POWER
FORECAST 2012

WILLISTON BASIN
OIL AND GAS RELATED
ELECTRICAL LOAD GROWTH FORECAST

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Acknowledgements

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1. Executive Summary

The North Dakota Transmission Authority (NDTA) commissioned KLJ, an employee-owned, engineering, surveying and planning firm, to complete the Williston Basin Oil and Gas Related Electrical Load Growth Forecast (PF 12) and project future electrical load growth in the Williston Basin area.

The results of this extensive study and report will be used by NDTA, Basin Electric Power Cooperative (Basin Electric) and Montana-Dakota Utilities Co. (MDU) (the Partners) to effectively plan for critical infrastructure needs and development in North Dakota, South Dakota and Montana. The study and report includes analysis of petroleum-sector commercial and industrial development, employment, population growth and secondary employment.

Findings contained in this study and report forecast expected electrical load growth for the next 20 years, from 2012 to 2032, in the study area which spans regions across North Dakota, South Dakota and Montana. These regions and the 43 counties they represent are shown in Figure 1. Numbers and figures in the Executive Summary were calculated from a demand amount averaged between historically observed energy use values and maximum oilfield electrical load requirements, and represent the study's most likely (consensus) scenario. Energy use for prior years was provided by the Partners and used to establish a 2011 baseline.

By the end of the study period in 2032, the 43 counties within the Williston Basin will require 2,512 megawatts (MW) of additional electrical demand, related to oil and gas development, to accommodate population growth, new ancillary business development and more than 30,000 additional wells (Table 1).

Williston Basin Cumulative Total New Wells					
	2012	**2017**	**2022**	**2027**	**2032**
High Scenario	2,097	12,551	21,801	29,115	34,126
Consensus Scenario	2,062	11,748	20,219	26,415	30,487
Low Scenario	2,027	10,141	16,881	21,586	24,865
There were 12,013 existing wells in the three study regions by the end of 2011.					

Table 1: Williston Basin Cumulative Total New Wells
Source: KLJ

The projected electrical load represents a 208 percent increase from the 1,209 MW area load demand required in 2012. The rise to the expected 3,721 MW electrical demand will consist of rapid increases up to 2017 followed by steady growth through 2032 (Figure 2).

Region 1: *Northeastern Montana and northwestern North Dakota, including the following counties:*

- *MT: Daniels, Phillips, Roosevelt, Sheridan, Valley*
- *ND: Bottineau, Burke, Divide, McHenry, McLean, Mountrail, Pierce, Renville, Rolette, Sheridan, Ward, Wells, Williams*

Region 2: *East central Montana and west central North Dakota, including the following counties:*

- *MT: Dawson, Garfield, McCone, Prairie, Richland, Wibaux*
- *ND: Billings, Dunn, Golden Valley, McKenzie, Mercer, Oliver, Stark*

Region 3: *Southeastern Montana, southwestern North Dakota and northwestern South Dakota, including the following counties:*

- *MT: Custer, Carter, Fallon, Powder River*
- *ND: Adams, Bowman, Hettinger, Slope*
- *SD: Butte, Harding, Meade, Perkins*

Figure 1: WILLISTON BASIN STUDY REGIONS
Source: North Dakota Transmission Authority

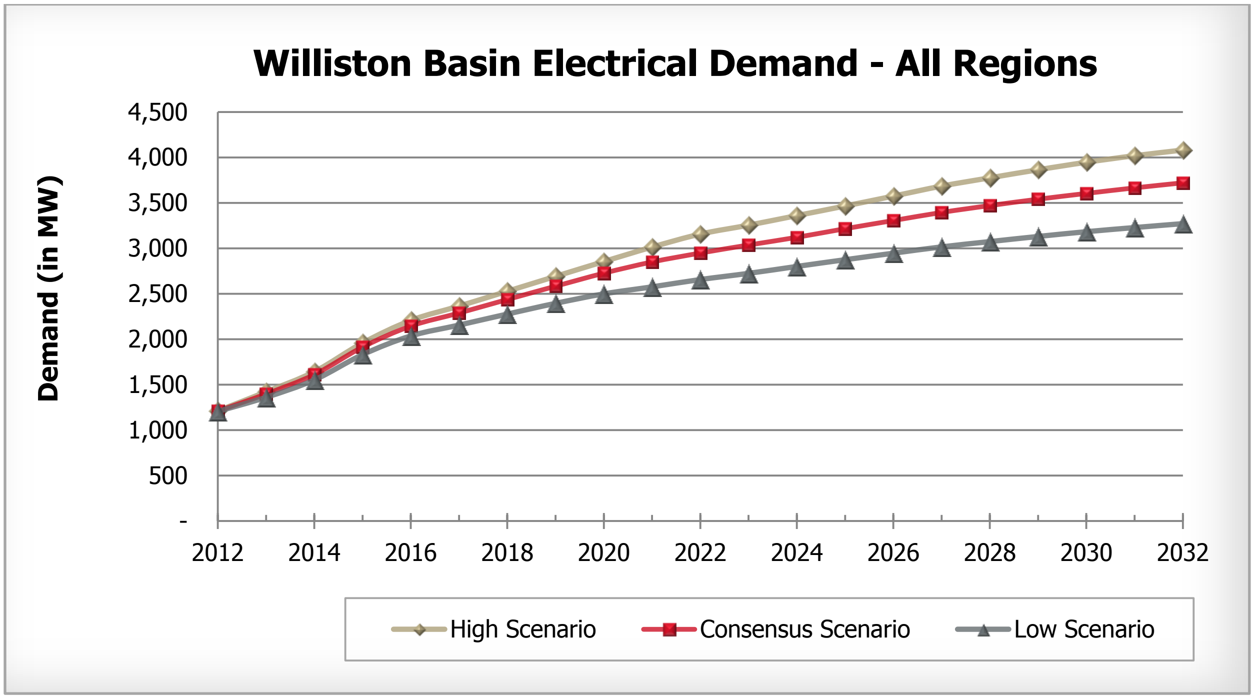

Figure 2: Williston Basin Electrical Demand – All Regions
Source: KLJ

The period between 2012 and 2017 represents the most significant increase in the 20-year study period with a rise to 2,288 MW, nearly doubling today's demand in the study region. Between 2017 and 2032 the expected growth continues steadily representing maturing oilfield development, near completion of pipeline build-out and stabilization of well pumping requirements.

The number of wells creates the most significant energy demand throughout the 2012 to 2032 study period. The rapidly growing number of wells, represented by large commercial and industrial sectors of the study area, begins to quickly overshadow the electrical demand growth from other energy sectors.

Region 1 will demand the most electricity of the three regions, almost 1,998 MW. Region 1 encompasses five Montana counties and 14 North Dakota counties. Region 2, made up of six counties in Montana and seven counties in North Dakota, will demand the next highest amount of electricity at 1,495 MW. Region 3 trails behind with a little more than 228 MW and includes 12 counties—four in each of the three states of North Dakota, South Dakota and Montana. Counties that will experience the highest megawatt demand increase in each of the three regions are indicated in Table 2.

Also of major significance are areas within the three regions that have been classified as future oilfield infrastructure loads for electrical power needs. These oilfield infrastructure loads, or locations of future significant oil and gas facilities, explain large increases in remote counties outside core oilfield development areas. These oilfield infrastructure loads also contribute to increases in population, which ignites higher electricity demands.

Counties by Region Experiencing Highest Electrical Demand Increase			
Location	**2012 Demand**	**2032 Demand**	**Total Increase**
Region 1			
Williams, ND	186 MW	617 MW	431 MW
Mountrail, ND	74 MW	322 MW	248 MW
Ward, ND	190 MW	276 MW	86 MW
Region 2			
McKenzie, ND	122 MW	535 MW	413 MW
Dunn, ND	39 MW	270 MW	231 MW
Stark, ND	85 MW	235 MW	150 MW
Region 3			
Fallon, MT	23 MW	54 MW	31 MW
Meade, SD	20 MW	41 MW	21 MW
Bowman, ND	26 MW	39 MW	13 MW

Table 2: Counties by Region Experiencing Highest Electrical Demand Increase
Source: KLJ

These high-density growth areas include all or portions of three Montana counties and eight North Dakota counties. The three Montana counties, which hug the northwestern North Dakota border, are Sheridan, Roosevelt and Richland. The eight North Dakota counties, huddled in the northwestern corner of the state are Divide, Williams, McKenzie, Billings, Stark, Dunn, Burke and Mountrail.

The backbone of this report is the bounty of information and assumptions obtained through project research and stakeholder interviews. Final information and assumptions were then factored into a GIS-based computer modeling system to obtain the forecast results. The model includes layers that identify electrical demand in terms of existing base load, population growth and future oilfield infrastructure development. Additionally, environmental and socioeconomic factors are incorporated to adjust the model for policy. Figure 3 depicts the location of forecasted oil and gas related electric loads 20 years from 2012.

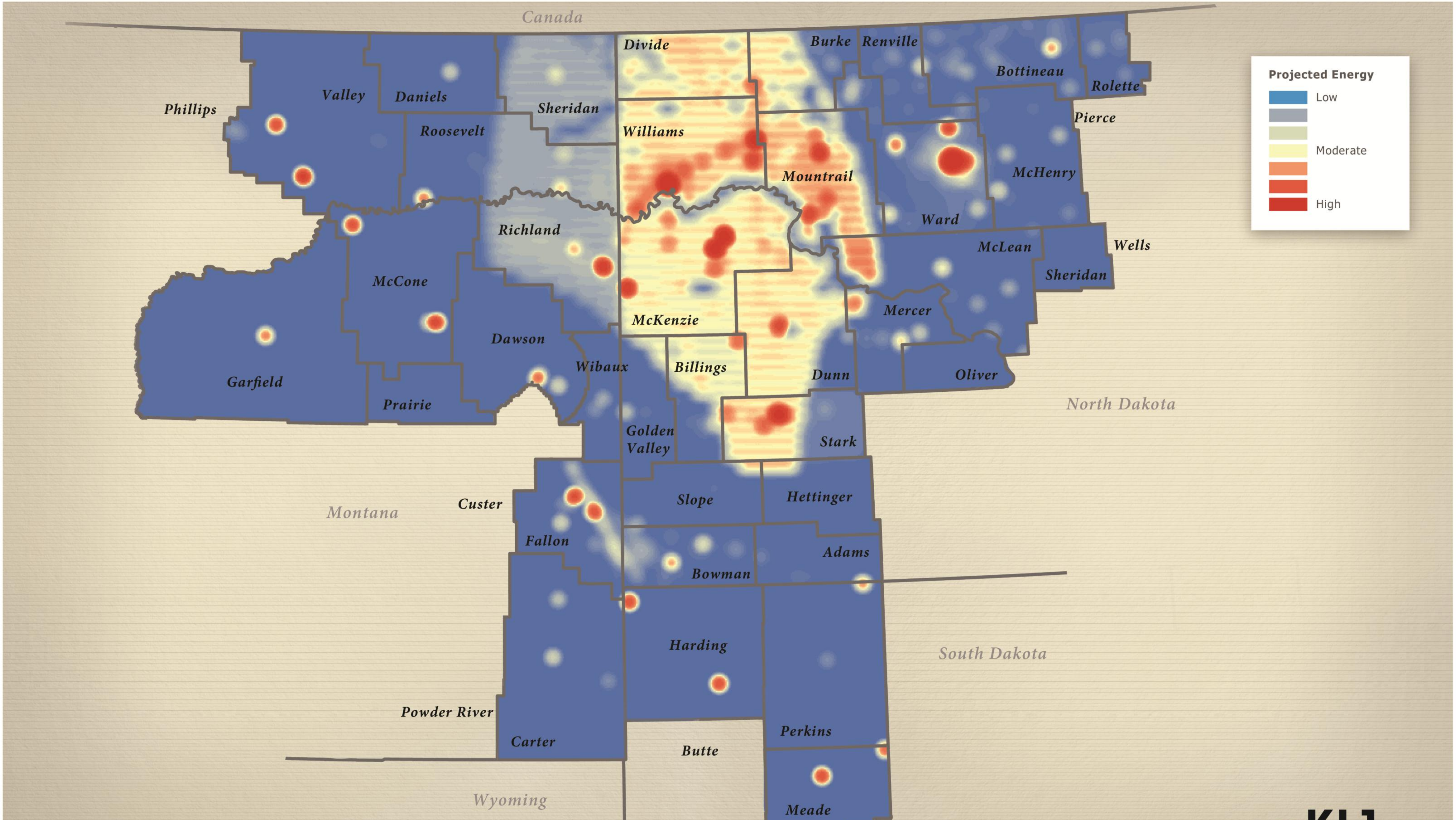

Figure 3: ELECTRICAL LOAD FORECAST 2032 – RELATIVE ENERGY

Source: KLJ

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2. Background

In light of recent and anticipated oil and gas development impacts on electrical demand and transmission capacity, the Partners request projections of future electrical loads for the three regions identified in Figure 1. The forecast identifies the magnitude and timing of electrical loads per region and county-level, per year, over 20 years. This study, which will be used by the Partners, considers new electrical load expected from oil and gas activity in the Williston Basin, along with the ancillary services that accompany such development.

2.1 Williston Basin and Bakken Formation

The Williston Basin is an oval-shaped, subsurface sedimentary basin with the deepest point near Watford City, ND. This major structural feature of central North America spans approximately 200,000 square miles. The basin reaches approximately 475 miles north and south from southern Saskatchewan, Canada to northern South Dakota. The basin also extends 300 miles east and west from the eastern third of North Dakota into western North Dakota and eastern Montana (Figure 4).

The Bakken, a large subsurface formation within the Williston Basin, is known for its rich petroleum deposits. The oil-producing formation, initially discovered in 1953, has been experiencing a steady and substantial increase in oil production since 2004, when the application of horizontal drilling technologies and hydraulic fracturing (fracing) facilitated oil extraction from previously unviable deposits.

The Bakken Formation is considered the main reservoir and source of a large portion of the oil generated and produced in the Williston Basin. Formed during the late Devonian, a period and system of the Paleozoic Era, Bakken shale is naturally fractured and considered both a petroleum source rock and reservoir.

The Bakken Formation consists of three members: 1) the upper Bakken, 2) the middle Bakken and 3) the lower Bakken. A fourth Bakken Formation member, the Pronghorn Member underlying the lower Bakken has also been proposed. The upper and lower members are organic rich black shales with greater than 1 percent carbonaceous material. The middle member is a dolomitic shaley siltstone. Located just above the Bakken Formation is the Lodgepole Formation, and lying completely below the Bakken Formation is the Three Forks Formation.

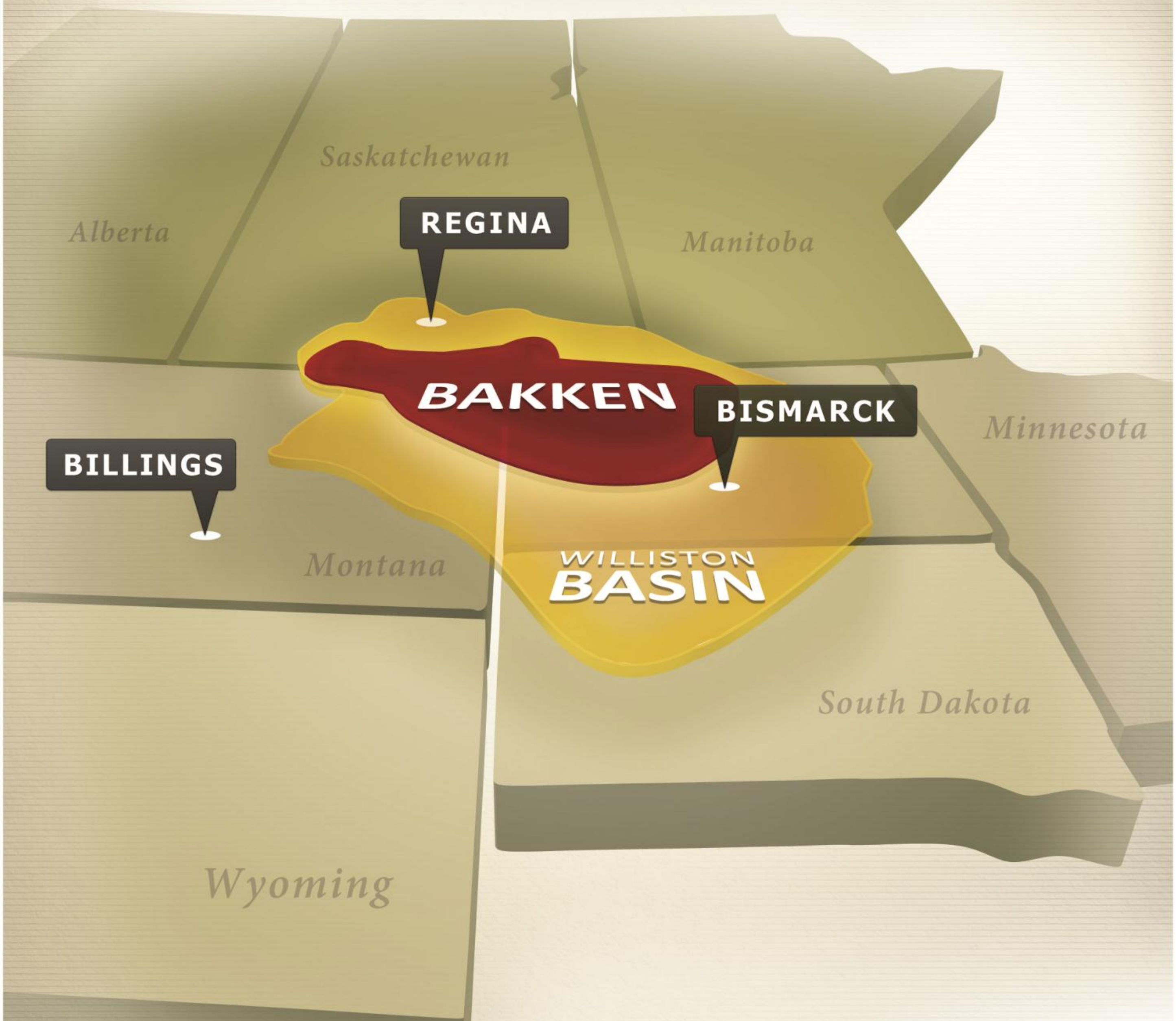

Figure 4: WILLISTON BASIN AND BAKKEN FORMATION
Source: KLJ

KLJ

An intracratonic basin, the Williston Basin is filled with approximately 16,000 feet of sedimentary rocks representing every geologic system of the Phanerozoic, the current geological eon. This nearly continuous deposition of sediments shown in the geologic record makes the Williston Basin one of only a handful of basins worldwide with that distinction.

In 1951, Amerada's Clarence Iverson No. 1 well struck commercial quantities of oil at a depth greater than 11,000 feet just south of Tioga, ND. The discovery led to a boom in leasing and drilling activities in the Williston Basin, especially along the prolific Nesson Anticline.

Production in the Devonian/Mississippian Bakken Formation began in 1953, but was quickly overshadowed by much more prolific oil production in the overlying Mission Canyon, Spearfish and other formations within the Williston Basin. While the Bakken Formation was believed to be the original source rock for the majority of oil found in most Williston Basin oil-producing formations, it was challenging to produce oil from the Bakken itself. The challenge was due to low levels of porosity and extremely low levels of permeability found in the formation. Apart from production related to structure-induced natural fracturing, or from limited sandier members (Sanish Sand/Pronghorn Member), there was little emphasis on targeting the Bakken. This lack of attention to the Bakken changed dramatically in the 1980s and early 1990s when geologic investigations and modeling led to mapping the naturally occurring fracture swarms, which, if intersected by vertical and later horizontal well bores, could be prolific producers of high-quality crude oil.

Exploration and development of oil from the naturally fractured Bakken Formation waned for nearly a decade due to low oil prices and scarcity of untapped naturally fractured zones. Horizontal drilling of the more porous middle Bakken and introduction of fracing in the mid-2000s has led to the current resurgence of interest in the Bakken. The result has been a drilling boom in the Bakken and adjacent permeable zones, such as the Three Forks Formation.

While past interest in the Bakken was tied to the occurrence and identification of naturally occurring fractures, today's drilling and completion technologies allow oil and gas production companies to create numerous controlled fractures throughout the oil-bearing expanse of this highly prolific oil formation (Figure 5).

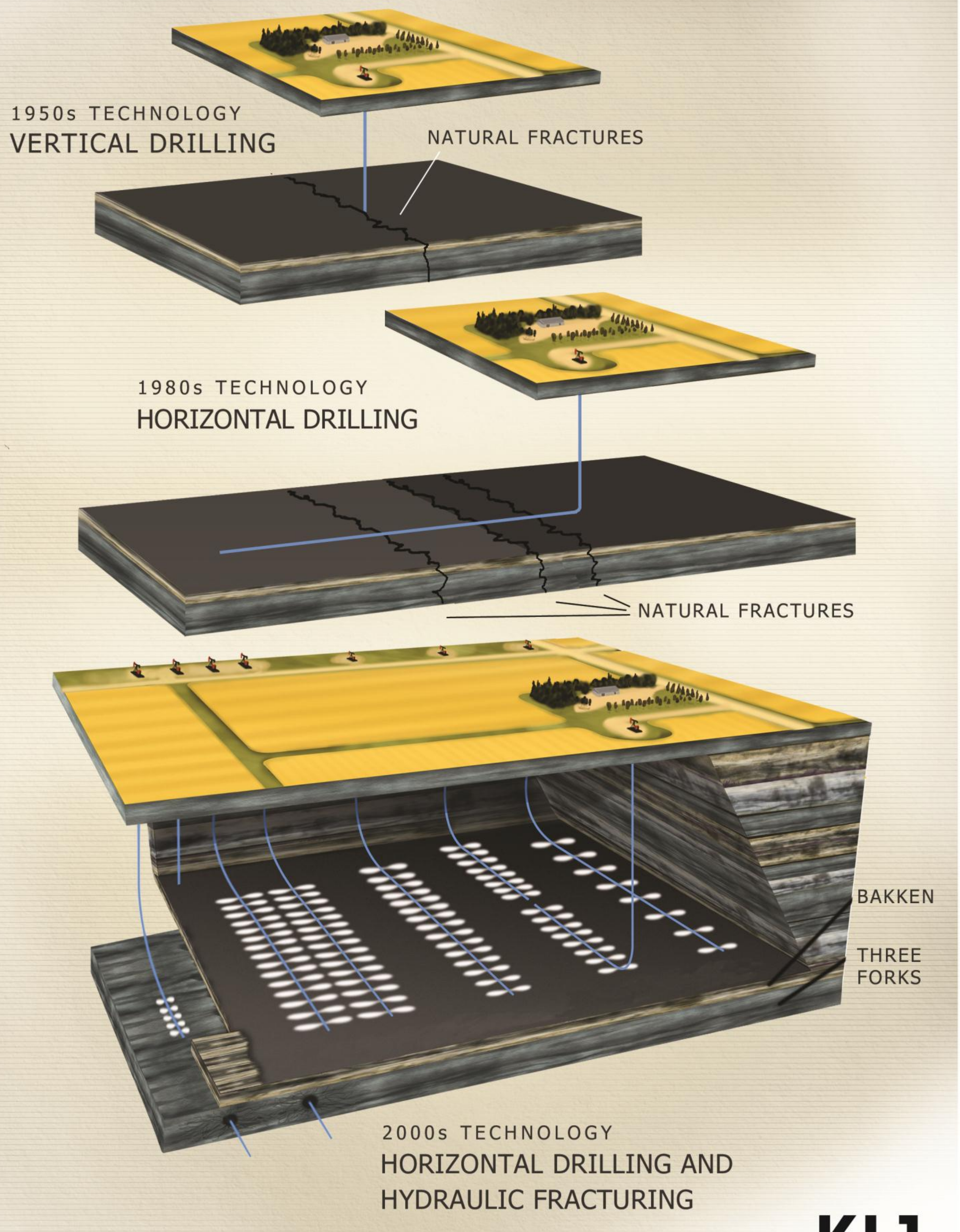

Figure 5: PROGRESSION OF DRILLING TECHNOLOGY

Source: KLJ

2.2 Study Area

Recent oil and gas related growth in the Williston Basin region is affecting the ability to plan for future electrical load capacity for the Partners and rural electric cooperatives located in North Dakota, Montana and South Dakota. The scope of the study focuses on electric utilities' service areas encompassing the Williston Basin within the United States (U.S.) as shown in Figure 6.

Figure 6: Williston Basin - Three Study Regions
Source: North Dakota Transmission Authority

2.3 Research Methodology

The Power Forecast 2012 (PF 12) report contains information and assumptions obtained through project research and stakeholder interviews. The information and assumptions are factored and input into a GIS-based computer modeling system to better facilitate geospatial planning for upcoming load requirements. The future of oil and gas development in the Williston Basin is uncertain. Therefore, three electrical load growth scenarios were modeled: 1) a less than expected outlook, 2) an expected, or consensus, viewpoint and 3) a higher than expected expansion of the current Williston Basin over a 20-year period.

The power forecast report involved establishing basic load forecast assumptions that model outputs applicable to oil and gas development. The most advantageous approach to creating base assumptions of the oil and gas industry's electrical needs was to gather expert information from major stakeholders operating in the study area, develop assumptions and seek industry validation.

Future power requirements are based largely on the rate and extent of development in the Williston Basin shale formations. Additional factors that may influence oilfield development include transportation infrastructure modifications, addition of oil and gas processing facilities, housing supply and new government policies or regulations.

2.4 Base Assumptions

The following sections outline base assumptions established from stakeholder interviews and derived from expert opinion of professionals within the oil and gas industry.

The assumptions are influenced by the number of drilling rigs, drilling rig efficiencies and producing wells in a specific region, between 2012 and 2032. The metrics are estimated from public and historical information and depend on an assumed development growth pattern.

2.4.1 Drilling and Drilling Rigs

Exploration and production efforts within the Williston Basin are not geographically uniform, some areas and fields are more economical. New drilling will trend toward fewer rig moves and increased utilization of walking drill rigs and multiple well pads.

From August 2011 through July 2012, the number of drilling rigs in the Williston Basin averaged 217. The total number of drilling rigs in the Williston Basin will remain near 2012 levels or slightly lower (200 to 210) for the next three years. The number of wells per pad will vary from a single well in lower production areas to an average of six wells per pad at optimum locations. The rig count will decrease as drilling becomes more efficient.

The number of workover rigs is expected to increase and remain in the Williston Basin long after the study area is fully developed due to an increase in the number of well bores that will require normal service to extend their production life.

Typical industry expectations for continued drilling in the Williston Basin are as follows:

- Crude price at the wellhead remains at an average price of $75 (2012 USD) per barrel
- Bakken crude closely follows West Texas Intermediate (WTI) and maintains 75 to 80 percent of WTI futures
- Natural gas price averages $3 per million British thermal units (Btu) in 2012 and is expected to increase to $7 per million Btu in 2035
- Crude oil production is above 350 barrels per day during initial production and averages 35 barrels per day over the commercial life of the well
- Established recoverable reserves for all formations from a single well exceeds 350,000 barrels of oil and have an initial 1:1 or better Gas to Oil Ratio (GOR) of natural gas liquids (NGL) rich natural gas
- Total cost to develop a well remains less than $11.5 million (2012 USD)

2.4.2 Number of Wells per Rig per Year

Due to limitations of winter weather, load limits on roadways, clearance restrictions and moving-vehicle capacity, the rig-up and demobilization times cannot be substantially reduced. Longer horizontals will be drilled to maintain an economical oil rate that justifies drilling costs, which will require higher rated rigs and more powerful mud pumps. These longer lateral lengths will lead to an increased chance of downhole challenges and an increased probability of mechanical failure on the rig and auxiliary equipment. Each respective challenge will result in additional downtime and offsetting potential increases in technology and management factors.

According to the North Dakota Oil and Gas Division, there is a theoretical maximum of 15 wells that could be drilled per rig, per year. However, due to environmental and technological limitations, this study will assume the number of wells drilled per rig over the next 20 years will gradually increase from 10 wells per rig, per year in 2012, to 12 wells per rig, per year by 2032.

2.4.3 Fracing

As the pace of drilling levels off, the availability of fracing crews will become less of a concern. Frac-water treatment will become a common practice as the cost of treatment approaches the cost to procure and deliver frac-water. Central frac-water treatment facilities will consume large amounts of power, while environmental regulation may increase the timeline of planning efforts.

2.4.4 Bakken Crude Differential

Bakken crude 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 the additional costs incurred to deliver oil to the market. Additionally, the differential is affected because the majority of shale oil production is light and sweet, which requires additional investment by processors to properly refine these products, as previously they had focused on poorer quality crude. The differential will drop to 10 percent over the next five years as the following key issues are resolved:

- Lack of pipeline capacity and infrastructure to transport Bakken crude is addressed and refineries are adjusted or retrofitted to more readily process Bakken crude
- Bakken crude transported via rail replaces higher cost crudes (i.e. Brent), feeding refineries in eastern North America
- Glut of oil at Cushing, OK, is eliminated

2.4.5 Natural Gas

Natural gas pricing is largely determined by composition. Each source of natural gas has varying quantities of methane, the most abundant product today and NGLs, the more desirable product. Bakken wells are currently more profitable due to the higher ratio of NGLs. As transportation methods and electrical generation more readily utilize natural gas and as exports of liquid natural gas increase, the U.S. will likely see rising natural gas (methane) prices as demand increases from business, residential and international sources.

2.4.6 Secondary and Tertiary Oil Recovery

Secondary recovery is the stage of hydrocarbon production when an external fluid, such as water or gas is injected into reservoirs that have fluid communication with production wells. Water and gas injections act to maintain reservoir pressure and displace hydrocarbons toward the production wellbore. Tertiary recovery, or enhanced oil recovery (EOR), covers gas (CO_2, natural gas, nitrogen, etc.) injection, chemical injection, microbial injection or thermal recovery techniques to further increase the amount of oil that can be recovered.

Until the middle of 2012, the primary focus of producers in the Williston Basin was to secure leases, and their planning focus over the next decade was on increased density drilling. Currently, more attention is turning toward identifying secondary and tertiary recovery techniques as some areas have begun reaching their bubble point. The bubble point occurs when reservoir pressure and temperature conditions cause the natural gas in solution with the oil to come out of solution. At this point it is important for producers to maintain reservoir pressure to ensure continued oil production.

2.4.7 Power

A survey of oilfield loads from rural electric cooperatives in North Dakota showed 208 of 1,087 (19 percent) existing wells currently not tied to the grid. With each site representing 0.03 MW of electricity, this equates to 6.24 MW of electrical demand in that particular region. This figure only accounts for wells in production for which power has been requested. Assumptions used for the forecast model, based on rural electric cooperative and stakeholder input and analysis of existing wells, show the following:

- 80 percent are currently tied to the grid
- 95 percent will be tied to the grid in 10 years
- 97.5 percent will be tied to the grid in 15 years and remain at this level

Stakeholder interviews indicated on-site generation has significant cost and reliability issues. Converting to grid power is a large economic factor, especially for sites not located near sufficient distribution infrastructure.

2.4.8 Transportation

Truck traffic volume will begin to decrease within the years 2012 to 2014 as pipeline infrastructure for both crude oil and production water becomes available to producers. Water gathering systems will be implemented where high ratios of production water to crude oil exist, whereas production water will still be collected with trucks in lower water yield fields.

During stakeholder interviews, many addressed the need to reduce the number of trucks on the study regions roads. Now that developers have completed the major push to get their leases held, they will focus on becoming more efficient, thus reducing costs and maintenance. A major part of this efficiency will be moving more product into pipelines and off the road. In addition, the public sees the high truck volume as a nuisance and safety hazard. Therefore, the quicker the industry can reduce the truck traffic, the sooner these development impacts can be mitigated.

2.4.9 Labor

Skilled labor for the oil and gas industry within the study region is limited due to several factors. Education and training are trying to catch up to the rapid growth, and housing shortages continue to be an issue. Companies meet their requirements for skilled workers by importing labor from regional and national market resources and rotating existing skilled employees within project fields. As oilfields are developed and reach the production stage, the workforce will diminish in size and find employment in other states.

2.4.10 Housing

Housing constraints will remain for several years. Future demand for permanent housing will continue to increase as demand for housing results from both growth in permanent oil sector workforce and growth in employment associated with supporting commercial and service activity.

2.5 Stakeholder Input Process

The full scope of future oilfield development in the Williston Basin is unknown. To frame the context and scope of future possibilities, a series of stakeholder interviews were designed and conducted to solicit perceptions and opinions regarding current and expected development of the study regions. Oil and gas stakeholders were identified considering geographic location of their operations within the Williston Basin, and type of company operations; involvement with oilfield exploration and production (upstream), or involvement with the transportation of oil and gas (downstream).

The synthesized discussions, along with price expectations, provided the basis for low, consensus and high scenarios of future oilfield development in the Williston Basin. Additional factors, such as regulatory environment, infrastructure development, water resources and anticipated leasing activity, were combined with stakeholder input in developing the various scenarios.

Stakeholders and government professionals agree oil prices will have a greater impact on production and electrical load demand than pending legislative or regulatory initiatives. However, industry experts note that if meaningful changes to current public policies relating to taxation, environmental requirements or fracing processes associated with oil exploration are made, extraction or production development costs could be negatively impacted and have a subsequent impact on electrical load requirements. Stakeholders see their energy demands remaining at the current 2012 rates through the year 2017, pending unforeseen federal regulation.

3. Electrical Power Forecast

By combining land use and development data, spatial load forecasting tools are able to model the extents, locations and activity development timelines and translate results into system load modules. The forecast involves identifying typical energy consumption profiles for various load classes. Electric load is calculated by multiplying the rating of a device by the hours used and is measured in either kilowatt-hours (kWh) or megawatt-hours (MWh). Peak demand is an electrical load request that indicates the maximum amount of electricity a customer requests from a utility company for service at a single point in time, measured in either kilowatts (kW) or megawatts (MW). These load classes include residential and commercial loads and primary and secondary infrastructure load growth that results from oil and gas development.

Future electric energy loads are then calculated from the modeling of impending development activities. These are gained from the forecasted progression of oil and gas infrastructure build-out scenarios. The result is a spatial load forecast that includes three modules: 1) a base map of current electric load data, 2) future loads resulting from population increases based on demographic data and 3) future loads based on oil and gas development build-out scenarios.

Future loads include build-out assumptions as well as specific loads where known or forecasted large loads are anticipated at a known geographic point. Future population and point load modules are assigned parameters, which allows the model to adjust for how less tangible variables affect the industry. These variables, which may include social metrics, political factors and environmental influences, are then able to be adjusted in future model updates.

Of particular importance in the electrical power forecasts are the large number of anticipated wells going into operation across the study region over the next 20 years (2012 to 2032). Loads associated with a single well in the forecast model become significant very quickly. The study analysis indicates the observed demand of a single well pump in 2012 was 20 kW. However, it is feasible that the well pumps could potentially be operated utilizing a demand of 40 kW. To account for variance in well operations throughout the region, two calculations were made in the forecast model to demonstrate two power requirements:

- *Observed Demand Case:* The observed demand is using an average load of 22 kW per well site; 20 kW has been designated to the well pump load with miscellaneous loads (loads not located directly on a well pad but are associated with oilfield production and can be averaged on a per well basis) using 2 kW.
- *Maximum Demand Case:* The maximum demand case well pump load ramps up from 24 kW today to 40 kW in the first five years of the study and remain at 40 kW for the remainder of the study period. Miscellaneous loads ramp up from 6.6 kW today to 25 kW in the first five years and remaining at 25 kW for the remainder of the study period.

Both demand cases were calculated for low, consensus and high forecast scenarios. *For clarification purposes, the power numbers written into the text of the report are the average of the observed and maximum demand cases in the consensus scenario.*

3.1 Current Demand

Research results show the current 2012 demand for the three region area in this study is 1,209 MW. Of this, the residential category has the highest demand with urban residential demand at 217 MW and rural residential demand at 193 MW. Rural areas are defined as areas within the study region with lower populations per geographic square mile, typically, higher electrical load requirements per customer are generated due to agriculture-based needs. Urban areas are densely populated cities and towns, typically with lower electrical load requirements per customer due to shared municipal services.

Following residential is large commercial and industrial (C&I) at 432 MW. This is comprised of 307 MW for rural large C&I demand and 125 MW for urban large C&I demand. Just behind large C&I is small C&I at a combined total of 323 MW. The last, and lowest, category is miscellaneous demand at 43 MW, which includes loads, such as street lighting and irrigation. This represents 24 MW in rural areas and 19 MW in urban areas.

3.2 2017 Brings Rapid Rises

During conducted research, areas were identified as future oilfield infrastructure loads for electrical power needs. These high-density growth areas include all or parts of nine counties in North Dakota and three counties in Montana. Future oilfield infrastructure loads were identified by their projected petroleum infrastructure development as well as industrial and commercial growth areas. The growth ultimately leads to higher populations, in turn spurring higher electric energy usage. South Dakota counties lie outside the core area in which oilfield development is assumed to occur within the study period. Therefore, these counties are not included in the power load calculations.

The nine northwestern North Dakota counties are Divide, Wells, McKenzie, Billings, Stark, Dunn, Burke, Mountrail and McLean. The three northeastern Montana counties are Sheridan, Roosevelt and Richland.

Total, rising demand for electrical power five years from today brings the expected demand in 2017 up to 2,288 MW. This represents a 89 percent increase from the 2012 demand of 1,209 MW. The main reason behind this large increase over the five-year period is significant hikes in large C&I electrical demand. In 2017, this category will claim a 1,330 MW demand for electricity. Rural large C&I leads the increases with 1,107 MW, with urban large C&I at 222 MW. This sharp rise in large C&I results in a 208 percent increase over the 2012 large C&I total of 432 MW.

In 2017, combined demand for urban and rural residential is estimated to be 482 MW. Small C&I will experience the next largest numbers, with demand at a combined 431 MW. Miscellaneous usage is the lowest load area, but still has significant totals of 26 MW in rural areas and 19 MW in urban areas, for a combined total of 45 MW.

3.3 Energy Usage Continues to Increase in 2022

In 2022, electrical demand is still trending upward and will reach a total of 2,948 MW. Most of that demand consists of large C&I, which will grow to 1,875 MW, a 41 percent increase from 1,330 MW in 2017. By this time, residential demand will be at 526 MW and small C&I at 499 MW. Miscellaneous makes up the remainder of the 2017 demand totals at 47 MW.

3.4 2027 Experiences Increased Usage Across the Board

As in all the years in the 20-year span of this study period (2012 to 2032), there is not a decrease in any load areas in 2027. It also makes no difference if the loads are urban or rural—the numbers keep increasing across the board. Total electrical demand 15 years from today is predicted to be 3,395 MW, an increase of almost 181 percent from today's total of 1,209 MW.

Of the 3,395 MW of power demanded in 2027, large C&I is by far the largest category at 2,281 MW. Breaking down this total between rural and urban clearly shows the growth in the oil and gas industry as rural demand is 1,920 MW and urban demand is 361 MW. Rounding out the 2027 electrical demand numbers are 544 MW for residential, 520 MW for small C&I and 50 MW for miscellaneous.

3.5 Peak Demand Expected in 2032

Research indicates by 2032 demand for electrical power in the targeted 43 counties within the Williston Basin will balloon to 3,721 MW. This represents a hike of almost 208 percent from the 2012 demand of 1,209 MW.

Of the 3,721 MW projected total power demand, the bulk of the electricity—2,540 MW—will be used to power large C&I needs in the three region area that blankets North Dakota, South Dakota and Montana. While booming growth in large C&I is experienced in urban and rural areas, the rural areas will experience the largest gains in electrical power demand.

The second largest power demand 20 years from now will be residential, at 570 MW. This includes 358 MW demand and 212 MW demand for urban residential and rural residential categories respectively.

Small C&I will need the third largest amount of electricity with an urban and rural total demand of 559 MW. The breakdown is 256 MW for rural and 303 MW for urban areas. Accounting for the remaining expected power demand is miscellaneous sources at 52 MW.

Region 1, the most northern tier, will demand the most electricity at almost 1,998 MW (Figure 7, Table 4 and Table 7). Region 2 will demand the next highest amount of electricity at 1,495 MW (Figure 8, Table 5 and Table 8). Region 3 trails far behind with a little more than 228 MW (Figure 9, Table 6 and Table 9).

Figure 10 shows the estimated electrical demand under each scenario for the entire study area, and Table 3 summarizes the forecasted electrical demand and energy use respectively for each region.

