FIELD IMPLEMENTATION PLAN FOR A WILLISTON BASIN BRINE EXTRACTION AND STORAGE TEST

Phase I Topical Report

Prepared for:

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NOMENCLATURE

ABR	Australian Biorefining
AOR	area of review
API	American Petroleum Institute
ARM	active reservoir management
bbl	barrel
BEST	brine extraction and storage test
BHA	bottomhole assembly
BHC	borehole-compensated
BHP	bottomhole pressure
BHT	bottomhole temperature
BSEM	borehole-to-surface electromagnetics
BTEX	benzene, toluene, ethylbenzene, xylene
bwpd	barrels of water per day
CAPEX	capital expenditure
CBL	cement bond log
CCL	casing collar locator
CCS	carbon capture and storage
CLTH	clathrates
CO_2	carbon dioxide
CoLD	crystallization of high solubility salts at low temperature and deep vacuum
CP	casing pressure
DOE	U.S. Department of Energy
DRO	diesel-range organics
DSF	deep saline formation
ECMD	electrically conductive membrane distillation
EERC	Energy & Environmental Research Center
EM	electromagnetic
EPA	U.S. Environmental Protection Agency
ESP	electric submersible pump
FBA	fluorobenzoic acid
FCC	forced circulation crystallization
FF	falling film
FO	forward osmosis
FTE	freeze–thaw/evaporation
GR	gamma ray
GRE	Great River Energy
GRO	gasoline-range organics
HDH	humidification dehumidification
HSE	health, safety, and environment
LCA	life cycle analysis
LCM	lost circulation material
LM-HT	low momentum-high turbulence
LQC	log quality control
LTC	long-thread casing
MC	microclarification
MD	measured depth

MIT	mechanical integrity test
MPS	multiple-point statistics
MVA	monitoring, verification, and accounting
MVR	mechanical vapor recompression
NDAC	North Dakota Administrative Code
NDIC	North Dakota Industrial Commission
NDWC	North Dakota Water Commission
NEPA	National Environmental Policy Act
NETL	National Energy Technology Laboratory
NMR	nuclear magnetic resonance
NORM	naturally occurring radioactive material
O&G	oil and grease
OGTC	Oil & Gas Technology Center
PCOR Partnership	Plains CO_2 Reduction Partnership
PDC	polycrystalline diamond compact
PP	permit policy
PPE	personal protective equipment
ppt	parts per trillion
RIH	run in hole
RO	reverse osmosis
ROP	rate of penetration
SAGD	steam-assisted gravity drainage
SC	supercritical
SCADA	supervisory control and data acquisition
SDF	deep saline formations
SEM	scanning electron microscopy
SHF	saltwater-handling procedure
SOP	standard operating procedures
spf	shot per foot
SRS	steam-regenerable sorbent
SWD	saltwater disposal
TCLP	toxicity characteristic leaching procedure
TD	total depth
TDS	total dissolved solids
TEF	turboexpander-based freeze
TENORM	technologically enhanced naturally occurring radioactive material
TOC	top of the cement
TSS	total suspended solids
UIC	underground injection control
USDW	underground source of drinking water
VSEP	vibratory sheer enhanced processing
WHP	wellhead pressure
XRD	x-ray diffraction
XRF	x-ray fluorescence
ZLD	zero-liquid discharge

EXECUTIVE SUMMARY

The Energy & Environmental Research Center (EERC) successfully completed all technical work of Phase I, including development of a field implementation plan (FIP) for a brine extraction and storage test (BEST) in the North Dakota portion of the Williston Basin. This implementation plan was commissioned by the U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL) as a proxy for managing formation pressure plumes and measuring/monitoring the movement of differential pressure and CO_2 plumes in the subsurface for future saline CO_2 storage projects. BEST comprises the demonstration and validation of active reservoir management (ARM) strategies and extracted brine treatment technologies. Two prospective commercial brine injection sites were evaluated for BEST to satisfy DOE's goals. Ultimately, an active saltwater disposal (SWD) site, Johnsons Corner, was selected because it possesses an ideal combination of key factors making it uniquely suited to host BEST. This site is located in western North Dakota and operated by Nuverra Environmental Solutions (Nuverra), a national leader in brine handling, treatment, and injection.

An integrated management approach was used to incorporate local and regional geologic characterization activities with geologic and simulation models, inform a monitoring, verification, and accounting (MVA) plan, and to conduct a risk assessment. This approach was used to design a FIP for an ARM schema and an extracted brine treatment technology test bed facility.

The FIP leverages an existing pressure plume generated by two commercial SWD wells. These wells, in conjunction with a new brine extraction well, will be used to conduct the ARM schema. Results of these tests will be quantified based on their impact on the performance of the existing SWD wells and the surrounding reservoir system. Extracted brine will be injected into an underlying deep saline formation through a new injection well. The locations of proposed extraction and injection wells were selected during the Phase I efforts. These wells will be permitted as North Dakota Administrative Code Underground Injection Control Class II wells and will yield additional characterization data which will further refine the FIP in Phase II.

An array of surface and downhole monitoring techniques will validate ARM performance against predictive simulation results. Infrastructure will be constructed to manage extracted fluids at the surface and provide brine to a treatment test bed facility. Treatment of extracted brine can provide a means of reducing extracted brine disposal volumes, an alternate source of water, and/or salable products for beneficial use. A test bed facility will be constructed to provide a means of demonstrating these technologies on a wide range of brine concentrations. Screening criteria based on a techno-economic and life cycle assessment were developed to select high-salinity brine treatment technologies for extended duration treatment (30–60 days) in Phase II.

A detailed cost assessment determined total implementation costs for BEST of $19,901,065 million (DOE share $15,680,505). These costs are inclusive of all necessary equipment, infrastructure construction, operations and project closeout costs required to implement BEST.

An ideal combination of key factors makes the Johnsons Corner site uniquely suited to be the BEST demonstration.

ARM testing will occur in the Inyan Kara Formation, a regionally extensive deep saline formation previously identified as a prime target for commercial-scale CO_2 storage because of its superb geologic properties. This, combined with the fact that current brine injection operations at the Johnsons Corner site emulate commercial-scale CO_2 storage (volumetrically equivalent to >250,000 tons/yr CO_2), means the results of ARM in the Inyan Kara will be directly applicable to widespread adoption in carbon capture and storage (CCS) projects.

Operations at the Johnsons Corner site are ideally suited for conducting BEST. Long-term operations at the site have created a differential pressure plume that can be modified through ARM, and the established injection history allows for confident simulated predictions. The four-well design provides operational flexibility and monitoring capability to test ARM scenarios through a range of injection and extraction rates. Injection can be independently controlled into both SWD wells, and the extraction rate can be varied. Integration of the test bed facility with SWD operations provides the ability to generate tailored brine concentrations. A lower geologic horizon will be used for disposal of extracted water as a parallel to ARM implementation at CCS sites.

The EERC, in conjunction with its partners, have all the necessary expertise and resources to implement BEST. The successful completion of Phase 1 technical work was founded on strong and well-established partnerships. Nuverra Environmental Solutions has committed as a Phase II project partner, agreeing to implement BEST at its site and allowing the EERC to operate under existing site permits and surety bonds for brine treatment and brine-handling infrastructure. Nuverra has additionally agreed to acquire the remaining necessary permits to implement BEST and assume site liability at project closeout. Other key partners, Schlumberger Carbon Services and Computer Modelling Group Ltd. (CMG), both industry leaders in reservoir engineering software, have committed to partner with the EERC into Phase II. Schlumberger also possesses world-recognized expertise in well drilling, completions, and testing. Finally, the North Dakota Industrial Commission has committed to work with the EERC to ensure that all required permitting documents are approved in a timely manner. The EERC and its partnerships are ideally suited to accomplish Phase II objectives. The EERC has a multidisciplinary team of engineers, geologists, and scientists with extensive research and operational experience and cross-training in geologic characterization, geologic modeling, predictive simulation, MVA, risk assessment and operations related to injection and extraction of subsurface fluids, and CCS.

The Johnsons Corner BEST will benefit future CO_2 saline storage projects through development of engineering strategies that reduce stress on sealing formations, provide a mechanism for diverting a pressure or injected fluid plume from potential leakage pathways, and reduce area of review. In addition, BEST will provide evidence for increased storage capacity, improved storage efficiency, and improved geologic storage coefficients, including fundamental data for ARM scenarios. This project and the economics associated with it will directly contribute to the development of best practices for site characterization, site operations (including ARM and extracted brine treatment), monitoring, and site closure. The results derived from the implementation of the proposed brine extraction field test will provide a significant contribution to NETL’s Carbon Storage Program goals.

FIELD IMPLEMENTATION PLAN FOR A WILLISTON BASIN BRINE EXTRACTION AND STORAGE TEST

Phase I –Topical Report

1.0 OVERVIEW AND KEY FINDINGS

Deep saline formations (DSFs) constitute the largest potential global resource for the geologic storage of CO_2 (Intergovernmental Panel on Climate Change, 2005; IEA Greenhouse Gas R&D Programme, 2008; Intergovernmental Panel on Climate Change, 2014). Their use is, in turn, crucial to the successful scale-up of storage from pilot and demonstration projects to commercial operations. Active reservoir management (ARM), through formation water extraction, is a potential method for maximizing the utility of DSFs for CO_2 storage and thereby reducing some of the associated costs and impacts. Extraction of formation waters from CO_2 storage sites has the potential to improve reservoir storage volumes, aid in management of CO_2 plume migration, reduce cap rock exposure to CO_2 (through reduction of resulting CO_2 plume footprint size), manage storage reservoir pressure, and generate a new source of water for a variety of beneficial surface uses (Klapperich and others, 2013). It is expected, that in most cases, extracted water will be managed through direct injection into an appropriate saline formation. However, indirect benefits derived from the treatment and sale of the extracted water may provide additional economic incentives or cost offsets for formation water extraction. ARM strategies may also be used to mitigate concerns of over pressurization within a reservoir and interference from other CO_2 injection projects or other injection wells (Klapperich and others, 2013; Buscheck and others, 2011; Court and others, 2011). The location and number of extraction wells could improve injectivity and reduce the number of injection wells required.

The Energy & Environmental Research Center (EERC) successfully completed the Phase I development of a field implementation plan (FIP) for a Brine Extraction and Storage Test (BEST) in the North Dakota portion of the Williston Basin. This implementation plan was commissioned by the U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL) as a proxy to manage formation pressure plumes and measure/monitor the movement of differential pressure and CO_2 plumes in the subsurface for future saline CO_2 storage projects. BEST comprises the demonstration and validation of ARM strategies and extracted brine treatment technologies.

This report describes the steps which were taken to select this site and develop an implementation plan. These steps consisted of developing the following:

- Regional characterization
- Site selection
- Geologic model construction
- ARM schema through reservoir simulation
- Monitoring plans
- Site operation plans
- Site infrastructure design and implementation plan
- Water treatment technology evaluation, design, and implementation plans

- Site risk assessment
- Costing

Regional characterization of the Williston Basin focused on two widespread saline aquifer systems (Inyan Kara and Broom Creek Formations) that have also been identified as targets for future CO_2 storage activities (Glazewski and others, 2015). These saline systems serve as the primary target horizons for an extensive saltwater disposal (SWD) industry in western North Dakota. In addition, these formations underlie nearly all major point sources of CO_2 emissions in the region, and have an estimated combined CO_2 storage capacity of between 20 and 80 billion tons (Glazewski and others, 2015), with recent (unpublished) analysis suggesting 2 to 5 times more capacity. Two candidate sites were further characterized for suitability to successfully demonstrate ARM and water treatment aspects of BEST. One of the candidate sites is associated with the Great River Energy Coal Creek power plant. The other option was the Johnsons Corner SWD facility operated by Nuverra Environmental Solutions (Nuverra), a national leader in brine handling, treatment, and injection. Each site offered existing injection operations into the Inyan Kara Formation and other suitable formations, including the Broom Creek Formation, for the disposal of extracted brine. Geocellular models were constructed for each site using publicly available data. In addition to the models, each site was evaluated with respect to existing injection history, infrastructure, and permits. While the fundamental geology of each site was favorable for BEST, ultimately the Johnsons Corner site was selected because it possesses an ideal combination of key factors making it uniquely suited to host BEST. Nuverra has agreed to host the field test at its Johnsons Corner site.

To assess the Johnsons Corner site with respect to confidently influencing the differential pressure established through brine extraction and reinjection, a geocellular model of the project area was built that includes the Inyan Kara (extraction horizon), Broom Creek, and Amsden Formations (injection horizons). Petrophysical data from available well logs and core, along with an understanding of the depositional environments of the target formations, were used to distribute properties for various reservoir and nonreservoir facies. With respect to the Inyan Kara Formation at the Johnsons Corner site, successful dynamic simulation and history matching of the 8+ years of saltwater injection data provided confidence that the geocellular model of that formation is geologically representative of the project area. Dynamic simulation of brine injection into the Broom Creek Formation at Johnsons Corner was also performed to determine the ability of that formation to serve as a disposal zone for the brine extracted from the Inyan Kara. Although in the Johnsons Corner area there are no SWD injection wells into the Broom Creek Formation, the Formation is used for SWD in other areas of North Dakota. The simulation modeling conducted as part of the Phase I efforts indicated that the Broom Creek Formation at Johnsons Corner can accommodate the ARM extraction volumes.

The field implementation plan calls for the drilling and completion of two new wells in the vicinity of the existing SWD operation: one extractor well into the Inyan Kara Formation and one extracted brine injection well into the Broom Creek Formation (Figure 1-1). The siting process for those wells involved meeting the requirements of five competing aspects. Key among them were the ability to 1) clearly detect a pressure response in the existing injector wells, 2) dispose of extracted water, and 3) provide lower-salinity water to blend with incoming produced water to tailor salinities for the brine treatment testing aspect of the project.

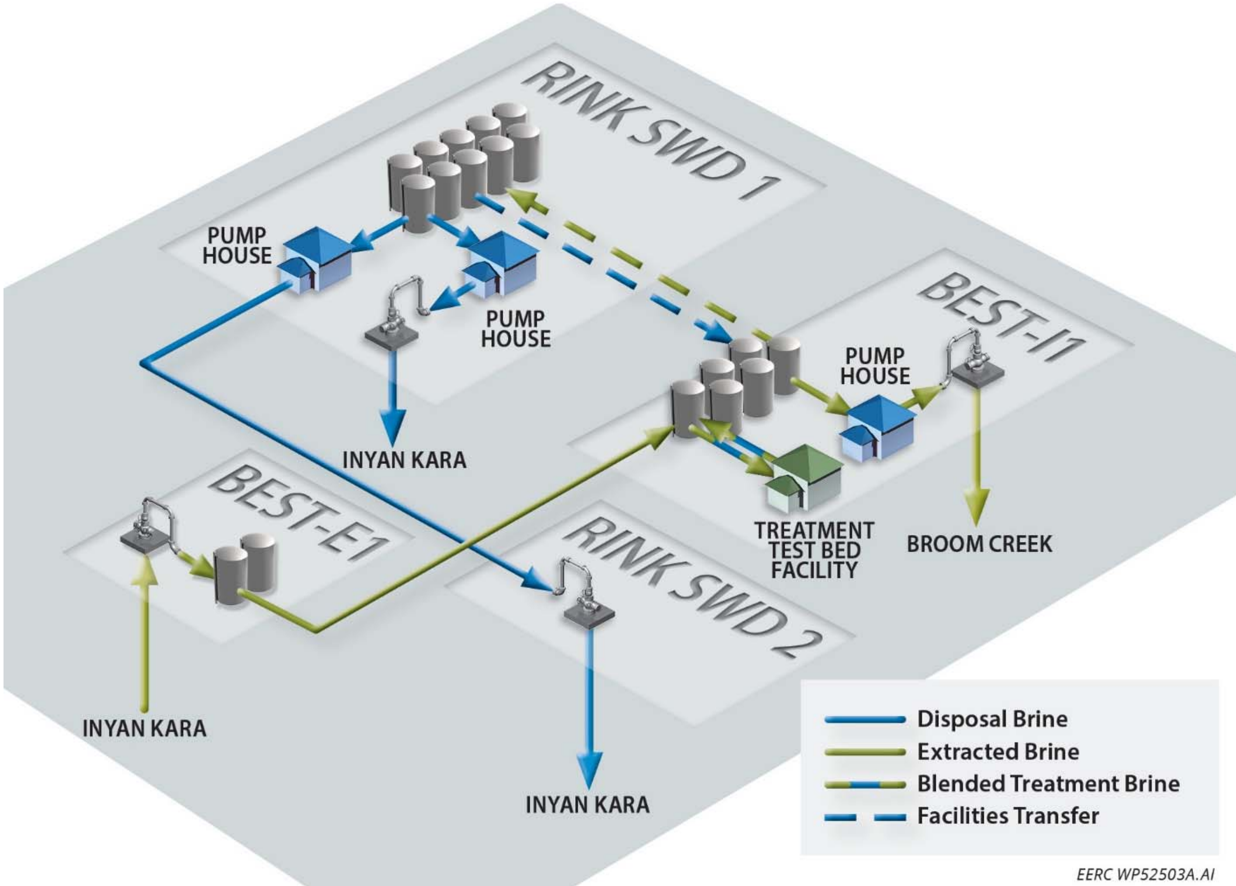


Figure 1-1. Conceptual illustration of the injection and extraction well configuration and the integrated water-handling and storage infrastructure and extracted brine treatment test bed facility.

Eighteen case studies in a pressure management plan were simulated using a final selection of well locations to provide detailed predictions of impacts to the pressure differentials and the salinity plume within the project area. Results of the predictions indicated that the extraction of 4000 bwpd from the Inyan Kara Formation should have an 18–52-psi impact on the bottomhole pressures (BHPs) at the existing injection wells. Because of the high permeability of the Inyan Kara and its ability to rapidly reflect perturbations in pressure, a 4000-bwpd extraction should show a 10–20-psi change at the injector wells within 10 days. This rapid response will allow for timely and effective experimentation at the site by adjustment of extraction rates and operating pressures. The simulation results also revealed the ability to create a notable modification in the development of the salinity plume in response to ARM efforts.

The EERC developed a goal-oriented, site-specific monitoring, verification, and accounting (MVA) plan for the Johnsons Corner project with two drivers in mind: 1) the technical goals of the project and 2) risk reduction and mitigation. The plan includes pre-ARM operation baseline characterization, active reservoir surveillance, and post-ARM operation final characterization. The MVA techniques are capable of providing validation of simulation predictions related to injection performance improvements and modifications to differential pressure plume and brine salinity distributions resulting from the ARM test. Iterative integration of these data sets into the day-to-day operations of the site will ensure that the collected MVA information supports the effective management of the ARM test program itself.

Rock and fluid physics modeling at the Johnsons Corner site indicated that p-wave impedance changes as a result of predicted pressure variations would be too small to discern with seismic methods, thus precluding the use of seismic monitoring at the project site. However, borehole-to-surface electromagnetics (BSEM) can leverage the salinity contrast between the brine character of the Inyan Kara Formation at the beginning of the project and at the end. The physical measurement of the salinity plumes will provide a means of validating or updating the geologic model that is the input to the predictive simulations. Validation of BSEM at the Johnsons Corner ARM test will yield valuable insight for an alternative technique for use at CO_2 storage sites where traditional surface seismic surveys are not viable.

Frequent iterative simulation modeling and history-matching efforts are the foundation for determining the effectiveness of the ARM operations. As such, it is critical that the geologic model of the Inyan Kara and Broom Creek Formations be as accurate as possible. To ensure this, a robust and quantitative analysis of core samples derived from the new injection well will be conducted. These analyses will be correlated to the new suites of logging data that will be acquired from both new wells.

Active reservoir surveillance in the Inyan Kara and Broom Creek Formations will largely be based on continuous monitoring of pressure, temperature, flow rates, and density from various points in both the downhole and surface wellhead environments. Data generated from active reservoir surveillance activities will also be incorporated into the iterative history-matching and model revision exercises.

An indicative field experimental scenario was chosen to serve as the basis of the ARM design and implementation plan. The scenario is divided into two stages, with the first stage intended to probe the reservoir and well responses to a specific sequence of injection and extraction tests to determine the level of performance interference among the wells and the capabilities of the system. A combined injection rate of 6800 bwpd is expected to be maintained throughout Stage One, which is the current average operating rate at the facility. The conduct of the project is designed to minimize disruption to ongoing commercial activity. Stage One results will be used to adjust Stage Two of the program to maximize the impact of ARM for achieving the project objectives. Stage Two of the scenario is characterized by more continuous extraction periods at a rate as high as practical to maximize the pressure impact on the injection wells and influence the evolution of the salinity distribution.

The field implementation plan will require the installation of an extraction well completed in the Inyan Kara Formation, an extracted brine disposal well completed in the Broom Creek Formation, brine-handling equipment (e.g., storage tanks, pipeline, etc.), and support infrastructure (e.g., additional power lines, access roads, etc.). Detailed well drilling and completion plans for the new wells and detailed plans for the layout and installation of brine-handling equipment and support infrastructure have been developed. Installation of these project elements will require several permits from the state of North Dakota and McKenzie County. The site operator, Nuverra, already has several of these permits and associated surety bonds in place and has agreed to acquire the remaining permits and bonding necessary to conduct BEST. A site development plan was designed to provide space and facilities to meet all drilling and operation requirements for the proposed BEST and the associated extracted brine treatment technology test bed.

The brines currently being injected into the Rink SWD 1 and Rink SWD 2 wells have a much higher salinity than the native Inyan Kara Formation water, with injected brine typically containing greater than 300,000 mg/L total dissolved solids (TDS). The higher salinity in the injected water provides the capability to blend injected brine with the extracted water to achieve a wide range of salinity for the extracted brine treatment test bed, including the DOE target level of 180,000 mg/L TDS.

Brine treatment technologies will be tested as a viable means of reducing brine disposal volumes. The test bed facility will provide a controlled environment to demonstrate and evaluate brine treatment technology performance on tailored brine compositions. Screening criteria will be used to select technologies to demonstrate extended duration treatment (30–60 days) of high-salinity brines for a range of beneficial use applications.

The EERC partnered with GE Global Research (GE) to develop an engineering design and site implementation plan for a test bed to evaluate brine treatment technologies that may be capable of treating high TDS extracted water. Phase I brine treatment technology assessment included evaluations of the strengths and weakness of several commercial and pilot-ready extracted water treatment technologies that might be demonstrated during test bed operations. The actual selection of individual technologies for testing will be conducted in Phase II using the screening and selection process developed in Phase I.

A research gap and life cycle analysis (LCA) were conducted. Modeling and techno-economic analyses provided the detailed energy and material balances to develop data to compare the cost-effectiveness of brine concentration versus brine crystallization using commercially available technologies. Brine concentration was determined to be the most cost-effective, largely because of the associated costs of handling and disposing of dried salts. Brine concentration using a falling film evaporator with mechanical vapor recompression (FF–MVR) served as the base case for LCA to compare developing and pilot-ready extracted water desalination technologies. Three pilot-ready techniques: forward osmosis, membrane distillation, and humidification–dehumidification desalination, and two techniques currently under development: clathrate-based and turbo-expander freezing, were compared to FF–MVR. The pilot-ready technologies are not currently economic unless low-cost energy sources like waste heat from a power plant are available. Additional research and testing is needed to improve the understanding of the economics of these technologies.

The research gap identified with the implementation of the desalination technologies is largely associated with the high salinity and hardness of brines that are anticipated to be extracted as part of carbon capture and storage (CCS). The capital and operating costs of desalination technologies will have to be weighed against the economic benefits, including the reduction in brine volume for disposal and the value of treated water or product. Fundamental knowledge derived from field demonstrations is required to fully evaluate applications to CCS as many of the technologies evaluated as part of the LCA and techno-economic analysis are in early stages of development or have not been optimized for high TDS brine treatment.

The Phase I technology assessment and LCA of pilot-ready technologies, along with physical and chemical characterization data of the extracted water at the Johnsons Corner site, provided the basis for the design of the brine treatment technology demonstration test bed. The test bed design includes pretreatment and the capability to blend extracted waters to the DOE target of 180,000 mg/L TDS or custom blending of extracted waters to simulate TDS levels from suitable CO_2 storage formations virtually anywhere on the globe.

A technology screening and selection process was developed that includes a scoring system that weights the areas of treatment cost, readiness level, safety considerations, and waste generation on a scale of 1 to 10. The selection process will give priority to those technologies associated with DOE-funded projects awarded for the development of innovative high TDS brine pretreatment and desalination technologies (DOE FOA [funding opportunity announcement] 0001095 and DOE FOA 0001238) that successfully satisfy technology screening criteria.

The successful Phase I design integration of the treatment test bed facility operations with the ARM demonstration provides a robust test system at the Johnsons Corner BEST site that is ideal for the duration of the Phase II project. The selection and demonstration of applicable extracted water treatment technologies at the Johnsons Corner test bed will address the research gap and provide necessary operating and performance data to allow development of the technologies to higher readiness levels.

A risk assessment was performed that included potential project-specific risks associated with the Johnsons Corner project. These risks were classified into 1) technical, 2) resource availability, 3) health, safety, and the environment (HSE), 4) site access, and 5) management categories. A preliminary assessment of the impact of each risk to cost and schedule identified no unacceptable project risks. Mitigation and remediation measures were proposed to achieve a safe and successful completion of the Johnsons Corner project.

Based on the results of Phase I, it is clear that the Johnsons Corner site is uniquely suited to be the BEST site based on the following qualities:

1) ARM testing will occur in the Inyan Kara Formation, a regionally extensive DSF previously identified as a prime target for commercial-scale CO_2 storage because of its superb geologic properties. This, combined with the fact that current brine injection operations at the Johnsons Corner site emulate commercial-scale CO_2 storage (volumetrically equivalent to >250,000 tons/yr CO_2), means the results of ARM in the Inyan Kara will be directly applicable to widespread adoption in CCS projects.

2) Recent and ongoing SWD operations at the Johnsons Corner site have created an ideal reservoir environment for conducting BEST. Long-term operations at the site via two Class II underground injection control (UIC) injection wells have created a differential plume that can be modified through ARM, and the established injection history allows for confident simulated predictions.

3) The four-well design provides operational flexibility and monitoring capability to test ARM scenarios through a range of injection and extraction rates. Injection can be independently controlled into both SWD wells, and the extraction rate can be varied. A lower geologic horizon will be used for disposal of extracted water as a parallel to ARM implementation at CCS sites.

4) While the native brine is expected to have salinities below 180,000 mg/L TDS, the produced water brines being delivered to the site have a salinity typically greater than 300,000 mg/L TDS. Thus integration of the extracted brine treatment test bed facility with Nuverra's Johnsons Corner SWD operations provides the ability to generate tailored brine concentrations and achieve the DOE target level of 180,000 mg/L TDS for the extracted brine treatment technology demonstrations.

5) The EERC capitalized on long-term existing working relationships with Nuverra, Schlumberger Carbon Services (Schlumberger), Computer Modelling Group Ltd. (CMG), and the State of North Dakota to create a field implementation plan that will ensure a successful demonstration of BEST at Johnsons Corner in Phase II.

6) Nuverra has committed as a Phase II project partner, agreeing to implement BEST at its site and allowing the EERC to operate under existing site permits and surety bonds for brine treatment and brine-handling infrastructure. Nuverra has additionally agreed to acquire the remaining necessary permits to implement BEST and assume site liability at project closeout. Other key partners, Schlumberger Carbon Services and Computer Modelling Group Ltd. (CMG), both industry leaders in reservoir engineering software, have committed to partner with the EERC into Phase II. Schlumberger also possesses world-recognized expertise in well drilling, completions, and testing. Finally, the North Dakota Industrial Commission (NDIC) has committed to work with the EERC to ensure that all required permitting documents are approved in a timely manner.

The Johnsons Corner BEST will benefit future CO_2 saline storage projects through development of engineering strategies that reduce stress on sealing formations, provide a mechanism for diverting a pressure or injected fluid plume from potential leakage pathways, and reduce area of review (AOR). In addition, BEST will provide evidence for increased storage capacity, improved storage efficiency, and improved geologic storage coefficients, including fundamental data for ARM scenarios. This project and the economics associated with it will directly contribute to the development of best practices for site characterization, site operations (including ARM and extracted brine treatment), monitoring, and site closure. The results derived from the implementation of the proposed brine extraction field test will provide a significant contribution to NETL's Carbon Storage Program goals.

2.0 INTRODUCTION

The EERC was commissioned by DOE NETL to create a FIP for a BEST in North Dakota. BEST consists of a demonstration of ARM and provides a test bed to demonstrate extracted water treatment technologies. The FIP consists of an engineering design and an operations strategy for demonstration of ARM and associated water treatment. The engineering design plan specifies the protocols and procedures for installing the site infrastructure. Methods for predicting, monitoring, and validating ARM are provided by the operations strategy. Completion of the FIP successfully meets all Phase I objectives.

The results of the field test are expected to benefit future CO_2 storage projects in saline formations through validation of engineering strategies that reduce stress on sealing formations and consequently reduce risk of breaching sealing formations, reduce risk of brine and CO_2 intrusion into other formations, increase storage capacity, and reduce AOR. The implementation plan includes a test bed to evaluate brine treatment technologies that may be capable of treating extracted water with high TDS for beneficial use as a means of managing and reducing brine disposal volumes. Practical, commercial-scale demonstrations of ARM strategies and water treatment technologies will further NETL's Carbon Storage Program's stated goals of developing technologies that ensure 99% storage permanence, improving reservoir storage efficiency while ensuring containment effectiveness, and developing best practices for storage site operators (U.S. Department of Energy National Energy Technology Laboratory, 2014).

DSFs constitute the largest potential global resource for the geologic storage of CO_2 (Intergovermental Panel on Climate Control, 2005; IEA Greenhouse Gas R&D Programme, 2008; Intergovermental Panel on Climate Control, 2014). ARM has been postulated to improve injectivity and manage CO_2 plume migration through pressure management via strategic formation water extraction (Davidson and others, 2014; Birkholzer and others, 2015; Cihan and others, 2015). Treatment of the extracted formation water can provide an alternate source of water and potential salable products for a variety of beneficial uses. These products may provide additional economic incentives or cost offsets for ARM (Klapperich and others, 2013). ARM strategies may also be used to mitigate concerns of over pressurization within a reservoir and interference from other CO_2 injection projects or other injection wells (Birkholzer and Zhou, 2009; Buscheck and others, 2011; Court and others, 2011; Zhou and Birkholzer, 2011; Klapperich and others, 2013).

The scope and scale of monitoring activities for CCS sites are dependent on the project's AOR. As defined by the U.S. Environmental Protection Agency (EPA), AOR is the maximum extent of the pressure plume (resulting from CO_2 injection activities) which contains enough head pressure to lift fluid from the storage reservoir to an underground source of drinking water (USDW) (U.S. Environmental Protection Agency, 2013). AOR delineates the region in which all potential natural and artificial conduits to the surface must be located and evaluated by a CCS site operator. If necessary, the operator is obligated to undertake corrective actions to remediate identified vertical migration pathways. Any reductions in the footprint of the pressure plume through ARM will likely result in reducing the number of conduits characterized and designated for corrective action. This corresponds to reduced costs and scope of required monitoring. In regions with a large number of wells, such as the Williston Basin, this can be a substantial cost reduction.

Two potential sites in the North Dakota portion of the Williston Basin were evaluated: the Johnsons Corner site in McKenzie County and the Coal Creek Station site (coal-fired power plant) in McLean County. Ultimately, the EERC developed the components of a field project to successfully execute BEST at the Johnsons Corner site, an active saltwater injection facility. This site had optimal geology, geography, and existing permits and infrastructure for conducting BEST. This report describes the steps which were taken to select this site and develop an implementation plan. These steps consisted of developing the following:

- Regional characterization
- Site selection
- Geologic model construction
- ARM schema through reservoir simulation
- Monitoring and site operation plans
- Site infrastructure design and implementation plan
- Water treatment technology evaluation, design, and implementation
- Site risk assessment
- Costing

The EERC has developed a philosophy that integrates site characterization, modeling and simulation, risk assessment, and MVA strategies into an iterative process to produce meaningful results for commercial subsurface injection and/or production operations (Figure 2-1) (Gorecki and others, 2012). Elements of any of these activities are crucial for understanding or developing the other activities. For example, as new knowledge is gained from site characterization, it reduces a given amount of uncertainty in geologic reservoir properties. This reduced uncertainty can then propagate through modeling, risk assessment, and MVA efforts. This approach has been applied in Phase I of the BEST project to develop a tailored technical design which will enable achievement of the project’s objectives while minimizing risk. This approach will also be implemented in the BEST Phase II efforts.

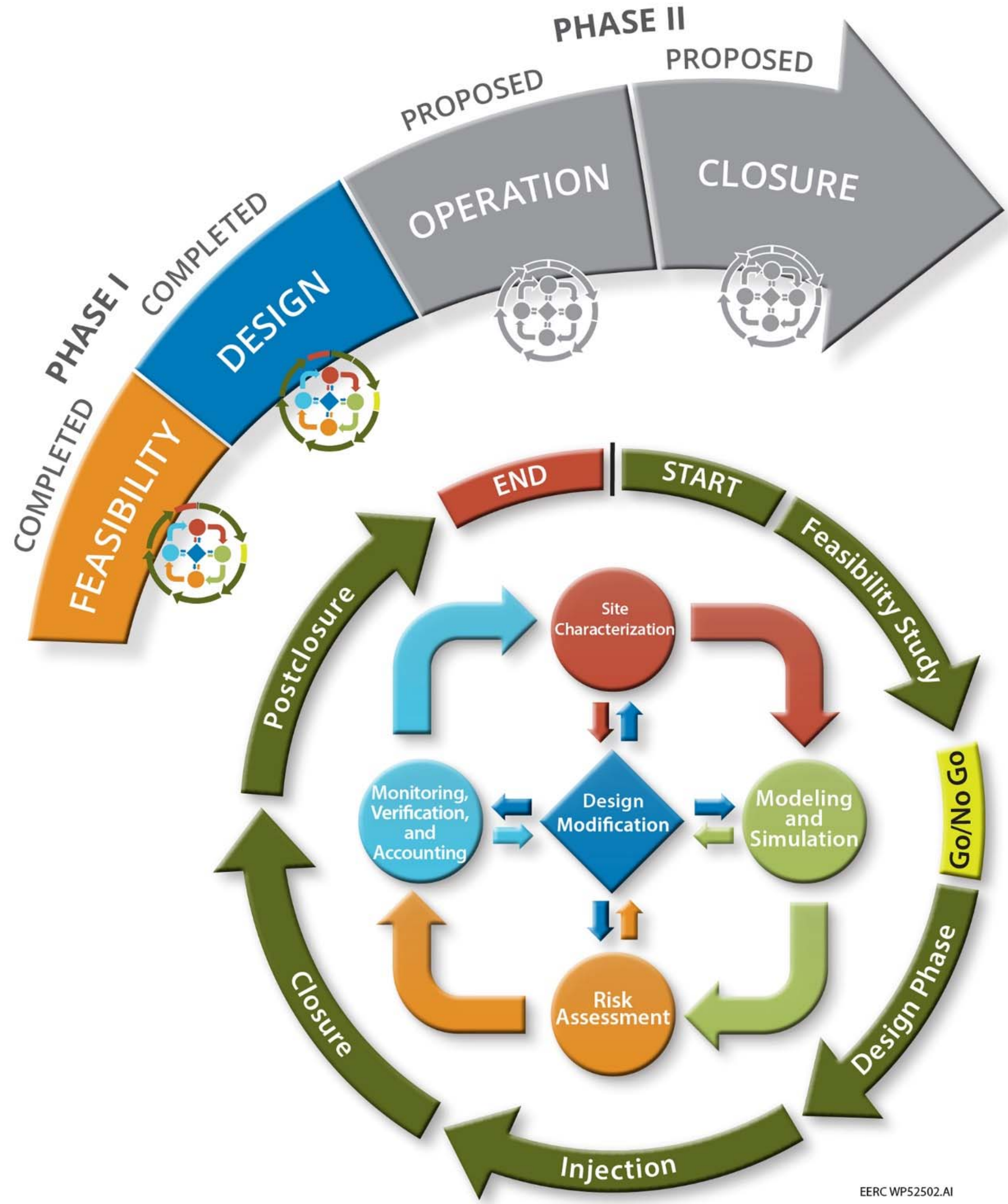


Figure 2-1. Integrated and iterative approach to project management. Each of these elements feeds into another, iteratively improving results and efficiency of evaluation, during each project phase.

3.0 REGIONAL GEOLOGIC CHARACTERIZATION

Through the Plains CO_2 Reduction (PCOR) Partnership, the EERC has extensively characterized the Williston Basin for CCS opportunities, including potential storage through CO_2 enhanced oil recovery and in regional DSFs. These efforts have included evaluation of the DSF systems of the Williston Basin for their CO_2 storage potential and identified approximately 70 to 230 billion tons of CO_2 storage resource within western North Dakota (Fischer and others, 2005a,b; Peck and others, 2012, 2014; Glazewski and others, 2015).

The Williston Basin is a large, intracratonic basin with a thick sedimentary cover in excess of 16,000 feet near its depocenter in western North Dakota (Figures 3-1 and 3-2). It is considered to be one of the most tectonically stable portions of the North American continent, with only a subtle structural character (Gerhard and others, 1982; Fischer and others, 2005a). The stratigraphy of the area is well studied, especially in those intervals associated with hydrocarbon production.

Downey and others (1987) examined the hydrogeology of the Williston Basin and divided the stratigraphic column into five regional aquifer and four regional aquitard systems. These aquifer systems constitute some of the largest confined systems in the United States and are key targets for large-scale deployment of CCS (Glazewski and others, 2015) (Figure 3-2). These five aquifer systems include one shallow freshwater aquifer system and four deep saline systems.

To select an ideal location to conduct BEST, the EERC focused on units of the Williston Basin that are extensively used for water injection, specifically the Inyan Kara Formation of the Dakota Group (AQ4) and the Broom Creek Formation of the Minnelusa Group (AQ3) (Figures 3-2 and 3-3). These stratigraphic horizons are regionally extensive and have demonstrated injectivity, competent confining layers, and high porosity and permeability. They are viable targets for geologic CO_2 storage and are shallow enough to minimize drilling and operating costs for BEST. In addition, these formations underlie nearly all major point sources of CO_2 emissions in the region, and they have an estimated combined storage capacity of between 20 billion and 70 billion tons of CO_2 (Glazewski and others, 2015; NATCARB, 2015), although recent (unpublished) estimations by the EERC suggest capacity may be two to five times greater.

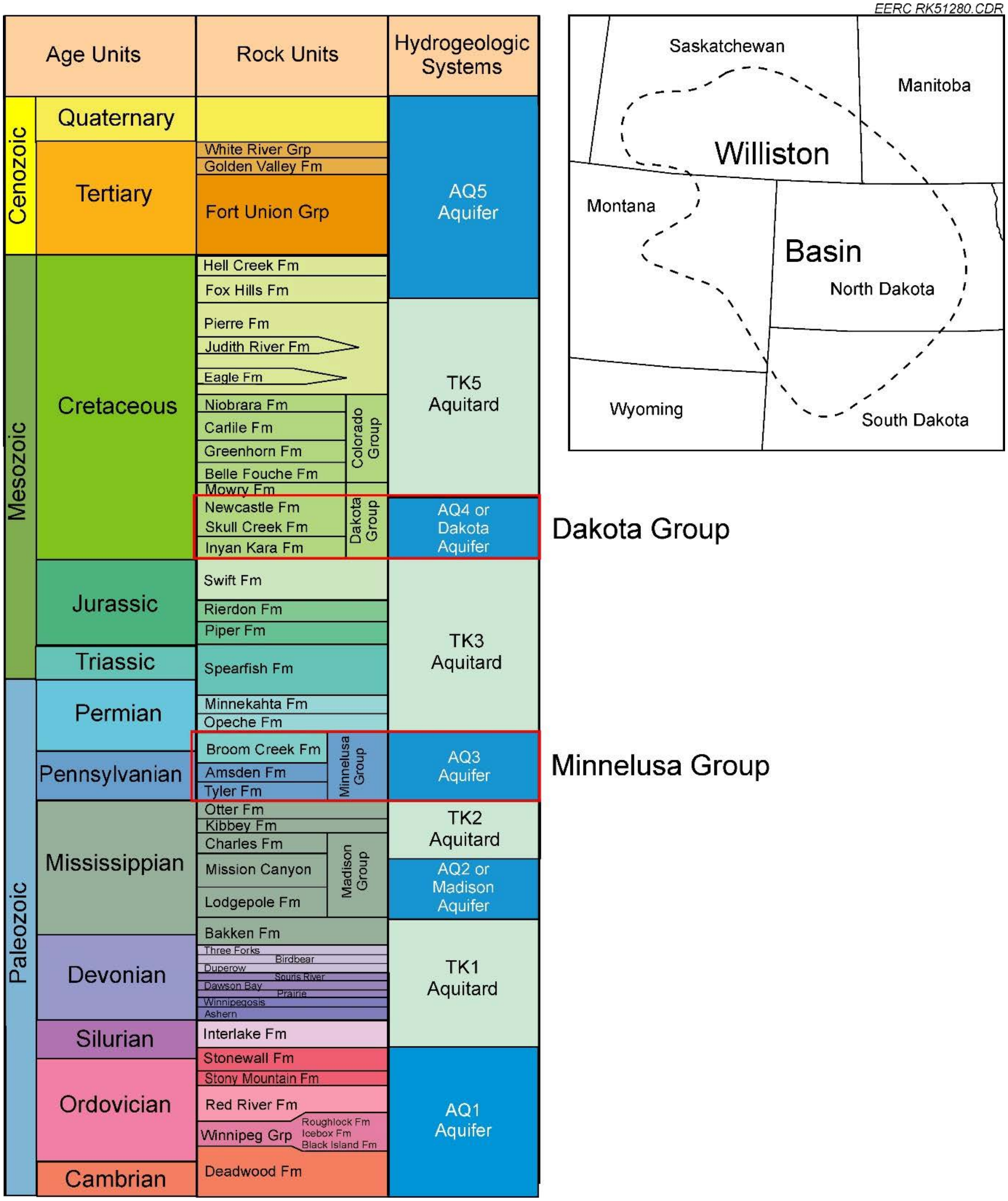


Figure 3-1. Williston Basin stratigraphic and hydrogeologic column (modified from Glazewski and others, 2015).

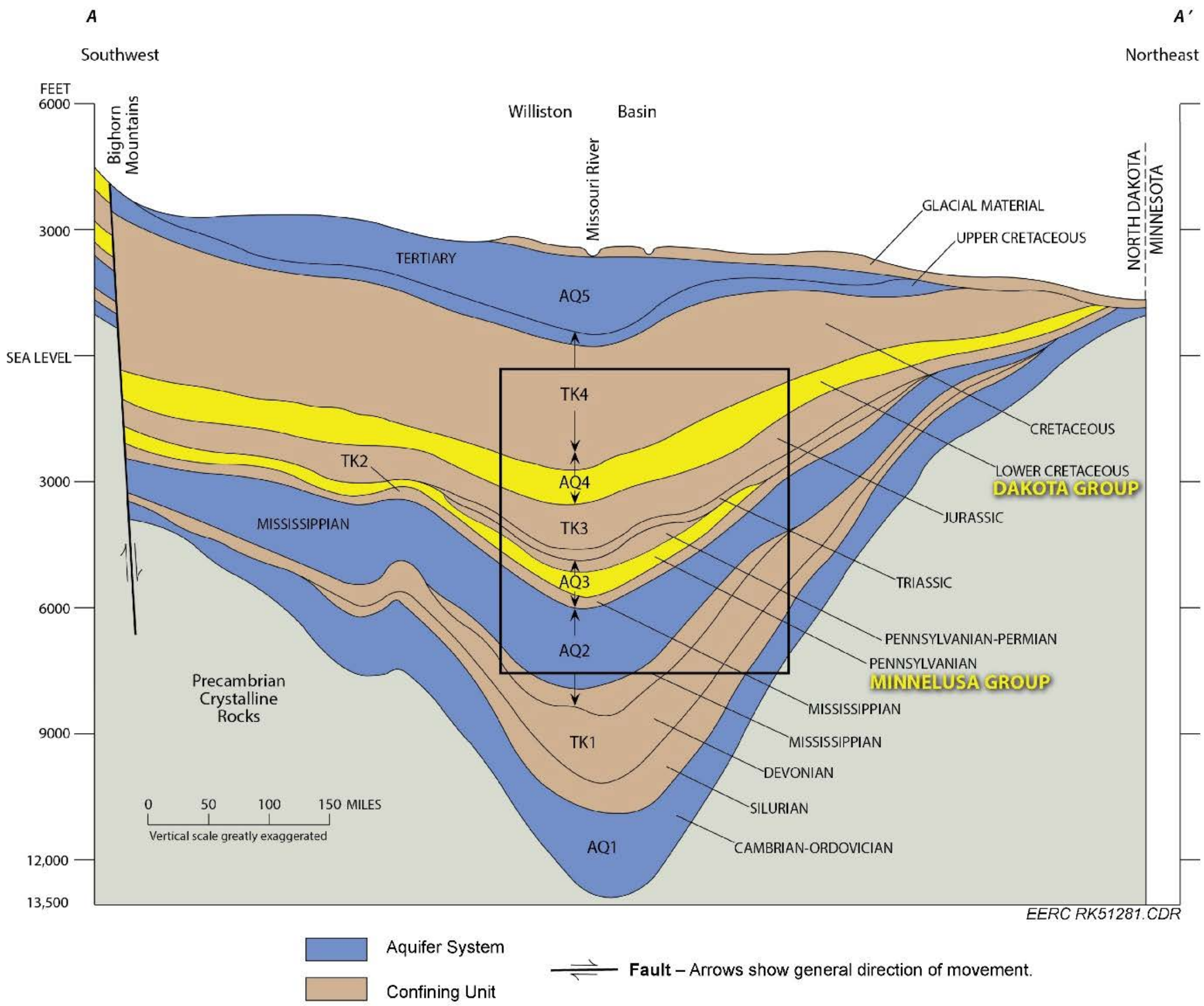


Figure 3-2. A cross section of the Williston Basin illustrating the five major aquifer systems. The Dakota and Minnelusa Groups are highlighted in yellow (modified from Downey and others, 1987). The portion of the basin evaluated is highlighted by the box.

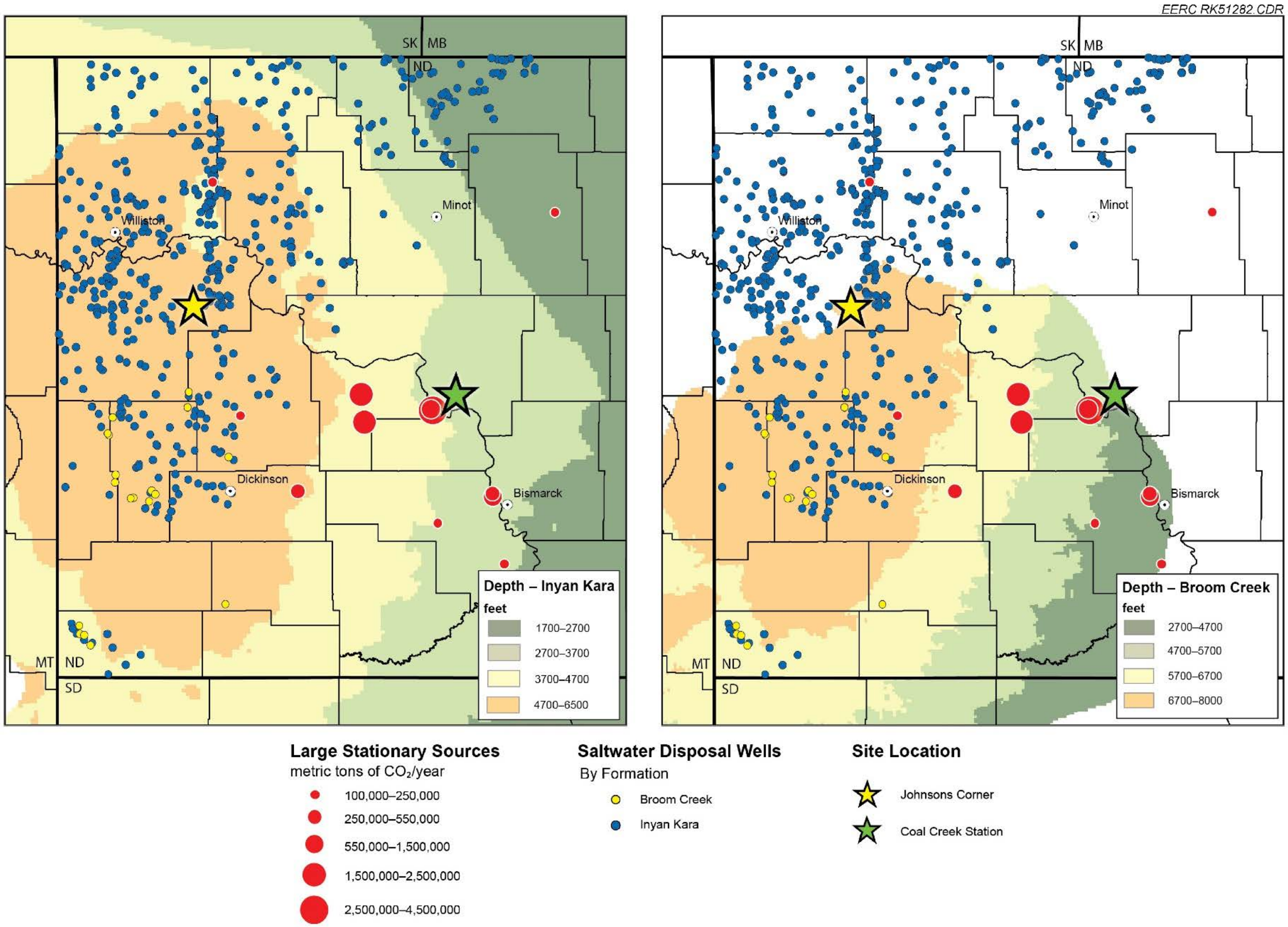


Figure 3-3. Regional extent of the Inyan Kara and Broom Creek Formations in relation to SWD wells and regional point sources of CO_2 emissions.

3.1 Inyan Kara Formation and Its Hydrogeology

The Inyan Kara Formation is a sequence of sandstones, mudstones, and shale representing the basal unit of the Lower Cretaceous Dakota Group of North Dakota (Figure 3-1) (Fischer, 2005b). The Inyan Kara Formation represents highly heterogeneous deposits of beach, barrier, estuarine, tidal, fluvio-deltaic, and shallow marine environments. Overlying the Dakota Group are several thousand feet of Cretaceous marine deposits, including nearly 1100 feet of shale in the Colorado Group, followed by 2300 feet of the Pierre Formation shale. The Jurassic Swift Formation underlies the Dakota Group and consists of up to 725 feet of shale with interbedded limestone. These low-permeability shales serve as effective vertical sealing units for the Inyan Kara Formation.

The surface of the Inyan Kara Formation in North Dakota follows the general structure of the Williston Basin (Figures 3-2–3-4). The depth of the Inyan Kara Formation ranges from nearly 6500 feet near the center of the basin on the western side of the state to approximately 300 feet near the eastern border of North Dakota. The Inyan Kara reaches maximum thickness of 500 feet near the Montana state line in McKenzie County (Figure 3-4) and pinches out near the eastern border of North Dakota. Analysis of Inyan Kara core samples indicates an average porosity of 20%. With respect to permeability, some areas of the Inyan Kara show permeability in excess of 1000 mD, supporting its use for BEST.

The natural hydrodynamic movement in the Inyan Kara Formation is generally from the southwest to northeast, with aquifer recharge occurring in the Black Hills of South Dakota (Figure 3-5). Regional flow rates in the Williston Basin are slow; estimated at less than 2 ft/yr (Downey, 1984). The native water of the Inyan Kara Formation ranges from brackish (1000 to 5000 mg/L TDS) to the south and east of the basin center to borderline saline (15,000 to 30,000 mg/L TDS) in the basin center and to the north into Saskatchewan (Figure 3-5). The Inyan Kara Formation is one of the primary horizons comprising AQ4 (Figure 3-1).

3.1.1 Parallels to CO_2 Storage

The Inyan Kara Formation is a regionally extensive DSF underlying nearly all of North Dakota and large portions of several other states (Sorensen and others, 2005; Sorensen and others, 2008) with geologic properties compatible with dense-phase CO_2 injection and storage. The Inyan Kara is widely used throughout western North Dakota for large-scale disposal injection of saltwater (Figure 3-3). According to the NDIC's UIC Class II well operations database, in 2014 approximately 198 million bbl of saltwater was injected into the Inyan Kara through 438 wells. On a volumetric basis (at reservoir conditions) this is greater than typical annual CO_2 emissions from all large stationary sources in the region (approximately 19 million tons of CO_2 in 2014) (Glazewski and others, 2015). This calculation implies that the Inyan Kara alone has been demonstrated, by way of SWD injection as a proxy, to be capable of supporting widespread large-scale injection of CO_2 such as might occur if CCS becomes broadly implemented. The 438 Inyan Kara SWD wells are scattered throughout 14 counties in western North Dakota. Those wells are often distributed as clusters but also often occur in relative isolation from other wells. Such a pattern of well distribution could be expected considering gradual adoption of wide-scale

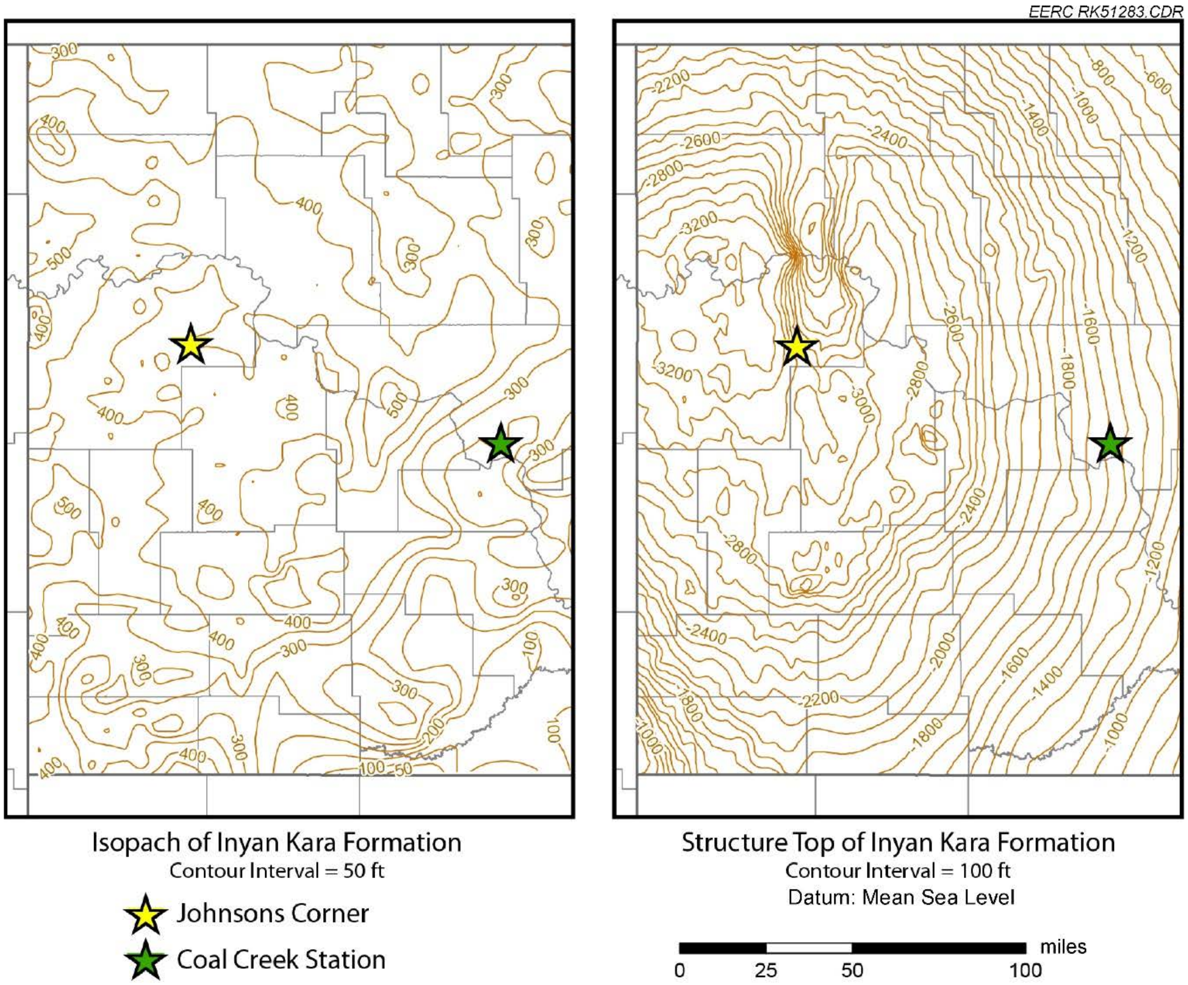


Figure 3-4. Left: isopach map of the Inyan Kara Formation in western North Dakota, contour interval = 50 feet (modified from LeFever, 2015). Isopach map shows the Inyan Kara is approximately 400 ft thick at both study sites. Right: structure contour map of the Inyan Kara Formation in western North Dakota, contour interval = 100 feet (modified from Anderson and Juenker, 2006).

CCS. Although the Inyan Kara is considered to be an open aquifer system, over time there will likely be regional pressure buildup and, ultimately, pressure interference between the injection wells as has been observed with SWD. Over extended time frames, application of ARM will be necessary to enable continued long-term operation of the injection sites. With that in mind, any ARM testing conducted in the Inyan Kara will serve as an ideal proxy for the use of ARM for CCS operations in regional DSFs. The lessons learned from ARM in the Inyan Kara will be broadly applicable to CCS operations in DSFs throughout the globe.

Based on Phase I simulation modeling, an estimated pressure differential of approximately 50 psi will be created by the proposed ARM program for conducting BEST in the Inyan Kara Formation at the Johnsons Corner site. It is important to consider that that a localized 50-psi

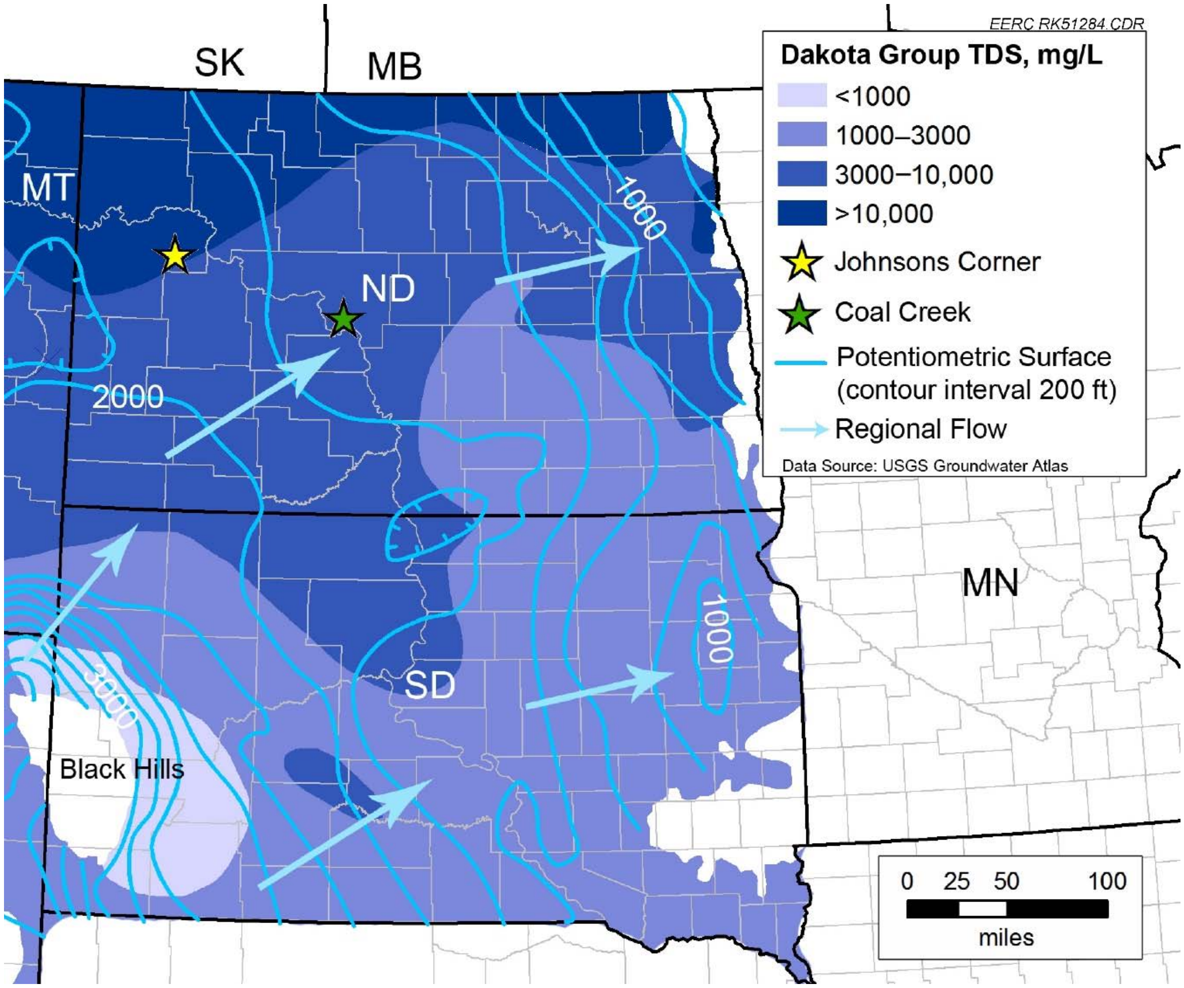


Figure 3-5. Potentiometric surface and TDS map of the Lower Cretaceous aquifers of the greater Williston Basin region, including the Inyan Kara Formation in North Dakota (adapted from Whitehead, 1996). Generalized regional flow from southwest to northeast is illustrated.

reduction in pressure brought about by the program will influence multiple square miles of the formation, such as would be the case in a large, high-permeability multiwell brine extraction operation supporting a commercial CCS project. The actual volume of incremental storage capacity that will be created from pressure reduction (even from a single extraction well), in many cases will be quite substantial. Furthermore, if additional extraction wells were to be developed in the area affected by the pressure reduction, the effectiveness of ARM would be further increased because of its additive effect on multiple wells.

While the precise amount of incremental storage capacity and reduction in AOR gained by a given reduction in pressure will vary considerably depending on the geologic conditions of any given formation, the ability to accurately measure, monitor, and predict such relatively small changes in pressure will be essential. These abilities will allow for cost-effectively operating ARM at CCS locations, improve storage capacity, and have far-reaching implications that will aid in making informed economic assessments regarding commercial implementation of CCS. As described above, the Inyan Kara is an excellent analogue for many DSFs that may be used for CCS, especially those that are open systems. As such, a demonstration of the ability to manage and accurately monitor changes in reservoir pressure of 50 psi or less will be broadly applicable to widespread deployment of CCS.

3.2 Broom Creek Formation and Its Hydrogeology

The Permian Broom Creek Formation comprises the upper portion of the Minnelusa Group (Figure 3-1) and consists of eolian and nearshore marine sandstone–carbonate cycles (Willis, 1959). In North Dakota, the extent of the Broom Creek Formation is restricted to the southwestern portion of the state (Figure 3-3) where it reaches a maximum thickness of 375 feet (Peck and others, 2014). Deposits of siltstone, mudstone, shale, salt, and anhydrite of the Opeche Formation overlie the Broom Creek Formation. The contact between the two formations can be seen in abrupt changes in resistivity and gamma ray (GR) logs from the porous Broom Creek sandstone to the basal Opeche salt (only present in some locations) or, more commonly, the basal Opeche siltstone.

The Broom Creek is part of the AQ3 Aquifer of the Williston Basin. A potentiometric surface map from Hoda (1977) shows a northeasterly flow direction with recharge occurring in the Black Hills. Salinity in the Broom Creek Formation ranges from fresh near the Black Hills to 325,730 mg/L TDS in McKenzie County, North Dakota (Hoda, 1977).

The Amsden Formation was included in the characterization and modeling efforts alongside the Broom Creek Formation to investigate potential for brine disposal. Results of these efforts indicated that the Broom Creek injectivity would be sufficient to accommodate the anticipated extraction volumes from the Inyan Kara. However, the characterization efforts of the Amsden indicated that it could serve to augment the injection capacity of the Broom Creek Formation if required.

It should be noted that the Amsden Formation was included in the characterization and modeling efforts alongside the Broom Creek Formation to investigate its additional potential for brine disposal. In the final analysis, it was determined that the Broom Creek has sufficient injectivity to accommodate the anticipated extraction volumes from the Inyan Kara. However, the characterization efforts of the Amsden indicated that it could serve to augment the injection capacity of the Broom Creek Formation if required.

4.0 SITE SELECTION

After screening and selection of the preferred formations to conduct BEST, operating partners with existing injection activities using these formations were sought by the EERC to host BEST. Experienced operators with established injection facilities were preferred as they possessed existing UIC permits for brine injection. Additionally, established injection sites possessed sufficient characterization and operating data to verify injectivity and were likely to have sufficient brine volumes on location to generate a differential pressure plume. Great River Energy (GRE) and Nuverra, each with a history of successful partnerships with the EERC, have established brine injection operations meeting these criteria.

Minnesota-based GRE operates the largest coal-fired power plant in North Dakota: Coal Creek Station. GRE recently installed a Class I disposal well on the property of Coal Creek Station, which is actively injecting into the Inyan Kara Formation for the purpose of disposing of wastewater from the facility. Reconnaissance-level modeling of the Coal Creek Station area was conducted to evaluate the potential to conduct BEST at this location. The results of site characterization and modeling indicated the presence of geologic properties that may be conducive to implementing BEST. However, the paucity of offset well data and the comparatively short injection history of the disposal well resulted in a relatively higher level of uncertainty at this site. Although the results of reconnaissance-level characterization in no way preclude implementation of BEST at this site, variability in ARM operational design parameters and associated costs of well installations were not ideal for the design and budgetary parameters of this project.

Nuverra is a national leader in brine handling, treatment, and injection with an extensive track record in providing environmentally compliant and sustainable energy solutions. Nuverra operates 18 North Dakota brine disposal sites, primarily targeting the Inyan Kara Formation. One of these sites, the Johnsons Corner site, was evaluated for its potential to serve as a host location. This location provides a documented pressure increase in the Inyan Kara resulting from two active SWD wells. The commercial SWD operation into multiple existing wells provides confirmation of injectivity, operational flexibility, and monitoring points for BEST. In addition, current brine injection operations at the Johnsons Corner site emulate commercial-scale CO_2 storage (volumetrically equivalent to >250,000 tons/yr CO_2). The 8-year injection history at this site coupled with significant offset well data also reduces uncertainty when ARM test design is considered. Nuverra partnered with the EERC to conduct pressure falloff testing on both existing wells to further reduce uncertainty in ARM design parameters. The ability to create tailored brine compositions through blending of extracted brine with other produced waters available on-site was determined to be a strong advantage for a brine treatment technology test bed facility. Based on reconnaissance-level screening, and the commercial scale of injection, the Johnsons Corner location was selected as an ideal site for conducting BEST.

4.1 Johnsons Corner Site

Upon selection of the Johnsons Corner site, a detailed site assessment was carried out to guide the development of this BEST implementation plan. The site is located in McKenzie County, North Dakota, in the E½ NW¼, Section 21, T150N, R96W, 5th principal meridian (longitude

102.975 W, latitude 47.801 N; Figure 4-1). The site is shared with industrial operations, including aggregate pit mining, clay pit mining, and disposal and recycling of concrete.

Nuverra operates two UIC Class II brine disposal wells, Rink SWD 1 and Rink SWD 2, on the eastern portion of the site (Figure 4-1). Rink SWD 1 and Rink SWD 2 are arranged in a roughly north–south alignment and are approximately 2000 feet apart. The two wells are completed into the Inyan Kara Formation, which has an estimated native salinity of 4500 to 6000 mg/L TDS. The state of North Dakota has an EPA aquifer exemption for injection of brines into the Inyan Kara Formation. According to the North Dakota Century Code (NDCC §43-02-05-03), the Inyan Kara Formation has been granted the status of an exempted aquifer in the western half of North Dakota, allowing for brine disposal. This exemption was granted because the Inyan Kara does not currently serve as a source of drinking water and is not expected to serve as a source of drinking water because of its depth and salinity concentration. Availability of high TDS brines also provides a

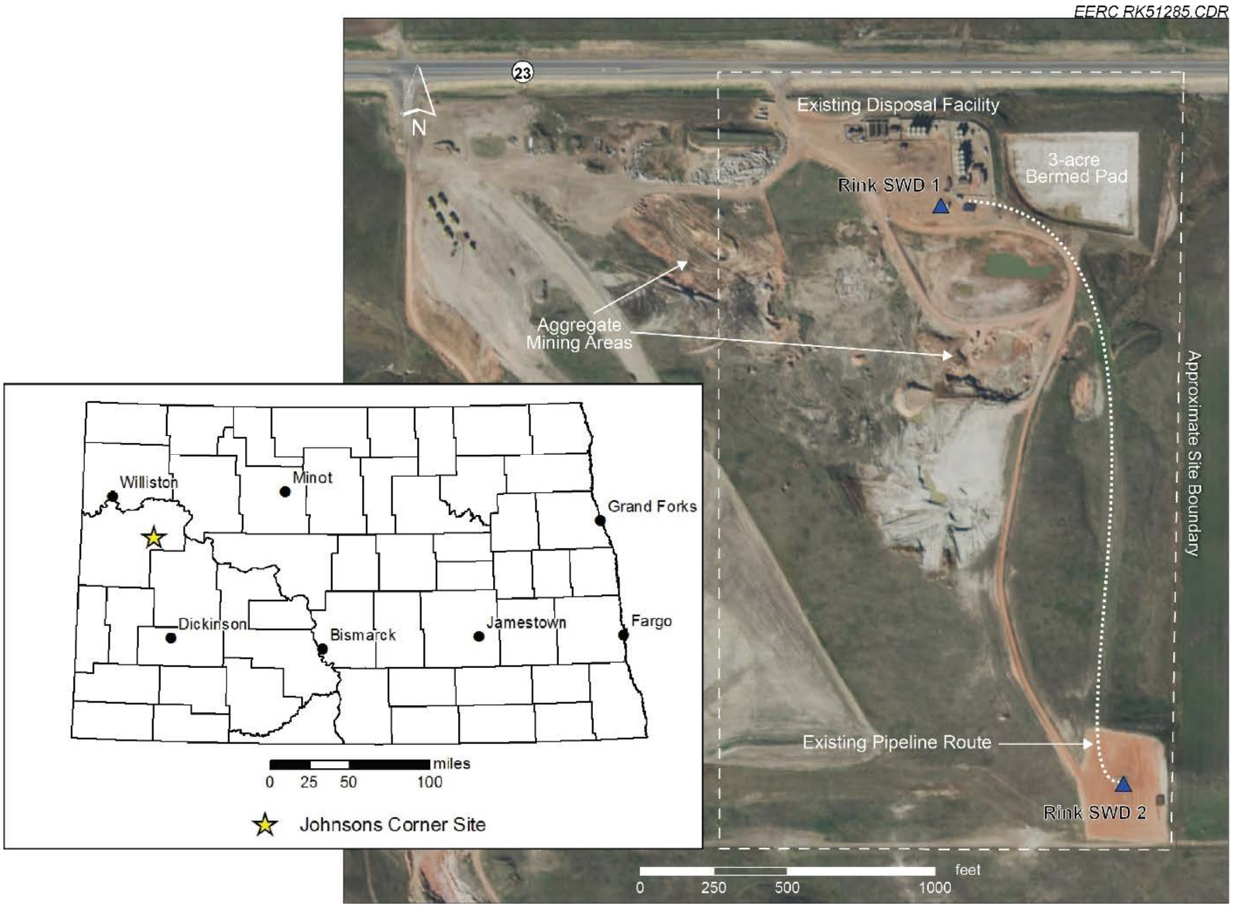


Figure 4-1. Aerial image of the Johnsons Corner site located in McKenzie County, North Dakota, highlighting the location of existing mining, lease roads, brine-handling facilities, pipeline, prepared pad for permitted extracted brine treatment facilities, and the existing Rink SWD 1 and Rink SWD 2 wells.

means to tailor the concentration of brines for water treatment technology demonstrations from 4500 mg/L TDS to >300,000 mg/L TDS (with a target of ~180,000 mg/L TDS).

The surface handling facilities at the Johnsons Corner site are rated to accept and process upward of 14,000 bbl/day of brine. The current average daily injection rate of the site is between 5000 and 7000 bbl/day, with water quality >300,000 mg/L TDS. The existing two-well infrastructure will enable operational flexibility to test a range of injection and extraction rates and schema for the proposed BEST.

Nuverra has an unoccupied 3-acre bermed pad located on the northeast corner of the Johnsons Corner site available for construction of a brine treatment facility. This pad is currently permitted and bonded for siting a brine treatment facility. Nuverra has agreed to allow the project access to this pad and provide or modify associated permits for conducting BEST.

The site is continuously operated and manned throughout the year. Nuverra is well versed with the operational challenges associated with brine injection. Nuverra also has experienced employees and a well-established network of contractors who are able to provide timely services, equipment, and repairs to the site as operational needs dictate. The site is ideally located immediately adjacent to North Dakota Highway 23 and approximately 15 miles from Watford City, North Dakota, which is home to many industry service providers as well as a wide variety of services and amenities necessary to conduct BEST, e.g. well service contractors, general construction contractors, hotels, and restaurants.

4.2 Rink SWD Wells

Rink SWD 1 has been operating since 2008, and Rink SWD 2 has been in operation since 2010. As of January 2016, the two wells have collectively injected over 13,000,000 bbl of brine into the Inyan Kara Formation at a depth of approximately 5200 feet below the surface (Table 4-1). Injected water typically has a salinity of >300,000 mg/L TDS. The EERC collected water samples for detailed chemical analysis (Table 4-2) to understand the character of the current injectate and predict the extent and salinity distribution of the current injection plume. It also provided a basis for the design of the water treatment technology test bed.

Nuverra provided the EERC with detailed specifications on the installation, modification, and injection history of the Rink SWD wells. Additionally, as part of Phase I efforts, Nuverra conducted pressure falloff on behalf of the EERC. This has allowed the EERC to calibrate and history-match geologic and simulation models to better predict the existing brine salinity and pressure distribution in the Inyan Kara Formation as part of its Phase I efforts.

Table 4-1. Attributes of Nuverra-Operated Injection Wells on the Johnsons Corner Site

Name	Rink SWD 1	Rink SWD 2
North Dakota Industrial Commission (NDIC) File Number	90123	90134
American Petroleum Institute (API) Number	33-053-90123-00-00	33-053-90134-00-00
UIC Number	A0272S0612D	A0272S0640D
Total Depth (TD), feet	5830	5818
Injection Start Date	November 2008	September 2010
Cumulative Saltwater Injected Through January 2016 (bbl)	7,474,416	5,881,270

Table 4-2. Detailed Chemical Analysis of Representative Injectate Water Sample

Sample	Parameter	Result, mg/L
53809-01	Produced water (1/21/16)	
	Alkalinity, as bicarbonate (HCO_3^-)	272
	Alkalinity, as carbonate ($CO_3^{=}$)	0
	Alkalinity, as hydroxide (OH^-)	0
	Alkalinity, total as $CaCO_3$	223
	Bromide	1080
	Calcium	22,800
	Chemical oxygen demand	13,000
	Chloride	200,000
	Magnesium	1420
	pH	5.71
	Potassium	9030
	Sodium	92,600
	Strontium	1830
	Sulfate	200
	TDS	335,000
	Total organic carbon	305

5.0 SITE CHARACTERIZATION AND GEOLOGIC MODELING

5.1 Introduction

The objectives of the site characterization and geologic modeling effort were to build a robust platform from which to test and evaluate the effectiveness of various operational ARM schema. Detailed regional and site-specific geologic property characterization of the primary formations related to injection and extraction of brine fluids in the study region was conducted. This characterization effort provided a geocellular structural framework and sound basis for distribution of site-specific geologic properties within that framework.

The geocellular model of the Johnsons Corner site encompasses a 6-mile by 6-mile (36-square-mile) area centered on the Rink SWD 1 and Rink SWD 2 wells (NDIC Well Numbers 90123 and 90134, respectively) (Figure 5-1). The model developed in this work was constructed with predominantly publicly available data, much of them available from NDIC, including well logs, formation top depths, core sample descriptions and analyses, completion and perforation data, injected volumes, and pressure measurements.

5.2 Structural Model

The modeling efforts focused on the Inyan Kara and Broom Creek Formations. Depth and thickness ranges of the formations of interest within the modeling extent are shown in Table 5-1.

The structural framework for the Johnsons Corner geocellular model was built in Schlumberger's Petrel E&P software platform using well logs from NDIC. Formation tops of the Inyan Kara and underlying Swift Formations were picked from the available GR logs with the aid of resistivity logs where available using conventions described in Wartman (1983), Murphy and others (2009), and Bader (2015). The Inyan Kara Formation was further subdivided into three zones (representing three main fining upward sequences) to help constrain the facies distribution within the model area (Figure 5-2). Relevant formation tops, including that of the Broom Creek, Amsden, and Tyler Formations were picked from GR logs (Figure 5-3) as described in Sorensen and others (2009) and Murphy and others (2009). The resulting modeled structural surfaces and isopachs are shown in Appendix A.1.

It should be noted that the Amsden Formation was included in the characterization and modeling efforts alongside the Broom Creek Formation to investigate its additional potential for brine disposal. In the final analysis, it was determined that the Broom Creek has sufficient injectivity to accommodate the anticipated extraction volumes from the Inyan Kara. However, the characterization efforts of the Amsden indicated that it could serve to augment the injection capacity of the Broom Creek Formation if required.

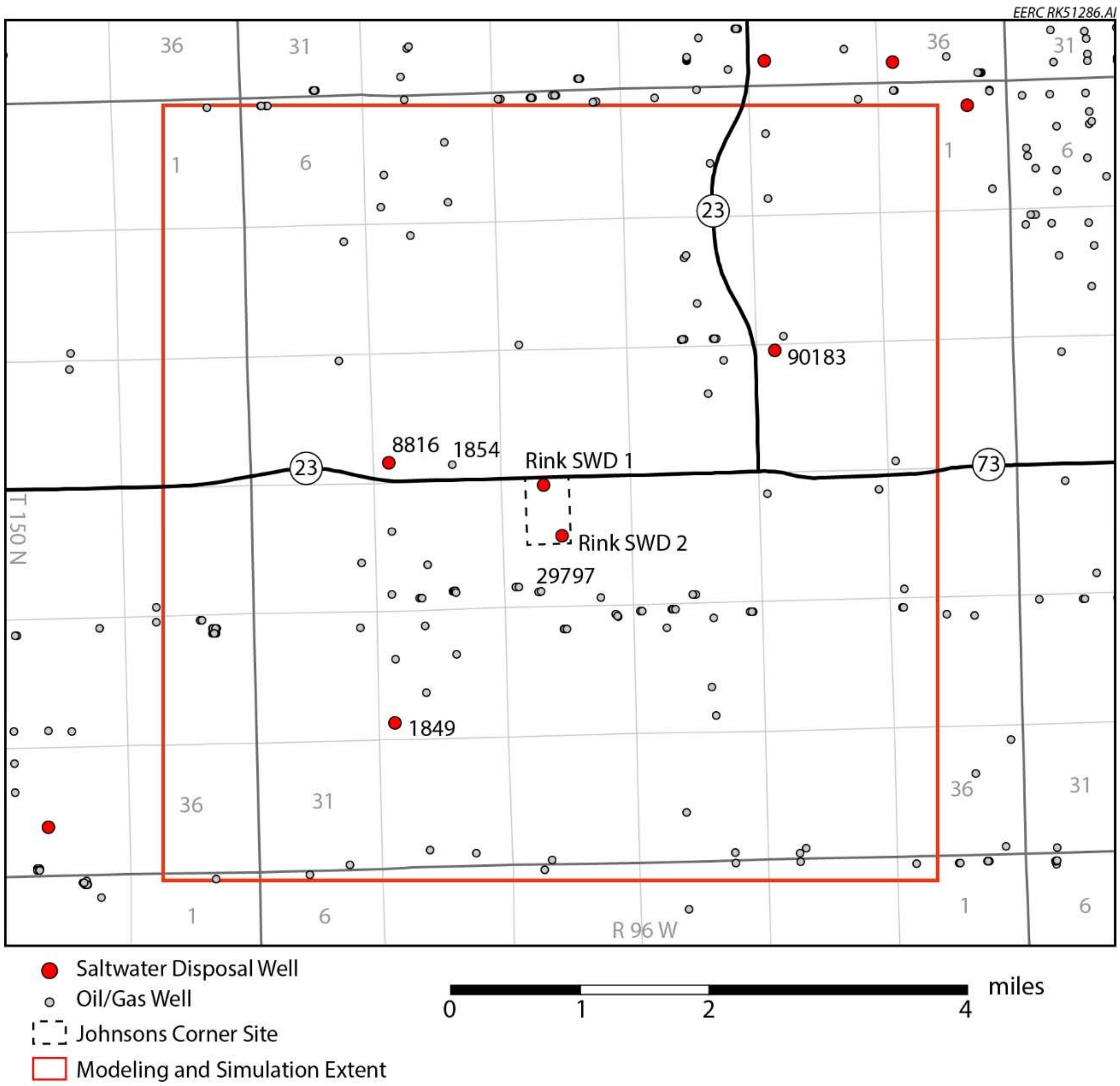


Figure 5-1. Map view of the Johnsons Corner model area. The model efforts focused on a 6-mile by 6-mile (36-mi^2) area, delineated by the red rectangle.

Table 5-1. Depth and Thickness Ranges for Formations of Interest

Formation	Depth, ft	Thickness, ft	Average Thickness, ft
Inyan Kara	4927–5359	338–475	390
Broom Creek	7248–7630	46–113	76

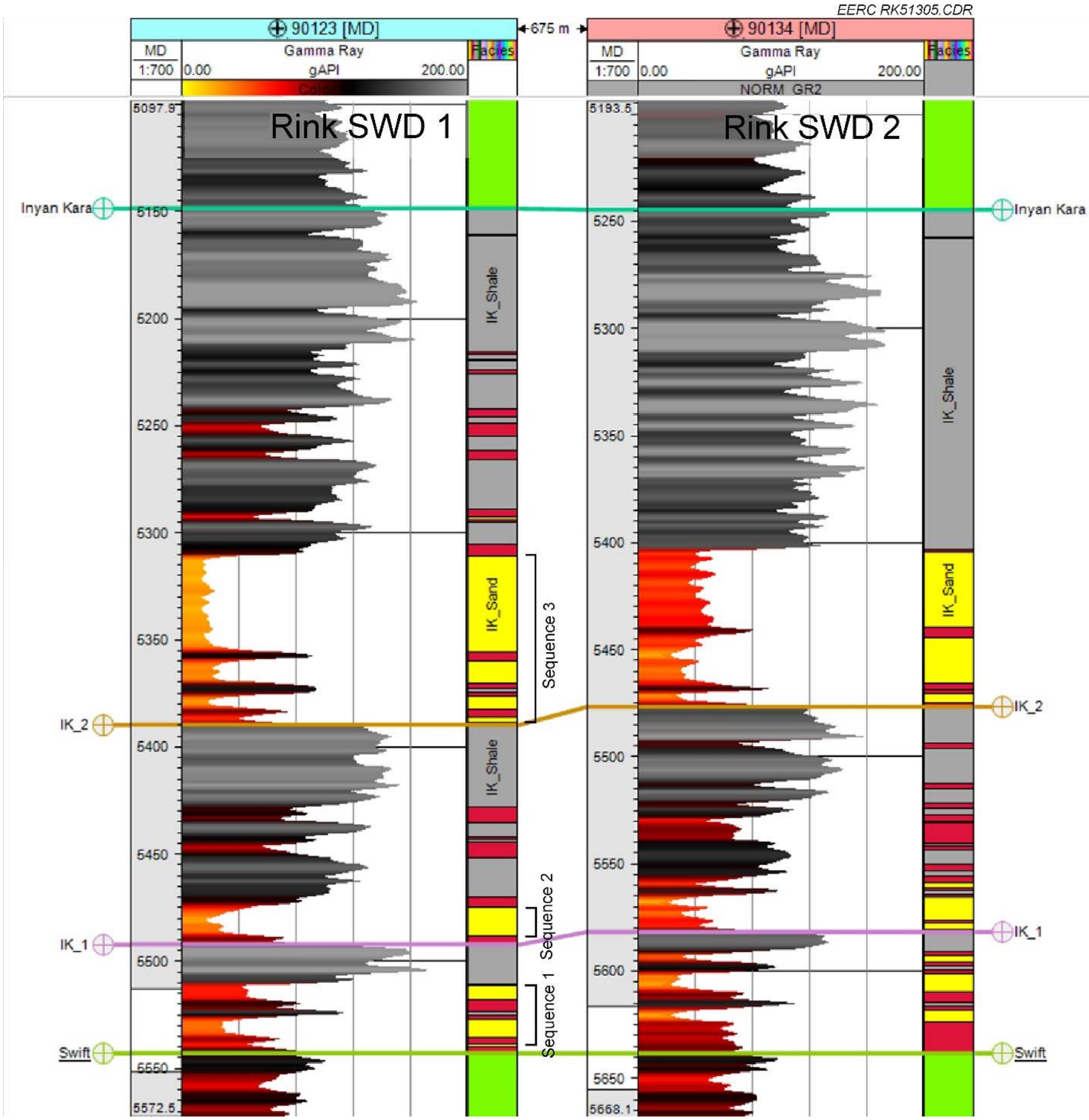


Figure 5-2. Correlation of injection wells Rink SWD 1 (left) and Rink SWD 2 (right). Curves shown for each well are GR and a facies log. The Inyan Kara Formation is split into three fining upward sequences.

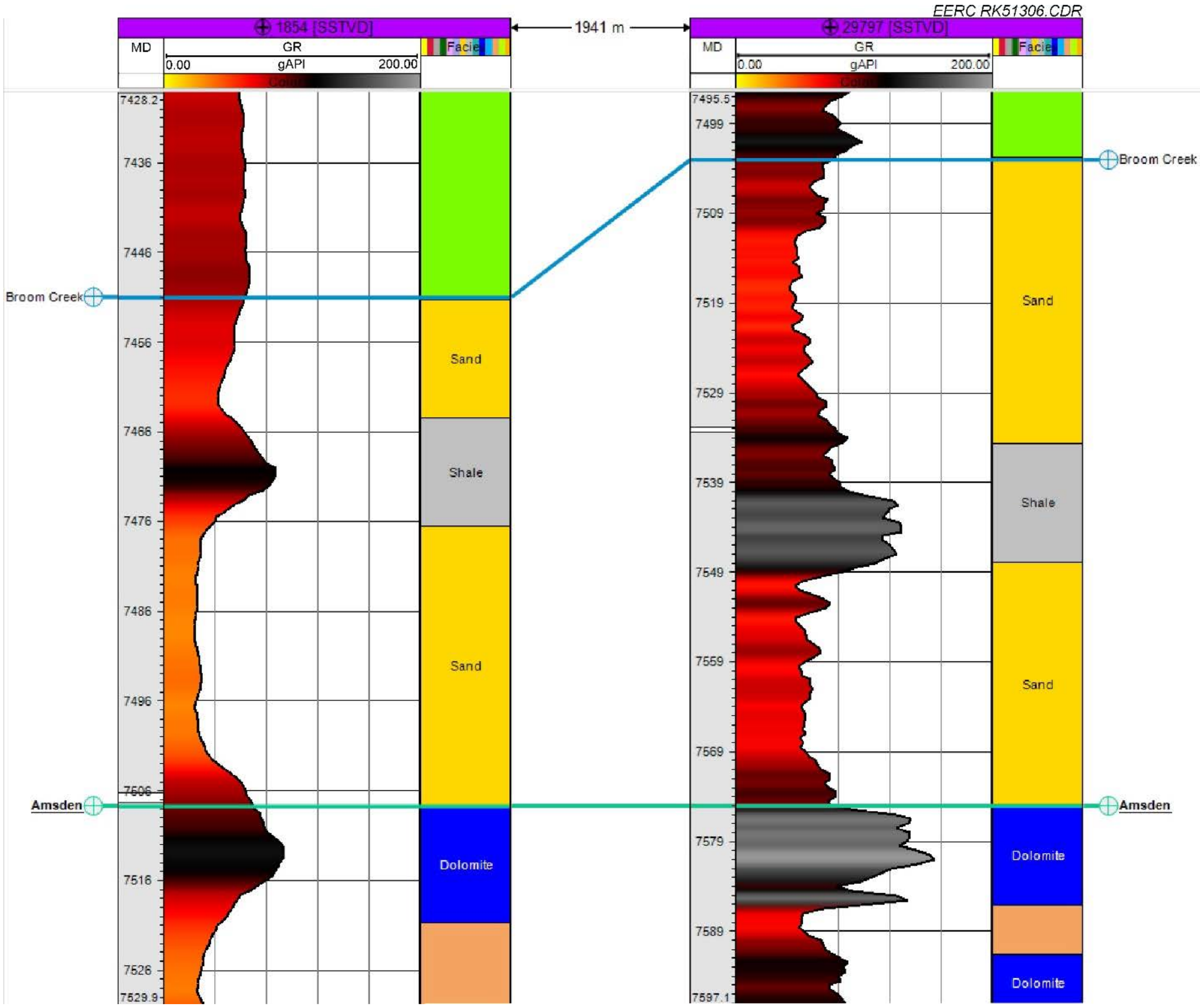


Figure 5-3. Correlation of wells 1854 (left) and 29797 (right), which are in close proximity to the Rink SWD wells (90123 and 90134). Curves shown are GR (left) and a facies log (right).

A structural grid was created by populating the study area with 164-ft × 164-ft cells. The grid was divided vertically into 81 layers encompassing the Inyan Kara Formation (top 40 layers), the combined Broom Creek and Amsden Formations (bottom 40 layers), and the interburden between the Inyan Kara and Broom Creek Formations (one layer). This approach resulted in an average layer thickness of approximately 10 ft, with the exception of the interburden layer which was much thicker (approximately 2000 ft). Using this configuration resulted in the structural grid containing nearly 3 million cells.

In addition to the two Johnsons Corner injection wells, the locations and completion details of three other saltwater injection wells were included in the model (NDIC Wells 1849, 8816, and 90183). Together the five wells were used in the subsequent history-matching process to understand local and regional pressure buildup resulting from water injection.

5.3 Facies Modeling

5.3.1 Inyan Kara Formation

The Inyan Kara Formation consists of heterogeneous clastic sequences deposited in several different environments which must be accounted for when facies distributions are assigned within the model. Examination of well logs and associated analysis of geologic core samples verified that normalized GR logs were able to provide reliable facies interpretations. This led to the separation of the formation into three basic facies: clean sand, silty sand, and shale. Geophysical well logs from 39 wells within the model area were selected to distribute these facies based on the log suite available for each of those wells.

Because of the heterogeneous nature of the Inyan Kara Formation, facies were distributed within the structural grid using multiple-point statistics (MPS). An in-depth discussion of the MPS method for distributing facies is not included in this report; however, more detail on this method may be found in a multitude of other publications, including Journel and Alabert (1989), Deutsch (1992), Strebelle and Journel (2002), Caers and Zhang (2004), Pyrcz and others (2008), Klenner and others (2014), and Bosshart and others (2015). The resulting Inyan Kara Formation facies model, constructed with conditioning to the 39 control wells, is shown in Figure 5-4.

5.3.2 Broom Creek Formation

In the Johnsons Corner area, the Broom Creek Formation is predominantly a sandstone reservoir with two discontinuous, interbedded shale layers (Peck and others, 2014). The upper shale layer, present in the northeast to central area of the model area, has a maximum thickness of approximately 16 ft. The lower shale layer is present throughout much of the model area but pinches out in the central portion and to the east. The maximum thickness for this layer is 30 ft. Top and bottom structural surfaces were created for each shale unit and used to constrain shale facies distribution. All other cells within the Broom Creek Formation were given properties of a sandstone facies; Figure 5-5.

5.4 Petrophysical Modeling

The core-based petrophysical properties of porosity and permeability were distributed in the geocellular model using a variogram-based geostatistical method with conditioning to the previously developed facies model. The variogram parameters used for these distributions were adapted from generalized variogram ranges of differing depositional environments as described in Deutsch (2008) and also discussed in Appendix A.1. Mean, minimum, maximum, and standard deviations were calculated from core sample measurements of porosity and used to guide the model’s porosity distribution. The porosity–permeability crossplots developed from the geologic core sample measurements and used in these efforts can be found in Appendix A.1.

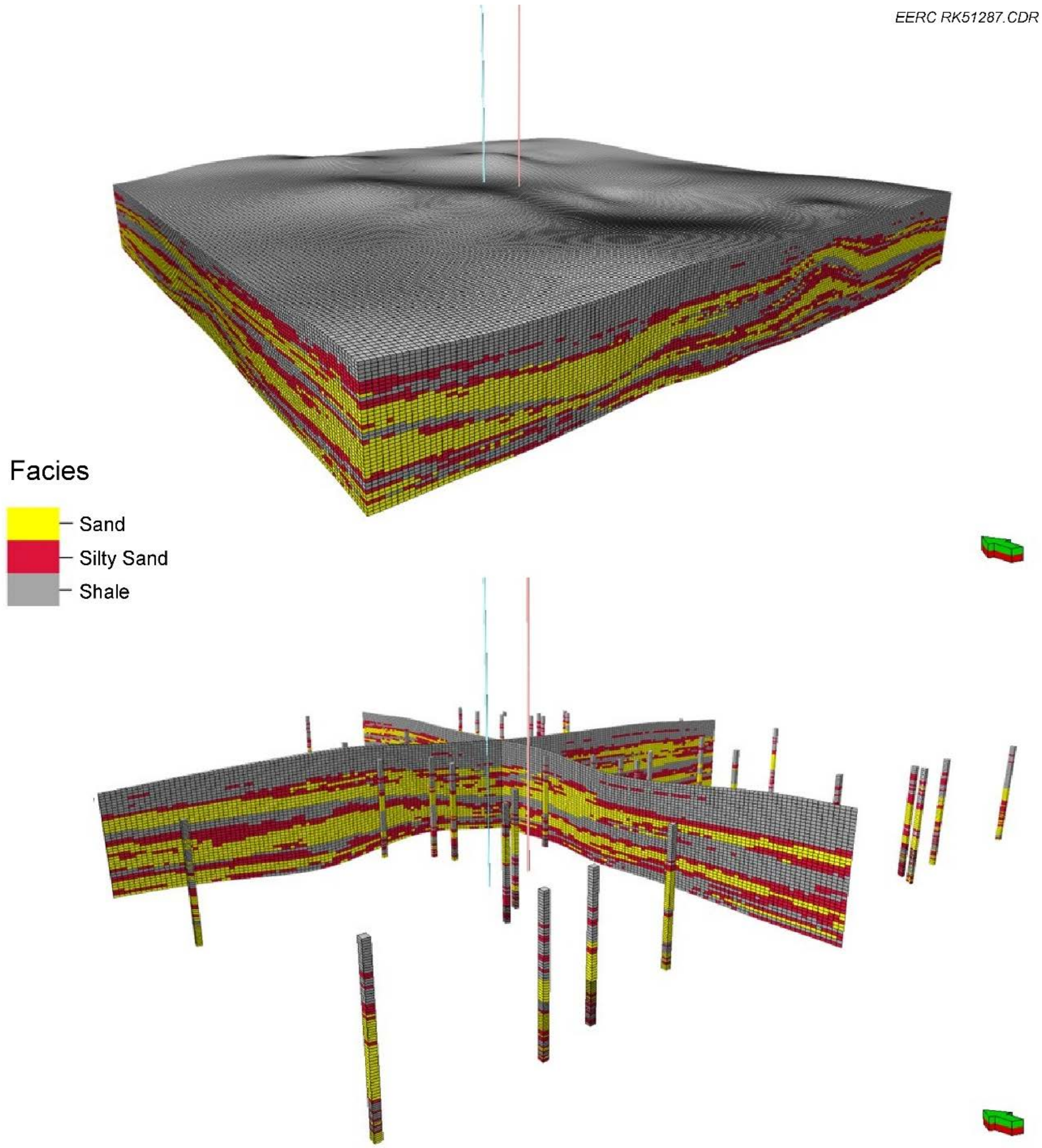


Figure 5-4. Facies distribution in the Inyan Kara Formation model. Top image illustrates the full Inyan Kara Formation model. Bottom image shows cross sections running through Rink SWD 2 in the north–south direction and Rink SWD 1 in the east–west direction, as well as the interspersed control points used to guide the MPS distribution, vertical exaggeration = 10×.

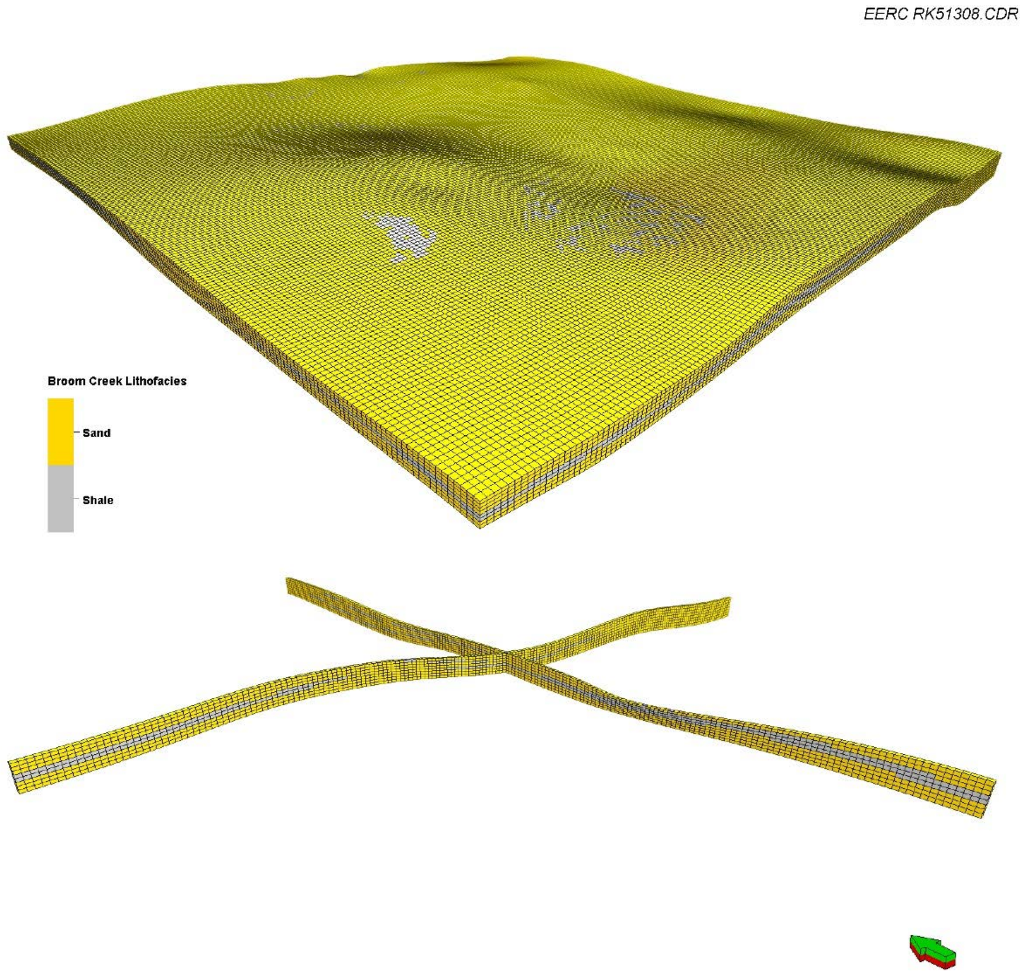


Figure 5-5. Facies distribution of the Broom Creek Formation portion of the model. The images illustrate the same full formation model view (top) and cross-section lines (bottom) as illustrated in Figure 5-4. Note that neither of the Rink SWD wells penetrates the Broom Creek, vertical exaggeration = 10×.

