.3.5).

Of particular note is the systematic reservoir characterization program, which included determining the permeability distribution within the open-borehole section (3,948 to 4,826 ft bgs), and particularly within the identified candidate reservoir formation (e.g., Mount Simon Formation: 3,918 to 4,417 ft bgs). This characterization information for the open borehole and candidate reservoir sections was previously presented by Kelley et al. (2012) and Spane et al. (2013). The permeability characterization methods used have varying scales of investigation and resolution and included both standard and SWC analysis, continuous wireline logging, and hydraulic testing (composite open-borehole and isolated interval/straddle-packer tests). The results of the field characterization investigation program were integrated and used to evaluate and quantify the injection potential for the Mount Simon reservoir. This included modeling of various injection well deployment designs to minimize the areal CO_2 footprint at the FutureGen 2.0 CO_2 storage site location.

4.4.3.1 *Well-Development Pumping*

Following a well acid treatment of the open-borehole interval to remove possible borehole damage effects (e.g., drilling mudcake), the emplaced treatment fluids were swabbed from the well using the work-over rig slick-line system, as discussed by Kelley et al. (2012). After removal of the acid treatment fluids from the well, an extended well-development program was implemented to produce Mount Simon Formation fluids. A total of approximately 92,570 gal (2,200 barrels) of formation water were withdrawn from stratigraphic borehole FGA-1 on February 7 and 8, 2012, using a downhole ESP to extend borehole/test-zone development activities prior to collecting formal reservoir fluid samples from the Mount Simon, and to produce reservoir fluid for subsequent use during reservoir hydrologic testing (e.g., injection tests). The well-development pumping also provided an “opportunistic” data set that was subsequently analyzed to provide an initial characterization estimate of reservoir hydraulic properties.

The pump was installed in the well at a depth of 1,546.4 ft bgs (bottom of pump assembly), and in-well downhole pressure was monitored continuously during pumping and the subsequent recovery period following each pumping test via a pressure sensor set near the pump setting depth (i.e., 1,542 ft). Well-development pumping was conducted as two discrete well-development events that each included a pumping (pressure drawdown) period followed by a recovery (pressure buildup) period. On February 7, approximately 34,990 gal (833 barrels) of reservoir water were pumped from the well over a period of 4.42 hours resulting in an average pumping rate of 132 gpm. On February 8, approximately 57,580 gal (1,371 barrels) of water were pumped from the well during an 8.65-hour well-development pumping period, resulting in an average pumping rate of 111 gpm.

Figure 4.30 shows the downhole pressure response recorded during and after each well-development pumping cycle. Because of the more uniform pumping rate that was maintained during the longer-duration well-development test conducted on February 8, 2012, this pumping cycle was the focus of analysis for initial reservoir hydrologic property assessment for the composite Mount Simon Formation intersected at stratigraphic borehole FGA-1. Figure 4.31 shows the composite analysis of the recovery pressure buildup and derivative response following termination of the second well-development test. Reservoir property estimates obtained from hydrologic packer tests (Section 4.4.3.3) were used as the basis for the initial type-curve analysis match, and then adjusted accordingly using curve-fitting algorithms contained in the commercially available hydrologic test analysis software, AQTESOLV (Duffield 2007). As indicated, a transmissivity of 39.7 ft^2/day (permeability-thickness, KB, value of 10,270 mD-ft), and storativity, S, of $4.34e^{-4}$ were estimated for the composite Mount Simon interval intersected by stratigraphic borehole FGA-1. The final hydraulic property estimate derived from the well-development recovery test analysis compares favorably with results obtained from hydrologic packer tests that are described in Section 4.4.3.3. The radius-of-investigation (i.e., the distance from the characterization well having the calculated, uniform hydraulic properties) for the well-development pumping test was ~300 ft. This estimated investigative scale for the well-development recovery test was defined as the distance over which the characterization test could resolve major changes in permeability or presence of impacting hydrologic boundary conditions.

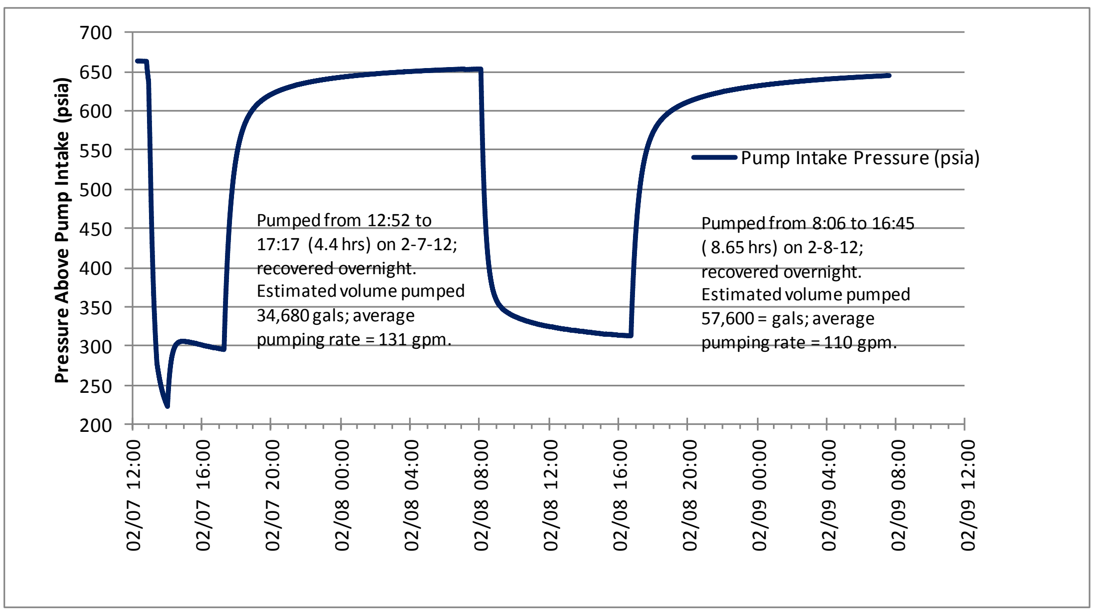


Figure 4.30. Downhole, In-Well Pressure Response (Probe Depth @ 1,542 ft bgs) during Well-Development Pumping Tests (February 7–8, 2012) (Kelley et al. 2012)

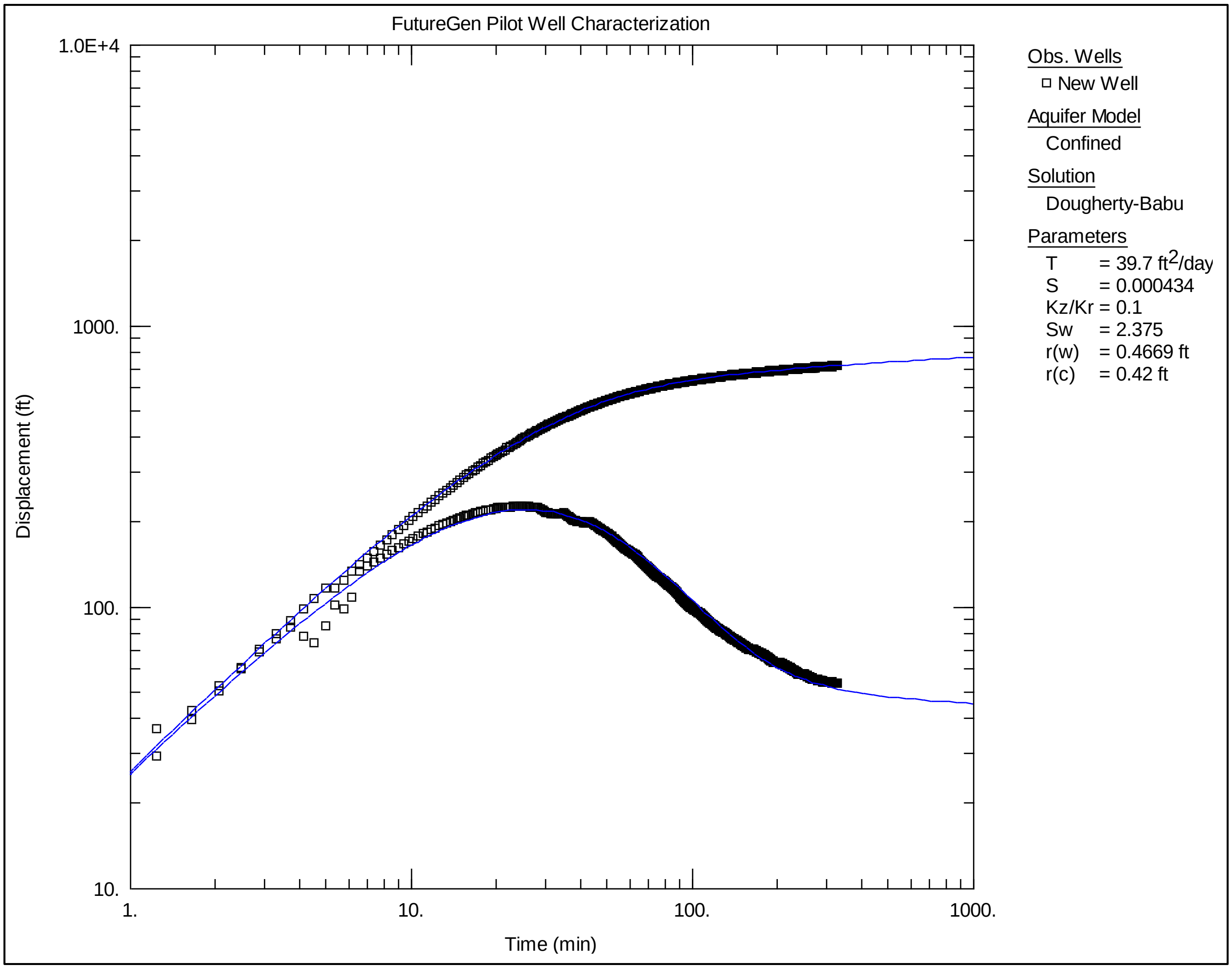


Figure 4.31. Analysis of Recovery and Recovery Derivative Well Pressure Response Following Completion of Second, Well-Development Pumping Cycle (equivalent permeability-thickness, KB, value of 10,270 mD-ft)

4.4.3.2 *Dynamic Flowmeter/Fluid Logging*

Dynamic flowmeter tests are commonly used as an initial reconnaissance tool for evaluating the vertical distribution of permeability (i.e., injectivity) within the entire open-borehole section, and for identifying specific reservoir intervals for subsequent detailed hydrologic test characterization (i.e., packer tests). To conduct the dynamic flowmeter test at stratigraphic borehole FGA-1, formation fluid previously pumped from the Mount Simon Formation during well-development activities was injected at a uniform rate during the course of the test. Dynamic flowmeter testing involves measuring the distribution of injection outflow from the open-borehole section, by logging the borehole with a wireline-deployed flowmeter, during the active injection process. The dynamic flowmeter testing conducted at stratigraphic borehole FGA-1 included both continuous and stationary flowmeter surveys using a commercially available spinner-type flowmeter. For continuous flowmeter surveys, the flowmeter is lowered at a constant "trolling" rate (e.g., 30 to 120 ft/min) starting from within the well cased section to a pre-determined depth near the bottom of the borehole, and then trolled back up the borehole at the same trolling rate to the initial depth setting within the well casing. The continuous flowmeter surveys are repeated a number of times (at the same or different injection and trolling rates) to establish corroboration of the outflow profile within the open-borehole section. Pre- and post-injection ambient flowmeter surveys are conducted at the same logging speeds and used to calibrate the flowmeter readings and serve as a reference/correction for dynamic flowmeter survey results.

For stationary dynamic flowmeter surveys, the flowmeter survey follows the same aspects of continuous flowmeter runs, except that the flowmeter is stopped repeatedly at prescribed depth interval locations (e.g., every 50 ft), and flow measurements are recorded over a short period of time (e.g., 3 to 5 minutes), before proceeding to the next stationary measurement depth location. The results from continuous and stationary flowmeter tests can be used to estimate the transmissivity (i.e., the permeability-thickness, KB) distribution directly by measuring the distribution of outflow rate from the borehole test section during a constant-rate injection test.

Two series of "dynamic" flowmeter tests were conducted in stratigraphic borehole FGA-1, including one series at a constant injection rate of 84 gpm (2 bpm), followed by a series conducted at a constant injection rate of 126 gpm (3 bpm). Each series of tests included making multiple logging passes across the open borehole at different logging speeds, ranging from 30 ft/min to 120 ft/min, as well as stationary measurements at several depths. Prior to performing the dynamic flowmeter test, several "ambient"/static logging surveys (i.e., during no injection) were also completed to provide baseline flowrate data needed to interpret/correct the dynamic logging run results. A comparison between the continuous and stationary flowmeter survey results (not shown) indicated that the stationary flowmeter surveys provided less variable results. This is attributed to the stability produced by the flowrate "averaging" aspect of stationary measurements vs. the much shorter recording period for respective depths inherent in continuous flowmeter surveys.

Hydrologic test responses obtained from stationary dynamic flowmeter logging tests indicate that the highest permeability zone within the open-borehole section (i.e., as indicated by the highest outflow from the borehole), occurred within the upper part of the Mount Simon Formation, and occurred over the depth interval from approximately 4,030 to 4,060 ft bgs (Figure 4.32). This section of higher permeability was also indicated by wireline (ELAN) logging results shown in Figure 4.33(b), and supported by inferred permeability distribution characteristics inferred from thermal-decay response plots obtained following termination of the dynamic flowmeter survey (Figure 4.34). It should also be noted the zone of higher permeability may extend above a depth of 4,030 ft bgs; however, the larger borehole drilling diameter above this depth (i.e., 14 to 16 in. between 3,934 and 4,018 ft) adversely impacts the resolution characteristics of the dynamic flowmeter log over this open-borehole depth interval. The dynamic flowmeter logging results also indicated that no significant injection potential within the Mount Simon Formation occurs below a depth of approximately 4,330 ft bgs.

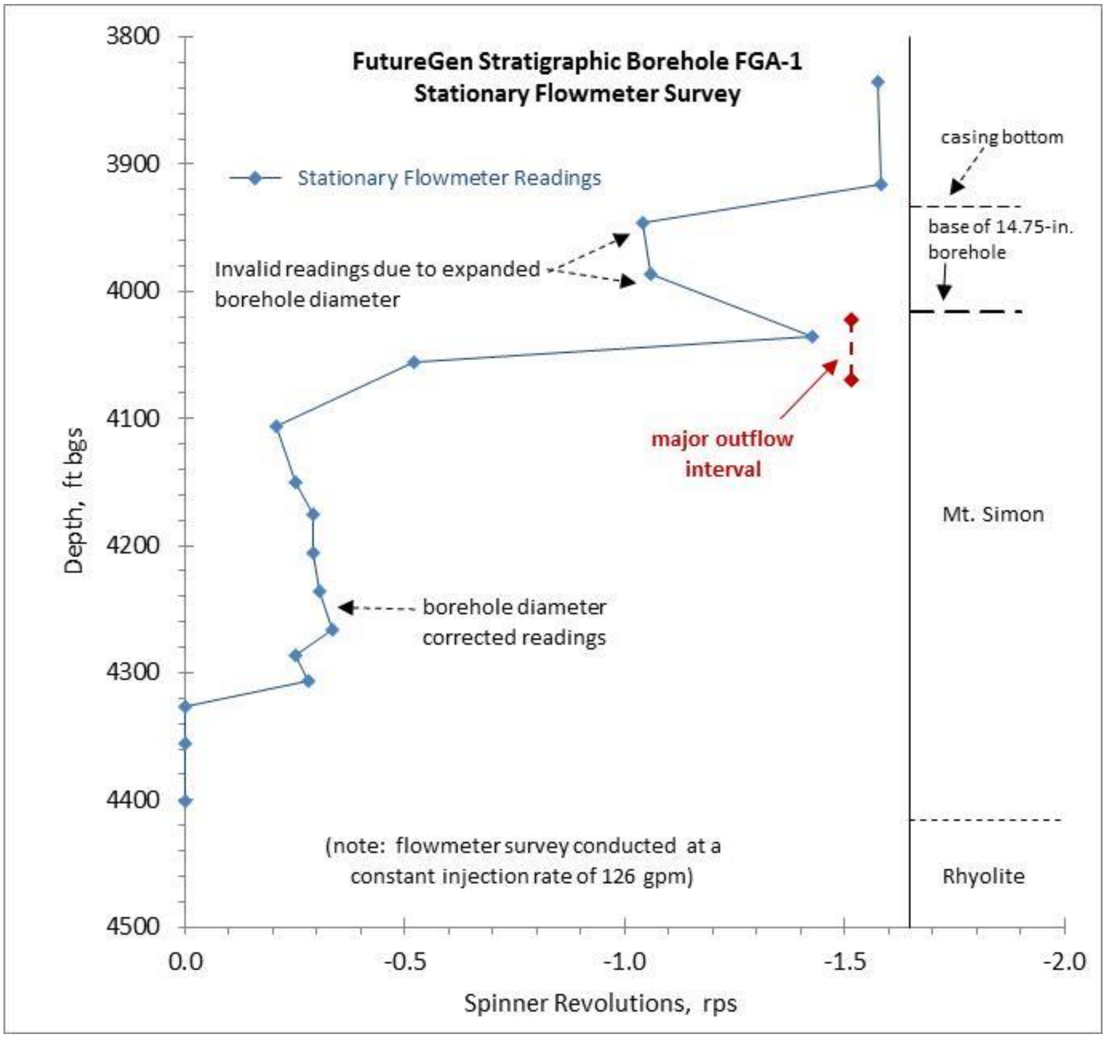
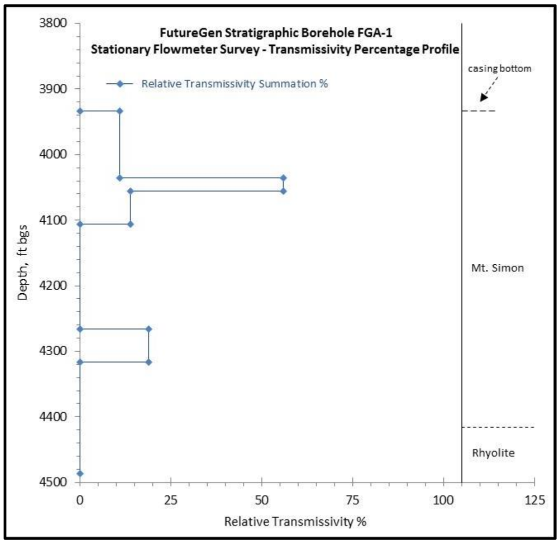


Figure 4.32. Stationary Dynamic Flowmeter Results with Inferred Major Mount Simon Formation Outflow Interval (for injection test conducted at 126 gpm)



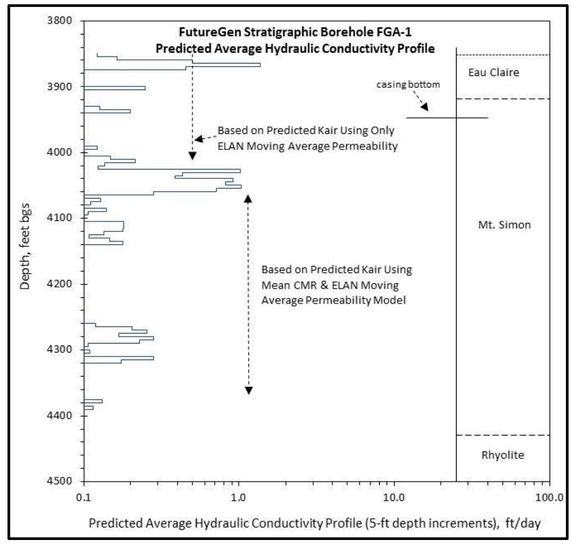


Figure 4.33. Comparison of Stationary Dynamic Flowmeter (a) and ELAN Predicted Hydraulic Conductivity Distribution (b) within the Open-Borehole Interval

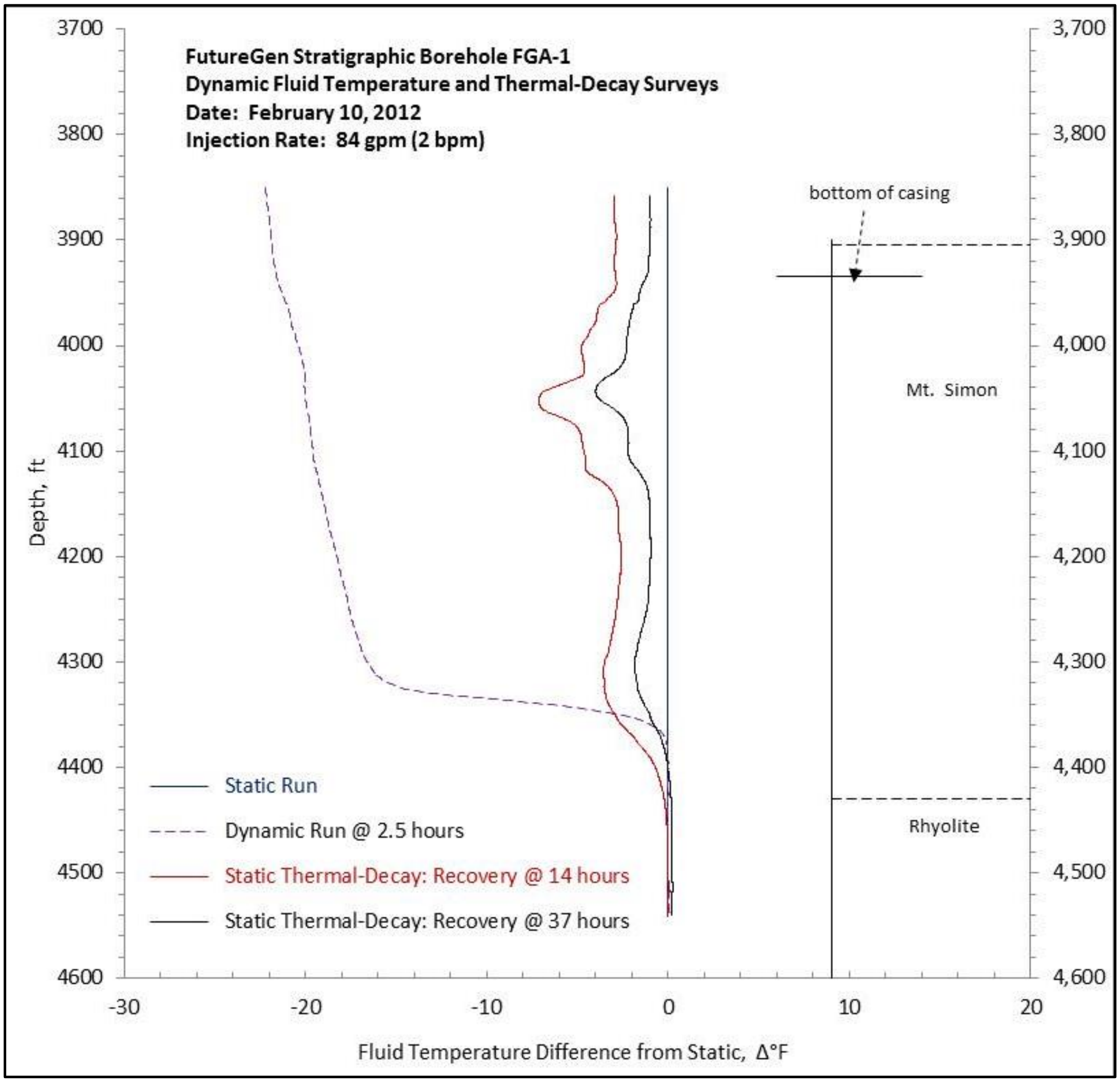


Figure 4.34. Inferred Major Higher Permeability Zones within the Open-Borehole Mount Simon Formation Section Based on Temperature Recovery/Decay Profiles

4.4.3.3 *Hydrologic Packer Tests*

The primary characterization method for determining composite layer transmissivity and average test-interval permeability within the Mount Simon reservoir was borehole hydrologic packer testing. Packer tests are hydrologic tests that involve isolating specific test intervals within the open borehole using inflatable packers affixed to tubing test string assemblies. Test intervals within the Mount Simon Formation were selected based on the inferred injection distribution obtained during the dynamic flowmeter/fluid temperature logging survey, and inferred permeability distribution obtained from wireline logs (e.g., combinable magnetic resonance [CMR] log, ELAN log). Precise packer depth setting locations were selected based on the results of various wireline geophysical surveys, including caliper, porosity, and density logs. Based on these results, two distinct Mount Simon zones were identified (an upper and lower Mount Simon Sandstone unit) for detailed borehole hydrologic packer test characterization.

As discussed by Kelley et al. (2012), two test string tubing sizes were used during the hydrologic test program (3.5-in.-OD and/or 7.0-in.-OD tubing) to maximize testing results for variable test interval permeability conditions. A downhole shut-in tool was used to minimize the impact of wellbore storage effects and to reduce test time for each test-interval characterization. The downhole testing system also included installation accommodations for memory pressure gauges to monitor pressures at several key test system locations, including below the bottom packer (when using a dual-packer configuration), within the test interval, inside the test tubing string above the downhole shut-in tool, inside packer inflation pressure, and in the annulus above the top packer. In addition, a real-time pressure gauge installed with a wireline truck on the surface via a wireline “wet connect” to flow-through connection, provided real-time monitoring of test-zone pressure below the shut-in tool during testing. The packer tests conducted in stratigraphic borehole FGA-1 relied primarily on performing a series of slug/drill-stem packer tests (DSTs) for determining test-zone permeability conditions. The slug/DST tests were conducted at varying stress levels to assess possible stress dependency in the hydraulic property conditions. The performance of multiple tests conducted at varying stress levels, also provided intermediate- to large-scale (i.e., 10 to >100 ft) hydraulic property information for the selected borehole test intervals.

The two Mount Simon test intervals were isolated (upper Mount Simon: 3,934 to 4,186 ft bgs; lower Mount Simon: 4,186 to 4,498 ft bgs) using a straddle-packer test tool, as well as a composite Mount Simon test (3,934 to 4,498 ft). All pressure records indicated that the upper and lower Mount Simon test zones were successfully isolated during the test characterization process.

Drill-stem packer tests conducted for the upper Mount Simon test interval (3,934 to 4,186 ft bgs) indicated a composite transmissivity range of 35.1 to 39.7 ft^2/day (permeability-thickness product of 9,075 to 10,265 mD-ft). Using an estimated contributing thickness of 185 ft within the tested interval (contributing thickness inferred from wireline log response), the calculated average permeability for this upper Mount Simon zone ranged between 49 to 56 mD. Examples of DST analysis figures for the upper Mount Simon, with indicated hydraulic properties and test conditions, are shown in Figure 4.35 and Figure 4.36.

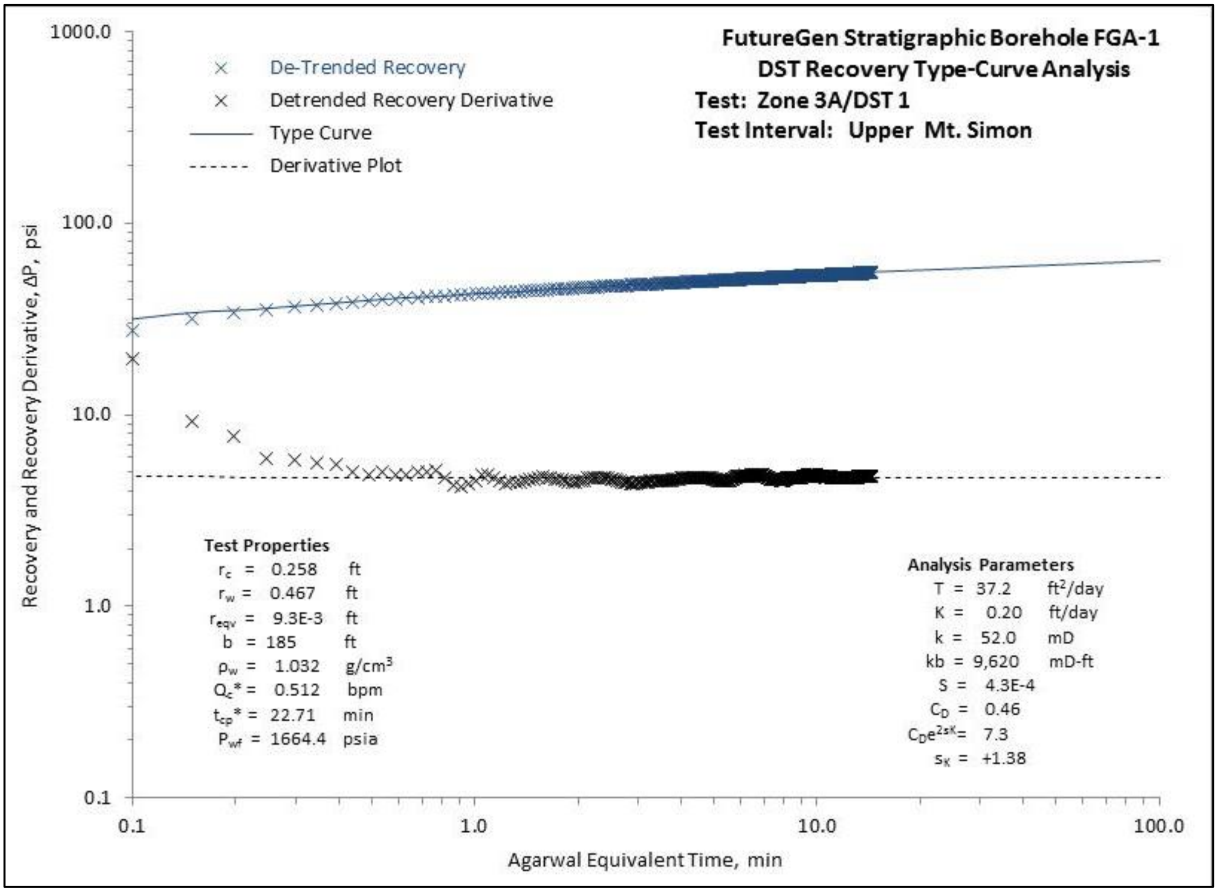


Figure 4.35. Example of a DST Type-Curve Test Analysis for the Upper Mount Simon Test Interval (Kelley et al. 2012)

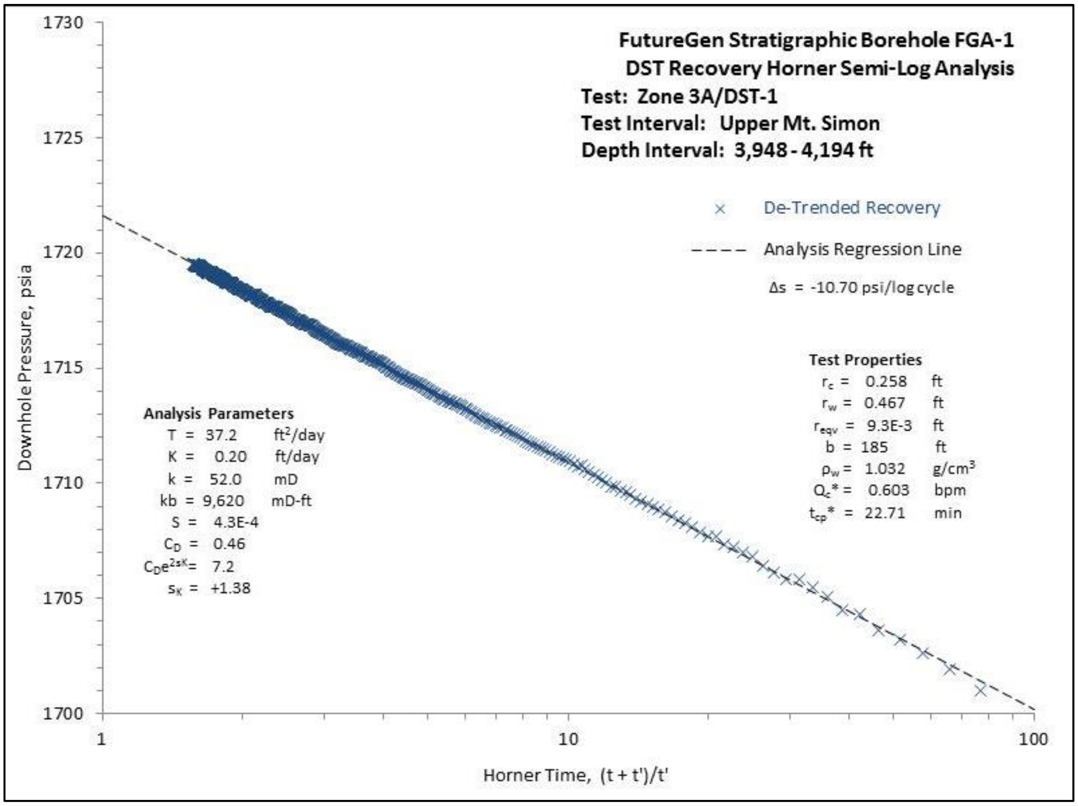


Figure 4.36. Example of a DST Recovery Horner Test Analysis for the Upper Mount Simon Test Interval (Kelley et al. 2012)

In contrast to the upper Mount Simon zone, the lower Mount Simon test interval (4,186 to 4,498 ft bgs) exhibited a significantly lower transmissivity and a composite formation condition. The composite formation condition in the lower Mount Simon interval was caused by a thin, enhanced permeability zone that extended a short distance from the borehole wall (e.g., ≤5 ft). This enhanced permeability inner zone is believed to be the result of well-development activities (e.g., acid washing) that were conducted prior to testing to remove mud filtrate from the borehole wall that accumulated during the well-drilling process. Results from the packer tests indicate a transmissivity range of 4.2 to 5.5 ft^2/day (permeability-thickness product of 1,060 to 1,405 mD-ft) for the enhanced inner zone, and a transmissivity range of 1.2 to 3 ft^2/day (permeability-thickness product of 300 to 765 mD-ft) for the outer, unaltered formation zone. The calculated permeability range for the lower Mount Simon test interval, assuming a 75-ft contributing thickness (contributing interval inferred from wireline response), is 14.1 to 18.8 mD for the inner zone and 3.9 to 10.2 mD for the outer zone, respectively. The composite test-zone condition is exhibited in the slug test response for the lower Mount Simon test interval shown in Figure 4.37, with indicated composite hydraulic property conditions. For this test analysis, the inner zone of slightly higher permeability conditions was estimated to extend to a radial distance of ~4.1 ft from the borehole.

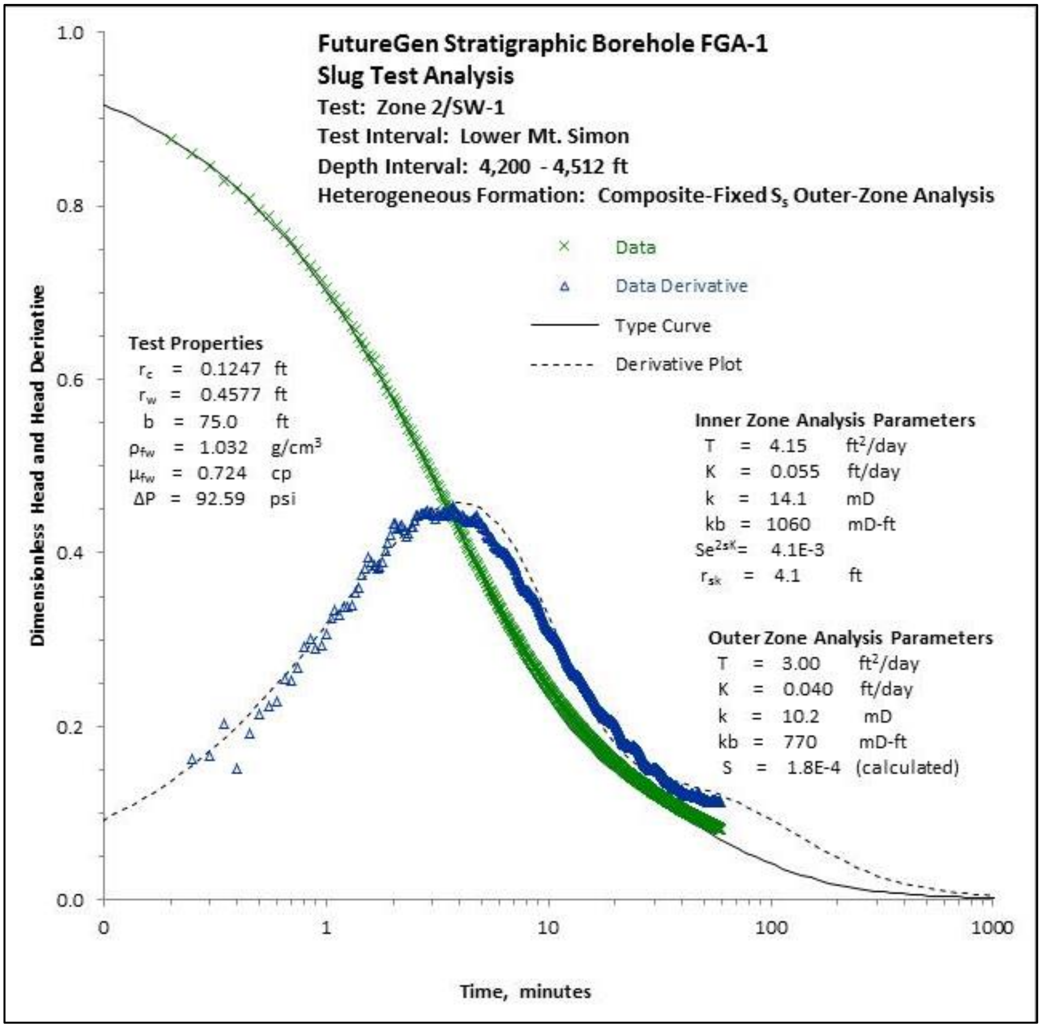


Figure 4.37. Example of a Composite Zone Slug Test Analysis for the Lower Mount Simon Test Interval (Kelley et al. 2012)

Based on the summation of the upper and lower Mount Simon packer tests, a composite transmissivity range of 36.5 to 42.7 ft^2/day (permeability-thickness product of 9,375 to 11,030 mD-ft) is indicated for the open-borehole section of the Mount Simon Formation. In addition, as shown in Figure 4.38 and as discussed by Spane et al. (2013), the cumulative summation of wireline-based ELAN permeability-thickness estimates also compares very favorably with results obtained from the larger scale hydrologic packer tests. The general correspondence in permeability-thickness values between small-scale (i.e., wireline ELAN logging) and larger scale hydrologic tests indicates that the hydraulic properties for the upper Mount Simon remained relatively uniform laterally from the borehole (i.e., over the scale of 10^0 to $>10^2$), and that the vertical profile distribution of permeability within the Mount Simon was representative of in situ conditions, as depicted in Figure 4.33(b).

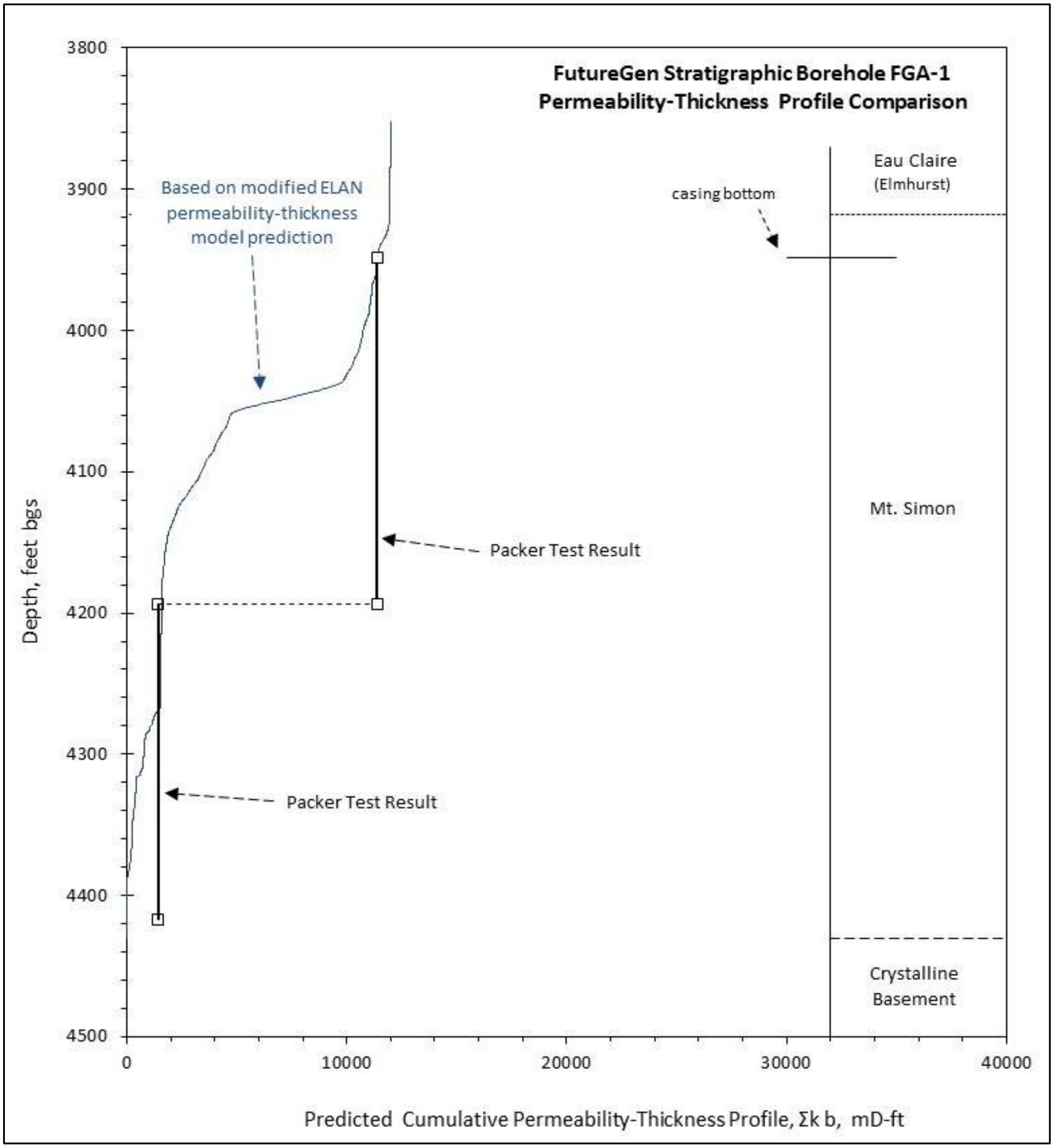


Figure 4.38. Comparison of Cumulative Permeability-Thickness: Modified ELAN Model and Hydrologic Packer Test Results (Spane et al. 2013)

4.4.3.4 *Hydrochemical and Isotopic Characterization*

Hydrochemical and isotopic characterization information are commonly used in assessing the evolution and interaction of subsurface formation fluids within/between their respective aquifer systems. However, because only two representative formation waters were collected from stratigraphic borehole FGA-1, an in-depth evaluation of hydrochemical and isotopic information, as it relates to lateral and vertical groundwater flow conditions at the FutureGen 2.0 CO_2 storage site, is limited.

This section provides a summary of hydrochemical and isotopic data collected for the St. Peter and Mount Simon Formations during the characterization of stratigraphic borehole FGA-1. The St. Peter represents the lowermost recognized USDW and is situated 1,962 ft above the top of the Mount Simon, which represents the primary injection reservoir formation. In all, only one St. Peter sample collected using a downhole wireline sampling device during drilling was considered to be representative, while five hydrochemical samples obtained during extensive well development of the Mount Simon Formation (see Section 4.4.3.1) after completion of drilling were evaluated as being representative of in situ formation conditions (i.e., non-contaminated drilling fluid). Only samples considered to be representative of test formation conditions are presented in the subsections and figures that follow. A more detailed discussion of collection methods, analyses performed, and pedigree/representativeness of the formation water sampling program is provided by Kelley et al. (2012).

4.4.3.4.1 General Hydrochemistry

Major cation and anion chemistry for representative water samples for the St. Peter and Mount Simon Formations are depicted graphically using the Piper Diagram in Figure 4.39. For comparison purposes, the figure also shows the composition of the surficial groundwater collected from a shallow monitor well at the FutureGen 2.0 CO_2 storage site, as well as the offsite source water that was used to make the drilling fluid during the borehole drilling. As shown in the figure, the Mount Simon samples are hydrochemically distinct (as shown by the plotting location separation) in comparison to either the St. Peter or shallow surficial groundwater or source water samples. Both the St. Peter and Mount Simon Formation waters can be classified as a NaCl hydrochemical water type; however, the Mount Simon Formation water had a higher relative abundance of calcium (Ca) compared to the St. Peter, while the St. Peter Formation water had a higher abundance of sulfate (SO_4) compared to that within the Mount Simon. The NaCl hydrochemical facies classification for the St. Peter and Mount Simon Formation waters is consistent with projects for the FutureGen 2.0 CO_2 storage site, based on surrounding regional groundwater conditions, as identified by Young (1992). Total dissolved solids concentrations were significantly different between the two formation waters, with the Mount Simon water samples having an average total concentration of ~47,000 mg/L, in contrast to the St. Peter Formation water sample with a TDS concentration of 3,400 mg/L. TDS concentrations for the drilling fluid source water and the shallow surficial groundwater were 260 and ~610 mg/L, respectively.

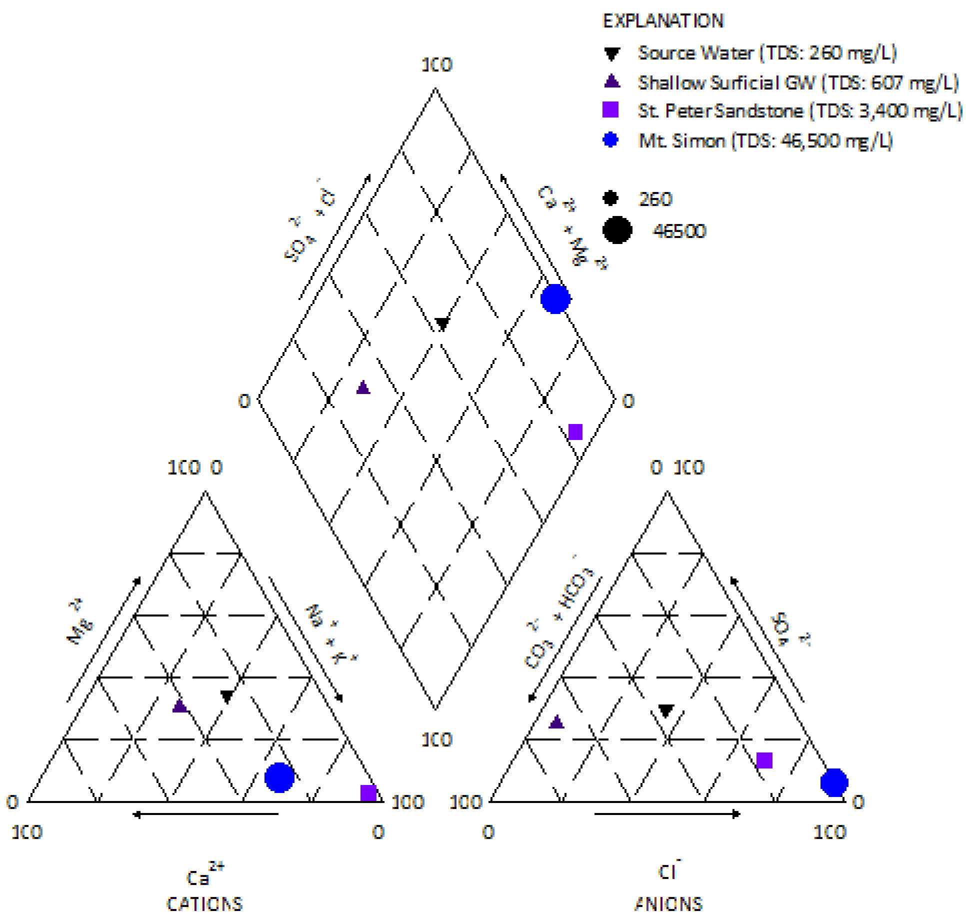


Figure 4.39. Piper Diagram for St. Peter and Mount Simon Water Samples (modified from Kelley et al. 2012)

4.4.3.4.2 Isotopic Data

Isotopic characterization data are commonly used in hydrologic investigations to establish the origin and source of groundwater within aquifer systems. As noted previously however, because of the limited number of representative formation water samples collected from stratigraphic borehole FGA-1 (and the lack of nearby, comparative regional formation water results), no comprehensive analysis of the source and origin of formation waters at the FutureGen 2.0 CO_2 storage site is possible. In the following sections, laboratory analysis results for environmental stable isotopes of oxygen, hydrogen, and carbon (dissolved inorganic carbon), along with analyses for unstable isotopes tritium, and carbon-14 are presented that were collected for the St. Peter and Mount Simon Formations, and for the drilling fluid source water and shallow, surficial groundwater collected at a shallow monitoring well at the FutureGen 2.0 CO_2 storage site.

4.4.3.4.2.1 Carbon Isotopes

Formation water samples were analyzed for stable carbon isotopes in dissolved inorganic carbon (i.e., for alkalinity and dissolved CO_2). Typical stable carbon isotope composition ($\delta^{13}C$) values in shallow groundwater are negative (depleted) relative to the universal standard due to fractionation processes occurring during photosynthesis or due to equilibration with atmospheric CO_2 (note: modern atmospheric CO_2 is approximately -7‰. The $\delta^{13}C$ content in St. Peter Formation water was slightly more depleted than modern atmospheric conditions, with a value of -8.1 ‰, while the Mount Simon Formation water samples were more depleted in comparison to the St. Peter, with $\delta^{13}C$ values that range from -15.1 to -15.6 ‰. The $\delta^{13}C$ content within the shallow surficial groundwater and for the drilling fluid source water is -11.4 ‰ and 13.7‰, which falls in between both the St. Peter and Mount Simon Formation water values.

4.4.3.4.2.2 Oxygen and Hydrogen Isotopes

$\delta^{18}O$ ($^{18}O/^{16}O$) and δD ($^{2}H/^{1}H$) results are reported in per mil (‰) deviation from Vienna Standard Mean Ocean Water (VSMOW). Results are plotted as $\delta^{18}O$ vs δD in Figure 4.40 along with the global meteoric water line for reference, as described by Craig (1961). The global meteoric water line describes the average relationship between hydrogen and oxygen isotope ratios in natural terrestrial waters (i.e., precipitation-derived surface waters), expressed as a worldwide average. The δD and $\delta^{18}O$ values for precipitation worldwide behave predictably, plotting along the global meteoric water line. As shown in the figure, results for the shallow surficial groundwater, the drill fluid source water, and for the St. Peter all plot close to the meteoric water line; whereas, samples for the Mount Simon Formation waters plot offset from the global meteoric water line, as might be expected for deeper and older groundwater systems.

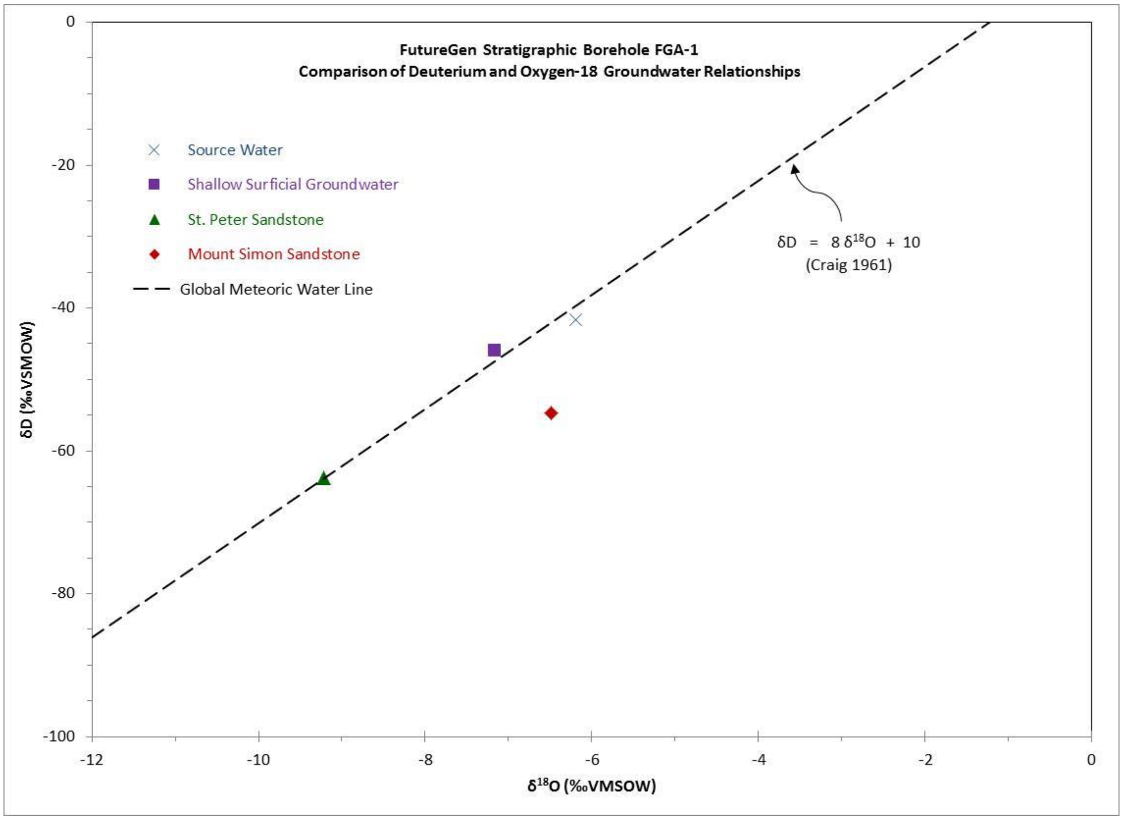


Figure 4.40. δD versus $\delta^{18}O$ for St. Peter and Mount Simon Formation Water Samples (Kelley et al. 2012)

4.4.3.4.2.3 Tritium (^{3}H)

Tritium was analyzed to help determine if formation water samples were contaminated by the presence of drilling mud during the sampling process. Tritium, ^{3}H, is a short-lived isotope of hydrogen with a half-life of 12.43 years. It is present in the atmosphere in both natural and anthropogenic forms. Because of its short half-life, its presence in groundwater samples provides evidence for active, recent recharge, and for deep groundwater samples, its presence is an indication of potential contamination of the sample by the borehole drilling process.

The St. Peter Formation sample had a low concentration of tritium (1.59 ± 0.23 TU). Because of its subsurface depth, tritium is not expected in the St. Peter water; therefore, this low level of tritium may suggest that the sample contained a small amount of drilling fluid contamination.

The average composite Mount Simon Formation water samples collected near the end of the extended well-development pumping were also analyzed for the presence of tritium. Tritium was not detected in any of these samples. No tritium analyses were performed on either the drilling fluid source water or on the shallow, surficial groundwater, but measurable activities would be expected.

4.4.3.4.2.4 Carbon-14 (^{14}C)

High activity levels of carbon-14 (^{14}C), expressed as percent modern carbon (PMC), were detected both in samples collected from the shallow, surficial groundwater (80.1 PMC) and the drilling fluid source water (88.6 PMC), with lower levels exhibited for both the St. Peter Formation and the Mount Simon Formation. Because of their relative depth and expected groundwater age, ^{14}C would not be expected in either the St. Peter or the Mount Simon Formations; therefore, the low activity levels detected in these samples may suggest that the formation water samples contained a small amount of modern fluid that was used to drill the well and/or to condition the borehole after drilling was completed. Regionally, however, the presence of ^{14}C activities within St. Peter and Mount Simon groundwaters have been detected and have been interpreted as being due to the presence of past glacial recharge conditions (e.g., Siegel 1989; Young 1992). The PMC content for St. Peter and Mount Simon Formation waters ranged from 3.3 to 6.0 PMC, respectively, which has an uncorrected apparent ^{14}C age of between 22,610 to 27,400 years before present (BP). It is not known whether contamination or past glacial recharge is responsible for the presence of ^{14}C within these formation waters.

4.4.3.5 *Pressure/Depth Profile Relationship*

Static pressure versus depth relationships for the stratigraphic borehole FGA-1 were developed from field static pressure test measurements obtained using three different field test characterization methods: 1) Schlumberger MDT surveys; 2) standard hydrologic straddle-packer characterization tests, and 3) geomechanical straddle-packer hydraulic fracturing (minifrac) tests. The pressure/depth relationships presented in this report provide a more thorough evaluation of static pressure/depth data and profile relationships for stratigraphic borehole FGA-1 than were previously presented by Kelley et al. (2012). This evaluation also includes more recently acquired static pressure/depth data that were obtained in conjunction with geomechanical characterization tests conducted in 2013 as reported by Cornet (2014). Specifically, static pressure/depth regression relationships were established within the injection reservoir interval and over the composite depth interval from the St. Peter Sandstone to the base of the Mount Simon injection reservoir interval.

Pressure-depth relationship information was used to support a variety of FutureGen 2.0 programmatic activities, including;

- Area-of-Review (AoR) pressure-front/critical pressure calculations
- initial formation pressure conditions for numerical modeling pressure simulations of CO_2 injection operations
- in situ geomechanical fracture-gradient determinations input
- FutureGen 2.0 project technical characterization reports and UIC Class VI permit support applications.

An in-depth description of the pressure-depth data used to establish the pressure profile and gradient at stratigraphic borehole FGA-1 and hydrogeologic inferences are provided in Appendix 4B.

Figure 4.41 shows the projected pressure/depth profile for the composite formation test intervals based on a simple linear-regression model fit for all of the pressure/depth measurement data. As indicated in the figure, incorporating the subnormal Silurian and St. Peter pressure-depth data causes the composite regression line to intersect/cross the projected freshwater hydrostatic pressure/depth profile at a depth of ~3,150 ft bgs (note: see Appendix 4B for a discussion of causative subnormal pressure conditions). Using the composite regression relationship to predict pressure-depth conditions over the large intervening interval, the absence of data between the St. Peter Formation and the top of the Mount Simon Formation assumes that a hydraulic potential continuum exists for vertical groundwater flow. This assumption is not realistic given the presence of regionally recognized low-permeability confining/caprock horizons. When laterally extensive, low-permeability confining layers are present, pressure/depth profile offsets are commonly indicated and are produced by observable pressure/depth gradients across the intervening confining layer. It is reasonable to assume that similar offsets in the pressure/depth profile exists at the FutureGen 2.0 CO_2 storage site as imposed by low-permeability caprock horizons within the Proviso and Lombard Members of the Eau Claire Formation (i.e., between a depth of 3,425 and 3,838 ft bgs).