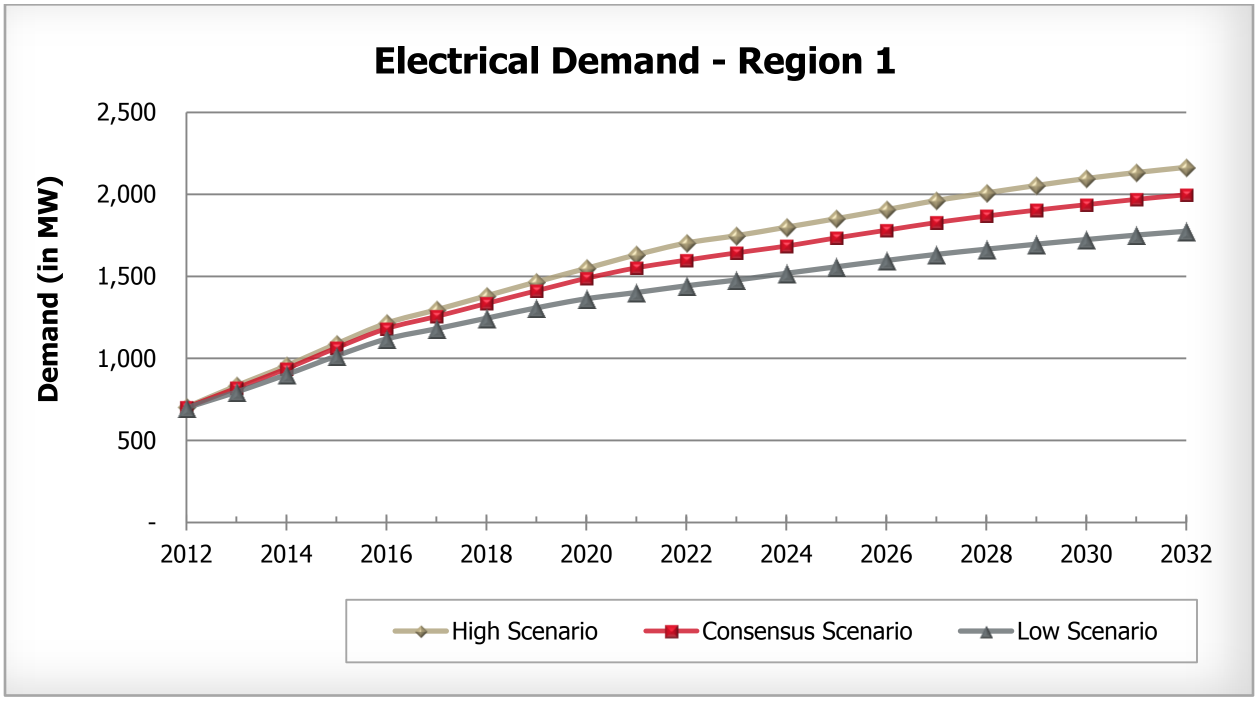

Figure 7: Electrical Demand - Region 1
Source: KLJ

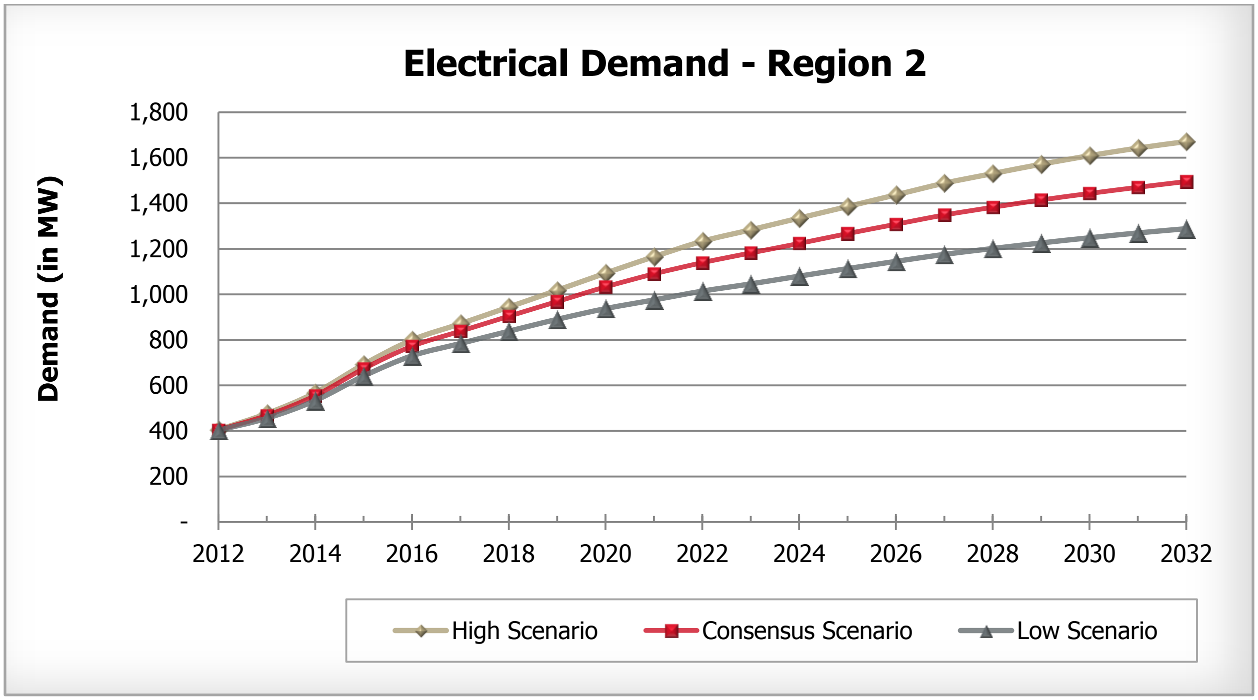

Figure 8: Electrical Demand - Region 2
Source: KLJ

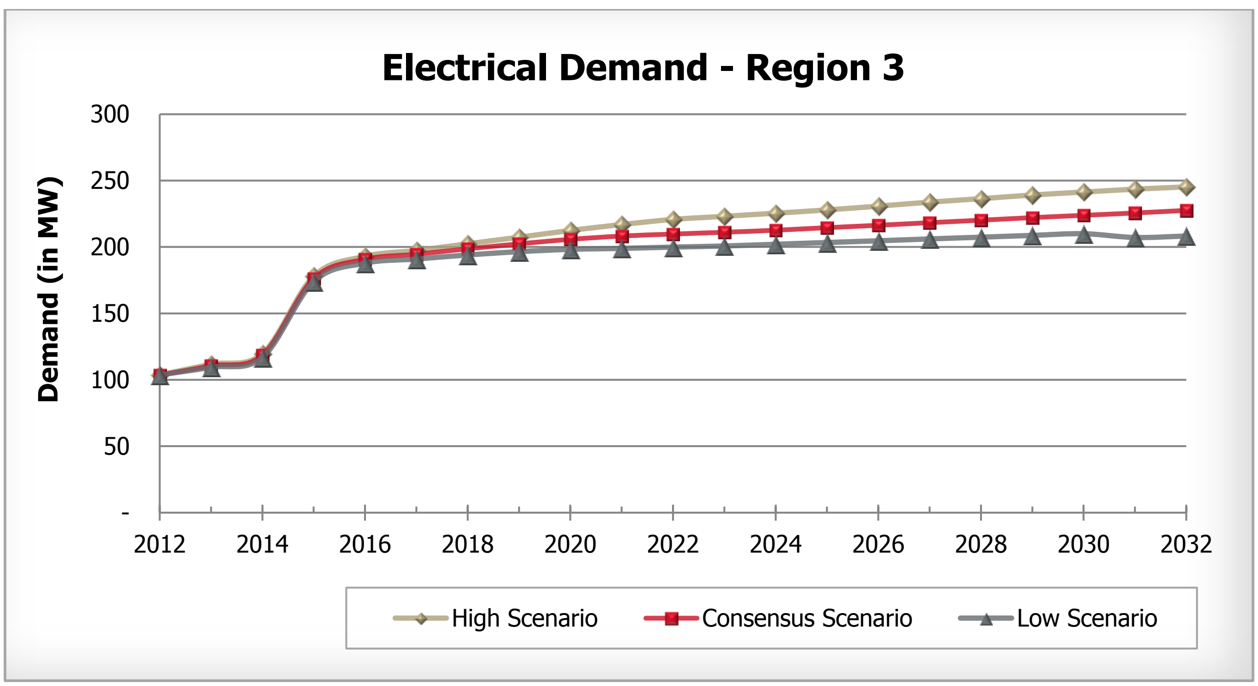

Figure 9: Electrical Demand - Region 3
Source: KLJ

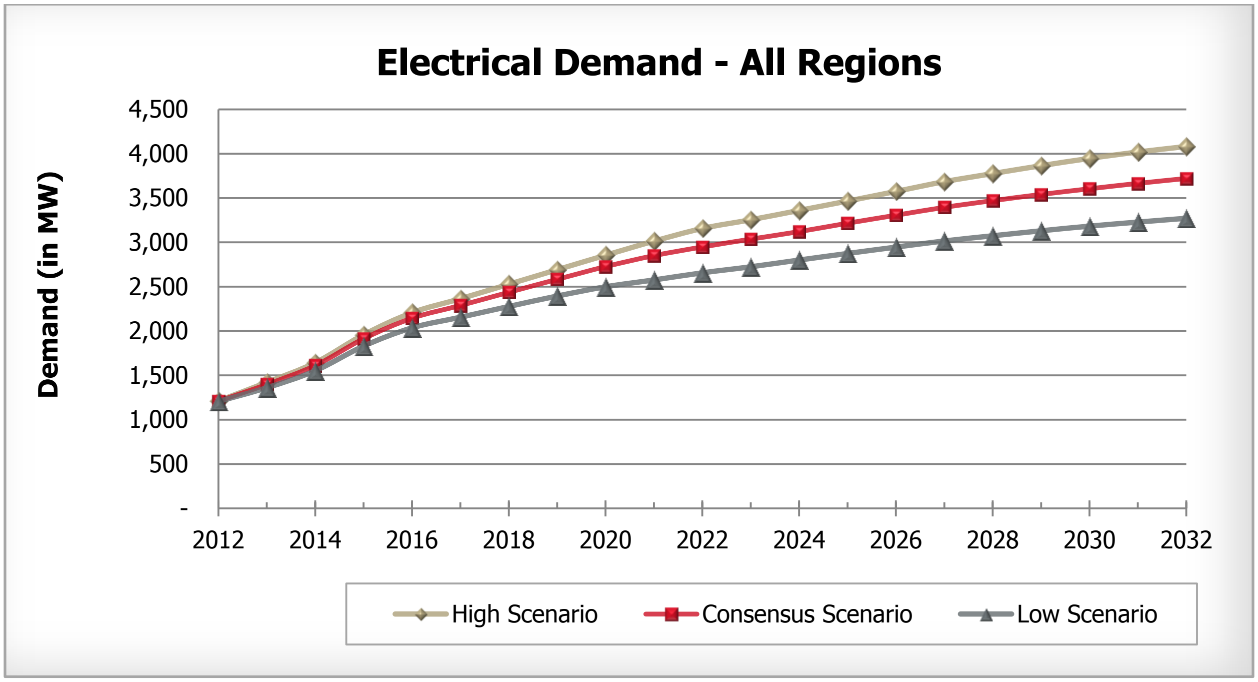

Figure 10: Electrical Demand - All Regions
Source: KLJ

Forecasted Electrical Loads - All Regions					
Demand (MW)					
	2012	2017	2022	2027	2032
Region 1	701	1,256	1,599	1,828	1,998
Region 2	404	838	1139	1348	1495
Region 3	104	195	210	218	228
Total Demand	**1,209**	**2,288**	**2,948**	**3,395**	**3,721**
Energy (MWh)					
Region 1	3,977,246	7,945,361	10,387,903	12,058,128	13,217,653
Region 2	2,476,678	5,677,350	7,887,167	9,445,752	10,489,326
Region 3	600,749	1,272,543	1,356,960	1,404,199	1,449,922
Total Energy	**7,054,673**	**14,895,254**	**19,632,031**	**22,908,079**	**25,156,901**

Table 3: Forecasted Electrical Loads - All Regions
Source: KLJ

Consensus Scenario - MW Electrical Demand by County for Region 1					
	2012	**2017**	**2022**	**2027**	**2032**
Williams	186	397	504	569	617
Mountrail	74	175	243	291	322
Ward	190	235	257	264	276
Divide	31	94	149	187	212
Burke	22	59	86	106	118
Roosevelt	35	57	77	95	109
Sheridan (MT)	17	43	68	90	107
McLean	25	39	52	61	66
Bottineau	40	49	51	51	52
Valley	20	35	36	36	37
Renville	17	26	26	26	27
Rolette	18	20	21	23	25
McHenry	19	22	23	23	23
Daniels	4	5	5	6	6
Sheridan (ND)	1	1	1	1	1

Table 4: Consensus Scenario - MW Electrical Demand by County for Region 1
Source: KLJ

Consensus Scenario - MW Electrical Demand by County for Region 2					
	2012	**2017**	**2022**	**2027**	**2032**
McKenzie	122	288	404	483	535
Dunn	39	121	190	239	270
Stark	85	141	187	213	235
Richland	61	111	142	169	190
Billings	22	57	84	103	115
Dawson	23	31	35	38	41
McCone	7	33	34	35	36
Mercer	22	24	25	26	27
Golden Valley	8	14	19	22	24
Garfield	6	7	7	8	9
Wibaux	4	6	6	7	7
Oliver	5	5	5	5	5
Prairie	1	1	1	1	1

Table 5: Consensus Scenario - MW Electrical Demand by County for Region 2
Source: KLJ

Consensus Scenario - MW Electrical Demand by County for Region 3					
	2012	**2017**	**2022**	**2027**	**2032**
Fallon	23	50	52	53	54
Meade	20	34	37	39	41
Bowman	26	34	37	37	39
Harding	4	30	31	31	31
Hettinger	8	13	17	19	20
Slope	4	7	9	10	11
Perkins	7	8	9	10	10
Carter	3	9	9	10	10
Adams	7	9	10	10	10

Table 6: Consensus Scenario - MW Electrical Demand by County for Region 3
Source: KLJ

Consensus Scenario - MWh Energy by County for Region 1					
	2012	**2017**	**2022**	**2027**	**2032**
Williams	1,087,776	2,561,456	3,319,625	3,799,503	4,130,605
Mountrail	492,746	1,267,795	1,783,774	2,149,176	2,379,919
Divide	205,799	683,220	1,105,491	1,404,066	1,590,045
Ward	947,290	1,209,517	1,303,174	1,324,776	1,368,146
Burke	154,580	438,579	654,921	810,376	905,907
Sheridan (MT)	99,966	281,365	457,899	609,095	726,832
Roosevelt	190,875	340,611	479,442	598,905	692,906
McLean	132,917	235,350	331,261	399,979	441,823
Bottineau	235,288	303,597	310,238	309,816	312,738
Valley	103,966	213,100	216,455	219,855	223,422
Renville	109,575	174,575	176,389	175,857	176,454
Rolette	90,834	97,263	103,589	109,885	118,966
McHenry	97,266	108,208	112,603	111,798	113,369
Daniels	22,033	24,696	27,386	29,804	31,889
Sheridan (ND)	6,335	6,030	5,657	5,237	4,633

Table 7: Consensus Scenario - MWh Energy by County for Region 1
Source: KLJ

Consensus Scenario - MWh Energy by County for Region 2					
	2012	**2017**	**2022**	**2027**	**2032**
McKenzie	838,553	2,090,506	2,973,321	3,591,105	3,980,267
Dunn	269,325	903,062	1,438,255	1,818,962	2,056,229
Stark	442,488	822,690	1,125,535	1,304,227	1,442,552
Richland	377,801	716,407	926,527	1,105,701	1,247,830
Billings	166,011	436,327	649,076	802,281	896,277
McCone	32,757	240,951	245,385	248,996	252,465
Dawson	116,683	165,920	182,998	196,959	210,170
Golden Valley	44,275	90,857	124,921	146,706	161,601
Mercer	113,589	118,690	122,783	126,964	132,482
Garfield	28,135	33,229	36,936	39,955	42,857
Wibaux	19,350	30,744	33,375	35,520	37,575
Oliver	23,457	23,078	22,618	22,490	22,704
Prairie	4,253	4,887	5,438	5,886	6,316

Table 8: Consensus Scenario - MWh Energy by County for Region 2
Source: KLJ

Consensus Scenario - MWh Energy by County for Region 3					
	2012	**2017**	**2022**	**2027**	**2032**
Fallon	145,399	349,101	357,733	362,194	366,746
Bowman	176,022	230,341	241,061	243,312	248,665
Meade	99,985	208,573	218,513	227,375	236,739
Harding	22,237	227,987	229,706	231,242	232,865
Hettinger	42,596	71,842	98,026	113,198	124,527
Slope	25,502	45,554	61,840	72,537	79,609
Carter	16,316	56,685	60,093	61,675	63,287
Perkins	36,370	38,870	42,537	45,805	49,259
Adams	36,323	43,590	47,450	46,862	48,226

Table 9: Consensus Scenario - MWh Energy by County for Region 3
Source: KLJ

3.6 Modeling the Load Growth Forecasts

A GIS software program was used to model the electric spatial load growth within the three study regions that blanket the 43 counties in portions of North Dakota, South Dakota and Montana. Using GIS analysis, a set of low, consensus and high market scenarios were modeled for the 20-year study period (2012 to 2032). Each of the three scenarios consisted of an existing electrical load map created from 2012 data (Figure 11), which was then layered with the specific scenarios population projections modules (Figure 12) and expected oilfield development modules (Figure 13). The mapping included in this document is reflective of the consensus scenario only.

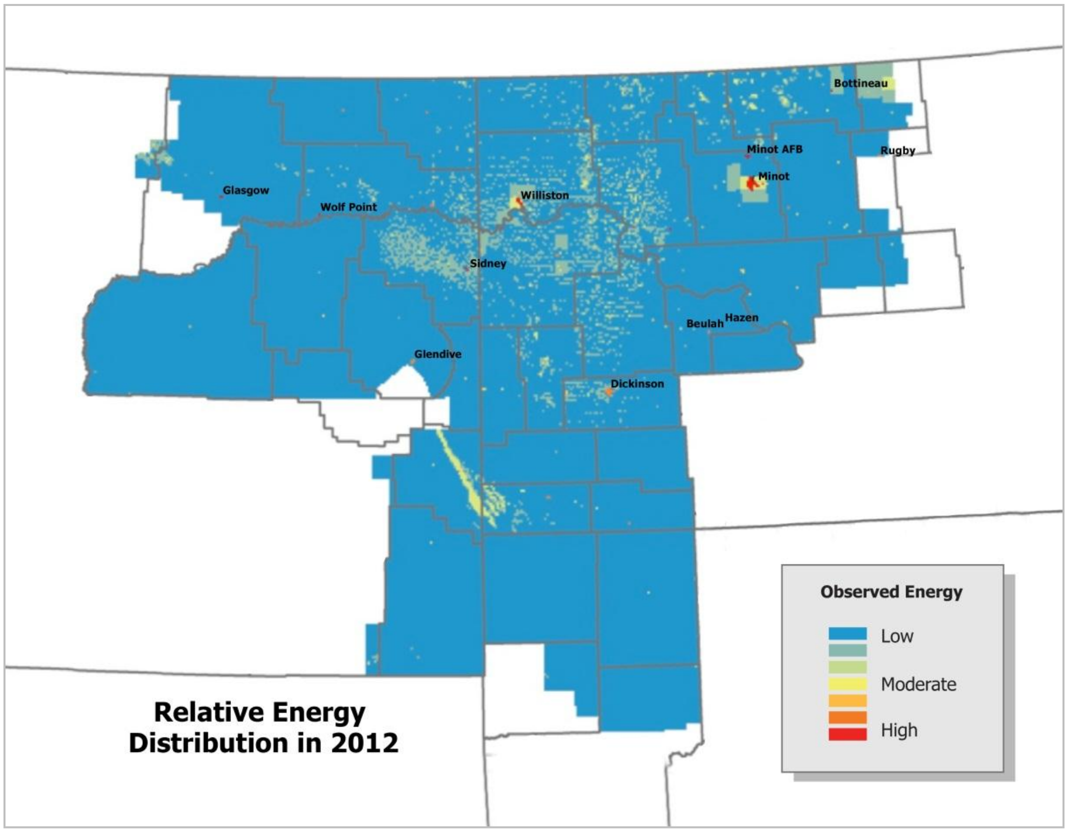

Figure 11: Relative Energy Distribution in 2012
Source: KLJ

3.6.1 Current Load Distribution

The current load distribution module was developed from data consisting of existing and public geographic information and reflects current energy usage. Power demand metrics were compiled from data provided by electric utility companies. The current residential and non-residential load data was then modeled with current oil development load data (oil well infrastructure load) and produced the current load module data, which are calculated in kilowatt-hours per year (kWh), per square mile (pixel) as shown in Figure 11. The base power load is distributed between urban and rural classifications in four classes across the study area: 1) large C&I, 2) small C&I, 3) residential and 4) miscellaneous loads.

3.6.2 Population Load Distribution

A new data layer and map associated with energy related to population projections was produced by using the yearly population estimates in each county. Demographic data was obtained from federal, state, county and local agencies. In addition, policy issues and oil and gas related population variances that affect housing growth were obtained and analyzed. Demographic data consists of the following data points:

- Existing housing data
- Residential growth forecasts
- Commercial growth forecasts

The data was combined with information gained from stakeholder interviews pertaining to industry demographics, household size and housing preferences of the stakeholders' workforce. This resulted in an expected growth scenario dependent on only a few variables, including the number of oil and gas drilling rigs operating in a region and technological advancements that reduce the number of skilled workers per industry segment. Future electric load growth associated with population growth is shown in Figure 12.

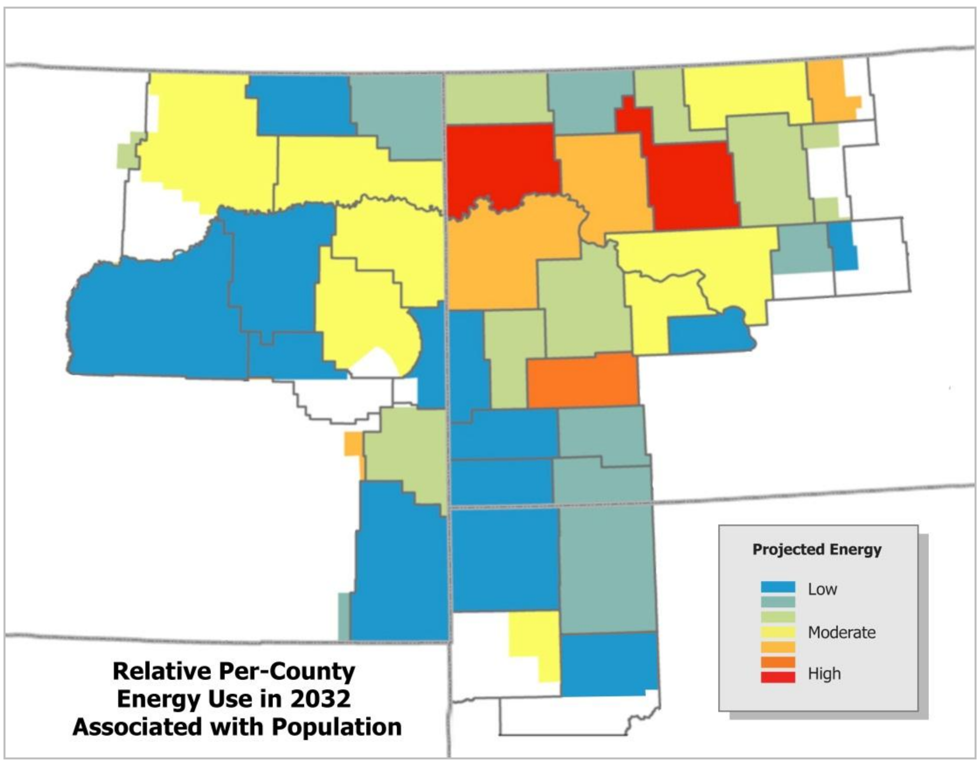

Figure 12: Relative Per-County Energy Use in 2032 Associated with Population
Source: KLJ

3.6.3 Future Electric Loads

Main factors in developing a model illustrating future development of electric load include the relative load required by both the producing formation associated with the number of wells and related infrastructure, and the geographic boundaries of those future developing loads. The PF 12 modeling process was developed through an assessment of known power loads and estimations of future loads as determined by stakeholder input, analysis of oilfield development and population growth projections. Certain future load factors are not included due to the lack of reliable, dependable or consistent data. However, these factors can be regarded as a significant demand. They will be tracked, monitored and factored in future forecast studies as consistent data is made known and recorded.

Electric load elements that could be factored into future forecast studies are as follows:

- *Secondary and Tertiary Recovery for new Williston Basin wells*: Currently, the vast majority of new wells are under primary recovery power loads. As secondary, and then tertiary recovery techniques (including CO_2 injection) begin to be consistently deployed, timing, location and power loads for these methods can be factored into the model and existing well load values and parameters will be adjusted.

- *Gas Processing Facilities (2015-2019)*: In addition to processing plant loads already planned or currently in construction included in the model, it could be assumed that up to two additional large gas processing facilities will be built between 2015 to 2019. It is presently assumed the facilities would have the same level of demand as the existing planned facilities, and have a per facility demand of approximately 15 MW for every 100 million standard cubic feet a day (MMscf/d)of processing capability. If these potential plants move to a public planning stage, the loads will be assigned a value, location and date-of-operation and included in the model.

- *Production Water Treatment for Re-use Facilities*: Currently, water used for fracing and oilfield development comes from either wells sourcing from the groundwater aquifer or man-made water storage facilities such as Lake Sakakawea. If production water treatment facilities shift from a planning stage to a development stage, an appropriate load will be applied to the model. Currently, an estimated hourly demand of 75 kW would be required for every 10,000 barrels of water treated.

- *Major Oil Transmission Pipelines (2015-2017)*: Considering the potential daily production of crude oil in the Williston Basin, there is an increasing possibility of up to two major oil transmission pipelines with a capacity of at least 100,000 barrels of oil per day (bopd) each being constructed between 2015 to 2017. If and when these potential pipelines are firmly in a planning stage with a designated route and stated capacity, the model will assign the equivalent ratio of 2 MW per 100,000 barrels a day along every 20 miles of pipeline.

In the forecast model, it was assumed a minor percentage of load growth over the next 20 years would occur in geologic formations other than the Bakken/Three Forks formations. Given the assumption, an effort to map boundaries of the core area of future Bakken/Three Forks production was initiated using a variety of source materials and personal communication with geologists and regulatory personnel working for both private and governmental entities. It was further assumed there would be relatively uniform production quantities across the length and breadth of the core development area. Although oil and gas drilling activities progresses and changes over time, sufficient historical drilling, modeling and mapping data does not exist at this time to refine this assumption.

Areal boundaries were determined based on the mapped extents of mature Bakken deposits, documented initial production results of the last 10 years of Bakken/Three Forks wells, regional groundwater flow directions and personal communication. Within the study region, a boundary delineating the core Bakken/Three Forks development area within North Dakota and Montana was established. From these extents, a 1,280-acre spacing grid was created for the study area and trimmed at the Bakken/Three Forks core boundary.

The resulting array of 1,280-acre spacing units allowed counting existing and potential spacing units already drilled or could be drilled. The count tallied more than 6,000 spacing units in North Dakota and greater than 2,000 spacing units in Montana that could conceivably be leased for oil and gas drilling. As drilling progresses into the future, there will most likely be areas outside of this core area that will have Bakken/Three Forks development, and conversely, areas within the core that will not have future development. Current North Dakota State regulations allow up to eight Bakken/Three Forks wells per 1,280-spacing unit. Montana allows a maximum of four Bakken/Three Forks wells per spacing unit. A consensus value of 5.98 wells per North Dakota spacing unit and 2.1 wells per Montana spacing unit was used as a metric for ultimate well-based load across the core area. Future electric load growth was then calculated by subtracting the number of existing Bakken/Three Forks wells from the consensus number for each individual spacing unit, ultimately deriving the potential growth in well-based electric loads.

Future oil and gas development energy requirements, measured in kWh per year per square mile, were developed and resulted in the 2032 oilfield infrastructure map as illustrated in Figure 13. Future oilfield infrastructure loads and associated build-out scenarios are considered significant loads. These loads were estimated from oil and gas industry stakeholder opinions, or had been considered to most likely occur within the study area. Future oilfield infrastructure loads generally consist of the following:

- Locations of proposed petroleum infrastructure development loads obtained from oil and gas stakeholder interviews and future build-out scenarios
- Location and size of future large industrial loads based on forecasted industrial growth
- Location and size of future large commercial loads based on estimated oil and gas build-out scenarios

Projected well counts for each year were used to develop well build-out portions of the future oilfield infrastructure load module. The well build-out scenarios were developed based on well spacing unit limits currently used in North Dakota and Montana and a total number of wells estimated per year in each region. The module assigned a uniform distribution of wells per spacing-unit, and assumed spacing units in each state would have the maximum number of wells currently estimated for the consensus scenario. Along with the estimated yearly well counts, high load demand assumptions, such as compressor stations, saltwater disposal sites, saltwater disposal pipeline booster pumps, oil pipeline booster pumps and proposed oil and gas refinery locations, were assigned to geographic locations (Figure 13).

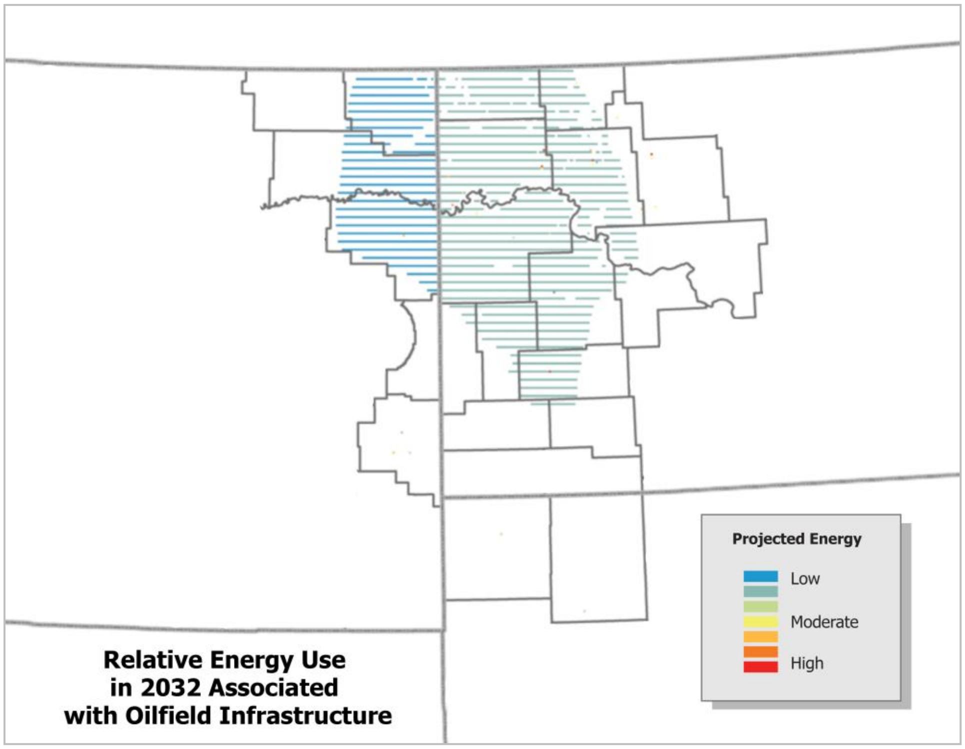

Figure 13: Relative Energy Use in 2032 Associated with Oilfield Infrastructure
Source: KLJ

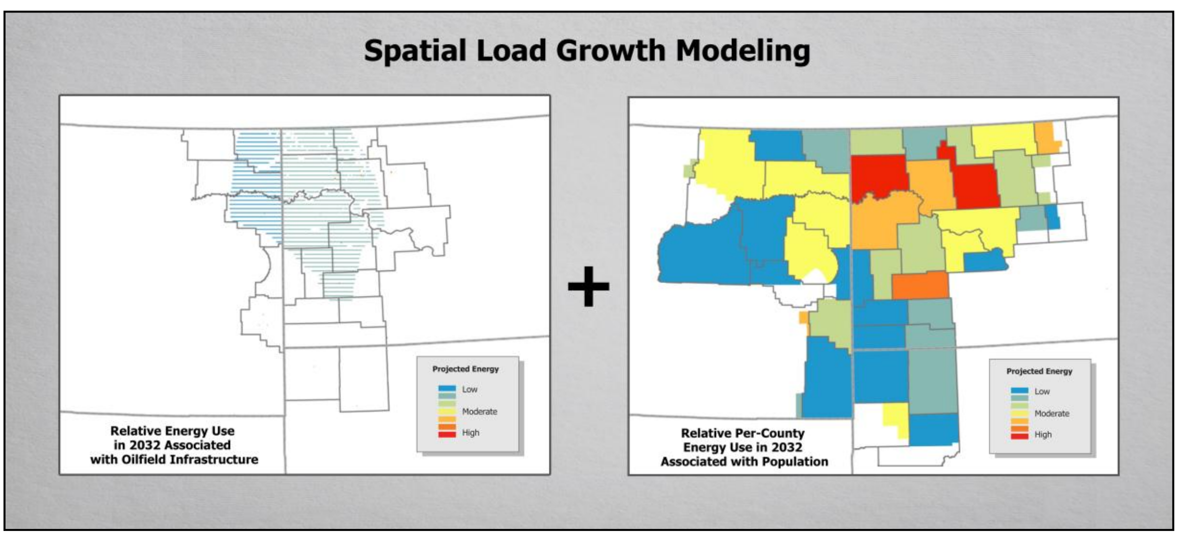

Figure 14: Spatial Load Growth Modeling
Source: KLJ

3.6.4 Forecast Model Map

When modeled in GIS (Figure 14), the final product produces the spatial electric load forecast per square mile, per year, as represented in Figure 15.

The combined modules also indicate significant temporary population increases in several towns located near development activities and large population increases of permanent residents in the larger cities (the population demographics module assumes permanent workers will gravitate toward residing in higher trade areas).

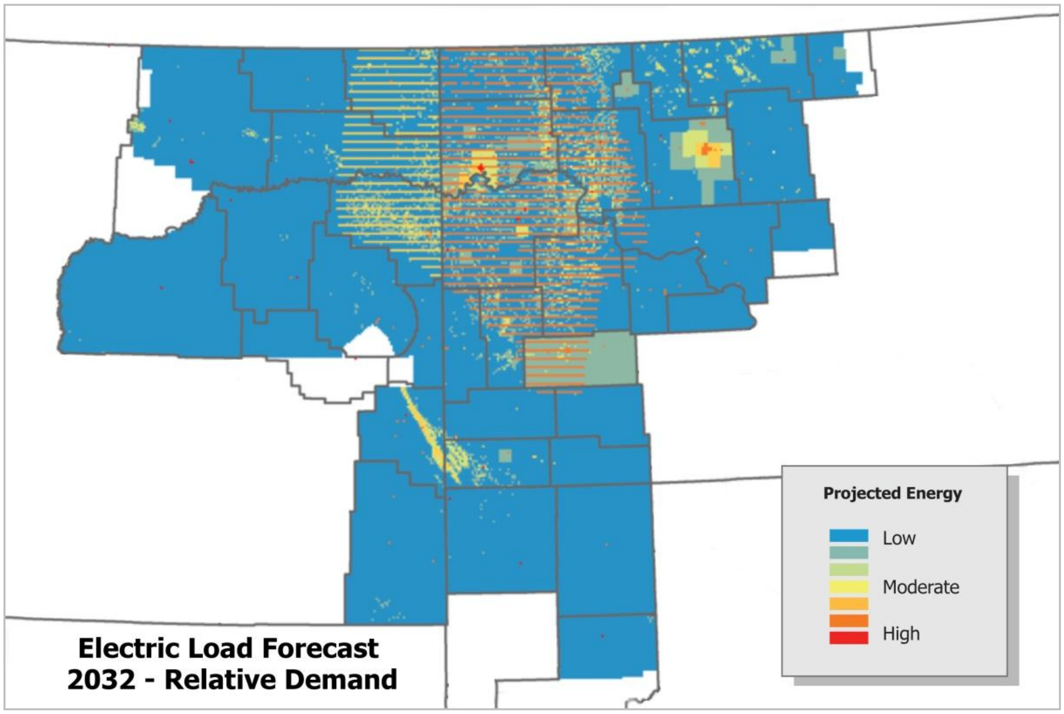

Figure 15: Electric Load Forecast 2032 - Relative Demand
Source: KLJ

4. Oil and Gas Development Details and Outlook

Energy costs related to oil and gas production can be broken into three broad stages: 1) lifting, 2) transporting and 3) processing. Determination of oil and gas development and production-related electric load requirements depend on factors such as the number of wells to be drilled and completed and gas, oil and water production rates. Typical drilling activities require reliable electrical energy to power a number of applications, such as separation, transportation and processing.

4.1 Oilfield Infrastructure Power Requirements

Electric-powered infrastructure vital for the oil and gas industry ranges from small loads, such as communication or monitoring devices that operate at low power of 12 watts, to large industrial loads, such as gas processing plants requiring upwards of 20 MW of demand. The following sections describe devices related to oil and gas infrastructure that have significant energy loads. All scenarios cover the 20-year forecast period.

Energy to drill and complete a well is sourced from onsite generators built into the drilling and workover rigs. After the well is completed, grid-tied electric energy is required for the primary recovery stage to lift fluid to the surface, separate the gas, oil, water and solids, compress and transport the oil and gas and treat and dispose of brine water and processing gases. In secondary and tertiary recovery stages, the energy required typically remains stable: although, additional electricity may be required to inject fluids into the reservoir and recycle the injectants.

Monthly meter data of oilfield-related electric loads indicate an average usage of 22 kW per oilfield site. An analysis of 1,000 oilfield sites show an average of 800 sites were connected to a utility's power grid during a given month (80 percent existing load, 20 percent impending load). The study assumes this 4:1 ratio is consistent across the entire Williston Basin. Additionally, it is assumed all leases held by only one well will see an addition of at least four additional wells per spacing unit in North Dakota and one additional well per spacing unit in Montana. Significant infrastructure loads are directly related to primary recovery of a single well. A low and high demand case for a well pump has been established for each study scenario.

Low Case: Assume demand for a single well pump is 20 kW today and remains at 20 kW for the entire study period.

High Case: Assume demand for a single well pump begins at 20 kW and ramps up to 40 kW over the first five years of the study to correlate with the expected completion of oil transportation infrastructure.

- Load Calculation Requirements
  - Load factors are not consistent.
  - Apply 0.90 load factor to oilfield infrastructure. Oilfield infrastructure is categorized as rural large C&I.
  - Residential, small C&I and large C&I load factors are included in average usage.
  - The following individual load factors will be used to convert energy to demand:
    - Urban residential – 0.40
    - Rural residential – 0.65
    - Urban Small C&I – 0.50
    - Rural Small C&I – 0.65
    - Urban Large C&I – 0.80
    - Rural Large C&I – 0.90
    - Urban Misc. – 0.4
    - Rural Misc. – 0.65
  - It is assumed 20 percent of all wells are presently not hooked up to the electrical grid.
  - It is assumed rural electric cooperatives will catch up over the study period at the following rate, but there will always be 2.5 percent of the wells not connected to the electrical grid.
    - Today – 20 percent off grid
    - Year 10 – 5 percent off grid
    - Year 15 through 20 – 2.5 percent off grid

The generic demand to annual energy conversion equation is as follows:

$$(energy)\ MWh = (demand)\ kW * \ 24\frac{hrs}{day} * 365\frac{days}{year} * \frac{1MW}{1000kw} * \ (Load\ Factor)$$

The generic well-related demand in kW conversion to energy use in MWh for the significant infrastructure is shown in Table 10.

To estimate impending load per year, these generic loads per well are applied to the well count derived from estimating the number of wells per county.

4.1.1 Lease Automatic Custody Transfer Unit

Lease Automatic Custody Transfer (LACT) units automate the process of sampling, measuring and transferring hydrocarbons between a buyer and seller. Composed of electric pumps and various instruments, these devices are typically used at individual well sites and truck unloading terminals.

4.1.2 Compressor Stations

Transporting natural gas from the wellhead to a processing plant through a pipeline requires placing compressor stations along the length of the pipeline to maintain constant pressure. Compressor stations use pumps ranging from 450 kW to 1,200 kW.

4.1.3 Saltwater Disposal Sites

Saltwater disposal sites vary in size and region due to the quantity of water produced at each wellhead. No linear relationship exists between bopd and barrels of water a day (bbls/d). Site variance at one site could be as great as 10:1 oil to water output and at another site the opposite at 1:10 oil to water output. Further, each area is unique in its varying formations. The assumptions for the 20-year forecast period under the consensus scenario are that about 540 additional saltwater disposal sites will be needed before peak production in the early 2020s. These disposal sites are assumed to be located within a 20 mile radius of producing wells.

4.1.4 Gas Processing Plants

Gas processing plants are located throughout the three study regions. Actual energy consumed by each plant depends on the amount of onsite generation utilized. Demand requests for the new 100 MMscf/d capacity plants have been 20 MW. Based on actual usage rates from local utilities, the forecast study used 15 MW as a more accurate representation of likely demand. Additional natural gas processing plants will be needed if drilling activities continue at current levels.

4.1.5 Booster Pump Stations

Booster pump stations increase oil pressure received through a main pipeline to transmit it to the next station or terminal. Using existing pipeline system and projected future infrastructure data as a baseline, 112 kW for every 20 miles of transmission line was determined.

