2014-2019

NORTH DAKOTA OIL AND GAS INDUSTRY IMPACTS STUDY

KLJ

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The North Dakota Oil and Gas Industry Impacts Study was commissioned to forecast the level of oil and gas production in the state of North Dakota and trends that may increase, decrease or stabilize production. The study area focuses on the 19 oil and gas producing counties with a timeframe of 2014-2019.The collaborative team of KLJ, based in Bismarck, ND, North Dakota State University's Agribusiness and Applied Economics Department (NDSU) in Fargo, ND, and the Energy and Environmental Research Center at the University of North Dakota (EERC) in Grand Forks, ND conducted the research and provided their expertise in preparation of this study.

The project team developed the study with valuable information from local government and oil and gas industry experts. The project team thanks the following report contributors:

- North Dakota Department of Mineral Resources
- North Dakota Oil and Gas Division
- North Dakota Geological Survey
- North Dakota Pipeline Authority
- Upper Great Plains Transportation Institute
- North Dakota Department of Transportation
- North Dakota Department of Health
- North Dakota Petroleum Council
- ONEOK, Inc.
- QEP Resources, Inc.
- Marathon Oil Corporation
- Hess Corporation
- Whiting Petroleum Corporation
- Neset Consulting Services, Inc.
- Center for Social Research North Dakota State University
- DN Consulting, Inc.
- Bootstrap Solutions
- Strom Center Dickinson State University

EXECUTIVE SUMMARY

The North Dakota Oil and Gas Industry Impacts Study (Study) was commissioned to forecast the level of oil and gas production in the state of North Dakota and trends that may increase, decrease or stabilize production. The study area focuses on the 19 oil and gas producing counties with a time frame of 2014-2019.The collaborative team of KLJ, based in Bismarck, ND, North Dakota State University's Agribusiness and Applied Economics Department (NDSU) in Fargo, ND, and the Energy and Environmental Research Center at the University of North Dakota (EERC) in Grand Forks, ND conducted the research and provided their expertise in preparation of this study.

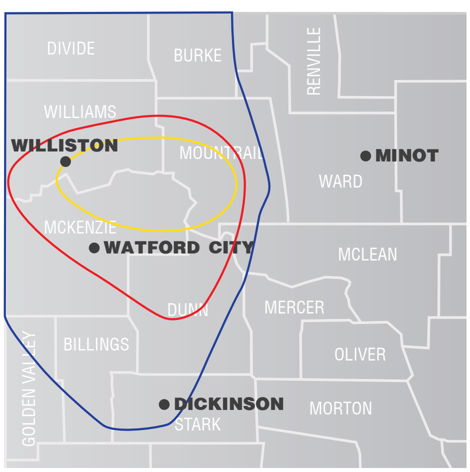
At the beginning of today's Bakken oil boom in North Dakota, the oil and gas industry did not have a comprehensive play book to develop the multiple producing layers of the early unconventional play. The oil play has matured, and companies have redefined drilling strategies and transitioned from an exploration phase into a sustainable production phase.

The study methodology incorporated three approaches to forecast the sustainability of oil and gas production: 1) economic analysis of the Bakken/Three Forks formation, 2) projections of population, employment and housing needs and 3) potential for CO_2 enhanced oil recovery (EOR). Each approach included establishing baseline assumptions and validating the assumptions with industry and North Dakota government agencies; reviewing trade journals, studies and reports; and continuous modeling and analysis.

Economic Analysis of the Bakken/Three Forks Formation

The oil and gas industry and its investors pursue shale ventures that will result in a positive cash flow. Individual companies deploy different strategies with varying timeframes in which they strive to make a profit. With that premises in mind, oil and gas industry averages were calculated to analyze the economics of drilling, completion and production operation and determined the levels of oil and gas production required at various price points in order for companies to achieve a positive return on investment in the Bakken/Three Forks benches located in the study area.

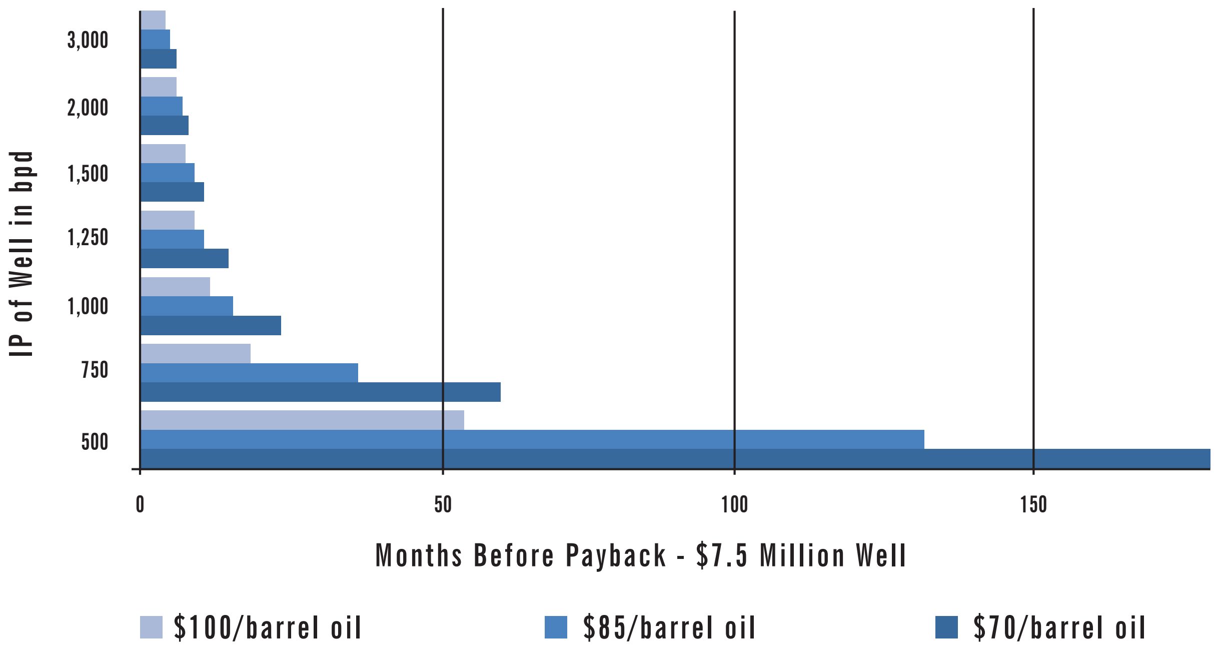
The data outlined the potential limits of three drilling target boundaries in the study area.



Bakken/Three Forks Drilling Target Boundary
Source: KLJ

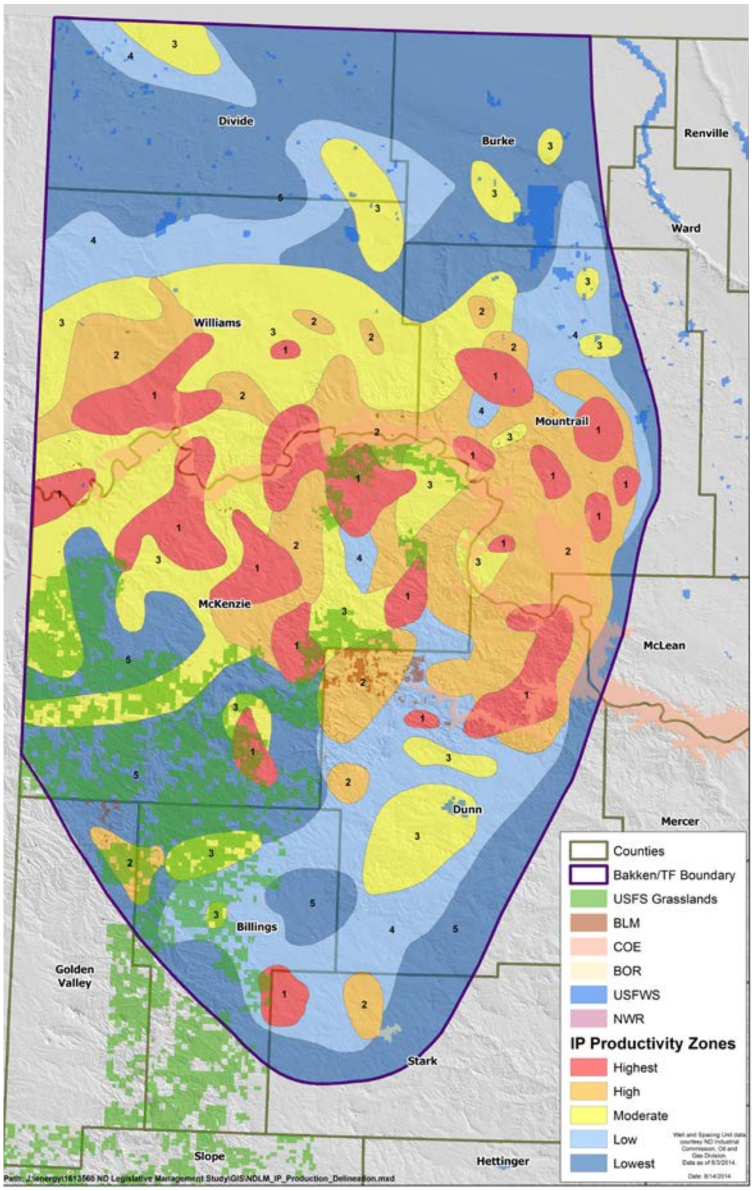
- The Bakken/Three Forks Boundary includes the middle Bakken and the 1st Three Forks bench. (Outermost boundary shown in blue)
- The 1st-2nd Three/Forks Bench Boundary includes the middle Bakken and up to two Three Forks benches. (Middle boundary shown in red)
- The 1st-4th Three Forks Bench Boundary includes the middle Bakken and up to four Three Forks benches. (Innermost boundary shown in yellow)
- Each bench is continually being analyzed by operators who have or will be drilling and evaluating different well completion designs. Several companies have announced positive test results, with potential of 5 to more than 20 horizontal hydraulically fractured wells per spacing unit.

Discussions with industry representatives established the baseline of three years as the timeframe in which companies generally expect to recover drilling and completion costs. Initial production of a well and its decline curve significantly effects the timeframe to recover costs. Utilizing the typical Bakken decline curve and a 2014 median of $85 per barrel the payback timeline comparison chart below confirms the challenges companies potentially have recovering costs. A well with an initial production of 500 barrels per day will take nearly 11 years before it begins to generate a profit, while wells with initial production of more than 1,250 barrels per day can expect to profit in the first year of production.



Payback Timeline Comparisons
Source: KLJ

Within the established Bakken/Three Forks Drilling Target Boundary, data available for non-confidential Bakken/Three Forks wells drilled between 2007 and June of 2014 provided by the North Dakota Industrial Commission—Department of Mineral Resources. The information was used in conjunction with the typical Bakken decline curve, 2014 well costs of $7.5 million and $85 per barrel of oil to illustrate development potential. Five zones were identified to show the areas of highest to lowest potential of economic return.



Areas of Relative Bakken/Three Forks Oil Productivity – IP Potential

Source: NDIC-DMR Oil and Gas Division; USFS; US BLM Montana State Office; COE; BOR; USFWS; NWR; North Dakota State Water Commission; USGS National Elevation Dataset (Compilation and productivity analysis: KLJ)

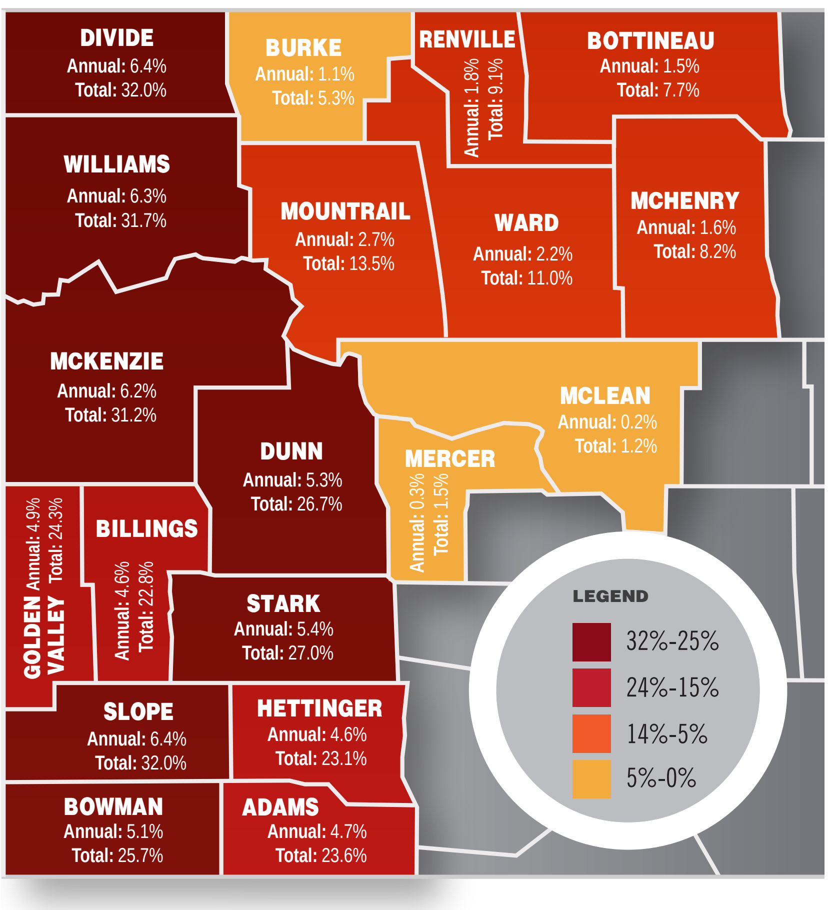
Over the course of the study period, the bulk of drilling/completion activities associated with oilfield activities will take place in the highest potential areas. However, should well drilling/completion costs dramatically decrease and/or oil prices dramatically rise, drilling, completion and associated activities could be expected to spread to lower potential areas as these areas would have a greater probability of reasonable payback periods and profits.

Socio-Economic Impacts of Employment and Population Projects and Housing Need

Population is a key component in the socio-economic modeling in planning for future infrastructure needs. During the next five years, the study period will have a continued increase in population as employment opportunities will exist for direct employment in the oil and gas industry, secondary employment associated with oil and gas, and employment in other industries.

Modeling estimates show growth in the Williston, Minot and Dickinson regions, respectively. The study does not provide specific data for communities. Factors that potently reduce employment growth such as housing, wages, and labor force availability were included in estimates of direct and secondary employment.

Each county in the study area has the potential to increase in population with some counties exceeding a 30 percent increase. The national average for manageable growth is 1.5 percent annually.

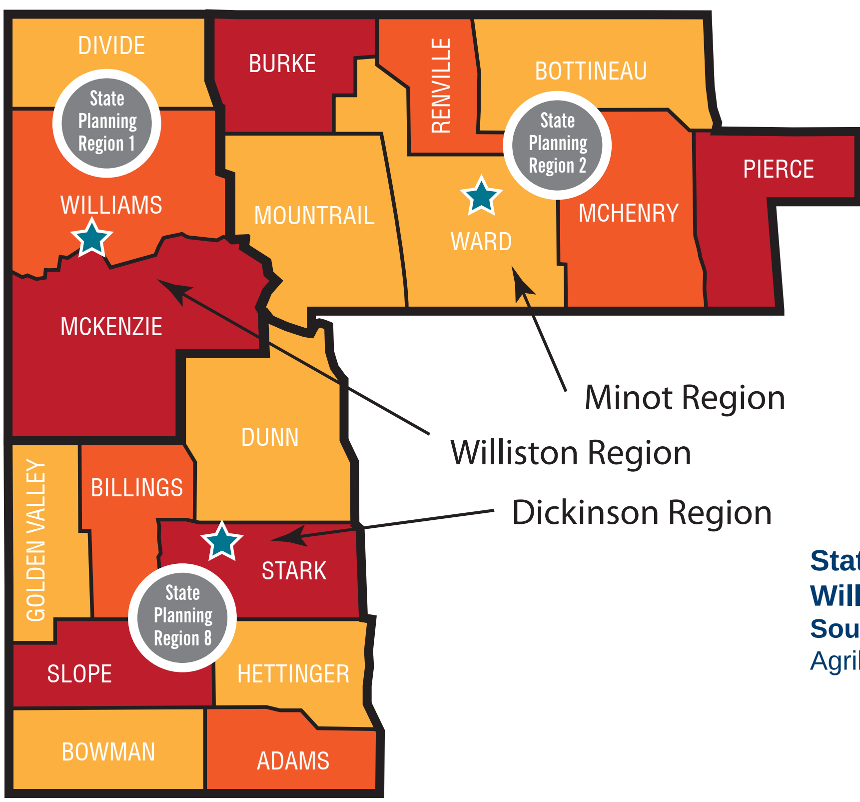


Population increase forecast at the county level
Source: NDSU Department of Agribusiness and Applied Economics

Housing needs in the study area will more than likely continue to grow in correlation with direct and secondary employment growth. Forecasted housing needs estimates were comprised of total housing requirement associated with employment, both long-term/permanent and temporary/development employment.

Housing needs have exceeded permanent housing supply due to the continued rate of oil and gas production. Any previous excess supply of permanent housing has long been utilized, removing elasticity in the housing market. Housing needs are being met by a combination of permanent housing such as houses and apartments in addition to crew camps, campers, skid shacks, mobile homes, hotels and conditional use lodging which includes living on the work site and lodging arrangements at business facilities. The modeling process identifies the need for housing, but does not evaluate market demand for housing nor does it use data on how the current housing need is being met among all of the housing options.

The housing needs are showcased in three regions Minot, Williston and Dickenson, not by individual counties nor communities.



State Planning Regions, Williston Basin, North Dakota
Source: NDSU Department of Agribusiness and Applied Economics

Housing Needs, Total Units, by Scenario, Dickinson Region, North Dakota, 2014-2019			
Year	Low Scenario	Medium Scenario	High Scenario
2014	31,908	32,439	33,311
2015	34,358	35,111	36,117
2016	36,560	37,408	38,467
2017	38,549	39,410	40,672
2018	40,406	41,140	42,921
2019	41,573	42,606	45,016

Housing Needs, Total Units, by Scenario, Minot Region, North Dakota, 2014-2019			
Year	Low Scenario	Medium Scenario	High Scenario
2014	54,903	55,312	55,873
2015	56,170	56,796	57,458
2016	57,401	58,175	58,808
2017	58,361	59,334	59,934
2018	59,564	60,656	61,312
2019	60,476	61,741	62,372

Housing Needs, in Total Units, by Scenario, Williston Region, North Dakota, 2014-2019			
Year	Low Scenario	Medium Scenario	High Scenario
2014	41,063	42,353	45,100
2015	44,397	46,622	50,737
2016	47,770	50,660	55,754
2017	50,173	53,778	59,190
2018	52,069	55,916	61,307
2019	54,071	58,037	63,420

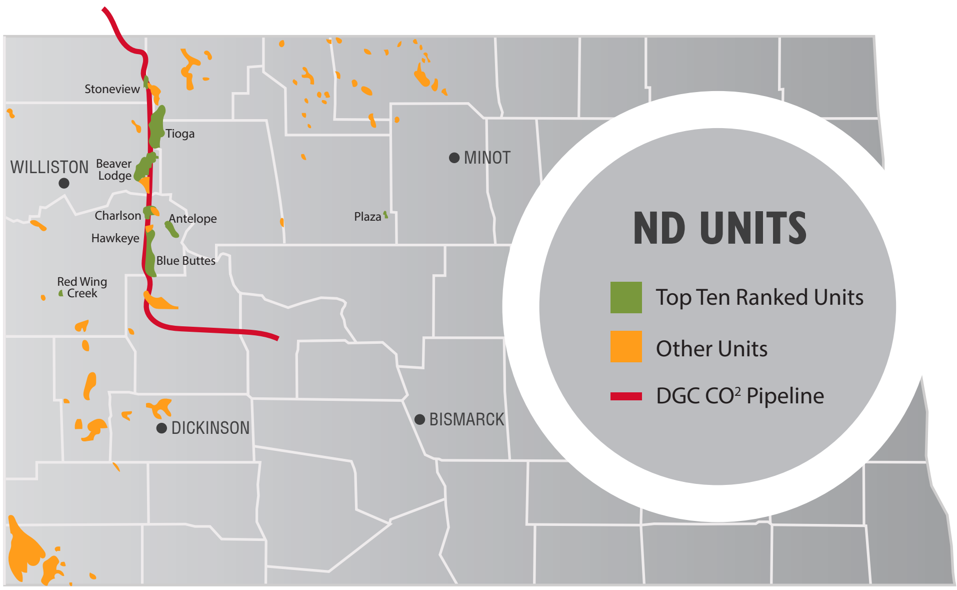
Sensitivity analysis revealed population forecasts are responsive to both a change in housing units and occupancy rates. Small changes in either component resulted in noticeable swings in population.

If future housing is not provided at a level approaching the forecasted values, population will be less than estimated for the study. Workers will find it difficult to bring family members to the state, or difficult to start families. Accordingly, the study area’s population will be skewed towards unaccompanied working adults without spouses and dependents. Communities are assumed to be willing and able to supply housing at levels that meet projected needs. Some communities may be more or less inclined or able to supply housing, but on a regional level, the model assumes that housing supply will meet housing needs.

CO_2 Enhanced Oil Recovery

CO_2 EOR has the potential to increase oil production in North Dakota and was therefore included in the study forecast. Modeling and analysis proves there is significant opportunity in North Dakota to produce additional oil from well-established conventional oilfields through CO_2 EOR.

Conventional oil fields that were more likely to convert from water flood to CO_2 flood within the study period were identified and ranked by near term potential. The top 10 ranked conventional oilfields have a combined estimated recovery of between 87.2 and 186.2 MMbbl (one million barrels), requiring 13.9 to 83.6 MMt (million metric ton) of CO_2. In total, 86 conventional oilfields have a combined estimated recover between 280 and 631 MMBBl, requiring between 47 to 283 MMt of CO_2.



North Dakota Oil and Gas Impact Study 2014-2019 Study Area
Source: EERC

In conjunction with other nontraditional technologies, such as horizontal drilling and hydraulic fracturing, CO_2 EOR should be recognized as part of a long-term production strategy for North Dakota oilfields. Primary challenges in increasing production during the study period include acquiring sufficient CO_2 and for oil and gas companies to invest in this form of EOR.

Baseline Assumptions

In additional to the modeling and analysis completed as part of the study, baseline assumptions were identified and validated. Assumptions were influenced by variables such as: number of drilling rigs, producing wells in a specific region, technological advances in drilling and completion, development of oil, gas and water transportation infrastructure, environmental regulations, global markets and economics.

The assumptions were part of the project team's methodology. The most prominent assumptions forecasting the sustainability of the study area are listed below.

Global and Local Economics:

» Growing oil demand will be balanced by energy efficiency and increased supply from the Canadian oil sands and global shale plays.

» Drilling in North Dakota will remain consistent throughout the study period as long as oil prices are $70 to $100 per barrel.

» Refining capacity for light, sweet crudes in the Gulf coast will be filled by production from the Permian Basin and the Eagle Ford shale plays, which will drive Bakken crude export to refineries on the east and west coast.

» Natural gas consumption will continue to increase substantially as transportation methods and electrical generation more readily utilize natural gas and as exports of liquid natural gas increase.

» US sourced light, sweet crude may be approved for export during the course of the study period, but Bakken crude may experience significant pricing pressure/discounting prior to any approval.

» Global demand for crude oil will continue to increase at an annual rate of at least 1 MMbd throughout the study period.

Infrastructure:

» Surface transportation maintenance and new construction will be a major investment for North Dakota and the oil and gas industry.

» There is the potential for production to reach 2 MMbd, however infrastructure constraints will cap oil production at 1.7 MMbd during the study period.

» New federal regulations will increase rail shipping costs but rail will be the primary method of transporting oil to refineries.

» Power entities will increase permanent and temporary power access where economical and if permitting can be obtained. Increased infill drilling will concentrate demand for power supply in more defined locations.

Environment:

- » As federal and state regulations are developed the oil and gas industry will strive to be compliant before obtaining penalties.
- » Economic opportunity will accelerate new technologies to mitigate spills and clean up contaminated areas.
- » Natural gas flaring targets established by the NDIC will be difficult to achieve during the first two years of the study period. Flaring will decrease as infrastructure is built and new technology is used to increase capture rates.

Technology:

- » Drilling, oil recovery and production technology advancements will continue to evolve and oil and gas companies will concentrate future advancements on labor efficiency, infill drilling processes and lowering overall operations costs.
- » Two CO_2 sources could enhance oil production through CO_2 EOR in North Dakota.
- » Automation will be geared toward improving pipeline gathering and remotely controlled and monitored transportation systems for operators to mitigate risks.

Socio-Economics:

- » Social disruptions associated with increased employment opportunities and growing populations will continue.
- » Housing costs and cost-of-living will likely remain high during the first part of the study. Additional permanent and temporary housing supply will respond to the market and prices will begin to drop.
- » Demands for medical, law enforcement, schools and other public/private services will remain high as population continues to increase. At the end of the study period population stabilization will lessen demand on public/private services.
- » Community resources will continue to be strained throughout the study period until funding mechanisms are established to structure long-term financing for infrastructure and public services.

The next five years are forecasted for sustainable oil and gas production in the state of North Dakota. While there are undoubtedly conditions and events that could impact these expected outcomes, the oil and gas industry will continue to invest in the Bakken/Three Forks Formation if the economics of drilling prove profitable.

KLJ, EERC and NDSU appreciate the opportunity to conduct the research and offer the North Dakota Oil and Gas Industry Impacts Study to assist North Dakota Legislative Management in its legislative vision for long-term policy initiatives.

Methodology

METHODOLOGY

Study Area

The study area is defined as the 19 oil and gas producing counties in western North Dakota.

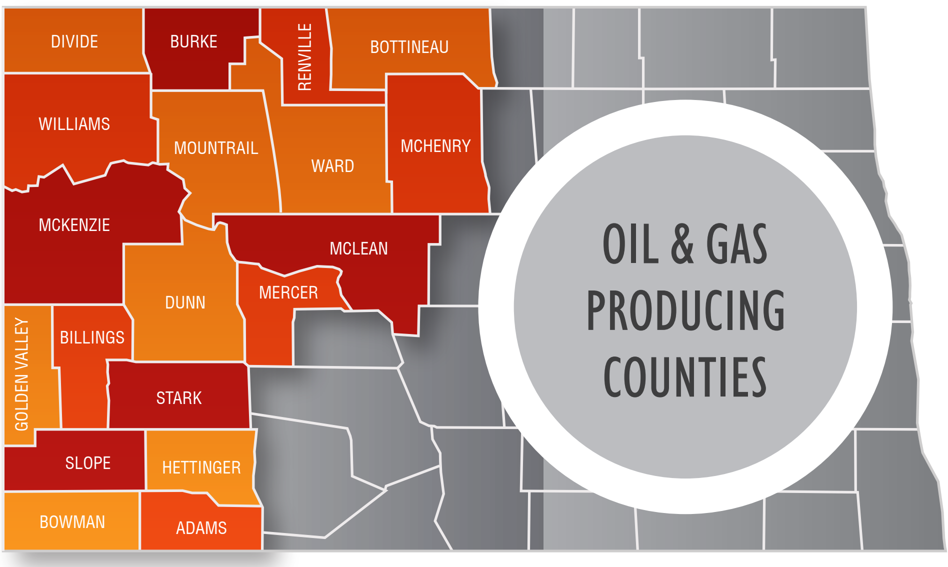


Figure 1: North Dakota Oil and Gas Industry Impacts Study 2014-2019 Study Area
Source: KLJ

Economic Analysis Forecast Methodology—KLJ

KLJ analyzed and modeled the economic potential of the Bakken/Three Forks Formation to determine potential profitability areas within a specific drilling target boundary. The analysis also incorporated Bakken crude pricing variables, baseline assumptions, and literature reviews.

Baseline assumptions were developed by evaluating, historical, current and forecasted trends detailed in trade journals, reports, and news articles. The assumptions were sorted into five categories: global and local economics, infrastructure, environment, technology and socio-economics. The assumptions were drafted by KLJ, NDSU, and EERC and validated through conversations with industry stakeholders and government agencies.

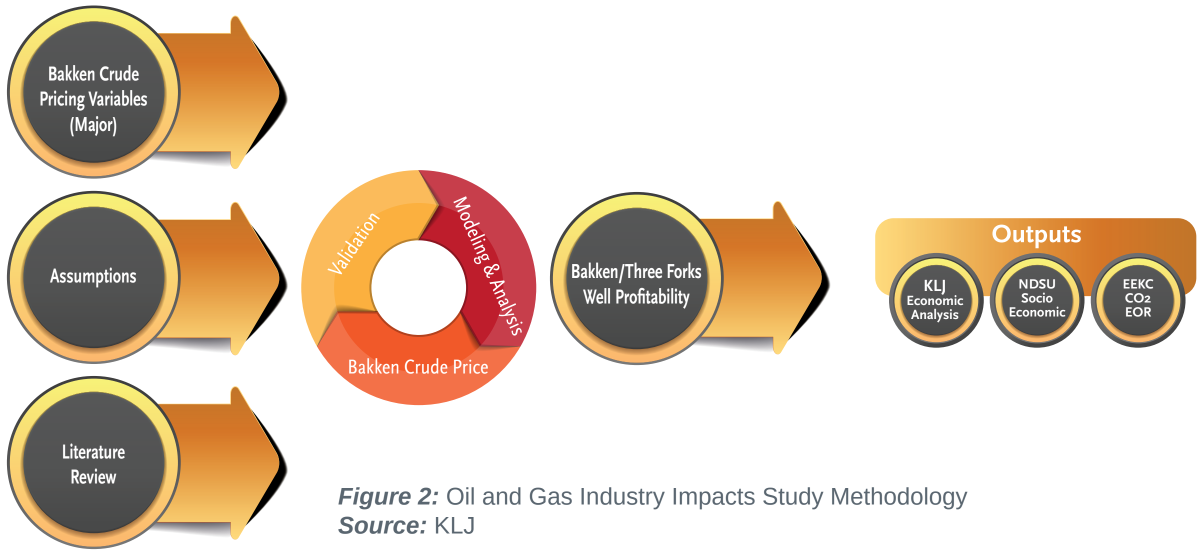


Figure 2: Oil and Gas Industry Impacts Study Methodology
Source: KLJ

Bakken crude pricing variables identified analyzed the industry's ability to be profitable, thus allowing continued development and reinvestment into the Bakken. These variables are global, national and local in nature and revolve around economics, environment, resources, regulation and government policy. The variables continuously monitored during the course of the study include:

Fairly Consistent:

- US refining capacity
- ND county regulations
- ND state regulations
- Federal regulations
- Number of unitized fields (non Bakken)
- Number of wells operating in unitized fields (non Bakken)
- Oil production from the unitized fields (non Bakken)
- Drilling activity on the unitized fields (non Bakken)
- Estimated DGC CO_2 pipeline capacity
- North Dakota gas rig counts

Variable:

- US crude oil importation
- ND Pipeline export capacity
- ND Gas processing plant numbers/capacities
- ND Crude-By-Rail (CBR) export capacity
- Bakken crude market destinations
- Oil rig counts on Federal surface ownership
- ND oil counties electric power supply
- ND Bakken/Three Forks "hotspots"
- ND Bakken/Three Forks "multi-pay regions"
- ND landowner issues

Highly Variable:

- ND oil production
- ND number of producing oil wells
- ND oil wells awaiting completion
- ND gas production
- Gas hub prices
- Williston Basin sweet crude price
- Brent crude versus West Texas Intermediate (WTI) price differential
- Williston Basin sweet crude versus WTI price differential
- Competing shale basin rig counts
- North Dakota Energy Related rig counts
- North Dakota oil rig counts
- North Dakota horizontal rig counts
- North Dakota non-Bakken/Three Forks rig counts
- ND weekly oil/gas permits
- ND weekly oil/gas well spuds
- ND ratio of leasehold/wildcat versus infill oil wells (statewide and by county and reservation)
- ND Bakken/Three Forks well costs
- Competing shale basin well costs
- ND gas flaring percentages/amounts

During the modeling process, analysts sought to broadly determine the economics of drilling, completion and production operation in the Bakken/Three Forks and determined the levels of oil and gas production required at various price points in order for companies to achieve a positive return on investment. GIS maps were developed utilizing published decline curves and proprietary well profitability modeling programs to apply generalized well profitability metrics to individual locations in the study area containing non-confidential Bakken/Three Forks oil well data.

NDSU modeling updated the study area population forecast, workforce demographics and housing analysis. EERC provided analysis of potential CO_2 EOR in North Dakota. The data was incorporated into the comprehensive forecast to evaluate oil and gas production increase, decrease and sustainability during the study period.

CO_2 Enhanced Oil Recovery Methodology—EERC

EERC determined which oil producing units in North Dakota were more likely to convert from waterflood to CO_2 flood within 2014 – 2019. Results were achieved by 1) identifying meaningful screening and ranking criteria for oilfield units, 2) summarizing the data for units in North Dakota and 3) ranking those units in order of CO_2 EOR near-term potential, based on a scoring system.

A list of 123 current and terminated units in North Dakota was created from the North Dakota Industrial Commission website and other sources. Unit reservoir characteristics were drawn mainly from an internal EERC database, but other sources were used to verify certain information.

During the screening process, 37 units were not included in the ranking process for various reasons. The remaining 86 conventional oil units comprise 1,057 active oil and gas production wells out of a statewide total of 9,639 active oil and gas wells as of April 1, 2014.

The pre-screened conventional units were ranked according to reservoir and development characteristics. Four criteria were used to rank units for near-term CO_2 EOR potential:

- Distance from each unit to existing CO_2 pipelines
- Well spacing
- Estimated incremental oil
- Estimated unit reworking

The screening and ranking process took into account general engineering and economic guidelines; however, further analysis of engineering challenges unique to each unit remains important. Additional analysis including detailed geologic assessment and static or dynamic computer modeling of CO_2 injection into the target pool to discover challenges will be needed before tertiary development begins.

Figure 3: Stages of EOR project evaluation and development
Source: EERC

Socio-Economic Methodology—NDSU

NDSU modeled socio-economic impacts of the oil and gas industry as it relates to workforce, housing, population and community attributes. Population is a key component in the socio-economic modeling methodology in planning for future infrastructure needs. Population is usually forecasted using standard cohort demographic models; however, due to rapidly changing conditions in the Williston Basin, traditional demographic tools are inadequate.

For purposes of evaluating shale energy development in the Williston Basin, an alternate method was developed that linked direct and secondary employment to population in western North Dakota. Labor coefficient estimates for several segments of the petroleum industry were obtained that reflect operating conditions in the Basin in 2012. The model estimates labor for drilling, hydraulic fracturing, gathering systems construction and oilfield service such as well site operations, crude oil pipelines and gas plant operations. Labor coefficients from 2014 were adjusted in the model to reflect anticipated changes in employment requirements based on changes in production practices and influences of future technological change on industry labor requirements.

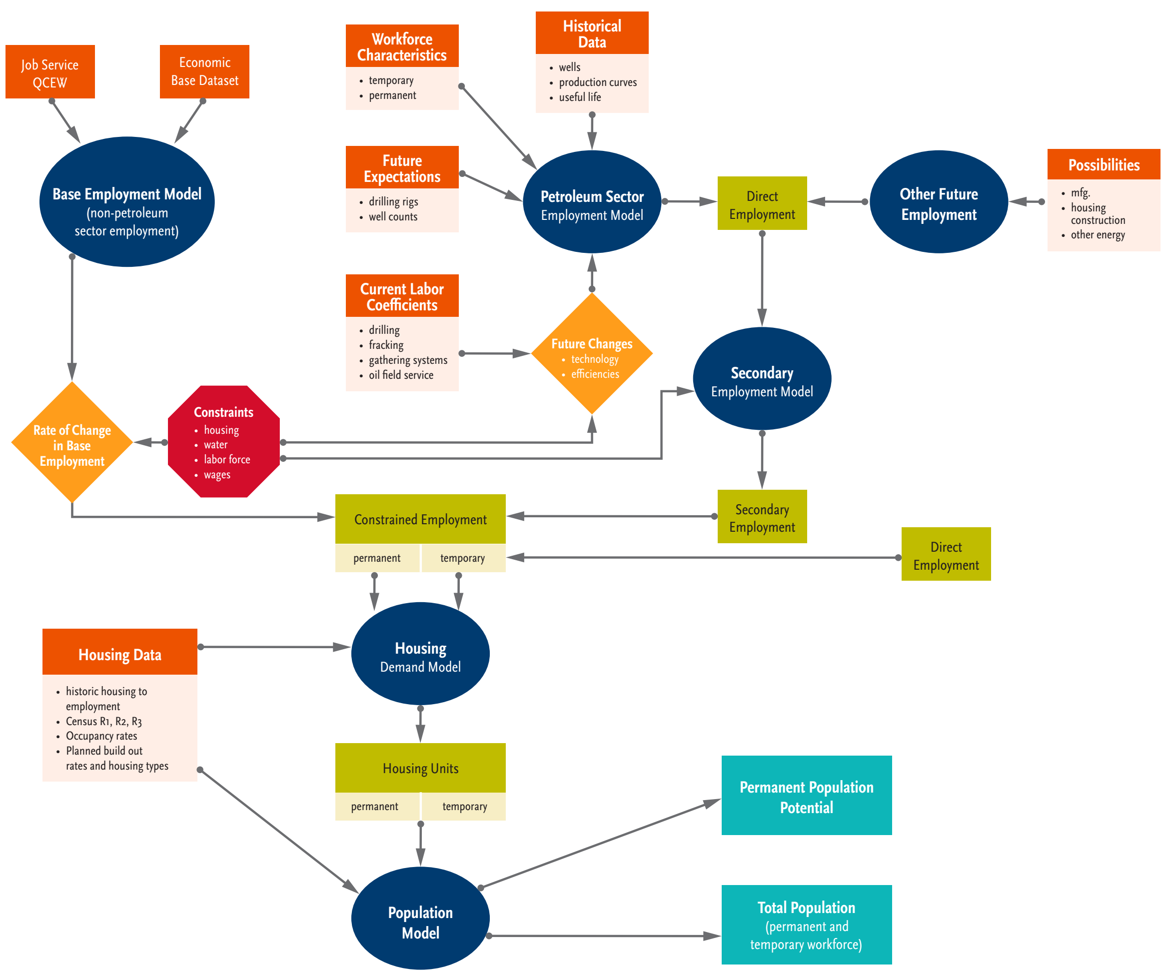


Figure 4: NDSU Methodology Diagram
Source: NDSU Department of Agribusiness and Applied Economics

NDSU's methodology separated employment in western North Dakota into three groups: 1) employment in the petroleum industry 2) secondary employment associated with petroleum industry employment and 3) employment in other industries and economic sectors. Constraints such as housing regulate the amount of future employment change in the base industries (e.g., manufacturing, tourism), as well as serve to adjust employment coefficients within the petroleum sector. Secondary employment creation was linked to direct employment in the petroleum sector and was adjusted to reconcile current employment coefficients to traditional input-output analysis multipliers.

The model estimated total economy-wide employment, and for purposes of the study, reflects the Williston, Minot and Dickinson regions, respectively. The study does not provide specific data for communities. Employment estimates consisted of three main components: direct employment in the oil and gas industry, secondary job creation and employment in other industries and sectors. Factors that potentially reduce employment growth such as housing,wages, and labor force availability were included in estimates of base employment and secondary employment.

Gross levels of housing need based on projected employment growth at the regional level was modeled based on historic data of the regional supply of housing units from 2000 through 2010 and historical employment (i.e., quarterly census of employment and wages), which produced a baseline from which future expected housing needs can be linked to future employment. Early in 2014, updated data on housing supply and occupancy rates and reported Quarterly Census of Employment and Wages from Job Service of North Dakota employment were incorporated into the model. The housing model is dynamic and allows for the relationships between employment and housing needs to change over the study period.

EERC and NDSU's studies are located in the Appendices.

Economic Analysis of the Bakken/ Three Forks Formation

Economic Analysis of the Bakken/Three Forks Formation

The oil and gas industry and its investors pursue shale ventures that will result in a positive cash flow. Individual companies deploy different strategies with varying time frames under which they strive to make a profit, but all companies ultimately seek a positive return on investment. During the 2014-2019 study period analysts forecasted the oil and gas industry will maximize production in concentrated areas with proven potential to recover drilling and completion costs and diminish exploration drilling.

Oil and gas industry averages were calculated to determine the costs of drilling, completion and production operations in the Bakken/Three Forks Formations located in the study area. Using average costs and oil and gas production levels,[1] price points were identified where industry can more than likely achieve a positive return on investment. Once price points were identified, published production decline curves and proprietary well profitability modeling programs were utilized to develop well profitability metrics which were applied to individual locations containing non-confidential Bakken/Three Forks oil wells. The modeling process outlined a Bakken/Three Forks Drilling Target Boundary (Figure 5).

Drilling around the periphery of the Bakken/Three Forks Drilling Target Boundary was not included in the modeling due to minor contribution to overall production. Areas outside of the target boundary only equals slightly more than 44,000 barrels of oil per day, or four percent of total production. In June 2014, the month-to-month increase in daily Bakken/Three Forks production[2] was greater than the total contribution of more than 3,300 wells outside of the boundary, and evidence indicates no significant changes to total production percentages during the study period. Future drilling and production from the Madison Group, as well as the Red River, Spearfish and Tyler Formations, which will be drilling targets during the study time frame, are anticipated to have minor localized impacts, but were not modeled.

The Bakken/Three Forks Drilling Target Boundary, which roughly corresponds with an initial 24-hour production (IP) value threshold of 100 barrels of oil based on historic, non-confidential Bakken/Three Forks well production data published from 2007 through May 2014. Figure 5 visualizes the probable Bakken/Three Forks' commercial extent in North Dakota. The boundary encompasses approximately 12,000-square miles and wells with IP's of <100 barrels are generally located outside the boundary while wells with IP values of >100 barrels are within the boundary.

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[1] As reported by the North Dakota Industrial Commission—Department of Mineral Resources

[2] As reported by North Dakota Industrial Commission—Department of Mineral Resources August 2014 Director's Cut report

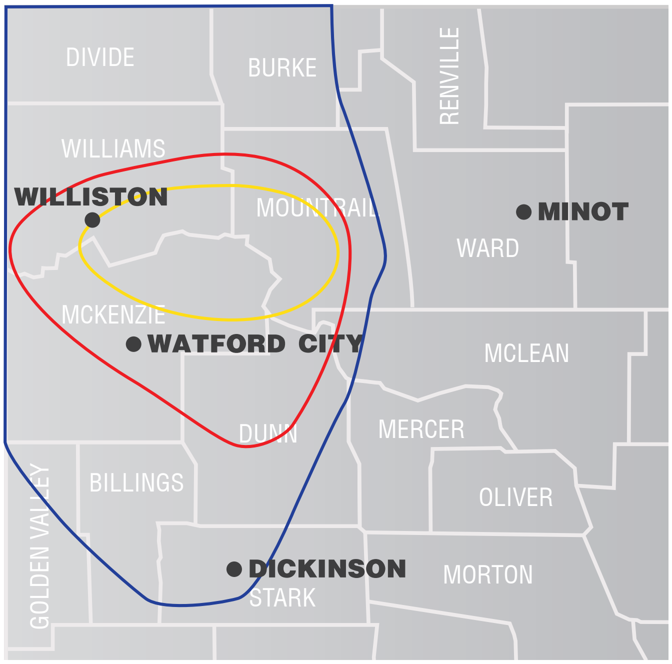

Figure 5: Bakken/Three Forks Drilling Target Boundary
Source: KLJ

Figure 5 illustrates the potential limits of three drilling target boundaries for the Bakken/Three Forks play.

- The Bakken/Three Forks Boundary includes the middle Bakken and the 1st Three Forks bench. (Outermost boundary shown in blue)
- The 1st-2nd Three/Forks Bench Boundary includes the middle Bakken and up to two Three Forks benches. (Middle boundary shown in red)
- The 1st-4th Three Forks Bench Boundary includes the middle Bakken and up to four Three Forks benches. (Innermost boundary shown in yellow)
- Each bench is continually being analyzed by operators who have or will be drilling and evaluating different well completion designs. Several companies have announced positive test results, with potential of 5 to more than 20 horizontal hydraulically fractured wells per spacing unit.

Bench boundaries were compiled after multiple discussions with geologists from the North Dakota Geological Survey. The Three Forks Formation is extensive and reaches far beyond Bakken Formation boundaries. Based on bench boundary mapping, the study indicates that the greatest level of impact with the most wells and most production per spacing unit will be within the boundaries of the 1st through 4th Three Forks Bench delineation. The area has an areal extent of slightly more than 1,600 square miles.

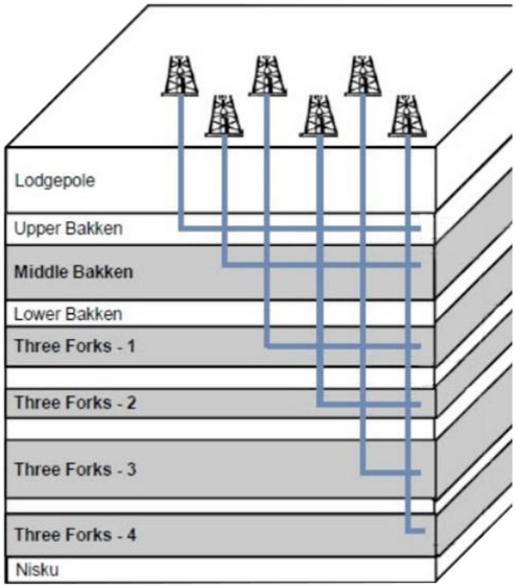

Figure 6: Bakken/Three Forks Benches
Source: Company data, Goldman Sachs Global Investment Research

In the early stages of the Bakken/Three Forks play, companies acquired mineral leases throughout much of the Williston Basin where previous mapping had shown the Bakken Formation to be present. Areas of the Bakken studied by private and public entities, determined to have thermally mature i.e., potentially hydrocarbon producing zones, were sought. In an effort to hold expensive mineral leases, oil companies typically began to drill at least one well in each leased spacing unit. Drilling to hold leases was still common in 2014, although at a greatly diminished scale when compared to the 2007-2012 time frame of the Bakken/Three Forks unconventional oil play.

During spring 2013, active changes in drilling patterns were detected in the Bakken/Three Forks play and theorized an evolution of drilling technology. KLJ analysts developed a Development/Infill (D/I) Ratio modeling program to determine the ratio between wildcat and/or lease hold drilling versus infill or pad drilling. Figure 7 presents a timeline of D/I during which holding leases was the industry's primary objective versus infill drilling. Infill drilling became predominant in the first half of 2012.

From 2007 to 2012, Bakken/Three Forks wells with long laterals and hydraulic fracturing completion services were extremely expensive, with many costing $10 to $12 million per well. Costs were elevated due to the following factors: shortages of large drilling rigs and experienced crews, shortages of completion equipment and crews, shortages of well and completion related material/supplies, drilling and completion experimentation, and weather and logistical challenges. Oil prices reached highs of greater than $120 per barrel in 2010. Announcements of wells initially producing more than 3,000 barrels per day were pervasive, and as every well produced some oil, euphoria spread throughout the oil industry. Sufficient production history did not exist to accurately characterize unconventional Bakken/Three Forks production decline curves, and operators continued to invest millions of dollars into drilling costs to secure mineral leases. By 2012, the euphoria had begun to fade for some operators as decline curves were modeled from production of leasehold wells. Operators discovered some areas were never going to cover the costs of multi-million dollar wells.

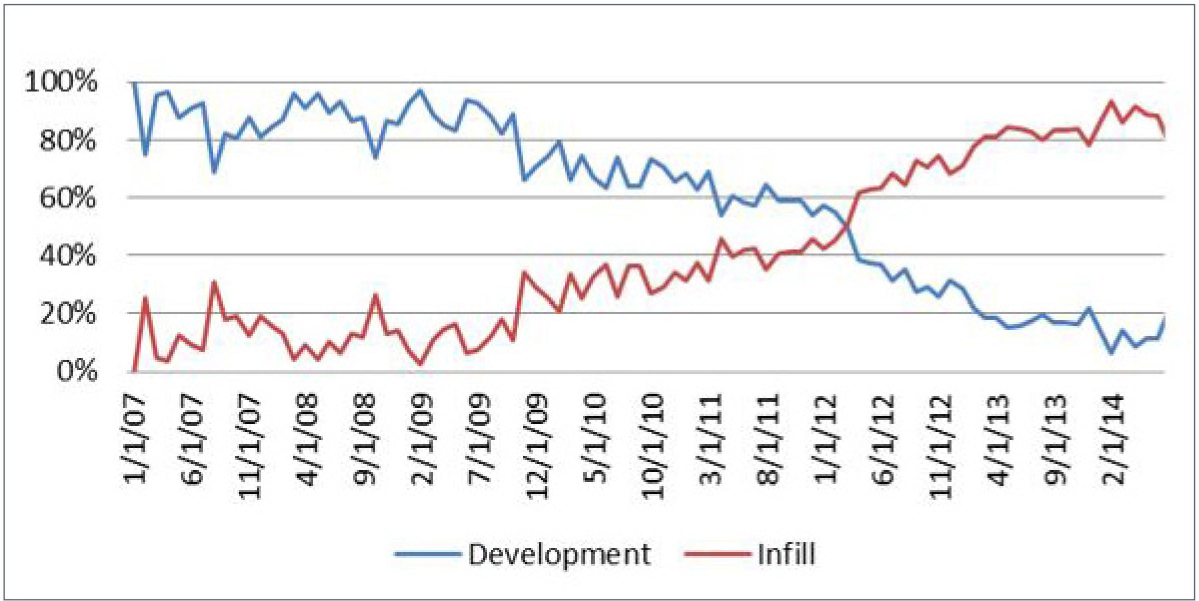

Figure 7: Development/Infill Drilling Ratio
Source: KLJ

Figure 8 is a typical Bakken well decline curve and illustrates the steep decline curves that some companies were/are facing. As shown in the typical decline curve, daily oil production is greatly diminished after the first two years, and whether or not a well will be profitable has a very strong correlation to the well's IP and production decline curve. Operators may slow a well's production for operational and well/reservoir longevity reasons after establishing the IP. If drilling and subsequent completion processes were optimum, the IP would be a close approximation of what the geologic formation would be capable of producing.

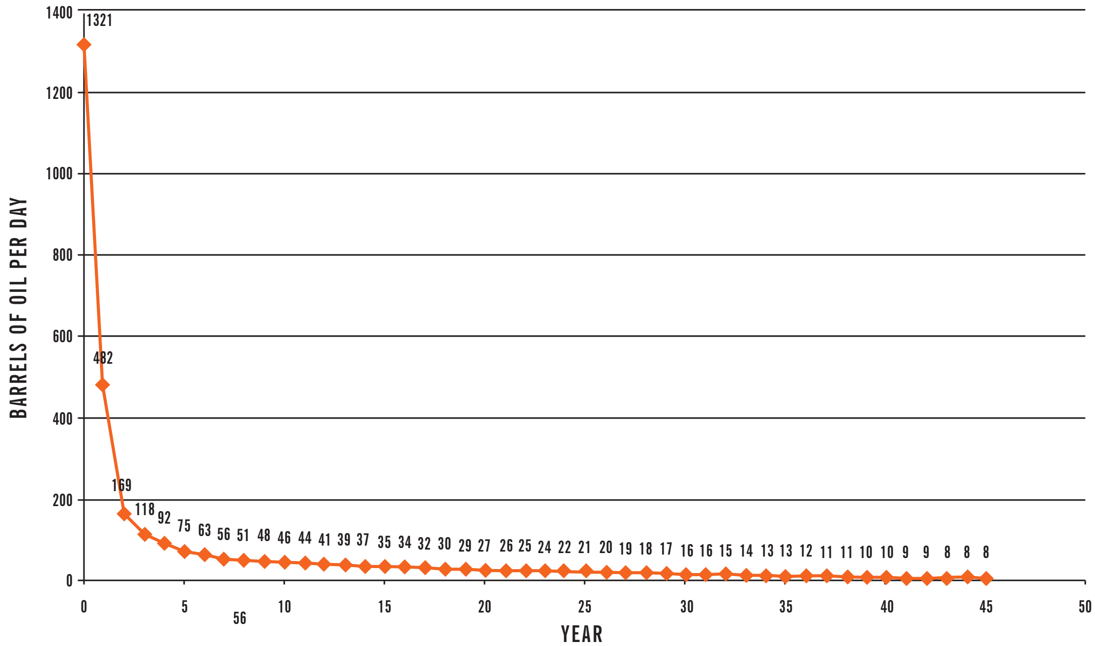

Figure 8: Typical Bakken Well Production
Source: North Dakota Industrial Commission-Department of Mineral Resources

Proprietary petroleum engineering well analysis modeling software was utilized to calculate a profit from drilling, completion and operating investment. The production decline curve used by the modeling software was adjusted to approximate a typical Bakken well decline curve shown in Figure 8. Additional inputs included 2014 pricing for: per barrel of oil, per Mcf of gas, well costs, and the well IP (in barrels per day). North Dakota 2014 royalty, tax and well operating costs were also part of the model, but were associated to input variables. The model used generalized data for comparative purposes, therefore, some companies and wells may perform better for a given well IP than the study's modeling comparisons. The use of a different decline curve could project better or worse well economics for a given well cost and IP, and thus lower or raise the minimum IP required for a well to attain profitability. Numerous sensitivity scenarios utilizing various inputs were changed and then remodeled. Examples of pricing sensitivity scenarios included: oil ranging from $35 to $450 per barrel, $2.50 to $12 per Mcf, and well drilling costs ranging from $5 million to $10 million.

