URTeC: 5445

Completion Design Evolution for Saltwater Disposal Injection Wells in the Bakken Play

Darren D. Schmidt,* Energy & Environmental Research Center, University of North Dakota; Jeffrey W. Bader, Ashleigh Day, and Mark Bohrer, North Dakota Department of Mineral Resources

This paper was prepared for presentation at the Unconventional Resources Technology Conference held in Houston, Texas, USA, 26–28 July 2021.

Abstract

Disposal of produced water is a critical component of unconventional oil development. The significant increase in Bakken production over the past decade in concert with the expansion of saltwater disposal wells geographically, places new demands on the storage reservoir. Development has spurred investigations of the reservoir and well performance. Specific to the Williston Basin and Bakken play, new disposal wells do not always meet injectivity expectations, and some operating wells decrease in performance over time. Operators have responded with well interventions and new well completion techniques. Well data collected from the North Dakota Department of Mineral Resources are used to provide an analysis. Baseline well performance, well testing, and a review of the developments in recent well completions are discussed. Analysis compares calculated performance to field data and highlights the potential for improved injectivity.

Introduction

The North Dakota Department of Mineral Resources (ND DMR) regulates the disposal of produced water from oil and gas wells through the Underground Injection Control (UIC) Program established by the Safe Drinking Water Act to protect underground sources of drinking water. The UIC Program is overseen by the U.S. Environmental Protection Agency (EPA). ND DMR has regulatory primacy over Class II and Class III injection wells in North Dakota. Class II wells are either designed for disposal of oilfield fluids or as injection wells for enhanced oil recovery. Class III wells are for subsurface mineral mining, of which none are currently operating in the state. ND DMR regulates the permitting, construction, operation, and closure of injection wells.

Permitting and well construction regulations are structured to protect groundwater sources. A typical well construction diagram for a saltwater disposal (SWD) well is provided in Figure 1. Some of the various permitting, construction, and operating requirements include the following:

- Public hearing and notice.
- Notification to surface owners within ¼ mile.
- Geotechnical analysis of shallow aquifers.
- Geologic requirement for the target formation to have upper and lower confining zones to prevent migration of fluids into other formations.
- Casing and cement requirement to protect and isolate all formations, protect pipe through salt sections, and isolate the uppermost sand of the Dakota Group.
- Review of geology, injection pressure, well construction, neighboring wells, sampling from freshwater wells, and analysis of the injected fluid.
- Tubing is required, and the tubing packer must be set at an approved depth.
- The operator must demonstrate mechanical integrity.
- The operator must demonstrate adequate cement.
- The operator must submit monthly reports with injected volumes and stabilized surface injection pressure.
- The operator must report first injection date.
- The operator must monitor tubing and casing pressure.
- Remedial work must be reported.

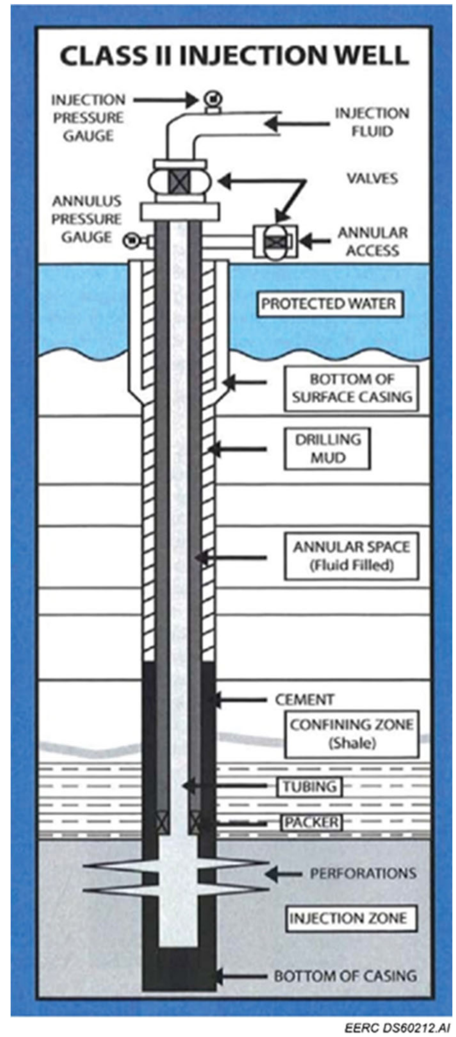

Figure 1. Typical injection well (Bohrer and Day, 2021).

Geology

The Inyan Kara Formation is of specific importance as it consists of thick sandstone bodies deposited in incised valleys present along the coastline of the Cretaceous Western Interior Seaway. These valleys were incised by north-northwesterly flowing rivers that drained into the seaway from highlands to the east-southeast. The valleys formed at sea level in the Cretaceous seaway dropped in North Dakota twice over a period of approximately 10 million years. Sea level eventually rose again, and the valleys were flooded, forming estuaries where very clean reservoir sands were deposited, again in two transgressive events. Eventually the sea completely inundated the area, and the overlying marine units were deposited. Incised valley Inyan Kara sandstones are porous (20%–30% porosity) and permeable (darcy level); thus they are ideal for injection of produced water and the lateral continuity of the units allows for injected water to move into the formation, especially along incised valley trends (Bader, 2019).