4.1.6 Oil Reservoir Storage

Stakeholder interviews aided in determining the total load requirements at oil reservoir storage facilities. Loads varied from 900 kW to 1,350 kW, with many sites drawing 60 to 70 percent of the total anticipated demand. Stakeholders indicated many sites are anticipating a doubling of load-out capacity over the next 20 years.

System components for these facilities include pumps, LACT units, mixers and other various small electrical systems.

4.1.7 Rail Load-Out Facilities

Rail load-out facilities for crude oil transportation continue to spring up throughout the study region. Ten sites are now in development. An additional 10 sites are planned in North Dakota including Banner-Dore, Fryburg, Dickinson and Zap. Electric loads for rail loading facilities range from 450 kW to 1,500 kW.

4.1.8 CO_2 EOR Projects Energy Requirements

Today, several experimental pilot projects are being conducted in the Bakken Formation and Williston Basin to determine the most effective recovery methodology to ensure future long-term production. At this point, there is not enough conclusive data available to know what the future recovery methodology will be, or to accurately estimate the electrical loads associated with that methodology. Electrical loads for widespread secondary and tertiary recovery are not included in this forecast model. One CO_2 EOR project is being developed in the Cedar Creek anticline area of the Williston Basin. Estimates of future electrical demand received from the producer developing that project are included within the model at that location only.

<table>
<tr><th colspan="6">Generic Assumptions of Significant Infrastructure Energy Use</th></tr>
<tr><th>Device</th><th>Assumption</th><th>Device Metric</th><th>Ratio</th><th>Average Demand Per Well (kW)</th><th>Average Energy (MWh)</th></tr>
<tr><td>Well Pump</td><td>Average well pump is 65hp. Well pumps tied to Variable Frequency Drives</td><td></td><td>1:1</td><td>30</td><td>237</td></tr>
<tr><td>Compressor station</td><td>1 well produces 50 Mscf/d (averaged)</td><td>1:7,500 Mscf/d gas</td><td>1:150 wells</td><td rowspan="3">13.6</td><td rowspan="3">107</td></tr>
<tr><td>SWD site</td><td>1 well produces 300 bbls/d brine (averaged)</td><td>1:6,000 bbls/d brine</td><td>1:20 wells</td></tr>
<tr><td>Booster pump (oil)</td><td>1 well produces 40 bopd (averaged)</td><td>1:15,000 bopd</td><td>1:375 wells</td></tr>
<tr><td rowspan="8">Well pad</td><td>Wells pads include:</td><td rowspan="8"></td><td rowspan="2">1:2 wells MT</td><td rowspan="2">11.6</td><td rowspan="2">91</td></tr>
<tr><td>LACT unit</td></tr>
<tr><td>Vapor recovery unit</td><td rowspan="3">1:6 wells ND</td><td rowspan="3">5.8</td><td rowspan="3">46</td></tr>
<tr><td>Transfer pumps</td></tr>
<tr><td>Separator</td></tr>
<tr><td>Lighting</td><td rowspan="3">1:1 wells SD</td><td rowspan="3">20.4</td><td rowspan="3">161</td></tr>
<tr><td>Heating</td></tr>
<tr><td>Instrumentation</td></tr>
<tr><td colspan="4">Total per MT well:</td><td>55.2</td><td>435</td></tr>
<tr><td colspan="4">Total per ND well:</td><td>49.4</td><td>390</td></tr>
<tr><td colspan="4">Total per SD well:</td><td>64</td><td>505</td></tr>
</table>

Table 10: Generic Assumptions of Significant Infrastructure Energy Use
Source: KLJ

4.2 Well Site Power Load Assumptions

For load growth modeling, a per-year ratio of 10 wells per drilling rig is assumed to gradually increase to 12 wells per drilling rig over the next 20 years. Multiplying the estimated rig count for each county by the wells per year provides a high-level assumption of the number of wells drilled throughout the study period.

4.3 Drilling Activity Forecasts

Future drilling activity projections primarily depend on reviewing historical drilling activities and assessing current and near-term drilling climate. Typical drilling plans are controlled by a myriad of factors that range from reservoir size to the well pattern. Well spacing and the well pattern of most reservoirs in the Williston Basin follow development of unconventional shale oilfields in other geographic regions. Reservoir flow capacity after stimulation, drive mechanism, well life, drilling and completion cost and environmental relief cost are also key factors in drilling plans.

The number of wells to be drilled is determined by the production plan, preparation of drill site, number of wells per drill site, well construction time and the rigs availability, labor and service. To maintain an economical oil rate, cost reduction is a tradeoff of any increase in well complexity. The majority of wells in the Williston Basin require stimulation. Therefore, the availability of fracing equipment, materials and crews act as a constraint to developers' drilling plans.

Two factors—volatile oil prices and the geological nature of the Bakken Formation—create uncertainty about future drilling activity in the Williston Basin. The main driver to produce Bakken oil is a higher than average oil price. The diversity of Bakken shale leads to two-year drilling plans instead of five-year plans, as is common in conventional oil and gas reservoirs.

Operator plans for drilling activities beyond one to two years are highly uncertain and rely on results of new wells in the next two years. Oil prices lower than approximately $60 per barrel approach a marginal revenue threshold that economically encourages reduction or scaling back of many drilling plans in the Williston Basin. Therefore, Bakken shale geology plus oil price uncertainty require a low, consensus and high forecast scenarios for drilling activity. Drilling forecasts were estimated for the Williston Basin after studying historical drilling activity dating back to 2005, evaluating drilling efficiency, examining the availability of rigs and reviewing the drilling plans. Estimated future rig counts are shown in Figure 16.

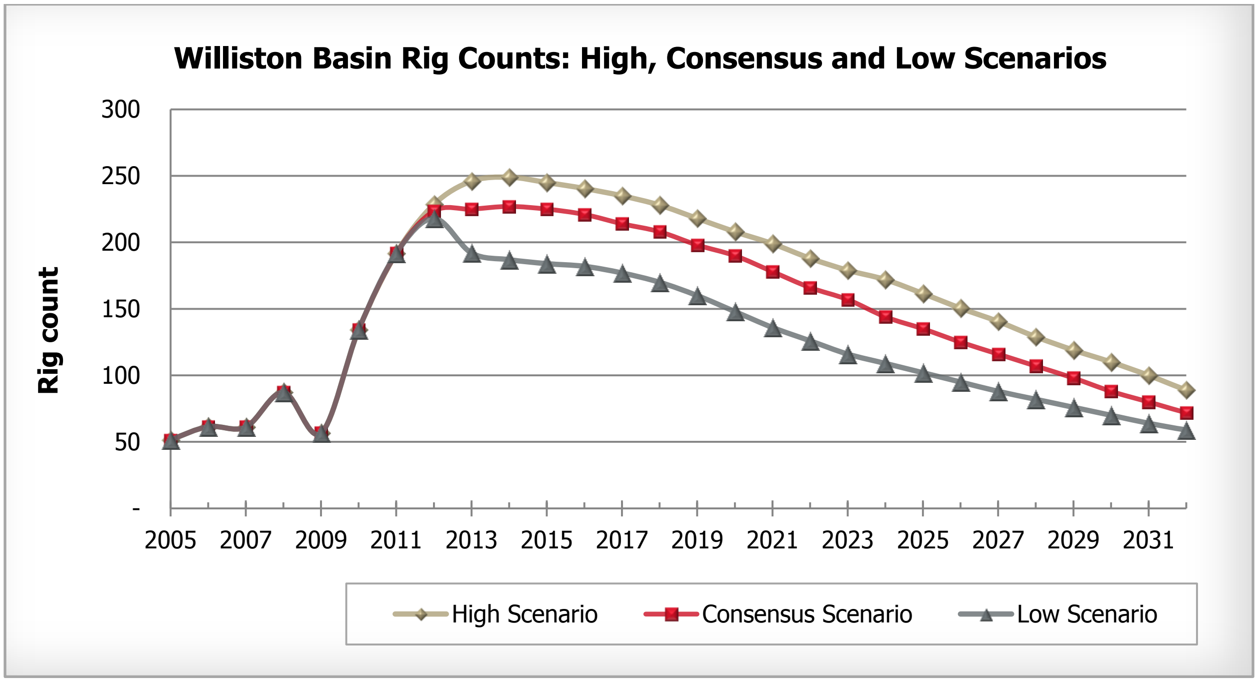

Figure 16: Williston Basin Rig Counts - High, Consensus and Low Scenarios
Source: University of North Dakota

4.4 Existing and Undrilled Well Production Forecast

With the typical well production profiles and future drilling activity, three production scenarios corresponding to the three drilling activity scenarios were forecasted. The following assumptions were applied to the production forecast:

- 10 wells per rig, per year in 2012 increases to 12 wells per rig, per year by 2032
- Drilling plan information received from stakeholder interviews of operators who presently contract 80 percent of rigs in the Williston Basin were used to estimate total drilling plans
- Fracing capacity is sufficient to stimulate the new wells
- Production profiles of typical wells are valid for existing and new wells
- Gas-oil ratios, water-oil ratios and well life of new wells are the same as those of existing wells
- Performances of new injectors are the same as those of the existing wells
- Water injection follows historical trends
- Gas injection trends become flat
- Energy required to inject water and gas per unit remains constant over the study period

Figure 17, Figure 18 and Figure 19 show total production forecasts in the study region for oil, gas and water under each scenario. Oil, gas and water production forecasts in Regions 1, 2 and 3 are shown in Appendix A.

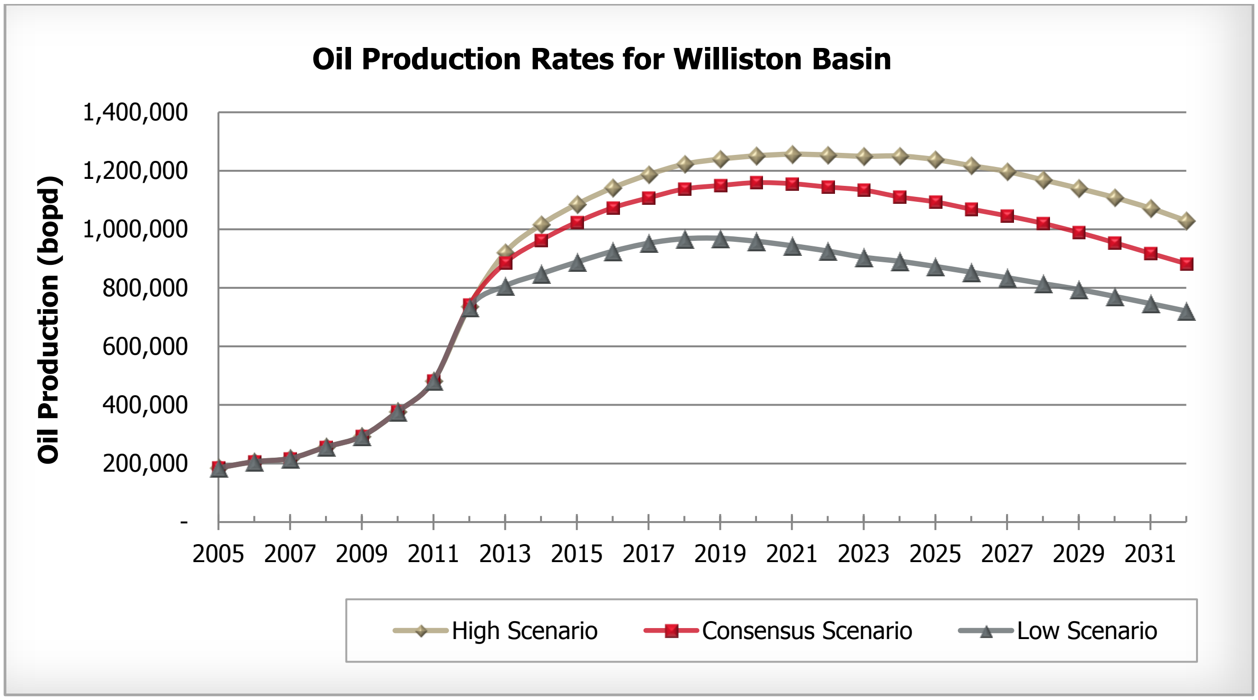

Figure 17: Oil Production Rates for Williston Basin
Source: University of North Dakota

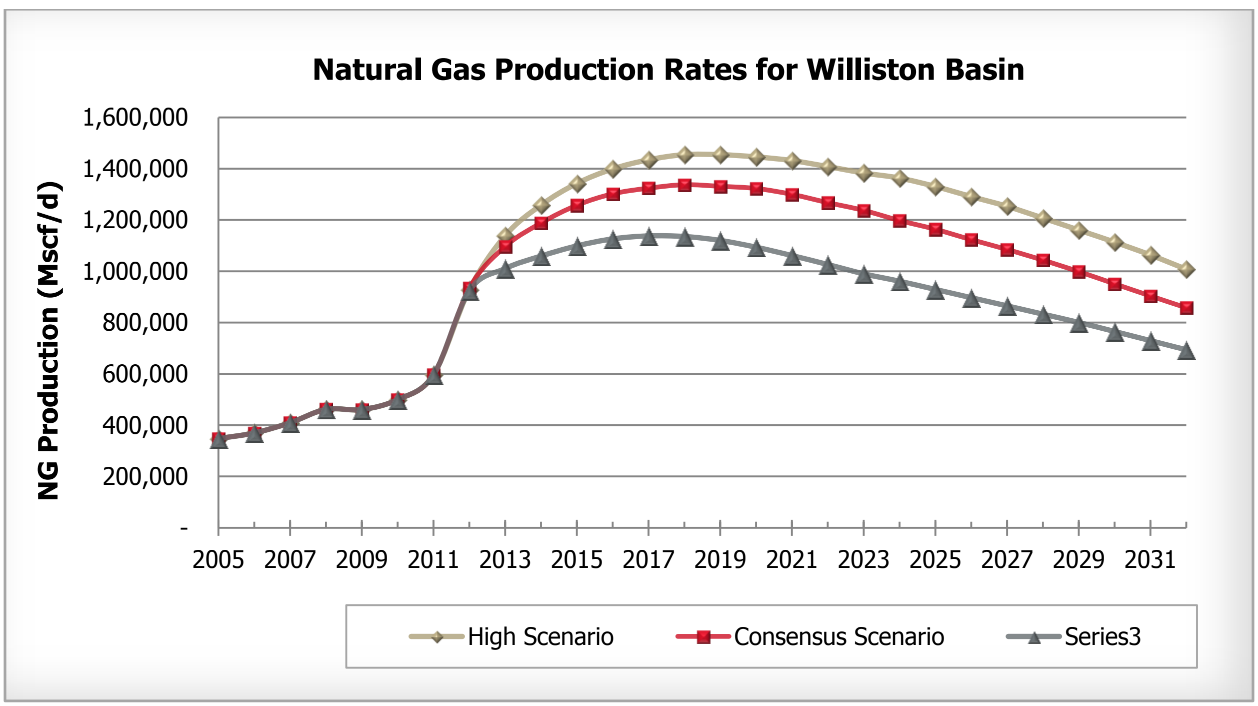

Figure 18: Natural Gas Production Rates for Williston Basin
Source: University of North Dakota

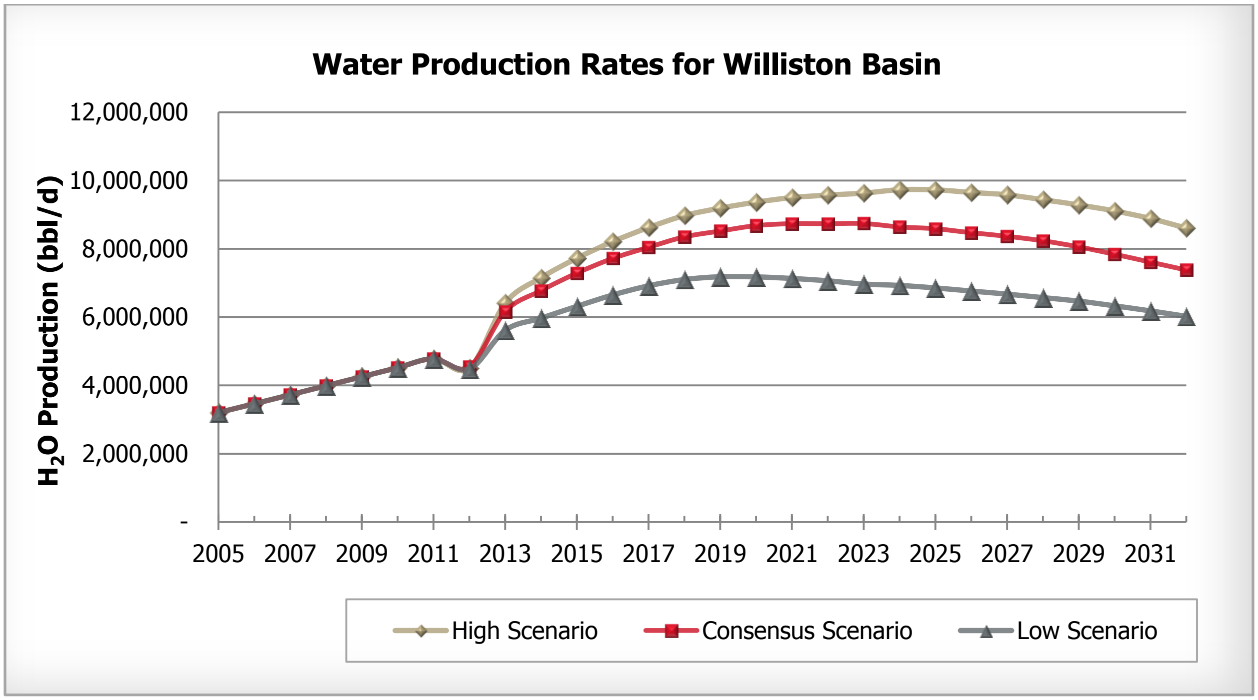

Figure 19: Water Production Rates for Williston Basin
Source: University of North Dakota

4.5 Oil Development by Region

Oil occurrence and production in the Williston Basin are controlled by interaction of several identifiable factors. Major factors are regional groundwater flow patterns, the location and extent of petroleum source rocks, burial depth/thermal maturity of source rocks, existence of reservoir rocks, structural/stratigraphic and permeability traps and petroleum migration conduits. Increasing improvements in deciphering the interaction of these factors, as well as improving drilling and well completion techniques, creates the current Bakken/Three Forks play in the Williston Basin.

Geologic formations currently receiving the most interest (in descending layer, or age order) are: 1) the Spearfish Formation; 2) the Tyler Formation; 3) the Bakken Formation and 4) the Three Forks Formation. Of these four formations, areas with potential as resource plays, rather than conventional trap plays, are generating the highest levels of interest due to their widespread nature and nearly 100 percent success rates.

A trap play is a traditional or conventional oilfield in which a structural feature, such as an anticline (an arch of stratified rock), or stratigraphic feature prevents migrating oil from continuing to move any further. Trap plays are easy to exploit with simple vertical wells due to the reservoir rock being porous and permeable and having high hydrocarbon/water ratios. Examples of trap plays in North Dakota are the Antelope, Newburg and Wiley fields.

A resource play, on the other hand, is an unconventional play that does not require any type of below-ground structure to hold and trap oil. Oil is not able to easily migrate away from the place it was generated, and is instead usually trapped within or adjacent to the source rock. Rather than having well-defined boundaries, source plays can be much more widespread and are controlled mainly by oil generation zones and source rock properties. The Bakken, and perhaps Utica shales, are examples of resource plays in North America.

4.5.1 Region 1 – Northern Region

In many areas of the Bakken/Three Forks play, as many as eight wells per 1,280-acre spacing unit are allowed. This number could change in the future if additional productive members or benches are identified. It appears the majority of development will happen within the area encompassed by mature or core portions of the Bakken Formation. However, the influence of regional groundwater flows and migration conduits appear to extend production to the north and east of the thermally mature oil generation areas.

Counties within Region 1 (Figure 20) that already have, or are likely to have, substantial Bakken/Three Forks development include North Dakota's western Ward, Burke, Mountrail, Divide and Williams and Montana's Sheridan and Roosevelt. Additionally, geothermal anomalies—that may have locally enhanced oil generation along the eastern margin of the Bakken Formation—could result in Bakken/Three Forks oil production in eastern Bottineau, Rolette and northern McHenry counties as well as in southeastern McLean County, all in North Dakota. Oil development in these non-core areas would likely not come about unless oil prices rise dramatically and/or after the core areas are fully developed.

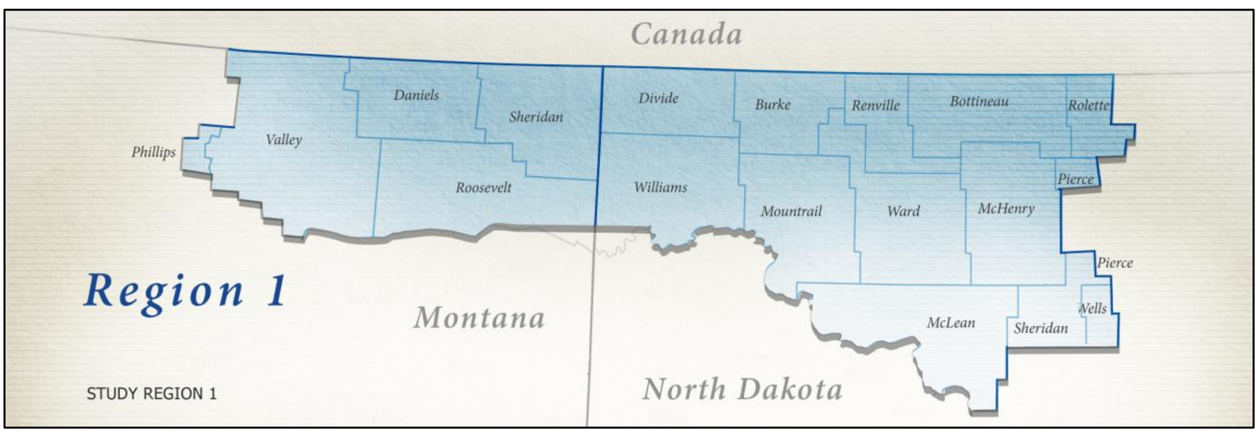

Figure 20: Study Region 1
Source: KLJ

Although the Spearfish Formation is not a source rock like the Bakken or Tyler Formations, and thus will not be considered a resource play, it is generating interest along its northeastern margin. Some developers are simply using horizontal drilling and modern completion techniques as infill drilling within older existing trap-based fields. Some of these new Spearfish wells are even extending production into areas that were historically uneconomical. Oil production from some of these wells is similar to a large percentage of Bakken/Three Forks wells. The cost to drill and complete these approximately 3,000-foot deep wells is a small fraction of the cost to develop the deeper and longer Bakken wells. New Spearfish development activity is centered in Bottineau County of North Dakota. Over the next 20 years, more than 40 wells could be drilled and completed in this play. It is anticipated that there will be scant Tyler Formation production within Region 1.

4.5.2 Region 2 – Central Region

Region 2 development will be within the area encompassed by mature portions of the Bakken Formation, although, the influence of structural elements and migration conduits appear to extend or enhance production in areas both within and adjacent to the core.

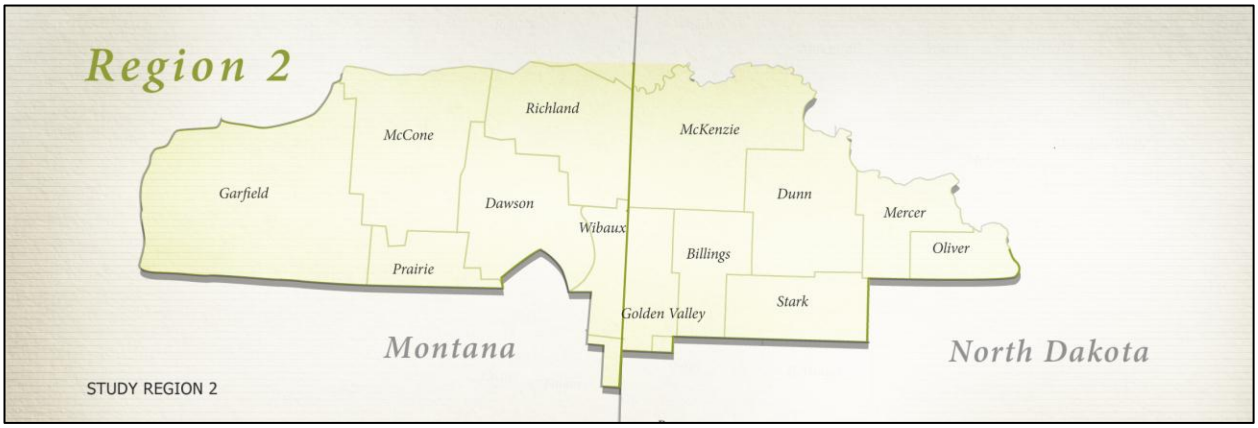

Figure 21: Study Region 2
Source: KLJ

Counties within Region 2 (Figure 21) that already have, or are likely to have, substantial Bakken/Three Forks development include the North Dakota counties of western Mercer, Dunn, Stark, McKenzie, Billings and Golden Valley, and the Montana county of Richland. Additionally, geothermal anomalies, which may have locally enhanced oil generation along the eastern margin of the Bakken Formation, could result in future Bakken/Three Forks oil production in eastern Oliver County of North Dakota.

The Tyler Formation is an extensive formation underlying much of western North Dakota, eastern Montana and extending well into South Dakota. The formation is broken into three major facies (rock formed in different environments). One of these, the Central Basin Marine Facies, produced deposits with characteristics similar to the Bakken shale members. Thus, in that portion of the Tyler Formation, there may be a similar resource play as that found in the Bakken/Three Forks. Since the Tyler Formation is located above the Bakken layer and is being drilled through by numerous Bakken/Three Forks wells, its potential (or lack thereof) will eventually be proven.

A likely scenario is additional horizontally drilled and hydraulically fractured wells that tap into the overlying Tyler Formation will occur in close proximity to the numerous wells tapping the underlying Bakken/Three Forks. The core area of this activity encompasses primarily McKenzie County, ND.

Additional potential associated with the Tyler Formation could come in the form of infill drilling and/or field expansions using modern drilling and completion techniques in areas that have had decades of Tyler production from vertical wells. Those existing fields are located in a sandy (non-source rock) Shoreline Facies in Stark and Billings counties of North Dakota.

A second potential play could occur in the Central Montana Trough, a western extension of the Williston Basin that stretches out toward Garfield County, MT. There, the Tyler Formation and the underlying Heath Formation (a shale source rock) have created excitement with past production and recent testing. It is yet to be seen if Heath/Tyler thicknesses and rock characteristics are conducive to the use of technologies that have led to development activity seen in the Bakken/Three Forks. If this second play takes off, it will likely require different completion techniques, resulting in a lag from the Bakken/Three Forks development timing. Though the Spearfish Formation is present throughout much of Region 2, unlike in Region 1, it is unlikely to experience any development in this region during the next 20 years.

4.5.3 Region 3 – Southern Region

Much of Region 3 (Figure 22) is underlain by the Three Forks Formation, with a small area of mature Bakken Formation extending southward into this southern region. However, due to the absence of source rocks and predominant groundwater flow directions toward the northeast, sweeping any mobile oil in its path out of Region 3, it is unlikely there will be any level of Bakken/Three Forks development similar to that found further north. At most, there may be some modest development in northern portions of Slope and Hettinger counties in North Dakota. As with Region 2, it is also unlikely that any Spearfish production will occur.

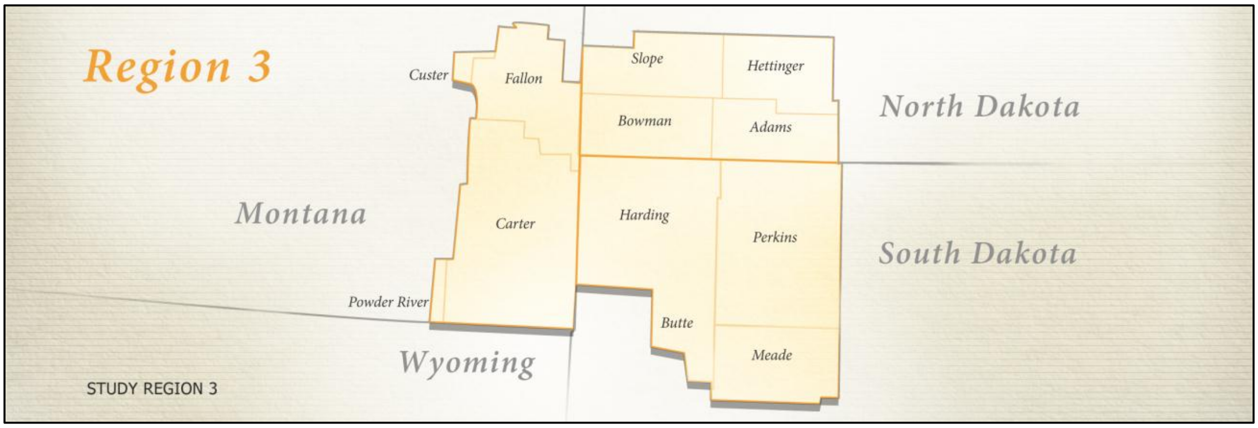

Figure 22: Study Region 3
Source: KLJ

While there has been extensive development of the Ordovician Age Red River Formation throughout much of Region 3, none of the formations of focus in this report—with the exception of the Tyler Formation—have shown production within Region 3. Oil production from the Tyler Formation in Region 3 has been limited to a small area in the northeastern part of Slope County, ND, however, the Tyler Coastal/Deltaic Plains Facies produced deposits that may be suitable as both a source rock and potential resource play.

The primary area for a Tyler Formation resource play in Region 3 may be found in Slope and Hettinger counties in North Dakota. If so, it would likely require much higher oil prices and/or completion of the Bakken/Three Forks development to warrant exploration and development for oil in this area.

4.6 Drilling Rig Efficiency

Advancements in technology and management optimization will increase rig efficiency and/or reduce rig time for each well drilled. This is based on the assumption that well geometry and reservoir properties remain the same. Total rig time, from drilling to completion, includes rig mobilization, rig-up, drilling, completion, demobilization, maintenance and nonproductive time due to downhole problems. Well stimulation, such as fracing, is performed by a fracing rig and is not counted toward rig time.

This report assumes the average number of wells drilled in a single pad in the previous five years will increase over the next 20 years as drilling multi-well pads increase. Operators have implemented a batch drilling campaign to reduce moving and rig-up times in the Williston Basin. Despite this, no significant improvement in moving rigs between wellheads in the same pad or to different pads is expected. The percentage reduction in moving and rig-up times is expected to be less than 10 percent over the next 20 years.

The unconventional nature of the Bakken Formation creates a longer learning curve than a conventional reservoir. The high uncertainty in the reservoir’s properties is also an obstacle to improving drilling times.

The lateral lengths of existing horizontal wells in North Dakota are expected to continue to increase to retain an oil rate that economically justifies the initial costs. Some of the existing rigs in the Williston Basin will need upgrading before drilling the longer lateral length wells.

Rig efficiencies in North Dakota from 1998 to 2011 are shown in Figure 23. The decline in yearly wells drilled per rig from 2005 to 2011, in comparison with the data from 1998 to 2004, is the result of an increase in the overall percentage of horizontal wells. The average rig efficiency during the 2005 to 2011 period is 8.8 wells drilled each year per rig. An analysis of the factors and information gained from stakeholder interviews resulted in a forecast of an increase from 10 wells per rig, per year in 2012, to 12 wells per rig per year at the end of the study period in 2032.

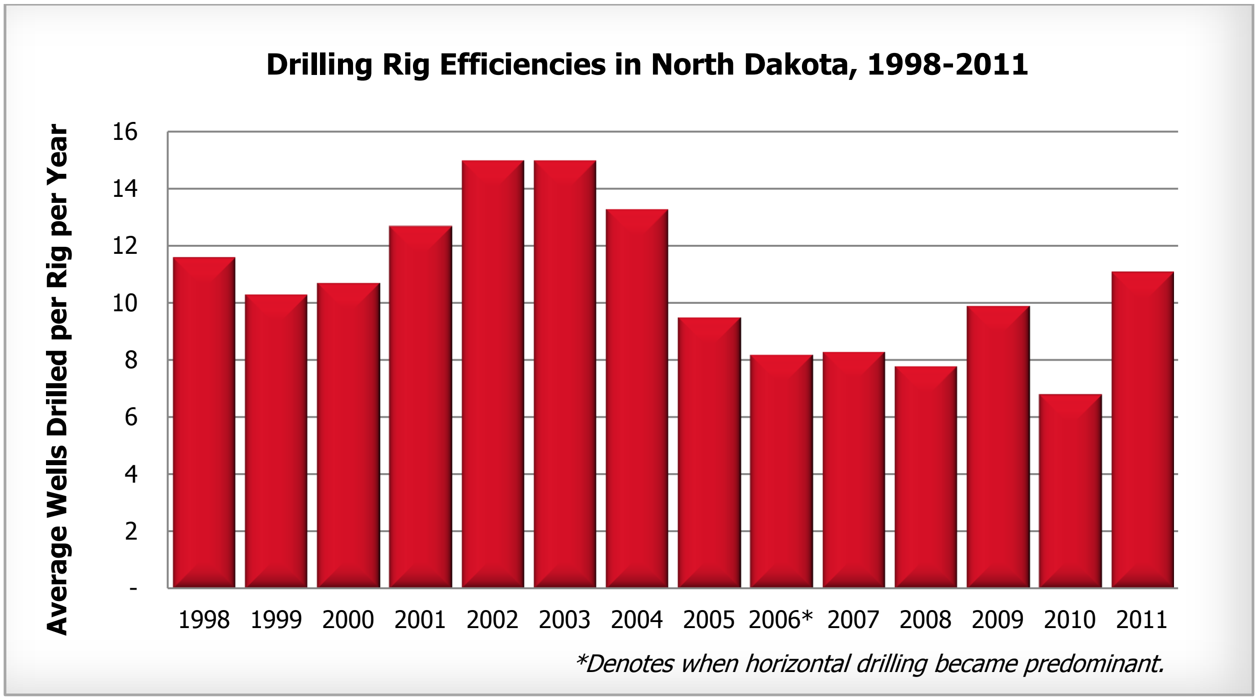

Figure 23: Drilling Rig Efficiencies in North Dakota, 1998-2011
Source: North Dakota Industrial Commission, University of North Dakota (Compilation: KLJ)

4.7 Water Injection Forecasts

Water injection forecasts were based on historical trends. Regulations require produced water meet certain environmental requirements before it is disposed in an injection well. Producers opt to either inject production water from oilfield activities back to the aquifer or depleted zone. As some waterflood projects also inject the treated oilfield water back into reservoirs to improve the rate of oil recovery, the total injected water volume is slightly higher than the produced water. The estimated total water injection volume in the three study regions are shown in Figure 24.

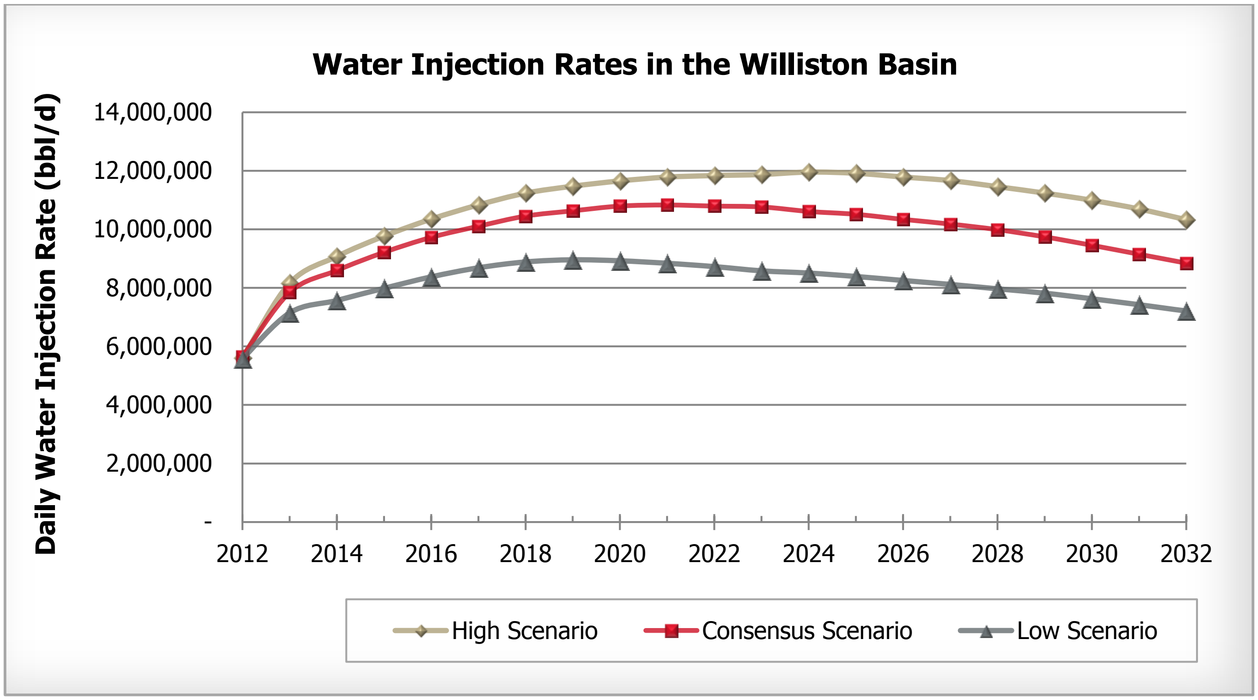

Figure 24: Total Water Injection Rates in the Williston Basin
Source: University of North Dakota

4.8 Well Lifecycle and Reservoir Analysis

Wells move through a lifecycle, which begins with analyzing and understanding the geology of an area, moving through evaluating risk and cost and ultimately working through compliance and regulatory requirements. Once drilling is complete, wells can operate with a productive lifecycle through several recovery stages until production no longer is economically viable.

Recovery of hydrocarbons from an oil reservoir commonly occurs in three stages: 1) primary, 2) secondary and 3) tertiary, or EOR. The primary and secondary recovery stages account for about 70 percent of total oil production in the Williston Basin. It is difficult to distinguish between primary, secondary and tertiary recovery when the three methods coexist. Oil production from a single well can be the combined result of the two or three recovery methods, although, the secondary and tertiary stages as defined below were not incorporated into the forecast model:

- *Primary recovery*: During the primary recovery stage, pressure from the reservoir forces hydrocarbons from the pores in the formation to move to the well bore, using the natural energy of the reservoir as a driver. The three principal primary recovery drive mechanisms in the Williston Basin are 1) water drive, 2) gas drives (cap gas drive and solution gas drive) and 3) gravity drainage.

- *Secondary recovery:* This is the stage of hydrocarbon production when an external fluid, such as water or gas is injected into reservoirs that have fluid communication with production wells. Water and gas injections act to maintain reservoir pressure and displace hydrocarbons toward the wellbore. The most common secondary recovery techniques are gas injection and water flooding, where gas is injected into the gas cap and water is injected into the production zone to sweep oil from the reservoir.

  Secondary recovery stage reaches its limit when injected fluid (water or gas) is produced in considerable amounts from the production well and production is no longer economical. The successive use of primary recovery and secondary recovery in an oil reservoir produces about 15 to 40 percent of the original oil in place (OOIP). The waterflooding and high-pressure air injection recovery methods currently being implemented in the Williston Basin are included as part of the current load modeling. As secondary recovery techniques come online, they will be included in future forecast modeling.

- *Tertiary recovery:* Tertiary recovery, or EOR, covers gas injection, chemical injection, microbial injection and thermal recovery. In the Williston Basin, CO_2 EOR projects have been successful in recovering substantial volumes of oil. The tertiary recovery methods that account for approximately 30 percent of current oil production in the Williston Basin are included as part of the 2012 load modeling. As tertiary recovery techniques come online, they will be included in future forecast modeling.

Economically, a well's life ends when revenue from production cannot cover cost. A well's life can also end due to mechanical problems, low reservoir potential, wellbore collapse, excessive water production or simply lease expiration. After reviewing geological and petroleum engineering data in the Williston Basin and identifying the reservoir model by integrating geological and engineering interpretations, it was determined that well lifecycles will vary within the study region. Wells in North Dakota and Montana have an approximate 25-year lifecycle, 10 years longer than South Dakota wells, which have an approximate 15-year lifecycle.

A well lifecycle alone is not enough to define the total production of a well. The annual production rate accounts for the remainder. Production rate is controlled by reservoir pressure, reservoir size, drive mechanism, rock and fluid properties, heterogeneity of reservoir, well spacing, well geometry, recovery method and reservoir energy measurement. Oil and gas production rates decline as a function of time. Loss of reservoir pressure or changing relative volume of produced fluids is usually the cause.