5.4.1 Porosity

Porosity in the model ranged from a low of 1% to a high of 40%. The Inyan Kara Formation clean sand facies mean porosity and standard deviation (calculated from core measurements) were 28% and 5.3%, respectively, while the silty sand facies mean porosity was 13% with a standard deviation of 3.5%. The shale facies effective porosity was distributed bivariately with measured depth, resulting in values ranging from 1% to 7%. The modeled Inyan Kara petrophysical properties are shown in Figure 5-6.

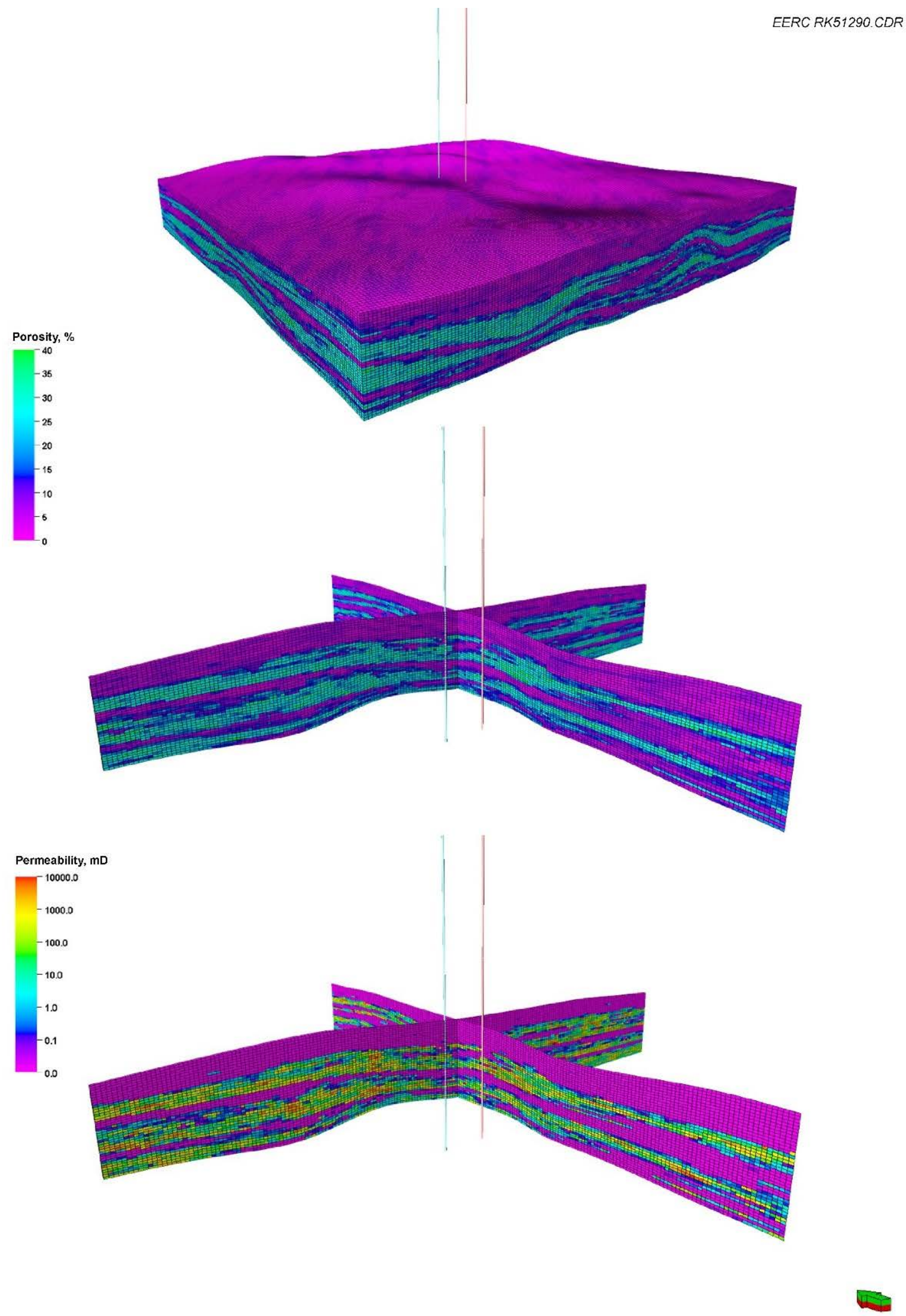


Figure 5-6. Inyan Kara Formation porosity (top) and cross sections displaying porosity (middle) and permeability (bottom). Cross sections through the model show the petrophysical properties at the two primary injection wells. The north–south trending cross section intersects Rink SWD 2 and the east–west trending cross section intersects Rink SWD 1, vertical exaggeration = 10×.

Based on core measurements and porosity logs developed in previous modeling efforts at the EERC (Sorensen and others, 2009), porosity within the sand facies of the Broom Creek Formation ranged from 3% to 30% with a mean of 15.9% and a standard deviation of 3.2%. The shale facies porosity was distributed bivariately with measured depth, resulting in values ranging from 1% to 4%. Overall Broom Creek porosity ranged from 1% to 30% with an average of 13%.

5.4.2 Permeability

Permeability in the Inyan Kara Formation clean sand and silty sand facies ranged from a low of 0.01 to a high of 1.0×10^4 mD as both extremes were reported in core sample measurements,. Permeability was distributed from a bivariate relationship derived from a porosity–permeability crossplot (constructed from core sample measurements) for the clean sand and silty sand facies and with a generic shale porosity–permeability crossplot for the shale facies. The permeability range for the shale facies ranged from 1.0×10^{-6} to 0.1 mD.

There were a limited number of core-measured permeability values for the Broom Creek Formation. These data were used to establish an upper bound of 370 mD for the Broom Creek in an effort to avoid overestimating permeability (and consequently the injectivity of the formation). Permeability was distributed using a bivariate relationship derived from the Broom Creek porosity–permeability crossplot for sand facies and with a generic shale porosity–permeability crossplot for the shale facies (Appendix A.1). The range for permeability in the Broom Creek sand facies was 35 to 370 mD with an arithmetic mean of 147 mD. Permeability in the shale facies ranged from 1.0×10^{-6} to 0.1 mD.

Future data collected in BEST Phase II from within the Broom Creek Formation, as proposed in the following sections of this Field Implementation Plan, will be key in reducing uncertainty regarding the injectivity of the Broom Creek. If injectivity into the Broom Creek Formation proves to be higher than simulated, additional operational flexibility will be gained, as increased extraction rates from the Inyan Kara Formation will be possible. These increased rates will directly increase the project's capacity to modify the existing brine and pressure plumes.

5.5 Other Reservoir Properties

Temperature and pressure are additional properties that were created in the model to aid in the simulation of injection and extraction of brine. A temperature gradient of 0.018°F/ft was derived for the Inyan Kara Formation from an average surface temperature of 42°F and formation temperatures at depth, according to the U.S. Geological Survey's National Produced Water Geochemical Database (Blondes and others, 2014). The resulting Inyan Kara temperature ranged from 131° to 144°F. Similar efforts resulted in temperatures ranging from 173° to 180°F in the Broom Creek.

A pressure gradient of 0.433 psi/ft was used to distribute the pressure property through the formation. The resulting formation pressure ranged from 2169 to 2487 psi. A pressure gradient for the Broom Creek Formation was calculated to be 0.451 psi/ft from drill stem test data. This gradient corresponds to formation pressures between 3305 and 3485 psi in the Broom Creek.

5.6 Deterministic Geologic Modeling

In order to expedite the results of dynamic modeling required for the development of the operational design package for ARM, static modeling efforts were consolidated in the construction of one focused geologic realization which is described in this report. This realization was later validated through a robust history-matching analysis discussed in the next chapter.

Geologic core data available for all formations of interest in this project (Inyan Kara and Broom Creek Formations) were limited, increasing the uncertainty present in the interpretations of petrophysical property distributions for the modeling effort. Current site operations demonstrate more than adequate injection and extraction capability in the Inyan Kara Formation. In order to avoid the potential of overestimating the injectivity of the Broom Creek Formation, a conservative approach was taken with respect to interpreting the available data. Injectivity of the Broom Creek Formation is a key ARM design parameter. Extraction rates from the Inyan Kara Formation will be constrained by injection rates into the Broom Creek Formation. The use of this conservative interpretation in the numerical simulation resulted in injection rates that are more than adequate to achieve the goals for this project. If the injectivity of the Broom Creek Formation has, in fact, been underestimated, it means the project will have greater operational flexibility.

The Inyan Kara Formation is a highly heterogeneous sequence of fluvio–deltaic and marginal marine deposits. This heterogeneity could introduce compartmentalization effects in unexpected areas. However, from the history-matching efforts of legacy wells (active from 1961 up to the present) in proximity to the Johnsons Corner site, there appears to be no lack of communication in key regions of the area of interest. This further supports the suitability of this site for ARM operations.

6.0 RESERVOIR SIMULATION

Reservoir simulation was carried out using CMG's GEM reservoir simulation software on the Johnsons Corner model in three distinct steps. First, history matching of existing injection data for the site and the surrounding area was performed to account for the historic and current operation of brine disposal wells. This process provided the opportunity to adjust the reservoir description within the model to coincide with actual performance, resulting in a model with the ability to confidently predict reservoir behavior, thereby increasing confidence in the ability to execute the Phase II project according to plan. Second, a series of simulations were executed to test potential extraction well locations for suitability when compared to a list of project constraints. Third, a series of injection and extraction scenarios were performed to gauge performance of the Phase II project wells under a variety of conditions.

When the Phase I project team was satisfied that a robust subsurface representation was created and the extraction well location was determined, an indicative field scenario was created and tested in the history-matched model. This scenario is described in detail in the ARM Operations section of the report.

6.1 History Matching

Because of the high level of detail and the fine grid cell size of the geologic model, it was necessary to upscale the model to a computationally efficient size while maintaining a suitable level of geologic detail and resolution for simulation of the well and interwell behavior. The total number of active cells that describe the Inyan Kara Formation where history matching is conducted was reduced from 3,000,000 to 630,000. A grid cell size of 165 ft was retained over the primary investigation area as shown in Figure 6-1.

The simulation model assumed open boundary conditions, which allowed lateral water flux through simulation boundary without pressure buildup. This is representative of the Inyan Kara Formation throughout the region, which is widely used as a SWD zone. These conditions are comparable to future basin-scale CO_2 disposal scenarios where multiple simultaneous CO_2 storage projects are envisioned to operate within the same formation.

The reported average monthly injection rates were used as model input. Since BHP data are not available for these wells, average monthly wellhead pressure (WHP) was matched. The history match was primarily achieved by applying a global permeability reduction of 20% over the entire model, with smaller localized reductions around individual wells. The history-matching process also incorporated well workover events and adjustments made in skin factor, tubing size, and tubing roughness. The history-matching result is shown in Figure 6-2, and as can been seen, a reasonable history match was achieved at each well. This adds a considerable degree of confidence that the site will perform as anticipated. Additional details describing the history-match work can be found in Appendix A.2, including discussion regarding the simulated size and shape of the existing brine plume and the associated pressure plume.

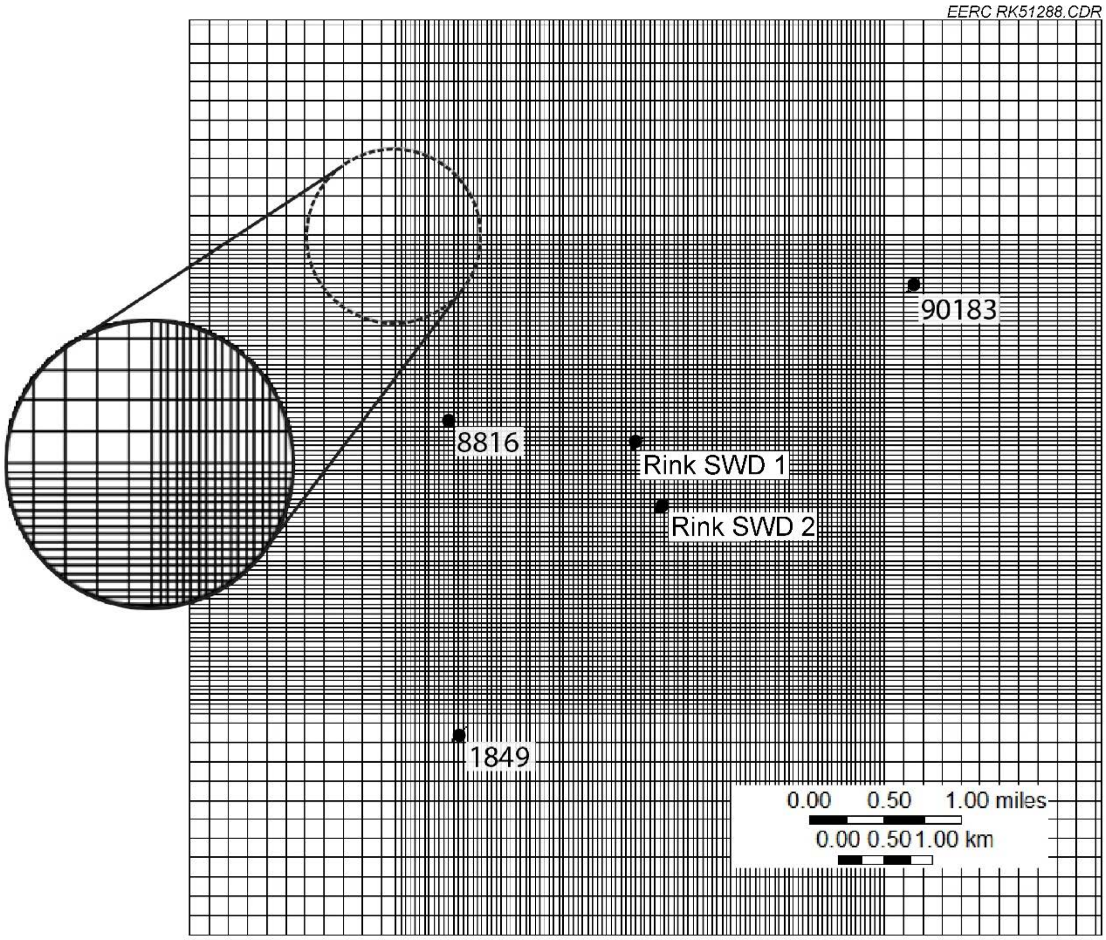


Figure 6-1. The uniform-tartan grid system configuration of the reservoir simulation model (6-mile by 6-mile area). The primary investigation area is represented by the fine uniform interior gridding.

6.2 Well Location Simulations

Several simulations were executed to select effective locations for the BEST-E1 and -I1 wells when compared to five competing constraints:

1. Suitable surface location
2. Clear pressure response in the injection wells
3. Avoiding high salinity in extraction water
4. Minimizing extraction ratio
5. Ability to dispose of extraction water

Each of these constraints and their relevance to the ARM activities are discussed below.

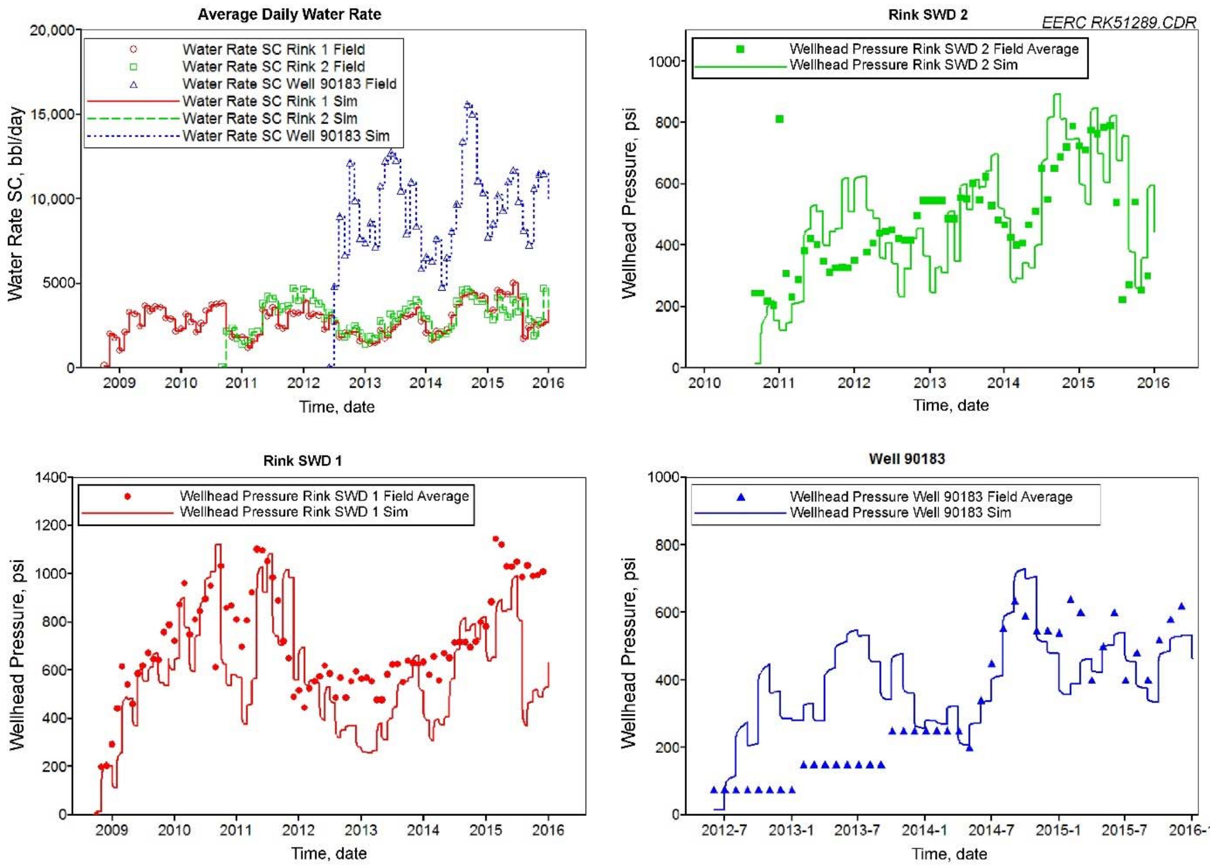


Figure 6-2. Wellhead pressure history match of Rink SWD 1 and Rink SWD 2 capture the operating trends of their injection and operating histories. Reported WHP data may be imprecise, as suggested by the early pressure history of the offset Well No. 90183.

6.2.1 Suitable Surface Location

As noted earlier, there are ongoing commercial operations at the project site. This includes not only the Nuverra brine disposal facilities but also surface mining of aggregate materials and a materials recycling facility. These active areas cannot be interfered with, limiting the options for wellsite selection. The remaining area within the project site offers options for well locations, including those areas that have already been prepared for development but are unoccupied or have been reclaimed after the conclusion of mining operations (Figure 6-3).

6.2.2 Clear Pressure Response in the Injector Wells

The project target extraction horizon is characterized by high permeability; therefore, a rapid pressure response at the injection wells is expected and the distances between the project wells are not a concern from that perspective. However, the high permeability also implies relatively low pressure gradients through the project area. The pressure response at the injection wells is thus expected to be relatively small, in the range of 20 to 50 psi. High-accuracy BHP gauges will be

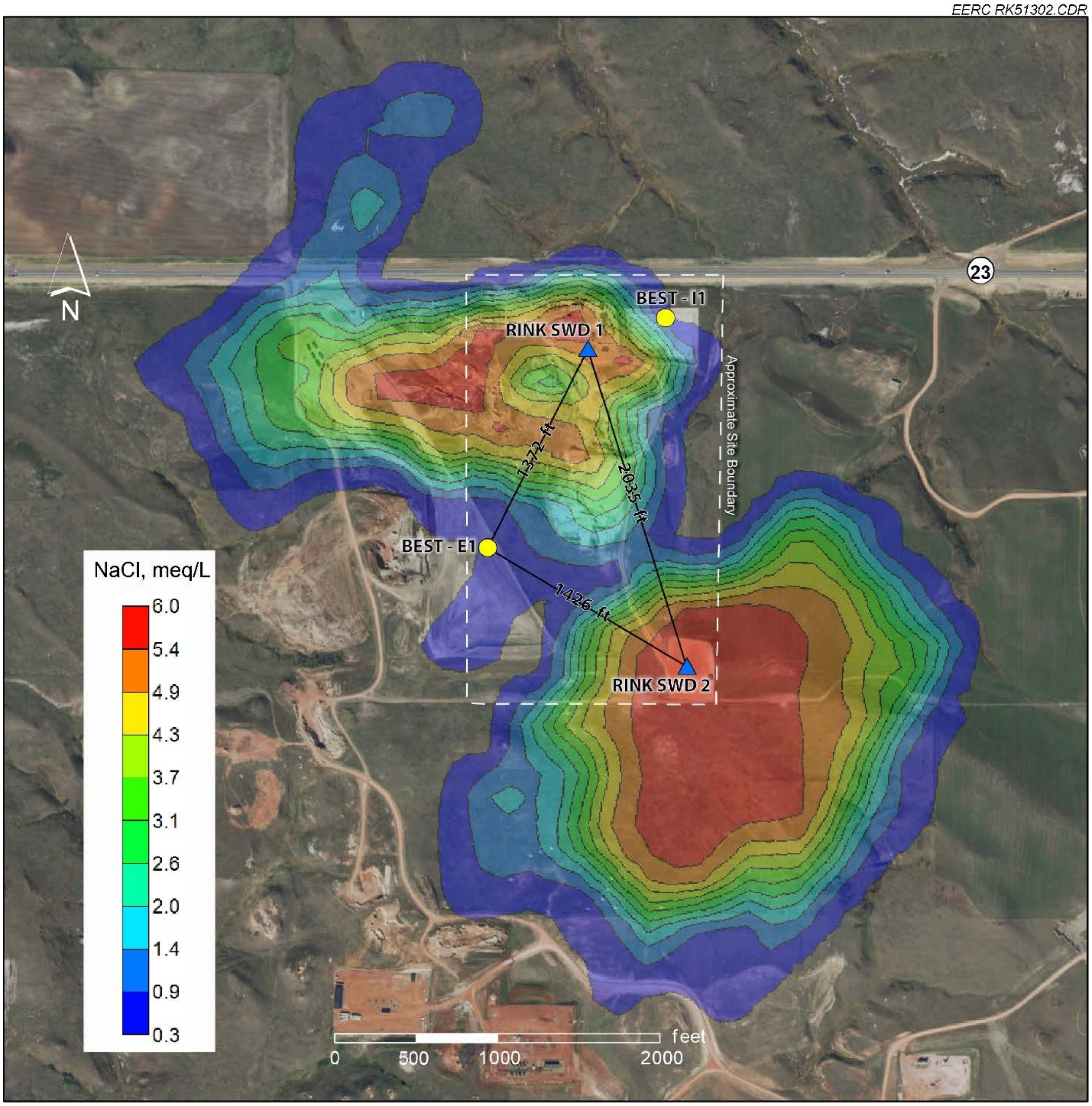


Figure 6-3. Distribution of the salinity plume on 1 April 2017 (as determined by simulation, within the Inyan Kara Formation superimposed over a site map). Proposed project wells are identified.

used throughout the project and should record these pressure responses without difficulty. Pressure response is a function of extraction rate, and extraction will generally be performed at as high a rate as practicable.

6.2.3 Avoiding High Salinity in the Extraction Water

Native brine in the Inyan Kara has a salinity of approximately 5500 mg/L TDS while the injection water will have a salinity of >300,000 mg/L TDS. Therefore, salinity of the extraction water may be quite variable over the project lifetime, depending on the location of the well and the extraction rate. Extracted brine with very high salinity is to be avoided because of the implication of detrimental circulating of injected water and because this may limit the ability to blend water at the surface to form suitable waters for the treatment test facilities. However, well placement far from the salinity plume implies an attenuated pressure response, which is also detrimental to project execution.

Furthermore, circulating of injected fluids does not serve as a good proxy for economic ARM at a CCS site. ARM implementations at a CCS site would seek to avoid breakthrough of injected CO_2. This would minimize the associated energy and processing costs of separation and reinjection of produced CO_2 for as long as possible, or require shut-in of the existing extraction well and drilling a new one.

6.2.4 Minimizing Extraction Ratio

Generally, the extraction ratio (volume of water extracted/volume of water injected) can be maximized by placing the extraction well close to the injectors, ideally between the injectors. However, in this true industrial-scale application, such well placement will produce high-salinity brine. Similarly, extraction wells placed in CCS sites would also seek to minimize production of injected CO_2. Therefore, a preferred location will be as close to the injectors as possible while still avoiding the salinity plume. Within the open, unbounded reservoir conditions at the site, a higher extraction ratio should be expected compared to sites or formations with a closed reservoir system.

6.2.5 Ability to Dispose of Extraction Water

Inyan Kara Formation water extracted from BEST-E1 will be disposed of via the BEST-I1 well, which will be completed in the Broom Creek Formation. The Broom Creek appears to have an injection capacity of at least 4000 bwpd, and the proposed extraction well location and project design basis must reflect the limitation of this expectation. However, if the Broom Creek disposal interval exceeds expectations, the extraction rate will likely be increased to use that potential. This will allow for greater operational flexibility when the ARM testing scenarios are conducted.

6.2.6 Discussion

The most easily identifiable constraints, surface location and the distribution of the salinity plume as determined by simulation, were chosen as the first siting factors to consider for the BEST-E1 well. Superposition of an image of the surface site with the expected salinity plume at 1 April 2017 yielded relatively few defined areas suitable for locating the extractor well, as shown in

Figure 6-3. Several potential extractor locations were tested in the simulation to determine pressure and/or rate response at the injection wells and the brine salinity profile of the extracted water. Inevitably, there is a trade-off between pressure response at the injection wells and salinity of the extracted brine. Pressure response and extraction ratio are generally maximized by locating the extractor close to the injection wells. However, such close proximity raises the salinity profile of the extracted brine, suggesting a higher degree of cycling of injected brine. Several extraction rates were tested for most locations, ranging from 1500 to 10,000 bwpd. A design basis rate of 4000 bwpd was ultimately selected for extraction and disposal of formation brine. Preferred well locations with an extraction rate of 4000 bwpd indicated a BHP response range of 18 to 52 psi at the existing injectors, with the Rink SWD 1 injection well showing the greater response and the Rink SWD 2 injection well a somewhat lesser response.

Location selection was more straightforward for the BEST-I1 well. The site operator requested that a Broom Creek injection well be located near the existing injection facilities, specifically within the prepared site area at the northeast corner of the project property, in order to minimize the surface footprint of the project. Within the prepared site's limited area, the most favorable reservoir properties for injection were the northeast. See Figure 6-3 for the well's location. The simulated injection profile for BEST-I1 suggests a stabilized rate of 4300 bwpd conservatively assuming a wellhead injection pressure of 1800 psi and an unstimulated completion interval (skin factor = zero). Discussion of upside potential for increased injectivity in the BEST-I1 well is given in Appendix A.2.

6.3 Extraction and Injection Scenarios

The history-matched simulation was used to test several potential extraction and injection scenarios for the wells. Results of these test scenarios were used to help guide creation of the detailed ARM design. The simulated operational life of the BEST-E1 and -I1 wells for the Phase II project is premised to start on 1 April 2017 and continue until 1 January 2020. All operating scenarios cover this time period and are listed in Table 6-1. The list was developed to cover a range of extraction rates that provide a range of the pressure responses (Cases 1 to 6) and a range of rate responses (Cases 7 to 12) from the active injection wells. Cases 13 through 16 gauge the stability of the selected design basis (Case 4) to changes in operating conditions of the commercial injection wells. Case 17 tested more optimistic operating conditions for the Broom Creek water disposal interval, and Case 18 tested reservoir and well response to tracer injection.

Assuming the standard operating injection conditions of 6800 bwpd, the BEST-E1 well was produced in a series of different rates: 1500, 2400, 3000, 4000, 5000, and 10,000 bwpd (Cases 1 through 6). These extraction rates were selected for a variety of specific reasons. The 1500-bwpd case was selected as the reasonable minimum rate needed to satisfactorily execute the project. The 2400-bwpd case represents the effect of an adverse ruling from regulatory authorities limiting injection pressure for the BEST-I1 well. The 3000-bwpd and 5000-bwpd cases represented the initial estimated minimum and maximum operating range for the BEST-E1 submersible pump. The 4000 bwpd case reflects the expected injection capability of the BEST-I1 well. The

Table 6-1. List of Simulation Extraction and Injection Scenarios

BEST Proposal Simulation Cases					1 April 2017 – 1 January 2020
Case No.	**BEST-E1, bwpd***	**BEST-I1, bwpd***	**RINK-1, bwpd***	**RINK-2, bwpd***	**Comment**
0	0	0	3400	3400	No BEST project (BAU)**
1	−1500	1500	3400	3400	Constant injection rate series
2	−2400	2400	3400	3400	
3	−3000	3000	3400	3400	
4	−4000	4000	3400	3400	Design basis
5	−5000	5000	3400	3400	
6	−10,000	10,000	3400	3400	
7	−1500	1500	whp 958	whp 450	Constant injection pressure series
8	−2400	2400	whp 958	whp 450	
9	−3000	3000	whp 958	whp 450	
10	−4000	4000	whp 958	whp 450	
11	−5000	5000	whp 958	whp 450	
12	−10,000	10,000	whp 958	whp 450	
13	−4000	4000	6500	7500	Maximum injection
14	−4000	4000	1700	1700	Low injection
15	−4000	4000	6500	0	Rink SWD 1 only
16	−4000	4000	0	7500	Rink SWD 2 only
17		5200			Broom Creek sensitivity
18	−4000	4000	3400	3400	Tracer sensitivity

* Except where indicated as WHP.
** BAU = Business as usual.

10,000-bwpd case represented the reasonable maximum extraction rate considering the BEST-E1 tubing design, as well as for selecting an extraction rate greater than the expected combined Rink SWD 1 and Rink SWD 2 injection rate.

The BHP response for Rink SWD 2 is seen in Figure 6-4. It shows the BHP response of the well in the 4000 bwpd extraction design basis (Case 4) is stable at approximately 40 psi. The response of Rink SWD 1 is similar and is shown in Appendix A.2. Note that a sustained and continuous pressure decline is observed only for Case 6, where the 10,000-bwpd extraction rate is the only case where extraction exceeds the baseline 6800-bwpd injection rate. Figure 6-5 displays a detailed view of the pressure response of Case 4 for these two wells. The graph shows that a 10- to 20-psi pressure response should be detectable within 10 days at the Rink SWD 1 and Rink SWD 2 wells, allowing for timely and effective experimentation at the site by adjustment of rates and operating pressures.

An alternative perspective from this series of extraction cases can be made by varying the standard operating injection condition from a fixed injection-rate condition to a fixed WHP condition (Cases 7 through 12).

For this series of cases, the injection rates are seen to rise with increasing extraction rate. Please see Appendix A.2 for more details regarding the performance of the Rink injection wells.

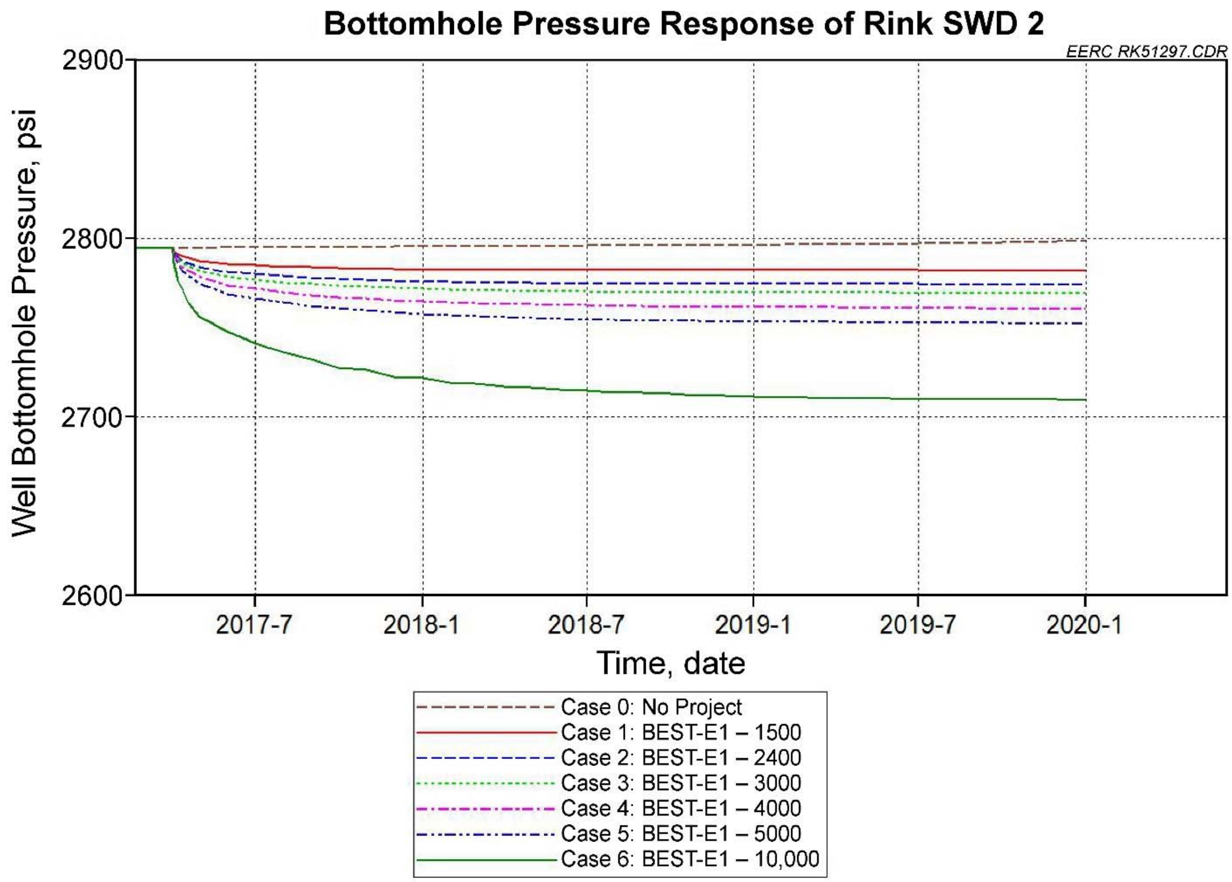


Figure 6-4. Rink SWD 2 BHP response to different extraction rates, assuming a stable 3400-bwpd injection rate into each of the Rink SWD wells.

During the project lifetime, the commercial injection rates at the Rink SWD 1 and Rink SWD 2 wells may vary. To test the strength of the selected design basis, additional injection profiles, Cases 13 through 16, as indicated in Table 6-1, were also considered.

These cases show that the two injection wells very rapidly restabilize their BHP, regardless of the variation of injection rate conditions. Their response to the extractor well should be little affected by their own operating constraints after a short period of adjustment. Therefore, the project design basis is robust with respect to changes in the rates for the injection wells.

Two additional special sensitivity cases were performed. The first was to estimate the upper range of Broom Creek injectivity (Case 17) by assuming a wellhead injection pressure of 2000 psi and an acid stimulation skin factor of –2. This case resulted in an injection capability of 5200 bwpd, which helps confirm the ability to dispose of the water extracted from the BEST-E1 well. The second special sensitivity case injected different chemical tracers into the Rink SWD 1 and Rink SDW 2 wells (Case 18). The tracers spread through the injection interval, and both were detected at the BEST-E1 well within 6 to 20 months.

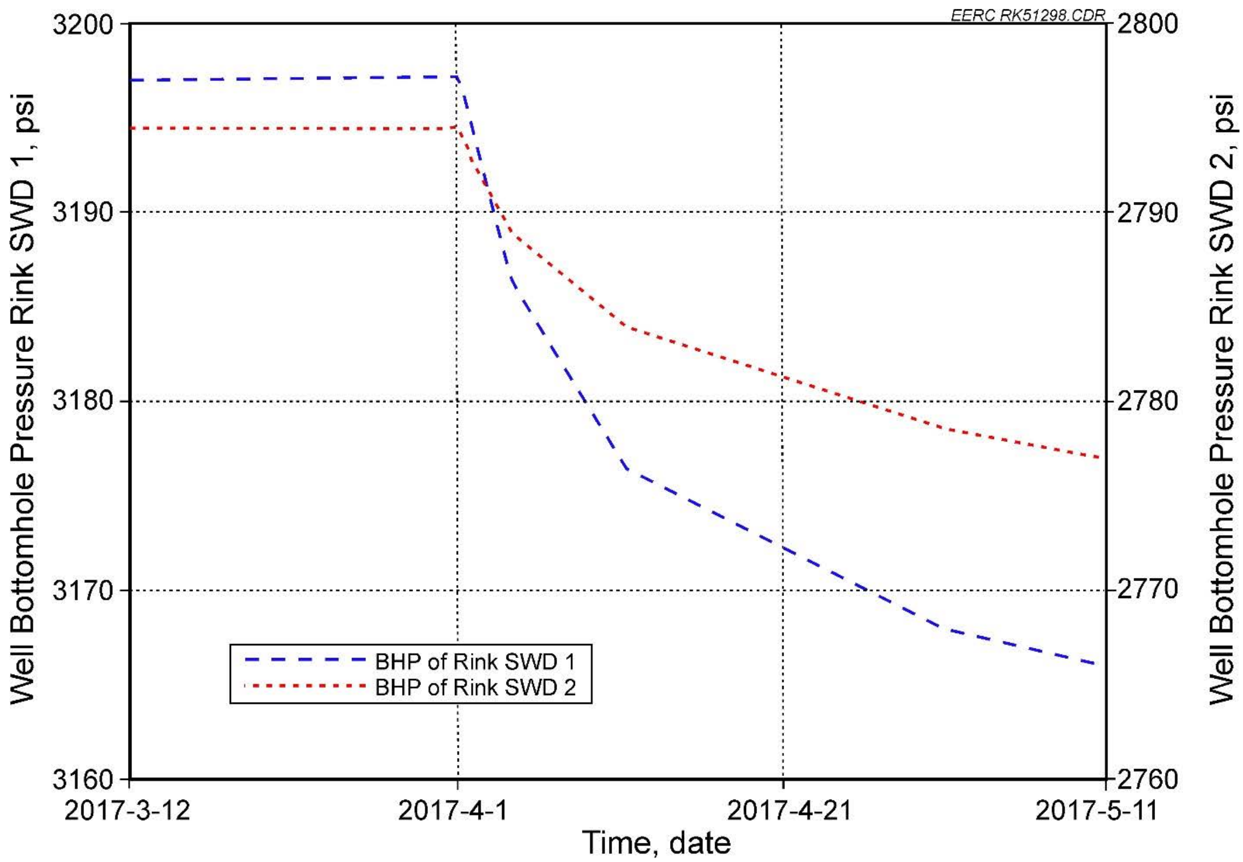


Figure 6-5. Detailed BHP response of Rink SWD 1 and SWD 2 with a 4000-bwpd extraction rate and a 3400-bwpd injection rate into each of the Rink SWD wells. A 10- to 20-psi pressure change is recorded within 10 days of extraction start.

6.4 Design Basis Injection Scenario

From the above-described simulations, Case 4 is selected as the design basis scenario. Nuverra has stated an operating preference to maintain injection based on rate rather than injection pressure. The existing average injection rate of 6800 bwpd is selected as the project's operating standard. Also, considering that the estimated injectivity of the BEST-I1 well is 4300 bwpd, the 4000-bwpd extraction rate is a conservative assumption. This design basis serves as a generalized proxy for the project injection program and was the starting point for creation of the more detailed Field Experimental Scenario that is described later.

Performance of the BEST-E1 extraction well for the design basis is given in Figure 6-6. It shows there is a high level of permeability at these locations since the pressure drawdown is only 60 psi for the extraction rate of 4000 bwpd. Also shown is the expected salinity profile of the extracted water, which varies only slightly during the life of the project. Both parameters suggest stable performance of the extraction well during the life of the project.

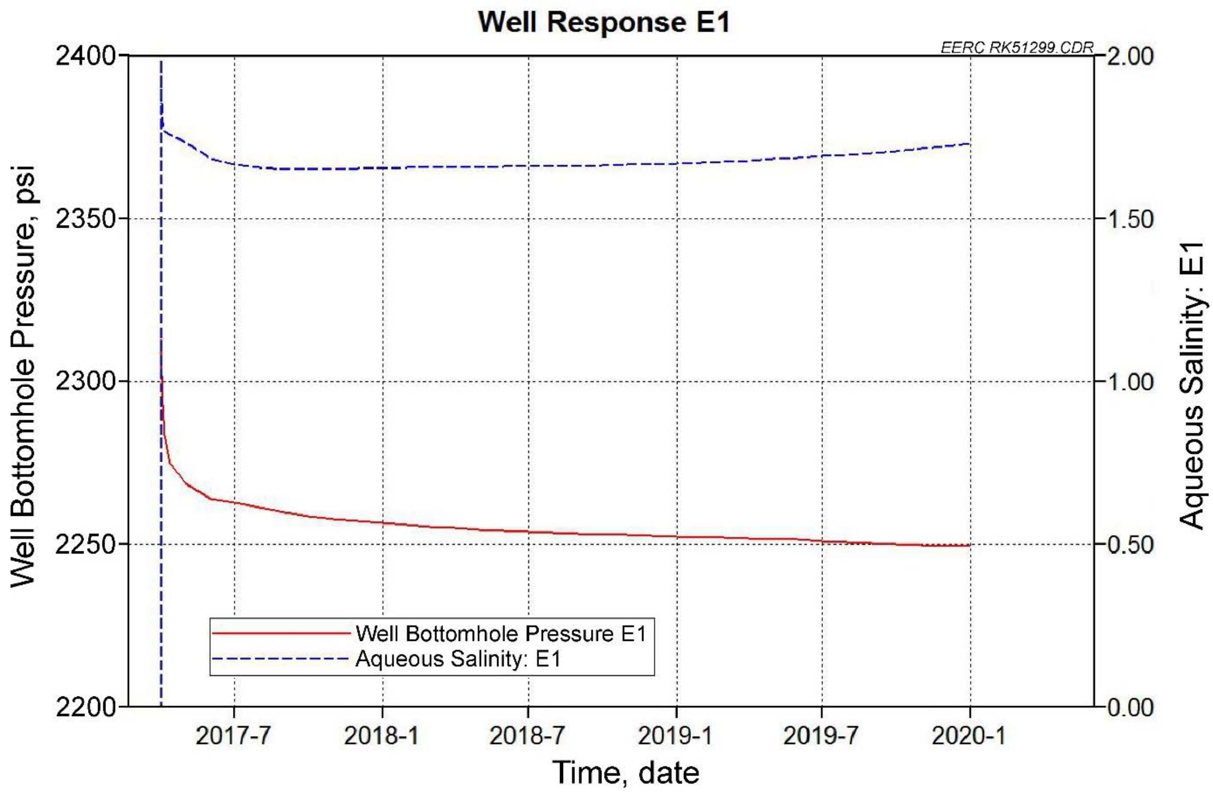


Figure 6-6. BHP and salinity changes predicted for the BEST-E1 extraction well at a 4000-bwpd extraction rate during the project lifetime. Limited pressure decline of the well is indicative of high permeability in the area.

7.0 RISK ASSESSMENT

A risk assessment was performed as part of the Phase I design implementation plan. The risk assessment included the identification of potential risks originating from or otherwise associated with the Johnsons Corner project. The risk identification and assessment were performed by experts with related technical, operational, HSE, and management experience and knowledge of the Johnsons Corner host site and project objectives. The project-specific risks identified during the Phase I risk assessment are grouped into five general classifications:

- Technical
- Resource availability
- HSE
- Site access issues
- Management

As part of the Phase I risk assessment, a project-specific risk register was created, which included 58 potential individual risks. The majority (39 out of 58) of the risks were considered technical in origin. A preliminary assessment of the impact of each risk to cost and schedule was developed based on geologic data, laboratory results, historical injection data, and reservoir history matching and extraction/injection scenario simulation modeling that were available through March 15, 2016.

The risk assessment identified no unacceptable project risks. Mitigation and remediation measures were proposed and developed to achieve a safe and successful completion of the Johnsons Corner project. The risk register with the 58 individual risks and mitigation and remediation measures is presented in Appendix B. A discussion of broad categories of risk and related mitigation and remediation is presented below.

7.1 Technical Risks

Core Data: Collection of core data from the Inyan Kara and Broom Creek Formations will be required to enhance existing Phase I geologic models and simulation. Attainment of core data will be enhanced through site meetings with the rig crew to develop coring procedures, with the geologist on location to provide oversight of core point selection. Proper core tool selection will be based on expected geology. Logs and rate-of-penetration (ROP) from offset wells can be used to provide well control to select the core point. While BEST-I1 is the primary target for core collection, as a contingency, BEST-E1 and sidewall cores can be obtained to provide critical samples.

Injection Pressures and Volume Rates: Injection of brine into the Broom Creek Formation will be required at a sufficient rate to match withdrawal from the Inyan Kara. Injectivity could be limited by lower than expected parting pressure or lower than expected permeability. Options exist to redesign the ARM test program based on possible injection volume constraints and include revising the location of the BEST-E1 well closer to Rink SWD 1 and Rink SWD 2 wells. Further identified options include 1) perforating additional zones in the Broom Creek interval to increase injection volumes, 2) using Rink SWD 1 and Rink SWD 2 wells combined with on-site storage/buffer capacity, or 3) obtaining NDIC approval to stimulate (acidize or hydraulically fracture) the Broom Creek interval to increase injectivity.

Operations: Operations activities include drilling, casing, cementing, completion, downhole tool placement, and testing. The EERC will be working with experienced drillers and other personnel (e.g., Schlumberger) familiar with the Williston Basin geology. Additionally, EERC personnel are experienced with the geology/hydrogeology of the Johnsons Corner site. The EERC will ensure that all UIC and state permitting requirements and recommended practices are followed. The EERC will work closely with project partners, contractors, and the DOE project manager to develop sufficient contingency action plans to prevent extended project delays in the event of deviations from normal operations activities. The location and availability of backup equipment will be determined prior to each job.

Climatic Conditions: Site operations, including extracted brine treatment activities, will be conducted year-round. Conditions exist to present moderate challenges, typically associated with equipment freezing. The extracted brine treatment test skid and ancillary equipment will be located in a heated enclosure. Where appropriate, all infrastructure associated with the Johnsons Corner project extraction/injection (tanks, piping, instrumentation, etc.) sensitive to freezing will be heat-traced and insulated, buried, and/or enclosed. Additionally, adequate flow rates will be maintained, or idle equipment will be drained to prevent freezing. Remote monitoring of flowmeters and pressure gauges will be utilized to identify potential issues.

Brine Reactivity: Potential exists for injected brines extracted from the Inyan Kara to interact with native constituents in the Broom Creek Formation to reduce permeability (e.g., solids precipitation, swelling clay) or cause scale buildup. Prior to completion of BEST-I1, chemical analysis of produced/injected fluids will be performed to identify potential interactions. Subsequent tests for potential formation brine, produced brine, and rock interactions will be conducted using fluid and core samples obtained from BEST-I1. Mitigation options presuming unfavorable brine interactions would include swapping the application of BEST-I1 and Rink SWD 1 and/or Rink SWD 2 wells (in cooperation with Nuverra) in order to conduct the ARM tests as planned. Chemical treatments on wells and infrastructure will be employed as necessary to minimize scale buildup and maintenance issues.

Waste Generation: The potential exists to produce naturally occurring radioactive material (NORM) during the filtering of sub 300-μm suspended solids from the feed stream to the extracted brine treatment skid/facility. Filter media will be tested for the presence of NORM, and the regulatory compliant standard procedures will be followed for its disposal. For NORM levels exceeding 50 pCi/gm, disposal will occur at a Resource Conservation and Recovery Act Subtitle C landfill facility. Drill cuttings and waste fluids generated from the drilling of the two new wells will be managed by Nuverra and disposed of in one of its state-approved sites. Generation and disposition of other wastes (solid or liquid) is discussed in the National Environmental Policy Act (NEPA) Environmental Questionnaire. Likely wastes include traditional municipal solid waste, on-site analysis residues, and materials from maintenance activities.

Contamination of USDW: The Johnsons Corner project is unlikely to cause contamination of USDW lying above the Inyan Kara extraction interval. Extraction from the Inyan Kara will result in a reduction of formation pressure compared to a business-as-usual case, lowering the risk of upward fluid migration. Further, injection into the Broom Creek Formation is below the Inyan Kara Formation, preventing upward migration beyond the Inyan Kara. All UIC Class II well and state permitting requirements and recommended practices will be followed. Well placement will be performed by Schlumberger, and the EERC site manager will ensure that best practices for drilling, cementing, and completions are followed and that mechanical integrity test (MIT) and wellbore integrity tests show proper isolation prior to brine extraction and reinjection.

Water Quality for Treatment: The potential exists for the brine extracted from the Inyan Kara to be out of the range desired for surface treatment demonstrations, particularly near the beginning of ARM operations. To facilitate compliance, the brine test facilities are designed with the ability to blend produced water from the BEST-E1 well with other produced and freshwater available on-site, allowing tailored brine salinity ranging between approximately 4500 to >300,000 mg/L TDS at rates up to 25 gpm.

7.2 Resource Availability

Project Partners/Contractors: Partnerships and financial cost share are a crucial aspect of the implementation of this proposed field demonstration effort, and there exists a risk for one or all participants to defer their obligation of financial and technical collaboration. To ensure successful collaboration, the EERC has been continually engaged with all current and potential partners, has secured letters of commitment, and has worked to structure contracts accordingly to minimize this risk. The EERC also has a significant working history and professional relationship with a majority of the partners identified to be a part of this effort.

Personnel Availability: The complex and multidisciplinary nature of this project yields a risk that loss or turnover of personnel will impact the expertise necessary to complete the project. To minimize this risk, the EERC has a diverse multidisciplinary team of engineers, geologists, scientists, and technicians with extensive research and operational experience and cross-training in geological characterization, geologic modeling, predictive reservoir simulation, monitoring operations, and risk assessment related to the injection and extraction of subsurface fluids during CO_2 storage and CO_2 enhanced oil recovery efforts. The EERC is committed to providing the necessary personnel resources to effectively carry out the activities outlined in the scope of this work. The EERC is also willing to hire and train additional personnel to cover the project scope and sufficiently cross-train all project personnel to minimize downtime.

7.3 Health, Safety, Environment

Personnel and Visitor Safety: A safe work site is considered foremost in the completion of an EERC-directed project. Any on-site project activities present a risk of injury or various health impacts to employees or visitors. Safety training regarding hazard avoidance, personal protective equipment requirements and use, and injury response/first aid will be required of all site operating personnel, and third parties (contractors). All visitors will be escorted by EERC or Nuverra personnel. Proper monitoring (e.g., H_2S/O_2) will be utilized where potential hazards could develop (monitoring or equipment shelters/enclosures). Standard operating procedures (SOP) will be developed for all standard operating and repair activities to be conducted by EERC personnel.

Proper training for operations staff based on the SOPs will be required. In addition to ensuring safe operating conditions, training activities will minimize unintended damage to equipment. Nonstandard procedures will be reviewed with the management team and discussed during "tailgate" meetings to be held prior to conducting field/site activities. The site manager will be responsible to ensure proper communication with and between the operations team and site contractors. Intrinsically safe equipment will be used in enclosed areas when prudent or required.

The potential for brine spills exists any time brines are handled on the surface. All activities will be conducted in accordance with regulatory requirements. Recommended practices will be followed wherever applicable. All locations with surface brine storage will be lined and beamed to prevent uncontained spills. Leak detection will be incorporated into flow lines and pipelines and frequently monitored. Spill detection and monitoring will be incorporated into pipelines and flow lines following best practices. Safeguards and automatic shutdowns will be designed into surface brine-handling infrastructure, and remote monitoring will be incorporated to monitor operational performance. Visual inspections will be performed daily, and all personnel will be trained in the safe operation of equipment.

7.4 Site Access Issues

Permitting and Facilities Construction: A letter of commitment and cost share have been secured from Nuverra, the host site operator, allowing development of the Johnsons Corner project and rights of access. The EERC has a demonstrated history of close cooperation and strict adherence with North Dakota regulatory agencies regarding permitting requirements and guidelines. A letter of support has been obtained from NDIC. Engagement with other area stakeholders will be initiated immediately upon project award. The project will not be moving fluids to or from the site. Nothing of value will be commercially sold as part of this test, precluding the need for negotiations on mineral or pore volume rights.

7.5 Management

Project Management and Organization: Effective project management and organization are key to successful implementation of the defined project objectives and program goals. There exists the opportunity for project management, organization, communication, and schedules to break down, resulting in inability to complete tasks on time, with high quality, and within budget. The EERC has a proven track record of managing complex and high-budget CO_2 storage and oil and gas-related projects, including projects funded by DOE's Carbon Storage Program. Furthermore, the EERC, and specifically this project team, has a long-standing relationship with the project partners: Nuverra, Schlumberger, and CMG. As a result, the necessary working relationships, standardized workflow processes, communication protocols, and contractual procedures have been established to ensure successful collaboration on the current proposed project. Planning meetings, conference calls, Webinars, and regular e-mail and phone communication will occur to ensure coordination of participants and minimize risk. Also, the project management plan, developed as part of this project, clearly defines the roles and responsibilities of participating team members. Key personnel will be selected and the project structured to ensure cross training and redundancy of the core technical team to further mitigate potential project impacts.

7.6 Summary

If the Johnsons Corner site is selected for Phase II funding, a second round of risk assessment (the Phase II risk assessment) will be conducted. The Phase II risk assessment will update the Phase I risk assessment following the collection of additional site and laboratory data and the conduct of additional simulation modeling during the early stages of Phase II (e.g., after the collection and analysis of core samples).

8.0 JOHNSONS CORNER ARM DESIGN

8.1 ARM Plan Design

Based on the results of the modeling, an indicative field experimental scenario was chosen to serve as the basis of the proposed ARM design and installation plan.

The scenario is divided into two stages. Table 8-1 summarizes the timetable and events of the experimental scenario. The first stage is intended to probe the reservoir and well responses to a specific sequence of injection and extraction tests to determine the level of performance interference among the wells and the capabilities of the system. Results of the first stage of the scenario will be used to adjust the second stage of the program to maximize the results for achieving the project objectives.

During the first stage of the scenario, the BEST-E1 well alternates between extraction and shutdown periods. The duration of these periods are expected to be sufficient to see a pressure response in the injection wells and allow for pressure restoration to the normal field operating conditions. Several injection rate combinations will be tested during this period. Note that a combined injection rate of 6800 bwpd is maintained throughout Stage One, which is the currently

Table 8-1. BEST Indicative Experimental Scenario (1 April 2017 – 1 January 2020)

				Description, bwpd			
Test	**Days**	**End Date**	**BEST-E1**	**BEST-I1**	**Rink SWD 1**	**Rink SWD 2**	**Comment**
	0	**1-Apr-17**		**Stage One**			**Start data collection**
1	10	10-Apr-17	0	0	3400	3400	Observe
2	20	30-Apr-17	−4000	4000	3400	3400	Start interference testing program
3	10	10-May-17	0	0	3400	3400	Inject tracer
4	21	31-May-17	−5000	5000	3400	3400	Maximum rate test
5	10	10-Jun-17	0	0	3400	3400	
6	20	30-Jun-17	0	0	6800	0	
7	20	20-Jul-17	−4000	4000	6800	0	
8	11	31-Jul-17	0	0	6800	0	
9	20	20-Aug-17	0	0	0	6800	
10	20	9-Sep-17	−4000	4000	0	6800	
11	11	20-Sep-17	0	0	0	6800	End interference testing
				Stage Two			
12	61	20-Nov-17	−2500	2500	3400	3400	Minimum pump rate step
13	61	20-Jan-18	−4000	4000	3400	3400	Middle rate step
14	61	22-Mar-18	−5000	5000	3400	3400	Maximum rate step
15	10	1-Apr-18	0	0	3400	3400	Observe
16	30	1-May-18	−4000	4000	3400	3400	Repeat testing as needed
17	182	30-Oct-18	−4000	4000	3400	3400	
18	20	19-Nov-18	0	0	3400	3400	Observe
19	182	20-May-19	−4000	4000	3400	3400	
20	11	31-May-19	0	0	3400	3400	Observe
21	183	30-Nov-19	−4000	4000	3400	3400	End of extraction program
22	31	31-Dec-19	0	0	3400	3400	Observe
	1014		−3,354,500	3,354,500	3,417,000	3,417,000	End of test. Totals

assumed average operating rate at the facility. The conduct of the project is designed to minimize disruption to ongoing commercial activity. Actual injection rate at the time of project execution will be determined by the commercial operating requirements and operating flexibility at that time. For example, given current injection rates, Nuverra does not foresee any problems with injecting all of the site's disposal brine into only one of the Rink SWD wells for the period of time likely to be required for ARM testing.

It will be important for the project to determine as early as practical the maximum performance of the BEST-I1 well, as this may have important implications for Stage Two operations. One extraction period will be a maximum extraction rate test. The actual rate will be determined by the maximum sustainable performance of the BEST-I1 injection well. These Stage One test periods will be rigorously examined using pressure transient analysis techniques to determine permeability and skin condition of each well. The data will also be entered into the simulation and the history match updated to refine model performance before optimizing the Stage Two operating periods.

Stage Two of the scenario will be reviewed based on the results of Stage One. Therefore, the Stage Two extraction and shut-in periods may vary from those indicated in the table. The rate levels may also vary depending on the established system performance. However, it is anticipated that Stage Two operations will be characterized by more continuous extraction periods at a rate as high as practical to maximize the pressure impact on the injection wells and influence the evolution of the salinity distribution. The data from the Stage Two operations will be entered into the simulation for a rigorous evaluation of the impacts made by project operations.

Figure 8-1 displays the predicted BHP response of the Rink SWD 2 well during Stage One of the experimental scenario. Response is visible not only to changes in the extraction rate but also to changes in the injection rates of Rink SWD 1 and Rink SWD 2 wells, such as the occurrences on June 10 and July 31 (Table 8-1).

Pressure response is observable because of changes in both extraction and injection rates of both Rink SWD 1 and 2 wells. The simulated pressure response of all of the project wells during the full duration of the project is presented in Figure 8-2.

The described experimental scenario has been simulated, and the results are displayed in Figure 8-3. The upper half of the figure shows the pressure distribution of the area on 1 January 2020, assuming that no project is performed. The lower half of the figure shows the pressure response of the wells at that date if the experimental scenario is carried out. Figure 8-4 is an image of the differential of reservoir pressure with and without extraction. Regional pressure is reduced up to 30 psi; BHP at Rink SWD 2 is reduced approximately 40 psi and approximately 50 psi for Rink SWD 1. Figure 8-5 contains companion images showing the salinity distribution in the test area without and with the extraction project. Figure 8-6 is an image of the differential movement of the injected brine plume.

In general, salinity is reduced around the perimeter of the Rink SWD 2 plume and increased between the Rink SWD 2 and the BEST-E1 wells as the extractor pulls the plume toward it. Growth

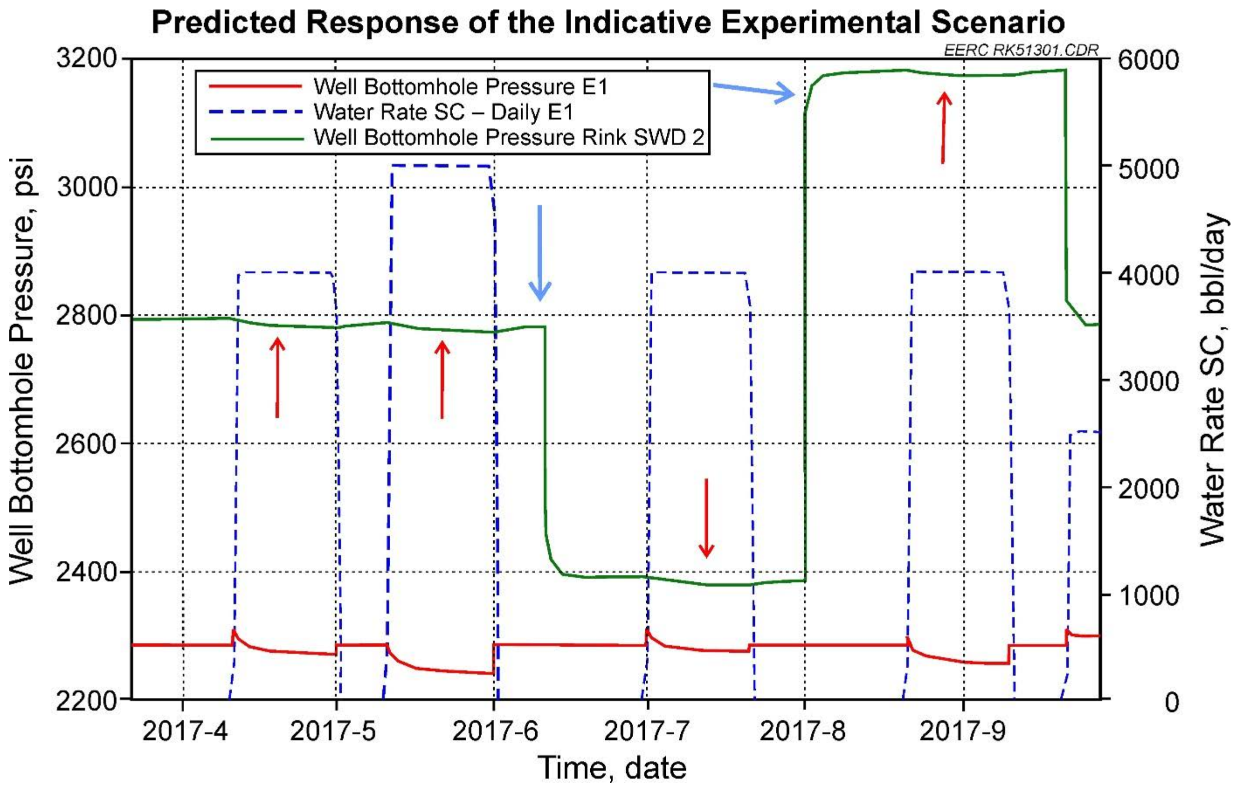


Figure 8-1. Predicted pressure response of the Rink SWD 2 well to changes in extraction rate. Changes in BHP due to changing injection rates are clearly visible (indicated by blue arrows). However, subtle dips in the BHP of Rink SWD 2 also occur in response to fluid extraction from the BEST-E1 well (indicated by red arrows).

of the plume to the southwest of the extraction well has been arrested. This indicates an ability to manage an injected plume migration.

If successful, a demonstration will result in a validated simulation model that will allow for accurate extrapolation of more aggressive pressure management scenarios and, ultimately, a more cost-effective design.

8.2 Chemical Tracer Injection

A single dose of separate chemical tracers will be injected into both the Rink SWD 1 and Rink SWD 2 wells. The tracer will allow measurement of the residence time and speed of propagation of injected water from each well through the reservoir. This will improve numerical simulation and interpretation of the project performance. More importantly, the introduction of tracer-laden water near the start of the project will, upon detection at the BEST-E1 well, provide an additional and independent means to verify the ability of ARM techniques to affect the movement of the brine plume at the site. Finally, addition of tracers allow brine injected after the start of ARM testing to be differentiated from brine injected before the start of ARM testing. Data related to breakthrough will be invaluable for estimating cost-effectiveness of ARM in relation to future CO_2 operations considering the use of ARM strategies.

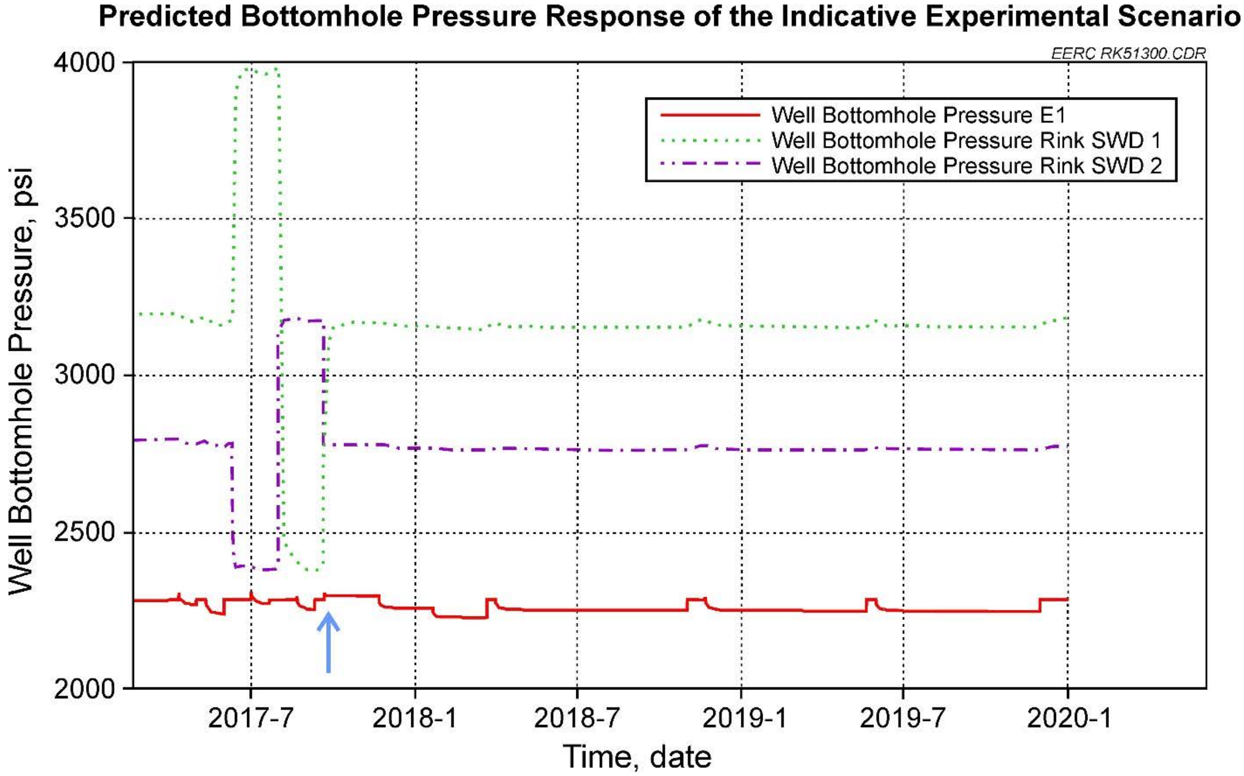


Figure 8-2. BHP response of the wells during the entire project experimental scenario. The end of interference testing and Stage 1 is indicated by the blue arrow. Changes in pressure responses of Rink SWD 1 and 2 to changing test parameters are visible throughout the experimental run.

Tracers will consist of ProTechnics proprietary water-soluable chemical tracers IWT 1000 and IWT 1100. These nonradioactive chemical tracers are members of the fluorobenzoic acid (FBA) family. Rink SWD 1 will have a total injected amount of 30 liters of IWT 1000. Rink SWD 2 will have a total injected amount of 20 liters of IWT 1100. ProTechnics calculated volume with a safety factor of 10 (i.e., 10× the anticipated volume needed for detection at the BEST-E1 well). They calculated this based upon the information presented in Table 8-2. These tracers will be injected at surface a few weeks after BEST-E1, and BEST-I1 are fully operational. An example of the tracer response at the BEST-E1 is shown in Figure 8-7. Samples will be collected from BEST-E1 prior to injecting chemical tracers in order to establish baseline conditions. Once the chemical tracers are injected, the water-sampling program will be carried out (Table 8-3). Samples will be analyzed at ProTechnics, Houston, Texas, facility where the tracer can be detected at a limit of 10 parts per trillion (ppt). Once tracer/s are detected, additional samples will be analyzed to establish the precise breakthrough time. Reservoir simulation will also be used to predict the estimated tracer breakthrough and adjust the sampling program in order to minimize the number of samples requiring analysis by ProTechnics.

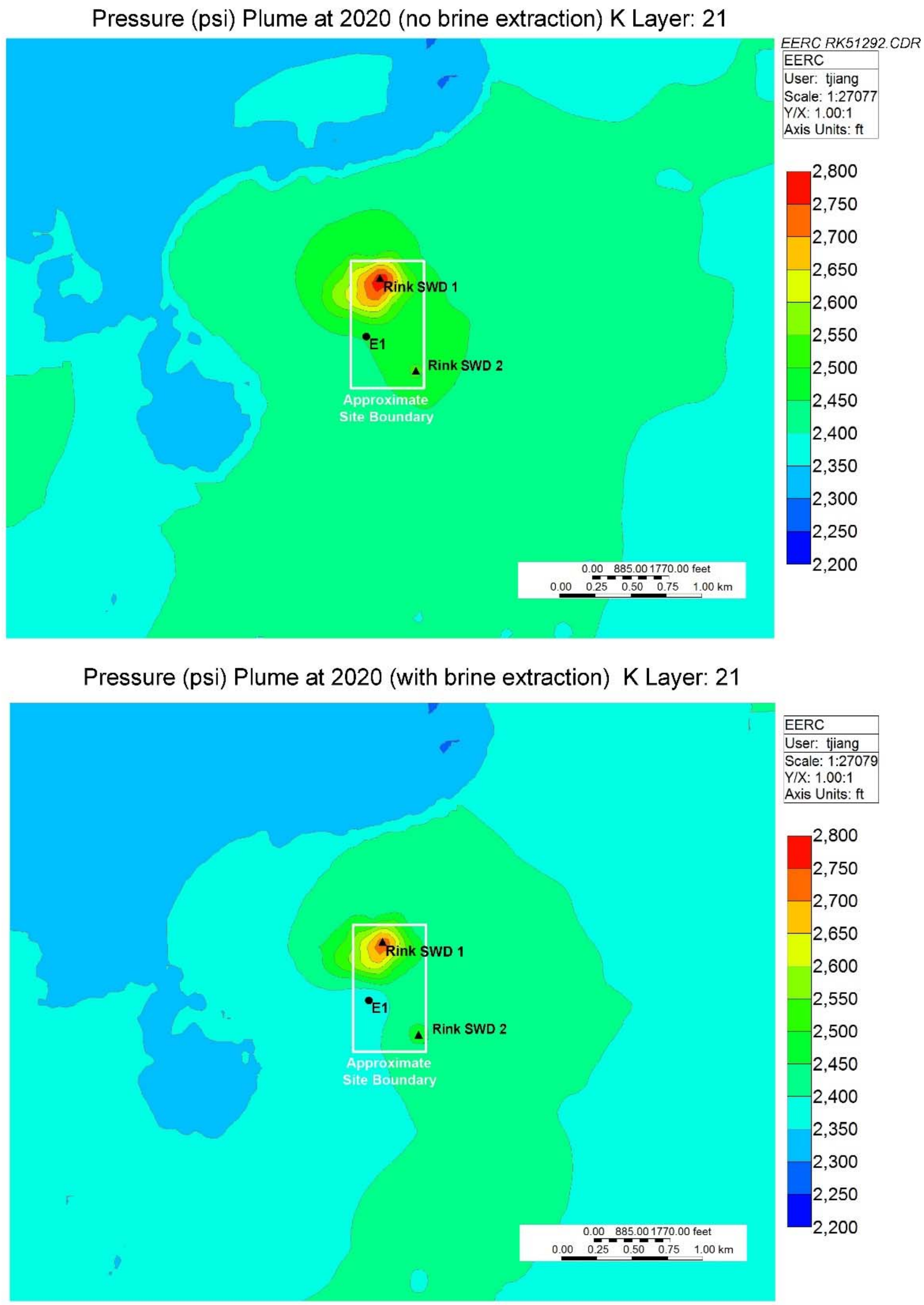


Figure 8-3. Comparison in developed pressure plume in January 2020 at the Johnsons Corner site without extraction and with the extraction experimental scenario. The case without extraction, aka the "business as usual" case (above), shows an elevated pressure plume which covers the majority of the project site. Contrast this with the pressure plume after the planned extraction scenario (below) which shows a regional pressure decrease of 20–30 psi. Larger pressure decreases are visible near the Rink SWD 1 and 2 wells.

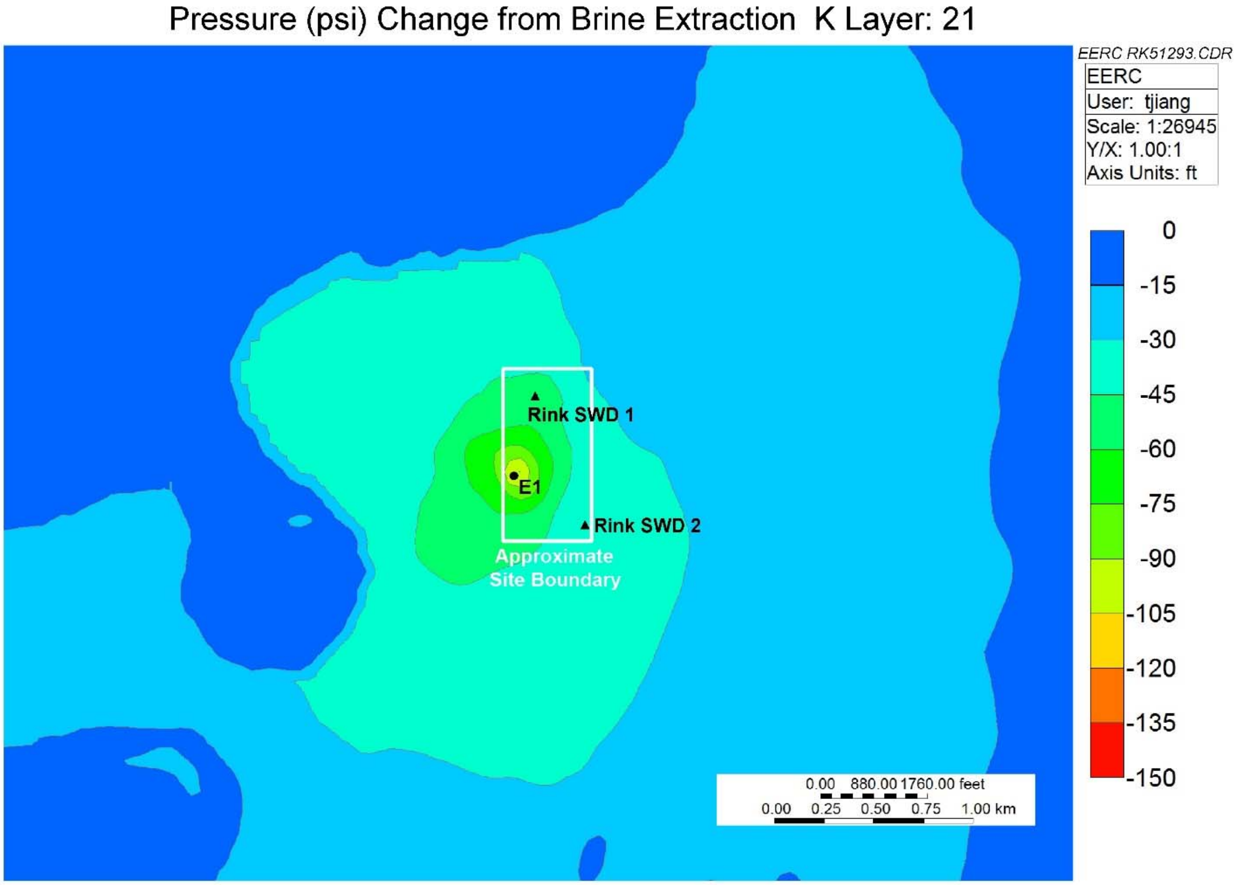


Figure 8-4. Reservoir pressure difference map illustrating the influence of the extraction scenario in the year 2020 (subtraction of the extraction experimental scenario from the business as usual scenario in Figure 8-3). Regionally, pressure is reduced up to 30 psi. The BHP at Rink SWD 2 is reduced approximately 40 psi and at Rink SWD 1 by approximately 50 psi.

Table 8-2. Interwell Data Used to Design Tracer Program

Interwell Tracer Data	
Project Type	Disposal well
Formation	Inyan Kara (sandstone and shale)
Gross Thickness of Injection Zone	400 feet
Desired Radius of Investigation	1400–1600 feet
Porosity	15%
Water Saturation	>90%
Water Cut	100%
H_2S Concentration	Not in formation, but injected
Previously Used Tracers	No

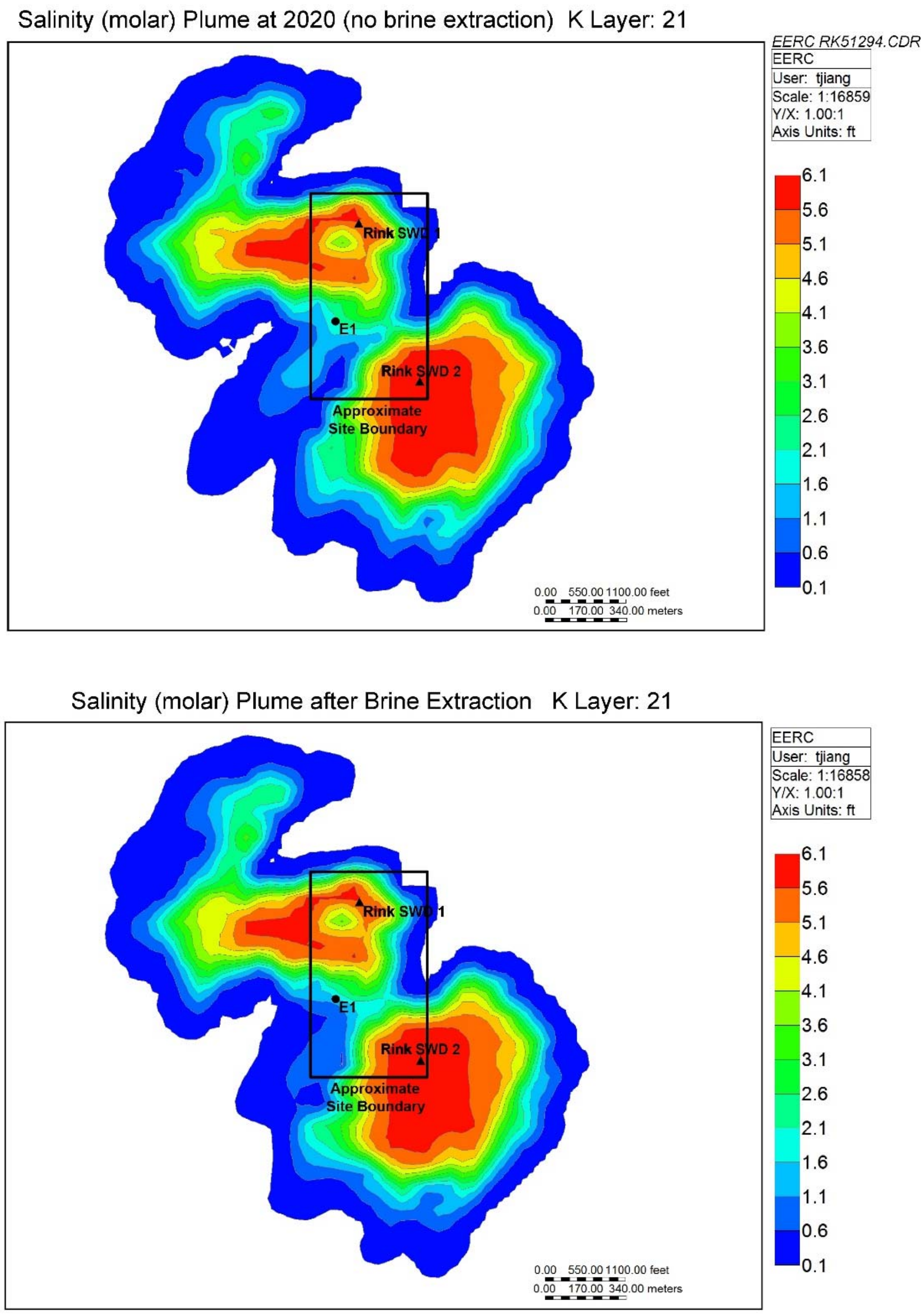


Figure 8-5. Salinity (molar concentration) of plume development in January 2020 without brine extraction, business as usual (above), and with the extraction experimental scenario (below). Note the significantly reduced footprint of the plume on the southwest side of the site.

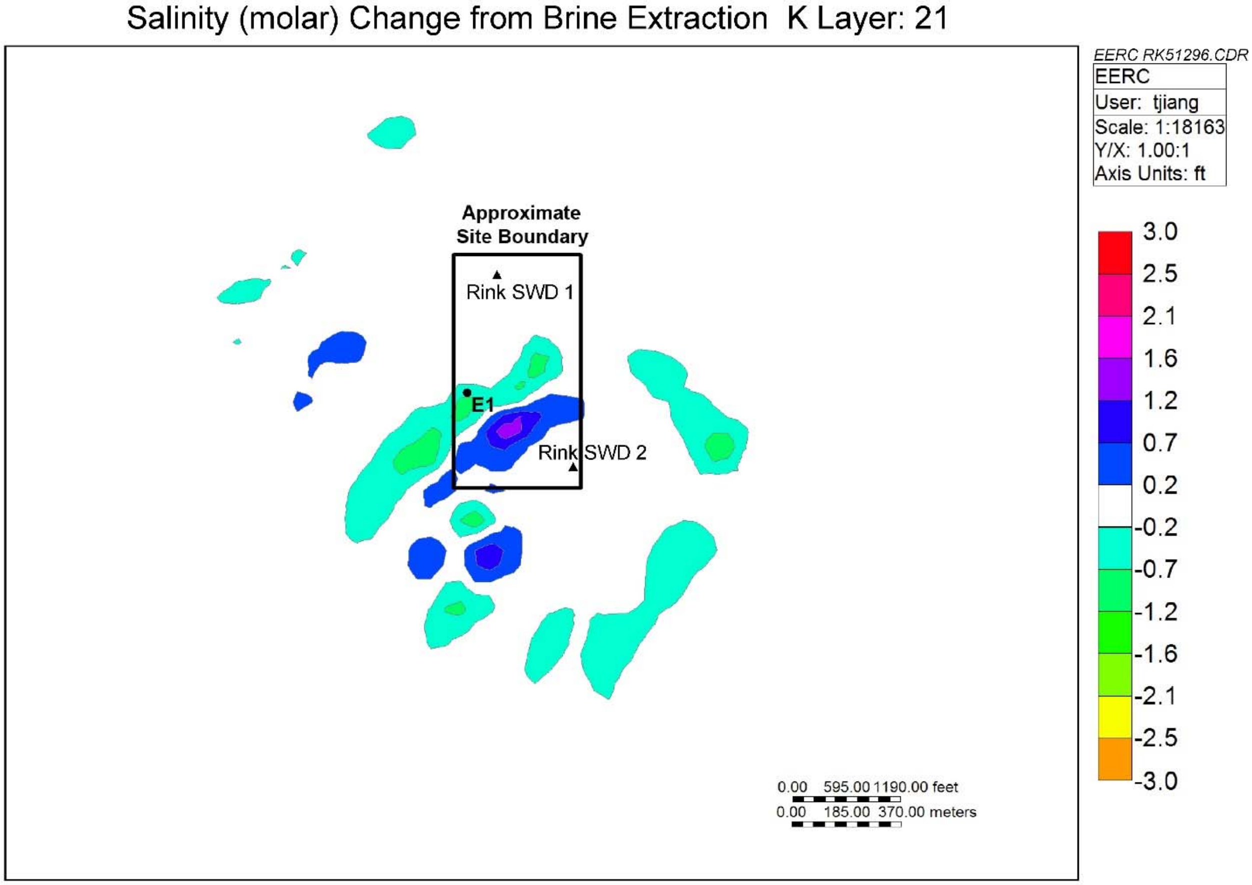


Figure 8-6. Salinity difference map (molar concentration) illustrating the influence of the extraction scenario in the year 2020 (subtraction of the extraction experimental scenario from the business as usual scenario in Figure 8-5). Salinity increases are noted by darker colors, and salinity decreases are noted by lighter colors. A ring of salinity decrease is visible around Rink SWD 2 as the brine plume is drawn inward toward the BEST-E1 well and replaced by native formation water. Salinity increases are visible in areas where flow has concentrated the salinity plume.

Table 8-3. Tracer Sample Collection Interval

Production Well	Months 1–2 One/week	Months 3–6 One/2 weeks	Months 7–24+ One/month
BEST-E1	8	8	18
Total Samples Collected		34	
Total Samples Analyzed		~12 (1/3 of all samples collected)	

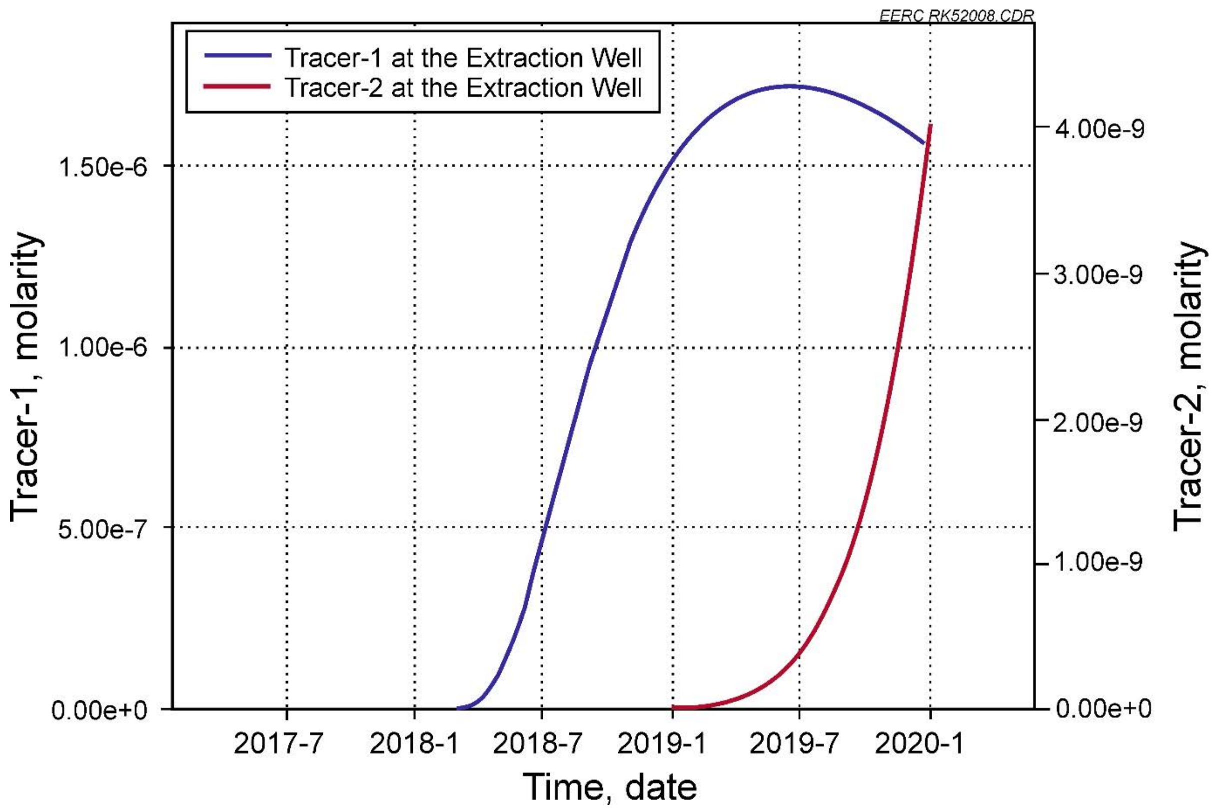


Figure 8-7. Tracer response at the BEST-E1 extraction well. Time of tracer injection is May 2017. Tracer 1 is injected into the Rink SWD 1; tracer 2 is injected into the Rink SWD 2 well.

9.0 MVA PROGRAM

9.1 Overview

9.1.1 Goals

The concept of ARM for CCS is in an early stage of development. While ARM has been postulated to both improve injectivity and provide a means of managing CO_2 plume migration, MVA data from actual field demonstrations are necessary to validate these concepts. Once these concepts are validated, simulators can be applied more confidently to a variety of ARM implementation scenarios, and the associated economics of those implementations can be explored. Ultimately, if ARM is shown to provide a cost-effective means of improving CCS performance, either through improved storage capacity or reduced AOR, it may become a valuable component of future CCS storage operations.

As a result, a robust MVA program at the Johnsons Corner site is needed to develop the fundamental data sets to assess the changes occurring in the subsurface as a result of ARM. Furthermore, the iterative integration of these data sets into the day-to-day operations of the site will ensure that the collected MVA information supports the effective management of the ARM test program itself. The primary goals of the MVA plan for the Johnsons Corner project are as follows:

- Provide a technical basis for assessing the effectiveness of ARM implementation.

- Validate simulation predictions related to injection performance improvements, differential pressure plume, and brine salinity distribution resulting from the ARM test.

- Evaluate MVA techniques capable of assessing and tracking changes in injected fluid and differential pressure plume movement resulting from ARM.

- Address HSE components related to the ARM test.

- Address technical issues associated with the ARM test, and allow those tests to operate more efficiently.

9.1.2 Differences Between BEST and CCS

Although DOE's BEST Program aims to develop a technology that supports the implementation and operation of CO_2 storage projects, there will be no CO_2 injection associated with the Johnsons Corner ARM testing. Because there will be no CO_2 injected, the approach to MVA at the Johnsons Corner site will be substantially different from MVA for CO_2 storage. The primary difference is that the physical and chemical properties of brine are significantly different from those of CO_2. For instance, CO_2 is buoyant and will always seek to rise within a geologic column, whereas injected brine is not buoyant and is more likely to sink within a geologic column. Commercial SWD operations are compliant with all UIC regulations and the proposed new installations would also comply with these regulations. Furthermore, compared to a business as usual case, BEST would reduce the potential of out-of-zone migration through any open conduits, should they exist. This translates into a brine plume generated by this project having a reduced risk of migrating upward into a USDW, the shallow subsurface, or the surface. This means that the MVA plan for the Johnsons Corner ARM test does not need to expend resources on detailed baseline characterization and subsequent frequent monitoring of porous formations overlying the brine injection zone sealing formation, overlying USDWs, soil vadose zone, or surface waters. Baseline water quality testing of neighboring water production wells will be conducted as part of the UIC Class II permits that will be required for the project. This results in an MVA plan almost exclusively dedicated to validating the results and performance of the ARM test as opposed to meeting regulatory requirements for CO_2 storage.

A monitoring technique commonly employed at CO_2 injection sites is time-lapse seismic surveys, a proven technique for monitoring commercial CO_2 storage. However, substituting brine for CO_2 makes seismic monitoring a challenge. Analysis of rock and fluid physics modeling at the Johnsons Corner site indicated that p-wave impedance changes due to salinity variations would be too small to discern with seismic methods. In addition, pressure modeling revealed that anticipated pressure differences would be of low magnitude and dissipate rapidly away from the wells because of the high permeability and unbounded nature of the reservoir. This rapid pressure dissipation makes it unlikely that a pressure plume would be imaged on a seismic difference display. Therefore, seismic techniques for pressure plume tracking will not be applied to the Johnsons Corner ARM test.

Instead of seismic methods, an electrical monitoring method called BSEM can leverage the high-salinity contrast between the injected brine and the native Inyan Kara water to provide an image of the salinity plumes around the injector wells at the beginning of the project and at the end. BSEM measurements are processed to produce a resistivity volume. Resistivity is inversely related to the salinity of the brine, so as the plume salinity changes with distance from the injection wells, low resistivity near the wells will increase until it reaches the background level associated with the in situ brine, providing a measure of the spatial distribution of salinity plumes.

The physical measurement of the salinity plumes provides a means of validating or updating the geologic model that is the input to the predictive simulations. Before and after images will be differenced to provide additional insight. By combining multiwell downhole pressure measurements and the physical measurement of the salinity plumes, a complete validation of the method of monitoring the differential pressure and injected fluid plumes is achieved. Sensitivity modeling of the Johnsons Corner site indicates BSEM as a viable technology for tracking the injected brine salinity plume in the Inyan Kara Formation. Additional details pertaining to the evaluation of MVA techniques and their suitability to meet the objectives of this project are discussed in Appendix A.

It is anticipated that the use of BSEM at the Johnsons Corner site will also serve as a useful analogue for its use at future CCS sites. This is because the magnitude of resistivity contrast between CO_2 and brine would be larger than those anticipated between two brines. Therefore, this technique would likely be equally as viable for monitoring injected CO_2 plumes at a CCS site. Demonstrating the effectiveness of BSEM at the Johnsons Corner ARM test will yield valuable insight for an alternative technique for use at CO_2 storage sites where traditional surface seismic surveys are not viable because of site-specific reservoir or surface conditions.

9.1.3 Johnsons Corner Site MVA Design

A site-specific, technical, goal-oriented, and risk-based monitoring plan is designed to mitigate negative impacts and reduce uncertainties by iterative application of monitoring and risk analysis (Canadian Standards Association, 2012). The trend in recent years among MVA planners has been to integrate site characterization, modeling and simulation, risk assessment, and monitoring strategies into an iterative process to produce robust, broadly defensible MVA plans (Gorecki and others, 2012). With that in mind, the EERC has developed a goal-oriented, site-specific MVA plan for the Johnsons Corner project, which includes pre-ARM operation baseline characterization, geologic model update and predictive simulation, operational risk management, active reservoir surveillance or MVA, and post-ARM operation final characterization.

The Johnsons Corner MVA plan was developed with two drivers in mind: the first to address the technical goals of the project (which encompasses both ARM validation and improving operational efficiency) and the second to address risk reduction and mitigation. As no CO_2 is being injected at the Johnsons Corner site, risk refers to project technical risk (e.g., injected brine interactions with the formation rock causing reduction in injectivity, ability to identify breakthrough of injected fluids in the extraction well). This means that the MVA plan is a joint product of the ARM operational plan and a technical risk assessment. With respect to risk, the MVA plan is primarily focused on early detection of the occurrence of the most serious risks and their mitigation (see Appendix B). Another objective for the Johnsons Corner MVA plan is avoidance of negatively impacting the commercial SWD operations; rather, it should support them as would be similarly expected for implementations associated with a commercial CCS project. Therefore, technologies with the potential to disrupt SWD operations (or CO_2 injection operations) were excluded.

The Johnsons Corner MVA plan includes characterization and monitoring elements that encompass the local USDWs and deep subsurface environments. The MVA technology matrix for Johnsons Corner will include geophysical logs, well testing, wellbore integrity monitoring, and a variety of downhole and surface instrumentation (e.g., pressure and temperature sensors, flowmeters, etc.). MVA technologies to be frequently used over the life of the project will be deployed at locations selected according to their surface accessibility and spatial relationship to the predicted plume. The timing of MVA events will be planned according to technical need and cost-effectiveness.

The specific elements of the Johnsons Corner MVA plan can be divided into three major categories: 1) baseline characterization, 2) active reservoir surveillance, and 3) infrastructure surveillance. A detailed discussion of each is provided below.

9.2 Baseline Characterization

Baseline characterization includes activities to determine the baseline compositions and qualities of the ARM test formation (Inyan Kara), the extracted water disposal formation (Broom

Creek), and the two nearest freshwater wells. Characterization is a key component to the Johnsons Corner MVA plan, as improved characterization will aid in interpretation of MVA data, guide the timing and frequency of MVA data collection, and reduce risk associated with the overall project. It also includes the baseline BSEM survey to measure the shape and distribution of the site's existing salinity plume prior to extraction operations.

The rock and fluid properties of the ARM test formation and extracted water disposal formations at the Johnsons Corner site will be thoroughly quantified to demonstrate their ability to support the goals of the field test. Those data will also provide invaluable information that will guide the design and operation of site equipment and infrastructure. The rock and fluid properties will also serve to establish reservoir conditions for improved model and simulation development and validation.

Determining the effectiveness of the ARM operations with respect to the Inyan Kara reservoir pressure regime will require frequent iterative simulation modeling and history-matching efforts. It is, therefore, critical for the geologic model of the Inyan Kara Formation at the Johnsons Corner site to be as finely detailed and accurate as possible. While the Rink SWD 1 and Rink SWD 2 wells have characterization data associated with them, including geophysical logs and 8 years of injection history, it will still be necessary to perform a robust characterization of the Inyan Kara at both the injection well and extraction well locations. For the Inyan Kara brine extraction zone, it is important to have a quantitative understanding of the rock properties of the reservoir. It is also necessary to quantitatively understand the correlations between the core-derived properties and the porosity and permeability interpretations from the geophysical logs. The core analysis data from the new injection can then be extrapolated to the well logs that were collected from the Rink SWD 1 and Rink SWD 2 wells, providing the project team with a more accurate view of the Inyan Kara reservoir at Johnsons Corner. These data will be used to revise and improve geologic models and simulation predictions for the site in order to better design, operate, and interpret ARM tests at the site.

In accordance with the UIC Class II requirements, samples from the two nearest freshwater wells to the Johnsons Corner site will be sampled and analyzed. It is required that a certified and registered lab provide quantitative analyses of samples from each well. The nearest wells were most recently sampled and analyzed prior to the 2008 installation of Rink SWD 1.

9.2.1 Geologic Core Sample Collection

Geologic core samples will be collected and analyzed from the Inyan Kara and Broom Creek Formations. Analysis of this new core will allow for the:

1) Building of more robust porosity and permeability correlations to update the geologic model and enabling more accurate predictive simulations of fluid flow and pressure response.

2) Investigation of potential geochemical reactions catalyzed by injection of nonnative brine, with potential implications to injection and/or extraction capacities.

Analyses proposed for these core samples include thin section analysis (to assess mineralogy, grain size, sorting, and morphology; diagenetic effects, and to assist facies interpretations), x-ray fluorescence (XRF; to give insight into sample chemistry), x-ray diffraction (XRD; to assess mineralogy and clay typing), scanning electron microscopy (SEM; as a validation technique for XRD), porosity and permeability testing, brine permeability testing (to investigate fluid replacement within samples when flushed with brines of differing salinities), geochemical analyses with a range of brine salinities (to investigate mineralogic and other chemical reactions which may have implications for injection or extraction activities and to design the fluid program for step rate tests), and nuclear magnetic resonance (NMR; to assess total versus effective porosity over a range of brine compositions). The anticipated coring and core analysis program is presented in Table 9-1.

9.2.2 Well Logging and Downhole Testing

Well log data will be acquired in each of the four wells (BEST-E1, BEST-I1, Rink SWD 1, and Rink SWD 2). The following well logs are planned: triple combination, borehole-compensated (BHC) sonic, spectral GR, capture spectroscopy, cement bond logs (CBL), and injection profiles. A unique logging program has been designed for each well (Table 9-2).

- The triple combination ("triple combo") will provide a wide variety of physical property measurements of the openhole environment. Data produced from this tool will include GR, neutron porosity, density, photoelectric factor, spontaneous potential, temperature, and resistivity logs. These logs will provide the ability to assess formation top depths (previously estimated from nearby wells), lithology, and petrophysical characteristics (which will be important in identifying well test and completion intervals and correlating core test data to offset wells).

- BHC sonic will provide a means for derivation of sonic porosity (a metric of connected, fluid-filled pore space), which will prove useful in zones characterized with complex lithologies.

- Spectral GR logs provide a means by which lithology can be interpreted and aid in core-to-log correlation.

- Capture spectroscopy logs provide an assessment of mineralogy and lithology and enhance extrapolation of core/log correlations of geologic properties based on lithology profiles to offset wells.

- Reservoir temperature logs measure borehole fluid temperature to establish reservoir conditions and provide information needed to design safe, low-risk infrastructure (i.e., pipeline specifications).

- Casing bond logs and casing collar locator (CCL) logs will provide an assessment of cement quality (and any associated remedial cementing operations that are required), a measurement of cement top, and a depth correlation for perforation and installing downhole equipment in relation to geology.