Technological improvements and drilling and completion efficiencies over the last two years have significantly lowered drilling costs from $10 million to $12 million and reduced drilling time of an average Bakken/Three Forks well. Data presented by the North Dakota Pipeline Authority illustrated the tremendous improvements in drilling rig efficiencies that have occurred since 2007, a time when a large drilling rig capable of drilling the long laterals common in the Bakken/Three Forks could only spud eight to nine wells per year (North Dakota Pipeline Authority, 2014).

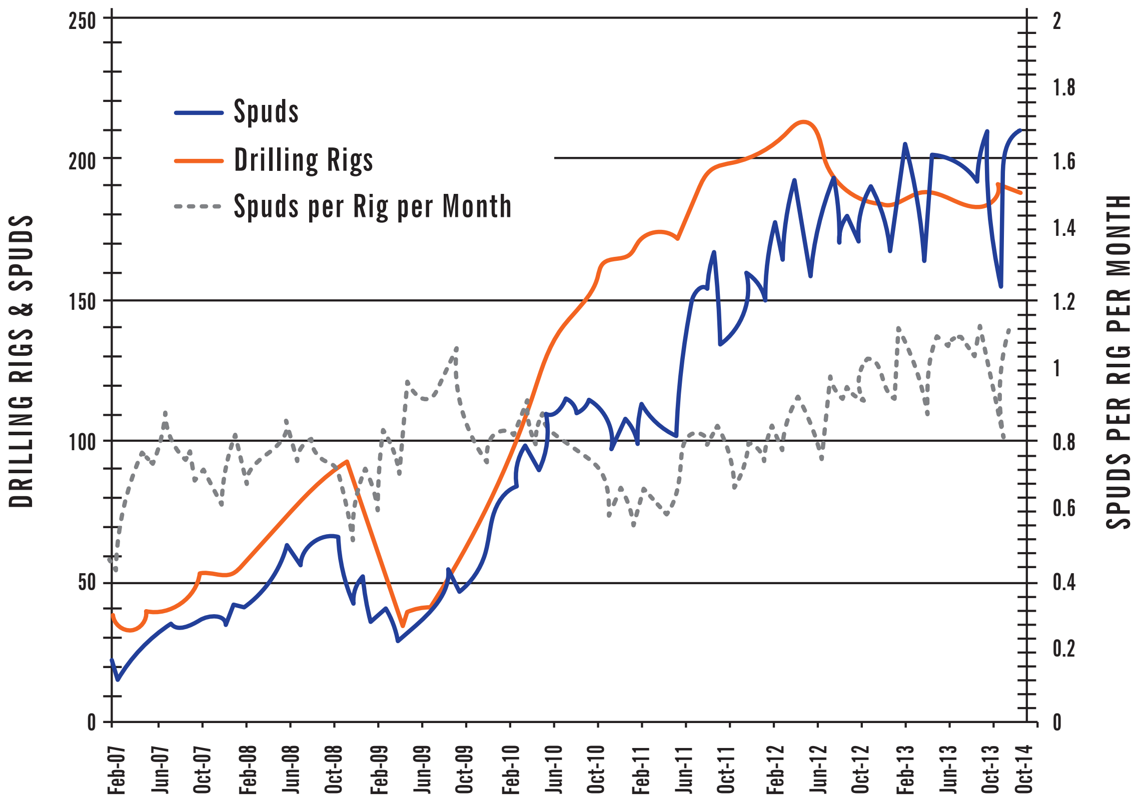

Figure 9: ND Drilling Statistics
Source: North Dakota Pipeline Authority

As of 2014, rigs were able to spud more than 13 wells per year. With decreased drilling times, Bakken/Three Forks wells with nearly two-mile long lateral legs cost roughly $8 million, and less common Bakken/Three Forks wells with shorter (about one mile) laterals cost roughly $5.5 million. Figure 10 modeled payback time lines using baseline pricing of $7.5 million for well cost, median oil price of $85 per barrel (+/- $15) and gas at $4 per Mcf.

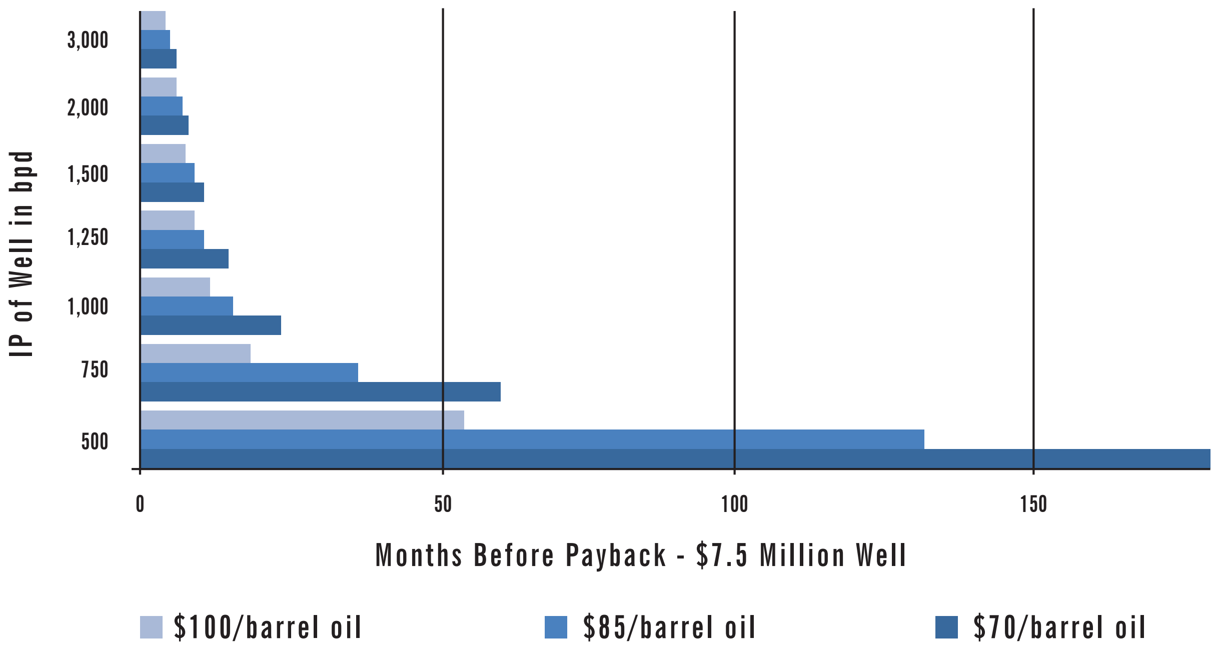

Figure 10: Payback Timeline Comparisons
Source: KLJ

The modeling In Figure 10 shows significant impact of oil pricing on the economics of a well. At $70 per barrel price, a well IP of 500 bpd would never recover its costs. In order to recover well costs within 5 years, a 500 bpd IP well would need oil prices to exceed $100 per barrel. In stark contrast, modeling sensitivity scenarios such as large drops in prices down to $35 per barrel with high IP wells, which are common in parts of the Bakken/Three Forks, still have positive economic returns. Based on modeling outputs, IPs of 500 bpd or less will not be attractive to companies if well costs equal $7.5 million, and oil prices are in the vicinity of the 2014 average price of $85 per barrel. Conversely wells in the 500 to 750 bpd IP range are attractive, but susceptible to oil price fluctuations. Wells having at least 1,000 bpd IPs are attractive at current or higher oil prices, and for the most part, will still be attractive even with a reduction in oil prices. In discussions with industry representatives, companies generally expect to recover costs in three years or less, and a five-year payback time frame would be acceptable only in very unusual circumstances.

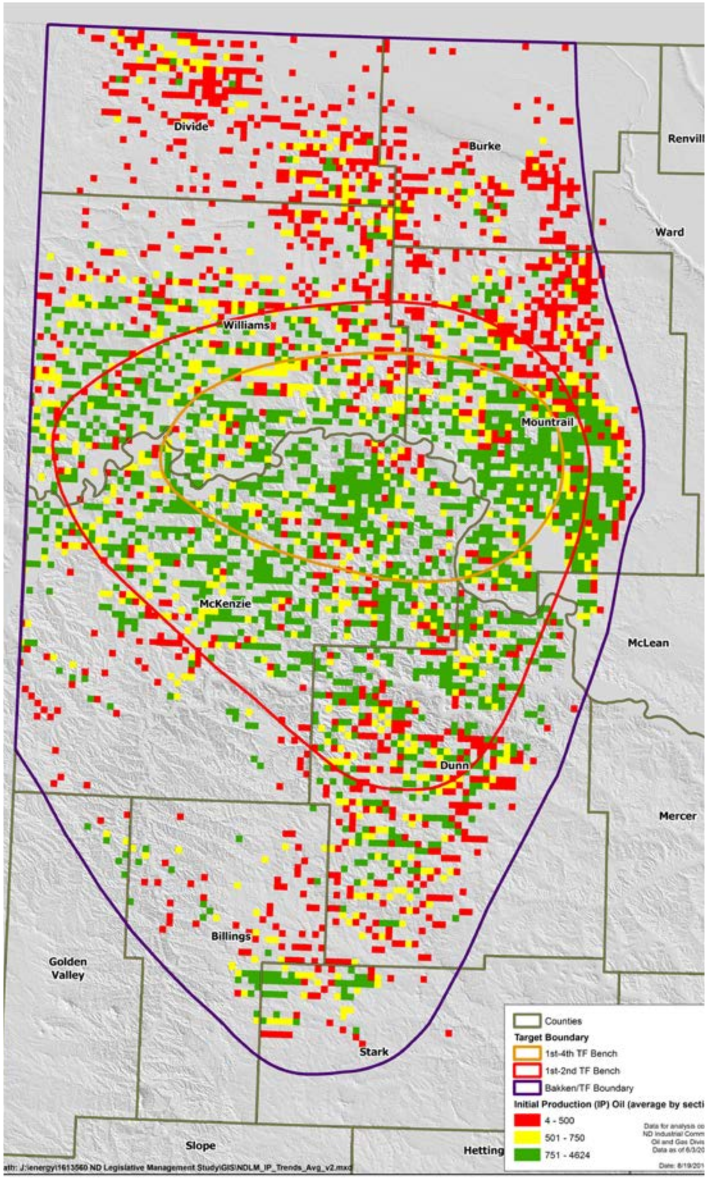

Figure 11: Average IP (in barrels) for Bakken/Three Forks Wells (2007-14) by Section
Source: NDIC-DMR Oil and Gas Division; North Dakota State Water Commission; USGS National Elevation Dataset (Compilation and Analysis: KLJ)

Figure 11[3] illustrates locations within the study area dominated by wells with <500 bpd IPs, wells with IPs between 501 and 750 bpd and large areas dominated by wells with >1,000 bpd IPs.[4]

Anomalous high or low IP values are present within areas dominated by a different value. While irregular well data sorted in a clear and orderly format is ideal, the arrangement would not be natural. Anomalously high IP wells more than likely intersected natural traps that have concentrated oil and/or intersecting natural fractured zones that are able to channel additional oil to the well bore from far beyond the engineered permeability zone created during the hydraulic fracturing/completion process. Likewise, anomalously low IP values could be a result of well drilling and/or completion problems, natural issues such as natural water flooding or water-flushing of oil along naturally occurring fracture zones. Anomalous values need to be considered, but area trends are most important for planning purposes.

Areas within the Bakken/Three Forks Drilling Target Boundary (Figure 5) showing no well IPs did not have data available at the time of the study. A lack of wells in some areas within the boundary are likely a result of areas protected by state or federal government, while the lack of wells within other areas may be the result of poor drilling success most likely credited to geologic conditions not being optimal for hydrocarbon creation, storage and subsequent extraction.

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[3] A larger print of Figures 11, 12, 13, 14 and 15 is located in Appendix A

[4] IP values were attached to the individual section in which the surface location for that well is located. If multiple wells meeting the criteria were located in a single section, the IP values were averaged to create a single IP value. Using the Township, Range, Section grid for locating the section specific IP values allowed GIS analysts to create Figure 11, which was classified using breakpoint values derived from the decline curve and well payback modelling.

While Figure 10 illustrates payback based on costs, oil pricing and timelines, Figure 12 illustrates well payback and profitability levels in a spatial way, and depicts where wells will likely be profitable based on the model economics rather than simply measuring what factors make a well profitable.

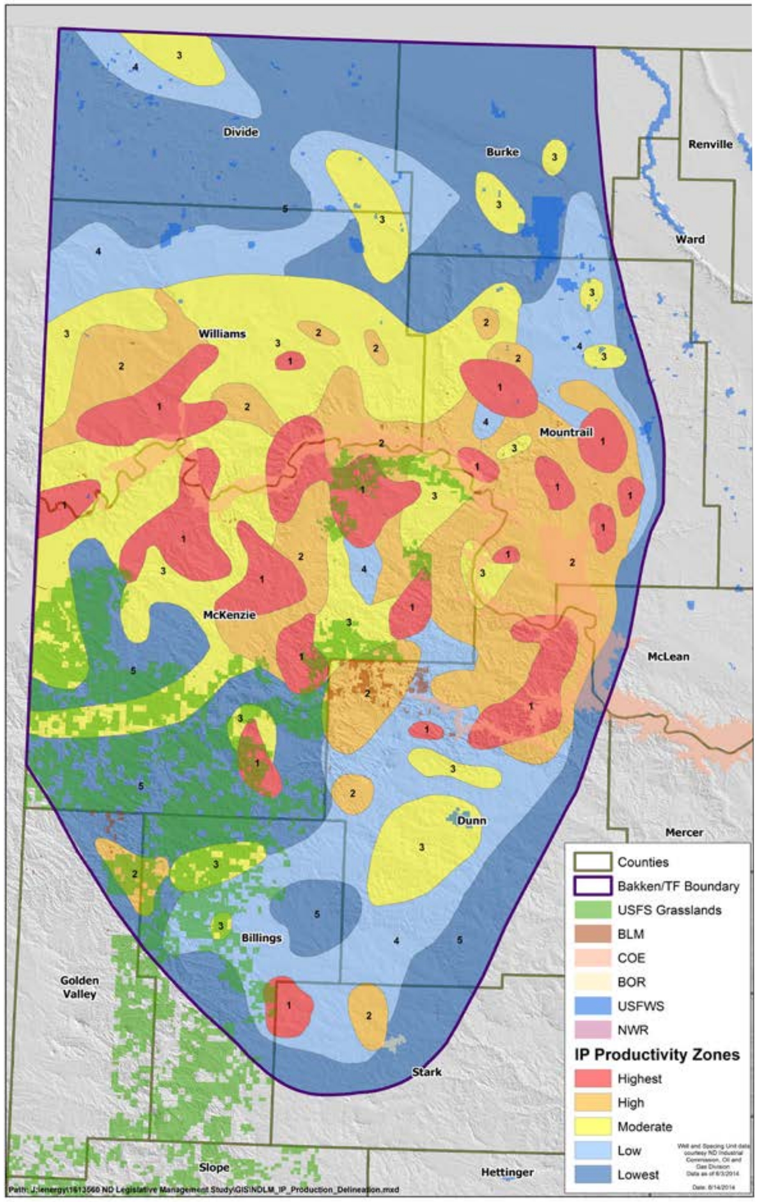

Figure 12: Areas of Relative Bakken/Three Forks Oil Productivity – IP Potential
Source: NDIC-DMR Oil and Gas Division; USFS; US BLM Montana State Office; COE; BOR; USFWS; NWR; North Dakota State Water Commission; USGS National Elevation Dataset (Compilation and Analysis: KLJ)

Bakken/Three Forks oil productivity IP potential is categorized into five colored zones in Figure 12. Wells drilled in the lowest dark blue zone (approximately 4,100 square miles) would be least attractive due to the assumption of wells drilled in that area would be less likely to recover costs. One exception might be in the US Forest Service (USFS) Grasslands area, where a lack of recent drilling made it difficult to accurately determine potential productivity. The light blue zone (approximately 2,000 square miles) is marginally attractive, as wells drilled in this zone have a higher potential to show a slight profit. The moderate yellow zone (approximately 2,550 square miles) should have a reasonable payback period and good profitability. Wells drilled in the yellow zone may be more susceptible to extended payback times and loss of profitability if oil prices were to drop below $70 per barrel. Wells drilled in the high orange zone (approximately 1,850 square miles) have the potential for relatively short payback times, higher profits, and ability to remain profitable through some oil price fluctuations. Finally, the highest red zone (approximately 1,300 square miles) has the potential for very short, less than one year payback time, good profits and should remain profitable even with severe drops in oil prices.

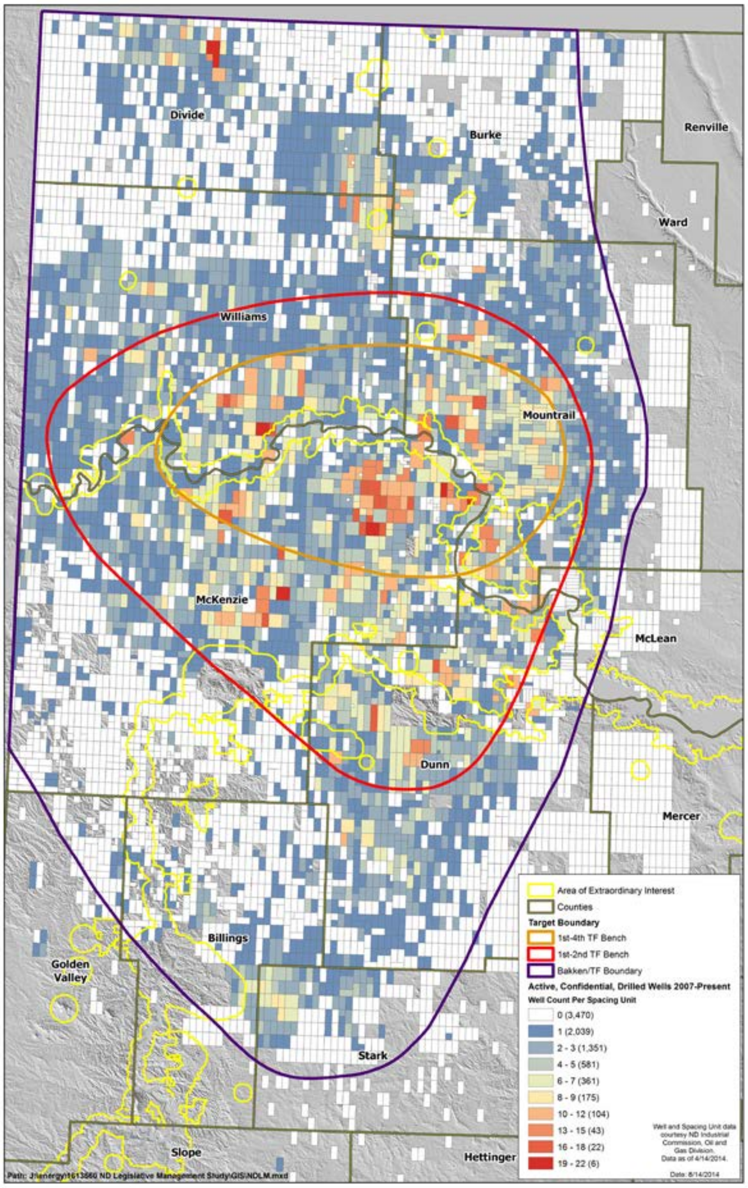

Figure 13: Bakken/Three Forks Well Drilling Intensity (2007-14) by Spacing Unit
Source: NDIC-DMR Oil and Gas Division; North Dakota State Water Commission; USGS National Elevation Dataset (Compilation and Analysis: KLJ)

Over the course of the study period, the bulk of drilling/ completion activities and associated oilfield activities will take place in warmer colored zones. However, should well costs dramatically decrease and/or oil prices dramatically rise, drilling, completion and associated activities could be expected to spread into cooler zones, as wells drilled in cooler zones would have a greater chance of reasonable payback periods and profits.

As might be expected, and especially with the dominance of infill and multi-well pad drilling since 2012, warmer zones have much greater well densities than cooler zones, as companies seem to be focusing on areas where they can get the best returns on their investments. In spatially tying existing Bakken/ Three Forks wells drilled since 2007 to various IP Productivity Zones, analysts were able to determine well densities with the highest zone having densities of approximately 1.7 wells per square mile, the high zone having densities of approximately 1.5 wells per square mile, the moderate zone having densities of approximately one well per square mile, the low zone having densities of 0.7 wells per square mile and the lowest zone having a density of only 0.2 wells per square mile. More than 20 wells could potentially be drilled in individual spacing units, which are typically two square miles, that may contain the Middle Bakken and up to four Three Forks benches.

Apart from mapping existing and potential well productivity by zones (Figure 12), it is informative to see where companies have and have not focused drilling efforts from 2007 to 2014 in the Bakken/Three Forks. GIS analysts generated Figure 13 showing the size and location of established spacing units and how many wells have been drilled in each spacing unit based on NDIC-DMR data. As of April 2014 data, a large number of established spacing units depicted in white have never been drilled. Similar to Figure 12, cool colors indicate little interest perhaps due to development/lease holding wells, while warmer colors indicate infill/multi-well pads.

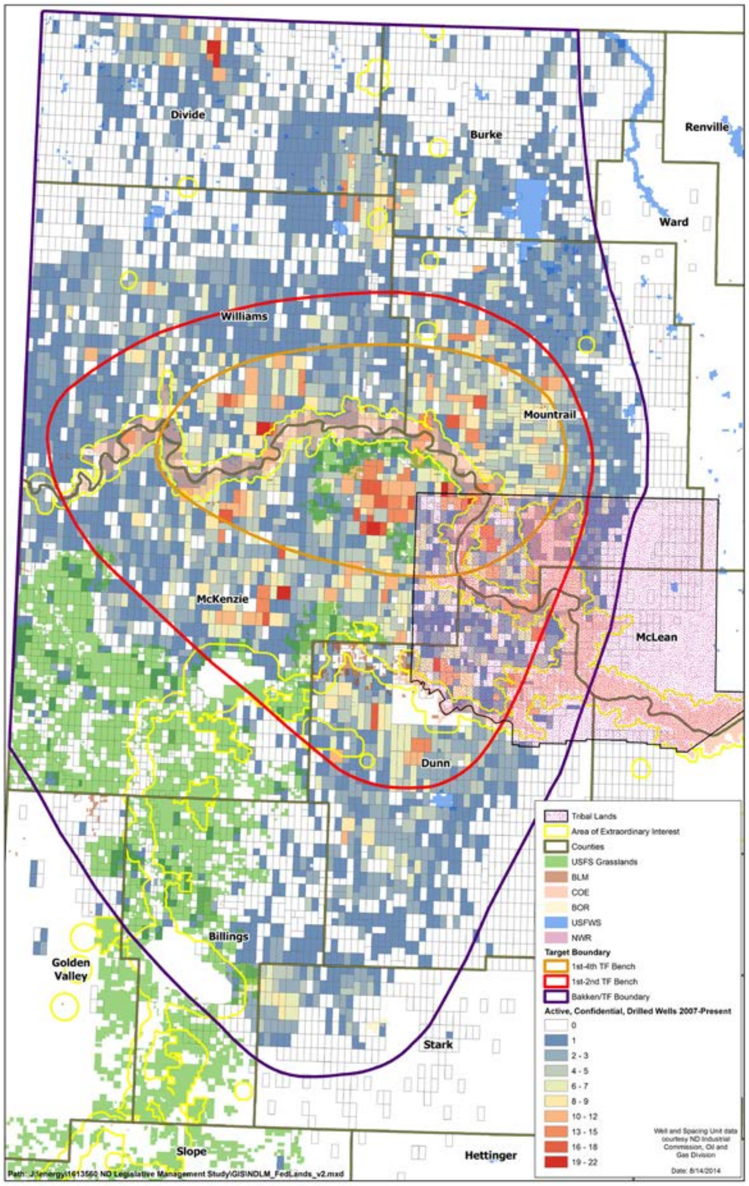

Figure 14: Bakken/Three Forks Well Drilling Intensity (2007-14) by Spacing Unit – With Select Federal Jurisdictions
Source: NDIC-DMR Oil and Gas Division; USFS; US BLM Montana State Office; COE; BOR; USFWS; NWR; North Dakota State Water Commission (Compilation and Analysis: KLJ)

While figures 12 and 13 present general areal agreement between the warm zones, the agreement is not ideal, which is likely due to the locations of mineral acre blocks controlled by numerous oil companies operating in the study area. While a company may not have mineral acres in the most productive zones, the operator may drill numerous wells in the most productive acres they control, regardless of the fact that an adjacent operator may have drilled only a few wells in what is potentially a much more productive zone. If one company held the mineral rights to the entire Bakken/Three Forks play, the drilling and production pattern would have little resemblance to what currently exists. It is also worth noting there are several areas within the Bakken/Three Forks Drilling Target Boundary (Figure 5) that have not had spacing units established i.e., areas showing a shaded relief/ topographic background. Some of these areas with no spacing units are located in National or State Parks or other excluded/extraordinary interest areas, still other areas have no determined deviation.

Drilling densities are different between privately held lands and federally-controlled lands. The contrast is especially visible in lands managed by USFS, which are primarily located in the Bakken/Three Forks Drilling Target Boundary southwestern portion as illustrated in Figure 14. Very few spacing units are drilled in USFS lands, even though it is an area underlain by mature, potentially hydrocarbon producing Bakken shale and the underlying Three Forks Formation. The lack of spacing units drilled in the area dominated by USFS lands is more than likely a result of

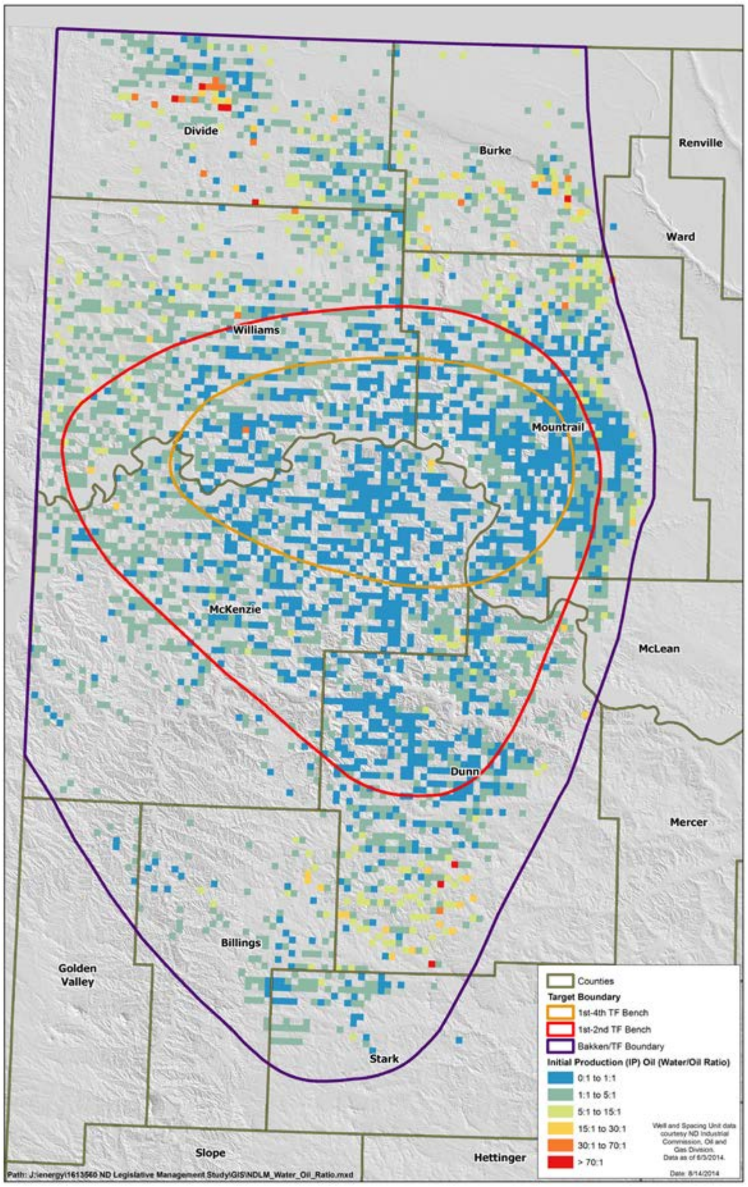

Figure 15: Bakken/Three Forks Wells (2007-14) Produced Water to Oil Ratio – Averaged by Section
Source: NDIC-DMR Oil and Gas Division; North Dakota State Water Commission; USGS National Elevation Dataset (Compilation and Analysis: KLJ)

regulatory compliance rather than poor geologic conditions. The USFS National Grasslands within the Bakken/Three Forks Drilling Target Boundary is approximately 1,085-square miles, or about nine percent of the drilling target area.

If the lack of drilling is indeed for regulatory reasons, then those policies could change during the five-year forecast period leading to similar oil and gas-related impacts seen in the rest of the Drilling Target Boundary area. Differences in spacing unit drilling densities can also be seen along the boundary of the Fort Berthold Reservation's Tribal lands. Those well density differences are likely not related to differences in the geology or production potential between Tribal lands, which are federally administered and adjacent private lands.

In addition to well costs, drilling decisions are impacted by oil prices, IPs, and location-specific added costs. The cost of producing, separating, storing, transporting and disposing of saltwater will be important during the study period.

Figure 15 illustrates the well IP ratio of oil to saltwater and then averaged by section. Areas dominated by cool colors are ideal, while areas dominated by warm colors are facing additional operating costs due to higher quantities of saltwater. Several noteworthy factors exist concerning the listed ratios. For instance, wells producing in the dark blue areas may produce zero to one barrel of saltwater for every barrel of oil produced, while wells producing in red areas would produce 70 or more barrels of saltwater for every barrel of oil produced. Additionally, for most wells the ratio of oil to water production becomes worse over the life of the well. The IP value shown would generally be the best or most oil-rich ratio seen over the life of the well.

Economic Analysis of the Bakken/Three Forks Formation Trends

- Drilling levels will remain stable over the five-year study period, with an adequate supply of potentially high producing spacing units left to drill.
- Drilling will likely remain concentrated in and around the 1st through 4th Three Forks Bench Drilling Target Boundary on Figure 5.
- If oil prices drop during the five-year period, areas of active drilling may contract to areas of high productivity potential Figure 12 (Appendix A).
- If oil prices increase during the five-year period, areas of active drilling may expand into areas of low productivity potential Figure 12 (Appendix A).
- Changes in federal policies may lead to greatly increased activities in areas that have seen little recent activity – primarily the National Grasslands Figure 14 (Appendix A).
- Areas with high produced water ratios will be avoided by some companies, and existing wells may be abandoned prematurely due to poor economics Figure 15 (Appendix A).
- There are no indications that would prevent Bakken/Three Forks production from increasing year-over-year during the five-year study period.

Global and Local Economic Analysis

Interesting market trends emerged during the third quarter of 2014 as the energy market reacted to news coming out of the Middle East and other oil exporting regions. Several significant news events and disruptions in major oil and gas exporting regions occurred over the last year, including the conflict between Ukraine and Russia, internal turmoil in Libya, the civil war in Syria, the spread of ISIS through Syria and much of Iraq, the ongoing unrest in Nigeria and Venezuela, and numerous other smaller incidents in the world's major oil and gas exporting regions. Previously any hint of disruption in those areas would cause a quick spike in crude oil prices. The year 2014 marked a lack of volatility and was instead characterized by relative price stability.

Market stability is credited to major increases in North American oil and gas production from unconventional sources such as the Bakken/Three Forks, the Marcellus, the Eagle Ford, the Permian Basin, and the Alberta oil sands. Greatly increased production and indications of increased long-term supplies from this stable and dependable part of the world appears to have had a calming effect on energy markets that traditionally have been reactive to news coming from oil producing regions. Within the US itself, there is far less dependence on oil imports from regions that are unstable, and while oil prices are historically relatively high – prices are also stable. The recent abundance of natural gas from unconventional sources has not only brought great long-term stability to natural gas supplies, but also lowered prices to a level that are the envy of much of the world. In fact, stable supplies and relatively low prices compared globally for natural gas in North America led many firms, both domestic and international, to create or move gas dependent chemical production facilities to the US.

While the large increase in North American production has had a stabilizing effect on natural gas and petroleum supplies and pricing, North Dakota oil and gas markets and prices will be impacted by the global market, global consumption, supplies, and prices for oil/petroleum products.

The Energy Information Administration's (EIA) Short-Term Energy Outlook (STEO), March 2014 report, shows global consumption of liquid fuels has risen at an annual rate of approximately 1.6 MMbd over the last five years, with 2013 averaging 90.4 MMbd (US Energy Information Administration, 2014b). That annual increase of approximately 1.6 MMbd brings into perspective that a bigger than "Bakken-size" new play or increased production of that level was needed to be found worldwide each year of the last five years in order to satisfy growing demand.

While world production has generally kept up with consumption, there have been periods of lagging production which has had an effect on maintaining relatively high pricing of liquid fuels. The August 2014 EIA STEO, projected more modest annual growth in demand globally of 1.1 MMbd in 2014 and 1.4 MMbd in 2015. EIA data shows demand for liquid fuels in the US and in the western hemisphere as a whole, has been relatively stable even slightly diminished over the last seven years, although US liquid fuels consumption is projected to grow by 90,000 bpd in 2015 (US Energy Information Administration, 2014a).

Most of the growth in the US is in the form of hydrocarbon gas liquids. Globally since 2007 liquid fuels demand growth has come principally from China and other emerging economies primarily Asian, which are expected to be the driving force behind increased consumption in the immediate future. Production increases to meet global consumption increases have and are projected to come almost entirely from North America. The EIA projects production will meet demand over the next two years with global consumption projected to be approximately 93.5 MMbd by the end of 2015.

The consumption of crude oil and petroleum products in the US peaked in August 2005, at 21.67 MMbd. By December of 2013 consumption had dropped to 19.1 MMbd. According to the August 2014 EIA-STEO, US liquids fuel consumption is projected to remain near the 19 MMbd mark through 2015 (US Energy Information Administration, 2014a).

Petroleum refining capacity in the US grew from about 16.5 MMbd in 2000 to about 17.9 MMbd in January 2014, even though both the number of refineries and the number of refining companies decreased over that time period. The EIA reported in July 2014 that US petroleum refineries had refined a record input of 16.8 MMbd (US Energy Information Administration, 2014c). The top five companies in 2013 hold 44 percent of the refining capacity in the US. The largest single refinery in the US is the Motiva refinery, Port Arthur, Texas, which is jointly owned by Shell and Saudi Refining.

Quantities of the top origins for US imported oil and petroleum products include imported crude that might be refined in the US, with some of the refined products being shipped back to the country of crude oil origin.

The top locations of US imported oil and petroleum products as reported in 2014 and 2008 are:

- In May 2014 imports totaled 9.38 MMbd. The top five countries of origin that month were:
  - Canada = 3.26 MMbd
  - Saudi Arabia = 1.24 MMbd
  - Mexico = 0.80 MMbd
  - Venezuela = 0.77 MMbd
  - Russia = 0.35 MMbd
- In December of 2008 imports totaled 12.61 MMbd. The top five countries of origin that month were:
  - Canada = 2.60 MMbd
  - Saudi Arabia = 1.47 MMbd
  - Mexico = 1.23 MMbd
  - Venezuela = 1.16 MMbd
  - Nigeria = 0.94 MMbd
- US Crude and Petroleum products imports (gross) peaked at 14,697,000 bpd in August 2006, and as of May 2014 equaled 9,380,000 bpd – a reduction of 5,317,000 bpd from the peak.
- US crude oil imports averaged 7.16 MMbd in May 2014. The top five countries of origin for US imported crude oil were (May 2014):
  - Canada = 2.74 MMbd
  - Saudi Arabia = 1.22 MMbd
  - Mexico = 0.75 MMbd
  - Venezuela = 0.72 MMbd
  - Iraq = 0.35 MMbd

According to the Council on Foreign Relations' publication Policy Innovation Memoranda 34, "The Case for Allowing U.S. Crude Oil Exports," since the 1970s, it has been illegal in the US to export domestically produced crude oil without a license from the US Department of Commerce. Over the past four decades, few licenses have been given and those given have been for small amounts (Council on Foreign Relations, 2013). In most cases licenses for the export of US crude have been given to countries that supply the US with refined petroleum products. While it is essentially illegal to export crude oil, there are no restrictions on the export of refined petroleum products derived from crude oil refined in US refineries – including either domestically or internationally sourced crude oil. Although the US has exported refined petroleum products and small amounts of crude oil for several decades, the recent development of oil production from unconventional resources such as the Bakken Formation, has jump-started the petroleum export business and with it the US economy. Beginning approximately in 2006, the export of refined petroleum products and small amounts of crude from the US grew steadily from about 1 MMbpd to more than 4.1 MMbd, a more than four-fold increase in eight years (US Energy Information Administration, 2014d). Exports of US refined petroleum products have gone mainly to Mexico, Canada, and other Western Hemisphere countries (US Congressional Research Service, 2012).

As US refiners are both reaping the rewards of a plentiful and relatively discounted domestic crude oil supply, and also realizing the domestic crude oil supply will continue for decades. Refinery capacity is being expanded, new refineries built, and refineries reconfigured to better process light, sweet crudes instead of the heavier and more sour grades that were previously deemed to be the best long-term sources. At the same time, many producers hoping to increase the value of their produced crudes are pushing to overturn or modify the federal ban on the export of US produced crude. Removing the ban could have an energizing effect on production in the Bakken.

Importation of Russian crude oil and petroleum products dropped sharply in the final two months of 2013 to 265,000 bpd from an October 2013 total of 555,000 bpd, although it has since risen back to approximately 354,000 bpd as of May 2014. Russia in the most recent years, has been one of the top five countries of origin for net imports of crude oil and petroleum products to the US (US Energy Information Administration, 2014e).

The import of petroleum from Russia/Soviet Union was negligible prior to 2002, after which it generally increased reaching a recent high of 809,000 bpd in May of 2009 similar to the monthly production of Bakken oil in North Dakota in 2013 (US Energy Information Administration, 2014f). Russia has immense reserves of oil and gas within its borders and is currently exploring many of these using conventional drilling and completion techniques.

The introduction of western drilling and completion techniques in the pursuit of unconventional resources in Russia will almost certainly lead to recoverable reserve estimates that dwarf those of any other country. Just one basin in Russia the West Siberian Basin, which has been assessed by the US Geological Survey (USGS), is said to be “the largest petroleum basin in the world for petroleum volume.” The USGS reported that this one basin has total discovered, recoverable (conventional) oil and gas volumes of more than 360 billion barrels of oil equivalent (US Geological Survey, 2011). One can only imagine the size of reserves in this one basin if unconventional resources are assessed and eventually tapped using the modern drilling and completion methods that are being used in the Bakken/Three Forks. Of course whether or not western technology is shared with Russia, or if there will even be a western market for Russian oil and gas is currently a subject of some debate following Russia’s recent incursions into neighboring Ukraine. Energy aggressive China may be the ultimate beneficiary of Russia’s massive energy resources.

Production of crude oil including bitumen based in Canada is projected to increase by approximately 1 MMbd by 2018. In addition to firmly established production goals in the Western Canada Sedimentary Basin including the Alberta Basin there is the possibility of new production in Mexico over the next five years and beyond. After reaching a high of approximately 3.84 MMbd in 2004, production in Mexico has steadily plummeted to approximately 2.94 MMbd at the end of 2012 as production from the super-giant Cantarell oil field has been in decline. Oil production in Mexico has been controlled by the state-owned petroleum monopoly PEMEX, and foreign investment and advanced technologies have been kept out of play in Mexico. In December 2013 a new president was elected into power partially on the pledge to dismantle PEMEX’s 75-year old monopoly (Hussain, 2013). Subsequently there has been approval of reforms leading to potential foreign investment, due in great part to the high level of oil-related funding the national government has relied on. If foreign investment and technological expertise does come to Mexico, it could lead to a resurgence in Mexican oil production much of which will be exported to the US. In addition to off-shore, heavy oil production targets there are also unconventional resource targets that will likely be explored in Mexico. The Eagle Ford Formation in Mexico is a southern extension of the prolific Eagle Ford Formation (shale) in Texas. An analysis of unproved but technically recoverable shale oil resources in Mexico estimates that there may be more than 13 billion barrels of recoverable oil (US Energy Information Administration, 2013). While renewed foreign investment may stem the downturn in oil production in Mexico, it is unlikely that development of shale resources there will have much impact on production until toward the end of 2018.

The Bakken Formation is producing light, sweet crude with an API gravity range of 36 to 44 degrees (average 38-40), and a sulfur content of approximately 0.2 percent. Light crudes are easier to process and produce more high-value products like gasoline, diesel and aviation fuel than medium or heavy crudes. Light crudes have a gravity of 31.1 degrees up to about 55 degrees (higher API gravities indicate condensates), with the most valuable crudes worldwide falling in the range of 40 to 45 degrees API gravity. The amount of sulfur in crude oil, measured as a percentage, dictates whether the crude is considered sweet (<0.5 percent sulfur) or sour (>0.5 percent sulfur). Since sulfur is a contaminant and costly to remove, sweet crude is generally worth more than sour crude.

For pricing purposes, Bakken crude is generally measured against the properties of various competing benchmark crudes. Major benchmark crudes include:

» WTI = API gravity 39.6 and sulfur at 0.24 percent
» Brent Crude (Brent/North Sea) = API gravity 38.06 and sulfur at 0.37 percent
» Bonny Light (Nigeria) = API gravity 32.9 and sulfur at 0.16 percent
» Isthmus-34 Light (Mexico) = API gravity 33.74 degrees and sulfur at 1.45 percent
» Dubai Crude (Persian Gulf) = API gravity 31 degrees and sulfur at 2 percent
» OPEC Reference Basket (ORB) = API gravity 32.7 degrees and sulfur at 1.77 percent

In December 2013, the US imported approximately 7.75 million bpd of crude with various API grades. Looking at the country of origin for the US importation of crude oil similar to Bakken crude (>36 degrees API, sulfur <0.5 percent) from December 2013 EIA data, the following list of countries has been compiled:

» Algeria
» Angola
» Azerbaijan
» Canada
» Mexico
» Nigeria
» Norway
» Russia
» Thailand

Global and Local Economic Trends

- Growing oil demand will be balanced by energy efficiency and increased supply from the Canadian oil sands and global shale plays.
- Drilling in North Dakota will remain consistent throughout the study period as long as oil prices remain between $70-$100 2014 USD per barrel.
- Refining capacity for light, sweet crudes in the Gulf coast will be filled by production from the Permian Basin and the Eagle Ford shale plays, which will drive Bakken crude export to refineries on the east and west coast.
- Natural gas consumption will continue to increase as companies readily utilize natural gas and as exports of liquid natural gas increase.
- US sourced light, sweet crude may be approved for export during the course of the study period, but Bakken crude may experience significant pricing pressure/discounting prior to any approval.
- Global demand for crude oil will continue to increase at an annual rate of at least 1 MMbd throughout the study period.

Socio-Economic Effects of Oil and Gas Industry

Socio-Economic Analysis

A few years ago, stakeholders were just beginning to understand the long-term implication of shale oil development in the study area. As that understanding continually develops, questions are emerging about long-term growth implications as the state and local communities adjust to increasing permanent populations and permanent increases in demands for infrastructure and public services. Forecasted values for employment, housing needs and population potential were presented, and the implications for social, economic and fiscal impacts were discussed (Appendix B).

Employment Projections

Employment projections consist of three main components: direct employment in the oil and gas industry, secondary job creation and employment in other industries and sectors.

Oil and Gas Sector Employment

Industry employment shifts will occur as near-term increases are primarily due to slowly accumulating employment in oilfield service operations and steady to slightly declining employment in drilling and hydraulic fracturing operations (Figure 16). A continuation of those trends is expected beyond the 2014-2019 period, and long-term employment in the petroleum sector will increasingly become more of a function of the number of wells as long-term employment in drilling and hydraulic fracturing will continue to decline.

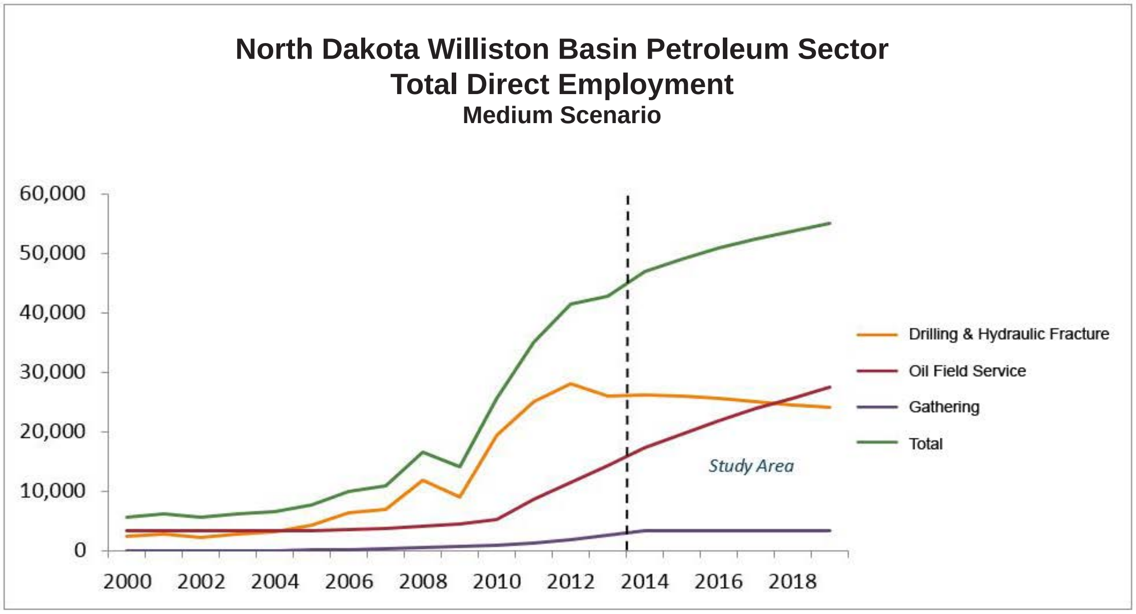

Figure 16: Direct Employment in Petroleum Industry, by Scenario, Williston Basin, North Dakota, 2000 through 2019
Source: NDSU Department of Agribusiness and Applied Economics

Current employment in the petroleum sector is expected to transition from one weighted heavily on a temporary oilfield development workforce to an industry that will be more dominated by long-term permanent employment. The industry is expected to retain a substantial portion of total employment related to temporary oilfield development jobs over the next five years (Figure 17).

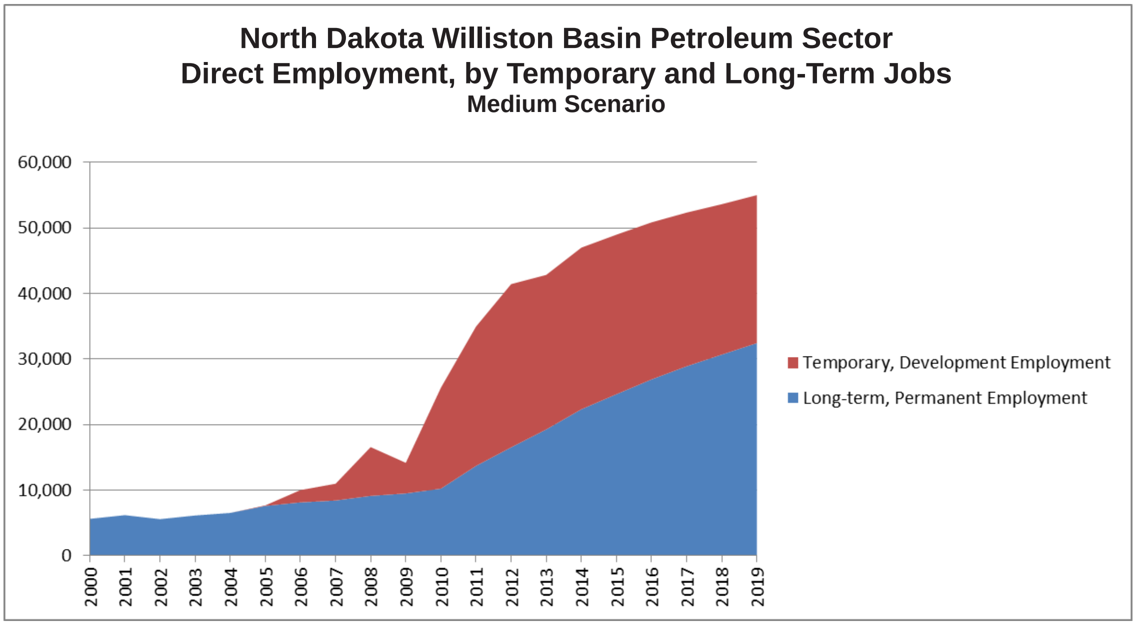

Figure 17: Long-term/Permanent and Temporary/Development Employment
Source: NDSU Department of Agribusiness and Applied Economics

Total Employment

Total employment in the Williston Basin includes changes in other industries and changes in direct and secondary employment associated with the petroleum sector. Because employment growth effects in the petroleum sector differ throughout the study area, total employment in the North Dakota portion of the Williston Basin was modeled on a regional basis. State Planning Regions 1, 2 and 8, which correspond with the trade areas of Dickinson, Minot and Williston, provided the geographic scope for employment modeling. Separate estimates of total employment were developed for each region.

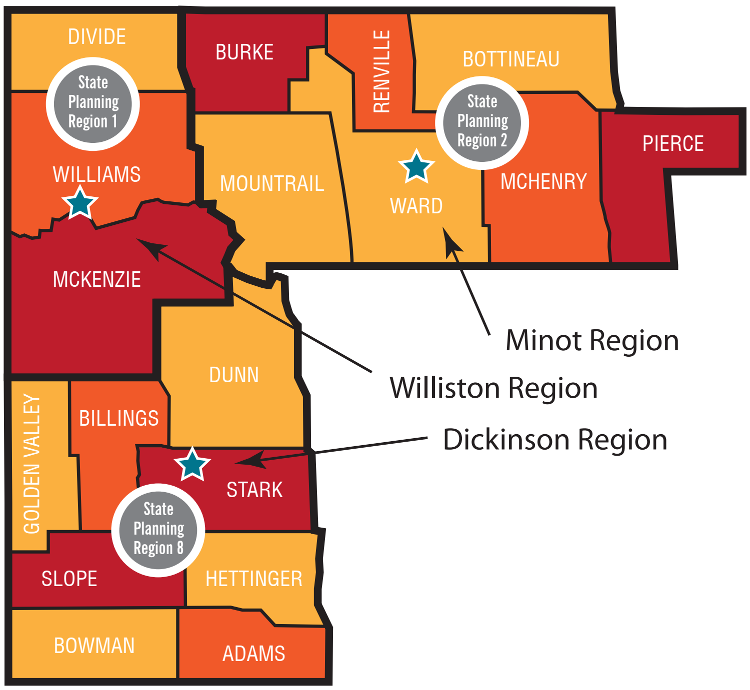

Figure 18: State Planning Regions, Williston Basin, North Dakota
Source: NDSU Department of Agribusiness and Applied Economics

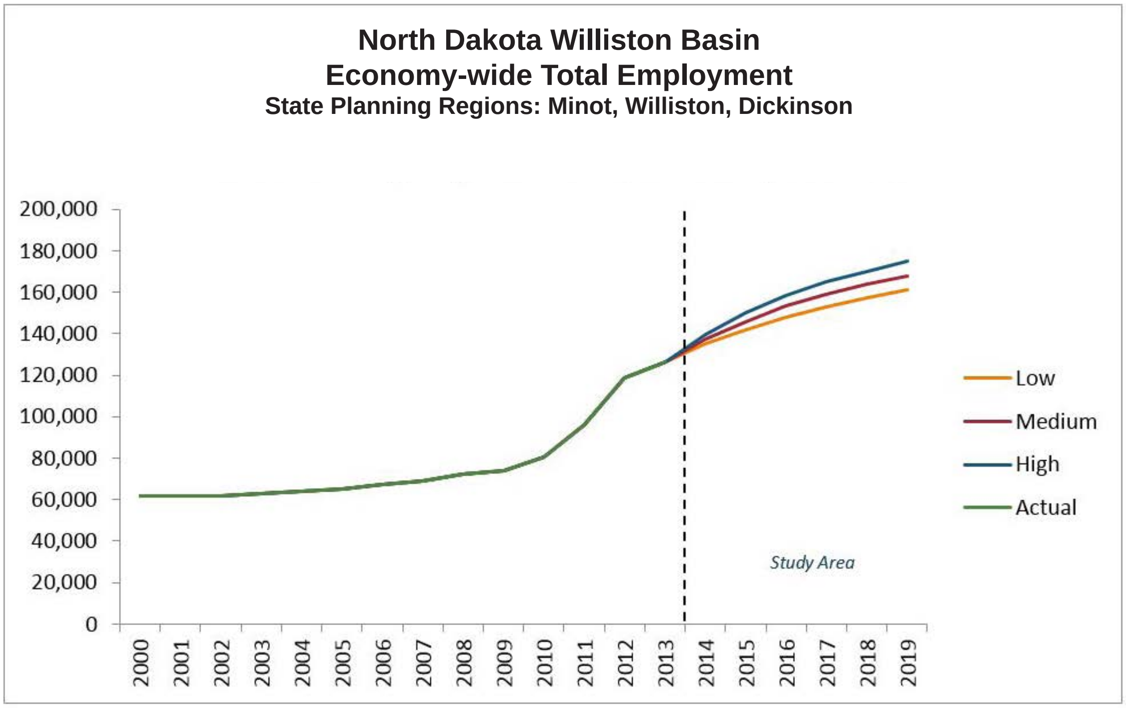

Figure 19: Total Employment, by Scenario, North Dakota Williston Basin, 2000–2019
Source: NDSU Department of Agribusiness and Applied Economics

Williston Region - Total Employment

Williston region employment grew rapidly from 2010 through 2012. About mid-way through 2012, the push to secure leases subsided and the development pace decreased from approximately 213 rigs in June to 183 rigs in December 2012. The drop in rig counts in the last half of 2012 is largely responsible for the change in regional employment growth projections show employment in the region continuing to grow over the 2014 through 2019 period. (Figure 20).