Fitting a line through performance history and assuming this same line trends similarly into the future forms the basis for the decline curve analysis concept. Historical production and injection data was analyzed to identify effects and construct three typical well production profiles through their expected lifecycles for the study region with a non-linear regression method. Figure 25 shows the production profiles of typical wells in North Dakota, Montana and South Dakota. All three drop in production and follow a curve decline, indicating the typical reservoir performance of shale oil.

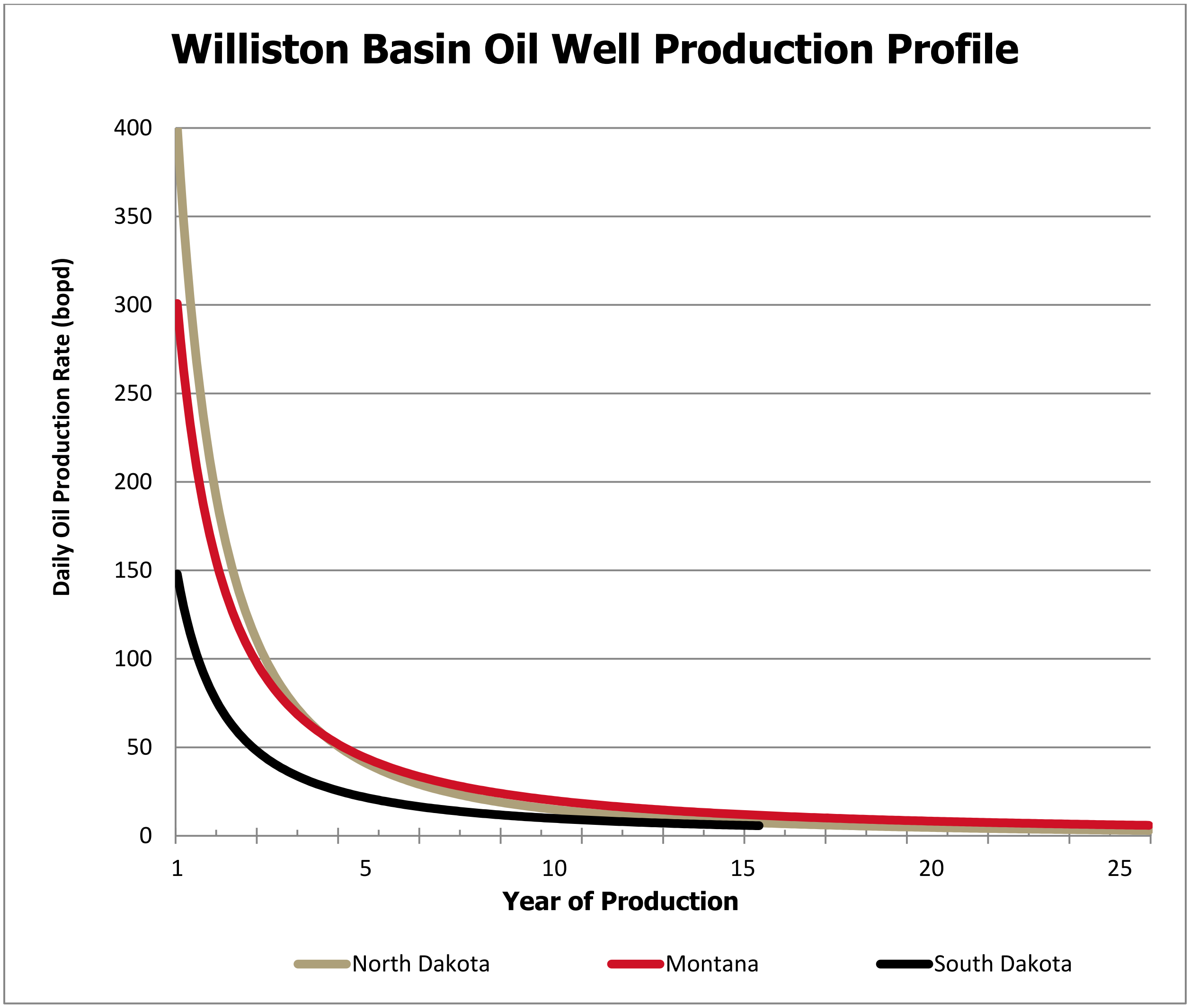

Figure 25: Williston Basin Oil Well Production Profiles
Source: University of North Dakota

4.9 Oil Price Forecasts

Oil price predictions have historically been unreliable and current pricing trends are volatile, further complicating data analysis. Market volatility and differing assumptions about the future of the world economy are reflected in the range of price projections for both the short-term and the long-term. However, most projections show prices rising over the entire course of the projection period (although slowing after 2025). The projections range from $95 to $116 per barrel in 2015, a difference of $21 per barrel, and from $98 to $145 per barrel in 2035, a difference of $47 per barrel. The wide range underscores the uncertainty inherent in the projections.

Historically, New York Mercantile Exchange (NYMEX) crude trades near the Brent Oil price (Brent) with a small premium. While often quoted in the U.S. media as the global price of oil, the price at Cushing, OK (Cushing) is not currently representative of world oil prices. Since late 2010, Brent and NYMEX prices have diverged with WTI at Cushing, often selling more than $20 below Brent price (Figure 26).

Oil from Canada and the Bakken Formation in North Dakota caused local supply at Cushing to exceed demand of the refiners served by pipelines, depressing the local price but not international prices. A return to the normal price relationship with WTI to Brent awaits improved pipeline access between Cushing and refineries on the Gulf of Mexico.

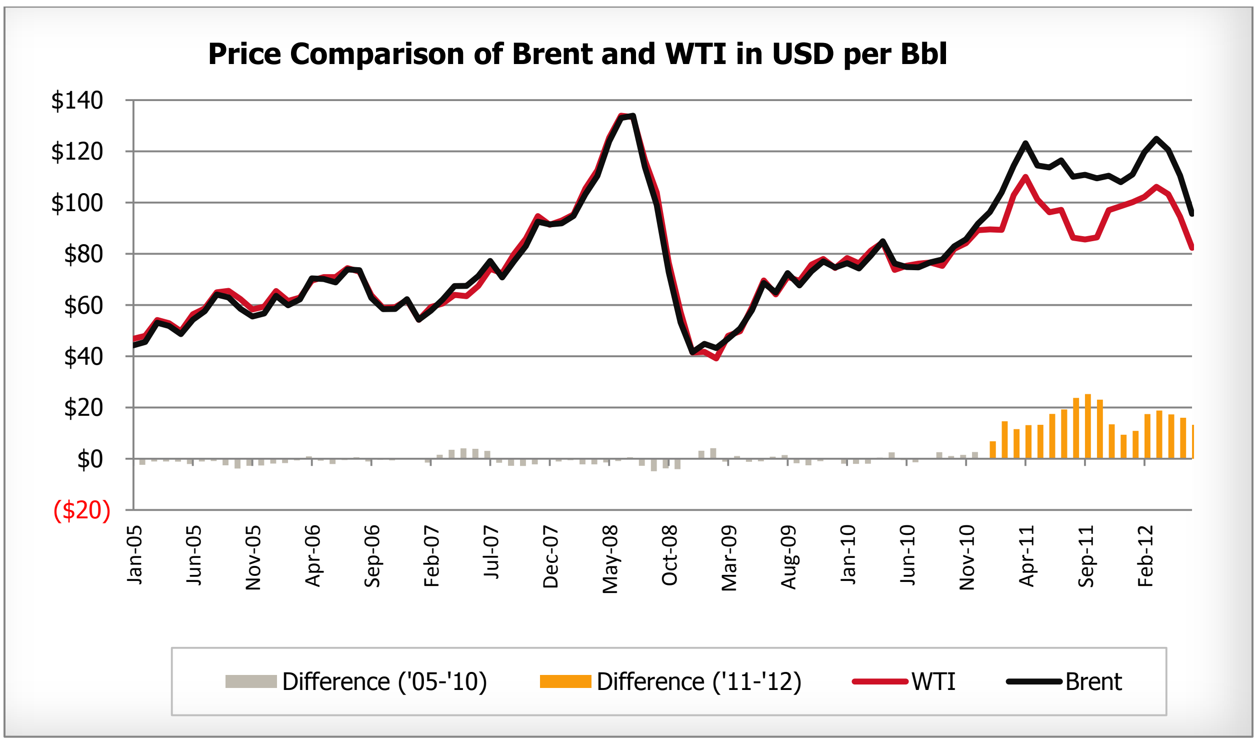

Figure 26: Price Comparison of Brent and WTI in USD per Bbl
Source: Indexmundi (Compilation: KLJ)

Predicting the future price of oil presents many challenges as industry experts have not been able to identify a formula based on historical trends. Leading research agencies have calculated prices (Table 11) to be the oil trend per barrel for 2015 to 2035. The different prices for the Energy Information Administration's two cases indicate a higher demand scenario (Case 1) and a lower demand scenario (Case 2). Stakeholder input interviews and analysis indicate the price will rise at a slightly faster pace than predicted. Stakeholder interviews also indicated an approximate break-even point between profit and costs to be at $45 per barrel at the wellhead (2012 USD). Fluctuations in the value of the dollar, however, create a higher concern for production quantities.

Oil Price Forecasts (2015-2035) in 2012 Dollars (Brent USD)

	2015	2020	2025	2030	2035
Energy Information Administration (Case 1)	$116.91	$126.68	$132.56	$138.49	$144.98
Energy Information Administration (Case 2)	$95.41	$109.05	$118.57	$124.17	$126.03
International Energy Agency	$106.30	$118.10	$127.30	$134.50	$140.00
IHS Global Insight	$99.16	$72.89	$87.19	$95.65	$98.08
Average*					
Standard deviation between forecasts	$8.19	$20.48	$17.59	$16.74	$18.23
Consensus market price projections (average of all oil price forecasts)	$104.45	$106.68	$116.41	$123.20	$127.27
Low market price projections (consensus less deviation)	$96.26	$86.20	$98.82	$106.46	$109.04
High market price projections (consensus plus deviation)	$112.64	$127.16	$134.00	$139.94	$145.50

** The Average line separates independent forecasts (above) from KLJ calculated forecasts (below).*

Table 11: Oil Price Forecasts (2015-2035) in 2012 Dollars (Brent USD)
Source: U.S. Energy Information Administration, International Energy Agency and IHS Global Insight (Compilation: KLJ)

Global oil supply capacity is growing at unprecedented levels and U.S. oil output is a primary factor for this change. The development of more than 20 tight shale oil formations will result in a dramatic increase in overall oil supply. A recent Harvard study suggest that as much as 17 trillion barrels of oil remains in the ground globally from conventional and unconventional sources.

While transportation is lacking to move these resources, the low cost of extraction allows profitability at lower price points.

4.9.1 Current Limitations for Bakken Crude

Since 2009, production from the Bakken Formation has increased drastically, inciting the Bloomberg Report to include Bakken crude in its crude oil spot pricing report. In the trending history of oil prices, WTI had closely mirrored Brent, however, due to global supply issues in 2010, Brent pulled ahead of WTI.

Historically, Bakken crude has sold at a discount when compared against WTI crude. The discount can fluctuate from $11 to $22 (or roughly a 10 to 25 percent discount). The majority of this discount can be attributed to pipeline capacity issues, but other factors, such as buyer preference and contractual obligations, can also directly impact the price for Bakken crude oil.

Some contributing factors to the price variance between Bakken crude, WTI and Brent include:

- *Pipeline inefficiencies*: Current lack of pipeline infrastructure in the Williston Basin increases costs for transportation to refineries, as most of the crude oil has to be transported by rail or truck
- *Sweet crude stockpile*: Refinery capacity issues, combined with increased production, have created an overabundance of sweet crude reserve supply
- *Refinery preference*: U.S. refineries are configured to process heavy crude rather than domestic sweet crude, therefore they receive lower margins when processing sweet crude
- *Additional shale formations*: Producer production efforts are migrating to other shale formations such as the Eagle Ford in Texas and the Niobrara in Colorado
- *U.S. trade agreements*: The U.S. cannot export crude with 55 or higher American Petroleum density to other countries

4.10 Oil Price Forecasts and Impacts to Electric Load

To assist the Partners in providing adequate electric supply without overbuilding infrastructure, low, consensus and high market scenarios on oil prices were developed.

4.10.1 Low Market Scenario

Assumption: Bakken crude margins decrease to a break-even point and price per barrel remains substantially lower than current levels.

- Producers will maintain drilling to hold leases in productive fields
  - Producers will continue to follow established drilling plans drilling in-fill wells
- Drilling rate remains the same
  - Cost to drill decreases due to competitive services market
- Drilling rig count remains below 175 (less than 2,000 wells per year) as long as oil prices remain at a theoretical low
  - Wildcat (drilling in new areas/fields) rigs decrease substantially
  - Drilling rigs continue to focus on proven profitable areas
  - Drilling rigs in less profitable areas will relocate or be idled
  - Only newer more productive rigs will be utilized
- Producers will stop pumping low production wells (wells producing less than 25 bopd)
  - Producers will pump just enough to meet contractual obligations
  - Producers will rotate between wells to maintain a monthly level of production
- Exploration crews and related infrastructure will decrease
  - Seismic and related staffing decreases
  - Wells will use less overall energy as they produce just enough to remain active
  - Peaking demand from an individual well will remain the same and energy usage will be reduced as pumps cycle, ultimately reducing the load factor of the well
- Housing constraints are mitigated in the near-term
  - Secondary job growth and base employment growth approach normal levels mid-way through the planning period of 2012 to 2032
  - Longevity of temporary workforce presence is reduced

4.10.2 Consensus Market Scenario

Assumption: Bakken crude profit margins maintain the equivalent of 2012 levels.

- Drilling will remain at 2012 levels for the next several years, rig counts will remain near 200
  - About 2,000 wells will be completed annually for the next several years
- Production activity will remain at 2012 rates
- Wildcat or speculative drilling will remain at current levels
- Drilling activity will focus on proven fields in North Dakota and eastern Montana
- Housing constraints remain for several years
  - Constraints reduce the rate of secondary job growth
  - Constraints hold back growth of base employment in the short-term
  - Substantial temporary workforce remains in the industry throughout the next decade
  - New facilities (such as frac-water treatment and proppant manufacturing) are developed

4.10.3 High Market Scenario

Assumption: Bakken crude margins increase as prices per barrel increase significantly and remain substantially elevated above 2012 price equivalents.

- Lease purchases lead the following indicators:
  - Rig counts approach 220 in the near-term
    - At least 2,400 wells drilled each year
  - Drilling plans are more aggressive
  - Wildcatting increases
  - Drilling in the Three Forks Formation increases
- Expansion into Montana and South Dakota
  - Number of drilling/fracing/seismic exploration crews increases
  - Number of crew camps increases
- Pipeline and support infrastructure increases
- Newer technologies (such as EOR, drilling and fracing) are developed, tested and applied at a faster rate
- New facilities (such as frac-water treatment and proppant manufacturing) are developed

5. Pipelines, Refining and Gas Processing

Rapid increases in crude oil, natural gas and NGL have strained the existing pipeline infrastructure in the Williston Basin. Insufficient pipeline capacity has restricted refinery, processing and market accessibility. It has even forced flaring of natural gas and discounted pricing of regionally produced crude oil.

To accommodate projected increases in production levels, the region will require significant additional pipeline infrastructure over the next several years, and possible expansions and additions of processing and refining facilities. Limited existing pipeline capacity has led to challenges in the ability to move oil and gas within the Williston Basin and the ability to export oil and gas out of the Williston Basin.

5.1 Crude Oil Pipelines

The ability to move oil within the basin is crucial as oil from the well sites needs to be moved to a centralized hub or interconnecting transmission pipeline for transfer to market. Although thousands of miles of gathering pipeline exist within the region, even more are needed and will be developed as production increases, incremental export pipeline capacity is provided or the need to decrease truck transport continues.

Equally important to transporting oil within the study area is the ability to export oil out of the region to market. Few pipelines currently provide export capacity from the Williston Basin, which has forced oil developers to utilize expensive alternatives, such as rail transportation. However, current pipeline projects should result in pipeline export capacity out of the Williston Basin reaching 538,000 bopd by the end of 2012.

To meet projected crude oil transportation needs, the study area's existing pipeline will need to be expanded and new pipeline will need to be built. Existing crude oil pipelines are as follows:

- *Enbridge*: The Enbridge North Dakota System consists of 330 miles of crude oil gathering and 620 miles of interstate transportation pipeline. The system gathers crude oil from 22 oilfields in North Dakota and Montana and delivers about 210,000 bopd to Clearbrook, MN, and 25,000 bopd to the Steelman terminal in Saskatchewan, Canada. Enbridge provides the largest pipeline export capacity out of the region and is proposing additional expansions to its North Dakota system.

- *Butte Pipeline*: The 16-inch, 323-mile crude oil pipeline begins near Baker, MT, and terminates at Guernsey, WY. The system gathers crude oil from the Cedar Creek Anticline area near Baker, MT, and, through various nearby interconnects, transports additional crude from the Williston Basin, eastern Montana and Canada to Guernsey. Current export capacity from the Williston Basin on the Butte Pipeline system is 160,000 bopd. Proposed expansion projects, including the Butte Loop, could potentially provide an additional 110,000 bopd capacity by the end of 2014.

- *Tesoro*: Tesoro owns and operates 750 miles of crude oil gathering and transmission pipeline in the Williston Basin region. The pipeline system delivers all Tesoro's Mandan Refinery crude oil supply, about 68,000 bopd.

- *Plains Pipeline*: Plains Pipeline owns and operates various crude oil pipeline systems within the Williston Basin. The systems provide critical gathering and transmission pipeline infrastructure required to transport Williston Basin produced crude from the wellhead to key interconnecting pipelines ultimately to export it from the region. Plains has several ongoing or proposed pipeline projects that will increase pipeline capacity both within and out of the Williston Basin.

- *Bridger and Belle Fourche Pipeline*: The Bridger and Belle Fourche Pipeline systems, both True Oil companies, span several counties in western North Dakota and eastern Montana providing crude oil gathering and transportation services within the region.

  While neither pipeline system provides ultimate export capacity out of the Williston Basin, they both provide vital pipeline capacity for transferring Williston Basin produced crude within the region and to a strategic pipeline interconnect hub near Baker, MT. Expansions of the Bridger and Belle Fourche Pipeline systems are expected to continue into the future.

In addition to these transmission type pipeline systems, significant midstream gathering pipeline systems in the region provide critical infrastructure for transporting crude oil from the well head to key pipeline hubs, interconnect locations and loading facilities.

Projected Williston Basin Study Area Crude Oil Pipeline Export Capacity (End 2012)	
Pipeline System	**Export Capacity (bopd)**
Enbridge System	235,000
Butte System	160,000
Plains System	75,000
Tesoro System (Refined Product)	68,000
Crude Oil Export Capacity (end of 2012)	**538,000**

Table 12: Projected Williston Basin Study Area Crude Oil Pipeline Export Capacity (End 2012)
Source: North Dakota Pipeline Authority

The projected pipeline capacity indicated in Table 12 assumes the Butte expansion, Plains Bakken North and Tesoro Refinery projects will be complete by the end of 2012.

5.2 Proposed Crude Oil Pipelines

The need for increased capacity to transfer oil both within and out of the region has led to 12 crude oil pipeline projects that are either in the planning, design stage or under construction (Figure 27 and Table 13).

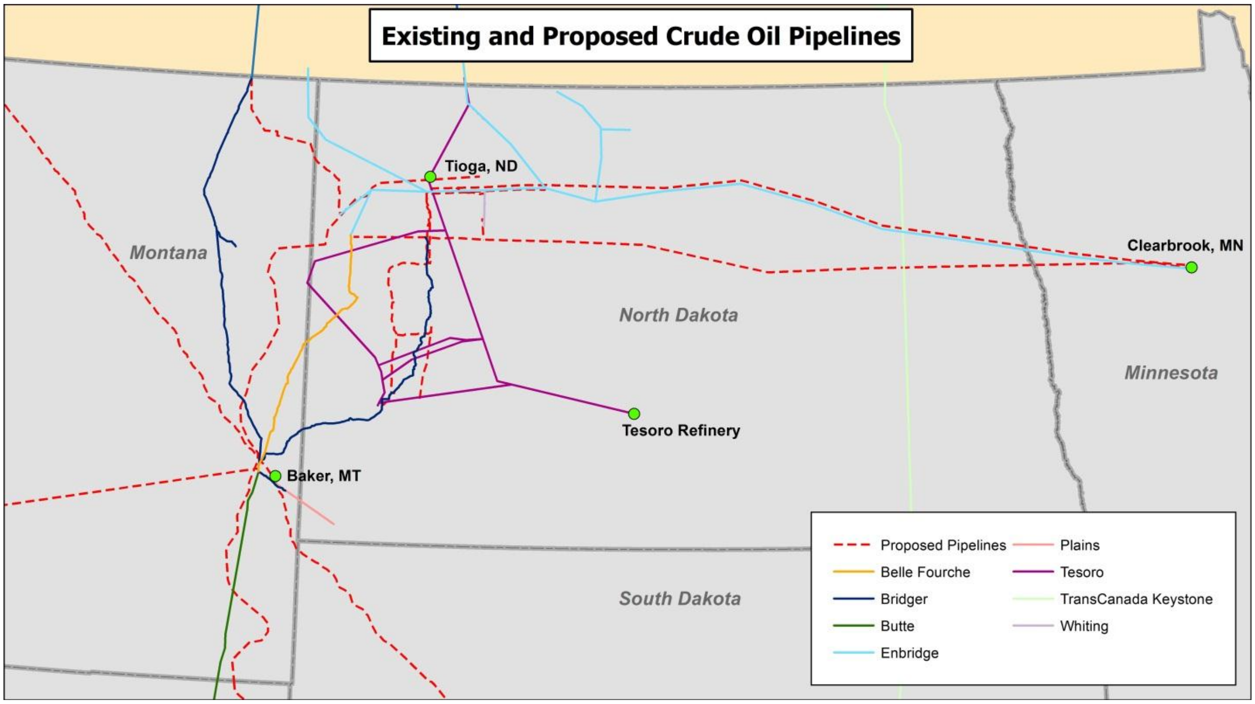

Figure 27: Existing and Proposed Crude Oil Pipelines
Source: KLJ

Williston Basin Proposed Pipeline Projects						
Proposed Pipeline Name	**Origin**	**Terminus**	**Proposed Capacity**	**Pipeline Length (miles)**	**Projected Timeline**	**Estimated Power Demand** (MW)**
Proposed Crude Oil Pipelines						
BakkenLink Pipeline	Beaver Lodge, ND	Fryburg, ND	75,000 bopd	132	Late 2013	2.81
Enbridge Bakken Expansion	Pipeline replacement between Lignite and Kenaston, ND		120,000 bopd	11	Early 2013	4.5
Enbridge Beaver Lodge Loop	Beaver Lodge, ND	Berthold, ND	148,500 bopd	56	Mid 2013	8.35
Enbridge Sandpiper	Beaver Lodge, ND	Clearbrook, MN	325,000 bopd	450	Late 2014/Early 2015	18.28
Enbridge Sanish Pipeline Project	Johnson Corner, ND	Beaver Lodge, ND	60,000 bopd	42	Late 2013	1.13
High Prairie Pipeline	Alexander, ND	Clearbrook, MN	150,000 bopd	450	Late 2013	11.25
ONEOK Bakken Crude Express	Stanley, ND	Cushing, OK	200,000 bopd	1,300	Late 2015	22.5
Plains Baker to Billings	Baker, MT	Billings, MT	50,000 bopd	200	Mid 2013	0.94
Plains Bakken North	Trenton, ND	Raymond, MT	75,000 bopd	103	Late 2012	1.41
Plains Killdeer to Dickinson	Killdeer, ND	Dickinson, ND	10,000 bopd	33	Unknown	0.19
Plains Nelson to Ross Pipeline	Stanley, ND	Ross, ND	47,000 bopd	17	Late 2012	0.88
TransCanada Keystone XL	Hardisty, Alberta	Steele City, NE	800,000* bopd	1,179	Late 2014/Early 2015	122.4
Proposed Natural Gas Liquid (NGL) Pipelines						
ONEOK Bakken Pipeline	Sidney, MT	Northern Colorado	60,000 Bbls/d	525	Mid 2013	4.5
ONEOK Stateline to Riverview	Stateline Gas Plant	Sidney, MT	65,000 Bbls/d	53	Late 2012	1.22
Vantage Pipeline	Tioga, ND	Empress, Alberta Canada	60,000 Bbls/d	430	Late 2013	0
Proposed Natural Gas Pipelines						
Alliance Tioga Lateral	Tioga Gas Plant	Sherwood, ND	106,500 mscfd	79	Mid 2013	4.8

** Only 100,000 bopd of capacity will be available out of the study region.*

*** Estimated Power Demand is the total anticipated power demand associated with the proposed pipeline facilities within the study region.*

Table 13: Williston Basin Proposed Pipeline Projects
Source: North Dakota Pipeline Authority, North Dakota Public Service Commission, U.S. Federal Energy Regulatory Commission (Compilation: KLJ)

5.3 Natural Gas Pipelines

Wells that extract crude oil in the Williston Basin also produce a significant amount of natural gas. The natural gas produced is liquids rich, requiring processing before it is considered a dry, saleable natural gas. Processing natural gas separates hydrocarbon liquids (y-grade mixture) from the natural gas stream and is required to reduce the natural gas stream's heating value and remove excess liquids. This allows it to meet the transmission pipeline's gas quality tariff. Further processing of the y-grade mixture, referred to as fractionization, results in the separation of hydrocarbon liquids into constituents including ethane, butane, propane and natural gasoline. These valuable byproducts are marketed as commodities.

Gathering or midstream pipeline systems move raw gas from the wellhead to the processing plant. Transmission pipeline systems then transport the processed gas to market. As cited by the North Dakota Department of Mineral Resources, 29 percent of total natural gas production was flared in 2011 due to the region's insufficient gathering pipeline capacity and processing infrastructure.

While some pipeline capacity to transport natural gas out of the Williston Basin exists, the region's infrastructure, particularly the gas gathering infrastructure, is constricted. The anticipated increase in gas production within the region will require significant future development of both gas gathering and processing infrastructure. Additional infrastructure will facilitate market access and decrease flaring levels.

The existing natural gas pipeline export options from the Williston Basin are as follows:

- *Northern Border Pipeline*: This 1,407-mile interstate natural gas pipeline has a capacity of about 2.4 billion standard cubic feet per day (Bscf/d). It extends from the Montana-Saskatchewan border near Port of Morgan, MT, and travels directly through the Williston Basin to a terminus near North Hayden, IN. The majority of Northern Border's supply gas is sourced from the Western Canadian Sedimentary Basin resulting in the Williston Basin facing direct competition for Northern Border's pipeline capacity.

- *Alliance Pipeline*: The system transports liquid-rich natural gas from northeastern British Columbia and northwestern Alberta, Canada to a terminus near Chicago IL. The 36-inch, 886-mile pipeline has a capacity of 4.6 Bscf/d. Aux Sable's Prairie Rose Pipeline transfers liquid-rich Williston Basin gas to the Alliance Pipeline through an interconnect near Bantry, ND. The Prairie Rose line has an estimated capacity of 110 MMscf/d. Alliance is the lone regional pipeline to provide take-away capacity for liquid-rich gas. Several regional pipeline projects proposing new interconnects with Alliance are being considered. Alliance has additional capacity available to transport natural gas out of the Williston Basin.

- *WBI Energy*: Although WBI Energy (WBI) is not considered a typical long-haul pipeline solely dedicated to the export of natural gas or directly connected to a traditional market hub, WBI owns and operates more than 3,700 miles of natural gas transmission and gathering pipeline facilities in North Dakota, South Dakota, Montana and Wyoming. The system is located in the heart of the Williston Basin and provides natural gas transmission and storage services. WBI has several interconnects to the

Northern Border Pipeline that are not at capacity and could provide additional export capacity for regionally produced natural gas to reach the Midwest market. WBI is the supplier of natural gas to MDU, the local distribution company throughout the Dakotas, Montana and Wyoming. This allows Williston Basin produced gas to be distributed to consumers within the immediate region. WBI has recently completed several projects to allow more natural gas online and provide additional pipeline capacity in the region.

5.4 Proposed Natural Gas and Natural Gas Liquid Pipelines

While recent low natural gas prices have led to little incentive for pipeline companies to develop new natural gas pipelines, recent increase in gas processing and attractive NGL prices have resulted in some proposed NGL projects (Table 14 and Figure 28).

Williston Basin Proposed Natural Gas and NGL Pipeline Projects					
Project Name	**Origin**	**Terminus**	**Proposed Capacity**	**Pipeline Length (mi.)**	**Projected Timeline**
ONEOK Bakken Pipeline	Sidney, MT	Northern Colorado	60,000 (Bbls/d NGL)	525	Mid 2013
ONEOK Stateline to Riverview	Stateline Gas Plant	Sidney, MT	65,000 (Bbls/d NGL)	53	Late 2012
Vantage Pipeline	Tioga Gas Plant	Empress, Alberta, Canada	60,000 (Bbls/d NGL)	430	Late 2013
Alliance Tioga Lateral	Tioga Gas Plant	Sherwood, ND	106,500 (mscfd NG)	79	Mid 2013

Table 14: Williston Basin Proposed Natural Gas and NGL Pipeline Projects
Source: North Dakota Pipeline Authority, North Dakota Public Service Commission, U.S. Federal Energy Regulatory Commission (Compilation: KLJ)

5.5 Proposed Natural Gas Processing Facilities

Increased production of liquid-rich natural gas within the region in addition to attractive NGL pricing has resulted in significant demand for natural gas processing.

Currently, 21 natural gas processing facilities are in the study region, having a processing capacity of approximately 810 MMscf/d. In addition, five new facilities are either in construction or planning stages, along with an expansion to an existing processing facility in Tioga, ND. These projects have potential to increase natural gas processing capacity in the region by approximately 64 percent, or an additional 520 MMscf/d, all are scheduled to come on line by the end of 2014 (Table 15 and Figure 28).

Proposed Gas Processing Facilities and Capacities				
Proposed Gas Processing Facilities	**Proposed Capacity (MMscf/d)**	**County**	**Estimated Power Requirements (MW)**	**Project Timeline**
Hess - Tioga Expansion	130	Williams	18	Late 2012
ONEOK - Stateline I	100	Williams	15	Late 2012
ONEOK - Stateline II	100	Williams	15	Early 2013
Plains - Ross	50-75	Mountrail	5.25	Mid 2013
New Frontier Midstream - South Heart	40	Stark	4.7	Mid 2013
ONEOK - Garden Creek II	100	McKenzie	15	Late 2014

Table 15: Proposed Gas Processing Facilities and Capacities
Source: North Dakota Public Service Commission, North Dakota Pipeline Authority

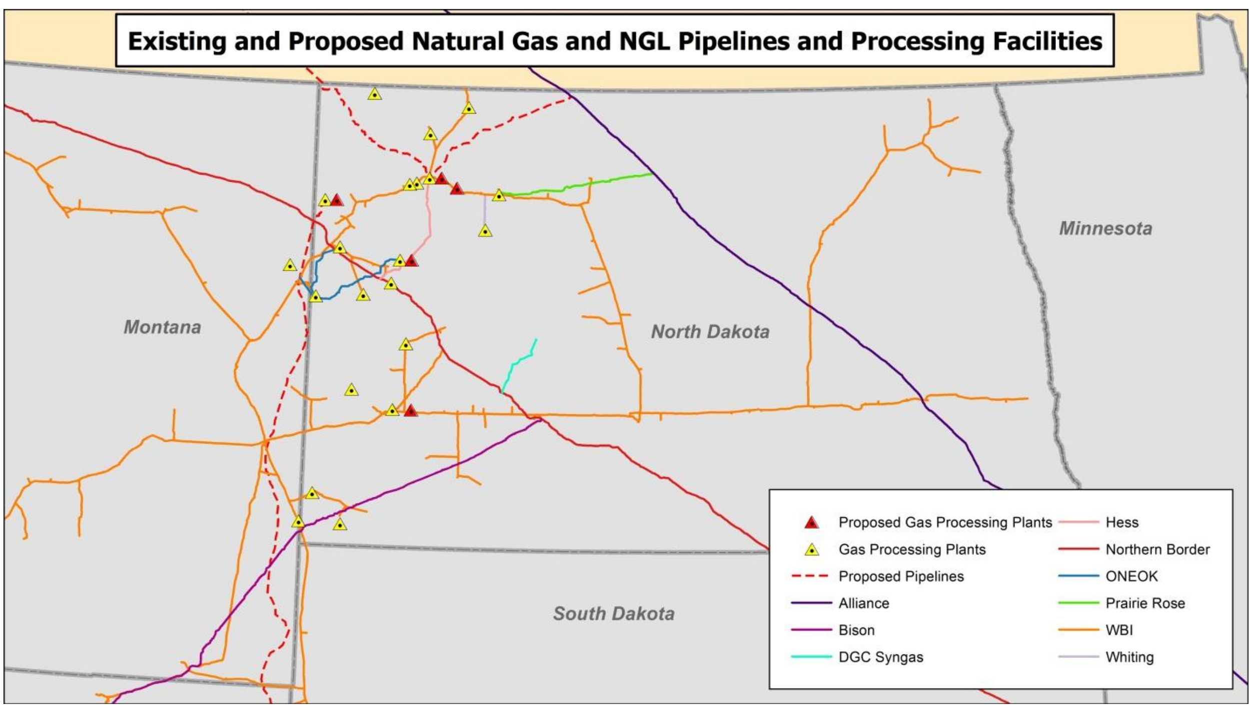

Figure 28: Existing and Proposed Natural Gas and NGL Pipelines and Processing Facilities
Source: KLJ

5.6 Potential Pipeline Electrical Load Growth

The potential power load for ongoing and proposed pipeline projects was estimated through stakeholder and publically available information and assumptions based on general power requirements of similar pipeline facilities.

In addition to the proposed pipeline projects detailed, additional pipeline infrastructure for both gas and oil gathering will be required. Although scant information is publicly available on potential gas and oil gathering system development, an infrastructure demand metric based on potential future well production was developed. By using potential well locations and production volumes, potential gathering pipeline and gas processing loads can be quantified through the load growth model (Table 13).

5.7 Williston Basin Oil Refining

Raw, or unprocessed, crude oil has few industrial uses. Refining crude oil allows components to be processed into marketable petroleum products such as gasoline, diesel fuel, jet fuel, heavy heating oils and liquefied petroleum.

The Williston Basin has just one crude oil refining facility, the Tesoro Refinery in Mandan, ND. It is one of only 144 refineries in the U.S. in 2012. Combined, these 144 refineries have a crude oil distillation capacity of 17.3 million barrels per day (Figure 29).

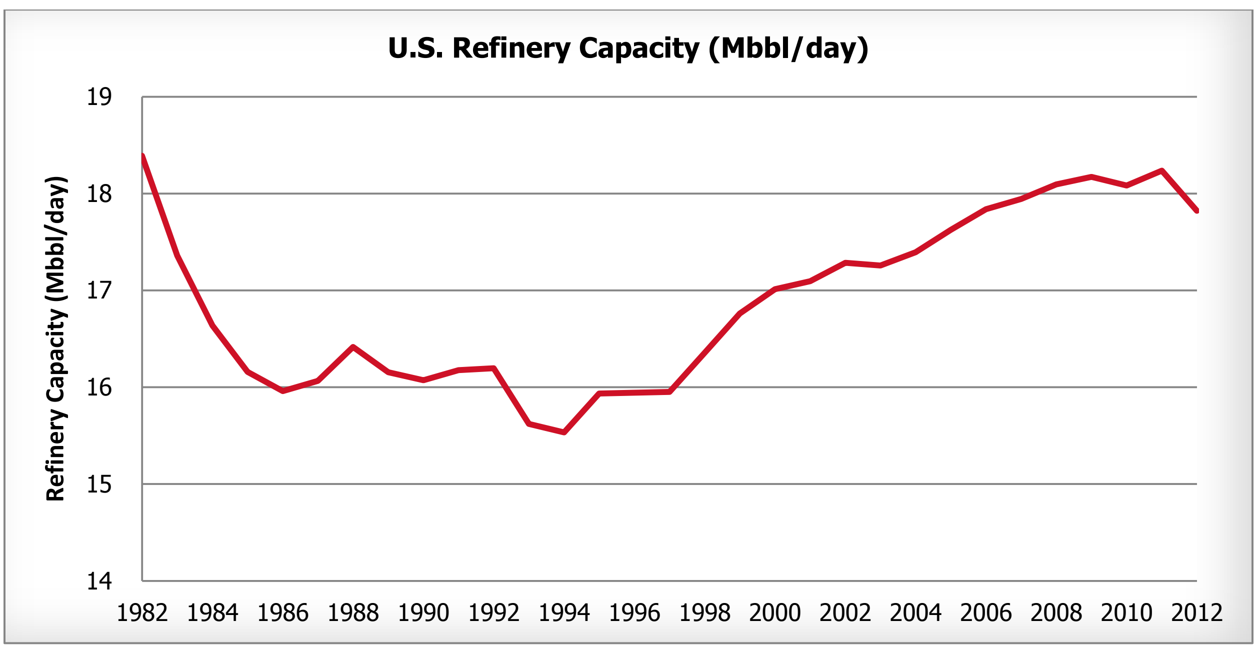

Figure 29: U.S. Refinery Capacity
(Million Barrels per Day)
Source: U.S. Energy Information Administration

Since 1954, the Tesoro Refinery has refined primarily domestic crude from North Dakota and eastern Montana. Spurred by the increased crude production from the Bakken, in addition to rising local demand for diesel fuel, the plant has expanded its refining capacity to 68,000 bopd.

The majority of Williston Basin crude oil is transported via pipeline or rail to refining facilities outside the region.

5.8 Proposed Williston Basin Oil Refining

No new large-scale refineries have been built in the U.S. in 35 years. However, due to the abundance of discounted Bakken crude oil, lack of regional refining capacity and high demand for fuels, the Williston Basin may soon be home to three small-capacity refineries. These small-scale proposed refineries, all in different stages of planning and permitting, would produce primarily diesel fuel to meet the growing demands related to the Williston Basin. The three proposed refineries are as follows and shown in Figure 30, along with the existing Tesoro Refinery in Mandan, ND.

- *MHA Nation Clean Fuels Refinery*: The Mandan, Hidatsa and Arikara Nation (MHA Nation) Clean Fuels Refinery is proposed on the Fort Berthold Reservation west of Makoti, ND, in Ward County. If built, the refinery will have a capacity of 15,000 bopd and produce diesel fuel to supply local demand within the region. The refinery will also produce naphtha, a byproduct used in Canada to dilute heavy tar sand crude oil.

  The project is awaiting final approvals from the Environmental Protection Agency (EPA). Construction is expected to take 18 to 24 months for this refinery project, which has been in process since 2003.

- *Trenton Diesel Refinery*: Proposed by Dakota Oil Processing LLC, this refinery would be located three miles southwest of Trenton, ND, in Williams County. The plant would have a capacity of 20,000 bopd and an expected initial production of 16,400 bopd. The refinery would produce butane, propane, light and heavy naphtha, kerosene, diesel fuel, industrial diesel and heavy fuel oil. At full capacity, the plant could produce 8,000 bopd of quality diesel fuel.

  Dakota Oil Processing has received an air quality permit from the North Dakota Department of Health and is awaiting a water treatment permit. If approved, construction would begin in late 2012 and take about 18 months to complete.

- *MDU Resources – Calumet Refining*: MDU Resources and Calumet Refining have proposed a new refinery about five miles southwest of Dickinson, ND, in Stark County. The 20,000 bopd diesel refinery, which is in the initial engineering and study phase, would serve the growing diesel demands of the agricultural and Bakken-related sectors. Any remaining crude oil would be shipped to other Calumet-owned facilities to be further refined into gasoline, solvents, lubricants or feedstock for the manufacturing industry. The group anticipates submitting permit applications to the state in 2012. Construction estimates are 24 months, with an expected operational date of late 2014.

