APPENDIX B

Energy & Environmental Research Center

# SUMMARY OF THE BAKKEN WATER ASSESSMENT REPORT

Tuesday, August 30, 2016

Energy Development and Transmission Committee Meeting
Bismarck, North Dakota

Bethany Kurz

Critical Challenges. **Practical Solutions.**

# ACKNOWLEDGMENTS

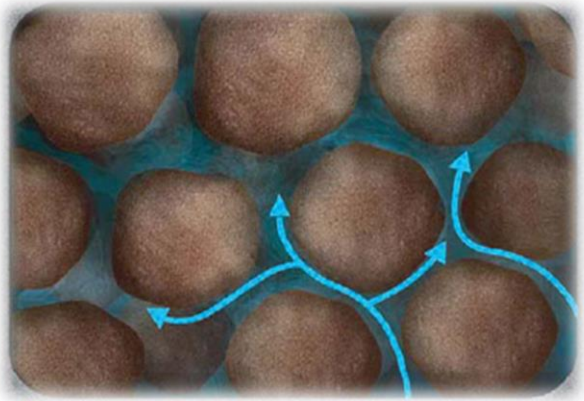

- Funding for this effort and ongoing work is provided by the North Dakota Industrial Commission (NDIC) Oil and Gas Research Program (OGRP) and members of the oil and gas industry through the Bakken Production Optimization Program.
- EERC Project Team – Dan Stepan, Brad Stevens, Kyle Glazewski, Tom Doll, Justin Kovacevich, and Chad Wocken.
- Special thanks to the NDIC Department of Mineral Resources (DMR) and the North Dakota State Water Commission (ND SWC) for provision of information and data sets used for this assessment.

# ASSESSMENT GOALS

- Provide a snapshot of current water management practices and trends in the Bakken.
- Evaluate the capacity of water supply and disposal facilities to accommodate current and projected demand.
- Discuss technological advances that could affect future water use practices in the Bakken.
- Assess the “need” for future water-recycling and reuse scenarios.
- Outline one or more future water management strategies that could help optimize surface operations.

# POROSITY AND PERMEABILITY

- The amount of oil in a reservoir and industry's ability to remove it are determined by the porosity and permeability of the reservoir rock.
- Porosity is the percentage of pore volume or void space within rock.
- Permeability determines how well fluids move through a rock.
  - Depends on how many pore spaces are in a rock and whether or not the pores are connected.



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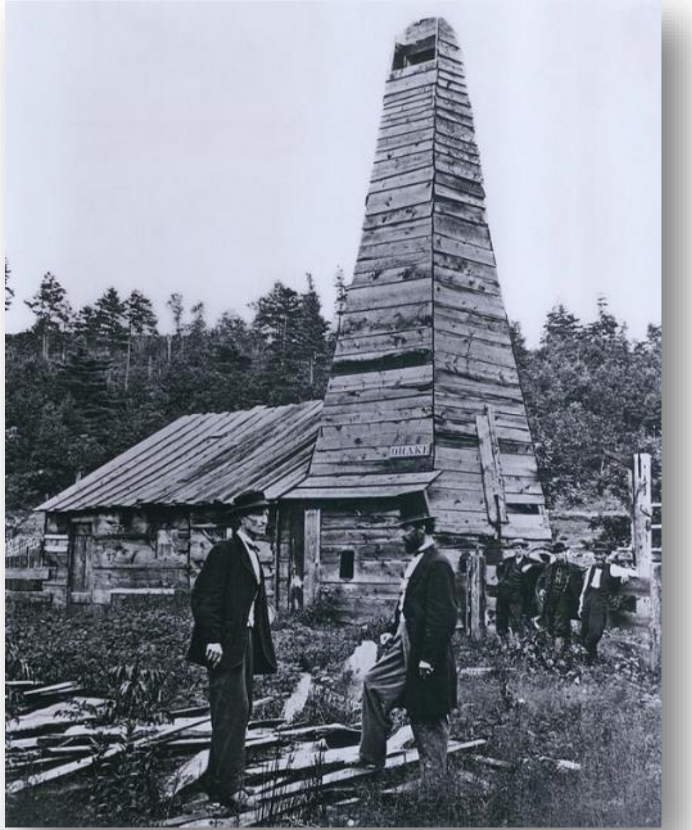
# PERMEABILITY

- Rocks that transmit fluids readily, such as sandstone, are permeable and have many (relatively) large, well-connected pores.

- Impermeable rocks tend to be finer-grained such as shale and siltstone, with smaller, fewer, or less interconnected pores.

# HISTORICAL OIL/GAS EXTRACTION

- Historically, oil and gas reservoirs were in rocks that had relatively high permeability and/or porosity – “low-hanging fruit.”
- With advances in horizontal drilling and hydraulic fracturing, industry is now able to economically extract oil and gas from unconventional reservoirs, meaning rocks that have low porosity and permeability.



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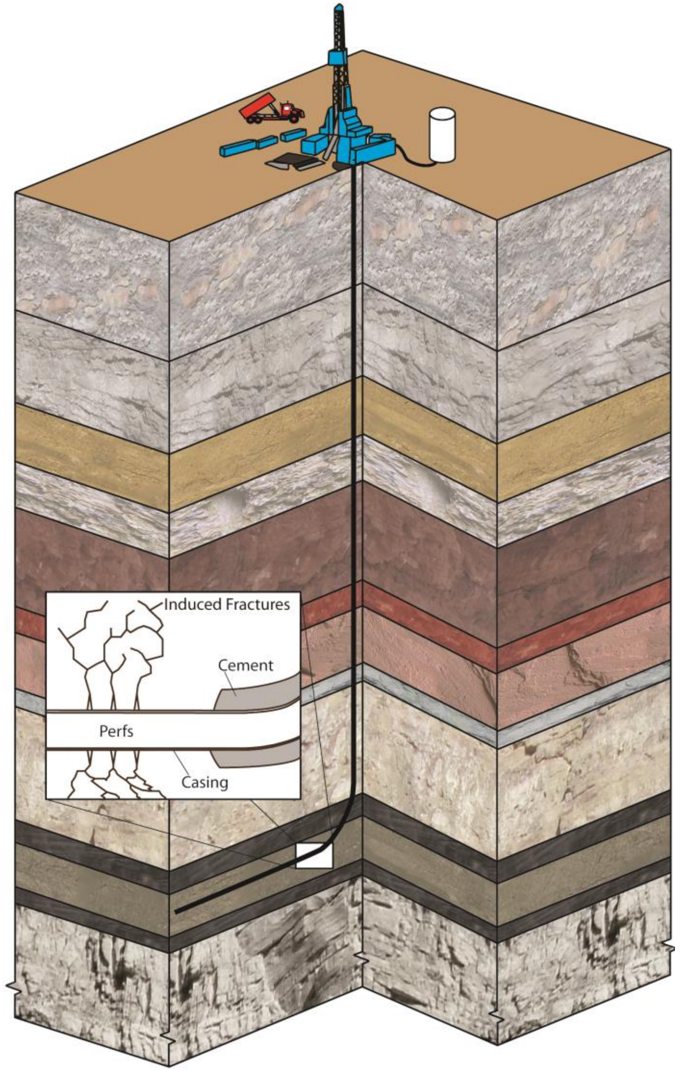
# BRIEF EXPLANATION OF HYDRAULIC FRACTURING

- A technique used to extract oil and gas from very “tight” rocks (low permeability) in the subsurface.
- To produce oil and gas from these reservoirs, a mixture of water, proppant and, to a lesser degree, chemical additives is injected into the reservoir at high pressures to create fractures in the rock.
- These fractures create a pathway for hydrocarbons to move through the reservoir to be extracted.

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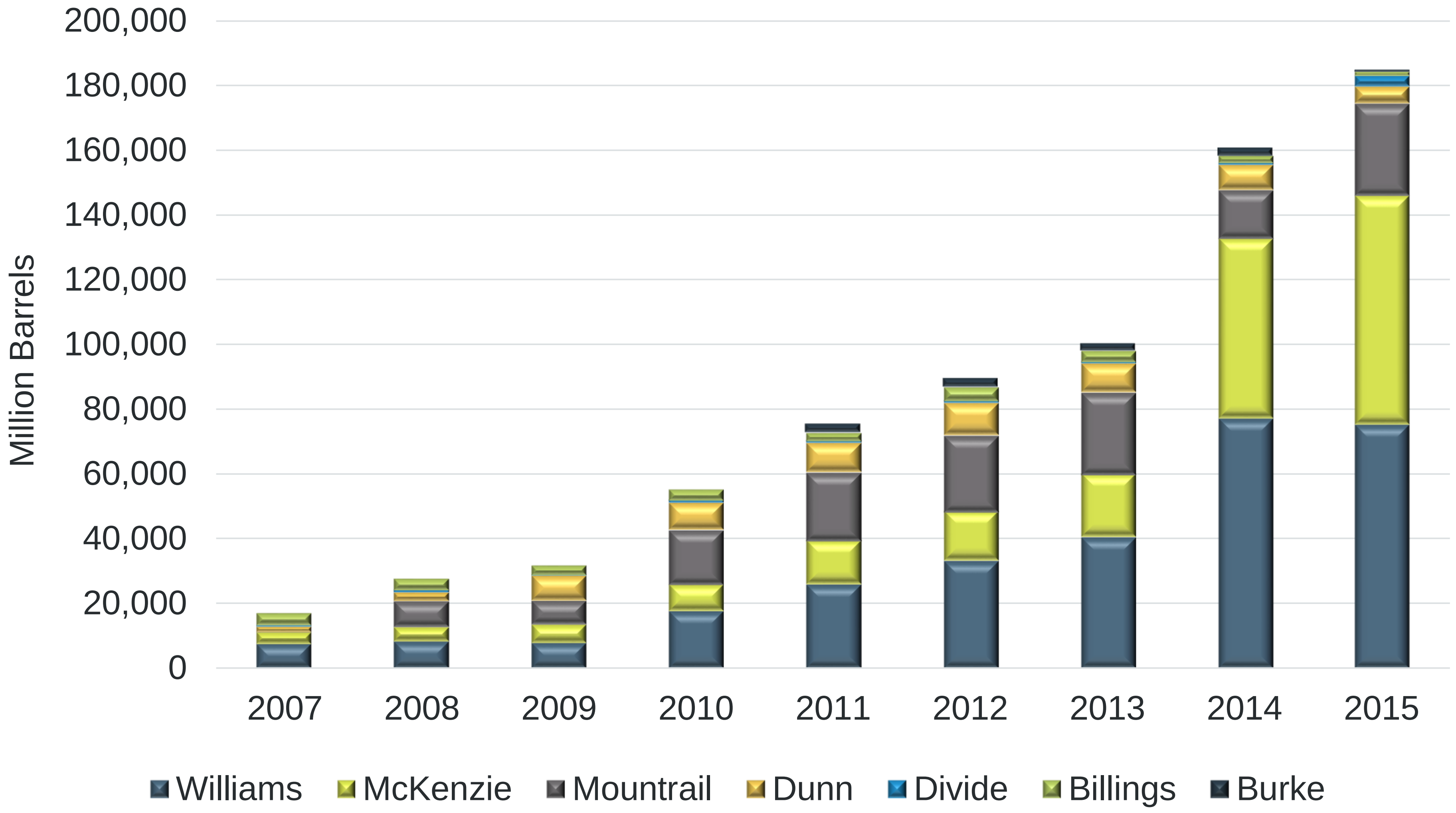
# KEY CHANGES THAT HAVE AFFECTED WATER MANAGEMENT IN THE BAKKEN OVER THE PAST DECADE

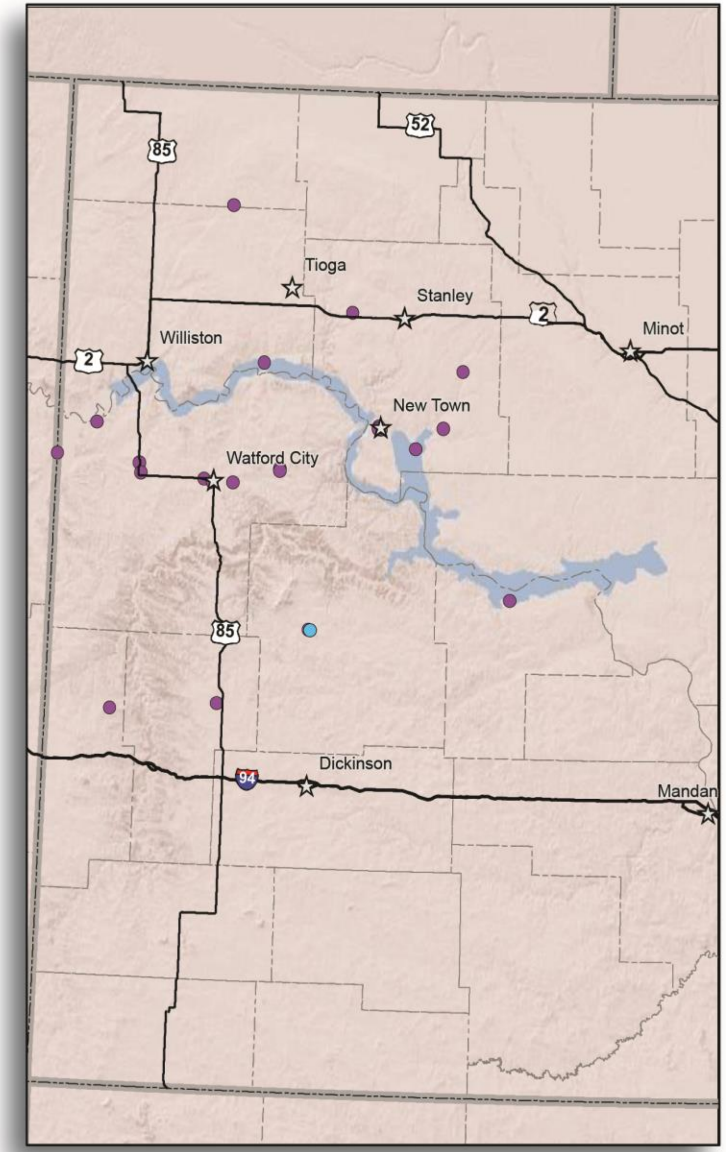
- Significant changes in completions designs and associated water use:
  - Single-stage fracturing → multiple-stage fracturing
  - Longer laterals
  - Linear gels → crosslinked gels → slickwater
- Increased access to freshwater supplies and greatly improved water supply infrastructure
- Multi-well pads
- Improved salt-tolerant fracturing fluids

# INDUSTRIAL WATER USE: 2007–2015

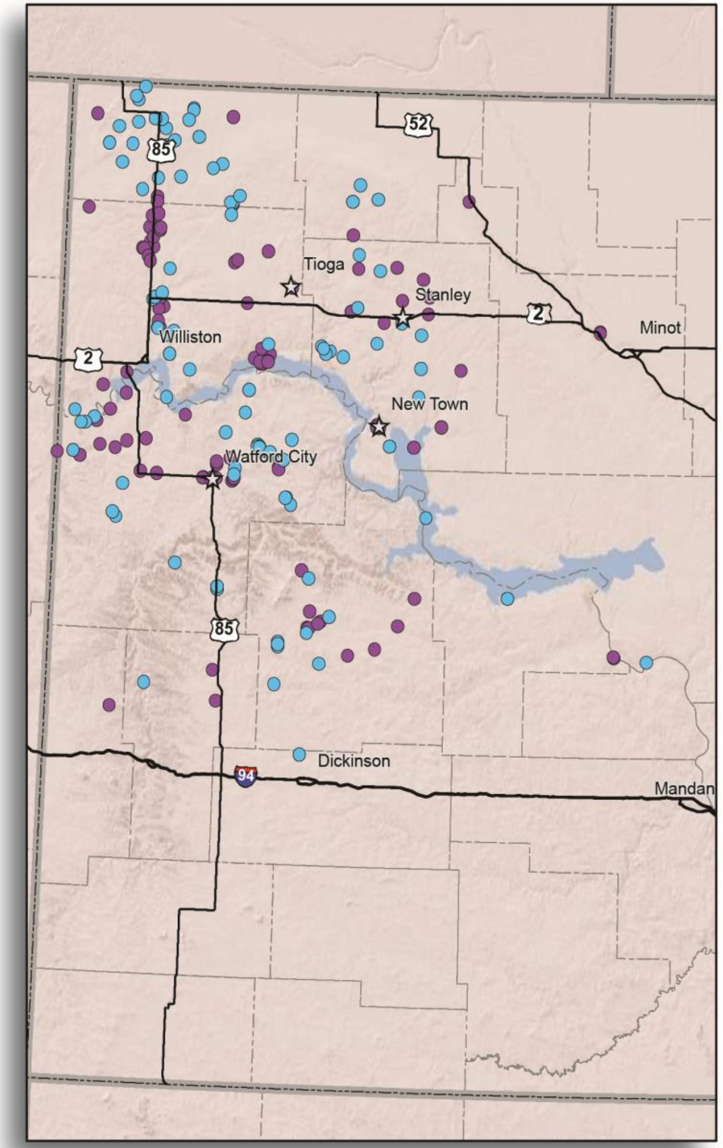



**Data Source: ND SWC**

2008




2013



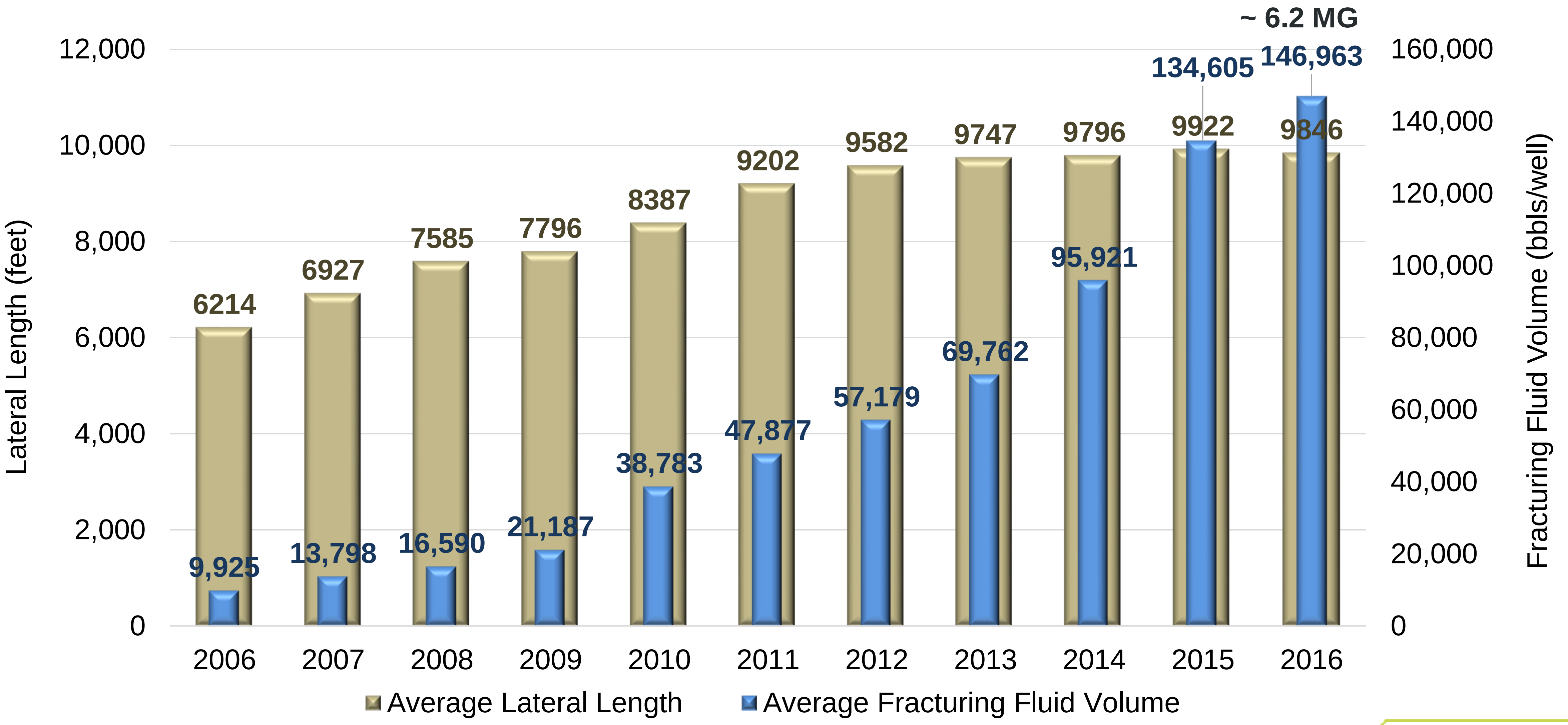

Data Source: ND SWC

| Active Water Supply Locations By Year | 2008 | 2010 | 2013 |
|---|---|---|---|
| Water Permit | 23 | 48 | 121 |
| Temporary Permit | 2 | 4 | 108 |

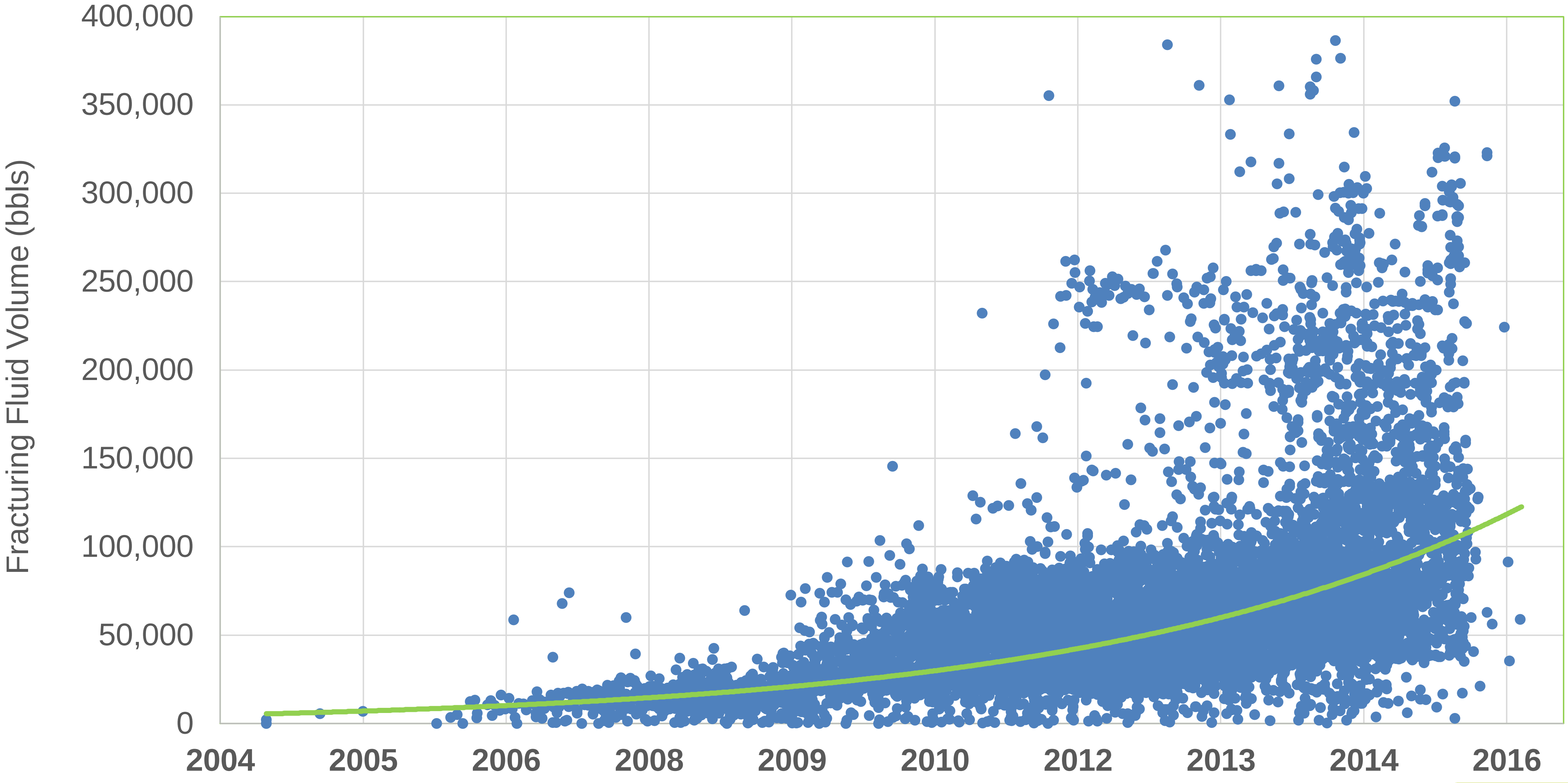
0 25 50
miles

Practical Solutions.