Table 9-1. Anticipated Core Analysis Program for the Johnsons Corner Site

Formation	Organization/ Lab	Inyan Kara	Broom Creek	Objective
Core Preparation				
Total Core, ft	Schlumberger	90	60	
Core Transportation	Core Laboratories	–	–	
Core Slabbing	Core Laboratories	–	–	Sample preparation, core description, sample selection
Core Photos	Core Laboratories	–	–	Sample preparation, core description, sample selection
Sample Cutting	EERC	20	15	Sample preparation
Sample Interval Photos	EERC	20	15	Sample preparation
Sample Prep and Distribution	EERC	20	15	Sample preparation
Thin Section Preparation	Wagner Petrographic	20	15	Core description, porosity assessment
Core Analysis				
Spectral Gamma Ray	Core Laboratories	–	–	Core to log correlation, sample selection/evaluation
XRD	EERC	5	5	Mineralogy, core to log correlation, fluid/matrix interactions
XRD Clay Typing	EERC	5	5	To be determined based on XRD and brine perm test results, identify swelling clays that could impact permeability/injection rates, evaluate need for treatment/stimulation programs,
XRF	EERC	5	5	Sample chemistry for validating XRD and geochemical evaluations
SEM Morphology	EERC	5	5	Mineralogy, chemistry, detailed descriptions of pore lining for core to log correlation
Thin Section Description/ Photography	EERC	20	15	Mineralogy, grain size, sorting, angularity pore filling
Bulk Volume Scan	EERC	20	15	Used to calculate porosity
Porosity	EERC	20	15	Generate improved core-to-log correlations, improved geologic characterization and simulation modeling,
Air Permeability	EERC	20	15	Generate improved core-to-log correlations, improved geologic characterization and simulation modeling, direct model input
Cyclic Brine NMR	EERC	0	3	Correlate fluid density changes to downhole logs Capillary pressure curves generated
Geochemical Evaluation	EERC	0	2	Identify interactions between native reservoir brine, injected brine, and rock that could impact permeability/injectivity (precipitation, swelling clays, scaling, etc.)
Supplies	EERC			NA
Reporting				
Analysis, Interpretation, and Reporting	EERC			

Table 9-2. Proposed Characterization and Test Program for the BEST-E1, BEST-I1, Rink SWD 1, and Rink SWD 2 Wells

Technique/Well/Interval	Quantity	Justification
Core Collection		
BEST-I1		
Inyan Kara	90 ft (~5300−5390 MD)	Build a core-to-log porosity and permeability correlation to aid in extrapolation of ARM test results to other areas. Investigate chemical/mineralogical reactions within Inyan Kara Formation exposed to Rink SWD 1 and Rink SWD 2 injectate to inform AMR test design and interpretations and to mitigate operational factors that could lead to equipment failures. Understand injected fluid and tracer movements within the Inyan Kara Formation to aid in design of tracer study. Investigate treatment programs that may be necessary for the BEST-E1 well.
Broom Creek	60 ft (~7450−7510 MD)	Test for fluid and mineralogical reactions with anticipated injected fluid chemistries that could affect permeability, to mitigate operational factors that could lead to reduced injectivity or equipment failures and to select fluid chemistry for step rate test. Build a core/log correlation for porosity and permeability to reduce uncertainty in injectivity predictions and to inform ARM test parameters (ARM extraction volumes in the BEST-E1 will be constrained by maximum brine injection rates in BEST-I1).
Step Rate Test		
BEST-I1		
Broom Creek	1	Determine formation parting pressure to accurately determine maximum injection pressure/rate (ARM extraction volumes in BEST-E1 will be constrained by maximum brine injection rates in BEST-I1). Calculate injectivity index and determine an injection rate at various WHP/BHP.

Continued…

Table 9-2. Proposed Characterization and Test Program for the BEST-E1, BEST-I1, Rink SWD 1, and Rink SWD 2 Wells (continued)

Technique/Well/Interval	Quantity	Justification
Well Logging		
BEST-I1		
Triple Combo and BHC[1] Sonic	TD-surface (~8000 ft)	Quantify variability in reservoir properties within the ARM test area within the Inyan Kara and Broom Creek Formations. Provide an input for enhanced geomodeling and predictive simulation of brine injection into Inyan Kara/Broom Creek Formations to improve ARM test design and interpretations. Generate core/log correlations that can be extrapolated to surrounding areas and hypothetical ARM cases for investigating optimization based on ARM test results. Select well test intervals and well completion intervals.
Capture Spectroscopy/Spectral GR	TD-IK top (~3000 ft)	Lithology, identify clays that could affect injectivity, core/log correlations.
Fluid Sampling	Broom Creek – one sample	Collect reservoir fluid sample for testing of potential fluid and mineralogical reactions between injected fluid chemistry, formation fluid chemistry, select step rate test fluid chemistry, and formation mineralogy that could affect injectivity.
CCL/CBL	TD-surface (~8000 ft)	Regulatory requirements, cement top, cement bond quality, zonal isolation.
BEST-E1		
Triple Combo	TD-surface (~5700 ft)	Quantify variability in reservoir properties within the ARM test area within the Inyan Kara Formation. Provide an input for enhanced geomodeling and predictive simulation of brine injection into Inyan Kara/Broom Creek Formations to improve ARM test design and interpretations. Generate core/log correlations that can be extrapolated to surrounding areas and hypothetical ARM cases for investigating optimization based on ARM test results. Select well test intervals and well completions intervals. Estimate reservoir temperature for use in pipeline design and establish reservoir conditions for model validation.
CCL/CBL	TD-surface (~5700 ft)	Regulatory requirements, cement top, cement bond quality, zonal isolation.
Rink SWD 1		
Injection Profile Log	IK (~100 ft)	Allocate injection through Inyan Kara interval to improve predictions and interpretation of ARM tests and tracer study. Extrapolate results to surrounding areas and hypothetical ARM cases for investigating optimization based on ARM test results.
Rink SWD 2		
Injection Profile Log	IK (~100 ft)	Allocate injection through Inyan Kara interval to improve predictions and interpretation of ARM tests and tracer study. Extrapolate results to surrounding areas and hypothetical ARM cases for investigating optimization based on ARM test results.

[1] Borehole compensated.

- Injection profile logs in the Rink SWD 1 and Rink SWD 2 wells will provide a means of allocating brine injection and brine extraction to the different zones of the Inyan Kara Formation. This allocation will improve and validate modeling-based predictions and support the interpretation of ARM tests and tracer studies.

- Formation fluid and pressure sampling will be used to acquire fluid sampling for the Broom Creek interval to test for potential fluid and mineralogical reaction between the formation and nonnative brine, which could affect injectivity.

9.2.3 Characterization for the Broom Creek Formation

Injectivity into the extracted brine disposal zones will affect ARM test operating parameters. Specifically, the maximum extraction rate from the Inyan Kara Formation and associated BEST-E1 electric submersible pump (ESP) and the BEST-I1 injection pump specifications will be constrained by maximum extracted brine disposal rate. The Broom Creek Formation is not as commonly used for injection purposes in North Dakota and is not a source of hydrocarbons; thus limited characterization and injection data exist for that formation in proximity to the Johnsons Corner location. While available regional data (e.g., injection rates, operator discussions, core analysis, well logs) suggest that injectivity into this formation is likely sufficient, lack of nearby offset data leads to an elevated degree of uncertainty (i.e., elevated risk) regarding the porosity, permeability, mineralogy, and injectivity into the Broom Creek Formation. There is also a risk that there may be geochemical reactivity between the injected brine, the native brine, and the mineralogy of the Broom Creek Formation (e.g., incompatibility between the brine and the clays), which could reduce injectivity.

To reduce the uncertainty and mitigate the risk posed by the potential for limited Broom Creek injectivity, it is critical that this formation at the Johnsons Corner site be thoroughly characterized. Geologic core samples will be collected and analyzed to determine mineralogy (with an emphasis on clay typing to determine the potential for clay swelling), porosity, permeability, and geochemical reactivity to Inyan Kara brines. A step rate test will be performed in the Broom Creek to determine the maximum injection rate that is possible without fracturing the reservoir (these data may be used in support of increasing maximum permitted injection pressure). The step rate test will also provide an injectivity index (maximum injection rates at various WHP/BHP) and better define operational flexibility which is constrained by the upper limits of brine injectivity within the Broom Creek Formation.

Fluid samples from the Broom Creek Formation will be collected to select the proper fluid chemistry for the step rate test and to help identify and predict potential geochemical changes (and subsequent clay swelling) that might occur as a result of mixing Inyan Kara brine with Broom Creek brine. A program of well logging focused on the Broom Creek Formation will also be conducted. If geochemical reactions or clay swelling is found to be a significant impairment to injection, several mitigation measures (acidizing, perforating additional intervals, swapping injection fluids/chemistry between Rink SWD 1 and BEST-I1, hydraulic stimulation, etc.) are available and discussed in the project risk assessment (Appendix B).

9.2.4 Baseline BSEM Survey

Baseline characterization will include the acquisition of a BSEM survey to obtain a measured image of the injection brine plume prior to ARM testing. These data will support validation of the input geologic model used as the basis for the predictive simulations. The plume shape and salinity distribution are measurable representations of the actual reservoir geologic character that can be used to improve the statistically derived geologic model. By injecting electric current into the reservoir formation and monitoring its return at the surface, the resistivity profile in the reservoir can be mapped in three dimensions and can be used to derive an image of the salinity plume.

The method is very low impact on the surface but does require access. The electrical nature of the source is not a health and safety hazard, but it could impact instrumentation in the well. For this reason the survey is planned after drilling and completing the injection well but prior to installation of any instrumentation such as pressure gauges. The survey will be carried out using both the BEST-I1 and the Rink SWD 2 well.

9.3 Active Reservoir Surveillance

Active reservoir surveillance includes the numerous activities designed and conducted to observe and quantify 1) tracking of pressure plume movement; 2) the effects of extraction on the Inyan Kara in terms of reservoir pressure, fluid chemistry, and fluid movement; and 3) the effects of injection on the Broom Creek Formation in terms of reservoir pressure and injection flow rates. The data generated by these monitoring activities will be the primary means by which ARM operations can be matched to simulation predictions, thereby supporting the interpretation and validation of the ARM testing operations. The Rink SWD 1, Rink SWD 2, and BEST-E1 wells will be used for the monitoring of conditions in the Inyan Kara Formation. The conditions of the Broom Creek Formation will be monitored using the BEST-I1 injection well. The data generated by these systems will also be key for managing ARM and surface operations and be used to mitigate HSE risks.

Active reservoir surveillance in the Inyan Kara will largely be based on continuous monitoring of pressure, temperature, flow rates, and fluid density from various points in both the downhole and surface wellhead environments (Figure 9-1, Table 9-3). Gauges in the three Inyan Kara wells will provide BHP and temperature data. The BEST-E1 well will have redundant downhole pressure/temperature gauges in the form of a casing-conveyed pressure/temperature gauge installed near the top of the Inyan Kara Formation and a pressure/temperature gauge mounted on the sensor of the ESP. Digital tubing pressure sensors will be used to provide continuous monitoring of pressure, including extraction pressure from the extraction well, and injection pressure from the Rink SWD 1 and Rink SWD 2 wells. In addition, when combined with flowmeter and density meter data, WHP on all wells can be used to provide an estimate of BHP in the event of BHP gauge failure. Casing pressure sensors on all four wells will serve as a means of monitoring wellbore integrity. Flowmeters and fluid density meters in the extraction well and the Rink SWD 1 and Rink SWD 2 wells will provide the ability to account for fluid extraction and injection volumes (i.e., mass balance). They will also identify changing fluid properties (e.g.,

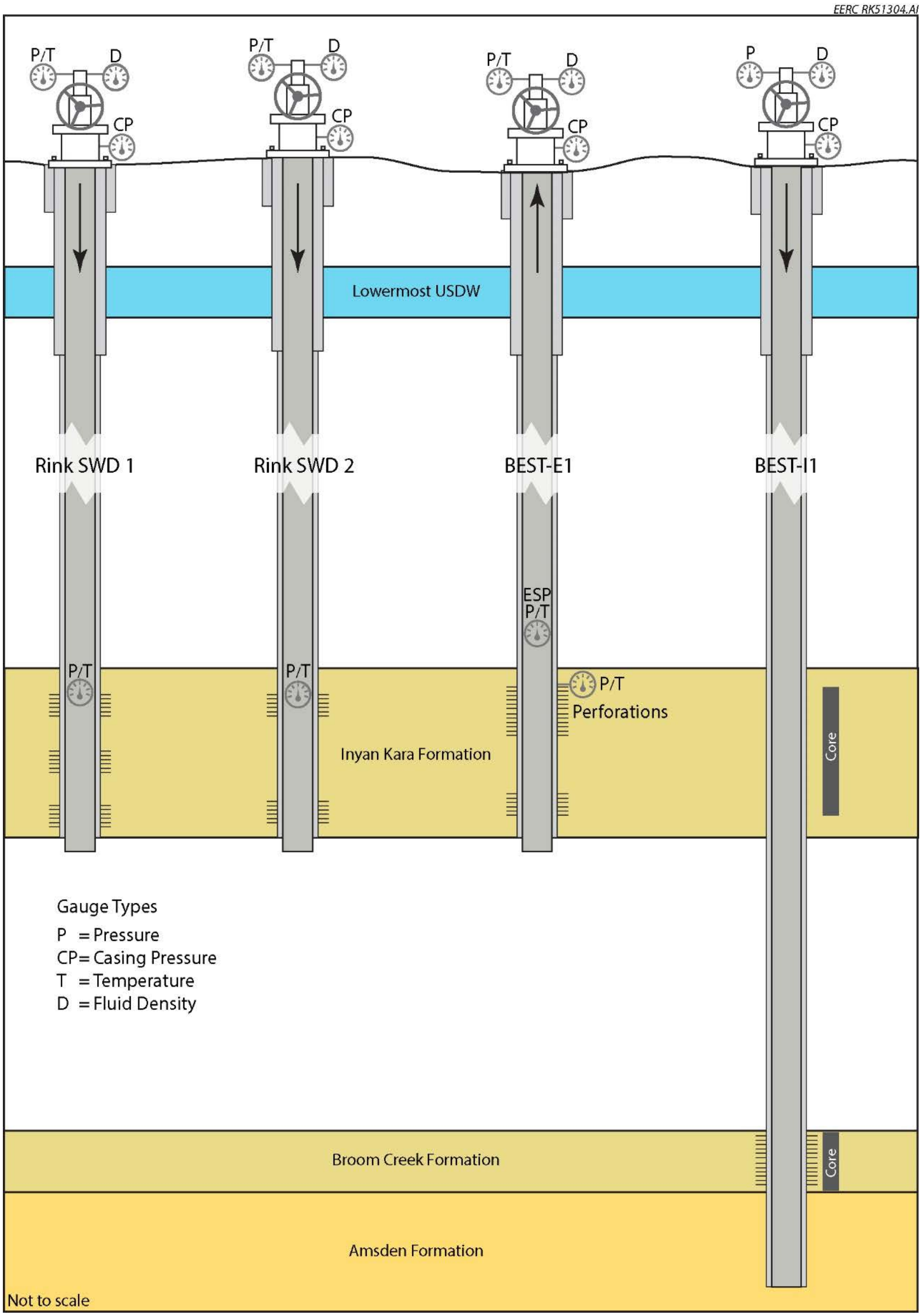


Figure 9-1. Schematic illustrating the active reservoir monitoring systems proposed for the BEST-E1, BEST-I1, Rink SWD 1, and Rink SWD 2 wells.

Table 9-3. Summary of ARM Monitoring and Surveillance Program for the BEST-I1, BEST-E1, Rink SWD 1, and RINK SWD 2 Wells

Technique/Well	Interval Monitored	Measurement	Frequency	Justification
BHP/BHT[1] Gauges				
BEST-E1 (ESP and casing conveyed)	Inyan Kara	Pressure/ temperature	Continuous	Monitor pressure regime throughout the experiment, correct WHP for fluid friction, ARM interpretation/validation, pressure interference testing, shut-in testing
Rink SWD 1 (suspended)	Inyan Kara	Pressure/ temperature	Continuous	Monitor pressure regime throughout the experiment, correct WHP for fluid friction, monitor reservoir pressure when injection is idle, ARM interpretation/validation, pressure interference testing, shut-in testing
Rink SWD 2 (suspended)	Inyan Kara	Pressure/ temperature	Continuous	Monitor pressure regime throughout the experiment, correct WHP for fluid friction, monitor reservoir pressure when injection is idle, ARM interpretation/validation, pressure interference testing, shut-in testing
Digital Tubing and Casing Pressure				
BEST-I1	Broom Creek	Pressure	Continuous	Monitor injection pressure, wellbore integrity monitoring
BEST-E1	Inyan Kara	Pressure	Continuous	Monitor extraction pressure, wellbore integrity monitoring
Rink SWD 1	Inyan Kara	Pressure	Continuous	Monitor injection pressure, wellbore integrity monitoring
Rink SWD 2	Inyan Kara	Pressure	Continuous	Monitor injection pressure, wellbore integrity monitoring
Flowmeters				
BEST-I1	Broom Creek	Flow rate	Continuous	Accounting/mass balance
BEST-E1	Inyan Kara	Flow rate	Continuous	Accounting/mass balance
Rink SWD 1	Inyan Kara	Flow rate	Continuous	Accounting/mass balance
Rink SWD 2	Inyan Kara	Flow rate	Continuous	Accounting/mass balance
Fluid Density				
BEST-I1	Broom Creek	Density	Continuous	Accounting/mass balance, interpretation of fluid properties and BHP
BEST-E1	Inyan Kara	Density	Continuous	Accounting/mass balance, interpretation of fluid properties and BHP
Rink SWD 1	Inyan Kara	Density	Continuous	Accounting/mass balance, interpretation of fluid properties and BHP
Rink SWD 2	Inyan Kara	Density	Continuous	Accounting/mass balance, interpretation of fluid properties and BHP
Water Sampling				
BEST-E1	Inyan Kara	Water chemistry/tracer via production samples	Variable, periodic	Monitor for changes which indicate brine plume/tracer breakthrough, sample collection from production stream
BSEM				
BEST-I1 Rink SWD 2	Inyan Kara	Borehole EM source and surface receivers	Baseline and 1 repeat at end of project	Image the salinity plume and distribution, calibrate simulator predictions

[1] Bottomhole temperature.

Continued…

Table 9-3. Summary of ARM Monitoring and Surveillance Program for the BEST-I1, BEST-E1, Rink SWD 1, and RINK SWD 2 Wells (continued)

Technique/Well	Interval Monitored	Measurement	Frequency	Justification
Tracer Survey				
Rink SWD 1 – Injector Rink SWD 2 – Injector BEST-E1 – Monitor	Inyan Kara	Chemical tracer	Periodic	Identify breakthrough of injected brine, distinguishing brine injected after start of extraction from brine injected prior to start of injection, calibrate and validate simulation predictions

brine salinity) and be used to correlate WHP to BHP. This system will also allow for shut-in pressure monitoring of the Inyan Kara Formation.

The active reservoir surveillance component of the MVA plan will include tracer studies. Specifically, tracers will be introduced into the Inyan Kara reservoir through the Rink SWD 2 and Rink SWD 1 injection wells. Formation fluids from the BEST-E1 well will be periodically sampled and analyzed for the tracers. The tracer studies will provide indications of the speed and direction of movement within the brine plume and a means of independently distinguishing and confirming breakthrough of brine injected from the Rink SWD 1 and Rink SWD 2 wells after the start of ARM testing from brine injected prior to ARM testing. These data, in turn, will enable the modification and validation of geomodel properties and simulation predictions with respect to fluid flow regimes, thereby leading to more accurate interpretations of other reservoir surveillance data and provide guidance to subsequent ARM operations. Understanding the occurrence of breakthrough is also valuable data regarding economics for future CCS operations, as these operations would seek to avoid experiencing CO_2 breakthrough as a result of ARM.

9.4 Infrastructure Surveillance

9.4.1 Tank Monitoring

The fluid level in each storage tank will be continuously monitored to minimize the risks of spills and support management of ARM and extracted brine treatment operations, particularly with respect to minimizing downtime. Two different forms of tank-level monitoring equipment will be deployed for the BEST-E1 and BEST-I1 locations. A float system will track tank levels and activate a low-level kill switch and a high-level activation switch on the charge pumps. The tanks will also be outfitted with radar-level sensing equipment as a redundant spill/overflow safety and environmental risk mitigation measure. Tank-level information will be incorporated into the remote sensing system and provide key data on available brine volumes and buffer capacity to aid in ARM and water treatment operations management and planning.

9.4.2 Flowmeters

Flowmeters will be installed on all transfer pumps, charge pumps, the injection pump, and both ends of the pipeline (see Appendix D.7.7). These flowmeters, distributed throughout the brine-handling infrastructure, will provide a means of monitoring for leaks across the entire pipeline and flowline system. The flowmeters also provide detailed accounting of fluid transfer between the extraction site, injection site, and to and from the water treatment demonstration facility. This accounting is necessary to distinguish water extracted and reinjected as part of the ARM test from commercial SWD operations which pay royalties for water disposal based on injection volumes. All flowmeters will also be tied into a remote sensing system.

9.4.3 Pump Pressure Management

Injection, transfer, and charge pumps will all be fitted with high-pressure and low-pressure kill systems with battery backup motor control valves in the event of a power failure. This will ensure the safety of personnel, equipment, and the environment. It will minimize the risk of exceeding injection pressure limitations set by the state. It will also minimize the risk of damage to equipment because of overpressures. Injection pumps will also include mechanical pressure relief valves as a secondary means of shutting down operations before the injection pressure limit is reached.

9.4.4 Pipeline Monitoring System

The approach taken to monitor and detect leaks of the proposed pipeline involves two components: monitoring with devices coupled with supervisory control and data acquisition (SCADA) and physical leak detection devices employed along the pipeline.

The pipeline will be outfitted with a flowmeter and digital pressure gauges on the inlet and outlet ends of the pipeline where they connect to other infrastructure. These devices can be read locally but more importantly will also provide a reading back to a central SCADA system. The flow rate and pressure at both ends will be compared in real time by the SCADA to verify correlation with measured readings from the start, while daily total flow volumes from the two flowmeters will be compared daily and verified to be within a certain percentage of each other. All of these measurements will be done as an accounting of volume extracted and an early detection of any flow anomalies (an indication of a leak).

In addition to these traditional, less sophisticated leak detection methods, HydraProbes will be installed every 75 ft along the pipeline in the backfill adjacent to the pipe, in accordance with guidelines set forth by the EERC (2015). The HydraProbes are capable of simultaneously measuring moisture, electrical conductivity, and temperature. These measurements will be sent back to the SCADA system for real-time and long-term collection of these measurements.

All surface flow lines will be within containment and visually inspected on a daily basis.

9.4.5 Remote Sensing System

All digital data (casing pressure, tubing pressure, flowmeter data, fluid density data, BHP, BHT, tank level, pipeline, and flowline monitoring data, etc.) will be tied into a real-time remote monitoring and data-logging system. This system will be used to 1) improve site operations and planning efficiency, 2) mitigate HSE risks by providing a snapshot of system health and allowing minimal response times to any operational deviation, and 3) provide automated control and shutdown of key systems in the event of an unanticipated deviation in performance.

9.5 Iterative Modeling, Simulation, and Prediction

The use of iterative modeling, simulation, and prediction are essential components of the ARM monitoring program. The results of those efforts, when conducted in conjunction with active reservoir surveillance and combined with the BSEM surveys imaging brine plume distribution, will serve as the primary basis for validation of the effectiveness of the ARM operations. The optimization of reservoir storage space through the manipulation of pressure using ARM is a complex process that depends on the full breadth of geologic conditions within the reservoir system. A wide variety of data that describe the petrophysical, geomechanical, hydrodynamic, geochemical, and geothermal conditions of the reservoir, at scales ranging from near wellbore- to local site-scale, are necessary to identify, quantify, and map the effects of fluid extraction on reservoir pressure and the evolution of brine salinity distribution. Static and dynamic numerical modeling is a means of using these data to understand, evaluate, and predict those effects. The baseline modeling and simulations that were used to develop the ARM implementation plan presented in this document will also serve as the starting point for the subsequent modeling and simulations. These models and associated predictive simulations will be enhanced through additional characterizing and monitoring data and iteratively updated during the extraction operations. As such, the application of active reservoir surveillance data to iterative modeling, simulation, and prediction is an essential component of the Johnsons Corner MVA efforts for assessing and validating ARM performance.

The reliability and inherent usefulness of the iterative modeling, simulation, and prediction elements of the MVA program is heavily influenced by the quantity and quality of the data upon which they are based. In particular, the validation component of the MVA plan relies on the ability to precisely quantify and determine the spatial distribution of the differential pressure caused by extraction. Those determinations will largely be based on the results of modeling activities, especially history matching. A model that is based on a more limited data set will yield outcomes with greater degrees of uncertainty. The level of uncertainty in model predictions for Inyan Kara pressure differentials related to ARM can be reduced by the history matching of 1) past fluid injection activities in the Rink SWD 1 and Rink SWD 2 wells and 2) observations of reservoir response from those same wells during ARM operations. To ensure a high degree of reliability and reduce the uncertainty of the geologic model and associated predictive simulations of differential pressure changes, the continuously generated data from active reservoir surveillance activities will be used to conduct iterative history-matching and model revision exercises.

From an MVA perspective, the primary outputs of the iterative modeling, simulation, and predictive exercises will be maps of differential pressure distribution at selected time intervals. Specific time intervals (i.e., iterations) will be selected to represent different stages of testing conducted under the ARM operations. The initial iteration and the final iteration will be compared to images of the brine plume that will be generated by the preinjection and postinjection BSEM surveys. Together, these results will be used to validate simulation predictions.

9.6 Final Site Characterization

Final site characterization includes activities designed and conducted to determine the ending compositions and qualities of the extraction target formation (i.e., produced brine compositional analysis). It also includes a second BSEM survey at the end of the active extraction operations to determine the shape and distribution of the site’s high-salinity injection plumes after extraction operations have ceased. These data will provide validation for simulation predictions and an assessment of the validity of BSEM for tracking injected fluid plumes under ARM conditions.

10.0 JOHNSONS CORNER IMPLEMENTATION PLAN

The experimental scenario described will require the installation of an extraction well completed in the Inyan Kara Formation (BEST-E1), an extracted brine disposal well completed in the Broom Creek Formation (BEST-I1), brine-handling equipment (e.g., storage tanks, pipeline, etc.), and support infrastructure (e.g. additional power lines, access roads, etc.).

Installation of these project elements will require several permits from the state of North Dakota and McKenzie County. The site operator, Nuverra, already has several of these permits and associated surety bonds in place, and has agreed to acquire the remaining permits and bonding necessary to conduct BEST.

A site implementation plan has been developed to provide space and facilities to meet drilling and operation requirements for the proposed BEST. Figure 10-1 illustrates the existing and proposed infrastructure at the Johnsons Corner site. The proposed test will require:

- Construction of facilities and drilling of a well on the BEST-E1 location.
- Construction of facilities, installation of the command center, and drilling of a well on the BEST-I1 location.
- Pipeline and utilities installation to link the BEST-E1, BEST-I1, and Rink SWD locations.

Details pertaining to the extracted brine treatment technology test bed, including the design and installation plan are discussed in Section 11.0.

A process flow diagram illustrating major components and unit operations of the Johnsons Corner site is provided in Figure 10-2. All design and implementation activities have been examined by the project team to maximize efficiency and minimize construction time and cost. During drilling and completion operations, BEST-E1 and BEST-I1 will be drilled and completed in stages, as will installation of the brine-handling infrastructure, in order to improve cost-efficiency of resources deployed on-site.

The first well drilled will be BEST-I1, which allows additional time for geochemical testing and characterization of core and log data. Drilling BEST-I1 first also allows the option of gathering cores and wireline logs on BEST-E1 if they are not successfully acquired from BEST-I1. Immediately after drilling BEST-I1, the rig will be moved to the BEST-E1 location to minimize mobilization/demobilization costs. Completion of both wells will be carried out once the final perforation intervals for both wells have been determined. The wells will be completed consecutively; first BEST-I1 will be completed and will immediately be followed by BEST-E1. This will minimize mobilization/demobilization costs of the workover rig and allow more time to install infrastructure and water treatment facilities on the BEST-I1 location. Installation of additional infrastructure and downhole monitoring equipment for Rink SWD 1 and Rink SWD 2 will also be done consecutively to improve cost-efficiency. For the same reasons, utilities for each site will also be installed consecutively.

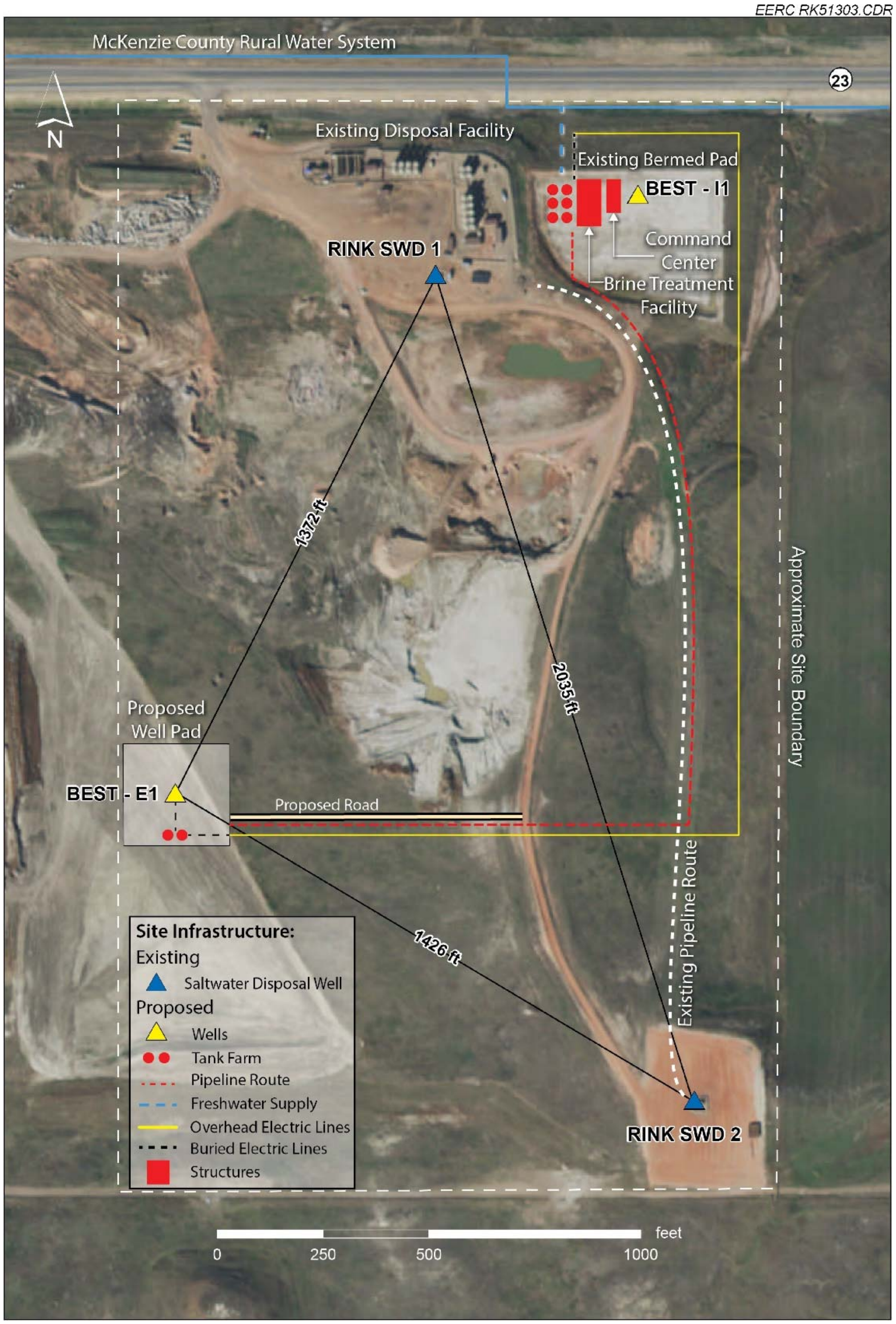


Figure 10-1. Map showing the location of existing and proposed infrastructure at the Johnsons Corner site.

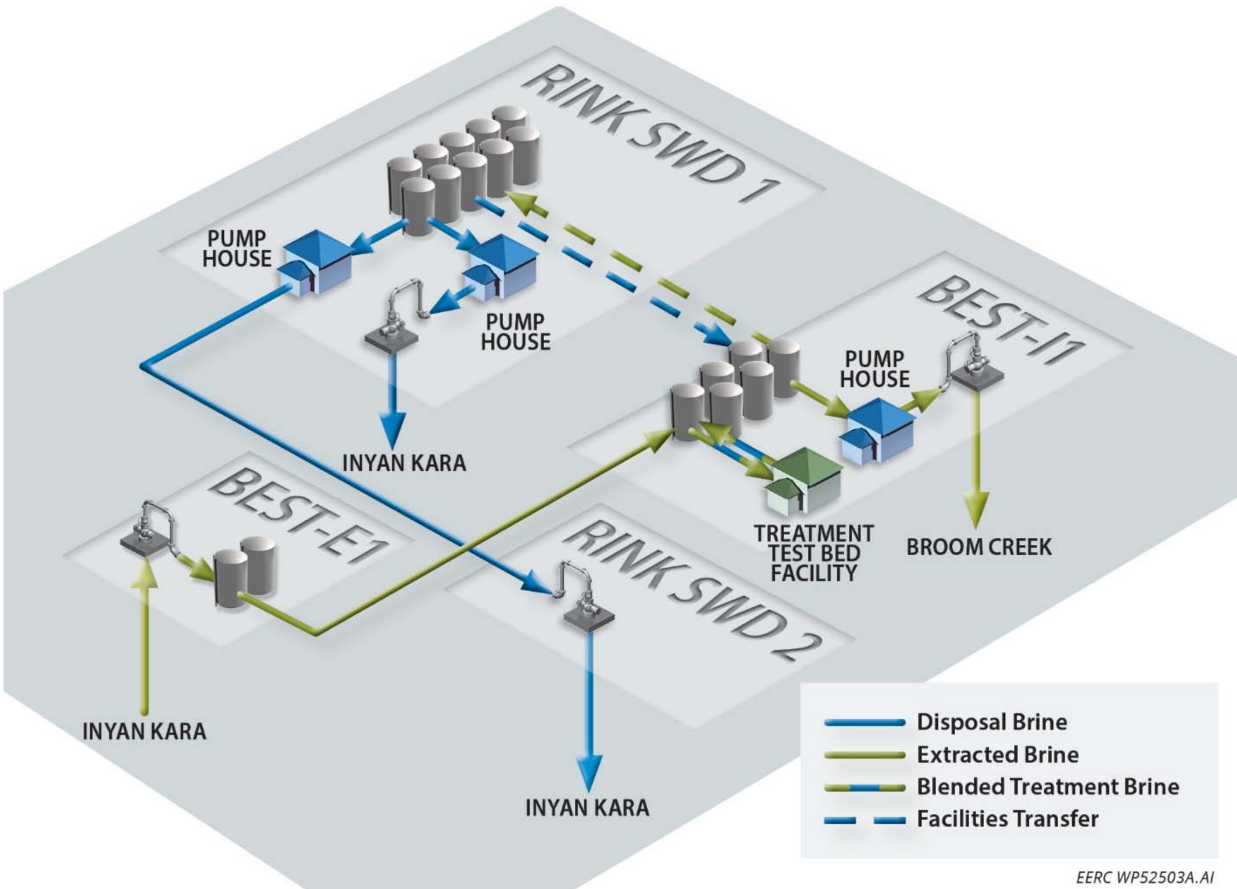


Figure 10-2. Conceptual illustration of the injection and extraction well configuration and the integrated water-handling and storage infrastructure and extracted brine treatment test bed facility.

10.1 Permitting

Nuverra has agreed to obtain all permits and provide all necessary surety bonds for the two new wells, brine-handling and storage infrastructure, and extracted brine treatment facilities necessary to conduct the proposed project. NDIC and the North Dakota State Water Commission are the primary regulatory and permitting authorities. They have been engaged with the EERC while the design and implementation plans were developed and are prepared to work with the EERC and Nuverra to ensure that all necessary and required documents are submitted with the permit applications. If awarded, the EERC will provide support to Nuverra through the permitting process. As the project manager, the EERC will ensure that all necessary permits are in place and that planned activities are in compliance with permit requirements prior to construction and operation of the proposed facilities. A brief summary of the permitting process is provided below. Full details regarding the permitting process can be found in Appendix C.

The BEST-E1 and the BEST-I1 wells will be permitted as UIC Class II wells under North Dakota Administrative Code UIC rules and regulations. These wells and associated infrastructure will require the submission of six applications to receive the necessary permits: two "Application for Permit to Drill (NDIC Form 1)," two "Application for Injection – NDIC Form 14" permits, one permit for constructing a saltwater handling facility, and one application for a temporary source water appropriation permit to be renewed annually for one additional year with the North Dakota State Water Commission.

Once the NDIC and North Dakota State Water Commission permits are received, the EERC will work with Nuverra to submit and receive appropriate McKenzie County building permits. Nuverra has existing agreements allowing for site access, permission to drill, and water disposal into the pore space. The proposed extracted brine treatment technology test bed and brine storage infrastructure are expected to fall under existing Nuverra permits.

10.2 BEST-I1 Location

Prior to permitting, a survey will be conducted to delineate the BEST-I1 location boundaries and the location of the wellhead. The survey package will include a cut-and-fill and grading plan, associated elevation maps, and utility locates. A partial pad is already in place for this facility. Once completed, the necessary information will be submitted with the permit package.

Upon receiving a permit to drill, a contractor will finalize construction of the drilling and facilities pad for the BEST-I1 site, which is currently partially constructed. This will include the necessary grading to construct a drilling and facilities pad. It will also include necessary cut-and-fill and grading to construct a road. The pad provides sufficient space for a laydown area for a drilling rig, casing, and support equipment; brine-handling infrastructure; and water treatment facilities which will be installed after the well is completed. See Figure 10-1 for location design.

The pad will be constructed by lining with a geotextile liner to provide soil stability and to prevent seepage in the event of a spill. The geotextile liner will be covered with improved surface material (native soil mixed with Class 13 road gravel) to provide stability and compaction. The pad will then be topped with a locally native material known as scoria, which is analogous to gravel, to provide a firm top base and reduce rutting and standing water on location.

To provide access to the BEST-I1 location, a road will be constructed to connect with an existing road approximately 20 ft to the south. The road will be approximately 16 ft wide and excavated, graded, and topped with approximately 4 inches of scoria. The construction of the road and BEST-I1 pad is designed to provide consistent all-season access for industrial equipment and operations (e.g., drill rig, workover rig, roustabout, etc.) for the duration of the project with minimal need for maintenance.

The BEST-I1 site will use the existing 1-ft berm to minimize runoff in the event of spring melt or heavy rain and to act as secondary containment in the event of a spill on location. This is not a regulatory requirement; however, it is being employed as a best practice for mitigating environmental risk. Any runoff will drain into a constructed basin for collection and disposal. It is anticipated that the site pad and road will require approximately 1 week to complete after the design has been approved and the permits are finalized.

After the pad is constructed, a cellar will be dug, and a small top-hole drilling rig will be used to install and cement 80 ft of 16-in. conductor casing to surface to isolate unconsolidated sediments and protect shallow water zone (as required by permit). This 80 feet of conductor casing also allows appropriate room for the primary drilling rig to operate. After the conductor casing is installed, a primary drilling rig will be mobilized to the site and rigged up to begin drilling operations. A closed-loop system will be used with no reserve or cutting pits on location (as state law requires). Following state regulations, NDIC will be informed of spudding within 24 hr. The surface hole will be drilled to 1850 ft with freshwater gel mud using a 12¼-in. bit, after which surface casing will be installed and cemented to surface to protect USDWs. After surface casing operations are completed, a blowout preventer will be installed and pressure-tested.

Apart from coring activities, the remainder of the well will be drilled with an 8³/₄-in. bit and saltwater gel mud. Saltwater mud is used to minimize potential interaction with subsurface strata by balancing the mud chemistry with the native formation fluids. A saltwater mud is also used to prevent hole enlargement. The first core will be collected from an estimated depth interval of 5301–5391 ft (90 ft) in the Inyan Kara Formation. Drilling will resume until the next coring point is reached at an estimated depth of 7460 ft, where 60 ft of core will be collected from the Broom Creek Formation. Drilling will recommence and proceed to an estimated total depth (TD) of 7971 ft. An 8³/₄-in. PDC (polycrystalline diamond compact) bit and saltwater gel mud will be used for drilling. After reaching TD, the hole will be conditioned, and well logging will be conducted following the logging program described in Table 9-2.

After logging is completed, the hole will be conditioned for casing and cement. Seven-inch production casing will be run and cemented from TD to surface casing to ensure wellbore integrity. After casing is completed, a 5000-lb night cap will be installed for pressure control, and the drilling rig will be rigged down and mobilized to the BEST-E1 location.

A summary of the drilling and completions casing plan for BEST-I1 is shown in Table 10-1. TD and perforated intervals will be determined by an experienced on-site EERC geologist or engineer based on drilling and logging data. The estimated drilling time for BEST-I1 is 20 days. A detailed drilling prognosis for the BEST-I1 well can be found in Appendix D.1.1.

A workover rig will be mobilized to location and rigged up on the BEST-I1 well for well completions. The EERC will notify NDIC of its intent to complete the well before completion operations as stipulated by permit requirements. After rig up, the wellbore will be cleaned out to prepare for completion. To provide assurance of a quality cement job and secure connections between lengths of casing, a casing integrity pressure test (~2000 psi) will be conducted on the production casing. If the casing fails or the pressure fails, the primary engineer will be consulted and solutions employed, followed by retesting.

Upon a successful casing integrity pressure test, a wireline CBL with GR and CCL will be run from TD to surface to evaluate cement integrity and satisfy NDIC requirements. GR will be run from TD to surface. These logs are required by state regulation (NDIC) and will be used to depth-correlate the perforating interval. If CBL logs indicate issues with the top of cement (TOC) or cement bond quality, the primary engineer will be consulted and solutions employed, followed by retesting.

Table 10-1. Anticipated Drilling and Completions Summary for BEST-I1

String	Depth Interval,[1] ft	Bit Size, in.	Mud Type	Casing Diameter, Grade, and Type	Cement Interval, ft
Conductor	0–80	26	Freshwater	16 in., 42 lb/ft, grade B&C	0–80
Surface	0–1850	12¼	Freshwater gel	9⅝ in., 40 lb/ft, grade J55, LTC[2]	0–1850
Production	0–7971	$8^3/_4$	Saltwater gel	7 in., 26 lb/ft, grade L80, LTC	Surface–7971
Core Intervals	5301–5901 7460–7520				
Perforated Interval (4 spf [shot per foot], 90 deg)	7470–7535				

[1] All depths are approximate.
[2] Long-thread casing.

The production casing will be perforated into the Broom Creek Formation at an interval of 4 spf and a 90° phasing providing a 0.46-in. exit hole diameter and ~28-in. penetration. Specific perforating intervals in the Broom Creek will be determined based on interpretation of the logging results.

Injection tests with multiple rates and associated falloff pressure measurements will be used to assess the level of fluid communication with the formation. Based on calculations using results from the injection test, an acid stimulation will be performed to ensure the perforations are open. A packer will be set 50–100 ft above the top perforation following NDIC requirements using 4½-in., 10.5-lb/ft J55 internally coated tubing. Corrosion-inhibiting fluids will be employed to minimize wear of the packer and to provide additional casing protection. MIT will be performed on the well to a pressure of 1500 psi unless otherwise recommended by NDIC. Following state protocol, NDIC will be contacted to witness the MIT. Upon approval from NDIC, the well will be ready for installation of surface equipment.

The workover rig will be removed and the site cleared to allow installation of the remaining surface equipment and flowlines. Digital casing and tubing pressure, density, and flowmeters gauges will be connected to a SCADA system to provide real-time remote monitoring of well conditions. It is anticipated workover operations will require approximately 2 weeks to complete.

A summary of the completions program can be found in Table 10-1 and Figure 10-3. The entire completions program for the BEST-I1 well can be found in Appendix D.1.6.

After the well is completed, brine-handling facilities, infrastructure, command center, and water treatment facilities will be installed on the pad. The facilities will consist of flowlines, six

EERC RK51313.CDR

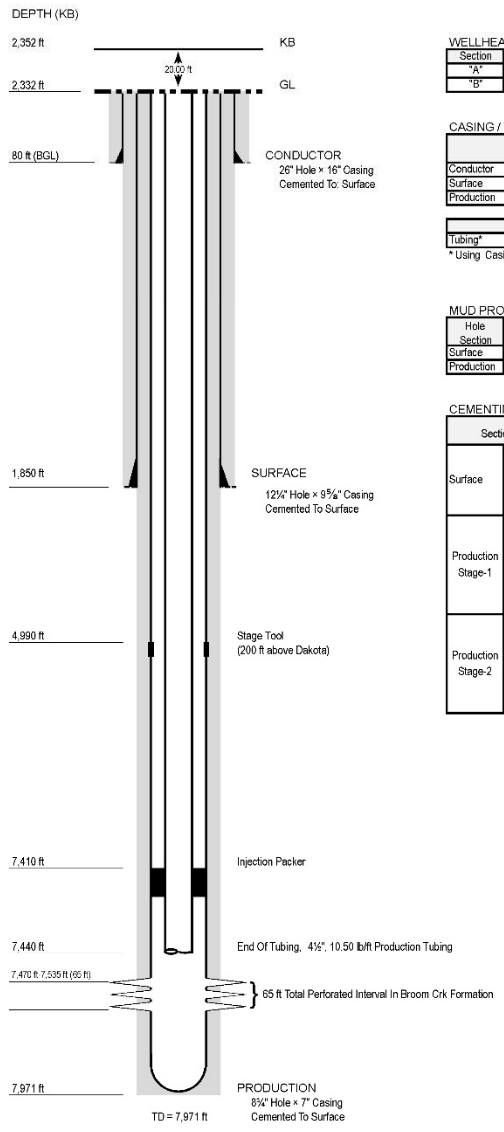
Schlumberger Carbon Services

NTG NEW TECH GLOBAL

ENERGY & ENVIRONMENTAL RESEARCH CENTER (EER
BRINE EXTRACTION INJECTION WELL: BEST - I1
PLANNED WELLBORE SCHEMATIC

Location: McKenzie Co., North Dakota
(Near Watford City)
Sec 21, Twn :150N Rng 96W

Date: 4/1/2016
Version: 5



WELLHEAD EQUIPMENT

Section	Item	Description
"A"	Casing Head	9⅝" SOW × 11" 5000 psi WP
"B"	Tunging Head	11" 5000 psi WP × 4½" 5000 psi WP

CASING / TUBING PROGRAM

	Hole Size	Casing OD	Weight	Grade	Conn	ID	Drift	Collapse	Burst	Joint
Conductor	26"	16"	42.00 lb/ft	B&C	PE	15.500	-	-	-	-
Surface	12¼"	9⅝"	40.00 lb/ft	J-55	LT&C	8.835	8.679	2,570	3,950	520,000
Production	8¾"	7"	26.00 lb/ft	L-80	LT&C	6.276	6.151	5,410	7,240	511,000

	Size	Lined?	Weight	Grade	Conn	ID	Drift	Collapse	Burst	Joint
Tubing*	4½"	Lined	10.50 lb/ft	J-55	LT&C	4.052	3.927	4,010	4,790	146,000

* Using Casing As Tubing

MUD PROGRAM

Hole Section	Interval	Type	MW (lb/gal)	VIS (sec/qt	PV (cP)	YP (lb/100 ft^2)	WL (cc/30 min)	Cl (ppm)
Surface	80'-1,850'	Freshwater	8.6-9.0	30-35	n/a	n/a	NC	n/a
Production	1,850'-7,971'	SW Gel	10.2-10.4	40-46			6 - 8	150,000-170,000

CEMENTING PROGRAM

Section		Sacks	Density (ppg)	Yield (ft³/sx)	Excess (%)	Vol (bbl)	TOC (feet)	Recipe
Surface	Lead	300	11.8	2.65	75%	141.4	0'	Class "G" + 2.0% BWOB D053 + 4.0% BWOB D079 + 0.25 lb/sx WBWOB D130 + 2.0% BWOC S001
	Tail	172	15.8	1.16	75%	35.5	1,550'	Class "G" + 0.25 lb/sx WBWOB D130 + 1.0% BWOC S001
Production Stage-1	Lead	172	11.5	2.16	30%	66.1	5,500'	Class "G" + 1.0% BWOC D013 + 0.20% BWOB D046 + 1.3% BWOC D079 + 0.07% BWOB D208 + 0.30% BWOC D238 + 3.0% BWOW M117
	Tail	99	15.8	1.16	30%	20.5	7,400'	Class "G" + 0.2% BWOC D046 + 0.20% BWOC D065 + 0.30% BWOC D153 + 0.30% BWOC D167 + 0.50% BWOC D800
Production Stage-2	Lead	448	11.5	2.16	30%	172.3	0'	Class "G" + 1.0% BWOC D013 + 0.20% BWOB D046 + 1.3% BWOC D079 + 0.07% BWOB D208 + 0.30% BWOC D238 + 3.0% BWOW M117
	Tail	34	15.8	1.16	30%	7	5,300'	Class "G" + 0.2% BWOC D046 + 0.20% BWOC D065 + 0.30% BWOC D153 + 0.30% BWOC D167 + 0.50% BWOC D800

FORMATION TOPS

Formation	KB
Greenhorn	4,395 ft
Mowry	4,844 ft
Skull Creek	4,964 ft
Dakota (Inyan Kara)	5,190 ft
Swift	5,588 ft
Rierdon	5,688 ft
Spearfish	6,600 ft
Top of Pine Salt	6,807 ft
Base of Pine Salt	6,856 ft
Minnekata	7,040 ft
Opeche	7,083 ft
Top of Opeche Salt	7,123 ft
Base of Opeche Salt	7,193 ft
Broom Creek	7,470 ft
Amsden	7,535 ft
Tyler	7,871 ft
TD	7,971 ft

NOT TO SCALE

Figure 10-3. BEST-I1 well schematic.

500-bbl fiberglass tanks and a charge pump, transfer pumps, injection pump, and water treatment facilities (Figure 10-4) to inject extracted fluid into the BEST-I1 wellbore and perform water treatment operations. The Best-I1 location will be used to supply water to the brine treatment test bed facilities and dispose of extracted water from the BEST-E1 well. An aboveground flowline outfitted with digital density, pressure, and flowmeters will connect the BEST-I1 wellhead to the 500-bbl fiberglass production tanks.

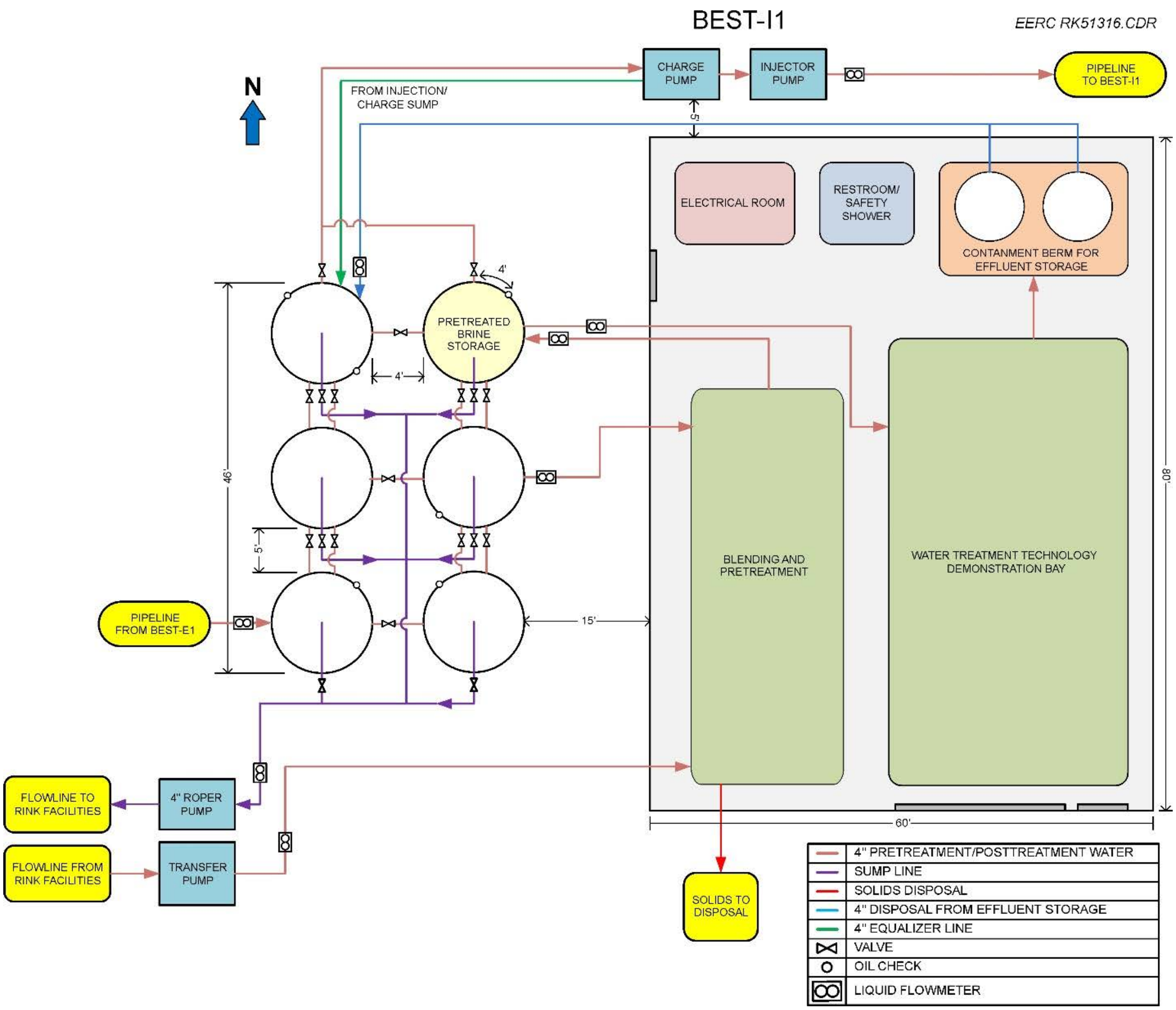


Figure 10-4. Flow path of fluids on BEST-I1 site.

Extracted water from BEST-E1 will enter five 12-ft × 25-ft heat-traced and insulated 500-bbl fiberglass tanks connected in series. These tanks will be installed to 1) remove any pressure head from the extracted fluid, 2) provide solids settling prior to entering water treatment facilities and injector pump for disposal, and 3) provide buffer capacity between the pipeline and disposal operations. An additional tank will be dedicated to supply water to the water treatment demonstration facilities. This tank will provide storage and flow equalization for the water treatment demonstrations. After extracted fluid has traveled through tanks and mixed with effluent from the water treatment facilities, a charge pump housed in an insulated enclosure and incorporating a 300-µm filter pot will be used to pull water from the tanks and inject it into the BEST-I1 wellbore. The charge pump will be outfitted with high-pressure, low-pressure, and low-tank-level kill switches and a high-tank-level activation switch. The tanks will also be outfitted with radar-level sensing equipment as a redundant spill/overflow safety measure and to provide tank-level information to aid in operational planning. A transfer pump will also be installed to allow for transfer of fluids from BEST-I1 facilities to existing Rink SWD facilities. This allows fluid to be transferred throughout all facilities and provides operational flexibility (in the form of additional buffer capacity). See Figure 10-4 for a detailed drawing of flow path and operational flexibility in site facility design.

All flowlines and valves will be heat-traced, insulated, and installed aboveground to facilitate easy leak detection. Flowlines will consist of 4-in. SDR (standard dimension ratio) 11 poly pipe rated at 160 psi and will be installed aboveground to facilitate easy leak detection. In addition to the location berm, additional containment will be installed around the perimeter of on-site storage following state regulatory requirements. This will provide the capacity to contain a minimum of 1.5 times the total volume of the largest tank and total extracted volume for 1 day. Detailed build lists, equipment specifications, and installation procedures can be found in Appendix D.7.

After completion of the well and facilities, the brine-handling facilities will go through a shakedown process and be inspected for leaks. Once the integrity of the system is confirmed and tested and BEST-E1 facilities are operational, the system will be put into operation as outlined by the ARM experimental scenario design.

10.3 BEST-E1 Location

Prior to permitting, a survey will be conducted to delineate the BEST-E1 location boundaries and the location of the wellhead. The survey package will include a cut-and-fill and grading plan, associated elevation maps, and utility locates. Once completed, the necessary information will be submitted with the permit package.

Upon receiving a permit to drill, a contractor will be used to construct the drilling and facilities pad for the BEST-E1 site. This will include performing the necessary cut-and-fill and grading to construct a drilling and facilities pad and road. The pad is anticipated to be 250 × 250 ft and is designed to minimize the surface footprint while providing sufficient space for drilling operations, the brine-handling infrastructure which will be installed after the well is completed, and any well work that may be needed after the brine-handling infrastructure is installed (Figure 10-1).

The pad will be constructed by excavating and stockpiling the original topsoil. The excavated area will be lined with a geotextile liner to provide soil stability and serve as a mitigation measure to prevent seepage in the event of a spill. The geotextile liner will be covered with improved surface material (native soil mixed with Class 13 road gravel) to provide stability and compaction. The pad will then be topped with a native material known as scoria, which is analogous to gravel, to provide a firm top base and to reduce rutting and standing water on location.

To provide access to the BEST-E1 location, a road will be constructed to connect with an existing road approximately 700 ft to the east. The road will be approximately 16 ft wide and excavated, graded, and topped with approximately 4 in. of scoria. The construction of the road and BEST-E1 pad is designed to provide consistent all-season access for industrial equipment and operations (e.g., drilling rig, workover rig, roustabout, etc.) for the duration of the project with minimal need for maintenance.

The site will be enclosed by a 1-ft berm to minimize runoff in the event of spring melt or heavy rain event and will act as containment in the event of a spill on location. This is not a regulatory requirement; however, it is being employed as a best practice for mitigating environmental risk. Any runoff will drain into a constructed basin for collection and disposal. It is anticipated that the site pad and road will require approximately 3 weeks to complete after the design has been approved and the permits are finalized.

After the pad is constructed, a cellar will be dug and a small top-hole drilling rig will install 80 ft of 16-in. conductor casing and cement-to-surface to isolate unconsolidated sediments and protect shallow water zone (as required by permit). This 80 feet of conductor casing also allows appropriate room for the primary drilling rig to operate. After the conductor casing is installed, a primary drilling rig will be mobilized to the site and rigged up to begin drilling operations. A closed-loop mud system will be used with no reserve or cutting pits on location (following state law). Following state regulations, NDIC will be informed of spudding within 24 hr. The surface hole will be drilled to 1850 ft with freshwater gel mud using a $12^{1}/_{4}$-in. bit, after which surface casing will be installed and cemented to surface to protect USDWs. After surface casing operations are completed, a blowout preventer will be installed and pressure-tested.

Upon successful testing of the blowout preventer, drilling will continue to an estimated TD of 5688 ft with an 8¾-in. PDC bit and saltwater gel mud system. Saltwater mud is used to minimize potential interaction with subsurface strata by balancing the mud chemistry with the native formation fluids. Saltwater mud is also used to prevent hole enlargement. After TD is reached, the hole will be conditioned and well logging will be conducted following the logging program described in Table 9-2.

After logging is completed, the hole will be conditioned for casing and cementing operations. A casing-conveyed pressure/temperature gauge will be installed approximately 350 ft above the casing shoe. Casing installation will continue following PROMORE MORE^{C} standard installation procedures. The casing will be cemented from TD to 1350 ft, 500 ft into surface casing to ensure wellbore integrity. After casing is completed, a cap will be installed to provide pressure control, and the drilling rig will be released and mobilized off location.

A summary of the drilling and completions casing plan for the BEST-E1 well is shown in Table 10-2. TD, the location of the downhole pressure/temperature gauge, and perforated intervals will be determined by an experienced on-site EERC geologist or engineer based on drilling and

Table 10-2. Anticipated Drilling and Completions Summary for BEST-E1

String	Depth Interval,* ft	Bit Size, in.	Mud Type	Casing Diameter, Grade, and Type	Cement Interval, ft
Conductor	0–80	26	Freshwater	16 in., 42 lb/ft, grade B&C	0–80
Surface	0–1850	12¼	Freshwater gel	9⅝ in., 40 lb/ft, grade J55, LTC	0–1850
Production	0–5688	8¾	Saltwater gel	7 in., 26 lb/ft, grade L80, LTC	1350–5688
Pressure/Temperature Gauge	5306				
Perforated Interval (4 spf, 90 deg)	5348–5416 5500–5520				

* All depths are approximate.

logging data. The estimated time from moving the drilling rig onto the site to final rig release is estimated to be 12 days. A detailed drilling prognosis and drilling procedure for the BEST-E1 well can be found in Appendix D.2.1.

After the primary drilling rig is moved off of the location, a workover rig will be mobilized and rigged up on BEST-E1 to complete the well. The EERC will notify NDIC of its intent to complete the well before completion operations as stipulated by permit requirements. After rig up, the wellbore will be cleaned out to prepare for completion work. To provide assurance of a quality cement job and secure connections between lengths of casing, a casing integrity pressure test (~2000 psi) on the production casing will be conducted. If the casing fails or the pressure fails, the primary engineer will be consulted and solutions employed, followed by retesting.

Upon a successful casing integrity pressure test, a wireline CBL including a GR/CCL log will be acquired from TD to 300 ft above TOC to evaluate cement integrity and to locate the cement top. GR will be run from TD to surface. These logs are required by state regulation (NDIC) and will be used to depth-correlate the perforating interval. If CBL logs indicate issues with TOC or cement bond quality, the primary engineer will be consulted and solutions employed, followed by retesting.

The production casing will be perforated into the Inyan Kara Formation at an interval of 4 spf and a 90° phasing providing a 0.46-in. exit hole diameter and ~28-in. penetration. Specific perforating intervals in the Inyan Kara will be determined based on interpretation of the logging results. The top of the perforating interval will be located a minimum of one casing joint below the casing-conveyed pressure temperature gauge as correlated via the CCL log to minimize potential damage to the external gauge system.

As with BEST-I1, injection tests with multiple rates and associated fall-off pressure measurements will be used to assess the level of fluid communication with the formations. If injectivity is found to be unsatisfactory based on results of the injection test, an acid stimulation may be performed to ensure the perforations are open.

Following the injection test, a tubing-conveyed ESP will be deployed into the wellbore. This will be done with 4½-in., 10.5-lb/ft J55 internally coated tubing. The intake will be placed at approximately 5298 feet MD and be a minimum of 50 ft above the top perforation. The ESP cable will be strapped to the tubing, and sensor testing will be conducted approximately every 1000 ft (20 stands of tubing). Once the ESP is installed and tested, the wellhead will be installed, and the workover rig will be rigged down and mobilized off location. Remaining installation of the ESP surface equipment, casing and tubing pressure gauges, and the casing-conveyed gauge will be done and tied into a SCADA data system.

The ESP will provide a targeted production rate of 4000 bbl/day with the ability to modify this rate by approximately ±40% (i.e., 2500 to 6500 bbl/day). This flexibility will provide operational control of the ARM test and is anticipated to be sufficient to produce a measurable pressure response in Rink SWD 1 and Rink SWD 2. It is anticipated workover operations will require approximately 2 weeks to complete.

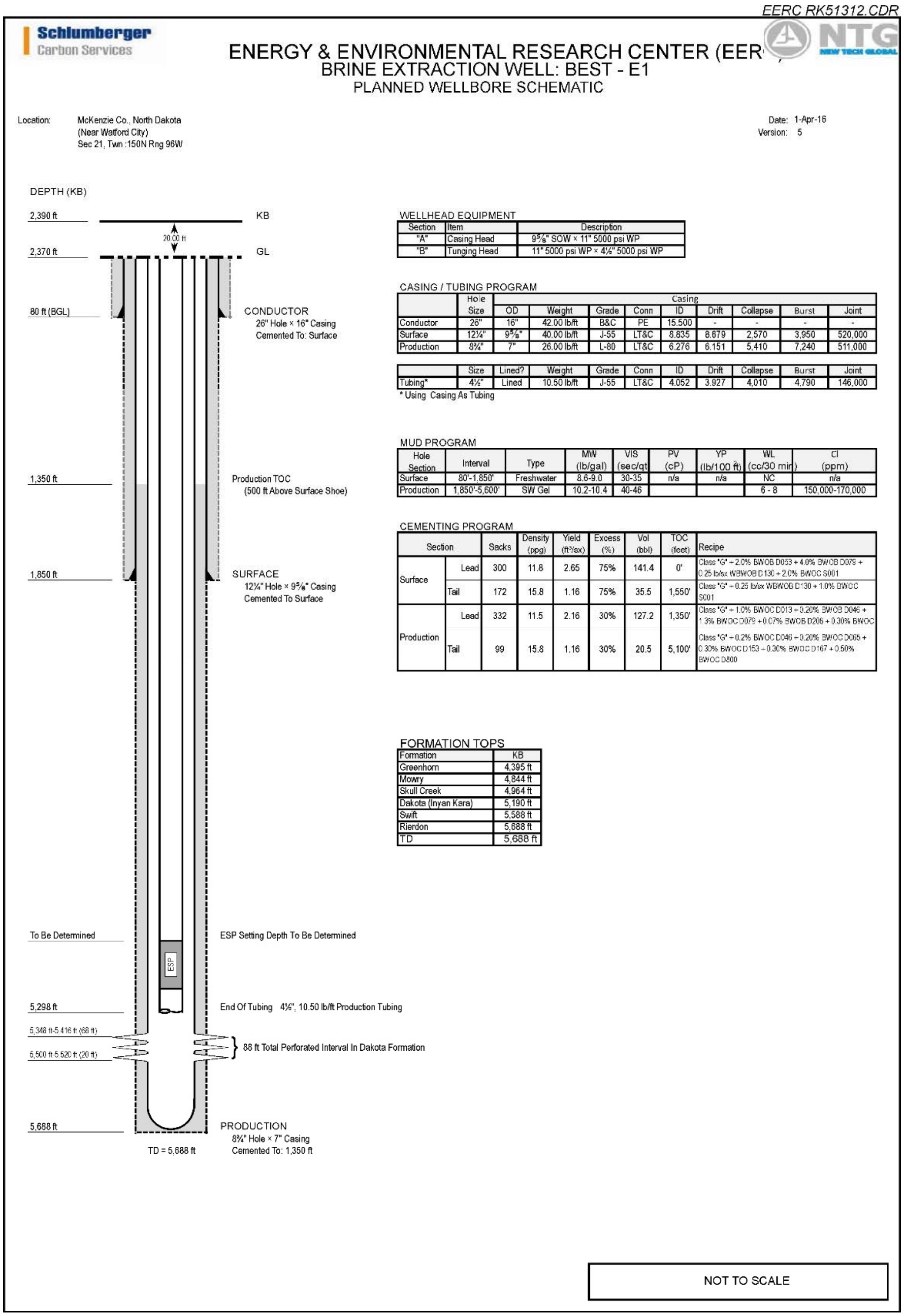
Downhole pressure at the BEST-E1 well is considered a critical component of the ARM MVA program. While the casing-conveyed pressure gauge is considered to provide the most accurate and precise measurement of BHP, the well will be equipped with two additional means of providing either direct or inferred measurement of BHP: 1) a digital tubing pressure gauge and fluid density meter and 2) a BHP gauge on the ESP sensor.

A summary of the completions program can be found in Table 10-2 and Figures 10-5–10-6. A detailed completions program and operating procedure for the BEST-E1 well can be found in Appendix D.2.6.

After the well is completed, brine-handling facilities will be installed on the pad. The facilities will consist of flowlines, a two-phase water knockout separator, a flare pit, two 500-bbl fiberglass tanks, and a charge pump with filtration (Figure 10-7) which will inject extracted fluid into the pipeline connected to the BEST-I1 tank battery.

An aboveground flowline outfitted with digital fluid density, pressure, and flowmeters will connect the BEST-E1 wellhead to a 6 ft × 20 ft two-phase water knockout separator rated at 75 psi. Any associated or dissolved gas in the extracted water stream will be diverted from the test separator to a flare pit on location. While produced gas is not expected, the flare system is being installed as a safety and risk mitigation measure. Any time fluid is injected into a reservoir, as is being done with the existing SWD wells, the potential exists for bacteria or chemical reactions that produce biogenic gas and/or H_2S. Any produced gas will be metered, documented, and flared on location.

Produced water will exit the two-phase separator and move through a flowline to two 12 × 25-ft heat-traced and insulated 500-bbl fiberglass tanks connected in series. These tanks will be installed to 1) remove any pressure head from the extracted fluid, 2) provide solids settling prior to entering the pipeline, and 3) provide buffer capacity between the wellhead and pipeline. A charge pump housed in an insulated enclosure will incorporate a 300-µm filter pot and be used to pull water from the tanks and inject it into an underground pipeline connected to the BEST-I1 tank



WELLHEAD EQUIPMENT

Section	Item	Description
"A"	Casing Head	9⅝" SOW × 11" 5000 psi WP
"B"	Tunging Head	11" 5000 psi WP × 4½" 5000 psi WP

CASING / TUBING PROGRAM

	Hole	Casing								
	Size	OD	Weight	Grade	Conn	ID	Drift	Collapse	Burst	Joint
Conductor	26"	16"	42.00 lb/ft	B&C	PE	15.500	-	-	-	-
Surface	12¼"	9⅝"	40.00 lb/ft	J-55	LT&C	8.835	8.679	2,570	3,950	520,000
Production	8¾"	7"	26.00 lb/ft	L-80	LT&C	6.276	6.151	5,410	7,240	511,000

	Size	Lined?	Weight	Grade	Conn	ID	Drift	Collapse	Burst	Joint
Tubing*	4½"	Lined	10.50 lb/ft	J-55	LT&C	4.052	3.927	4,010	4,790	146,000

* Using Casing As Tubing

MUD PROGRAM

Hole Section	Interval	Type	MW (lb/gal)	VIS (sec/qt	PV (cP)	YP (lb/100 ft²)	WL (cc/30 min)	Cl (ppm)
Surface	80'-1,850'	Freshwater	8.6-9.0	30-35	n/a	n/a	NC	n/a
Production	1,850'-5,600'	SW Gel	10.2-10.4	40-46			6 - 8	150,000-170,000

CEMENTING PROGRAM

Section		Sacks	Density (ppg)	Yield (ft³/sx)	Excess (%)	Vol (bbl)	TOC (feet)	Recipe
Surface	Lead	300	11.8	2.65	75%	141.4	0'	Class "G" + 2.0% BWOB D053 + 4.0% BWOB D079 + 0.25 lb/sx WBWOB D130 + 2.0% BWOC S001
	Tail	172	15.8	1.16	75%	35.5	1,550'	Class "G" + 0.25 lb/sx WBWOB D130 + 1.0% BWOC S001
Production	Lead	332	11.5	2.16	30%	127.2	1,350'	Class "G" + 1.0% BWOC D013 + 0.20% BWOB D046 + 1.3% BWOC D079 + 0.07% BWOB D206 + 0.30% BWOC
	Tail	99	15.8	1.16	30%	20.5	5,100'	Class "G" + 0.2% BWOC D046 + 0.20% BWOC D065 + 0.30% BWOC D153 + 0.30% BWOC D167 + 0.50% BWOC D800

FORMATION TOPS

Formation	KB
Greenhorn	4,395 ft
Mowry	4,844 ft
Skull Creek	4,964 ft
Dakota (Inyan Kara)	5,190 ft
Swift	5,588 ft
Rierdon	5,688 ft
TD	5,688 ft

Figure 10-5. BEST-E1 well schematic.

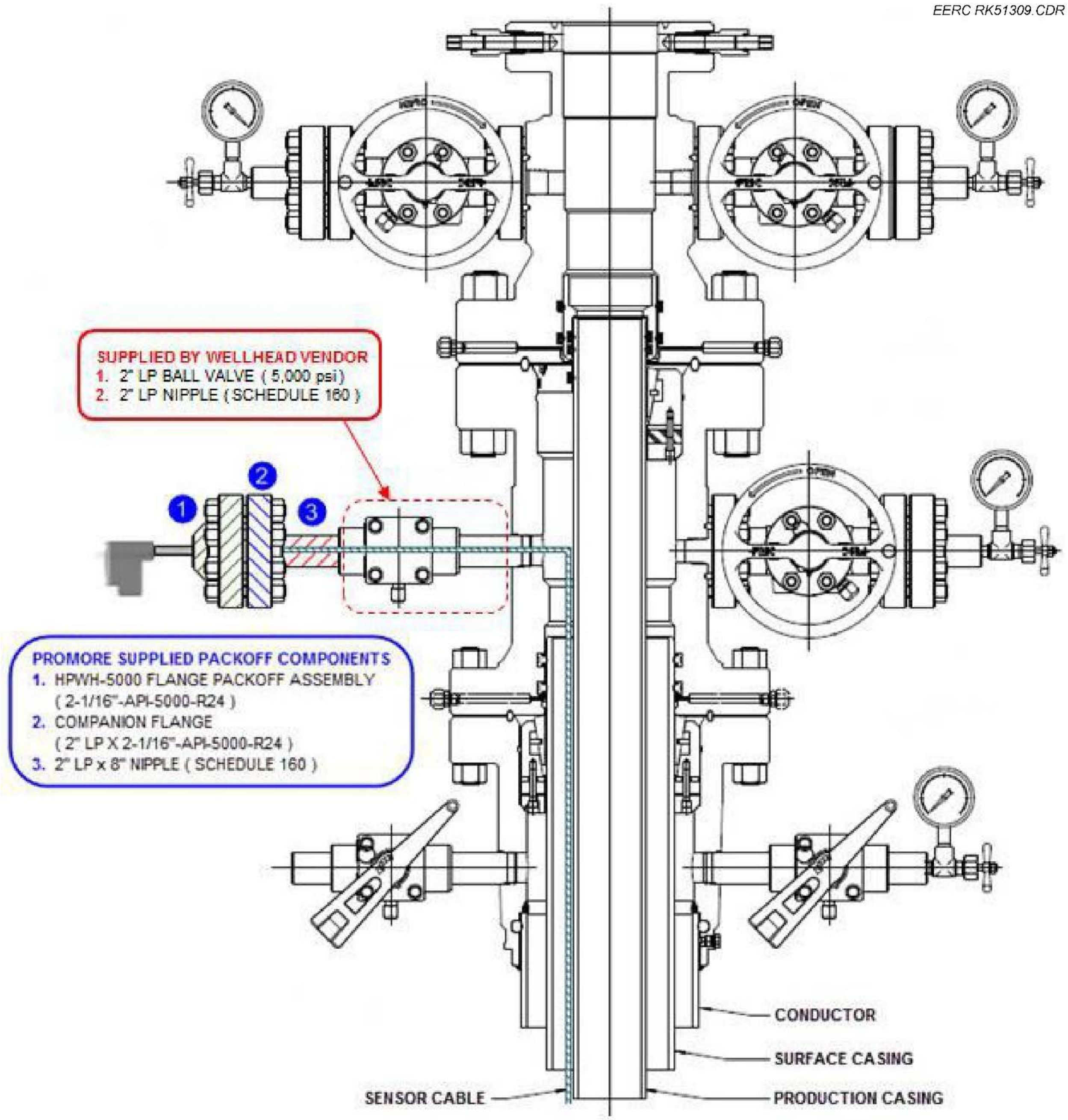


Figure 10-6. PROMORE wellhead schematic showing the additional packoff assembly necessary for installation of the downhole instrumentation.

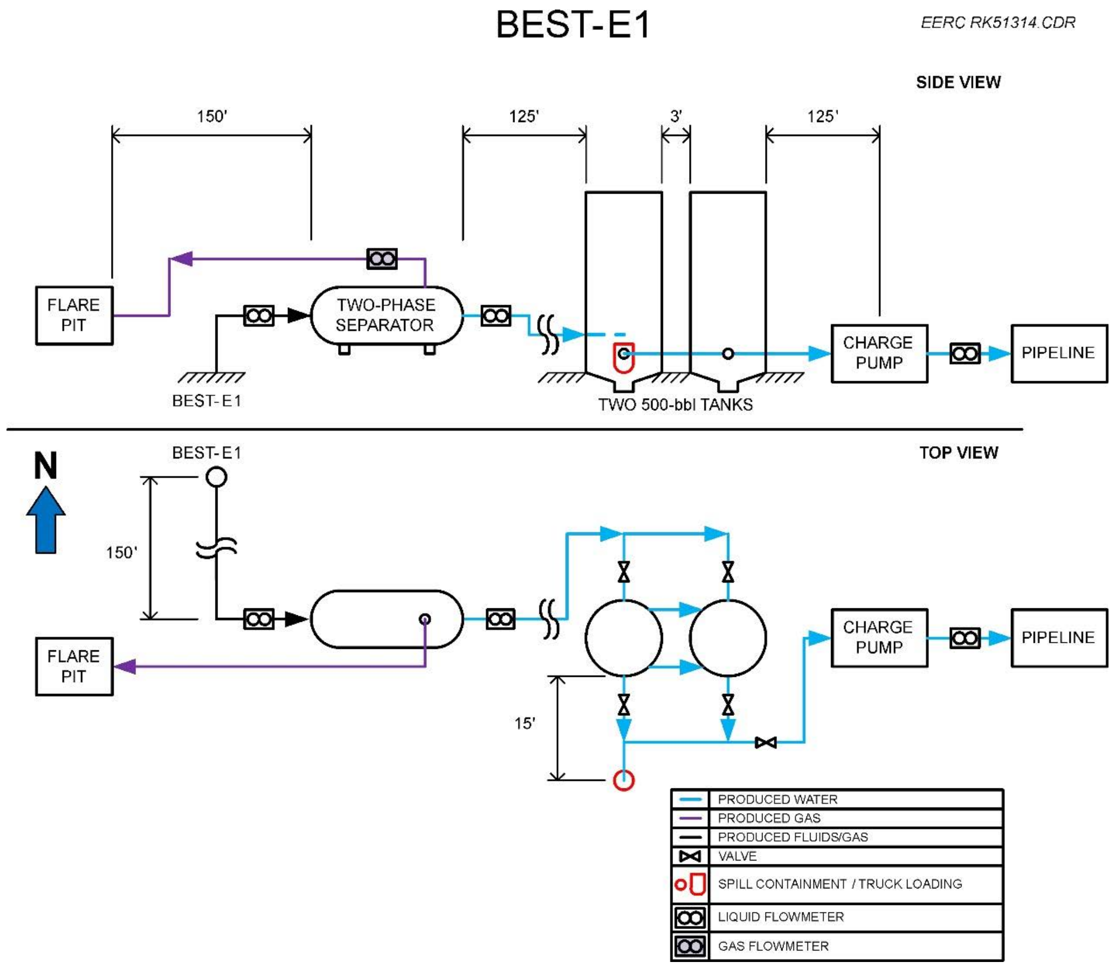


Figure 10-7. Engineering schematic of BEST-E1 facilities showing the location of major equipment and the process flow diagram between the wellhead and pipeline.

battery. The charge pump will be outfitted with high-pressure, low-pressure, and low-tank-level kill switches and a high-tank-level activation switch. The tanks will also be outfitted with radar-level sensing equipment as a redundant spill/overflow safety and environmental risk mitigation measure. Additionally, tank-level information will provide key data on available brine volumes and buffer capacity to aid in ARM and water treatment operations.

All flowlines and valves will be heat-traced, insulated, and installed aboveground to facilitate easy leak detection. Flowlines will consist of 4-in. SDR11 poly pipe rated at 160 psi and will be installed aboveground to facilitate daily visual inspections for leak detection. In addition to the location berm, containment will be installed around the perimeter of on-site storage following state regulatory requirements. This will provide the capacity to contain a minimum of 1.5 times the total volume of the largest tank and total extracted volume for 1 day. Detailed build lists, equipment specifications, and installation procedures can be found in Appendix D.7.

After the well and facilities are completed, the brine-handling facilities will go through a shakedown process and be inspected for leaks. Once the integrity of the system is confirmed and tested and BEST-I1 facilities are operational, the system will be put into operations as outlined by the ARM experimental scenario design.

10.4 Pipelines and Utilities

10.4.1 Pipeline Selection

Pipeline materials were selected based upon extracted water parameters. The expected parameters of the extracted waters are a temperature range of 135°–155°F, TDS that will be increasing from 4500 to 150,000 mg/L, and the possibility of low concentrations of H_2S. Those parameters led to the choosing of a spoolable reinforced plastic class of pipe to be used to transport the extracted formation water from BEST-E1 to BEST-I1 (see Appendix D.4 Pipeline Infrastructure for more details).

10.4.2 Pipeline Installation and Inspection

The pipeline from BEST-E1 to BEST-I1, route shown in Figure 10-1, will be approximately 2500 ft in length. All aspects of the pipeline installation will follow recommended practices put forth in the EERC report, *Liquids Gathering Pipelines: A Comprehensive Analysis*, (2015), and thus will meet or exceed existing as well as the gathering line rules currently being proposed by NDIC. After installation, hydrostatic integrity testing of the pipeline will be performed by the EERC (see Appendix D.4 Pipeline Infrastructure for more details).

The EERC will be responsible for on-site supervision and inspection during the trench construction and pipeline installation. In addition to the EERC, it is likely NDIC will assign a state inspector for the installation of the pipeline. Along with supervision and inspection, monitoring and detection of leaks will employ monitoring with devices coupled with SCADA and physical leak detection devices employed along the pipeline. The EERC will install HydraProbes every 75 ft along the pipeline in the backfill adjacent to the pipe (see Appendix D.4 Pipeline Infrastructure and Appendix D.4.2 Hydraprobe Technical Information for more details).

10.4.3 Utilities

Utilities will include electricity and freshwater supply for the BEST-I1 site. Electricity will include both overhead and buried electrical lines on both BEST-E1 and BEST-I1 sites. BEST-E1 will include a 500-kVA transformer in order to supply enough power to run the ESP and surface equipment. BEST-I1 will include a 260-kVA transformer in order to supply enough power to run surface equipment and provide tie-in to the water treatment demonstration building and associated equipment. These will be installed by McKenzie Electric Co-op. All hookups relating to surface equipment will be handled by infield, qualified electricians/technicians.

Freshwater will be installed by the McKenzie County Water Resource District. This will be used for cooling of brine water treatment equipment and for use in the command center and brine water treatment buildings for potable water. See Figure 10-1 for proposed routing of electrical and freshwater.

10.5 Rink SWD Facilities

Additions to the existing Rink SWD 1 and Rink SWD 2 facilities include: digital pressure sensors on both the tubing and casing, density meters on the flowline, PROMORE MORE^{S} suspended downhole digital BHP and temperature gauges, interrogator on the surface to interpret data from downhole gauges, and a flowmeter on the charge pump from the existing Rink SWD facilities to BEST-I1 extracted brine treatment facilities. This charge pump will be used to blend produced fluid with BEST-E1 extracted fluid to reach target TDS levels for the water treatment phase. A flowmeter on the transfer pump will monitor flow from BEST-I1 tank battery to existing Rink SWD facilities. This transfer pump will provide operational flexibility and additional buffer capacity by providing the ability to ship fluid from BEST-I1 facilities to the existing Rink SWD facilities. Reference Appendix D.5.4 and D.7 for further details of equipment used.

10.6 Summary

Overall, sites BEST-E1 and BEST-I1 have been designed to allow operational flexibility. BEST-E1 is targeted for 4000 bbl/day of production with the ability to change this rate by approximately 40% (i.e., 2500 to 6500 bbl/day). All infrastructure is designed to handle up to 6500 bbl/day, with storage of 1000 barrels of extracted fluid on the BEST-E1 wellsite. BHP and temperature will be monitored in the wellbore with two systems: PROMORE MORE^{C} casing-conveyed single-point pressure/temperature gauge and Summit’s ESP sensor. Monitoring of tubing and casing pressure will be done through digital pressure sensors on the wellhead. Monitoring of fluid density will be handled by a density flowmeter on the flowline near the wellhead. Monitoring of the flow rate will be handled by three flowmeters throughout the system. See Figure 10-4 for location of each. Gas will be measured by a digital flowmeter on the outlet of the gas line on the two-phase separator before flaring on location. Extracted fluid will be transported by pipeline to BEST-I1 tank battery.

The BEST-I1 site has been designed to allow fluid to be transferred where it is needed on location whether it be to injection, the water treatment demonstration facilities, and/or the existing Rink SWD facilities. All infrastructure is designed to handle up to 4300–6500 bbl/day, depending on injection pressure, with storage of 3000 bbl of extracted fluid on the BEST-I1 well site, with a combined on-site storage from the BEST-E1 and BEST-I1 of 4000 bbls. Monitoring of tubing and casing pressure will be digital pressure sensors on the wellhead. Monitoring of density will be handled by a density flowmeter on the flowline near the wellhead. Eight flowmeters will be used to monitor flowrate across the system. See Figure 10-8 for location of each flowmeter.

11.0 EXTRACTED BRINE TREATMENT DEMONSTRATION FACILITY DESIGN AND IMPLEMENTATION

The EERC partnered with GE Global Research (GE) to develop an engineering design and site implementation plan for a test bed to evaluate brine treatment technologies that may be capable of treating high TDS extracted water. The extracted water from the Johnsons Corner test site is representative of water that may be extracted from CO_2 storage sites as part of ARM strategies. The design and implementation plan includes facilities, equipment, instrumentation, and monitoring to evaluate technologies capable of treating high TDS brines produced through ARM. Specific activities performed included:

- Conducting a research gap and water treatment technology assessment.
- Conducting water treatment technology modeling and LCA.
- Developing a screening process for selecting water treatment technologies to be pilot-tested.
- Developing a detailed design of an extracted water treatment technology demonstration test bed to host a wide array of technology capabilities.
- Developing a cost estimate and justification for the construction and operation of the technology demonstration test bed.

11.1 Regional Water Quality Assessment

11.1.1 Inyan Kara Water Quality Assessment

According to Whitehead (1996), Inyan Kara Formation water is expected to have a TDS of approximately 4500–6000 mg/L in the area of the Johnsons Corner site. Data from drill stem tests was available from 18 Inyan Kara Formation wells. However, data from 17 of these wells were found to be nonrepresentative, as they were either too distant or were interpreted to be contaminated (e.g., appearing to contain a mixture of drilling mud and formation fluid because of the presence of extremely high salinity and dominance of sodium and chloride ions). Data from one well (No. 2923) were considered to be representative of the Johnsons Corner site.

Well No. 2923 is situated in the southern portion of Billings County, approximately 80 miles to the south–southwest of the Johnsons Corner site. The sample from the Inyan Kara Formation indicates a sodium measurement of 3100 mg/L and chloride of 4000 mg/L, with a TDS measurement of 8260 mg/L. After 8 years of injection of >300,000 mg/L TDS brine into Rink SWD 1 and Rink SWD 2 wells will likely have altered salinity distribution in the Inyan Kara at Johnsons Corner (Figure 6-3). Further, continued brine injection coupled with BEST-E1 extraction is expected to result in continuously increasing levels of salinity in extracted fluids throughout the BEST demonstration.

Because of the paucity of water quality data and the potential variability of salinity in the extracted water from BEST-E1 over the course of the project, it is necessary to consider the better characterized and higher salinity brines injected into the Inyan Kara at the Johnsons Corner site.

11.1.2 Johnsons Corner Injected Water Quality Assessment

The brines currently being injected into the Rink SWD 1 and Rink SWD 2 wells have a much higher salinity than the native Inyan Kara Formation water, with injected brine typically containing >300,000 mg/L TDS. Table 11-1 lists average concentrations of key constituents based on EERC laboratory analyses of four different injected water samples. The higher salinity in the injected water provides the capability to blend injected brine with the extracted water to achieve the DOE target level of 180,000 mg/L TDS for the brine treatment test bed. The Johnsons Corner site also provides the ability to blend and demonstrate treatment on a range of extracted water salinities from approximately 4500 to over 300,000 mg/L TDS.

Table 11-1. Johnsons Corner Injected Water Quality Characteristics (all values in mg/L unless otherwise noted)

Parameter	Value
pH	6.06
Specific Gravity, unitless	1.2
Sodium	90,600
Potassium	9440
Calcium	27,700
Magnesium	1320
Strontium	2370
Phosphorus	<20
Silicon	<30
Fluoride	<10
Sulfate	25
NO_2/NO_3 as Nitrogen	<6
Bromide	196
Chloride	211,000
HCO_3 Alkalinity	206
CO_3 Alkalinity	0
$CaCO_3$ Alkalinity	169
OH Alkalinity	0
TDS at 180°C	303,000
Total Suspended Solids (TSS) at 105°C	187
Total Organic Compound	44
Chemical Oxygen Demand (total)	4000
Chemical Oxygen Demand (soluble)	4000
Ammonia as Nitrogen	2960
TDS	343,000
Total Hardness as $CaCO_3$	74,500
Ion Balance, %	2.24

11.2 Assessment of Treatment Technologies for High TDS Brines

Extracted water treatment technologies compatible with ARM must be capable of addressing a range of water quality characteristics that depend largely on the location and type of formation targeted for CO_2 storage. Suitable formations are anticipated to range from deep saline formations to depleted oil and gas reservoirs, each having potentially different formation water characteristics, particularly with respect to levels of suspended and dissolved solids, hardness, and organics content. Successful extracted water treatment likely requires multiple unit operations in the overall treatment system and will almost certainly require pretreatment to remove suspended solids and dissolved organics ahead of any desalination technology to prevent performance inhibition.

A technology assessment was conducted to better understand the research gap and determine the readiness level of potential pilot-ready and commercial technologies with the potential to be utilized to pretreat and desalinate waters with salinities as high as 325,000 mg/L TDS. The assessment included a comparison of the treatment capabilities, performance, and energy requirements of applicable technologies, where data were available. A summary of the technologies assessed is provided below.

11.2.1 Pretreatment Technologies

Pretreatment technologies provide for the removal of certain constituents that would otherwise inhibit or interfere with the operation of downstream unit operations. For extracted water, these constituents would likely include fine suspended solids or turbidity, dissolved organic matter, and scale-causing divalent ions or hardness. Pretreatment technologies include suspended solids separation, adsorption, and softening.

11.2.1.1 Mechanical Particulate Separation

There are a range of mechanical particulate separation technologies that are commercially practiced. In addition, GE's microclarification (MC) process is expected to be pilot-ready in 2016. A summary of the technologies, along with strengths and weaknesses, is listed in Table 11-2.

11.2.1.2 Membrane Filtration

Membrane microfiltration provides an absolute barrier to particulates larger than 0.5–1.5 µm, and ultrafiltration provides an absolute barrier to particulates and free oil droplets larger than 0.01 µm. Table 11-3 shows some key characteristics of pilot-ready membrane microfiltration, ultrafiltration, and nanofiltration technologies.

Table 11-2. Characteristics of Pretreatment Technologies: Mechanical Particulate Separation

Technology	Contaminants Treated	Strengths	Limitations
Gravity Settling[a]	Particulates	Equalizes flow, accommodates upsets, simple, low energy, minimal operation and maintenance	Large footprint, long settling time required to remove small particles
MC[b]	Particulates, oil and grease (O&G)	Small footprint vs. conventional settling, removes 5–15-µm particles	Potential for fouling, no flow equalization capacity, needs piloting
Hydrocyclones[a]	Particulates, O&G	Minimal energy, removes 5–15-µm particles	Potential for fouling, no flow equalization capacity, scale-up requires multiple parallel units
Gas Flotation[a]	Particulates, O&G	Removes 25-µm particles (3–5 µm with coagulation pretreatment)	Higher pressures required for high-temperature feeds
Media Filtration[a]	Particulates, O&G, total organic compound	No TDS limitations, coagulation pretreatment improves removal	Media replacement/ regeneration
Mechanically Assisted Filtration[c]	Particulates	Self-cleaning, low footprint, able to handle high solids	Fouling tendency of mesh screens

[a] Reference: Colorado School of Mines, 2009.
[b] GE pilot-ready technology.
[c] Examples: Tekkleen™, Spiral Water Technologies, Tequatic™.

Table 11-3. Characteristics of Pilot-Ready Membrane Filtration Pretreatment Technologies

Technology	Contaminants Treated	Strengths	Limitations
Oil-Tolerant Microfiltration	Particulates >1 µm	Low fouling in presence of excess flocculant, oily particulates	Needs field pilot validation
Oil-Rejecting Ultrafiltration[a]	Free oils, particulates >0.01 µm	Commercially proven product	Each new application needs pilot validation
Nanofiltration	Divalent, multivalent ions; organics, microbials	Selectivity toward hardness species	Requires pilot validation

[a] GE Power & Water MW-Series Ultrafilic® Ultrafiltration membrane.

Because ultrafilters are typically configured as spiral-wound elements, they require upstream microfiltration in order to prevent fouling. Depending on the application, it is recommended to use either a 5–10-µm cartridge filter or a 0.5–1.5-µm membrane microfilter upstream of an ultrafilter to provide for effective RO (reverse osmosis) treatment. Nanofiltration is well established for softening brackish water and has a potential application for high TDS extracted water softening.

11.2.1.3 *Soluble Organics Removal*

Soluble organics such as BTEX (benzene, toluene, ethylbenzene, xylene), DRO (diesel-range organics), GRO (gasoline-range organics), and naturally occurring organic matter must be removed from brines prior to desalination in order to protect downstream equipment. In applications that include crystallization, soluble organics must be removed in order to avoid sludge buildup in the crystallizer. There is a wide range of commercially available sorbents for soluble organics removal from brines, including activated carbons and regenerable synthetic carbons (e.g., DOW’s Ambersorb™ and Optipore™). In addition, GE has recently developed a low-cost steam-regenerable sorbent (SRS) for organics removal from brines.

11.2.1.4 *Electrocoagulation*

RecyClean Services is developing a process to substantially remove the biological, hydrocarbon, divalent cation, and boron concentrations in high TDS brines. The primary goal of the technology is to recycle produced flowback water so that it can be reused for hydraulic fracturing operations, but it can also be used for pretreatment of extracted water brines ahead of desalination. The process involves ozonation of the brine, pH adjustment, and applying an electric current to cause coagulation and precipitation of dissolved or suspended matter. An inorganic polymer is then added to increase coagulation, and the solids are allowed to settle, leaving water that can be used in hydraulic fracturing operations. RecyClean has a trailer-sized demonstration unit that can be moved to a site for initial testing of the technology.

11.2.2 *Desalination Technologies*

There are several commercial and pilot-ready desalination technologies that can have application for water recovery from high TDS extracted brine. These technologies, however, tend to be energy-intensive and have not been extensively documented in the treatment of high TDS water (180,000 mg/L). Table 11-4 provides a summary of operating ranges and energy requirements for desalination technologies.

11.2.2.1 *Falling Film–Mechanical Vapor Recompression (FF–MVR) Evaporation*

FF–MVR evaporators yield distilled water and a brine concentrate. To maximize the water recovery, sufficient pretreatment must be conducted to avoid scaling as the brine is concentrated to a final brine concentration of about 300,000 mg/L. If needed, scale inhibitors can be added to the brine concentrator feed.

Table 11-4. Summary of Commercial and Pilot-Ready Desalination Technologies

Technology	Maximum Concentrate TDS, mg/L	Product Water TDS, mg/L	Typical Desalination Energy Requirements, kWh/m^3 product water	Pretreatment Required (contaminants that must be removed)
Principal Energy Source: Electricity				
MVR[a]	295,000	<100	18.5	Soluble organics, O_2
Principal Energy Source: Heat or Refrigeration				
MD[b]	280,000 (24 wt%)	<10	14	Particulates, organics, surfactants
FO/RO[a]	200,000[c]	<350	275 (distillation column + brine stripper)	Soluble organics, particulates
HDH[d]	295,000	<100	684 (without energy recovery)	Scaling salts, organics, particulates
Freeze–Thaw[a]	>40,000	1000	Passive (seasonal)	None
CoLD Crystallization[e]	>295,000	<100	187 kWhe + 3610 kWh steam[f]	NORM,[g] TCLP[h] metals

[a] Reference: Colorado School of Mines, 2009: MVR = mechanical vapor recompression and FO–RO = forward osmosis and reverse osmosis.
[b] Reference: Hardy and Shapiro, 2014.
[c] Reference: McGinnis, 2013.
[d] Humidification dehumidification.
[e] Crystallization of high solubility salts at low temperature and deep vacuum.
[f] Reference: Shaw, 2011.
[g] Naturally occurring radioactive material.
[h] Toxicity characteristic leaching protocol.

11.2.2.2 Membrane Distillation

Membrane distillation is a thermally driven membrane separation process that employs a vapor pressure gradient created between a warm saline feed solution and a cold distillate product separated by a hydrophobic microporous membrane. This membrane allows water vapor, but not liquid water, to permeate. Water evaporates on the feed side of the membrane, passes through the hydrophobic porous membrane, and condenses on the cold distillate side. Membrane distillation is not limited to low TDS brine desalination; it can be applied to saline streams approaching saturation. Pretreatment to remove organics, particulates, and surfactants is required, as fouling and membrane “wet out” must be prevented in order to maintain good membrane distillation performance. Because membrane distillation typically operates at subatmospheric pressures, low-grade heat may be utilized as the primary heat source. Further, vapor recompression may be used for heat economy.

11.2.2.3 Forward Osmosis

FO uses the spontaneous diffusion of water across a semipermeable membrane into a high-salinity draw solution from a relatively lower-salinity feed solution. Subsequent reconcentration of the diluted draw solution generates pure water product and concentrated draw solution for recycle to the FO unit. Draw solution regeneration can be conducted using thermal processes (e.g., steam stripping). Dissolved solids (e.g., NaCl) from the raw brine feed that are not rejected by the FO membrane appear in the draw solution stripping column bottoms product. Although FO does not require hydraulic pressure, the energy requirements of draw solution regeneration are significantly greater than those of a standard RO desalination system because of the high concentrations of solutes in the draw solution necessary to desalinate a high TDS brine. The use of ammonium bicarbonate draw solutions is attractive because of the potential for NH_3 and CO_2 recovery with moderate heating. At temperatures of about 60°C and above, ammonium bicarbonate decomposes to ammonia and carbon dioxide gases, which can be removed from the product water using vacuum steam stripping (McCutcheon, 2005). The absence of hydraulic pressure is expected to make FO membranes less prone to fouling by particulates than RO membranes, which may render the FO pretreatment process less expensive than an RO pretreatment process.

11.2.2.4 Humidification Dehumidification

In HDH, hot carrier gas is generated using a gas-fired burner. The carrier gas heats brine in a high-mass-transfer-rate humidifier in which water is evaporated from the heated brine. This water is recovered in the dehumidifier. In the current design, the gas leaving the dehumidifier is vented to the atmosphere. Future designs may include gas recycle for heat recovery. The energy usage for this process is much higher than for membrane distillation, FO, or FF–MVR. However, if waste heat is available, this process may be attractive because of its relatively low CAPEX (capital expenditure).

In a recent article, many schemes for desalination by HDH have been reviewed (Narayan, 2011) GE has been developing a low-CAPEX HDH system for applications where low-cost energy is available (e.g., flare gas or waste heat from exhaust gas).

11.2.2.5 Freeze–Thaw

Freeze–thaw (FT), developed by the EERC, comprises spraying feed water on freeze pads during cold months to yield pure ice and concentrated brine (liquid). The brine drains from the ice, and when the ice melts, the pure water can be collected. Because this technology utilizes ambient conditions for heat removal, it is only applicable in cold weather. Further, the footprint required to treat commercial flow rates of extracted water (500 gpm) is too large to be feasible (Colorado School of Mines, 2009).

11.2.2.6 Low-Temperature Crystallization

Veolia Water Technologies has patented the CoLD crystallization process, which generates a mixed salt product, but claims cost advantages over conventional crystallization (Gallot, 2011). Low-pressure operation lowers the boiling point of the brine, allowing water to evaporate at lower temperature. In the CoLD process, brine is heated in an evaporator but at reduced temperature (<60°C) and pressure (<1 atm). At lower temperature, solubilities of Group II metal salts such as $CaCl_2$ are reduced, allowing crystallization at lower concentrations and temperatures. This process gives rise to precipitation of a mixed salt (mostly $CaCl_2$ + NaCl), which may be landfilled. This process also eliminates the need for chemical softening (lime, soda ash) and the associated sludge disposal. A cost analysis of the CoLD process for zero-liquid discharge (ZLD) treatment of

Marcellus shale gas produced water showed a cost advantage over conventional technology (pretreatment followed by MVR crystallization) (Shaw, 2011).

11.2.2.7 Crystallization

ZLD is achieved in many desalination application areas, including thermoelectric power generation (flue gas desulfurization, cooling tower blowdown), synthetic fuels (Sasol), and SAGD (steam-assisted gravity drainage) heavy oil recovery. In ZLD applications, high TDS brine or evaporator blowdown is evaporated in a crystallizer to yield a solid salt product and a small crystallizer purge stream. Crystallization installations are capital-intensive, resulting in treatment costs (CAPEX + OPEX [operating expenditure]) of about \$8/m^3 brine treated (Klapperich and others, 2013). This relatively high cost is due to both the energy cost and the capital cost for the crystallizer and associated heat exchange equipment, which requires titanium on most fluid-wetted surfaces.

Several alternatives have been proposed to save energy costs. For example, extractive crystallization (Zijlema, 2000) utilizes diisopropyl amine as a nonsolvent to precipitate NaCl from aqueous solution. Although this system uses 29% less energy than a 4-effect conventional crystallizer, the added capital cost due to solvent management leads to a higher overall production cost for the extractive crystallization process.

