SUBTASK 3.2 – PRODUCED WATER MANAGEMENT THROUGH GEOLOGIC HOMOGENIZATION, CONDITIONING, AND REUSE

Final Topical Report

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EERC DISCLAIMER

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DEFINITIONS

Acre-foot – 1 acre-foot equals 325,851 gallons, enough water to cover an acre of land 1 foot deep.

Bakken petroleum system production – Includes both Bakken and Three Forks production.

Barrel (bbl) – One barrel equals 42 gallons.

cm^3 – Cubic centimeter.

Flowback water – Hydraulic fracturing fluid that is produced back out of the wellbore upon completion of the hydraulic fracturing stimulation. Depending on the formation being hydraulically fractured, a percentage of the hydraulic fracturing fluid remains in the formation.

FracFocus – A publicly accessible website where oil and gas production operators can disclose information about ingredients used in hydraulic fracturing fluids at individual wells (fracfocus.org).

Hydraulic fracturing – An oil and gas well stimulation process that typically involves injecting water, sand, and chemicals under high pressure into a formation via the well. This process is intended to create new fractures in the rock as well as increase the size, extent, and connectivity of existing fractures. Hydraulic fracturing is a well stimulation technique used commonly in low-permeability rocks like tight sandstone, shale, and some coal beds to increase oil and/or gas flow to a well from petroleum-bearing rock formations. Application of hydraulic fracturing is one of the cornerstone techniques that results in commercial oil production from the Bakken. Nearly all Bakken petroleum system wells are hydraulically fractured.

Lay-flat hose/pipe – Lay-flat hose is made from polyvinyl chloride (PVC). As the name suggests, one of its key properties is the ability to be laid flat for storage purposes; it is used for the delivery of water in roles such as construction or irrigation when it is not easy to transport water.

Makeup water – Water used for hydraulic fracturing.

Maintenance water – Freshwater injected into a producing well to reduce salt and scale precipitation within the well tubing that can reduce production. Maintenance water is a common practice to prevent the high salt content of Bakken production water from precipitating in wells and inhibiting production.

Mbbl – Thousand barrels.

MMbbl – Million barrels.

Produced water – Includes a combination of flowback water and native formation brine that is coproduced with oil during production. Produced water volumes in this document include flowback and native formation brine.

Saltwater disposal (SWD) – A produced water management method of reinjecting produced water back into the subsurface for the purposes of disposal.

Slickwater fracturing – A method of hydrofracturing that involves adding chemicals to water to increase fluid flow. Slickwater fracturing typically uses higher volumes of water compared to gel-based fracturing.

Total dissolved solids (TDS) – A measure of the dissolved combined content of all inorganic and organic substances present in a liquid. TDS concentrations are often reported in part per million (ppm) or milligram per liter (mg/L).

Water cut – The ratio of produced water to the volume of total liquids produced (produced water volume/total liquids volume).

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EXECUTIVE SUMMARY

The Energy & Environmental Research Center (EERC) was awarded a contract by the North Dakota Industrial Commission (NDIC) Oil and Gas Research Program (NDIC No. G-051-101) to conduct a study on the recycling of water used in oil and gas operations, also known as produced water, from oil- and gas-producing regions of North Dakota as directed by Section 19 of North Dakota House Bill 1014. This final report provides a compilation of results of the study, which include regulatory, scientific, technological, and feasibility methods and considerations associated with North Dakota produced water management. The report provides a synopsis of this project's previously submitted produced water assessment report entitled "Produced Water Management and Recycling Options in North Dakota" (Energy & Environmental Research Center, 2020), with updated values provided as appropriate. The report provides the results from the investigation of a novel produced water management strategy, referred to as geologic homogenization, conditioning, and reuse (GHCR), which aims to use a subsurface geologic formation as a natural medium for managing produced water recycling and reuse.

Water management is a significant technical and economic challenge for sustainable oil and gas production, and water volumes are intrinsically linked to oil production volumes. North Dakota oil production rose to over 1.5 million barrels (MMbbl)/day in 2019, and despite a downturn in oil price in early 2020, North Dakota oil production has recovered to 1.1 MMbbl/day as of August 2021. Bakken petroleum system development between 2008 and 2020 has resulted in a nearly fourfold increase in produced water volumes to 642 MMbbl/yr in 2020 after peaking at 740 MMbbl/yr in 2019 and a fivefold increase in saltwater disposal (SWD) volumes to 565 MMbbl/yr in 2020 after a peak of 682 MMbbl/yr in 2019. Produced water and SWD volumes are forecasted to double by 2030.

SWD is the primary method of produced water management used in North Dakota, with approximately 95% of the SWD volume occurring through subsurface injection into sandstones of the Dakota Group (Dakota). Localized pressurization of the Dakota resulting from SWD and projected increases in produced water volumes could impact the economics of North Dakota oil production. As a result, there is an emerging need to pursue alternative produced water management approaches, including recycling and reuse. While produced water recycling is not yet widespread, commercial operators are making strides in overcoming the technical challenges of using high salinity produced water in completion operations (Marathon Oil, 2020). As water management continues to be a key focal point in companies' environmental, social, and governance (ESG) initiatives, focus on water management, including recycling, will likely continue to increase.

Laboratory column testing, field sample collection, geologic modeling and numerical simulation, and techno-economic analysis all indicate that GHCR could feasibly be implemented as a potential water management option. Laboratory column testing and field sample collection indicate that the Inyan Kara sandstone and native formation fluid are capable of homogenizing with the Bakken produced water to a point where the fluid composition appears to stabilize. Extracting that stabilized fluid could be considered homogeneous and capable of providing

individual batches of hydraulic fracturing fluid. Numerical simulation results indicate that extraction of fluids from the Inyan Kara in a GHCR implementation scenario is capable of reducing formation pressure, which would help ease localized pressurization of the Inyan Kara and extend the available capacity for nearby existing SWD wells. Economic analysis indicates that there are scenarios where GHCR implementation can be a competitive or even lower-cost option than a conventional water management approach. Site-specific conditions will dictate the economic potential of GHCR, but potentially attractive sites for GHCR implementation will be those that are located above a pressurized zone of the Inyan Kara, need six or more Bakken infill wells, and face high costs for conventional SWD and/or freshwater. Based on the regulatory review, drilling into the Inyan Kara for SWD and to harness as a source water for industrial use have precedent in North Dakota, and a workable regulatory solution for GHCR seems likely. However, restrictions in the state regarding surface storage and transport of produced fluids may limit some activities, which will affect how GHCR could ultimately be implemented.

In summary, this study reveals pursuing GHCR can be a viable approach to water management in North Dakota. The GHCR concept addresses some of the challenges that hinder the more traditional approaches to recycling in the industry. Furthermore, an assessment of the current landscape of water management within the state reveals the ongoing trend of increasing volumes of produced water and SWD. Projections reveal that the volumes of produced water that need to be managed are expected to double over the next decade (Energy & Environmental Research Center, 2020). With the continued development of the Bakken and continuing driving factors related to ESG initiatives, implementing a practice such as GHCR is a feasible approach to adding recycling of produced water to industry within the state.

This subtask was cofunded through the EERC–U.S. Department of Energy Joint Program on Research and Development for Fossil Energy-Related Resources Cooperative Agreement No. DE-FE0024233. Nonfederal funding was provided by the North Dakota Industrial Commission Oil and Gas Research Program.

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Marathon Oil, 2020, Sustainability report: https://cdn.sanity.io/files/ghcnw9z2/website/91744eb6ef8fbe59505a911c6b8d2e8dd9a537fa.pdf?dl (accessed November 2021).

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1.0 INTRODUCTION

The Energy & Environmental Research Center (EERC) was awarded a contract by the North Dakota Industrial Commission (NDIC) Oil and Gas Research Program (OGRP) (NDIC No. G-051-101) to conduct a study on the recycling of water used in oil and gas operations, also known as produced water, from oil- and gas-producing regions of North Dakota as directed by Section 19 of North Dakota House Bill 1014. This final report provides a compilation of results of the study, including regulatory, scientific, technological, and feasibility methods and considerations associated with North Dakota produced water management. The report provides a synopsis of this project's previously submitted produced water assessment report entitled "Produced Water Management and Recycling Options in North Dakota" (Energy & Environmental Research Center, 2020), with updated values provided as appropriate. The report will provide the results from the investigation into a novel produced water management strategy, referred to as geologic homogenization, conditioning, and reuse (GHCR), which aims to use a subsurface geologic formation as a natural medium for managing produced water recycling and reuse.

Throughout this report, reference will be made to data collected from "Bakken" wells. This is intended to indicate wells within the North Dakota portion of the Bakken petroleum system (Bakken), which includes wells produced from the Three Forks Formation and the Bakken Formation (Figure 1-1). Data shown throughout Section 2.0 will largely focus on the 2008 to 2020 (last complete year of record) time period, with other dates noted when appropriate. In the first half of 2020, the spread of the COVID-19 pandemic led to shutdowns and implementation of restrictions across the world. States enacted a variety of temporary restrictions to limit the gathering of people, which greatly impacted airline and ground travel. Refiners of gasoline and jet fuel are the first and fourth consumers of crude oil in the United States, and the reduction in demand impacted oil prices and crude oil stocks. The market conditions forced operators to reduce production rates to avoid exceeding storage capacity. The unique conditions are reflected in the data sets within Section 2.0, which generally show peak values in 2019 and a reduction in 2020, reflecting the downturns in production. However, looking into 2021, oil prices and production levels have returned to a more "normal" level, so one would expect the water management data sets to bounce back.

Water management represents a significant technical and economic challenge for sustainable oil and gas production, and water volumes are intrinsically linked to oil production. With sustained levels of production in North Dakota, there will be significant demand for freshwater use and produced water management (i.e., formation water and flowback water) and associated disposal. North Dakota surpassed 1.5 million barrels (MMbbl) per day of oil production in November 2019 (North Dakota Department of Mineral Resources, 2020), and despite a downturn in oil price in early 2020, production in the state has recovered to 1.1 MMbbl/day in August 2021 (North Dakota Department of Mineral Resources, 2021). Oil prices appear to have recovered, as oil prices increased from ~\$8/bbl (North Dakota light sweet crude) in May 2020 to over \$70/bbl in October

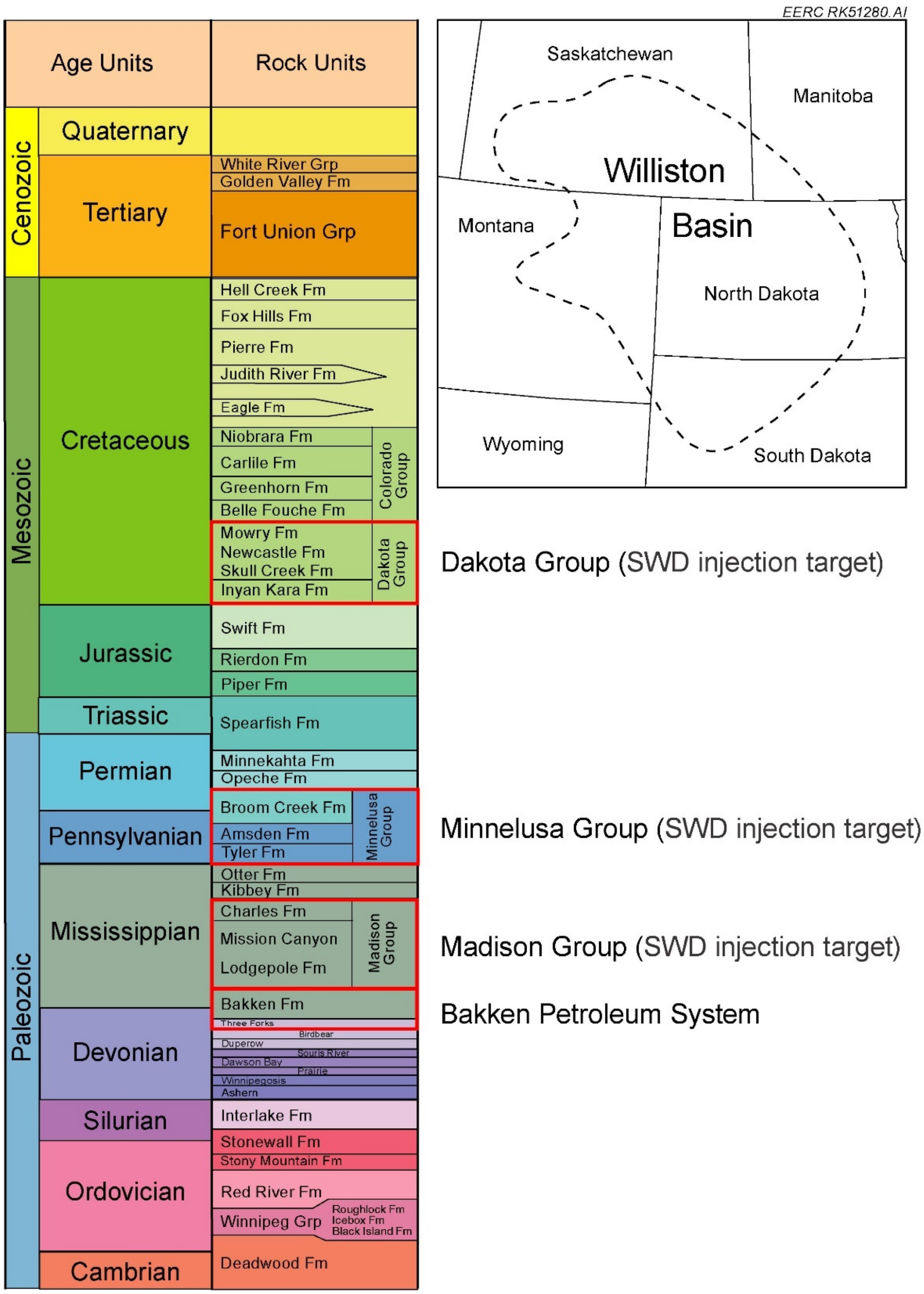

Figure 1-1. North Dakota stratigraphic column (SWD is saltwater disposal).

2021. Even accounting for the slowdown, produced water volumes exceeded 600 MMbbl for 2020, which exceeds 2018 volumes. Furthermore, using conservative projections, produced water volumes are forecasted to more than double by 2030 (Energy & Environmental Research Center, 2020).

The EERC has been investigating the GHCR concept, which uses a subsurface geologic formation as a natural medium for produced water management. This concept takes advantage of the hypothesized natural processes occurring in the subsurface (e.g., filtering, mixing, diluting, etc.) and extracts the water at some distance from a disposal well. GHCR uses existing oil and gas industry practices by using an extraction well to produce a mixture of native formation water that is mixed with produced water from SWD operations. If viable, the GHCR concept could address recycling challenges by producing a better, more consistent quality fluid while also providing subsurface storage that eliminates some of the environmental risks behind water handling required for traditional recycling methods. The investigation into the GHCR concept and accompanying results are described in this report.

2.0 BAKKEN WATER MANAGEMENT

Water management within the oil and gas industry in North Dakota can be broken into three general components: freshwater use, produced water, and SWD. These three components are all closely related, and they all generally follow the same trends as oil production, in this case production primarily from the Bakken. As oil production increases, freshwater consumption trends increase, as more freshwater is used for drilling, completion, and well maintenance activities. Likewise, increased oil production brings increased volumes of produced water, which includes flowback (water from stimulation activity) and formation water (primarily from the Bakken). Finally, as produced water volumes increase, that water needs to be disposed of, which, in North Dakota, primarily means increased volumes of SWD.

Bakken water management was discussed in greater detail in the EERC's report entitled "Produced Water Management and Recycling Options in North Dakota" (Energy & Environmental Research Center, 2020), and Section 2.0 will provide a short review, taken from the EERC report, of Bakken water management, with some relevant updates to the data provided (i.e., values updated to include 2020, where appropriate).

2.1 Freshwater Trends

Freshwater is used in the oil and gas industry in a variety of applications. Water is a primary component of drilling mud, which lubricates and cools the drill bit and removes drill cuttings from the wellbore. In unconventional well stimulations, freshwater mixed with chemicals is used to hydraulically fracture and stimulate a well. Freshwater is used to maintain well operation. This "maintenance water" typically transports chemicals down the annulus of a well to treat downhole components for scaling, corrosion, and other undesirable operational conditions. The nearly saturated properties of Bakken produced water can require dilution from maintenance water to prevent precipitation of salts in production tubing and surface equipment. While not used on every producing well, this technique, known as well maintenance, brine dilution, desalting, or well flushing, typically uses 15–50 bbl/well/day, with the volumes per well depending on the local conditions (e.g., total dissolved solids [TDS] of formation fluids, temperature drop in the wellbore) of the individual well.

The vast expansion of water supply and associated handling infrastructure in the Bakken region has helped industry meet water demand for oil and gas development. Information on changes that have occurred in water use as a result of oil and gas development in North Dakota is derived from reported industrial water use from the North Dakota State Water Commission (NDSWC) and reported water use for hydraulic activities from Enverus (Drilling Info) and FracFocus. Since 2008, annual oil and gas-related water use in North Dakota has increased from just over 13.5 MMbbl (~1740 acre-feet) in 2008 to more than 290 MMbbl (~37,380 acre-feet) in 2019 before dropping down to 140 MMbbl (~18,000 acre-feet) in 2020 (Figure 2-1).

Improved stimulation techniques, increase in lateral lengths, and the number of fracture treatment stages have led to an increase in the volumes of fluid (freshwater mixed with fracturing chemicals) injected per well during a stimulation from about 15,000 bbl per well (~1.9 acre-feet per well) in 2008 to about 215,000 bbl per well (~25.8 acre-feet per well) in 2020 (Figure 2-1), as derived from data available from over 14,600 wells completed over that time period. Over the last 5 years (2016–2020), freshwater use for hydraulic fracturing is about 80% of the oil and gas industry's total freshwater use volumes, based on NDSWC-reported use and FracFocus- and Enverus-reported clean water use. Contributing to water demand are the success and emerging prevalence of slickwater stimulations that require pumping 3 to 4 times the volume of water at a higher injection rate than previous gel-based stimulations.

Freshwater use on a per-well basis has grown substantially over the last decade. Trends indicate that while water use has begun to stabilize, freshwater use will continue to remain high. Total water use during the next several years will be driven by number of producing wells completed and increasing water use per well. Sustained freshwater use directly contributes to and is proportional to flowback, which is one of several contributors to produced water volumes. Increased water volumes impact the economics of oil production through water supply and water disposal costs.

While freshwater use volumes for the oil and gas industry have grown over the recent decade, the industry's share of total freshwater use when compared to all water users is relatively small. From 2016 to 2020, oil-related industrial water use is 1.18 billion bbl (~151,000 acre-feet), representing 9% of North Dakota's total freshwater use of 13.8 billion bbl (~1.78 million acre-feet). As shown in Figure 2-2, oil industry water use trails volumes used for irrigation, municipal, and power generation uses.

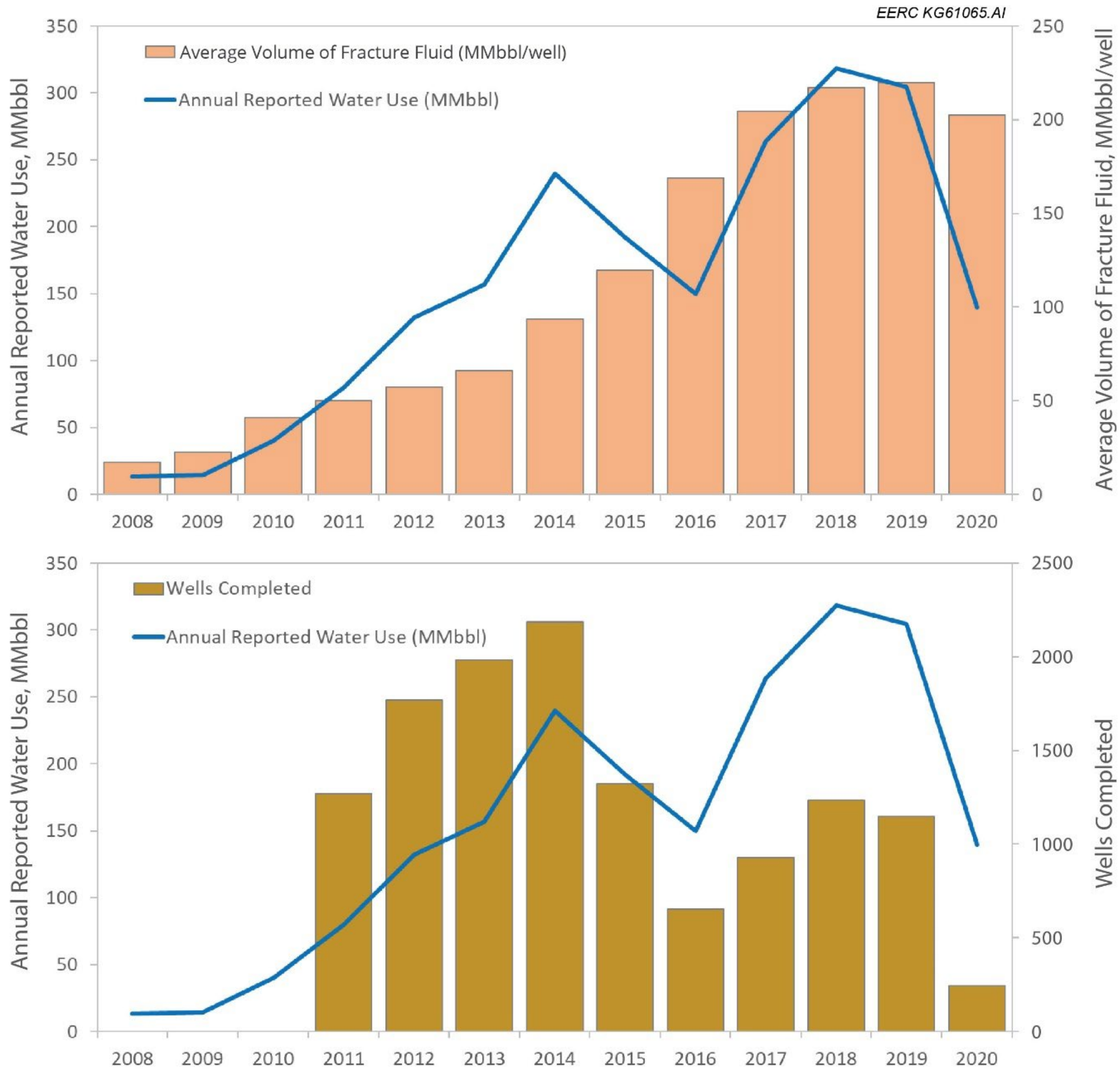

Figure 2-1. Plot showing industrial water use in MMbbl from permitted sites for oil-related activities (left *y*-axis) from 2008 through 2020 as compared to the average fracture fluid volume per well (top panel, MMbbl, right *y*-axis) and the wells completed in each year (bottom panel, right *y*-axis) (data source: NDSWC and Enverus).

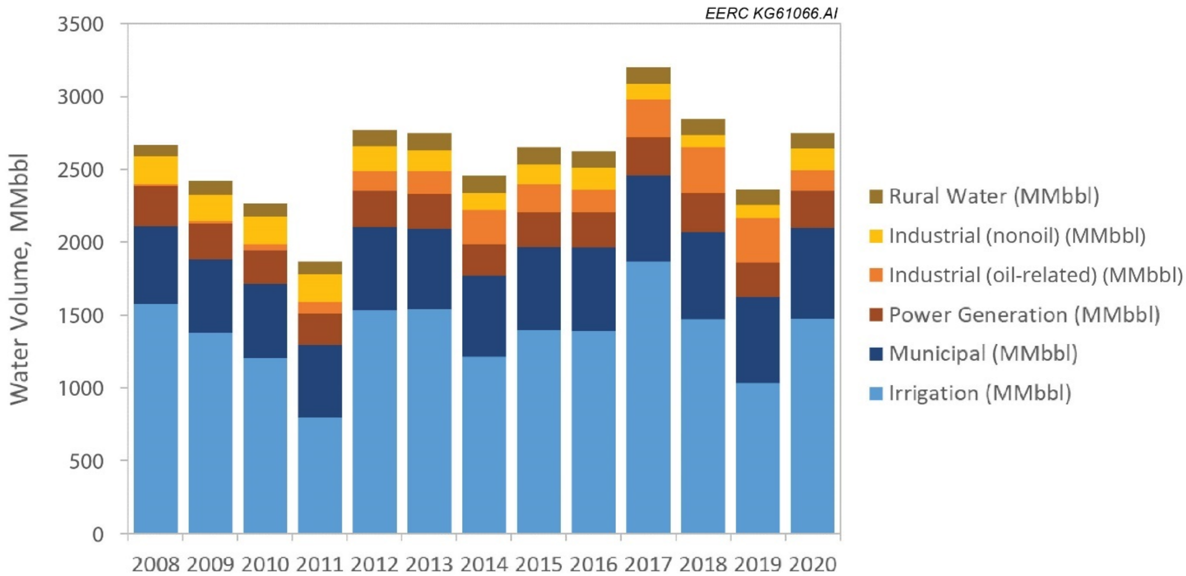

Figure 2-2. Freshwater use 2008–2020 by water use (data source: NDSWC).

2.2 Bakken Produced Water Trends

Produced water refers to brine that is coproduced with oil. Produced water volumes presented in this document include both water that was injected during well stimulation (i.e., hydraulic fracturing) and flows back during production, also referred to as flowback water, and native formation brine that is coproduced with oil. The volumes of produced water vary by geologic formation and location, and terms such as water cut describe the ratio of water produced compared to the volume of fluids produced (i.e., water and oil). Bakken production is typically associated with 1–1.5 bbl of produced water per bbl of oil (water cut of ~50%). Bakken produced water is highly saline, with TDS ranging up to 350,000 mg/L. As a point of comparison, seawater is approximately 35,000 mg/L TDS, or 10 times less salty than typical Bakken brine.

Produced water volumes for the state of North Dakota have increased from 150 MMbbl/yr in 2008 to 642 MMbbl/yr in 2020 after peaking at 740 MMbbl/yr in 2019. The volumes of water produced from the Bakken increased from 6.4 MMbbl/yr in 2008 to 519.7 MMbbl/yr in 2020 (Table 2-1). While the increase is partially attributable to a greater number of producing wells, the average volume of water produced per well is also increasing.

As annual oil production increases, trends suggest that annual water production will increase as well, and in some areas at an even greater rate with higher water cuts on a per-well basis. Increased water production volumes will be associated with increased water management costs, impacting the economics of oil production.

Table 2-1. Trend in Produced Water Generation in the Bakken Since 2008*

Year	Total Producing Bakken Wells	Total Produced Water, MMbbl	Average Annual Produced Water per Well, bbl
2008	887	6.4	7169
2009	1356	12.2	8971
2010	2136	32.6	15,282
2011	3387	64.1	18,934
2012	5184	135.3	26,092
2013	7151	194.1	27,138
2014	9326	283.9	30,438
2015	10,777	337.3	31,297
2016	11,425	313.8	27,464
2017	12,368	370.0	29,914
2018	13,575	493.1	36,325
2019	14,762	599.4	40,606
2020	15,073	519.7	34,481

* North Dakota Industrial Commission (2021).

2.3 Bakken Produced Water Chemistry

An essential component in the advancement of water recycling and reuse opportunities in North Dakota is the understanding of produced water chemistry. Publicly available data indicate that the water chemistry varies considerably throughout the Williston Basin, making water treatment options challenging and may require varying treatment approaches. Bakken produced water is regarded as highly saline, with TDS concentrations generally on the order of 300,000 mg/L and levels approaching 350,000 mg/L not uncommon. According to a study by the U.S. Bureau of Reclamation and Colorado School of Mines comparing produced water from basins across the western United States, the Williston Basin exhibits the most geographical variance by state of any of the basins studied (Benko, 2008).

To gain a better understanding of Bakken water quality and variability, produced water samples were taken, during this project, from various SWD sites throughout the Williston Basin. TDS levels ranged from 242,000 to 340,000 mg/L (Figure 2-3). For comparison, the average salinity of ocean water is 35,000 mg/L. The majority of the TDS content in Bakken produced water is from high sodium and chloride concentrations; however, other constituents are also present in significant quantities, such as calcium, sulfate, and magnesium. Calcium content has been reported at ranges between 7540 and 13,500 mg/L, with magnesium, potassium, strontium, and sulfate all reported in concentrations of 1000 ppm or greater (Stepan and others, 2010). This was confirmed with samples taken during this project that show calcium content ranges from 13,200 to 22,600 mg/L. Magnesium samples ranged from about 1000 to 1500 mg/L, while potassium ranged from 4500 to 9700 mg/L. While not impossible to treat, the high-TDS waters produced from the Bakken are challenging to handle when developing economical water treatment and reuse options. Figure 2-4 presents the applicability of desalination technologies over a range of TDS

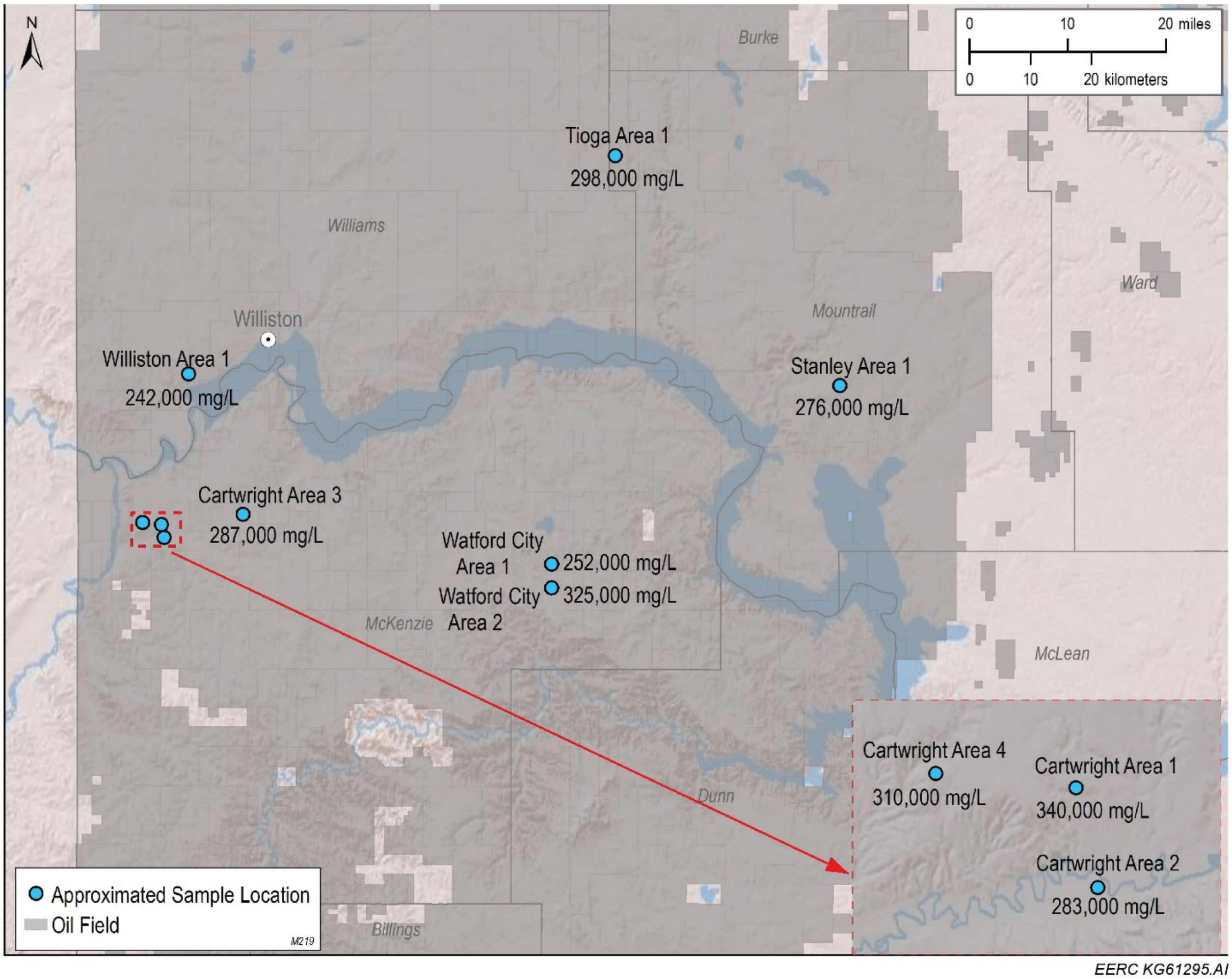

Figure 2-3. Approximate locations of Bakken produced water samples collected during this project.

concentrations. Traditional desalination technologies such as reverse osmosis (RO) typically are capable of treating waters with TDS levels up to 40,000 mg/L. Thermal treatment technologies such as mechanical vapor recompression (MVR) are more applicable to treating high-TDS waters, such as those found in certain Bakken flowback situations, particularly if MVR is coupled with pretreatment to reduce the concentration of divalent ions typically associated with scaling. Even with pretreatment, the very high sodium chloride in Bakken produced water requires special consideration for treatment components to prevent wellbore corrosion. Expensive alloys or metals such as titanium that are resistant to corrosion and chloride stress cracking will be required for high-temperature thermal recovery processes treating chloride-rich Bakken flowback water (Stepan and others, 2010).

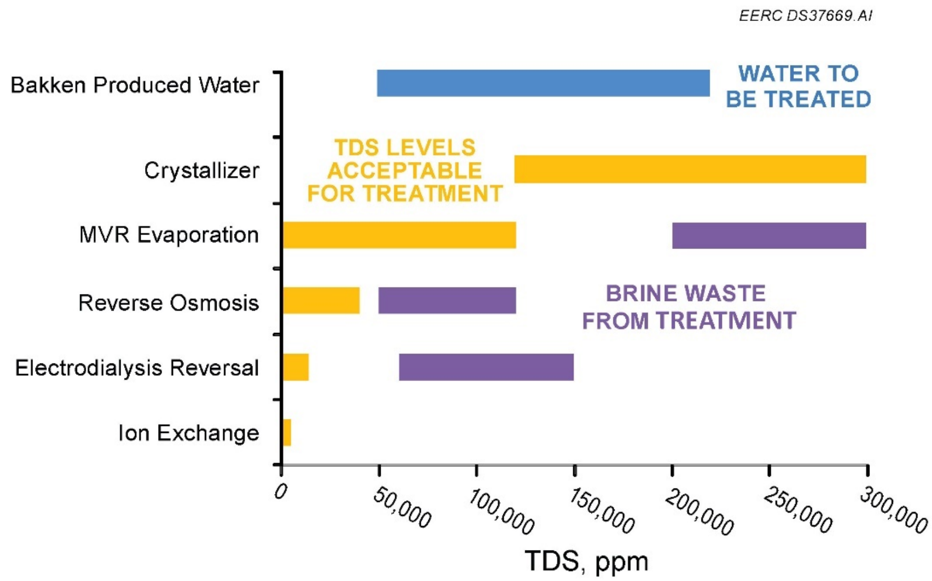

Figure 2-4. Applicability of various desalination technologies.

In addition to high salt content, Bakken water typically contains various metals and other elements (e.g., barium, iron, lithium, etc.) (Stepan and others, 2010) that could be of particular interest for critical mineral recovery and extraction. To the EERC's knowledge, no comprehensive studies have been conducted to systematically identify high-value materials (HVMs) within Williston Basin brines produced from North Dakota, although a limited number of brine analyses performed by the EERC as well as brine characterization data collected by the U.S. Geological Survey (USGS) provide enough compelling data to suggest that a more targeted evaluation of HVMs in the North Dakota portion of the Williston Basin may be warranted. Analysis of lithium in Bakken produced water samples collected and analyzed shows that there are some locations where lithium concentrations are near or above 100 mg/L (what is considered by some to be an economically recoverable concentration). Samples tested had a range of 57–113 mg/L (see Appendix A for full analyses), with most of the higher concentrations found toward the western side of the Williston Basin near the Montana border. Elevated concentrations of iron and barium were also observed in this area. Thus, while HVM concentrations may not be elevated across the entire basin, there are locations that may warrant further investigation.

Recycling and reuse applications tolerant of high-TDS levels such as hydraulic fracture makeup water are the most practical applications for Bakken produced water. Treatment options that target low-TDS levels such as domestic or agricultural use are logistically challenged at industrial scales for high-TDS fluids that contain >30% high-salinity solids that would need to be subsequently disposed of. Further treatment and use for agricultural, domestic, or municipal uses are not recommended or likely to be tolerated until the health effects of all chemical constraints are understood. Therefore, in-industry recycling and reuse applications or mineral recovery applications are likely the most practical and viable options in the near term.

2.4 SWD Trends

Just as freshwater supply locations have increased as a result of North Dakota's expanding oil and gas industry, so has the number of disposal wells, commonly referred to as SWD wells. While SWD wells are used to dispose of maintenance and production water for conventional oil and gas production, the majority of the SWD wells in North Dakota are a result of Bakken production. While most produced water is disposed of through SWD wells, some produced water is recycled and used in secondary recovery (e.g., waterflood) or during drilling and completion operations. Available data do not provide for specific use volumes; however, there will be a difference in total SWD volumes and produced water volumes reflected in the data. Figure 2-5 shows the total volume of fluid injected into North Dakota SWD wells by year since 1956, illustrating the dramatic and exponential increase in SWD volumes as a result of Bakken development. The primary injection zones for SWD are formations of the Dakota Group, the Minnelusa Group, and the Madison Group (Figures 1-1 and 2-6). SWD volumes for the Madison and Minnelusa have remained relatively steady, as shown in Figure 2-6. Over 95% of SWD in North Dakota is going into the Dakota, primarily into the Inyan Kara Formation, the Dakota's lowermost sandstone interval. The Inyan Kara is an ideal target for SWD, with proper confining zones and a long history of successful operation. Since 1956, nearly 7.0 billion bbl of produced water has been injected into North Dakota SWD wells (North Dakota Industrial Commission, 2021). Forecasts indicate that by 2030, 1.96 to 2.69 billion bbl of produced water will need to be managed annually (Energy & Environmental Research Center, 2020).

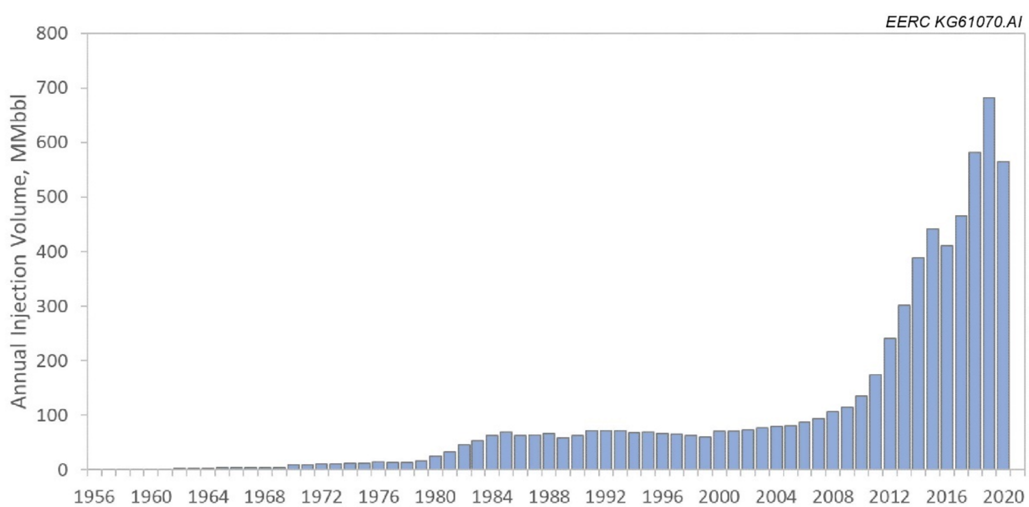

Figure 2-5. Volumes of all water injected into North Dakota SWD wells since 1956 (data source: North Dakota Industrial Commission, 2021).

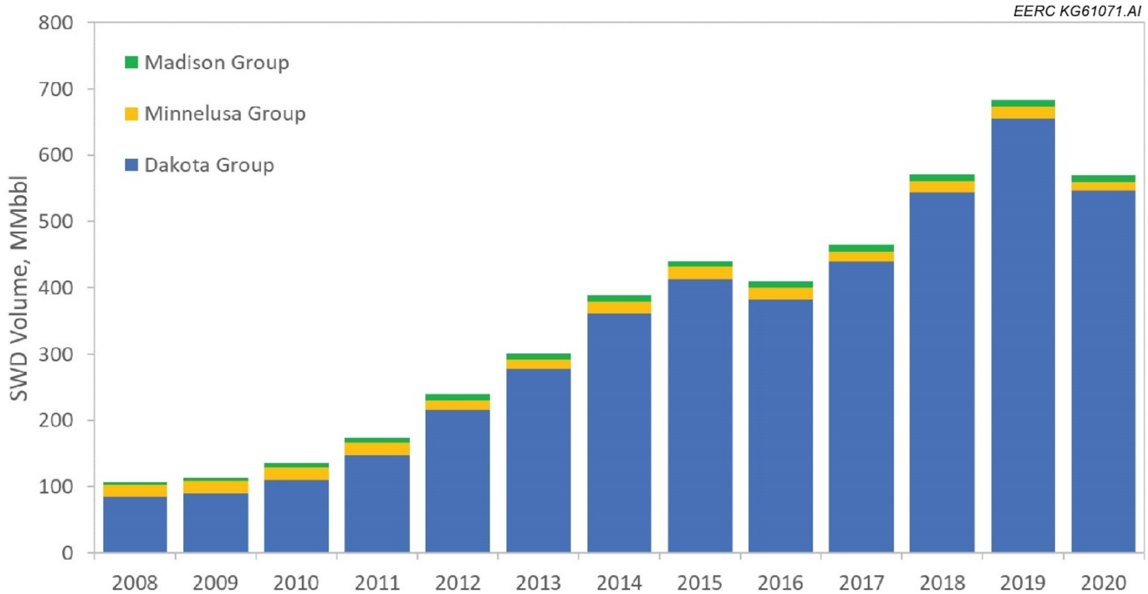

Figure 2-6. Annual SWD injection volume by geologic group from 2008 to 2020 (data source: North Dakota Industrial Commission, 2021).

In addition to SWD well performance, localized areas of pressurization of the Dakota's Inyan Kara Formation in proximity to higher-density areas of SWD wells is resulting in operational changes and added expense for Bakken operators when drilling new production wells. Operators in the region apply the best industry practices when drilling through these pressurized zones. A higher-density drilling fluid is needed when drilling through areas with increased formation pressure.

In some cases, operators need to install an additional casing string (Basu and others, 2019) to manage pressure while drilling by mechanically isolating the Inyan Kara, as illustrated in Figure 2-7. Installation of the additional casing string is reported to increase the impacted cost of Bakken wells by about \$500,000–\$750,000. At a potential 10%–15% increase in well cost, the additional casing string becomes a factor for operators when considering capital placement, economics, and profitability (Personal Communication, Bakken producers, 2020).

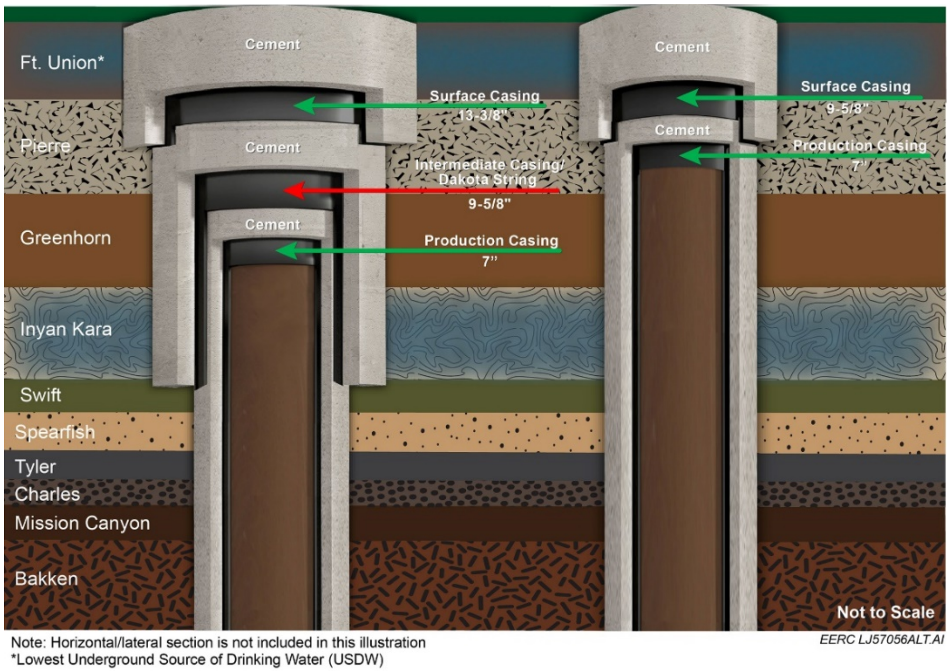

Figure 2-7. Illustrative diagram for a well using an intermediate casing string, or "Dakota string" (left wellbore), and a typical well diagram without the addition of a Dakota string (right wellbore).

2.5 Produced Water Recycling and Reuse Discussion

The general trend associated with oil- and gas-related produced water management in North Dakota has been a sustained increase of freshwater use, increasing water production, and increasing SWD volumes. Tremendous volumes of water are being managed in the region, and the continued trend of increasing volumes may present challenges for SWD into the Inyan Kara Formation. The current approach to water management provides the most cost-efficient means of disposal and limits the amount of handling/processing of produced water, thereby reducing the risk of spills. The Inyan Kara's geographic extent, relatively shallow depth, proper confining zones, and injectability provide a SWD target that is suitable across the entire Bakken producing region in the state. However, should current approaches to SWD in the Inyan Kara ever become technically or economically challenged, then alternative produced water management options for North Dakota may be desirable.

One target for reuse of produced water is as makeup water for hydraulic fracturing fluids. Water volumes for hydraulic fracturing are averaging 200,000 bbl/well for a single well stimulation, resulting in significant logistical hurdles for use to aggregate temporary storage of those volumes of water on-site for a single well stimulation. In regions where this type of reuse is occurring, operators are using a hybrid approach where 50%–70% of the makeup water volume is produced water, while the remaining volumes are made up of freshwater to in part help alleviate the storage challenge.

Safely handling high-TDS produced water for recycling poses a risk if not properly contained. Recycling of produced water may result in generation and disposal of technologically enhanced naturally occurring radioactive material (TENORM) and other by-products of the recycling process (e.g., salts, metals). This occurs as solids settle in tanks and concentrate NORM, and if these solids are classified as TENORM, they require compliant disposal with the associated costs and regulations.

While produced water recycling is not yet widespread in North Dakota, commercial operators are making strides in overcoming the technical and regulatory challenges of using high-salinity produced water in completion operations (Marathon Oil, 2020). Despite some of the aforementioned challenges, oil and gas operators are increasingly driven by environmental, social, and governance (ESG) considerations. According to the United Nations Principles for Responsible Investment, ESG integration is defined as "the explicit and systematic inclusion of ESG issues in investment analysis and investment decisions." Put another way, ESG integration is the analysis of all material factors in investment analysis and investment decisions, including environmental, social, and governance (ESG) factors" (United Nations Principles for Responsible Investment, 2018).

While ESG has been around for a while, the topic has been of increasing discussion in recent years. According to an article in Hart Energy's October 2021 Energy ESG Report, many of the drivers regarding ESG in the United States thus far have come from the investment community. What started out as a push from social impact investors and institutional investors has now moved to the mainstream investment community, with the impacts to the oil and gas community being profound. In the last 2 years, ESG penetration in the sector has gone from awareness to all-out disclosure by a significant percentage of publicly traded companies (Hart Energy October 2021 Energy ESG, 2021). While disclosures are currently voluntary (this can likely change pending proposed rules by the Securities and Exchange Commission regarding climate risk disclosure) and vary depending on the company, many companies report voluntary disclosure topics based on the Sustainability Accounting Standards Board (SASB) Index. One of the main topics in the SASB Index regarding the environmental aspect of ESG is water management. This includes items such as the amount of freshwater used, the volume of produced water generated, and percent injected via Class II injection well as well as the amount recycled for use in other wells (Sustainability Accounting Standards Board, 2018).

Given the large amounts of freshwater typically required for oil and gas operations and SASB disclosure metrics, this has become a major focal point for companies when it comes to ESG reporting. For example, some companies track their water intensity, which is defined as the barrels of water used in completions per barrels of oil equivalent produced (Continental Resources, 2020). This gives the ability for companies to track their reduction in freshwater use year over year. As companies are looking to reduce their freshwater use, they are also recognizing the need for innovations that enable the recycling and reuse of flowback and production water for future operations. This is currently being done, with some fracture companies creating custom fluid chemistry such as friction reducers that is compatible with the highly saline production water, allowing operators to use that recycled water for future fracture jobs, thereby displacing freshwater usage with water recycling and reducing the pressure on local freshwater sources (Liberty, 2020). While the variability in water chemistry can be challenging to developing the proper fluid chemistry needed for produced water recycling, a concept like GHCR could result in a more consistent water chemistry and more favorable economics, enabling increased use.

2.6 Produced Water Recycling Approach—GHCR Concept

A component of the NDIC OGRP (NDIC Contract G-051-101) project cofunded by the U.S. Department of Energy (DOE) Fossil Energy (FE) Program awarded to the EERC includes a techno-economic assessment of using a geologic formation to treat produced water for beneficial reuse applications through the GHCR approach. GHCR is a novel produced water management approach that uses a subsurface geologic formation as a natural medium for managing produced water recycling and reuse. Produced water is already injected into the subsurface via SWD wells (Figure 2-8), and the concept seeks to take advantage of the hypothesized natural processes occurring in the subsurface (e.g., filtering, mixing, diluting, etc.) and to extract the water at some distance from the disposal well (Figure 2-9). The extracted water, which is presumably of significantly higher quality (i.e., lower TDS) than the injected produced water, is hypothesized to be more conducive for use in hydraulic fracturing makeup water or other beneficial uses or subsequent treatment, thus reducing oil and gas industry freshwater demand. Additionally, the extraction of water will slow the pressurization of SWD targets, thus extending the life of disposal wells and reducing the need for additional disposal wells in the future.

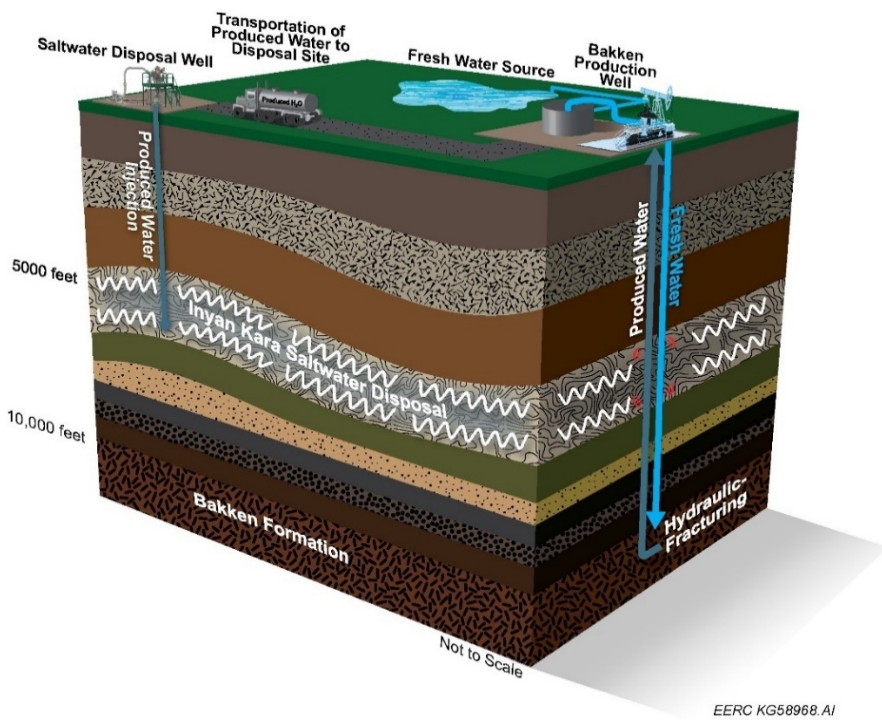

Figure 2-8. Traditional approach to water management.

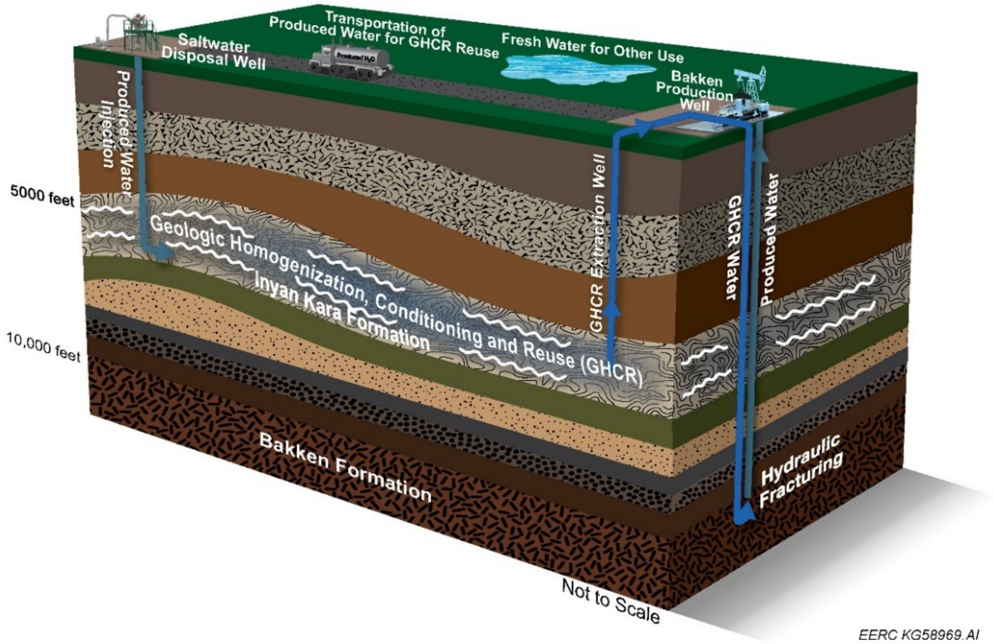

Figure 2-9. GHCR concept involving the addition of an extraction well and utilizing that water as hydraulic fracturing makeup water for Bakken wells.