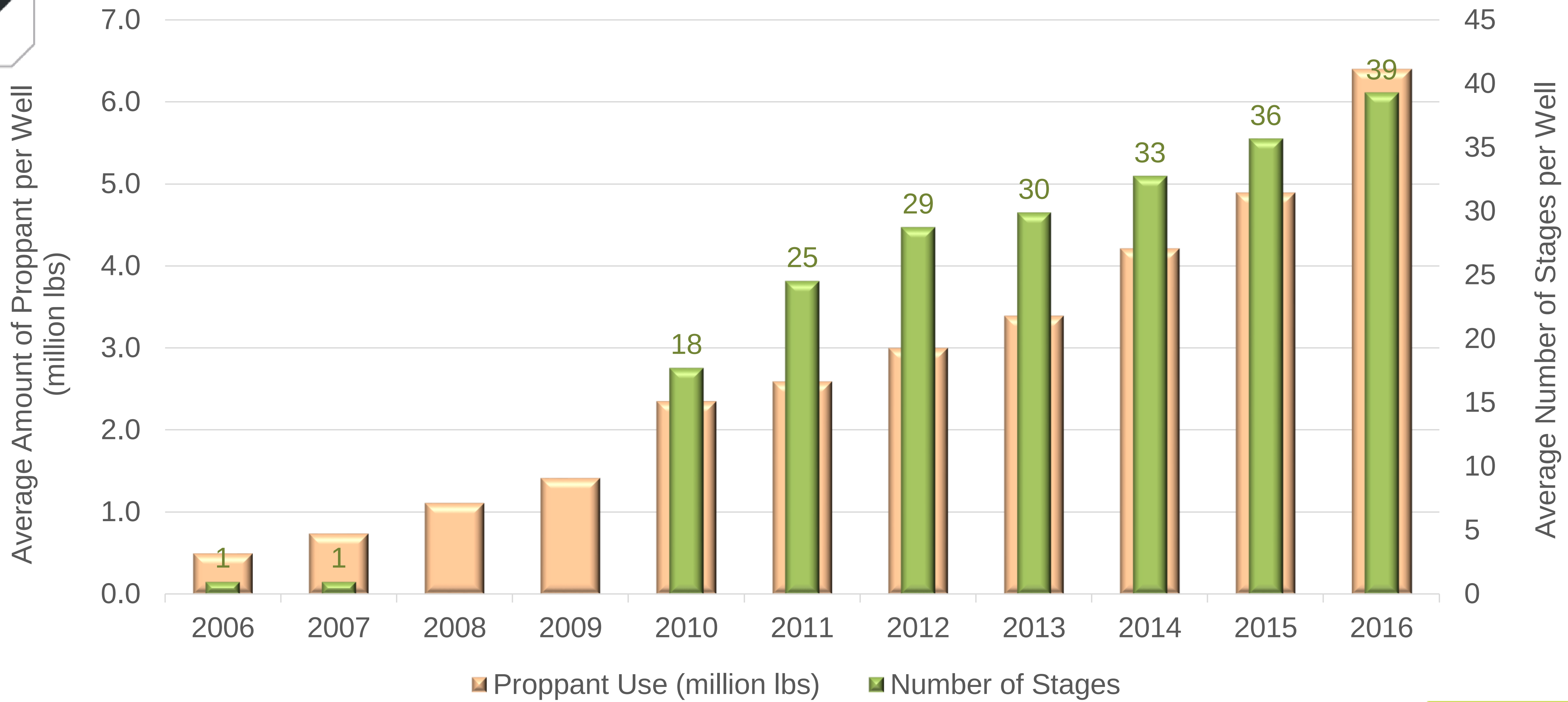
# TRENDS IN LATERAL LENGTH AND FRACTURING FLUID VOLUMES



# FRACTURING FLUID VOLUMES USED FOR INDIVIDUAL WELLS



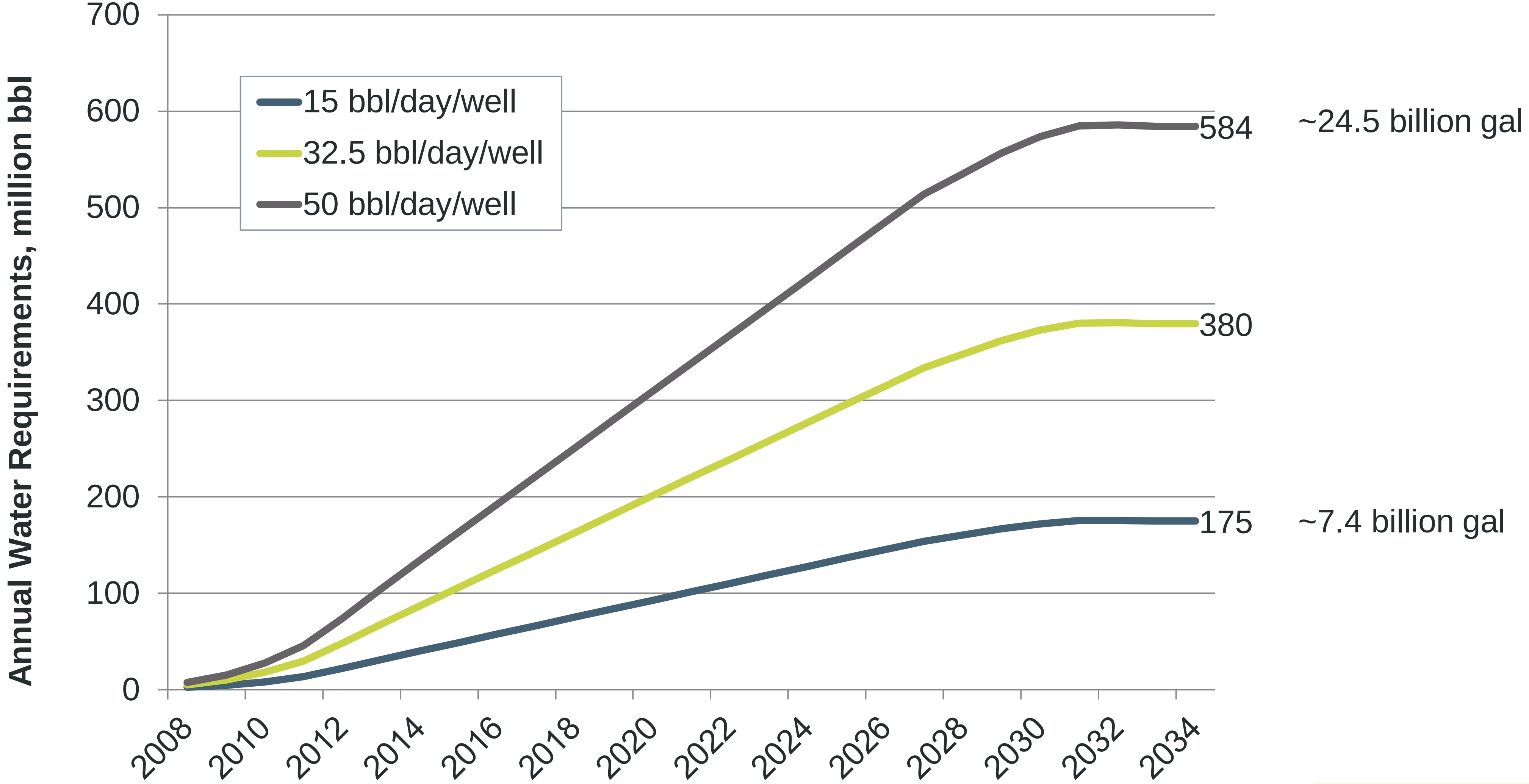
# TRENDS IN PROPPANT USE AND FRACTURING STAGES



# MAINTENANCE WATER NEEDS

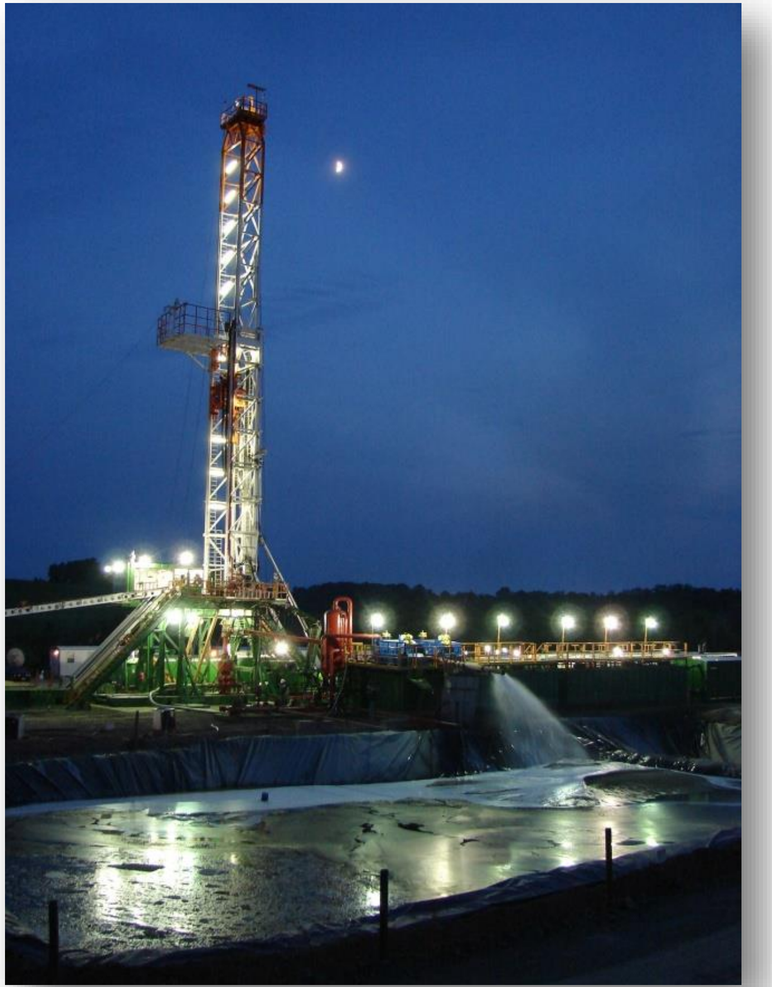
- Also called brine dilution and well flushing.
- DMR estimates ~15 bbl (630 gal) per day per well.
- EERC partners have indicated higher volumes are sometimes used – 30–50 bbl (1260–2100 gal) per day per well.
- EERC projection assumes:
  - 2000 new wells drilled per year until 2035.
  - 20% of wells require no maintenance water.
  - 80% of wells require maintenance water that ranges from a low of 15 bpd/well to a high of 50 bpd/well.
  - An average well lifetime of 20 years.

# PROJECTED FUTURE MAINTENANCE WATER NEEDS

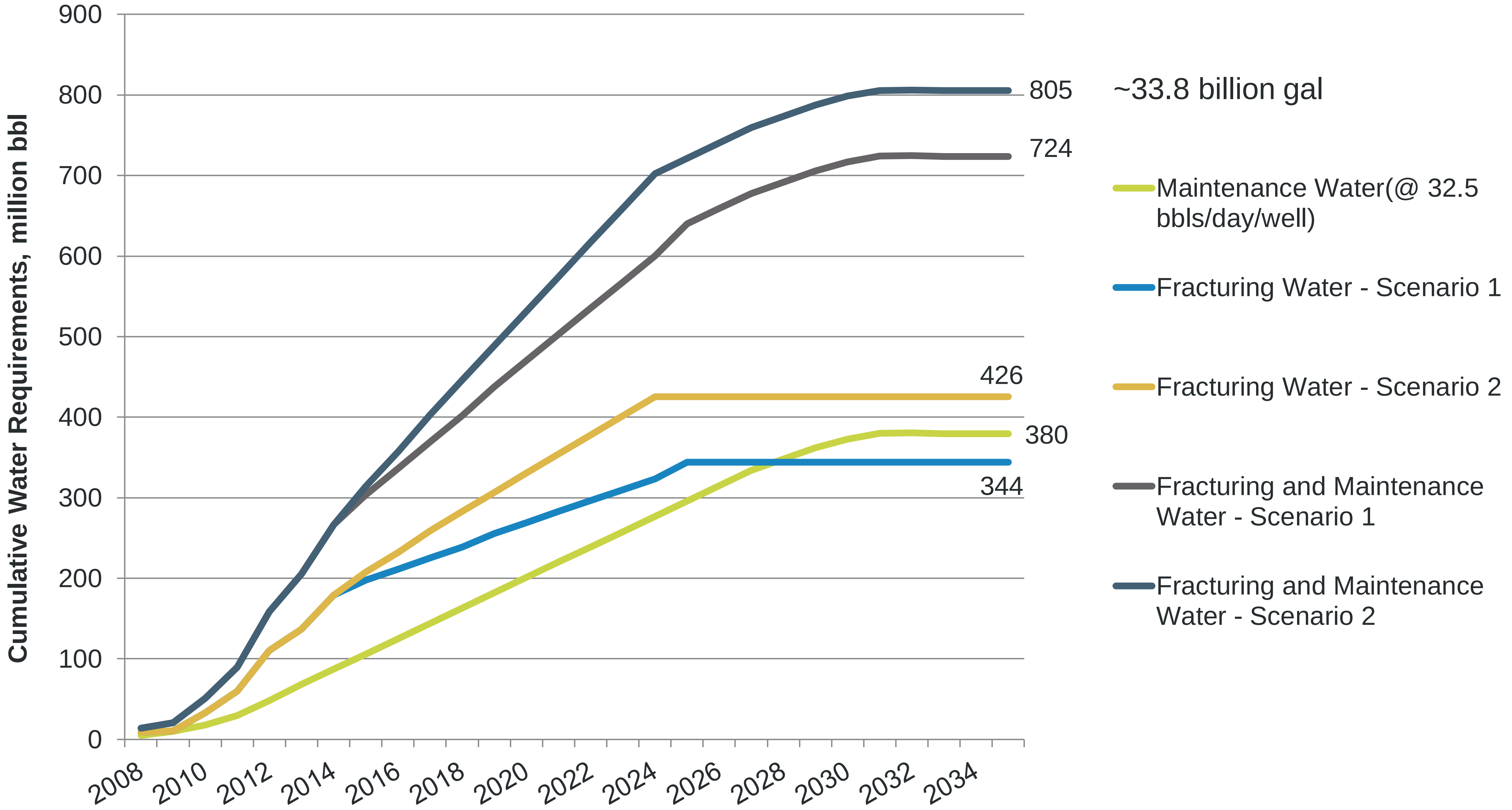


# PROJECTED FUTURE FRACTURING WATER NEEDS

- Assumes freshwater is used for well stimulation.
- Assumes 2000 new wells drilled per year until 2035.
- Scenario 1:
  - Assumes 4% annual increase in slickwater stimulations for the next 10 years.
- Scenario 2:
  - Assumes 7% annual increase in slickwater stimulations for the next 10 years.
- Assumes that after 10 years, a plateau is reached.



# PROJECTED FUTURE FRACTURING AND MAINTENANCE WATER NEEDS

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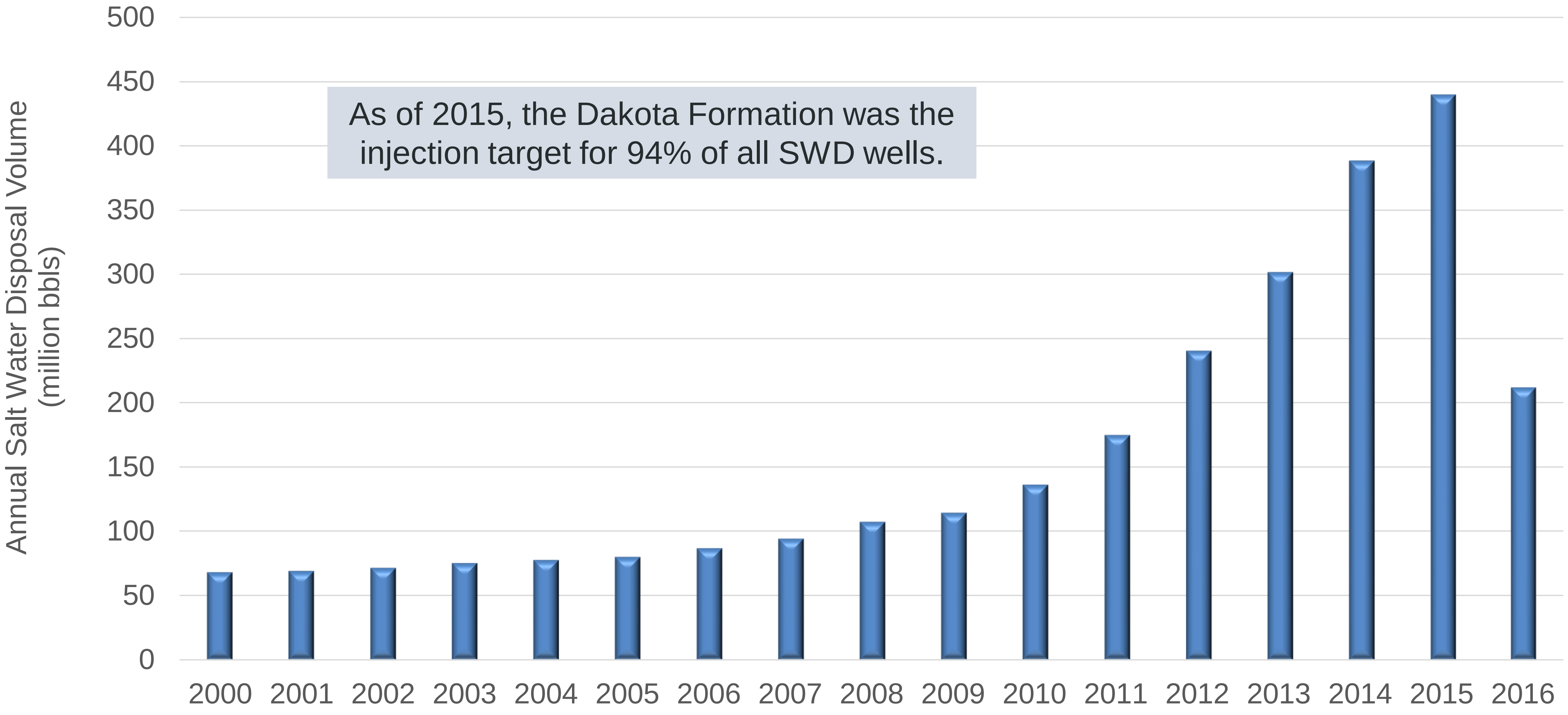
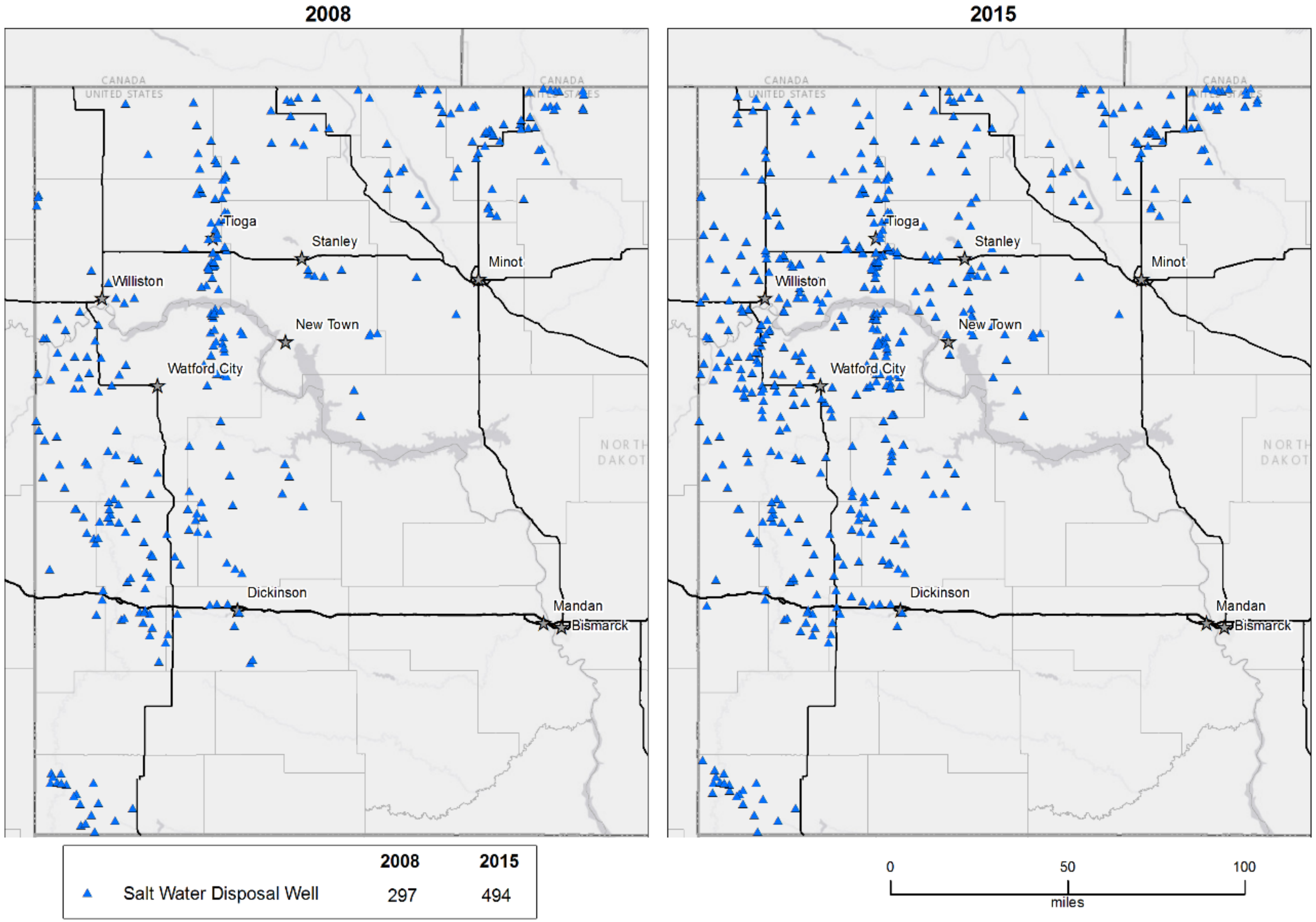
# SALTWATER DISPOSAL (SWD) IN NORTH DAKOTA




As of 2015, the Dakota Formation was the injection target for 94% of all SWD wells.

