WILLISTONBASIN

The Williston Basin:
Greasing the Gears for Growth in North Dakota

BENTEK Energy

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NORTH DAKOTA PIPELINE AUTHORITY
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Executive Summary

At the request of the North Dakota Pipeline Authority and the North Dakota Industrial Commission, BENTEK has conducted an analysis of the Williston Basin with the objective of forecasting natural gas production growth through 2025 to determine if adequate natural gas pipeline infrastructure exists in North Dakota. In particular, the study focused on how the gas-to-oil ratio (GOR) may change over the life of a Williston Basin well. Additionally, BENTEK investigated NGL content in such a well's gas stream and how it might change over time. Based on these analyses, the existing natural gas infrastructure was assessed to determine if additional transport capacity is required.

The reservoir engineering review indicates that the Bakken and Three Forks oil decline curves are steeper than the associated gas decline curves. The primary driver is the falling reservoir pressure in the Bakken and Three Forks formations. As the pressure in the reservoir declines and reaches its bubble point pressure, the natural gas that is dissolved in the oil will escape, allowing it to be captured in the gas stream. Therefore, BENTEK projects a rising gas-to-oil ratio for the basin, similar to the GOR observed in the Montana portion of the Williston Basin.

Based on the GOR analysis and a favorable outlook for oil prices and demand, associated gas production is expected to climb steeply over the forecast horizon (2012-2025). Under the Base Case scenario, gross gas production will rise from 536 MMcf/d in 2011 to 3.1 Bcf/d in 2025. BENTEK also provided Low and High Case scenarios, which predict 2025 gross gas production of 2.01 Bcf/d and 3.8 Bcf/d, respectively. These growth expectations will push the basin into a more leading role in supplying the U.S. natural gas market. The trend of natural gas liquids (NGL) content of the gas stream over time over time is less clear. Reservoir engineering analysis suggests that the NGL content may rise as the reservoir pressure falls, similar to the GOR. While publicly available processing plant data is consistent with this theory on an aggregate basis, the analysis of a subset of wellhead data is inconclusive.

While forecasting oil production was not a primary objective of the study, it is an essential part of determining the associated gas forecast. Under the Base Case, production in North Dakota could more than quadruple by 2025 to more than 2 MMb/d. This forecast is driven by the relative expected return from oil, which is also an important component of determining the competitiveness of Williston natural gas supply versus other basins across North America. BENTEK estimates that an average Williston well currently yields a 58% rate of return,

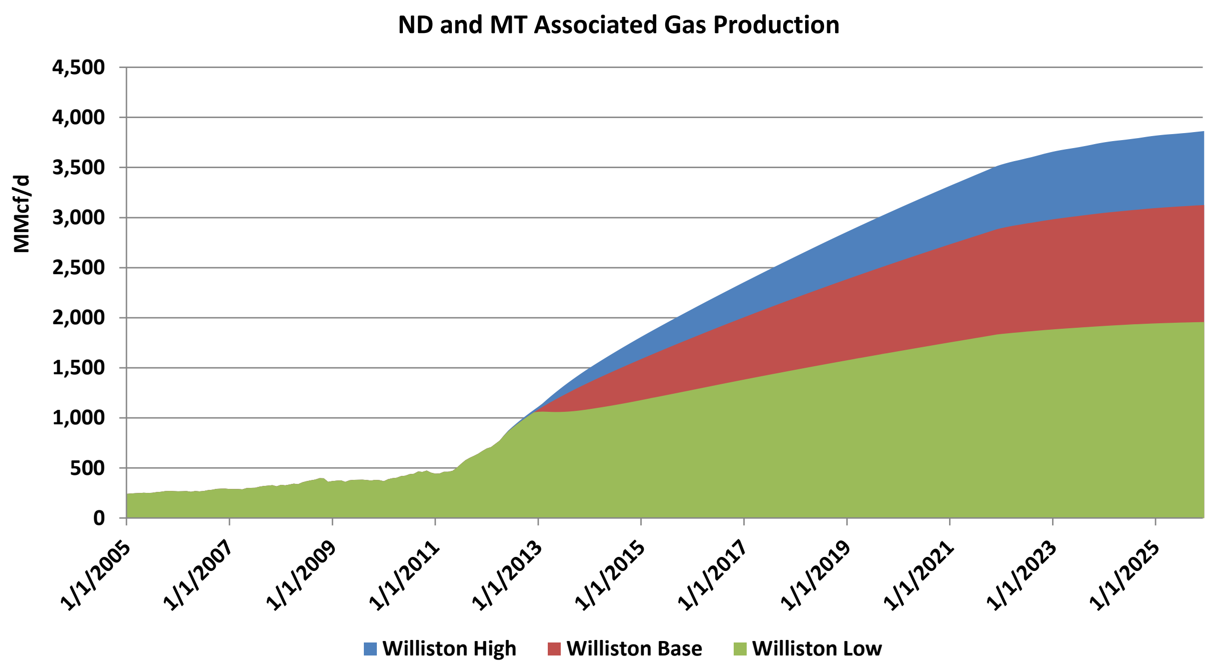


Figure 1. SOURCE: HPDI

making it one of the best performing basins in the North America. This high rate of return enables producers in the area to economically compete for transport space on the natural gas pipeline grid.

The Williston currently faces competition from western Canada for pipeline space to Chicago and other Upper Midwest markets, linking the pricing structure in both regions. However, oil sands demand and new LNG exports are expected to consume a significant portion of western Canadian supply going forward. This, along with continued declines in Canadian natural gas supply, will tighten the Canadian supply/demand balance and alleviate some of the pressure on the Williston market, easing access to long-haul pipeline space.

In the Northeast, Marcellus production will continue to rise and may seek markets to the west, including Chicago. However, superior economics in the Williston and competitive transportation rates will enable the basin to retain a strong foothold on midwest markets.

Given the ability of Williston Basin production to compete with neighboring basins for pipeline space, sufficient interstate pipeline capacity exists in the long term, to support production expectations in the area. However, other gas infrastructure in North Dakota is insufficient to handle the influx of associated gas. Several projects are planned to increase gathering, lateral and processing capacity. In the long term, more gathering and processing capacity projects will be required to move the 3.1 Bcf/d of gross gas expected under the Base Case scenario. If market dynamics shift such that current interstate pipeline infrastructure is inadequate to support both Canadian and Williston supply, several shorter term options exist. These options include increased local utilization, expansions of existing infrastructure and reversals of existing infrastructure.

Overall the Williston Basin is expected to continue to grow rapidly in North Dakota. Investment in the region will be greased by strong overall economics for production out of the basin and relative economics to competing supply areas.

North American Natural Gas Market Overview

The North American natural gas market is undergoing dramatic changes as new technology and efficiency improvements in the exploration and production (E&P) sector continue to drive rapid gas production growth. High gas prices, particularly in 2008 when Henry Hub soared to $13/MMBtu, provided the funds needed for exploration and production research and testing. New techniques such as pad drilling, drill-bit steering, hydraulic fracturing and other processes in all phases of E&P operations were applied and improved. The results started to become evident in the middle of the past decade in some traditional production areas but also in numerous new unconventional gas plays, including the Pinedale/Jonah field in Wyoming, the Piceance in Colorado, the Barnett in North Texas, the Fayetteville in Arkansas, the Woodford in Oklahoma, the Haynesville in North Louisiana and the Marcellus in Pennsylvania. Total U.S. Lower 48 natural gas production climbed by more than 16 Bcf/d or 35%, in only eight years from 47.5 Bcf/d on average in 2005 to 63.9 Bcf/d this year-to-date (see Figure 2). This rapid growth had a number of important market consequences that are discussed in this overview section, including significant pipeline construction, much weaker gas prices, displacement of marginal gas supply such as gas imports from Canada and other countries (liquefied natural gas or LNG), and a recent shift away from dry gas drilling to areas that are rich in oil and liquids. It also prompted a transfer of technology and process improvements to the oil exploration and production sector, leading to expectations of oil market changes similar to what already has occurred in gas and what is beginning to take place in gas liquids. Gas demand also has surged higher, particularly in the power sector where natural gas as a fuel for power generation is displacing coal.

Understanding these events is important for determining how the Williston Basin fits into the overall North American energy market. In a way, the Williston Basin represents a microcosm of the changes and challenges taking place in the entire E&P sector. While oil and liquids currently show the greatest promise for Williston producers, natural gas production still has its own share of potential rewards given low production costs, adequate

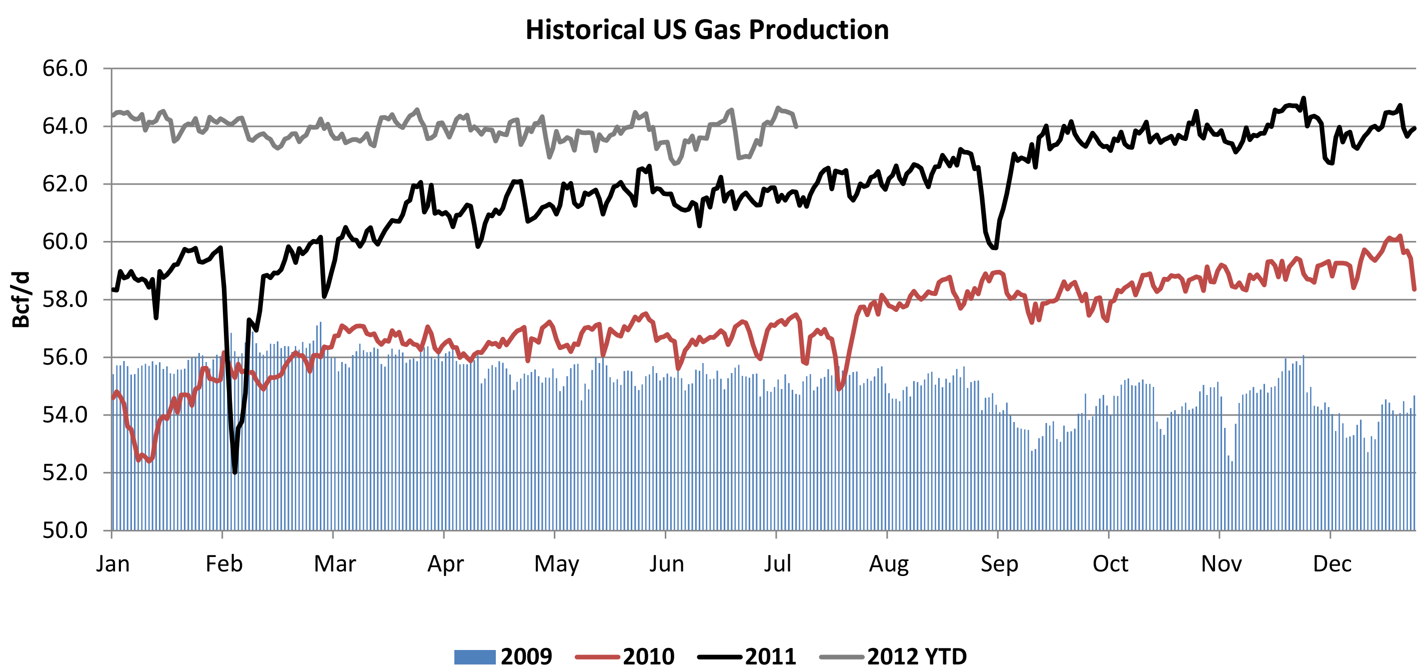


Figure 2. SOURCE: BENTEK

infrastructure, market access and potential displacement of more expensive supply serving the same markets.

Unconventional U.S. Gas Production Growth

A few U.S. unconventional plays have been the major drivers behind the 35% increase in U.S. gas production since 2005 (see Figure 3). Among them are the Haynesville in North Louisiana, where gas production increased to 6.3 Bcf/d in 2011 from only 0.9 Bcf/d in 2005. Drilling and production recently has declined in the Haynesville due to poor natural gas market conditions, but given the right environment, no other U.S. producing area can respond as quickly as the Haynesville. Production from the Marcellus shale, mostly in Pennsylvania, has increased to 5.3 Bcf/d this year-to-date from only about 0.2 Bcf/d in 2005. Barnett shale gas production rose to 5.6 Bcf/d on average in 2011 from 1.6 Bcf/d in 2005. Other major growth areas have included the Fayetteville in Arkansas where production increased 2.5 Bcf/d from 2005 through 2011, the Eagle Ford in East Texas, where production has averaged 3.7 Bcf/d this year-to-date compared to 1.8 Bcf/d in 2005, and the Woodford in Oklahoma where production has increased to 1.6 Bcf/d from 0.9 Bcf/d in 2005. In addition, the application of unconventional drilling techniques in the Rockies, West Texas and the Anadarko Basin of Oklahoma also have contributed to gas production growth.

Growing Pipeline Infrastructure

The emergence of the Pinedale/Jonah fields and the growth of production in the Piceance Basin in Colorado in the early-to-mid 2000s led to the planning and development of the 1,700-mile, 1.8 Bcf/d Rockies Express (REX) pipeline from the Rocky Mountain region to the Midwest and Northeast in 2008 and 2009. The emergence of the Barnett shale, Woodford shale and other unconventional plays in Texas, Oklahoma, Arkansas and Louisiana in the mid-and-late 2000s led to the construction of numerous large multistate pipeline systems to bring gas to premium eastern markets. Among those were multiple Gulf South pipeline expansions, Midcontinent Express, Gulf Crossing, Fayetteville Express, Southeast Supply Header and others. More recently the growth of the Marcellus shale in the Northeast region led to a number of major pipeline expansions starting in 2010, and many others are still being developed as the Marcellus continues to grow. Billions of dollars in pipeline and storage field

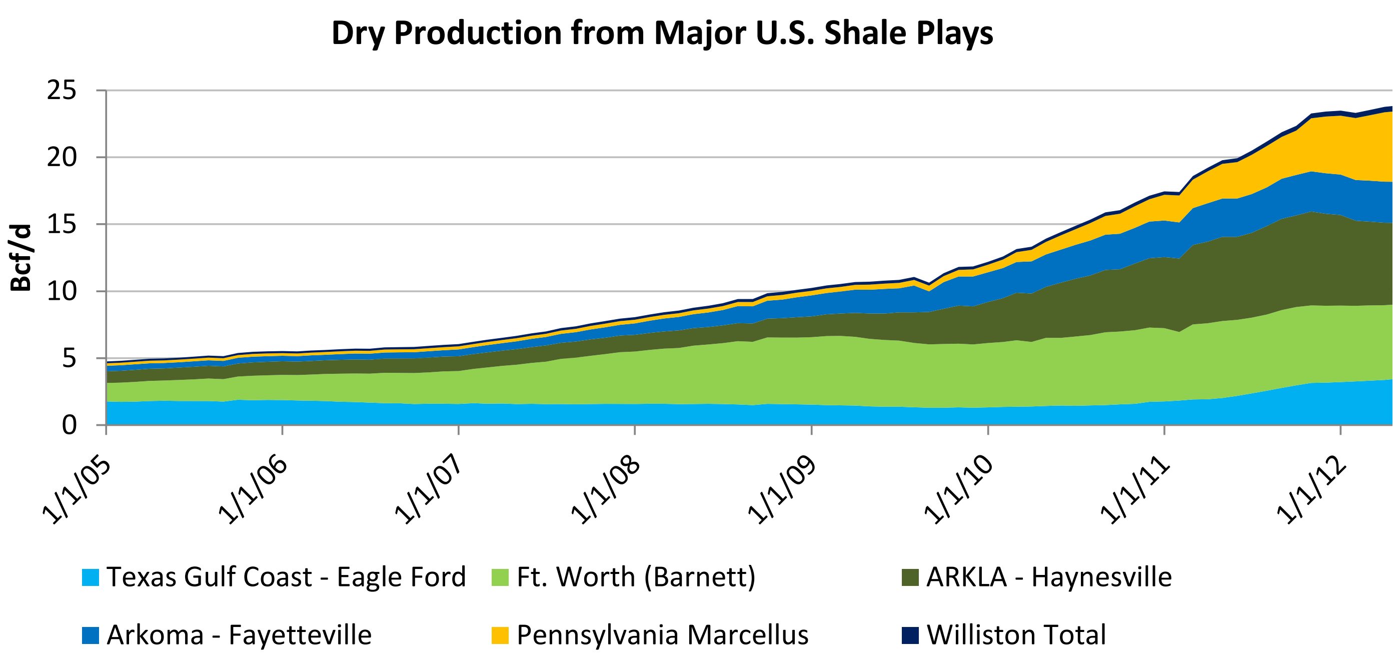


Figure 3. SOURCE: HPDI

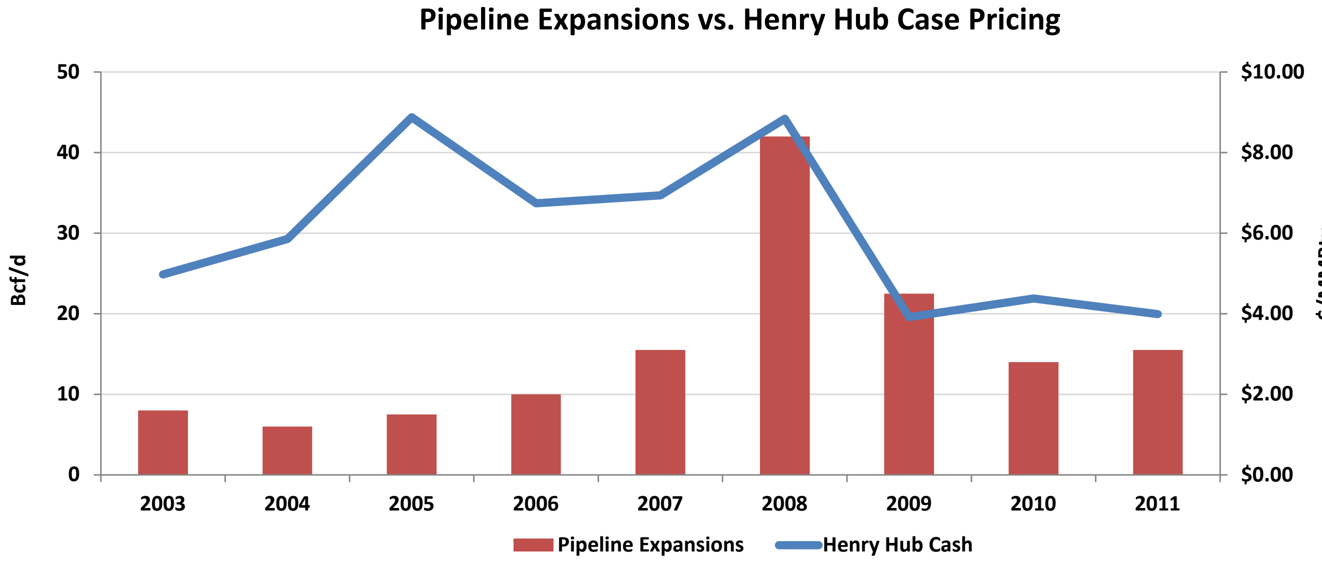


Figure 4. SOURCES: ICE, BENTEK PROJECT TRACKER

construction spending characterized the past five to 10 years of U.S. gas production growth.

Falling Prices and Collapsing Price Spreads

Henry Hub prices tumbled more than 70% from the $8.85/MMBtu average seen in 2008 to the average of $2.38 so far in 2012 (see Figure 4). The economic crisis contributed to those price declines, but the economy masked the underlying market oversupply that became clearly evident in 2012 when prices fell to lows not seen since the 1990s despite a continuing economic recovery and record gas demand from the power sector.

Price spreads across the continent also have collapsed. The U.S. market from coast to coast has become more closely tied together and competition among supply basins for market share has intensified. Gas in the Rockies is competing for access to the same markets served by suppliers in the Offshore Gulf and western Canada. Less efficient, more expensive producing areas are being priced out of markets they once served.

Pipeline Flow Changes & Supply Displacement

With new production and pipelines, U.S. producers in the new unconventional plays have grabbed greater market share in premium market areas, particularly in the U.S. Northeast and Southeast, which reduced the market share available to traditional supplies and imports. Traditional long-haul pipeline systems began receiving gas at new locations either in the middle of their systems or even at the downstream ends. This resulted in new transportation and rate challenges for pipelines and the loss of market share for producers who previously supplied the pipeline.

Some pipelines even began shipping gas in the opposite direction of their traditional transportation patterns. For example, the Appalachian Basin was producing about 2.1 Bcf/d of gas in 2008, but increased to an average of almost 5.2 Bcf/d in 2011 and peaked at 8.4 Bcf/d in June 2012. Much of this new supply has entered the Tennessee Gas Pipeline system in Pennsylvania, and Tennessee Gas ended up with a new "null point" location on its system from which gas started flowing in both directions, including toward its traditional supply area as well as its traditional market area.

With so much supply entering the traditional pipeline grid at the downstream end, supply from Canada, the Southeast and other regions that historically served the Northeast was not needed, and long-haul pipeline flows from these areas declined. Backhauls of gas to traditional supply areas became common. These trends are increasing and are likely to spread to other areas because of gas production growth in places such as the Utica play in

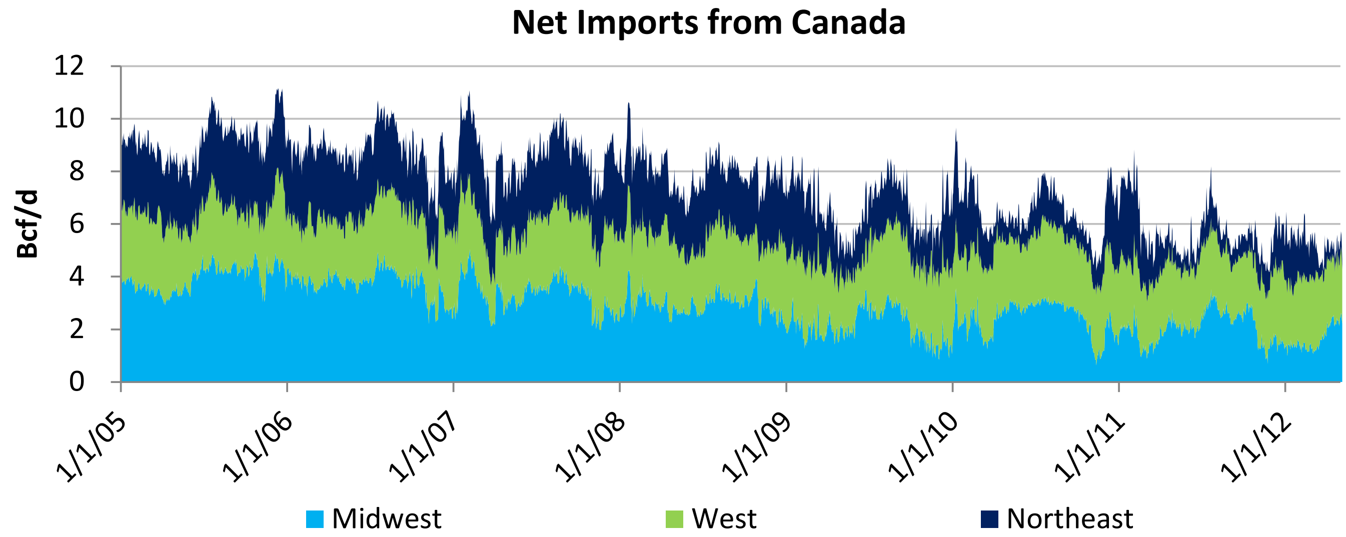


Figure 5. SOURCE: BENTEK

Ohio and the Bakken play in the Williston Basin of North Dakota.

U.S. Imports Decline

From 2005 to 2011, U.S. LNG sendout fell 60% and has averaged only 0.5 Bcf/d year-to-date in 2012 compared to an annual peak of 2.2 Bcf/d in 2007 (see Figure 11). Over the same period, Canadian imports plummeted nearly 40%, or about 3.5 Bcf/d to an average of 5.7 Bcf/d. Growing U.S. unconventional production and new pipeline construction enabled U.S. producers to capture a growing share of U.S. markets, displacing imports and other traditional supply sources.

Figure 5 shows monthly imports of Canadian gas into the three major U.S. regions: the West, Midwest and Northeast. The largest import declines have taken place in the Midwest and Northeast regions because of Marcellus production growth, construction of the Rockies Express and other pipelines, and contract expirations on TransCanada's mainline pipeline from western Canada.

These trends are likely to continue as Northeast gas production grows. Significant additional pipeline infrastructure is expected to come online to facilitate the movement of more Marcellus supply into the Northeast, but also into the Midwest and eastern Canada, further displacing Canadian gas flows in the U.S. Midwest and eastern markets. As this report will discuss, the growth of gas production from the Williston Basin will further exacerbate this trend, negatively impacting Canadian imports.

Most of Canada's gas production comes from the Western Canadian Sedimentary Basin (WCSB), primarily in Alberta and British Columbia. This production area is remote relative to many U.S. markets, resulting in relatively high pipeline transportation costs. In addition, new unconventional production in the U.S. is being produced at a lower cost than conventional Canadian production, and new U.S. pipelines are providing U.S. unconventional producers new access to markets formerly served by Canadian gas.

The Rockies Express system enabled production from the Rocky Mountain region to more directly compete with Canadian gas for market share in the Midwest and Northeast markets. Further downward pressure on Canadian imports occurred when the Bison and Ruby pipelines were built out of the Rockies in 2011. As these new pipelines enabled more U.S. gas supply to reach markets that have long included a large amount of Canadian gas, contract termination on Canadian long-haul pipelines, such as TransCanada, resulted in even higher transportation costs to U.S. markets. These cost increases put Canadian suppliers at an even greater disadvantage.

Canadian production costs also include royalty payments to the provinces, and in recent years provincial governments chose to increase royalties, resulting in additional economic disincentives for producers. Canadian production fell about 18% from 2005 to 2011, or about 3.2 Bcf/d. The Canadian provinces quickly learned about their royalty mistakes and in late 2009, a readjustment

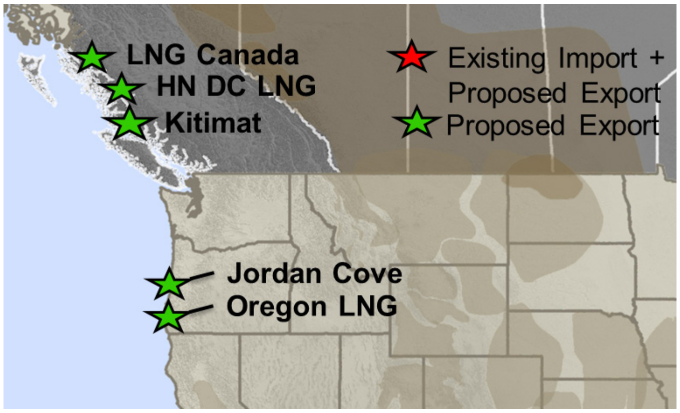


Figure 6. SOURCE: BENTEK

to Alberta's royalties made drilling and production more appealing. British Columbia enacted similar changes that started to spur development. These changes coincided with rising oil prices that have sparked a recent increase in drilling activity in Canada. As a result, Canadian gas production declines have started to slow. From 2007 to 2010 Canadian production fell at a rate of 2.7 Bcf/d. However, from 2010 to the present, production has fallen just 0.4 Bcf/d. Declines from conventional Canadian gas resources are starting to be offset by increases in unconventional Canadian producing areas, such as the Montney, Duvernay and Horn River plays in British Columbia and Alberta, and by associated gas produced from fields that are rich in natural gas liquids and oil.

Canada still has a large gas resource, significant liquids-rich production and a number of unconventional gas plays that rival plays in the U.S. The country remains among the world's largest natural gas producers, ranking third behind the U.S. and Russia. With declining market share in the U.S., Canadian suppliers are beginning to look toward the global LNG market as a destination for their gas.

Four LNG projects totaling as much as 3.8 Bcf/d of capacity are being considered and two with 1.6 Bcf/d of capacity are well underway toward development on the Pacific Coast of British Columbia (see Figure 6). The projects include the small Douglas Channel LNG export terminal, which is expected to provide 0.25 Bcf/d of export capacity as early as 2013, and the 1.3 Bcf/d Kitimat LNG project being planned by Apache and EOG. Kitimat LNG is expected to begin service in 2016. Shell also is considering a 1.2 Bcf/d LNG export project in Kitimat, and BG Group is evaluating potential LNG exports from the Port of Prince Rupert but has not formally announced project plans. A previous plan by Shell for a project in Prince Rupert would have provided 1 Bcf/d of export capacity.

These Canadian LNG projects holds several important advantages in the global LNG market, including large gas resources, favorable project economics, strong incentives to export and close proximity to Asian markets. LNG shipping costs from Canada to the world's fastest-growing demand markets are projected to be among the lowest of global suppliers. These projects, if constructed, would be an important demand source for Canadian gas, which is expected to continue losing U.S. market share.

BENTEK forecasts Canadian exports to the U.S. will decline at an average annual rate of 0.4 Bcf/d through 2017, at which time U.S. exports are expected to average just 3.2 Bcf/d. This will leave more supply in western Canada and force suppliers there to develop alternatives to the U.S. market.

Canadian gas demand, particularly from bitumen production in the oil sands areas in Alberta, is growing substantially, but not enough to compensate for declining exports to the U.S. In total there currently are about 92 operational oil sands projects in the three Alberta production areas, which use about 1.4 Bcf/d of gas. By 2017, about 150 oil sands projects are expected to be active, consuming as much as 2.2 Bcf/d of gas. Gas demand from the oil sands is projected to increase by about 800 MMcf/d from levels in 2011 to 2017. However, the oil sands cannot consume all of the gas that is expected to be produced or displaced from the U.S. market. Consequently, the prospects for Canadian LNG exports to Asian markets are growing.

Drilling Costs and the Shift to Liquids

Natural gas prices recently have fallen to extreme lows not seen in decades, and producers are shifting drilling rigs to oil and liquids-rich plays because crude and natural gas liquids (NGL) prices are much higher than natural gas prices. Prices for oil (West Texas Intermediate crude at Cushing, OK) remain quite high relative to gas particularly on a per-MMBtu-basis (see Figure 7). NGL prices (Mont Belvieu) are beginning to decline, but also are high relative to gas.

These high oil and NGL prices have led to a major increase in the number of rigs operating in liquids-rich plays such as the Eagle Ford in South Texas, the Permian in West Texas, the Anadarko in Oklahoma and the Williston in

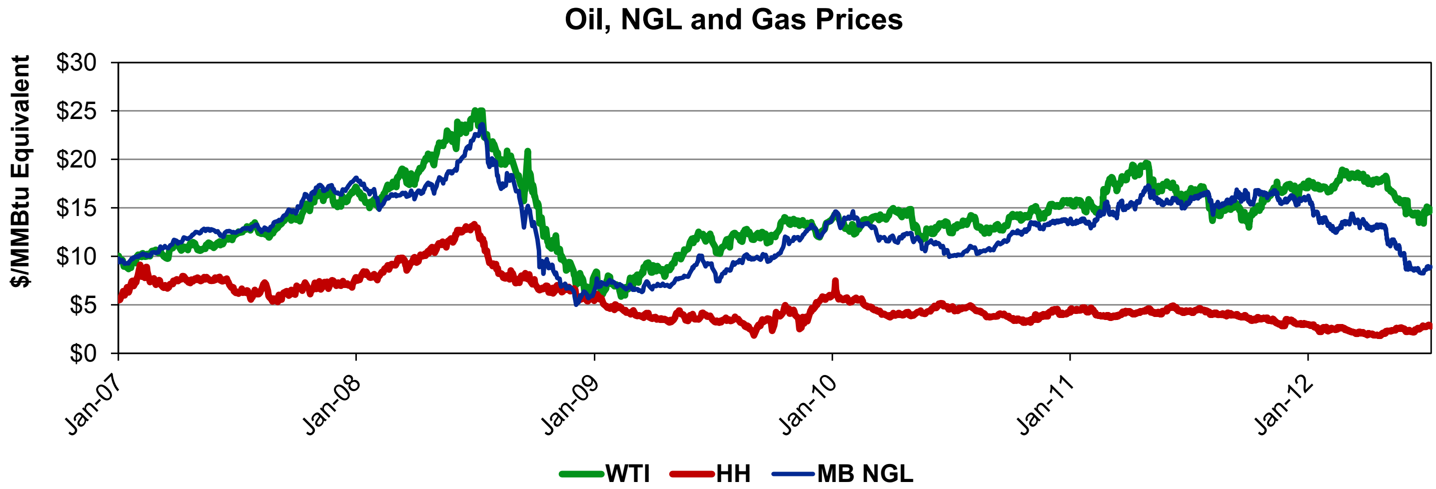


Figure 7. SOURCES: ICE, EIA, PLATTS

North Dakota and Montana. Gas-directed drilling nationwide has fallen to 10-year lows, but drilling in plays with oil and gas liquids has grown dramatically. The number of rigs drilling in June in the Permian Basin, for example, totaled 521, up 302 rigs from levels seen in January 2010.

Figure 8 reveals a major migration of resources away from lean gas basins to basins with higher BTU content from the beginning of 2010 to June 2012. The liquids-rich portions of the Marcellus, Eagle Ford, Permian, Anadarko and Williston have all seen significant increases in active rigs since January 2010, while drilling in the Barnett, East Texas and Haynesville, among other primarily dry gas areas has fallen sharply.

The map shows the number of rigs active in each of the producing areas — numbers on the left — and the changes in the number of active rigs — numbers on the right — since January 2010.

Rates of return[1] from wells in some dry gas plays, such as the Haynesville in North Louisiana and the Barnett in North Texas, have dropped into negative territory, but producers in the liquids-rich areas, such as the Anadarko are earning in excess of a 20% return. Average rates of return by basin are discussed in more detail in the Williston Oil and Gas Production chapter.

Crude Awakening

Oil and liquids producers are only beginning to apply the technological advances and process improvements that revitalized the U.S. natural gas market over the past decade, but a noticeable impact is taking place on oil production. U.S. crude oil production has posted year-over-year gains for the last five years. A similar trend has not occurred since the 1960s (see Figure 9), which coincided with peak U.S. oil production in 1970. Several plays are fueling the oil resurgence, including a number of unconventional plays in the traditional Permian Basin, the Eagle Ford shale in South Texas, the Bakken/Three Forks in the Williston, the Granite Wash and others in the Anadarko Basin. A number of other oil plays are only beginning to emerge, such as the Niobrara in the Denver-Julesburg and Powder River basins, and the Utica in the Appalachian Basin.

Oil production growth is driving massive infrastructure development similar to what occurred in the gas industry over the past decade. More than 75 oil pipeline expansions are planned over the next five years in addition to 25 rail expansions and seven major refinery projects.

Oil and NGL prices, and the technological and process improvements in the E&P sector, have prompted these market changes and have enabled producers to earn favorable rates of return on drilling even in a low-gas-price environment. Should oil prices retreat due to a surplus of oil, however, internal rates of return in the oil-rich plays

1. BENTEK has developed a financial model that calculates internal rates of return (IRR) from a typical well in each of the major U.S. plays in an effort to compare well performance. IRRs allow for an apples-to-apples comparison of well economics among dry gas, wet gas and oil plays. The process begins with company financials, including 10Qs, 10Ks, investor presentations, news releases and transcripts from earnings calls. These sources are reviewed and production data is collected for each play. This producer-reported data is collected for each component of the IRR analysis. IRR components include drilling and completion costs, operating expenses, initial production (IP) rates, BTU content, decline curves, production taxes and royalty rates. The production data is then reviewed in order to determine a representative set of assumptions for each play.

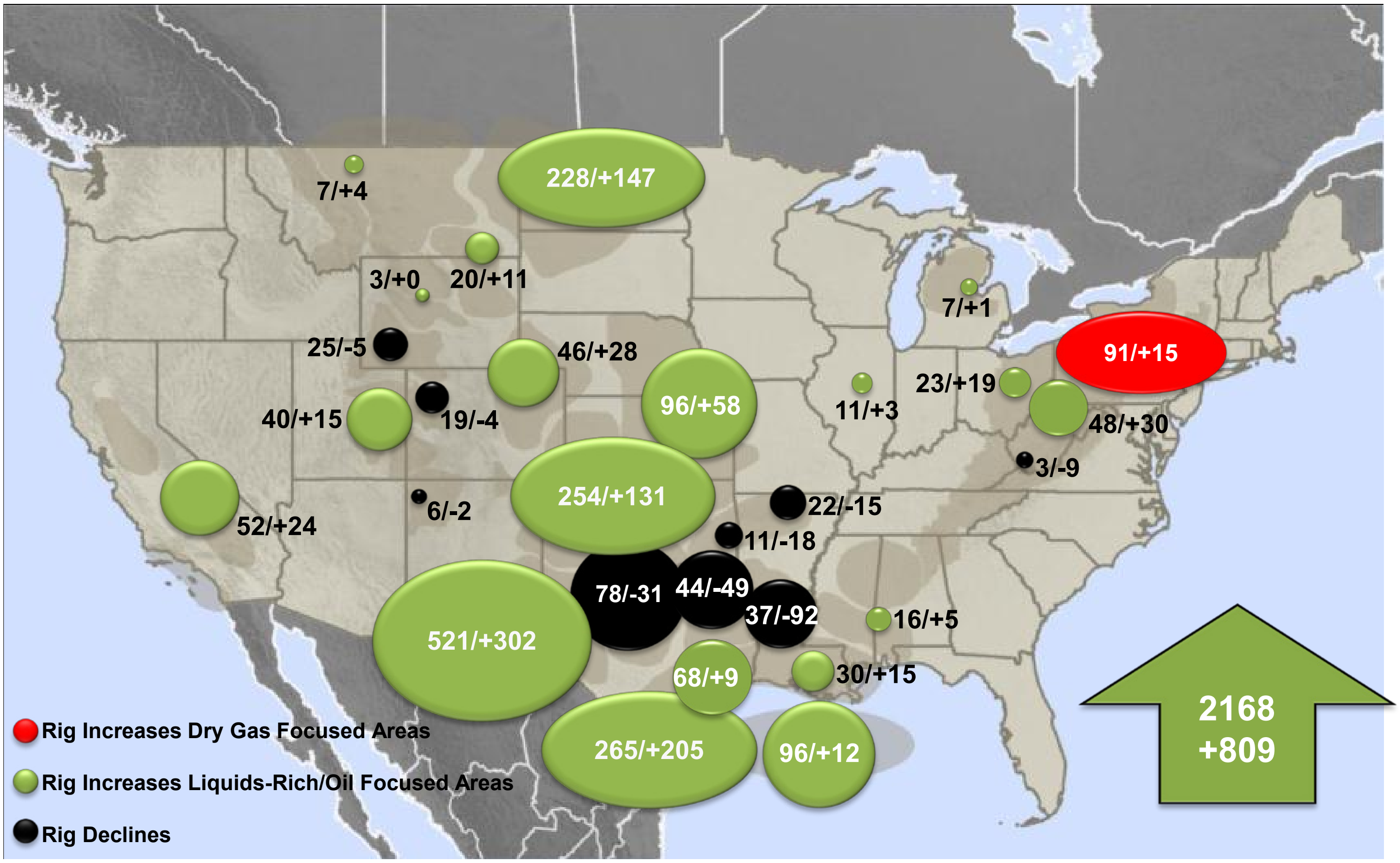


Figure 8. SOURCE: RIGDATA

will also fall. A sensitivity analysis surrounding oil prices and internal rates of return in the Williston is discussed in more depth in the IRR section of the Williston Oil and Gas chapter.

The spread between West Texas Intermediate (WTI) prices at Cushing and Brent, an international crude benchmark, is expected to suffer through a volatile period. From 1987 to 2009, WTI traded at approximately a $1.50 premium to Brent. In 2010, the spread tightened and WTI

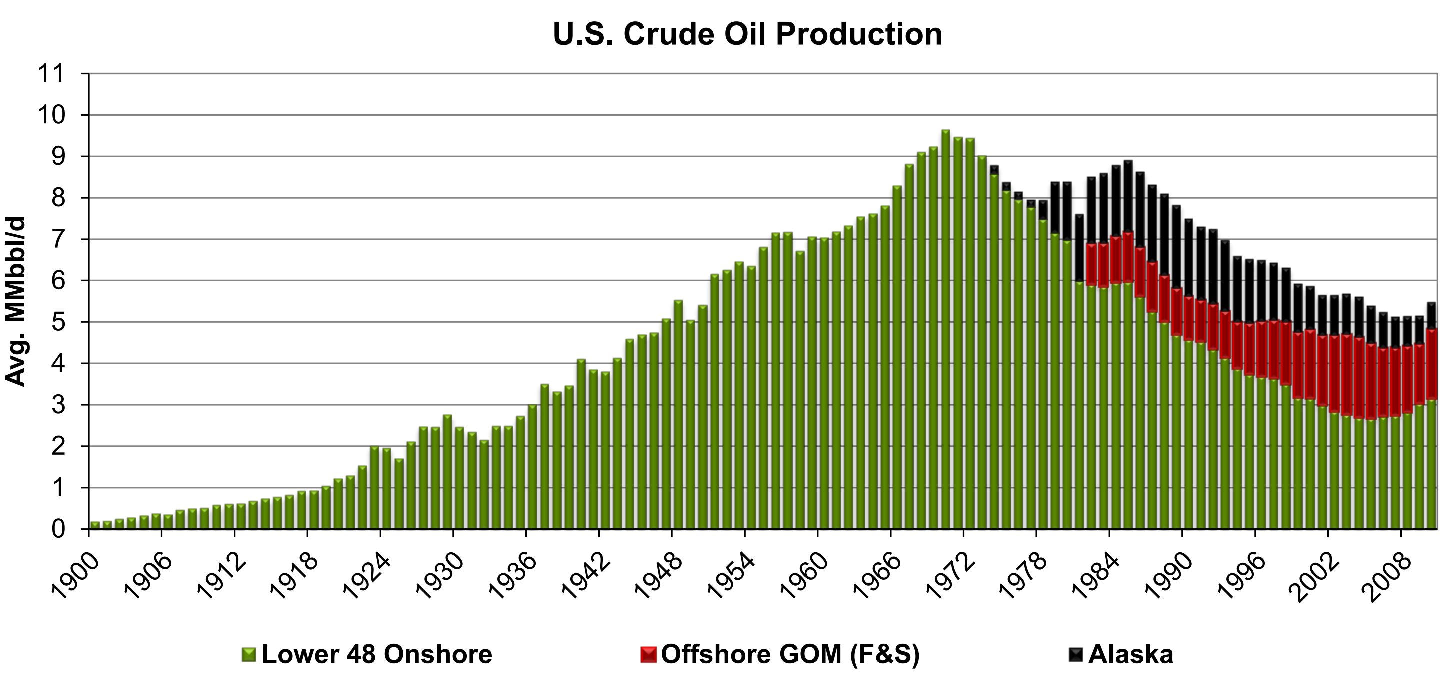


Figure 9. SOURCE: BENTEK

began trading at a slight discount. Then in 2011, WTI spot prices plummeted to a low of $29.59/bbl less than Brent crude and averaged ($15) for the year. BENTEK expects WTI to remain deeply discounted to Brent over the next five years. The forecast, based on U.S. and Canadian market fundamentals, shows WTI tumbling to a discount of nearly ($20) in 2017 as supply growth eventually outpaces announced pipeline capacity additions, and regional refinery demand increases for light crude oil.

Lower oil prices and transportation constraints due to rapid production growth are expected to result in oversupply in some areas, which could reduce rates of return and lead to a drilling slow-down. An upcoming section in this report examines potential scenarios for the Williston where deeper discounts to WTI are expected over the next five years. Increasing transportation capacity from the Bakken to Cushing would alleviate depressed prices in the Williston, and several projects are planned with this purpose.

U.S. Gas Production Forecast

The shift in drilling to higher-return areas that are less gas-focused has not prompted a significant gas production decline. Total U.S. natural gas production has remained relatively flat near the record highs seen last fall. One of the reasons for this resilience is a backlog of wells in a number of producing areas where producers are awaiting frac crews or infrastructure to bring wells on-stream. Most of the well backlog is in the Marcellus and Eagle Ford shales. Another reason production is holding relatively steady is the growing associated gas supply coming from oil and gas liquids plays where drilling has been increasing substantially.

The surge in oil and liquids drilling nationwide is helping to foster continuing natural gas production growth. Gas production rates from many of these areas are lower than rates from some of the major dry gas plays, such as the Haynesville in North Louisiana, but gas production growth is still taking place.

In the Williston Basin for example, the rig count on the North Dakota side of the basin has nearly tripled since January 2010 from around 70 to more than 200 in June 2012. Williston oil production has increased 375 Mb/d, or 93% over that period but gross natural gas production has grown by more 0.5 Bcf/d to an estimated 0.86 Bcf/d. While oil has been the main attraction, growing gas production has prompted a number of midstream and pipeline expansions. Williston Basin Interstate (WBI), for example, has expanded its systems in several places. Alliance Pipeline has proposed a new lateral to interconnect Hess's Tioga Processing Plant to the Alliance mainline and more than 0.3 Bcf/d of new gas processing capacity has been constructed in the past several years while another 0.3 Bcf/d is being built.