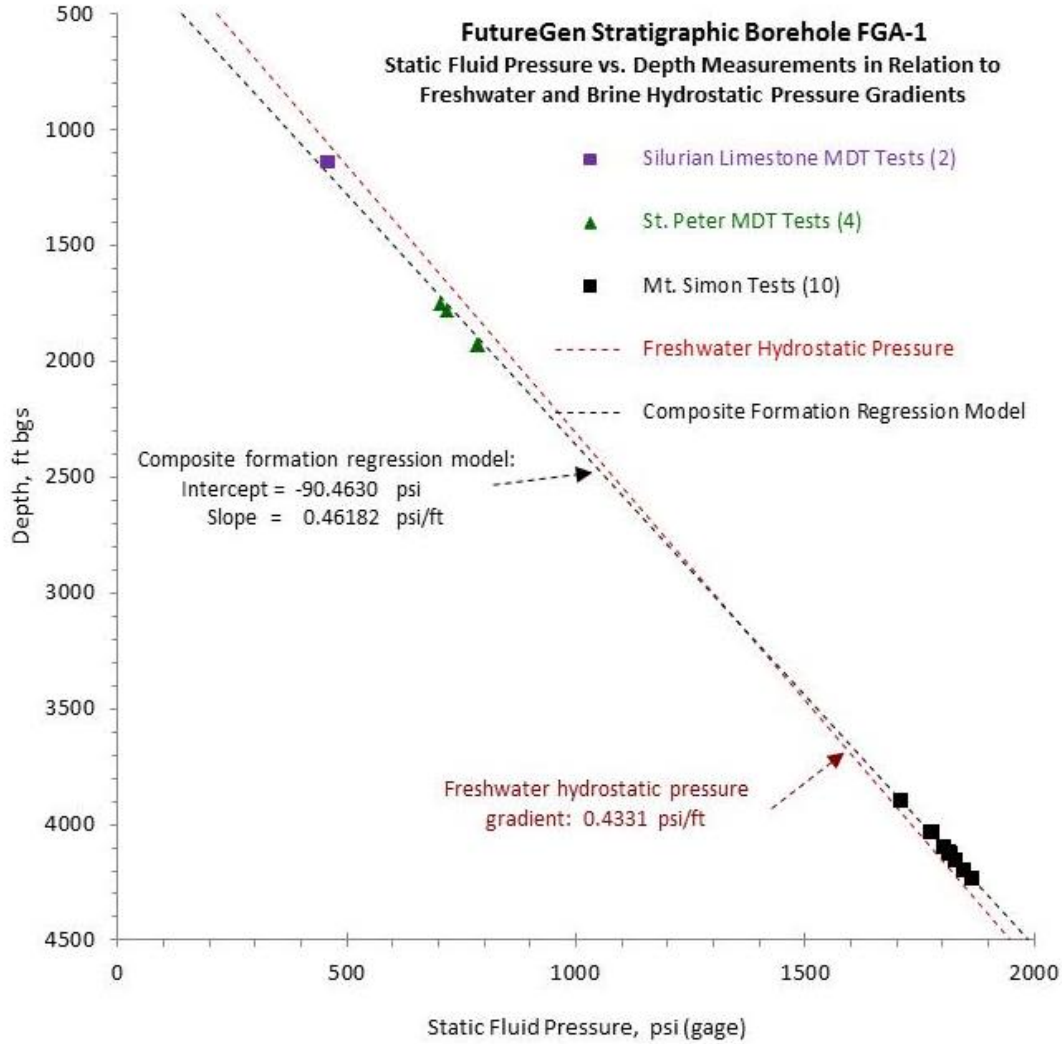


Figure 4.41. Comparison of Silurian Limestone, St. Peter Formation, and Mount Simon Formation Pressure/Depth Measurements with the Freshwater Hydrostatic Pressure Gradient Profile and Composite Formation Linear-Regression Model

To provide hydrogeologic analysis support to the observed pressure/depth relationships, an equilibrated static fluid temperature depth profile in stratigraphic borehole FGA-1 was also examined. Static fluid temperature profiles can provide hydrogeologic inferences concerning significant changes in the permeability depth profile surrounding the cased well section. These significant changes in stratigraphic permeability are commonly associated with observable changes or deflections of the static fluid temperature gradient, which are associated with the significant changes in advective groundwater flow and thermal conductivity conditions within the surrounding stratigraphic units. Generally, thick and laterally extensive low-permeability confining layers are indicated by high-temperature/depth-gradient conditions, which imply the predominance of conductive heat flow over these depth intervals, due to the lack of significant, advective groundwater flow within or across these units.

Figure 4.42 provides an interpretive hydrogeologic conceptual model that quantifies and accentuates the differences in temperature/depth gradients, based on linear-regression analysis of selected depth intervals of the static fluid temperature/depth survey. The static fluid temperature/depth survey was performed on November 8, 2013, at stratigraphic borehole FGA-1, approximately 1.5 years after completion of drilling and hydrologic testing activities at the borehole site. Based on these temperature gradient regression analysis constructions and observed static pressure/depth relationships, the following hydrogeologic conditions are inferred for the FutureGen 2.0 CO_2 storage site location:

- two major low-permeability regional caprock/confining layer hydrogeologic units are identified based on higher temperature gradient intervals:
  - an upper composite confining layer consisting of the New Albany and Maquoketa Shales, and
  - a lower composite confining layer consisting of low-permeability units within the Proviso and Lombard Members of the Eau Claire Formation.

The temperature/depth-gradient conditions exhibited for the intervening confining/caprock layers are approximately twice those exhibited for the intermediate and regional brine flow systems (i.e., 2.7E-2 ˚C/m vs 1.3E-2 ˚C/m)—conditions which are attributed to the lack of significant advective groundwater flow within the confining/caprock layer to dissipate heat flow conditions.

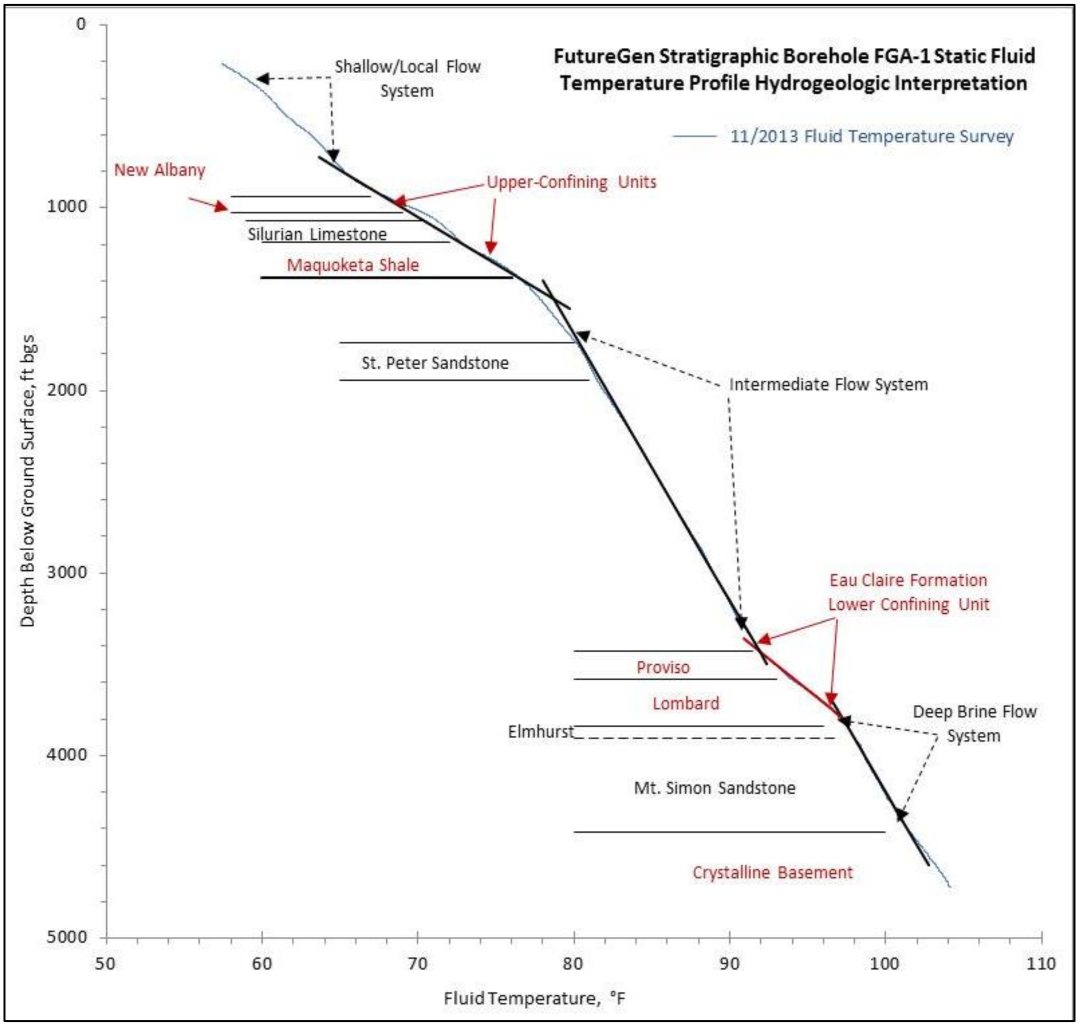


Figure 4.42. Interpretative Hydrogeologic Conceptual Model, Based on Static Fluid Temperature/Depth Profile Conditions at Stratigraphic Borehole FGA-1 (Note: ˚C = (˚F – 32)/1.8)

Coupled with static fluid-pressure/depth data obtained from field test measurements, these two regionally recognized caprock/confining layer horizons appear to effectively isolate three postulated groundwater flow systems:

- a shallow/local groundwater flow system developed to the top of the New Albany confining layer, under freshwater hydrostatic gradient conditions,
- an intermediate groundwater flow system consisting of permeable hydrogeologic units located between the base of the Maquoketa Shale and the top of the Proviso Member of the Eau Claire Formation, under subnormal to freshwater hydrostatic pressure gradient conditions (i.e., 0.4018 to 0.4331 psi/ft), and

- a deep, regional brine groundwater flow system consisting of permeable units of Elmhurst and Mount Simon Formations (effectively isolated from the overlying intermediate groundwater flow system by the lower composite Eau Claire confining/caprock horizon), which is under brine hydrostatic pressure gradient conditions (i.e., 0.4401 psi/ft).

The depth limit of the subnormal pressure gradient conditions for the intermediate groundwater flow system is not well-defined because of the paucity of static pressure/depth field measurements at the stratigraphic borehole FGA-1 location. Additional borehole measurement data would be required within the intervening depth interval to resolve the pressure/depth relationships across this depth interval.

Based on the hydrogeologic inferences provided by the static fluid temperature/depth profile (Figure 4.42) and observed average pressure gradient measurements, a composite confining layer/offset pressure-depth model was developed to predict pressure/depth conditions at the stratigraphic borehole FGA-1 location. Figure 4.43 shows the results of the predicted pressure/depth profile for stratigraphic borehole FGA-1 based on this model and using the observed average pressure/depth-gradient relationships shown in Figure 4.41 for the test-interval depths between the identified intervening confining/caprock horizons:

- freshwater hydrostatic gradient (0.4331 psi/ft) between land surface to top of the New Albany Shale
- average Silurian Limestone pressure gradient (0.4018 psi/ft) between the base of the New Albany Shale and top of the Maquoketa Shale
- average St. Peter Sandstone pressure gradient (0.4048 psi/ft) between the base of the Maquoketa Shale and the top of the Eau Claire Formation (top of the Proviso Member)
- average Mount Simon brine pressure gradient (0.4401 psi/ft) from the base of Lombard Member of the Eau Claire Formation to the top of the crystalline basement.

As indicated in Figure 4.43, the major pressure/depth-gradient offsets occur across the New Albany and Eau Claire confining layer/caprock horizons using this conceptual model approach. The composite confining layer pressure gradient offset model is considered to provide a more representative depiction of pressure/depth profile conditions (i.e., Figure 4.41) than predictions based on the composite formation linear-regression model shown in Figure 4.36. As noted in Figure 4.43, however, considerable uncertainty exists for the predicted pressure profile conditions over the depth interval of ~2,000 to 3,800 ft, because of the lack of field measurement data. It is expected that the pressure/depth profile would transition from subnormal to freshwater hydrostatic pressure/gradient conditions at some depth location within this interval. This postulated pressure gradient profile transition, however, is not reflected in the interpretive temperature/depth profile shown in Figure 4.42.

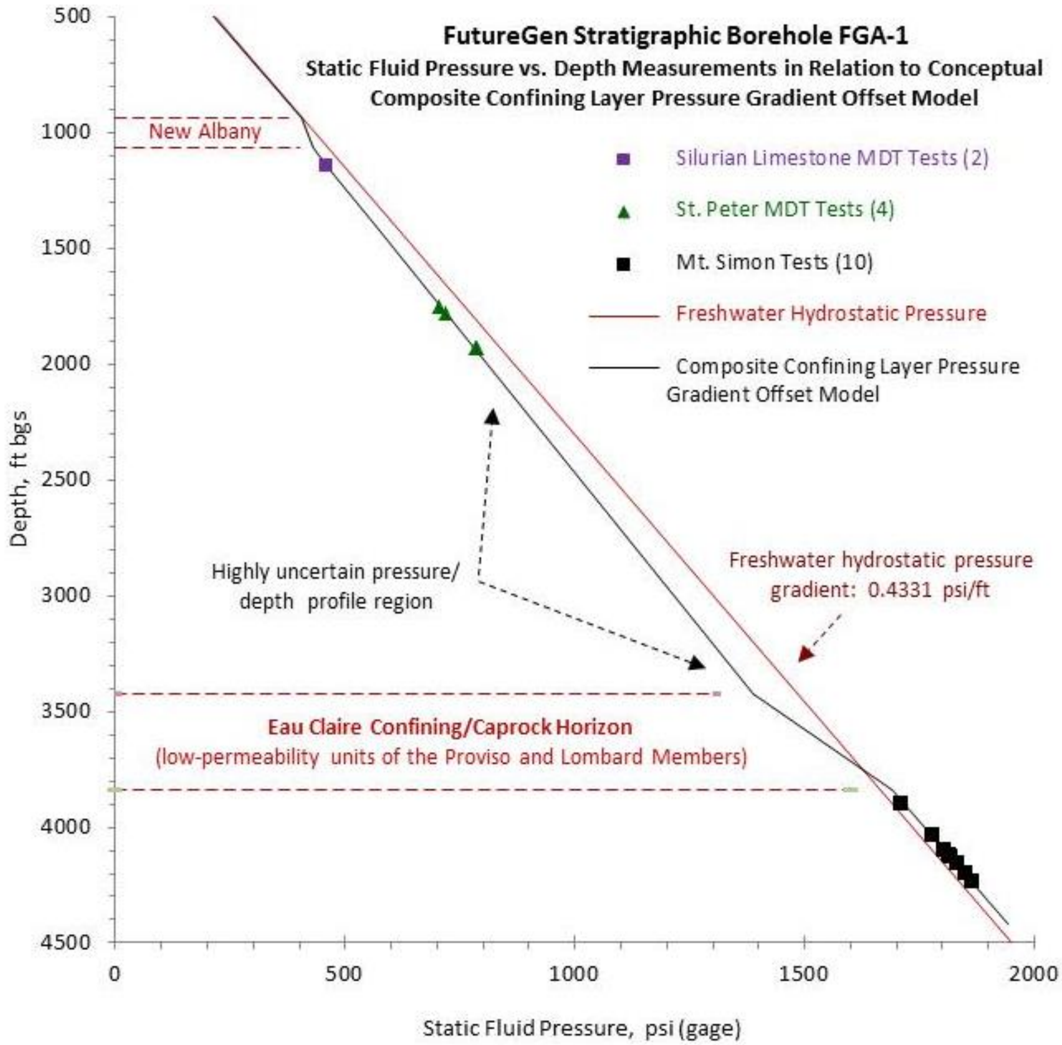


Figure 4.43. Comparison of Silurian Limestone, St. Peter Formation, and Mount Simon Formation Pressure-Depth Measurements with Freshwater Hydrostatic Pressure Gradient Profile and Composite Formation Confining Layer Offset Model

4.4.3.6 *Salient Hydrogeologic Characterization Findings*

Important hydrogeologic findings obtained from the detailed characterization program implemented at stratigraphic borehole FGA-1, as presented by Kelley et al. (2012) and Spane et al. (2013), are summarized below:

- The stratigraphy encountered above the Mount Simon Sandstone at stratigraphic borehole FGA-1 is consistent with surrounding regional geologic relationships project for the FutureGen 2.0 CO_2 storage site.
- The Mount Simon Sandstone occurs from 3,904 to 4,403 ft bgs, and is approximately 500-ft thick at stratigraphic borehole FGA-1. This reservoir thickness is more than 200 ft

narrower than anticipated based on regional geologic data. This appears to be due to the fact that the Precambrian bedrock that underlies the Mount Simon occurs at a shallower depth than anticipated, which may represent a local “high” on the Precambrian bedrock surface.

- The Eau Claire Formation, which directly overlies the Mount Simon Sandstone and includes the primary confining unit, occurs from 3,425 to 3,904 ft bgs (479-ft thick) at the stratigraphic borehole FGA-1 location. All three members of the Eau Claire Formation (i.e., the Proviso, Lombard, and Elmhurst) are present at the FutureGen 2.0 CO_2 storage site location. The upper two units (composing 413 ft of the total 479 ft of Eau Claire Formation thickness) have characteristics that suggest that this section of the Eau Claire would serve as a capable confining unit for the underlying Mount Simon injection reservoir. The confining nature for these upper two members of the Eau Claire is also supported by inferential patterns in the static fluid temperature/depth profile for stratigraphic borehole FGA-1, as discussed in Section 4.4.3.5. This is also consistent with regional information concerning the sealing characteristics of the Eau Claire Formation.
- The lowermost member (Elmhurst) of the Eau Claire Formation is a sandstone unit with properties similar to the underlying Mount Simon Sandstone. Because of these similar physical characteristics, the Elmhurst Sandstone is considered to be part of the identified injection reservoir section at the FutureGen 2.0 CO_2 storage site, and provides additional CO_2 storage capacity, above what is provided directly by the upper Mount Simon Sandstone reservoir.
- The St. Peter Sandstone, which occurs from 1,740 to 1,942 ft bgs, appears to have sufficient porosity and permeability to serve as a monitoring zone for the detection of potential upward migration of CO_2 from the underlying storage reservoir. Other potential monitoring zones may exist below the St. Peter Sandstone, (e.g., New Richmond Sandstone, Gunter Sandstone, Ironton Sandstone); however, some of these units are located below the Potosi Formation, which represents a significant drilling hurdle because of the potential for severe lost drilling-fluid circulation.
- Baseline hydrochemistry data were obtained for fluid samples collected from the St. Peter and the Mount Simon Sandstones. The hydrochemical characteristics are consistent with projected regional information for the FutureGen 2.0 CO_2 storage site. Formation water within the St. Peter is a brackish NaCl water type with a TDS content of approximately 3,400 mg/L, whereas, fluid within the Mount Simon Formation is a concentrated NaCl brine with a TDS content of approximately 47,000 mg/L. Hydrochemical results for the St. Peter Formation are based on a single small-volume sample, whereas results for the Mount Simon Formation are based on composite samples collected during extensive well development/pumping of this unit.
- Detailed discrete-depth/profile measurements of reservoir fluid pressure indicate that the St. Peter Formation (hydrostatic pressure gradient of 0.41 to 0.42 psi/ft) was slightly

under-pressured in comparison to normal freshwater hydrostatic conditions (0.433 psi/ft). The Mount Simon Formation hydrostatic pressure gradient (0.44 to 0.45 psi/ft) was slightly higher than normal freshwater hydrostatic conditions but was consistent with a calculated hydrostatic pressure gradient (0.448 psi/ft) for a fluid having the salinity of the Mount Simon fluid obtained from stratigraphic borehole FGA-1. A comparison of these pressure/depth data also demonstrates that there is a natural upward vertical hydraulic gradient (i.e., flow potential) between the Mount Simon Formation and the overlying St. Peter Formation.

- Based on the series of open-borehole slug/DST packer tests conducted in the stratigraphic borehole FGA-1, the upper Mount Simon test interval (3,934 to 4,186 ft bgs) had a composite transmissivity that ranged from 35.1 to 39.7 ft^2/day (permeability-thickness product of 9,075 to 10,265 mD-ft). The calculated permeability for this composite interval, assuming a 185-ft contributing thickness within the tested interval (based on the results of wireline logs and flowmeter logging data), ranged from 49 to 56 mD. In comparison, the lower Mount Simon test interval (4,186 to 4,498 ft bgs) exhibited a significantly lower transmissivity. The lower Mount Simon test interval also exhibited a composite formation condition that was caused by a thin (e.g., ≤5-ft) enhanced permeability zone surrounding the borehole. This enhanced permeability inner zone is believed to have been caused by the well-development activities (acid washing) conducted prior to testing to remove residual drilling-mud filtrate from the borehole wall. Results from the packer tests indicated a transmissivity range of 4.2 to 5.5 ft^2/day (permeability-thickness product of 1,060 to 1,405 mD-ft) for the enhanced inner zone, and 1.2 to 3 ft^2/day (permeability-thickness product of 300 to 765 mD-ft) for the outer, unaltered formation zone. The corresponding permeability range for the lower Mount Simon test interval, assuming a 75-ft contributing thickness, is 14.1 to 18.8 mD for the inner zone and 3.9 to 10.2 mD for the outer zone.
- Hydrologic test responses obtained from dynamic flowmeter logging tests indicated that the highest permeability zone within the open-borehole section, occurred within the upper part of the Mount Simon Formation, and occurred over the depth interval from approximately 4,016 to 4,046 ft bgs. This section of higher permeability was also indicated by wireline (CMR and ELAN) logging results, and is supported by thermal-decay response plots obtained following termination of the dynamic flowmeter survey. It should also be noted the zone of higher permeability may extend above a depth of 4,016 ft bgs; however, the larger borehole drilling diameter above this depth (i.e.,14 to 16 in. between 3,934 and 4,016 ft bgs) adversely affected the resolution characteristics of the dynamic flowmeter log over this open-borehole depth interval. The dynamic flowmeter logging results also indicated that no significant injection potential within the Mount Simon occurs below a depth of approximately 4,346 ft bgs.

4.4.4 Geomechanical Testing Program

Numerous aspects of the design and operational activities of the FutureGen 2.0 CO_2 storage site are dependent on the geomechanical properties of the targeted reservoir zone, as well as for the overlying confining zone and the underlying crystalline Precambrian basement. Detailed state-of-stress geomechanical information within the subsurface is of paramount importance in successfully designing well-drilling/completion aspects, as well as assessing the risk of induced seismicity and the potential for creating and/or reopening pre-existing fractures—all of which help ensure the safe long-term storage of injected CO_2. A multiphase in situ stress characterization program was implemented for the FutureGen 2.0 CO_2 sequestration project. The first phase, conducted in 2013, focused on determining the state-of-stress within the injection reservoir and underlying crystalline basement complex. The second proposed phase of geomechanical characterization, which would have mainly focused on the caprock, was planned to be conducted in new boreholes that would have been drilled as part of extended phases of the project.

4.4.4.1 *Initial In Situ Stress Characterization Program*

The FutureGen 2.0 geomechanical in situ stress characterization program was largely designed by Francois Cornet (Geostress), an internationally recognized expert in subsurface geomechanical characterization testing. The recommendations for conducting the in situ characterization program both at stratigraphic borehole FGA-1 and for the overall program are captured in Appendix 4.C. Briefly stated, the general objectives of the in situ stress characterization program consisted of evaluating the following:

- the vertical variation of the minimum principal stress magnitude in the Eau Claire Formation to determine the maximum acceptable pore-pressure value for the Mount Simon Sandstone that will not create any disruption (i.e., fracturing) to the overlying caprock;
- the minimum principal stress direction and its magnitude in the Mount Simon Formation, to determine the maximum acceptable injection pressure for CO_2 sequestration and to establish bounds for the magnitude of the maximum horizontal principal stress. (Note: these determinations provide essential information for the design of the drilling program for the four horizontal wells, i.e., optimum drilling direction, mud weight, etc.);
- the complete stress field in the crystalline basement rock to determine the maximum acceptable pore pressure in the Mount Simon Sandstone that will not generate seismicity large enough to be classified as a “nuisance” (detectable by the general public). Determining the stress field within the basement complex also serves to establish a constraint on the maximum differential stresses imposed by sequestration activities within the Mount Simon reservoir/formation.

Borehole minifrac tests proposed and described in Appendix 4.C are well-suited for identifying the stress field when hydraulic fracture (HF) tests are used in combination with a field test program including hydraulic tests on pre-existing fractures (HTPFs). Comprehensive explanations of the theory and methods applied for the stress determination for each test method and their specific test objectives are presented in the geomechanical appendix (Appendix 4.C).

The overall geomechanical in situ stress program recommended that HF tests be conducted both in the Eau Claire Formation and in the underlying Mount Simon Formation, and that a combination of HTPF and HF tests be performed in the crystalline basement rock. However, because stratigraphic borehole FGA-1 was cased into the upper Mount Simon, the Eau Claire caprock horizons could not be characterized in the initial field testing program, and characterization testing of the Eau Claire Formation was proposed to be conducted in future/planned boreholes that were to be drilled at the site. Based on the open-borehole/formation availability, the optimum initial geomechanical characterization program at stratigraphic borehole FGA-1 recommended performing nine hydraulic tests (five HF and four HTPF) in the crystalline basement for a complete determination of the vertical stress profile and five HF tests in the Mount Simon Sandstone for determining the direction and amplitude of the minimum principal stress in the Mount Simon Formation. Discussion and details regarding the identification of the location of the tests and testing procedure are provided in Appendix 4.C (Sections 4.C-1 and C-2).

4.4.4.2 *Stratigraphic Borehole FGA-1 Field Geomechanical Test Results*

The following is a summary of results obtained during the geomechanical field test characterization within stratigraphic borehole FGA-1. Detailed descriptions, analyses, and interpretations of these field test results are presented by Cornet (2014), Cornet et al. (2014), Appriou et al. (2014a, b), and Kelley et al. (2014).

The first phase of the geomechanical field testing was conducted during November and December 2013, and involved a combination of HF tests and HTPFs conducted within the open-borehole section of stratigraphic borehole FGA-1. The Mount Simon reservoir and underlying crystalline basement rock were the only geologic formations available in the open-borehole interval for geomechanical field test characterization. Due to limitations imposed by schedule constraints, the optimum field testing program outlined in Section 4.4.4.1 could not be fully implemented. As a result, a minimum (but technically adequate) field geomechanical characterization program approach was adopted for the Phase 1 field testing at stratigraphic borehole FGA-1. A total of three HF tests within the Mount Simon, and five hydraulic tests (3 HF and 2 HTPF) within the underlying crystalline basement were completed. (Figure 4.44 shows the test depth locations). The objective of the HF tests was to provide a constraint on principal stress directions and on the minimum horizontal principal stress magnitude, while the objective of the HTPF tests focused on constraining the magnitude of both the vertical and the maximum horizontal principal stress components. Created and existing fractures' directional components (dip and azimuth) were determined by analysis of pre- and post-testing fracture wireline imaging log surveys (FMI and Ultrasonic Borehole Imager; note: only pre-test survey results were available for the UBI). Figure 4.45 is a FMI image of a created fracture.

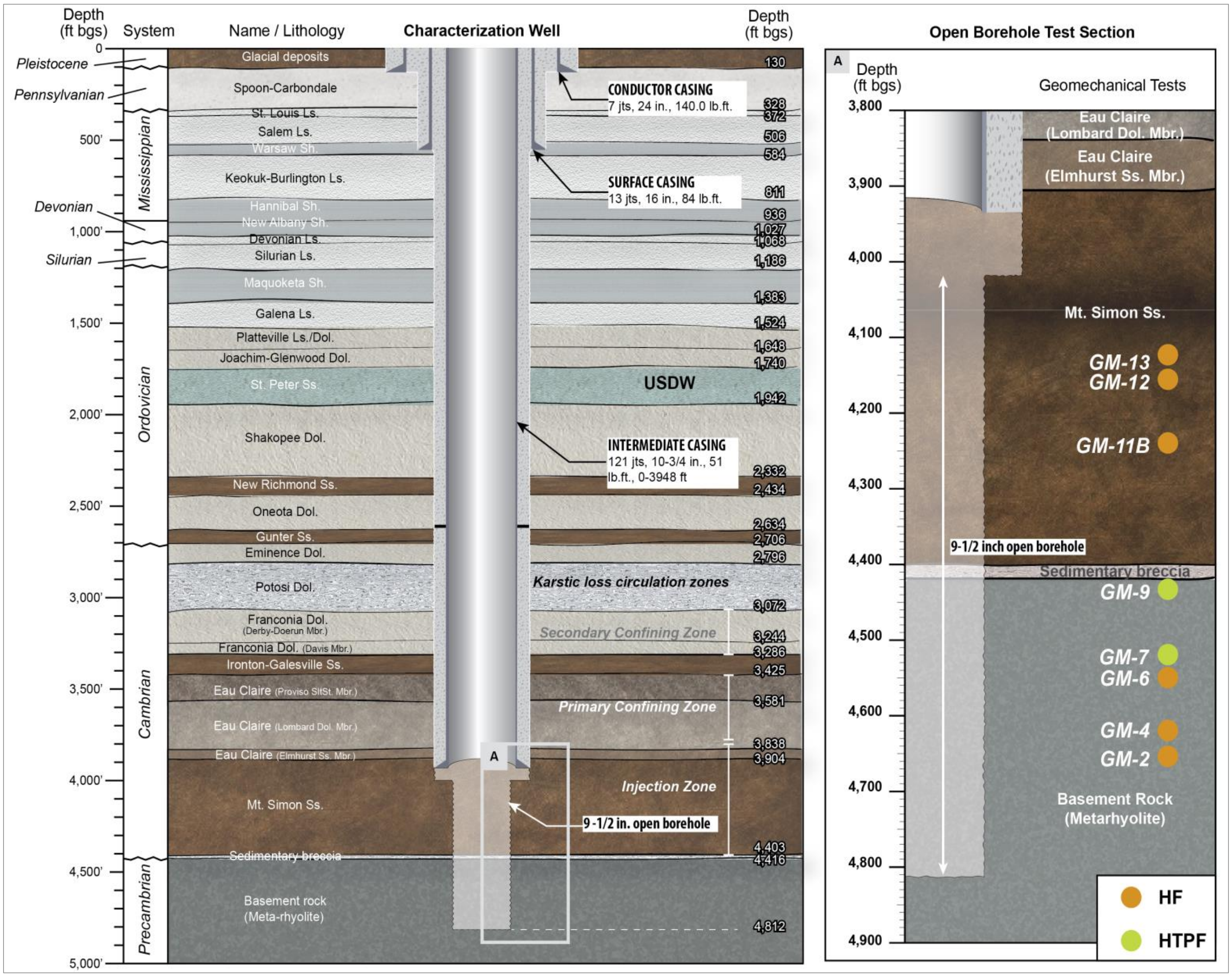


Figure 4.44. Stratigraphic Borehole FGA-1 Characterization and Geomechanical Test Intervals

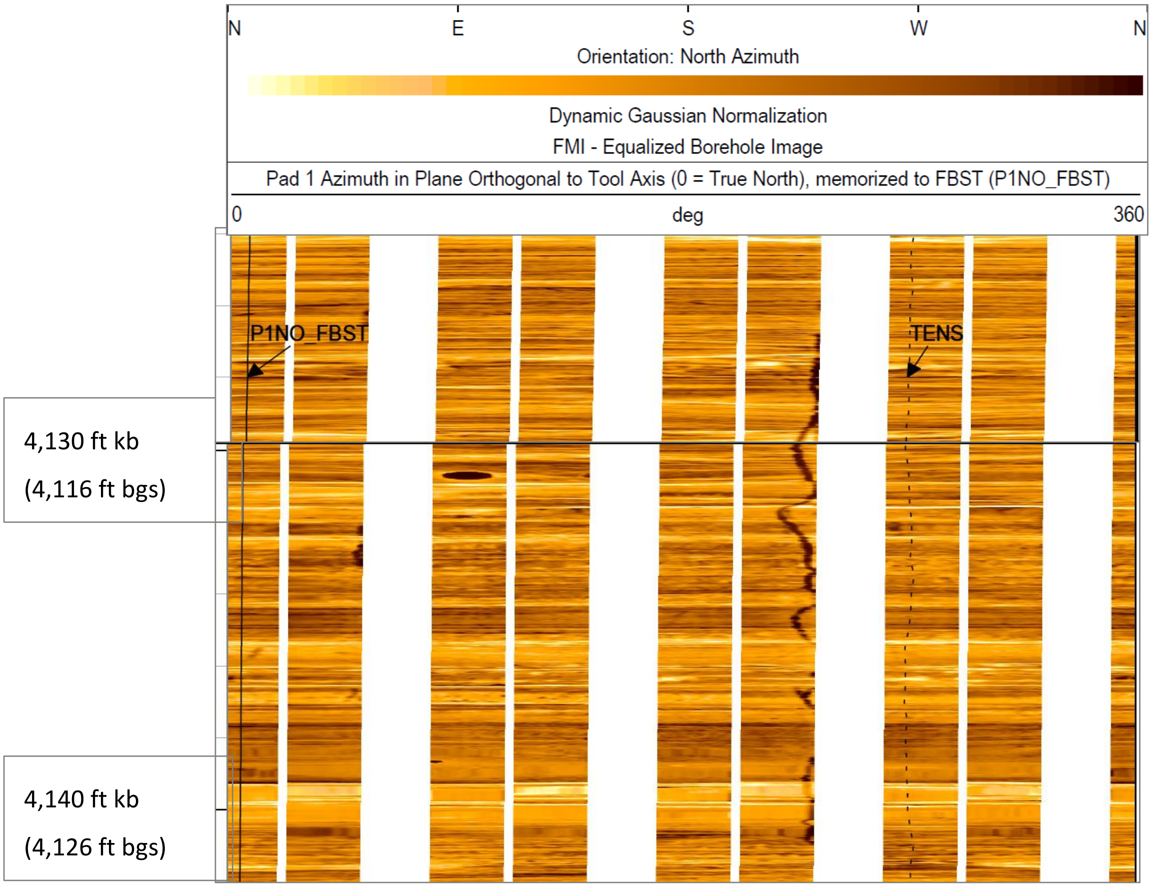


Figure 4.45. FMI Log Image of a Fracture Created in HF Test Zone GM-13 (the fracture is vertical and oriented northeast-southwest)

Results from the field geomechanical characterization program indicate that one of the principal stress directions is aligned with the vertical direction throughout the characterization depth investigated (i.e., between 4,120 and 4,655 ft bgs). The maximum horizontal principal stress direction within the Mount Simon Formation is oriented N 51± 3°E, based on a comparison between pre- and post-test electrical borehole wall imaging logs. Planned horizontal injection wells oriented parallel to this direction within the Mount Simon would be less susceptible to borehole instability during well construction. Within the underlying crystalline basement formation, images of pre-existing and newly created hydraulic fractures exhibited more complexity and indicated a small rotational azimuth aspect in comparison to the overlying Mount Simon. The observed complex basement fracture system was again consistent with a principal stress direction being vertical; but a maximum horizontal principal stress direction value N 65 ± 18°E was indicated (uncertainty for the 99% confidence level). The general maximum horizontal principal stress directional attributes were in general agreement with previously cited regional maximum horizontal stress directions (N48 ± 30°E) reported by Haimson and Doe (1983), which was obtained for the crystalline basement rock in northern Illinois at similar test-interval depths and using similar borehole characterization test methods.

The minimum principal horizontal stress magnitude, σ_h, within the Mount Simon Formation was well constrained and ranged between a value of 22.34 MPa (3,240 psi) at a depth of 4,157 ft (1,267 m), and 19.31 MPa (2,800 psi) at 4,235 ft (1,291 m). Such wide-ranging and nonlinear behaviors for the minimum horizontal stress magnitudes are likely attributable to local variations in mechanical properties within the formation, and are quite common in sedimentary formations. This fact underlines the need for multiple, in situ formation measurements of this parameter, and non-reliance on assumed, simple linear, fracture-gradient relationships. For the crystalline basement rock, σ_h varies in a more consistent manner with depth, according to the following local linear relationship:

$$\sigma_h = 26.9 + 0.022\,(z-1356) \tag{1}$$

where, σ_h is expressed in MPa, and depth, z, in m.

Based on this relationship, σ_h is less than the calculated principal vertical stress component (based on simple rock density considerations). This implies that the minimum principal stress component is likely to remain in the horizontal plane at greater depths (i.e., $\sigma_h < \sigma_v$).

The maximum horizontal principal stress magnitude, σ_H, both in the Mount Simon and in the crystalline basement rock, is less constrained and based solely on initial fracture breakdown pressure characteristics. The maximum horizontal principal stress magnitudes for both formations, however, were consistently greater than that computed for the vertical stress component. This established stress relationship ($\sigma_h < \sigma_v < \sigma_H$) is referred to as a strike-slip faulting tectonic style, and it describes the most likely failure mechanism that would occur within the Mount Simon and basement, in the presence of anomalously imposed high pore-pressure conditions.

To prevent development of instabilities (i.e., borehole deformation, fracturing, etc.) because of imposed high pore pressures, the injection pressure must remain smaller than the minimum principal stress conditions. Based on the Phase I characterization results for σ_h, and using an assumed 90% conservative weighting factor, limiting the Mount Simon reservoir pressure buildup to ≤4.86 MPa (705 psi) above static reservoir conditions during injection would likely prevent hydraulic fracturing within the reservoir and prevent significant seismic events within the crystalline basement.

4.4.5 Vertical Seismic Profiling (VSP) Program

This section summarizes the three principal phases of the 2013 FutureGen 2.0 CO_2 storage VSP program: (1) the data-acquisition phase, (2) the data-processing phase, and (3) the data-interpretation phase. Descriptions of the VSP program are provided by Schlumberger (2013), Hardage (2013b), and Sullivan (2014). Location of the 2013 FutureGen 2.0 CO_2 storage VSP program and the 2011 FGA 2D surface seismic survey are shown in Figure 4.46. Details of the 2D seismic survey provided are in Section 4.2.2.

Reflection seismic data provide the primary technology for imaging subsurface geology between and distal to wellbores; and where rock physics properties are suitable, seismic data can provide important carbon, capture, utilization, and storage (CCUS) monitoring modalities. Seismic data also provide the subsurface framework for locating microseismic events and reducing risk of induced seismicity. Seismic data provide the most reliable geophysical imaging of the subsurface at the FutureGen 2.0 CO_2 storage site, and the high-quality VSP data acquired in this survey represent not only excellent images, but also provide a methodology and best practices for acquiring high-quality data in other parts of the western Illinois Basin as well as at other seismically difficult CCUS sites.

Modern three-component surface seismic and VSP receivers can record shear (S) wave modes that are generated at the surface or converted from P-waves in the subsurface (e.g., P-wave down to the reflector, vertically oriented Sv to the receiver). Each collected waveform can potentially produce a separate data volume and new images.

Figure 4.46. Location of Borehole VSP (Stratigraphic Borehole FGA-1) and Surface Seismic Data Acquired at the FutureGen 2.0 CO_2 Storage Site

4.4.5.1 *VSP Acquisition*

As a consequence of the review of the total reprocessed 2D seismic data and wellbore data by Battelle and outside geophysical experts in late 2012, a request for proposals for zero offset, plus walk-away or walk-around surveys, was sent to three viable seismic vendors in January 2013. After vendor selection and contract finalization with the VSP contractor, a review of soil conditions at the FutureGen 2.0 CO_2 storage site determined that off-road access for the vibroseis trucks would not be feasible within the time frame defined for Phase II supplemental characterization activities. A third survey program approach of a zero-offset VSP plus up to 16 offset VSP surveys was constructed and reviewed by Battelle, the VSP contractor, and by outside VSP and surface seismic expert Dr. Bob Hardage of the University of Texas. The acquisition and processing were highly successfully, and the results of this program show no evidence that faults traverse the Mount Simon or breach the Eau Claire Formation sealing layer (Hardage 2013b). Most of the material in this section relates to the data-processing and data-interpretation phases of the VSP project.

Borehole seismic surveys are an established method for characterizing subsurface geologic conditions, and have been a standard oilfield technology for several decades. VSP surveys are conducted by placing seismic sources at the Earth's surface and monitoring the seismic signals produced by the surface sources with an array of receivers that are placed in a borehole.

Placing seismic sensors in the borehole and locating seismic sources on the Earth's surface allow the recording of much higher frequencies than is possible when sensors are only placed on the surface. As a result of approximately twice the frequency content, resolution of subsurface features is considerably increased. In addition to recording higher frequency data, borehole seismic data typically have a higher signal-to-noise ratio.

Standard modern receivers are three-component (3C) and simultaneously measure seismic wave displacements along three orthogonal directions. Ground displacements induced by seismic waves possess orientations relative to the direction the wave propagates. Seismic waves are grouped into two major types, compressional or P-waves and shear or S-waves, each with different velocities and different propagation characteristics. Measurement of a single displacement direction can provide time and amplitude information but cannot determine the directional orientation of the seismic waves. Three-component receivers overcome this limitation and are critical to assessing mode conversion and seismic anisotropy.

The February 2013 borehole seismic program at the FutureGen 2.0 CO_2 storage site consisted of a zero-offset location and 15 offset locations (Figure 4.47). The VSP receiver well was the 4,826-ft-deep stratigraphic borehole FGA-1; the Elmhurst/ Mount Simon Sandstone storage target is between 3,852 and 4,439 ft KB, and the lower part of the well was uncased from 3,948 to 4,826 ft KB. Site access for seismic source trucks was good, with fairly level topography; but off-road acquisition was limited to winter and frozen ground conditions because of crop production.

The original VSP data-acquisition plan was to acquire walk-around VSP data at 17 source stations encircling the stratigraphic borehole FGA-1 calibration well. However, all source station locations had to be positioned on local roads because of late winter thaw conditions (Figure 4.47). For logistical reasons, data were not acquired at source stations 4 and 6.

Data acquisition was conducted at the zero-offset position and 15 of the originally designed 17 offset (OVSP) source stations with a 20-level array of 3C receivers at 15-m vertical spacing. The total number of receiver stations ranged from 89 to 40. The seismic source was generated by one vibroseis truck, and the single-sweep frequency was 6–120 Hz with 16 seconds length. The VSPs at the 15 offset source stations encircled the receiver well as a sparse walk-around VSP. The walk-around geometry generated a spoke wheel of 2D images, centered on stratigraphic borehole FGA-1. Data from stations 9, 8, 7, and 5 allowed processing as a short walk-away survey. Schlumberger Carbon Services acquired and processed the data; its final report is in Schlumberger (2013). Dr. Bob Hardage provided overview and advice during all aspects of the VSP program. His independent review of Schlumberger's processing is in Hardage (2013b).

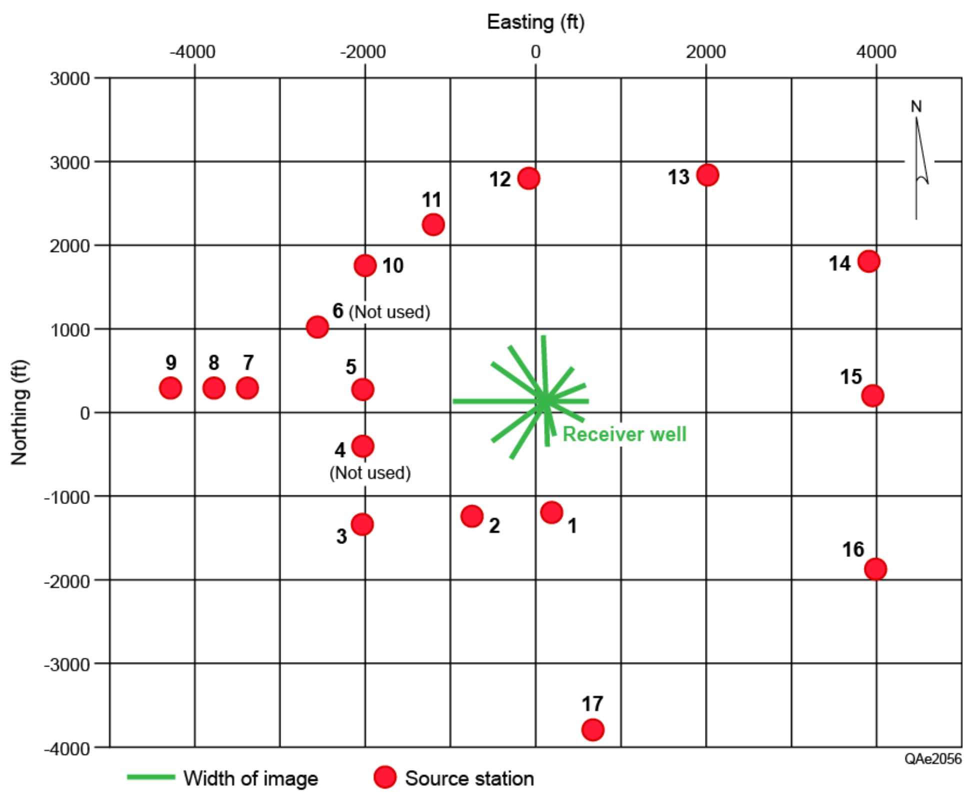


Figure 4.47. Zoom View of Walk-Around VSP Source Stations. The lateral dimensions of good-quality VSP images (Table 4.11) are indicated by the lengths of the lines in the green spoke wheel pattern centered on the stratigraphic borehole FGA-1.

The extent of the Mount Simon Sandstone that was imaged from each source offset is indicated on Figure 4.47 by the green spoke wheel pattern radiating away from stratigraphic borehole FGA-1. The widths of these VSP images are listed in Table 4.11. The highest receiver position was 75 ft below the surface. It is important for the uppermost position to be as shallow as possible, because the VSP image width increases as the height of receiver stations increase above the target. The outer edge of a VSP image is often deleted for offset stations for multiple reasons, including distortion due to limited aperture of the sensor array, velocity errors, the increasing horizontal direction of approach angles of seismic ray paths traveling from the farthest reflection points, and because of ray path refractions.

Table 4.11. Widths of VSP P-P and P-SV Images Away from the Stratigraphic Borehole FGA-1

Source station	Width of P-P image (ft)	Width of P-SV image (ft)
1	550	300
2	800	500
3	800	700
4*	Not used	Not used
5	1100 combined (Source stations 5, 7, 8 and 9)	1100 combined (Source stations 5, 7, 8 and 9)
6*		
7		
8		
9		
10	800	700
11	800	700
12	800	550
13	500	550
14	500	650
15	500	650
16	500	600
17	400	400

*Not used QAe2056(a)

4.4.5.2 *VSP Processing*

Examination of intermediate processing products helped determine depths and sources of seismic noise and attenuation of signal at the FutureGen 2.0 CO_2 storage site. This section addresses multiples, attenuation, and mode conversion. It should be noted that although surface statics were not specifically analyzed, the prominent vertical disruptions observed in the surface P-wave data are not present in the VSP data.

Primary reflection events are created at acoustic impedance boundaries by the down-going first arrival, and up-going multiples are created at these same interfaces by down-going events that arrive at later times. The multiple generators in the VSP data coincide with interfaces between shallow shales and limestones and deeper unconformities. Importantly, by adaptively subtracting the inside-corridor stack processing product (Figure 4.48) from the outside-corridor stack, a VSP multiples model can be produced for removal of multiples during processing of surface seismic surveys.

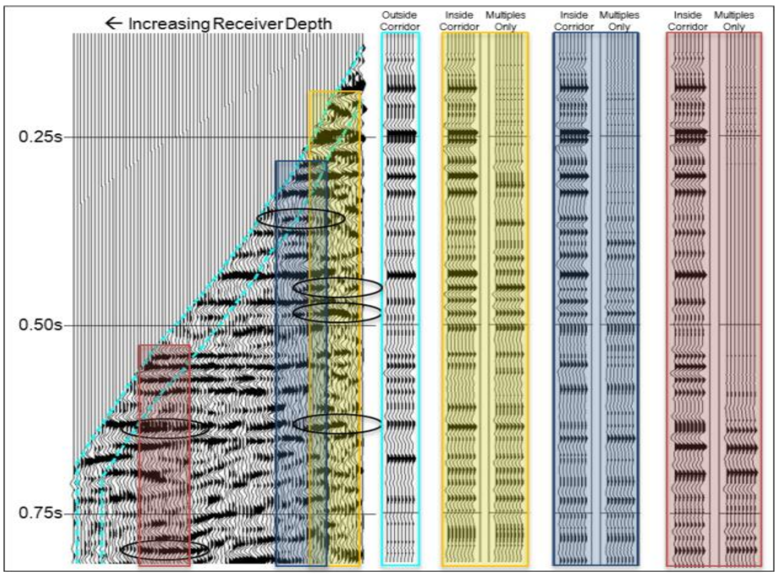


Figure 4.48. Zero-Offset VSP with Location of Sources of Interbed Multiples. This processing product allows the removal of a persistent form of noise from future surface seismic surveys.

Analysis of the losses caused by seismic attenuation in the zero-offset P-wave VSP indicated that there are two attenuating zones: within the Pennsylvanian rocks of the first 400 ft of the subsurface and near an unconformity at 1,400 ft at the top of the Galena Limestone. The Sv wavefield extracted by the 3C vector wavefield decomposition from one of the OVSPs was evaluated. The evaluation identified additional attenuation zones near unconformities at the base of the New Richmond Sandstone and at the base of the Ironton Sandstone. Surface seismic is affected twice by these features. Attenuation in the shallow Pennsylvanian section may be caused by methane associated with thin coals as well as noncommercial traces of natural gas. As expected, the P-Sv data were far less affected by attenuation.

Depth of mode conversion can be determined by analyzing the horizontal components of the zero-offset VSP and the Sv wavefield extracted by the 3C vector wavefield decomposition from the OVSPs. Within the zero-offset VSP, strong converted waves were generated from events at approximately 500 ft, 1,200 ft, the top of the St. Peter Formation, and at the Knox unconformity at the base of the St. Peter. OVSP analysis indicates mode conversion and attenuation occurred near the unconformity at the top of the Eau Claire Formation seal.

Direct-S modes can be generated at the surface by standard vertical P-wave sources (Hardage et al. 2011). The advantage of direct-S modes is that S-S images can be constructed with standard common-midpoint (CMP) rather than by specialized common-conversion-point (CCP) software required for imaging P-Sv data.

The zero-offset data, with receivers extending upward to within 75 ft of the surface, allow down-going S modes to be tracked back to point of origin. Analysis of the intermediate processing products revealed that the vertical vibrator deployed across the sequestration site was generating both direct-P and direct-S modes. Thus, future S-S imaging of the geology across the FutureGen 2.0 CO_2 storage site with a vertical vibrator is feasible.

Shear-wave splitting analysis indicated moderate anisotropy, but the low number of offset stations and the large angles between the offset VSPs precluded robust analysis with this survey. An analysis of the surface-generated fast shear-wave data indicated the azimuth of maximum horizontal stress to be N65E for the overburden, which is comparable to the azimuth independently determined from full waveform sonic log data and separately from induced tensile fracture data in wellbore image logs.

Velocity models were constructed from the data and include a flat layer model generated from the zero-offset data, and 2.5 D velocity models, one for each offset station, with anisotropy that best fits data from each station. Velocity pull-ups in P-Sv images compared with P-wave images for identical stations indicate that additional removal of anomalous frequencies and modeling of the velocity field are still required to reproduce the correct velocity field for the site. VSP velocity data provide critical input for building 3D velocity models that are essential for microseismic monitoring of injection operations.

4.4.5.3 *Seismic Images*

The offset VSPs at the FutureGen 2.0 CO_2 storage site produced 2D seismic images that extend from 400 to 800 ft away from the receiver well. The processed VSP data indicate no resolvable faults and no vertical seismic anomalies. As expected, both P-P and P-Sv data produced images of the Eau Claire seal and Mount Simon reservoir that had a higher frequency content and higher resolution than was present in the surface 2D P-wave data. In addition to imaging six reflectors within the Elmhurst- Mount Simon interval, a velocity contrast at the base of the proposed injection zone was well imaged and easily mapped in both P-P (Figure 4.49) and P-Sv data sets. Importantly, the P-Sv VSP images had greater reflection strength, displayed less attenuation, and were of higher resolution than the P-P images (Figure 4.50).

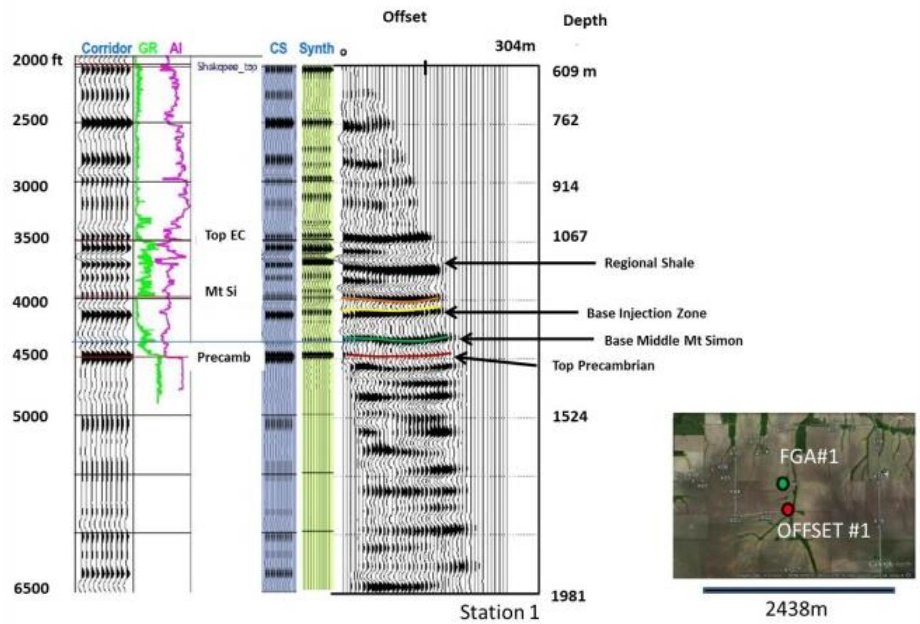


Figure 4.49. VSP P-Wave Details of the Mount Simon Geology, Along with the Corridor Stack, Gamma Ray, Acoustic Impedance, and P-Wave Synthetic

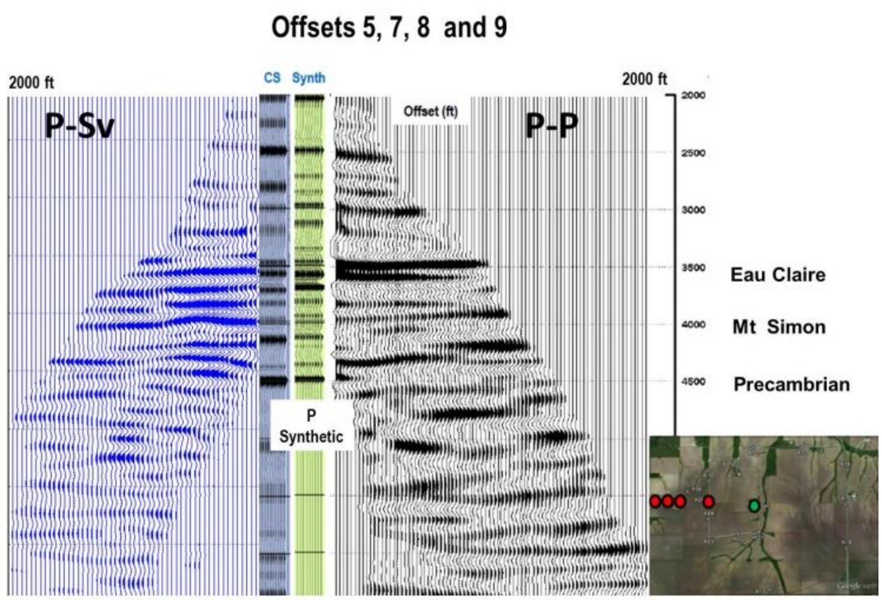


Figure 4.50. Comparison of P-P and P-Sv Images for Combined Offset Stations 5, 7, 8, and 9, Along with the Corridor Stack and the P-wave Synthetic. Note the greater number of reflectors in the Eau Claire Formation interval. Slight pull-ups in the P-Sv image compared to the P-P image indicate that high-frequency shear multiples may still be present and that the P-Sv velocity model can be improved.

Images produced by interferometric migration of the VSP direct wave are less sensitive to velocity estimation and static errors (Wapenaar et al. 2010). An example of interferometric processing of the P-wave and P-Sv data (Paulsson 2014) is shown in Figure 4.51. Again the P-Sv image has an increased number of reflectors for a given interval within the sedimentary section.

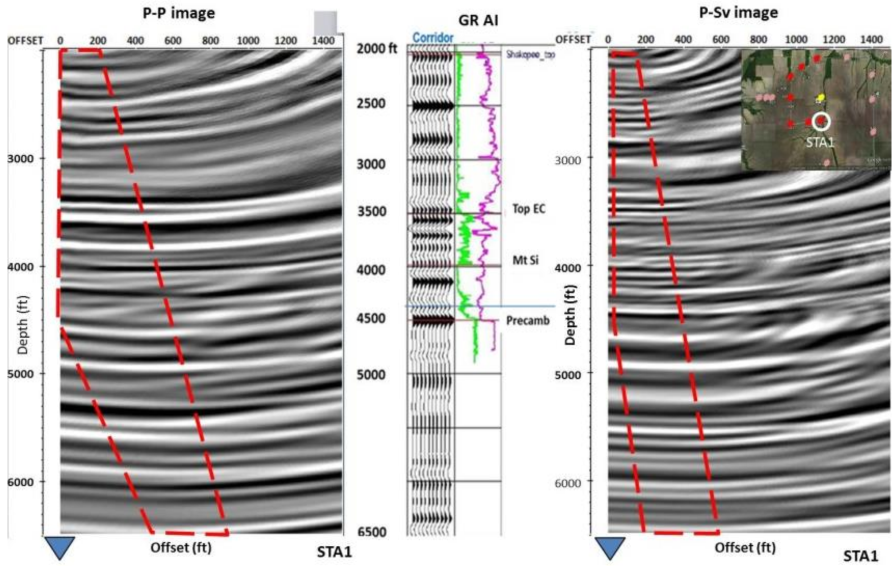


Figure 4.51. Comparison of P-P and P-Sv Wave Interferometric Direct Wave Migration for Offset Station 1. Note the increased number of reflectors above and in the Eau Claire Formation interval of the P-Sv data. The red dashed outline shows the area for interpretation.

4.5 Local Site Geology and Conceptual Model

The geologic properties of the FutureGen 2.0 CO_2 storage site provide critical input for developing a conceptual model of the site. The conceptual model is a fundamental part of the four UIC Class VI Permits awarded by the U.S. Environmental Protection Agency (EPA) to the Alliance for the construction and operation of up to four CO_2 injection wells. This section provides site-specific information about the St. Peter Sandstone Formation,(which is the lowest federally designated USDW); the Franconia/Davis secondary and Eau Claire primary confining zones; the Ironton/Galesville saline aquifer above the Eau Claire Formation; the Elmhurst/Mount Simon injection/storage zone; and the Precambrian basement rock which is the lower confining zone. Additional information about the geology of the FutureGen 2.0 CO_2 storage site is provided in Section 4.2.2 (seismic data) and in Chapter 2 of the Alliance Supporting Documentation report (2013); numerical modeling of the storage interval and confining zones is reviewed in Section 4.5. Unless specified, all depths are given in feet below the Kelly Bushing datum, which is 14 ft above ground level.

4.5.1 Stratigraphy

The subsurface lithostratigraphic units, as recognized in stratigraphic borehole FGA-1, are shown in Figure 4.52 and in Table 4.12, and are described in detail by Kelley et al. (2012a and b). This section briefly reviews the general stratigraphy of the FutureGen 2.0 CO_2 storage site.

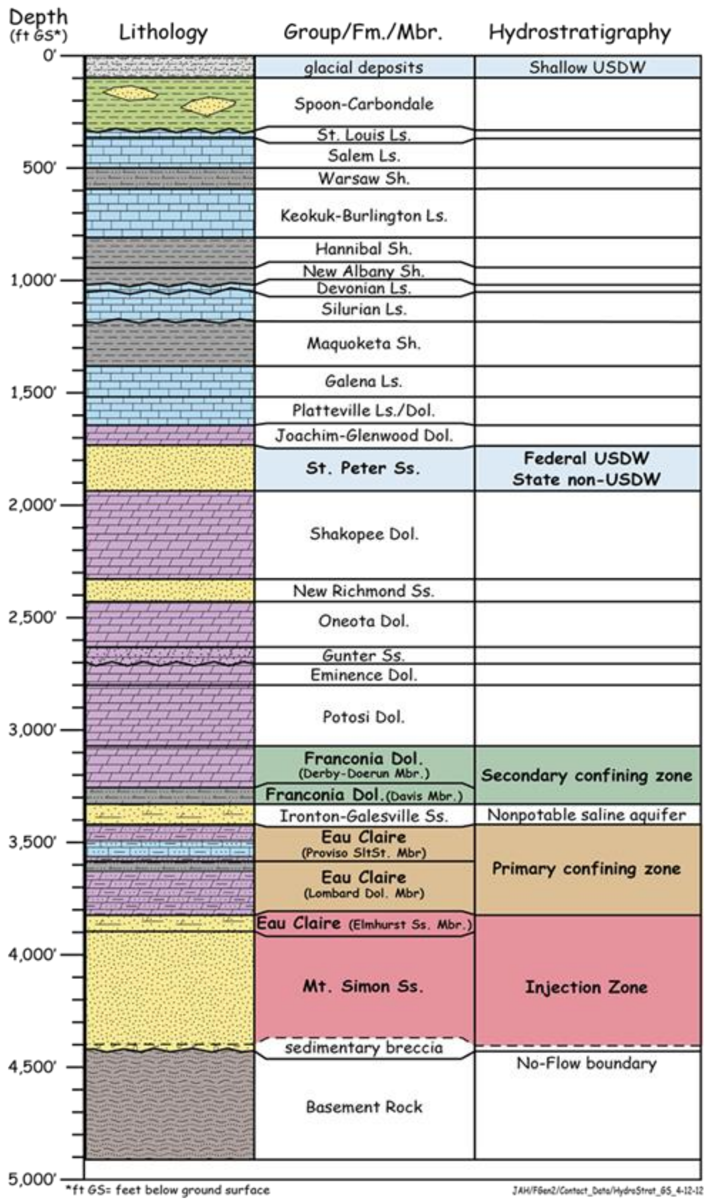


Figure 4.52. Stratigraphy of the Subsurface Units at the Stratigraphic Borehole FGA-1 in Morgan County. Depths are shown in feet below ground surface.