The Dakota Group is a unique stratigraphic unit in the Williston Basin well suited for disposal (Figure 2; Bader, 2016). Shallow potable groundwaters are located ½ mile above the Dakota Group and are separated from the disposal zone by impermeable shales. The Swift Formation underlies the Dakota

Group and consists of up to 700 feet of shale. The rocks below the Swift are generally where commercial volumes of petroleum are located. Casing cement is used to isolate geologic formations, and wells are required to have adequate isolation from the Dakota Group in accordance with North Dakota Administrative Code § 43-02-03-29. Underground disposal zones are also required to be separated from basement rock units that could potentially induce seismic activity if introduced to injected water. This is highly unlikely, as the Dakota Group is vertically distanced from the basement rocks by 2 miles of sedimentary rocks that have many laterally extensive impermeable salts. Fluid disposal occurs in the Inyan Kara Formation within the Dakota Group, shown in Figure 2. The Inyan Kara Formation is an attractive disposal zone because of the presence of porous and permeable sandstones that are ideal for injection. Bounding the Inyan Kara are the upper and lower confining zones: the Mowry and Swift Formations, respectively. These formations include shales that provide confinement respective of the sandstones within the Inyan Kara Formation. Other formations include the Newcastle and Skull Creek. The Newcastle, where present, consists of permeable sands; however, it is discontinuous across the basin. If excluded as a target for disposal, the Newcastle can provide a geologic pressure relief zone. The Skull Creek is a shaley formation and provides confinement in addition to the Mowry Formation. The Dakota Group provides the geologic properties essential for underground injection.

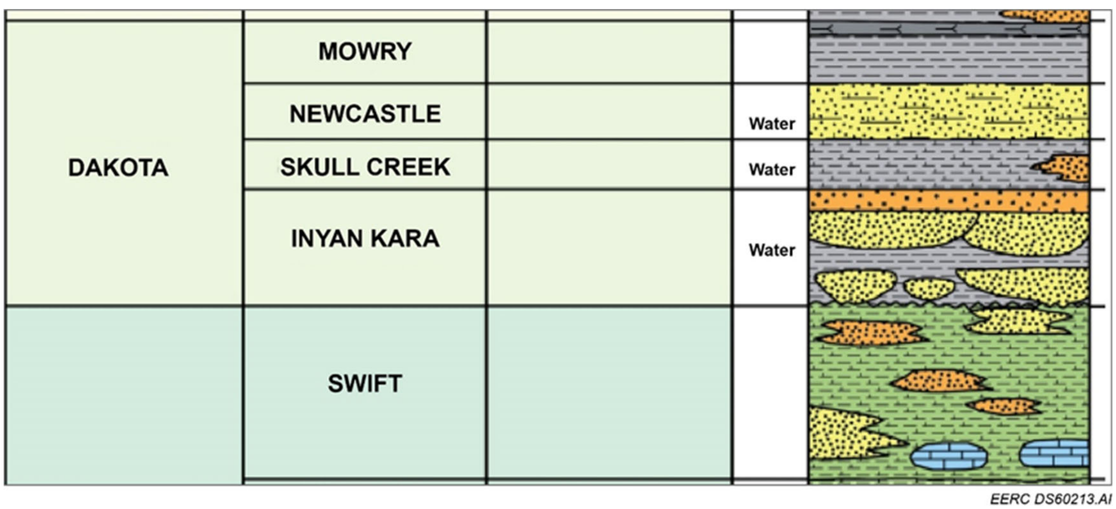

Figure 2. Dakota Group geology (Murphy et al., 2009).

Well Completions

SWD well completion methods in the Williston Basin are evolving to increase injection capacity, address poor performance, and improve facility economics. A geographic trend is evident for wells completed prior to 2006 in which the majority of disposal wells were drilled to service unitized oil fields along the Nesson Anticline. Inyan Kara sands in this geographic area tend to be thick, well-connected, and provide good injectivity. Inyan Kara sandstone thickness maps produced by the North Dakota Geological Survey (NDGS) (Bader et al., 2016) identify well locations and sand trends. Other wells of this period located north and south of Williston, North Dakota, were positioned along Highway 85 and near other developed highways. Historically, SWD injection wells are vertical completions perforated through 7-in. casing over an interval of 300 to 500 feet. Common tubing sizes range from 2⅜ to 3½ in. Investments in gathering infrastructure after 2006, coincident with Bakken development, resulted in a geographic dispersion of new SWD wells and a doubling of the well count. Therefore, produced water volumes provided in Figure 3 have increased almost tenfold since 2006. The increased demand combined with new wells completed in areas with limited sand connectivity and thickness have resulted in poor performance for some SWD wells. Operators attempting to overcome poor performance are attempting variations of directional and horizontal well completions.

Directional and horizontal well completions, although significant, do not yet dominate new SWD completions. Data from 64 wells completed between 2018 and 2020 show that over half (58%) of the completions are vertical wells and, of the remaining 42%, 70% are directional versus horizontal. Most of the directional and horizontal completions (75%) were spud in 2018 or more recently. Horizontal injection wells were attempted as early as 2013. There is an increasing trend in nonvertical SWD well completions; however, vertical well completions appear to be favored along the Nesson Anticline (Figure 4), where Inyan Kara geology has greater storage capacity and there is less demand on the injection reservoir. Conversely, directional and horizontal injection wells are completed in areas where injection tends to be more challenging.