**Data Source: ND SWC**

# SWD WELLS IN THE DAKOTA




| | 2008 | 2015 |
|---|---|---|
| Salt Water Disposal Well | 297 | 494 |

Data Source: ND SWC



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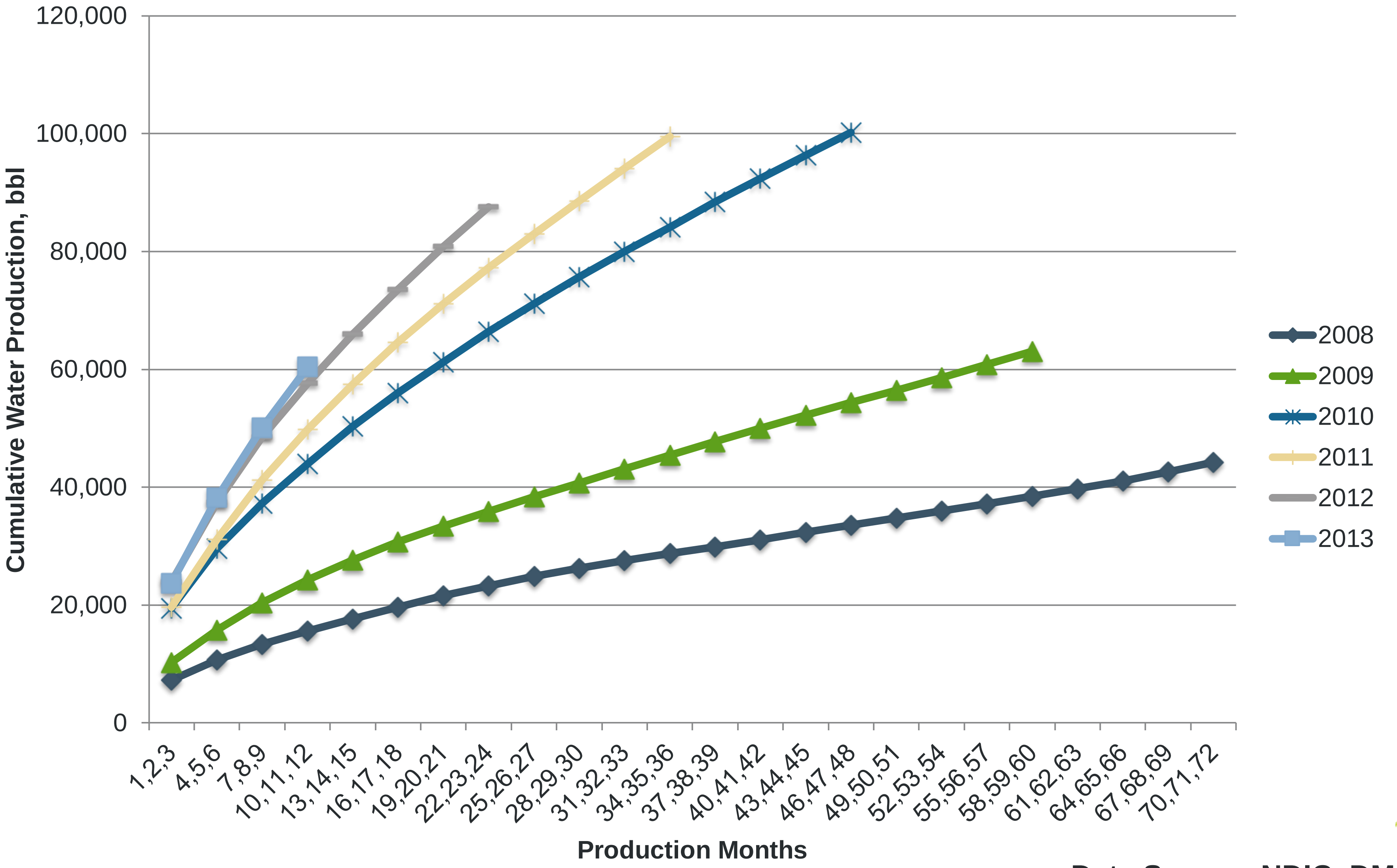
# BAKKEN PRODUCED WATER

| Year | Total SWD,[1] million bbl/yr | Bakken Produced Water Volume, million bbl/yr | % of Total SWD from Bakken Produced Water |
|---|---|---|---|
| 2008 | 107 | 6 | 6 |
| 2009 | 114 | 12 | 11 |
| 2010 | 136 | 33 | 24 |
| 2011 | 174 | 64 | 37 |
| 2012 | 239 | 130 | 54 |
| 2013 | 301 | 190 | 63 |
| 2014 | 388 | 281 | 72 |
| 2015 | 439 | 334 | 76 |

[1] **Data Source: ND SWC**

# AVERAGE BAKKEN WELL CUMULATIVE WATER PRODUCTION

## (based on year completed)




Data Source: NDIC, DMR

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# PROJECTED BAKKEN PRODUCED WATER GENERATION

- Assumes 2000 wells drilled per year.
- Based on average Bakken produced water volumes for 2012–2014 (~26,000 bbl/year/well).

| Year | Estimated Number of Bakken Wells | Estimated Annual Bakken Produced Water Generation, million bbl |
|---|---|---|
| 2020 | 21,183 | 551 |
| 2025 | 31,183 | 811 |
| 2030 | 39,290 | 1021 |
| 2035 | 40,000 | 1040 |

# ESTIMATED FUTURE DISPOSAL NEEDS

2014 disposal volumes: ~386 million bbl in 487 SWD wells.

– Average annual injection volume per SWD well: 793,000 bbl.

| Year | Add'l Disposal Wells Needed for Produced Water Disposal | Add'l Disposal Wells Needed for Maintenance Water Flowback | Total Estimated Add'l Disposal Wells Needed |
|---|---|---|---|
| **2025** | 671 | 372 | **1043** |
| **2035** | 998 | 479 | **1477** |

# TECHNOLOGICAL ADVANCES RELATED TO WATER-RECYCLING/REUSE FEASIBILITY

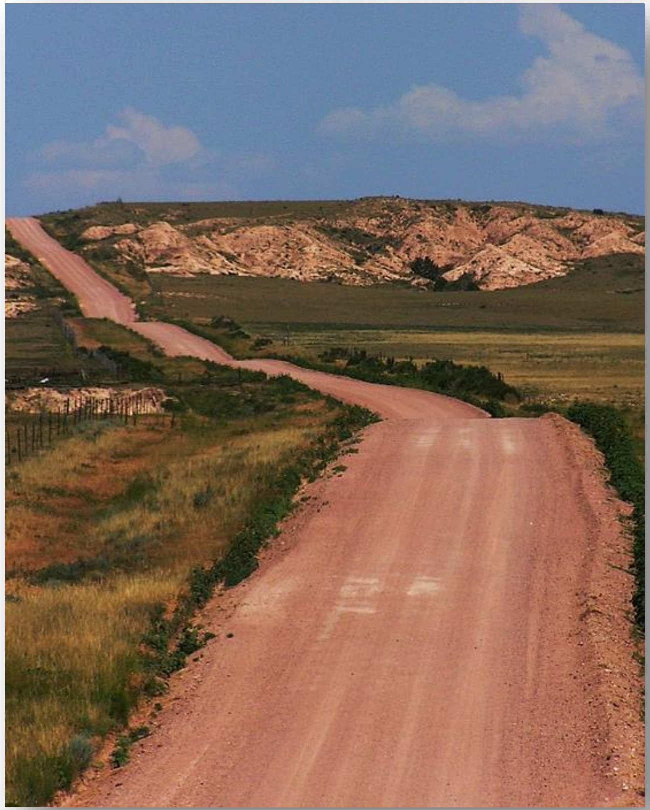
- Development of more robust salt-tolerant fracture fluid systems.
  - Treatment to potable quality not required.
  - Suspended solids and iron removal sufficient in many cases.
- Potential for novel treatment (forward osmosis).
- Increased saltwater-gathering pipelines and centralized storage facilities.

# WATER-RECYCLING AND REUSE DETERRENTS

- Relatively inexpensive freshwater supplies.
- Expanded freshwater supply infrastructure.
- Relatively abundant water supplies in the Missouri River system.
- Numerous deep-well disposal sites, and no major concerns with induced seismicity.
- High Bakken formation water salinity.
- Logistics and safety issues with large volumes of saltwater storage and regulations preventing open tank or pit storage.

# WATER-RECYCLING AND REUSE DRIVERS

- High transportation costs.
- Issues associated with trucking.
  - Road maintenance costs.
  - Dust generation and air emissions.
- Projected future freshwater demand and large volumes of produced water generation.
- Potential occurrence of a drought that limits freshwater availability.



# FUTURE DISPOSAL CONCERNS

- Does the Dakota Sandstone have the capacity to handle future disposal needs?
- Where might we run into disposal issues (because of geology, proximity to other wells, pressurization)?
- Are there areas that we should target for siting of future SWD wells?

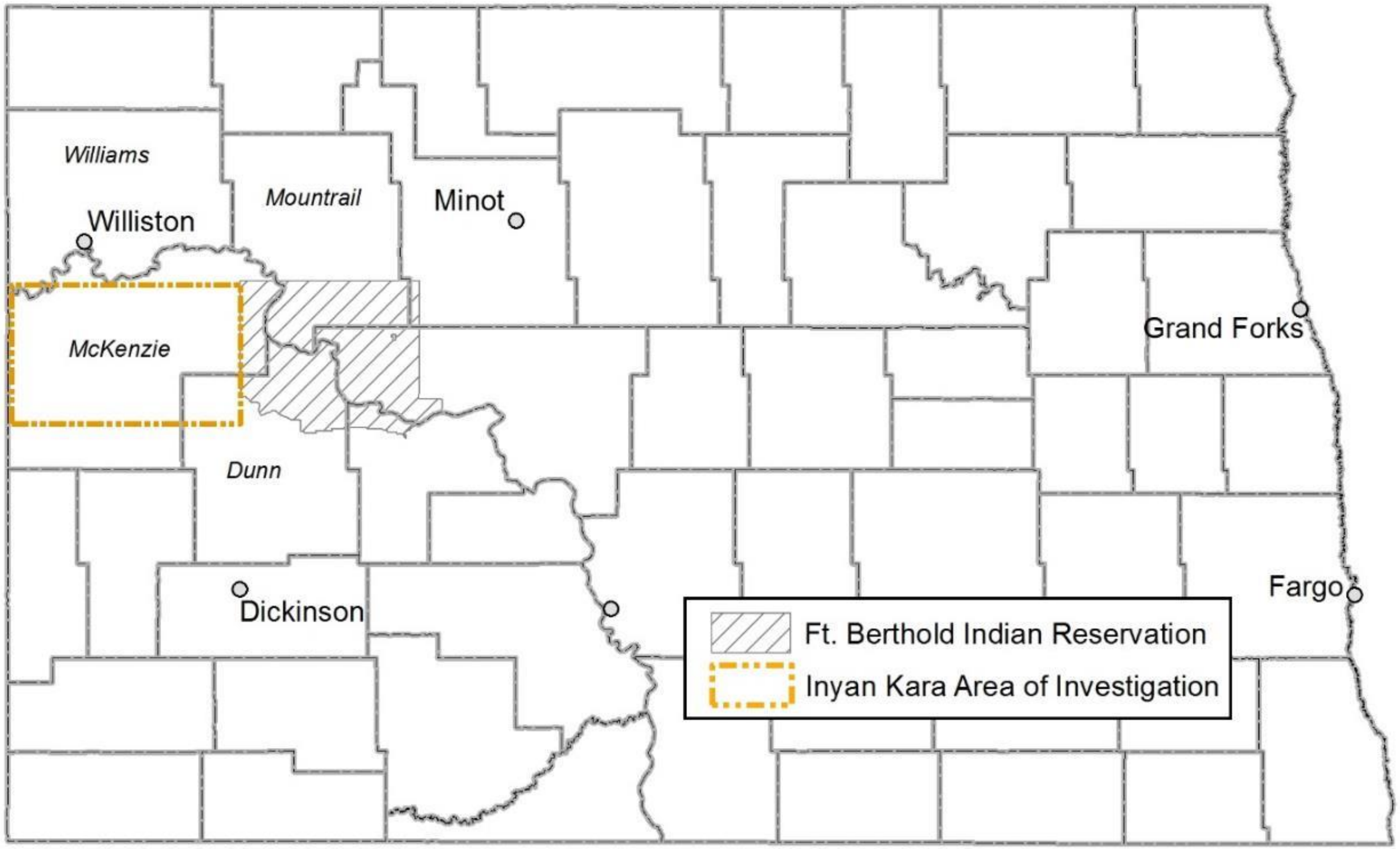
Photo: VWS Oil and Gas

# DAKOTA SANDSTONE (INYAN KARA) SWD CAPACITY ASSESSMENT

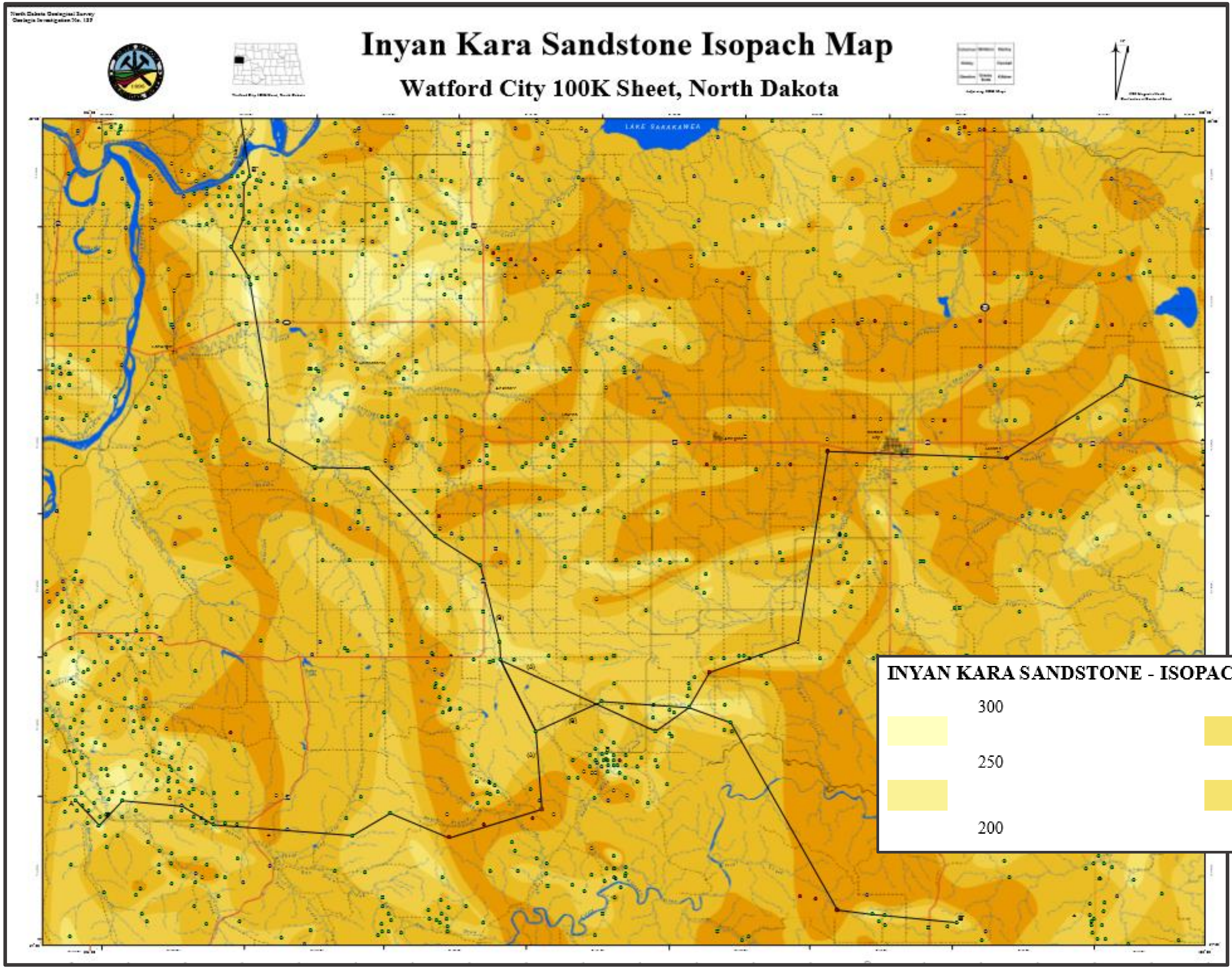
- Goals:
  - To evaluate the disposal capacity of the Dakota.
  - To predict locations where additional disposal may be optimal or problematic based on formation geology and proximity to existing SWD wells.
- Includes collaboration with DMR/North Dakota Geological Survey (NDGS) which has a project under way to map the clean sand intervals within the Dakota.
- Approach is to develop a more detailed geologic model within the area currently mapped by NDGS as well as broad-scale geologic modeling for the remaining Bakken region.

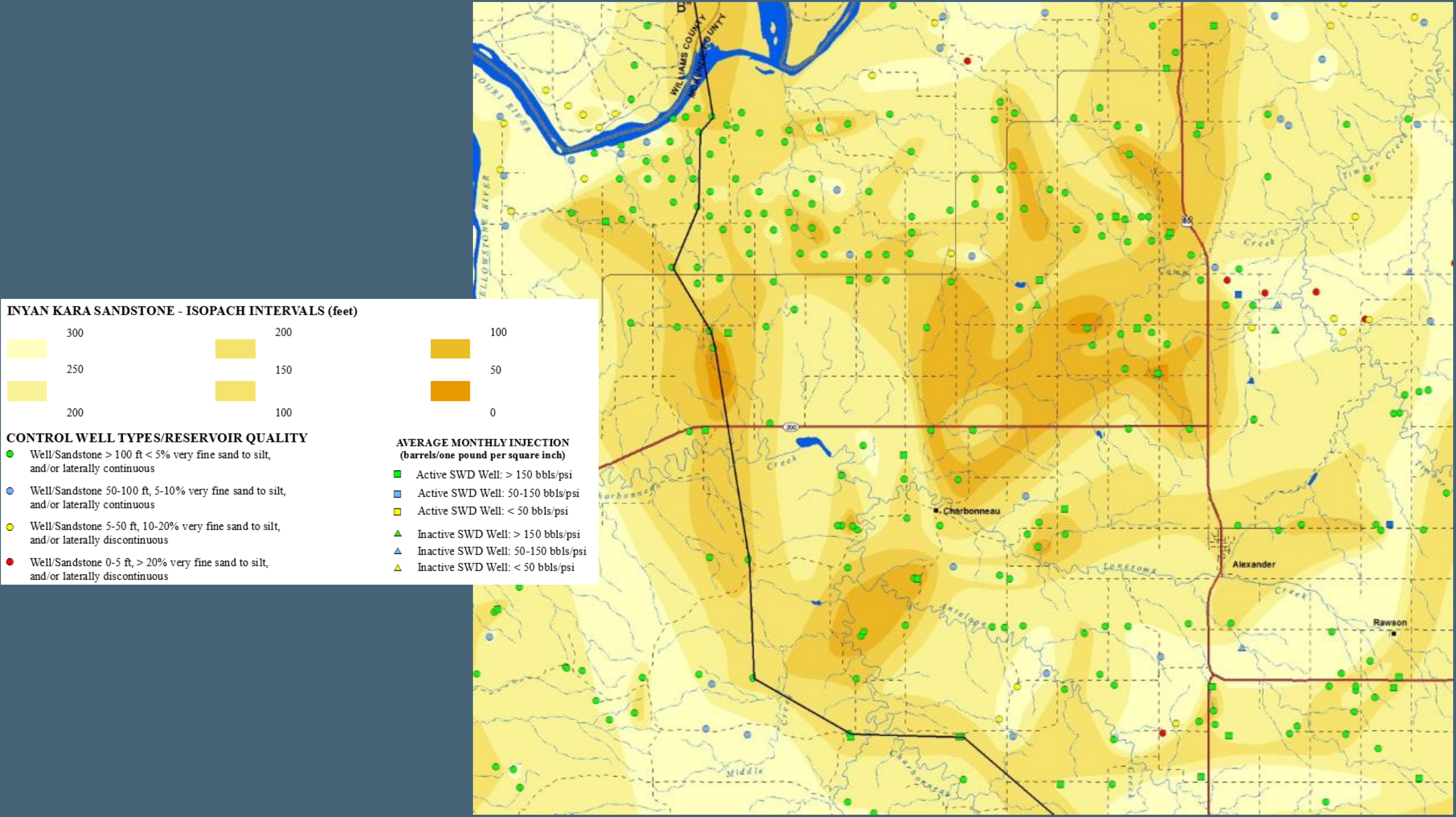
# DAKOTA (INYAN KARA) DETAILED MODELING EXTENT

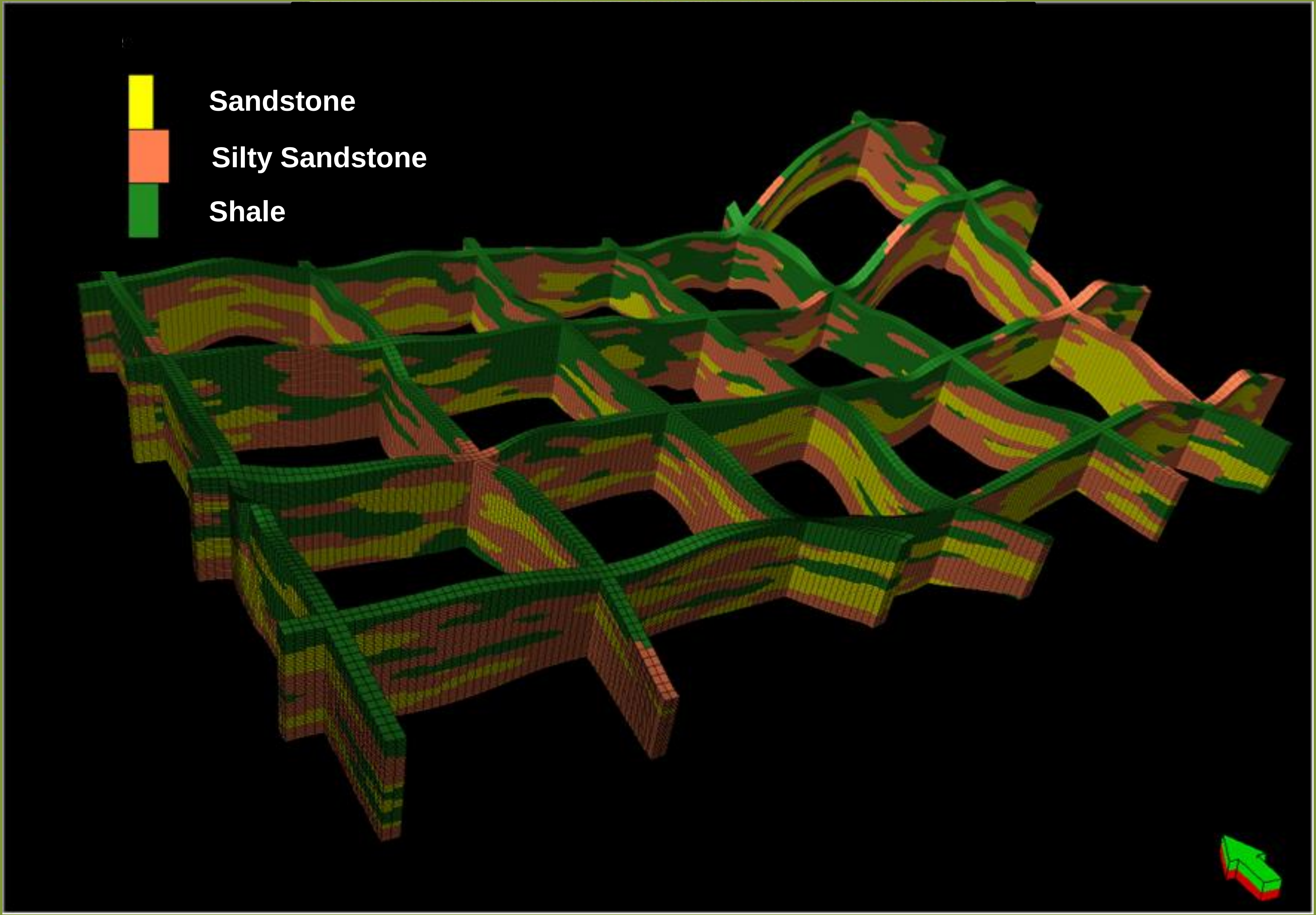
~2400 square miles



# NDGS Dakota (Inyan Kara) Sandstone Thickness Map




INYAN KARA SANDSTONE - ISOPACH INTERVALS (feet)
300
250
200
200
150
100
100
50
0
CONTROL WELL TYPES/RESERVOIR QUALITY
Well/Sandstone > 100 ft < 5% very fine sand to silt, and/or laterally continuous
Well/Sandstone 50-100 ft, 5-10% very fine sand to silt, and/or laterally continuous
Well/Sandstone 5-50 ft, 10-20% very fine sand to silt, and/or laterally discontinuous
Well/Sandstone 0-5 ft, > 20% very fine sand to silt, and/or laterally discontinuous
AVERAGE MONTHLY INJECTION
(barrels/one pound per square inch)
Active SWD Well: > 150 bbls/psi
Active SWD Well: 50-150 bbls/psi
Active SWD Well: < 50 bbls/psi
Inactive SWD Well: > 150 bbls/psi
Inactive SWD Well: 50-150 bbls/psi
Inactive SWD Well: < 50 bbls/psi
WILLIAMS COUNTY
MCKENZIE COUNTY
Charbonneau
Alexander
Rawson
200
85


Sandstone
Silty Sandstone
Shale

# ONGOING MODELING AND RELATED WORK

- The models will be used to simulate several scenarios, including current practices and multiple potential future scenarios.
  - This will aid in identifying areas that may experience pressurization issues in the future and to target areas for future SWD well siting.
- Efforts are under way to use decline curve analysis to better understand how water (and oil and gas) production varies from field to field over time.
  - This will allow us to more accurately estimate what future produced water volumes may look like.
- An evaluation of potential alternate SWD targets is proposed as an activity through Phase 2 of the Bakken Production Optimization Program.


http://travelnd.areavoices.com/2011/05/12/add-american-landmarks-to-your-summer-travel-plans/

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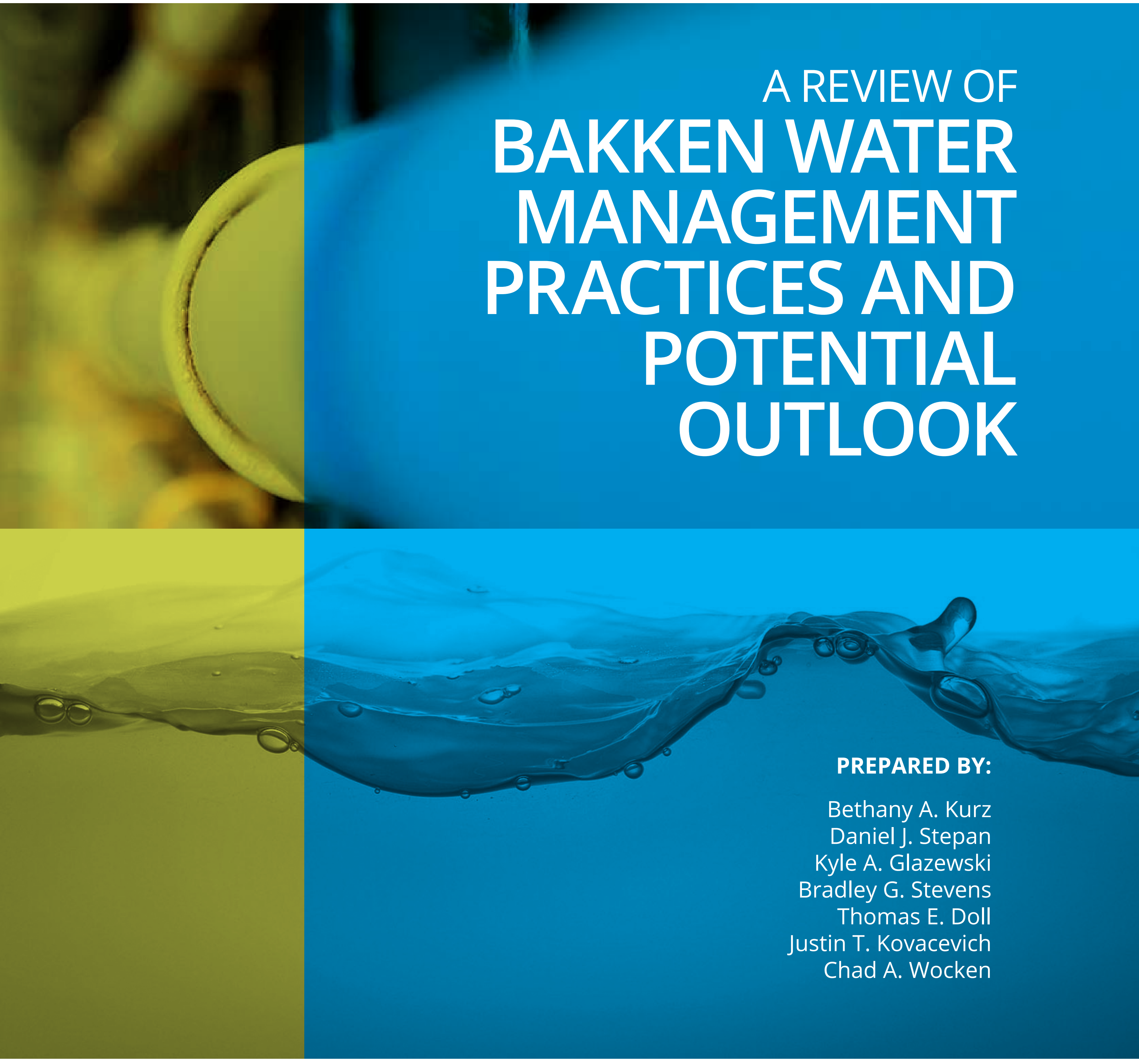
**FINAL REPORT**

**PREPARED FOR:**

Members of the Bakken Production Optimization Program



# A REVIEW OF BAKKEN WATER MANAGEMENT PRACTICES AND POTENTIAL OUTLOOK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March 2016

## EERC DISCLAIMER



## NDIC DISCLAIMER



## ACKNOWLEDGMENTS

The EERC would like to express its sincere gratitude to the North Dakota Industrial Commission's Department of Mineral Resources, the North Dakota State Water Commission, and the members of the Bakken Production Optimization Program for sharing of data and knowledge. We are also very appreciative of those partners who donated their time to review the report and provide input.

