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Oil & Gas Research Council

PRODUCED WATER MANAGEMENT AND RECYCLING OPTIONS IN NORTH DAKOTA

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DEFINITIONS

Acre-feet – 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.

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 PVC. As the name suggests, one of its key properties is the ability to be laid flat for storage purposes; they are used for the delivery of water in roles such as construction or irrigation when it is not easy to transport water.

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 parts per million (ppm) or milligrams per liter (mg/L).

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

FINAL REPORT ON PRODUCED WATER MANAGEMENT AND RECYCLING OPTIONS IN NORTH DAKOTA – 2020

EXECUTIVE SUMMARY

The Energy & Environmental Research Center was awarded a contract by the North Dakota Industrial Commission (NDIC) Oil & 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 2020 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 also provides an assessment of North Dakota produced water management practices and trends and discusses associated opportunities, challenges, and industry perspectives aggregated from top producers and service companies operating in the Williston Basin.

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, North Dakota oil production has recovered to over 1 MMbbl/day as of July 2020. Bakken petroleum system development between 2008 and 2019 has resulted in a nearly fourfold increase in produced water volumes to 740 MMbbl/yr and a fivefold increase in saltwater disposal (SWD) volumes to 683.5 MMbbl/yr. 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 injection into sandstones of the Dakota Group (Dakota). No produced water recycling was found to be occurring in North Dakota, with the exception of the reinjection of coproduced water associated with secondary waterflood recovery in select conventional fields. While there has been limited prior technical success using produced water as hydraulic fracture makeup water dating back to 2015, commercial adoption has been precluded by regulatory, logistical, and economic challenges.

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. Investing resources to pursue recycling/reuse options and other solutions to address emerging produced water management challenges now could help curtail and defer operational and cost impacts of produced water management on the economics of North Dakota oil production in the future. Several options include characterization of alternative SWD targets, integrated produced water pipeline systems to transport produced water to more suitable SWD locations, surface storage alternatives that reduce risk for recycling, and novel approaches to implementing recycling and reuse in North Dakota.

Other key messages from this assessment include:

- Freshwater use on a per well basis has grown substantially over the last decade. Total water use during the next several years will be driven by number of well completions and increasing water use per well. Increased water use volumes for well stimulation impact the economics of oil production through both water supply and water disposal costs.

- Bakken wells use a large volume of fluid for stimulations (200,000 bbl/well on average) over the course of a few days. Logistics require the total volume to be transported and stored on location in advance of a stimulation job.

- Distributed freshwater supply systems and introduction of lay-flat pipe have substantially reduced freshwater supply and transportation costs. However, because of the high salinity and health, safety, and environmental risks associated with produced water, the success seen with the application of lay-flat pipe for freshwater transport cannot be replicated for produced water.

- Cumulative produced water is following an increasing trend. Average water cut per well also continues to increase each year. The trend suggests that total water production will increase at an even greater rate, resulting in increased water management costs that directly correlate to oil value on a per barrel basis.

- In the suppressed or low-oil-price environment, water management costs were confirmed to be driving shut-in and restart priority.

- North Dakota has been fortunate to have a one-size-fits-all solution to produced water management with SWD into the Dakota. The Dakota's geographic extent, relatively shallow depth, and injectability have made it a SWD target that is suitable across the entire Bakken producing region in the state. Based on the forecasted increasing volumes of produced water and associated SWD, that may not always be the case. Alternative solutions are not as ubiquitous across the entire Bakken producing region.

- Pressurization of the Dakota is leading to increased drilling costs and may limit SWD capacity, leading to increased transportation and disposal volume, thus increasing SWD costs. The issue will be exacerbated in core development areas, which have historically been more insulated from price depressions, leading to an emerging trend toward less economical wells in these areas.

FINAL REPORT ON PRODUCED WATER MANAGEMENT AND RECYCLING OPTIONS IN NORTH DAKOTA – 2020

INTRODUCTION

The Energy & Environmental Research Center (EERC) was awarded a contract by the North Dakota Industrial Commission (NDIC) Oil & 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 also provides an assessment of North Dakota produced water management practices and trends and discusses associated opportunities, challenges, and industry perspectives, aggregated from top producers and service companies operating in the Williston Basin.

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). Data shown throughout the report will largely focus on the 2008 to 2019 (last complete year of record) time period, with other dates noted when appropriate.

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, 2020b), and despite a downturn in oil price, production in the state has recovered to over 1 MMbbl/day in July 2020 (North Dakota Department of Mineral Resources, 2020a). Oil production appears to gradually be recovering, as oil prices increased from $7.92/bbl (North Dakota light sweet crude) in May to over $30/bbl in July 2020. Even accounting for a slowdown, produced water volumes are projected to exceed 500 MMbbl for 2020, which exceeds 2018 volumes.[1] Furthermore, using conservative projections, produced water volumes are forecasted to more than double by 2030.

To accommodate the projected growth of oil and gas production, state and industry leaders will have to adapt and seek solutions for the growing demand for water to be used in oilfield operations and produced water management and associated disposal options. While conventional oil fields are still producing in North Dakota, over 95% of oil is produced from the Bakken. That trend is expected to continue. This report will primarily focus on water management in relation to Bakken development.

[1] Assumes a water cut of 58% and an average oil production of 800,000 bbl/day for the rest of 2020.

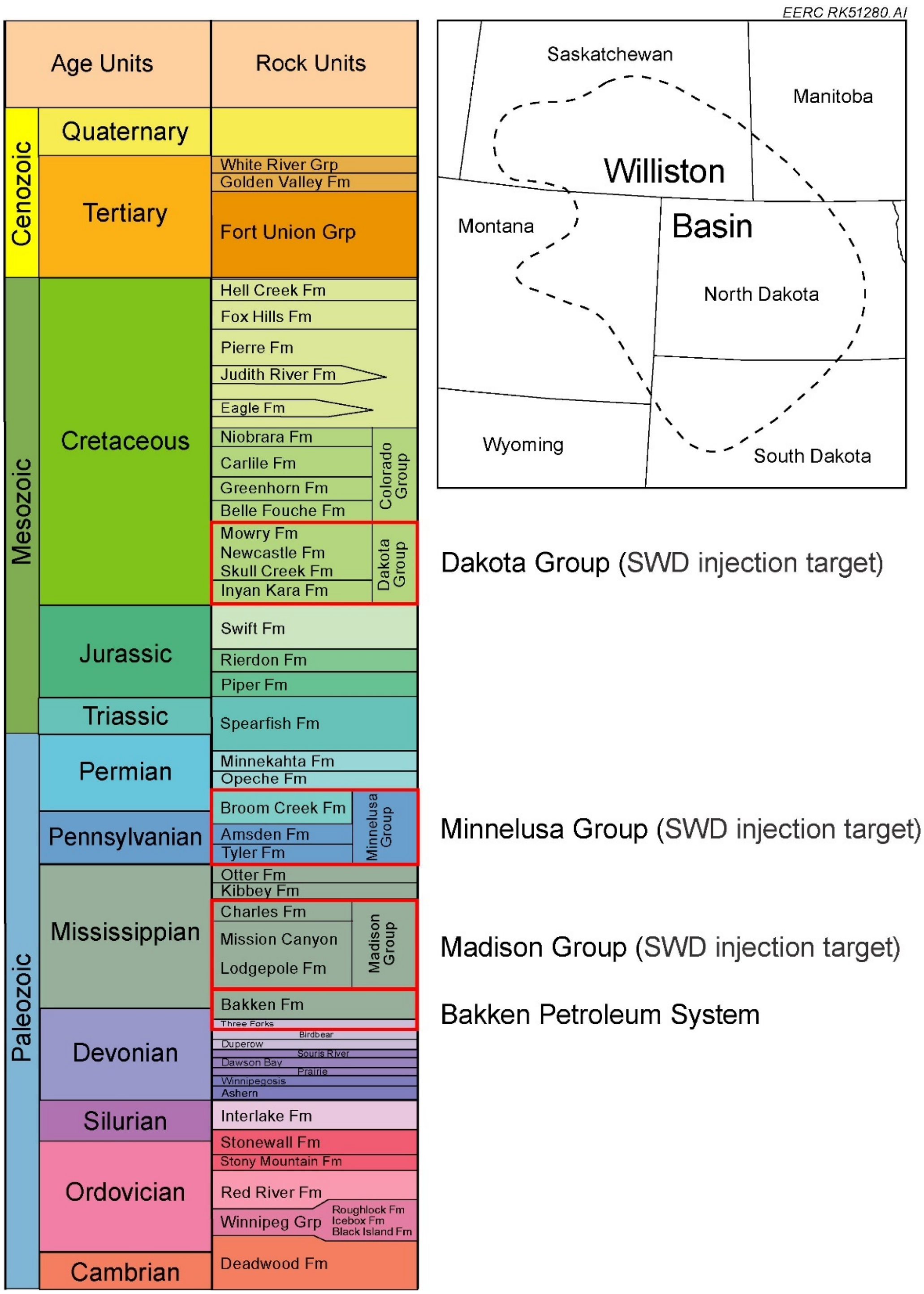

Figure 1. North Dakota stratigraphic column (SWD is saltwater disposal).

BAKKEN WATER MANAGEMENT

Freshwater Use

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. Because of high total dissolved solids (TDS) content in the formation water produced with Bakken oil, operators in North Dakota inject freshwater during production to help prevent salt precipitation and buildup within the wellbore that can restrict production. 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., TDS of formation fluids, temperature drop in the wellbore) of the individual well.

Freshwater use has increased 20-fold since 2008 to more than 290 MMbbl.

Well maintenance typically uses 15–50 bbl/well/day, depending on local conditions of the individual well.

Freshwater is transported by two primary methods, pipeline and truck. Transport method varies among operating companies and by location, and the increased prevalence of distributed water supply systems and pipeline development (including lay-flat hose) are leading to greater volumes of transport via pipeline. Trucking rates are approximately \$100/hour, and total supply cost is influenced by not only the distance traveled but wait times to pick up freshwater. The distance of transport varies by location of the well, water depots, and pipelines. The significant infrastructure development in western North Dakota has reduced the economics of freshwater acquisition and transport, and costs are generally \$2–\$4/bbl of water, according to industry sources. When separating out the costs, acquisition ranges from \$0.25 to \$1.10 per bbl, while the remaining costs are dependent on transport method (i.e., pipeline or truck) and distance. A well using 200,000 bbl of water as hydraulic fluid makeup water (average in 2020) equates to \$400,000 to \$800,000 in water supply costs to stimulate a well.

The cost for freshwater acquisition and transport is generally \$2–4/bbl of water. An average water supply cost to stimulate a well as of 2020 is estimated to be \$400,000 to \$800,000.

While pipelines have a higher up-front capital cost, they allow for 24/7 transport of fluids, whereas transport by truck can be affected by other factors such as weather (i.e., blizzards), seasonal load restrictions (i.e., limits road access or increases transportation cost), and truck availability. Interruptions in the availability of truck transport have direct impact on production, as operations can be halted when fluids cannot be moved to/from the wellsite.

Freshwater Trends

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 fracturing 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 (Figure 2).