Table 4.12. Stratigraphic Units in the Stratigraphic Borehole FGA-1. Depths are shown in ft below ground surface, and depth below Kelly Bushing, which is 14 ft above ground level.

Formation Name	Age	Thickness (ft)	Top Depth (ft bgs)	Top Depth (ft KB)
Pennsylvanian Undifferentiated	Pennsylvanian	198	130	144
St. Louis Limestone	Mississippian	44	328	342
Salem Limestone	Mississippian	134	372	386
Warsaw (Borden) Siltstone/Shale	Mississippian	78	506	520
Keokuk/Burlington Siltstone	Mississippian	227	584	598
Hannibal (Osage) Shale	Mississippian	125	811	825
New Albany Shale	Devonian	91	936	950
Devonian Limestone	Devonian	41	1,027	1,041
Silurian Limestone	Silurian	118	1,068	1,082
Maquoketa Shale	Ordovician	197	1,186	1,200
Trenton/Galena Limestone	Ordovician	141	1,383	1,397
Platteville Limestone	Ordovician	124	1,524	1,538
Joachim Limestone	Ordovician	69	1,648	1,662
Glenwood Dolomite	Ordovician	23	1,717	1,731
St. Peter Sandstone	Ordovician	202	1,740	1,754
Shakopee Dolomite (Knox)	Ordovician	390	1,942	1,956
New Richmond Sandstone	Ordovician	102	2,332	2,346
Oneota Dolomite	Ordovician	200	2,434	2,448
Gunter Dolomite/Sandstone	Ordovician	72	2,634	2,648
Eminence Dolomite	Cambrian	90	2,706	2,720
Potosi Dolomite	Cambrian	276	2,796	2,810
Franconia Dolomite	Cambrian	172	3,072	3,086
Davis Dolomite	Cambrian	72	3,244	3,258
Ironton Sandstone/Dolomite	Cambrian	109	3,386	3,330
Eau Claire Carbonate/Siltstone (Proviso)	Cambrian	156	3,425	3,439
Eau Claire Siltstone/Shale (Lombard)	Cambrian	257	3,581	3,595
Eau Claire (Elmhurst)	Cambrian	66	3,838	3,852
Mount. Simon Sandstone	Cambrian	499	3,904	3,918
Conglomerate	Cambrian	13	4,403	4,417
Basement	Precambrian	396	4,416	4,430
Total Drill Depth			4,812	4,826

Interpretation of formation tops that were picked in stratigraphic borehole FGA-1 well are based on correlation with wells in the ISGS database as well as comparison of the well cuttings with lithologies in driller logs and published descriptions.

Regional changes in stratigraphy are illustrated in diagrammatic cross sections in Figure 4.53 and Figure 4.54. Note that eastward thickening of the stratigraphy reflects two periods of basin subsidence: during development of the proto-Illinois (or Mount Simon) Basin with greatest thickness of sediment accumulation in the northeastern part of the greater Illinois Basin and during Ordovician-Pennsylvanian basin subsidence with greatest sediment accumulation in southern Illinois.

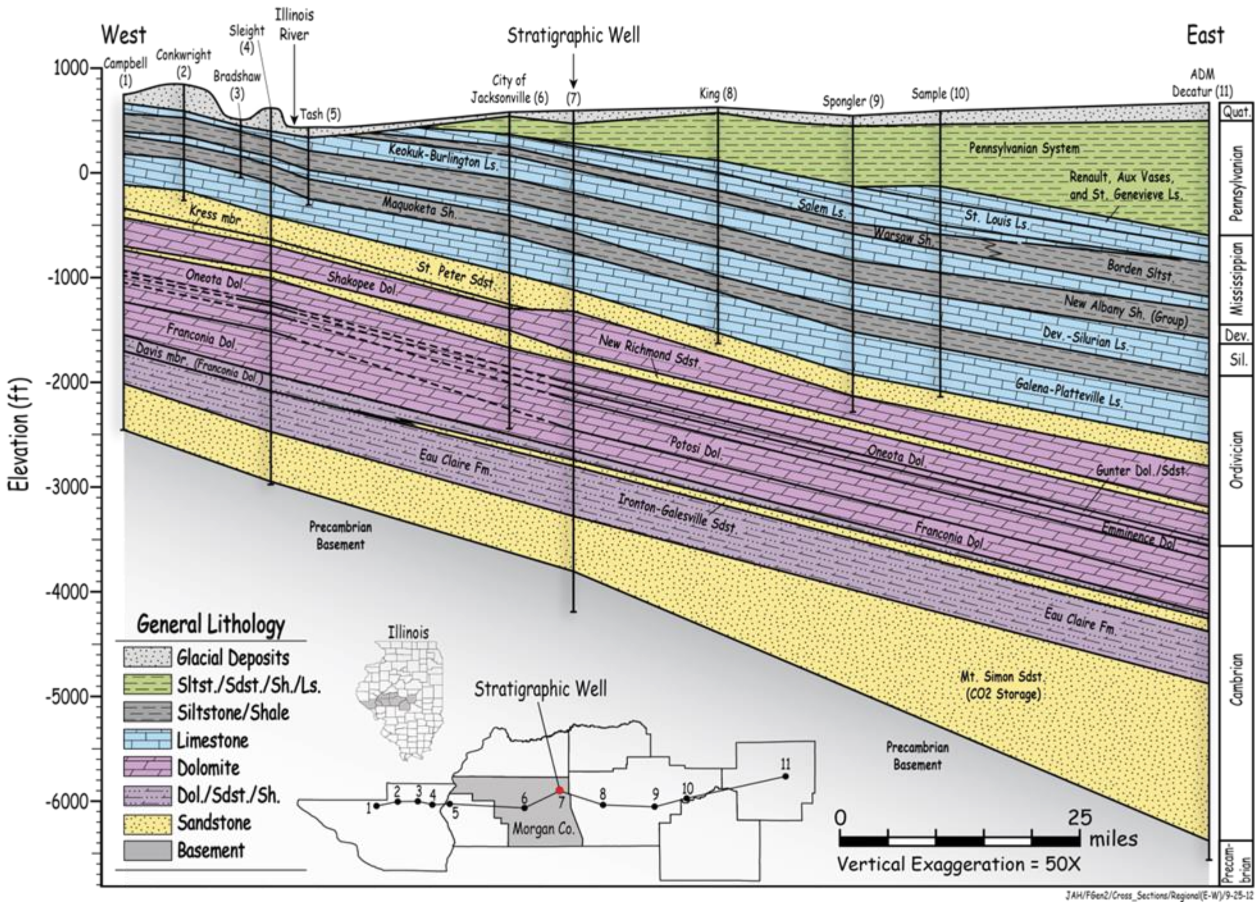


Figure 4.53. Relation of the Stratigraphic Borehole FGA-1 to Regional East-West Geology of Western Illinois. Note increase in Mount Simon thickness east of the FGA-1 well.

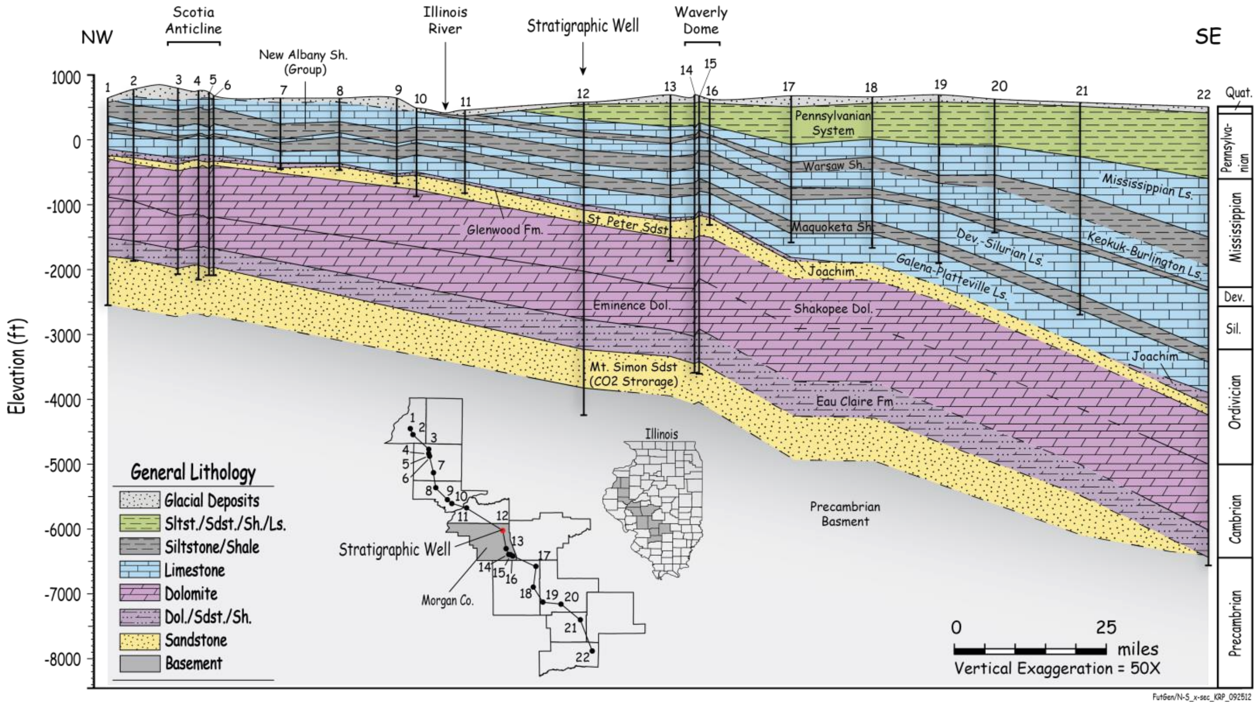


Figure 4.54. Relation of the Stratigraphic Borehole FGA-1 to the Less-Constrained Regional North-South Geology. Note that the Waverly Dome wells are the only other Mount Simon penetrations in Morgan County.

4.5.2 Geologic Structure

Geologic structure greatly influences the seal integrity, reservoir continuity, and stability or migration of an injected CO_2 plume. This section briefly reviews regional and FutureGen site-specific structural data. Additional site-specific structural information as determined from 2D seismic data is provided in Section 4.2; gravity data are discussed in Section 4.2.1. Site-specific geomechanical data are discussed in Section 4.4.

The principal geologic structure near Morgan County is the very broad Sangamon Arch (see Section 4.1). Within northeastern Morgan County, there are no mapped faults and no known karst or fracture systems associated with the Sangamon Arch (Whiting and Stevenson 1965; Kolata and Nelson 1991). The 15 miles of 2D seismic data acquired along state and county roads at the FutureGen 2.0 CO_2 storage site did not show any features that could be large vertical faults (Hardage 2013a; McBride in Sullivan 2013); and the 2013 VSP data did not distinguish any faults within its near-well (400–800 ft) area of investigation (Hardage 2013b). In addition McBride (in Sullivan 2013) concluded there are no large throw faults in the regional ISGS Knox line (ISGS 2013) that could be projected into the FutureGen 2.0 CO_2 storage site (see Section 4.2 for location of the ISGS line).

Structural attitude strongly controls the stability or migration of an injected CO_2 plume. Geophysical well logs provided considerable structural data for features intersected by the borehole. Resistivity-based image logs allowed calculation of structural strike and dip of beds and fractures in the rock face of the wellbore. In particular, structural dip over the Mount Simon interval is low, with a mean of 1.8° N67E. The mean structural dip of the overburden is 1.1° at an azimuth of N111E.

Image log and whole-core data indicate that there are very few open or conductive natural fractures in the Mount Simon and overlying primary and secondary seals. The azimuth of maximum horizontal stress in the Mount Simon is N65E as determined by induced tensile fractures in the FMI resistivity-based image log, and confirmed by the azimuth of fast shear wave as determined by the full waveform sonic log (Sullivan et al. 2013). These state-of-stress data are supplemented by the 2013–2014 borehole-based field geomechanical testing program (Section 4.4). Analysis of the hydraulic fracturing “minifrac” data allowed determination that the fault regime is strike slip, meaning that slip on undetected faults would likely have this sense of motion.

The Schlumberger fracture analysis (StrucView) log summarizes faults and folds in a pseudo-cross section of the well. This log indicates that no macro faults are present in the wellbore: neither in the reservoir, seal, overburden, nor in the 300 ft of penetrated basement rock. “Micro faults” (conjugate fracture sets or fractures that indicate minor shear slip) occur at four depths in the shallow section of the borehole: at 1,120, 1,179, and 1,572 ft KB (Figure 4.55), and one set in the Precambrian basement. Healed conjugate shear fractures occur above the St. Peter Formation at 1,749 ft KB (Figure 4.56). No “micro faults” occur in the secondary seal, in the Eau Claire or in the Mount Simon Formations. The strikes of the “micro faults” in the Platteville and Precambrian basement are very similar and are shown in Figure 4.57. Additional structural discussion is provided by Sullivan et al. (2013).

Basement structure and topographic relief can greatly influence operational reservoir and plume behavior. All of the stratigraphic borehole FGA-1 wireline borehole data are consistent with low topographic relief on the basement at the well site. The presence of cobble-sized, very angular meta-rhyolite clasts in a 16-ft conglomerate interval immediately above the basement was captured in core and in image logs (Figure 4.58) and is interpreted to be basal Mount Simon channel and alluvial fan deposition proximal to a low-relief outcrop of Precambrian meta-rhyolite. The sedimentary dip changes uphole from west to east and northeast after only 16 ft of conglomerate deposition and suggests deposition adjacent to a low-relief basement outcrop, rather than deposition in a large alluvial fan adjacent to a high-relief feature. Mineralogical and sedimentological characteristics of the matrix of the conglomerate support that the angular meta-rhyolite clasts are not indicative of a fault (see core description by Core Laboratories [2012]).

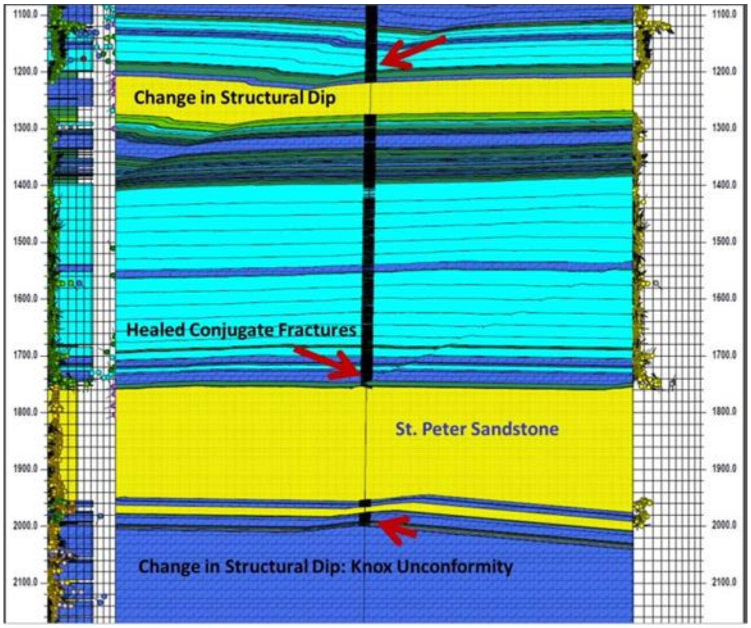


Figure 4.55. Segment of Schlumberger Structural Analysis Pseudo-Cross-Section Log. This log indicates “micro faults” or conjugate shear fractures in the shallow overburden at 1,120 and 1,179 ft KB, and one set at the top of the St. Peter Formation. No macro faults or “micro faults” are present in the Knox carbonates, the Eau Claire, or the Mount Simon.

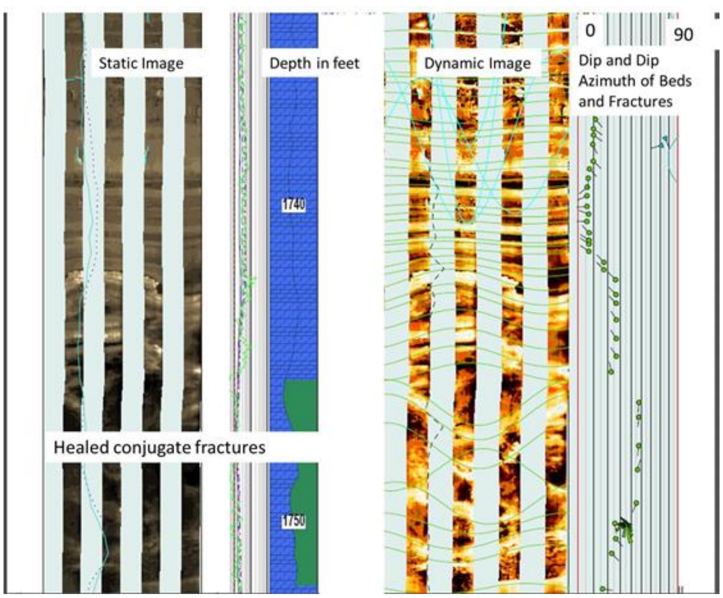


Figure 4.56. Healed Conjugate Fractures above the St. Peter Formation at 1,745 ft KB

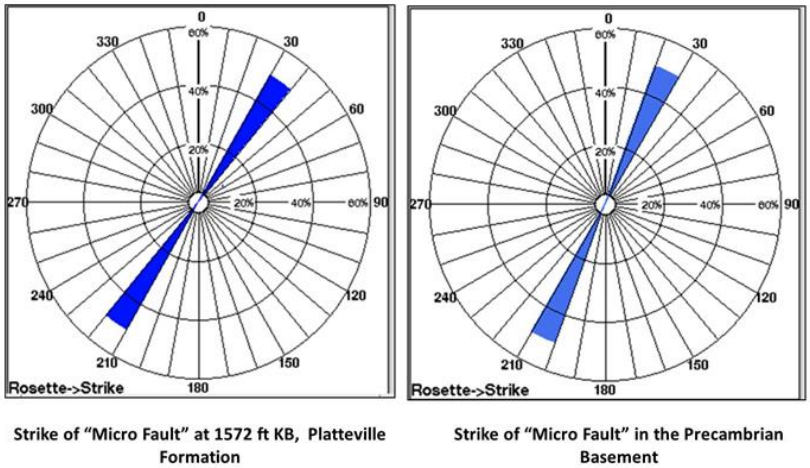


Figure 4.57. Strike Azimuth of One "Micro Fault" in the Platteville Formation (Left) and One in the Precambrian Basement (Right)

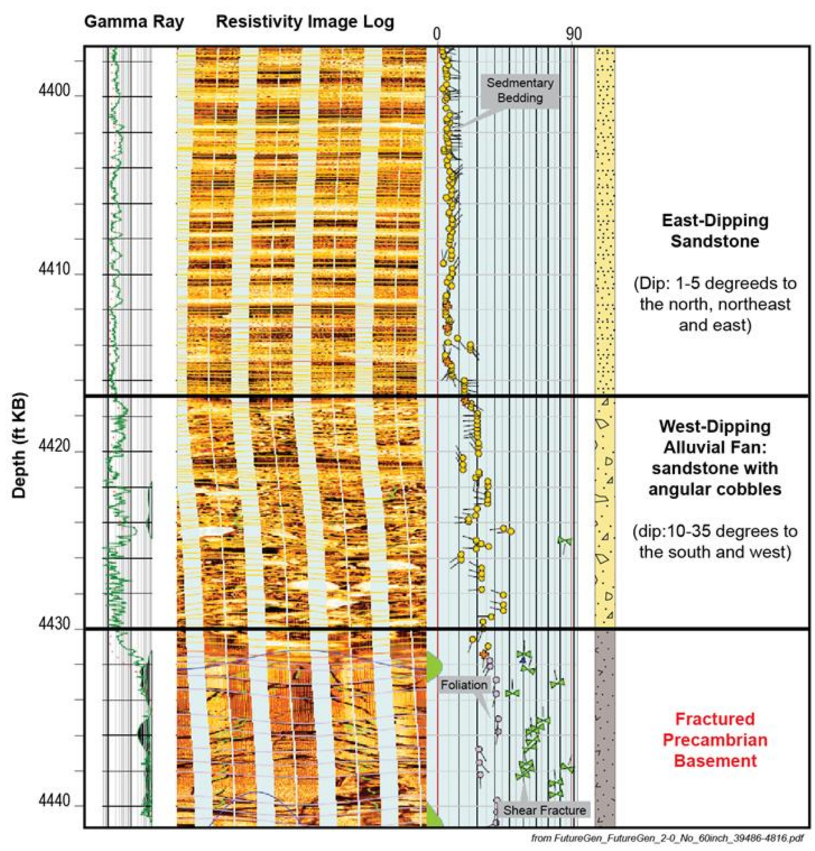


Figure 4.58. Interpreted FMI Image Log of Mount Simon Cobble Conglomerate Overlying the Precambrian Basement in Stratigraphic Borehole FGA-1. Depth is in feet below the Kelly Bushing, which is 14 ft above ground level.

The wellbore structural dip data, together with new high-resolution VSP seismic sections that radially image 400–800 ft away from stratigraphic borehole FGA-1, do not indicate the presence of either a localized basement topographic high or fault block high at the well site. No faults are present within any of the short seismic cross sections generated by the 15 offset VSPs (Hardage 2013b). Wellbore data are compatible with regional mapping and interpretation that the site is located on a low-relief margin of the deeper Cambrian age basin to the east. This low-relief, basin flank interpretation is supported by 15 miles of 2D surface seismic data and by regional and site-specific gravity surveys (Section 4.2).

Growth faults are self-healing slumps that are active at time of deposition, and are often associated with areas where basin margins become steeper. A small basement-involved Mount Simon growth fault is interpreted near the eastern end of the FGA east-west seismic 2D line outside of the projected plume; larger Mount Simon growth faults are also interpreted on the regional ISGS Knox 2D regional seismic line about 10 miles northeast of the FutureGen 2.0 CO_2 storage site (Sullivan 2013). All of these interpreted growth faults appear to coincide with increased eastward thickening of the Mount Simon Formation (Figure 4.59).

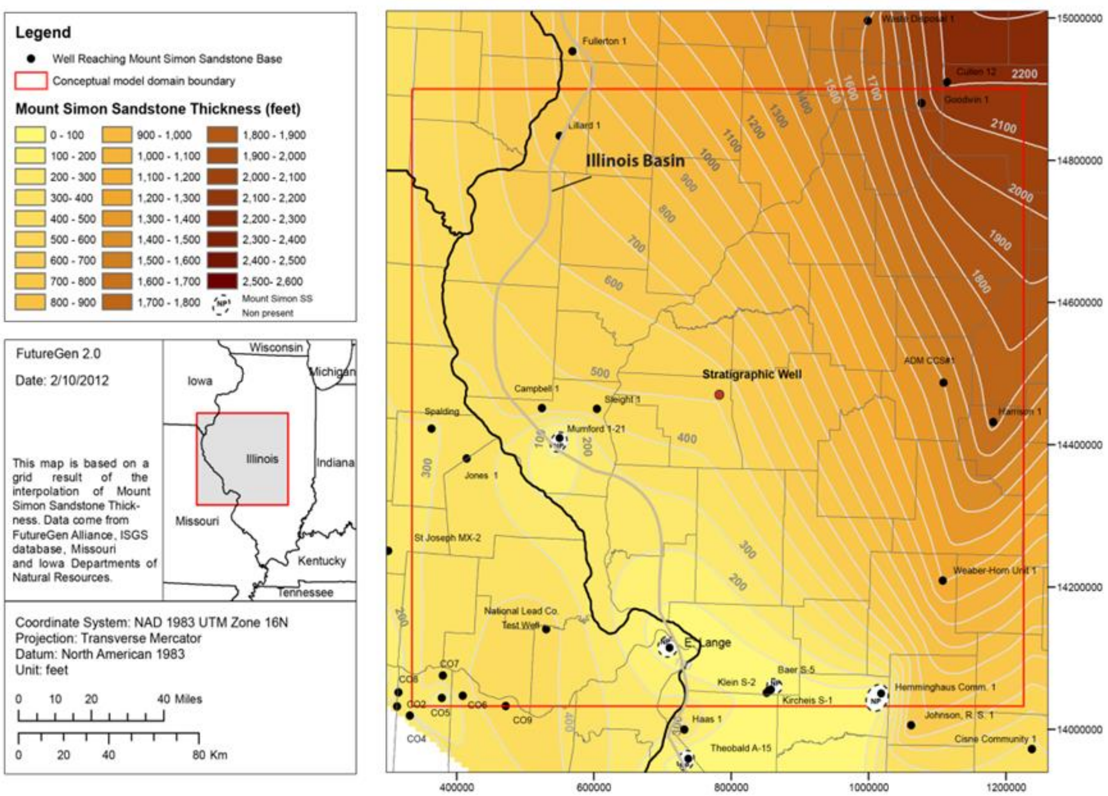


Figure 4.59. Regional Mount Simon Thickness Map Indicating a Low-Relief Western Basin Margin Flank Location for the Storage Site. White areas represent areas of non-deposition over basement paleotopographic highs.

4.5.2.1 *St. Peter Sandstone USDW*

In Illinois, the federally designated St. Peter Sandstone USDW is an unusually pure, uniformly rounded, and sorted quartz sandstone that grades south of Illinois into sandy carbonates. The St. Peter is approximately 210 ft thick in the FGA-1. In drill cuttings, the unit consists of clear to slightly frosted, well sorted, and rounded to sub-rounded, medium- to coarse-grained and poorly consolidated sandstone in the upper third of the section with relatively high porosity (20%). The St. Peter is more cemented with lower porosity (10–12%) toward the base of the section, with minor presence of pyrite. The presence of clay coatings on sand grains helps preserve original depositional porosity in the upper part of the section. Two rotary SWCs were recovered out of four attempts in the St. Peter. Mudlog gas shows were very low: no chromatograph gas show was recorded above 8 units through the St. Peter.

In the youngest part, the St. Peter thickens into a broad east-northeast belt of thick and permeable off-shore marine bar sands (termed the Starved Rock lithofacies by Willman et al. [1975]). This marine bar system pinches out northwest and southeast, and subdivides the entire Ordovician Illinois Basin into two sub-basins, where poorly sorted sandstones, shaley dolomites, and shale of the Glenwood Formation accumulated to the northwest, and more carbonate-dominated lithologies of the Dutchtown and Joachim were deposited in the southern sub-basin (Willman et al. 1975). Wireline log signatures and rock cuttings indicate that both northern basin Glenwood Formation and southern basin Joachim Formation are present above the St. Peter in stratigraphic borehole FGA-1, suggesting proximity to the linear bar sandstones of the Starved Rock lithofacies. The upper part of the St. Peter near Quincy (see Willman et al. 1975) and at the FutureGen 2.0 CO_2 storage site appears to be at the southern edge of the Starved Rock lithofacies. Importantly, the St. Peter at stratigraphic borehole FGA-1 could be in communication with this narrow but laterally extensive northeast trending belt of highly permeable sandstones.

4.5.2.2 *Franconia Secondary Confining Zone*

The combined 244-ft (74-m) interval of the Cambrian Franconia Dolomite Formation (Figure 4.60) forms a secondary confining zone for the Mount Simon and Elmhurst injection zones. The Franconia lithology, as observed in well cuttings, is dominated by tan to light brown, microcrystalline dolomite. Dolomite in cuttings from the upper part of the Franconia contains minor amounts of fine-grained, clear, and sub-rounded quartz sand. The lower part of the Franconia is slightly pyritic and glauconitic, cream to light brown, microcrystalline dolomite with scattered grains of clear, sub-rounded quartz sand.

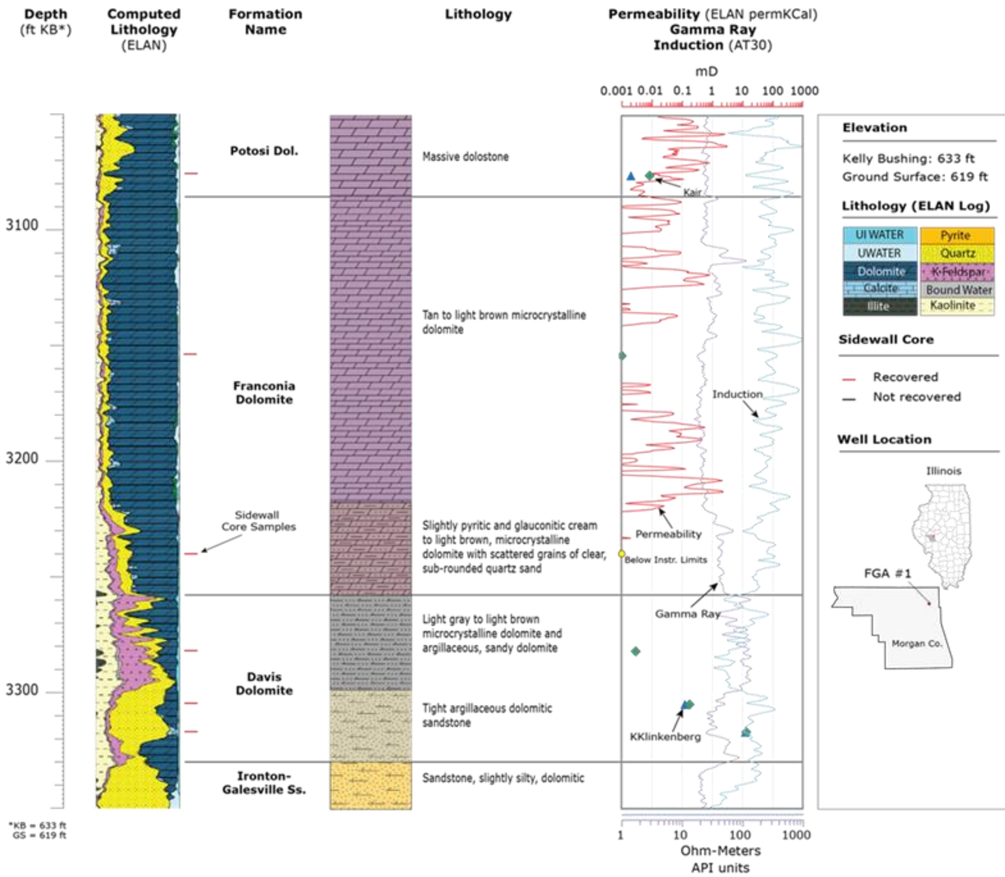


Figure 4.60. ELAN Wireline Permeabilities and Lithologies in the Franconia-Davis Secondary Confining Zone. Locations of rotary SWCs are indicated on lithology log; depths are measured from the Kelly bushing, which is 14 ft above ground surface.

The underlying Davis Member in stratigraphic borehole FGA-1 is low-permeability, light gray to light brown, microcrystalline dolomite and argillaceous (shaley), sandy dolomite. The lowermost part of the unit is a low-permeability dolomitic sandstone that marks the upward transition from the Ironton Sandstone Formation. The Davis Member dolomites laterally and regionally grade into low-permeability shales (Willman et al. 1975).

The ELAN computed logs (see Section 4.4.1 for explanation of ELAN headers) indicate that effective porosities (total porosity minus shale effect or clay-bound water) in the Franconia range from <0.01 to 7 percent, with an average of 3 percent; effective porosities in the Davis interval range from <0.01 to 3 percent, with an average of 0.1 percent in the upper part of the Davis, and an average effective porosity of 0.79 percent in the lower part of the unit.

Computed ELAN logs indicate that permeabilities are generally below the wireline tool limit of 0.01 mD throughout the secondary confining zone (Figure 4.60). Two rotary SWCs were cut in the Franconia, and three SWCs were cut in the Davis Member. Laboratory-measured rotary

SWC (horizontal) permeabilities (Table 4.13) were very low (0.001−0.000005 mD). A relatively high porosity (7.8 percent porosity and 12.5-mD permeability) value was recorded for one Davis SWC. This appears to represent an isolated thin (less than 1 ft) sand stringer within the lower Davis Member.

Table 4.13. Rotary Sidewall Core Permeabilities from the Secondary Confining Zone. Depths are in ft below Kelly bushing.

Formation	Depth (ft KB)	Horizontal Permeability (mD)
Franconia Dolomite	3,126	<0.000005
Franconia Dolomite	3,212	0.000006
Davis	3,254	0.001
Davis	3,277	0.125
Davis	3,289	12.5

Vertical core plugs are generally used for directly determining vertical permeability, and there are no vertical plug samples from stratigraphic borehole FGA-1 for determining vertical permeability or for determining vertical permeability anisotropy in the secondary confining zone. However, Kv/Kh ratios of 0.007 have been reported elsewhere for similar Paleozoic carbonates (Saller et al. 2004).

4.5.2.3 *Ironton-Galesville Sandstone*

The first bedrock aquifer above the Eau Claire Formation confining zone in Morgan County is the Cambrian Ironton-Galesville Sandstone. Although the Ironton-Galesville Sandstone serves as a water source in northern Illinois where it may reach a thickness of 200 ft (Buschbach and Bond 1974; Willman et al. 1975), it is not used as a water-supply source in Morgan or surrounding counties. Regionally, this aquifer system includes two separate lithostratigraphic formations—the Galesville and Ironton Formations; the former sandy dolomite is separated in some localities from the overlying dolomitic Ironton Sandstone by a minor unconformity (Willman et al. 1975). Within stratigraphic borehole FGA-1, the top of the Ironton-Galesville Sandstone occurs at a depth of 3,300 ft KB and is139 ft thick. The entire interval, except for the lowermost 15 ft and the uppermost 10 ft consists of non-dolomitic sandstone.

No fluid samples were collected from the Ironton/Galesville interval. Calculated salinities, however, based on wireline resistivity survey results and observed temperature conditions indicate an average salinity concentration of approximately 15,000 mg/L in stratigraphic borehole FGA-1. Similar calculations based on wireline log response results for the Mount Simon Sandstone indicate an average salinity concentration of about 52,000 mg/L, which compares well to a laboratory-measured TDS value of ~47,500 mg/L. This difference in calculated salinity concentration between the Ironton and Mount Simon Sandstones supports regional information that the intervening Eau Claire Formation acts as a hydrologic barrier above the combined Elmhurst/Mount Simon injection zone.

Porosity in the Ironton/Galesville Sandstones continues as far south as the Waverly field (Figure 4.61), about 15 miles south of the FutureGen 2.0 CO_2 storage site. It is important to note that the wireline log of the Ironton/Galesville interval has a higher gamma-ray signature, appears to be more shaley, and appears to lose porosity in the Sleight N#1, about 34 miles west in Pike County (Figure 4.62). Thus, considerable uncertainty is associated with the westward extent of clean, porous sandstone in this important monitoring unit.

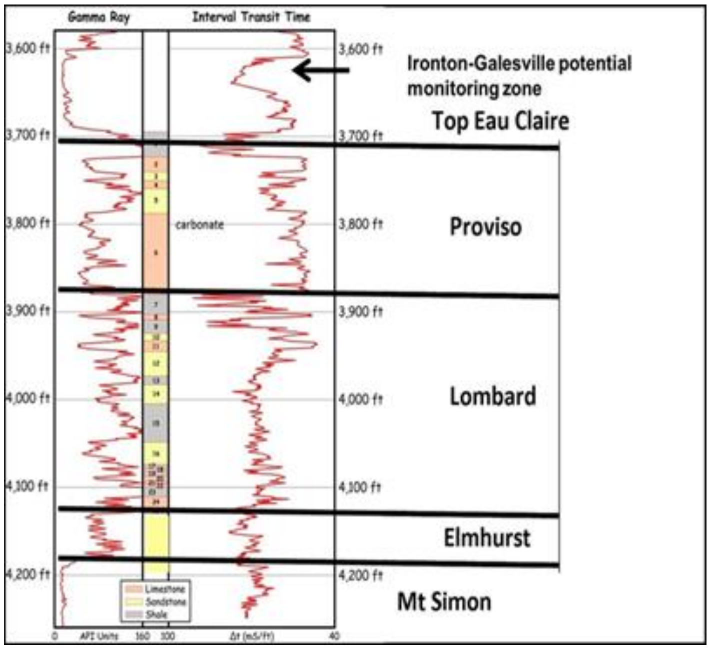


Figure 4.61. Sonic Porosity in the Ironton-Galesville Formation of the Criswell 1–16 Well in the Waverly Field. This well is about 15 miles south of the FutureGen 2.0 CO_2 Storage Site. The wireline log signatures provide important confirmation of the southward extent of the porous monitoring zone.

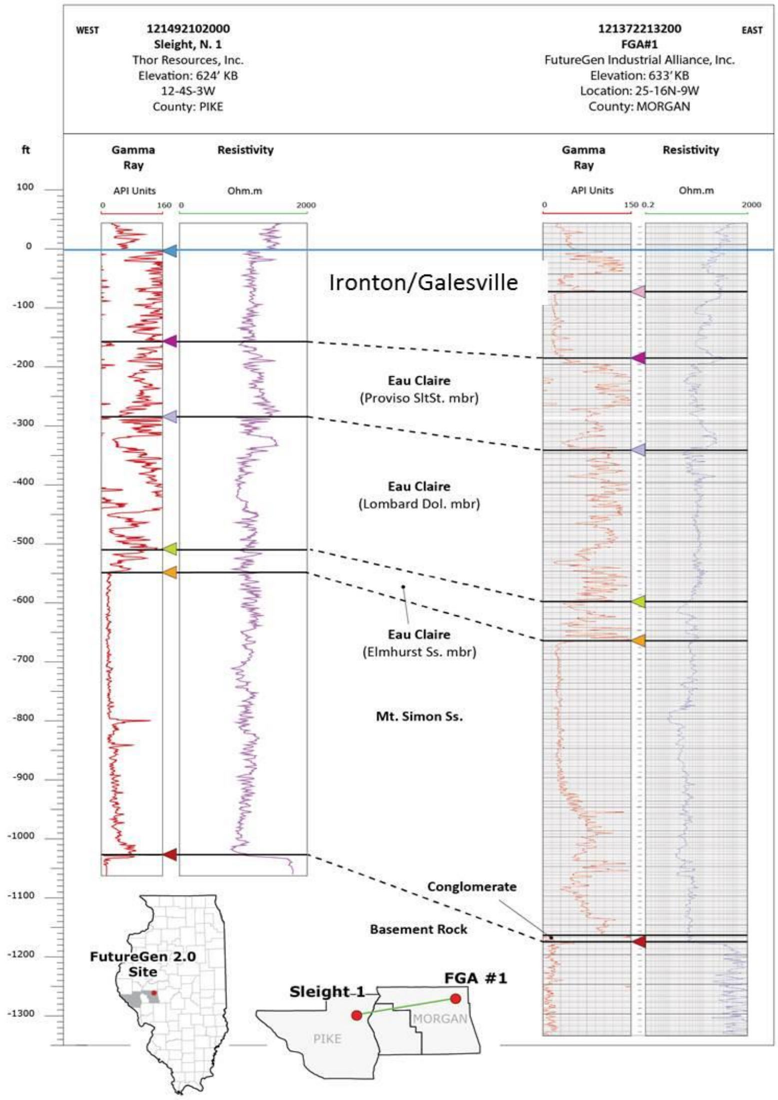


Figure 4.62. Change in Wireline Gamma Ray and Resistivity Signatures of the Ironton/Galesville Formation from the Stratigraphic Borehole FGA-1 Site Westward to the Sleight N#1 well in Pike County. The higher gamma ray signature in the Sleight N#1 well indicates a westward loss of sandstone suitable for monitoring. Distance between the two wells is 34 miles.

4.5.2.4 *Proviso and Lombard Confining Zone*

The Proviso and Lombard Members of the Eau Claire Formation form the primary confining zone for the FutureGen 2.0 CO_2 storage site, and regionally provide upper confinement at 38 natural-gas storage reservoirs in Illinois (Buschbach and Bond 1974; Morse and Leetaru 2005).

The combined thickness of these strata is 413 ft at stratigraphic borehole FGA-1. Eighty feet of whole core were obtained in the Lombard Member of the Eau Claire Formation, along with 13 rotary SWCs. In addition, 10 rotary SWCs were collected in the Proviso Member.

Rock cuttings and rotary SWCs lithologies from the upper Proviso Member include tan to light brown, dense, occasionally glauconitic microcrystalline, slightly dolomitic limestone. The lower half of the Proviso Member is a tan to cream, argillaceous, and slightly silty microcrystalline dolomite with interbedded siliceous cemented quartz sandstone. The sand grains are very fine- to fine-grained, sub-rounded, and clear to white with occasional glauconite.

Thinly bedded to laminated siltstone and mudstone dominate lithologies in the Lombard; whole core and rotary SWCs indicate lithologies are extremely heterolithic. Well cuttings include red to light brown, non-calcareous shale near the top of the member with tan to light brown, siliceous, finely crystalline dolomite. Thin bands of dolomite are present in some rotary SWCs. Minor abundances of glauconite are present in drill cuttings throughout the section, and trace amounts of oolites were observed in cuttings near the top of the unit. Thin beds of quartz sandstone are present in the Lombard, immediately overlying the Elmhurst Member.

Wireline and core-based lithology and permeability for the primary confining zone are shown in Figure 4.63. The computed lithology track reflects the upward decrease in quartz silt and increase in carbonate in the Proviso Member, along with an accompanying decrease in permeability. The permeabilities of the rotary SWCs in the Proviso range from 0.000005 mD to 1 mD (Table 4.14); the one sample lower than 0.0001 mD is not shown in the figure. Permeabilities in the Lombard Member range from 0.001 mD to 28 mD, reflecting the greater abundance of siltstone in this interval, particularly in the lowermost part of the member, where it grades up from the sand-rich Elmhurst Member. The upward decrease in computed log permeability (red curve in the permeability panel) reflects decreasing sand and silt supply and possibly increasing water depths and lower energy in the Eau Claire depositional environment.

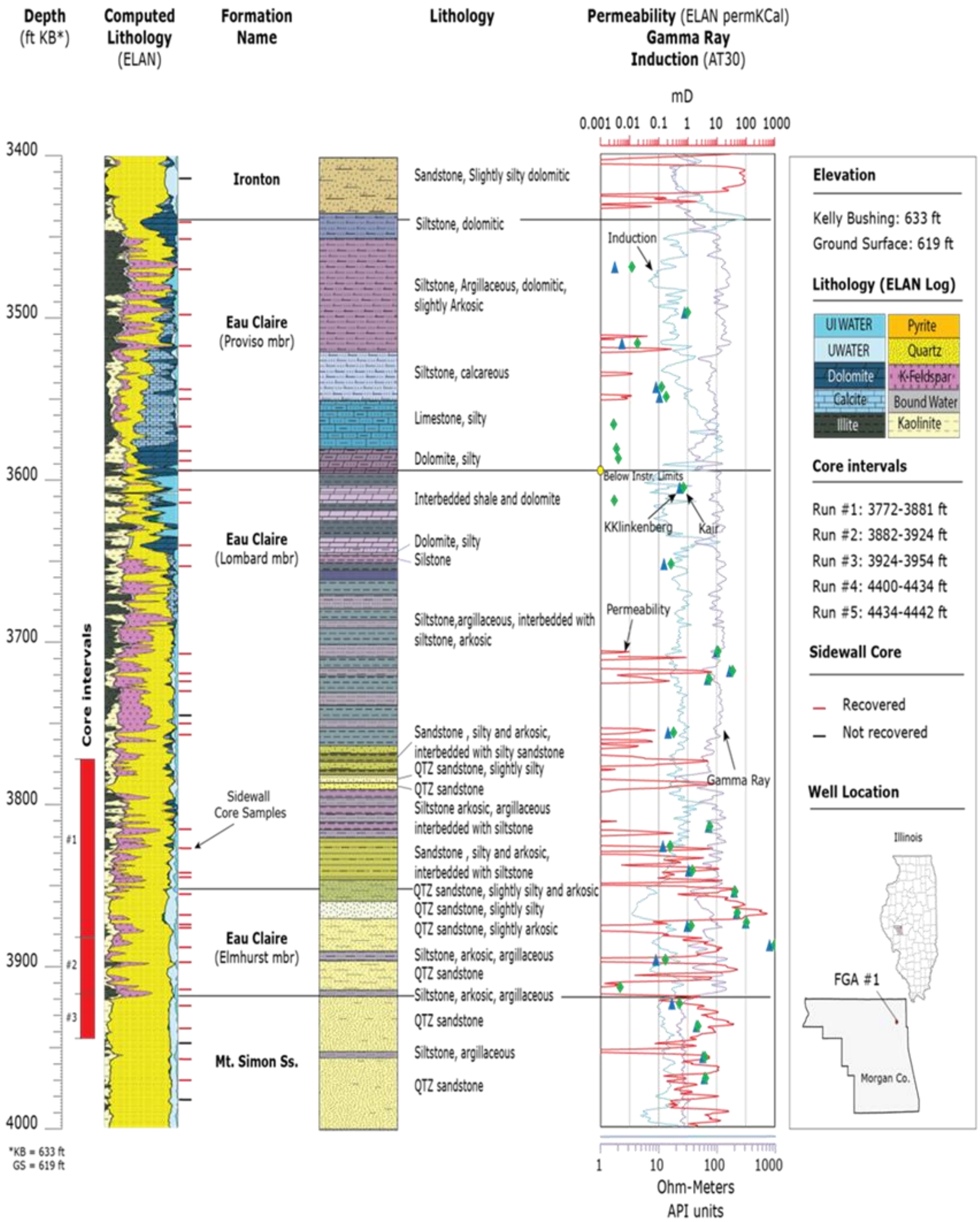


Figure 4.63. Relationship between Lithology, Mineralogy, Sidewall Core, and Wireline Log Computed (ELAN) Permeabilities for the Eau Claire Formation and Uppermost Mount Simon Intervals in Stratigraphic Borehole FGA-1. One Proviso sample with permeability less than 0.0001 mD is not shown. Depths are in feet below Kelly Bushing.

Table 4.14. Measured Permeabilities of Proviso Member Rotary Sidewall Cores. Depths are in feet below Kelly Bushing.

Formation	Depth (ft bgs)	Horizontal Permeability (mD)
Eau Claire (Proviso Member)	3,441	0.0001
Eau Claire (Proviso Member)	3,451	0.0001
Eau Claire (Proviso Member)	3,470	0.003
Eau Claire (Proviso Member)	3,498	0.795
Eau Claire (Proviso Member)	3,517	0.005
Eau Claire (Proviso Member)	3,544	0.082
Formation	Depth (ft bgs)	Horizontal Permeability (mD)
Eau Claire (Proviso Member)	3,550	0.108
Eau Claire (Proviso Member)	3,567	0.0005
Eau Claire (Proviso Member)	3,582	0.001
Eau Claire (Proviso Member)	3,588	0.001
Eau Claire (Proviso Member)	3,594	0.000005

It is important to note that regional well-log correlations and drilling data indicate that the Lombard and Proviso Members of the Eau Claire Formation do not pinch out against paleotopographic highs west of the proposed FutureGen 2.0 CO_2 storage site. Instead, these confining units appear to be laterally continuous and overstep the Precambrian highs in Pike County.

4.5.2.5 *Elmhurst Storage Interval*

Stratigraphic borehole FGA-1 was extensively characterized, sampled, and geophysically logged during drilling. These resulting data, together with the regional data, form the basis for developing a conceptual model. Intervals where full diameter core and rotary sidewall drill cores were acquired are shown in Figure 4.64. A total of 177 ft of whole core was collected from the lower Lombard-upper Mount Simon Sandstone and 34 ft were collected from the lower Mount Simon Sandstone-Precambrian basement interval. In addition to whole drill core, a total of 130 SWC plugs were obtained from the combined interval of the Eau Claire Formation, Mount Simon Sandstone, and the Precambrian basement.

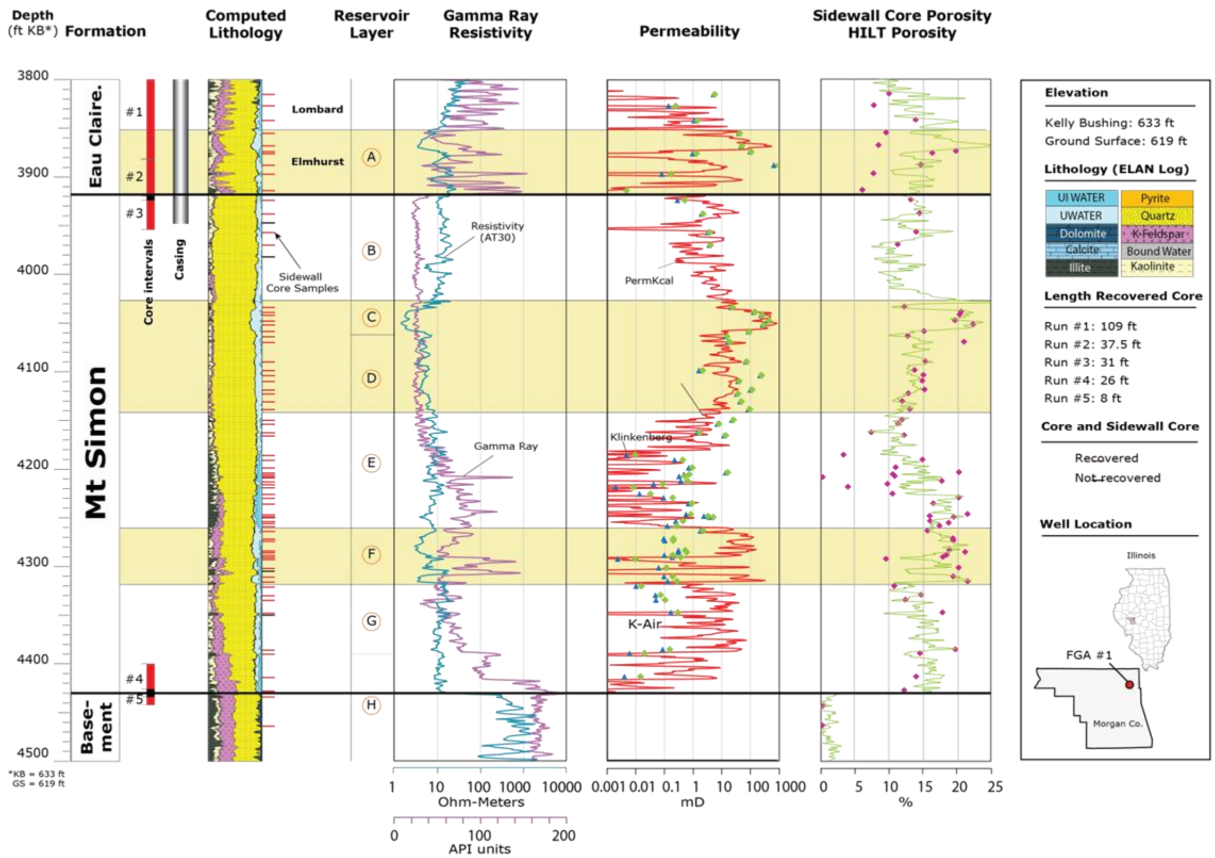


Figure 4.64. Mineralogy, Wireline Log Characterization, and Hydrologic Units of the Lower Lombard to Basement Interval

Cored intervals in stratigraphic borehole FGA-1 (Figure 4.64) are indicated with red bars; rotary SWC and core plug locations are indicated to the left of the lithology panel. Standard gamma ray and resistivity curves are shown in the second panel; ELAN-calculated permeability (red curve) is in the third panel, along with measurements of permeability for each rotary SWC. Neutron- and density-crossplot porosity is shown in the fourth panel, along with lab-measured porosity for core plugs and rotary SWCs. Reservoir layer C within the Mount Simon Formation is the proposed injection zone.

The entire 66 ft of Elmhurst interval was cored in stratigraphic borehole FGA-1; in core, the Elmhurst includes hematite-stained upper medium- to fine-grained quartz sandstones, fine-grained arkose, laminated silty sandy mudstones, and thin heterolithic mixes, with thin fossils and sub-horizontal burrows, and is interpreted as being deposited within a transgressive tide-dominated shallow marine environment (Core Laboratories 2012). Where Elmhurst sandstones have low clay content, they tend to have quartz or feldspar cements. Complete core descriptions of the Elmhurst in the stratigraphic borehole FGA-1 are available in Core Laboratories (2012).

The increase in abundance of calculated potassium feldspar in the Elmhurst compared to the upper Mount Simon on the ELAN log is noteworthy. In the Manlove gas storage field, Morse and Leetaru (2005) reported a positive correlation between abundance of feldspar and decreasing grain size, with the greatest abundance of feldspar recognizable in point counts of fine sandstone. A considerable amount of the calculated potassium feldspar appears to be feldspar silt and cements. Regionally, the Elmhurst sandstones are porous, permeable, and in hydrologic communication with the Mount Simon Sandstone (Buschbach and Bond 1974; Morse and Leetaru 2005).

Regional wireline log correlations and core/cuttings descriptions indicate that the Elmhurst, which represents a widespread marine transgression, is remarkably similar in thickness (50–70 ft) and character from Morgan County to the Manlove Natural-Gas Storage field in Champaign County (central Illinois), where it serves as part of a natural-gas storage reservoir (Morse and Leetaru 2005). The Elmhurst sandstones are replaced by non-reservoir heterolithic mudstone facies at the ADM Decatur site (Freiburg et al. 2012).

West of the FutureGen 2.0 CO_2 storage site, the Elmhurst is present, but thins and is locally missing due to non-deposition over basement highs in some Pike County wells. South of the FutureGen 2.0 CO_2 storage site, the Elmhurst in the Waverly field Whitlock 7–15 well is about 50 ft thick and has up to 15% cased-hole neutron porosity; the 50-ft-thick Elmhurst in the Waverly Criswell 1–16 well sonic log indicates about 25 ft of elevated but uncalibrated porosity. Thus the Elmhurst storage interval appears to be regionally extensive.

4.5.2.6 *Mount Simon Storage Interval*

Several major reservoir intervals were recognized in the Mount Simon interval of the stratigraphic borehole FGA-1 based on grain size, clay content, and permeability (Figure 4.63). Reservoir Layers A−D have cleaner gamma-ray signatures and lower feldspar and clay contents, except for thick hematitic clay cements at the top of the Mount Simon. The sandstones in this interval tend to be more texturally and mineralogically mature, and have a strong eolian component, based on quartz grain rounding and frosting (Core Laboratories 2012).

Reservoir Layer E has increased illite and minor feldspar content and low permeabilities. The image log suggests this interval is dominated by poorly sorted granule and gravel conglomerates. The lower Mount Simon Layers F and G have a lower abundance of clay, but none of the lab-measured core permeabilities reach 10 mD. Unlike the Decatur site (Freiburg 2013), there is no permeable arkose in the lower part of the Mount Simon, and no “Pre-Mount Simon” marine sandstone. It should be noted that Mount Simon Sandstone wireline log porosity is not a good predictor of permeability unless corrected for clay content, grain size, and other parameters (Frailey et al. 2011; Rockhold et al. 2014).

On wireline logs (Figure 4.65), the best porosities and permeabilities of the Mount Simon Sandstone Formation are over a 20-ft interval from 4,040 to 4,060 ft KB. Rotary SWCs from this interval include friable sandstone. In a thin section (Figure 4.66), the quartz sandstone at 4,048 ft is moderately compacted, moderately well sorted, and upper medium-grained. Porosity of the sample is 19.5% with 417 mD permeability. Core Lab interpreted the depositional environment as a non-marine channel with allochthonous (originating from some distance away) lithic grains. There is no potassium feldspar in the sample. Black/brown iron oxide coats appear to have prevented the development of overgrowth quartz cements; there is a minor amount of detrital clay, and some pore filling kaolinite clay. Authigenic kaolinite has replaced some grains.

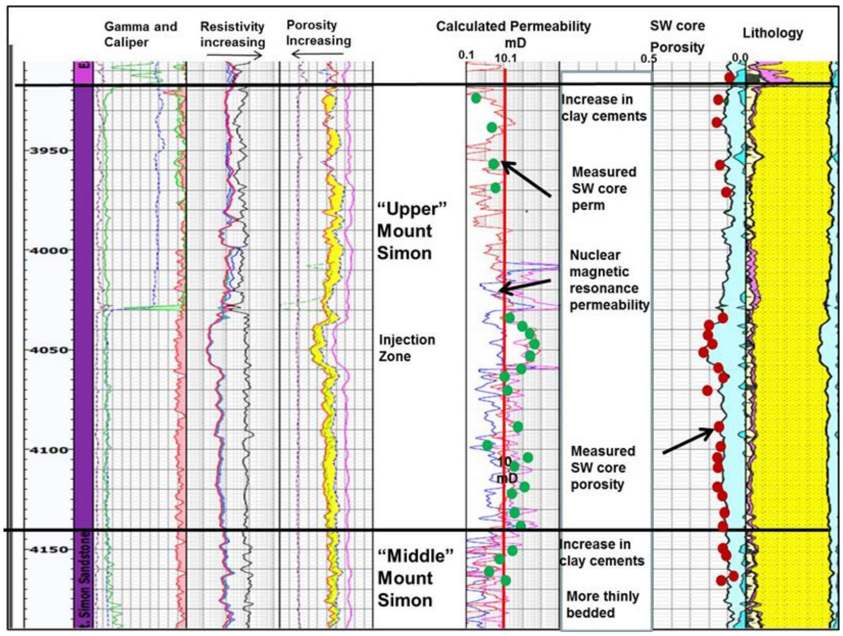


Figure 4.65. ELAN Wireline Log Signatures and Porosity/Permeability Data for the Upper Part of the Mount Simon Formation. The base of Reservoir Layer D is at 4,140 ft KB.

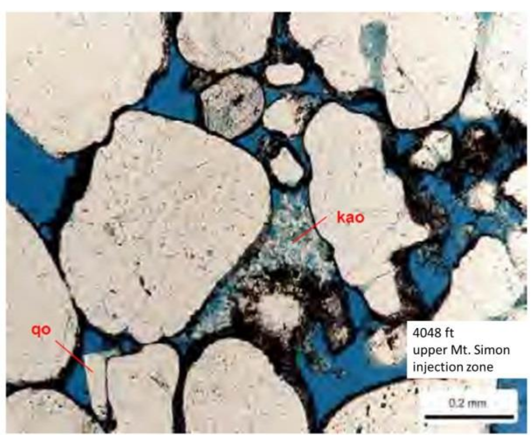


Figure 4.66. Rotary Sidewall Core Thin Section of Quartz Arenite from the Proposed Injection Zone. Kao is kaolinite clay; qo is quartz overgrowth cement. The dark material is iron oxide cement.

The thin section from 4,070 ft is a moderately to heavily compacted, mineralogically mature, well-rounded, moderately well-sorted medium-grained quartz sandstone, with a trace of chert. No feldspar grains are present. Although the larger grain size is favorable for effective porosity development or retention, intergranular pores are reduced by kaolinite and iron oxide. Dark brown/black iron oxide appears to have nucleated on the clay cements. Porosity is 20.8% but permeability drops to 16.7 mD in this sample. The heavy compaction likely contributes to the drop in permeability.

4.5.2.6.1 Mount Simon Environment of Deposition

Based on vertical changes in lithofacies that indicate abrupt and prolonged changes from windborne to waterborne deposits, and on apparent truncation surfaces, at least three unconformity-bounded packages of continental lithofacies can be interpreted from the available Mount Simon wireline log and core data in stratigraphic borehole FGA-1. These packages are, from bottom to top:

- conglomerate and pebble to coarse-sand-dominated, planar bedded sheet deposits and cross-stratified finer grained sandstones in the lower 120 ft of the formation, with feldspar, illite, and kaolinite decreasing up-section;
- minor conglomerate, plus poorly sorted, compacted and cemented, dominantly planar bedded sheet sands, with markedly increased feldspar, illite, and kaolinite in the middle of the Mount Simon; and
- rare pebble conglomerates in the upper Mount Simon with an increase in planar stratified and cross-stratified medium-grained sandstones with better sorting, and thin bedded, planar to laminated very fine-grained sandstones.