The GHCR concept could address many of the recycling challenges outlined in the previous section, and the results of the investigation are reported in the subsequent sections of this report. By utilizing existing SWD infrastructure and the geologic formation as a storage container, the concept may provide a starting point to address some economic and environmental challenges surrounding the concept of recycling. This project investigated the techno-economic viability and potential benefits of the GHCR concept including the following:

- By adding an extraction well to existing SWD sites, the implementation of GHCR could be accomplished at a lower price point than installing traditional water-processing/recycling facilities.
- By using the geologic formation in lieu of surface storage and extracting water on demand, the potential for produced water spills is greatly reduced and the approach provides virtually unlimited on-demand storage/supply capacity.
- By using the geologic formation as a natural treatment, GHCR extracted water may have fewer problem constituents and greater consistency in composition, thus reducing or eliminating waste handling.
- Withdrawing water from the formation would slow pressurization.

The EERC, through the State Energy Research Center (SERC), has investigated subsurface pressure management while drilling using temporary brine extraction. The project (Connors and others, 2020) modeled subsurface pressures between a SWD well and an extraction well in the Dakota. Results indicated that brine extraction could theoretically be used to temporarily reduce Dakota pressure while drilling to avoid the need to install a Dakota water string. Results indicated that an extraction well 10,000 feet from a SWD well, temporarily extracting brine between 5000 and 25,000 bbl/day (bpd) and using or reinjecting off-site, could temporarily reduce Dakota pressure to allow drilling a Bakken well(s) in an area impacted by elevated pressure without requiring an intermediate water string.

3.0 LABORATORY AND FIELD EVALUATION OF GHCR CONCEPT

Laboratory column testing and fluid sampling at a commercial SWD site with an associated extraction well helped evaluate the physical processes and efficacy of the GHCR concept. The goal of the testing was to better understand the physical processes that would likely occur in a commercial setting where the GHCR concept would be implemented. The results from the laboratory testing and fluid sampling were used to inform the geologic modeling and numerical simulation efforts described in Section 4.0. The laboratory column testing consisted of three separate column tests, with each designed to understand the interactions occurring between native Inyan Kara Formation chemistry water, Bakken produced water, and Inyan Kara Formation (rock) material. The three column tests are described in Section 3.1. The fluid testing at a commercial SWD site is described in Section 3.2.

3.1 Laboratory Column Testing

The laboratory column testing was designed to replicate Bakken SWD into the Inyan Kara Formation to understand the natural processes that would occur in the subsurface. The column testing aimed to gain insight into the potential water chemistry that could be expected with water extracted from the Inyan Kara Formation if the GHCR concept was implemented. The laboratory column testing was separated into three separate tests, as described in Sections 3.1.1, 3.1.2, and 3.1.3, and were referred to as the sand column, outcrop column, and core column, respectively. The sand and outcrop tests were run in the same system utilizing a glass column. The core column was run in a separate specialized core holder but utilizing the same enclosures and sampling hardware. Column flow rates were chosen to target a 36-day residence time based on minimum residence time observed in the geologic model representing the brine extraction and storage test (BEST) field location discussed in Section 3.2. A temperature of 170°F based on field measurements for the Inyan Kara Formation was initially targeted in the column but had to be reduced to 150°F because of excessive evaporation and gas production in the column. More detailed schematics and preparation methods for both systems are provided in Appendix B.

3.1.1 Sand Column Test

The first laboratory column test was conducted to evaluate injected Bakken produced water with synthetic Inyan Kara Formation water and a quartz sand to replicate Inyan Kara sand filtering. This initial column test acted as a control experiment to evaluate the filtration efficacy of the sand and any reactions that occur through bacteria development in the produced water/formation matrix.

The size distribution of the sand is shown in Table 3-1. The size distribution is predominantly larger than 70 mesh (66.5% mass). Table 3-2 shows the initial test conditions of the column using packed and saturated quartz sand. Throughout testing with quartz sand, the flow properties of the column were not impacted significantly.

Table 3-1. Sand Column Test – Pure Quartz Sand Size Distribution

Screen Size (U.S. mesh)	Retained, %
50	33.0
70	33.5
80	16.6
100	10.4
120	3.9
140	1.2
200	0.7
Pan	0.8
Total	100.0

Table 3-2. Sand Column Test – Starting Conditions

Temperature, °F	150
Injection Pressure, psig	1–2
Target Flow Rate, mL/min	0.135
Permeability, mD	6473
Sand Mass, kg	35.424
Sand Density, g/cm^3	2.65
Sand Volume, cm^3	13,368
Column Volume, cm^3	19,635
Sand Volume, %	68
Column Porosity, %	32

Prior to injection of Bakken produced water, the sand column was saturated with synthetic Inyan Kara brine prepared in the laboratory. Both the produced water and synthetic brine were analyzed for key parameters prior to testing, and results are presented in Table 3-3. Injection began on September 23, 2020, and ran through February 16, 2021, for a total of 146 days. The injection rate was set to achieve a flow-through residence time of 36 days to mimic model estimates of field conditions for Bakken produced water being injected into, migrating through, and subsequently extracted from the Inyan Kara Formation at the BEST field site (described in Section 3.2). (Figure 4-20 in the modeling section can be referenced for injection interruptions and rates.) Interruptions and flow reductions were occasionally observed due to system issues such as damaged tubing or clogs.

Table 3-3. Sand Column Test – Inyan Kara Synthetic Brine and Bakken Produced Water Analysis

	Inyan Kara Brine	Bakken Produced Water
Date	July 1, 2020	July 16, 2020
pH	6.78	5.66
Conductivity, mS/cm	19.8	246
Density, g/mL	1	1.2
TDS, mg/L	11,400	325,000
Alkalinity, HCO_3, mg/L	NA[1]	109
Sodium, mg/L	4000	93,500
Potassium, mg/L	120	9700
Calcium, mg/L	283	21,200
Magnesium, mg/L	14.6	1140
Strontium, mg/L	NA	1810
Chloride, mg/L	6670	195,000
Bromide, mg/L	NA	966
Sulfate, mg/L	283	209
Iron, mg/L	NA	127
Boron, mg/L	0	580
Barium, mg/L	NA	41.9
Lithium, mg/L	NA	94.6
Manganese, mg/L	NA	15.3
Total Organic Carbon (TOC), mg/L	NA	145
Total Suspended Solids (TSS), mg/L	<10	185

[1] Not analyzed – minor and trace components were not included in the synthetic brine and therefore not analyzed.

Brine samples exiting the column were collected daily, with the exception of weekends. The column was allowed to run continuously over the weekend, and fluid was collected on the next business day. Fluid conductivity analysis was performed on each collected sample, and a complete set of parameters were analyzed for eight samples collected periodically throughout the test. The parameters included pH, TDS, density, sodium, potassium, calcium, magnesium, strontium, chloride, bromide, sulfate, iron, boron, barium, lithium, manganese, zinc, TSS, and TOC. Testing concluded when the concentrations of the parameters evaluated had reached a plateau. Water chemistry results are presented in Appendix A.

Conductivity data indicated breakthrough of injected Bakken produced water occurred on Day 18 at the column exit as evidenced by the increase in conductivity (Figure 3-1). Initial observations indicated the GHCR test column was effectively filtering TSS as evidenced by the consistently low (ranging from <10 to 50 mg/L) TSS in the samples collected at the exit of the column relative to the 180 mg/L TSS measured for the Bakken produced water being injected into the column (Figure 3-2). This TSS reduction provides evidence the packing of the column was sufficient and that there were no high-permeability preferential flow pathways present in the column that could contribute to nonrepresentative results.

With the exception of sulfate (Figure 3-3), other major analytes (Appendix A, Figures A-1–A-5) trended with conductivity and TDS (Figure 3-4), providing data on the volumetric (pore-volume basis) efficacy of the GHCR process relative to flow rate. The TDS, conductivity, and sulfate values were used to calibrate reservoir simulation models described in Section 4.0. TOC increased over time but at a lower rate than the other analytes (Figure 3-5). The observed trends in sulfate (Figure 3-3) and TOC are potentially indicative of bacterial activity, and select samples were evaluated for sulfate-reducing bacteria. BART (biological activity reaction test) biodetector test kits were used to evaluate whether sulfate- reducing bacteria were present in samples collected from the laboratory column test. The five samples tested were a blank (deionized water), the synthetic Inyan Kara brine, and three column outlet samples collected at 1-month increments. No presence of these bacteria was found, indicating that sulfate-reducing bacteria were not likely the cause for the reduction in sulfate. The changing chemistry of the injected brines (i.e., reductions in sulfate and other organic constituents) may be from other geochemical reactions.

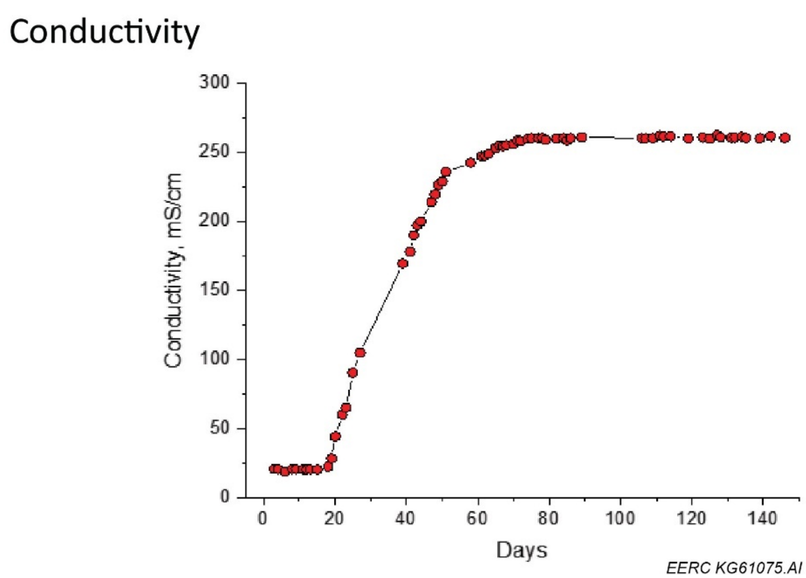

Figure 3-1. Conductivity measurements of laboratory sand column test outlet fluid samples. Results indicate that breakthrough of injected Bakken produced water occurred on Day 18, with a reading of 22.3 mS/cm.

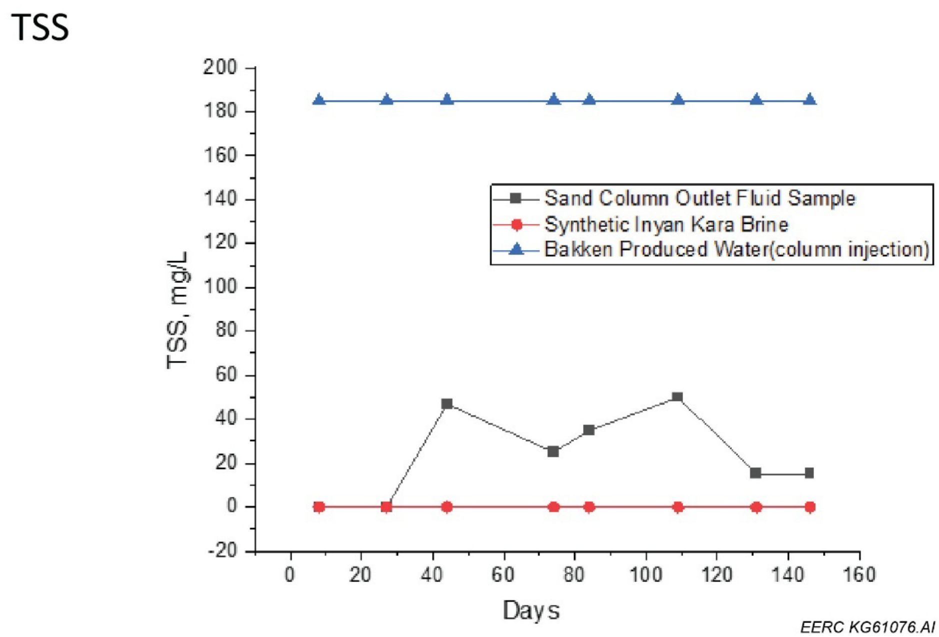

Figure 3-2. TSS measurements of laboratory sand column test outlet fluid samples. Results indicate packing of the column was sufficient and that there were no high-permeability preferential flow pathways present in the column that could contribute to nonrepresentative results.

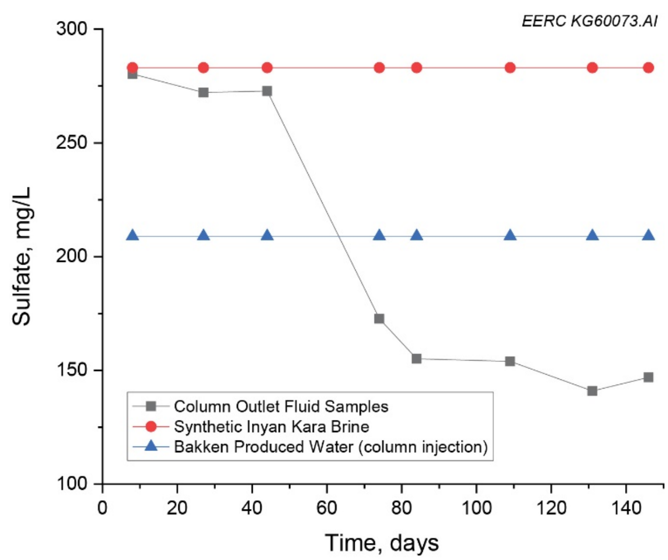

Figure 3-3. Sulfate measurements of laboratory sand column test samples (synthetic Inyan Kara brine used to saturate the column, Bakken produced water injected into the column, and fluid samples collected from the column outlet). Reduction of sulfate over time to levels below those present in the injected Bakken produced water could be indicative of chemical reactions occurring within the system.

TDS

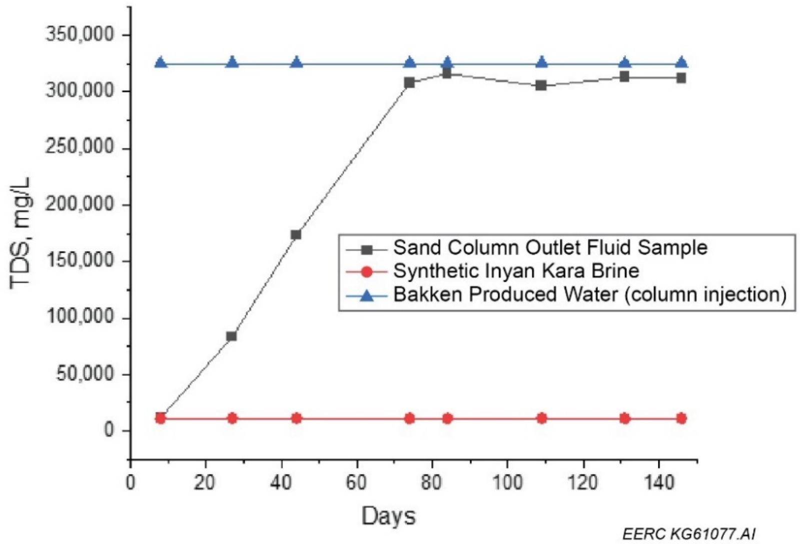

Figure 3-4. TDS measurements of laboratory sand column test samples (synthetic Inyan Kara brine used to saturate the column, Bakken produced water injected into the column, and fluid samples collected from the column outlet). Gradual increase of TDS provides an indication of injected Bakken produced water breakthrough at the column outlet and efficacy of the GHCR process.

TOC

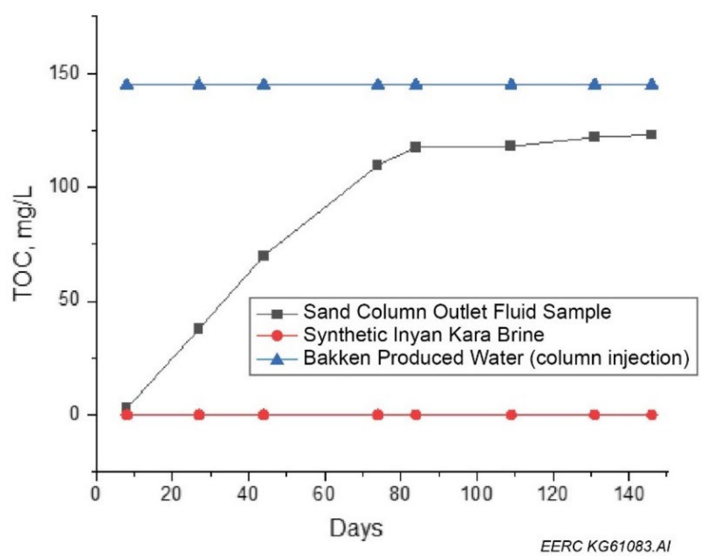

Figure 3-5. TOC measurements of laboratory sand column test samples (synthetic Inyan Kara brine used to saturate the column, Bakken produced water injected into the column, and fluid samples collected from the column outlet). The lower rate of increase in TOC could be indicative of chemical reactions occurring within the system.

X-ray fluorescence (XRF) spectroscopy and x-ray diffraction (XRD) analysis were performed on the sand samples pretest and posttest. This analysis helped to identify accumulation of filtered solids, precipitates, and formation of any new mineral phases due to interactions between the injected fluids and/or between the fluids and the quartz sand. Table 3-4 shows the pretest and posttest XRF results, and Table 3-5 shows the posttest XRD results. The pretest XRD was not run because the initial sand was verified to meet a specification of greater than 99.7% silica.

Table 3-4. Sand Column Test – XRF Results for Pretest and Posttest Samples from the Inlet and Outlet of the Column

Oxide	Pretest	Posttest Inlet	Posttest Outlet
SiO_2	99.76	93.36	96.91
Na_2O	0.08	1.74	1.72
Cl	0.00	0.58	0.59
CaO	0.00	0.34	0.27
Fe_2O_3	0.11	0.13	0.17
K_2O	0.00	0.17	0.13
Al_2O_3	0.08	0.07	0.11
SrO	0.00	0.03	0.03
TiO_2	0.02	0.02	0.03
P_2O_5	0.01	0.01	0.01
MnO	0.00	0.00	0.00
SO_3	0.01	0.01	0.03
BaO	0.00	0.01	0.00
MgO	0.01	0.01	0.01
Unknown	0.00	0.50	0.00

Table 3-5. Sand Column Test – XRD Results for Posttest Samples from the Inlet and Outlet of the Column

Phase	Column Inlet, wt%	Column Outlet, wt%
Quartz	96.4	96.3
Halite	3.1	3.2
Brookite	0.4	0.5

XRF results (Table 3-4) show that the initial sand is very clean at 99.7% silica with minor impurities. After testing, samples from the inlet and outlet both showed an accumulation of salts and iron from XRF analysis. The concentration was slightly higher in the inlet versus the outlet, indicating that the column still had some remaining capacity for filtration. XRD analysis (Table 3-5) of the inlet and outlet shows the formation of halite and brookite at similar concentrations. The Total XRF analysis shows approximately a 6% accumulation of solids in the quartz sand at the inlet.

3.1.2 Inyan Kara Outcrop Column

The second laboratory column study was conducted to better understand the reactions taking place between the injected Bakken produced water, the native Inyan Kara Formation water, and the actual formation material (rock). The outcrop column used Inyan Kara Formation material collected from a roadside outcrop near Rapid City, South Dakota.

The size distribution of the Inyan Kara outcrop sand was significantly finer than the pure quartz sand used in the previous test, as shown in Table 3-6, with sand primarily smaller than 140 mesh (72.5% mass). The initial conditions for the outcrop column test are presented in Table 3-7.

Table 3-6. Outcrop Column Test – Inyan Kara Outcrop Sand Size Distribution

Screen Size (U.S. mesh)	Retained, %
50	9.9
70	3.3
80	1.5
100	3.7
120	3.3
140	5.9
200	21.5
Pan	51.0
Total	100.0

Table 3-7. Outcrop Column Test – Starting Conditions

Temperature, °F	150
Injection Pressure, psig	2.95
Flow Rate Target, mL/min	0.135
Permeability, mD	36.0
Sand Mass, kg	34.673
Sand Density, g/cm^3	2.677
Sand Volume, cm^3	12,950
Column Length, cm	255
Column Diameter, cm	10
Column Volume, cm^3	19,635
Sand Volume, %	66.0
Column Porosity, %	34.0

Since there was not enough Bakken produced water and synthetic brine left from the sand column test to complete the outcrop column test, a new Bakken produced water sample was collected and a new Inyan Kara synthetic brine prepared. Both the produced water and synthetic brine were analyzed for key parameters prior to testing, and results are presented in Table 3-8.

Injection began on June 23, 2021, and ran through September 15, 2021, with a period of 14 days in July and 12 days in August when the column stopped flowing and was down for maintenance. Excluding those days, the test ran for 57 days.

Table 3-8. Outcrop Column Test – Inyan Kara Synthetic Brine and Bakken Produced Water Analysis

	Inyan Kara Brine	Bakken Produced Water
Date	April 22, 2021	June 3, 2021
pH	7.46	5.34
Conductivity, mS/cm	19.5	259
Density, g/mL	1	1.2
TDS, mg/L	10,780	340,000
Alkalinity, HCO_3, mg/L	77	52
Sodium, mg/L	3860	90,100
Potassium, mg/L	105	7570
Calcium, mg/L	279	22,600
Magnesium, mg/L	26.5	1340
Strontium, mg/L	15.8	1710
Chloride, mg/L	6010	213,000
Bromide, mg/L	NA[1]	1070
Sulfate, mg/L	267	185
Iron, mg/L	NA	100
Boron, mg/L	NA	455
Barium, mg/L	NA	41.9
Lithium, mg/L	NA	94.6
Manganese, mg/L	NA	15.3
TOC, mg/L	NA	145
TSS, mg/L	<10	1930

[1] Not analyzed – minor and trace components were not included in the synthetic brine and therefore not analyzed.

As with the sand column test, fluid samples exiting the column were collected regularly. Conductivity analysis was performed on each collected sample, and a complete set of parameters were measured for eight samples selected periodically throughout the test. The parameters measured were the same as those for the sand column test, and testing concluded when the concentrations of the parameters evaluated had reached a plateau. See Appendix A for all water parameter results.

Conductivity data indicated breakthrough of injected Bakken produced water occurred on Day 26 as evidenced by the increase in conductivity (Figure 3-6). This was approximately 8 days longer than when breakthrough occurred in the sand column testing. Since the flow rates for both tests were similar, the later breakthrough is likely due to increased reactivity due to the significantly finer Inyan Kara sand resulting in a higher surface area and higher reactivity than the quartz sand (Table 3-1 and Table 3-6).

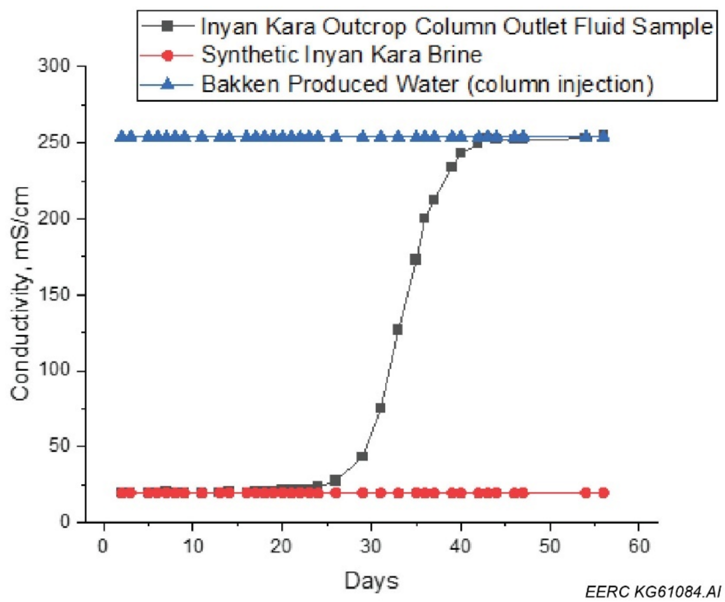

Figure 3-6. Conductivity measurements of laboratory outcrop column test outlet fluid samples. Results indicate that breakthrough of injected Bakken produced water occurred on Day 26, with a reading of 23.3 mS/cm.

Similar to the sand column testing, most analytes followed an increasing trend with the TDS, except for magnesium and sulfate (Figures 3-7, 3-8, and 3-9 and Appendix A Figures A-6–A-9). Between Days 33 and 47, magnesium concentrations at the outlet actually exceeded the original concentration of the Bakken injection brine and then began to decrease to injection brine levels at the end of the test. Sulfate concentrations exceeded the injection brine concentration throughout most of the testing, with levels decreasing the last 7 days.

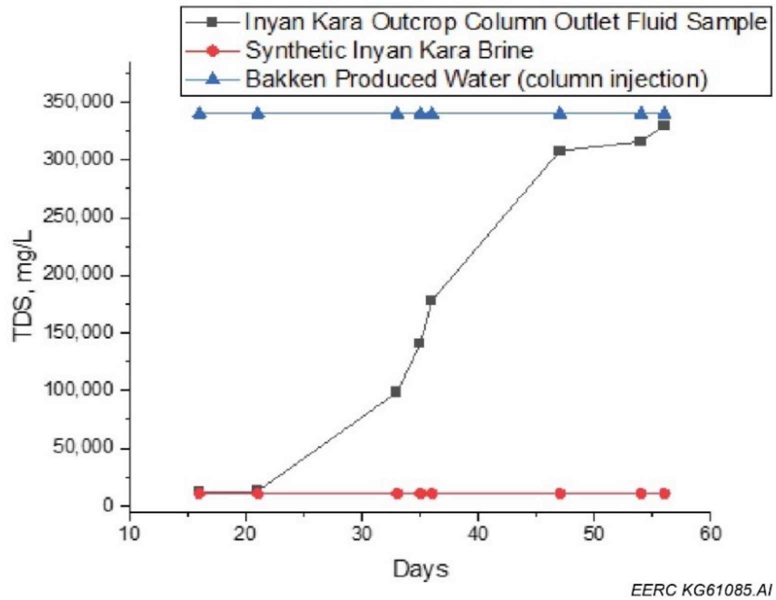

Figure 3-7. TDS measurements of laboratory outcrop column test samples (synthetic Inyan Kara brine used to saturate the column, Bakken produced water injected into the column, and fluid samples collected from the column outlet). Gradual increase of TDS provides an indication of injected Bakken produced water breakthrough at the column outlet and efficacy of the GHCR process.

The TSS concentration of the Bakken injection brine used for the outcrop column testing was significantly higher than that of the brine used in the sand column testing (1930 mg/L versus 185 mg/L), yet results indicate the outcrop material was extremely effective in filtering the solids (Figure 3-10). Levels were reduced from 1930 to 16 mg/L in the first outlet sample tested at Day 17 and remained low throughout the entire test.

The TOC concentrations remained relatively stable throughout the testing, with a few values exceeding the initial brine concentration (Figure 3-11). This could be a result of organic matter present in the native outcrop material and being extracted by the brine.

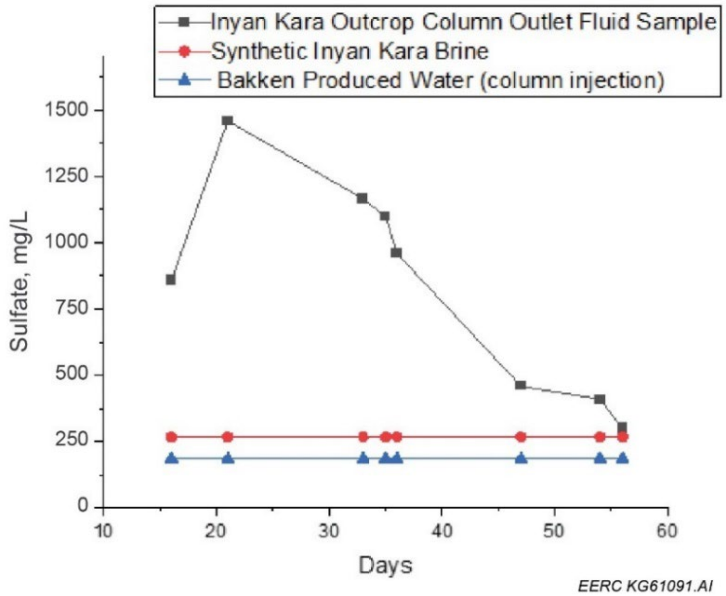

Figure 3-8. Sulfate measurements of laboratory outcrop column test samples (synthetic Inyan Kara brine used to saturate the column, Bakken produced water injected into the column, and fluid samples collected from the column outlet). The source of the elevated initial sulfate content is unknown. The initial concentration of 1200 mg/L represents an approximately 0.017% of the sand column mass. This is a concentration below the detection limits of XRD and also represents the lower detection limit from XRF. It may be due to slight leaching of sulfates from the Inyan Kara outcrop material, a result of sorption and desorption from the media or some other mechanism. Additional testing is required to make a clear determination as to the source of the variation, which was outside the scope of this effort.

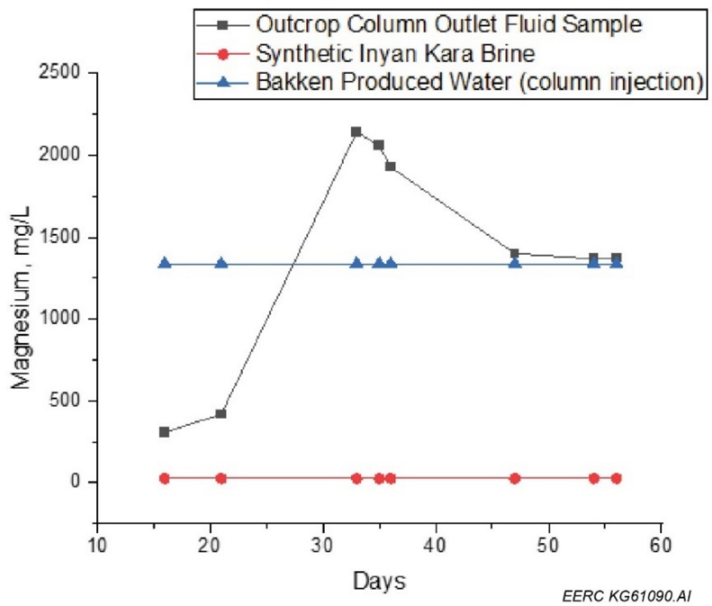

Figure 3-9. Magnesium measurements of laboratory outcrop column test samples (synthetic Inyan Kara brine used to saturate the column, Bakken produced water injected into the column, and fluid samples collected from the column outlet). The spike in magnesium concentrations between Days 33 and 47 may be due to slight leaching of magnesium from the Inyan Kara outcrop material, a result of sorption and desorption from the media or some other mechanism. Additional testing is required to make a clear determination as to the source.

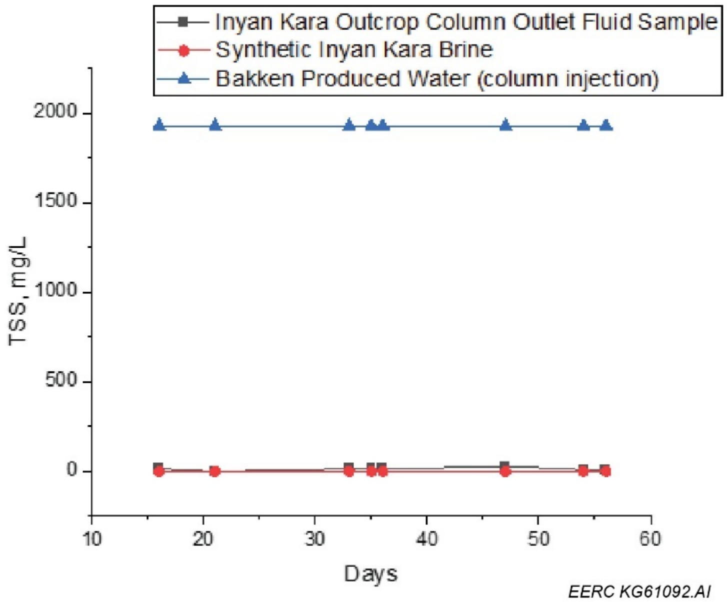

Figure 3-10. TSS measurements of laboratory outcrop column test outlet fluid samples. Results indicate packing of the column was sufficient and that there were no high-permeability preferential flow pathways present in the column that could contribute to nonrepresentative results.

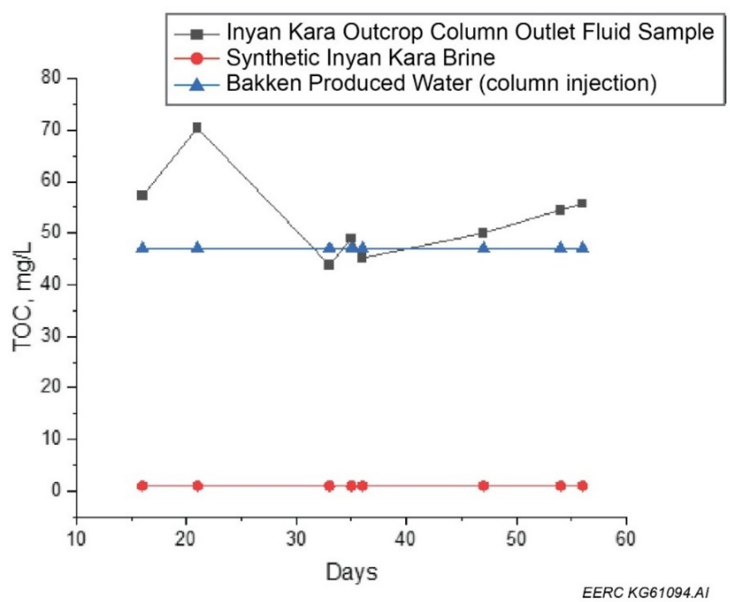

Figure 3-11. TOC measurements of laboratory outcrop column test samples (synthetic Inyan Kara brine used to saturate the column, Bakken produced water injected into the column, and fluid samples collected from the column outlet).

XRF and XRD analysis were performed on the Inyan Kara outcrop samples pretest and posttest. This analysis helped to identify accumulation of filtered solids, precipitates, and formulation of any new mineral phases due to interactions between the injected fluids and formation sand for comparison to quartz sand. Table 3-9 shows the pretest and posttest XRF results, and Table 3-10 shows the pretest and posttest XRD results.

Table 3-9. Outcrop Column Test – XRF Results for Pretest and Posttest Samples from the Inlet and Outlet of the Column

Oxide	Pretest	Posttest Inlet	Posttest Outlet
SiO_2	92.00	80.89	86.28
Al_2O_3	3.31	3.91	2.96
Fe_2O_3	2.86	2.97	2.83
TiO_2	0.65	0.59	0.60
K_2O	0.47	0.80	0.57
CaO	0.41	1.14	0.83
SO_3	0.11	0.13	0.10
MgO	0.09	0.12	0.06
P_2O_5	0.04	0.05	0.04
MnO	0.03	0.03	0.03
BaO	0.02	0.01	0.01
V_2O_5	0.01	0.01	0.01
SrO	0.01	0.06	0.04
NiO	0.00	0.00	0.00
Cl	0.00	6.02	3.20
Na_2O	0.00	3.28	2.44

Table 3-10. Outcrop Column Test – XRD Results for Pretest and Posttest Samples from the Inlet and Outlet of the Column

Analysis – Rietveld	Pretest	Post-Column Inlet	Post-Column Outlet
Quartz	86.3	69.1	67.8
Kaolinite	6.9	6.0	5.1
Goethite	4.5	8.1	6.0
Illite/Muscovite	1.2	2.0	0.8
Epsomite	0.4	2.0	1.6
Anhydrite	0.2	0.2	0.5
Halite	0.1	11.5	16.8
Sylvite	0.03	0.1	0.4
Other	0.5	0.9	0.9

XRF results (Table 3-9) show that initially the outcrop material contains approximately 92% silicon dioxide. Posttesting samples from the inlet and outlet both showed an accumulation of mainly salts from XRF analysis. Similar to the quartz sand, the concentration was slightly higher in the inlet versus the outlet, indicating that the column still had some remaining capacity for filtration. Iron oxide seems to be mostly saturated near 2.9%, and the XRD analysis (Table 3-10) of the inlet and outlet shows a reduction in kaolinite. This is likely due to clay fines being mobilized and washed from the system during filling and some fines being produced out. This fines migration also likely led to the eventual clogging of the column, which ended the test because of an inability to maintain flow at a safe injection pressure. The Inyan Kara outcrop material was more reactive and better trapped solids than the sand column. The XRF results showed a trapped concentration of solids exceeding 11% versus 6% with pure quartz sand. Similarly, XRD showed a concentration of approximately 17% nonquartz solids retained by the outcrop material compared to less than 4% retained by the pure quartz sand. The increased capacity for filtration is likely because of increased surface area due to fine, smaller-than-200-mesh particles and a higher reactivity due to a more diverse mineral composition. This resulted in accumulation of additional minerals such as goethite, epsomite, and anhydrite and much larger concentrations of halite.

3.1.3 Inyan Kara Core Column

The third and final laboratory column test was conducted using Inyan Kara core sections obtained from NDIC Well 90383 (BEST I1). This core test was performed to look for geochemical changes in the produced output in comparison to the outcrop test. These core samples are unique in that they have been previously exposed to Bakken produced water at the injection site, and the core samples were not exposed to the same weathering as outcrop materials. The contrast between the outcrop and core tests helped identify the similarities and differences between the materials and their GHCR-related performance, and the additional testing better-informed model calibration. Table 3-11 shows the attributes of core plugs that were presaturated with synthetic Inyan Kara brine.

Table 3-11. Core Column Test – Data for Core Plugs Used in Core Flood Test

No.	Depth, ft	Mass Dry, g	Mass Sat., g	Diameter, cm	Length, cm	Mass Diff., g	Vol. Pore, mL	Vol. Bulk, mL	Porosity, %
1	5303	124.833	137.82	3	8.93	12.987	12.987	63.1225	20.57
2	5316.7	127.812	139.595	3	8.88	11.783	11.783	62.7690	18.77
3	5302	126.123	138.795	3	8.9	12.672	12.672	62.9104	20.14
4	5314.5	153.234	161.547	3	8.79	8.313	8.313	62.1328	13.38
5	5315.5	127.567	140.49	3	8.92	12.923	12.923	63.0518	20.50
6	5320.7	129.21	140.66	3	8.9	11.45	11.45	62.9104	18.20
7	5322.7	128.326	140.8	3	8.9	12.474	12.474	62.9104	19.83
8	5293.5	128.37	142.875	3	9.1	14.505	14.505	64.3241	22.55
9	5291	120.217	132.824	3	8.57	12.607	12.607	60.5778	20.81
10	5286	123.804	139.415	3	9.03	15.611	15.611	63.8293	24.46
11	5296	124.04	137.055	3	8.98	13.015	13.015	63.4759	20.50
12	5288	116.59	130.706	3	8.53	14.116	14.116	60.2950	23.41
13	5313	139.57	151.194	3	9.26	11.624	11.624	65.4551	17.76
14	5297.5	118.943	130.346	3	8.66	11.403	11.403	61.2139	18.63
						Total	**175.483**	**878.9784**	**19.97**

The Inyan Kara cores were loaded into the core holder in random order and treated as a single composite core section for the purposes of testing. The core test was particularly challenging because extremely low injection rates were required to attempt to hit the same 36-day residence time. The minimum achievable injection rate of 0.007 mL/min represents approximately an 18-day residence time, or about half the desired residence time. The reduced injection rates result in reduced sample volume rates relative to the sand and outcrop columns. The reduced volumes meant that TSS was not analyzed for the column, although based on visual observations, the output water was relatively clear. Again, the goal of this core test was to look at geochemical changes between the core and outcrop material, and the physical filtering of TSS was not imperative for this core test, especially considering the output fluid volumes were limited. Furthermore, XRD/XRF analysis was not performed on the core column as had been done on the two other column tests. This is primarily due to the 14 core sections that were used to fill the core holder, and each individual core would need to undergo XRD/XRF analysis, which was time- and cost-prohibitive.

Table 3-12 shows the conditions at the start of the core flood test and bulk properties of the composite core.

Table 3-12. Core Column Test – Starting Conditions

Temperature, °F	150
Injection Pressure, psig	30
Target Flow Rate, mL/min	0.007
Permeability, mD	2.00
Grain Mass, kg	1.789
Grain Density, g/cm^3	2.543
Grain Volume, cm^3	703
Core Length, cm	124.35
Core Diameter, cm	3.00
Core Bulk Volume, cm^3	879
Sand Volume, %	80.0
Core Porosity, %	20.0

The same Bakken produced water and Inyan Kara synthetic brine used for the outcrop column test were used for the core flow-through test; however, another sample of the Bakken brine was collected from the transfer container and analyzed to confirm the concentrations just prior to injection. Another sample was collected and analyzed at the end of the test, since there appeared to be some settling in the transfer container over the course of the testing. The results of TDS and corresponding analytes show a decrease in concentrations from the start of the test to the end of the test. Results are presented in Table 3-13, and both sets of data are included in the figures in this section.

Bakken produced water injection for the core flow-through test began on July 27, 2021, and ran through October 18, 2021, for a total of 83 days.

Table 3-13. Core Column Test – Inyan Kara Synthetic Brine and Bakken Produced Water Analysis

	Inyan Kara Brine	Bakken Produced Water – Start	Bakken Produced Water – End
Date	April 22, 2021	July 27, 2021	October 20, 2021
pH	7.46	4.04	3.46
Conductivity, mS/cm	19.5	240	230
Density, g/mL	1	1.2	1.15
TDS, mg/L	10,780	319,000	236,000
Alkalinity, HCO_3, mg/L	77	0	0
Sodium, mg/L	3860	89,400	67,500
Potassium, mg/L	105	8270	5620
Calcium, mg/L	279	21,000	16,700
Magnesium, mg/L	26.5	1230	1010
Strontium, mg/L	15.8	1710	1270
Chloride, mg/L	6010	195,000	142,000
Bromide, mg/L	NA[1]	1020	702
Sulfate, mg/L	267	290	258
Iron, mg/L	NA	71.5	14.8
Boron, mg/L	NA	513	428
Barium, mg/L	NA	13.5	10.5
Lithium, mg/L	NA	98.7	62.5
Manganese, mg/L	NA	21.3	19.9
TOC, mg/L	NA	71	24.7
TSS, mg/L	<10	NA	NA

[1] Not analyzed – minor and trace components were not included in the synthetic brine and therefore not analyzed.

Because the Inyan Kara core material used in this test was significantly smaller in scale than column tests, the injection flow rate was reduced to a minimum achievable flow rate of 0.007 mL/min to maximize residence time. This resulted in samples being collected at the outlet less frequently, ranging from 7 to 10 days between sample collection. When enough volume of water was generated at the column outlet to collect the first sample on Day 10, breakthrough had already occurred based on a conductivity reading of 40.7 mS/cm (Figure 3-12). Although the day of actual breakthrough could not be determined, it was still fewer days than either the sand column test or the outcrop column test (Day 18 and Day 26, respectively). The lower volumes of collected samples resulted in TSS not being measured for the core column.

Although there was a slight decrease in TDS of the Bakken injection brine throughout the testing, the data show trends similar to those in the sand column and outcrop column testing. Most analytes followed an increasing trend with conductivity and TDS, except for sulfate (Figures 3-12–3-15). The sulfate concentration spiked above the injection brine level at the start of the test but leveled off for the remainder of the test.

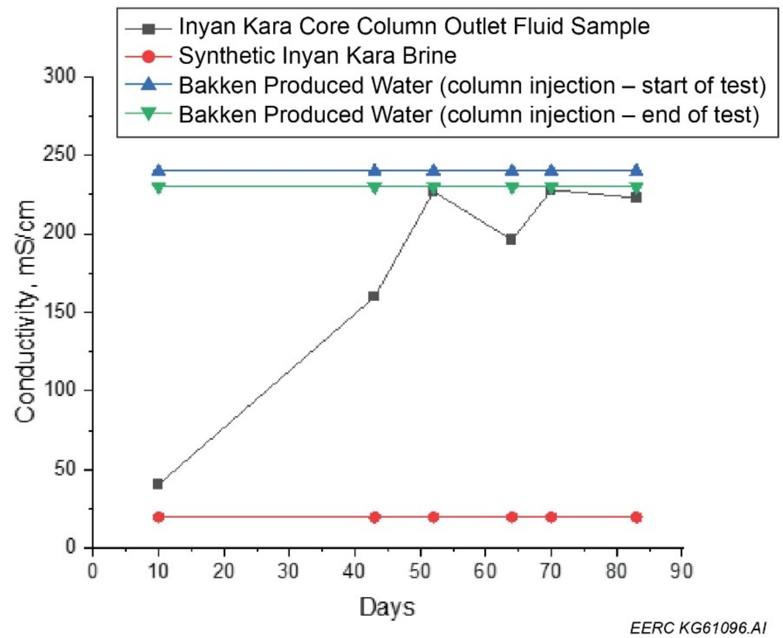

Figure 3-12. Conductivity measurements of laboratory core column test outlet fluid samples. Results indicate that breakthrough had occurred prior to the first outlet sample being collected on Day 10, with a reading of 40.7 mS/cm.

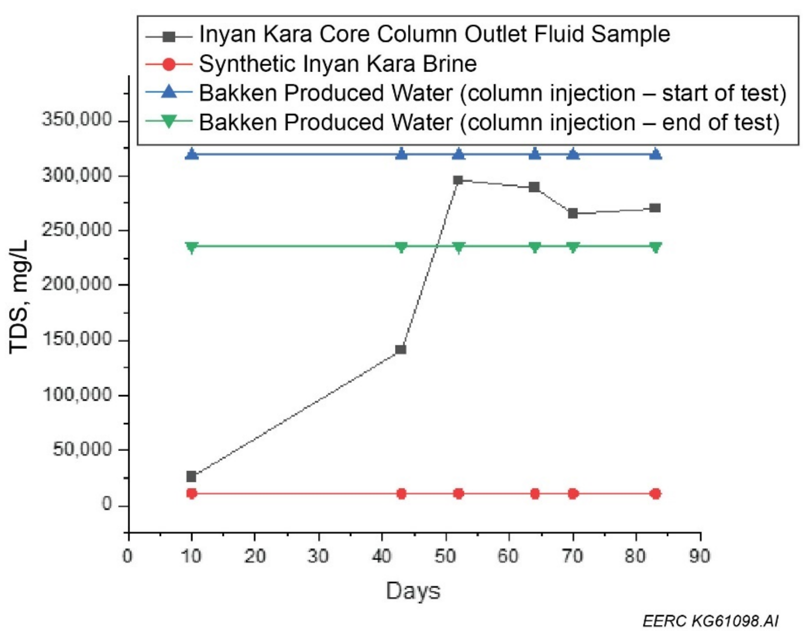

Figure 3-13. TDS measurements of laboratory core column test samples (synthetic Inyan Kara brine used to saturate the column, Bakken produced water injected into the column, and fluid samples collected from the column outlet).

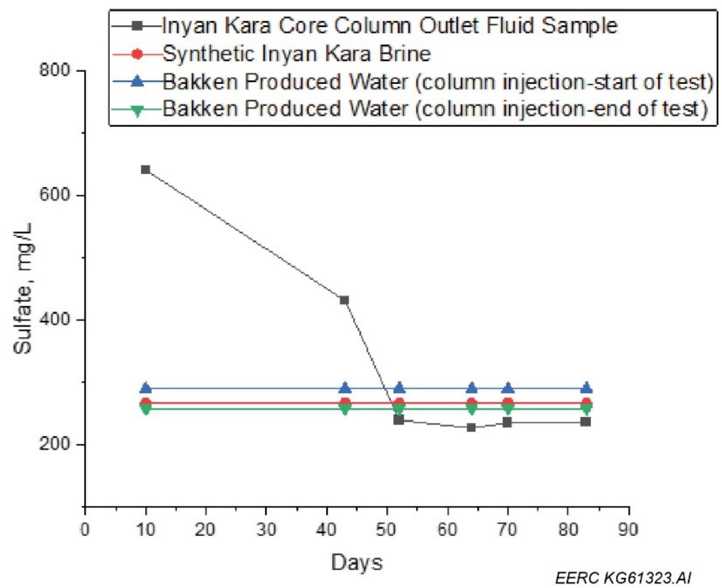

Figure 3-14. Sulfate measurements of laboratory core column test samples (synthetic Inyan Kara brine used to saturate the column, Bakken produced water injected into the column, and fluid samples collected from the column outlet). Similar to the outcrop test, an initial elevated sulfate saturation of 600 mg/L was observed. This represents less than 0.016% of the core material by mass. As with the outcrop test, additional testing is required to determine the source of these initially elevated sulfate levels.

It is worth noting that each of the outlet samples collected throughout the core column test had a distinct hydrocarbon layer on the surface of the sample. Since this was not observed in the previous Inyan Kara outcrop column study, and the fact that the same Bakken produced water was used for injection, it seems reasonable that the hydrocarbons were coming from the core material. This was supported by the TOC measurements, which ranged from 2× to 10× higher than the original Bakken injection brine (Figure 3-15).

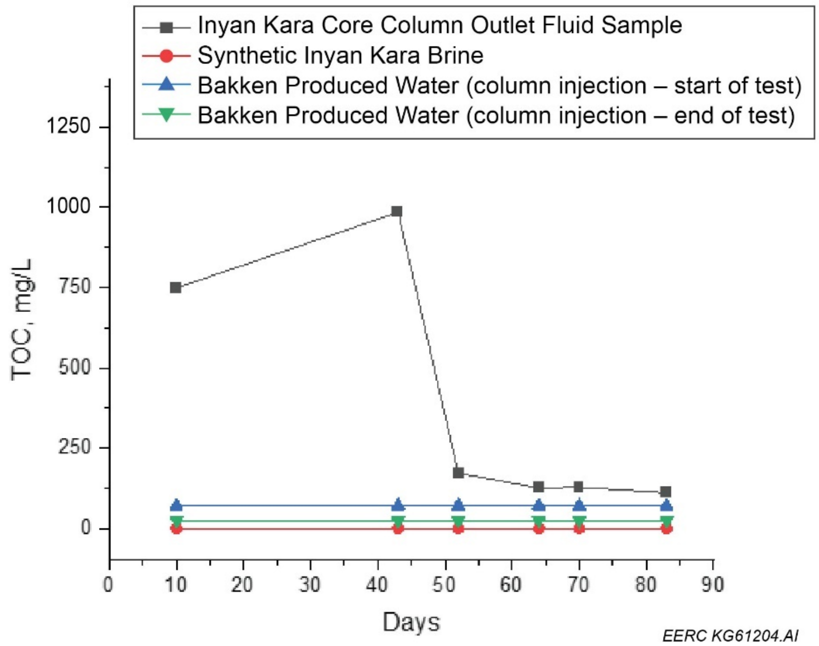

Figure 3-15. TOC measurements of laboratory core column test samples (synthetic Inyan Kara brine used to saturate the column, Bakken produced water injected into the column, and fluid samples collected from the column outlet). The fluid samples collected at the core outlet had a distinct hydrocarbon layer on the surface.

3.1.4 Key Observations for the Three Laboratory Column Tests

- All three column tests were effective in homogenizing the Bakken produced water chemistry to a consistent conductivity and TDS level by the end of the testing.

- Most major ions followed a similar increasing trend and plateau with TDS and conductivity, with the exception of sulfate. Sulfate followed roughly an inverse trend, with a unique pattern depending on which column was tested.

- Magnesium and sulfate in the outcrop column test showed a spike in concentrations in the middle of the test period. Leaching and/or sorption/desorption mechanisms are suspected.

- Both the sand column and outcrop column tests were effective in filtering TSS. Because of reduced sample volumes collected in the core column test, TSS could not be measured at the outlet.

- Because of the possible presence of organic matter in the Inyan Kara outcrop material and visible hydrocarbons being extracted from the Inyan Kara core, it was difficult to evaluate the efficacy of the laboratory GHCR process for TOC.

- It is possible that contamination of the BEST core from previous Bakken SWD injection may have led to deposits in the core that leached into the low-TDS Inyan Kara synthetic brine, resulting in an artificially accelerated breakthrough measurement.

- The Inyan Kara outcrop showed a greater efficacy for filtration when compared to the sand column control test. As evidenced by the accumulation of species that were more concentrated in the exposed material compared to the pure quartz. Contributing factors are likely the much higher surface area of the smaller Inyan Kara particles (<200 mesh versus >70 mesh) and the more diverse composition, allowing more opportunities for reaction as evidenced by XRF and XRD analysis of pretest and posttest sand samples.

3.2 Field Evaluation

The GHCR concept involves extracting water from the same geologic formation where SWD is occurring. Typically, there are no wells producing from the same formation in the same area where SWD is occurring. However, the EERC has partnered with Nuverra Environmental Solutions (Nuverra) on a multiyear project to demonstrate new strategies and methods of injection well operation. This project, referred to as BEST, is being conducted at the Nuverra-operated Johnsons Corner site, which was established in 2008 as a commercial SWD facility. The BEST site provides a unique opportunity because there was an extraction well (BEST E1) installed that produces fluids from the Inyan Kara sandstone, which is the SWD injection target for two SWD wells (Rink 1 and 2), as shown in Figure 3-16. The two Rink SWD wells have been injecting since 2008 (Rink 1) and 2010 (Rink 2), and the extraction BEST E1 was installed October 2018, just outside of the expected saltwater plumes, which were estimated based upon geologic model and simulation outputs for the BEST site. While the BEST E1 well was initially installed to evaluate the ability to manage the SWD reservoir, the arrangement of project wells offers the opportunity to evaluate the GHCR concept at a commercially operating SWD location.

Figure 3-16. BEST project site. Fluid samples were collected from the BEST E1 well to test the efficacy of the GHCR concept at a commercial SWD site.

3.2.1 Field Sampling Results

Water samples were collected regularly from the BEST E1 well between October 2018 and October 2021 to monitor the water quality for Bakken produced water being injected into, migrated through, and subsequently extracted from the Inyan Kara Formation at the BEST E1 well. As with the laboratory column testing, a complete set of parameters were measured for each collected field sample. The parameters measured were the same as those for the laboratory tests, and testing continued for the duration of this GHCR project.