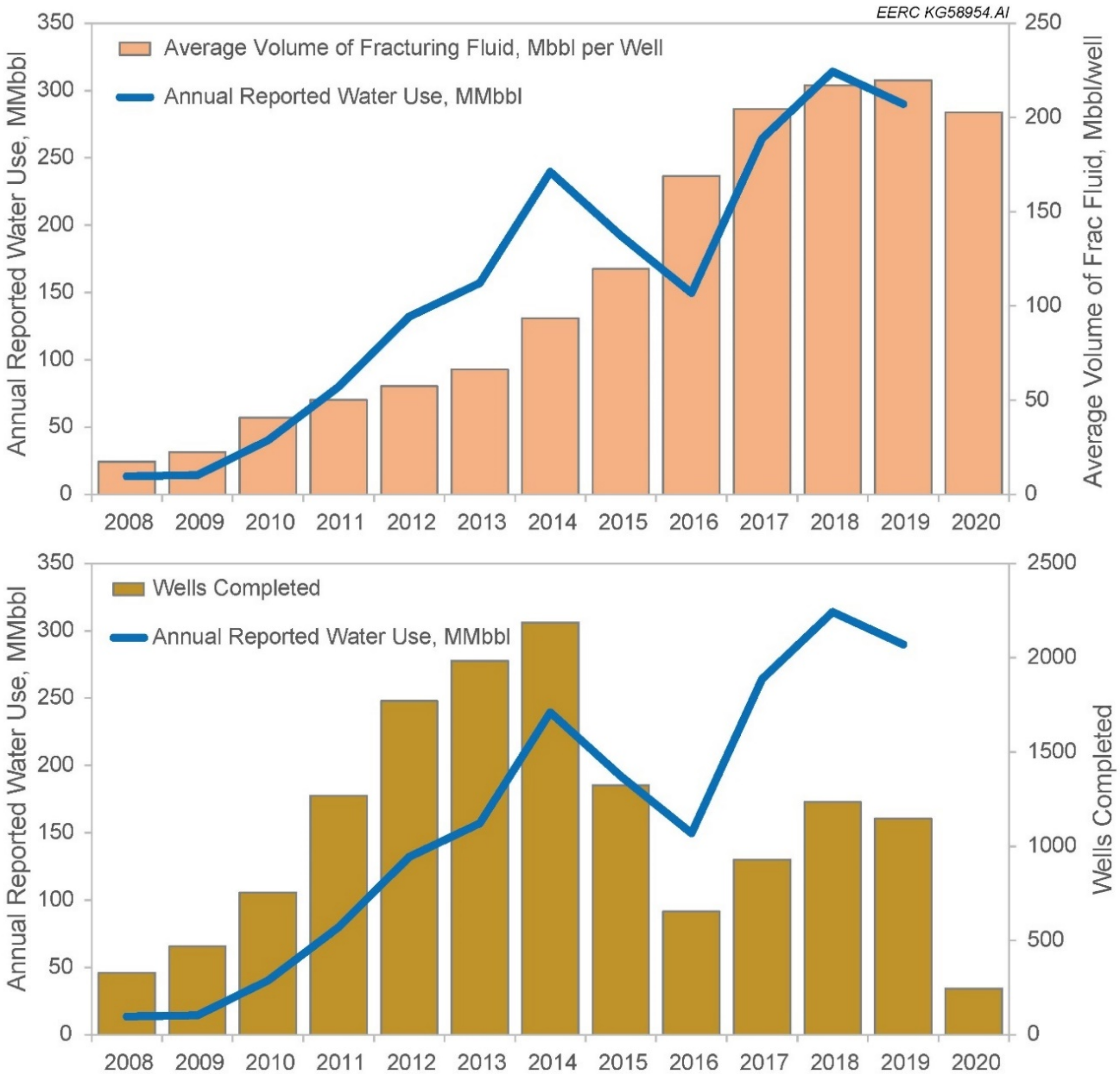

Figure 2. Plot showing industrial water use in MMbbl from permitted sites for oil-related activities (left *y*-axis) from 2008 through 2020 as compared to the average fracture fluid volume per well (top panel, Mbbl, right *y*-axis) and the wells completed in each year (bottom panel, right *y*-axis) (data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

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 200,000 bbl per well (~25.8 acre-feet per well) in 2020 (Figure 2), as derived from data available from over 14,000 wells completed over that time period. Over the last 5 years (2015–2019), freshwater use for hydraulic fracturing is about 87% of the oil and gas industry's total freshwater use volumes, based on NDSWC-reported use and FracFocus-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. Injection rates for slickwater stimulations are typically in excess of 70 barrels per minute (bpm), whereas gel-based stimulations range from 30 to 40 bpm (Pearson and others, 2013).

Over the last 5 years, freshwater use for hydraulic fracturing represents 87% of the oil and gas industry's total freshwater use in North Dakota.

Figure 3 is a scatter plot showing the volume of fracturing fluid used for each Bakken well completed from 2008 through 2020. This plot, updated and modified from Pearson and others (2013), reflects the continued increase in slickwater-based stimulations that started to gain popularity around 2012.

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

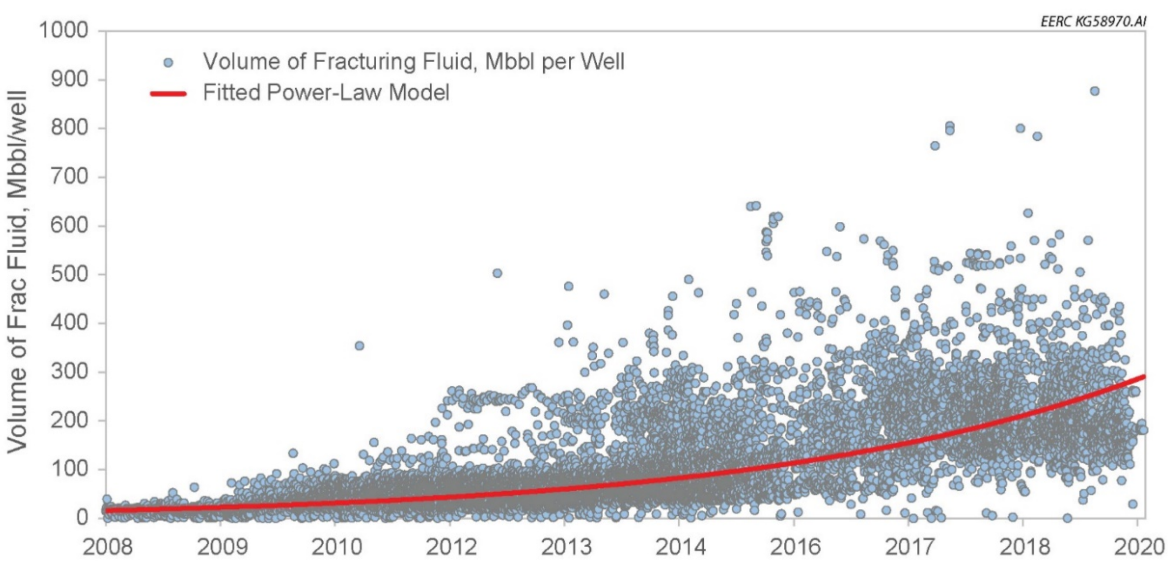

Figure 3. Plot showing the average volume of fracturing fluid (Mbbl per well) used for each Bakken well completed between 2008 and 2020 (data source: Enverus). The red line shows a fitted power-law model through the data points of the form $y = ax^b$, where a = 6.00E-122, b = 26.64, x = date, and y = average volume of frac fluid (Mbbl per well).

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.

Water Appropriation

A consideration for recycling of produced water is the accessibility and cost of freshwater for oil and gas industry use as well as access and cost of SWD relative to alternative practices. Should western North Dakota experience a significant drought that constrains water supplies, the oil and gas industry would be among the first to be impacted. North Dakota water permitting is managed by NDSWC. The prioritization for water use in North Dakota is codified in North Dakota Century Code Chapter 61-01, entitled Appropriation of Water (2020). Priority water use follows §61-04-06.1, Preference in Granting Permits. This section states, "When there are competing applications for water from the same source, and the source is insufficient to supply all applicants, the state engineer shall adhere to the following order of priority:

1. Domestic use.
2. Municipal or public use.
3. Livestock use.
4. Irrigation use.
5. **Industrial use**.
6. Fish, wildlife, and other recreational uses."

Water permits will be prioritized to nearly all other users before industrial users. Furthermore, within each of these categories, the priority is given to the earliest-issued permit. Given this water appropriation structure within the state of North Dakota, a drought should be considered in the context of its potential impact on future water supply for the oil and gas industry. While the recent climate trends have afforded adequate water supplies to meet the state's needs, significant droughts have occurred in North Dakota's history, such as in the 1930s and late 1980s. Several producers interviewed noted concern that a future drought could impact their water supplies, which is placing an emerging focus on identifying alternative water supplies including potential to recycle and reuse produced water within the industry. If produced water from the Bakken is recycled, it would not require a water appropriation permit for beneficial reuse based on North Dakota Century Code §61-04-02.

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. Over the past 5 years (2015–2019), oil-related industrial water use is 1.2 billion bbl (~156,000 acre-feet), representing 9% of North Dakota's total freshwater use of 13.5 billion bbl (~1.75 million acre-feet). As shown in Figure 4, oil industry water use trails volumes used for irrigation, municipal, and power generation uses.

From 2015 to 2019, oil and gas industry freshwater use represents 9% of North Dakota's freshwater use.

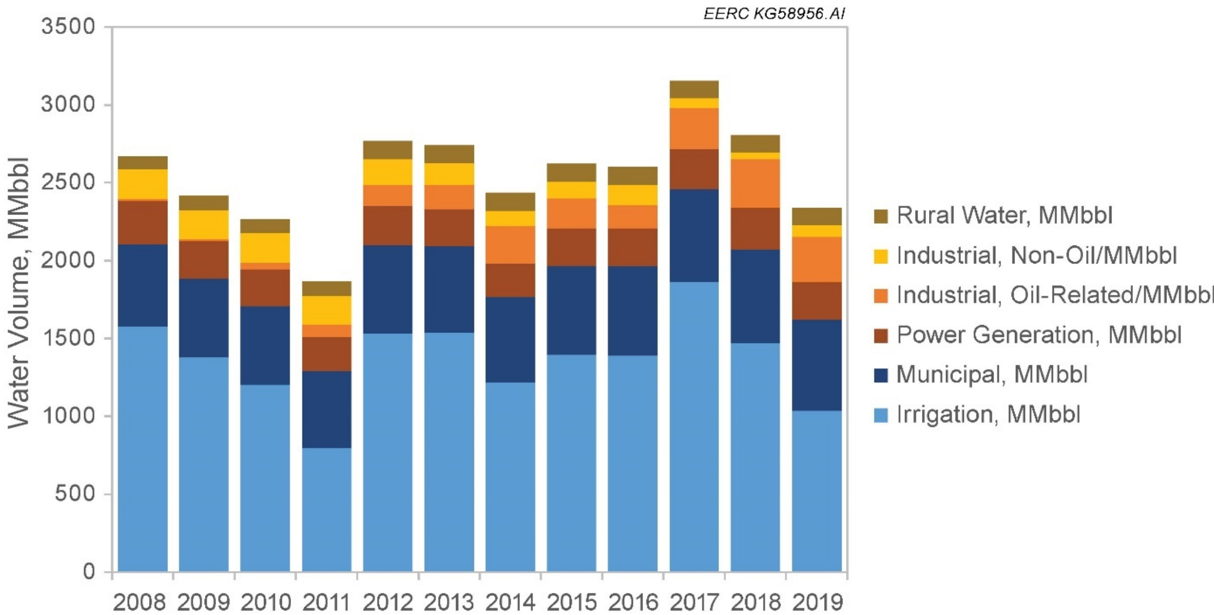

Figure 4. Freshwater use 2008–2019 by water use (data source: NDSWC).

- *Freshwater use on a per well basis has grown substantially over the last decade. Total water use during the next several years will be driven by number of well completions and increasing water use per well. Increased water use volumes for well stimulation impact the economics of oil production through both water supply and water disposal costs.*
- *Bakken wells use a large volume of fluid for stimulations (200,000 bbl/well on average) over the course of a few days. Logistics require the total volume to be transported and stored on location in advance of a stimulation job.*
- *Distributed freshwater supply systems and introduction of lay-flat pipe have substantially reduced freshwater supply and transportation costs. However, because of the high salinity and health, safety, and environmental risks associated with produced water, the success seen with the application of lay-flat pipe for freshwater transport cannot be replicated for produced water.*

Bakken Produced Water Management

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 barrel 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.