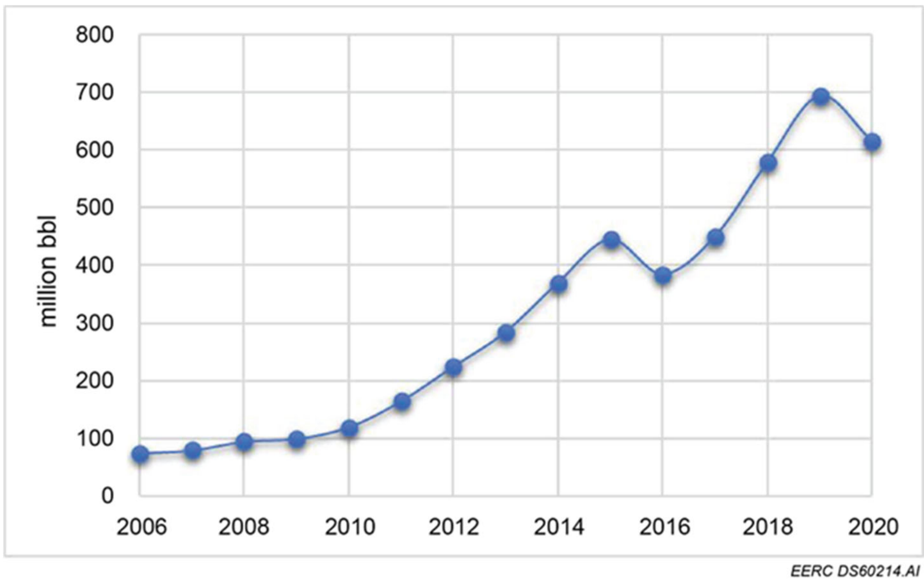

Figure 3. North Dakota annual produced water volume.

Methods

Well file data collected from ND DMR are used to examine directional and horizontal SWD wells. A study area is defined in Figure 5 that includes 27 active injection wells. Data include spud date, perforations, true vertical depth, measured depth, well path, casing size, tubing size, completion details, average injection pressure, average flow rate, and estimated net sand thickness. Collected data were used to calculate injectivity index. The injectivity index is determined by dividing the flow rate by the difference in the flowing bottomhole pressure and far-field reservoir pressure (barrels per day/pounds per square inch [bpd/psi]). The calculation provides a relative indication of the injectivity with respect to reservoir conditions. The reservoir is assumed to be normally pressured for all wells. Bottomhole pressure is determined from the average surface pressure and the hydraulic head associated with fluid density and true vertical perforation depth. Injectivity is mapped in Figure 5 and plotted in Figure 6.

Methods to improve the capacity of SWD wells include reducing friction, altering the permeability of the formation (k), or changing the pay zone dimension (h). Directional and horizontal well completions are an attempt to alter the pay zone dimension, illustrated in Figure 7. Improved flow capacity is examined by applying conventional petroleum engineering methods. Flow in SWD wells is characterized by

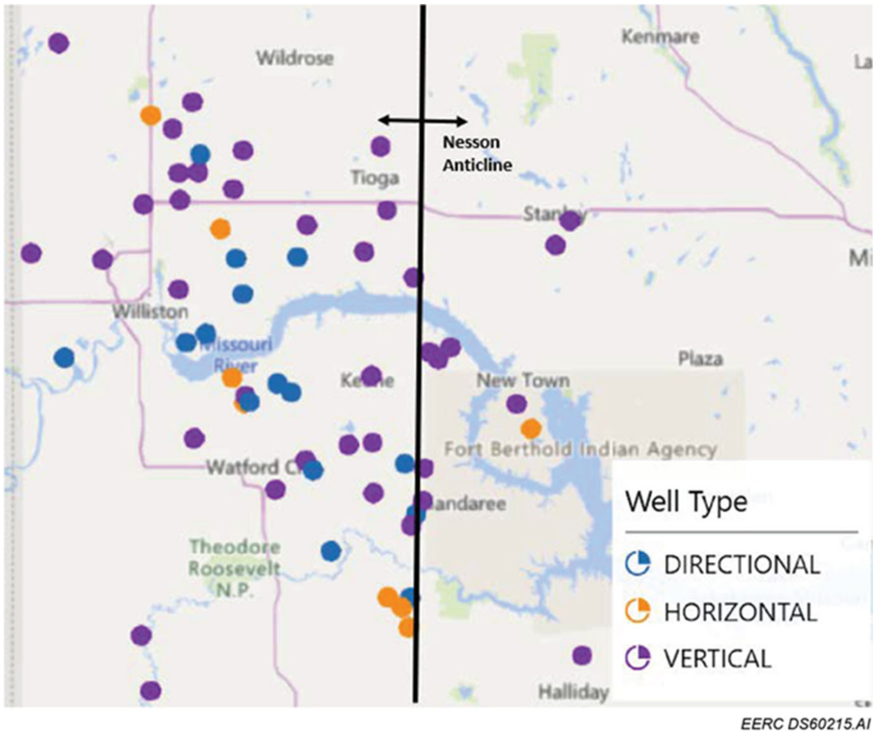

Figure 4. SWD wells completed 2018–2020.