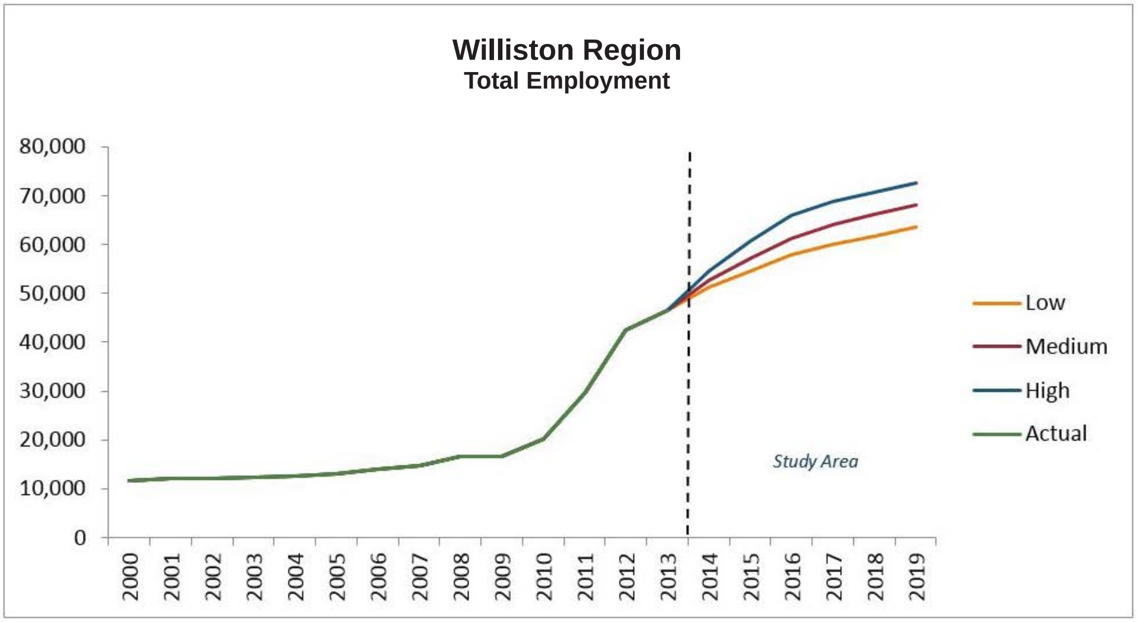

Figure 20: Total Employment, by Scenario, Williston Region, North Dakota, 2000-2019
Source: NDSU Department of Agribusiness and Applied Economics

The modeling system examines the amount of secondary employment added since 2011. Analysis of the Williston region's employment change from 2009-2014 shows that initially much of the employment growth was related to jobs in the oil and gas sector. While oil and gas industry employment continues to grow, the share of regional employment attributable to secondary jobs is growing. It is clear the economy is adding employment in retail trade, personal services, business services and commercial activity.

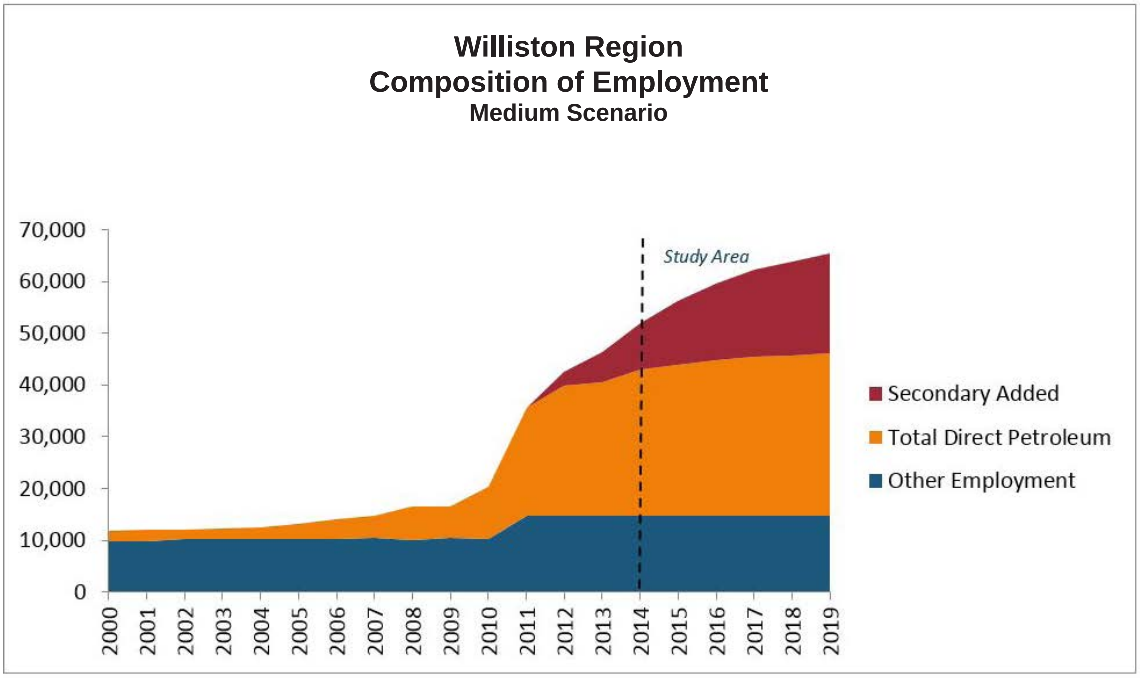

Figure 21: Composition of Total Regional Employment, Medium Scenario, Williston Region, North Dakota, 2000-2019
Source: NDSU Department of Agribusiness and Applied Economics

Minot Region - Total Employment

Employment in the Minot region is forecasted to expand over the 2014 through 2019 period (Figure 22). However, petroleum industry employment represents a smaller percentage of total regional employment, and the differences between the low, medium and high petroleum sector scenarios have less percentage change in total employment in the Minot region compared to the Williston or Dickinson regions.

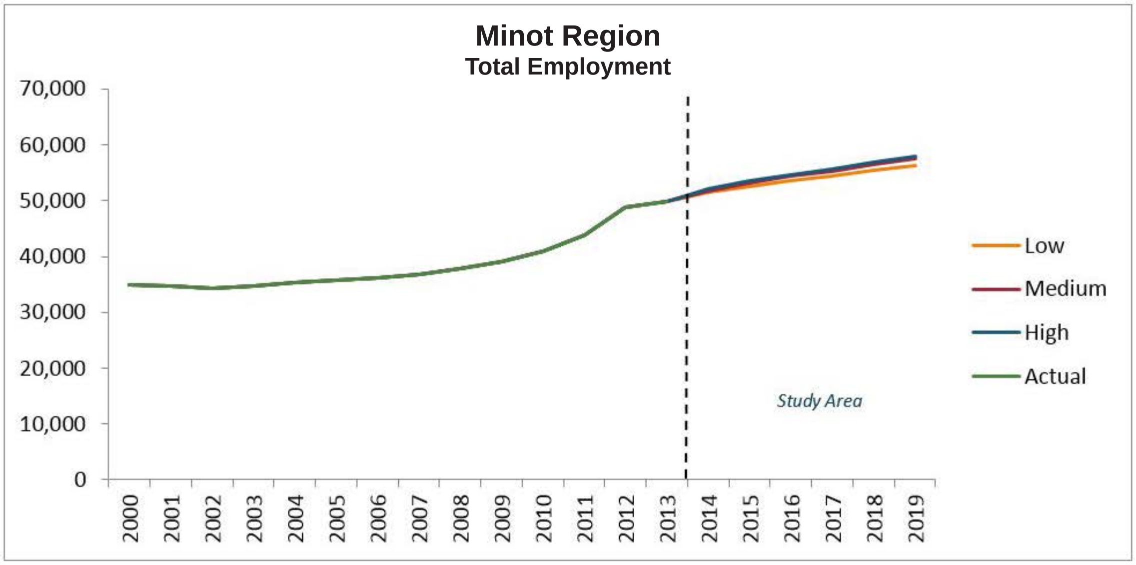

Figure 22: Total Employment, by Scenario, Minot Region, North Dakota, 2000-2019
Source: NDSU Department of Agribusiness and Applied Economics

Much like observations from the Williston and Dickinson regions, growth in oil and gas sector employment will continue over the projection period. Growth in secondary jobs also will continue over the projection period; however, the change in employment in other industries such as employment not associated with oil and gas industry in the Minot region will be a larger relative driver of employment change than found in the Williston and Dickinson regions.

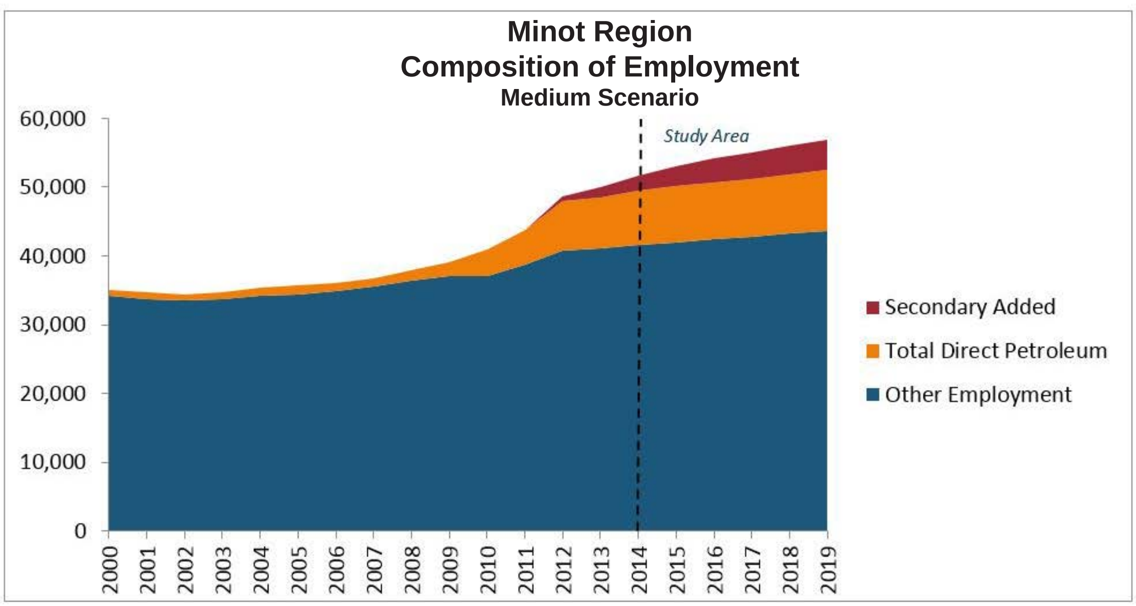

Figure 23: Composition of Total Regional Employment, Medium Scenario, Minot Region, North Dakota, 2000-2019
Source: NDSU Department of Agribusiness and Applied Economics

Dickinson Region - Total Employment

Dickinson region employment also is forecast to expand over the 2014 through 2019 period. The petroleum industry employment represents a smaller percentage of total regional employment than the Williston region, but a larger percentage than the Minot region. Similarly, the differences between the low, medium and high petroleum sector scenarios are less than for the Williston region but more than the Minot region.

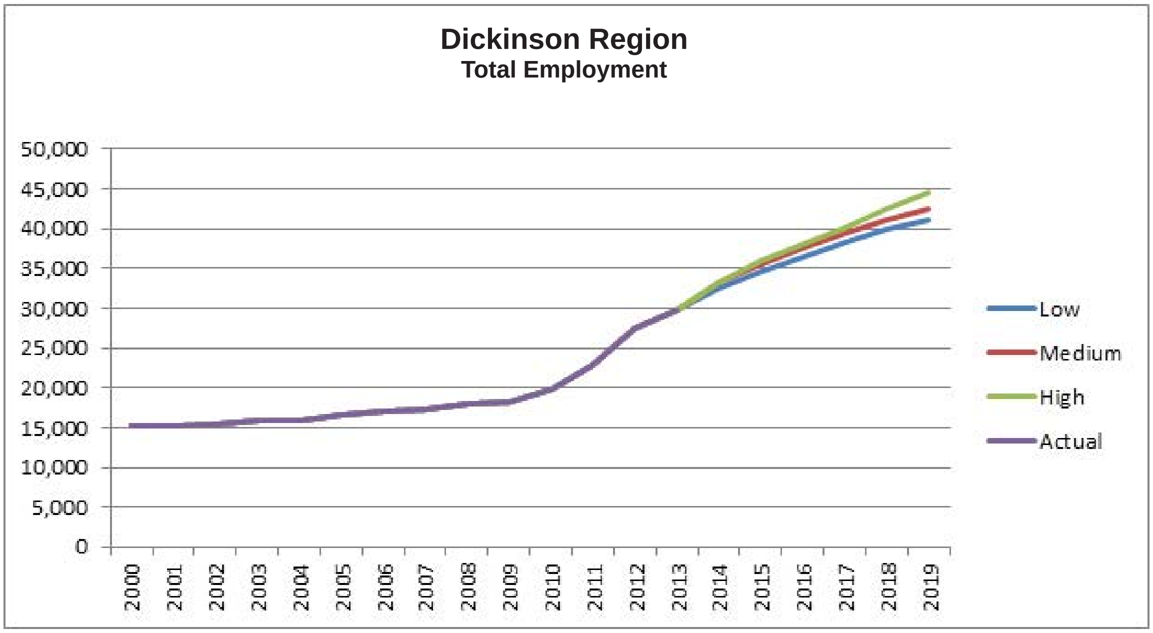

Figure 24: Total Employment, by Scenario, Dickinson Region, North Dakota, 2000-2019
Source: NDSU Department of Agribusiness and Applied Economics

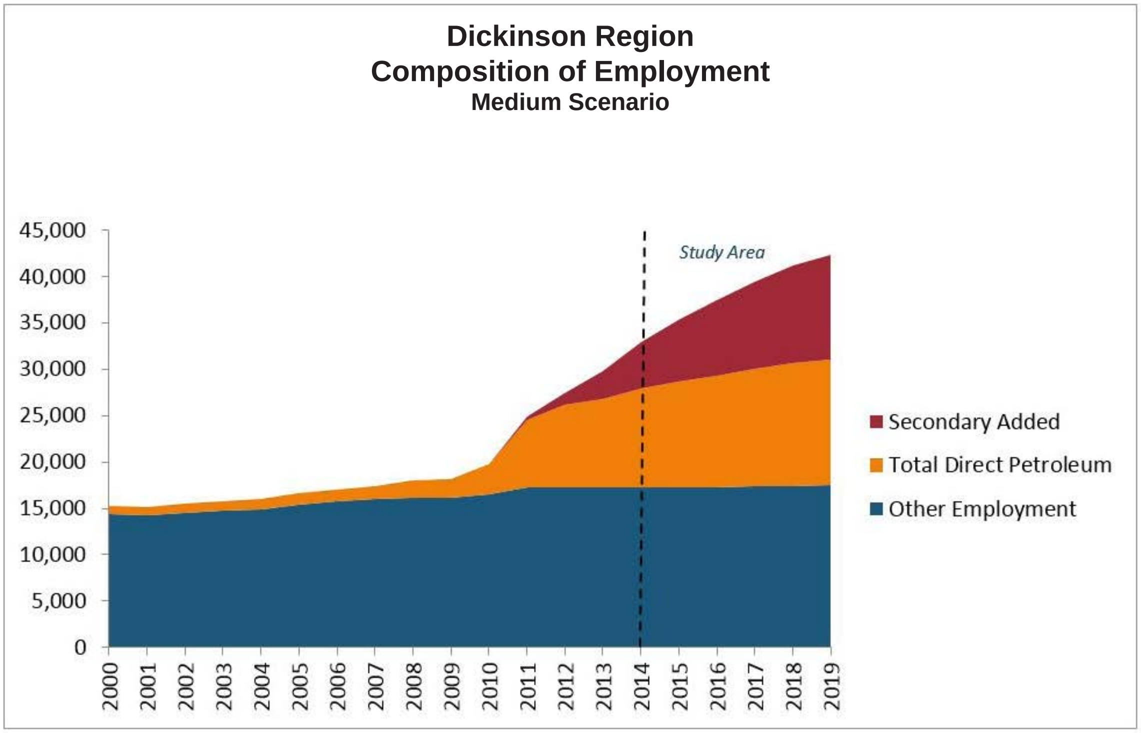

Figure 25: Composition of Total Regional Employment, Medium Scenario, Dickinson Region, North Dakota, 2000-2019
Source: NDSU Department of Agribusiness and Applied Economics

Housing Needs

Despite recent increases in housing supply, housing needs continue to grow as the region adds employment in the petroleum industry and as secondary jobs are added in the Williston Basin. Forecasted housing needs estimates are comprised of total housing requirements associated with employment, both long-term/permanent and temporary/development employment.

Because of the rate of energy development expansion in the Williston Basin and associated growth in employment, housing needs have exceeded permanent housing supply. Any previous excess supply of permanent housing has long been utilized, removing elasticity in the housing market. Williston Basin housing needs are now being met by a combination of permanent housing (houses, apartments), crew camps, campers, skid shacks, mobile homes, hotels and conditional use lodging such as living on the work site and lodging arrangements at business facilities.

The modeling process identifies the need for housing, but does not evaluate market demand for housing nor does it use data on how the current housing need is being met among all of the housing options.[5]

Williston Region - Housing Needs

Nearly paralleling changes in the Williston region's total employment, housing needs are forecasted to grow considerably in each scenario. Figure 26 shows the change in forecasted total housing need based on forecasted change in employment. In the medium scenario, total housing needs would increase by more than 15,000 units from 2014 through 2019.

Housing Needs[1], in Total Units, by Scenario, Williston Region, North Dakota, 2014-2019

Year	Low Scenario	Medium Scenario	High Scenario
2014	41,063	42,353	45,100
2015	44,397	46,622	50,737
2016	47,770	50,660	55,754
2017	50,173	53,778	59,190
2018	52,069	55,916	61,307
2019	54,071	58,037	63,420

[1] *Includes traditional permanent housing units (single family houses, apartments) and non-traditional temporary workforce accommodations (crew camps, conditional use permits).*

Figure 26: Housing Needs, in Total Units, by Scenario, Williston Region, North Dakota, 2014-2019
Source: NDSU Department of Agribusiness and Applied Economics

[5] *An important understanding of the model's output is that the model produces future population forecasts based on expected housing needs, not expected housing supply. Since future supply of housing is unknown, an implied assumption in the modeling process is that future rates of housing supply equal future rates of housing need. The best description of model output is therefore population potential – potential being defined as what the population is likely to be if housing needs are actually supplied and occupancy rates match historic conditions.*

Minot Region - Housing Needs

Growth in the Minot region's overall housing needs is nearly proportional to the changes in total employment. Figure 27 shows the change in total housing need based on forecasted change in employment. In the medium scenario, total housing needs increased by 6,430 units, or by 12 percent. The change in housing needs was not proportional to changes at the regional level.

Housing Needs, Total Units, by Scenario, Minot Region, North Dakota, 2014-2019			
Year	Low Scenario	Medium Scenario	High Scenario
2014	54,903	55,312	55,873
2015	56,170	56,796	57,458
2016	57,401	58,175	58,808
2017	58,361	59,334	59,934
2018	59,564	60,656	61,312
2019	60,476	61,741	62,372

Figure 27: Housing Needs, in Total Units, by Scenario, Minot Region, North Dakota, 2014-2019
Source: NDSU Department of Agribusiness and Applied Economics

Dickinson Region - Housing Needs

Dickinson region employment growth was forecasted to increase by about by 28 percent in the medium scenario over the 2014 to 2019 period, which translated into an increase in housing needs of about 9,500 units. Figure 28 shows the change in total housing need based on forecasted change in employment. Similar to the pattern observed in the Minot Region, the relative projected housing needs were not the same across all counties in the region.

Housing Needs, Total Units, by Scenario, Dickinson Region, North Dakota, 2014-2019			
Year	Low Scenario	Medium Scenario	High Scenario
2014	31,908	32,439	33,311
2015	34,358	35,111	36,117
2016	36,560	37,408	38,467
2017	38,549	39,410	40,672
2018	40,406	41,140	42,921
2019	41,573	42,606	45,016

Figure 28: Housing Needs, in Total Units, by Scenario, Dickinson Region, North Dakota, 2014-2019
Source: NDSU Department of Agribusiness and Applied Economics

Population Forecasts

The study area lacks a good baseline population estimate because the US Census only reports a measure of permanent population. The 2010 Census figures undoubtedly underestimated the study area's overall population. Incorporating the population not counted by the Census into an estimate of service population is critical for communities, businesses and government planning activities. Even though a portion of the service population includes residents of other states, while in the Williston Basin, they still use and require services, both public and private.

Sensitivity analysis revealed population forecasts are responsive to both a change in housing units and occupancy rates. Small changes in either component resulted in noticeable swings in population. A better understanding of workforce characteristics, current housing supply and communities' ability to address future housing needs is needed to refine population projections.[6]

If future housing is not provided at a level approaching the forecasted values, population will be less than estimated for this study. Workers will find it difficult to bring family members to the state, or difficult to start families. Accordingly, the region's population will be skewed towards unaccompanied working adults without spouses and dependents. Communities are assumed to be willing and able to supply housing at levels that meet projected needs. Some communities may be more or less inclined or able to supply housing, but on a regional level, the model assumes that housing supply will meet housing needs.

Williston Region - Population

The Williston region total population potential was estimated in each of the three scenarios over the 2014-2019 period (Figure 29). Growth in total population was largely driven by forecasted growth in regional employment over the study period. Average annual growth in population could be around six percent in the Williston region.

The Williston region was estimated to have a total population potential around 97,000 at the end of 2014 in the medium scenario, which includes permanent residents, shift workers, seasonal construction workers and dependents and spouses of workers living in non-permanent lodging arrangements. The total population potential in 2019 was estimated to be around 130,000 for the Williston region, assuming housing is supplied and occupancy rates remain valid (Figure 30).

[6] NDIC has funded a study to examine employment patterns, housing preferences, and general characteristics and attitudes of workers in the North Dakota oil and gas industry. It is anticipated that insights from the study may improve the ability to estimate population thresholds and forecast future population change. Preliminary results of that study are expected near the end of 2014. For more information, contact Dr. Hodur (nancy.hodur@ndsu.edu) or Dean Bangsund (d.bangsund@ndsu.edu).

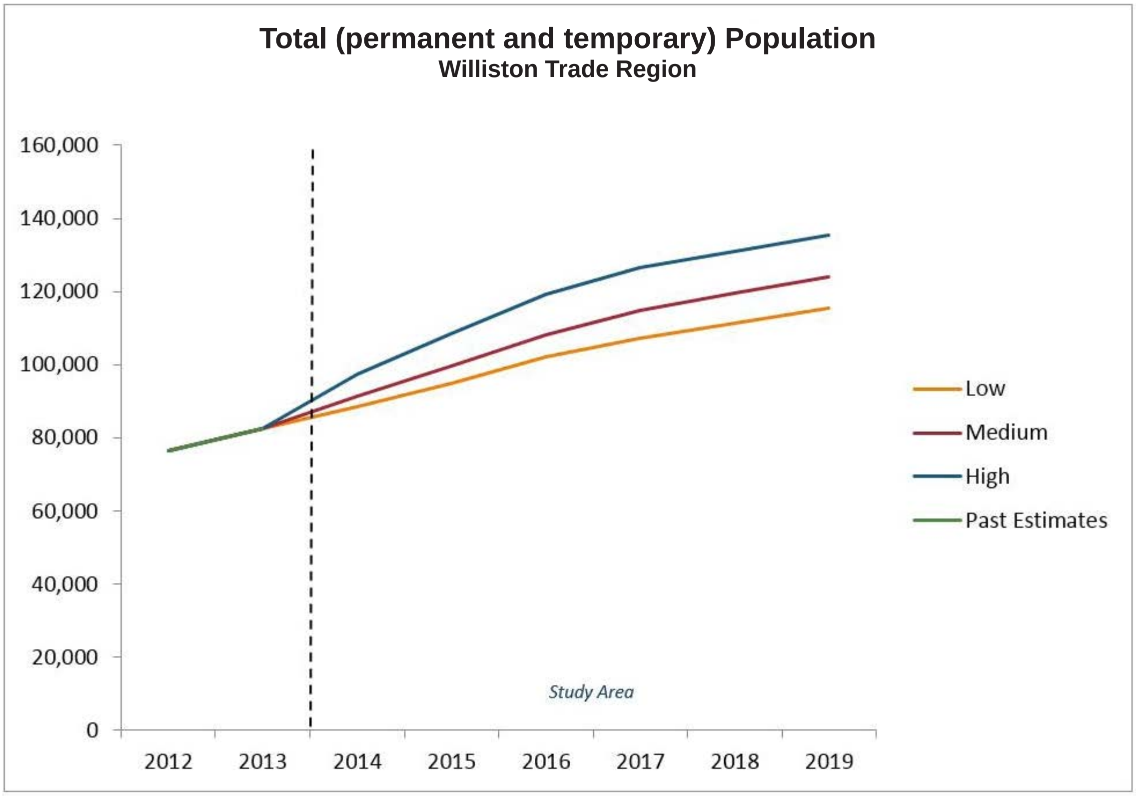

Figure 29: Total Permanent and Temporary Population, Williston Trade Region, North Dakota, 2010-2019
Source: NDSU Department of Agribusiness and Applied Economics

Population Potential, by Scenario, Williston Region, North Dakota, 2014-2019			
Year	**Low Scenario**	**Medium Scenario**	**High Scenario**
2014	93,857	96,806	103,085
2015	100,461	105,497	114,808
2016	108,093	114,633	126,161
2017	113,532	121,689	133,935
2018	117,822	126,526	138,726
2019	122,352	131,325	143,506
Average Annual Change	**5.5%**	**6.3%**	**6.9%**

Figure 30: Population Potential, by Scenario, Williston Region, North Dakota, 2014-2019
Source: NDSU Department of Agribusiness and Applied Economics

Minot Region - Population

The Minot region total population potential was estimated to grow in each of the three scenarios over the 2014-2019 period (Figure 31). Growth in total population potential was largely driven by forecasted growth in regional employment over the period, although the relative difference in population among the scenarios is smaller in the Minot region than in the other regions. Average annual growth in population could be around two percent in the Minot region.

The Minot region was estimated to have a total population potential around 126,700 at the end of 2014 in the medium scenario, which includes permanent residents, shift workers, seasonal construction workers and dependents and spouses of workers living in non-permanent lodging arrangements. The total population potential in 2019 was estimated to be around 140,000 for the Minot region, assuming housing is supplied and occupancy rates remain valid (Figure 32).

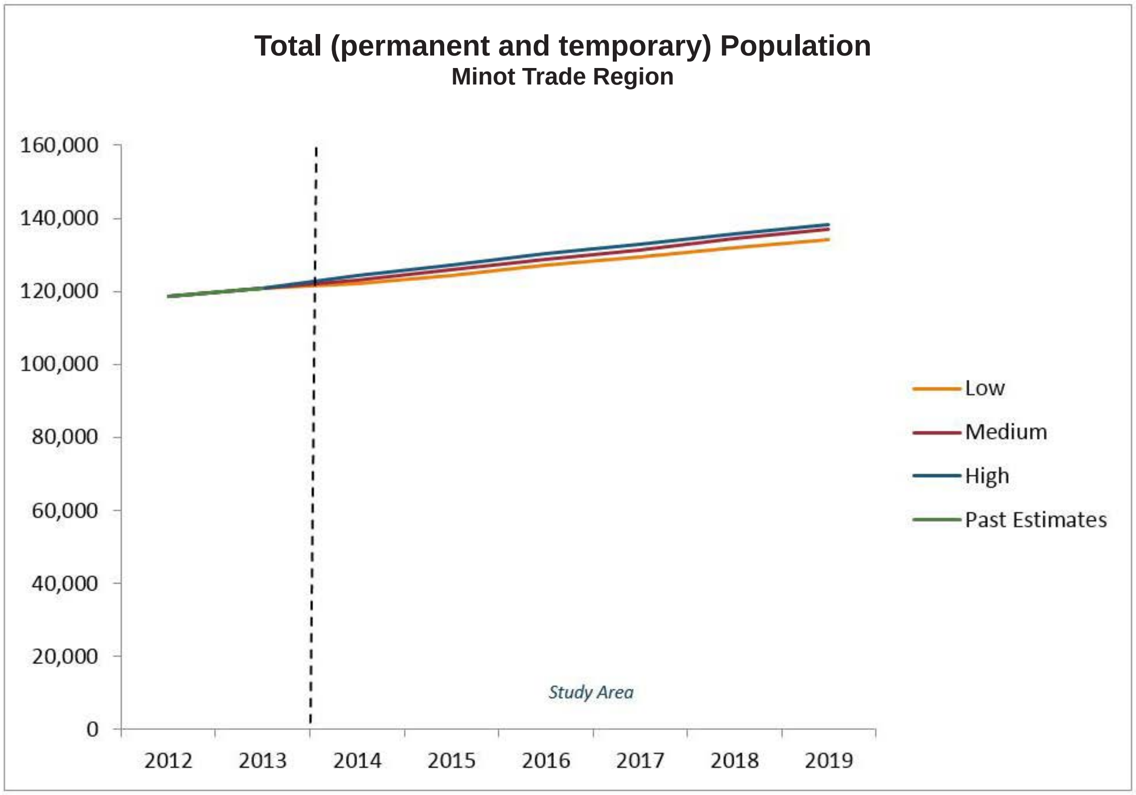

Figure 31: Total Permanent and Temporary Population, Minot Trade Region, North Dakota, 2010-2019
Source: NDSU Department of Agribusiness and Applied Economics

Population Potential, by Scenario, Minot Region, North Dakota, 2014-2019			
Year	Low Scenario	Medium Scenario	High Scenario
2014	125,763	126,699	127,985
2015	127,780	129,204	130,711
2016	130,608	132,370	133,810
2017	132,821	135,036	136,402
2018	135,588	138,075	139,568
2019	137,694	140,574	142,010
Average Annual Change	**1.8%**	**2.0%**	**2.1%**

Figure 32: Population Potential, by Scenario, Minot Region, North Dakota, 2014-2019
Source: NDSU Department of Agribusiness and Applied Economics

Dickinson Region - Population

The Dickinson region total population potential was estimated to grow in each of the three scenarios over the 2014-2019 period (Figure 33). The relative difference in population among the scenarios was larger in the Dickinson region than in the Minot region, but lower than growth potential forecasted in the Williston region. Average annual growth in population could be around five percent in the Dickinson region.

The Dickinson region was estimated to have a total population potential around 60,000 at the end of 2014 in the medium scenario, which includes permanent residents, shift workers, seasonal construction workers and dependents and spouses of workers living in non-permanent lodging arrangements (Figure 34). The total population potential in 2019 was estimated to be around 77,000 for the Dickinson region, assuming housing is supplied and occupancy rates remain valid.

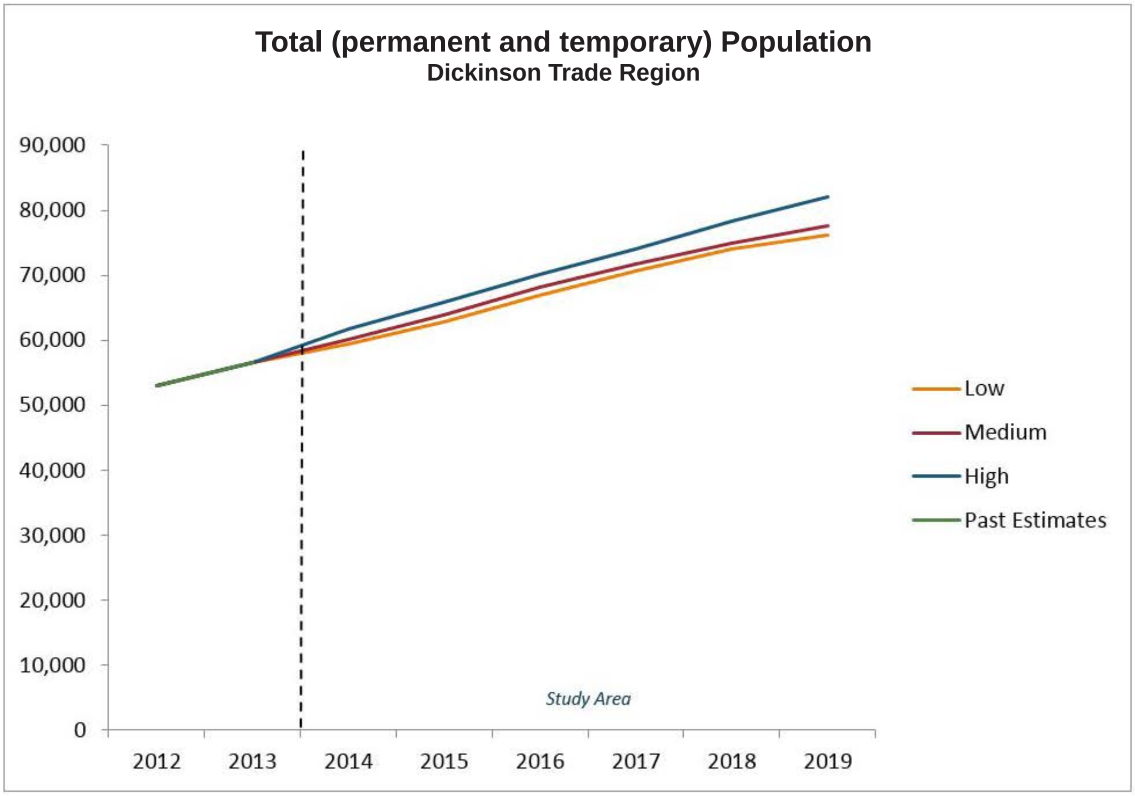

Figure 33: Total Permanent and Temporary Population, Dickinson Trade Region, North Dakota, 2010-2019
Source: NDSU Department of Agribusiness and Applied Economics

Population Potential, by Scenario, Dickinson Region, North Dakota, 2014-2019

Year	Low Scenario	Medium Scenario	High Scenario
2014	58,990	59,970	61,583
2015	62,409	63,778	65,605
2016	66,429	67,970	69,895
2017	70,063	71,629	73,922
2018	73,461	74,795	78,033
2019	75,605	77,483	81,866
Average Annual Change	**5.1%**	**5.3%**	**5.9%**

Figure 34: Population Potential, by Scenario, Dickinson Region, North Dakota, 2014-2019
Source: NDSU Department of Agribusiness and Applied Economics

Quality of Life Analysis

NDSU analyzed social and socio-economic issues surrounding rapid resource development. The synthesis of early work examining the consequences of rapid energy development in rural areas of the western US led to the “boomtown” model, or “social disruption hypothesis” (Jacquet and Kay 2014). Essentially, the modern understanding of rapid energy development effects – substantial population change, in-migration of workers, overwhelmed public services, degradation of quality-of-life factors, community planning and development challenges.

Current social impact assessments include both qualitative and quantitative measures of rapid natural resource development effects on small communities. The boomtown model of energy development and associated community impacts has been applied to recent unconventional shale gas and oil plays (Jacquet 2009; Macke and Gardner 2012; Doherty 2012).

The following is a synthesis of expectations and observations linked to rapid energy developments (Jacquet and Kay 2014; Putz et al. 2011; Macke and Gardner 2012; Doherty 2012; BBC Research and Consulting 2013).

- Development of natural resources requires a substantial labor force. Local labor supply is usually inadequate to fulfill those needs, resulting in an influx of new workers to an area.
- Local communities often experience a substantial increase in population relative to initial thresholds.
- As population increases, community resources and services become inadequate.
    - Housing supply is exhausted, leading to housing shortages and cost escalations.
    - Public utilities cannot keep up to increased demands.
    - Demands for medical, law enforcement, schools and other public/private services increase and can become overwhelmed.
    - Local governments experience lags from when impacts occur and when funding mechanisms provide revenues.
- Wage rates escalate, putting additional pressure on housing markets.
- Recreational amenities are inadequate for the increased population, and when combined with cost-of-living increases, quality of life attributes become compromised.
- Communities are unable to address growth in both scale and pace to satisfy new workforce. Workers become disenfranchised with living arrangements and are not engaged in the community.
- Workforce issues include high turnover and challenges recruiting and retaining qualified workers.
- The number and rates of crime increase in the region.

As of 2014, the study area was experiencing many of the classic boomtown challenges associated with rapid natural resource development. Unconventional energy developments, such as the Bakken have distinctly different localized effects as a result of the intensity and duration of oilfield development and operations compared to traditional energy developments.

Socio-Economics Trends

- Housing costs and cost-of-living will likely remain high during the first part of the study. Additional permanent and temporary housing supply will respond to the market and prices will begin to drop.
- Demands for medical, law enforcement, schools and other public/private services will remain high as population continues to increase. At the end of the study period population stabilization will lessen demand on public/private services.
- Community resources will continue to be strained throughout the study period until funding mechanisms are established to structure long-term financing for infrastructure and public services.

CO_2 Enhanced Oil Recovery Potential

KLJ

CO_2 Enhanced Oil Recovery Analysis

EERC conducted an evaluation of the near-term (2014–2019) potential for future oil production from CO_2 - EOR operations in the conventional oil fields of North Dakota. The baseline study focused on an examination of existing conventional oil fields currently undergoing secondary recovery operations and provides the basis for estimates of incremental oil production through the process of CO_2-based EOR. In addition, an evaluation of likely and potential near-term CO_2 sources was conducted. Screening of predetermined oil fields with the greatest CO_2 EOR potential combined with information pertaining to the proximal and likely CO_2 sources allowed identification of which fields are the most likely candidates to come online as tertiary producers within the study time window and beyond. The unconventional Bakken Formation was not evaluated as part of the CO_2 EOR study.

CO_2 EOR is a mature oil development tool that can be used to reinvigorate conventional oil fields currently under waterflood or to extract oil from tight reservoirs where waterflood would be ineffective (Gunter and Longworth, 2013). In conjunction with other nontraditional technologies such as horizontal drilling and hydraulic fracturing, CO_2 EOR should be recognized as part of a long-term production strategy for North Dakota oil fields.

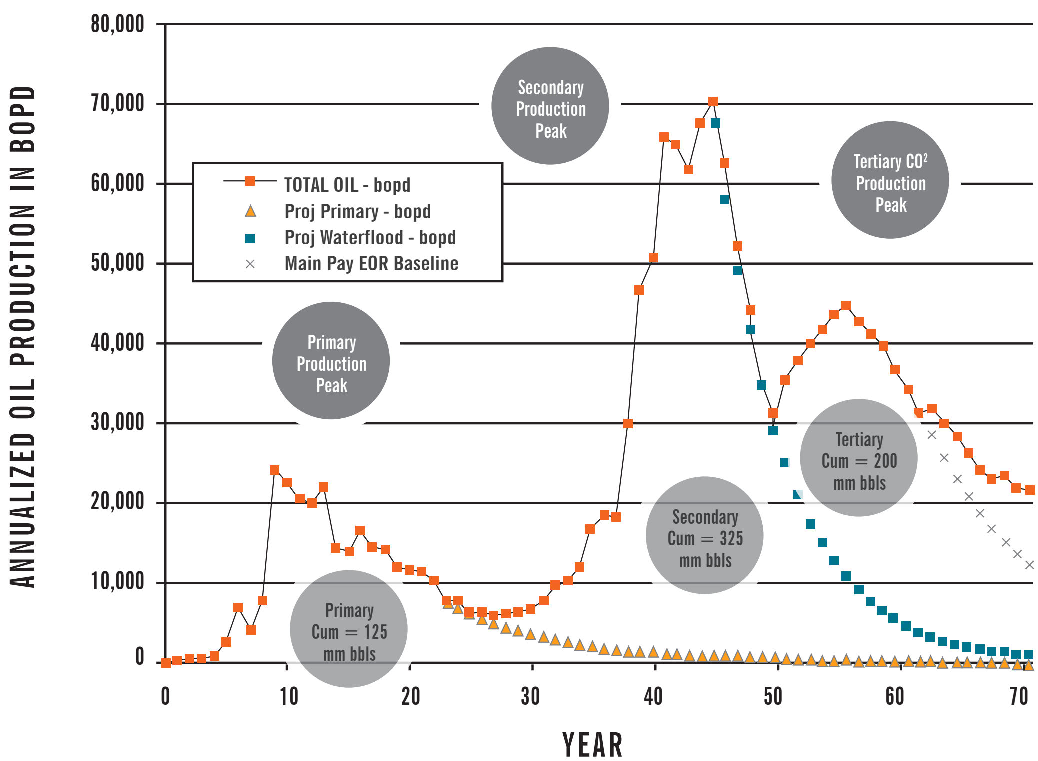

Figure 35: Example of field decline curve
Source: EERC

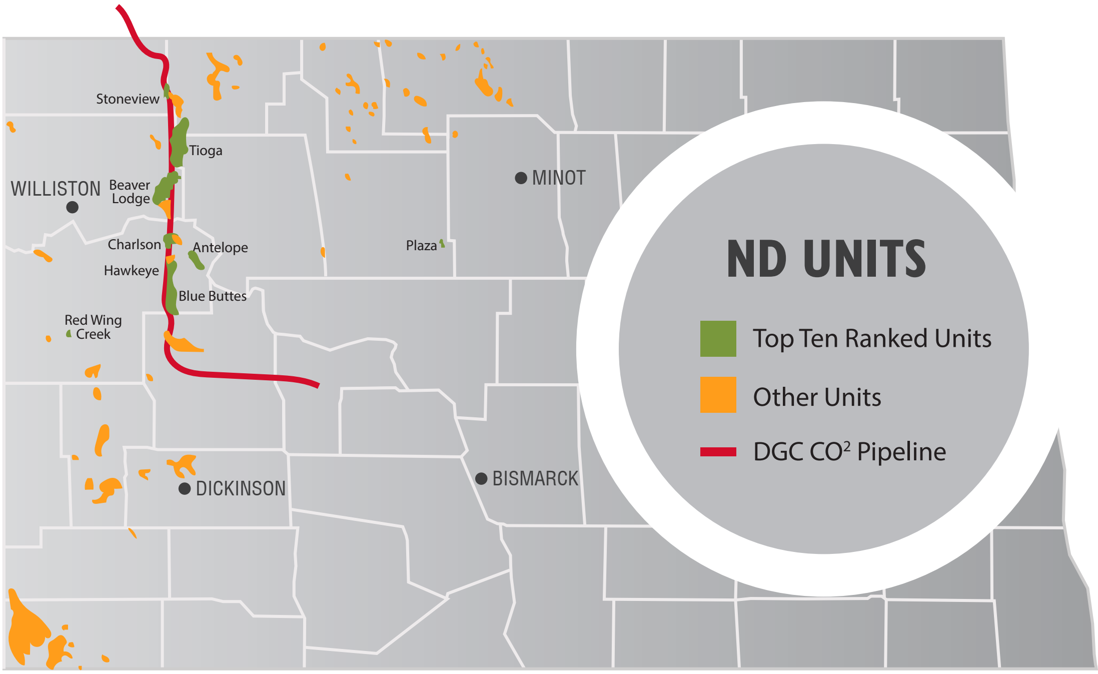

Figure 36: Geographical distribution of units showing the ten highest-ranked CO_2 EOR possible targets in North Dakota
Source: EERC

EERC's study emphasized factors that contribute to the economic success of new CO_2 floods in existing conventional oil units and uses those criteria to screen and rank North Dakota unitized fields to calculate the relative likelihood of each unit to produce oil as part of a CO_2 EOR operation within the next 5 years (before 2020). Screening criteria used include 1) oil production, 2) non-Bakken production, 3) nonterminated unit agreements, 4) waterflood initiated more than 10 years ago, and 5) passing previous screening studies. Scoring and ranking criteria for the 86 North Dakota units which met the screening criteria were 1) proximity to CO_2 supply pipeline, 2) estimated incremental oil, 3) well spacing, and 4) estimated required field maintenance. The top ten ranked units have a combined estimated recovery of between 82.7 million and 186.2 MMbbl, requiring between 13.9 million and 83.6 million tons (MMt) of CO_2. Total combined estimated recovery from the 86 ranked units studied is between 280 and 631 MMbbl, requiring between 47 and 283 MMt of CO_2.

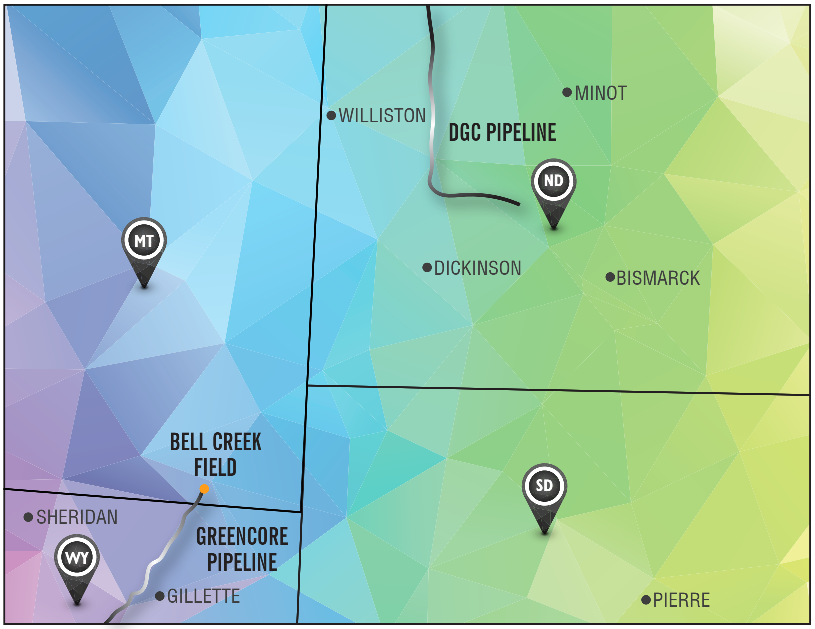

Figure 37: Overview map of EERC's study area showing CO_2 pipelines
Source: EERC

Two CO_2 pipelines may act as near-term sources for a North Dakota tertiary recovery. The CO_2 supply from the Dakota Gasification Company (DGC) is currently delivered via pipeline to the Weyburn–Midale CO_2 project in southeastern Saskatchewan, Canada. However, the Boundary Dam Power Plant near Estevan, Saskatchewan, is scheduled to begin delivering CO_2 to Saskatchewan oil fields in late 2014, which may enable DGC to begin marketing CO_2 to North Dakota oilfield operators. The Greencore pipeline, which currently terminates at the Bell Creek Field in southeastern Montana, is the next-closest existing source of CO_2 to North Dakota. Outside of a new CO_2 capture project at an existing power plant or other large-scale stationary CO_2 source, these two pipelines are the only large-scale near-term sources of CO_2 in the region.

There is significant opportunity in North Dakota to produce additional oil from well-established conventional oil fields through CO_2 EOR. The primary challenges in the near term are the acquisition of sufficient CO_2 and a focus by operators on this target and away from the attractiveness of the Bakken petroleum system. There is strong potential that, within the 5-year time frame which is the focus of this study, the Bakken petroleum system may develop into a CO_2 EOR target, which would have a large effect on these projections and would be expected to be a strong driver of CO_2 EOR in North Dakota.

CO_2 EOR Trend

Large potential incremental oil recovery is used as a screen for candidate fields, which is primarily based on high values of original oil in place and a successful water flood known as secondary recovery. Amortizing capital over small volumes of incremental oil is economically challenging; therefore, a strong economic drive is needed to initiate a CO_2 EOR flood. Only two substantial sources of CO_2 were identified that had high likelihood of availability within the next five years. Without a significant and sustained CO_2 supply, CO_2 EOR development in North Dakota cannot move forward.

Forecasted Baseline Assumptions

FORECASTED BASELINE ASSUMPTIONS

Baseline assumptions were established as a starting point for conducting the economic analysis of the Bakken/Three Forks Formation, socio-economic impacts of population and workforce growth and the potential of CO_2 EOR to increase North Dakota's overall oil production. The assumptions were drafted and validated during the second phase of the study.

The assumptions were formulated based on meetings with industry stakeholders and North Dakota government agencies in addition to data extracted from trade journals, reports, presentations and observed trends of working in the study area. The final baseline assumptions were influenced by variables such as: number of drilling rigs, producing wells in a specific region, technological advances in drilling and completion, development of oil, gas and water transportation infrastructure, environmental regulations, global markets and economics.

After gathering data and conversations with stakeholders, the assumptions were organized in five categories: global and local economics, infrastructure, environment, technology and socio-economics. Within each of the categories assumptions were defined that would have the greatest potential impact on oil and gas development in the study area during the 2014-2019 timeframe. During the validation process stakeholders confirmed if the assumptions would help sustain, increase or decrease 2014 production levels. Based on continual validation received from stakeholders and monitoring of data during phases three and four of the study, the assumptions were used to measure modeling accuracy.

The following is the baseline assumptions and variables incorporated into the study.

Global and Local Economics

- Drilling and Drilling Rigs
- Drilling and Rig Efficiency
- Total Well Counts/Extent of Development
- Well Completion
- Oil and Gas Pricing
- Bakken Crude Differential
- Natural Gas
- Global Market Infrastructure
- Surface Transportation
- Pipeline
- Rail
- Power
- Right-of-Way

Infrastructure

- Surface Transportation
- Pipeline
- Rail
- Power
- Right-of-Way

Environmental

- Water Resources
- Spills
- Oilfield Waste
- Air Quality-Natural Gas
- Hydraulic Fracturing
- Endangered Species

Technology

- Drilling and Hydraulic Fracturing Advancements
- Monitoring and Automation Implementation
- $C0_2$ Enhanced Oil Recovery in Conventional Oil Fields

Socio-Economic

- Labor
- Population
- Housing
- Community Attributes

GLOBAL AND LOCAL ECONOMICS

Baseline Assumptions

Drilling and Drilling Rigs

Description: Exploration and production efforts within the North Dakota portion of the Williston Basin study area are not geographically uniform. Drilling has trended toward fewer rig moves and increased utilization of walking drill rigs and multiple well pads. In 2012, the number of infill wells drilled exceeded the number of first wells in an exploration area drilled. Since 2012, infill drilling has more than doubled compared to first well drilling counts. Batch drilling and completions are becoming more commonplace, optimizing production. Workover rigs are needed to extend production.

Assumption: The number of wells per pad will vary from a single well in lower production areas to an average of six wells per pad and more than 12 at optimum locations. The rig count will stay the same or decrease slightly as drilling becomes more efficient. Infrastructure will be developed to accommodate 1.4-1.7 million barrels per day (MMBd). Leases in highly productive areas are secured, and most companies will not exhaust drilling of their assets in the next five years. Batch drilling and well completions, in combination with North Dakota weather patterns, are creating inconsistent production streams and new infrastructure needs.

Drilling and Rig Efficiency

Description: Technology and process improvements are rapidly reducing drilling, well completion time and overall costs. From 2012-2014, the cost to drill and hydraulically fracture a long horizontal well was reduced from about $12 million to $8 million. In that time frame, drilling had decreased 10 days, requiring 26 days or less to drill a new well. Oil drilling rigs in North Dakota drilled an average of more than 13 wells per rig in 2013. During the exploration phase, winter weather limitations, load limits, clearance restrictions, vehicle capacity limitations and rig-up and demobilization times significantly impacted rig efficiency. During the infill development phase, rig efficiency is primarily affected by pad drilling processes and technological advancements in drilling and completion.