In the years leading up to this GHCR project work, the Rink SWD wells typically received Bakken produced water for disposal via truck. However, conversations with personnel operating the Rink wells revealed that the continued development of other SWD wells in the area that receive produced water via pipeline delivery resulted in the Rink SWD wells receiving limited Bakken produced water, and, therefore, the SWD wells received primarily gas condensate water from nearby gas-processing facilities over the most recent ~18 months. Oil well operators favor routing their produced waters through pipelines to other SWD locations in the area. The gas condensate waters have significantly lower TDS values (ranging from ~100,000 to 180,000 mg/L) than typical Bakken produced water (~300,000–330,000 mg/L). While this operational change may affect the samples collected, this information was incorporated into the field modeling and simulation efforts to account for any impacts on the evaluation of GHCR efficacy.

Similar to the laboratory column testing, most analytes followed an increasing trend with the TDS (Figure 3-17, Appendix A), except for TOC and sulfate (Figures 3-18 and 3-19). The parameters shown plateaued at values about 15% to 30% below the average values of the Rink injection brine, with the exception of the increases found in TOC and sulfate. The reduced values show the potential of the GHCR concept in a field setting. The fluctuations of the TOC and sulfate may be indicative of geochemical reactions or biological activity occurring in the formation, where bacteria utilize organic carbon to reduce dissolved sulfate in the water to insoluble sulfide species which would precipitate out of solution. If the sulfides were then exposed to injected fluids of differing chemistries, such as brine that contained species that are oxidative to sulfide (such as dissolved oxygen, nitrate, manganese [+4], iron [+3]), the sulfide would oxidize back to sulfate and appear in solution. (Bolles, 1998). The increased reductions of analytes during the most recent 18 months of monitoring may be due to the increased percentage of lower-TDS gas condensate water injection.

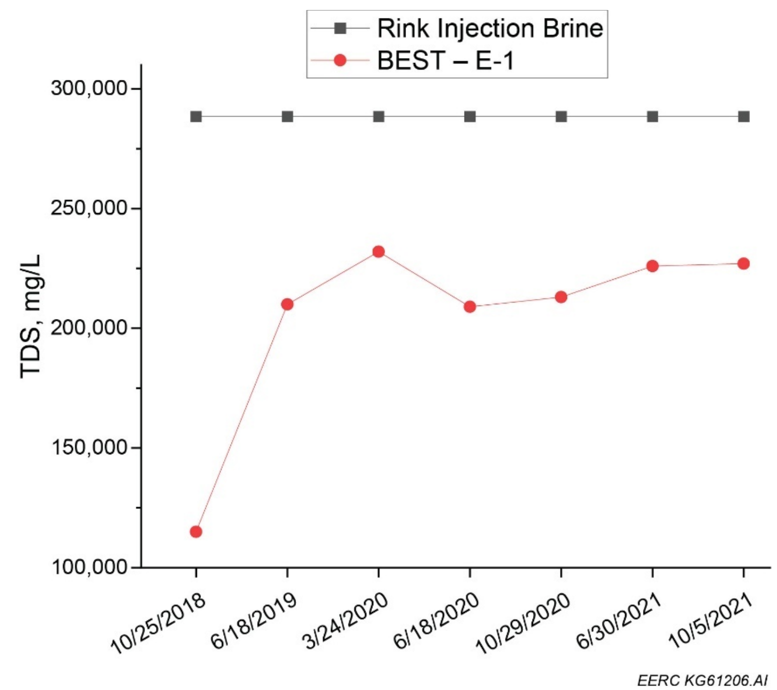

Figure 3-17. TDS measurements collected from the BEST E1 well. Measurements plateau at about 225,000 mg/L.

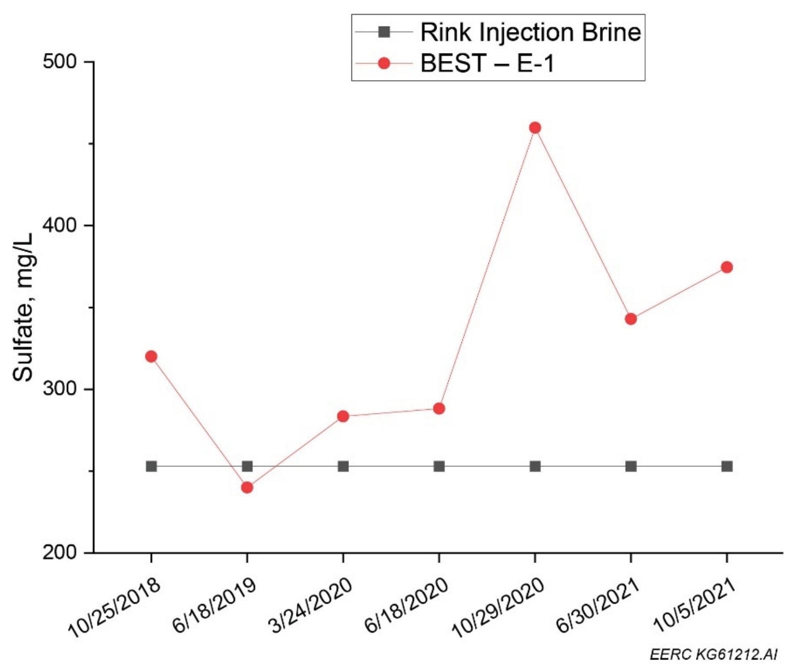

Figure 3-18. Sulfate measurements collected from the BEST E1 well. These concentration fluctuations may be caused by biological activity occurring in the reservoir where injected sulfates are reduced to sulfide by bacterial activity and then subsequently oxidized back to sulfate upon injection of and exposure to water with potential oxidative species, such as oxygen, nitrate, iron, and manganese.

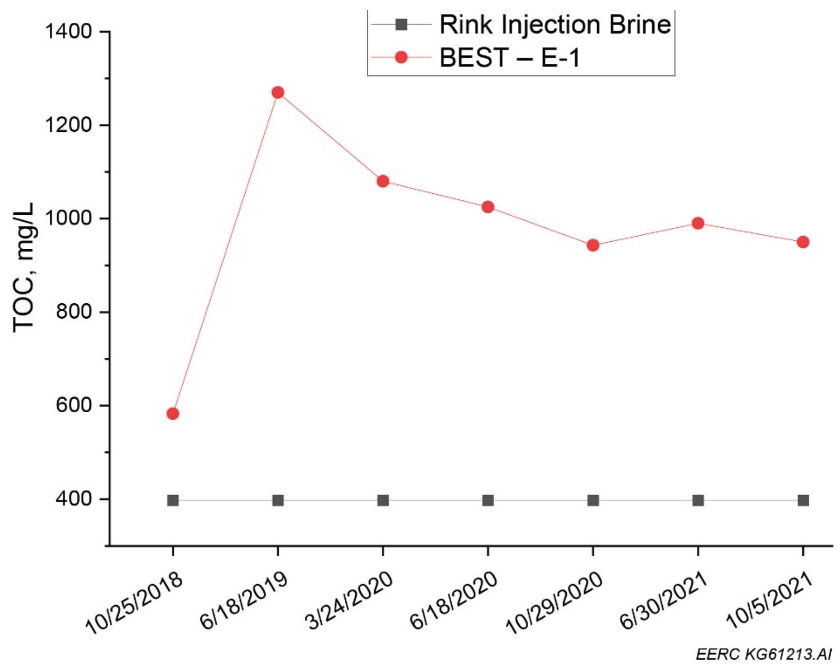

Figure 3-19. TOC measurements collected from the BEST E1 well. The Inyan Kara site has been injecting Bakken produced water over several years, resulting in a significant presence of hydrocarbons. The increased TOC concentration is likely due to the introduction of organics and could possibly be a driving factor for biological activity in the formation.

3.2.2 Key Observations from the Field Sampling and Evaluation

- Significant increases in several parameters measured during the field sampling effort indicate movement of the injected produced water (from Wells Rink 1 and 2) toward the extraction well (BEST E1) within a few months of the commencement of production operations.

- The rapid movement of the injected brine, and ultimate change in extracted water chemistry, was anticipated and confirmed by computer modeling efforts that assessed pressure and water chemistry compositional effects at the injection and extraction wells.

- The fact that the components of the dissolved constituent chemistry (i.e., TDS, sodium, chloride, etc.) leveled off below the injected produced water concentrations may likely be due to interactions with components of the formation that are causing a "buffering" effect of the fluid chemistry.

- Compositional chemistry changes, primarily decreases in concentration, in the recent 18 months of monitoring are likely due to changes in injected water chemistry (i.e., injection of less saline gas condensate water).

- Fluctuations of TOC and sulfate may be indicative of geochemical reactions or biological activity occurring in the formation.

- The reduced, and relatively consistent, values of TDS and associated ions show the potential of the GHCR concept in a field setting.

4.0 GEOLOGIC MODELING AND NUMERICAL SIMULATION EVALUATION OF GHCR CONCEPT

The modeling and simulation evaluation involved a field model of the Inyan Kara Formation within the study area and a laboratory-scale simulation model built with information provided from the columns and core holder experiments described in Section 3.0. The subsections within Section 4.0 describe the field simulation model, while the laboratory-scale simulation models are described in Appendix C. Some additional scenarios derived from the field simulation efforts are also shown in Appendix D. The objective of the modeling and simulation activity was to provide enough information to characterize and validate the efficacy and performance of the GHCR concept based on the observed differences in water chemistry, rock mineralogy, and geochemistry. This was achieved by calibrating and matching the numerical laboratory-scale model with the laboratory experiment data. Once the model was developed, it was used to evaluate different operational scenarios to assess the technical feasibility of using the Inyan Kara Formation as a geologic solution for produced water management and recycling of produced water. An additional benefit is to provide a potential solution for pressure control in the formation due to the constant water disposal injection.

Numerical simulation studies for evaluating the GHCR concept used Computer Modelling Group's (CMG's) GEM, a compositional reservoir simulation module. A compositional simulator is one of the most mechanistically accurate methods to solve compositional multiphase fluid flow processes. Compositional simulators utilize cubic equations of state, such as Peng–Robinson, which calculates thermal dynamic properties of fluids within the reservoir, including the resulting mixture of fluids when the disposal water with a higher salinity concentration is injected and dissolved into the native formation brine. During the simulation process, the geochemical model was included in the numerical model to account for the aqueous fractions and mineral precipitation/dissolution through the water injection time. The geochemical modeling allows the simulator to calculate the stoichiometry of chemical equilibrium, dissolution and precipitation, and ion exchange reactions directly from mineral and aqueous reactions introduced into the simulation model.

4.1 Field Numerical Models

Field numerical simulations were conducted using the Inyan Kara Formation geomodel. Simulations were carried out using CMG's GEM 2018.1, a compositional reservoir simulation module, with the addition of the geochemical modeling. The geochemical modeling improves the representation of the native Inyan Kara water and the Bakken produced water injection salinities as well as the rock mineral properties in order to evaluate any potential interactions between the water and the rock. The calculated temperature and pressure, along with a reference datum depth, were used to initialize the reservoir equilibrium conditions for performing numerical simulation (Figure 4.1).

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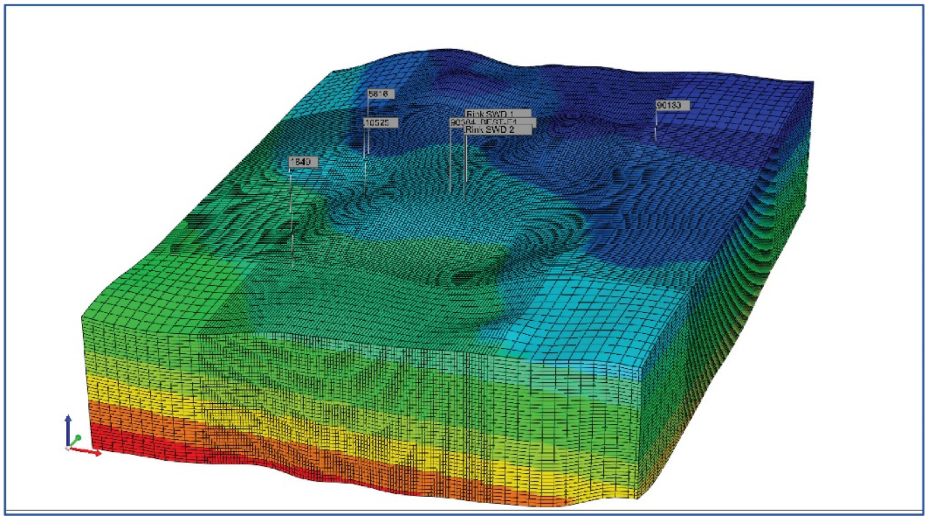

Figure 4-1. Field numerical model for Inyan Kara Formation.

The Inyan Kara geomodel used in the evaluation of the GHCR concept was provided from the BEST project's geologic modeling efforts. The model was previously history-matched using field data from water injector wells within the area of evaluation, including the water injector wells Rink SWD1 and SWD2, injector Well 10525, and Well 90183. The last data available used during the history match were from June 2021. The simulation model boundaries were assigned as an open condition, and the reservoir was assumed to be 100% brine-saturated with an initial formation salinity of 11,700 ppm TDS.

The numerical modeling allowed for simulation of mixing between the water injected from the Rink 1 and Rink 2 SWD wells (salinity of 197,000 ppm TDS) and the formation brine. The salinity value was calculated during the history match process, which matched the simulation's water density results with the data obtained from water samples collected in the field. During the history match, the permeability was regionally tuned by applying a multiplier to match reservoir properties.

The Inyan Kara model was also evaluated and calibrated using the salinity concentrations from different Bakken produced water samples collected at different times for this GHCR project. The model showed a decent calibration with the salinity values from the samples analyzed in the laboratory. For simplicity, the results shown in this report are for the simulation results using a 197,000-mg/L salinity concentration for injected Bakken produced water, which was calculated during the model history match.

4.2 Field Simulation Work Descriptions

Different operational scenarios and sensitivities were evaluated during 20 years of injection and production prediction from 2022 to 2042. The scenarios include varied distances between BEST location wells (Rink 1 and Rink 2 SWD wells) and production wells (simulates GHCR water production), number of production wells, and injection and production water rates, with the purpose of evaluating the changes in the GHCR production water volumes and the potential decrease of Inyan Kara formation pressure (Table 4-1).

Table 4-1. Field Numerical Simulation Scenarios

Scenario	Number of Additional Production Wells	Distance Between Water Production Wells and Rink SWD 1 and Rink SWD 2
1	E1 well	
2	E1 + two production wells	0.5 miles
3	E1 + two production wells	1.0 miles
4	E1 + three production wells	0.3 miles
5	E1 + two production wells	0.5 miles
6	E1 + four production wells	0.5 miles
7	E1 + five production wells	0.5 miles
8	E1 + five production wells	0.3 miles

Within the field simulation model, the distance between the BEST E1 well and the Rink SWD 1 was 0.286 miles and BEST E1 and the Rink SWD 2 was 0.254 miles (Figure 4-2). Four injector wells were identified in the area of interest and included in the numerical model: Rink SWD 1, Rink SWD 2, NDIC 10525, and NDIC 90183 (Figure 4-2).

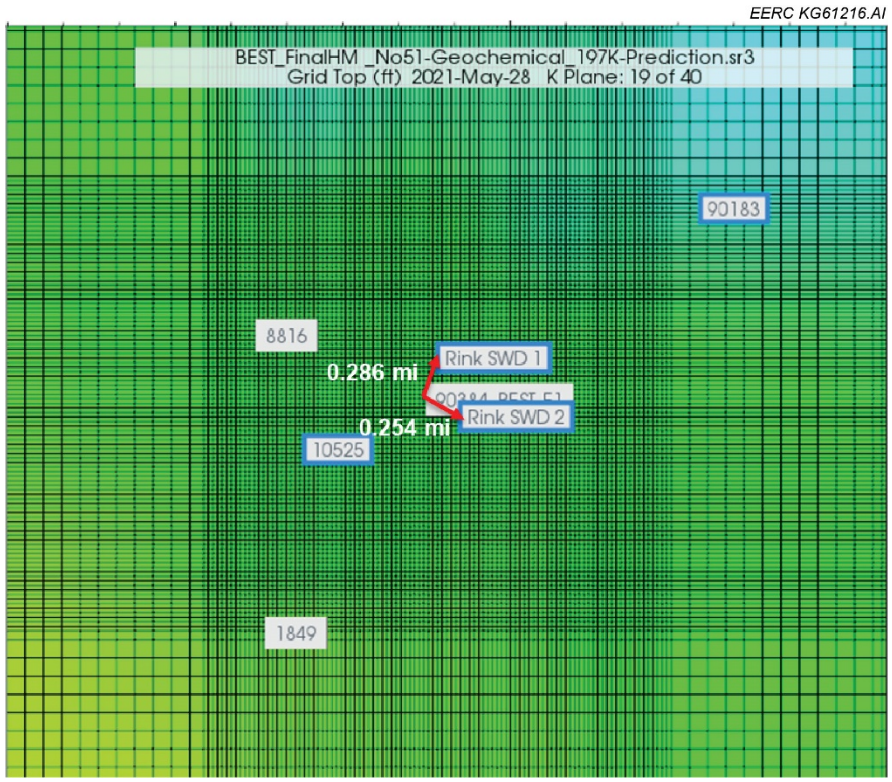

Figure 4-2. Field numerical model showing the distance in miles from the E1 producer well to Rink SWD 1 and SWD 2 – Scenario 1.

The additional production wells were placed at a distance no greater than 1 mile from the Rink SWD 1 and SWD 2 wells. The production water rate for the BEST E1 well was assumed to be the same as the field data at about 4900 bpd. Initially, a 6000-bpd water production rate was assumed for the new production wells. Two to five production wells were incorporated into the model within the BEST study area. The addition of the two to five production wells, along with the evaluation of the varied distances of those wells, helps to evaluate any potential changes in the BEST E1 water salinity while assessing their contribution to better controlling/reducing the pressure in the Inyan Kara Formation.

4.3 Field Numerical Modeling and Simulation Results

The field numerical simulation model for the Inyan Kara Formation around the BEST location allowed for evaluation of different operational scenarios for GHCR implementation (Table 4-1). The scenarios include a sensitivity analysis on the number of production wells to be added near the current BEST location (E1 and Rink SWD wells), the variable distance between the added production wells with respect to the BEST location, and the production and injection water rates for the added production wells.

All the cases were initially evaluated at two different salinity values: 197,000 ppm calculated to history match the simulation result with the brine density from the sample collected in the field and a salinity of 325,000 ppm for the injector wells based upon one of the last Bakken produced water samples collected from the field. For simplicity, and to preserve the history match in the model, the results using a Bakken produced water salinity of 197,000 ppm will be shown in this report.

4.3.1 Sensitivity Analysis – Number of Wells and Distance Between Wells

The sensitivity analysis evaluated the number of production wells that would be implemented as part of GHCR implementation and the distance between these added wells and the BEST location. The minimum number of production wells was two, leading to a total of three producing wells when BEST E1 is considered. Similarly, the maximum number of production wells was five, for a total of six producing wells. The additional wells were placed in an area around the current BEST location with well distances of 0.3 to 1.0 mile between the Rink SWD injector wells and the added production wells, as shown in Figure 4-3. Initially, the production wells were simulated using a water production rate of 6000 bpd to follow similar historical values for the BEST E1 production well. The production rate for the BEST E1 well was kept the same as the latest water production rates observed in the field of around 4900 bpd.

This subsection provides results on two of the scenarios (i.e., Scenarios 1 and 4), while the results for the remaining scenarios are provided in Appendix D. Scenarios 1 and 4 provide contrasting scenarios: Scenario 1 represents the status quo approach to water management continuing to operate in the BEST area and Scenario 4 provides an example of what could happen should multiple GHCR wells be installed in close proximity to the BEST location.

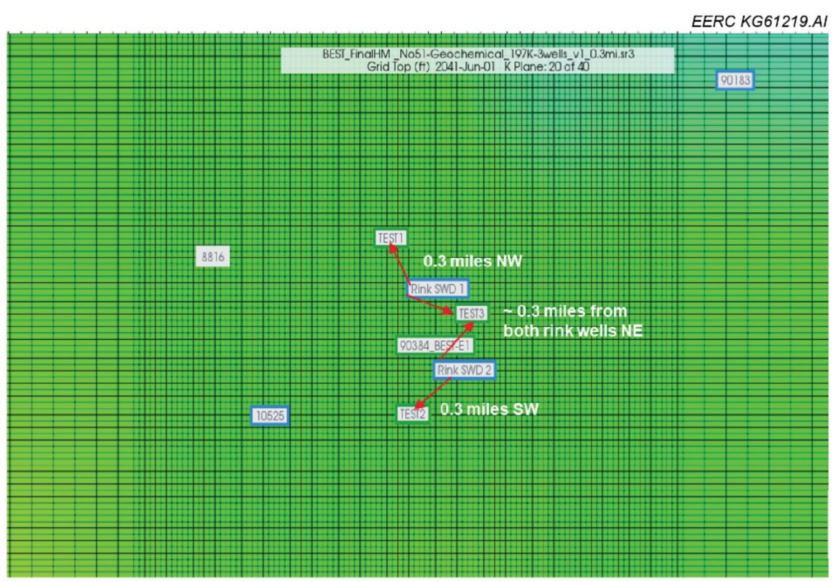

Figure 4-3. Three production wells with a distance between Rink SWD 1 and SWD 2 of 0.3 miles – Scenario 4.

In Appendix E, changes in the injection water rates were evaluated by reducing injection volumes by 50% of current (as of June 2021) operational volumes for the SWD wells in the BEST modeling area. A complete shutdown of the water injector wells during the 20-year injection/production predictions was simulated to evaluate injection rate effects on the field's formation pressure. In addition, a case increasing the maximum production rate for the new wells to a value around 30,000 barrels of water per day (bwpd) was evaluated to predict pressure depletion.

Scenario 1

Simulation results have shown that having production from only the BEST E1 well, Scenario 1, under the current injection and production operational conditions, TDS can increase from the initial value of 117,000 mg/L (ppm) at the end of the history match in June 2021, to around 170,000 ppm at the end of the 20 years. The results also indicated a constant pressure increase over 3100 psi under the current operational conditions with no other operational changes within the formation within the model area (Figures 4-4–4-6). This scenario indicates that continued SWD in the area, specifically from the Rink 1 and Rink 2 SWD wells, will result in increasing salinity values as the target reservoir continues to fill with the injected produced waters. Production from the single BEST E1 well is not enough to impact (e.g., reduce) formation pressures within the area.

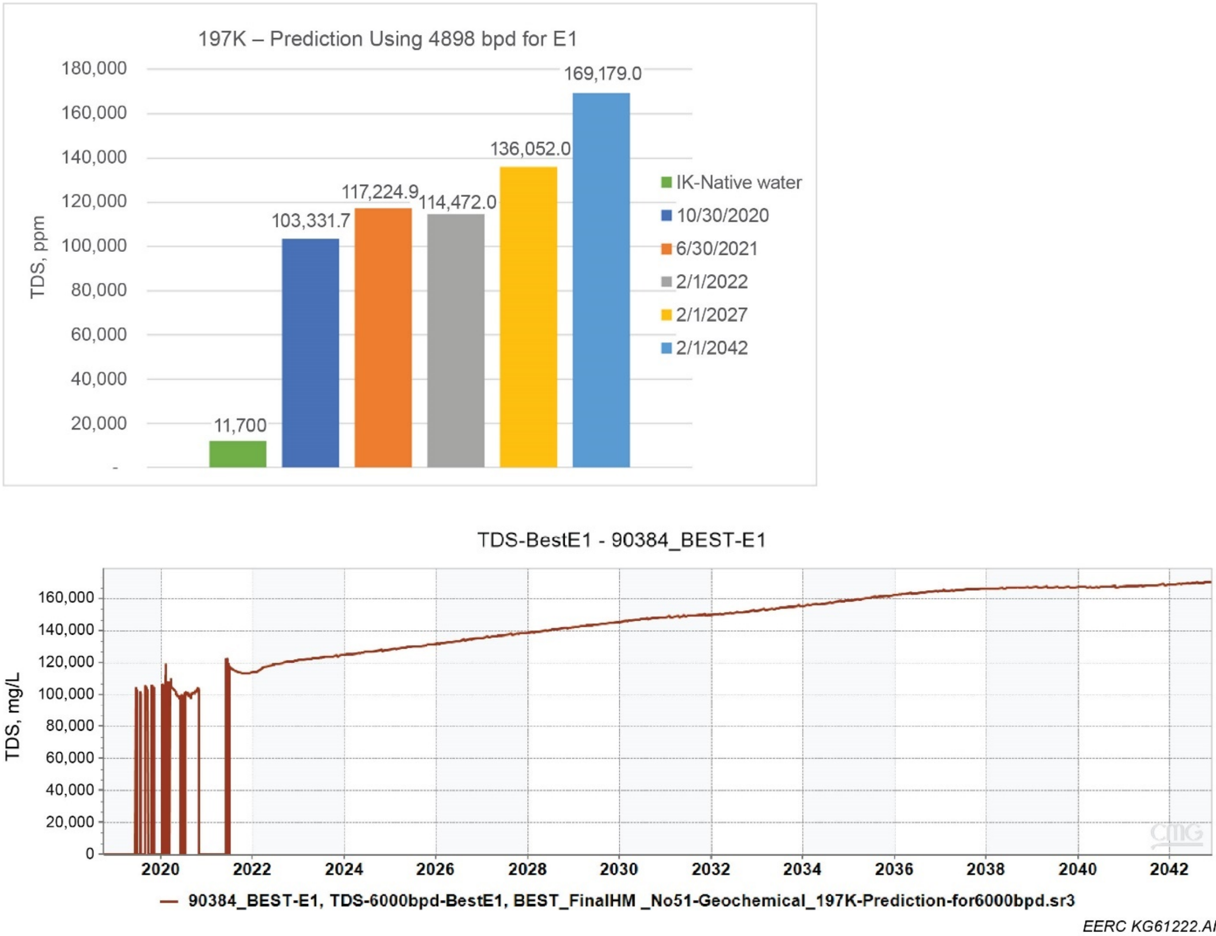

Figure 4-4. Scenario 1 TDS values for BEST E1 producer well during the simulated prediction of 2022 to 2042.

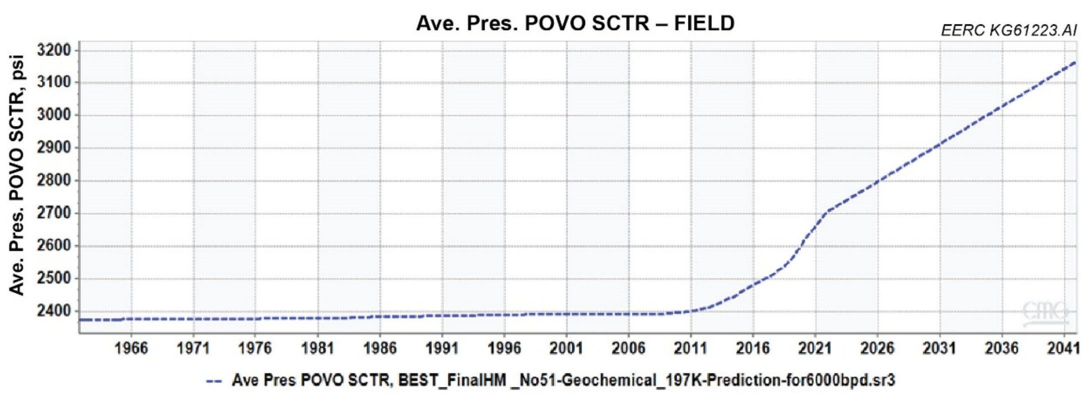

Figure 4-5. Scenario 1 formation pressure with only water production from BEST E1 well.

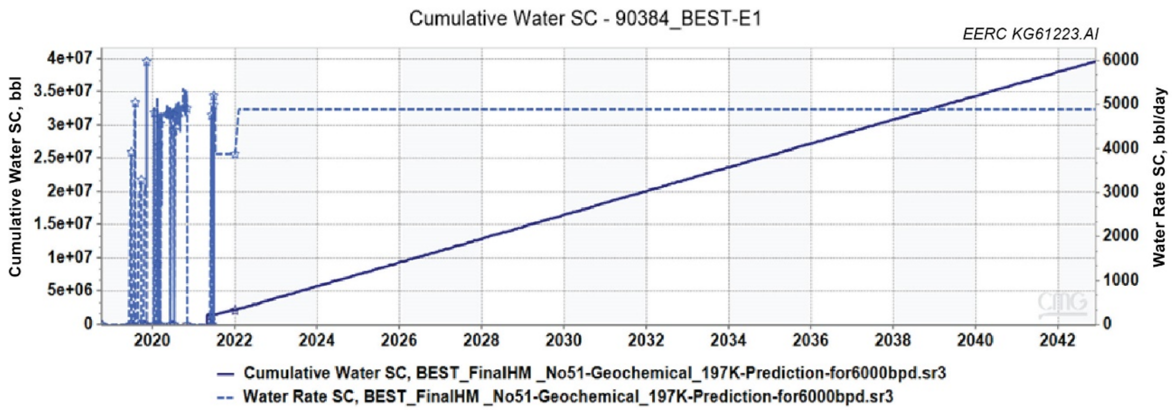

Figure 4-6. Scenario 1 total water produced and water rate for BEST E1 well.

Scenario 4

Adding more production wells into the BEST area can reduce the salinity in the BEST E1 well along the 20 years of predictions and can help control the pressure in the formation. Simulation results for Scenario 4, when three production wells were added in the area with a distance between wells of 0.3 miles and with a water production rate for the additional producer wells of 6000 bpd, showed a decrease in the water salinity for the BEST E1 well from 169,000 to 156,000 mg/L at the end of the 20 years. Also, a decrease in formation pressure was observed, with a reduction of over 400 psi, from about 3100 psi with only the BEST E1 operating to about 2700 psi with the three production wells (Figures 4-7 and 4-8). The additional three production wells also resulted in the total water produced of 177 MMbbl (Figure 4-9). This represents an increase of 347% in comparison with the volume produced by only the BEST E1 well.

This scenario provides an example of changes in the reservoir should the GHCR concept be implemented. The simulation results clearly show that the additional waters extracted from the Inyan Kara Formation would reduce formation pressure at the BEST location. Additionally, a by-product of the removal of fluids is the reduced salinities observed at BEST E1. This reduction at BEST E1 is likely due to the manipulation of the saltwater plumes from the Rink 1 and 2 SWD wells. By extracting water from the formation at simulated production wells (e.g., the GHCR concept wells), the saltwater plumes are drawn toward the production wells, thus keeping the higher-TDS waters from moving directly toward the BEST E1 well as would be seen in Scenario 1.

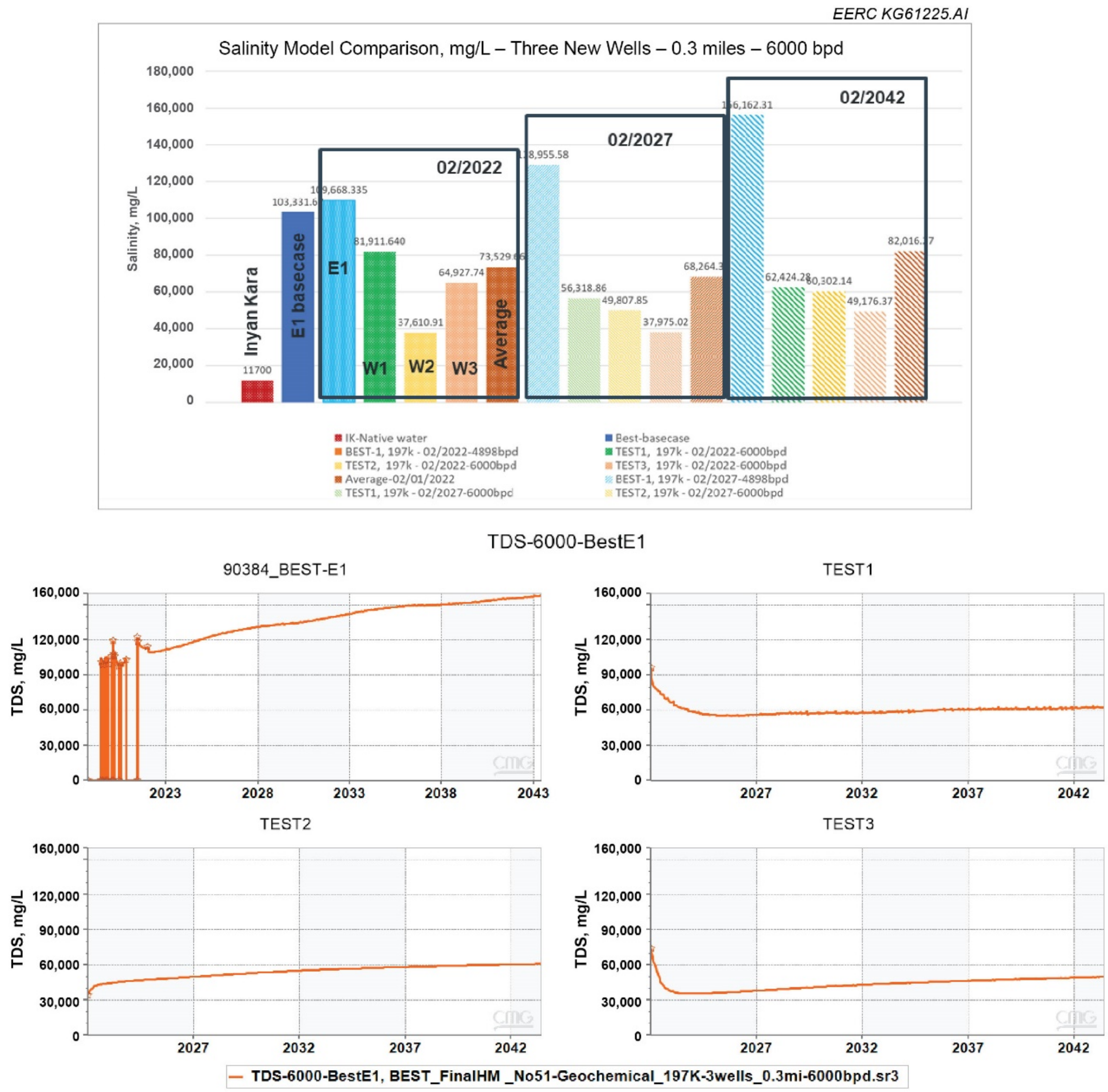

Figure 4-7. Scenario 4 changes in the water salinity (TDS) for each of the four production wells.

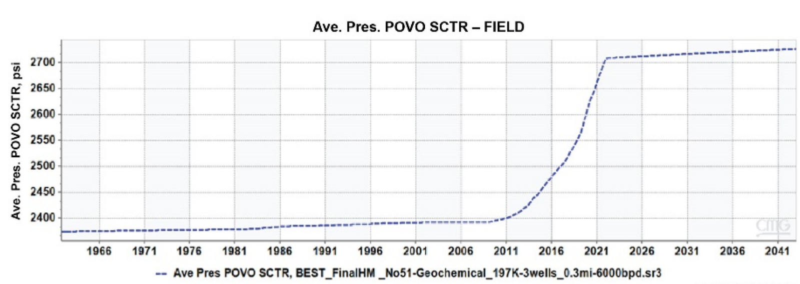

Figure 4-8. Scenario 4 formation pressure with water production from BEST E1 well plus three production wells.

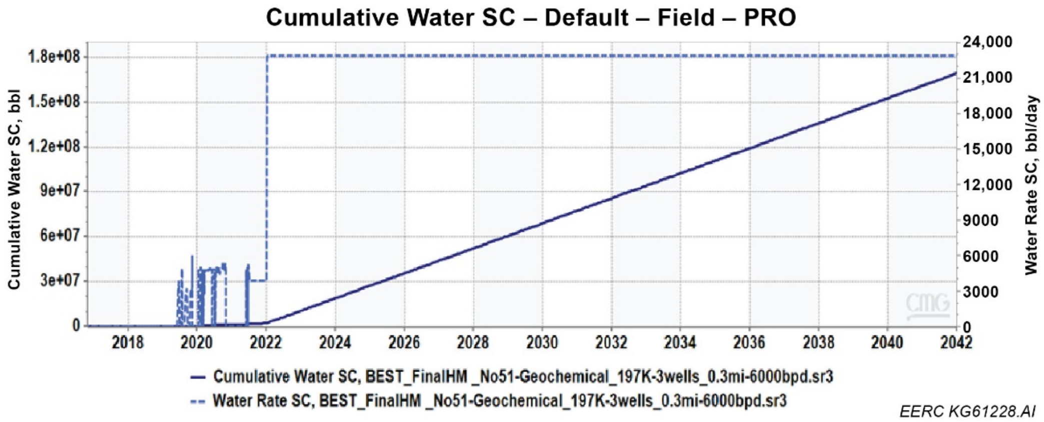

Figure 4-9. Scenario 4 formation pressure with water production from BEST E1 well plus three production wells.

Additional Scenarios

Appendix D shows the simulation results for the additional scenarios. In general, the simulation results for this evaluation showed that adding more production wells to the current BEST E1 well may increase the total water produced from about 39.6 MMbbl up to 267 MMbbl. Also, the pressure in the formation can be reduced and controlled in some cases from over 3100 to about 2400 psi under the operational condition evaluated in these simulations. The constant increase in the pressure currently observed in the BEST area is primarily due to water disposal activity.

The simulation results show that the distance between wells may reduce the water salinity concentration for the water produced and improve the water quality in general. For Scenario 3, where the production wells are placed at 1.0 mile from the BEST location, water salinity concentrations for the production wells were close to native Inyan Kara water of around 11,700 mg/L. The reason for the reduced salinity observed in the simulation results is that the SWD plume at Rink SWD 1 and 2 is not reaching the production wells placed at the 1.0-mile distance, even during the 20 years of SWD injection. Comparing Scenarios 2 and 3 (conditions described in Table 4-1), the formation pressure did not change for the two cases, and only changes in TDS were observed, thus making these scenarios not ideal for GHCR as there was no benefit in formation pressure reduction.

On the other hand, with the production wells at a distance of 0.3–0.5 miles from the BEST location, simulation results showed a decrease in the water salinity for the BEST E1 well and a considerably lower salinity concentration for the new production wells. Simulated cases showed an average water salinity from all the wells (BEST E1 and additional production wells) even lower than 100,000 mg/L, depending on the number of additional wells and the distance between wells. The reduction in the salinity depends on the number of production wells added and their distance from the BEST location. A lower salinity was observed when the production wells were placed at a distance of 0.5 miles from the BEST location, as compared to the values at a well distance of

0.3 miles. These values are considerably lower than when only the BEST E1 wells is producing. Figure 4-10 shows the average salinity values from all the production wells in each of the simulated scenarios.

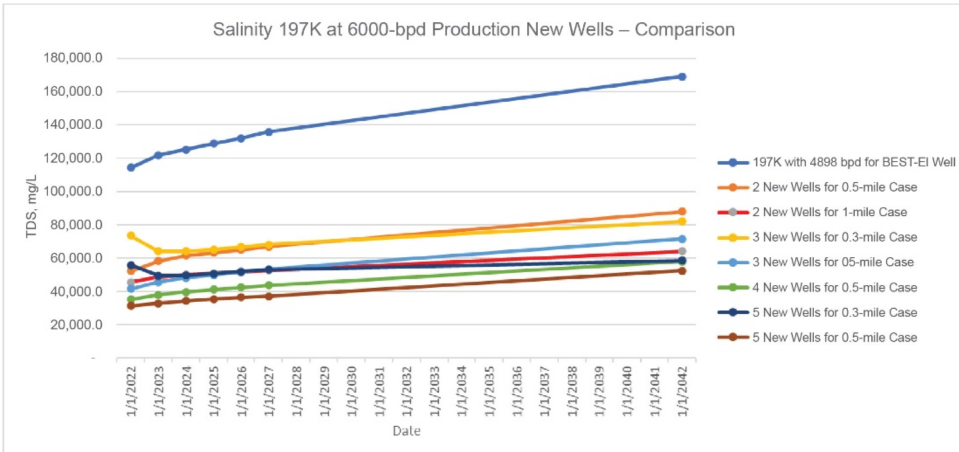

Figure 4-10. Average salinity values calculated from all the producer wells in accordance with each of the scenarios.

Tables 4-3 and 4-4 summarize the field simulation results for the different well layouts and operational conditions evaluated, and the tables show the simulated values at the end of the 20-year simulation. In general, two or more production wells installed as an example of GHCR implementation results in reductions in water salinity and formation pressures across the modeled area, regardless of the given well distances (Table 4-3). Salinity and pressures will vary depending on the number of production wells installed and their distances relative to the BEST location.

Reducing the injection rate of the water injector (i.e., SWD) wells in the area can contribute to greater reductions in water salinity and formation pressures in a GHCR implementation scenario. Table 4-4 summarizes the simulation results when the water injection (i.e., SWD) rates were reduced to half of the current field operation values.

Table 4-2. Summary of the Simulation Results for the Number of Wells and Distance Between Wells

Scenario	Conditions	Total Vol. Produced, bbl	Total Produce Rate, bbl/day	Average Salinity at the End of 20 years, mg/L	Field Pressure at the End of 20 years, psi
1	Prediction	39,600,000	4900	169,200	3170
2	Two new wells – 0.5 miles	131,165,000	16,900	87,962	2873
3	Two new wells – 1.0 miles	131,165,000	16,900	64,170	2873
4	Three new wells – 0.3 miles	177,476,000	22,900	82,020	2726
5	Three new wells – 0.5 miles	177,476,000	22,900	71,530	2726
6	Four new wells – 0.5 miles	212,900,000	28,900	54,000	2575
7	Five new wells – 0.5 miles	268,747,000	34,900	50,800	2418
8	Five new wells – 0.3 miles	268,747,000	34,900	54,570	2418

Table 4-3. Summary of the Simulation Results When the Water Injection (SWD) Rate Was Reduced for the Number of Wells and Distance Between Wells

Scenario	Conditions	Total Vol. Produced, bbl	Total Produce Rate, bbl/day	Average Salinity at the End of 20 years, mg/L	Field Pressure at the End of 20 years, psi
1	Prediction	39,600,000	4900	124,200	2885
2	Two new wells – 0.5 miles	131,165,000	16,900	62,895	2606
4	Three new wells – 0.3 miles	177,476,000	22,900	47,904	2417
6	Four new wells – 0.5 miles	212,900,000	28,900	36,096	2273
8	Five new wells – 0.3 miles	268,474,000	34,900	36,560	2117

4.4 Key Observations from Numerical Simulation

- Simulation results have shown that a constant increase in the pressure in the formation and in the water salinity concentration due to the water disposal activity in the area will continue if no operational changes are made and normal SWD operation continues.

- Adding more water production wells in the area with a production rate around 6000–7000 bwpd and with a significant decrease in the injection rate would help to decrease the pressure in the Inyan Kara Formation from an initial pressure of over 2700 psi (where only the BEST E1 well is producing) to 2450–2500 psi.

- The addition of more production wells to the current BEST E1 well not only would contribute to a decrease and control of the pressure in the reservoir but would increase the volume and reduce the salinity of the water produced.

- The results have shown a well distance between 0.3 and 0.5 miles from Rink SWD 1 and SWD 2 is favorable for a reduction in the water salinity, thus improving the water quality to be potentially used in other field operations.

- A 50% reduction of the current operational water injection (i.e., SWD) rate in the BEST area resulted in a reduction of the water salinity and reservoir pressure, without diminishing the volume of water produced.

5.0 TECHNO-ECONOMIC ANALYSIS OF GHCR CONCEPT

This activity consisted of a techno-economic analysis (TEA) of GHCR as an approach to Bakken water management. It begins with a review of technical and regulatory drivers that impact how GHCR could be implemented, followed by a study of GHCR implementation costs. All findings are then used to inform a discussion regarding the outlook for GHCR in North Dakota.

GHCR is hypothesized to be a more sustainable water management approach because it couples fluid extraction with disposal injection in the Inyan Kara Formation, which is North Dakota's primary SWD target. After drilling, the extracted fluid is recycled and used for hydraulic fracturing makeup water for new wells which lowers freshwater demand. After the GHCR well is done being used to supply water and during oil production, it can be converted and used for on-site SWD to minimize the cost and risk of transporting produced water. The latter point is significant as produced water management is widely identified as the single largest lease operating expense (LOE) in the Bakken (e.g., Figure 5-1).

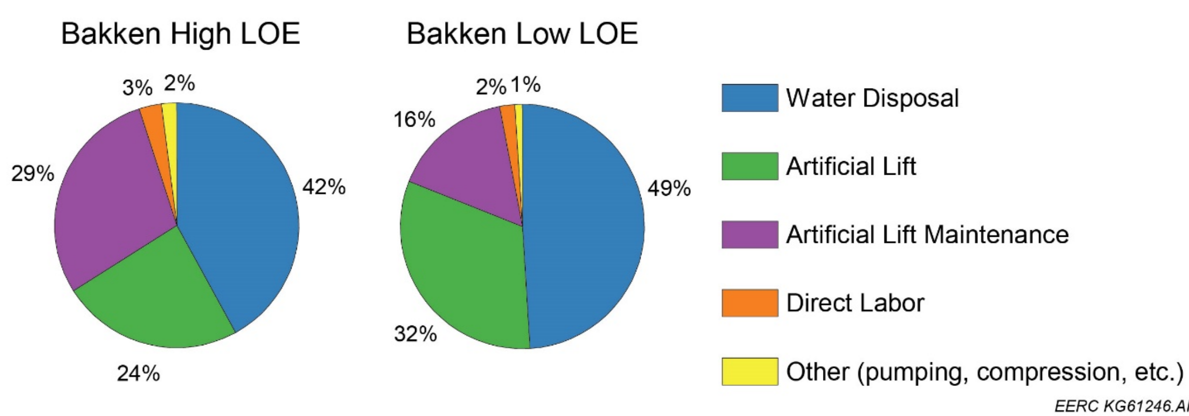

Figure 5-1. Typical Bakken LOE breakdowns (IHS Global Inc., 2015).

5.1 TEA Technical Inputs

Several sources of input information were used to create the full-scale model of GHCR performance, including results from other activities under this project, prior studies, and reviewer feedback. The basis and rationale for each key TEA assumption are discussed in this section.

5.1.1 Inyan Kara Pressure Management

One of the benefits of producing fluid from a GHCR well is to locally reduce formation pressure or to slow pressure rise in an area with simultaneous disposal injection. For an active SWD facility, pressure management could extend the useful life of the disposal well and perhaps also reduce the operating power cost to inject fluid. From an injection standpoint, the maximum allowable pressure is 90% of the calculated fracture gradient of the cap rock (Connors and others, 2020). In certain areas of the Williston Basin where SWD injection is high, the Inyan Kara Formation exceeds the standard hydrostatic pore pressure gradient of 0.433 psi/ft and is accommodated for by using an increased drilling mud weight or the use of an additional drill string casing to prevent water influx during drilling of the Inyan Kara interval (Connors and others, 2020). From the standpoint of a Bakken operator, the key benefit of pressure reduction through fluid extraction would likely be the potential to locally reduce formation pressure and avoid the use of extra casing for wells drilled in the affected area.

Data to evaluate the potential magnitude of pressure reduction primarily came from a prior study by Connors and others (2020) that evaluated the impact of Inyan Kara water extraction on localized formation pressure reduction. That study modeled the effects of water production rate and total produced volume on the formation pressure at several distances from the producer well. In order to evaluate the pressure reduction potential of GHCR, a subset of results from Connors and others (2020) were replotted in Figure 5-2 to indicate the affected distances, along with the produced fluid volumes that would be expected in a GHCR application, which were based on a Bakken average value of 200,000 bbl per completion (Energy & Environmental Research Center, 2020). Each curve in Figure 5-2 represents the distance at which formation pressure was reduced by 135 psi, which was one of the threshold scenarios assumed by Connors and others (2020) to avoid using a Dakota string.

With respect to the TEA, Figure 5-2 shows that significant pressure reductions can be achieved from the withdrawal volumes that would be expected from a GHCR production well and that the effect extends a greater distance as the production rate increases. However, the longest affected distance is approximately ¼ mile (~1300 ft), which implies that a GHCR producer would need to be similarly close to the location of the oil wells to provide a beneficial effect. Therefore, a GHCR well might be expected to benefit wells on the same drill spacing unit (DSU) having nominal dimensions of 1 mile by 2 miles, or perhaps adjacent DSUs if the wells were sufficiently close to the border, but likely not any further.

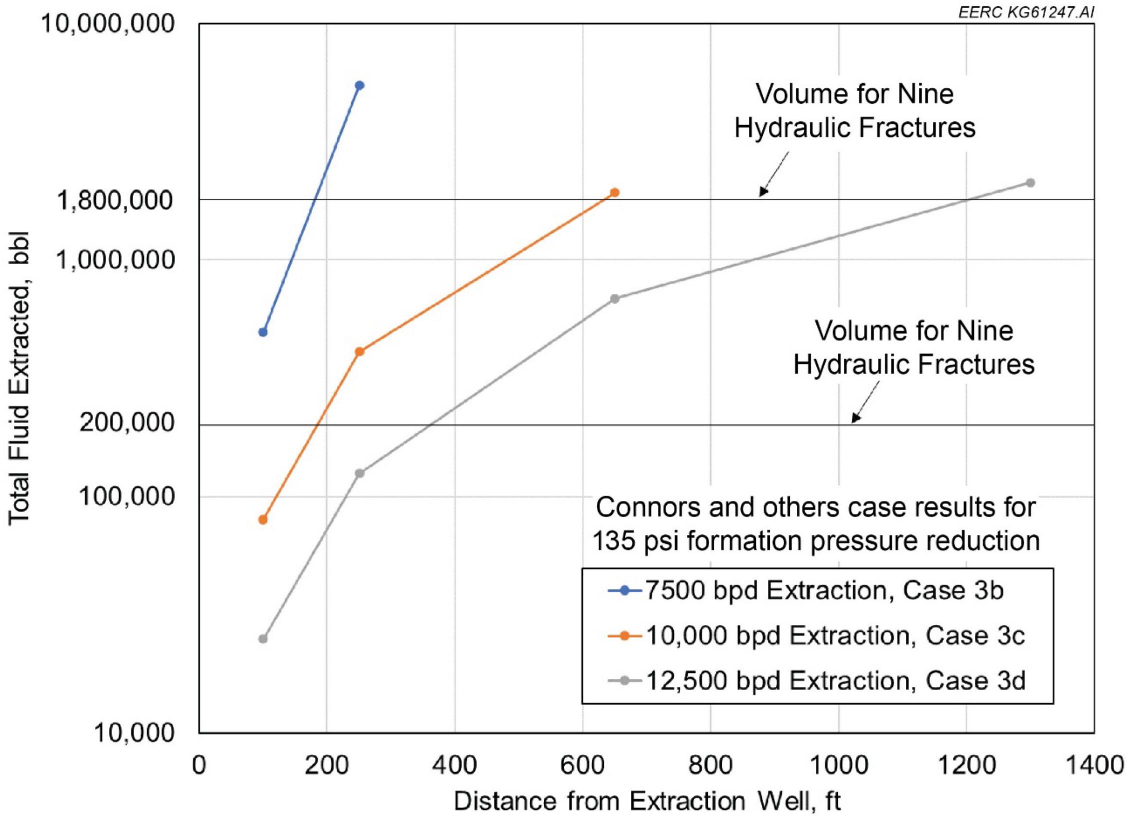

Figure 5-2. Connors and others (2020) model results replotted according to pressure-affected distance.

The size of the pressure-affected zone is one factor that will impact the utility of GHCR pressure management; another is obtaining the proper sequencing of GHCR fluid production and drilling of the oil well(s) that might benefit from pressure reduction. For example, assuming that a series of infill oil wells can be positioned within the pressure-affected zone of a GHCR producer well, the fluid would need to be produced prior to infill drilling to be of any benefit. However, that creates an issue of where the produced fluid should go during drilling, since surface storage of produced water in large, open-top brine tanks, earthen ponds, or liquid waste pits has historically not been allowed in North Dakota. Three hypothetical scenarios were identified that might allow for the proper sequencing.

1. The infill wells on a DSU are drilled and completed sequentially rather than drilled and completed as a group. In this way, the extracted fluid used for completing the first well creates the pressure-affected zone for the second well, and so on.

2. The produced fluid is used for completions on a neighboring DSU, and these occur prior to drilling the DSU that contains the GHCR producer well.

3. Two GHCR wells are drilled: a producer that creates the needed temporary pressure relief zone near the infill wells and an injector that is used to dispose of the produced fluid away from the

pressure-affected zone. After infill drilling, one or both of the GHCR wells are used to produce fluid for fracturing, and after completion, one of the wells is converted for SWD.

Of these examples, only Scenarios 2 and 3 appear compatible with the typical pattern of group drilling and completion in the Bakken. In Scenario 2, the produced fluid is simultaneously used for fracturing, while in Scenario 3, the fluid is temporarily stored in the Inyan Kara using an injector well. Given these limitations in matching pressure relief with well drilling, the TEA modeled both outcomes for the GHCR cases, i.e., the oil well costs were calculated both with and without the use of a Dakota string.

5.1.2 GHCR Produced Fluid Characteristics

Another hypothesized benefit of GHCR was that the quality of the produced water would be improved after passage through the Inyan Kara Formation; effectively the formation would serve as a very large filtering and conditioning element. The core flow tests and field site sampling reported under Section 3.0 generally show this to be the case. For example, suspended solids content of the flow-through liquid was largely reduced, thereby demonstrating a filtering function. Based on these positive results, the TEA cases that included produced fluid recycling were assumed to use 100% recycled fluid with no substantive water treatment following production.

Equally important to recycling potential was the produced fluid's consistency i.e., the uniformity in the fluid's chemical composition over the entire volume needed for a completion. Operator feedback suggested that completion fluid chemistries can be tailored to use a wide range of produced water composition; however, consistency was key (Energy & Environmental Research Center, 2020). Consistency is of most concern during breakthrough i.e., when the produced fluid composition changes from being largely formation fluid to a steady-state mixture of formation fluid and injected saltwater since fluid produced prior to and after breakthrough will very likely be suitable for recycling. To evaluate the composition changes during breakthrough, Section 4.0 field modeling results were reviewed for cases that resulted in breakthrough. Based on the observed rates of composition change, it was determined that changes due to breakthrough would likely be insignificant over individual batches of 200,000 bbl, which was assumed to be a typical volume needed for an individual completion.