Feldspar and illite content greatly decreases above 4,180 ft KB, but minor amounts of kaolinite continue to be present. Finally, the uppermost 14 ft of the Mount Simon cored interval contains burrow trace fossils in iron oxide cemented, medium-grained sandstone.

The lower two lithofacies packages are interpreted as recording the development of horizontal deflation super surfaces that truncate cross-stratified dune deposits and form the basal boundaries of desert braided plain deposits and truncated water-laid sheet sands. The upper sequence of continental lithofacies of the Mount Simon records a change from a higher abundance of very poorly sorted, water-laid deposits to more texturally and mineralogically mature sediments that are interpreted as sheet sands, truncated eolian dunes with thin kaolinite-rich claystones, and thin, distal braid channels. This uppermost continental sequence is overlain by a subtle unconformity and a fourth, very thin depositional package with iron oxide cements and sedimentary structures that reflects marginal marine to high-water-table continental environments of deposition. The interpreted sequence stratigraphy is shown in Figure 4.67.

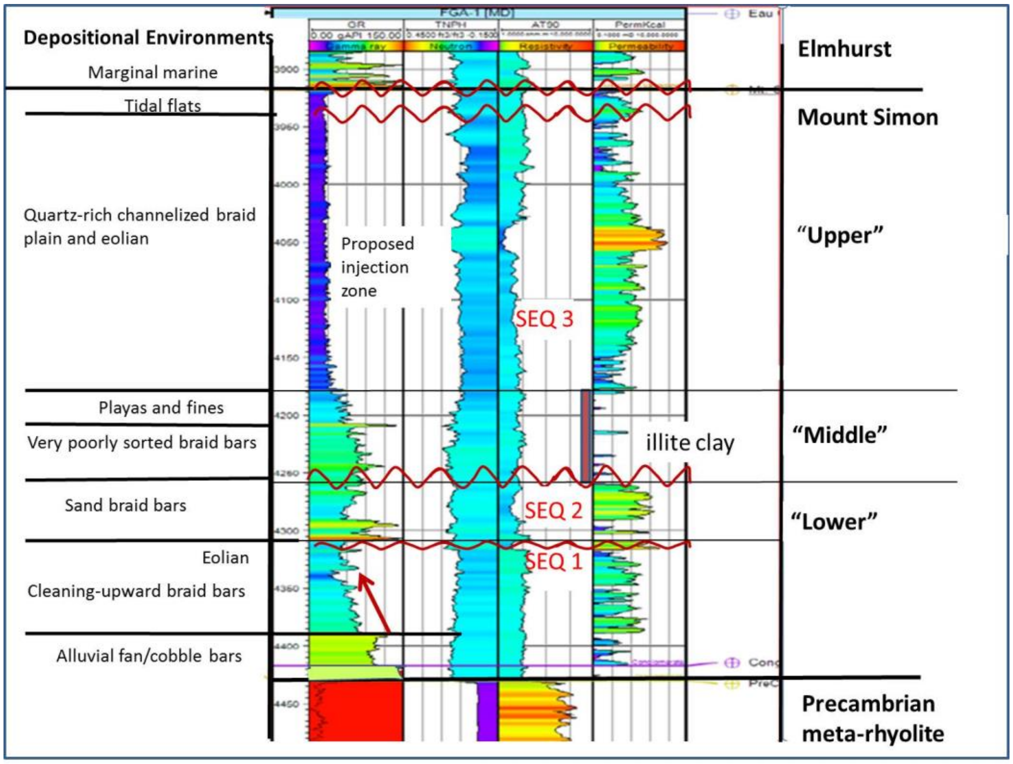


Figure 4.67. Interpreted Sequence Stratigraphy and Depositional Environments for Stratigraphic Borehole FGA-1 Mount Simon Sandstone Formation. Curves from left to right are gamma, total porosity, resistivity, and log-calculated permeability. Log-calculated permeability is higher than core-measured permeability.

It is important to note that the acoustic impedance below the proposed injection zone and at the top of Sequence 1 each generated a seismic reflector in the VSP data from stratigraphic borehole FGA-1 (Figure 4.68), and that these architectural reservoir elements should be seismically mappable across the site and perhaps beyond. See Sullivan et al. (2015) for additional details.

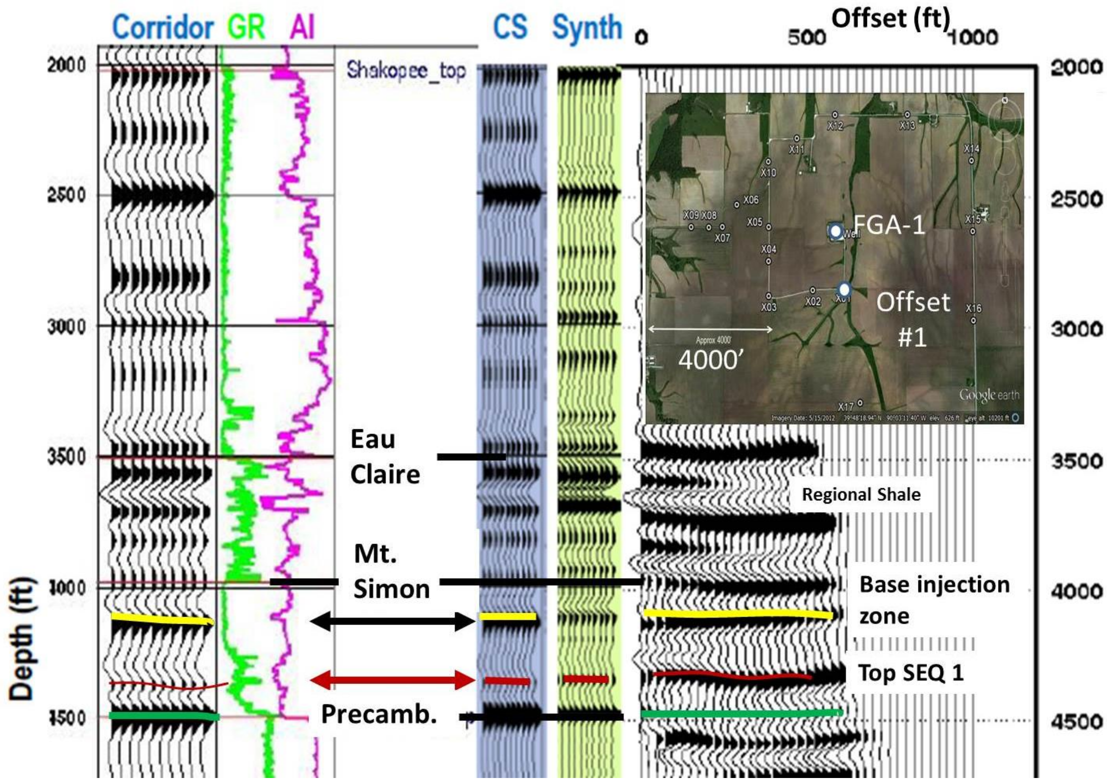


Figure 4.68. Offset 1 P-wave VSP with Four Seismically Mappable Components of the Mount Simon Stratigraphy, along with the Corridor Stack, Gamma Ray, Acoustic Impedance, and P-wave Synthetic.

4.5.2.6.2 Regional Continuity of the Mount Simon Formation

Except for locations where the Mount Simon Formation is thin or not present due to localized basement highs, there appears to be little major change in regional thickness or wireline log character of the Mount Simon westward from the FutureGen 2.0 CO_2 storage site to the Sleight N#1 well in Pike County, approximately 33 miles to the west.

The log character of the Mount Simon in the Sleight N#1 well (see Figure 4.62) and the neutron-density crossplot porosity of up to 22% suggests, but does not confirm, the regional development of porosity in the upper part of the Mount Simon across the western flank of the Illinois Basin. To the south, the Waverly Whitlock 7–15 has up to 15% neutron porosity in the upper 200 ft of the Mount Simon. Lateral variability and azimuthal trend of porosity and permeability development in the upper Mount Simon could have considerable effects on well design and design of monitoring programs. This uncertainty cannot be decreased until other wells are drilled into the Mount Simon in the western part of the basin.

4.5.2.7 *Precambrian Basement*

Three hundred ninety-six feet of the Precambrian basement were drilled and logged. Eight feet of whole core and eight rotary SWCs were recovered. In whole core and rotary SWCs, the Precambrian basement lithology consists of gray/green/red very finely crystalline meta-rhyolite (Figure 4.69).

Feldspar staining of thin-section samples revealed the dominance of cryptocrystalline quartz, along with potassium feldspar, minor plagioclase, opaque titanium oxide, and rare grains of partially adsorbed metamorphic garnet. There is no orientation of crystals, no flow features, and no identifiable phenocrysts other than the very rare corroded (metamorphic) garnets. Quartz-filled veins and open fractures are locally present in the core; in microscopic view the fractures are lined with titanium oxide.

Wireline log calculations of permeability in stratigraphic borehole FGA-1 indicate that fractures in the Precambrian rock may be conductive; and laboratory measurements of rotary SWCs indicate the unfractured rock has extremely low permeabilities. Of seven rotary SWCs analyzed for permeability, five were below instrument measurement levels and two were between 5.83 and 5.95×10^{-5} mD.

FMI image logs indicate highly fractured zones throughout the drilled interval. Photographs and thin-section descriptions for the Precambrian meta-rhyolite are available in the FGA-1 Core Lab Core Analysis Report (Core Laboratories 2012).

Figure 4.69. Precambrian Meta-Rhyolite from Stratigraphic Borehole FGA-1. Longitudinal and end view of full diameter core. End view shows altered surfaces along fractures.

4.5.2.7.1 Regional Aspects of the Basement Rock

Rhyolite is not an uncommon lithology in the Illinois Basin. Although the Precambrian basement at the ADM Decatur site was originally reported as granite lithology, it has since been revised to porphyritic rhyolite. At that site, the rhyolite appears to be unmetamorphosed, and has identifiable phenocrysts (Freiburg et al. 2014). Rhyolite from a well in Pike County was also unmetamorphosed. It is important to note the parent rock properties of the basement rock at the FutureGen 2.0 CO_2 storage site: the massive metamorphic rock does not contain individual grains of feldspar and would not have generated arkosic sandstones as a weathering product.

There are no published data to indicate the amount of topographic relief on the basement across Morgan County. The closest Mount Simon well penetrations are in Waverly field in southeast Morgan County. There, only the uppermost 200 ft of the Mount Simon were drilled, and there are no data to indicate the complete thickness of the Mount Simon at that location. The two reprocessed 2D seismic lines at the FutureGen 2.0 CO_2 storage site are poorly constrained at the depth of the Precambrian basement, but may show low-relief erosional features (Section 4.2.2). The VSP data do not indicate any basement relief near stratigraphic borehole FGA-1 (Section 4.4.5).

4.6 Reservoir Design

4.6.1 Laboratory Studies of Biogeochemical Processes

Laboratory-scale experiments were conducted with Mount Simon Sandstone and Eau Claire Formation cores from the FutureGen 2.0 CO_2 storage site to evaluate changes in water quality and formation permeability, and associated biogeochemical processes resulting from the sc-CO_2 injection into the brine aquifer. This evaluation was conducted because the injection of sc-CO_2 could lead to decreased permeability (from precipitation or substantial microbial growth), increased permeability (from mineral dissolution), and changes in the mobility of major components (such as precipitation of carbonate mass) and trace metals. In addition, changes in multifrequency electrical resistivity associated with sc-CO_2 injection were measured to evaluate the potential for field-scale application of electrical resistivity tomography (ERT) to monitor injected CO_2 distribution. Results summarized in this section are described in detail by Vermeul et al. (2014). These fluid displacement experiments using rock cores were conducted under aquifer temperature (38^{o}C) and pressure (1500−1800 psi) conditions in flow-through high-pressure 1D columns. ISCO syringe pumps were used to provide inlet, outlet, and confining pressure. Electrical resistivity measurements were conducted in columns constructed of PEEK (polyether ether ketone), with stainless steel current electrodes at the each end of the core and silver/silver chloride potential electrodes near the center of the core.

Results showed that the displacement of the brine (density ~1.05 g/cm^3, viscosity 1.05 cP) by sc-CO_2 (density 0.7 g/cm^3, viscosity 0.06 to 0.1 cP) was not efficient by advection, because sc-CO_2 travels predominantly in larger pores, leaving a significant amount brine in smaller pores.

After 10 pore volumes (PVs) of sc-CO_2 injection, sc-CO_2 saturations in the cores were between 25 and 40%, and after 100 PVs of injection, sc-CO_2 saturations were increased to between 50 and 65% (Figure 4.70). In contrast, brine displacement of the sc-CO_2-filled core was more efficient, with brine saturations reaching 45 to 70% after 10 PVs of brine injection. The upper Mount Simon Sandstone hydraulic conductivity averaged $1.1 \pm 1.7 \times 10^{-5}$ cm/sec, with a small anisotropy (horizontal/vertical Ksat = 2.9). There was an apparent decrease in the hydraulic conductivity correlated with 1) increasing interaction time among sc-CO_2, brine, and rock core; 2) increasing percentage of sc-CO_2 relative to brine in the fluid interacting with core; and 3) increasing injection amount (i.e., number of PVs). The hydraulic conductivity decreasing could be caused by 1) precipitate formation, 2) microbial biomass growth, and/or 3) iron oxide particulate movement. Particulate transport experiments showed some increase in iron oxide mass transported as a result of sc-CO_2 injected (110 mg solids/g core). However it was unclear whether the movement and plugging of the particulates in the core resulted in the observed higher pressure drop, indicating decreased formation permeability; or the column end frit clogging resulted in the higher pressure drop. Some microbial growth was observed as a result of sc-CO_2 injection into cores, but the effect was small and did not influence formation permeability.

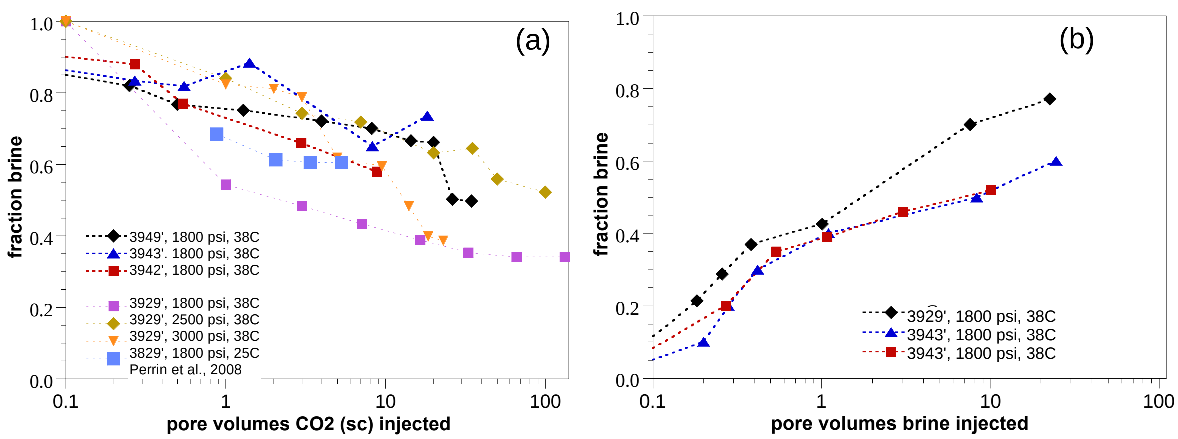


Figure 4.70. Experimental Data Showing Residual Brine Saturation in Rock Core after a) sc-CO_2 Injection into Brine-Saturated Mount Simon Cores to Displace Brine as a Function of Pore Volumes Injected (left plot), and b) Brine Injection into sc-CO_2-Saturated Cores

As the sc-CO_2 displaces the brine in larger pores and carbonate partitions into the brine, the resulting acidification (pH 3 to 4) causes short-term mineral dissolution, ion desorption, and iron oxide particulate movement. Major geochemical changes observed over 1.2 years include 1) significant increase in Mg^{2+}, K^{+}, and SO_4^{2-} concentrations (10s to 100s of mmol/L, Figure 4.71); 2) dissolution of the hematite coating on the quartz grains; and 3) precipitation of NaCl and KCl (Figure 4.72). The observed increase in Mg^{2+} and K^{+} concentrations are high enough and the same order of magnitude as carbonate (in the 10 to 300 mmol/L range) that there may be an influence on carbonate solubility. The rate of mineral dissolution appeared to be on the order of 100s of hours, based on the slow increase in Mg^{2+}, K^{+}, Na^{+}, and SO_4^{2-} concentrations. Electron microprobe analysis of the sandstone after year-long experiments showed the formation of some NaCl, KCl, and minor amounts of Pb-oxide, and forsterite precipitates, but none was in an amount large enough to significantly change the hydraulic conductivity.

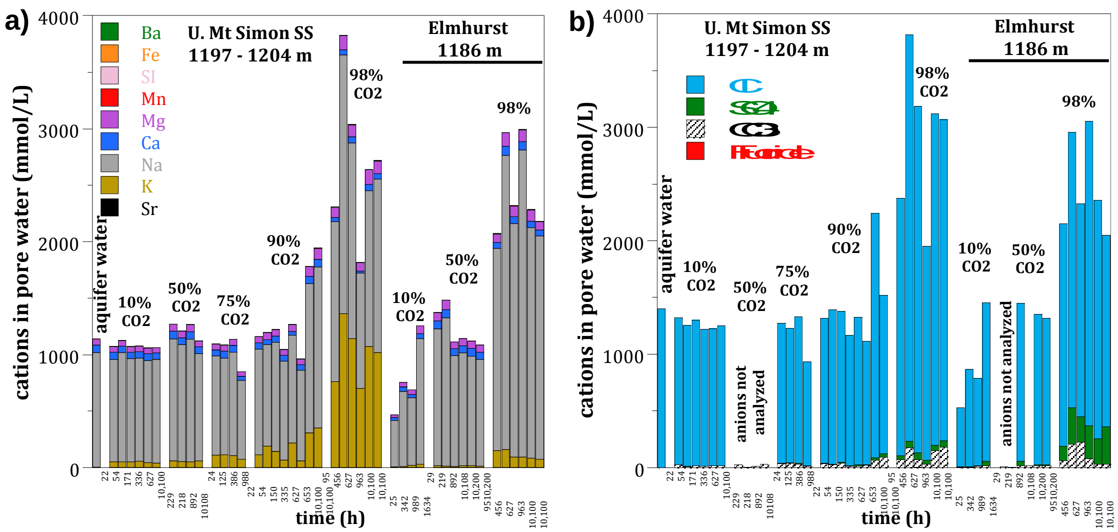


Figure 4.71. Major Cation (a) and Anion (b) Changes in Mount Simon or Elmhurst Formations with Different CO_2/Brine Mixtures over Time (x-axis) Using Crushed Core Material. Groupings are different percentages of CO_2 with a balance of brine (e.g., 10% CO_2 is 90% brine).

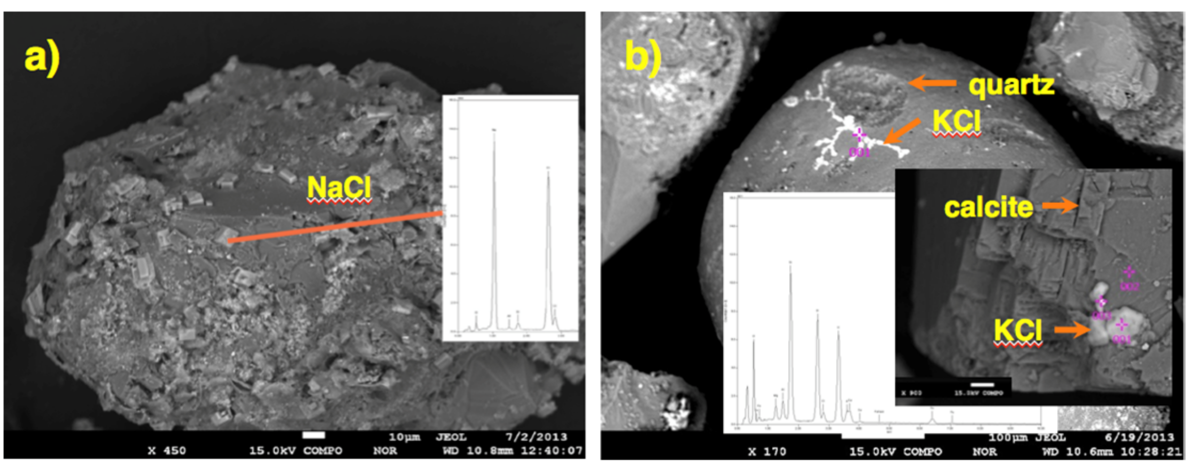


Figure 4.72. Electron Microprobe Analysis of Upper Mount Simon Sandstone Treated with 98% sc-CO_2 and 2% Brine at 12.4 MPa and 38°C for 1.2 Years Showing the Formation of a) NaCl and b) KCl on Quartz and Calcite

Increased trace metal concentrations were observed during sc-CO_2 injection (i.e., acidification), including Si, Fe, Ba, Mn, Sr, Ni, Al, and Sn (Figure 4.73). Geochemical simulations show that over the long term, as the pH is buffered, carbonate should precipitate as aragonite, calcite, and magnesite.

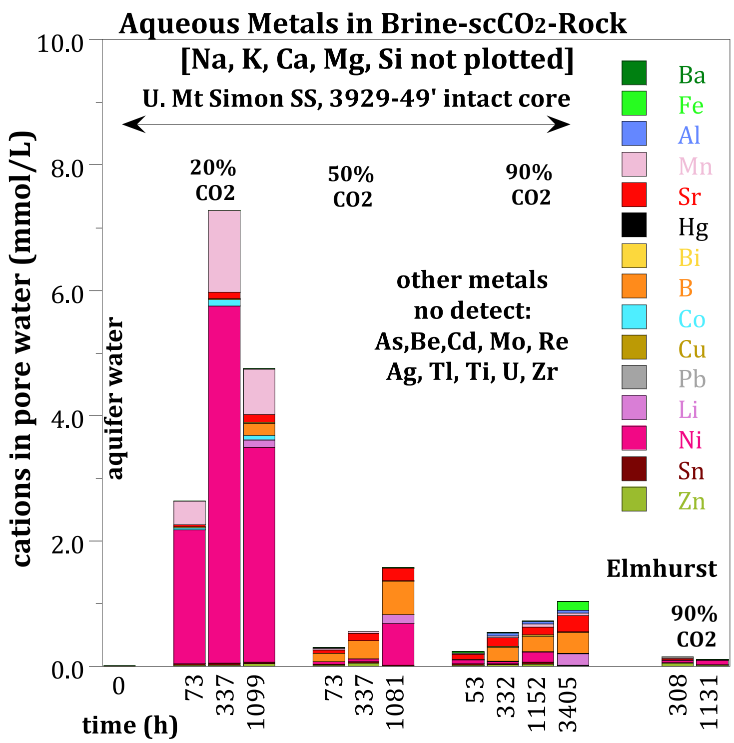


Figure 4.73. Aqueous Trace Metal Changes at Different sc-CO_2/Brine Ratios in Rock Core

The microbial biomass measured in the untreated Mount Simon Sandstone at 3,930 ft (1,197 m) depth was $4.02 \pm 4.01 \times 10^5$ cells/g, within the range previously reported for marine-deposited sediments. Anaerobic microbial growth was observed that correlated with higher sc-CO_2 concentration only (23.5x) by 1,300 h (Figure 4.74). Less aerobic microbial growth was observed correlated with sc-CO_2 concentration (7.6x) by 1,300 h. This result is consistent with (but does not prove) methanogenesis occurring where the in situ microbial population is using CO_2 (i.e., carbon is the electron acceptor in this case) for methane production. The presence of oxygen that would occur near the injection well would inhibit methanogenesis. Overall, the 23.5x growth observed would have no influence on permeability in the Mount Simon Sandstone.

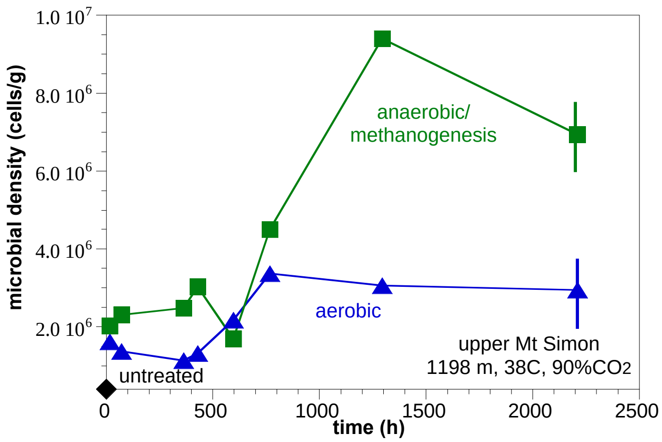


Figure 4.74. Influence of Additions of sc-CO_2 and Minor Gas/Trace Metals on Microbial Growth at 38°C as a Function of Time in Aerobic and Anaerobic Systems. Vertical bars on points represent ± standard deviation.

Finally, the electrical resistivity change from 100% brine to 100% sc-CO_2 was in the expected range (3x to 5x), with most of the change observed between 70% to 100% sc-CO_2. Field-scale conditions simulated using these laboratory-measured electrical resistivity changes indicated resolution was insufficient at the field site using surface electrodes due to the depth of injection (3,940 ft [1,200 m]).

Overall, experimental data indicated that injection of sc-CO_2 into the Mount Simon Sandstone brine-filled cores resulted in small geochemical changes over the short term (<1.5 years) of testing period, with some iron oxide particulate movement.

4.6.2 CO_2 Injection Modeling

4.6.2.1 *Initial Scoping Study for Preliminary Storage Site Design*

Prior to the availability of data from stratigraphic borehole FGA-1, preliminary numerical simulations were conducted using the STOMP- CO_2 (White et al. 2013a, b) simulator to provide some scoping-level predictions for injection of CO_2 at the proposed FutureGen 2.0 CO_2 storage site location (White and Zhang 2011). The structure of the saline Mount Simon Sandstone reservoir was determined based on evaluation of regional data. In the Morgan County area, the depth to the top of the Mount Simon Sandstone was assumed to be 4,050 ft and the total thickness of the reservoir was estimated to be 850 ft, based on regional maps provided by the ISGS (http://sequestration.org/map.htm). Regional information suggested that in this area, the Mount Simon Sandstone is underlain by impermeable Precambrian granite, and overlain by the Eau Claire shale. The scoping simulations assumed a vertical injection well open to the lowermost 300 ft of the Mount Simon Sandstone reservoir.

The lateral extent of the model domain varied depending on the injection scenario, but the model boundaries were established to be at a distance from the injection well at which there would be no boundary effects on the simulation. The grid spacing was 15 ft at the location of the injection well(s) and geometrically increased in both x and y away from the well. Vertical discretization varied based on the conceptual model being evaluated.

The lateral boundary conditions were set to hydrostatic pressure, and it was assumed that the reservoir is continuous with no faults or impermeable boundaries present. Isothermal conditions were assumed, which are appropriate if the injected CO_2 is at a temperature similar to the formation temperature.

Two different conceptual models were used for the reservoir:

1. An equivalent homogeneous medium (EHM)
2. A three-layer reservoir consisting of the Mount Simon Upper (MS1) layer with a thickness of 300 ft, the Mount Simon Middle (MS2) layer with a thickness of 380 ft, and the Mount Simon Arkosic Sandstone (MS3) layer with a thickness of 170 ft. The layered configuration was based primarily on the description by Zhou et al. (2010).

Table 4.15 shows the hydraulic properties assigned to the layers in both the EHM and three-layer model.

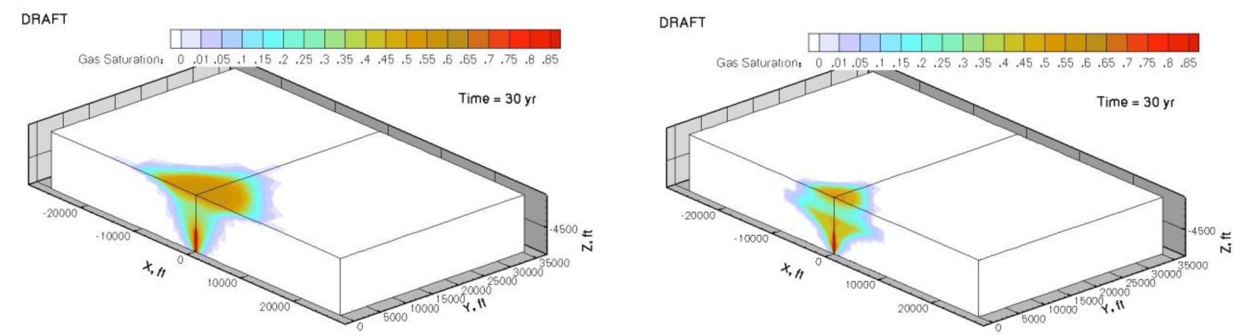
Table 4.15. Hydraulic Properties for the Three-Layer Structure and the EHM

Formation	Porosity (-)	Horizontal Permeability, K_h (10^{-15} m^2)	Vertical Permeability, K_v (10^{-15} m^2)	Entry Pressure, P_e (10^5 pa)	λ	Pore Compressibility (1/psi)
MS1	0.096	37.1	3.71	0.142	0.567	2.52×10^{-6}
MS2	0.123	213.0	21.30	0.086	0.567	2.52×10^{-6}
MS3	0.171	417.1	41.71	0.025	0.567	2.52×10^{-6}
EHM	0.123	192.3	8.307	0.0803	0.567	2.52×10^{-6}

Single-well and multiple-well (2 wells) simulations were performed, assuming a total injection rate of 1.3 MMT/yr. In total, 12 simulations were conducted to investigate the impact of reservoir heterogeneity (i.e., stratification) and to optimize the well spacing between two wells and the duration of injection.

Simulation results showed that introducing layered heterogeneity to the model had a significant impact on the plume shape and plan view footprint. Although residual trapping is a process that was modeled in these scenarios, structural trapping of the CO_2 was the dominant mechanism for limiting plume growth in these simulations. Introducing layered heterogeneity into the conceptual model decreased the areal footprint of the plume. This is because, in a layered reservoir, some CO_2 accumulates and spreads laterally at the fine-over-coarse interface within the reservoir

(Figure 4.75b). Conversely, in a homogeneous reservoir, the injected CO_2 accumulates and spreads at the top of the reservoir immediately below the confining layer (Figure 4.75a). Consequently, comparing the CO_2 distribution in an EHM reservoir, a smaller fraction of CO_2 in a layered reservoir accumulates at the very top of the reservoir. There was also a general trend that showed an increase in plume acreage with an increase in well spacing. To better predict the plume shape and footprint, site-specific characterization data were necessary to construct a conceptual model that better represented the reservoir character in three dimensions.



(a) (b)

Figure 4.75. Gas Saturation Profiles after 30 Years of Injection for the (a) Equivalent Homogeneous Medium Model and (b) Three-Layer Model

4.6.2.2 *Evaluation of Vertical Well Configuration for CO_2 Injection with and without Brine Extraction*

Once preliminary stratigraphic borehole data were available, it became apparent that the original assumptions for the reservoir character required modification. Data from wireline logs, reservoir testing, and core sample analyses provided information about the vertical distribution of porosity and permeability at the location of the stratigraphic borehole FGA-1. Simulations were performed to evaluate the reservoir injectivity and provide well configuration options based on the knowledge of the geology derived from the stratigraphic borehole. Although the complete data set was not yet available, simulations could be used to evaluate possible injection and well configuration scenarios based on the new preliminary knowledge of the vertical distribution of the reservoir properties.

The continuous wireline log data were calibrated using discrete laboratory core measurements to provide a more representative estimate of reservoir properties such as permeability and porosity. From these calibrated wireline-survey measurements, statistical or average values for permeability and porosity were assigned to layers representing zones of similar hydrologic properties to construct a new conceptual model of the reservoir based on site-specific information. This approach is summarized in the UIC permit application (Alliance 2013). Based on these data, the Mount Simon Sandstone was subdivided into 17 layers, and the Elmhurst

Sandstone (member of the Eau Claire Formation) was subdivided into 7 layers (Figure 4.76). These units formed the injection zone. The overlying Lombard and Proviso Members of the Eau Claire Formation were subdivided respectively into 14 and 5 layers. The Ironton Sandstone was divided into four layers, the Davis Dolomite into three layers, and the Franconia Formation into one layer. Some layers (labeled "split" in Figure 4.76) have similar properties but have been subdivided to maintain a reasonable layer thickness within the computational model. The computational model was constructed using these layers for the vertical discretization and property assignment. It is important to note that the permeability at the field scale may be different from the initial values based on wireline logs, reservoir testing, and core sample analyses.

The vertical distribution of reservoir properties in this new conceptual model presented several considerations for a new operational well design:

- The maximum horizontal permeability of the Mount Simon (310 mD) was associated with a 23-ft-thick layer referred to as MS11. The second largest value of permeability (21 mD) was in the 24-ft-thick MS8.
- The maximum horizontal permeability of the Elmhurst Formation (184 mD) was associated with the 10-ft-thick Elmhurst6. The second largest value of permeability (20.4 mD) was in the 10-ft-thick Elmhurst7.
- The maximum horizontal permeability of the Lombard Formation (424 mD) was associated with the 9-ft-thick Lombard5. The second largest value of permeability (16.6 mD) was in the 10-ft-thick Lombard10.

This resulted in a conceptual model with relatively thin layers with high permeability, compared to the 300-ft-thick injection zone that was considered in the preliminary scoping simulations. Therefore, multiple injection wells needed to be considered. This would result in a larger plume footprint, and therefore plume and pressure management through brine extraction was considered.

A series of well configuration scenarios was simulated to evaluate options for vertical wells, both with and without brine extraction. These scenarios include the following:

- Vertical injection wells
  - Vertical injection wells screened in 1) the Mount Simon and 2) in both the Mount Simon and Elmhurst
  - Two vertical injection wells screened in the Mount Simon with well distances ranging from about 2 to 5 miles
- Combined vertical injection and brine extraction wells
  - Varying number of wells
  - Varying well locations.

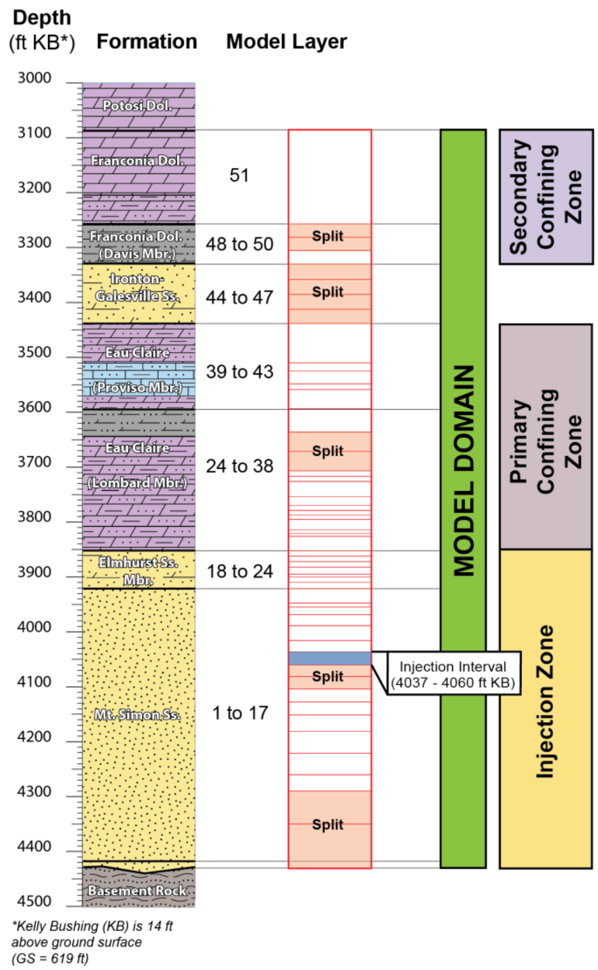


Figure 4.76. Division of Stratigraphic Layers to Create Computational Model Layers

The simulations indicated that the injectivity with two vertical injection wells, regardless of the screen lengths and position, with or without extraction wells, would not meet the expected injection rate of 1.3 MMT/yr.

4.6.2.3 *Evaluation of Lateral-Injection-Well Design*

Because the use of vertical injection wells was not expected to meet the target injection rate, injection of CO_2 using lateral wells in the Mount Simon Formation (MS11) was investigated. Another limitation for the injected CO_2 management was that the plume footprint needed to avoid sensitive properties that were present on all sides of the proposed injection site. Therefore, several different injection-well configurations were investigated:

- Lateral injection wells of different lengths (2,000 or 4,000 ft) in the Mount Simon (MS11)
- Lateral injection wells with injection into both the Mount Simon and Elmhurst

- Varying numbers (2, 3, or 4) of lateral injection wells
- Varying locations of lateral wells.

The results indicated that

- The injectivity rate of 1.3 MMT per year could be met with three or more lateral injection wells.
- Using four lateral injection wells would provide some flexibility in well length, orientation, and maintenance so that the injectivity can be met and the plume shape could be controlled.

4.6.2.4 *UIC Permit Application Modeling*

The scenario with four lateral wells injecting into the Mount Simon (MS11) was considered to be the most representative case and hence was used in the UIC permit application. An expanded 100 × 100-mile conceptual model was constructed to represent units below the Potosi Dolomite interval including the Franconia, Ironton, Eau Claire (Proviso, Lombard, and Elmhurst), Mount Simon, and Precambrian Formations. These surfaces were gridded in EarthVision® based on borehole data and regional contour maps to make up the stratigraphic layers of the computational model. Based on this geologic model, a 3D, boundary-fitted numerical model grid was constructed to have constant grid spacing (200 ft) with higher resolution in the area influenced by the CO_2 injection (3- by 3-mi area), with increasingly larger grid spacing moving out in all lateral directions toward the boundary.

The conceptual model hydrogeologic layers were defined for each stratigraphic layer based on zones of similar hydrologic properties. The hydrologic properties (permeability, porosity) were deduced from geophysical well logs, reservoir testing, and SWCs. The lithology, deduced from wireline logs and core data, was also used to subdivide each stratigraphic layer of the model. The hydrologic properties generated from the site-specific data were assigned to the model layers as described in Section 4.6.2.2 and as shown in Table 4.16. Capillary pressure data determined from site-specific cores were not available at the time the model was constructed. However, tabulated capillary pressure data were available for several Mount Simon gas storage fields in the Illinois Basin. The data for the Hazen No. 5 Well at the Manlove Gas Field in Champagne County, Illinois (Alliance 2006) were the most complete and were therefore used to generate Brooks-Corey parameters.
The reservoir was assumed to be under hydrostatic conditions with no regional or local flow conditions. Site-specific data derived from field tests were available for pressure, temperature, and salinity, and were used to assign initial conditions for the model. A temperature gradient was specified, but the initial salinity was considered to be constant for the entire domain. A summary of the initial conditions is presented in Table 4.17.

Table 4.16. Summary of the Hydrologic Properties Assigned to Each Model Layer

	Model Layer	Top Depth (ft bkb)	Top Elevation (ft)	Bottom Elevation (ft)	Thickness (ft)	Porosity	Horizontal Permeability (mD)	Vertical Permeability (mD)	Grain Density (g/cm3)	Compressibility (1/Pa)
Primary Conf. Zone	Franconia	3086.00	-2453	-2625	172	0.0358	5.50E-06	3.85E-08	2.82	7.42E-10
	Davis-Ironton3	3258.00	-2625	-2649	24	0.0367	6.26E-02	6.26E-03	2.73	3.71E-10
	Davis-Ironton2	3282.00	-2649	-2673	24	0.0367	6.26E-02	6.26E-03	2.73	3.71E-10
	Davis-Ironton1	3306.00	-2673	-2697	24	0.0218	1.25E+01	1.25E+00	2.73	3.71E-10
	Ironton-Galesville4	3330.00	-2697	-2725	28	0.0981	2.63E+01	1.05E+01	2.66	3.71E-10
	Ironton-Galesville3	3358.00	-2725	-2752	27	0.0981	2.63E+01	1.05E+01	2.66	3.71E-10
	Ironton-Galesville2	3385.00	-2752	-2779	27	0.0981	2.63E+01	1.05E+01	2.66	3.71E-10
	Ironton-Galesville1	3412.00	-2779	-2806	27	0.0981	2.63E+01	1.05E+01	2.66	3.71E-10
Primary Confining Zone	Proviso5	3439.00	-2806	-2877	71	0.0972	1.12E-03	1.12E-04	2.72	7.42E-10
	Proviso4	3510.00	-2877	-2891	14	0.0786	5.50E-03	5.50E-04	2.72	7.42E-10
	Proviso3	3524.00	-2891	-2916	25	0.0745	8.18E-02	5.73E-04	2.77	7.42E-10
	Proviso2	3548.50	-2916	-2926	10	0.0431	1.08E-01	7.56E-04	2.77	7.42E-10
	Proviso1	3558.50	-2926	-2963	38	0.0361	6.46E-04	4.52E-06	2.77	7.42E-10
	Lombard14	3596.00	-2963	-3003	40	0.1754	5.26E-04	5.26E-05	2.68	7.42E-10
	Lombard13	3636.00	-3003	-3038	35	0.0638	1.53E-01	1.53E-02	2.68	7.42E-10
	Lombard12	3671.00	-3038	-3073	35	0.0638	1.53E-01	1.53E-02	2.68	7.42E-10
	Lombard11	3706.00	-3073	-3084	11	0.0878	9.91E+00	9.91E-01	2.68	7.42E-10
	Lombard10	3717.00	-3084	-3094	10	0.0851	1.66E+01	1.66E+00	2.68	7.42E-10
	Lombard9	3727.00	-3094	-3121	27	0.0721	1.00E-02	1.00E-03	2.68	7.42E-10
	Lombard8	3753.50	-3121	-3138	17	0.0663	2.13E-01	2.13E-02	2.68	7.42E-10
	Lombard7	3770.50	-3138	-3145	8	0.0859	7.05E+01	7.05E+00	2.68	7.42E-10
	Lombard6	3778.00	-3145	-3153	8	0.0459	1.31E+01	1.31E+00	2.68	7.42E-10
	Lombard5	3785.50	-3153	-3161	9	0.0760	4.24E+02	4.24E+01	2.68	7.42E-10
	Lombard4	3794.00	-3161	-3181	20	0.0604	3.56E-02	3.56E-03	2.68	7.42E-10
	Lombard3	3814.00	-3181	-3189	8	0.0799	5.19E+00	5.19E-01	2.68	7.42E-10

	Model Layer	Top Depth (ft bkb)	Top Elevation (ft)	Bottom Elevation (ft)	Thickness (ft)	Porosity	Horizontal Permeability (mD)	Vertical Permeability (mD)	Grain Density (g/cm3)	Compressibility (1/Pa)
	Lombard2	3821.50	-3189	-3194	5	0.0631	5.71E-01	5.71E-02	2.68	7.42E-10
	Lombard1	3826.50	-3194	-3219	26	0.0900	1.77E+00	1.77E-01	2.68	7.42E-10
Injection Zone	Elmhurst7	3852.00	-3219	-3229	10	0.1595	2.04E+01	8.17E+00	2.64	3.71E-10
	Elmhurst6	3862.00	-3229	-3239	10	0.1981	1.84E+02	7.38E+01	2.64	3.71E-10
	Elmhurst5	3872.00	-3239	-3249	10	0.0822	1.87E+00	1.87E-01	2.64	3.71E-10
	Elmhurst4	3882.00	-3249	-3263	14	0.1105	4.97E+00	1.99E+00	2.64	3.71E-10
	Elmhurst3	3896.00	-3263	-3267	4	0.0768	7.52E-01	7.52E-02	2.64	3.71E-10
	Elmhurst2	3900.00	-3267	-3277	10	0.1291	1.63E+01	6.53E+00	2.64	3.71E-10
	Elmhurst1	3910.00	-3277	-3289	12	0.0830	2.90E-01	2.90E-02	2.64	3.71E-10
	MtSimon17	3922.00	-3289	-3315	26	0.1297	7.26E+00	2.91E+00	2.65	3.71E-10
	MtSimon16	3948.00	-3315	-3322	7	0.1084	3.78E-01	3.78E-02	2.65	3.71E-10
	MtSimon15	3955.00	-3322	-3335	13	0.1276	5.08E+00	2.03E+00	2.65	3.71E-10
	MtSimon14	3968.00	-3335	-3355	20	0.1082	1.33E+00	5.33E-01	2.65	3.71E-10
	MtSimon13	3988.00	-3355	-3383	28	0.1278	5.33E+00	2.13E+00	2.65	3.71E-10
	MtSimon12	4016.00	-3383	-3404	21	0.1473	1.59E+01	6.34E+00	2.65	3.71E-10
	MtSimon11 *(injection Interval)*	4037.00	-3404	-3427	23	0.2042	3.10E+02	1.55E+02	2.65	3.71E-10
	MtSimon10	4060.00	-3427	-3449	22	0.1434	1.39E+01	4.18E+00	2.65	3.71E-10
	MtSimon9	4082.00	-3449	-3471	22	0.1434	1.39E+01	4.18E+00	2.65	3.71E-10
	MtSimon8	4104.00	-3471	-3495	24	0.1503	2.10E+01	6.29E+00	2.65	3.71E-10
	MtSimon7	4128.00	-3495	-3518	23	0.1311	6.51E+00	1.95E+00	2.65	3.71E-10
	MtSimon6	4151.00	-3518	-3549	31	0.1052	2.26E+00	6.78E-01	2.65	3.71E-10
	MtSimon5	4182.00	-3549	-3588	39	0.1105	4.83E-02	4.83E-03	2.65	3.71E-10
	MtSimon4	4221.00	-3588	-3627	39	0.1105	4.83E-02	4.83E-03	2.65	3.71E-10
	MtSimon3	4260.00	-3627	-3657	30	0.1727	1.25E+01	1.25E+00	2.65	3.71E-10
	MtSimon2	4290.00	-3657	-3717	60	0.1157	2.87E+00	2.87E-01	2.65	3.71E-10

Table 4.17. Summary of Model Initial Conditions

Parameter	Reference Depth (bkb)	Value
Reservoir Pressure	4,048 ft	1,790.2 psi
Aqueous Saturation		1.0
Reservoir Temperature	3,918 ft	96.6°F (35.9°C)
Temperature Gradient		0.00672°F/ft
Salinity		47,500 ppm

Boundary conditions were established with the assumption that the reservoir is continuous throughout the region and that the underlying Precambrian unit is impermeable. Therefore, the bottom boundary was set as a no-flow boundary for aqueous fluids and for the CO_2-rich phase. The lateral and top boundary conditions were set to hydrostatic pressure using the initial condition with the assumption that each of these boundaries is distant enough from the injection zone to have minimal to no effect on the CO_2 plume migration and pressure distribution.

Injection into four lateral wells with a wellbore radius of 4.5 in. was modeled with the lateral leg of each well being located within the best layer of the injection zone to maximize injectivity. The CO_2 mass injection rate was distributed among the four injection wells for a total injection rate of 1.1 MMT/yr for 20 years. A maximum injection pressure of 2,252.3 psi was assigned at the top of the open interval (depth of 3,850 ft bgs), based on 90% of the fracture gradient (0.65 psi/ft).

The representative case scenario was simulated for a total time of 100 years to predict the migration of CO_2 and formation fluids. The results demonstrated that the injection rate of 1.1 MMT/yr could be attained with the four lateral injection wells. Most of the CO_2 mass occurred in the CO_2-rich (or separate-) phase, with 20 percent occurring in the dissolved phase at the end of the simulation period. Residual trapping began to take place once injection ceased, resulting in about 15 percent of the total CO_2 mass being immobile at the end of 100 years.

The CO_2 plume formed a cloverleaf pattern as a result of the four lateral-injection-well design. A cross-sectional view of the CO_2 plume is presented as slices through the well centers and along the well trace (Figure 4.78). Plume growth occurred both laterally and vertically as injection continued. Most of the CO_2 resided in the Mount Simon Sandstone, with a small amount entering the Elmhurst and the lower part of the primary confining zone (Lombard). Once injection ceased at 20 years, the lateral growth became negligible but the plume continued to move slowly, primarily upward. Once CO_2 reached the low-permeability zone in the upper Mount Simon it began to move laterally. There was no additional CO_2 entering the confining zone from the injection zone after injection ceases.

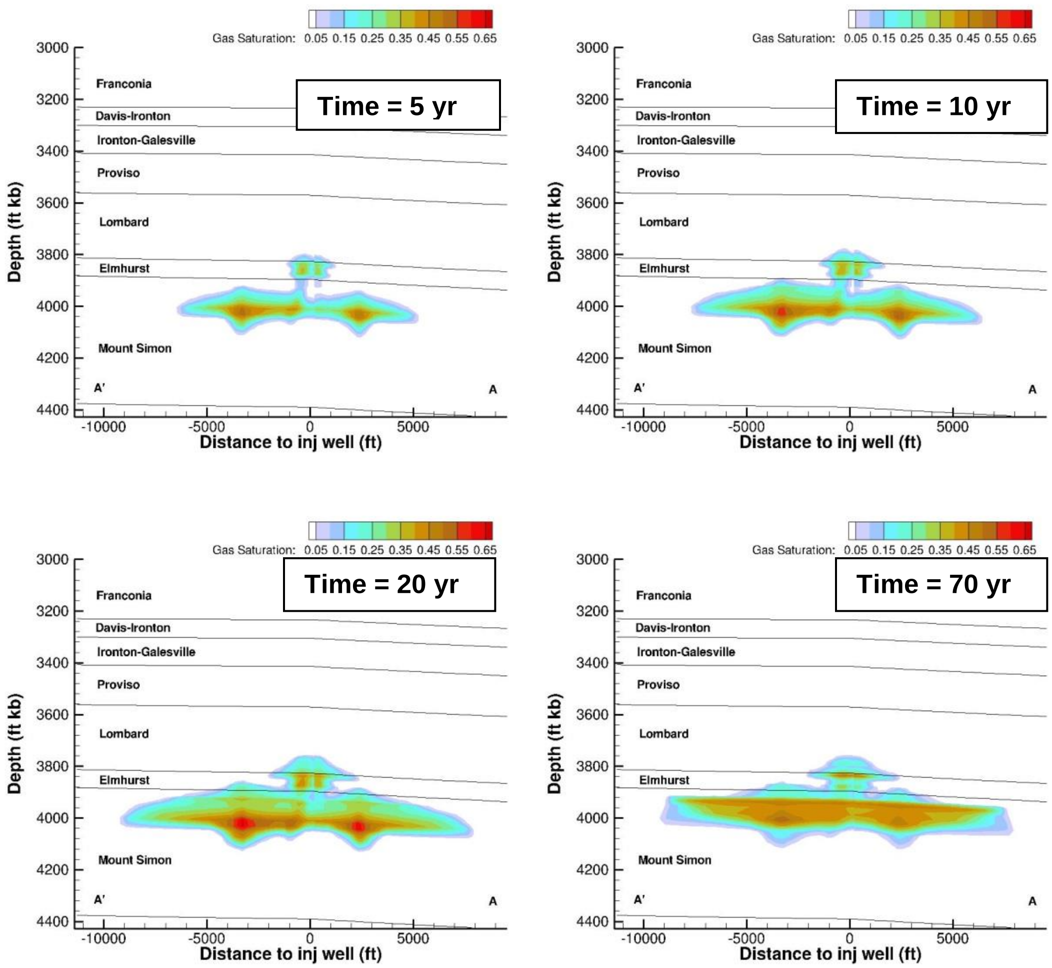


Figure 4.77. Cutaway View of CO_2-Rich Phase Saturation along A-A' (Wells 1 and 3) for Selected Times (5 Years, 10 Years, 20 Years, and 70 Years)

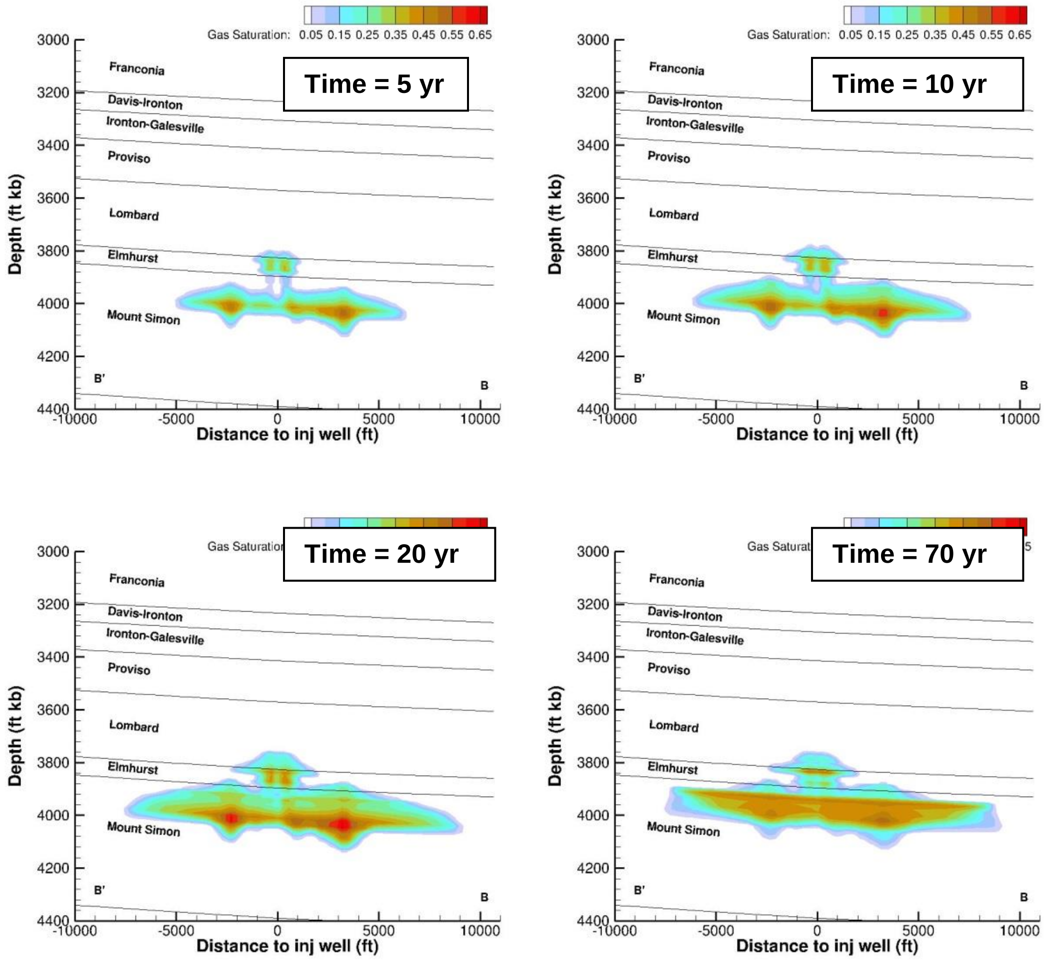


Figure 4.78. Cutaway View CO_2-Rich Phase Saturation along B-B' (Wells 2 and 4) for Selected Times (5 Years, 10 Years, 20 Years, and 70 Years)

4.6.2.5 *Method for Delineating the Area of Review from Model Results (White et al. 2011)*

Delineating the AoR of the injected separate-phase CO_2 plume is required by the EPA permit application for UIC Class VI wells. However, the regulations do not specifically define how the extent of the plume is to be determined. A common approach for determining the extent of the separate-phase CO_2 plume is to use the maximum extent based on gas or CO_2-rich phase saturation, and it often uses an arbitrary cut-off value for saturation. The FutureGen 2.0 Project therefore determined a methodology for determining the extent of CO_2 plume based on the mass of CO_2 rather than the saturation (White et al. 2011).

In general, most of the CO_2 injected for storage exists in the subsurface in the supercritical phase, assuming appropriate injection-zone pressure and temperature. Some of the CO_2

dissolves in the aqueous phase. Using the CO_2-rich phase saturation as a defining parameter for the CO_2 plume extent is subject to overprediction due to numerical model choices such as grid spacing. In addition, the gas saturation is dependent on rock porosity and the gas density is dependent on pressure and temperature. Consequently, determining the CO_2 plume extent based on CO_2 saturation may be misleading especially for rocks with very low porosity. In addition, because of the potential for fingering and narrow channeling of CO_2 in continuous layers of relatively high permeability, the CO_2 plume extent determined using this approach may be controlled by preferential flow-through fingers or channels.

Therefore, to accurately delineate the plume size, a methodology that used the vertically integrated mass per unit area (VIMPA) of CO_2 was developed. This ensures that the plume extent is defined based on the distribution of the mass of CO_2 in the injection zone. The VIMPA is calculated as follows:

$$VIMPA_{i,j} = \sum_k \frac{M_{i,j,k}}{A_{i,j,k}}$$

where
M = the total CO_2 mass in a cell,
A = the horizontal cross-sectional area of a cell,
i and j = cell indices in the horizontal directions, and
k = the index in the vertical direction.

The VIMPA may be calculated for the CO_2-rich phase, the dissolved CO_2, or the total CO_2 for the entire vertical depth or for a specific layer or layers (e.g., the injection zone). The VIMPA distributes non-uniformly in the horizontal plane. Generally, the VIMPA is larger near the injection well and decreases gradually away from the well. For certain geologic conditions, the plume size defined by the area that contains all of the CO_2 mass can be very large, while in fact, most of the mass may reside in a subregion of that area.

For the purposes of AoR determination, the FutureGen 2.0 Project initially defined the extent of the plume as the contour line of VIMPA, within which 99.0 percent of the CO_2-rich phase (separate-phase) mass is contained. The acreage (areal extent in acres) of the plume was calculated by integrating all cells within the plume extent. Therefore, the CO_2 plume referred to in the UIC permit application was defined as the area containing 99.0 percent of the CO_2 mass.

It is noted that the CO_2 plume size is different from the AoR, which is the larger extent encompassed by the boundary of CO_2 plume and the boundary of pressure differential. The pressure boundary was determined as the 10 psi of pressure differential.

4.6.2.6 *Uncertainty Analysis*

Modeling underground CO_2 storage involves many conceptual and quantitative uncertainties, primarily resulting from uncertainty in parameters such as permeability, porosity, saturation, and relative permeability functions, along with the geologic description of the injection zone and confining zone. To address these uncertainties for the UIC permit applications, Monte Carlo simulations were conducted based on the representative case presented in the UIC permit application. The analysis focused on a parsimonious set of parameters that strongly influence the CO_2 plume size.

The effects of scaling factors associated with porosity, permeability, and fracture gradient on injectivity and plume size were evaluated. The three scaling factors were independent variables, while the rock type and other mechanical/hydrological properties for the geological layers were treated as dependent variables, which vary according to scaling.

The global sensitivity of selected output variables, including the percent of CO_2 mass injected, the acreage of the plume, the acreage of the projected plume, and the percent variation of the plume area relative to the representative case, was analyzed. The projected acreage of the plume was calculated for cases where less than 100 percent of the CO_2 mass was injected, providing a normalization of the plume area for direct comparison across cases. Both marginal (individual) and joint (combined) effects were evaluated.

Thirty-two cases were defined from the representative case model using the quasi-Monte Carlo sampling technique to represent a statistical distribution of possible cases based on the selected parameters. Simulation results indicated that increasing the porosity produced a smaller predicted plume area. Varying the permeability also resulted in a smaller plume area, but with a slightly weaker effect, primarily because in this case only a narrow range of permeability values across layers was considered.

4.6.2.7 *Simulated CO_2 Plume Area and Injected Mass*

The proposed injection-well design at the FutureGen 2.0 CO_2 storage site consisted of four horizontal injection wells (laterals) originating from a common well pad. Modeling such a design can be challenging because of the disparity in length scales between the near-field region (near the wells) and the far-field region (entire reservoir storage system), and specifically the need for appropriate numerical resolution to model processes throughout the system, which can result in an impractical number of grid cells and associated computational run times. In collaboration with Lawrence Berkeley National Laboratory, two independent approaches for modeling the near field were investigated (White et al. 2014), one that is implemented in STOMP- CO2 (White et al. 2013a, b) and the other that is implemented in T2Well/E CO2H (Pan and Oldenburg 2013). In addition to evaluating the importance of the wellbore-reservoir coupling scheme, a variety of grid resolutions was considered in the STOMP- CO2 simulations to explore the effects of grid-spacing choices.