Assumption: Technological advancements in unconventional oil and gas drilling will continue to reduce well drilling and development costs. Increased infill drilling will utilize current infrastructure and decrease surface impacts. The number of wells drilled per rig will likely increase approximately five percent each year during the study period.

Total Well Counts/Extent Of Development

Description: Recoverable oil and gas in the Bakken and Three Forks Formations make it the largest continuous oil accumulation in the US and accounts for more than half of all domestic-assessed tight oil resources. The second largest continuous oil accumulation in the US is the combined resources of the Eagle Ford Shale and Austin Chalk in Texas and Louisiana. Conservative government estimates state that 40,000 wells would be required to fully develop the Bakken and Three Forks Formations and could take 20 years or more to complete drilling activities and at least 50 years to produce all of the accessible oil, assuming 2014-2019 technology capabilities.

Assumption: The Three Forks Formation has several benches, or layers, economical for development. Overall physical size and resource potential of individual benches is being refined, implying near-term difficulty in predicting well counts for that formation. Total well counts in the North Dakota Williston Basin are projected to reach 40,000 to 120,000, based on the price of crude remaining between $70 to $100 (USD 2013) per barrel. Production companies will focus on increased drilling densities, exploring other benches and experimenting with drilling and completion methodologies that will result in higher production rates, increased timeline to fully develop assets and improved economics to develop a spacing unit.

Well Completion

Description: Weather, Logistical challenges, technical challenges and oil pricing has delayed well completion within the study area. The completion services industry operating in North Dakota is experimenting with a variety of perforation methods, variable numbers of hydraulic fracturing stages also referred to as batch drilling, and a variety of proppant types and quantities to maximize profitability of individual wells. Completion costs can vary widely depending on the methodologies and material quantities used, as well as by the impact of severe weather conditions. Producers are addressing some of the cost variables by reducing completion activities during winter weather conditions, which result in slowed and more costly completion efforts.

Assumption: Fluctuations in weather and oil prices affect the backlog of wells awaiting completion in the study area. Well completions will be managed separately from drilling in order to meet individual producers' business capital needs. Batch completions combined with harsh winters will drive cyclic development.

Oil and Gas Pricing

Description: The Bakken crude price at the wellhead closely follows WTI and maintains 75 to 80 percent of WTI futures. The price differential between WTI and Brent will average $10. Crude price at the wellhead remains steady at $75 (2013 USD) per barrel, which given decreasing well costs, is sufficient to attract investment capital in more productive Bakken areas. Breakeven points for individual wells will vary by company and area, with breakeven points generally estimated to be in the $30-$40 per barrel range in core play areas within Dunn, McKenzie, Mountrail and Williams County.

Assumption: Oil price will always cycle higher and lower due to global supply and demand contingent on consumption, weather and political actions. Growing oil demand will be balanced by energy efficiency and increased supply from the Canadian Oil Sands and global shale plays. Oil prices will not have a significant effect on drilling in North Dakota as long as $70 to $100 (2013 USD) per barrel is achieved at the wellhead. Oil and gas production is the only way to recover drilling costs, and capital investments will continue to be made as long as the economics support a return on capital. If the ROI rate capital decreases in the Bakken, operators will pursue other oil shale plays. If the cash flow is less than the investment cost due to commodity price, too large of a differential or declining production, capital will shift to different plays.

Bakken Crude Differential

Description: Bakken crude at the wellhead has a historical differential of 20 to 25 percent discount compared to WTI prices for a barrel of oil. The differential between Bakken Crude and WTI is generally due to the additional costs incurred to deliver oil to refineries, which are heavily concentrated along the US Gulf Coast and east and west coasts. It is also affected by the limited amount of US refining capacity configured to refine light, sweet crude. The majority of shale oil production is light and sweet, which while easier to refine than heavier grades of crude, must now compete for limited refining capacity. Most US refineries have configured to handle less costly heavier, sour crude from domestic sources and/or imported from Canada, the Middle East, Mexico and Venezuela — leaving refineries with less capacity and financial incentive to refine higher priced domestic-sourced light, sweet crude. Heavier crude is refined into many more products, purchased at lower costs and can be expanded into additional barrels of product as carbon chains are shortened.

Assumption: Lack of infrastructure, refinery capacity and export regulations will prevent an equilibrium between Bakken crude and WTI during the study period. The Bakken to WTI differential will average a spread of $5-$10. Refining capacity for light, sweet crudes in the Gulf coast will be filled by production from the Permian Basin and Eagle Ford shale plays, which will drive Bakken crude exports to refineries on the east and west coasts.

Natural Gas

Description: Natural gas pricing is largely determined by composition. Each natural gas source has varying quantities of methane, the most abundant product today, and natural gas liquids, which has historically demanded a higher premium. Currently, Bakken-derived gas is more valuable than natural gas from conventional dry-gas plays due to the higher ratio of natural gas liquids such as ethane, propane, butane, isobutane and pentanes. Natural gas can help drive the Bakken's vitality.

Assumption: Natural gas consumption will continue to increase substantially as transportation methods and electrical generation more readily utilize natural gas and as exports of liquid natural gas increase. The US will likely see natural gas (methane) prices rise as demand increases from business, residential and international sources. Liquefied Natural Gas (LNG) technologies will become economical in the Bakken, and companies will use this technology to develop more options that allow greater utilization of liquid-rich natural gas. Methane utilization for enhanced oil recovery will increase·

Global Market

Description: Global consumption of crude oil has risen at an annual rate of approximately 1.6 MMbd over the last five years. Oil demand in the US and the west as a whole has been relatively stable (even slightly diminished) over the last seven years, while China and other emerging economies (mostly Asian) are expected to be the driving force for increased consumption in the near future. Current global oil consumption equals approximately 91 MMbd, and US oil consumption at the beginning of 2014 equaled approximately 18.5 MMbd. US refining capacity is less than consumption at approximately 17.75 MMbd. Increased production of light, sweet crude in the US has already significantly reduced the US's importation of foreign-sourced light, sweet crude. Production increases to meet global consumption increases and are projected to come almost entirely from North America.

Since the 1970s, US laws state the export of domestically-produced crude oil is illegal without a license from the US Department of Commerce. In the intervening years, very few licenses have been granted and only for small amounts of allowable export. There are no restrictions on the export of refined petroleum products derived from crude oil refined in US refineries – including either domestically or internationally-sourced crude oil. Although the US has exported refined petroleum products (and small amounts of crude oil) for several decades, the recent development of oil production from unconventional resources, such as the Bakken Formation, has jump-started the petroleum export business and with it the US economy. Beginning in approximately 2006, the export of refined petroleum products (and small amounts of crude) from the US grew steadily from approximately 1 MMbd to over 4.4 MMbd in 2013.

Assumption: Global demand for crude oil will continue to increase at an annual rate of at least 1 MMbd over the study period. Production increases required to meet global consumption increases during 2014-2019 will come primarily from North America. US light, sweet crude will displace comparable imports in US refineries. US sourced light, sweet crude may be approved for export during the course of the study period; however, Bakken Crude may experience significant pricing pressure/discounting prior to that approval.

INFRASTRUCTURE

Baseline Assumptions

Surface Transportation

Description: Since 2007, North Dakota's traffic fatality rate has risen steeply, while the national average has fallen steadily over the past decade. Congestion on roadways and roads that were not built to handle heavy traffic, in addition to an out-of-state population unaccustomed to North Dakota travel conditions, has drastically impacted overall safety of local and county roads, highways and the interstate. Road durability, dust control, congestion and limited financial resources will continue to impact local and state governments, the oil, gas and agriculture industries, residents and tourists.

Assumption: Trucking and traffic levels will remain at 2014 levels, even though trucking demand per barrel of oil will decrease. Pipeline infrastructure build out will be the primary reason for continued truck traffic congestion. State investment in local and county roads, highways and the interstate will be necessary to ensure public safety. Federal transportation funding may decrease to the state of North Dakota during the study period.

Pipeline

Description: Four pipeline types are experiencing growth.

- Gas gathering – Instrumental and required; oil gathering – optional, easy to reach wells that are already connected, trucks can gather oil that pipelines have not reached and reduce spills, improve efficiency and reduce truck traffic.

- Produced water gathering for treatment or disposal – optional, pipelines used to reduce spills, improve efficiency and reduce truck traffic.
- Fresh water distribution for hydraulic fracturing – provide improved efficiency, accommodate centralized treatment and reduce truck traffic.
- Transmission pipelines are used to export oil from local tank farms to national markets.

Transmission pipeline capacity in 2014 was sufficient at 580,000 barrels per day. Export pipelines compete primarily with railroad shipping as producers utilize both export systems for market flexibility. New gathering systems reaching wells are essential in order to minimize flaring and address air quality concerns, minimize spill potential and reduce truck traffic. Easement acquisition for new pipeline corridors is the primary challenge during construction.

Assumption: Gathering pipeline infrastructure will continue to be built-out over the next five years at current rates. Exporting oil out-of-state will continue to be accomplished utilizing both rail and pipeline to maintain market flexibility. The amount of oil moved through pipelines is driven by the pricing differential between WTI and Brent. Southbound pipelines from the Bakken will be underutilized and difficult to fill to capacity.

Rail

Description: In 2013, rail transported 72 percent of Bakken Crude to market with the capacity to transport 965,000 barrels per day. Rail shipping costs $7 (2014 USD) more per barrel to transport by pipeline; however, producers utilize both rail and pipeline to capture higher market share based on fluctuating Bakken Crude pricing differentials. North Dakota's largest economy, agriculture, has been negatively impacted due to increased shipping of oil, record crop production and harsh winter weather. Recent high-profile train wrecks carrying Bakken Crude have prompted the attention of lawmakers and federal regulators.

Assumption: Rail will continue to export the majority of crude during the study period. Producers prefer to have flexibility in shipping options and will continue to utilize both rail and pipeline to maintain market flexibility. Midstream pipeline companies exporting Bakken Crude out-of-state will continue to compete heavily with Class I rail for contracts. Crude by rail shipping will not impact North Dakota's agricultural industry long-term unless agriculture production remains at 2013 levels and extreme winter weather impacts overall shipping. Stricter federal regulations implemented during the study period requiring new crude shipping cars and improvements to rail infrastructure will increase shipping costs.

Power

Description: The most recent electrical demand forecast, completed at the end of 2012, showed an approximate 200% increase in regional electrical demand between 2012 and 2032. The increase was due to oilfield development, and the most significant portion of growth was predicted to occur between 2012 and 2017. Regional electric cooperatives continue working to build the grid out to the loads. Many producers utilize temporary power sources, such as diesel and flare gas for fuel. Lack of power supply on the Fort Berthold Reservation presents significant concerns, as approximately one-third of the state's oil production comes from the Reservation.

Assumption: During the study period, 90 percent of electrical infrastructure will be built out and tied to the grid. Electrical demand will be supported by additional base load natural gas generation, natural gas distributed generation and completion of the Basin Electric Antelope Valley Station to the Neset 345kV transmission line. Electrical service will not restrict the growth of new facilities; however, right-of-way issues may slow development. Power supply has the potential to become an acute problem. Distributed generation for power supply will provide a solution on the Fort Berthold Reservation.

Right-of-Way

Description: In the study area, right-of-way costs have become significant as land owners are fatigued from the Bakken oil play's pace and longevity. Land owner frustration resulting from continual lack of remediation practices is compounded by industry buyouts where new owners of the current infrastructure do not assume liability of previous installation or uphold remediation agreements.

Assumption: Future infrastructure will be impacted by right-of-way costs. The pace and cost of right-of-way acquisition will slow infrastructure installation and will result in additional costs and inefficiencies. If the state and industry establish right-or-way corridors and remediation regulations, securing right-of-way will become more cost effective.

ENVIRONMENTAL

Baseline Assumptions

Water Resources

Description: Significant quantities of water are required for the well completion process. Water can come from fresh water sources or treatment and re-use of produced water. Currently, fresh water options, such as Lake Sakakawea, are the most economical for producers.

Assumption: There is an adequate water supply for producers without affecting other North Dakota industries such as agriculture. Technological advances will increase water re-use for production when economic. The state will increase regulations on fresh water and production water. Operational costs of obtaining, handling, treating and disposing water will increase.

Protection of Land and Natural Resources

Description: Spill prevention and mitigating impacts to the environment in addition to complying with state reporting requirements will continue throughout the study period. Saltwater spills are much more problematic than oil spills.

Assumption: As production increases the risk of spills increases. More spills will occur, some spills potentially more serious than others. North Dakota currently has 18,000 miles of pipeline, and by completion of the study North Dakota could have an additional 13,000 – 15,000 miles of pipeline (gas, oil, produced water and fresh water). Stricter regulations and fines will be implemented for saltwater and oil spills. Economic opportunity will accelerate new technologies to mitigate spills and clean up contaminated areas.

Oilfield Waste

Description: Hazardous substances are contained in some oil and gas industry waste that is created during development. Violations in 2014 related to improper disposal of Naturally Occurring Radioactive Materials (NORM) waste heightened awareness of the issues. The North Dakota Department of Health commissioned a study to assess the amount of NORM waste being generated from development activities, while also evaluating the state's waste disposal regulations.

Assumption: The North Dakota Department of Health will review and adjust, if necessary, the safe threshold for NORM waste disposal (as measured in picocuries per gram). Stricter regulations on illegal dumping will be enforced.

AIR QUALITY-NATURAL GAS

Description: Natural gas is flared for one of two reasons: either a well is not tied into a gas gathering system, or wells are tied-in but do not have the line/processing capacity to take product away from the location. On average, almost 30 percent of all natural gas is being flared in the Bakken. Oil and gas companies are currently responding to rules to capture gas at the wellhead immediately after well completion instead of flaring.

Assumption: Oil and gas companies will focus on reducing flaring to limits as outlined by 2014 NDIC Flaring Goals. Infill wells per pad may be limited to prevent exceeding natural gas emission limitations until infrastructure is in place to capture excess gas. Air emission triggers will be tripped, requiring emission reductions. EPA will have new regulatory actions specific to methane emissions in place by the end of the study period.

Hydraulic Fracturing

Description: EPA will continue to provide oversight, guidance and, where appropriate, rulemaking to protect potential impacts on drinking water and ground water due to hydraulic fracturing. The state has not waited for EPA to establish rules but rather has taken the lead to address concerns regarding water contamination and hydraulic fracturing.

Assumption: The state will continue to enforce rules pertaining to hydraulic fracturing. EPA will not stop hydraulic fracturing; however, new regulation requirements will continue to increase hydraulic fracturing costs.

Endangered Species

Description: Endangered and threatened species listed within the study area include the following: the black-footed ferret, interior least tern, gray wolf, pallid sturgeon, whooping crane and the piping plover. As of 2014, four additional species are proposed for listing within the study area, while the gray wolf is proposed for de-listing. The northern long-eared bat is proposed endangered, while the rufa red knot and Dakota skipper are proposed threatened. Designated critical habitat for the piping plover, as well as proposed critical habitat for the Dakota skipper, is also located within the study area. The USFWS will make a determination for each of these species within one year of each proposed rule. Two candidate species, Sprague's pipit and the greater sage grouse, were reviewed by USFWS in November 2013 and are precluded from listing in North Dakota. Surveys are required prior to construction to determine potential impacts to each species and its associated habitat. In the event a listed species or suitable habitat are present, actions are taken to avoid, mitigate or minimize impacts.

Assumption: The threatened and endangered species list will increase during the study period. Based on the life cycle and habitat requirements of newly listed species, additional mitigation techniques may be required and planning timelines extended. Oil and gas companies will prioritize infill wells and focus less on exploration.

TECHNOLOGY

Baseline Assumptions

Drilling and Hydraulic Fracturing Advancements

Description: Since 2008, oil and gas companies have made significant advances in penetrating multiple benches in the Williston Basin's Three Forks Formation. Drilling rigs are faster and more mobile, oil production has surpassed forecasts each year and the cost to drill and complete short and long horizontal wells has almost been reduced by 50 percent.

Assumption: Drilling, oil recovery and production technology advancement will start to slow as oil and gas companies will concentrate future advancements on labor efficiency. During the study period, implementation of automated system monitoring and controls will either reduce or transition a segment of the labor force. Robotic compact drilling rigs will require smaller crews, just as automated production systems will continue to reduce production personnel. Workforce will become more diversified instead of specialized.

Monitoring and Automation Implementation

Description: Process automation and instrumentation includes five segments: process automation, process instrumentation, process analyzer and flow compute and leakage detection system. The process automation and instrumentation market in the oil and gas industry are driven by the need to upgrade outdated oil and gas platforms and emphasize safety and security.

Assumption: Automation will likely be geared toward improving pipeline gathering and remotely controlled/monitored transportation systems. When full pipeline gathering systems operate with automation, all industry-related traffic will see significant reductions; however, as the field matures, maintenance traffic will increase. Wear and tear on the road system will decrease when heavy truck use is reduced. Automation will create additional demands for labor skilled in Information Technology. Operators will catch small problems before they become bigger, more costly problems, and gain enhanced production efficiencies.

Co_2 Enhanced Oil Recovery In Conventional Oilfields

Description: An increasing trend was observed in 2014 where oil and gas producers actively sought to develop tertiary recovery projects applicable in the near-term for conventional reservoirs within the Williston Basin and eventually for unconventional reservoirs such as the Bakken/Three Forks.

Assumption: Large potential incremental oil recovery is used as a screen for candidate fields, which is primarily based on high values of original oil in place and a successful water flood known as secondary recovery. Amortizing capital over small volumes of incremental oil is economically challenging; therefore, a strong economic drive is needed to initiate a CO_2 EOR flood. Only two substantial sources of CO_2 were identified that had high likelihood of availability within the next five years. Without a significant and sustained CO_2 supply, CO_2 EOR development in North Dakota cannot move forward.

SOCIO-ECONOMIC

Baseline Assumptions

Employment Projections

Description: Separate estimates are made for both employment related to development activities and oilfield service and maintenance activities. In the near term of the study timeline, the majority of industry employment will be associated with industry development activities, including the following: construction of gas, oil and water gathering systems, development of processing facilities and related infrastructure and well development (e.g., drilling and hydraulic fracturing activities). Batch drilling and completions in combination with North Dakota weather patterns are causing development to be more cyclical, creating more of a demand for labor associated with well completions in the spring, summer and fall and less demand in the winter.

Assumption: Permanent employment, defined as long-term jobs relative to oilfield life, will steadily grow as more wells are added. Uncertainty still remains as to what percentage of long-term jobs are held by individuals not likely to become North Dakota residents. The industry will continue to show labor efficiency improvements, both in terms of increased output per labor unit and in reductions in labor requirements for some activities. The total labor required to develop and operate wells will decrease. The response of secondary jobs created from primary oil and gas jobs has been clearly identified as lagging within western North Dakota. Despite high housing costs, wage rate inflation and labor shortages, secondary job growth is expected to expand over the next five years. Labor requirements will continue to be cyclic, requiring higher levels of temporary labor in the spring, summer and fall and lower levels during the winter months.

Population

Description: Employment growth is the driving metric in population estimates. Population forecasts for the study area represent population potential. Current modeling practices include: assuming the region is willing and able to add housing equal to the projected level of demand; population potential is linked to historic occupancy rates that suggest future households in permanent housing have similar characteristics to traditional households in the region; and temporary residents are modeled to have similar household characteristics as permanent residents.

Assumption: Population will continue to be comprised of a growing number of permanent residents (i.e., analogous to census-based estimates) and a steady number of temporary or non-permanent residents. It remains necessary to generate two types of population: permanent population based on permanent employment and temporary population based on temporary employment related to oilfield development activities. The two estimates combine to produce a service population, which includes individuals that work in North Dakota and live elsewhere.

Housing

Description: Housing demand utilizes separate estimates for permanent housing, based on permanent employment, and temporary housing, based on temporary employment related to oilfield development activities. Housing constraints will remain in the study area. Housing stock has increased and hotel rooms are now available for short-term stays. Overly inflated housing prices for both single family and multi-family units continues to affect the likelihood of stabilizing the study area's permanent workforce and overall livelihood.

Assumption: Housing demand will continue to grow as the permanent workforce and related secondary job response continues to expand. Because housing demand still is greater than housing supply, near-term projections require nearly proportional changes in housing demand for proportional changes in employment.

It will be necessary to describe housing demand using separate estimates for permanent housing, based on permanent employment, and temporary housing, based on temporary employment related to oilfield development activities.

Community Attributes

Description: For decades, most communities in the Williston Basin dealt with strategies for the provision of public goods and services in a climate of population stagnation or decline. Shale oil development has dramatically changed the region's economic landscape, and now communities must manage unprecedented growth. Current development has focused largely on addressing infrastructure to provide basic needs, such as housing, roads and water and sewer capacity. While communities struggle to meet those basic needs, long-term development also must incorporate the provision of public goods and services, community amenities and other factors that address the region's quality of life attributes.

Assumption: In addition to the most basic public goods and services, community viability, livability and other quality of life attributes are important elements of development for a regional economy undergoing tremendous growth. Williston Basin residents will desire the same quality of life attributes generally found in other areas of the state and country. Recreational opportunities, access to health care and day care, quality education, arts, shopping, adequate law enforcement and emergency services and mitigation of noise, congestion and crime all must be incorporated into community development. Continued development that does not incorporate quality of life amenities will contribute to workforce turnover, affect workforce recruitment and reinforce negative assumptions that the state is a place to work but not live.

VARIABLES

The following is a list of qualified variables tracked for modeling and forecasting purposes:

Fairly Consistent

- US refining capacity
- ND county regulations
- ND state regulations
- Federal regulations
- Number of unitized fields (non-Bakken)
- Number of wells operating in unitized fields (non-Bakken)
- Oil production from the unitized fields (non-Bakken)
- Drilling activity on the unitized fields (non-Bakken)
- Estimated DGC CO_2 pipeline capacity
- North Dakota gas rig counts

Variable

- US crude oil importation
- ND pipeline export capacity
- ND gas processing plant numbers/ capacities
- ND Crude-By-Rail (CBR) export capacity
- Bakken crude market destinations
- Oil rig counts on federal surface ownership
- ND oil counties electric power supply
- ND Bakken/Three Forks “hotspots”
- ND landowner issues
- ND Bakken/Three Forks “multi-pay regions”

Highly Variable

- ND oil production
- ND number of producing oil wells
- ND oil wells awaiting completion
- ND gas production
- Gas hub prices
- Williston Basin sweet crude price
- Brent crude versus West Texas Intermediate (WTI) price differential
- Williston Basin sweet crude versus WTI price differential
- Competing shale basin rig counts
- North Dakota Energy related rig counts
- North Dakota oil rig counts
- North Dakota horizontal rig counts
- North Dakota non-Bakken/Three Forks rig counts
- ND weekly oil/gas permits
- ND weekly oil/gas well spuds
- ND ratio of leasehold/wildcat versus infill oil wells (statewide and by county and reservation)
- ND Bakken/Three Forks well costs
- Competing shale basin well costs

Glossary and References

GLOSSARY

A	
Automation	Use of control systems to reduce need for human work.
B	
Batch Drilling	A process that involves drilling and completing the same section of multiple wells before proceeding to the subsequent section, and is a more efficient approach than drilling the wells separately.
Bitumen	A naturally occurring viscous mixture, mainly of hydrocarbons heavier than pentane, that may contain sulphur compounds. In its natural occurring viscous state, it is not recoverable at a commercial rate through a well.
bopd	Barrels of oil per day.
Brent North Sea Market Pricing	Currently recognized international oil price benchmark. Generally compared to WTI for benchmarking.
Brine	Water containing salts in solution, such as sodium, calcium or bromides. Brine is commonly produced along with oil.
C	
CO_2 EOR	C02 Enhanced Oil Recovery. Involves flooding oil reservoirs with injected CO_2 to displace oil contained within. At the start of a well's lifecycle, oil will flow freely via the pressure gradient, known as primary production. CO_2 EOR recovers 5 percent to 40 percent of the oil originally in place.
Constraints	Limitations or restrictions.
D	
Demobilization	The process of disassembling drilling equipment or taking equipment and crews off-site.
DGC	Dakota Gasification Company.
Direct Employment	Employment which is directly working for companies involved with the development of oil and gas production and operations.
E	
Eagle Ford Shale Play	The Eagle Ford Shale (EFS) is possibly the largest single economic development in the history of the state of Texas and ranks as the largest oil and gas development in the world based on capital invested.
EOR	Enhanced Oil Recovery.

G	
GIS	Geographic Information System.
H	
Hydraulic Fracturing	The forcing open of fissures in subterranean rocks by introducing liquid and proppants, at high pressure, to extract oil or gas.
I	
Incremental Oil	Oil that would not have been recovered without a new pressure maintenance scheme, improved pressure maintenance scheme or other enhanced oil recovery scheme methods, but does not include heavy oil.
Infill Wells	Wells that are on previously held leases.
M	
Mcf	Thousand cubic feet.
MMBd	Million Barrels Per Day.
MMbbL	One million barrels.
MMt	Million Metric Tons.
Multi-Well Pad	A pad which has more than one well.
P	
Pad Drilling	Drilling Multiple Wells on a Single Pad.
Permian Basin	An oil-and-gas-producing area located in west Texas and the adjoining area of southeastern New Mexico.
Produced Water	Water trapped in underground formations that is brought to the surface during oil and gas exploration and production.
Proppant	Particles, typically sand or ceramic, mixed with fracturing fluid to hold fractures open after a hydraulic fracturing process.
R	
Rig Moves	The use of commercial trucks to dismantle a drilling rig and associated equipment such as cat walks, pipe tubes and tables, compressors, fuel tanks and shacks, and to transport the drilling rig and associated equipment from one location to another location, where it will be reassembled.
S	
Secondary Employment	Employment generated indirectly from oil and gas development such as retail and commercial businesses necessary to support the population influx.
Secondary Recovery	Extraction of oil or natural gas under artificially induced pressure after the natural flow has ceased.

T	
Tertiary Recovery	Traditionally, the third stage of hydrocarbon production, comprising recovery methods that follow water flooding or pressure maintenance. The principal tertiary recovery techniques used are thermal methods, gas injection and chemical flooding.
U	
US EIA	US Energy Information Administration.
Unconventional Reservoirs	Unconventional reservoirs are essentially any reservoir that requires special recovery operations outside the conventional operating practices. Unconventional reservoirs include reservoirs such as tight-gas sands, gas and oil shale, coalbed methane, heavy oil and tar sands, and gas-hydrate deposits.
USD	US Dollar.
W	
WTI	West Texas Intermediate, also known as Texas light sweet, is a grade of crude oil used as a benchmark in oil pricing.

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Appendix A

Maps

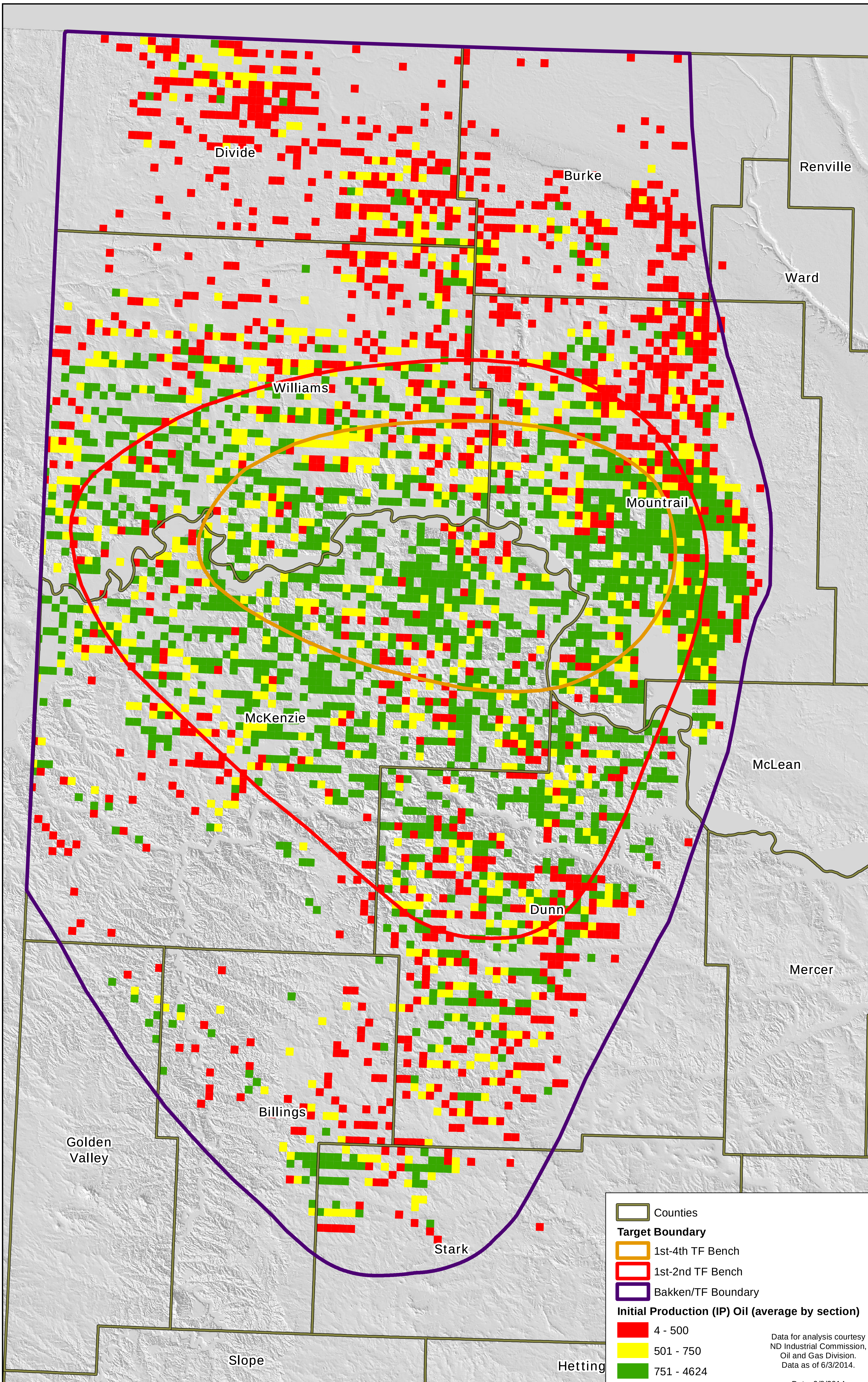

Figure 11: Average IP (in barrels) for Bakken/Three Forks Wells (2007-14) by Section

Source: NDIC-DMR Oil and Gas Division; North Dakota State Water Commission; USGS National Elevation Dataset (Compilation and Analysis: KLJ)

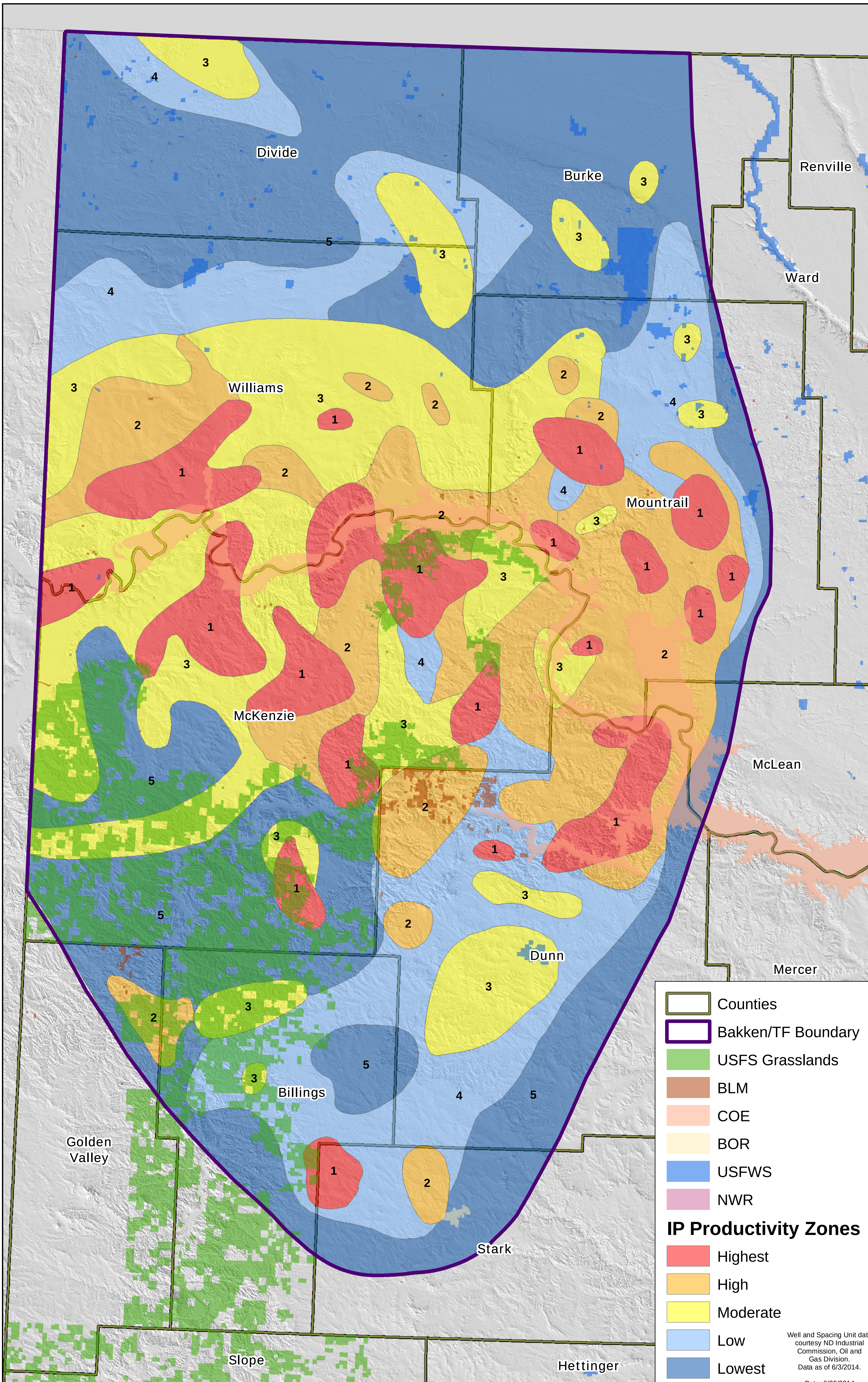

Figure 12: Areas of Relative Bakken/Three Forks Oil Productivity – IP Potential
Source: NDIC-DMR Oil and Gas Division; USFS; US BLM Montana State Office; COE; BOR; USFWS; NWR; North Dakota State Water Commission; USGS National Elevation Dataset (Compilation and Analysis: KLJ)

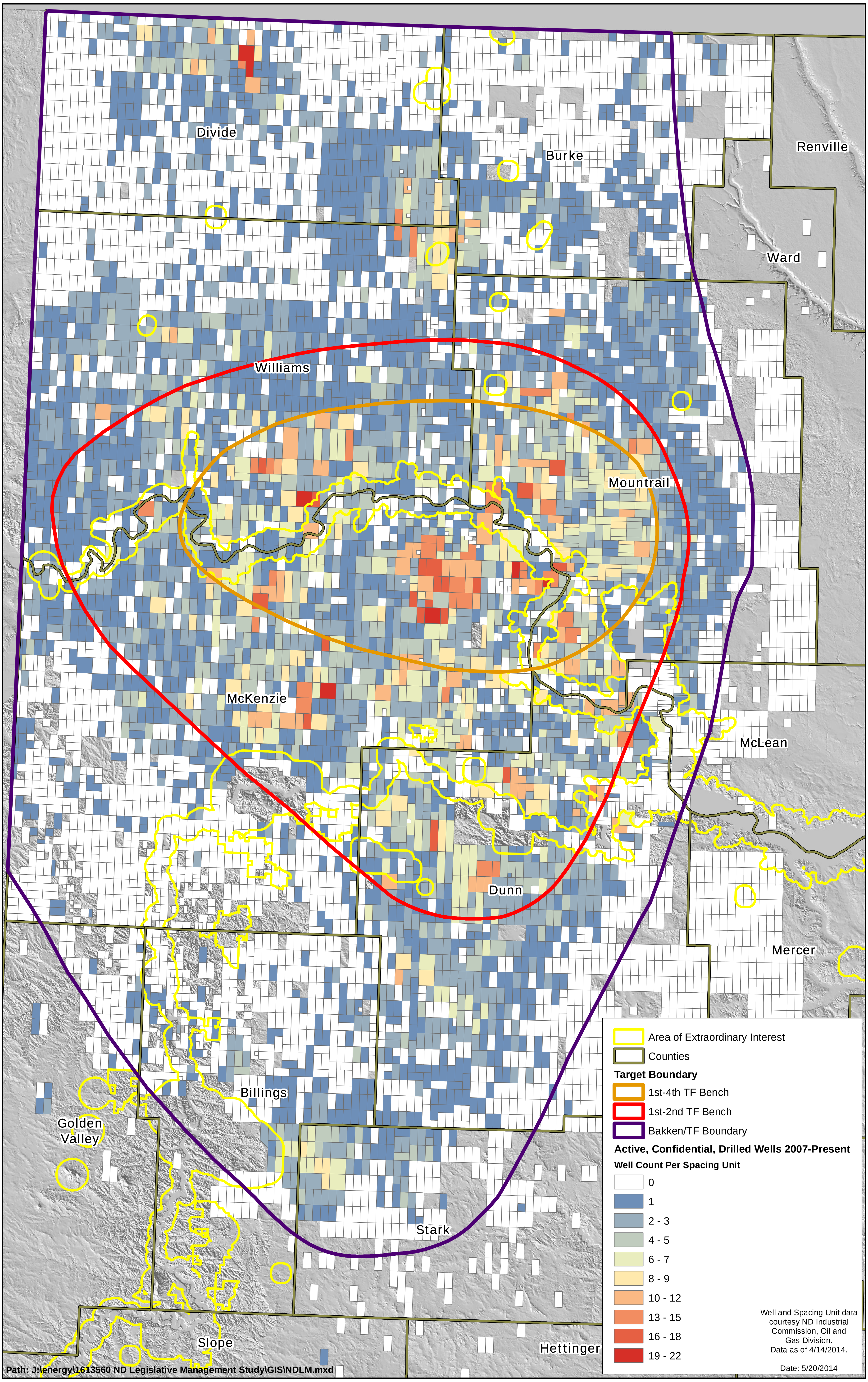

Figure 13: Bakken/Three Forks Well Drilling Intensity (2007-14) by Spacing Unit
Source: NDIC-DMR Oil and Gas Division; North Dakota State Water Commission; USGS National Elevation Dataset (Compilation and Analysis: KLJ)

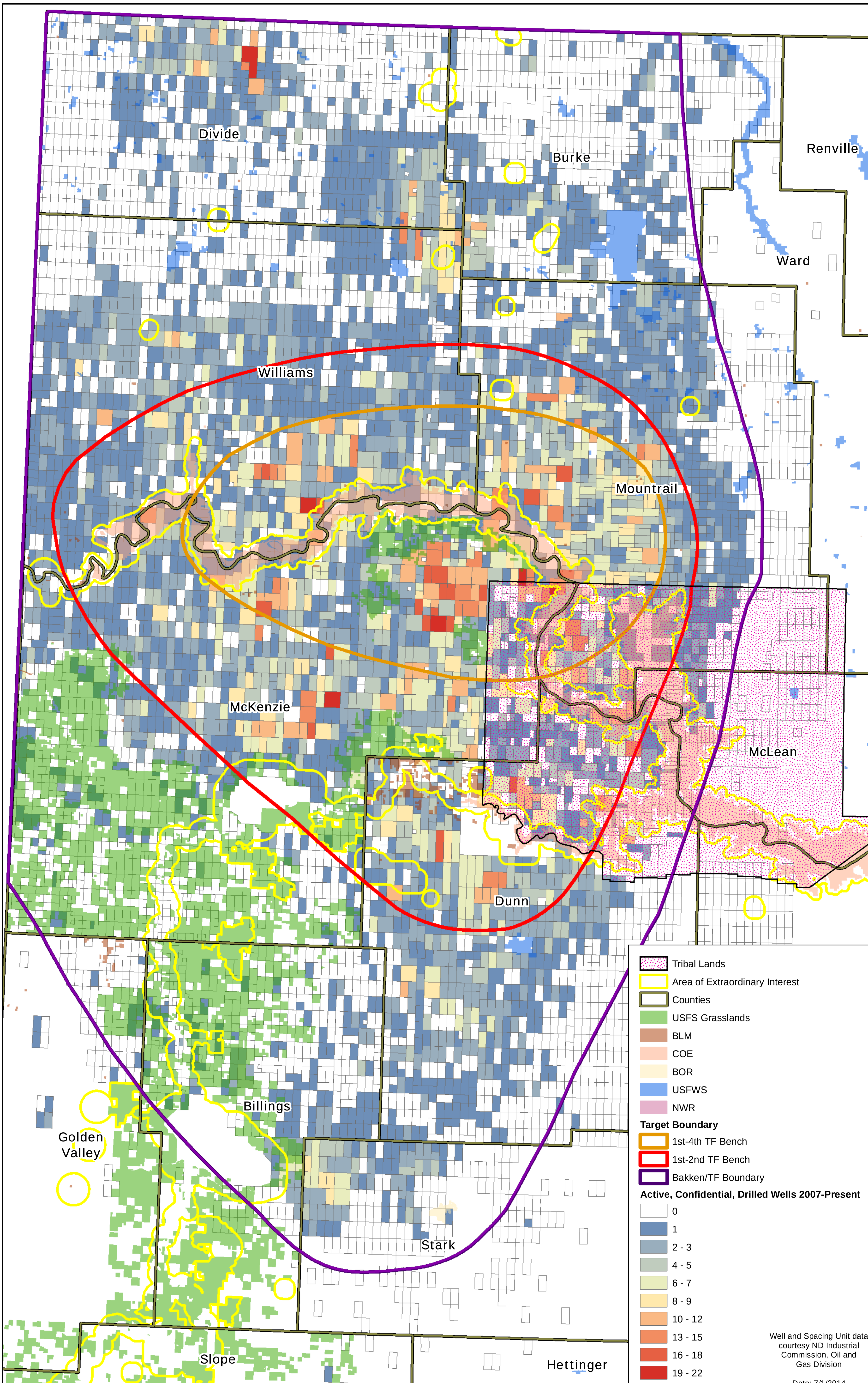

Figure 14: Bakken/Three Forks Well Drilling Intensity (2007-14) by Spacing Unit – With Select Federal Jurisdictions
Source: NDIC-DMR Oil and Gas Division; USFS; US BLM Montana State Office; COE; BOR; USFWS; NWR; North Dakota State Water Commission (Compilation and Analysis: KLJ)

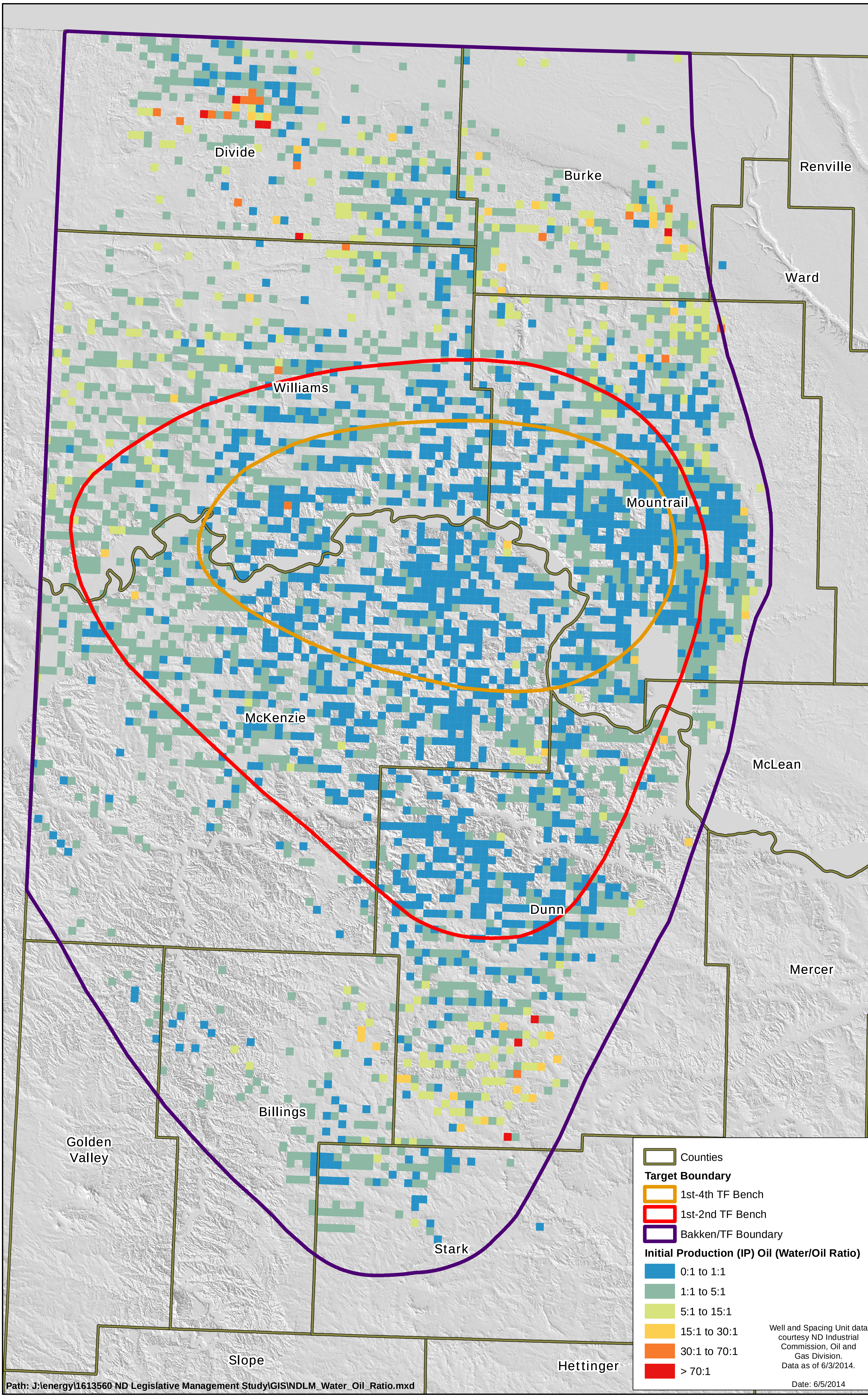

Figure 15: Bakken/Three Forks Wells (2007-14) Produced Water to Oil Ratio – Averaged by Section
Source: NDIC-DMR Oil and Gas Division; North Dakota State Water Commission; USGS National Elevation Dataset (Compilation and Analysis: KLJ)

Appendix B

NDSU: Socio-Economic Effects of Oil and Gas Industry in Western North Dakota 2014-2019

NDSU NORTH DAKOTA STATE UNIVERSITY

Socio-Economic Effects of Oil and Gas Industry in Western North Dakota 2014 to 2019

North Dakota Legislative Management
North Dakota Oil and Gas Impacts Study

July, 2014

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Background and Objectives

A few years ago local community leaders, planners, economic development specialists, state legislators, agency managers, public and private investors, and other stakeholders were just beginning to understand the long-term implication of shale oil development in the Williston Basin. As that understanding increases, questions are emerging about the implications of long-term growth as the state and local communities adjust to increasing permanent populations and permanent increases in demands for infrastructure and public services.

Expansion in the oil and gas industry in western North Dakota has created multiple challenges for governments and businesses as they work to address the many issues related to growth in employment, demands for infrastructure, and delivery of public services. Recent work by state agencies, planners, and researchers has produced a better understanding of the potential *pace* and *size* of oil field development. Several sets of projections relating to the *pace* and *size* of oil field development were made in 2012 (Bentek Energy 2012, KLJ 2012, Bangsund and Hodur 2013a, North Dakota Department of Mineral Resources 2012). At that time, the industry was just beginning to finalize lease holds on major tracks of the Bakken Formation and considerable uncertainty existed as to the future pace of development following the rush to secure mineral leases.

The current understanding is that elevated levels of oil field development will likely continue for over a decade, but the pace of development will likely be slower than observed during the peak drilling rates in the summer of 2012. Aside from an expectation of prolonged development in the Williston Basin, several new insights are emerging from the oil and gas industry in North Dakota that will have implications on employment, housing, population, public and private infrastructure, and delivery of public services.

A key factor is that well densities (how many wells can be drilled effectively in a predetermined area) are increasing. Current research is showing that wells can be closer to each other than previously thought without greatly altering the profitability of the individual wells. Further, in some areas, overall recovery rates for oil wells also are increasing.

Another evolving understanding being gleaned from current industry activity and ongoing research in the Basin is that the Three Forks Formation, another shale formation positioned below the Bakken Formation, is a potentially larger reservoir than previously thought. The prevailing understanding is that several benches or layers of the Three Forks Formation are economical to develop. This was not widely understood just a few years ago.

To make the process of forecasting industry change even more challenging, the industry is becoming more efficient. Labor requirements within the industry are changing, both in terms of labor requirements for some activities and the amount of output per unit of labor for other activities.

Secondary job response in the Williston Basin is now a much larger portion of the overall change in jobs than was the case just a few years ago. In the early stages of development, much of the employment change in the Williston Basin was related directly to employment in the oil and gas industry.

The changing pace of development, along with new insights on well spacings, well output, industry efficiencies, and additional economically-viable shale formations means the combined understanding of economics, technology and geology is still evolving in the Williston Basin. As a result of the dynamic factors present in the Williston Basin, projections should be updated frequently to incorporate new information and provide revised expectations for the duration and size of oil field development.

Future projections will no doubt change again. Regardless, the state currently faces substantial challenges--the workforce is growing, oil field development will be larger and likely will take longer to develop than previously understood, infrastructure demands will continue to strain local governments, and cost-of-living and quality of life factors are beginning to resonate with local interests as communities try to grow and develop under long-term uncertainty.

This report is part of a larger study funded by the North Dakota Legislative Management Council to gain a better understanding of what to expect with oil and gas development over the next five years. It is due to the continually changing circumstances and increasing understanding of shale oil potential that policymakers and public stakeholders need frequent assessments to guide them in developing effective strategies to manage a growing economy in the Williston Basin.

The purpose of this report is to provide a broad overview of the potential socio-economic effects of the oil and gas industry in the Williston Basin over the 2014-2019 period. Expectations for employment, housing needs, and population potential are explored, along with discussions on general social and economic effects.

Study Assumptions

The follow assumptions, insights, and analysis factors guided the development of the projections of employment, housing, and population.

Rig Count/Pace of Oil Field Development

Pace of oil field development is likely to continue at a rate similar to current rig counts. Expectations are that rig counts may fluctuate but not differ greatly from the range observed over the past 18 months.

-) Mineral leases are largely secure.
-) Industry focused on in-fill drilling.
-) Most companies will not exhaust drilling on their assets in the next 5 years.
-) Industry wants to maintain competition and cost savings during well development, and is focused more on efficiency factors to influence rate of development than large adjustments in drilling rig fleet.
-) A steady pace of development means employment in that part of the industry will remain relatively constant, but by adding more wells and infrastructure, overall employment in the industry will continue to expand.

Policy and Regulation

The projections were made absent of any major policy or regulatory factors substantially altering the economic landscape for shale oil development in North Dakota.

-) no fracking or other environmental regulations altering the ability to use current technologies.
-) local or state policies influencing gas capture or other similar initiatives are not likely to affect industry's ability to operate at current pace.

Total Well Counts/Extent of Development

The development of shale oil in North Dakota represents a moving target. Understanding of geology, technology, and economics within the Bakken and Three Forks Formations is still evolving. As such, for many individuals, governments, and businesses affected by the industry, there will remain some uncertainty as to the future size of development and the long-term timeline. This uncertainty is likely to influence investment, development, and planning in the Basin.

-) This premise is consistent with prospectus statements by oil firms that they will have increased drilling densities. This implies more wells than previously thought and increased time to fully develop assets.
-) This premise is consistent with new information from research on well drilling densities (e.g., EERC-UND Bakken Optimization Program)
    -) Wells can be placed in closer proximity that originally thought without greatly

altering the economic profitability of the individual wells.

-) Higher well counts in many spacing units

-) Increased recovery rate.

-) The Three Forks Formation is likely to have several 'benches' or layers that will be economical for development. This was not widely understood a few years ago. However, overall physical size of the individual benches is being refined implying near-term difficulty in predicting well counts for that formation.

-) It may be some time before a clear consensus emerges on the overall size of shale oil development in western North Dakota as measured by physical metrics such well counts, gas plants, and pipeline capacity and measured by economic metrics such as workforce, tax revenues, and economic development.