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Continued. . .

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# NOMENCLATURE

| | |
|---|---|
| AST | aboveground storage tanks |
| Bakken | Bakken Petroleum System |
| bbl | barrel |
| bpd | barrels per day |
| BPOP | Bakken Production Optimization Program |
| CFU | colony-forming units |
| DMR | Department of Mineral Resources |
| EC | electrocoagulation |
| IRB | iron-reducing bacteria |
| MGD | million gallons per day |
| NAWSP | Northwest Area Water Supply Project |
| NDAC | North Dakota Administrative Code |
| NDDMR | North Dakota Department of Mineral Resources |
| NDIC | North Dakota Industrial Commission |
| NDSWC | North Dakota State Water Commission |
| RO | reverse osmosis |
| SRB | sulfate-reducing bacteria |
| SWPP | Southwest Pipeline Project |
| SWD | saltwater disposal |
| TDS | total dissolved solids |
| TSS | total suspended solids |
| WAWSP | Western Area Water Supply Project |
| WWTP | wastewater treatment plant |

## A REVIEW OF BAKKEN WATER MANAGEMENT PRACTICES AND POTENTIAL OUTLOOK

## EXECUTIVE SUMMARY

Water is a valuable commodity in the Bakken petroleum system (Bakken) region of western North Dakota for drilling, completion, production, and maintenance-related activities. Over the past decade, water use patterns in the Bakken have changed dramatically. Current data and water use projections based on data from the North Dakota Industrial Commission, the North Dakota State Water Commission, and efforts by the Energy & Environmental Research Center suggest that, absent a prolonged drought, there appears to be sufficient freshwater supply for continued operations in the Bakken; however, the large volumes of produced water generated now and in the future may warrant a proactive approach by industry to increase produced water recycling and reuse.

The primary demand for freshwater in the Bakken is for hydraulic fracturing and well maintenance. Hydraulic fracturing techniques have evolved from single-stage operations to multiple-stage stimulations, with over 30 stages now common. Water use has increased from 20,000 barrels for single-stage, gel-based hydraulic fracturing to over 200,000 barrels for multistage slickwater fracturing, and the percentage of slickwater stimulations has been increasing since 2012.

Well maintenance, or brine dilution, water has created a more recent demand for freshwater in Bakken operations. The high salt content of Bakken produced water necessitates the introduction of freshwater into the well to reduce the amount of salt and scale precipitation within the well tubing that, ultimately, reduces production. While maintenance water demand is variable throughout the play, the projections herein suggest that it may account for roughly 50% of total future freshwater demand. Current estimated freshwater demand for hydraulic fracturing and well maintenance is approximately 267 million barrels a year and may increase threefold by 2035.

The unprecedented oil and natural gas production in North Dakota has also resulted in a substantial increase in the volume of produced water being generated. The primary mechanism of disposal in North Dakota is saltwater injection, most of which occurs in the Dakota Formation. While saltwater disposal (SWD) volumes have already increased by 341% from 2008 to 2014, broad projections herein suggest that produced water generation may increase by another 328% between 2014 and 2035. When combined with the estimated disposal needs for well maintenance water that requires disposal, it suggests that close to 1500 new disposal wells may be needed by 2035. This does not include the possible increase in produced water generation if the trend of increasing volumes of water for hydraulic fracturing continues. The reliance of industry on the Dakota aquifer as a disposal target warrants an assessment to determine the long-term impacts of produced water injection and to evaluate the capacity of alternative SWD targets.

While improvements in fracturing fluid formulations enable the use of high-salinity water as a source of makeup water, it is estimated that less than 5% of the wells drilled in 2014 utilized produced water for fracturing fluid makeup. This is, in part, due to a lack of incentives to recycle and reuse produced water in the Bakken region, regulations that prohibit the use of open pits and

impoundments for the storage of saltwater, and the additional costs associated with the safety measures and permitting required for saltwater storage. Before widespread brine recycling and reuse can occur, industry and regulators will need to define the regulatory process and acceptable containment practices required for large-scale saltwater storage.

This report provides a summary of water use and handling trends in the Bakken, estimation of future water supply demand and disposal needs, an overview of potential treatment technologies, considerations for recycling and reuse, a summary of the implications of the report findings for our partners, and recommendations for future work.

## A REVIEW OF BAKKEN WATER MANAGEMENT PRACTICES AND POTENTIAL OUTLOOK

### INTRODUCTION

Water use and management in western North Dakota have changed dramatically over the past decade as a result of the unprecedented growth and development of the Bakken petroleum system (Bakken) and consequent adaptations by the state and industry to meet the rapidly growing need for increased water supply and disposal options. The Energy & Environmental Research Center (EERC) has been closely tracking the issues related to Bakken water management since 2008 and evaluating the technical and economic feasibility of various technological advancements and water-handling practices. Most recently, as part of efforts being conducted through the Bakken Production Optimization Program (BPOP), the EERC is working to identify and evaluate potential technological advances that could help optimize water use and handling in the Bakken, to project future water supply and disposal needs, and to assess potential environmental risks associated with Bakken water transport and storage.

This EERC report was compiled for the sponsors and members of BPOP to:

- Provide a snapshot of current water management practices and trends in the Bakken.
- Summarize changes in water use practices that have occurred in the Bakken since early Bakken development (~2008–2014 time frame).
- Evaluate the capacity of water supply and disposal facilities to accommodate current and projected demand.
- Discuss technological advances that could affect future water use practices in the Bakken.
- Outline potential water recycling and reuse scenarios that may be of interest to our partners for in-depth evaluation.

Several data sets were provided to the EERC for compilation of this report which proved to be invaluable in the assessment of past and future water management practices (Table 1). The EERC would like to offer its sincere appreciation and gratitude to the North Dakota Industrial Commission (NDIC) and to the North Dakota State Water Commission (NDSWC) for their help and for provision of these data sets to the EERC.

**Table 1. Key Sources of Historic and Current Water Management Data Used in This Report**

| Source | Data Provided |
|---|---|
| NDIC<br>Department of Mineral Resources (DMR)<br>Oil and Gas Division | • Well data (location, status, type, production/injection volumes, etc.)<br>• Produced water volumes<br>• Hydraulic fracturing information (fluid use, pounds of proppant, lateral length, number of stages, treatment date)<br>• Saltwater disposal (SWD) volumes |
| NDSWC | • Water permit information (location, status, type, volume of water used, volume of water allocated)<br>• Water depot information |

## PREVIOUS WORK

As oil and gas development in the Bakken began to increase in the mid- to late 2000s, there was uncertainty in the region over the availability of freshwater resources needed to meet the increasing demands for hydraulic fracturing in North Dakota. There were a limited number of water depots, a relatively long and often contested permitting process for new water depots, concerns about depletion of fresh groundwater resources, and significant barriers from federal agencies regarding withdrawals from Lake Sakakawea. To help address that uncertainty, the EERC conducted two projects: a Phase 1 effort that investigated the potential to reuse flowback water from hydraulic fracturing operations (Stepan and others, 2010) and a subsequent Phase 2 effort that investigated the treatment of nonpotable groundwater for use in hydraulic fracturing (Kurz and others, 2011).

The Phase 1 project investigated treatment and recycling of Bakken frac flowback water as a means to reduce the demand for freshwater and provide a supplemental supply near drilling and fracturing activities. The character of the frac flowback water with respect to both quantity and quality presented significant challenges for widespread water-recycling opportunities. A relatively small percentage (17% to 47%; 23% on average) of the water used for hydraulic fracturing was recovered in a reasonable time frame (2 to 10 days). Further, the dissolved solids levels in the flowback increased rapidly to observed levels as high as 220,000 mg/L. These factors presented significant challenges for developing cost-effective treatment strategies with the goal of producing freshwater, even with the most robust technologies available at the time, and widespread recycling was deemed unlikely to be economically viable.

The Phase 2 project, which was conducted from 2010 to 2011, in conjunction with Hess Corporation, successfully demonstrated the technical and economic feasibility of using reverse osmosis (RO) treatment of brackish groundwater from the Dakota aquifer to produce freshwater for use in hydraulic fracturing. GE Water Process and Technologies (GE) was contracted to provide a mobile pretreatment and RO system. The project demonstrated greater than 70% treated water recovery and greater than 90% removal of major ions. Over 25 million gallons (595,000 bbl) of brackish groundwater was treated during the demonstration, producing over 17.8 million gallons (424,000 bbl) of high-quality freshwater for use in hydraulic fracturing. The brine concentrate generated from the process was deep well injected.

While the previous work conducted by the EERC is only 4 to 6 years old, significant changes have occurred in the Bakken region that impact water use, handling, and the feasibility of recycling and reuse. These changes include:

- Hydraulic fracturing technology developments.
- Substantial improvements to the water supply and disposal infrastructure.
- Modifications to the water appropriations hierarchy.
- Changes in federal agency restrictions to waters of Lake Sakakawea.
- Increased produced water generation.
- Increased awareness of well maintenance water/brine dilution demands.
- Technological advancements that enable saline water use in fracturing fluids.
- Increased concern and public pressure over brine transport, storage, and spills.

These changes, which are described and discussed in greater detail throughout the body of this report, have resulted in both challenges and opportunities in water management in the Bakken play. For example, while the oil and gas industry has more technologically viable water recycling/reuse options available than would have been imagined 5 years ago, operational, logistical, regulatory, and environmental risk issues appear to be significant barriers to wide-scale implementation of water recycling and reuse.

Throughout this document, reference will be made to data collected from "Bakken" wells. This is intended to indicate wells within the Bakken petroleum system and, therefore, includes data from wells completed in the Three Forks as well as the Bakken.

## HYDRAULIC FRACTURING DEVELOPMENTS AND IMPACTS ON FRESHWATER USE

Initial oil production from the Bakken Formation occurred through traditional vertical wells dating back to 1953 through 1985 (Pearson and others, 2013; Nordeng and LeFevre, 2011). In 1986, the first horizontal wells were drilled into the formation and generally consisted of upper Bakken shale horizontal wellbores producing from natural fractures with preperforated liners. In 2000, industry began to use stimulation practices for horizontal wells that were typically openhole, single-stage completions, which resulted in significant productivity gains when coupled with the use of uncemented liners.

By 2006, well stimulation practices typically entailed low-viscosity, high-rate injection of fracturing fluids that included freshwater with sand, friction reducers, antiscalants, surfactants, biocides, and oxidizing breakers. Single-stage fracture stimulations were the standard practice; fracturing fluid volumes averaged about 23,000 barrels (1 million gallons) of freshwater coupled with up to 2 million pounds of proppant (Nordeng and LeFevre, 2011); and pumping rates were typically on the order of 110 barrels per minute (bpm).

In 2007, the first multistage fracture was completed in the Parshall Field and was rapidly duplicated in other areas of the Bakken. By 2008, the average stage count per well was about ten (Nordeng and LeFever, 2011); this count steadily increased to an average of 32 stages per well by the end of 2014. As shown in Figure 1, average lateral lengths of wells have increased from about 6200 feet in 2006 to 9700 feet in 2014. The shift in average lateral lengths of ~7500 feet in 2008 to ~9500 feet in mid-2012 was a result of NDIC establishing the standard spacing units within the Bakken at 1280 acres, which effectively required operators to drill 9500-foot laterals in order to hold a drilling spacing unit (Pearson and others, 2013).

As a result of the increase in lateral lengths and the number of fracture stages, the volumes of fluid (freshwater mixed with fracturing chemicals) injected per well have gradually increased from about 10,000 barrels per well in 2006 to almost 90,000 barrels per well in 2014 (Figure 1). Part of this increase in water use is also because of the expanding use of slickwater stimulations, which, because of the low viscosity of the fracturing fluid system, require pumping 3 to 4 times the volume of water at a higher injection rate than gel-based stimulations. Injection rates for slickwater stimulations are typically in excess of 70 bpm, whereas gel-based stimulations range from 30 to 40 bpm (Pearson and others, 2013).

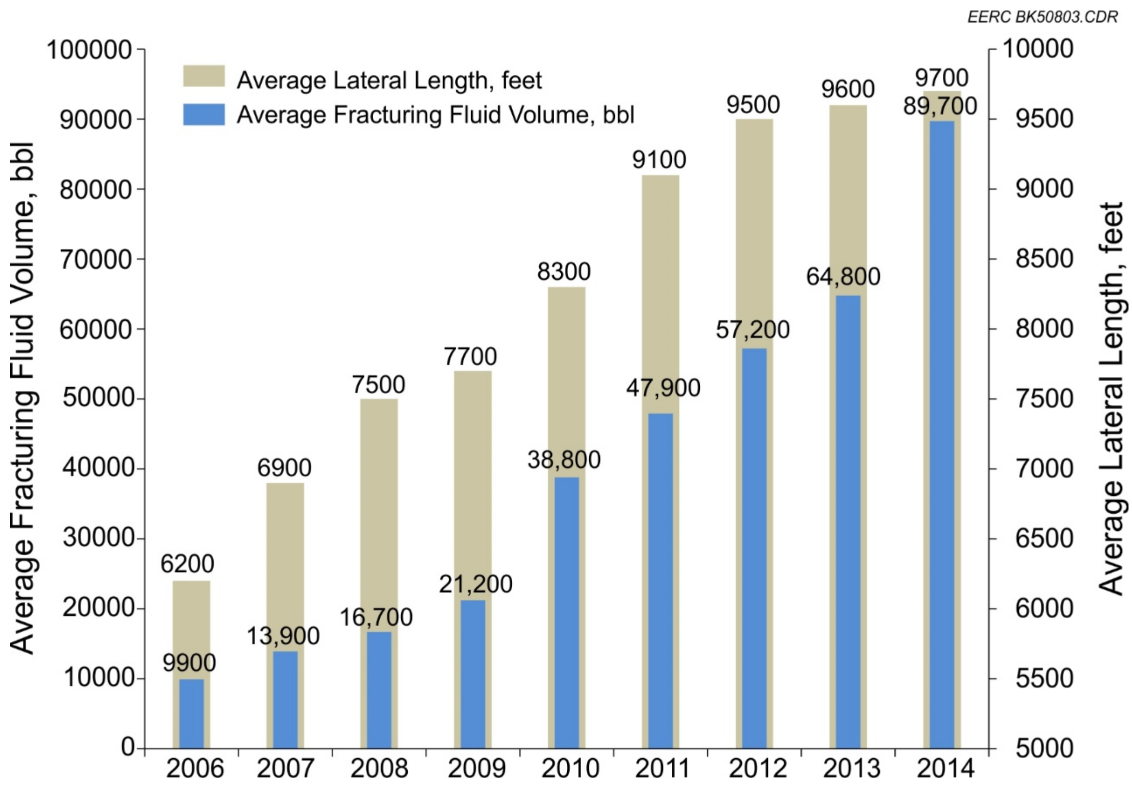


Figure 1. The increase in average lateral lengths and fracturing fluid volumes per well from 2006 through 2014 (based on data provided by the North Dakota DMR [NDDMR]).

Figure 2 is a scatter plot showing the volume of fracturing fluid used for each Bakken well completed from 2006 through 2014. The cluster of wells requiring fluid volumes in the 150,000–300,000-bbl range from 2012 through 2014 are likely slickwater-based stimulations, based on 2012 data summarized by Pearson and others (2013). Table 2 shows the distribution of wells and fracture fluid volumes greater or less than 150,000 bbl for 2012 through 2014 and shows the increase in the number of wells using slickwater-based stimulations (assumed fracture fluid volumes greater than 150,000 bbl). In 2014, approximately 12% of the wells were stimulated using fracture fluid volumes greater than 150,000 bbl, and the average fracture fluid volume of those wells was 240,600 bbl. The average fluid volumes used for wells that were injecting less than 150,000 bbl (assumed to represent gel-based stimulations) was about 69,000 bbl.

The freshwater used for well stimulation is typically from a potable water supply or from a surface water body. The water was traditionally stored in many mobile 500-bbl fracture tanks (Figure 3); however, as the volume of water required for well stimulations has increased, there has been a shift toward the use of larger, temporary storage impoundments referred to as water corrals (Figure 4). Water corrals can be constructed to suit various water volume needs but typically range from 24,000 to 42,000 bbl in capacity.

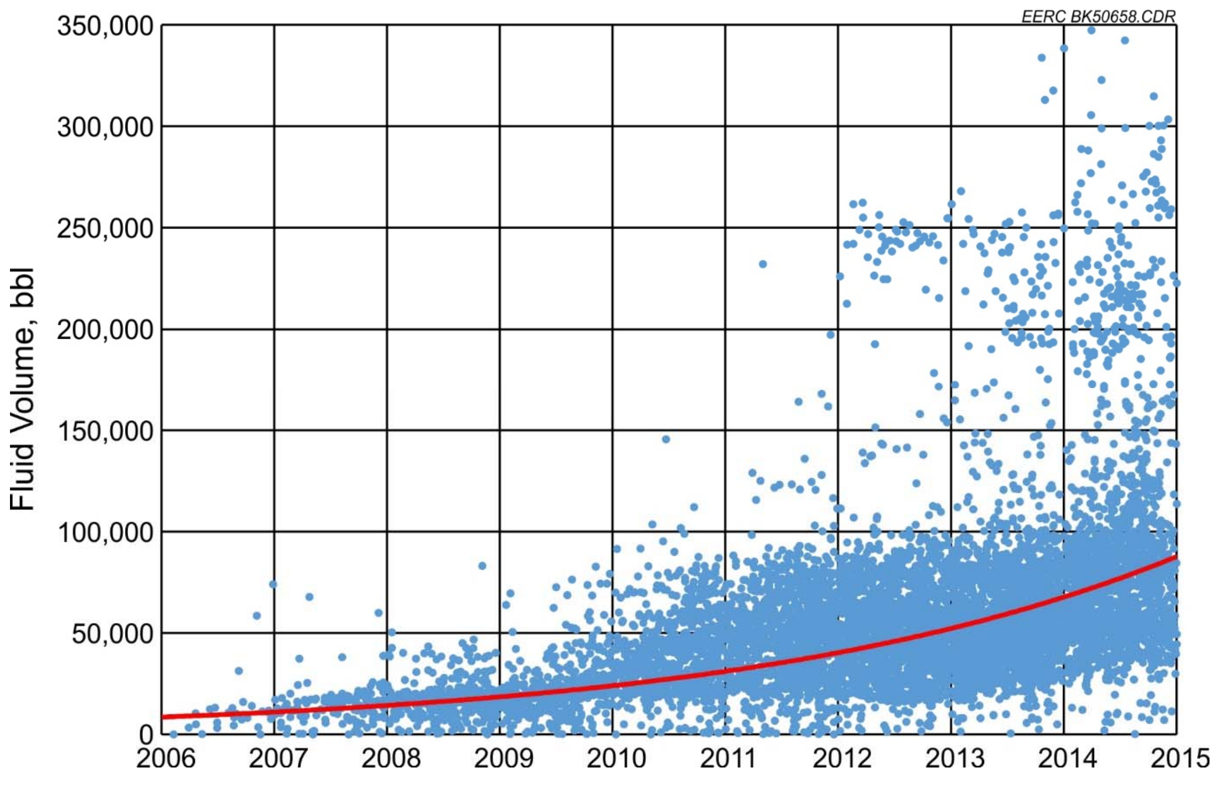


Figure 2. A plot of the fracturing fluid volumes used for each Bakken well completed from 2006 through 2014 (based on data provided by NDDMR).

**Table 2. The Distribution of Wells and Average Fracture Fluid Volumes Greater or Less Than 150,000 bbl for 2012 through 2014 (based on data provided by NDDMR)**

| 2014 Fracture Fluid Volumes | Number of Wells | Percentage of Wells | Average Fluid Volume, bbl |
|---|---|---|---|
| Volume Greater Than 150,000 bbl | 237 | 12 | 240,600 |
| Volume Less Than 150,000 bbl | 1740 | 88 | 69,200 |
| **2013 Fracture Fluid Volumes** | **Number of Wells** | **Percentage of Wells** | **Average Fluid Volume, bbl** |
| Volume Greater Than 150,000 bbl | 94 | 5 | 238,600 |
| Volume Less Than 150,000 bbl | 1916 | 95 | 56,300 |
| **2012 Fracture Fluid Volumes** | **Number of Wells** | **Percentage of Wells** | **Average Fluid Volume, bbl** |
| Volume Greater Than 150,000 bbl | 53 | 3 | 250,600 |
| Volume Less Than 150,000 bbl | 1710 | 97 | 51,200 |


Figure 3. Multiple frac tanks located on a Bakken well site being prepared for stimulation (photo taken by the EERC in 2009).

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Figure 4. An example of a water corral (image source: http://dragonenergyequipment.com).

## CHANGES IN BAKKEN FRESHWATER DEMAND AND SUPPLY OPTIONS

The availability of freshwater was a key concern during the early stage of Bakken development. Over the 2006 to 2010 time frame, the rate of drilling and completion operations rapidly increased, and the development of water supply infrastructure was unable to keep up with the fast pace of development. While there were abundant supplies of freshwater available in Lake Sakakawea and the Missouri River system, there were a limited number of water depots, and they could supply only a fraction of the anticipated freshwater demands. Having water available in a timely manner was a critical element to completing operations and establishing mineral leases. As a result, water haulers would spend hours waiting in line to fill up at the available water supply locations and then transport that water over long haul distances.