BENTEK expects U.S. gas production to continue growing over the next five years as associated gas production grows, backlogged wells are completed in the Marcellus and Eagle Ford, emerging plays such as the Utica shale

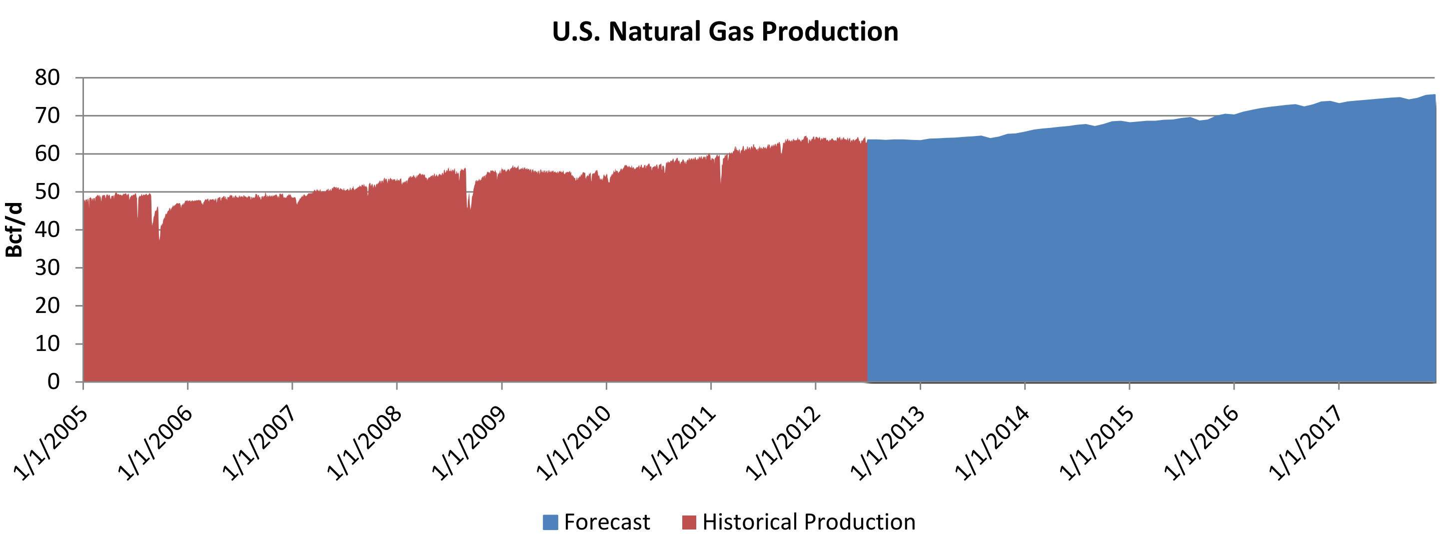


Figure 10. SOURCE: BENTEK

add incremental volumes and gas demand, particularly from the power sector, increase substantially.

Production in the Lower 48 states is expected to grow 5% (equivalent to 3.0 Bcf/d) between 2011 and 2013, and by 2017, U.S. production is expected to average 74.9 Bcf/d, a 22% increase from average levels in 2011 (see Figure 10). For 2012, production is expected to average 63.9 Bcf/d.

Much of the growth over the next five years is expected to come from the Northeast region, particularly from the Marcellus and Utica shales in the Appalachian Basin, but gas production also is expected to grow in a number of other basins across the U.S., including the Williston. An incremental 10 Bcf/d of production could come from the Marcellus and Utica plays by 2017, while growth from the basins in Texas, particularly the Eagle Ford, and the Southeast/Gulf could total about 7.5 Bcf/d between now and 2017. Williston Basin gross gas production is expected to increase 1.6 Bcf/d by 2017 from average levels in 2011.

Given the expected U.S. gas production growth, particularly in the Marcellus and Utica, marginal supply will continue to be displaced. This means conventional U.S. production and Canadian imports will continue declining. The Northeast region receives about an average 12 Bcf/d of gas from other supply regions. But with average annual Northeast production expected to increase by 10 Bcf/d from 2011 through 2016, the region will be substantially reducing the amount of gas it takes in from other supply areas, including Canada, the Southeast, the Midcontinent and the Rockies. Displaced gas in these other supply areas will have to be diverted to other markets, or production in these regions will have to decline.

It will be challenging for the Northeast market to quickly adjust to these supply changes, but the potential for additional supply growth is substantial. As a result, there will be strong incentives to export Northeast gas supply as LNG to global markets. Should Northeast LNG projects be unsuccessful, the supply growth in the region will continue to weigh on the U.S. natural gas market.

In the Southeast, dry gas production growth has slowed because of recent weak market conditions and these changes are expected to continue until LNG export terminals are built along the Gulf Coast. Several LNG export projects are planned with some likely to begin service in 2016.

Similar conditions are likely in the Midwest where growing production from the Williston, Anadarko and increasing inflows from the Southeast and Northeast are expected to compete for market share. This report focuses mainly on how Williston Basin gas production growth participates in regional market dynamics.

U.S. Gas Demand

While U.S. production grew 30% or 14.1 Bcf/d from 2005 to 2011, U.S. demand from the residential/commercial (res/comm), industrial and power sectors, and from exports to Mexico, increased only 12%, or 6.8 Bcf/d over that period. Figure 12 shows the historical breakdown of natural gas demand in the U.S. Demand growth in the res/comm and industrial sectors was particularly lethargic due to the economic crisis. Res/Comm demand grew only 2%, while industrial demand inched 4% higher. The biggest demand gains from 2005 to 2011 were in the

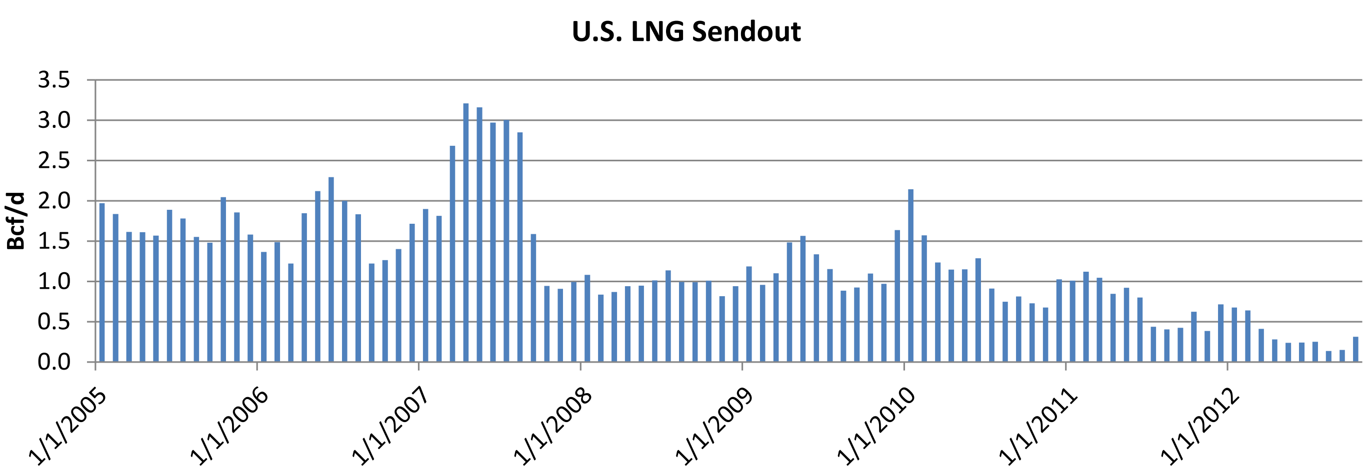


Figure 11. SOURCE: BENTEK

power sector, an increase of 32%, or about 5.1 Bcf/d, and power is expected to continue to be the fastest growing demand sector.

Res/Comm

Res/Comm demand represents the largest component of natural gas demand in the upper Midwest region at 2.0 Bcf in 2011. Res/Comm averaged 61% of total Midwest demand during the years of 2005 through 2009. Since that time, the sector's demand has decreased to 55% in 2010 and 52% and 2011 as industrial activity accelerated and power producers began to leverage gas as a fuel source over coal.

The primary uses of natural gas within the res/comm sector are space heating, water heating and cooking, with space heating representing the single largest component of res/comm demand. Additional end uses of natural gas in res/comm include clothes dryers, pool heating, outdoor lighting and gas-fired air conditioning. Based on these sources of demand, extremely cold winters and hot, humid summers in the Midwest result in highly seasonal res/comm demand.

When modeling future demand in the res/comm sector, weather influences demand more than any other input variable. Res/Comm only experiences robust year-over-year growth when year-over-year weather varies enough to drive a change in space heating. Two additional variables to consider when estimating res/comm trends include customer counts and efficiency gains. The customer counts variable measures the number of private dwellings and commercial establishments that use natural gas. In general, customer counts will grow over time as population rises. In turn, the larger population will require more residential dwellings, representing a positive relationship between customer counts and res/comm demand. In the long run, commercial customers will also grow to support rising residential customer counts. Figure 13 shows the natural gas burned per customer trending down historically in the Midcon Market, while the number of customers in that region has risen over that time.

Efficiency gains, however, decrease the natural gas demand per customer over time. Efficiency gains are accomplished through more efficient appliances and higher-quality insulation. On average, a newly constructed home is better insulated than a house built one decade earlier and therefore should require less energy to heat.

Another factor influencing natural gas demand is the potential for fuel switching. Natural gas competes with propane and heating oil as a space heating fuel in the Midwest. Natural gas for space heating requires supporting infrastructure before the switch can be executed. As infrastructure is developed, homes can switch from another fuel source to natural gas. There are about 500,000 homes in the Midwest that use heating oil, but there are about 2,500,000 homes that are using propane, according to the EIA.

BENTEK's res/comm forecasts use an assumption of 30-year average weather and an efficiency gain of 0.5% per year applied to the weather-normalized natural gas burn per customer. Customer counts are rebounding slowly from 2011 at the rates of 0.1% for 2012, 0.4 % for 2013, 0.8% for 2014, and falling into the long-term growth rate

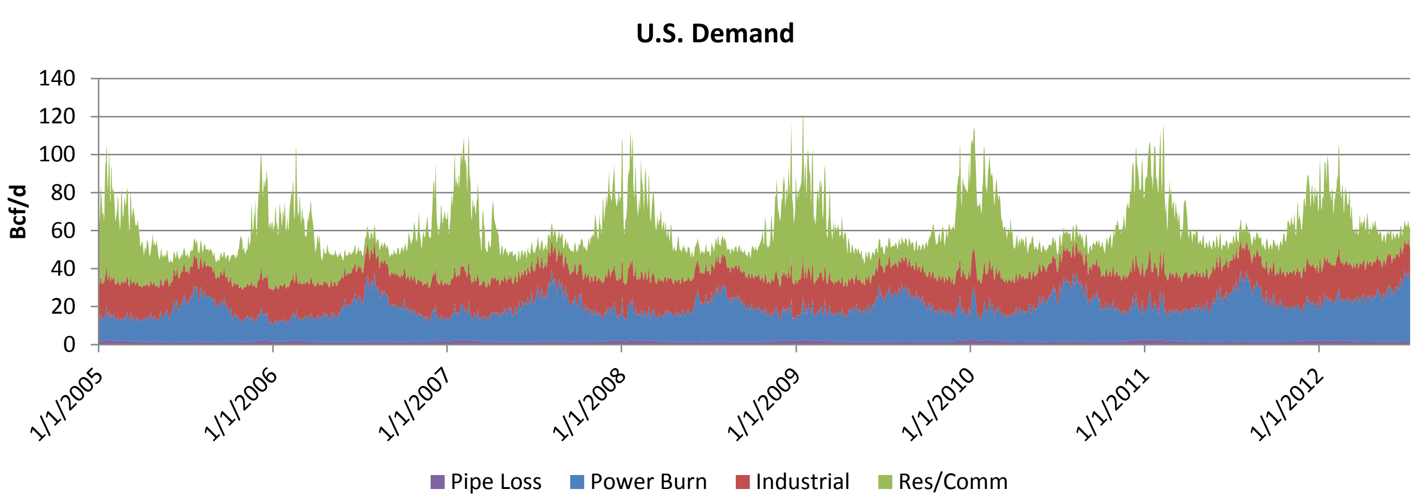


Figure 12. SOURCE: BENTEK

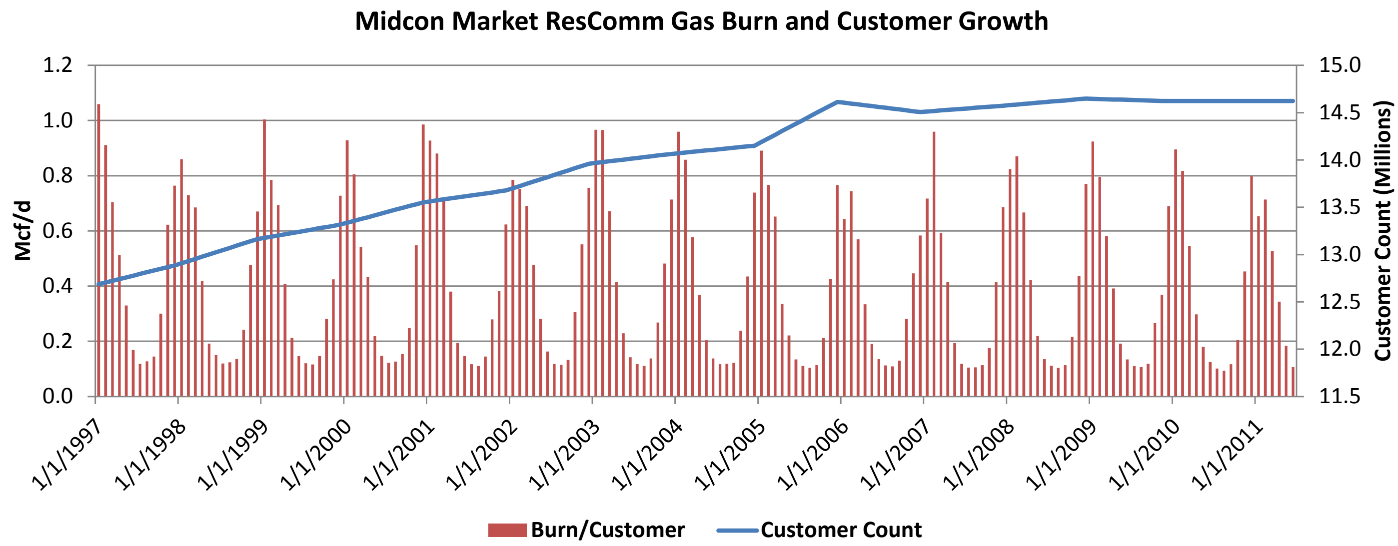


Figure 13. SOURCE: EIA

of 1% year for 2015 and beyond. This drives BENTEK's res/comm demand-forecasted volumes to rise 0.5% year over year.

Industrial

Industrial demand represented about 29% of total natural gas demand in the Midwest from 2005 through 2009. Today, industrial demand represents about 35%, or 1.3 Bcf, of total natural gas demand in the region. Industries that use natural gas as a feedstock stand to benefit the most from low natural gas prices. In the upper Midwest, the chemicals industry drives growth for industrial demand. Natural gas demand in the Midwest region has grown out of the recession lows set in 2009 to new highs not seen in the past seven years.

BENTEK expects growth in industrial demand to continue in the region, with a long-term growth rate of approximately 1.2%. Growth will be stronger in 2013 and 2014, at 1.6% and 2.1%, respectively, driven by the completion of new or expanded industrial facilities. Industrial demand is normalized to 30-year average weather and benchmarked to GDP, which has a forecasted growth rate of 3% per year according to the U.S. Congressional Budget Office.

Power

Power demand represented only 7% of total natural gas demand in the Midwest between 2005 and 2009. In the Midwest, power generation is supported by Powder River Basin coal, which is the cheapest coal supply in the United States. Inexpensive low-sulfur coal supplies into this region have limited natural gas market share gains in this sector historically. Recent weak natural gas prices

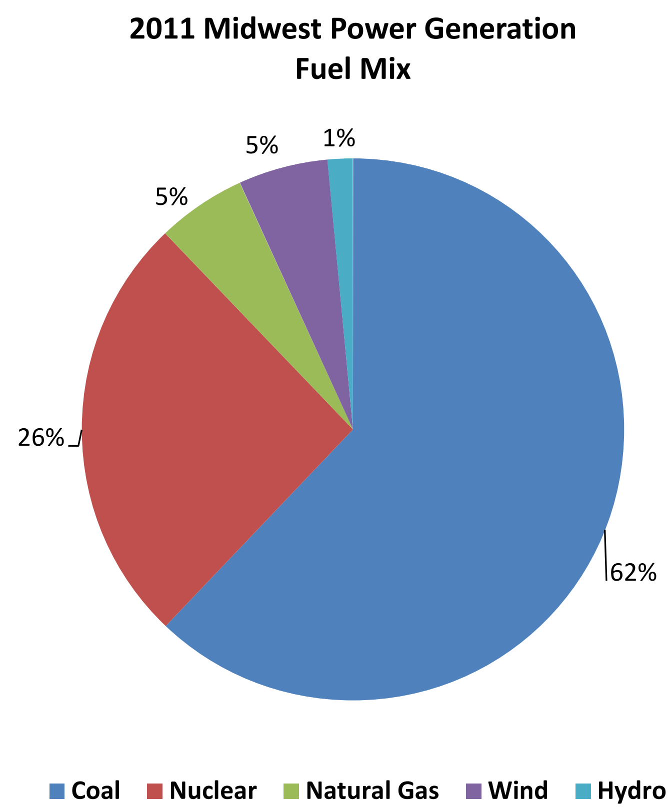


Figure 14. SOURCE: EIA

have allowed gas-fired power plants to make modest market share gains at the expense of coal-fired plants, driving natural gas power demand to 10% in 2011, and 14% year-to-date.

Approximately 62% of the electric power generation in the Midwest comes from coal-fired power plants, as shown in Figure 14. Nuclear generators account for 26% of Midwest power generation and natural gas-fired plants represent 5%. For 2011, the natural gas burn from power equates to approximately 309 Bcf of natural gas in 2011, of which only 1,900 Mcf was burned in North Dakota. Environmental regulations and low natural gas prices favor gas-fired generation over coal and oil, positioning gas turbines to make some market share gains in the Midwest going forward.

BENTEK forecasts power demand to grow as overall demand for electricity grows due to the attractive price of natural gas relative to coal, emissions limits and new power plant builds. Total generation for the Midwest is forecasted to grow at 0.8% annually, but power demand will grow 2.4% annually as natural gas plants gain market share relative to coal plants due to coal plant retirements and gas plant new builds. This will likely increase the demand for gas-fired generation in the region. Natural gas pipeline capacity into the region will limit the increase in gas burn. These factors represent risks to the longer-term outlook for gas generation in the Midwest.

Transportation

Demand from the transportation sector is small and will remain small, even if rapid adoption of natural gas-fueled vehicles takes place. Currently, there are about 125,000 compressed natural gas (CNG) and 3,000 liquefied natural gas (LNG) vehicles on U.S. roads, which consumed 90 MMcf/d of natural gas in 2010. This vehicle count pales in comparison to the 250,000,000 gasoline- and diesel-fueled vehicles in service today. Adoption has been slow in part due to a lack of infrastructure despite the attractive price of natural gas relative to gasoline. There are approximately 900 CNG and 75 LNG refueling stations in the U.S., compared to over 100,000 locations for gasoline and diesel. The infrastructure will not grow without critical mass and the market will struggle to grow without the supporting infrastructure.

Transportation demand will climb even without the rapid construction of infrastructure. Fleet vehicles stand to convert quite easily. The infrastructure needed to support fleet vehicles is localized to the facility the vehicle returns to every night. Long-haul LNG vehicles also are feasible but will require infrastructure along routes before switching becomes attractive. Companies are developing "clean" highways, where fueling stations are constructed along a freight highway corridor. Long-haul companies can then convert their trucks to LNG.

The market and the infrastructure for CNG and LNG vehicles will struggle to grow rapidly. However, demand will continue to grow. The economic benefits as well as the environmental benefits will support growth in this sector.

Pipe Loss

Pipe loss is gas consumed in the operation of pipelines, mainly as a fuel for compressor stations. Pipe loss is a linear function of the three main components of demand: Res/Comm, Industrial, and Power. Within the Midwest region, pipe loss is measured at 86 MMcf, or 2.3%, of total demand. As growth occurs in res/comm, industrial, and power, growth will occur in pipe loss as well.

Forecast

Average annual gas demand from these sectors is expected to increase about 16% or a total of 10.4 Bcf/d from the 2011 average to 2017, and much of that growth will continue to come from the power sector. Low gas prices, particularly relative to coal, and increasing environmental regulations from the Environmental Protection Agency and some states, will boost gas usage in the power sector 14% over the next five years or about 3.6 Bcf/d. In addition to this growth, industrial demand is expected to grow 8% or 1.4 Bcf/d and res/comm demand is expected to increase 4% or about 0.9 Bcf/d. Mexico is planning a major expansion of its gas transportation and distribution network and greater reliance on U.S. natural gas. Consequently, Mexican exports are forecast to grow about 0.6 Bcf/d between 2011 and 2017, a 43% increase.

These large demand gains are expected partly in response to the oversupplied conditions and low prices that have formed in the U.S. market over the past several years.

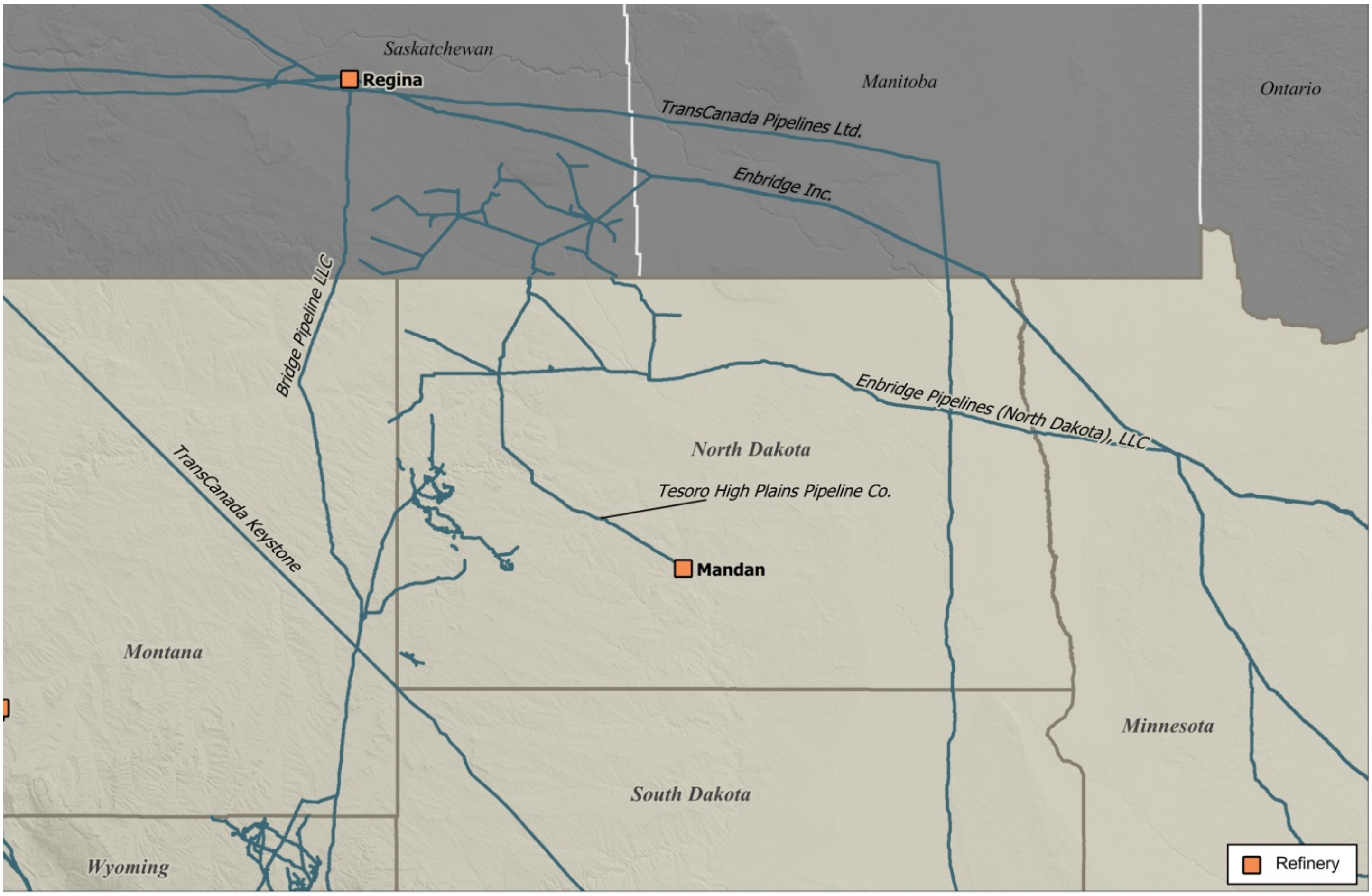


Figure 15. SOURCE: BENTEK

The Williston Basin and Regional Markets

Overview

The Williston Basin of North Dakota and Montana is home to the Bakken and Three Forks formations, two world-class oil resources that make up one of the largest contiguous oil reserves in the United States. Williston oil production increased more than 400%, or 630 Mb/d, from January 2005 to June 2012, and gross gas production grew more than 250%, or 620 MMcf/d. Over the next decade, this producing area is expected to contribute the second-largest amount of incremental oil production to the U.S. market, behind only the Permian Basin, and its gas production additions are expected to rival some of the largest producing areas nationwide. These production additions will create significant opportunities but also major challenges in infrastructure development, market access and displacement of traditional supply from other producing areas in the U.S. and Canada.

Williston producers must use creative transportation methods due to oil transportation constraints and long distances to markets. There are only a few major oil pipelines operating and one local refinery. Out of necessity, significant quantities of oil are transported by rail and truck. Constraints and distance to markets also have led to deep oil price discounts compared to WTI in Cushing, OK. In 2011, Bakken producers were receiving about $11/bbl less than WTI on average for their light sweet crude, and at times Bakken discounts have dropped to as low as ($20/bbl). Natural gas gathering, processing and other constraints also exist despite large pipelines that traverse the region. Even with gas prices as low as $2/MMbtu, significant revenue potential exists for companies willing to alleviate constraints by investing in additional gas infrastructure.

Another disadvantage for Williston Basin producers is the harsh climate. The basin is subject to severe cold weather, which leads to unfavorable working conditions

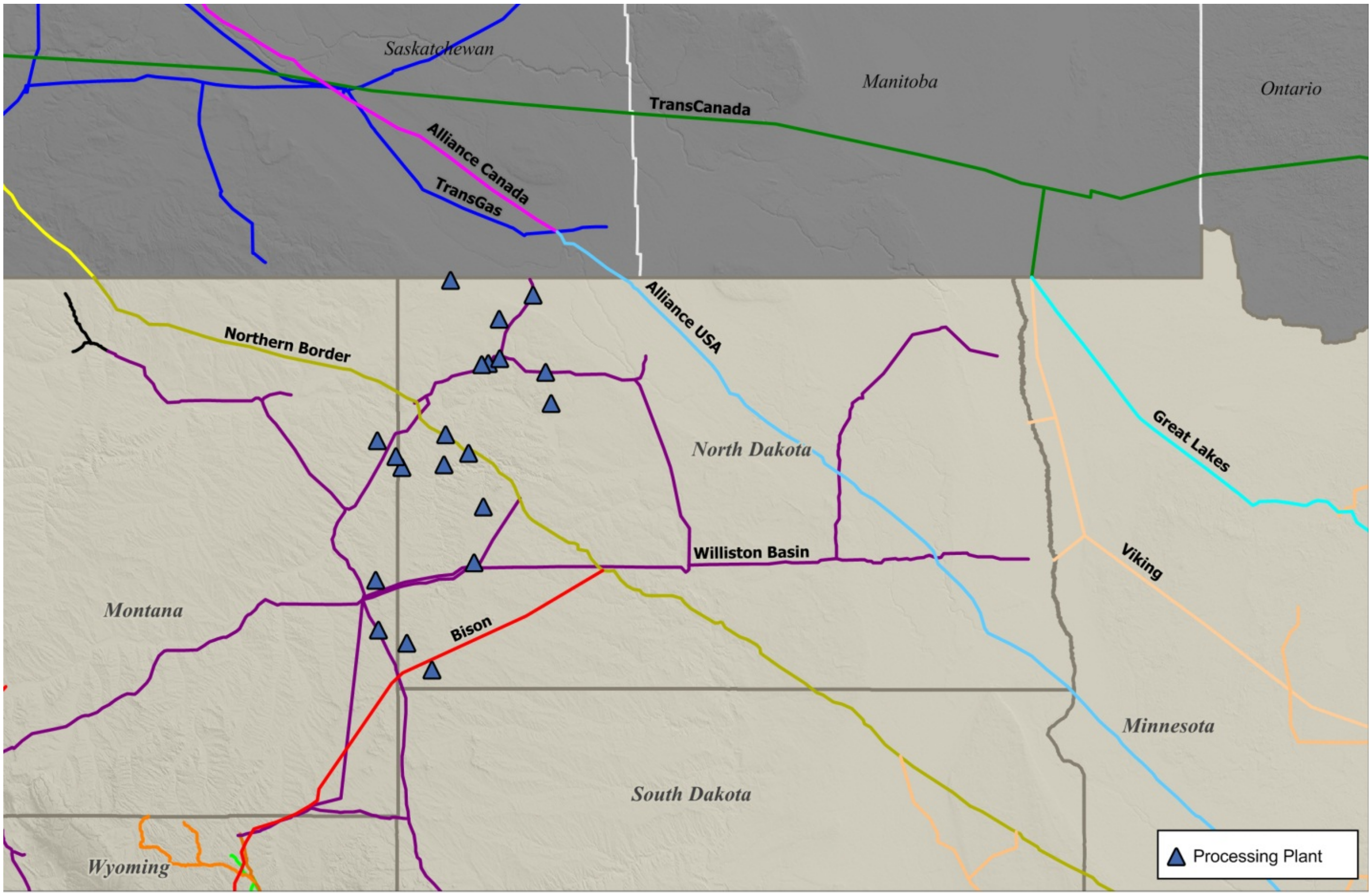


Figure 16. SOURCE: BENTEK

and drilling and completion difficulties often resulting in seasonal production curtailments.

Nevertheless, strong oil and liquids economics continue to attract a large number of producers and encourage transportation and market solutions. Figure 15 shows the current oil infrastructure in the region. Six major oil pipeline expansions, nine rail expansions, three proposed refineries, one refinery expansion, three gas- and liquids-pipelines and four gas processing plants are planned to support Bakken growth over the next several years.

The Williston Basin spans both PADD 2 and PADD 4 in the oil market, with nearly 90% of its production coming from North Dakota (PADD 2) and the remainder coming from Montana (PADD 4). Most of its oil production serves markets in PADD 2.

In the gas market, Williston production moves mainly to markets in the Midwest on several pipeline systems, including Northern Border Pipeline (NBPL), Alliance Pipeline, and WBI Energy Transmission. WBI serves regional demand in the residential, commercial and industrial sectors mainly in Montana, and can also deliver gas into NBPL, Alliance, Colorado Interstate Gas (CIG) and to a lesser extent, Kinder Morgan Interstate Gas Transmission (KMIGT) (see Figure 16). NBPL and Alliance are primarily Canadian gas transporters, while CIG and KMIGT transport primarily gas from the central Rocky Mountain region. While some space exists on these systems today, significant flow supply will have to be displaced to accommodate Williston Basin gas production growth. This dynamic is addressed in more detail in the Bringing Williston Basin Gas to Market section.

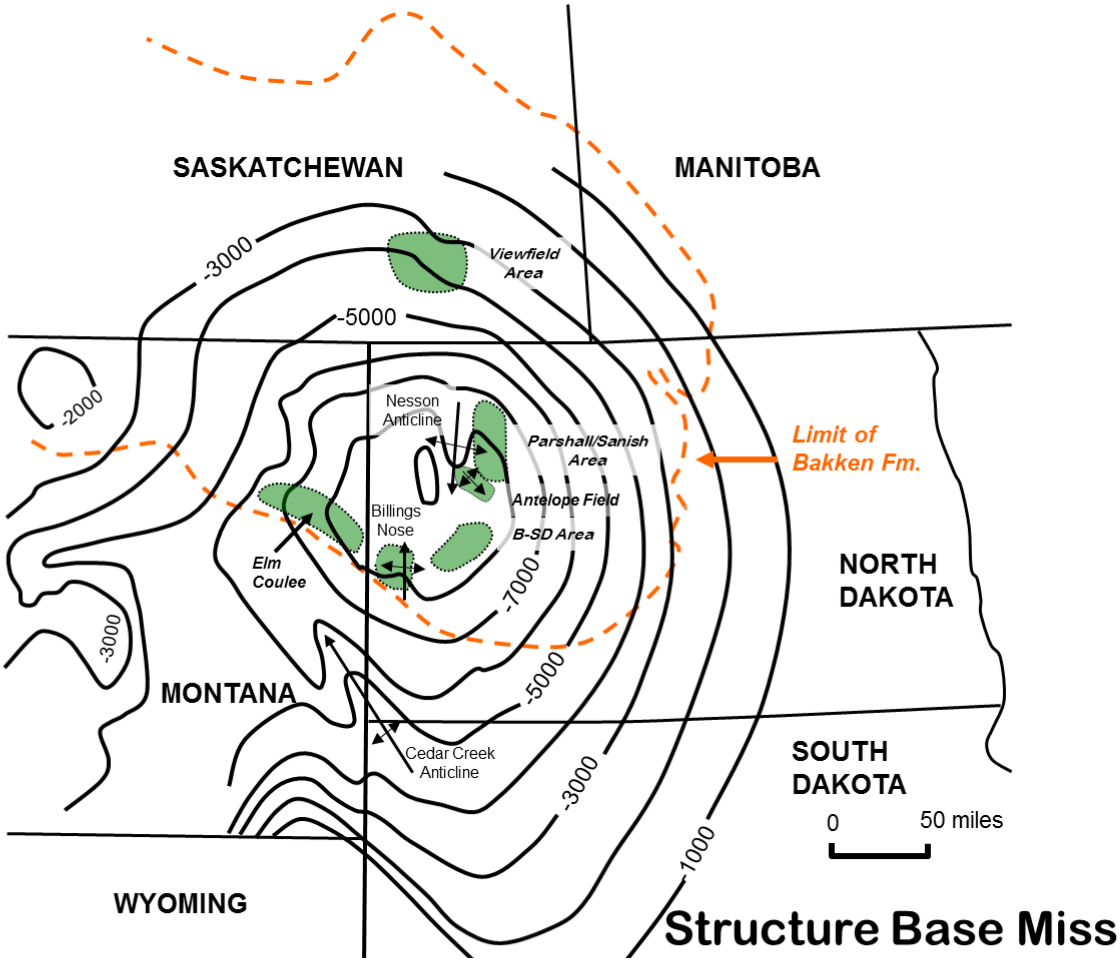


Figure 17. Structure contour map on base of Mississippian for Williston Basin. Limits of the Bakken are shown by dashed line. Recent giant oil fields being developed include Elm Coulee, Parshall/Sanish area and the Viewfield area. The oldest Bakken/Three Forks production is from Antelope Field discovered in 1953.

Williston Basin Geology

The Williston Basin is a large, intracratonic sedimentary basin that occupies parts of North Dakota, Montana, South Dakota, Saskatchewan, and Manitoba (see Figure 17). The Mississippian-Devonian Bakken petroleum system in the basin is characterized by low-porosity and permeability reservoirs, organic-rich source rocks, and regional hydrocarbon charge. This unconventional play is the current focus of exploration and development activity by many operators because of its significant hydrocarbon potential. Estimates of oil generated from the petroleum system range from 10- to 400-billion barrels. The U.S. Geological Survey (USGS) has estimated that the mean technologically recoverable hydrocarbon resources in the Bakken petroleum system include about 3.65 billion barrels of oil, 1.85 Tcf of associated/dissolved natural gas, and 148 MMbbl of natural gas liquids. The North Dakota Industrial Commission and North Dakota Geological Survey have recently estimated that 2.1 billion barrels oil are recoverable from the Bakken and 1.9 billion barrels are recoverable from the Three Forks[(2)].

The Bakken petroleum system, the primary target of operators, consists of the Bakken formation, lower Lodgepole and upper Three Forks (see Figure 18). The Mississippian-age Bakken consists of three members: (1) upper shale; (2) middle silty dolostone or dolomitic siltstone and sandstone; (3) lower shale[(3)]. The middle dolomite, known as the middle Bakken, is the principal oil reservoir and is on average 10,500 to 11,000 feet deep. Both the upper and lower shales are organic-rich marine shales and also serve as source rocks for the middle Bakken. The Devonian-age Three Forks also is a targeted formation. It is a shaley dolomite, typically found at

2. LeFever and Helms, 2006
3. LeFever, 2008

10,600 to 11,000 feet. The quality of crude produced from these two formations is light-sweet with gravity of around 38-42° API and a sulfur content of 0.13% to 0.20%.

The first well in the Bakken formation was drilled in 1951, but it wasn't until the discovery of the Elm Coulee Field in eastern Montana in 2000 that the full potential of the Bakken formation began to be realized (see Figure 17). Elm Coulee became the proving ground for U.S. unconventional oil development. The field was developed using horizontal drilling. However, it was not until around 2004 to 2005 that the use of multi-stage fracturing was fully utilized. Before that time, a lateral was fractured with a single stage. Therefore, zones were not isolated, and as a result, only a portion of a lateral was fractured. Later, isolation of various stages of a lateral using "plug-and-perf" technology, together with other advances made in multi-stage fracturing, increased production rates and ultimate recovery estimates substantially. These technologies propelled the field to become one of the most prolific oil producers in the U.S. Elm Coulee currently (December 2011) produces about 42 Mb/d of oil, while at its peak in August 2006 the field produced about 52 Mb/d. The decline in production belies the field's status as the proof-of-concept for unconventional crude production.

The technology developed and the lessons learned in Elm Coulee were transferred 115 miles east to North Dakota's Sanish and Parshall field areas located mainly in Mountrail County, ND. EOG Resources was the first operator to transfer its expertise to this area, in 2006. Its initial discovery well produced 463 boe/d during the first 30 days of its production period, and EOG's next 11 wells averaged 1,198 boe/d initially. EOG's success prompted several other operators to move in, and total Bakken production reached about 100 Mb/d in 2006. By 2007, 20 rigs were operating in Mountrail County. The area containing the greater Sanish and Parshall fields currently produces about 137 Mb/d or 23% of the total Williston Basin production.

More recently, drilling activity has moved west of the Nesson Anticline to Williams and McKenzie counties, ND. The knowledge cultured in Elm Coulee, Sanish and Parshall continues to be transferred to other areas in the basin and beyond. The play has expanded in North

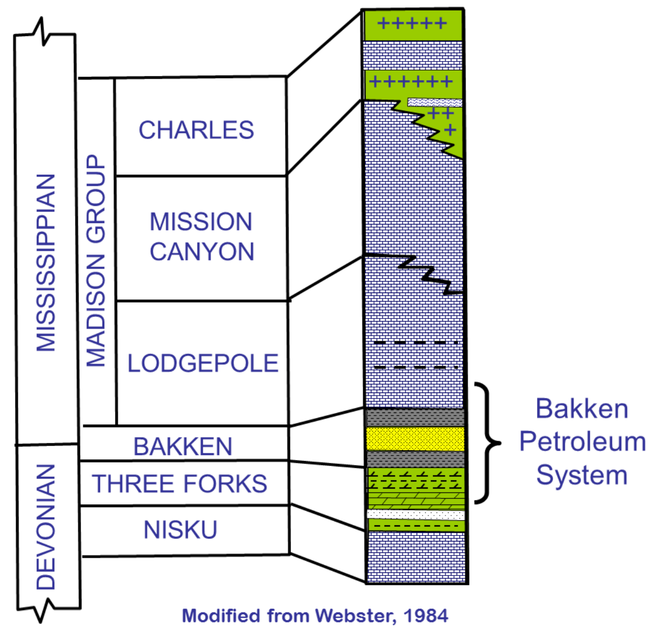


Figure 18. The Bakken petroleum system consists of reservoirs in the lower Lodgepole, Bakken, and middle and upper Three Forks. Technical recoverable resource from these intervals are approximately 4 billion barrels and 2 to 3 Tcf.

Dakota, but also in Montana, and even into Saskatchewan and southern Alberta.

Geologic History

The Williston Basin probably originated as a craton-margin basin and evolved to an intracratonic basin during the Cordilleran orogeny[4]. Sedimentation occurred throughout much of the Phanerozoic and the thickness of the stratigraphic section is approximately 16,000 feet. Many unconformities are described in the stratigraphic section, but rocks of all of the Phanerozoic time periods are represented by some deposits. Paleozoic strata consist mainly of cyclic carbonate deposits; the Mesozoic and Cenozoic strata consist mainly of siliciclastics.

During the Late Devonian and Early Mississippian, the basin was an area of active subsidence in a broad shelf area that existed along the western margin of North America. The proto-Williston Basin was an extension of

4. Gerhard, 1990

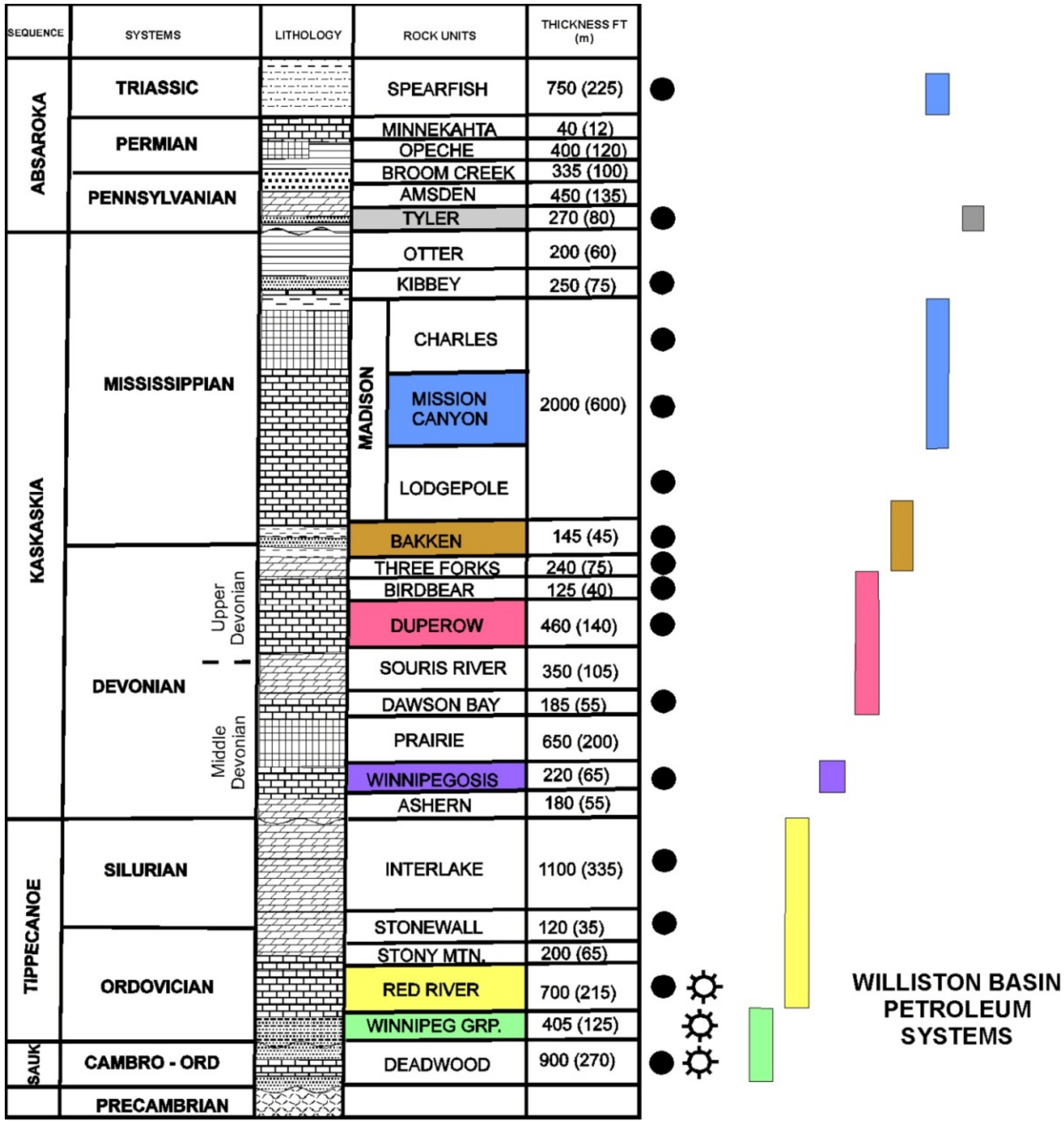


Figure 19. Stratigraphic column for the Williston Basin illustrating seven petroleum systems. The Bakken petroleum system consists of source beds in the Bakken (upper and lower shales) and reservoirs in the lower Lodgepole, middle Bakken, and middle and upper Three Forks. Modified from LeFever 1992; Anna, 2009.

the Devonian Elk Point Basin of Canada and situated in tropical regions near the equator.

Three Precambrian provinces underlie the Williston Basin: Superior craton, the Trans-Hudson orogenic belt, and the Wyoming craton[5]. These provinces trend north-south and structures associated with them have strongly influenced later sedimentation and structural features. Notable structural features with a north grain in the Williston Basin include the Nesson, Billings, Little Knife, and Tree Top anticlines. Northwest-trending prominent structural feature include the Cedar Creek, Antelope, and Poplar anticlines. Periodically these structural features reactivated through time[6].

The structure of the Williston Basin at the base of the Mississippian is illustrated in Figure 17. The basin is semi-circular in shape and prominent structural features are the Nesson, Billings, Little Knife, and Cedar Creek anticlines. Many of the structural features have a documented ancestral origin and influenced Paleozoic sedimentary patterns[7]. Recurrent movement on Precambrian faults

5. LeFever, 1992

6. LeFever, 1992; Gerhard et al., 1990
7. Gerhard et al., 1990

or shear zones is seen elsewhere in the Rocky Mountain region[8].

The Nesson anticline is the location of the first oil discoveries in the 1950s. The first oil production on the Nesson anticline was from the Silurian Interlake formation in 1951 and subsequent oil production was established from the Mississippian Madison Group (the main producer in the basin). The Williston Basin produces mainly oil from several Paleozoic reservoirs. The probable source rock to reservoir rock petroleum systems is illustrated by Figure 19.

The Bakken petroleum system is thought to have created a continuous type of accumulation in the deeper parts of the Williston Basin[9]. A continuous accumulation is a hydrocarbon accumulation that has some or all of the following characteristics: pervasive hydrocarbon charge throughout a large area; no well-defined, oil- or gas-water contact; diffuse boundaries; commonly is abnormally pressured; large in-place resource volume, but low recovery factor; little water production; geologically controlled "sweet spots"; reservoirs commonly in close proximity to mature source rocks; reservoirs have very low matrix permeability; and water occurs up-dip from hydrocarbons. The Bakken petroleum system meets all of these characteristics.