Other Factors

There exists the possibility for a number of potential factors that could influence oil production in the Williston Basin, such as geopolitical disruptions affecting world oil markets, changes in domestic macro-economic policies (e.g., Federal Reserve interest rate hikes), and changes in national energy policies and environmental considerations (e.g., oil export ban). However, the projections were made without considerations for the 'what if' consequences of national or international factors that could affect oil production in North Dakota. Other considerations included:

-) The widespread adoption of enhanced oil recovery (EOR) was not modeled.

-) No constraints to moving crude oil out of the Williston Basin.

-) No substantial price discounts accruing to North Dakota oil producers from changes in domestic market preferences for light sweet crude.

Projection Methods

Population is a key component in planning for future infrastructure needs. Population is usually forecast using standard cohort demographic models; however, due to rapidly changing conditions in the Williston Basin, traditional demographic tools are inadequate. Those traditional methods lack data to adjust birth rates and in-migration rates, and those models fail to address the unique characteristics of the current workforce in the Williston Basin.

Employment Forecasts

For purposes of evaluating shale energy development in the Williston Basin, an alternate method was developed that linked employment to population (Bangsund and Hodur 2012; Bangsund et al. 2012) (Figure 1). Bangsund and Hodur (2012) developed a process to model changes in direct and secondary employment associated with the petroleum sector in western North Dakota. Estimates of labor coefficients for several segments of the petroleum industry were obtained that reflect operating conditions in the Basin in 2012 (North Dakota Department of Mineral Resources 2012a). The model estimates labor for drilling, fracking, gathering systems construction, and oil field service (e.g., well site operations, crude oil pipelines, gas plant operations). Current labor coefficients are adjusted in the model to reflect anticipated changes in employment requirements based on changes in production practices and influences of future technological change on industry labor requirements.

The methodology developed by Bangsund et al. (2012) separates employment in western North Dakota into employment in the petroleum industry, secondary employment associated with petroleum industry employment, and employment in other industries and economic sectors. Constraints regulate the amount of future employment change in the base industries (e.g., manufacturing, tourism), as well as serving to adjust current employment coefficients within the petroleum sector. Secondary employment creation is linked to direct employment in the petroleum sector, and is adjusted to reconcile current employment coefficients to traditional input-output analysis multipliers (Bangsund and Hodur 2012).

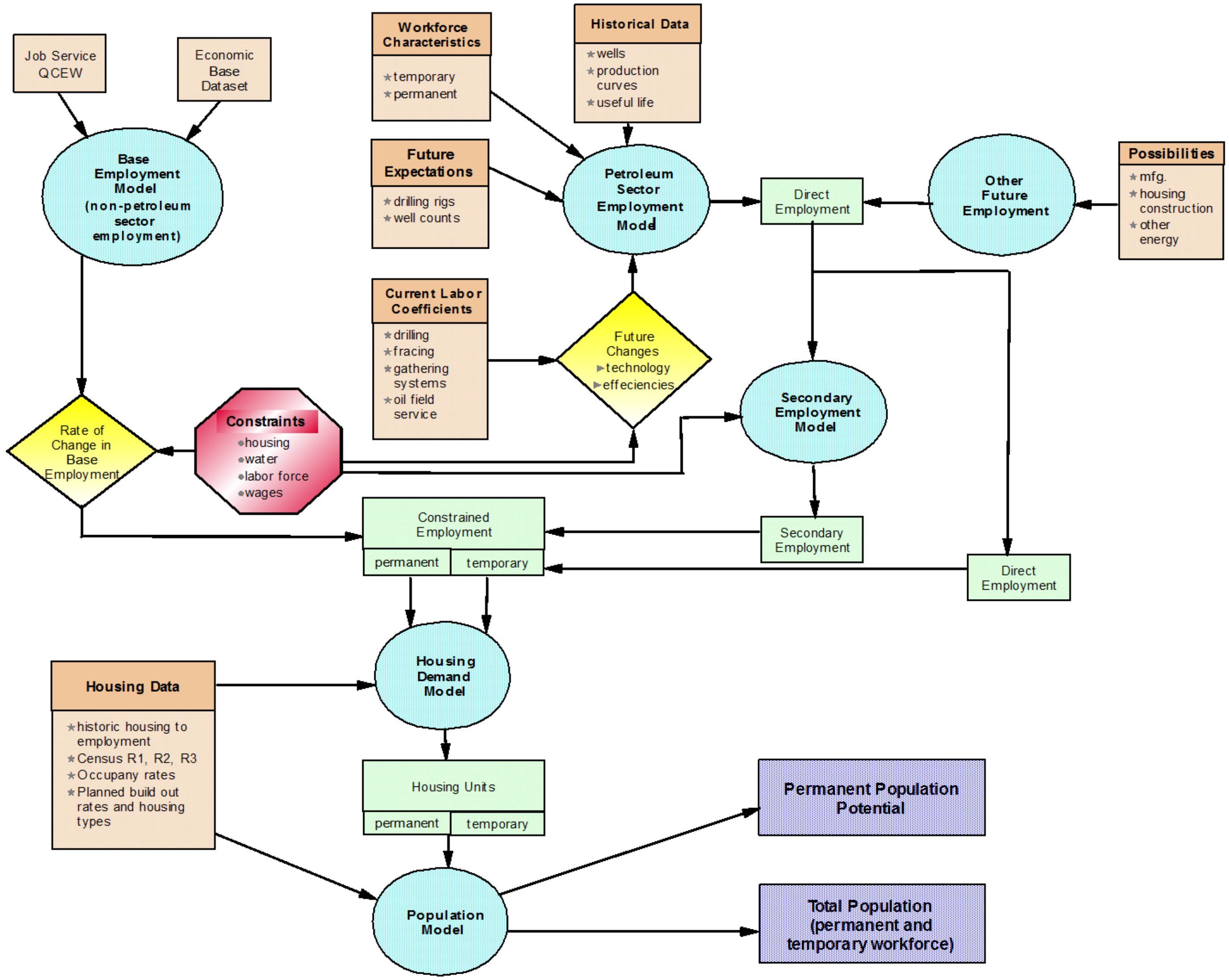

Figure 1. Employment, Housing, and Population Modeling Overview
Source: Bangsund et al. (2012).

The model estimates total economy-wide employment at the State Planning Region level. State Planning Region 1, 2, and 8 are reflective of the Williston, Minot, and Dickinson regions, respectively. Employment estimates consist of three main components: direct employment in the oil and gas industry, secondary job creation, and employment in other industries and sectors.

Petroleum Industry: Direct employment in the petroleum industry was estimated for drilling, hydraulic fracturing (fracing), construction of in-field gathering systems, and oil field service for each development scenario (for more detail on model design see Bangsund and Hodur 2012).

Employment in the petroleum industry was based on rig counts, well completions, number of existing wells and labor requirements for various aspects of the industry. Separate employment estimates were produced for exploration activities such as drilling and fracing, production operations such as well upkeep, infrastructure maintenance and transportation, gas plant operations, and construction of oil field infrastructure and gathering systems. Labor coefficients in the model are adjusted over time to reflect anticipated changes in labor requirements, production practices, and technological efficiencies.

Secondary Job Creation: The additional jobs expected to accrue over the projection period in the Williston Basin as a result of expansion of the oil and gas industry were estimated using a variety of methods (see Bangsund and Hodur 2012). Examples of these jobs include doctors, teachers, mechanics, home builders, sales people, store clerks, accountants, lawyers, and other jobs in the general economy.

Other Industries: Changes in total covered employment (i.e., Quarterly Census of Employment and Wages from Job Service North Dakota) in each region from 1990 through 2010 was evaluated after removing direct employment in the oil and gas industry. Trend analysis of the time-series change in total employment in the remaining industries and economic sectors provided the basis for predicting future employment in non-petroleum related industries. The observed change in employment in other industries prior to 2010 was different in each region. In the Williston area, employment was nearly flat, showing only small amounts of growth in employment in other economic sectors after removing employment in the oil and gas sector. In the Dickinson region, total employment showed steady growth after removing petroleum employment from the historical data. A similar situation was observed in the Minot region, as regional employment growth was observed from 1990 through 2010 after removing employment in the oil and gas sector.

Constraints on Employment Growth: Factors that potentially reduce employment growth (i.e., housing, wages, labor force availability) were included in estimates of base employment and secondary employment [see Bangsund and Hodur (2012) for a more in-depth discussion on employment constraints].

Long-term/permanent and Temporary/development Employment: The model divides petroleum sector employment into long-term/permanent and temporary/development employment.

Drilling and fracking, infrastructure construction, and construction of gathering systems are categorized as *temporary/development workforce*. A primary assumption in the forecasting model is that temporary employment represents jobs that are shorter-lived than the life-cycle of the oil fields. So while those workers may be onsite or in the state for an extended period, the model classifies those jobs as temporary relative to the life cycle of oil field development. Another perspective is that those jobs would largely disappear if development stopped in the oil fields.

The *long-term/permanent workforce* represents jobs related to oil well maintenance, pipeline operations, gas plant/processing activities, and other jobs that would remain even if development stopped in the oil fields. The model treats secondary jobs as long-term employment. A primary assumption in the forecasting model is that long-term jobs will be comprised of individuals who work in the Williston Basin and are established permanent residents of North Dakota.

The delineation between long-term/permanent and temporary/development workforces is important since those groupings help to show how employment in the industry will adjust, and change over time. Additional perspectives are that workers holding short-term jobs may have different demands for goods and services, housing, and infrastructure than workers with long-term jobs. While exact composition of the characteristics of individuals working in the various segments of the industry is unknown, housing needs can be estimated separately for those two classifications. Showing how the level of housing need changes is helpful in understanding that both permanent and temporary housing is required in the Williston Basin.

Estimated Housing Needs

The model estimates gross levels of housing need based on projected employment growth at the regional level. The original architecture of the model was based on historic data on the regional supply of housing units from 2000 through 2010 (U.S. Census Bureau 2012a,b,c,d) and historical employment (i.e., quarterly census of employment and wages) (Job Service North Dakota 2012), which produced a baseline from which future expected housing needs can be linked to future employment. Early in 2014, updated data on housing supply and occupancy rates (U.S. Census Bureau 2014a, b, c) and reported QCEW employment (Job Service North Dakota 2014) were incorporated into the model. The housing model is dynamic, and allows for the relationships between employment and housing needs to change over the projection period.

Estimates of Total Housing Needs: Analysis of the change in housing supply, regional employment, and comparisons to past housing and employment relationships revealed an approximate proportional change in housing need to increased employment in most areas of the Williston Basin. Any excess supply of housing has long been absorbed removing elasticity in the housing market. An inelastic market for housing exists when housing supply fails to keep pace with housing needs. New demand should produce a proportionate increase in supply. While that relationship is relevant to current conditions, those assumptions are relaxed over time in the model as housing supply is expected to grow and more closely equal demand. However, the modeling system does not predict housing supply.

Housing Needs at the County Level: Housing needs are first estimated at the regional level due to workforce mobility and shifting availability of housing supply among cities and counties within a region. Workers can, and often do, reside and work in different counties within a region. Regional housing needs are allocated to counties within each region based on trends in county housing data showing the relative county share of total regional housing. In some counties, their share of housing in a region is increasing, both in relative terms (i.e., percentage of all housing in the region) and in absolute terms (i.e., total housing units in the county are increasing). In other counties, recent trends indicated the supply of housing is increasing in absolute terms but not in relative terms (i.e., the number of housing units are increasing, just not proportional to the rate of change at the regional level).

Housing Mix in Each County: Recent building trends reveal a disproportionate shift to multi-family units in North Dakota (Center for Social Research 2012; Hodur and Bangsund 2013). The future housing mix (i.e., the number of single family versus multi-family homes and apartments) in most counties was adjusted to reflect this trend. Accordingly, regional housing needs, based on projected employment, were allocated among Williston Basin counties according to historic regional distributions and recent trends in the distribution of housing units. This effort produced an estimate of total housing needs at the county level. It is possible that the distribution of housing units among cities and counties may change in the future as many communities near oilfield development have yet to formalize long-term housing plans. Until additional data are available, regional housing needs were allocated among individual counties based on historic distributions and emerging trends.

Housing Needs by Employment Duration: The modeling system uses forecasts of total workforce (both development/temporary and permanent/long-term workers) to project total housing needs. The model also evaluates housing needs associated with only permanent/long-term employment. The two estimates of housing need help demonstrate the importance of including temporary housing in the near term and planning to provide adequate permanent housing in the long run.

Total Housing Needs: Total housing needs include the needs for both permanent/long-term employment and development/temporary employment.

Permanent (only) Housing Needs: Permanent housing needs are associated with permanent workforce, and more closely align with changes oil field service employment, and expectations for additional employment in personal service, education, medical, retail, commercial, and other sectors in the future.

Forecasts of Population Potential

Historic data on occupancy rates (U.S. Census Bureau 2014b), and current information on build out rates and the anticipated future mix of housing types (e.g., houses, apartments, mobile homes) are combined in a population model that tracks a region's potential population (see Figure 1). The model essentially combines persons-per-household occupancy rates by county and type of housing with estimates of future housing needs by county and type of housing to estimate population potential. The modeling process produces two estimates of population potential.

Permanent Population Potential: Permanent population potential is directly linked to estimated permanent housing needs. The model assumes that occupants of permanent housing work in the region and are established residents. Spouses and children of permanent workers living in the region also would be counted as permanent residents. Permanent population is consistent with population measured by the U.S. Census Bureau. Long-term planning for housing, infrastructure, public and social services and potential public revenue streams should focus on the permanent population.

Total Population Potential: Also called service population, this estimate includes those living in permanent housing (permanent population) and those living in temporary housing (which could be either temporary or permanent residents). Temporary population includes individuals not counted by the U.S. Census Bureau who claim residency in other states, work for short durations in the region, do not have permanent addresses in the region or are otherwise associated with seasonal or short-term employment (relative to the life-span of the oil fields). Incorporating temporary population into an estimate of service population is critical for communities, businesses and government planning requirements since those individuals use and require good and services, both public and private.

Key Assumptions to Estimating Population Potential: The modeling approach relies on several key assumptions. Understanding those conditions is necessary to appropriately interpreting the housing and population forecasts.

Ability to Supply Housing: Communities are assumed to be willing and able to supply housing at levels that meet projected needs. Some communities may be more or less inclined or able to supply housing, but on a regional level, the model assumes that housing supply will meet housing needs. An important understanding of the model's output is that the model produces future population forecasts based on expected housing needs, not expected housing supply. Since future supply of housing is unknown, an implied assumption in the modeling process is that future rates of housing supply equal future rates of housing need. The best description of model output is therefore population potential–potential being defined as what the population is likely to be if housing needs are actually supplied, and occupancy rates match historic conditions.

Characteristics of Temporary and Permanent Population are Similar: Temporary population was assumed to have similar characteristics as the permanent population. Current and future temporary workforce characteristics are unknown. However, it was assumed occupancy rates for temporary workers were similar to occupancy rates for permanent workers.

Use of Historical Occupancy Rates - Population estimates were made by applying person-per-household occupancy rates to estimates of housing demand for various types of housing units (single family, multi-family). While the model relies on the most recent Census occupancy rates (U.S. Census 2014b), it is unclear if those occupancy rates are applicable to all housing conditions in the Williston Basin. At this time, data to adjust occupancy rates outside of those provided by the U.S. Census are not available, so a key assumption in this study was that historical occupancy rates remain valid.

Use of Employment as a Metric for Determining Housing Needs: At the time the modeling process was constructed, traditional approaches to estimating future population in the Williston Basin would not work due to a lack of accurate data on migration rates, employment change, and traditional birth/death trends. Employment was viewed as the best viable metric from which to construct estimates of housing need in the Basin. The prevailing understanding is that employment remains a reliable metric to estimate total housing need, but is insufficient by itself to measure market-based housing demand[1].

[1]Market demand for housing would involve understanding the price and income elasticity associated with housing options in the Williston Basin. In other words, a certain amount of housing is in demand at various price points or costs and those prices/costs vary with personal income, location, and buyer preferences. While the need for housing exists for all individuals working in the Basin, not all of those workers are willing or able to secure permanent housing. Some workers may prefer to use some form of temporary housing as their expectation for remaining employed in the region is limited or short-lived. Others may have invested in campers or other lodging arrangements, and are unwilling at current housing prices/costs to switch their lodging arrangements. Even others may be hesitant to acquire (either purchase or rent) permanent housing due to expectations for future price declines, perceived risks associated with job tenure, or do not qualify for financing. Still other workers may be retaining a permanent residence outside of the region, either elsewhere in ND or in another state, and therefore only need minimal lodging arrangements while working in the region. Therefore, the lack of affordable housing has forced many people to seek out cheaper, less risky alternative housing options, and possibly perpetuated the use of shift work or rotational work schedules to lessen the need for permanent housing.

Scenario Analysis

Future development of shale formations in the Williston Basin is unknown. To frame the context and scope of future possibilities, projections are developed based on insights from industry leaders, expectations for well spacings, and geographic factors associated with current and expected development of the Williston Basin. The synthesization of existing data provides the basis for development of a high estimate, medium estimate, and low estimate of the future shale oil development in the Williston Basin. Those development scenarios provide the foundation to model employment change, housing needs, and population potential in the Williston Basin.

The modeling process and results have been used by the City of Dickinson in their comprehensive planning effort (Bangsund et al. 2012), used in the ND Housing Finance Agency's Statewide Housing Needs Assessment (Center for Social Research 2012), used by the ND Transmission Authority's comprehensive study of future electrical load growth in the Williston Basin (KLJ 2012), used in a study to examine short-run and long-run population change in the City of Williston (Hodur and Bangsund 2013), used in a study funded by the ND Association of Oil and Gas Producing Counties to estimate future student enrollments in selected school districts in the Williston Basin (Hodur et al. 2013), and used recently by VisionWest Consortium in the development of their strategic plan for sustainable growth in oil producing counties and communities (VisionWest Consortium 2014b).

In all of the previous studies, several scenarios have been used to frame the range of likely outcomes in the Williston Basin. Despite all of the work to better understand what the future holds for oil and gas development in the Basin, it is impossible to forecast all of the economic, social, regulatory, and environmental factors that can influence how the industry develops and produces oil and gas in the Williston Basin. Therefore, deterministic scenarios remain the best strategy to frame a range of future possibilities, and highlight the uncertainty that remains in predicting future oil and gas activities.

Employment, Housing, and Population Projections

The scope of future oil field development in the Williston Basin is unknown. Accordingly, three scenarios are used to address the uncertainty associated with the rate and extent of future oil field development.

Low: The basic premise for the low scenario is that economic conditions or overall economic climate are worse than current conditions.

Medium: The medium scenario was designed around the premise that economic conditions remain relatively similar to conditions in 2013.

High: The high scenario considers an improved economic climate relative to conditions in 2013.

Drilling Activities

The number of drilling rigs is an important factor in the rate of oil field development, and has direct implications on employment in the Basin. A higher number of rigs means the state adds wells at a rate faster than a lower rig count. This rate of change has implications for employment associated with drilling and fracking activities, and has underlying effects on oil field service employment, since those metrics are tied to the number of wells in the state. Rig counts were estimated for North Dakota for the three scenarios (Figure 2). Rig counts increase from current levels in the high scenario, reaching around 198 rigs at the end of the 5-year period. The medium scenario has rig counts staying relatively unchanged around the mid 180s over the projection period, while counts decline to 165 rigs in the low scenario.

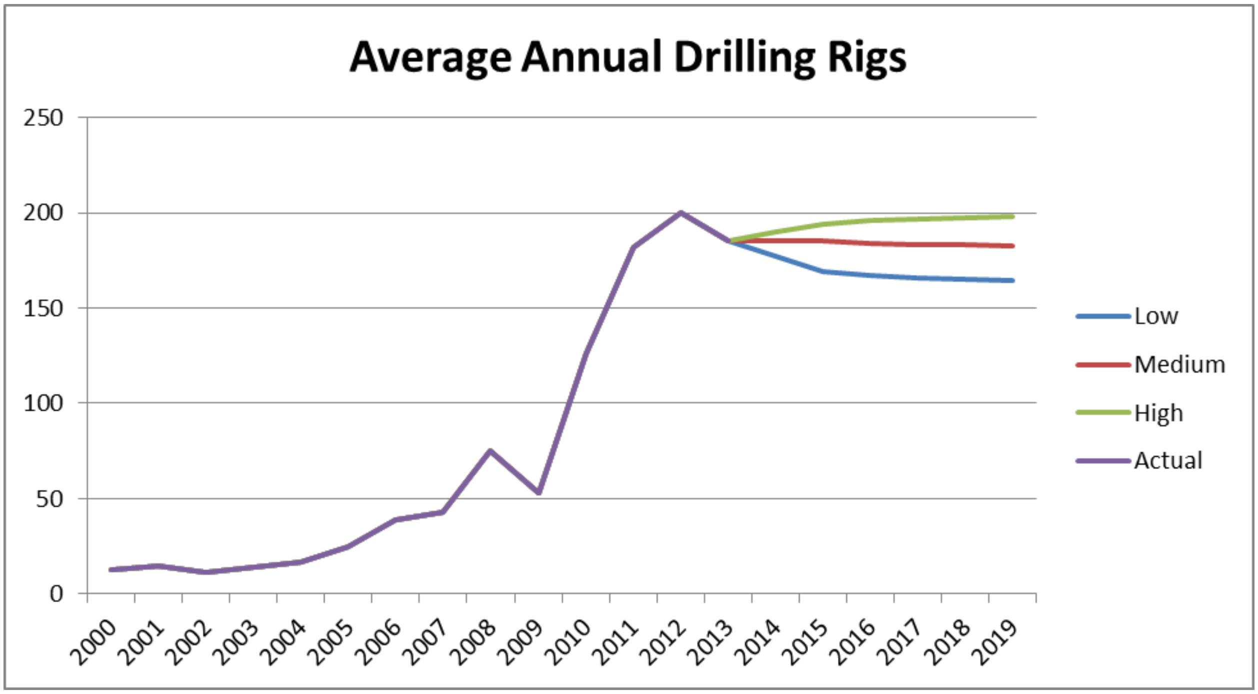

Figure 2: Average Annual Rig Counts, North Dakota, 2000 through 2019

Well Counts

The number of producing oil wells is another key metric to describe the extent or size of oil field development. North Dakota is projected by 2019 to have about 23,600 operating wells in the low scenario, 24,900 operating wells in the medium scenario, and around 25,800 operating wells in the high scenario (Figure 3). Well counts are a function of expected well life, both non-shale and shale wells, and new producing wells added over a projection period. New producing wells added over a period are a function of rig counts and drilling efficiencies. Drilling efficiencies reflect the number of wells capable of being drilled by each rig over a one-year period. Drilling efficiencies have increased in recent years as drilling activities are migrating from being predominantly associated with single well (per location) drilling to drilling on multi-well pads. Future drilling efficiencies are incorporated into the model, and fleet drilling efficiencies ranged from 12.4 wells/rig/year to 13.7 wells/rig/year[2] over the projection period.

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[2]About 6 percent of the drilling fleet operating in North Dakota represents rigs drilling water disposal wells. Those rigs are included in the model for purposes of estimating employment. However, the number of oil wells drilled per rig per year is adjusted in the model so that an overall drilling coefficient per rig can be applied to the entire drilling fleet. The coefficient for wells/rig/year for rigs only drilling oil wells will be slightly higher than the fleet efficiency coefficient used in the projections.

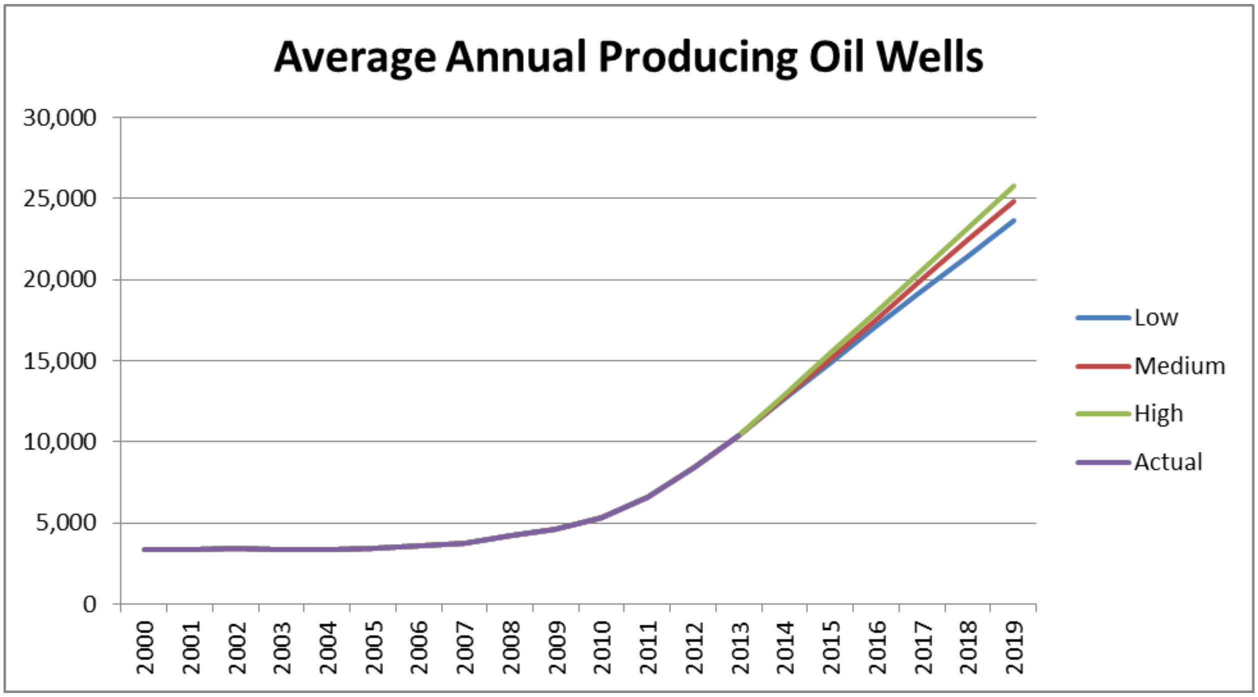

Figure 3: Average Annual Operating Oil Wells, North Dakota, 2000 through 2019

Employment Projections

Projections of employment consist of three main components: direct employment in the oil and gas industry, secondary job creation, and employment in other industries and sectors.

Oil and Gas Sector Employment

Petroleum sector employment in North Dakota was projected to continue to increase from 2014 to 2019, depending upon the rate of future oil field development (Figure 4). In the near-term, a change in rig counts between the low and upper scenarios (i.e., rigs counts ranging from 165 to 198 rigs) will result in employment growth in the oil and gas sector.

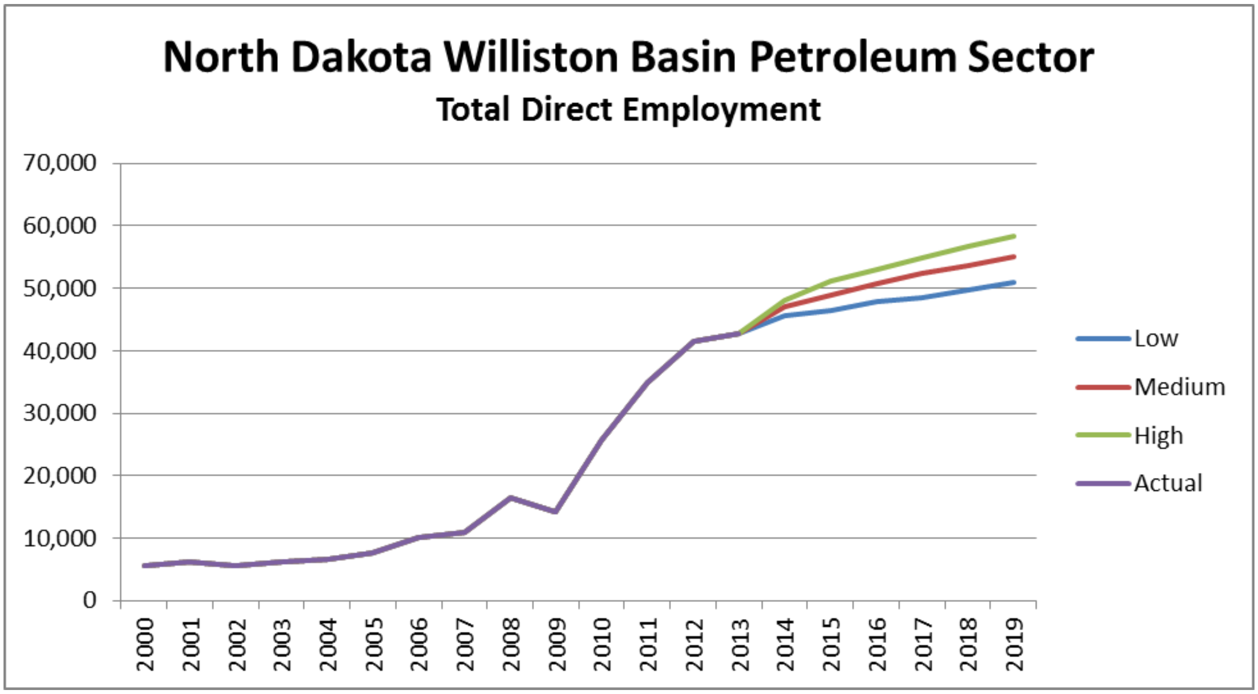

Figure 4: Direct Employment in Petroleum Industry, by Scenario, Williston Basin, North Dakota, 2000 through 2019

Employment shifts within the industry will occur as near-term increases in employment are primarily due to slowly accumulating employment in oil field service and steady to slightly declining employment in drilling and fracing operations (Figure 5). A continuation of those trends is expected beyond the 2014-2019 period, and long-term employment in the petroleum sector will increasingly become more of function of the number of wells as long-term employment in drilling and fracing will continue to decline.

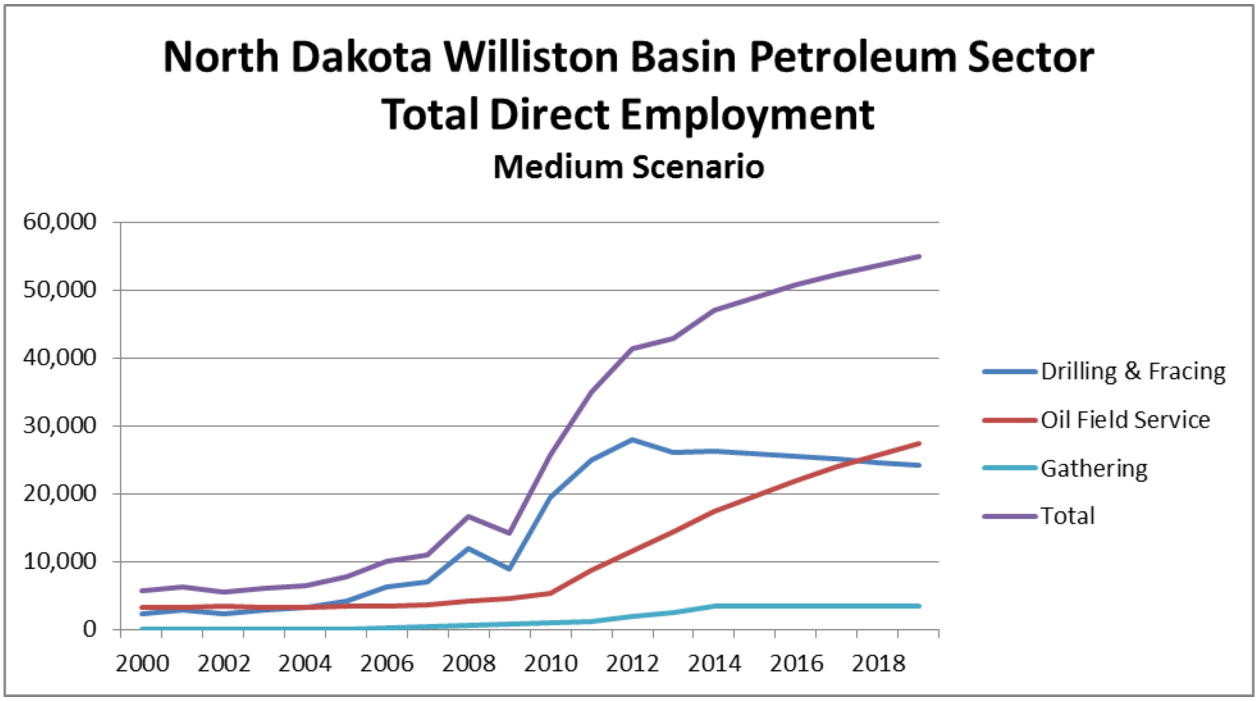

Figure 5: Direct Employment in Petroleum Industry, by Industry Segment, Medium Scenario, North Dakota, 2000 through 2019

Current employment in the petroleum sector is expected to transition from one weighted heavily on a temporary/development workforce to an industry that will be more dominated by long-term/permanent employment. The industry is expected to retain a substantial portion of total employment related to temporary/development jobs over the next five years (Figure 6).

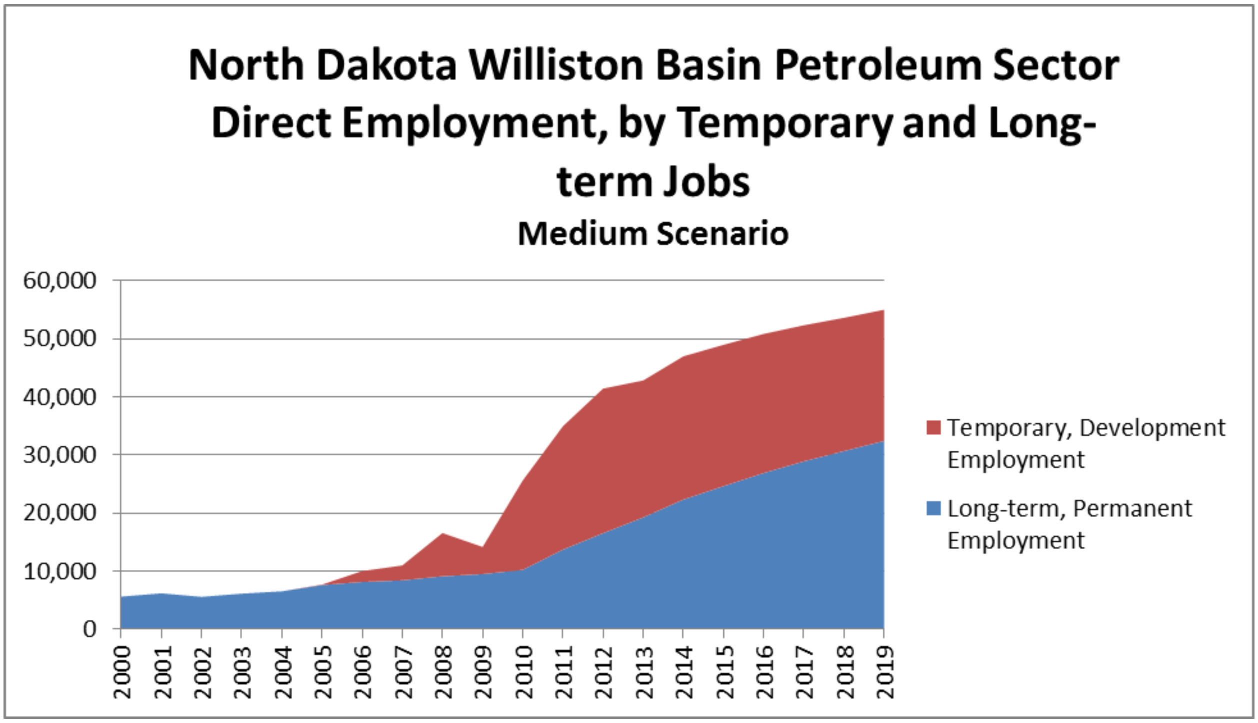

Figure 6: Long-term/permanent & temporary/development employment

Total Employment

Total employment in the Williston Basin includes changes in other industries (base employment) and the change in direct and secondary employment associated with the petroleum sector. Because the effects of employment growth in the petroleum sector differ throughout the Williston Basin, total employment in the North Dakota portion of the Williston Basin was modeled on a regional basis. State Planning Regions 1, 2 and 8, which correspond with the trade areas of Dickinson, Minot, and Williston, provided the geographic scope for employment modeling (Figure 7). Separate estimates of total employment were developed for each region.

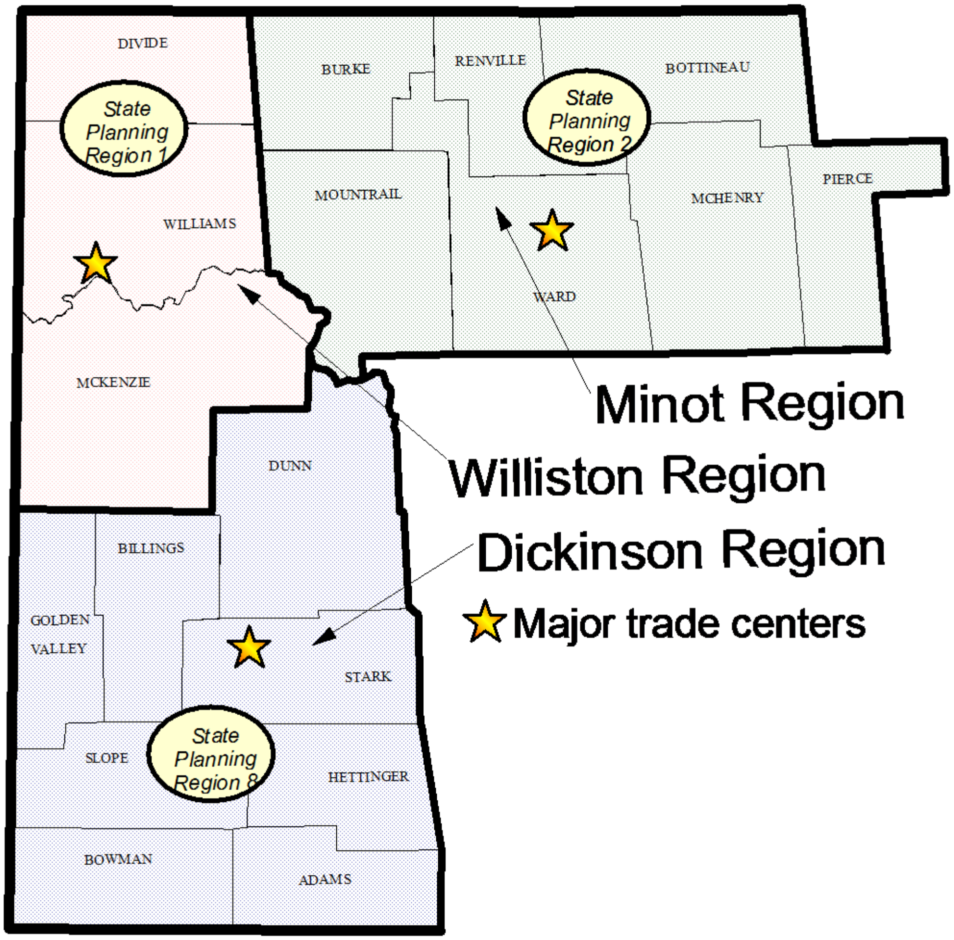

Figure 7: State Planning Regions, Williston Basin, North Dakota

Total employment in the North Dakota portion of the Williston Basin continues to increase in the near term due largely to expansion of petroleum sector employment and growth in secondary employment (Figure 8).

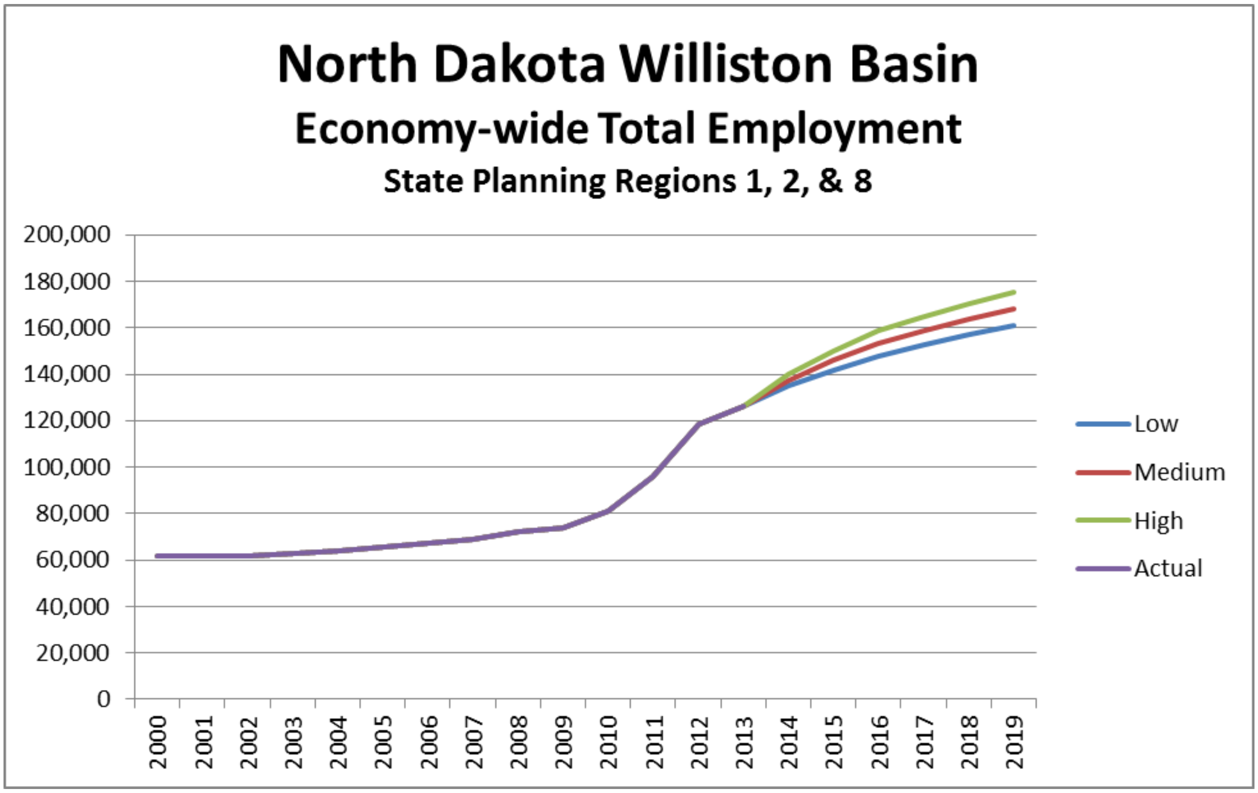

Figure 8: Total Employment, by Scenario, North Dakota Williston Basin, 2000 - 2019

Williston Region–Total Employment

Employment in the Williston region grew rapidly from 2010 through 2012. About mid-way through 2012, the push to secure leases subsided and the pace of development went from around 213 rigs in June to 183 rigs in December, 2012. The drop in rig counts in the last half of 2012 is largely responsible for the change in the growth of employment in the region. Projections show employment in the region continuing to grow over the 2014 through 2019 period (Figure 9).

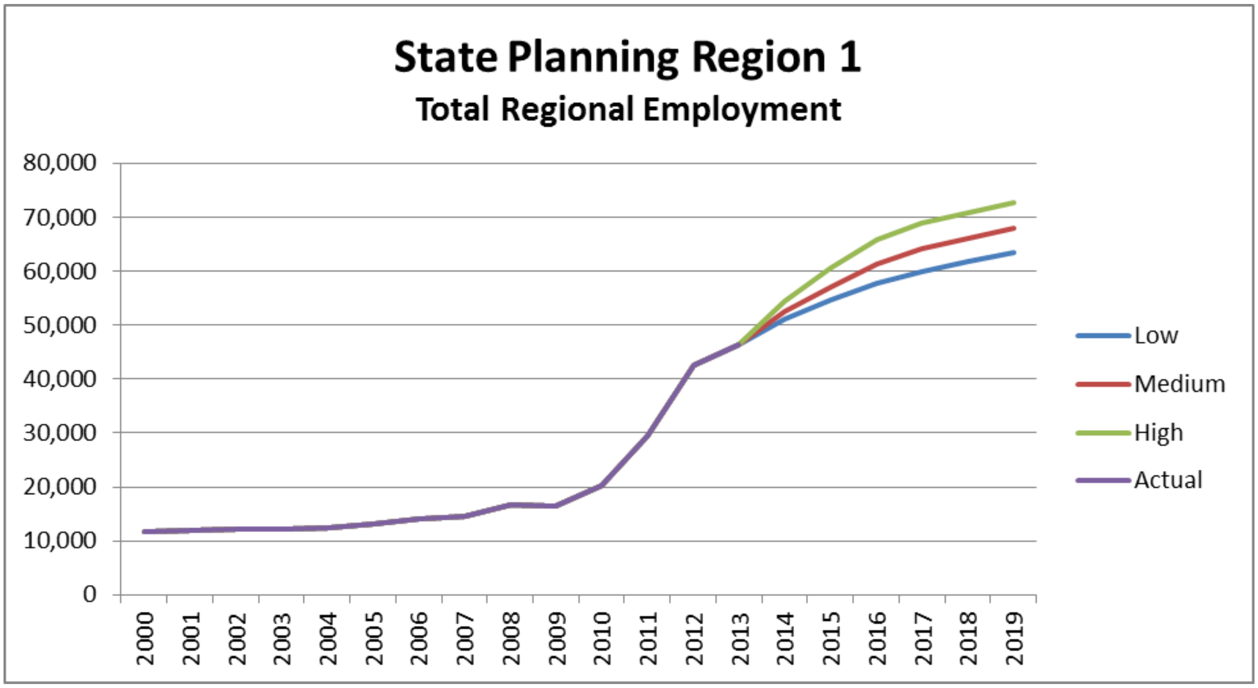

Figure 9: Total Employment, by Scenario, Williston Region, North Dakota, 2000-2019

The modeling system examines the amount of secondary employment added since 2011. Analysis of employment change in the last five years in the Williston region shows that initially much of the employment growth was related to jobs in the oil and gas sector. While oil and gas industry employment continues to grow, the share of regional employment attributable to secondary jobs is growing. It is clear that the economy is adding employment in retail trade, personal services, business services, and commercial activity. From 2014 through 2019, secondary job creation will continue to lag the change in employment in the oil and gas sector, but is forecasted to expand over the period (Figure 10).

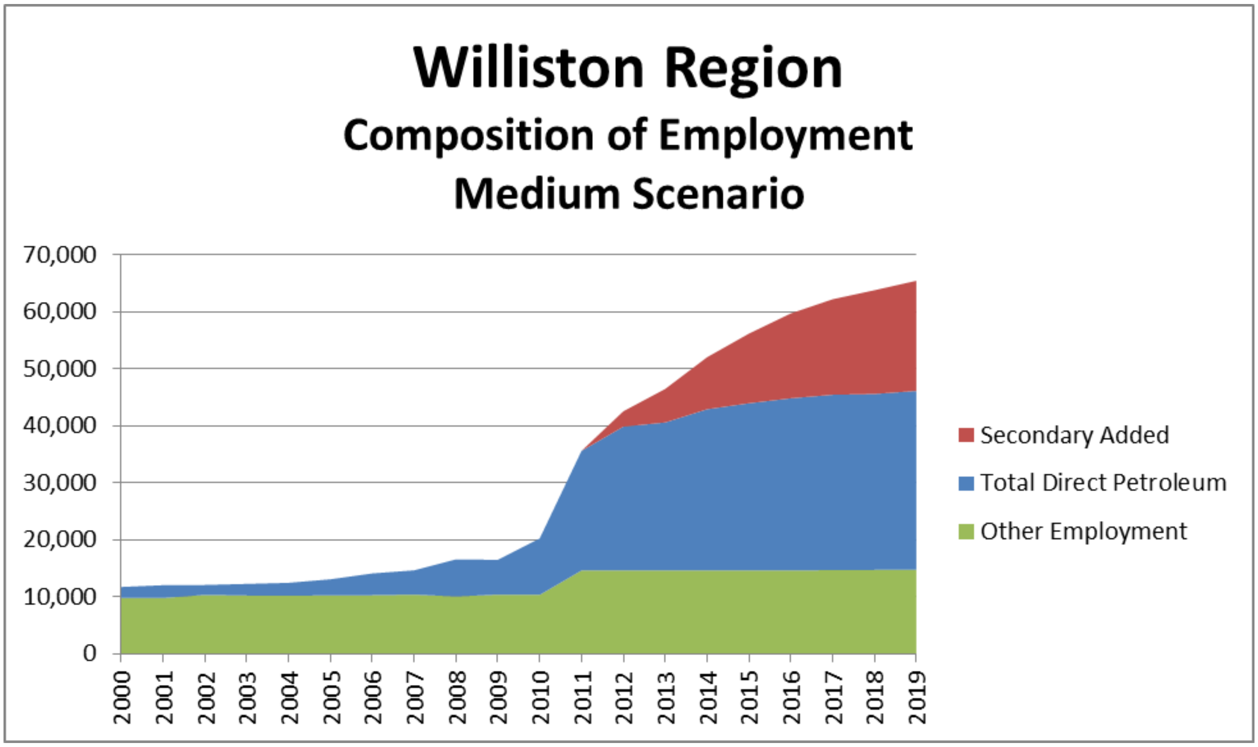

Figure 10: Composition of Total Regional Employment, Medium Scenario, Williston Region, North Dakota, 2000-2019

Minot Region–Total Employment

Employment in the Minot region is forecasted to expand over the 2014 through 2019 period. However, petroleum industry employment represents a smaller percentage of total regional employment, and the differences between the low, medium, and high petroleum sector scenarios have less percentage change in total employment in the Minot region compared to the Williston or Dickinson regions.

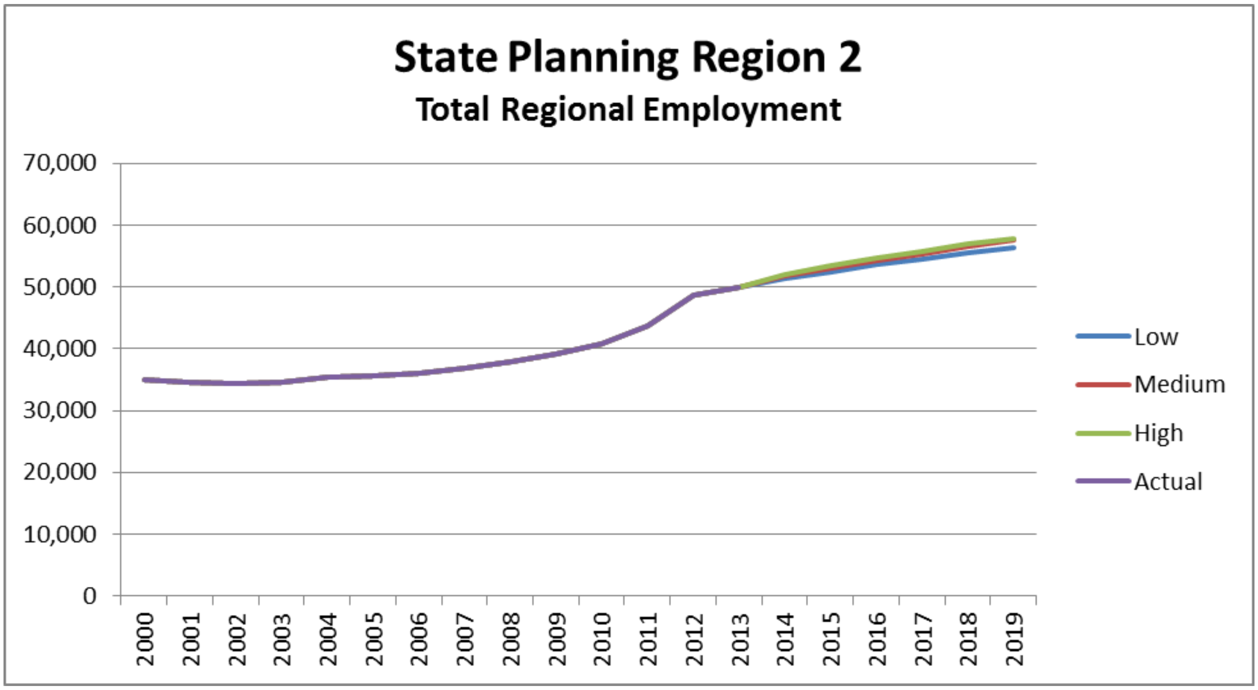

Figure 11: Total Employment, by Scenario, Minot Region, North Dakota, 2000-2019

Much like observations from the Williston and Dickinson regions, growth in oil and gas sector employment will continue over the projection period. Growth in secondary jobs also will continue over the projection period. However, the change in employment in other industries (i.e., employment not associated with oil and gas industry) in the Minot region will be a larger relative driver of employment change than found in the Williston and Dickinson regions.