The early concerns related to water availability have been tempered because of some key developments that have provided greater access to freshwater for the oil and gas industry. These developments include:

- Expansion of municipal water treatment plant capacities.
- Development and expansion of water supply pipelines.
- Modification of the water appropriation hierarchy.
- Provision of easements and access to 100,000 ac-ft/yr from Lake Sakakawea.
- The use of small surface water supplies.

### Expansion of Municipal Water Treatment Plant Capacities

Water treatment plant upgrades and expansion of treatment capacity are critical in meeting increasing water demands for municipal, rural, and industrial uses. The city of Williston is an example of treatment plant expansions, with capacity increases to 14 million gallons per day (MGD) in 2014 and, ultimately, a planned expansion to 21 MGD to be completed in 2015 (Wirtz, 2014). Excess capacity from the treatment plant expansion supplies potable water to the Western Area Water Supply Project (WAWSP) (described below). Other water treatment expansion projects include the city of Parshall, which is expanding its capacity from 0.5 to 2.5 MGD, with the potential to expand to 10 MGD, and an expansion of McKenzie Rural Water, which is planned to provide about 4 MGD to Watford City and other water users (Schuh, 2010).

### Development and Expansion of Water Supply Pipelines

One of the major changes related to water supply and availability of freshwater resources has been the development and/or expansion of water supply pipelines in western North Dakota. The three major pipeline projects include WAWSP, the Southwest Pipeline Project (SWPP), and the Northwest Area Water Supply Project (NAWSP). While these pipelines were generally built to provide water for municipal and domestic use, the extra pipeline capacity has provided a valuable water supply resource for the oil and gas industry.

WAWSP is a domestic water supply project to meet the growing municipal, rural, and industrial water needs of northwestern North Dakota and supplies drinking water to Williston, Watford City, Ray, Tioga, Stanley, Wildrose, and Crosby. The projected future water supply capacity of the project at the time of development was 28 MGD (Ormer, 2011). A key attribute of WAWSP is the ability to provide unused pipeline capacity during population growth to the oil and gas industry to pay for a majority of the project. Upgrades to and expansion of the Williston Water Treatment Plant allow the opportunity to provide potable water to WAWSP, along with groundwater supplied by the water treatment plant in Ray, North Dakota. Figure 5 is a map showing the existing and future infrastructure components of WAWSP (Wirtz, 2014).

SWPP is a regional water supply system that draws water from Lake Sakakawea and serves the people in southwest North Dakota—with plans to expand. A map of SWPP is provided in Figure 6.

NAWSP is a water supply project to supply water to the people of northwestern North Dakota. Project construction began in 2002 but has been contested through a lawsuit brought both by Manitoba (biota transfer concerns) and the state of Missouri (negative depletion of water in the Missouri River). When ultimately completed, NAWSP is designed to supply 26 MGD. Figure 7 is a map that shows the components of NAWSP.

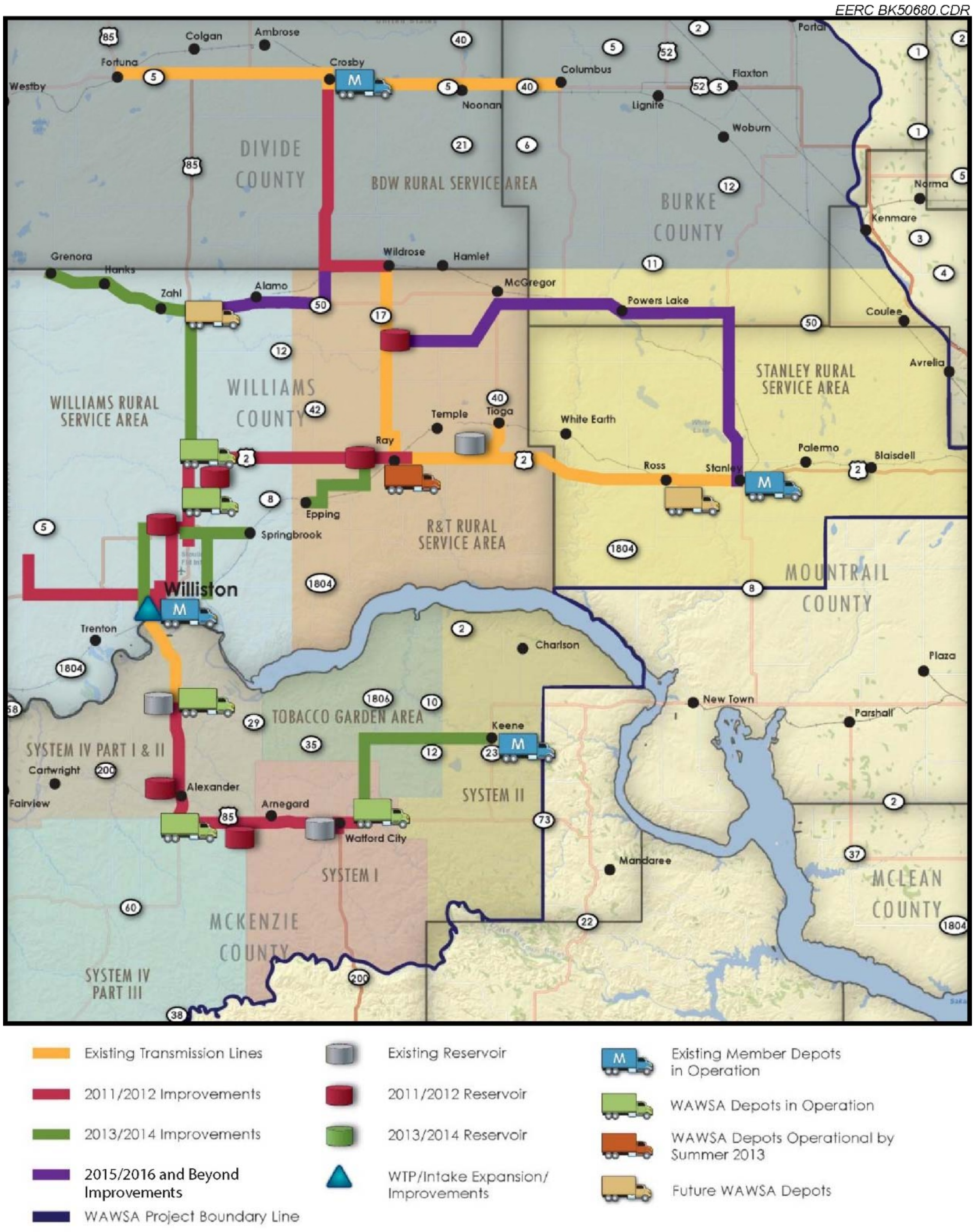


Figure 5. Major infrastructure components of WAWSP as of October 2014 (image taken from Wirtz [2014]).

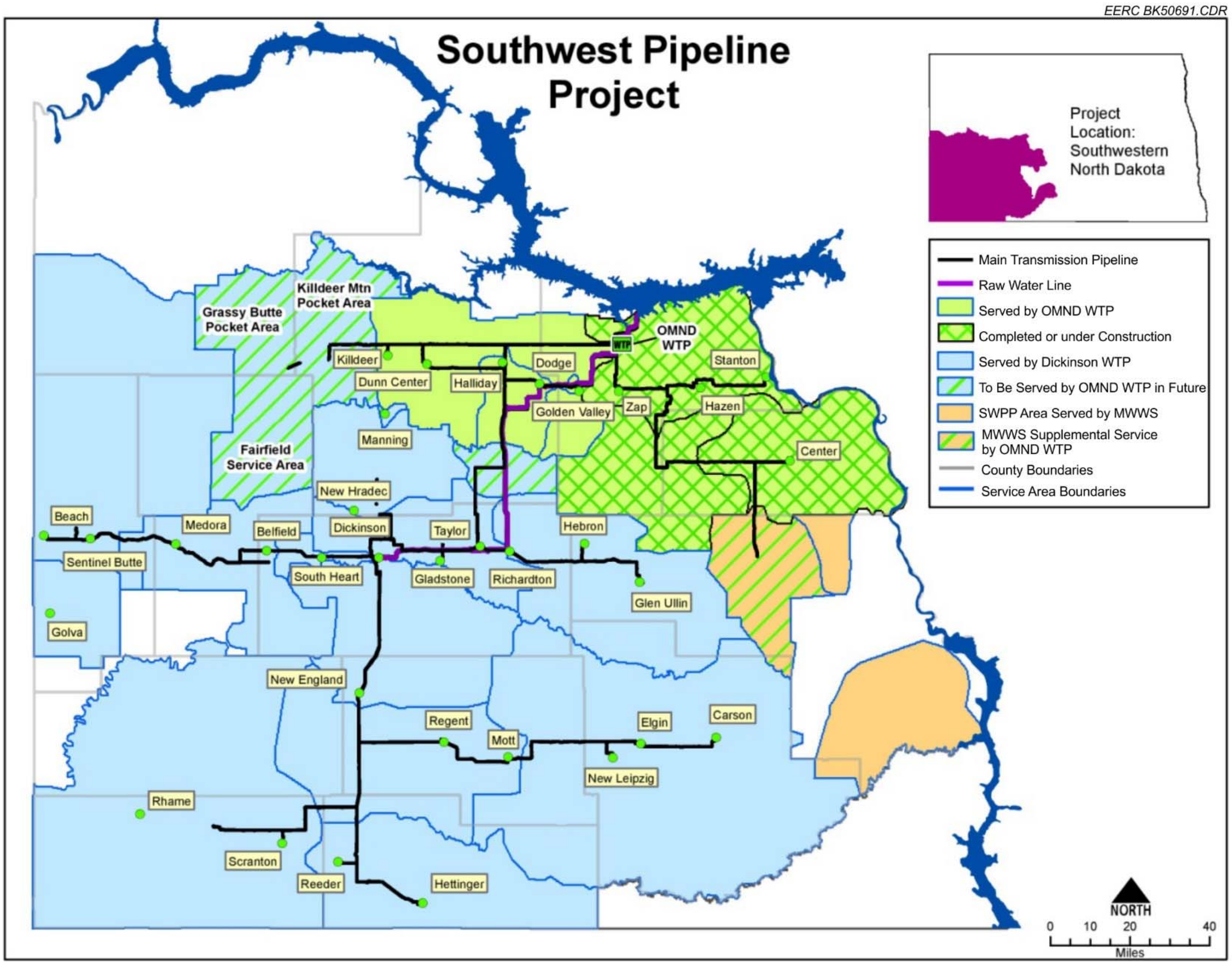


Figure 6. The major infrastructure components of SWPP (Southwest Pipeline Project, 2015).

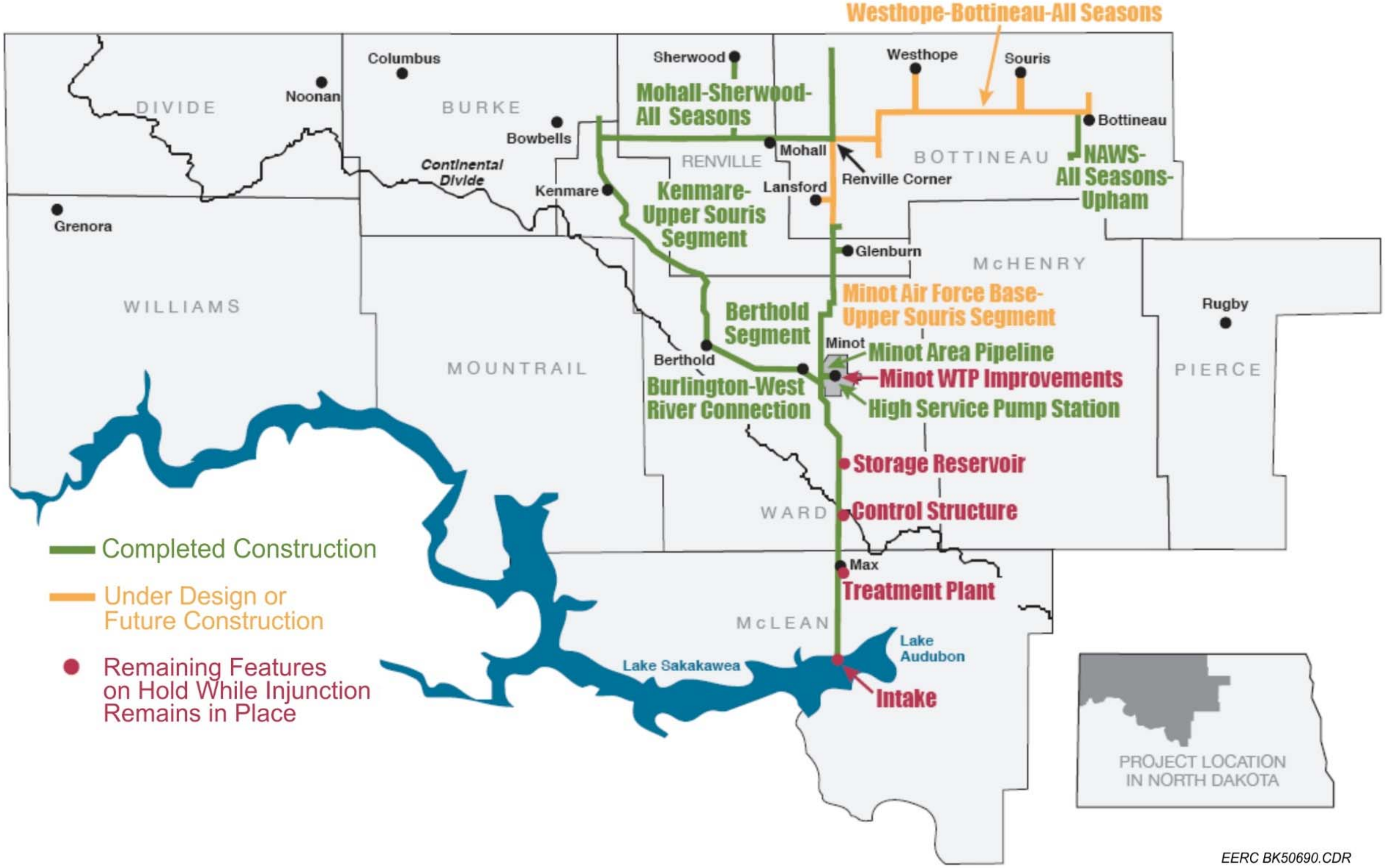


Figure 7. The major infrastructure components of NAWSP (North Dakota State Water Commission, 2015).

### Changes in the Water Use Hierarchy

The state of North Dakota recognizes a hierarchy of uses for water appropriation in the following order:

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

North Dakota does not allow the transfer of groundwater rights away from irrigation uses (North Dakota Century Code § 61-01-01.2). Traditionally, as long as no other appropriation is injured, the water use could only be changed to a superior use in the hierarchy (North Dakota Century Code § 61-04-16.1). Recently, however, the state has an internal policy to accommodate a change in purpose of use through the authorization of temporary water permits (Schuh, 2010).

### Increased Access to Lake Sakakawea

The Corps had restricted access to Missouri River flows within the boundaries of Lakes Sakakawea and Oahe. That left only ten Missouri River miles accessible to industrial water users within the heart of North Dakota's oil country. Proposed actions based on the conduct of a Lake Sakakawea Surplus Water Report suggested executing surplus water supply contracts with potential municipal and industrial users for yields of 100,000 acre-feet of water, the equivalent of 775.8 million barrels (U.S. Army Corps of Engineers, 2010).

### Use of Small Surface Water Bodies

The state of North Dakota has authorized and provided temporary permits for the use of small surface water impoundments for use in hydraulic fracturing. The water quality in these sources can vary depending on the drainage area and are more likely to contain higher populations of sulfate- and iron-reducing bacteria (SRB and IRB) in bottom sediments which may require the use of higher doses of biocide during hydraulic fracturing. It is important for industry to be aware of the various sources of freshwater that a water hauler may be transporting since it could be very difficult to remove SRB from a water truck or from a fracture tank unless the containers are thoroughly cleaned and all sludge is removed. Otherwise, the well completions crew may underestimate the amount of biocide needed to control the bacteria.

### Changes in Industrial Water Use

The vast improvements that have been made to the water supply infrastructure in the Bakken region have helped industry meet the rapidly increasing water demand for oil and gas development. To assess the changes that have occurred in industrial water use as a result of oil and gas development in the Bakken, NDSWC shared a database with the EERC that contains information on permitted water use in the state. Since 2008, industrial water use in the Bakken region has increased more than tenfold, from just over 13 million barrels (546 million gallons) in 2008 to just over 153 million barrels (6.4 billion gallons) in 2013 (Figure 8).

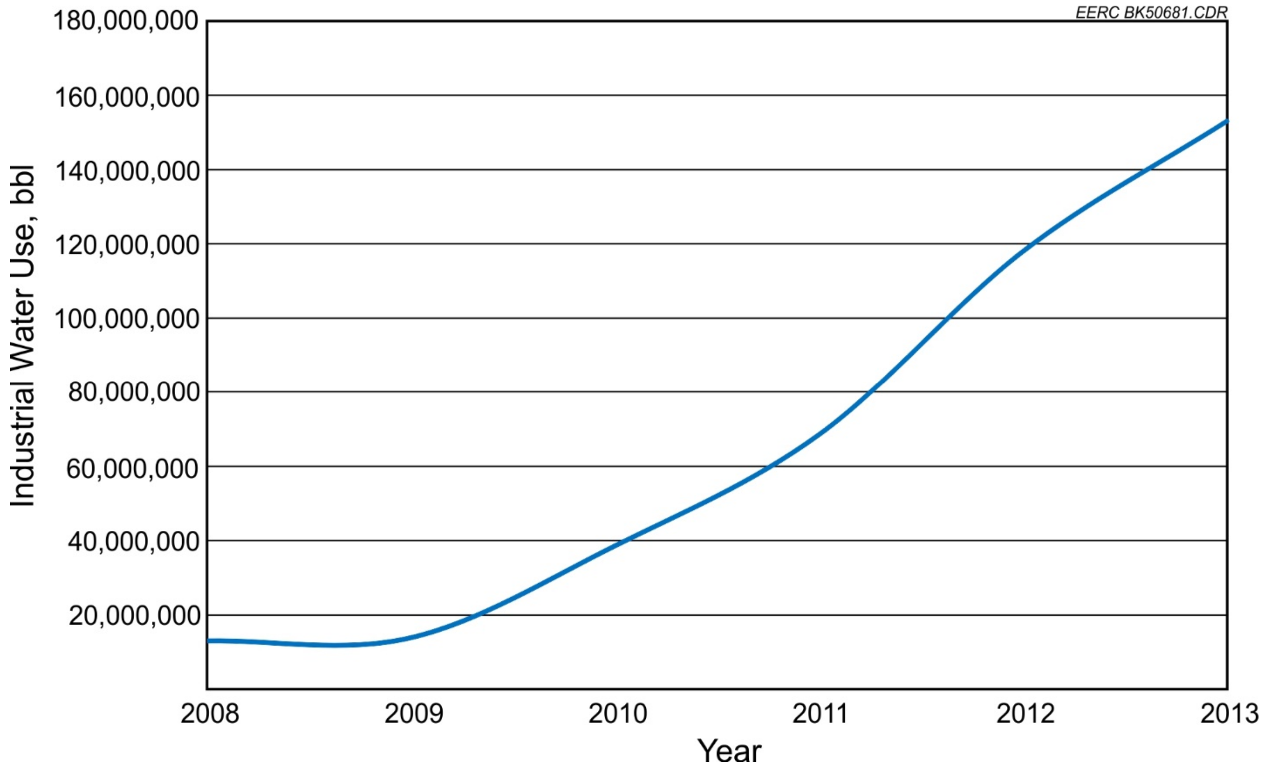


Figure 8. Plot of industrial water use from 2008 through 2013 (data source: NDSWC).

The EERC used water permit location information in the database to map the expansion of industrial water use permits over time. To better understand the difference in the various types of water permits issued by NDSWC, a brief description is warranted. Permits for water use are broken into two types: water permits and temporary permits. Water permits are issued for more than one calendar year, whereas temporary permits are issued for only one calendar year. Temporary water permits are normally active as they are issued on a year-to-year basis. Temporary permits may also be issued in cases where water is transferred from one designated use to another (i.e., irrigation to industrial), a practice that has become very common as the oil and gas industry's demand for water has increased. Temporary water permits are also attractive to industry because they typically require a shorter wait time for approval.

As shown in Figure 9, the number of active industrial water use permits increased more than tenfold in the past 8 years, from 23 permits in 2008 to over 120 in 2013. Likewise, temporary water permits gained in popularity over the same time frame, with two in existence in 2008 to 108 as of 2013.

Another way of tracking water distribution and pending changes to the water supply infrastructure is to look at existing and pending water depot locations throughout the Bakken region (Figure 10, data courtesy of NDSWC). Based on the number of undeveloped and pending water depots as of 2014, which together account for almost double the number of developed water depots, the freshwater supply infrastructure continues to expand very rapidly.

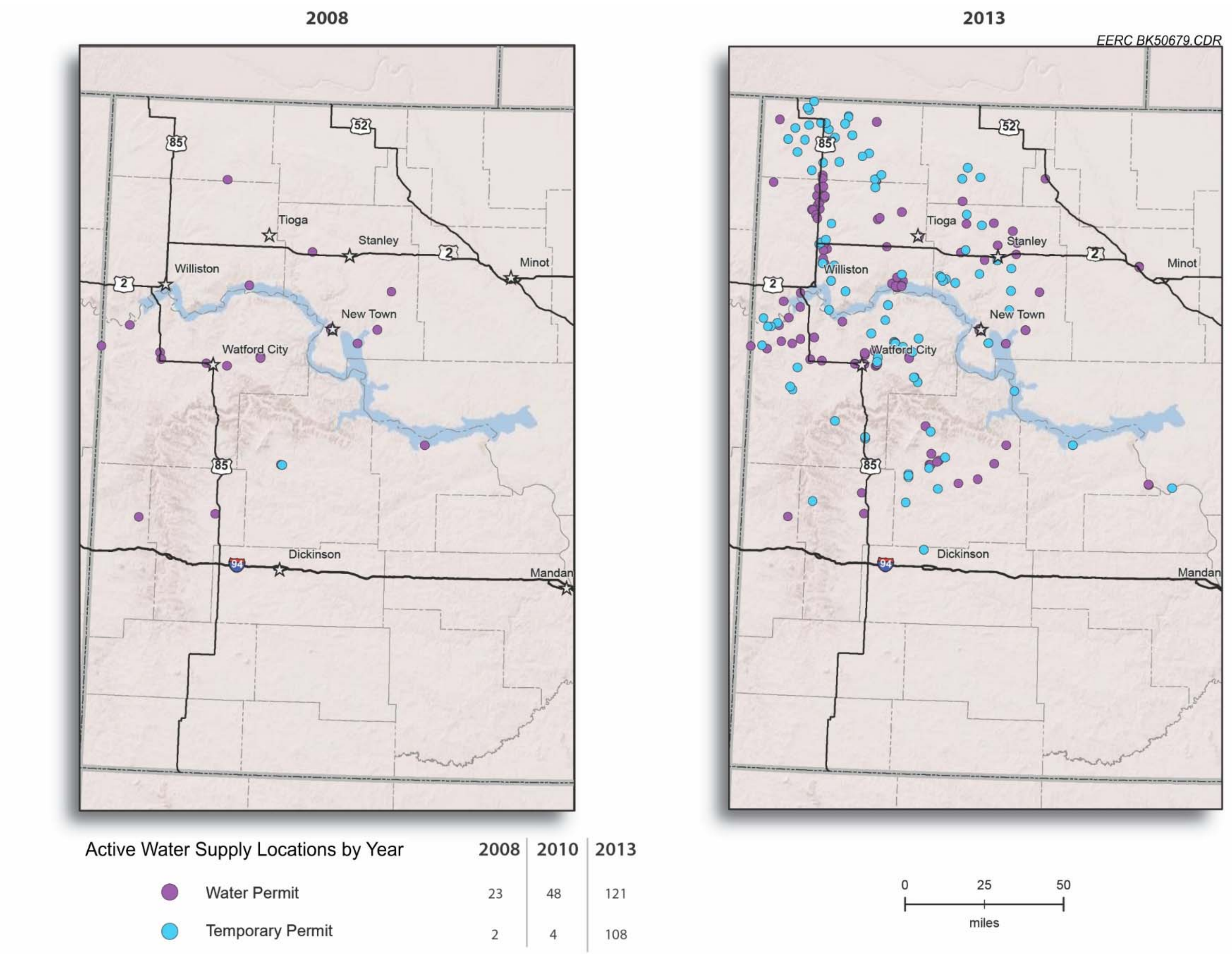


Figure 9. Perfected and temporary industrial water permit locations – 2008 and 2013 (data source: NDSWC).