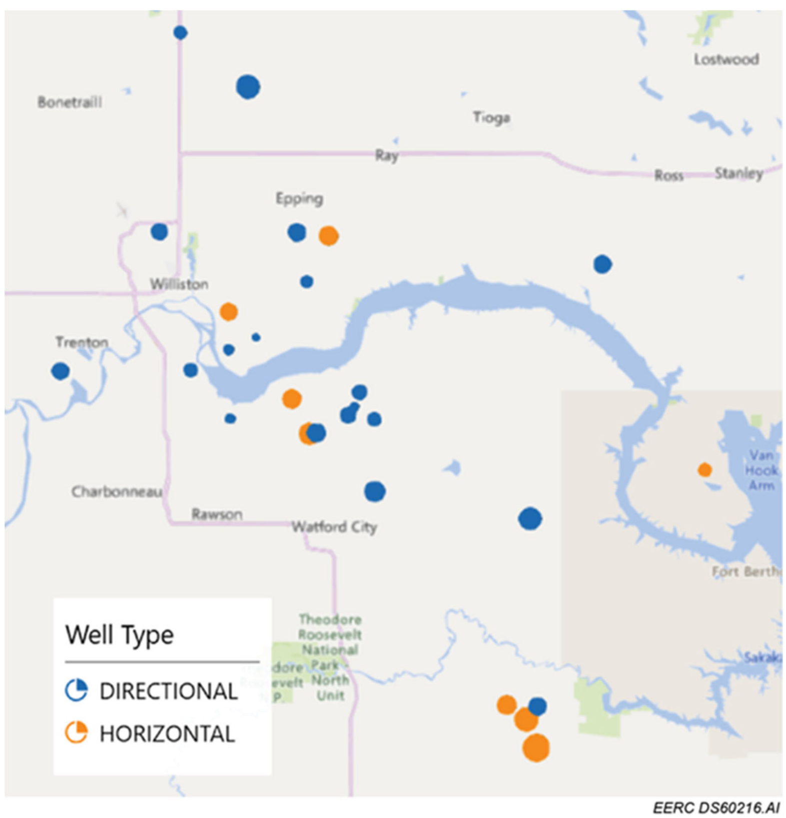

Figure 5. Study area (marker size indicative of injectivity).

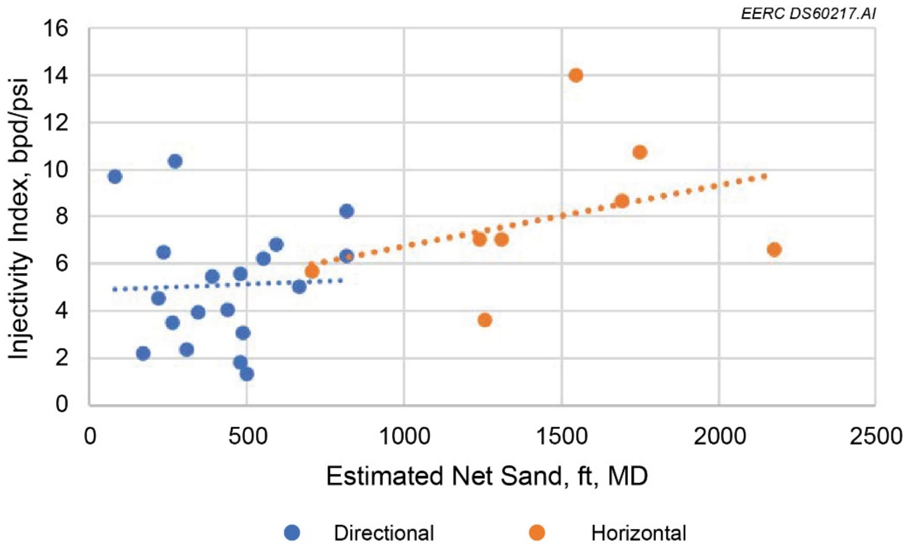

Figure 6. Relationship of injectivity and net pay.

Equation 1, the radial flow equation (Towler, 2002). This equation can be combined with an empirical relationship to determine pressure drop of water in tubulars known as the Hazen–Williams equation. A mathematical model is developed by combining the two equations and using an iterative solution to solve for injection rate relative to friction pressure. This method is used to evaluate flow capacity relative to the pay zone dimension. Altering near-wellbore permeability is also considered. The effect of the altered zone can be evaluated using Equation 2 (Tiab and Donaldson, 2004), which is the relationship for radial flow in series. A method other than hydraulic fracturing is examined in this study, which includes cutting solution channels in the rock near the wellbore. The relationship in Equation 3**Error! Reference source not found.** is used to model the altered permeability radially for a solution channel. The altered permeability zone is illustrated in
Figure 8.

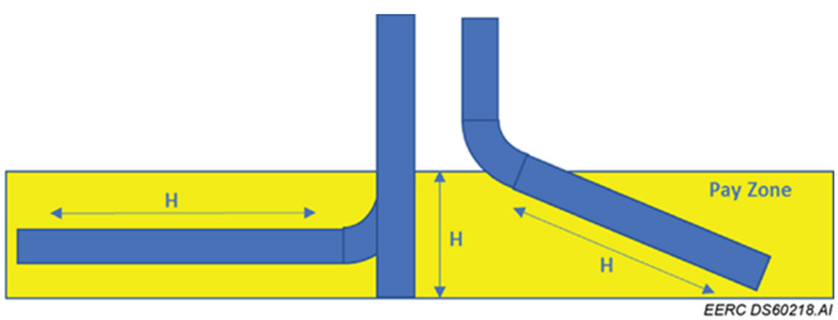

Figure 7. Pay zone alteration.

$$q = 0.00708kh(p_w-p_e)/\mu B \ln(r_e/r_w) \quad \text{[Eq. 1]}$$

$$k_{avg} = k_a k_e \ln(r_e/r_w) / k_a \ln(r_e/r_a) + k_e \ln(r_a/r_w) \quad \text{[Eq. 2]}$$

$$k_{mc} = (n_c \pi r_c^2/A)\, k_c + (1- n_c \pi r_c^2/A)\, k_m \quad \text{[Eq. 3]}$$

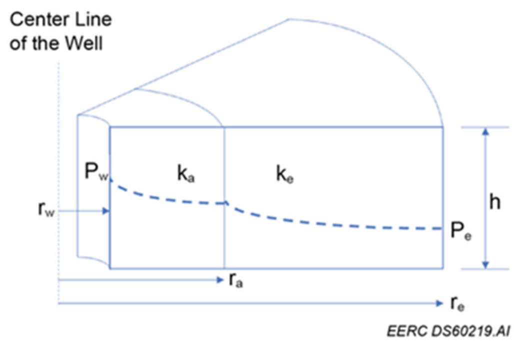

Figure 8. Radial flow and permeability in series.