Many of the reservoirs in the Bakken petroleum system have low porosity and permeability (i.e., 6% to 10% porosity and less than 0.1 md permeability). Productive areas or "sweet spots" are localized areas of improved reservoir permeability through natural fracturing or development of matrix permeability, or a combination of both.

Major Fields

The Elm Coulee, Parshall and Sanish fields are among the major fields that have propelled the Williston onto the national stage as a major U.S. oil-producing area. But there are many others that characterize this important basin's history. Although the first wells were drilled in the basin in the early 1950s, it took nearly 50 years of further exploration before the Elm Coulee field was discovered in 2000 with horizontal completions in the middle Bakken. The Elm Coulee field is located in the western part of the Williston Basin in northeastern Montana. Prior to horizontal drilling in 2000, the area had scattered

1953	**Discovery of Antelope Field Establishment of production in Bakken and Three Forks**
1961	**Shell Elkhorn Ranch #41X-5-1 drilled, discovery well for depositional limit play on Billings Nose Established production from upper Bakken shale**
Late 1970s	**Vertical well drilling upper Bakken shale on Billings Nose**
1987	**First horizontal well drilled in upper Bakken shale in Billings Nose area**
1996	**Albin wells completed in middle Bakken "Sleeping Giant" concept developed**
2000	**First horizontal wells in middle Bakken Elm Coulee Field discovered**
2006	**Parshall, Sanish Fields discovered**

Figure 20. Bakken Exploration History in U.S. Williston Basin.

vertical well production (marginal to uneconomic) from the Bakken, with the Bakken as a secondary objective for wells targeting deeper horizons.

Horizontal drilling began in Elm Coulee in 2000 and to date over 600 horizontal wells have been drilled. Horizontal drilling and fracture stimulation of the horizontal leg are important technologies that enable a low permeability reservoir to produce. Stratigraphic trapping plays a key role at Elm Coulee[10]. The estimated ultimate recovery for the Elm Coulee field is over 200 MMbbl of oil. Cumulative production from the Elm Coulee area from the Bakken to April 2010 totaled 122 MMbbl of oil and 100 Bcf of gas.

Another major field in the basin is the Parshall field on the east side of the Nesson anticline, which was discovered in 2006 with a horizontal completion in the middle Bakken. EOG drilled and completed the 1-36 Parshall (Sec. 36, T150N, R90W) producing 463 b/d of oil and 128 Mcf/d of gas. Through April 2012, the field has produced 58 MMbbl of oil and 25 Bcf of gas from 241 wells completed in the Bakken and Three Forks formations. This field illustrates that significant production from the middle Bakken and Three Forks exists in North Dakota. The Parshall field connects to the Sanish field to the west and the Ross field to the north. The Sanish was also

8. Weimer, 1980
9. Nordeng, 2009

10. Sonnenberg and Pramudito, 2009

discovered in 2006 by Whiting Petroleum. The field has produced 44 MMbbl of oil and 29 Bcf gas through April, 2012 from 319 wells.

Williston Exploration

Antelope Field

This section reviews the history of Williston exploration and discovery of these and other fields. The Bakken has seen several cycles of exploration and development since the 1950s (see Figures 20 - 22). The earliest discovery occurred in the Antelope field of North Dakota in 1953 and development continued into the 1960s with 63 wells that targeted the Bakken and upper Three Forks on a tightly folded structure.

The wells were drilled vertically and after a sand-oil fracture stimulation treatment, were capable of producing an average of 209 b/d. Antelope field has produced 11 MMbbl of oil and 20 Bcf of gas from the Three Forks/ Bakken interval. The average cumulative production per Three Forks well was 550 Mbbl of oil and 1.4 Bcf of gas.

Following the Antelope discovery, exploration proceeded slowly. All three members of the Bakken and the upper Three Forks were perforated in Antelope and production established these formations as petroleum reservoirs in the basin. Interestingly, recent horizontal

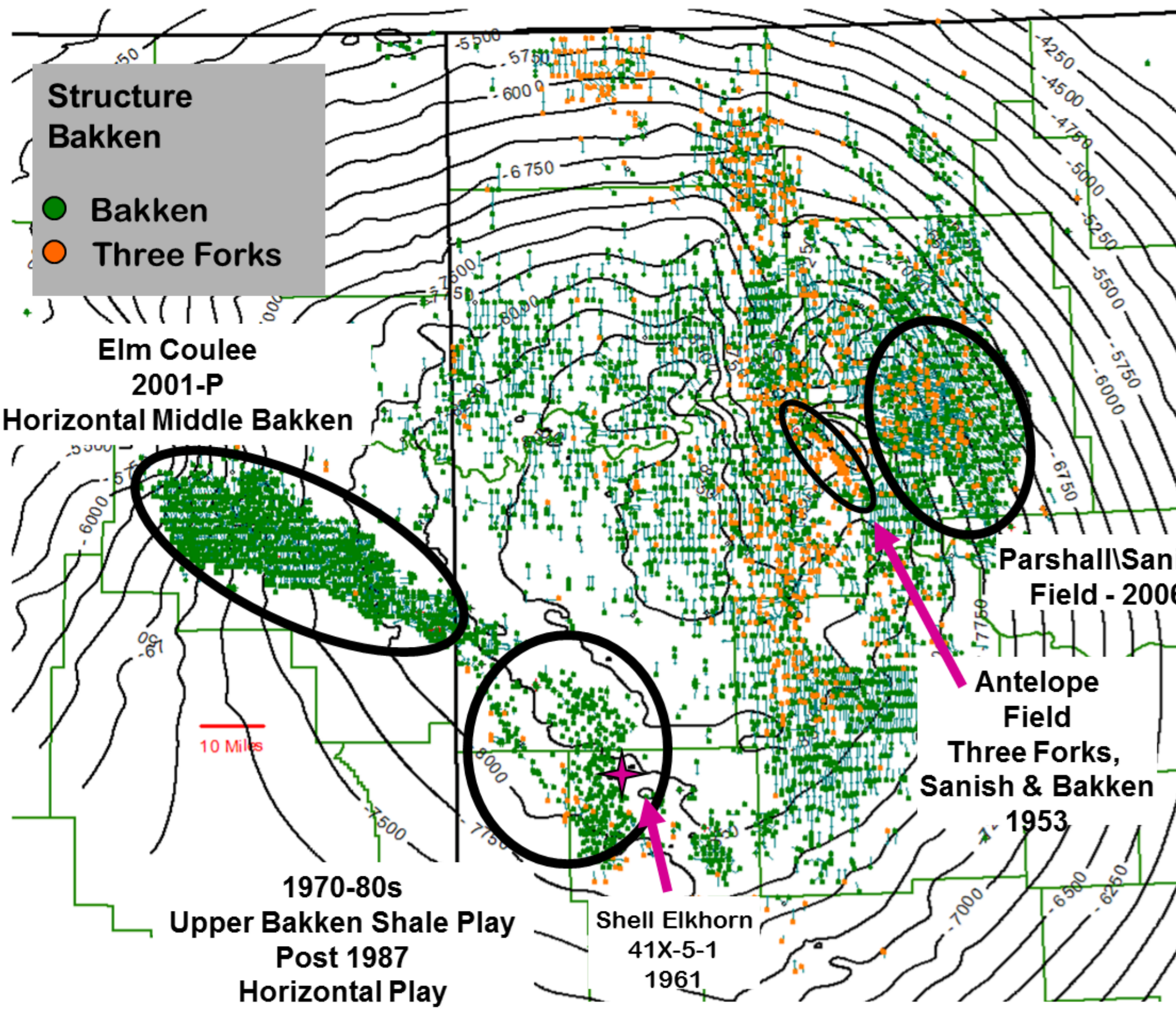


Figure 21. Drilling history of the Bakken petroleum system includes the following: first discoveries Antelope Field 1953; Shell Elkhorn 41X-5-1 well completed in 1961; Elm Coulee development 2000 to present; Parshall/Sanish development 2006 to present. Most of the other productive areas shown have been drilled since 2005.

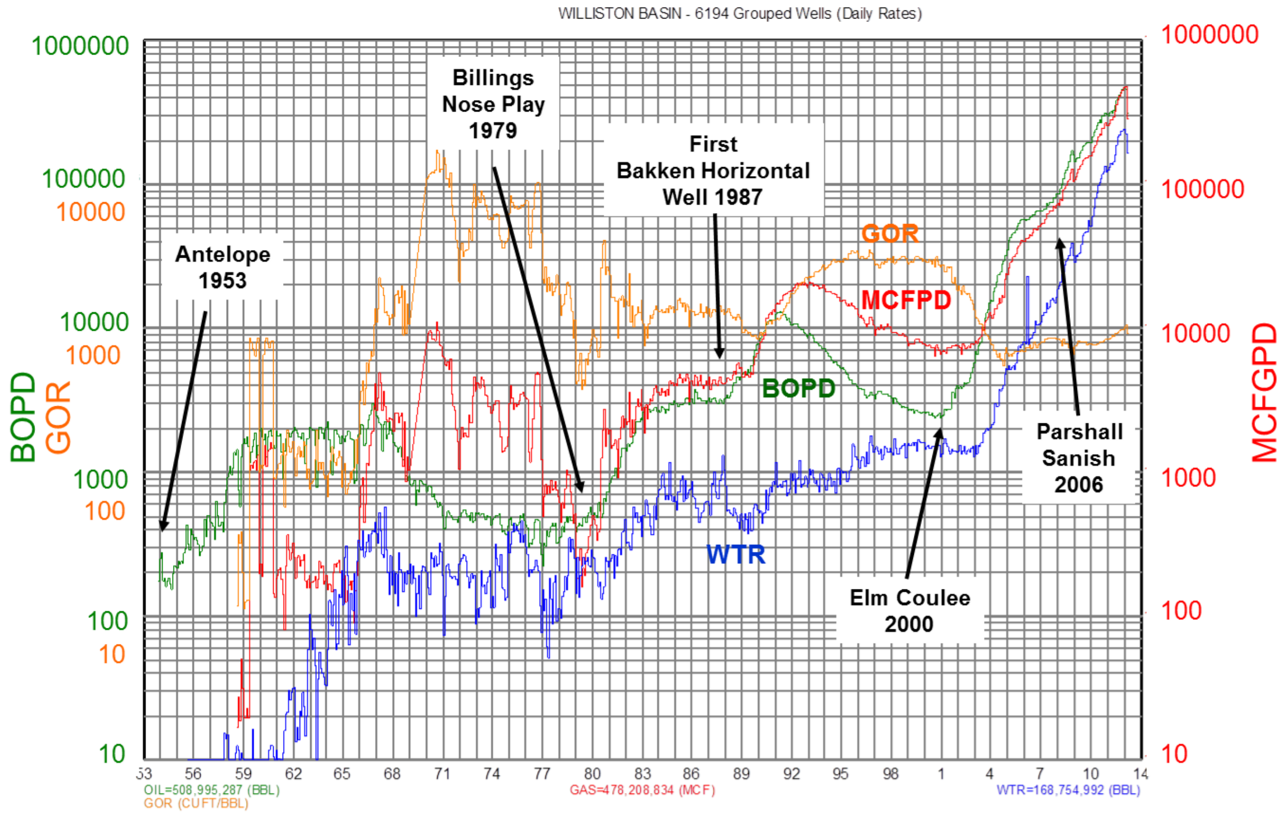


Figure 22. Production curve for the Bakken and Three Forks, U.S. Williston Basin. Several cycles of activity are noted: Antelope discovery and development; Billings Nose vertical play (1979) followed by Billings Nose horizontal wells 1987 to 1994; Elm Coulee discovery and development (2000 to present); Parshall/Sanish and other developments from 2006 to present.

wells have been drilled in the Antelope field area with very good results.

Elkhorn Ranch Field

The next significant discovery in the Bakken was by Shell in the Elkhorn Ranch field in 1961[11]. The upper Bakken shale was completed in the well as a secondary objective after the deeper primary objective, the Red River zone (Ordovician), was not successful. The Elkhorn Ranch well was significant in that it showed that reserves could be found in the upper Bakken shale. Because of product prices and remoteness, the next Bakken well was not drilled until 1976 (see Figures 21 - 22). This area then became known as the "Bakken Fairway" area and occurs along the southwest margin of the Bakken depositional basin in the general area of the Billings Nose (see Figure 17). Where the Bakken thins, fracture density increases[12]. Wells drilled in the "fairway" targeted the upper Bakken shale and other Paleozoic horizons (both shallower and deeper). Sand-oil fracture stimulation treatment was used on these wells.

Horizontal drilling in the upper Bakken shale commenced in 1987 in the fairway area[13]. The first horizontal well, drilled by Meridian, was the #33-11 MOI well (Sec. 11, T143N, R102W, Elkhorn Ranch field) which had a horizontal displacement of 2,603 feet in the Bakken. The well produced a steady 258 b/d of oil and 299 Mcf/d of gas for the first two years. The success of this well set off the horizontal drilling phase of the upper Bakken shale. The play continued into the 1990s with over 20 operators. Product prices declined significantly in the 1990s, and along with the somewhat unpredictable production in the upper Bakken shale, brought this phase to a close. The fairway play met with mixed results. Good producing wells were often offset with poor producing wells. In addition, some pressure depletion and cross-well communication was reported[14]. Because of mixed results in the fairway trend and low product prices, the Bakken again returned to the status of being a secondary objective rather than a primary exploration objective. This status

11. Billings Nose area
12. Sperr, 1991

13. LeFever, 2006
14. LeFever, 2006

changed with the discovery of significant reserves in the middle Bakken in the Elm Coulee field. The discovery and development of the middle Bakken resulted in the most significant of the exploration cycles to date.

Elm Coulee Field

The Elm Coulee in Richland County, MT, was discovered in 2000. The play was conceived by a Billings independent, Dick Findley, who had noted mud log shows in the middle Bakken while targeting deeper Nisku targets. The key well for identifying the potential in the Bakken was the Kelly/Prospector Albin FLB 2-33 well (Sec. 33, T24N, R57E; Richland County). The well, drilled to test the Nisku and the deeper horizons was unsuccessful, so the Bakken secondary objective was pursued. The 2-33 well was perforated in only the middle Bakken because of the indications of hydrocarbons seen on the mud log (whereas the upper shale typically would be perforated as well). The well was treated with a water-sand fracture stimulation (instead of the more normal oil-frac) consisting of 80,260 gallons of water and 151,800 pounds of sand. The middle Bakken flowed 157 barrels of oil for the first 20 days beginning in March of 1996 and was producing 80 b/d of oil after three months. The results of this well were very encouraging and thus the concept that a large field existed in the area that had previously been developed through with over 100 wells. An area 4 to 5 miles wide and 30 miles long was mapped out where the porosity development along with high resistivity was observed. Findley originally termed his prospective area "sleeping giant" because it had been drilled through many times. Several re-entries/recompletions were done in the late 1990s to pursue the play (the price of oil at the time the play developed was $8 per barrel). Horizontal drilling in the middle member started in 2000 which lead to the discovery and continuous development of the Elm Coulee field since that time. Individual horizontal wells are sand-water fracture stimulated and have initial production of 200 to 1200 b/d of oil and estimated ultimate recoveries of 300 to 750 MMbbl of oil per well. The field is estimated to have an ultimate recovery of greater than 200 MMbbl of oil (Walker et al., 2006). Technology plays a very important role in this development with horizontal drilling and fracture stimulation.

The Elm Coulee discovery and development prompted operators to also target the middle Bakken in North Dakota. Prior to Elm Coulee most operators targeted only the upper shale in the Bakken. The expansion of the play into North Dakota is currently underway and has resulted in new discoveries including the Parshall and Sanish fields. Denver independent Michael Johnson is credited for recognizing the potential of the Parshall area, putting an acreage block together, and selling the prospect to EOG Resources. EOG is credited for recognizing the potential of the area and drilling the discovery well. Whiting Petroleum geologist, Orion Skinner, is credited for recognizing the thick Bakken development in areas east of the Nesson anticline and acquiring acreage in what turns out to be the Sanish field (adjoins the Parshall field). The new discoveries in North Dakota suggest the existence of an extremely large unconventional resource play. Product prices will probably influence this cycle too. Although regarded as a maturely drilled basin, the Williston continues to yield giant oil discoveries.

Parshall-Sanish Fields

Horizontal wells in the Parshall-Sanish areas target specific facies (C, D, E) of the middle Bakken. Production is related to fracture development and matrix development in the middle Bakken. The original oil-in-place in the Parshall greater area is estimated by various operators to be 8 to 11 MMbbl of oil per section for the Bakken and 4 to 6 MMbbl per section for the Three Forks. Wells are drilled on either 1280-acre spacing units or 640-acre spacing units. Estimated ultimate recoveries for the Bakken are 600 to 900 MMbbl of oil per section; estimated ultimate recoveries for the Three Forks are 350 to 500 MMbbl of oil per section. The recovery factor for the tight reservoirs is approximately 8%. Current well costs are in the $5 to $6 million range. Because of high production rates, wells can pay out in four to six months. Some operators prefer the 1280-acre spacing units over the 640-acre spacing units because of cost savings associated with drilling one well rather than two. Operators are fracture-stimulating wells with more than ten frac stages. On the west side of the Nesson anticline, one operator is reported to have used 36 frack stages in a 10,000 ± foot lateral.

Additional Exploration

Various methods have been proposed to explore for the Bakken (Sperr, 1991; Rogers and Mattox, 1985). The methods include: exploring along the depositional edge (more susceptible to fracturing and fracture spacing decreases as bed thickness decreases); exploring structural flexures and lineaments; looking for Prairie Salt dissolution areas as they may be areas of more intense fracturing; looking for geothermal anomalies (increased hydrocarbon generation may cause more intense fracturing); looking for primary reservoirs (i.e., middle Bakken); looking for fractured areas identified by well logs. The fracture signature on well logs has been described by Hansen and

Long (1991). Recognition of fractures on well logs will be discussed further in a subsequent section.

The latest cycle of exploration and development in the Williston Basin is the most significant to date. Production for the U.S. part of the Williston Basin has gone from 2,500 b/d of oil to nearly 500,000 b/d of oil (see Figure 22).

Bakken Geology

The Bakken formation ranges in thickness from a wedge edge to over 140 feet, with the thickest area located in northwest North Dakota east of the Nesson anticline. The three members of the Bakken become thin and converge toward the margins of the basin and have an overlapping relationship with the underlying Three Forks formation. The contact between the Bakken and Three Forks is probably conformable in the deep parts of the basin and unconformable along the basin flanks. The Bakken also is overlain by the Lodgepole formation.

The three members may represent two regressive-transgressive cycles of sedimentation[15]. Following Three Forks deposition, major uplift and erosion occurred along the margins of the basin[16]. With a subsequent relative sea-level rise and low-energy transgression, the lower Bakken shales were deposited. Another regressive event resulted in the middle Bakken depositions followed by the next transgressive event which deposited the upper Bakken shale.

The upper and lower shale members are potential source rocks and are lithologically similar throughout much of the basin[17]. The shales are potential source beds for the Bakken, Three Forks and Lodgepole/Mission Canyon formations[18]. The shales are dark-gray to black, hard, siliceous, slightly calcareous, pyritic, massive to fissile and generally either break along horizontal fractures or with conchoidal fractures. The shales contain radiolaria, conodonts, ostracodes, small cephalopods, small brachiopods, and Tasmanites (algae) fossils[19]. The shales are dissimilar in that the upper shale lacks limestone and the greenish-gray shale beds found locally in the lower shale[20]. Secondary pyrite occurs disseminated throughout the shale interval and as individual laminations and lenses. The shales consist of dark organic material, clay, silt-sized quartz, and some calcite and dolomite. The shale is kerogen-rich in the deeper parts of the basin and the organic material is distributed evenly throughout. The Bakken kerogen is an amorphous kerogen inferred to be sapropelic and the composition consists of 70% to 95% amorphous material, zero to 20% herbaceous material, up to 30% coaly material (recycled opaque material), and 5% woody material[21]. Webster (1984) believes the amorphous material has an algal origin because of the high hydrocarbon-generating capacity of the material determined from pyrolysis (> 500 mg HC/g OC at shallow depths). He describes the total organic carbon (TOC) content of the Bakken shales as averaging 11.3%. Schmoker and Hester (1983) derived an equation to calculate TOC content using bulk density logs.

The upper and lower shale are interpreted to have been deposited in an offshore marine anoxic or oxygen-restricted environment during periods of sea level rise[22]. The anoxic conditions may have resulted from a stratified hydrologic regime[23]. The stratified water column is envisioned as having an upper water layer that is well oxygenated and nutrient rich. High organic production occurred in this layer (probably planktonic algae). With the death of the organisms, they sank through stagnant bottom waters and were deposited. Anoxic conditions are created by restricted circulation and in part by destruction of organic matter by consuming organisms that remove oxygen and release hydrogen sulfide[24]. Anoxic conditions are indicated by the lack of benthic fauna and burrowing, and high TOC content. The Bakken may be part of a continent-wide anoxic event that took place from Late Famennian through Kinderhookian time[25]. The Bakken is correlative with the Woodford-Percha-Leatham-Sappington-Exshaw-Cottonwood Canyon source rock facies of the western Cordilleran and southern craton-margin geosynclines and the Antrim-Sunbury-New Albany-Chattanooga and equivalent source rock facies of the Appalachian geosyncline[26].

The Bakken is not thermally mature throughout the Williston Basin. The shales are thermally immature in the eastern part of the basin and characterized on well logs by low resistivity (i.e., water-wet). In the western Williston, the shales are characterized by high resistivity and thought to be oil-wet[27]. Hydrocarbons are non-con-

15. Meissner et al., 1984
16. Webster, 1984
17. Webster, 1984; Dow, 1974
18. Meissner et al., 1984
19. Webster, 1984
20. Pitman et al., 2001

21. Webster, 1984
22. Pitman et al., 2001; Webster, 1984; LeFever et al., 1991; Price, 1984
23. Webster, 1984; Smith and Bustin, 1996; 2000
24. Webster, 1984; Meissner et al., 1984
25. Meissner et al., 1984
26. Meissner et al., 1984
27. Meissner, 1978

ductive, which results in the extremely high resistivities. Further evidence of the presence of hydrocarbon saturation comes from core analyses and also plots of pyrolysis data (i.e., production index versus depth plots or pyrolysis S1 versus depth plots) with depth[28]. These data clearly indicate that the Bakken shales are oil-saturated where they have high resistivity. Wetability tests in the Bakken illustrate that the upper and lower shales are oil-wet while the Lodgepole, middle Bakken, and Three Forks intervals are water-wet[29]. Price (2000) and Price and LeFever (1992) noted the extremely high oil-to-water ratios associated with Bakken production suggesting most of the water has been displaced by the hydrocarbon generation. The ratios are 200 to 800:1 with the mean being 300:1. The small amount of co-produced water may be dissolved in Bakken oil, and exsolves during production or it can be produced from matrix of the reservoir rocks.

Organic maturity has recently been modeled using the Time-Temperature Index (TTI) method by Nordeng (2008) and Nordeng and LeFever (2008). Their models suggest that organic maturity started approximately 100 million years ago. Carlisle (1991) suggests that hydrocarbon generation started in the early Cretaceous. Webster (1984) utilized TTI plots to conclude that oil generation initiated approximately 75 million years ago (late Cretaceous).

A lot of the oil generated in the Bakken black shales may have been expelled into the middle member of the Bakken or the upper Three Forks. A part of the oil generated also remained in the Bakken shales. Price and LeFever (1994) also presented evidence that most of the oil generated in the Bakken stayed in the Bakken and did not migrate into the overlying Madison group. Earlier investigators thought the Bakken shales sourced reservoirs in the Bakken and the entire Madison group[30].

The middle member of the Bakken was deposited in a shallow-water setting following a rapid sea level drop, resulting in a regressive event[31]. In the central part of the basin, the middle member consists of argillaceous, greenish-gray, highly fossiliferous, pyritic siltstones which indicate an environment that was moderately well-oxygenated but occasionally dysaerobic. The upper parts of the middle member have cross-stratified sandy intervals which suggest strong current action[32].

28. Webster, 1984; Price et al., 1984

29. Cramer, 1986, 1991

30. Dow, 1974; Williams, 1974; Meissner, 1978

31. Meissner et al., 1984; Smith and Bustin, 1996

32. LeFever et al., 1991

The mineralogy of the middle Bakken is variable across the basin and consists of 30% to 60% siliciclastic material (quartz and feldspar), 30% to 80% carbonate (calcite and dolomite), minor matrix material (illite, smectite, chlorite, and kaolinite)[33]. The sources of the detrital fraction in the middle Bakken are thought to be from the north and northwest (Webster, 1984).

The middle Bakken can be subdivided into multiple facies (see appendix A-2)[34]. All the facies are thought to be shelf related and appear to represent a shallowing upward sequence followed by a water-deepening event. The facies from bottom to top are: facies A, a fossiliferous calcareous siltstone; facies B, bioturbated calcareous clay-rich siltstone to very fine-grained sandstone; facies C, a thinly-bedded to laminated calcareous very fine-grained sandstone; facies D, the highest energy facies, and consisting of fine-grained sandstone to carbonate grainstones; facies E, the start of the water deepening and consisting of thinly-bedded, occasionally microbial-laminated, to parallel laminated siltstone; and facies F, a fossiliferous dolomitic to calcitic siltstone. The facies are widespread across the Williston Basin with some exceptions. Facies D is only locally developed; the amount of dolomite changes from area to area; production is associated with matrix development in facies C, D and E and microfracturing. Facies B and C produce at Elm Coulee (facies D is not present) whereas, facies C, D and E produce in the Sanish and Parshall areas.

Thickness variations in the Bakken result from a variety of factors including varying depositional rates, paleostructures created by either basement fault movement or Devonian Prairie evaporite dissolution and the onlap of units towards the basin edges. Structural features such as the Nesson anticline have dramatically influenced Bakken depositional patterns and also influenced hydrocarbon migration. The thickest Bakken in the Williston Basin occurs just to the east of the Nesson anticline. The thickening in this area occurs in all three members of the Bakken formation.

Prairie Salt Formation

The Devonian Prairie Salt evaporite occurs about 800 to 1100 feet (244 to 335 meters) beneath the Bakken formation. Regional and local dissolution is known to have occurred in the Prairie[35]. Dissolution occurs both as a roughly linear front and also in isolated semi-circular

33. LeFever, 2007

34. LeFever et al., 1991; Canter et al., 2008

35. LeFever and LeFever, 2005; Gerhard et al., 1990; Parker, 1967; Rogers and Mattox, 1985; Martiniuk, 1991 areas. Dissolution of the Devonian Prairie evaporite occurred at multiple times during the Paleozoic and Mesozoic (Rogers and Mattox, 1985; Parker, 1967). Isopach thicks in formations above Prairie thins help document the timing of dissolution. Models suggested for salt dissolution include: (1) depositional facies control (dissolving fluids move through permeable beds adjacent to the salt horizon); (2) compaction and dewatering of surrounding sediments (supplied the fluid necessary for salt dissolution); (3) surface water recharge at the outcrop (resulting basinward flow dissolved salts); (4) direct or indirect result from minor tectonic movement related to Precambrian basement features (e.g. faults created pathways for fluids)[36]. Dissolution of the Prairie occurred during Bakken time and affected Bakken sediments[37].

Upper Three Forks Formation

Note: See appendix for supplemental figures.

The upper Three Forks is evolving into a significant resource play in the basin (see Figures A-1 and A-2). To date over 829 wells (including the older wells at Antelope) have been completed in the upper Three Forks. The upper Three Forks consists largely of silty dolostones which are interbedded with green chloritic mudstone. A variety of facies have been reported in the upper Three Forks which range in depositional environment from subtidal to supratidal[38]. Locally a burrowed sandstone or dolomite unit named the Sanish or Pronghorn is present at the top of the upper Three Forks. Debate exists whether the sandstone belongs in the Three Forks or if it is part of the Bakken Formation. LeFever (2011) has proposed that the name Sanish be eliminated and the Pronghorn name replace it.

The Pronghorn and upper Three Forks have low permeabilities and porosities. The original discovery at the Antelope field in 1953 established the Sanish/Pronghorn and upper Three Forks as a viable reservoir in the Williston Basin. The upper Three Forks remained fairly dormant until recently-drilled horizontal wells have indicated its large potential.

The NDIC has recently estimated that the Three Forks will have recoverable reserves of 1.9 billion barrels of oil across much of the Williston Basin. The Three Forks play coincides with the Bakken play adding significantly to the reserves across the basin.

Middle Three Forks Formation

The middle Three Forks also consists largely of silty dolostones which are interbedded with green chloritic mudstones. The facies are similar to the upper Three Forks and the depositional environment is thought to be subtidal to supratidal. The reservoir characteristics of the middle Three Forks are similar to those of the upper Three Forks.

Continental Resources in their May 2012 investor presentation announced the results of two middle Three Forks wells. The CLR Charlotte 2-22H had an initial production of 1396 barrels of oil equivalent per day (boe/d) and the CLR Sunline 11-1TF-25H had an initial production of 1023 BOE/d. Thus, the early results from the middle Three Forks are encouraging.

Bakken and Three Forks Reservoirs

The Bakken reservoirs range from silty dolostones and sandstones to bioclastic limestone units. In most areas the reservoir is characterized by low porosity (< 10%) and low permeability (< 0.1 md) from core analysis. Fracturing is not included in these numbers. Several authors have noticed that dolomitization of the reservoir plays a role in the development of matrix permeability and also makes the reservoir more brittle in terms of its mechanical stratigraphy.

The Bakken is interpreted as being deposited in an intertidal to subtidal environments of deposition.

The Three Forks (both middle and upper) are interpreted to be silty dolostones with similar low porosities and permeabilities to those observed in the middle Bakken. The Three Forks has significantly more clay interbeds than the middle Bakken.

Production and GOR Analysis

Note: See appendix for supplemental figures.

Figure 22 illustrates the dramatic recent production increases observed in the Williston Basin from the Bakken and Three Forks. The production chart also illustrates that the gas-oil-ratio (GOR) changes with time. The GOR from both the Antelope and Billings Nose areas increased

36. LeFever and LeFever, 2005; Martiniuk, 1991
37. Martiniuk, 1991; Rogers and Mattox, 1985; Sperr, 1991
38. Dumonceaux, 1984; Berwick, 2008

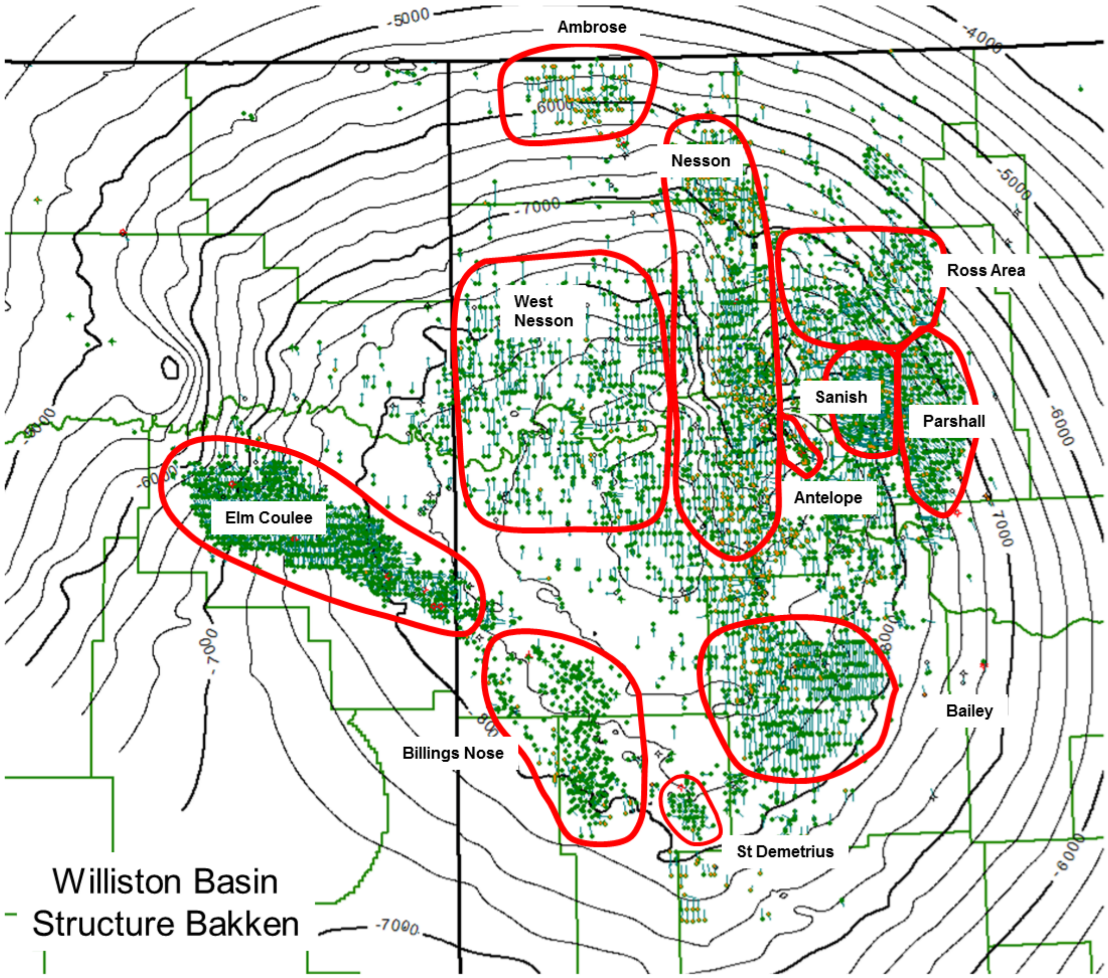


Figure 23. Areas studied in this report for production and GOR analysis.

dramatically after several years and after new wells ceased to be drilled. GORs start at less than 1 Mcf/bbl and increase to over 2 Mcf/bbl in many cases.

Figure 23 and supplemental figures in the appendix (A-3 to A-35) examine production and GORs from several areas in the Williston Basin. Figure 23 shows the areas studied in this report for production and GOR analysis. The U.S. Williston Basin has been subdivided into the following areas for this analysis: Antelope, Billings Nose, Elm Coulee, Parshall, Sanish, Nesson Anticline, Ambrose, West Nesson, Bailey and St. Demetrius.

Antelope Area

The Antelope area was discovered in 1953. Initial production was 200 b/d of oil and increased to approximately 3000 b/d of oil during the development of the field. The field was developed with vertical wells in the 1950s but currently the flanks of the field are being developed with horizontal wells. Initial GORs were 0.2 Mcf/bbl but increased to over 10 Mcf/bbl when development drilling ceased. During the 1980s and 1990s the GOR was 4 to 5 Mcf/bbl . Cumulative production from the Bakken/Three Forks is 14.9 MMbbl and 29.3 Bcf gas. The recent horizontal drilling activity in the field has lowered the field GOR substantially. The current field GOR is about 1 Mcf/bbl.

Billings Nose Area

The Billings Nose area was developed in the late 1970s and 1980s by vertical wells targeting the upper Bakken shale. The Billings Nose area has produced over 36 MMbbl oil and 70 Bcf gas. In 1987 the first upper Bakken shale horizontal was drilled. Horizontal drilling continued into the early 1990s until the price of oil collapsed. Production in the area peaked during 1991-1992 at over 10 Mb/d. The GOR for the area was approximately 1 Mcf/bbl from 1976 to 1990. After 1990 the GOR gradually increased to more than 3 Mcf/bbl. Recent horizontal drilling activity has lowered the GOR because of dramatic increases in oil production.

Elm Coulee Area

The Elm Coulee area of Montana was discovered in 2000 and development continues today. Elm Coulee has largely been developed on 1280-acre spacing. Elm Coulee has produced 122 MMbbl of oil and over 100 Bcf gas. The field GOR during the 2000s has gone from 0.5 Mcf/bbl to more than 1 Mcf/bbl. The reason for the increase in GOR is that the number of infill wells has decreased dramatically. The GOR trend at Elm Coulee is on a fairly continuous upward trend.

Parshall Field

The Parshall Field was discovered in 2006. The field has been developed by EOG on 640-acre spacing. Most of the wells are oriented north-northwest. The field has produced 57.9 MMbbl of oil and 25.3 Bcf of gas. The GOR for the field is much lower than other producing areas largely because it is located at the up-dip margin of Bakken production. The GOR has gone from approximately 0.25 to 0.6 Mcf/bbl.

Sanish Field

The Sanish Field is located to the west of Parshall. The field has closely-spaced Bakken wells in addition to recent Three Forks wells and is drilled on 1280-acre spacing. The field has produced 43.8 MMbbl of oil and 28.6 Bcf of gas. The field is down-dip from Parshall and has a higher GOR. The GOR has ranged from 0.5 Mcf/bbl to approximately 0.8 Mcf/bbl.

Nesson Anticline

The Nesson anticline has Bakken production that dates back to the late 1950s. The recent drilling activity on the anticline has dramatically increased production. Cumulative production for the studied area on the

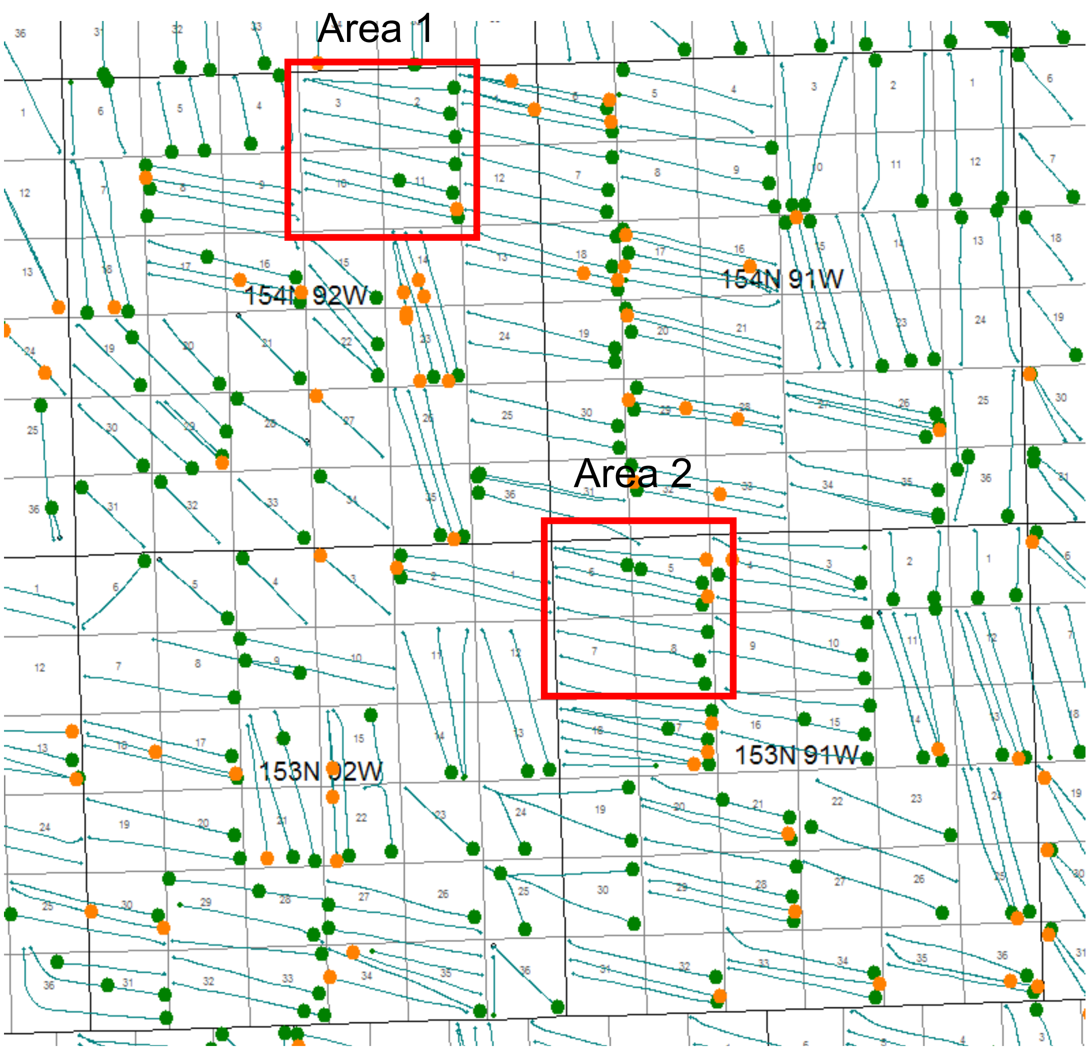


Figure 24. Two areas were selected in the Sanish field to determine if any affects of infill drilling could be observed . Area one is sections 2, 3, 10, and 11, T154N, R92W; Area two is sections 5, 6, 7, 8, T153N, R91W. Both areas contain at least six Bakken wells.

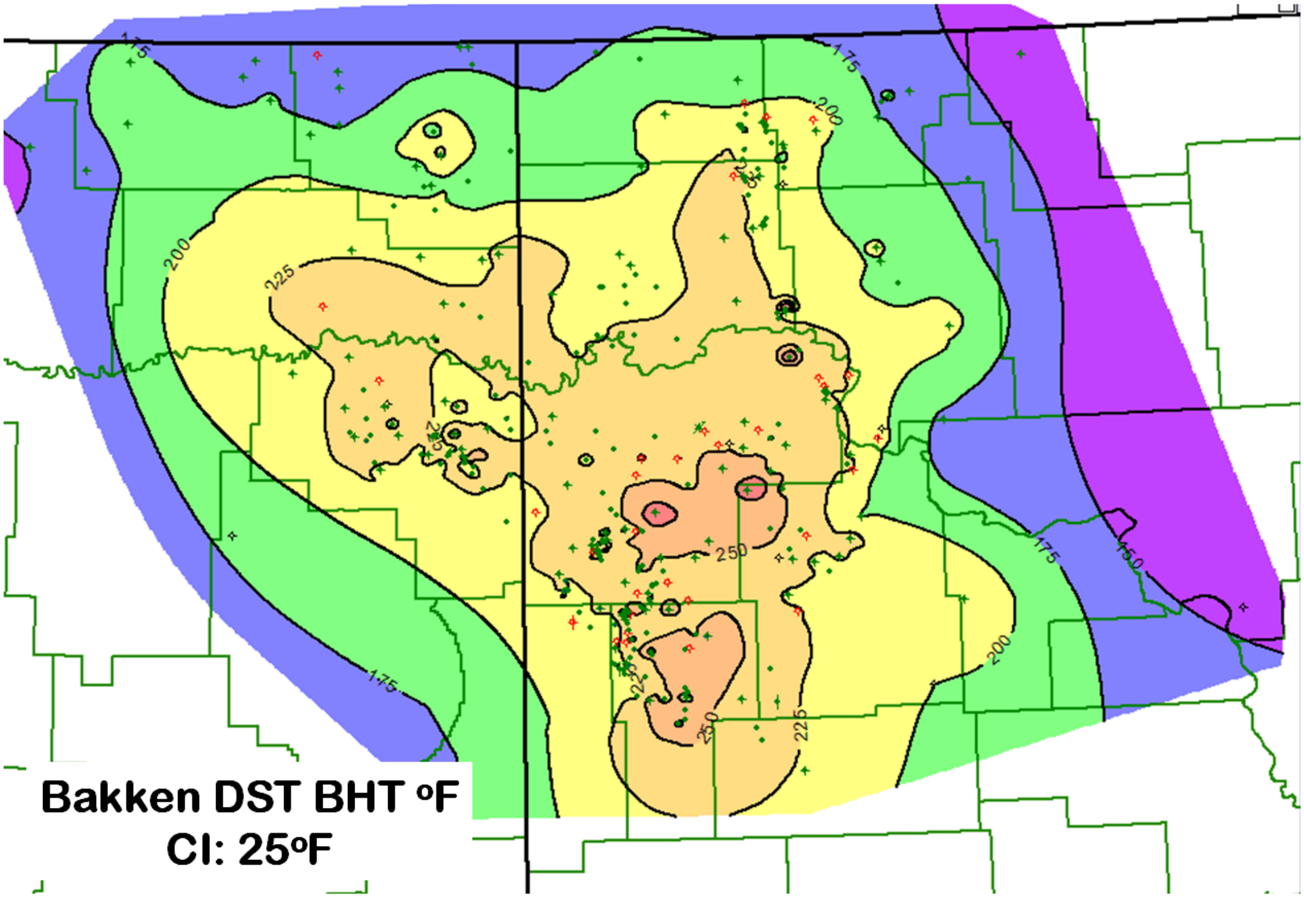


Figure 25. Bakken bottom hole temperature map from DST data. Note the high bottom hole temperatures in central part of map.

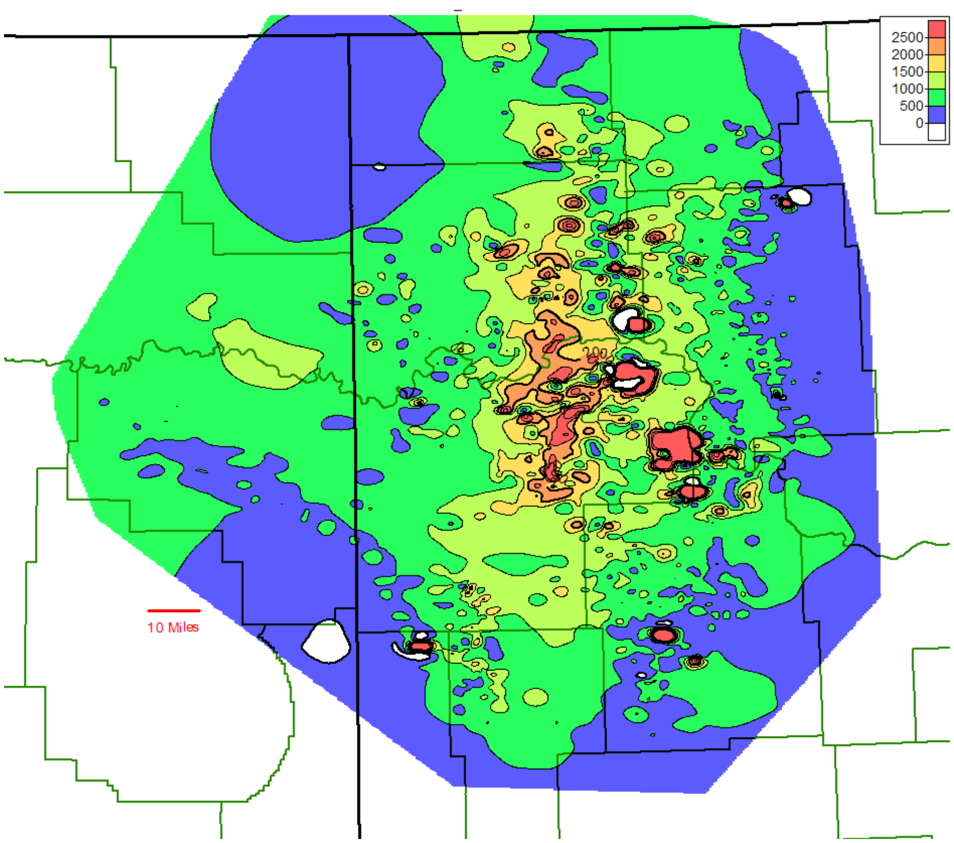


Figure 26. Initial GOR data from IPs. Highest GOR values coincide with high bottom hole temperatures.