Bakken produced water is highly saline, with TDS ranging up to 350,000 mg/L.

Produced water is transported by two primary methods, pipeline and truck, and the method varies by operating company and location. The significant infrastructure development in western North Dakota has reduced the economics of produced water transport and disposal, and costs are generally \$2.10–\$4.00/bbl of water, according to industry sources. Of this cost, injection is \$0.45–\$0.65/bbl, while the balance is dependent on transport method (i.e., pipeline or truck) and distance. Pipeline transport is typically on the order of \$0.25–\$0.50/bbl less than trucking but fluctuates with distance and location. For example, greater elevation changes across the landscape require additional pumps, thus increasing pipeline transport price.

Produced water transport and disposal costs are generally \$2.10–\$4.00/bbl of water.

Produced water volumes for the state of North Dakota have increased from 150 MMbbl/yr in 2008 to 740 MMbbl/yr in 2019. The volumes of water produced from the Bakken increased from 6.4 MMbbl/yr in 2008 to 599.4 MMbbl/yr in 2019 (Table 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 (Table 1, Figure 5a). Figure 6 illustrates the spatial and temporal changes in produced water generation. Produced water volumes have continued to increase with average cumulative oil production per well (Figure 5b). Wells in 2008 had lower volumes of produced water, and a majority of the wells had a lower water cut[2] (Figure 7). In 2015, the number of wells and total water volume per well increased (Table 1, Figure 6). There is also a greater geographic distribution of wells, revealing a "core area" with lower water cut compared to the surrounding area (Figure 7). In 2018, total water produced and average water volumes increased (Table 1, Figure 6), the area of lower water cut was reduced in size (Figure 7), and the geographic distribution of wells decreased, as demonstrated by fewer wells to the north and south portions of the 2018 maps. The average water cut in 2018 across the basin was just over 50%, or more than

Produced water volumes increased nearly fourfold since 2008, topping 740 million bbl/yr in 2019.

[2] Water cut is calculated for each well and is the volume of water produced divided by the total volume of fluids (water + oil) produced.

Table 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

* North Dakota Industrial Commission (2020).

1 barrel of water per barrel of oil. Figure 5c illustrates a trend of average water cut increasing each year, and the drop in water cut observed during the first 3 months of production shows the influence of flowback water.

As annual oil production increases, trends suggest that annual water production will increase at an even greater rate. Increased water production volumes will be associated with increased water management costs, impacting the economics of oil production. In suppressed or low-oil price environments, water management costs in 2020 are confirmed to influence shut-in and restart priority.

The trends in water production and water cut illustrated in Figures 5–7 and Table 1 can be attributed to two primary factors:

- Improved well stimulation techniques and larger stimulations result in larger stimulated reservoir volumes and an improved ability to contact the pore fluids within the reservoir.

- A decrease in reservoir pressure over time may allow for increased migration of water from within the reservoir (Cenegy and others, 2011) or into the reservoir from the overlying Lodgepole Formation or the underlying Birdbear Formation, especially if fractures were generated during well stimulation that extend beyond the target reservoir and remain transmissive throughout production.

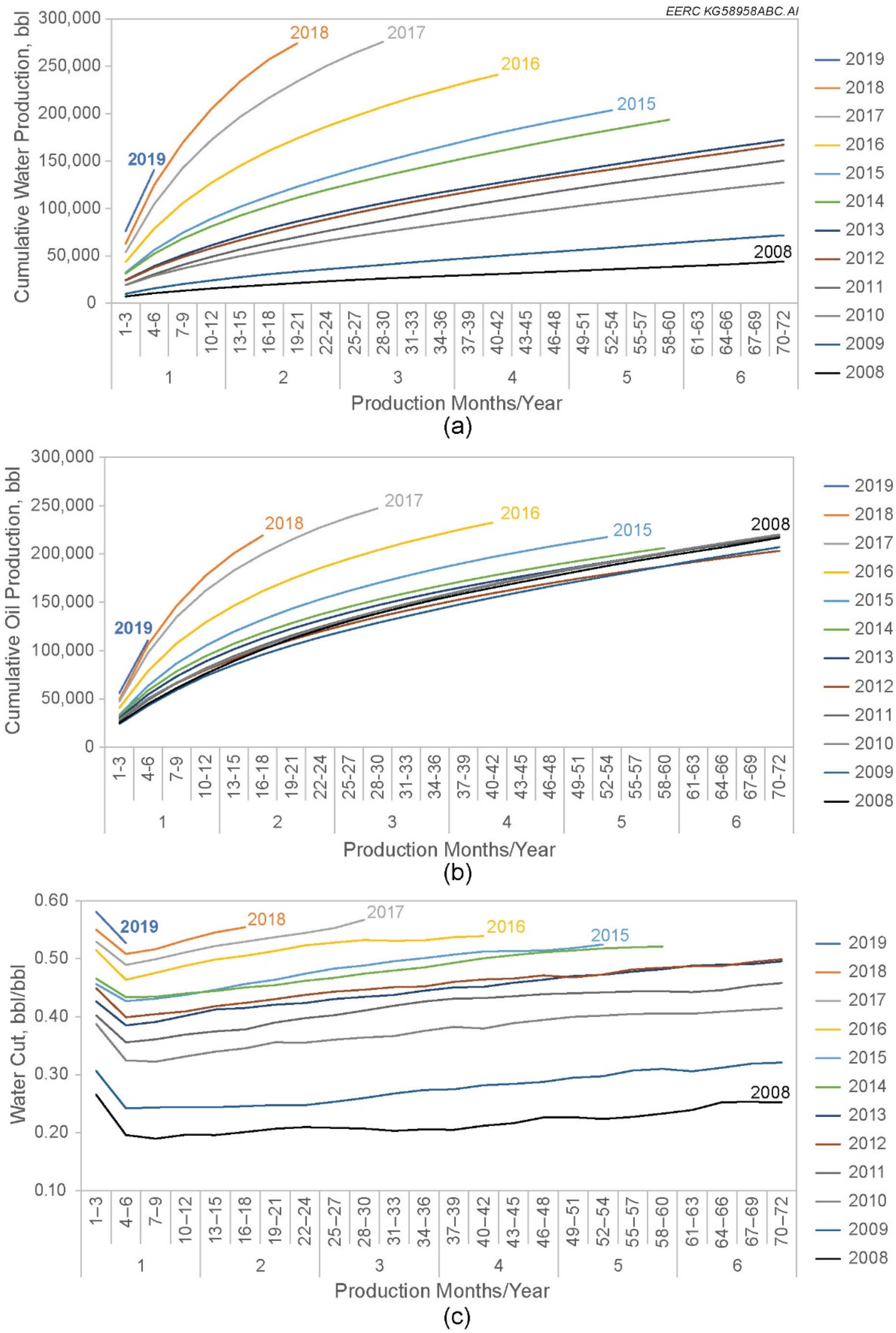

Figure 5. a) Average cumulative water production by number of months on production, b) average cumulative oil production by production month, and c) average water cut by production month for well vintages spanning 2008 to 2019 (data source: North Dakota Industrial Commission, 2020).

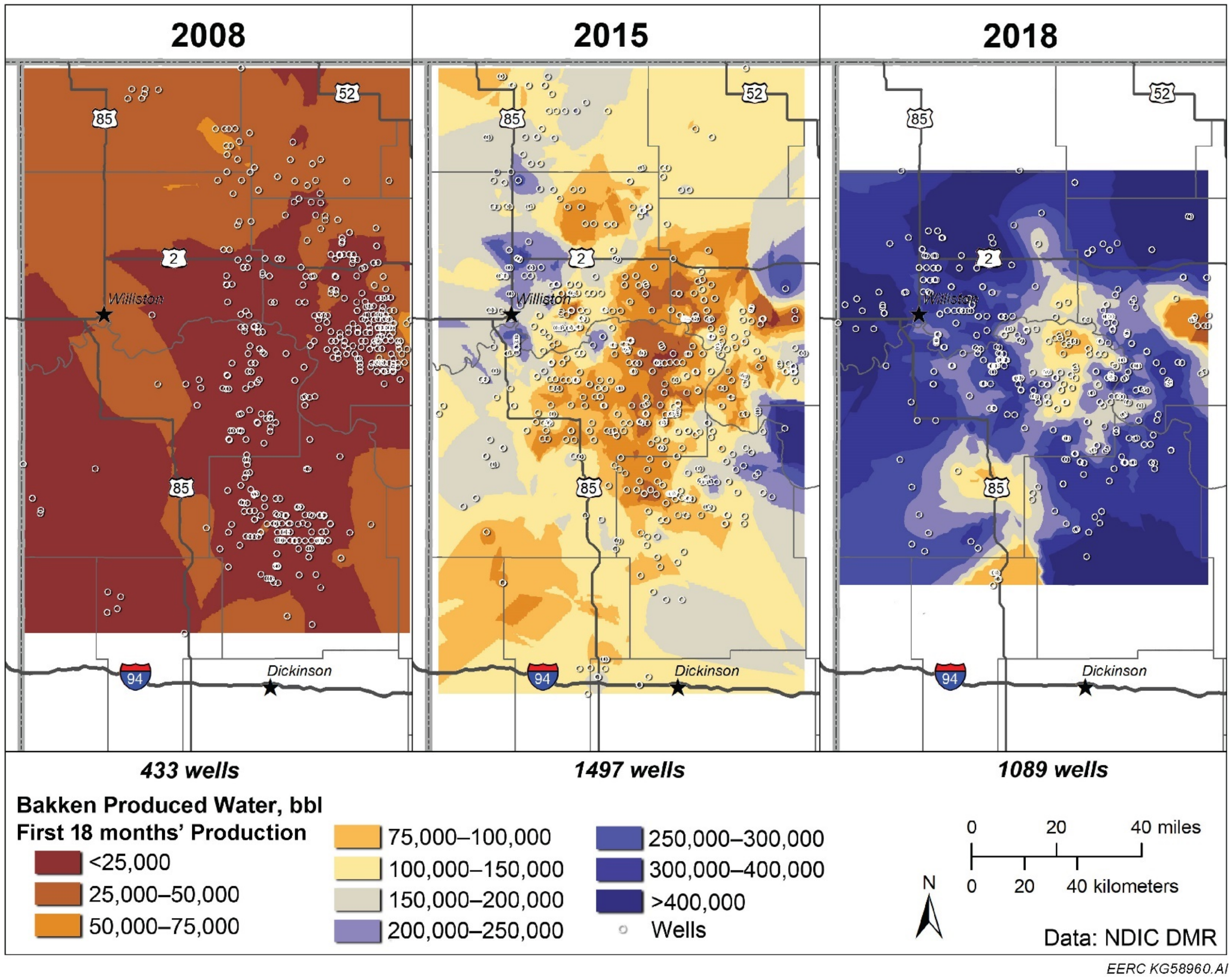

Figure 6. Cumulative produced water generated from Bakken and Three Forks wells during the first 18 months of production (data source: North Dakota Industrial Commission, 2020).