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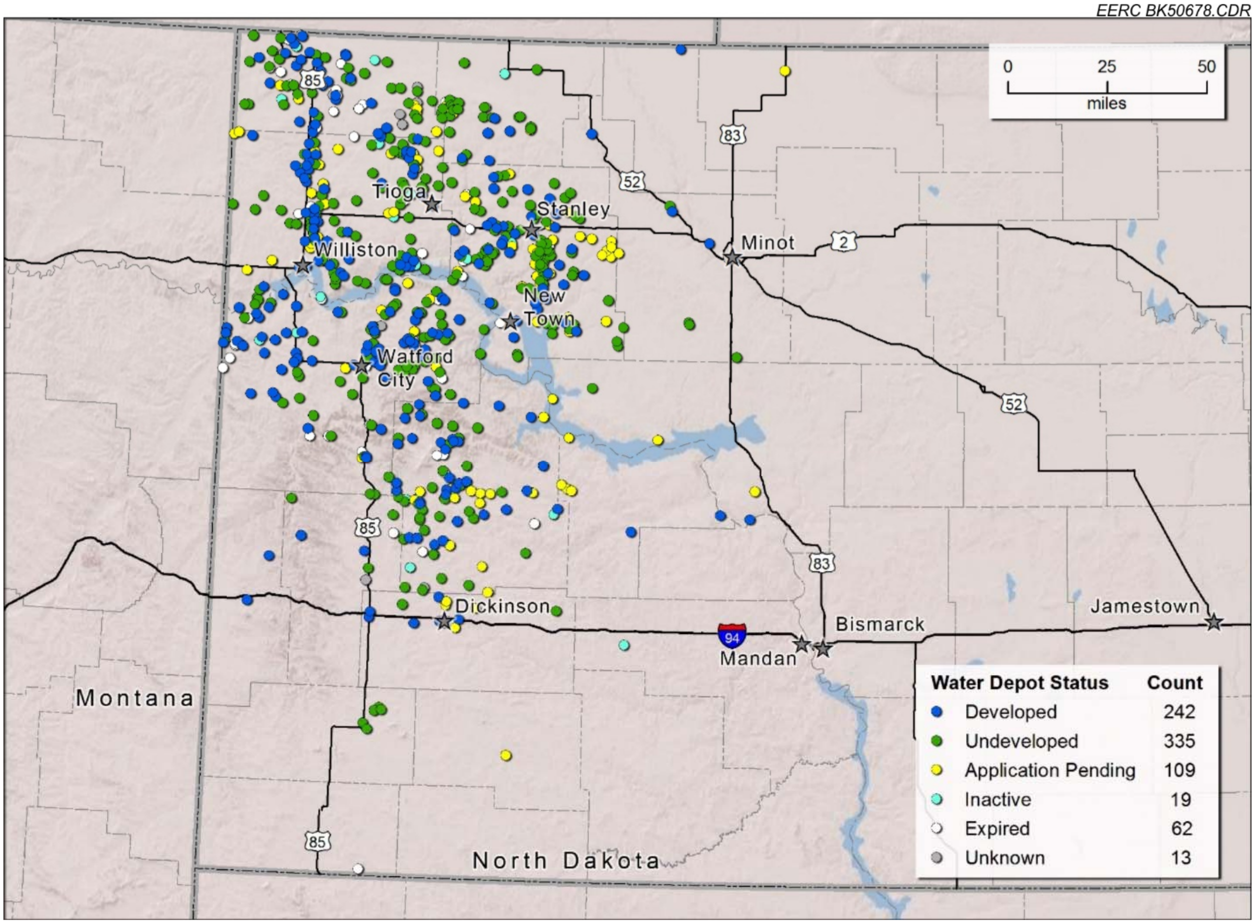


Figure 10. Water depot status across western North Dakota as of 2014 (data source: NDSWC).

## PROJECTIONS OF FUTURE FRESHWATER DEMAND

To evaluate the freshwater supply capacity and infrastructure in comparison to the growing needs of industry, the EERC attempted to estimate the future freshwater needs for hydraulic fracturing as well as maintenance water. As Bakken development began to ramp up in the late 2000s, the primary focus of the state and industry was on the water needs for hydraulic fracturing and availability of freshwater supply sources. As wells were drilled and activity shifted more toward resource development, industry became more aware of the freshwater volumes needed for long-term maintenance of Bakken wells to avoid fouling due to the high salt content of the formation water that is produced along with hydrocarbons.

### Maintenance Water Projections

The extreme salinity of Bakken produced water, which can approach 300,000 mg/L TDS (total dissolved solids), necessitates routine flushing of the production casing with freshwater to help prevent scale deposition and to remove accumulated salts. This is sometimes referred to in industry as well maintenance, brine dilution, desalting, or well flushing. In some cases, larger volumes of water are used periodically for flushing, while in others, a steady stream of freshwater is supplied continuously downhole though a small-diameter tube that runs alongside the production tubing.

The amount of freshwater needed for well maintenance depends on several different factors, including produced water salinity, chemistry, quantity, and formation pressure; however, it is unclear at this time how those factors influence maintenance water demand spatially and/or temporally. One of the challenges in determining maintenance water needs for Bakken wells is the lack of available data. NDSWC does track freshwater use through its permitting system; however, the permitting process does not collect information specifying water use purpose. NDIC also does not require operators to report how much water is pumped down the wellbore for maintenance. Based on discussions with field operations personnel, the volume of water injected downhole for well maintenance is typically subtracted from the reported produced water volumes.

Preliminary estimates by NDDMR indicated that approximately 15 bbl/well/day (600 gallons per well per day) of freshwater would be required for well flushing and maintenance. Information that EERC researchers gathered from industry members has indicated that as high as 30 to 50 bbl/well/day of freshwater may be common in the central and northern portions of the basin (Industrial partner, personal communication, 2014). However, the EERC has yet to collect sufficient data to assemble a comprehensive understanding of maintenance water needs throughout the Bakken play. It is still unclear which chemical and/or physical parameters have the greatest impacts on scaling tendencies of Bakken produced water. In addition, different producers employ different chemical programs and/or different mechanisms for injecting freshwater for well maintenance which can lead to widely varying maintenance water requirements across North Dakota. In an effort to develop estimates for future maintenance water needs, several assumptions were made. These assumptions were used to generate the plot illustrated in Figure 11 and include the following:

- 2000 new wells drilled/completed a year
- 20% of wells requiring no maintenance water
- 80% of wells requiring maintenance water that ranges from a low of 15 bbl/well/day to a high of 50 bbl/well/day
- An average well lifetime of 20 years

Based on these assumptions, the "high" projection, at 50-bbl/well/day maintenance water demand, results in a freshwater demand of 584 million bbl/yr by 2035 or 67 MGD. The low projection (15 bbl/well/day) results in an estimated maintenance water demand of 175 million bbl/yr by 2035, or 20 MGD. An average estimated maintenance water requirement for Bakken wells (32.5 bbl/well/day) would require 380 million bbl/yr by 2035, or 44 MGD.

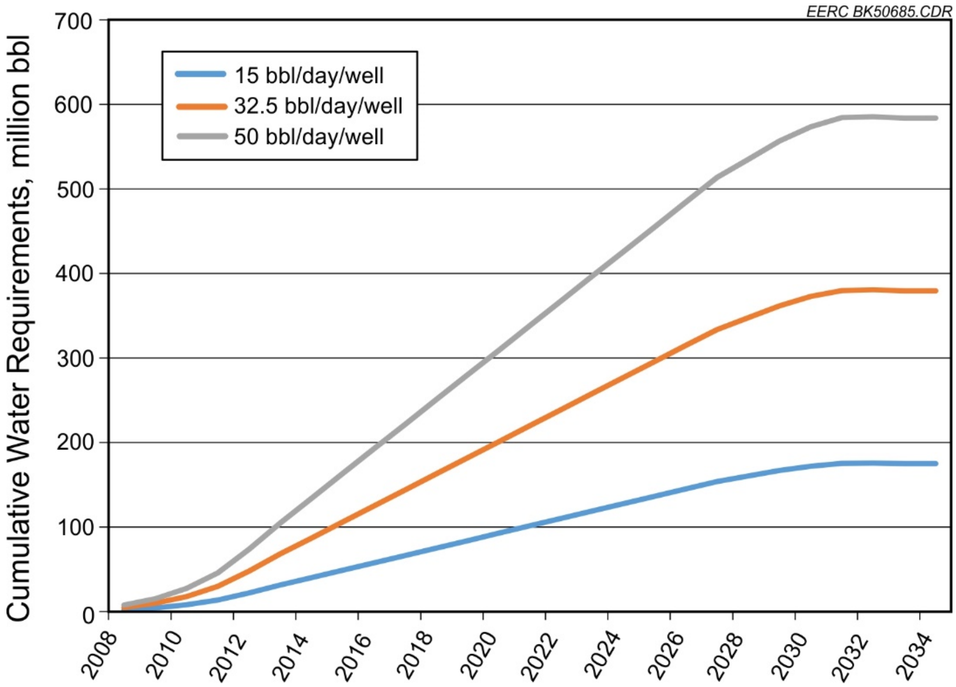


Figure 11. Estimated maintenance water demand scenarios.

Figure 12 presents a projected total freshwater demand that includes potential water use scenarios for both hydraulic fracturing and well maintenance. These projections assume the following:

- 2000 new wells drilled/completed a year
- 80% of wells requiring an average maintenance water demand of 32.5 bpd
- An average well lifetime of 20 years
- Scenario 1:
  - Assumes 4% annual increase in slickwater stimulations for the next 10 years, after which a plateau is reached.
- Scenario 2:
  - Assumes 7% annual increase in slickwater stimulations for the next 10 years, after which a plateau is reached.

To create this chart, the actual hydraulic fracturing fluid volumes reported by NDDMR were used through 2014. Beyond 2014, two scenarios were evaluated based on assumed increases in slickwater completions. The conservative estimate, Scenario 1, assumes that the number of slickwater stimulations increases 4% annually for the next 10 years, after which a plateau is reached. The second scenario, Scenario 2, assumes that the average annual increase in slickwater stimulations is 7%, which is the percent increase in these types of completions from 2013 to 2014. Based on the above assumptions, a very preliminary estimate of future freshwater demand for hydraulic fracturing and well maintenance needs is between 620 and 722 million bbl/year by 2025 and between 703 and 805 million bbl/year by 2035. For comparison, 805 million bbl is more than 4 times the treatment capacity of the Williston water treatment plant operating at a peak design capacity of 21 MGD.

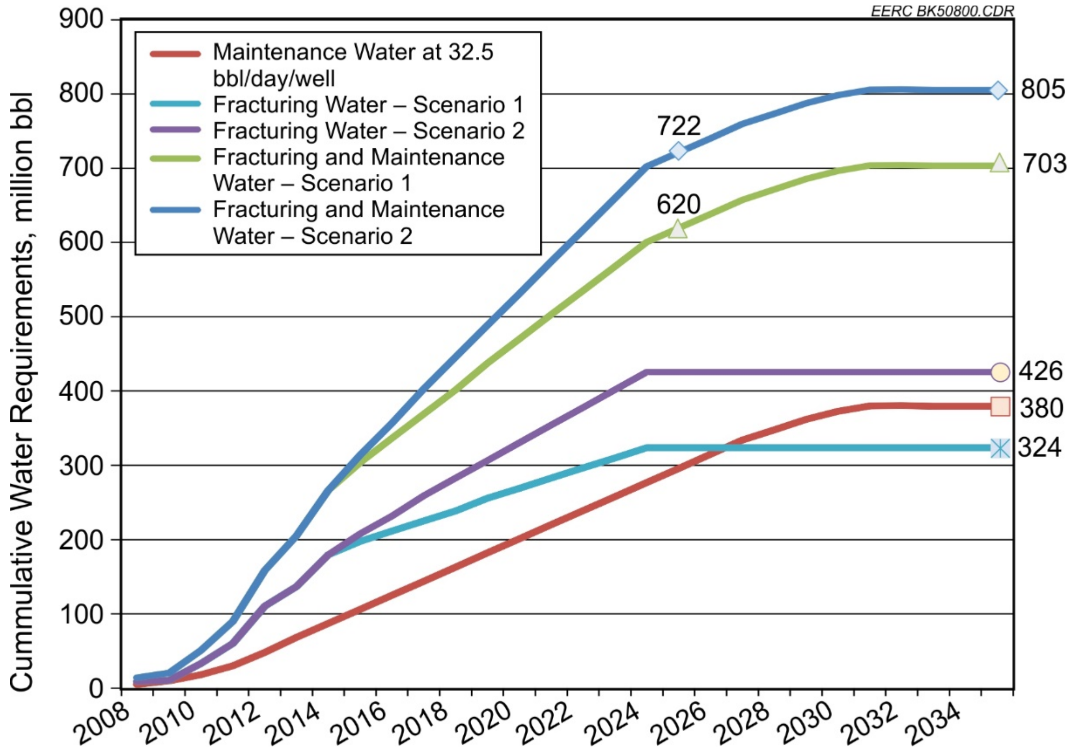


Figure 12. Projected total freshwater demand.

Projecting the future use of water in hydraulic fracturing is dependent on multiple variables. As discussed in earlier sections of this report, technological advancements in well completion technologies continue to be implemented. How these changes may or may not affect freshwater demand remains to be seen. As of 2015, the largest unknown with respect to well completion technologies that may affect water use is slickwater stimulations. Since slickwater fracturing requires 3 to 4 times the water volume of gel-based fracturing, a significant increase in these types of fracture treatments could significantly affect freshwater demand. In the near term, some of the projected increase in water demand will likely be reduced because of fewer rigs and the growing backlog of completions.

The above estimates should be used very cautiously given the number of unknowns that could affect future freshwater demands, some of which include:

- Dependence of maintenance water demand on a number of factors that vary significantly depending on geographic location and on the selected practices of different Bakken producers.
- Changes in hydraulic fracturing techniques and resulting impacts to freshwater demand.
- Increased use of produced water for hydraulic fracturing (to be discussed later in this report).
- Changes in the rate of drilling and completions.

## TRENDS IN BAKKEN PRODUCED WATER GENERATION

Just as considerable changes have occurred in Bakken well stimulation practices and associated water use over the past decade, significant increases have also occurred in the volumes of produced water generated from Bakken wells. Figure 13 illustrates the expansion of Bakken drilling activity and the changes in produced water generation both spatially and temporally. To generate this figure, the average volume of produced water generated per well during the first 18 months of production was calculated. Each map within the figure was created using data only from wells completed in the corresponding year. For example, the left-most image in Figure 13 is a map of the average produced water generation during the first 18 months of production for Bakken wells completed in 2008. In 2014, over 270 million barrels of produced water was generated from Bakken wells over the course of the year, which is an average of almost 81 bbl/day per well.

Figure 14 illustrates the increase in produced water generation from Bakken wells over time as compared to oil production. To normalize the data so that trends from multiple years could be shown on a single graph, the monthly water and oil production values for each Bakken well were averaged for each quarter of production. The average quarterly fluid production for all wells completed in a given year were then used to calculate average cumulative fluid production for that year. While cumulative oil production has remained relatively consistent regardless of year, cumulative water production has increased with each consecutive year, although the difference in water production between 2012 and 2013 is less than the difference between any other years, possibly indicating a reduction in the rate of increase. Note that the cumulative water production is strongly influenced in the first quarter by the volume of water used for well stimulation; however, it is unclear how long the injected fracturing fluids affect produced water generation.

Increased water production in wells that have been completed more recently without a concurrent increase in oil production has resulted in an increase in the average water cut of Bakken wells. Figure 15 illustrates the spatial changes in water cut of Bakken wells over time, where water cut is expressed as a percentage of water relative to the total volume of liquids produced during Months 2 through 19 of production (a total of 18 months of production). The first month of production was excluded from the data used to create these maps so that the spatial trends could be examined without the influence of frac flowback. The average water cut across the play is just over 50%, or one barrel of water per barrel of oil, with certain wells producing over 10 barrels of water per barrel of oil.

Figure 16 depicts the average water cut of Bakken wells per each quarter of production for wells drilled in the years 2008 through 2013. In this graph, the first month of fluids production was included to illustrate the influence of frac flowback on water cut during the first quarter of production. Again, the first month of production was excluded from the maps to illustrate the spatial variability in water cut without the influence of hydraulic fracturing water. Similar to the trends exhibited in produced water generation, the average water cut per well is higher for wells completed more recently. In addition, the average water cut increases over time since the rate of oil production decreases faster than the decrease in water production.

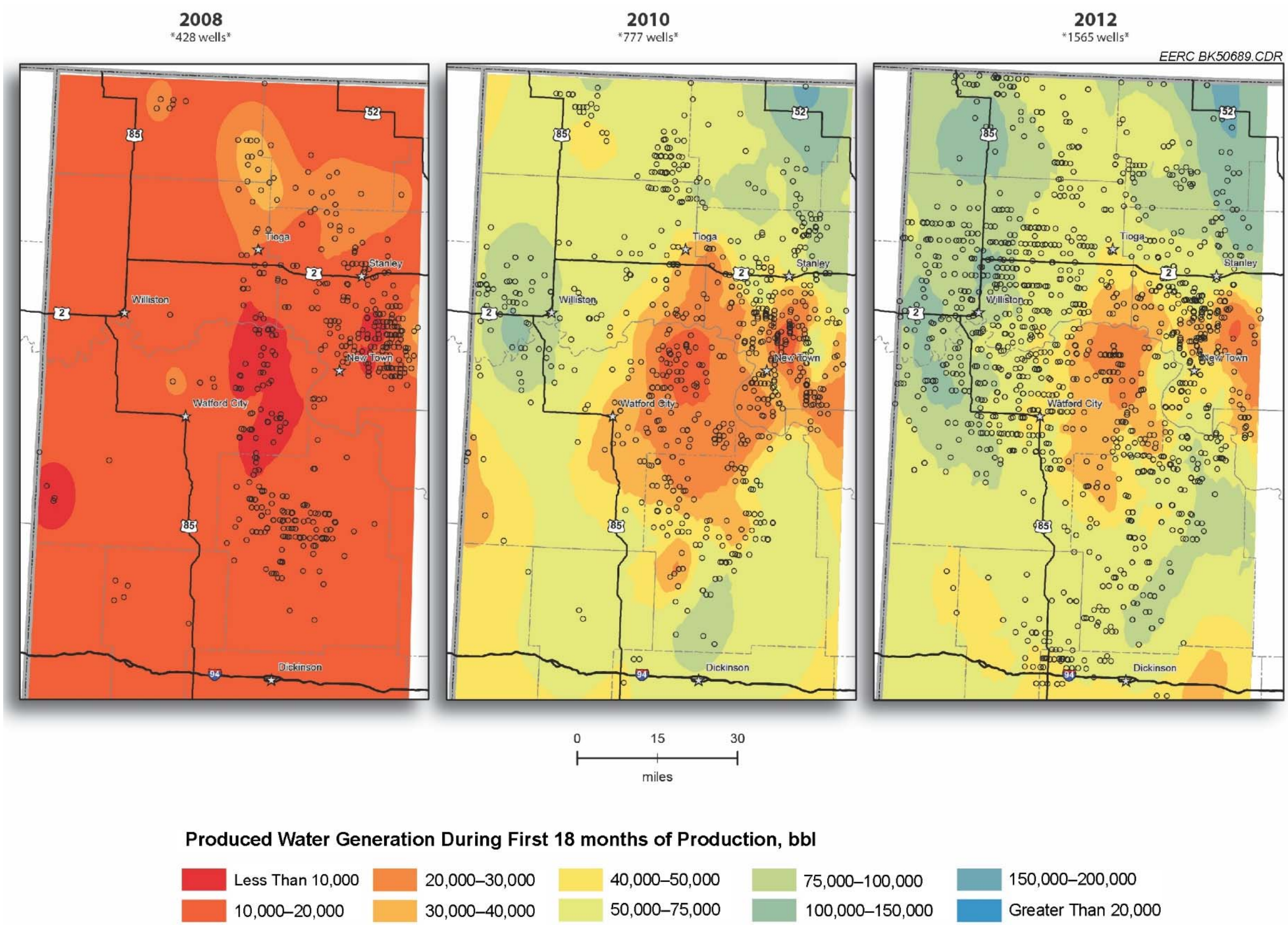


Figure 13. Average produced water generated from Bakken wells during the first 18 months of production (data source: NDIC).

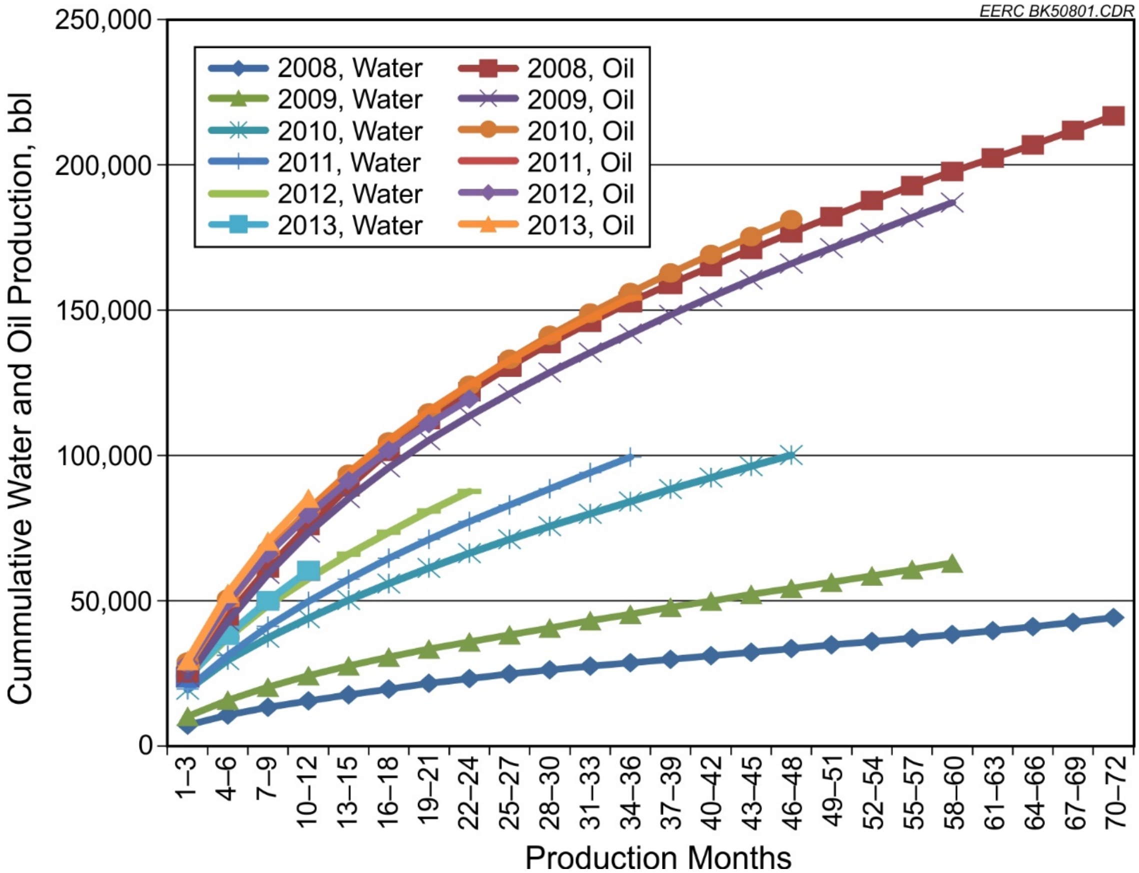


Figure 14. Average quarterly cumulative fluids production for wells completed in years 2008 through 2013 (data source: NDIC).