GHCR water management also requires that a sufficient quantity of fluid is produced before reservoir pressure depletion and that the production rate roughly matches the demand set by hydraulic fracturing, which by design is a short-duration, high-flow process. Field modeling results reported in Section 4.0 and Appendix D were again used to evaluate the potential production under conditions where the formation pressure alone was used to drive fluid to the surface. In general, these results appear to show no significant limitations for GHCR due to the quantity of produced fluid. Likewise, the rate of production could also be supported, but, of course, the actual production potential will be dependent on site-specific reservoir conditions. One trend highlighted by the modeling was that multiple GHCR wells producing in aggregate could supply a target production rate for a longer period compared to using only a single producing well. Therefore, while a single-well GHCR system might be technically possible in pressurized areas of the Inyan Kara, a system based on multiple production wells will likely be adaptable to more Bakken locations and offer a greater range of production rates.

5.2 Regulatory Considerations

5.2.1 Review of Regulatory Environment

While understanding the technical and economic feasibility of GHCR is important, additional key regulatory considerations need to be addressed to permit a project of this nature. Produced water management in association with oil and gas production in the state of North Dakota is predominantly regulated by NDIC's Department of Mineral Resources (DMR) Oil and Gas Division. The North Dakota Century Code (NDCC) establishes general authority for NDIC DMR jurisdiction to regulate disposal of saltwater and oilfield wastes (NDCC Section 38-08-04 subsection 1b). NDIC DMR regulates produced water management associated with oil and gas exploration and production. Specifically, NDIC DMR handles the different components of produced water management including the water produced at the wellsite in association with oil and gas production, the transportation of produced water via underground gathering pipeline, saltwater-handling facilities associated with storing and managing produced water at surface facilities, and the disposal of the produced water in a SWD injection well. SWD wells are regulated as Class II injection wells under the federal underground injection control (UIC) program. NDIC DMR received primary regulatory authority over Class II injection well activities (i.e., Class II primacy) from the U.S. Environmental Protection Agency (EPA) in 1983. This regulatory authority applies to all Class II injection well activities in the state of North Dakota, except for Indian Lands where EPA maintains Class II regulatory authority. NDIC DMR began regulating produced water transportation via underground gathering pipelines in 2013. In 2015, the North Dakota Legislature expanded NDIC DMR's authority to include the construction and operation of crude oil and saltwater underground gathering pipelines.

The North Dakota Department of Water Resources, formerly known as the State Water Commission, regulates water appropriation in the state, including groundwater. The State Engineer is charged with managing the use of the state's waters as directed under NDCC Chapter 61-04 and Article 89-03 of the North Dakota Administrative Code (NDAC). This regulatory authority includes water source wells that would be necessary to extract formation fluid if the GHCR concept were implemented. Water source wells used to extract water from geologic formations, including the Inyan Kara Formation, exist today in North Dakota oil and gas operations. These wells provide a working fluid that is injected in the mineral-bearing reservoir for enhanced oil recovery operations. In addition, current water source wells are used to provide water for hydraulic fracturing and other oilfield operations. In North Dakota, there are currently 68 water supply wells used predominantly to supply water for enhanced oil recovery operations (Figure 5-3). The water appropriation permit is issued by the North Dakota Department of Water Resources and identifies the total quantity of water permissible to extract and the maximum withdrawal rate. In addition, the well is permitted and regulated by NDIC DMR in a dual permitting process.

Table 5-1 identifies the regulatory authority and applicable state regulations based on the particular phase of produced water management.

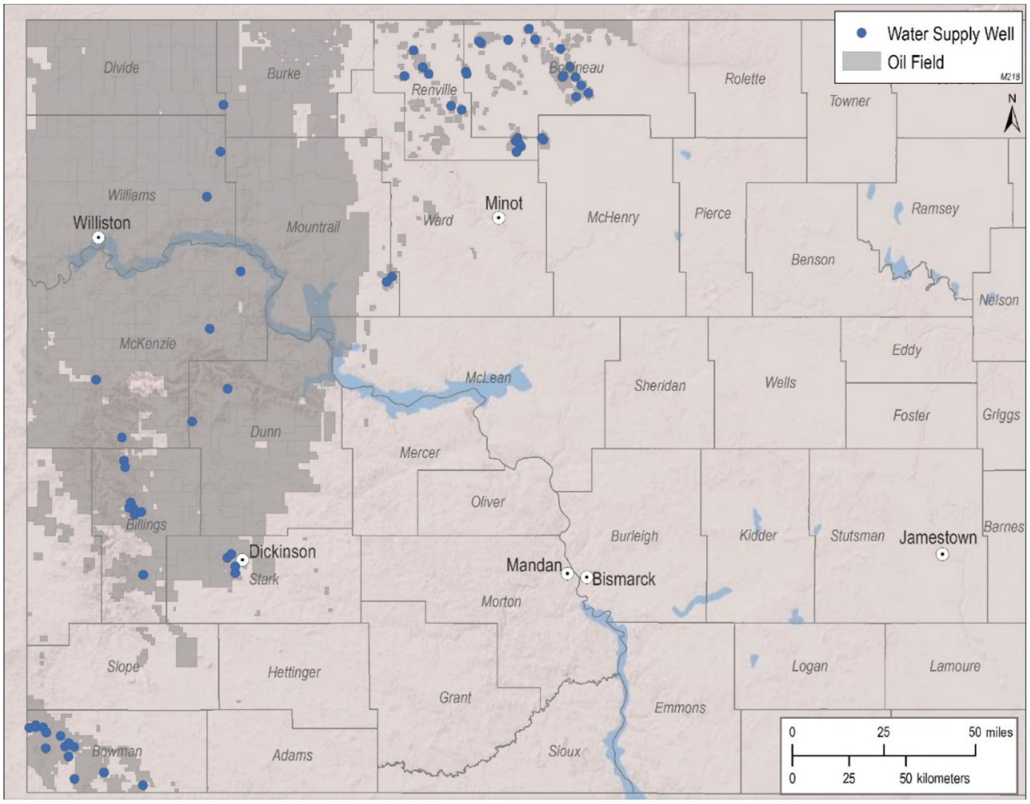

Figure 5-3. Active water supply wells in North Dakota.

Table 5-1. Summary of North Dakota Regulations Relevant for GHCR Produced Water Regulatory Jurisdictions and References

Produced Water Management Activity	Regulatory Authority	Regulatory Framework
Produced Water (includes Class II SWD injection wells)	NDIC DMR Oil and Gas Division	(Class II SWD injection wells) NDAC Chapter 43-02-05 Underground Injection Control
Produced Water Pipelines (underground gathering pipelines)	NDIC DMR Oil and Gas Division	NDCC Section 38-08-27 Controls, Inspections, and Engineering Design on Crude Oil and Produced Water Underground Gathering Supplies NDAC Section 43-02-03-29.1 Crude Oil and Produced Water Underground Gathering Pipelines
Saltwater-Handling Facilities	NDIC DMR Oil and Gas Division	NDAC Section 43-02-03-53 Saltwater-Handling Facilities; NDAC Section 43-02-03-53.1 Saltwater-Handling Facilities Requirements; NDAC Section 43-02-03-53.2 Saltwater-Handling Facilities Siting; NDAC Section 43-02-03-53.3 Saltwater-Handling Facilities Construction and Operation Requirements; NDAC Section 43-02-03-53.4 Saltwater-Handling Facilities Abandonment and Reclamation Requirements
Water Source Well	North Dakota Department of Water Resources	NDCC Chapter 61-01 and NDAC Section 89-03-01

From a regulatory standpoint, GHCR water management can be divided into three operational steps, all of which will have to comply with regulatory oversight:

1. Operating a water production well (i.e., water source well) from a deep formation (i.e., Inyan Kara) to produce fluids for industrial use.

2. Transporting produced water either on- or off-pad for use in hydraulic fracturing, maintenance water needs, or other commercial uses.

3. Operating a Class II SWD injection well.

Steps 1 and 3 have established frameworks in place, but Step 2 could introduce new scenarios that may require regulatory clarification. Specifically, using produced fluid for hydraulic fracturing will require transporting large volumes of fluid over a relatively short duration of time, and the normal methods of delivering freshwater may not apply to higher-TDS produced fluids, for example, the use of temporary lay-flat hose. Lay-flat hoses are used in the oil fields in North Dakota but have been only permitted to transport freshwater for use in hydraulic fracturing. Regulatory guidance is necessary for the use of temporary hoses to transport produced brine. There is also regulatory uncertainty related to the long-term surface storage of produced fluids, as NDIC DMR has not normally allowed the use of large open-top brine tanks or earthen ponds utilized in oil and gas production operations, specifically in drilling and hydraulic fracturing.

Regulations for saltwater-handling facilities can be found in NDAC Section 43-02-03-53, which outlines the necessary permits and infrastructure required for surface facilities used to manage large volumes of produced water. The main focus of these regulations are the protection of freshwater sources and the near-surface environment as Section 43-02-13-53.2 states that "all saltwater handling facilities must be sited in such a fashion that they are not located in a geologically or hydrologically sensitive area." NDAC Section 43-02-03-53 provides the permitting process for saltwater-handling facilities, including construction standards. NDAC Section 43-02-03-53.3 Saltwater-Handling Facility Construction and Operation Requirements, outlines the necessary safety barriers that need to be erected such as creating a dike around saltwater tanks and the saltwater-handling facility location. "Dikes must be of sufficient dimension to contain the total capacity of the largest tank plus one day's fluid throughput." NDIC DMR regulations for saltwater-handling facilities are specific to facilities that are not colocated with a SWD well.

5.2.2 Review of Various States' Regulation of Produced Water

A produced water regulatory review for the larger oil and gas-related water-producing states was conducted to identify similarities or differences, if any, with the North Dakota regulatory frameworks. During the analysis of state policy and legislation, it was noted that regulation does not currently exist in many states with regard to the reuse or recycle of produced water. States such as Texas and New Mexico have recently enacted bills that have created groups and consortiums to further research and develop methods. However, the language in many of these bills and enacted laws shows an indication for continued research to enhance state knowledge and provide guidance for policy coverage in this industry. Oklahoma has recently engaged an adjusted bonding regulation providing further incentive for oil and gas businesses to reuse and/or recycle produced water.

Table 5-2. Produced Water Ownership and Liability Findings in Six States

Disclaimer: This table should not be considered a legal opinion regarding the ownership of or liability for produced water under all circumstances. It is merely a compilation of general research conducted on behalf of the Ground Water Protection Council (GWPC).

State	**Groundwater Right Doctrine**	**Produced Water Ownership**		**Produced Water Liability**	
		Operator	Landowner	Operator	Other Persons
New Mexico	Prior appropriation		X[1]	X	X
North Dakota	Prior appropriation		X[2]	X[3]	X
Oklahoma	Reasonable use	X[4]		X	
Pennsylvania	Reasonable use	[5]	[5]	X	
Texas	Absolute Ownership Rule		X	X	X[6]
Wyoming	Prior appropriation		X[2]	X	

Specific provisions that may apply to or modify the information contained in Table 5-2 include the following:

1 In New Mexico, the term "possession" is often used because actual water ownership is by contract only.

2 Water is not owned, but pore space is the property of the surface rights owner.

3 Operator is immunized from liability if transferred to a commercial oilfield special waste-recycling facility.

4 Produced water ownership in Oklahoma resides with the oil and gas operator except that landowners have "domestic use" of water flowing across the property (Mack Oil Co. v. Laurence, 389 P.2d 955 [Okla. 1964]).

5 The Pennsylvania Legislature has not explicitly defined who owns produced water. As a result, produced water is likely owned by either the landowner or the oil and gas operator. However, use of groundwater off of the premises is considered unreasonable and unlawful per se if other users' rights are interfered with (Bishop, 2006; Weston and Burcat, 1990).

6 Texas limits tort liability for sellers or transferors of recycled produced water (3 Texas Natural Resources Code Annotated § 122.003[a] [2015]).

Texas oil and gas produced water jurisdiction is overseen by the Texas Commission on Environmental Quality. This agency oversees wastewater surface discharge from state oil and gas well production in the industry. The Railroad Commission of Texas has jurisdiction of wastewater from the oil and gas industry if the produced water is used in other methods such as reuse, dust suppression, impoundment maintenance, evaporation, or irrigation (Texas Commission on Environmental Quality, 2021). While both departments oversee water use and dispersant in the state of Texas, there are few guidelines that dictate the industrial use of produced water. There is movement within the state legislature to further knowledge of produced water constituents, reuse, and recycling opportunities. In June 2021, Texas creating the Texas Produced Water Consortium which aims to study the economics and environmental impact of reused produced water (Texas Produced Water Consortium, 2021). With Texas's interest in expanding produced water research, more detailed policy may emerge to give way to a clear path for produced water business.

New Mexico has taken a similar path to Texas. The New Mexico Legislature (2019) adopted the Produced Water Act on July 1, 2019, which defines produced water as "fluid that is an incidental byproduct from drilling for or the production of oil and gas." This act identifies the responsible parties for all aspects of produced water, which include use, handling, disposal, transfer, selling, conveying, transport, recycle, reuse, or treatment of produced water. It also further encourages the research and development of industrial uses of produced water. Although, New Mexico does not have an existing permit process for produced water, as outlined in Section 19.15.34.8 Requirements for Reuse, Recycling or Disposal of Produced Water, Section 19.15.34.8A(1) states that, "No permit registration is required from the division for the re-use of produced water for drilling, completion, production, pressure maintenance, secondary recovery or enhanced recovery of oil or natural gas of wells pursuant to 19.15.34 NMAC." This policy acknowledges the need for continued research into this topic as Section 19.15.34.8A(3) states, "research using produced water is to be encouraged through pilot projects approved by the division."

Oklahoma recently signed into law, Senate Bill 1875 in May 2020, also known as the Oil and Gas Produced Water and Waste Recycling Reuse Act (State of Oklahoma, 2020). This bill clarifies that "produced water and waste is the property of the oil and gas producer until it is officially transferred to another person. It also shields liability from those who process wastewater into recycled water and/or transport this recycled water for further use in oil and gas production" (Oklahoma Senate, 2020). This recent movement demonstrates that Oklahoma is on the path for the advancement of creating guidance and regulations for produced water business.

Regulatory guidance on produced water exists in other states in the form of waste management, but not to the extent that is required for GHCR to become an industrial resource. Oklahoma has paved the way in policy recently, with the realization for the need for additional guidelines. In comparing the rules and regulations to the those from North Dakota, it is evident that produced water is an emerging industry for which many regulators are looking to provide proper policy guidelines.

5.2.3 Regulatory Discussion

Based on the regulatory review, the tasks of drilling into the Inyan Kara for SWD and for producing water for industrial use have precedent in North Dakota, and a workable regulatory solution for GHCR seems likely. However, restrictions in the state regarding surface storage and transport of produced fluids may limit some activities, which will affect how GHCR could ultimately be implemented.

The NDIC DMR Oil and Gas Division has typically not allowed surface storage of large open-top brine tanks or earthen ponds utilized in oil and gas operations, specifically in drilling and hydraulic fracturing. These prohibitions would seem to restrict recycling facilities in North Dakota. On the other hand, GHCR would appear to be allowed under current NDIC DMR precedent, provided it can operate without a large surface storage buffer. The performance impact of a minimal fluid storage buffer is that the production rate of GHCR produced fluid would need to nearly match the rate the fluid is used for hydraulic fracturing.

Lay-flat hose is used in North Dakota for the temporary transport of freshwater, but its application to recycled fluids may run counter to the state's efforts to eliminate produced water spills. An alternative to temporary hose transport is trucking, but this option is more costly.

One possible solution for the temporary transport of recycled fluids is if the GHCR producer and the wells being completed were in close proximity on the same pad. In such a case, it is conceivable that the entire transport line would be within the pad's containment berm to limit regulatory concerns.

5.3 GHCR Cost Modeling

All TEA cases were based on the same underlying oil production scenario, which was the infill development of a single DSU that has an existing parent well. Nine infill wells were assumed to be added based on the infill well density observed in areas of the Bakken where infill development has not been completed and where there has been the need to use a Dakota string, e.g., north of Williston, North Dakota (Connors and others, 2020). Specifically, infill density was characterized by units of the Lone Tree Lake and East Fork Fields. Workover of the parent well was not included as part of the TEA.

Four TEA case studies were evaluated to investigate the value proposition of GHCR water management. Details of the studies, one of which was a model of conventional Bakken practice, are summarized in Table 5-3, which is followed by brief descriptions.

- Conventional water management consisted of conventionally sourced freshwater for both hydraulic fracturing and maintenance water needs and off-site produced water disposal at a SWD facility. This case assumed there is a Dakota string that would be required for the oil wells.

Table 5-3. TEA Case Details

Case	Conventional	GHCR 1	GHCR 2	On-Site SWD
Potential to Eliminate Dakota String	No	Yes	Yes	No
Number of GHCR/SWD Wells	0	1	2	1
On/Off-Site SWD	Off-site	On-site	On-site	On-site
Fracture Fluid Water Source	Fresh	Produced	Produced	Fresh
Maintenance Water Source	Fresh	Fresh	Produced	Fresh

- The GHCR 1 case assumed one Inyan Kara well is drilled and used to produce fluid for hydraulic fracturing, either on the same DSU or a nearby unit. Fluid production could lower formation pressure and, if its proximity and timing aligned, may avert the need for a Dakota string on subsequent oil wells drilled nearby. After production, the single GHCR well is converted for on-site SWD, but since it can no longer be used for fluid production, maintenance water needs would be met from a conventional freshwater source.

- The GHCR 2 case assumed drilling two Inyan Kara wells to increase the likelihood of achieving the maximum benefits of GHCR. Initially the two wells would be set up as a producer and injector pair to create a zone of reduced formation pressure where the associated oil wells could be drilled without a Dakota string. After drilling, both GHCR wells are used to produce fracture fluid, and after the completion phase, one of the GHCR wells is converted to on-site SWD while the other continues to produce fluid for maintenance water needs.

- The on-site SWD does not include a production phase to support hydraulic fracturing. Instead, the well is only used during oil production for on-site SWD. As with the conventional case, no fluid is produced from the SWD well, and there is no opportunity to reduce Inyan Kara pressure to possibly avoid using a Dakota string on the associated oil wells.

5.3.1 Cost Assumptions

The scope of the TEA included initial investments for the oil well and facilities, along with any GHCR water management investments (e.g., GHCR well or wells and facilities). Oil well completion costs were also counted as initial investments. Future costs included LOEs during the production phase, as categorized in Table 5-4.

Table 5-4. TEA Considered Costs

	Initial Investments		Future Costs
TEA Case	**Drilling**	**Completion**	**Production LOE**
Conventional	Oil well with Dakota string; surface facilities	Freshwater-based fracture fluid	Nonwater LOE, off-site SWD, fresh maintenance water
GHCR 1 and 2	Oil well with/without Dakota string; surface facilities; GHCR wells and surface infrastructure.	Produced fluid-based fracture fluid	Nonwater LOE; on-site SWD; fresh or produced maintenance water
On-Site SWD	Oil well with Dakota string; surface facilities; SWD well and surface infrastructure	Freshwater-based fracture fluid	Nonwater LOE; off-site SWD; fresh maintenance water

Cost values used for the nominal TEA calculations are presented in Table 5-5, along with the basis used to identify them. As noted in the table, several costs were based on typical assumptions noted in well file disclosures or from direct feedback by various operators. These values were used here to be consistent with the general evaluation criteria for Bakken wells and were not based on the detailed analysis of a specific project.

Table 5-5. Nominal TEA Costs

TEA Input	Assumed Value	Basis
Oil Well Drilling and Completion	$6,800,000/well	(IHS Global Inc., 2015)
Dakota String Addition	$500,000/well	(Connors and others, 2020)
Oil Production Facilities	$600,000/well	(IHS Global Inc., 2015)
Inyan Kara Well Cost	$1,500,000/well	Feedback about existing SWD facilities
GHCR Facilities	$1,000,000 for initial well; $500,000 for second well	Feedback about existing SWD facilities
Freshwater Cost	$3.00/bbl delivered	(Energy & Environmental Research Center, 2020)
On-Site Produced Water Cost	$0.70/bbl	Typical operating cost for conventional freshwater (Energy & Environmental Research Center, 2020)
Off-Site SWD	$3.00/bbl	(Energy & Environmental Research Center, 2020)
On-Site SWD	$0.55/bbl	Typical operating cost for conventional SWD (Energy & Environmental Research Center, 2020)
Maintenance Chemicals	$0.30/bbl maintenance fluid	Feedback, based on 10% of freshwater charge
Nonwater LOE	$5.00/bbl oil	Nonwater LOE fraction from (IHS Global Inc., 2015)
Wellhead Oil Value	$50.00/bbl	Typical well file value
Wellhead Gas Value	$3.00/MMBtu	Typical well file value
Royalty Assumption	20% oil and gas revenue	Typical well file value
Oil Tax Rate	10% oil revenue	Typical well file value
Gas Tax Rate	$0.10/Mcf gas	Typical well file value

5.3.2 Oil and Gas Production Profiles

Oil and gas decline curves were developed from Bakken-average data prepared by the North Dakota Pipeline Authority (Kringstad, 2020). Both profiles are plotted in Figure 5-4. The estimated ultimate recovery based on the profiles was 534 MMbbl for oil and 1594 MMscf for gas after 30 years of production. Given their lesser financial impact, natural gas liquids were not included in the TEA.

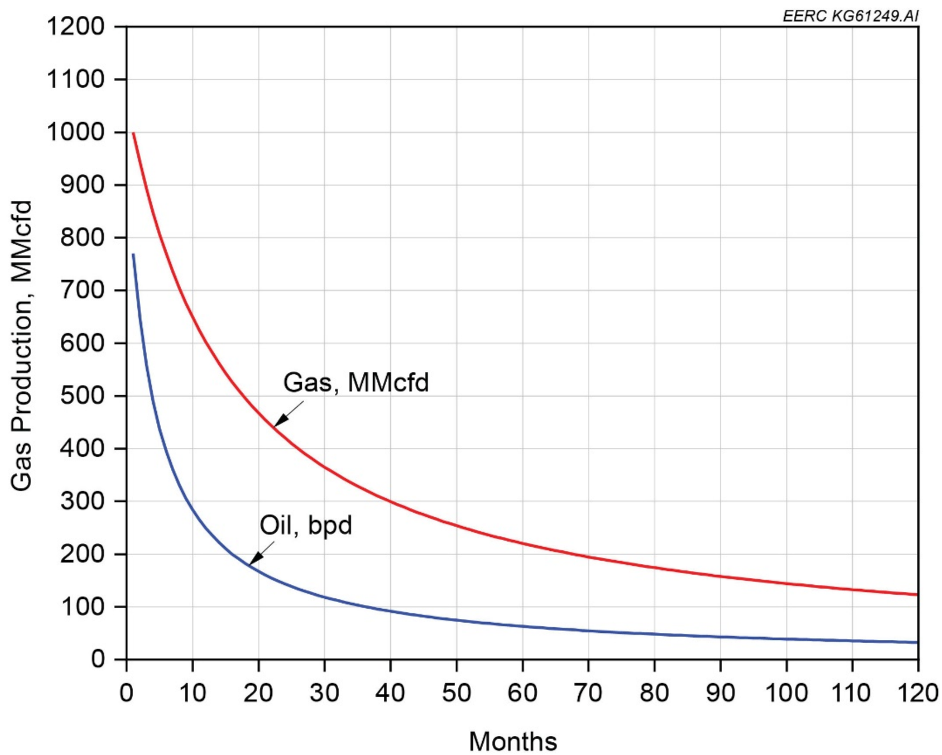

Figure 5-4. Oil and gas decline curves assumed in the TEA.

5.3.3 Water Demand and Disposal Profiles

Similar to oil and gas production, demand and production profiles were developed for the water streams associated with Bakken oil development. These streams included the water demand for hydraulic fracturing, the water produced with oil that needs disposal, and the maintenance water demand.

Hydraulic fracturing water is needed during the completion phase of an oil well and is a relatively short-duration, but high-intensity water demand. For the TEA, a water demand typical of recent slickwater fractures, 200,000 bbl, was assumed (Energy & Environmental Research Center, 2020), and the rate was spread evenly over a typical completion time of 4 days. The other water demand is for maintenance water, which is needed during oil production to dilute the produced water and prevent salt precipitation. Industry guidance identified an average value of

35 bpd per well for maintenance water (Energy & Environmental Research Center, 2020). For the TEA, it was assumed that maintenance water would start 12 months after initial oil production, when oil production was estimated to drop to roughly one-third its initial production value. In the GHCR 2 case, produced fluid is used for maintenance; however, it was assumed that more of it would be needed to achieve an equivalent level of dilution compared to fresh maintenance water. In the TEA, it was assumed that 20% more produced water, or a total of 42 bpd, was needed for maintenance purposes. A graphical summary of both water demand streams is presented in Figure 5-5.

Water disposal from the water produced alongside oil production was based on the Bakken-average oil decline curve in Figure 5-4 and the assumption of a 0.58 water cut (Energy & Environmental Research Center, 2020). The total produced water quantity was 738 MMbbl over 30 years. As noted in the SWD profiles of Figure 5-6 for the GHCR cases, the GHCR wells were assumed to be converted to SWD only after the final oil well completion (since the GHCR wells were needed to provide fracture fluid). Therefore, in the TEA, it was assumed that these cases relied on off-site SWD until all hydraulic fracturing was complete.

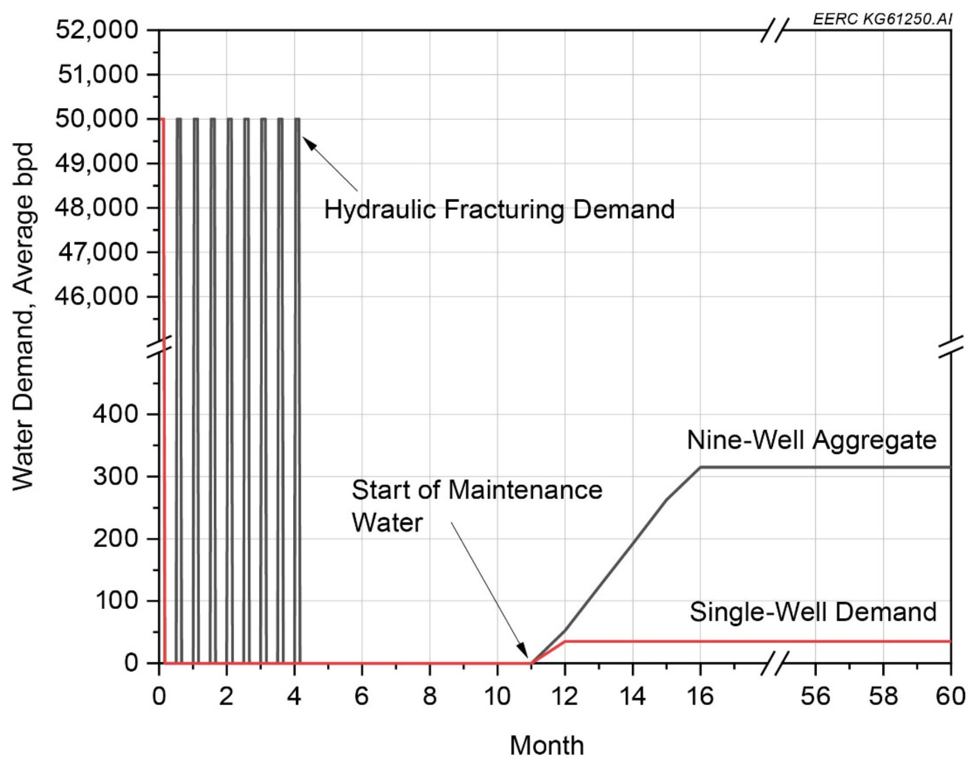

Figure 5-5. Time profiles for water demand assumed in the TEA.

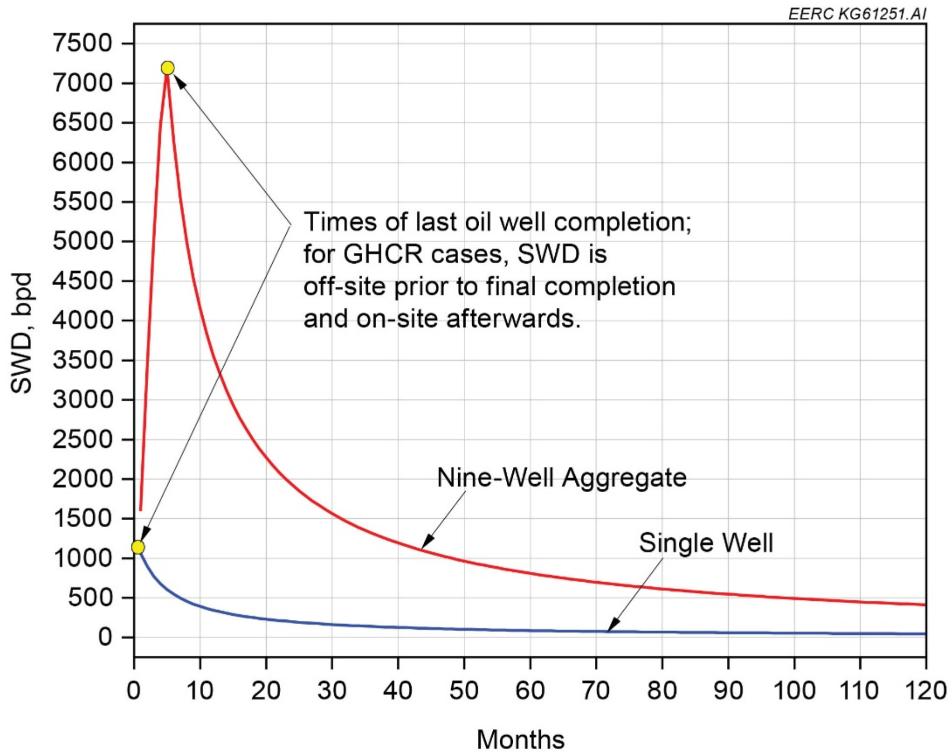

Figure 5-6. SWD profiles assumed in the TEA.

5.4 TEA Results

Summary economic metrics for the TEA cases are presented in Table 5-6 and include commonly used values such as the net present value (NPV), internal rate of return (IRR), simple payback period, and return on investment (ROI). The NPV metric assumed a 10% discount rate, which was the typical value found in well files for various Bakken operators. IRR calculations compute the resulting discount rate for a zero NPV and did not require a rate assumption. The latter two metrics of simple payback and ROI do not incorporate a discount rate.

As for results, economic metrics for the conventional case are somewhat conservative compared to Bakken well files; however, the case does not appear to have an unusually low NPV. The GHCR and SWD options that involved adding an Inyan Kara well (or wells) reflect the appropriation of those costs on a per-oil-well basis, and the nominal TEA assumption was that all nine infill wells could be supported by a single GHCR 1 or on-site SWD well or a single well pair for GHCR 2. Therefore, the NPVs for the GHCR/on-site SWD options spread development costs over nine oil wells.

Table 5-6. Economic Evaluation Metrics for the Nominal TEA Case Assumptions

	Conventional	GHCR 1		GHCR 2		On-Site SWD
Dakota String	Yes	Yes	No	Yes	No	Yes
Oil Wells Supported	NA[1]	9	9	9	9	9
10% NPV per Well	$1,843,000	$3,007,000	$3,503,000	$3,067,000	$3,563,000	$2,695,000
IRR	17.4%	22.6%	26.0%	22.2%	25.4%	20.7%
Simple Payback, yr	3.52	2.77	2.44	2.85	2.52	3.00
ROI, No Discount	1.91:1	2.15:1	2.29:1	2.20:1	2.33:1	2.06:1

[1] Not applicable.

Economic metrics for both GHCR and the on-site SWD cases suggest that all of these options could be more competitive than the conventional approach to water management. The GHCR 1 and 2 options produce NPVs similar to each other when comparing cases that have the same Dakota string assumption. For example, both GHCR cases that assumed the use of a Dakota string had NPVs over $3.5MM. However, as discussed in the case descriptions, the GHCR 2 case likely offers a more certain path to eliminating the Dakota string because produced fluid from the first well can be injected in the second, and a tertiary link to completions on a separate DSU does not need to be made. Finally, the on-site SWD case fell between the other options; it was more competitive than the conventional case but less so than any of the GHCR cases.

Insight into the underlying TEA drivers is provided in Figure 5-7, which is a breakout of the cost contributors for each case. In the figure, the NPVs that correspond to those in Table 5-6 are represented as the difference between the net revenue potential, which was the same for all cases since no impacts to hydrocarbon production were assumed, and the top of the TEA cost column as illustrated for the conventional case. As shown, all TEA cases had common values for the cost of the oil well and the nonwater portion of the LOE (e.g., artificial lift maintenance and electricity). Differences exist for the fracture fluid depending on whether freshwater or produced fluid was used; similarly, for the present value (PV) of the maintenance water supply, only the GHCR 2 case could capitalize on lower-cost produced fluid.

Significant differences appear among the present values for SWD, with the most costly being the conventional case since it relied exclusively on off-site SWD. The minor difference between GHCR 1 and 2 and the on-site SWD case is due to the fact that there was no delay in using the SWD well for produced water disposal, whereas with GHCR 1 and 2, the early months of produced water were assumed to be disposed of off-site since the GHCR well(s) was still being used to produce fluid for hydraulic fracturing.

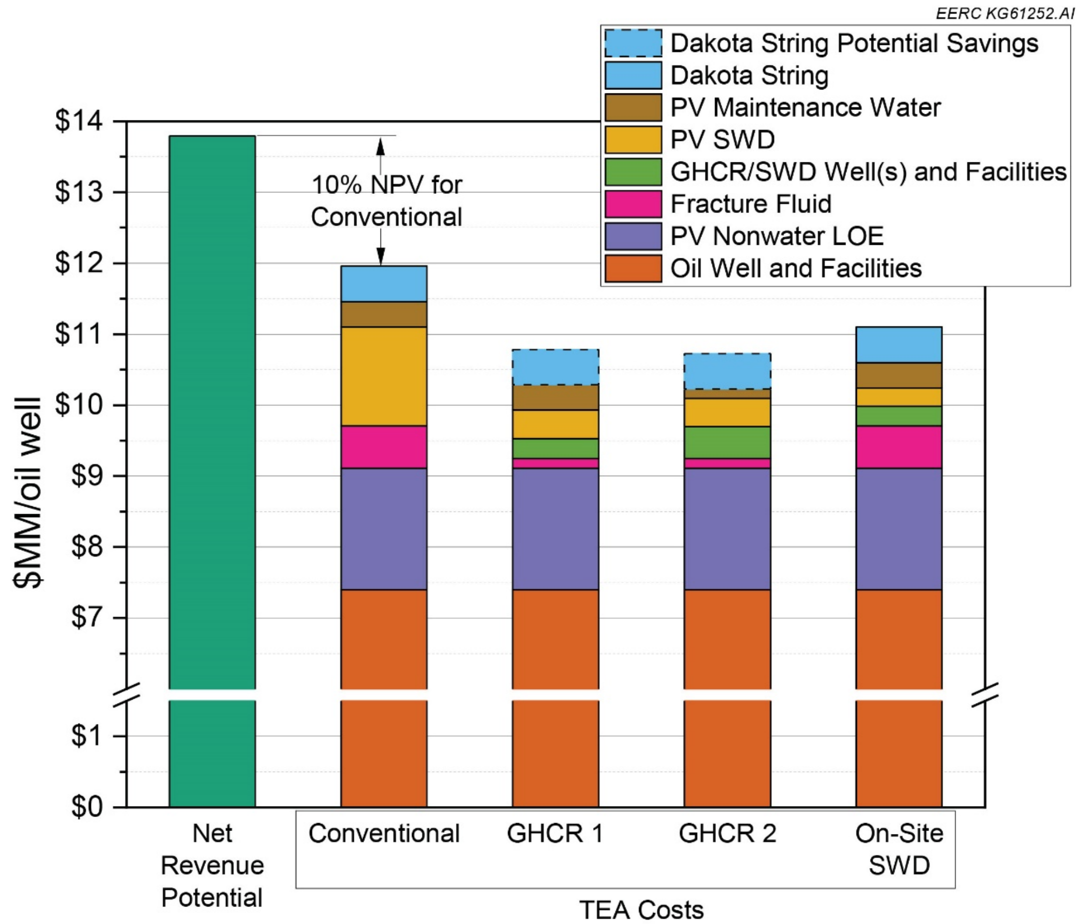

Figure 5-7. NPV cost breakdowns for the nominal-value TEA cases (10% discount rate assumed).

Inspection of Figure 5-7 shows that savings in SWD over the oil well's lifetime is the primary source of cost reduction when applying GHCR or on-site SWD. Lesser but noticeable savings appear possible from using recycled fluid for hydraulic fracturing over freshwater. However, the use of recycled fluid for maintenance water does not appear to be as clear-cut, since the metrics for GHCR 1 and 2 were quite close when comparing cases that had the same Dakota string assumption. These results suggest that the investment cost to develop the second GHCR well has a similar magnitude to the lifetime savings in maintenance water costs. However, if the second GHCR 2 well allows for the Dakota string to be eliminated when it would otherwise be needed under GHCR 1, then the investment seems more favorable.

The previous results in Table 5-6 and Figure 5-7 are only for one set of TEA assumptions. To further evaluate GHCR water management, several sensitivity studies were performed for key parameters that included: off-site SWD cost, freshwater cost, and the number of supported oil wells.

Results from the SWD cost study are shown in Figure 5-8, which shows that the conventional case is most impacted by SWD cost since all the others primarily used on-site SWD. As the cost of off-site SWD is reduced, the conventional NPV increases, up to the point that it would equal that for on-site SWD at a fee of approximately $1.15/bbl. However, the fee would need to be reduced to approximately $0.10/bbl for the conventional NPV to match the GHCR cases with a Dakota string. As expected, as off-site SWD increases in cost, the conventional case rapidly loses value. The GHCR cases have a slight sensitivity to off-site SWD cost because they were assumed to use off-site disposal until all hydraulic fracturing was complete.

Freshwater cost is a key parameter for those cases that use it for fracturing and/or maintenance. The sensitivity results are shown in Figure 5-9, and as expected, the GHCR 2 case is unaffected since it did not use any freshwater. The GHCR 1 cases are impacted because of the assumed use of freshwater for maintenance, and the conventional and on-site SWD cases have identical sensitivity because they used freshwater for both fracturing and maintenance. Where freshwater is low-cost (i.e., less than $2/bbl), the NPV advantage of GHCR over on-site SWD erodes to the point that the values begin to converge. Value distinctions grow as freshwater costs increase, including between GHCR 1 and 2 which were previously somewhat inseparable under the nominal TEA assumptions.

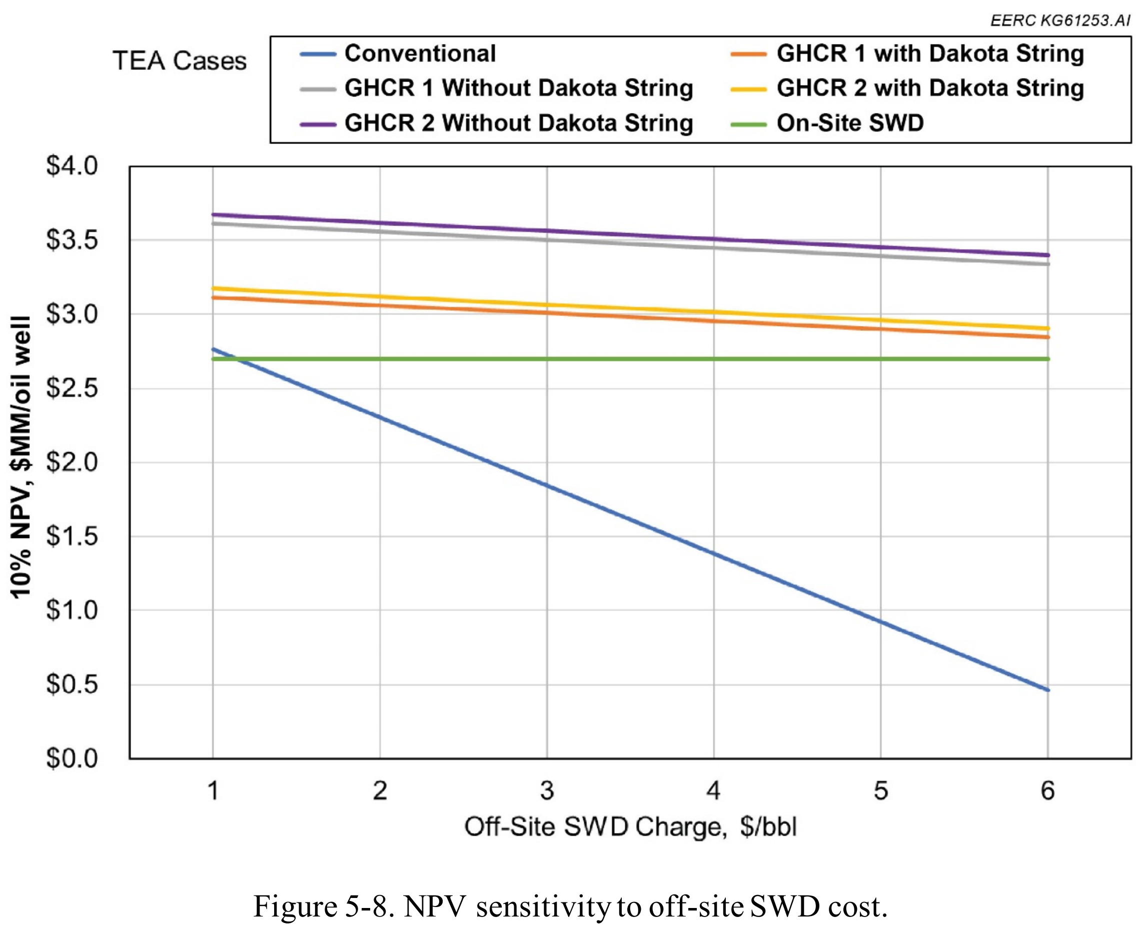

Figure 5-8. NPV sensitivity to off-site SWD cost.

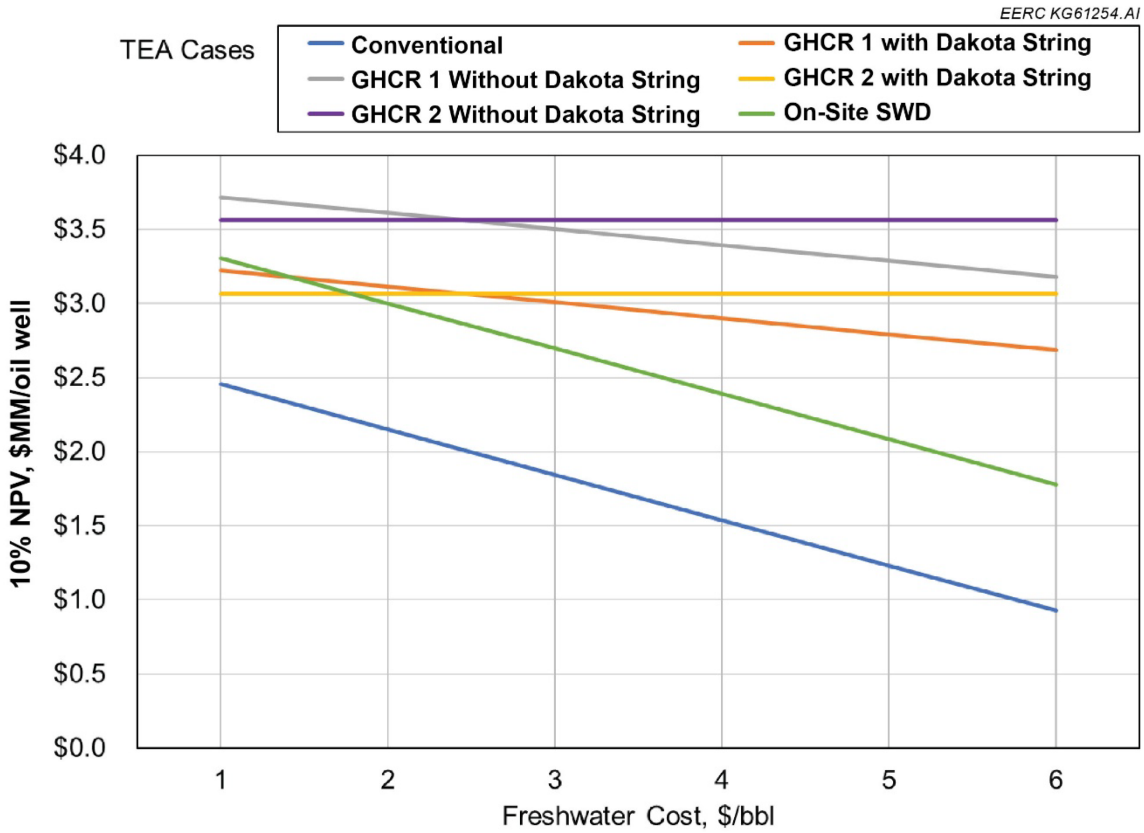

Figure 5-9. NPV sensitivity to freshwater cost.

The final sensitivity study is for the number of oil wells that each GHCR or on-site SWD well is assumed to support. These results are show in Figure 5-10 as a function of the oil well to GHCR/SWD well ratio. This ratio determines how many producing oil wells support the cost of GHCR/SWD well development. At the minimum value of one oil well per GHCR/SWD well (or one well pair for GHCR 2), all of the GHCR/SWD cases appear less competitive than conventional water management. However, NPVs for the GHCR/on-site SWD cases rapidly normalize at six or more oil wells per GHCR/SWD well, which suggests the minimum DSU size target for development.

5.4.1 Centralized GHCR

The TEA results thus far have been based on the local application of GHCR at a single DSU. However, a centralized model of GHCR water management can also be considered that is analogous to siting of the central treatment facilities found in the Permian Basin. Potential advantages of centralization include the following.

- Lower-cost GHCR well development since the cost of GHCR producer and injector wells can be distributed over many more active oil wells compared to those on a single DSU.

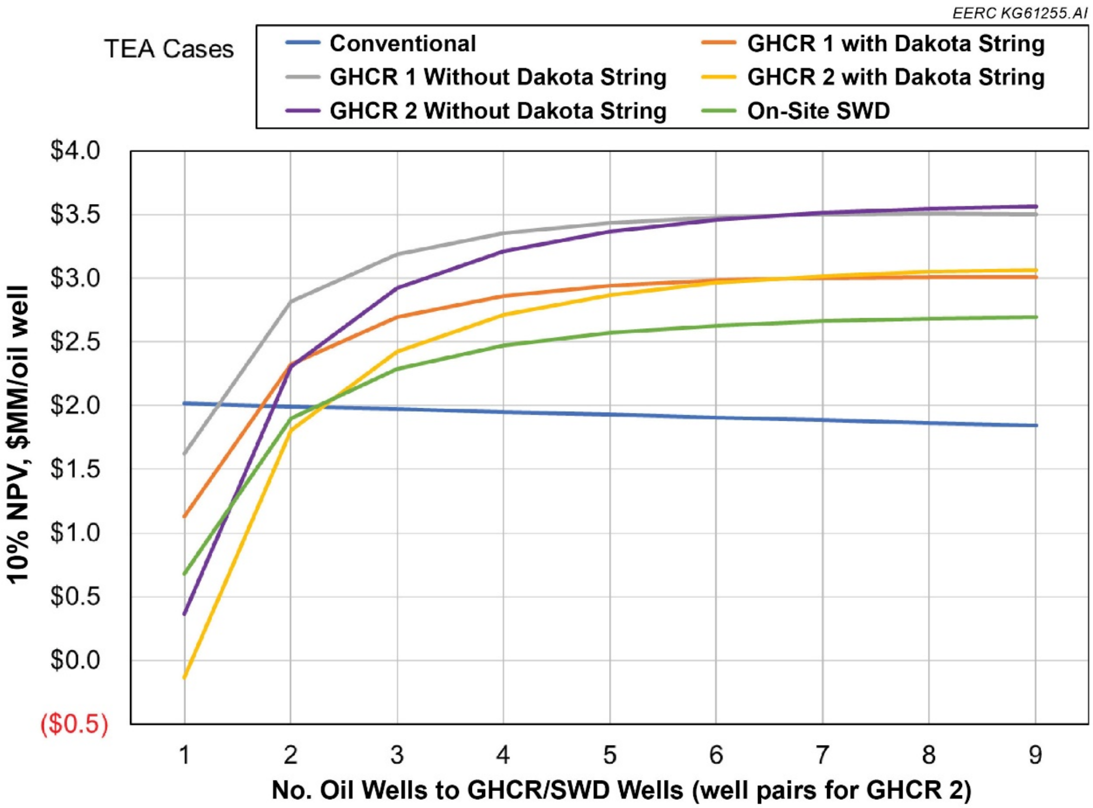

Figure 5-10. NPV sensitivity to the ratio of oil wells to GHCR wells.

- Improved reliability for supplying on-demand fluid for hydraulic fracturing. At a centralized facility, a plurality of producer wells might be used to meet the demand profile of hydraulic fracturing, while simultaneous SWD injections could be used to manage formation pressure and prevent depletion.

- Continued support of a key ESG goal by drastically reducing the demand for freshwater but still offering the potential for third-party operation.

On the other hand, centralized GHCR would apparently undermine the potential savings from reduced transport of recycled fracture fluid and SWD. As the distance between the DSU and the central facility increases, these costs would also increase. Additionally, the increased distance between GHCR water production and oil well placement would likely mean that the localized reduction in formation pressure would be insufficient to eliminate the Dakota string. One final consideration would be the regulatory uncertainty regarding the temporary transport of produced fluids from a central facility to hydraulic fracturing sites.

An overview of central versus local GHCR implementation features is presented in Table 5-7. In summary, centralized GHCR would ultimately be expected to approach the cost and reliability of conventional water management but with the advantage of significantly reducing freshwater demand.

Table 5-7. Qualitative Comparison of Cost Drivers Between Local and Central GHCR

Cost Driver	On-DSU GHCR	Centralized GHCR
GHCR Well Development	Rapid price normalization achieved with six or more oil wells.	Costs per oil well expected to decline further as more than one DSU is served.
Dakota String	Possibly avoid extra casing if sequencing of fluid production can occur before drilling.	Unlikely to affect well casing design, given the longer distance to a central GHCR extraction well.
Fracture Fluid	Minimum-cost fluid expected, given close proximity of the on-site producer well.	Higher-cost fluid impacted by transportation from a central facility producer well.
SWD Cost	Minimum-cost disposal, given close proximity.	Higher-cost SWD due to added transport to central facility.
Maintenance Water	Marginally cost effective to produce on-site compared to moderate-cost freshwater.	Likely to be similar to moderate-cost freshwater because of the transport cost from the central facility.
Technical Risk	Risk from producing fracture fluid at a high rate using a small number of wells and no pressure maintenance.	Reduced risk of meeting fracture fluid production targets, given the dedicated facility function and simultaneous pressure maintenance from SWD injections.
Regulatory Risk	Potentially few regulatory complications if the GHCR well and transport line can be entirely within containment.	Regulatory complications may arise from the need to temporarily distribute produced fluids for fracturing, potentially with lay-flat hose as in other basins.
ESG Targets	Supports freshwater reduction targets.	Supports freshwater reduction targets.

5.5 Key Observations from the TEA

5.5.1 Technical Evaluation

- GHCR appears to be capable of providing useful services of fluid storage, homogenization, and limited conditioning for fluid volumes that are typical of hydraulic fracturing operations in the Bakken.

- The conditioning aspect of GHCR does not appear to reach the highest standards that are used elsewhere for produced water recycling (i.e., production of a clear, chloride salt brine) but is not likely to be a limiting factor as to whether the fluid can be fully recycled for completions.

- GHCR appears capable of homogenizing the produced fluid such that changes to fluid composition are gradual, and individual batches of hydraulic fracturing fluid could be considered homogeneous.

- Producing fluids from a GHCR well also show the potential to locally reduce Inyan Kara Formation pressure to the point that it might be possible to eliminate the Dakota string on oil wells drilled nearby.
  - For the formation modeling that was analyzed, the pressure-affected distance from the GHCR producing well was approximately ¼ mile, suggesting that a GHCR production well could impact the oil wells on the same DSU, or at most, an adjacent DSU if the wells were placed near a common boundary.
  - In addition to the size of the pressure-affected zone created by GHCR fluid production, sequencing the operation to happen before oil well drilling and having a place to put the fluids must also be considered. Using only a single GHCR well means that the produced fluid might need to be transported off the DSU and perhaps used for the completion of nearby wells. It might be possible to use two GHCR wells on the DSU as a producer–injector pair to create temporary formation pressure relief without transporting fluid off-site.

- A potential risk associated with GHCR appears to be with matching the rate of fluid production to the demand needed by hydraulic fracturing. By design, hydraulic fracturing is a short-duration, high-flow process, and it may prove difficult to produce fluid at the needed rate using a single GHCR well. Increasing the number of GHCR producing wells will likely increase the reliability of providing on-demand produced water for hydraulic fracturing.

- Installing two GHCR wells appears to improve the likelihood of achieving the maximum possible benefits with GHCR.
  - Two wells might be used to lower formation pressure and thus avoid the expense of using a Dakota string without having to transport fluid off-site.
  - Two wells might also be a more reliable way to produce fluid at the rate it is needed for hydraulic fracturing since the flow resistance pressure for two wells is theoretically reduced to one-quarter the value needed with a single well.

5.5.2 Regulatory Considerations

- The tasks of accessing, injecting, and producing Inyan Kara water for industrial uses akin to GHCR appear to have precedent in North Dakota, and it is likely that a workable permitting strategy can be identified.

- GHCR seems to offer an alternative to the centralized produced water recycling facilities that are found in the Permian basin and elsewhere, and which typically store produced fluids above ground in lined ponds. The GHCR approach appears to be consistent with North Dakota's current prohibition of brine storage in surface impoundments.