Three cases were developed to compare the wellbore-reservoir coupling schemes used by the two simulators: 1) a radial model of the vertical portion of the injection well, 2) a simplified 3D model of the injection zone containing one horizontal well assuming one-quarter mirror symmetry of four radiating horizontal wells, and 3) a composite case of one well with both vertical and horizontal sections open to the reservoir. The injectivity (pressure rise for a given mass injection rate) and plume development were compared.

4.6.2.7.1 Case 1: Vertical Well in the Elmhurst Formation

A radially symmetric model of the vertical portion of the injection well was developed to evaluate the wellbore-coupling schemes for a vertical well (Figure 4.79). The model domain was represented by the seven layers of the Elmhurst Formation used in the UIC permit application modeling (see Table 4.18 for hydrologic properties). The top and bottom boundaries were closed and the lateral boundary was open. The variably spaced grid was finer at the well and increased outward. The specified injection rate was 0.0912 MMT/yr, occurring in the four lowermost layers of the model and representing 1/12th of the total injection planned for the FutureGen 2.0 CO_2 storage wells. The injection temperature was specified as 38.4°C at the wellhead in the T2Well simulations. STOMP-CO2 requires the injection temperature to be specified at the top of the injection zone. Therefore, CO2Flow, a steady-state, 1D flow simulator used for the FutureGen 2.0 wellbore modeling (Stewart 2014; Stewart et al. 2012), was used to estimate pressure drop and fluid state evolution as CO_2 moves through the injection tubing. A wellhead temperature of 38.4°C and injection rate of 1.1 MMT/yr produced an injection temperature of 54.5°C for the top of the screened interval in the Elmhurst.

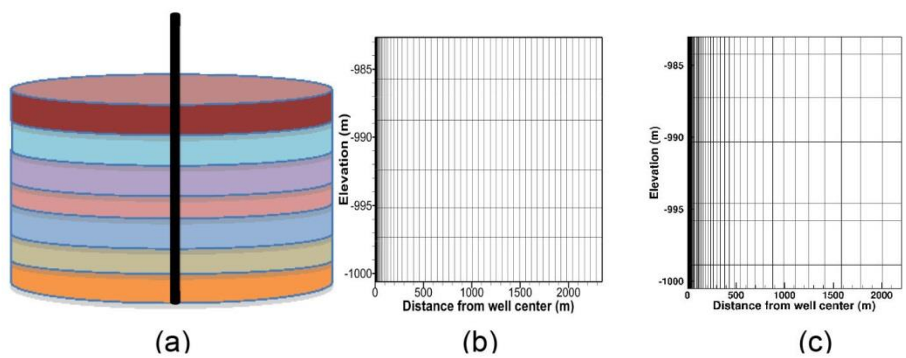


Figure 4.79. Conceptual Model (a) and Radially Symmetric T2Well/TOUGH2 Grid (b) and STOMP-CO2 Grid (c) Used for Case 1

Table 4.18. Changes in Parameter Values and the Assumed Standard Deviation for Sensitivity Analysis

	Name	Parameter Symbol	Units	Ln-Transformed?	ΔX or b†	Assumed σ_x
1	Porosity	por	$m^3 m^{-3}$	No	0.01	0.01
2	Horizontal Permeability	kh	mD	Yes	0.1	0.095
3	Vertical Permeability	kv	mD	Yes	0.1	0.095
4	Gas Entry Pressure	pe	m	Yes	0.1	0.095
5	Pore Size Distribution Parameter Lambda	lambda	-	No	0.1	0.1
6	Residual Water Content	srw	-	No	0.1	0.1
7	Maximum Trapped Gas Content	srn	-	No	0.1	0.1
8	Grain Density	rho_g	$kg\ m^{-3}$	No	100	100
9	Pore Compressibility	comp	pa^{-1}	Yes	0.1	0.095
10	Thermal Conductivity	kt	$W\ m^{-1} K^{-1}$	Yes	0.1	0.095
11	Heat Capacity	cp	$J\ kg^{-1} K^{-1}$	No	100	100

†b for the ln-transformed variables and ΔX for other variables

The results from both simulators compared favorably, and showed the bottomhole pressure decreasing with time due to a decrease in resistance as the CO_2 plume advances in the reservoir and enters higher permeability layers (see Figure 4.80). After approximately 8 years of injection, the free CO_2 migrates into the higher permeability layers above the perforations.

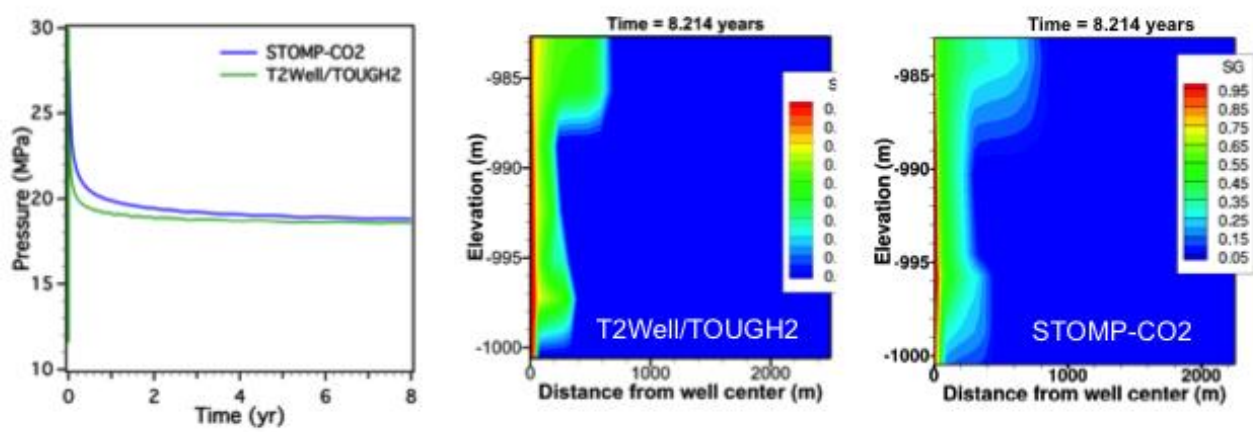


Figure 4.80. Case 1 Simulation Results

4.6.2.7.2 Case 2: Lateral Well in the Mount Simon Formation

The 3D model of the injection zone for Case 2 contained one 2,000 ft-long horizontal well in the Mount Simon11 unit (MtS11), assuming one-quarter mirror symmetry of the four radiating horizontal wells. An injection rate of 0.252 MMT/yr and injection temperature of 40°C were assumed. Figure 4.81 shows the conceptual model and the numerical grid used in T2Well/ECO2H and STOMP-CO2 simulations. The layers above MtS11 are lumped into a single layer (MtSup) with the averaged hydraulic parameters (geometric average for vertical permeability and arithmetic average for others), while the layers below MtS11 (MtSlo) are lumped in the same way. In the T2Well/ECO2H simulations, the wellbore was exactly represented in the grid with local refinement near the well in the X-Z plane as well as in the X-Y plane to accurately capture the flow behavior near the well. The STOMP-CO2 simulations assumed 1-ft grid spacing in x and y, and 3 ft spacing in z near the well, increasing outward.

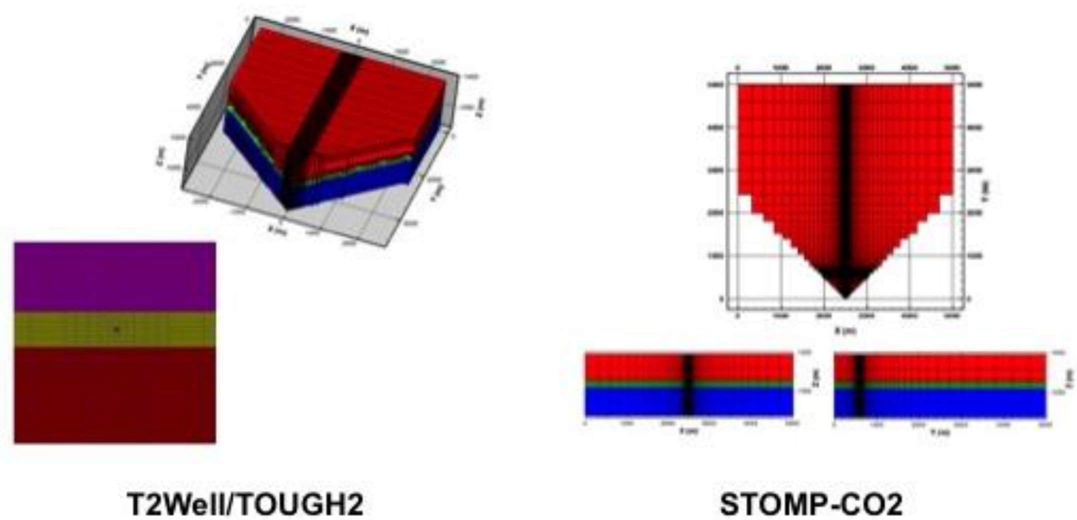


Figure 4.81. Conceptual Model and the Numerical Grid Used in T2Well/ECO2H and STOMP-CO2 Simulations

The results from both simulators (Figure 4.82) showed that pressure drop along the horizontal well is small (from heel to toe). The pressure at the top of the model domain showed a similar response, but with lower magnitude. The plume shape differences are due in large part to differences in grid resolution.

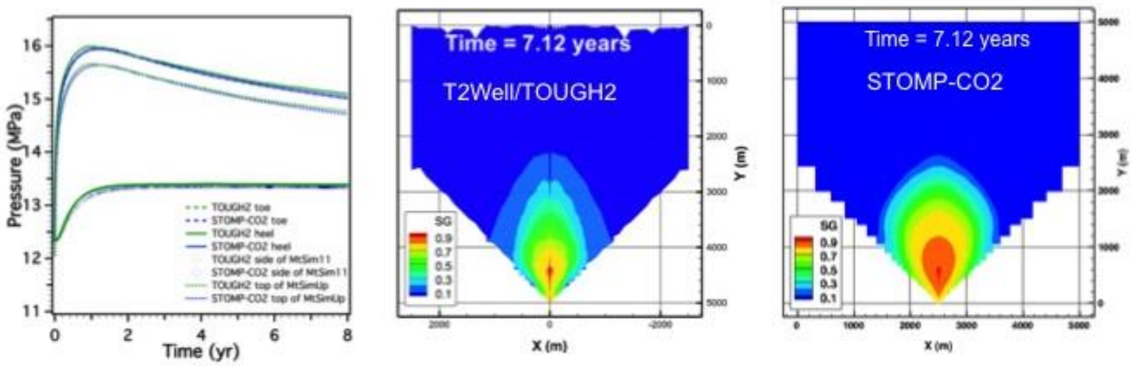


Figure 4.82. Simulation Results for Case 2 for both T2Well/ECO2H and STOMP-CO2

4.6.2.7.3 Case 3: Composite Model

Because the T2Well/ECO2H and STOMP-CO2 simulators have different capabilities, Case 3 was modeled by each team using a different approach. For T2Well/ECO2H, a combined vertical and horizontal well injection scenario was considered to investigate the performance of the entire system (Figure 4.83). To carry out this simulation, the radial symmetrical grid described in Case 1 was connected to the 3D grid of the horizontal well (Case 2) via the well. Only one-quarter of the mass flows from the bottom of the vertical well to the horizontal well because the horizontal well domain composes only one of the actual four horizontal wells; this was accomplished by diverting three-quarters of the mass flow from the bottom of the vertical directly into an artificial sink (i.e., ¾ of the mass arriving at the bottom of the vertical well is numerically removed from the system). The STOMP-CO2 simulations were based on the model used for the UIC permit applications and modeled the full domain with all four lateral wells (Figure 4.84). STOMP-CO2 does not model processes within the wellbore and assumes a constant injection temperature. Therefore, CO2Flow (a steady-state, 1D flow model) was used to estimate the pressure drop and fluid state evolution as CO_2 moves through the injection tubing. A wellhead temperature of 38.4°C and injection rate of 1.1 MMT/yr produced an injection temperature of 54.5°C for the top of the screened interval in the Elmhurst Formation. This was slightly lower than that calculated by T2Well.

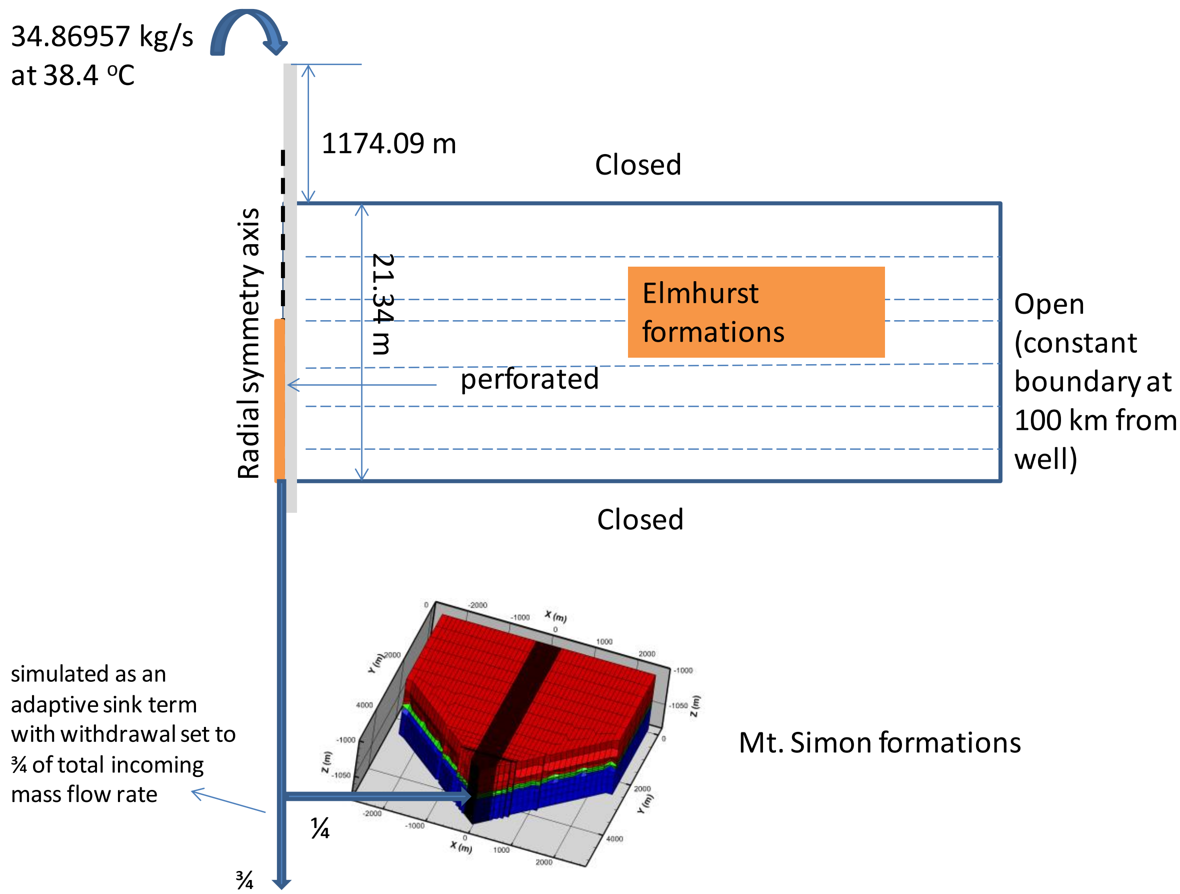


Figure 4.83. Conceptual Model and Grid Used by T2Well/ECO2H for Case 3

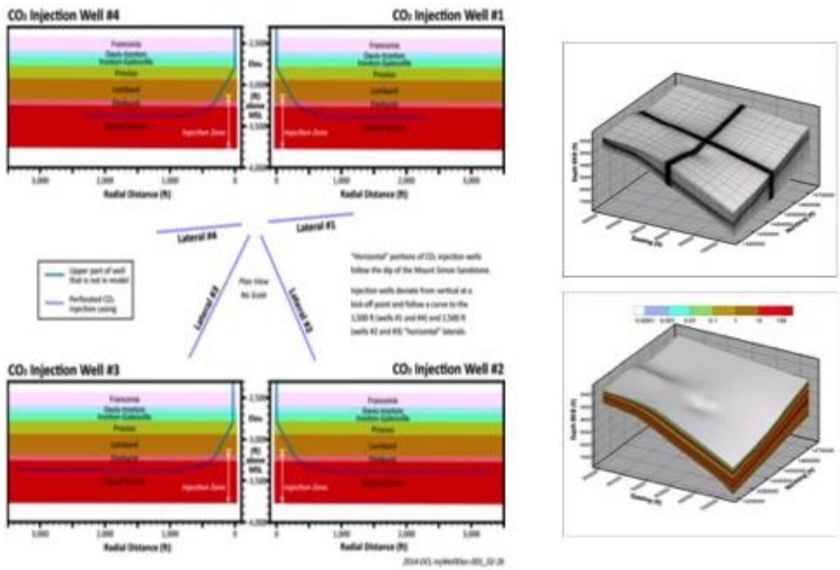


Figure 4.84. Conceptual Model and Grid Used by STOMP-CO2 for Case 3

Case 3 simulation results show both models predicting that CO_2 is mainly discharged from the section near the end of the horizontal well, in large part as a result of the interference from the other horizontal wells.

4.6.2.8 *Local Sensitivity Analysis*

A local sensitivity coefficient (LSC) method was proposed to investigate the sensitivity of input parameters and initial conditions (Zhang et al. 2014). In general, simulation results are affected by uncertainties associated with numerous input parameters, the conceptual model, initial and boundary conditions, and factors related to injection operations. Furthermore, the uncertainties in the simulation results also vary in space and time. The key need is to identify the uncertainties that critically affect the simulation results and quantify their impacts. The LSC, defined as the response of the output in percent, was used to rank the importance of model inputs on outputs. The uncertainty of an input with higher sensitivity has larger impacts on the output. The LSC is scalable by the error of an input parameter. The composite sensitivity of an output to a subset of inputs can be calculated by summing the individual LSC values.

The conceptual model for the site consisted of 31 layers, each of which was assigned a unique set of input parameters based on those used for the UIC permit application (Alliance 2013) as briefly summarized in Section 4.6.2.4. The sensitivities to 11 parameters for each of the 31 layers were investigated relative to the representative case. The parameters, changes in parameter values, and the assumed standard deviation are summarized in Table 4.18. In total 341 (= 31×11) parameters were evaluated. In addition, the sensitivities to seven inputs that describe the initial conditions of the simulation were examined (Table 4.19).

Table 4.19. Changes in Initial Conditions and Assumed Standard Deviation for Sensitivity Analysis

	Name	Parameter Symbol	Units	Ln-Transformed?	ΔX	Assumed σ_x
1	Salt Fraction	c	-	No	0.01	0.01
2	Salinity Gradient	cg	ft^{-1}	No	0.00001	0.00001
3	Injection-Zone Pressure	p	psi	No	10	10
4	Temperature	t	°F	No	10	2
5	Temperature Gradient	tg	°F ft^{-1}	No	0.001	0.001
6	Fracture-Pressure Gradient	fg	psi ft^{-1}	No	0.065	0.065
7	Injection Temperature	t	°F	No	5	5

For CO_2 injectivity and plume size, about half of the uncertainty is due to only 4 or 5 of the 348 inputs and three-quarters of the uncertainty is due to about 15 of the inputs. The initial conditions and the properties of the injection layer and its neighboring layers contribute to most of the sensitivity. Overall, the simulation outputs were very sensitive to only a small fraction of the inputs. However, the parameters that are important for controlling CO_2 injectivity are not the same as those controlling the plume size. The three most sensitive inputs for injectivity were the horizontal permeability of MtS11 (the injection layer), the initial fracture-pressure gradient, and the residual aqueous saturation of MtS11, while those for the plume area were the initial salt concentration, the initial pressure, and the initial fracture-pressure gradient. The advantages of requiring only a single set of simulation results, scalability to the proper parameter errors, and easy calculation of the composite sensitivities make this approach very cost-effective for estimating AoR uncertainty and guiding cost-effective site characterization, injection-well design, and monitoring network design for CO_2 storage projects.

4.6.2.9 *Analysis of Heterogeneity Effects on Injectivity*

The effect of heterogeneity on injectivity at the FutureGen 2.0 CO_2 storage site was investigated by developing geologic models using stochastic simulation, assuming a range of horizontal correlation lengths for generating facies distributions. STOMP-CO2 simulations were run using these geologic models.

A STOMP-CO2 simulation with 31 model layers and 500- × 500-ft horizontal grid spacing in the central 3-mile-square area surrounding the injection was used as the base case. To avoid boundary-pressure effects, the full extent of the model was 100 square miles, with progressively larger grids outside the central 3-mile-square area. The base case simulation, with homogeneous layers that extend throughout the entire 100-mile-square domain, represented the assumption that the layers observed in stratigraphic borehole FGA-1 have an infinitely long correlation length.

For the heterogeneous simulations, each of the 31 layers in the coarse-grid models was treated as a distinct facies, and the SISIM simulator from the GSLIB package (Deutsch and Journel 1998) was used to simulate the effect of progressively shorter horizontal correlation lengths. Four different correlations lengths, also termed range distances, were considered: 1000, 10,000, 100,000 and 1,000,000 ft (approximately 0.189, 1.89, 18.9, and 189 miles). Three different stochastic realizations of each horizontal correlation length were generated, for a total of 12 geologic models. Figure 4.85 and Figure 4.86 each show an example of one realization. The 31 facies were grouped by formation and each formation was simulated separately to avoid having a facies from one formation appear in another formation.

The facies distributions generated using SISIM were read into STOMP-CO2 as rock type distributions. The same hydraulic properties (permeability, porosity, etc.) were assigned to the 31 facies as were used for the 31 layers in the base case simulation. The STOMP-CO2 simulation included pressure-limited CO_2 injection into four horizontal injection wells over a 20-year period.

Simulation results showed that shorter correlation lengths used for generating the facies distributions resulted in a lower total mass of CO_2 injected. The horizontal wells were located in a 23.5-ft-thick model layer that, in the homogeneous model, was a relatively high-permeability layer surrounded by lower-permeability layers. The shorter the correlation length used in generating the geologic model, the less continuous this high-permeability layer became. This analysis demonstrated that considering heterogeneity is important, in particular when the injection zone is a thin horizontal layer.

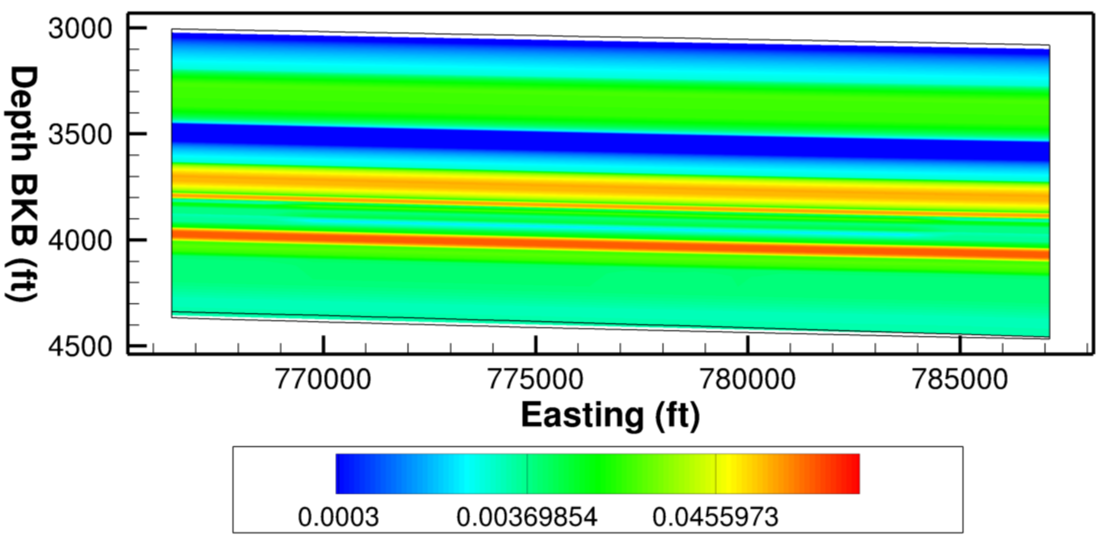


Figure 4.85. One Realization of Intrinsic Permeability (Darcy) with a Correlation Length of 189 Miles. The deepest high-permeability zone is the target injection zone**.**

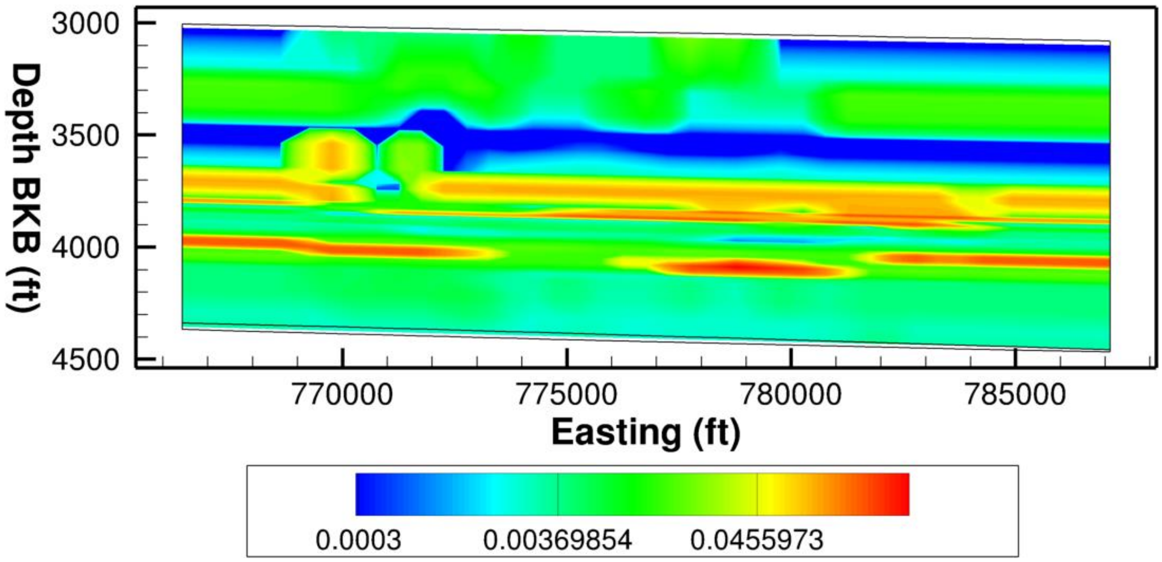


Figure 4.86. One Realization of Intrinsic Permeability (Darcy) with a Correlation Length of 1.89 Miles. The deepest high-permeability zone is the target injection zone.

4.6.2.10 *Estimation of Rock Mechanical, Hydraulic, and Thermal Properties Using Wireline Log and Core Data*

Wireline log and core data from the first stratigraphic borehole at the site were analyzed to evaluate rock mechanical, hydraulic, and thermal properties. Mineral volume fractions and other log-derived data were used with core data for estimation and calibration of parameters needed for reservoir modeling. In anticipation of future needs, workflows were developed for efficient data assimilation and parameterization of reservoir models for the site.

Schlumberger Carbon Services (Westerville, OH) provided geophysical wireline logging results for total and spectral gamma, neutron, density, photoelectric cross section, sonic dipole, resistivity, elemental capture, and CMR. Computed fluid and mineral volume fractions and permeability estimates were also provided by Schlumberger with the ELAN log suite. A total of 177 ft of whole core was collected from the lower Eau Claire-upper Mount Simon Sandstone and a total of 34 ft was collected from the lower Mount Simon-Precambrian basement interval. A total of 130 SWC plugs were also obtained from the combined Eau Claire Formation, Mount Simon Sandstone, and Precambrian basement. Core Laboratories (Houston, TX) provided core characterization services. Measurements on selected cores included matrix density, porosity, permeability, mercury injection capillary pressure (MICP) data, relative permeability, bulk and grain compressibilities, and triaxial strength tests. Thermal conductivity was measured on samples of whole core by PNWD. DSTs were also performed by PNWD over the 3,948–4,194 ft below Kelly Bushing (KB) depth interval within the upper Mount Simon Formation for calculation of field transmissivity.

Log-derived matrix densities were computed from the bulk density log and corrected fluid density data. The total porosity was estimated as one minus the sum of the mineral volume fractions. Permeability was estimated using the Coates and KSDR models (Coates and Dumanoir 1974), with the latter based on CMR. However the CMR log data were only available for the open section of the borehole, below the 3,970 ft depth (KB). Permeability estimates were also generated by PNWD using the k-Lambda model (Herron et al. 1998), which was calibrated to both core and field DST results.

4.6.2.11 *Impacts of injection Temperature and Schedule on Injectivity*

The average temperature of the reservoir at the FutureGen 2.0 CO_2 storage site is about 97°F. The injection of CO_2 for the permit application assumed continuous injection without considering any pump shut-offs for system maintenance. The temperature of the injected CO_2 and the operational schedule can affect the injectivity, reservoir pressure, and plume size. Therefore, simulations were conducted to investigate the impacts of injection temperature and operational schedule on CO_2 migration in the reservoir. The following simulation scenarios were considered:

- Continuous injection:
  - cm30_57f: CO_2 injection with assumed CO_2 temperatures of 57°F (13.9°C)
  - cm30_77f: CO_2 injection with assumed CO_2 temperatures of 77°F (25°C)
  - cm30_97f: CO_2 injection with assumed CO_2 temperatures of 97°F (36.1°C)
  - cm30_117f: CO_2 injection with assumed CO_2 temperatures of 117°F (47.2°C).

- Injection with 72.875 days shut-off for an 18-month period:
  - cm30_d2: CO_2 injection with assumed CO_2 temperatures of 57°F (13.9°C)
  - cm30_a2: CO_2 injection with assumed CO_2 temperatures of 77°F (25°C)
  - cm30_b2: CO_2 injection with assumed CO_2 temperatures of 97°F (36.1°C)
  - cm30_c2: CO_2 injection with assumed CO_2 temperatures of 117°F (47.2°C).

Results:

Higher injection temperature will lead to
- higher injection pressure
- larger plume size
- higher injectivity.

Pump shut-off will lead to
- higher maximum injection pressure
- lower injectivity.

4.6.2.12 *Extension of the Relative Permeability to Zero Water Content*

The calculation of the relative permeability of the aqueous (wetting) or non-aqueous (non-wetting) phase using models such as those in Burdine (1953) and Mualem (1976) is based on the definition of the effective saturation. It assumed that the flow is negligibly small when a porous medium is at or less than the residual wetting-phase saturation, S_{wr}. Practically, the reasons for the finite value of S_{wr} are that the dominant historical water-content measurements were in the wet range and the typical soil water-retention data demonstrated an asymptotic behavior.

Webb (2000) extended the classical retention function (e.g., Brooks and Corey 1966; van Genuchten 1980) to the oven-dry condition with the adsorption-based model of Campbell and Shiozawa (1992). The Webb (2000) extension has been used in numerical simulator—e.g., the STOMP flow simulator (White et al. 2013a)—to describe the relationship between wetting-phase saturation and capillary pressure from zero to full saturation. The Webb (2000) model did not address the calculation of relative permeability at low water content.

To solve this problem, Zhang (2011) redefined S_{wr} and the effective saturation for the condition of $S_w < S_{wc}$, the critical wetting-phase saturation, or $h < h_c$, the critical capillary pressure. In this way, the original definition of retention function and corresponding compatible relative permeability can be used without additional change. In the Zhang (2011) model, no algebraic relationship was found to explicitly express the capillary pressure as a function of S_w when $S_w < S_{wc}$. Hence, an iterative process would be needed to find the h values corresponding to $S_w < S_{wc}$. The algorithm is feasible to implement, but it would cost extra computation time.

To circumvent the needed iteration process in a numerical simulator, the Zhang (2011) model was modified so that explicit algebraic expressions are available for both $S_w(h)$ and $h(S_w)$, while compatible retention and relative permeability can still be obtained. In addition, the relative permeability compatible with the extended retention for the non-aqueous phase is derived.

4.6.3 Thermo-Mechanical Reservoir Behavior

The impact of temperature variations of injected CO_2 on the mechanical integrity of a reservoir is a problem rarely addressed in the design of a CO_2 storage site. The geomechanical simulation of the FutureGen 2.0 CO_2 storage site presented here takes into account the complete modeling of heat exchange between the environment and CO_2 during its transport in the pipeline and injection well before reaching the reservoir, as well as its interaction with the reservoir host rock.

The first step of the evaluation consists of determining the temperature at the bottom of the injection well. A computer program, CO2Flow, was specifically developed for this purpose. It can rigorously solve energy and momentum balances for CO_2 in pipelines and injection wells while considering changes in fluid state over the relevant conditions.

The second step comprises the geomechanical modeling of the CO_2 injection in the reservoir. This is performed using the STOMP-CO2/ABAQUS® sequentially coupled simulator. The developed capability uses the Pacific Northwest National Laboratory's STOMP multi-fluid flow simulator, which solves conservation equations for component mass (i.e., water, CO_2, and salt) and energy on a structured orthogonal grid (White and Oostrom 2006; White et al. 2012) interfaced with the commercial ABAQUS® (2011) finite element packages. STOMP-CO2 is used to calculate the aqueous pressure, aqueous saturation, gas pressure, gas saturation, and temperature for each node and time step. The information from STOMP-CO2 is then passed to ABAQUS at each selected time step, to calculate strains, stresses (including thermal stresses), and fluid pressure; update the permeability and porosity; and evaluate a fracture criterion.

The details of these two modeling steps are presented and the results in terms of stresses and potential fracture development in the reservoir are discussed for various injection temperatures.

4.6.3.1 *From the Plant to the Reservoir: CO2Flow*

Several aspects of a geological CO_2 storage project require the calculation of expected conditions along the flow path from the fluid source (e.g., a power plant with CO_2 capture), through pipelines and equipment, down an injection well, and ultimately to the storage formation. The computer program CO2Flow was written to support scoping analyses, permitting, and system design associated with geological CO_2 storage. The program estimates pressure drop and fluid state evolution as CO_2 moves through pipelines and injection tubing. A steady-state, 1D flow model is used to calculate the pressure drop along a discrete number of pipeline or well elements (a complete description of the model can be found in Stewart et al. 2012). This computer model uses the well-established Span and Wagner (1996) state equations for CO_2 to describe changes in fluid properties while flowing through pipelines and down injection wells. The program marches from the inlet of the pipeline to the end of the injection tubing, solving steady-state energy and momentum balances for discrete pipe segments. Cases examined covered a range of flow rates as well as seasonal variations in the temperature of the surroundings. The model included heat transfer from the fluid in the pipeline, which is a strong function of soil thermal conductivity. Because seasonally varying soil thermal conductivities have not yet been characterized over the entire pipeline route, a range of values was used in the model to bracket conditions that will likely exist. Basic features of the CO2Flow program have been checked using hand calculations, and predictions for full well simulations have been validated by comparison to data from injection tests at the American Electric Power (AEP) Mountaineer test site near New Haven, West Virginia.

For the FutureGen 2.0 Project, the flow path includes a pipeline 28.2 miles (45.4 km) in length, followed by a vertical well section that extends to a depth of 3180 ft (970 m) below the ground surface, followed by a curved segment having a radius of 830 ft (253 m) leading to the final horizontal well segment. The current design calls for the perforated well section to begin in the curved segment, which places the top of the injection interval somewhat higher than the horizontal portion of the well. A linear distance of 814 ft (248 m) along the curved segment to the beginning of the perforations corresponds to a TD of 3,870 ft (1,181 m) bgs.

The pressure boundary condition for a calculation encompassing the entire flow path from fluid source to repository is generally the pressure at the top of the perforated well section required to push a given flow rate of fluid into the geological formation. The pressure required at the top of the perforated injection interval will vary over the course of injection operations as the formation is pressurized by injection and then relaxes during outages. The fluid temperature is usually specified at the CO_2 source. In such a case, the calculation marches from the fluid source to the top of the injection interval, and the pressure at the source is iterated until the required pressure at the top of the injection interval is met.

The flowing fluid is subject to frictional losses in both the pipeline and injection-well tubing. Hydrostatic pressure changes are also accounted for, although the average slope of the proposed FutureGen pipeline is small, with only a 184-ft (56-m) increase from the plant to the wellhead. The majority of the pressure change as the fluid moves down the injection well is due to hydrostatic effects.

When the CO_2 travels along the pipeline from the plant, it is cooled by exchange of heat with the surroundings. The rate of cooling depends primarily upon the temperature of the surroundings and the thermal conductivity of the soil in which the pipeline is buried, but also on the fluid velocity, which is in turn a function of the pressure along the flow path between the plant and wellhead.

When injection is first initiated, significant heat transfer between the injected fluid and the rock surrounding the vertical well is expected to moderate the temperature of the fluid and pull it toward the formation temperature at depth. However, the rate of heat transfer is expected to decrease over time, as a zone of rock around the well moves closer to thermal equilibrium with the fluid. A limiting case after long time periods of steady injection is therefore considered to be adiabatic flow of fluid in the well. Under these conditions, the fluid temperature moving down the well still changes due to Joule-Thomson effects.

Well and pipeline flow simulations were carried out for a number of conditions, covering expected injection pressures, fluid flow rates, and seasonal temperature variations. Soil thermal conductivity depends upon the soil composition and the water content, which will vary with the season. A range of soil thermal conductivities was therefore used in the simulations to bracket the rate of heat transfer expected in the pipeline. Extreme high and low values of 2.6 and 0.35 $W.m^{-1}.K^{-1}$ are suggested by Kreith et al. (2011). High and low values of 1.25 and 0.50 $W.m^{-1}.K^{-1}$ are likely more representative of the agricultural soil and moisture ranges expected along the FutureGen 2.0 pipeline route. The conditions chosen to be most representative of long, steady injections were those of nominal flow rate (1.1 Mt/yr) and maximum pressure at the top of the injection interval (90% of estimated fracture pressure).

Table 4.20 shows input parameters for a representative case examined using the CO2Flow program. Table 4.21 shows calculated (or specified) CO_2 temperatures and pressures at the plant, wellhead, and top of the injection interval for summer and winter seasons. The total CO_2 flow is assumed to be split evenly between four identical wells. This case assumes adiabatic conditions in the wells themselves. This calculation does not include any pressure drop due to throttling or control valves, but will likely be included in the final system in order to control the pressure and distribute flow between the four injection wells. If a given pressure drop were taken across control valves at the wellhead, then the pressure in the pipeline and at the plant would be higher by approximately that amount.

The CO_2 injection temperature at the top of the injection interval varies between 28 and 55.4°C using the extreme case scenarios. Yearly average fluid temperature within the formation varies between 42°C using extreme soil conductivities and 47°C using a more reasonable range of soil conductivities for the planned pipeline route. This is a good estimate of the actual injection temperature, considering that the thermal mass of the rock around the well will tend to buffer any transient extremes. These values are compared to a set of injection temperatures used in the geomechanical modeling step in the following section.

Table 4.20. Input Parameters for Example Pipeline and Well Case

Parameter	Value	Unit
Average annual flow rate	1.10	Mt/yr
System availability fraction	0.85	
Maximum required injection pressure	156.3 (2266	bar psia)
Pipeline length	45.4	km
Pipeline slope (rise/run)	0.00124	
Pipeline element length (for numerical integration)	40	m
Fluid temperature at plant	45	°C
Average soil surface temperature (summer)	26.2	°C
Average soil surface temperature (winter)	1.4	°C
Soil thermal conductivity (summer)	0.35–0.5	W.m-1.K-1
Soil thermal conductivity (winter)	1.25–2.6	W.m-1.K-1
Pipeline cover depth	1.52	m
Pipeline inside diameter	0.257	m
Pipeline outside diameter	0.273	m
Length of vertical well segment	970.5	m
Well curved segment radius of curvature	253	m
Distance along curved segment to perforations	248	m
Well element length (for numerical integration)	1	m
Injection tubing inside diameter	0.074	m
Pipe absolute roughness (pipeline and well tubing)	4.6 × 10-5	m

Table 4.21. Calculated Fluid Conditions at Various Points Assuming Soil Conductivities of 2.6 $W.m^{-1}.K^{-1}$ in Winter and 0.35 $W.m^{-1}.K^{-1}$ in Summer

Location	Temperature (°C)		Pressure (bar)	
	Winter	Summer	Winter	Summer
Plant	44.7	44.7	85.5	111.4
Wellhead	17.6	39.2	67.9	95.5
Top of injection interval	28.0	55.4	156.3	156.3

4.6.3.2 *Reservoir Geomechanical Modeling: STOMP + ABAQUS*

4.6.3.2.1 STOMP/ABAQUS Computational Tool

In the STOMP/ABAQUS coupled approach, STOMP models are built to simulate aqueous and CO_2 multiphase fluid flows in the reservoirs. The ABAQUS model reads STOMP output data for cell center coordinates, gas pressures, aqueous pressures, temperatures, and saturations and imports these data into its mesh using a mapping procedure developed for the exchange of data between STOMP and ABAQUS at selected times. ABAQUS has constitutive models implemented via user subroutines to compute stiffness, stresses, strains, slip factor, fracture criterion, pore pressure, permeability, porosity, and capillary pressure using the STOMP output data, and provides STOMP with the updated permeability, porosity, and capillary pressure at the selected times. The capillary pressure was computed in terms of the air-entry pressure, permeability, and porosity based on a model used by Rutqvist and Tsang (2002). A modification of the STOMP/ABAQUS computational tool was made to allow evaluation of thermal stresses based on a thermo-poroelastic constitutive model. The computed fracture criterion is the Mohr-Coulomb criterion (Jaeger and Cook 1979), where hydraulic fracture is predicted to occur at a grid element if the fluid pressure exceeds the least compressive principal stress. In other words, the Mohr-Coulomb criterion is verified if the least compressive effective principal stress that defines the pressure margin to fracture (PMF) attains or exceeds zero.

4.6.3.2.2 Modeled Domain

The domain is discretized into 60 × 60 × 31 numerical grid cells (Figure 4.87). The grid is refined near the center of the domain, where the four horizontal injection wells are located. Each horizontal well has an internal wellbore radius of 0.1143 m (4.5 in.). The imposed injection mass rate was 651 t/day (7.54 kg/s) for the smaller two wells and 1085 t/day (12.56 kg/s) for the other two wells with larger extensions. The maximum well-top pressure was 155.3 bar (2,252 psi).

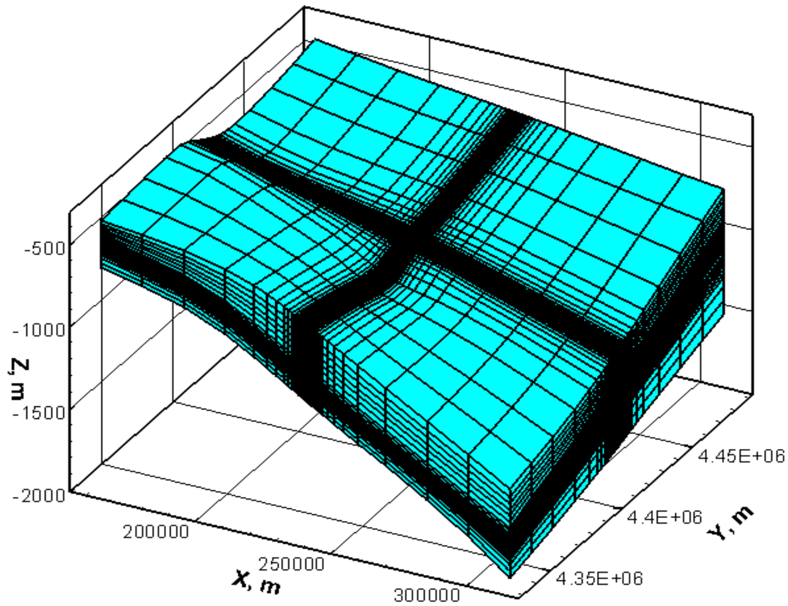


Figure 4.87. Mesh of the Study Domain

4.6.3.2.3 Material Properties

Young's modulus and Poisson's ratio for the geomechanical model are taken from anisotropic elastic properties logs collected on stratigraphic borehole FGA-1. Examination of histograms of Young's modulus and the Poisson's ratio by layer indicated that the data for many of the layers were skewed; therefore, median values of the properties were calculated for each layer, rather than the mean. The layering is based on a 31-layer model provided by the FutureGen 2.0 modeling team (see Section 4.6.2).

Thermal expansion coefficients are estimated for each layer using a multi-step process. The composition of the solid phase of the materials is taken from the ELAN log. Thermal expansion coefficients of the pure phase minerals were taken from the literature, primarily (McKinstry 1965; Robertson 1988; Fei 2013). The thermal expansion coefficient of the rock in each layer is then estimated by taking a weighted average of the pure phase mineral thermal expansion coefficients, where the weights are the volume percentages of each mineral in the solid phase. The median thermal expansion coefficient is then calculated for each layer.

4.6.3.2.4 Initial and Boundary Conditions

The geothermal gradient is assumed to be 1.22×10^{-2}°C/m and the reference salt mass fraction is assumed to be 4.75%. Different boundary conditions are appropriate for flow boundaries and are applicable to the conservation equations for water, CO_2, and salt mass. A zero flux boundary condition specifies an impermeable boundary for flow or transport at the bottom boundary. Zero flux boundary conditions are applied for the gas phase along all boundaries.

Initial values of aqueous pressure, temperature, and salt mass fraction in the nodes adjacent to a boundary surface were used as constant boundary conditions.

4.6.3.3 *Results and Discussion*

The model has been developed for four different temperatures (47°C, 36°C, 25°C, and 14°C) but we are presenting the results for 36°C, a high-temperature case but still below the expected range of injection temperature (see Section 4.6.3.1), and for 14°C representing the extreme low-temperature case.

Figure 4.88 provides the evolution of temperature, fluid pressure, and PMF vs. time at selected points along well 1 for the 36°C case. Minimal temperature change was observed for the 20-year period, and the fluid pressures rapidly evolved and stabilized at about 15.5 MPa (2,250 psi) after 2 years. These variations of temperature and fluid pressure did not cause any concerns because the predicted PMFs were well below zero. The results are similar for the three other wells.

For the case where the injection temperature is 14°C, the temperature distributions predicted by STOMP at the selected locations show a larger decrease in temperature for some nodes in all the wells. Figure 4.89 shows the results for well 1 but they are very similar in the other wells. In particular, location number 30635 in well 1 experiences a larger decrease in temperature of about ~6°C at 20 years. The PMF is far exceeded in this case. The fluid-pressure evolutions are similar to those for the 36°C case. The exceedance of the fracture criterion is caused by the decrease in temperature associated with the lower injection temperature.

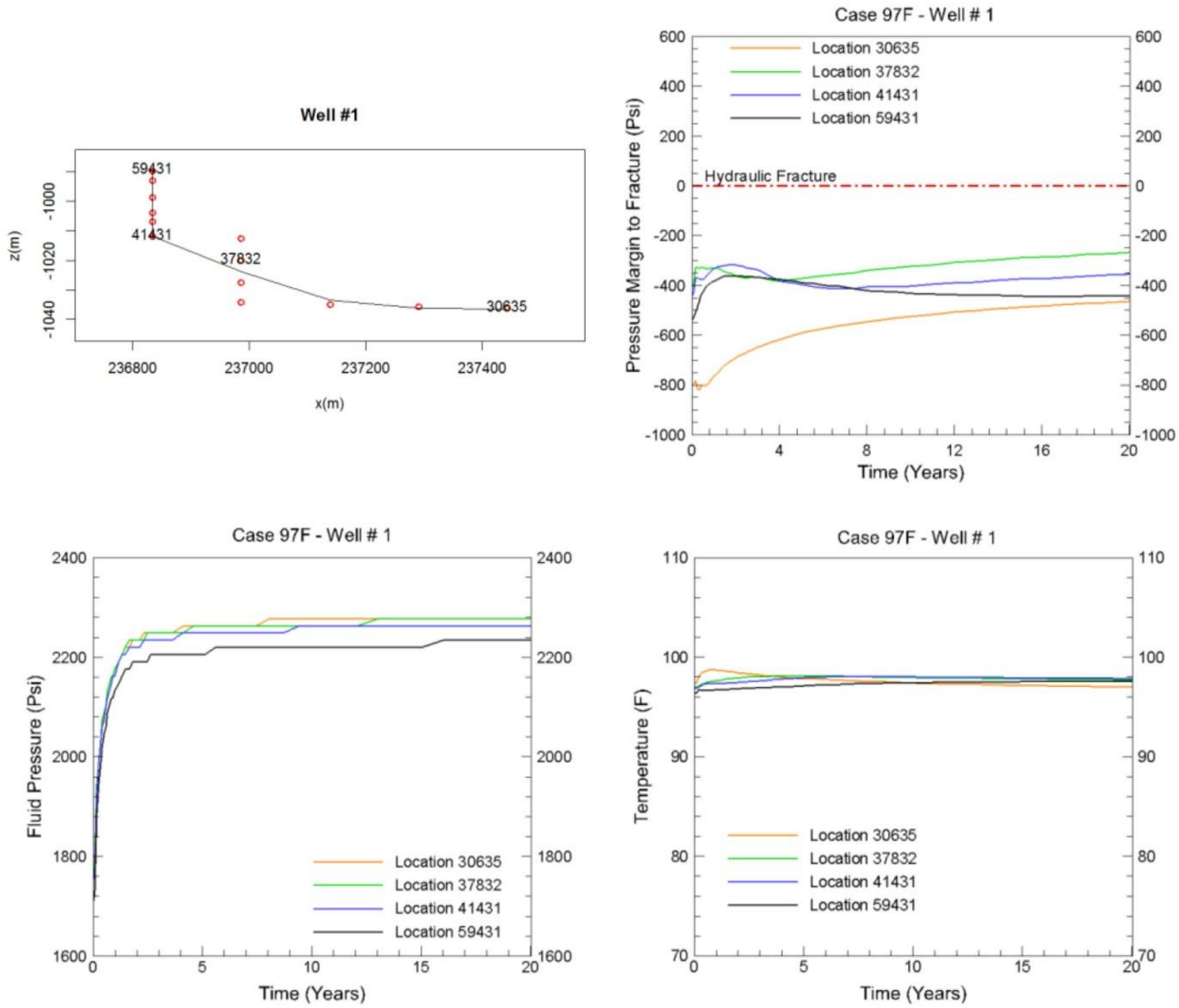


Figure 4.88. Well Path with Node Locations (upper left) and PMF vs. Time (upper right) for Well 1 for the 36°C Case. Fluid-pressure and temperature histories for four nodes are shown in the lower left and right, respectively.

The earliest exceedance of PMF occurs after approximately 2 years of injection (Figure 4.89) because of the significant drop in temperature around the well. An expanded view showing PMF distributions in the full vertical sections of the model (not represented here) indicates that the zone predicted to exceed the fracture criterion is confined within the Mount Simon Formation, and does not approach the upper layers of the model, including the seal.

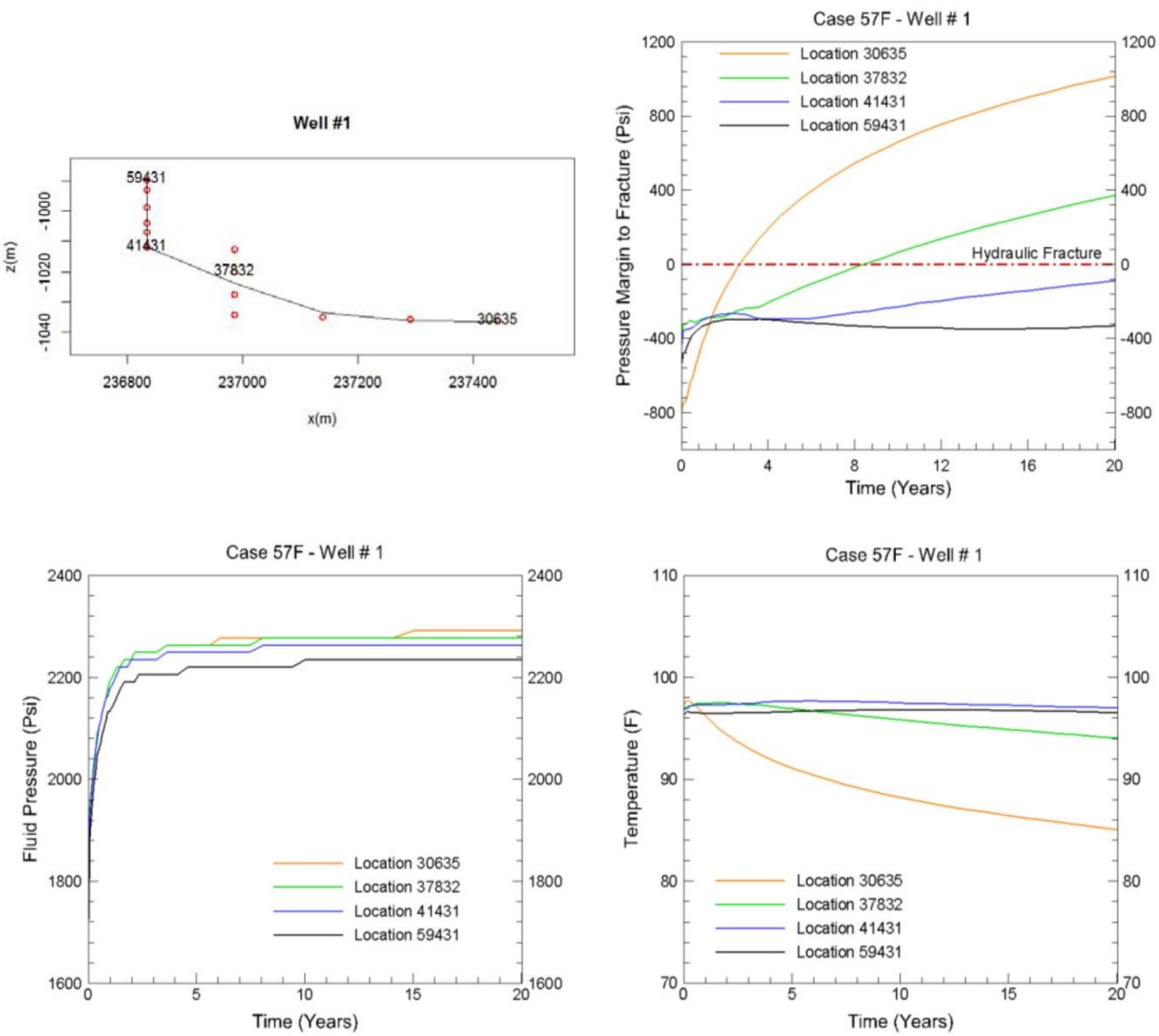


Figure 4.89. Well Path with Node Locations (upper left) and PMF vs. Time (upper right) for Well 1 for the 14°C Case. Fluid-pressure and temperature histories for four nodes are shown in the lower left and right, respectively.

The minor differences in injectivity that occurred for the different temperature cases do not affect the comparison of the models. The fluid-pressure curves presented in Figure 4.88 and Figure 4.89 are nearly identical, indicating that the cause for exceedance of the fracture criterion around and at the wells for the 25°C and 14°C cases was due to thermal effects.

The geomechanical evaluation of thermal stresses indicates that failure of the reservoir rock due to thermally induced fracturing is not expected for injection temperatures of 36°C or higher. In that temperature range, the injection temperature would be at or above the natural reservoir temperature. Increasing the temperature of the reservoir by CO_2 injection would render the principal effective stresses more compressive, and as a consequence, increase the PMF. For the 36°C case, the PMF fracture criterion was not exceeded at any location.

Thermally induced fracturing would be predicted to occur for injection temperatures of 25°C or below. Injection temperatures in that range would lower the reservoir temperature near the wellbore by ~4°C after 20 years for an injection temperature of 25°C, and as much as 6°C for an injection temperature of 14°C. Formation fracture would be predicted to occur at affected nodes after 2–4 years of injection. However, the zones where the PMF would exceed the fracture criteria for those injection temperatures were found adjacent to the wellbore and in nearby nodes. For none of the considered cases did the expected zone of fracturing extend above the Mount Simon Formation or approach the seal layers.

Thus, if injection temperatures at the reservoir are 36°C or higher, thermal fracturing should not be an issue for the FutureGen 2.0 injection wells. Because results of the pipeline and wellbore transport modeling (see Section 4.6.3.1) suggest that the injection temperatures would be in the range from 42°C to 47°C, thermally induced fracturing would not be expected to occur.

4.6.3.4 *Conclusion*

The modeling of CO_2 transport in the pipeline and the injection well leads to yearly average injection temperatures of 42°C using extreme soil conductivities for the planned pipeline route, and of 47°C using a more reasonable range of soil conductivities. These two temperatures are close to the actual reservoir temperature and well above the critical temperature of 25°C where limited reservoir fracturing could occur based on geomechanical modeling. It can be concluded that thermally induced fractures of the reservoir are very unlikely to occur at the FutureGen 2.0 CO_2 storage site.

4.7 Monitoring, Verification, and Accounting

The Monitoring, Verification, and Accounting (MVA) program design for the FutureGen 2.0 Project includes geohydrologic, geochemical, and geophysical components for characterizing the complex fate and transport processes associated with CO_2 injection and storage. This monitoring program was designed to verify that the FutureGen 2.0 CO_2 storage site is operating as permitted and is not endangering any USDWs. A more detailed description of the monitoring program is available in the FutureGen 2.0 – CO_2 Pipeline and Storage Project Testing and Monitoring Plan (Appendix 4D).

4.7.1 Monitoring Program Overview

The primary objective of the monitoring program is to implement a suite of monitoring technologies that are both technically sound and cost-effective and provide an effective means of 1) monitoring the evolution of the CO_2 plume and pressure front, 2) evaluating CO_2 mass balance, and 3) detecting any unforeseen loss in CO_2 containment. The monitoring program design includes injection-well testing and monitoring activities, groundwater-quality monitoring immediately above the primary confining zone and in the lowermost USDW aquifer, and injection-zone monitoring that will consist of 1) direct pressure monitoring, 2) direct geochemical monitoring, and 3) indirect (i.e., geophysical) monitoring of the CO_2 plume and pressure-front evolution. The monitoring infrastructure includes a network of deep monitoring wells and a surface-based network of combined passive seismic/surface deformation monitoring stations. The CO_2 injection stream is continuously monitored as part of the instrumentation and control systems; injection stream monitoring also includes periodic collection and analysis of grab samples to track CO_2 composition. A summary of the selected monitoring technologies and measurement frequency is provided in Table 4.22.

Both direct and indirect measurements are used collaboratively with numerical models of the injection process to verify that CO_2 is effectively sequestered within the targeted deep geologic formation and that the stored CO_2 mass is accounted for. The approach is based in part on early-detection monitoring wells that target regions of increased leakage potential (e.g., areas of highest pressure buildup containing wells that penetrate the caprock). Leak-detection monitoring can be divided into two distinct modes. The first is “detection” mode, which focuses on detecting a leak at the earliest possible opportunity. Because of its larger areal extent of detectability, this mode will most likely be informed by changes in fluid pressure, although localized changes in aqueous geochemistry might also be detected. If a leak is detected, this would trigger a secondary “assessment” mode of monitoring wherein the focus would be on quantifying the rate and extent of the leak. This mode would continue to be informed by pressure data, but characterization of changes in aqueous geochemistry within the early-leak-detection monitoring interval would likely play an increased role in the assessment. In the assessment mode, monitoring costs may increase if additional analytes and/or more frequent sample collection are required to adequately characterize the leak. While carbon capture and sequestration (CCS) projects must plan for both modes of leak-detection monitoring, the expectation is that the assessment mode would never be required.

A comprehensive suite of geochemical and isotopic analyses are performed on fluid samples collected from the reservoir and overlying monitoring intervals. These analytical results are used to characterize baseline geochemistry and provide a metric for comparison during operational phases of the project. A primary design consideration for “detection” monitoring is minimizing life-cycle cost without sacrificing the ability to detect a leak. As a result, only selected parameters measured during the baseline monitoring period would be routinely measured during operational phases of the project. Indicator parameters are used to the extent possible to inform the monitoring program. Once baseline conditions and early CO_2 arrival responses have been established, observed relationships between analytical measurements and indicator parameters are used to guide less frequent aqueous sample collection in later years.