Results

Directional and horizontal SWD well completions share some characteristics; however, there are clear differences in complexity and exposure to the target pay zone. Techniques vary by operator, and some evolution of design is evident. Consistency is operator-specific, and a few operators appear to be using similar directional methods. Horizontal completions have been largely dominated by one operator, and a progression in design is apparent.

Casing and tubing design is generally similar for most wells. Historically SWD wells, both vertical and nonvertical, have been completed with 7-in. production casing. Where older vertical wells have utilized 3½-in. tubing or less, all directional and horizontal wells have used 4½-in. tubing or greater. Well file records indicate that vertical wells have been upgraded from 3½ to 4½ in. tubing to minimize friction losses and maximize capacity. The injection capacity of a well can be maximized by assessing friction and increasing the permitted injection pressure; however, if surface equipment has a limited pressure rating, the alternative is to increase tubing size. Tubing sizes greater than 4½ in. require larger production casing. Six wells, both horizontal and directional completions, use 7⅝-in. casing to accommodate 5½-in. tubing. No obvious correlation exists regarding larger tubing size and flow capacity among the wells studied. Friction losses have a greater impact at high flow rates. Only two of the wells studied with 5½-in. tubing are operating at an average injection rate above 10,000 bpd where tubing friction effects are more severe.

Directional wells can be described as three types of completions, depicted in Figure 9 (North Dakota Department of Mineral Resources, 2018): 1) a constant inclination angle of <40° is maintained across the target zone, 2) a constant inclination angle of >60° is maintained across the target zone, and 3) a continuous curve is drilled across the target zone. Production casing is extended into the target zone, cemented, and perforated. Some directional well completions deviate from the above descriptions. There is no observable relationship between the type of directional completion and injectivity for the studied wells.

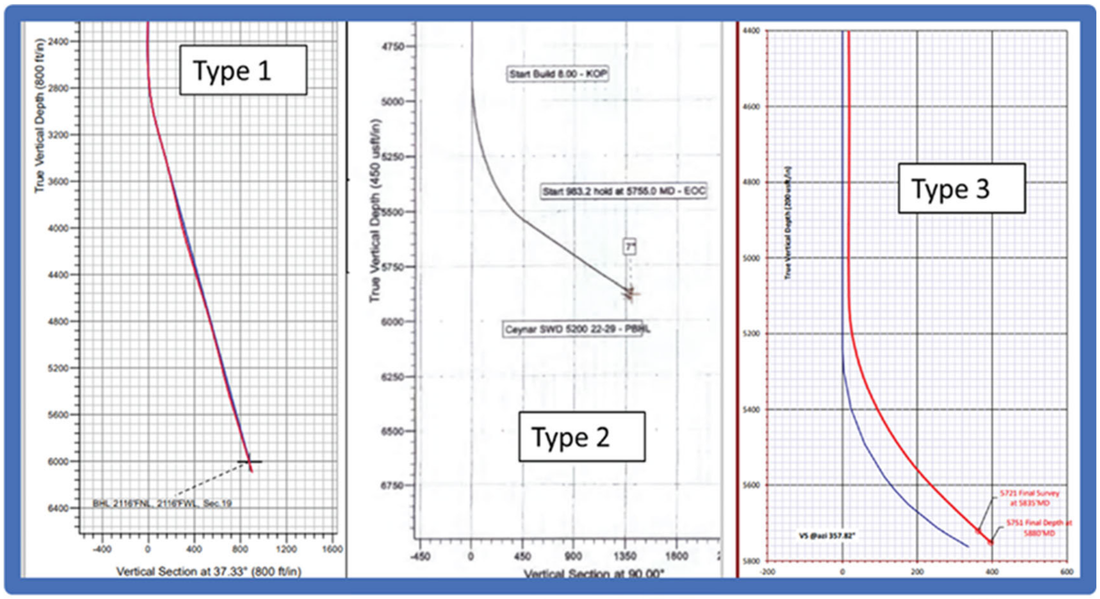

Figure 9. Directional SWD well completions, Type 1 <40°, Type 2 >60°, Type 3 curve.

Horizontal completions can also be described by three types, depicted in Figure 10 (North Dakota Department of Mineral Resources, 2018). The lateral section is completed as a combination of cemented liner and open hole, an uncemented perforated liner, or a cemented liner. Liners have ranged in size from 4½ to 7⅝ in. diameter. The evolution is to increase liner size, cement, and perforate. Lateral lengths have ranged from 1000 to 2500 feet, with an average length of 1700 feet. There is no observable injectivity difference regarding the style of horizontal completion; however, an observable trend is evident regarding lateral length. Figure 6 provides the calculated injectivity respective of the estimated net sand. Longer laterals appear to provide improved injectivity. The horizontal wellbore provides significant contact with the target sand, effectively increasing the pay zone variable with respect to darcy flow. Figure 11 (North Dakota Department of Mineral Resources, 2018) provides an example of the lateral gamma signature along the horizontal wellbore, demonstrating effective sand contact.