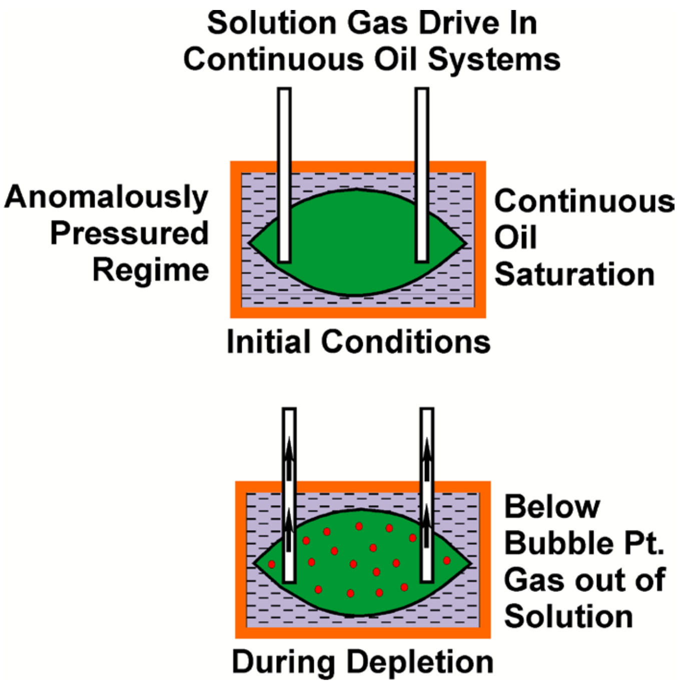


Figure 27. Solution gas drive mechanism for continuous oil reservoirs. Below the bubble point, gas will come out of solution in the reservoir. This results in the higher GORs seen through time in the Bakken.

Nesson anticline is 73.3 MMbbl oil and 116 Bcf of gas. The GOR for the area is higher than surrounding areas because of gas migration and the presence of the anticline. The GOR is about 1.5 Mcf/bbl and is on the increase. The ending GOR on Figure A-20 is approximately 1.9 Mcf/bbl. The daily rate of oil production on the Nesson anticline is about 80 Mb/d of oil. The GOR in this area is expected to rise once infill activities have ceased. The GOR in the past has been 10 Mcf/bbl.

Ambrose Area

The Ambrose area is northwest of the Nesson Anticline. The area is being drilled on 1280-acre spacing. The area is largely operated by Samson and consists mainly of wells drilled to the Three Forks. The area has produced 4.2 MMbbl oil and 3.5 Bcf of gas. The GOR has been around 1 Mcf/bbl.

West Nesson Anticline

The West Nesson anticline area is located west of the Nesson anticline and east of the North Dakota – Montana border. This area has historical Bakken production which dates back to 1981. The area is currently being drilled on 1280-acre spacing. Brigham and others have recently raised production from this area to over 100 Mb/d of oil and 100 MMcf/d of gas. Cumulative production from the area is 36.9 MMbbl of oil and 43 Bcf gas. The GOR in the past has been high (>5Mcf/bbl) but is currently around 1 Mcf/bbl because of the enormous recent drilling activity. Overall oil production from this area has increased dramatically.

Bailey Area

The Bailey study area is located southeast of the Nesson area and contains 506 wells. Cumulative production is 36 MMbbl oil and 21 Bcf gas. The area is drilled on 1280-acre spacing. The GOR is currently about 0.6 Mcf/bbl. Historical GOR numbers have been around 1 Mcf/bbl.

St. Demetrius Area

The St. Demetrius study area is located east of the Billings Nose study area and has a cumulative production of 1.3 MMbbl oil and 1.3 Bcf gas. The area was developed after Elm Coulee using largely dual laterals and 1280-acre spacing. The GOR has been steady at 1 Mcf/bbl.

Ross Area

The Ross study area is located north of the Parshall field. This area has cumulative oil production of 20 MMbbl oil and 13.5 Bcf of gas and is being drilled on 1280 acre spacing. The GOR for this area is between 0.7 and 0.8 Mcf/bbl.

Infill Drilling Activity

Two areas in the Sanish field study were picked to see if any significant changes could be observed in the areas associated with infill drilling (Figure 24). The first area is located in sections 2, 3, 10 and 11 in T154N, R92W. The second study area is located in sections 5, 6, 7 and 8 in T153N, R91W. Each area is about 4 square miles and contains up to six Bakken wells.

Decline curves were examined for each area to determine if any depletion issues could be observed or if any significant changes in GOR were occurring (see appendix).

The production decline curves show that initial rates for infill drilling locations are similar to the original wells in the area. Initital production (IP) rates and production are a function of the geology, drilling and completion.

The two examples examined above did not show any dramatic change in IP rates over time.

Bottom Hole Temperatures and Initial GOR from IPs

Initial GORs are related to the bottom hole temperature observed in the Bakken petroleum system. Figures 25 and 26 compare the bottom hole temperatures (extracted from DST data) with the IP data reported from the completion reports. In general, a temperature anomaly occurs in the middle part of the Williston Basin. This temperature anomaly coincides with geochemical data anomalies reported by Price et al., 1984.

A western extension of this heat flow anomaly also causes elevated temperatures and higher GORs in northern Richland and southern Roosevelt counties, MT.

The highest GORs observed in North Dakota coincide with the bottom hole temperature anomalies and also the presence of the Nesson anticline.

The Parshall field area has the lowest GOR values and coincides with the eastern limit of Bakken production. The Sanish field area is slightly higher and ranges from 0.5 to 1 Mcf/bbl. Elm Coulee GOR values initially were approximately 0.5 Mcf/bbl.

Continuous Oil Drive Mechanisms

Continuous oil accumulations have a reservoir drive mechanism that is solution-gas or depletion drive (see Figure 27). A depletion drive reservoir is one in which the predominant producing mechanism is fluid expansion. There is not a down-dip water accumulation available for pressure support. Gas is in solution in the reservoir until the bubble point is reached. Once the bubble point is reached in the reservoir, both an oil phase and gas phase will be present. This generally results in a dramatic increase in gas production in wells in addition to a decrease in oil production. Thus, this reservoir drive mechanism results in gas-oil-ratio changes during the life of the field and wells (i.e., the GOR rises through time).

Williston Oil & Gas Production

Oil production from the Williston Basin has soared more than 400% in the past five years to more than 800 Mb/d as of this June, establishing the Bakken as one of the top oil-producing plays in the United States. This massive oil production growth has been accompanied by a substantial increase in associated natural gas production. Although gas makes up a small part of the production stream from Williston wells, Williston gas production still has grown more than 250% from January 2005 to an average of more than 600 MMcf/d in June 2012. Both oil and gas production from this basin are expected to grow between 2012 and 2025 even if oil prices decline to $50/bbl.

The Williston has substantial room to grow, and producers are planning to ramp up drilling even more. The basin covers 143,000 square miles. To date, only about 15% of the area has been drilled, including about 6,800 total wells. The North Dakota section of the Williston contains 5,300 wells, while on the Montana side, about 1,500 wells have been completed. The North Dakota Oil & Gas Division expects drilling and infrastructure development could continue in the Bakken region for the next 15 to 20 years, with another 10,000 wells drilled during that period. Then, oil production may continue for another 50 to 100 years.

In April 2008, the USGS estimated the amount of technically recoverable hydrocarbons in the Bakken — using technology available at that time — at nearly 3.65 billion bbl of oil, 1.85 Tcf of gas and 148 MMbbl of liquids. The agency said the Bakken was the largest continuous oil reserve in the Lower 48 states. However, the USGS is about to complete another reserves study of the basin in 2013 and is expected to reveal a much larger resource than what was found in the first study. Harold Hamm, CEO of Continental Resources, the largest producer in the play, believes the Williston Basin could contain up to 24,000 MMbbls of technically-recoverable oil. The first USGS study did not even consider the reserve potential of the Three Forks formation, which underlies the Bakken.

Activity & Guidance

BENTEK expects this producing area to grow rapidly over the next five years, representing the largest incremental oil supply increase in the Rocky Mountain region and far overshadowing production growth from its southern neighbors, the Uinta and the Niobrara plays. Producers are flocking to the basins and long-standing operators are planning to increase drilling. The vast resources of the Williston Basin will provide Americans with a reliable source of energy for decades to come.

The number of rigs operating in the Bakken hit a new peak of 231 in June, compared to just 41 horizontal rigs in May 2009. Of all rigs operating in the basin, 96% are drilling horizontal wells. The number of active operators in the Williston has risen to nearly 50 compared to fewer than 30 at the beginning of 2007. Many Williston operators that have disclosed their drilling plans have indicated an eagerness to ramp up drilling in North Dakota, but if producer guidance is accurate, oil pipeline takeaway capacity could remain constrained and producers will continue to be reliant on rail transportation.

Continental Resources

This section provides a snapshot of operators in the basin. There are several well-known larger companies operating in the play as well as pure-play drillers who are exclusively drilling in the basin. The most active operator is Continental Resources, which had 76 rigs in operation in June. The company has been the most active operator from the beginning of 2006. Since then, Continental has almost tripled its production. The company's Bakken production grew 51% in the year between 2Q2010 and 2Q2011, and 58% of Continental's 421 MMboe of proved reserves are located in the Williston.

Continental is the pioneer of a number of technological advances in the basin that have now become the norm. The company was the first to complete a 1,280-acre, long-lateral multi-stage frac in 2007. Continental also was the champion of the 24-hour continuous frac (2009), and first to develop a four-well, single-pad drilling concept (ECO-Pad Technology). These technical advances pioneered by Continental have enabled it to achieve some of the highest initial production rates in the basin. In 2007 and 2008, the company moved to long laterals and continuous frac operations. IP rates rose as a result. In 2007, 30-day IP rates averaged 154 b/d. By 2009, they had risen by 53% to 292 b/d. Data shows further improvements in 2010 and 2011 as Continental continued to refine its operations. Continental's production-growth target for year-end 2011 was 36-39% higher than in 2010, with the majority of the growth coming from the company's Bakken activity.

Whiting Petroleum

Whiting Petroleum is the second most-active producer in the Williston Basin. Whiting, like Continental, is mostly a pure-play Bakken producer with 18 active rigs in June. About half of Whiting's rigs are operating in the southern part of the basin in Billings, ND, in the Lewis and Clark field. Average 30-day IP rates for its wells drilled in the area came in at 430 Boe/d, according to the company.

Brigham Oil and Gas

Brigham Oil and Gas is another producer with most of its activity in the Bakken. It had 15 rigs operating in June. The company was acquired by Statoil last October in a cash deal valued around $4.7 billion. Through the purchase, Statoil gained 375,000 net acres in the Bakken and 40,000 net acres in other areas of the country. Brigham boasts some of the highest oil IP rates in the Bakken, at a 30-day average of 697 b/d per well during 4Q2010. This compares to a 30-day IP of 480 b/d for Whiting and 390 b/d for Continental during the same time. With a 12-rig program, Statoil should be able to complete 130 to 140 wells per year.

Hess

Hess is operating a 14-rig program with plans to ramp up to 16 rigs in the near future. The company owns approximately 900,000 net acres and expects to increase its production in the basin from 35,000 boe/d in 2011 to 120,000 boe/d in 2016. Hess is constructing a 54 Mb/d rail facility and expanding its Tioga Gas Plant to keep pace with and augment returns from its growing production.

Other Operators

While most of the top operators have plans to increase activity over the next year, Newfield Exploration is reducing its drilling activity in the Bakken. Rising service costs are the main reason. Newfield reported drilling and completion costs of $11 million per well in 3Q2011, an increase of nearly $2 million from a year ago. Newfield has reduced its operated rigs to three from the five it operated in September and is deferring 13 completions until the beginning of 2012. Smaller operators are likely feeling the burden of rising service costs more than the large established players in the basin.

Other prominent operators in the Williston include Petro Hunt, Marathon, EOG Resources, Oasis Petroleum, Exxon Mobil, Slawson Exploration, ConocoPhillips and Occidental Petroleum.

In summary, despite rising service costs, the top producers in the basin have plans to increase drilling over the next year. As shown in the section below, the strong economics of the Williston Basin continue to encourage increased activity.

Internal Rates of Return Analysis

A closer look at returns on investment in the Williston Basin reveals why producers are so eager to ramp up drilling in the basin. Williston wells on average provide producers with among the most attractive rates of return of any wells in other plays and basins across the country. High oil production rates and high BTU gas production are among the major reasons.

In order to determine the competitiveness of the major oil and gas producing plays in North America, BENTEK developed a financial model to calculate a representative internal rates of return (IRR) from typical wells in each play. The BENTEK IRR analysis includes data and information from company financials, including financial reports, investor presentations, news releases and transcripts from earnings calls. Producer-reported data is collected for multiple production characteristics and costs, including drilling and completion costs, operating expenses, initial production rates, BTU content, decline curves, production taxes and royalty rates. The production data is then reviewed in order to determine a representative set of assumptions for each play. IRRs allow for an apples-to-apples comparison of well economics between dry gas, wet gas and oil plays and are used to analyze how sensitive returns are to changes in gas prices, oil prices, NGL prices, drilling costs and initial production rates. It is important to note that the analysis does not take into account full-cycle exploration and production costs, which typically include costs for acreage acquisition and exploration. BENTEK considers these expenses to be sunk costs.

The IRR model is a discounted cash flow model and uses a 10% discount rate to calculate the return for a typical well in each play. BENTEK uses the 12-month average forward strip for each regional pricing point for the gas

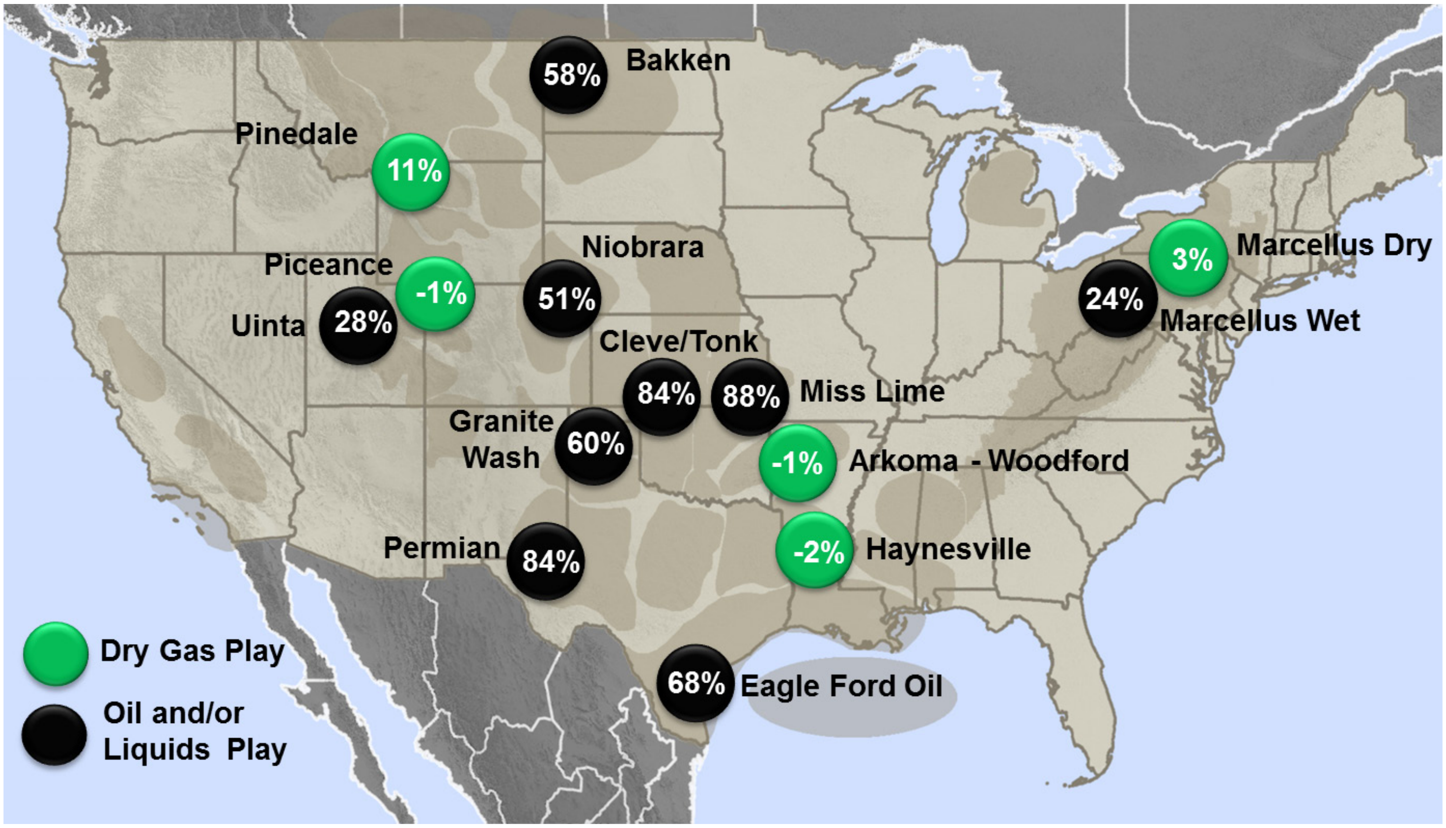


Figure 28. SOURCES: COMPANY REPORTS, BENTEK

price assumptions. The current gas price assumptions are in the range of $2.45 to $2.86/Mcf. The six-month average WTI crude price, plus or minus the regional price differential, is utilized for the oil price assumptions, which are currently in the range of $84.40 to $100.43/barrel. For natural gas liquids, a weighted average price is applied, based on current Mt. Belvieu prices and the average composition of a typical barrel of NGLs in each region. The NGL price assumptions are also adjusted for an average percent of proceeds contract for each region, resulting in current NGL prices in the range $22.60-$45.22 barrel.

The highest-return plays in North America are those with significant oil production and high BTU gas. At current prices, the plays in which the production mix is more heavily weighted towards oil yield the highest returns. These high-return oil plays include the Bakken, Permian, Eagle Ford, Niobrara and several plays in the Anadarko Basin.

With current price assumptions, a typical well in the Bakken is earning a healthy 58% return (see Figure 28). The Anadarko Basin, which stretches from the Texas Panhandle to western Oklahoma, includes plays with some of the best returns in the country, including the Granite Wash, Cleveland/Tonkawa and the Mississippi Lime. These plays all produce a valuable combination of oil and NGLs, pushing returns in the range of 60% to almost 90%. Texas also contains other high return areas, including the Permian Basin and the wet gas and oil windows of the Eagle Ford. In this low-gas-price environment, the dry plays are all struggling to achieve returns above the 10% cost of capital. In fact, the IRR in the Haynesville, and the dry areas of the Marcellus and the Arkoma-Woodford, are all hovering around zero. Refer to Figure 29 for some of the IRR data assumptions for a play-by-play comparison of some of the key producing areas that were included in the analysis.

When analyzing the attractiveness of a particular play, it is important to understand how sensitive the returns are to changes in prices and other assumptions included in the analysis. The returns for plays where the production mix is more heavily weighted towards oil are the most sensitive to changes in oil prices. Refer to Figure 30 for an overview of the production mix in each play. With the production mix in the Bakken so heavily weighted towards oil, fluctuations in oil prices have a direct impact on the revenue stream, and therefore, profitability. Like most of the oil plays included in the analysis, returns fall below 20% when oil prices approach $50/barrel as seen in Figure 31. With a considerable amount of NGL production in the mix, the return in the Mississippi Lime and Granite Wash plays of the Anadarko Basin earn a 30%

Major Data Assumptions for IRRs

Play/Basin	D&C Cost	Initial Production Rate (30-Day) Gas (Mcf/d)	Oil (B/d)	NGLs (B/d)	BTU Content	Processed GPM	IRR	Price Assumptions * Gas	Oil	NGL
Anadarko Cleveland/Tonkawa	$4,000,000	2,400	250	243	1,210	4.25	**84%**	**$2.74**	**$100.43**	**$25.46**
Anadarko Mississippian	$3,000,000	700	200	71	1,210	4.26	**88%**	**$2.74**	**$100.43**	**$25.46**
Arkoma-Woodford (Dry)	$5,000,000	4,200	-	-	1,020	-	**-1%**	**$2.72**	**-**	**-**
Bakken	$8,500,000	400	700	60	1,300	6.30	**58%**	**$2.85**	**$84.55**	**$28.95**
Cana-Woodford	$8,500,000	4,000	80	286	1,150	3.00	**10%**	**$2.74**	**$100.43**	**$25.46**
Eagle Ford Oil	$7,500,000	400	600	38	1,200	3.99	**68%**	**$2.82**	**$100.20**	**$25.05**
Eagle Ford Wet	$8,125,000	4,500	300	563	1,250	5.25	**38%**	**$2.82**	**$100.20**	**$25.05**
Granite Wash	$7,000,000	7,000	300	875	1,250	5.25	**60%**	**$2.74**	**$100.43**	**$25.46**
Haynesville	$8,875,000	11,000	-	-	1,020	-	**-2%**	**$2.86**	**-**	**-**
Horn River	$13,100,000	12,000	-	-	1,020	-	**-1%**	**$2.45**	**-**	**-**
Marcellus Dry	$5,000,000	5,500	-	-	1,020	-	**3%**	**$2.79**	**-**	**-**
Marcellus Wet	$5,000,000	4,500	-	295	1,140	2.75	**24%**	**$2.79**	**-**	**$45.22**
Montney	$5,500,000	4,500	35	134	1,080	1.25	**16%**	**$2.45**	**$87.00**	**$33.83**
Niobrara (DJ)	$4,500,000	400	300	55	1,270	5.78	**51%**	**$2.73**	**$90.40**	**$22.60**
Permian - Delaware Basin	$5,800,000	500	550	63	1,250	5.29	**84%**	**$2.76**	**$100.20**	**$24.75**
Piceance	$2,000,000	1,600	-	76	1,110	2.00	**-1%**	**$2.73**	**-**	**$22.60**
Pinedale	$4,800,000	6,000	40	-	1,020	-	**11%**	**$2.65**	**$88.61**	**-**
Uinta	$3,800,000	1,500	200	36	1,060	1.01	**28%**	**$2.73**	**$84.40**	**$22.60**

Figure 29. SOURCE: BENTEK

Production Mix for Major US Plays

Play/Basin	Production Mix Gas	Oil	NGLs	IRR
Anadarko Cleveland/Tonkawa	40%	31%	30%	**84%**
Anadarko Mississippian	26%	55%	19%	**88%**
Arkoma-Woodford (Dry)	100%	-	-	**-1%**
Bakken	6%	87%	7%	**58%**
Cana-Woodford	61%	8%	30%	**10%**
Eagle Ford Oil	8%	87%	5%	**68%**
Eagle Ford Wet	40%	21%	39%	**38%**
Granite Wash	43%	14%	42%	**60%**
Haynesville	100%	-	-	**-2%**
Horn River	100%	-	-	**-1%**
Marcellus Dry	100%	-	-	**3%**
Marcellus Wet	69%	-	31%	**24%**
Montney	81%	4%	15%	**16%**
Niobrara (DJ)	12%	74%	14%	**51%**
Permian - Delaware Basin	9%	81%	9%	**84%**
Piceance	76%	-	24%	**-1%**
Pinedale	96%	4%	-	**11%**
Uinta	50%	42%	8%	**28%**

Figure 30. SOURCES: COMPANY REPORTS, BENTEK ESTIMATES.

return at current NGL prices, even if oil were to fall to $50/barrel.

It is important to know what percentage of the production mix is natural gas and how to determine whether returns in a particular play are sensitive to changes in NGL prices and the BTU content of the gas. As in Figure 32, changes in NGL prices have the most impact on returns in the Granite Wash, Eagle Ford wet window, Anadarko-Cleveland and the wet region of the Marcellus. Each of those plays produce high BTU gas and have a production mix that is heavily weighted toward gas and NGLs. Even though the gas stream from a typical Bakken well has a relatively high BTU content, the returns in the Bakken are insensitive to changes in NGL prices because there is not a significant amount of gas produced from Bakken wells. And with lackluster demand putting downward pressure on ethane and propane prices, the price of a

IRR Sensitivities to Changes in Oil Prices

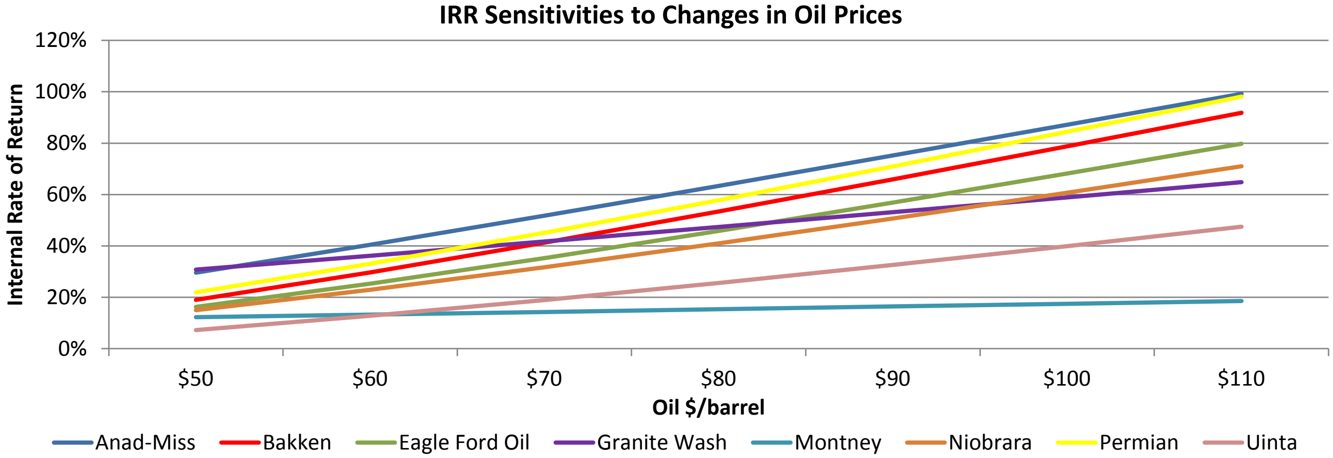


Figure 31. SOURCES: COMPANY REPORTS, BENTEK ESTIMATES. GAS AND NGL PRICES ARE HELD CONSTANT AT CURRENT ASSUMPTIONS.

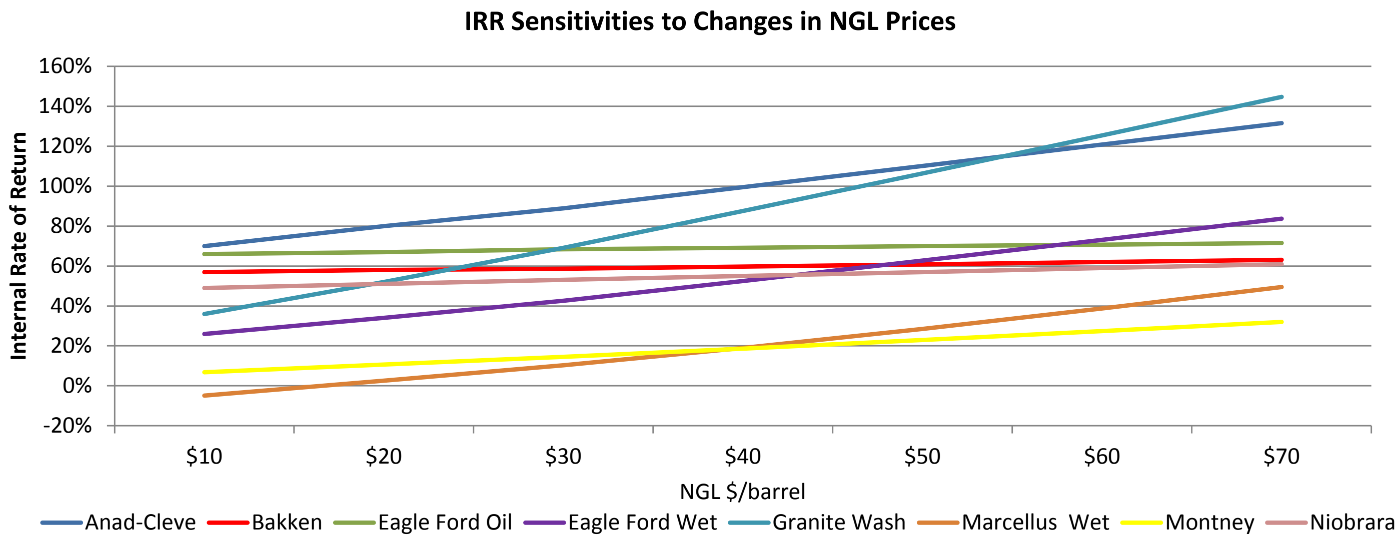


Figure 32. SOURCES: COMPANY REPORTS, BENTEK ESTIMATES. GAS AND OIL PRICES ARE HELD CONSTANT AT CURRENT ASSUMPTIONS.

typical barrel of NGLs has fallen in 2012. Therefore, those plays that rely more heavily on NGLs, such as the Granite Wash and the wet window of the Eagle Ford, have experienced declining returns in 2012.

IRR Sensitivities to NGL Prices

Currently there is limited ethane extraction or NGL pipeline infrastructure in the Bakken, which has forced producers to keep ethane in the gas stream (known as ethane rejection). With ethane prices falling significantly this year, Bakken producers would not benefit from processing ethane. With the production mix in the Bakken so heavily weighted toward oil, fluctuations in gas and NGL prices have an immaterial influence on returns in the play. In fact, if a producer were to choose to flare the gas and give away the NGLs, the current Bakken IRR would only fall from 58% to 56%. Conversely, if gas and NGL prices were to rise to $7/Mcf and $50/barrel, respectively, the return for a typical well in the Bakken would only increase a few percentage points.

Drilling and completion costs rose for many plays in 2011, as companies were under pressure to provide completion services to the rapidly-growing rig counts in many liquids-rich and oil plays across the U.S. While service costs rose in most plays last year, the Bakken, Eagle Ford and the Granite Wash saw the largest increases in average drilling and completion costs, at least $1 million per well. However, as long as oil prices remain strong, the IRRs for those plays that produce oil will remain robust.

While a Bakken well is more expensive to drill and complete than most other plays, Bakken wells produce a significant amount of oil. Figure 33 shows IRR sensitivities to drilling and completion costs and oil initial production rates. As Bakken producers, such as Abraxas Petroleum and Continental Resources, move increasingly toward pad drilling, drilling and completion costs should decrease, improving returns. Bakken producers are also drilling longer lateral wells, which are more expensive, but result in higher IP rates. For example, a 9,000-foot lateral well in the Bakken would cost approximately $11 million to drill and complete, produce at an initial rate of 1,000 b/d, and earn a return around 67%.

When compared to the other major oil and gas producing plays in North America, the Bakken provides better-than-average returns in the current price environment where the economics of wet-gas plays are not as favorable as a year ago when an average barrel of NGLs was approximately $50/bbl. Figure 34 shows the returns for the Bakken and other oil-producing basins at an oil price of $70/bbl and NGL prices. The NGL price is based on a relationship with the oil price and varies from 30% to 50% NGL:Oil. The figures reveal that the Bakken is

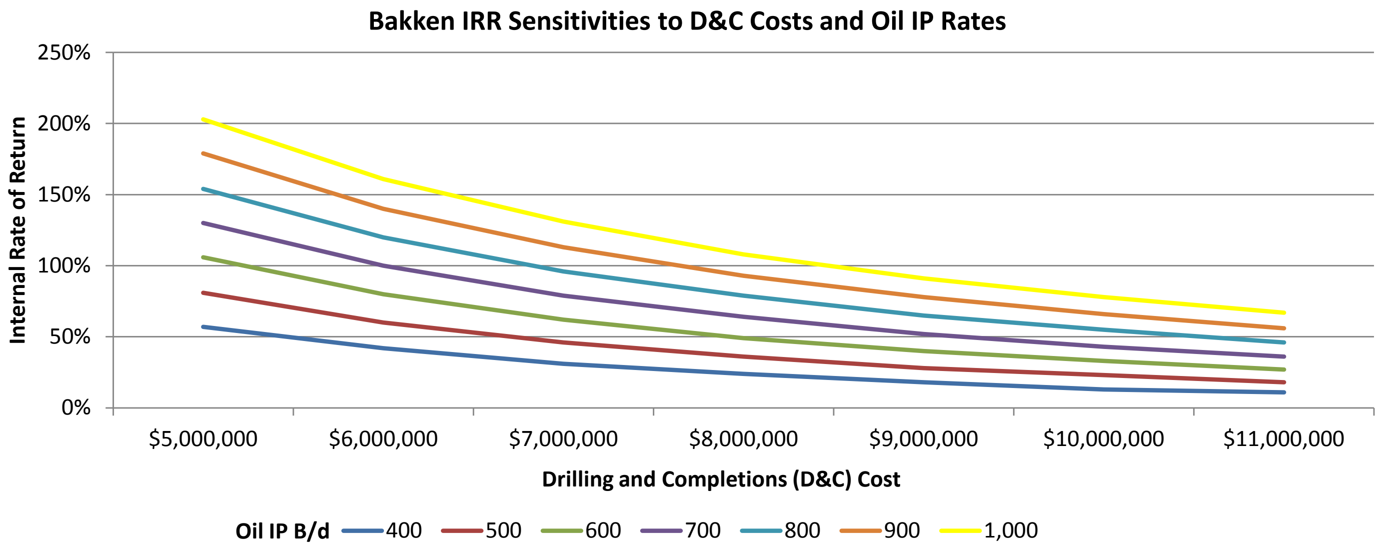


Figure 33. SOURCES: COMPANY REPORTS, BENTEK ESTIMATES

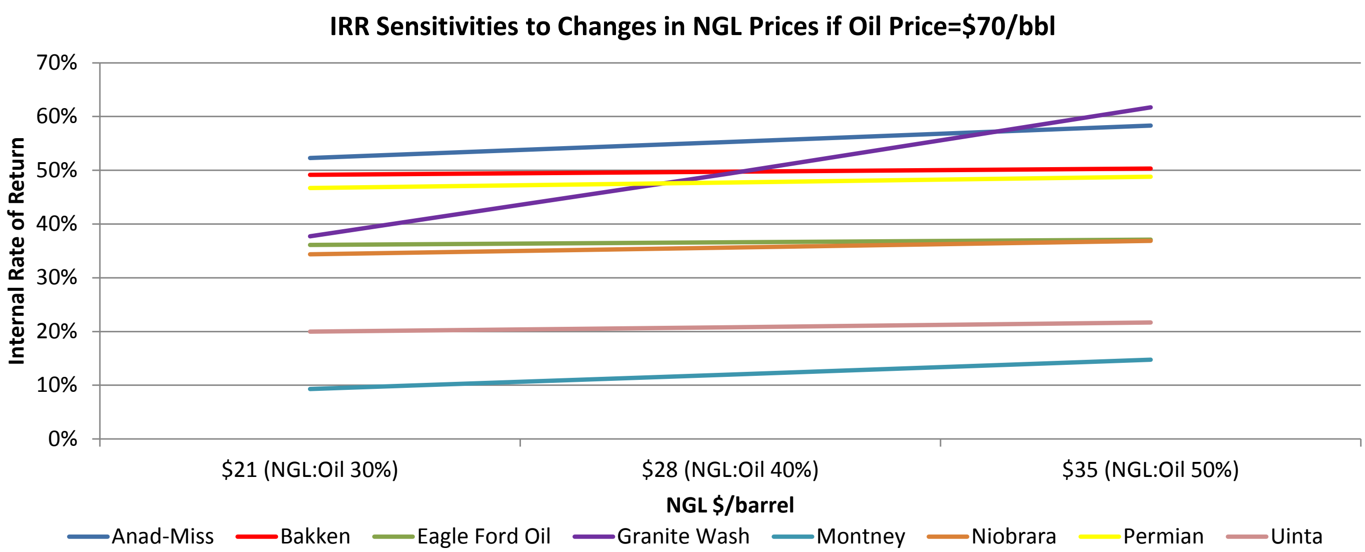


Figure 34. SOURCE: COMPANY REPORTS, BENTEK ESTIMATES.

competitive and remains attractive in a wide range of NGL price scenarios.

Scenario Analysis

Strong economics are the key driver of Williston Basin oil production growth and will continue to propel the basin's output higher in the future. The current pace of drilling is sufficient to push the Williston to an average of 1,777 Mb/d in 2017 and 2,180 Mb/d in 2025 from about 480 Mb/d in 2011. The majority of the growth will come from the North Dakota portion of the basin.

BENTEK has assembled three possible production scenarios for the Williston Basin. First, the Base Case will be considered where adequate oil infrastructure exists for the next five years. Additionally, the High Case considers the impact of inadequate oil pipeline capacity and drilling efficiencies throughout the basin. The final scenario, the Low Case, predicts the production from the region should wellhead oil prices fall to $50.

For all scenarios, BENTEK assumes an oil IP rate of 400 b/d and gas IP rate of 340 Mcf/d. The production declines inherent in BENTEK's oil and gas decline curves are shown in Figure 35. In general, oil production from Williston wells declines more quickly than gas production, resulting in a GOR of 1.5 in the later years of well life. As discussed in the Production and GOR Analysis section

Williston Basin Decline Curves- Annual Rates

Year	Oil Decline Rate	Gas Decline Rate
1	65%	58%
2	30%	30%
3	22%	10%
4	19%	5%
5	16%	5%
6	10%	5%
7	10%	5%
8	5%	5%
9	5%	4%
10	2%	2%

Figure 35. SOURCE: BENTEK

of the Williston Basin Geology chapter, a GOR of this level has been observed historically in the Williston Basin.

Base Case

In BENTEK's Base Case scenario, the number of wells drilled in the future remains fixed at 2012 levels of approximately 2,350 wells per year through 2021. After this time, the number of new wells begins to decline as the prime drilling locations are developed across the most prospective acreage. In Figure 36, the lines represent the wells drilled each year. The lines become horizontal beginning in 2012, reflecting the wells drilled reaching a plateau of 2,400 in North Dakota and an additional 250 in Montana. In 2022, the lines develop negative slopes as the inventory begins to deplete.

Since 2006, drill days have remained in the range of 25 to 30 days as the lateral length of wells has nearly doubled, as shown in Figure 37. This trend suggests that producers continue to identify drilling efficiencies to offset the increasing lateral lengths. BENTEK expects that lateral will remain near the 9,000-foot level for the near future, allowing producers the opportunity to realize drilling efficiency gains. The bars in Figure 36 show rigs declining to 124 in North Dakota and 13 in Montana from current levels of 195 and 19, respectively, reflecting these gains.

BENTEK believes the most significant driver of the efficiency gains will be the switch from drilling a single horizontal well per pad to pad drilling such as Continental Resources' method. Based on available data, Continental has drilled 4 wells from a single ECO-Pad in as little as 48 days, equating to an average of 12 days per well. Considering all of the results, Continental averages 19 days to drill each of the four wells from an ECO-Pad. By comparison, the average time to drill a single well from a pad in the Williston Basin between 2010 and June 2012 was 30 days, suggesting efficiency gains of at least 11 days are possible.

Figure 38, demonstrates the efficiencies realized by Continental in the basin. Each bar represents an ECO-Pad, which targets two wells in the Bakken and two wells in the Three Forks. Each of the wells requires less time to drill than an average horizontal well in the region.

Based on the estimated drilling and completion cost savings of 10% per well, Continental plans to add nearly 30

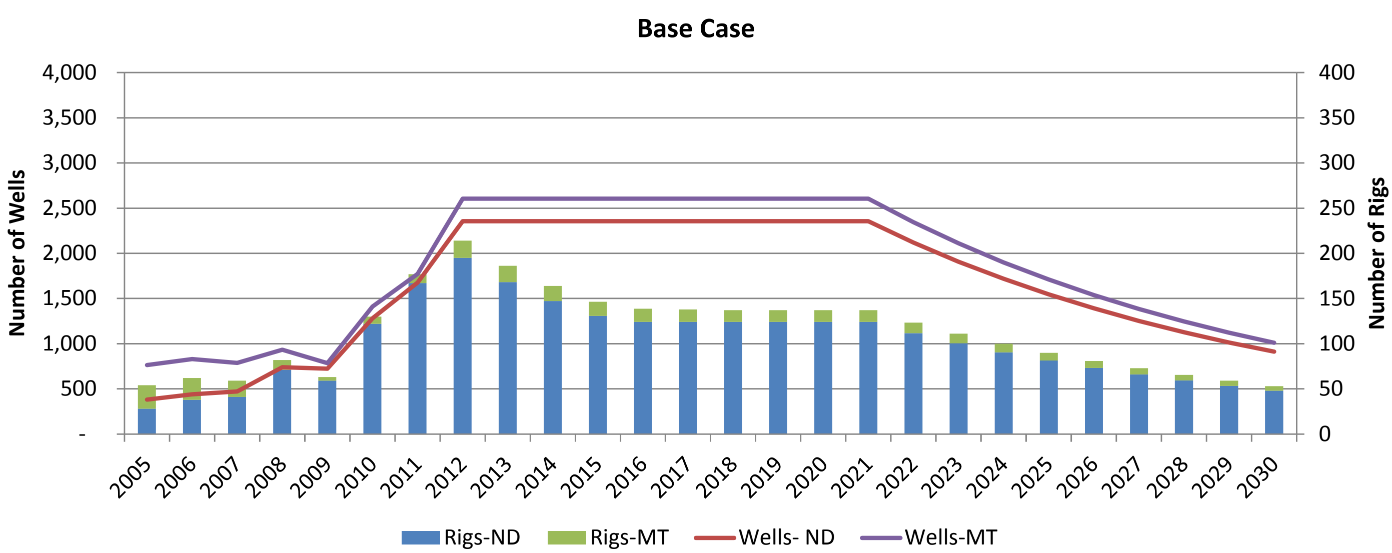


Figure 36. SOURCES: BENTEK, RIGDATA, HPDI

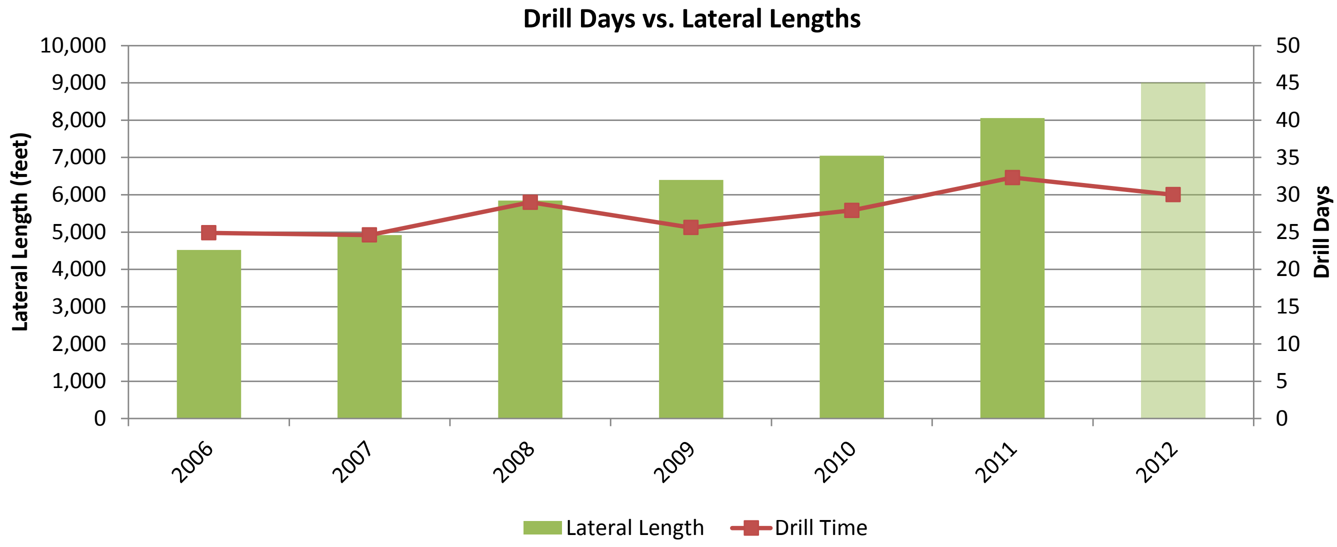


Figure 37. SOURCES: BENTEK, RIGDATA, HPDI

ECO-Pad projects in 2012. Other producers are likely to follow suit, given the opportunity to realize similar efficiency gains and cost reductions.

The efficiency gain of decreasing drill times will be included in our scenario forecasts and assumes all rigs move to pad drilling by 2016. Currently, one well is drilling 10 to 11 wells every year. By 2016, one rig will be able to drill 19 wells per year based on efficiency gains achieved by pad drilling. That represents nearly a 90% increase in efficiency per rig over the next five years.