- Temporary transport of produced fluid from a GHCR well to the hydraulic fracturing site might pose a regulatory challenge for recycling these fluids. Above ground, lay-flat hose appears to be used extensively for this purpose in other shale plays, but given the increased risk of spills, using it in North Dakota with produced fluids will require regulatory review and approval.

- Without off-pad transport, GHCR costs would need to be recouped from benefits accrued on a single DSU, which was the nominal assumption used in this TEA.

5.5.3 Economic Analysis

- From an economic standpoint, it appears that GHCR could be a lower-cost option than a conventional water management approach that relies on freshwater and off-site SWD. Using the nominal TEA assumptions, the GHCR cases had a 60% to 90% higher NPV and a 0.7- to 1-year shorter simple payback time than the conventional approach. In general, the up-front investment required to develop GHCR infrastructure was recouped primarily from SWD savings over the life of the project.

- Sites that are potentially attractive for GHCR are those that are located above a pressurized zone of the Inyan Kara, need six or more infill wells, and face high costs for conventional SWD and/or freshwater.

- Adding a second GHCR well to produce maintenance water appeared marginally cost-effective on its own, without accounting for other possible benefits of the second well such as eliminating the Dakota string.

- In comparing on-DSU GHCR and a centralized model, the centralized concept may undermine the key cost savings from on-site, low-cost SWD, and it could face more regulatory restrictions with respect to recycled fluid transport. However, it would likely require less up-front investment (on a per-oil-well basis), and it would still support reductions in freshwater use and possibly help manage Inyan Kara pressure.

6.0 CONCLUSIONS

The general trend associated with oil- and gas-related water management in North Dakota has been a sustained increase of freshwater use, increased water production, and increased SWD volumes. Tremendous volumes of water are being managed in the region, and the continued trend of increasing volumes may present challenges for SWD into the Inyan Kara Formation. The current approach to water management provides the most cost-efficient means of disposal and limits the amount of handling/processing of produced water, thereby reducing the risk of spills. The Inyan Kara's geographic extent, relatively shallow depth, proper confining zones, and injectability provide a SWD target that is suitable across the entire Bakken producing region in the state. However, should current approaches to SWD in the Inyan Kara ever become technically or economically challenged, then alternative produced water management options for North Dakota may be desirable.

Produced water recycling and in-industry reuse is of interest to the state of North Dakota and the oil and gas operators in the state. Recycling of produced water faces regulatory, technical, logistical, and economic challenges that have thus far precluded widespread commercial adoption. Such challenges are associated with large-volume transport, aggregation, and the need for large-scale temporary surface storage of high-TDS brines needed to supply a high-rate 200,000-bbl hydraulic fracture stimulation. However, commercial operators are making strides at overcoming these technical challenges as interest in recycling has grown, and some operators have begun implementing produced water recycling as they aim to reduce their freshwater consumption (Marathon Oil, 2020).

The GHCR concept could address many of the recycling challenges outlined in this report (e.g., large-volume transport, large-scale temporary surface storage of high-TDS fluids, etc.). By utilizing existing SWD infrastructure and the geologic formation as a storage container, the concept can provide an approach to address some of the economic and environmental challenges surrounding recycling of produced water.

The technical evaluation of the GHCR concept consisted of laboratory column flow-through testing, field sampling at a commercial SWD location that has a water production well targeting the same formation, and geologic modeling and numerical simulations. These efforts indicate that the GHCR concept appears to be capable of providing fluid storage, homogenization, and some conditioning for fluid volumes that are typical of hydraulic fracturing operations in the Bakken. Depending on the volumes of water extracted and locations of the relevant wells, implementing the GHCR concept could reduce formation pressure at the DSU level. One potential challenge to the implementation of GHCR is matching the rate of fluid production to the demand needed for hydraulic fracturing. Depending on the site-specific characteristics of the reservoir, more than one GHCR well may be needed to provide sufficient water supply within the short-duration time frame for a well completion.

The regulatory and economic evaluation of the GHCR concept revealed that there are pathways to implementation. There are likely workable permitting strategies that can be identified to implement a GHCR commercial operation. The GHCR approach is consistent with the state of North Dakota's restrictions for brine storage in large, open-top surface impoundments; however, lay-flat hose, while frequently used in other jurisdictions, would require regulatory review and approval in North Dakota. Economically, it appears that GHCR could be a competitive or even lower-cost option over conventional water management approaches. Sites that are potentially attractive for GHCR are those that are located above a pressurized zone of the Inyan Kara, need six or more infill wells, and face higher costs for conventional SWD and/or freshwater.

In summary, this study reveals pursuing GHCR can be a viable approach to water management in North Dakota. The GHCR concept addresses some of the challenges that hinder the more traditional approaches to recycling in the industry. Furthermore, an assessment of the current landscape of water management within the state reveals the ongoing trend of increasing volumes of produced water and SWD. Projections reveal that the volumes of produced water that needs to be managed is expected to double over the next decade (Energy & Environmental Research Center, 2020). With the continued development of the Bakken and continuing driving factors related to ESG initiatives, implementing a practice such as GHCR is a feasible approach to adding recycling of produced water to industry within the state.

7.0 MILESTONES

The completed milestone table can be found in Table 7-1.

Table 7-1. Milestones

Milestone Title/ Description	Planned Completion Date	Actual Completion Date	Verification Methods	Comments
M1 – Inyan Kara Outcrop Rock Samples Collected for GHCR Lab Test	6/30/2020	6/30/2020	Reported in subsequent quarterly report	Quartz sand with various grain sizes to replicate Inyan Kara grain distribution and porosity was purchased.
M2 – Laboratory and Field Validation of GHCR Concept Initiated	7/31/2020	7/30/2020	Reported in subsequent quarterly report	
M3 – Produced Water Quality Assessment Completed	10/1/2020	9/30/2020	Reported in subsequent quarterly report and in D4	D4 submitted to DOE Technical Monitor.
M4 – Findings Review with BPOP Member Technical Advisory Group	5/31/2021	5/31/2021	Reported in subsequent quarterly report	
M5 – Techno-Economic Assessment Completed	8/31/2021	11/30/2021	Relevant findings and results presented in the final report	Moved to 11/30/2021 as discussed with DOE Technical Monitor.

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APPENDIX A

FULL LABORATORY SAMPLE ANALYSIS AND ADDITIONAL COLUMN SAMPLE GRAPHS

FULL LABORATORY SAMPLE ANALYSIS

Sand Column Water Chemistry

Sample ID	Date	pH	Conductivity	Density	Sodium	Potassium	Calcium	Magnesium	Iron	Strontium	Silicon	Boron	Sulfate	Bromide	Chloride	Alkalinity, HCO_3	Alkalinity, $CaCO_3$	TDS	TOC	TSS	Barium	Lithium	Manganese	Zinc
			mS/cm	g/mL	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L
Inyan Kara Synthetic Brine	7/16/2020	6.78	19.8	1.00	4000	120	280	14.6	NA[1]	NA	<10	0	280	NA	6670	NA	NA	11,400	NA	<10	NA	NA	NA	NA
Bakken Produced Water	7/1/2020	5.66	246	1.20	93500	9700	21,200	1140	127	1810	<10	580	209	966	195,300	109	89.6	325,000	145	185	41.9	94.6	15.3	18.4
Sand Column Outlet Sample 1	10/1/2020	7.91	20.4	1.01	4220	129	342	3.6	<1	<0.5	<10	2.7	280	<20	6740	146	120	11,800	2.8	<10	0.27	<0.5	0.71	0.50
Sand Column Outlet Sample 2	10/20/2020	6.94	105	1.06	23300	1940	6450	357	<1	519	<10	165	272	259	50,200	59.8	49.0	83,500	37.8	<10	4.0	21.2	5.5	1.58
Sand Column Outlet Sample 3	11/6/2020	6.29	200	1.11	46800	4790	11,100	612	<1	907	<10	319	273	539	107,000	62.0	51.0	173,000	69.9	47	5.6	41.8	8.3	11.7
Sand Column Outlet Sample 4	12/6/2020	5.50	260	1.19	86600	9090	19,200	1020	<1	1520	<10	514	173	945	189,000	42.0	34.4	308,000	110	25	8.6	76.1	13.9	30.2
Sand Column Outlet Sample 5	12/16/2020	5.39	261	1.19	89500	9440	20,400	1130	<1	1690	<10	574	155	989	192,000	40.8	33.5	316,000	118	35	9.7	82.6	15.2	32.3
Sand Column Outlet Sample 6	1/10/2021	5.44	261	1.20	87700	9610	20,400	1140	<1	1720	<10	554	154	924	182,000	36.1	29.5	305,000	118	50	9.0	80.2	15.1	24.7
Sand Column Outlet Sample 7	2/1/2021	5.49	261	1.20	89400	9710	20,900	1150	<1	1730	<10	576	141	994	188,000	42.1	34.5	313,000	122	15	7.1	83.3	15.5	24.5
Sand Column Outlet Sample 8	2/16/2021	5.55	261	1.20	90600	9620	20,300	1150	<1	1720	<10	582	147	954	187,000	71.0	58.2	312,000	123	15	6.8	81.2	15.2	25.4

Inyan Kara Outcrop Column Water Chemistry

		pH	Conductivity	Density	Sodium	Potassium	Calcium	Magnesium	Iron	Strontium	Silicon	Boron	Sulfate	Bromide	Chloride	Alkalinity, HCO_3	Alkalinity, $CaCO_3$	TDS	TOC	TSS	Barium	Lithium	Manganese	Zinc
Sample Description	**Date**		mS/cm	g/mL	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L
Inyan Kara Synthetic Brine	4/22/2021	7.46	19.5	1.01	3860	105	280	26.5	NA	15.8	<10	NA	267	NA	6010	76.9	63	10,780	<1	<10	NA	NA	NA	NA
Bakken Produced Water	6/3/2021	5.34	259	1.20	90,100	7570	22,600	1340	100	1710	<10	455	185	1070	213,000	52.1	42.7	340,000	46.6	1930	34.9	80.6	25.4	36.3
Outcrop Column Outlet Sample 1	7/9/2021	7.97	20.0	1.00	3570	80.2	480	308	<1	14.0	18	6.1	857	<20	6530	313	256	12,100	57.2	16	0.98	<1	0.64	<1
Outcrop Column Outlet Sample 2	8/1/2021	7.84	21.1	1.00	3600	97.8	600	418	<1	14.8	19	5.8	1460	<20	6510	472	387	13,000	70.4	<10	0.35	<1	1.9	<1
Outcrop Column Outlet Sample 3	8/13/2021	7.05	127	1.07	26,200	507	8070	2140	<1	468	15	21	1170	270	59,200	235	192	98,500	43.8	15	2.3	13.3	18.4	<1
Outcrop Column Outlet Sample 4	8/25/2021	6.94	173	1.09	38,400	1100	10,800	2060	<1	715	17	37	1100	437	85,900	166	136	141,000	49.0	20	2.9	25.9	23.7	<1
Outcrop Column Outlet Sample 5	8/26/2021	6.81	200	1.13	48,200	1870	13,200	1930	6.3	917	16	64	959	547	109,000	155	127	178,000	45.2	13	3.8	39.0	28.7	1.0
Outcrop Column Outlet Sample 6	9/6/2021	5.66	252	1.22	86,900	6820	20,700	1400	4.5	1620	12	360	458	954	188,000	80.3	65.8	308,000	50.0	30	10.9	78.6	35.4	27.6
Outcrop Column Outlet Sample 7	9/13/2021	5.52	253	1.20	90,100	7580	21,300	1370	4.2	1690	12	420	409	1000	191,000	74.0	60.6	316,000	54.5	10	11.2	82.5	30.4	32.1
Outcrop Column Outlet Sample 8	9/15/2021	5.52	255	1.20	90,400	7580	21,900	1370	<1	1700	11	424	300	994	205,000	69.9	57.3	330,000	55.7	12	11.3	106	30.3	32.0

[1] Not analyzed.

Inyan Kara Core Column Water Chemistry

Sample Description	Date	pH	Conductivity	Density	Sodium	Potassium	Calcium	Magnesium	Iron	Strontium	Silicon	Boron	Sulfate	Bromide	Chloride	Alkalinity, HCO_3	Alkalinity, $CaCO_3$	TDS	TOC	TSS	Barium	Lithium	Manganese	Zinc
			mS/cm	g/mL	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L
Inyan Kara Synthetic Brine	4/22/2021	7.46	19.5	1.01	3860	105	279	26.5	0	15.8	NA	NA	267	NA	6010	76.9	63	10,780	<1	<10	NA	NA	NA	NA
Bakken Produced Water – Start of Test	7/27/2021	4.04	240	1.20	89,400	8270	21,000	1230	71.51	1710	<10	513	290	1020	195,000	0	0	319,000	71.0	NA	13.5	98.7	21.3	34.1
Core Column Outlet Sample 1	8/6/2021	7.23	40.4	1.01	7500	680	2010	112	22.4	172	<10	47	642	65	14,400	257	211	25,800	749.5	NA	0.54	5.6	6.6	2.7
Core Column Outlet Sample 2	9/8/2021	3.95	160	1.10	39,400	2940	10,400	651	248	796	<10	173	432	414	85,000	0	0	141,000	984.8	NA	2.0	40.8	19.6	20.6
Core Column Outlet Sample 3	9/17/2021	4.16	227	1.19	83,200	6760	20,600	1210	75.77	1560	<10	426	239	862	180,000	0	0	296,000	171.9	NA	5.3	88.2	26.5	39.1
Core Column Outlet Sample 4	9/29/2021	4.13	196	1.18	79,200	6470	19,500	1180	43.18	1500	<10	430	227	830	179,000	0	0	289,000	126.4	NA	5.9	73.7	26.1	36.4
Core Column Outlet Sample 5	10/5/2021	4.16	228	1.18	76,200	6330	19,100	1130	42.08	1440	<10	422	235	821	159,000	0	0	265,000	128.5	NA	5.7	70.5	24.7	34.3
Core Column Outlet Sample 6	10/18/2021	4.24	223	1.17	77,700	6300	18,800	1150	38.5	1480	<10	424	237	807	163,000	0	0	270,000	111.5	NA	6.1	72.4	24.6	33.3
Bakken Produced Water – End of test	10/20/2021	3.46	230	1.15	67,500	5620	16,700	1010	14.77	1270	12	428	258	702	142,000	0	0	236,000	24.73	NA	10.5	62.5	19.9	28.7

Bakken Produced Water Chemistry

Sample Description	Date	pH	Conductivity	Density	Sodium	Potassium	Calcium	Magnesium	Iron	Strontium	Silicon	Boron	Sulfate	Bromide	Chloride	Alkalinity, HCO_3	Alkalinity, $CaCO_3$	TDS	TOC	TSS	Barium	Lithium	Manganese	Zinc
			mS/cm	g/mL	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L	mg/L
Watford City Area 1	3/24/2020	5.70	227,000	1.16	68,000	6960	17,200	981	95.9	1490	<20	446	298	833	155,000	93.9	77.0	252,000	650.0	560	31.0	66.7	16.1	15.6
Watford City Area 2	7/1/2020	5.66	246,000	1.20	93,500	9700	21,200	1140	127.0	1810	<20	580	209	966	195,000	109.0	89.6	325,000	145.0	185	41.9	94.6	15.3	18.4
Stanley Area 1	9/29/2021	5.24	245,000	1.18	79,400	4860	16,800	1490	78.2	1040	<20	270	434	777	171,000	15.0	13.0	276,000	59.0	NA	7.4	57.3	6.3	7.9
Tioga Area 1	9/29/2021	4.82	251,000	1.18	91,100	5690	16,000	1420	138.0	1160	<20	460	325	781	181,000	0.0	0.0	298,000	37.0	NA	13.5	67.9	7.6	7.0
Cartwright Area 1	6/3/2021	5.34	259,000	1.20	90,100	7570	22,600	1340	100.0	1710	<20	455	185	1070	213,000	52.1	42.7	340,000	35.0	1930	34.9	80.6	25.4	36.3
Cartwright Area 2	9/30/2021	5.02	248,000	1.20	87,000	6910	20,000	1260	114.0	1520	<20	640	343	911	164,000	7.2	5.9	283,000	26.0	NA	31.3	113.0	22.4	22.3
Cartwright Area 3	9/30/2021	5.30	246,000	1.19	79,900	6580	21,100	1240	192.0	1740	<20	560	376	914	174,000	29.8	24.4	287,000	60.0	NA	30.0	95.1	26.3	23.5
Cartwright Area 4	9/30/2021	5.15	253,000	1.22	90,000	7500	20,500	1240	137.0	1550	<20	600	339	887	187,000	16.0	13.1	310,000	65.0	NA	32.6	93.9	22.9	24.6
Williston Area 1	9/29/2021	5.60	244,000	1.17	74,700	4530	13,200	1080	73.0	966	<20	520	294	598	146,000	70.7	57.9	242,000	117.0	NA	13.1	81.5	14.4	7.9

[1] Not analyzed.

Additional Sand Column Test Samples

Na

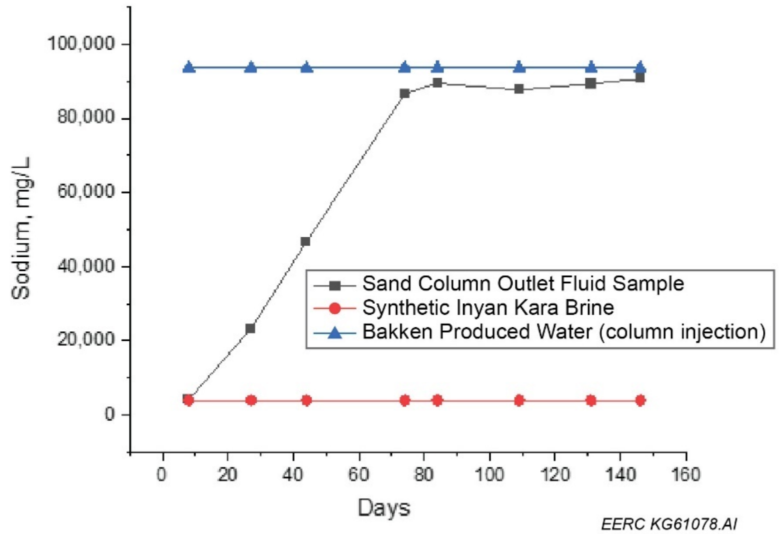

Figure A-1. Sodium measurements of laboratory sand column test samples (synthetic Inyan Kara brine used to saturate the column, Bakken produced water injected into the column, and fluid samples collected from the column outlet). Sodium concentrations follow the same trend as conductivity and TDS.

Cl

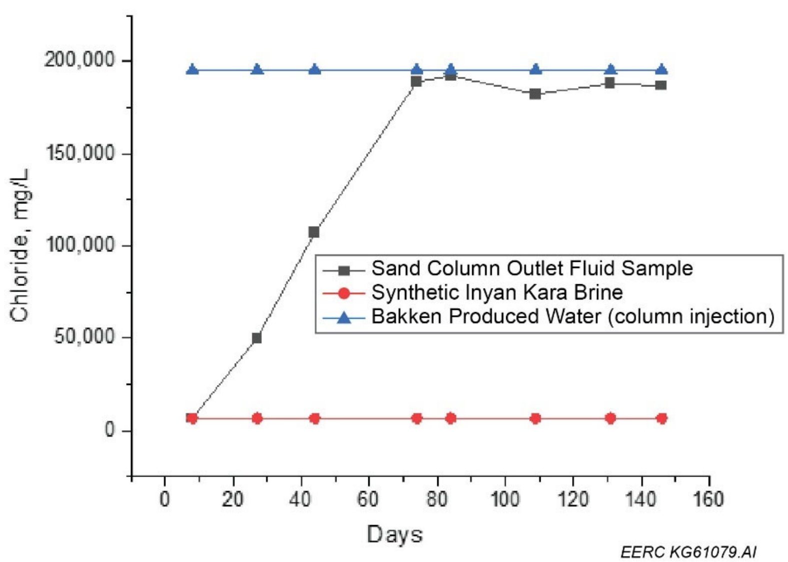

Figure A-2. Chloride measurements of laboratory sand column test samples (synthetic Inyan Kara brine used to saturate the column, Bakken produced water injected into the column, and fluid samples collected from the column outlet). Chloride concentrations follow the same trend as conductivity and TDS.

Ca

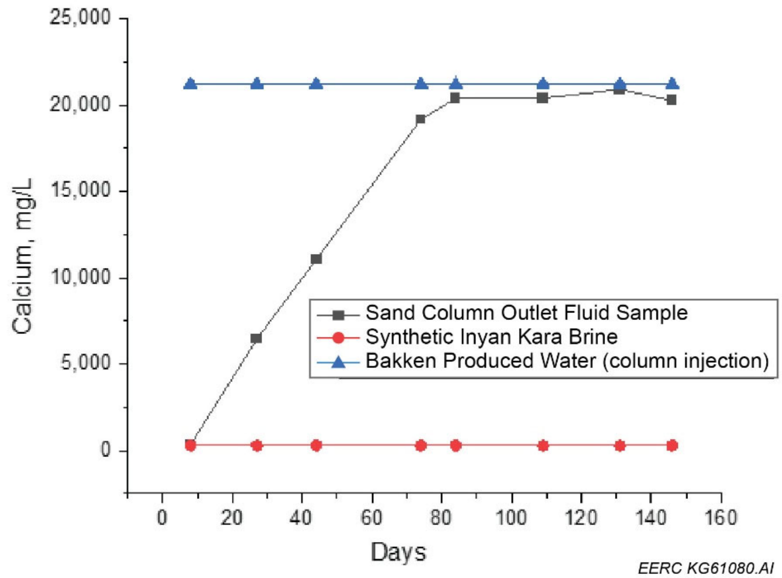

Figure A-3. Calcium measurements of laboratory sand column test samples (synthetic Inyan Kara brine used to saturate the column, Bakken produced water injected into the column, and fluid samples collected from the column outlet). Calcium concentrations follow the same trend as conductivity and TDS.

K

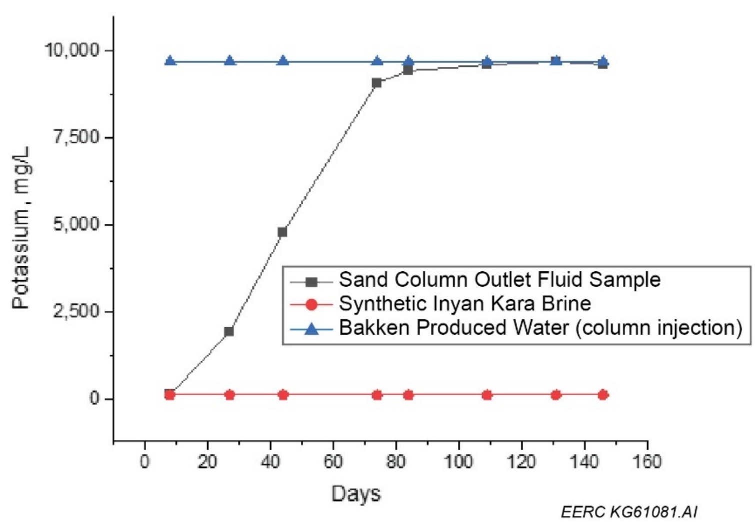

Figure A-4. Potassium measurements of laboratory sand column test samples (synthetic Inyan Kara brine used to saturate the column, Bakken produced water injected into the column, and fluid samples collected from the column outlet). Potassium concentrations follow the same trend as conductivity and TDS.

Mg

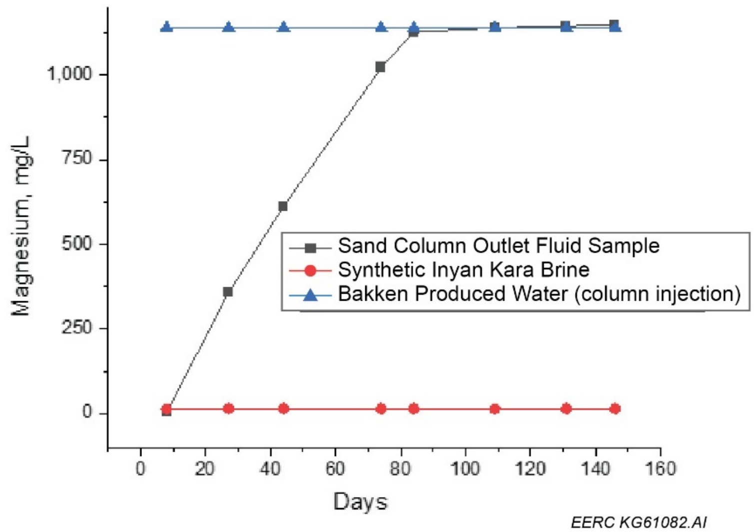

Figure A-5. Magnesium measurements of laboratory sand column test samples (synthetic Inyan Kara brine used to saturate the column, Bakken produced water injected into the column, and fluid samples collected from the column outlet). Magnesium concentrations follow the same trend as conductivity and TDS.

Additional Outcrop Column Test Samples

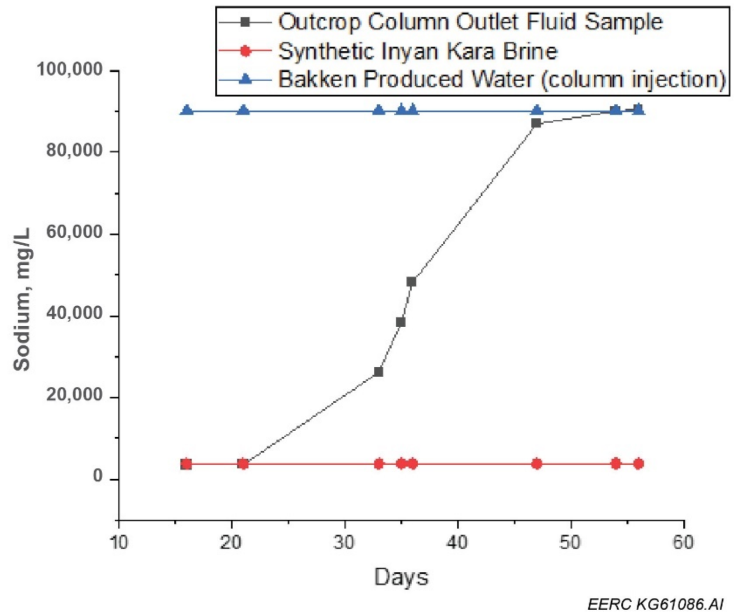

Figure A-6. Sodium measurements of laboratory outcrop column test samples (synthetic Inyan Kara brine used to saturate the column, Bakken produced water injected into the column, and fluid samples collected from the column outlet). Sodium concentrations follow the same trend as conductivity and TDS.

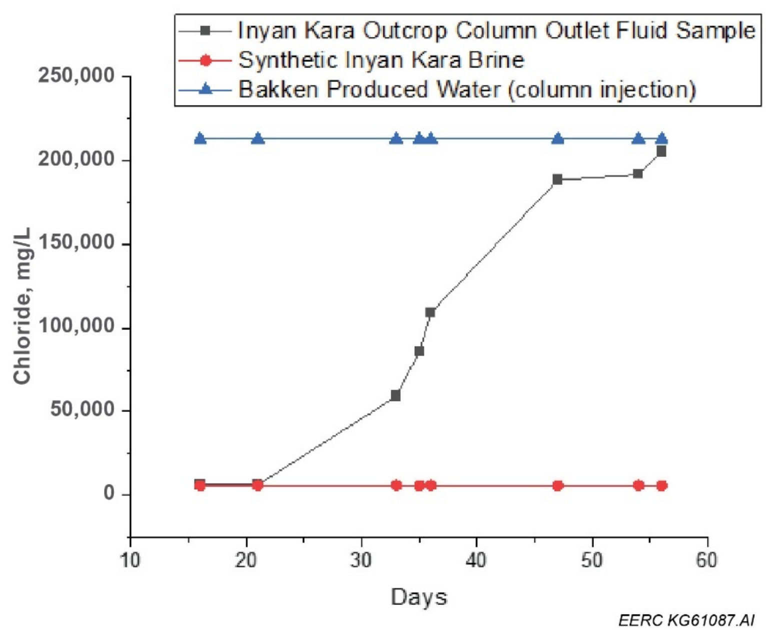

Figure A-7. Chloride measurements of laboratory outcrop column test samples (synthetic Inyan Kara brine used to saturate the column, Bakken produced water injected into the column, and fluid samples collected from the column outlet). Chloride concentrations follow the same trend as conductivity and TDS.

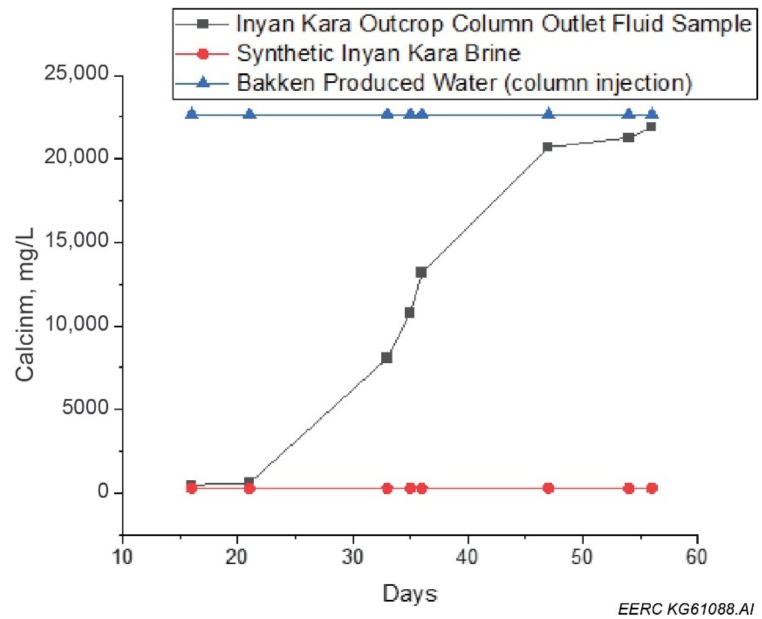

Figure A-8. Calcium measurements of laboratory outcrop column test samples (synthetic Inyan Kara brine used to saturate the column, Bakken produced water injected into the column, and fluid samples collected from the column outlet). Calcium concentrations follow the same trend as conductivity and TDS.

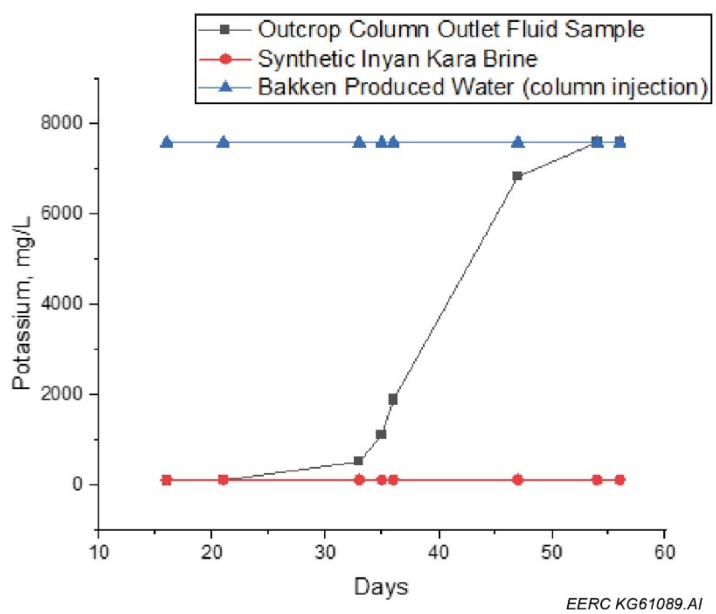

Figure A-9. Potassium measurements of laboratory outcrop column test samples (synthetic Inyan Kara brine used to saturate the column, Bakken produced water injected into the column, and fluid samples collected from the column outlet). Potassium concentrations follow the same trend as conductivity and TDS.

Additional Core Column Test Samples

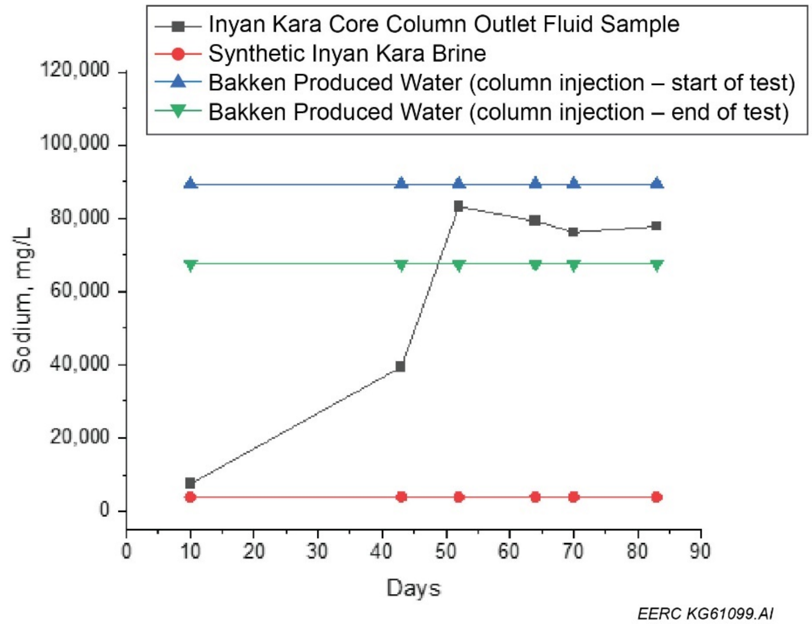

Figure A-10. Sodium measurements of laboratory core column test samples (synthetic Inyan Kara brine used to saturate the column, Bakken produced water injected into the column, and fluid samples collected from the column outlet). Sodium concentrations follow the same trend as conductivity and TDS.

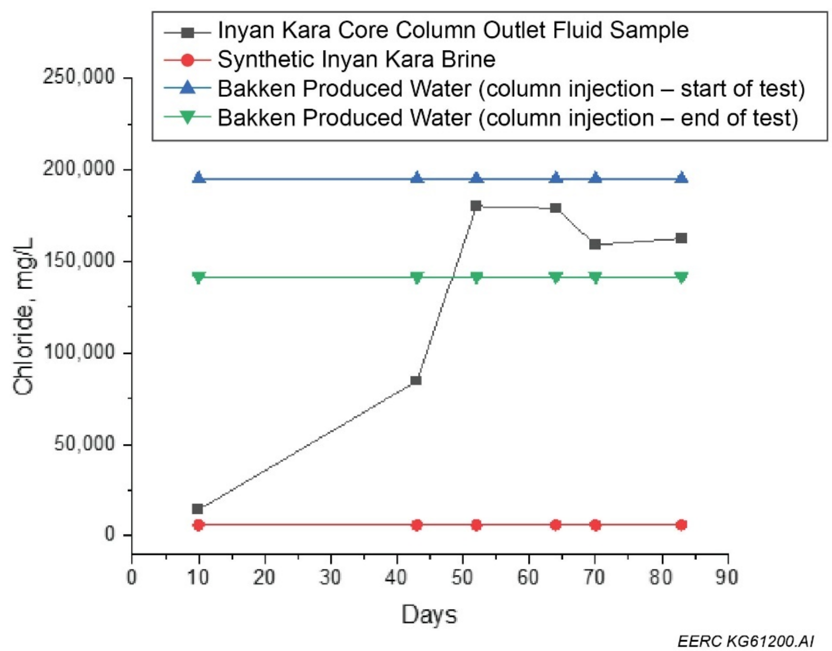

Figure A-11. Chloride measurements of laboratory core column test samples (synthetic Inyan Kara brine used to saturate the column, Bakken produced water injected into the column, and fluid samples collected from the column outlet). Chloride concentrations follow the same trend as conductivity and TDS.

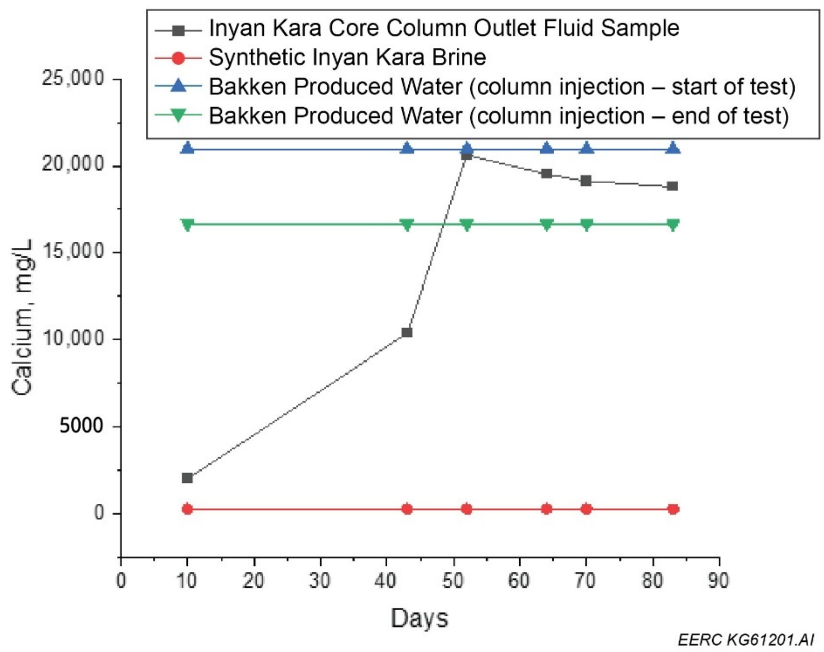

Figure A-12. Calcium measurements of laboratory core column test samples (synthetic Inyan Kara brine used to saturate the column, Bakken produced water injected into the column, and fluid samples collected from the column outlet). Calcium concentrations follow the same trend as conductivity and TDS.

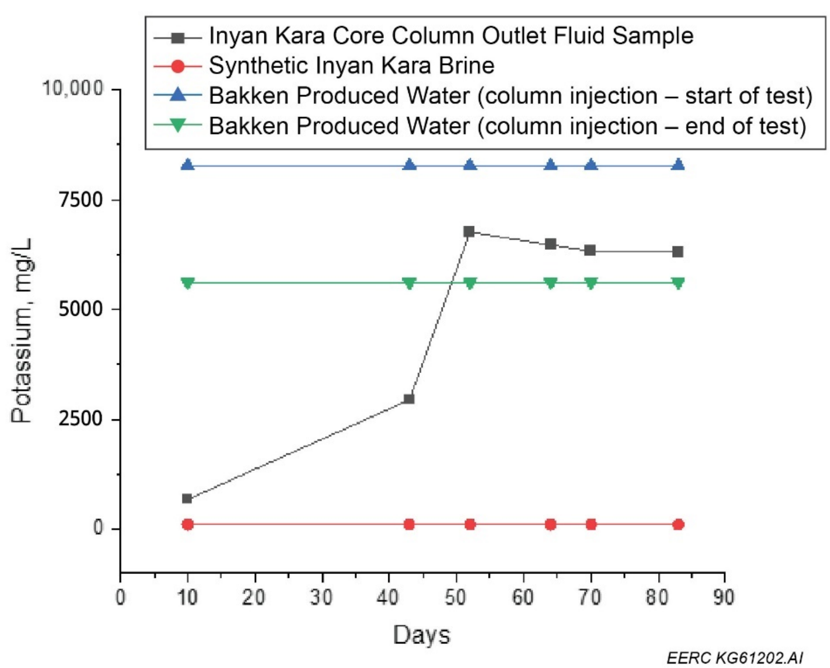

Figure A-13. Potassium measurements of laboratory core column test samples (synthetic Inyan Kara brine used to saturate the column, Bakken produced water injected into the column, and fluid samples collected from the column outlet). Potassium concentrations follow the same trend as conductivity and TDS.

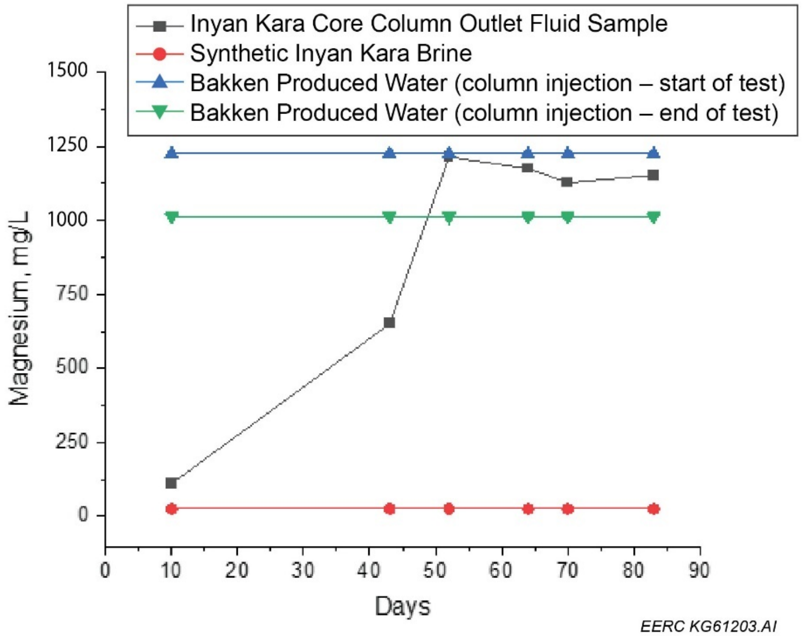

Figure A-14. Magnesium measurements of laboratory core column test samples (synthetic Inyan Kara brine used to saturate the column, Bakken produced water injected into the column, and fluid samples collected from the column outlet). Magnesium concentrations follow the same trend as conductivity and TDS.

Additional Field Sample Data

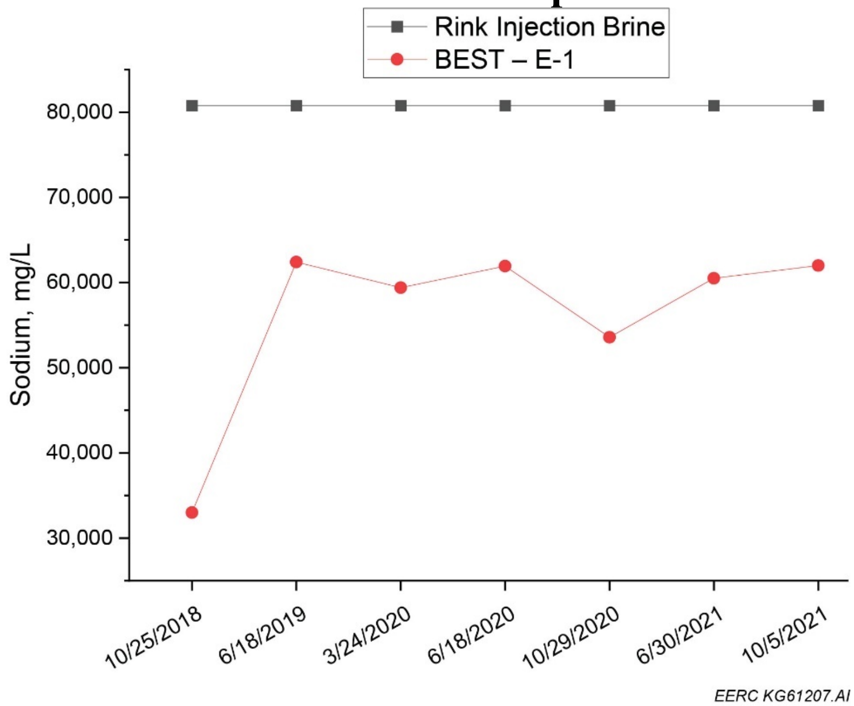

Figure A-15. Sodium measurements collected from the BEST E1 well. Data show a trend similar to TDS.

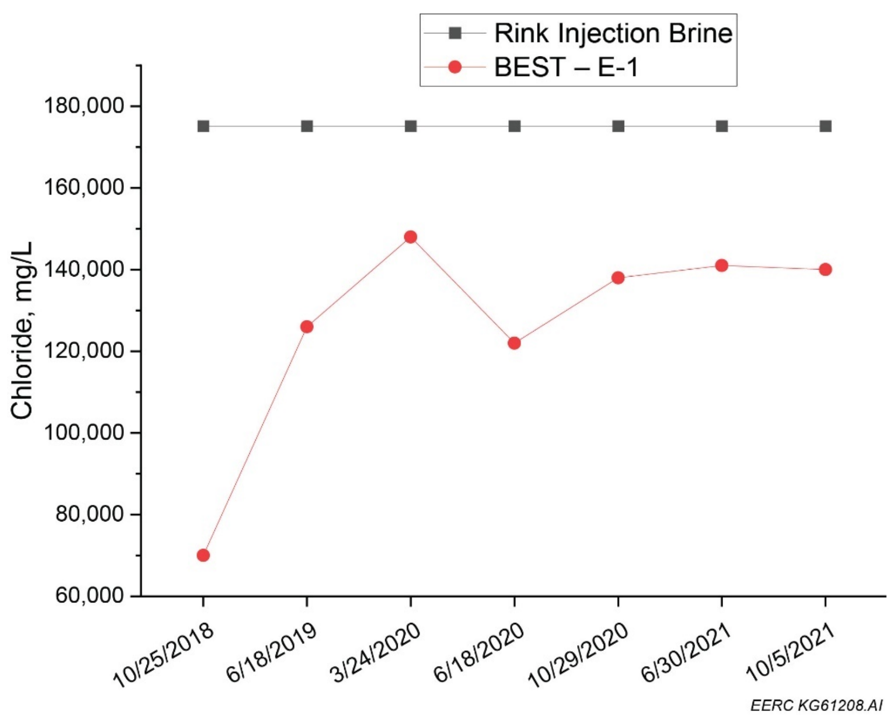

Figure A-16. Chloride measurements collected from the BEST E1 well. Data show a trend similar to TDS.

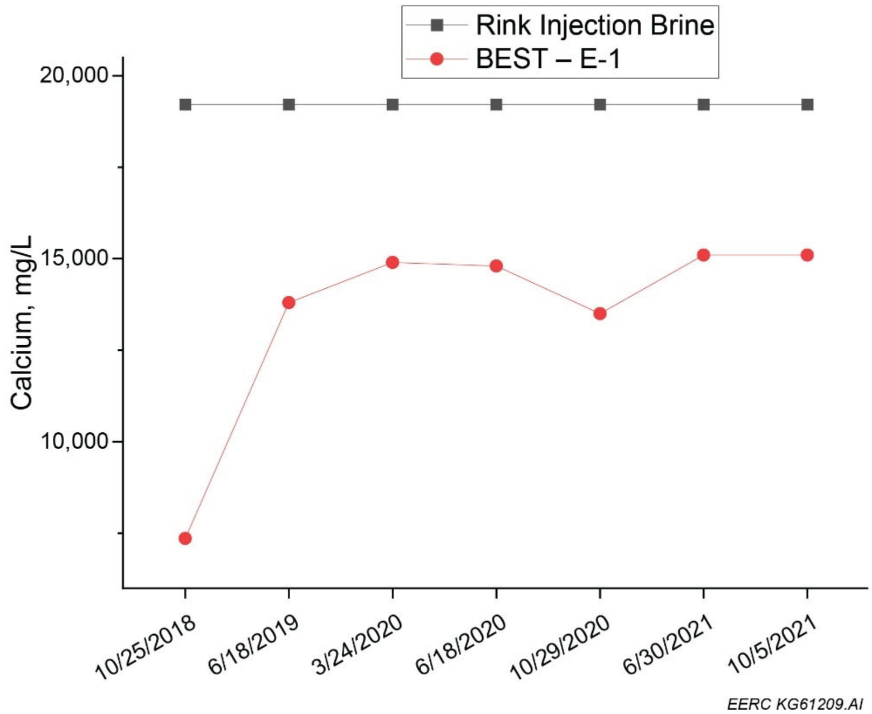

Figure A-17. Calcium measurements collected from the BEST E1 well. Data show a trend similar to TDS.

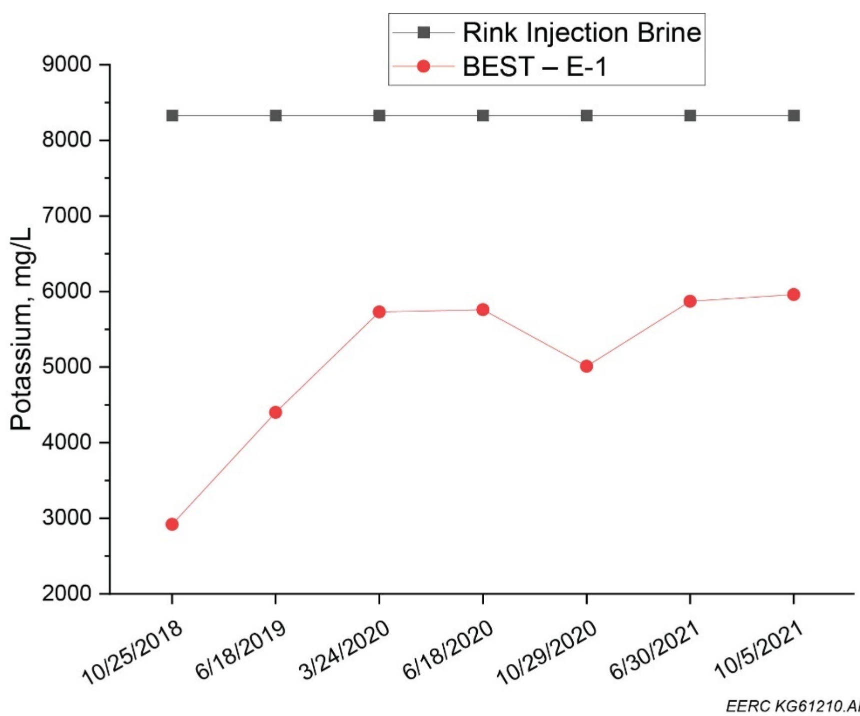

Figure A-18. Potassium measurements collected from the BEST E1 well. Data show a trend similar to TDS.

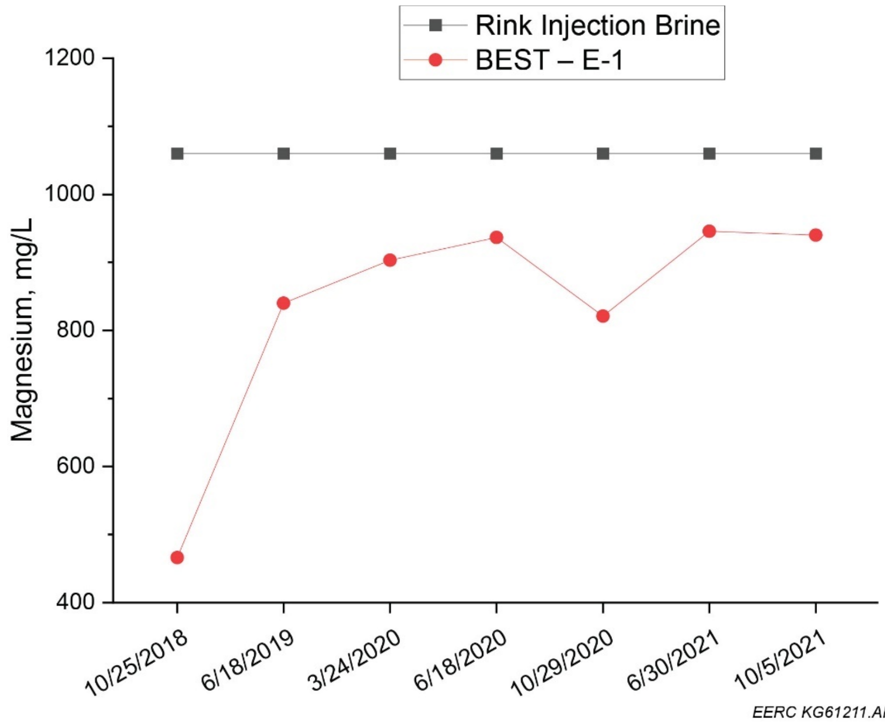

Figure A-19. Magnesium measurements collected from the BEST E1 well. Data show a trend similar to TDS.

APPENDIX B

LABORATORY COLUMN CONSTRUCTION AND PREPARATION

LABORATORY COLUMN CONSTRUCTION AND PREPARATION

Construction and Preparation of the Sand and Outcrop Column

The glass column was mounted in an aluminum frame and oriented vertically for filling. During the fill procedure, a 100-W concrete vibrating motor was attached to the frame to vibrate the column and help remove air and pack the sand as the column was filled. Several liters of synthetic Inyan Kara brine were used to fill the column approximately 1 meter full before sand was dropped in slowly. The vibration-induced liquefaction in the sand column allowed air to easily escape and expedited packing of the column. Every approximately 50 cm of fill the cap was placed on the column and a hard vacuum pulled while the column vibrated to help remove any residual trapped air, allowing for the best achievable packing of the test media.

Figure B-1 shows a picture of the column, wrapped with heat tape for temperature control, with the orange vibration motor attached ready to be filled. An accounting of sand mass loaded into the column was maintained to provide an estimate of porosity based on sand composition and mineral density. Once fully packed and saturated with Inyan Kara brine, the column was positioned between the injection oven (left) and sampling oven (right), and lines were purged with fresh brine and connected to the system.

The fully assembled system is shown in Figure B-2. A 5–10-cm^3 Argon stream is used to purge the oven and help reduce oxidation of produced water held in the injection oven on the left. A low-speed mixer is used to help prevent the formation of precipitate crystals and keep the fluid uniform for long-duration testing. Produced water is pulled from the 5-gallon produced water vat through a 200-mesh filter using a peristatic pump. Reciprocating style pumps were not able to be used because of the extreme TDS of the brine. Produced water pushed out of the pump is forced into the injection end of the column (left) and out the production end of the column (right). The fluid coming out of the production end then enters the sampling oven where an array of 100-mL sampling syringes were used to measure fluid production rates and collect produced fluid samples for analysis.

A basic system schematic is shown in Figure B-3. Initial permeability tests were completed using the synthetic Inyan Kara brine prior to starting injection of the high salinity Bakken produced water. A pressure transducer and pressure relief were connected as shown to allow for long-term monitoring of injection pressure and calculation of column permeability and to prevent risk of overpressurization.

The Sand Column test was carried out using clean kiln-dried quartz sand, and then the column was emptied and cleaned before the Outcrop Column test was performed using sand collected from Inyan Kara outcrop samples.