Disposal of the salt product is also a complicating factor. Salt product to be landfilled as nonhazardous solid waste must pass the toxicity characteristic leaching procedure (TCLP), which means that the leach rate for heavy metals such as barium must be below a regulated level. If the salt product is to be reused, it must also pass specific state regulations. For example, if the recovered salt is to be used as road-deicing salt, it must have a barium concentration no higher than that of rock salt, which is about 5 mg/L (Kaufmann, 1960).

11.2.2.8 Hydrochloric Acid Production

Australian Biorefining (ABR) Process Development has developed an electrochemical process that is currently at the pilot level for producing hydrochloric acid and other products from high TDS brines. It uses an electrolytic cell consisting of an anode chamber which is separated from a cathode chamber by an anion exchange membrane. Metal chloride-containing brine is fed to the cathode chamber where electric current passing through the cathode electrolyzes water into hydrogen gas and hydroxyl ions. The electric current is typically between 200 and 2000 amp/square meter of electrode. In the cathode chamber, hydroxyl ions react with metal ions to form metal hydroxides, some of which precipitate on the electrode and are then scraped off, which reduces fouling of the membrane. Remaining divalent cations in solution are precipitated as carbonates by adding carbon dioxide to the remaining cathode solution. The chloride ions pass through the membrane and are oxidized at the anode to form chlorine gas. The hydrogen and chlorine are then reacted with ultraviolet light or over a catalyst to form hydrogen chloride gas which is then dissolved in water. The remaining water can be used for hydraulic fracturing operations or further purified with RO.

In a test of the technology, 15 liters of Bakken brine was treated over 13 hours. From the demonstration, it was seen that essentially complete removal of the magnesium is possible; significant reduction in all components was achieved; and production of HCl, NaOH, $Mg(OH)_2$, and $CaCO_3$ was shown.

11.2.2.9 DOE FOA 0001095 and 0001238 Technologies

Under two DOE funding opportunities, projects were awarded for the development of innovative high TDS brine pretreatment and desalination technologies. Under DOE FOA 0001095 "Innovative Concepts for Managing Water in Fossil Fuel Based Energy Systems," the following projects were awarded. The technologies are being tested at the bench scale and are scheduled for completion in late 2016.

Southern Research Institute – Treatment of Produced Water from Carbon Sequestration Sites for Water Reuse, Mineral Recovery and Carbon Utilization

- Several new cleanup systems include vibratory sheer enhanced processing (VSEP) filtration followed by thermal distillation using a low momentum–high turbulence (LM–HT) concentrator. Southern Research Institute is also developing methods to solidify/stabilize waste brine and salt from an evaporator.

General Electric Company – Water Desalination Using a Multiphase Turboexpander

- Brine is cooled and sprayed into pressurized air which goes through a turboexpander where it is atomized and cooled. The water freezes and ice crystals are separated from the brine.

Research Triangle Institute – Fouling-Resistant Membranes for Treating Concentrated Brines for Water Reuse in Advanced Energy Systems

- Electrically conductive membrane distillation (ECMD). The electrically conductive membrane is supposed to reduce scale formation.

University of Illinois – An Integrated Supercritical System for Efficient Produced Water Treatment and Power Generation

- Brine is heated and pressurized to a supercritical (SC) state which should precipitate the salt (only 100 mg/L soluble in SC water). The salt is then filtered from SC water with a high-temperature carbon membrane. SC water is then expanded through a turbine to make electricity.

University of Pittsburgh – Development of Membrane Distillation Technology Utilizing Waste Heat for Treatment of High-Salinity Wastewaters

- Membrane distillation uses waste heat from a power plant or compressor station. The University of Pittsburgh is testing both direct contact membranes (liquid water on the clean side) and vacuum assist (vapor on the clean side).

Under DOE FOA 0001238 "Water Management and Treatment for Power Plant and CO_2 Storage Operations," the awarded projects primarily focused on the design of pilot-scale systems, although there is some bench- and pilot-scale testing of technologies. These projects are scheduled for completion in the spring of 2017.

Research Triangle Institute – Low-Energy Water Recovery from Subsurface Brines

- Research Triangle Institute is testing water extraction from brine using various nonaqueous solvents.

Ohio University – Advanced Integrated Technologies for Treatment and Reutilization of Impaired Water in Fossil Fuel-Based Power Plant Systems

- Ohio University is applying several pretreatment technologies to produce the SC water precipitation of salts. The clean water would be used for makeup water in a power plant.

General Electric Company – Model-Based Extracted Water Desalination System for Carbon Sequestration

- GE is using modeling and some technology validation testing to design a pilot-scale test system for desalination of 180K TDS brine.

11.2.3 Technology Assessment Summary

Several pretreatment and desalination technologies may have applicability to the treatment of high TDS extracted waters, including commercially available, pilot-ready, and potential technologies presently under development. Most technologies identified to date will not be cost-effective if the goal is the production of freshwater. However, technologies that produce salable commodity products and significantly reduce the costs associated with disposal of extracted water may have more favorable overall economics. It is anticipated that continued development of treatment technologies to address high TDS extracted brines may overcome the economic and operational constraints associated with treatment. Demonstration of applicable technologies at a pilot-ready or commercial scale of development using highly saline formation waters is needed to determine overall treatment efficacy and develop detailed life cycle analyses.

11.3 Water Treatment Technology Techno-Economic and Life Cycle Assessment

ARM at CCS sites may benefit from treatment of extracted high TDS waters (>180,000 mg/L TDS) for beneficial use applications and as a means of managing and reducing extracted brine disposal volumes. Reducing the volume of extracted brine that is reinjected into another subsurface formation has a strong potential to reduce equipment (e.g., number and size of pumps, wells, etc.) and energy costs associated with brine reinjection. Extracted brine treatment can provide an alternative source of water for domestic or industrial uses and/or provide salable products for a variety of beneficial uses. These products may provide economic incentives or cost offsets for CCS while reducing the subsurface footprint required for brine disposal at CCS sites employing ARM.

Large-scale extracted brine desalination (500-gpm design basis) presents significant technical and economic challenges. An Aspen Plus™ model with the electrolytes package by OLI Systems Inc. was developed to enable calculation of all stream compositions and flow rates as well as energy requirements for desalination. Modeling of the desalination processes was also used to develop and size the design of the extracted brine treatment test bed facilities for BEST at the Johnsons Corner site.

Modeling and techno-economic analyses provided the detailed energy and material balances to develop data to compare the cost effectiveness of brine concentration versus brine crystallization using commercially available technologies. The commercially available technologies were compared: GE's FF brine contactor with MVR was compared against two NaCl crystallization techniques: 1) forced circulation crystallization with mechanical vapor recompression (FCC–MVR) and 2) FF–MVR brine concentration followed by FCC–MVR crystallization. Based on the per unit volume of distillate/purified water recovered, costs for the three commercial processes were similar. For extracted water desalination in support of CCS, GE recommended treatment to produce a brine concentrate instead of producing dry NaCl because the high capital and energy costs associated with generating (drying, milling, and transporting) and disposing of a solid NaCl product was determined to be prohibitive.

The FF–MVR process served as the base water treatment technology and was compared against five alternative technologies: 1) FO, 2) membrane distillation, 3) HDH, 4) clathrates (CLTH), and 5) turbo-expander-based freeze (TEF) process. These five alternative desalination technologies were selected based on the ability of the effluent stream to be disposed of through reinjection and the assumption of an ability to achieve pilot-ready status within the time frame of the proposed BEST. The model basis for comparison was 1) treatment of 180,000 mg/L TDS brine, 2) processing at 500 gpm, 3) production of brine concentrate at 295,000 mg/L, and 4) a distilled/purified water yield of 42%.

Table 11-5 presents the theory of brine concentration for each technology as well as options (cases) for providing thermal energy to the process.

The research gap identified with implementation of desalination technologies is largely associated with the high salinity and high hardness of brines that are anticipated to be extracted as part of CCS. The capital and operating costs of currently available technologies will have to be weighed against the economic benefit derived from lower disposal costs of the reduced volume of brine concentrate and any potential value of the treated water or product stream. The selection and demonstration of applicable extracted water treatment technologies at the Johnsons Corner test bed will address the research gap and provide necessary operating and performance data to allow development of the technologies to higher readiness levels. Extracted brine treatment technology demonstrations will provide the necessary data for operating (heat, electricity, disposal, consumables) cost estimates that will be instrumental in the preparation of full LCA for cradle-to-grave technology comparison.

Desalination technologies FO, membrane distillation, HDH, and CLTH have the potential to provide moderately to significantly lower cost options, depending on the method of energy/heat supply, relative to the commercial base technology FF–MVR. The lowest cost for these four alternatives is associated with the "Case 2" option for energy supply provided in Table 11-5. Further overall desalination cost reduction could come from value-added use of the distillate/purified water and/or the brine concentrate currently directed toward reinjection.

Table 11-5. Comparison of Desalination Technologies and Methods for Energy Supply

Technology	Theory of Operation	Methods for Energy Supply
FF–MVR	Evaporation method by which a blower, compressor or jet ejector compresses and increases the pressure of the produced vapor. The compressed vapor generates an increase in the condensation temperature such that the vapor can serve as the heating medium for solution being concentrated.	Vapor compression performed by a mechanically driven compressor or blower
FO	Uses the spontaneous diffusion of water across a semipermeable membrane into a high-salinity draw solution from a lower-salinity feed solution. Reconcentration of the diluted draw solution generates pure water product and concentrated draw solution for recycle to the FO unit.	Case 1 – thermal energy (e.g., steam) Case 2 – electrically driven mechanical vapor compression
Membrane Distillation	Membrane separation process employing a vapor pressure gradient between warm (evaporating) saline feed solution and cold (condensing) distillate product. Hydrophobic microporous membrane allows water vapor, but not liquid water, to permeate.	Case 1 – heat (e.g., low-pressure steam) Case 2 – electrically driven mechanical vapor compression
HDH	Hot carrier gas heats brine in a high-mass-transfer-rate humidifier. Water is evaporated from the heated brine and is recovered in the dehumidifier.	Case 1 – propane-fired burner (without heat recovery) Case 2 – flare gas or waste heat from exhaust gas
CLTH	A mixture of brine and a “guest” molecule (e.g., cyclopentane) are cooled to form a matrix of water molecules around the guest. The lower density CLTH is gravity-separated from the brine concentrate. CLTH is heated to allow phase separation of water and the water-immiscible guest molecule (which is recycled).	Case 1 – surfactant used to disperse cyclopentane in brine Case 2 – alternate developmental method for dispersing cyclopentane
TEF	Brine is cooled by expansion of a mixed stream of compressed gas (e.g., air) and brine in a turboexpander. It is assumed that the process yields a brine concentrate and ice (from which pure water is recovered).	Electrically driven compressor and turboexpander

11.4 Extracted Water Treatment Technology Selection Process

The EERC will identify technologies with the potential to successfully treat high TDS extracted water (180,000 mg/L on average). At a minimum, each technology must comply with the host site’s HSE requirements and will be reviewed and approved by the technical team managing and operating the Johnsons Corner pilot technology demonstration test bed facility.

The EERC will solicit information on additional technologies from DOE and its network of industry contacts. The EERC will confirm interest from technology providers in supplying critical treatment technology information and participating in potential site demonstration. Letters of commitment from the selected technology providers will be obtained, and any necessary confidentiality agreement will be executed prior to demonstration phases of the project.

Preliminary screening criteria have been developed that are broad enough to apply to a large number of candidate technologies for demonstration. The criteria will discriminate among technology alternatives while avoiding duplication of demonstrations of the same basic technology type.

Technology screening criteria will include the potential of a given technology to:

1. Treat water to a variety of effluent water quality criteria based on beneficial reuse:
   a. Industrial reuse (fracturing water, 10-lb brine).
   b. Commercial and/or domestic reuse (low TDS nonpotable).

2. Enable the use of other technologies (i.e., novel pretreatment).

3. Produce and recover salable products from the extracted water, such as hydrochloric acid.

4. Provide a relatively high yield of treated water or other product(s).

5. Provide a significant reduction (>30%) in the volume of water to be reinjected following treatment.

6. Operate within the treatment facility constraints of footprint and utilities.

Selection criteria have been developed to assist in technology selection. The technologies will be scored on a scale of 1 to 10 in the areas of treatment cost, readiness level, safety considerations, and waste generation. The ranking of technologies will be accomplished through the following weighting factors.

11.4.1 Treatment Cost (40%)

Technologies that have the most reasonable costs (capital and operating) relative to a reduction in extracted brine disposal costs and the value of the treated water or products(s) will score the highest. Those technologies that have projected operating costs that are significantly greater than the combined value of reduced extracted brine disposal costs and the treated water of the product will receive a lower score. It is anticipated that costs for desalination will be directly related to energy requirements and the energy efficiency of the treatment technology.

11.4.2 Readiness Level (30%)

Identified technologies that are more mature in development will be given a preferential score. Additionally, technologies that allow demonstration periods of sufficient duration to identify key operational issues (scaling, equipment corrosion, etc.) will receive a higher score, along with technologies having the design ability to be scalable to 500-gpm brine treatment rates.

11.4.3 *Safety Considerations (20%)*

Technologies that require operation with hazardous or nonconventional materials that necessitate specialized training or the use of advanced personal protective equipment (beyond flame-retardant clothing, hardhats, and safety glasses) will receive a lower score. Any technology found to present an operational hazard or personnel safety concern will be excluded from consideration.

11.4.4 *Waste Generation (10%)*

Waste generation is a distinct possibility for technologies capable of treating and concentrating heavy brines. Technologies that minimize the amount of secondary wastes (sludges and/or salt cakes) that have no identified economic value or result in additional treatment costs and/or disposal in a special waste landfill will receive a higher score.

The selection process will give priority to those technologies associated with DOE-funded projects awarded for the development of innovative high TDS brine pretreatment and desalination technologies (DOE FOA 0001095 and DOE FOA 0001238) that successfully satisfy technology-screening criteria. If a given technology satisfies the screening criteria and is among those selected for demonstration, additional consideration may be given to those technology providers that have the ability to provide cost share that reduces the cost of demonstration. The results of the technology screening and ranking process will be presented to DOE for review with final technology selection determined through meetings of appropriate stakeholders. The EERC will then develop a schedule of operations for the selected technologies. Technology demonstration activities will be coordinated to coincide with active formation water extraction during active reservoir management testing.

11.5 Treatment Technology Demonstration Test Bed

The proposed project site is a SWD location where high-salt-content brines (in excess of 300,000 mg/L TDS) are being injected. The site has attributes that provide for blending BEST-E1 extracted water with SWD brine to simulate the composition of extracted waters from virtually any location on the globe, ranging from 4500 to >300,000 mg/L TDS. This capability offers a high degree of flexibility for the demonstration of technologies having a wide range of treatment capabilities.

The test bed design incorporates pretreatment operations for suspended solids (turbidity) removal, dissolved organics removal, and optional hardness (scale-causing constituents) removal prior to desalination technology demonstrations.

The treatment technology test bed will be housed in a 60-ft × 80-ft insulated steel building. The building will be heated to provide for year-round operation of the demonstration facility and accommodate technologies with throughput capacities ranging from 5 to 25 gpm and larger, depending on technology readiness level. Technologies having a footprint sized to fit on a standard semitractor trailer (53 ft long) will be accommodated inside the building. Modular systems having a larger footprint would require demonstration outdoors and likely during warm weather months but could be accommodated with minor modification to the facility. A generalized layout of the demonstration test bed facility is shown in Figure 11-1.

11.5.1 Test Bed Extracted Water Pretreatment System

Based on water characteristic data and information provided by the EERC, GE Global designed the pretreatment system. Extracted water generated from managing formation pressure and understanding the differential pressure plume movement will be utilized as feedwater for the extracted brine treatment technology demonstrations. Initial Phase I modeling and simulation results predicted that extracted water quality (BEST-E1) will change over the course of the ARM demonstration, from initial TDS levels as low as 4500 mg/L to as high as 150,000 mg/L at the end

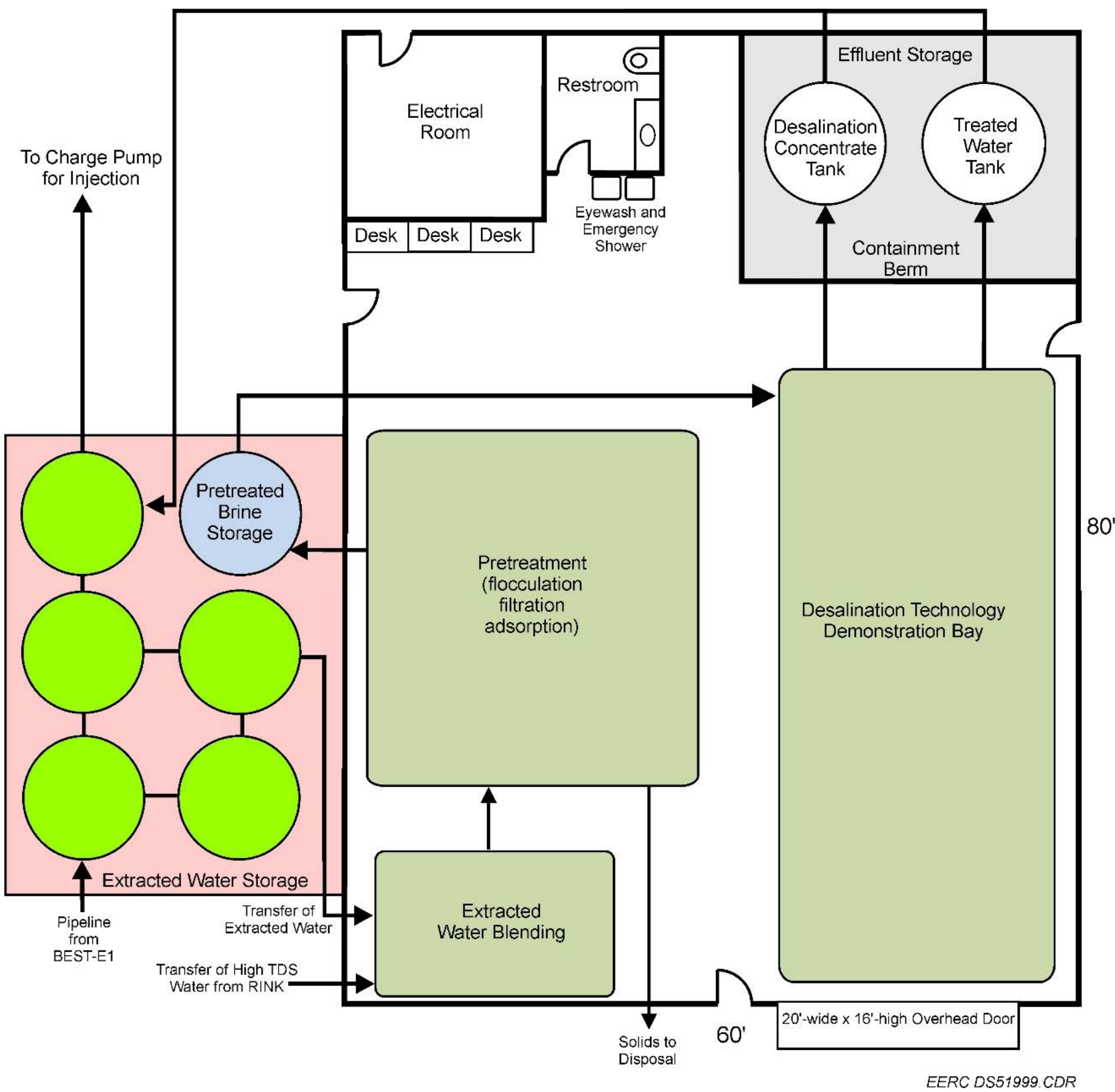


Figure 11-1. Johnsons Corner treatment technology test bed layout.

of the project period. The selected site allows for blending of the extracted water with other formation brines at the SWD facility. This will provide the capability to blend waters to the target TDS level of 180,000 mg/L or any custom-blended TDS level to suit the capabilities and/or limitations of technologies selected for demonstration, including those that might serve as smaller individual unit operations in larger, more complex treatment systems.

Extracted water for the treatment technology demonstrations will be withdrawn from one of the 500-barrel extracted water storage tanks (Figure 11-1) located near the demonstration facility and injection well (BEST-I1). In situations where a more concentrated brine is desired for a particular water treatment technology demonstration, the extracted water will be blended with high-TDS brine from the SWD facility. That brine will be collected from a tank farm just upstream of the existing disposal pumps, prior to any chemical injection to enhance injectability. The two waters will be blended to produce a brine of desired TDS concentration (e.g., 180,000 mg/L).

Blended brine will be processed through a pretreatment system to remove suspended solids (flocculation/settling/media filtration) and dissolved organics (activated carbon adsorption) constituents that may inhibit the operation of certain technologies. When technologies that are tolerant of suspended solids and organics, such as electrocoagulation, are tested, the pretreatment system will not be operated. To enhance the test bed's capabilities to host the greatest diversity of technology types, the facility design will have the capability to incorporate an optional skid-mounted softening operation to accommodate the demonstration of certain thermal-based treatment technologies where the reduction of hardness and subsequent scaling issues would be significant operating issues.

In order to ensure consistent and safe operation of the pretreatment facility, both water composition and key process operating parameters will be monitored. The Johnsons Corner pilot pretreatment facility will include real-time measurements of flow rates, temperatures, pressures, pH, TDS (via conductivity), and TSS (via turbidity). For example, in order to maintain the TDS in the blended water feed tank, blended water conductivity will be measured, and the feed rate of production water to the blend tank will be adjusted. Key samples will be also analyzed by EERC laboratories to establish an independent analysis of specific streams.

The performance of the pretreatment process will be measured by the extent of removal of brine impurities (TSS, free and dissolved organics and, optionally, hardness). A key challenge is to ensure that the coagulant dose is correct for the current feed to the system. Real-time turbidity measurement will help meet this challenge. A second challenge is to stay ahead of breakthrough on media filtration equipment by timely backwashing and on adsorption equipment by timely adsorbent renewal. Again, real-time turbidity analysis around key pretreatment unit operations will enable an effective media filter backwashing protocol. In order to avoid organics breakthrough from the adsorbent bed, a real-time or near-real-time measurement system for dissolved organics is needed. The automated purge-and-trap gas chromatographic method has been used successfully on several industrial wastewater treatment facilities. This method is potentially useful for monitoring for organics breakthrough in the adsorbent bed. Hach TOC measurement kits may also be tested for this purpose.

In addition to the GE pretreatment system design, the EERC solicited independent pretreatment and test bed facility designs from regional consultants familiar with working on comparable projects in western North Dakota. Two respondents designed similar overall approaches for suspended solids and dissolved organics removal. They demonstrated thorough knowledge of local building and construction requirements as considered in the respective facility designs at the Johnsons Corner site. These three bids were subsequently used to estimate costs provided in the Phase II project budget.

11.5.2 Waste Management Plan

Assuming a blended water feed rate of 10 gpm with 500 mg/L TSS, it was estimated that approximately about 10 lb/hr (1680 lb/week) of a 25 wt% solids in sludge could be generated during pretreatment operations. Assuming this sludge meets acceptance criteria as nonhazardous waste, e.g., technologically enhanced naturally occurring radioactive material (TENORM) <50 pCi/gm ^{226}Ra + ^{228}Ra and heavy metals do not exceed Resource Conservation and Recovery Act TCLP standards, it will be disposed of as nonhazardous waste. In the unlikely event that measured TENORM levels exceed 50 pCi/gm, the EERC will contract with a Subtitle C landfill facility for the transport and disposal of the sludge.

11.5.3 Technology Demonstrations

The Johnsons Corner test bed will accommodate the demonstration of technologies that use either electricity or propane as a primary energy source. The design electrical power to the test bed facility will be 300 kW, which should accommodate most pilot-ready technologies. Propane is designed to be delivered from a 5000-gallon propane tank. Based on the technology assessment, it is anticipated that the equivalent of 220 gallons a day of propane may be required for pilot-ready technology demonstrations. Based on the technology assessment and LCA results, noncontact cooling water requirements ranged from 10 to around 30 gpm, depending on the technology and scale of development. The source of the cooling water will be freshwater from the McKenzie County Water Resource District pipeline. Cooling water recirculated through a chiller/heat exchanger will provide the cooling needs of a given technology demonstration. Following the technology demonstration period, blowdown from the cooling water system will be transferred to the extracted water tank farm and disposed of in the BEST-I1 injection well.

Treatment technology demonstration is anticipated to result in the generation of a low-salt treated water stream and a concentrate stream, estimated to be around 295,000 mg/L TDS based on a 180,000 mg/L TDS feed water. Treated water and concentrate effluents from the technology demonstration will be collected in 3000-gallon polyethylene tanks in the test bed facility. Periodically, the contents of those tanks will be transferred to the extracted water tank farm for disposal into BEST-I1.

Based on the results of the technology screening and selection process, and confirmation of the technology provider’s participation, the EERC will develop a schedule of operations. Scheduling of technology demonstration activities will be coordinated to coincide with active formation water extraction during ARM testing. It is anticipated that selected demonstrations will be conducted over a period of 30 to 60 days during which time detailed energy and process performance data will be collected. The longer-duration test runs will help provide indicators of operational and performance issues that would not be apparent during short-term testing.

EERC staff will assist with connection of the technology to the test bed to ensure proper operation of a given technology and operate the test bed facility. Technology providers are expected to conduct their own operations and develop and conduct their own performance and monitoring plan. Once the technology is operating under steady-state operating conditions, EERC engineering staff will conduct an energy and material balance around the system, measuring all inputs of energy, chemical usage, and brine influent flow, as well as effluent flows including treated water (or product) and concentrate. The EERC will collect samples of influent brine and all effluent streams and conduct detailed independent analyses to characterize aqueous samples. Analyses will include pH, alkalinity, hardness, major cations and anions, TSS, TDS, and TOC.

Data collected during the technology demonstration will be shared with the technology provider. The EERC will compile, reduce, and evaluate all operating and performance data and prepare a report detailing pertinent aspects of the technology demonstration for submission to DOE.

11.6 Water Treatment Design Summary

The water treatment technology test bed was designed to accommodate the demonstration of technologies capable of treating extracted water having a target TDS level of 180,000 mg/L through the blending of on-site formation waters. Extracted water pretreatment operations include suspended solids removal, organics removal, and an option for softening to reduced hardness. The test bed pretreatment operations offer the flexibility to blend on-site formation waters to represent extracted water TDS levels from any suitable CO_2 storage DSFs. The ability to provide multiple degrees of pretreatment for solids reduction, organics removal, and optional softening operations provides a robust test bed facility capable of demonstrating a full range of technology capabilities at development scale, ranging from small pilot systems to semitractor trailer-mounted systems. The test bed location (adjacent a state highway) at an operating industrial water-handling facility provides easy access and the potential for maintenance and operation of a technology demonstration facility beyond the duration of the BEST Phase II project.

12.0 COST ACCOUNTING AND BENEFIT ANALYSIS

12.1 Benefits

The Johnsons Corner BEST will benefit future CO_2 saline storage projects through development of engineering strategies that reduce stress on sealing formations, provide a mechanism for diverting a pressure or injected fluid plume from potential leakage pathways, and reduce AOR. In addition, BEST will provide evidence for increased storage capacity, improved storage efficiency, and improved geologic storage coefficients including fundamental data for ARM scenarios. This project and the economics associated with it will directly contribute to the development of best practices for site characterization, site operations (including ARM and extracted brine treatment), monitoring, and site closure. The results derived from the implementation of the proposed brine extraction field test will provide a significant contribution to NETL's Carbon Storage Program goals. Specific project benefits are listed below:

1. This project will provide an evaluation and understanding of the effects of various ARM strategies.

2. This project will develop engineering strategies/approaches to quantitatively effect changes in differential formation pressure and to monitor, predict, and manage differential pressure plume movement in the subsurface for future CO_2 storage projects in saline formations.

3. The Johnson Corner project will obtain valuable information on the ability of brine treatment technologies to produce water for beneficial use from high TDS waters.

4. This project will be conducted in a formation considered for CO_2 storage and involves interaction with commercial-scale CCS volumes of injected fluid. As such, the project is directly relevant to verifying engineering strategies/approaches for managing and monitoring increases in formation pressure analogous to commercial-scale CCS activities.

5. Project outcomes will provide stakeholders with insight into strategies to reduce AOR and manage elevated formation pressures, subsequently reducing project risk. Reductions in risk will contribute to increased public and regulatory acceptance, thus addressing potential barriers to CCS deployment.

6. This project will provide a significant contribution to DOE's Carbon Storage Program Goals 1 and 2 by validating technologies that will improve reservoir storage efficiency, ensure containment effectiveness, and/or ensure storage permanence by controlling injected fluid plumes in a representative CO_2 storage target.

7. This project directly contributes to DOE's Carbon Storage Program Goal 3 by providing fundamental data to improve storage coefficients, using ARM related to the respective depositional environments investigated.

8. This project will support DOE's Carbon Storage Program Goal 4 by producing information that will be useful for inclusion in DOE best practices manuals (including those related to site operations, site characterization, simulation, and risk, and MVA).

12.2 Costs

Estimated project costs for the Johnsons Corner BEST were compiled for both ARM demonstration (subsurface) and the water treatment test bed facility (brine) activities (Table 12-1). Key subsurface activities which are budgeted include labor and travel costs for planning and permitting activities, well drilling and completions, ARM surface infrastructure installation, site characterizations and modeling, field operations, data processing, and project decommissioning. Key extracted brine treatment test bed estimates include planning and permitting activities, building construction, test bed facility installation, test bed operations, and shakedown, utility costs, analytical testing, and data processing and project closeout of the test bed facility.

Table 12-1. Total Estimated Project Implementation Cost for Subsurface and Extracted Brine Activities

Activity	DOE Funding	Cost Share	Total
ARM Demonstration	$12,570,331	$4,220,560	$16,790,891
Extracted Brine Treatment Test Bed	$3,110,174	–	$3,110,174
Total Project Cost	**$15,680,505**	**$4,220,560**	**$19,901,065**

13.0 CONCLUSIONS

The EERC was commissioned by DOE NETL to develop a field implementation plan for BEST (Brine Extraction and Storage Test) in the Williston Basin. Based on technical, operational, and logistical criteria to conduct BEST, the EERC recommends that the Phase II pilot test be integrated with an operating SWD site (Johnsons Corner) in western North Dakota. Site operator Nuverra is committed to hosting the field test at its Johnsons Corner site and contributing resources leading to the successful execution of the project. The geologic conditions at the Johnsons Corner site provide the ideal experimental conditions to effectively test brine movement and understand differential pressure plumes in the subsurface to validate predictive models. A technical design package for the pilot test, focused on testing and validating approaches for ARM and extracted water treatment strategies, was specifically developed for the identified site. The proposed four-well design provides operational flexibility and monitoring capability to test ARM scenarios through a range of injection and extraction rates. Planned BSEM and active reservoir surveillance, coupled with iterative simulation modeling and history-matching efforts, will document the effectiveness of the ARM operations. In addition to operational flexibility, the Johnsons Corner site provides the ability to generate tailored brine compositions for use in a fit-for-purpose surface facility designed to demonstrate technologies capable of treating high TDS brines for beneficial use. A risk assessment conducted as part of the design implementation plan identified no unacceptable project risks. This proposed field implementation plan will meet all DOE goals for Phase II of the BEST Program.

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APPENDIX A

RESERVOIR MODELING AND SIMULATION

RESERVOIR MODELING AND SIMULATION

A.1 GEOLOGIC MODEL DEVELOPMENT

The objectives of the site characterization and modeling effort were to build a robust platform from which to test and evaluate the effectiveness of proposed new-well operational schema of ARM (active reservoir management). Detailed regional and site-specific geologic property characterization of the primary formations related to injection and extraction of brine fluids in the study region was conducted. This characterization effort provided a geocellular structural framework and sound basis for distribution of site-specific geologic properties within that framework. The structural framework for the Johnsons Corner geocellular model was built in Schlumberger's Petrel E&P software platform.

The geocellular model of the Johnsons Corner site encompasses a 6-mile by 6-mile (36-square-mile) area centered on the Rink SWD (saltwater disposal) 1 and Rink SWD 2 wells (NDIC Well Numbers 90123 and 90134, respectively) (Figure A-1). The model developed in this work was constructed with publicly available data, much of the data available from the North Dakota Industrial Commission (NDIC), including well logs, formation top depths, core sample descriptions and analyses, completion and perforation data, injected volumes, and pressure measurements. The formations of interest in these modeling efforts included the Inyan Kara, Broom Creek, and Amsden Formations (Figure A-2).

The location of cored wells in the Inyan Kara Formation, as well as cores for the Broom Creek and Amsden Formations (for following discussion), are displayed in Figure A-3. Generally speaking, limited geologic core data are available for each of the formations of interest. There is, however, one Amsden Formation cored well approximately 3 miles northeast of the Johnsons Corner site, indicating complex lithologies but some intervals characterized with permeabilities exceeding 100 mD (see Section A.1.3, Figure A-9).

The sandy intervals of the Inyan Kara Formation, from the analyses of available core samples, are composed predominantly of quartz, with minor components including feldspars, coal and interspersed plant fragments, some siderite nodules/concretions, some iron staining, and calcitic cement. Core analysis data for sandstones of the Inyan Kara indicate an average porosity of about 20% and a geometric average permeability of approximately 60 mD.

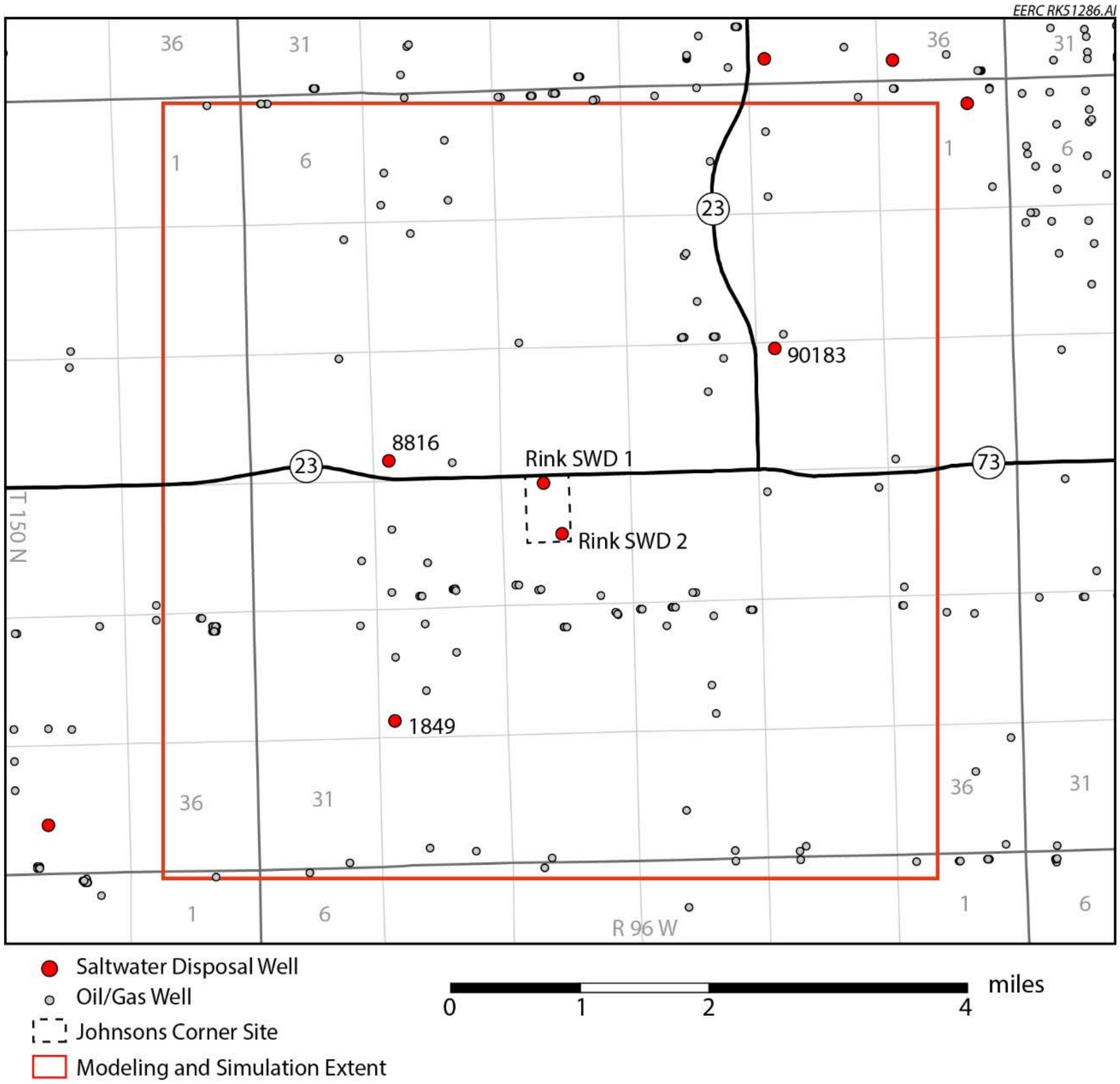

Figure A-1. Map view of the Johnsons Corner model area. The model efforts focused on a 6-mile by 6-mile (36-mi^2) area (red rectangle).

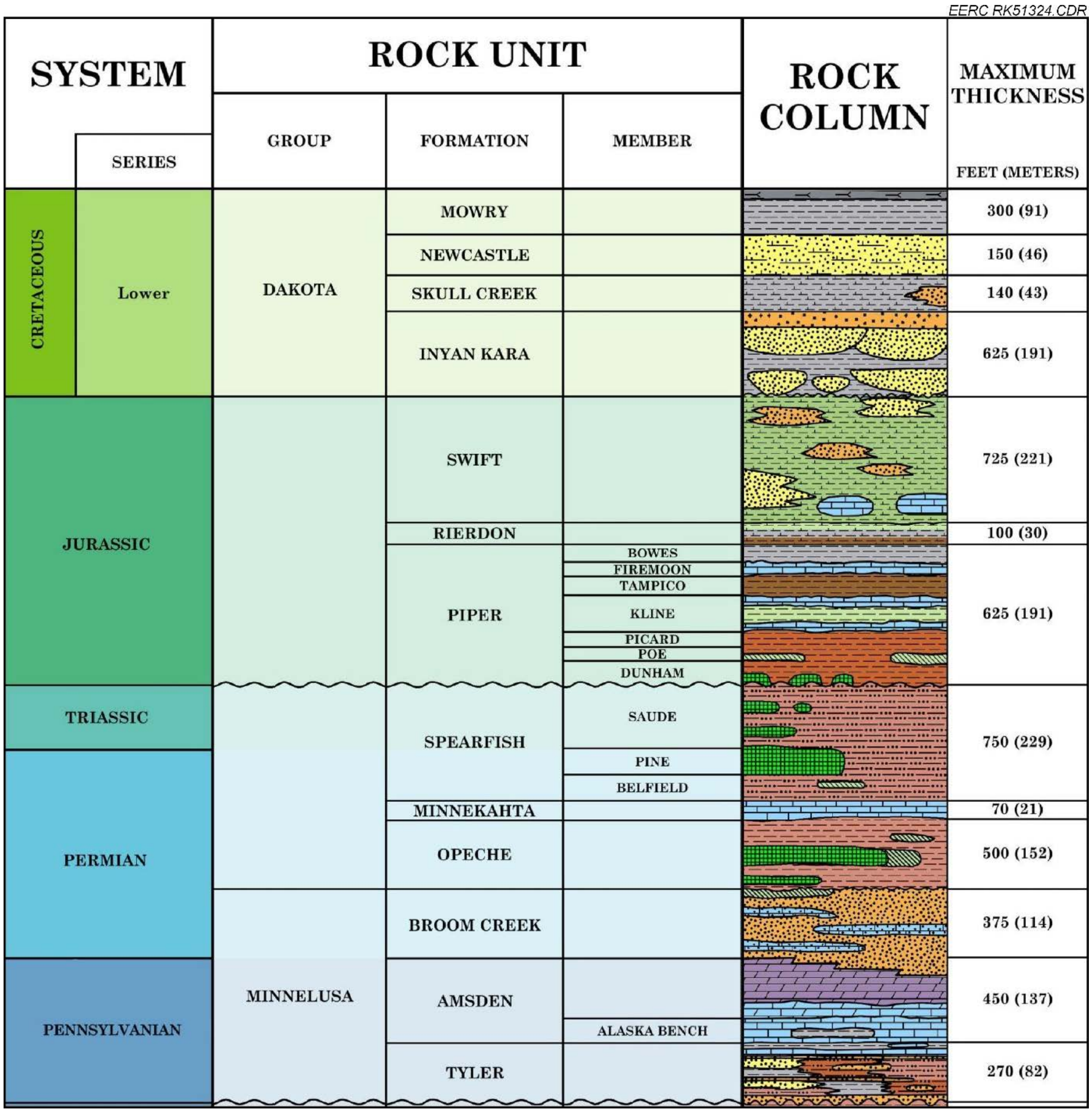

Figure A-2. Williston Basin stratigraphic adapted from Murphy and others (2009).

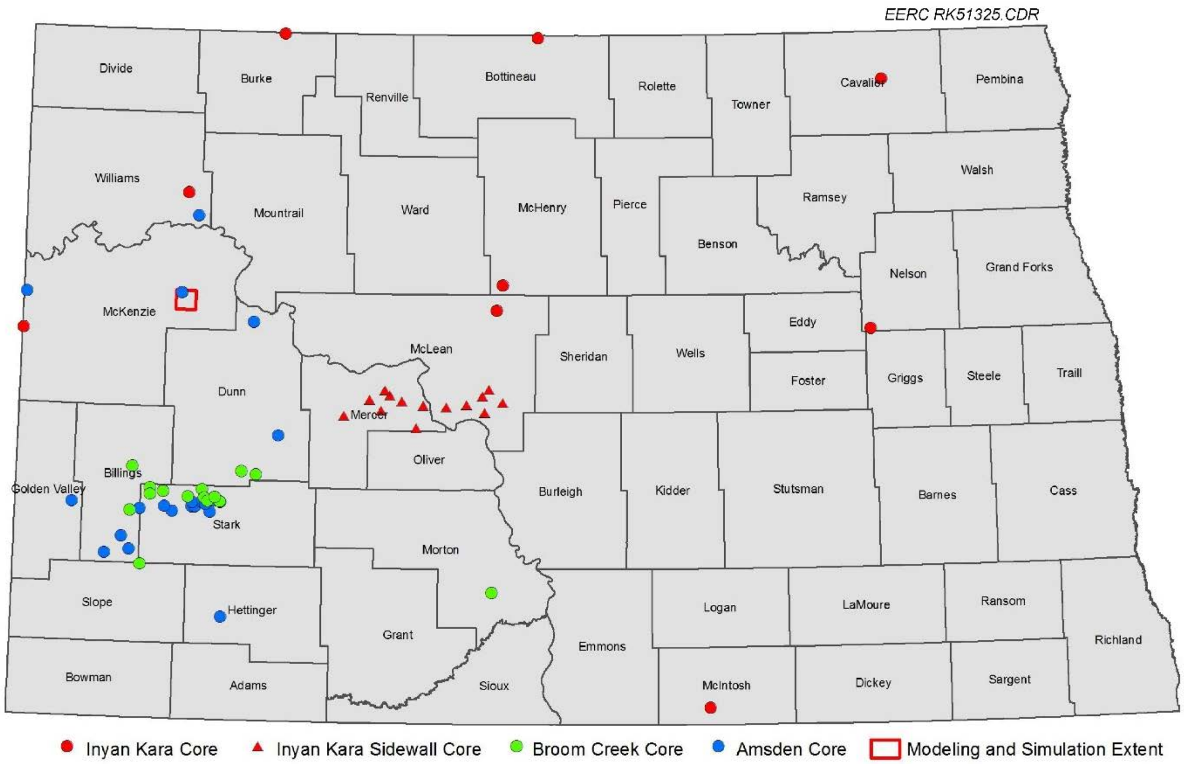

Figure A-3. Inyan Kara, Broom Creek, and Amsden cored well locations and the Johnsons Corner project area of interest.

A.1.1 Structural Model

The structural framework for the Johnsons Corner geocellular model was built in Petrel using well logs from NDIC. Formation tops of the Inyan Kara and Swift Formations were picked from the available gamma ray logs with the aid of resistivity logs where available, as described in Wartman (1983), Murphy and others (2009), and Bader (2015). The Inyan Kara Formation, within the Johnsons Corner model area, was subdivided into three zones (three main fining upward sequences) to help constrain the facies distribution within the model area. Broom Creek, Amsden, and Tyler Formation tops were picked from gamma ray logs, as described in Sorensen and others (2009) and Murphy and others (2009). Model structural surfaces and isopachs are shown in Figures A-4 and A-5.

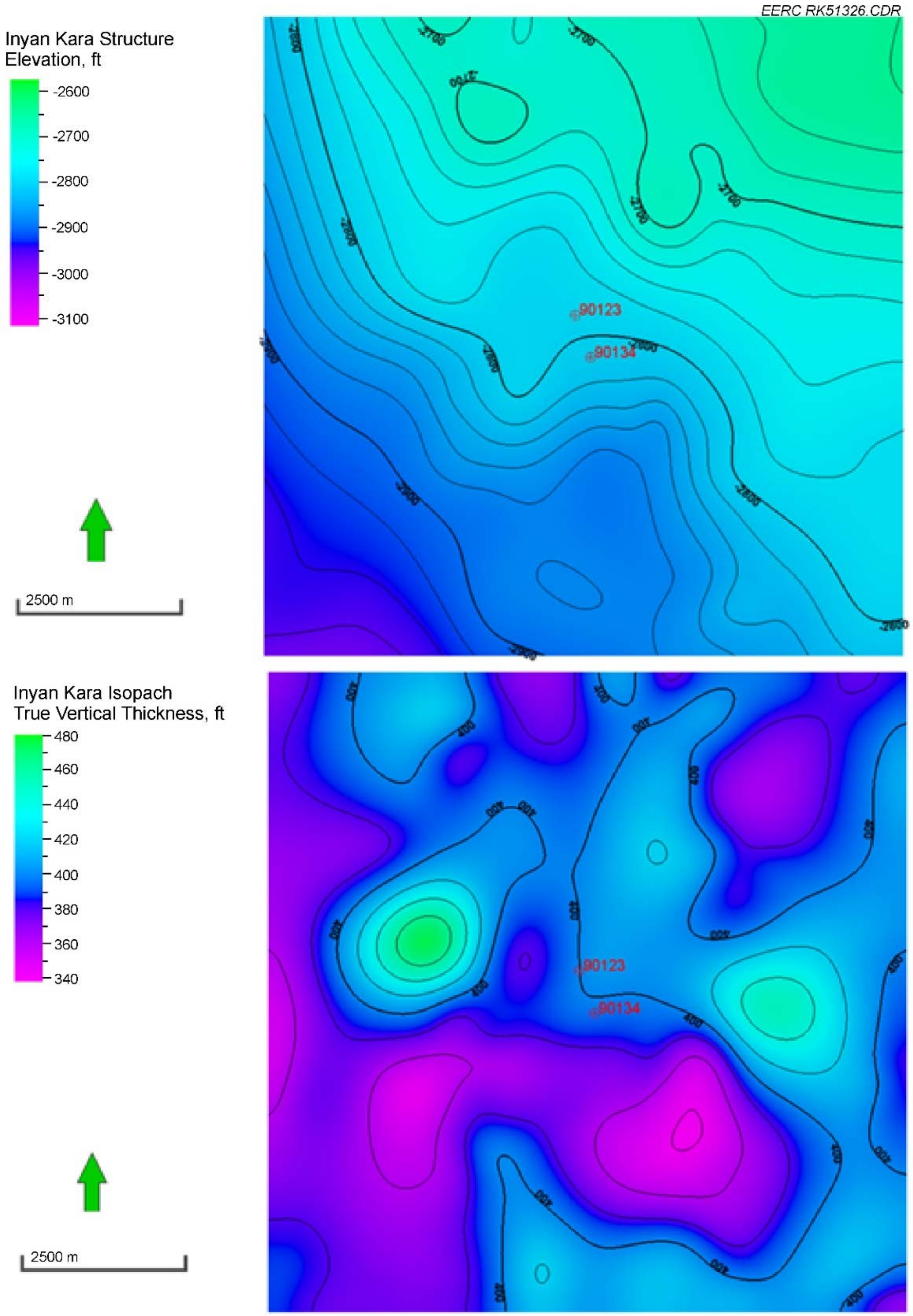

Figure A-4. Top: structure contour map on top of the Inyan Kara Formation within the Johnsons Corner study area. Datum: mean sea level. Bottom: isopach map of the Inyan Kara Formation within the Johnsons Corner study area. Injection Wells 90123 (Rink SWD 1) and 90134 (Rink SWD 2) are shown in red. Contour interval = 20 ft.

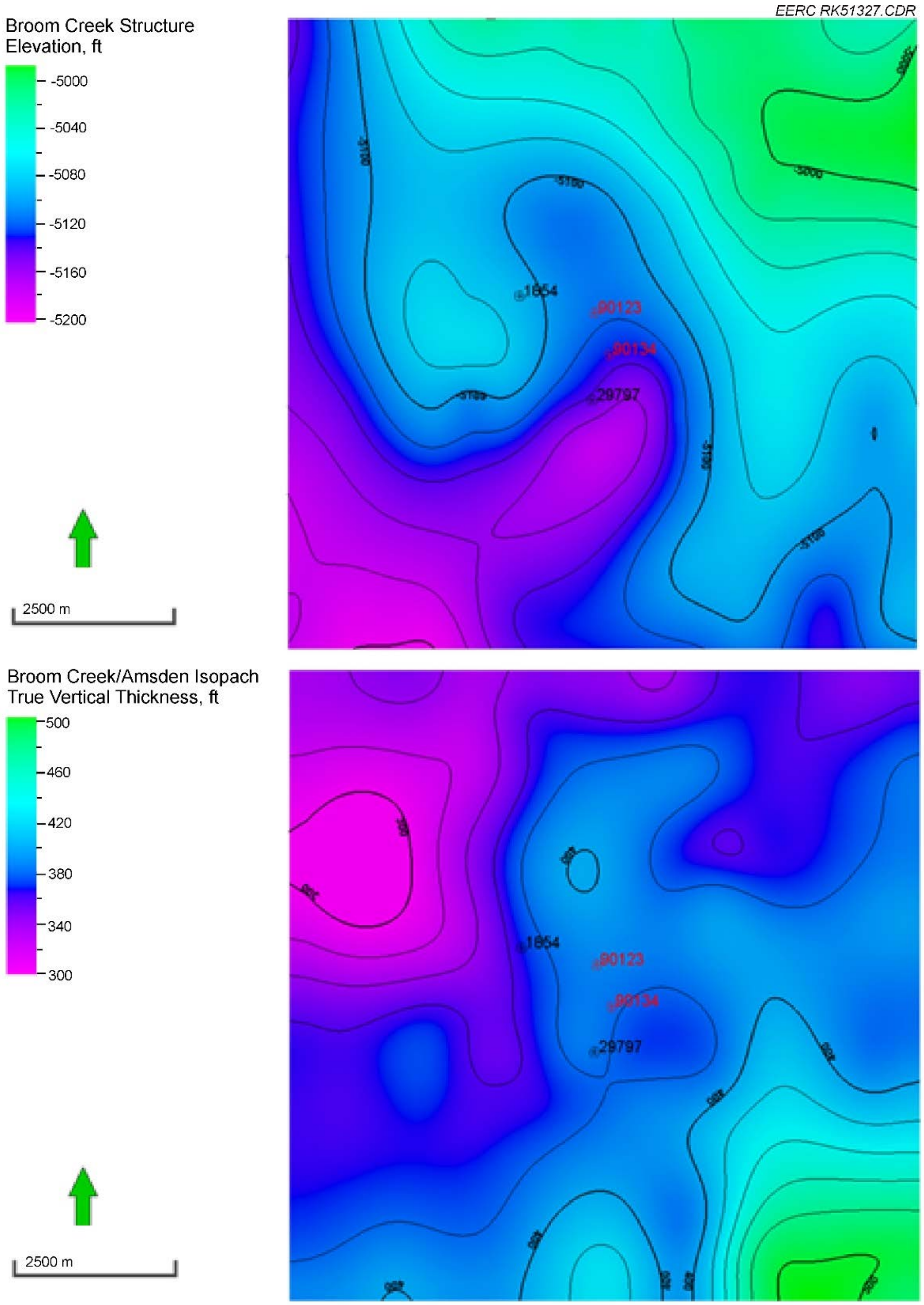

Figure A-5. Top: structure contour map on top of the Broom Creek Formation within the Johnsons Corner study area. Datum: mean sea level. Bottom: isopach map of the combined Broom Creek and Amsden Formations within the Johnsons Corner study area. Injection Wells 90123 (Rink SWD 1) and 90134 (Rink SWD 2) are shown in red. Neighboring wells that intersect the Broom Creek/Amsden are shown in black. Contour interval = 20 ft.

A.1.2 Facies Modeling

Inyan Kara Formation

The Inyan Kara Formation consists of heterogeneous clastic sequences deposited in several different environments. Examination of well logs and associated analysis of geologic core samples verified that normalized gamma ray logs were able to provide reliable facies interpretations. This led to the separation of the formation into three basic facies: clean sand, silty sand, and shale. Well logs from 39 wells within the model area were selected to distribute these facies based on the log suite available for each of those wells.

Because of the heterogeneous nature of the Inyan Kara Formation, facies were distributed using multiple-point statistics (MPS). An MPS training image was constructed to capture both the vertical and horizontal facies associations of the Inyan Kara Formation (Figure A-6). The relative proportions for the upscaled cells in the Inyan Kara model were clean sand, 31%, silty sand, 27%, and shale 42%, with roots in the proportions noted in the original control points' facies logs.

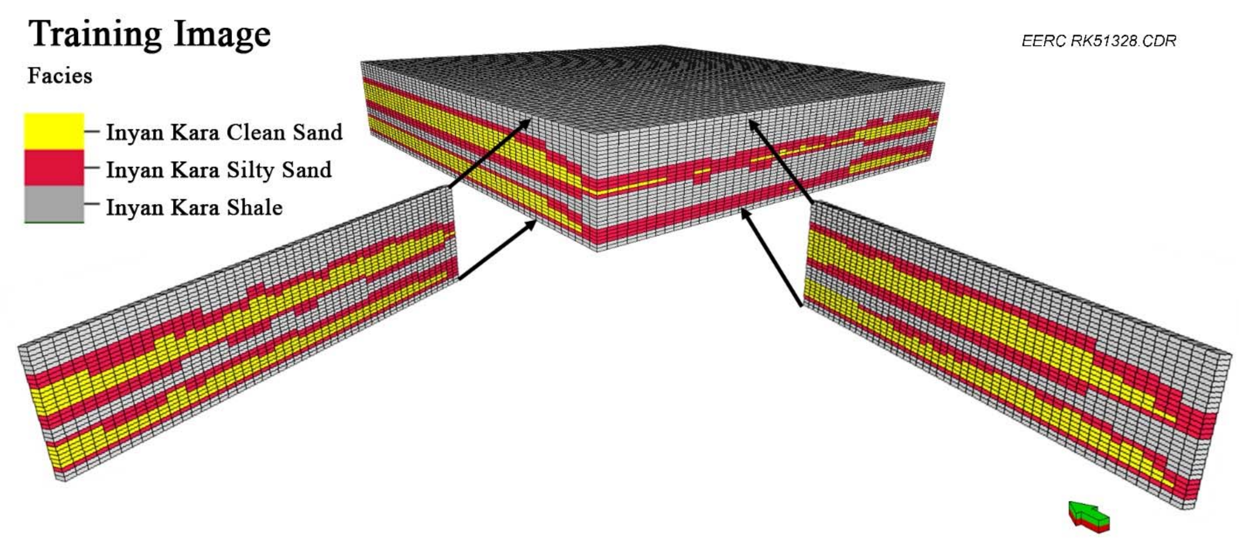

Figure A-6. Training image grid used in MPS facies distribution. Clean sand is yellow, silty sand is red, and shale is gray. Cross sections in the X and Y direction show the internal structure of the training image.

A.1.3 Petrophysical Modeling

The petrophysical properties (porosity and permeability) were distributed in the geocellular model with conditioning to the facies model. Distributions were achieved using variogram-based geostatistical methods guided by ranges of properties from core sample measurements. The porosity/permeability crossplots developed from the geologic core sample measurements and used in these distributions are shown below (Figures A-7–A-9).

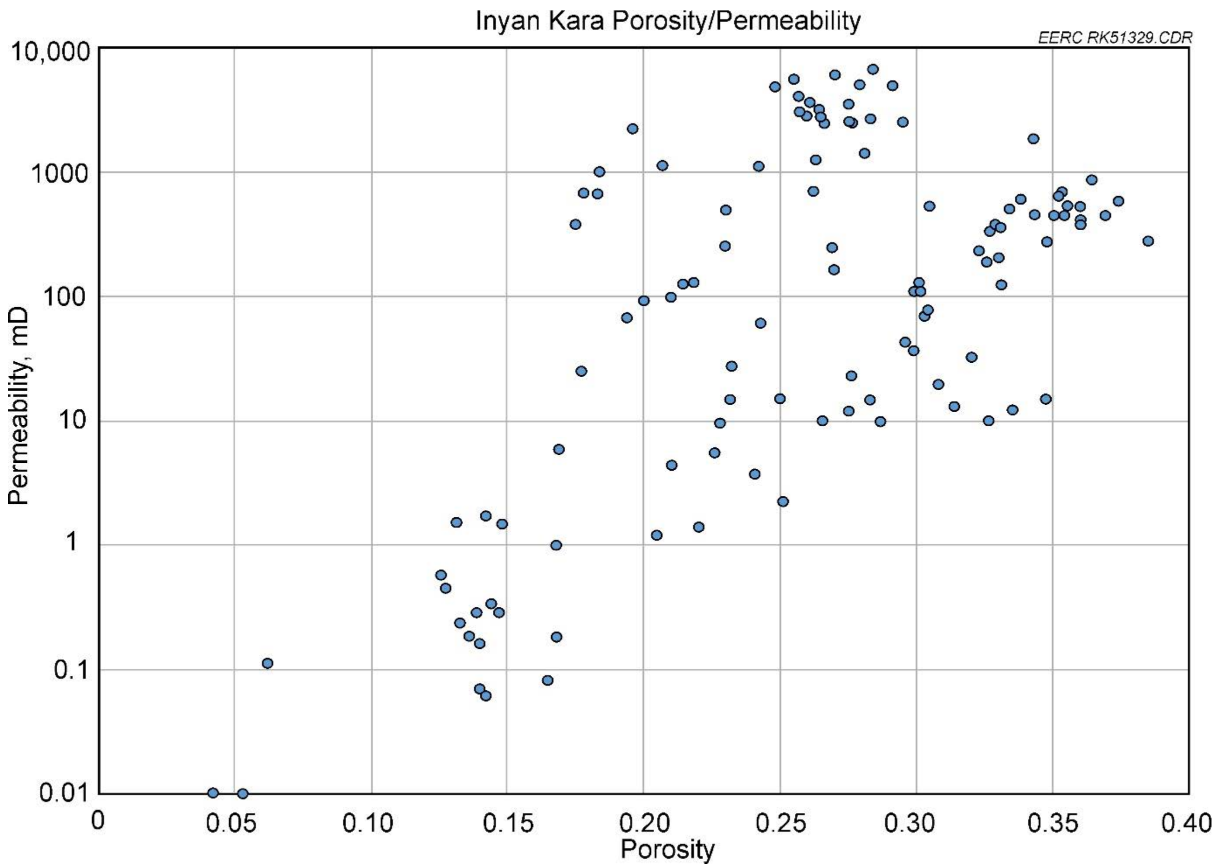

Figure A-7. Inyan Kara core porosity/permeability crossplot.

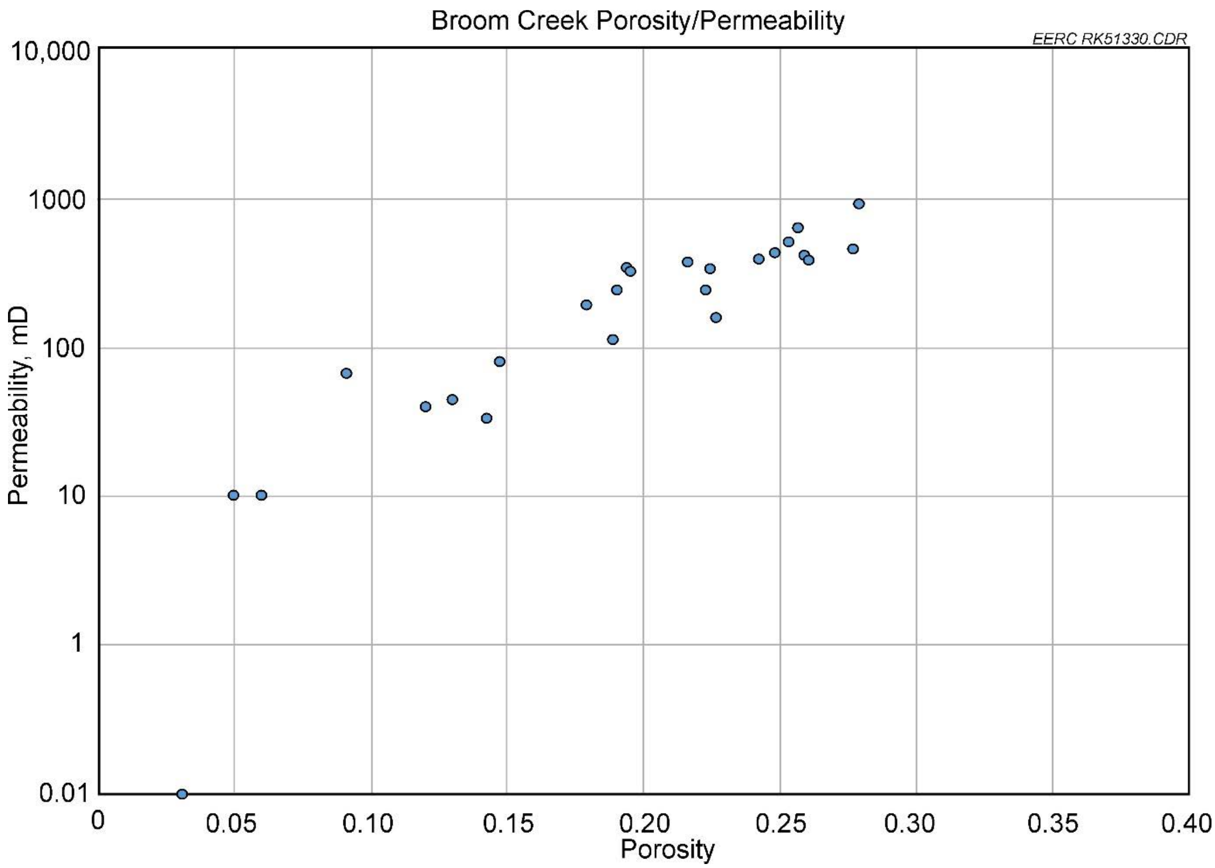

Figure A-8. Broom Creek porosity/permeability crossplot.

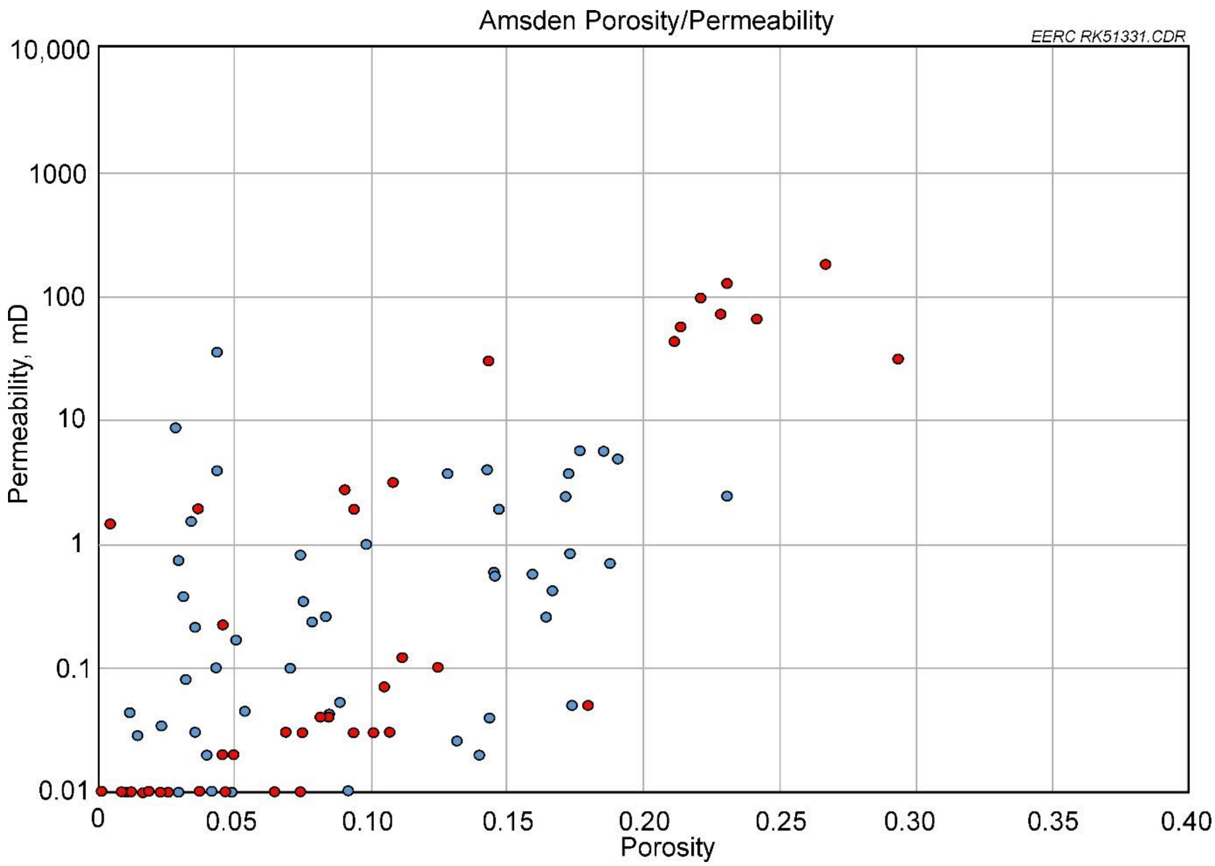

Figure A-9. Amsden porosity/permeability crossplot. This crossplot was developed from three North Dakota wells (Wells 1412, 9106, and 26249). Well 1412 (plotted in red) was approximately 3 miles from the area of interest and contained some measured permeabilities greater than 100 mD, while few values for the other two more distant wells exceeded 10 mD.

A.1.4 Variograms

Variogram ranges used to distribute petrophysical properties within the Inyan Kara Formation were determined from generalized variogram ranges of a sandstone delta found in Deutsch (2008). The major, minor, and vertical ranges for the Inyan Kara were given values of 3369, 919, and 10 ft, respectively. The orientation of the major direction was determined to be 34 degrees east of north through variance mapping of upscaled well log properties.

Variogram ranges used to distribute petrophysical properties within the Broom Creek Formation were modified from generalized variogram ranges of an eolian environment (Deutsch, 2008) to reflect a more isotropic variance (subtle anisotropy noted in variance mapping of upscaled well log properties). The major, minor, and vertical ranges for the Broom Creek were given values of 1194, 951, and 10 ft, respectively.

In the Amsden Formation, variogram ranges were again modified from generalized variogram ranges of a shallow dolomite shelf and a shallow sandstone shelf (Deutsch, 2008). The major, minor, and vertical ranges for the Amsden nonreservoir facies were 31,174, 24,941, and 10 ft, respectively. The major, minor, and vertical ranges for the Amsden reservoir facies were 15,243, 12,192, and 10 ft, respectively.

Model petrophysical property distributions are shown in Figures A-10–A-14.

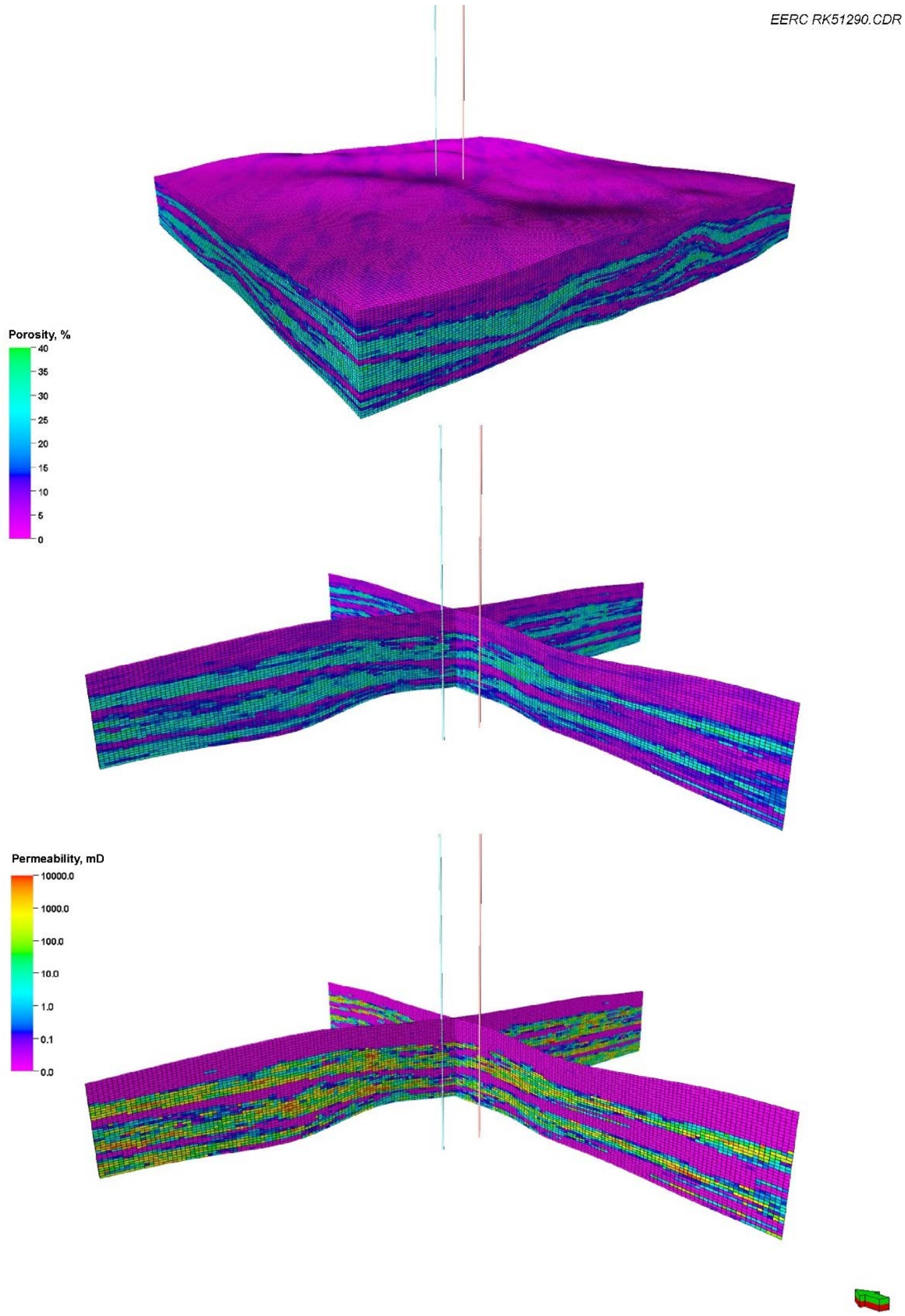

Figure A-10. Inyan Kara Formation porosity (top) and cross sections displaying porosity (middle) and permeability (bottom). Cross sections through the model show the petrophysical properties at the two primary injection wells. The north–south trending cross section intersects Rink SWD 2, and the east–west trending cross section intersects Rink SWD 1. Vertical exaggeration = 10×.

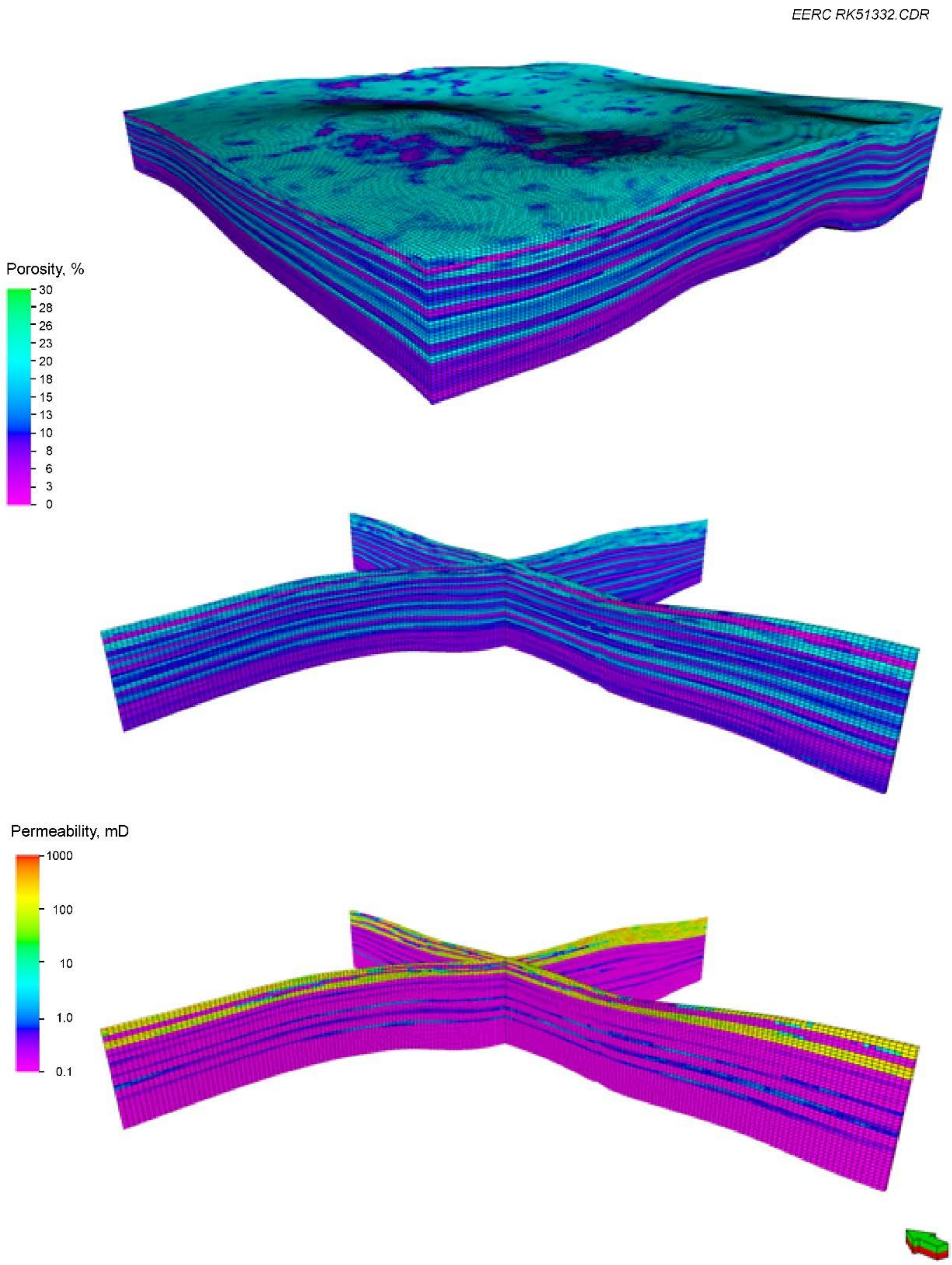

Figure A-11. Broom Creek and Amsden Formation model porosity (top) and cross sections depicting porosity (middle) and permeability (bottom) distributions. Cross sections through the model show the petrophysical properties at the locations of the two primary injection wells (though these two wells do not penetrate into the Broom Creek or Amsden). The north–south trending cross section intersects Rink SWD 2, and the east–west trending cross section intersects Rink SWD 1. Vertical exaggeration = 10×.

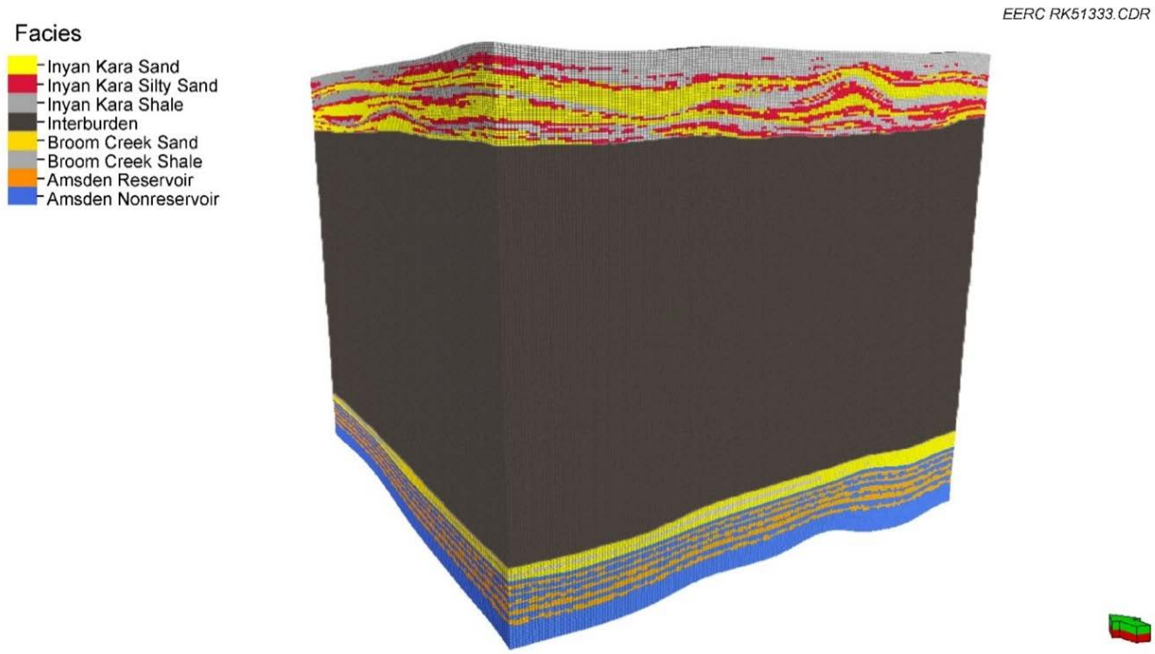

Figure A-12. Entire grid facies property, including the Inyan Kara, Broom Creek, and Amsden Formations, as well as the interburden between the Inyan Kara and Broom Creek. The interburden (shown in dark gray) was excluded from detailed facies modeling.

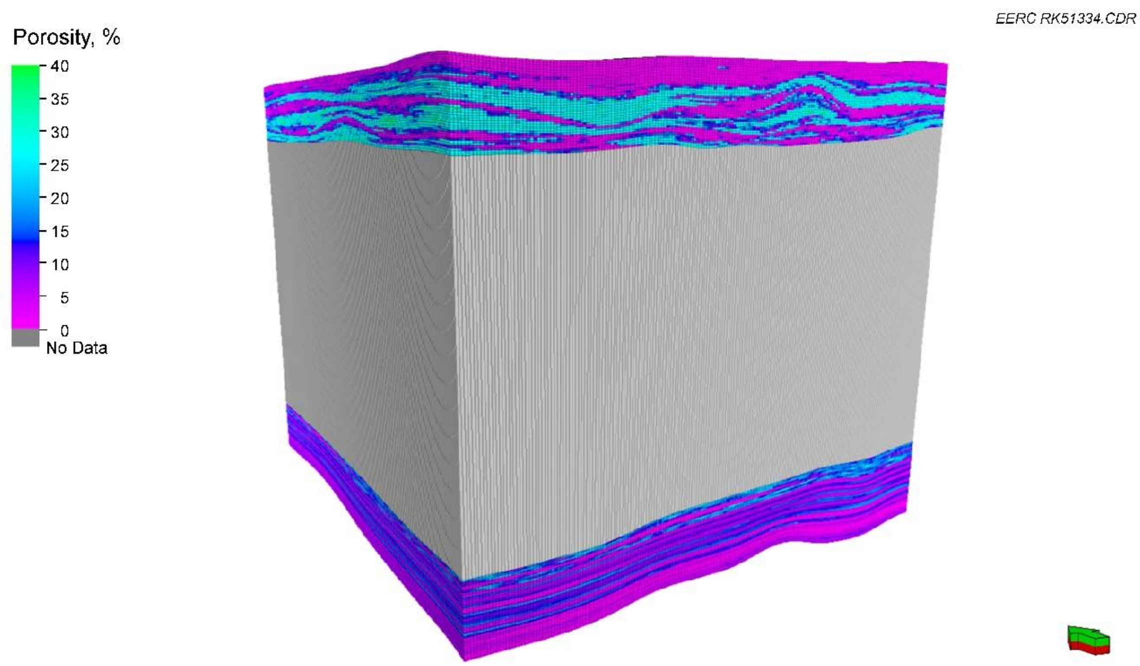

Figure A-13. Entire grid porosity property, including the Inyan Kara, Broom Creek, and Amsden Formations, as well as the interburden between the Inyan Kara and Broom Creek. The interburden was excluded from the porosity distribution (shown in gray).

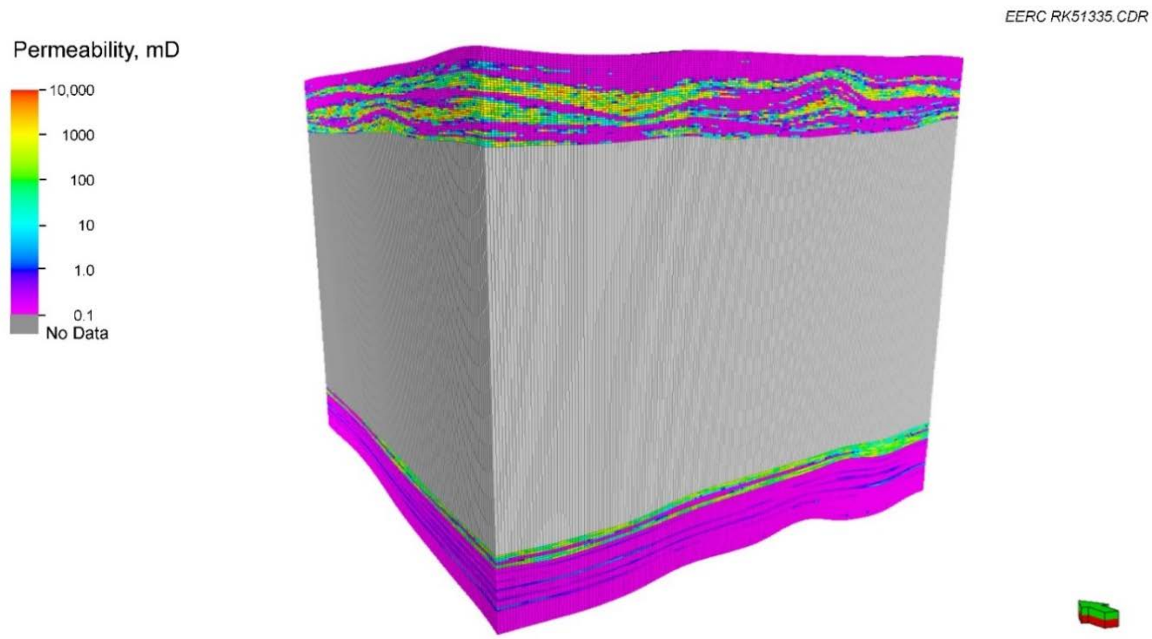

Figure A-14. Entire grid permeability property, including the Inyan Kara, Broom Creek, and Amsden Formations, as well as the interburden between the Inyan Kara and Broom Creek. The interburden was excluded from the permeability distribution (shown in gray).

A.2 RESERVOIR SIMULATION

A.2.1 History Matching

The purpose of history matching is to get a good estimation and adjustment of geologic models by evaluating the historical flow performance, reservoir parameters, and field events that significantly affect flow behavior, thus enabling predictive pressure and salinity plume development to aid in operational planning. The history-matching workflow is shown in Figure A-15. Although history matching is a time-consuming process, it provides insight to increase understanding of the reservoir, and the predictive results are important in field planning and reservoir management. All reservoir simulation was carried out using Computer Modelling Group's GEM reservoir simulation software.

Because of the level of detail and the grid cell size of the geologic model, it was necessary to upscale this model to a computationally efficient size while maintaining geologic detail and resolution for simulation. The lower 41 layers (combined Broom Creek and Amsden Formations) were turned inactive for Inyan Kara injection and extraction simulation purposes. This enabled relatively fast computational efficiency while still capturing the heterogeneity of the formation. The Inyan Kara layers were then upscaled by judiciously coarsening the fine cells that extended beyond the middle area where the Rink SWD 1 and Rink SWD 2 wells are located (shown in Figure A-16). The total number of cells was reduced from 3 million to 1.3 million, and the number of active cells that describe the Inyan Kara Formation where history matching is conducted was reduced to 630,000. Finer grid spacing was retained over the primary investigation area of pressure and salinity plume development.

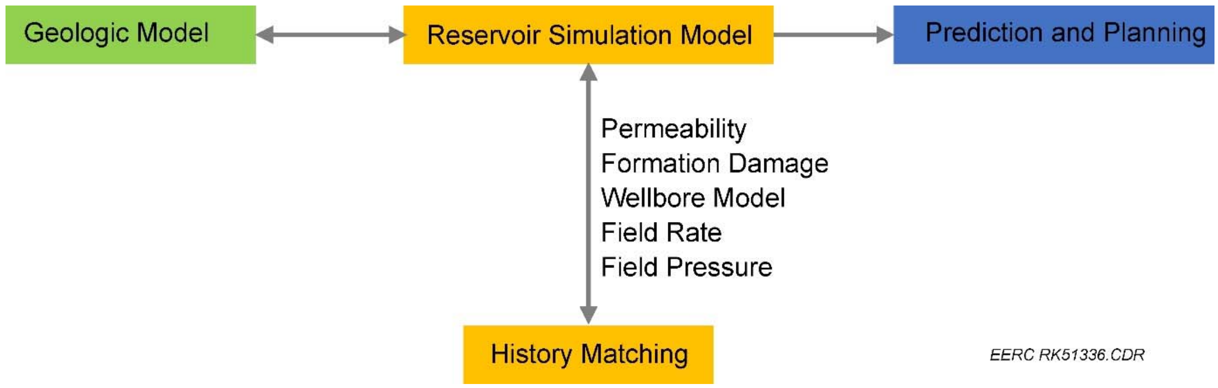

Figure A-15. Workflow for reservoir simulation, history matching, and prediction.

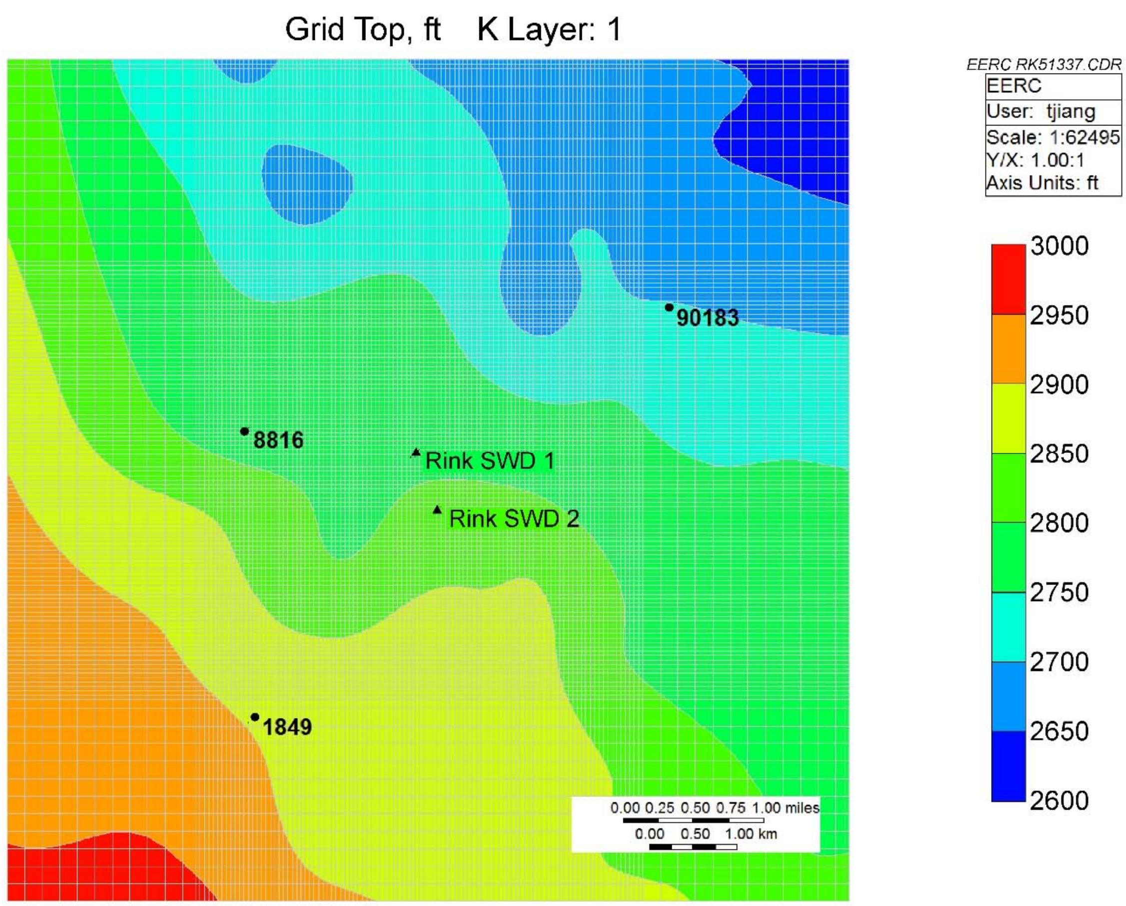

Figure A-16. The reservoir simulation model with a uniform-tartan grid system superimposed on the Inyan Kara top structure map (6 miles by 6 miles).

The water saturation in the simulation model was set to 100%, and the initial salinity was set to 5583 mg/L TDS (total dissolved solids), both representative of native reservoir conditions. As reported earlier, the injected water salinity data obtained from laboratory analyses had an average value of 304,000 mg/L TDS. Since this is considered a single-phase model (only water present in the formation), capillary pressure can be neglected. The relative permeability curve was generated to represent a sandstone with an intermediate wettability condition and an endpoint of 99% absolute permeability at 100% water saturation (Figure A-17).

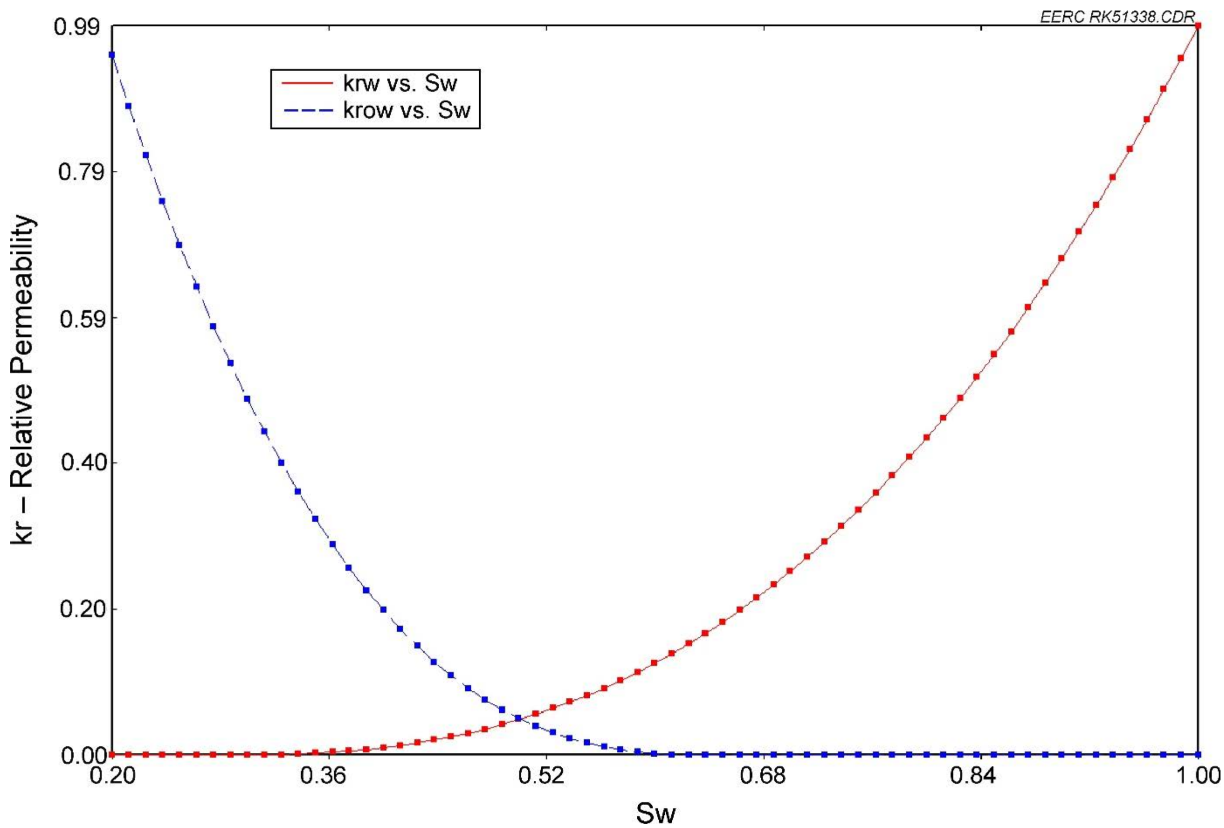

Figure A-17. Relative permeability curves used in the model.

The simulation model assumed open boundary conditions, which allowed lateral water flux through simulated boundary aquifers with minimal pressure buildup. This is representative of the Inyan Kara Formation throughout the region where it is widely used as a SWD zone. These conditions are comparable to future basin-scale CO_2 disposal scenarios where multiple simultaneous CO_2 storage projects are envisioned to operate within the same formation.

Preliminary simulations based on the geologic model data suggested the permeability needed to be reduced in order to improve the match with the historical data. This was achieved by applying a global permeability reduction of 20% over the entire model with smaller localized reductions around individual wells. Field data indicated the Rink SWD 1 well received a well stimulation via acidizing in 2011 and larger diameter tubing was installed in Rink SWD 2 in 2015. The history-matching simulation incorporated these adjustments, as well as adjustments made in local permeability reduction, skin factor, and tubing roughness, to match average wellhead pressure with the known average daily injection rate. Bottomhole pressure data were not available for these wells.

Before history-matching the pressure response for Rink SWD 1 and 2, it was important to evaluate the potential for pressure interference from Well 8816 and Well 1849 to the Rink SWD wells. These wells began injection as early as 1963 and ended injection operation by January 1, 2003. The history of these wells was history-matched, and their residual pressure influence was simulated from January 1, 2003, until the month before Rink SWD 1 started injection in October 2008 (Figure A-18). The layer shown represents the largest lateral extent of the pressure plume generated by Well 8816. It can be seen that Well 8816, which is the closest Inyan Kara injection well to Rink SWD 1 and Rink SWD 2, has no pressure impact on these wells; therefore, pressure interference was neglected for history-matching the pressure response of Rink SWD 1 and Rink SWD 2.

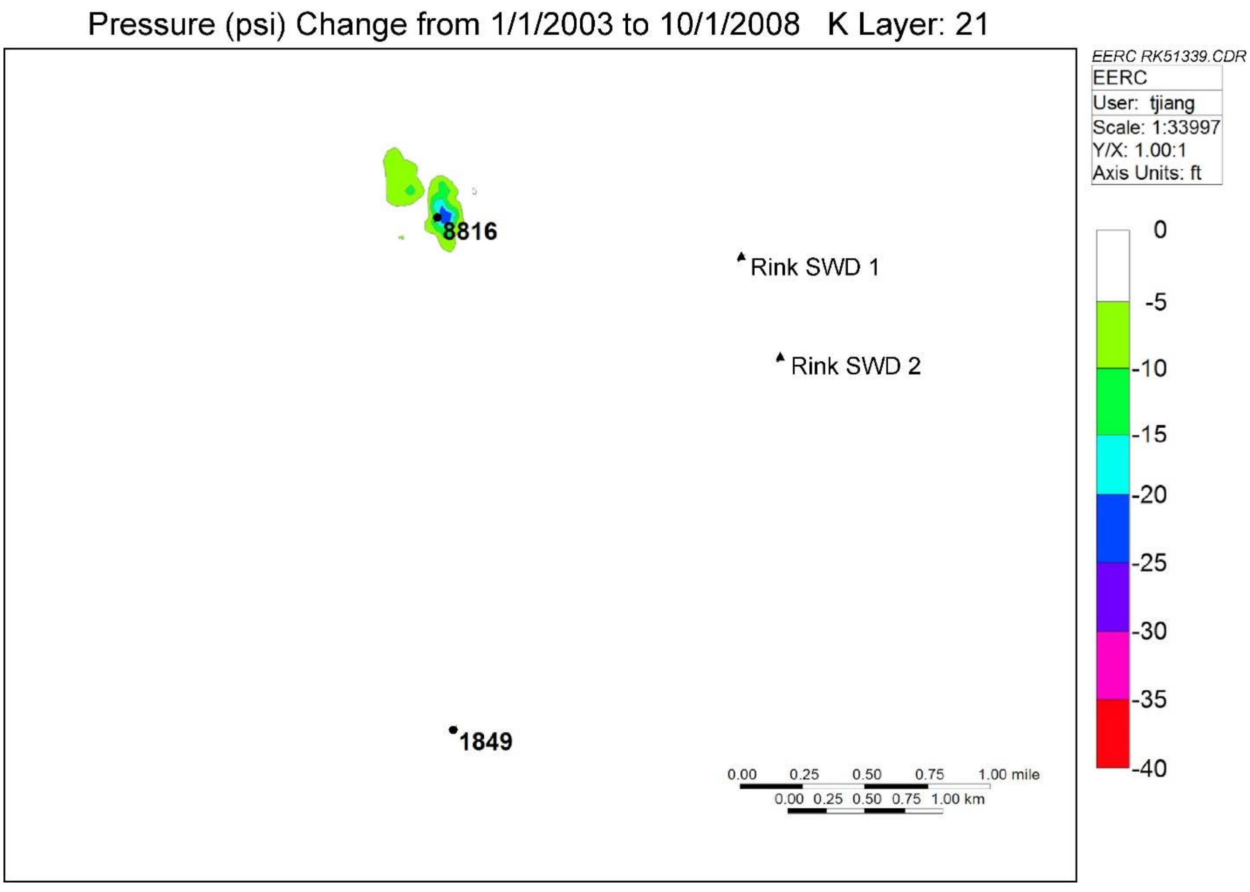

Figure A-18. Pressure difference map from January 1, 2003, to October 1, 2008, illustrating the maximum pressure differential resulting from Well 8816.

The history-matching result is shown in Figure A-19. The simulation pressure response has a good match with the reported wellhead pressure of each well by reconciling the local permeability adjustments, skin factor, and the wellbore model.