The Hazen–Williams equation combined with Equation 1 is used to compare the calculated injection rate for a vertical, directional, and horizontal well. Assumptions are based on SWD well testing from Schmidt et al. (2019). Pay zone thickness is selected at 300, 876, and 2000 feet, respectively. A nonlinear relationship is provided in Figure 12 regarding injection rate and net pay. The relationship suggests there is limited capacity improvement beyond present lateral lengths.

Horizontal completions appear to outperform directional completions; however, geology likely plays a significant role. Well performance is displayed geographically in Figure 5. The average reported injection rates for horizontal wells are over 13,000 bpd with rates approaching 20,000 bpd. Only a few directional wells achieve greater than 10,000 bpd injection. Regarding the map in Figure 5, there is known reservoir pressure constraints in the area near Williston, ND, and Inyan Kara sands are less connected and less prevalent to the west (Bader et al. 2016). Therefore, it is not surprising that performance of directional wells in this area is constrained. Furthermore, when examining off-set vertical wells similar performance is observed. The only discernable difference in well performance is provided in Figure 6 in which injectivity appears to be noticeably different for increased wellbore exposure to the pay zone.

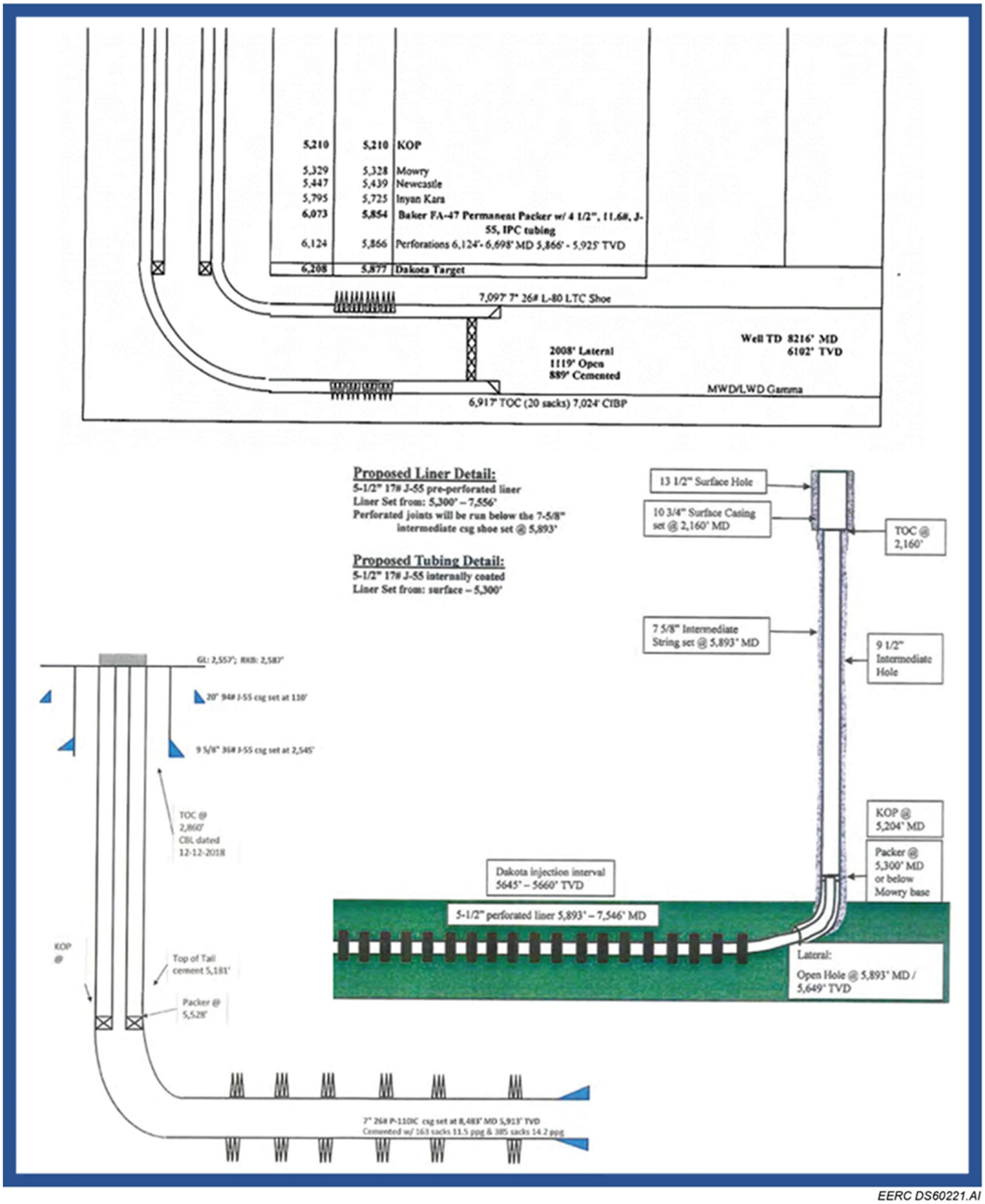

Figure 10. Horizontal SWD well completions.