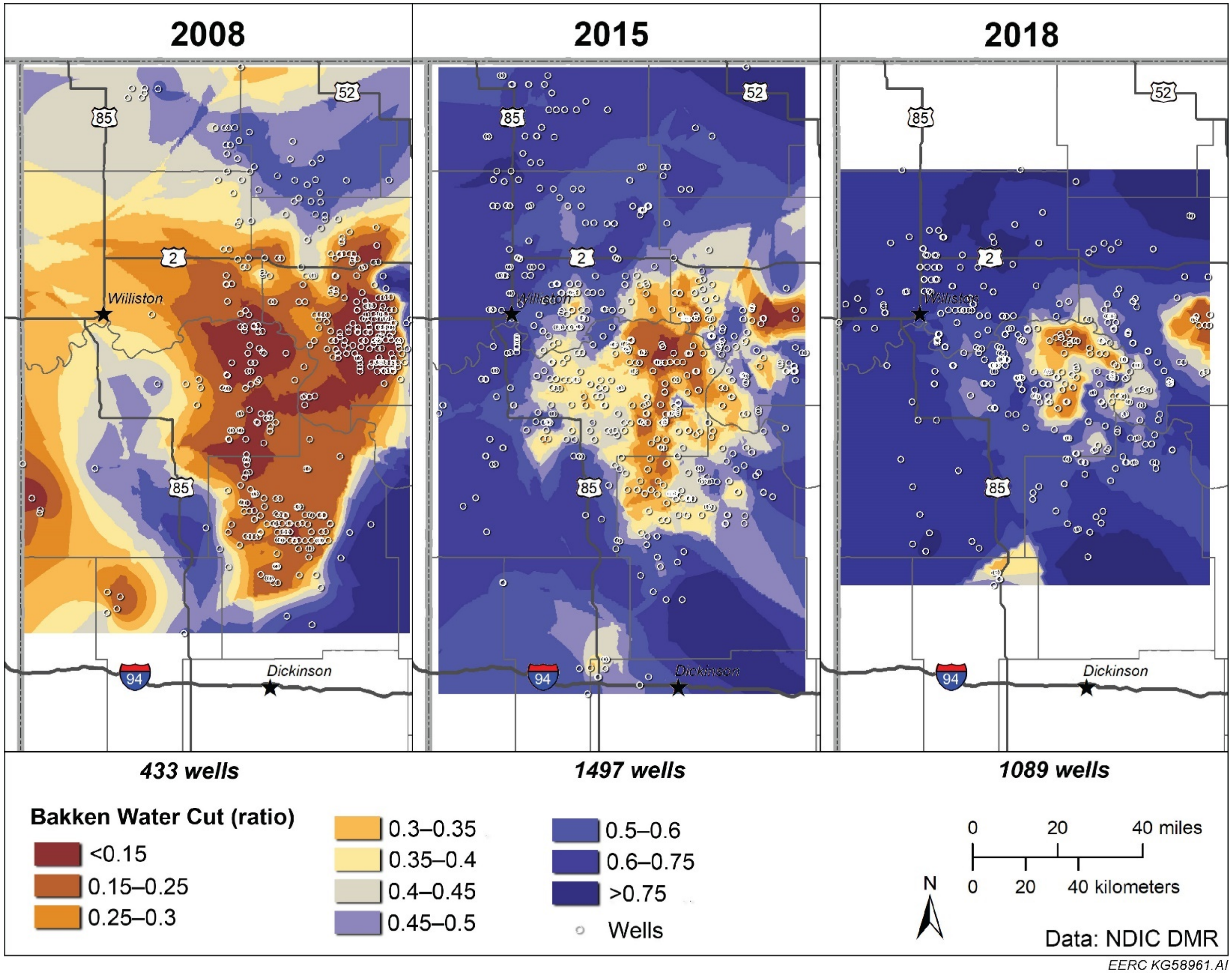

Figure 7. Cumulative water cut of Bakken and Three Forks wells during Months 1–18 of production (data source: North Dakota Industrial Commission, 2020).

Produced Water Projections

The data presented clearly illustrate that produced water volumes continue to increase. Produced water volumes over the next decade will be dependent on the number of new wells brought online, volume of flowback, and water cut associated with geology/geographic regions within the Bakken play. To develop projections of future produced water volumes, an extrapolation method was applied to the historical trends to generate forecasts or produced water under three different active well scenarios. The forecast used the observed trends from 2017 to 2019 and three different assumptions for the well count growth rate from 2020 to 2030. By using the most recent years of record, well completion techniques and water production trends were reflective of the most recent development trends.

The forecast scenario assumes that the rate of well completions could follow three possible trajectories:

- High: Well counts maintain the linearly increasing trend observed from January 1, 2017, through October 1, 2019, which showed a slope of 90 additional completed wells per month.

- Middle: Well counts increase at 50% of the linearly increasing trend observed from January 1, 2017, through October 1, 2019, or 45 additional completed wells per month.

- Low: Well counts increase at 25% of the linearly increasing trend observed from January 1, 2017, through October 1, 2019, or 23 additional completed wells per month.

Next, the forecasts apply a water rate (bbl/well) to the forecasted well count to estimate the volume of produced water each month. The approach assumes that water production rates will maintain the linearly increasing trend observed from January 1, 2017, through October 1, 2019, which showed a slope of 35 additional bbl per well per month. Therefore, the combined approach accounts for an increasing well count and an increasing water rate per well.

Given these assumptions, the number of active wells expected by 2030 ranges from nearly 21,000 (low) to just over 29,000 wells (high) (Figure 8). These active wells would be expected to produce water volumes between 1.96 billion and 2.69 billion bbl/yr (Figure 8). If the actual produced water volumes fall within this projected range, North Dakota could anticipate the need to manage more than double or even triple the volumes of produced water compared to 2019.

North Dakota could anticipate the need to manage between 1.96 billion and 2.69 billion bbl/yr of produced water annually by the year 2030, more than double the volumes of produced water in 2019.

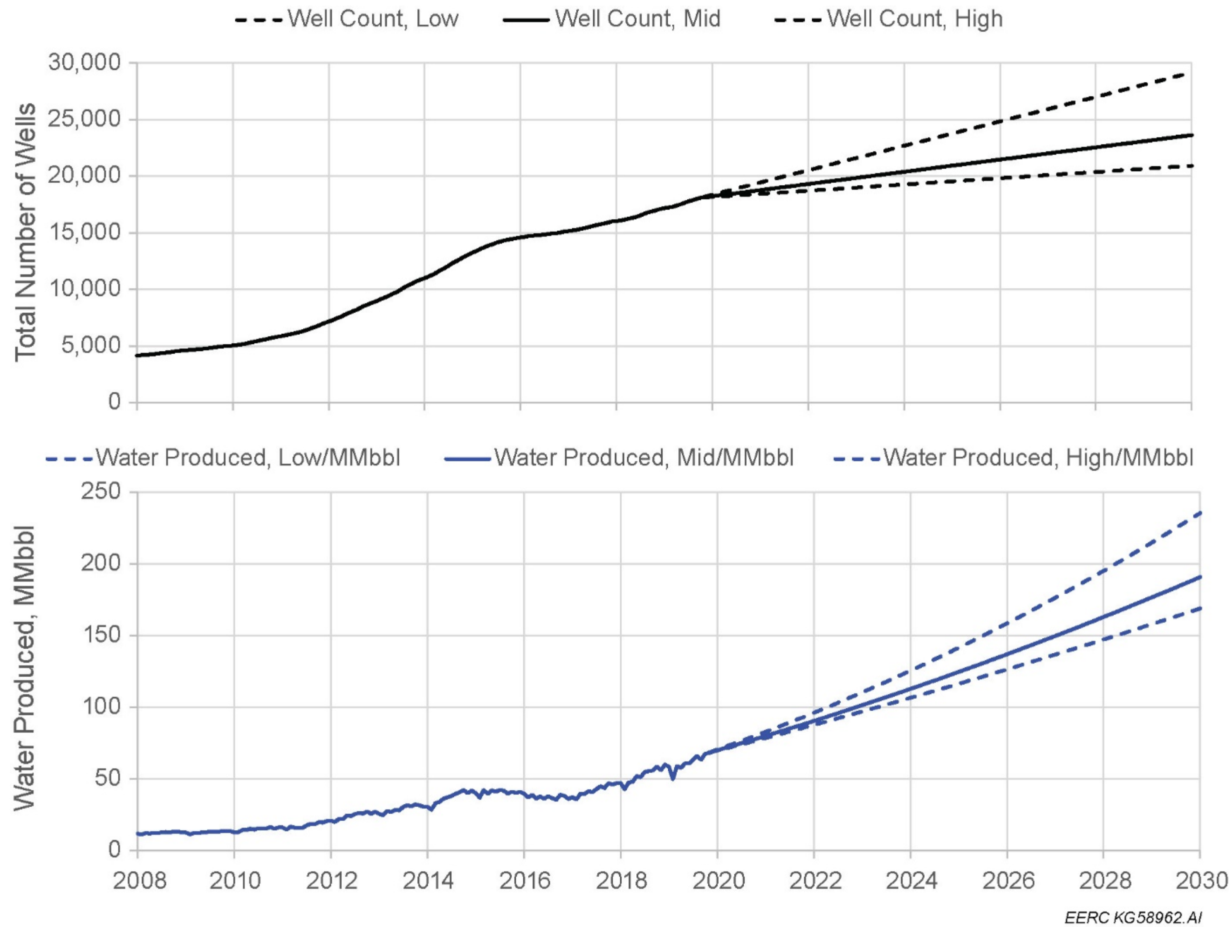

Figure 8. Actual (2008–2019) and projected (2020–2030) well counts under three different growth assumptions as noted in the text (top) and the associated monthly produced water volumes (bottom).

Produced Water Chemistry

An essential component in the advancement of water recycling and reuse opportunities in North Dakota is understanding of the produced water chemistry. Limited publicly available data indicate that the water chemistry varies considerably throughout the Bakken, 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. 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). While not impossible to treat, these factors do make for significant challenges when developing economical water treatment and reuse options, particularly the high TDS levels. Figure 9 presents the applicability of desalination technologies over a range of TDS 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). Additional produced water chemistry data would be beneficial to better understand the water quality and variability across the Bakken, helping to advance the economics of water treatment options to development in North Dakota.

The majority of the TDS content in Bakken produced water is from high sodium and chloride concentrations.

Traditional desalination technologies such as reverse osmosis (RO) typically are only capable of treating waters with TDS levels up to 40,000 mg/L.

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

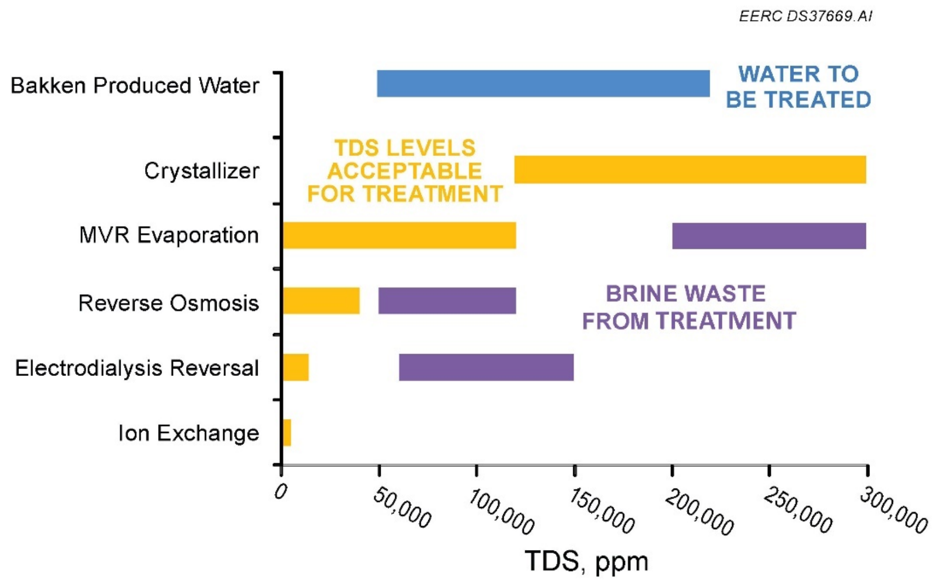

Figure 9. Applicability of various desalination technologies.

in 110 Bakken produced water samples collected and analyzed by the EERC shows that there are some locations where lithium concentrations are above 100 mg/L (what is considered by some to be an economically recoverable concentration), with a range of 138–196 mg/L. The USGS produced water quality database includes lithium concentration data from over 100 wells located in the Williston Basin, and of those wells, 12 have lithium concentrations greater than 100 mg/L, with a range of 118–400 mg/L (U.S. Geological Survey, 2017. Thus, while lithium concentrations may not be elevated across the entire basin, there are locations that may warrant further investigation.