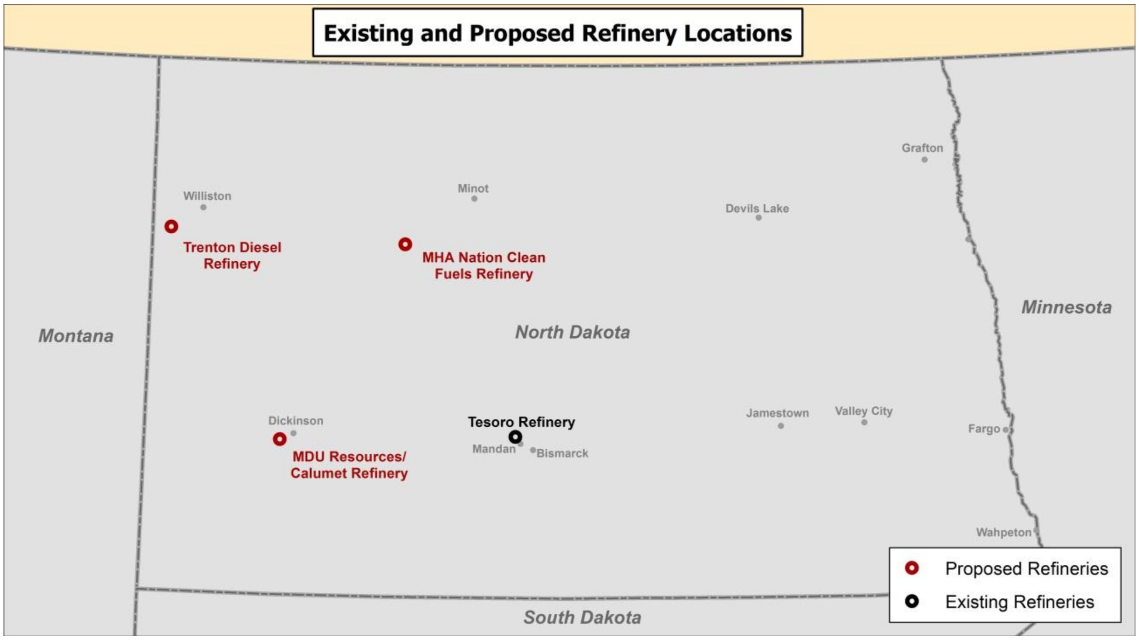

Figure 30: Existing and Proposed Refinery Locations
Source: KLJ

The three proposed refining facilities, coupled with the recent expansion of the Tesoro Refinery, could mean a regional refining capacity of 123,000 bopd by 2014. This is an increase of 81 percent from the region's capacity of 68,000 bopd in 2012 (Table 16).

Williston Basin Refinery Capacity		
Refinery	**Current Capacity (bopd)**	**Proposed Capacity (bopd)**
Tesoro (2012 expansion)	68,000	-
MHA Nation Clean Fuels Refinery	0	15,000
Trenton Diesel Refinery	0	20,000
MDU Resources - Calumet Refining	0	20,000
Regional Refinery Capacity Totals	**68,000**	**55,000**

Table 16: Williston Basin Refinery Capacity
Source: U.S. Environmental Protection Agency, Dakota Oil Processing, LLC, Tesoro Corporation, Bismarck Tribune (Compilation: KLJ)

5.9 Potential Electrical Load Growth

Utilizing estimated power requirements from Table 13 as an anticipated load growth metric, it is assumed a ratio of 1 megawatt would be required for every 4,000 barrels per day of future refining capacity added within the study area.

The estimated potential electrical load for the proposed refineries is detailed in Table 17.

Additional and Proposed Refineries			
Proposed Refinery	**Proposed Capacity (bopd)**	**Estimated Power Requirements**	**Projected Timeline**
MHA Nation Clean Fuels Refinery	15,000	4 MW	Late 2013
Trenton Diesel Refinery	20,000	5 MW	Late 2013
MDU Resources - Calumet Refining	20,000	5 MW	Late 2014

Table 17: Additional and Proposed Refineries
Source: U.S. Environmental Protection Agency, Dakota Oil Processing, LLC, Tesoro Corporation, Bismarck Tribune (Compilation: KLJ)

5.10 Natural Gas

Recent technological innovations and changes to production practices in the natural gas industry have brought drastic changes over the last decade. Natural gas pricing has steadily decreased as new technology has opened up shale gas production in several states. Traditionally, the domestic supply was largely produced by five states, but shale production has expanded natural gas production to include 20 states.

The future projections provided by several major industry agencies vary based on production expectations, regulations, legislation and other factors. For this reason, the projected prices vary, but each agency agrees that natural gas prices will increase over the next 20 years. Key driving factors for this are the increasing industrial sector demand, the shift from net importer to net exporter for the U.S. and increasing energy consumption. At the high end, IHS Global Insight believes consumption may increase by 39 percent, while the Interindustry Forecasting Project at the University of Maryland (INFORUM) is the most conservative at a 3 percent rise.

The U.S. Energy Information Administration (EIA), in the Energy Outlook 2012, claims recovered shale natural gas will account for 49 percent of total U.S. production by 2035 compared to 23 percent in 2010.

Because of improved technologies, production practices and transportation support, increasing supply of natural gas has resulted in lower prices per unit sold, reflected in the rapidly decreasing prices at Henry Hub and other locations across the country. Industrial energy consumption, according to the EIA, will increase 0.6 percent each year until 2035.

In 2010, the U.S. imported 11 percent of its natural gas supply; by 2035, many forecasts predict the U.S. will be a net exporter. Improved pipeline support and the rapidly developing shale production are seen as the primary drivers for this shift. It is also a primary reason why many agencies believe the price will steadily increase as we move toward 2035.

Historically, natural gas has been traded per million Btu (MMBtu) or per thousand cubic feet. The NYMEX also predominately trades in MMBtu. The pricing in Figure 31 and Table 18 is based on an average of the daily closing prices from Henry Hub in Louisiana. While almost no projections believe that the prices will recover to 2005 levels, many believe $7 MMBtu is realistic for 2035.

While transportation limitations often lead to short-range sales of natural gas and the Federal Energy Regulatory Commission (FERC) limits the usage of pipelines in regards to natural gas sales, many refer to the Henry Hub spot prices as one of the more reliable national price indicators for natural gas.

20-Year Natural Gas Price Forecasts in 2012 USD per MMBtu			
	2015	**2025**	**2035**
Energy Information Administration (EIA)	$4.29	$5.63	$7.37
Strategic Energy & Economic Research (SEER)	$4.28	$6.29	$7.70
Energy Ventures Analysis (EVA)	$4.07	$6.47	$7.26
IHS Global Insight (IHSGI)	$4.75	$4.82	$5.13
Average*			
Standard deviation between forecasts	$0.29	$0.75	$1.17
Consensus market price projections (average of all gas price forecasts)	$4.35	$5.80	$6.87
Low market price projections (consensus less deviation)	$4.06	$5.05	$5.69
High market price projections (consensus plus deviation)	$4.63	$6.55	$8.04

**This line separates independent forecasts (above) from KLJ calculated forecasts (below).*
Henry Hub spot market price forecasts based on per million Btu.

Table 18: 20-Year Natural Gas Price Forecasts in 2012 USD per MMBtu
Source: U.S. Energy Information Administration, Strategic Energy & Economic Research, Energy Ventures Analysis, IHS Global Insight (Compilation: KLJ)

Methods in which projections can be measured include volume and energy produced as well as multiple sources to measure pricing changes. Henry Hub market price is viewed by many federal agencies and forecasters as the standard in the U.S. For this reason, the forecasts are shown as price per MMBtu sold at Henry Hub.

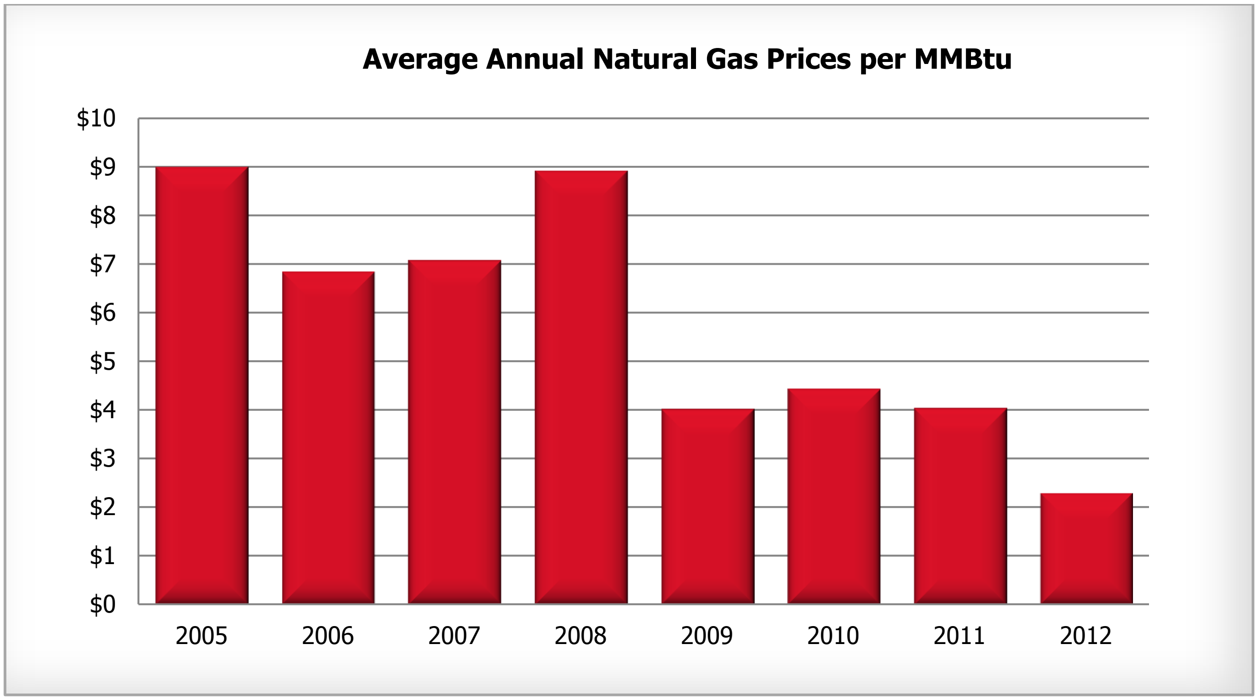

Figure 31: Average Annual Natural Gas Prices per MMBtu
Source: Henry Hub

5.10.1 Major Natural Gas Market Shares

The U.S. EIA projects industrial natural gas usage may increase as much as 8 percent from 2010 to 2035 and believes natural gas will continue to provide the largest segment of energy to the industrial sector.

Its high-end projections claim as much as 33 percent of industrial energy needs will be met by natural gas by 2035. Energy Ventures Analysis (EVA) and INFORUM both predict even more rapid growth (23 percent) within the industrial sector.

Increasing demands on natural gas for transportation are relatively low compared to historical transportation trends and other markets. Fuel economy and low growth in personal travel are primary reasons for this trend. These categories are commonly tracked by vehicle miles traveled and have been steadily decreasing due to fuel prices and economic conditions. The transportation sector should experience energy consumption growth of 0.1 percent per year, according to the EIA and EVA.

5.10.2 Natural Gas Characteristics

Methane, the primary component of natural gas, typically accounts for 70 to 90 percent of total volume produced (Table 19). When natural gas contains more than 95 percent methane, it is considered dry natural gas. Wet natural gas, including NGLs, sells at a substantial premium to dry natural gas and is forecasted to continue this trend to 2035. The major impurities found in natural gas include ethane, propane and butane. Individual commodity markets, which can increase revenues for companies, exist for these resources, however, removal of the resources from natural gas results in increased costs for the processing facilities.

Hydrogen sulfide is another characteristic of natural gas that can impact price, processing costs and ability to resell. The EPA monitors these levels as part of its protection of the environment and air quality. Bakken natural gas is predominantly sweet, which means it has lower levels of hydrogen sulfide. The key difference between sweet and sour natural gas is that sweet gases can be directly sold to consumers while sour natural gas must first be treated.

According to the U.S. Energy Information Administration's Annual Energy Outlook 2012, Henry Hub market price for dry natural gas is predicted to be at $7.37 per thousand cubic feet in 2035.

Natural Gas Key Characteristics		
Characteristic	**Bakken**	**Texas/Wyoming**
Methane Content	70-90% (Wet)	70-99% (Wet/Dry)
Hydrogen Sulfide levels	Sweet (Lower levels)	Sweet (Lower levels)
Carbon Dioxide levels	Low	Low
Natural Gas is considered dry at 95% methane levels.		
Hydrogen Sulfide levels are monitored by the EPA.		

Table 19: Natural Gas Key Characteristics
Source: KLJ

6. Population Estimate Modeling

Population is a key component in planning for future infrastructure needs. Population is typically forecasted using standard cohort demographic models. Due to rapidly changing conditions in the Williston Basin, existing demographic tools are inadequate and little to no data exists to adjust key demographic metrics, such as birth rates and in-migration rates. Further, existing models do not take into consideration the unique characteristics of the workforce in the Williston Basin and study region. Accordingly, an alternate method of estimating population based on projected employment was developed. Projected employment growth in the Williston Basin will be used to project housing demand. Application and comparison of persons-per-household occupancy rates to estimates of housing demand for various types of housing units will estimate population potential for the Williston Basin.

Rapid expansion of oil and gas related development is the fundamental catalyst behind the socio-economic transformation in the Williston Basin. Prior to the recent expansion in the petroleum-sector, unemployment in the region was very low and rapid expansion has created significant employment opportunities as the region currently has more jobs than available individuals. Accordingly, projected employment is an appropriate alternate metric to estimate population growth and provides the most reasonable approach to estimating future population.

A model was developed to estimate changes in direct and secondary employment associated with the petroleum-sector in the Williston Basin. However, oil and gas employment represents only one economic sector, therefore, the approach was comprehensive and included changes in other industries and secondary jobs tied to the petroleum-sector in the region as well.

6.1 Temporary Workforce and Permanent Workforce

Workforce characteristics vary according to the type of oilfield development activity. For this reason, petroleum-sector employment was divided into two categories: temporary workforce and permanent workforce. The workforce for certain activities such as drilling and fracing, infrastructure construction and gathering systems construction consist largely of temporary workers. Temporary workers are often residents of other states and work in a location until the job is complete and then move on to the next job site. Temporary workforce may also be shift-workers with alternating patterns of working and non-working periods. Even though workers may be onsite for an extended period, they are viewed as a temporary workforce relative to the life cycle of oilfield development and are not considered established residents of the state in which they work.

The permanent workforce is comprised of individuals who work in the Williston Basin and are established permanent residents of the state in which they work, in the case of this report, North Dakota, South Dakota or Montana. Oilfield service employment is an example of the type of industry activity that consists of a largely permanent workforce. The delineation between permanent and temporary workforces is significant as each group of workers has different demands for goods and services, housing and infrastructure.

Employment projections were based on rig counts, well completions, number of existing wells and labor requirements for various industry aspects. Separate employment estimates were produced for exploration activities such as drilling and fracing, production operations such as well operations, infrastructure maintenance and transportation and construction of oilfield infrastructure and gathering systems. Labor coefficients were adjusted over the study period to reflect anticipated changes in labor requirements, production practices and technological efficiencies.

Three scenarios were modeled low, consensus and high:

- *Low scenario*: Assumes a gradual decline in drilling activity that would begin in 2012 and continue for the next several decades. Current levels of overall employment within the sector are likely to remain elevated for the next five to seven years, after which, total employment in the petroleum sector starts to decline throughout the remainder of the 20-year study period.
- *Consensus scenario*: Petroleum-sector employment continues to grow for another 8 to 10 years, after which, employment would decline as the industry pulls back on drilling activity and construction activities associated with infrastructure and gathering systems are completed.
- *High scenario*: Petroleum-sector employment continues to grow over the next 8 to 12 years, after which, total petroleum-sector employment exhibits a declining trend as the industry scales back drilling activities.

The model produced regional employment estimates based on the low, consensus and high scenario. The model also produced differentiated employment by type of oilfield activity and by permanent and temporary workforce. Estimates of regional employment, which is petroleum-sector employment, employment in other industries and sectors of the economy, and secondary employment were used as the baseline for modeling housing demand and population. See Appendix B for details regarding the employment model.

7. Housing Demand Modeling

Due to the expansion rate of energy development in the Williston Basin and the resulting growth in employment, the demand for housing has outstripped supply. Any excess supply of housing has long been absorbed removing elasticity in housing supply. 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.

An examination of the direct ratio of employment-to-housing showed how growth in employment, combined with the existing shortage of housing, suggested an increase in one job would be expected to result in demand for one housing unit. Because demand for housing far outstrips the supply of housing, the employment-to-housing model assumed a 1:1 correlation between employment and housing in the near-term. That assumption was relaxed over time as housing supply is expected to grow and more closely equal demand. A housing demand model was used to estimate future housing demand based on regional employment projections.

The employment-to-housing model linked changes in the total workforce, temporary and permanent, to projected demand for housing. Permanent and temporary housing demand was modeled to increase in the near-term and then decline slightly or remain steady over time as contractions in the petroleum-sector workforce occur. Employment projections indicate substantial levels of temporary housing will be required for nearly a decade. Long-term permanent housing demand is projected to increase substantially in all scenarios and in all regions (Figure 32, Figure 33 and Figure 34). While much of the growth in permanent housing demand is due to changes in workforce within the petroleum industry, demand for housing will also be a function of expectations of growth in other sectors. While secondary effects are modeled throughout the planning period, in later stages, it is expected there will be additional growth in secondary employment and other commercial sectors.

In the near-term, the workforce is mobile and will respond to the availability of housing; however, in the long-term, the workforce will desire housing to be in reasonable proximity to the oilfields. Accordingly, regional demand for housing based on projected growth in employment was allocated among Williston Basin counties according to the historic distributions and recent trends in distribution of housing units. Recent building trends also reveal a disproportionate shift to multi-family units in North Dakota. The housing mix (single family, multi-family) per county was adjusted to reflect the shift. 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 is available, housing demand was allocated among study counties based on historic distributions and emerging trends with adjustments in the mix of housing units as appropriate data was available.

The cost and lack of housing is constraining growth in other sectors of the economy as well. Expectations for normal economic response to creating secondary employment will not be realized until housing becomes available at a price that enables additional (service and commercial industries) workers to locate to the region. In addition to constraining secondary job creation, the housing shortage is also inhibiting the existing industries ability to add workforce. Housing shortages and the lack of public goods and services are a result of the current constrained economy. These shortages can lead to displacement and crowding-out effects that may have substantial implications for the long-term diversity and economic health of the Williston Basin.

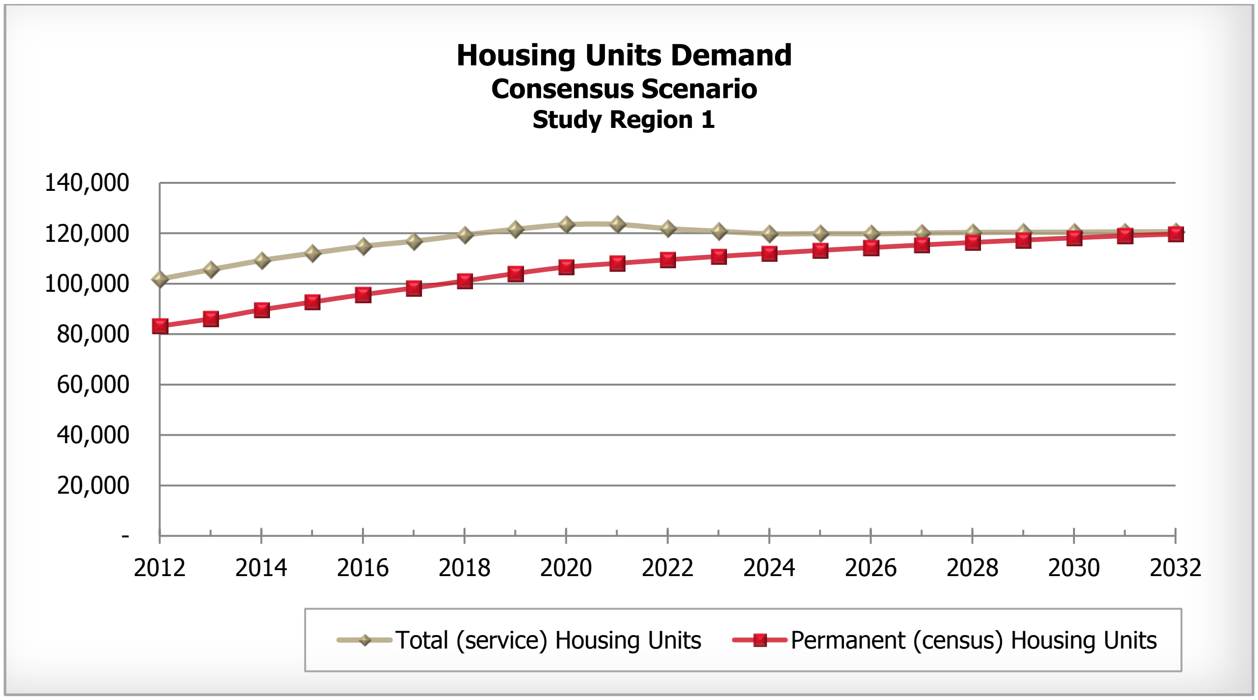

Figure 32: Housing Units Demand - Consensus Scenario - Study Region 1
Source: North Dakota State University

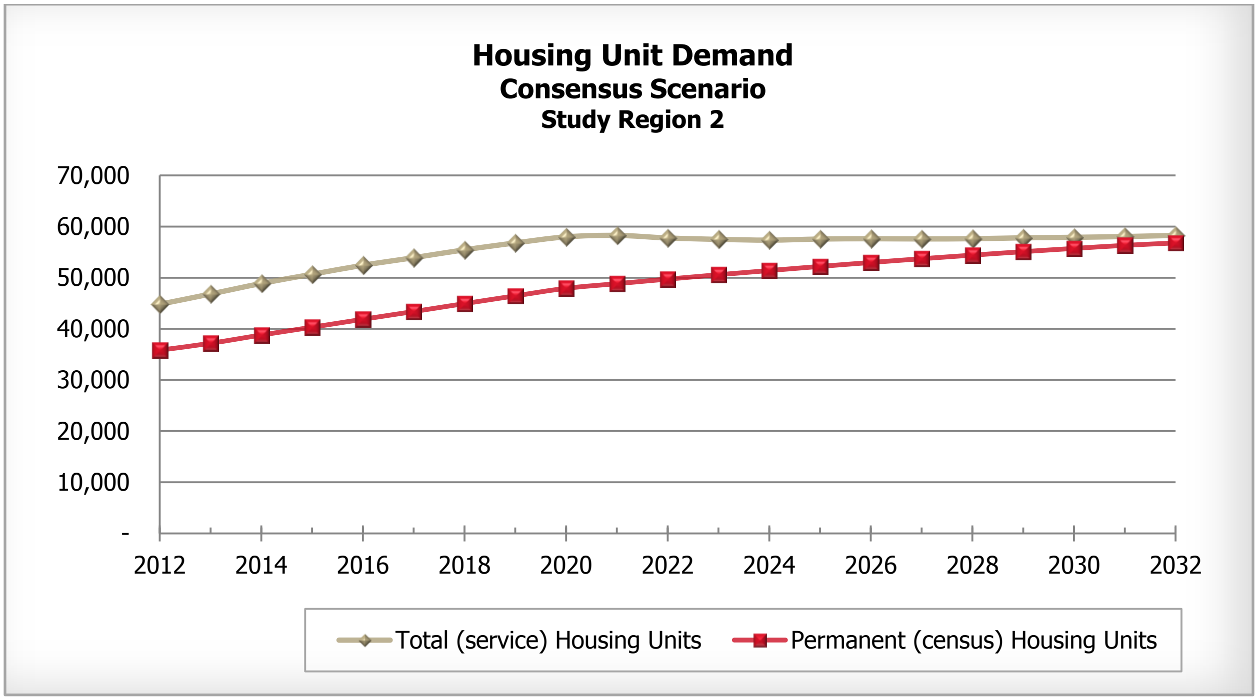

Figure 33: Housing Unit Demand - Consensus Scenario - Study Region 2
Source: North Dakota State University

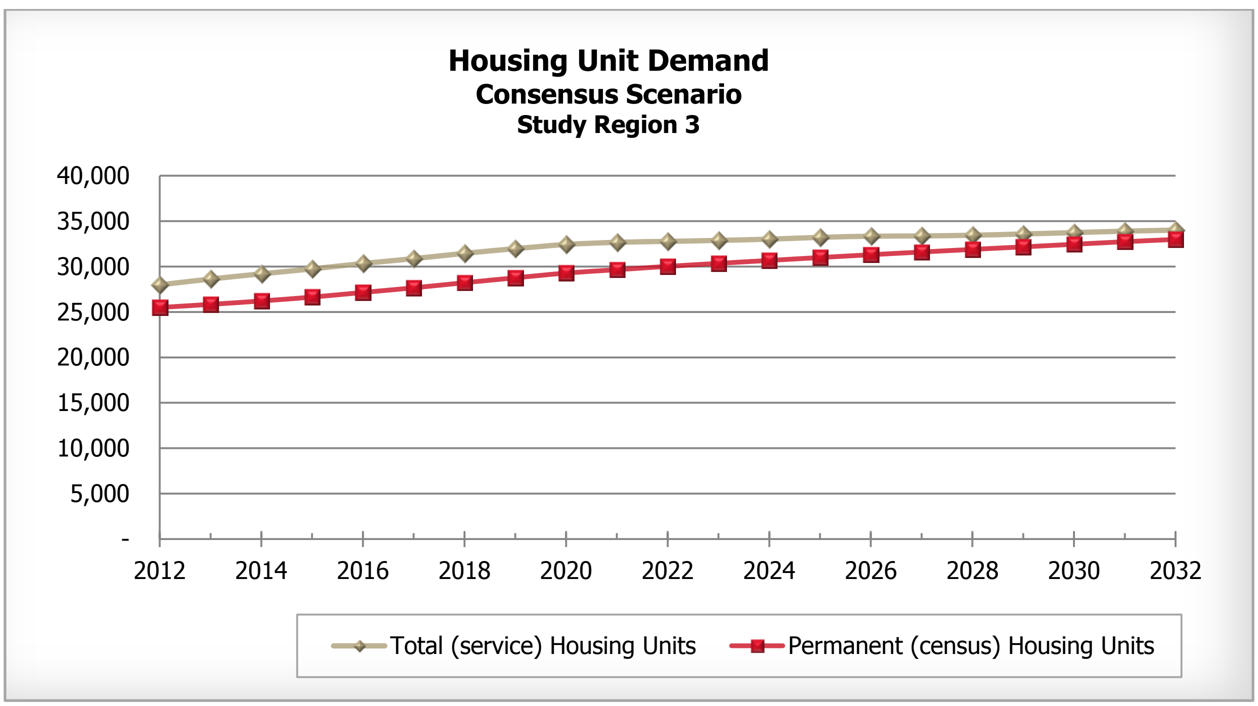

Figure 34: Housing Unit Demand - Consensus Scenario - Study Region 3
Source: North Dakota State University

8. Permanent and Service Population

The final step in estimating the Williston Basin population potential was to apply occupancy rates by housing type, by county, to convert housing demand estimated in Section 7 into population estimates. Two population estimates were required to describe the unique circumstances present in the Williston Basin: permanent population and total service population. The permanent population is comprised of individuals who work in state and are established residents of that state. Permanent population is also consistent with population measured by the U.S. Census Bureau. The total service population is the sum of the permanent population and the temporary population.

8.1 Permanent Population

Permanent population is expected to parallel changes in permanent employment in the petroleum-sector. Permanent employment in the petroleum-sector is primarily a function of the number of wells. As well counts in the Williston Basin increase, so does permanent population. While employment in the petroleum-sector may be the driving force in the Williston Basin, long-term employment and population is not only a function of the petroleum-sector, but also other businesses and industries. Accordingly, changes in employment in other industries were included in the employment model. Long-term planning for housing, infrastructure, public and social services and potential public revenue streams should focus on the permanent population.

Modeling suggests that the 2012 consensus scenario permanent population potential in the Williston Basin was just over 305,000, an increase of 7.25 percent over the 2010 U.S. Census Bureau numbers. The permanent population over the 20-year planning period was modeled to increase by 35 to 50 percent, depending on the development scenario. Region 1 had the greatest absolute potential population, Region 2 the greatest potential percentage change and Region 3 has the smallest potential change in both absolute and relative terms.

8.2 Total Service Population

Modeling under the consensus scenario suggests the 2012 total service population potential in the Williston Basin is just under 370,000, with a temporary workforce of about 40,000 and a temporary population of about 65,000. To put the service population and temporary workforce estimate in context, using North Dakota Job Service data (2011 Quarterly Census of Employment and Wages), nearly 106,000 jobs, of which approximately 30,000 fit the definition of temporary, were reported in oil-producing counties in the Williston Basin in North Dakota. Jobs reported by North Dakota Job Service are actual observed numbers of jobs in oil and gas development within the study region of North Dakota.

Depending on the level of oilfield development, the total service population in the Williston Basin is expected to increase for the next 6 to 12 years. Over the next two decades, the total service population in Regions 1 and 2 will increase, plateau and then decrease until the point when the service population equals the permanent population (Figure 35, Figure 36). Service population and permanent population are expected to slowly increase over the study period for Region 3. The population trend in Region 3 is largely a function of a growing economy and the characteristics of oil development scenarios where rig counts remain constant over the 20-year period (Figure 37).

Future change in total service population was forecasted to be less than the change in permanent population. Based on forecasted change from 2012 to 2032, total service population within the greater Williston Basin was estimated to increase by 12 percent to 27 percent, depending upon development scenario. The modest increase in the total service population over the planning period is the result of growth in the permanent population exceeding the decline in the temporary population. Population patterns parallel changes in the regional workforce.

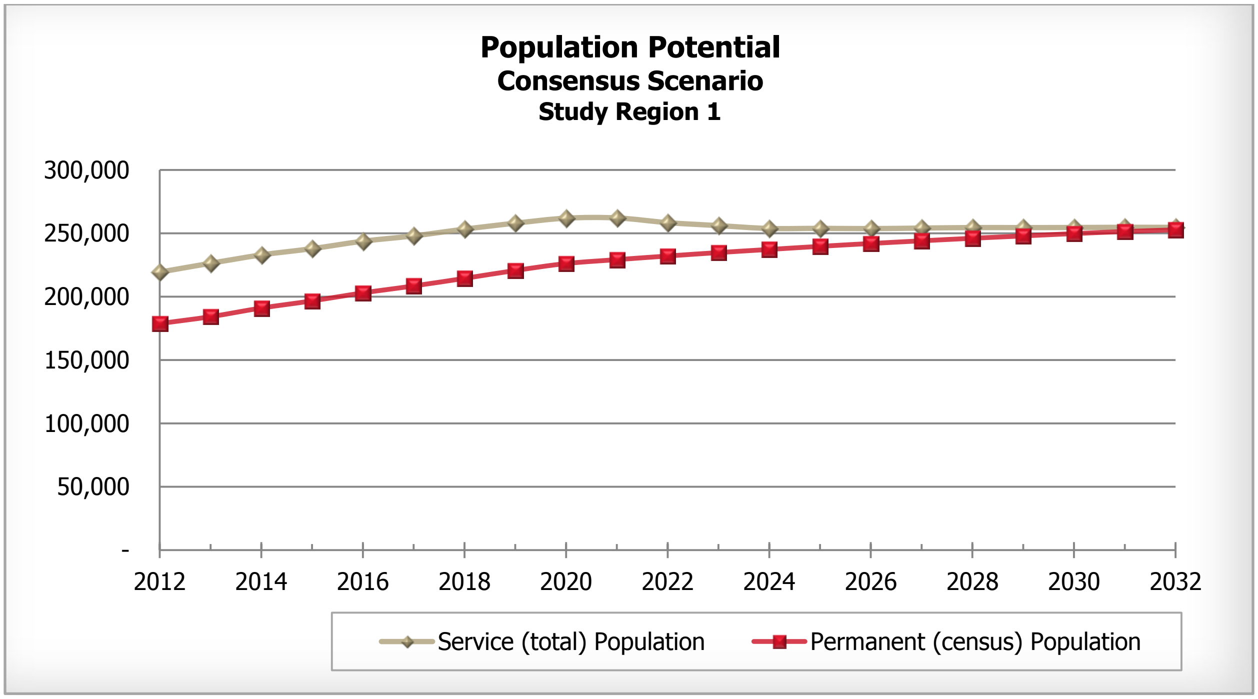

Figure 35: Population Potential - Consensus Scenario - Study Region 1
Source: North Dakota State University

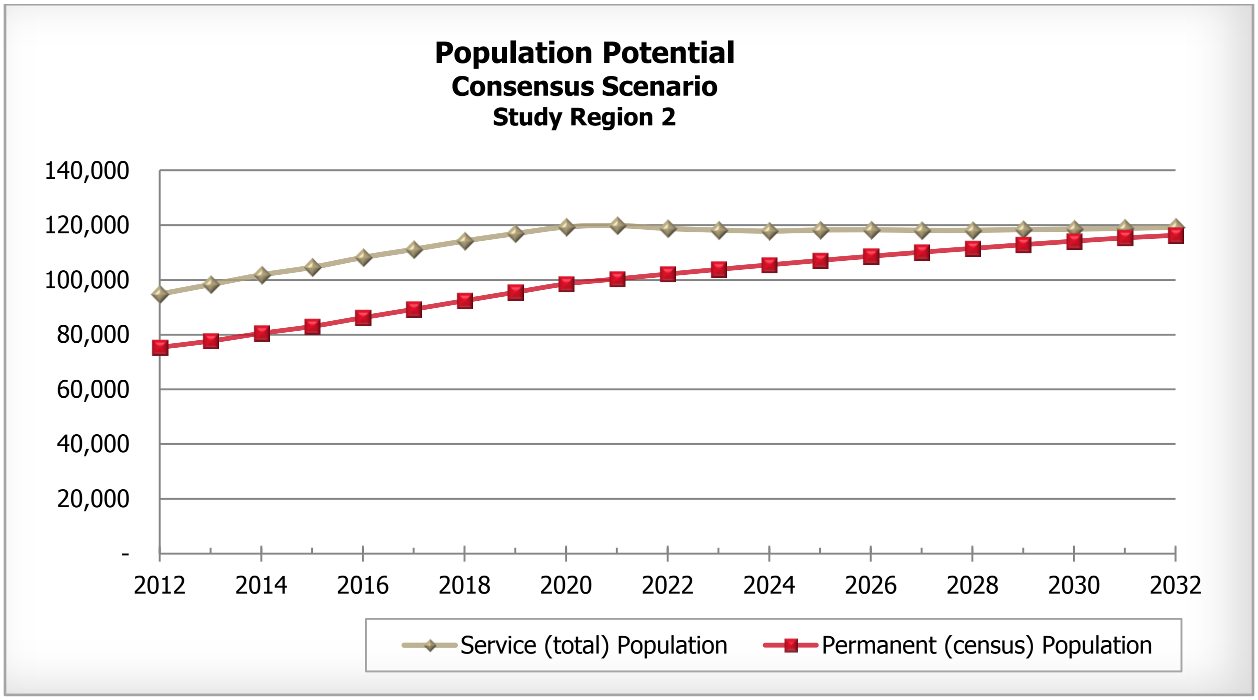

Figure 36: Population Potential - Consensus Scenario - Study Region 2
Source: North Dakota State University

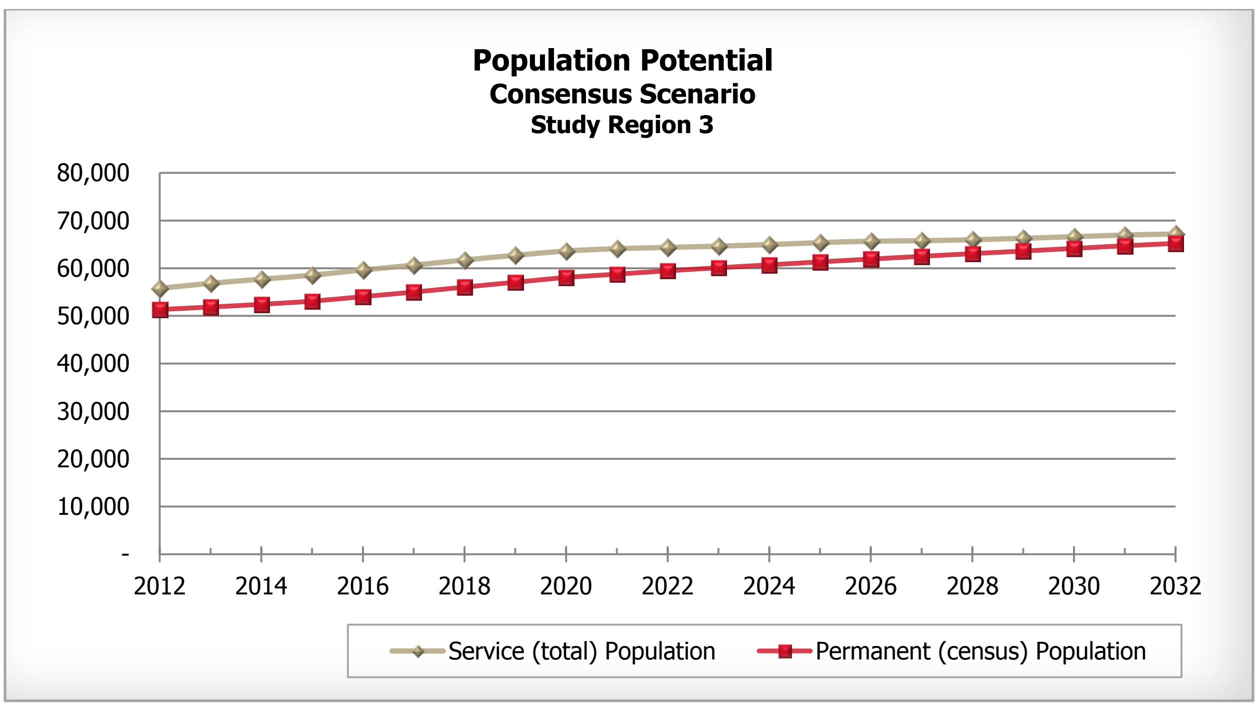

Figure 37: Population Potential - Consensus Scenario - Study Region 3
Source: North Dakota State University

8.3 Population Estimate Assumptions

As described in Section 6, a large portion of the workforce is considered temporary, at least relative to the oilfield life cycle. Most workforce associated with drilling and fracing, gathering systems infrastructure and construction are temporary workers; therefore, a portion of the regional population is also considered temporary. The total service population includes permanent residents and 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 short-term employment or temporary residency in the region (reference Section 6 and Appendix B for details of permanent and temporary workforce).

Population estimates were made by applying person-per-household occupancy rates to housing demand estimates for various types of housing units (single family, multi-family, etc.). Occupancy rates for each type of housing unit by county were based on U.S. Census Bureau data from the 2010 American Community Survey (ACA). The severe housing shortage and the assumption that the housing shortage has forced higher occupancy rates than historical values. Actual occupancy rates were likely underestimated; however, this is the only available data. Occupancy rates for each type of housing unit, by county were applied to housing demand estimates to estimate population potential at the county level. Population estimates represent regional population potential and were based on several key assumptions:

- Communities are willing and able to supply housing at levels that meet the projected demand. 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 demand. While the future supply of housing is unknown, forecasted values represent population potential if housing demand is met.
- The temporary population has similar characteristics as 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.
- Historic occupancy rates remain valid.

Sensitivity analysis revealed the employment-to-housing-to-population model was responsive to both a change in housing units and occupancy rates. Small changes in either component resulted in large swings in population. As a further understanding of workforce characteristics and communities' ability to address future housing needs is developed, population projection refinements will take place.

Further, the Williston Basin lacks a good baseline population estimate. Because the U.S. Census Bureau only reports what is termed in this assessment as the permanent population, the 2010 Census Bureau figures for the Williston Basin undoubtedly underestimated the service population. Incorporating the temporary population into an estimate of total service population is critical for communities, businesses and government planning activities. Even though a portion of the service population are residents of other states, while in the Williston Basin they still use and require goods and services, both public and private.

9. Legislative Factors

Federal, state and local enacted and pending policies with potential impacts to electric load requirements were identified for the study region. A team of private-industry and government officials assessed potential future impacts on oil development in the Williston Basin. Fracing is the one potential issue that could have a substantial impact on future development in the Williston Basin. Legislation and/or regulatory initiatives need to be monitored closely over the next few months. Based on present discussions at the federal and state level, fracing issues are not expected to have any measureable impacts over the next two to four years. The Public Policy and Legislation matrix located in Appendix E identifies current issues under discussion and in various forms of legislative or regulatory process. The initiatives are not considered to have sufficient interest to be formally adopted in the near future.

Oil prices will have a greater impact than pending legislative or regulatory initiatives on production, therefore electrical load demand. However, industry experts are concerned that if meaningful changes are made to current public policies relating to taxation, environmental requirements or fracing processes associated with oil exploration, extraction or production development costs could be negatively impacted. These potential changes could have an impact on electrical load requirements going forward. The team's conclusion was to monitor initiatives at the federal and state level; however, all indications currently lean toward limited negative or positive impacts for the next three to five years.

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10. Glossary

Term	Definition
Anticline	An arch of stratified rock in which the layers bend downward in opposite directions from the crest.
bbl	Barrel.
bbls/d	Barrel(s) per stream day. The maximum number of barrels of input that a distillation facility can process within a 24-hour period when running at full capacity under optimal crude and product slate conditions with no allowance for downtime.
Bcf/d	Billion cubic feet per day.
bopd	Barrels of oil per day.
Bitumen	A naturally occurring viscous mixture, mainly of hydrocarbons heavier than pentane, that may contain sulphur compounds and that, in its natural occurring viscous state, is not recoverable at a commercial rate through a well.
Brent	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.
Btu	British thermal unit.
C&I	Commercial and Industrial.
Consensus	General agreement of expert opinions derived from a likely scenario or set of scenarios.
Constraints	Limitations or restrictions.
Crew camps	Confined living quarters created to house oilfield workers.
Direct Employment	Employment related to oil and gas development activities.
Demand	An electrical load request that indicates the maximum amount of electricity a customer requests from a utility for service at a single point in time, commonly measured in kilowatts.
Downhole	Located in a wellbore, as opposed to a location on the Earth's surface.