Figure B-1. Left – glass column mounted to insulated aluminum enclosure ready to be filled with sand. Right – column in the last stages of being filled with saturated sand. Glass end cap installed for pulling vacuum.

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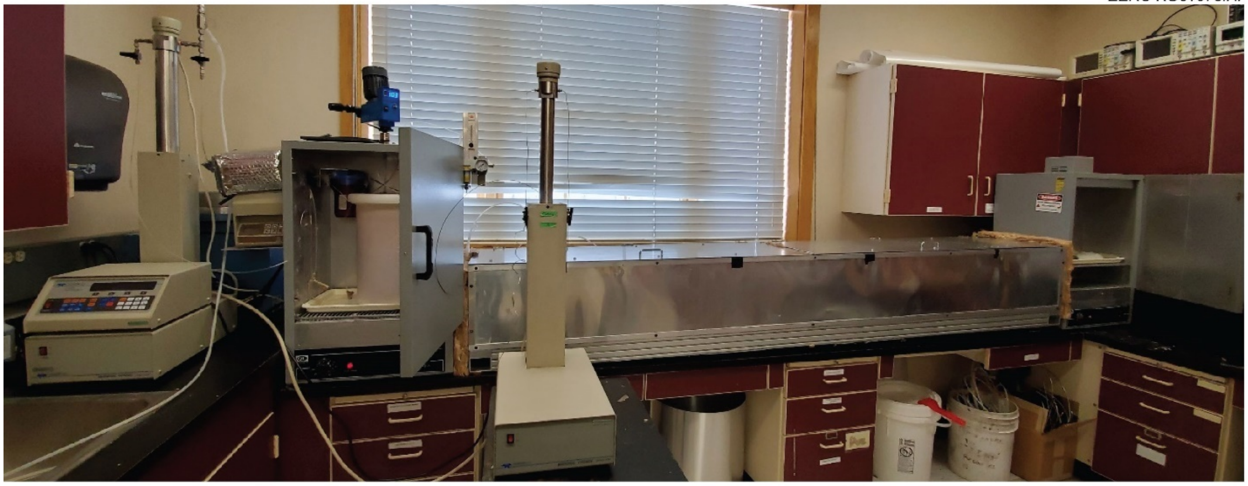

Figure B-2. Left – glass column mounted to insulated aluminum enclosure ready to be filled with sand. Right – column in the last stages of being filled with saturated sand.

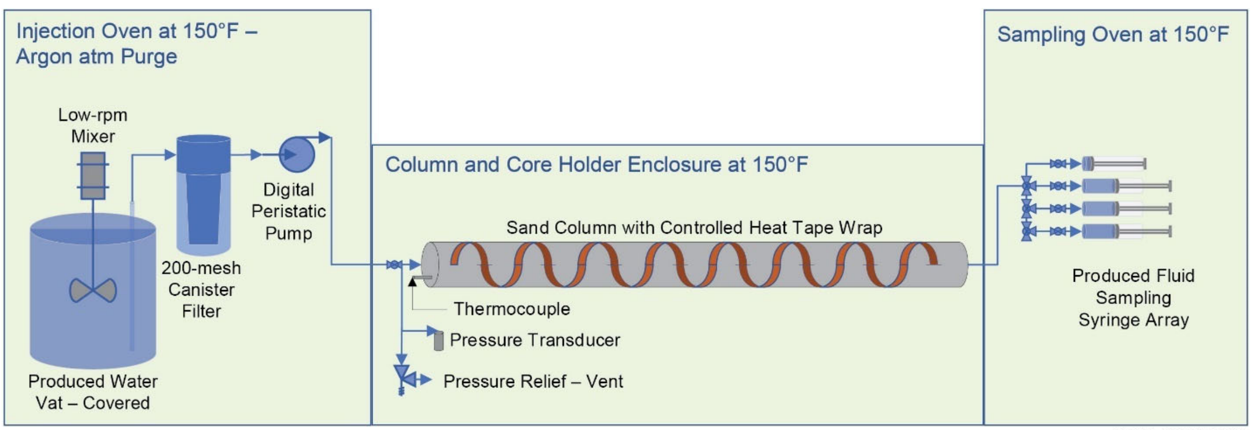

Figure B-3. Schematic of sand column test apparatus.

Construction and Preparation of the Core Flood Column

The core flood experiment was set up to use the same ovens, enclosures, and sampling system as the column tests except utilizing a custom-assembled Hassler-style core holder that was about 1.5 meters long. Figure B-4 shows the schematic for the core flood test.

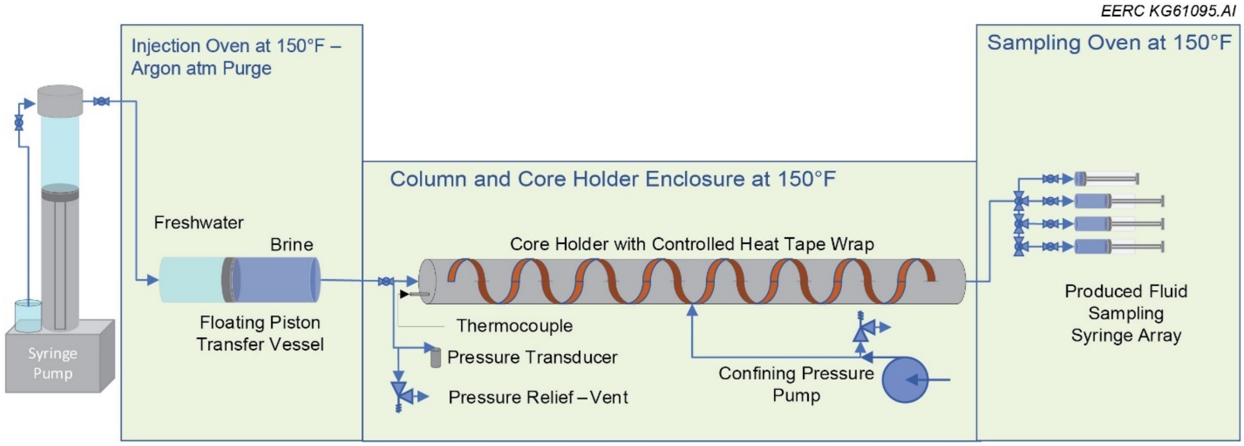

Figure B-4. Schematic of core flood system.

Bakken produced water was pulled from the same vat and 200-mesh filter system used in the column experiments to fill the floating piston transfer vessel. A more specialized and controlled pumping system was required to hit the minimum flow threshold of 0.007 mL/min. This was calculated as the target flow rate to achieve approximately 36-day residence time given the calculated core properties.

APPENDIX C

LABORATORY SIMULATION MODELS

LABORATORY SIMULATION MODELS

Laboratory-Scale Numerical Model

Three laboratory-scale numerical models were built and simulation work conducted based on the two column tests (sand column and outcrop column) and core holder test (core column) described in Section 3.0. The three laboratory simulation models were constructed using the column test information, including the data for the grain/core samples, the Inyan Kara synthetic brine, the injected Bakken produced water salinity, and injection/production operational conditions (Figure C-1). The salinity value from the produced brine (column outlet) for the numerical model was evaluated over time and compared against the salinity for the samples collected from the column outlets during the laboratory experiment. These laboratory-scale numerical models were simulated using Computer Modelling Group Ltd.'s (CMG's) GEM 2020.10 module, with the addition of the geochemical modeling. The data used for the geochemical modeling include the water chemistry for the ion/cation components in the initial and the injection brines as well as the rock minerology data.

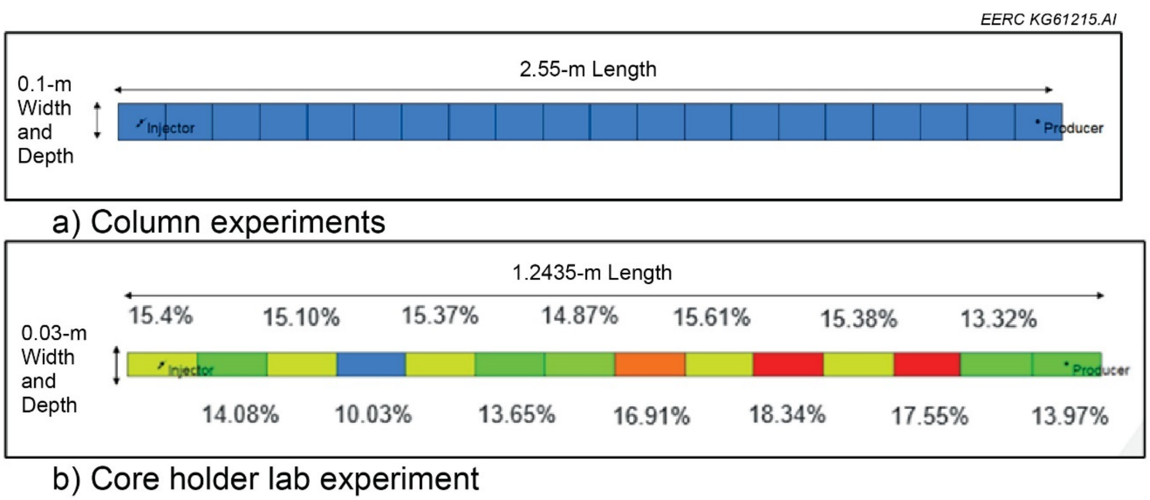

Figure C-1. Laboratory-scale numerical model.

The properties of each column test differed from each other, including the variables such as injection pressure and flow rate. The two column tests (i.e., sand and outcrop columns) were created with homogeneous properties such as permeability, saturation, salinity, and porosity. The core column model was homogeneous in permeability, saturation, and salinity, but had heterogeneous properties for porosity. Other parameters included in the laboratory-scale numerical model were the native Inyan Kara synthetic water composition and the water chemistry for the injected Bakken produced water, including the ions/cations and total dissolved solids (TDS) concentration.

The data input for each GEM model were evaluated against the results of the laboratory reports for accuracy and precision. Also, to accurately create the laboratory-scale simulation model and make comparisons with the data from the laboratory column tests, the geochemical modeling from the GEM simulator was used. The data needed for the geochemical model and chemistry reactions were water chemistry data for the injected Bakken produced water and for the native Inyan Kara Formation water, as well as the mineralogy information from the Inyan Kara Formation (rock) material. The molarity from each of the aqueous components of the brines from the water samples were calculated, and these data were used to feed the laboratory-scale numerical model to simulate the water salinity for the brines.

Once all the necessary parameters were collected from the laboratory tests, historical injection rates, maximum bottomhole pressure (BHP), and well injection and production constraints were included in the numerical model. The laboratory data included the average injection pressure and produced (outlet) sample volumes over time. The injection pressure was not violated during the simulation and was only used to ensure that pressures did not exceed the average injection pressure.

After the laboratory-scale models were created and populated with column test data, the simulation was run for the same duration as the laboratory tests to evaluate how the TDS measurements changed over time. The simulated values were compared against the laboratory results, which evaluated how the produced fluid's TDS changed over time.

Calibration of numerical model parameters is done to address differences between simulated and laboratory TDS values. The model parameters adjusted depend on a variety of factors, including the permeability and porosity values for the laboratory columns, but primarily to account for changes in the injection rates due to multiple maintenance periods during the column tests. Each of these adjustable parameters was analyzed for their validity and accuracy and evaluated during the simulation until an appropriate match in TDS values was found.

The laboratory-scale numerical models need to be history-matched and calibrated with data from the laboratory tests to accurately represent the dynamics of the different scenarios and processes.

Laboratory-Scale Model Simulation Results

Sand Column Test

The CMG laboratory sand column model was created to match all the physical and chemistry properties and operational conditions under which the sand column test was conducted in the laboratory. The model had length, width, and depth dimensions of 2.55, 0.1, and 0.1 meters, respectively. The water saturation, porosity, and permeability of the samples were set at 100%, 32%, and 6473 mD, respectively.

The production rates from the laboratory experiment as a function of time were included in the numerical model. The rates were relatively steady state, and modeling in CMG was performed with just a few variations in the model for a better match with the laboratory data. Figure C-2 shows the production and injection rates for the sand column test model. Tables C-1 and C-2

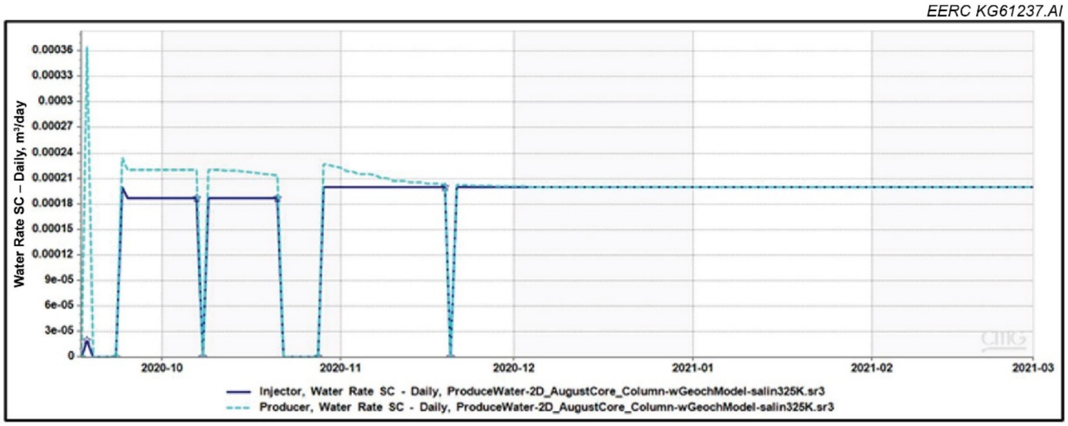

Figure C-2. Sand column injection and production rates in cubic meters per day.

Table C-1. Initial Inyan Kara Water Salinity for the Aqueous Components Used in the Numerical Model

Component	mg/L
Bicarbonate	0
Calcium	283
Chloride	6668
Hydrogen	1.7e-4
Hydroxide	1.0e-3
Magnesium	15
Potassium	120
Sodium	4004
Sulfate	283
Density, g/mL	**1.0**
TDS, mg/L	**11,400**

summarize the laboratory results of the Inyan Kara initial water salinity and the results from the injected Bakken produced water salinity, respectively. The results of the simulation were compared to the laboratory-measured values to determine overall accuracy (Table C-3, Figure C-3).

Table C-2. Water Chemistry for the Injection Bakken Produced Water Used in the Numerical Model

Component	mg/L
Bicarbonate	109
Bromide	966
Calcium	21,220
Chloride	195,256
Hydrogen	2e-3
Hydroxide	7e-5
Magnesium	1138
Potassium	9696
Sodium	93,540
Strontium	1808
Sulfate	209
Density, g/mL	**1.20**
TDS, mg/L	**325,000**

Table C-3. TDS from the Column-Scale Numerical Model Values Versus Laboratory TDS Values

Date	Laboratory, mg/L	Simulated, mg/L	% Error
October 1, 2020	11,800	10,305	12.7
October 20, 2020	83,500	59,907	28.2
November 6, 2020	173,000	176,069	1.8
December 6, 2020	308,000	307,177	0.3
December 16, 2020	316,000	308,504	2.4

The injected Bakken produced water pH was evaluated in the numerical model to track the changing pH as the produced water migrated through the sand column. The initial pH value for the injected Bakken produced water was around of 6.78, while the native Inyan Kara water had a pH value of 5.66. Figure C-4 shows the graphical representation from the simulation results of how the pH through the column changed as a function of time.

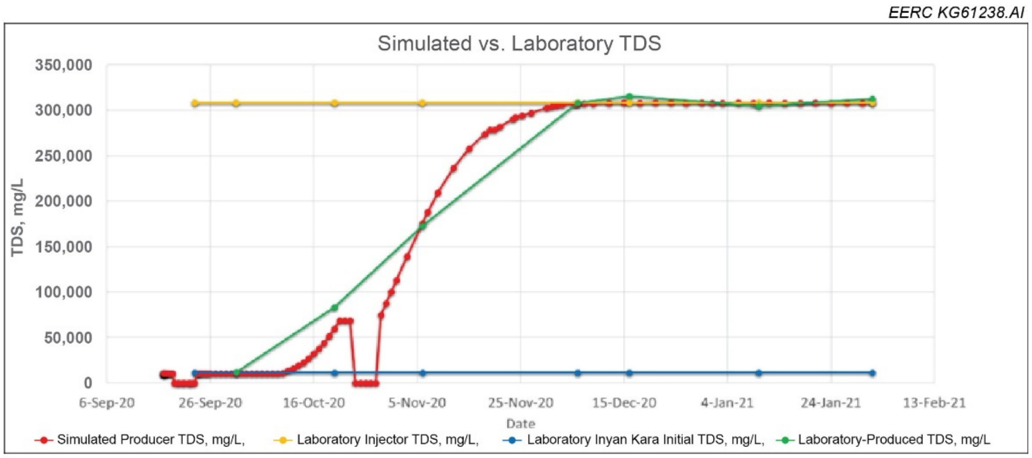

Figure C-3. Simulation results for the produced (outlet) TDS (red line) versus laboratory values (green line). Initial TDS for Inyan Kara water from the laboratory is in blue, and the injected Bakken produced water concentration is in yellow.

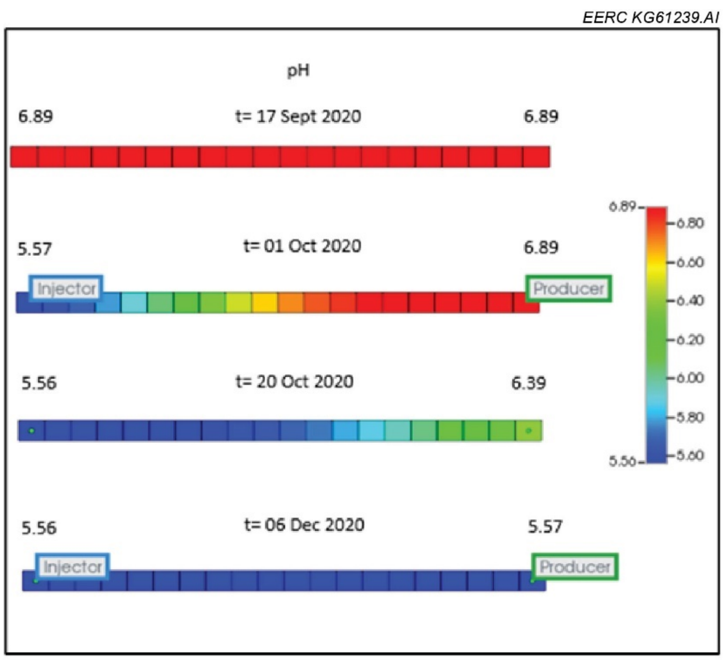

Figure C-4. Graphical representation of the column and the variation in pH as a function of time for the laboratory-scale numerical model.

Simulation results for the salinity predominantly comprised sodium and chloride ions. The sodium ion comprised an average of 29% of the total aqueous solution, and the chloride ion comprised an average of 60% of the total aqueous solution. Together these ions comprised an average of 90% of the total TDS. Figures C-5–C-7 show the simulation results versus laboratory results for sodium, chloride, and sulfate ions, respectively.

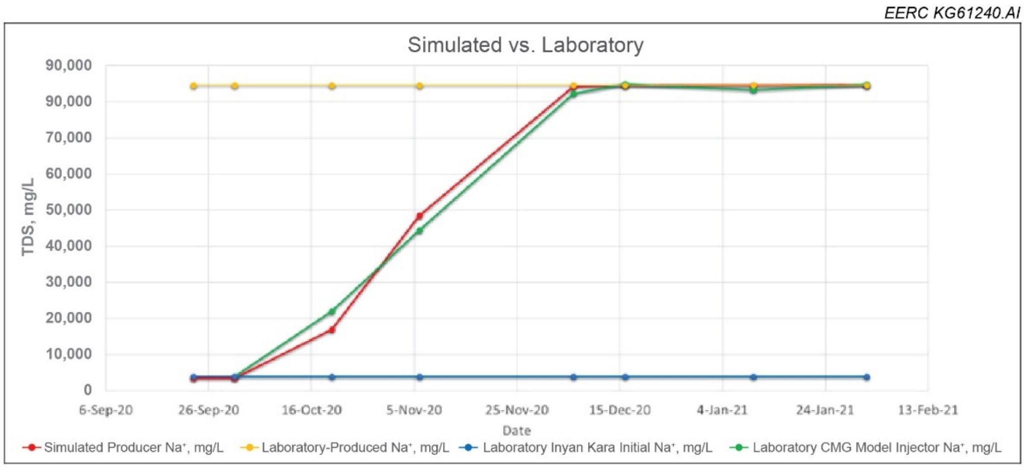

Figure C-5. Simulation results for produced sodium ion values (red line) versus laboratory values (green values). Initial TDS for Inyan Kara water from the laboratory is in blue, and the injected Bakken produced water concentration is in yellow.

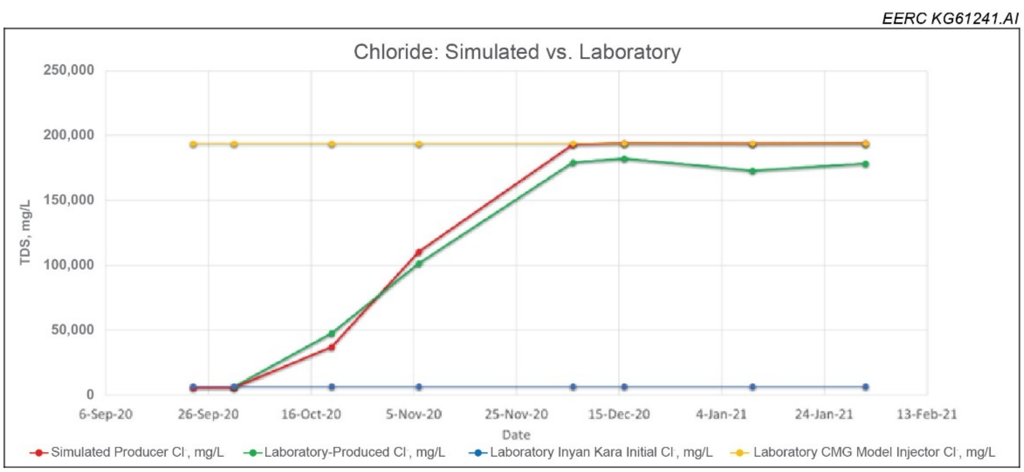

Figure C-6. Simulation results for produced chloride ion values (red line) versus laboratory values (green values). Initial TDS for Inyan Kara water from the laboratory is in blue, and the injected Bakken produced water concentration is in yellow.

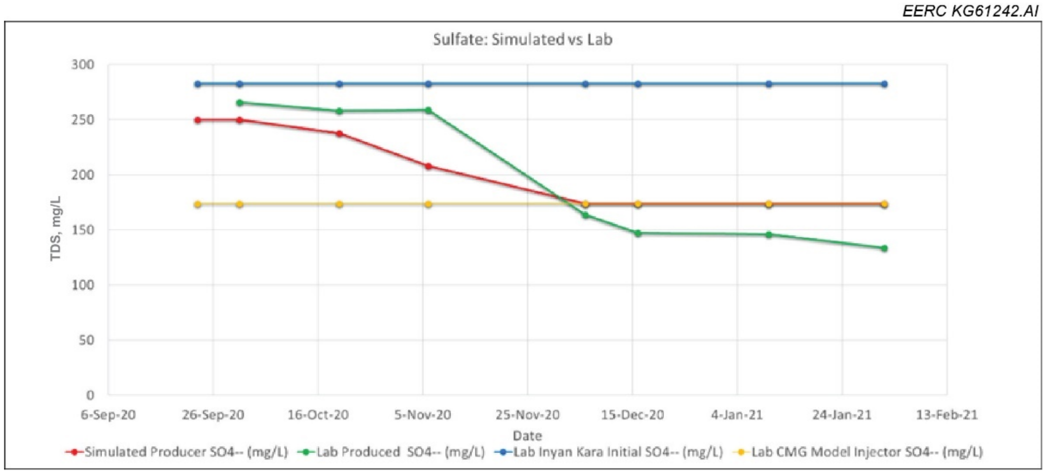

Figure C-7. Simulation results for produced sulfate ion values (red line) versus laboratory values (green values). Initial TDS for Inyan Kara water from the lab is in blue, and the injected Bakken produced water concentration is in yellow.

Outcrop Column Test

A laboratory-scale numerical model with data from the outcrop column test was constructed in CMG GEM v2020.1 to calibrate and match with the experiment data. All the data needed to build the model was provided from the outcrop column test, and the test was conducted similarly to the sand column test, but the test differed in the initial Inyan Kara salinity was 10,600 mg/L, and the sand was from Inyan Kara Formation outcrop material. Figure C-8 shows the laboratory-scale model constructed in CMG with column dimensions of 2.55 meters in length, 0.1 meters width, and 0.1 meters in depth. The water saturation, porosity, and permeability of the samples were set at 100%, 35%, and 36 millidarcy respectively.

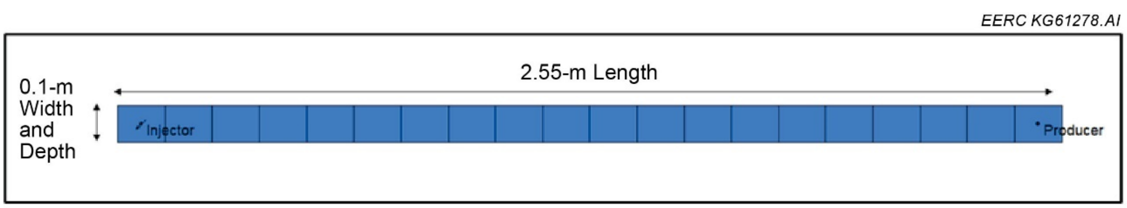

Figure C 8. Laboratory-scale numerical model for the second column experiment.

Injection rates were not easily measured in the laboratory; consequently, the production rates as a function of time for the outcrop column numerical model was input after performing interpolations on the injection rates. The model was created using this method because it provided the most efficient calibration control to achieve better salinity results. The historical production log did provide room for rate adjustments due to system clogging, pump leaks, and downtime during the duration of the column test. The data used in the numerical model were verified beforehand for any modeled injection rates that deviated from the historical log, such as rates during maintenance downtime or documented leaks. Figure C-9 shows the injection and production rates for the numerical mode. Tables C-4 and C-5 correspond to the column test data for the Inyan Kara water salinity and the injected Bakken produced water salinity used during the numerical simulation.

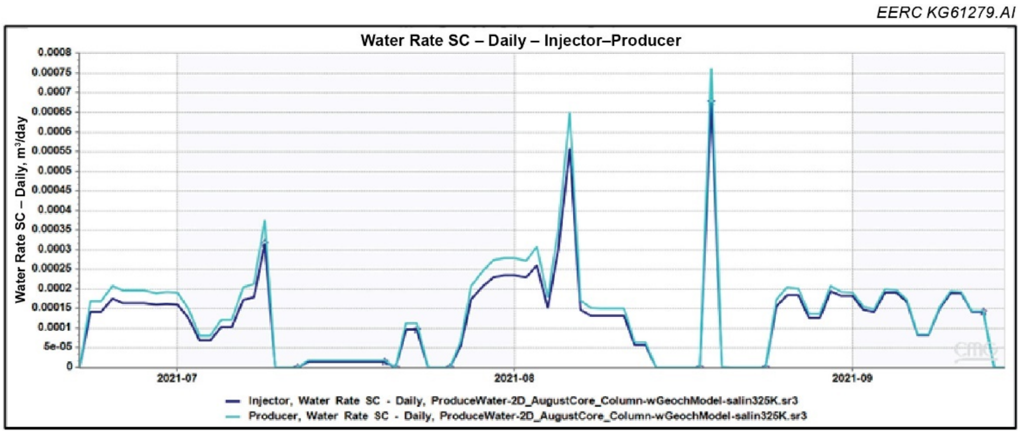

Figure C-9. Injection and production rates for the numerical model.

Table C-4. Initial Inyan Kara Water Salinity in Anions/Cations Components Used in the Numerical Model

Initial Water Inyan Kara	
Component	**mg/L**
Bicarbonate	77
Calcium	279
Chloride	6033
Hydrogen	3e-5
Hydroxide	4e-3
Magnesium	26
Potassium	105
Sodium	3861
Strontium	16
Sulfate	268
Density, g/mL	**1.0**
TDS, mg/L	**10,600**

Table C-5. Injected Bakken Produced Water Salinity in Anions/Cations Components Used in the Numerical Model

	Injected Water
Component	**mg/L**
Bicarbonate	52
Bromide	1073
Calcium	22,679
Chloride	212,886
Hydrogen	4e-3
Hydroxide	3e-5
Magnesium	1339
Potassium	7580
Sodium	90,215
Strontium	1717
Sulfate	185
Density, g/mL	**1.20**
TDS, mg/L	**337,675**

The simulated total dissolved solids (TDS) values were compared against the laboratory values to determine overall accuracy. Table C-6 shows the results from the laboratory and the results from the simulation. Figure C-10 shows the TDS results from the duration of the simulation compared with the laboratory TDS values.

Table C-6. TDS Values Versus Laboratory Values

Date	Laboratory, mg/L	Simulated, mg/L	% Error
July 9, 2021	12,019	10,742	10.6
August 1, 2021	12,956	14,286	10.3
August 13, 2021	98,245	96,792	1.5
August 25, 2021	140,622	150,148	6.8
August 26, 2021	177,074	160,463	9.4
September 6, 2021	307,501	268,849	12.6
September 13, 2021	315,217	299,339	5.0

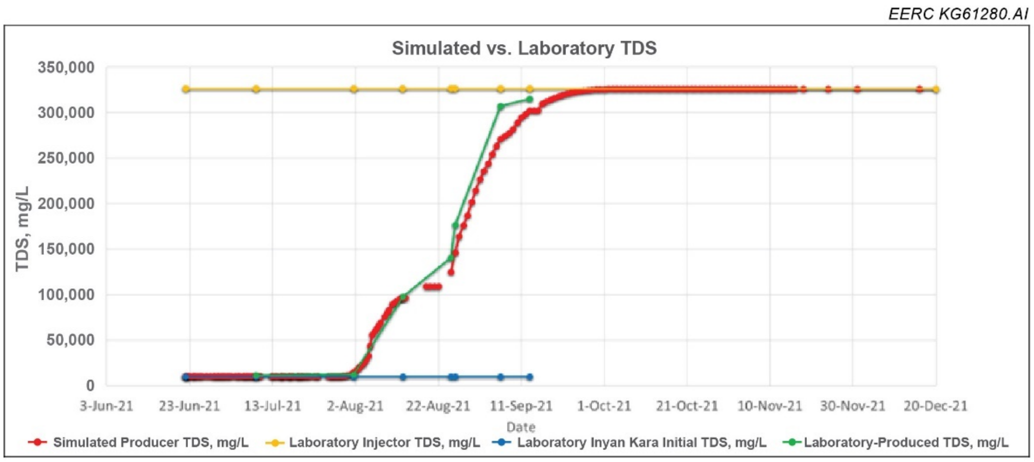

Figure C-10. TDS values from numerical simulation (red line) versus laboratory values (green line). Yellow straight line corresponds to the injected Bakken produced water, and the blue line corresponds to the native Inyan Kara water.

Some issues encountered with the laboratory pumping system included some clogging and maintenance. The laboratory injection rate for the sample was not recorded during this period of time and, therefore, was estimated from the sample results. The injection rate estimates were calculated from pressure differences, pumping efficiency, and TDS result comparisons.

The pH of the injected water had a value of 5.34, while the Inyan Kara native water had a pH value of 7.46. Figures C-11 and C-12 show the graphical representation and the graph of the changes in the pH through the column as a function of time, respectively. At time t = 0, the column is completely saturated with the Inyan Kara native water, and the pH is changing as a function of the injection time until the column is 100% saturated by the injection water.

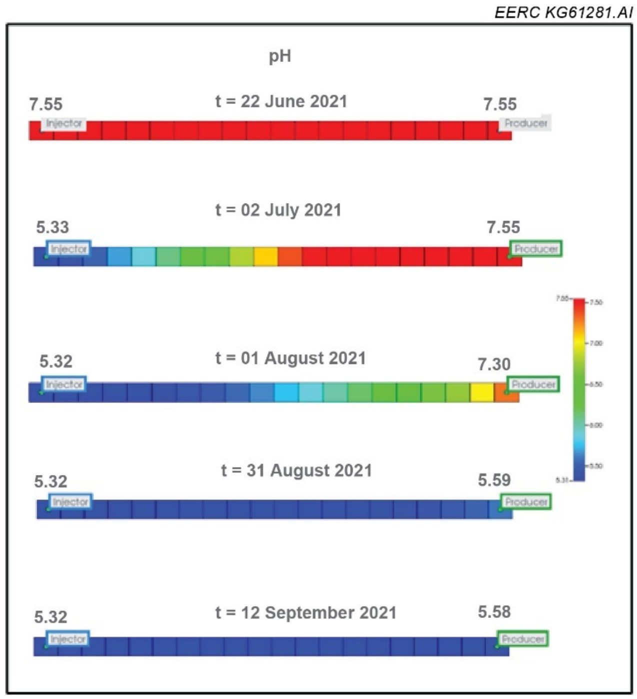

Figure C-11. Graphical representation of the column showing the changes in pH values at different time periods.

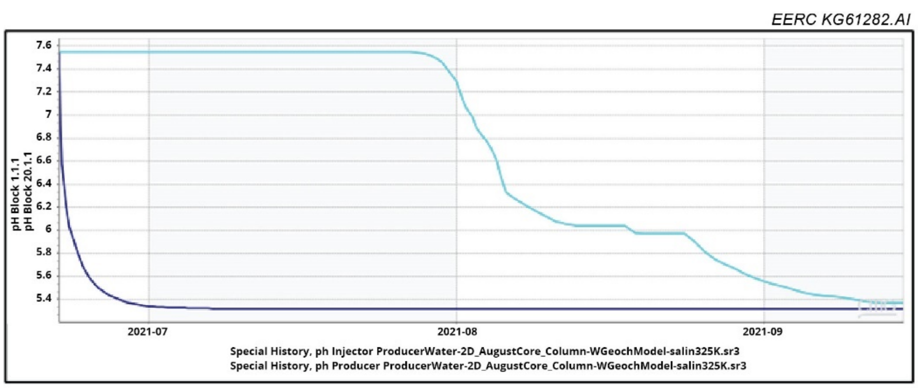

Figure C-12. pH values in function of time for the laboratory-scale numerical simulation.

The two water components that predominantly composed the salinity were sodium and chloride ions. The sodium ion composed an average of 28% of the total aqueous solution. The chloride ion composed an average of 58% of the total aqueous solution. Together these ions were responsible for an average of 86% of total TDS. Figures C-13, C-14, and C-15 show the simulation results versus the results from the laboratory of the sodium, chloride, and sulfate ions, respectively.

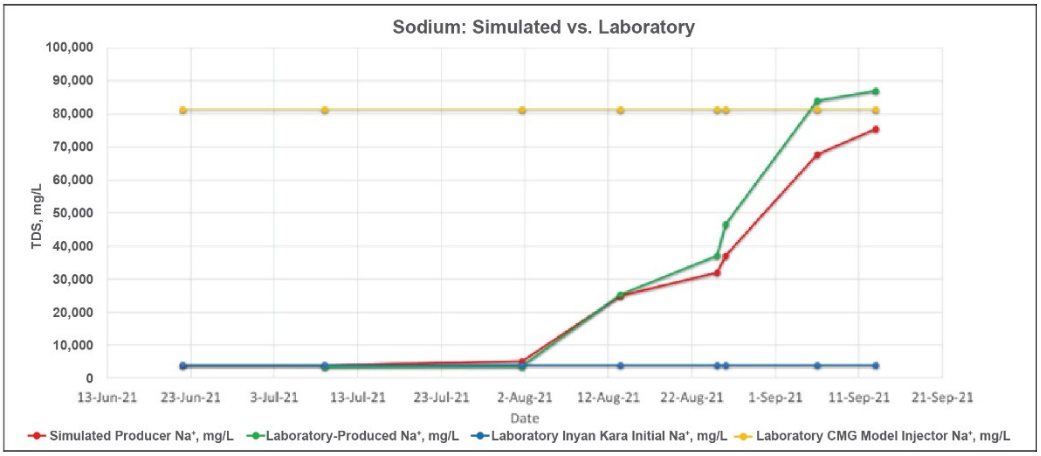

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Figure C-13. Simulation results for sodium vs. laboratory value.

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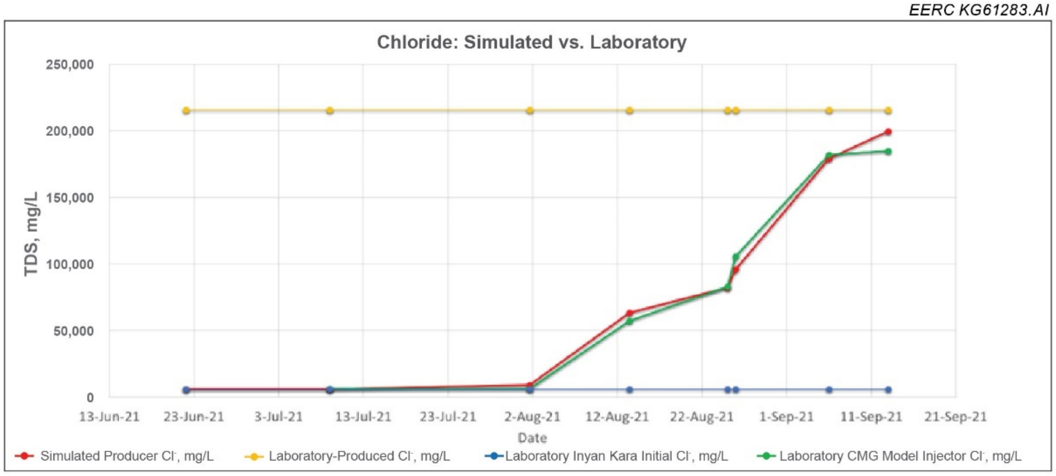

Figure C-14. Simulation results for chloride vs. laboratory value.

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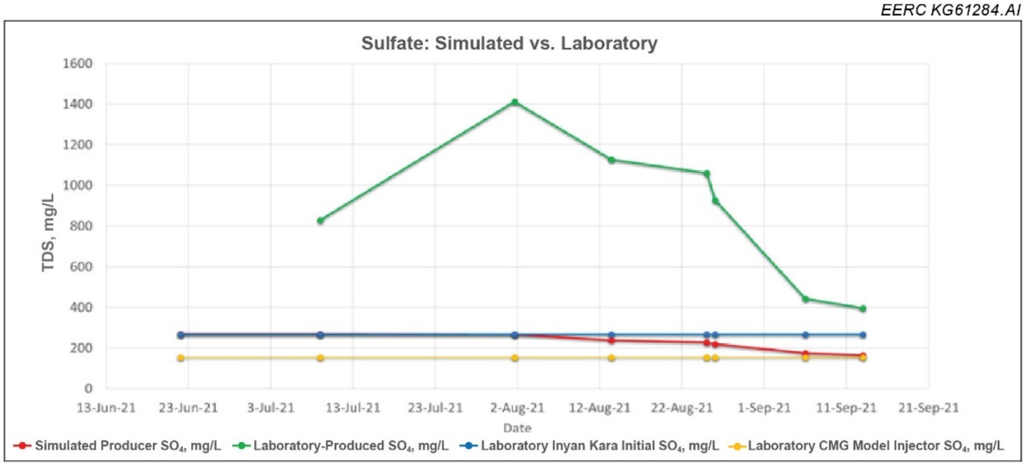

Figure C-15. Simulation results (red line) for sulfate vs. laboratory value (green line).

The ions sodium and chloride from simulation are showing a very good match with the laboratory data. The sulfate concentration from the laboratory seems higher than the value from simulation and from the concentration for the native Inyan Kara water and water injection. This can be attributed to some crystal precipitation from the interaction between the rock and the water in the column experiment.

Core Column Test

The core column test numerical model was created and run using CMG GEM 2020.1. The laboratory-scale model was built based on data provided during the laboratory core column test, as described in the Section 3.0. Some of the parameters included in the model and provided from the laboratory are porosity values and length per core for each core used in the experiment. These parameters varied and were modeled during the laboratory simulation as accurately as possible. The water saturation and permeability of the core samples were provided from the laboratory data and set at 100% and 1.75 mD, respectively, into the numerical model.

The duration of the core column test was approximately 2 months and was represented in the model. To achieve a better match, some experimental conditions and issues could not be represented in the numerical model. For example, some issues were encountered during the laboratory experiment with crystallization within the pump tube that could not accurately be modeled in CMG because of the unknown injection salinity.

The numerical model was set up with length, width, and depth dimensions of 1.2435, 0.03, and 0.03 meters, respectively. Figure C-16 shows the numerical model dimensions and porosity across each grid section.

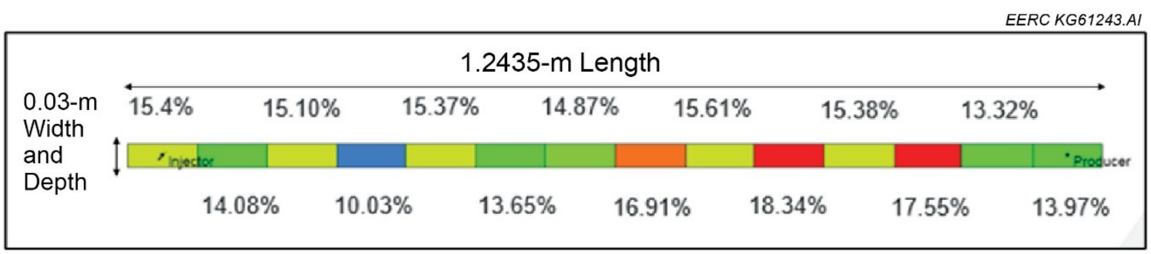

Figure C-16. Laboratory-scale numerical model representing the core holder experiment. The figure shows the dimensions for the model and percent porosity in each of the core segments.

The laboratory data provided from the core column test include the production rates as a function of time for the core sample. The production rates were interpolated as injection rates and then input in the model as injection rate constraints as a more efficient approach when adjusting the system inputs to match laboratory TDS values (Figure C-17).

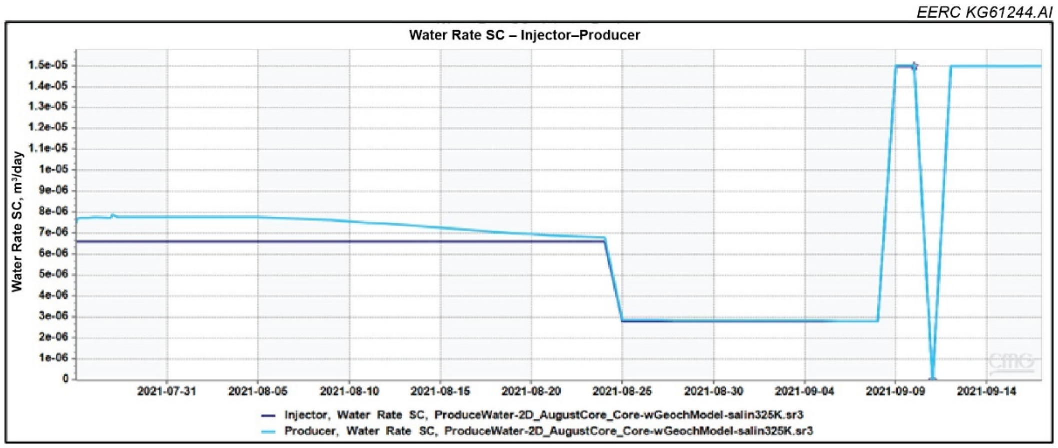

Figure C-17. Core column injection rate (dark blue) and production rate (light blue).

The water salinity concentration and ion/cations composition used during the laboratory experiment for the native Inyan Kara Formation and for the Bakken produced water injected during the test are shown in Table C-7 and C-8, respectively. This information was included in the model as aqueous fraction in molality to evaluate the interactions between water and rock using the geochemical modeling in CMG.

Table C-7. Synthetic Water Chemistry Composition for the Native Inyan Kara Formation Water

Component	mg/L
Calcium	279
Carbonate	77
Chloride	6033
Hydrogen	3e-5
Hydroxide	4e-3
Magnesium	26
Potassium	105
Sodium	3861
Sulfate	268
Strontium	16
Density, g/mL	**1.0**
TDS, mg/L	**10,600**

Table C-8. Water Chemistry for the Injected Bakken Produced Water Used During the Laboratory Experiment

Component	mg/L
Bicarbonate	52
Bromide	1073
Calcium	22,679
Chloride	212,886
Hydrogen	4e-3
Hydroxide	3e-5
Magnesium	1339
Potassium	7580
Sodium	90,215
Strontium	1717
Sulfate	185
Density, g/mL	**1.20**
TDS, mg/L	**337,675**

The TDS values calculated from the numerical simulation were compared to the values for the samples collected during the laboratory column test. Table C-9 shows the results from the column test, and the results from the simulation are shown in Figure C-18. Figure C-18 shows the TDS values during the duration of the simulation compared with the column test values in order to view the produced salinity changes as a function of time.

Simulation results show the water breakthrough occurred around September 10, with a constant water salinity value around 304,000 mg/L. Because of issues during the setup of the experiment, only two data points from the samples collected in the experiment were included for comparison.

Table C-9. TDS Results and Comparison of Two Different Water Samples with the Values from the Numerical Simulation

Date	Laboratory, mg/L	Simulated, mg/L	% Error
August 6, 2021	25,598	22,979	10.2
September 17, 2021	294,786	308,392	4.6

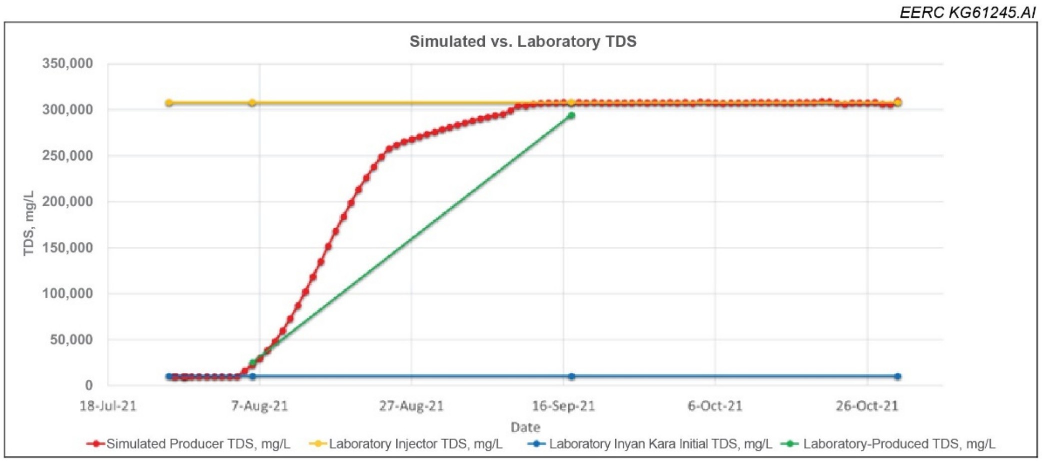

Figure C-18. TDS values for the numerical simulation (red line) compared with the values obtained from samples collected during the laboratory column test (green line).

In general, the simulation results have shown that the laboratory-scale simulation model provides a good match with the laboratory data despite some difficulties during the setup of the column test, which cannot be represented in the numerical model. The laboratory-scale numerical modeling results demonstrate that the simulation may be used in conjunction with laboratory column tests to better represent and understand the different mechanisms that may occur during a particular process.

As in the previous column experiment, the pH for the core holder was also recorded from the simulation model results. The pH of the injected water was at a value of 5.34, while the native Inyan Kara water had a pH value of 7.46. Figures C-19 and C-20 show the graphical representation and the graph, respectively, for the simulation results of how the pH through the core changed as a function of time.

The core column test is initially completely saturated with the Inyan Kara water. During the injection, Figure C-19 shows how the pH changes throughout the column until it gets saturated with the injected Bakken produced water to a pH of 5.57, which is very close to the original injected water pH.

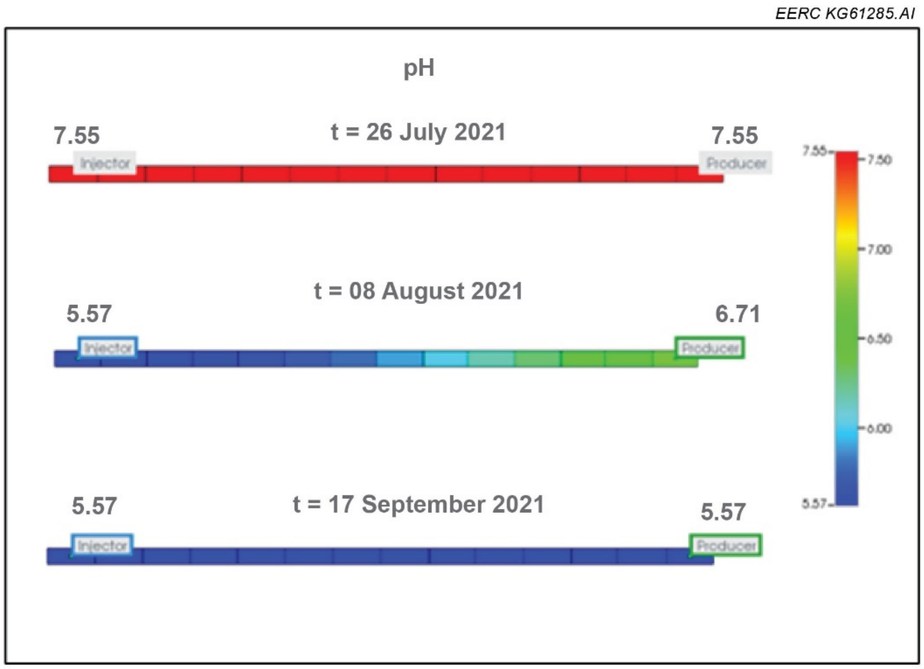

Figure C-19. Graphical representation from the simulation showing the changes in the pH value at different times.

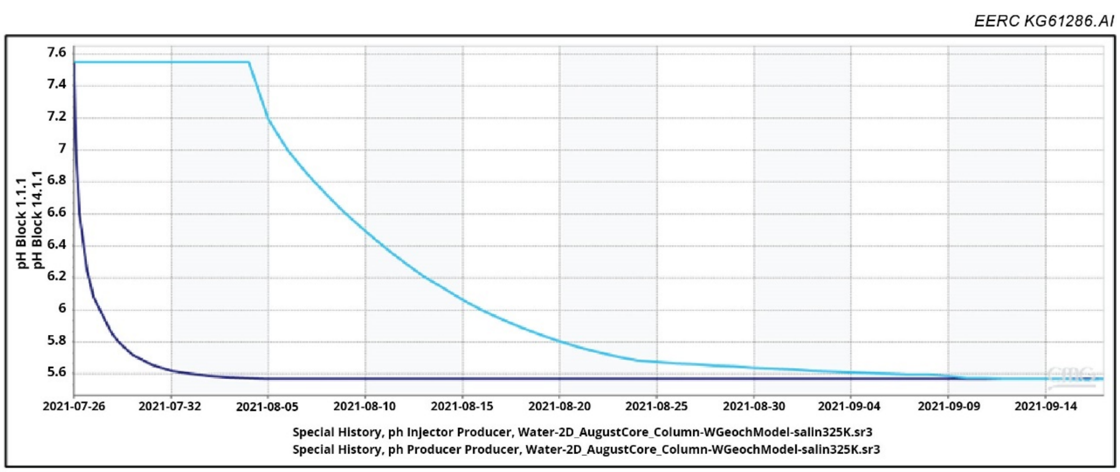

Figure C-20. Simulation results for pH as function of time for the injection and production waters.

Similarly, to the previous experiments, the two components that predominantly composed most of the salinity were sodium and chloride ions. The sodium ion composed an average of 29% of the total aqueous solution for each laboratory evaluation. The chloride ion composed an average of 59% of the total aqueous solution for each laboratory evaluation. Together these ions were responsible for an average of over 87% of total TDS. Figures C-21 to C-23 show the results of the simulated sodium concentration, chloride, and sulfate ions over time as compared to laboratory values.

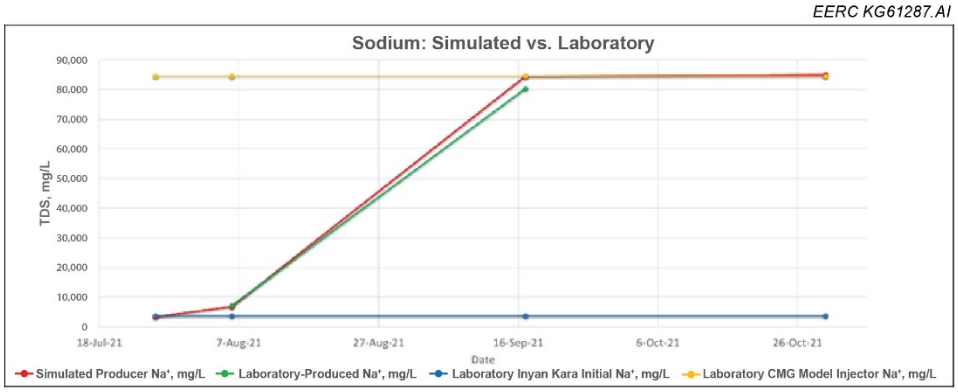

Figure C-21. Simulation results for sodium (red line) vs. laboratory values (green line).