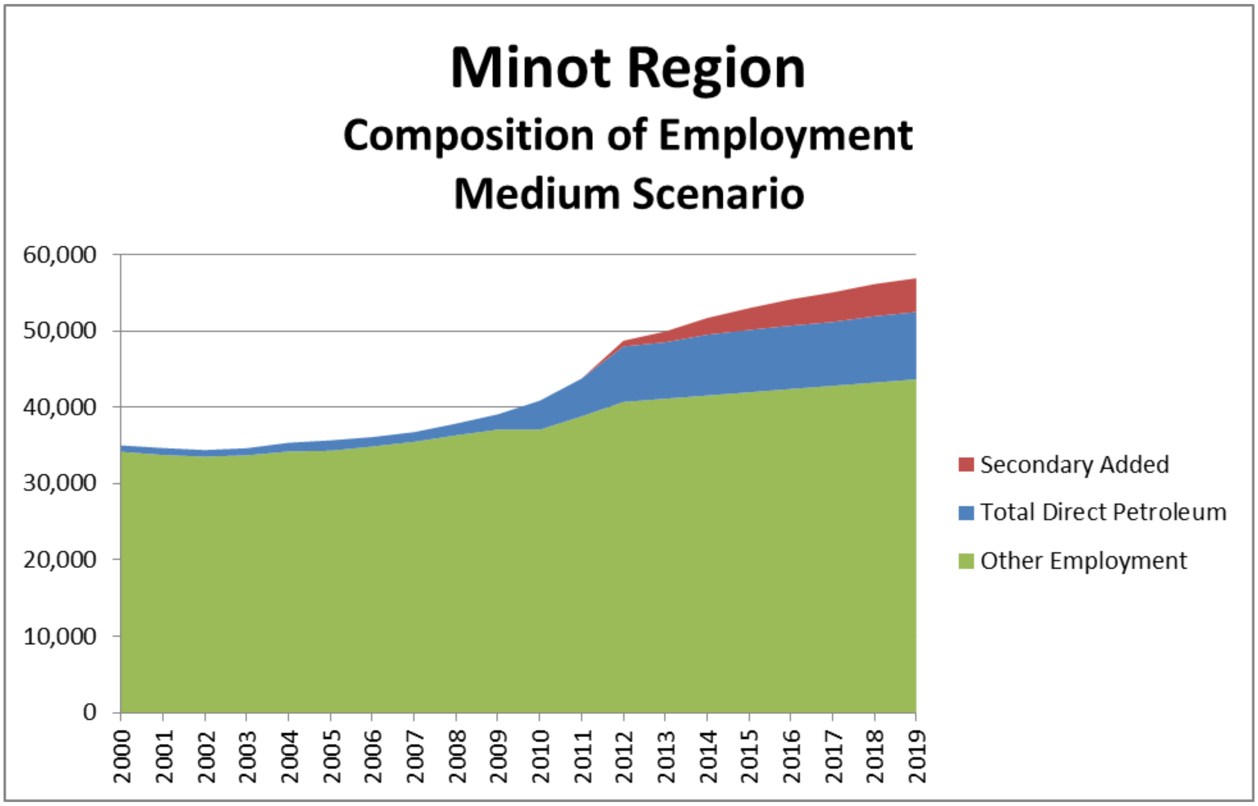

Figure 12: Composition of Total Regional Employment, Medium Scenario, Minot Region, North Dakota, 2000-2019

Dickinson Region–Total Employment

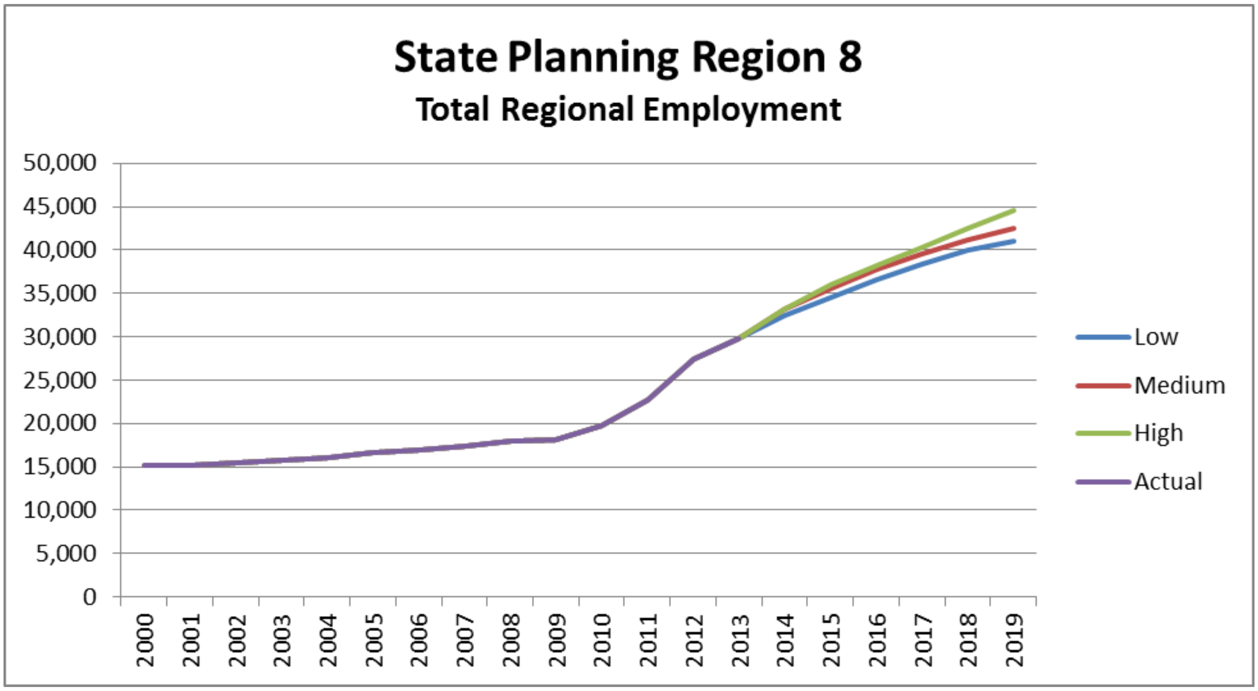

Figure 13: Total Employment, by Scenario, Minot Region, North Dakota, 2000-2019

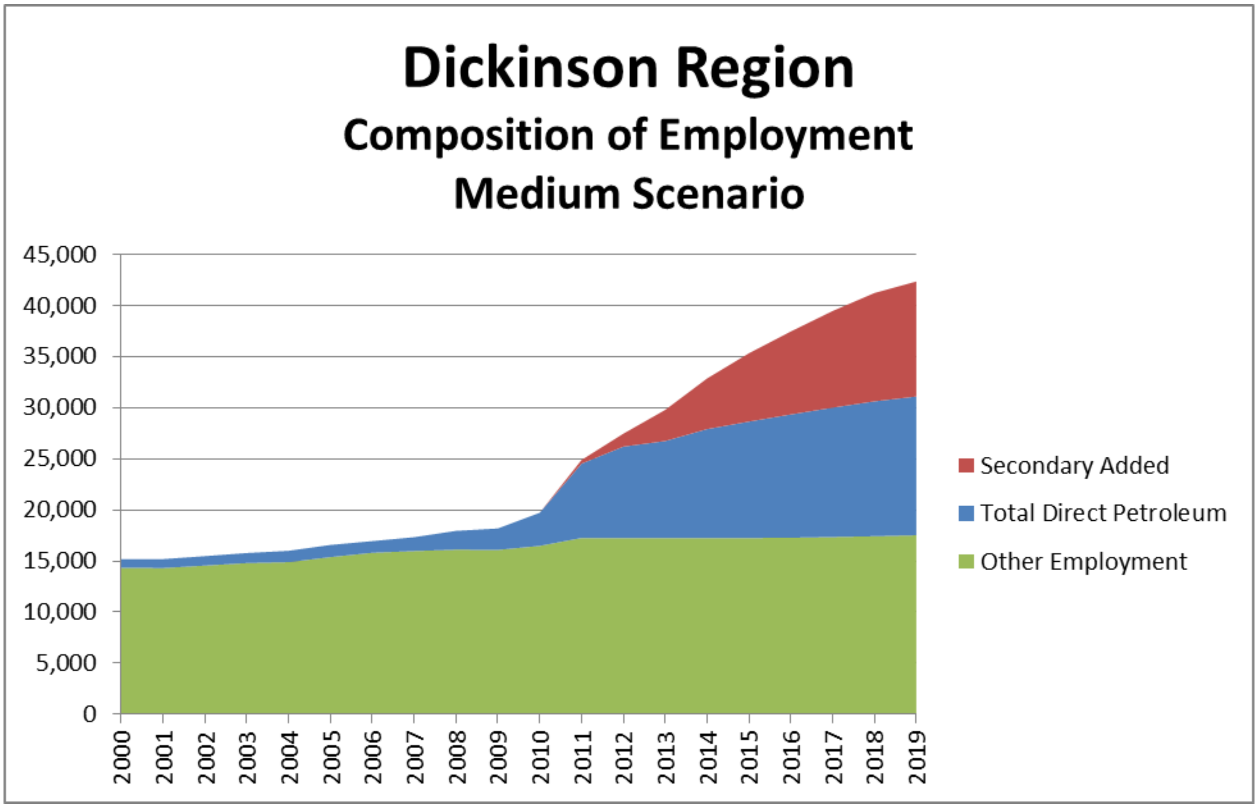

Figure 14: Composition of Total Regional Employment, Medium Scenario, Minot Region, North Dakota, 2000-2019

Housing Needs

Despite recent gains in housing supply, housing needs continue to grow as the region adds employment in the petroleum industry and as secondary jobs are added in the Williston Basin. Forecasted estimates of housing need are comprised of total housing requirements associated with employment, both long-term/permanent and temporary/development employment.

Because of the rate of expansion of energy development in the Williston Basin and associated growth in employment, housing needs have outstripped permanent housing supply. Any excess supply of permanent housing has long been absorbed removing elasticity in the housing market. An inelastic market for housing exists when housing supply fails to keep pace with housing demand and any new demand results in a proportionate increase in supply. Housing needs in the Williston Basin are now being met by a combination of permanent housing (houses, apartments), crew camps, campers, skid shacks, mobile homes, hotels, and conditional use lodging (living on the work site, lodging arrangements at business facilities).

The modeling process identifies the need for housing, but does not evaluate market demand for housing nor does it use data on how the current housing need is being met among all of the housing options.

An important understanding of the model's output is that the model produces future population forecasts based on expected housing needs, not expected housing supply. Since future supply of housing is unknown, an implied assumption in the modeling process is that future rates of housing supply equal future rates of housing need. The best description of model output is therefore population potential–potential being defined as what the population is likely to be if housing needs are actually supplied, and occupancy rates match historic conditions.

Williston Region

Nearly paralleling changes in total employment in the Williston Region, housing needs are forecasted to grow considerably in each scenario. Table 1 contains forecasts of the change in total housing need based on forecasted growth in employment. In the medium scenario, total housing needs would increase by over 15,000 units from 2014 through 2019 (Table 1).

The change in total housing needs for each of the counties in the Williston region were proportional to the regional change in total housing needs. An evaluation of data on the change in employment within the region's counties and the relative change housing units supplied in each county over the 2000-2012 period indicated proportional changes among the counties in the Williston Region (Table 2).

Table 1. Housing Needs, in Total Units, by Scenario, Williston Region, North Dakota, 2014-2019

Year	Low Scenario	Medium Scenario	High Scenario
2014	41,063	42,353	45,100
2015	44,397	46,622	50,737
2016	47,770	50,660	55,754
2017	50,173	53,778	59,190
2018	52,069	55,916	61,307
2019	54,071	58,037	63,420

Table 2. Housing Needs by County, in Total Units, Medium Scenario, Williston Region, North Dakota, 2014-2019

Year	Divide County	McKenzie County	Williams County
2014	3,446	8,178	30,728
2015	3,793	9,003	33,826
2016	4,122	9,782	36,756
2017	4,376	10,385	40,569
2018	4,550	10,797	42,108
2019	4,722	11,207	43,415

Minot Region

Growth in overall housing needs in the Minot region is nearly proportional to the changes in total employment. Table 3 contains forecasts of the change in total housing need based on forecasted growth in employment. In the medium scenario, total housing needs increased by 6,430 units or by 12 percent (Table 3).

The change in housing needs among counties in the Minot region was not proportional to the changes at the regional level. Growth in total housing units in Mountrail and Ward Counties were estimated at 15 and 13 percent, respectively, compared to 12 percent for the region. Growth in total housing needs in Bottineau, Burke, McHenry, Pierce, and Renville Counties were estimated to be lower than the regional average (Table 4).

Table 3. Housing Needs, Total Units, by Scenario, Minot Region, North Dakota, 2014-2019

Year	Low Scenario	Medium Scenario	High Scenario
2014	54,903	55,312	55,873
2015	56,170	56,796	57,458
2016	57,401	58,175	58,808
2017	58,361	59,334	59,934
2018	59,564	60,656	61,312
2019	60,476	61,741	62,372

Table 4. Housing Needs, by County, Total Units, Medium Scenario, Minot Region, North Dakota, 2014-2019

Year	Bottineau County	Burke County	McHenry County	Mountrail County	Pierce County	Renville County	Ward County
2014	5,253	1,619	3,620	5,362	2,652	1,676	35,129
2015	5,362	1,649	3,699	5,539	2,704	1,711	36,132
2016	5,459	1,676	3,769	5,709	2,750	1,741	37,071
2017	5,534	1,695	3,825	5,858	2,785	1,765	37,872
2018	5,623	1,719	3,890	6,024	2,827	1,793	38,780
2019	5,689	1,735	3,939	6,169	2,857	1,813	39,539

Dickinson Region

Employment growth was forecasted to increase by about by 28 percent in the medium scenario over the 2014 to 2019 period, which translated into an increase in housing needs of about 9,500 units (Table 5). Table 5 contains forecasts of the change in total housing need based on forecasted growth in employment. Similar to the pattern observed in the Minot Region, the relative supply of housing has not been even among the region's counties. Growth in total housing units needed in Dunn and Stark Counties were estimated to increase by 31.4 and 33.2 percent, respectively, compared to 31.3 percent for the entire region (Table 6).

Table 5. Housing Needs, Total Units, by Scenario, Dickinson Region, North Dakota, 2014-2019

Year	Low Scenario	Medium Scenario	High Scenario
2014	31,908	32,439	33,311
2015	34,358	35,111	36,117
2016	36,560	37,408	38,467
2017	38,549	39,410	40,672
2018	40,406	41,140	42,921
2019	41,573	42,606	45,016

Table 6. Housing Needs, by County, Total Units, Medium Scenario, Dickinson Region, North Dakota, 2014-2019

Year	Adams County	Billings County	Bowman County	Dunn County	Golden Valley County	Hettinger County	Slope County	Stark County
2014	2,375	875	2,973	3,827	1,694	2,453	750	20,164
2015	2,513	925	3,161	4,078	1,795	2,600	793	21,542
2016	2,630	967	3,324	4,297	1,882	2,724	830	22,757
2017	2,726	1,002	3,463	4,486	1,954	2,828	860	23,821
2018	2,803	1,029	3,580	4,646	2,013	2,913	884	24,737
2019	2,836	1,040	3,640	4,736	2,041	2,951	894	25,270

Population Forecasts

The Williston Basin lacks a good baseline population estimate. Because the U.S. Census only reports a measure of permanent population, the 2010 Census figures undoubtedly underestimated the overall population in the Williston Basin. Incorporating the population not counted by the Census into an estimate of service population is critical for communities, businesses and government planning activities. Even though a portion of the service population includes residents of other states, while in the Williston Basin, they still use and require services, both public and private.

The modeling process converts the need for housing into various types of housing. That conversion process also relies on historical data to suggest how the mix of housing in the individual counties is changing. Population estimates are then made by applying person-per-household occupancy rates to estimates of the mix of housing units needed (single family, multi-family, mobile homes). While the model relies on the most recent Census occupancy rates (U.S. Census 2014b), it is unclear if those occupancy rates are applicable to all housing conditions in the Williston Basin. At this time, data to adjust occupancy rates outside of those provided by the U.S. Census are not available, so a key assumption in the current modeling system is that historical occupancy rates remain valid. Also, since the model does not have a true estimate of total housing supply (permanent housing is set in the model using U.S. Census inter-decennial estimates), adjustments for occupancy rates in non-traditional lodging arrangements are not addressed in the model.

Despite those limitations, applying occupancy coefficients for various housing types, accounts for the presence of dependents and spouses of accompanying workers. The service population would therefore include an estimate of all the individuals living in housing types that are not counted by the U.S. Census (e.g., skid shacks, campers, crew quarters) and include those individuals who may be working in the region for short-periods while retaining residency outside the region.

Sensitivity analysis revealed the population forecasts are responsive to both a change in housing units and occupancy rates. Small changes in either component resulted in noticeable swings in population. A better understanding of workforce characteristics, current housing supply, and communities' ability to address future housing needs is needed to refine population projections[3].

If future housing is not provided at a level approaching the forecasted values; population will be less than estimated in this study. Workers will find it difficult to bring family members

[3]The North Dakota Industrial Commission has funded a study to examine employment patterns, housing preferences, and general characteristics and attitudes of workers in the oil and gas industry in North Dakota. It is anticipated that insights from that study may improve the ability to estimate population thresholds and forecast future population change. Preliminary results of that study are expected near the end of 2014. For more information on that study, contact Dr. Hodur (nancy.hodur@ndsu.edu) or Dean Bangsund (d.bangsund@ndsu.edu).

to the state, or difficult to start families. Accordingly, the region's population will be skewed towards unaccompanied working adults without spouses and dependents. Communities are assumed to be willing and able to supply housing at levels that meet projected needs. Some communities may be more or less inclined or able to supply housing, but on a regional level, the model assumes that housing supply will meet housing needs. An important understanding of the model's output lies in realizing that the model produces future population forecasts based on expected housing needs, not expected housing supply. Since future supply of housing is unknown, an implied assumption in the modeling process is that future rates of housing supply equal future rates of housing need. The best description of model output is therefore population *potential*–potential being defined as what the population is likely to be if housing needs are actually supplied, and occupancy rates match historic conditions.

Williston Region

Total population potential was estimated in each of the three scenarios over the 2014-2019 period (Figure 15). Growth in total population was largely driven by forecasted growth in regional employment over the period. Average annual growth in population could be around 6 percent in the Williston region.

The Williston region was estimated to have a total population *potential* around 97,000 at the end of 2014 in the medium scenario, which includes permanent residents, shift workers, seasonal construction workers, and dependents and spouses of workers living in non-permanent lodging arrangements (Table 7). The total population potential in 2019 was estimated to be around 130,000 for the Williston region, *assuming* housing is supplied and occupancy rates remain valid.

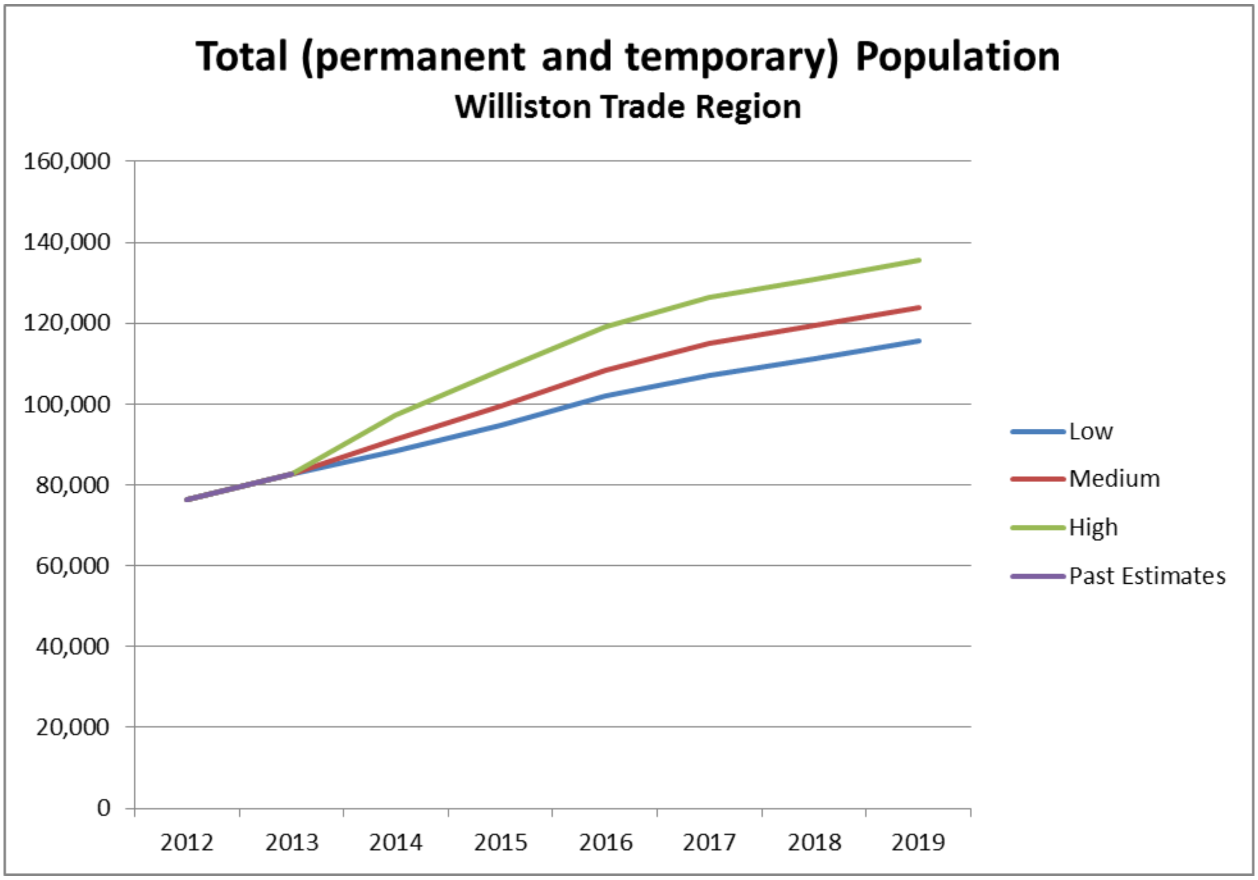

Figure 15. Population Potential, Williston Region, North Dakota, 2012-2019

Table 7. Population Potential, by Scenario, Williston Region, North Dakota, 2014-2019

Year	Low Scenario	Medium Scenario	High Scenario
2014	93,857	96,806	103,085
2015	100,461	105,497	114,808
2016	108,093	114,633	126,161
2017	113,532	121,689	133,935
2018	117,822	126,526	138,726
2019	122,352	131,325	143,506
Average Annual Change	5.5%	6.3%	6.9%

Table 8. Population Potential, by County, Medium Scenario, Williston Region, North Dakota, 2014-2019

Year	Divide County	McKenzie County	Williams County
2014	6,678	19,726	70,402
2015	7,247	21,419	76,831
2016	7,874	23,274	83,485
2017	8,359	24,706	88,623
2018	8,691	25,688	92,146
2019	9,021	26,663	95,641
Average Annual Change	6.2%	6.2%	6.3%

Minot Region

Total population potential was estimated to grow in each of the three scenarios over the 2014-2019 period in the Minot region (Figure 16). Growth in total population potential was largely driven by forecasted growth in regional employment over the period, although the relative difference in population among the scenarios is smaller in the Minot region than in the other regions. Average annual growth in population could be around 2 percent in the Minot region.

The Minot region was estimated to have a total population *potential* around 123,500 at the end of 2014 in the medium scenario, which includes permanent residents, shift workers, seasonal construction workers, and dependents and spouses of workers living in non-permanent lodging arrangements (Table 9). The total population potential in 2019 was estimated to be around 137,000 for the Minot region, *assuming* housing is supplied and occupancy rates remain valid.

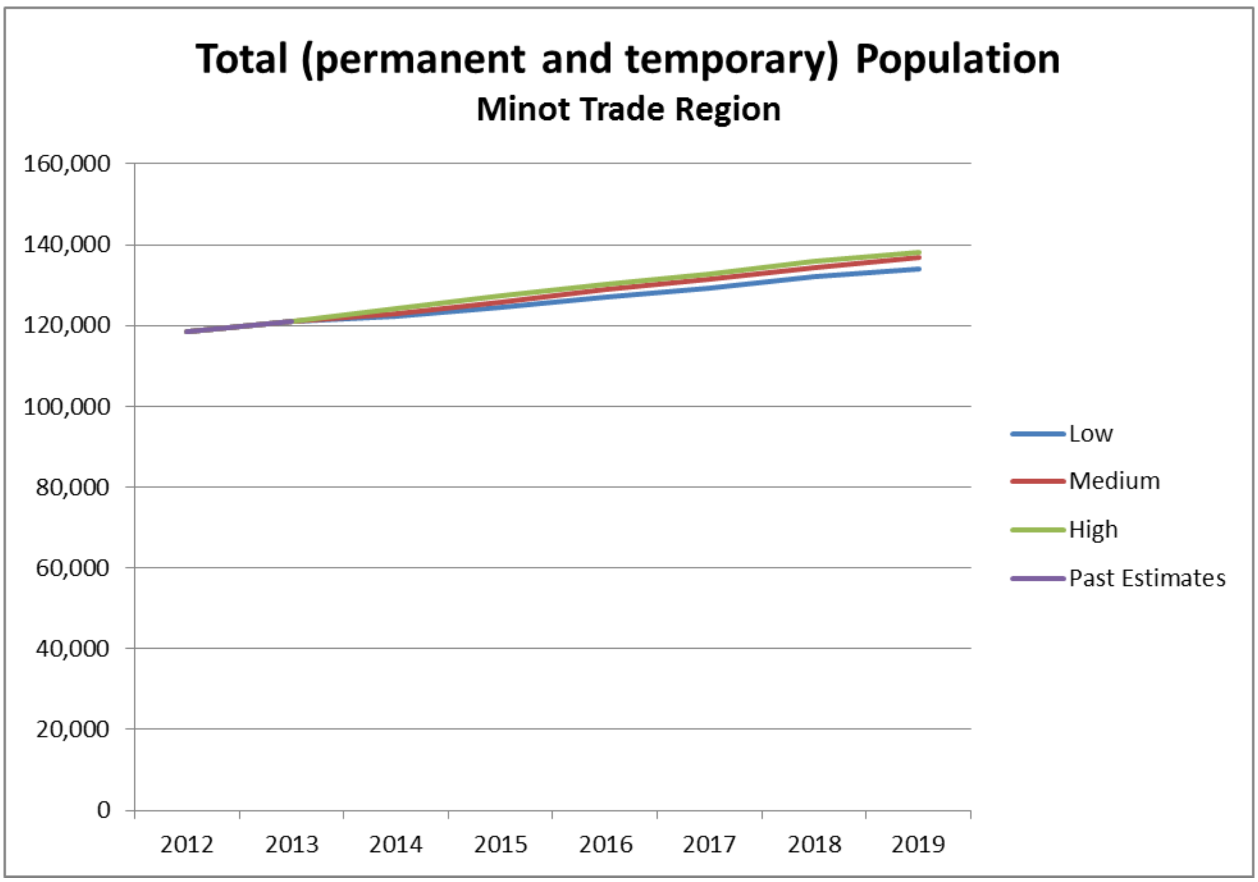

Figure 16. Population Potential, Minot Region, North Dakota, 2012-2019

Table 9. Population Potential, by Scenario, Minot Region, North Dakota, 2014-2019

Year	Low Scenario	Medium Scenario	High Scenario
2014	125,763	126,699	127,985
2015	127,780	129,204	130,711
2016	130,608	132,370	133,810
2017	132,821	135,036	136,402
2018	135,588	138,075	139,568
2019	137,694	140,574	142,010
Average Annual Change	1.8%	2.0%	2.1%

Table 10. Population Potential, by County, Medium Scenario, Minot Region, North Dakota, 2014-2019

Year	Bottineau County	Burke County	McHenry County	Mountrail County	Pierce County	Renville County	Ward County
2014	10,807	3,161	7,705	13,011	5,501	3,858	82,656
2015	10,991	3,169	7,816	13,358	5,548	3,905	84,418
2016	11,190	3,220	7,965	13,766	5,643	3,975	86,612
2017	11,344	3,257	8,082	14,126	5,714	4,029	88,484
2018	11,526	3,303	8,220	14,528	5,800	4,092	90,606
2019	11,660	3,334	8,324	14,876	5,861	4,139	92,380
Average Annual Change	1.5%	1.1%	1.6%	2.7%	1.3%	1.8%	2.2%

Dickinson Region

Total population potential was estimated to grow in each of the three scenarios over the 2014-2019 period in the Dickinson region (Figure 17). The relative difference in population among the scenarios was larger in the Dickinson region than in the Minot region, but lower than growth potential forecasted in the Williston region. Average annual growth in population could be around 5 percent in the Dickinson region.

The Dickinson region was estimated to have a total population *potential* around 60,000 at the end of 2014 in the medium scenario, which includes permanent residents, shift workers, seasonal construction workers, and dependents and spouses of workers living in non-permanent lodging arrangements (Table 11). The total population potential in 2019 was estimated to be around 77,000 for the Dickinson region, *assuming* housing is supplied and occupancy rates remain valid.

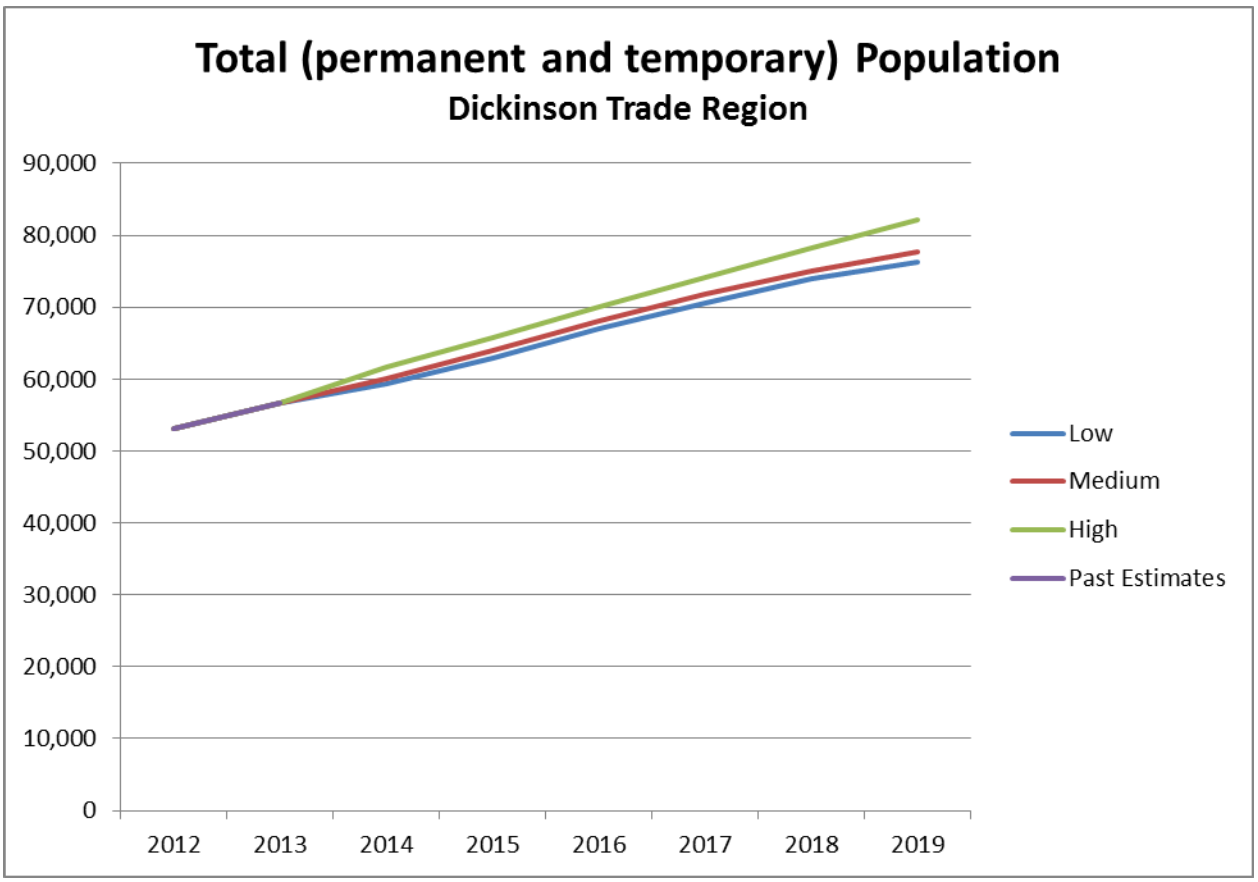

Figure 17. Population Potential, Dickinson Region, North Dakota, 2012-2019

Table 11. Population Potential, by Scenario, Dickinson Region, North Dakota, 2014-2019

Year	Low Scenario	Medium Scenario	High Scenario
2014	58,990	59,970	61,583
2015	62,409	63,778	65,605
2016	66,429	67,970	69,895
2017	70,063	71,629	73,922
2018	73,461	74,795	78,033
2019	75,605	77,483	81,866
Average Annual Change	5.1%	5.3%	5.9%

Table 12. Population Potential, by County, Medium Scenario, Dickinson Region, North Dakota, 2014-2019

Year	Adams County	Billings County	Bowman County	Dunn County	Golden Valley County	Hettinger County	Slope County	Stark County
2014	3,327	1,301	4,805	5,735	2,489	3,706	1,334	37,273
2015	3,549	1,382	5,124	6,127	2,653	3,911	1,538	39,496
2016	3,755	1,461	5,449	6,529	2,812	4,144	1,626	42,195
2017	3,928	1,527	5,729	6,879	2,947	4,342	1,701	44,575
2018	4,072	1,582	5,970	7,182	3,061	4,508	1,762	46,658
2019	4,188	1,626	6,171	7,438	3,154	4,643	1,811	48,453
Average Annual Change	4.7%	4.6%	5.1%	5.3%	4.9%	4.6%	6.4%	5.4%

Social Impacts

Several recently published papers have provided reviews of literature dealing with the broad subject of social impacts related to rapid natural resource development in rural communities (Putz et al. 2011; Doherty 2012; BBC Research and Consulting 2013; Jacquet and Kay 2014). Research into the social issues surrounding rapid resource development can be traced back to expansion of the oil and gas industry, coal mining, power plant construction, and large-scale water management projects in the 1950s and 1960s. Studies into the social and socio-economic impacts of natural resource development continued in the 1970s and early 1980s as western United States underwent rapid expansion of coal, oil, and natural gas extractions, partly in response to the Arab Oil Embargo and US domestic energy policies (Murdock and Leistritz 1979).

The synthesis of the early work examining the consequences of rapid energy development in rural areas of western United States lead to the 'boomtown' model or 'social disruption hypothesis' (Jacquet and Kay 2014). Essentially, the modern understanding of the effects of rapid energy development–substantial population change, in-migration of workers, overwhelmed public services, degradation of quality-of-life factors, among other issues such as community planning and development challenges–emerged as a model to characterize and generalize the impacts on rural communities experiencing rapid growth and economic disruption. However, much of the early work focused on qualitative aspects (e.g., attitudes, perceptions) of the communities and residents impacted by rapid developments. Subsequent evaluations, and research into the phenomenon of how communities are impacted by substantial and rapid natural resource developments, incorporated more quantitative methodologies, examined longitudinal perspectives, narrowed the focus to case-study approaches, and attempted to refrain from broad-sweeping conclusions (BBC Research and Consulting 2013; Jacquet and Kay 2014).

Current social impact assessments include both qualitative and quantitative measures of the effects of rapid natural resource development on small communities. The boomtown model of energy development and associated community impacts has been applied to recent unconventional shale gas and oil plays (Jacquet 2009; Macke and Gardner 2012; Doherty 2012). However, adjustments to the understanding and applicability of the boomtown model to generalize the effects of unconventional oil and gas developments were emerging during the mid 1980s (Gramling and Brabant 1986). These adjustments are reflective of the difference in scale (e.g., geographic footprints), length and pace of energy development, connectivity and isolation of impacted communities, mechanisms to share and distribute energy-related public revenues, and general composition of energy industries between conventional energy development of the 1970s and 1980s with modern unconventional (e.g., shale) energy developments. Despite the differences between the social impacts observed during the 1970s and 1980s and those more recently observed with shale energy development, a number of generalizable effects can still be used to describe the social and socio-economic effects of rapid natural resource development.

The following is a synthesis of expectations and observations linked to rapid energy developments (Jacquet and Kay 2014; Putz et al. 2011; Macke and Gardner 2012; Doherty 2012; BBC Research and Consulting 2013).

- Development of natural resources requires a substantial labor force. Local labor supply is usually inadequate to fulfill those needs, resulting in influx of new workers to an area.

- Local communities often experience a substantial increase in population relative to initial thresholds.

- As population increases, community resources and services become inadequate.
    - Housing supply is exhausted, leading to housing shortages and cost escalations.
    - Public utilities cannot keep up to increased demands.
    - Demands for medical, law enforcement, schools, and other public/private services increase, and can become overwhelmed.
    - Local governments experience lags from when impacts occur and when funding mechanisms provide revenues.

- Wage rates escalate, putting additional pressure on housing markets.

- Recreational amenities are inadequate for the increased population, and when combined with cost-of-living increases, quality of life attributes become compromised.

- Communities are unable to address growth in both scale and pace to satisfy new workforce. Workers become disenfranchised with living arrangements, and are not engaged in the community.

- Workforce issues include high turnover and challenges recruiting and retaining qualified workers.

- The number and rates of crime increase in the region.

It is clear that much of the Williston Basin is experiencing many of the classic boomtown challenges associated with rapid natural resource development. What is less clear is to what extent the impacts on North Dakota communities will follow the traditional prescriptions described in the social impact literature. Unconventional energy developments have distinctly different localized effects as a result of the intensity, and duration of oil field development and operations compared to traditional energy developments. Researchers are just beginning to understand the potential long-term ramifications of these differences on the social impacts of affected communities.

Based on projections for increases in employment, housing needs, and population, the following general social impacts are likely to be observed in the next five years in the Williston Basin.

- Social disruptions associated with increased employment opportunities and growing populations will continue

- Housing costs and cost of living will likely remain high

- Demands for medical, law enforcement, schools, and other public/private services increase

- Community resources will continue to be strained

Economic Impacts

NDSU studies examining the economic contribution of the petroleum industry to the North Dakota economy have been conducted biennially since 2005. The studies measure the gross business volume (direct and secondary economic activity), state and local tax revenues, and employment linked to exploration, production, transportation, and processing of oil and gas in North Dakota (Bangsund and Leistritz 2007, 2009, 2010; Bangsund and Hodur 2013b). Those studies found that the economic effects from the oil and gas industry have increased dramatically since the initial stages of shale oil development in the Williston Basin. Another study by IHS Inc. (2012), provided year-point estimates of the economic contribution in the oil and gas industry in 2012, 2020 and 2035 for U.S. states. That study suggested the economic contribution of the oil and gas industry, measured using value-added economic activity, would continue to grow in North Dakota from 2012 through 2020.

From 2005 through 2011, the primary driver of economic growth in the industry in North Dakota was associated with exploration and development of new wells (Figure 18). In real terms, the expenditures made by oil operators (firms owning oil wells) for leasing, drilling, fracking, and well completions increased over 1,100 percent from 2005 through 2011. Contrasting that growth, expenditures made in North Dakota for oil and gas production (general business expenses of firms owning oil wells, severance taxes, expenses for well maintenance and oil field services) increased about 290 percent in real terms over that same period. In terms of absolute expenditures, the industry spent nearly $2 in exploration/development for every $1 associated with oil and gas production from 2009 through 2011. During that period, the industry was intensely pursing lease holds in the Williston Basin, and that process resulted in a continuing increase in rig counts through the middle of 2012. Since 2012, the industry has pulled back from the drilling intensity needed to secure lease holds, and has demonstrated that in-field drilling is likely to be conducted at a pace lower than observed during the lease hold phase of drilling.

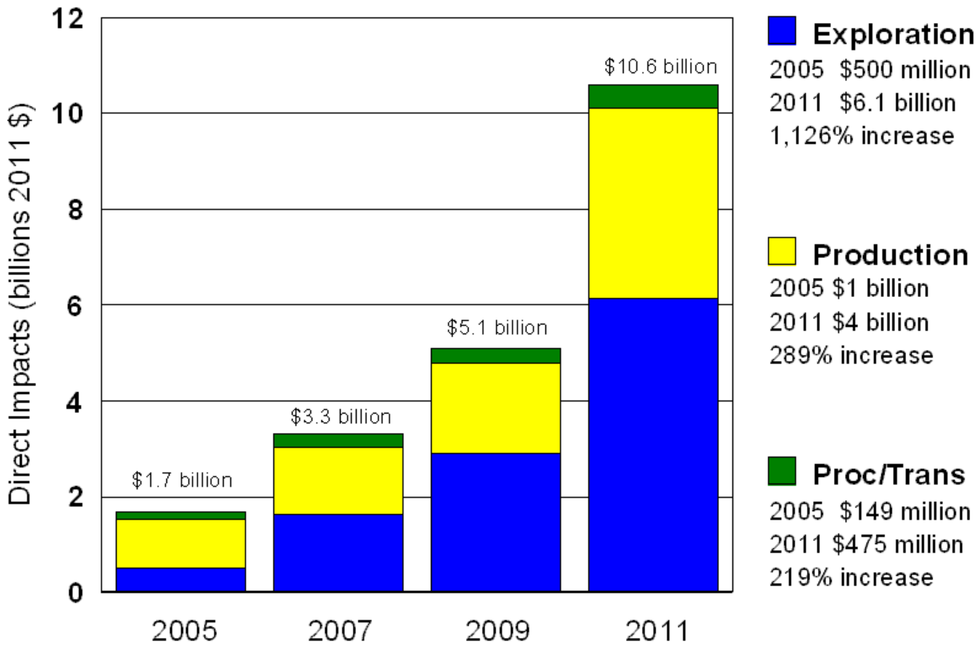

Figure 18. Estimated In-state Expenditures and Retained Earnings, Oil and Gas Industry, North Dakota, 2005 through 2011.
Source: Bangsund and Hodur (2013b).

Looking forward, what is the prognosis for the statewide economic effects associated with the oil and gas industry in North Dakota? Combining recent studies on the economic contribution of the oil and gas sector in North Dakota with projections of rig counts and well counts yielded the following insights.

• Exploration/Development--economic impacts likely to moderate, but remain steady. Costs to drill a well have moderated in the last 18 months; however, steady drilling activity is likely to result in relatively constant level of expenditures by the industry for well drilling, fracking, and well completions.

• Oil and Gas Production--economic impacts will increase, which includes activity associated with oil field service, well maintenance, and other industry service requirements in the oil patch. Severance taxes will be subject to production volumes and prices received by oil operators in North Dakota. With projections for production to slowly increase from around 1 million barrels per day to 1.2 million barrels per day, constant prices would result in increases in severance tax revenues, where as small declines in prices would probably act to keep severance tax revenues steady.

• Processing and Transportation--economic impacts from those industry activities will increase in the future as more processing capacity is brought on-line in the state and as pipeline and rail loading capacities are expanded to handle an anticipated growth in oil and gas production. However, economic effects from this segment of the industry have been shown to be much lower than the impacts from exploration or production.

• Infrastructure--economic impact from those activities will remain steady as the industry continues to add gathering systems to collect and move crude oil, gas, and brine water and as the industry adds other facilities associated with recycling, business centers, and transportation networks. A study by IHS Global (2013) recently forecasted capital spending associated with oil and gas transportation and storage infrastructure, and predicted the oil and gas industry will continue to infest substantially in natural gas and crude oil infrastructure in the Midwest region of the U.S.

• Economic Leakage and Secondary Business Activity--A key part of the economic effects of the state's basic-sector industries is the amount of goods, inputs, and services directly supplied by in-state firms. Also, as part of the secondary economic effects[4], provision of goods and services to the petroleum industry and the in-state spending of personal income generated in the state are important components of the overall economic effects of the industry. The degree to which the ND economy can expand and provide goods and services to the industry and the expanded workforce will affect the level of secondary business growth in the state. In the case of employment, workers that are not residents of the state, but rather commute in/out of the state for work, have much different spending patterns than workers that reside permanently in the state. Bangsund and Hodur (2013b) found that about half of the development expenses necessary to drill, frack, and complete a well were associated with goods and services directly provided by out-of-state firms. The economic leakage associated with the acquisition of goods and services from firms in other states presents the state with economic opportunities. Also, considerable economic opportunity exists to retain a larger percentage of the personal income produced by employment in the industry. Quantitative data on the percentage of workers in the Williston Basin currently employed in North Dakota but retaining permanent residency in other states in unknown.

Debate on national energy policy is likely to intensify in coming years as domestic issues emerge pertaining to oil export restrictions and domestic energy infrastructure. A complex set of conditions are coalescing within the U.S. petroleum energy markets which is spurring debate on oil export policy. Those factors include a preference by U.S. refineries to use heavy crude since

[4]Secondary economic effects are often divided into induced and indirect effects. Induced effects are a measure of the business activity generated as a change in demand for goods and services in a given economic sector works through other sectors in a specified economy. Indirect effects measure how a change in personal spending, which is linked to a change in personal income (e.g., wages, salaries, proprietor earnings), also creates additional business activity as firms need to acquire more inputs and services to meet the additional demand associated with consumer spending.

most facilities recently invested in ‘cracking’ equipment calibrated for heavier crudes, supply of domestic light crude has been increasing and national production has been forecasted to continue to increase, U.S. domestic crude oil consumption is largely stagnant, and perceived positive economic benefits to the U.S. economy from expansion of domestic oil supplies though unconventional sources. The combination of those factors, among others, has lead to the speculation that the U.S. will see a surplus of light crude oil in the future. One means to address the new changes is to allow domestically produced crude oil to be exported and sold in international markets. In 2014, members of the U.S. Senate Committee on Energy and Natural Resources asked the Energy Information Association to provide insight into several specific issues relating to a remove of crude oil export ban in the U.S. The issue of exporting crude oil is now being debated as part of current U.S. energy policy.

Three recent reports--ICF International (2014), IHS Global (2014), and a policy brief by Resources for the Future (Brown et al. 2014)--each evaluated the national economic implications of removing existing crude oil export bans. The ICF International (2014) and IHS Global (2014) studies are lengthy, and details pertaining to assumptions and modeling techniques will not be covered here. Instead, a brief synopsis of the conclusions and implications for North Dakota are presented.

Brown et al. (2014) discussed a series of anticipated market reactions to lifting the crude oil export ban in the U.S. The study suggests that light crude oil prices in the Midwest would rise towards world prices, the resulting increase in crude oil in international markets would in turn put downward pressure on international crude oil prices, assuming no meaningful response from OPEC. Improved efficiency in refinery operations and competitive pressures were expected to reduce the crack spread, which would lead to another series of market reactions. Those reactions would be an increase in the supply of refined products while also seeing a boost in international demand for crude oil, putting downward pressure on prices on refined products and upward pressure on crude oil prices. Given the above market movements, the world price of crude oil increases slightly ($0.15 barrel), but crude oil prices in the Midwest region of the United States would increase much more ($6.49 barrel). The study suggested those price effects could translate into an increase in domestic oil supply from the Midwest of around 84,000 barrels per day. Additionally, the associated increase in worldwide refinery output would increase, and domestically the U.S. would see a reduction in gasoline prices ranging from 1.7 to 4.5 cents per gallon. The study also speculated on the potential likely responses from OPEC, but concluded that there was little consensus on OPEC behavior associated with a lifting of the U.S. export ban.

ICF International (2014) evaluated four scenarios to gauge the potential domestic and international market response to removing the U.S. crude oil export ban. The four scenarios were based on a high and a low future price spread between West Texas Intermediate and Brent crude prices and a base case of no crude oil exports and an alternative case allowing crude oil exports. The study suggested that domestic oil production would increase if exports were allowed and imports of heavier crude oil would increase, but the U.S. would remain a net importer of crude oil. An increase in U.S. crude oil in the world market would lead to slight declines in world oil prices. However, domestically, the differential between WTI and Brent crude narrows, resulting in price increases for WTI crude. Higher WTI prices were expected to result in increases in oil drilling rates relative to the base case of no crude oil exports. The study further extended the analysis to evaluating potential market responses for refined petroleum products, and the subsequent consumer price effects in the U.S. Allowing crude oil exports was expected to result in price decreases around 3.8 cents per gallon, weighted by gasoline, heating oil, and diesel fuel. Relative to the base case of no crude oil exports, the economic impacts were estimated to be an increase in employment, government revenues, and national GDP.

IHS Global (2014) provided an analysis of the potential price, production, and economic effects of comparing two base cases (expected and potential) of future domestic oil production with free trade and restrictive trade policies. The study estimated that lifting an export ban on crude oil would result in an increase in domestic crude oil production above expected and potential future production forecasts. The net economic effects (i.e., those effects above what is expected from the industry) of allowing crude oil exports would be lower consumer prices for gasoline, increased investment in oil and gas production, and increases in GDP, employment, and government revenues. Other impacts included discussion of the change in petroleum-related trade imbalance, change in average annual personal income of U.S. households, refining capacities, and price effects.

Overall market responses to a lifting of the crude oil export ban largely hinge on market elasticities[5]. A number of dynamic elements would be placed into motion in a reversal of crude oil export policy in the U.S. It is important to recognize that market drivers and mechanisms change, and sometimes market behavior, especially global market response from other oil exporting countries (e.g., OPEC nations) is difficult to predict. Also, market responses tend to adjust and change overtime, and can introduce dynamic elements and market forces which make precise and definitive conclusions from broad sweeping policy changes difficult to predict. Perhaps the conclusions from such a policy change will evolve as the issue receives more debate, but the current understanding is that removing the export ban in the U.S. might be positive to prices for oil production in the Williston Basin. Generally, a reversal of U.S. policy on exporting crude oil would act to alleviate congestion in existing domestic markets and likely strengthen domestic prices for light sweet crude. If domestic prices for light sweet crude were to increase as a result of domestic exports, conclusions at this time suggest those effects might increase the forecasted pace and scale of oil field development in unconventional shale plays. Those conclusions are predicated on a host of factors playing out in international oil markets, and are also contingent upon a number of assumptions, many of which could work to reduce the effectiveness of price responses associated with U.S. oil exports if market responses differ from predicted. Regardless, if price effects (both the type and magnitude anticipated by recent studies) on light sweet crude are positive, but remain insufficient to increase production in the Williston Basin above what would occur without a change in national policy, North Dakota

[5]Elasticity is a measure the responsiveness of changes in one variable to the changes in another variable. Market elasticities are often measured for changes in demand or supply relative to changes in prices.

could benefit from an increase the value of oil production, which would be translated into an increase severance tax collections. Any consensus on what direction the U.S. is leaning on crude oil export policy would be premature; however, the issue could have direct implications for North Dakota.

Fiscal Impacts

With large state fiscal surpluses and growing revenues from an expanding state economy, near-term fiscal health of the state government does not appear to be a primary concern. Near-term expectations for steady physical and economic output from the oil and gas industry act to reinforce those perceptions.

The future fiscal health of local governments in the Williston Basin is likely to garner more debate than concerns of fiscal health with state government. Recent research by Duke University (Raimi and Newell 2014), as part of the Duke University Energy Initiative, evaluated the fiscal conditions facing selected local governments in a number of shale energy developments around the United States. The research project collected data on the revenues and costs to city and county governments directly impacted by shale energy development.

While some dimensions of that research are ongoing and more reports are scheduled to be published in the future, the conclusions drawn to this point are that the net fiscal condition (revenues minus costs) have generally been positive for most shale energy developments around the country. However, the local fiscal impacts of shale energy development in Montana and North Dakota were clearly identified as running counter to conditions found in other regions of the United States.

Raimi and Newell (2014) highlighted the net fiscal condition experienced by selected county and city governments in western North Dakota impacted by shale energy development. The local governments included were the counties of Dunn, McKenzie, and Williams, and the cities of Watford City, Williston, and Dickinson. The net fiscal conditions in North Dakota ranged from small to large net negative, and were generally considered worse for municipalities than for counties.

The study indicates that local government revenues have increased, in relative terms, more than generally found with local governments in other shale energy impacted regions in the United States. However, the intensity of development relative to the initial size of the local economy (i.e., jobs, population) is perhaps the most significant among the regions evaluated in the study.

The authors conclude that the scale and speed of population growth has led to costs increasing more than changes in revenues for the local governments in the Williston Basin. Conclusions regarding the net fiscal condition looking forward were not addressed by the study.

The net fiscal condition of local governments in the Williston Basin in the future will be a function of numerous factors. Revenues, both in terms of shared severance taxes and local collections of property and sales taxes, will play a critical role in the fiscal condition of local governments. Costs incurred by governments attempting to manage employment and population growth will be the other primary factor.