Term	Definition
Downstream	Companies involved with transportation of oil and gas.
Energy	The amount of electrical energy used over a period of time, commonly measured in kilowatt-hours. For devices that will constantly consume electricity year-round, energy is determined by multiplying the amount of electricity the device consumes (kilowatts) by the number of hours in a year (8,760 hours).
EOR	Enhanced Oil Recovery.
EPA	Environmental Protection Agency.
EVA	Energy Ventures Analysis.
Facies	Rock formations with different formation, composition, and fossil content characteristics.
FERC	Federal Energy Regulatory Commission.
GIS	Geographic Information System.
GOR	Gas-to-Oil Ratio.
Henry Hub	A natural gas pipeline located in Erath, Louisiana that serves as the official delivery location for futures contracts on the NYMEX.
hp	A standard unit of power, equal to 746 watts.
IEA	International Energy Agency.
IHSGI	IHS Global Insight.
Impending Loads	Electric loads currently served by onsite-generation that are scheduled to be connected to the grid.
In-fill Wells	Wells that are on previously held leases.
INFORUM	Interindustry Forecasting Project at the University of Maryland.
Injectants	Products used to clear undesirable elements from a well.
Intracratonic Basin	A sedimentary basin found within continental margins, with obvious signs of frequent connection to the sea as shown by intermittent phases of marine carbonate and evaporite sedimentation.

Term	Definition
kVA	Kilovolt-ampere. A unit used to measure the product of voltage and amperes, or a measure of the level of apparent power a generator or transformer could deliver to a circuit with a power factor of one.
kW	One thousand watts.
kWh	Kilowatt-hours (One thousand watt-hours).
LACT	Lease Automatic Custody Transfer Unit. A system providing for the automatic measurement, sampling and transfer of oil from the lease location into a pipeline.
LNG	Liquefied Natural Gas. Natural gas that has been converted to liquid form for ease of storage or transport.
Mcf	Thousand cubic feet.
MMBtu	One million British thermal units.
MMP	Minimum miscibility pressure. At constant temperature and composition, the lowest pressure at which first- or multiple-contact miscibility (dynamic miscibility) can be achieved.
MMscf/d	One million standard cubic feet per day. The customary unit for measuring the flow of natural gas. 'Standard' means that the measurement is adjusted to standard temperature (60 °F) and pressure (14.7 psig).
Multi-well pad	A pad that has more than one well.
MVA	Millions of volt-amperes. A measure of apparent power. Apparent power is the product of the voltage (in volts) and the current (in amperes).
MW	Megawatts (1 million watts).
MWh	Megawatt hours (1 million watt-hours).
NG	Natural gas. A gaseous mixture of hydrocarbon compounds, the primary one being methane.
NGL	Natural gas liquids. Classified according to vapor pressures as low (condensate), intermediate (natural gasoline) and high (liquefied petroleum gas) vapor pressure, and are liquid at surface in field facilities (or in gas-processing plants).

Term	Definition
NYMEX	New York Mercantile Exchange.
OECD	Organization for Economic Cooperative Development. An international organization helping governments tackle the economic, social and governance challenges of a globalized economy.
OOIP	Original Oil in Place. Estimated amount of total oil that is located in a formation. Not all oil in place is recoverable.
OPEC	Organization of the Petroleum Exporting Countries. An intergovernmental organization whose stated objective is to "coordinate and unify the petroleum policies of member countries." Created at the Baghdad Conference on September 10-14, 1960.
Pad Drilling	Multiple Well Pads.
Peak demand	Defined in kilowatts: the amount of electrical generation capacity available at any time to satisfy maximum load.
Permanent Workforce	Permanent workforce is comprised of individuals who have established a permanent residence in the state in which they work.
Primary Infrastructure	Equipment and/or facilities directly related to developing oil and gas resources.
Proppant	Particles mixed with fracturing fluid to hold fractures open after a hydraulic fracturing treatment.
Resource Play	An unconventional area that does not require any type of belowground structure to hold and trap oil.
Rural	Areas in the study region with lower populations per geographic square mile – typically higher electrical load requirements per customer due to agriculture-based needs.
Secondary Employment	Employment generated indirectly from oil and gas development.
Secondary Infrastructure	Equipment and/or facilities that result from oil and gas resource development.
SWD	Saltwater Disposal.

Term	Definition
Temporary Workforce	Workers who are often residents of another state and work in a location until the job is complete and then move on to the next job site. Temporary workforce may also be shift-workers with alternating patterns of working and non-working periods.
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.
Transmission Constraints	Inadequately sized transmission lines serving an area that has significant impending loads.
Trap Play	Traditional or conventional oilfield in which a structural feature, such as an anticline, prevents oil from continuing to move to the surface.
Upstream	Companies involved with oilfield exploration and production.
Urban	Areas in the study region which are densely populated cities and towns – typically lower electrical load requirements per customer due to shared municipal services.
USD	U.S. Dollar.
U.S. EIA	United States Energy Information Administration.
VRU	Vapor recovery unit.
WAG	Water alternating gas.
Watt	A measure of energy conversion or transfer, defined as one joule per second.
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 – Oil, Gas and Water Production per Region Exhibits

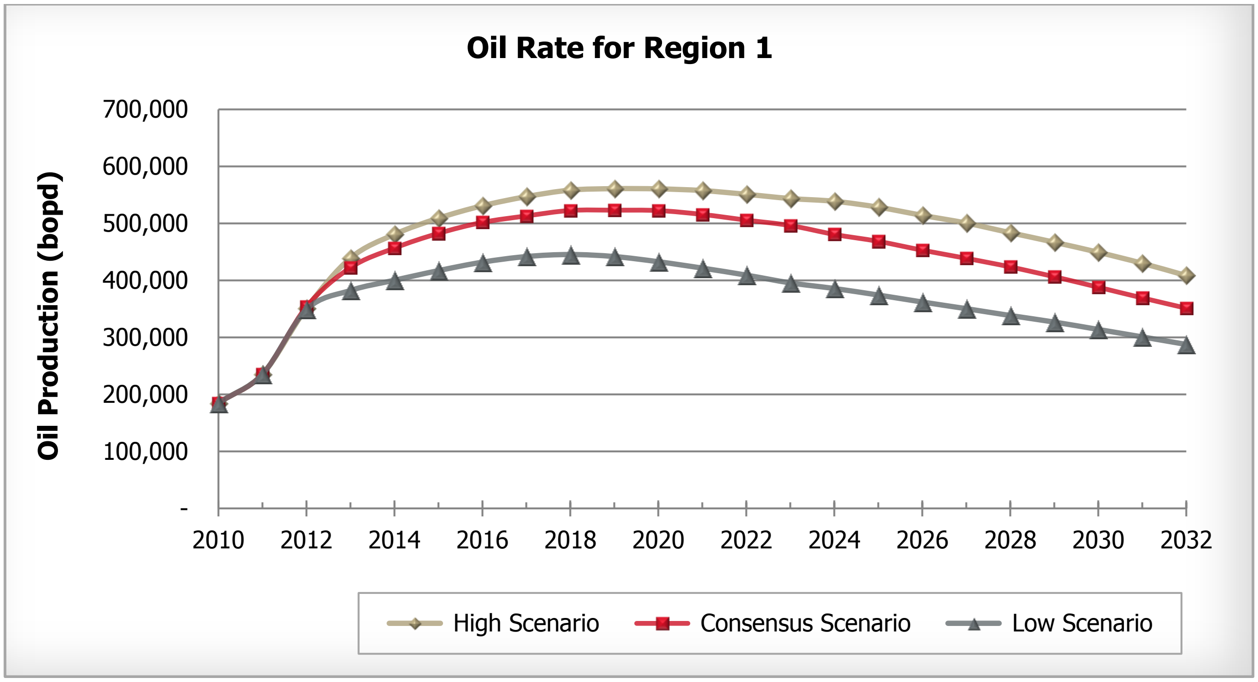

Exhibit A-1: Oil Rate for Region 1
Source: University of North Dakota

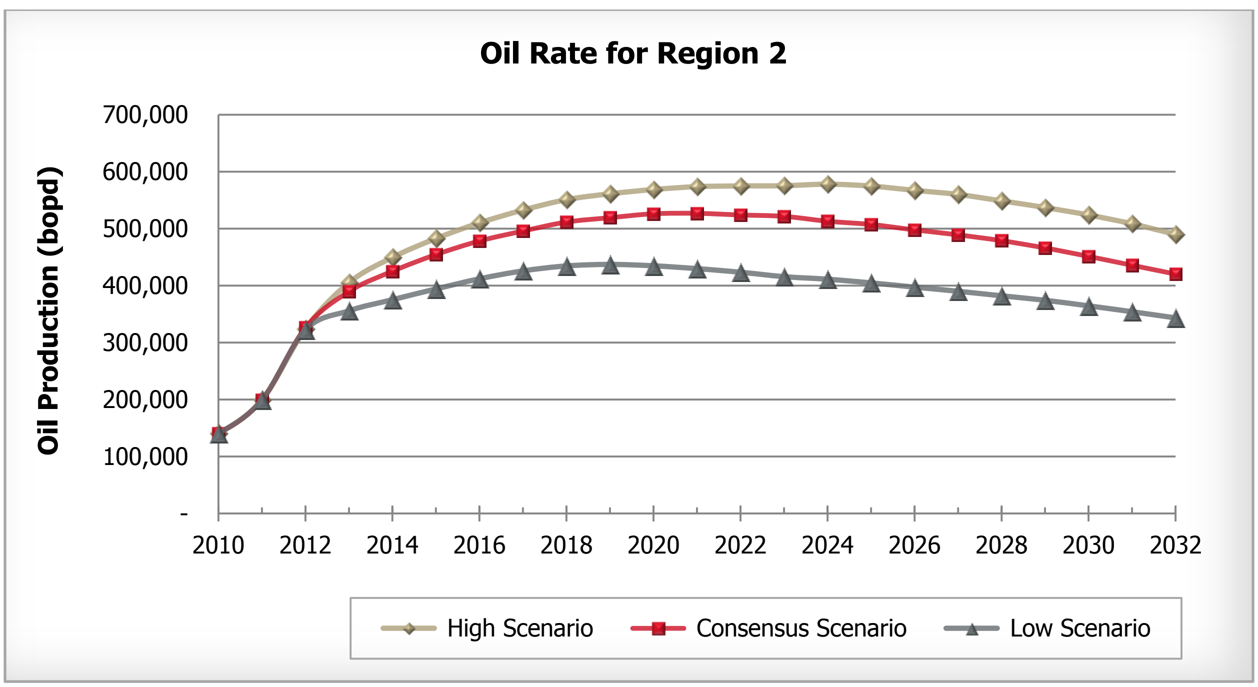

Exhibit A-2: Oil Rate for Region 2
Source: University of North Dakota

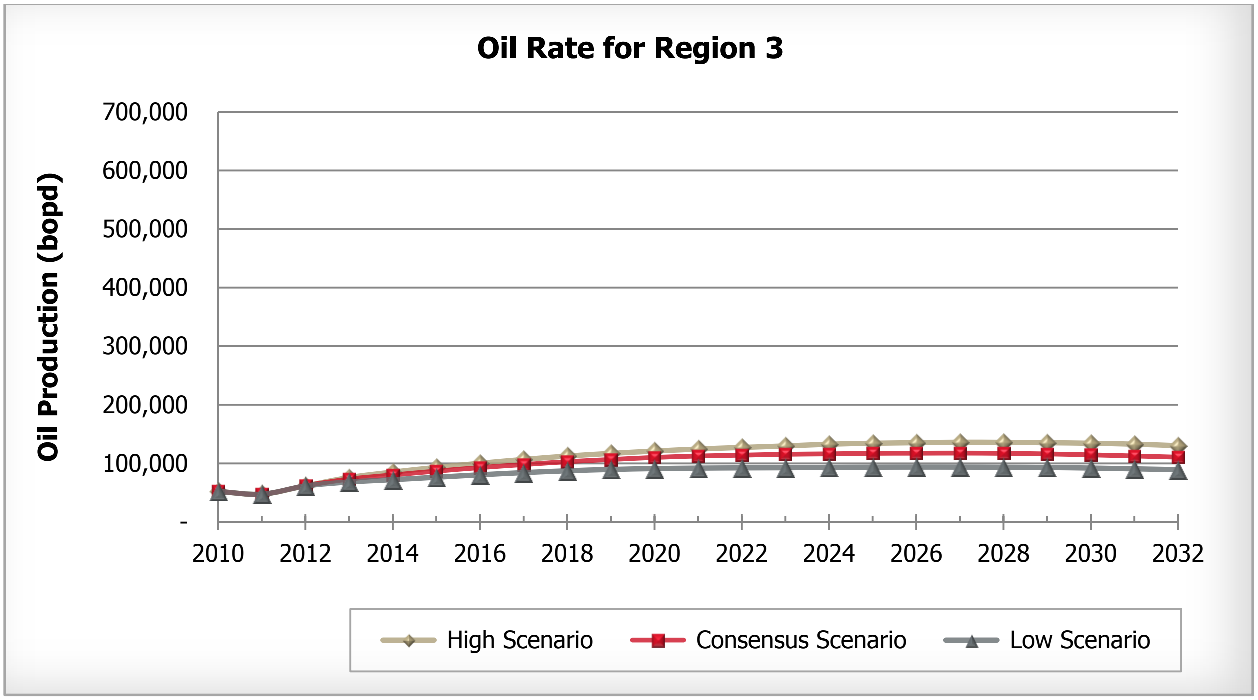

Exhibit A-3: Oil Rate for Region 3
Source: University of North Dakota

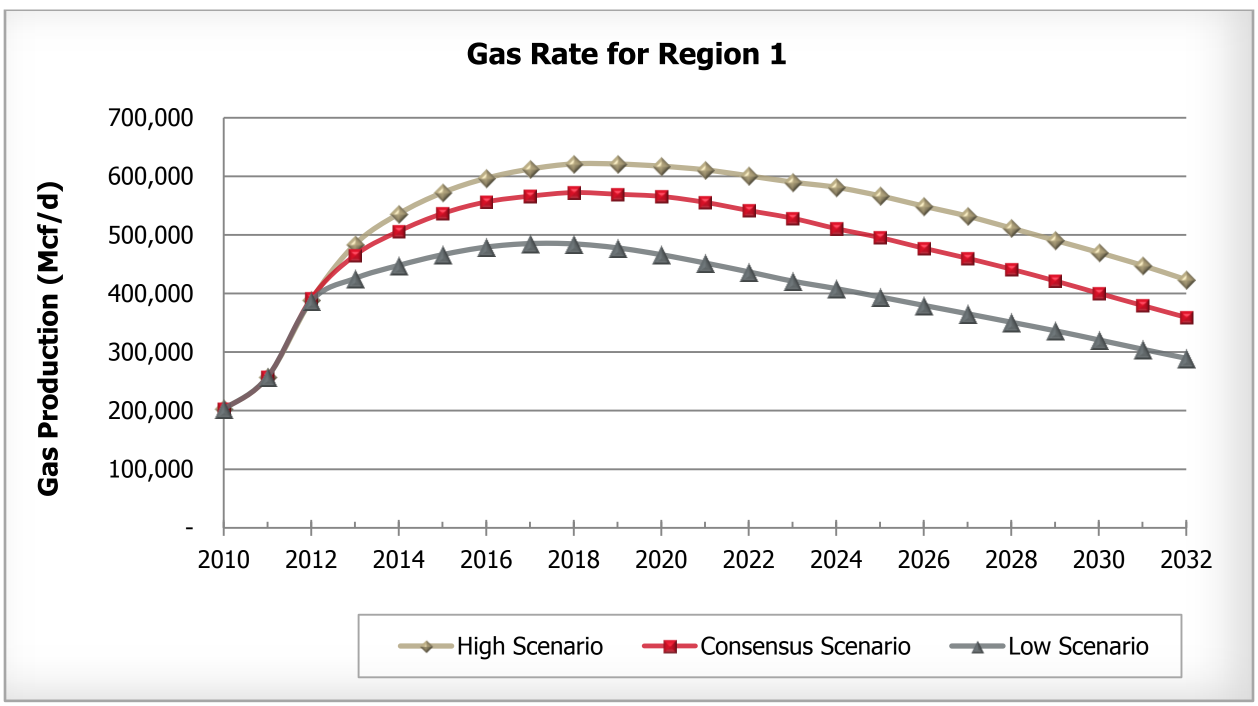

Exhibit A-4: Gas Rate for Region 1
Source: University of North Dakota

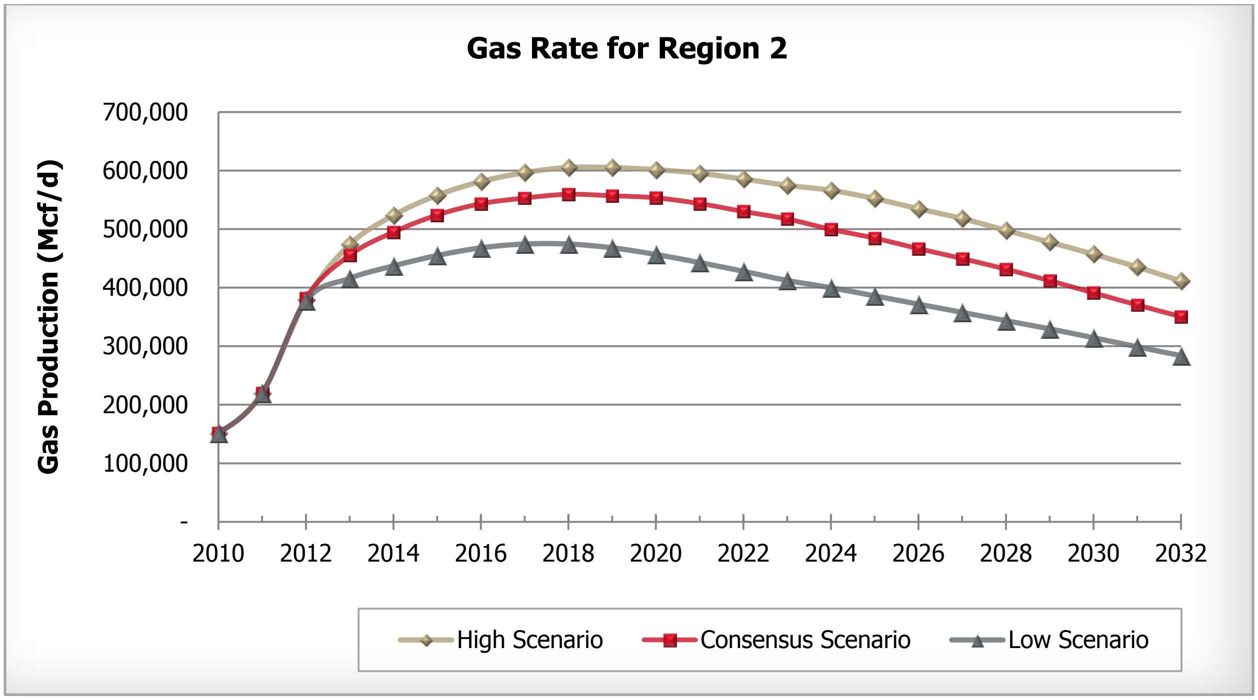

Exhibit A-5: Gas Rate for Region 2
Source: University of North Dakota

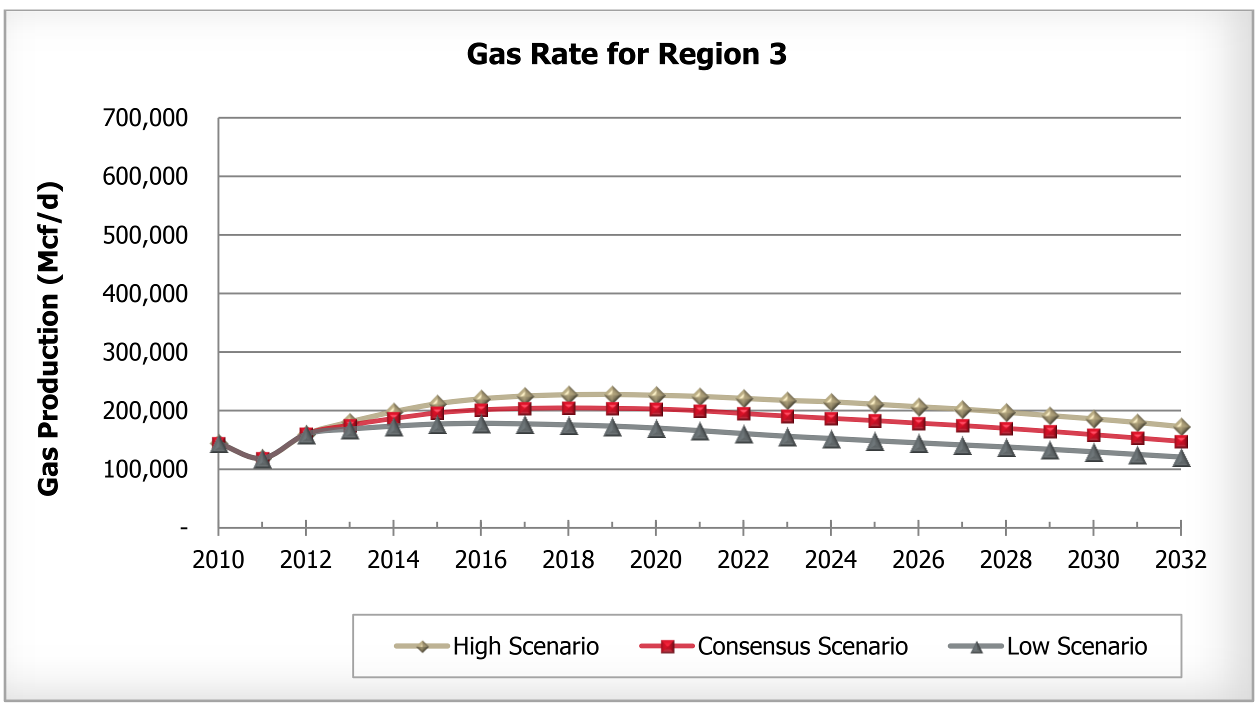

Exhibit A-6: Gas Rate for Region 3
Source: University of North Dakota

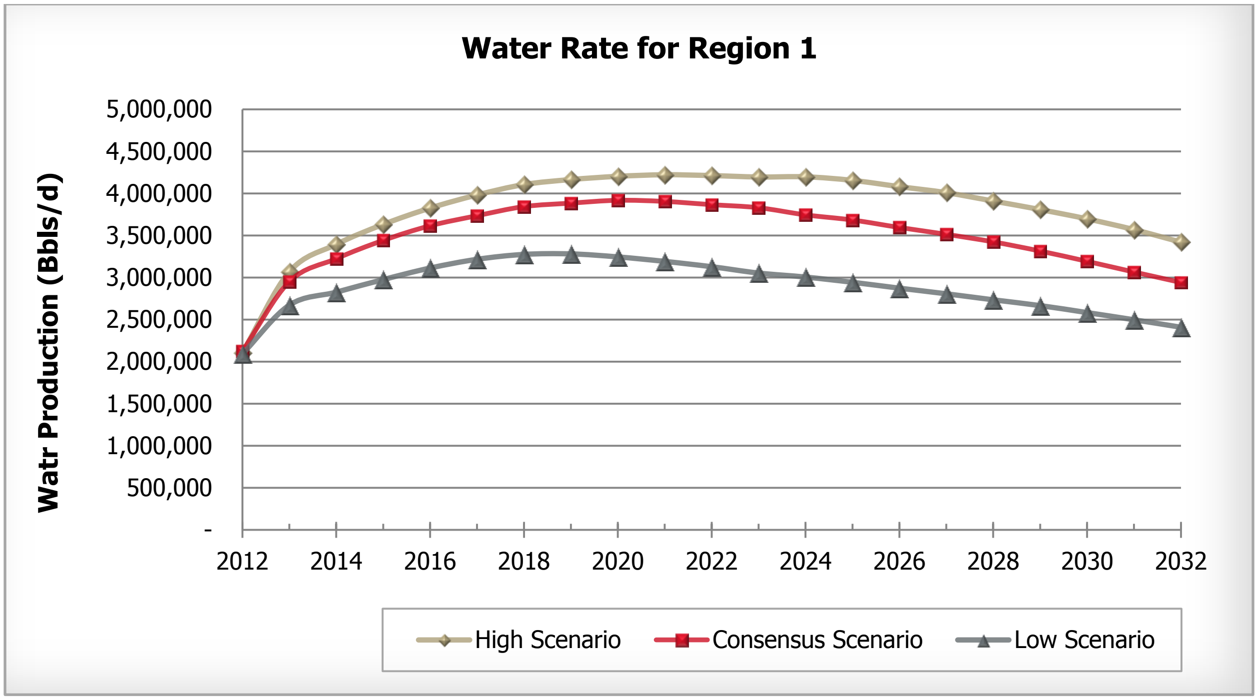

Exhibit A-7: Water Rate for Region 1
Source: University of North Dakota

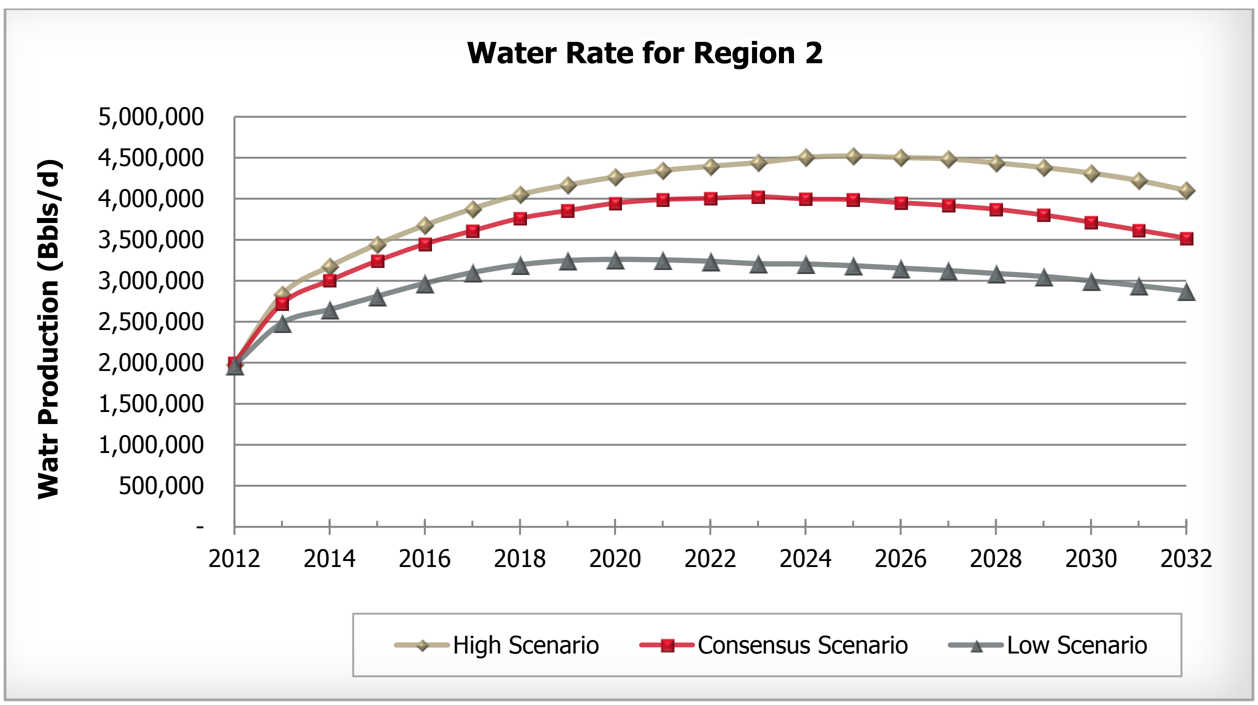

Exhibit A-8: Water Rate for Region 2
Source: University of North Dakota

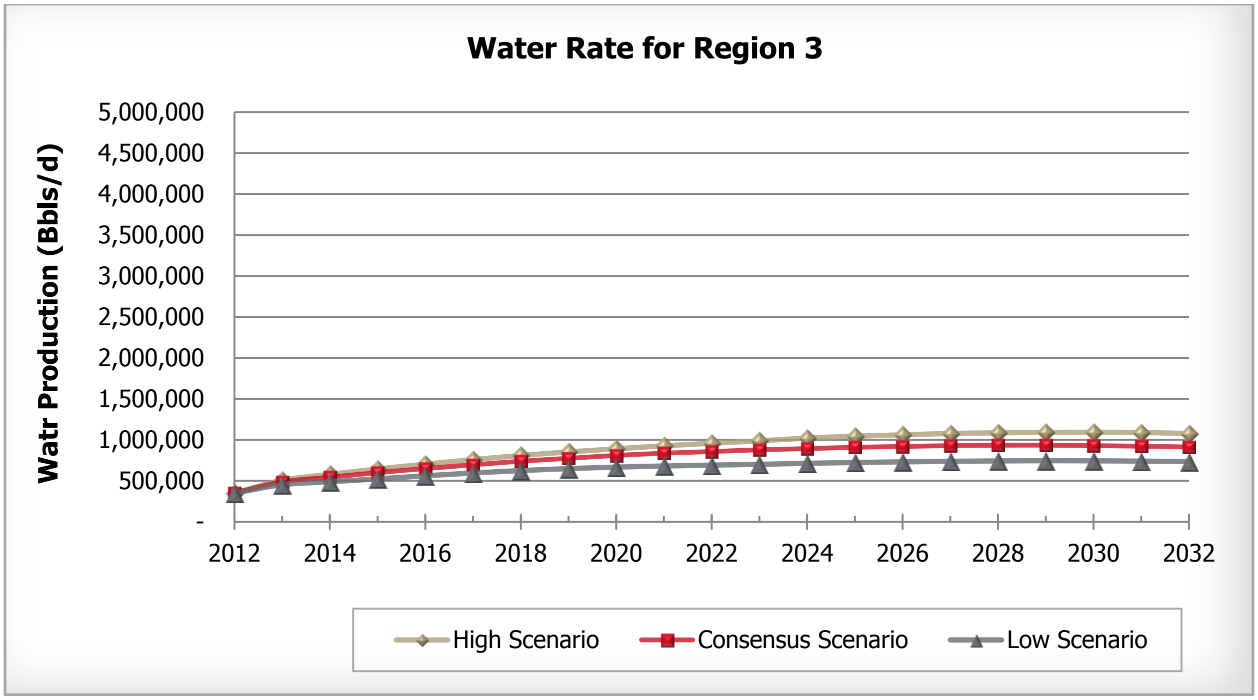

Exhibit A-9: Water Rate for Region 3
Source: University of North Dakota

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Appendix B – Employment Projections

Total employment in the petroleum-sector in North Dakota, Montana and South Dakota is expected to continue to increase over the next several years. North Dakota petroleum-sector employment is expected to peak between 2018 and 2024, depending upon the rate of future oilfield development. Montana peak employment occurs a few years later, but exhibits the same characteristics as the employment contraction in North Dakota. Petroleum-sector employment in South Dakota is minor, both in a relative context to oil and gas employment in other regions of the Williston Basin and to overall employment in the region (Exhibits B-1, B-2 and B-3).

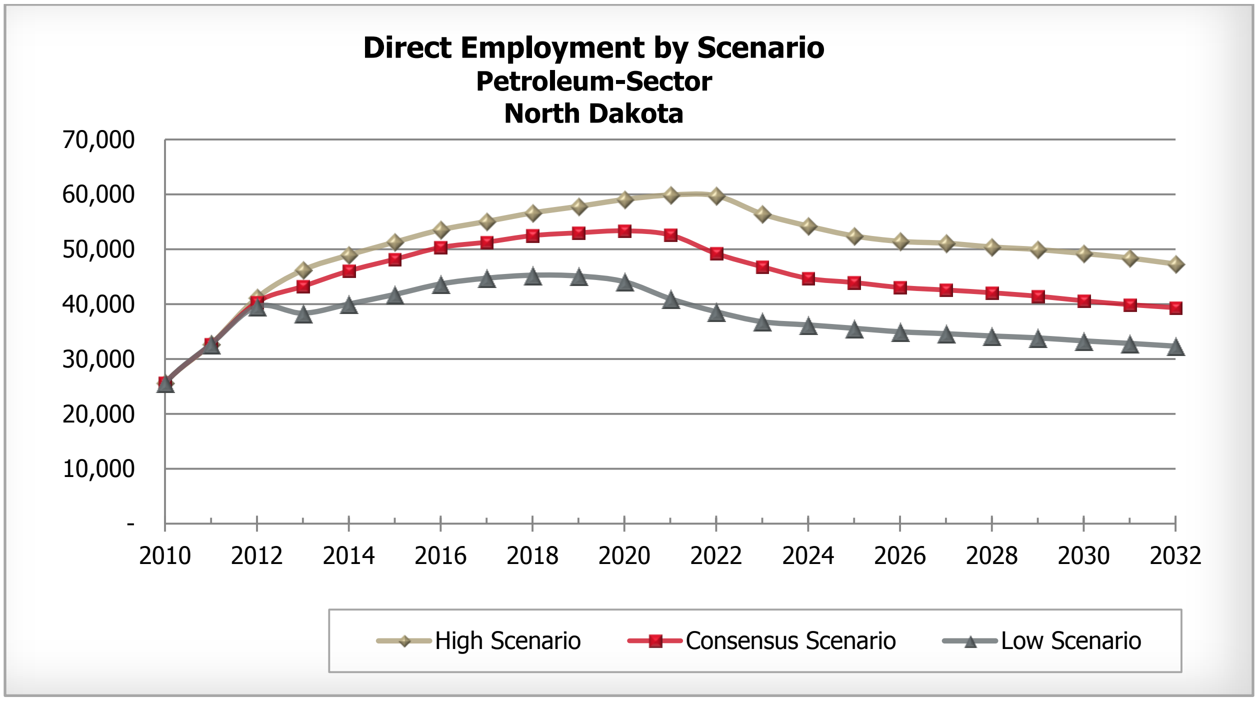

Exhibit B-1: Direct Employment by Scenario - Petroleum-Sector - North Dakota
Source: North Dakota State University

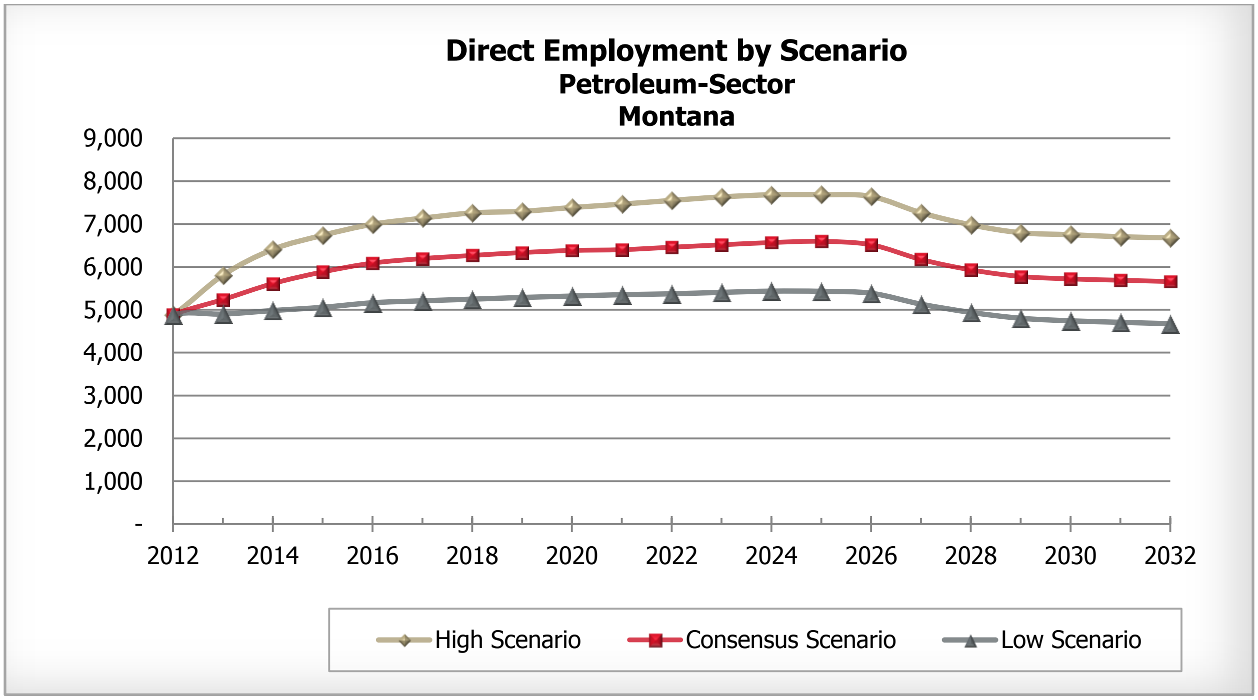

Exhibit B-2: Direct Employment by Scenario - Petroleum-Sector - Montana
Source: North Dakota State University

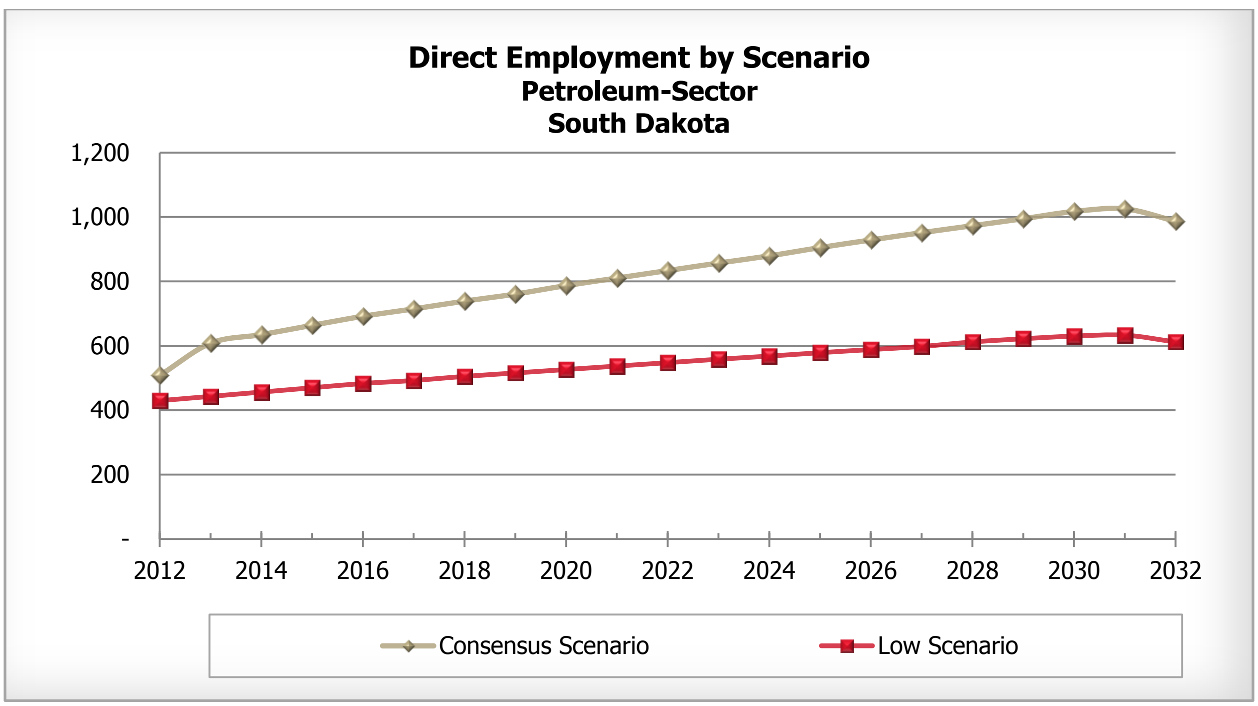

Exhibit B-3: Direct Employment by Scenario - Petroleum-Sector - South Dakota
Source: North Dakota State University

Petroleum-Sector Employment

The petroleum-sector was divided into three primary segments: 1) oilfield development, 2) oilfield service and 3) construction of oilfield gathering systems.

Oilfield development includes well drilling and fracing operations. Oilfield service includes oil well operation and maintenance, infrastructure maintenance, gas processing and oil and gas transportation from production to collection points and transportation of crude oil to in-state and out-of-state destinations. Construction of oilfield gathering systems represents labor to develop pipelines and other infrastructure to collect and distribute oil, gas and water in the oilfields.

The pattern of petroleum-sector employment in South Dakota indicates a slowly growing trend until approximately two-thirds of the way through the planning period of 2012 to 2032, when construction labor is expected to decrease, resulting in a decline in overall employment.

Primary reasons for total employment in the petroleum-sector exhibiting a sustained declining trend after achieving peak employment is related to rig count projections and changes in labor requirements associated with drilling and fracing operations and construction of gathering systems. After removing much of the labor associated with constructing oilfield gathering systems, changes in employment within the industry become largely driven by oilfield service and well development.