Table 4.22. Monitoring Frequencies by Method and Project Phase

Monitoring Category	Monitoring Method	DOE Active Phase: Baseline 3 yr	DOE Active Phase: Injection (startup) ~3 yr	DOE Active Phase: Injection ~2 yr	Commercial Phase: Injection ~15 yr	Commercial Phase: Post-Injection 50 yr
CO_2 Injection Stream Sampling and Analysis	Grab sampling and analysis	3 events, during commissioning	Quarterly	Quarterly	Quarterly	NA
CO_2 Injection Stream Monitoring	Continuous monitoring of injection process (injection rate, pressure, and temperature; annulus pressure and volume)	NA	Continuous	Continuous	Continuous	NA
Corrosion Monitoring	Corrosion coupon monitoring of injection-well materials	NA	Quarterly	Quarterly	Quarterly	NA
Mechanical Integrity Testing (ACZ/USDW wells excluded)	PNC and temperature logging (frequency shown for injection wells)	Once after well completion	Annually	Annually	Annually	Annually until wells plugged
	Cement-evaluation and casing inspection logs	Once after well completion	During well workovers	During well workovers	During well workovers	NA
	Annular pressure monitoring	NA	Continuous	Continuous	Continuous	NA
Pressure Fall-Off Testing	Injection-well pressure fall-off testing	NA	Every 5 yr	Every 5 yr	Every 5 yr	NA
Groundwater-Quality Monitoring	Fluid sampling and analysis in ACZ and USDW monitoring wells	3 events	Quarterly	Semi-Annually	Annually	Every 5 yr
	Electronic P/T/SpC probes installed in ACZ and USDW wells	1 yr min	Continuous	Continuous	Continuous	Continuous
Direct CO_2 Plume and Pressure-Front Monitoring	Fluid sample collection and analysis in SLR monitoring wells	3 events	Quarterly	Semi-Annually	Annually	Every 5 yr
	Electronic P/T/SpC probes installed in SLR wells	1 yr min	Continuous	Continuous	Continuous	Continuous
Indirect CO_2 Plume and Pressure-Front Monitoring	Passive seismic monitoring	1 yr min	Continuous	Continuous	Continuous	Continuous
	Integrated deformation monitoring	1 yr min	Continuous	Continuous	Continuous	Continuous
	Time-lapse gravity	3 events	Annually	Annually	Annually	NA
	PNC logging of RAT wells	3 events	Quarterly	Quarterly	Annually	Annually

ACZ = above confining zone; NA = not applicable; PNC = pulsed-neutron capture; P/T/Spc = pressure, temperature, and specific conductance; RAT = reservoir access tube; SLR = single-level in-reservoir; USDW = underground source of drinking water.

If a significant CO_2 and/or brine leakage response is detected, a modeling evaluation would be used to assess the magnitude of containment loss and make bounding predictions regarding the potential for CO_2 migration above the confining zone, including any resulting impacts on shallower intervals, and ultimately, the potential for adverse impacts on USDW aquifers or other ecological receptors. Observed and simulated arrival responses at the early-leak−detection wells and shallower monitoring locations would be compared throughout the life of the project and results would be used to calibrate and verify the model, and improve its predictive capability for assessing the long-term environmental impacts of any fugitive CO_2. If pressure and/or geochemical responses in deep early-leak−detection monitoring wells were to indicate that primary confining zone leakage had occurred, a comprehensive near-surface-monitoring program could be activated to fully assess environmental impacts relative to previously established baseline conditions.

The MVA program addresses prediction uncertainty by adopting an “adaptive” or “observational” monitoring approach (i.e., the monitoring approach would be adjusted as needed based on observed monitoring and updated modeling results). This monitoring approach would continually evaluate monitoring results and make adjustments to the monitoring program as needed, including the option to install additional wells in outyears to verify CO_2 plume and pressure-front evolution and/or evaluate leakage potential. The design is based on the Alliance’s conceptual understanding of the site and predictive simulations of injected CO_2 fate and transport. The model used in the design analysis was parameterized based on site-specific characterization data collected from the initial stratigraphic borehole and reflection seismic surveys conducted at the FutureGen 2.0 CO_2 storage site (Kelley et al. 2012b), and it also considers other available regional data including the effects of structural dip, regional groundwater flow conditions, and the potential for heterogeneities or horizontal/vertical anisotropy within the injection zone and overburden materials (Alliance 2013).

The monitoring well network, which includes both injection-zone monitoring wells and monitoring wells installed immediately above the primary confining zone, is designed to detect unforeseen leakage from the reservoir as soon after the first occurrence as possible. Two aquifers above the primary confining zone are monitored for any unforeseen leakage of CO_2 and/or brine out of the injection zone. These include the aquifer immediately above the confining zone (Ironton Sandstone) and the St. Peter Sandstone, which is separated from the Ironton by several carbonate and sandstone formations and is considered to be the lowermost USDW at the site. In addition to directly monitoring for CO_2, wells are monitored for changes in geochemical and isotopic signatures that provide indication of CO_2 and/or brine leakage. Direct monitoring of the lowermost USDW aquifer is required by the EPA’s UIC Program for CO_2 geologic sequestration (75 FR 77230) and is a primary objective of this monitoring program. Wells are also instrumented to detect changes in the stress regime (via pressure in all wells and microseismicity in selected wells) to avoid over-pressurization within the injection or confining zones that could compromise sequestration performance.

The monitoring well network design consists of two wells monitoring changes within the injection zone (Elmhurst/Mount Simon Sandstones), two wells within the first permeable interval immediately above the primary confining zone (Ironton Sandstone), one well within the lowermost USDW (St. Peter Sandstone), and three reservoir access tubes (RATs), which are used to monitor CO_2 saturation in the reservoir and caprock. Well locations are shown in Figure 4.90 and a hydrogeologic cross section illustrating the relative position and depth interval of the various wells is shown in Figure 4.91.

At the direction of the UIC Program Director, no surface or near-surface monitoring methodologies were included as a requirement of the Class VI UIC permit. Even though near-surface monitoring is not required at the FutureGen 2.0 CO_2 storage site, the monitoring program incorporated several monitoring approaches, including surficial groundwater monitoring, surface-water monitoring, soil-gas monitoring, atmospheric monitoring, and an evaluation of spatiotemporal mapping of vegetation and surface conditions through remote sensing. Baseline data sets were collected will be reported in publicly available documents. Based on the conceptual understanding of the subsurface environment, early and appreciable impacts on near-surface environments would not be expected, so extensive networks of surficial aquifer, surface-water, soil-gas, and atmospheric monitoring stations were not included in the monitoring network design.

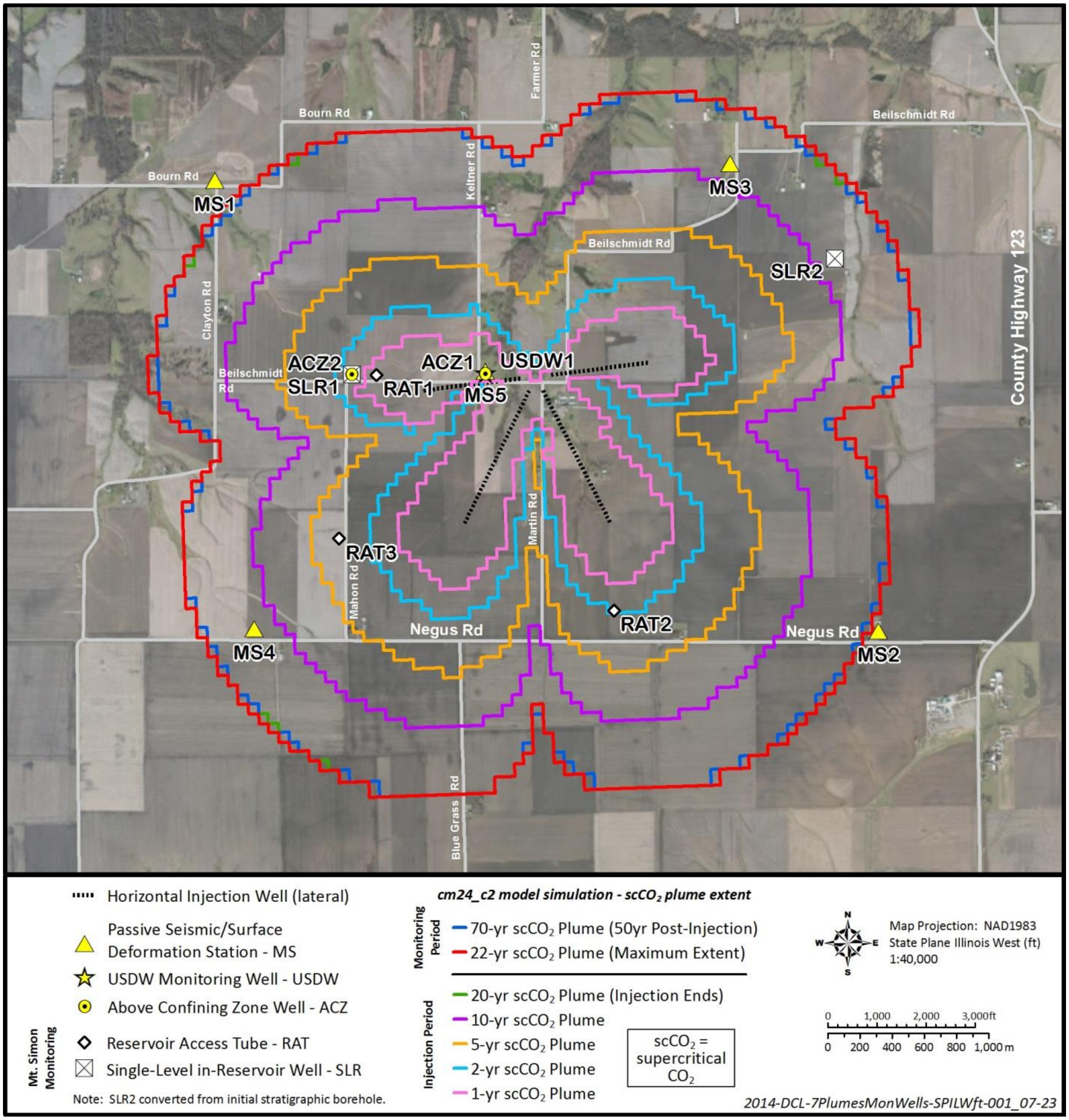


Figure 4.90. Nominal Well Network Layout for the Injection and Monitoring Wells and Modeled sc-CO_2 Plume. The monitoring well locations are approximate and subject to landowners' approval.

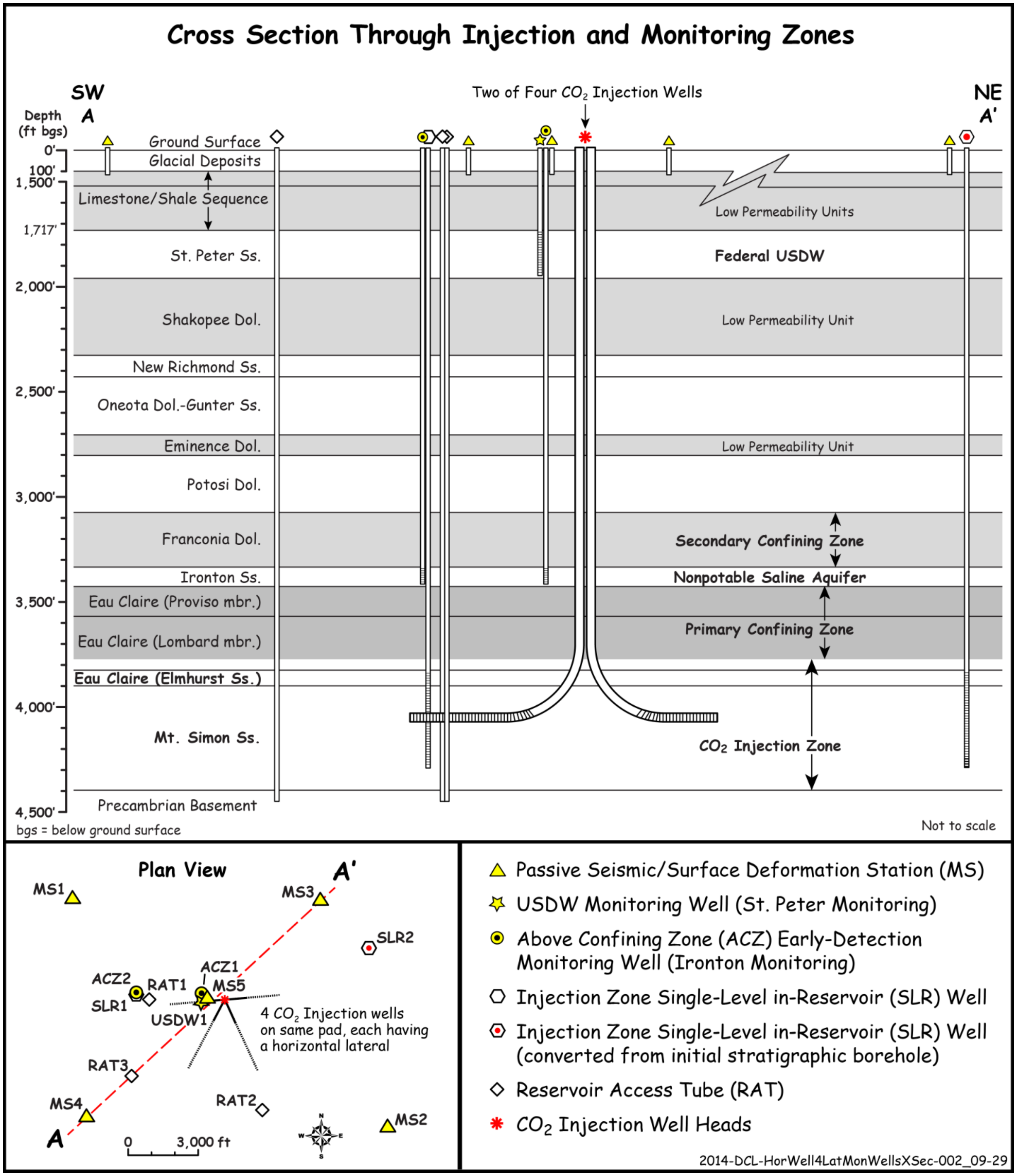


Figure 4.91. Cross-Sectional View of the Injection and Monitoring Well Network

4.7.2 Evaluation of Geophysical Monitoring Methodologies

Geophysical monitoring methods are sensitive to subsurface conditions that can change as a result of changes in fluid saturation or pressure associated with CO_2 injection. Geophysical monitoring methods considered for the FutureGen 2.0 CO_2 storage site included ERT, passive seismic monitoring, 2D and 3D surface seismic surveys, VSP, cross-well seismic imaging, time-lapse gravity, magnetotelluric soundings and controlled-source electromagnetics, integrated deformation monitoring, and pulsed-neutron capture (PNC) logging. This comprehensive suite of technologies was evaluated with respect to site-specific conditions and subjected to a screening process; then suitable methodologies were selected for deployment as part of the monitoring program. This selection process, which is documented in detail by Vermeul et al. (2014), considered the level of sensitivity, spatial resolution; the costs to install and operate; and potential interference with other monitoring activities. Technologies that were selected for implementation included passive seismic monitoring, time-lapse gravity, integrated deformation monitoring, and PNC logging.

Integrated deformation monitoring and passive seismic monitoring are two indirect monitoring techniques that can detect and characterize development of the pressure front resulting from injection of CO_2. The objective of deformation monitoring is to provide a means of detecting any asymmetry in the CO_2 plume development and to help guide the adaptive monitoring strategy. The objective of the passive seismic monitoring network is to accurately determine the locations, magnitudes, and focal mechanisms of injection-induced seismic events with the primary goals of

- addressing public and stakeholder concerns related to induced seismicity,
- estimating the spatial extent of the pressure front from the distribution of seismic events, and
- supporting assessments of caprock integrity and the potential for containment loss.

Another indirect monitoring technique—PNC logging—is the primary means of tracking the advancement and evolution of the CO_2 plume. Time-lapse gravity provides additional low-cost measurements that supplement the PNC logs and support the assessment of plume evolution.

4.7.3 Evaluation of Leakage Detection Capabilities

A modeling assessment was conducted to evaluate the potential for water-quality impacts associated with any unforeseen loss of sc-CO_2 and/or brine containment resulting from sc-CO_2 storage operations. This preliminary evaluation focused on the first permeable interval (Ironton Sandstone) above the primary confining zone to assess early-leak−detection capabilities and considered both pressure response and geochemical signals in the overlying Ironton Sandstone. Results from this study were used to inform the early-leak-detection monitoring design. A detailed discussion of this assessment is provided by Vermeul et al. (2014).

A series of leakage scenarios were evaluated that approximate leaks of different magnitudes from an artificial penetration or some other localized source of leakage. These initial scoping-level leakage scenarios assumed 1% of the total planned sc-CO_2 injection mass (22 MMT) was leaked (0.22 MMT) over three different time periods as follows:

- 1% of total injected mass leaked over 20 years (0.011 MMT/yr)
- 1% of total injected mass leaked over 100 years (0.0022 MMT/yr)
- 1% of total injected mass leaked over 500 years (0.00044 MMT/yr).

In addition, a 20-year brine leakage case was simulated with the brine volume equivalent to the 1% sc-CO_2 volume.

Results from this preliminary modeling evaluation demonstrated that leak-detection sensitivity could be distinguished between the leak-detection signals associated with the various leakage scenarios. A joint evaluation of both the sc-CO_2 and brine simulations shows that pressure is likely to be the earliest indicator of leakage, given the rapid pressure responses seen for the 20-, 100-, and 500-year scenarios (Figure 4.92). Accounting for the accuracy and resolution of the pressure sensors specified in the monitoring program design (2 and 0.05 psi, respectively), it is expected that a pressure response would be detected within a week for all of the 20- and 100-year leakage scenarios, at all of the distances from the leak and depths within the permeable unit above the leak (i.e., Ironstone Sandstone) that were evaluated. For the 500-year leakage scenario, higher resolution equipment may be necessary for pressure detection, given that the only pressure value thresholds crossed were 0.2 psi at all selected distances and depths. Pressure responses above the lowest threshold value (0.2 psi) within ~450 ft from the leak location generally respond quickly, from essentially instantaneously to within 24 hours of the start of leakage. Higher threshold pressures and more distal locations take longer for detection and in some cases may not be detected at all, as shown in Figure 4.92.

Figure 4.93 compares the arrival times of dissolved CO_2 (for sc-CO_2 simulations) and tracer (for brine simulations) above specified concentration thresholds. As expected, these geochemical signals are much more localized and take much longer to develop than the pressure responses. In addition, because of the buoyancy effect associated with sc-CO_2 injection, early-leak-detection monitoring for these leakage scenarios is best achieved through upper zone monitoring, particularly as monitoring distances from the leakage source increase. It should be noted that the dissolved CO_2 arrival time results assume that no dissolved CO_2 is present prior to the sc-CO_2 leak (i.e., does not account for baseline dissolved CO_2 concentrations). However, these results, along with tracer arrival time results for the brine leakage case, are presented as a proxy for intrinsic sc-CO_2 injection-related and co-injected tracer-related signals that might be present at the leading edge of the sc-CO_2 plume.

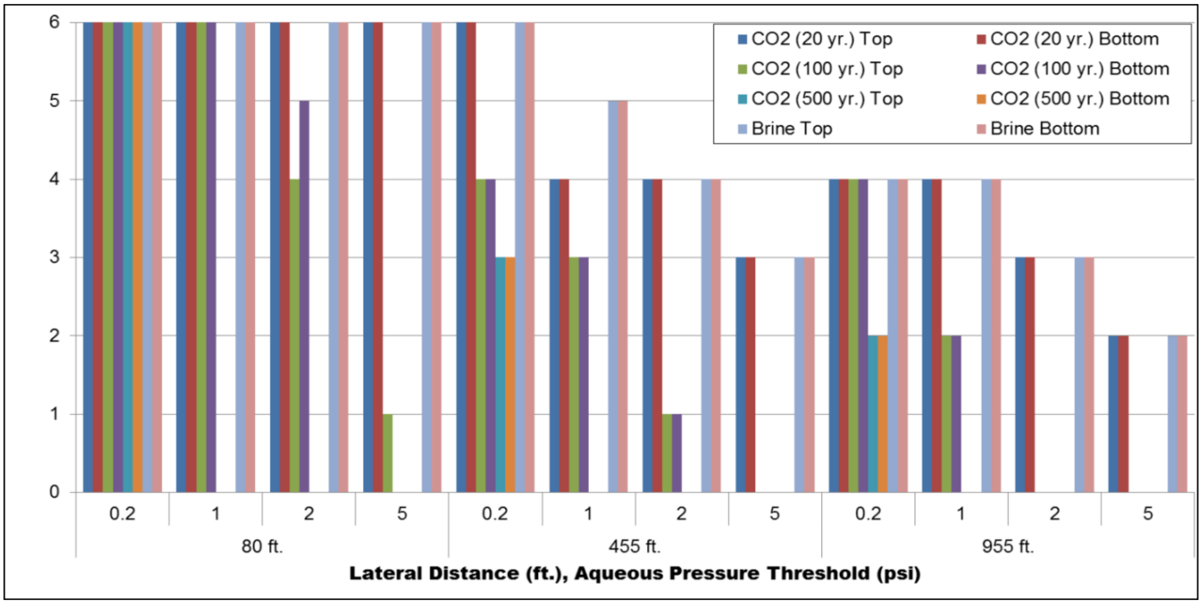


Figure 4.92. Time in Days (y-axis) to First Detection of Pressure Responses Exceeding Specified Threshold Values (0.2, 1, 2, and 5 psi) Calculated from the Simulated Leak Cases in the Top and Bottom of the Ironton Sandstone at Three Distances from the Leak

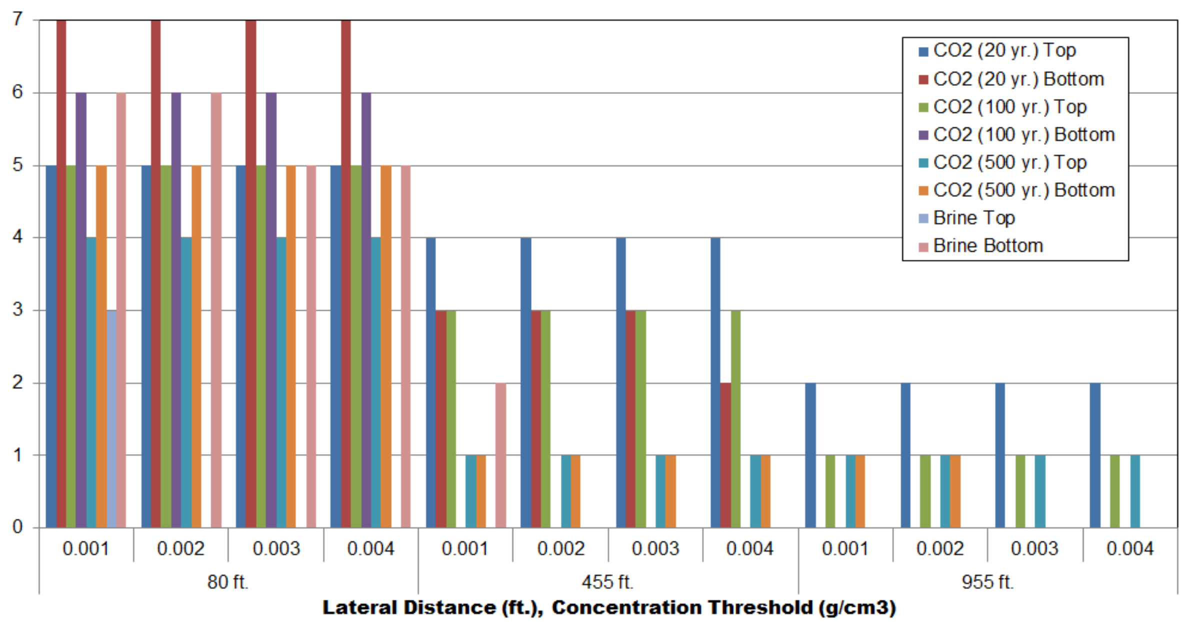


Figure 4.93. Time in Days (y-axis) to First Detection of Dissolved CO_2 Concentrations and Tracers (for the brine leakage case) Exceeding Specified Threshold Values Calculated from the Simulated Leak Cases in the Top and Bottom of the Ironton Sandstone at Three Distances from the Leak

No geochemical signals for either the sc-CO_2 or brine simulations occurred in less than a day and arrivals generally occurred on timescales ranging from months to years. At the closest lateral monitoring location (~80 ft), a geochemical arrival response is predicted to occur within a year or two for all of the sc-CO_2 leakage cases considered. Tracer arrival in the brine leakage case is predicted to occur within a month at the bottom of the Ironton and within 5 years at the top (i.e., the opposite response from that observed for the sc-CO_2 leakage cases, which are affected by sc-CO_2 buoyancy). The geochemical arrival response was less pronounced at more distal locations. For the largest sc-CO_2 leakage rate case (20-year leakage), the dissolved CO_2 arrival in the upper zone is predicted to occur within 2 years at the ~450-ft lateral distance and within 10 years at the ~ 950-ft lateral distance.

Results from this preliminary modeling effort are expected to be highly sensitive to layering and heterogeneities within the Ironton Sandstone. Low-permeability layers within the Ironton Sandstone would inhibit the upward buoyant migration of sc-CO_2 and would also influence the aqueous pressure responses. For this study, the Ironton Sandstone Formation was assigned uniform properties for the entire unit.

4.7.4 Area of Review

The AoR is defined by EPA as "the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity," and requires that "The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and displaced fluids, and is based on available site characterization, monitoring, and operational data" [40 CFR 146.84.(a)]." The regulation states that the "Owners or operators of injection wells are required to identify any potential conduits for fluid movement, including artificial penetrations (e.g., abandoned well bores) within the AoR, assess the integrity of any artificial penetrations, and perform corrective action where necessary to prevent fluid movement into a USDW [40 CFR 144.55, 146.84(d)]" (EPA 2013, pg. 1).

The AoR is defined as the maximum extent of either the separate-phase CO_2 plume or where the pressure front caused by injection could cause brines migrating from the reservoir into the lowermost USDW through a hypothetical open conduit, whichever is greater. The maximum extent of the sc-CO_2 plume and the reservoir pressure buildup from injection were estimated based on predictions from the reservoir model. Pressure-front calculations were based on focused leakage scenarios (i.e., faults, leaky wells, or abandoned boreholes).

The calculated hydraulic heads from the pressures and fluid densities measured in the Mount Simon Sandstone at the FutureGen 2.0 CO_2 storage site during drilling of stratigraphic borehole FGA-1 (Kelley et al. 2012b) ranged from 47.8 to 61.6 ft higher than the calculated hydraulic head in the St. Peter Sandstone, the lowermost USDW (Figure 2.30 of Alliance [2013]). Based these measurements, simplified critical pressure calculations based on the open conduit concept were not applicable under site conditions (e.g., EPA 2013, Equation 1, pg. 39) because the injection formation was already “over-pressured” relative to the lowermost USDW (i.e., ambient hydraulic heads in the reservoir are greater than lowermost USDW).

The EPA guidance provides three other methods of estimating acceptable pressure increases applicable to “over-pressured” reservoirs (EPA 2013). An alternative method was assessed based on the approach described by Birkholzer et al. (2013), which uses the ASLMA analytical model (Cihan et al. 2011, 2013) and includes ranges of parameters for damaged wells or abandoned boreholes. The results of this analysis was reported by Williams et al. (2014) and showed that the maximum pressures simulated at the maximum extent of the predicted sc-CO_2 plume would lead to negligible leakage into the lowermost USDW under a range of leaky well scenarios. However, these scenarios included fluid losses into the intervening permeable zones (i.e., thief zones) between the reservoir and lowermost USDW and were ultimately not considered sufficiently conservative for the EPA Class VI permit.

Although the open conduit approaches are not strictly applicable under FutureGen 2.0 CO_2 storage site conditions, the EPA used results from these approaches to define the site-specific pressure-front AoR as the maximum extent of the 10 psi contour of pressure differential during the life of the project (Table 13 in Attachments B in EPA, 2014), which it determined to be conservative and protective of the USDW. Using the pressure differential predictions from the reservoir model, the maximum extent of the 10 psi contour (which occurs 60 years after the beginning of the injection) was delineated. The resulting AoR extends approximately 24 miles radially around the injection well (Figure 4.94) and includes most of Morgan County and portions of seven other counties.

EPA Class VI regulations require the identification of all confining zone penetrations within the AoR that may become a preferential pathway for leakage of CO_2 and/or formation brine fluids out of the injection zone, and if necessary, performance of corrective actions to prevent leakage that could potentially cause endangerment to a USDW. The following evaluations were performed within a 25-mi^2 Survey Area that extends beyond the predicted maximum extent of the sc-CO_2 plume: 1) identify existing penetrations; 2) determine if any penetrations extend below the primary confining zone, thereby presenting a risk of leakage that may require corrective actions; and 3) identify corrective actions and define the approach that will be taken to prevent leakage that could endanger a USDW. No wells were identified within the Survey Area that required corrective action. A general survey of the AoR outside the Survey Area was conducted by reference of publicly available information. Maps of existing water wells, oil and gas wells, miscellaneous wells, coal mines, surface water, and geologic structures were submitted to complete the permit requirements.

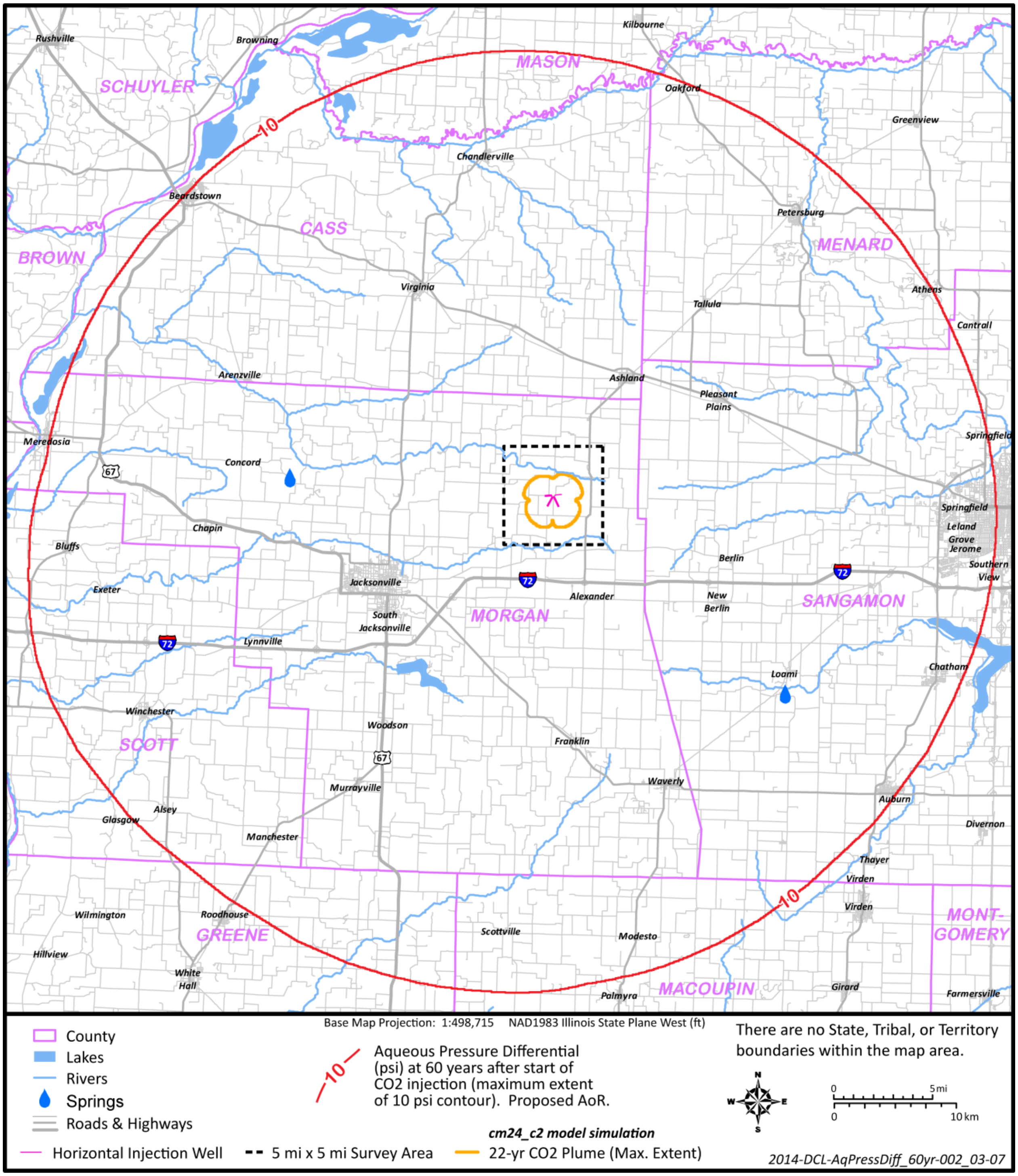


Figure 4.94. FutureGen Area of Review Inclusive of the CO_2 Plume and the Area of Elevated Pressure Delineated as the 10 psi Contour at 60 Years

4.7.5 Post-Injection Site Care

The FutureGen 2.0 MVA program includes a post-injection site care and site closure component that would be implemented to meet the requirements of 40 CFR 146.93. The MVA program calls for monitoring groundwater quality and tracking the position of the CO_2 plume and pressure front for a period of 50 years, or until a demonstration of non-endangerment of USDWs has been approved by the UIC Program Director pursuant to 40 CFR 146.93(b)(3). Following approval for site closure, the Alliance would plug and abandon all monitoring wells, restore the site to its original condition, and submit a site closure report and associated regulatory-required documentation.

The monitoring methodologies and frequencies specified for this period are shown in Table 4.22. Monitoring activities would be conducted using the same monitoring well network and geophysical monitoring infrastructure as would be used during active phases of a CO_2 injection (see Figures 4.90 and 4.91). Carbon dioxide plume and pressure-front tracking would be accomplished using both direct (pressure and aqueous chemistry measurements) and indirect methods. The suite of indirect geophysical monitoring methods that were identified for tracking the areal extent, evolution, and fate and transport of an injected CO_2 plume during the post-injection site care and site closure period included PNC logging, passive seismic monitoring, integrated surface deformation monitoring, and time-lapse gravity surveys.

4.8 Plugging and Abandonment of Subsurface Infrastructure

Stratigraphic borehole FGA-1 was plugged (cemented) and abandoned the week of April 20-24, 2015. The well was plugged in accordance with the IDNR, Division of Oil and Gas well-plugging requirements. The Division of Oil and Gas issued the drilling permit for the well and therefore had responsibility for plugging and abandonment requirements. Therefore, a well-plugging plan was prepared and submitted to the Division prior to the start of field work for approval. In addition, the work was witnessed by the local Division inspector, Steve Cook. Schlumberger, on behalf of the Alliance, was the main contractor responsible for plugging the well. Schlumberger made arrangements with several subcontractors to provide key services for the job, including a service rig operator (Pioneer), a well-cementing company (Franklin), a wireline company (Wayne County Wireline), and others. Labor was provided by Operating Engineers Local, Pipefitters 137, and Laborers 477 of Springfield, Illinois, through Rouland Construction Services of Jacksonville, Illinois.

In general, the plugging procedure involved the following main activities: installing a cast-iron bridge plug near the bottom of the 10-3/4-in. casing, emplacing a lower (~50-ft-thick) cement “plug” immediately above the bridge plug, emplacing an upper (~450-ft-thick) freshwater cement plug that extended from near the base of the surface casing to land surface, cutting and removing the casing strings approximately 6 ft below current grade, welding a steel plate on the top of the cut-off casing stubs (labeled with the well’s API number), and backfilling the location.

The detailed plugging procedure implemented in the field is given in Table 4.23. A diagram of the well as plugged is shown in Figure 4.95.

Table 4.23. Well-Plugging and Abandonment Procedure

Date	Procedure
4/20	• Moved in work-over rig and rigged up (Pioneer Oilfield Services)
4/21	• Pioneer removed upper section of the wellhead to the casing hanger. • Rigged up wireline unit (Wayne County Wireline) and went in hole with gauge ring and junk basket to confirm clearance for bridge plug • Ran in the well and set a 10-¾-in. cast-iron bridge plug at a depth of 3,900 ft, which is the middle of the second to bottom joint of 10-3/4-in. intermediate casing, as per IDNR requirement • Rigged down wireline unit • Pioneer re-attached wellhead and nippled up packoff to control pressure when pumping cement. • Pioneer began running in hole with seven joints of 3-½-in. tubing.
4/22	• Steve Cook of the IDNR was onsite to observe plugging operation; five staff members watched from offsite as a learning experience. • Pioneer ran in hole to 3,898 ft with 3-½-in. tubing. • Franklin rigged up cement truck and pumped bottom cement plug with 50 sacks Class A cement (15.8 ppg; yield 1.18 cu ft/sk). • Pioneer pulled tubing to 450 ft, laying down tubing for removal from site. • Franklin rigged up cement truck and pumped upper plug with 219 sacks Class A cement (15.6 ppg; yield 1.18 cu ft/sk). • Pioneer removed remaining 450 ft of tubing. • Franklin topped off cement to surface with additional 19 sacks; cement top at 4 ft from surface.
4/23	• Pioneer removed remaining wellhead components. • Pioneer rigged down and began to demob at 14:00. • Rouland supplied operators from 965 and dug a large pit 9 ft deep to accommodate cutting the three casing stings: 24 in. conductor, 16 in. surface and 10-¾ in. intermediate. • Welder from Pipefitters 137 began to cut casing at 6 ft below current grade. Windows were cut in the 24 in. and cement in the 24 in./16 in. annulus removed. Windows were cut in the 16 in., no cement in the 16 in./10-¾-in. annulus.
4/24	• Welder from Pipefitters 137 finished cutting the 10-¾-in. casing and welded a plate to cover all three strings. Welder labeled plate with well API number. • Rouland supplied operators from 965 and a tractor and lifted cut casing and remaining wellhead out of pit. • Rouland supplied operators from 965 to backfill trench.

The shallow groundwater monitoring well located on the drilling pad near stratigraphic borehole FGA-1 was also plugged and abandoned during the week of April 20–24, 2015 (Figure 4.96). The procedure entailed the following steps: filling the 20-ft-deep, 2-in.-diameter PVC screen and casing with bentonite; cutting and removing the uppermost 6 ft of casing; and backfilling the hole. The four bollards surrounding the shallow water well were then removed. The plugging work was performed by the ISGS (Jack Aud) and witnessed by the Department of

Environmental Health inspector, Dale Bainter. An as-built diagram of the well was shown previously in Figure 4.21.

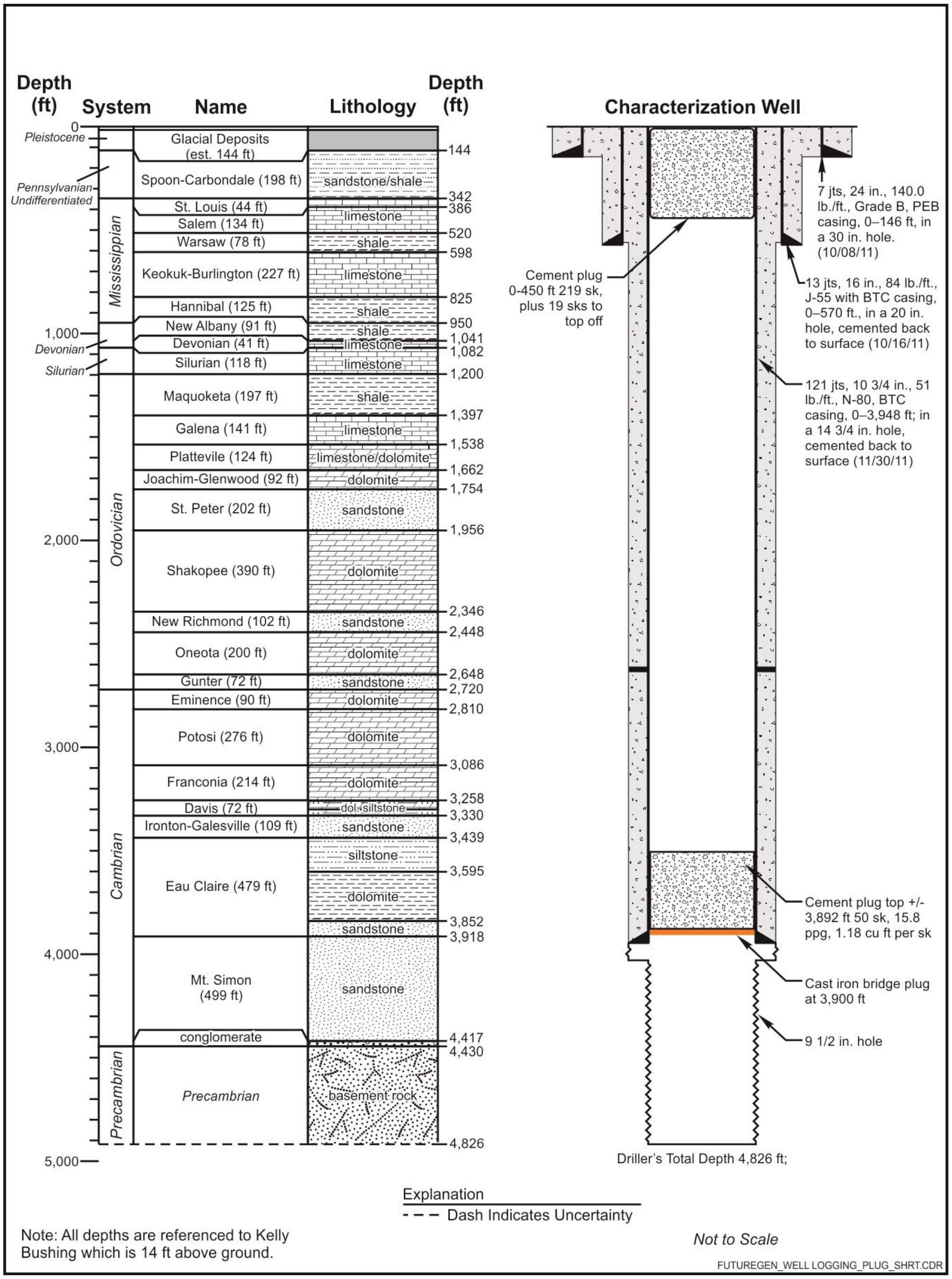


Figure 4.95. Diagram of Well as Plugged

Figure 4.96. Photographs of the Stratigraphic Borehole FGA-1 Plugging Operation

4.9 Costs

4.9.1 Front End Engineering and Design Cost Estimates

The Front End Engineering and Design (FEED) cost estimate was developed for each work element, corresponding to work categories (chapters) discussed in the FEED document. Cost estimates were developed using a detailed work and material estimate sheet whereby cost elements are tabulated. This detailed estimate sheet included task indices, item descriptions, quantities, unit costs, costs, subcontractor costs, and total costs for each line item material or labor element. Line item cost estimates were arranged according to categorization as direct or indirect costs. Contingency estimates were applied to the combined total of direct and indirect costs. Ancillary cost items such as subcontractors, management, permits, taxes, bonds, duties, freight, and rentals were explicitly itemized to facilitate later summary.

In the FEED report, vendor procurement quotes were obtained for over 95 percent of major equipment/material capital costs. Cost estimates reflected input from experienced drilling personnel. Multiple meetings and discussions with a drilling contractor were used to focus on the constructability of injection and monitoring wells, including delivery, onsite handling, erection and sequencing.

4.9.1.1 *Cost Estimate Categories*

The cost estimate for the injection and storage portion of the FutureGen 2.0 Project was presented in a format consistent with the materials-construction services-support format used for the power plant and pipeline portions of the project; the cost estimate included the following categories:

- materials
- construction services
- characterization
- rental equipment and consumables
- construction management
- travel expenses.

The definitions below were related to the subsurface infrastructure, which covered the wells at the storage site and the systems built at the surface to monitor and maintain the wells. Wells included the four horizontal injection wells and eight monitoring wells. One of the horizontal injection wells was to be drilled as a vertical pilot well prior to being completed as the first injection well. The monitoring wells were to consist of two single-level completion monitoring wells (one of which was to be the completed stratigraphic well that was drilled in 2011), three RAT cased borings (one of which was to be extensively characterized), two above confining zone (ACZ) monitoring wells, and one USDW monitoring well. The surface system chosen was the APS (Annular Pressurization System), which was to monitor and maintain pressure on the annual spaces of the four injection wells.

Definitions here cover the life-cycle costs of the storage site well system and APS from construction, through operations and maintenance, and finishing with well and site closure:

- materials, construction services, characterization, rental equipment, and consumables are direct costs.
- construction management and related travel expenses are indirect costs.

4.9.1.1.1 Materials

4.9.1.1.1.1 Construction Materials

Costs for materials incorporated into the construction of all proposed wells and the APS at the FutureGen 2.0 CO_2 storage site were provided within the FEED. Material costs for the wells included casing and tubing, cement, wellhead and Christmas tree components, and well-completion materials including packers, completion fluid, permanent monitoring instrumentation equipment installed in the wells, and well screens. Material costs for the APS construction included the pressure monitoring and control ski, controls equipment, construction supplies, a compressed air system, chemicals for system treatment, and instrumentation.

4.9.1.1.1.2 Operations and Maintenance Materials

Material costs for well operations and maintenance (O&M) included replacement for downhole equipment such as packers, downhole safety valves and monitoring equipment, replacement tubing, and replacement wellhead valves. Material costs for the APS O&M included the replacement equipment and compressed air cylinders costs.

4.9.1.1.1.3 Plugging and Abandonment Materials

Material costs for the well-plugging and abandonment (P&A) consisted of cement for plugging the wells.

4.9.1.2 *Construction Services*

This category should be prefaced with a note that the construction services terminology does not accurately describe the type of work being performed in the O&M or the P&A tasks; however, the “construction services” label here has been defined to include services that are required for the construction, operations, and post-operations well life cycle.

4.9.1.2.1 Construction Phase

Contracted labor and services were directly required to drill and construct wells and their associated components, including the APS. Costs included in this category related to the well construction included the drilling and service rig contractors, casing running services, mudlogging, onsite consultation and oversight (safety, drilling and completion expert, regional geologist), welding services, drilling waste management, directional drilling services, site facilities and maintenance services, and well-completion services such as wellbore cleanup and perforation. Costs included in the category related to the APS construction included skid manufacturer startup and commissioning services as well as piping and electrical installation services.

4.9.1.2.2 Operation and Maintenance Phase

Contracted labor and services are directly required to operate and maintain the storage site wells and their associated components, including the APS. Costs included in this category related to the well O&M program include the service rig contractor, performing the annual MIT, field services for running downhole equipment, field services for installation of downhole pressure control, servicing of the wellhead valves, pump truck services, rental tank cleaning, fluid hauling and disposal services, onsite consultation and oversight (safety, well-maintenance expert), and site maintenance services. Costs included in this category related to the APS O&M program included instrument calibration and inspections and recertification.

4.9.1.2.3 Plugging and Abandonment Phase

Contracted labor and services are directly required to plug and abandon the storage site wells. Costs included in this category included the service rig contractor, plugging fluids and cement waste management, welding services, onsite consultation and oversight (safety, P&A expert), wellhead removal service), and site maintenance services.

4.9.1.3 *Characterization*

The characterization cost included labor and services that supported the characterization of the wells. This cost component was only presented in the construction costs because no costs were planned for characterization of the wells in the scope of work (storage site construction, maintenance, and closure) during the O&M or P&A phases of work. Costs included in this category were for wireline logging, sidewall coring, fluid sampling, core and fluid sample analysis, as well as reservoir-testing services.

4.9.1.4 *Rental Equipment and Consumables*

Costs for renting equipment and for consumables during well construction, O&M, and P&A composed this category. Rental costs included costs for wellhead pressure control, rental oilfield equipment, office trailers, and general rentals. Costs for consumables included those for equipment fuel, drilling fluids, and fresh water.

4.9.1.5 *Construction Management*

Costs incurred for technical oversight and management of the drilling, testing, and construction of all wells are included in this cost category. Construction management included technical staffing by Battelle − Pacific Northwest Division (PNWD) during well construction.

4.9.1.6 *Travel Expenses*

Costs incurred by PNWD personnel to travel to and from construction activities are travel expenses. These indirect costs included air fare, lodging, and per diem payments.

4.9.1.7 *Present Value Estimate (Un-Escalated)*

All cost estimates were in present value 2013 dollars. Capital costs were estimated as overnight construction costs with no adjustment for inflation over the 3.5-year construction and baseline monitoring period. Operating cost estimates were also estimated in 2013 dollars with no adjustment for value change in the future through approximately 2086 at the end of the post-injection monitoring operations.

The total capital cost estimated for the construction of the injection wells, wellhead, monitoring systems related to injection, subsurface USDW protection monitoring equipment and monitoring wells was estimated at $126 million in the definitive cost estimate. Following successful contract negotiations, and refinements to the final design, the most recent estimate is $111 million.

4.9.2 Construction Costs

Information concerning construction costs is available in Appendix 4G.

4.10 Conclusions

4.10.1 Lessons Learned and Project Successes

UIC Permit Application

Almost four years after the final rule for geologic storage of CO_2 was published, Region V of the U.S. Environmental Protection Agency (EPA) issued the first-ever Class VI underground injection control (UIC) permits for carbon sequestration in the United States to the FutureGen Industrial Alliance Inc. on August 29, 2014. These four permits marked a major milestone for the Carbon Capture and Storage (CCS) community, establishing officially the first attempt within

the United States to capture and store underground large volumes of CO_2 emissions from an industrial-scale coal-fired power plant.
The Class VI rules required minimum technical criteria to protect USDWs, including an assessment of the geologic, hydrogeologic and geomechanical properties of the storage site. The 2D-seismic data acquisition in January 2011 and characterization activities at the initial stratigraphic borehole at the storage site in the fall of 2011 marked the first steps of the UIC permitting process. Extensive characterization activities described in this chapter were conducted concurrently with the development of the permit applications. The permit applications were submitted to the U.S. EPA on March 2013, and a completeness review was conducted in April 2013. The draft decision was announced in March 2014, after almost one year of open dialogue between the Alliance and EPA. In all, the permitting process was conducted over a three-year period, in the end producing a permit application that satisfied both the regulatory requirements of the UIC program and the operational obligations of the project. The challenges encountered during development of the permit were somewhat unique, owing to 1) the commercial-scale nature of the project (i.e., a relatively large injection rate and total mass of CO_2 stored), and 2) the fact that the permit applications were one of the first sets of applications submitted to the EPA. The EPA and the Alliance worked in collaboration to understand and overcome the obligations and constraints of both parties.

The design of the monitoring system and delineation of the Area of Review were among the numerous topics requiring extensive dialogue in order to come to an acceptable, site-specific approach. Obtaining an insurance policy for the financial responsibility was also very challenging; in the end a Trust Fund instrument was selected as the preferred approach. The Alliance and EPA discussed at length the requirements for injection pressure measurements, in particular the relation between the downhole and wellhead pressures. The UIC class VI rule uses a simplified calculation that does not take into account the physical behavior of CO_2 within the well casing and under some conditions, would lead to lower operational limits on injection pressure that could have a significant impact on site operations.

After a period of public comments and response lead by U.S. EPA, the final permits were issued in August 2014. The decision was later appealed, and the Environmental Appeals Board dismissed the appeal on April 28, 2015. The permits became effective May 7, 2015. The UIC Class VI permitting process required a substantial effort from a dedicated, multidisciplinary team with experience in relevant technical areas. Frequent dialog with the regulatory agency was critical to the success of this effort.

Early-leak-detection monitoring and adoption of an “adaptive” monitoring approach were a key elements of the monitoring program that demonstrated technical rigor and helped assure regulatory acceptance of the project. Another primary lesson learned was the importance of having site specific information from a stratigraphic borehole during the design and permitting phases of the project. Collection of refection seismic data and installation of a stratigraphic borehole were key components of site characterization and had a significant impact on development of the site conceptual model and resulted in changes in our understanding of injection zone thickness and hydraulic/geomechanical properties. Although the stratigraphic borehole was not specifically required as an element of the UIC Class VI permit application, the information obtained from this borehole was instrumental in developing the technical basis for the injection design and monitoring program. The importance of a stratigraphic borehole is especially true for projects developed in areas where existing well data are limited or non–existent. Although collection of these data are a regulatory requirement prior to the start of injection, when possible a stratigraphic borehole should be drilled as early in the process as possible so that this important site-specific information can be incorporated into the initial design and permitting efforts for the CO_2 sequestration site.

2D Seismic Acquisition and Processing

Although the existing seismic data cannot rule out the presence of small-displacement, near-vertical faults, nor the presence of low-vertical-displacement strike slip faults within the FutureGen 2.0 projected plume area (Hardage 2013a), two senior geophysical interpreters independently concluded that there are no large offset faults in any of the areas crossed by the 2D surface seismic lines (Hardage 2013a; McBride in Sullivan 2013). A 3D seismic survey (preferably with 3 component receivers that can collect both P-wave and converted S-wave data) is required in order to definitively detect and image any small offset faults that may exist in the site subsurface, away from the borehole.

One of the most important lessons learned in conducting seismic programs is the absolute need for technical team personnel and seismic experts to oversee and stay in very close contact with contracted acquisition crews and processing groups. Having seismic experts present or in immediate contact at all stages promotes a highly professional atmosphere, eliminates errors, provides an awareness of real-time opportunities for additional solutions to processing challenges, and provides team geologists/geophysics with critical insights for future seismic programs.

Understanding the 2D seismic issues at the FutureGen 2.0 CO_2 storage site required a borehole VSP program in order to analyze the origins of seismic noise that result from the combination of acquisition, processing, and complexity of the subsurface. There is also 2D seismic noise that results from out-of-plane reflections and that can only be resolved by 3D acquisition.

Probably the greatest geologic cause of poor 2D data quality at the FutureGen 2.0 CO_2 storage site is the result of the unconformable erosional contacts above most of the formations. These irregular surfaces and sharp seismic velocity changes generate multiples, scatter and attenuate energy, and generate seismic mode conversions. For surface-based seismic, this occurs twice: on down-going energy and again on the up-going energy. At the Morgan County site this situation is further complicated by vugs and cavernous karst/hydrothermal porosity in the Potosi. Stacked unconformities, sharp velocity contrasts, and Potosi lost-circulation zones are likely to be an acquisition and processing problem for most of the western margin of the Illinois Basin. Similar poor data quality is apparent in the western part of the regional ISGS Knox line, but the problem may be accented over the Sangamon Arch. It should also be noted that outside experts expressed the view that the acquisition methodology and parameters of the Q-Land MAS system may not be appropriate for this region.

There are no discernable faults within the 12 high-resolution, short 2D VSP seismic lines that surround the characterization well (Hardage 2013a).

The VSP program (Section 4.4.5) and interferometric VSP processing demonstrated that excellent near-wellbore P-wave and converted P-S−wave images can be generated for the internal architecture of Mount Simon as well as the Precambrian topography in the western Illinois Basin. Close collaboration with the contractor processing team resulted in a high-quality product. In final deliverables, converted-wave images were superior to P-wave images, both for standard processing products and interferometric processing. Acquisition of converted-wave data is highly recommended for all surface 2D and 3D seismic programs. In addition, parameters derived from 2D/3D seismic data provide the best means for constructing a robust sitewide velocity model, which is critical for the accurate location and monitoring of microseismic events.

Although VSP and surface seismic provide the crucial framework for confining zones and reservoirs, rock physics modeling (Hardage 2014) indicates that the reservoir at the FutureGen 2.0 CO_2 storage site is too thin and too well cemented to allow seismic detection of variable saturations of sc-CO_2. In contrast, 2D and 3D seismic will detect gas chimneys formed by fugitive CO_2 above 2,500 ft.

Geophysical Wireline Well-Logging Surveys

Except for the magnetic resonance log on the intermediate run, and the large-diameter sidewall coring tool, all tools worked satisfactorily at the stratigraphic borehole FGA-1 site. The contractor field personnel were knowledgeable and provided good insights and advice. Because of the algorithms used in processing wireline logs, it is desirable to use the same suite of logs and same acquisition company for multiple logging runs and multiple boreholes.

It is also important to have a single designated service company petrophysicist as the log analyst, if possible, to provide insight into the sometimes “black box” methods of calculating petrophysical properties used in generating log porosities and permeabilities. This was especially important in calculating effective porosity and bulk volume irreducible water, and in integrating rock, fluid, and wireline data to derive estimates of elastic properties, thermal conductivity, and rock-matrix specific heat capacity for input in non-isothermal numerical reservoir simulations. In particular, for the stratigraphic borehole FGA-1 data, a k-Lambda model (Herron et al. 1998) for calculating intrinsic permeability provided better results when compared to horizontally oriented core data and hydrologic field tests than did the Schlumberger Coats and KSDR (Schlumberger 1989) models (see Rockhold et al. 2014). An alternative approach is that of Frailey et al. (2011) who used Mount Simon petrophysical facies, based on binning Archie’s cementation m values (Archie 1942) to derive horizontal perm (kh) estimation, using log-log regression relationships between core porosity and perm data for different petrophysical facies at the ADM site. The regression relationships were then used to predict permeability from the wireline log-derived porosity. Both Frailey et al. (2011) and Rockhold et al. (2014) computed the vertical permeability (kv) for their respective reservoir model layers as the harmonic mean of the log-derived k values.

One lesson learned was the need for fully adequate high-quality relative permeability data (from core analysis). These data allow a better determination of the combination of porosity logs and derived fluid volume data (e.g., ELAN BndWater, UIWater) to use for computing irreducible water saturation and for providing a consistent analysis of the combined log and core data sets.

A sample of the ELAN header and log, calibrated with porosity and permeability data from rotary sidewall and core plugs are shown in Figure 4.97 and a comparison of the acoustic image log and the resistivity-based image log are shown in Figure 4.98 and Figure 4.99. (The key for the ELAN log figures is shown in Figure 4.100.) The resistivity-based image log (FMI) is far superior to the acoustic UBI in sedimentary sections for imaging texture and permitting measurement of stratigraphic and structural dip. The UBI may be preferred for imaging fractures for specific lithologies, but was not of sufficient quality in the stratigraphic borehole FGA-1 to consider its use as the only fracture imaging tool.

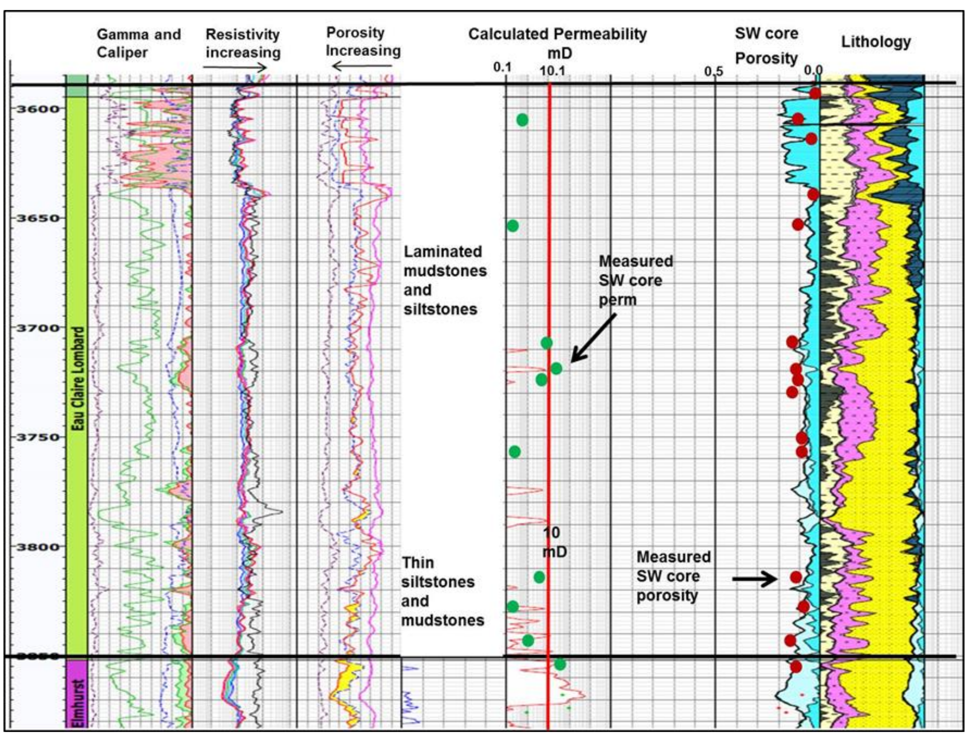


Figure 4.97. ELAN-Calculated Petrophysical Properties of the Eau Claire Lombard Member Plotted with Measured Rotary Sidewall Core Data

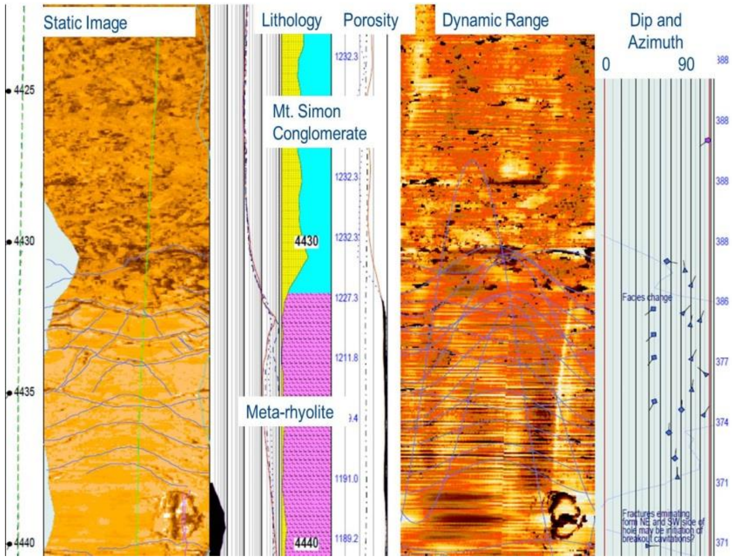


Figure 4.98. UBI Acoustic Image of the Contact between the Mount Simon Formation and Precambrian Meta-Rhyolite in Stratigraphic Borehole FGA-1. Blue lines and sinusoids are natural fractures; green lines are drilling-induced fractures. Tadpole tails are dip azimuth of fractures.