High Case

In BENTEK's High Case scenario, the number of wells drilled will remain at just under 2,900 wells per year, the level which is forecasted for 2013. The number of active rigs will decline from 202 in 2013 to 152 in 2016, as drilling efficiencies from pad drilling are realized. Beginning in 2016, the rig count plateaus at 152. The reduction in rigs over time stems from the expectation that efficiencies from pad drilling will offset any rig declines. Figure 39 shows the active rig and well assumptions for this scenario. Note that at the peak in 2018, over 3,500 wells will be drilled each year with 187 active rigs in North Dakota and Montana.

Low Case

In the Low Case, BENTEK assumes that field (wellhead) prices fall to $50/bbl for a sustained period of time. The core areas of McKenzie, Mountrail, Dunn and Williams counties will continue to see drilling activity, but at a slower pace. The price drop will force 70 rigs out of operation in North Dakota between 2012 and 2013. A total of 123 rigs will be out of operation by 2016 in North Dakota, representing nearly 20% of the current fleet. Another 15 rigs will leave the Montana portion of the basin by 2016. See Figure 41 for North Dakota rig count details by county.

The price decline would have a larger impact on active rig count in areas that have the lowest internal rates of return. Specifically, BENTEK believes rigs would cease to operate in these fringe areas and internal rates of return would fall below 10%. Due to the significant rig declines, approximately 1,400 wells would be drilled each year in North Dakota and Montana between 2013 and 2021 as shown in Figure 40. The number of new wells will decline more quickly beginning in 2022 as drill site inventories are exhausted.

Migration of Drilling Activity

The future drilling areas of the Williston Basin are as follows: 1. Area between Billings Nose and west Nesson; 2. area north of west Nesson; 3. North Ross; 4. East Roosevelt County, MT; 5. Poplar Dome area; 6. Sheridan and Daniels counties, MT (see appendix A-48). Operators are currently drilling wells testing these expansion areas. Some of these lands are tribal lands or federal acreage which may slow down the drilling and testing.

Area 1 is between the Billings Nose area and the west Nesson area in southern McKenzie County, ND. Operators have had excellent results in this area to date.

Area 2 is located in northern Williams County, ND, and southern Divide County, ND. The area has potential for both middle Bakken and Three Forks. New wells have

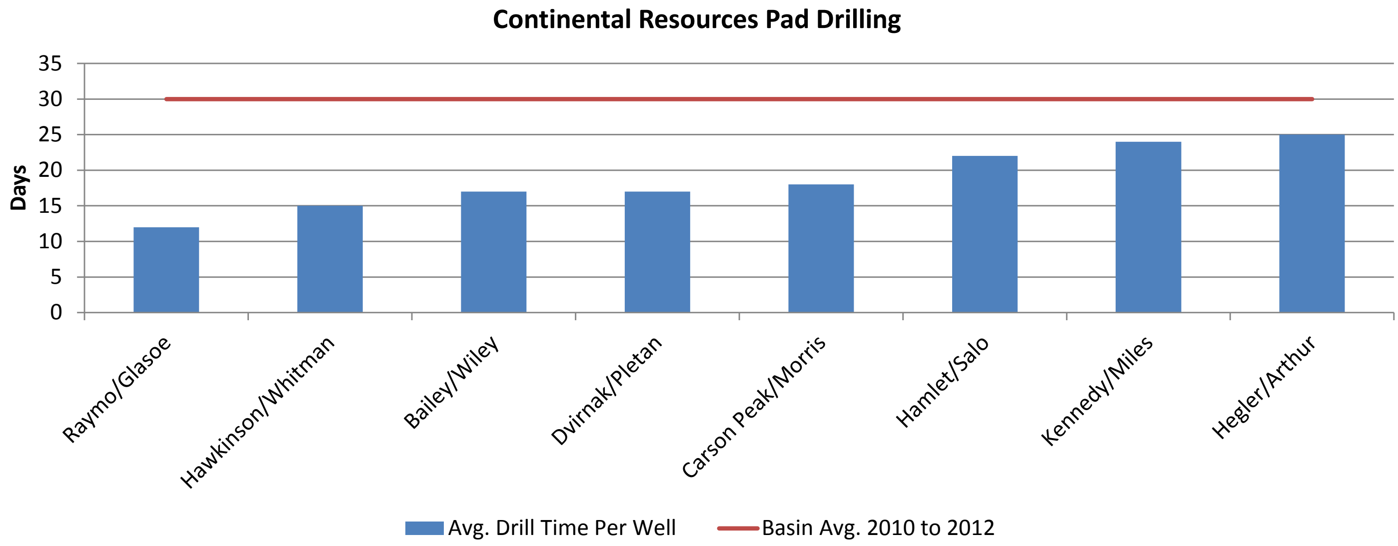


Figure 38. SOURCES: BENTEK, RIGDATA

been drilled in northern Williams County, ND, by Samson, G3, and Newfield.

Area 3 is located in Burke County, ND. Operators in the area include Cirque, Prima Exploration, Fidelity, Oasis, Samson and Hess. The area has potential for both the Three Forks and Bakken. IP rates have been lower than in surrounding counties.

Area 5 is in Roosevelt County, MT, and includes the Poplar Dome and areas to the west. This area is very lightly drilled. Good shows are present in the Bakken and Three Forks in this area so it is anticipated that drilling activity will eventually occur in this area.

Area 6 is in Sheridan and Daniels counties in Montana. This area is very lightly drilled but seeing new activity by companies such as Samson and Apache. The Three Forks is very prospective and potential also exists in the middle Bakken.

The most prospective areas for the Bakken and Three Forks with proven potential are areas 1, 2 and 4. The other areas have great potential but aren't seeing much drilling activity currently.

Currently the most active counties are Williams, Mountrail, McKenzie and Dunn for the Bakken. Stark County is seeing a lot of Three Forks drilling.

Approximately 200 rigs are currently operating in the North Dakota Williston Basin. This activity level is expected to remain high unless the price of oil drops

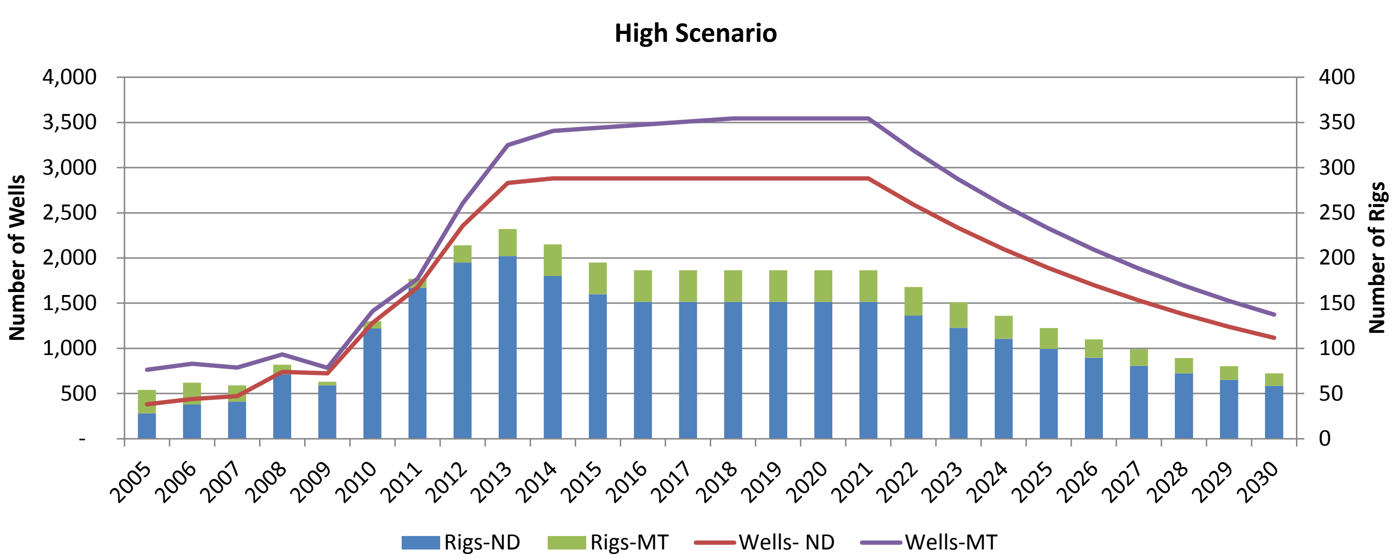


Figure 39. SOURCES: BENTEK, RIGDATA, HPDI

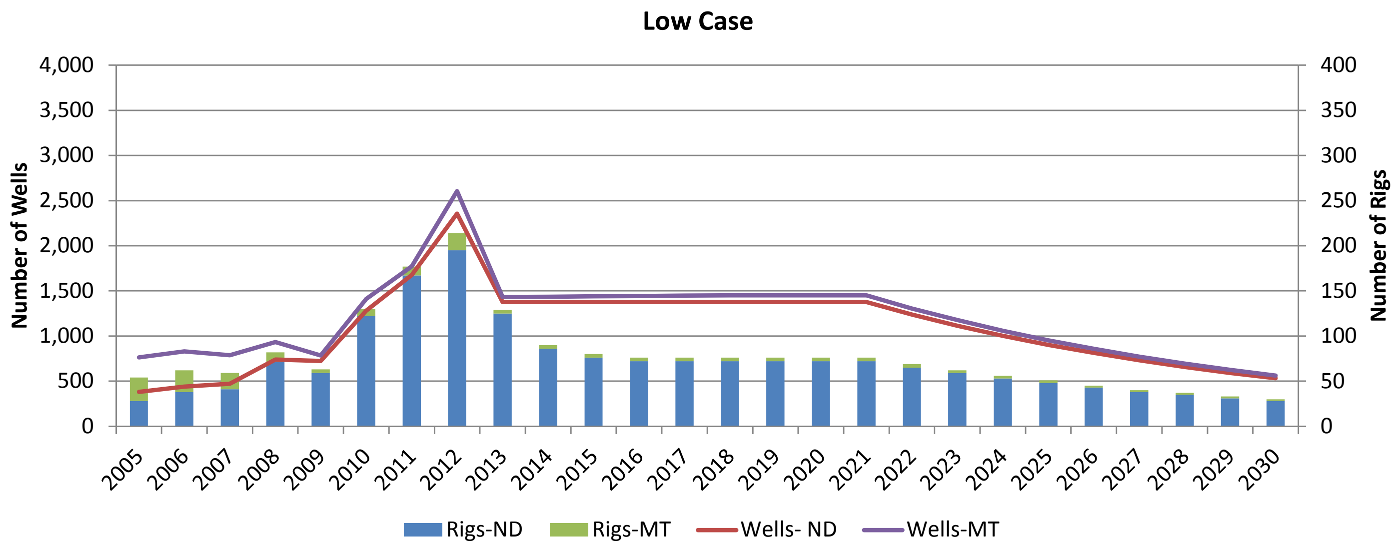


Figure 40. SOURCES: BENTEK, RIGDATA, HPDI

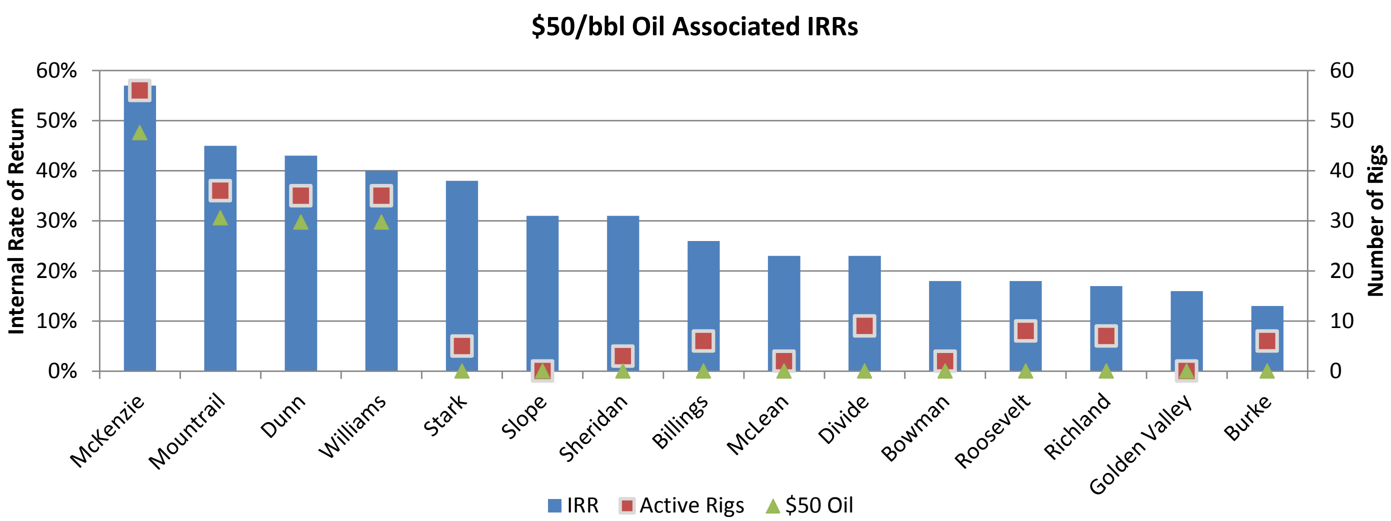


Figure 41. SOURCE: BENTEK, RIGDATA, HPDI

unexpectedly. Current Williston Basin sweet crude price is $64.68/bbl (*Montana Oil Journal*).

A decline in oil prices will impact drilling activity in the Williston Basin. The counties that will be the least affected are McKenzie, Williams, Mountrail, and Dunn in North Dakota. Infill drilling activity and recompletions should continue in Richland County, MT. Fewer wells are expected in Burke and Divide counties if the price declines. These areas have a slightly higher water production which may discourage operators.

Oil Production Forecast

The Base Case scenario (see Figure 42, red and green areas) holds the number of wells drilled per year at a constant rate of approximately 2,350 per year in North Dakota and 250 per year in Montana through 2021. By 2022, BENTEK believes the best Williston acreage will be developed and that the number of new wells will decline by approximately 10% annually due to a reduction in well site inventory. Considering these well forecasts, average annual oil production will rise to nearly 1,777 Mbbl/d in 2017 from approximately 479 Mbbl/d in 2011, an increase of more than 250%. By 2025 oil production will reach 2,180 Mbbl/d. Infrastructure announcements

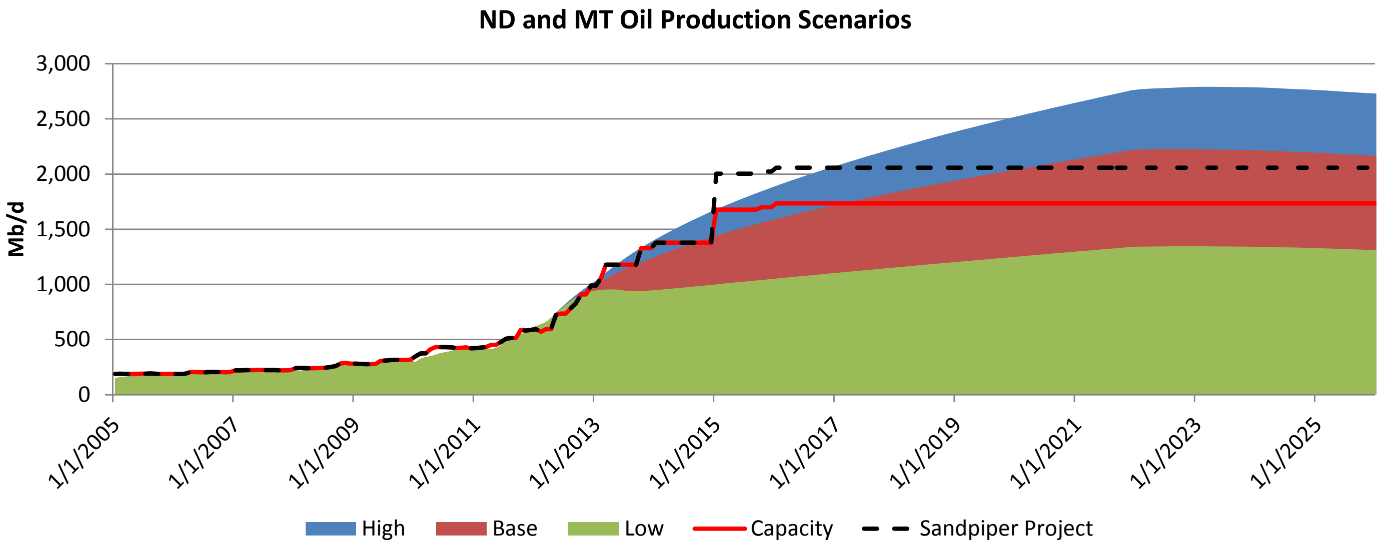


Figure 42. SOURCES: BENTEK, HPDI

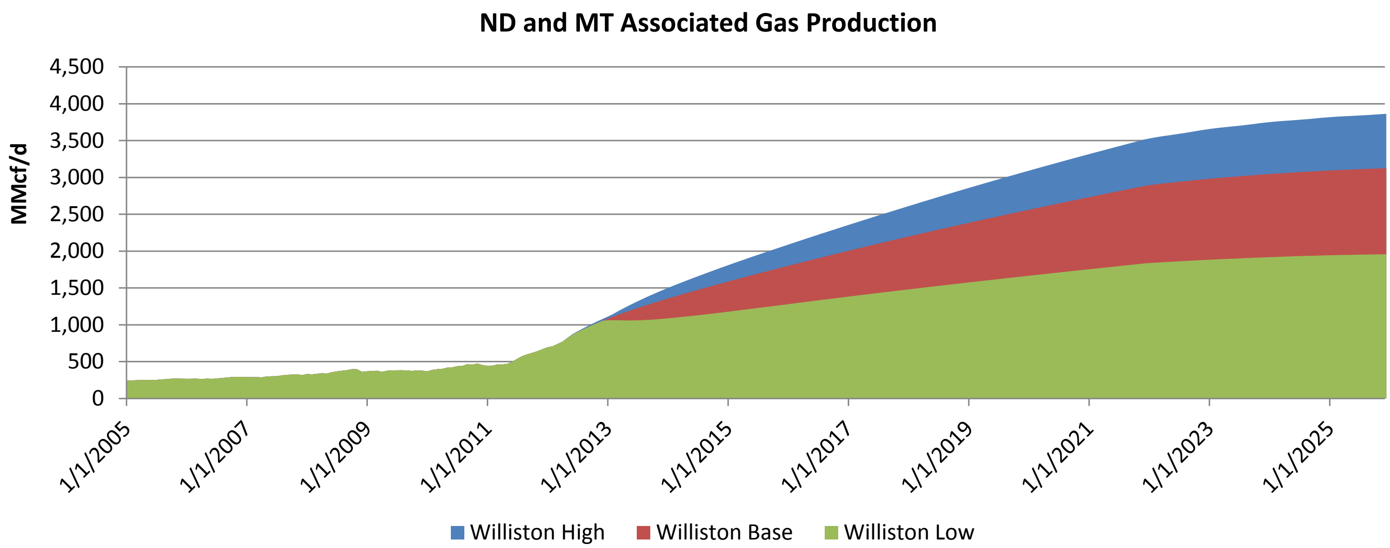


Figure 43. SOURCES: BENTEK, HPDI

appear to be nearly sufficient until 2020, if Enbridge's Sandpiper Pipeline is built. If Sandpiper is not built in 2015, additional oil capacity would be needed in 2017.

The green area shows a low-case forecast scenario that includes a drop to $50 oil prices and a decline of 70 rigs from the current fleet, which includes a 20% drop in active rigs in the core areas. In the low case, only about 1,400 wells are drilled annually in North Dakota compared to 2,350 per year in the base case through 2021. After this time, the well count will decline at an annual rate of approximately 10%, similar to the base case. At this level of activity, production would grow to only 1,077 Mb/d in 2017 and remain near that level through 2025. Oil transportation projects would likely be cancelled under this scenario.

The blue area shows the high case scenario which includes a higher well count per year, reaching a peak of 2,880 in 2013 and remaining at that level until 2021. Montana wells would peak at 665 between 2018 and 2021. The high case forecast would propel oil production to nearly 2,151 Mb/d in 2017 and nearly 2,750 in 2025. This production scenario would test the limits of infrastructure. By the end of 2016, production would overwhelm currently-announced projects, even with

Enbridge's proposed Sandpiper Pipeline (capacity of 325 Mb/d) in 2015.

Gas Production Forecast

The natural gas production forecasts for the Williston include the same scenario assumptions as the oil production forecast along with an expected gas-oil ratio (GOR) analysis. The GOR indicates that North Dakota horizontal wells begin slightly below a 1:1 ratio, with gas IPs of about 340 Mcf/d and oil IPs of about 400 b/d (a ratio of about 0.85). The type curves show that this ratio grows with time, as the oil wells decline at a rate faster than the gas wells. For example, at six years the ratio is 1.5 to 1.0, and at 11 years, the ratio is about 2:1. The type curves for Montana wells indicate similar characteristics. The growth of GOR over time is reflected in the type curves and in BENTEK's gas forecast.

Figure 43 shows the gas production forecasts for the three scenarios for the North Dakota and Montana portions of the basin. The Base Case scenario shows gas production rising from current levels through 2025 as wells in North Dakota continue to be added. BENTEK expects an increase in gas production from an average of about 536 MMcf/d in 2011 to 2.1 Bcf/d in 2017 and 3.1 Bcf/d in 2025.

The Low Case scenario, which includes oil prices falling to below $50 for a sustained period and 70 fewer rigs operating, indicates that gas production would increase from 536 MMcf/d in 2011 to 1.4 Bcf/d in 2017 and 2.0 Bcf/d in 2025.

The High Case calls for gas production growth about 3.3 Bcf/d from average levels in 2011 to an annual average of 3.8 Bcf/d in 2025. The average in 2017 is projected to be about 2.5 Bcf/d under this scenario.

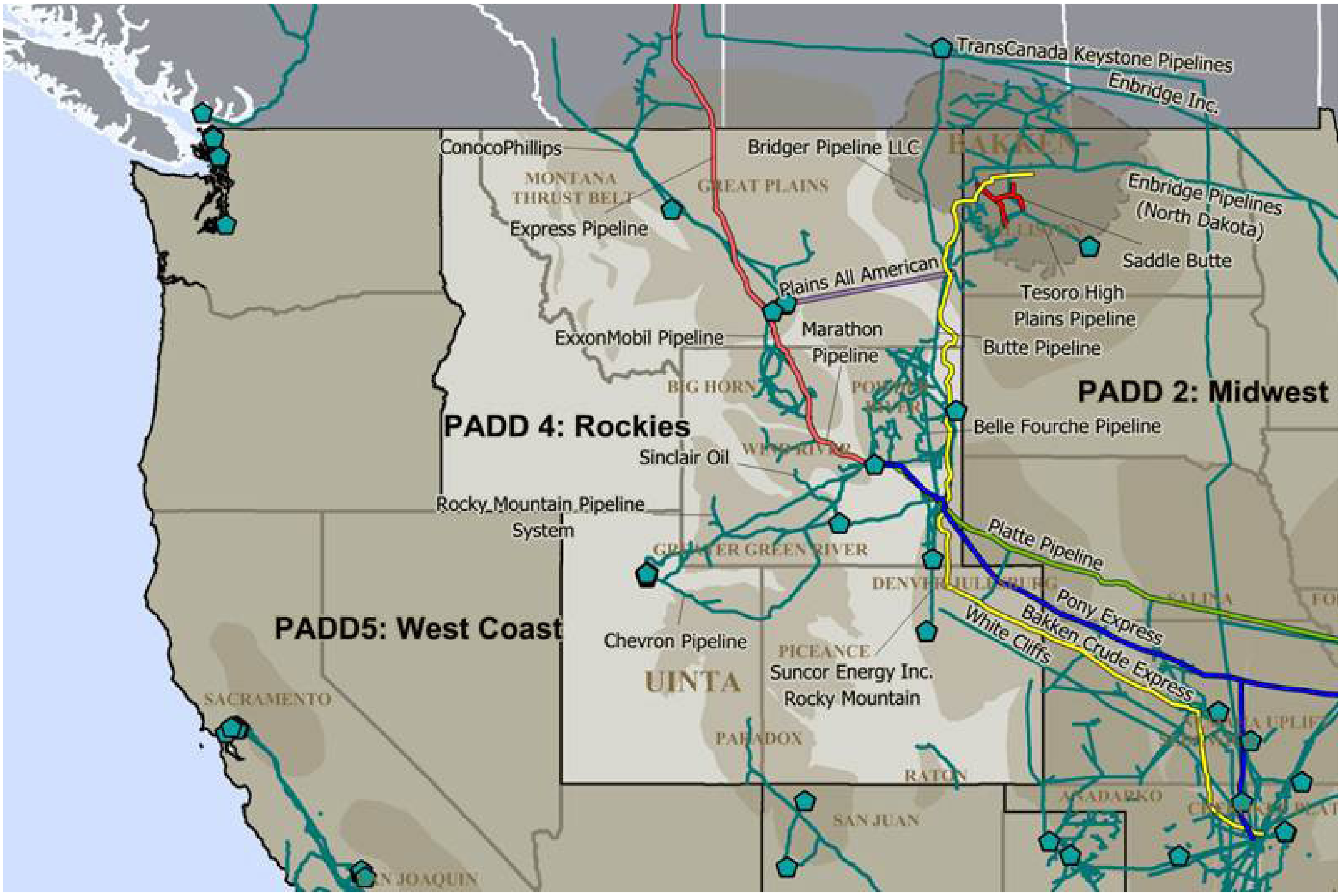


Figure 44. SOURCE: BENTEK

Oil Markets and Infrastructure

Crude oil production in the Williston Basin is transported to one local refinery and to downstream markets on two major pipelines and several rail facilities. These facilities have been barely enough to accommodate the rapid production growth in the basin, leading to at times steep price discounts to WTI. Four refinery expansions are planned in the basin that will add about 65 Mb/d of refining capacity over the next three years. In addition there are nine crude oil pipeline expansions planned that will add 1 MMb/d of takeaway capacity, and there are seven additional rail expansions planned to accommodate oil production growth. BENTEK estimates that the pipeline and refinery projects will be inadequate to keep up with expected growth and the producers in the basin will continue to rely on more expensive transportation options such as rail and truck over the forecast period.

Refining

Tesoro's Mandan Refinery began operations in 1954 and has a capacity of 58 Mb/d, which is being fully utilized. The refinery is served by a 750-mile crude oil gathering and mainline system. Mandan manufactures gasoline, diesel fuel, jet fuel and heavy fuel oil along with liquefied petroleum gas, all of which are shipped via truck to markets in North Dakota and Minnesota.

After local refining demand is satisfied, remaining Williston crude oil supply moves out of the area on two major pipelines, Enbridge's 185 Mb/d North Dakota system and Bridgers' 150 Mb/d Butte Pipeline. The Enbridge system ships about 211 Mb/d of crude eastward to the company's terminal in Clearbrook, MN, and another 25 Mb/d north to the Enbridghe mainline and on to

Clearbrook terminal. Butte takes 150 Mb/d of Bakken crude to Guernsey, WY.

Enbridge recently completed two expansion projects. The first expansion removed 5 Mb/d of sour crude transportation service from the pipeline and added 25 Mb/d of sweet crude capacity. The added capacity has been fully utilized. There also no longer are interruptions in pipeline flows to segregate shipments of sour and sweet crude. The second project on the Enbridge North Dakota system was the Portal Line Reversal, which involved the reactivation and flow reversal of 85.7 miles of existing pipeline between Berthold, ND, and Enbridge's Steelman terminal in Saskatchewan.

The Butte Pipeline is a 16-inch diameter, 323-mile crude oil pipeline system from Baker, MT, to Guernsey, WY. Bridger added 32 Mb/d of capacity to the system in 3Q2011, bringing capacity up to 150 Mb/d.

Oil Transportation Options

With the sudden growth of Williston Basin oil production, transportation capacity has struggled to keep pace. Two main oil transport options currently exist in the Williston Basin: pipeline and rail. Pipeline transport is the preferred option as it is the least expensive. However, all pipelines out of the Williston Basin are currently running near capacity.

Rail transport is more expensive than shipping on a pipeline on a variable cost basis. However, building a rail loading facility takes only 12 to 15 months, whereas trying to expand or build a new pipeline can take several years. Williston Basin producers have relied on rail as a quick fix to its growing production needs.

The third and final transport choice and option of last resort for Williston crude is long-haul trucking crude volumes to Canada. Again, this is a last resort due to the expense of such transport. However, during times of tight oil transportation, Williston producers have relied on long-haul trucking to Canada to fill the transportation gap.

Pipelines

Three main oil pipeline options exist for Williston Basin producers and are shown in Figure 44. The first option is to ship crude west into the Clearbrook, MN, market on Enbridge's North Dakota system. The North Dakota system runs from the western part of North Dakota west into Clearbrook, MN. The pipeline has undergone several expansions and has the ability to transport 210 Mb/d. The pipeline is currently 100% utilized.

The second option is to ship crude north from the Williston Basin into Canada. Enbridge's newly-completed 25-Mb/d Portal Link project allows for the transfer of volumes from Berthold, ND, north to the Steelman terminal in Saskatchewan. At the terminal, the crude then flows on Enbridge's Westpur system where it connects to Enbridge's 2,500-Mb/d mainline system in Cromer, Manitoba. On the Enbridge Mainline, Bakken producers must compete for space with Canadian oil.

The third pipeline transport option for Bakken producers is to ship volumes south into the lower Rockies crude oil market. The Butte Pipeline transports 150 Mb/d from Baker, MT, to Guernsey, WY, and is currently the only pipeline which travels south out of the Bakken. At Guernsey, Bakken barrels compete for demand at local refineries and also for space to exit the PADD 4 market on the Platte Pipeline. The Platte Pipeline is a 165-Mb/d pipeline, which runs from Casper, WY, to Wood River, IL. The pipeline carries lower Rockies barrels (Powder River and Denver-Julesburg basin production) as well as Canadian barrels it receives from an interconnect with Express Pipeline. Platte Pipeline also runs full on a daily basis.

Rail

As stated earlier, rail transportation has been able to help fill the gap between growing production and pipeline capacity. Currently, there are 15 existing rail loading facilities in North Dakota with the ability to transport approximately 420 Mb/d. The main destination for railed volumes has been the Gulf Coast market. However, there has been talk of volumes going to California, Washington, Philadelphia and even to Eastern Canada via rail. While rail is a more expensive transport option when compared to pipelines, it does provide the flexibility to choose an end market and has been an integral part in the basin to help alleviate near-term transportation bottlenecks.

Truck

The final transport option is to truck volumes to nearby pipelines. The main long-haul route is north from the basin into Canada. In Canada, the volumes are then transferred to Enbridge's mainline where they are tranported back into the U.S. to the Clearbrook, MN, market. During the past few months, about 40 Mb/d was transport from the Bakken by truck into Canada.

Pipeline Expansions

Despite new transportation additions over the past several years, the transportation market remains tight in the basin. In anticipation of further growth in crude oil production and more transportation constraints in the Bakken, several companies have proposed new pipeline projects, including:

- ONEOK's Bakken Crude Express Pipeline has an announced capacity of 200 Mb/d and will transport crude 1,300 miles from the Bakken to Cushing, OK. The estimated in-service date is 2015.

- The expansion of the Butte Mainline will add 120 Mb/d of capacity from Baker, MT, to Guernsey, WY, beginning in 2015.

- Banner Pipeline's Banner project would transport 100 Mb/d of Bakken crude from Baker, Montana to the Pony Express Pipeline in Guernsey, Wyoming. An in-service date for this project has not been announced.

- Saddle Butte's High Prairie Pipeline has an announced capacity of 150 Mb/d and would transport Bakken crude to Enbridge's terminal in Clearbrook, MN. Recent news puts this project into question as Enbridge has refused to allow High Prairie an interconnect at the terminal.

- The Keystone XL project would add 508 Mb/d of capacity between Alberta, Canada and Steele City, NE. Approximately 100 Mb/d of this capacity would transport Bakken crude beginning in 2015.

- Enbridge announced the Sandpiper Pipeline project with 325 Mb/d of capacity with an estimated in-service date in 2015.

Considering only these larger projects, the Williston Basin stands to gain nearly 1 MMbbl/d of additional pipeline capacity by 2015. However, this capacity may not be sufficient to transport all of the oil that will be produced. Hence, BENTEK expects rail to be a necessity for Bakken producers to move crude out of the region. By the end of 2013, more than 400 Mb/d of rail capacity will be available for Bakken producers and BENTEK expects capacity to be nearly fully utilized by the end of 2013.

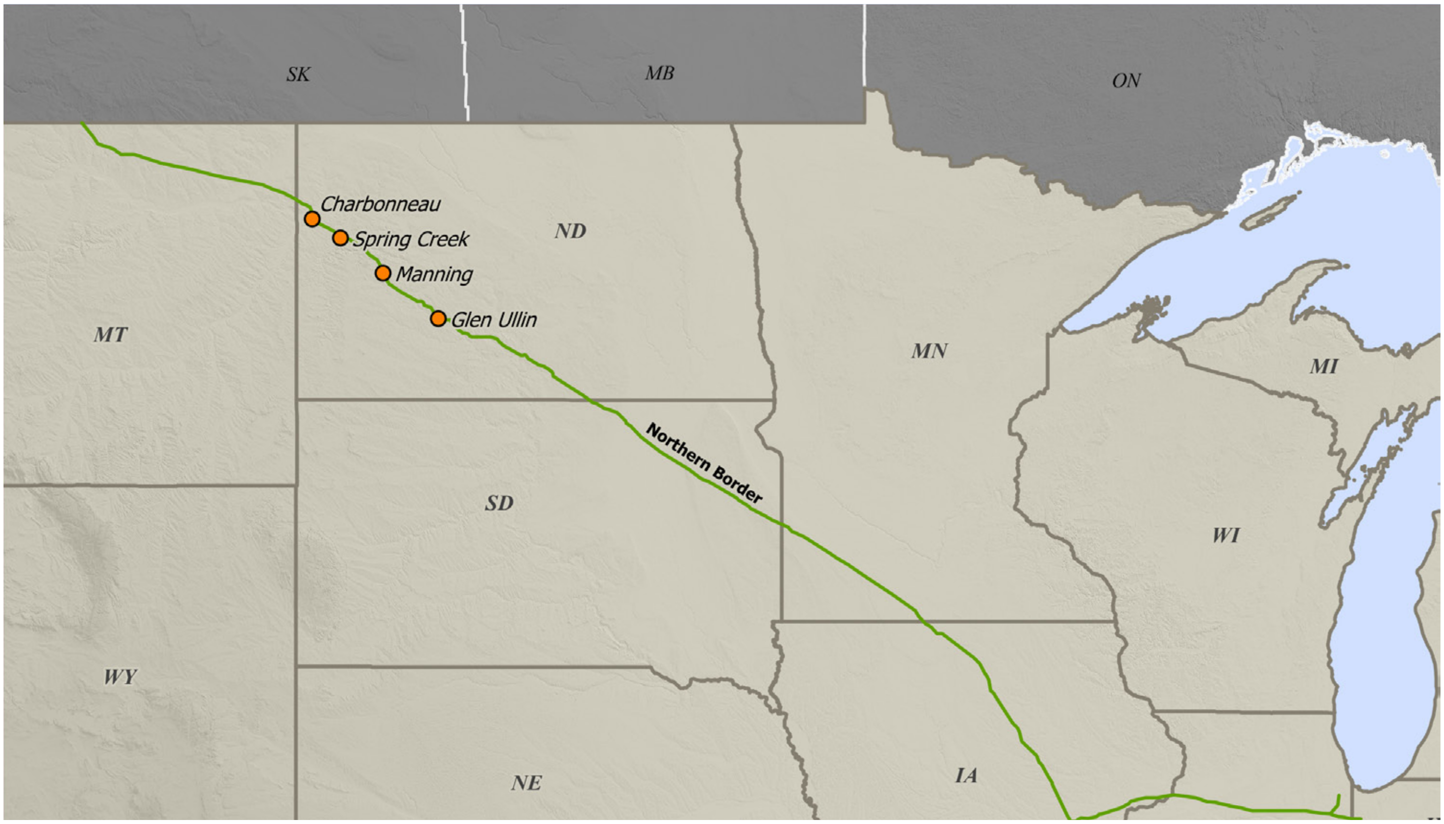


Figure 45. SOURCE: BENTEK

Gas Pipeline Infrastructure

Three main interstate systems currently serve the Williston: Northern Border Pipeline (NBPL), Alliance Pipeline and WBI Energy Transmission. The remaining gas being produced in the basin that is not consumed locally or delivered to these interstate pipelines is flared because of inadequate gas gathering and processing infrastructure. Over the forecast period, several gas gathering and processing expansions are planned, as well as additional pipeline laterals to the interstate systems. More gas gathering, processing and lateral capacity will be needed based on BENTEK's expectations of Williston production growth. The projects currently planned, however, will enable a significant increase in gas delivered to the interstate pipelines, and these interstates also

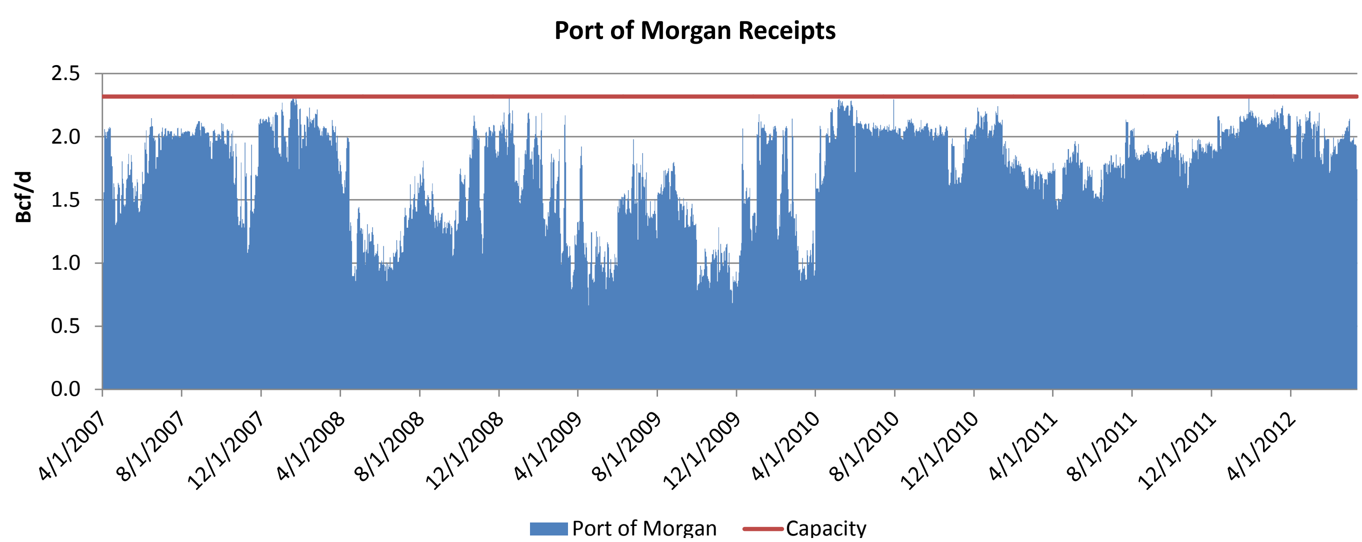


Figure 46. SOURCE: BENTEK

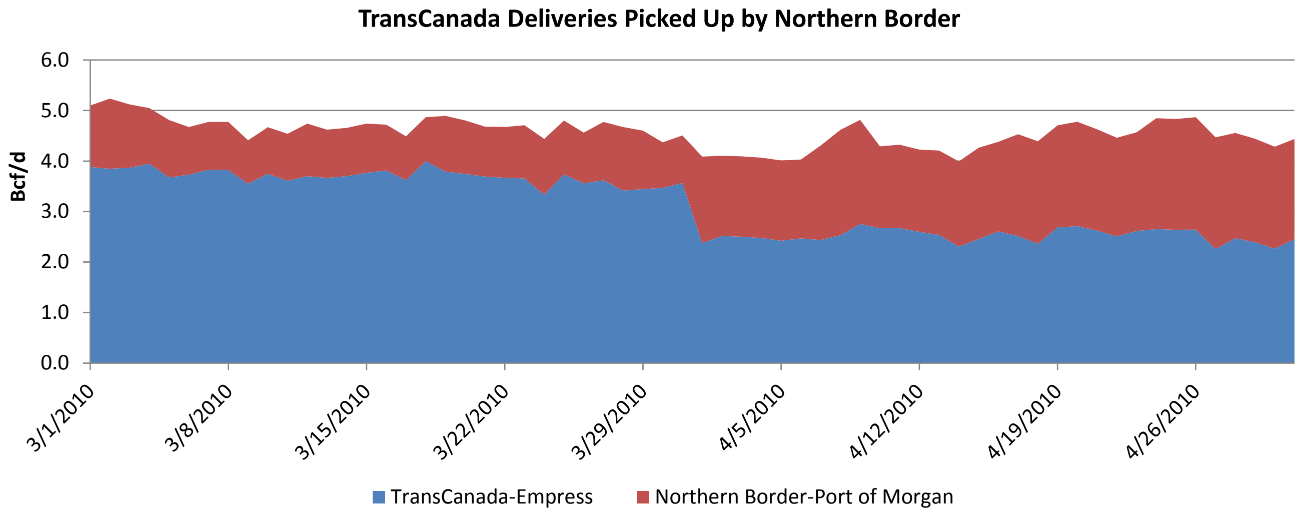


Figure 47. SOURCE: BENTEK

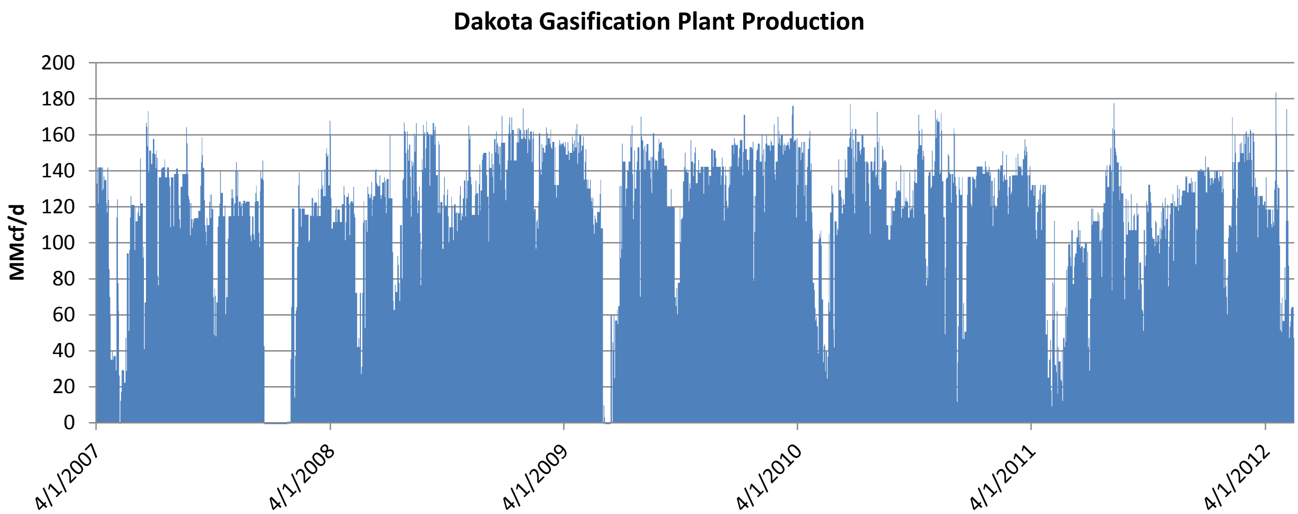


Figure 48. SOURCE: BENTEK

have the transportation capacity to receive additional Williston Basin volumes. Although there is not enough open capacity currently to accommodate all of the projected production growth, BENTEK believes that a variety of incentives will be in place to enable all of the projected production from the basin to eventually make its way into the existing interstate pipeline systems.

WBI, which currently takes the largest amount of Williston Basin production, serves regional demand in the residential, commercial and industrial sectors, and also can deliver gas to take-away pipelines, including NBPL, Alliance, Colorado Interstate Gas, and to a lesser extent, Kinder Morgan Interstate Gas Transmission. WBI has room on its system to take more production from the Williston and could expand its receipt and delivery capacity to accommodate even greater volumes.

NBPL and Alliance currently move large volumes of Canadian gas to Midwest markets. While there is existing space on these pipelines to take some additional Williston Basin production, the flowing volumes of Canadian gas also could be displaced by growing Williston Basin gas production given the right market incentives and the desire of capacity holders on these systems to release their contracted pipeline capacity or to move Williston gas to market.