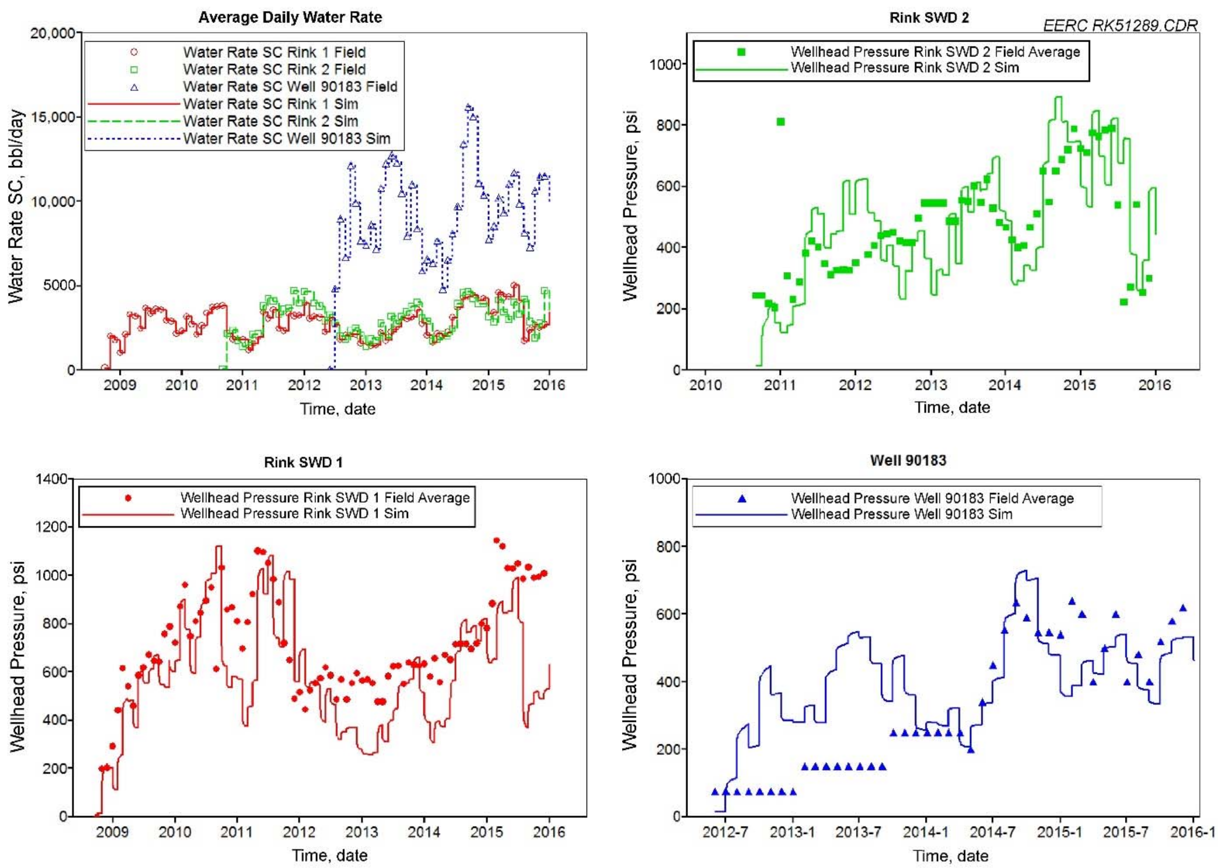

Figure A-19. Pressure history match for Rink SWD 1, Rink SWD 2, and offset Well No. 90183.

Generally, decreasing the local permeability or increasing the skin factor results in increased bottomhole pressure response. Increasing the tubing size or improving the tubing internal roughness coefficient (i.e., replacing old tubing with new tubing) decreases fluid flow friction in the tubing, thus reducing the pressure loss between bottomhole and wellhead. It is also worth noting that the simulation's flow equation is based on steady-state flow, whereas the recorded field-reported wellhead pressures might be indicative of an instantaneous value or transient flow conditions. Thus simulation pressures vary slightly from the reported average pressure data.

Note that only one estimated wellhead pressure value is reported a month and, therefore, may be imprecise. The match of wellhead pressure for the site wells Rink SWD 1 and Rink SWD 2 reflects the changes in injection rate and events of the well history. The injection rates for these two wells are nearly equal for most of their history, as shown by the image in the upper left of Figure A-19, reflecting Nuverra's preferred operating practice at the time. Note, however, that equal injection rates do not equate to equal wellhead injection pressure. The Rink SWD 1 pressure is generally higher because of a somewhat lower k-h product. Both of the two wells have also had different remedial work performed during their operating life, which is accounted for in the simulation. Offset Well No. 90183 is also shown in the figure because of its high injection rate and proximity to the project wells. Wellhead pressure match for this well is good in the later half of its history where the reported data appear more realistic than in the first half of its operating life. Well 90183 is not operated by Nuverra; therefore, a more detailed description of its history is not available.

An initial shut-in pressure test for the Rink SWD 1 and Rink SWD 2 wells was conducted, in which the wells were shut in after injecting at rates of 6131 and 7404 bwpd, respectively. Rink SWD 1 showed an instantaneous pressure drop of 360 psi, and Rink SWD 2 showed an instantaneous pressure drop of 50 psi. Thus the tubing friction for Rink SWD 1 was greater than that of Rink SWD 2, as expected because of the smaller diameter tubing in the Rink SWD 1.

Description of the existing salinity and pressure plume development at the site is critical in determining the optimal location of a new extraction well. The salinity plume development for Rink SWD 1 and Rink SWD 2 at the end of the history-matching period, December 31, 2015, is shown in Figure A-20. The plumes from each well are not only deflected away from each other because of pressure interference but also deflected to the west and south as they are both influenced by the operation of the more distant Well 90183 located to the northeast of the other wells.

The pressure plume is significantly larger than the salinity plume, as shown in Figure A-21. The pressure plume indicates that, with a relatively higher injection rate at Well 90183, the pressure plume expanded from northeast to southwest. The pressure plume also reached the northern boundary of the model. This demonstrates why it was important to employ an open boundary model system to effectively avoid an artificial pressure buildup phenomenon caused by closed boundaries or strong aquifer influx which may substantially decrease the potential injectivity. For comparison purposes, a closed boundary simulation case was also modeled. The size and shape of the salinity plume was quite similar compared to an open boundary system, but the pressure buildup was several hundred psi higher for the closed boundary case and does not reflect the operating history of the wells (compare Figure A-21 to Figure A-22).

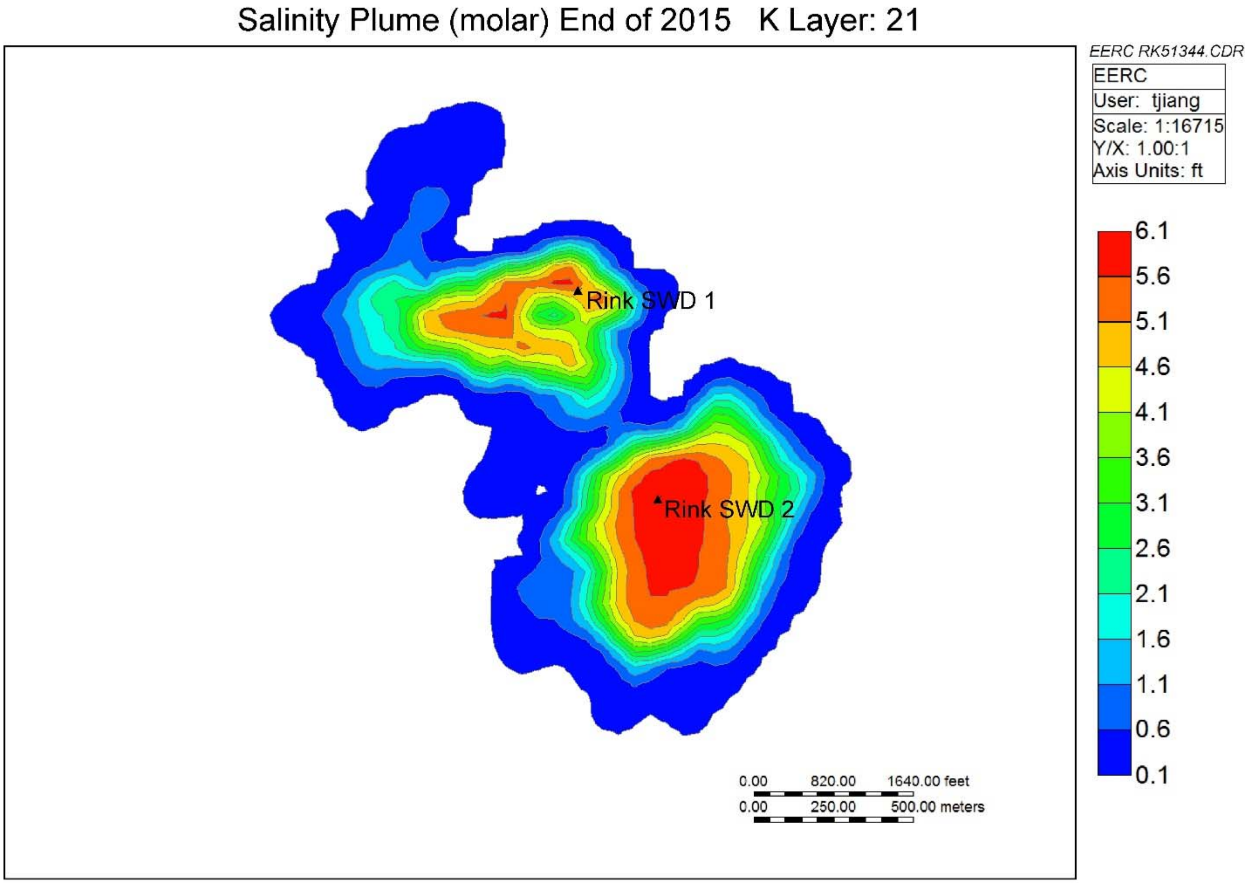

Figure A-20. Salinity plume development (molar concentration). Layer 21 indicates the maximum areal extent at the end of year 2015.

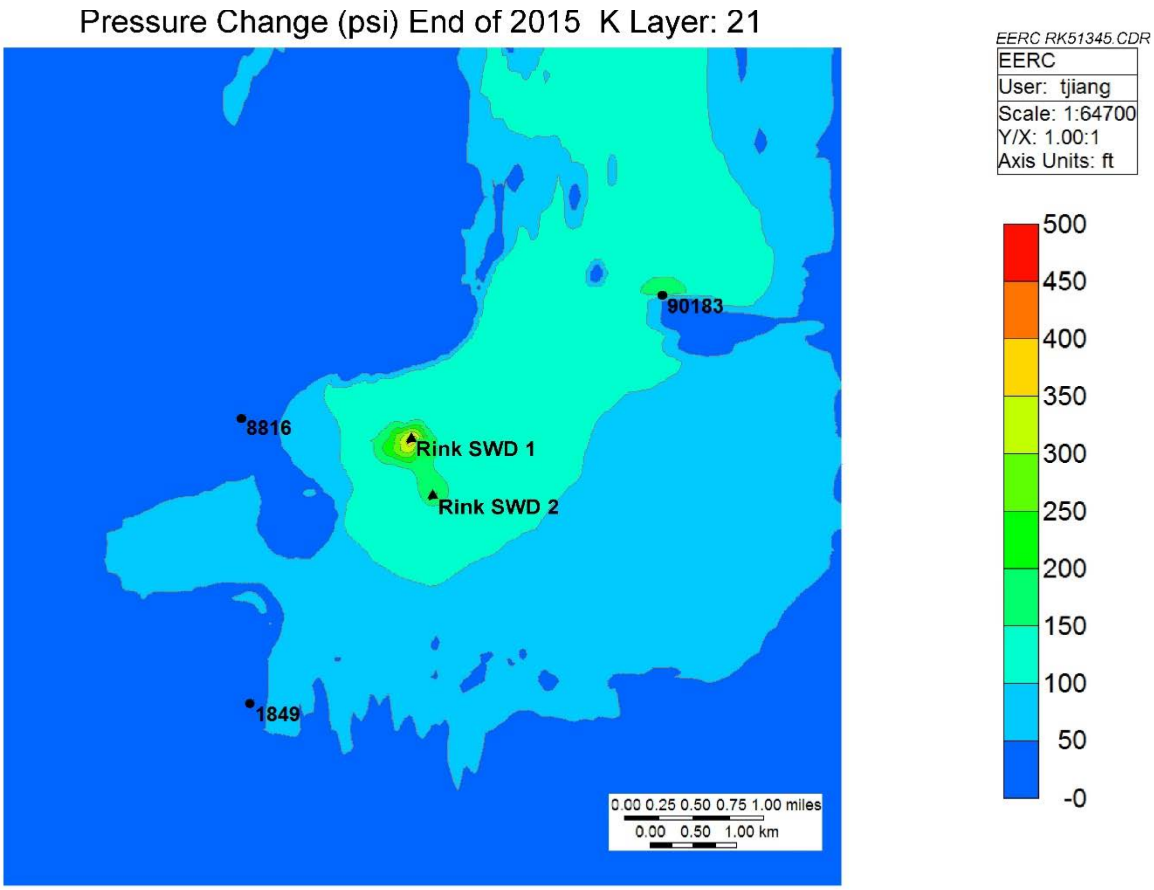

Figure A-21. Differential pressure plume distribution (psi) from year 1961 to 2015.

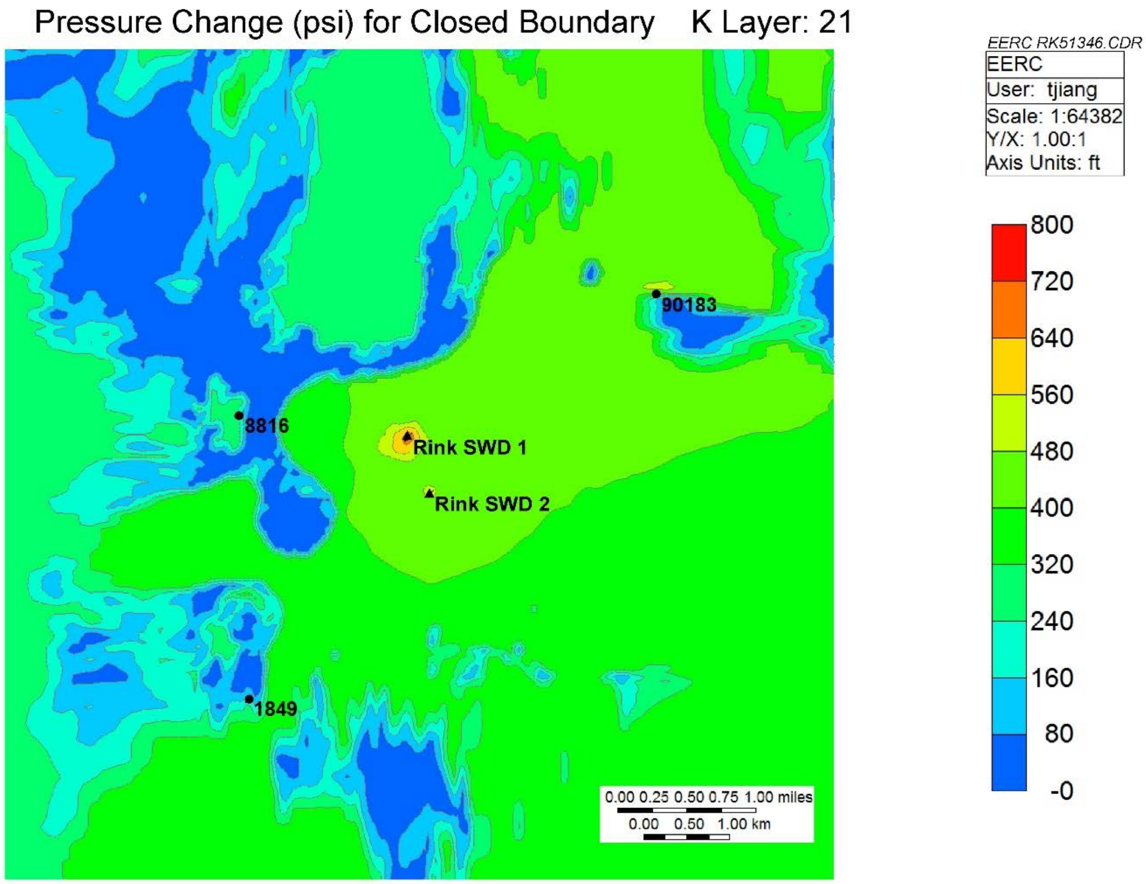

Figure A-22. Pressure buildup for the closed boundary system sensitivity case (psi).

A.2.2 Predictive Simulations

Predictive simulation was used to determine well locations and rates. The reservoir modeling effort to select effective locations for the BEST-E1 and -I1 wells demanded the reconciliation of several competing constraints:

- Clear pressure response in the injection wells
- Avoiding high salinity in the extraction water
- Minimizing extraction ratio
- Ability to dispose of extraction water
- Suitable surface location

Each of these constraints and their relevance to the ARM activities are discussed below.

Clear Pressure Response in the Injector Wells

The project target horizon is characterized by high permeability; therefore, a rapid pressure response at the injection wells is expected, and the distances between the project wells is not a concern from that perspective. However, the high permeability also implies relatively low pressure gradients through the project area. The pressure response at the injection wells is thus expected to be relatively small, in the range of 20 to 50 psi. High accuracy bottomhole pressure gauges will be used throughout the project and should record these pressure responses without difficulty. Pressure response is a function of extraction rate, and extraction will generally be performed at as high a rate as practicable.

Avoiding High Salinity in the Extraction Water

Native brine in the Inyan Kara has a salinity of approximately 5000 mg/L TDS, while the injection water will have a salinity of >300,000 mg/L TDS. Therefore, salinity of the extraction water may be quite variable, depending on the location of the well and the extraction rate. Extracted brine with very high salinity is to be avoided because of the implication of detrimental circulating of injected water and because this may limit the ability to blend water at the surface to form suitable waters for the treatment test facilities. However, a well placement far from the salinity plume implies an attenuated pressure response which is also detrimental to project execution.

Furthermore, circulating injected fluids does not serve as a good proxy for economic ARM at a CCS site. ARM implementations at a CCS site would seek to avoid breakthrough of injected CO_2. This would also minimize the associated energy and processing costs of separation and reinjection of produced CO_2 for as long as possible or require shut-in of the existing well and drilling of a new one.

Minimizing Extraction Ratio

Generally, extraction ratio can be minimized by placing the extraction well close to the injectors, ideally between the injectors. However, in this true industrial-scale application, such a well placement will produce a high-salinity brine. Similarly, extraction wells placed at CCS sites would also seek to minimize production of injected CO_2. Therefore, a preferred location will be as close to the injectors as possible while still avoiding the salinity plume. Within the open, unbounded reservoir conditions at this site, a higher extraction ratio should be expected compared to sites or formations with a closed reservoir system.

Ability to Dispose of Extraction Water

Inyan Kara Formation water extracted from BEST-E1 will be disposed of via the BEST-I1 well, which will be completed in the Broom Creek Formation. The Broom Creek appears to have an injection capacity of at least 4000 bwpd, and the proposed extraction well location and project base case design must reflect the limitation of this expectation. However, if the Broom Creek disposal interval exceeds expectations, the extraction rate will likely be increased to use that potential. This will allow for greater operational flexibility when the ARM testing scenarios are conducted.

Suitable Surface Location

As noted earlier, there are ongoing commercial operations at the project site. This includes not only the Nuverra water disposal facilities but also surface mining of aggregate materials and a materials recycling facility. These areas cannot be interfered with, limiting the options for wellsite selection. However, other areas have already been prepared for development and are unoccupied. Other areas have been reclaimed after mining operations ceased. These areas also offer favorable sites for well locations.

Well Location Selections

The most easily identifiable constraints, surface location and the distribution of the salinity plume as determined by simulation, were chosen as the first siting factors to consider for the BEST-E1 well. Super imposition of a satellite image of the property boundary and the expected salinity plume at 1 April 2017 yielded relatively few defined areas for locating the extractor without deviated drilling, as shown in Figure A-23. Several potential extractor locations were tested in the simulation to determine pressure and/or rate response at the injection wells as well as the brine salinity profile of the extracted water. Inevitably, there is a trade-off between pressure response at the injection wells and salinity of the extracted brine. Pressure response and extraction ratio are generally maximized by locating the extractor close to the injection wells. However, such close proximity raises the salinity profile of the extracted brine, suggesting a degree of cycling of injected brine. Therefore, locations close to or in the edge of the salinity plume were generally preferred, but the degree of pressure interference with the injection wells was prioritized. Several extraction rates were tested for most locations, ranging from 1500 to 10,000 bwpd. Although a base case rate of 4000 bwpd was selected for extraction and disposal of formation brine based upon a conservative estimate of injectivity for the BEST-I1 location, preferred well locations with an extraction rate of 4000 bwpd indicated a range of bottomhole pressure response of 18 to 52 psi at the injectors, with the Rink SWD 1 injection well showing the greater response and Rink SWD 2 injection well a somewhat lesser response, as shown in Table A-1. The anticipated range of extracted brine salinity is also shown in the table.

Location selection was more straightforward for the BEST-I1 well. The site operator requested that a Broom Creek injection well should be located near the existing injection facilities, specifically within the prepared site area at the northeast corner of the project property, in order to minimize the surface footprint of the project site. Within the prepared site, the most favorable reservoir properties for injection were at the northeast corner. Considering the deeper depth of the Broom Creek Formation and the North Dakota regulatory practice for permitting of water disposal wells, the anticipated allowed maximum wellhead injection pressure will be approximately 2000 psi. The simulated injection profile for BEST-I1 is given in Figure A-24. This shows a stabilized rate of 4300 bwpd conservatively assuming a wellhead injection pressure of 1800 psi and an unstimulated completion interval (skin factor = zero). Further, the formation permeability for this location appears to be conservatively estimated when compared to existing Broom Creek injectors in western North Dakota. Finally, the Amsden Formation, immediately below the Broom Creek, contains several additional sandstone intervals that will be characterized for their injection potential. Therefore, an estimated disposal rate of 4000 bwpd should be easily achievable at this location, and the potential exists for extraction and disposal of rates above 4000 bwpd. The result of the well location selection process is shown in Figure A-25.

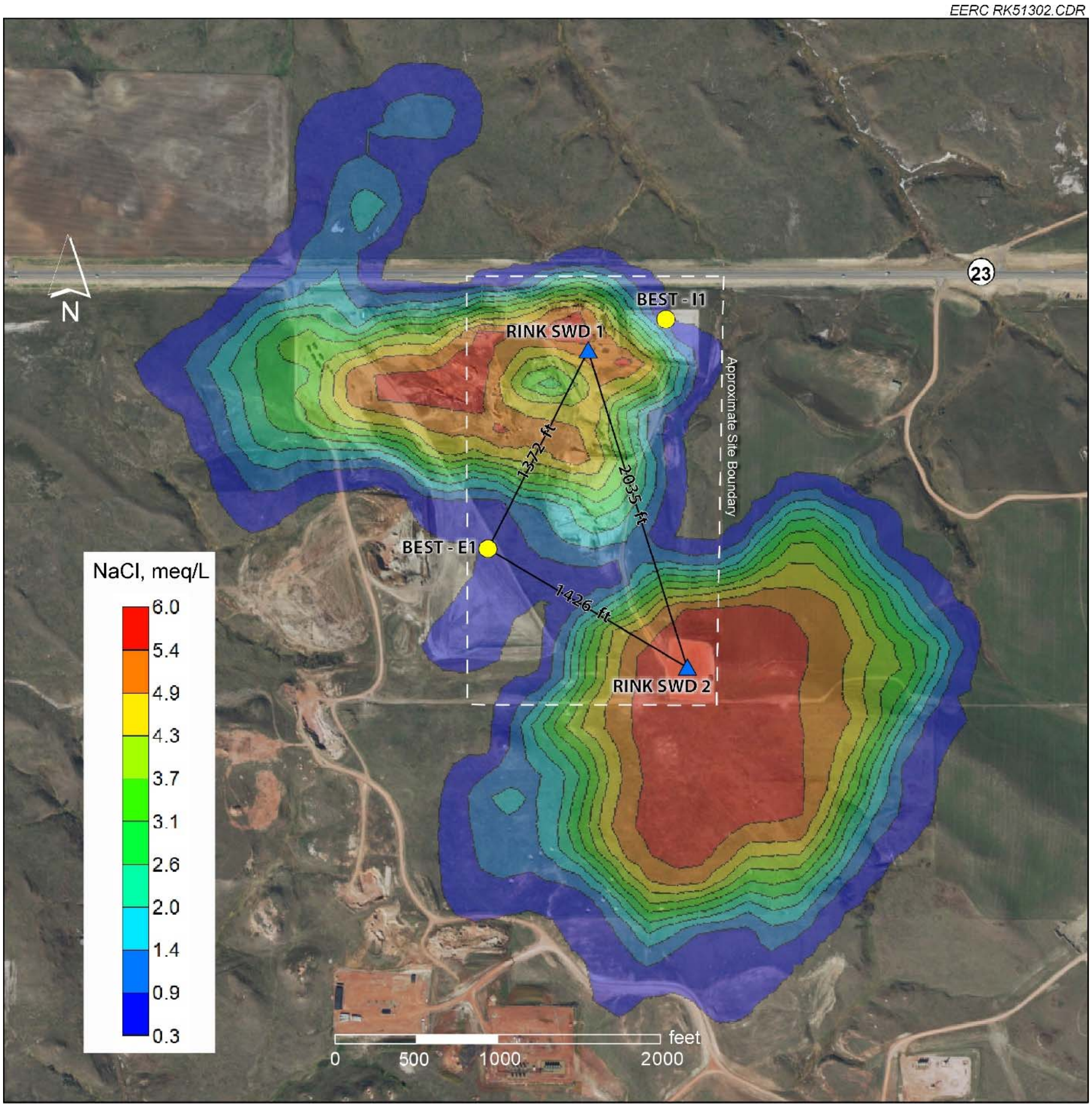

Figure A-23. Interpreted salinity distribution within the Inyan Kara Formation on 1 April 2017 superimposed over a site map. Salinity scale is NaCl molarity. Existing and proposed project wells are named.

Table A-1. Extraction Well Test Locations with Pressure Interference and Salinity Impact

Well No.	ΔWHP,* psi Rink SWD 1	Rink SWD 2	Salinity Change (molal)
E1	41	28	1.50–1.50
E2	26	23	0.47–0.91
E3	40	27	0.91–1.19
E4	17	22	0.55–1.32
E5	41	23	1.39–0.85
E6	23	18	0.57–0.63
E7	22	24	0.20–0.97
E8	51	30	2.21–1.61
E9	45	25	1.36–1.63
E10	37	22	0.92–1.40
E11	22	23	0.2–0.83
E12	52	25	1.9–1.86

* Wellhead pressure.

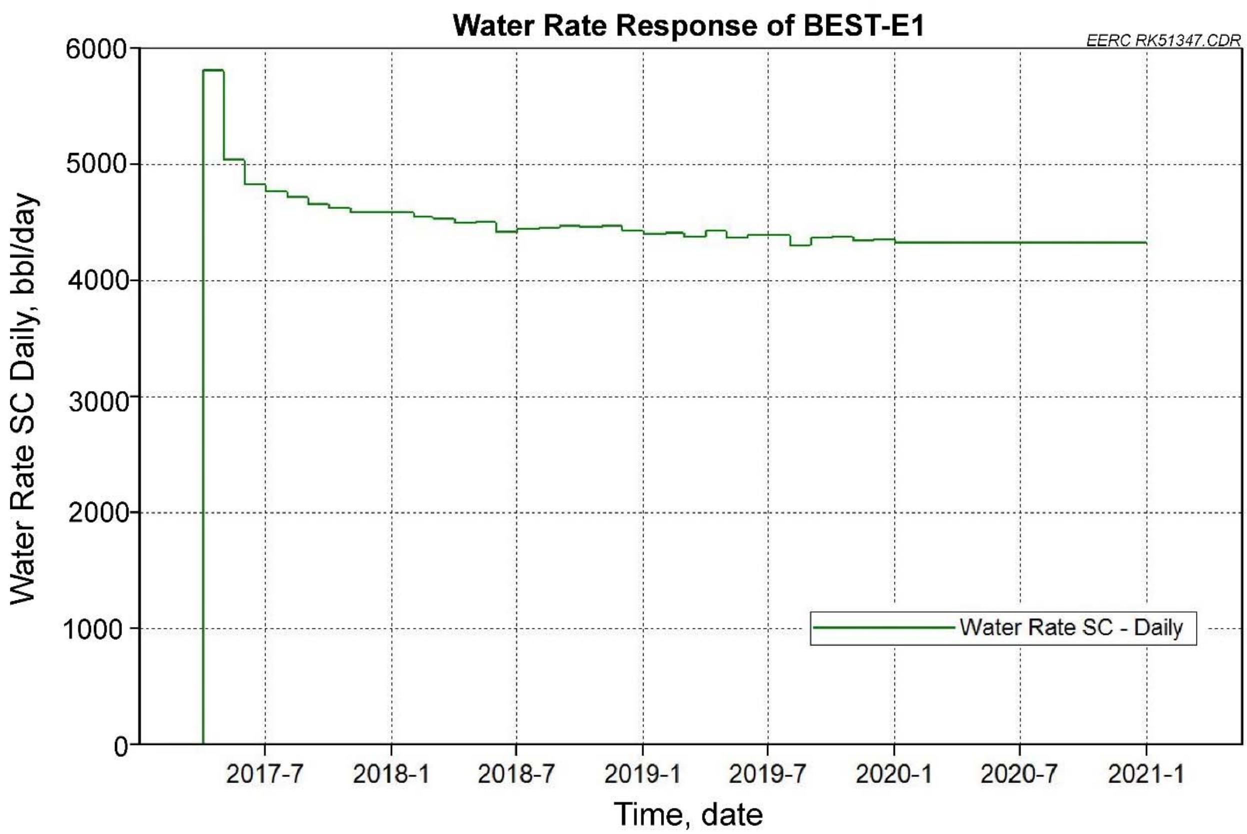

Figure A-24. Anticipated base case of water injectivity for well BEST-I1, Broom Creek Formation extracted water disposal well (SC = standard conditions).

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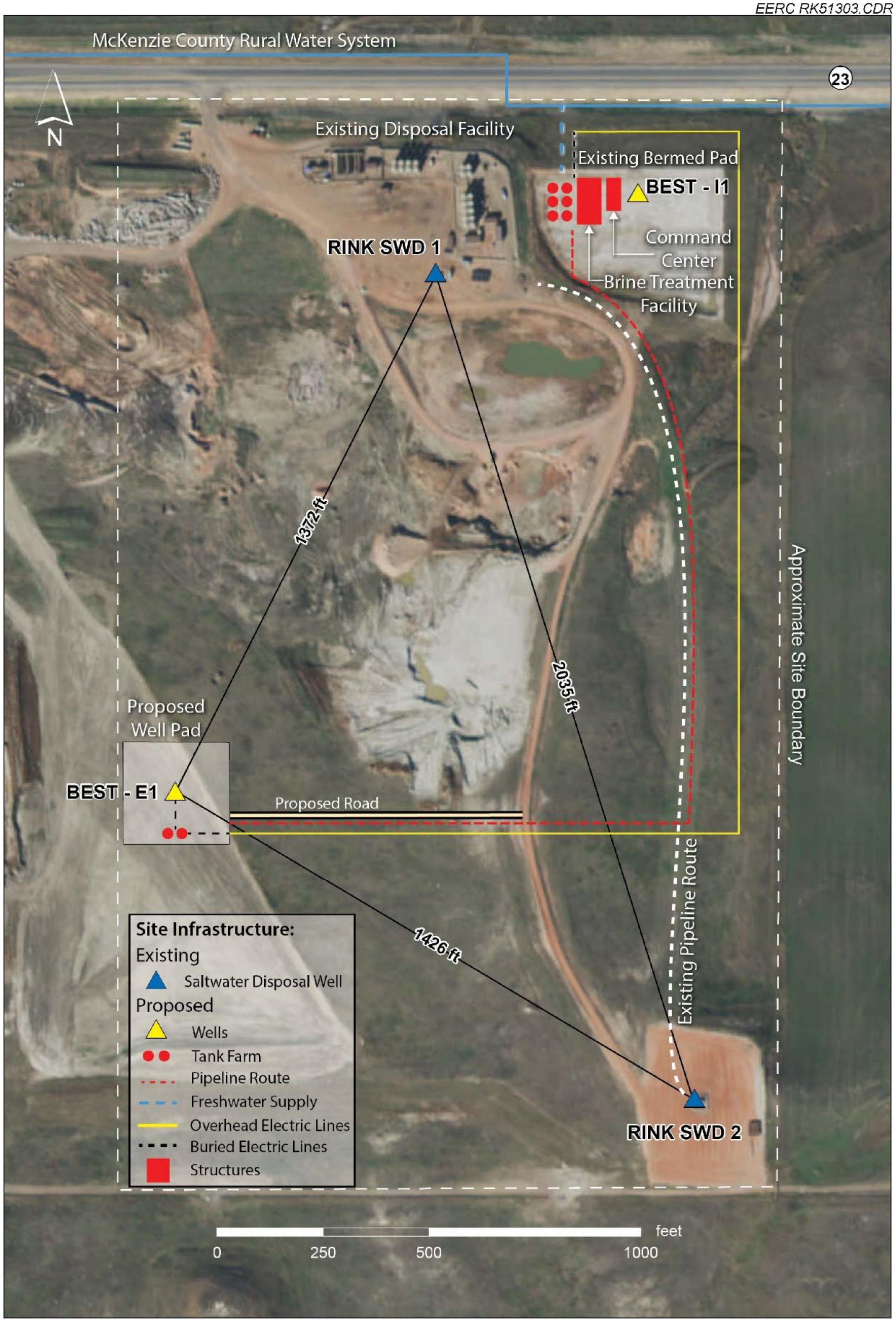


Figure A-25. Selected well locations for Johnsons Corner project execution and placement of associated new infrastructure.

Extraction and Injection Scenarios

The history-matched simulation was used to test several potential extraction and injection scenarios for the wells. Results of these test scenarios were used to help guide creation of the detailed ARM design. For these simulations, the operational life of the BEST-E1 and -I1 wells for the Phase II project is premised to start on 1 April 2017 and continue until 1 January 2020. All operating scenarios cover this time period. These scenarios are listed in Table A-2. The list was developed to cover a range of extraction rates that provide a range of the pressure responses (Cases 1 through 6) and a range of rate responses (Cases 7 through 12) from the active injection wells. Cases 13 through 16 gauge the stability of the selected base case (Case 4) to changes in operating conditions of the commercial injection wells. Case 17 tested more optimistic operating conditions for the BEST-I1 water disposal interval, and Case 18 tested reservoir and well response to tracer injection.

Table A-2. List of Simulation Extraction and Injection Scenarios

BEST Proposal Simulation Cases					**1 April 2017 – 1 January 2020**
Case No.	**BEST-E1, bwpd***	**BEST-I1, bwpd***	**RINK-1, bwpd***	**RINK-2, bwpd***	**Comment**
0	0	0	3400	3400	No BEST project (BAU)**
1	−1500	1500	3400	3400	Constant injection rate series
2	−2400	2400	3400	3400	
3	−3000	3000	3400	3400	
4	−4000	4000	3400	3400	Base case
5	−5000	5000	3400	3400	
6	−10,000	10,000	3400	3400	
7	−1500	1500	WHP 958	WHP 450	Constant injection pressure series
8	−2400	2400	WHP 958	WHP 450	
9	−3000	3000	WHP 958	WHP 450	
10	−4000	4000	WHP 958	WHP 450	
11	−5000	5000	WHP 958	WHP 450	
12	−10,000	10,000	WHP 958	WHP 450	
13	−4000	4000	6500	7500	Maximum injection
14	−4000	4000	1700	1700	Low injection
15	−4000	4000	6500	0	Rink SWD 1 only
16	−4000	4000	0	7500	Rink SWD 2 only
17		5200			Broom Creek sensitivity
18	−4000	4000	3400	3400	Tracer sensitivity

* Except where indicated as WHP.
** BAU = business as usual.

To bring the history-matched simulation up to 1 April 2017 from the end of history at 1 January 2016, the existing injector wells, Rink SWD 1 and Rink SWD 2, were assumed to continue operating at a fixed average injection rate. The 2015 average injection rate for both the Rink SWD 1 and Rink SWD 2 wells is 3400 bwpd. This simulation was continued until

1 January 2020 and is used in the evaluation as the assumed standard operating condition at the site if no project is performed at the Johnsons Corner site (Case 0).

Assuming the standard operating injection condition, the E1 well was extracted for a series of different rates, 1500, 2400, 3000, 4000, 5000, and 10,000 bwpd (Cases 1 through 6). These extraction rates were selected for a variety of specific reasons. The 1500-bwpd case was selected as the reasonable minimum rate needed to satisfactorily execute the project. The 2400-bwpd case represents the effect of an adverse ruling from regulatory authorities limiting injection pressure for the BEST-I1 well. The 3000-bwpd and 5000-bwpd cases represent the initial estimated minimum and maximum operating range for the BEST-E1 submersible pump. The 4000-bwpd case reflects the expected injection capability of the BEST-I1 well. The 10,000-bwpd case represents the reasonable maximum extraction rate considering the BEST-E1 tubing design as well as selecting an extraction rate greater than the expected combined Rink SWD 1 and Rink SWD 2 injection rate.

The bottomhole pressure responses for Rink SWD 1 and Rink SWD 2 are seen in Figures A-26 and A-27, respectively. Figure A-26 also shows the bottomhole pressure response of Rink SWD 1 in the 4000-bwpd extraction base case (Case 4) is stable at approximately 50 psi. It should be noted that a sustained and continuous pressure decline is observed only for Case 6 where the 10,000-bwpd extraction rate is the only case where extraction exceeds the 6800-bwpd injection rate. Figure A-27 also tells a similar story for the Rink SWD 2 well where the bottomhole pressure reduction for the Case 4 base case is approximately 40 psi. Figure A-28 displays a zoomed-in view of the pressure response of Case 4 for these two wells which shows that a 10- to 20-psi pressure response should be detectable within 10 days, allowing for timely and effective experimentation at the site by adjustment of rates and operating pressures.

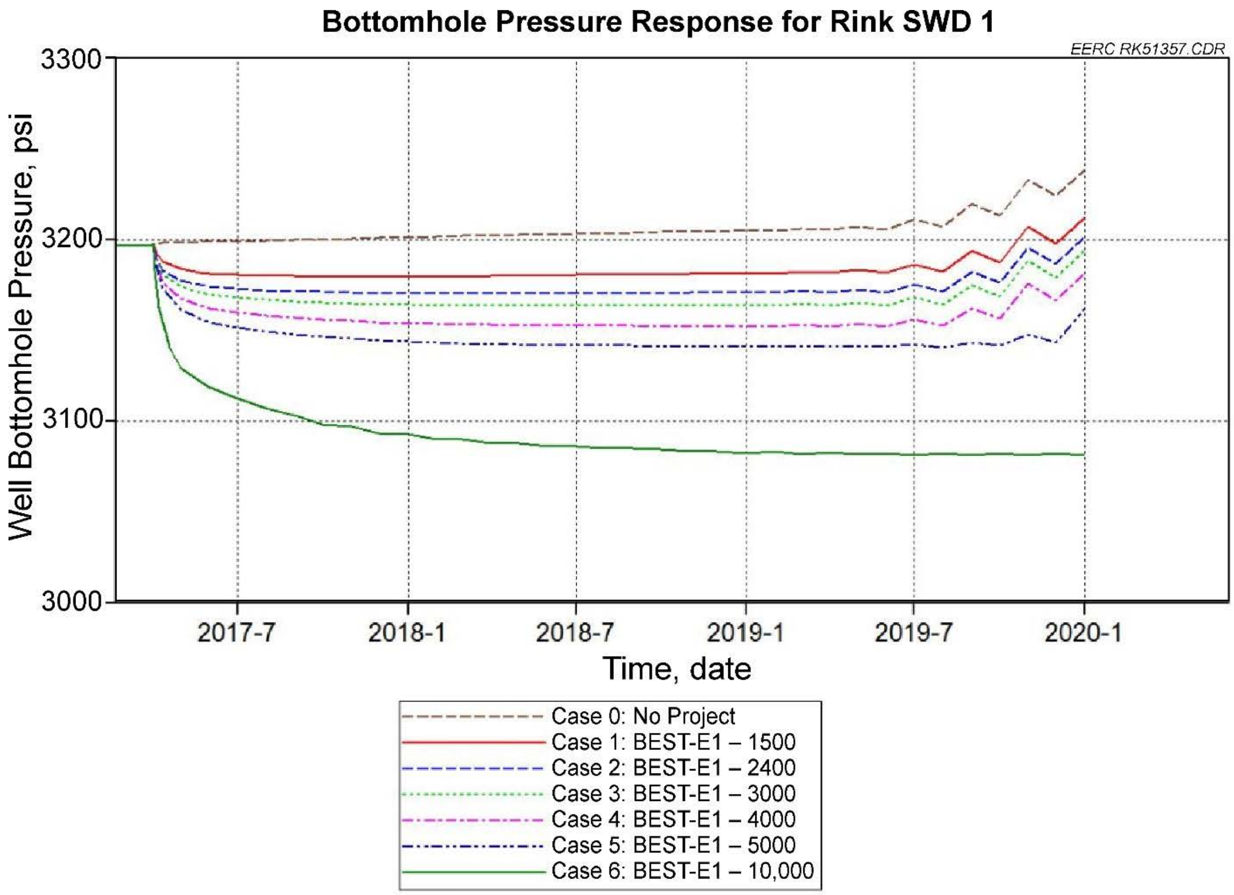


Figure A-26. Rink SWD 1 bottomhole pressure response to different extraction rates, assuming a stable 3400-bbl/day injection rate into each of the Rink SWD wells.

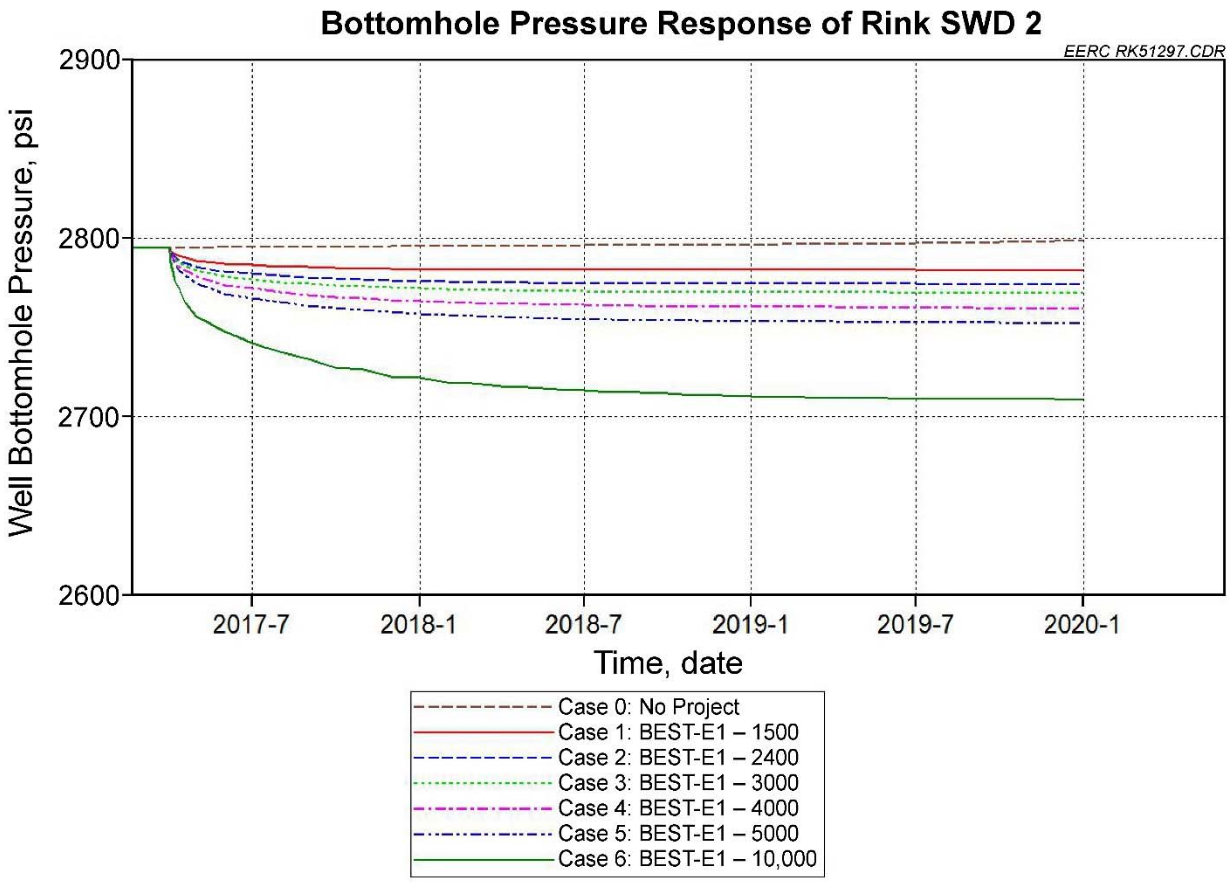


Figure A-27. Rink SWD 2 bottomhole pressure response to different extraction rates, assuming a stable 3400-bbl/day injection rate into each of the Rink SWD wells.

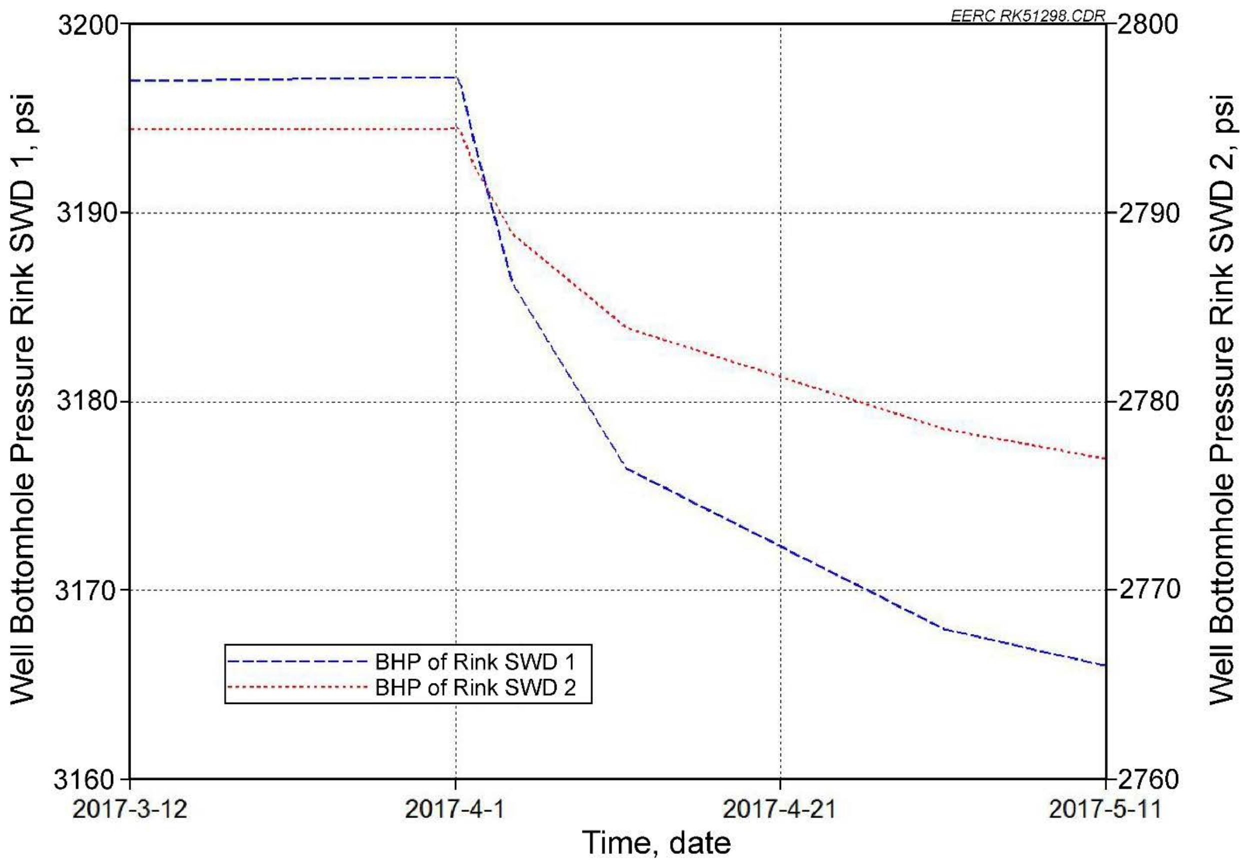


Figure A-28. Detailed bottomhole pressure response of Rink SWD 1 and Rink SWD 2, respectively, with 4000-bwpd extraction rate and 3400-bbl/day injection rate into each of the Rink SWD wells. A 10 to 20 psi pressure change is recorded within 10 days of extraction start.

An alternative perspective from this series of extraction cases can be made by varying the standard operating injection condition from a fixed injection rate condition to a fixed wellhead pressure (WHP) condition (Cases 7 through 12). These simulation results are presented in Figures A-29 and A-30. Injection rates are seen to rise with increasing extraction rate. From these results, the site extraction ratio, $\Delta V_{ext}/\Delta V_{inj}$, can be calculated. Depending upon the extraction rate, the extraction ratio varies for the Rink SWD 1 well but not significantly for the Rink SWD 2 well. The ratio declines modestly for the site as extraction rate increases, as tabulated in Table A-3.

From the above-described simulations, Case 4 is selected as the base case scenario. Nuverra has stated an operating preference to maintain injection based on a fixed rate that slowly varies as operating requirements demand, rather than a fixed injection pressure. Also, considering the estimated injectivity of the BEST-I1 well is 4300 bwpd, the 4000-bwpd extraction rate with the standard operating injection condition is selected as the project's operating base case.

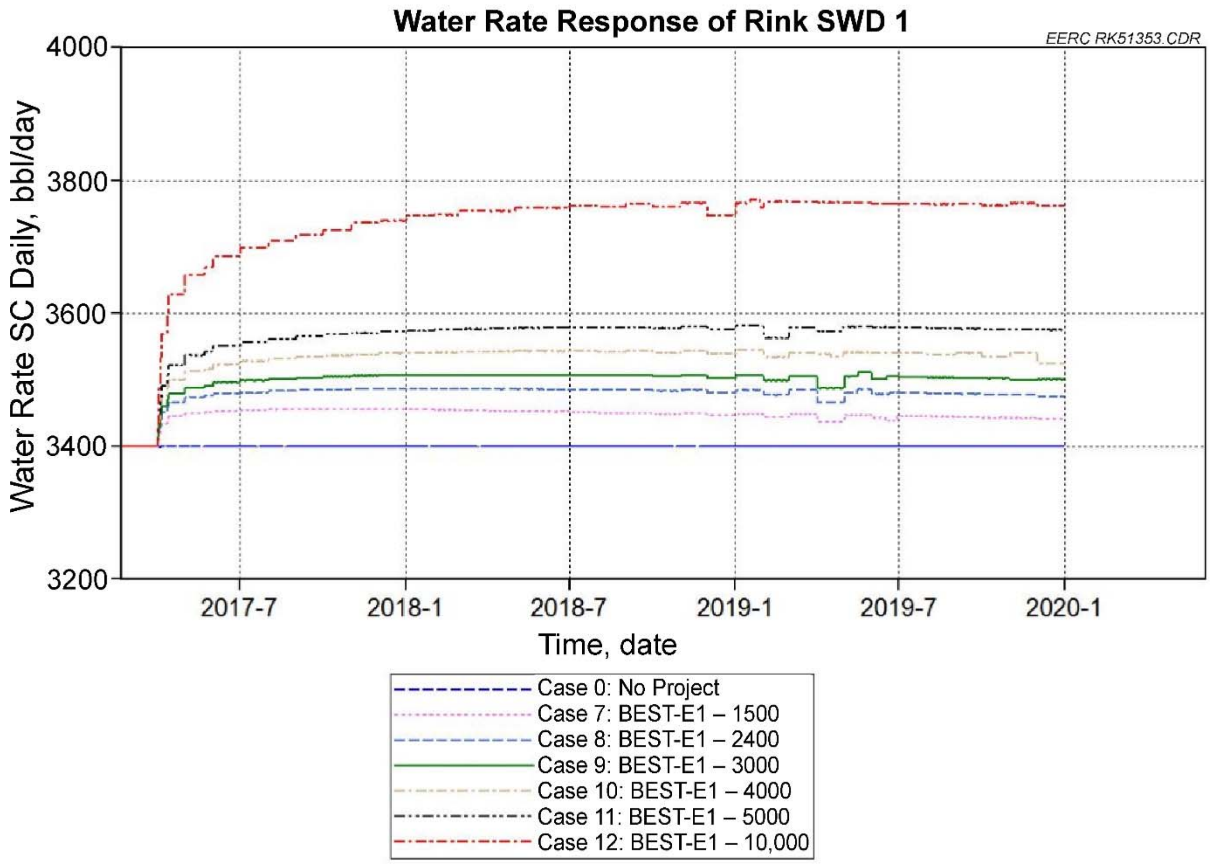


Figure A-29. Rink SWD 1 injection rate response to different extraction rates, assuming a stable wellhead pressure of 958 psi.

During the project lifetime, the commercial injection rates at the Rink SWD 1 and Rink SWD 2 wells will vary. To test the strength of the selected base case, four additional injection profiles were considered:

- The maximum allowable rates for Rink SWD 1 and Rink SWD 2 are 6500 and 7500 bwpd, respectively (Case 13). This is an unlikely maximum scenario:
- A low injection rate scenario representing 50% of the standard injection condition (Case 14)
- Maximum injection into the Rink SWD 1 with zero injection into the Rink SWD 2 (Case 15)
- Zero injection into Rink SWD 1 and maximum injection into Rink SWD 2 (Case 16)

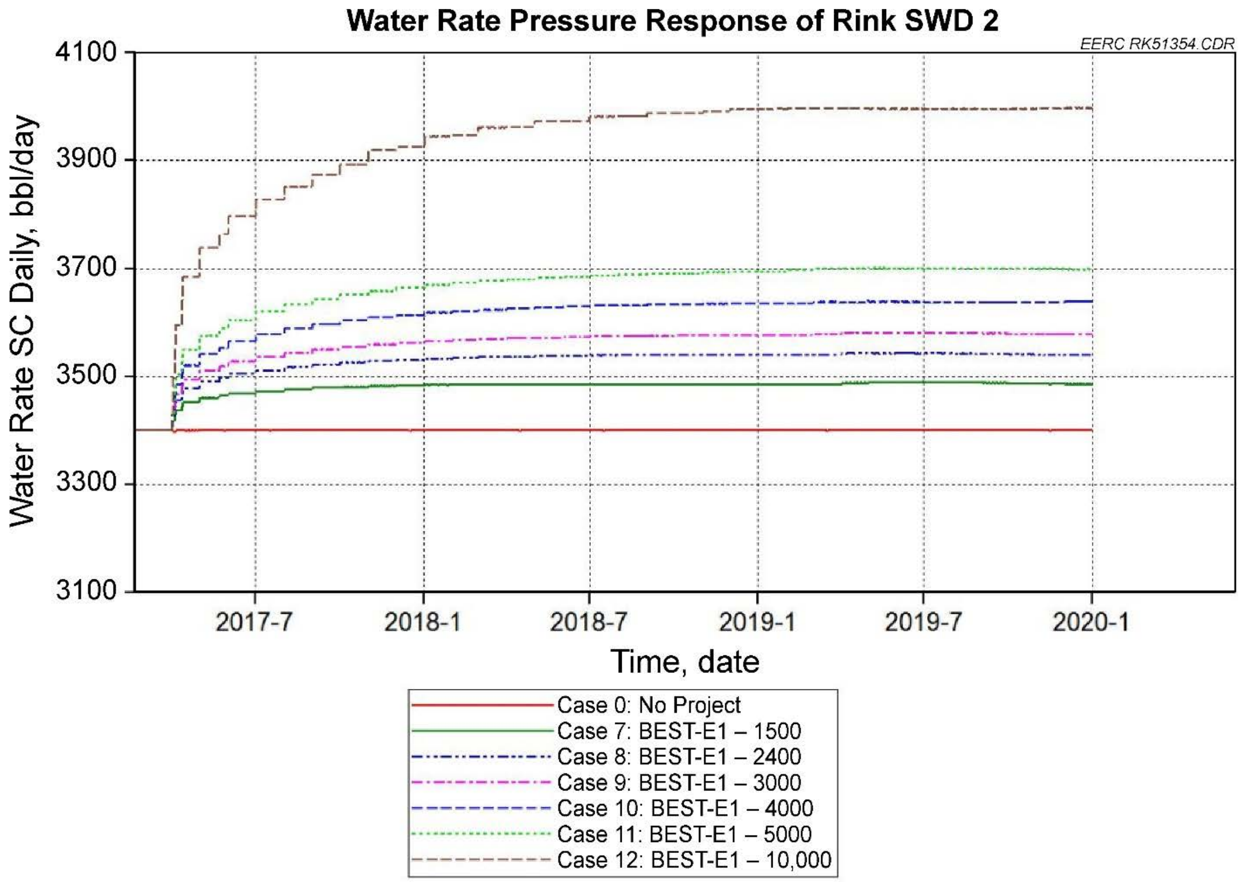


Figure A-30. Rink SWD 2 injection rate response to different extraction rates, assuming a stable wellhead pressure of 450 psi.

Table A-3. Extraction Ratio Calculated for Different Extraction Rates

Case No.	Description (bwpd) BEST-E1	Rink SWD 1	Rink SWD 2	Total Inj. Rate	Extraction Ratio Rink SWD 1	Rink SWD 2	Site Total
7	−1500	3441	3487	6928	36.6	17.2	11.7
8	−2400	3475	3541	7016	32.0	17.0	11.1
9	−3000	3501	3579	7080	29.7	16.8	10.7
10	−4000	3541	3639	7180	28.4	16.7	10.5
11	−5000	3575	3699	7274	28.6	16.7	10.5
12	−10,000	3762	3997	7759	27.6	16.8	10.4

These cases show that the two injection wells very rapidly restabilize their bottomhole pressure, regardless of the variation of injection rate conditions. Their response to the extractor well should be relatively little affected by their own operating constraints, after a short period of adjustment. Therefore, the project base case is robust with respect to changes in the rates for the injection wells. Results of these sensitivities are presented in Figures A-31 and A-32.

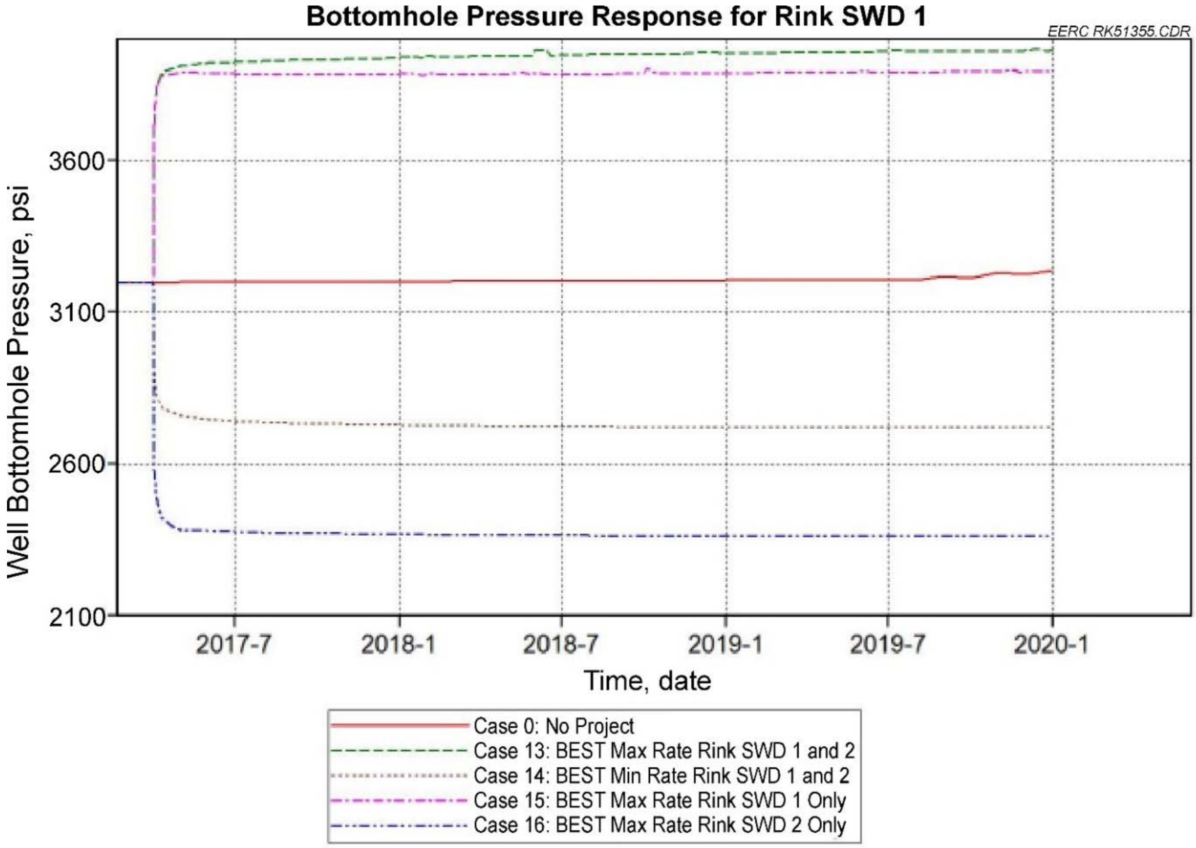


Figure A-31. Bottomhole pressure response of Rink SWD 1 for Cases 13 through 16.

Two additional special sensitivity cases were performed. The first special sensitivity case was run to estimate the upper range of the Broom Creek injectivity (Case 17). This case assumed a wellhead injection pressure of 2000 psi and an acid stimulation skin factor of −2. This case resulted in an injection capability of 5200 bwpd, without the benefit of perforations in the deeper Amsden Formation, which helps confirm the ability to dispose of the water extracted from the BEST-E1 well. The second special sensitivity case injected a different chemical tracer into the Rink SWD 1 and Rink SWD 2 wells (Case 18). The tracers spread through the injection interval, and both were detected at the BEST-E1 well.

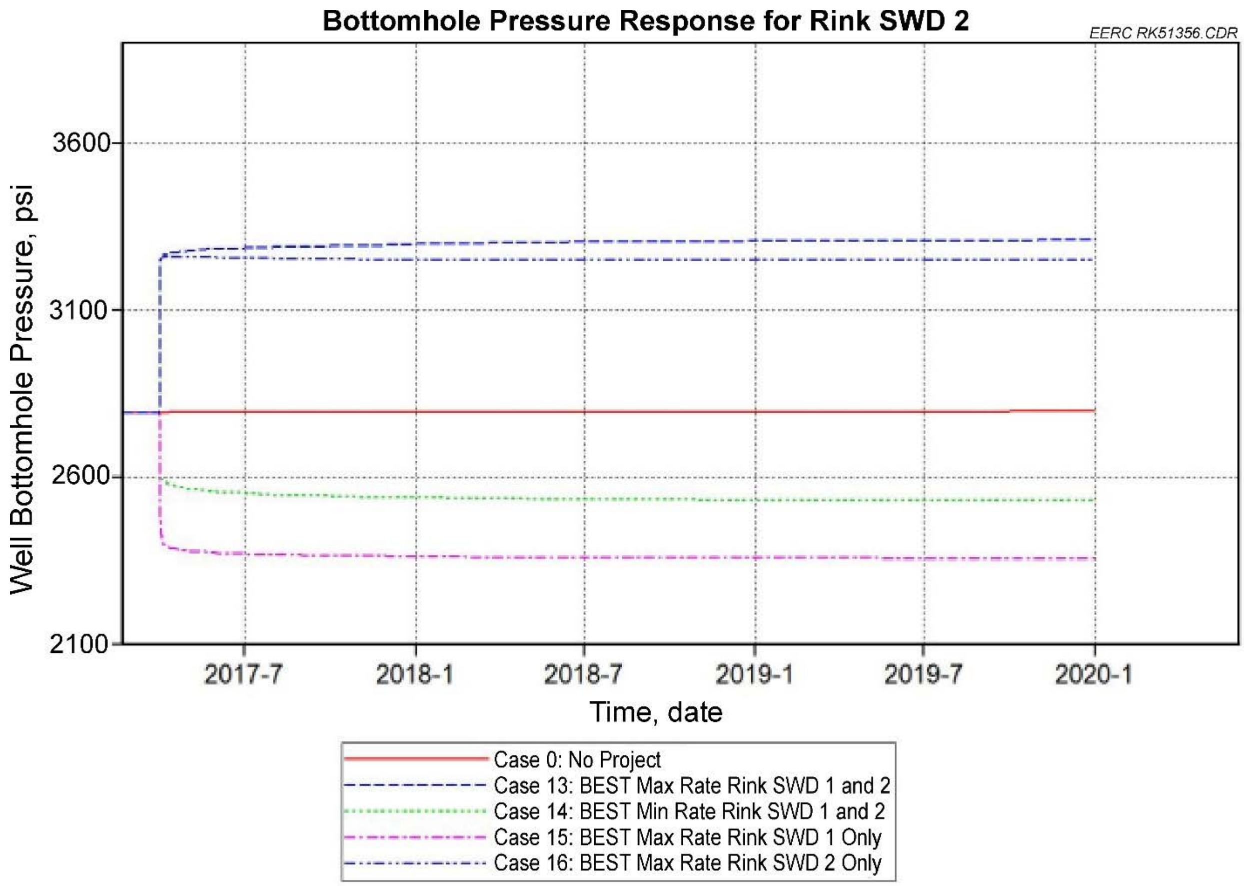


Figure A-32. Bottomhole pressure response of Rink SWD 2 for Cases 13 through 16.

Base Case Injection Scenario

As mentioned earlier, from the 18 sensitivities that were described, Case 4 was selected as the base case. It serves as a generalized proxy for the project injection program and was the starting point for creation of the more detailed Field Experimental Scenario that is described later.

The Case 4 bottomhole pressure behavior for wells Rink SWD 1 and Rink SWD 2 is given in Figures A-26 and A-27, respectively. Bottomhole pressure for the BEST-E1 extraction well is given in Figure A-33 which suggests there is a high level of permeability at this location since the pressure drawdown is only 60 psi for the extraction rate of 4000 bwpd.

The salinity of the extracted water is expected to be variable at the BEST-E1 location during the project lifetime. Native formation brine in the reservoir has a low salinity, approximately 0.1 molar NaCl, while injected water at the site is very saline, approximately 5.0 molar concentration or higher. As shown in Figure A-33, the BEST-E1 is expected to extract water with a salinity of approximately 1.7 molar concentration.

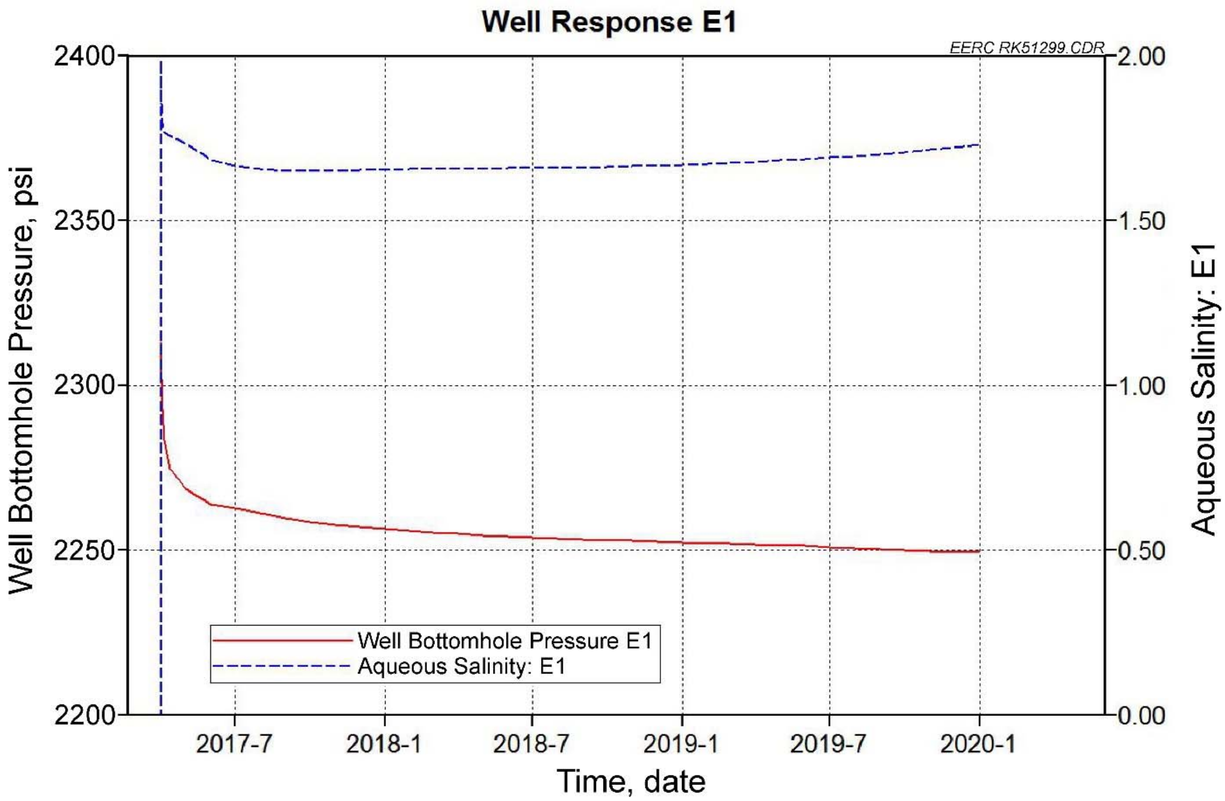


Figure A-33. Bottomhole pressure and salinity performance of the BEST-E1 extraction well.

At the end of the fluid extraction program on 1 January 2020, the project will have caused substantial changes to the pressure and salinity plumes at the site, compared to no intervention by a Johnsons Corner BEST project (Simulation Case 0). Figure A-34 shows the project area pressure distribution without the project. Figure A-35 shows the area's pressure distribution with the project (Simulation Case 4). Figure A-36 shows the pressure difference map between the two cases. Figure A-37 shows the footprint of the salinity plume if no project is performed. Figure A-38 shows the salinity plume with the project, and Figure A-39 displays the salinity difference map which shows how the distribution of the plume has been moved, particularly in the area surrounding the Rink SWD 2 well as more saline brine has been pulled toward the extraction well.

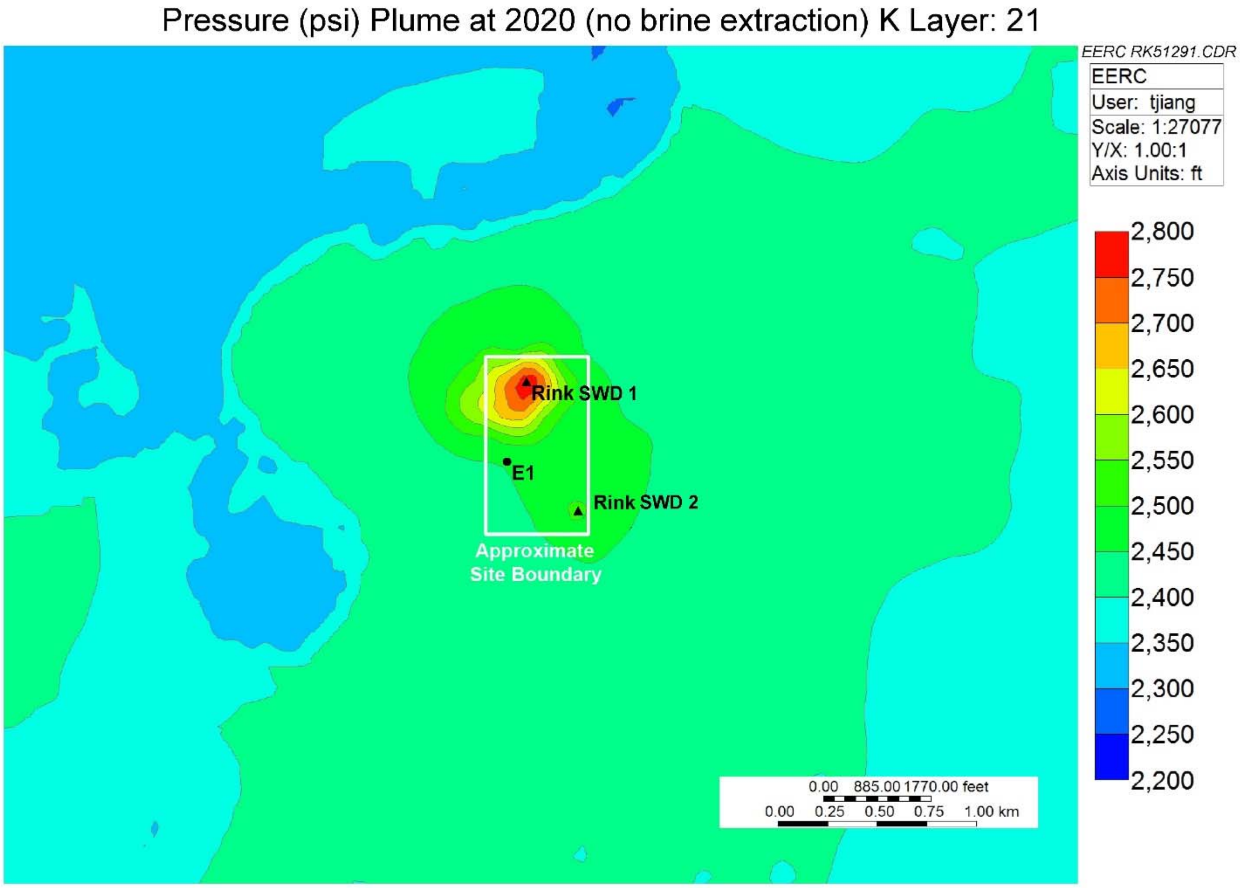


Figure A-34. Pressure (psi) plume development without the BEST project, showing an elevated pressure plume which covers the majority of the project site

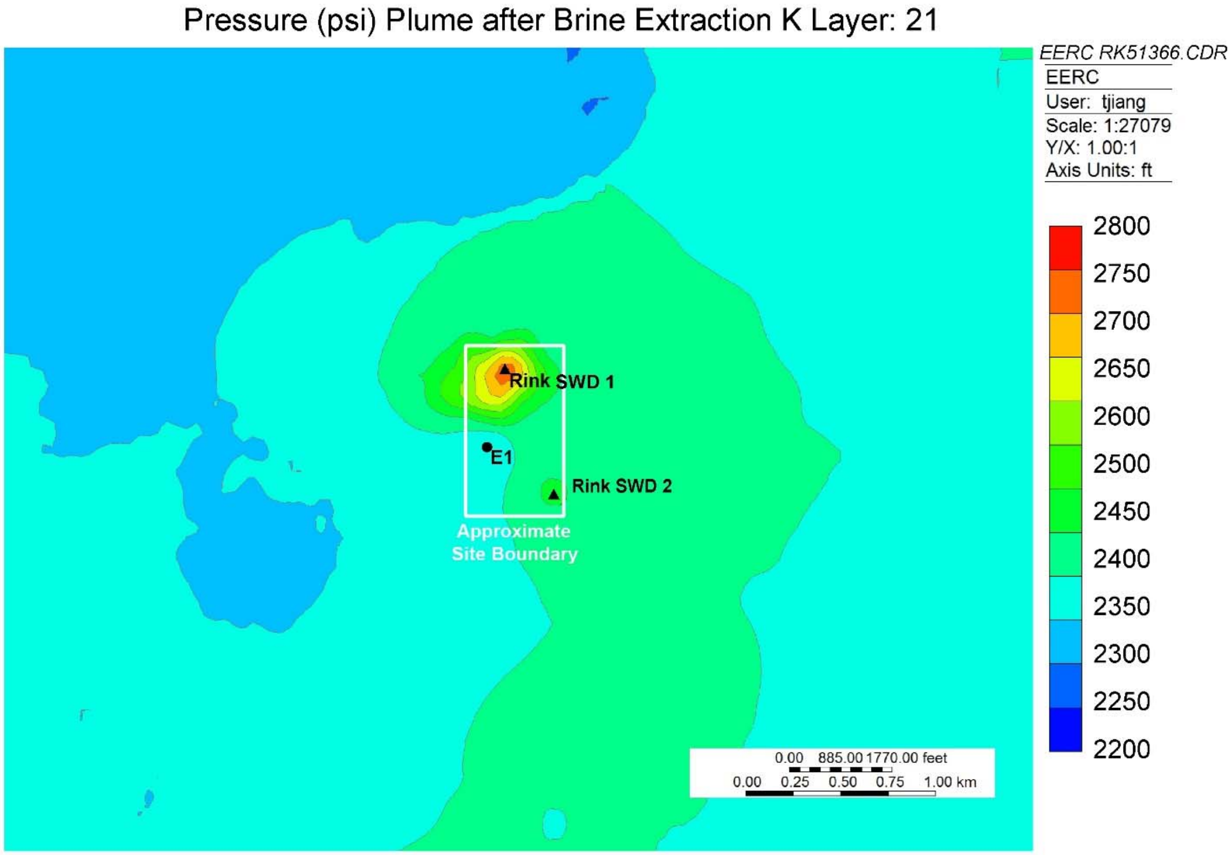


Figure A-35. Pressure (psi) plume development after Johnsons Corner project end (4000-bwpd extraction rate), showing a regional pressure decrease of 20–30 psi. Larger pressure decreases are visible near the Rink SWD 1 and 2 wells.

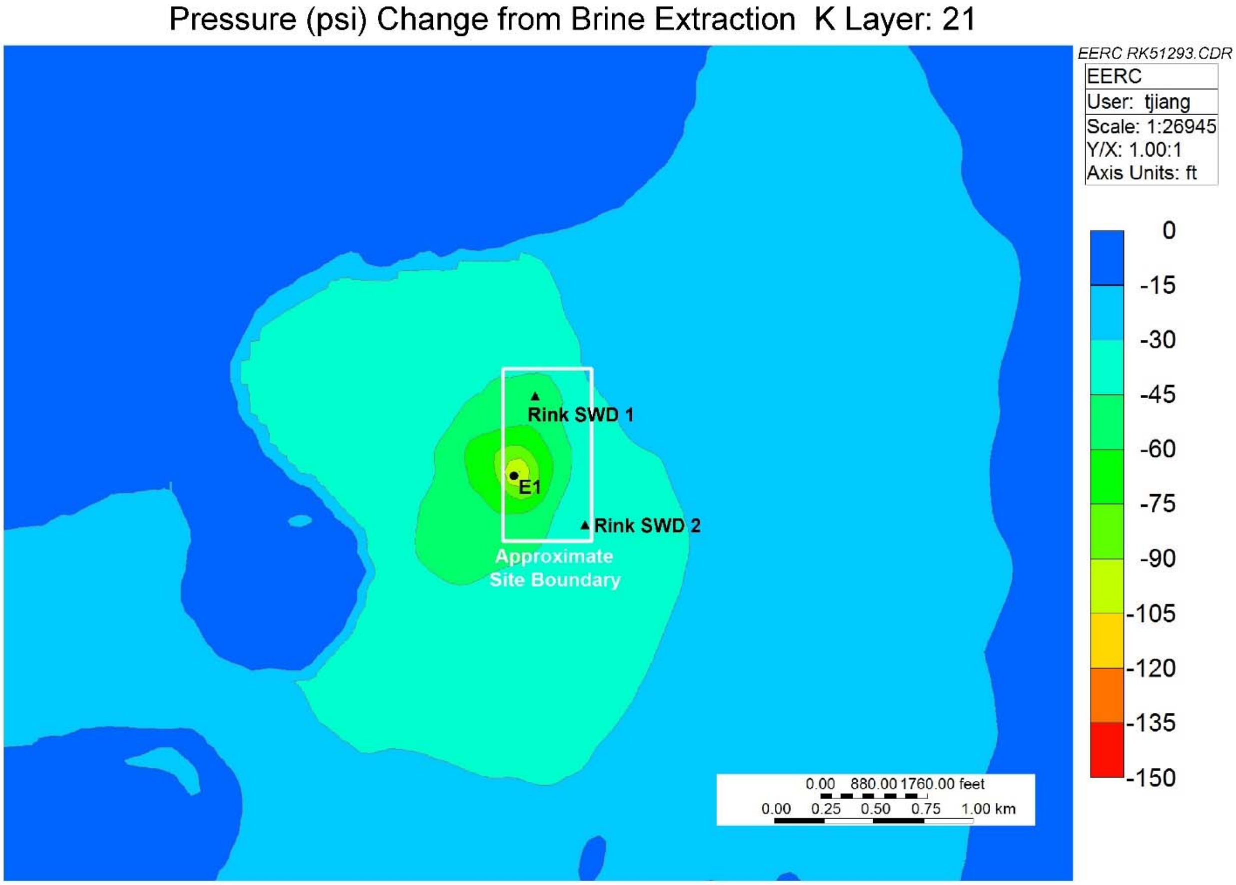


Figure A-36. Pressure (psi) difference map illustrating the influence of the extraction scenario in the year 2020.

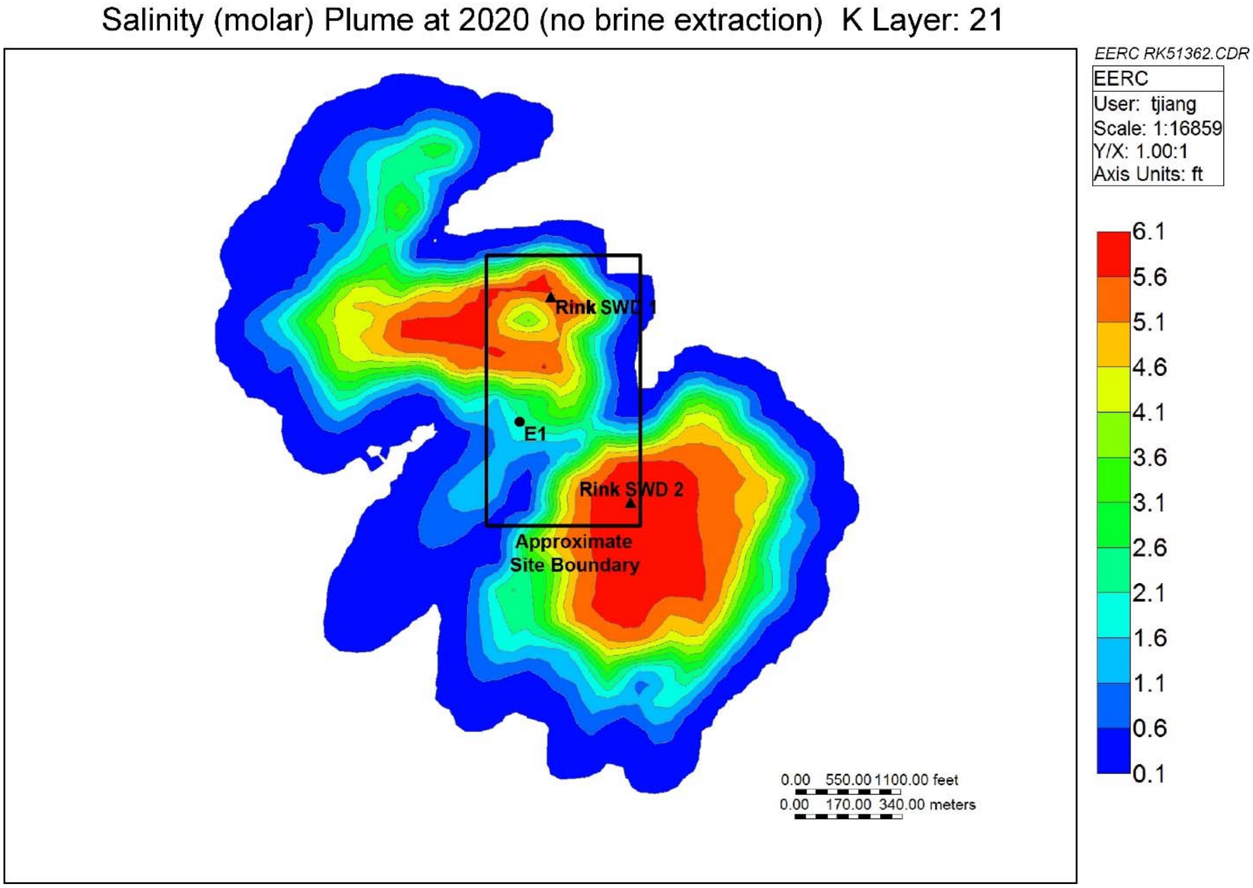


Figure A-37. Salinity (molar concentration) plume development without brine extraction.

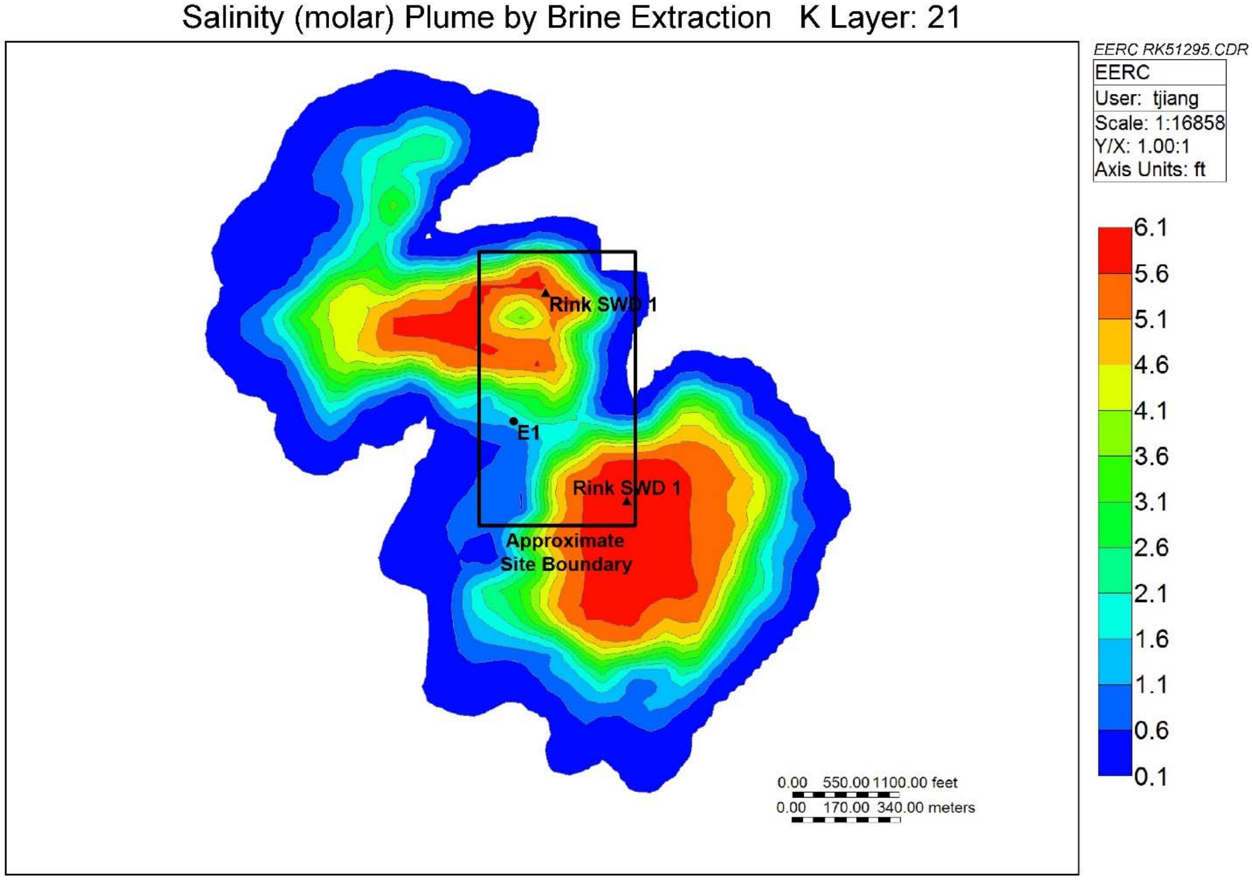


Figure A-38. Salinity (molar concentration) plume development after Johnsons Corner pilot end (4000-bwpd extraction rate). Note the significantly reduced footprint of the plume on the southwest side of the site.

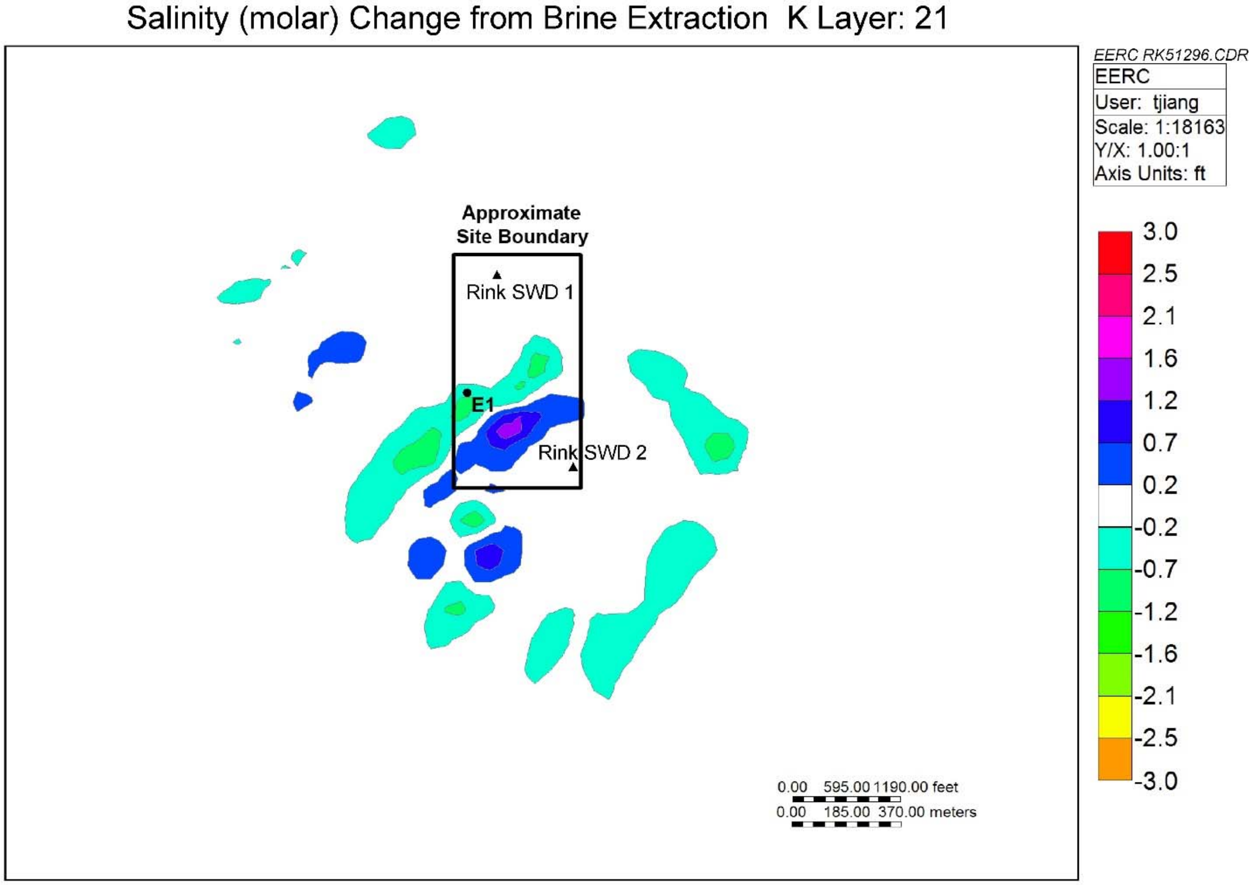


Figure A-39. Salinity difference map (molar concentration) illustrating the influence of the extraction scenario in the year 2020.

A.3 ROCK AND FLUID PHYSICS SENSITIVITY MODELING AND GEOPHYSICAL MONITORING

A.3.1 Introduction

The rock and fluid physics sensitivity modeling was performed to determine the geophysical monitoring techniques that might be used in this project to track the movement of the injected brine versus the native brine. The objective is to image the brine plume evolution, fingering, and distribution in the interwell spacing within the Inyan Kara Formation as low-salinity brine is extracted while highly saline brine is injected and to provide a means of validating and updating the simulation model. This is especially important with the unique nature of this brine–brine mixing (single-phase) project, where dynamic changes in the geophysical parameters are expected to be smaller than usually observed in carbon capture and storage (CCS) or CO_2 enhanced oil recovery (EOR). Geologic- and engineering-consistent rock and fluid physics modeling showed that a time-lapse controlled-source electromagnetic (CSEM) method is the geophysical method of choice in the Johnsons Corner pilot. Also, understanding that the underlying aim of this project is to provide an analogous approach to CCS, time-lapse CSEM is also suited for carbon storage monitoring. The justifications for this choice of method are as discussed here. Equally, the workflow established would be used, in a reverse order, to provide updating information for the geologic and fluid flow simulation models.

The three main dynamic parameters of importance in this brine versus brine tracking, from the geophysical point of view, are:

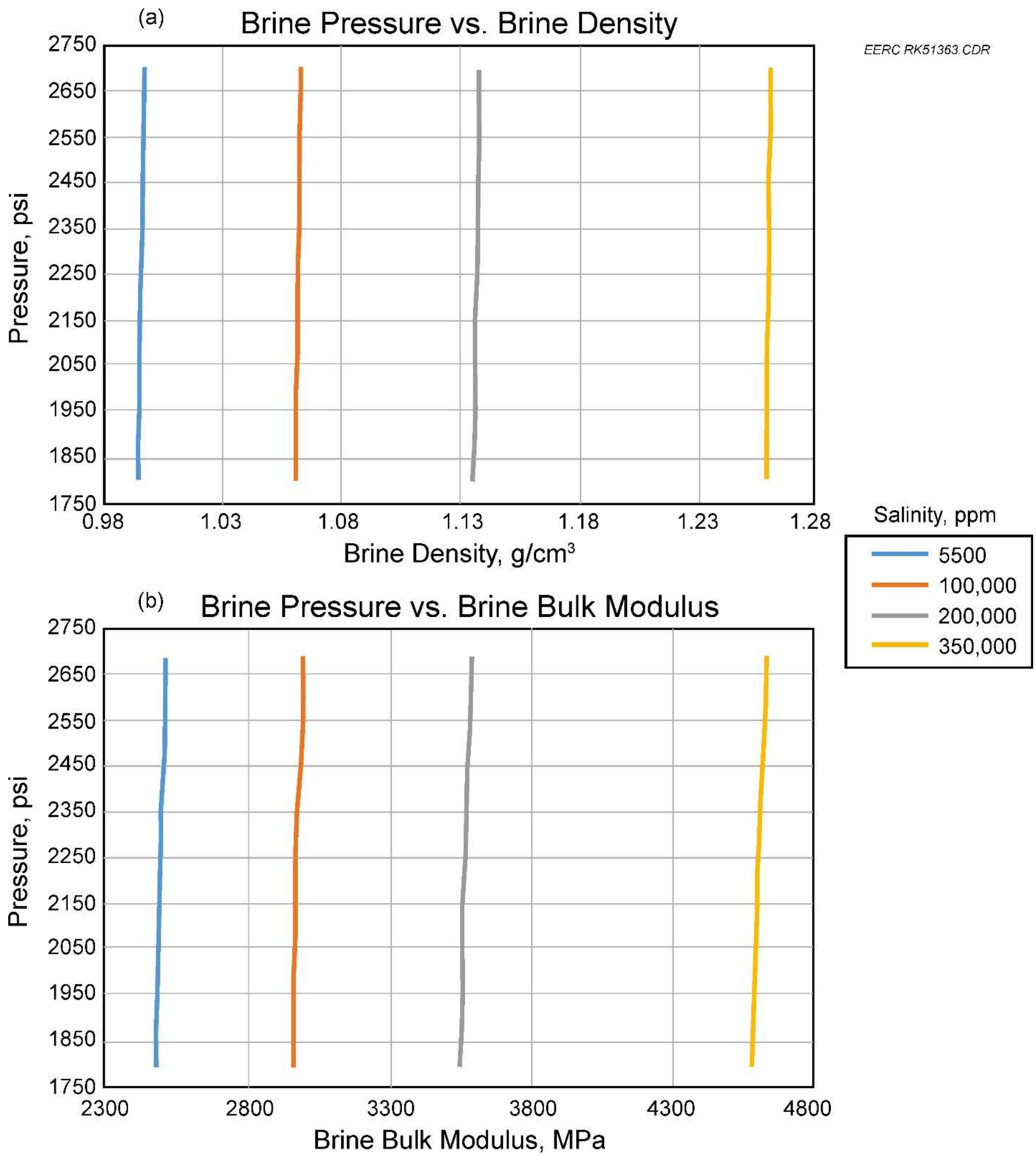
- Temperature changes due to cooling effects of cold water injection.
- Pressure changes due to the diffusion effect of pressure differential during injection and extraction.
- Salinity changes due to diffusion and fluid substitution effects during high-salinity brine injection coupled with low-salinity brine extraction.

Change in each of these effects can aid the plume-tracking process. However, from the engineering point of view, the cooling effect is expected to be restricted to the vicinity of injectors, as the mixed brine temperature is expected to quickly equilibrate to the reservoir temperature conditions. Therefore, focus was placed on examining the geophysical sensitivity to dynamic changes in pressure and salinity in an isothermal reservoir condition.

Several published articles (e.g., Batzle and Wang, 1992; Han and Batzle, 2002) have shown that density, velocity, and bulk modulus of reservoir brines are functions of salinity (that is, the NaCl equivalent of the ionic composition), pressure, and temperature. Also, the electrical resistivity of brines (R_b) depends on salinity and temperature only (Archie, 1942; Crain, 1986). While seismic depends on the primary acoustic parameters (density and bulk modulus) and the derived parameters (velocity and, most importantly, the P-impedance), CSEM depends only on the electrical resistivity (or conductivity, which is the inverse of resistivity). Microgravity measurements could also be a possible method for salinity tracking, as it is sensitive to changes in brine density. Thus the density information obtained from the acoustic properties' calculation is examined. Therefore, for this project, we compared the sensitivities of these three geophysical methods to the brine–brine plume tracking, considering the available reservoir geologic information and the simulated fluid flow conditions in this project. The CSEM and microgravity methods depend on change in salinity, while the seismic method depends on the combined changes in salinity and pressure. A workflow described by Salako and others (2015) was implemented.

A.3.1.1 Brine Fluid Physics

First, Han and Batzle's (2002) empirical model was used to obtain the pressure versus brine density, brine bulk modulus, brine velocity, and brine acoustic impedance crossplots (shown in Figure A-40) for ranges of salinity values expected during brine–brine mixing in this project at an average reservoir temperature of 135°F. We later included the rock effects.


EERC RK51363.CDR
(a)
Brine Pressure vs. Brine Density
Pressure, psi
2750
2650
2550
2450
2350
2250
2150
2050
1950
1850
1750
0.98
1.03
1.08
1.13
1.18
1.23
1.28
Brine Density, g/cm³
Salinity, ppm
5500
100,000
200,000
350,000
(b)
Brine Pressure vs. Brine Bulk Modulus
Pressure, psi
2300
2800
3300
3800
4300
4800
Brine Bulk Modulus, MPa

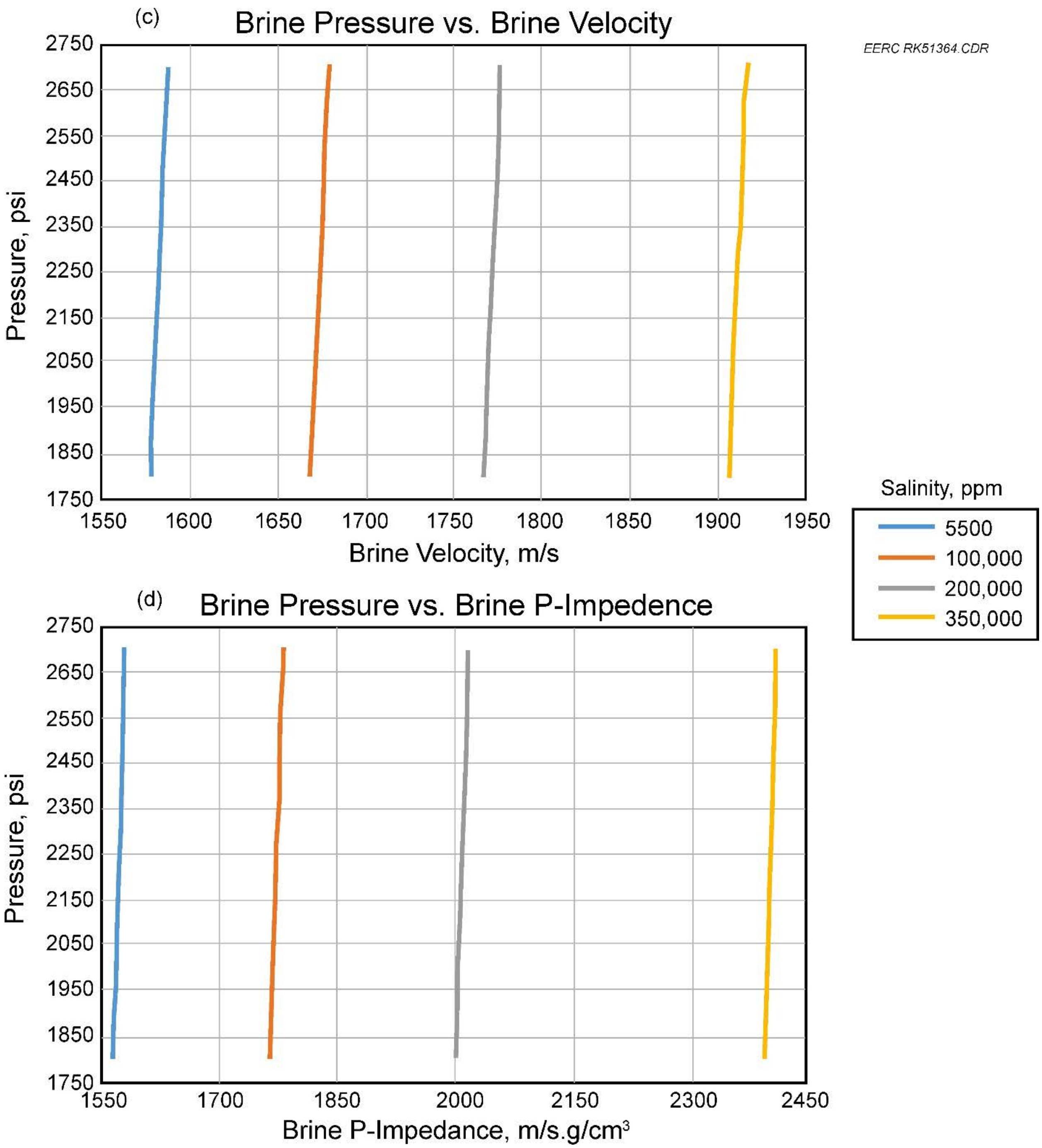


Figure A-40. Plots of pressure versus a) brine density, b) brine bulk modulus, c) brine velocity, and d) brine P-impedance at an average reservoir temperature of 135°F for different salinities as indicated (using Han and Batzle, 2002).