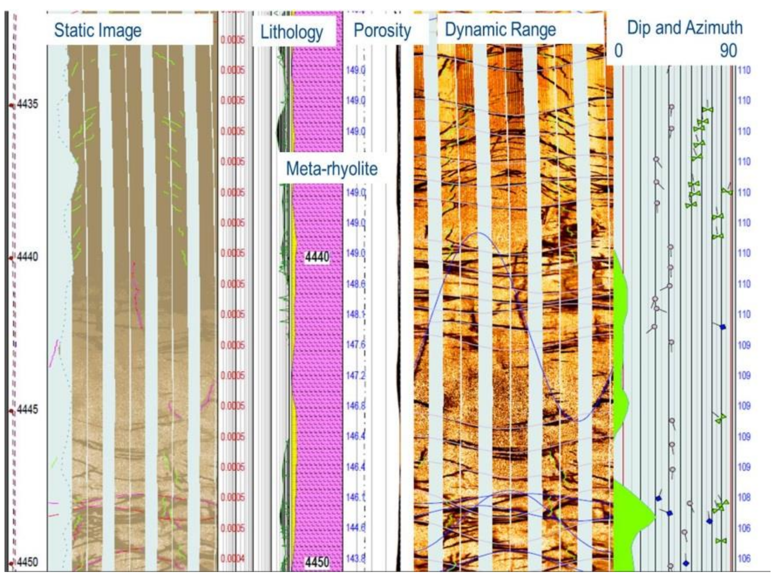


Figure 4.99. FMI Resistivity-Based Image Log over the Upper Section of the Precambrian Meta-Rhyolite. Note depth for comparison with previous figure. Blue lines and sinusoids are natural fractures; green are drilling induced. Round tadpole heads are foliation; bow-tie symbols are fractures.

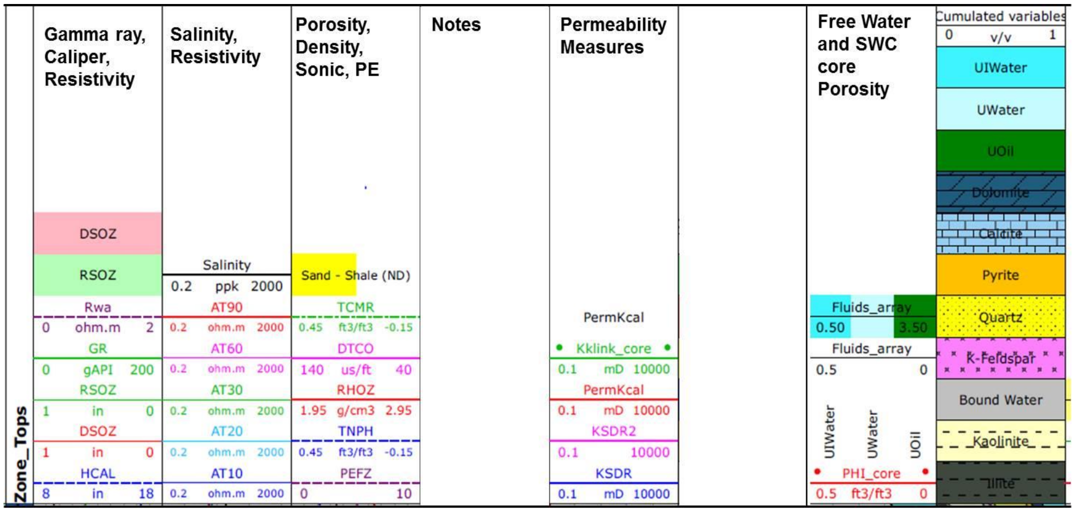


Figure 4.100. Key for ELAN Log Figures. Full acronym definitions are in http://www.glossary.oilfield.slb.com/.

Laboratory Core Analysis

Interactions with the commercial core analysis laboratory were, on the whole, very satisfactory.

Evaluation of the results of the special core analyses showed that some of these methods and analyses were not applicable to support multi-fluid flow simulations of the sc-CO_2−brine system. The methods were for the Steady-State Relative Permeability, Counter Current Imbibition, and Threshold Entry Pressure. PNWD staff members visited Core Lab in November 2013 to improve our understanding of these methods and to develop revised procedures to be used in future core analyses. These procedures are summarized in Appendix 4F-2.

Vertical Seismic Profiling (VSP) Program

Current CCUS sites and many CCS sites are in areas that have low saturations of natural gas above the CO_2 storage reservoir. Surface seismic P-wave energy at these sites will be attenuated. Thus, converted-wave data will be essential for detailed imaging of potential above-storage-zone monitoring zones.

Although all of the data produced by the 2013 VSP program produced images that are far superior to the 2011 2D surface seismic images, 3D3C VSP and 3D3C surface seismic will provide better spatial placement of events than is provided by any of the 2D seismic methods.

Rock physics modeling indicates that the rock and fluid properties of the Mount Simon and Elmhurst in stratigraphic borehole FGA-1 limit the use of seismic monitoring in detecting time-lapse differences in saturation of CO_2 within the reservoir (Hardage 2014). However, the comparison of VSP and surface seismic time-lapse P- and S-wave data is a demonstrated technology for detecting gas phase and is a viable technology for detecting fugitive gas in the shallow overburden.

Intermediate processing products strongly indicate that the vertical vibrator source at the FutureGen 2.0 CO_2 storage site generated both direct-P and direct-S modes. Although processing of S-S mode data remains challenging, VSP S-S imaging of the geology across the area with a vertical vibrator appears feasible.

Acquiring 3C seismic data is becoming more common for improving imaging of CCS and CCUS sites. But even when acquired, converted-wave data are often underused or relatively unexamined. At the FutureGen 2.0 CO_2 storage site, an examination of processing products allowed identification of sources of seismic noise related to multiples and attenuation. Although offset stations were too sparse to determine shear-wave splitting, fast shear-wave data indicated the azimuth of maximum horizontal stress to be N65E for the overburden, comparable to the azimuth independently determined from sonic and image logs.

FutureGen 2.0 CO_2 storage site P-wave VSP seismic images are highly superior to surface seismic P-wave images, and P-Sv data display higher resolution than P-wave VSP. Interferometric migration, being less subject to velocity anisotropy, particularly improves P-Sv imaging, and appears to be a technology with considerable potential.

Parameters derived from 3C data sets are vital to improve traditional surface seismic processing and to constrain velocity models for microseismic monitoring. Multicomponent acquisition provides insights for understanding or improving subsurface imaging in onshore areas with old, fast rocks, or under shallow oil and gas fields, typical of many areas being considered for CO_2 storage. Although efficacy will vary by site, we suggest that converted-wave seismic data should become a standard part of subsurface characterization of CO_2 storage sites.

Finally, it should be noted that the field geomechanical testing included hydraulic fracturing “minifrac” data, which allowed determination that the fault regime is strike slip, meaning that slip on undetected faults would likely have this sense of motion (see Section 4.4.4). Strike-slip faults may have very small vertical displacement, and could still be present, but unsampled by the VSP.

<u>Hydrologic Test Characterization</u>

An integrated approach that combined use of multiple test characterization methods of varying scales of resolution was implemented at the stratigraphic borehole FGA-1 for quantifying the permeability conditions and vertical profile structure within the Mount Simon Formation injection reservoir. The multiple-characterization methods included inferred permeability characteristics based on permeability-focused, geophysical wireline well-logging surveys (ELAN and CMR) and dynamic flowmeter surveys, and direct permeability measurements based on standard and SWC analyses and standard hydrologic packer field testing results. The relatively close correspondence between the inferred summation permeability-thickness response obtained from the ELAN wireline logging results in comparison to that obtained directly from the much larger scale dynamic flowmeter surveys and standard hydrologic packer tests, lends credence to the reservoir permeability vertical depth profile conditions estimated from the wireline logging results. The combined characterization approach provides the best opportunity of addressing the upscaling of borehole-derived characterization information for application in modeling of long-term, operational-scale injection performance at the FutureGen 2.0 CO_2 storage site.

Geomechanical Test Characterization

The successful completion of Phase I of the planned geomechanical field test characterization program for determining the state-of-stress within the environment of the Mount Simon Formation injection reservoir demonstrated the utility of and need for conducting multiple borehole geomechanical straddle-packer tests for fully characterizing in situ stress conditions. These types of direct stress measurement tests are considered to be far superior to estimated stress conditions inferred from elastic wireline logging responses. Information derived from the geomechanical field testing program not only establishes the state-of-stress within the subsurface, but also provides highly critical information about maximum threshold reservoir injection pressure conditions to assure low fracture generation potential within reservoir and caprock horizons, and low induced micro-seismicity with the underlying basement complex; establishing the fracture-gradient/depth relationship for the site; and designing injection-well orientations to enhance borehole stability conditions.

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APPENDICES

5 VISITOR, RESEARCH, AND TRAINING CENTER

This chapter describes the concept development for a visitor, research, and training (VRT) facility, known as the FutureGen Center, for the FutureGen 2.0 project. Development of a limited, but related, visitor experience at the power plant site, which would have been part of the Oxy-combustion Power Plant Project, is also addressed.

5.1 Background

5.1.1 Inclusion of VRT as Integral Part of FutureGen 2.0

The CO_2 Pipeline and Storage Site Project Cooperative Agreement included development of a VRT facility as a component of the Statement of Project Objectives. The VRT facility was included as an incentive to Illinois communities to host the FutureGen 2.0 Project, particularly the CO_2 storage site. Included in the project scope was DOE's FutureGen 2.0 Environmental Impact Statement, which included an analysis of the potential environmental impacts of construction and operation of the VRT facility. The projected cost of such a facility was assumed to be approximately $50 million. During the project development process, the VRT facility came to be referred to as the FutureGen Center.

5.1.2 Contractor Selection

In furtherance of the project objectives, the Alliance issued a Request for Proposals in April 2013 (RFP 1.2-30). The Statement of Work explained that the VRT facility would showcase near-zero emission coal technology, including carbon capture and storage, and should address the role that coal can play as part of a clean energy future. For proposal purposes, the Statement of Work noted that the VRT was expected to be approximately 45,000 square feet, with the final size determined in the planning process. To help ensure the long-term relevance and financial stability of the VRT facility, portions of the facility were proposed to have secondary community uses. The design of the facility was planned to reflect green design principles.

In response to the Alliance's RFP, six proposals were received. Based on a thorough review and the completion of an objective scoring process developed by the Contract Development Team, the Alliance selected and retained Westlake Reed Leskosky (WRL), a highly qualified and nationally recognized architectural firm. Architect Magazine ranked WRL #1 in sustainable design in 2012 and #1 overall among the nation's architectural firms in 2014. The civil engineering firm on the team was Benton & Associates of Jacksonville, Illinois.

Over the next several months, WRL and its team developed a conceptual design, front-end engineering design (FEED) and its associated definitive cost estimate, conceptual content for the exhibition space, and a concept for the visitor experience at the Meredosia Energy Center.

5.2 Proposed Location

Because of the importance of the FutureGen Center and its value to the local community, the Jacksonville City Council passed a resolution in July 2013 granting the Alliance permission to use approximately three acres in Jacksonville Community Park for the FutureGen Center. The Morgan County Board of Commissioners passed a similar resolution of support. The Jacksonville Chamber of Commerce currently uses a small building on the proposed site; the building would have been removed and the Chamber of Commerce relocated if the FutureGen Center were to have been built in Community Park. Design of the FutureGen Center fully embraced the park location and, anticipating its place in the community as an icon for an environmentally (and energy) conscious future, took into account the need to preserve existing trees and open space while positively impacting the area.

5.3 Description and Potential Uses

As designed, the total FutureGen Center building area was approximately 51,000 square feet on two levels (one of which was underground). The design featured three major components: (1) a visitor and interpretive center (10,000 square feet); (2) research, education, and training facilities (28,000 square feet); and (3) administration/office space (6,700 square feet). Building services and infrastructure would have required approximately 5,700 square feet. Table 5.1 provides a description of the FutureGen Center functions as designed, with the associated square footage for each function. The Front-End Engineering Design and Definitive Cost Estimate are contained in Appendix 5A. Facility drawings are contained in Appendix 5B. Artist renderings of the interior and exterior of the FutureGen Center are contained in Appendix 5C.

Table 5.1. FutureGen Center Functions

VISITOR AND INTERPRETIVE CENTER	**10,200 SF**
Interactive Exhibit Gallery	
RESEARCH, EDUCATION, AND TRAINING	**28,450 SF**
Lecture Hall / Auditorium STEM Classrooms Research Center Training Facility	
ADMINISTRATIVE	**6,743 SF**
Offices	
BUILDING SERVICES / INFRASTRUCTURE	**5,700 SF**
Mechanical / Electrical Storage	
TOTAL BUILDING AREA	**51,093 SF**

Visitor and Interpretive Center

Intended for a wide audience from schoolchildren to adults, the visitor and interpretive center would have included an interactive exhibit gallery organized around four energy-focused content modules: energy choices, energy balance, energy technology, and energy future. The energy technology area would have addressed the technology involved in the FutureGen 2.0 project: an interactive process wall that diagramed the steps from coal extraction to production and distribution of electricity, a simulated power plant control room with interactive monitors, and a re-created geological extrusion that demonstrated carbon storage. The center would have included visitor amenities including ticketing, coat check, and a shop. A more comprehensive description of the planned FutureGen Center visitor exhibits is contained in Appendix 5D.

Research, Education, and Training

This component of the FutureGen Center would have included a lecture hall, science-technology-engineering-mathematics (STEM) classrooms, a research center, and a training room that included a wet laboratory. The lecture hall/auditorium would have seated approximately 300 people, with the additional capacity to accommodate up to 150 more people via temporary seating. This would have allowed large national and international power plant and carbon capture and storage-related meetings, conferences, and symposia to be held in Jacksonville near both the power plant and the injection site. The local public school system and the three local colleges also expressed a need for this type of facility to enhance their educational programs.

There would have been flexible classroom space (able to be configured for between one and six classrooms or meeting spaces) that could have been used as breakout rooms for conferences, as classrooms to complement the learning experiences at the visitor center, or as meeting rooms for local groups or businesses when not otherwise in use. As designed, each of the classrooms would have been outfitted with video and Internet capability.

The research center would have included a computational laboratory and library for active research relating to the FutureGen 2.0 project. This space would have served as a resource for professional study as well as for academic study and research by local colleges and high schools, accommodating approximately 18 students.

The training room would have consisted of a flexible laboratory space geared for STEM education. This space would have been a resource to the local school district (grades kindergarten through 12th), which could have used supplemental laboratory space to expand science education outside of the regular school classroom. The physical infrastructure would have included laboratory sinks and gas connections, as well as adjustable tables to allow for a variety of configurations or open floor space to provide maximum flexibility. As designed, the space would have accommodated approximately 19 students for laboratory experiments.

Administration

The FutureGen Center would have provided office space for the Alliance and DOE for the duration of the project. When not needed for those purposes, the office space could have been used by other local entities.

Building Services/Infrastructure

In addition to the mechanical and electrical systems needed for the facility, this area would have included approximately 3,000 square feet for storage. Alternatively, the space would have been appropriate for use by Morgan County and Jacksonville emergency personnel as a security center for the protection of all components of the FutureGen 2.0 project and to promote a coordinated response to any other local or regional emergency situation. The construction materials for the shell and underground location were designed to meet federal emergency response regulations (any fit-out would have been paid for by the users).

5.4 Stakeholder Activity

5.4.1 Public Communications

Prior to issuing the Request for Proposals for the design of the VRT, the Alliance sought input from local stakeholders and the Citizens Board established by the Alliance to make the FutureGen 2.0 project more accessible to the community. With respect to the VRT, the Alliance sought citizens' views on potential function and design factors: whether the community would want new construction or rehabilitation of existing building(s), potential community functions to be included in the facility, and potential long-term funding sources for operating costs. Above all, the Alliance wanted to ensure that any facilities that were built using federal funds were sustainable and that the mission/vision and operating principles of these facilities included community input. In August and November 2013, the Alliance invited various community organizations to meet with WRL to learn about design plans and offer input.

5.4.2 State, federal, and local governments

The Alliance also kept state and local government officials aware of its planning for the VRT. As noted above, the Jacksonville City Council and the Morgan County Board of Commissioners passed resolutions supporting the use of Community Park for the FutureGen Center, which demonstrates the high level of support provided by local officials. The Alliance also continued to brief DOE on the expected design, cost, function, and exhibition content.

5.5 Long-term Sustainability

Although federal funds would have been used to design and construct the FutureGen Center, no federal funds would have been available for its operating expenses. In order to ensure that the federal funds that were spent for design and construction were not wasted, it was critical that the FutureGen Center, once constructed, was financially self-sustaining over time and did not become an underutilized building that could not be cost-effectively operated and maintained. Any building designed and constructed using federal funds should be able to continue to provide benefits to U.S. taxpayers, including those in Illinois and Morgan County, for a substantial period of time in order to justify its initial construction cost.

The Alliance sought DOE approval for the preparation of a business plan for the FutureGen Center. The purpose of the plan was to (1) develop a rigorous estimate of all operating costs of the FutureGen Center as currently designed over a 20- to 25-year period; (2) identify all potential revenue-generating uses of the facility, including use by government, educational, research, business, and non-profit organizations; and (3) describe the potential revenue streams that would be available to provide the operating expenses for the FutureGen Center over the planning period. If it had been approved by DOE, the resulting business plan would have described how the FutureGen Center should be utilized, managed, and operated to ensure the long-term financial sustainability of the facility and realize maximum long-term benefits to DOE and to the citizens of Illinois and Morgan County.

While detailed information regarding operating costs and revenue sources would not have been available until a business plan was complete, it is clear that facility user fees would have been necessary to fund the operation and maintenance expenses of the FutureGen Center. Thus, allowing for spaces that fulfilled the visitor, research, and training needs for which the facility was purposed would have provided for sustainability over time through short-term or long-term lease agreements. Entities that expressed interest in using the FutureGen Center spaces were:

- City of Jacksonville (underground security center, training facility)
- Jacksonville School District (classrooms, research center)
- Illinois College (classrooms, research center)
- MacMurray College (classrooms, research center)
- Lincoln Land Community College (classrooms, research center, training facility)
- Jacksonville Chamber of Commerce (office space)
- Jacksonville Regional Economic Development Council (office space)
- Jacksonville Visitor and Convention Bureau (office space)
- Jacksonville Center for the Arts (lecture hall/auditorium, classrooms)

Because the proposed site selected for the FutureGen Center was prominently located in Jacksonville's Community Park, it was critical that the facility be viewed as a welcome resource to the community.

5.6 Cost

5.6.1 Definitive Cost Estimate

As of January 2014, the estimated construction cost of the FutureGen Center was approximately $49 million. Table 5.2 provides a description of how those estimated costs were derived. The Definitive Cost Estimate is contained in Appendix 5A.

Table 5.2. FutureGen Center Estimated Construction Cost, 2014

Prepared by Westlake Reed Leskosky:
Based on Opinion of Probable Cost from CCS estimate dated 01.15.14

Hard Costs	
New Construction	
Construction Cost (Hard cost) excluding design contingency and escalation	23,898,783
Site Construction Cost – (Included with construction cost)	N/A
Design Contingency @ 7%	1,873,665
Subtotal Construction Cost (Hard cost) including design contingency, excl escalation	**25,772,448**
Escalation (4%) July 2014 const start	1,145,612
Subtotal Construction Cost (Hard Cost) including design contingency, incl escalation	**26,918,060**
Exhibit Costs (Fit-out of exhibit and interpretive spaces), excluding fees	3,150,000
General Conditions and Contractor Overhead and Profit (125)	2,867,854
Total Construction Cost including design contingency and escalation, AV and Exhibits, General Conditions, Contractor OH&P	**32,935,914**

Soft Costs	
Design services	
Exhibit Fit-Out (18% of exhibit cost)	600,000
Stage 1 Initial Concept Design Services	290,750
Design services (AISMEP and Specialties @ 125 of const cost including performance equipment but excluding exhibits), excl. site – Stage 2 – 4	**3,363,928**
Sitework design services (12% of Sitework cost)	120,000
Off-site design coordination (Sitework)	153,758
Reimbursable Expenses (4% of all design services)	147,502
Building Commissioning	27,500
Measurement and Verification	25,300
Stakeholder Design Coordination (user scope)	300,000
Signage and Environmental Graphics Design Allowance	30,000
Geothermal Conductivity Testing	10,000
Code consulting	6,072
Subtotal design services	**5,074,810**

Table 5.2. cont.

Other soft costs (Architect – designated)	
Furniture, Fixtures, and Equipment (FFE) Allowance	500,000
AV systems	500,000
Data/IT allowance	200,000
Building Permits	50,000
Utility Assessment Fee	50,000
Builder's risk insurance	225,000
Construction Testing and Inspection	75,000
Construction Contingency (3% of construction)	716,963
Phase I environmental	10,000
Subtotal	**2,326,963**
Category 2: Owner-designated soft costs	
Demolition of Chamber of Commerce Building (included in estimate)	-
Transportation Capital	1,000,000
Land Acquisition	2,200,000
PILOT Payment	500,000
Owner Legal Services	200,000
Owner Project Management	1,500,000
Owner's Reserve	1,000,000
G+A	1,000,000
Working Capital	250,000
Two year operating cost, including maintenance, utilities, and staff	1,150,000
Subtotal Owner's Soft Costs	**8,800,000**
Subtotal Soft Costs	**16,201,773**
Total Project Cost (Building and Site including construction and design contingency)	**$49,137,687**
Below the Line Costs	
Auditorium Equipment (Funded by local organizations)	$1,167,300
Emergency Operation Equipment /Fit-Out	$600,000
Temporary Gallery Fit-Out	$500,000
Subtotal Below the Line Costs (hard and soft, excluding contingency)	**$2,267,300**

5.6.2 Cost Reasonableness

The estimated $49 million cost of the FutureGen Center was judged to be “reasonable,” as the term is used in the Federal Acquisition Circular (FAR 31.201-2) Cost Principles. A cost is “reasonable” if it does not exceed that which would be incurred by a prudent person in the conduct of competitive business (FAR 31.201-3).

Given the prominent and central location of the facility in Jacksonville’s Community Park, the FutureGen Center design needed to respect the existing character of the park and ensure that the architecture and landscaping was appropriate for a park setting. Further, as a component of the FutureGen 2.0 project, the Alliance wanted the design to evoke the progressive mission of the clean energy project. The size of the building was appropriate for the uses for which it was intended. These aspects of the FutureGen Center demonstrated that its expected cost was reasonable.

5.7 Power Plant Visitor Experience

WRL also conceived a plan for a modest visitor experience at the Meredosia Energy Center, oxy-combustion power plant. The concept included an entry visitor’s pavilion, a van tour of the site, a tour of the turbine hall and control room, a roof tour, and a walkway to the Illinois River. Figure 5.1 shows the site layout that was proposed.

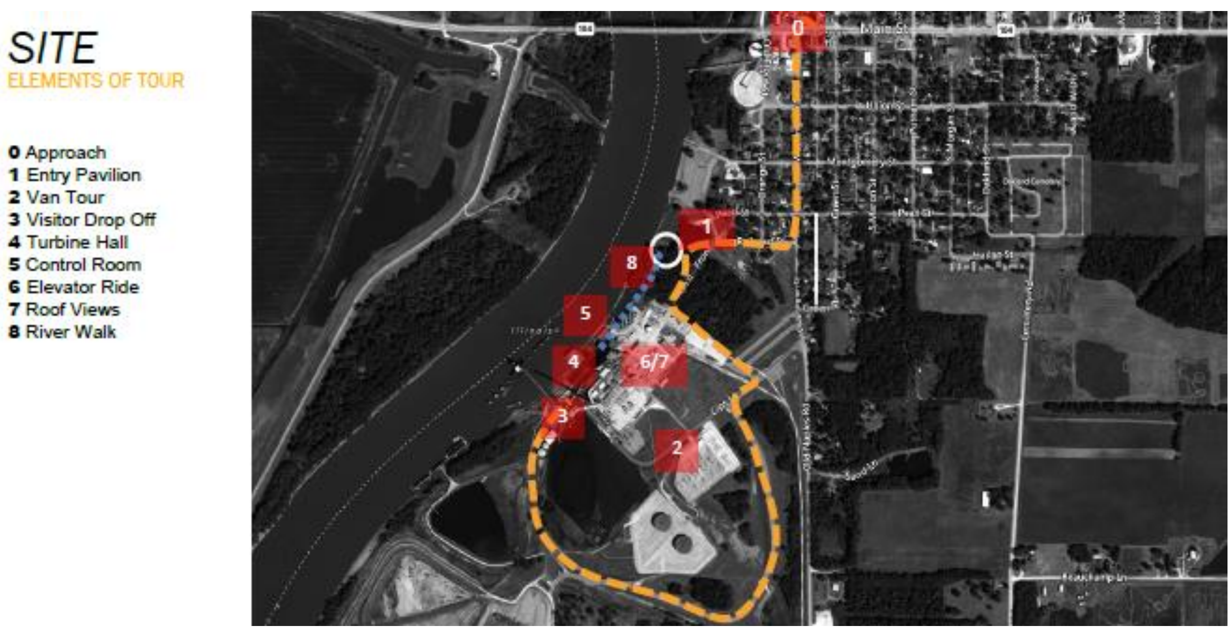

Figure 5.1. Elements of Power Plant Visitor Experience Tour

5.8 Appendices

Appendix 5A – Front-End Engineering Design and Definitive Cost Estimate

Appendix 5B – Drawings

Appendix 5C – Artist Renderings

Appendix 5D – FutureGen Center Visitor Exhibits

6 PERMITTING

6.1 Introduction

This chapter summarizes the status of authorizations, permits, approvals, and certifications required from federal, state, regional, and local agencies for the construction and operation of the CO_2 pipeline, underground CO_2 storage facility, and associated monitoring systems. In a few instances, the permitting agency also included the scope of activities planned for the Meredosia Energy Center. This chapter summarizes the permitting actions originally identified in the FutureGen 2.0 Pipeline and Storage Project Permitting Plan and identifies the status of those actions as of January 2015. It also identifies the agency point-of-contacts (POCs) for each permitting action and includes an appendix containing all agency submittals and responses. The information is provided to support future CO_2 sequestration projects.

The FutureGen 2.0 Project was structured in four phases, which will be referred to throughout this chapter. These phases were:

- Phase I: Project Definition
- Phase II: National Environmental Policy Act (NEPA), Permitting, and Design
- Phase III: Construction and Commissioning
- Phase IV: Operations and Post-Operations Monitoring

During Phase I of the project, informal consultations were held with all permitting agencies to clarify each permitting or approval requirement and to identify and acquire data needed for permit applications. As of January 2015, permit applications had been submitted to all agencies for those permits or approvals required prior to the start of project construction. Most of the requisite permits were received during Phase II. During Phases III and IV, most permitting compliance activities would have involved post-construction and operational compliance monitoring and reporting as required by the permits and approvals acquired during Phase II.

6.2 Regulatory Requirements

Several federal, state, and local regulations required permits or approvals before activities planned as part of the Pipeline and Storage Project could be initiated. This section summarizes the regulatory requirements for the project.

6.2.1 Summary of Regulatory Approach

Federal regulations relevant to the FutureGen 2.0 Project include the National Environmental Policy Act (NEPA) of 1969, as amended (42 United States Code [USC] 4321 *et seq.*); the Safe Drinking Water Act (SDWA) (Part 40 of the Code of Federal Regulations [CFR] 141-149); the National Historic Preservation Act (NHPA) (16 USC 470 *et seq.*); the Clean Water Act (CWA) (33 USC 1251 et seq.); the Endangered Species Act of 1973 (ESA) (16 USC 1531 *et seq.*); the Migratory Bird Treaty Act of 1918 (MBTA) (16 USC 703 *et seq.*); the Clean Air Act (CAA) (42 USC 7401 *et seq.*); the Rivers and Harbors Act (33 USC 403 *et seq.*); and the Pipeline

Inspection, Protection, Enforcement and Safety Act (Public Law 109–468—Dec. 29, 2006). In many cases, authority to grant permits related to these acts has been delegated to state agencies. For example, consultation related to the NHPA was held with the Illinois Historic Preservation Agency (IHPA) and some permits under the CWA were issued by the State of Illinois. Permits for other actions (e.g., road crossing, road construction and sewage disposal) are issued by counties or other local entities. A brief discussion of these permits and approvals is included in the following sections.

6.2.2 Federal Authorizations, Permits, and Certifications

This section summarizes federal permit requirements and identifies where enforcement is delegated to the state.

National Environmental Policy Act of 1969, As Amended

NEPA requires federal agencies to consider environmental values in their decisions by considering the environmental impacts of their proposed actions and alternatives to those actions prior to proceeding with the proposed actions. Section 102 of the Act directs that an environmental impact statement (EIS) be prepared for major federal actions that significantly affect the quality of the human environment. The federal agency must prepare a draft EIS for public and other agency review. The U.S. Environmental Protection Agency (USEPA) reviews and comments on draft EISs prepared by other federal agencies and maintains a national filing system for all EISs. Following public, other agency, and USEPA review, the agency prepares a final EIS and publishes a record of decision (ROD) in the *Federal Register* documenting the agency's decision. This ROD is required prior to initiating the actions described in the EIS and, in some cases, is required prior to the completion of permit applications or the issuance of permits by other agencies.

To support DOE's development of the EIS for the FutureGen 2.0 Project as a whole, the Alliance prepared an Environmental Information Volume (EIV) that included an executive summary, the purpose and need for the project, alternatives to the proposed action, a project and facility description, an affected environment description, and agency contacts. Using this and other data, DOE developed the draft and final EISs and ROD.

Permit or Authorization:	NEPA ROD
Responsible Agency:	DOE National Energy Technology Laboratory, Morgantown, West Virginia
Agency POC:	Cliff Whyte M/S: I07, National Energy Technology Laboratory 3610 Collins Ferry Road, P.O. Box 880, Morgantown, WV 26507–0880, ATTN: FutureGen 2.0 Project; email: cliff.whyte@netl.doe.gov; telephone: 304–285–2098.

Status at Project Suspension:	FEIS issued October 2103. Record of Decision (ROD) issued January 22, 2014. Mitigation Action Plan issued March 2014.
Documentation Available:	As of May 2015: FEIS can be found at: http://energy.gov/nepa/downloads/eis-0460-final-environmental-impact-statement. ROD can be found at: http://energy.gov/nepa/downloads/eis-0460-record-decision. Mitigation Action Plan can be found at: http://energy.gov/sites/prod/files/2014/04/f14/EIS-0460-MAP-2014.pdf

Safe Drinking Water Act

The SDWA is a federal law that ensures the quality of Americans' drinking water. Under the SDWA, USEPA sets standards for drinking water quality and oversees the states, localities, and water suppliers who implement those standards. Under the authority of the SDWA, USEPA has developed the Underground Injection Control (UIC) Program. This program is responsible for regulating the construction, operation, permitting, and closure of injection wells that place fluids underground for storage or disposal. One class of UIC well, Class VI, is used for geologic sequestration (GS), which is the process of injecting CO_2 from a source through a well into one or more deep subsurface formations.

The SDWA is implemented in Illinois through the Illinois Groundwater Protection Act (IGPA). Illinois' program for water protection has been approved by USEPA Region 5 under the federal SDWA. However, the IGPA program of Illinois does not include regulatory review or approval of Class VI wells. Instead, Class VI UIC permits are issued by USEPA Region 5 once regulatory requirements have been satisfied. Requirements of the UIC permit process include development of a project plan, site characterization, development of a well construction plan, development of a monitoring plan, development of a post-injection site care plan, and demonstration of adequate financial assurance.

Issuance of a UIC permit requires demonstrating compliance with nine specific evaluation criteria, including extensive site characterization, comprehensive monitoring of numerous aspects (e.g., well integrity, CO_2 injection and storage, groundwater quality during the injection operation and the post-injection site care period), and financial responsibility to assure the availability of funds for the life of the project.

The Alliance submitted its permit application for its four proposed injection wells on March 15, 2013; this information was supplemented in May 2013 in response to comments from USEPA. On August 29, 2014, USEPA issued UIC VI permits for all four of the Alliance's planned injection wells. On October 1, 2014, the Leinberger family and the Critchelow family, both of which own property in the vicinity of the project, challenged USEPA's issuance of the UIC VI permits to USEPA's Environmental Appeals Board. On April 28, 2015, the Environmental Appeals Board denied the appeal stating that "*Petitioners have identified no clear error of fact or law, abuse of discretion, or matter of policy warranting the [Environmental Appeals] Board's review under 40 C.F.R.§ 124.19(a)(4)*."

Permit or Authorization:	Class VI UIC permit
Responsible Agency:	USEPA Region 5, Chicago, Illinois
Agency POC:	Jeff McDonald 77 W. Jackson Blvd. Chicago, IL 60604-3590 312-353-6288
Status at Project Suspension:	UIC permits issued for four wells on August 29, 2014. Permit issuance appealed by two local property owners on October 1, 2014. Petitioners appealed; however, USEPA denied the appeal on April 28, 2015.
Documentation Available:	Documents related to the UIC Class VI permitting can be accessed on EPA Region 5 website (http://www.epa.gov/Region5/water/uic/futuregen/index.htm)

Provided in the attached USEPA/UIC Appendix 6A:

1. UIC Permit Applications for FutureGen 2.0 Morgan County Class VI UIC Wells 1, 2, 3, and 4
2. FutureGen Alliance Response to RAI of November 14, 2013
3. FutureGen Alliance Response to USEPA RAI of October 31, 2013
4. USEPA UIC Class VI Permit and Attachments for FutureGen Well #1 issued on August 29, 2014 (permit# IL-137-6A-0001)
5. USEPA UIC Class VI Permit for FutureGen Well #2 issued on August 29, 2014 (permit # IL-137-6A-0002)
6. USEPA UIC Class VI Permit for FutureGen Well #3 issued on August 29, 2014 (permit # IL-137-6A-0003)
7. USEPA UIC Class VI Permit for FutureGen Well #4 issued on August 29, 2014 (permit # IL-137-6A-0004)
8. USEPA Order Denying Review, UIC Appeal Nos. 14-98 to 14-71

Clean Water Act

The CWA regulates the discharge of pollutants into the waters of the United States and quality standards for surface waters. The basis of the CWA was enacted in 1948 and was called the Federal Water Pollution Control Act; however, the Act was significantly reorganized and expanded in 1972. The Clean Water Act became the Act's common name with amendments in 1977. Under the CWA, USEPA has implemented pollution control programs (e.g., setting wastewater standards for industry and setting water quality standards for all contaminants in surface waters). The CWA made it unlawful to discharge any pollutant from a point source into navigable waters without a permit. USEPA's National Pollutant Discharge Elimination System (NPDES) permit program controls discharges (USEPA 2011).

Section 401 of the CWA requires that before a federal agency can issue a license or permit for construction or other activity, it must have received, from the state in which the activity would take place, written certification that the activity will not cause or contribute to a violation of relevant state water quality standards.

Section 402 of the CWA created the previously mentioned NPDES permit program. Point sources must obtain a discharge permit from the proper authority (usually a state, but sometimes USEPA, a tribe, or a territory) to discharge a pollutant into navigable waters.

Although most commonly associated with activities that involve filling of wetlands, Section 404 of the CWA primarily deals with one broad type of activity – the placement of dredged or fill material into waters of the United States. Wetlands are one component of waters of the United States; however, there are numerous other types (e.g., intermittent streams, small perennial streams, rivers, lakes, bays, estuaries, and portions of the oceans).

The 404 permit program is administered jointly by USEPA and the U.S. Army Corps of Engineers (USACE) through a joint permit application process (JPA). The USACE handles the actual issuance of permits (both individual and general) and determines whether a particular plot of land is a water of the United States. In addition, the USACE has primary responsibility for ensuring compliance with permit conditions, although USEPA does play a role in compliance and enforcement.

In Illinois, the Illinois Environmental Protection Agency (IEPA) is responsible for implementing Sections 401 and 402 of the CWA. The primary element of this implementation as it relates to the Pipeline and Storage Project is the issuance of NPDES permits under Section 402 for the stratigraphic well sites, injection site, and CO_2 pipeline. In accordance with IEPA guidance, this activity includes the preparation of NPDES permitting requirements, Storm Water Pollution Prevention Plan(s) (SWPPP), and the Notice of Intent for the CO_2 pipeline, injection wells, and monitoring wells. NPDES permitting activities are described further in Section 6.3.1 of this chapter. A Section 401 certification from the IEPA is also needed as part of the USACE's issuance of a 404 permit; in Illinois, a Section 401 certification application is filed concurrently with a USACE 404 permit application via a JPA submitted to the USACE, the Illinois Department of Natural Resources (IDNR), and IEPA.

Authorization from the USACE would be required under Section 404 of the CWA for the discharge of fill or dredged material into waters of the United States associated with construction of the CO_2 pipeline, access roads, injection site, and other project features. USACE uses a “Nationwide Permit” system to authorize certain routine activities expected to have limited impacts on waters of the United States. A Nationwide Permit meets the requirements of Section 404(b)(1) of the CWA and is certified by IEPA to meet Section 401 of the CWA as long as the associated general, state, and local permit conditions are met by the permitted project. USACE Nationwide Permit 12 (NWP 12) applies to Utility Line Activities that are expected to have a very limited impact, defined as “activities required for the construction, maintenance, repair, and removal of utility lines and associated facilities in waters of the United States, provided the activity does not result in the loss of greater than 0.5 acre of waters of the United States (Sections 10 and 404).” A “utility line” is defined as any pipe or pipeline for the transportation of any gaseous, liquid, liquefiable, or slurry substance, for any purpose. During the route selection process for the CO_2 pipeline, efforts were made to satisfy the Section 404(b)(1) requirements by selecting a CO_2 pipeline route that avoided streams and wetlands, and by using horizontal borings and that can be permitted under NWP 12. CO_2 Pipeline route siting efforts were successful in keeping wetland losses to less than 0.1 acre, in order to meet NWP General Condition 23 regarding mitigation.

In its JPA, the Alliance committed to avoid impacts to waters of the United States through a combination of siting and the use of horizontal borings (under any such features that cannot be avoided). The CO_2 pipeline route was developed in such a way so as to minimize the number of wetlands or stream crossings. Field surveys to delineate wetlands and streams occurred early in Phase II. These survey results were shared with USACE and with the CO_2 pipeline design team to determine where horizontal borings were needed. The USACE conducted their jurisdictional determination and agreed the project would qualify for a NWP 12. Pipeline route siting efforts were successful in keeping wetland losses to less than 0.1 ac, thus meeting General Condition 23 of NWP 12 regarding mitigation. Authorization of NWP 12 was received from the USACE on November 13, 2013.

The associated injection well pad, monitoring well pads, and access road locations were designed to completely avoid waters of the United States.

Permit or Authorization:	USACE NWP 12 under Section 404 of the CWA, and IEPA Section 401 and IEPA NPDES Permits under Section 402
Responsible Agencies:	USACE, St. Louis Branch, St. Louis, Missouri, IDNR, and IEPA, for CWA Sections 401 & 404 IEPA for CWA Section 402
Agency POCs:	US Army Corps of Engineers, Regulatory Branch St. Louis District 1222 Spruce St

St Louis, Missouri 63103-2833
Attn: Tyson J. Zobrist, Project Mng/Biologist
tyson.j.zobrist@usace.army.mil
314-331-8578

Illinois Environmental Protection Agency, Bureau of Water
Permits Section, Division of Water Pollution Control
1021 North Grand Avenue East
Springfield, IL 62794-9276
Attn: Al Keller, Manager, Permit Section and Darren Grove, staffer
Al.Keller@illinois.gov
217-782-0610
Darren.Gove@illinois.gov
(217) 524-3033

Illinois Department of Natural Resources
Office of Water Resources
Downstate Regulatory Programs
One Natural Resources Way
Springfield, Illinois 62702-1271
Attn: Mike Diedrichsen, P.E.
Mike.Diedrichsen@Illinois.gov
217-782 -3863

Status at Project Suspension:	A JPA submitted to the USACE, IEPA, and IDNR on October 30, 2013 under Section 401 and 404. Authorization of NWP 12 was received from the USACE on November 13, 2013.
Documentation Available:	Provided in the attached USACE Appendix 6B: 1. JPA 2. USACE NWP 12 Authorization 3. IEPA CWA Section 401 determination

National Historic Preservation Act

Section 106 of the NHPA and the Illinois State Agency Historic Resource Preservation Act require state and federal agencies, and projects funded by the state or federal government, to consider the effects of their actions on historic properties listed in, or eligible for, the National Register of Historic Places. The compliance process requires that the applying agency, which is DOE for the FutureGen 2.0 Project, identify and consult the appropriate State Historic Preservation Officer (SHPO) and Tribal Historic Preservation Officer (THPO). In addition, applying agency is directed to solicit public input and to identify other potential consulting parties.

The applying agency is then tasked with identifying historic properties within the area of potential effect. For the FutureGen 2.0 Project, the Alliance has assisted DOE in this process. If the agency finds that historic properties are present, it works with the SHPO and THPO to assess possible adverse effects. Consultation usually results in a Memorandum of Agreement (MOA), which outlines the agreed upon measures that the agency will take to avoid, minimize, or mitigate adverse effects. If a MOA is executed, the agency proceeds with its undertaking under the terms of the MOA. At any time during this process, if the agency finds that historic properties are not present or affected, the agency provides documentation to the SHPO and THPO and may proceed with its undertaking in 30 days as long as there is no objection by the SHPO and THPO.

A key initial step in the NHPA compliance process for the Pipeline and Storage Project was the establishment of a programmatic agreement (PA) that was executed by DOE, the Alliance, the Illinois SHPO and the Advisory Council on Historic Preservation. The PA was developed to ensure that historic properties and cultural resources are taken into account in the planning for, and conduct of, project actions in a proactive manner. The PA outlines the federal undertaking, identifies the responsible agencies involved with the project, and documents the agreed upon approach to completing the Section 106 consultation. A PA was signed by all parties in July 2013.

This effort entailed data gathering and interpretation through historic references, executing onsite (field) surveys of affected lands, and developing and executing monitoring and/or mitigation plans as needed. Affected lands included the stratigraphic well, monitoring wells, injection wells, pipeline right-of-way (ROW), activities at the Meredosia Energy Center, and other facilities (e.g., the training and visitor center). This work was to be completed at the conclusion of Phase II.

Additional actions taken for project activities to comply with the NHPA are summarized as follows:

- **Injection wells**– Prepared a Phase I Cultural Resources Survey Report summarizing site surveys and background information for submission to the SHPO including monitoring and/or mitigation plans. Provided copies of IHPA approval to DOE and other permitting agencies.
- **Monitoring wells**– Prepared a Phase I Cultural Resources Survey Report summarizing site surveys and background information for submission to the Illinois Historic Preservation Agency including monitoring and/or mitigation plans. Provided copies of IHPA approval to DOE and other permitting agencies.
- **CO_2 Pipeline** – Prepared an overall project draft Phase I Cultural Resources Survey Report for the CO_2 pipeline summarizing site surveys and background information for submission to IHPA including monitoring and/or mitigation plans. At the time of project suspension, all but one parcel had been surveyed. Completion of surveys and the report were waiting upon

land owner access authorization. Copies of SHPO approval were supplied to DOE and other permitting agencies. Phase I Cultural Resources Survey Reports for the CO_2 pipeline occurred in a phased approach as landowner permissions were obtained. Because DOE directly contracted for the surveys of the Meredosia Energy Center, the first phase directed by the Alliance addressed the area leaving the Meredosia Power Plant headed east toward U.S. Highway 67. Portions of the pipeline route, including the high priority flood plain and bluff areas, were surveyed in 2012 and Phase I reports were submitted to IHPA. Geomorphological testing of the flood plain occurred in November 2013 and a fact sheet was prepared in advance to facilitate communications with stakeholders including property owners. A work plan was prepared and approved by the SHPO prior to excavations. A draft report with the geomorphological test results was prepared, but was not submitted to the SHPO. In July 2014 a draft Phase I Cultural Resource Survey report was prepared for the 29 mile CO_2 pipeline corridor within the Illinois Department of Transportation's right-of-way. This draft report was in the process of being updated due to accommodating route changes to the CO_2 pipeline and did not get finalized and submitted to the SHPO prior to project suspension.

- **Visitor, Research, and Training Facilities** – Prepared a Phase I Cultural Resources Survey Report summarizing site surveys and background information for submission to Illinois SHPO, including a monitoring and/or mitigation plan. Provided copies of IHPA approval to DOE and other permitting agencies. At the time of project suspension, the draft Phase I Cultural Resources Survey Report had not been reviewed or submitted to the SHPO. The field work was completed in March 2014.

Permit or Authorization:	SHPO (IHPA) concurrence on PA/MOA and a monitoring/mitigation plan
Responsible Agency:	IHPA, Springfield, Illinois
Agency POC:	Joe Phillippe, Archaeologist Joe.Phillippe@illinois.gov (217) 785-1279 Illinois Historic Preservation Agency 1 Old State Capitol Plaza Springfield, IL 62701
Status at Project Suspension:	1. Programmatic Agreement (PA) among IHPA, DOE and the Alliance was signed on July 25, 2013. 2. Phase 1 walkover surveys were completed on all pipeline parcels except the Kircher parcel. Submittal of field survey results to the SHPO were pending completion of this past parcel survey. 3. Interim action cultural survey results for well pads and road widenings were submitted to the SHPO and concurrences were received on the no impact findings.

Documents Available: Provided in the attached IHPA Appendix 6F:

1. Programmatic Agreement among IHPA, DOE and the Alliance
2. Incomplete reports on interim actions that were in process at the time of project suspension.

U.S. Endangered Species Act

Section 7 of the USESA requires consultation with the U.S. Fish and Wildlife Service (USFWS) regarding the potential for project activities to adversely impact federally listed threatened or endangered species. Federally listed species that could occur in the project area in Morgan County included the decurrent false aster (*Boltonia decurrens)*, Indiana bat (*Myotis sodalis*), and eastern prairie fringed orchid (*Platanthaera leucophaea)* (USFWS 2012). Decurrent false aster was the only federally listed species known to occur within the 4-mile-wide CO_2 pipeline corridor. There are no known occurrences of federally listed species within the Morgan County injection site region of interest. The USESA process requires concurrence from USFWS that no adverse impact will occur or consultation on appropriate mitigation measures. Site-specific surveys were completed and a Biological Assessment was prepared for USFWS that determined the proposed project activities may affect but would not likely adversely affect any of the listed species covered. The USFWS concurred with the project's findings and informal consultation was concluded.

The effort to comply with Section 7 of the USESA entailed data-gathering and interpretation through state and federal registries, executing onsite (field) surveys of affected lands, and developing and executing mitigation measures as needed. Affected lands included the stratigraphic well, monitoring wells, injection wells, pipeline ROW, and the Meredosia Energy Center. This work was completed by the development and implementation of procedures and training for the protection of ecological resources.

Permit or Authorization: Concurrence from USFWS that no adverse impact will occur

Responsible Agency: USFWS, Marion, Illinois

Agency POC: Matt Mangan, Fish & Wildlife Biologist
matthew_mangan@fws.gov
618-997-3344 x345
US Fish & Wildlife Services
Marion Illinois Sub-Office
8588 Route 148
Marion, IL 62959

Status at Project Suspension:	USFWS concurred with Alliance's and DOE's determination of no adverse effects on federal species assuming potential Bat habitat trees would only be cut between November 1 and February 28 of any given year.
Documents Available:	Provided in the attached USFWS Permitting Appendix 6K: 1. Alliance's Biological Assessment 2. USFWS's Biological Opinion

Migratory Bird Treaty Act of 1918

The MBTA establishes federal responsibilities for the protection of nearly all species of birds, their eggs, and nests. The USFWS has statutory authority and responsibility for enforcing the MBTA. The MBTA was implemented during the 1916 convention between the United States and Great Britain for the protection of birds migrating between the United States and Canada. Similar conventions between the United States and Mexico (1936), Japan (1972), and the Union of Soviet Socialists Republics (1976) further expanded the scope of international protection of migratory birds. New treaties are incorporated into the MBTA as amendments and provisions are implemented domestically. These four treaties and their enabling legislation, the MBTA, established federal responsibilities for the protection of nearly all species of birds, their eggs, and nests. The MBTA made it illegal for people to "take" migratory birds, their eggs, nests, or feathers. "Take" is defined in the MBTA to include by any means or in any manner, any attempt at hunting, pursuing, wounding, killing, possessing or transporting any migratory bird, nest, egg, or part thereof. The Bald and Golden Eagle Protection Act affords additional protection to all bald and golden eagles. A listing of migratory birds protected under the MBTA is maintained by the USFWS (2012).

A permit is not required for the MBTA. However, take of migratory birds is prohibited. Thus, compliance with MBTA may result in timing restrictions on construction activities if migratory bird nests are found in the project area. Based on the construction schedule and habitat in the impact areas, field surveys and construction worker training would have been conducted as needed.

Permit or Authorization:	A permit is not required for the MBTA
Responsible Agency:	USFWS, Marion, IL same contact information as above for USESA

Clean Air Act

The CAA defines USEPA's responsibilities for protecting and improving the nation's air quality and the stratospheric ozone layer. The CAA was incorporated into the USC as Title 42, Chapter 85. In Illinois, CAA requirements are implemented by IEPA, Bureau of Air, Division of Air Pollution Control. This includes permits for both minor and major sources of release.

At the time of project suspension, a stationary 125-kVA diesel generator was planned to be used at the injection site for emergency power for the control building and the injection systems. A permit for its operation was sought and received from the IEPA on December 4, 2014. The project planned to inject all CO_2 routed to the storage site underground. Under normal operating conditions, no CO_2 would be vented along the pipeline or at the injection site.

On October 30, 2009, USEPA published the Mandatory Reporting of Greenhouse Gases (GHG) rule (74 FR 56260) at 40 CFR 98, requiring reporting from facilities that directly emit GHGs to the atmosphere ("direct emitters") as well as suppliers of products that would release GHGs if combusted, oxidized, or used ("suppliers"). In November 2010, USEPA amended 40 CFR 98 with reporting requirements for six additional source categories (subparts L, DD, QQ, RR, SS, and UU); subpart RR, Geologic Sequestration of Carbon Dioxide, comprises any well or group of wells that inject a CO_2 stream for long-term containment in subsurface geologic formations. The amendments brought the project into the coverage of the rule; however, it is important to note that although the rule requires monitoring and reporting of GHGs, it does not require control of GHGs. In addition, USEPA notes that the requirements under subpart RR are intended to complement existing requirements under the Class VI SDWA's UIC Program.

According to subpart RR or 40 CFR 98, there are no GHG threshold limits for reporting; therefore, all sources of this type are required to be reported. Portions of the rule directly relevant to this project include:

Part 98.442—details what GHGs to report

Part 98.443—provides methods for calculating the mass of CO_2 sequestered

Part 98.444—details monitoring requirements for CO_2 received, injected, and produced.

Part 98.556—details data reporting requirements

Part 98.448—provides details on a required GS monitoring, reporting, and verification plan (MRV) for the facility; USEPA must approve all GS plans

Permit or Authorization:	A permit for the emergency generator operation was sought and received from the IEPA on December 4, 2014. No other air permits required
Responsible Agency:	IEPA, Bureau of Air, Division of Air Pollution Control, Springfield, Illinois

Rivers and Harbors Act

Section 14 of the Rivers and Harbors Act of 1899 (33 USC 408) provides that the Secretary of the Army, on the recommendation of the USACE Chief of Engineers, may grant permission for the temporary occupation or use of any sea wall, bulkhead, jetty, dike, levee, wharf, pier, or other work built by the United States. This permission will be granted by an appropriate real estate instrument in accordance with existing real estate regulations. The CO_2 pipeline route certified by the Illinois Commerce Commission would have crossed a federally listed dike, Coon Creek Dike, using horizontal boring to pass under the dike and the creek.

In November 2014, the Alliance provided the following items to the USACE: construction plan, site layout plan, project schedule, communication plan, safety procedures, emergency procedures, company experience record, contingencies plan, and drilling fluid management plan. Four copies of the proposed drilling plan (half-sized drawings) were also submitted. The USACE posed a few questions in January 2015 to which the Alliance responded in a revised permit application in February 2015. On April 10, 2015, USACE advised that it had sent a letter to the local Coon Run Drainage and Levee District in which USACE recommended approval under Section 408 for the project.

Permit or Authorization:	Levee Boring Permit
Responsible Agency:	USACE, St. Louis District, St. Louis, Missouri, and Coon Run Drainage and Levee District
Agency POCs:	USACE Ed Rodriguez Robles - Civil Engineer US Army Corps of Engineers St. Louis District Office 1222 Spruce St. St. Louis, MO 63103 Office: 314-331-8397 Edward.C.RodriguezRobles@usace.army.mil Coon Run Drainage & Levee District Tom Burrus, Commissioner (217) 248-5511 tom@burrusseed.com 200 Capital Way Jacksonville, IL 62650
Status at Project Suspension:	1. Application submitted November 14, 2014. 2. USACE comment received January 5, 2015. 3. Revised application submitted February 6, 2015. 4. USACE sent letter recommending approval to Coon Run Drainage & Levee District April 10, 2015. 5. Coon Run Drainage & Levee District received the USACE recommendation to approve the permit after project suspension and therefore has not taken action on the application.
Documentation Available:	Provided in the attached USACE Permitting Appendix 6B: 1. Application 2. USACE comments 3. Responses to Comments

Pipeline Inspection, Protection, Enforcement and Safety Act

The Pipeline Inspection, Protection, Enforcement and Safety Act (Public Law 109–468—Dec. 29, 2006) provides for enhanced safety and environmental protection in pipeline transportation, to provide for enhanced reliability in the transportation of the nation's energy products by pipeline, and for other purposes. Specifically applicable to FutureGen 2.0 are the regulations, located at 49 CFR 195, which apply to pipeline facilities and the transportation of hazardous liquids or CO_2 associated with those facilities that are administered by the Pipeline and Hazardous Material Safety Administration (PHMSA) under the U.S. Department of Transportation (DOT).

Effective January 1, 2012, each operator of a hazardous liquid pipeline or pipeline facility must obtain from PHMSA an Operator Identification Number (OPID). An OPID is assigned to an operator for the pipeline or pipeline system for which the operator has primary responsibility. To obtain an OPID, an operator must complete an OPID Assignment Request USDOT Form PHMSA F 1000.1 through the National Registry of Pipeline and Liquefied Natural Gas (LNG) Operators in accordance with 49 CFR 195.58. The Alliance may obtain its own unique OPID or may rely on the OPID of its operating contractor.

An operator must notify PHMSA of any of the following events no later than 60 days before the event occurs:

(i) Construction or any planned rehabilitation, replacement, modification, upgrade, uprate, or update of a facility, other than a section of line pipe that costs $10 million or more. If 60-day notice is not feasible because of an emergency, an operator must notify PHMSA as soon as practicable;

(ii) Construction of 10 or more miles of a new hazardous liquid pipeline; or

(iii) Construction of a new pipeline facility.

The CO_2 pipeline had been designed to meet PHMSA's requirements for hazardous liquid pipelines contained in 49 CFR 195. The pipeline design includes features such as mainline isolation valves to isolate pipeline sections, a leak detection system, and a SCADA system to communicate information and data. Uninterruptible power supplies were to be incorporated into the design of the pipeline operation system in the event a power failure occurs. These safety features would reduce the likelihood of a release from the pipeline and minimize its magnitude in the unlikely event a release occurs.

Under 49 CFR 195 (specifically, 49 CFR 195.452), a pipeline integrity management program may be required for a hazardous liquid pipeline or CO_2 pipeline that may cross or affect a high consequence area (HCA), unless the pipeline operator effectively demonstrates that the pipeline could not affect the area. The rule defines a HCA as a high population area, an "other populated area," a commercially navigable waterway (49 CFR 195.450), or an unusually sensitive area (49 CFR 195.6). As used in this part, an unusually sensitive area means a drinking water or ecological resource area that is unusually sensitive to environmental damage from a hazardous liquid pipeline release.

The Alliance, applying federal standards of population density to define HCAs, determined that the CO_2 pipeline would not cross or affect any HCA. Accordingly, absent future HCA or regulatory changes, the Alliance demonstrated that the CO_2 pipeline would not be subject to the Integrity Management Program regulations at 49 CFR 192.450 and 195.452 and therefore an Integrity Management Program would not be required.

Nevertheless, in the event that a future HCA change may occur, and to ensure compliance with requirements imposed by the Illinois Commerce Commission in its certification of the CO_2 pipeline, the Alliance prepared an initial Integrity Management Program. On December 19, 2014, the Alliance transmitted its initial, draft Integrity Management Program to PHMSA.

The Office of Pipeline Safety (OPS) maps HCAs on the National Pipeline Mapping System[1] (NPMS). The NPMS is a geographic information system (GIS) created by USDOT, PHMSA, and OPS in cooperation with other federal and state governmental agencies and the pipeline industry. After construction, GIS files of the as-built location of the pipeline would have been submitted to NPMS/PHMSA as required.

PHMSA Submittals

- Provided PHMSA with the project description and CO_2 pipeline route maps, and documented this filing to meet the requirements for filing under the Illinois CO_2 Pipeline and Transportation Act discussed further this chapter.
- Obtained an OPID for the Alliance from PHMSA.
- By letter dated December 19, 2014, the Alliance transmitted a copy of its initial, draft Integrity Management Program to PHMSA along with an explanation and acknowledgement that an Integrity Management Program was not required for the CO_2 pipeline at that time.
- By letter dated December 19, 2014, the Alliance provided notice to PHMSA, pursuant to 49 CFR 195.8, of the Alliance's intent to construct a CO_2 pipeline, and that the pipeline would be made of steel.

NPMS Requirements

Section 15 of the Pipeline Safety Improvement Act of 2002 requires operators of pipelines and LNG plants (except distribution and gathering lines) to submit the following information to the NPMS:

- Geospatial data appropriate for use in the NPMS or data in a format that can be readily converted to geospatial data.

[1] https://www.npms.phmsa.dot.gov/default.htm

- The name and address of the person with primary operational control to be identified as its operator.
- A means for a member of the public to contact the operator for additional information about the pipeline facilities. PHMSA developed an online operator contact search that satisfies this requirement.
- Updates of the information to reflect changes.

NPMS timing is concurrent with initial notification of PHMSA. Pipeline route maps were provided to PHMSA as pdf files with each submittal; however formal submittal of the as built pipeline route GIS files to NPMS/PHMSA did not occur before project suspension.