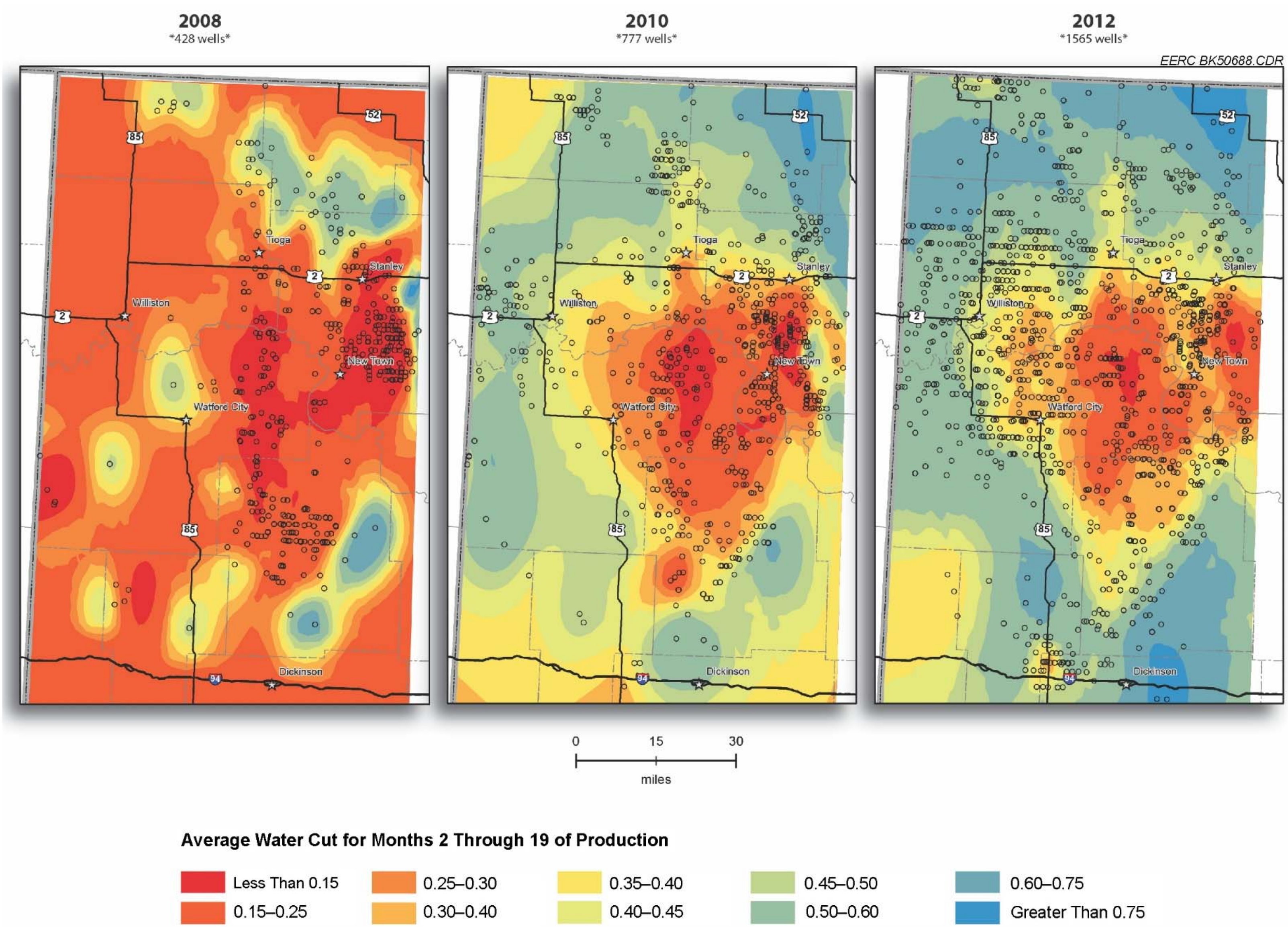


Figure 15. Average water cut of Bakken and Three Forks wells during Months 2 through 19 of production (data source: NDIC).

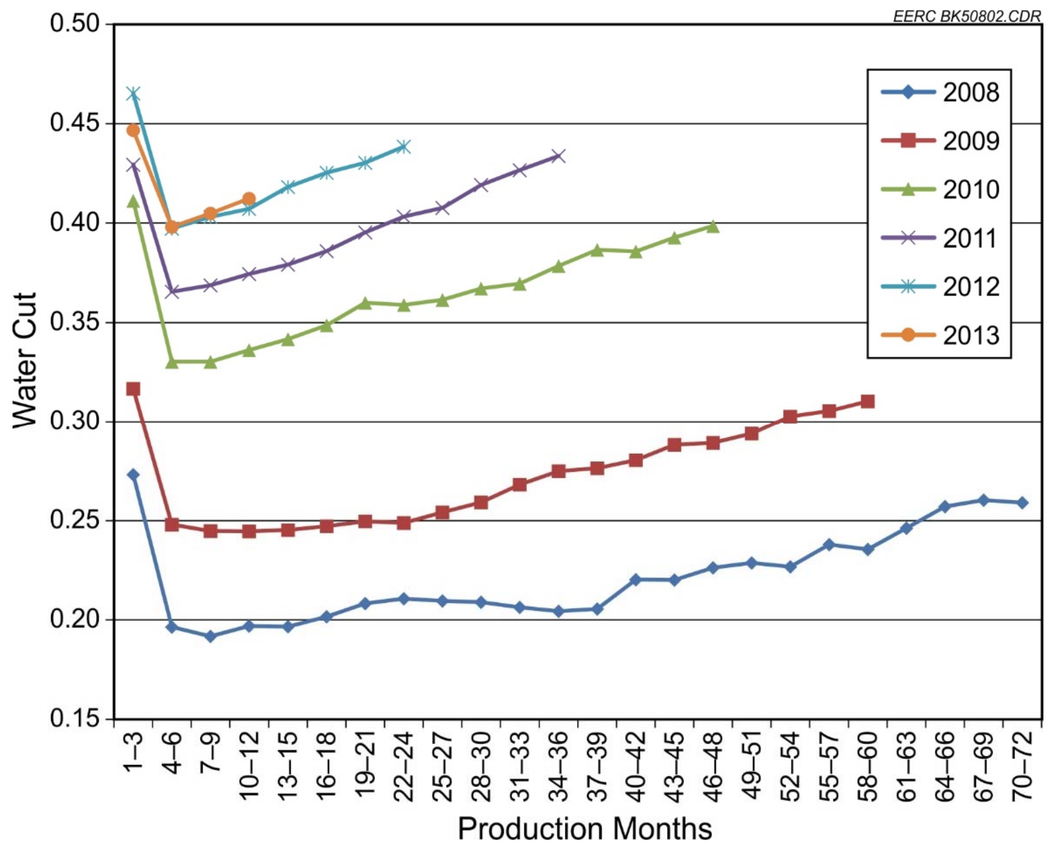


Figure 16. Average water cut by quarter for wells drilled in years 2008 through 2013 (data source: NDIC).

The trends in water production and water cut illustrated in the last four figures (Figures 13–16) can be attributed to several potential factors:

- Improved well stimulation techniques and longer laterals 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, especially if fractures were generated during well stimulation that extends upward (Industrial partner, personal communication, April 2015).

- As development continues, more Bakken wells are being drilled farther away from the center of the basin and into areas of the Bakken petroleum system that have a higher water content.

- Three Forks wells generally have a higher water content than wells drilled into the Bakken; thus an increase in the number of Three Forks wells could increase average water production.

## PRODUCED WATER DISPOSAL

### Current SWD Volumes

Just as freshwater supply locations have increased as a result of the expanding oil and gas industry, so has the number of produced water disposal wells in the Bakken region. The traditional transport mechanism for brines produced from Bakken wells has been semi-tractor trailers moving brine from drilling and production locations to SWD wells. Typical hauling volumes of approximately 120 to 160 bbl per truck make the task of moving an ever-growing volume of produced water increasingly expensive and impactful to infrastructure and communities. As a result, the number of saltwater pipelines that are used to collect and aggregate produced water from individual wells to larger, temporary saltwater storage locations and also to SWD sites has also increased.

Table 3 and Figure 17 show the total injection volumes for SWD wells in North Dakota from 2006 through 2014. The primary injection zones are the Dakota Group, the Minnelusa Group, and the Madison Group Formations. Because the “other” category of injection targets represented such a small volume of disposal, that category is not displayed in Figure 17. As of 2014, the total disposal volumes were more than 386 million barrels annually, 93% of which (by volume) was injected into the Dakota Group, also referred to as the Dakota Formation.

The lower Cretaceous Dakota Formation is a saline aquifer system that has TDS values that vary depending on location. In eastern North Dakota, TDS values are typically below 10,000 mg/L; however, in western North Dakota, values can be in the 10,000–30,000-mg/L range, making it an acceptable formation for injection. The Dakota Formation has an excellent disposal capacity, and it is approximately 1500 to 2000 feet shallower than other saline aquifers, which makes it a more economical target for injection.

**Table 3. Total SWD Injection Volumes from 2006 to 2014 (million bbl/year)***

| | Dakota Group | Madison Group | Minnelusa Group | Other | Grand Total |
|---|---|---|---|---|---|
| 2006 | 73.0 | 2.9 | 11.3 | 0.5 | 87.6 |
| 2007 | 77.3 | 3.3 | 13.7 | 0.3 | 94.5 |
| 2008 | 84.8 | 4.2 | 17.9 | 0.2 | 107.1 |
| 2009 | 89.8 | 5.5 | 18.8 | 0.1 | 114.1 |
| 2010 | 110.0 | 6.4 | 19.6 | 0.0 | 136.0 |
| 2011 | 147.8 | 7.9 | 18.9 | 0.0 | 174.5 |
| 2012 | 214.7 | 9.0 | 14.9 | 0.0 | 238.7 |
| 2013 | 277.1 | 9.6 | 14.4 | 0.0 | 301.1 |
| 2014 | 359.6 | 8.9 | 18.1 | 0.0 | 386.5 |

* Data source: NDIC.

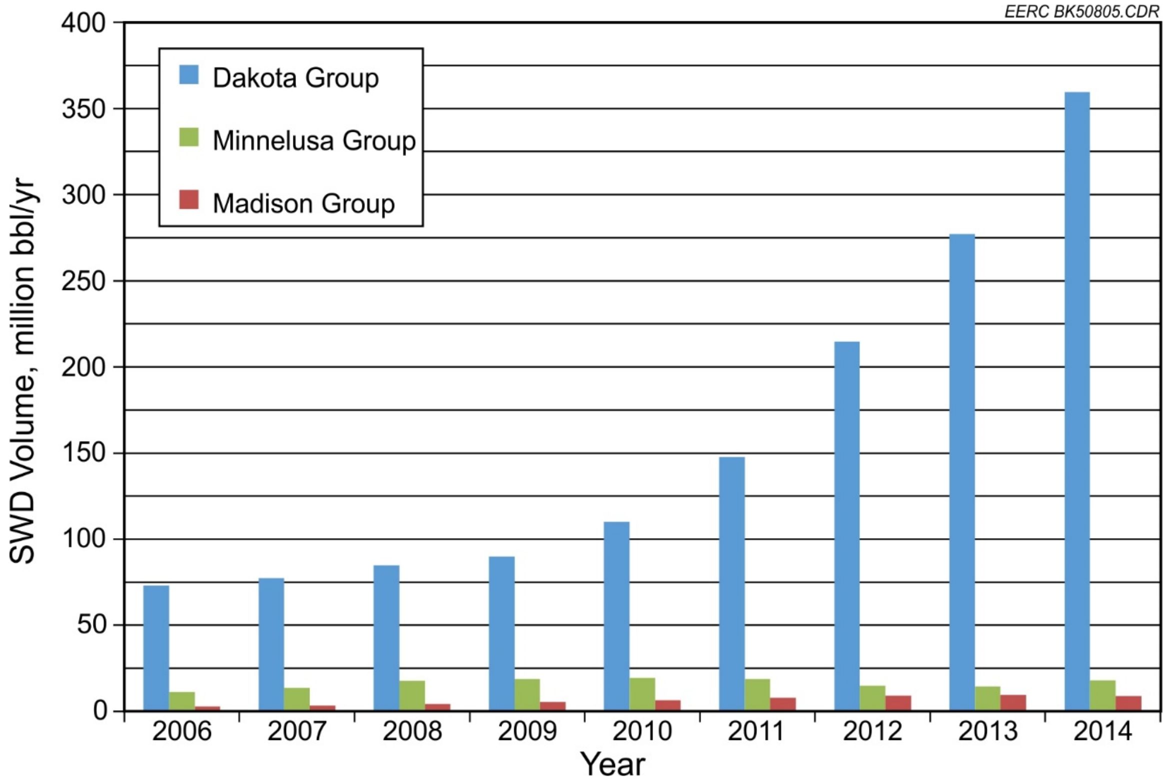


Figure 17. Annual SWD volume by injection target from 2006 to 2014 (data source: NDIC).

Figure 18 shows the total volume of water injected into SWD wells by year since the 1956 and illustrates the dramatic increase in recent years resulting from the injection of Bakken flowback and produced water. Figure 19 compares the location of active SWD wells between 2006 and 2014. A 67% increase in the number of regional disposal wells, from 292 to 487, occurred during that time frame, and the increase in disposal volume increased by 341%, from 87.6 to 386.5 million barrels.

Table 4 illustrates how Bakken development and associated produced water generation have impacted SWD in western North Dakota. In 2006, produced water generated from the Bakken accounted for only 1.3% of all SWD. In contrast, 2014 Bakken produced water disposal accounted for 70% of all SWD. That is a tremendous increase in the past decade, especially considering that the number of SWD wells almost doubled in that same time frame.

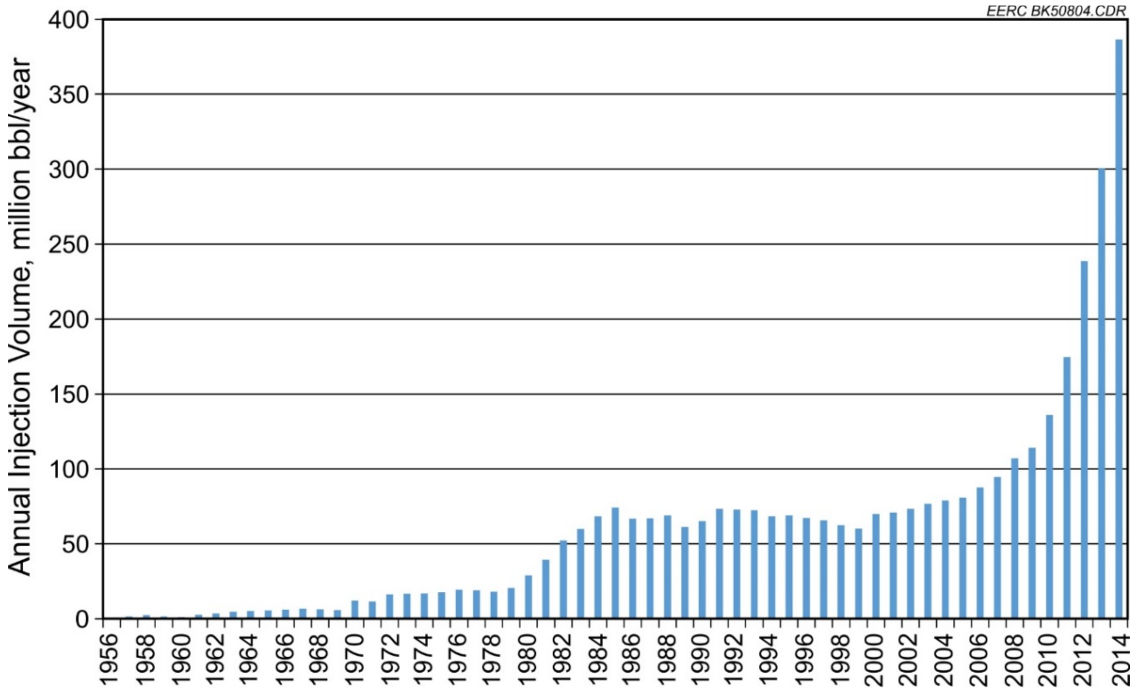


Figure 18. Volumes of water injected into all SWD wells since 1956 (data source: NDIC).

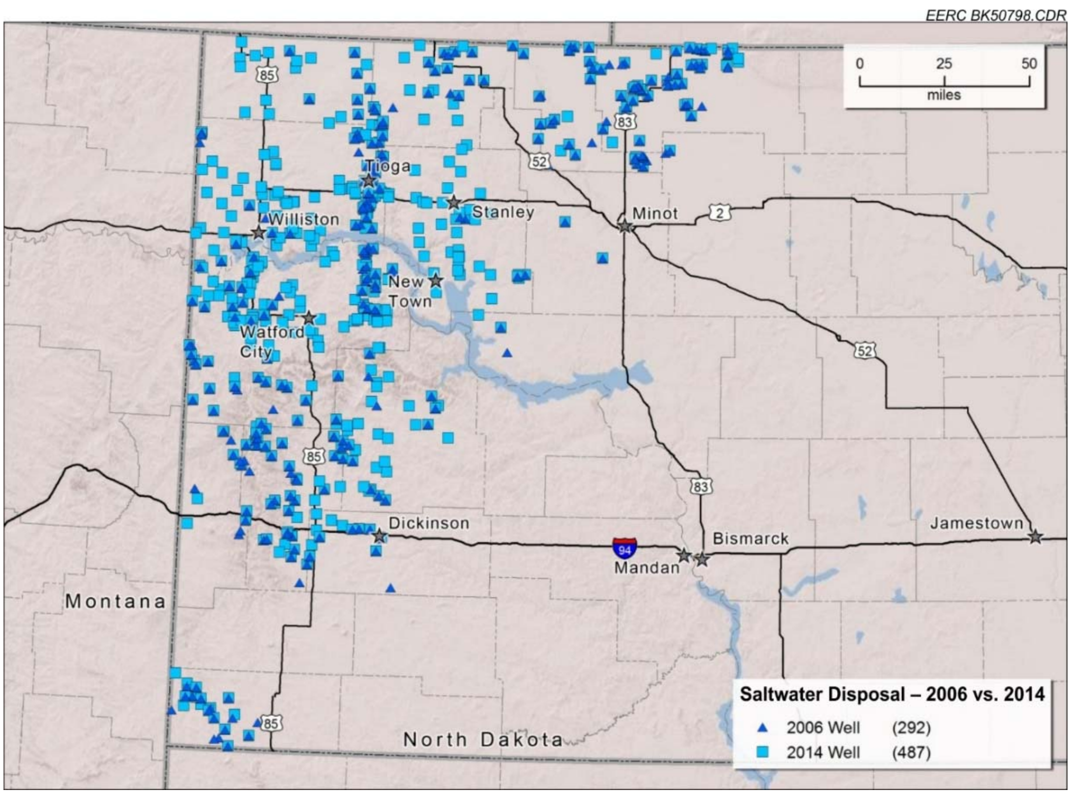


Figure 19. Comparison of active SWD well locations between 2006 and 2014 (data source: NDSWC).

**Table 4. Impact of Produced Water Generation**

| Year | Total SWD in All Formations, million bbl/yr | Volume of Produced Water Generated from Bakken Wells, million bbl | Total SWD from Bakken Produced Water, % |
|---|---|---|---|
| 2006 | 88 | 1.2 | 1.3 |
| 2007 | 95 | 2.4 | 2.5 |
| 2008 | 107 | 7.0 | 6.5 |
| 2009 | 114 | 12.8 | 11.2 |
| 2010 | 136 | 33.2 | 24.4 |
| 2011 | 174 | 63.7 | 36.6 |
| 2012 | 239 | 129.9 | 54.3 |
| 2013 | 301 | 190.2 | 63.2 |
| 2014 | 386 | 270.4 | 70.0 |

**Future SWD Needs**

Oil and gas production activities in the Bakken will continue to drive the need for SWD for the foreseeable future. While there may be advances in reusing produced water, the anticipated volume of produced water will necessitate ongoing use of SWD wells that will continue injecting into the Dakota Formation and, possibly, other formations if capacity in the Dakota becomes limited. While many factors could influence future produced water generation in the Bakken, a very general estimate of future production can be made using historical data. Table 5 shows the increase in the total number of Bakken wells since 2008 and the concurrent increase in produced water generation. While the current trend shows an increase in average produced water volumes per well every year, if we take a conservative approach and assume that the average annual produced water generation per Bakken well will remain at the 2014 value of 29,450 bbl/well/year then the associated predicted produced water volumes in subsequent years are the values listed in Table 6.

**Table 5. Trend in Produced Water Generation in the Bakken Since 2008**

| Year | Total Bakken Wells | Total Produced Water Generation, million bbl | Average Annual Produced Water Generation per Well, bbl |
|---|---|---|---|
| 2008 | 538 | 6.4 | 11,868 |
| 2009 | 1047 | 12.1 | 11,585 |
| 2010 | 1893 | 32.6 | 17,201 |
| 2011 | 3144 | 63.7 | 20,263 |
| 2012 | 5073 | 129.9 | 25,597 |
| 2013 | 7183 | 190.2 | 26,473 |
| 2014 | 9183 | 270.4 | 29,450 |

**Table 6. Projected Water Generation in the Bakken***

| Year | Estimated Number of Bakken Wells | Estimated Annual Bakken Produced Water Generation, million bbl | Estimated Number of SWD Wells at an Average Annual Injection Rate of 793,000 bbl | Additional SWD Wells Needed Beyond Those Existing in 2014 |
|---|---|---|---|---|
| 2020 | 21,183 | 624 | 787 | 300 |
| 2025 | 31,183 | 918 | 1158 | 671 |
| 2030 | 39,290 | 1157 | 1459 | 972 |
| 2035 | 40,000 | 1178 | 1485 | 998 |

* Assumes a well lifetime of 20 years.

Current data (for 2014) indicate that nearly 386 million barrels a year of produced water are being injected into the subsurface, primarily the Dakota Formation, via 487 disposal wells. This equates to an average annual injection volume at each disposal well of 793,000 bbl for 2014. At that injection rate and using the estimated Bakken produced water generation, by 2025 approximately 1158 SWD wells would be required for disposal of the produced water and approximately 1485 SWD wells by 2035 (Table 6). By 2025, that would be an increase of more than 670 disposal wells compared to the 2014 well count, and an increase of almost 1000 disposal wells by 2035.

<u>These projections do not include the estimated 380 million barrels per year possibly required for maintenance water needs by 2035, which will also require disposal.</u> That could increase the number of SWD wells required to meet capacity in 2035 by an additional 479 wells, bringing the total additional number of SWD wells needed to just under 1480 wells.

One final caveat is that by using the average produced water volumes generated from Bakken wells over the past 3 years, it assumes that there will be no increase in the future volumes of water used for well stimulation. If slickwater stimulations continue to increase in popularity, there could be significantly larger volumes of water being used for hydraulic fracturing, most of which will eventually return to the surface and require disposal.

<u>The same precautions about using these projections that were stated in the previous section apply here as well.</u> There is so much uncertainty with respect to the pace of long-term Bakken development, especially as oil prices remain uncertain. In addition, over the past 8 years, there have been unprecedented changes in Bakken well stimulation and completion practices that have dramatically affected water needs and handling practices. It is impossible to predict what might happen over the next decade, never mind the next two decades. At any rate, if these projections are even close, it suggests that additional disposal wells will be needed to address growing demand. It also suggests that despite anecdotal evidence from industry suggesting the unlimited capacity of the Dakota as an injection target, it might be worth a more in-depth look at the long-term sustainability of the aquifer.

## OPPORTUNITIES AND ISSUES ASSOCIATED WITH PRODUCED WATER RECYCLING AND REUSE IN THE BAKKEN

### Drivers and Deterrents for Recycling and Reuse

To better understand the potential drivers and deterrents for recycling and reuse of Bakken flowback and produced water, it helps to compare the water management situation in the Williston Basin with other major shale/unconventional plays in the country. The primary factors that drive water recycling and reuse across the country include consistent availability of freshwater resources and injection/disposal options. Also of importance are the potential for induced seismicity in a particular region, reservoir water quality, and transportation-related issues. Of the aforementioned factors, most are currently not strong drivers for recycling in the Bakken region because:

- Freshwater supplies are readily available and relatively inexpensive, and there are many locations from which to acquire water.
- The water supply available in the Missouri River system and Lake Sakakawea is abundant, and the general public seems to understand that withdrawals from these sources are minor in terms of the total available water capacity.
- Numerous deep well injection disposal sites are available to Bakken operators, and induced seismicity is not a concern. Current science indicates that earthquakes originate from faults in the granite rock formations that are much deeper (generally ~10,000 feet deeper) and older than the sedimentary rocks where disposal injection occurs in North Dakota (www.dmr.nd.gov/oilgas/undergroundfaq.asp#mr10). In addition, the Oil and Gas Division of the NDDMR has proactively implemented rules to help ensure that fluids are not injected in close proximity to known or suspected faults, that wells are constructed in a manner to prevent movement of fluids into unauthorized zones and, if necessary, that seismic monitoring is established at particular wellsites.
- The salinity of the Bakken Formation water is very high.

In the Bakken region, perhaps the key drivers that may entice industry to consider water recycling and reuse are transportation-related issues and trucking costs. The high volume of truck traffic in the Bakken region generates issues related to road maintenance, dust generation, air emissions, and truck congestion (especially at water depots and disposal well sites). As a result, the costs for freshwater acquisition and water disposal fees are low when compared to the costs for freshwater transportation to and produced water transportation from well sites (Table 7). Water recycling and reuse could reduce transportation-related costs and the associated issues if hydraulic fracturing flowback fluids and/or produced water could be captured, recycled, and reused for drilling, hydraulic fracturing, or maintenance water on the same or adjacent sites.