Next, Crain's (1986) empirical equation (Equation A-1) was used to calculate brine resistivity (R_b) as a function of a range of salinity values expected during brine–brine mixing in this project at an average reservoir temperature of 135°F (Figure A-41).

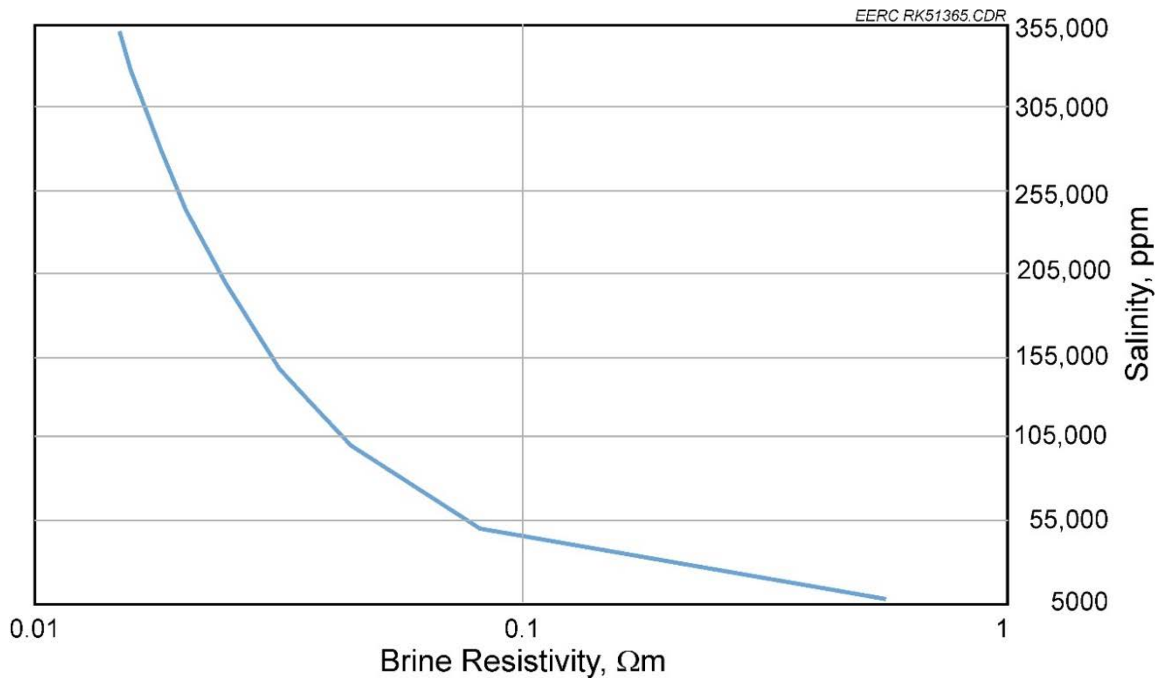


Figure A-41. Plots of brine salinity versus brine resistivity (using Crain, 1986).

$$R_b = \left(\frac{400,000}{T \times S}\right)^{0.88}$$ [Eq. A-1]

where R_b is the resistivity of brine, T is the brine temperature (essentially the same as the reservoir temperature in °F), and S is the salinity (in mg/L of NaCl solution).

Table A-4 shows the comparison between the acoustic and electric properties as functions of the dynamic reservoir properties and why electric properties are favorable for this project. The acoustic properties of brine calculated provide negligible sensitivity, for example 0.4% to 0.9% change in P-impedance was obtained for 400 to 900 psi change in pressure respectively. But there is a good sensitivity (13% to 20% change in P-impedance) to the 100,000 to 150,000 mg/L TDS change in brine salinity. However, the two effects of pressure and salinity changes are usually inseparable in seismic response, and in this project, the low-pressure effect is expected to weaken the effect of salinity as we move away from the injection well. The brine density contrasts, due only to salinity changes, are considered to be low for microgravity response.

In addition, the brine electric calculations (resistivity or its inverse, conductivity) show a very significant sensitivity to change in brine salinity. There is a progression in resistivity change with salinity change, −46% change in resistivity (equivalent of 84% change in conductivity) for a salinity change of 100,000 mg/L TDS and −55% change in resistivity (equivalent of 124% change in conductivity) for a salinity change of 150,000 mg/L TDS.

Table A-4. Comparison of the Acoustic and Electric Properties of Brines as Functions of the Dynamic Reservoir Properties, deduced from Figures A-40 and A-41

Dynamic Reservoir Property		Acoustic Property of Brine					Electric Property of Brine	
		Change in Brine Density, g/cm³	Change in Brine Bulk Modulus, MPa	Change in Brine Velocity, m/s	Change in P-Impedance, m/s·g/cm³	Percentage Change in P-Impedance	Percentage Change in Resistivity	Percentage Change in Conductivity
Change in Brine Pressure, psi	400	0.0011	21	4.9	7	0.4		
	900	0.0025	46	11	16	0.9		
Change in Brine Salinity, mg/L TDS	100,000	0.0752	595	98	237	13	−46	84
	150,000	0.198	1034	140	394	20	−55	124

A.3.1.2 Fully Brine-Saturated Rock Physics

Rock and fluid flow conditions were simulated using Gassmann's (1951) equation for fluid substitution and Archie's (1942) equation for acoustic and resistivity modeling, respectively.

For acoustic modeling, it is worth mentioning that the effective bulk modulus of the mixing fluids (in the case, only brine) plays a significant role in the Gassmann fluid substitution. Usually for three-phase porous media containing brine, oil, and gas, the effective fluid bulk modulus is given by Wood's (1955) equation (Equation A-2):

$$\frac{1}{K_f} = \frac{S_b}{K_b} + \frac{S_o}{K_o} + \frac{S_g}{K_g}$$ [Eq. A-2]

Where K_f is the bulk modulus of mixed fluid in a pore space. K_b, K_o, and K_g are the bulk moduli of brine, oil, and gas, respectively in a pore space. S_b, S_o, and S_g are the saturations of the brine, oil, and gas (which may be CO_2) in a pore space. Equation A-2 is responsible for the high sensitivity of time-lapse seismic to a small quantity (S_g) of gas injection or CO_2 storage in a saline brine formation, because gas has very high compressibility (i.e., very low bulk modulus) (Johnston, 2013). In this scenario with only brine phase, $Kf = Kb$, so the bulk modulus changes will be very minimal, thus minimal changes in velocity and P-impedance. This presents a major challenge to seismic brine–brine tracking.

Effective density of fully brine-saturated rock is given by the density mixing equation:

$$\rho_{sat} = \rho_m(1 - \Phi) + \rho_b\Phi$$ [Eq. A-3]

where ρ_{sat}, ρ_m, ρ_b are the density of fully brine-saturated rock, density of rock matrix, and the density of brine and Φ is porosity. This has an impact in lowering the change in density of the saturated rock during brine-to-brine substitution, in comparison to brine-to-CO_2 substitution where there is a lot of density changes as CO_2 is substituted for brine. For the brine-to-CO_2 fluid substitution, the second term on the right-hand side of Equation A-3 will be changed to the summation of the products of the porosity, the density and saturation of each of the two fluids, such that alteration in the saturation will add significant change in the acoustic properties of rock partially saturated with brine and CO_2.

For the electric modeling, Archie's equation (Equation A-4) shows that porosity scaling has a constant effect on the change in the resistivity of a fully brine-saturated rock as a function of change in rock–brine resistivity due to change in brine salinity:

$$R_t = \Phi^{-2} R_b \qquad \text{[Eq. A-4]}$$

where R_t and R_b are the resistivity of the fully brine-saturated rock and the resistivity of brine respectively.

Using the history-matched simulation model, acoustic property calculations show that for a combination of pressure change of 400 psi and salinity change of 100,000 mg/L (best case scenario), we have a corresponding 1.6% time-lapse change in P-impedance. Our field experience has shown that, for an onshore project of this nature, with the current advanced acquisition and processing technologies, high-quality 4-D seismic data could only image P-impedance changes equal to or above 4%. This shows that conducting 4-D seismic surveys in this project, where pressure change is expected to be smaller than 400 psi, may not provide benefit to the objectives of tracking brine pressure and salinity plumes. The very low percentage density change (2.5%) in this case also means conducting microgravity surveys may not provide measurable signal for the objectives of geophysical monitoring in this project. Modeling for CO_2–brine substitution, which has much higher density contrast than the brine–brine case for this Johnsons Corner pilot project, had earlier shown that microgravity measurement is not beneficial in this project.

However, for the same salinity change, and even for as low as a 50,000 mg/L salinity change, electric resistivity calculations show significant change in resistivity (between −25% to −40%) around the injector. There is about 316 S/m change in conductivity between the injector (Rink SWD 2) where the high-salinity brine is injected, to zero change in conductivity about 1000 ft away in the in situ low-salinity brine between (2013 to 2015). Therefore, conducting 4-D CSEM surveys might be useful in tracking the brine salinity plume in this project, going forward, based on the history-matched model. We recognize the importance of forward modeling of the CSEM electric or magnetic field from resistivity and inverse modeling of resistivity from the CSEM electric or magnetic field in order to ascertain the applicability of CSEM to the specific field configuration we have in this Johnsons Corner pilot project. Therefore, we consulted with the CSEM data acquisition company GroundMetrics to carry out forward and inverse CSEM modeling.

Preliminary results indicate that conducting the 4-D CSEM before and after the brine extraction process will offer a high-resolution time-lapse resistivity image. This data acquisition is expected to reveal the brine evolution in the Inyan Kara reservoir over the operational period of the Johnsons Corner project. Despite continuous high-salinity brine injection for the past 8 years, the planned project at this site indicates that there is still about 80,000 ppm salinity contrast expected over the period of the project, which can be imaged by the time-lapse CSEM.

One other important conclusion to be drawn from this rock physics analysis is that while 4-D seismic is an established method for CO_2 storage and/or CO_2 EOR monitoring, it has been shown here that it is not an appropriate method for brine–brine tracking. However, 4-D CSEM can be applied to both CO_2 storage monitoring and brine–brine salinity plume tracking. For CO_2 storage monitoring, we would expect increased resistivity near the injector, which is a reverse order to what we see here (drop in resistivity at the injector due to high-salinity brine injection into freshwater).

A.3.2 Geophysical Monitoring

Project objectives include validation of the means of predicting and monitoring the differential pressure plume movement in the subsurface. Validation will be achieved in two parts. The use of bottomhole pressure measurements in three of the project wells will allow the engineers to make adjustments to the simulation model to match those results, but a uniqueness problem remains as multiple geological realizations could provide the same result. The remaining part of the objective will be achieved by using geophysical monitoring to track the brine plumes or a proxy for the plumes in order to validate the input geologic model used as the basis for the predictive simulations. The shape and distribution of salinity within the brine plumes are a measureable representation of the actual reservoir geologic character which can be used to compare and improve the geologic model.

Several geophysical monitoring technologies were considered for the project, but because of the unique challenges presented by the brine-on-brine injection and the geologic storage characteristics of the project site, a variant of CSEM called borehole-to-surface electromagnetics (BSEM) was the method selected for implementation. BSEM has a high chance of success to track the brine plumes, as the salinity contrast between injected fluid and in situ brine results in a mappable and trackable resistivity profile that is directly related to salinity content.

Reservoir simulation plume and pressure modeling, together with rock and fluid physics modeling showed that geophysical methods other than BSEM that were investigated would likely fail because of the special characteristics of the project site. Other methods considered included borehole microgravity, 3-D and 4-D surface seismic, 3-D and 4-D vertical seismic profiles (VSP), and interferometric synthetic aperture radar (InSAR).

A.3.2.1 Insufficient Density Contrast for Borehole Microgravity

Borehole microgravity can measure changes in bulk density and the movement of fluids with different densities in the subsurface. Simulations for the project site indicate that salinity plumes currently in place after 8 years of injection extend out a radius greater than 1000 feet from the injection wells. Much of the plume is a mixing zone as salinities eventually drop to the levels of the native brine at some distance from the injection wells. Rock physics modeling showed the greatest bulk density contrast possible between areas with the most saline injectate and areas with the native brine to be about 4%. Previous modeling experience suggests this will be too small a difference to be measureable with borehole microgravity at the lateral distances necessary, especially when the actual mixing zone contrasts would be even lower.

A.3.2.2 P-Wave Impedance Contrast Likely to Be Buried in Noise

4-D surface seismic and 4-D VSP can be used to monitor time-lapse changes of pressure, density, and velocity. Density and velocity changes together create impedance contrasts (p-wave impedance = p-wave velocity × bulk density) which is what seismic methods most commonly image. 4-D difference displays show changes in impedance over a time interval. Rock physics modeling results showed that velocity changes in the reservoir rock due to brine salinity changes will be on the order of 1%. Factoring in bulk density changes, the greatest p-wave impedance contrast due to salinity changes from brine movement would be less than 5% given a best case scenario. When analyzing seismic reflection data for noise, a 10% value (−20 dB on an amplitude spectrum) is a common cutoff. Therefore, this small impedance change would likely be buried in the background noise and indiscernible, so it is unlikely that seismic methods would be able to show changes to the salinity plumes on a 4-D time-lapse display.

Obtaining a 4-D seismic image of a pressure plume, specifically the shape of the extraction well drawdown pressure plume, would be a possibility if a sufficient pressure differential existed and could be maintained. However, simulation pressure profiles show that the high permeability and unconfined nature of the reservoir resulted in relatively small pressure differences away from the wells that slowly dissipated, even with large volume drawdowns or injections. The conclusion is that for the project site in question, seismic monitoring methods would not be successful in identifying changes to the brine plume or provide a useful image of the pressure plume.

InSAR Results Expected to Be Impacted by Aggregate Mining

Aggregate mining activity at the Johnsons Corner site will create ongoing ground disturbances and likely inhibit the ability to produce conclusive results from InSAR technology. The phase change of the waves reflected back to the satellite for any one display pixel are the summed contributions of many smaller surrounding targets. It is assumed that over time the contributions remain constant. This assumption would not be valid at this site.

Strong Resistivity Response due to Salinity Contrasts Works in Favor of BSEM

BSEM uses an electrical source in one or more wells opposite the formation of interest together with an array of receivers on the surface. By injecting an electrical current into the formation, measurement of the electric field across the surface array is made. Model fitting allows the measurement to be related to the spatial resistivity in the formation of interest. For the current project, spatial resistivity is directly related to the salinity of the formation fluids which defines the shape of the salinity plumes. Multiple surveys provide a means of monitoring spatial resistivity changes caused by changes in the shape of the salinity plume.

The project configuration is ideal for time-lapse BSEM. The geology is gently dipping layers (less than 3 degrees) with no significant structural variations, and the high-salinity contrast in the reservoir results in a resistivity contrast of two orders of magnitude between injected fluids and in situ fluids. This measureable contrast will allow for mapping the changes in the shape of the brine plume over time. Several wells within the project area allow flexibility in survey design and direct access to the zone of interest. At least two surveys are envisioned: a baseline before extraction starts and a monitor at the end of the extraction experiments. Each will provide an image of the salinity plume that can be used to validate the predictive simulations. A difference display will illuminate the changes in plume shape and salinity over the time interval of the experiment. Operational considerations may allow for an additional monitor survey during the course of the experiment.

For a commercial-scale CO_2 storage facility, time-lapse seismic methods are a proven monitoring technology. However, the same characteristics that allow BSEM to work for the Johnsons Corner site would exist at many potential commercial-scale CO_2 storage sites because the salinity contrast between injected CO_2 and in situ brine would be very large. So while the brine-on-brine injection at the current project requires BSEM to monitor the plumes, the BSEM technique provides a valid alternate method that could be applied with equal success at CO_2 storage facilities in place of seismic techniques if desired or necessary because of access or permitting reasons.

Operational Design for BSEM Surveys

The objective of the BSEM survey is to obtain an image of the injection brine plumes to validate the input geologic model used as the basis for the predictive simulations. The plume shape and distribution of salinity within the brine plumes are a measureable representation of the actual reservoir geologic character which can be used to improve the statistically derived geologic model. By injecting electric current into the reservoir formation and monitoring its return at the surface, the resistivity profile in the reservoir can be mapped in three dimensions. The resistivity image is a direct proxy for the salinity plumes.

Key factors in the survey design include:

- The Johnsons Corner site provides ample flexibility for BSEM survey design.
- To achieve the best image of the saline plume, the downhole source tool will be run in two wells.
- Best results are achieved if the source tool can be placed opposite the reservoir formation.
- The downhole source tool has a diameter of 3.5” which makes it too large for the Rink SWD 1 injection well but not Rink SWD 2, BEST-E1, or BEST-I1.
- Access to the Inyan Kara Formation in Rink SWD 2 is not possible because of the packer 50 to 100 feet above the zone of interest, but this limitation can be overcome by proper modeling.

- A baseline survey will be acquired prior to the extraction experiments, at completion of the extraction well and new injection well, but prior to installation of any electrical instrumentation.

- A monitor survey will be acquired at the conclusion of the extraction experiment and after electrical instrumentation is removed, including the pump in the extraction well.

- Wells which can provide access directly to the Inyan Kara Formation include the BEST-E1 extraction well prior to the installation of the pump and the BEST-I1 at any time after it is cased.

The survey method and its planned configuration at the Johnsons Corner site are preliminary but will involve a downhole electrical source operating in two wells with a surface array of up to 1500 receiver modules covering an area up to 3.4 square miles (Figure A-42). The target wells are BEST-E1 and BEST-I1 after completion, but prior to installation of instruments or pump. A monitoring truck controls the electrical source and monitors the operational status of the surface array (via Wi-Fi) at all times. An electrode consisting of a perforating gun housing attached to a monofilament wireline will be lowered into the well and hung opposite the Inyan Kara. Electric current injected into the reservoir will travel laterally through the formation in all directions about half the distance of the depth, ~2750 ft, before returning to the surface to be detected by the receiver modules. Global positioning system (GPS) clocks keep the components synchronized (Figures A-43 and A-44). The survey takes 1 to 2 days a well, plus a week to lay out and retrieve the array. The method is very low impact on the surface but does require access. The electrical nature of the source is not a health and safety hazard, but it could impact instrumentation in the well. For this reason, the survey is planned after drilling and completing the extraction and injection wells, but prior to installation of any instrumentation such as pressure gauges.

After the 7–12-day acquisition field work, the data are reduced at the processing center. Processing time is expected to take 45–90 days, with the final product being a data volume of resistivity values in SEG-Y format that can be loaded into an interpretation application such as Petrel or Kingdom (Figure A-45).

The acquisition and processing and interpretation process will be repeated at the end of the extraction experiment.

EERC RK51367.CDR

Figure A-42. Surface sensor used in borehole to surface EM surveys. An array of several hundred sensors are deployed on the surface during the survey (courtesy GroundMetrics).

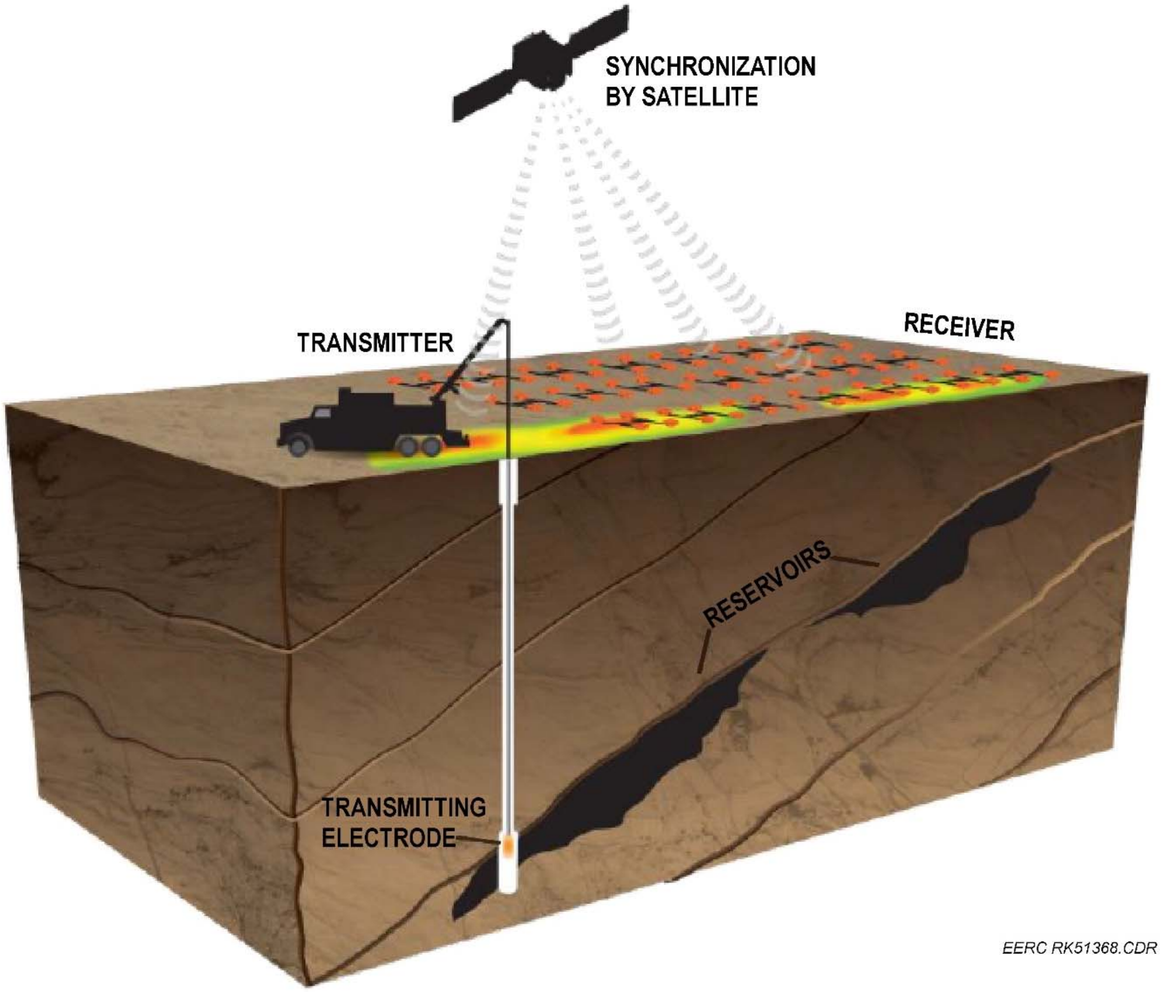


Figure A-43. Schematic from GroundMetrics, a BSEM provider, shows the survey geometry with a downhole electrode, surface transmitter, and surface receiver array synchronized by GPS satellite (courtesy GroundMetrics).

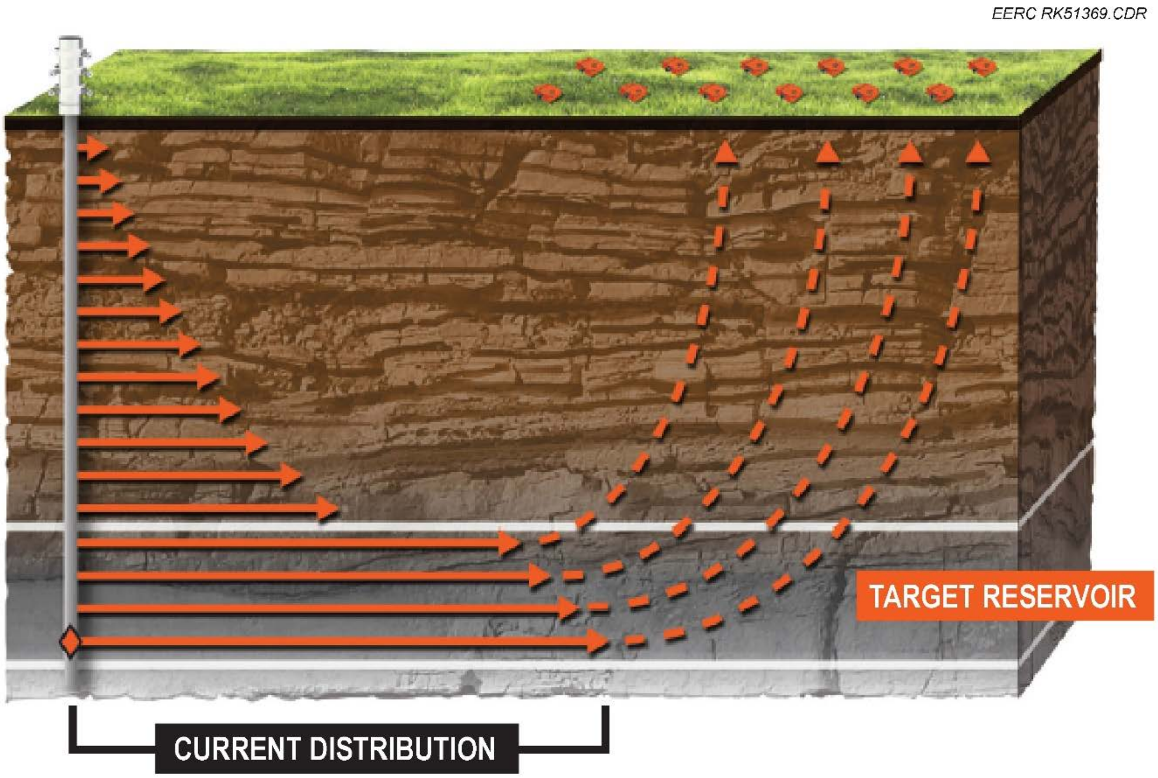


Figure A-44. Schematic of injected current moving through the target reservoir and returning to the surface where it is detected by the sensors (courtesy GroundMetrics).

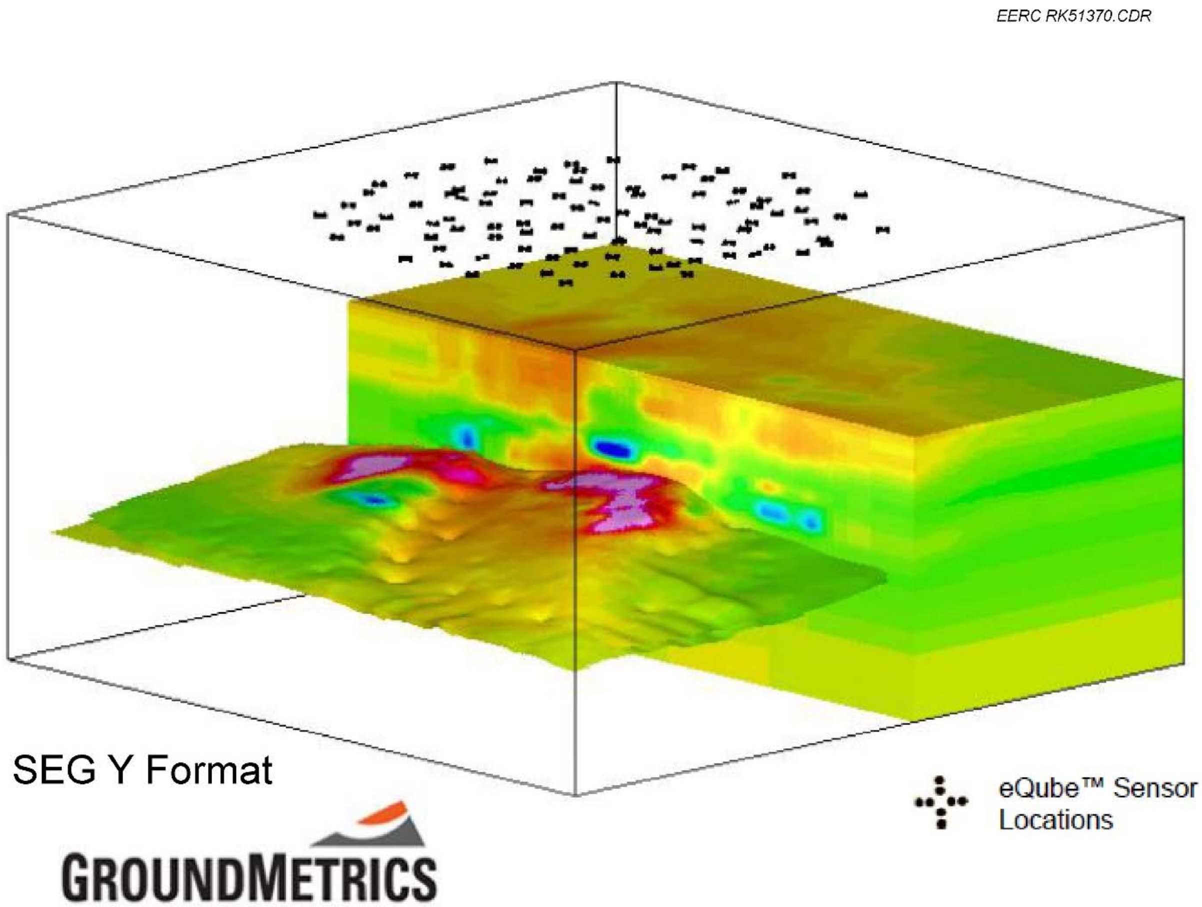


Figure A-45. Resistivity volume deliverable in SEGY format ready for interpretation (courtesy GroundMetrics).

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APPENDIX B

RISK ASSESSMENT

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The Phase 1 risk assessment for the Johnsons Corner project consisted of identifying the risks to the project, estimating the magnitude of each risk, and proposing possible mitigation/ remediation activities to minimize the risk.

RISK IDENTIFICATION

Risk identification for the Johnsons Corner pilot involved the determination of which risks were relevant to the project and yielded a preliminary risk register (Tables B-1–B-5). The risk register was developed and validated by experts with related technical, operational, HSE (health, safety, and environment), and management experience and knowledge of the Johnsons Corner site and the project objectives. The project-specific risks were assigned to one of five general classifications:

- Technical
- Resource availability
- HSE
- Site access issues
- Management

RISK ESTIMATION

The risk estimation phase of the risk assessment consisted of an analysis of the risks in the risk register and the development of a semiquantitative ranking of their overall risk to the project. The risks were rated using a combination of the likelihood of occurrence and the potential severity of the resulting impact. The risk severity was based on impact to cost and/or schedule for completing the Johnsons Corner pilot. These assignments were based on geologic data, laboratory results, historical injection data, and reservoir history-matching and extraction/injection scenario simulation modeling that were available prior to March 15, 2016. The likelihood and severity criteria, developed by the project technical experts, are presented below.

Likelihood of Risk

Score	Range, %
1	<1
2	1 to 10
3	>10 to 25
4	>25 to 50
5	>50

Severity Criteria

Score	Cost Severity, $	Schedule Severity, months
1	<100,000	<1
2	100,000 to <500,000	1 to 3
3	500,000 to <1,000,000	>3 to 6
4	1,000,000 to 3,000,000	>6
5	>3,000,000	>6

The rank of each risk was determined by the equation, rank = likelihood + severity, where scores of 1 to 5 were established for both of these parameters. This summation process resulted in a risk rank value for each individual risk, ranging anywhere from 2 (i.e., likelihood = 1 and severity = 1) to 10 (i.e., likelihood = 5 and severity = 5). The risk rank values were grouped into four zones, characterized by the following qualitative descriptions of risk:

- Risk rank value = 2 to 4: low, or negligible, risk
- Risk rank value = 5 to 6: transition zone, warranting close monitoring
- Risk rank value = 7 to 8: serious risk
- Risk rank value = 9 to 10: extreme criticality

RISK MITIGATION/REMEDIATION

Potential mitigation and remediation measures were proposed and developed to facilitate successful completion of the proposed ARM (active reservoir management) and water treatment tasks at the Johnsons Corner site. Risk mitigation and remediation measures were provided by the technical, operational, HSE, and management experts participating in risk identification and estimation.

Table B-1. Technical Risks Identified and Potential Mitigation/Remediation Strategies for the Johnsons Corner Site

No.	Risk	Possible Mitigation/Remediation
1	Lost circulation while drilling.	Have sufficient volume of LCM (lost circulation material) and other drilling fluid materials on-site while drilling in order to control and maintain circulation.
2	Lost tools during drilling (twist off BHA [bottomhole assembly], logging tools, etc.).	Use tools according to standards set for contractor equipment. Continually check and function test equipment as needed. Regularly perform maintenance on equipment as recommended for contractor equipment.
3	Unable to collect any cores from Broom Creek Formations.	Offset well logs and rate of penetration (ROP) from offset wells will provide well control to select the core point. The geologist on location will provide oversight of core point selection. Site meetings with the rig crew will develop coring procedures. Proper core tool selection will be based on expected geology. BEST-E1 and sidewall cores will provide a contingency for core collection.
4	Unable to collect any cores from Inyan Kara Formation.	Offset well logs and ROP from offset wells will provide well control to select the core point. The geologist on location will provide oversight of core point selection. Site meetings with the rig crew will develop coring procedures. Proper core tool selection will be based on expected geology. BEST-E1 and sidewall cores will provide a contingency for core collection.
5	Logging data are unusable.	Ensure proper calibration and precheck logging tools. The geologist on location will monitor and ensure well log quality control (LQC). The drilling program will be designed to minimize deviation, prevent rough or swelling borehole, and washout conditions. Backup logging tools will be kept on standby.
6	Unable to run casing to zone of interest.	Follow operating procedures recommended by the equipment manufacturer. Have lubrication material (i.e., beads, fluids) on-site during casing operations. Condition and maintain drilling fluid in wellbore prior to running casing.
7	Bad cement job.	A cement squeeze job procedure will be on standby as a contingency. The selected completions design incorporates suspended downhole P/T (pressure/temperature) gauges rather than casing-conveyed gauges to allow the ability to rotate and reciprocate during cementing. Cement volumes will be calculated using caliper logs, and the cement engineer will design the cement program based on actual well conditions.
8	Salt formations (the Pine, Dunham, and Opeche) located above the Broom Creek Formation “pinch off” or wash out the injection well after drilling and/or during injection operations.	Cement will be placed past salt formations, and the proper casing weight/strength will be selected to minimize risk of pinch-out. The mud control program will be designed in consultation with the mud engineer. Fast ROP will be employed through potential salt zones to minimize washout.
9	Nuclear logging tool is lost in the extraction well.	Ensure good hole conditions prior to logging (proper mud system, good filtercake, note any lost circulation zones, minimize swelling of clays or washout areas, low deviation hole). Follow Schlumberger logging standard operating procedure (SOP) (tension alarms and shutdowns, logging/tripping speed limits, etc.).
10	Non-nuclear logging tool is lost in the injection well.	Ensure good hole conditions prior to logging (proper mud system, good filtercake, note any lost circulation zones, minimize swelling of clays or washout areas, low deviation hole). Follow Schlumberger logging SOP (tension alarms and shutdowns, logging/tripping speed limits, etc.).

Continued . . .

Table B-1. Technical Risks Identified and Potential Mitigation/Remediation Strategies for the Johnsons Corner Site (continued)

No.	Risk	Possible Mitigation/Remediation
11	Poor core recovery.	Offset well logs and ROP from offset wells will provide well control to select the core point. The geologist on location will provide oversight of core point selection. Site meetings with the rig crew will develop coring procedures. Proper core tool selection will be based on expected geology. BEST-E1 and sidewall cores will provide a contingency for core collection.
12	Broom Creek/Amsden Formation parting pressure is lower than regional fracture gradient causing a reduction in maximum permitted injection pressure.	Redesign the ARM test program based on injection volume constraints. Consider revising the location of the BEST-E1 well closer to Rink SWD 1 and Rink SWD 2 wells. Investigate an option to obtain a permit to stimulate (acidize) the Broom Creek/Amsden interval to increase injectivity. Other options include perforating additional zones on the Broom Creek/Amsden interval to increase injection volumes or use Rink SWD 1 and Rink SWD 2 wells combined with on-site storage/buffer capacity.
13	Perforating guns do not fire.	Follow Schlumberger perforation loading, arming, and running SOPs. Perform pre-RIH (run in hole) tests of equipment and cable. Utilize new o-rings on all connections. Rerun perforating guns as a contingency.
14	Running tools (pressure gauges, etc.) results in damage or breakage.	Follow PROMORE and Schlumberger installation SOPs. Hold initial job safety and operations briefing meeting with all personnel and rig crew members on-site. Rerun gauges as a contingency. Do not reciprocate or rotate pipe during installation. Utilize cannon clamps and standoffs on alternating joints with bands in between.
15	Unable to get a pressure test (MIT [mechanical integrity test]) on packer for injection well.	Hydrotest tubing while tripping in hole to avoid collar/tubing leaks. As another option, pull tubing and packer and run in with new packer.
16	Inability to produce sufficient water volumes from Inyan Kara Formation to affect a significant injectivity change on the Rink SWD 1 and Rink SWD 2 wells	Use Nuverra/EERC on-site storage/buffer capacity to reduce injection rates in the Rink SWD 1 and Rink SWD 2 wells. Perform injection/production and interference testing to ensure pressure communication between wells. Revise simulation predictions based on best available data and new data acquired from characterization efforts during test.
17	Initial Broom Creek Formation injectivity is not sufficient to match extraction from Inyan Kara	Redesign the ARM test program based on injection volume constraints. Consider revising the location of the BEST-E1 well closer to Rink SWD 1 and Rink SWD 2 wells. Investigate an option to obtain a permit to stimulate (acidize) the Broom Creek/Amsden interval to increase injectivity. Other options include perforating additional zones on the Broom Creek/Amsden interval to increase injection volumes or use Rink SWD 1 and Rink SWD 2 wells combined with on-site storage/buffer capacity.
18	Reactivity of Broom Creek Formation with injected fluid reduces permeability.	Test for potential formation brine, produced brine, and rock interactions using fluid and core samples obtained from the BEST-I1 well. Consider swapping application of BEST-I1 and Rink SWD 1 and/or Rink SWD 2 wells in cooperation with site operator in order to conduct test as planned.
19	Project tests are delayed because of extraction well issues.	Revise the test plan based on a new time line. Work closely with project partners, contractors, and U.S. Department of Energy (DOE) project manager to develop sufficient contingency action plans to prevent extended project delays. Track location and understand lead times for all equipment and plan accordingly.

Continued . . .

Table B-1. Technical Risks Identified and Potential Mitigation/Remediation Strategies for the Johnsons Corner Site (continued)

No.	Risk	Possible Mitigation/Remediation
20	Contamination of overlying underground sources of drinking water (USDW) – extraction from Inyan Kara results in reduced pressure.	Extraction from the Inyan Kara will result in reduced formation pressure lowering the risk of upward fluid migration. Injection into the Broom Creek/Amsden Formations is below the Inyan Kara Formation preventing upward migration beyond the Inyan Kara. Follow all UIC underground injection control) and state permitting requirements and recommended practices. Follow Schlumberger best completions practices and ensure good cement job prior to injection/extraction. Perform MIT and wellbore integrity tests to ensure proper isolation prior to injecting/extraction.
21	Wellbore (casing) integrity failure.	Follow all UIC and state permitting requirements and recommended practices, follow Schlumberger best completions practices, ensure good cement job prior to injection/extraction, run MIT and wellbore integrity tests to ensure proper isolation prior to injecting/extraction
22	Wellbore equipment failure (ESP [electric submersible pump], fiber-optic cables, P&T sensors).	Track the location and understand lead times of backup equipment. Work closely with project partners, contractors, and DOE project manager to develop sufficient contingency action plans to prevent extended project delays. Repair/replace equipment as necessary.
23	Inexperienced operations staff cause failure/damage to wells or equipment.	Develop SOP procedures for all standard and repair activities. Ensure proper training and experience for operations staff based on the SOPs. Review nonstandard procedures with the management team. Implement tailgate meetings prior to conducting activities. Build system safeguards (equipment/personnel) into the design where reasonable. Ensure proper communication between site manager and operations team.
24	Injected/extracted brine causes scale buildup, sanding in well.	Perform chemistry analysis of produced/injected fluids to identify potential interactions. Utilize chemical treatments on wells to minimize scale buildup and maintenance issues. Perform acid or chemical treatments as necessary.
25	Injection into Rink SWD 1 and Rink SWD 2 wells is halted prior to successful execution of BEST project.	Construct the ARM test design to ensure that the highest priority and minimal project objectives are met as soon as possible within the project time line. Coordinate and engage with site operator to deliver sufficient fluid volumes to the site to meet project objectives. Projections of the fluid volume on-site indicates this risk is unlikely during the duration of the project. Conduct the test exclusively using BEST-E1 and BEST-I1 wells. Consider conducting test in the Broom Creek/Amsden Formation.
26	Inability to generate a pressure pulse/plume because of insufficient fluid injection volume/rate.	In cooperation with the site operator, consider swapping applications of the BEST-I1 and Rink SWD 1 or Rink SWD 2 wells to conduct the test as planned. Coordinate with the site operator to use buffer capacity to deliver sufficient fluid volumes to site to meet required project objectives.
27	Tubing failure in injector or extraction wells.	Repair/replace tubing as necessary. Install digital casing/tubing pressure gauges for remote monitoring to minimize downtime.
28	Brine tanks or other surface equipment freezes up.	Heat tape/trace, bury, and/or enclose all infrastructure sensitive to freezing. Maintain adequate flow rates to prevent freezing. Install land remote monitoring flowmeters and pressure gauges to identify potential issues. Utilize hot oil to unthaw frozen equipment as needed.
29	Downhole pressure gauge failure.	Ensure the installation SOP and best practices are followed. Perform remote monitoring of gauges to minimize downtime. Repair/replace faulty gauges as necessary.
30	Wellhead casing or tubing pressure gauge failure.	Perform remote monitoring of gauges to minimize downtime. Repair/replace faulty gauges as necessary.

Continued . . .

Table B-1. Technical Risks Identified and Potential Mitigation/Remediation Strategies for the Johnsons Corner Site (continued)

No.	Risk	Possible Mitigation/Remediation
31	Inability of surface EM (electromagnetic survey) to image brine plume within Inyan Kara Formation.	This risk should be considered mitigated or retired because service provider analyzed site data, including depth of target, thickness of target, resistivity contrast, probable acquisition geometry, a nearby resistivity well log, and the availability of wells that will have access to the Inyan Kara Formation. Their assessment was that imaging the brine plumes was feasible.
32	Tracers are unable to be detected because of interference by other chemical constituents in sampled water or diluted because of high injection volumes.	Work with the tracer service provider to engineer tracer injection volumes based on detailed site characterization and simulation. Develop and ensure sufficient sampling frequency to detect early breakthrough.
33	Tracer does not reach sampling point.	Simulate reservoir flow paths to ensure sampling points will intercept injected tracers. Work with the tracer service provider to engineer tracer injection volumes based on detailed site characterization and simulation.
34	Inability to validate differential pressure plume movement.	Redundant monitoring systems will be in place (downhole and tubing pressure gauges and EM methods) to minimize this risk.
35	Water quality does not match treatment test requirements.	The brine test facilities are designed with the ability to blend produced water from the BEST-E1 well with other produced and freshwater available on-site, allowing brine salinity ranges between approximately 320,000 ppm and 3000 ppm to be tailored in our test facilities at rates up to 45 gpm.
36	Seasonal temperatures affect ability to test treatment technologies.	Brine treatment test facilities will be located in a heated enclosure which provides the ability to conduct brine treatment testing year-round.
37	Inexperienced operations staff cause damage to facilities.	Employ experienced operations staff and ensure proper systems training. Build in safeguards on equipment where reasonable. EERC operations staff will operate facilities during third party brine treatment tests.
38	Filter socks from brine filtering exceed naturally occurring radioactive material (NORM) limits for disposal in North Dakota.	Test filter socks for the presence of NORM. Follow the regulatory compliant standard procedures of the site operator for disposal of NORM-containing materials in regulatory-approved methods.
39	Delays with treatment area equipment placement/operation impact project objectives.	Revise the test plan based on a new time line. Work closely with project partners, contractors, and DOE project manager to develop sufficient contingency action plans to prevent extended project delays. Engage with the treatment technology provider throughout the project.

Table B-2. Resource Availability Related Risks Identified and Potential Mitigation/ Remediation Strategies for the Johnsons Corner Site

No.	Risk	Possible Mitigation/Remediation
1	Unable to reach agreement with or partners pull out of project.	Engage with the site operator and project partners/contractors throughout the project. Procure letters of commitment and structure contracts to minimize this risk.
2	Partners pull out of project from a cost-share standpoint.	Engage with the site operator and project partners/contractors throughout the project. Procure letters of commitment and structure contracts to minimize this risk. Identify additional cost-share providers.
3	Site operator is acquired by another operating company that does not want to participate in test.	Structure contracts to minimize this risk.
4	Unexpected construction issues are encountered resulting in cost overruns or inability to meet proposed project time line.	Engage closely with project partners, contractors, and DOE project manager to develop sufficient contingency action plans to prevent extended project delays. Track location and understand lead times for all equipment and plan procurements accordingly.
5	Loss or turnover in personnel results in loss of expertise and inability to complete the project.	Provide sufficient cross training of all project personnel to minimize downtime. Hire and train additional personnel to cover project scope.
6	Damage causes significant delay to project.	Build in structure reinforcement and equipment safety/protection where reasonable. Engage closely with project partners, contractors, and DOE project manager to develop sufficient contingency action plans to prevent extended project delays. Track location and understand lead times for all equipment procurements/repairs and plan accordingly. Carry insurance to cover damages.

Table B-3. Health, Safety, and Environment Risks Identified and Potential Mitigation/Remediation Strategies for the Johnsons Corner Site

No.	Risk	Possible Mitigation/Remediation
1	Operations staff has serious personal injury incident.	Require and provide appropriate safety training of all personnel on-site. Require and provide appropriate training on equipment/facilities. Ensure regular communication between the site manager and operations staff. Develop a safety training program for all site visitors and third parties, and ensure they have appropriate training before working on-site. Develop SOPs for all standard operations/repair activities and employ preactivity meetings prior to nonstandard operations.
2	H_2S levels in pump houses exceed 8-hour exposure limit for personnel.	Install H_2S monitors with Hi and Hi-Hi alarm thresholds. Provide safety training to operations personnel regarding first confirming safe conditions for entering buildings. Have externally mounted alarm annunciator/display on pump house.
3	Contained leakage/spills of high TDS brine from surface equipment contaminates surface soil/water.	Construct a berm, and line all surface facility locations according to best practices. Incorporate safeguards/automated shutdown in the design of all surface facilities. Incorporate remote monitoring to minimize time to leak detection. Follow permit and regulatory requirements applicable to surface facilities. Develop an emergency response plan, overseen by a project-specified lead, to respond to any incidents.
4	Uncontained leakage/spills of high TDS (total dissolved solids) brine from surface equipment contaminates surface soil/water.	Incorporate safeguards into the design of all surface facilities. Incorporate remote monitoring to minimize time to leak detections. Follow permit and regulatory requirements applicable to surface facilities. Develop an emergency response plan, overseen by a project-specified lead, to respond to any incidents.
5	Injection of brine into the Broom Creek Formation causes seismicity that can be felt.	Operate within permitted injection/extraction limits. The injection horizon is not on a known fault or near bedrock, so there is minimal risk of induced seismicity.
6	A buried pipeline leaks.	Incorporate safeguards in the design of all surface facilities. Incorporate remote monitoring to minimize time to leak detections. Follow permit and regulatory requirements applicable to surface facilities. Develop an emergency response plan, overseen by a project-specified lead, to respond to any incidents. Follow recommendations for buried pipeline installation to minimize risk of leaks. Employ totalizing flowmeters and sensors tied into a remote monitoring system to minimize time to detections.
7	An unburied flowline leaks.	Incorporate safeguards in the design of all surface facilities. Incorporate remote monitoring to minimize time to leak detections. Follow permit and regulatory requirements applicable to surface facilities. Develop an emergency response plan, overseen by a project-specified lead, to respond to any incidents. Employ totalizing flowmeters and sensors tied into remote monitoring system to minimize time to detections. Perform daily visual inspections by host site operations personnel. Site flowlines inside of berm and lined location.
8	Buried pipelines are breached by digging operations.	Install trace wire along pipeline right away. Ensure an accurate survey of the pipeline location and all other buried utilities and pipelines on-site prior to any digging or placement of footings/posts/supports.
9	Injury to personnel or visitor because of site hazards.	Require and provide on-site safety training to site operations personnel regarding hazard avoidance, PPE (personal protective equipment) requirements and use, and injury response. Ensure all visitors are escorted by EERC or Nuverra personnel. Utilize proper monitoring (e.g., H_2S/O_2) where potential hazards could develop.

Table B-4. Site Access-Related Risks Identified and Potential Mitigation/Remediation Strategies for the Johnsons Corner Site

No.	Risk	Possible Mitigation/Remediation
1	Unable to get drilling or construction permit because of objections of local stakeholders.	Initiate engagement with area stakeholders immediately upon project award. Ensure site operator has appropriate site access to conduct test. The project will not be bringing to or removing fluids from the site nor will anything of value be commercially sold as part of this test. Follow all permitting requirements and guidelines. Obtain letter of support supplied by regulatory authority.
2	Unable to get drilling or construction permit because of regulatory agency.	Initiate engagement with area stakeholders immediately upon project award. Ensure site operator has appropriate site access to conduct test. The project will not be bringing to or removing fluids from the site nor will anything of value be commercially sold as part of this test. Follow all permitting requirements and guidelines. Obtain letter of support supplied by regulatory authority.

Table B-5. Management-Related Risks Identified and Potential Mitigation/Remediation Strategies for the Johnsons Corner Site

No.	Risk	Possible Mitigation/Remediation
1	Organization of the BEST team is unclear as are the roles and responsibilities of the individual team members, resulting in confusion, inefficient operations, and overall poor performance.	The project management plan clearly defines the roles and responsibilities of participating team members. Planning meetings, conference calls, Webinars, and regular e-mail communication will occur to ensure coordination of all participants and minimize risk.
2	Project management controls do not operate effectively and are unable to demonstrate BEST team’s ability to deliver quality work products on schedule and within budget.	The EERC and other members of this project team (Nuverra and Schlumberger) have a long-standing relationship. Planning meetings, conference calls, Webinars, and regular e-mail communication will occur to ensure coordination of all participants and minimize risk.

APPENDIX C

PERMITTING

PERMITTING

This appendix details the specific steps necessary to complete and acquire the necessary permits. Project partner Nuverra will acquire all required permits for the site with direct assistance from the Energy & Environmental Research Center (EERC).

PERMIT TO DRILL

The Application for Permit to Drill (Form 1) requires that all applications for a permit to drill be accompanied with a certified and accurate plat map completed by a registered surveyor showing the location of the proposed well with reference to true north, the nearest lines of a governmental section, the latitude and longitude of the proposed well location (to the nearest tenth of a second), the ground elevation, and the proposed road access to the nearest existing public road.

The vertical well drilling application will include estimated depth to the top of important geologic markers, estimated depth to top of objective horizons, and the proposed depth of the well. For this project, the producing well (BEST-E1) will be drilled to the Swift Formation approximately 5688 feet, and the disposal well (BEST-I1) will be drilled to a depth of 7971 feet into the Tyler Formation. Each well will be accompanied by certified plat by a registered surveyor showing the internal dimensions of the spacing or drilling unit.

The application will include the proposed mud program, the proposed casing program (including size and weight, the setting depth of each casing string, the estimated amount of cement to be used [including the top of cement], and a detailed production pad facilities layout plat showing cut-and-fill diagrams and the proposed cuttings pit). For this project, the EERC will be using a closed-loop system rather than a cuttings pit. The EERC will provide any other information as requested by the North Dakota Industrial Commission (NDIC).

INSTRUCTIONS[1]

APPLICATION FOR PERMIT TO DRILL – FORM 1 SFN 4615

Instructions

1. All applications for permit to drill must be e-filed, except in extenuating circumstances. Operators must file an ePermit authorization form, and e-mail to apd@nd.gov. The Bismarck office will then issue a user-ID and password to access the online Form 1 or Form 1H.

2. Please refer to Section 43-02-03-16 of the North Dakota Administrative Code (NDAC) regarding an application for permit to drill.

[1] www.dmr.nd.gov/oilgas/rules/forms/form1.pdf

3. Wellsite preparation other than surveying and staking is forbidden prior to approval of an application for permit to drill.

4. Verbal approval may be given for site preparation by the Director in extenuating circumstances, although no drilling activity shall commence until the application is approved.

5. The application for permit to drill shall be accompanied by a bond pursuant to Section 43-02-03-15 NDAC, or the applicant must have previously filed such bond with the Commission, otherwise the application is incomplete.

6. Any incomplete application for permit to drill received by the Commission has no standing and shall not be deemed filed until it is completed.

7. The application for a permit to drill a well shall be accompanied by an accurate plat certified by a registered surveyor showing the location of the proposed well with reference to the nearest lines of a governmental section and referenced to true north. Also, the application must include an accurate pad layout which indicates cut and fill and the proposed cuttings pit location. In addition, a production pad facilities layout plat is required.

8. The application for permit to drill a directional well shall be accompanied by an accurate plat certified by a registered surveyor showing the internal dimensions of the spacing or drilling unit.

9. The application for permit to drill shall be accompanied by a drilling prognosis which shall include the following: the proposed total depth (including measured depth if appropriate) to which the well will be drilled, the estimated depth to the top of important geologic markers, the estimated depth to the top of objective horizons, the proposed mud program, the proposed casing program including size and weight, the proposed depth at which each casing string is to be set, the proposed amount of cement to be used, and the estimated top of cement.

10. A gamma ray log must be run to ground level, CBL [cement bond log]) must be run on the intermediate or production casing, and openhole logs are required (unless waived by the Director).

11. The application for permit to drill shall be accompanied by the general completion technique.

12. The application for permit to drill shall comply with NDIC-PP (Permit Policy) 1.01, 1.02, 1.03, 1.04, 1.05, 1.06, 2.01, 2.02, 2.03, and 2.04. Also, the application shall include confirmation that a legal street address was requested as required by NDAC 43-02-03-16.

13. The application for permit to drill shall be accompanied by a permit fee of $100.

14. The approved application for permit to drill shall terminate and be of no further force and effect unless a well is drilling, or has been drilled, below surface casing on the first anniversary of the date of issuance or renewal.

APPLICATION FOR INJECTION

The Application for Injection (Form 14) must be accompanied with the surface and bottomhole location, including the appropriate geologic data on the injection zone and the confining zones. It must also include the estimated bottomhole fracture pressure of the top confining zone, average and maximum daily rate of fluids, and average and maximum requested surface injection pressure. The geologic name and depth to base of the lowermost underground source of drinking water which may be affected by the injection shall be provided. A plat map depicting the area of review (¼-mile radius) and detailing the location, well name, and operator of all wells in the area of review and injection wells, producing wells, plugged wells, abandoned wells, drilling wells, dry holes, and water wells must be included. The plat map shall also depict faults, if known or suspected. The permit application will also include a description of any potential corrective action for wells penetrating the injection zone in the area of review.

The application will include a plat map with legal descriptions of land ownership within the area of review along with copies of letters sent with an affidavit of mailing, certifying that all landowners within the area of review have been notified of the proposed wells. The notice will inform the landowners that comments or objections may be submitted to the Commission within 30 days, and/or that a hearing will be held at which comments or objections may be submitted.

Schematic drawings will be generated and include the proposed wellbores and surface facility construction, including the size, location, and purpose of all tanks; the height and location of all dikes; and containment including all areas underlain by a synthetic liner and the location of all flowlines.

A certified and registered lab will provide quantitative analyses of freshwater from the two nearest freshwater wells, including legal descriptions for each well, as well as provide the required quantitative analyses of representative samples of water to be injected and a list identifying all source wells, including legal location.

INSTRUCTIONS[2]

FORM 14 APPLICATION FOR INJECTION

Instructions

1. Attach a list identifying all attachments.

2. The operator, well name and number, field or unit, well location, and any other pertinent data shall coincide with the official records on file with the Commission. If it does not, an explanation shall be given.

[2] www.dmr.nd.gov/oilgas/rules/forms/form14.pdf

3. If an injection well is to be drilled, an Application for Permit to Drill – Form 1 (SFN 4615) shall also be completed and accompanied by a plat prepared by a registered surveyor and a drilling fee.

4. Attach a lithologic description of the proposed injection zone and the top and bottom confining zones.

5. Attach a plat depicting the area of review (¼-mile radius) and detailing the location, well name, and operator of all wells in the area of review. Injection wells, producing wells, plugged wells, abandoned wells, drilling wells, dry holes, and water wells must be included. The plat shall also depict faults, if known or suspected.

6. Attach a description of the needed corrective action on wells penetrating the injection zone in the area of review.

7. Attach a brief description of the proposed injection program.

8. Attach a quantitative analysis from a state-certified laboratory of freshwater from the two nearest freshwater wells, including a legal descriptions.

9. Attach a quantitative analysis from a state-certified laboratory of a representative sample of water to be injected.

10. Attach a list identifying all source wells, including location.

11. Attach a legal description of land ownership within the area of review. List ownership by tract or submit in plat form.

12. Attach an affidavit of mailing certifying that all landowners within the area of review have been notified of the proposed injection well. This notice shall inform the landowners that comments or objections may be submitted to the Commission within 30 days, or that a hearing will be held at which comments or objections may be submitted, whichever is applicable. Include copies of letters sent.

13. Attach all available logging and test data on the well that has not been previously submitted.

14. Attach schematic drawings of the injection system, including current wellbore construction and proposed wellbore and surface facility construction.

15. Attach a Sundry Notice – Form 4 (SFN 5749) detailing the proposed procedure.

16. Attach a diagram representing the traffic flow and the maximum number of trucks staged on-site.

17. Attach a printout of a map obtained at www.nd.gov/gis/apps/HubExplorer/ with surficial aquifers (under hydrography) active and the proposed location plotted on the printout.

18. Read Section 43-02-05-04 of the NDAC to ensure that this application is complete.

19. The original and two copies of this application and attachments shall be filed with the NDIC Oil and Gas Division, 600 East Boulevard, Department 405, Bismarck, ND 58505-0840.

OTHER PERMITS

In addition to the above, the EERC and Nuverra anticipate and plan to meet pending proposed rule changes to Section 43-02-03-29.1 Underground Gathering Pipelines and to Section 43-02-03-53 Saltwater Handling Facilities (SHF), allowing for the installation of flowlines, tanks, and a pipeline at the Johnsons Corner Site.

Nuverra will submit the North Dakota Water Commission (NDWC) Application for Source Water Appropriation for the extraction well and will renew the permit as required annually.

The EERC plans on constructing a building to house the water treatment testing equipment. This will require a zoning permit, request for physical address, and a building permit. Nuverra will submit and receive the necessary permits from the McKenzie County Building & Planning Department to construct the building; the permit will cost approximately $2365. Nuverra will also apply for an electrical permit for the new construction through the state of North Dakota.

In addition, Nuverra will also acquire a permit for an office/laboratory skid at approximately $1.50 per sq. ft per year, a permit for an injection plant skid at approximately $250, and a septic permit (approximately $200) from the Upper Missouri District Health (UMDH) for a 1200-gallon tank with a chamber-style drain field (actual specifications will be determined by UMDH).

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http://county.mckenziecounty.net/usrfiles/Building_permit_fee_schedule.pdf
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APPENDIX D

DRILLING AND COMPLETION, INSTRUMENTATION, INFRASTRUCTURE, PLANS, SPECIFICATIONS, AND IMPLEMENTATION

DRILLING AND COMPLETION, INSTRUMENTATION, INFRASTRUCTURE, PLANS, SPECIFICATIONS, AND IMPLEMENTATION

D.1 DRILLING AND COMPLETION BEST-I1

D.1.1 EERC DRILLING PLAN

Developed drilling procedure for the BEST-I1 well based on industry standard procedures. Plan details geologic marker tops, well evaluation program, pressure control equipment, borehole size, casing programs, mud programs, and additional procedures for the proposed well.

BEST-I1
Location: NE ¼ NW ¼ Sec. 21 T. 150N R 96W
Elevation: 2332' GL, 2352' KB
McKenzie County, North Dakota

Estimated Tops of Important Geologic Markers

Estimated depth and thickness of formations, members, or zones potentially containing usable water, oil, gas or other valuable deposits. All prospectively valuable deposits will be within 9 5/8" casing or 7" production casing that will be cemented and be stored in tanks on location.

Marker	Depth, ft (MD*)	Datum, SS**	Resources
Greenhorn	4354	−2002	
Mowry	4805	−2453	
Skull Creek	4920	−2568	Water
Dakota (Inyan Kara)	5146	−2794	Water
Swift	5550	−3198	
Rierdon	6057	−3705	
Spearfish	6600	−4248	Oil
Top of Pine Salt	6807	−4455	
Base of Pine Salt	6856	−4504	
Minnekata	7040	−4688	
Opeche	7083	−4731	
Top of Opeche Salt	7123	−4771	Salt
Base of Opeche Salt	7193	−4841	
Broom Creek	7470	−5118	
Amsden	7535	−5183	
Tyler	7871	−5519	Oil/nitrogen
TD (total depth)	7971	−5619	

* Measured depth.
** Subsea.

Evaluation Program

Mudlogging: A mud log will be run from 1850 ft to TD. The mudlog will include total gas chromatograph and sample cuttings – 30-ft sample intervals in the vertical hole.

Logging: Openhole logging will be conducted by Schlumberger (SLB) upon completion of drilling. A borehole-compensated (BHC) sonic and triple combo will be run from TD to surface. Spectroscopy/spectral GR (gamma ray) from TD to Inyan Kara top and an injection profile log will be captured over the Broom Creek Formation. A cement bond log (CBL) will be run as required by North Dakota Administrative Code (NDAC) Section 43-02-03-31 to determine the cement has set over the casing.

Cores: Cored intervals are 5301–5391 ft Inyan Kara, 7460–7520 ft Broom Creek.

Pressure Control Equipment

A. Type: 11-inch double-gate hydraulic BOP (blowout preventer) with 11-inch annular preventer with 5000-psi casing head.

B. Testing Procedure

The annular preventer will be pressure-tested to 50% of stack-rated working pressure for 10 minutes or until provisions of the test are met, whichever is longer. The BOP, choke manifold, and related equipment will be pressure-tested to approved BOP stack working pressure (if isolated from surface casing by a test plug) or to 70% of surface casing internal yield strength (if BOP is not isolated by a test plug). Pressure will be maintained for 10 minutes or until the requirements of the test are met, whichever is longer. At a minimum, the annular and BOP pressure tests will be performed:

1. When the BOPE (BOP equipment) is initially installed.
2. Whenever any seal subject to test pressure is broken.
3. Following related repairs.
4. At 30-day intervals.

Annular will be function-tested weekly, and pipe and blind rams will be activated each trip. All BOP drills and tests will be recorded in the International Association of Drilling Contractors (IADC) driller’s log.

C. Choke Manifold Equipment

All choke lines will be straight lines unless turns use tee blocks or are targeted with running tees and will be anchored to prevent whip and reduce vibration.

D. Accumulator

The fluid reservoir capacity will be double accumulator capacity, and the fluid level will be maintained at manufacturer recommendations. An accumulator precharge pressure test will be conducted prior to connecting the closing unit to the BOP stack.

D.1.2 DRILLING PROGRAM

Surface Casing **Surface to 1850'**

Conductor: 16" set at 80'
Hole Size: 12¼"
Mud: Freshwater, mud weight 9.0 ppg (pounds per gallon)
Bits: Tricone, conventional assembly
Procedure: Set 16" conductor pipe to 80'
Drill to casing setting depth, 100' below Fox Hills Formation (per state requirements)

Run casing with float shoe and collar and cement, weld on 5000M casing head. Install 11" × 5000M drill stem adapter. Nipple up (NU) 5000M BOPE. Test to 5000 psi for 15 minutes, American Petroleum Institute (API) 16C

Casing: 9-5/8" 40# J-55 LTC (long thread casing) – new Set at 1850 ft

Size	Weight	Grade	Conn	Collapse psi	Burst psi	ID	Drift	Joint Strength, 1000 lb	Body Yield, 1000 lb
9-5/8"	40 lb/ft	J-55	LTC	2750	3950	8.835"	8.679"	520	630

Csg (casing) Torque (Tq): 9-5/8" Tq (ft-lb) Optimum 5200 Min. 3900 Max. 6500
Centralizers: TBD (to be determined) in field
Cement: Lead Slurry: 300 sacks (sk), reciprocating pipe slowly while cementing
Class G cement with 2% D-53 thixotrophy agent, 4% D-79 extender, 0.25#/sk D-130 flake lost circulation additive and 2% $CaCl_2$ accelerator. Mix weight 11.8 ppg, yield 2.64 cu ft/sk, water 15.88 gallon/sk
Tail slurry: 172 sk
Class G with ¼ #/sk D-130 flake and 1% $CaCl_2$ accelerator.
Run 20 bbl freshwater ahead.
Note: volumes calculated assuming 75% excess over 12¼" hole size
Monitor returns, and note cement volume to surface. Catch cement samples and mix water. If cement is not at surface after the job, state (and federal if applicable) authorities must be notified for "top job." Cement must achieve 500 psi compressive prior to drill out. Min. WOC (wait on cement) is 24 hours (WOC time includes all time not drilling).

Surface Casing to Core Point 1 1850' to 5301'

Hole Size:	8 3/4"
Mud:	Saltwater gel
Bits:	Polycrystalline diamond compact (PDC), 1.5 degree mud motor assembly
Procedure:	Before drilling: test casing for 5 min to 500 psi Drill up to 20' of new hole, perform 11.5 ppg or field-calculated ppg needed for estimated mud weight (EMW) formation integrity test (FIT) for 15 min Drill to Core Point 1 Condition hole. Trip out of hole (TOOH).

Core 1 Inyan Kara 5301' to 5391'

Hole Size:	8"
Mud:	Saltwater gel
Bits:	Core head and 90' core barrel assembly
Procedure:	Drill core TOOH.

End of Core 1 to Core Point 2 5391' to 7460'

Hole Size:	8-3/4"
Mud:	Saltwater gel
Bits:	PDC, 1.5 degree mud motor assembly
Procedure:	Ream cored interval Drill to Core Point 2 Condition hole. TOOH.

Core 2 Broom Creek 7460' to 7520'

Hole Size:	8"
Mud:	Saltwater gel
Bits:	Core head and 60' core barrel assembly
Procedure:	Drill core TOOH.

End of Core 2 to TD 7520' to 7971'

Hole Size:	8-3/4"
Mud:	Saltwater gel
Bits:	PDC, 1.5 degree mud motor assembly
Procedure:	Ream cored interval Drill to TD of 7971' Condition hole. TOOH. Wireline log and test well. Condition mud for cement. Run casing, stage tool set at 4990', and cement.

Casing: 7" 26# L-80 LTC – New Set at: 7971 ft

Size	**Weight**	**Grade**	**Conn.**	**Collapse psi**	**Burst psi**	**ID**	**Drift**	**Joint Strength, 1000 lb**	**Body Yield, 1000 lb**
7”	26 lb/ft	L-80	LTC	5410	7240	6.276”	6.151”	511	604

Csg Torque: 7” Tq (ft-lb) Optimum 5110 Min. 3833 Max. 6387
Centralizers: TBD in field
Cement: Stage 1, reciprocating pipe slowly while cementing
Lead Slurry: 172 sk
Class G with 1% D-13 retarder, 0.2% D-46 antifoam, 1.3% D-79 extender, 0.07% D-208 viscosifier, 0.3% D238 fluid loss additive, 3% BWOW (by weight of water) M117 KCl. Mix weight: 11.50 ppg, yield 2.16 cu ft/sk, mix water 12.79 gal/sk
Tail slurry: 99 sk
Class G with 0.2% D 46 antifoam, 0.2% D65 dispersant, 0.3% D153 antisettling agent, 0.3% D-167 fluid loss additive, 0.5% D800 retarder mix wt 15.8 ppg, yield 1.16 cu ft/sk and mix water 5.08 gal/sk. Drop bomb and open stage tool, circulate for 1 hour before pumping Stage 2.
Note: volumes calculated assuming 30% excess over 8¾” hole size
Stage 2
Lead slurry: 448 sk
Class G with 1% D-13 retarder, 0.2% D-46 antifoam, 1.3% D-79 extender, 0.07% D-208 viscosifier, 0.3% D238 fluid loss additive, 3% BWOW M117 KCl. Mix weight: 11.50 ppg, yield 2.16 cu ft/sk, mix water 12.79 gal/sk
Tail slurry: 34 sk
Class G with 0.2% D 46 antifoam, 0.2% D65 dispersant, 0.3% D153 antisettling agent, 0.3% D-167 fluid loss additive, 0.5% D800 retarder mix wt 15.8 ppg, yield 1.16 cu ft/sk and mix water 5.08 gal/sk
Note: volumes calculated assuming 30% excess over 8¾” hole size

Finalize Well Rig down cementers. Install 5000-psi night-cap. Rig down and move rig.

D.1.3 DRILLING TIME LINE

SLB estimates 20 days required for well drilling and construction, which is shown in Figure D-1.

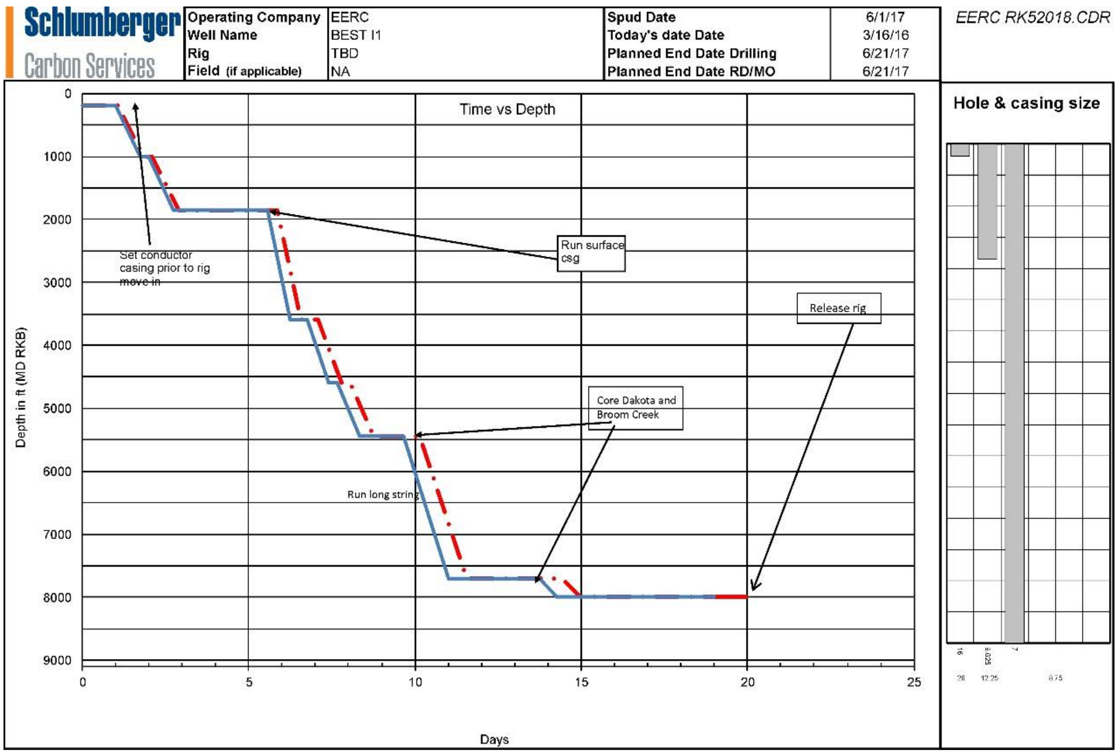


Figure D-1. Proposed time line for BEST-I1 well drilling provided by SLB.

D.1.4 WELL SCHEMATIC OF THE BEST-I1 DETAILING DEPTHS AND SPECIFICATIONS OF CASING, CEMENT, AND PERFORATIONS

Figure D-2 shows SLB's well schematic.

EERC RK51313.CDR

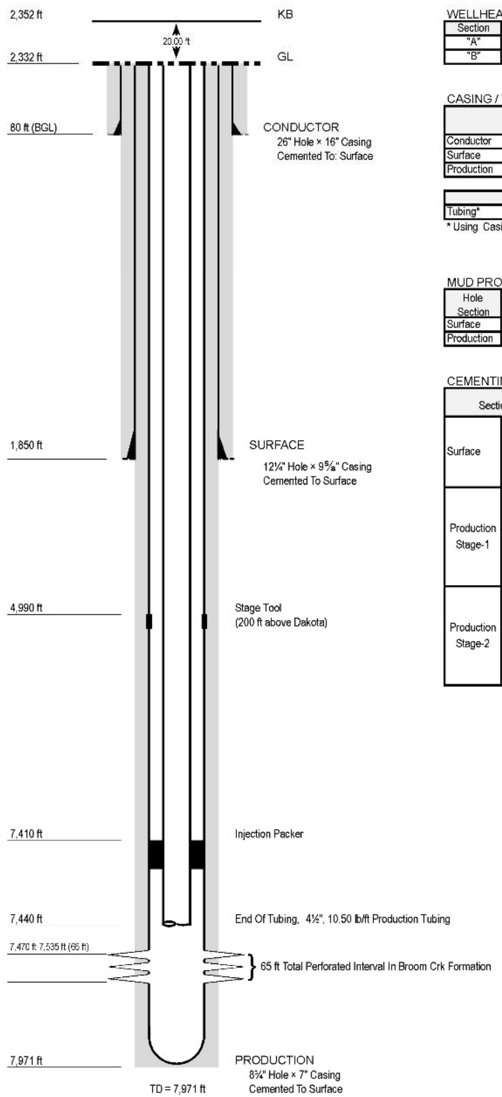
Schlumberger
Carbon Services

NTG
NEW TECH GLOBAL

ENERGY & ENVIRONMENTAL RESEARCH CENTER (EERC)
BRINE EXTRACTION INJECTION WELL: BEST - I1
PLANNED WELLBORE SCHEMATIC

Location: McKenzie Co., North Dakota
(Near Watford City)
Sec 21, Twn :150N Rng 96W

Date: 4/1/2016
Version: 5



WELLHEAD EQUIPMENT

Section	Item	Description
"A"	Casing Head	9⅝" SOW × 11" 5000 psi WP
"B"	Tunging Head	11" 5000 psi WP × 4½" 5000 psi WP

CASING / TUBING PROGRAM

	Hole Size	Casing								
		OD	Weight	Grade	Conn	ID	Drift	Collapse	Burst	Joint
Conductor	26"	16"	42.00 lb/ft	B&C	PE	15.500	-	-	-	-
Surface	12¼"	9⅝"	40.00 lb/ft	J-55	LT&C	8.835	8.679	2,570	3,950	520,000
Production	8¾"	7"	26.00 lb/ft	L-80	LT&C	6.276	6.151	5,410	7,240	511,000

	Size	Lined?	Weight	Grade	Conn	ID	Drift	Collapse	Burst	Joint
Tubing*	4½"	Lined	10.50 lb/ft	J-55	LT&C	4.052	3.927	4,010	4,790	146,000

* Using Casing As Tubing

MUD PROGRAM

Hole Section	Interval	Type	MW (lb/gal)	VIS (sec/qt)	PV (cP)	YP (lb/100 ft²)	WL (cc/30 min)	Cl (ppm)
Surface	80'-1,850'	Freshwater	8.6-9.0	30-35	n/a	n/a	NC	n/a
Production	1,850'-7,971'	SW Gel	10.2-10.4	40-46			6 - 8	150,000-170,000

CEMENTING PROGRAM

Section		Sacks	Density (ppg)	Yield (ft³/sx)	Excess (%)	Vol (bbl)	TOC (feet)	Recipe
Surface	Lead	300	11.8	2.65	75%	141.4	0'	Class "G" + 2.0% BWOB D053 + 4.0% BWOB D079 + 0.25 lb/sx WBWOB D130 + 2.0% BWOC S001
	Tail	172	15.8	1.16	75%	35.5	1,550'	Class "G" + 0.25 lb/sx WBWOB D130 + 1.0% BWOC S001
Production Stage-1	Lead	172	11.5	2.16	30%	66.1	5,500'	Class "G" + 1.0% BWOC D013 + 0.20% BWOB D046 + 1.3% BWOC D079 + 0.07% BWOB D208 + 0.30% BWOC D238 + 3.0% BWOW M117
	Tail	99	15.8	1.16	30%	20.5	7,400'	Class "G" + 0.2% BWOC D046 + 0.20% BWOC D065 + 0.30% BWOC D153 + 0.30% BWOC D167 + 0.50% BWOC D800
Production Stage-2	Lead	448	11.5	2.16	30%	172.3	0'	Class "G" + 1.0% BWOC D013 + 0.20% BWOB D046 + 1.3% BWOC D079 + 0.07% BWOB D208 + 0.30% BWOC D238 + 3.0% BWOW M117
	Tail	34	15.8	1.16	30%	7	5,300'	Class "G" + 0.2% BWOC D046 + 0.20% BWOC D065 + 0.30% BWOC D153 + 0.30% BWOC D167 + 0.50% BWOC D800

FORMATION TOPS

Formation	KB
Greenhorn	4,395 ft
Mowry	4,844 ft
Skull Creek	4,964 ft
Dakota (Inyan Kara)	5,190 ft
Swift	5,588 ft
Rierdon	5,688 ft
Spearfish	6,600 ft
Top of Pine Salt	6,807 ft
Base of Pine Salt	6,856 ft
Minnekata	7,040 ft
Opeche	7,083 ft
Top of Opeche Salt	7,123 ft
Base of Opeche Salt	7,193 ft
Broom Creek	7,470 ft
Amsden	7,535 ft
Tyler	7,871 ft
TD	7,971 ft

NOT TO SCALE

Figure D-2. Well schematic provided by SLB.

D.1.5 PROPOSED DRILLING PLAN FOR THE BEST-I1 WELL FROM SCHLUMBERGER

See Figures D-3 and D-4.

Schlumberger Carbon Services

EERC RK52011.CDR

NTG NEW TECH GLOBAL

ENERGY & ENVIRONMENTAL RESEARCH CENTER
BRINE EXTRACTION INJECTION WELL: BEST - I1
WELL PLAN

Date: 4/1/2016 Version No.: 05

Well Name: BRINE EXTRACTION INJECTION WELL: BEST - I1 API No.: AFE No.:

LOCATION

SURFACE Location: Section 21, Township 150N, Range 96W (5th P.M.) McKenzie County, North Dakota

BOTTOM HOLE Location: Section 21, Township 150N, Range 96W (5th P.M.) McKenzie County, North Dakota

DRILLING PROCEDURE

1. Move in and rig up rig.
   - Cellar pre-installed, Conductor pre-set at 80' below ground level, rat- and mouse-holes already drilled.
   - Be sure rig is level and is centered over the hole.
   - RU closed-loop system (no reserve pit, no cuttings pit).
   - Inform NDIC of rig mobilization.
   - Inform NDIC of spud within 24 hrs. of spudding.
2. MU Surface Hole BHA.
3. RIH and drillout Conductor Shoe.
4. Drill 12¼" Surface Hole To 1,850' with Freshwater Gell mud.

General Frewshwater Mud Properties

Interval		Mud Wt	Funn'l Vis	Fluid Loss	Chlorides
From	To	(lb/gal)	(sec/qt)	(ml/30min)	(mg/L)
80'	1,850'	8.6 - 9.0	30 - 35	NC	Freshwater

5. Circulate hole clean (use viscous sweeps as necessary), short trip, circulate and condition mud for cementing. POH.
6. RU to run Surface Casing.
7. Run 9⅝", 40#, J55, LTC casing to 1,850'.

Casing Properties

Size	Weight	Grade	Connection	ID	Drift	Collapse	Burst	Jt Strngth	Body Yield
9⅝"	40.00 lb/ft	J55	LTC	8.835"	8.679"	2,570 psi	3,950 psi	520 kips	630 kips

8. RU Cementers and cement Surface Casing to surface.
   - Displace with 9.0 ppg Mud.
   - Use Top Plug only.
   - Bump plug with 500 psi over final displace ment pressure.
   - Hold Bump Pressure for 3 - 5 minutes & release.

Cement Properties

	Sacks	Density	Yield	Excess	Vol	TOC	Slurry Recipe
Lead	300 sx	11.8 ppg	3 ft³/sx	75%	141 bbl	Surface	Class "G" + 2.0% BWOB D053 + 4.0% BWOB D079 + 0.25 lb/sx WBWOB D130 + 2.0% BWOC S001
Tail	172 sx	15.8 ppg	1 ft³/sx	75%	36 bbl	1,550'	Class "G" + 0.25 lb/sx WBWOB D130 + 1.0% BWOC S001

9. RD Cementers.
10. WOC
11. Install a 9⅝" SOW × 11", 5000 psi WP Slip On Weld Casing Head
12. NU and test BOP.
13. MU Production Hole BHA
14. RIH. Change mud system over to Saltwtater Gel.
15. Drill out Surface shoetrack and shoe.
16. Drill 8¾" Production Hole with Saltwtater Gel to Core Point No. 1: 5,301'.

General Saltwtater Gel Properties

Interval		Mud Wt	Funn'l Vis	Fluid Loss	Chlorides
From	To	(lb/gal)	(sec/qt)	(ml/30min)	(mg/L)
1,850'	7,971'	10.2 - 10.4	40 - 46	6 - 8	150,000 - 170,000

17. Circulate and condition mud for coring.
18. POH. LD BHA. PU 8" × 5¼" Core head and 90' core barrel.
19. RIH and cut Core No. 1: 5,301' - 5,391' (90') in the Dakota.

Figure D-3. SLB-provided drilling procedure (page 1).

Schlumberger Carbon Services

EERC RK52012.CDR

ENERGY & ENVIRONMENTAL RESEARCH CENTER

BRINE EXTRACTION INJECTION WELL: BEST - I1

WELL PLAN

Date: 4/1/2016 Version No.: 05

Well Name: BRINE EXTRACTION INJECTION WELL: BEST - I1 API No.: AFE No.:

20. POH with Core No. 1 and lay down same.
21. PU 8¾" bit and BHA.
22. RIH and ream cored interval.
23. Continue drilling to Core Point No. 2: 7,470'.
24. Circulate and condition mud for coring.
25. POH. LD BHA. PU 8" × 5¼" Core head and 90' core barrel.
26. RIH and cut Core No. 2: 7,470' - 7,535' (65') in the Broom Creek.
27. POH with Core No. 2 and lay down same.
28. PU 8¾" bit and BHA.
29. RIH and ream cored interval.
30. Continue drilling to Total Depth: 7,971'.
31. Circulate hole clean (use viscous sweeps as necessary), short trip, circulate and condition mud for logging. POH. LD BHA.
32. RU Logging Company and log Production Hole. Run CBL through Surface Casing.
33. RD Logging Company.
34. Make a wiper trip to TD. Circulate hole clean (use viscous sweeps as necessary), short trip, circulate and condition mud for cementing.
35. POH laying down drill string.
36. RU to run Production Casing.
37. Run 7", 26#, L80, LTC casing to 7,971'.
    - Run Stage Tool at: 4,990'

Casing Properties

Size	Weight	Grade	Connection	ID	Drift	Collapse	Burst	Jt Strngth	Body Yield
7"	26.00 lb/ft	L80	LTC	6.276"	6.151"	5,410 psi	7,240 psi	511 kips	604 kips

45. RU Cementers and cement Production Casing.
    - Stage 1

Stage-1	Sacks	Density	Yield	Excess	Vol	TOC	Column	Slurry Recipe
Lead	172 sx	11.5 ppg	2.65 ft³/sx	30%	66 bbl	5,500'	1,900'	Class "G" + 1.0% BWOC D013 + 0.20% BWOB D046 + 1.3% BWOC D079 + 0.07% BWOB D208 + 0.30% BWOC D238 + 3.0% BWOW M117
Tail	99 sx	15.8 ppg	1.16 ft³/sx	30%	21 bbl	7,400'	571'	Class "G" + 0.2% BWOC D046 + 0.20% BWOC D065 + 0.30% BWOC D153 + 0.30% BWOC D167 + 0.50% BWOC D800

46. Finish Stage 1 and drop bomb to open Stage Tool.
47. Circulate 1 hr. through open Stage Tool, and pump Stage 2.
    - Stage 2

Stage-1	Sacks	Density	Yield	Excess	Vol	TOC	Column	Slurry Recipe
Lead	448 sx	11.5 ppg	2.65 ft³/sx	30%	172 bbl	0'	5,300'	Class "G" + 1.0% BWOC D013 + 0.20% BWOB D046 + 1.3% BWOC D079 + 0.07% BWOB D208 + 0.30% BWOC D238 + 3.0% BWOW M117
Tail	34 sx	15.8 ppg	1.16 ft³/sx	30%	7 bbl	5,300'	200'	Class "G" + 0.2% BWOC D046 + 0.20% BWOC D065 + 0.30% BWOC D153 + 0.30% BWOC D167 + 0.50% BWOC D800

- Displace with ±9.0 ppg Brine.
- Use Top Plug only.
- Bump plug with 500 psi over final displace ment pressure.
- Hold Bump Pressure for 3 - 5 minutes & release.

48. RD Cementers.
49. ND BOPs.
50. Install night-cap (11", 5000 psi WP × 4½", 5000 psi WP Tubing Head) will be installed during completion operations.
51. Clean pits, RD and Move out rig.

Figure D-4. SLB-provided drilling procedure (page 2).

D.1.6 EERC COMPLETION PROCEDURE

The BEST-I1 completion procedure developed by the Energy & Environmental Research Center (EERC) describes the operations and equipment required to safely and efficiently complete the proposed well.

BEST-I1 WELL
PROPOSED COMPLETION PROCEDURE

Before rig up:

- Notify the North Dakota Industrial Commission (NDIC) as required.
- Work road, location, and pit as needed for safe operation; install rig anchors; and test to 20,000 lb (or as required).
- Confirm actual casing depths with engineer, and inspect casing heads/valves.
- Confirm hole is loaded with fluid.

1. Move in and rig up (MIRU) workover rig. Install BOPs, and test low/high 250 psi/4500 psi. Move in rental tools: 2-7/8” 6.5 lb/ft L-80 work string and 4½” IPC tubing.
2. Run in hole (RIH) with 6-1/8” bit, four drill collars and 2-7/8” L-80 work string. Drill out DV (differential valve) tool and continue to clean out production casing to plug back total depth (PBTD), circulate hole clean with clean produced saltwater. TOOH.
3. RIH with 6-1/8” bit, scraper, four drill collars and 2-7/8” work string. Clean hole to PBTD and circulate hole with clean produced saltwater. Pressure-test production casing to ±2000 psi.
   a. If casing fails pressure test, contact primary EERC engineer for further instructions.
   b. Implement solutions.
   c. Continue completion after successful production casing test.
4. TOOH with tubing, lay down bit, scraper, collars, and tubing.
5. MIRU SLB Wireline Services. Install lubricator and RIH with CBL-CCL (casing collar locator)-GR and log from PBTD to 300’ above TOC (top of cement, anticipated at surface). Review CBL with EERC engineer. If necessary, apply 1000 psi pressure to production casing and repeat.
6. Make up perforating guns, loaded 4 spf (shots per foot), 90° phasing with charges providing a 0.46” exit hole and ±28” penetration. Perforate well depths as directed by geologist and engineer using lubricator, noting casing reaction after each firing. RDMO (rig down and move out) SLB Wireline.
7. RU (rig up) to establish pump in injection rate down production casing. Establish injection rate at 0.5, 1.0, 1.5, 2.0, 3.0, and 5.0 bpm (barrels per minute), and allow each to stabilize for 10 minutes prior to increasing to the next target injection rate. Shut down injection and record ISIP (initial shut-in pressure) and fall-off pressure with real time data. The injection procedure is subject to change based on the judgment of on-site engineer.
   - Evaluate data to develop a procedure to isolate and break down individual zones with 15% hydrochloric acid (with additives) to ensure proper communication with the reservoir. Overdisplace each treatment with 50+ bbl of lease water
8. Make up 7” × 3-1/2” AS1-X coated packer, 3-1/2” × 4-1/2” 13-Chrome cross-over, 1-joint of 4-1/2” IPC tubing, and 13-Chrome 4-1/2” × 3.81” ID X-Nipple. RIH with remainder of 4-1/2”

IPC tubing. Place packer ±50’–100’ above top perforation (avoid setting packer in casing collar). Space out tubing to land with ±30,000 lb compression on tubing.

9. RU and pump ±150 bbl corrosion-inhibited packer fluid down 4-1/2” tubing, and displace with ±105 bbl clean saltwater (placing packer fluid between the 4-1/2” tubing and 7” casing).
10. Set packer with 1/4 right-hand turn and place ±30,000 lb compression on packer.
11. Land tubing with tubing head, lock down, and secure.
12. Nipple down (ND) BOP and NU wellhead. See Section D.1.7 for BEST-I1 wellhead schematic.
13. Contact NDIC to witness MIT (mechanical integrity test) 24 hr prior to MIT test. MIT well to 1500 psi or as directed by NDIC, charting pressure test. NDIC must witness MIT in accordance with state regulations. Well is ready for injection upon MIT approval from NDIC.
14. Load out surplus equipment. RDMO workover rig, continuing to be careful of wellhead equipment.
15. Clear and clean location.

Well ready for installation of surface equipment to initiate injection.

D.1.7 PROPOSED COMPLETION PROCEDURE FOR THE BEST-I1 WELL FROM SLB

See Figures D-5 and D-6.

Schlumberger Carbon Services

EERC RK52013.CDR

NTG NEW TECH GLOBAL

ENERGY & ENVIRONMENTAL RESEARCH CENTER

BRINE EXTRACTION INJECTION WELL: BEST - I1

WELL PLAN

Date: 4/1/2016 Version No.: 05

Well Name: BRINE EXTRACTION INJECTION WELL: BEST - I1 API No.: AFE No.:

LOCATION

SURFACE Location: Section 21, Township 150N, Range 96W (5th P.M.) McKenzie County, North Dakota

BOTTOM HOLE Location: Section 21, Township 150N, Range 96W (5th P.M.) McKenzie County, North Dakota

COMPLETION PROCEDURE

1. Move in and rig up completion rig.
   - Include pump and pit.
   - Inform NDIC within 24 hrs. of moving in completion rig.
2. Check for pressure on well.
3. Remove night-cap.
4. Install 11", 5000 psi WP × 4½", 5000 psi WP Tubing Head
5. NU and test BOPs.
5. PU 6⅛"bit and casing scraper on Work String.
6. RIH and tag up on PBTD.
7. Reverse circulate well clean with brine.
8. POH with work string and LD casing scraper and bit.
9. RU wireline unit and run CBL from PBTD to surface
10. Perforate well with casing guns as follows:

From	To	Interval	Density	Phasing	Hole	Penetration
7,470'	7,535'	65'	4 spf	90°	0.46"	28"

11. RD wireline unit.
12. PU treating packer with 4' - 6' pup-joint tail pipe.
   - Secure tandem memory gauges to tail pipe with cannon-clamps.
13. RIH with treating packer on work string.
14. Set treating packer at ±7,420' (approximately 50' above top perforation at 7,470').
   - Correlate with CBL so that packer is not set in a casing collar.
15. RU pump-truck(s) and lines. Test lines.
16. Start injecting 2% KCl water and determine fomation feeding rate.
   - Depending on results, a ball-out may be used to open formation.
   - An acid job may be performed if necessary.
17. Start Step-Rate Test
   a. Start injecting 2% KCl water and determine fomation feeding rate.
   b. Inject at constant rate for 30 - 45 minutes until pressure is somewhat stable.
   c. Increase injection rate in 0.5 bbl/min increments until formation parting pressure is observed.
   d. Continue for two more stages to confirm fracturing is occurring.
   e. Shut down and record ISIP.
   f. Allow pressure to fall off for and additional 30 minutes to observe formation fracture closure.
18. Release packer, reverse well clean, POH.
19. LD packer and guages.
20. RIH with OE work string to ±7,450'.
21. Perform acid clean up of perforations. (May not be necessary)
   - Pump ±3,500 gallons of acid
   - Use ball-sealers to divert acid.
   - Over displace acid.
   - Specific perflush and acid receipes, rates, etc. to be determined.
22. POH with work string.

Figure D-5. SLB-provided completion procedure (page 1).

EERC RK52014.CDR

Schlumberger Carbon Services

ENERGY & ENVIRONMENTAL RESEARCH CENTER

BRINE EXTRACTION INJECTION WELL: BEST - I1

WELL PLAN

Date:	4/1/2016			Version No.:	05
Well Name:	BRINE EXTRACTION INJECTION WELL: BEST - I1	API No.:		AFE No.:	

23. Rig up to run production tubing and Packer.
24. PU Packer and Tail Assembly.
25. Run Packer on 4½", 10.50#, J-55, LT&C, Lined Production String.
26. Run Packer to 7,410' (60' above top perforation at 7,470').
27. Set Packer At 7,410' and land tubing in tubing head with EOT at 7,440'
28. Install BPV at surface or RU slickline and install BPV downhole.
29. ND BOPs.
30. NU tree.
31. Recover BPV.
32. RD Completion Rig.

NOTE: A longer term Step Rate test may be performed based on results above.

Figure D-6. SLB-provided completion procedure (page 2).

D.1.8 WELLHEAD SCHEMATIC OF THE BEST-I1 WITH NECESSARY PRESSURE CONTROL EQUIPMENT FOR SALTWATER INJECTION

See Figure D-7.

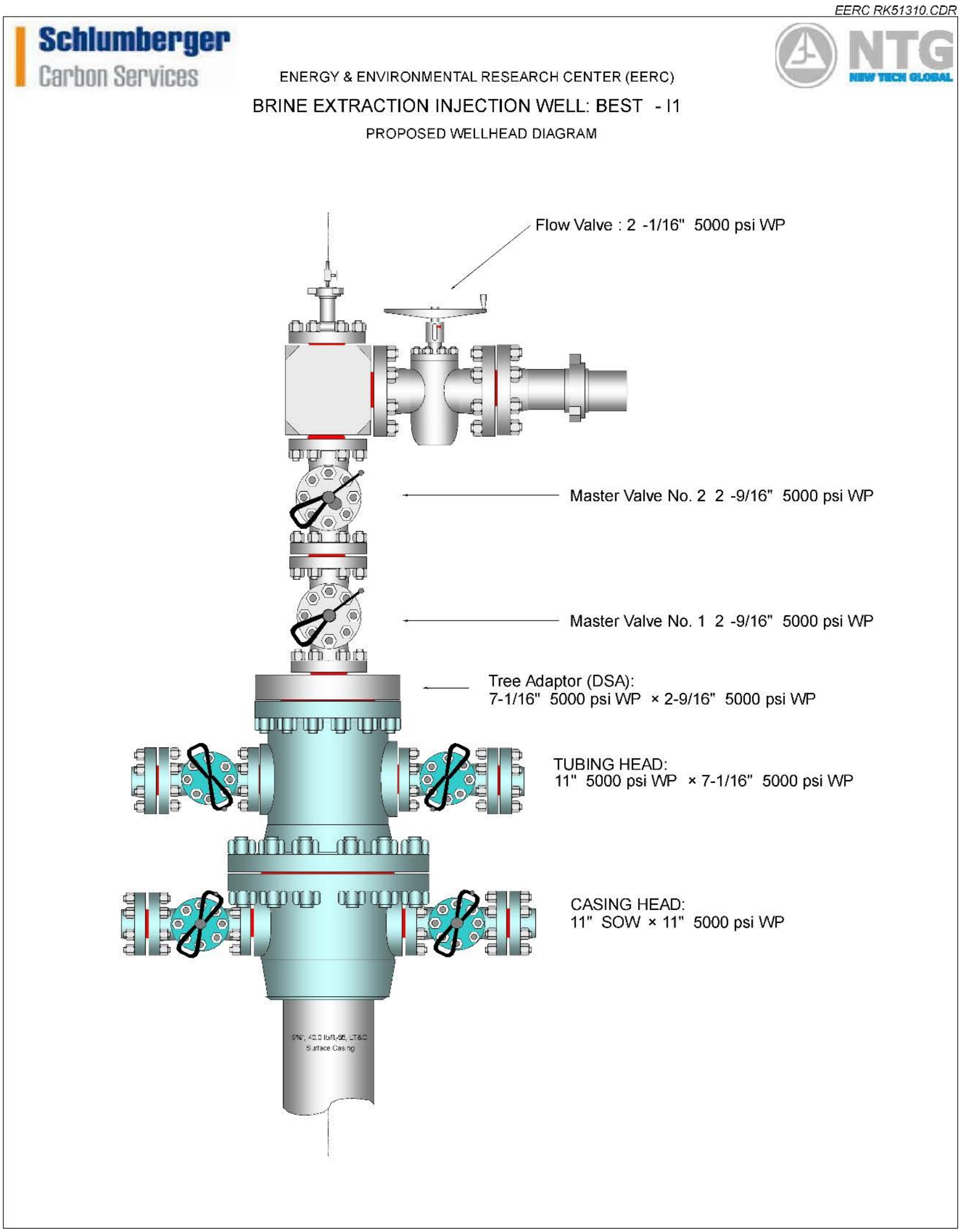


Figure D-7. BEST-I1 wellhead schematic with necessary pressure control equipment for saltwater injection provided by SLB.

D.1.9 SURFACE INFRASTRUCTURE ILLUSTRATIONS FOR BEST-I1

See Figures D-8 through D-11.

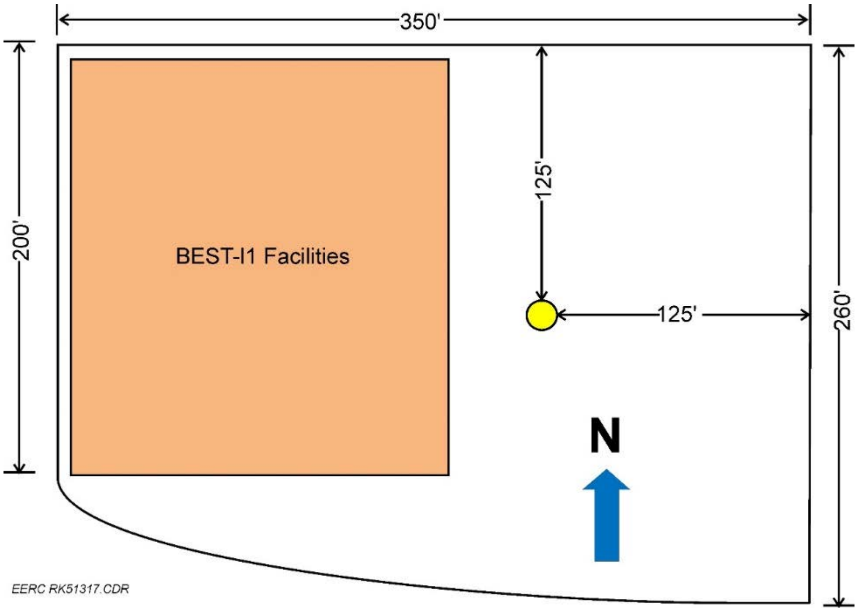


Figure D-8. Placement of facilities in relation to BEST-I1 injection well.