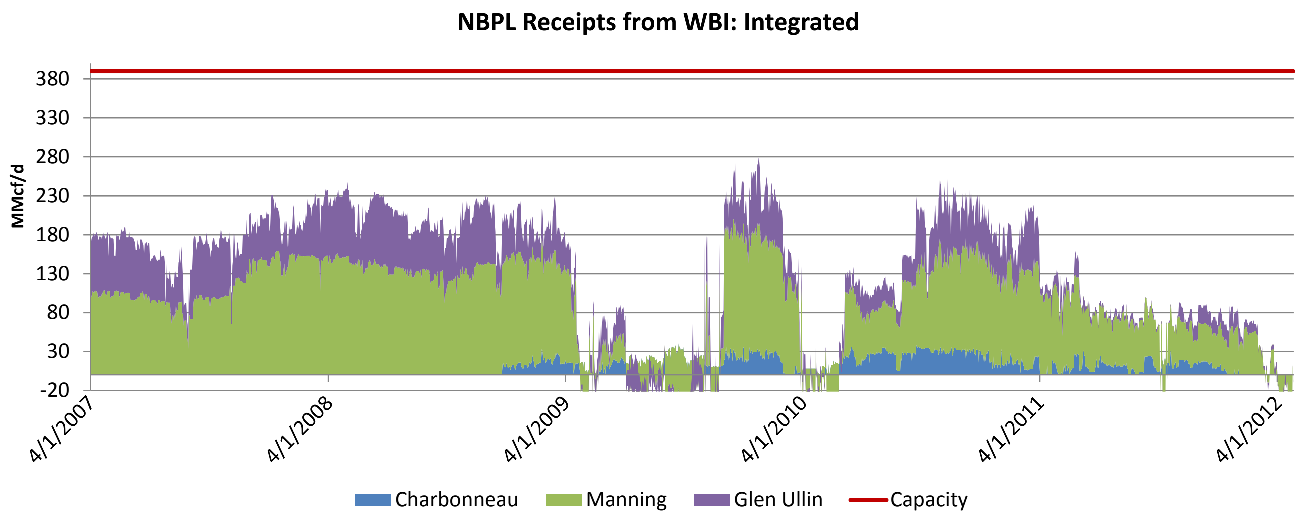


Figure 49. SOURCE: BENTEK

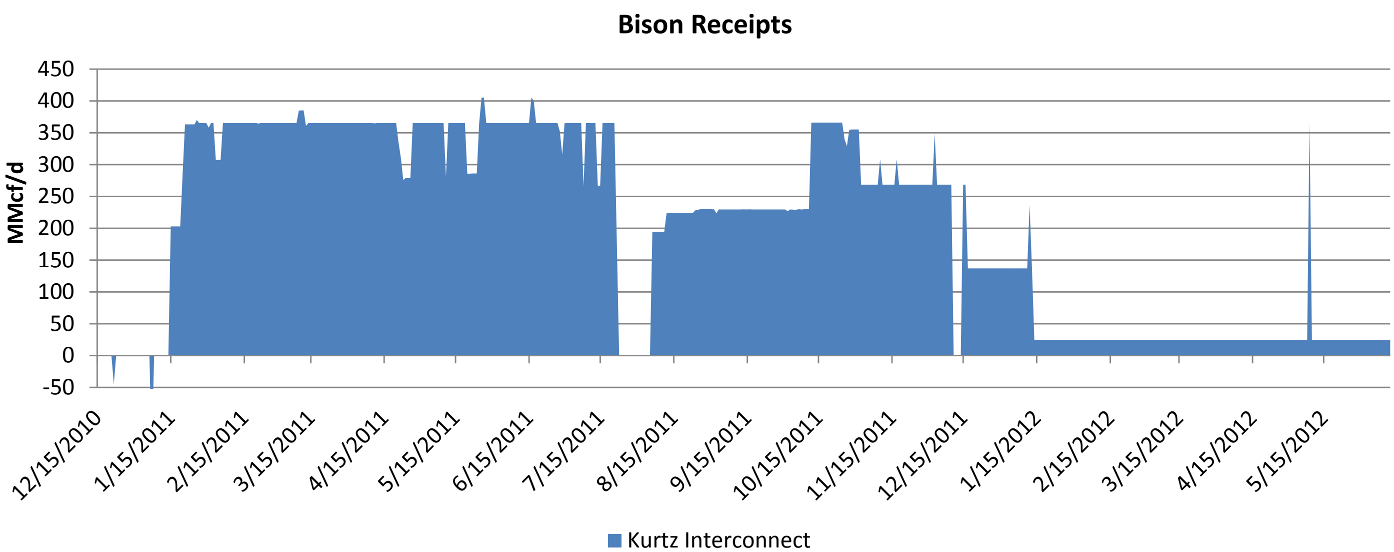


Figure 50. SOURCE: BENTEK

This section provides details and analysis of current and expected gas flows on these pipeline systems and a discussion of other infrastructure requirements in the basin.

Northern Border Pipeline

The NBPL system is a large-scale gas pipeline that crosses North Dakota. NBPL stretches 1,249 miles from the Canadian border at Port of Morgan, MT, to its end point at Hayden, IN (see Figure 45).

The majority of NBPL's throughput volume is currently received from Foothills Pipeline at the Canadian border. Most of the gas flowing into NBPL originates at the Nova Inventory Transfer system (NIT) at Empress, AB, and is transported to Port of Morgan by Foothills. NBPL has a design throughput capacity of 2.4 Bcf/d (see Figure 46).

Between 2007 and 2009, gas receipts at Port of Morgan were subject to large seasonal swings, falling to 1 Bcf/d in the summer and rising to 2 Bcf/d in the winter heating season. In 2010, however, seasonal swings became less pronounced and average annual flows increased from about 1.3 Bcf/d in 2009 to about 2 Bcf/d. This shift in market dynamics was brought about by two significant events: the REX system extension moved beyond Midcontinent delivery points to other interconnects in the Northeast region at Clarington, OH; and the expiration and de-contracting of firm capacity on the TransCanada mainline (see Figure 47).

On April 1, 2010, REX deliveries to Midcontinent pipelines serving markets in the Upper Midwest and Chicago areas (ANR, Panhandle Eastern, Midwestern and NGPL)

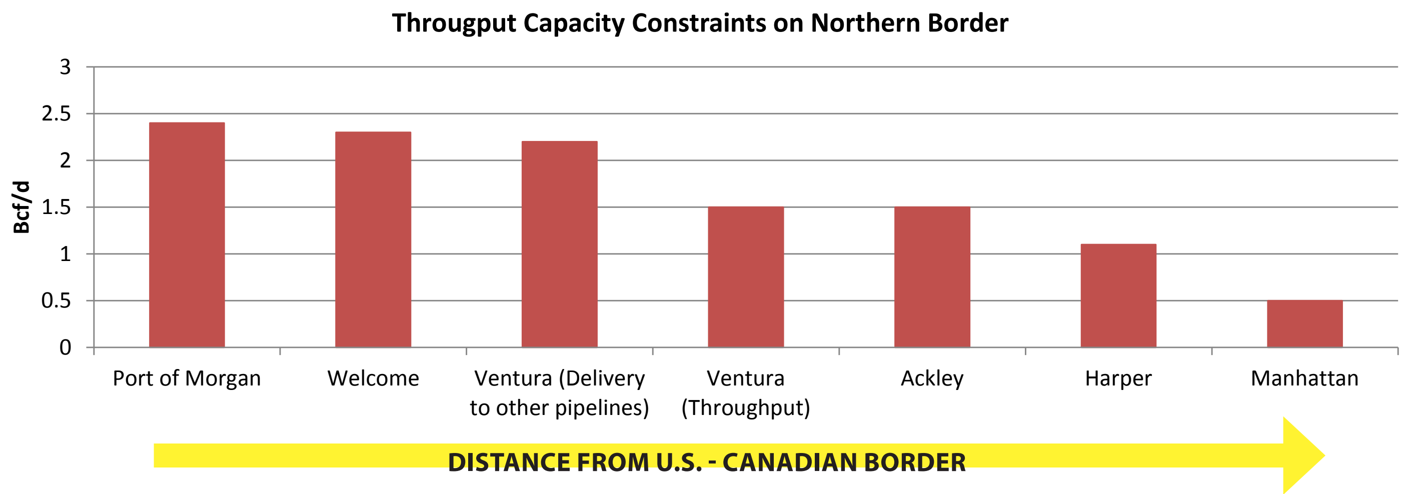


Figure 51. SOURCES: BENTEK, COMPANY REPORTS

declined and gas flowing on REX migrated east to new interconnects with pipelines serving the Northeast markets (Tennessee Gas, Texas Eastern, Columbia Gas and Dominion). During April 2010, some Northeast region gas demand that had been served by Canadian supply via long-haul TransCanada mainline deliveries switched to new supply available from REX in the Clarington area. The Canadian supply that was displaced by this new REX extension into the Northeast was forced to seek out markets in the Chicago area via NBPL.

North Dakota

The potential for NBPL to receive more gas from the Williston in North Dakota is substantial. There are 10 NBPL receipt points in North Dakota, none of which are flowing at capacity. This could change rapidly if economic conditions warrant the displacement of Canadian supply by Williston Basin gas.

NBPL receives an average of about 137 MMcf/d of gas from the Dakota-gasification receipt point, which is capable of taking 160 MMcf/d (see Figure 48).

WBI has four interconnects with NBPL. Three interconnects are located on WBI's integrated pipeline system: Charbonneau, with a capacity of 60 MMcf/d; Manning with 200 MMcf/d; and Glen Ullin, 130 MMcf/d. WBI also interconnects with NBPL via its Spring Creek lateral at ONEOK's Garden Creek plant. The receipt points on the integrated WBI system are currently under-utilized and are flowing about 10 MMcf/d, 20 MMcf/d and 10 MMcf/d, respectively (all volumes are average throughput for May 2011 through April 2012). These points offer additional outlets for North Dakota gas and WBI could expand receipts and deliver capacity to accommodate additional Williston volumes (see Figure 49).

Bison Pipeline, which serves the Powder River Basin, has capacity to deliver 407 MMcf/d into NBPL at its Kurtz receipt point, and is currently flowing about 25 MMcf/d. This is covered in greater detail in the Bison Pipeline section (see Figure 50).

NBPL Processing Plant Receipts

There are several active processing plants that deliver residue gas into NBPL, and additional plants are planned. The high BTU quality of gas associated with Bakken oil drilling will continue to require the addition of processing capacity in the region (see further detail in the Gas Processing section). Including planned processing capacity infrastructure that will be connected to the NBPL system (either directly or through deliveries from WBI), capacity for delivery of processed gas to NBPL will reach more than 1 Bcf/d by the end of 2013.

NBPL Markets

About 1.5 Bcf/d of the 2.4 Bcf/d of throughput capacity on NBPL is available to serve markets downstream of Ventura, IA, as depicted in Figure 51. NBPL's capacity telescopes downward from 2.4 Bcf/d to 1.5 Bcf/d in the segment downstream of Ventura. When the pipeline is running close to full capacity, a minimum of 0.9 Bcf/d must be delivered at markets upstream of, and including, the interconnect with Northern Natural Gas (NNG) at Ventura. When Ventura demand is strong enough, it can receive most of the throughput volume with total receipt point capacity of 2.3 Bcf/d. The balance of throughput not delivered to Ventura is then bound for downstream

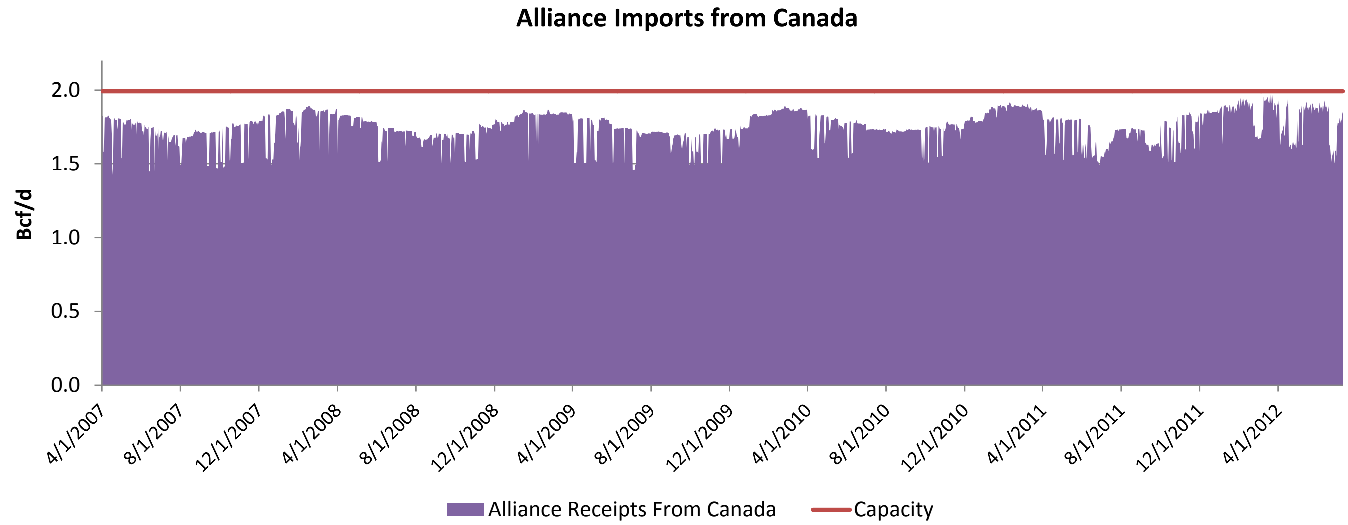


Figure 52. SOURCE: BENTEK

markets, including interconnects with Natural Gas Pipeline (NGPL) at Harper, IA, Peoples Gas Light & Coke at Manhattan, IL, Midwestern Gas Transmission Co. at Channahon, IL, and NIPSCO at Hayden, IN. The Chicago-area markets comprise a very large demand center that can exceed 4.5 Bcf/d during peak demand periods.

NBPL Service Contracts

NBPL's shipper mix is made up of 31% producers, 34% marketers, and 24% LDCs. Contracts expiring thus far in 2012 have been extended or re-contracted; expirations later this year total more than 600 MMcf/d and are expected to be extended or re-contracted.

Canadian producers are likely to retain capacity on NBPL as long as markets available via NBPL provide the best netbacks. Canadian producers are expected to protect their market access by holding onto NBPL capacity as long as netbacks are expected to remain favorable for transportation to Midwest markets. In other words, as long as netbacks are favorable for Canadian shippers, the NBPL capacity held by Canadian shippers is likely to remain unavailable for usage by Williston Basin suppliers.

Alternatively, if Canadian shippers on NBPL are actively engaged in third-party marketing, they may opt to sell their Canadian gas into other markets, while buying alternative supply at North Dakota receipt points to ship on their NBPL capacity. They would be able to do this type of alternative-supply dispatch as long as this option is compatible with relevant royalty-payment rules and other conditions.

The activity taking place on Bison Pipeline is one example of how shippers are optimizing available pipeline capacity. Wyoming producer-marketers with capacity on Bison and on NBPL have been able to capture greater value in the market by ceasing shipments on the new Bison system and selling Wyoming production in other markets. They are able to maintain utilization of NBPL capacity downstream of Bison by nominating alternate supply at the Port of Morgan receipt point, monetizing the attractive price spread across the NBPL system (see Figure 50).

North Dakota Williston Basin producers do not have as many market options as Canadian producers. The gas that is captive to WBI or NBPL has few alternatives. Because of these limitations, North Dakota gas must compete with the Canadian gas. The non-producer shippers on NBPL (marketers and LDCs) will be motivated by price. Based on the rate-of-return advantages of Bakken gas compared to Canadian production and supply available in other U.S. regions, BENTEK expects Bakken gas to win the competition, enabling Williston Basin producers to provide the lowest gas supply price to those non-producer shippers that are price-motivated.

The exception to this is the scenario explained above, in which NBPL capacity is held by a producer of Canadian gas, and that producer lacks options or refuses to use alternate supply to serve markets and instead continues to utilize NBPL capacity for traditional long-haul deliveries. BENTEK expects that this behavior will be the

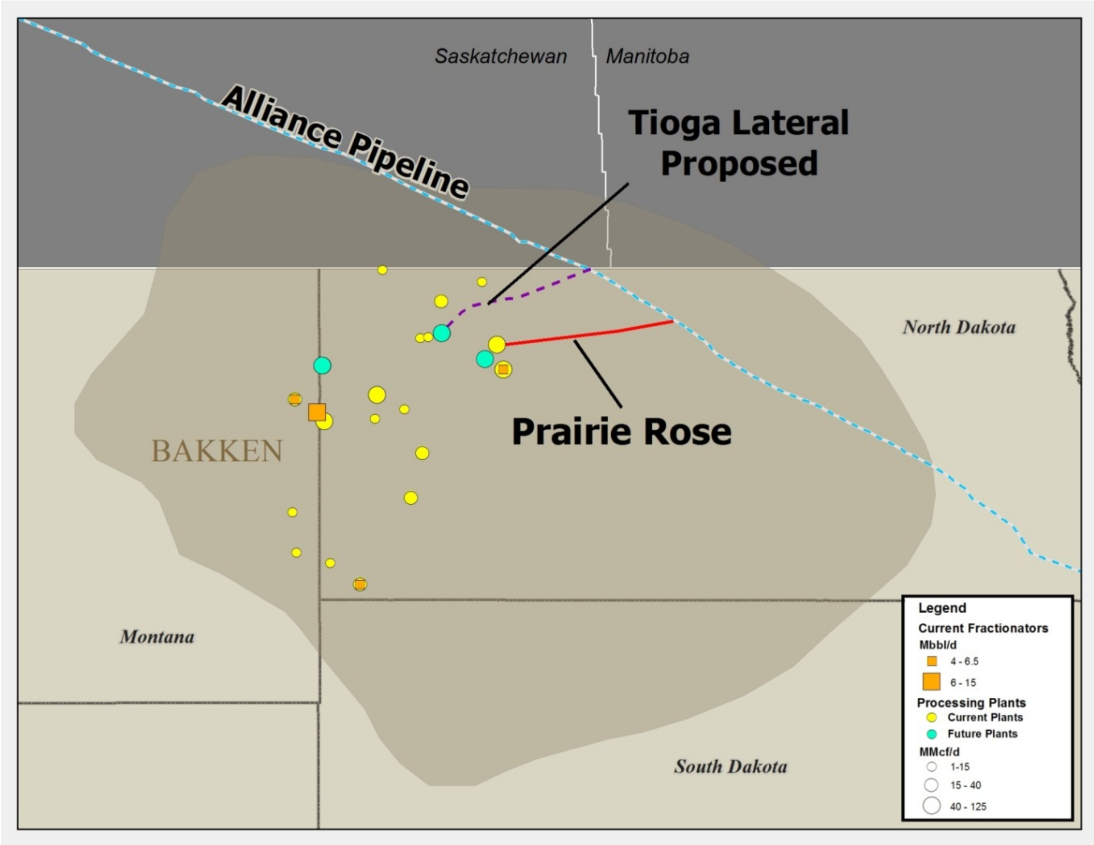


Figure 53. SOURCE: BENTEK

exception, as the largest producer-shippers on NBPL are also producer-marketers.

Alliance Pipeline

Alliance is a 2,400 mile system that is certificated to transport 1.6 Bcf/d of liquids-rich gas from near the border of British Columbia and Alberta to the 2.1 Bcf/d Aux Sable processing plant near Chicago. About 95% of the gas currently flowing on Alliance Pipeline is sourced in Canada (see Figure 52).

Alliance Markets

The Aux Sable plant receives all inlet gas from Alliance. It was designed with a capacity of 2.1 Bcf/d in order to accommodate subsequent Alliance mid-point compression expansions, which have yet to be added. Residue gas from the tailgate of the Aux Sable plant may be delivered to NICOR, Peoples Gas Light & Coke, NGPL, ANR, Midwest Gas Transmission, Guardian Pipeline and Vector Pipeline.

U.S. Receipt Points

Alliance has expanded its rich-gas receipt point capacity in the U.S. It currently has one receipt point in North Dakota at its interconnect with the Prairie Rose Pipeline, which has the capacity to transport 80 MMcf/d of rich gas from the Palermo gas processing plant in Mountrail County, ND. The planned Tioga Lateral project would be the second lateral bringing gas to Alliance from the Williston Basin (see Figure 53). It will begin moving liquids-rich gas from the Hess Tioga plant to an interconnect with Alliance just south of the Canadian border in Renville County, ND, in 3Q2013. The design capacity for the 80-mile 12-inch diameter lateral is 106 MMcf/d. Williston receipt capacity on Alliance will total 186 MMcf/d when both laterals are operational, and additional capacity could be added, allowing Williston producers to avoid in-basin processing by sending their liquids-rich gas to Alliance and the Aux Sable plant near Chicago. The alternative supply dispatch option, explained in the NBPL section above, also could be viable for Alliance shippers.

Alliance Service Agreements

Alliance has 1.4 Bcf/d of its 1.6 Bcf/d of capacity under firm contracts through 2015. The current shipper mix is 49% producers, 34% marketers, 11% LDCs and 6%

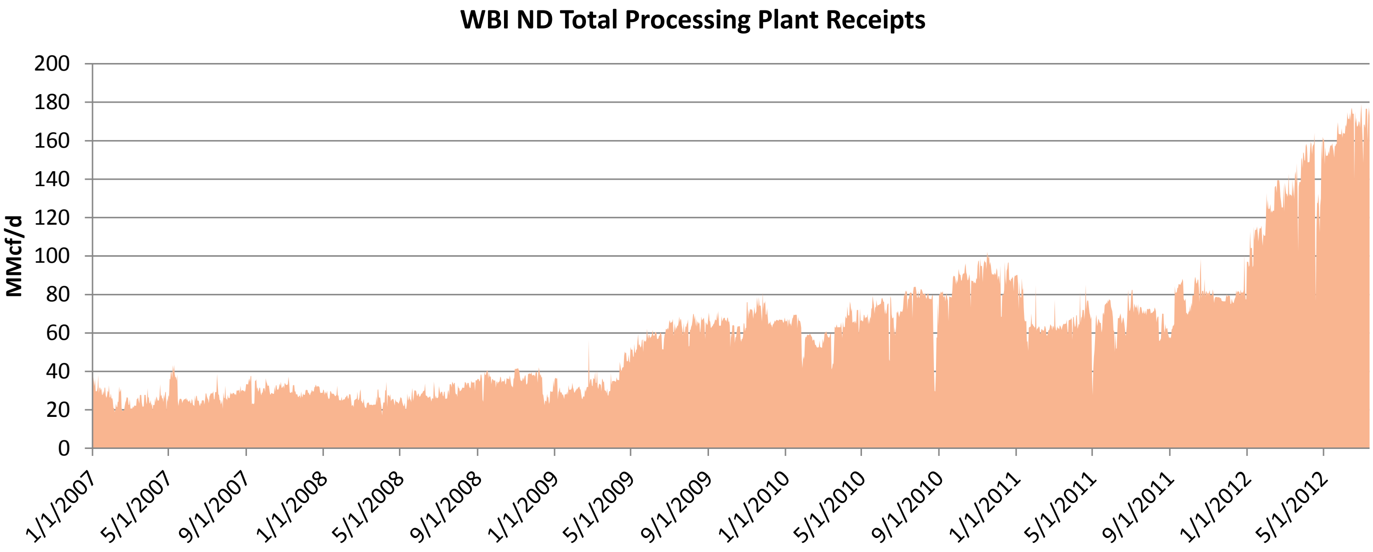


Figure 54. SOURCE: BENTEK

pipelines. Recent deliveries have exceeded contracted capacity, at times reaching 1.7 Bcf/d, because of Alliance's Authorized Overrun Service (see Figure 52).

The Alliance Pipeline is regulated by the National Energy Board in Canada and the Federal Energy Regulatory Commission in the U.S., requiring two tariffs and two contracts for cross-border transmission. On the U.S. side, shippers with contracts expiring in 2015 have until six months prior to contract expiration to exercise rights of first refusal (ROFR) on contracted capacity. On the Canadian side, Alliance is in negotiations with the shippers over potential contract extensions that will begin in 2015. These negotiations include discussions about the potential for re-purposing the pipeline. Among the items up for discussion are creating a third gathering capacity component allowing producers to deliver gas into a supply pool where they could sell supply to long-haul shippers. Alliance plans to determine the level of Canadian segment contract extensions by the end of 2012 whether by negotiation or by open season.

However, this will create an ROFR-timing challenge. While Alliance may know future capacity commitments on the Canadian segment by 2013, it still will be contractually obligated to the holders of U.S. capacity until six months' prior to the 2015 expirations. While a party might decide not to extend capacity on its Canadian segment, it could remain undecided for almost two years regarding its U.S. segment capacity. U.S. shippers could wait for further

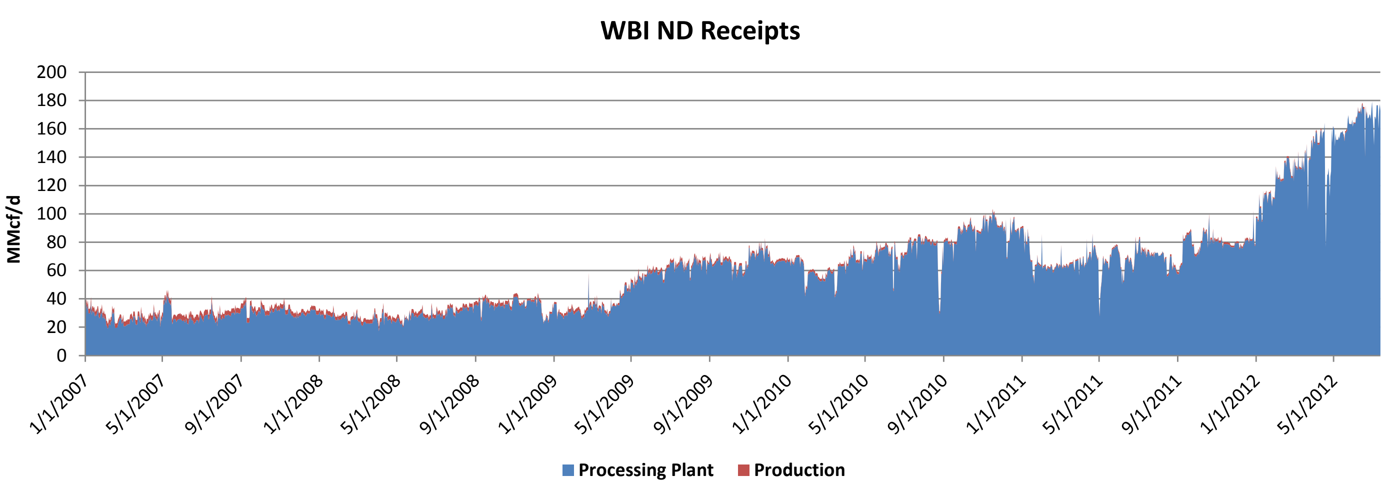


Figure 55. SOURCE: BENTEK

development of Williston receipt projects before deciding whether to re-contract their U.S. capacity in 2015.

The current lack of shipper commitments to extensions leaves open the possibility that the gas currently moving on Alliance could go on alternate paths after expiration.

Transportation Rates

The currently effective reservation rates on Alliance are C$0.92/Mcf for the Canadian segment, and US$0.61/Mcf for the U.S. segment. Authorized Overrun Service is available to firm shippers on a pro-rata basis for no additional fee, bringing the per-unit 100% load factor throughput charge down to approximately C$0.80/Mcf and US$0.53/Mcf for the Canadian and U.S. segments, respectively.

Interruptible transportation on Alliance may be a future option for its current firm shippers upon contract expiration. A net-back analysis similar to NBPL may determine, prior to the execution of contract extensions, that the better option for the Canadian gas is for it to be processed in British Columbia or Alberta and then be

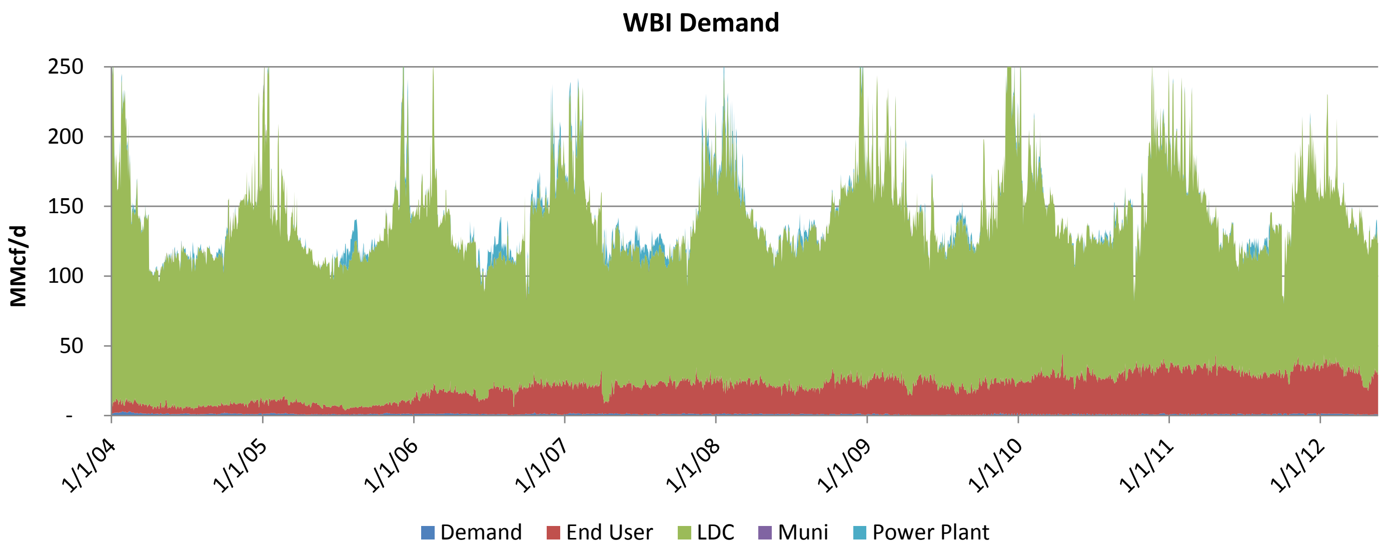


Figure 56. SOURCE: BENTEK

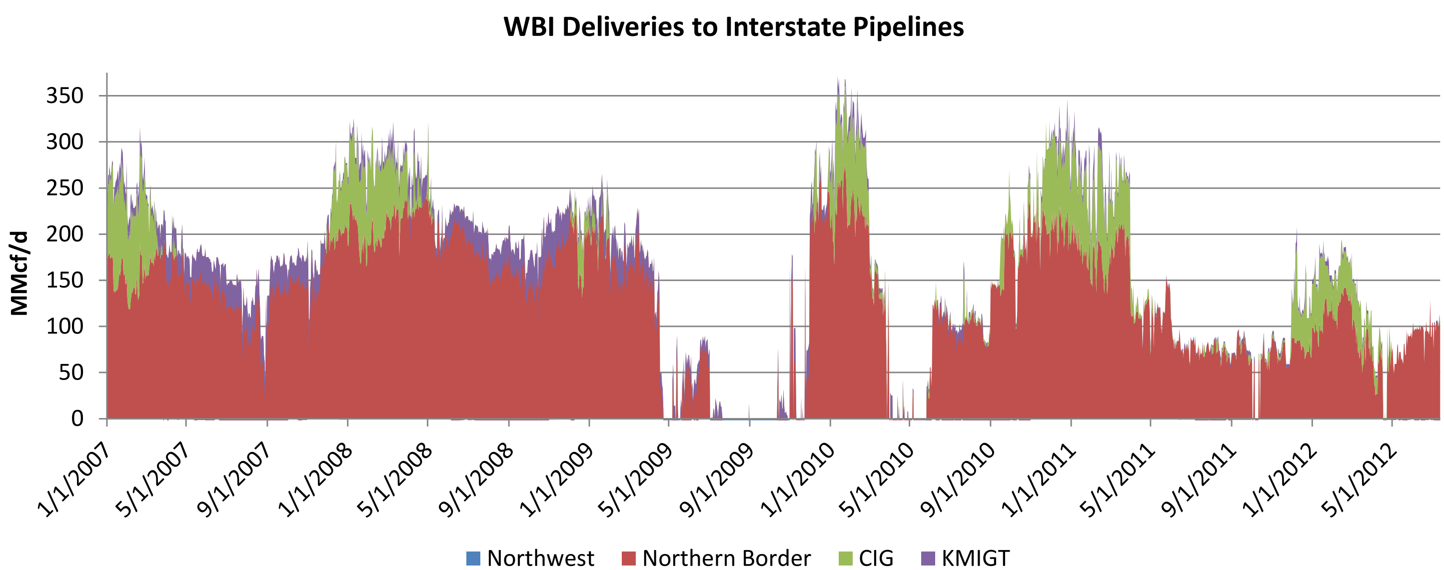


Figure 57. SOURCE: BENTEK

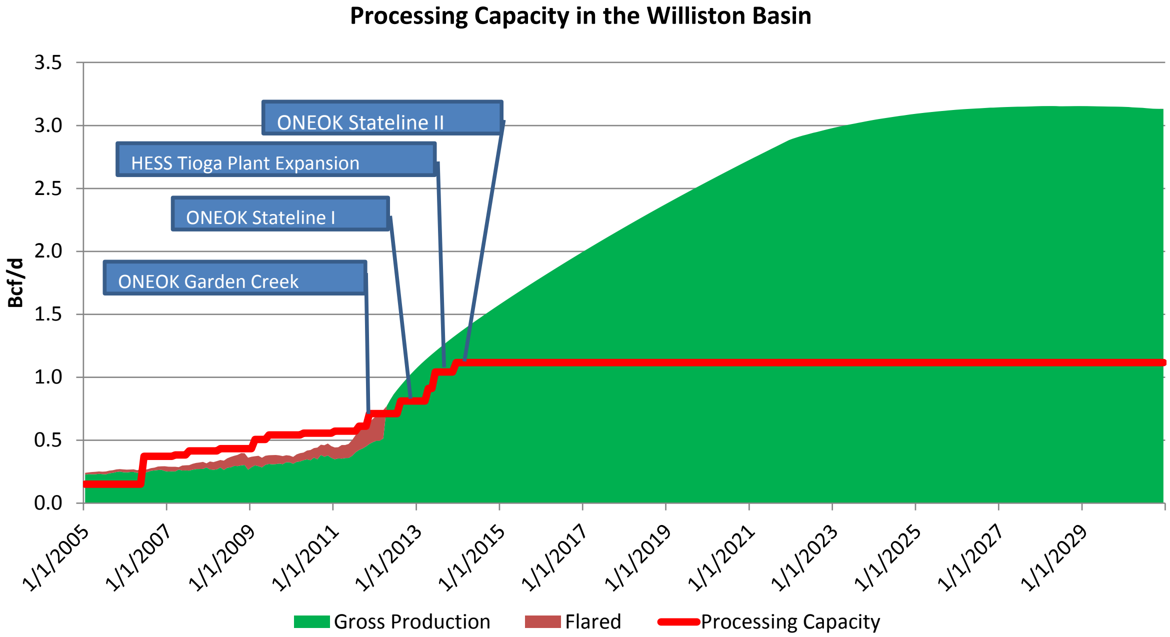


Figure 58. SOURCES: HPDI, BENTEK, NORTH DAKOTA PIPELINE AUTHORITY.

Williston Basin Processing Plant Capacity

Plant	Owner	State	County	Capacity	Expansion
Tioga Gas Plant	Hess Corporation	ND	Williams	120	130
Badlands	Hiland Partners	ND	Bowman	40	0
Norse/McGregor	Hiland Partners	ND	Divide	25	0
Watford City	Hiland Partners	ND	McKenzie	50	0
Garden Creek	ONEOK Partners	ND	McKenzie	100	0
Lignite	ONEOK Partners	ND	Burke	6	0
Marmath	ONEOK Partners	ND	Slope	7.5	0
Grasslands	ONEOK Partners	ND	McKenzie	100	0
Stateline I	ONEOK Partners	ND	McKenzie	-	100
Stateline II	ONEOK Partners	ND	McKenzie	-	100
Little Knife	Petro-Hunt	ND	Billings	32	0
Little Missouri	Saddle Butte Pipeline	ND	McKenzie	45	0
Ambrose	Sterling Energy	ND	Divide	0.5	0
Red Wing Creek	True Oil Co.	ND	McKenzie	4	0
Belfield	Whiting Oil & Gas	ND	Stark	30	0
Ray	Whiting Oil & Gas	ND	Williams	10	0
Ross	Plains	ND	Mountrail	-	75
Robinson Lake	Whiting Oil & Gas	ND	Mountrail	90	0
Nesson	XTO Energy Inc.	ND	Williams	10	0
Palermo	Aux Sable	ND	Mountrail	110	0
Total				780	405

Figure 59. SOURCES: COMPANY REPORTS, PROJECT TRACKER, NORTH DAKOTA PIPELINE AUTHORITY.

.dispatched to other markets, including to the West Coast for export as LNG if that option becomes available. A small amount of LNG exports are planned from Douglas Channel on the Pacific Coast of British Columbia next year and a much larger amount is planned in 2016 from a proposed terminal in Kitimat, BC.

To the extent that current Alliance shippers elect a different market option after contracts expire in 2015, Alliance would become available as a rich-gas transportation option for Bakken producers seeking take-away capacity. But given expected production growth and proposed lateral capacity, the capacity would be limited to 186 MMcf/d unless additional infrastructure projects like Prairie Rose Pipeline and the Tioga Lateral are constructed.

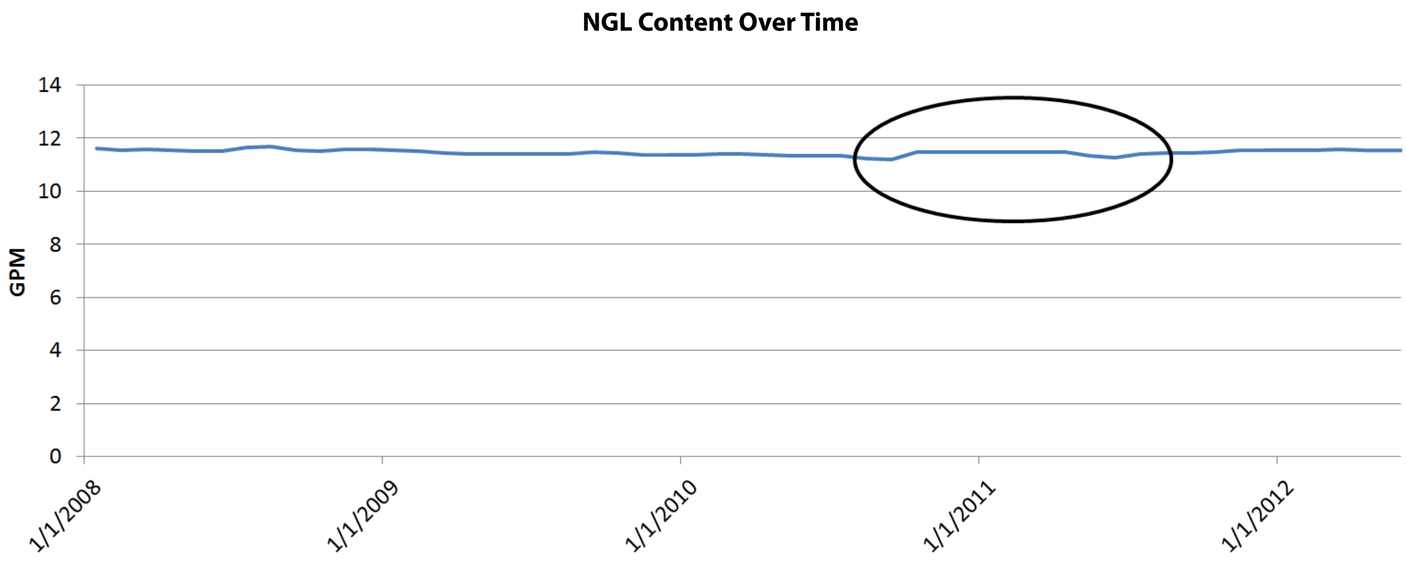
WBI Energy Transmission

WBI is a reticulated pipeline system that serves parts of North and South Dakota, Montana and Wyoming. The pipeline is an important link in the supply chain for the inter-regional transportation of Bakken gas. It is the principal mode of storage and transportation for Montana Dakota Utilities (MDU), an LDC that is the largest holder of capacity on the system with more than 50% of firm transportation capacity. Marketers hold about 26% of firm capacity; producers 14%; and end users 2%.

WBI has capacity to deliver more gas to NBPL and could expand as opportunities arise. WBI's location in western North Dakota and eastern Montana make it a logical option for expanding transportation and delivery capacity for Bakken gas. Projects to attach processing plants to the WBI system have been completed and more are planned, including ONEOK's Garden Creek and Stateline I and II projects, from which WBI will transport processed gas to interconnects with NBPL for long-haul take-away (see Figure 54).

WBI Receipts

Supply sources for WBI include on-system supply from northern Rockies and Bakken gas, as well as interconnects



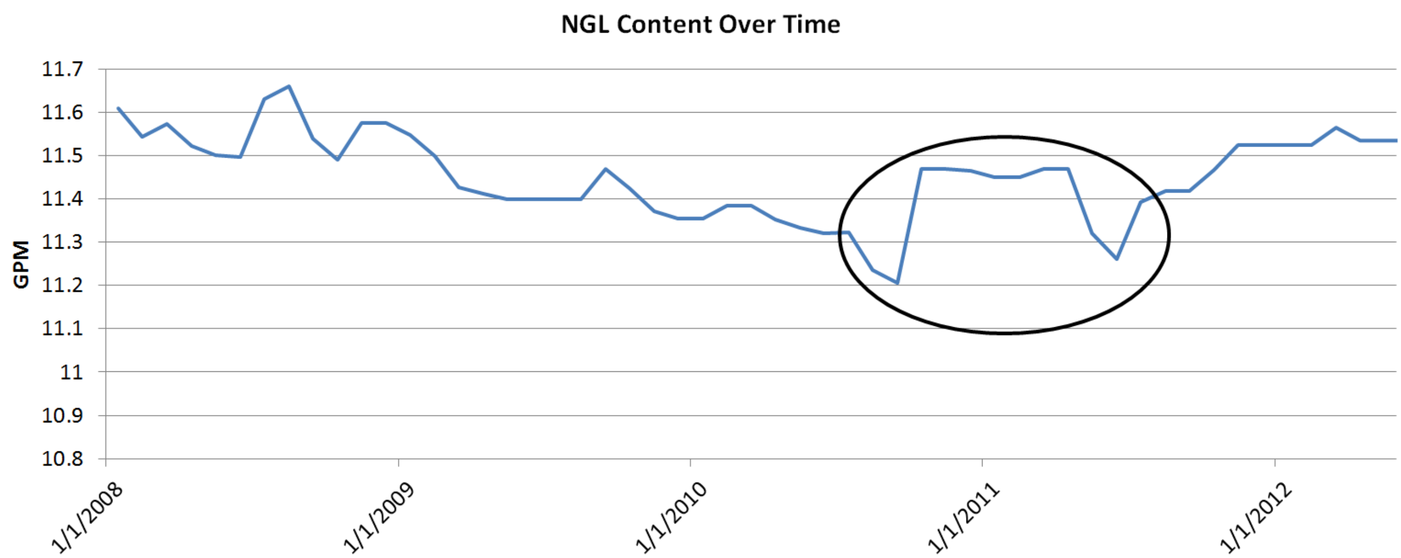


Figure 60. SOURCE: COMPANY DATA

with processing plants and pipelines. Average daily throughput on the WBI system decreased at points in Montana and Wyoming in 2010 due to production declines in the Bowdoin field in Montana, the Baker field in Wyoming, and the Powder River Basin in northeastern Wyoming. North Dakota receipts from the new processing plants began to increase in 2009, rapidly climbing in the past year (see Figure 55).

WBI Markets

Demand on the WBI system has been steady at about 150 MMcf/d for several years and is not expected to increase materially. The primary market for WBI is the LDC load of MDU. LDC demand represents about 80% of the total (see Figure 56).

WBI delivers gas to NBPL, CIG, KMIGT, MIGC and Northwestern. These off-system deliveries currently total about 195 MMcf/d, but have declined over the past three years from an average of 213 MMcf/d in 2011, 302 MMcf/d in 2010 and nearly 400 MMcf/d in 2009. The largest amount (about 75% of the total) of deliveries to pipelines goes to Northern Border at the Glen Ullin, Manning

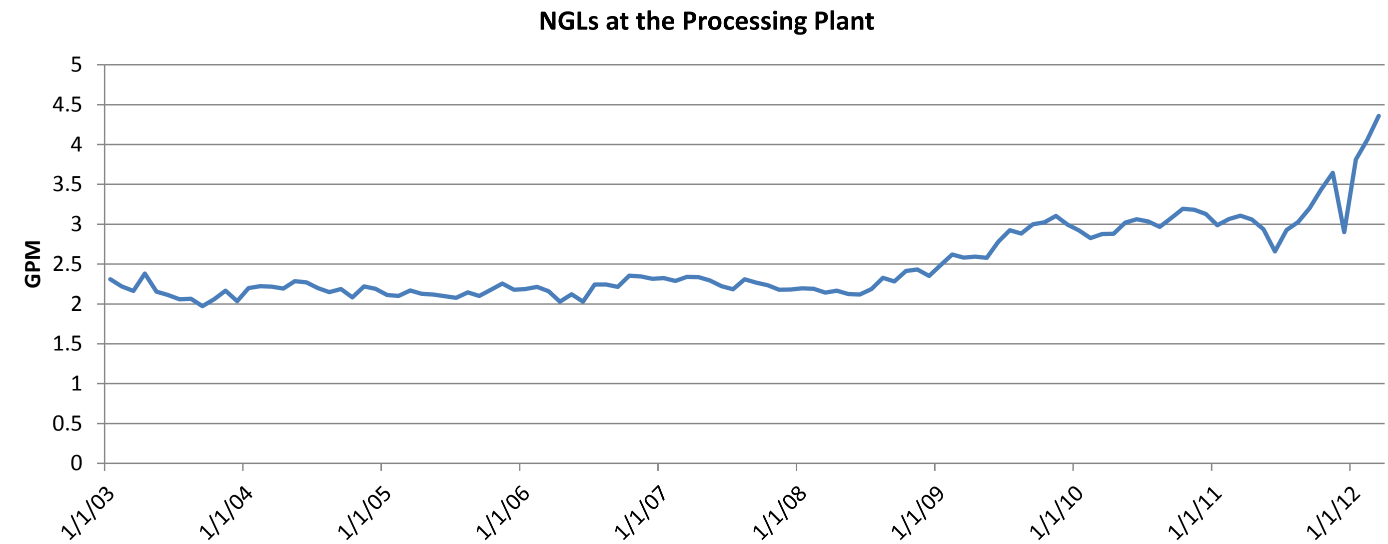


Figure 61. SOURCE: SUPPLY DATABANK

and Charbonneau interconnects. The second largest goes to CIG at the Elk Basin interconnect (see Figure 57).

WBI Storage

WBI's storage capacity is among the largest in North America, with a combined 193 Bcf working capacity at three storage fields. MDU holds almost 70% of all firm storage capacity.