Bakken produced water may contain high-value materials (HVMs) and other elements (e.g., barium, iron, lithium, etc.) that could be of interest for critical mineral recovery and extraction. However, no known studies have been conducted to systematically identify HVMs within Bakken produced water.

Rare-earth elements (REEs) consist of the lanthanide series of elements with atomic numbers from 57 to 71, including lanthanum (La), cerium (Ce), praseodymium (Pr), neodymium (Nd), samarium (Sm), europium (Eu), gadolinium (Gd), terbium (Tb), dysprosium (Dy), holmium (Ho), erbium (Er), thulium (Tm), ytterbium (Yb), lutetium (Lu), and also yttrium (Y) and scandium (Sc). Because of their unique properties, REEs are crucial materials used in an array of consumer goods and electronics, energy system components, and military defense applications. However, the United States is currently 100% reliant on importing these critical materials, and alternative domestic sources of REEs need to be identified within the United States to alleviate a reliance on outside sources. REE concentrations have only been analyzed by the EERC in a total of four produced water samples, and while REE concentrations were below detection, previous work to characterize the REE content of Williston Basin coals has shown that REE concentrations can vary widely across an area. In addition, this past year, the EERC identified a Bakken shale sample that had REE concentrations above 2400 parts per million (equivalent to mg/L in fluid samples),which may indicate measurable quantities of REEs in the associated produced water at that location. Additional evaluation and analysis of the REE content in the rocks and formation fluids across the Williston Basin are warranted.

In addition to lithium and REEs, there are other potential HVMs, such as cobalt, manganese, and copper, that could be present in Williston Basin brines; however, additional work is needed to analyze these constituents in produced water and/or formation fluid samples to determine if the HVM content occurs in significant enough quantities for economical recovery. Additional data would provide for a more comprehensive understanding of the water chemistry of Bakken produced water throughout the Williston Basin. Future work is also needed to evaluate existing and emerging technologies for HVM and REE recovery in high-salinity brines to determine if they are applicable to the brines produced in the Williston Basin.

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.

Furthermore, as SWD has continued to increase over the last 60 years, a better understanding of the chemistry of the disposed fluid would provide valuable insight to the potential interaction between the injected fluids and the native geochemical and petrophysical properties of the Dakota Group (Dakota), the primary injection formation, and potential alternative SWD targets. As areas of reported formation pressurization and questions of injection capacity within the Dakota have begun to emerge, understanding the interaction between the fluids and the formations that are or may be targeted for SWD injection will be paramount for the long-term management of produced water in North Dakota.

- *Cumulative produced water is following an increasing trend. Average water cut per well also continues to increase each year. The trend suggests that total water production will increase at an even greater rate, resulting in increased water management costs that directly correlate to oil value on a per barrel basis.*
- *In the suppressed or low-oil-price environment, water management costs were confirmed to be driving shut-in and restart priority.*

Produced Water Disposal

> *The Dakota has been the primary geologic interval for SWD in North Dakota since 1956.*

Since 1956, the Lower Cretaceous Dakota, which includes the Inyan Kara, Skull Creek, Newcastle, and Mowry Formations, has been the primary interval for SWD in North Dakota. Underground injection control (UIC) Class II injection is permitted for the Dakota; however, lowermost sands of the Inyan Kara Formation are typically the target injection zone for SWD (Bader, 2017). For SWD, the Dakota is normally perforated over a 400-foot interval, but injection is typically only into the most permeable sands (Schmidt and others, 2019). The Dakota is prevalent and laterally extensive throughout the oil producing regions of North Dakota, with depths ranging from 1800 to 6220 feet and a thickness averaging 700 feet in areas coinciding with use for SWD (North Dakota Geological Survey, 2020).

Permeability is typically sufficient to support high rates of injection, with some areas of the formation showing permeability in excess of 1 Darcy, and an average porosity of 20%. Overlying the Dakota are several thousand feet of Cretaceous marine sedimentary deposits, including thousands of feet of shale, the Pierre Formation, in the Colorado Group. The Pierre shale serves as a low-permeability barrier that prevents the upward migration of brine from the Dakota into the Fox Hills Formation, effectively sealing the Dakota Group and protecting the lowermost USDW. The Jurassic Swift Formation underlies the Dakota and consists of several hundred feet of shale with interbedded limestone. These low-permeability shales serve as effective vertical sealing units for the Dakota, making it a suitable option for SWD (Hamling and others, 2016). Dakota formation water TDS values can reach 30,000 mg/L, making it an acceptable formation for injection of Class II fluids, based on NDIC permitting requirements.

> *The Pierre shale serves as a barrier preventing any migration of brine from the Dakota into the Fox Hills Formation, the lowermost underground source of drinking water (USDW) in North Dakota.*

All geologic formations currently used for SWD in North Dakota are located thousands of feet above the Precambrian basement rock where seismicity typically originates, resulting in a low likelihood of induced seismicity. The depth of the Dakota provides for lower drilling costs for SWD wells compared to other disposal formation targets, such as the deeper Minnelusa Group (Figure 1). This, along with Dakota formation thickness and lateral extent throughout the basin, has historically provided North Dakota with essentially a one-size-fits-all approach to produced water management. Previous work evaluating long-term storage capacity of the Dakota indicates that while the formation, as a whole, still has significant long-term storage capacity, there are localized areas within the Bakken that already exhibit increased pressurization

> *All geologic formations currently used for SWD in North Dakota are located thousands of feet above the Precambrian basement rock, resulting in a low likelihood of induced seismicity.*

effects as a result of SWD. Modeling simulations suggest that the localized areas of elevated pressure could expand in size and magnitude with continued SWD in the northern portion of McKenzie County, a core producing area of North Dakota's oil and gas production. Continued SWD injection at the predicted rates could result in the need for operators to curtail SWD rates to meet the maximum allowable injection pressure (MAOP) as defined by UIC Class II injection permit compliance (Ge and others, 2018). As SWD into the Dakota Group continues to increase, capacity issues and pressurization are starting to emerge in some areas of western North Dakota. This results in lower injection rates and higher average injection pressures for SWD wells (Schmidt and others, 2019). High average injection pressures have been observed in the central part of Williams County and McKenzie County near the Missouri River. This gradual pressurization and capacity constraints will necessitate SWD transport to areas further away from producing well locations, resulting in additional traffic in local communities and increased transportation costs. Areas with high cumulative injection rates that could be most impacted by capacity injectivity issues correspond to the Nesson Anticline near the border of Williams and Mountrail Counties.

Operations and workover work can sometimes be performed to improve performance of the SWD well but affect the economics of the SWD. Pressurization within the Dakota is impacting drilling operations and increasing drilling costs for new Bakken production wells. Research on alternative produced water management options for North Dakota could ease the implications of SWD performance capacity, increased areas of localized pressurization, and its economic impacts affecting Bakken production wells.

As capacity issues within the Dakota drive SWD further from areas of core Bakken production, additional traffic in local communities and increased transportation and disposal costs will impact the economics of Bakken production.

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 through SWD wells, some produced water is used in secondary recovery (e.g., waterflood) or during drilling 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 10 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

SWD wells are used to dispose of maintenance and production water related to oil and gas production. The majority of the SWD wells in North Dakota are related to Bakken production.

Bakken development. The primary injection zones for SWD are the Dakota, formations of the Minnelusa Group, and formations of the Madison Group (Figures 1 and 11). SWD volumes for the Madison and Minnelusa have remained relatively steady, as shown in Table 2. Over 95% of SWD in North Dakota is going into the Dakota, primarily into the Inyan Kara Formation, the Dakota's lowermost sandstone interval. Since 1956, nearly 5.8 billion bbl of produced water has been injected into North Dakota SWD wells (North Dakota Industrial Commission, 2020). Forecasts indicate that by 2030, 1.96 to 2.69 billion bbl of produced water will need to be managed annually.

Between 2008 and 2019, active SWD wells have increased 80%, with SWD volumes increasing fivefold.

Over 95% of SWD in North Dakota is going into the Dakota, primarily into the Inyan Kara Formation, the Dakota's lowermost sandstone interval. Since 1956, nearly 5.8 billion bbl of produced water has been injected into North Dakota SWD wells (North Dakota Industrial Commission, 2020). Forecasts indicate that by 2030, 1.96 to 2.69 billion bbl of produced water will need to be managed annually.

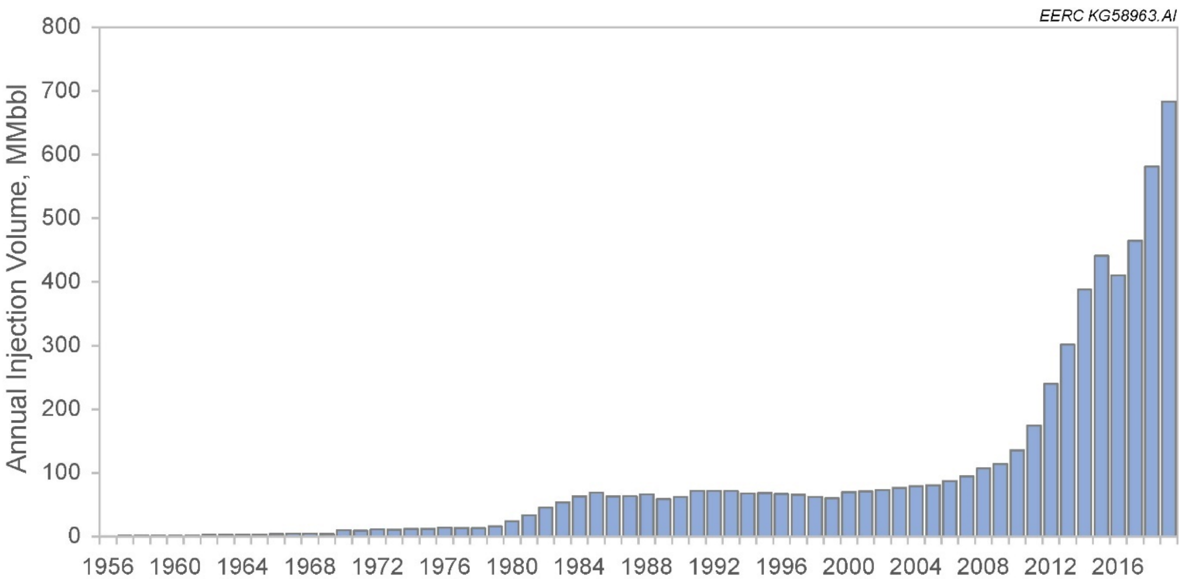

Figure 10. Volumes of all water injected into North Dakota SWD wells since 1956 (data source: North Dakota Industrial Commission, 2020).