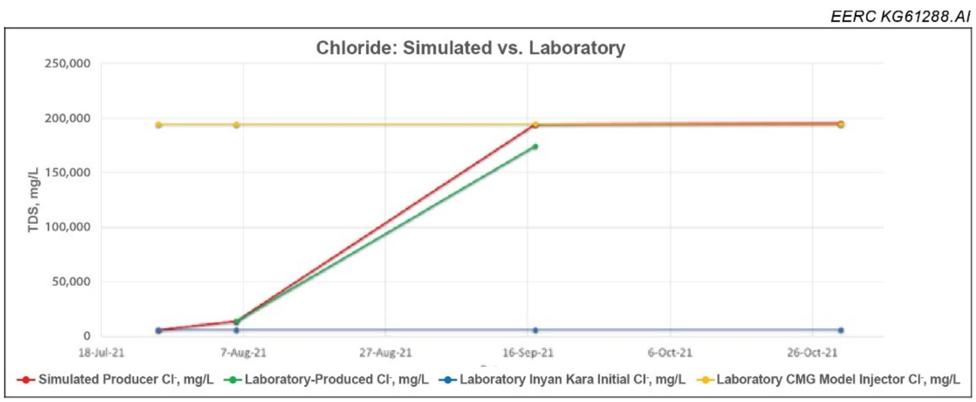

Figure C-22. Simulation results for chloride (red line) vs. laboratory values (green line).

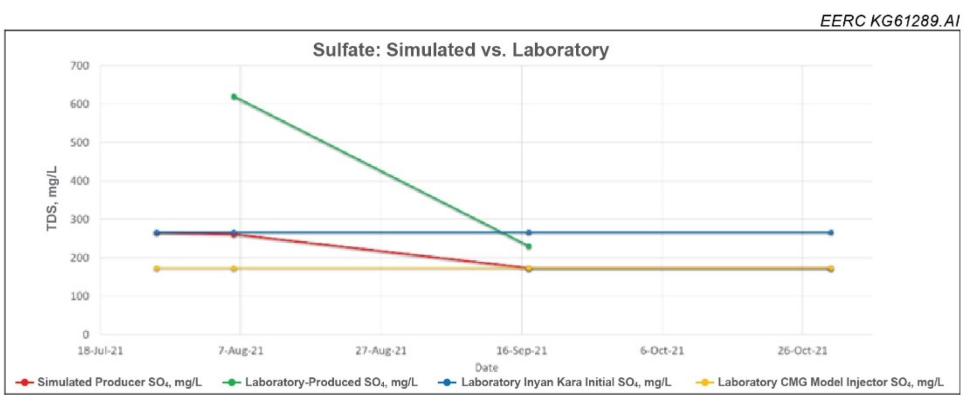

Figure C-23. Simulation results for sulfate (red line) vs. laboratory values (green line).

The simulation results showed that the results obtained from the lab-scale numerical model match well with the values from the laboratory experiments. In some cases, the simulation was able to reach closer values for the injection water salinity than the values from the laboratory experiment. The change in ions/cations were compared for all three lab experiments to determine how quickly the breakthrough occurs for each laboratory experiment. Figures C-24 to Figure C-26 show the change in sodium, chloride, and sulfate ions as a function of time for the three laboratory experiments for comparisons and to understand the variations for these ions with the differences between the experiments.

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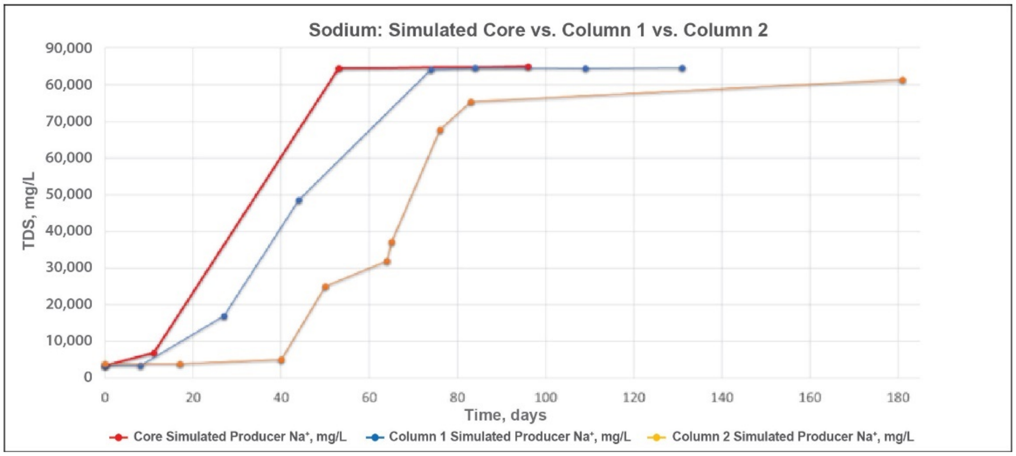

Figures C-24. Simulation results for the three lab experiments for sodium, first column with Berea rock (blue line), second column with Inyan Kara rock (yellow line) and core holder using Inyan Kara composite cores (red line).

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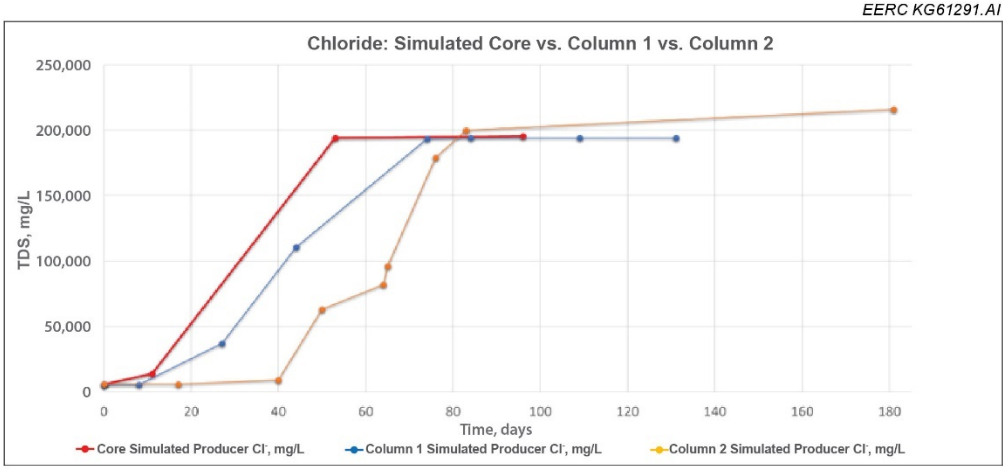
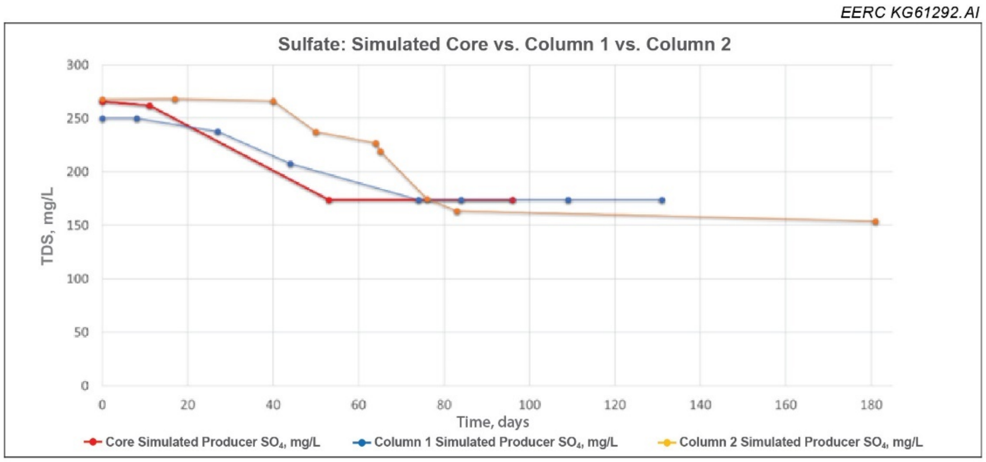


Figures C-25. Simulation results for the three lab experiments for chloride, first column with Berea rock (blue line), second column with Inyan Kara rock (yellow line) and core holder using Inyan Kara composite cores (red line).



Figures C-26. Simulation results for the three lab experiments for sulfate, first column with Berea rock (blue line), second column with Inyan Kara rock (yellow line) and core holder using Inyan Kara composite cores (red line).

For sodium and chloride ions, simulation results show the breakthrough of water in the producer wells for the core holder occurred before the other two experiments, in around 55 days after injection started. The second column laboratory experiment is showing a breakthrough in about 80 days after injection started. The differences in the breakthrough time may be due to the differences in the type of rock between experiments which yield to different water mobilities and other physicochemical mechanisms between the injection water and the type of rock used for each of the experiments.

The change in moles for each of the modeled minerals was analyzed for outcrop column test and the core column test for being the ones using rock from the Inyan Kara Formation. The information for the minerals including quartz, siderite, calcite, illite, kaolinite, chlorite, albite, K-feldspar, and anhydrite were included into the lab-scale numerical model using the geochemical modeling capability in CMG GEM simulator.

Both simulation numerical models were run for 100 years at a constant injection rate for each of the experiments to evaluate any potential precipitation and dissolution effect. Figures C-27 and C-28 show the change in moles for each of the minerals included into the model based on the XRD data provided for the Inyan Kara mineral rock composition. The simulation results have shown that for a 100-year time period any changes from the initial condition may occur because of any chemical reaction for interaction between the rock and/or the brine, including precipitation and dissolution of the minerals present in the rock.

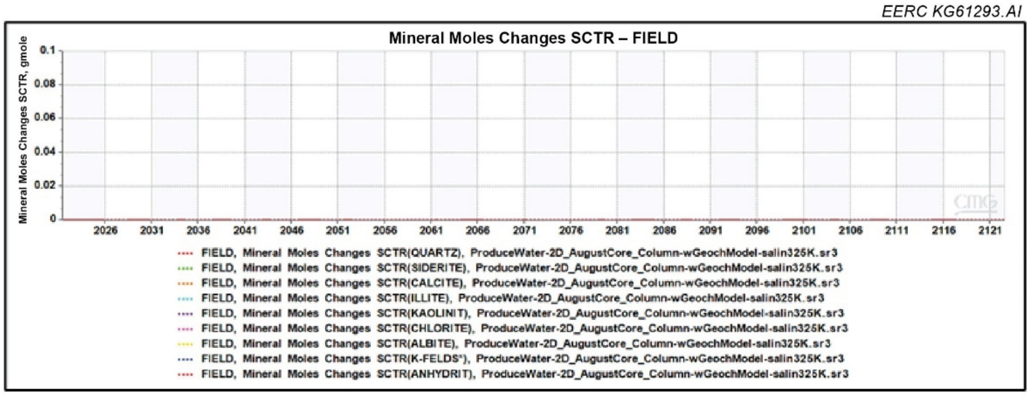


Figure C-27. Mineral mole changes for the outcrop column test.

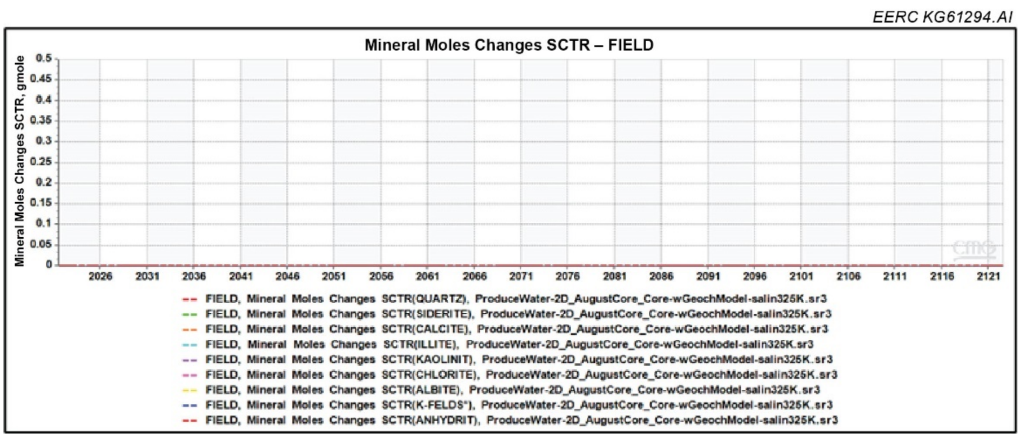


Figure C-28. Mineral mole changes for the core column test.

APPENDIX D

ADDITIONAL FIELD SIMULATION RESULTS

ADDITIONAL FIELD SIMULATION RESULTS

Some of the simulation results were shown in Section 4 of this project. In this appendix and to complete the simulation evaluation, more results are shown for the field-scale numerical model study.

Field Numerical Model

In Section 4.0, the simulation results for Scenario 1, with the current operating conditions in the field for the SWD injection wells and the BEST E1 production well, and Scenario 4, with three production wells in the area at a distance of 0.3 miles from the Rink 1 and 2 SWD (saltwater disposal) wells were presented. For all the cases, water injection salinity of 197,000 ppm is used to preserve the history match of the model. This appendix shows additional scenarios that were denoted in Table 4-1. Each numbered scenario (e.g., scenario 1, 2, 3, etc.) represents the matrix of production well distances and number of production wells, as shown in Table 4-1. Each scenario is separated into an “a” and “b” (e.g., 2a, 4a, 6b, 8b, etc.). Each “a” scenario has water injection (i.e., SWD) at normal operational volumes. The “b” scenarios are evaluating the observed changes when water injection (i.e., SWD) is reduced for the injection wells in the model area.

Scenario 2a

Two production wells were placed at a distance of 0.5 miles from the Rink 1 and 2 SWD wells (Figure D-1). The production wells are producing at a water rate of 6000 bwpd, meanwhile the BEST E1 well is producing at the same water rate from the field, 4900 bwpd.

Figure D-2 shows the water salinity for each of the wells in this scenario. There is an observed general reduction in the BEST E1 well salinity with the addition of more production wells in comparison with Scenario 1. Figure D-3 shows a reduction in the formation pressure from an initial value of 3170 psi when only the BEST E1 well is producing, to 2870 psi with the two production wells.

The simulation result shows an increase on the total water volume produced when two production wells are added in this scenario with total volumes at about 131 MMbbl (Figure D-4). Water production increases by 230% in comparison to the initial water volume produced of 39.6 MMbbl when only the BEST E1 well is producing.

Figure D-1. Field numerical model showing the location for two production wells and the distance from the wells to Rink 1 and 2 SWD wells – Scenario 2 (a and b).

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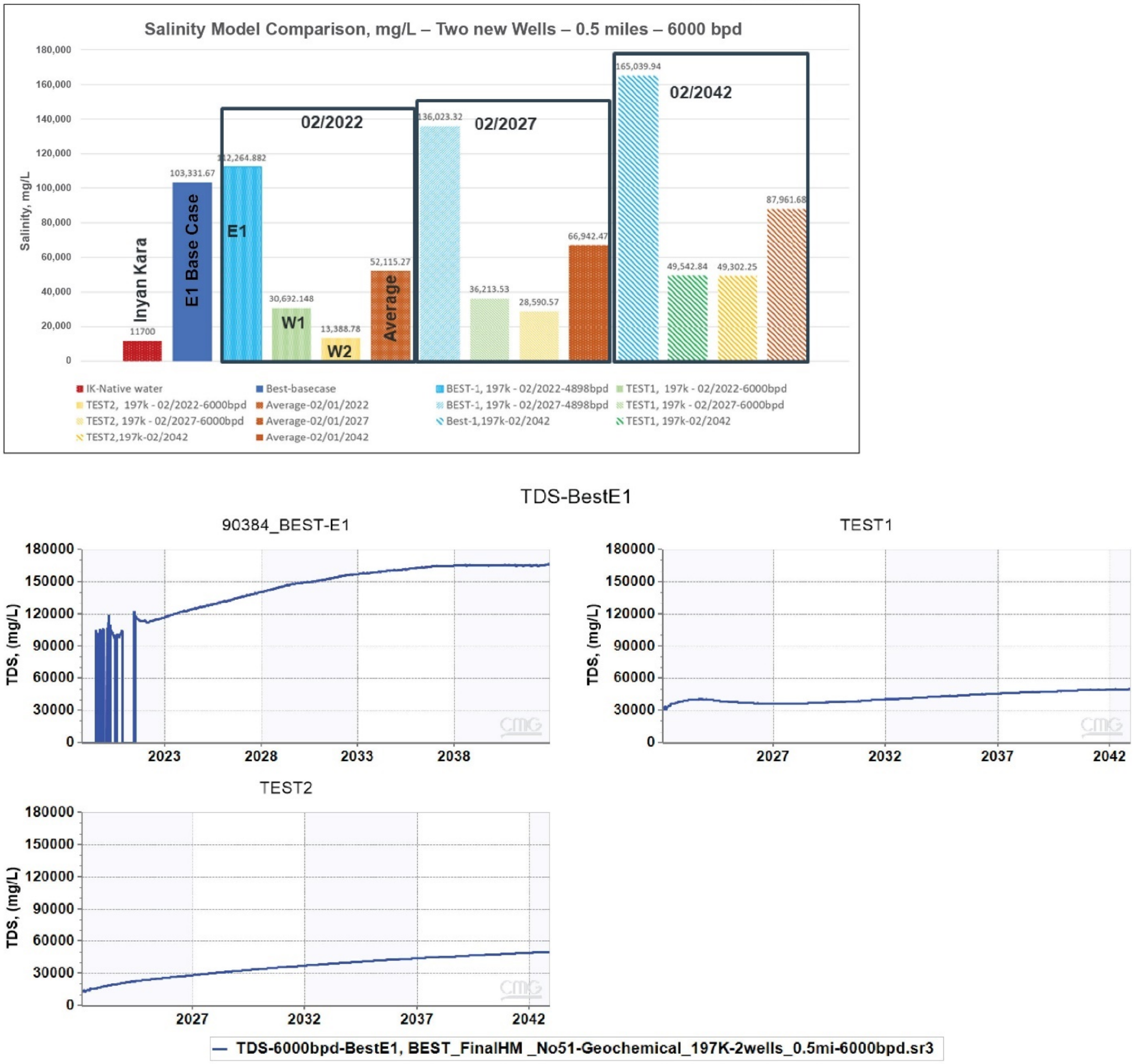


Figure D-2. Water salinity for Scenario 2a.

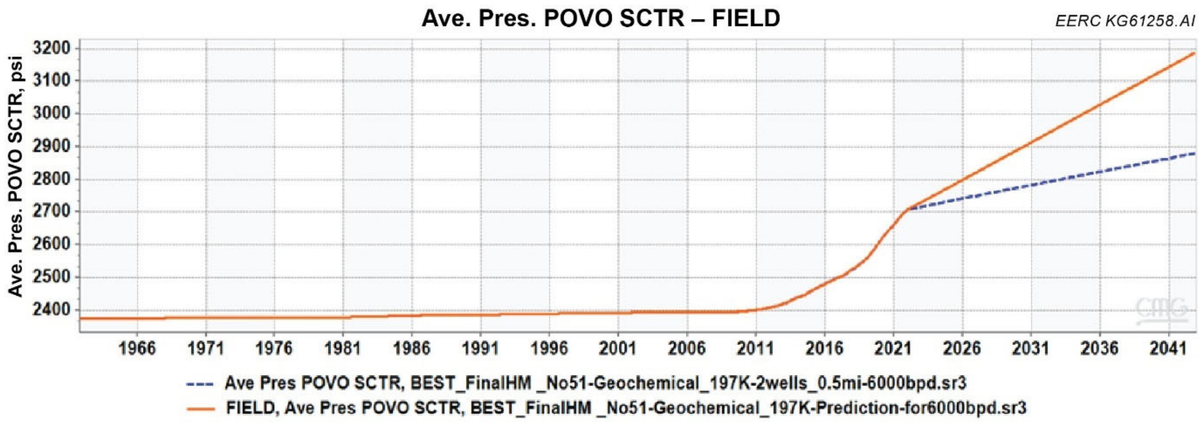


Figure D-3. Formation pressure comparison for Scenario 2a (blue line) and with only BEST E1 as the producing well (orange line).

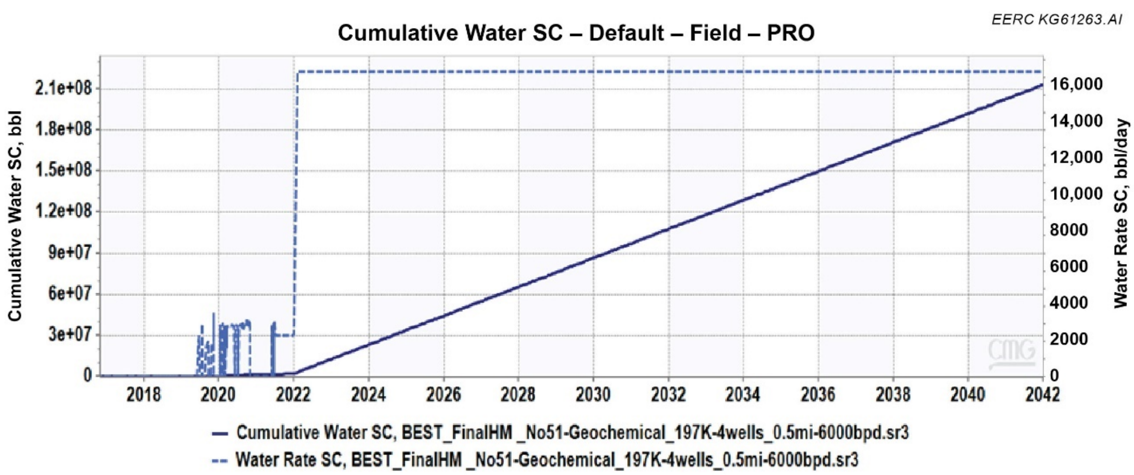


Figure D-4. Cumulative water produced and water produce rate for Scenario 2a.

Scenario 2b

Scenario 2b corresponds to the cases when two production wells are placed at a distance of 0.5 miles from the Rink 1 and 2 SWD wells (the same as Scenario 2a), and the water injection rate was decreased to 50% from the current operational conditions for the injector wells in the model (Rink SWD1 and SWD2, Well 90183, and Well 10525). The scenario also evaluated shutting in all of the injector wells in order to better understand the effect of water injection rates on water salinity, water production rate, and formation pressure.

Figures D-5 to D-8 show the simulation results for the total water injection volume, water production volume, the formation pressure, and the water salinity for the producer wells, respectively. The simulation results show a slight difference in the total water produced when the injection rate for wells in the area are reduced 50% from the current operational value. When the water injection rate is reduced, results indicate a decrease in the formation pressure and in produced water salinity.

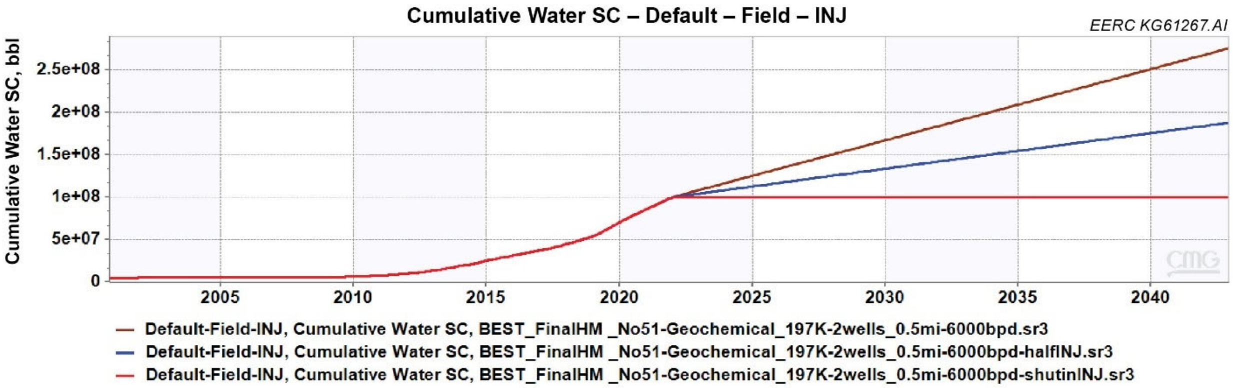


Figure D-5. Cumulative injection volume for Scenario 2b.

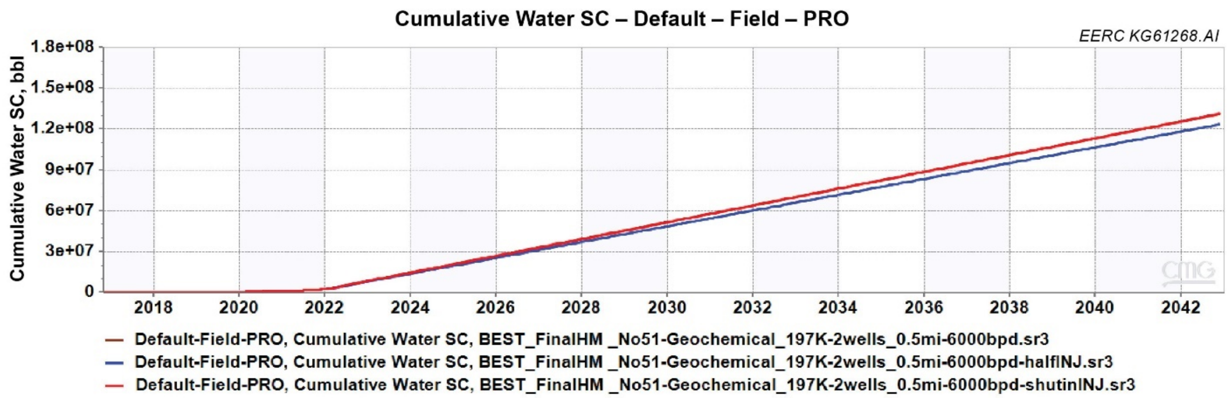


Figure D-6. Cumulative production volume for Scenario 2b.

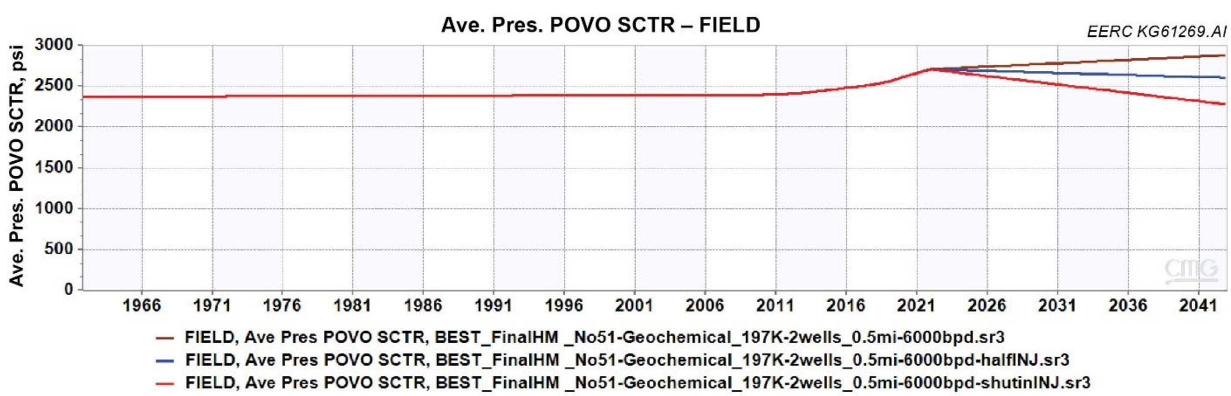


Figure D-7. Field pressure for Scenario 2b.

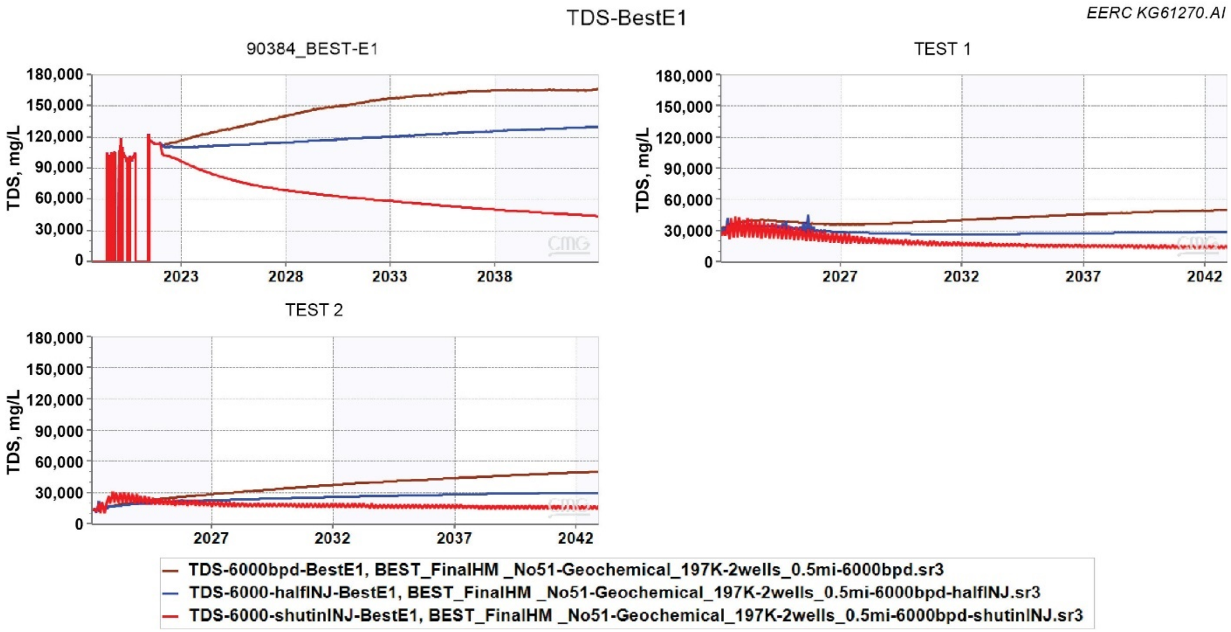


Figure D-8. Water salinity for Scenario 2b.

Scenario 3a

Scenario 3a represents two production wells placed at a distance of 1.0 mile from the Rink 1 and 2 SWD wells (Figure D-9). The production wells are producing at a water rate of 6000 bwpd, meanwhile the BEST E1 well is producing at the same water rate from the field, 4900 bwpd. Because the water injection and production rates are the same as Scenario 2a, there are no differences with respect to the total volume produced and the pressure in the formation for this scenario.

The primary difference between Scenarios 2 and 3 is represented in the variation on the water salinity values for these two cases (Figure D-10). The simulation results show salinity values similar to native Inyan Kara Formation water for the production wells. This indicates that salinity plumes for the SWD wells are not reaching the production wells for the duration of the simulation period of 20 years. Therefore, this 1.0-mile distance is likely to have minimal impact on the SWD wells in terms of reducing formation pressure.

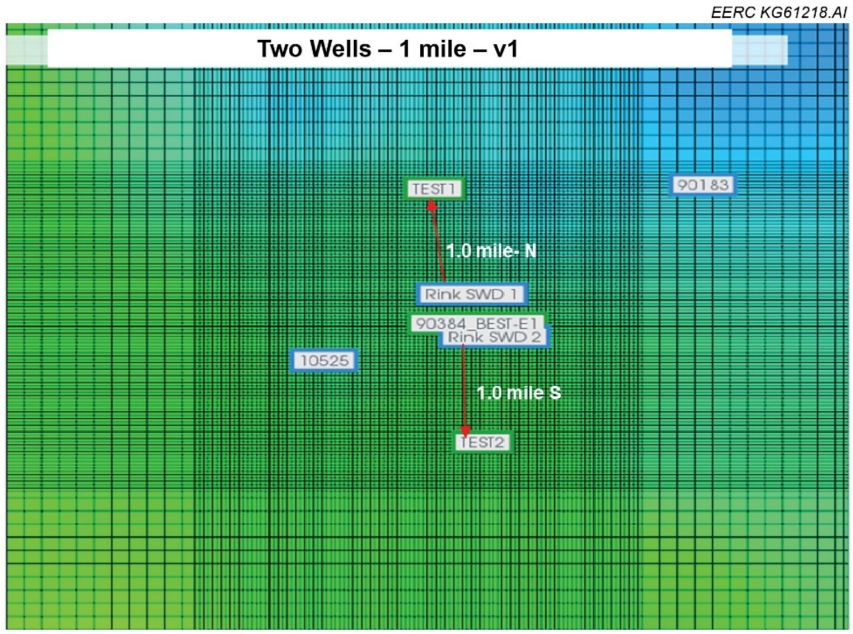


Figure D-9. Two production wells with a distance of 1.0 miles from Rink 1 and 2 SWD wells – Scenario 3.

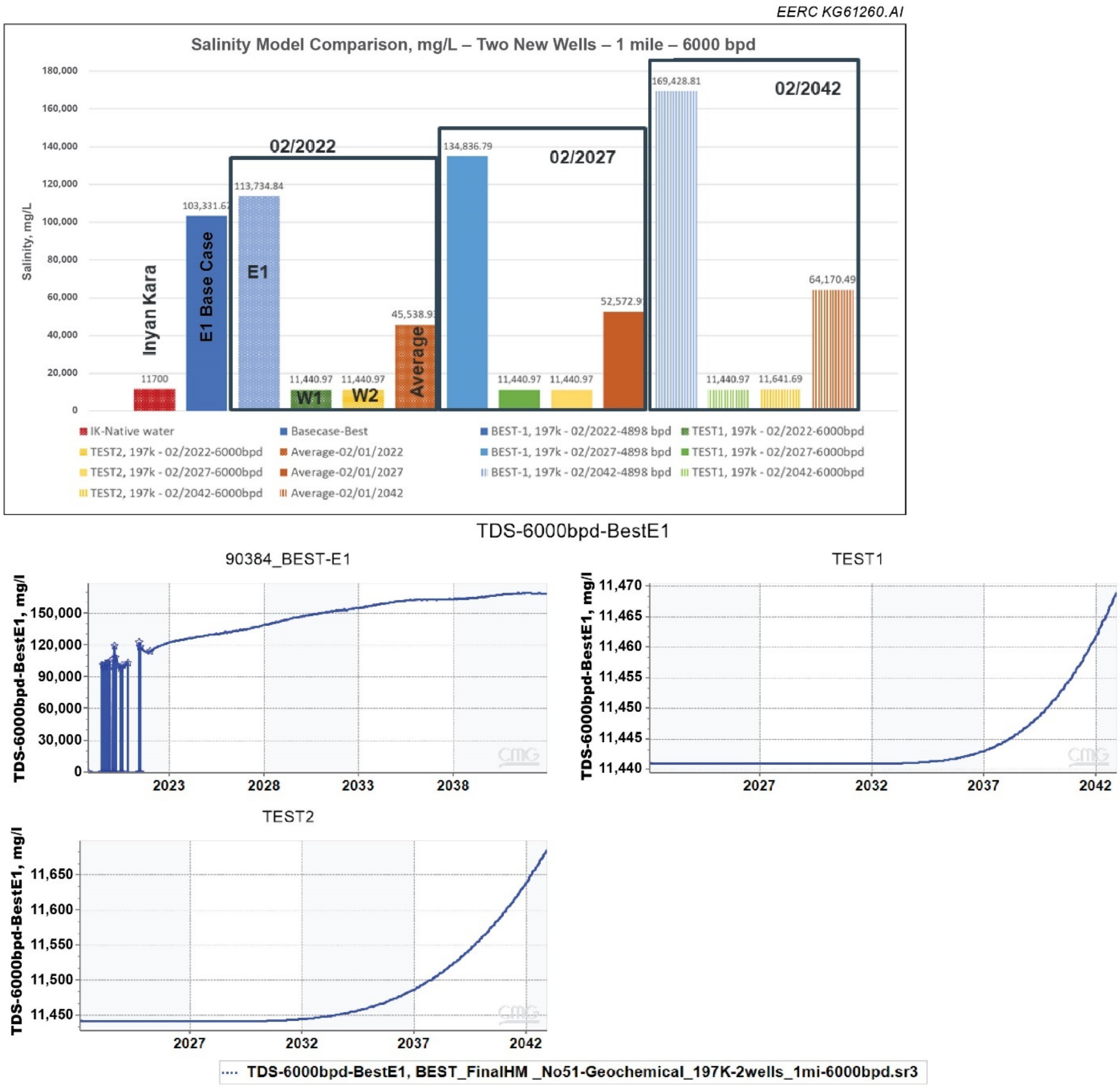


Figure D-10. Water salinity for Scenario 3a.

Scenario 5a

Scenario 5a evaluated three production wells placed at a distance of 0.5 miles from the Rink 1 and 2 SWD wells (Figure D-11). The simulation results for Scenario 5a are similar to Scenario 4a (in Section 4.0) when the production well distance was 0.3 miles from the Rink 1 and 2 SWD wells.

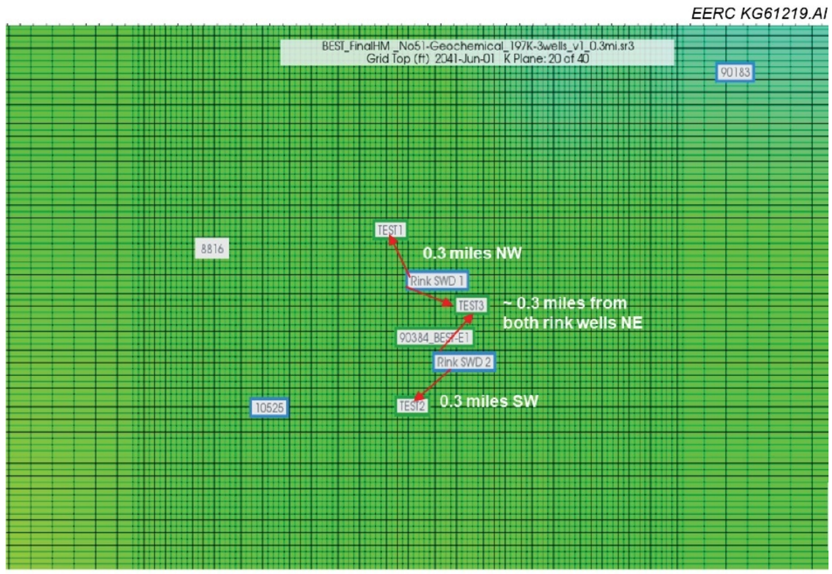


Figure D-11. Three production wells located 0.5 miles from Rink 1 and 2 SWD wells – Scenario 5.

The main difference between these two scenarios are in the water salinity concentrations, likely due to the well distance from the water injector wells, see Figure D-12. Scenario 5a's distance of 0.5 miles between the production wells and Rink SWD wells yielded a reduction in salinity values when compared to Scenario 4a.

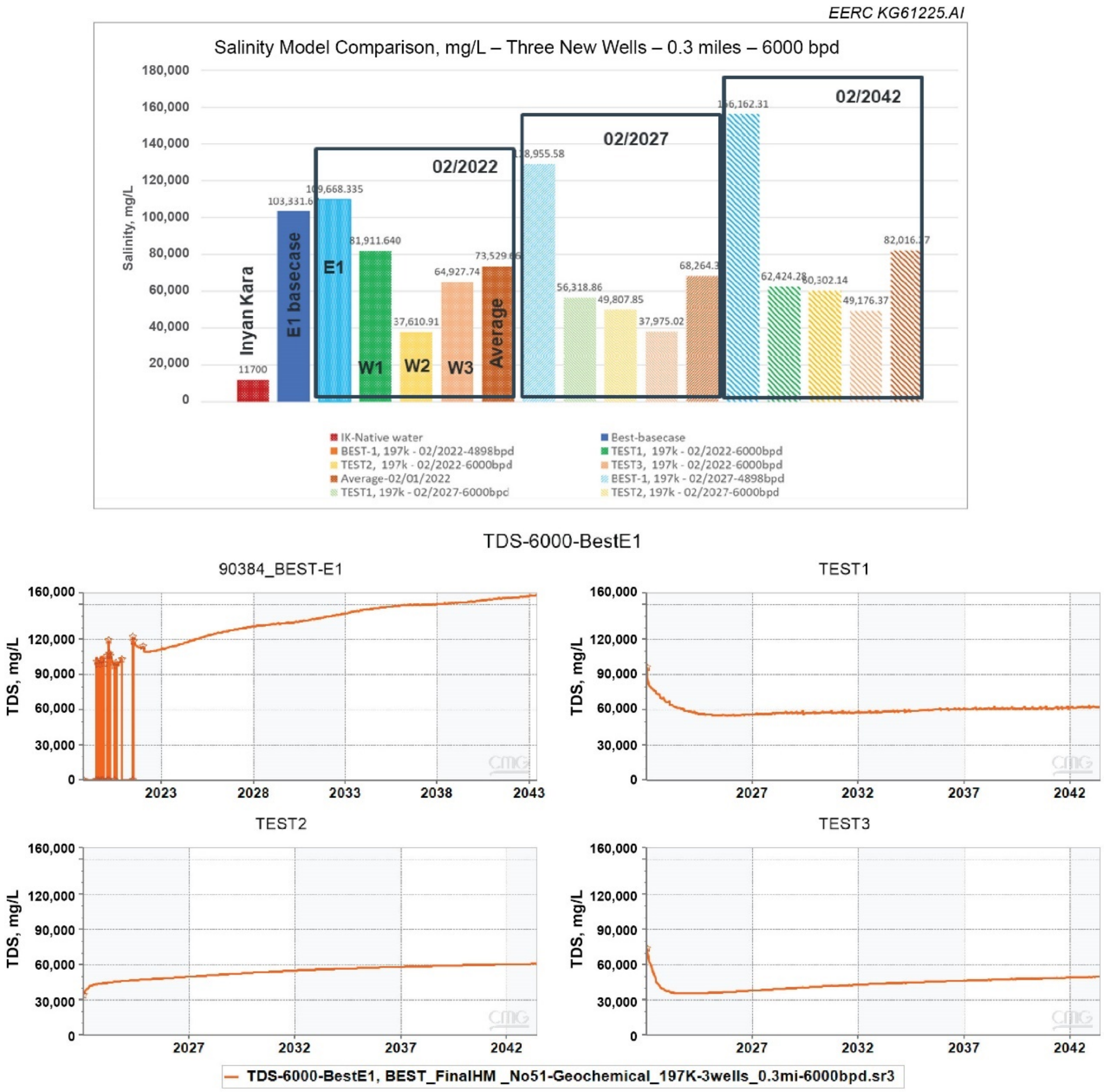


Figure D-12. Water salinity for Scenario 5a.

Scenario 6a

Scenario 6a evaluated four production wells placed a distance 0.5 miles from the Rink 1 and 2 SWD wells (Figure D-13). The production wells are producing at a rate of 6000 bwpd, and BEST E1 is producing at the current field operational rate of 4900 bwpd.

Figure D-14 illustrates the reduced salinity resulting from the increase in production wells and subsequently higher production volumes. The overall production of water from the four wells is 210 MMbbl (Figure D-15), which represents an increase of 435% over the current production from the BEST E1 well. The simulated scenario also found a decrease in formation pressure (Figure D-16) from 3170 to 2580 psi at the end of the 20-year simulation period. However, a decrease in formation pressure can be seen at the beginning of the simulation period.

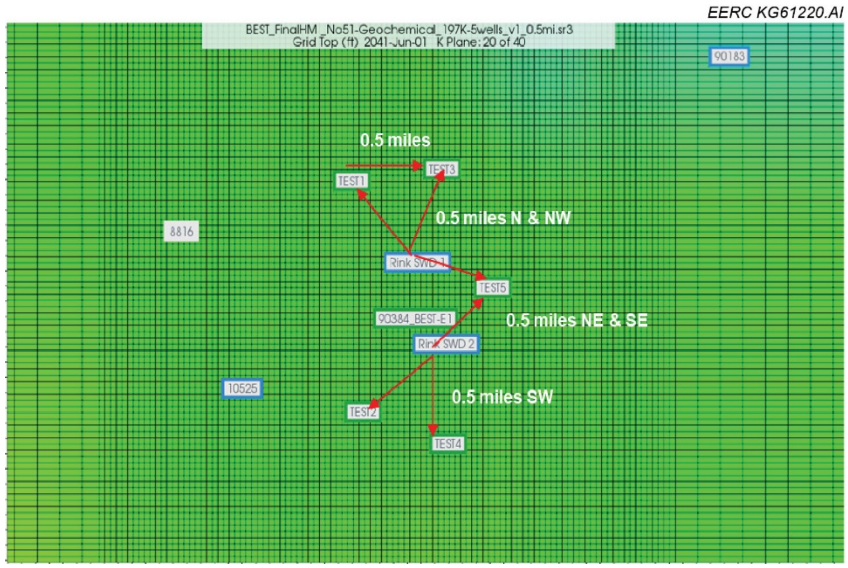


Figure D-13. Four production wells a distance of 0.5 miles from Rink 1 and 2 SWD wells: Scenario 6.

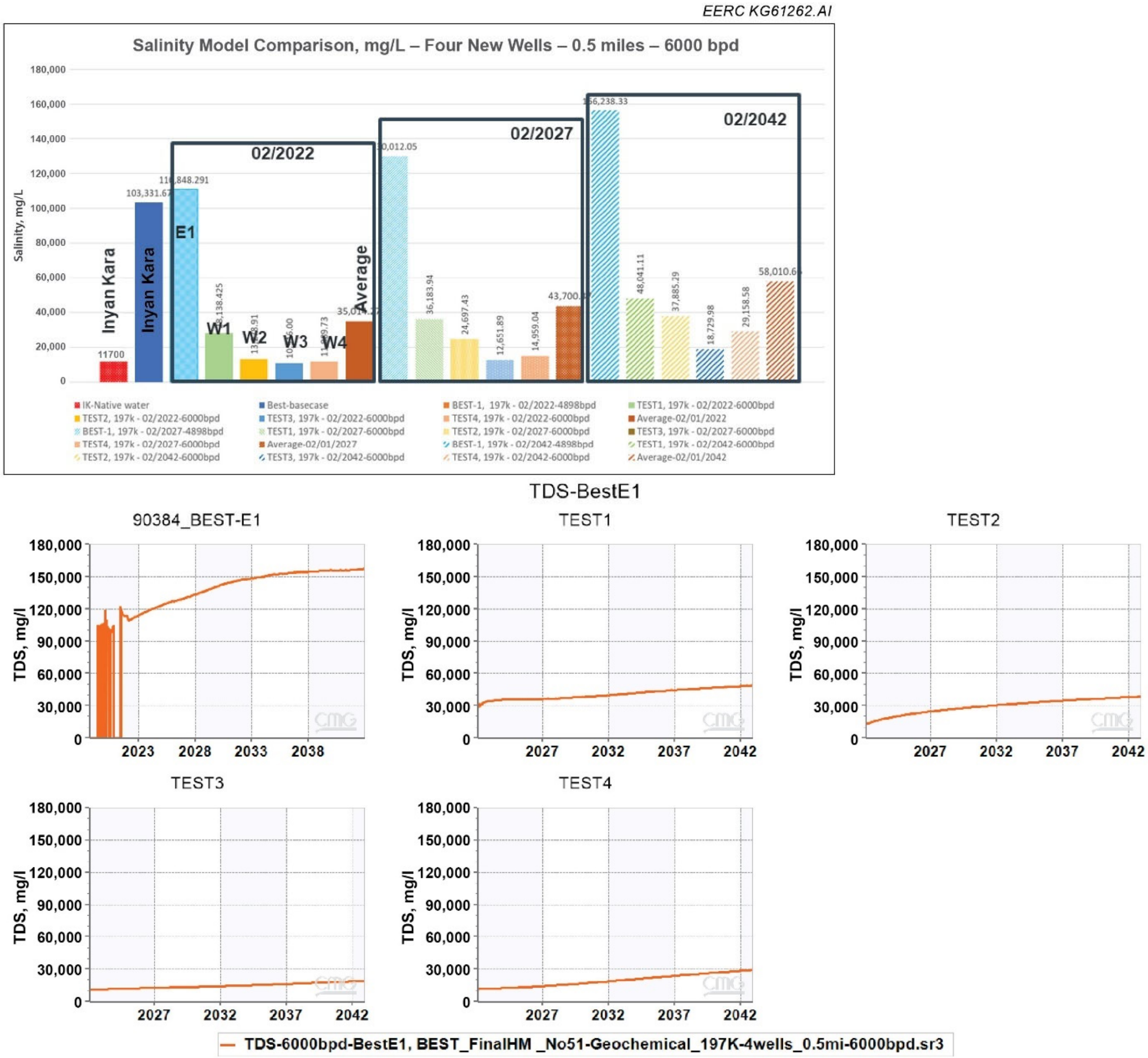


Figure D-14. Water salinity for Scenario 6a.

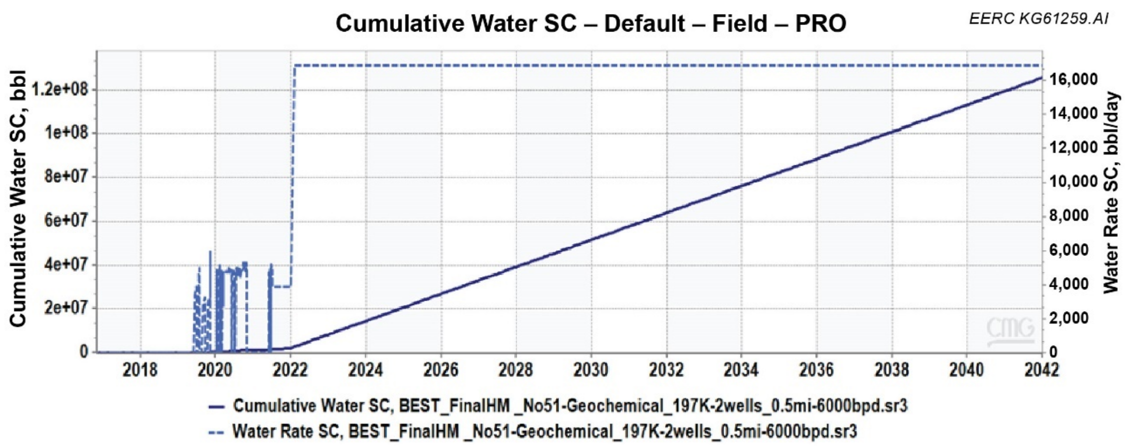


Figure D-15. Cumulative production water and production rate for Scenario 6a.

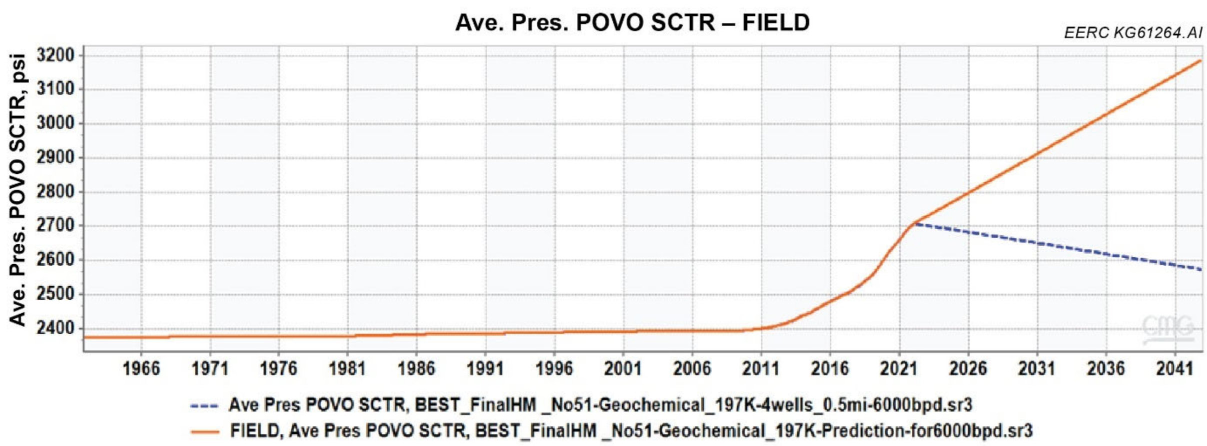


Figure D-16. Formation pressure comparison for Scenario 6 (blue line) and with only BEST E1 producing (orange line).

Scenario 6b

Scenario 6b follows the same well arrangement as Scenario 6a (Figure D-12) with production wells 0.5 miles from Rink 1 and 2 SWD wells. The difference between the two scenarios is the water injection rate in Scenario 6b is decreased to 50% from the current operational conditions for the injector wells in the model (Rink SWD1 and SWD2, Well 90183, and Well 10525). The scenario also evaluated shutting in all of the injector wells in order to better understand the effect of water injection rates on water salinity, water production rate, and the formation pressure.

The simulation results showed no changes, as expected, on the water produced for this scenario (Figure D-17) with a production rate of 4900 bwpd for BEST E1 and 6000 bwpd for the added production wells. When compared to Scenario 6a, the reduction in injection volumes (either 50% or shut-in) results in lower formation pressures (Figure D-18) and reduced salinity in producing waters (Figure D-19).

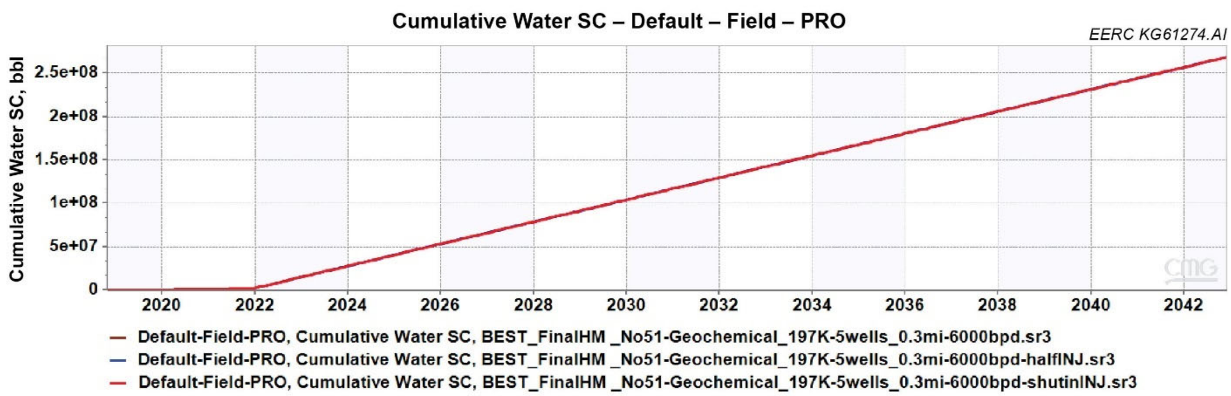


Figure D-17. Cumulative water production volume for Scenario 6b. There are no observed changes in water production when injection rates are decreased.