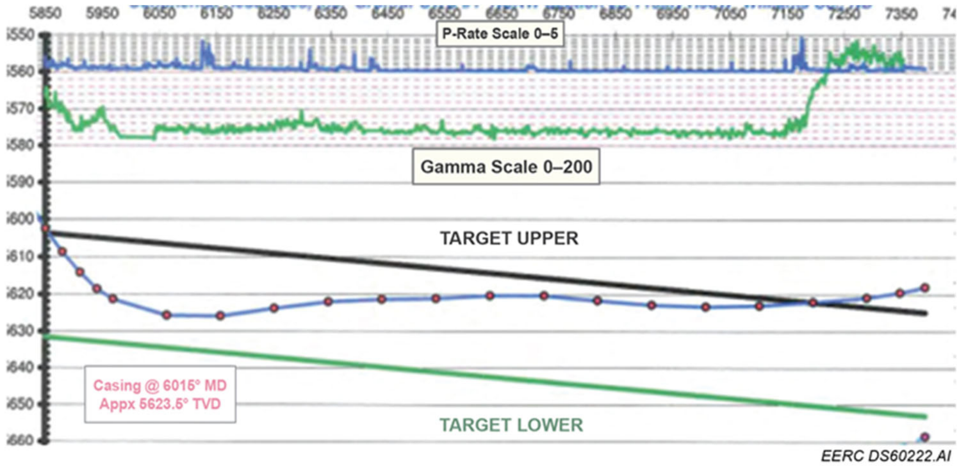

Figure 11. Horizontal well control.

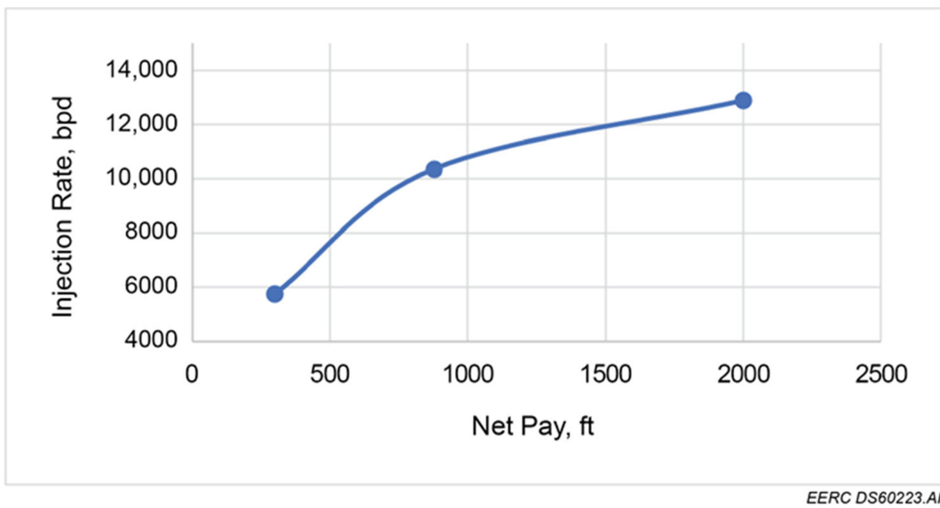

Figure 12. Estimated injection rate relative to net pay (h).

Altering reservoir permeability can be used to improve SWD well capacity. This can be accomplished by hydraulic fracturing or other methods. Hydraulic fracturing techniques must be limited to avoid compromising the geologic confinement of the disposal zone and may not be preferred. A procedure referred to as radial drilling has been proposed as an alternative to hydraulic fracturing (Dickinson and Dickinson, 1985). Recently, this method has been practiced in the Niobrara Shale (Potapenko et al., 2021). The procedure includes water jet-cutting a circular channel in the rock perpendicular to the wellbore. The channel can be extended in the reservoir up to 300 feet. The technique is limited to vertical wells and must be designed to avoid cutting channels out of zone. Radial drilling has been attempted in one SWD well in North Dakota.

Radial drilling was applied to the Alfred Brown SWD well in 2017. Well file records indicate that injection rate was improved from 1100 to 2000 bpd. Three zones of sandstone were targeted for stimulation. The two upper zones were drilled, creating three lateral channels per zone, and the lower zone was drilled with two lateral channels. Because of subsurface interferences, the lateral lengths were limited to less than 50 feet. A model was constructed using Equations 1–3 combined with the Hazen–Williams equation to estimate permeability alteration and to calculate flow capacity. Radial flow in parallel was assumed respective of the vertically stacked sandstone targets. A 2.2-fold permeability increase was calculated which matches the field results.

The same model was applied to a generic vertical SWD well to predict potential capacity improvement. A pay zone thickness of 300 feet, average permeability of 40 millidarcies, and drilling of four laterals ½ in. in diameter is assumed. The model predicts a tenfold permeability increase, resulting in a doubling of injectivity. Permeability alteration appears to have the potential to improve flow capacity by 100%.

Discussion

SWD is a critical component to successful oil production. Over half of the fluid volume produced at the wellhead is typically produced water. The safe and successful disposal of these volumes is important, along with cost-competitiveness. Figure 13 provides the history of SWD wells drilled in North Dakota. A significant increase in SWD wells occurred in the 1980s and has repeated in the past decade. However, only recently has SWD well technology begun to evolve to the point where improvements can be initially evaluated. Enabling SWD wells to economically operate in geographic areas where rock properties are more challenging improves the sustainability of oilfield operations.

The development of horizontal completions for SWD are not as popular among operators as directional wells. This is likely due to the lower cost and complexity of directional completions. Evidence appears to support continued development of horizontal wells with respect to injectivity; however, horizontal SWD wells have not yet been tested in proximity to known areas of limited reservoir injectivity. Where horizontal wells are compared to offset wells, injectivity appears to be improved.

Although horizontal wells appear to outperform directional wells in terms of injectivity and total capacity, directional wells show improved injectivity with increased net pay. The data in Figure 6 do not indicate a substantial trend of improved injectivity with net pay for directional wells; however, a positive trend is evident upon elimination of a few data outliers. This trend does appear to be consistent with the same trend for horizontal completions, which reinforces the relationship of positive injectivity with increased net pay. Future application of directional and horizontal wells will likely progress based on costs and economics.