Bison Pipeline

The Bison Pipeline connects Powder River Basin coalbed methane to the NBPL mainline at compressor station No. 6. This 302 mile, 30-inch diameter pipeline went in service in January 2011. It has design capacity to deliver

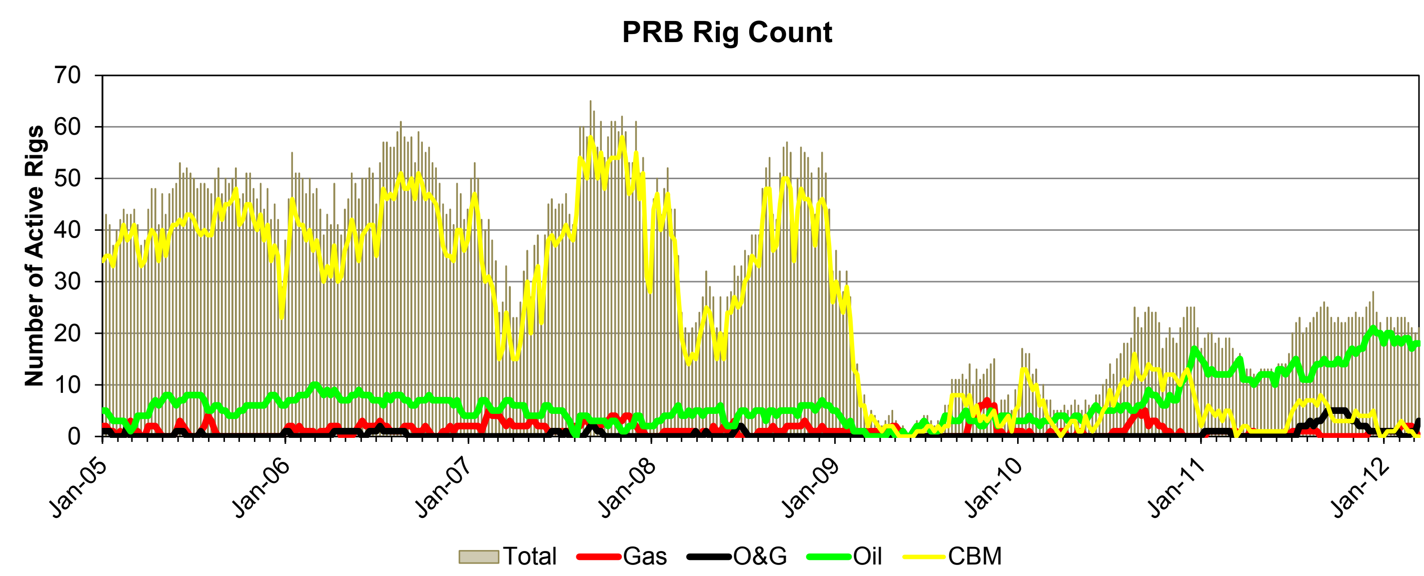


Figure 62. SOURCE: RIGDATA

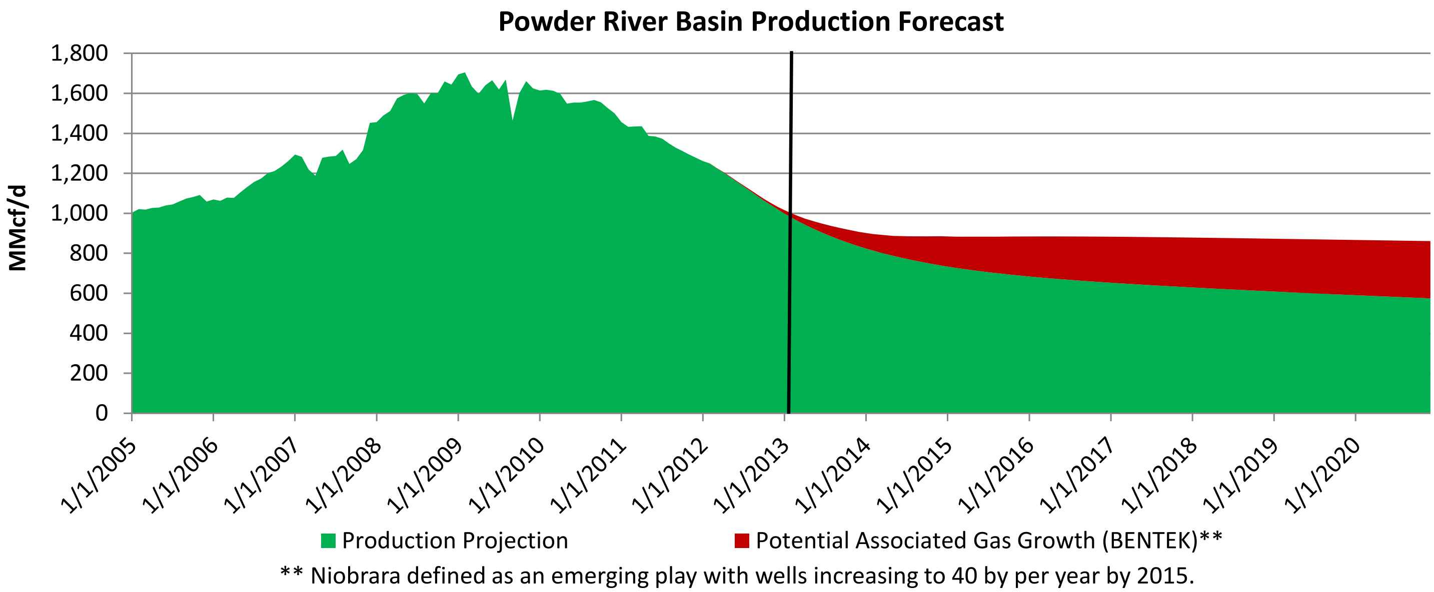


Figure 63. SOURCE: HPDI

407 MMcf/d to NBPL, but has consistently flowed only 25 MMcf/d since late 2011.

Bison was built for the anticipated growth in Powder River Basin gas that has yet to materialize. The economics for competing gas plays in other basins are superior to the Powder River. This has caused capital to re-deploy to the basins with higher rates of return, such as the Bakken oil play.

Powder River gas now mainly flows south to Cheyenne Hub via WIC and CIG as it had done prior to construction of Bison. Bison capacity holders, who also have companion capacity downstream of Bison on NBPL, are able to optimize their NBPL capacity and capture better netback prices by purchasing third-party gas for transmission on their NBPL capacity, leaving idle the Bison capacity (see Figure 50 and the discussion of alternate dispatch in the NBPL section).

Gas Processing

Gas processing utilization in the Williston is currently about 50% of capacity due to lack of connectivity between the gas being produced and the processing plants. Expansions to the processing plant fleet and gas gathering systems are planned and will be necessary to capture the value of the natural gas and NGLs currently produced in North Dakota (see Figure 59). Several expansions are planned between now and the end of 2013, including those listed in Figure 58.

Infrastructure Investment Opportunities

With the current lack of midstream and gathering infrastructure in the Williston Basin, significant quantities of natural gas and NGLs cannot be processed locally. In the future, additional processing capacity or alternative uses for natural gas must be developed. Given expected production growth, significant revenue can be captured by companies willing to invest in additional infrastructure in the region. The following assumptions form the basis of this analysis:

- Production trends follow the Base Case production forecast.
- NGLs represent 33% of the volume of gross gas (using 8 gallons of NGLs per Mcf (GPM).
- Dry natural gas is valued using Henry Hub forward prices less a $0.40 basis to approximate prices that would be received in the field.
- BENTEK price forecasts for NGLs serve as reasonable approximations for future values of these products, less transportation and fractionation fees of $0.19 and $0.05, respectively.
- A barrel of NGLs consists of 41.64% ethane, 28.33% propane, 6.98% normal butane, 9.55% isobutene and 13.51% natural gasoline.

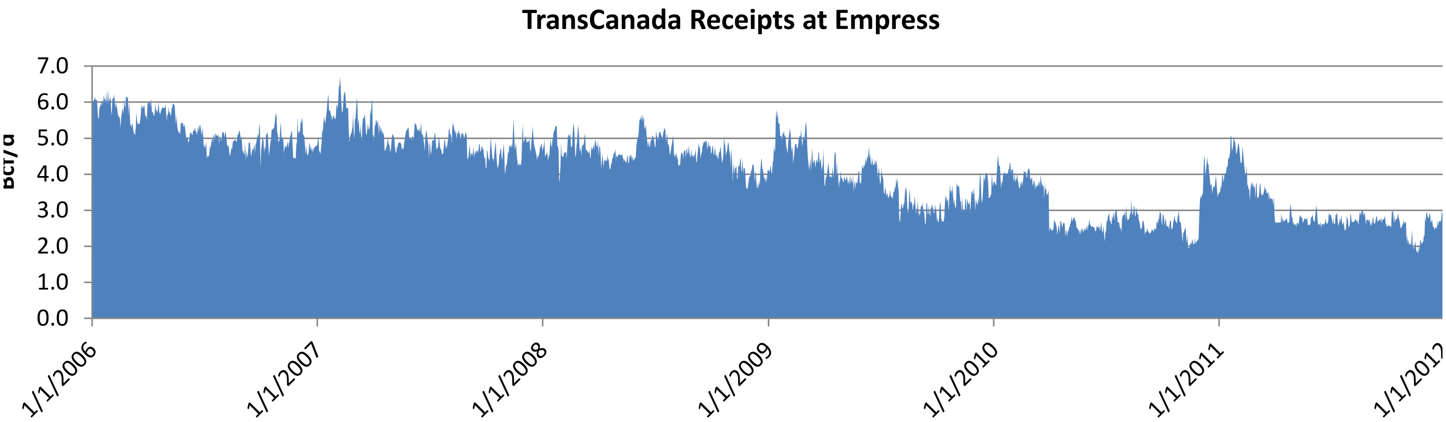


Figure 64. SOURCE: BENTEK

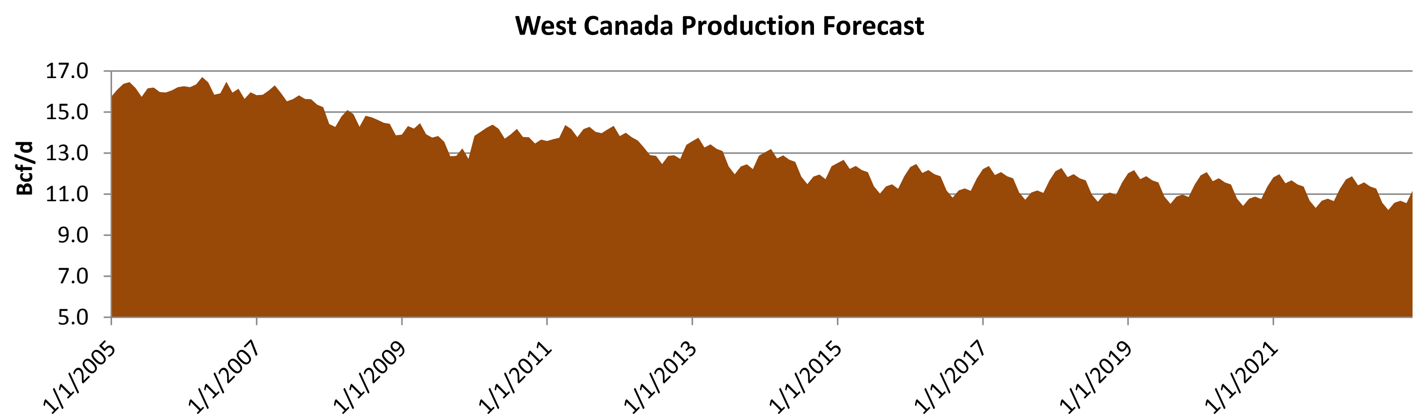


Figure 65. SOURCE: BENTEK

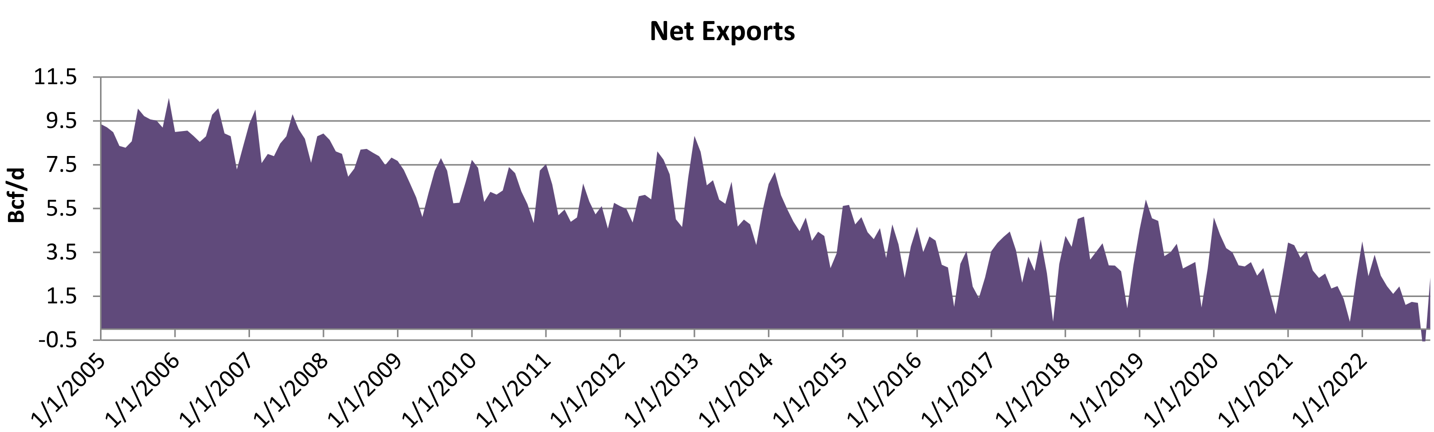


Figure 66. SOURCE: BENTEK

- Only infrastructure projects listed on the North Dakota Pipeline Authority's website will be completed.

The analysis does not consider any royalties or severance taxes which might be collected. Additionally, the analysis assumes that no NGLs are collected at the wellhead, e.g., natural gasoline collected at drip stations. Under these assumptions, 2.6 Bcf/d of processing capacity would be necessary to handle the growth in natural gas production that will occur according to the Base Case. BENTEK estimates that approximately $50 billion in revenue could be captured by companies that invest in this necessary processing infrastructure.

Other uses for natural gas also exist and could reduce the processing capacity requirements. It is a less expensive alternative to CO_2 for enhanced oil recovery (EOR) operations in the basin. This technique calls for the natural gas is injected into a nearby well to flood reservoir, forcing more oil out of the rock and improving total oil recovery. Additionally, results of a feasibility study sponsored by the North Dakota Corn Growers Association found that natural gas could be used in the manufacture of nitrogen fertilizer. Plans for a $1 billion fertilizer plant are already underway.

NGL Content in Bakken and Three Forks Gas

Little analysis exists in the public domain regarding how the NGL production from a Bakken or Three Forks well will vary over time. From a theoretical standpoint, it is reasonable to conjecture that the gallons of NGLs per Mcf of gas (GPM) will rise over time as the reservoir's pressure continues to fall. A lower pressure would allow the NGLs to bubble out of the oil, mimicking the behavior characterized by the rising GOR. Unfortunately, the data BENTEK could obtain neither substantiates nor refutes this hypothesis, perhaps due to the data's limited time horizon. Thus to fully answer this question for the basin, the heat content of the gas must be measured frequently at the wellhead.

BENTEK obtained data corresponding to a subset of wells owned by one operator in the Williston. All gas was processed by a midstream asset developer in the region and GPM measurements were taken once or twice per year on average. Figure 60 shows the average GPM from a sample of 43 wells operating during the entire horizon (January 2008 through April 2012). Figure 60 (second graph) reduces the Y-axis range used in Figure 60 at top, allowing the variations in GPM to be readily observed. Note that the circled area shows GPMs first declining, then rising and declining again between late 2010 and early 2011. Hence, a clear trend cannot be discerned from the data available.

BENTEK also investigated the relevant publicly-available NGL production data at the processing plant. A cursory analysis of the NGLs produced at all processing plants in North Dakota demonstrates a positive trend, as shown in Figure 61. While it is tempting to believe that NGL production from a well will rise over time based on this graph, many factors could explain this trend. Some other reasons include: a change in producer focus towards wells with higher NGL content, a rising GOR, improved processing plant efficiencies and flaring of significant amounts of gas which might distort the true production of NGLs from the region.

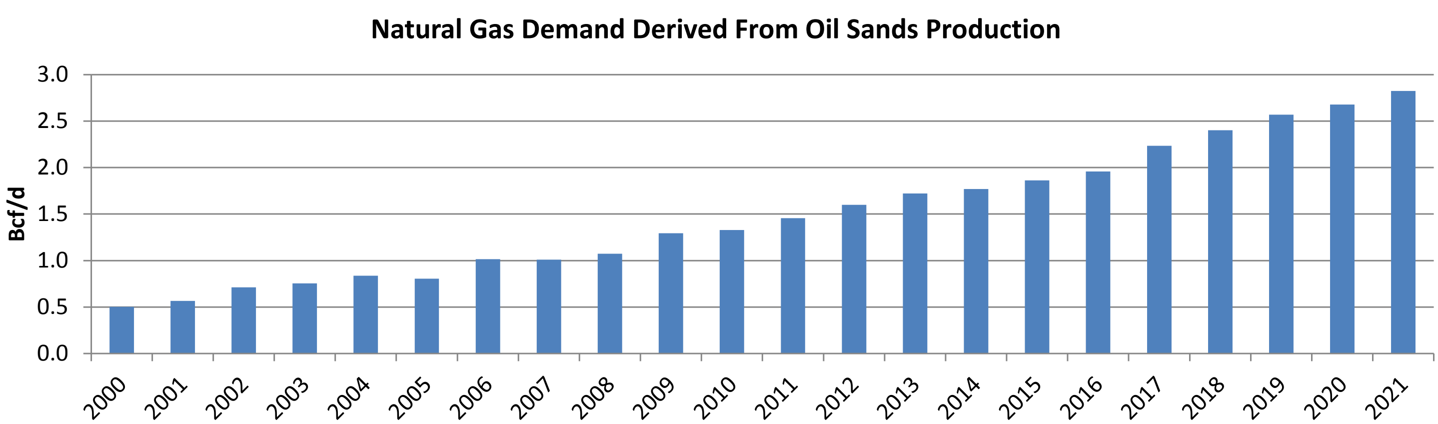


Figure 67. SOURCE: ECRB

Foreign Partner	Origin	Size	N.A. Partner
Inpex	Indonesia	2 Tcf	Nexen
Kogas	South Korea	1.2 Tcf	EnCana
Petronas	Malaysian	5.5 Tcf	Progress
Mitsubishi	Japan	16.1 Tcf	EnCana
Sinopec	China	5 Tcf	Daylight Energy
PetroChina	China	8 Tcf	Shell

Figure 68. SOURCE: COMPANY REPORTS

NGL Transportation Infrastructure

A large portion of the NGL barrels produced in North Dakota are consumed locally. The remaining NGLs are transported by rail or truck or included in the rich-gas stream that is transported on the Prairie Rose Pipeline from the Palermo Plant to the Alliance Pipeline.

New pipeline projects are planned that will move NGLs from the Williston Basin to market centers. Similar to the gas processing arena and crude oil transportation, it is expected that pipeline projects to deliver gas liquids will continue to be developed as future production gains make pipelines the cost-effective mode of transportation.

ONEOK Partners is constructing an NGL pipeline from Sidney, MT, to an interconnect with its 50% owned existing Overland Pass Pipeline in northeast Colorado, for ultimate delivery to Y-grade markets near Conway, KS. The project will move up to 60 Mb/d of Y-grade NGLs and is expandable with additional pump facilities to 110 Mb/d. The pipeline route will traverse approximately 500 miles and is estimated to cost between $430 and $550 million. The anticipated in-service date is early 2013.

In addition to the Bakken pipeline, Vantage Pipeline has proposed a 430-mile pipeline that would move up to 40 Mb/d of liquid ethane, expandable to 60 Mb/d. The pipeline route runs from the Hess Tioga plant to petrochemical markets near Empress, Alberta. The project received NEB approval this year and is expected to be in-service in mid-2013 pending timely approvals from the U.S. Department of State as well as North Dakota.

Competing Supply

Gas production from the Williston competes for market access mainly with gas produced in the Central Rockies and with Canadian imports on NBPL and Alliance. Williston Basin producers have an advantage over competing supply by being mainly a by-product of oil production. High oil and liquids prices relative to natural gas cover the cost of oil, NGL and dry gas production, providing substantial returns per well for Williston producers. Consequently, producers are able to accept low prices for their gas without negatively impacting well returns. This gives them an advantage over gas producers in Canada and the Rockies.

Rockies Production

As gas prices have fallen, Rocky Mountain region producers have pulled out of many conventional basins

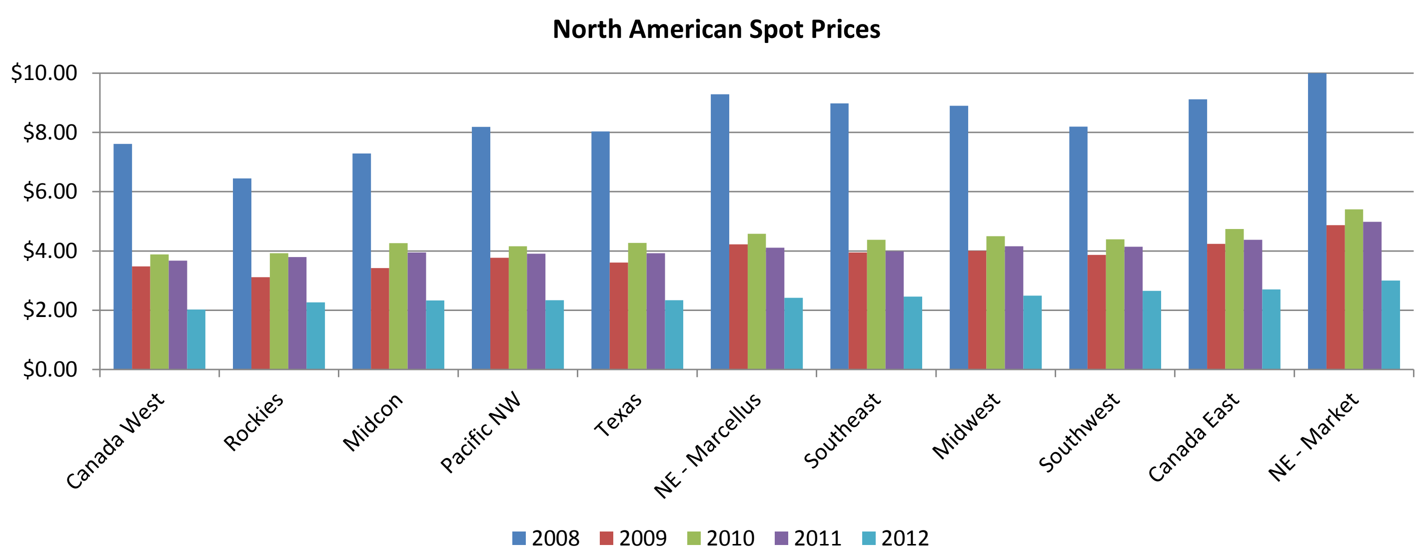


Figure 69. SOURCE: ICE

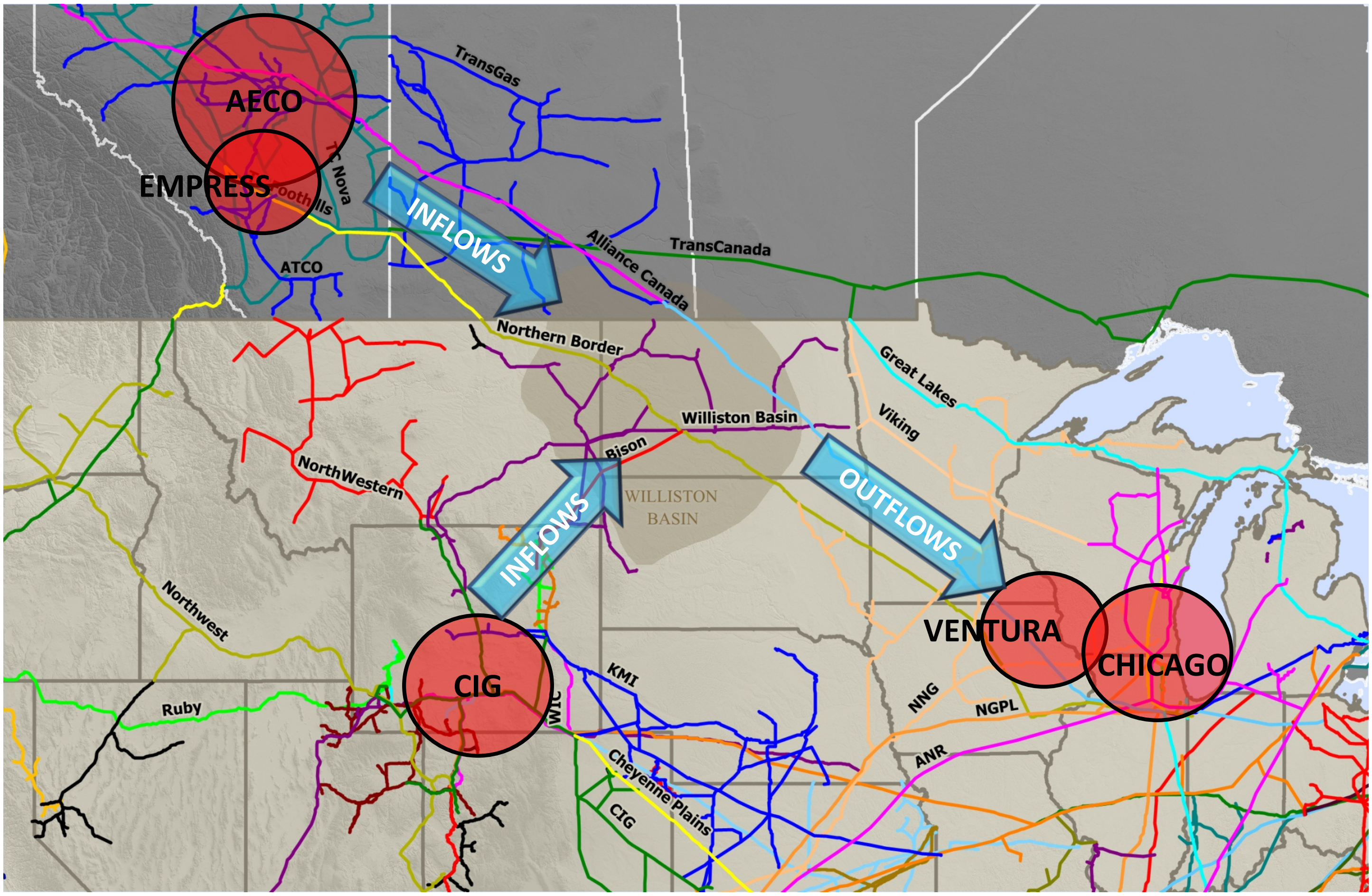


Figure 70. SOURCE: BENTEK

and some unconventional plays that lack liquids content. Coalbed methane (CBM) drilling in places such as the Powder River Basin in Wyoming has declined as well as drilling in some lean-gas shale plays such as the Haynesville. While this exodus has not yet substantially impacted overall U.S. natural gas growth trends in the U.S., it has impacted growth in the Rockies and in Canada.

The Powder River is significant in that it has historically fed supply into Montana and the Dakotas to either meet local demand off of Williston Basin Interstate Pipeline (WBI) or to reach Northern Border. The Bison Pipeline also was built last year to reach the NBPL system, but volumes flowing on the pipeline have declined as producers have found better alternative routes to Midcontinent/Midwest markets.

As prices have fallen, natural gas production in the Powder River has declined significantly. CBM drilling, which made up a majority of the drilling activity in the basin, all but vanished as natural gas prices slumped. Figure 62 below depicts that shift in CBM drilling activity, which exceeded 60 rigs in 2006 and 2007, but has now dwindled to single digits or even zero.

More recently there has been an uptick in oil- and liquids-directed drilling from exploration of several formations including the Niobrara, Turner and Sussex, amongst others. Results from this drilling activity suggest the basin will yield significant oil and natural gas liquids (NGL) resources, but it is not expected to reverse the overall declining trend in natural gas production. BENTEK estimates that under current drilling activity, natural gas production in the basin will decline by 0.4 Bcf/d from its current level of 1.0 Bcf/d over the next 10 years. However, additional resources are being deployed into the area in pursuit of oil and NGLs, which could reduce that decline to around 0.2 Bcf/d, as shown in Figure 63.

For parties serving demand in Montana and the Dakotas, this shift in production has resulted in lower volumes moving north and more space on pipelines for Williston Basin production. Powder River supply delivered to WBI and Bison pipelines has fallen more than 330 MMcf/d year-to-date compared to the same period in 2011. This

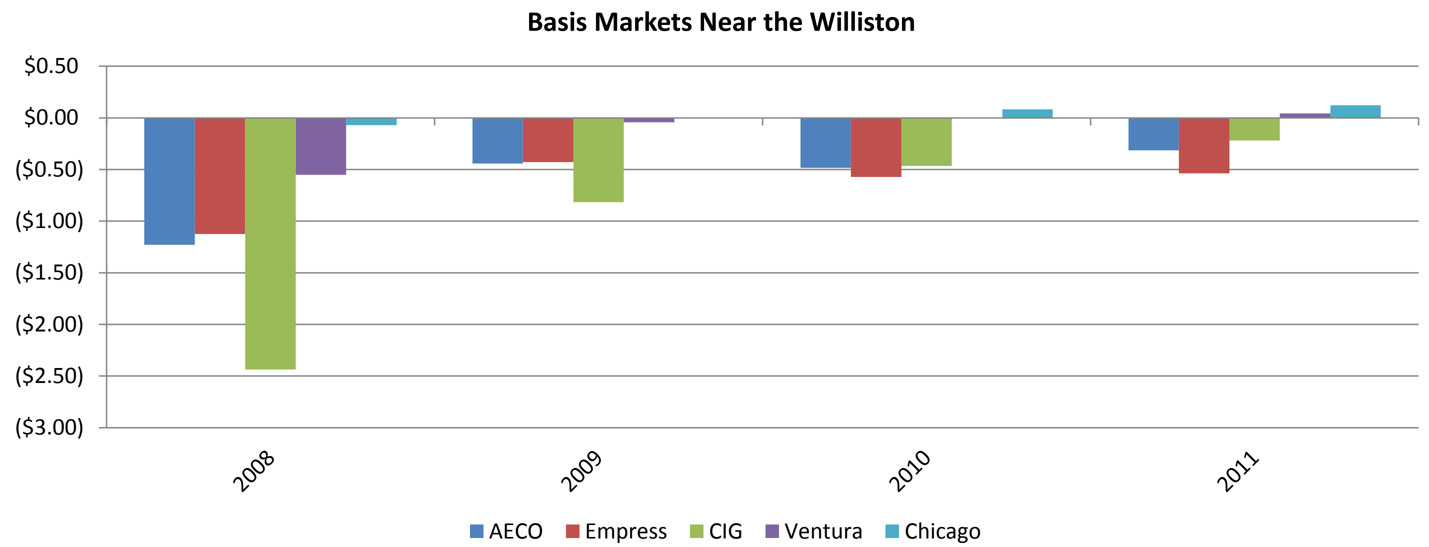


Figure 71. SOURCES: ICE, NGX

is good news for Williston Basin producers requiring additional pipeline space to regional markets.

Canadian Gas

As Williston Basin gas production grows, Williston producers will have to price their gas low enough to make it attractive to shippers on the Alliance and Northern Border pipelines, the two main Canadian import pipelines serving the Midwest region. Canadian imports on Alliance and Northern Border have increased more than 350 MMcf/d year-to-date as shippers on NBPL have brought in more Canadian gas as a replacement for moving Powder River Basin production into NBPL via Bison pipeline, and as Canadian producers also have lost market share in the Northeast region. As Northeast market share declines, Canadian supplies must seek out other markets or reduce their production. They are doing both.

Canadian producers in the WCSB continue to be squeezed out of U.S. markets by lower overall North American prices, lower spreads between markets and high transport costs to move gas to market. The long term outlook suggests Canadian production will continue to be pressured lower.

By 2007, production received by TransCanada (see Figure 64) began a steady decline from about 5 Bcf/d to about 3 Bcf/d. BENTEK forecasts for western Canadian supply to continue its decline, but at a slower pace than was experienced during the past five years, dropping from

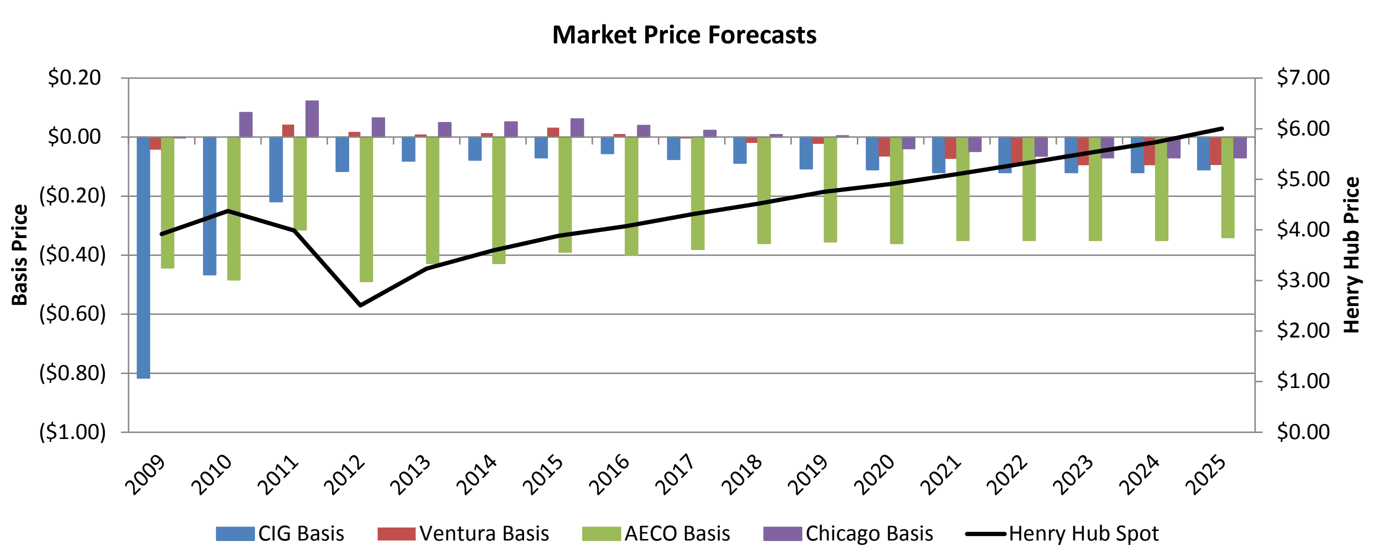


Figure 72. SOURCE: BENTEK

an average of 13.4 Bcf/d in 2011 to 12.1 Bcf/d in 2021 (see Figure 65).

As shown in Figure 66, U.S. demand for Canadian imports is declining rapidly, even faster than the decline in Canadian production, leading to a supply overhang. The average daily export to the U.S. was 9.2 Bcf/d in 2005, but just 6.5 Bcf/d in 2011. BENTEK forecasts continued declines in exports to the U.S., reaching 2.6 Bcf/d by 2016, and an additional 3.3 Bcf/d decrease in the five-year period.

Oil Sands Gas Demand

Domestic oil sands production offers another alternative demand market for Canadian suppliers. The Energy Resources Conservation Board (ERCB) forecasts gas demand from oil sands development to grow from 1.46 Bcf/d in 2011 to 2.83 Bcf/d by 2021, an increase of 1.37 Bcf/d (see Figure 67). BENTEK forecasts total Canadian demand to increase by 1.5 Bcf/d over the same period. Canadian production is forecasted to decline from 13.55 Bcf/d in 2011 to 12.36 Bcf/d in 2021, representing a total decline of 1.2 Bcf/d. With production forecasted to decline by 1.2 Bcf/d and demand forecasted to increase by 1.5 Bcf/d during the reference period, the Canadian market could be about 2.7 Bcf/d shorter by 2021. Add to that the development of export capacity on the West Coast, and it is easy to see relief from the pressure to export to the U.S. This relief in pressure is timely as increasing Williston basin production continues displacing Canadian supply.

Despite declines in production, there has been an infusion of foreign capital into the development of vast technically and economically recoverable reserves in British Columbia and Alberta in anticipation of LNG exports. Joint ventures with Asian firms such as Petronas, KOGAS, Mitsubishi, PetroChina, and Sinopec are targeting production in the Montney, Horn River, Duvernay, Jean Marie, Liard and Cordova Embayment plays, and contribute to the future need for LNG export capacity. Nearly 3 Bcf/d of additional processing and transport capacity is planned to be in service by 2017, including the 1 Bcf/d to 1.4 Bcf/d Pacific Trails Pipeline that will supply gas to the Kitimat export facility.

Current producers in Alberta and British Columbia have been attracted to joint ventures with foreign investors who have provided funding for development and who also may provide markets abroad for water-borne LNG exports from Canada.

As Canadian natural gas production declines and Canadian demand increases from oil sands production and eventually from LNG exports, Canadian prices eventually will rise, which will benefit Williston Basin producers.

Until that time, prices in the Williston will have to be low enough to remain more attractive than moving Canadian gas to Midwest markets. Prices for tailgate production coming out of Canada through the Empress/McNeil straddle plants on its way toward Northern Border have averaged $0.53 below Henry Hub in 2011, making it one of the weakest pricing points in the North America.

However, the rise and fall of natural gas prices will have a minimal impact on Williston producer decisions to drill. Consequently, Williston Basin producers are expected to remain in a position to compete favorably with gas from the Rockies and Canada.

Infrastructure Investment Opportunities

As discussed in the North American Natural Gas Market Overview, changes in overall production dynamics as well as the construction of new pipeline infrastructure across North American has led to significant changes in pricing dynamics in the last few years. In addition to the drop in underlying price levels, several regional markets have switched positions with respect to relative strength in the overall market. Figure 69 shows average spot prices across North America. The graph shows that the Rockies region was one of the weakest-priced markets in 2008 and 2009 at $6.45 and $3.12, respectively. However, in the last three years the Canadian West market has fallen to the weakest regional market. The graph also depicts the magnitude of the collapse of regional price spreads across the country due to both the addition of new pipeline infrastructure connecting regional markets as well as the decrease in the underlying price: When pipeline corridors have available capacity spreads collapse to the variable cost of transmission; when the underlying price is low, the variable costs are low since this component is largely a function of fuel, lost and unaccounted-for reimbursements. In 2008, the spread from the weakest regional market to the strongest was

$3.68. By 2011 that spread fell to $1.19 and continues to trend lower in 2012.

The Williston Basin does not have an actively-traded spot price point on the Intercontinental Exchange (ICE) or an index published in *Platts Gas Daily*. Regionally, the formation sits between Canada West, the Rockies, the Mid-continent and the Midwest regions. With the exception of the Midwest market, this group of regions are, and have historically been, the weakest-priced markets in the continent, as shown in Figure 69.

There are several pricing points around the Williston Basin, both upstream and downstream of Bakken production receipt locations. Figure 70 below shows a map of the Williston Basin region with the major interstate pipelines that serve the area. As shown in the map, the major pricing points upstream of the area include AECO, Empress and CIG. Conversely, downstream pricing points include Ventura and the Chicago Citygate. The arrows on the map represent the historical direction of natural gas flows through the region.

The basis differential to the Henry Hub for each of these markets has shifted over the past several years. These changes are reflective of both constraints that have existed on the pipeline grid as well as the downward shift in the underlying price in North America. Figure 71 shows the average yearly basis in each of these markets. The graph reflects the significant pricing discount Rockies producers faced in 2008 and 2009, prior to the completed construction of the Rockies Express Pipeline (REX), which alleviated significant constraints in the region and helped connect Rockies' production with premium markets in the east.

Historically, the North Dakota market was tied in part to the Rockies market due to interconnects with CIG, KMI and various Powder River Pipelines that pulled gas out of the Rockies into the markets served primarily by WBI. However, in the past few years, the strongest price correlation for North Dakota is with the Alberta supply market.

Since Northern Border is effectively full, incremental volumes coming out of the Bakken that are delivered into Northern Border must compete with supply coming from Canada, causing the correlation between prices in Alberta and North Dakota receipts onto Northern Border. The price difference is approximate to the differences in variable costs of transmission to the Northern Border system. This price relationship can also vary at times due to seasonal dynamics and the related shifts in supply and demand.

The closest Canadian price to the Williston Basin is Empress. Empress reflects the price of lean natural gas supply at the tailgate of several straddle plants on TransCanada's Nova system. From Empress, natural gas can either be delivered into TransCanada's mainline headed east or into the Foothills System, which interconnects with Northern Border at the U.S. and Canadian border.

While Canada has slipped to become one of the weakest-priced markets in the country, the expectation is for improvement in the coming years. Despite increased production from the Montney, Horn River and other active unconventional resource plays in the area, overall production in Canada is expected to decline. The net result of these factors will cause the Canadian market balance to tighten and provide an offset to displacement of Canadian supply from the Bakken and other U.S. producing basins. This sequence of events will make Canadian supply less marginal, thus supporting relative strength in western Canadian prices.

Figure 72 shows BENTEK's expectation for basis pricing around the Williston Basin through 2025. While overall Canadian pricing is not currently expected to climb above any of the neighboring pricing points, Western Canada is expected to tighten relative to each of those markets. In 2012, AECO basis is expected to weaken with respect to 2011, due to low U.S. demand and high storage inventories across North America. Subsequent years should show some improvement as basis falls below ($0.40) in 2015 with more significant improvement in 2017, when LNG export capacity is expected to come online.

As a result of the improvement in pricing in Canada, the market for producers of Bakken gas will also see improvement. This will result in increased returns from current and future investments made in gathering and processing capacity to move growing natural gas supply to takeaway options on WBI, Northern Border and Alliance.

Bringing Williston Basin Gas to Market

The Williston Basin is already expected to be a major component of the U.S. oil market. Current estimates anticipate that the Williston Basin could grow to 1.8 MMb/d by 2017, representing 18 % of total U.S. oil production. By 2025 that level could grow to 2.2 MMb/d under BENTEK's base case and 2.8 MMb/d under a high-case scenario. But few participants in the industry have thought of the Williston as a major supplier to the U.S. gas market. Given BENTEK's base-case scenario and expectations that U.S. dry gas supply will grow to 75.5 Bcf/d by 2017, the Williston Basin could represent 1.5 Bcf/d or 2% of the U.S. dry gas market. That is dramatic growth considering that the Williston currently only represents around 0.65% of U.S. dry gas supplies.

Delivering this supply to downstream markets will be an important step toward ensuring that the benefits of this resource are realized. Currently the local market around the Williston can absorb on average around 140 MMcf/d, primarily off WBI. However, as the resource grows, shippers will increasingly need to utilize long-haul transportation pipelines to move gas into downstream markets. Northern Border Pipeline and Alliance Pipeline are currently the primary systems that serve the region. While each of these systems in heavily utilized, the superior economics of the Williston will enable producers to price-compete with upstream supply coming from Canada and Rockies, displacing current flows on those systems. Additionally, as contracts on Northern Border and Alliance roll off in the coming years, new and current shippers will increasingly gain the option to source their gas supply in the Williston.

Figure 73 below plots BENTEK's base-case dry gas production curve, using a 33% shrink factor, versus current and proposed metered capacity out of the Williston and total pipeline capacity. The seasonal fluctuations reflect WBI's ability to inject and withdraw gas from storage. The graph oversimplifies how production in the Williston will find its way to market due to potential operational constraints between the wellhead and the metered capacity. However, assuming new midstream infrastructure is constructed to process supply in the area, and that any operational constraints for moving that supply into Alliance, Northern Border and WBI are addressed, dry gas production in the basin is not expected to exceed long-haul pipeline capacity to move that supply to market.