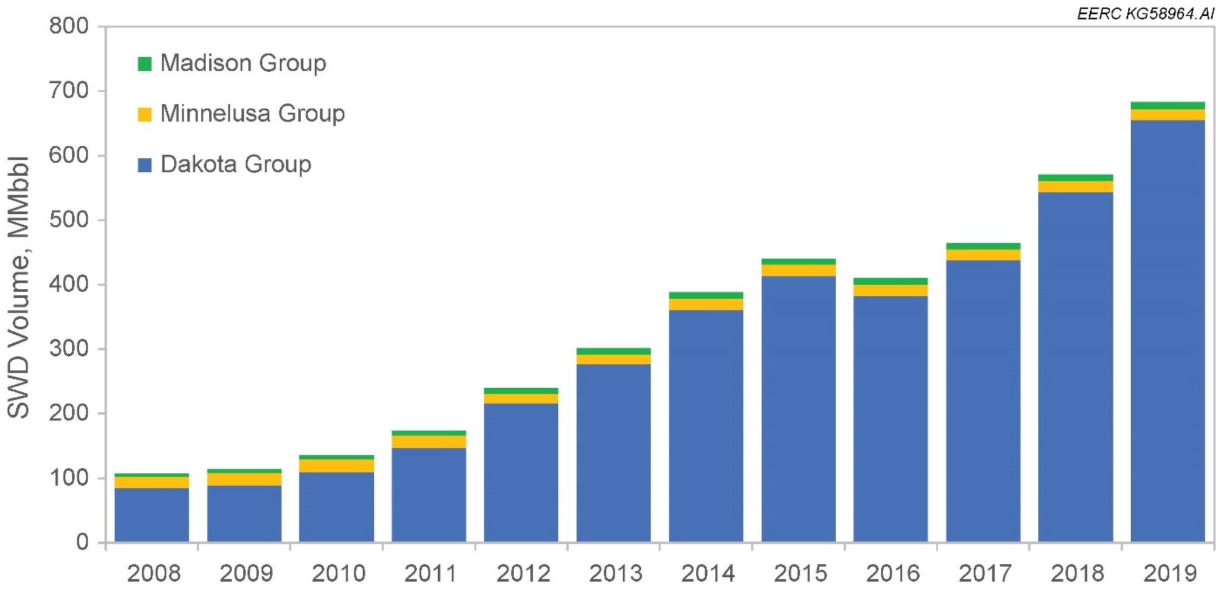

Figure 11. Annual SWD injection volume by geologic group from 2008 to 2019 (data source: North Dakota Industrial Commission, 2020).

Table 2. Total SWD Injection Volumes from 2008 to 2019, MMbbl/yr*

	Dakota Group	Madison Group	Minnelusa Group	Other	Total
2008	84.5	1.1	17.9	3.3	106.8
2009	89.5	1.2	18.8	4.3	113.8
2010	109.6	1.2	19.6	5.1	135.5
2011	147.5	1.3	19.0	6.6	174.3
2012	215.9	1.4	15.0	7.7	239.9
2013	277.3	1.2	14.4	8.4	301.3
2014	361.1	1.0	18.1	7.9	388.0
2015	413.3	0.9	18.6	8.0	440.8
2016	383.0	0.9	16.9	9.0	409.9
2017	438.8	0.8	16.1	8.7	464.5
2018	553.7	0.8	17.3	9.5	581.3
2019	655.1	0.7	17.8	9.8	683.4

* Data source: North Dakota Industrial Commission, 2020.

Figure 12 illustrates the 80% increase in the number of active SWD wells between 2008 (297) and 2019 (537) and highlights the increase in new SWD wells in the areas related to Bakken production. During that same period, disposal volumes increased to over 683 MMbbl, an increase of 450% (North Dakota Department of Mineral Resources, 2020d). If SWD injection was evenly distributed per well, this would equate to an average annual injection volume at each disposal well of 1.3 MMbbl for 2019. However, as Figure 12 illustrates, injection volumes are not evenly

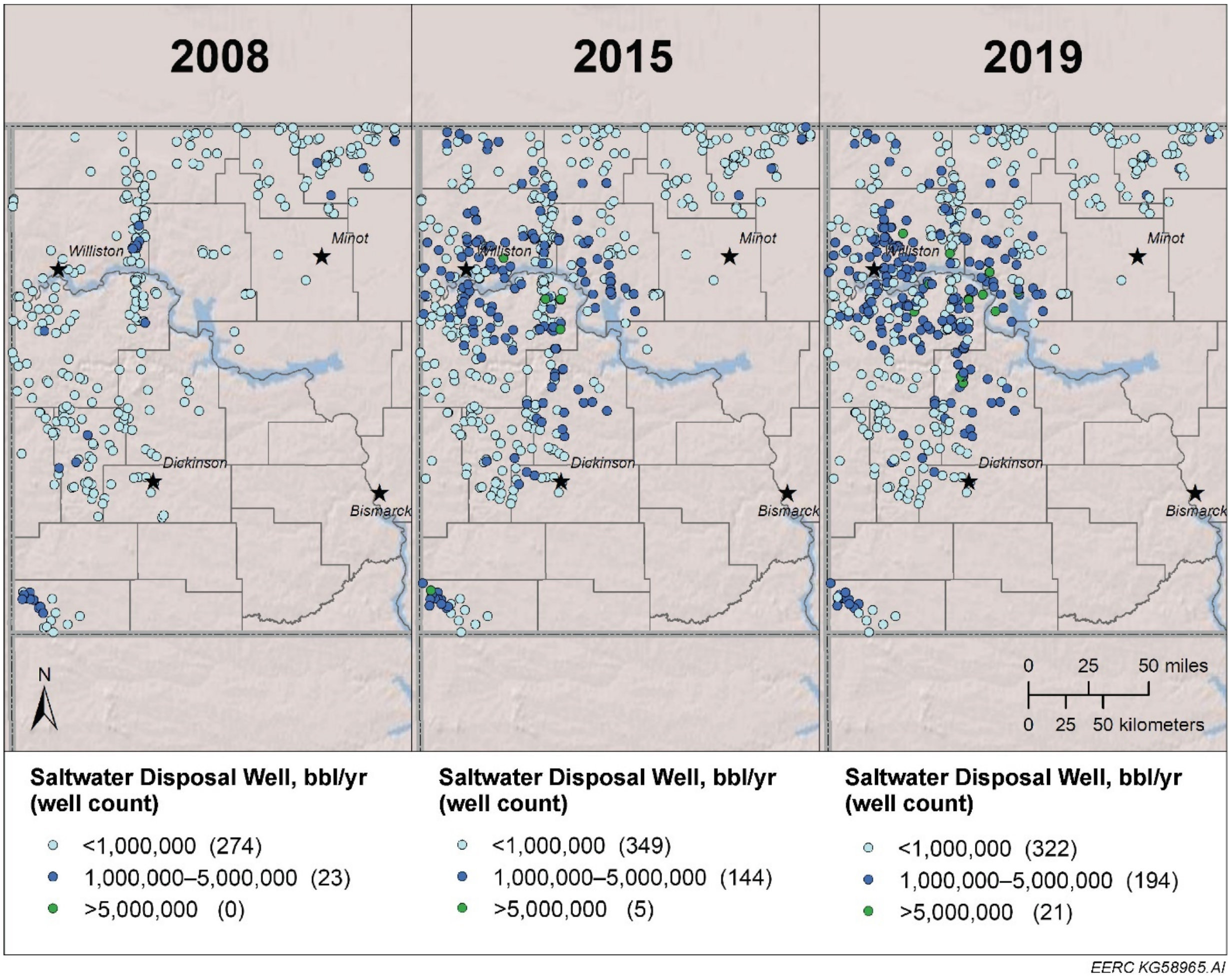

Figure 12. Comparison of SWD well volumes between 2008 and 2019 (data source: North Dakota Industrial Commission, 2020).

distributed throughout all of the SWD wells in the state. As the map shows, in 2008, while there were nearly 300 active SWD wells within the state, almost 40% of the total volume of injected fluids was injected via 23 wells.

Injection volumes are not evenly distributed throughout all of the SWD wells in the state. In 2008, almost 40% of the total volume of injected fluids was injected via 23 wells. In 2019, the number of SWD wells injecting over 1 MMbbl each year rose to over 200 wells, representing over 80% of the total SWD volume for the year.

In 2019, the number of SWD wells injecting over 1 MMbbl each year rose to over 200 wells, representing over 80% of the total SWD volume for the year. These high-volume wells are commonly related to areas of increased Bakken production. As of July 2020, the Fort Berthold Reservation produced over 250,000 bbl/day (North Dakota Industrial Commission, 2020), representing approximately 25% of North Dakota's annual oil production volumes. The majority of produced water associated with this oil production is disposed of at nearby SWD sites. The federal jurisdiction under the U.S. Environmental Protection Agency (EPA) has additional permitting constraints, resulting in fewer SWD well permits. This results in much of the produced water often being trucked to the outside perimeter of the reservation for disposal at SWD sites nearby.

The Fort Berthold Reservation represents 25% of North Dakota's annual oil production volumes.

Historic trends have suggested that rather than the number of SWD wells increasing proportionally to the volume of produced water being generated, the volume of brine injected at individual SWD wells is substantially increasing, correlating with areas of core Bakken production. NDIC well file data and discussions with Bakken operators and SWD companies indicate that the highest SWD rates are associated with areas of core production, including locations near Williams and McKenzie County and the boundaries of the Fort Berthold Reservation. Of the top SWD wells by injection volume for 2020, the majority were third-party-operated (e.g. not operated by the oil production company) and in areas located near these core Bakken production areas.

Of the top SWD wells by injection volume for 2020, the majority were non-producer-operated and located in areas of core Bakken production near the Williams and McKenzie County boundary and the boundaries of the Fort Berthold Reservation.

In addition to SWD well performance, the pressurization of the Dakota in proximity to SWD wells is already resulting in significant impacts and expense for Bakken operators when drilling new production wells. A higher-density drilling fluid is needed when drilling through areas with increased formation pressure in the Dakota caused by SWD. The higher-density drilling fluid increases hydrostatic pressure in the wellbore and could result in the unintentional fracture of the underlying formations. These localized areas of pressurization from SWD have resulted in the need to install an additional casing string (Basu and others, 2019) to manage pressure while drilling by mechanically isolating the Dakota, as illustrated in Figure 13. There are more than 200 wells that have been identified as having needed an additional casing string (Figure 14). This does not include wells currently listed under confidential status as of June 2020. Figure 14 displays the wells by the year they were completed, with the

Localized areas of pressurization from SWD have resulted in the need to install an additional casing string to manage pressure while drilling new Bakken production wells.

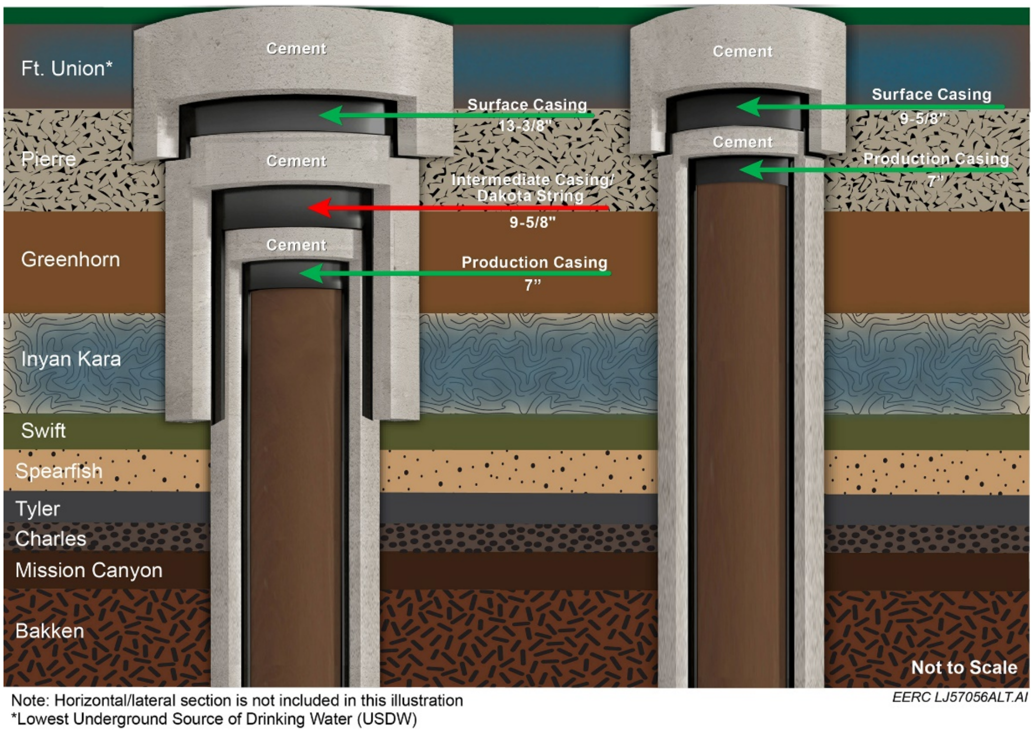

Figure 13. Illustrative diagram for a well using an intermediate casing string, or “Dakota String” (left wellbore) and a typical well diagram without the addition of a Dakota String (right wellbore).