The combination of declining rig counts and changes in labor requirements associated with efficiencies in future drilling operations reduces labor at a rate slightly greater than the rate of labor increase in the oil service industry segment. This pattern exists throughout the remainder of the study period and acts to slowly decrease overall employment levels in the industry. Labor efficiencies associated with oilfield service offset some labor gains associated with an increase in well counts; this trend contributes to the slow decline in overall employment. While the oil service industry segment grows employment, the employment does not grow at a rate proportional to the change in well counts.

- *Low scenario*: Even in a situation of gradual decline in drilling activity that would begin in 2012 and continue for the next several decades, current levels of overall employment within the sector are likely to remain elevated for the next five to seven years. After, total employment in the petroleum-sector starts to decline throughout the remainder of the 20-year period.

- *Consensus scenario*: Total petroleum-sector employment continues to grow for another 8 to 10 years, then exhibits a declining trend as the industry pulls back on drilling activity and the industry removes construction employment associated with gathering systems.

- *High scenario*: Overall employment in the petroleum sector continues to increase over the next 8 to 12 years and consistent with observations in the other scenarios, total petroleum-sector employment exhibits a declining trend as the industry eventually scales back drilling activity.

Temporary and Permanent Workforce

Delineation for temporary and permanent workers within the oil and gas industry was created separately for drilling, fracing, gathering systems construction and oilfield service industry segments. A key aspect to understanding future labor characteristics and the implications of a changing labor dynamic within the industry is to identify and quantify the amount of short-term labor and long-term labor requirements within the industry. Workforce characteristics also play an important role in the techniques used to estimate secondary employment, and have substantial implications for projecting short-term and long-term housing needs.

Employment shifts within the industry are present in all scenarios as near-term increases in employment are primarily due to growth in gathering systems employment, steady employment in drilling and fracing operations and slowly accumulating employment in oilfield service (Exhibit B-4, B-5 and B-6). Toward the end of the planning period, employment in the petroleum-sector is largely a function of the number of wells, as employment in drilling and fracing is greatly reduced, and employment in gathering systems construction is mostly removed from the Williston Basin.

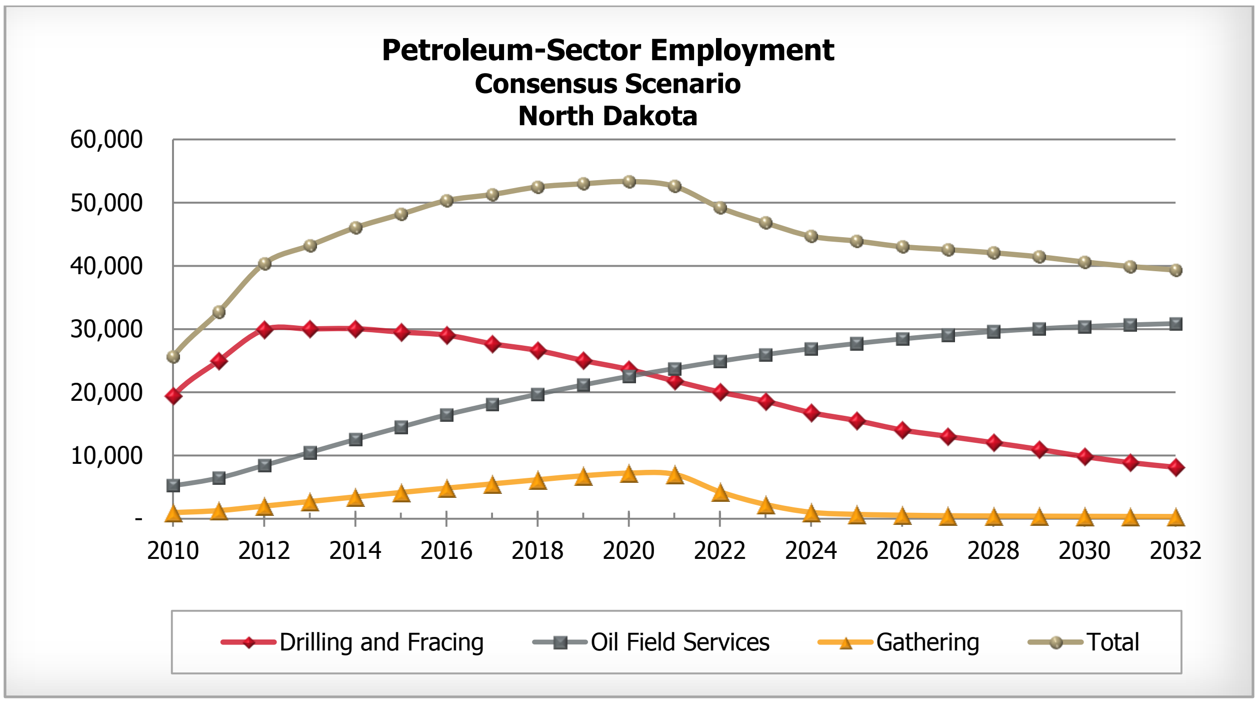

Exhibit B-4: Petroleum-Sector Employment Consensus Scenario North Dakota
Source: North Dakota State University

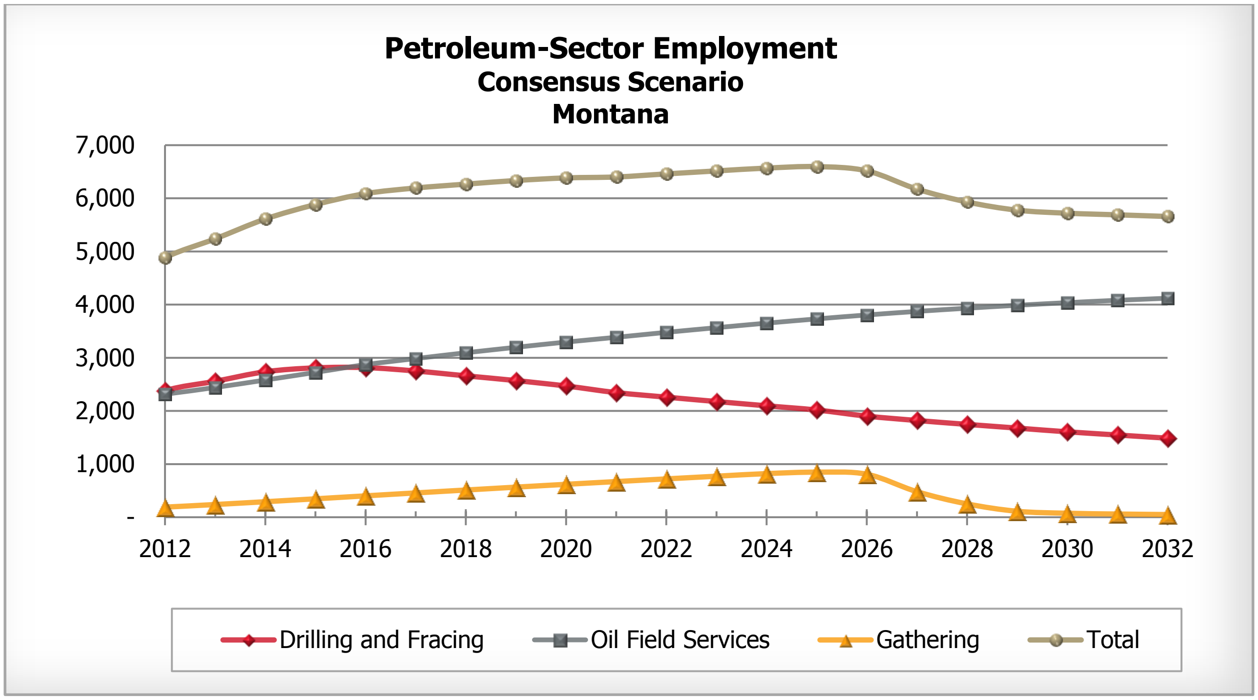

Exhibit B-5: Petroleum-Sector Employment – Consensus Scenario - Montana
Source: North Dakota State University

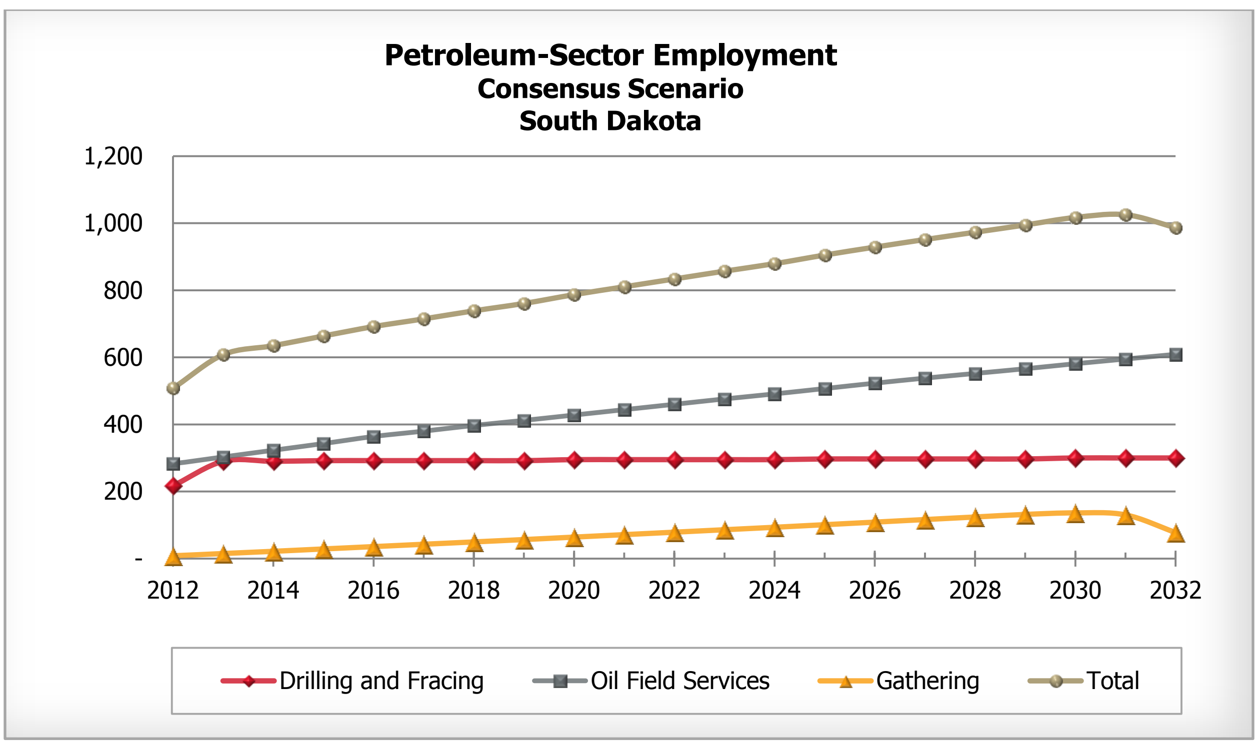

Exhibit B-6: Petroleum-Sector Employment Consensus Scenario South Dakota
Source: North Dakota State University

Two salient observations regarding changes of petroleum-sector employment in the next several decades are observed in this assessment:

1. Across all scenarios petroleum-sector employment peaks and then declines
2. The composition of the workforce in the petroleum sector is expected to be much different in the next 20 to 30 years

Although future wells are expected to require less labor to maintain and service than current requirements, the main industry driver in 10 to 20 years will be the number of wells and associated activities, such as pipelines and processing plants. Future expectations for well numbers in the Williston Basin in all scenarios are considerably higher than current well counts.

Estimates suggest temporary jobs within the industry will be around 60 percent of the total workforce in North Dakota, 20 percent in Montana and 35 percent in South Dakota. Percentages will vary according to expectations on the rate and extent of future oilfield development. Across all scenarios, temporary workforce peaks about the same time as overall peaks in oil and gas employment and then temporary workforce rapidly declines throughout the remainder of the planning period. While the temporary workforce is decreasing, permanent employment, including oilfield service employment, will grow. As oilfield service employment grows, so do demands for permanent housing and commercial activity. Therefore, current employment in the petroleum-sector is dominated by a temporary workforce, but as future employment increases and decreases over the next 20 to 30 years, employment in the industry will transition to that associated with permanent employment (Exhibit B-7, B-8 and B-9).

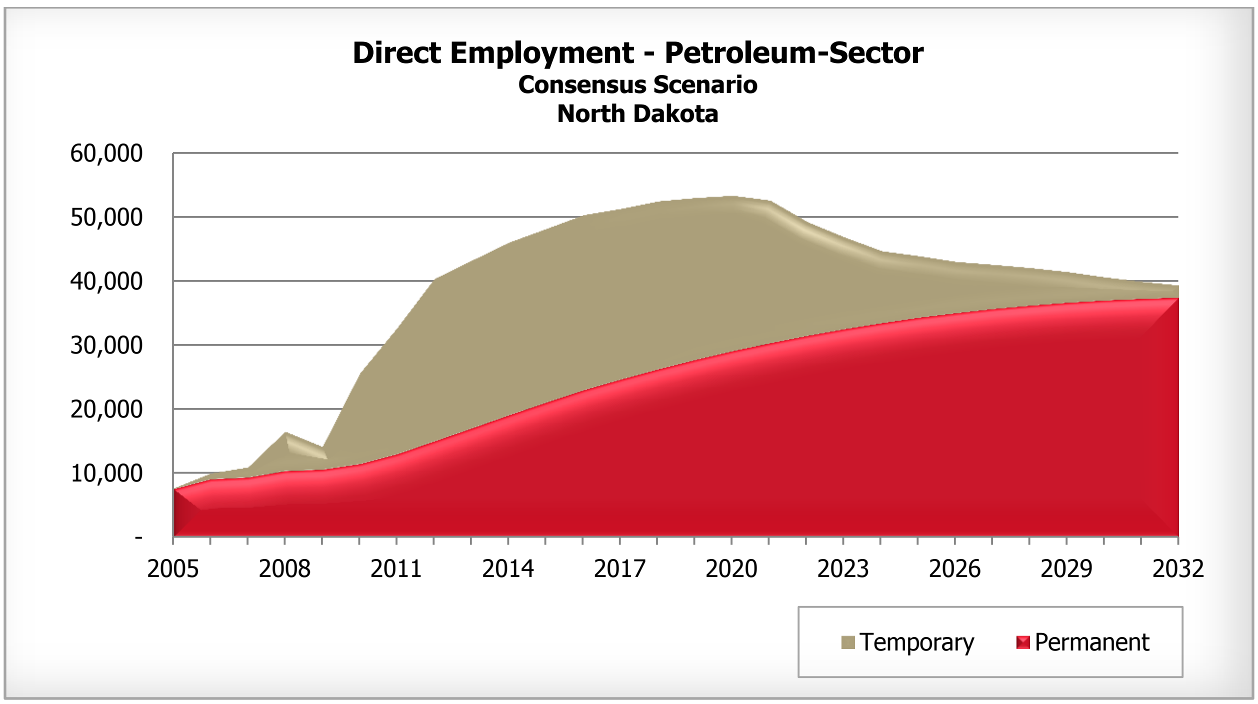

Exhibit B-7: Direct Employment - Petroleum-Sector - Consensus Scenario - North Dakota
Source: North Dakota State University

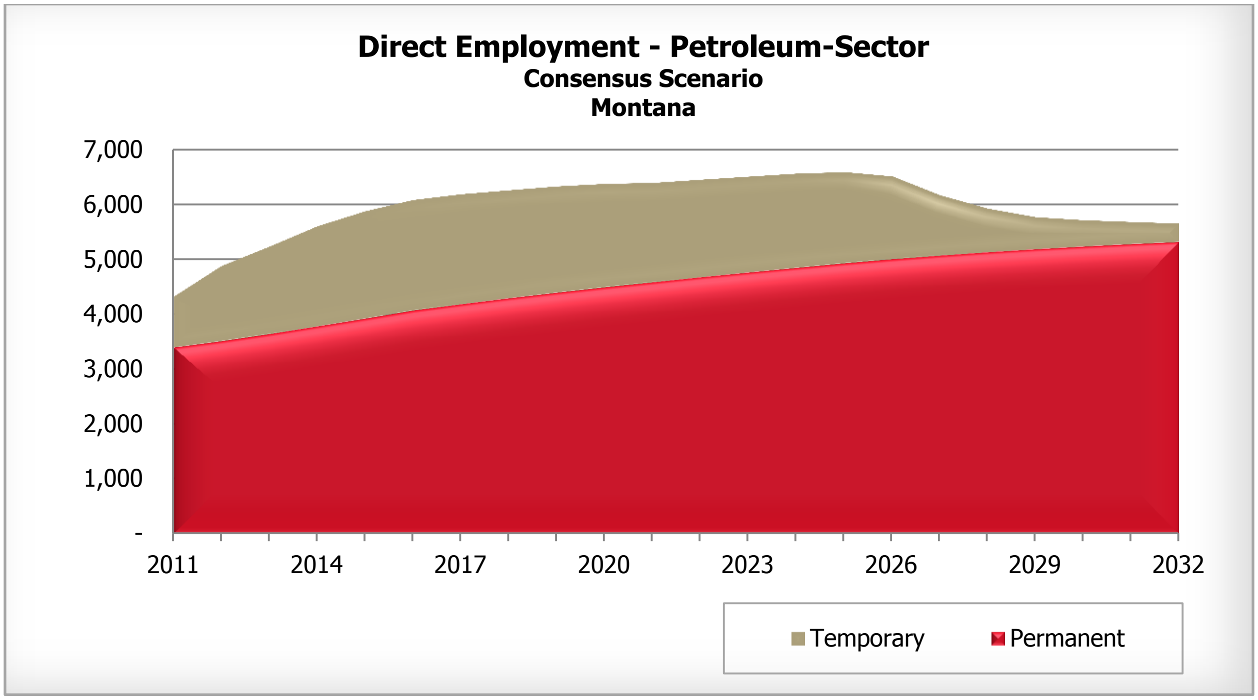

Exhibit B-8: Direct Employment - Petroleum-Sector - Consensus Scenario - Montana
Source: North Dakota State University

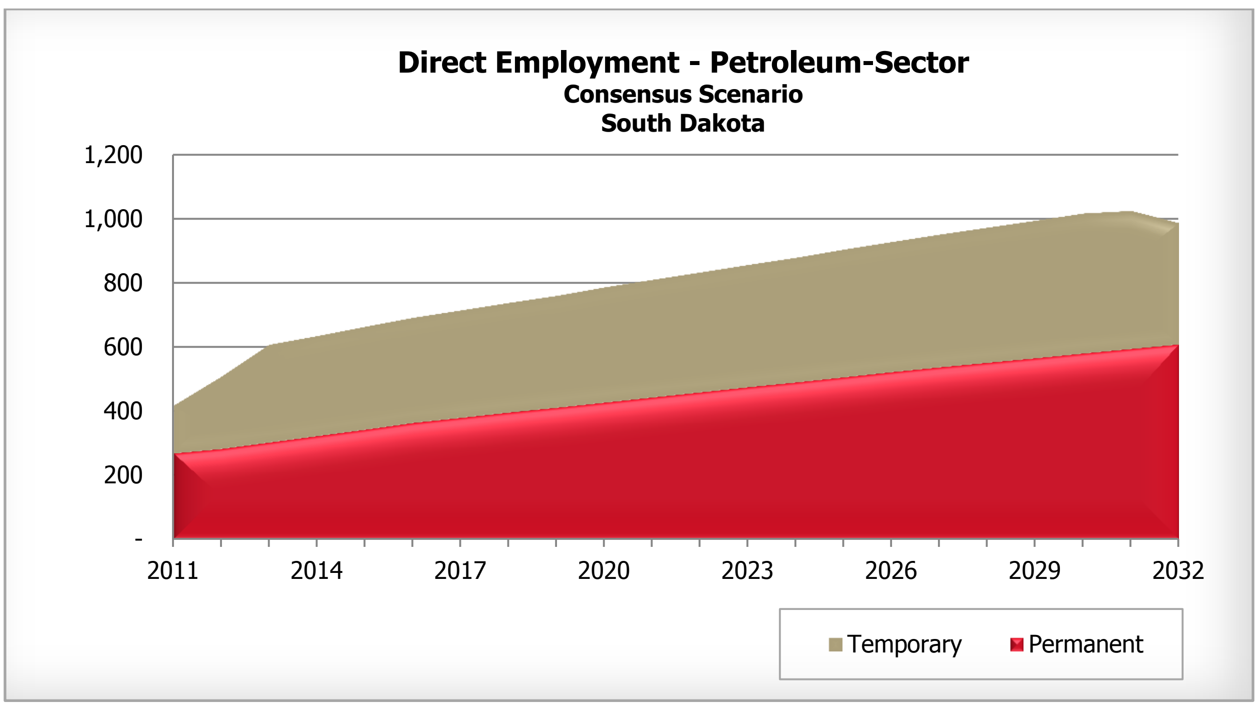

Exhibit B-9: Direct Employment - Petroleum-Sector - Consensus Scenario - South Dakota
Source: North Dakota State University

Regional Employment

Total future employment in the Williston Basin includes both permanent and temporary employment, and is a function of change in base employment and change in direct and secondary employment associated with the petroleum-sector. Employment constraints (such as housing, wages and labor force availability) are included in estimates of base employment, petroleum-sector direct employment and secondary employment.

Total employment in the Williston Basin, among the three states in this study, continues to increase in the near-term (Exhibit B-10, B-11 and B-12) due largely to expansion of petroleum-sector employment. Total regional employment is expected to decline at the point corresponding to peak petroleum-sector employment. This is largely due to anticipated rapid reductions in construction employment upon completion of oilfield-gathering systems. However, several factors are expected to contribute to a stabilization and subsequent modest growth of overall regional employment in later stages of the planning period.

The sharp and pronounced employment contraction in the petroleum-sector is largely expected to be associated with temporary construction employment. Removal of a large portion of temporary workforce reduces constraints on housing. Simultaneously, permanent workforce continues to grow, enhancing demand for long-term delivery of services and commercial activity.

Over the same period, reductions in housing constraints are expected as communities and trade centers have sufficient time to coordinate construction of long-term housing allowing the economy in the Williston Basin to begin addressing labor needs for service and commercial operations. Further, with a growing labor force and reductions in housing constraints, constraints on growth in base employment (all other industries) are expected to moderate slightly. These dynamic elements of regional employment combine for a long-term employment stabilization in the Williston Basin after an expected contraction in petroleum-sector employment. The following charts utilize a planning region where possible, such as State Planning Region 1, 2 and 8, as utilized by the North Dakota Department of Commerce (Exhibit B-10). These North Dakota planning regions are separate from the PF 12 study regions; however, they help determine population and housing impact.

Despite overall employment in the Williston Basin stabilizing after the contraction in petroleum-sector employment, the consequences and effects of the petroleum-sector employment change are not equally shared in all regions of the study area.

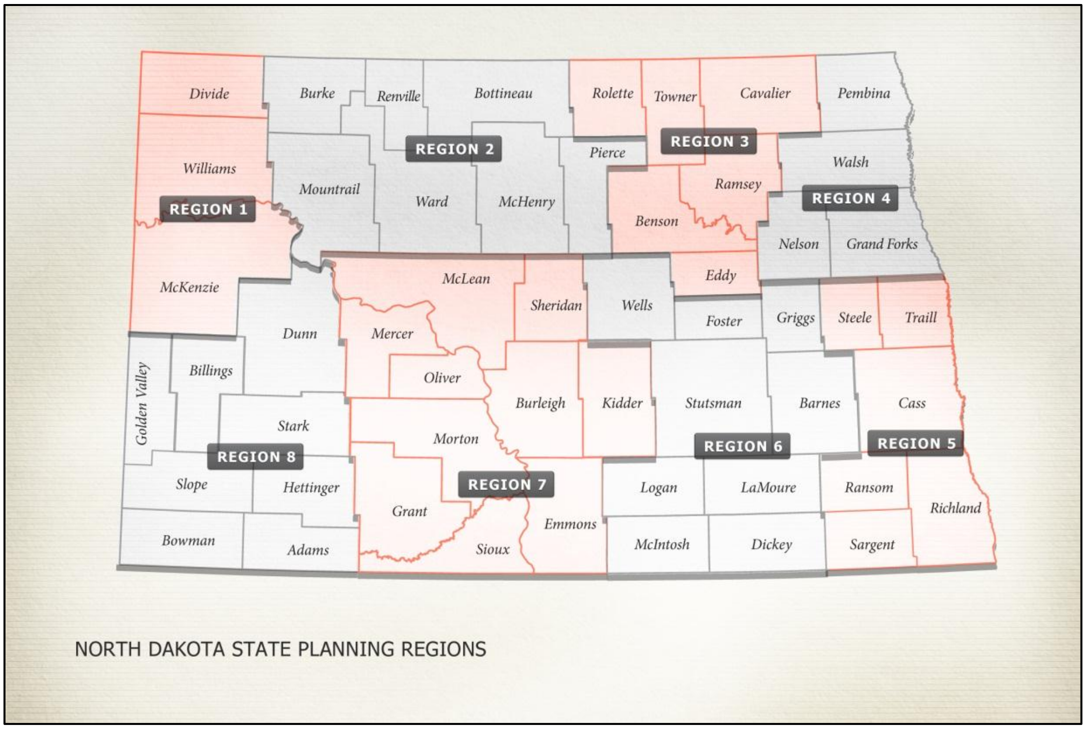

Exhibit B-10: North Dakota State Planning Regions
Source: North Dakota Department of Commerce Website

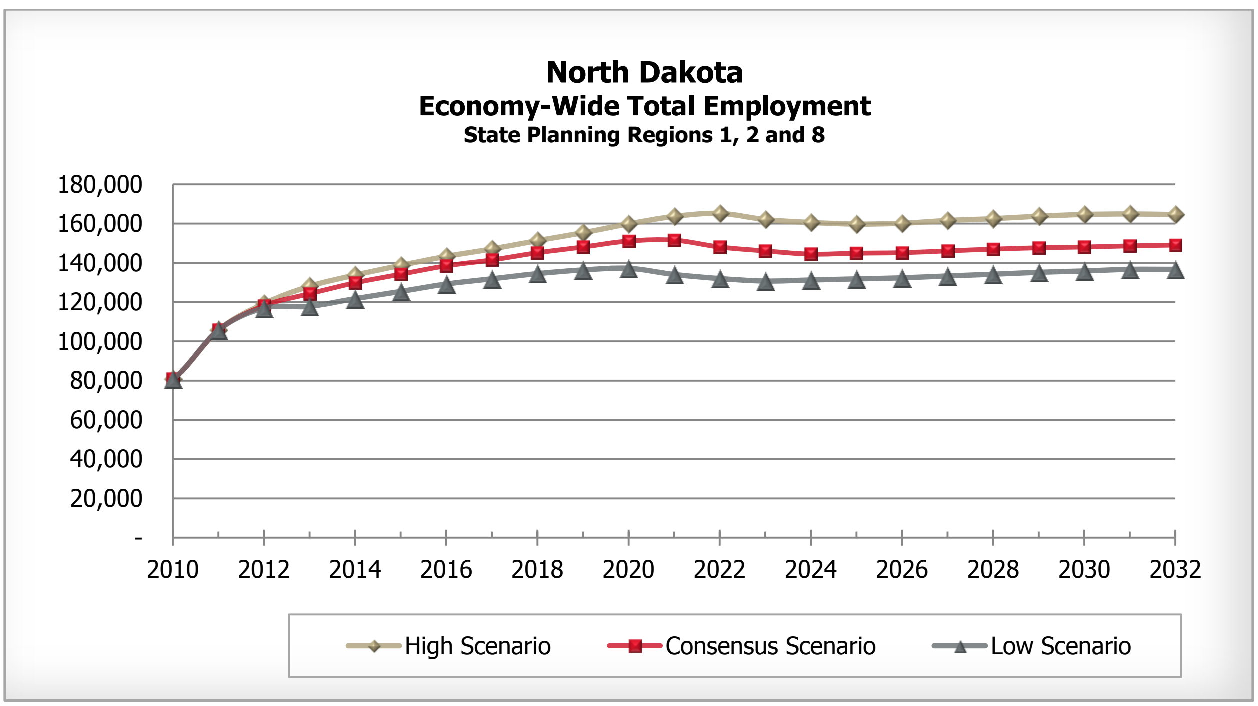

Exhibit B-11: North Dakota Economy Wide Total Employment - State Planning Regions 1, 2 and 8
Source: North Dakota State University

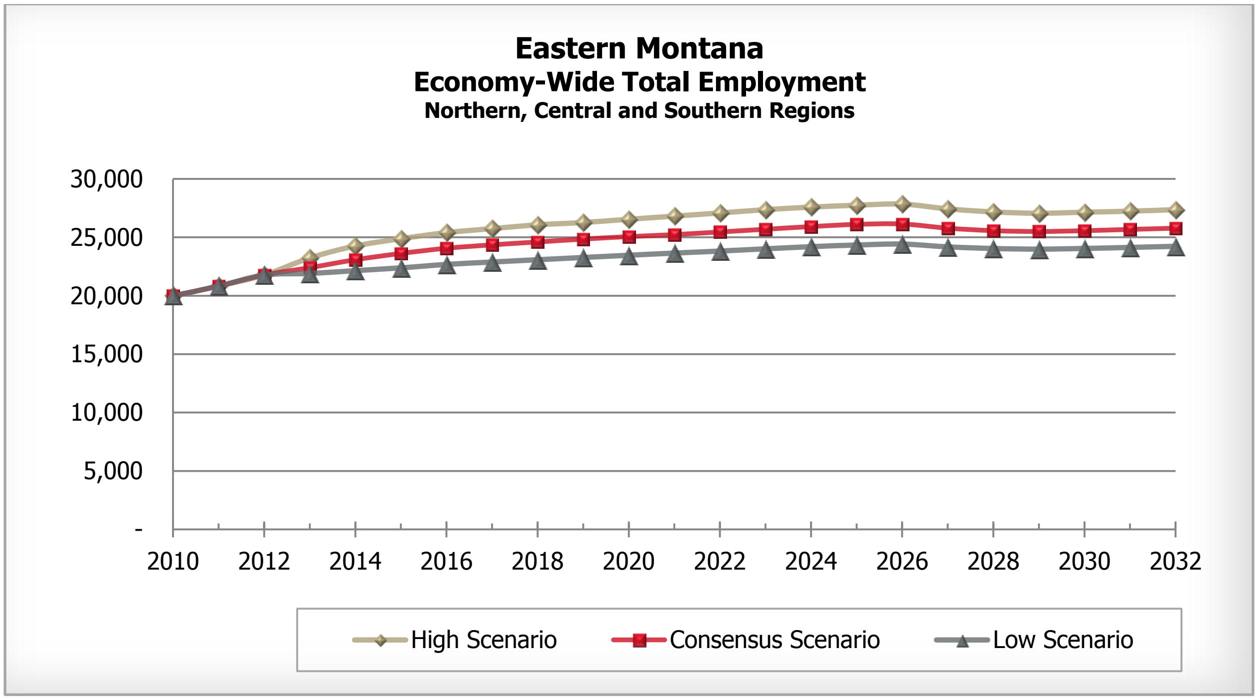

Exhibit B-12: Eastern Montana Economy Wide Total Employment - Northern, Central and Southern Regions
Source: North Dakota State University

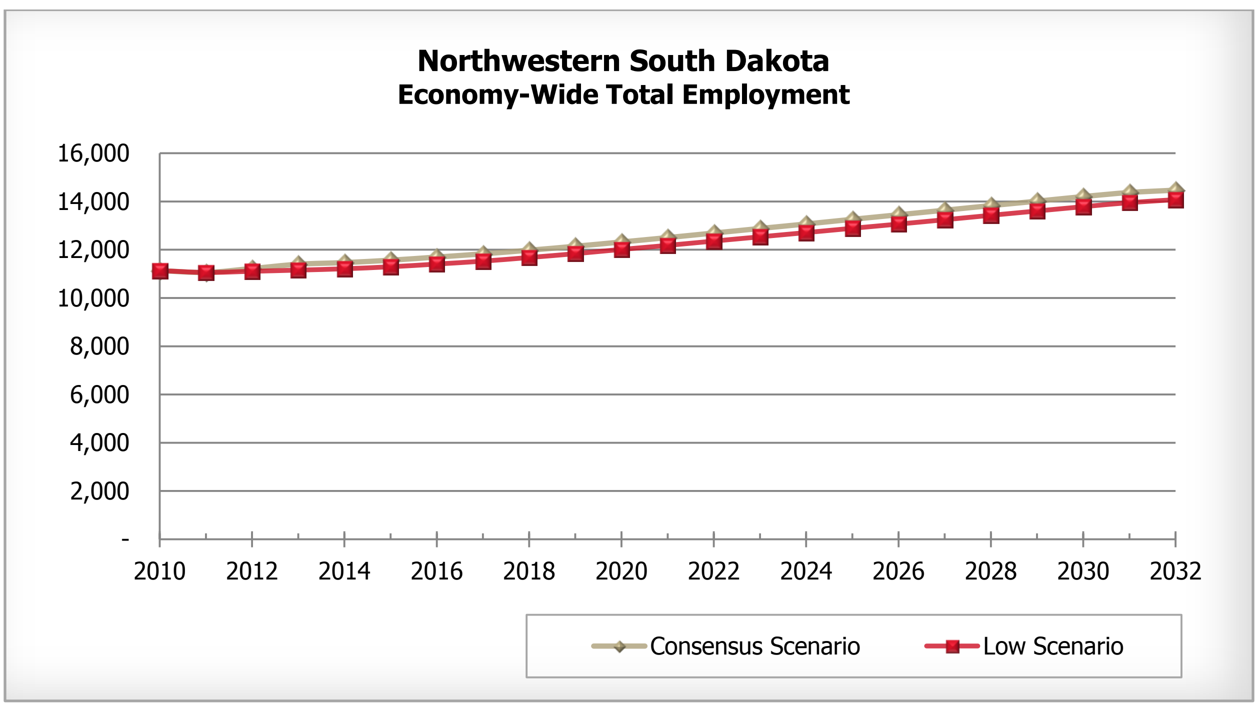

Exhibit B-13: Northwestern South Dakota Economy-Wide Total Employment
Source: North Dakota State University

Williston Region – State Planning Region 1

The Williston region is the most influenced of the North Dakota regions by changes in current and expected employment in the Williston Basin (Exhibit B-14). The regional economy is extremely sensitive to changes in petroleum-sector employment, as the industry comprises a considerable share of total employment in the region. Further, the pace of change in total employment in the region has overwhelmed local resources, further straining the regional economy in its ability to add commercial and service employment. Recent growth in total employment in the region has been entirely driven by changes in petroleum-sector employment in the last four to six years. Going forward, expansions or contractions in employment will have immediate effects in the region as base industries appear to be stagnant.

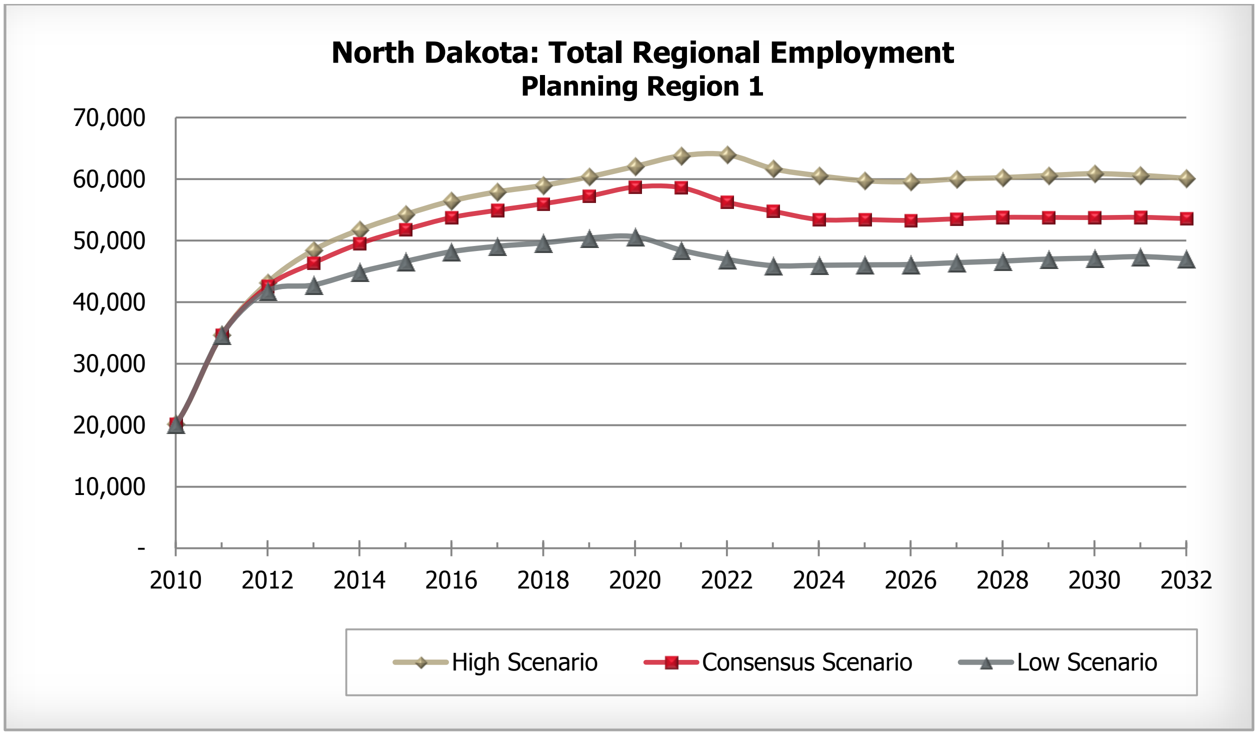

Exhibit B-14: North Dakota: Total Region Employment - Planning Region 1
Source: North Dakota State University

Minot Region – State Planning Region 2

The robust Minot regional economy would be perhaps the least impacted of all North Dakota regions from substantial changes in petroleum-sector employment (Exhibit B-15). While petroleum-sector employment represents a growing proportion of regional employment in the Minot area, it is expected to remain a minor component of the overall economy in the future. Changes in employment in base industries in the Minot region show growth without influence of recent petroleum-sector expansion.

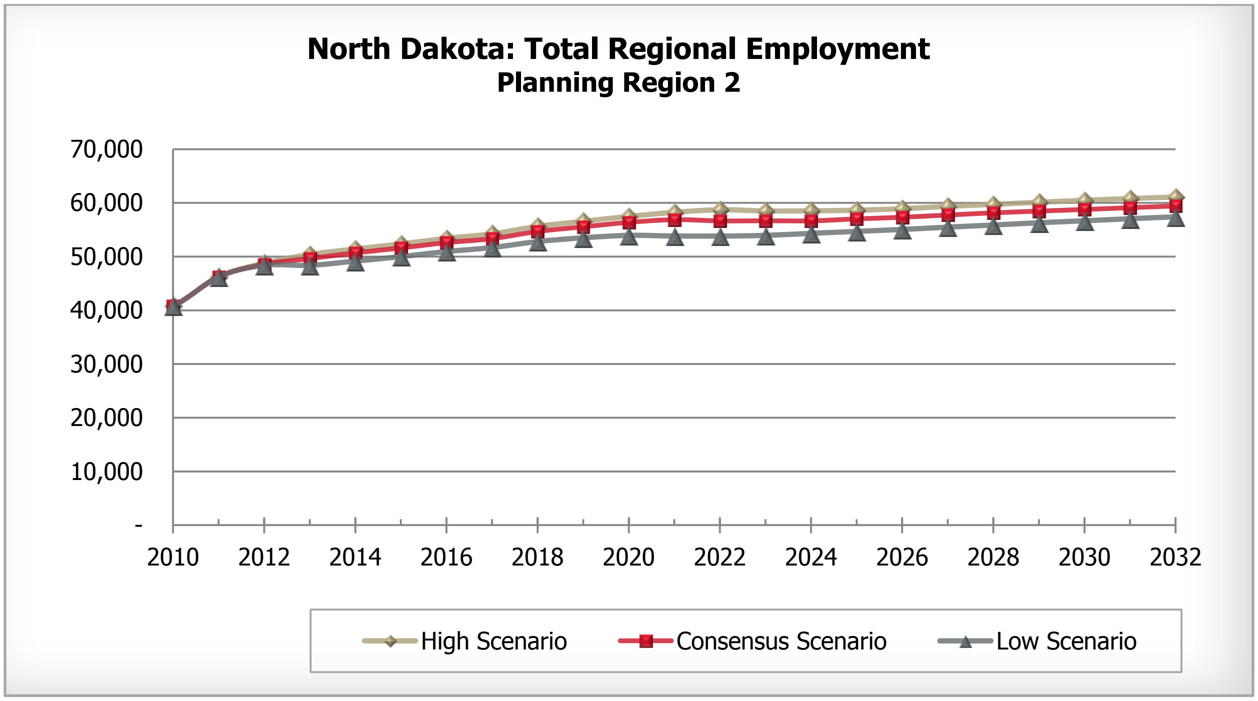

Exhibit B-15: North Dakota: Total Region Employment - Planning Region 2
Source: North Dakota State University

Dickinson Region – State Planning Region 8

Future effects of petroleum-sector employment in the Dickinson region could range from severe to moderate, depending upon the level of future development in the Tyler Formation. Unlike development of the Bakken Formation, which has had the greatest impact in the Williston area, employment and other impacts of an expansion into the Tyler Formation would disproportionately occur in the Dickinson area. It is expected that continued development in the Three Forks Formation will remain a major factor impacting the Dickinson area economy.