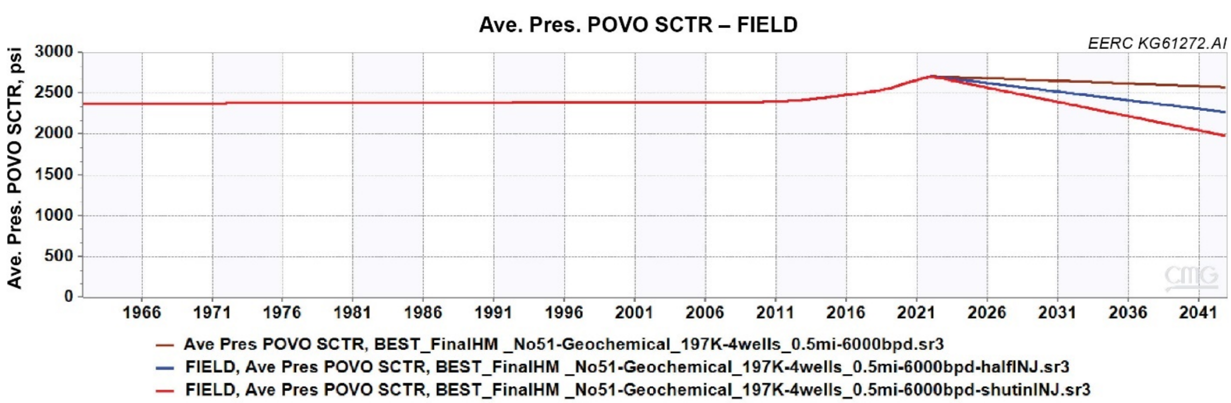


Figure D-18. Field pressure for Scenario 6b.

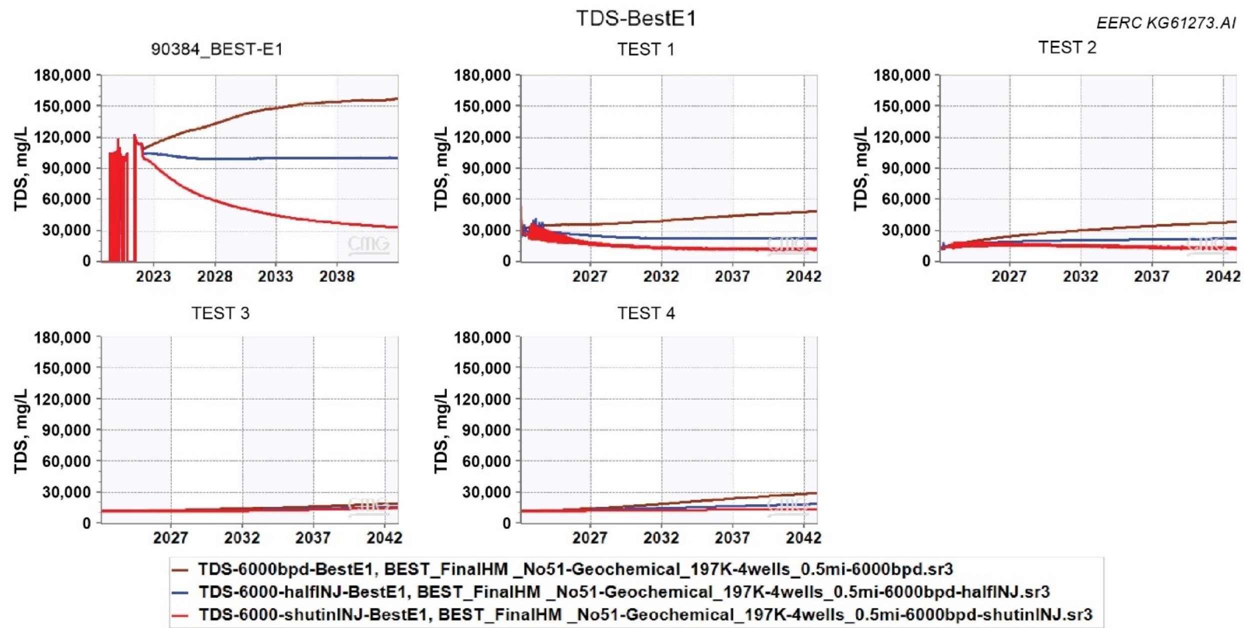


Figure D-19. Water salinity for Scenario 6b.

Scenario 6c

Scenario 6c follows the same well arrangement as Scenarios 6a and 6b (Figure D-12) with production wells 0.5 mile from Rink 1 and 2 SWD wells. The difference in Scenario 6c was the increase of water production rates to 30,000 bwpd (from 6000 bwpd). The objective was to evaluate the effect of increased production rates on water salinity and formation pressure under normal injection conditions or when injection wells were shut in.

The simulation of Scenario 6c predicted a field pressure depletion response with the water production rate of 30,000 bwpd for both cases, regardless of whether SWD water injection continues in the field or SWD water injection is shut in (Figures D-20, D-21). TDS reductions are observed with the increase in water production for this scenario in a manner similar to the other presented scenario results, although the timestep resolution in this particular simulation restricted the visualization of the model result, so no resultant table could be displayed.

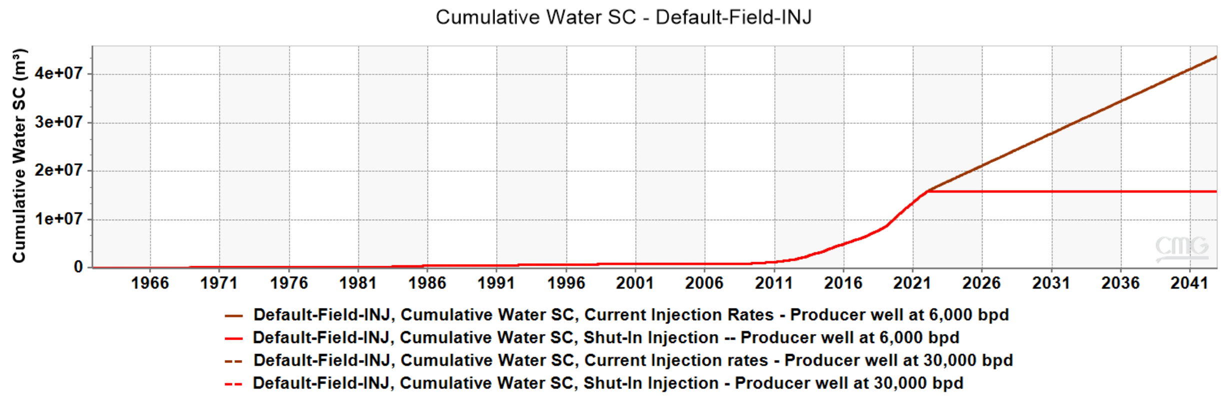


Figure D-20. Cumulative injection volume for Scenario 6c.

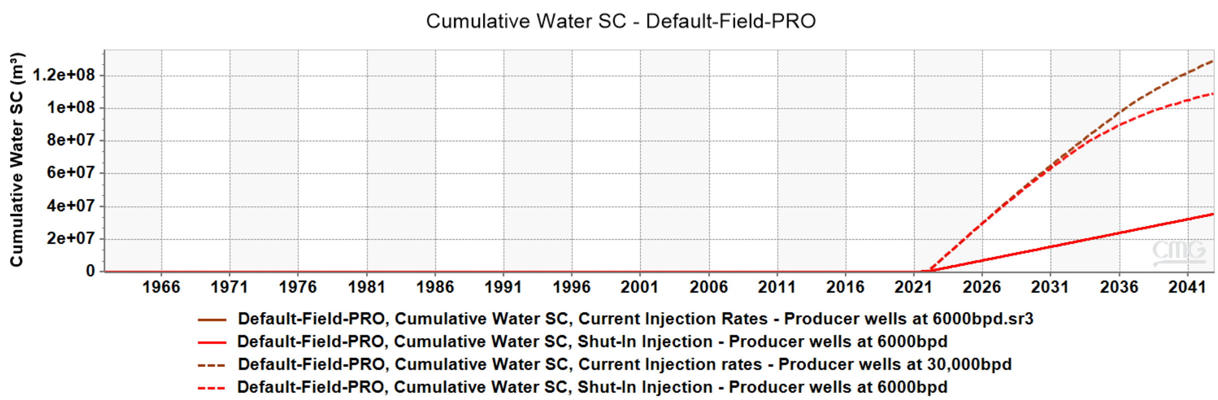


Figure D-21. Cumulative water produced for Scenario 6c.

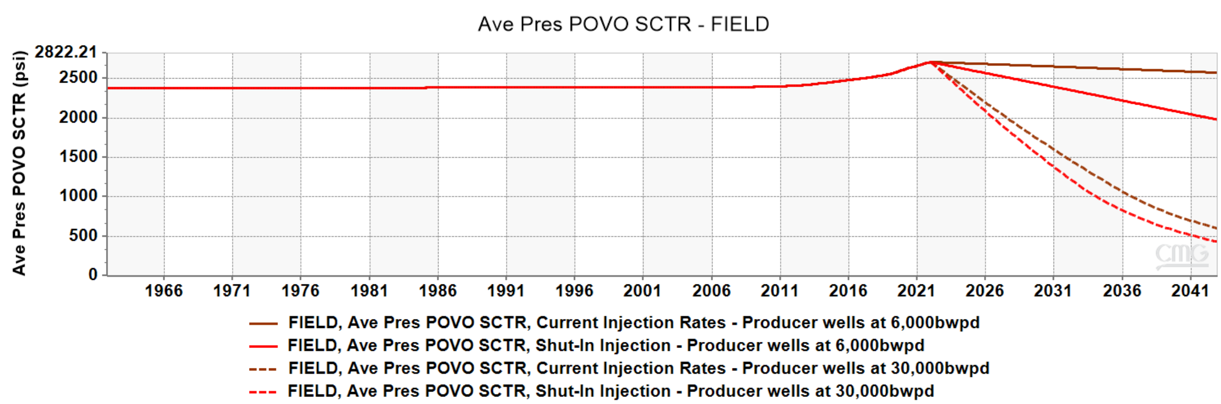


Figure D-22. Simulated field pressure for Scenario 6c.

Scenario 7a

Scenario 7a evaluated five production wells placed at 0.3 miles from Rink 1 and 2 SWD wells (Figure D-23). Simulation results indicated a slight increase in the produced water salinity for this scenario when compared to Scenario 6a (Figure D-24). With the addition of the five production wells, the cumulative water volume produced increased from 39.6 MMbbl for BEST E1 well solo production (at 4900 bwpd) to almost 270 MMbbl, an increase of about 580% for the simulated scenario (Figure D-25). Scenario 7a also shows a decrease in formation pressure to 2420 psi at the end of the simulation period of 20 years (Figure D-26), a reduction of approximately 24% from initial operating conditions.

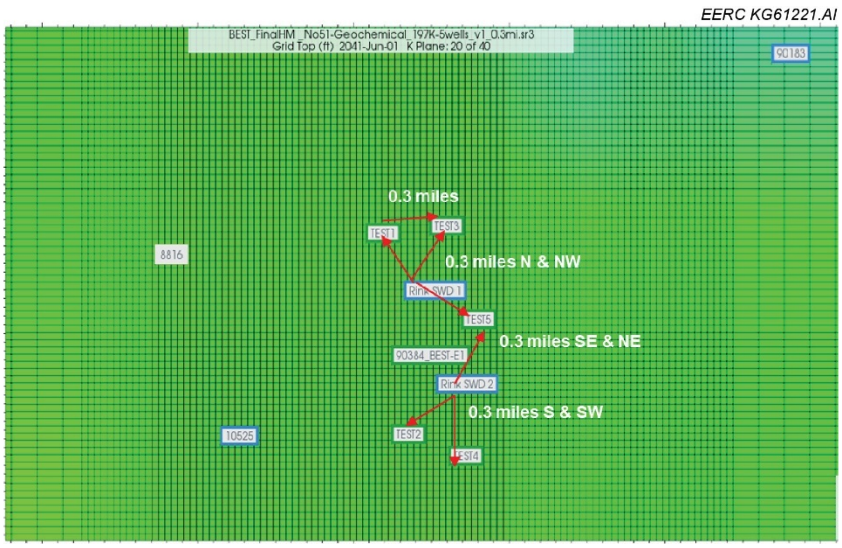
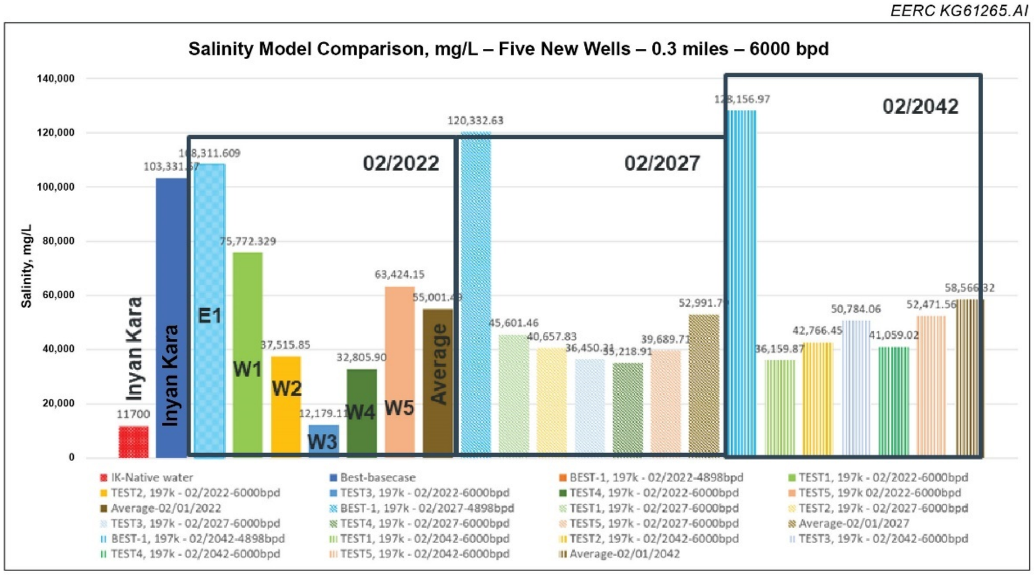


Figure D-23. Five production wells with a distance of 0.3 miles from Rink 1 and 2 SWD wells – Scenario 7.



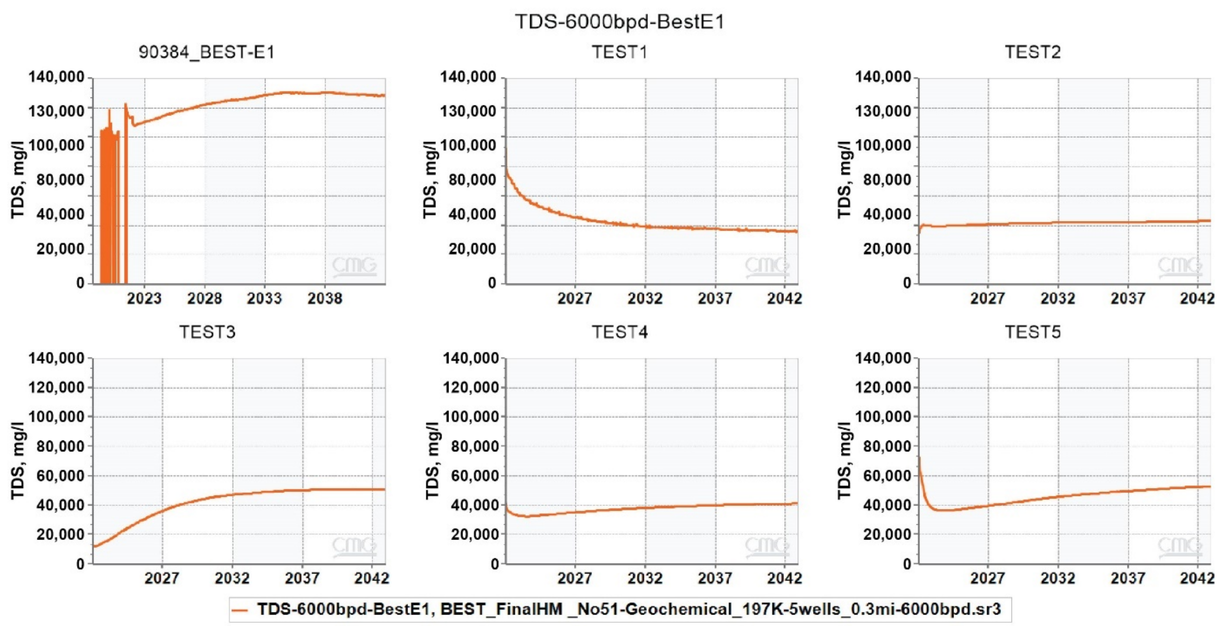


Figure D-24. Water salinity results for Scenario 7a.

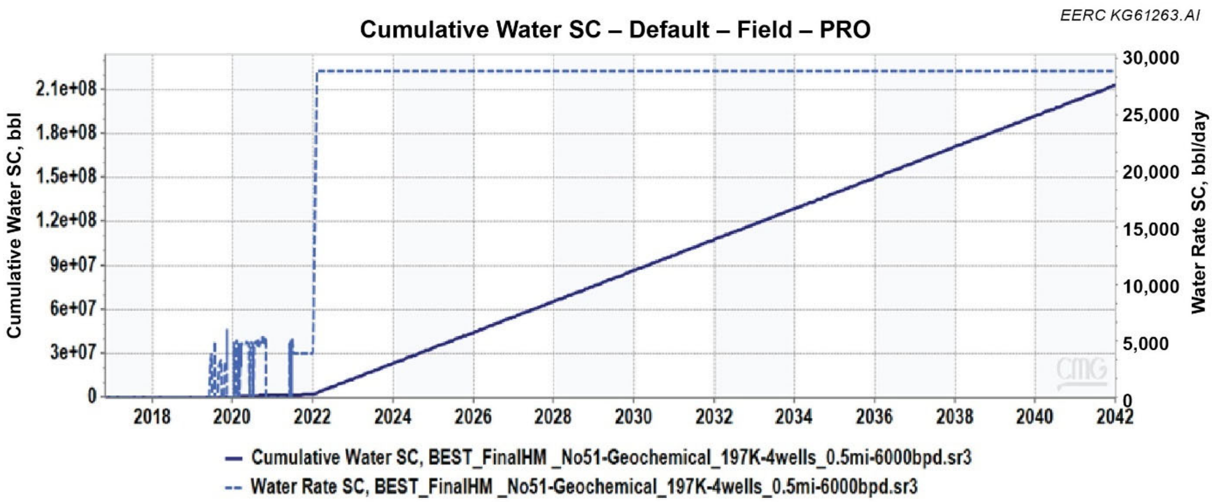


Figure D-25. Cumulative production water and water production rate for Scenario 7a.

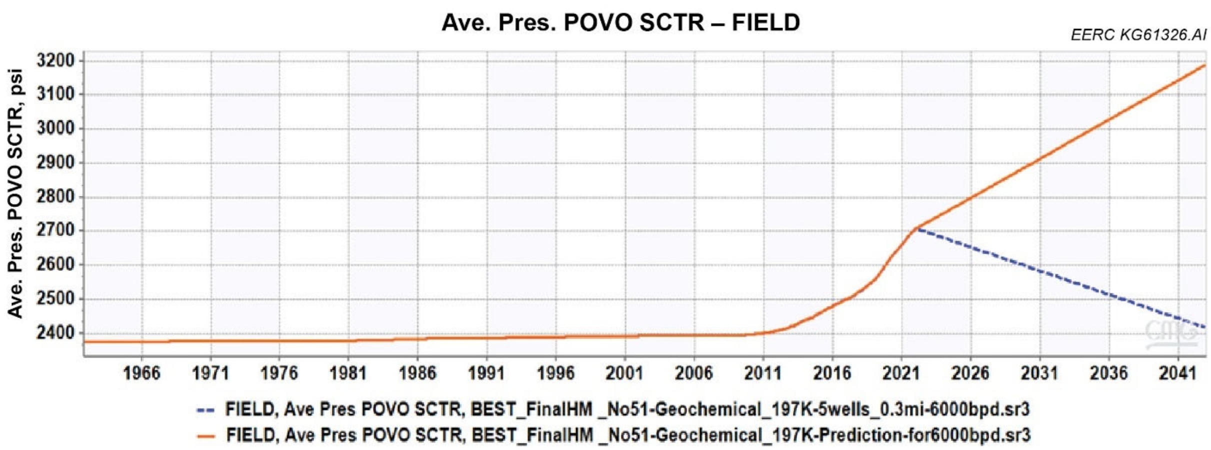


Figure D-26. Formation pressure comparison for Scenario 7a (blue line) and with only BEST E1 as a producing well (orange line).

Scenario 8a

Scenario 8a evaluated five production wells placed at 0.5 miles from Rink 1 and 2 SWD wells (Figure D-27). Figure D-28 illustrates the water salinity for each of the production wells during the 20 years of simulation. The results show a decrease in the water salinity for Scenario 8a as compared to Scenario 7a, with the decrease likely resulting from the difference in well distances (0.5 miles vs. 0.3 miles) between the production wells and the Rink 1 and 2 SWD wells.

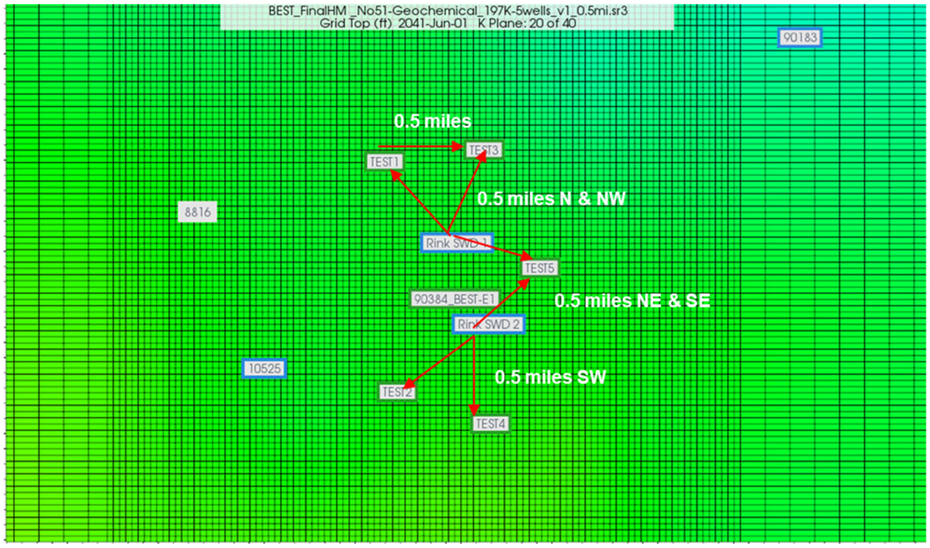


Figure D-27. Five production wells with a distance of 0.3 miles from Rink 1 and 2 SWD wells – Scenario 8.

Figure D-28. Water salinity for Scenario 8a.

Scenario 8b

Scenario 8b corresponds to five production wells placed at a distance of 0.3 miles from the Rink 1 and 2 SWD wells in the same arrangement as Scenario 8a (Figure D-27), and the water injection rate was decreased 50% from the current operational conditions for the injector wells in the model (Rink SWD1 and SWD2, Well 90183, and Well 10525). The scenario also evaluated shutting in all the injector wells in order to better understand the effect of water injection rates on water salinity, water production rate, and the formation pressure.

The simulation results showed no changes, as expected, on the water produced for this scenario (Figure D-29) with a production rate of 4900 bwpd for BEST E1 and 6000 bwpd for the added production wells. When compared to Scenario 8a, the reduction in injection volumes (either 50% or shut-in) results in lower formation pressures (Figure D-30) and reduced salinity in producing waters (Figure D-31). The simulation results for the water salinity when the injection wells are shut in is not shown in Figure D-31. The result showed an inconsistent curve behavior because of numerical issues during the simulation, potentially due to the number of wells and the volumes for water injected and produced.

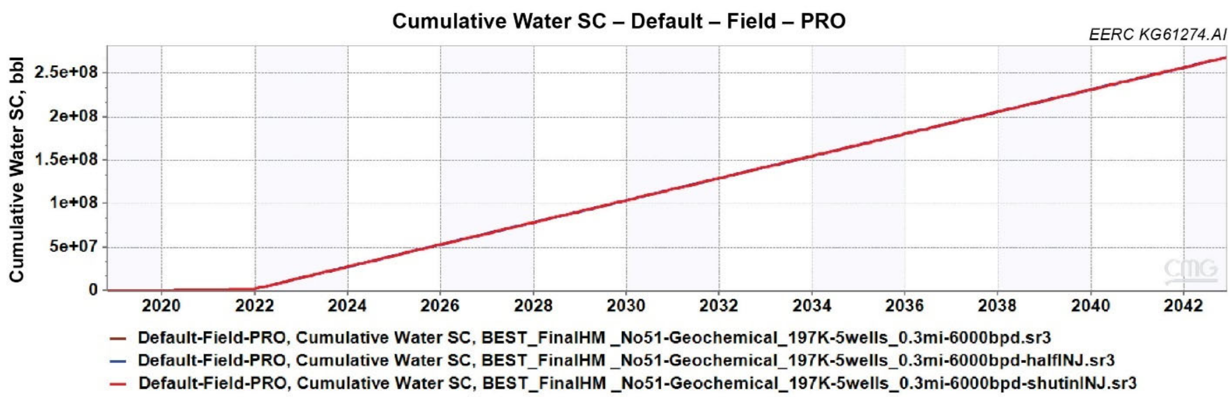


Figure D-29. Cumulative water production volume for Scenario 8.b.

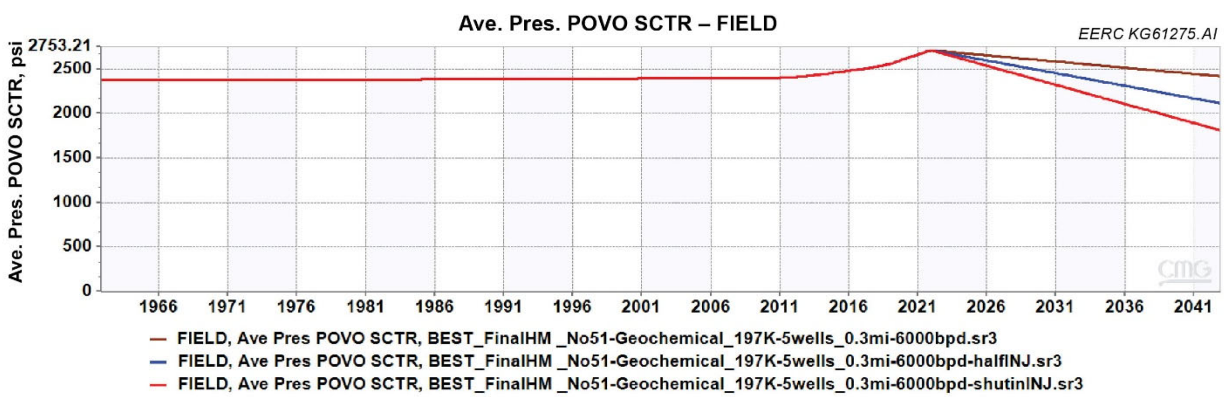


Figure D-30. Field pressure for Scenario 8.b.

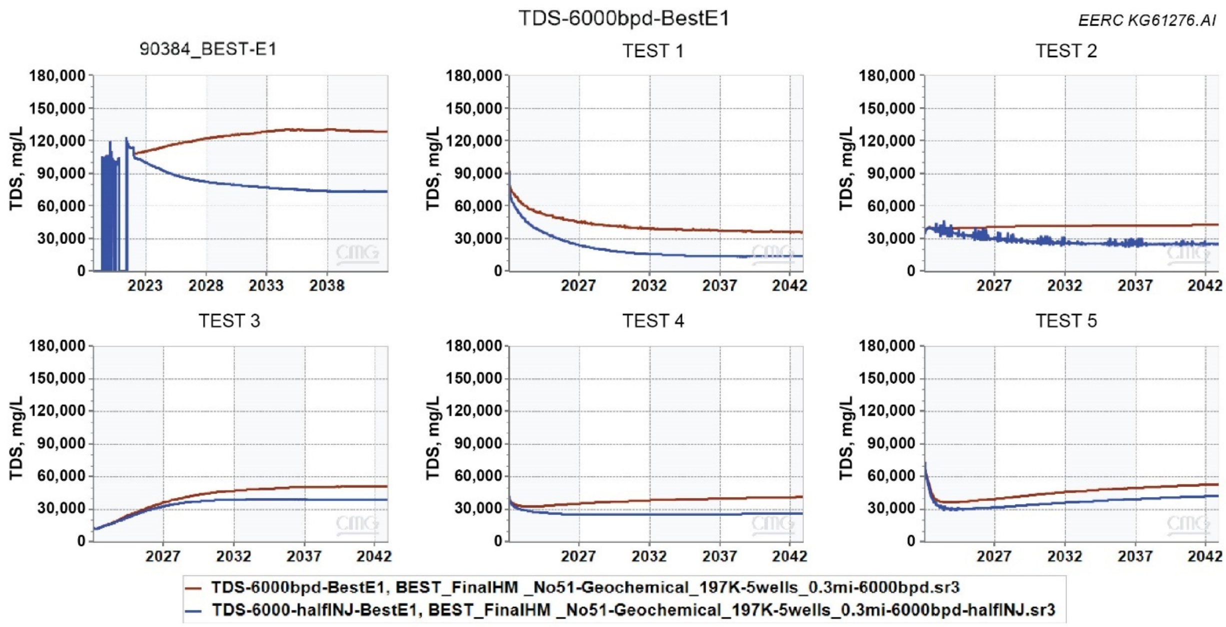
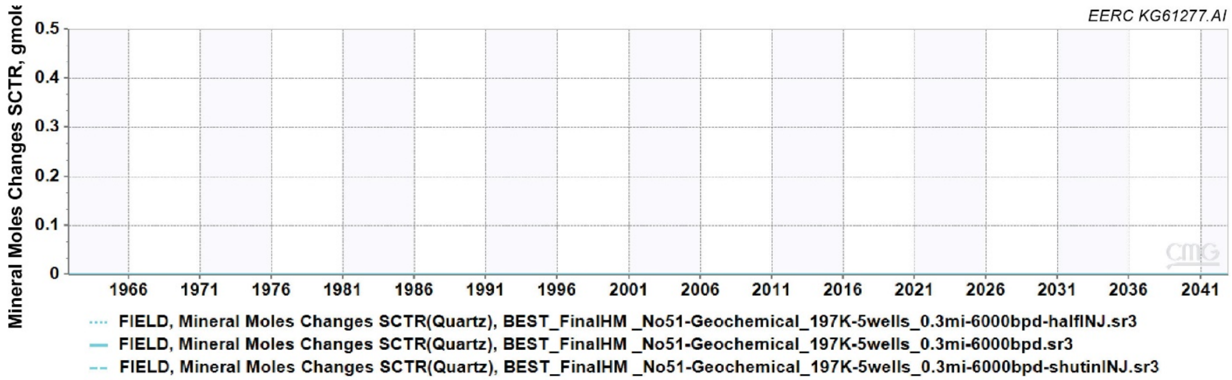


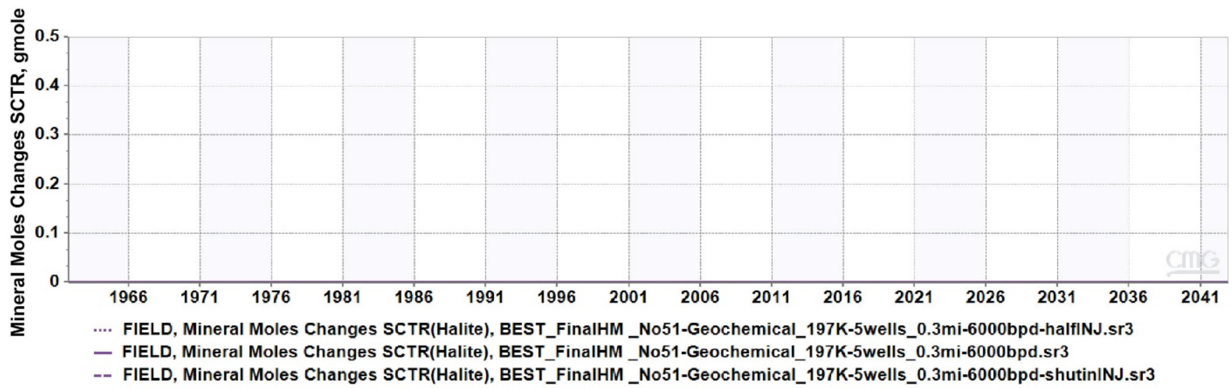
Figure D-31. Water salinity for Scenario 8b.

Geochemical Modeling

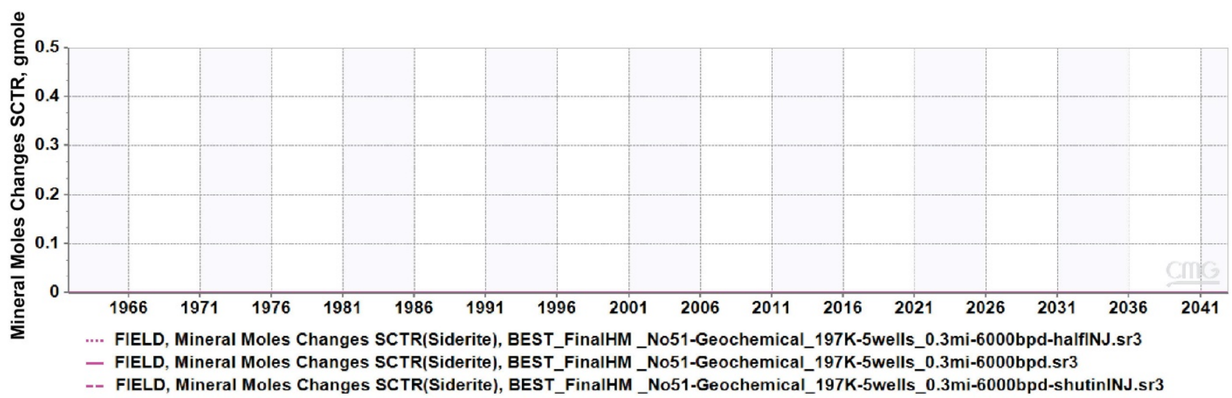
The geochemical modeling from CMG GEM allows evaluating potential chemical reactions that may occur in the reservoir because of interaction between the two different waters (injection and native Inyan Kara water) and the minerals from the rock. The simulation results did not show any potential mineral dissolution and/or precipitation because of these chemical reactions during the simulation period of 20 years. Figure D-32 shows the simulation results for one of the cases under study for the minerals quartz, halite, and siderite, each analyzed using XRD on the Inyan Kara rock material. Only these three minerals were included in the geochemical modeling to speed up the simulation time because of the chemical reactions in the model.



a) Mineral mole changes for Quartz



b) Mineral mole changes for Halite



a) Mineral mole changes for Siderite

Figure D-32. Mineral molar changes for quartz, halite, and siderite.

APPENDIX E

WATER RATE SENSITIVITY ANALYSIS

WATER RATE SENSITIVITY ANALYSIS

Simulation scenarios evaluated the water injection rate, as the GHCR (geologic homogenization, conditioning, and reuse) concept relies on supplying a sufficient volume of water for recycling applications (i.e., hydraulic fracture fluid makeup water). Based on the previous simulation results, only selected scenarios deemed to be the most representative were used for the water rate evaluation.

Two operational conditions were included for this analysis: a) a reduction in the water injection rate to half of the volume currently recorded through July 2021 for Rink SWD 1 and SWD 2, Well 90183, and Well 10525 and b) a complete shut-in of the water injection wells during the 20 years of predictions to evaluate the behavior of the production wells and the pressure in the formation under this condition (Table E-1).

Table E-1. Scenarios for Water Rate Evaluation

Scenario	Conditions	Production Rate, bwpd[1]	Water Rate, bwpd
1b	BEST E1 well	4900	1) SWD 1 = 2591 SWD 2 = 2405 2) Shut-in
2b	E1 + two additional wells at 0.5 miles from Rink SWD 1 and SWD 2	E1 = 4900 Additional wells = 6000	1) SWD 1 = 2591 SWD 2 = 2405 2) Shut-in
4b	E1 + three additional wells at 0.3 miles from Rink SWD 1 and SWD 2	E1 = 4900 Additional wells = 6000	1) SWD 1 = 2591 SWD 2 = 2405 2) Shut-in
6b	E1 + four additional wells at 0.5 miles from Rink SWD 1 and SWD 2	E1 = 4900 Additional wells = 6000	1) SWD 1 = 2591 SWD 2 = 2405 2) Shut-in
8b	E1 + five additional wells at 0.3 miles from Rink SWD 1 and SWD 2	E1 = 4900 Additional wells = 6000	1) SWD 1 = 2591 SWD 2 = 2405 2) Shut-in

[1] Barrel of water per day.

Scenario 1b

The simulation results have shown a decrease in the pressure in the Inyan Kara Formation when the water production rate is decreased. In the current scenario, having only one production well, BEST E1, producing at a rate between 2900 and 5300 bwpd, and with an injection rate over the production rate range would overpressurize the formation because more water is injected than can be produced. Reducing the water rate in the injection wells and/or increasing the production rate with the addition of production wells would help to control and reduce the pressure into the formation.

Figure E-1 shows the different water injection rates evaluated and their effect on the total volume produced from the E1 well. The brown line represents the water injection wells at the current field operational conditions, the blue line corresponds to the 50% reduction of current water injection rates, and the red line is when the water injection is shut in. The simulation is showing that the reduction or even the shut-in of the water injection rate does not diminish the total water produced at BEST E1 during the 20 years of simulation. Even though water production is not affected, the simulation shows a decrease in the pressure in the formation and a decrease in the salinity concentrations observed at the BEST E1 well (Figures E-2 and E-3). Simulation results showed that controlling the injection conditions, by a potential reduction or a short-duration well shut-in within close proximity, may yield a reduction in the formation pressure and water salinity concentrations without impacting the total volume of water produced.

The changes in the pressure are going from around 3170 psi under the current operational conditions, and if nothing is done in the reservoir (brown line), to 2880 and 2590 psi when the water rate is reduced to half of the current value and the injector is shut in, respectively, at the end of the 20-year time frame in this evaluation (Figure E-3).

A decrease in the water salinity observed at the BEST E1 production well also occurs when the water injection rate decreases from the current operational conditions (Figure E-4). The reduction in the water salinity concentration in the BEST E1 production well will provide a better-quality water for use in hydraulic fracturing operations or for other beneficial uses.

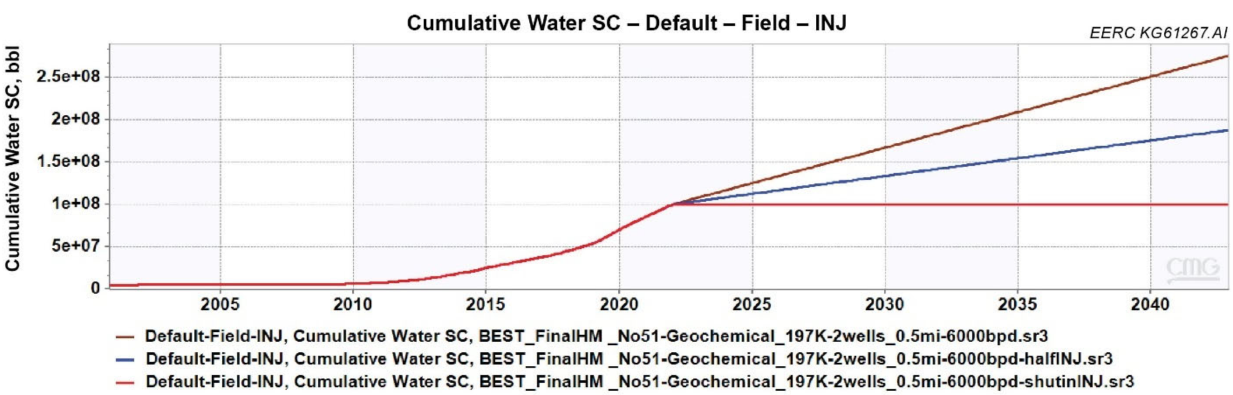


Figure E-1. Cumulative injection from the injector wells (SWD1 and SWD2, Well 90183, and Well 10525) at different injection rates.

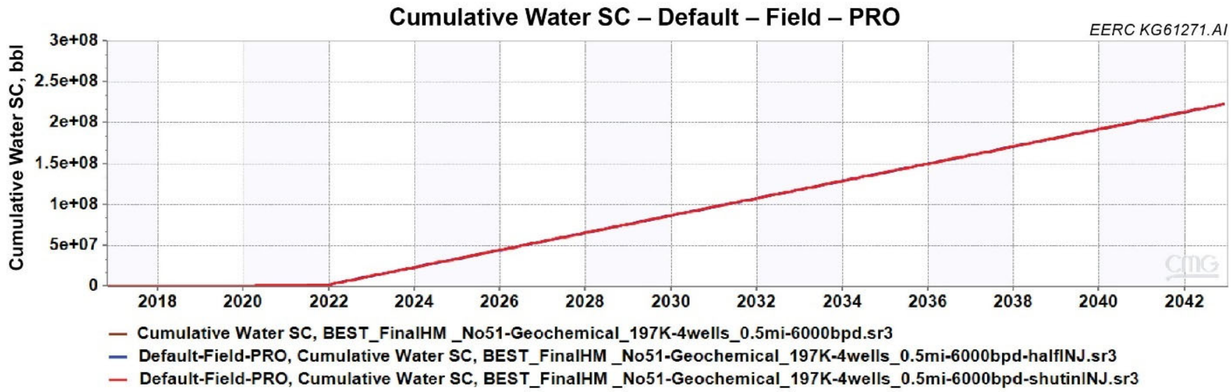


Figure E-2. Cumulative production for BEST E1 production well at different injection rates. The differences in water injection rate do not affect the cumulative water produced, resulting in overlapping curves.

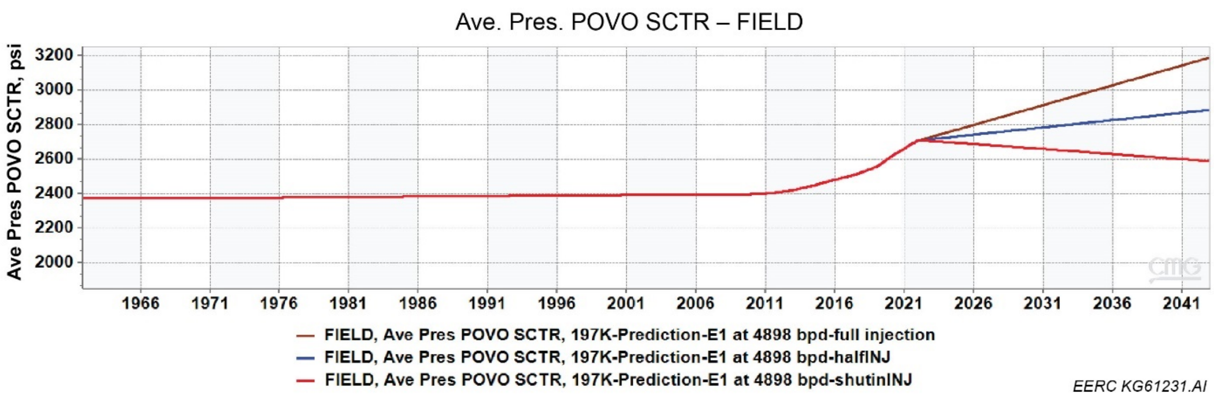


Figure E-3. Variations in the pressure in the Inyan Kara Formation when the water injection rate is decreased to half of the current operation volume (blue line) and the injectors are shut in (red line).

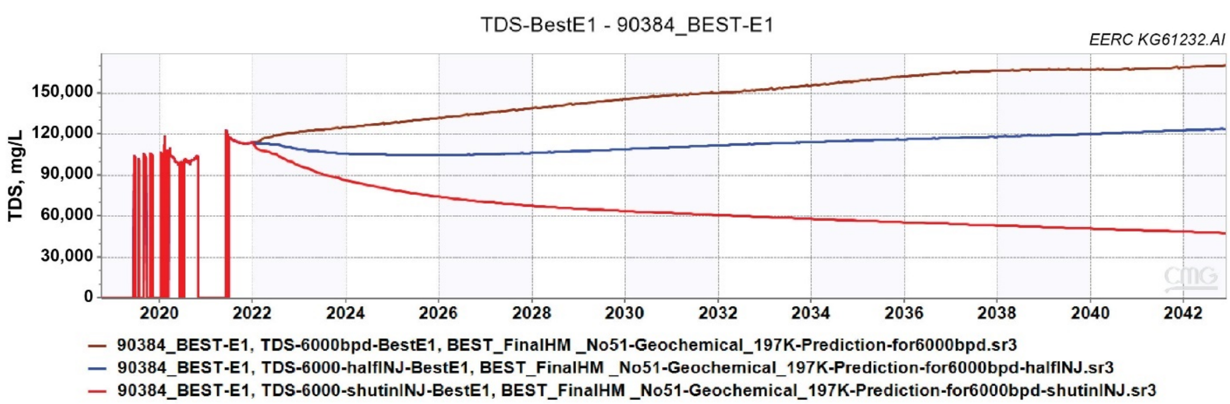


Figure E-4. Changes in the water salinity for BEST E1 production well for the changes in the water injection rate.

Scenario 4b

Similar simulation results to Scenario 1b were observed in this simulation scenario. Consistent reduction in the water salinity concentrations (i.e., TDS) for each of the production wells and a decrease in the pressure of the formation is observed with the additional production wells and/or with the reduction in the water injection rate. These observed conditions do not impact the cumulative water that can be produced in a GHCR implementation scenario regardless of the operational changes.

Figures E-5–E-8 show the simulation results when three production wells were added to the current BEST E1 well with a distance from the BEST location of 0.3 miles. More simulation results for the other scenarios evaluated can be seen in Appendix D.

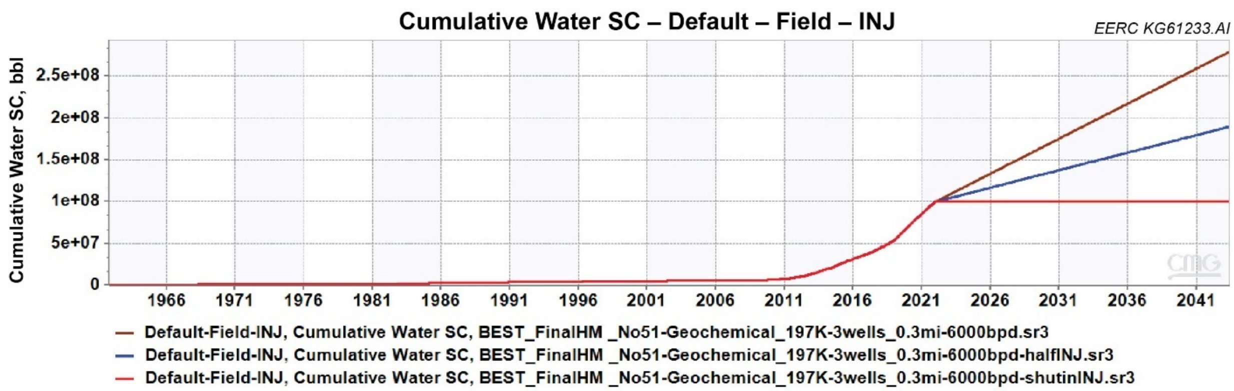


Figure E-5. Cumulative water injection with the current injection rate (brown line), when the water rate is reduced to half of the current operation rate condition (blue line), and when the water injectors in the area are shut in (red line) for the scenario with three production wells added.

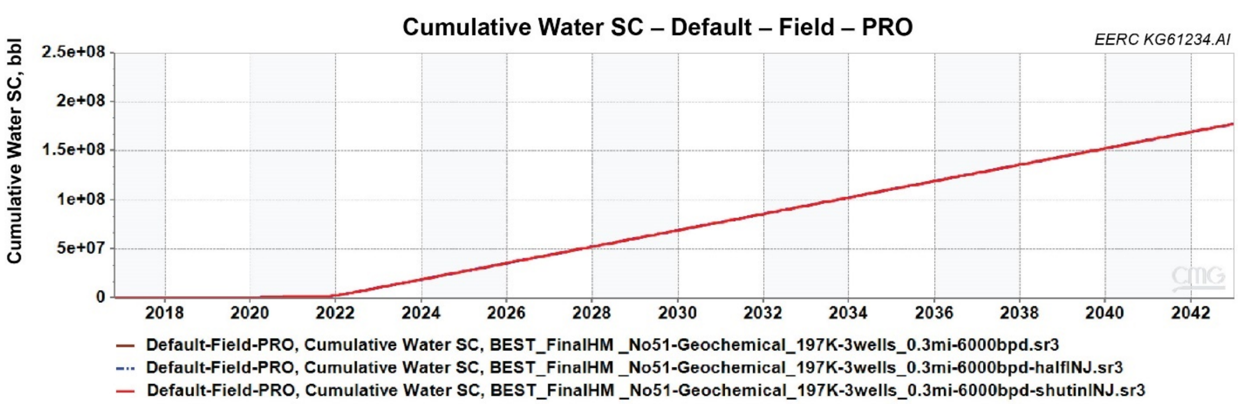


Figure E-6. Cumulative production at different water injection rates with three production wells added.

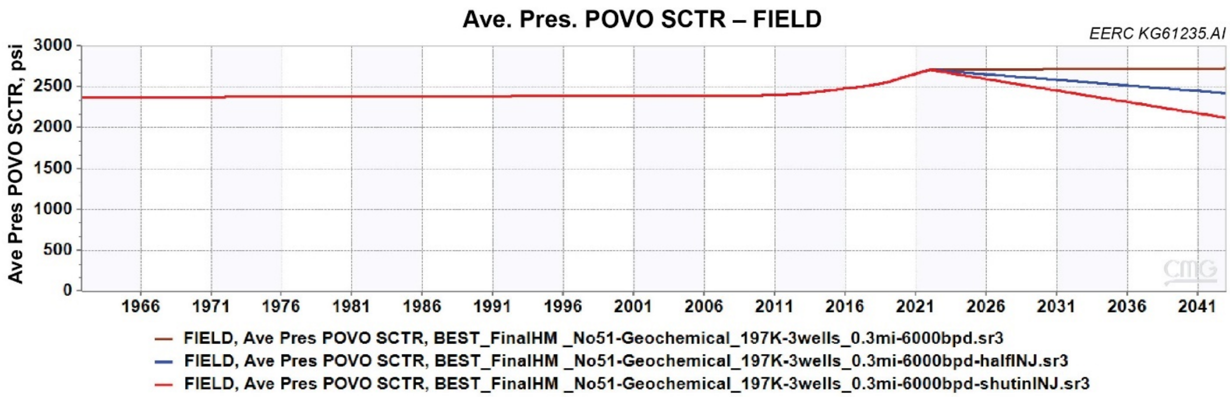


Figure E-7. Variations on the pressure in the formation when the water injection rate is decreased to half of the current operation volume (blue line) and the injectors are shut in (red line) with the scenario with three additional production wells.

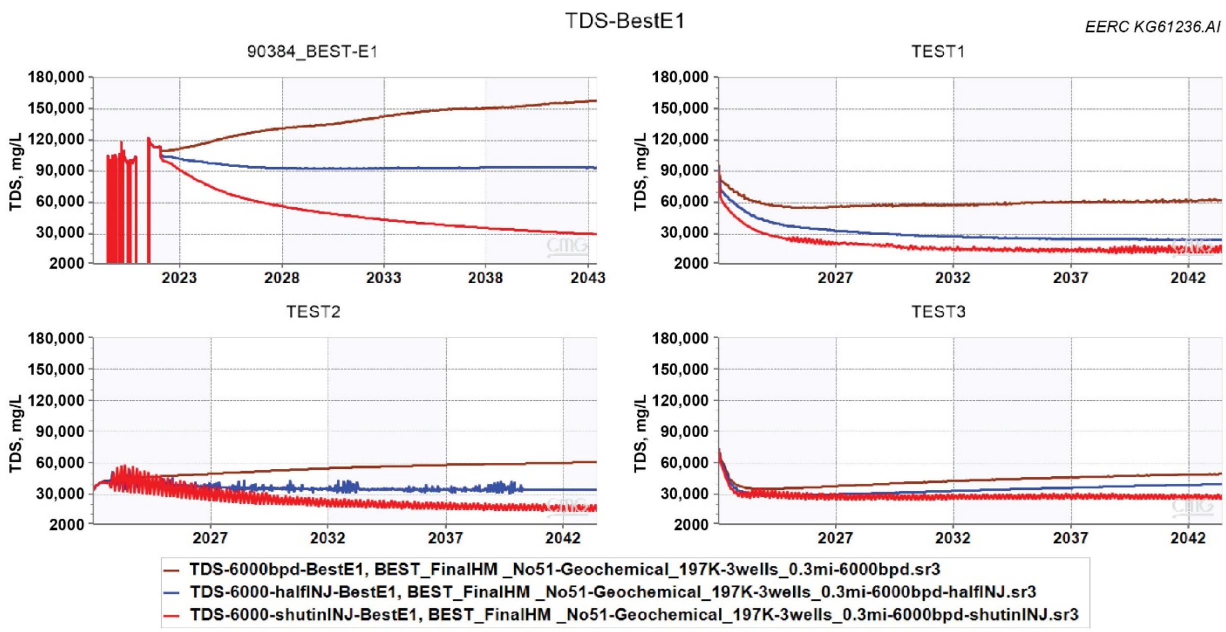


Figure E-8. Changes in the water salinity when the water injection rate is decreased to half of the current operation volume (blue line) and the injectors are shut in (red line) with the scenario with three additional production wells.

Figure E-5 shows the cumulative water injection at the end of the 20 years of operation for the three different injection rates.

As in the case described above, when the BEST E1 well was the only production well, the simulation results showed that a decrease in the injection water rate is not affecting the total produced volume, but a reduction in formation pressure and the total produced water salinity (TDS) is observed.

The zig-zag shut-in (red) line shown in Figure E-8 may correspond to a numerical issue from the simulator because of producing more water than is injected into the formation for this scenario. The TDS parameter is calculated using the formula property in the simulator and is dependent on the mole fraction for the ions/cations in the water as a function of the water volume produced.