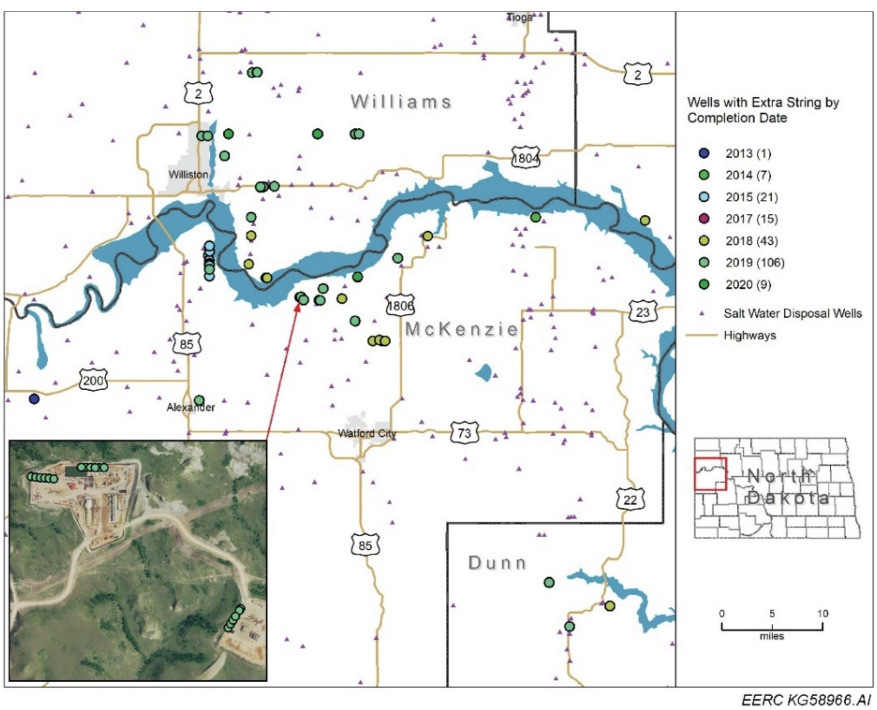

Figure 14. Map of Bakken production wells with Dakota Strings, displaying 202 wells by year of well completion. Many of the displayed wells share well pads, overlapping the symbols at the given map extent (inset map shows example).

first additional casing string being installed in August 2013 and seven more installed in 2014. By 2019, that number had increased to over 100, accounting for nearly 10% of the total wells completed in North Dakota that year (North Dakota Industrial Commission, 2020). While there are some outliers, the majority of the wells requiring an additional casing string are correlated to areas of core production and increased SWD volumes (North Dakota Industrial Commission, 2020). Installation of the additional casing string is reported to increase the impacted cost of Bakken wells by about $500,000. 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 between the Bakken and other basins, such as the Permian. (Personal Communication, Bakken Producers, 2020).

As of June 2020, over 200 wells have been identified as having an additional casing string installed to isolate the Dakota during the drilling of new Bakken wells. Additional casing string costs are an additional ~$500,000 per well and were required for nearly 10% of the total wells completed in North Dakota in 2019.

Pressurization of the Dakota increases drilling costs and may constrain SWD capacity, leading to longer transport and higher SWD costs which impose an economic stressor on oil and gas development. This could be particularly impactful to core producing areas of the Williston Basin, which have historically been the most resilient to low-oil-price environments but also tend to have the largest produced water volumes and are beginning to see capacity and pressurization impacts that affect production costs, allowing for preservation of key workforce and services, which allows for efficient recovery when prices rebound.

As of March 2020, there were 16,280 producing oil wells in North Dakota, with 91% (14,896) of those wells targeting the Bakken and Three Forks Formations.

As of March 2020, there were 16,280 producing oil wells in North Dakota, with 91% (14,896) of those wells targeting the Bakken and Three Forks Formations (North Dakota Department of Mineral Resources, 2020a). Bakken oil and gas are projected to continue to increase for the coming decades (North Dakota Department of Mineral Resources, 2020a), driving a need for SWD or alternative recycle and reuse options. As Bakken production continues to rise, produced water generation and subsequent disposal will continue to increase at a relative pace as continued well maintenance is needed and new wells continue to come online. With a low-end estimate for the Bakken of 21,000 producing wells by 2030, 1.96 billion bbl/yr of produced water is projected by 2030, resulting in 1.76 billion bbl/yr in SWD. With a high estimate of over 29,000 wells, SWD is projected to increase to 2.69 billion bbl/yr, presented in Figure 15. While the Dakota has and will continue to accommodate billions of barrels of SWD, emerging pressurization and capacity challenges are contributing to a growing need to look at alternative SWD or recycling and reuse options, which affect the economics of North Dakota's oil production.

As Bakken production continues to rise, produced water generation and subsequent disposal are forecasted to double or triple by 2030 as continued well maintenance is needed and new wells continue to come online.

SWD into the Dakota, with its shallow depth, large capacity, and ubiquitous presence throughout the Bakken producing region, has historically represented a one-size-fits-all solution to produced water management in North Dakota. Forecasts and emerging trends suggest it may not be a permanent solution for the long term. While alternate geologic SWD targets exist, they are not as regionally extensive and are more costly to operate because of their depth and capacity. Likewise, produced water recycling and reuse face economic and technical challenges. While there are options for a Plan B, it will likely not be a one-size-fits-all approach.

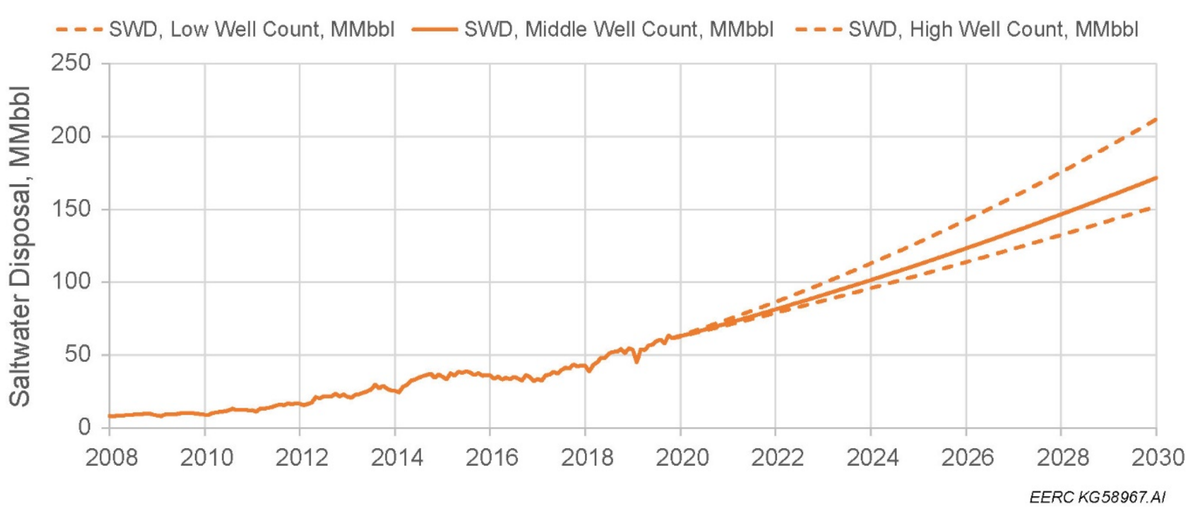

Figure 15. Actual (2008–2019) and projected (2020–2030) SWD under three different growth assumptions as noted in the text.

- *North Dakota has been fortunate to have a one-size-fits-all solution to produced water management with SWD into the Dakota Group. The Dakota Group's geographic extent, relatively shallow depth, and injectability have made it a SWD target that is suitable across the entire Bakken producing region in the state. Based on the forecasted increasing volumes of produced water and associated SWD, that may not always be the case. Alternative solutions are not as ubiquitous across the entire Bakken producing region.*
- *Pressurization of the Dakota Group is leading to increased drilling costs and may limit SWD capacity, leading to increased transportation and disposal volume, thus increasing SWD costs. The issue will be exacerbated in core development areas, which have historically been more insulated from price depressions, leading to an emerging trend toward less economical wells in these areas.*

OPPORTUNITIES IN WATER MANAGEMENT

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. Projections show that produced water volumes and subsequent disposal are forecasted to rise significantly in the next decade (Figure 16). Tremendous volumes of water are being managed in the region, and the forecasted increases may make the business-as-usual approach of SWD into the Dakota untenable in the long term.

	Well Count			Water Produced, MMbbl			Saltwater Disposal, MMbbl		
Year	Low	Middle	High	Low	Middle	High	Low	Middle	High
2020	18,288	18,475	18,857	884	894	912	796	804	821
2021	18,564	19,015	19,937	992	1016	1066	893	915	959
2022	18,840	19,555	21,017	1103	1145	1230	992	1030	1107
2023	19,116	20,095	22,097	1216	1278	1406	1094	1150	1265
2024	19,392	20,635	23,177	1332	1418	1592	1199	1276	1433
2025	19,668	21,175	24,257	1451	1562	1790	1306	1406	1611
2026	19,944	21,715	25,337	1573	1712	1998	1415	1541	1798
2027	20,220	22,255	26,417	1697	1868	2218	1527	1681	1996
2028	20,496	22,795	27,497	1824	2029	2448	1642	1826	2203
2029	20,772	23,335	28,577	1955	2196	2689	1759	1976	2420

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Figure 16. Summary of annual forecasted water production and disposal to 2030.

The current business-as-usual approach to water management continues to be the preferred method among industry, as it provides the most cost-efficient means of disposal and limits the amount of handling/processing of produced water, thereby reducing the risk of spills. North Dakota has been fortunate to have a one-size-fits-all solution to produced water management with the Dakota. The Dakota's geographic extent, relatively shallow depth, and injectability provide a SWD target that is suitable across the entire Bakken producing region in the state. Based on forecasted increasing volumes of produced water and associated SWD, that may not always be the case, and alternative solutions are not applicable across the entire Bakken producing region. The implications of SWD performance capacity, increased areas of localized pressurization, and economic impacts affecting Bakken production wells will require alternative produced water management options for North Dakota.

The implications of SWD performance capacity, increased areas of localized pressurization, and economic impacts affecting Bakken production wells will require alternative produced water management options for North Dakota.

Alternative SWD targets include the Minnelusa Group (primarily the Broom Creek and Amsden Formations) and formations of the Madison Group. Minnelusa SWD is occurring on the southern edge of Bakken development, and Madison Group SWD is occurring in the southwest part of the state along the Cedar Creek Anticline. The Madison Group occurs throughout western North Dakota, including within the entire area of the Bakken. The Broom Creek Formation occurs in North Dakota in an area roughly south and west of the Missouri River and extending into Montana and South Dakota. Each of these potential SWD targets are deeper for SWD, resulting in increased costs when compared to the Dakota. Additionally, these formations are being explored as resources for CO_2 storage in parts of southwest and central North Dakota. This could create competition for the resource by reducing the potential capacity for SWD. The viability of these two alternative SWD horizons and depleted conventional oil and gas fields should be further evaluated as a potential supplement to Dakota SWD.