Other research into the fiscal effects of unconventional energy development on local communities has been conducted by Headwater Economics (2011, 2012). Those studies concluded that development of shale oil in western North Dakota and eastern Montana presents greater challenges to communities than conventional oil development. Shale oil will likely produce higher well counts and prolonged levels of development activity, thereby placing more continuous strain on local governments. Also discussed was that effects on local infrastructure are more intensive with unconventional oil development compared to conventional oil development. Therefore, local impacts of resource development are likely to occur over longer periods, and the localized effects are expected to be greater in magnitude that observed with conventional oil development. The studies highlighted the importance of providing proper timing of revenue sharing, due in part to the lags between well drilling and production, the rapid decline in oil production from shale wells, and the prognosis for extended periods of intensive oil development. Those dynamics suggest that policies developed for mitigating the impacts of conventional oil development on local communities may not be well suited to mitigating the impacts of unconventional oil development.

Considering the 5-year prognosis steady well drilling activity, expansion of employment in the oil and gas industry, and growth in employment in other sectors of the regional economy, growth in both permanent and service populations will continue to pressure local government finances in the Williston Basin. As the economy expands, demands for services, infrastructure, and social amenities also will grow. For decades, most communities in the Williston Basin dealt with strategies for the provision of public goods and services in a climate of population stagnation or decline. Shale oil development has dramatically changed the economic landscape in the region, and now communities must manage unprecedented growth in employment and population, and deal with prolonged periods of oil development that will place a continuous strain on local infrastructure. Current development has focused largely on addressing infrastructure to provide basic needs, such as housing, roads, and water and sewer capacity. While communities struggle to meet those basic needs, long-term development also must incorporate the provision of public goods and services, community amenities, and other factors that address quality of life attributes in the region.

Overview of Long-term Effects of Rapid Development

The impacts of energy development have been discussed, researched, and debated for as long as fossil fuels have served as the primary source of energy in the United States. A brief examination of literature was conducted to draw perspectives on the issues discussed in this report. Insights gained from recent shale gas plays perhaps hold the most relevance to the current energy development in the Williston Basin.

A key theme to employment change associated with rapid natural resource development pertain to how the influx of workers creates issues for local communities and regional economies. Some of these impacts have been categorized into distinct periods that coincide with the type and focus of industry activities (Jacquet 2009, Macke and Gardner 2012). Others have described these effects in more general context as how they relate to community-level impacts (Leistritz et al. 1982, Seifert 2010, Putz et al. 2011).

Generally, the effects of rapid development result in wage escalation, labor force shortages, housing shortages, increases in living costs, and strain on local private and public resources. There are both short-term and long-term consequences of those effects.

The short-term impacts disrupt local economies as rapid population and employment change strain local infrastructure. These conditions result in shortages for housing, labor, and regional resources (Macke and Gardner 2012, Jacquet 2009, Putz et al. 2011, Seifert 2010). Competition for resources prevents local economies from adding lower wage employment (e.g., retail trade, lodging, consumer services).

The long-term effects associated with heightened competition for labor, housing, and regional resources are associated with a decline in the overall economic health of other industries (Macke and Gardner 2012, Farren et al. 2012, Putz et al. 2011, Headwaters Economics 2008, Humphreys 2007). These effects have been given several terms (e.g., resource curse, crowding out, Dutch Disease), but regardless of the name, the result is that local and regional economies have less diversity, less resiliency, and an increased propensity for reduced economic output in the long run. Additional concerns include prevention of new industries from emerging in the affected regions (Seifert 2010).

Crowding out effects can also be demonstrated by evaluating changes in basic-sector employment relative to non-basic sector employment. An assessment by Seifert (2010), using QCEW data from Job Service North Dakota, revealed that employment is becoming less diverse in the Williston Basin as the regional economy experiences substantial growth in oil and gas industry employment. Observations from the North Dakota Input-Output Model Database reveal a similar trend as the ratio of basic-sector employment to non-basic sector employment is increasing in the Williston Basin (Coon et al. 2012).

Effects of rapid resource development can vary dramatically among affected communities (Raimi and Newell 2014; Jacquet 2009; Putz et al. 2011). Some of the factors discussed in previous sections describing constraints to job creation are consistent with observations of crowding out effects during the development phase of oil and gas resources. In addition, employment has already become less diverse in the Williston Basin which is consistent with other discussions describing concerns for the long-term viability of non-oil and gas industries in areas experiencing rapid development of natural resources.

Conclusions

The goals of this report were to provide a broad overview of potential socio-economic effects of the oil and gas industry in the Williston Basin from 2014 through 2019. Forecasted values for employment, housing needs, and population potential were presented and the implications for social, economic, and fiscal impacts were discussed.

Employment

- Employment in the oil and gas industry in the Williston Basin will continue to grow but at a pace slower than observed in the previous five years.

- Growth in secondary jobs is expected to continue despite housing costs and availability and workforce shortages.

- Total employment in the Williston Basin will continue to grow over the next 5 years due to a combination of growth in the oil and gas industry and secondary job creation (e.g., retail, transportation, wholesale, personal services, business services, finance, government sectors).

- The rate of growth in total employment from 2014 through 2019 is forecasted to be less than the rate of growth from 2009 through 2012.

Housing Needs

- Housing needs continue to grow with an increase in employment.

- Lack of affordable housing will continue to support a number of negative drivers
    - Force some workers to remain living in non-traditional lodging arrangements
    - Reinforce wage escalation and high cost of living
    - Reinforce employment patterns involving periods of on-work/off-work that enable workers to leave the region when not working
    - Continued reliance on commuting in/out of the region
    - Negative driver for quality of life of residents and workers

Population

- The key driving metric in population change in the Williston Basin remains the growth in employment.

- Permanent population will be largely driven by the supply of permanent housing in the region.

• Due to a lack of housing, the region will continue to have a total (service) population that is substantially larger than the permanent population measured by the U.S. Census.

• Forecasted rates of change that are possible in the Williston Basin suggest continued difficulty in meeting the needs for public infrastructure and public services. The potential for growth rates to be above 2 percent annually is considered likely in the majority of oil producing counties.

Fiscal Issues

• Recent research is indicating the net fiscal balance is negative for local governments affected by shale oil development in western North Dakota.

• Local governments will continue to be pressured financially over the next five years

- Employment and population are expected to continue to expand.
- Steady rates of drilling and development will continue to impact local infrastructure.
- Community needs will extend beyond traditional infrastructure (e.g., roads/streets, housing, sewer/water) and will include delivery of public services and quality of life amenities.

Forward Looking Issues

• Domestic energy policy as it relates to oil and gas infrastructure and oil exports is likely to be debated in the coming years and has direct implications for North Dakota.

• Williston Basin will continue to need adequate capacity to ship an increasing supply of crude out of the region.

• The long-term effects associated with competition for labor, housing, and other resources are associated with a decline in the overall economic health of other industries. The potential exists for those macro-economic effects to become a concern in western North Dakota and should be part of a broad policy to ensure economic health of all industries in the state.

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Appendix C

NDSU: Quality of Life in the Oil Country: Perceptions, Perspectives and Future Implications

NDSU NORTH DAKOTA STATE UNIVERSITY

Quality of Life in the Oil Country: Perceptions, Perspectives, and Future Implications

North Dakota Legislative Management
North Dakota Oil and Gas Impacts Study

August, 2014

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NDSU NORTH DAKOTA STATE UNIVERSITY

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About the Author

Felix Fernando is a doctoral student in the Natural Resources Management Program, with a focus on sociology and economics, at North Dakota State University (NDSU). He has an MBA also from NDSU. His undergraduate education is in environmental sciences and business. His research focuses on studying the social and economic conditions created by the oil boom in western North Dakota and its influences on quality of life, community values, and community planning and development.

This report is based on original research conducted as a part of the doctoral dissertation

Introduction

Conditions created by oil development are the biggest driving force of Quality of Life (QoL) in western North Dakota. Although factors such as marital status, health, and age cause differences in QoL at an individual or personal level, it's possible to construct a realistic QoL framework that is useful in community planning and development, by examining the conditions and context of oil development and its impact on community constituents. QoL depends on both monetary and non-monetary factors or conditions. Many non-monetary conditions (both positive and negative) caused by the oil development affect the whole community. These conditions can be organized under four main domains or spheres that make up a person's life: family experience, employment experience, social experience, and community experience. Figure 1 lists these non-monetary conditions, which undergird the four domains that affect the whole community.

Monetary factors include both income and cost of living considerations. At a stakeholder cluster or group level, there are considerable income disparities between lease or mineral rights owners, business owners, oil industry workers, and other groups such as service industry workers (retail, dining, childcare, and recreation, etc.), public servants (law enforcement, teachers, nurses, city maintenance staff, etc.), senior citizens, and others on fixed incomes. Exorbitant or unaffordable rents (or home prices) account for significant differences in cost of living between those who own a home and those who do not. As a result, differences in QoL among heterogeneous stakeholder clusters seems to stem mainly from two factors: positioning in the economic/income structure and level of exposure to local inflation, which is largely driven by status of home ownership (owned/rented). Figure 1 is organized such that perception of QoL of a stakeholder group changes from positive to negative when moving from left to right (the stakeholder groups on left have a positive perception of QoL compared to stakeholder groups in the right). The next section provides a brief description of QoL of each cluster.

Please Note: The stakeholder clusters analyze and explicate QoL at a group level based on income and cost of living considerations. An individual might belong to more than one cluster. For example, a person might work in the service industry and own his home while another person working in the service industry might be living in rented housing. The QoL of these two persons will be different as described in the proceeding sections. The section on individual perception of QoL discusses how individual circumstances and contexts influences and determines their QoL.

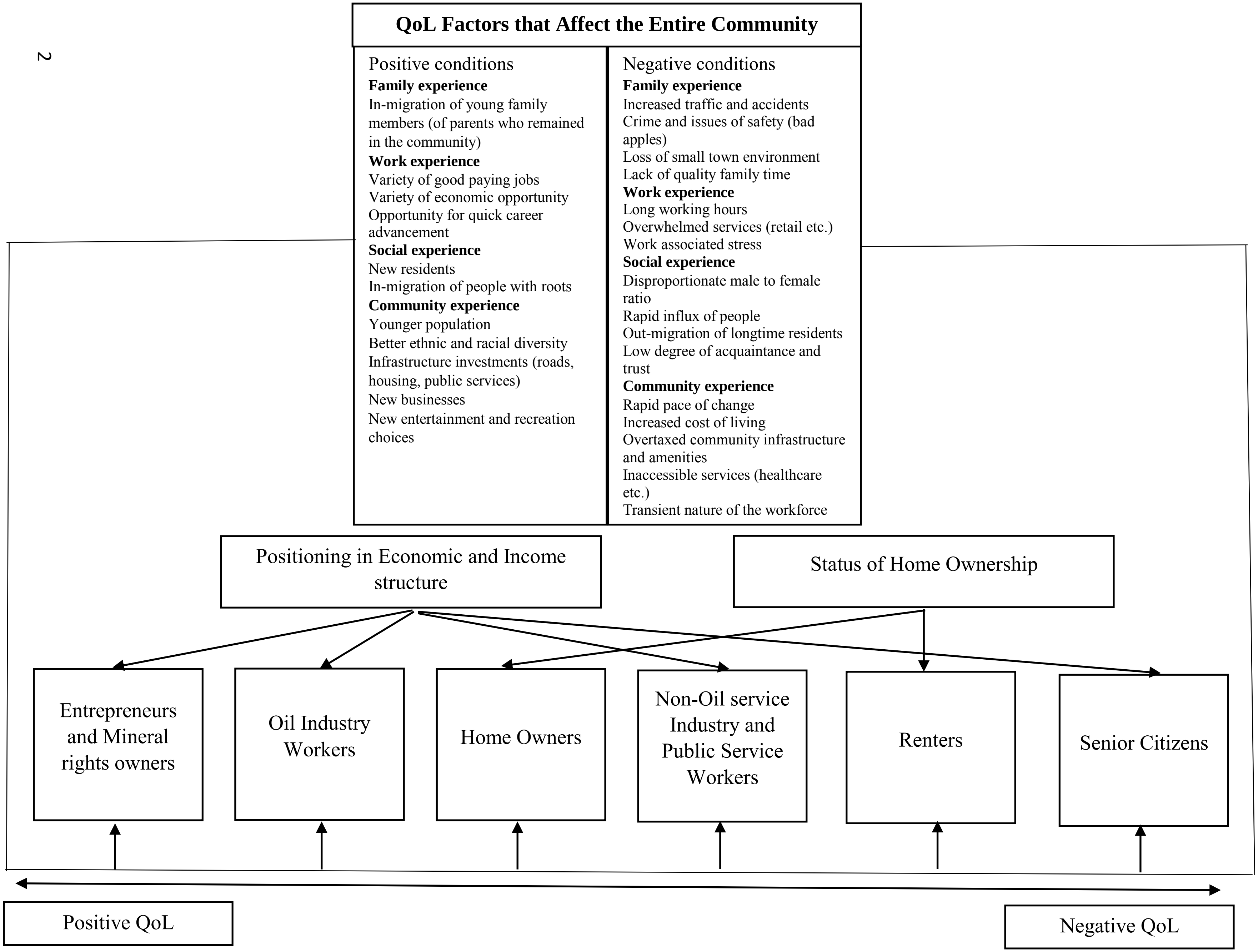

Figure 1: QoL in Western North Dakota

The Community Cluster (Conditions that affect the whole community)

Oil development has created many positive conditions that affects QoL. The biggest positive impact is the favorable work experience. Oil industry and associated services have generated a variety of primary and secondary jobs. In addition the increase in population has led to increased employment in virtually every economic sector of the community resulting in lower unemployment, job security, and opportunities for career advancement. Conversely, the work experience has been negatively affected by long hours and work schedules, overwhelmed supporting services, and work associated stress.

Community experience also has been positively affected by oil development. Communities that experienced declining populations for many years are experiencing growth. Most of the incoming people are younger, lowering the average age of the community. The incoming people with diverse cultures and ethnicities bring with them a variety of food choices, arts, and ethnic experiences to what were once homogenous communities. In addition, oil development has spurred infrastructure investments (housing, roads and other infrastructure), new businesses (dining retail, shopping etc.), new entertainment and recreation choices (community centers, city parks), and efforts to enhance public services.

However, the positive impacts on the community experience have been compromised by several negative impacts. Most of these impacts are created by too many people living in a community that wasn't designed or developed to accommodate the present way of life. These include: rapid pace of change, increase in cost of living, overtaxed community infrastructure (crowded schools, roads, emergency services), and inaccessible or lack of available amenities (restaurants, health care, retail, and other businesses). Transient (people who are in the community for a short period of time and move away or those workers who go back to their home communities during days off and holidays) nature of the workforce decreases the level of commitment and treatment of the community as a place of home where the communities become merely a place of work. The lack of commitment and concern for the community can lead to irresponsible acts (littering) and behavior (bar fights, reckless driving, etc.) that affects QoL of residents.

Increased demand for virtually every community amenity/ service as a result of rapid influx of people has made accessing services such as healthcare, daycare, and social services a considerable challenge for all community members. Although many people have experienced higher incomes, increase in cost of living has offset the positive effect on monetary QoL (part of QoL that is based on income and economic benefits), especially for those living on rented housing. Furthermore, QoL of people living in small rural communities has been negatively affected by noise, increased traffic on rural roads, and dust. Although traffic might not be heavy compared to traffic in a larger city or metro area, the change is substantial as it is perceived though the lens of life before the boom where traffic was non-existent.

Social experience has been positively affected by in-migration of people with roots in the community and new residents to the community. The economic opportunity created by the boom has brought back many young people who grew up in western North Dakota, but moved away looking for better opportunities. These people have re-established their friendships and social relationships. Comparatively, disproportionate male to female ratio, rapid influx of people, and out-migration of longtime residents has negatively affected the social experience. In addition, busy work schedules and long work hours do not allow sufficient time for socializing. Residents no longer know most other residents in the community or in their neighborhoods (low degree of acquaintance), which was the norm before the boom. As a result, the unity and trust in each other within the community has been negatively affected.

Western North Dakota was considered as a suitable place to raise a family before the boom by the people living in the area. In-migration of young family members who moved away has positively affected the family experience as parents are happy to have them back in the community. However, the family experience has been negatively affected by increased traffic and accidents, loss of small town environment, crime and issues of safety, and transient people who do not care about the community. Irrespective of whether increase in crime is proportional to increase in population, residents' perception regarding crime and safety in their community has changed. Additionally, extended work schedules or long work hours limit the amount of time that families can share together.

Entrepreneurs and Mineral Rights Cluster

This cluster includes mineral rights owners, other easement (pipelines etc.) or lease owners, business owners, and land lords. These people have experienced substantial income gains because of the oil boom. As a result, their monetary QoL has substantially improved. However, they also are affected by the negative factors outlined in the community cluster. As a result, their perception of QoL is a tradeoff between positive and negative factors and how they prioritize factors that constitute QoL.

Oil Industry Worker Cluster

Most people working in the oil industry or associated services enjoy high incomes. But many oil jobs are physically exhausting, require long hours of work, and demand specific training or skills. Therefore, these aren't jobs that any worker could undertake. The high incomes provide ability to spend, which improves the monetary QoL that positively affects the family experience. However, long hours of work can generate stress, pressure, and lack of quality time to spend with family, which negatively affects the family experience and social experience.

Non-oil Industry Cluster

Non-oil industry cluster includes land owners who don't own mineral rights or other leases (including farmers), private service industry workers (retail, dining, entertainment, child care, and other services), and public service workers (city/county government workers, nurses, social service workers, teachers, law enforcement, emergency workers, and maintenance workers). There is a considerable disparity in income between this stakeholder group and other high income earners (entrepreneurs, oil industry workers, and lease rights holders etc.). Although non-oil workers enjoy increased incomes compared to conditions before the boom or compared to elsewhere in the country, the high cost of living has off-set much of the potential improvement in QoL because of increased income. The high prices of newly constructed homes has also made it very difficult for many people working in the service industry to buy a house. As a result, many new people who moved into the community that work in the service industry are living in rented housing and the high rents are the main reason for substantial increase in cost of living. Additionally, many people in the service industry are working long and extended hours or in some cases working 2-3 jobs in order to afford the cost of living, which has negatively affected their work, social, and family experiences.

Home Owners Cluster

Home ownership was identified as the biggest factor which determines the level of exposure to cost of living or local inflation. Those who own the house they live in are only exposed to an increase in the general cost of living. The situation is much different for people living in rented housing as the cost of rented housing has increased by two or three fold in some cases, which has substantially increased their the cost of living. Owning a home (especially owning a home before the boom) insulates a person from such negative impacts or substantial increases in cost of living.

Additionally, prices of most newly constructed single family homes are over $250,000 and are not easily affordable to many people working in non-oil jobs. Therefore, owning a home in present housing market conditions is a considerable challenge for many new residents, especially if they are not working in the oil industry. As a result, some young families or residents moving into the community have had to move in with their parents or share housing with several others to make it affordable. Therefore, it is possible for an extended family to be living in the same house, which is not customary and negatively affects QoL.

Renter Cluster

Renter cluster includes people living in rented properties (homes and apartments). As explained above this is a stakeholder cluster that has been negatively affected by the oil boom. A swift increase in demand for housing has increased the rents and housing prices two or three fold. As a result, some renters have had to share living arrangements with several others which negatively affects their QoL. Instances of people sharing a home with 6-12 others were expressed during the interviews.

Senior Citizens Cluster

Senior citizens (those who have reached the age of retirement) are one of the stakeholder groups (as a group) that has been negatively affected by the oil boom. Seniors on fixed incomes (if they don't benefit from minerals or other leases) don't have the capability to adapt to a rapid or substantial increase in the cost of living. As a result, most seniors living in rented housing have been negatively affected by increased rents. In addition, seniors are affected by difficulties in getting around due to traffic, loss of way of life they are accustom to, overwhelmed community amenities (and the resulting waiting lines), inability to access services such as healthcare (few doctors serving the entire community), which negatively affects their social and community experience. These factors have compelled or forced some seniors to leave the community.

Individual Perception of QoL

In order to understand QoL from a personal/individual perspective it's important to consider how many and which clusters an individual belongs to. For example, examination of figure 1 shows that a mineral rights owner living elsewhere might enjoy the best QoL as mineral rights provide financial benefits while not having to endure negative impacts outlined under the community cluster. However, mineral rights owners living in the community also are affected by the negative factors identified under the community cluster. Their perception of QoL is therefore a tradeoff between positive (economic and other positive factors outlined in the community cluster) and negative factors of the community cluster. Comparatively, a senior living in rented housing or a service industry worker living in rented housing most likely has the worst perception of QoL. A service industry worker living in rented housing comparatively makes less money (than a person working in the oil industry) but still has to bear the high costs and might have to share housing with several people to make it affordable, resulting in negative perception of QoL. A senior who owns his home does not face the exorbitant rents but has to bear the other changes outlined under the senior citizens cluster. Therefore, by examining and identifying the different clusters an individual belongs to it's possible to gain a realistic understanding of individual perception of QoL.

Potential Future Changes in QoL

Whether QoL of stakeholder groups identified in this report will improve or become worse within the next 5 years depends on certain projections, assumptions, and factors.

- Level of drilling: Can be expected to continue at current rates generating and maintaining the current levels of employment and economic activity (Lynn Helms, Industrial Commission)
- Interest for employment in the Bakken area: One of the main reasons for the rapid influx of people into the communities in western North Dakota is the lack of economic opportunity in some parts of the country. But as the national economy recovers, job creation in other parts of the country may have a significant impact on the decision to stay in the Bakken area, especially on those employees who don't have any roots, connections, or family in the area. But population in the area is expected to continue increase as per the population projections (Bangsund and Hodur: NDSU Employment, Housing and Population projections, 2014).

- Population dynamics: With in-migration of younger people and families the average age in the community can be expected to decrease (North Dakota State Data Center). As a result, community needs will reflect the needs of a younger population. Therefore, QoL life decisions will have to consider the changes in population dynamics.

- Housing demand: The demand for housing is expected to grow as per the housing projections (Bangsund and Hodur: NDSU Employment, Housing and Population projections, 2014).

Under these circumstances the demand for community services and amenities can be expected to grow in the next 5 years. As a result, the future direction of change in QoL will depend on five main factors or drivers. Figure 2 summarizes these potential conditions and future direction of QoL for the next 5 years. The section below describes these factors and their potential influence on QoL.

- Availability of affordable housing: The increase in housing supply should address the increase in housing demand and as a result according to demand and supply mechanisms the rent and housing prices can be expected to come down to a certain level. But the extent of reduction in rents and housing prices also depends on several other factors such as higher initial investment costs as a result of high real estate prices, higher costs of construction (labor and materials), shorter expected payback periods, and transition from temporary worker housing to conventional housing. If the rents/housing prices decrease it will largely improve the QoL of people working in non-oil service industry, public sector, and seniors. But if housing affordability continues to remain an issue it will instigate a cycle that will affect several stakeholder groups and overall community in several ways.

    - Seniors or non-oil service industry workers living on rented housing have been and will continue to be severely strained by housing costs. They may have to share housing with several other tenants. Such living situations negatively affects the QoL of these community members. Subsidized housing, especially for seniors living on rented housing will improve QoL as seniors don't have the capacity to increase their income.

    - If non-oil service industry workers move out because they cannot find suitable and affordable housing, it will create a significant challenge for existing service industry businesses and potential new businesses. Shortage of labor in the service industry will continue to challenge delivery of services, stress the existing workforce, and create longer waiting lines or service times or the industry will have to further increase wages, which will adversely affect cost of living.

  - Similar to the service industry, lack of affordable housing hinders expansion of public services as many existing and potential employees might not be able to find affordable and suitable housing. As a result, many public services such as law enforcement, health, education, emergency services, and city services face a tough challenge when trying to hire new employees to cater to the increased demand. Many local government entities have to offer housing in order to attract potential employees. Although several temporary housing solutions (such as buying or constructing houses or apartment complexes) have been adopted, available housing units are fully occupied and there is a need to recruit more employees to satisfy the needs of a growing population. Inability to enhance public services will adversely affect QoL.

  - Residents or young families with local roots who moved back into the community, may initially move in with parents or extended family. If they are working in the oil industry then they would have the economic capability to eventually move into a home of their own. But if they are not working in the oil industry, the current high housing prices pose a significant challenge for owning a home. As a result, extended living conditions (living with parents or with many others) for a long period of time can negatively affect QoL.

  - Lack of affordable housing also affects oil industry employees and other employees who want to bring their families to western North Dakota, especially if they are unable to sell their homes elsewhere under present housing market conditions of those communities. As a result, the workforce can become transient where they work in western North Dakota while their homes and families are elsewhere (Although some workers are transient by choice more workers would be tempted to bring their families if they can find suitable and affordable housing). These workers who don't have their families close by might experience lack of quality family time or family support that will negatively affect their QoL.

  - Potential new businesses will face the challenge of securing the necessary workforce. As a result it might affect business decisions to move into the community.

- Level of investment in community infrastructure: Investments in roads, housing, and other community infrastructure such as parks, other recreational choices, and community centers will enhance the QoL (such as the new community center in Williston or additions to community center in Dickinson). Better roads will address issues of traffic, safety, and accidents, which will improve QoL. Community centers and recreational choices will provide opportunities for community members to become engaged and build social networks and relationships.

- Level of investment in public services: Investment in public services such as law enforcement directly affects QoL by improving the sense of safety and security in the community. Better schools, health, and other public services will address the needs of a younger population, which will improve QoL.

- Attraction of new businesses: New businesses will enhance the choices and variety of services available to the community members. New businesses will also ease the burden on existing businesses, especially in the retail and dining sectors.

- Community integration and interaction programs: Before oil development, community members used to know almost everyone else in the community, which contributed towards trust and unity within the community. The rapid influx of people has affected or disrupted some of these social networks. Therefore, it's important to develop community programs that will bring together and enhance integration among community members to build trust and unity.

Conclusion

It might be very difficult to manage or sustain certain QoL factors such as the small town environment or rapid pace of change during a period of social and economic transformation. Many of the communities in western North Dakota might never revert to the small town communities they were before shale oil development, especially if the expected magnitude and extent of oil and gas development becomes a reality. Therefore, there is less control over these factors that affect QoL. However, focusing efforts and resources on the five forces or drivers (availability of affordable housing, investment in community infrastructure, investment in public services, attraction of new businesses, and community integration programs) identified in this report can significantly improve the QoL for all members in the communities of western North Dakota within the next five years.

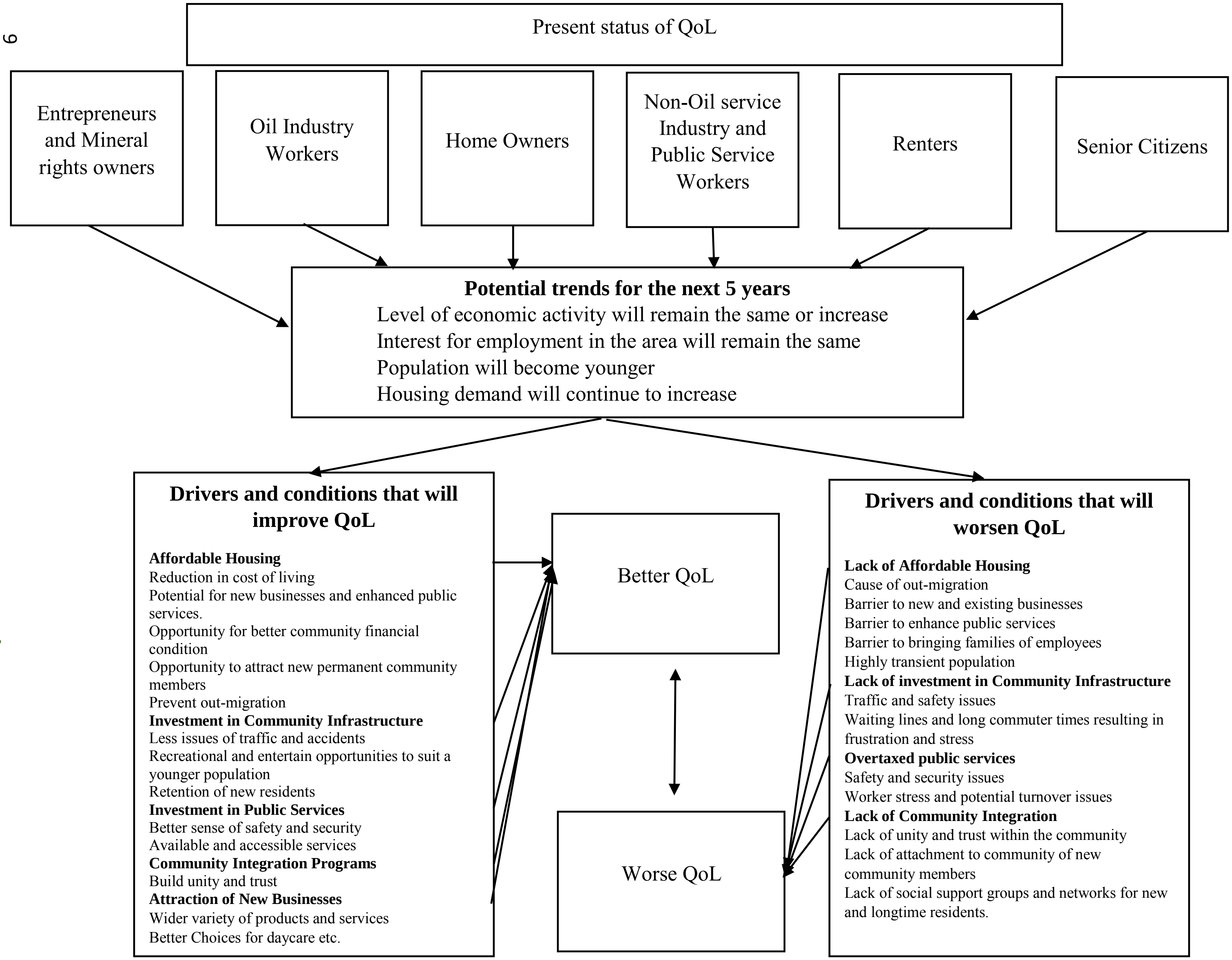

Figure 2: Potential future direction of QoL

Appendix D

EERC: Evaluation of Near-Term (5-year) Potential for Carbon Dioxide Enhanced Oil Recovery in Conventional Oil Fields in North Dakota

EERC
Energy & Environmental Research Center®
Putting Research into Practice

EVALUATION OF NEAR-TERM (5-YEAR) POTENTIAL FOR CARBON DIOXIDE ENHANCED OIL RECOVERY IN CONVENTIONAL OIL FIELDS IN NORTH DAKOTA

Final Report

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2014-EERC-07-07 July 2014

EERC DISCLAIMER

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EXECUTIVE SUMMARY

Kadrmas, Lee & Jackson commissioned the Energy & Environmental Research Center (EERC) to complete a study of near-term (5-year) potential for carbon dioxide enhanced oil recovery (CO_2 EOR) in North Dakota.

CO_2 EOR is a mature oil development tool that can be used to reinvigorate conventional oil fields currently under waterflood or to extract oil from tight reservoirs where waterflood would be ineffective (Gunter and Longworth, 2013). In conjunction with other nontraditional technologies such as horizontal drilling and hydraulic fracturing, CO_2 EOR should be recognized as part of a long-term production strategy for North Dakota oil fields.

This report emphasizes factors that contribute to the economic success of new CO_2 floods in existing conventional oil units and uses these criteria to screen and rank North Dakota unitized fields to calculate the relative likelihood of each unit to produce oil as part of a CO_2 EOR operation within the next 5 years (before 2020). Screening criteria used include 1) oil production, 2) non-Bakken production, 3) nonterminated unit agreements, 4) waterflood initiated more than 10 years ago, and 5) passing previous screening studies. Scoring and ranking criteria for the 86 North Dakota units which met the screening criteria were 1) proximity to CO_2 supply pipeline, 2) estimated incremental oil, 3) well spacing, and 4) estimated required field maintenance. The top ten ranked units have a combined estimated recovery of between 82.7 million and 186.2 million barrels of oil (MMbbl), requiring between 13.9 million and 83.6 million tons (MMt) of CO_2. Total combined estimated recovery from the 86 ranked units studied is between 280 and 631 MMbbl, requiring between 47 and 283 MMt of CO_2.

Two CO_2 pipelines may act as near-term sources for a North Dakota tertiary recovery. The CO_2 supply from the Dakota Gasification Company (DGC) is currently delivered via pipeline to the Weyburn–Midale CO_2 project in southeastern Saskatchewan, Canada. However, the Boundary Dam Power Plant near Estevan, Saskatchewan, is scheduled to begin delivering CO_2 to Saskatchewan oil fields in late 2014, which may enable DGC to begin marketing CO_2 to North Dakota oilfield operators. The Greencore pipeline, which currently terminates at the Bell Creek Field in southeastern Montana, is the next-closest existing source of CO_2 to North Dakota. Outside of a new CO_2 capture project at an existing power plant or other large-scale stationary CO_2 source, these two pipelines are the only large-scale near-term sources of CO_2 in the region.

There is significant opportunity in North Dakota to produce additional oil from well-established conventional oil fields through CO_2 EOR. The primary challenges in the near term are the acquisition of sufficient CO_2 and a focus by operators on this target and away from the attractiveness of the Bakken petroleum system. **There is strong potential that, within the 5-year time frame which is the focus of this study, the Bakken petroleum system may develop into a CO_2 EOR target, which would have a large effect on these projections and would be expected to be a strong driver of CO_2 EOR in North Dakota. The Bakken system has, specifically, not been evaluated as part of this study.**

EVALUATION OF NEAR-TERM (5-YEAR) POTENTIAL FOR CARBON DIOXIDE ENHANCED OIL RECOVERY IN CONVENTIONAL OIL FIELDS IN NORTH DAKOTA

INTRODUCTION

As part of a larger scope of investigation for the North Dakota Legislative Management Committee led by Kadrmas, Lee & Jackson (KLJ), the Energy & Environmental Research Center (EERC) conducted an evaluation of the near-term (2014–2019) potential for future oil production from carbon dioxide (CO_2)-based enhanced oil recovery (EOR) operations in the conventional oil fields of North Dakota. This baseline study (reported here) focused on an examination of existing conventional oil fields currently undergoing secondary recovery operations and provides the basis for estimates of incremental oil production through the process of CO_2-based EOR. In addition, an evaluation of likely and potential near-term CO_2 sources was conducted. Screening of predetermined oil fields with the greatest CO_2 EOR potential combined with information pertaining to the proximal and likely CO_2 sources allowed identification of which fields are the most likely candidates to come online as tertiary producers within the study time window and beyond.

CO_2 EOR

Production of oil resources in conventional oil fields proceeds in multiple phases. Primary oil production occurs when oil in the ground is either forced out of the ground by internal pressure or lifted by wellhead pumps. Over time, less oil is available to be pumped to the surface, and a declining amount of oil is recovered (Figure 1). Secondary production (or waterflood) occurs when a group of wells within a field (ranging from several to several hundred) is unitized. Unitization can be defined in both engineering and legal terms: the first meaning that all oil extracted from the unit is to be pooled as one source, and the second is determining how revenue from that oil is to be divided among the unit owners. Secondary recovery converts some wells to water injectors, the water into which increases the pool pressure and sweeps oil toward production wells (hence the legal definition; injection well owners are contributing to the unit's total production, but they are not directly getting any oil out of the pool).

Tertiary oil recovery, often referred to as EOR, can be initiated when waterflood production declines to the point at which it is only marginally economical. A common injectate in this phase of field development is CO_2. As with waterflood operations, CO_2 EOR programs also employ injection and production wells, and the injection wells will commonly switch between CO_2 and water. While water is an immiscible liquid for recovery (it does not mix with oil), CO_2 injected above the minimum miscibility pressure (MMP) interacts with the oil to create swelling (and, hence, increased reservoir pressure) and reduce the viscosity of the oil. These physical changes allow CO_2 to sweep more oil toward production wells than water alone (Jarrell and others, 2002). Immiscible CO_2 floods are also possible but not as efficient (Gunter and Longworth, 2013). The most important consideration of CO_2 EOR is the availability of CO_2 in enough quantity at an affordable price (Stilwell and others, 2009; Gunter and Longworth, 2013).

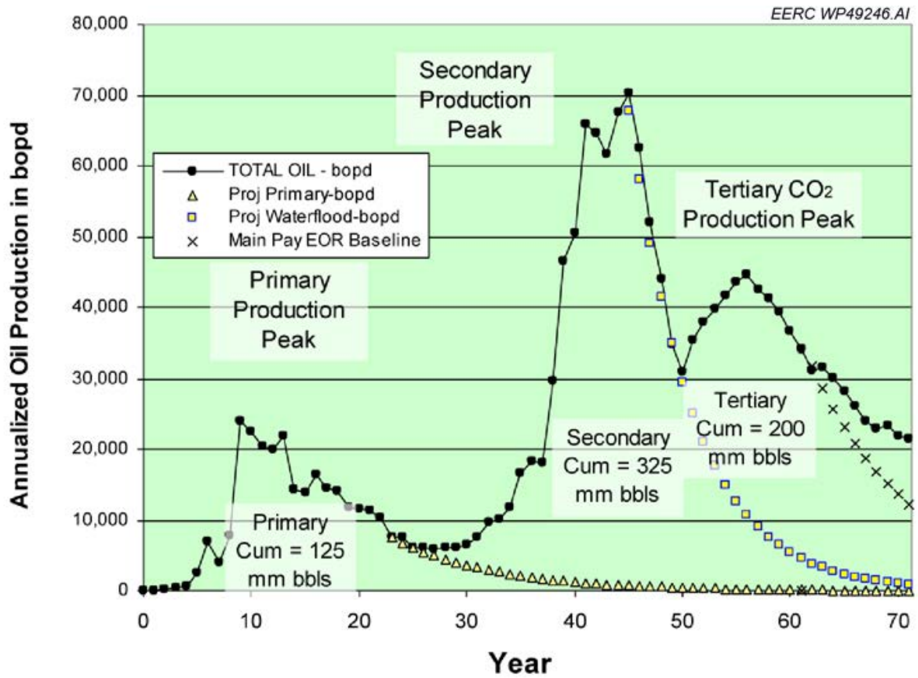

Figure 1. Example of field decline curve (from Hill and others, 2013).

CO_2 EOR has higher up-front costs than primary or secondary production, mostly related to reworking of existing wells, construction of CO_2 injection and recycling infrastructure in the field, and CO_2 supply pipeline construction (Godec, 2011); however, these costs can be offset in large enough fields because of an estimated tertiary recovery of at least 8% of the original oil in place (OOIP) (Gunter and Longworth, 2013; Jarrell and others, 2002).

North Dakota Unitized Fields

In modern hydrocarbon production field practices, prior to the initiation of subsurface activities that will affect the fluid distribution and production within an area, mineral ownership tracts may be legally combined to form a larger working area. The process of establishing a geologically and legally defined zone and combining individual ownership tracts within that zone is referred to as unitization, and the working area created by this process is referred to as a unit. The effective result of unitization is primarily threefold: 1) the correlative rights of all mineral owners within the designated area are protected, 2) net revenues are apportioned among all parties with interests in the field, and 3) injection and reservoir management practices are coordinated to improve the efficiency of petroleum extraction (Sorensen and others, 2009).

It is often stated that oil reservoirs that have demonstrated good waterflood response are the best candidates for successful CO_2 flooding (Nelms and Burke, 2004; U.S. Department of Energy, 2010). The basis for this generalization is that the geologic properties of a reservoir that are conducive to profitable waterflood operations will also be favorable to a CO_2 flood. It is this relationship that focused the work of this effort and earlier efforts on unitized fields.

The geographic distribution of unitized fields in North Dakota can be broken down into four general areas: 1) the Cedar Creek Anticline (CCA) in the southwest, 2) the Nesson Anticline in the north, 3) the greater Billings nose area, and 4) the northeast tier (Figure 2).

Previous Work

At least four previous studies have addressed the possibility of CO_2 EOR in North Dakota oil units (Nelms and Burke, 2004; Smith and others, 2005, 2009; Bohrer and others, 2006). The most comprehensive of these is split between Nelms and Burke (2004) (methodology and results) and Burke (2005) (data and output). Multiple methods were used by these authors to screen established units for CO_2 EOR potential (Table 1). Gunter and Longworth (2013) created a scoring and ranking method for Alberta, Canada, oil pools, but it was limited to those pools in which a pilot CO_2 EOR operation had occurred. The previous studies have estimated that CO_2 EOR in North Dakota could produce between 261 and 286 MMbbl of incremental oil (oil beyond secondary recovery) and store about 141 MMt of CO_2.

METHODS

Objectives

The objective of this study was to determine which North Dakota oil units are more likely to convert from waterflood to CO_2 flood within the next five years (2014–2019). This was accomplished by 1) identifying meaningful screening (Figure 3) and ranking criteria for oilfield units, 2) summarizing these data for units in North Dakota, and 3) ranking those units in order of CO_2 EOR near-term potential, based on the scoring system described as follows.

Overview and Prescreening

A list of 123 current and terminated units in North Dakota was created from the North Dakota Industrial Commission (NDIC) Web site and other sources (Nelms and Burke, 2004; Smith and others, 2005, 2009; Bohrer and others, 2006; Burke, 2005). Unit reservoir characteristics were drawn mainly from an internal EERC database, but other sources were used to verify certain information. OOIP values were taken mainly from the NDIC Web site.

During the screening process, 37 units were not included (Table 2) in the ranking process for various reasons that include age (less than ten years since waterflood injection began), the unit was terminated, it produced natural gas only, it was screened out by Nelms and Burke (2004) and Burke (2005) for reservoir-specific reasons, and it was in an unconventional oil reservoir (Bakken units were not included in the current analysis). The remaining 86 conventional oil units comprise 1057 active (as of April 1, 2014) oil and gas production wells out of a statewide total of 9639 active oil and gas wells. Ninety-four new wells have been spudded in these units in the last 12 months (April 2013 – March 2014), although well type remains confidential for most. A total of 2356 new wells were spudded in North Dakota during this period (North Dakota Industrial Commission, 2014).

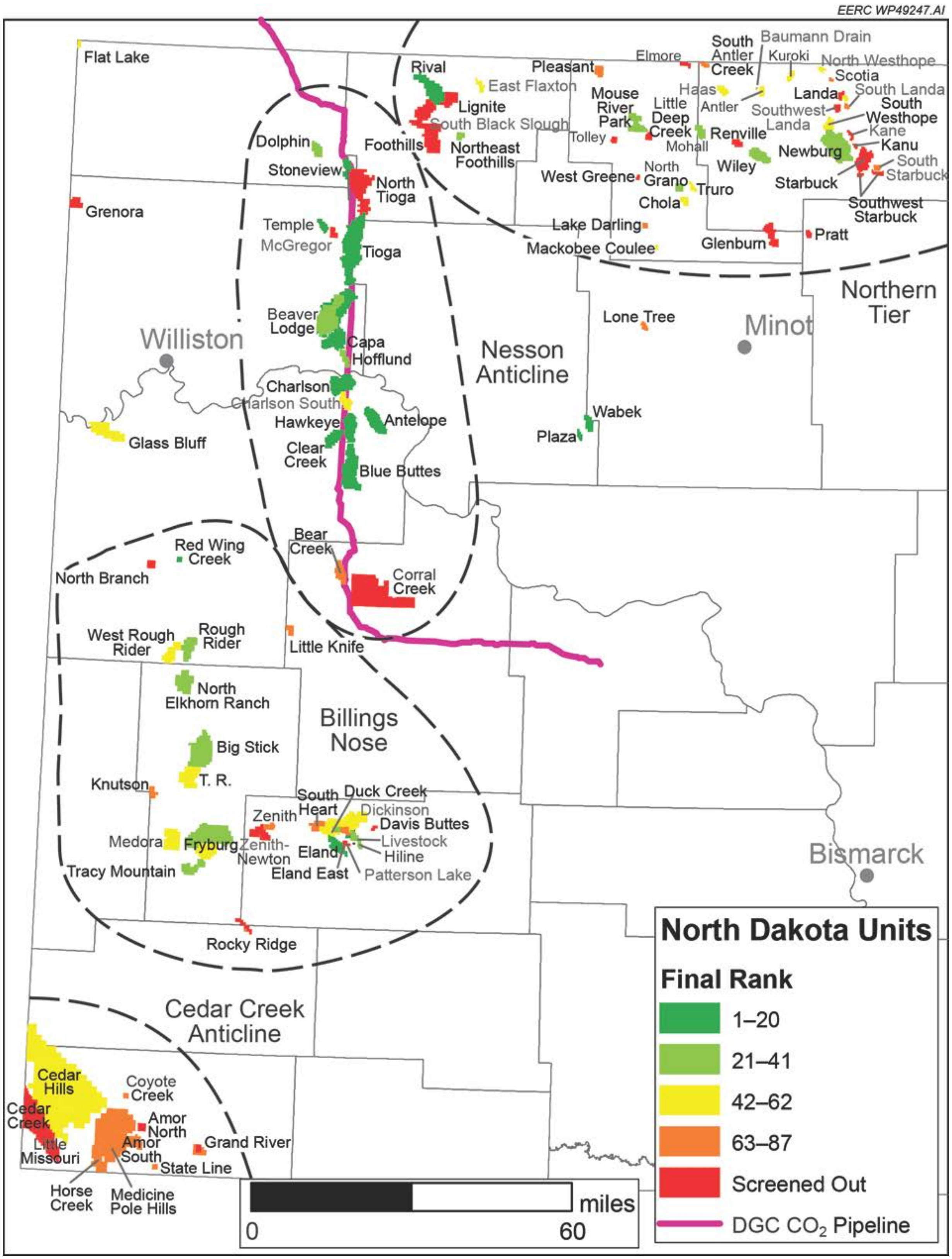

Figure 2. Geographic distribution of units (color-coded according to final rank).

Table 1. CO_2 EOR Screening Criteria Used in Previous Studies

Source:	Nelms and Burke, 2004	Bohrer and others, 2006	Smith and others, 2006, 2009, from Bachu and others, 2004
Reservoir Depth, ft*	>2500		
Reservoir Pressure, psi			>200 greater than MMP (1450–2175)
Reservoir Temperature, °F			90–250
Oil Gravity, °API	>25		27–48
Oil Viscosity, cP	<10		
Porosity, %	>12		
Permeability, mD	>10		
Waterflood Oil Recovery Factor, % OOIP	20–50		
Waterflood Response	"Good"		
Active Wells		>5 (Madison) >3 (Devonian) >2 (Red River)	
Water Saturation, %		<45 (Madison, Devonian) <50 (Red River)	
Primary EUR, bbl		>1,000,000	

* Proxy for pressure.

The prescreened conventional units were ranked according to reservoir and development characteristics. Four criteria were used to rank units for near-term CO_2 EOR potential:

- Distance from each unit to existing CO_2 pipelines
- Well spacing
- Estimated incremental oil
- Estimated unit reworking

Each is described in more detail below.

Each criterion yielded a numeric value that was used to create a rank score for that unit that expresses the relative fitness of the unit, with lower scores being more fit. For example, the unit with the 10th-largest estimated incremental oil value (Newburg/Spearfish–Charles) received a rank score of 10. Units with equal values for a given criterion were given equal rank scores, and the next rank score was skipped (Table 3). For example, if two units have a criterion rank score of 12, the next-ranked unit would have a rank score of 14; if three units had a rank score of 23, the next-ranked unit would have a rank score of 26. Final rank scores for each unit were calculated as the sum of each of the criterion rank scores. All criteria scores were equally weighted.

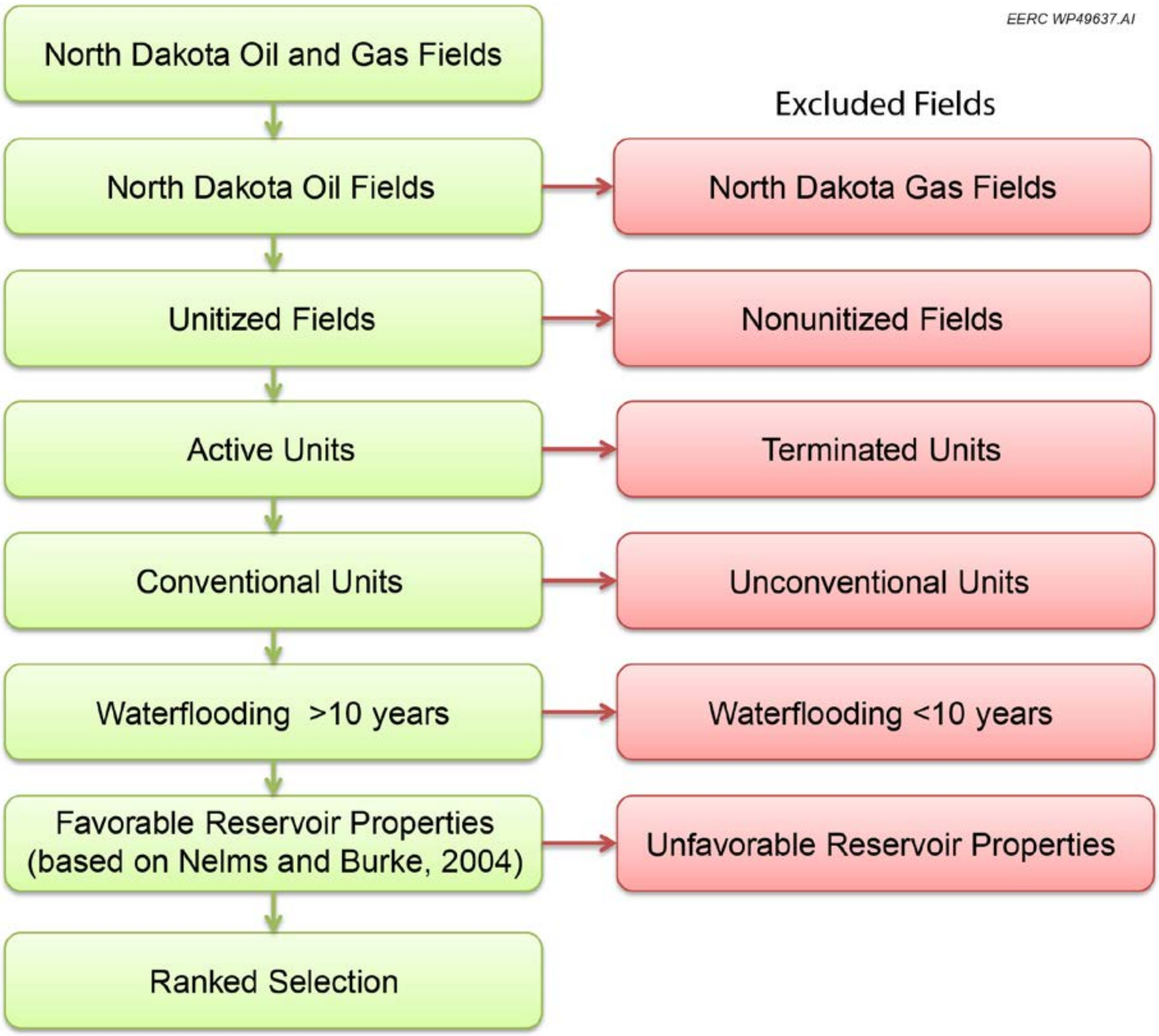

Figure 3. Screening process for North Dakota oil fields.

Although the screening and ranking process described here takes into account general engineering and economic guidelines, analysis of the engineering challenges unique to each unit remains important. Such analysis may include detailed geologic assessment and static or dynamic computer modeling of CO_2 injection into the target pool to discover challenges before tertiary development begins (Figure 4, second stage).

Distance to Existing CO_2 Pipelines

Providing a substantial, efficient, and consistent supply of CO_2 to an EOR project requires a means of transportation from CO_2 sources (natural or anthropogenic). The only realistic option is the use of pipelines, and pipeline construction is expensive (approximately $75,000 per mile per inch of pipe internal diameter; e.g., 1 mile of 10-inch pipe would cost $750,000), so distance from potential units was determined to be an important factor in estimating which unitized field may be first to initiate a CO_2 flood. Two existing CO_2 pipelines are potentially accessible to

Table 2. North Dakota Units Screened Out of Additional Analysis

Field Unit	Reason Screened Out
Cedar Creek Pierre	Natural gas only
Little Missouri Pierre	Natural gas only
Patterson Lake Lodgepole	Natural gas only
Foothills Madison	Unit agreement terminated
Grenora Madison	Unit agreement terminated
Lignite Madison	Unit agreement terminated
North Black Slough Midale	Unit agreement terminated
North Tioga Madison	Unit agreement terminated
Rocky Ridge Southeast Heath T[1]	Unit agreement terminated
Rocky Ridge Central Heath	Unit agreement terminated
South Black Slough Midale–Rival	Unit agreement terminated
Zenith–Bell Heath	Unit agreement terminated
Zenith Heath	Unit agreement terminated
Corral Creek Bakken	Bakken producer
Grand River Red River	Did not pass screening by Nelms and Burke (2004)
Davis Buttes Tyler	Did not pass screening by Nelms and Burke (2004)
Renville Madison	Waterflood less than 10 years
Eland East Lodgepole	Waterflood less than 10 years
Tolley Madison	Waterflood less than 10 years
Glenburn North Madison	Waterflood less than 10 years
McGregor Winnipegosis	Waterflood less than 10 years
Elmore Madison	Waterflood less than 10 years
Glenburn South Madison	Waterflood less than 10 years
West Green Madison	Waterflood less than 10 years
Glenburn Central Madison	Waterflood less than 10 years
Pratt Madison	Waterflood less than 10 years
Landa West Madison	Waterflood less than 10 years
Starbuck Madison	Waterflood less than 10 years
North Branch Devonian	Waterflood less than 10 years
Kanu Madison	Waterflood less than 10 years
Little Deep Creek Madison	Waterflood less than 10 years
Southwest Starbuck Madison	Waterflood less than 10 years
Southwest Landa Madison	Waterflood less than 10 years
Southwest Starbuck Spearfish	Waterflood less than 10 years
Kane Madison	Waterflood less than 10 years
Amor North Red River	Waterflood less than 10 years
Zenith Newton–Heath	Unit agreement terminated

[1] Two units with this name exist; one is still operational. The T (terminated) notation differentiates them on the NDIC Web site.