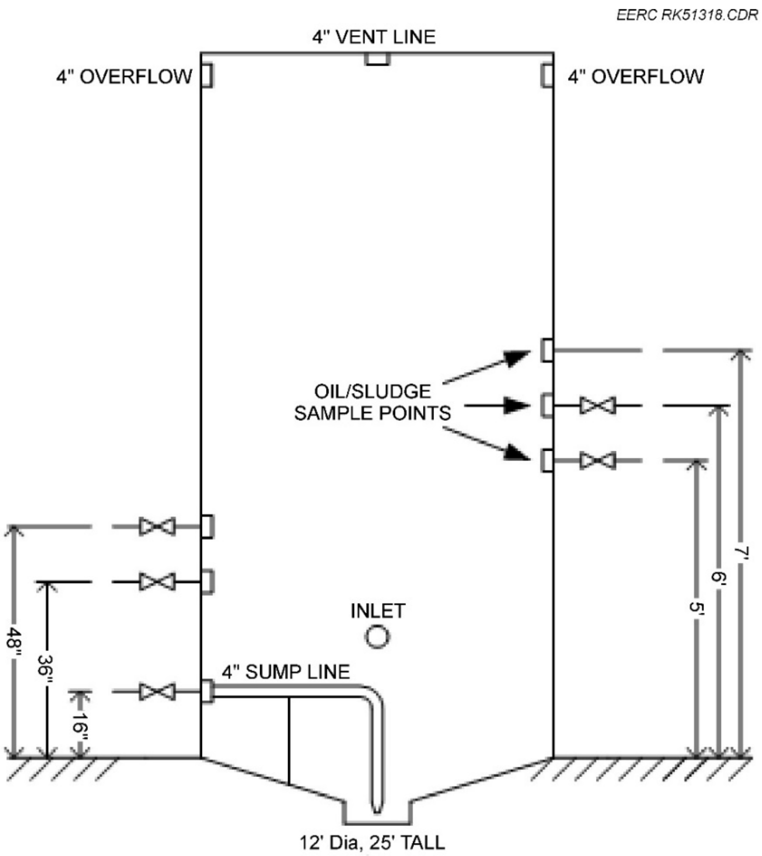


Figure D-9. Individual 500-bbl fiberglass tank schematic.

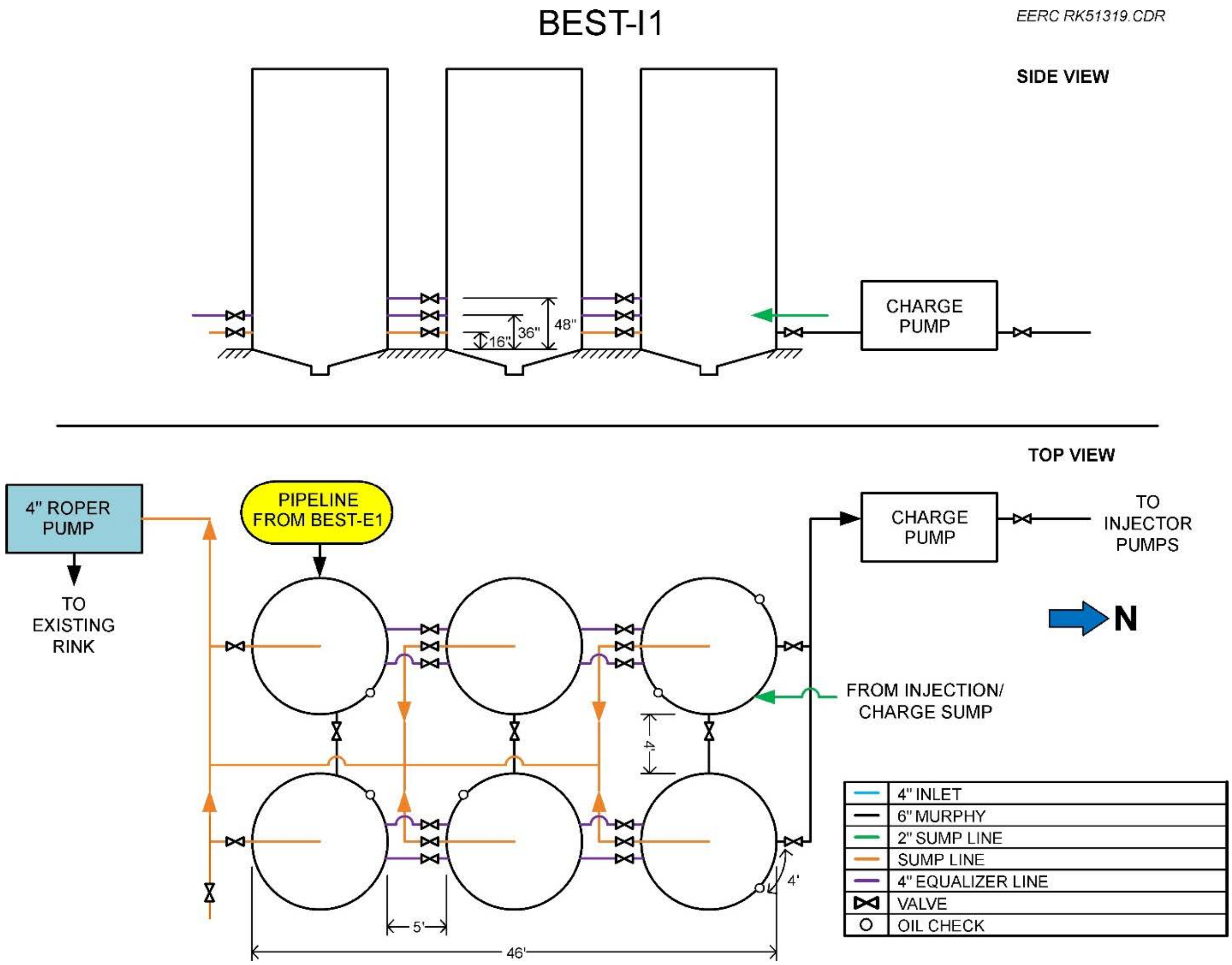


Figure D-10. BEST-I1 tank farm schematic.

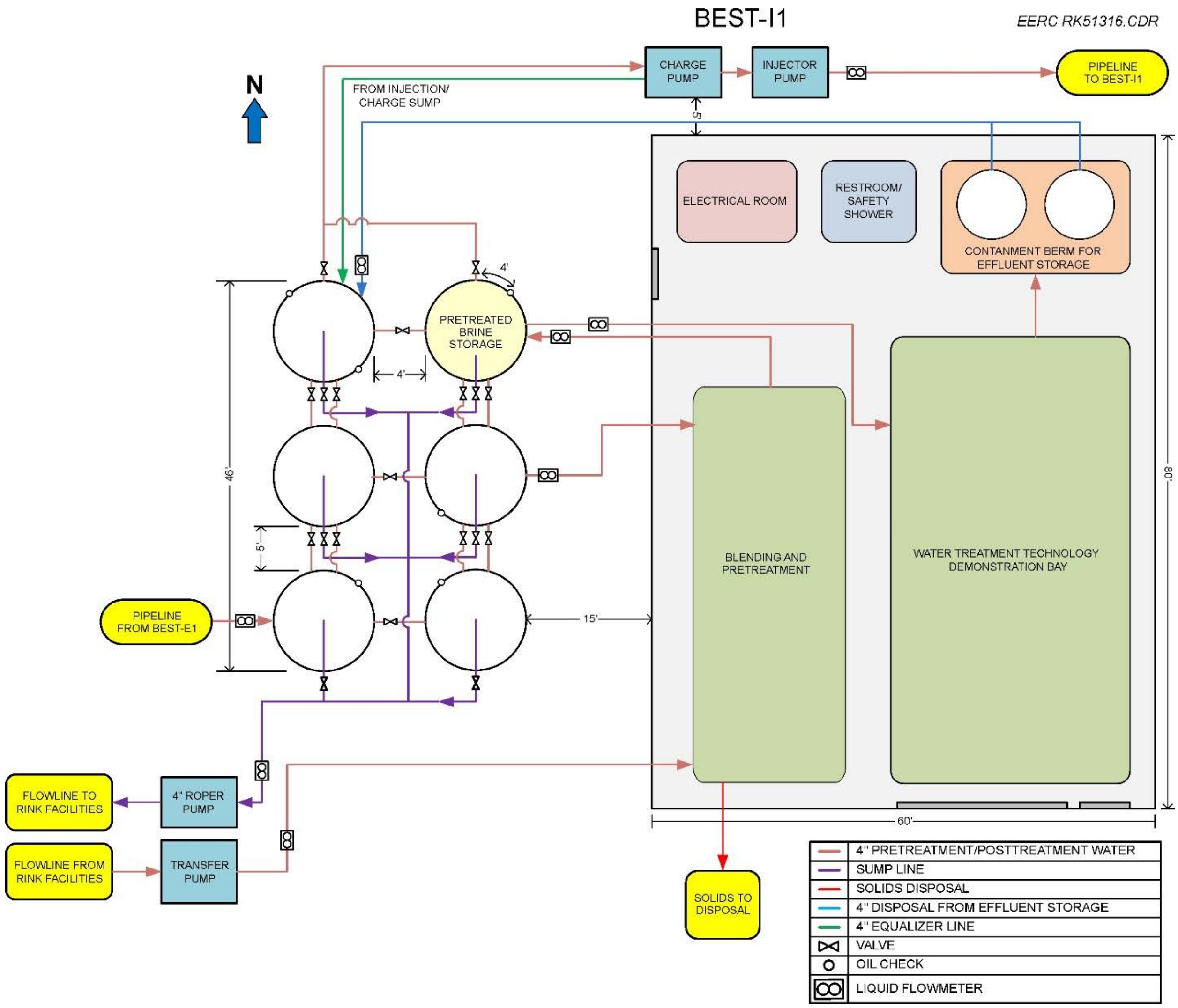


Figure D-11. Flow path of fluids on BEST-I1 site.

D.2 DRILLING AND COMPLETION BEST-E1

D.2.1 EERC DRILLING PLAN

Developed drilling procedure for the BEST-E1 well based on industry standard procedures. Plan details geologic marker tops, well evaluation program, pressure control equipment, borehole size, casing programs, mud programs, and additional procedures for the proposed well.

BEST-E1
Location: SE ¼ NW ¼ Sec. 21 T. 150N R 96W
Elevation: 2370’ GL, 2390’ KB
McKenzie County, North Dakota

Estimated Tops of Important Geologic Markers

Estimated depth and thickness of formations, members, or zones potentially containing usable water, oil, gas, or other valuable deposits. All prospectively valuable deposits will be within 9-5/8” casing or 7” production casing that will be cemented and stored in tanks on location.

Marker	Depth (MD)	Datum (SS)	Resources
Greenhorn	4395	−2005	
Mowry	4844	−2454	
Skull Creek	4964	−2574	Water
Dakota (Inyan Kara)	5190	−2800	Water
Swift	5588	−3198	
TD	5688	−3298	

Evaluation Program

Mudlogging: A mud log will be run from 1850’ to TD. Mudlog will include total gas chromatograph and sample cuttings – 30’ sample intervals in the vertical hole.

Logging: Openhole logging will be conducted by SLB upon completion of drilling. A triple combo will be run from TD to surface. Reservoir temperature log will be run over Inyan Kara. A CBL will be run as required by NDAC Section 43-02-03-31 to determine the cement has set over the casing.

DST (drillstem test): No DSTs are currently planned.

Cores: No cores are currently planned.

Pressure Control Equipment

A. Type: 11-inch double-gate hydraulic BOP with 11-inch annular preventer with 5000-psi casing head.

B. Testing Procedure
The annular preventer will be pressure-tested to 50% of stack-rated working pressure for 10 minutes or until provisions of test are met, whichever is longer. The BOP, choke manifold, and related equipment will be pressure-tested to approved BOP stack working pressure (if isolated from surface casing by a test plug) or to 70% of surface casing internal yield strength (if BOP is not isolated by a test plug). Pressure will be maintained for 10 minutes or until the

requirements of the test are met, whichever is longer. At a minimum, the annular and BOP pressure tests will be performed:

1. When the BOPE is initially installed.
2. Whenever any seal subject to test pressure is broken.
3. Following related repairs.
4. At 30-day intervals.

Annular will be function-tested weekly, and pipe and blind rams will be activated each trip. All BOP drills and tests will be recorded in IADC driller's log.

C. Choke Manifold Equipment
All choke lines will be straight lines unless turns use tee blocks or are targeted with running tees and will be anchored to prevent whip and reduce vibration.

D. Accumulator
The fluid reservoir capacity will be double accumulator capacity, and the fluid level will be maintained at manufacturer recommendations. An accumulator precharge pressure test will be conducted prior to connecting the closing unit to the BOP stack.

D.2.2 DRILLING PROGRAM

Surface Casing **Surface to 1850'**

Conductor: 16" set at 80'
Hole Size: 12 ¼ "
Mud: Freshwater, mud weight 9.0 ppg
Bits: Tricone, conventional assembly
Procedure: Set 16" conductor pipe to 80'
Drill to casing setting depth, 100' below Fox Hills Formation (per state requirements)
Run casing with float shoe and collar and cement, weld on 5000M casing head. Install 11" x 5000M drillstem adapter. NU 5000M BOPE. Test to 5000 psi for 15 minutes, API 16C
Casing: 9-5/8" 40# J-55 LT&C – new Set at: 1850 ft

Size	Weight	Grade	Conn.	Collapse psi	Burst psi	ID	Drift	Joint Strength, 1000 lb	Body Yield, 1000 lb
9 5/8"	40 lb/ft	J-55	LTC	2750	3950	8.835"	8.679"	520	630

Csg Tq: 9-5/8" Tq (ft-lb) Optimum 5200 Min. 3900 Max. 6500
Centralizers: TBD in field
Cement: Lead Slurry: 300 sk, reciprocating pipe slowly while cementing
Class G cement with 2% D-53 thixotrophy agent, 4% D-79 extender, 0.25#/sk D-130 flake lost circulation additive and 2% $CaCl_2$ accelerator.
Mix weight 11.8 ppg, yield 2.64 cu ft/sk, water 15.88 gallon/sk

Tail slurry: 172 sk
Class G with ¼ #/sk D-130 flake and 1% $CaCl_2$ accelerator.
Run 20 bbl freshwater ahead.
Note: volumes calculated assuming 75% excess over12-1/4” hole size
Monitor returns, and note cement volume to surface. Catch cement samples and mix water. If cement is not at surface after the job, state (and federal if applicable) authorities must be notified for top job. Cement must achieve 500 psi compressive prior to drill out. Min WOC is 24 hours (WOC time includes all time not drilling).

Surface Casing to TD **1850’ to 5688’**

Hole Size: 8 3/4”
Mud: Saltwater gel
Bits: PDC, 1.5 degree mud motor assembly
Procedure: Before drilling: test casing for 5 min to 500 psi
Drill up to 20’ of new hole, perform 11.5 ppg or field-calculated ppg needed for EMW FIT for 15 min
Drill to TD of 5688’
Condition hole for logs. TOOH.
Wireline log well.
Condition mud for cement.
Run 350’ of casing with float shoe and collar, install PROMORE MORE^{C} system.
Finish running casing and cement.
Casing: 7” 26# L-80 LT&C – new Set at: 5688 ft

Size	Weight	Grade	Conn.	Collapse psi	Burst psi	ID	Drift	Joint Strength, 1000 lb	Body Yield, 1000 lb
7”	26 lb/ft	L-80	LTC	5410	7240	6.276”	6.151”	511	604

Csg Tq: 7” Tq (ft-lb) Optimum 5110 Min 3833 Max 6387
Centralizers: Cannon casing clamp centralizers on each joint collar
Cement: Lead slurry: 332 sk, reciprocating pipe slowly while cementing
Class G with 1% D-13 retarder, 0.2% D-46 antifoam, 1.3% D-79 extender, 0.07% D-208 viscosifier, 0.3% D238 fluid loss additive, 3% BWOW M117 KCl. mix weight: 11.50 ppg, yield 2.16 cu ft/sk, mix water 12.79 gal/sk.
Tail Slurry: 99 sk
Class G with 0.2% D 46 antifoam, 0.2% D65 dispersant, 0.3% D153 anti settling agent, 0.3% D-167 fluid loss additive, 0.5% D800 retarder, mix wt 15.8 ppg, yield 1.16 cu ft/sk, and mix water 5.08 gal/sk
Run 25 bbl mud push express spacer at 10.5 ppg ahead of cement.
Note: volumes calculated assuming 30% excess over 8 3/4” hole size.

Finalize Well RD cementers, install 5000 psi night-cap, RD, release, and move rig.

D.2.3 DRILLING TIME LINE

SLB estimates 12 days for well drilling and construction which is shown in Figure D-12.

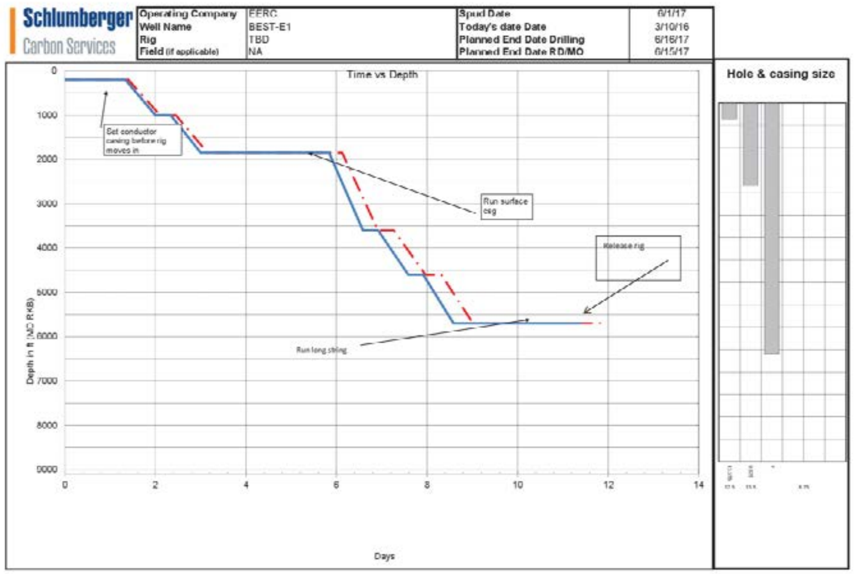


Figure D-12. Proposed time line for BEST-E1 well drilling provided by SLB.

D.2.4 WELL SCHEMATIC OF THE BEST-E1 DETAILING DEPTHS AND SPECIFICATIONS OF CASING, CEMENT, AND PERFORATIONS

See Figure D-13.

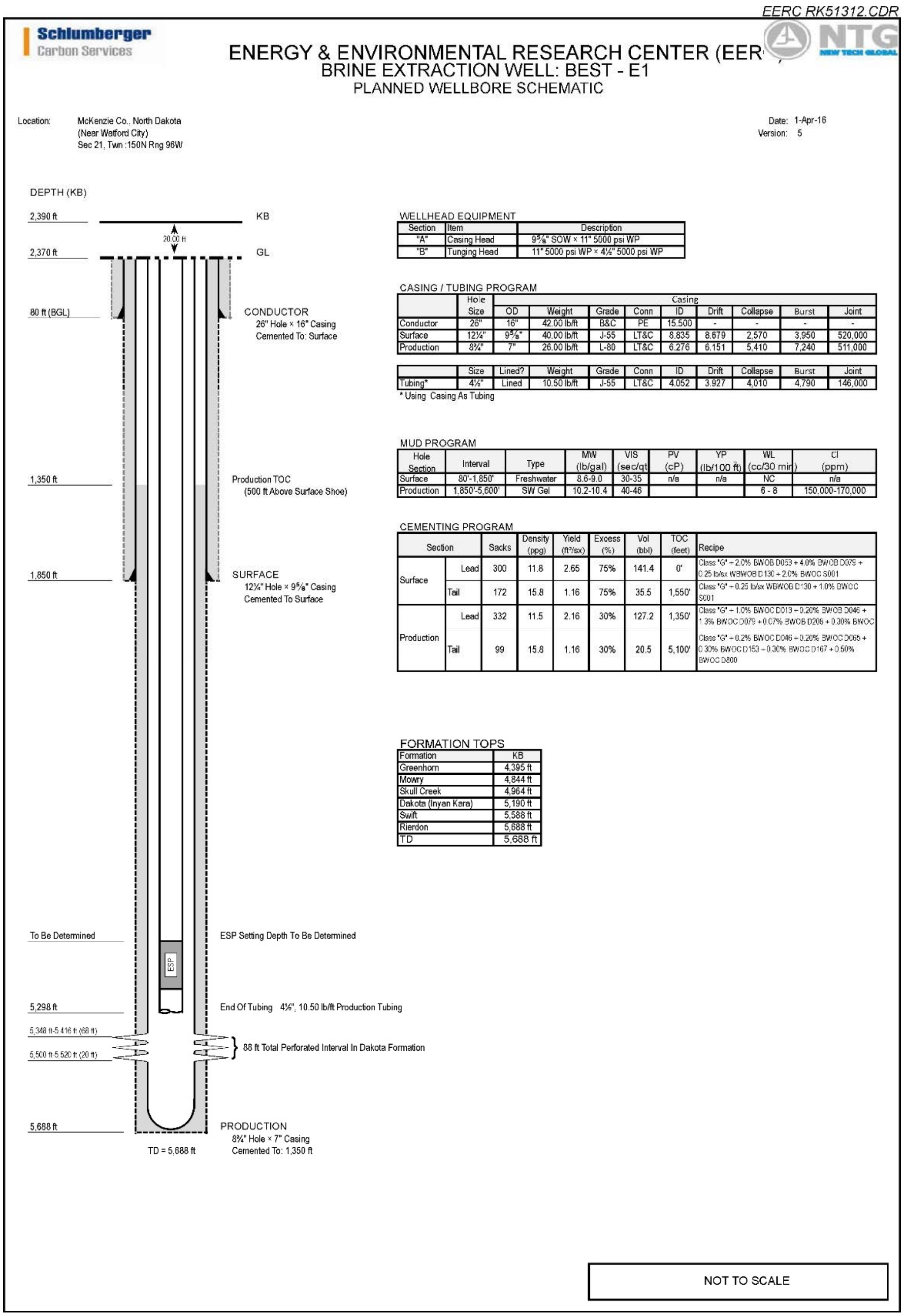


Figure D-13. Well schematic provided by SLB.

D.2.5 PROPOSED DRILLING PLAN FOR THE BEST-E1 WELL FROM SLB

See Figures D-14 and D-15.

Schlumberger Carbon Services

EERC RK52015.CDR

NTG NEW TECH GLOBAL

ENERGY & ENVIRONMENTAL RESEARCH CENTER

BRINE EXTRACTION WELL: BEST - E1

WELL PLAN

Date: 4/1/2016 Version No.: 05

Well Name: BRINE EXTRACTION WELL: BEST - E1 API No.: AFE No.:

LOCATION

SURFACE Location: Section 21, Township 150N, Range 96W (5th P.M.) McKenzie County, North Dakota

BOTTOM HOLE Location: Section 21, Township 150N, Range 96W (5th P.M.) McKenzie County, North Dakota

DRILLING PROCEDURE

1. Move in and rig up rig.
   - Cellar pre-installed, Conductor pre-set at 80' below ground level, rat- and mouse-holes already drilled.
   - Be sure rig is level and is centered over the hole.
   - RU closed-loop system (no reserve pit, no cuttings pit).
   - Inform NDIC of rig mobilization.
   - Inform NDIC of spud within 24 hrs. of spudding.
2. MU Surface Hole BHA.
3. RIH and drillout Conductor Shoe.
4. Drill 12¼" Surface Hole To 1,850' with Freshwater Gell mud.

General Frewshwater Mud Properties

Interval		Mud Wt	Funn'l Vis	Fluid Loss	Chlorides
From	To	(lb/gal)	(sec/qt)	(ml/30min)	(mg/L)
80'	1,850'	8.6 - 9.0	30 - 35	NC	Freshwater

5. Circulate hole clean (use viscous sweeps as necessary), short trip, circulate and condition mud for cementing. POH.
6. RU to run Surface Casing.
7. Run 9⅝", 40#, J55, LTC casing to 1,850'.

Casing Properties

Size	Weight	Grade	Connection	ID	Drift	Collapse	Burst	Jt Strngth	Body Yield
9⅝"	40.00 lb/ft	J55	LTC	8.835"	8.679"	2,570 psi	3,950 psi	520 kips	630 kips

8. RU Cementers and cement Surface Casing to surface.
   - Displace with ±9.0 ppg Mud.
   - Use Top Plug only.
   - Bump plug with 500 psi over final displace ment pressure.
   - Hold Bump Pressure for 3 - 5 minutes & release.

Cement Properties

	Sacks	Density	Yield	Excess	Vol	TOC	Slurry Recipe
Lead	300 sx	11.8 ppg	3 ft³/sx	75%	141 bbl	Surface	Class "G" + 2.0% BWOB D053 + 4.0% BWOB D079 + 0.25 lb/sx WBWOB D130 + 2.0% BWOC S001
Tail	172 sx	15.8 ppg	1 ft³/sx	75%	36 bbl	1,550'	Class "G" + 0.25 lb/sx WBWOB D130 + 1.0% BWOC S001

9. RD Cementers.
10. WOC
11. Install a 9⅝" SOW × 11", 5000 psi WP Slip On Weld Casing Head
12. NU and test BOP.
13. MU Production Hole BHA
14. RIH. Change mud system over to Saltwtater Gel.
15. Drill out Surface shoetrack and shoe.
16. Drill 8¾" Production Hole with Saltwtater Gel to 5,688'.

General Saltwtater Gel Properties

Interval		Mud Wt	Funn'l Vis	Fluid Loss	Chlorides
From	To	(lb/gal)	(sec/qt)	(ml/30min)	(mg/L)
1,850'	5,688'	10.2 - 10.4	40-46	42529.0	150,000 - 170,000

17. Circulate hole clean (use viscous sweeps as necessary), short trip, circulate and condition mud for logging. POH. LD BHA.
18. RU Logging Company and log Production Hole. Run CBL through Surface Casing.
19. RD Logging Company.

Figure D-14. Drilling procedure provided by SLB (page 1).

Schlumberger Carbon Services

ENERGY & ENVIRONMENTAL RESEARCH CENTER
BRINE EXTRACTION WELL: BEST - E1
WELL PLAN

EERC RK52016.CDR
NTG NEW TECH GLOBAL

Date: 4/1/2016 Version No.: 05
Well Name: BRINE EXTRACTION WELL: BEST - E1 API No.: AFE No.:

20. Make a wiper trip to TD. Circulate hole clean (use viscous sweeps as necessary), short trip, circulate and condition mud for cementing.
21. POH laying down drill string.
22. RU to run Production Casing.
23. Run 7", 26#, L80, LTC casing to 5,688'.

Casing Properties

Size	Weight	Grade	Connection	ID	Drift	Collapse	Burst	Jt Strngth	Body Yield
7"	26.00 lb/ft	L80	LTC	6.276"	6.151"	5,410 psi	7,240 psi	511 kips	604 kips

24. RU Cementers and cement Production Casing to 1,350'.
    - Displace with 8.4 ppg Freshwater.
    - Use Top Plug only.
    - Bump plug with 500 psi over final displace ment pressure.
    - Hold Bump Pressure for 3 - 5 minutes & release.

Cement Properties

	Sacks	Density	Yield	Excess	Vol	TOC	Slurry Recipe
Lead	332 sx	11.5 ppg	3 ft³/sx	30%	127 bbl	1,350'	Class "G" + 1.0% BWOC D013 + 0.20% BWOB D046 + 1.3% BWOC D079 + 0.07% BWOB D208 + 0.30% BWOC D238 + 3.0% BWOW M117
Tail	99 sx	15.8 ppg	1 ft³/sx	30%	21 bbl	5,100'	Class "G" + 0.2% BWOC D046 + 0.20% BWOC D065 + 0.30% BWOC D153 + 0.30% BWOC D167 + 0.50% BWOC D800

25. RD Cementers.
26. ND BOPs.
27. Install night-cap (11", 5000 psi WP × 4½", 5000 psi WP Tubing Head) will be installed during completion operations.
28. Clean pits, RD and Move out rig.

Figure D-15. Drilling procedure provided by SLB (page 2).

D.2.6 EERC COMPLETION PROCEDURE

The BEST-E1 completion procedure developed by the EERC describes the operations and equipment required to safely and efficiently complete the proposed well.

BEST-E1 WELL
PROPOSED COMPLETION PROCEDURE

Before RU:

- Notify NDIC as required.
- Work road, location and pit as needed for safe operation, install rig anchors, and test to 20,000 lb (or as required).
- Confirm actual casing depths with engineer and inspect casing heads/valves.
- Confirm hole is loaded with fluid.

1. MIRU workover rig. Install BOPs and test low/high 250 psi/4500 psi. Move in rental tools and 2-7/8” 6.5 lb/ft L-80 work string and 4½” IPC tubing.
2. RIH with 6-1/8” bit, scraper, four drill collars and 2-7/8” work string. Clean hole to PBTD and circulate hole with clean produced salt water. Pressure test production casing to ±2000 psi.
   a. If casing fails pressure test, contact primary EERC engineer for further instructions.

b. Implement solutions.

c. Continue completion after successful production casing test.

3. TOOH, laying down tubing, collars, scraper, and bit.
4. MIRU SLB Wireline Services. Install lubricator and RIH with CBL-CCL-GR and log from PBTD to 300’ above TOC (inside surface casing). Run GR to surface following NDIC requirements. Review CBL with EERC engineer. If necessary, apply 1000 psi pressure to production casing and repeat.
5. Make up perforating guns, loaded 4 spf, 90° phasing with charges providing a 0.46” exit hole and ±28” penetration. Perforate well depths as directed by geologist and engineer using lubricator, noting casing reaction after each firing. RDMO SLB Wireline.
6. If necessary and budget allows, RU to establish pump in injection rate down production casing. Establish injection rate at 0.5, 1.0, 1.5, 2.0, 3.0 and 5.0 bpm, and allow each to stabilize for 10 minutes prior to increasing to the next target injection rate. Shut down injection and record ISIP and fall-off pressure with real time data. The injection procedure is subject to change based on the judgment of the on-site engineer.
   - Evaluate data for stimulation. If well needs stimulation, a procedure will be designed to isolate and break down individual zones with 15% hydrochloric acid (with additives) to ensure proper communication with the reservoir. Overdisplace each treatment with 50+ bbl of lease water.
7. MIRU Summit ESP (electric submersible pump) with ESP motors, pumps, sensors, etc., and spooler with cable. Pick up ESP (keeping all parts dry until in the hole), and assemble as directed by Summit ESP running procedure (to be supplied onsite). Test sensor every 20 stands of tubing run or approximately every 1000’.
   - The well will be produced using a Summit ESP. The ESP intake will be placed at a depth of 5,298 feet, approximately 50 feet above top perforation. The production rate will be targeted at 4000 bbl/day with the ability to change this rate by approximately 40% variance (i.e., 2500 bbl/day to 6500 bbl/day). This flexibility will allow a noticeable difference to be observed in current injector wells Rink SWD 1 and Rink SWD 2. A 562 series motor will produce 360 HP and will include extended run life thrust bearings. The pumps, three total, will be 513 series with a total of 176 stages and will utilize the manufacturer’s premium seals. This will minimize risk of solids or formation fines damaging the motor and pumps. See Section D.3 for the design schematic for Summit ESP assembly. All downhole components feature external coating and internal trim for possible H_2S conditions. The electrical cable will also be of extra heavy construction for possible H_2S conditions. We will use Summit’s high-end quartz bottomhole pressure and temperature sensor, Model No. QESP-3500E. This gauge will allow highly accurate, real-time bottomhole pressure and temperature readings. See Section D.3 for Summit Quartz QESP-3500E specifications.
8. Once ESP is ready to RIH, continue running in hole with 4-1/2” IPC tubing, strapping ESP cable to tubing with two straps per joint to a sufficient depth to produce desired volume, setting depth initially designed to be within 50’ of top perforation. Test sensor every 20 stands of tubing run or approximately every 1000’.
9. Make tubing and cable feed-through connections to tubing head; confirm connections.
10. Land tubing with tubing head, lock down, and secure.
11. ND BOP and NU wellhead and test.
12. Make up final connections for ESP, and test to confirm it is operational.

13. Load out surplus equipment. RDMO workover rig, continuing to be careful of wellhead equipment.
14. Clear and clean location. Install and connect remaining Summit ESP surface equipment and flowline.

D.2.7 PROPOSED COMPLETION PROCEDURE FOR THE BEST-E1 WELL FROM SLB

See Figure D-16.

EERC RK52017.CDR

Schlumberger Carbon Services

ENERGY & ENVIRONMENTAL RESEARCH CENTER
BRINE EXTRACTION WELL: BEST - E1
WELL PLAN

NTG NEW TECH GLOBAL

Date: 4/1/2016 Version No.: 05

Well Name: BRINE EXTRACTION WELL: BEST - E1 API No.: AFE No.:

LOCATION

SURFACE Location: Section 21, Township 150N, Range 96W (5th P.M.) McKenzie County, North Dakota

BOTTOM HOLE Location: Section 21, Township 150N, Range 96W (5th P.M.) McKenzie County, North Dakota

COMPLETION PROCEDURE

1. Move in and rig up completion rig.
   - Include pump and pit.
   - Inform NDIC within 24 hrs. of moving in completion rig.
2. Check for pressure on well.
3. Remove night-cap.
4. Install 11", 5000 psi WP × 4½", 5000 psi WP Tubing Head
5. NU and test BOPs.
5. PU 6⅛ bit and casing scraper on a Work String.
6. RIH and tag up on PBTD.
7. Reverse circulate well clean with brine.
8. POH with work string and LD casing scraper and bit.
9. RU wireline unit and run CBL from PBTD to surface
10. Perforate well with casing guns as follows:

From	To	Interval	Density	Phasing	Hole	Depth
5,348'	5,416'	68'	4 spf	90°	0.46"	28"
5,500'	5,520'	20'	4 spf	90°	0.46"	28"

11. RD wireline unit.
12. RIH with open-ended work string.
13. Perform acid clean up of perforations.
   - Pump ±7.500 gallons of acid
   - Use ball-sealers to divert acid.
   - Over displace acid.
   - Specific perflush and acid receipes, rates, etc. to be determined.
14. POH with work string.
15. Rig up to run production tubing and ESP.
16. PU ESP and cable.
17. Run ESP and cable on 4½", 10.5#, J55, STC lined tubing, clamping cable on Production Tubing.
18. Run ESP to EOT @ 5,298' (50' above top perforation at 5,348').
19. Land tubing and secure ESP cable.
20. Install BPV at surface or RU slickline and install BPV downhole.
21. ND BOPs.
21. NU tree.
21. Recover BPV.
22. Test ESP.
22. RD Completion Rig.

Figure D-16. Completion procedure provided by SLB.

D.2.8 WELLHEAD SCHEMATIC OF THE BEST-E1 WITH NECESSARY PRESSURE CONTROL EQUIPMENT FOR SALT WATER EXTRACTION

See Figure D-17.

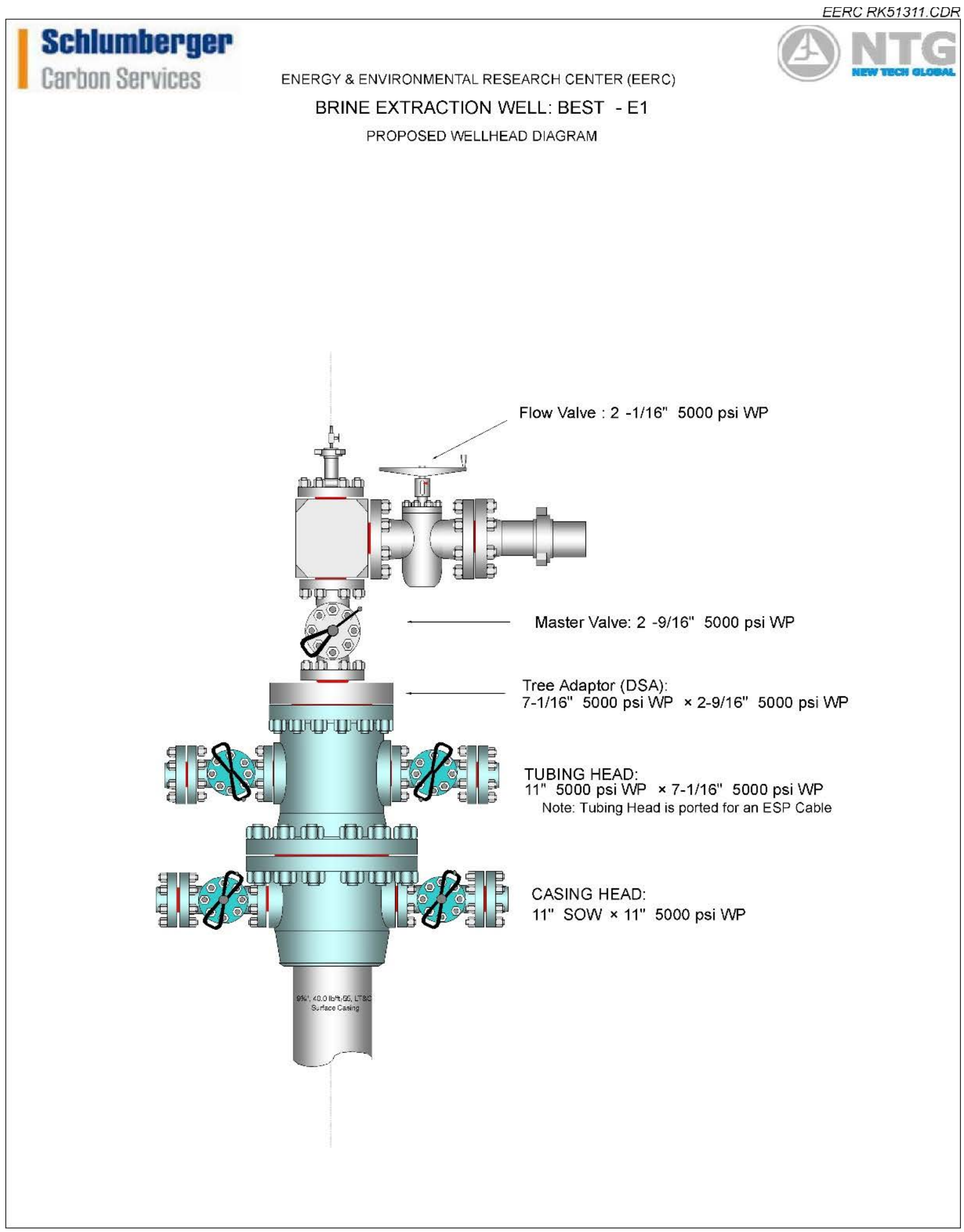


Figure D-17. BEST-E1 wellhead schematic provided by SLB.

D.2.9 SURFACE INFRASTRUCTURE ILLUSTRATIONS BEST-E1

See Figure D-18.

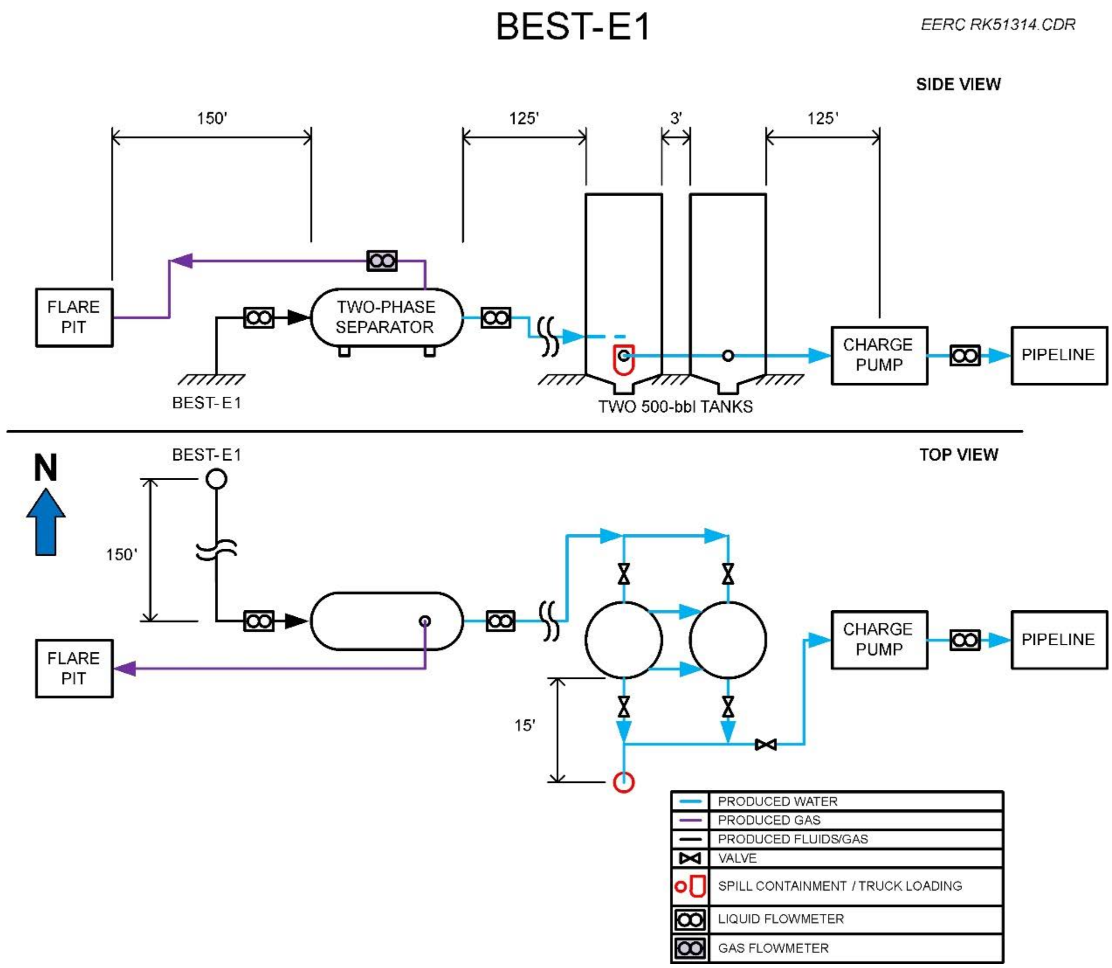


Figure D-18. BEST-E1 engineered drawings of flow path.

D.3 SUMMIT ESP SPECIFICATIONS

A Summit ESP was chosen because of its reliability and the accuracy of the bottomhole sensor in the tool. Summit offices in North Dakota are also in close proximity to the Johnsons Corner site should problems arise with the pump. See Figure D-19.

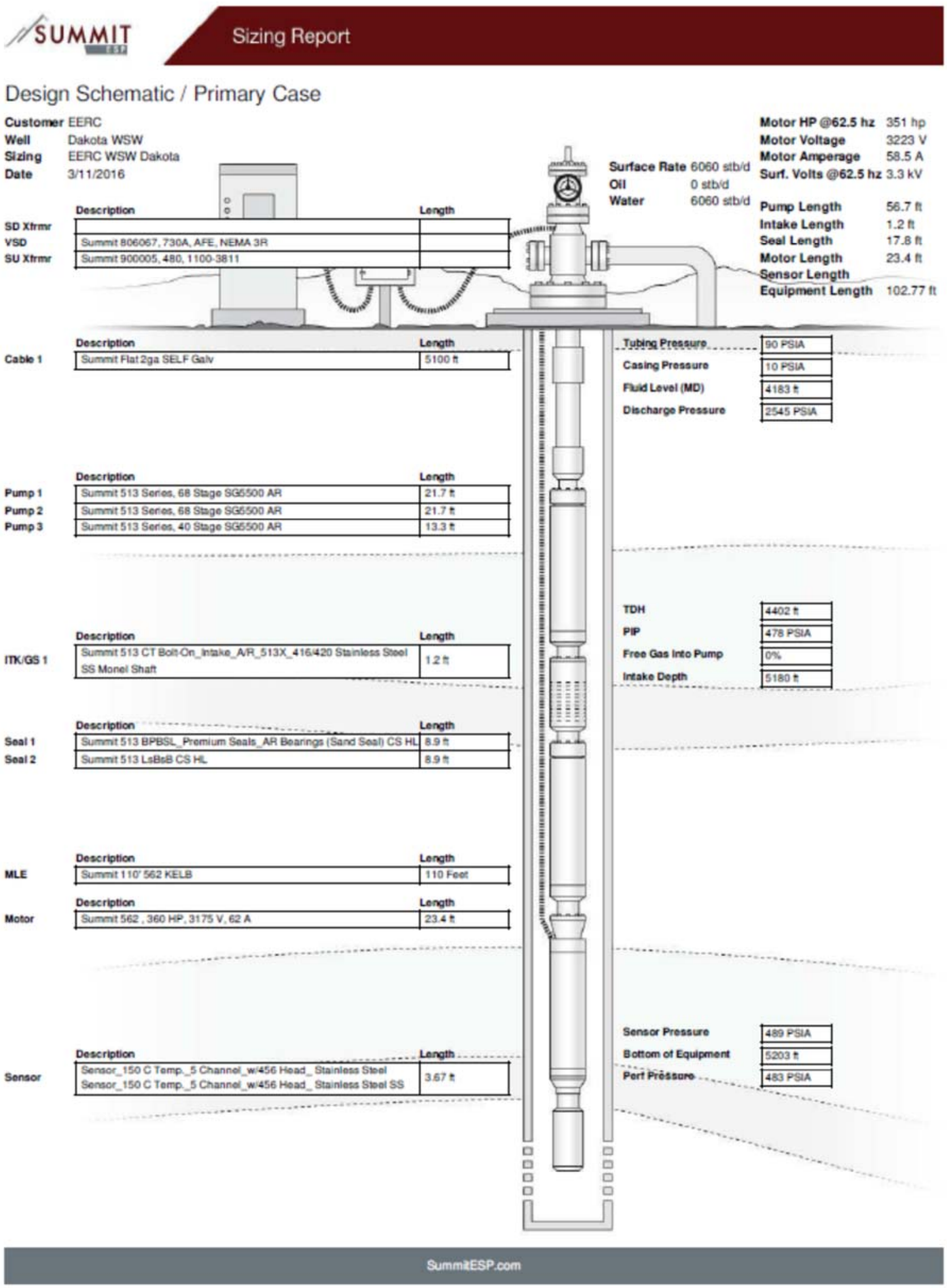
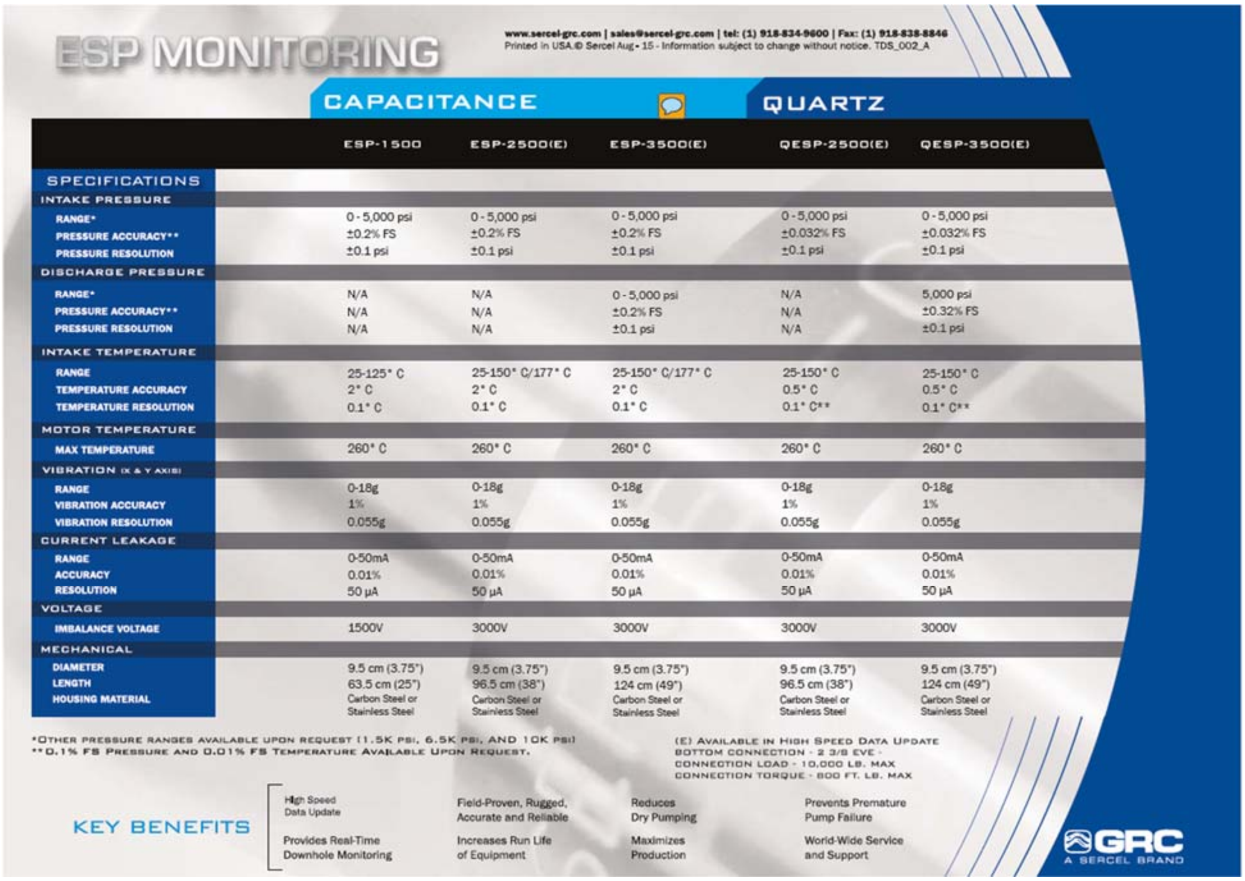


Figure D-19. Design schematic for Summit ESP assembly provided by Summit.

D.3.1 ESP SENSOR, QESP-3500(E), USED IN THE BEST-E1 WELL

See Figure D-20.



ESP MONITORING

www.sercel-grc.com | sales@sercel-grc.com | tel: (1) 918-834-9600 | Fax: (1) 918-838-8846
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SPECIFICATIONS	CAPACITANCE ESP-1500	CAPACITANCE ESP-2500(E)	CAPACITANCE ESP-3500(E)	QUARTZ QESP-2500(E)	QUARTZ QESP-3500(E)
INTAKE PRESSURE					
Range*	0 - 5,000 psi	0 - 5,000 psi	0 - 5,000 psi	0 - 5,000 psi	0 - 5,000 psi
Pressure Accuracy**	±0.2% FS	±0.2% FS	±0.2% FS	±0.032% FS	±0.032% FS
Pressure Resolution	±0.1 psi	±0.1 psi	±0.1 psi	±0.1 psi	±0.1 psi
DISCHARGE PRESSURE					
Range*	N/A	N/A	0 - 5,000 psi	N/A	5,000 psi
Pressure Accuracy**	N/A	N/A	±0.2% FS	N/A	±0.32% FS
Pressure Resolution	N/A	N/A	±0.1 psi	N/A	±0.1 psi
INTAKE TEMPERATURE					
Range	25-125° C	25-150° C/177° C	25-150° C/177° C	25-150° C	25-150° C
Temperature Accuracy	2° C	2° C	2° C	0.5° C	0.5° C
Temperature Resolution	0.1° C	0.1° C	0.1° C	0.1° C**	0.1° C**
MOTOR TEMPERATURE					
Max Temperature	260° C	260° C	260° C	260° C	260° C
VIBRATION (X & Y AXIS)					
Range	0-18g	0-18g	0-18g	0-18g	0-18g
Vibration Accuracy	1%	1%	1%	1%	1%
Vibration Resolution	0.055g	0.055g	0.055g	0.055g	0.055g
CURRENT LEAKAGE					
Range	0-50mA	0-50mA	0-50mA	0-50mA	0-50mA
Accuracy	0.01%	0.01%	0.01%	0.01%	0.01%
Resolution	50 μA	50 μA	50 μA	50 μA	50 μA
VOLTAGE					
Imbalance Voltage	1500V	3000V	3000V	3000V	3000V
MECHANICAL					
Diameter	9.5 cm (3.75")	9.5 cm (3.75")	9.5 cm (3.75")	9.5 cm (3.75")	9.5 cm (3.75")
Length	63.5 cm (25")	96.5 cm (38")	124 cm (49")	96.5 cm (38")	124 cm (49")
Housing Material	Carbon Steel or Stainless Steel	Carbon Steel or Stainless Steel	Carbon Steel or Stainless Steel	Carbon Steel or Stainless Steel	Carbon Steel or Stainless Steel

*Other pressure ranges available upon request (1.5K psi, 6.5K psi, and 10K psi)
**0.1% FS Pressure and 0.01% FS Temperature Available Upon Request.

(E) Available in High Speed Data Update
Bottom connection - 2 3/8 EVE -
Connection load - 10,000 lb. max
Connection torque - 800 ft. lb. max

KEY BENEFITS

- High Speed Data Update
- Provides Real-Time Downhole Monitoring
- Field-Proven, Rugged, Accurate and Reliable
- Increases Run Life of Equipment
- Reduces Dry Pumping
- Maximizes Production
- Prevents Premature Pump Failure
- World-Wide Service and Support

GRC
A SERCEL BRAND

Figure D-20. Summit Quartz QESP-3500E specifications.

D.3.2 SUMMIT ESP SIZING REPORT

Appendix D-1 details the sizing specifications of the Summit ESP designed for the Johnsons Corner site.

D.4 PIPELINE INFRASTRUCTURE

D.4.1 SELECTION, INSTALLATION, AND MONITORING

This section details the selection, installation procedures, and postinstallation leak monitoring of the on-site pipeline infrastructure.

Pipeline Selection

Pipeline material selection was based on the following extracted water parameters:

Temperature:	135°–155°F
Total Dissolved Solids (TDS):	4500 mg/L initially, increasing to 150,000 mg/L
Possibility of H_2S:	Yes, but at low concentrations

The spoolable reinforced plastic pipe is the preferred class of pipe for transporting saline and produced waters in the Williston Basin as they exhibit excellent chemical resistance and pressure ratings, as well as superior qualities related to the ease of installation. Within the spoolable reinforced plastic pipe class, two-line pipes are being considered for use in the proposed demonstration: FlexSteel and Flexpipe. An evaluation of 4-inch diameter, 1500-psi rated pipe was based on pipe characteristics and water characteristics.

FlexSteel, manufactured by FlexSteel Pipeline Technologies, Inc., consists of a steel reinforcing layer between an inner and outer high-density polyethylene (HDPE) layer, while Flexpipe, manufactured by Flexpipe Systems (a division of ShawCor Ltd.), is an inner and outer HDPE layer with either a dry fiberglass or steel-reinforcing layer. Both pipes employ a hydraulic process for installing fittings and couplings. A summary of pertinent pipe characteristics of the FlexSteel and Flexpipe line pipes are shown in Table D-1.

Table D-1. Summary of Line Pipe Characteristics.

Parameter	FlexSteel	Flexpipe
ANSI Class	600	600
Nominal Diameter, in.	4	4
ID, in.	3.669	3.90
Outside Diameter, in.	4.688	5.11
Reel Length, ft	2789	1870
Maximum Operating Temperature, °F	180	180
Maximum Operating Pressure, psi	1500	1500
Reinforcing Material	Helically wound steel	Helically wound dry fiberglass
Fitting Installation Method	Hydraulically swaged	Hydraulically compressed

Trench Construction and Pipeline Installation

A pipeline will be installed from BEST-I1 to BEST-E1 in the approximate route shown in Figure D-21. The proposed pipeline will be approximately 2500 feet in length terminating at both ends with flanged connections. All aspects of the pipeline installation will follow recommended practices put forth in the EERC report, *Liquids Gathering Pipelines: A Comprehensive Analysis* (2015), and thus will meet or exceed the proposed gathering line rules currently being proposed by NDIC.

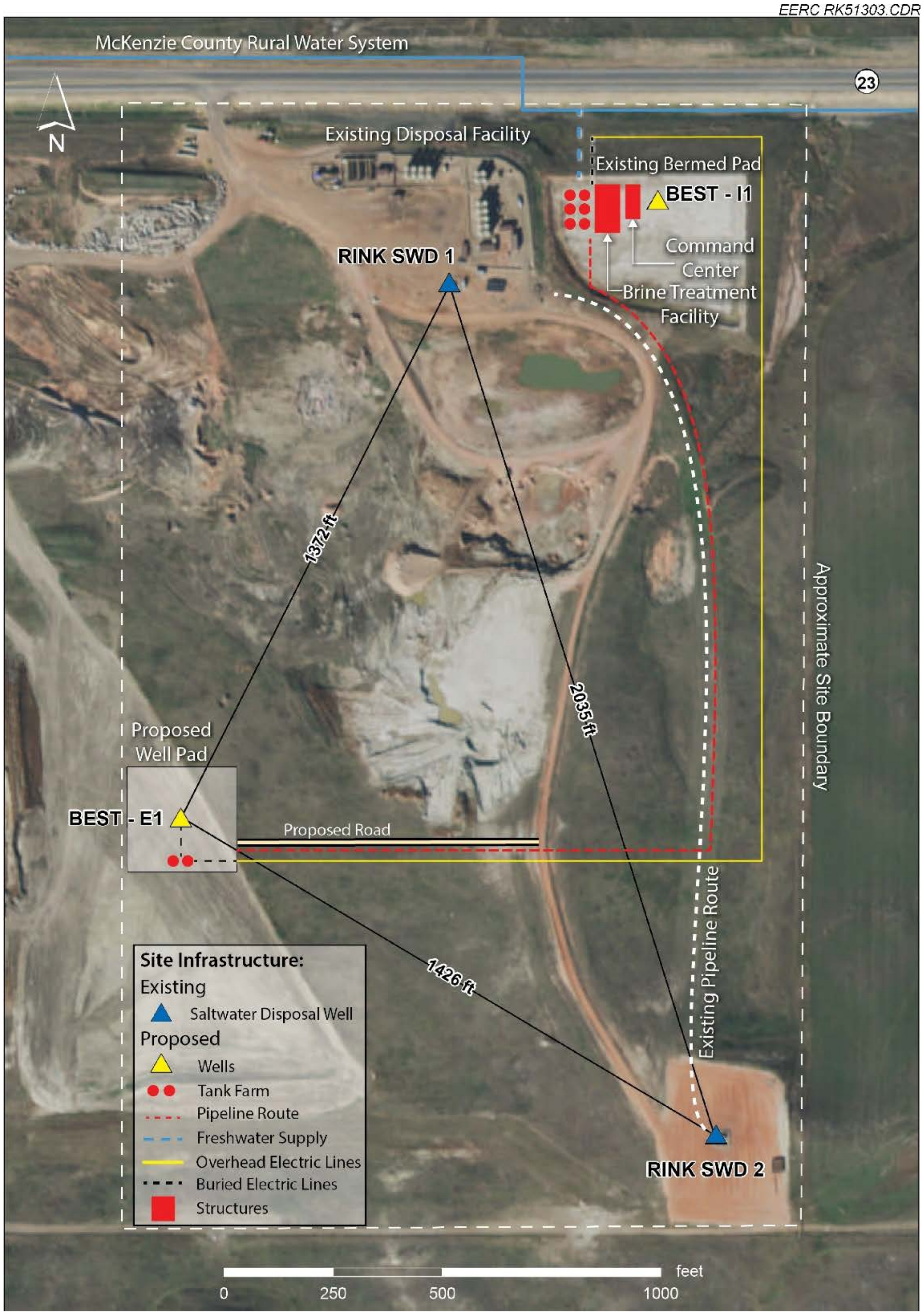

Figure D-21. Pipeline in study area.

Excavation

Topsoil will be stripped and stockpiled separately from other excavated material such that it can be replaced as a final step of the backfilling process. A trench will be excavated with attention paid to maintaining a relatively flat, undisturbed bottom to allow for solid, uniform support for the pipeline. The trench will be excavated to a depth such that a minimum of 6 feet of ground cover is maintained over top-of-pipe, while the trench width will be excavated to ensure sufficient sidewall clearance for proper backfilling (minimum of 6 inches).

The trench sidewalls will be constructed to minimize sloughing of material into the trench. This will be based on observed soil conditions during the excavation. If entry into the trench is deemed necessary, the sidewalls will be excavated to meet OSHA (Occupational Safety and Health Administration) requirements for entry/egress.

Once the trench is excavated visual inspection will be performed of the entire trench to ensure the trench is free of rocks, debris, and other foreign material, and a minimum of 6 inches of granular bedding material, such as a sand, will be placed in the trench bottom to ensure uniform pipeline support.

Stringing and Joining

Upon delivery to the site and during the stringing process, the outer layer of the pipe will be inspected for damage. Any notable damage will be documented, and a determination will be made as to whether the damaged section must be “cut out” and replaced.

The pipe will be strung out based on manufacturer recommendation. Two methods are most likely, either the pipe will be pulled from a stationary reel or the free end will be held stationary and the pipe will be reeled out from a mobile reel.

Given the length of the proposed pipeline, it is possible that a single reel will be sufficient to make the entire run, requiring no joints. Although this is preferred, a single joint may be required. All end fittings and joints (if required) will be installed by the pipe manufacturer. If a joint is required, it will be determined by the pipe manufacturer whether that joint is made at the surface or in the trench.

Lowering-In and Backfilling

Special care will be taken to provide adequate support to the pipe during the lowering-in process to avoid weakening the pipe by inducing excessive stresses or causing damage to the outer surface. With the pipe in the trench, another visual inspection of the trench will be performed to ensure no rocks, debris, and other foreign material have fallen into the trench, and to ensure the pipeline is support and sidewall clearances are met.

The initial backfill phase (from bedding to spring line) is critical to ensuring pipeline longevity, and for this reason, the initial backfill will be performed with either “clean” excavated material or a better-performing material. The initial backfill material will be carefully placed and compacted using caution not to damage the pipe.

Once the spring line is reached, backfilling will continue with rock- and debris-free excavated material placed in 6-inch lifts and compacted (secondary backfill). This process will continue until the pipe is fully covered to a depth of 12 inches.

Final backfilling will continue with excavated material being placed and compacted in approximately 12-inch lifts until near-grade is reached. During the entire backfill process, all personnel will be responsible for identifying and removing large rocks and foreign material.

Figure D-22 has been provided to better understand the various backfilling terms and phases as described above.

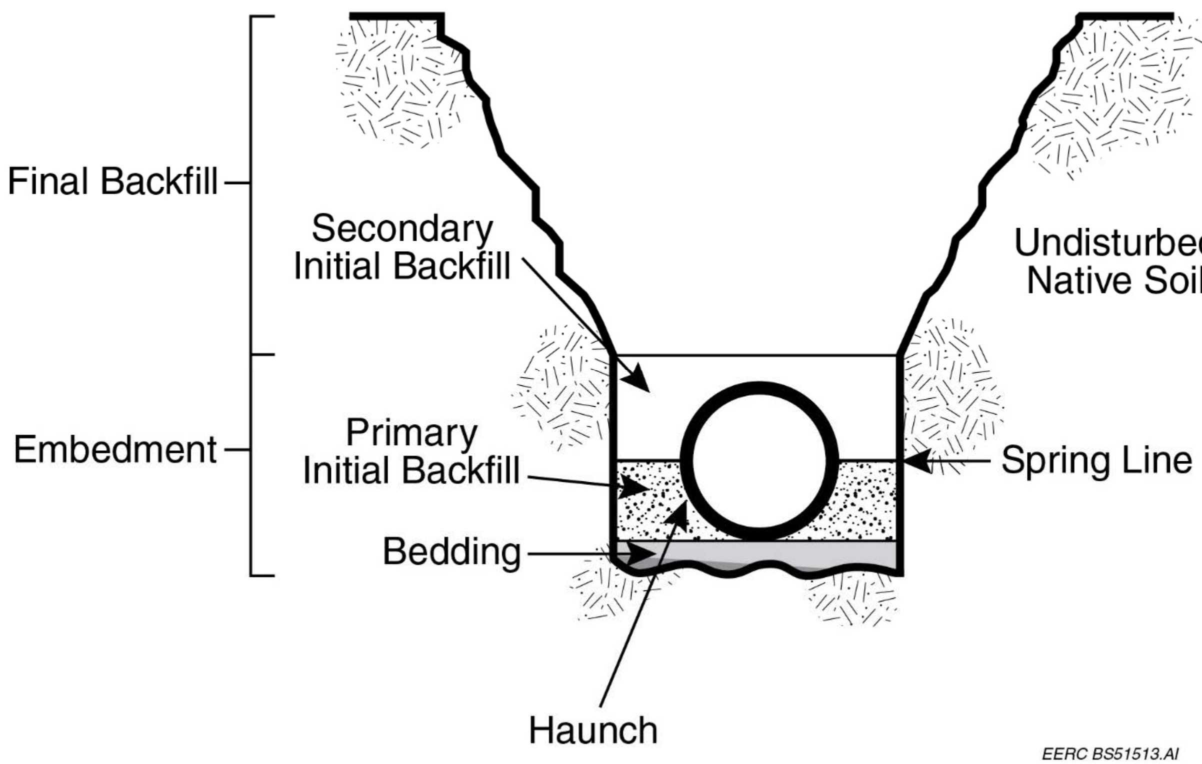

Figure D-22. Cross section of pipeline trench and backfill stages (Plastic Pipes Institute, 2009).

Pipeline Integrity Testing

Upon completion of the pipeline installation and backfilling, the EERC will perform a hydrostatic pipeline integrity test. In general terms, the hydrostatic testing involves filling the pipeline with water (while venting evacuated air) and pressurizing the pipe to pressures higher than its maximum operating pressure (typically 1.25 times the maximum operating pressure) to ensure the pipe, joints, and fittings can operate without leaking. In some cases, the pipe manufacturer defines specific hydrostatic testing procedures, and in this case, those would be followed.

Reclamation

Once the pipeline integrity testing is complete and satisfactory results are observed and documented, the pipeline right-of-way (ROW) will be reclaimed to its original condition (or as close as possible). The ground surface will be recontoured to the original grade with stockpiled topsoil, and the ROW will be reseeded with appropriate vegetation. Erosion control devices will be used where necessary.

Inspection

The EERC will be responsible for on-site supervision and inspection during the trench construction and pipeline installation as well as notify the state inspector. It is very likely that NDIC will assign a state inspector to be consistent with the proposed rules related to the installation of these types of pipelines. It is also likely the state inspector will be present during the pipeline integrity testing.

Monitoring and Leak Detection

The approach taken to monitor and detect leaks of the proposed pipeline involve two aspects: monitoring with devices coupled with supervisory control and data acquisition (SCADA) and physical leak detection devices employed along the pipeline.

The pipeline will be outfitted with an ABB ProcessMaster FEP 300 electromagnetic flowmeter and digital pressure gauges on the inlet and outlet ends of the pipeline where they connect to other infrastructure. These devices can be read locally but more importantly will also provide a reading back to a central SCADA system. The flow rate and pressure at both ends will be compared real-time by the SCADA to verify correlation with measured readings from initial, while daily total flow volumes from the two ABB ProcessMaster FEP 300 electromagnetic flowmeters will be compared daily and verified to be within a certain percentage of each other. All these measures will be done as an accounting of volume extracted as well as an early detection of any flow anomalies (an indication of a leak).

The ABB ProcessMaster electromagnetic flowmeter sets the standard for the process industry and meets the various requirements of NAMUR (Standardization Association for Measurement and Control in Chemical Industries). See Section D.7.7 for an image of FEP 300 ABB electromagnetic flowmeter in the field. The ProcessMaster is a universal device, and as such, cost will be improved for operation with increased safety. Additional benefits for selecting the ProcessMaster flowmeter for pipeline flow rate monitoring and associated operations include the following (ABB flowmeter datasheet):

- Flow performance: The response time is especially short; with its advanced filtering methods, the device improves accuracy even under difficult conditions by separating the noise from the measuring signal. This leads to a maximum measuring error of 0.2% of rate. The ABB ProcessMaster also consists of self-cleansing, double-sealed polished measuring electrodes to enhance the device's reliability and performance.

- Easy and quick commissioning: Advanced data storage inside the sensor eliminates the need to match sensor and transmitters in the field. The onboard sensor memory automatically identifies the transmitter. A self-configuration function is run to replicate all sensor data and specific transmitter parameters, which eliminates the opportunity for errors and leads to increased start-up speed and reliability.

- Intuitive, **convenient** navigation: The factory-set parameters can be modified quickly and easily via the user-friendly display and the noncontact buttons without opening the housing.

- Universal transmitter – powerful and flexible: The backlit display can be easily rotated without the need for any tools. The contrast is adjustable and the display fully configurable.

- Ensured quality: ProcessMaster is designed and manufactured in accordance with international quality procedures (ISO 9001), and all flowmeters are calibrated on nationally traceable calibration rigs to provide the end user with complete assurance of both quality and performance of the meter.

In addition to these traditional, less sophisticated leak detection methods, the EERC intends to install HydraProbes every 75 feet along the pipeline in the backfill adjacent to the pipe. The HydraProbe, manufactured by Stevens Water Monitoring Systems, Inc., is capable of simultaneously measuring moisture, electrical conductivity, and temperature. These measurements will be sent back to the SCADA system for real-time and long-term collection. Use of these devices is a secondary attempt at quickly detecting a leak should one occur.

D.4.2 HYDRAPROBE TECHNICAL INFORMATION

HydraProbes will be used along the pipeline route to detect for any potential leaks (Figures D-23–D-26). These probes are used by other pipeline operators and can be tied into the SCADA system. Technical information on the probes is provided below.

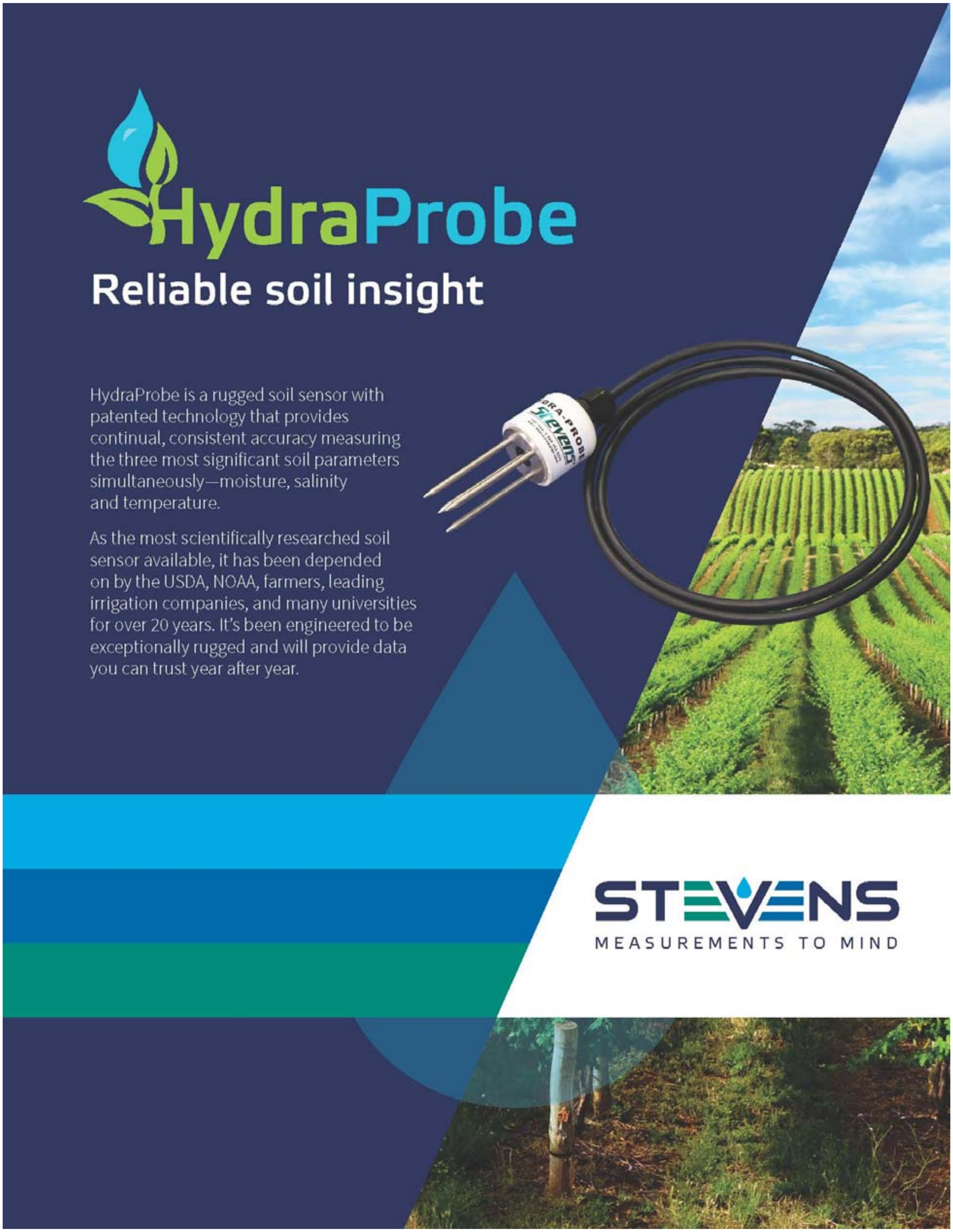

Figure D-23. HydroProbe-provided specification sheet (page 1).

The Science
Behind HydraProbe

The HydraProbe's "dielectric impedance" measurement principle differs from TDR, capacitance, and frequency soil sensors by taking into account the energy storage and energy loss across the soil area using a 50 MHz radio frequency wave.

Unlike other soil sensors, this unique, patented method separates the energy storage (real dielectric permittivity) from the energy losses (imaginary dielectric permittivity). The HydraProbe's detailed mathematical and signal characterization of the dielectric spectrum helps factor out errors in the soil moisture measurement such as temperature effects, errors due to salinity, and soil type.

This method has passed the most rigorous scientific peer review from dozens of journals such as the Vadose Zone Journal, American Geophysical Union, and The Journal of Soil Science Society of America.

Patented Sensor Technology

HydraProbe uses unique "Coaxial Impedance Dielectric Reflectometry" to provide consistent long-term accuracy of moisture, bulk EC and temperature in any soil type. This also provides low inter-sensor variability, so every sensor measures the same without the need to calibrate.

MOISTURE | SALINITY (BULK EC) | TEMPERATURE

HydraProbe to Go

The HydraProbe Field Portable puts the power of HydraProbe in the palm of your hand.

Take soil measurements anywhere for those applications not requiring a permanent soil monitoring system. Your Apple or Android device communicates wirelessly with the HydraProbe using an ad-hoc wi-fi radio link.

Simply insert the probe into the soil, and tap on the "Sample" button in the HydroMon or POGOTurfPro app. The GPS location, date and time of each measurement is recorded along with the soil measurement data. All data can be saved and emailed as a .CSV file for analysis in Excel.

Figure D-24. HydroProbe-provided specification sheet (page 2).

RELIABLE

Continual, long-term data without calibration.

- Stable—no sensor drift, ensuring continual accuracy.
- Patented technology that accurately measures moisture and bulk electrical conductivity permits more accurate optimization of watering and fertilization than with just moisture.
- Depended on by the USDA, NOAA, leading irrigation companies, and many universities for over 20 years. Used by the USDA Soil Climate Analysis Network for ground truthing of satellite-based soil imaging.
- Soil moisture calibration has been rigorously peer-reviewed, making it one of the most trusted soil sensors available.

RUGGED

Durable stainless steel tines, fully potted components, compact sealed design and a 5-year warranty.

- Can remain in-situ indefinitely, or relocated and redeployed without worry.
- Ideal for remote locations, harsh environments and applications where data is critical.
- Enables measurement of native (undisturbed) soil, even hard-packed clay.
- Industry-leading 5-year warranty.

SIMPLE

Set it and forget it.

- Repeatable accuracy and stability without the need for calibration in most soils.
- Digital sensor using the SDI-12 or RS485 protocol—no setup, just connect to data logger. Compatible with any SDI-12/RS485 capable data logger.
- Zero maintenance required.

ACCURATE

Consistent research-grade accuracy every season, every location.

- Unparalleled spatial and temporal measurement consistency. No sensor-to-sensor variations across locations, seasons, soil types or moisture range.
- Instant measurement of the 3 most significant soil parameters simultaneously.
- Unlike most TDR or capacitance-based sensors, HydraProbe is less sensitive to changes in temperature, salinity, and soil mineralogy.

About Bulk EC (Salinity)

- The bulk EC (electrical conductivity) of the soil is correlated to the soil's salinity because salts when mixed with water will conduct electricity. The bulk EC parameter is sometimes called "salinity".
- Many nutrients are salts—a source of salinity. Nutrient accumulation, poor drainage and saline irrigation water can lead to the unwanted buildup of salinity in soil.
- High bulk EC can affect moisture readings and create errors with capacitance based moisture sensors. HydraProbe's soil moisture measurement is less sensitive to salinity than other capacitance based probes.
- The soil bulk EC can change dramatically with water content and can be affected by the quality of the irrigation water, fertilization, drainage, and other natural processes.
- Compaction, clay content and organic matter, can influence moisture holding trends over time, also affecting bulk EC capacities in soil.
- The effect of bulk EC on the moisture availability to a plant's roots is great. As salinity changes the water needs also change.
- A temperature corrected bulk EC parameter is available so the user can make comparison independent of soil temperature.
- Because Hydra Probe also measures the dielectric permittivities, algorithms can be applied to approximate the EC of the soil pore water allowing for better soil salinity characterizations.

Figure D-25. HydroProbe-provided specification sheet (page 3).

TECHNICAL SPECIFICATIONS

MEASUREMENT	ACCURACY	RANGE
Real dielectric permittivity (isolated)	± ≤1.5% or 0.2 whichever is typically greater	1 to 80 where 1 = air, 80 = distilled water
Soil moisture for inorganic & mineral soil	± 0.01 WFV for most soils ± ≤0.03 max for fine textured soils*	From completely dry to fully saturated
Bulk electrical conductivity	± 2.0% or 0.02 S/m whichever is typically greater*	0.01 to 1.5 S/m
Temperature**	± 0.3° C	-10° to +55° C
Inter-sensor variability	± 0.012 WFV (θ m^3 m^{-3})	n/a

**Accuracy may vary with some soil textures. ** Extended temperature range sensor (down to -30° C) available*

ELECTRICAL AND COMMUNICATION

	SDI-12	RS485
Power supply	9-20 VDC	9-20 VDC
Power consumption	<1 mA idle / 10 mA active	<10 mA idle / 30 mA active
Cable	3-wire: power, ground, data	4-wire: power, ground, com+, com-
Max. cable length	60 m (197 ft.)	1,219 m (4,000 ft.) Non-spliced: 304.8 m (1,000 ft.)
Baud Rate	1200	9600
Communication protocol	SDI-12 Standard v. 1.2	Custom or open spec
Addressing	Serial; allows multiple sensors to be connected to any RS485 or SDI-12 data logger via a single cable.	

ENVIRONMENTAL

Operating Temperatures	• In soils: freezing to +55° C • Standard temperature probe range: -10° C to +55° C • Extended temperature probe range: -30° C to +55° C*
Storage Temperatures	-40° C to +55° C
Water Resistance	Tolerates continuous full immersion
Cable	18 gauge (20 gauge for RS-485/analog), UV resistant, direct burial
Vibration and shock resistance	Excellent; potted components in PVC housing and 304 grade stainless steel tines

PHYSICAL

Length	4.9" (124 mm)
Diameter	1.6" (42 mm)
Weight	7 oz. (200 g)
Cable weight	0.86 oz/ft (80g/m)
Sensing volume (cylindrical region)	Length: 2.2" (5.7 cm) Diameter: 1.2" (3.0 cm)

** "Extended Temperature Range" version available, which can measure down to -22° F (-30° C) for research, cold-climate, high-altitude, arctic applications or any other measurement situation where there will be significant below-freezing ground temperatures.*

ORDERING INFORMATION

PART #	DESCRIPTION
93640-025 / 63646-025	HydraProbe with 25' (7.62 m) cable, SDI-12 / RS485
93640-050 / 63646-050	HydraProbe with 50' (22.86 m) of cable, SDI-12 / RS485
93640-100 / 63646-100	HydraProbe with 100' (30.48 m) of cable, SDI-12 / RS485
93633-003	HydraProbe Field Portable

STEVENS

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www.stevenswater.com

Figure D-26. HydroProbe-provided specification sheet (page 4).

D.5 PROMORE TECHNICAL DOCUMENTS

D.5.1 PROMORE RINK SWD 1 AND RINK SWD 2 INSTALLATION PROCEDURE

Appendix D-5 details the procedures required to successfully install the PROMORE MORE^{S} (suspended) Monitoring System in the Rink SWD 1 and Rink SWD 2 wells at the Johnsons Corner site.

D.6 PROTECHNICS JOHNSONS CORNER INTERWELL TRACER SURVEY

Appendix D-6 details the design specifications for a chemical tracer study at the Johnsons Corner site using both Rink SWD injection wells. The test design includes volumes of tracers to be injected, proposed sampling schedule, and a description of the product to be provided by ProTechnics after analysis is completed.

D.7 PUMP, FLOWMETER, PRESSURE SENSOR, TANK SENSOR, AND COMMAND CENTER ADDITIONAL TECHNICAL INFORMATION

D.7.1 INJECTION PUMP-RELATED TECHNICAL INFORMATION

The J-165T-5M model pump was selected for use as the BEST-I1 injection pump (Figures D-27–D-29). It will include 2½” plungers with 5” stroke, allowing a maximum pressure rating of 2000 psi and maximum injection rate of 4373 bbl/day. This pump model is currently in use at the current Rink wells, allowing for existing knowledge of pump operation and maintenance.

Figure D-27. National J-165T-5 in field photo.

ROTATING RIGHT

NATIONAL OILWELL 165T-5 TECHNICAL DATA SHEET

NATIONAL OILWELL

Formerly J-165

Triplex Plunger Pump **165T-5_**

Rated input horsepower
"T" Triplex
Stroke length (in.)
Fluid end pressure ranges
"L" Low, "M" Medium, "H" High

This 5" stroke pump is designed for a variety of fluid transfer applications operating at low, medium or high pressures.

Field Connections in. (mm)

Pump Model	Discharge Connection Size	Suction Connection Size
165T-5L	3 (76.2) API-2000# RTJ	6 (152.4) ANSI-150 F.F.
165T-5M	2 (50.8) API-5000# RTJ	4 (101.6) ANSI-150 F.F.
165T-5H	2 (50.8) ANSI-2500 RTJ	3 (76.2) API-2000# RTJ

Dimensions

Pump Type	Length	Width	Height
165T-5L	65-1/2"	51-7/8"	22-7/8"
165T-5M	64-5/8"	51-7/8"	22-7/8"
165T-5H	64-1/4"	51-7/8"	22-7/8"

Pump Specifications

Pump Size (Max. Plunger Diameter x Stroke) in. (mm) ....4 x 5 (102 x 127)
Rated BHP At 400 RPM (Kw) 165 (123)
Rated Plunger Load, pounds (Kg)..............9,800 (4,445.2)

Maximum Working Pressure: PSI (kPa)
"L" Model Discharge Pressure 1,650 (11,376)
"M" Model Discharge Pressure 3,120 (21,508)
"H" Model Discharge Pressure..............5,000 (34,473)

Crankshaft Extension: in. (mm)
Diameter..............4-1/8 (104.7)
Length..............5-7/8, 8-1/8 (231.5, 206.4)
Keyway (Width x Depth) ....1 x 1/2 (25.4 x 12.7)

Pinion Shaft Extension, if gear unit supplied (mm)
Belt Or Chain Drive: Diameter 3 (76.2)
Length..............6-3/16 (157.16)
Keyway (Width x Depth) ....3/4 x 3/8 (19.05 x 9.53)
Direct Drive: Diameter 3 (76.2)
Length..............6-3/16 (157.16)
Keyway (Width x Depth) ....3/4 x 3/8 (19.05 x 9.53)

Oil Capacity: Gallons (L)
Crankcase 8 (30)
Gear Unit (Varies with Ratio)..............2-1/4 to 3-1/2 (8.52 to 13.25)

Weight: Pump Only On Wood Shipping Skids - Lbs. (Kg)..............4,000 (1814)
Gear Unit - Lbs. (Kg) 800 (363)

Standard Equipment

Aluminum Bronze Fluid End
Aluminum Bronze Valve Covers
Aluminum Bronze or Stainless Steel Stuffing Boxes
Bronze Stuffing Box Internals
Ceramic or Tungsten Carbide Plungers
General Service or Kevlar Plunger Packing
Stainless Steel Intermediate Rods
Fluid King Spherical Valves
Double Extended Crankshaft
Oil Level Dipstick
Crankcase Breather

Optional Equipment

Alternate Fluid End Materials
Alternate Fluid End Valve Styles
Custom Designs For Specialized Applications

Accessories

Bolt On Style Gear Reducers
2.8:1 Ratio 3.22:1 Ratio 3.46:1 Ratio
4.38:1 Ratio 4.96:1 Ratio

Packing Lubricator
Pulsation Dampeners
Relief Valves
Valve Service Kit
Complete Unitization Services

Quick Maintenance Features

- Horizontal Design
- Large Power End Covers
- Easy Access For Bearing Adjustment
- Separate Crosshead/Plunger Construction
- Open Frame Construction
- Removable Stuffing Boxes
- Interchangeable Valves

Figure D-28. National J-165-T specification data sheet (page 1).

Continuous Duty Performance Data (Volumes Indicated Are Displacement of Incompressible Fluid)

English Units

Plunger Dia. In.	Plunger Area Sq. In.	BPD Per RPM	GPM Per RPM	Max. Press. PSI	100 RPM* BPD	100 RPM* GPM	150 RPM* BPD	150 RPM* GPM	200 RPM BPD	200 RPM GPM	250 RPM BPD	250 RPM GPM	300 RPM BPD	300 RPM GPM	350 RPM BPD	350 RPM GPM	400 RPM BPD	400 RPM GPM
165T-5L																		
2 3/4	5.9396	13.2291	0.3857	1650	1323	38.57	1984	57.85	2646	77.14	3307	96.42	3969	115.71	4630	134.99	5292	154.28
3	7.0686	15.7437	0.4590	1387	1574	45.90	2362	68.85	3149	91.80	3936	114.75	4723	137.70	5510	160.65	6297	183.60
3 1/4	8.2958	18.4770	0.5387	1181	1848	53.87	2772	80.80	3695	107.74	4619	134.67	5543	161.61	6467	188.54	7391	215.48
3 1/2	9.6212	21.4289	0.6248	1019	2143	62.48	3214	93.71	4286	124.95	5357	156.19	6429	187.43	7500	218.66	8572	249.90
3 3/4	11.0447	24.5995	0.7172	887	2460	71.72	3690	107.58	4920	143.44	6150	179.30	7380	215.16	8610	251.02	9840	286.88
4	12.5664	27.9888	0.8160	780	2799	81.60	4198	122.40	5598	163.20	6997	204.00	8397	244.80	9796	285.60	‡11195	‡326.40
165T-5M																		
2	3.1416	6.9972	0.2040	3120	700	20.40	1050	30.60	1399	40.80	1749	51.00	2099	61.20	2449	71.40	2799	81.60
2 1/4	3.9761	8.8558	0.2582	2465	886	25.82	1328	38.73	1771	51.64	2214	64.55	2657	77.46	3100	90.37	3542	103.28
2 1/2	4.9088	10.9331	0.3188	2000	1093	31.88	1640	47.81	2187	63.75	2733	79.69	3280	95.63	3827	111.56	4373	127.50
2 3/4	5.9396	13.2291	0.3857	1650	1323	38.57	1984	57.85	2646	77.14	3307	96.42	3969	115.71	4630	134.99	5292	154.28
165T-5H																		
1 1/2	1.7672	3.9359	0.1148	5000	394	11.48	590	17.21	787	22.95	984	28.69	1181	34.43	1378	40.16	1574	45.90
1 3/4	2.4053	5.3572	0.1562	4075	536	15.62	804	23.43	1071	31.24	1339	39.05	1607	46.86	1875	54.67	2143	62.48
2	3.1416	6.9972	0.2040	3120	700	20.40	1050	30.60	1399	40.80	1749	51.00	2099	61.20	2449	71.40	2799	81.60
Brake Horsepower Required:					41		62		83		103		124		144		165	

Metric Units

Plunger Dia. mm	Plunger Area Sq. cm.	M^3/D Per RPM	L/Min Per RPM	Max. Press. kPa	100 RPM* M^3/D	100 RPM* L/Min.	150 RPM* M^3/D	150 RPM* L/Min.	200 RPM M^3/D	200 RPM L/Min.	250 RPM M^3/D	250 RPM L/Min.	300 RPM M^3/D	300 RPM L/Min.	350 RPM M^3/D	350 RPM L/Min.	400 RPM M^3/D	400 RPM L/Min.
165T-5L																		
70	38.3200	2.1033	1.4598	11376	210	145.98	315	218.97	421	291.97	526	364.96	631	437.95	736	510.94	841	583.93
76	45.6040	2.5031	1.7373	9559	250	173.73	375	260.60	501	347.46	626	434.33	751	521.19	876	608.06	1001	694.93
83	53.5213	2.9377	2.0389	8145	294	203.89	441	305.84	588	407.79	734	509.73	881	611.68	1028	713.63	1175	815.57
89	62.0721	3.4070	2.3647	7023	341	236.47	511	354.70	681	472.94	852	591.17	1022	709.40	1192	827.64	1363	945.87
95	71.2562	3.9111	2.7146	6118	391	271.46	587	407.18	782	542.91	978	678.64	1173	814.37	1369	950.09	1564	1085.82
102	81.0737	4.4499	3.0886	5377	445	308.86	667	463.28	890	617.71	1112	772.14	1335	926.57	1557	1081.00	‡1780	‡1235.44
165T-5M																		
51	20.2684	1.1125	0.7721	21508	111	77.21	167	115.82	222	154.43	278	193.04	334	231.64	389	270.25	445	308.86
57	25.6522	1.4080	0.9772	16994	141	97.72	211	146.59	282	195.45	352	244.31	422	293.17	493	342.03	563	390.90
64	31.6694	1.7383	1.2065	13790	174	120.65	261	180.97	348	241.29	435	301.62	521	361.94	608	422.26	695	482.59
70	38.3200	2.1033	1.4598	11376	210	145.98	315	218.97	421	291.97	526	364.96	631	437.95	736	510.94	841	583.93
165T-5H																		
38	11.4010	0.6258	0.4343	34470	63	43.43	94	65.15	125	86.87	156	108.58	188	130.30	219	152.02	250	173.73
44	15.5180	0.8517	0.5912	28092	85	59.12	128	88.68	170	118.23	213	147.79	256	177.35	298	206.91	341	236.47
51	20.2684	1.1125	0.7721	21508	111	77.21	167	115.82	222	154.43	278	193.04	334	231.64	389	270.25	445	308.86
Kilowatts Required:					31		46		62		77		92		108		123	

*For operations below 200 RPM an auxiliary lubrication system is required.
Volume is based on 100% volumetric efficiency. Brake horsepower is based on 90% mechanical efficiency.
‡Requires Fluid King spherical valves for proper operation at listed RPM.

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T6E 4M9

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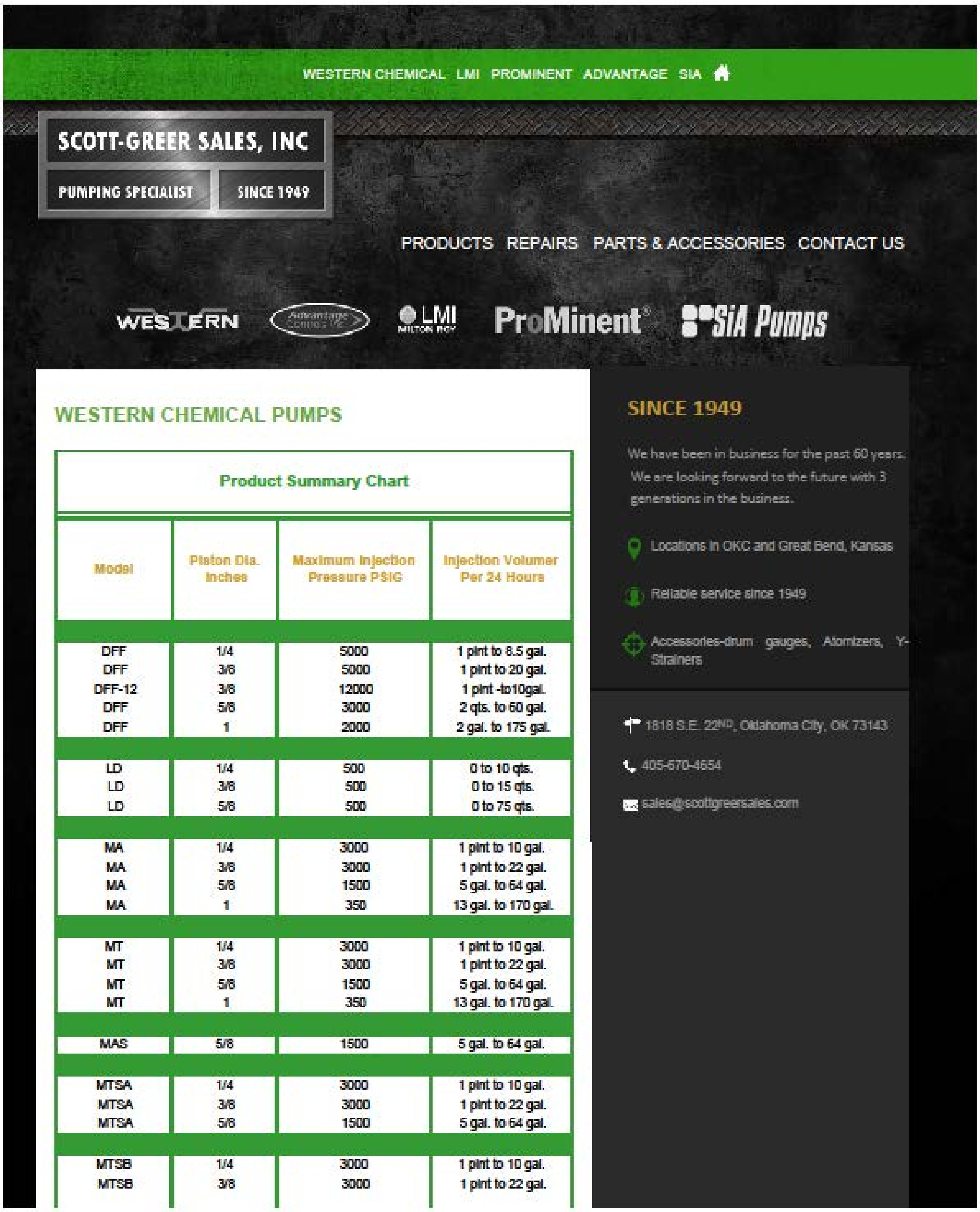
Figure D-29. National J-165-T specification data sheet (page 2).

D.7.2 WESTERN CHEMICAL PUMPS SPECIFICATIONS

Western Chemical Pumps (Figure D-30) Model MA will be used to convey chemicals into the injection stream. The pump design for the BEST project to inject chemicals will be Model MA. This pump allows a maximum injection pressure of 3000 psi with 3/8" piston. This allows a range of 1 pint to 22 gallons a day.

Western Chemical Pump | Pumps for the Oil and Gas Industry



WESTERN CHEMICAL LMI PROMINENT ADVANTAGE SIA

SCOTT-GREER SALES, INC

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WESTERN CHEMICAL PUMPS

Product Summary Chart

Model	Piston Dia. Inches	Maximum Injection Pressure PSIG	Injection Volumer Per 24 Hours
DFF	1/4	5000	1 pint to 8.5 gal.
DFF	3/8	5000	1 pint to 20 gal.
DFF-12	3/8	12000	1 pint -to10gal.
DFF	5/8	3000	2 qts. to 60 gal.
DFF	1	2000	2 gal. to 175 gal.
LD	1/4	500	0 to 10 qts.
LD	3/8	500	0 to 15 qts.
LD	5/8	500	0 to 75 qts.
MA	1/4	3000	1 pint to 10 gal.
MA	3/8	3000	1 pint to 22 gal.
MA	5/8	1500	5 gal. to 64 gal.
MA	1	350	13 gal. to 170 gal.
MT	1/4	3000	1 pint to 10 gal.
MT	3/8	3000	1 pint to 22 gal.
MT	5/8	1500	5 gal. to 64 gal.
MT	1	350	13 gal. to 170 gal.
MAS	5/8	1500	5 gal. to 64 gal.
MTSA	1/4	3000	1 pint to 10 gal.
MTSA	3/8	3000	1 pint to 22 gal.
MTSA	5/8	1500	5 gal. to 64 gal.
MTSB	1/4	3000	1 pint to 10 gal.
MTSB	3/8	3000	1 pint to 22 gal.

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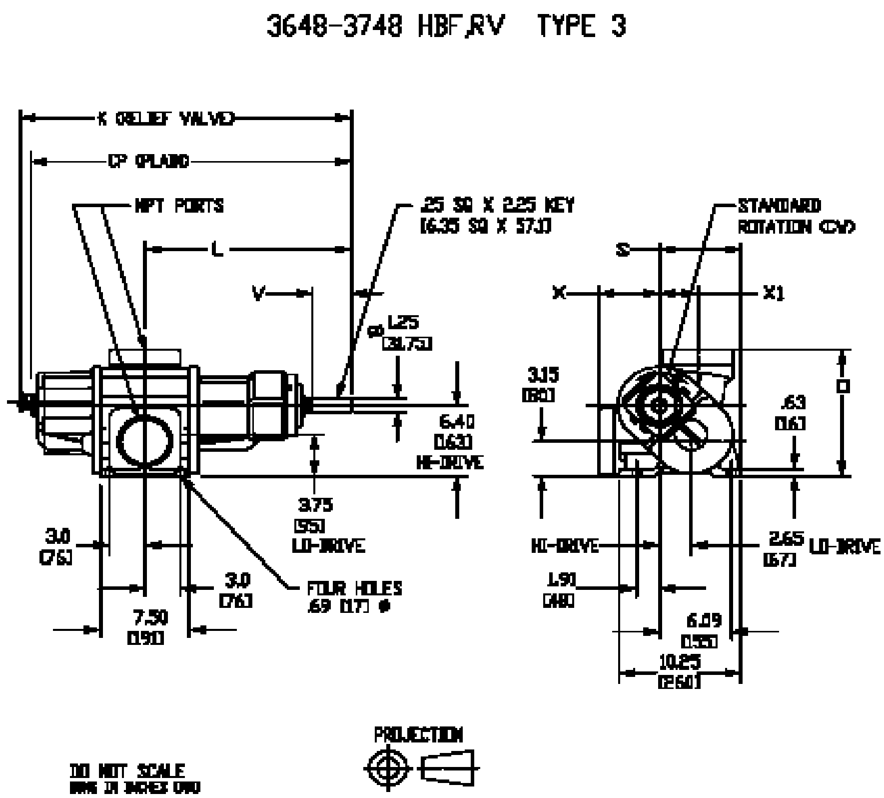
Figure D-30. Western Chemical Pumps specification data sheet.

D.7.3 ROPER PUMPS SPECIFICATIONS

Roper Pumps (Figure D-31) will be used to transfer fluids from the BEST-I1 facility to the existing Rink SWD facilities. Specifically, the Model 3648 HBF Type 3 pump will be used to transfer fluids. This pump is chosen for reliability and is currently in use at existing Rink facilities.



DO NOT SCALE
DIMS IN INCHES [MM]

PUMP	CP	K	L	D	PORTS	S	V	X	X1
3648 & 3748 HBF 3648 & 3748 HBFRV	27.02 [686]	27.93 [710]	17.38 [442]	11.50 [292]	4" FLANGED	6.84 [174]	3.94 [100]	5.10 [130]	3.25 [83]

Figure D-31. Roper Pumps specification data sheet.

D.7.4 GOULDS PUMPS SPECIFICATIONS

Goulds 3657 charge pumps (Figures D-32–D-35) will be used as a charge pump at the BEST-I1 and BEST-E1 facilities. The Goulds pump was chosen because of its reliability in operations and is currently in use at existing Rink facilities. These pumps will be equipped with stainless steel fluid ends with 2” discharge × 3” suction × 7” impeller.

Figure D-32. Goulds Pumps specification data sheet (page 1).

3657/3757 – A FULL RANGE OF PRODUCT FEATURES
3657/3757 – UNA GAMA COMPLETA DE CARACTERÍSTICAS DEL PRODUCTO

Superior Materials of Construction: Precision investment cast 316 stainless steel liquid end components for corrosion resistance and strength.