Given the geographic proximity of these formations to the Bakken, the viability of the Minnelusa and Madison Groups as SWD target backup options for SWD warrants further consideration as a potential supplement to Dakota SWD.

There is growing recognition that alternative approaches to produced water management, including recycle/reuse options, will be needed to address the increase produced water volumes that will result from continued Bakken development. There are significant concerns and hurdles that need to be considered for any potential water management solutions that could supplement Dakota SWD.

A significant hurdle in reusing produced water as makeup water is the ability to store large volumes of extremely high TDS water near the wellsite.

One target for reuse of produced water is as makeup water for hydraulic fracturing fluids. The concept of reusing produced water requires storing and processing large volumes of that high-TDS water near the wellsite over a very short period of time. Water volumes for makeup water for hydraulic fracturing are averaging 200,000 bbl/well for a single well stimulation, resulting in significant logistical hurdles 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 is also a concern. Assuming traditional recycling methods are used, transport and handling of the water at a centralized recycling facility introduces risk associated with large-volume spills. 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). An opportunity exists to assess whether there are valuable products that can be extracted from produced water. If a market could be developed that turns the waste to a valued product, the logistics in waste handling and economics of recycling could be a more viable option.

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An opportunity exists to assess whether there are valuable products that can be extracted from produced water. If a market could be developed that turns the waste to a valued product, the logistics in waste handling and economics of recycling could be a more viable option.

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 geologic homogenization, conditioning, and reuse (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 17), 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 18). 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.

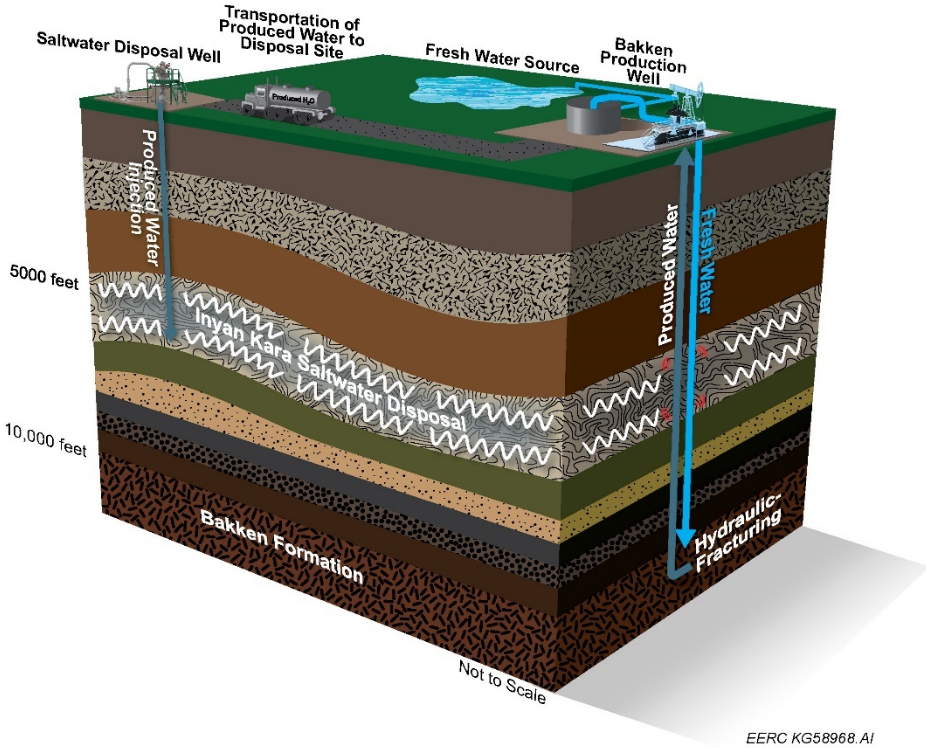

Figure 17. Traditional approach to water management.

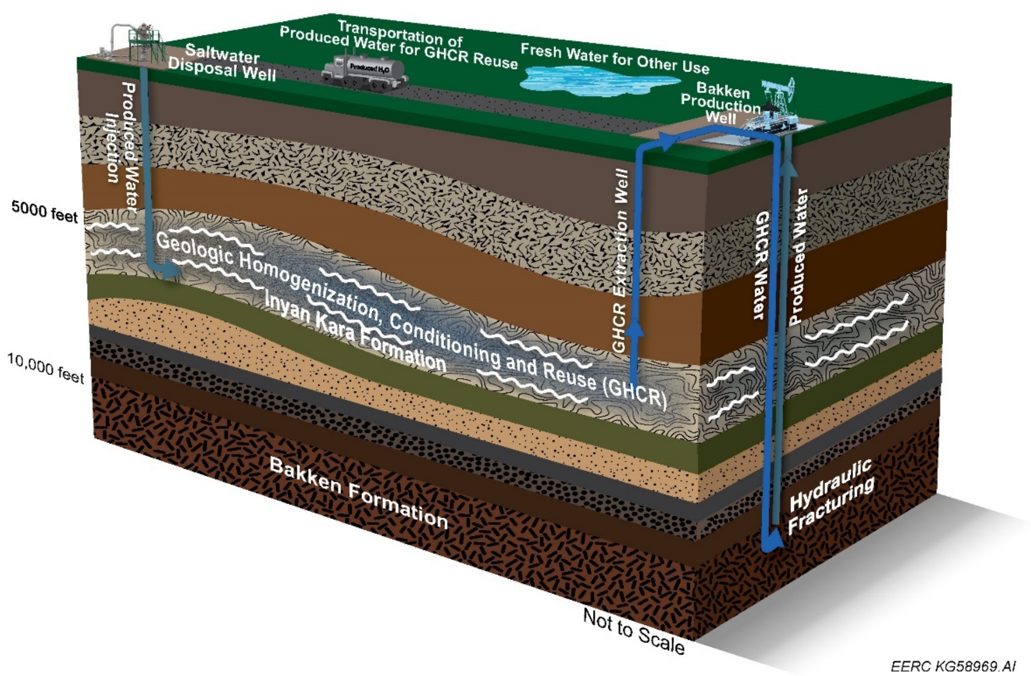

Figure 18. GHCR concept involving the addition of an extraction well and utilizing that water as hydraulic fracturing makeup water for Bakken wells.

If proven viable, the GHCR concept could address many of the recycling challenges outlined in the previous section. 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 is investigating the techno-economic viability and will look at potential benefits of the GHCR concept including:

- 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 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 water string. Results indicated that an extraction well 10,000 feet from a SWD well, temporarily extracting brine between 5000–25,000 bbl/day 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.

Results indicated that brine extraction could be used to temporarily reduce Dakota pressure while drilling to avoid the need to install a water string.

CONCLUSIONS

Water management has direct implications to the future economics of oil development and production in North Dakota. Today, almost 95% of North Dakota's produced water (or approximately 650 million barrels in 2019) is managed through SWD into the Dakota. The Dakota, with its tremendous capacity, relatively shallow depth, and ubiquitous presence throughout the oil producing region of North Dakota, has historically provided a one-size-fits-all approach to produced water management. However, with annual produced water rates increasing and projected to exceed 2 billion bbl/year by 2030 (more than double 2019 volumes), challenges are emerging that may impact the continued use of SWD into the Dakota as the almost exclusive means of produced water management in North Dakota.

Estimated freshwater sourcing and transportation costs range between $2 and $4/bbl. The volume of freshwater used for a Bakken well stimulation has increased dramatically over the past decade, now averaging more than 200,000 bbl of water per well, which equates to $400,000–$800,000 in freshwater cost on a per well completion basis. NDIC estimates 40,000 ($60/BO) to 85,000 ($80/BO) completed North Dakota wells are anticipated to fully develop the Bakken (of which just over 19,000 have been completed as of June 2020), indicating a continued long-term demand for freshwater. Some producing wells are additionally using 15–50 bbl/well/day of freshwater for production maintenance to prevent salt precipitation in producing wells that would otherwise inhibit production.

Estimated produced water transportation and SWD costs range between $2.10 and $4/bbl. Water cut in Bakken wells has steadily increased, more than doubling since 2008, and has now surpassed 50%. As a result, newly completed Bakken wells are now producing more than one barrel of water for every barrel of oil produced.

The year-over-year increase in freshwater use for hydraulic fracturing and the associated flowback volumes, increase in water cut, and increasing cumulative production rates coupled with a growing active well count have resulted in a more than fourfold increase in annual produced water volumes since 2008. Furthermore, the results of this study indicate that produced water volumes are projected to double again to exceed 2 billion bbl/year by 2030.

As a result of SWD in areas coinciding with the highest oil production, pressurization of the Dakota is beginning to be observed, which could limit disposal capacity and increase disposal costs (due to higher injection pressures or longer transportation distance) in the highest-producing areas of the Bakken. The techno-economic challenges of SWD are further compounded by the relatively recent need to install an additional casing string (estimated to cost $500,000 per well) to manage pressure and drilling fluid density when drilling new Bakken wells in areas impacted by pressurization in the Dakota. Nearly 10% of wells completed in 2019 were required to install the additional casing string. The areas impacted by pressurization of the Dakota are anticipated to continue to expand as SWD rates increase.

At sub-$50/bbl oil prices, water management costs could account for more than 10% of the market value of Bakken produced oil, which shifts the economics of oil production. The results of the study show that higher oil production has become increasingly tied to higher water production, so the economic challenge may be particularly exacerbated in core development areas with the highest production rates. This runs counter to previous times of economic adversity in the Bakken, during which the core development areas have historically been more resilient to low-oil-price environments. As a result, water management costs were a notable factor in Bakken production shut-in and restart priority during the low-oil-price environment of 2020.

Alternative options for produced water management exist but are not one size fits all and are generally less economical than current Dakota SWD. The use of alternative SWD targets such as the Minnelusa Group, Madison Group, or depleted conventional oil and gas targets is one such approach. While in aggregate these alternative potential SWD targets coincide with much of the oil-producing region of North Dakota, they are deeper, resulting in higher development and disposal costs, and are not nearly as ubiquitous in geographic extent. For example, the Broom

Creek Formation within the Minnelusa Group which is used as an alternative SWD target in southwestern North Dakota is primarily present in areas south and west of the Missouri River. The Madison Group is more extensive throughout the central and northern portions of the Bakken producing region; however, the presence of formation properties (e.g., porosity and permeability) suitable for large-scale SWD applications tends to be more intermittent.

Another potential approach is produced water recycling and in-industry reuse (e.g., for hydraulic fracturing makeup water). While here has been some limited prior technical success using produced water as hydraulic fracture makeup water dating back to 2015, the application faces regulatory, technical, logistical, and economic challenges which have thus far precluded commercial adoption. Such challenges are associated with large-volume transport, chemical variability, aggregation, and the need for large-scale temporary surface storage of high-TDS brines at a somewhat consistent composition needed to supply a high-rate 200,000-bbl hydraulic fracture stimulation. In short, the practices necessary to use high-TDS produced water for hydraulic fracturing create both logistical challenges and potential environmental hazards in the event of a spill or release, which render this approach unattractive to both industry and regulators.

While the extremely high TDS levels (>30% of the mass of Bakken produced fluids are chlorides) create a major obstacle for the adoption of treatment, recycling, and beneficial use options, there are innovative approaches being pursued that have the potential to better enable the development of produced water recycling and reuse. One such potential approach being developed by the EERC is the GHCR concept, which is currently being tested in the field by the EERC at a location near Watford City using funds provided by NDIC OGRP and the DOE FE Program.

Investment in developing and demonstrating alternative produced water management solutions (like the GHCR approach) now and understanding the techno-economic conditions that would lead to their commercial adoption will help the state hedge against the emerging challenges facing produced water management and the economics of Bakken production in North Dakota. Early or partial adoption of alternative practices could even curtail or delay some of the capacity and pressurization issues that are beginning to emerge.

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