Overall, current effects of petroleum-sector expansion in Dickinson are less than those experienced in the Williston area, but possibly greater than relative impacts in the Minot area. Prior to the current oil boom, the Dickinson regional economy had continued and sustained economic growth. However, future employment in the region is likely to be sensitive to changes in base employment and changes in petroleum-sector employment (Exhibit B-16).

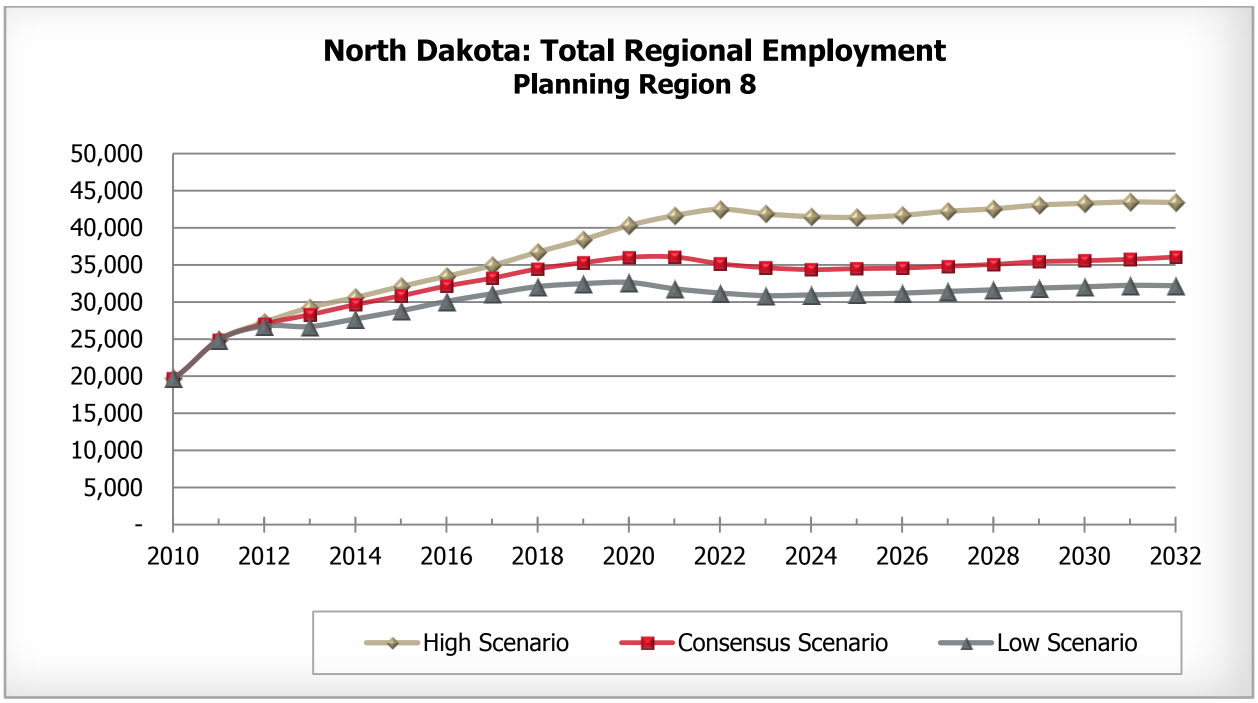

Exhibit B-16: North Dakota: Total Region Employment - Planning Region 8
Source: North Dakota State University

Northern Montana – Study Region 1

The northern tier counties in Montana have limited amounts of petroleum-sector employment and are not expected to heavily impact the future economy. Current estimates suggest, of the three study regions, the northern Montana region has the least likelihood of substantially impacting future petroleum-sector activities (Exhibit B-17).

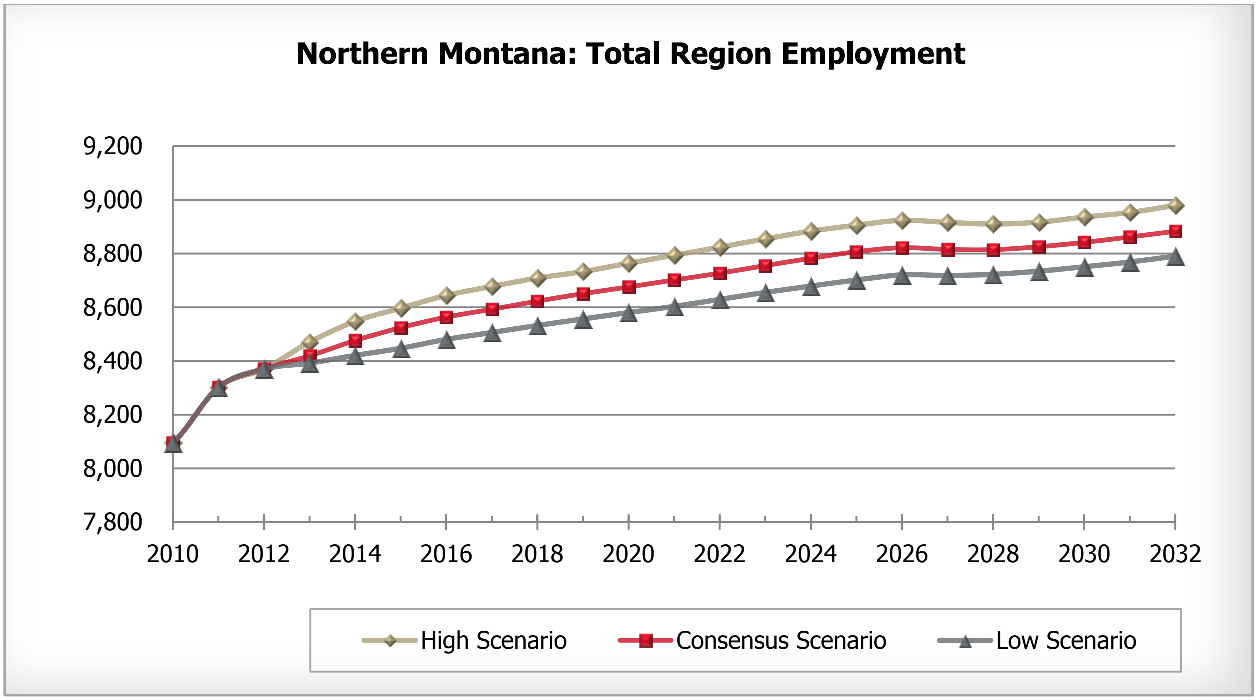

Exhibit B-17: Northern Montana: Total Region Employment
Source: North Dakota State University

Central Montana – Study Region 2

The central tier counties in Montana have the greatest amount of petroleum-sector employment of the three Montana regions (Exhibit B-18). However, base industries in the region have shown growth in employment outside of the petroleum-sector. Future petroleum activities are expected to be greatest in this Montana region, but not at a level that would curtail or eliminate long-term economic regional growth.

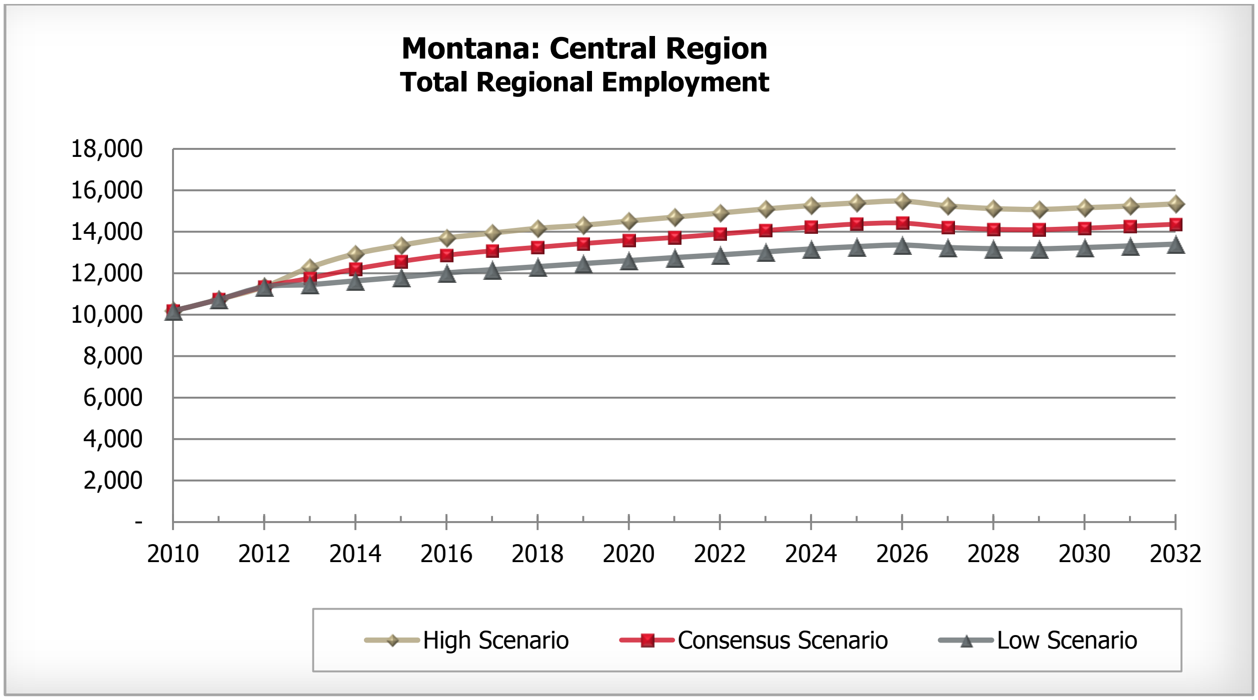

Exhibit B-18: Montana: Central Region Total Regional Employment
Source: North Dakota State University

Southern Montana – Study Region 3

This two-county region has a stagnant economy when removed from the influences of the petroleum-sector (Exhibit B-19). With low levels of total employment and swings in petroleum-sector employment, this would have substantial effects on the few trade centers in the region. However, future petroleum-sector employment is expected to fall within the range that has historically been observed in the region. Petroleum-sector activities will continue to play a large role in that region and should act to stabilize long-term regional employment.

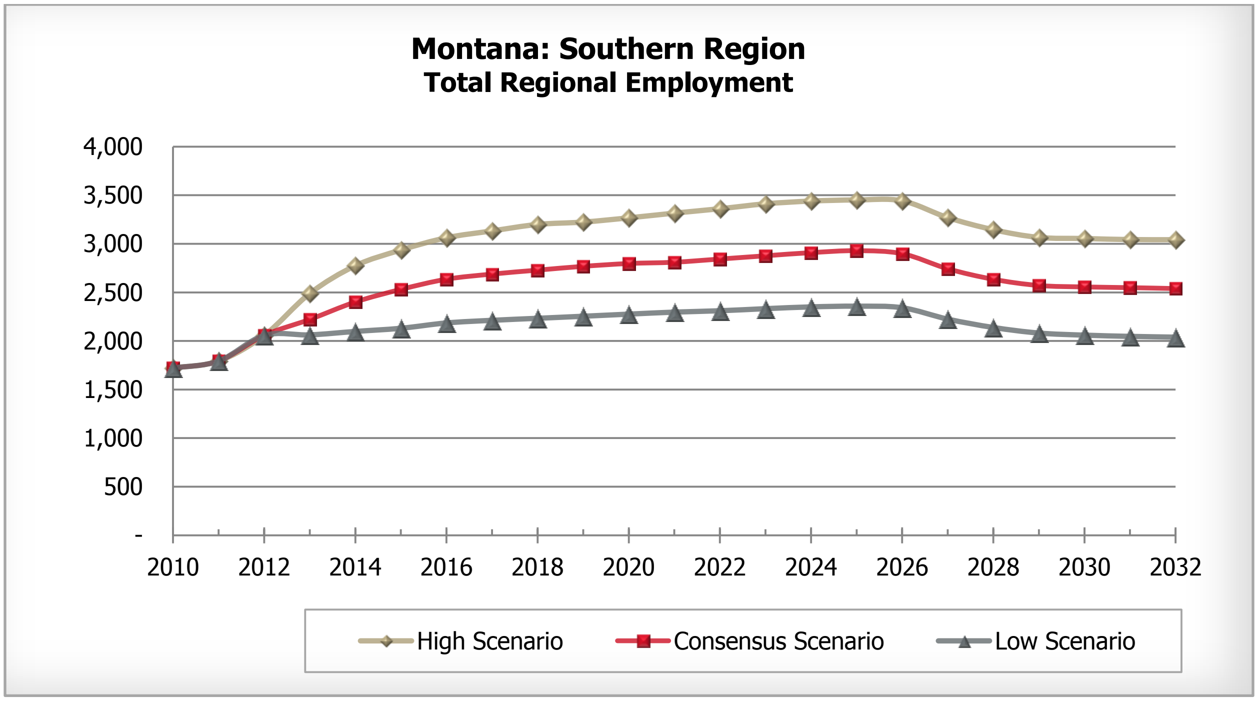

Exhibit B-19: Montana: Southern Region Total Regional Employment
Source: North Dakota State University

South Dakota

Petroleum-sector effects in this region are minimal, and the petroleum-sector is expected to remain a minor overall component of the regional economy in the future (Exhibit B-20). Employment data indicates the four-county region is heavily influenced by activities in Meade County, and is influenced substantially by the Black Hills economy. An expansion of petroleum-sector activities will potentially present problems in the northern portions of the region as few trade centers and little infrastructure exist in those counties. Substantial changes in petroleum-sector activities for the region are not expected in any of the scenarios examined in the study.

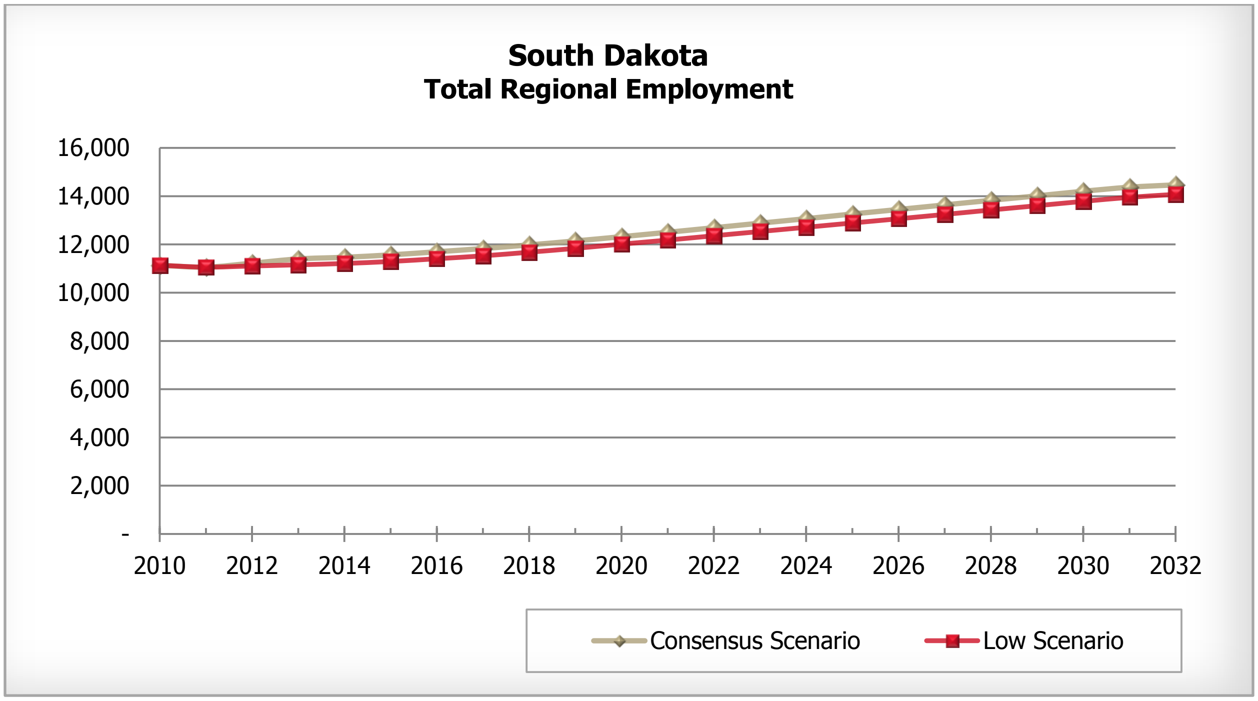

Exhibit B-20: South Dakota: Total Region Employment
Source: North Dakota State University

Additional Employment Observations

Additional observations regarding employment include:

- Looking beyond current development, long-term employment will remain high and be tied closely to labor needs associated with servicing the Williston Basin.
- Illustrations in this assessment display employment in the petroleum-sector 20 years from now remains at elevated levels compared to employment prior to development of the Bakken/Three Forks formations. Depending upon the number of wells the industry creates in the Williston Basin, employment 20 to 30 years from now is either above, equal to or only slightly below current levels. Regardless of the exact path forward in the Williston Basin, elevated levels of employment in the industry will remain for several decades.
- Influences of current and future petroleum-sector employment differ within regional economies in the Williston Basin. Considerable regional variation exists within this study area with respect to the overall economic health and relative influence of petroleum-sector employment. Due to the relative differences in the effects of petroleum-sector employment in the Williston Basin, expected changes in base industries and secondary job creation also vary within the region.
- Build-out scenarios for oil and gas development largely set the level of employment in the various study regions. While subtle differences exist in the assumptions on secondary job growth and constrictions on changes in base employment, those factors were determined to not be sufficiently different among the scenarios to alter trends in regional employment. Total employment over time was shown to be largely similar across all scenarios. The result is due to shifts in employment within the petroleum industry creating a peak and subsequent decline, with the shape also linked to the fundamental economic factors affecting various regional economies. These include constraints on secondary job creation and expectations for change in employment in other industries.

Appendix C - Reference Summaries

Maugeri June 2012 Harvard Report

Oil: The Next Revolution, a discussion paper authored by Leonardo Maugeri for the Belfer Center for Science and International Affairs, Harvard Kennedy School, was released June 2012. Maugeri reports on a variety of topics, including historical context, with forecasts to 2020 using several assumptions and concepts to present ideas.

U.S. oil output is one of the largest factors driving increased global oil supply capacity as recent advancements, namely horizontal drilling and hydraulic fracturing, have reduced the cost to recover oil from shale and tight oilfields. These technologies could revolutionize unconventional oil recovery across the world. Nationally, more than 20 massive shale and tight oil formations exist that are virtually untouched. The formations are in various stages of development, but production could reach 6.6 million barrels per day by 2020. Given nearly 65 percent of all drilling rigs are located in North America and new production capacity of these shale formations, total U.S. production could exceed Saudi Arabia production by 2020. The majority of this production is profitable at $50-65 per barrel (WTI pricing).

U.S. capacity faces several obstacles as oil capacity increases; these obstacles could reduce production by up to 50 percent. Transportation constraints have created three disconnected markets within the U.S. as the east and west markets lack adequate connections with the mid-continent/gulf market. With growing demand on the Cushing, OK facility and its pipeline infrastructure, many suppliers are being forced to use rail and trucks to move product. Three major pipeline projects are scheduled for completion in 2015, but even more capacity is needed to meet growing demand. Due to historic import trends, refineries along the Gulf Coast have heavily invested in processing heavier sour crude oil. The majority of shale oil production is light and sweet, which requires a major investment to properly refine these products. Environmental concerns include methane leakage into water, wastewater and chemical usage concerns and potential earthquakes.

The Bakken tight oil formation is a key to continued growth in oil capacity. It has 500 billion barrels of oil in place, with as much as 206 billion recoverable barrels. The addition of the Three Forks Formation could double these estimates and even these numbers could be underestimated. Initially, the costs involved with the Bakken play will be higher as the support infrastructure is still being developed. Another vital shale formation, the Eagle Ford Shale, has more drilling rigs than the Bakken and is located in the Western Texas Basin. Both formations are profitable at $50-65 per barrel (WTI pricing).

Globally, oil is not in short supply and continued investments will result in improved oil production by 2020. Average recovery rates will improve as shale production techniques begin to impact other regions. Currently, recovery rates range from 20 percent (among less developed nations) to 45 percent (within the U.S., Canada, Norway and the United Kingdom) but the probable recovery rate from the Bakken Formation is 50 percent. The world consumed 32 billion barrels of oil in 2011 and estimated remaining oil resources could be as high as 17 trillion barrels.

Market instability will make the oil market highly volatile until 2015. Several countries, including Iran, Iraq, China, Canada and the U.S., are keys to the future of the global oil market. As the tight and shale oil formations develop, the Western Hemisphere will become the center of oil exploration and production.

Raymond James Article (July 12, 2012)

In an article dated July 12, 2012, Raymond James and Associates (RJA) altered their 2013 forecasts. Their 2013 projections for WTI decreased from $83 to $65 and from $95 to $80 for Brent Crude Oil. The $15 Brent premium is a result of transportation constraints. RJA also corrected their 10-year WTI forecast from $90 to $80/bbl; Brent 10-year forecasts remain at $95/bbl. Global oil prices have begun reflecting these changes as prices have corrected to $20/bbl. The correction is the result of the European debt crisis, Iranian relations and recent negative economic data from the U.S. and China.

The adjusted forecast projections are the result of several changing factors within the market. The movement of rigs to higher production areas was more rapid than RJA projected and new rig additions have doubled estimates. For example, the Eagle Ford Formation rig count increased 227 percent from 4Q10 to 4Q11. Reported oil supply has also been six percent above projections as Eagle Ford, Williston and Permian Other production out-produced estimates. Combined, these three formations produced 115 Mbopd more than RJA projections. Due to the increased production, coupled with transportation constraints, a lag in supply hitting the market will result in a severe over-supply in the near future. RJA expects prices to stabilize at $65/bbl in 2013.

U.S. production projections include a 13 percent decline in onshore rig growth in 2013. Drilling will also slow in 2013 as WTI prices fall another $20/bbl over the next 18 months. RJA also believes rig counts will decrease by at least 10 percent, up to 700 rigs, as the WTI excess supply saturates the market. It should be noted that producers are often reluctant to drop rig counts, so rig count decreases could be lower than expected.

Natural Gas Liquids (NGL) account for 25 percent of total U.S. oil-related production and 20 percent of projected growth. RJA estimates for NGL include $0.64/gal in 2Q13 before rebounding in 2014 to $0.80/gal and $0.88/gal in 2015. With the shift to preference for heavier liquids, 75 percent of NGL value is tied to heavier liquids. NGL to crude oil pricing ratios have been deteriorating, which is expected to continue for several years.

Bentek Energy Report for NDPA (July 2012)

Bentek Energy released *The Williston Basin: Greasing the Gears for Growth in North Dakota* for the North Dakota Pipeline Authority in July 2012. The report provides an overview of the natural gas and oil markets within the Williston Basin and provides regional context supporting their report. Markets, production, transportation, competition, pipelines and short-term forecasts are covered within the report.

The natural gas market has seen dramatic changes in recent years as exploration and production have driven rapid growth. New technologies, such as pad drilling and hydraulic fracturing, and improved efficiencies have resulted in a 35 percent increase in production from 2005 to 2012. This sharp production increase has resulted in the creation of several new pipelines, weaker gas prices and a shift toward oil and liquid rich wells over dry natural gas production. Prices at Henry Hub have fallen 70 percent from 2008 to 2012 as supply has outpaced demand. With decreasing prices and a larger pipeline network linking regions, the price spread nationally is decreasing – allowing supply basins to compete in new markets. While many producers are shifting toward NGL/crude oil wells, production has not declined. Dry production has decreased, some are seeing negative rates of returns, but the increase in NGL production will result in 22 percent expected growth by 2017.

The demand for natural gas has increased 12 percent from 2005 to 2011 with 16 percent forecasted growth by 2017. Residential and commercial demands, at 52 percent in 2011, are the largest demand sector. This is expected to continue even as demand per customer decreases due to efficiency gains. In 2011, the industrial sector accounted for 35 percent of demand and is expected to grow 1.2 percent per year long-term. Power demands over time will continue to increase as natural gas supplants coal. Projected power growth is 0.8 percent overall while natural gas power growth will be 2.4 percent. Domestic supply will largely meet these demands as Canadian imports have declined 40 percent since 2007 and this trend is expected to continue due to transportation costs.

The oil market experienced gains for the last five years; largely driven by the shale and tight formations that are being developed regionally. As a result of these gains, massive infrastructure development is occurring to ensure product can be brought to market. However, the spread between WTI and Brent pricing is expected to suffer a volatile period and could reach $20 by 2017.

The Williston Basin contains the Bakken and Three Forks Formations and is expected to account for 18 percent of total U.S. production by 2017. Since 2005, oil production has increased more than 400 percent with gas production climbing 250 percent. The formations produce roughly 87 percent oil, 7 percent NGL and 6 percent natural gas with nearly 90 percent of total production occurring in North Dakota. Growth is expected to continue even if prices fall to $50/bbl (WTI) by 2025. Estimates indicate that as much as four billion barrels of oil are recoverable along with 1.85 Tcf of natural gas and 148 MMbbl NGL. The Bakken Formation is among the most attractive rate of returns across the country. The formation has exceptional production to offset the higher costs of setup, is insensitive to NGL price changes and has significant oil and higher BTU gas capacity.

Infrastructure within the region is largely viewed as inadequate as both major oil pipelines in the region are near capacity and natural gas has three main pipelines that cannot keep pace with demand. In addition to these five pipelines, North Dakota has 15 rail loading stations that transport oil and heavy usage of trucks to transport product. Regionally, the Tesoro Mandan refinery is being fully utilized at 58 Mb/d. Several major developments are in various stages of planning that will help reduce strain on the current structure. Four refinery expansions, six major oil pipelines, three natural gas and NGL pipelines, four gas processing plants and nine rail expansions are all in development but capacity is still expected to be a constraint on production.

Oil from these formations will continue to sell at an $11-20 discount to WTI due to transportation costs and distances. Williston Basin natural gas traditionally correlated closely to the Rockies pricing, but as pipeline flow has changed, Alberta pricing now has a stronger correlation. Within the region, Empress gas is the closest market price and as Canadian pricing improves the Bakken market will see improvements. Williston Basin natural gas has no daily spot price points on the Intercontinental Exchange or Platts Gas Daily.

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Appendix D - References

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Appendix E - Public Policy and Legislation Summaries

Public Policy and Legislation Summaries – Federal	
Name	**Summary**
Oil Recovery Credit	Provides requirements to claim tax credits related to oil recovery.
Marginal Wells Credit	Provides requirements to claim tax credits related to oil recovery.
Tertiary Injectant	Outlines and details requirements needed to claim tax deductions for injectants.
Manufacturing Deduction	Provides tax deduction requirements and eligibility for manufacturing deductions, also outlines special rules that may apply.
Accelerated Deduction	Provides rules and guidelines to claim alternative tax deduction rules.
Percentage Depletion	Provides rules and guidelines to claim alternative tax deduction rules.
Passive Loss Exemption	Provides requirements to claim passive loss exemptions, including conditions it may be claimed.
Amortization for Pollution Control	Provides rules for claiming itemized deductions regarding pollution control facilities.
Environmental Remediation Expense Deduction	Regarding taxation, provides rules allowing itemized deductions regarding environmental remediation.
Intangible Drilling Oil and Gas Deduction	Regarding taxation, provides rules allowing deductions and exemptions to the deduction.
Dual Tax Payer Deduction	Relates to taxation involving foreign countries.
First In First Out Accounting Rule	Provides full list of requirements associated with FIFO accounting.
Natural Gas Gathering Lines, 15 Year Depreciation	Provides rules for accelerated cost recovery involving taxation, includes details regarding methods allowed and periods covered.
Seven Year Amortization	Provides rules regarding itemized deductions and usage of seven year amortization.
Fuel Credit for Natural Gas	Allows taxation credits and outlines rules needed to claim.
Oil and Gas Arbitrage Bonds	Provides requirements that apply to all state and local bonds.
Marginal Well Credit Carryback	List requirements related to unused credits, provides time frames for their usage and limitations.

Public Policy and Legislation Summaries – Federal (Pending)	
Name	**Summary**
Oil Spill Liability	The bill may create a tax on oil to help recover a portion of possible oil spills and establish rates.
Hydraulic Fracturing	The bill may include legislation and regulations from the EPA and other sources and could directly impact fracing abilities.

Public Policy and Legislation Summaries – North Dakota	
Name	**Summary**
Oil Extraction Tax	Provides additional taxation related topics for extraction of oil, also details exemptions granted until June 20, 2013.
Oil and Gas Production Tax	Establishes taxation type for oil and gas, provides valuation guidelines and exceptions allowed.
Exploration Funds	Outlines uses of fund and applicable deposits into the fund, provides for uses and maximum amount of fund.
Damage Compensation	Outlines protection from undesirable effects of mineral development, sets maximum payments allowed and additional responsibilities for mineral developers.
Geophysical Exploration	Outlines permit process and penalties connected with exploration.
Oil and Gas Resource Control	Outlines full jurisdiction, funds, rights and costs associated with oil and gas resources and allows hydraulic fracturing.
Load and Mining Claims	Provides maximum limitations on load claims, gives direction on securing loads and deadlines.
Subsurface Exploration Damage	Defines obligations of mineral developer and limitations on damages owners may claim, also details other responsibilities and remedies.

Public Policy and Legislation Summaries – North Dakota (Pending)	
Name	**Summary**
Property Tax Relief Through Mill Levee Reductions Grants	The bill could alter community tax structure by restructuring taxation related to oil and gas.
Stripper Well Property Oil Extraction Tax Exemption	The bill may address and alter exemption rules.
Property Tax Relief via District Taxation Allocation	The bill could alter community tax structure by restructuring taxation related to oil and gas.

Public Policy and Legislation Summaries – South Dakota	
Name	**Summary**
Action for Injunction	Allows and outlines injunctions and actions to be taken in such cases.
Shutting Down and Sealing Property or Equipment by Security for Violation	Can result in cancellation of leases and bonds.
Violation of Law, Rule, Regulation or Order, Including Maximum Penalty Per Violation Per Day	Details penalties and regulations for violations.
Appeal From Rule Regulation or Order of Board for Any Person Adversely Affected	Establishes rules for appeals to decisions within the state.
Rights of Owners Within Unit Area to Property Acquired in Conduct of Unit Operation	Details the payment for expenses and rights, including alternative rights, that an owner may accept. Can result in limited participation based on specific rights taken.
Amendment of Order for Unit Operations	Provides conditions to be met to amend orders.
Order of Board for Unit Operation of a Pool	Provides guidelines and requirements to be met before orders become effective.
Well Logs and Reports	Requires and outlines responsibilities regarding mechanical well logs, surveys and reports.
Drilling Without Permit	Establishes criminal charges for illegal drilling, also includes perjury connected with illegal drilling.
Surface Restoration Bonds	Outlines terms and amounts of bonds needed for surface restoration of oil and gas development.
Conditions to be Met and Bond Amounts Needed for Wells	Establishes conditions and amounts for bonds connected with wells. $5,000 bond or $20,000 blanket bond are required but additional bonds may be required under board discretion.
Drilling Wells at Locations Other Than Prescribed When Authorized	Allows for drilling at secondary sites if prior approval is granted.
Owners Rights of Participation	Provides for payment of expenses and outlines rights of those involved in pool. Provides an alternative right to owners and results in limited participation. Rights of owners operating well or paying cost for benefit of another pooling order.
Oil and Gas Waste Prohibited	Waste of oil and gas is prohibited unless certain exceptions are satisfied.
Testing of Oil and Gas Wells Requirements	Limits production for inefficient wells, requires correction of poor rations or possible well sites.

Public Policy and Legislation Summaries – South Dakota (Continued)	
Name	**Summary**
Permit Application Fee	Provides rules for applying associated fees and authority over the process, requires agreement between developer and landowner.
Order of Board for Unit Operation of a Pool	Provides terms and conditions to be met to operate a pool under a prescribed plan.

Public Policy and Legislation Summaries – South Dakota (Pending)	
Name	**Summary**
Oil Production Surface Access Fee	The bill could result in a change in tax structure related to oil and gas.
Allowing Hydraulic Fracturing	The bill may include legislation to reevaluate the issue of hydraulic fracturing within the state.
Energy Development Loans	The bill could alter how communities and companies handle infrastructure.
Provides Terms and Conditions to be Met to Operate a Pool Under the Prescribed Plan	The bill could allow the state to create a committee to study the effects of oil and gas development.

Public Policy and Legislation Summaries – Montana	
Name	**Summary**
Production Tax Rates Imposed on Oil and Natural Gas	Outlines applicable taxation and exemptions that may apply to oil and gas, includes gas and specific item tax rates.
Requirements for Oil and Gas Operations	Provides requirements for operations including temporary and contingency options, lists requirements needed for operations.
Damage Mitigation	Provides for mitigation of damage resulting from oil and gas development, creates an account including fund amounts to reduce damage.
Permit Holder to Furnish Information to Surface Owner	Provides full list of information that must be supplied to surface owner.
Lessee to Prevent Waste	Establishes that waste from operations must be controlled to prevent damage to surrounding environment.
Production of Water From Oil and Gas Wells	Relates to the jurisdiction of hearings related to oil and gas conservation.

Public Policy and Legislation Summaries – Montana (Continued)	
Name	**Summary**
Permits for Construction Installation, Alteration or Use	Provides full details required to apply and receive permits, includes time frames, deadlines and costs.
Construction Blasting Restrictions, Requirements and Exemptions	A license is required to engage in construction blasting unless exceptions satisfied. Provides details on types of blasting that require license and uses excepted from rule.
Special Provisions	Allows the board to take special actions based on interests of the county involved.
Montana Oil Pipeline Safety Review Council	Currently working on several issues that could influence oil and gas development.
Notice of Drilling Operations	Outlines requirements including notices given to landowners of drilling operations, provides who must be notified and timelines.

Public Policy and Legislation Summaries – Montana (Pending)	
Name	**Summary**
Revise Condemnation Procedures	The bill could impact eminent domain laws.
Establish a Local Government Infrastructure Funding Program	The bill may provide funding assistance for impacted communities.
Generally Revise Taxation on Energy Producers	The bill may lower taxes for energy projects.
Provide Tax Credit for Property Owners Impacted by Pipeline/Transmission Lines	The bill could provide property tax credits to property owners.
Revise Penalty and Interest Provisions Related to Enforcement of Tax Laws	The bill may increase penalties and interest if out of compliance with tax laws.
Revise PSC Regulation of Common Carrier Pipelines	The bill could revise PSC regulation of common carrier pipelines.
Generally Revise Laws on Property Taxation	The bill may reduce taxes for centrally assessed properties.
Generally Revise School Funding	The bill may generally modify the funding distribution formula for state, county and city schools.
Revise Taxation on Fossil Fuel Infrastructure to Bring It Into Line with 'Clean and Green'	The bill may reduce taxation on fossil fuel infrastructure.

Crew Camp Regulation Summaries	
County, State	**Status**
Renville, ND	Currently have memorandums on crew camps.
Mountrail, ND	Currently have memorandums on crew camps.
Williams, ND	Currently have memorandums on crew camps.
Daniels, MT	RV sites can be approved by the planning board.
Richland, MT	Currently review crew camps via subdivision review.
Wibaux, MT	Currently review crew camps via subdivision review.
Powder River, MT	Reviewing a better way to handle crew camps, reviewing plan of use and will determine whether to allow crew camps and crew sites.
Valley, MT	Currently working on ordinances regarding crew camps.
Burke, ND	Currently working on ordinances regarding crew camps.
Pierce, ND	Currently working on ordinances regarding crew camps.
Wells, ND	Currently working on ordinances regarding crew camps.
Sheridan, ND	Currently working on ordinances regarding crew camps.
Oliver, ND	Currently working on ordinances regarding crew camps.
McKenzie, ND	Currently working on ordinances regarding crew camps.
McLean, ND	Currently working on ordinances regarding crew camps.
Custer, MT	Currently working on ordinances regarding crew camps.
Fallon, MT	Not planning on taking action by end of 2012.
Butte, MT	Not planning on taking action by end of 2012.
Meade, SD	Not planning on taking action by end of 2012.
Divide, ND	Has active ordinances regarding crew camps.
McHenry, ND	Has active ordinances regarding crew camps.
Billings, ND	Has active ordinances regarding crew camps.
Dunn, ND	Has active ordinances regarding crew camps.
Mercer, ND	Has active ordinances regarding crew camps.
Slope, ND	Has active ordinances regarding crew camps.
Hettinger, ND	Has active ordinances regarding crew camps.
Adams, ND	Has active ordinances regarding crew camps.
Golden Valley, ND	Has active ordinances regarding crew camps.

Crew Camp Regulation Summaries (Continued)	
County, State	**Status**
Stark, ND	Currently review crew camps on a case-by-case basis (strategy for crew camps is in development stage).
Ward, ND	Require special use permits.
Harding, SD	Require special use permits (strategy for crew camps is in development stage).

Federal Regulations Summaries	
Name	**Summary**
National Environmental Policy Act	Establishes guidelines and responsibilities to prevent damage to the environment. Designates authority for oversight and past history of the Act. Provides information about EPA structure.
National Historic Preservation Act	Focuses on perseveration of historic properties as a foundation to our society. Outlines requirements and obligations when related to historic areas.
Clean Water Act	Objective is to maintain or restore water supply for the country. Provides outlines on limitations of what can be released into water and outlines responsibilities. Refers to state and foreign controls over water supply.
Clean Air Act	Assigns responsibility for air control to State and local governments. Act focuses on protection of air quality and assistance to government in support.
Wilderness Act	Ensures land is secure for the American people – present and future generations – have the benefit of an enduring resource of wilderness.
Archaeological Resource Protection Act	Establishes protection for archaeological sites – both private and public.
Native American Graves and Repatriation Act	Establishes guidelines and protection for Tribal burial sites.
Threatened and Endangered Species Act	Protects and recovers imperiled species and the ecosystems upon which they depend.
Bald and Golden Eagle Protection Act	Provides protection for eagles and outlines penalties for violation.
Antiquities Act	Deems landmarks, structures and other historic objects to be national monuments if on government controlled land.
Air Rules for the Oil & Natural Gas Industry	EPA regulation of volatile organic compound (VOC) emissions generated during the completion state of hydraulically fractured natural gas wells.
Regional Haze Program	Requires development and implementation of air quality protection plans to reduce pollution causing visibility impairment.

Federal Regulations Summaries (Continued)	
Name	**Summary**
Emergency Planning and Community Right to Know Act (EPCRA)	Section 313, Toxics Release Inventory – Oil and gas extraction as an industry is not required to report.
GHG NSPS for Power Plants and Refineries	New source performance standards for emissions for CO_2 for new affected fossil fuel-fired electric utility generating units (EGUs).

North Dakota Environmental Regulations Summaries	
Name	**Summary**
Soil Conservation	Prevent soil erosion, preservation of resources and lands. Establishes authority and committees including powers and rights.
Emergency Costs	Allows for recovery of costs associated with environmental emergencies from responsible parties. Also establishes a fund to hold recovered money.
Ground Water Protection	Provides oversight into protection and authority regarding ground water. Details who is responsible and who cannot be charges for contamination.
Safe Drinking Water Act	Defines rules for safe water and provides authority over monitoring water systems. Allows for inspection of water systems. Provides for legal oversight, process and penalties.
Wetlands	Covers permit and penalties associated with draining wetlands. Provides supporting documentation for procedures.
Archaeological Resource Protection Act	Establishes protection for archaeological sites – both private and public.
Soil Conservation	Prevent soil erosion, preservation of resources and lands. Establishes authority and committees including powers and rights.

South Dakota Environmental Regulations Summaries	
Name	**Summary**
Air Pollution Control	Provides for state-wide prevention and support to local and regional programs. Outlines requirements, controls and limitations allowed under this Chapter.
Water Pollution Control	Provides for protection of water and treatment of water supplies. Establishes standards, permits, rules and penalties for the process.
Safe Drinking Water	Establishes regulations protection drinking water and delegates authority. Provides for fees, administration and penalties covered by this chapter.
Environmental Protection	Provides oversight into who can bring actions regarding pollution. Covers judicial aspects of environmental violations.
Oil Pipelines	Requires the use of an oil spill response plan. Provides details about preparing for worst case scenario and steps and items needed within plan.

Montana Environmental Regulations Summaries	
Name	**Summary**
Air Quality	Provides for administration and oversight of air quality. Establishes standards, permit process and penalties.
Water Quality	Provides for administration and oversight of water quality. Establishes standards, permit process and penalties.
Environmental Control Easement	Establishes easements and control, including authority oversight, over enforcement. Provides for qualified organizations and planning requirements.

Montana Environmental Regulations Summaries (Pending)	
Name	**Summary**
Eliminate Air Pollution Advisory Control Council	Could remove this council and the reporting requirement to it from other departments.
Ground Water Law Revision	Could update laws relating to ground water and water quality.