Frame Mounted Design: Flexibility of installation and driver arrangements.

Enclosed Impeller Design: Maximum efficiency and service life with no need for clearance adjustment. Key driven shaft connection with locknut.

Back Pull-Out Design: Simplifies maintenance by allowing the casing to remain in the piping during disassembly.

Close-Coupled Design: Compact design saves space and simplifies installation.

Casing Features: Investment cast AISI type 316 stainless steel, volute design for maximum efficiency. Vertical discharge standard, field modifiable to four standard positions.

Shaft and Sleeve: High strength steel, keyed design non-wetted. Protected from pumpage by O-ring seal and hooked design AISI type 316 stainless steel shaft sleeve.

Mechanical Seals: Standard Flowserve Type 31 seal with carbon versus Silicon-Carbide faces, Viton elastomers and 316 stainless steel metal components. Options are available for high temperature and mild abrasives.

Drive Motors: NEMA standard JM frame (close coupled) or T frame (frame mounted) are available in both single and three phase with a variety of enclosures and voltages to match your service requirements.

Materiales Superiores de Construcción: Los componentes de precisión para el líquido final son de fundición de acero inoxidable 316 para proporcionar mayor fuerza y resistencia a la corrosión.

Diseño de Caja Montada: Flexibilidad de instalación y ajustes del motor.

Diseño de Impulsor Encerrado: Máxima eficiencia y duración del servicio sin necesidad de tolerancias de ajustes positivos. Conexión del eje accionada por teclado con contratuerca.

Diseño con Caja de Rodamientos: Simplifica el mantenimiento, permitiendo que la carcasa permanezca en la tubería durante el desmontaje.

Diseño con Acople Compacto: El diseño compacto ahorra espacio y simplifica la instalación.

Características de la Carcasa: Construcción de fundición de acero inoxidable AISI tipo 316 y diseño de voluta para una eficiencia máxima. Descarga vertical estándar, modificable en campo a cuatro posiciones estándar.

Eje y Camisa: Acero de alta resistencia, diseño de teclado no mojable. Protegidos del líquido bombeado por el sello, anillo en O y camisa del eje diseño recurvado de acero inoxidable AISI tipo 316.

Sellos Mecánicos: Sello estándar Flowserve Tipo 31 con carbón contra caras de Silcar-Carburo, elastómeros de vitón y partes metálicas de acero inoxidable 316. Se encuentran disponibles sellos opcionales para mayor temperatura y abrasivos suaves.

Motores de Accionamiento: Se encuentran disponibles motores con caja JM estándar NEMA (acople compacto) o caja T (caja montada) en unifásicos y trifásicos con una variedad de cajas y voltajes para igualar los requisitos de su servicio.

3657/3757 PERFORMANCE COVERAGE, 3500 RPM – INVESTMENT CAST 316 STAINLESS STEEL
3657/3757 COBERTURA DE RENDIMIENTO, 3500 RPM – FUNDICIÓN DE ACERO INOXIDABLE 316

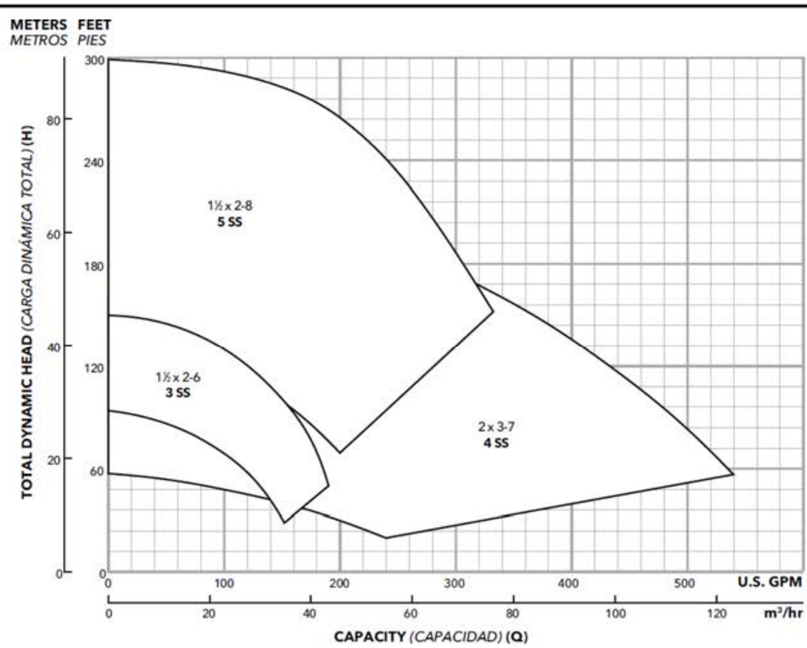


Figure D-33. Goulds Pumps specification data sheet (page 2).

3657/3757 NUMBERING SYSTEM
3657/3757 SISTEMA NUMÉRICO

Example Product Code, *Ejemplo del Código del Producto*

3 SS 1 H 1 D 0 R

Casing Rotation, Optional
R = 3 o'clock B = 6 o'clock L = 9 o'clock
NOTE: Rotation when viewed from suction end of pump. Standard discharge position is 12 o'clock.

Rotación de la cubierta, opcional
R = 3 hora B = 6 hora L = 9 hora
***NOTA:** Rotación cuando está visto del extremo de la succión de la bomba. La posición estándar de la descarga es las 12.*

Mechanical Seal and O-Ring
0 = Standard. For optional mechanical seal modify catalog order no. with seal code listed below.

Sello Mecánico y Anillo '0'
0 = Estándar. Para sello mecánico opcional modificar el número de orden del catálogo con la lista del código de sello que se encuentra abajo.

Mechanical Seal, *Sello Mecánico*

Seal, *Sello*	Rotary, *Rotatorio*	Stationary, *Estacionario*	Elastomers, *Elastómeros*	Metal Parts, *Partes Metálicas*	Part No., *Número de Pieza*	Casing O-ring, *Anillo en O de la Carcasa*
0	Carbon, *Carbón*	Silicone-Carbide, Silcar-Carburo	Viton, *Vitón*	316 SS, *316 Acero inoxidable*	10K27	Viton, *Vitón*
2			EPR		10K19	EPR
5	Sil-Carbide		Viton, *Vitón*		10K64	Viton, *Vitón*

Impeller Option Code...No Adder Required - For optional impeller diameters modify catalog order no. with impeller code listed below. Select optional impeller diameter from pump performance curve. **NOTE:** For trimmed impellers, use T for impeller code.

Código de opción del Impulsor... No Se Requiere Mezclador - *Para diámetros del impulsor opcional modificar el número de orden del catálogo con el código del impulsor anotado abajo. Seleccionar el diámetro del impulsor opcional de la curva de funcionamiento de la bomba. **NOTA:** Para los impulsores cortados, utilice T para el código del impulsor.*

Impeller Code, Código del Impulsor	3 SS 1½ x 2 - 6 Dia., Diámetro	4 SS 2 x 3 - 7 Dia., Diámetro	5 SS 1½ x 2 - 8 Dia., Diámetro
A	6	7	8 1/16
B	5⅝	6¾	7¾
C	5¼	6⅜	7½
D	4¾	5 15/16	7¼
E		5½	7
F		5⅜	6½
G		5 1/16	6¼
H		4⅝	6
J		4⅜	5⅞
K		3⅞	5½
L			5¼

NOTE: Not recommended for operation beyond printed H-Q curve. For critical application conditions consult factory.

***NOTA:** No se recomienda para funcionamiento más allá del indicado en la curva H-Q. Para condiciones críticas de aplicación consultar con la fábrica.*

NOTE: Impellers will be trimmed in 1/16" increments only. If you are ordering a trim within 1/16" of the standard impeller, you will receive the standard impeller trim.

***NOTA:** Los impulsores serán cortados en 1/16 " incrementos solamente. Si usted está pidiendo un ajuste dentro de 1/16 " del impulsor estándar, usted recibirá el ajuste estándar del impulsor.*

Driver, *Conductor*
1 = 1 PH, ODP 5 = 3 PH, TEFC 9 = 3 PH, TEFC Premium Efficiency, Eficiencia mejorada
2 = 3 PH, ODP 6 = 575 V, TEFC
3 = 575 V, ODP 7 = 3 PH, XP
4 = 1 PH, TEFC 8 = 575 V, XP 0 = 1 PH, XP

For frame mounted pumps substitute the letters "FRM".

Para las bombas de caja montada sustituir las letras "FRM".

HP Rating, *HP Potencia*
E = 1 HP G = 2 HP J = 5 HP L = 10 HP N = 20 HP
F = 1½ HP H = 3 HP K = 7½ HP M = 15 HP P = 25 HP

Driver: Hertz/Pole/RPM, *Motor: Hercios/Polo/RPM*
1 = 60 Hz, 2 pole, 3500 RPM 4 = 50 Hz, 2 pole, 2900 RPM
2 = 60 Hz, 4 pole, 1750 RPM 5 = 50 Hz, 4 pole, 1450 RPM
3 = 60 Hz, 6 pole, 1150 RPM

Material
SS = 316 stainless steel, acero inoxidable 316

Pump Size, *Tamaño de la Bomba*
3 = 1½ x 2 - 6 4 = 2 x 3 - 7 5 = 1½ x 2 - 8

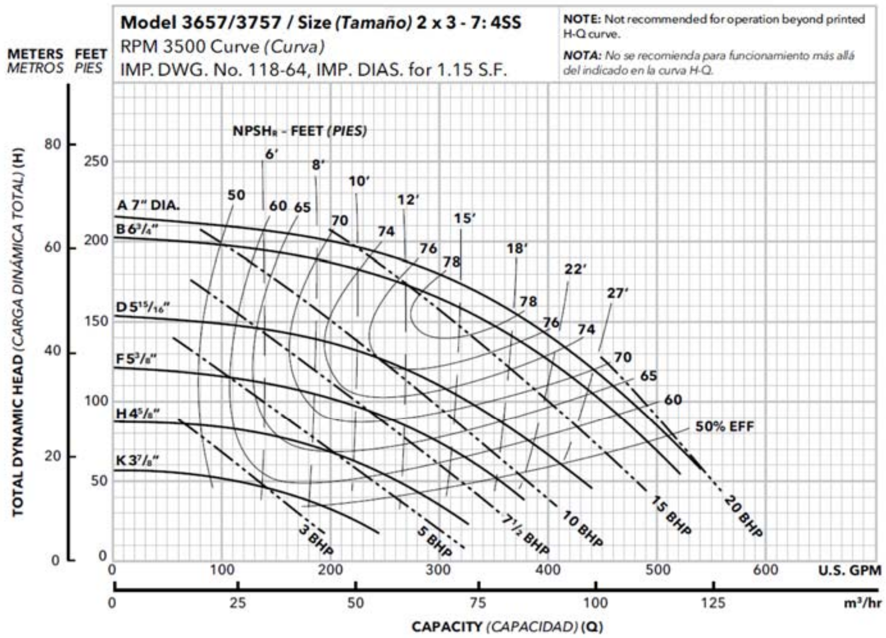
NOTE: Not all combinations of motor, impeller and seal options are available for every pump model. Please check with G&L Series on non-cataloged numbers.

***NOTA:** No todas las combinaciones de las opciones de motor, impulsor y sello se encuentran disponibles para cada modelo de bomba. Por favor, comprobar con G&L Series en los números no catalogados.*

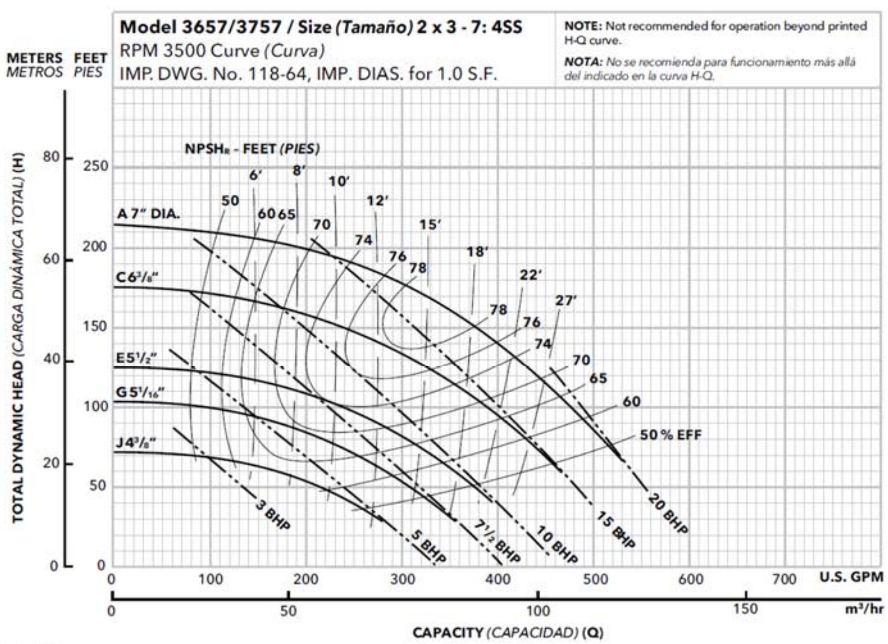
PAGE 12

Figure D-34. Goulds Pumps specification data sheet (page 3).

3657/3757 PERFORMANCE CURVES – 60 HZ, 3500 RPM
3657/3757 CURVAS CARACTERISTICAS – 60 HZ, 3500 RPM



Optional Impeller, Impulsor Opcional	
Ordering Code, Código de Pedido	**Dia.**
A	7"
B	6¾
D	5¹⁵⁄₁₆
F	5⅜
H	4⅝
K	3⅞



Optional Impeller, Impulsor Opcional	
Ordering Code, Código de Pedido	**Dia.**
A	7"
C	6⅜
E	5½
G	5¹⁄₁₆
J	4⅜

Figure D-35. Goulds Pumps specification data sheet (page 4).

D.7.5 MURPHY PRESSURE GAUGE SENSOR TECHNICAL INFORMATION

The following (Figure D-36) details the Murphy pressure gauge sensor that will be used to monitor the injection pressure in the BEST-I1 well. This is the industry standard pressure gauge and is currently used on the existing Rink wells and personnel who will operate this is properly trained on these.

EERC RK51322.CDR

Figure D-36. Image of Murphy pressure gauge sensor.

D.7.6 TANK MEASUREMENT SPECIFICATIONS

Tank fluid levels will be monitored with float and radar-level monitoring equipment. Details of this equipment are provided in Sections D.7.6.1 and D.7.6.2.

D.7.6.1 MURPHY TANK FLOAT MONITORING SYSTEM

Tank levels will be monitored with float sensing equipment from Murphy. This equipment will track tank levels for reducing spill/overflow to increase safety and mitigate environmental risk. This equipment was selected because it is currently being used at the operating disposal site, allowing for increased knowledge of the product.

D.7.6.2 RADAR TANK-LEVEL SENSING EQUIPMENT

Tank levels will be monitored with radar sensing equipment from Siemens Model SITANNS LR 250. This equipment will allow for monitoring of tank levels in real time through a computer interface. Radar tank-level equipment is currently in use at the operating disposal site, and Nuverra personnel are familiar with its operation. Technical information provided by Siemens can be found in Figures D-37–D-41.

Figure D-37. Siemens LR 250-provided specification data sheet (page 1).

Siemens radar level measurement

- Innovative product and design
- Industry-leading technology
- Easy to use, configure, and install

What do you want from your process instrumentation?

High performance
Unaffected by temperature, pressure, vapor, or extreme dust, radar technology can measure applications up to 100 meters (328 ft). Radar technology offers answers to these challenging conditions that other technologies can't handle. Plus, custom configurations are available upon request, ensuring Siemens has the answers for your unique application needs.

Quality
Siemens level measurement instruments come with extensive field experience. Our signal processing technology for level instruments is based on the experience of over a million instruments worldwide. Siemens global support network provides experienced technical help when and where you need it.

Trust
Industry leaders recognize the quality and durability of Siemens transmitters. Be it a large tank farm or a single vessel, Siemens transmitters can stand alone or be integrated in a network. Choose localized control or sophisticated data management and diagnostics.

Cost savings
Managing raw materials and finished products is essential for keeping processes efficient and optimizing inventory ordering and shipments. By knowing where materials are located, companies can use these resources more effectively, decreasing human intervention and increasing efficiency. As well, checking bin levels on a regular basis requires substantial labor costs.

Safety
Eliminate the need for constant human measurement from the top of vessels by providing accurate level indication to operators on the ground. With reliable radar level transmitters, you keep workers out of hazardous situations altogether. Plus, many of our transmitters feature SIL 2 for your applications requiring functional safety.

2

Figure D-38. Siemens LR 250-provided specification data sheet (page 2).

Radar for liquids and slurries

SITRANS LR250 is your first choice for liquid level measurement in storage and process vessels to 20 meters (66 ft). With its range of antennas, this transmitter can handle whatever you need it to. Its new encapsulated antenna and class-leading range of process connections mean that hygienic applications are no problem for this instrument.

For process vessels which may include turbulence, buildup, or foam, choose SITRANS LR200. Its low frequency better suits this environment and functions reliably in applications up to 20 meters (66 ft).

And for low-cost level measurement, SITRANS Probe LR offers a small process connection and operates at a low frequency.

SITRANS LR250 family features

- **Application flexibility** – from sanitary processes to harsh environments, choose from horn, PVDF, or encapsulated antenna designs
- **Easy to install** – small antennas and narrow beams allow installation practically anywhere on your vessel
- **Quick to configure** – Quick Start Wizard for simple setup
- **Process intelligence** – advanced echo processing for unparalleled performance
- **Reliable and accurate** – extremely high signal and low noise yields high performance, even with low dielectric media. Plus SIL 2 for applications requiring functional safety

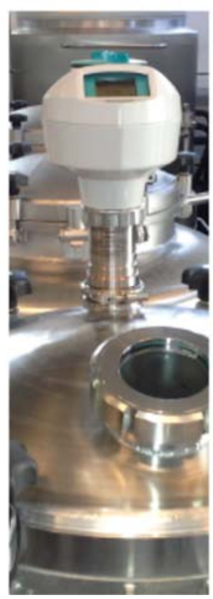


Figure D-39. Siemens LR 250-provided tank radar specification data sheet (page 3).

	SITRANS LR250	SITRANS Probe LR	SITRANS LR200
Order No.	7ML5431, 7ML5432, 7ML5433	7ML5430	7ML542x
	2-wire, 25 GHz pulse radar level transmitter for continuous monitoring of liquids and slurries in storage/process vessels.	2-wire, 6 GHz pulse radar level transmitter for basic continuous monitoring of liquids in storage vessels.	2-wire, 6 GHz pulse radar level transmitter for continuous monitoring of liquids. Ideally suited for complex, turbulent process vessels.
Range	20 m (66 ft)	20 m (66 ft)	20 m (66 ft)
Process temperature	-40 to 200 °C (-40 to 392 °F), process connection dependent	-40 to 80 °C (-40 to 176 °F)	-40 to 200 °C (-40 to 392 °F), process connection dependent
Process pressure	Up to 40 bar g (580 psi g), process connection dependent	Up to 3 bar g (43.5 psi g)	Up to 40 bar g (580 psi g), process connection dependent
Key features	• Narrow beam for easy setup and high performance • Process Intelligence – advanced echo processing for unparalleled performance • Graphical HMI • Quick Start Wizard and display diagnostics • 3-A, EHEDG EL Class 1 and EL Class 1 aseptic certification with TFM 1600 PTFE-wetted antenna parts (FDA and USP Class VI approved) for hygienic and sanitary environments • Antennas for aggressive conditions (acids, alkalis, and other corrosive chemicals) • SIL 2 for functional safety	• Process Intelligence echo processing • Hermetically sealed shielded polypropylene rod antenna with threaded process connection	• Process Intelligence – advanced echo processing for reliable performance • Graphical HMI • Quick Start Wizard and display diagnostics • Multiple antenna designs for application flexibility • Purging (self-cleaning) for buildup protection
Communications or outputs	• HART, PROFIBUS PA, or FOUNDATION Fieldbus • Enhanced EDD for SIMATIC PDM, Emerson AMS, SITRANS DTM (for PACTware), 375/475 handheld, for configuration and diagnostics	• HART • EDD for SIMATIC PDM for configuration and diagnostics	• HART or PROFIBUS PA • Enhanced EDD for SIMATIC PDM, Emerson AMS, SITRANS DTM (for PACTware), 375/475 handheld, for configuration and diagnostics

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Figure D-40. Siemens LR 250-provided tank radar specification data sheet (page 4).

Communications

Pairing intelligent radar field devices with SIMATIC NET architecture is a perfect mix. This combination gives you considerable cost savings through reduced installation efforts, predictive maintenance, and intelligent diagnostics. Siemens offers a wide range of Industrial Communication components specifically designed for reliable use in your industry.

Communication flexibility

Siemens provides communication flexibility. Siemens Totally Integrated Automation (TIA) approach offers ease of connection to a DCS system such as SIMATIC PCS 7 using industrial standards such as HART and PROFIBUS.

SIMATIC PDM software

SIMATIC PDM (Process Device Manager) is a manufacturer-independent software tool for the operation, configuration, parameterization, maintenance, and diagnosis of intelligent field instruments. Based on the EDD standard, it can be used independent of a specific automation system via a PC or programming device or as an integral part of the SIMATIC PCS 7 process automation system. Core functions include:

- Setup and modification of parameters (Quick Start Wizard)
- Comparison
- Plausibility checks
- Data management
- Commissioning functions

SIMATIC PDM offers communications via HART protocol, PROFIBUS DP, PROFIBUS PA, or other protocols. Operation via AMS and FDT (such as PACTware and Fieldcare) via SITRANS DTM are also available.

Remote digital displays

Siemens remote displays, SITRANS RD100 and SITRANS RD200, provide the flexibility of having a display where it is needed – in the field, in a panel, or in the control room.

Remote monitoring

SITRANS RD500 allows remote monitoring of Siemens radar using standard communication options such as Ethernet and cellular GPRS modem. This is the ideal complement to any remote monitoring application, allowing direct access to level readings via any computer (such as smart phones, laptops, or any device supporting a web browser, email, or sms).

In addition to remote monitoring and reporting, SITRANS RD500 also provides these remote features:

- Configuration
- Viewing of transmitter data
- Datalogging
- Event alarming
- Reporting and messaging

PROFIBUS

Siemens offers a range of instruments that connect to a PROFIBUS network. PROFIBUS is the fieldbus standard for complete production plants in all process sectors, and helps manufacturers achieve operational excellence and cost savings throughout the complete service life. It is the network solution with the most advantages for Totally Integrated Automation (TIA) providing digital communication between the automation system and field instrumentation on a single serial bus cable.

HART

HART is a serial transfer protocol used to transfer additional parameter data such as measurement range and configuration to the connected device through a 4 to 20 mA power loop. SIMATIC PDM can use this protocol to communicate configuration data to an instrument. Siemens offers HART as an option on many of its level instruments.

Model 375 HART field communicator and Emerson AMS

The handheld HART 375 field communicator and Emerson AMS software are EDD-based configuration and diagnostic tools for HART and Foundation Fieldbus devices. They both support the HART Communication Foundation (HCF) Library of EDDs. All Siemens HART devices have EDDs in the HCF library. Enhanced EDDs are included on some products providing additional functions such as Quick Start Wizards.

PROFIBUS DP, Modbus RTU, Allen-Bradley Remote I/O, and DeviceNet via SmartLinx

SmartLinx provides direct digital connection to commonly used industrial communication buses with true plug-and-play compatibility. Cards are available for PROFIBUS DP, Modbus RTU, Allen-Bradley Remote I/O, and DeviceNet. SmartLinx modules are fast and easy to install, and can be added at any time.

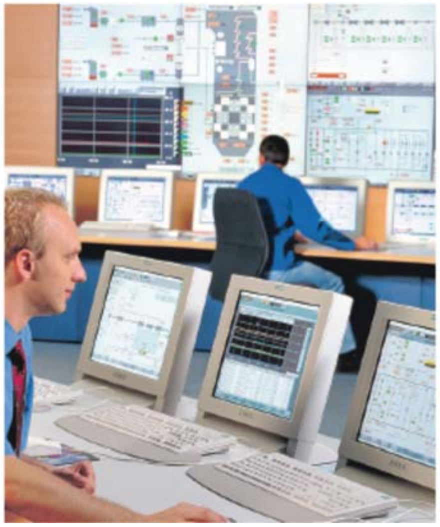

Figure D-41. Siemens LR 250-provided tank radar specification data sheet (page 5).

D.7.7 FLOWMETER TECHNICAL INFORMATION

FEP 300 ABB electromagnetic flowmeters monitor flow of fluids through pipelines and flowlines. The FEP 300 ABB electromagnetic flowmeter (Figure D-42) will be used because it is being used in the current saltwater disposal procedures on-site. Personnel on the site are trained in the operation of this flowmeter. These flowmeters also have a low margin of error in tracking volumes. Technical specifications for the flowmeter are described in Figures D-43 through D-45.

EERC RK51320.CDR

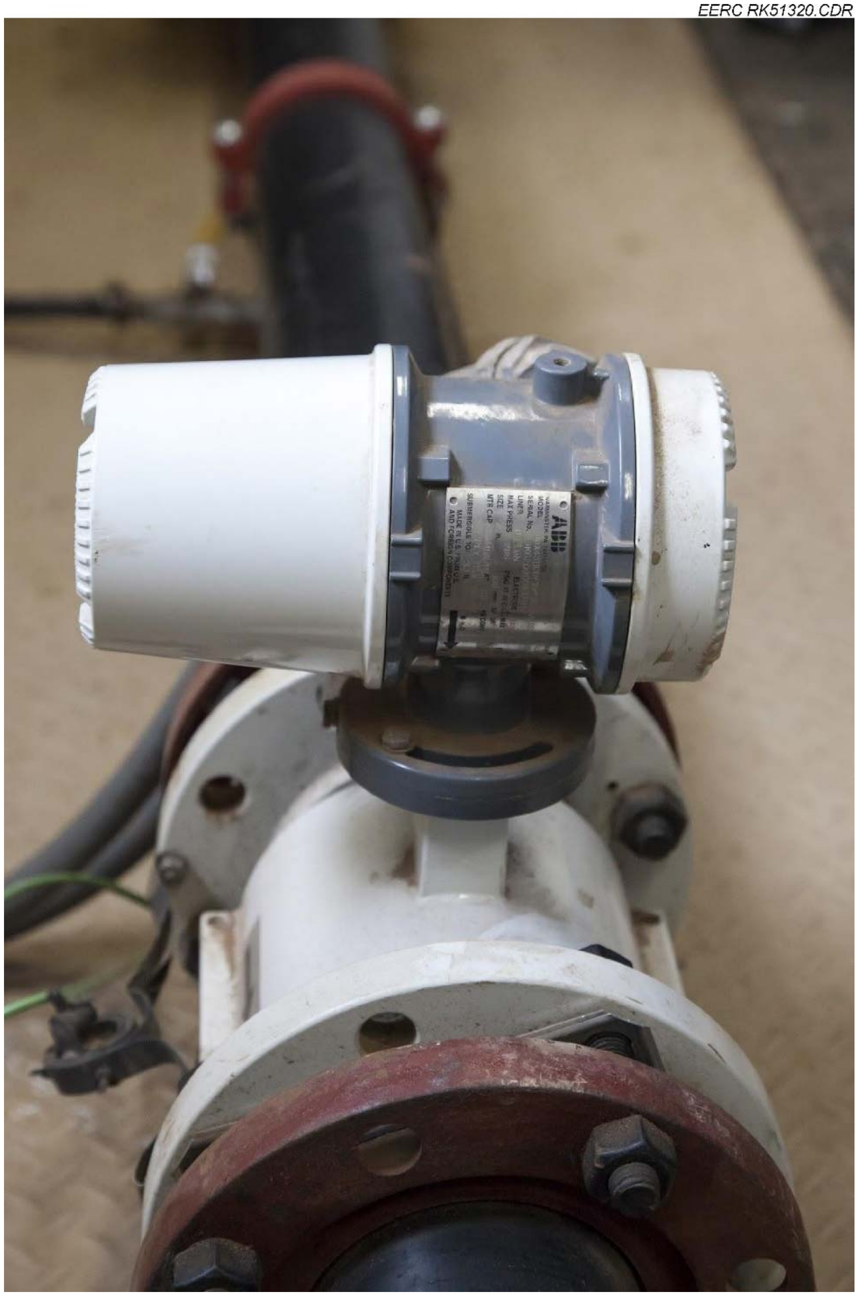

Figure D-42. Image of FEP 300 ABB electromagnetic flowmeter in field.

The Company

ABB is an established world force in the design and manufacture of instrumentation for industrial process control, flow measurement, gas and liquid analysis and environmental applications. As a world leader in process automation technology our worldwide presence, comprehensive service and application oriented know-how make ABB a leading supplier of flow measurement products.

Introduction

Setting the standard for the process industry

ProcessMaster is designed specifically to meet the increased requirements on advanced flowmeters. The modular design concept offers flexibility, cost-saving operation and reliability whilst providing a long service life and exceptionally low maintenance.

Integration into ABB asset management systems and usage of the selfmonitoring and diagnostic functions increase the plant availability and reduce downtimes.

ScanMaster - the diagnostic tool

Can I rely on the measured values?

How can I determine the technical condition of my device? ScanMaster can answer these frequently asked questions.

And ScanMaster allows you to easily check the device for proper functioning either through its Infra-red service port or through the HART commands.

Advanced diagnostic functions

Using its advanced diagnostic functions, the device monitors both its own operability and the process.

Limit values for the diagnostic parameters can be set locally. When these limits are exceeded, an alarm is tripped.

For further analysis, the diagnostic data can be read out via an advanced DTM. Critical states can, thus, be recognized early and appropriate measures can be taken.

As a result, productivity is increased and downtimes are avoided. The status messages are classified in accordance with the NAMUR recommendations.

In the event of an error, a diagnostic-dependent help text appears on the display which considerably simplifies and accelerates the troubleshooting procedure. The gives maximum safety for the process.

Flow performance

Using a higher excitation frequency for the transmitter, ProcessMaster is a flowmeter with an especially short response time. With its advanced filtering methods, the device improves accuracy even under difficult conditions by separating the noise from the measuring signal. This leads to a maximum measuring error of 0.2 % of rate. Self-cleaning, double-sealed polished measuring electrodes enhance the device's reliability and performance.

Easy and quick commissioning

Advanced data storage inside the sensor eliminates the need to match sensor and transmitter in the field. The on-board sensor memory automatically identifies the transmitter. On power-on, the transmitter self-configuration function is run and replicates all sensor data and TAG specific parameters into the transmitter. This eliminates the opportunity for errors and leads to an increased startup speed and reliability.

Intuitive, convenient navigation

The factory-set parameters can be modified quickly and easily via the user-friendly display and the non-contact buttons, without opening the housing.

The "Easy Set-up" function reliably guides unpracticed users through the menu step by step.

The softkey-based functionality makes handling a breeze - it's just like using a cell phone. During the configuration, the permissible range of each parameter is indicated on the display and invalid entries are rejected.

Universal transmitter - powerful and flexible

The backlit display can be easily rotated without the need for any tools. The contrast is adjustable and the display fully configurable. The character size, number of lines and display resolution (number of decimals) can be set as required. In multiplex operation, several different display options can be pre-configured and invoked one after the other.

The smart modular design of the transmitter unit allows for easy disassembly without the need to unscrew cables or unplug connectors.

Whether count pulses, 20 mA signals or the status output are active or passive, the universal transmitter always delivers the correct signal. HART is used as the standard protocol. Optionally, the transmitter is available with PROFIBUS PA or FOUNDATION Fieldbus communication.

The universal transmitter simplifies the spare parts inventory and reduces the stockholding costs.

Figure D-43. ABB-provided FEP 300 ABB electromagnetic flowmeter specification data sheet (page 2).

Assured quality

ProcessMaster is designed and manufactured in accordance with international quality procedures (ISO 9001) and all flowmeters are calibrated on nationally-traceable calibration rigs to provide the end- user with complete assurance of both quality and performance of the meter.

ProcessMaster - always the first choice

ProcessMaster sets the standard for the process industry. It meets the various requirements of NAMUR. ProcessMaster is a universal device according to the Pressure Equipment Directive. In compliance with the requirements of NAMUR, the devices are categorized under category III for pipelines. As a result, ProcessMaster can be used universally. This reduces costs and increases safety.

Overview of the ProcessMaster series

ProcessMaster is available in two series. ProcessMaster 300, which sets the standard in Process Flow measurement and ProcessMaster 500 with best in class extended functionality and options. The following table gives an overview.

	ProcessMaster	
	FEP300	**FEP500**
Measuring accuracy 0.4 % (optionally 0.2 %) of rate	X	-
Measuring accuracy 0.3 % (optionally 0.2 %) of rate	-	X
Batch functions Presetting counter, overrun correction, external start/stop, batch end contact	-	X
Other software functions Mass units, editable counter,	X	X
Two measuring ranges	-	X
Graphic display Line recorder function	X	X
Diagnostic functions Detection of gas bubbles or deposits on electrodes, conductivity monitoring, temperature monitoring, finger print, trend	-	X
Partially filled Recognition through partial filling electrode (TFE)	X	X
Hardware options Versions for extremely abrasive fluids: • Ceramic carbide liner, • Wolfram carbide electrodes, • Double layer electrodes	-	X
Startup functions Grounding check	-	X
Fieldbus PROFIBUS PA, FOUNDATION Fieldbus	X	X
Verifications / Diagnostic tool ScanMaster	X	X

This data sheet describes ProcessMaster 300.
For ProcessMaster 500 refer to data sheet DS/FEP500

Figure D-44. ABB-provided FEP 300 ABB electromagnetic flowmeter specification data sheet (page 3).

Overview – models

Integral mount design

FEP311 (without explosion protection)	FEP315 (Zone 2 / Division 2)	FEP315 (Zone 1 / Division 1)
1), 3) 2), 3) 2), 4) 2), 5)	1), 3) 2), 3) 2), 4)	2), 3) 2), 4)
		

Measured error	Default: 0.4 % of measured value, 0.2 % of measured value
Nominal diameter range	DN 3 ... 2000 (1/10 " ... 80 ")
Process connection[6]	Flange in accordance with DIN 2501 / EN 1092-1, ASME B16.5 / B16.47, JIS, AS2129
Nominal pressure	PN 10 … 100, ASME CL 150, 300, 600, 900, 1500, 2500
Liner	Hard rubber (DN 15 ... 2000), soft rubber (DN 50 ... 2000), PTFE (DN 10 ... 600), PFA (DN 3 ... 200), ETFE (DN 25 ... 600), Linatex (DN 50 ... 600)
Conductivity	> 5 µS/cm (20 µS/cm for demineralized water)
Electrodes	Stainless steel, Hastelloy B, Hastelloy C, platinum-iridium, tantalum, titanium, tungsten carbide
Process connection material	Steel, stainless steel
IP rating	IP 65, IP 67
Measuring medium temperature	-25 ... 180 °C (-13 ... 356 °F)
Power supply	100 ... 230 V AC (-15 / +10%), 24 V AC (-30 / +10%), 24 V DC (-30 / +30%)
current output	4 ... 20 mA, active or passive
Pulse output	Can be configured locally as active or passive using software
Switch output / switch input	Optoelectronic coupler, programmable function
Display	Graphical display, configurable
Housing	Integral mount design: choice of single-compartment housing or dual-compartment housing.
Communication	HART protocol (standard), PROFIBUS PA, FOUNDATION Fieldbus (option)
Explosion protection approvals	• ATEX / IECEx zone 1, 2, 21, 22 • NEPSI zone 1, 2 • FM / cFM Cl 1 Div 1 (≤ DN 300), Cl 1 Div 2 • GOST zone 1, 2
Pressure Equipment Directive 97/23/EC	Conformity assessment in accordance with category III, fluid group 1
CRN (Canadian Reg.Number)	On request

1) Single-compartment housing.
2) Dual-compartment housing.
3) Design level "B" sensor.
4) Design level "B" sensor, all versions made from stainless steel.
5) Design level "C" sensor, DN 25 … 600.
6) For information on flange thicknesses, see the chapters entitled "Dimensions for sensor design level „B"" on page 37 and "Dimensions for sensor design level „C"" on page 43.

Figure D-45. ABB-provided FEP 300 ABB electromagnetic flowmeter specification data sheet (page 4).

D.7.8 PRESSURE SENSOR SPECIFICATIONS

NOSHOK pressure sensors will be used in the pipeline and in the casing and tubing of all new and existing wells to continuously monitor pressures. NOSHOK pressure sensors are the industry standard in pressure sensor technology. Technical information about the sensors is provided in Figures D-46 and D-47.

Industrial Pressure Transmitters & Transducers

Current Output

CE

100 SERIES

- Vacuum and compound ranges through 0 psig to 15,000 psig
- Current output
- 316 and 17-4PH stainless steel wetted parts
- CE compliant to suppress RFI, EMI and ESD

APPLICATIONS

- HVAC
- Hydraulics & pneumatics
- Injection molding machines
- Railroad equipment
- Stamping & forming presses

SPECIFICATIONS

Output signal	4 mA to 20 mA, 2-wire
Pressure ranges	Vacuum through 0 psig to 15,000 psig Absolute from 0 psia to 15 psia through 0 psia to 300 psia
Accuracy	±0.5%full scale (BFSL); optional ±0.25%full scale (BFSL); (Includes the effects of non-linearity, hysteresis, non-repeatability, zero point and full scale errors)
Stability	≤ ±0.2%full scale for 1 year, non-accumulating
Adjustment	≤ ±10%full scale for zero and span
Response time	≤ 1 ms (between 10%and 90%full scale)
Pressure cycle limit	150 Hz
Durability	> 100,000,000 full scale cycles
Temperature ranges	Compensated 32 °F to 176 °F (0 °C to 80 °C) Effect ±0.017%full scale/ °F for zero and span Media -22 °F to 212 °F (-30 °C to 100 °C) Ambient -40 °F to 185 °F (-40 °C to 85 °C) Storage -40 °F to 212 °F (-40 °C to 100 °C)
Power requirement*	10 Vdc to 30 Vdc (4 mA to 20 mA, 2-wire)
Load limitations	≤ (Vpower supply -10)/.020 Amp
Proof pressure	3 times full scale for ranges 0 psi to 5 psi through 0 psi to 200 psi 1.75 times full scale for ranges 0 psi to 300 psi through 0 psi to 10,000 psi 1.5 times full scale for 0 to 15,000 psi
Burst pressure	3.8 times full scale for ranges 0 psi to 5 psi through 0 psi to 200 psi 4 times full scale for ranges 0 psi to 300 psi through 0 psi to 10,000 psi 3 times full scale for 0 psi to 15,000 psi
Measuring element	316 stainless steel for vacuum through 300 psi; 17-4PH stainless steel for ≥500 psi
Connection	316 stainless steel
Housing material	316 stainless steel
Environmental rating	IP65
Electromagnetic rating	CE compliant to EMC norm EN 61326:1997/A1:1998 RFI, EMI and ESD protection
Electrical protection	Reverse polarity, over-voltage and short circuit protection
Shock	1000 g's according to IEC 60068-2-27
Vibration	30 g's according to IEC 60068-2-6
Weight	Approximately 3.5 oz.

* Unregulated

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Figure D-46. NOSHOK-provided 100 Series pressure sensor transmitters and transducers specification data sheet (page 1).

ORDERING INFORMATION						
SERIES	**100**					
PRESSURE RANGES	**30vac** -30 inHg to 0 psig	**5** 0 psig to 5 psig	**200** 0 psig to 200 psig	**3000** 0 psig to 3,000 psig	**15A** 0 psia to 15 psia	
	30/15 -30 inHg to 15 psig	**10** 0 psig to 10 psig	**300** 0 psig to 300 psig	**4000** 0 psig to 4,000 psig	**30A** 0 psia to 30 psia	
	30/30 -30 inHg to 30 psig	**15** 0 psig to 15 psig	**500** 0 psig to 500 psig	**5000** 0 psig to 5,000 psig	**60A** 0 psia to 60 psia	
	30/45 -30 inHg to 45 psig	**25** 0 psig to 25 psig	**600** 0 psig to 600 psig	**6000** 0 psig to 6,000 psig	**100A** 0 psia to 100 psia	
	30/100 -30 inHg to 100 psig	**30** 0 psig to 30 psig	**750** 0 psig to 750 psig	**7500** 0 psig to 7,500 psig	**150A** 0 psia to 150 psia	
	30/150 -30 inHg to 150 psig	**60** 0 psig to 60 psig	**1000** 0 psig to 1,000 psig	**10000** 0 psig to 10,000 psig	**200A** 0 psia to 200 psia	
	30/200 -30 inHg to 200 psig	**100** 0 psig to 100 psig	**1500** 0 psig to 1,500 psig	**15000** 0 psig to 15,000 psig	**300A** 0 psia to 300 psia	
	30/300 -30 inHg to 300 psig	**150** 0 psig to 150 psig	**2000** 0 psig to 2,000 psig			
		psig = gauge pressure	psia = absolute pressure	Other ranges available on request		
ACCURACIES	**1** ±0.5%full scale (BFSL)		**2** ±0.25%full scale (BFSL)			
OUTPUT SIGNAL	**1** 4 mA to 20 mA, 2-wire					
PROCESS CONNECTIONS	**1** 1/8" NPT male	**3** SAE J1926-3:7/16-20 Adjustable		**9** SAE J1926-1:7/16-20		
	2 1/4" NPT male	**4** 1/8" NPT female		**10** G1/4 male		
ELECTRICAL CONNECTIONS	**1** 36" cable (connected to option 7)		**6** 1/2" NPT conduit (with 36" cable)		**25** M12 x 1 (4-pin)	
	2 4-pin Bendix		**7** Mini-Hirschmann (DIN EN 175301-803 Form C)		**36** Integral cable 36"	
	3 6-pin Bendix					
OPTION	**ST8** Threaded Orifice					

Please consult your local NOSHOK Distributor or NOSHOK, Inc. for availability and delivery information.

EXAMPLE **100 – 500 – 1 – 1 – 2 – 7 – ST8**

Series .... 100 Series
Pressure range .... 0 psig to 500 psig
Accuracy .... ±0.5%full scale (BFSL)
Output signal .... 4 mA to 20 mA, 2-wire
Process connection .... 1/4" NPT Male
Electrical connection .... Mini-Hirschmann
Option .... Threaded Orifice

Load Limitations 4 mA to 20 mA output		
Vmin	=	10V + (.020 x RL)
RL	=	Loop resistance (Ω) RL = RS + RW
RS	=	Sensor resistance (Ω)
RW		Wire resistance (Ω)

1/2" NPT conduit with 36" jacketed cable *** 6 pin Bendix** *** 4 pin Bendix** *** M12 x 1 (4-pin)**

Mini-Hirschmann

WIRING				
Wire	**Bendix 4-pin or 6-pin**	**Mini-Hirschmann**	**Cable**	**M12 x 1**
+ Supply	pin A	pin 1	Red	pin 1
+ Output	pin B	pin 2	Black	pin 3

* Note: Mate supplied separately or customer supplied.

Figure D-47. NOSHOK-provided 100 Series pressure sensor transmitters and transducers specification data sheet (page 2).

D.7.9 DENSITY METER SPECIFICATIONS

Density meters provide the ability to measure fluid extraction and injection volumes and identify changes in fluid properties. Data obtained from density meters will be used for calibration of the reservoir simulation model, which will allow for more accurate results. Emerson FDM 7828 density meters were chosen for the project because of their accuracy, adaptability, and ease of integration into our proposed SCADA system.

D.7.10 COMMAND CENTER

A multipurpose mobile command center will be purchased to provide office and work center space for project personnel and logistical support, a laboratory to conduct routine water analyses (pH, conductivity, alkalinity, hardness, etc.), conferencing and project-related meetings, bunk space, and secure storage for project supplies and equipment. Internet connectability for communications and data transfer capabilities will be provided with a Verizon Wireless hot spot device. A basic layout of the command center is illustrated below (Figure D-48).

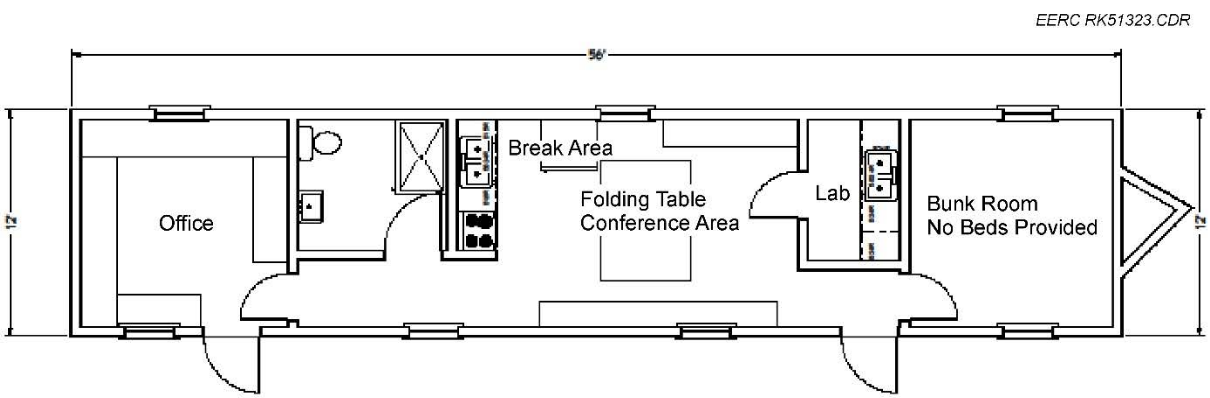


Figure D-48. Command center 12’ × 56’ layout design provided by contractor.

D.8 REFERENCES

Plastics Pipe Institute, 2009, Handbook of polyethylene pipe, 2d ed.

Energy & Environmental Research Center, 2015, Liquids gathering pipelines—a comprehensive analysis: Report for the North Dakota Industrial Commission and the North Dakota Legislative Energy Development and Transmission Committee, Grand Forks, North Dakota, Energy & Environmental Research Center, December.

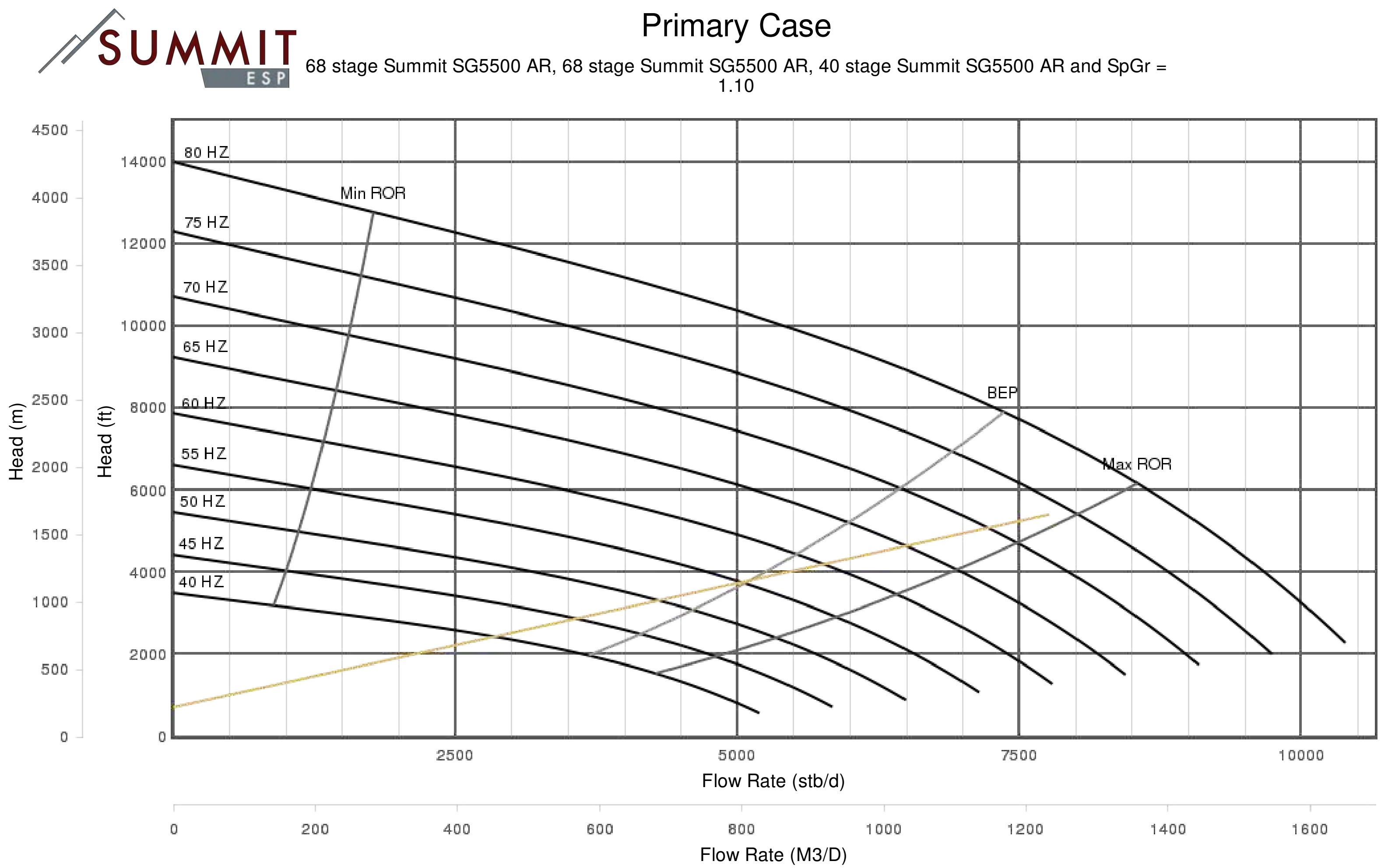
APPENDIX D-1

SUMMIT ESP SIZING REPORT

Sizing Report

Customer	Well Name	Sizing Name	Date
EERC	Dakota WSW	EERC WSW Dakota	3/11/2016

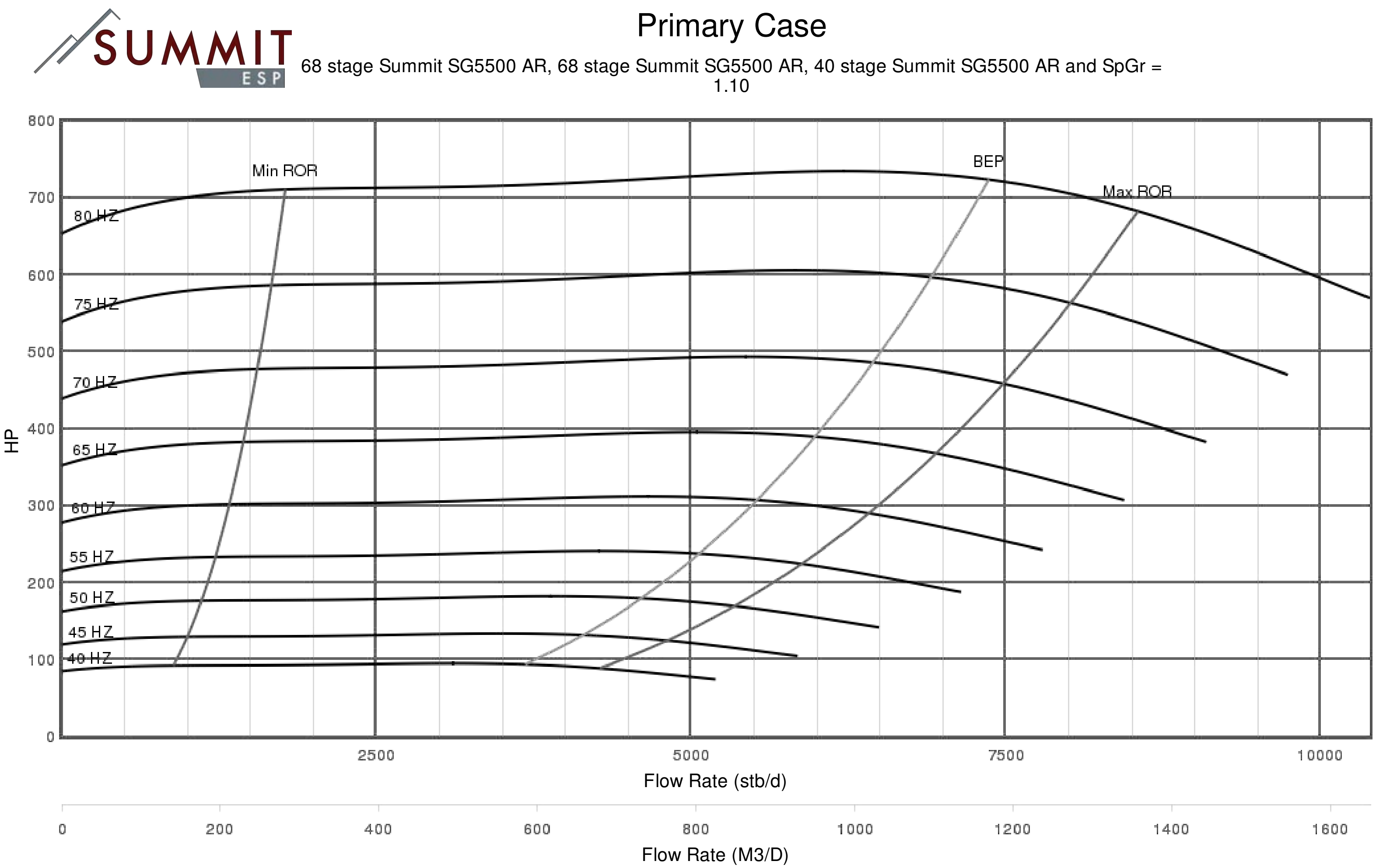
Head Curve (multifrequency)



Sizing Report

Customer	Well Name	Sizing Name	Date
EERC	Dakota WSW	EERC WSW Dakota	3/11/2016

BHP Curve (multifrequency)



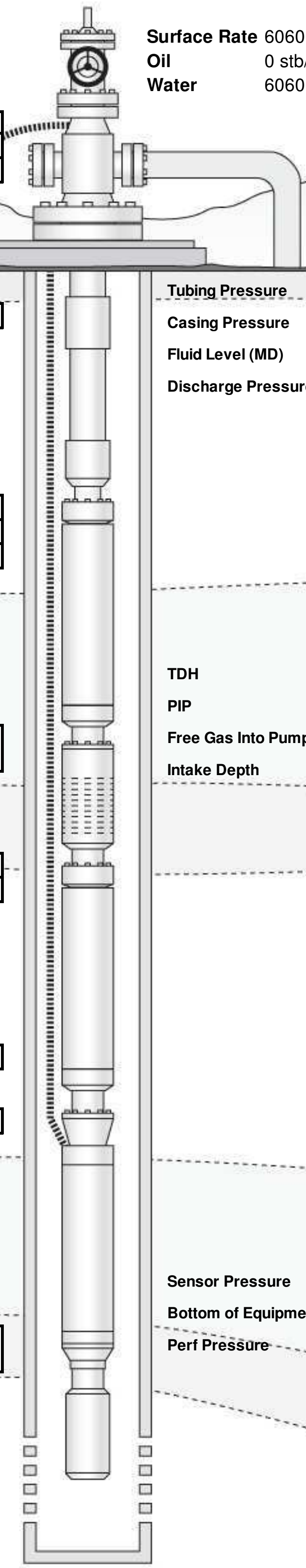
Sizing Report

Design Schematic / Primary Case

Customer EERC
Well Dakota WSW
Sizing EERC WSW Dakota
Date 3/11/2016

Surface Rate 6060 stb/d
Oil 0 stb/d
Water 6060 stb/d

Motor HP @62.5 hz	351 hp
Motor Voltage	3223 V
Motor Amperage	58.5 A
Surf. Volts @62.5 hz	3.3 kV
Pump Length	56.7 ft
Intake Length	1.2 ft
Seal Length	17.8 ft
Motor Length	23.4 ft
Sensor Length	
Equipment Length	102.77 ft



	Description	Length
SD Xfrmr		
VSD	Summit 806067, 730A, AFE, NEMA 3R	
SU Xfrmr	Summit 900005, 480, 1100-3811	

	Description	Length
Cable 1	Summit Flat 2ga SELF Galv	5100 ft

Tubing Pressure	90 PSIA
Casing Pressure	10 PSIA
Fluid Level (MD)	4183 ft
Discharge Pressure	2545 PSIA

	Description	Length
Pump 1	Summit 513 Series, 68 Stage SG5500 AR	21.7 ft
Pump 2	Summit 513 Series, 68 Stage SG5500 AR	21.7 ft
Pump 3	Summit 513 Series, 40 Stage SG5500 AR	13.3 ft

TDH	4402 ft
PIP	478 PSIA
Free Gas Into Pump	0%
Intake Depth	5180 ft

	Description	Length
ITK/GS 1	Summit 513 CT Bolt-On_Intake_A/R_513X_416/420 Stainless Steel SS Monel Shaft	1.2 ft

	Description	Length
Seal 1	Summit 513 BPBSL_Premium Seals_AR Bearings (Sand Seal) CS HL	8.9 ft
Seal 2	Summit 513 LsBsB CS HL	8.9 ft

	Description	Length
MLE	Summit 110' 562 KELB	110 Feet

	Description	Length
Motor	Summit 562 , 360 HP, 3175 V, 62 A	23.4 ft

Sensor Pressure	489 PSIA
Bottom of Equipment	5203 ft
Perf Pressure	483 PSIA

	Description	Length
Sensor	Sensor_150 C Temp._5 Channel_w/456 Head_ Stainless Steel Sensor_150 C Temp._5 Channel_w/456 Head_ Stainless Steel SS	3.67 ft

SUMMIT ESP

Sizing Report

Design Overview

Customer EERC
Well Dakota WSW
Sizing EERC WSW Dakota
Date 3/11/2016

Well Information

	Value	Primary Case
Casing		
	Size / Weight	7 x 26 (lb/ft)
Tubing		
	Size/Weight	4 1/2 x 9.5 (lb/ft)
Top of Perfs		
	Measured Depth	
	True Vertical Depth	
Fluid Properties		
	Oil API	21 API
	Water SG	1.1 SpGr
	Gas SG	0.65 SpGr
Well Test Info		
	Oil Rate	0 stb/d
	Water Rate	6000 stb/d
	Total Liquid Rate	6000 stb/d
	Water Cut	100 %
	Gas Rate	0 mscf/d
	Bubble Point	6000 PSIA (Calculated)
	Datum Point	5190 ft
	Static Datum Pressure	2200 PSIA
	Producing Datum Pressure	500 PSIA
	Surface Temperature	
Design Conditions		
	Tubing Size	4 1/2 x 9.5 (lb/ft)
	Tubing Length	5122 ft
	Pump Setting Depth	5180 ft
	Casing Pressure	10 PSIA
	Tubing Pressure	90 PSIA
	Desired Rate	6000 stb/d
	Pump Intake Pressure	495 PSIA

Equipment

	Value	Primary Case
Equipment Selection		
	Pumps	Summit 513 Series, 68 Stage SG5500 AR Summit 513 Series, 68 Stage SG5500 AR Summit 513 Series, 40 Stage SG5500 AR
	Intake/GS	Summit 513 CT Bolt-On_Intake_A/R_513X_416/420 Stainless Steel SS Monel Shaft
	Seal	Summit 513 BPBSL_Premium Seals_AR Bearings (Sand Seal) CS HL Summit 513 LsBsB CS HL
	Motor	Summit 562 , 360 HP, 3175 V, 62 A
	Sensor	Sensor_150 C Temp._5 Channel_w/456 Head_ Stainless Steel Sensor_150 C Temp._5 Channel_w/456 Head_ Stainless Steel SS

Theoretical Production Data

Value		Primary Case
Theoretical Production Data		
	Operating Frequency	62.5 hz
	Fluid Rate	6060 stb/d
	Gas Rate	0 mscf/d
	Oil Rate	0 stb/d
	Water Rate	6060 stb/d
	Tubing Pressure	90 PSIA
	Casing Pressure	10 PSIA
	Fluid Level (MD)	4183 ft
	Pump Discharge Pressure	2545 PSIA
	Pump Intake Pressure	478 PSIA
	Free Gas Into Pump	0%
	Sensor Pressure	489 PSIA
	Datum Pressure	483 PSIA
	Perf Pressure	483 PSIA

APPENDIX D-2

PROMORE INSTALL PROCEDURE MORE^{S}

Job Number	
Quote Number	**QC16-024-1**
Project Description	**Brine Extraction and Storage Test Project**
Well Location	**Rink 1 and Rink 2**

This procedure outlines the activities required to successfully install a PROMORE MORE^{S} (suspended) Monitoring System for EERC at their Brine Extraction and Storage Test (BEST) Project in McKenzie County, North Dakota. It covers the following activities:

Table of Contents

A. Project Description

EERC, based in Grand Forks, North Dakota, is instrumenting two (2) existing injection wells as part of their surveillance program for their BEST Project.

Wells scheduled for monitoring are Rink 1 and Rink 2. Both wells are vertical, with Dakota Formation injection depths (top perforation depth) at 5,324 feet and 5,404 feet; respectively. The monitoring system will be suspended, via tube encapsulated cable (TEC), from the top of the wellhead. The downhole gauge will exit the end of tubing, and be positioned immediately above the top perforations - providing real time pressure/temperature during injection and shut-in.

B. Downhole and Surface Equipment Required

Refer to *Appendix A – Downhole and Surface Equipment Check List*

C. Installation Tools Required

Refer to *Appendix B – Installation Tools Check List*

D. Spooling Unit and Equipment Required

Field service operations (gauge installation) will be coordinated between PROMORE, RECON Wireline Service and a local 3rd Party Crane Service . Each company will provide the following equipment and services:

PROMORE

1. Downhole gauge (Model: MS1-MT-5000-1.375)
2. Sinker bar (1.375 inch OD x 6 foot – threaded to bottom of gauge)
3. Instrument cable (Model: TEC-0.250" OD x 0.035" Wall-INC825-1 Conductor-300F)
4. Wellhead hanger/packoff assembly (Model: WHSA-5000)
5. Cable clamp hanger plate
6. Cable clamp
7. Top cable sheave
8. Lower cable sheave and sheave stand
9. Scaffold (to allow working at the top of the wellhead)

RECON Wireline Service

1. Hydraulic cable spooling unit (with pneumatic and mechanical drum brake)
2. Cable measuring head (digital counter with display)
3. Weight indicator assembly
4. Pressure control equipment (thru-tubing lubricator, packoff head, thru-tubing BOP)

3rd Party Crane Service

1. Crane unit (with sufficient mast extension to suspend the sheave and traveling hook to support the lubricator)

E. Equipment and Assistance Supplied by EERC

To ensure this installation is completed safely, and to expectations, PROMORE is requesting EERC provide the following assistance and supplies:

Pre-Job

1. Provide the following information
   a) Well name
   b) Confirm gauge depth (top of perforations)
   c) Confirm end of tubing (EOT) depth

d) KB elevation
e) Thread connection at top of wellhead (size and type – required prior to manufacturing)
f) Directions to location
g) Confirmation of date and time of installation
h) Contact information for EERC Wellsite Representative

F. Personnel Required

The PROMORE US Operations Coordinator (based in Houston, Texas) will be coordinating field installation operations and on-going customer service support. This individual will be responsible for directing project planning and ensuring pre-job testing of all equipment if performed.

PROMORE will provide one (1) Engineer and one (1) Operator. Likewise, RECON will provide one (1) Engineer and one (1) Operator.

The PROMORE Engineer will be responsible for:

1. Directing and supervising activities of all gauge-related personnel on location
2. Assembling the gauge on the instrument cable and confirming gauge operation before RIH
3. Cable measurement during installation, ensuring the gauge is landed at its required depth
4. Confirm gauge operation once gauge depth is reached
5. Makeup of gauge hanger and wellhead packoff assembly
6. Gauge tie-in to MOREVision surface data acquisition (gauge interrogator) unit
7. Tie-in data output to EERC SCADA on location (if applicable)
8. Confirm gauge operation prior to leaving location

RECON Wireline will provide necessary personnel to mobilize (and operate) the cable spooling unit and pressure control equipment.

G. Rig Up of Installation Equipment

<u>Pre-Installation Action</u>

1. EERC Safety Orientation of PROMORE and RECON personnel (if required).
2. Well site Safety Meeting to be conducted with the EERC Representative on location. Points to highlight include:
   a. Cable and mast unit placement near wellhead
   b. Sheave suspended from the mast unit
   c. Pressure control equipment and its proper operation
   d. Opening wellhead master valve – one person is responsible

3. Confirm required sensor depth with the EERC Representative on location. Confirm the instrument cable length available is sufficient.
4. The system will be monitoring reservoir pressure and temperature, and be landed immediately above the perforations.
5. Discuss and explain the landing out procedure and pressure rating of the PROMORE Wellhead Suspended Hanger Assembly (WHSA) with the EERC Representative.
6. Once these issues have been discussed, record sensor integrity readings on the PROMORE Field Receipt.

Cable Spooling Equipment Set Up

The injection well is perforated in an aquifer (Dakota Formation). Even though the well will be dead (zero pressure) during installation operations, full pressure control will be utilized; consisting of: packoff head, thru-tubing lubricator and thru-tubing BOP.

1. Verify the wellhead pressure is safe for personnel to work – zero (0) pressure.
2. Position the rear bumper of the RECON Wireline unit approximately fifty (50) feet from the wellhead.
3. The mast unit should be positioned 90 degrees to the cable spooling unit, with the rear bumper approximately ten (10) feet from the wellhead.
4. There must be a direct and clear line-of-sight between the RECON Engineer, operating the controls of the cable spooling unit, the wellhead and the cable sheaves.

   If the cable spooling unit cannot be positioned at the appropriate location, it must be positioned such that there is no danger of the instrument cable being damaged when running in the hole.
5. Erect the scaffolding beside the wellhead.
6. Dress the PIN threads on the WHSA (Appendix D) with approved thread lubricant/dope and tighten into the top of the wellhead.

   Visually inspect the inside of the WHSA body to confirm the lugs nuts are in their full “OPEN” position.
7. Dress the PIN threads of the wireline BOP cross-over sub (supplied by RECON) with thread lubricant/dope and tighten into the top of the WHSA.
8. Use the crane to hoist the BOP above the wellhead. Attach the thru-tubing wireline BOP to the cross-over sub.

   Ensure the BOP is outfitted with sealing inserts for 0.250 inch OD capillary tube cable.
9. Visually inspect inside the BOP to ensure rams are in the full “OPEN” position.
10. Starting close to the wellhead, assemble the pressure control equipment on the ground; consisting of:

a. Wireline packoff – with cable guides and seal inserts for 0.250 inch OD capillary tube
b. Lubricator joint (8 foot)
c. Lubricator pup joint with pressure bleed-off port and needle valve (3 foot)

Ensure the total length of lubricator is sufficient to house the PROMORE gauge and sinker bar.

10. Spool out approximately 75 feet of TEC onto the ground; in numerous “S” shapes. Ensure there are no obstacles or obstructions that may cause damage to the cable.
11. Pass the TEC thru the assembled lubricator – starting at the packoff head. The TEC cablehead will be pre-built on the TEC.

    Assemble the internal components associated with the lubricator packoff head and attach the hydraulic hose. Secure a lifting sling around the base of the packoff head.
12. Using a safety clevis, attach the top sheave to the boom of the crane.

    Do not attach the sheave to the traveling hook. The hook will be utilized for raising and lowering of the lubricator and wireline packoff.

    Open the side entry gate of the top sheave and feed the TEC into the wheel groove of the sheave. Close the gate and secure in position with the supplied safety pin.

    With the PROMORE Engineer holding the TEC cablehead, instruct the crane Operator to slowly raise the boom and position the top sheave directly above the wellhead.
13. Attach the bottom sheave to the wellhead via 0.750 inch OD wire rope sling and safety clevis.

    Position the sheave into the sheave stand.

    Open the side entry gate of the bottom sheave and feed the instrument cable into the groove wheel. Close the gate and secure in position with the supplied safety pin.
14. Lower the crane hook. Loop a lifting sling around the base of the lubricator packoff head and attach to the hook. Slowly raise the pressure control equipment above the wellhead.
15. Attach the sinker bar to the bottom of the gauge. Tighten.
16. Attach the TEC cablehead to the top of the gauge. Tighten. Record sensor integrity readings on the PROMORE Field Receipt.
17. The RECON Engineer will spool any excess TEC back onto the cable drum.

    The PROMORE Engineer must tend the cable to ensure it does not become damaged during re-spooling.

    Continuing spooling until the gauge tool is suspended above the wellhead.
18. If necessary, adjust the position of the top sheave to ensure the gauge tool is centered directly over the wellhead.

19. Lower the bottom of the gauge to ground level and zero the depth counter for KB elevation.

H. Running of Suspended Gauge and Instrument Cable

1. Visually inspect the inside of the BOP to confirm the seal rams are in their full "OPEN" position, and no obstructions exist.
2. The RECON Engineer will slowly reel in the cable, while the PROMORE Engineer guides the gauge into the lubricator.
3. Lower the lubricator and makeup the connection to the BOP.
4. Ensure the pressure bleed-off port (needle valve) associated with the lubricator is closed and oriented away from the crane and wireline unit.
5. Carefully pull the gauge to the top of the lubricator. The PROMORE Engineer must pull down on the capillary tube cable (between the wellhead and the wireline unit) to prevent "crowing-out" the gauge.
6. Designate the PROMORE Operator as the individual responsible for opening and closing the master valve.

   Although no pressure is anticipated, ensure the master valve is opened SLOWLY, to allow any pressure to equalize in the lubricator.

   Count the number of revolutions of the valve handle for the master valve to reach full open position.
7. With the wireline unit hydraulics in low gear, slowly descend the gauge into the well. It may be necessary to assist its descent by hand until sufficient line weight is in the hole.
8. Slow descent of the gauge as tubing bottom is neared.

   Continue slow descent until the bottom of the sinker bar is ten (10) feet below the top perforation depth. Stop descent and "pull back" past the intended landing depth by a distance equal to the length between the top of the BOP and the lag bolts associated with the WHSA wellhead hanger, plus an additional two (2) feet.

   The WHSA hanger and seal assembly is one (1) foot in length and will be built one (1) foot atop the BOP. When complete, and landed, the bottom of the sinker bar will be at the top perforation depth.
9. Once the proper depth is reached, stop the cable reel and engage the drum brake.

   Take note of, and record, the BHA weight on the weight indicator.

   Record sensor integrity readings on the PROMORE Field Receipt.
10. If instrument integrity is intact, proceed with building the surface hanger/packoff assembly.

I. Surface Termination of Instrument Cable

1. Close the wireline BOP rams; sealing around the instrument cable.

   Ensure the manual handles associated with the BOP are closed equally, to properly guide and seal around the capillary tube cable.

2. Slowly open the bleed-off valve on the lubricator. Allow all pressure (if any) to bleed-off.
3. Undo the connection between the top of the BOP and lubricator bleed-off pup joint.
4. Raise the lubricator stack eight (8) feet above the BOP.
5. The PROMORE Engineer will visually inspect the instrument cable seal within the BOP.

   Install the cable clamp hanger plate around the TEC and position it so it rests directly on top of the BOP.

7. Install the TEC cable clamp around the TEC. Ensure the bottom of the clamp is resting on the hanger plate. Mark the TEC at the top of the TEC cable clamp with a black marker.
8. Release tension on the TEC by spooling off one (1) foot of cable from the cable reel. Visually inspect the clamp and cable to ensure the cable is not sliding through the clamp – the black mark should not move.
9. Measure one (1) foot up from the top of the BOP. Mark the TEC with a permanent marker. This mark represents the intended cut point.
10. Attach twelve (12) feet of rope to the TEC, at a position one (1) foot above the intended cut point. Tie the rope to the wellhead, to ensure the TEC does not pull through the lubricator once it's cut.
11. Cut the TEC at the measured location and begin building the hanger/packoff assembly associated with the WHSA.
12. Once the hanger/packoff assembly is complete, re-attach the TEC (tied-off with rope) to the upper-most cable anchor of the hanger/packoff assembly.

    Apply Lithium (white) grease to the o-rings on the hanger/packoff assembly.

13. Slowly pull tension on the TEC with the wireline unit until line tension is re-gained.
14. Remove the TEC clamp and hanger plate.
15. Slowly lower the lubricator, guiding it as it passes over the hanger/packoff assembly.
16. Makeup the lubricator connection to the BOP. Close the bleed-off port on the lubricator.
17. Slowly open the BOP to its full "OPEN" position.
18. Slowly descend the gauge to land the hanger/packoff assembly in the WHSA body.
19. Tighten the lag bolts (3) associated with the WHSA body to anchor the hanger/packoff assembly in place.

    Equally tighten each lag bolt. Visual confirmation that the hanger/packoff assembly is properly landed is performed by locating the machined alignment groove in each lag bolt.

20. Open the bleed-off port on the lubricator. Once any trapped pressure is bled off, undo the BOP connection to the wellhead cross-over sub and raise the BOP and lubricator six (6) feet above the wellhead.
21. PROMORE Engineer to visually inspect the hanger/packoff assembly.
22. Remove the upper-most cable anchor associated with the hanger/packoff assembly.

    Record sensor integrity readings on the PROMORE Field Receipt.
23. Hand tighten the tapped bull plug into the WHSA body. This will protect the packoff/hanger assembly while installation equipment is rigged out.
24. Rig out pressure control equipment, sheaves, cable, wireline unit and mast unit.

    Release wireline unit and mast unit.
25. PROMORE Engineer will complete the secondary seal assembly associated with the WHSA.
26. Record sensor readings on the PROMORE Field Receipt.
27. Install "**DO NOT CLOSE VALVE . . . INSTRUMENTATION CABLE**" tag on master valve.
28. Consult with the EERC Representative, on location, to determine the placement of the MOREVision surface data acquisition unit and stand.
29. Build and install the surface instrumentation TECH cable (1-pair) from the explosion proof junction box (associated with the WHSA packoff) to the MOREVision unit.

    Leave sufficient slack (10 feet) at the wellhead and at the MOREVision; to allow for trenching and burying of the TECH cable.

29. If applicable, coordinate data output to EERC SCADA (on location) or wireless communication device with an EERC Automation Representative.

    Regardless, bottomhole pressure and temperature data will be archived to the internal memory associated with the MOREVision unit.

    Archive "30 Minute Post Installation" data set.

    PROMORE Engineer to set scan rate to 1 minute (60 seconds); unless otherwise directed by the EERC Representative on location.

J. MOREVision Surface Data Acquisition Unit

One (1) MORE^{S} System will be powered by solar panel / battery (stand alone power).

The surface data acquisition equipment consists of the following components:

1. MOREVision surface data acquisition unit
2. Surface electrical junction box
3. Solar panel – 1 unit
4. Solar panel battery - 2 units
5. Metal battery box (security box) – 2 units

6. Panel stand

The other well will have AC power available on location, and will be configured with:

1. MOREVision surface data acquisition unit
2. Surface electrical junction box
3. Backup battery - 1 unit
4. Metal battery box (security box) – 1 unit
5. Panel stand

K. Post Job Summary Requirements

The following reports will be generated prior to leaving location. These reports will be emailed to PROMORE's Houston office before 8:00 AM CST the following morning.

1. Field Receipt (*signed by EERC Representative on location*)
2. Job Report
3. Data Report (Instrument Integrity Report, Post Installation Data Plot)

L. Procedure Approvals

Written By – PROMORE	Dennis Larsen
Signature	
Date	March 15, 2016

Reviewed By – PROMORE	
Signature	
Date	

Reviewed By – EERC	
Signature	
Date	

Appendix A – Downhole and Surface Equipment Check List

Quantity	Description	Packed By	Verified By
Instrument Cable			
10,916 feet (2 Wells)	Tube Encapsulated Cable (TEC, 0.250" OD x 0.035" Wall, INC825, 1 Conductor, 300F)		
Data Acquisition Equipment			
2	MOREVision Unit		
2	MOREVision Panel Stand		
1	Solar Panel		
3	Solar Panel Battery		
2	Surface Electrical Junction Box		
TBD feet	Surface Instrumentation TECH Cable (1 Pair)		
Downhole Instrumentation Equipment			
2	MORE^{S} Gauge (MS1-MT-5000-1.375) *(Threaded bottom to accept sinker bar)*		
2	Sinker Bar (1.375" OD x 6 feet)		
Surface Termination Equipment			
2	WHSA Body (Rating: 5,000 psi) *(2.875" EUE PIN x 3.500" EUE BOX)* *Connection Size and Type TBC*		
2	Hanger / Packoff Assembly (Rating: 5,000 psi)		

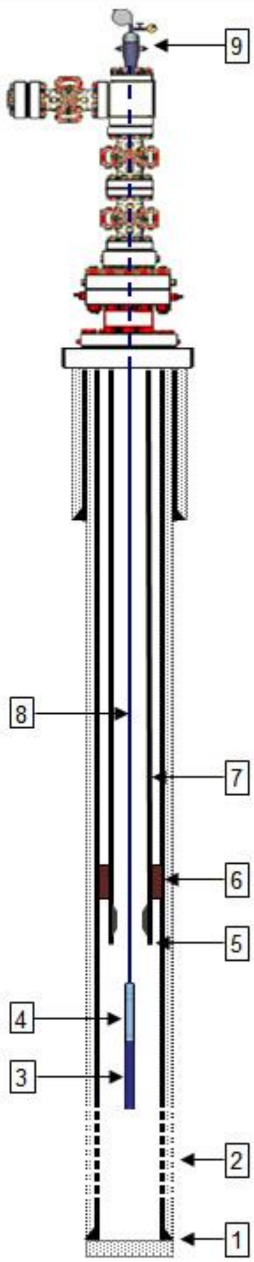
Appendix B – Installation Tools Check List

Quantity	Description	Packed By	Verified By
	Installation Tools		
1	36 inch OD Top Sheave *(with safety clevis)*		
1	36 inch OD Bottom Sheave *(with safety clevis and steel sling)*		
1	Sheave Stand		
1	Wireline BOP *(with seal inserts for 0.250 inch OD capillary tube)*		
1	Scaffolding		
1	Lubricator Joint *(8 foot)*		
	Lubricator Pup Joint *(3 foot with bleed-off port)*		
1	Wireline Packoff Head, Hydraulic Pump, Hydraulic Hose *(with seal inserts for 0,250 inch OD capillary tube)*		
1	Tube Encapsulated Cable Clamp		
1	Cable Clamp Hanger Plate		
1	Diagnostic Tools (Digital Volt Meter, LCR Meter, VI Meter)		

Appendix C – Wellbore Drawing ("Proposed")

Rink 1

PROMORE



DOWNHOLE WELL PROFILE

COMPANY	Environmental Engineering & Research Center	DATE	
WELL NAME	BEST Project - SWD1	DRAWN BY	D. Larsen

ELEVATIONS			TUBULARS		
KB	GL	KB - GL	HOLE SIZE	CASING OD	TUBING OD
				7.000 inch	3.500 inch

DOWNHOLE EQUIPMENT FROM BOTTOM UP

LABEL	DESCRIPTION	DEPTH (ftKB)
1	Production Casing	
2	Perforations - Dakota Formation (Top Perforation Depth)	5,324.0
3	PROMORE Sinker Bar - Bottom *(1.375" OD x 6 foot, Steel)*	5,324.0
4	PROMORE MORE^{S} Tool - Bottom *(MS1-MT-5000-1.375)*	5,318.0
5	Tubing Bottom (EOT)	5,309.0
6	Packer	
7	Injection Tubing *(3.500 inch with Inserts - **ID = 2.400 inch**)*	To Surface
8	PROMORE Instrument Cable *(TEC1, 0.25" x 0.035", 316SS [or Inc825], 1 Conductor, 300 F)*	To Surface
9	PROMORE MORE^{S} Wellhead Hanger / Packoff Assembly *(WHSA-5000)*	Surface

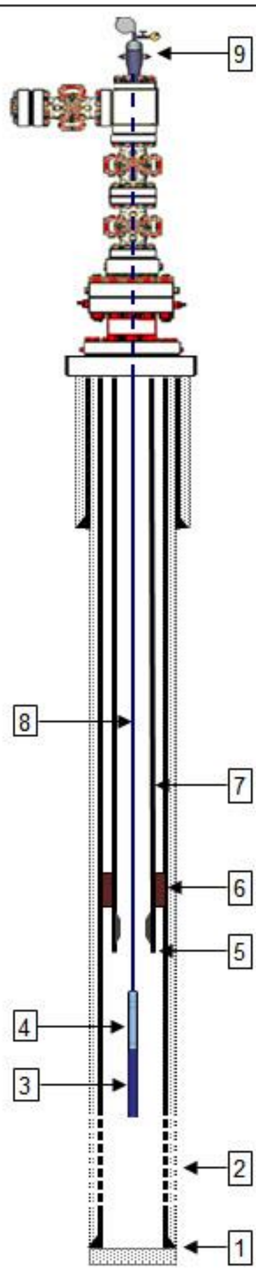
Proposed Drawing

REMARKS

1. Sensor Specifications: Pressure = 5,000 psi / Temperature = 300 Fahrenheit
2. Gauge Housing Specifications: 1.375 inch OD x 33 inches long
3. Sinker Bar Specifications: 1.375 inch OD x 72 inches long (30 lbs)

Rink 2

PROMORE



DOWNHOLE WELL PROFILE

COMPANY	Environmental Engineering & Research Center	DATE	
WELL NAME	BEST Project - SWD2	DRAWN BY	D. Larsen

ELEVATIONS			TUBULARS		
KB	GL	KB - GL	HOLE SIZE	CASING OD	TUBING OD
				7.000 inch	4.500 inch

DOWNHOLE EQUIPMENT FROM BOTTOM UP

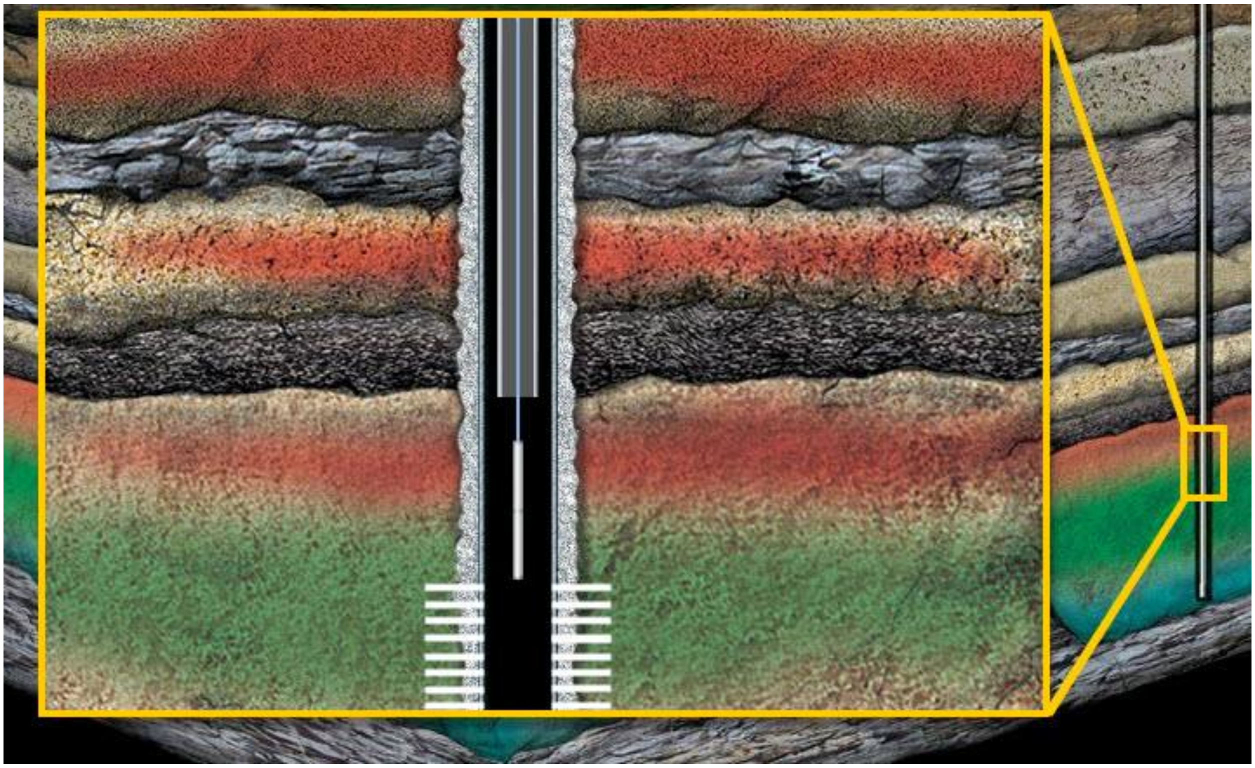
LABEL	DESCRIPTION	DEPTH (ftKB)
1	Production Casing	
2	Perforations - Dakota Formation *(Top Perforation Depth)*	5,404.0
3	PROMORE Sinker Bar - Bottom *(1.375" OD x 6 foot, Steel)*	5,404.0
4	PROMORE MORE^{S} Tool - Bottom *(MS1-MT-5000-1.375)*	5,398.0
5	Tubing Bottom *(EOT)*	5,349.0
6	Packer	
7	Injection Tubing *(4.500 inch - **ID = 3.833 inch**)*	To Surface
8	PROMORE Instrument Cable *(TEC1, 0.25" x 0.035", 316SS [or Inc825], 1 Conductor, 300 F)*	To Surface
9	PROMORE MORE^{S} Wellhead Hanger / Packoff Assembly *(WHSA-5000)*	Surface

Proposed Drawing

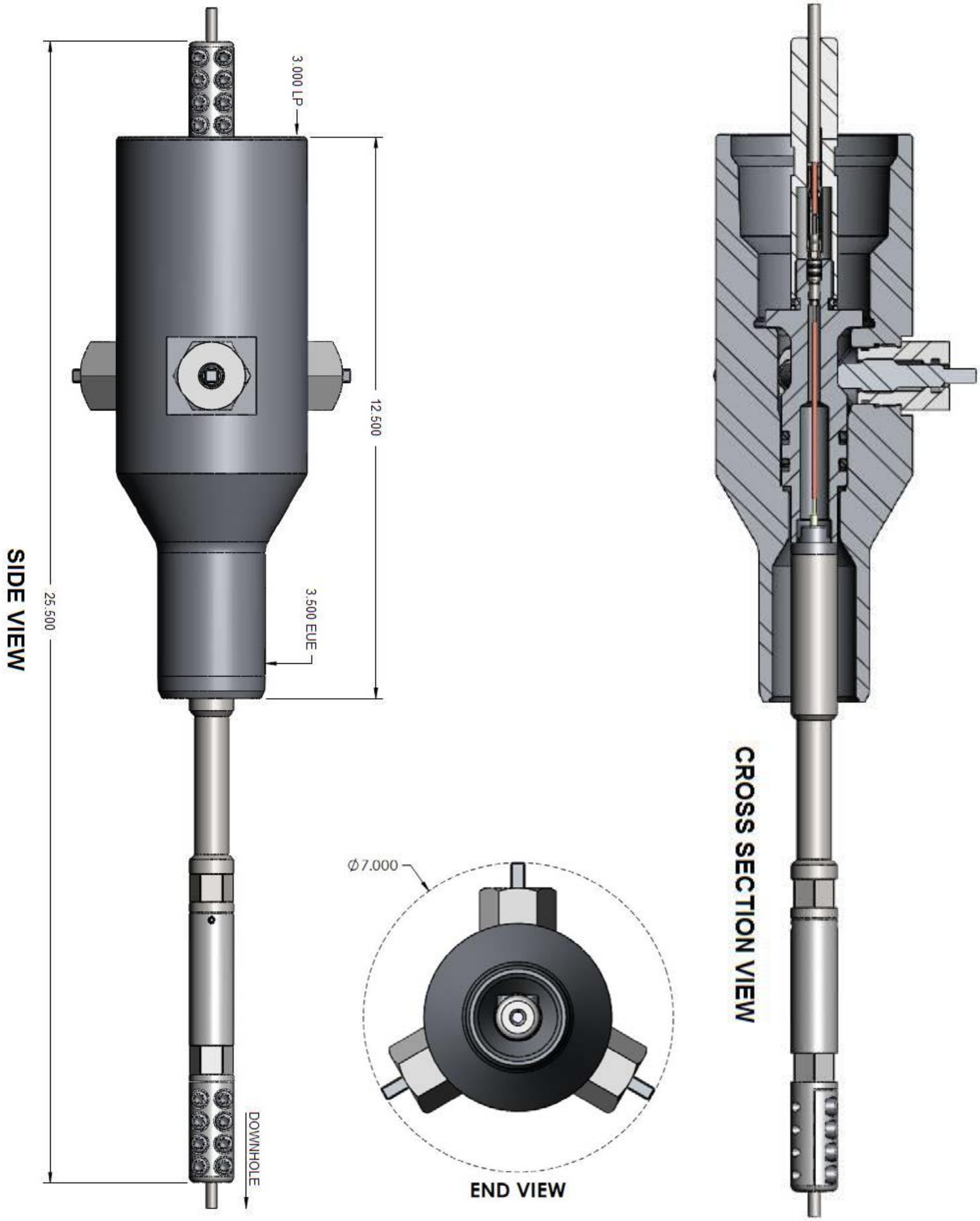
REMARKS

1. Sensor Specifications: Pressure = 5,000 psi / Temperature = 300 Fahrenheit
2. Gauge Housing Specifications: 1.375 inch OD x 33 inches long
3. Sinker Bar Specifications: 1.375 inch OD x 72 inches long (30 lbs)

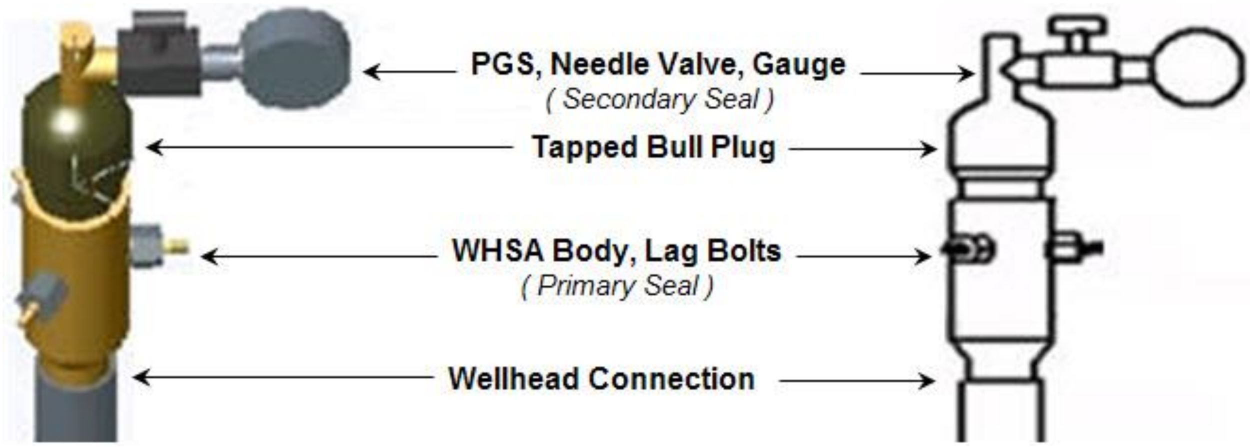
Appendix C – Wellbore Drawing ("Proposed") *(Continued)*



Appendix D – Instrument Cable Hanger Assembly and Termination Drawing



Appendix D – Instrument Cable Hanger Assembly and Termination Drawing
(Continued)



APPENDIX D-3

PROTECHNICS TRACER SURVEY

ProTechnics

EERC

Johnson Corner

Interwell Tracer Survey

Core Lab

EERC
Johnson Corner
McKenzie Co., ND

Proposal Submission Date: March 15, 2016

Estimated Job Execution Date:

Prepared For: Lonny Jacobson
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ProTechnics
713.328.2374/832.390.9845
Swathika.Jayakumar@corelab.com

INTRODUCTION

ProTechnics was requested by EERC to recommend an interwell well tracer survey for 2 Salt Water Disposal (SWD) wells in the Johnson Corner field.

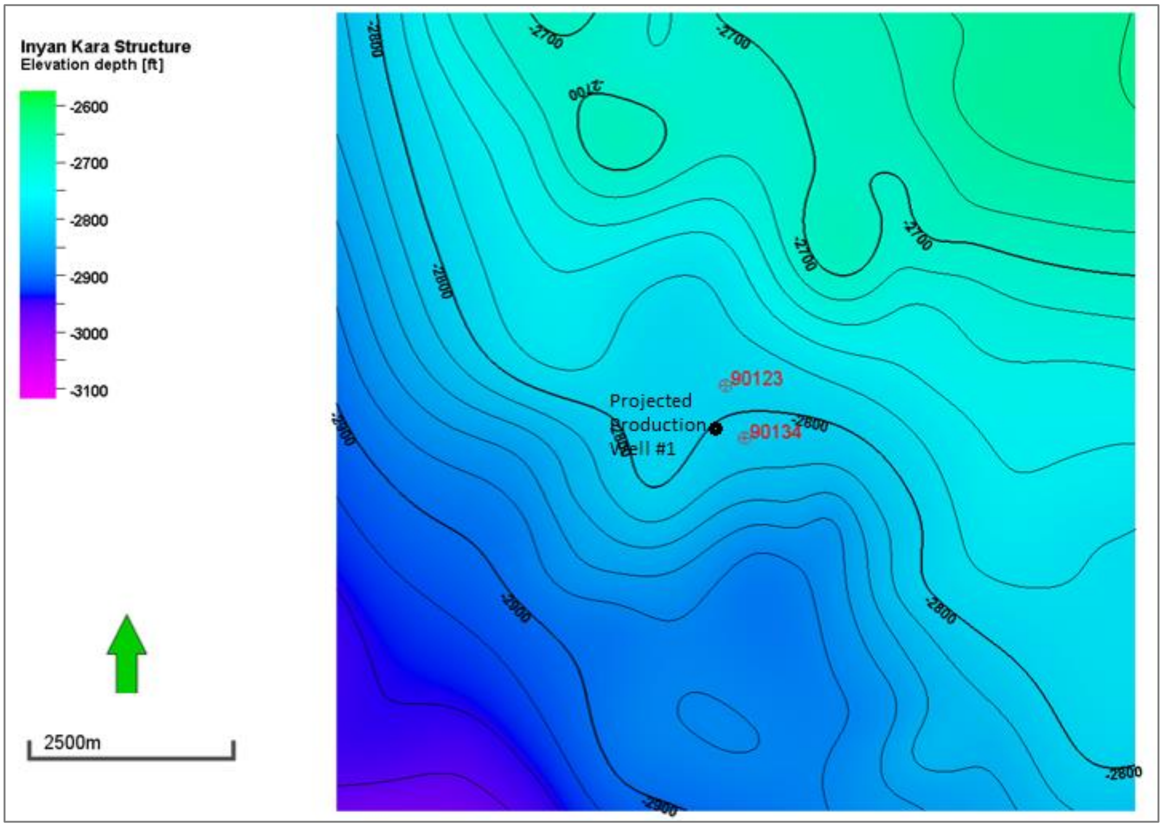
OBJECTIVES

The objectives of this tracer study is to understand fluid communication between the injectors and the offset producers.

INTERWELL TRACER DATA

Project Type:	Disposal Well
Formation:	Sandstone and Shale
Gross Thickness of Injection Zone:	400 ft.
Desired Radius of Investigation:	1400-1600 ft.
Porosity:	15%
Water Saturation:	>90%
Water Cut:	100%
H_2s Concentration:	Not in formation, but injected
Previously Used Tracers:	No

FIELD MAP


Inyan Kara Structure
Elevation depth [ft]
-2600
-2700
-2800
-2900
-3000
-3100
2500m
Projected
Production
Well #1
90123
90134
-2700
-2800
-2900

TRACER INJECTION DETAILS

Input Parameters	
Minimum Detection Limit	10 ppt.
Gross Pay, ft.	400
Porosity, fr.	0.15
Water Saturation	1 (Safety factor)
Radius of Investigation, ft.	1400-1600

Injector Name	Water Tracer	Tracer, L (10% sol)
Rink SWD 1	IWT 1000	30
Rink SWD 2	IWT 1100	20

SAMPLING SCHEDULE

An optimum sampling program for a tracer job usually has a higher sampling frequency in the beginning to cover the probability of early tracer breakthrough at production wells. This frequency is reduced in the latter part of the sampling program.

To establish a baseline of reservoir fluid, it is recommended to collect and analyze a 1 L water sample from each of the producers a few weeks before tracer injection. All other water samples collected during the project life should be 500 mL.

The table below presents a sampling schedule for 12 months. The proposed sampling schedule MUST start a day after the first tracer injection is completed and MUST be followed throughout accordingly. However, the proposed sampling schedule may change if tracers are detected and it may be extended beyond the 12 months proposed sampling schedule.

Production Wells	Month 1-2	Months 3-6	Months 7-24+
	Collection	Collection	Collection
	One / Week	One / 2 Week	One / Month
Producer 1	14	8	18
Total Samples Collected	**40**		
Total Samples Analyzed	**~14 (1/3rd of all samples collected)**		

DELIVERABLES AFTER TRACER INJECTION INCLUDE

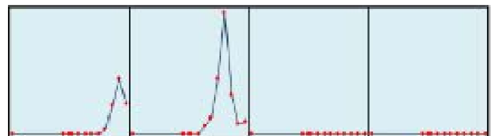
1. Tracer injection report.
2. A sample analysis report is typically sent 7-10 days after ProTechnics receives the samples.

Traced Injection Wells Listed Here

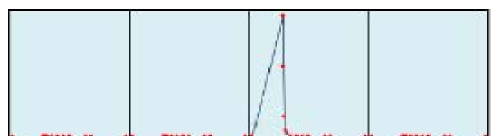
Tracer Samples from Producers Listed Here

Sample analysis reports will yield the breakthrough times and tracer concentrations within the produced water samples. A rapid breakthrough time combined with a high tracer concentration indicates a thief zone or high permeability channel.

Production Well	Sample Date	Injection Details			
		31-May-13	31-May-13	31-May-13	31-May-13
		D51	D56	D82	D33
		IWT 1000	IWT 1100	IWT 1200	IWT 1300
		Concentration, ppt			



Production Well	Sample Date	D51	D56	D82	D33
D49	30-Apr-13	0	0	0	0
	21-Jun-13	0	0	0	0
	27-Jun-13	0	0	0	0
	29-Jun-13	0	0	0	0
	6-Jul-13	0	98	0	0
	13-Jul-13	0	1343	0	0
	20-Jul-13	0	2532	0	0
	27-Jul-13	0	8374	0	0
	3-Aug-13	693	16348	0	0
	10-Aug-13	4356	5985	0	0
	17-Aug-13	6372	1615	0	0
	24-Aug-13	4632	2018	0	0



Production Well	Sample Date	D51	D56	D82	D33
D24	30-Apr-13	0	0	0	0
	1-Jun-13	0	0	171903	0
	1-Jun-13	0	0	99959	0
	2-Jun-13	0	0	29942	0
	3-Jun-13	0	0	9944	0
	4-Jun-13	0	0	5894	0
	9-Jun-13	0	0	951	0
	15-Jun-13	0	0	262	0
	21-Jun-13	0	0	190	0
	27-Jun-13	0	0	90	0
	13-Jul-13	0	0	81	0
	20-Jul-13	0	0	0	0
	24-Aug-13	0	0	0	0

3. A final quantitative analysis report will be submitted once the survey is concluded. This will include interwell swept pore volume calculations, injected water distribution, sweep efficiency and, flow- storage capacity between wells. This report will be sent in 3-5 days after ProTechnics receives the necessary injection/ production data from the operator.

*- A ProTechnics engineer will be available to discuss results and make changes to the sampling schedule throughout the life of the tracer survey

PROJECT COST

The total estimated cost of tracer injection operation is **$19,050.00**

- The above cost includes chemicals, equipment, injection, personnel, engineering, and supply of sample collection kits.
- Sample analysis is $300 per sample (includes analysis of all tracers present in the sample)

SAMPLE COLLECTION NOTES

a) Samples proposed for analysis will be shipped by client to:

ProTechnics
Attn: Tracer Lab
6510 W Sam Houston Pkwy N
Houston, TX 77041
(713) 328-2320

Samples should bear the following information on the provided labels, written in Sharpie, or indelible ink:

Company: EERC
Field name: Johnson Corner
Well name:
Sample # (corresponding to login sheet):
Date:

b) A sample login sheet should be filled out and sent with all samples proposed for analysis, with each sample # corresponding to the number written on the sample