Permit or Authorization:	PHMSA notifications and requirements prior to commencement of construction and operation of a CO_2 pipeline
Responsible Agency (PHMSA):	USDOT, PHMSA Pipeline Safety Central Region Office, Kansas City, Missouri
Responsible Agency (NPMS):	USDOT, PHMSA, Washington, DC
Agency POCs:	**For PHMSA**: Harold Winnie, Community Assistance & Tech Services (CATS) Harold.Winnie@dot.gov (816) 329-3836 PHMSA Kansas City 901 Locust St Kansas City, MO 64106 **For NPMS:** Katie Field, Project Manager, NPMS National Repository (703) 317-6294 npms-nr@mbakercorp.com DOT Contractor: Michael Baker Jr., Inc. 3601 Eisenhower Alexandria, VA 22304
Status at Project Suspension:	1. Operator Identification number (OPID) #39212 was assigned to the Alliance by PHMSA on December 5, 2014. 2. The Alliance's Operator Notification was filed with PHMSA on January 16, 2015.
Documentation Available:	Provided in the attached PHMSA Permitting Appendix 6C: 1. OPID application 2. PHMSA OPID authorization 3. ICC required Notification to PHMSA Administrator of intention to commence transportation of CO_2 by pipeline per 49 C.F.R.

195.8,

4. Operator Registry Notification, PHMSA Form 1000.2, 49 C.F.R. 195.64,
5. ICC required Notification regarding Integrity Management Program per 49 C.F.R. 195.452

Uniform Relocation Assistance and Real Property Acquisition Policies Act of 1970

The Uniform Relocation Assistance and Real Property Acquisition Policies Act of 1970 (URA) applies to any acquisition of real estate, including permanent easements, where federal funding is provided. The purpose is to ensure consistent treatment nationwide for landowners affected by federally financed programs. Although the requirements of this federal law are not technically mandates, federal agency heads are prohibited from approving any federal grants, program, project, contracts, or agreements benefitting any entity that does not follow the policies.

The CO_2 pipeline project would not have resulted in forced relocation of any homeowner or farmer. For that reason, the relocation aspects of the URA were not applicable. The real property acquisition requirements are set forth below:

- As soon as feasible, the Alliance must notify the landowner in writing of its interest in acquiring the landowner's property and the basic protections the landowner has under URA (49 CFR 24.102). These notifications were delivered to the all landowners of public record along the proposed CO_2 pipeline route in February 2013.
- Each parcel must be appraised *before* the initiation of negotiations unless the value of the proposed acquisition is estimated at $10,000 or less (42 USC 4651(2)).
    - The appraiser must be licensed or certified and "must have a sufficient understanding of the local real estate market" (49 CFR 24.102(c)(ii)(B)).
    - The landowner or his designated representative must be given the opportunity to accompany the appraiser during his inspection of the property (42 USC 4651(2); 49 CFR 24.l02(c)).
    - The appraisal must be in writing and contain support data and analysis in a prescribed form. It must meet Uniform Standards of Professional Appraisal Practice and the Uniform Appraisal Standards for Federal Land Acquisitions.
    - The appraisal must reviewed by a qualified review appraiser (49 CFR 24.104).

At the time of suspension all properties had been appraised; however, due to delays, reappraisals were required.

- Negotiations with the landowner:

- Before initiating negotiations with the landowner, the Alliance must establish an amount which it believes to be "just compensation" and that amount cannot be less than the appraisal (49 CFR 24.102(d)).
- At the inception of negotiations, the Alliance must give the landowner a written, dated, purchase offer which includes the precise description of the property. The landowner must be provided with the basis of the amount of the offer (49 CFR 24.102(e) and (f)), but the appraisal itself need not be provided.
- The landowner must be given a reasonable opportunity to consider the offer and to present material the owner believes is relevant to the parcel's value and to suggest modifications in the proposed terms and conditions of purchase (49 CFR 24.102(f)).
- The purchase price for the easement may exceed the just compensation amount, provided that a written justification is prepared for the federal funding agency stating the information, including trial risks, which support such payment.

At the time of project suspension, no negotiations had taken place with landowners on the pipeline route. However, five landowners had accepted the Alliance's written offer for a pipeline easement across their respective parcels of land.

Permit or Authorization:	Negotiated ROW easements
Responsible Agency:	Alliance and Legal owners of private property along pipeline ROW
Status at Project Suspension:	First URA Notification letters sent to all land owners of pipeline ROW during February 2013. All ROW parcels were appraised during CY 2013 & 2014. Reappraisals were begun in 2015 because all appraisals had expired. No negotiations with pipeline ROW landowners took place before project suspension.
Documentation Available:	URA Permitting Appendix 6M: Sample package of First URA Notification letters to land owners

Farmland Protection Policy Act (FFPA) (7 USC 4201)

Because the majority of the CO_2 pipeline route and well pads would have traversed or occupied farmland, the Farmland Protection Policy Act (FFPA) (7 USC 4201) requires an assessment of the conversion of farmland to non-farmland use.

Section 2 of the FFPA directs the USDA to develop criteria for identifying the effects of federal programs on the conversion of farmland to nonagricultural uses. The USDA procedures direct any federal agency in a project that has the potential to convert important farmland to non-farm use to contact the local office of the Natural Resources Conservation Service (NRCS) or USDA Service Center. NRCS uses a land evaluation and site assessment (LESA) system to establish a farmland conversion impact rating score on proposed sites of federally funded and assisted projects. This score is used as an indicator for the project sponsor to consider alternative sites if the potential adverse impacts on the farmland exceed the recommended allowable level.

The Alliance submitted maps of all the areas that would be impacted by the CO_2 pipeline or well pads to the USDA so they could complete their assessment on USDA form AD-1006, Farmland Conversion Impact Rating. The USDA/NECS, Illinois State Office completed the site assessment portion of the AD-1006, which assessed non-soil related criteria such as the potential for impact on the local agricultural economy if the land is converted to non-farm use and compatibility with existing agricultural use.

Permit or Authorization:	USDA Completion of Form AD-1006
Responsible Agency:	USDA, NRCS, Illinois State Office
Agency POC:	Tim Prescott, Resource Inventory Specialist USDA NRCS, Illinois State Office 2118 West Park Court Champaign IL 61821 217.353.6637 Timothy.Prescott@il.usda.gov
Status at Project Suspension:	USDA completed Form AD-1006 on March 5, 2014.
Documentation Available:	Provided in the attached USDA/NRCS Permitting Appendix 6L: 1. Alliance's submitted information to support USDA's AD-1006 evaluation 2. USDA/NRCS completed AD-1006 evaluation

6.3 State Permits Authorizations, Permits, and Certifications

This section summarizes state requirements for state authorizations, permits, approvals, and certifications. Some permits discussed are a result of federal regulations where enforcement has been delegated to a state entity.

6.3.1 Permits Associated With the CWA

As discussed in Section 6.2, Section 404 of the CWA establishes a program to regulate the discharge of dredged or fill material into waters of the United States, including wetlands, that is administered by the USACE. Under Section 401 of the CWA, all permits or licenses issued by the federal government for activities affecting waters of the United States must be certified by the state in which the discharge is to occur and that the activity will comply with the water quality standards of that state. The CO_2 pipeline and associated facilities were sited and designed to comply with USACE NWP 12, which fulfills the requirements of Sections 404 and 401 of the CWA as long as the proposed project meets all general, state, and local permit conditions. The

JPA process described under the USACE permitting section of this document coordinated both federal and state approvals for Section 404 and 401.

As discussed previously, the issuance of NPDES permits under USEPA requirements is delegated to the State of Illinois. The IEPA has developed guidance for the preparation of a NPDES permit in Illinois. In accordance with IEPA guidance, this activity includes meeting the requirements of the NPDES General Permit For Storm Water Discharges From Construction Site Activities (NPDES General Permit ILR10) and preparing an individual NPDES permit application for any non-stormwater discharges (e.g., pipeline hydrostatic pressure testing). The CO_2 pipeline, injection well pad, monitoring well pad, and access road construction would be covered by NPDES General Permit ILR10 provided a complete Notice of Intent and an acceptable SWPPP are submitted to the IEPA. These activities are dependent on pipeline and surface facility contractor input and, therefore, would occur in Phase II, but after selection of contractors. A Notice of Termination would be required later, in Phase III, following construction.

With few exceptions, the NPDES General Permit ILR10 does not authorize non-stormwater discharges. Because the pipeline construction contractor proposed to pressure test the pipeline using water (hydrostatic testing), an individual NPDES permit would have been required for the discharge of the water used for testing. Pipeline testing procedures were determined during Phase II; however, the actual testing would not be implemented until the pipeline is constructed. Testing protocols were established that called for pressurizing the pipeline in three ten-mile sections (between the planned block valves) beginning at the eastern most end of the pipeline and discharging to the Illinois River at the Meredosia Energy Center. Discharge of hydrostatic test waters had been previously authorized by IEPA under the NPDES permit for operations at the Meredosia Energy Center before it was shut down in 2011.

Permit or Authorization:	NPDES Stormwater General Permit for construction
Responsible Agency:	IEPA, Bureau of Water, Springfield, Illinois
Agency POC:	Illinois Environmental Protection Agency, Bureau of Water Permits Section, Division of Water Pollution Control 1021 North Grand Avenue East Springfield, IL 62794-9276 Attn: Al Keller, Manager, Permit Section and Darren Grove Al.Keller@illinois.gov Darren.Grove@illinois.gov P: 217-782-0610
Status at Project Suspension:	1. NPDES Permit #: ILR10T007 issued April 25, 2014 by IEPA for all well pads under CWA Section 402. 2. NPDES Permit for discharge of Pipeline Hydrostatic Test water would have used the Meredosia Energy Center's NPDES Permit#: IL0000116 modified December 13, 2013. 3. NPDES application for the pipeline construction was drafted by Patrick Engineering but not submitted to IEPA.

Documentation Available: Provided in IEPA/NPDES Permit Appendix 6E:

1. NPDES Permit Application – Storage Site Construction
2. NPDES Permit – Storage Site Construction Appendix
3. NPDES Permit Application – Pipeline Construction
4. NPDES Permit – Pipeline Construction
5. NPDES Permit for the Meredosia Power Station also for pipeline's hydrostatic test water

6.3.2 Drilling Permit

The stratigraphic well was permitted as a test well through IDNR's Office of Mines and Minerals. Form OG-7 requires information about the permit application, the purpose of the well, the depth of the well, the name of the driller, and the location for the well. Monitoring wells would have been permitted through the same process. Wells planned for installation that would have required drilling permits include the following:

- Stratigraphic well – completed in 2012
- Monitoring wells at preferred site

Permit or Authorization:	Drilling Permit
Responsible Agency:	IDNR, Office of Mines and Minerals, Oil & Gas Division, Springfield, Illinois
Agency POC:	Doug Shutt Illinois Department of Natural Resources Oil & Gas Division Permit Unit Tel: 217 782-3718 Fax:217 524-4819
Status at Project Suspension:	The plugging of the characterization well was coordinated with the Illinois Department of Natural Resources. No permit was required for closing the well. Well was plugged and abandoned on April 24, 2015
Documentation Available:	Provided in IDNR permitting Appendix 6D: • Permit for drilling the characterization well • Plugging report

6.3.3 Illinois State Agency Historic Resource Preservation Act

The Illinois State Agency Historic Resources Preservation Act (20 Illinois Compiled Statues [ILCS] 3420) (IHPA Act) was enacted to provide state government leadership in preserving, restoring, and maintaining the historic resources of the state. The IHPA Act establishes a program under which state agencies: (1) administer the historic resources under their control to foster and enhance their availability to future generations; (2) prepare policies and plans to contribute to the preservation, restoration, and maintenance of state-owned historic resources for the inspiration and benefit of the people; and (3) in consultation with the Director of Historic

Preservation, institute procedures to ensure that state projects consider the preservation and enhancement of both state-owned and non-state-owned historic resources.

Under the IHPA Act, IHPA's Director is responsible for evaluating any "undertaking" by a state agency or private entity to determine whether the undertaking may impose an adverse impact on a state historic resource. (The IHPA Act defines an undertaking as a project, activity, or program. An undertaking includes a project that is funded in part by state grant funds.) If IHPA's Director determines that the undertaking will have an adverse impact on a state historic resource, the IHPA Act instructs the Director to consult with the project's developer to develop a plan to eliminate or minimize the adverse impact on the state resource.

The procedures of the IHPA Act do not apply if an undertaking is being reviewed pursuant to Section 106 of the National Historic Preservation Act. Because the FutureGen 2.0 Project was subject to review under Section 106 of the National Historic Preservation Act, the provisions of the IHPA did not apply to the project. Instead, DOE, IHPA, and the Alliance entered into a programmatic agreement to comply with the National Historic Preservation Act. The programmatic agreement and other actions to be taken to comply with this National Historic Preservation Act and the IHPA Act are described in Section 6.2.2.

6.3.4 Illinois Carbon Dioxide Transportation and Sequestration Act

The Illinois Carbon Dioxide Transportation and Sequestration Act (the "CO_2 Transportation Act") (220 ILCS 75/1-1 *et seq.*) requires that a party obtain a certificate of authority from the Commission before the party constructs or operates a CO_2 pipeline. Pursuant to the CO_2 Transportation Act, the Illinois Commerce Commission is authorized to grant the certificate if an applicant meets the following conditions:

- The applicant is fit, willing and capable of constructing and operating the CO_2 pipeline;
- The applicant has entered into an agreement with a clean coal facility, a clean coal SNG facility, or another source that will supply CO_2 and result in a reduction of carbon emissions from the source;
- The applicant has filed all forms necessary to construct a CO_2 pipeline with the Pipeline Hazardous Materials Safety Administration ("PHMSA");
- The applicant has filed all permit applications necessary to construct a CO_2 pipeline with the U.S. Army Corps of Engineers;
- The applicant has entered into an Agricultural Impact Mitigation Agreement with the Illinois Department of Agriculture;
- The applicant has "the financial, managerial, legal and technical qualifications necessary to construct and operate the proposed carbon dioxide pipeline;" and
- The proposed CO_2 pipeline is consistent with the public interest and will provide public benefits.

The Alliance filed an application seeking a Certificate of Authority to construct and operate a CO_2 pipeline on March 29, 2013. To accommodate requests from certain landowners along the Alliance's proposed pipeline route, the Alliance filed a Motion to Amend its Application on July 31, 2013. On September 26, 2013, the Administrative Law Judge presided over an evidentiary hearing in connection with the Alliance's Amended Application. On February 20, 2014, the Commission issued a Final Order awarding the Alliance a Certificate of Authority to construct and operate a CO_2 pipeline, and approving the Alliance's preferred route for the CO_2 pipeline. The Commission's approval included the right to exercise condemnation authority (subject to compliance with the Illinois Eminent Domain Act) and was conditioned upon the Alliance obtaining all other necessary permits to construct the CO_2 pipeline.

Permit or Authorization:	The Act requires the Alliance to obtain a certificate of authority from the Commission for the construction and operation of the CO_2 pipeline
Responsible Agency:	Illinois Commerce Commission, Springfield, Illinois
Agency POC:	Illinois Commerce Commission Chief Clerk's Office 527 East Capitol Ave Springfield, IL 62701 217-782-7434
Status at Project Suspension:	1. The Illinois Commerce Commission issued a Certificate of Authority authorizing the construction of the Alliance's CO_2 pipeline by Order dated February 20, 2014.
Documentation Available:	Provided in Appendix 6G: 1. Application (and Amended Application) for a Certificate of Authority, and Testimony and Exhibits submitted as evidence in support of the Alliance's Application 2. Final Order from the Commission granting the Alliance a Certificate of Authority to construct and operate a CO_2 pipeline along an approved pipeline route Additional records relating to the Commission's proceedings on the Alliance's application may be accessed at the Commission's website under Docket No. 13-0252.

6.3.5 Approval of CO_2 Transportation and Storage Plans Pursuant to Section 5/9-202(h-7) of the Illinois Public Utilities Act

Section 5/9-220(h-7) of the Public Utilities Act ("PUA") states that "[n]o clean coal facility or clean coal SNG brownfield facility may transport or sequester carbon dioxide unless the Commission approves the method of carbon dioxide transportation or sequestration." 220 ILCS 5/9-220(h-7)(1). Section 5/9-220(h-7) requires the owner of a clean coal facility to file a "carbon dioxide transportation or sequestration plan" with the Commission, and requires the

Commission to "hold a public hearing within 30 days after receipt of the facility's carbon dioxide transportation or sequestration plan." 220 ILCS 5/9-220(h-7)(2). Section 5/9-220(h-7) directs the Commission to review such plans and approve carbon dioxide transportation "methods" the Commission determines are reasonable and cost-effective. *Id.* For purposes of this review by the Commission, the statute defines cost-effective as "a commercially reasonable price for similar carbon dioxide transportation or sequestration techniques." *Id.*

Section 5/9-220(h-7) states that the Commission "may not approve a carbon dioxide sequestration method if the owner or operator of the sequestration site has not received" one of the following permits:

1. An Underground Injection Control permit from the U.S. Environmental Protection Agency ("USEPA");
2. An Underground Injection Control permit from the Illinois Department of Natural Resources ("IDNR"); or
3. A permit similar to items 1 or 2 from USEPA or another state if the sequestration site is located outside of the State of Illinois.

On February 28, 2014, the Alliance filed a Petition seeking approval of its proposed CO_2 transportation and storage plans pursuant to Section 5/9-220(h-7) of the PUA. Per the statute, on March 27, 2014, the Commission hosted a public forum in Jacksonville, Illinois to consider the Alliance's Petition. On April 14, 2014, the Administrative Law Judge presided over an evidentiary hearing in connection with the Alliance's Petition. On May 13, 2014, the Commission issued a Final Order in which it approved the Alliance's CO_2 transportation and storage plans, finding the plans to be reasonable and cost-effective. The Final Order conditioned the Commission's approval of the plans on receipt by the Alliance of final Underground Injection Control permits from USEPA and the submission by the Alliance of a compliance filing with the Commission attaching the permits.

Permit or Authorization:	The Illinois Public Utilities Act requires the Alliance to obtain approval from the Commission for the Alliance's methods for transporting and storing CO_2
Responsible Agency:	Illinois Commerce Commission, Springfield, Illinois
Agency POC:	Illinois Commerce Commission: Chief Clerk's Office 527 East Capitol Ave Springfield, IL 62701 217-782-7434
Status at Project Suspension:	The ICC issued a Final Order approving the Alliance's methods for transporting and storing CO_2 on May 13, 2014. For the ICC's approval to become non-conditional, the Alliance must submit final Underground Injection Permits from USEPA to the Commission.
Documentation Available:	Provided in Appendix 6G: 1. Petition seeking approval for the Alliance's transportation and

storage methods for CO_2, and Testimony and Exhibits submitted as evidence in support of the Alliance's Application.
2. Final Order from the Commission approving the Alliance's CO_2 transportation and storage plans.

Additional records relating to the Commission's proceedings on the Alliance's Petition may be accessed at the Commission's website under Docket No. 14-0177.

6.3.6 Agricultural Impact Mitigation Agreement

The development of an Agricultural Impact Mitigation Agreement (AIMA) with the Illinois Department of Agriculture (IDOA) included the identification and assessment of agricultural lands impacted by the proposed project along the pipeline corridor and the development of an agreement with the IDOA regarding measures for mitigating construction impacts. An AIMA is a prerequisite for obtaining a Certificate of Authority from the Illinois Commerce Commission to construct and operate a CO_2 pipeline under the provisions of the Illinois Carbon Dioxide Transportation and Sequestration Act (the "CO_2 Transportation Act") (220 ILCS 75/1-1 *et seq.*) discussed in Section 6.3.4.

In addition, the Illinois Farmland Preservation Act (505 ILCS 75/1-1 *et seq*.), requires state agencies to establish agricultural land preservation policies and working agreements with IDOA. These documents guide state agencies in their efforts to minimize farmland conversion and other adverse agricultural impacts associated with their programs and activities. IDOA reviews the plans for construction and other development projects submitted by agencies to determine if they comply with the submitting agency's policy and working agreement. The Farmland Preservation Act also directs IDOA to conduct a study of the agricultural impacts of a project for certain state-funded projects if the project will result in the conversion of farmland to a non-agricultural purpose.

The Alliance negotiated an AIMA with IDOA and signed the final agreement in January of 2012. The AIMA would have been implemented throughout the course of the project, including post-construction monitoring of the effectiveness of mitigation measures.

Permit or Authorization:	Agricultural Impact Mitigation Agreement
Responsible Agency:	IDOA, Springfield, Illinois
Agency POCs:	Terry Savko (217) 785-4458 Terry.Savko@Illinois.gov IDOA, Bureau of Land and Water State Fairgrounds PO Box 19281 801 Sangamon Rd Springfield, IL 62794-9281

	Steve Chard, Acting Bureau Chief, IDOA, Bureau of Land and Water (217) 782-6297 Steve.Chard@Illinois.gov
Documentation Available:	Provided in Appendix 6I Signed AIMA

6.3.7 IDOT Pipeline ROW

As part of its CO_2 pipeline route selection process, the Alliance considered using public ROW to the extent possible to minimize impacts on private landowners as well as the environment. In 2011, the Alliance met with IDOT several times to discuss the process and approvals necessary for siting the pipeline within IDOT ROW along US Highway 67. Under the URA, IDOT is required to "establish procedures and make interpretations to implement its provisions." IDOT satisfied this requirement through its Land Acquisition Policies and Procedures Manual (IDOT 2012). The Illinois Highway Code (605 ILCS 5/9-113) provides that IDOT "may, by written consent, permit the use of land or other property under its jurisdiction for non-highway related uses." It is the responsibility of IDOT regional engineers to ensure that ROW acquisition and management is in conformity with state procedures. Morgan County is in IDOT Region 4, District 6.

IDOT was in the process of expanding portions of US Highway 67 between Meredosia and Jacksonville. As part of that expansion, IDOT was acquiring new ROW and managing existing ROW that the Alliance would seek permission to use for the CO_2 pipeline. The Alliance coordinated with IDOT on pipeline routing, and applied for a permit to install the CO_2 pipeline in the IDOT-controlled ROW adjacent to US Highway 67.

In addition to a non-highway ROW use permit, IDOT requires a permit for work in highway ROW per IDOT's regulations (*see* 92 Ill. Admin. Code 530), and notification at least 48 hours prior to excavation pursuant to the Underground Utility Facilities Damage Prevention Act (*see* 220 ILCS 50/4). The specific locations under which the CO_2 pipeline would cross IDOT highways are noted below.

Table 6.1. IDOT Road Crossings

Description	Crossing Method	Mile Post
Illinois Route 100	Horizontal Direction Drill	3.43
U.S. Route 67	Horizontal Direction Drill	7.23
Illinois Route 78	Jack and Bore	20.17

Permit or Authorization:	Permit for non-highway related use of Highway 67 ROW, permit for work in highway ROW (605 ILCS 5/9-113)
Responsible Agency:	IDOT, Region 4, District 6, Springfield, Illinois
Agency POCs:	Vince Madonia, P.E. Illinois Department of Transportation Region 4, District 6 Studies & Plans Project Engineer Phone: 217-785-9046 Email: vincent.madonia@illinois.gov Joe Angeli IDOT District 6 Permit Technician 217-782-7744 (Office) 217-836-4208 (Cell) Ms. Laura R. Mlacnik IDOT District 6 Land Acquisition Engineer 126 E. Ash Street Springfield, IL 62704-4766
Status at Project Suspension:	All necessary permits from the local agencies were obtained on February 27, 2015.
Documentation Available:	Provided in the IDOT permit Appendix 6H: 1. IDOT Highway Permit - Illinois Route 100 2. IDOT Highway Permit - U.S. Route 67 3. IDOT Highway Permit - Illinois Route 78

6.3.8 State Endangered Species

The Illinois Endangered Species Protection Act (520 ILCS 10/1-1 *et seq*.) required consultation with IDNR on state-listed threatened or endangered species that may occur in the project area. This effort entailed review and analysis of data from state and federal registries, executing onsite (field) surveys of affected lands, and developing and executing mitigation measures as needed. Affected lands included parcels near the power plant, stratigraphic well, monitoring wells, injection wells, pipeline ROW, and the Meredosia Energy Center. Specifically, consultation with IDNR involved discussions surrounding the Illinois chorus frog and the regal fritillary, a state-listed butterfly species, the ornate box turtle and western hognose snake that may occur in the pipeline ROW and could be impacted during construction. Efforts included data collection, identifying suitable habitat along the pipeline route, and conducting field surveys for the presence of the species. Since potential impacts to protected species and their habitat could occur from the proposed project activities, a conservation plan was submitted to IDNR. IDNR reviewed the conservation plan and issued an incidental take permit with mitigation measures agreed to by the Alliance.

Permit or Authorization:	Conservation Plan/Incidental Take Permit
Responsible Agency:	IDNR, Division of Natural Heritage, Springfield, Illinois
Agency POC:	Jenny Skufca Endangered Species Project Manager Illinois Department of Natural Resources One Natural Resources Way Springfield, IL 62702 (217) 557-8243 Jenny.Skufca@Illinois.gov
Status at Project Suspension:	1. Conservation Plan submitted on October 25, 2013. 2. IDNR comments received on November 21, 2013. 3. Response to Comment submitted on December 12, 2013. 4. Incidental Take Authorization issued by IDNR on August 13, 2014.
Documentation Available:	IDNR endangered species permitting documents provided in Appendix 6D include: 1. Conservation Plan 2. IDNR Comments 3. Revised Conservation Plan 4. Incidental Take Authorization

6.3.9 State Permit for Water Crossings

IDNR's Office of Water Resources (OWR) issues permits to demonstrate compliance with its administrative rules. (*See* 17 Ill. Admin. Rules §3700 - Construction in Floodways of Rivers, Lakes and Streams). IDNR issues permits for work in and along the rivers, lakes, and streams of the state, including Lake Michigan, for activities in and along the public waters, and for the construction and maintenance of dams.

In general, IDNR issues an individual formal permit to the applicant to demonstrate compliance with the rules. In some cases, however, IDNR has issued statewide, regional, and general permits to reduce paperwork for the applicant. The statewide and regional permits describe a general project type and set limits on the scope of the work. If the proposed work meets the specified limits, the project is approved under the statewide or regional permit.

Statewide Permit 8 (SWP 8), Authorizing the Construction of Underground Pipeline and Utility Crossings, is applicable to the Alliance's CO_2 pipeline. The purpose of this statewide permit is to authorize the construction of underground pipeline and utility crossings which pose an insignificant impact on those factors under the jurisdiction of IDNR. To be authorized by SWP 8, an underground pipeline crossing must meet certain conditions relating to depth of placement beneath a streambed, minimization of streamside disturbance, restoration of disturbed streambed and streamside vegetation, placement of shut-off valves relative to waterbodies, and notification of blasting during construction.

An individual permit application is not necessary for projects covered by a statewide or regional permit, which was the case for the FutureGen 2.0 Project. However, IDNR/OWR received a copy of the JPA submitted to the USACE for installation of the CO_2 pipeline under NWP 12 (Section 6.0), which contained a description of project activities related to pipeline water crossings.

Permit or Authorization:	SWP 8
Responsible Agency:	IDNR, Springfield, Illinois
Agency POC:	*See* contact information provided in Section 6.2.2.3
Status at Project Suspension:	SWP 8 process was completed.
Documentation Available:	*See* JPA documentation provided in Appendix 6B

6.4 County and Local Authorizations, Permits, and Certifications

This section discusses the permits needed in Morgan County.

6.4.1 Private Sewage Disposal Installation Permit

Illinois' Private Sewage Disposal Licensing Act (225 ILCS 225/1-1 *et seq.*) identifies the requirements for installing and operating a private sewage disposal system in the state. Implementation of the Act can be, and generally is, delegated to county health departments.

Permit or Authorization:	Septic system permit
Responsible Agency:	Morgan County Health Department
Agency POC:	Jeremy Kaufmann – 217-245-5111.
Status at Project Suspension:	Morgan County indicated that for the proposed usage at the injection well site (less than 2,000 gallons per day), a septic permit would cost $125 at the time of construction. No permit application had been filed before project suspension.
Documentation Available:	None

6.4.2 Road Crossings

The CO_2 pipeline was to connect the power plant in Meredosia, on the western edge of Morgan County, to the storage site in northeastern Morgan County. The pipeline route was to cross roads controlled by Morgan County and four Morgan County road districts as shown in Table below. Each of these crossings required permission from the local controlling unit of government. Pipeline design assumptions included boring under all roads. To construct the pipeline, the Alliance needed to obtain permission from Morgan County's engineer and Morgan County Road Districts #1, #3, #4, and #5.

Table 6.2. Morgan County and Morgan County Road District Road Crossings

Description	Crossing Method	Mile Post[a]	Local Agency
Old Naples Rd	Jack and Bore	0.72	Morgan County Road District 5
Yeck Rd	Jack and Bore	0.72	Morgan County
Cemetery Road	Jack and Bore	1.03	Morgan County Road District 5
Hart's Gravel Road	Horizontal Direction	6.33	Morgan County Road District 5
Dutch Land West	Open Cut	6.77	Morgan County Road District 4
St. Pauls Church	Jack and Bore	8.15	Morgan County Road District 4
Bethel Lane	Jack and Bore	8.73	Morgan County Road District 4
Crews Lane	Horizontal Direction	9.72	Morgan County Road District 4
Baseline Road	Jack and Bore	11.41	Morgan County Road District 3
Concord Arenzville	Jack and Bore	11.88	Morgan County
Joy Lane	Open Cut	13.26	Morgan County Road District 3
Catalpa Road	Open Cut	14.52	Morgan County Road District 3
Standley Lane	Jack and Bore	15.53	Morgan County Road District 3
Concord Road	Jack and Bore	16.32	Morgan County Road District 1
Poor Farm Road	Jack and Bore	16.96	Morgan County
Marisk Lane	Jack and Bore	17.60	Morgan County Road District 1
Ebenezer Church	Jack and Bore	18.35	Morgan County Road District 1
Arcadia Road	Jack and Bore	19.62	Morgan County Road District 1
Spradlin Road	Jack and Bore	20.72	Morgan County Road District 1
Hacker Road	Jack and Bore	22.25	Morgan County Road District 1
Strawn Crossing	Jack and Bore	24.27	Morgan County
Walpole Road	Open Cut	24.70	Morgan County Road District 1
Sinclair Road	Jack and Bore	25.70	Morgan County Road District 1
Clayton Road	Horizontal Direction	26.95	Morgan County Road District 1
Beilschmidt Road	Open Cut	27.05	Morgan County Road District 1
Mahon Road	Open Cut	27.50	Morgan County Road District 1
Beilschmidt Road	Jack and Bore	28.00	Morgan County Road District 1

(a) Distances are pipeline miles from a starting point on the Meredosia Energy Center

Permit or Authorization: (605 ILCS 5/9-101)

Responsible Agency: Morgan County Highway Department
Morgan County Road District 1
Morgan County Road District 3
Morgan County Road District 4
Morgan County Road District 5

Agency POCs: Matt Coultas
Morgan County
Engineer
Phone: 217-243-8491 (Office)
217-473-8096 (Cell)
651 Brooklyn Avenue
P.O. Box 458
Jacksonville, Illinois 62650

Justin Ring
Morgan County Road District 1 Commissioner
2209 Wheeler Road
Ashland, Illinois 62612
217-886-2300 (Office)

Chad Phelps
Morgan County Road District 3 Commissioner
1521 Dirt Road
Arenzville, Illinois 62611
217-370-5120 (Cell)

Brandon Staake
Morgan County Road District 4 Commissioner
672 Spunky Ridge Road
Meredosia, Illinois 62665
217-472-3019 (Shed)
217-370-8077 (Cell)

Todd Cooley
Morgan County Road District 5 Commissioner
144 Chrisman Drive
Meredosia, Illinois 62665
217-584-1986 (Office)
217-248-0162 (Cell)

Status at Project Suspension:	All necessary agreements from the local agencies were obtained on February 27, 2015.
Documentation Available:	Provided in the IDOT and Local roads permit Appendix 6H: 1. Morgan County Road District 1 approvals 2. Morgan County Road District 3 approvals 3. Morgan County Road District 4 approvals 4. Morgan County Road District 5 approvals

Local Road Impact Agreements

The Alliance entered into agreements with both Morgan County Road District 1 and Road District 8 for improvements to, maintenance for, and repair of the local roads system due to the impacts from construction activities planned for storage site.

Permit or Authorization:	(605 ILCS 5/6-101 *et seq.*)
Responsible Agency:	Morgan County Road District 1 Morgan County Road District 8
Agency POCs:	Justin Ring Morgan County Road District 1 Commissioner 2209 Wheeler Road Ashland, Illinois 62612 217-886-2300 (Office) Bill Critchelow Morgan County Road District 8 Commissioner P.O. Box 42 Alexander, Illinois 62601 217-478-2028
Status at Project Suspension:	Road Improvement, Repair and Maintenance Agreements were entered into with the two road districts on October 16 and 17, 2014. Following project suspension, in May 2015, the Alliance entered into Amendments to those agreements with the road districts to ensure that all damages caused during construction were accounted for.
Documentation Available:	Provided in the IDOT and Local Road Appendix 6H: 1. Morgan County Road District 1 road repair and maintenance agreement 2. Morgan County Road District 8 road repair and maintenance agreement

6.4.3 Building Permits

Morgan County has never adopted a county-wide zoning code, so building permits are not required for construction in unincorporated Morgan County. All of the construction activity for the storage site and pipeline was planned in unincorporated Morgan County and therefore no building permits were required.

A building permit from the city would have been required for the Visitor, Research and Training Center that was to be built within the city limits of Jacksonville. No permit had been applied for at the time the project was suspended.

6.4.4 Railroad Crossings

Current CO_2 pipeline design assumptions include boring under all railroads. Boring under the railroad will require a permit from the Norfolk Southern railroad and/or the Burlington Northern Santa Fe railroad, depending on specific routing from the Meredosia Power Plant.

At the time of project suspension, applications to both railroads had been submitted and questions addressed but the permits had not been received.

Permit or Authorization:	Railroad boring authorizations
Responsible Agency:	Burlington Northern Santa Fe (BNSF) Norfolk Southern (NS)
Agency POCs:	Both railroads use subcontractors to process boring permits For BNSF: Jones Lang LaSalle Brokerage, Inc. 4300 Amon Carter Blvd. Suite 100 Fort Worth, TX 76155 Attn: Vicki Norman, Permit Manager Region 4 for BNSF vicki.norman@am.jll.com For NS: AECOM 1700 Market Street Suite 1600 Philadelphia, PA 19103 Attn: John Zollers, Engineer 215- 606- 0408 john.zollers@aecom.com
Status at Project Suspension:	Applications to both BNSF and NS were pending approval.
Documentation	Provided in the Railroad Appendix 6J

Available:

1. BNSF Railway Crossing Permit Application Package
2. BNSF Railway Crossing Permit Approval Appendix
3. NS Railway Crossing Permit Application Package
4. NS Railway Crossing Permit Approval

6.5 Permitting Requirements by Project Activity

Table 6.1 identifies the permits needed for each element of the Pipeline and Storage Project, summarizing the information presented in Sections 6.2 through 6.4.

Table 6.3. FutureGen 2.0 Project Permit Needs

	U.S. DOE		U.S. EPA	IEPA		USACE		IHPA	USFWS	
	NEPA - EIS	**NEPA Interim Action**	**Class VI Underground Injection Control Permit**	**NPDES Permit**	**Clean Water Act Section 401 Certification**	**USACE Nationwide 12 Permit (Clean Water Act Section 404)**	**Permit for Boring Under Levee**	**Cultural Resources Programmatic Agreement**	**Concurrence of No Adverse Impact on T&E Species**	**Concurrence Related to MBTA**
Stratigraphic Well										
Pad Construction		X		X				X	X	X
Well Drilling		X						X		
Improving Roads		X		X				X		
Installing Water Lines		X		X				X		
Monitoring Wells										
Pad Construction	X			X				X	X	X
Improving Roads	X			X				X		
Well Drilling	X							X		
Storage Site										
Site Preparation	X		X	X				X	X	X
Injection Wells	X							X		
Facilities	X							X		
Improving Roads	X			X				X		
Installing Utilities	X			X				X		
Operation								X		
Pipeline										
Installing Pipeline	X			X	X	X	X	X	X	X
Other Facilities[(a)]	X							X		

Table 6.3. (continued)

	IDNR			IDOT, Private Landowners	U.S. DOT	ICC	IDOA	County Government		Rail Road Operator
	Drilling Permit	**Concurrence or Incidental Take Permit**	**Statewide Permit #8**	**Negotiated ROW Agreements**	**PHMSA Permit**	**Cert. of Authority/ Approval of Plans**	**Agricultural Impact Mitigation Agreement**	**Private Sewage Installation Permit**	**Permit for Road Modification**	**Permit to Cross Rail Road**
Stratigraphic Well										
Pad Construction		X								
Well Drilling	X									
Improving Roads									X	
Installing Water Lines										
Monitoring Wells										
Pad Construction		X				X				
Improving Roads									X	
Well Drilling	X					X				
Storage Site										
Site Preparation		X				X		X		
Injection Wells	X					X				
Facilities										
Improving Roads									X	
Installing Utilities										
Operation						X	X			
Pipeline										
Installing Pipeline		X	X	X	X	X	X			X
Other Facilities[(a)]										

(a) Permits that may be needed for the visitors, training, and research centers have not been identified at the time of suspension.

6.6 Project Success and Lessons Learned

The FutureGen 2.0 Project was the first attempt to site and design a pipeline from a CO_2 power plant source to a permanent injection and storage site (FutureGen 1.0 included the injection site on the same property as the power plant). As such, the project established a number of precedents and achieved several milestones, as described below.

1. The Alliance was awarded the first-ever Illinois Commerce Commission Certificate of Authority to construct and operate the pipeline, which was approved on February 20, 2014. The Alliance also obtained approval of the first-ever CO_2 Transportation and Storage Plan by the ICC on May 14, 2014.
2. Perhaps foremost in the project's achievements was the successful application for and receipt of the first Underground Injection Control Class VI Permits in the U.S., approved by the USEPA on August 29, 2014. The permits were subsequently challenged on October 1, 2014 and that challenge was denied on date April 28, 2015, completing the UIC permitting process.
3. Permits or approvals were required and received from the DOE, USEPA, USACE, USFWS, PHMSA, USDA, IEPA, IHPA, IDNR, ICC, IDOA, IDOT, railroad companies, and local governments.

Alliance team members briefed permitting agencies and local governmental units on the scope of the project early in the process and routinely informed the agencies of the project's progress and, where relevant, solicited agency input in the design and execution of required field studies. Often the results of field studies were informally shared with federal and state agencies before formal permit applications were submitted to confirm the adequacy of the studies and results in an attempt to prevent delays in the approval process once applications were formally submitted.

Several federal and state agency permitting officials expressed their appreciation for the regular and timely communications as it facilitated their interactions within and among the other agencies. The informal discussions with permitting officials, however, had limits. Reliance upon permitting personnel at certain state agencies without obtaining buy-in from decision-making leadership at the agencies led to confusion and delays in at least one case.

At the local level, regular meetings and communications with permitting officials for local governmental entities resulted in prompt approval for local permits. The local permitting efforts were enhanced by regular communications with local elected officials, who helped make sure all appropriate local officials were included in meetings. This comprehensive approach helped expedite the approval processes by ensuring full input from decision-makers and avoiding miscommunications.

For future projects, engaging in regular and early communications with permitting authorities is recommended. However, those communications, at the state and local level, should include both communications with permitting staff as well as communications with decision-making authorities at state agencies and local governments, which would include officials in the Director's Office for state agencies, and elected officials at the local level.

6.7 References

Clean Air Act, as amended (CAA). 42 USC 7401 *et seq.*

Endangered Species Act of 1973, as amended (ESA). 16 USC 1531 *et seq.*

Federal Water Pollution Control Act of 1972 (also referred to as Clean Water Act [CWA]). 33 USC 1251 *et seq.*

IDOT (Illinois Department of Transportation). 2012. *Land Acquisition Policies and Procedures Manual.* Illinois Department of Transportation, Bureau of Land Acquisition, Springfield, Illinois. September 2012 (Continually Updated Resource). Current version available at http://www.dot.state.il.us/landacq/lamanual/Land%20Acquisition%20Manual.pdf.

Illinois Environmental Protection Act. 415 ILCS 5/1-1 *et seq.*

Illinois State Agency Historic Resources Preservation Act. 20 ILCS 3420. |Accessed on June 25, 2011 at http://www.ilga.gov/legislation/ilcs/ilcs3.asp?ActID=372&ChapterID=5|

Migratory Bird Treaty Act of 1918 (MBTA). 16 USC 703 *et seq.*

National Environmental Policy Act of 1969, as amended (NEPA). 42 USC 4321 *et seq.*

National Historic Preservation Act of 1966 (NHPA). 16 USC 470 *et seq.*

Pipeline Inspection, Protection, Enforcement and Safety Act (Public Law 109–468—Dec. 29, 2006)

Rivers and Harbors Appropriation Act of 1899, as amended. 33 USC 403 *et seq.*

Safe Drinking Water Act (SDWA). 40 CFR 141-149

USFWS. 2012. Birds Protected by the Migratory Bird Treaty Act. April. Accessed September 24, 2012 at http://www.fws.gov/migratorybirds/RegulationsPolicies/mbta/mbtintro.html

USFWS. 2012. Illinois County Distribution of Federally Listed Endangered, Threatened, and Candidate Species. Accessed March 8, 2013 at: http://www.fws.gov/midwest/endangered/lists/illinois-cty.html

6.8 Appendices

Appendix 6A – U.S. Environmental Protection Agency Class VI Underground Injection Control Permits

Appendix 6B – U.S. Army Corps of Engineers

Appendix 6C – Pipeline Hazardous Materials Safety Administration

Appendix 6D – Illinois Department of Natural Resources

Appendix 6E – Illinois Environmental Protection Agency

Appendix 6F – Illinois Historic Preservation Agency

Appendix 6G – Illinois Commerce Commission

Appendix 6H – Illinois Department of Transportation and Local Road Districts

Appendix 6I – Illinois Department of Agriculture

Appendix 6J – Railroad Crossing Permits

Appendix 6K – U.S. Fish and Wildlife Service

Appendix 6L – Natural Resources Conservation Service

Appendix 6M – Uniform Relocation Assistance and Real Property Acquisition Policies Act Notification Packet

7 OPERATIONS PLAN

This chapter highlights the operations plan for the anticipated FutureGen 2.0 pipeline and storage project. The Alliance planned to issue two separate contracts for the operation of the FutureGen 2.0 CO_2 pipeline and storage site; one contract inclusive of the pipeline and subsurface injection and storage system operations (operations contract), and a separate contract for the monitoring, verification, and accounting (MVA) system operations (MVA contract). This chapter summarizes the scope of services that were anticipated for each operations contract.

7.1 Introduction and Background

The original pipeline and storage project operations plan envisioned the hiring of three distinct operators: the pipeline operator, the subsurface operator, and an MVA system operator. However, it was determined with adequate training during the commissioning and initial operations stages, the pipeline operator could also perform the routine operations and maintenance duties required for the subsurface systems as well as the collection of certain routine sampling data, thus consolidating two of the originally-conceived operations contracts into one. Overall responsibility of reviewing and monitoring pipeline and storage operations for adequacy would have fallen to the Alliance, while the daily operations of the pipeline and injection would have been the responsibility of the operations contractor. The remaining MVA responsibilities would have been covered in the MVA contract and that contractor would have provided objective technical expertise to the Alliance, conducted MVA, and maintained the UIC permit. This change in concept – consolidation of the “normal operations” into a single contract - would have substantially reduced the operating costs and increased the efficiency of the process, while also preserving a valuable independent, internal auditing function with the MVA contract.

The pipeline and storage operations contract term was expected to begin during commissioning and start-up and continue through 20 years of CO_2 transport and injection, synchronized with Oxy-Combustion power plant operations. Continuation of the operations contracts would have been contingent on annual reviews and renewals based on satisfactory performance for three- to five-year periods.

The Alliance searched for and communicated with a number of potential pipeline operators, but found limited interest in the project. See Chapter 1, Section 1.7 for more detail of the selection process. Primary considerations were the limited length of the pipeline, at approximately 28 miles, and the relatively undeveloped state of operations businesses servicing CO_2 sequestration. In addition to these fundamental issues, the closely related natural gas transport and storage industry was very busy during the contract development period, further pressuring the limited pool of resources. The contract development team continued efforts to find alternatives, and in May 2014 began discussions with Utility Safety and Design, Inc. (USDI), a Midwest pipeline system operator. Following a number of preliminary discussions and negotiations, an indicative operating agreement was prepared and agreed to by the operator and an attesting comfort letter was executed.

The operations contract execution was awaiting DOE approvals when project activities were ordered suspended on 28 January 2015. Additional detail of the CO_2 pipeline and storage operations contract development process can be found in Chapter 1.

Following the execution of the pipeline operations contract and the construction of the pipeline and subsurface facilities, commissioning and testing of the constructed facilities was to have taken place. Once the pipeline and injection system was successfully commissioned and tested, the operations activities would have been synchronized with the Oxy-Combustion power plant operations, followed by a 50-year post-operation monitoring phase, and finally closure. The major operations components that were to have taken place after construction included:

- Pipeline and injection facilities pre-commissioning
- Pipeline and injection facilities caretaking
- Final commissioning and pre-COD operations and training, expected between October 2017 and June 2018 (COD = commercial operation date)
- Initial operations during the first five years of CO_2 injection, anticipated from 2018 through 2022
- Continued operations during the remaining 15 years of CO_2 injection, or through 2037
- Observation phase, which consists of 50 years of monitoring following the cessation of CO_2 injection, or through 2087
- Decommissioning of the monitoring well system after the 50 year post-injection monitoring period

7.2 Approach

The operation and maintenance requirements for the four CO_2 injection wells and the well annulus pressurization system (APS) were to be performed by the CO_2 pipeline and storage operations contractor. The operations contractor's responsibilities would have been limited to the activities that require a regular presence on site, which included providing operations and maintenance of the APS, wellhead valves, and associated control systems. The MVA contractor would have been responsible for data capture and reporting functions in compliance with the UIC well permit, and would have performed the specialized subsurface well work and other tasks that were to be periodic in nature, such as monitoring, testing and maintenance of the other injection well components listed in subsections 7.2.1 and 7.2.2.

The following sections discuss in greater detail the roles of the operations contractors.

7.2.1 CO_2 Pipeline and Storage Operations Plan

The CO_2 Pipeline and Storage Operations plan required the CO_2 pipeline and storage operations contractor to manage, operate, and maintain the pipeline, injection, and storage facilities for and on behalf of the Alliance (or future owner). The operations contractor would have been responsible for ensuring that the facilities were operated in compliance with all applicable laws applying to a pipeline transporting liquid-phase CO_2, and maintaining a full awareness of applicable laws, including limitation statutes and regulations enforced by PHMSA and by the ICC. Additionally, the operations contractor would have been responsible for the surface and subsurface facilities management that would have been performed in accordance with the requirements of the Class VI UIC permits.

Operations would have been managed from the Site Control Building using a full staff during the day shift, and a one-person staff during evening and night shifts. The pipeline and injection facilities were planned to operate for at least 20 years during the injection period.

This plan called for the operations contractor to manage the pipeline and CO_2 flow from the custody transfer point at the power plant meter station, through the 28-mile pipeline, then through the meter station at the injection site and finally into the four injection wells. The operations contractor would have managed the injection system with the advice and consent of the Alliance and its MVA Contractor.

Additional operations responsibilities would have called for the operations contractor to operate the injection wells from the wellhead valve and flow protection assemblies, (also known as Christmas trees), through the block valve(s) and monitoring instruments and into the subsurface injection zone. The operations contractor was to be responsible for the wellhead valves and associated control systems and also the operation and routine maintenance of the annulus pressurization system (APS) that maintains a ring of pressure around the subsurface portion of the injection well pipe. The operations contract included the requirement for a continuous presence at the injection site to monitor instruments and equipment, as well as gather and maintain data from these systems. It was also proposed that the operations contractor perform regular sampling of CO_2 injectate from the CO_2 pipeline and submit samples on behalf of, and under the direction of the MVA contractor, to a designated laboratory for analysis per the EPA Class VI UIC permit requirements.

The operations contractor would also have been responsible for the following:

- Operation and maintenance requirements of the CO_2 pipeline as required by regulation, including 49 CFR Part 195 – Transportation of Hazardous Liquids by Pipeline
- Preventative maintenance, limited landscape maintenance, and material and equipment repairs
- Pipeline maintenance pigging
- Pipeline integrity inspection conducted at years 10, 15, and 20 of operations

The full-time control room operator (3 shifts per day, 168 hours per week, and 52 weeks per year) would have operated the injection wells and APS, and monitored them from the control room human-machine interface, which would have featured a graphical depiction of the process and provided audible and visual alarms as well as real-time and historical trending. Other operations contractor's duties related to the APS would have included:

- Respond to alarms associated with the APS and coordinate with the MVA contractor as necessary
- Responsibility for ensuring the proper APS shut down when injection is halted and restarted when injection is resumed; if injection into only one well is halted while maintaining injection into the other wells, it will be necessary to maintain APS operation for the operating wells and isolate the non-operating well
- Maintain records of annular fluid added to or lost from the APS
- Monitor the high-point vent on the APS system for each well for presence of CO_2; if gas is present, collect CO_2 in a high-pressure sample bottle and submit for laboratory analysis
- On a daily basis, record pressure, temperature and other parameters (e.g., tank level) from key points in the APS. This data will be automatically logged but the operator would be required to keep a paper record to ensure a high level of awareness of operating conditions and facilitate early identification of issues
- Perform the routine CO_2 leakage testing of surface equipment and review all accumulated data acquisition of CO_2 monitors that measure and record concentrations at the surface, including the control building, meter skid, pipeline flanges and connections, wellhead, and APS system, per guidance provided in Appendix 7A
- Notify the Alliance and the MVA contractor of unexpected component failures or recurring system operating problems that may require engineering support

The operations contractor would also have managed the surface facility operations for the 20-year operating life of CO_2 injection. It was assumed that surface facilities would require a single maintenance employee to perform building maintenance and grounds maintenance for the site and the remote monitoring sites.

Following the 20-year injection period, the control building at the storage site was to remain in operation to allow for continued data acquisition from and maintenance of subsurface monitoring sites. Once the post-injection monitoring period ended (assumed as 50 years after injection ceased), the remaining surface facilities and the surface sites would have been returned to agricultural use, or other beneficial use.

7.2.2 MVA Operations Plan

The MVA contractor's role would have been to plan, coordinate and oversee the major maintenance and testing events necessary for safe, compliant injection well operation, while the operations contractor would have provided support to the MVA contractor in implementing these activities. Typical activities that would have involved the MVA contractor included shutting down, securing, and restarting the injection system and APS for maintenance/testing events. The MVA contractor would also have arranged for specialty contractors to perform non-routine maintenance, such as mechanical integrity testing.

The MVA contractor's planned responsibilities:

- Plan and coordinate well workovers when needed, (including sub-contracting service rig and other specialized services and procuring replacement materials, equipment, and instrumentation)
- Coordinate unscheduled well workovers on an "as needed" basis. Components most likely to require replacement include the selected portions of the wellhead valves, the tubing string, the packer, and the bottom-hole pressure-and-temperature gauge and cable
- Oversee surface and subsurface component re-work, instrumentation service/calibration, and well testing/logging activities that require tight coordination to ensure thorough and timely completion. While the operations contractor can provide procurement of selected complementary services, the MVA Contractor would be the main point of contact, coordinator, and procurer of the bulk of workover services
- Compile, assimilate, and report injection-related data (e.g., injection rate, mass, wellhead and bottom-hole pressure and temperature, annular fluid volume gains and losses, etc.) as per requirements of the EPA Class VI UIC permit
- Compile, assimilate, and report work performed and results of mechanical integrity testing as per requirements of the EPA Class VI UIC permit
- Provide on-site personnel to provide technical assistance and training to the operations contractor during the start-up and commissioning of the APS and injection system
- Provide engineering support to operations contractor on an as-needed basis related to the APS and injection wellhead operations
- Develop shut-down and start-up procedures for the injection system/APS prior to commissioning and startup
- Coordinate annual mechanical integrity tests and 5-year pressure fall-off tests as required per the EPA Class VI UIC permit (including sub-contracting

specialized work such as wireline logging)

7.3 Results

The Alliance had achieved an indicative agreement with USDI, an operations contractor, to manage the CO_2 pipeline, subsurface routine maintenance, and surface maintenance. The Alliance had planned to negotiate a contract with Battelle as the MVA contractor, upon approval from DOE, to provide objective technical expertise to the Alliance, train operators, conduct MVA, and maintain the UIC permit, and perform the functions of an owner's representative.

7.4 Operations Cost Estimates

The operating costs are a result of estimates from the actual operations contract negotiations and values provided by Battelle to perform owner's representative services. The rolled up operational cost estimate for the CO_2 pipeline and storage system is estimated to be $102 million over the first 56 months. (See Section 1.8.2) In addition to the operations contracts, these costs include owners insurance, trust fund payments, royalties, and numerous assumptive costs for permitting, legal, security, and other functions.

7.5 Conclusions, Discussion, and Lessons-Learned

Several lessons-learned are suggested from the effort to engage a reliable CO_2 pipeline and injection operations contractor:

1. Many of the pipeline operators that were contacted wanted to own the asset that they would be managing. Once it was determined they would not have ownership of the pipeline, most of the operators had little or no interest.

2. CO_2 operations are specialized and since most pipeline operations relate to natural gas or other commodities, it may be difficult to acquire knowledgeable expertise to operate a new CO_2 facility. Therefore, the final operations of a site may require the addition of a CO_2-specific training program of an existing qualified operator. This approach was being pursued by the Alliance for the FutureGen project. A reputable pipeline operation company was engaged, but one that would need to obtain specialized CO_2 management training. This single point of responsibility was deemed a successful achievement and model for future operations.

3. An efficient approach to segregate maintenance and operation of the subsurface infrastructure from monitoring, verification, and accounting activities during the project's operational and post injection site care periods is essential. One of the accomplishments of the project was to establish that the Operations Contractor's (USDI) responsibilities were to be limited to the activities that required a regular presence on site, which included providing operations and maintenance of the APS, wellhead valves, and

associated control systems. The FGA Subsurface Monitoring Verification and Accounting (MVA) Contractor (Battelle) was to perform specialized subsurface well work and other tasks that are periodic in nature, such as monitoring, testing, and maintenance of the other components of the injection wells. Additionally, Battelle, given their expert knowledge of the design and operation of the subsurface infrastructure, would bring an owner's perspective and objectivity on high expense maintenance items, versus that of an industry well service provider. Battelle, as the storage subsurface designer, would have been present onsite through the first permit renewal and train USDI. USDI was chosen to manage the routine pipeline and storage site operations due to their expertise with pipelines and PHMSA reporting.

4. The Alliance was able to negotiate an innovative Incentives and Fees Schedule which included performance parameters driven by safety, availability, environmental audit performance, PHMSA audit performance, operating efficiency, and annual cost savings. The agreement's incentive details are included in Appendix 1E.

7.6 References

Transportation of Hazardous Liquids by Pipeline, the Pipeline Hazardous Materials Safety Administration ("PHMSA"), 49 CFR Part 195.

7.7 Appendix

Appendix 7A - Monitoring and Verification of CO_2 Transport

LIST OF FIGURES

LIST OF TABLES

ACRONYMS

2D	two-dimensional
3C	three-component
3D	three-dimensional
ACZ	above confining zone
AEP	American Electric Power
ACWP	Actual Cost of Work Performed
AIMA	Agricultural Impact Mitigation Agreement
Alliance	FutureGen Industrial Alliance
APS	Annulus Pressure System
AoR	Area-of-Review
ARRA	American Recovery and Reinvestment Act
BGS	below ground surface
BP	before present
Ca	Calcium
CAA	Clean Air Act
CAS	Columbia Analytical Services
CBL	current bond logs
CCUS	carbon, capture, utilization, and storage
CFR	Code of Federal Regulations
CMP	common-midpoint
CMR	combinable magnetic resonance
CO_2	carbon dioxide
COD	commercial operation date
CV	cost variances
CWA	Clean Water Act
DCE	Definitive Cost Estimate
DOE	U.S. Department of Energy
DOT	U.S. Department of Transportation
DST	drill-stem packer test

EIS	environmental impact statement
EIV	Environmental Information Volume
EGI	Exploration Development, Inc.
EHM	equivalent homogeneous medium
ELAN	ELemental ANalysis
EM	electromagnetic
EPA	U.S. Environmental Protection Agency
EPC	Engineering, Procurement, and Construction
ERT	electrical resistivity tomography
ESA	Endangered Species Act of 1973
FMI	Formation Micro-Imager
FEED	Front-end engineering design
GHG	greenhouse gas
GIE	Gulf Interstate Engineering
GIS	geographic information system
GPS	Global Positioning System
GS	geologic sequestration
HAZOP	hazard and operability study
HCA	high consequence area
HF	hydraulic fracture
HP	horsepower
HSE	Health, Safety, and Environment
HTPF	hydraulic tests on pre-existing fractures
ICC	Illinois Commerce Commission
IDNR	Illinois Department of Natural Resources
IDOA	Illinois Department of Agriculture
IEPA	Illinois Environmental Protection Agency
IGPA	Illinois Groundwater Protection Act
IGSN71	International Gravity Standardization Net 1971
IHPA	Illinois Historic Preservation Agency

IHPO	Illinois Historic Preservation Office
ILCS	Illinois Compiled Statues
IPCC	Intergovernmental Panel on Climate Change
ISGS	Illinois State Geological Survey
JPA	Joint Permit Application
JSA	Job Safety Analyses
KB	Kelly Bushing
KCl	potassium chloride
LCM	lose circulation materials
LEED	Leadership in Energy & Environmental Design
LNG	Liquefied Natural Gas
LOE	level of effort
LSC	local sensitivity coefficient
LWI	Les Wilson, Inc.
MBLV	main line block valve
MBTA	Migratory Bird Treaty Act
MDT	Modular Dynamic Testing
MICP	mercury injection capillary pressure
MOA	Memorandum of Agreement
MMT	million metric tons
MRV	monitoring, reporting, and verification
MS1	Mount Simon Upper
MS2	Mount Simon Middle
MS3	Mount Simon Arkosic Sandstone
MS11	Mount Simon Formation
MVA	monitoring, verification, and accounting
NaCl	sodium chloride
NCTE	no cost time extension
NEPA	The National Environmental Policy Act of 1969, as amended
NHPA	National Historic Preservation Act

NPDES	National Pollutant Discharge Elimination System
NPMS	National Pipeline Mapping System
NRAP	National Risk Assessment Partnership
NWP	Nationwide Permit
O&M	operations and maintenance
O_2	oxygen
OPID	Operator Identification Number
OPS	Office of Pipeline Safety
OWR	Office of Water Resources
P&A	plugging and abandonment
PA	programmatic agreement
Patrick	Patrick Engineering, Inc.
PEEK	polyether ether ketone
PHMSA	Pipeline and Hazardous Material Safety Administration
PMC	percent modern carbon
PNC	pulsed-neutron capture
POC	point-of-contact
PNWD	Pacific Northwest Division
PV	pure volume
RAT	reservoir access tube
RFP	Request for Proposals
ROD	record of decision
ROW	right-of-way
RTK	Real-Time Kinematic
S	shear
SCB	Site Control building
SDWA	Safe Drinking Water Act
SHPO	State Historic Preservation Officer
SOPO	Statement of Project Objectives
SO_4	sulfate

SSP	Source Selection Panel
STEM	science-technology-engineering-mathematics
SV	schedule variances
SWC	sidewall cores
SWPPP	Storm Water Pollution Prevention Plan
TD	total depth
TDS	total dissolved solids
THPO	Tribal Historic Preservation Office
TWT	two-way-time
UBI	Ultrasonic Borehole Imager
UCM	United Contractors Midwest
UIC	Underground Injection Control
URA	Uniform Relocation Assistance and Real Property Acquisition Policies Act of 1970
USACE	U.S. Army Corps of Engineers
USEPA	U.S. Environmental Protection Agency
USC	United States Code
USDA	U.S. Department of Agriculture
USDI	Utility Safety and Design, Inc.
USDW	underground source of drinking water
USFWS	U.S. Fish and Wildlife Service
USI	ultrasonic imaging
UTEP	University of Texas-El Paso
VIMPA	vertically integrated mass per area
VRT	Visitor, research, and training
VSMOM	Vienna Standard Mean Ocean Water
VSP	vertical seismic profiling
WRL	Westlake Reed Leskosky