Table 3. Example of Oil Unit Ranking with Tied Values

Unit	Distance to Pipeline, miles	Distance to Pipeline Rank
Blue Buttes Madison	0.22	10
Capa Madison	0.7	11
Beaver Lodge Devonian	1.37	12
Beaver Lodge Ordovician	1.37	12
Beaver Lodge Silurian	2.35	14
Antelope Devonian	3.65	15
Antelope Madison	3.65	15
Dolphin Dawson Bay	3.66	17

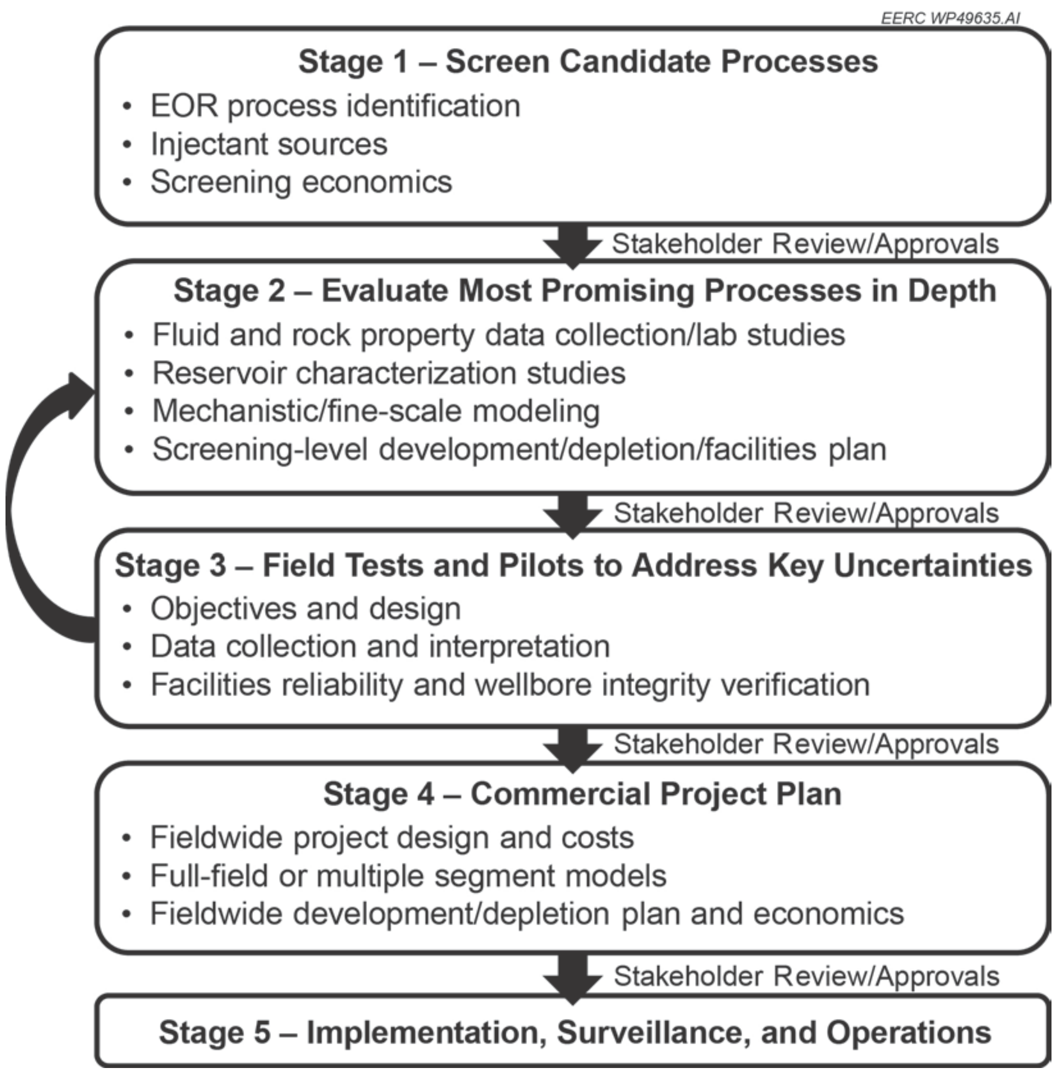

Figure 4. Stages of EOR project evaluation and development (modified from Telezke and others, 2008).

North Dakota operators: the Dakota Gasification Company (DGC) pipeline from Beulah, North Dakota, to Goodwater, Saskatchewan, and the Greencore pipeline that terminates at the Bell Creek Field in southeastern Montana (Figure 5). An extension of the Greencore pipeline into southwestern North Dakota along the CCA is planned for 2020 or later; the route is not known in detail at this time (Denbury, 2014). Assuming that CO_2 can be made available from the existing pipelines, each CO_2 EOR project would need to build an extension to the injection site. If the existing pipelines are not viable as CO_2 sources, new stationary sources will need to be brought online with CO_2 capture. Existing stationary CO_2 sources in western North Dakota are shown in Figure 6. Only seven sources produce more than 1 MMt CO_2 annually, with five sources located south and east of the DGC pipeline.

The remaining two sources include the DGC plant, which is connected to the pipeline, and the Antelope Valley Station (AVS), which is less than a mile to the beginning of the pipeline. The AVS source has CO_2 emissions between 7 and 8 MMt of CO_2 annually and represents a potential CO_2 source that could be easily added to the DGC pipeline in the future.

The distance to CO_2 pipeline was calculated as the distance from the nearest edge of each unit boundary to the nearest of the two pipelines. The nearest pipeline to each unit was used to create a rank score for that unit. Units were ranked according to pipeline distance in ascending order and then assigned ascending rank scores.

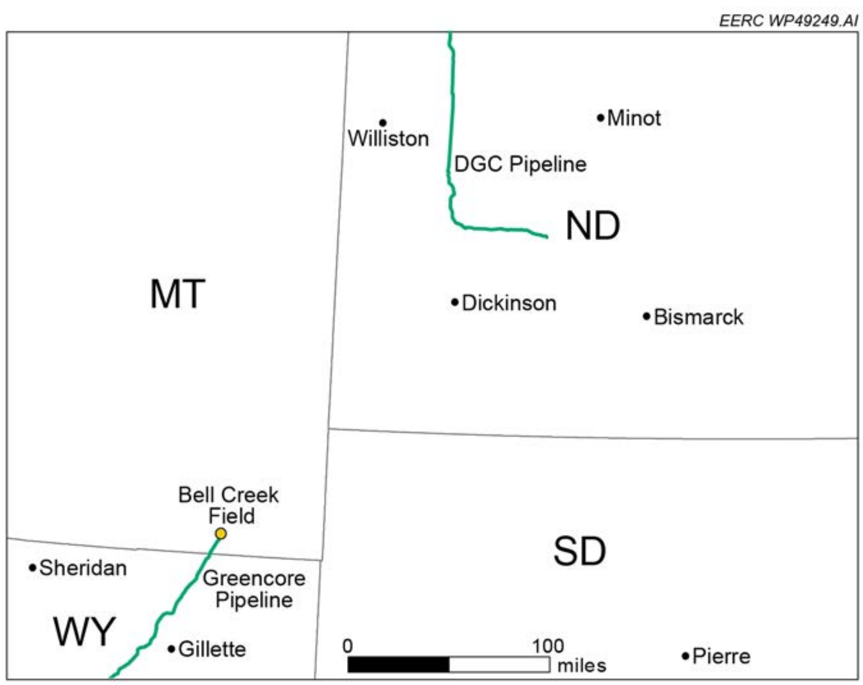

Figure 5. Overview map of study area showing CO_2 pipelines.

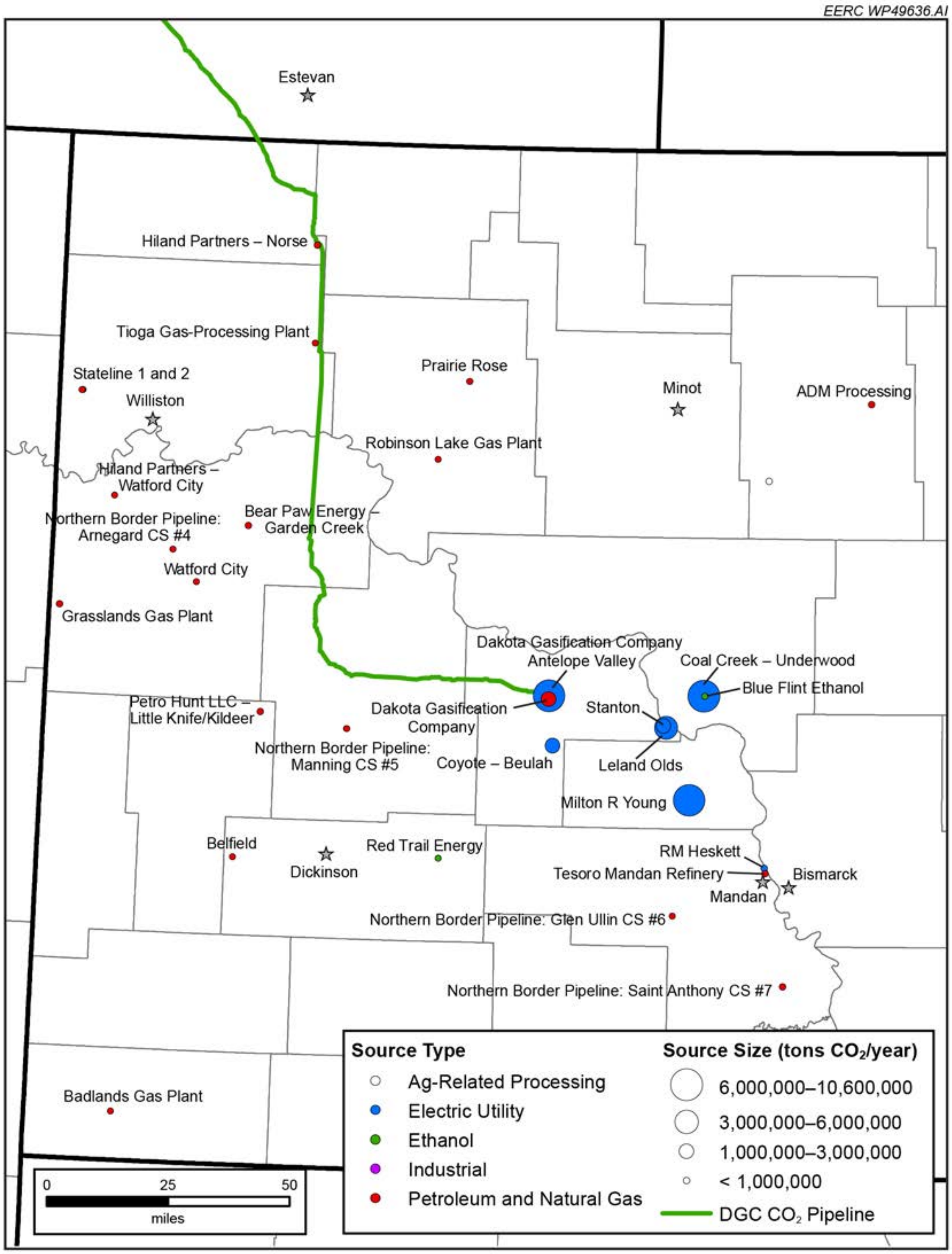

Figure 6. Stationary CO_2 sources in the study area.

Well Spacing

Well spacing within a unit is an important factor in the performance of CO_2 EOR. As spacing increases, a CO_2 flood becomes less efficient because of the greater volume of rock between injection and production wells. Spacing is expressed as the area from which each well is estimated to draw oil and gas (Table 4). Well spacing for each unit was obtained from Burke (2005), if available. Visual estimates of well spacing (in ArcGIS using NDIC unit boundaries and well locations) were made for each unit to confirm published values and fill in missing spacing values. Units with current spacing of less than 80 acres require little (or no) infill drilling to optimize efficiency (Nelms and Burke, 2004). Infill drilling can reduce well spacing and improve CO_2 flood efficiency, but adds additional cost to the conversion of a field to tertiary recovery. Units were ranked according to well spacing in ascending order and then assigned ascending rank scores.

Estimated Incremental Oil

A frequent value for estimating the amount of oil that can be recovered via CO_2 EOR is 8% of the OOIP (Smith and others, 2009; Nelms and Burke, 2004). The 8% value (recovery factor [RF]) was used in this investigation to rank units based on the amount of additional oil that could be recovered with CO_2 EOR. Final analysis of each unit includes estimates based on three RFs: 8%, 12%, and 18%. OOIP values were taken primarily from the NDIC Web site, although certain (higher) values have been used in recent years by various authors and in NDIC unit case files (Burke, 2005; Harju, 2006; Smith and others, 2009).

CO_2 required to produce the incremental oil for each unit was calculated but was not used as a ranking criterion. The equation is:

$$M_{CO2} = OOIP * \rho_{CO2STD} * RF * UF \qquad \text{[Eq. 1]}$$

Where M_{CO2} is the CO_2 storage resource mass estimate for geologic storage in oil and gas reservoirs in pounds. OOIP is the original oil in place in stock tank barrels, ρ_{CO2STD} is the density of CO_2 at industrial standard conditions (60°F and 1 atm pressure), RF is in percent, and UF is the net utilization factor (UF) in standard cubic feet (scf) of CO_2 per barrel of oil recovered.

Table 4. Well Spacing Conversions

Well Spacing	Wells per Quarter Quarter Section	Wells Per Quarter Section	Wells per Section
10 acre	4	16	64
20 acre	2	8	32
40 acre	1	4	16
80 acre	–	2	8
160 acre	–	1	4
320 acre	–	–	2
640 acre	–	–	1

The RF refers to the amount of oil that is expected to be produced as a result of CO_2 injection, also known as incidental oil production. The UF determines how much CO_2 is necessary to produce a barrel of oil. When the OOIP, RF, and UF are multiplied together, the result is the amount of CO_2 injected into the formation to produce the oil during the process. The three RF values mentioned earlier are based on reviews of published literature, and net UF values used in this study's calculations are 3000, 5000, and 8000 scf of CO_2 per barrel of oil recovered.

The unitized fields were ranked based on the predicted volume of incremental oil. Units were ranked according to estimated incremental oil in descending order and then assigned ascending rank scores.

Estimated Field Reworking

Oilfield reworking is a normal and natural part of the conversion between recovery phases. Between primary and secondary production, some wells must be converted to injection wells or new injection wells drilled. Between secondary and tertiary recovery, injection and production well integrity should be assessed to take into account the different fluid properties of water and CO_2 (Figure 4, third stage). Wellbore integrity is the ability of a well to maintain isolation of geologic formations and prevent vertical migration of fluids (Zhang and Bachu, 2011; Crow and others, 2010). Wells may need to be retrofitted with materials resistant to CO_2 corrosion. Corrosion of wellhead equipment or within cased wells can lead to leaks. For the purposes of this study, leakage is defined as a loss of CO_2 or other fluid from its intended storage formation and not necessarily losses to the atmosphere. Leakage of CO_2 is detrimental to operations because of the inability to maintain reservoir pressure and loss of purchased CO_2 before reaching the reservoir (or before it can be recycled).

Monetary and engineering investments to prepare a field for CO_2 injection are very field-dependent. In addition to the conversion of wells to CO_2 injectors, the installation of CO_2-handling equipment, flow lines, and modifications to production facilities, an assessment of wellbore integrity is needed. Wellbore integrity is not constant across all wells drilled, and it can be influenced by numerous factors (Watson and Bachu, 2007, 2008, 2009; Bachu and others, 2012). Wells with marginal or uncertain integrity will require additional focus (and time) to remediate. To estimate the potential for marginal integrity, a methodology was employed based on a relationship between the pace of drilling activity and surface casing vent flows that was developed by Watson and Bachu (2007; 2008; 2009; Bachu and others, 2012). Their research found a direct relationship between the pace of development and wells with integrity issues. In an extrapolation of that idea to this investigation, the percentage of wells per unit that were drilled (spudded) during the last North Dakota oil boom from 1974 to 1986 was used to rank fields on a predicted level of field reworking. This ranking is not meant to indicate the likelihood of a leak. An in-depth wellbore evaluation would be part of the CO_2 EOR field-level planning and preparation in which an operator would remediate potential issues.

Potential marginal integrity is a measure applied to the conglomerate of all wells drilled during a certain period over a certain area and is not indicative of the quality of practice of any one driller or operator. Potential marginal integrity was applied to the units under study by ranking units according to the percentage of wells drilled during the previous North Dakota oil boom in ascending order and then assigning ascending rank scores.

RESULTS

Final ranking of units using the four criteria discussed above results in rank sums ranging from 41 to 281. The distribution of rank sums is nearly normal (Figure 7). Figure 2 shows the geographic distribution of units. Results for each ranking criterion are summarized as follows. Supporting data sets include all ranked values and rank scores: ND_unit_ranking_2014-03-24.xlsx and ND_units_ranked_20140325.shp. Appendix A contains a data dictionary of data fields contained in the geographic information system (GIS) file.

Distance to CO_2 Pipeline

Of the 86 units that were analyzed, ten units are intersected by the DGC pipeline, 76 units are closer to the DGC pipeline, and ten are closer to the existing Greencore pipeline (Figure 5). Pipeline distance from each unit ranges from 0 to 100 miles. Relative to CO_2 pipelines, units are clustered at less than ten miles, 30 to 60 miles, and 80 to 100 miles (Figure 8). Eighteen units are within 10 miles of a CO_2 pipeline, a cutoff determined by Nelms and Burke (2004), and each of those units is within 5 miles (there are no units between 5 and 10 miles from a pipeline). Fifty percent of units are within 40 miles of a pipeline, all of which are located on or near the Nesson Anticline. The nearest North Dakota unit to the existing Greencore pipeline (Cedar Creek Ordovician) is 82.8 miles away.

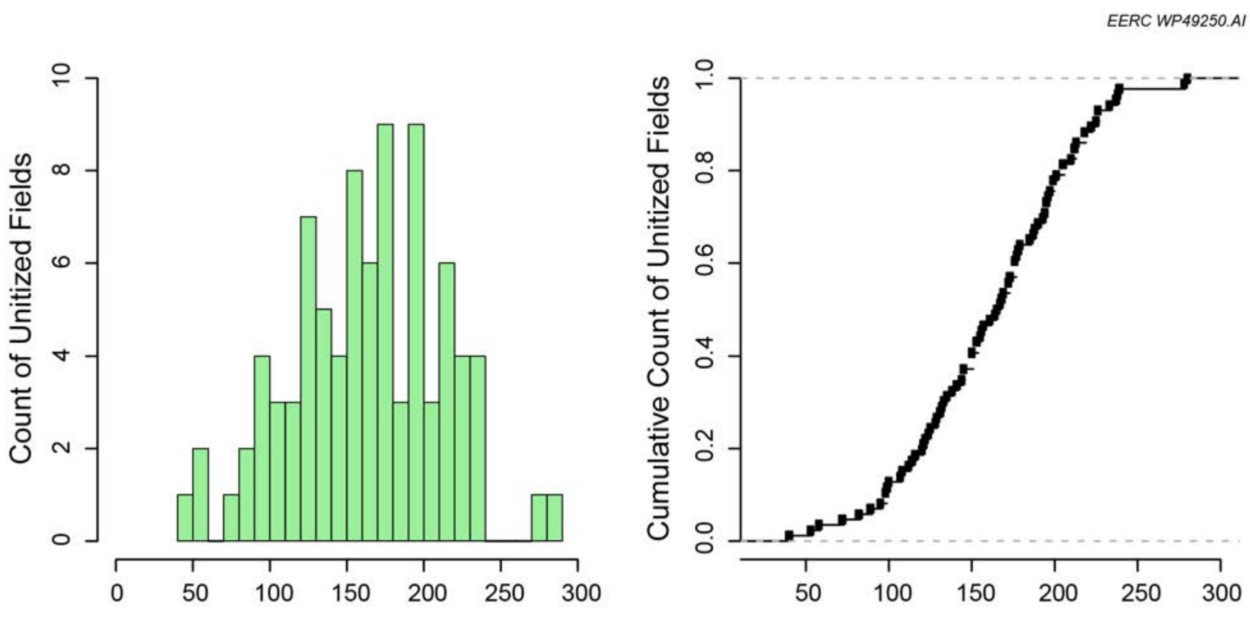

Figure 7. Sum of rank scores for North Dakota units as a) histogram and b) cumulative distribution plot.

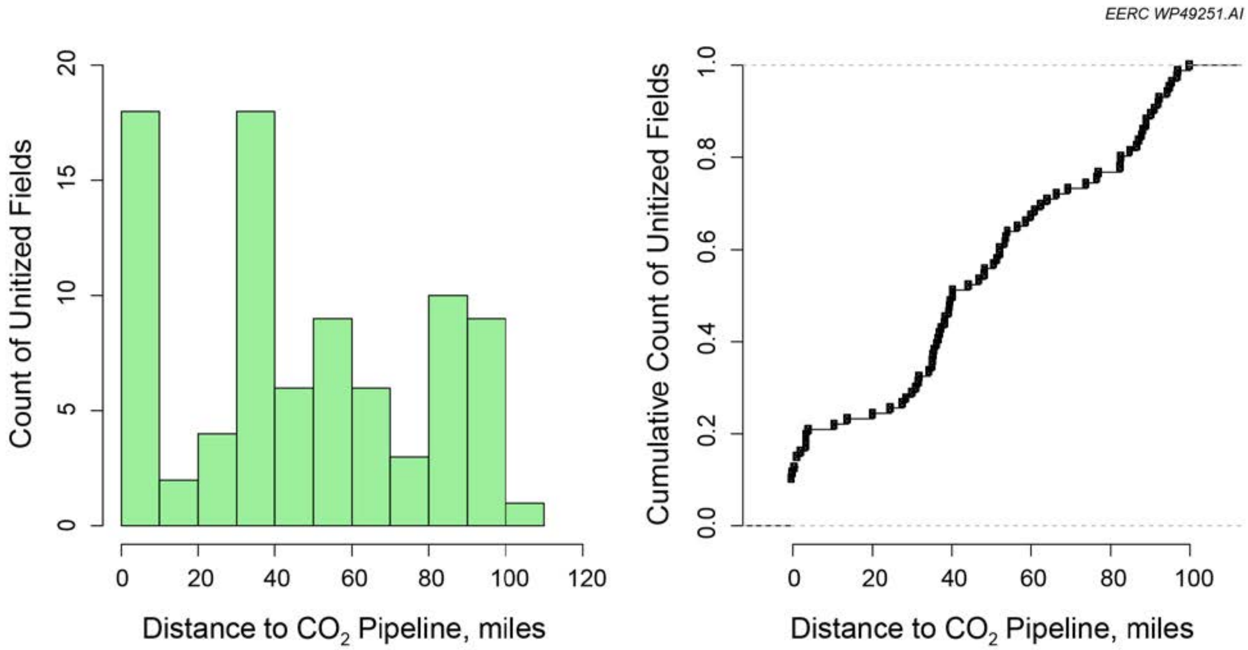

Figure 8. Distribution of distances to CO_2 pipelines as a) histogram and b) cumulative distribution plot.

Well Spacing

Well spacing was estimated for 85 units; one unit, Flat Lake East Ratcliffe, only appears to have a single active well within its boundaries. Well spacing ranges from 20 acres (two wells per quarter quarter section) to 640 acres (one well per section). Because of the standardization of spacing, there were many tied values, i.e., units with the same spacing and, therefore, the same rank score (Figure 9). Fifty percent of units have an estimated well spacing of 80 acres (two wells per quarter section) or less.

Estimated Incremental Oil

Estimated incremental oil at a RF of 8% ranges from 0.032 to 28.8 MMbbl (Figure 10). Most units are small. Forty percent of the units contain more than 2 MMbbl of CO_2 EOR incremental oil potential, the lowest amount deemed acceptable by Nelms and Burke (2004). Since oil prices have increased in the last ten years, a cutoff of 1 MM incremental barrels may be more appropriate; 55% of units contain more than 1 MMbbl of CO_2 EOR incremental oil potential.

Estimated Field Reworking

Spud date for parent fields skews positively, with about 50% of fields containing less than 30% of the wells drilled from 1974 to 1986, the last North Dakota oil boom (Figure 11). Twelve fields contain no wells spudded during this interval; one field contains no wells spudded outside

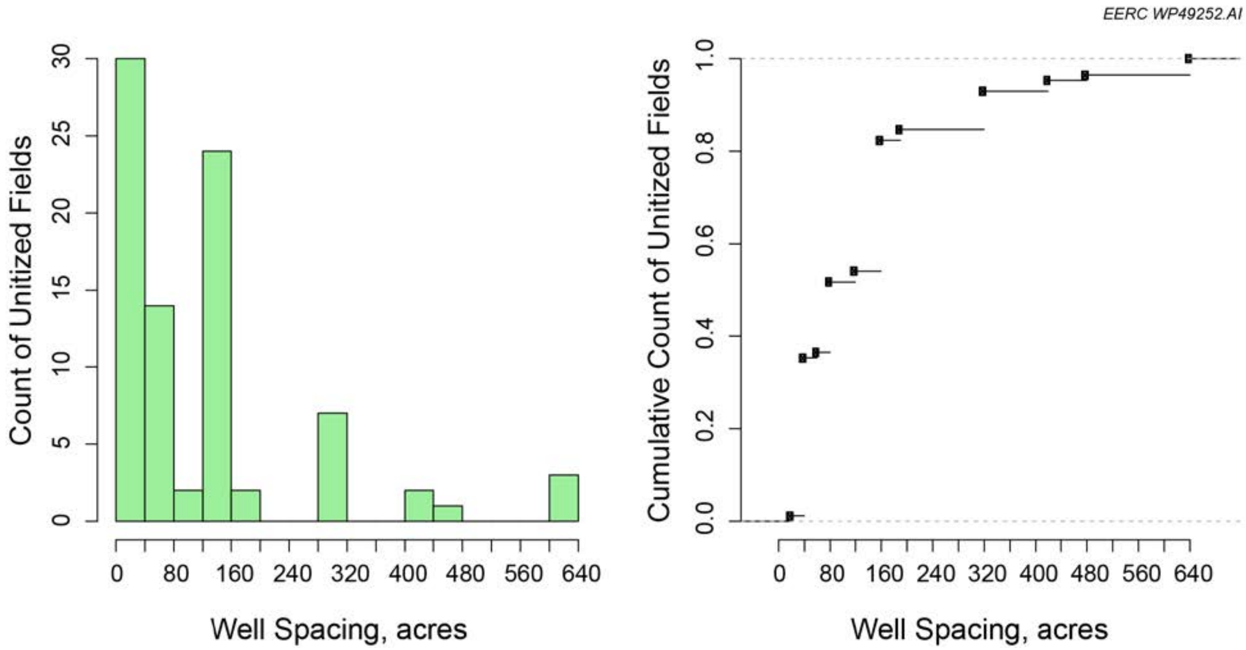

Figure 9. Distribution of well spacing as a) histogram and b) cumulative distribution plot.

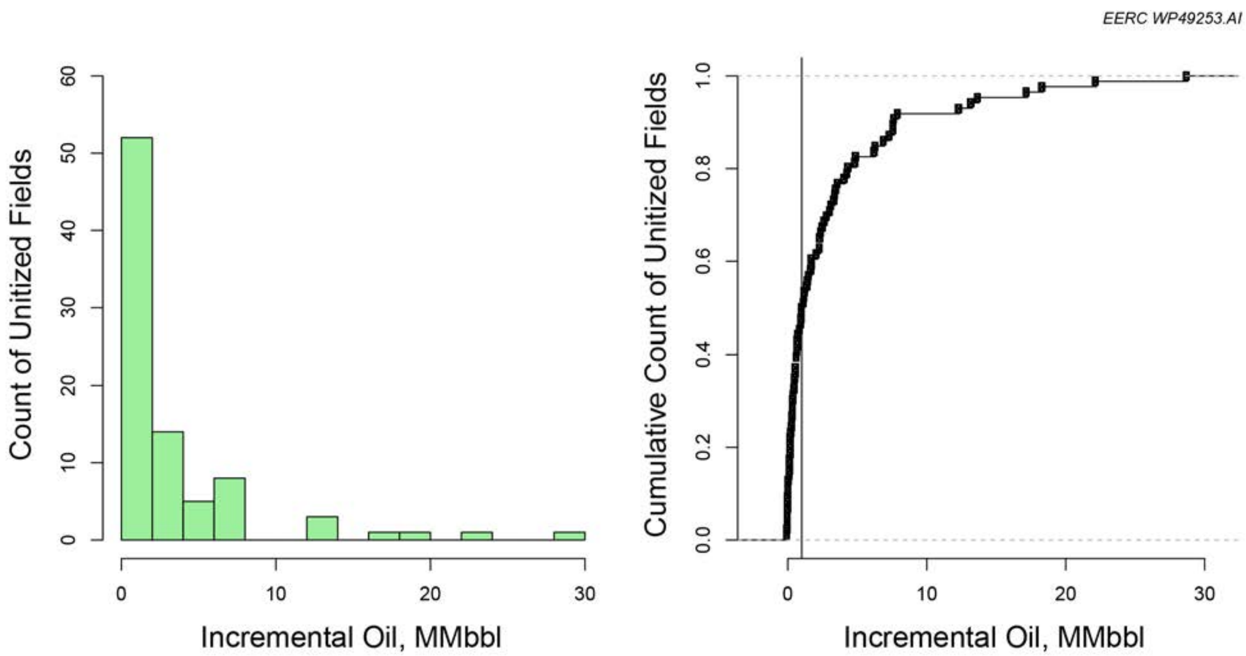

Figure 10. Distribution of estimated incremental oil as a) histogram and b) cumulative distribution plot.

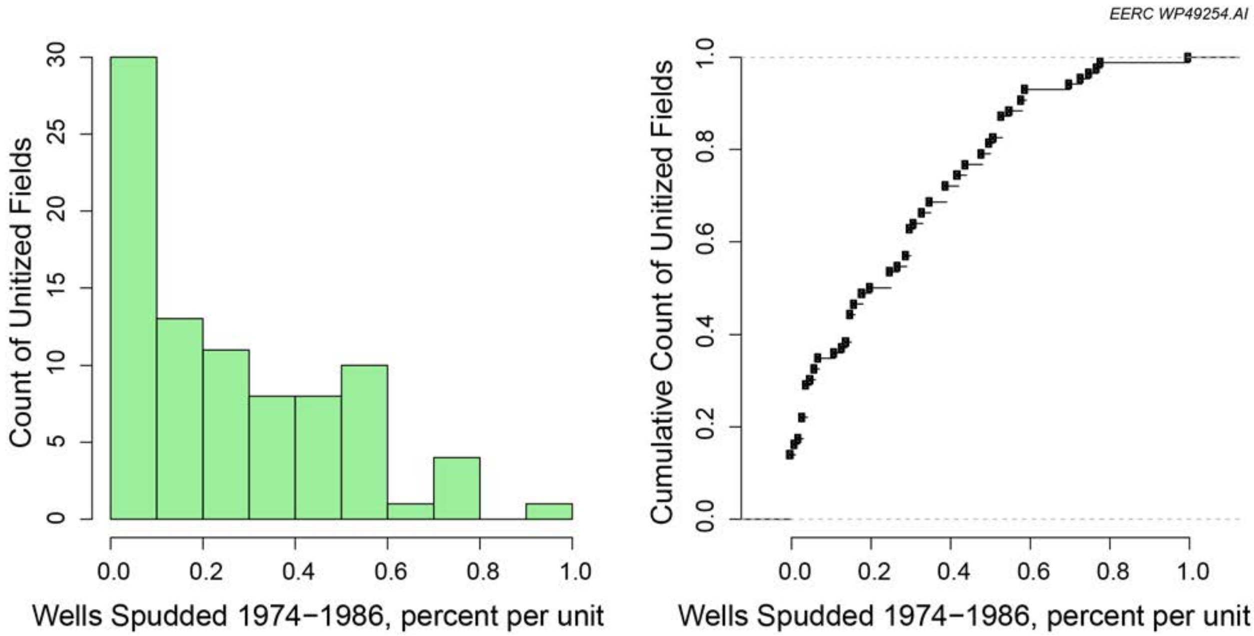

Figure 11. Distribution of percentage of well spud dates per parent field as a) histogram and b) cumulative distribution plot.

of this interval. Wells drilled during oil booms have been shown to have the potential for lower integrity (Watson and Bach, 2008; Bachu and others, 2012), and the potential wellbore integrity indicator was used to estimate the amount of preparation that may need to be done to a field for CO_2 EOR operations. This indicator is not meant to be used as an indication of wellbore leakage. An in-depth wellbore evaluation would be part of the CO_2 EOR field-level planning and preparation in which an operator would remediate any potential issues.

SYNTHESIS

The top ten ranked units have a combined estimated incremental recovery of between 82.7 and 186.2 MMbbl, requiring between 13.9 and 83.6 MMt of CO_2. These units (Figure 12) are the Hawkeye Madison, Tioga Madison, Beaver Lodge Madison, Antelope Madison, Beaver Lodge Devonian, Red Wing Creek Madison, Blue Buttes Madison, Plaza Madison, Stoneview Stonewall, and Charlson North Madison. Total combined estimated recovery from the 86 ranked units is between 280 and 631 MMbbl with a required injected volume of between 47 and 283 MMt of CO_2.

Weighting certain criteria more than others or removing all but the best-fitting units before the final ranking is calculated may improve the results, but was not attempted in order to avoid overfitting at the expense of field-specific engineering concerns.

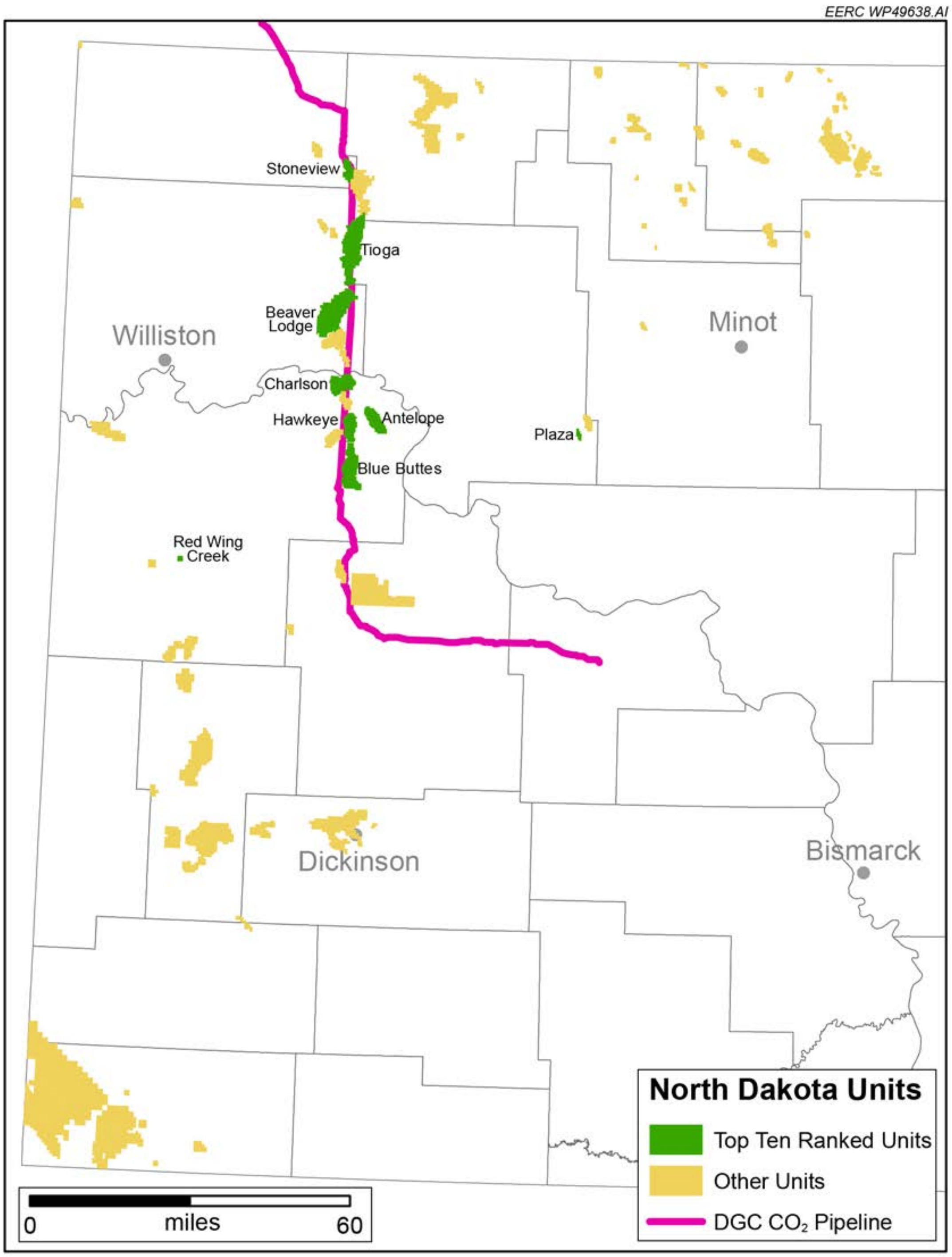

Figure 12. Geographic distribution of units showing the ten highest-ranked CO_2 EOR possible targets.

Units that are close to (or contain) existing CO_2 pipelines have lower (better) rank scores, which are weighted equally with the rank scores of large units with large estimated tertiary recovery values. Units that are large enough are well worth the infrastructure investment in pipeline construction (Figure 13).

DGC is contracted to deliver CO_2 via pipeline to the Weyburn unit in Saskatchewan, Canada, until 2016 and the neighboring Midale unit until 2025. Basin Electric Power Cooperative, 2011). It is projected that the Boundary Dam Power Station near Estevan, Saskatchewan, will be coming online in the second half of 2014 and may take the place of DGC as the primary CO_2 source for the Weyburn and Midale Fields. If this is the case, it will free up approximately 3 MMt of CO_2 per year from DGC for use within North Dakota, much of which could be used within the 5-year period in units along the Nesson Anticline, if area operators were inclined to do so. At present, only Denbury Resources Inc. (Denbury) has established a public goal of pursuing CO_2 EOR in North Dakota, but this does not negate the possibility of other operators (some of which perform CO_2 EOR in other states already) obtaining unitized fields in North Dakota for this purpose.

In particular, Denbury has made a shift in recent years toward a CO_2 EOR focus (Denbury Resources, Inc., 2010, 2011, 2012, 2013a, b). Although Denbury has divested its interests in the Bakken of North Dakota, it has gained the largest share of the oil development along the CCA in southwestern North Dakota and southeastern Montana. A pipeline extension north of the Bell Creek Field in Montana has been discussed for several years (Denbury Resources Inc., 2014),

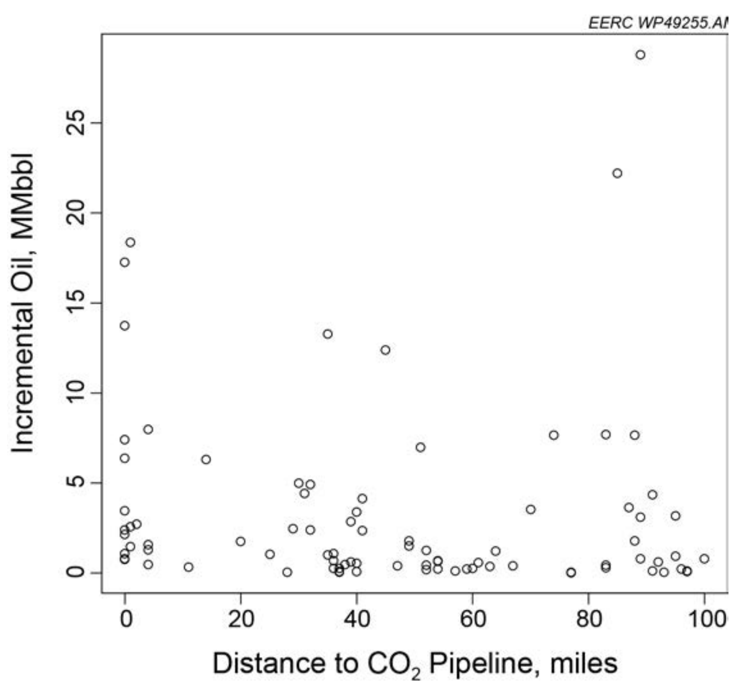

Figure 13. Relationship between incremental oil (RF = 0.08) and distance from units to nearest CO_2 pipeline.

but estimates differ on the location of the pipeline and which fields will be first targeted (Wolfe, 2010; Martin, 2013; Schnacke, 2010; Denbury Resources Inc., 2013b; Kuuskraa and DiPietro, 2014; Steffens, 2013). Denbury has, over the last few years, moved back the operational date of CO_2 EOR in the CCA; it currently stands at "beyond 2020" (Denbury Resources Inc., 2014).

Denbury's Greencore pipeline currently terminates in southeastern Montana, but if extended north to the CCA, should provide "plenty of CO_2" to the region (Dalrymple, 2012). However, it is unknown how much CO_2 would be provided to fields in North Dakota versus Montana. Although the possibility of recycling CO_2 from one EOR unit to another has been suggested—resulting in less CO_2 being left in each reservoir than was purchased for that reservoir—this is rarely the case (Melzer, 2012). All CO_2 injected into a particular unit should be expected to remain there. If CO_2 is anthropogenic, the result is a net storage of CO_2 during EOR operations and a positive effect of atmospheric greenhouse gas reduction.

Electrical power generation for increased activity in western North Dakota and eastern Montana will be an important factor to consider. New power station siting will depend on area electrical needs and fuel supply (most likely locally sourced coal, but possibly natural gas). Anticipated federal regulations regarding CO_2 emissions provide a not-insignificant impetus for new power stations to become pipeline sources for CO_2 EOR in nearby oil fields. By 2020, at least 2500 MW of electrical demand is estimated, up from 1500 MW in 2014 (Kadrmas Lee & Jackson Inc., 2012).

At this time, activity in the North Dakota portion of the Williston Basin is intensely focused on extracting oil from the Bakken Formation. The Bakken is predicted to continue its rapid return of capital investment cost in North Dakota for many years to come (Hicks, 2014). Many of the operators of the promising waterflood fields also have interest in the Bakken system but may be hesitant to focus their efforts and investment on CO_2 EOR in conventional oil fields, even if CO_2 becomes widely available. A strong likelihood exists in the near-term for CO_2 EOR technology to be successfully applied to unconventional reservoirs like the Bakken. At an estimated incremental recovery factor of 4% in North Dakota Bakken Fields, CO_2 EOR could be used to produce between 420 and 6800 MMbbl oil, requiring between 121 and 3155 MMt of CO_2. Although the Bakken prize will dwarf that of the combined conventional fields, it will be some time before CO_2 can be made available at the scale necessary to realize that potential (Sorensen and others, 2014).

CONCLUSIONS

Near-term CO_2 EOR in the top 10 ranked conventional oil fields of North Dakota have a combined estimated recovery of between 82.7 and 186.2 MMbbl, requiring between 13.9 and 83.6 MMt of CO_2. These units are the Hawkeye Madison, Tioga Madison, Beaver Lodge Madison, Antelope Madison, Beaver Lodge Devonian, Red Wing Creek Madison, Blue Buttes Madison, Plaza Madison, Stoneview Stonewall, and Charlson North Madison. Total combined estimated recovery from the 86 ranked unitized fields is between 280 and 631 MMbbl, requiring between 47 and 283 MMt of CO_2.

If the DGC pipeline goes under renewed contract with Weyburn–Midale, CO_2 supply for this potential EOR may not be available until either Denbury's Greencore pipeline is extended or additional captured CO_2 becomes available from existing power plants such as the AVS. In both cases, this is most likely to occur beyond the near-term 5-year time line. If CO_2 from the DGC pipeline becomes available for sale within the next year, it is possible that the Nesson Anticline units could be converted to tertiary recovery before 2020 because only short pipelines and taps would need to be constructed. This is dependent on unit-scale analysis of CO_2 EOR before reworking and infrastructure enhancements can begin.

There is strong potential that, within the 5-year time frame which is the focus of this study, the Bakken petroleum system may develop into a CO_2 EOR target, which would have a large effect on these projections and would be expected to be a strong driver of CO_2 EOR in North Dakota. The Bakken system has, specifically, not been evaluated as part of this study.

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APPENDIX A

DATA DICTIONARY

DATA DICTIONARY

BACKGROUND

This project produced an associated geographic information system data set in ESRI shapefile format. This associated data set includes outlines of all oilfield units in North Dakota, including terminated fields, with the scores for each ranking criterion.

DATA FIELDS AND DESCRIPTIONS

FID
Internal feature number.

Shape
Feature geometry.

Name
Unit name, expressed as FIELDNAME POOLNAME UNIT.
Source: North Dakota Industrial Commission (NDIC) database

Operator
Company operating the unit.
Source: NDIC database

Unitizedfo
Unitized geologic formation.
Source: NDIC

Rank_Sum
Sum of values used to rank unitized fields in order of likelihood of being converted to CO_2 enhanced oil recovery (EOR) before 2020. Equal to sum of Pipe_Rank, Boom_Rank, Space_Rank, and Incr_Rank.
Source: Energy & Environmental Research Center (EERC)

Final_Rank
Rank order of each unit using the Rank_Sum value. Lower values indicate greater likelihood of conversion of each unit to CO_2 EOR.
Source: EERC

Field
Name of the field of which the unit is a part.
Source: NDIC database

Field_Mod
For fields with multiple units, a modifier that distinguishes each unit from the others. Typically directional (north, south, west, etc.).
Source: NDIC database

Pool
Name of the producing reservoir for each unit.
Source: NDIC database

Unit_ID
Unique identification number for each unit. Unit_ID values matching '9xxx' pattern represent terminated units added to NDIC data set and do not match Unit_ID values outside of the related KLJ–EERC data set.
Source: NDIC, EERC

Pipe_Dist
The distance between the unit and the closest CO_2 pipeline (either the Dakota Gasification Company pipeline or the Greencore pipeline in southeastern Montana).
Unit: miles
Source: EERC, calculated from NDIC unit shapefile and EERC pipeline shapefile using ArcGIS

Pipe_Rank
Rank order of Pipe_Dist values. Lower Pipe_Rank indicates that the unit is closer to a CO_2 pipeline.
Source: EERC

Boom_Wells
Percent of wells in the parent field of each unit that were spudded during the 1974–1986 North Dakota oil boom. Wells drilled during oil booms are less likely to retain integrity over time and may need additional maintenance before CO_2 EOR began. See report text for references.
Units: percent as decimal
Source: NDIC, EERC

Boom_Rank
Rank order of Boom_Well values. Lower Boom_Well indicates that unit wells may require additional maintenance before CO_2 EOR commences.
Source: EERC

Well_Space
Average well spacing within each unit.
Units: acres per production well
Source: Burke, 2005; EERC

Space_Rank
Rank order of Well_Space values. Lower Space_Rank indicates units that require fewer new infill wells in order to begin efficient CO_2 EOR operations.
Source: EERC

Incr_Oil
Estimated incremental oil at 8% recovery factor. Incremental oil from tertiary production is estimated as a percentage of original oil in place (OOIP). Incremental oil for each unit is estimated as 8% of OOIP (see report for sources).
Source: NDIC, EERC

Incr_Rank
Rank order of Incr_Oil values. Lower Incr_Rank indicates units with greater estimated tertiary recovery from future CO_2 EOR operations.
Source: EERC.

Incr_Oil08
Estimated incremental oil at 8% recovery factor. Incremental oil from tertiary production is estimated as a percentage of OOIP. Incremental oil for each unit is estimated as 8% of OOIP (see report for sources). Provides lower limit for incremental oil estimates.
Source: OOIP from NDIC, calculation from EERC

Incr_Oil12
Estimated incremental oil at 12% recovery factor. Incremental oil from tertiary production is estimated as a percentage of OOIP. Incremental oil for each unit is estimated as 12% of OOIP (see report for sources). Provides medial incremental oil estimates.
Source: OOIP from NDIC, calculation from EERC

Incr_Oil18
Estimated incremental oil at 18% recovery factor. Incremental oil from tertiary production is estimated as a percentage of OOIP. Incremental oil for each unit is estimated as 18% of OOIP (see report for sources). Provides upper limit for incremental oil estimates.
Source: OOIP from NDIC, calculation from EERC

CO2_08_3K
CO_2 required at 8% recovery factor and 3000 cf/bbl utilization factor. CO_2 required to produce incremental oil is calculated using a recovery factor (percent of OOIP that can be recovered during tertiary recovery) and a utilization factor (amount of CO_2 that has to be injected to recover one barrel of oil). See report for discussion and formula. CO2_08_3K represents a lower-limit estimate of the amount of CO_2 required.
Units: short tons
Source: OOIP from NDIC, calculation from EERC

CO2_08_5K
CO_2 required at 8% recovery factor and 5000 cf/bbl utilization factor. CO_2 required to produce incremental oil is calculated using a recovery factor (percent of OOIP that can be recovered

during tertiary recovery) and a utilization factor (amount of CO_2 that has to be injected to recover one barrel of oil). See report for discussion and formula.
Units: short tons
Source: OOIP from NDIC, calculation from EERC

CO2_08_8K
CO_2 required at 8% recovery factor and 8000 cf/bbl utilization factor. CO_2 required to produce incremental oil is calculated using a recovery factor (percent of OOIP that can be recovered during tertiary recovery) and a utilization factor (amount of CO_2 that has to be injected to recover one barrel of oil). See report for discussion and formula.
Units: short tons
Source: OOIP from NDIC, calculation from EERC

CO2_12_3K
CO_2 required at 12% recovery factor and 3000 cf/bbl utilization factor. CO_2 required to produce incremental oil is calculated using a recovery factor (percent of OOIP that can be recovered during tertiary recovery) and a utilization factor (amount of CO_2 that has to be injected to recover one barrel of oil). See report for discussion and formula.
Units: short tons
Source: OOIP from NDIC, calculation from EERC

CO2_12_5K
CO_2 required at 12% recovery factor and 5000 cf/bbl utilization factor. CO_2 required to produce incremental oil is calculated using a recovery factor (percent of OOIP that can be recovered during tertiary recovery) and a utilization factor (amount of CO_2 that has to be injected to recover one barrel of oil). See report for discussion and formula.
Units: short tons
Source: OOIP from NDIC, calculation from EERC

CO2_12_8K
CO_2 required at 12% recovery factor and 8000 cf/bbl utilization factor. CO_2 required to produce incremental oil is calculated using a recovery factor (percent of OOIP that can be recovered during tertiary recovery) and a utilization factor (amount of CO_2 that has to be injected to recover one barrel of oil). See report for discussion and formula.
Units: short tons
Source: OOIP from NDIC, calculation from EERC

CO2_18_3K
CO_2 required at 18% recovery factor and 3000 cf/bbl utilization factor. CO_2 required to produce incremental oil is calculated using a recovery factor (percent of OOIP that can be recovered during tertiary recovery) and a utilization factor (amount of CO_2 that has to be injected to recover one barrel of oil). See report for discussion and formula.
Units: short tons
Source: OOIP from NDIC, calculation from EERC

CO2_18_5K
CO_2 required at 18% recovery factor and 5000 cf/bbl utilization factor. CO_2 required to produce incremental oil is calculated using a recovery factor (percent of OOIP that can be recovered during tertiary recovery) and a utilization factor (amount of CO_2 that has to be injected to recover one barrel of oil). See report for discussion and formula.
Units: short tons
Source: OOIP from NDIC, calculation from EERC

CO2_18_8K
CO_2 required at 18% recovery factor and 8000 cf/bbl utilization factor. CO_2 required to produce incremental oil is calculated using a recovery factor (percent of OOIP that can be recovered during tertiary recovery) and a utilization factor (amount of CO_2 that has to be injected to recover one barrel of oil). See report for discussion and formula. CO2_18_8K represents an upper-limit estimate of the amount of CO_2 required.
Units: short tons
Source: OOIP from NDIC, calculation from EERC