Permeability alteration is an interesting option for improving SWD capacity. Few field data are available to support radial drilling applications at present; however, initial data and first modeling results seem to indicate that there is potential to double the capacity of vertical well completions.

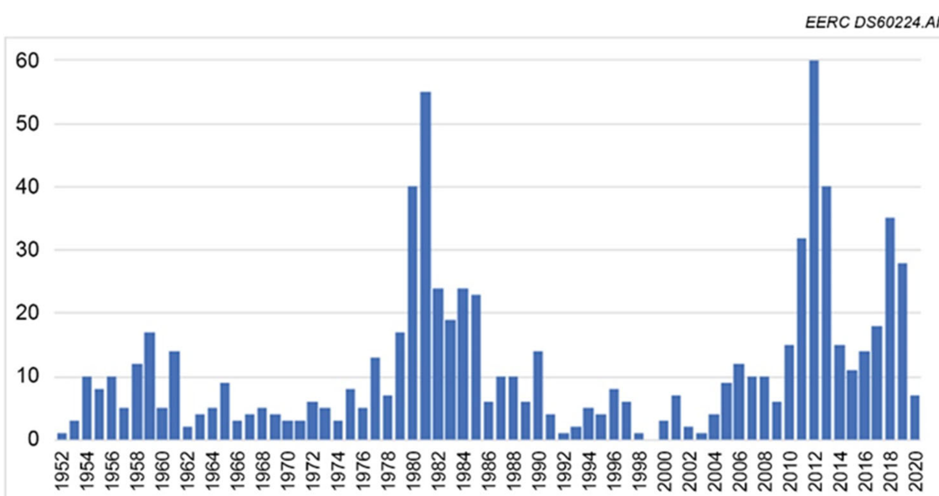

Figure 13. SWD wells spud annually in North Dakota.

Conclusions

- Over half of SWD well completions since 2018 are vertical wells.
- Directional SWD well completions account for 70% of nonvertical wells.
- Three types of directional wells are being pursued, which vary by angle of inclination through the target zone.
- Horizontal SWD well completions have evolved to cemented liners with maximum length of 2500 feet.
- The maximum casing size is 7⅝ in. to accommodate 5½-in. tubing and minimize frictional effects.
- Horizontal SWD well completions outperform all other completions relative to injectivity and total capacity.
- Reservoir quality greatly affects SWD well capacity.
- Permeability alteration using radial drilling appears to have good potential as a next technology evolution.

Nomenclature

A – cross-sectional area (cm^2)
B – formation volume factor (RB/STB)
H – pay zone (ft)
k – permeability (millidarcy)
k_a – permeability of altered zone (darcy)
k_{avg} – average permeability of altered zone and reservoir (darcy)
k_c – permeability of solution channels (darcy)
k_e – permeability of unaltered reservoir (darcy)
k_m – permeability of the rock matrix (darcy)
k_{mc} – average permeability of the channel matrix flow (darcy)
n_c – number of channels per unit area
p_e – reservoir pressure (psia)
p_w – bottomhole pressure (psia)
q – flow (bbl/day)
r_c – solution channel radius (cm)
r_a – radius of altered zone (cm)
r_e – radius of reservoir (cm)
r_w – wellbore radius (cm)
μ – viscosity (cp)

References

Bader, J. W. 2016. The Dakota Group of the Williston Basin: An Important Geologic Unit for Produced Water from Oil and Gas Development in North Dakota. *North Dakota Industrial Commission Geo News* 43 (1): 11–15.

Bader, J. W. 2019. A Sequence Stratigraphic Model for the Inyan Kara Formation, North Dakota. North Dakota Geological Survey, Report of Investigation No. 122.

Bader, J. W., Nesheim, T. O., and Ternes, S. A., 2016. Inyan Kara Sandstone Isopach Map, Williston 100K Sheet, North Dakota. North Dakota Geologic Survey, Geologic Investigation No. 198.

Bohrer, M. and Day, A. 2021. Saltwater Disposal and Injection. https://www.dmr.nd.gov/oilgas/presentations/McKenzieCoStewardship.pdf (accessed May 2021).

Dickinson, W. and Dickinson, R. W. 1985. Horizontal Radial Drilling System. Presented at the SPE 1985 California Regional Meeting, Bakersfield, California, March 27–29,1985. SPE 13949. https://eureka.slb.com:2083/10.2118/13949-MS.

Murphy, E. C., Nordeng, S. H., Juenker, B. L., and Hoganson, J. W. 2009. North Dakota Stratigraphic Column. North Dakota Geologic Survey Miscellaneous Series 91.

North Dakota Department of Mineral Resources. 2018. Well Index. https://www.dmr.nd.gov/oilgas/feeservices/flatfiles/flatfiles.asp (accessed May 2021).

Potapenko, D. I., Hart, T. B., Kibssgaard, P., Waters, G. A., Lewis, R. E., Utter, R. J., Brown, E., Ayala, S., Goudy, T., and Jelsma, H. H. 2021 The First Application of a Novel Reservoir Simulation Technology Comprising Radial Drilling and Hydraulic Fracturing in the Niobrara Shale. SPE-200837-MS.

Schmidt, D., Miguens, A. C., Wong, C., Hlava, K., and Pinkston, D. 2019. Saltwater Disposal Performance in the Williston Basin. SPE-195337-MS.

Towler, B. F., 2002. Fundamental Principles of Reservoir Engineering. SPE Textbook Series, Volume 8.

Tiab, D. and Donaldson, E. C. 2004. *Petrophysics*, second edition.