**Table 7. Approximate Water Acquisition, Disposal, and Transportation Costs in the Bakken**

| | Cost, $/bbl |
|---|---|
| Acquisition Costs | |
| Raw Water | 0.60–1.05 |
| Transportation | 0.65–5.00 |
| Disposal Costs | |
| Transportation | 0.65–9.00 |
| Deep Well Injection | 0.50–1.75 |
| Total Costs | 2.40–16.80 |

A previous EERC Bakken water assessment (Stepan and others, 2010) suggested that water recycling and reuse for hydraulic fracturing would likely not be cost-effective (at that time) because of the extremely high salt content, relatively low flowback recovery and produced water generation, and the need to produce freshwater for fracturing. However, in the past 3 years, significant technological developments related to salt-tolerant fracturing fluid systems allow the use of minimally treated produced water and have created new opportunities for treatment and recycling.

**Current Treatment Considerations**

Several key factors need to be considered when the potential for recycling and reuse for hydraulic fracturing fluid makeup water is assessed:

- How clean does the water have to be for reuse?
- Can/will the treated produced water be blended with freshwater?
- Which treatment technologies will work for a given situation?
- How will the recycled water quality affect the fracture fluid design?
- Is treatment and recycling cost-effective?

Table 8 presents typical characteristics of Bakken flowback and produced water compared to levels that are considered acceptable for water reuse quality characteristics using current (~2014) recycling technology (Grottenthaler and Kern, 2014). A pH between 6 and 10 is necessary for proper friction reducer performance and gel hydration, stability, and crosslinking. Total alkalinity levels less than 800 mg/L are desirable to reduce gel hydration concerns and prevent calcium carbonate scale concerns.

High concentrations of dissolved solids in Bakken produced waters present significant challenges in fracture fluid design. Reducing the levels of dissolved ions in Bakken produced water is desired to prevent scale formation, salt deposition, corrosion, and resultant production operations problems leading to well failure. Desired barium and sulfate levels for reuse are both less than 50 mg/L to prevent barium sulfate scale formation. Divalent ions ($Ca^{2+}$, $Ba^{2+}$, $Sr^{2+}$, and $Mg^{2+}$) can leave residue in the formation and should be no higher than the levels provided in Table 8.

**Table 8. Flowback and Produced Water Quality Characteristics and Reuse Guidelines**

| Parameter | Flowback | Produced Water | Desired for Reuse[1] |
|---|---|---|---|
| pH, units | 5.47–6.53 | 6.5 | 6–10 |
| Total Alkalinity, mg/L as $CaCO_3$ | | | <800 |
| Barium, mg/L | 7–25 | | <50 |
| Boron, mg/L | 40–192 | 350 | <20 |
| Calcium, mg/L | 7540–13,500 | 14,000–30,000 | <5000 |
| Chloride, mg/L | 90,000–133,000 | 135,000–200,000 | <120,000 |
| Iron, mg/L | ND[2]–120 | 50 | <50 |
| Magnesium, mg/L | 4–10.2 | 2300 | <2000 |
| Sulfate, mg/L | 300–1000 | 300 | <50 |
| Strontium, mg/L | 520–1010 | | <2000 |
| TSS,[3] mg/L | | 200 | <50 |
| SRB, CFU/mL[4] | | | $<10^2$ |
| Acid-Producing Bacteria, CFU/mL | | | $<10^2$ |

[1] Grottenthaler and Kern (2014).
[2] Not determined.
[3] Total suspended solids.
[4] Colony-forming units/milliliter.

Chlorides less than 120,000 mg/L allow for appropriate friction reducer performance. Iron less than 50 mg/L prevents iron precipitation issues, and TSS less than 50 mg/L is desired to reduce the potential for reduced flow through the proppant pack.

Levels of SRB and acid-producing bacteria should be less than 10 CFU/mL to prevent souring and corrosion associated with $H_2S$ oxidation products and to prevent corrosion of casing and surface equipment. The use of biocides such as glutaraldehyde should provide effective SRB control.

Treatment to satisfy desired reuse guidelines can be achieved through a variety of means including combinations of simple filtration, chemical precipitation/sedimentation, electrocoagulation (EC), EC + ozone, thermal processes, and membrane treatment processes.

Table 9 presents typical costs associated with treatment as well as the costs for SWD, not including storage or transportation costs. Simple filtration is the least expensive form of treatment, but it is typically the least effective for removing dissolved constituents. TSS removal is achieved with simple filtration, but little else is removed. Sand filters can be combined with other treatment media, such as granular activated carbon, to achieve a higher degree of overall treatment and dissolved organics removal.

Chemical precipitation processes (Figure 20) are capable of removing divalent ions from produced water and are often employed as a pretreatment to thermal processes to help reduce scale formation on heat exchange surfaces. Chemical precipitation/sedimentation process costs can vary significantly depending on the amount and type of chemical used. Additionally, these processes produce a filter cake/solids product that adds to overall treatment costs.

**Table 9. Typical Treatment Costs Associated with Produced Water Treatment (Grottenthaler and Kern, 2014)**

| Technology | Cost, $/bbl |
|---|---|
| Simple Filtration | 0.50–1.50 |
| Chemical Precipitation/Sedimentation | 2.00–8.00 |
| EC | 1.00–3.00 |
| EC/Ozonation | 1.50–4.00 |
| SWD (other shale plays) | 1.50–3.50 |

EERC DS37653.CDR

Figure 20. Chemical precipitation/sedimentation/filter press process.

EC is effective at removing oil droplets and suspended solids from produced water, with 95%–99% total petroleum hydrocarbon and TSS reductions reported. Pretreatment adds additional costs, as does EC in combination with other unit operation such as ozonation or ultraviolet light. EC coupled with ozonation (Figure 21) is a promising technique that has been reported to provide enhanced treatment and the removal of certain problematic divalent ions as well as provide advanced oxidation and disinfection. Treatment tests on Bakken produced water using EC/ozone have not been conducted; therefore, effectiveness has not been determined.

Thermal processes, while used in other shale plays, have limited applicability for the treatment of Bakken produced waters because of the extremely high levels of dissolved solids (> 200,000 mg/L). Certain membrane configurations, however, may have application to Bakken produced waters. The U.S. Department of Energy recently provided funding for the low-cost treatment of produced waters with TDS levels as high as 320,000 mg/L (Carney, 2015). Technology development projects that were funded and recently initiated included evaporation systems, membrane distillation, electrically conductive membrane distillation, and supercritical hydrophobic carbon-based membrane materials. The EERC will track the progress of these technology developments and assess potential application to Bakken produced waters. Electrodialysis is another technology that has a potential application for treating Bakken produced waters. The primary product of electrodialysis, however, is hydrochloric acid, not water treated for reuse.

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Figure 21. EC/ozonation process.

The choice of treatment technology for produced water depends on a number of factors, including the water quality required for the intended use, risk tolerance, company environmental policy, and cost. The development of a detailed database of treatment technologies applicable to Bakken flowback and produced water, including technology descriptions, capabilities, limitations, and costs may have utility for those in the oil and gas industry that are considering water recycling and reuse.

**Considerations for Existing and Alternative Water Supply Options**

Water use in the Bakken play is specifically dependent on the quality of water for an intended application. Tables 10 and 11 list attributes and considerations for various sources of water when used for fracturing and well maintenance (brine dilution) applications, respectively. Freshwater tends to be the preferred source for both applications. Performance of freshwater-based gel and slickwater stimulations are well understood and acceptable by industry standards; however, freshwater resources may become limited in situations of extended drought which could result in federal regulation of water in the Missouri River system to protect downstream interests in the resource.

**Table 10. Hydraulic Fracturing Water Sources and Issues**

| Source | Attributes | Considerations |
|---|---|---|
| Freshwater | Preferred source.<br>Easiest fracture fluid formation. | Resource may be limited in a drought.<br>Increasing demand may lead regulators to require alternate water sources. |
| Saline Groundwater (Dakota) | Generally simple chemistry.<br>Cost-effective treatment to high quality. | Target injection zone – potential quality degradation.<br>Potential source for fracturing fluid makeup. |
| Flowback Water | Can be used with minimal treatment.<br>On-site reuse reduces truck traffic. | Extremely high salinity. Presence of fracture chemicals. Complex fracturing fluid formulations required.<br>High-volume supply for relatively short period. |
| Produced Water | Abundant supply.<br>On-site reuse reduces truck traffic. | Extremely high salinity.<br>Treatment to "fresh" quality not cost-effective.<br>Complex fracturing fluid formulation required.<br>Open tank storage is prohibited, but can be approved on a case-by-case basis after notice and hearing. A new rule permitting large portable–collapsible receptacles for storage of fluids used in completion and well-servicing operations is being proposed, although no flowback fluids will be allowed. |



**Table 11. Maintenance Water Sources and Issues**

| Source | Attributes | Considerations |
|---|---|---|
| Freshwater | Preferred source – high quality water. | Resource may be limited in a drought.<br>Increasing demand may lead regulators to require alternate water sources. |
| Saline Groundwater (Dakota) | Generally simple chemistry.<br>May be used without treatment.<br>Cost-effective treatment to high quality. | Target injection zone – potential quality degradation. |
| Flowback Water | | Extremely high salinity requires treatment.<br>Treatment to "fresh" quality economically prohibitive.<br>Presence of fracture chemicals. |
| Produced Water | | Extremely high salinity requires treatment.<br>Treatment to "fresh" quality impractical.<br>Open tank storage is prohibited, but can be approved on a case-by-case basis after notice and hearing. A new rule permitting large portable–collapsible receptacles for storage of fluids used in completion and well-servicing operations is being proposed, although no flowback fluids will be allowed. |

The use of nonpotable water resources like groundwater from the Dakota Formation has, to the knowledge of report authors, not been evaluated as potential source water for hydraulic fracturing. The relatively low TDS levels in the Dakota (10,000 mg/L) suggest that it might have application for either fracturing or brine dilution. If a lower TDS water source is desired, previous EERC research demonstrated cost-effective treatment of Dakota groundwater using RO to produce a high-quality permeate stream suitable for a variety of beneficial uses (Kurz and others, 2011).

The use of wastewater treatment plant (WWTP) secondary effluent is also a potential water source for hydraulic fracturing. As western cities have expanded, so has the volume of wastewater requiring treatment, leading to expansion of WWTP capacity in many cities, including Dickinson, Williston, and Watford City. While WWTP secondary effluent may require some degree of tertiary treatment to remove undesirable components and/or require additional biocide treatment prior to use in hydraulic fracturing, it typically contains a low TDS concentration (<3000 mg/L).

Produced water may be used in hydraulic fracturing with minimal treatment (TSS and iron removal) in the case of high-volume, low-viscosity slickwater stimulations and only slightly more extensive treatment for crosslinked gel stimulations. The ability to treat produced water on-site has the potential to significantly reduce truck traffic. Even when used for fracturing, however, the necessary storage of large volumes of saltwater (80,000 to 240,000 bbl depending on fracture type) can create additional issues. North Dakota Administrative Code (NDAC) 43-02-03-19.3 prohibits the use of earthen pits or open receptacles for the storage of saltwater, drilling mud, crude oil, waste oil, or other waste except in an emergency and upon approval by the Director of Oil and Gas of the Industrial Commission, but can be approved on a case-by-case basis after notice and hearing. A new rule permitting large portable–collapsible receptacles for storage of fluids used in completion and well-servicing operations is being proposed, although no flowback fluids will be allowed. Further complicating the issue is that the treatment of flowback and produced water to freshwater quality is economically prohibitive given the high treatment costs and relatively low treated water yields associated with currently demonstrated technologies.

**Produced Water Disposal Alternatives**

Even if industry begins to recycle and reuse Bakken produced water in the near future, there will still be significant increases in the volumes of produced water and flowback (from well stimulation and from maintenance water) that will require disposal. Given that the Dakota Formation is the target injection zone for 93% of SWD (on a volumetric basis), additional options should be considered for disposal. Some producers have already encountered problems with overpressurization of the Dakota when drilling new Bakken wells, which can create complications in determining proper drilling mud weight to counteract the pressure encountered in the Dakota while minimizing mud loss in other zones (Personal communication, April 2015).

As previously shown, the key injection targets for SWD in the Bakken region include formations in the Dakota, Minnelusa, and Madison Groups. While the Dakota has been the key injection target to date, that is likely because of its shallower depth and demonstrated capacity as an injection target. Formations within the Minnelusa and Madison Groups may also be capable of accepting the large volumes of Bakken brine that will be generated in the future that require disposal; however, a focused assessment of the capacity of existing disposal targets to accept the projected future produced water volumes should be conducted. This could include an evaluation of SWD well spacing based on injection rates and formation thickness so as to minimize overpressurization issues.

### Produced Water Spill Remediation

While improved treatment technologies and the development of salt-tolerant fracturing fluid systems have greatly expanded the range of brine recycling and reuse options available to industry, some significant issues still need to be overcome related to safe saltwater storage and transportation practices. The number of saltwater spills and pipeline leaks has increased in the Bakken recently, generating concern from the state and the general public regarding saltwater storage and transportation practices. Data from NDIC indicate that the percentage of saltwater spilled annually compared to that which is produced is not much different than before Bakken development, accounting for only approximately 0.01% of the total volume of water produced. However, because of the scale of produced water generated, even small percentages of spills warrant action to reduce the likelihood of an event.

In many cases, remediation of brine spills is more complicated and time consuming than spills that contain only hydrocarbons. When brines containing sodium and chloride are spilled, the chemical environment within the soil is impacted, resulting in disruption of the soil structure and an osmotic imbalance that reduces water uptake by vegetation. Remediation of these spills requires the incorporation of calcium to liberate the sodium from the clay particles in the soil and a permanent movement of sodium ions to locations below the vegetative root zone. Once this is accomplished, vegetation can be reseeded, and soil health and productivity can be reestablished. The entire remediation process for any given site often takes multiple years.

The state and industry recognize the potential environmental impacts of brine spills and are working to fund research to develop improved remediation techniques. However, because of the high level of concern regarding brine spills, an added level of complexity is added to site operations related to the storage of large volumes of saltwater on-site (typically in excess of 60,000 bbl) if produced water is to be used for hydraulic fracturing.

### Produced Water Storage Options

Several types of storage options are available for produced water, including covered tanks, lined pits, bladder tanks, fracture tanks, and modular circular aboveground storage tanks (AST) or water corrals. The choice of storage depends on space availability, water volume, and regulations. NDAC 43-02-03-19.3 prohibits the use of earthen pits or open receptacles for the storage of saltwater, drilling mud, crude oil, waste oil, or other waste, but can be approved on a case-by-case basis after notice and hearing. A new rule permitting large portable–collapsible receptacles for storage of fluids used in completion and well-servicing operations is being proposed, although no flowback fluids will be allowed.

While traditional 500-bbl fracture tanks can be used for brine storage, they are more expensive and require more trucking than the use of larger-volume water storage, such as water corrals (Schmidt and others, 2015) where storage capacity typically ranges from 24,000 to 42,000 bbl. A demonstration project requiring the storage of 100% produced water was allowed with regulatory approval, subject to contingencies including the development of an emergency response plan. The project was conducted using a double-wall tank construction so that the brine would be contained in the secondary tank in the event of a catastrophic failure of the internal tank (Figure 22). Design features included the use of 40-mil liners; banding of the primary (internal) tank to prevent wall failure and compromising the external tank liner; sand fill to secure the

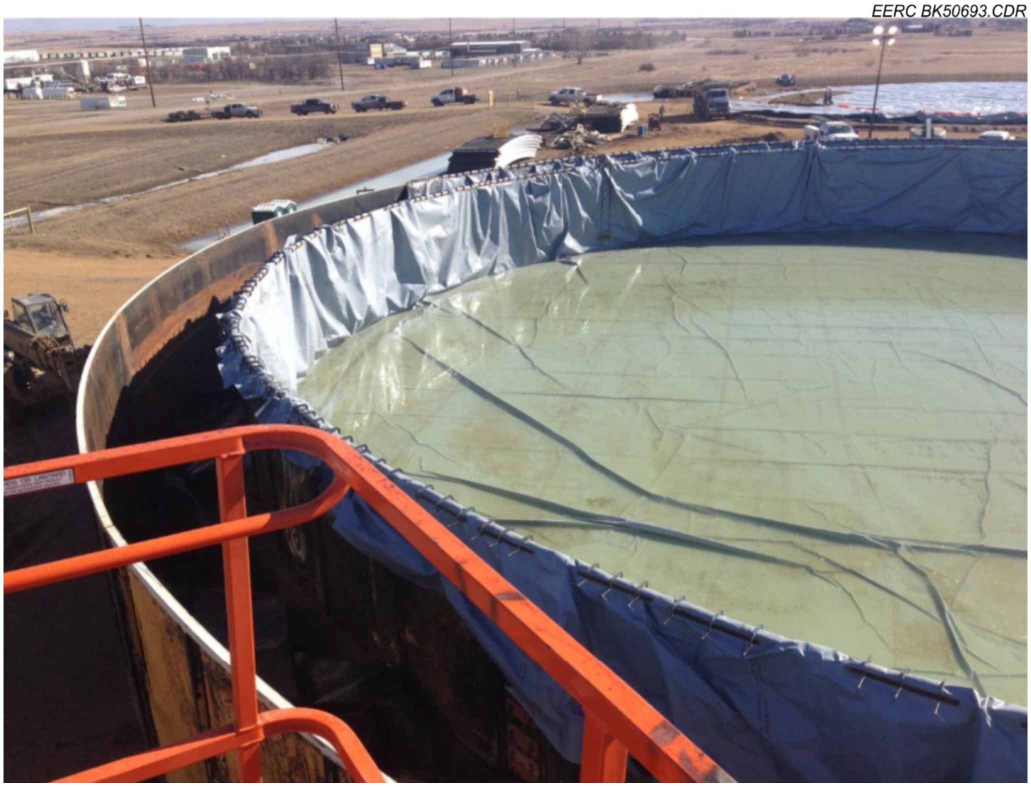


Figure 22. The double-walled water corral utilized by Statoil for produced water storage (image source: Schmidt and others, 2015).

secondary liner; layering, leveling, and geocloth support of the liners; bird netting; concrete barriers for erosion control in the event of a breach; liner protection; and antisyphon mechanisms. The produced water was treated using filtration (1 µm) before being utilized as source water for hydraulic fracturing.

Schmidt and others (2015) compared the economics of the produced water stimulation relative to a typical freshwater stimulation. In that case, the cost of the produced water stimulation was higher than that of freshwater stimulations. The additional costs were reportedly due to the fluid system (crosslink gels, high gel loading, and increased use of additives), containment systems, additional fracture tanks, costs of double-wall ASTs, water transfer pumps, filtration, additional personnel, and concrete barriers. They estimated a total cost difference of approximately $250,000 per well, with cost projected to decrease for multiwell pads but increase if additional water treatment is incorporated.

Table 12 lists potential volumes of storage and the area requirements to accommodate that storage for several different alternatives shown in Figure 23. To ensure uniform and consistent water quality from the beginning to the end of fracturing operations, it was assumed that the entire volume needed would be stored on-site: 80,000 bbl for a crosslinked gel completion and 240,000 bbl for a slickwater completion. Ensuring uniform water quality when storing large volumes of produced water from multiple sources in a large number of tanks can be a difficult task.

**Table 12. Water Storage Alternatives and Space Requirements**

| Storage Receptacle | Volume, bbl | Number of Tanks Required | | Approximate Footprint, acres | |
|---|---|---|---|---|---|
| | | 80,000 bbl Storage | 240,000 bbl Storage | 80,000 bbl Storage | 240,000 bbl Storage |
| Standard Frac Tank | 500 | 160 | 480 | 1.4 | 4.2 |
| Water Corral* | 42,000 | 2 | 6 | 1.2 | 3.5 |
| Lined Pit* | | 1 | 1 | 0.9 | 2.7 |
| Closed-Top Tank | 1000 | 80 | 240 | 0.4 | 1.3 |
| Bladder Tank | 5000 | 16 | 48 | 2.0 | 6.0 |

* Open top receptacles for comparison purposes.


Figure 23. Potential produced water storage options.

Closed-top tanks (15.6 ft diameter, 30 ft high) provide the smallest footprint for water storage, but the relatively small storage volume (1000 bbl) necessitates a relatively large number of tanks. Lined pits provide one of the most space-efficient storage alternatives but are presently prohibited under North Dakota regulations. Impermeable membrane covers designed to isolate saltwater from precipitation and runoff may prove viable but would require regulatory approval. Standard frac tanks (45 ft long and 8.5 ft wide) require a relatively larger footprint and a large number of tanks because of the 500-bbl storage capacity. Bladder tanks provide another option and a storage capacity of up to 5000 bbl each but have the largest storage footprint because of the relatively low profile (6 ft height). Pricing for the various alternatives was not investigated as part of this study but could certainly be considered if produced water fracturing becomes a more common practice.

If produced water recycling and reuse is to be implemented on a broader scale in the future, it will require collaboration between industry, regulators, and independent third-party institutions to determine viable large-scale storage options that minimize environmental risk. While initially the costs to implement produced water storage and reuse will likely be higher than using freshwater, as the practice becomes more widespread, efficiencies will be realized, and standard practice guidelines will be developed that will help lower the costs.

## DISCUSSION AND CONCLUSIONS

Water is a valuable commodity in the Bakken region for drilling, completion, production, and maintenance. Based on current data and water use projections (Table 13), there appears to be a sufficient freshwater supply for continued operations in the Bakken, especially with continued municipal water treatment expansion and water supply pipeline projects. However, as a result of oil and gas production, there is a tremendous amount of flowback, produced water, and waste maintenance water that will continue to require proper and safe storage, transportation and, ultimately, disposal (Table 13).

**Table 13. Summary of Estimated Future Freshwater Demand, Produced Water Generation, and SWD Well Needs**

| Year | Estimated Freshwater Demand for Fracturing and Well Maintenance,[1] million bbl | Estimated Annual Bakken Produced Water Generation, million bbl | Estimated Additional SWD Wells Needed Beyond Those Existing in 2014[2] |
|---|---|---|---|
| 2014 | 267 | 270[3] | 0 |
| 2020 | 470–531 | 624 | 553 |
| 2025 | 620–722 | 918 | 1044 |
| 2030 | 696–798 | 1157 | 1442 |
| 2035 | 703–805 | 1178 | 1477 |

[1] Based on the projections with an average well maintenance value of 32.5 bbl/well/day.
[2] Includes estimated disposal volumes for produced water and well maintenance. Excludes potential future disposal need related to increased fracturing fluid volumes.
[3] The 2014 Bakken produced water value was calculated using NDIC data and is not an estimate.

While most of the drivers for treatment and reuse of saltwater in other shale plays across the United States do not currently exist in the Bakken, recycling and reuse of produced water present a key opportunity for the oil and natural gas industry in western North Dakota. Based on the projections within this report, which suggest significant future freshwater demand and high volumes of produced water generation, industry is strongly encouraged to expand efforts in the application/demonstration of appropriate existing or emerging technologies to increase the amount of recycled and reused water. There are implications for the oil and natural gas industry not addressing the escalating use of freshwater, trucking, storage, and the corresponding increasing volumes of produced water disposal. At some point in the near future, the void left by industry inaction in this arena may be filled by legislative statute and/or rule making which may result in the development of mandates that could impact development, well stimulation operations, and costs of doing business.

To avert possible regulatory action, industry should consider significantly reducing the amount of freshwater required for well stimulation and well maintenance activities in the very near future. Recycling of frac flowback and Bakken produced water, and possible use of brackish water from other formations, should be evaluated from a technical and economic standpoint as a means of minimizing freshwater demand.

A proactive approach to solving the technical treatment, recycling, and storage hurdles for large volumes of high salinity water is recommended. An opportunity exists for an evolution in the use of temporary and permanent storage tanks, pits, and reservoirs; the use of pipelines to minimize transport/trucking fluids; the development of centralized produced water processing sites; and the requirements for additional water disposal wells, among other possible scenarios. This proactive approach should include development, testing, and use of environmentally safe engineered solutions. In addition, it is important that industry work closely with the key regulatory agencies with respect to produced water management, as a paradigm shift in rule interpretation will be required to permit certain solutions.

## FUTURE WORK

Based on the results of this effort, several potential areas of future work may benefit industry and the state. These include the following:

- Tracking produced water treatment technology developments that have application to the high-salinity produced water associated with the Bakken play and compiling a produced water treatment technology database of vendors, technologies, and demonstrated capabilities.

- A detailed assessment of opportunities for utilizing nonpotable groundwater resources like the Dakota aquifer and others for use in both hydraulic fracturing and well maintenance applications.

- A hydrogeologic assessment of the Dakota Formation and the associated long-term impacts of underground injection as a produced water disposal reservoir.

- An assessment of produced water storage options that provide cost-effective alternatives and would promote the utilization of produced water for hydraulic fracturing.

- Investigation of alternative uses for produced water – kill fluids, constituent/resource recovery, feedstock for chemical production strategies, dust control applications, deicing.

The EERC has the expertise, modeling, laboratory and analytical capabilities, and ability to develop required partnerships to conduct any of these activities in a timely manner with the utmost responsiveness to industry and state needs and requirements.

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