Competing For Chicago

Aside from local markets in North Dakota and neighboring states, the primary end-use markets for production from the Williston Basin are Chicago and other Midwestern cities. These markets are directly accessed from both Northern Border and Alliance. The Alliance system has a wet gas operational capacity of about 1.8 Bcf/d and has remained heavily utilized. After processing at the Aux Sable plant, dry gas is delivered to several interconnects in the upper Midwest market including ANR, Vector and Guardian pipelines. Northern Border delivers the majority of its throughput to NNG, Vector and ANR

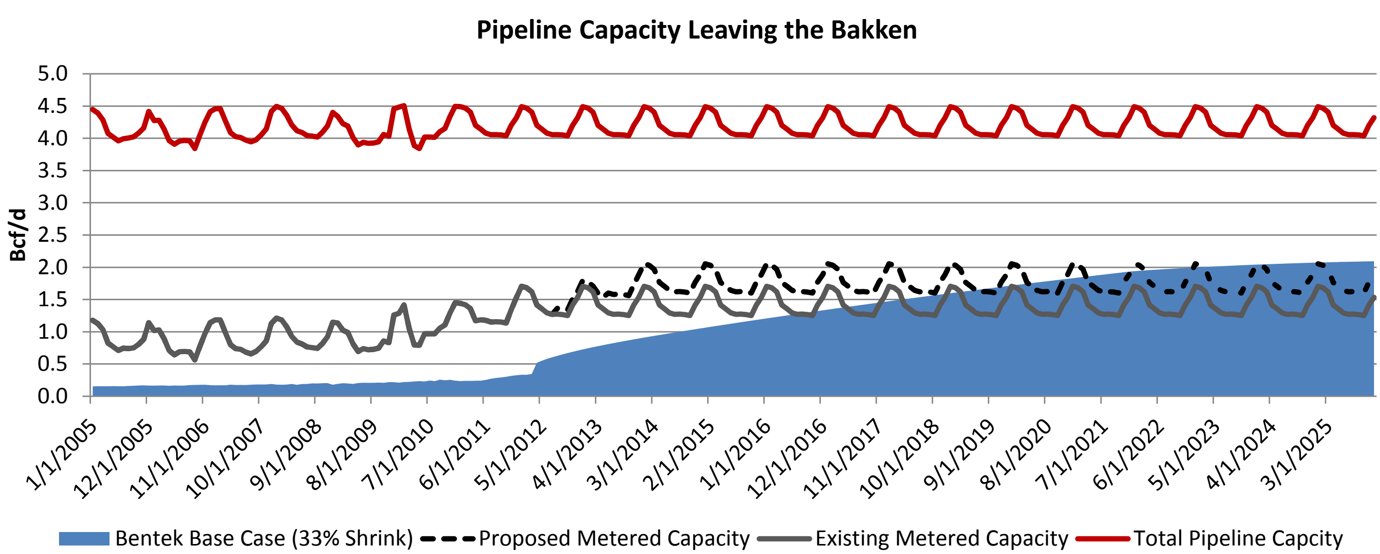


Figure 73. SOURCE: BENTEK

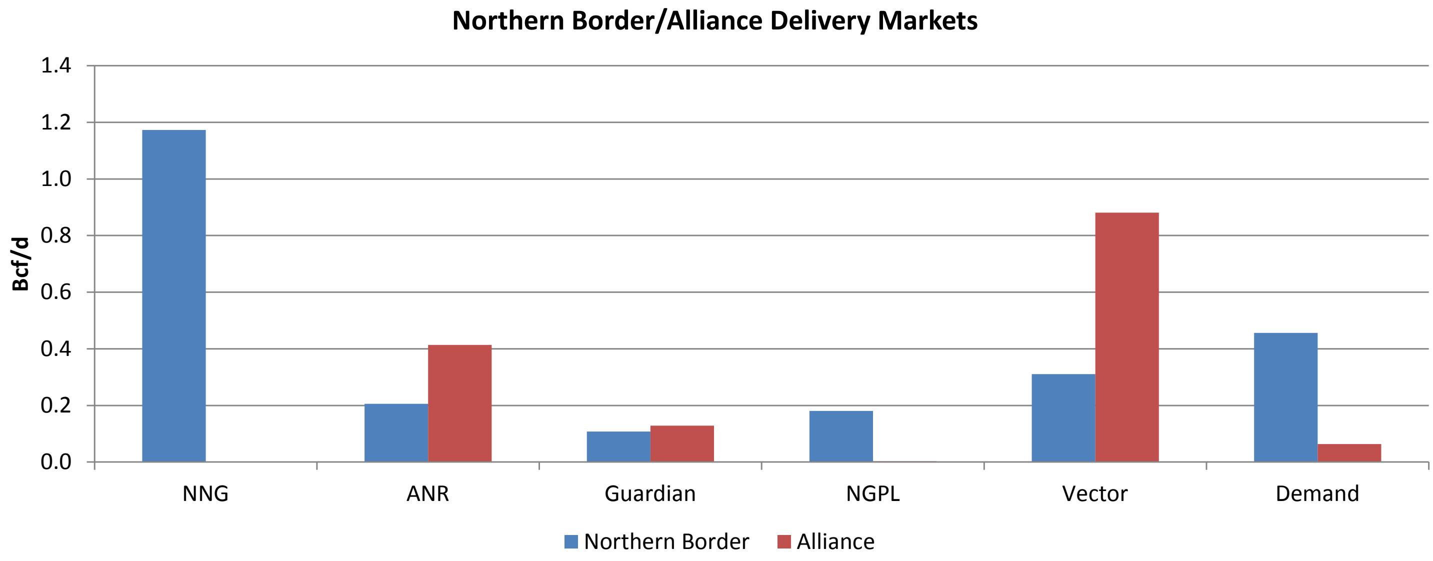


Figure 74. SOURCE: BENTEK

in addition to directly serving around 0.5 Bcf/d of end users. Figure 74 below gives a summary of average 2011 deliveries off each of these systems.

Several other regions are also competing to serve demand in Chicago and other Upper Midwest areas. Figure 75 shows a map of all major supply sources that currently push gas into the Midcon market. The figure also indicates that the Marcellus presents a future competitive supply source for the region.

Despite the competition, deliveries off Northern Border and Alliance are expected to remain extremely competitive into the Chicago market. As discussed before, one of the primary reasons for this is the competitive nature of the Williston as a natural gas supply source. According to the IRR analysis, returns in the Williston fall second only to gas produced in the Midcontinent, but are advantageous to returns from the Rockies, Southeast Gulf, Texas or potential supply from the Marcellus. Additionally, shippers moving gas from the Williston are competitively positioned with respect to transportation costs versus other supply areas. Figure 76 shows that on a variable rate basis, gas shipped on Northern Border from the Glen Ullin interconnect to the Chicago market costs \$0.16. Transportation costs for gas from the Rockies and Canada average more than the Williston Basin while costs from the Southeast/Gulf are slightly lower to variable cost from the Williston.

In the past, supply moving down Northern Border has faced competition for deliveries into Midwest. This competition was particularly evident in 2009 and 2010 when REX made significant deliveries to this market, prior to the completion of Phase 3 when it extended into the Northeast market. Figure 77 shows how deliveries from Northern Border into the Midwest fell during this period. The big difference during this period was that the Rockies and West were not as well-connected to the East Coast market, thus pricing in the region was weaker. During 2009, Opal basis averaged (\$0.78) versus an AECO average of (\$0.44) and an average at Empress of (\$0.43). Going forward, Rockies basis is not expected to be discounted as drastically due to the excess amount of pipeline capacity added by REX, Kern, Ruby and other pipelines in addition to the expectation that production in the region will slowly decline.

A more significant challenge may come from competition with growing production in the Midcontinent. Production in the Granite Wash, Mississippi Lime and Cleveland/Tonkawa is also expected to grow in the coming years based on strong economics. Potential gas production from these basins is represented in Figure 78. On a variable rate basis, production out of the Midcontinent may still be slightly disadvantaged compared to Williston Basin supply, but producers here may not have other options than to compete for markets and price their gas to move. As in the Williston, rates of return in many areas of the Midcontinent are strong even if the gas is given away. Additionally, given that the Midcontinent currently has limited options in moving gas to market, prices could

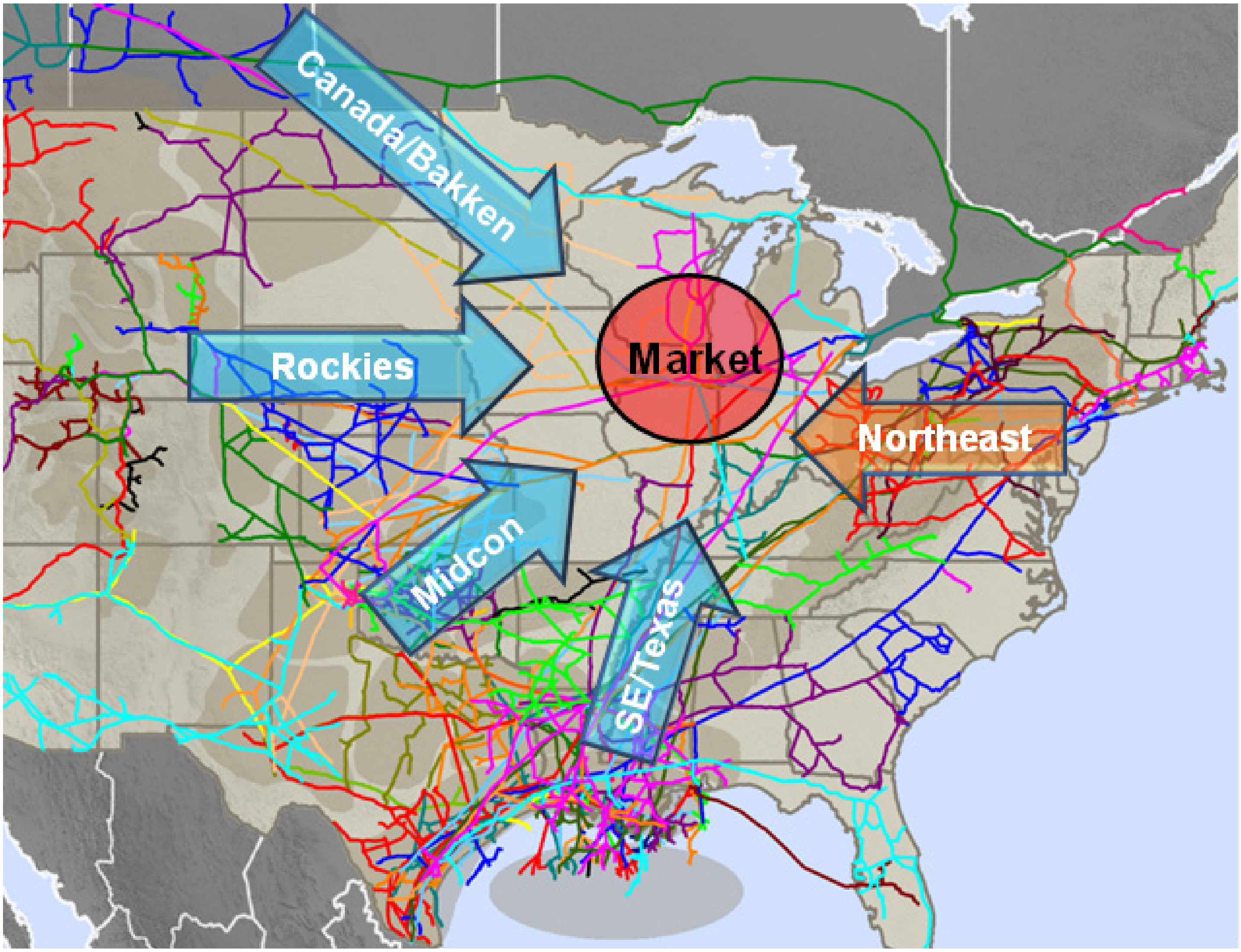


Figure 75. SOURCE: BENTEK

disconnect from the rest of the market as new supply comes online.

While growth in the Midcontinent could begin to displace some flows on Northern Border or Alliance, it is more likely to impact supply coming out of the Rockies or even Canada. Even assuming displacement of flows on Northern Border occurs to the extent seen in 2009, Northern Border would still be able to move around 1.6 Bcf/d of supply. And if Alliance is able to increase connectivity to carry away Williston Basin supply equal to half of its natural gas capacity, total takeaway from the Williston would be around 2.4 Bcf/d. With average deliverables on WBI around 300 MMcf/d, the Williston conservatively has around 2.7 Bcf/d of takeaway capacity, which is enough to support forecasted dry gas production through 2025.

The final potential competition for Williston Basin deliveries into the Upper Midwest is from growing Marcellus

Variable Transport Cost to Chicago at $4.00/MMBtu	
SE/Gulf	$0.12
Bakken	$0.16
MidCon	$0.16
Rockies	$0.22
Canada	$0.24

Figure 76. SOURCE: BENTEK

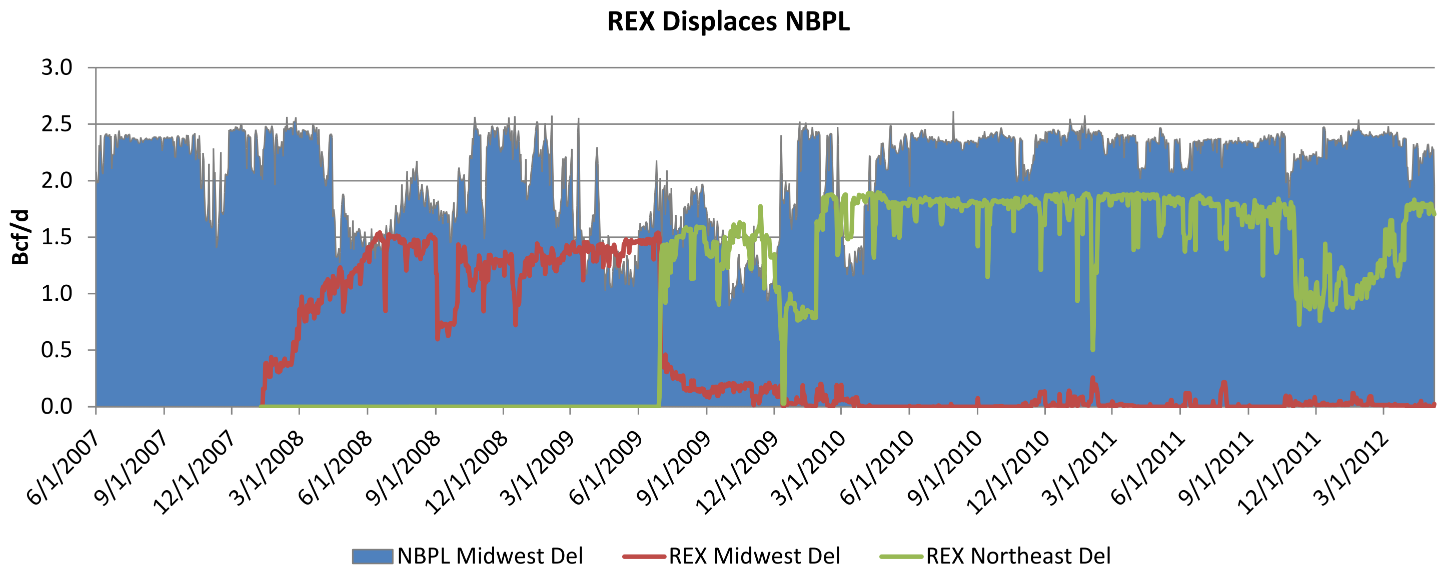


Figure 77. SOURCE: BENTEK

production. BENTEK currently expects that supply in the Northeast could to grow by more than 11 Bcf/d in the next decade. This growth is expected to dramatically reshape pipeline flows across North America. In addition to several backhaul projects that are already proposed from the Northeast to Canada and the Southeast/Gulf, ANR is floating a proposal to deliver gas back into the upper Midwest from the Marcellus. In 2011, the Rockies Express Pipeline filed with the Federal Energy Regulatory Commission to provide backhaul service out of the Marcellus. Rate schedules for these deliveries are still being developed but from a delivered-cost-of-gas perspective, variable rates are not as important as the supply cost. Rates are expected to be comparable to current rates form the Williston, thus as long as supply from North Dakota continues to remain discounted to supply coming out of the Northeast as well as other supply areas, Williston gas will remain part of the gas stack to the Upper Midwest.

Other Williston Basin Takeaway Options

While the existing physical long-haul capacity leaving North Dakota is expected to be large enough to transport Williston Basin production, there are other options that could provide additional capacity if necessary. Aside from constructing a new long-haul pipeline, several shorter-term options exist that could allow additional supply to leave the area. One of these options is to modify interconnects or reverse systems that are currently transporting Rockies gas into North Dakota. As was discussed earlier in the paper, there are several Powder River transportation pipes currently seeing reduced utilization because of production declines in the Rockies and growth in the Williston Basin. These systems may be utilized to transport gas back to the Rockies. This option may become increasingly attractive if Western markets continue to strengthen due to higher demand and declining production. Thus, regardless of whether the Williston Basin physically needs this option, it may prove to be an asset to the region in order to diversify delivery markets. This option would also put Williston Basin production in more direct competition with less economic wells drilled in the lower Rockies.

Additionally, if Williston Basin supply were to grow large enough to fully utilize both Northern Border and Alliance, it would likely mean that Canadian production and resources directed toward future Canadian supply had fallen drastically, or had found access to new markets such as West Canada LNG exports. As such, the Canadian market may begin to need some supply to meet local demand as well as growing oil sands and LNG demand. Therefore, it may become necessary to split Northern Border such that it moves supply both north and south out of the Williston, effectively doubling the takeaway capacity of the pipeline to 4.8 Bcf/d. While this is not expected to be necessary in the forecasted period, several other systems across the U.S. have experienced this same dynamic in a very short amount of time. In the Marcellus, Tennessee is now moving gas both east and west out of northern Pennsylvania and Transco is proposing to move gas both north and south once its Atlantic Access project comes online. In south Texas, several systems including

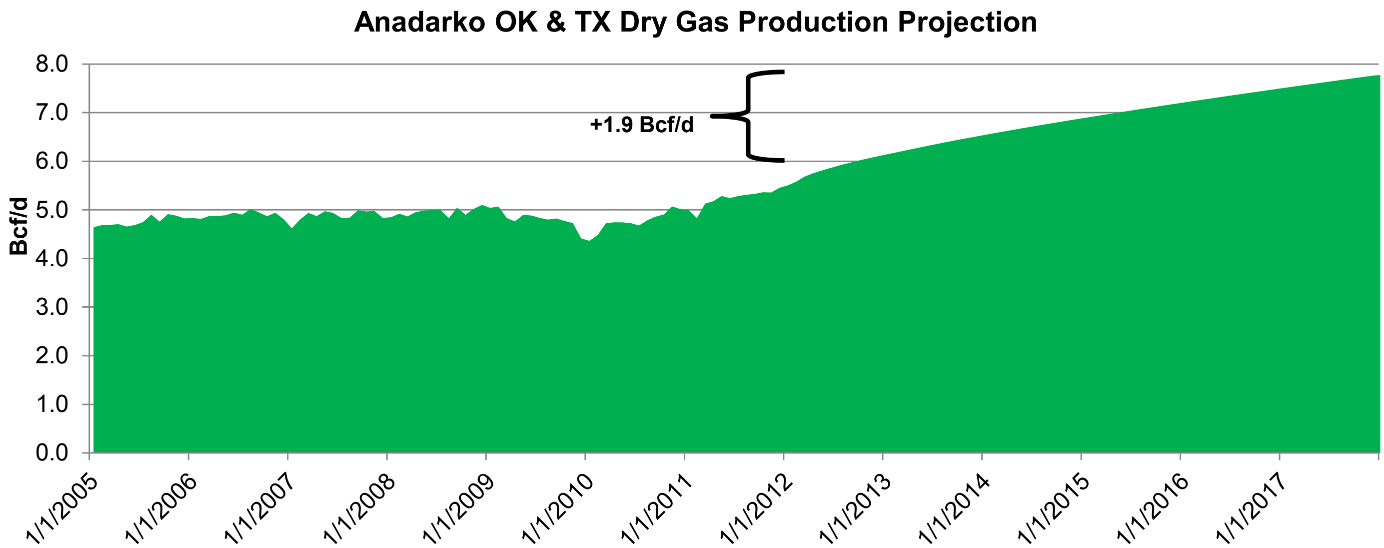


Figure 78. SOURCE: BENTEK

Tennessee and Texas Eastern will facilitate growth in the Eagle Ford by moving gas both north into Ship Channel and Louisiana as well as south into Mexico. These are just a few examples of systems that reconfigured pipeline dynamics to adjust to changing market conditions.

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Glossary

Basis – The differential that exists at a given time between the spot price of a given commodity and the futures price for the same or related commodity.

Brent price – Brent is the global benchmark price for Atlantic Basin crude oils. It classifies light sweet crude oil sourced from the North Sea. Brent crude is the source of much of the light sweet crude shipped to the U.S. East Coast and Gulf Coast markets.

Bbl - Barrel.

B/d - Barrels per day.

Btu - British thermal unit, a measure of heat content for various fuels.

Cubic foot - Measure of volume most commonly used for natural gas.

Express System - Express Pipeline System, includes both Express Pipeline and Platte Pipeline.

FERC - Federal Energy Regulatory Commission.

GOR - Gas-oil ratio.

IRR - Internal rate of return.

LDC - Local distribution company, e.g., a gas utility who distributes natural gas to its customers.

LLS price - Benchmark price of light sweet crude sourced in the Gulf Coast market, also known as Light Louisiana Sweet.

LNG - Liquified natural gas; natural gas which has been cooled to transform it into a liquid .

Midcontinent - An oil and gas basin in the central part of the U.S., encompassing Kansas, Oklahoma, Iowa, eastern Nebraska, southeastern New Mexico and the Texas Panhandle.

Mbbls – Thousands of barrels.

Mb/d – Thousands of barrels per day.

MBtu- Thousands of British thermal units.

MMbbls - Millions of barrels.

MMb/d - Millions of barrels per day.

MMBtu - Millions of British thermal units, 1 MMBtu=1dekatherm.

Mcf - Thousands of cubic feet.

Mcf/d - Thousands of cubic feet per day.

MMcf - Millions of cubic feet.

MMcf/d - Millions of cubic feet per day.

Natural gas liquids (NGL) - All liquid products extracted from the natural gas stream at a gas processing plant including ethane, propane, butane and natural gasoline.

PADD - Petroleum Administration for Defense Districts.

Processing plant – Facility which separates the natural gas liquids from the methane (natural gas).

Refinery runs - Actual processed throughput by refineries.

Res/Comm – Residential and commercial end users of natural gas.

TransCanada - TransCanada Pipelines Limited.

WTI price - Benchmark price of light sweet crude at the U.S. hub in Cushing, OK.

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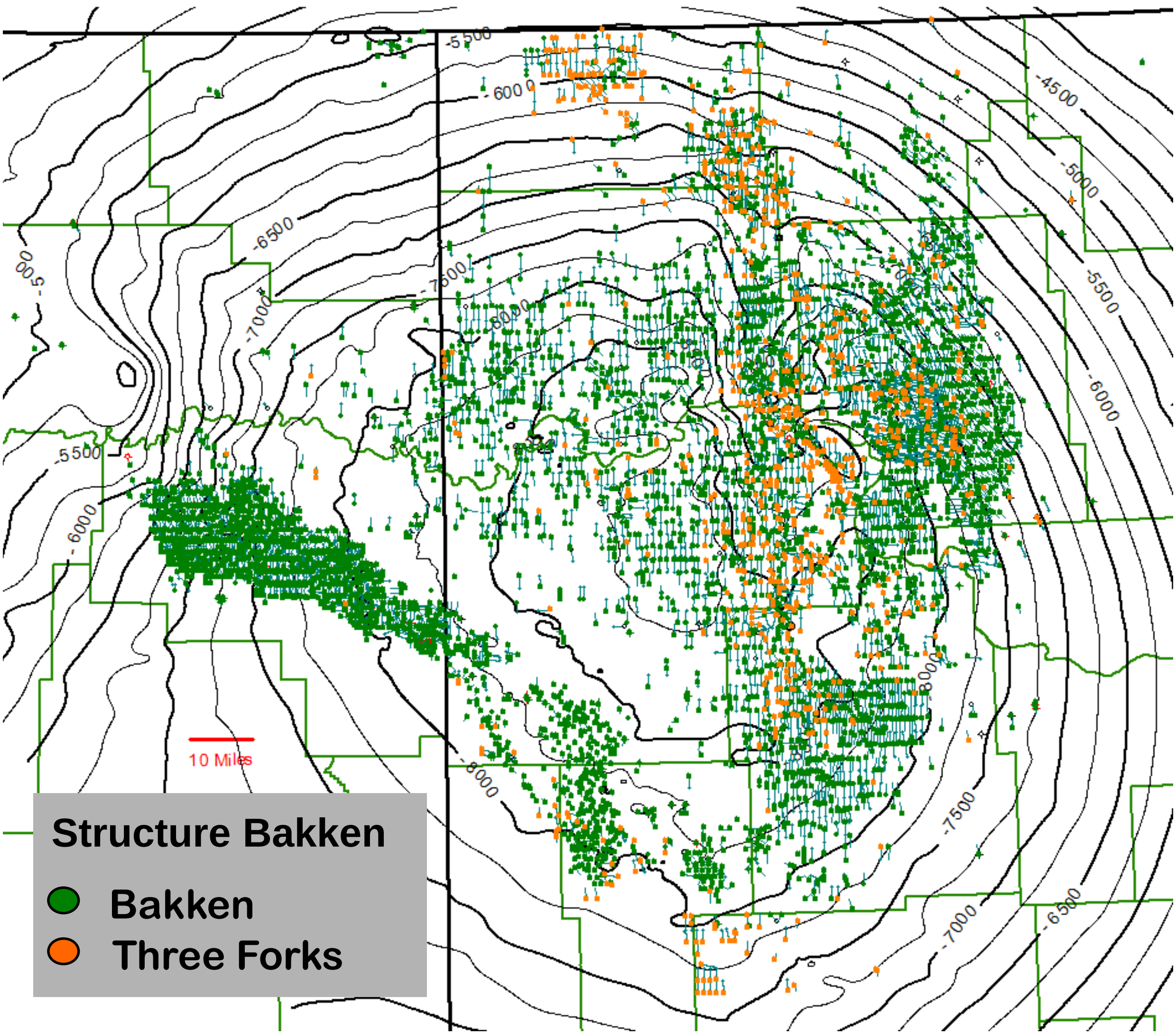
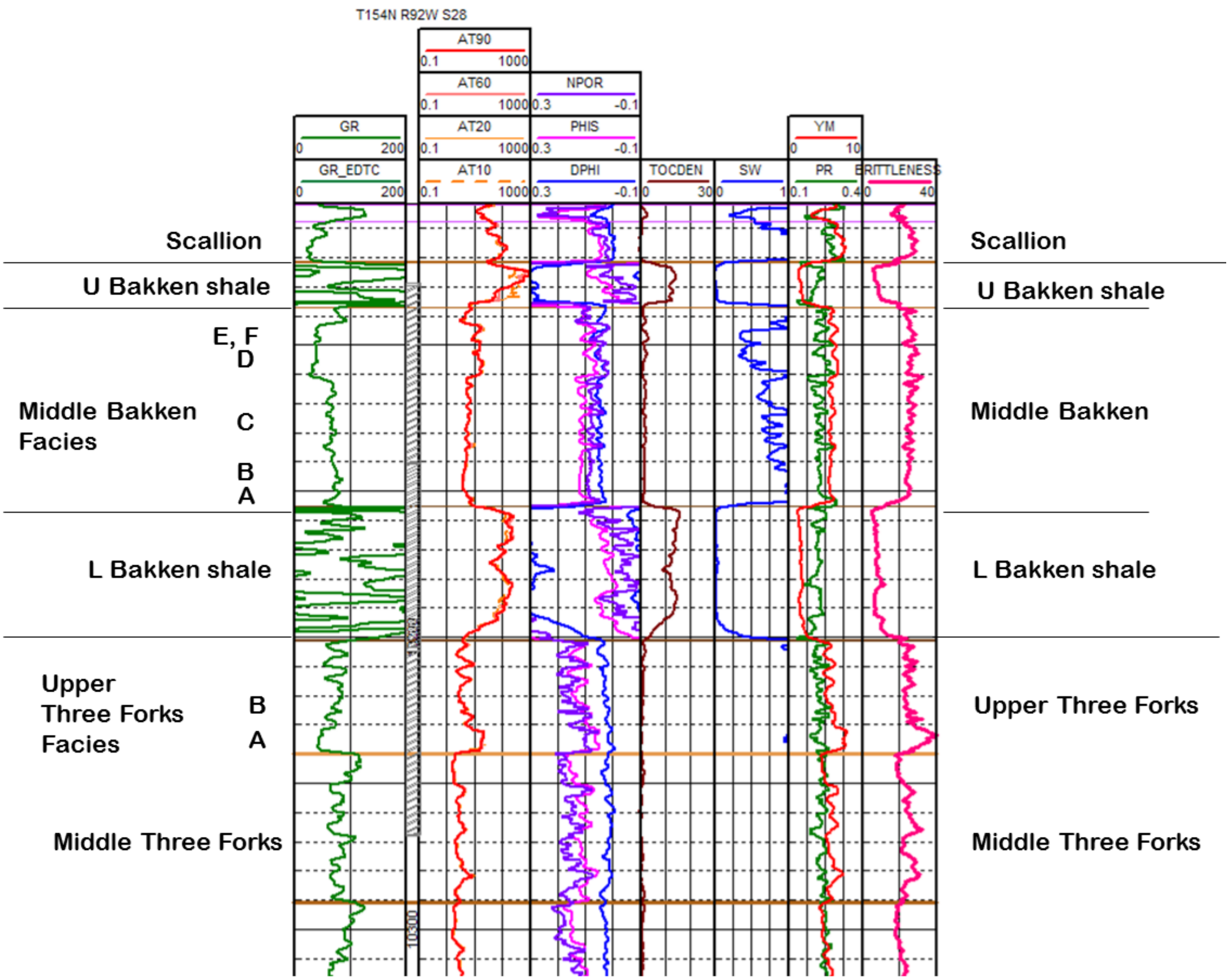
BENTEK Energy

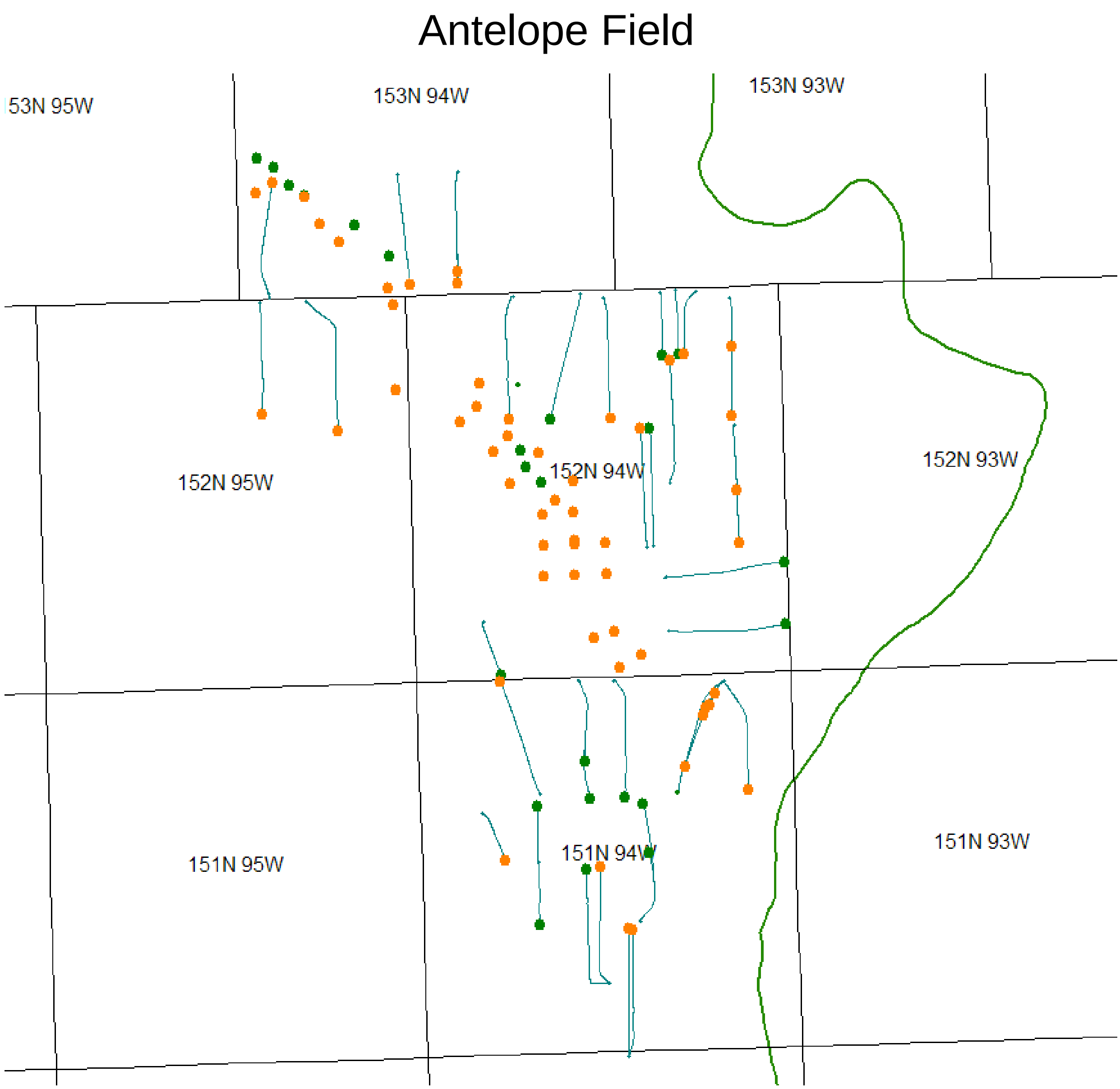
Appendix



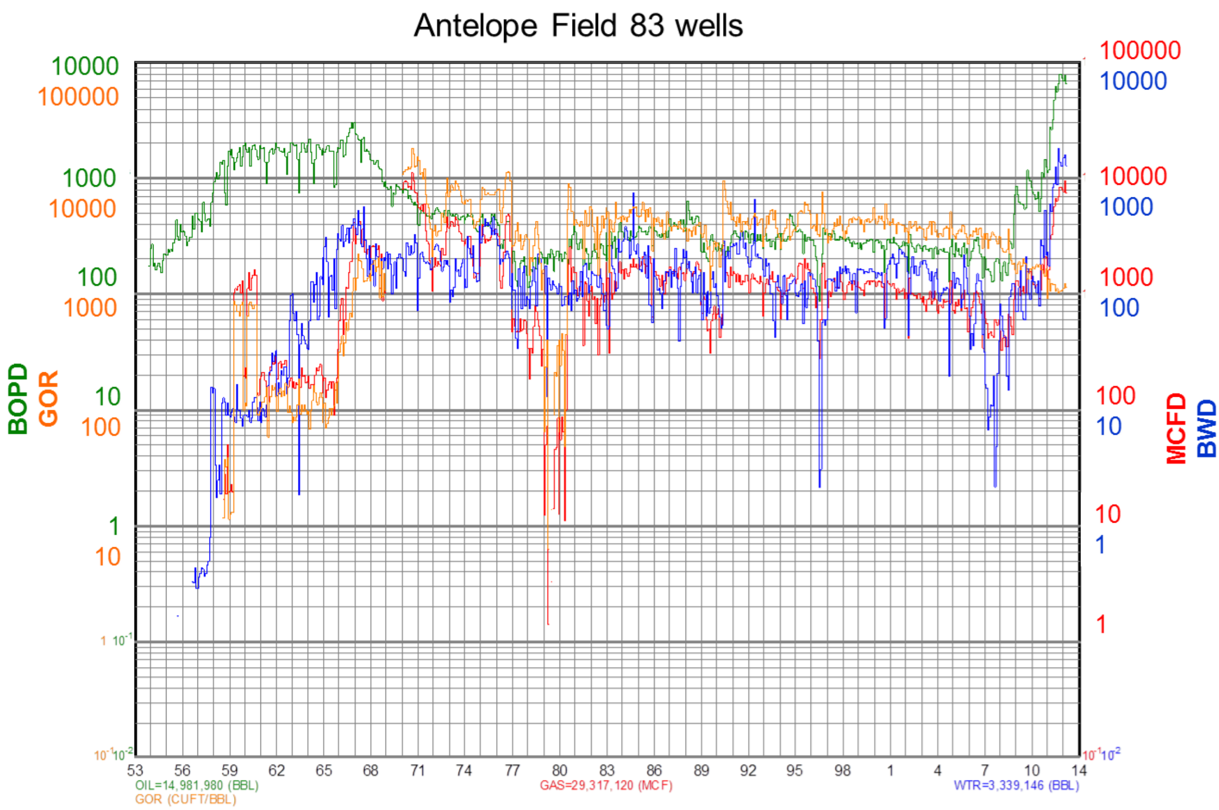
Appendix A1. Structure map on top of Bakken Formation, US part of Williston Basin. Green dots indicate Bakken producers; orange dots indicate Three Forks producers. Most wells are horizontal wells and drilled in a north-south orientation or a northwest-southeast orientation.



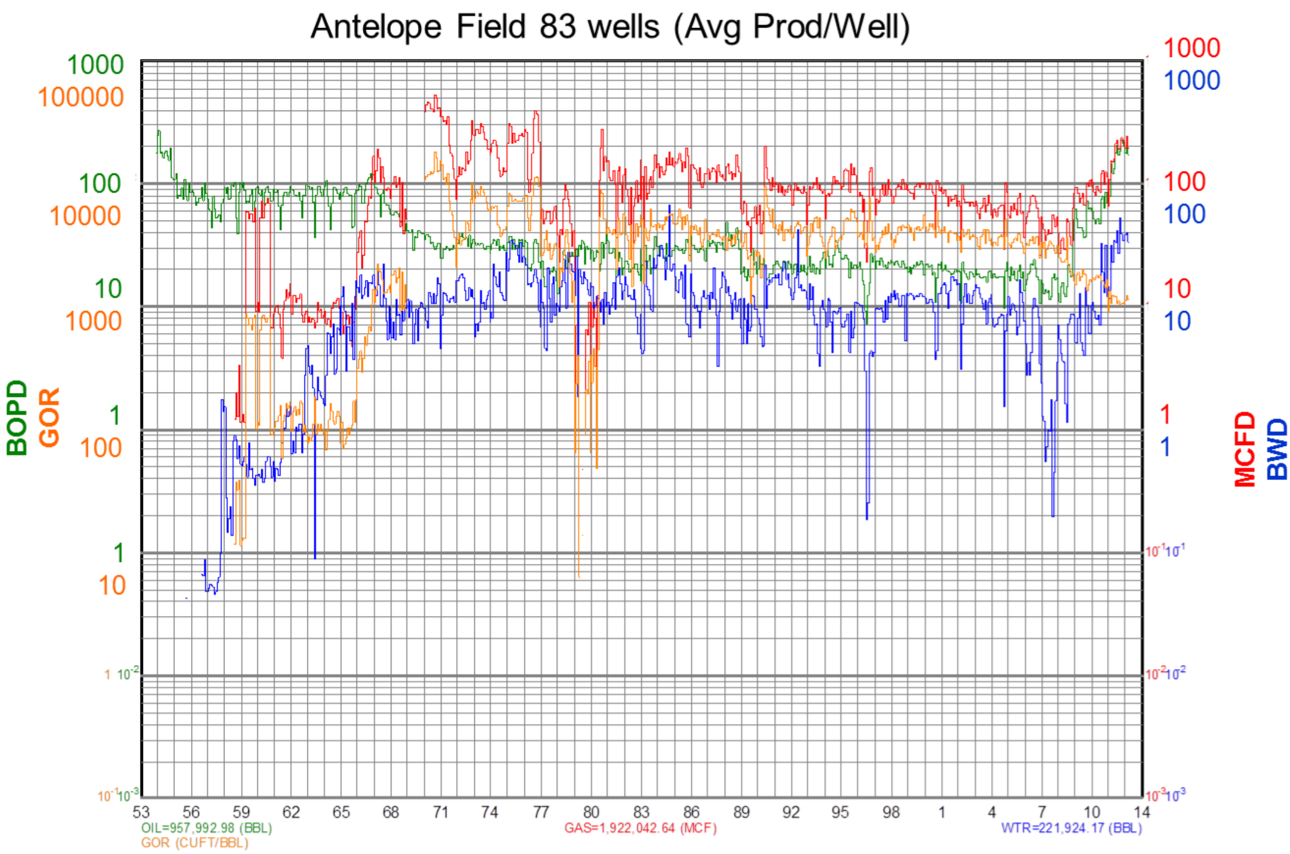
Appendix A2. Typical logs for the Bakken Petroleum System (Sec. 28-T154N-R92W). The main targets for horizontal drilling are the middle Bakken (facies C, D, E) and the upper Three Forks (facies A and B). Recent success has also been reported in the middle Three Forks (see text for discussion).



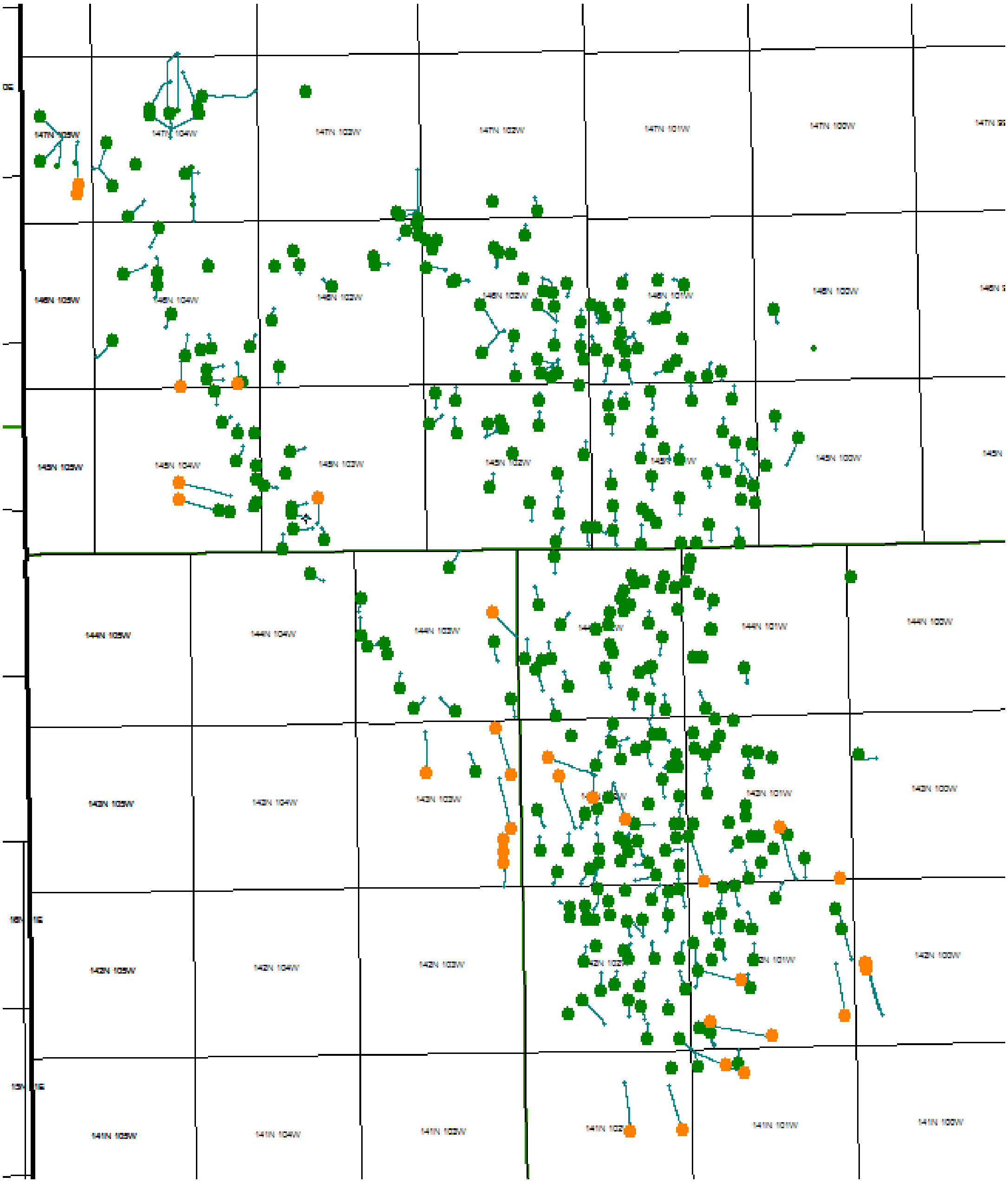
Appendix A3. Index map of Antelope Field. Field was discovered in 1953, New horizontal wells also shown. Green dots indicate Bakken production; orange dots indicate Sanish-Three Forks production.



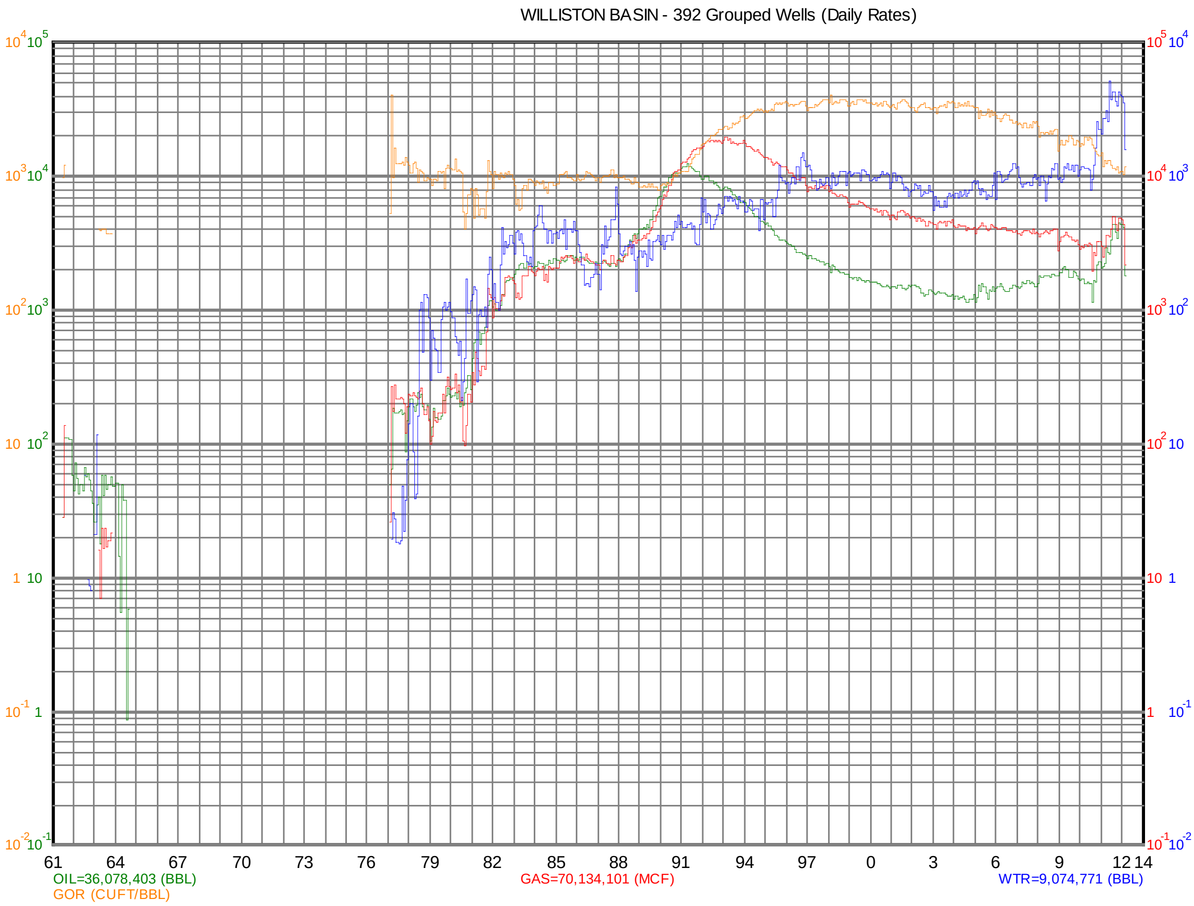
Appendix A4. Production curve Antelope Field.



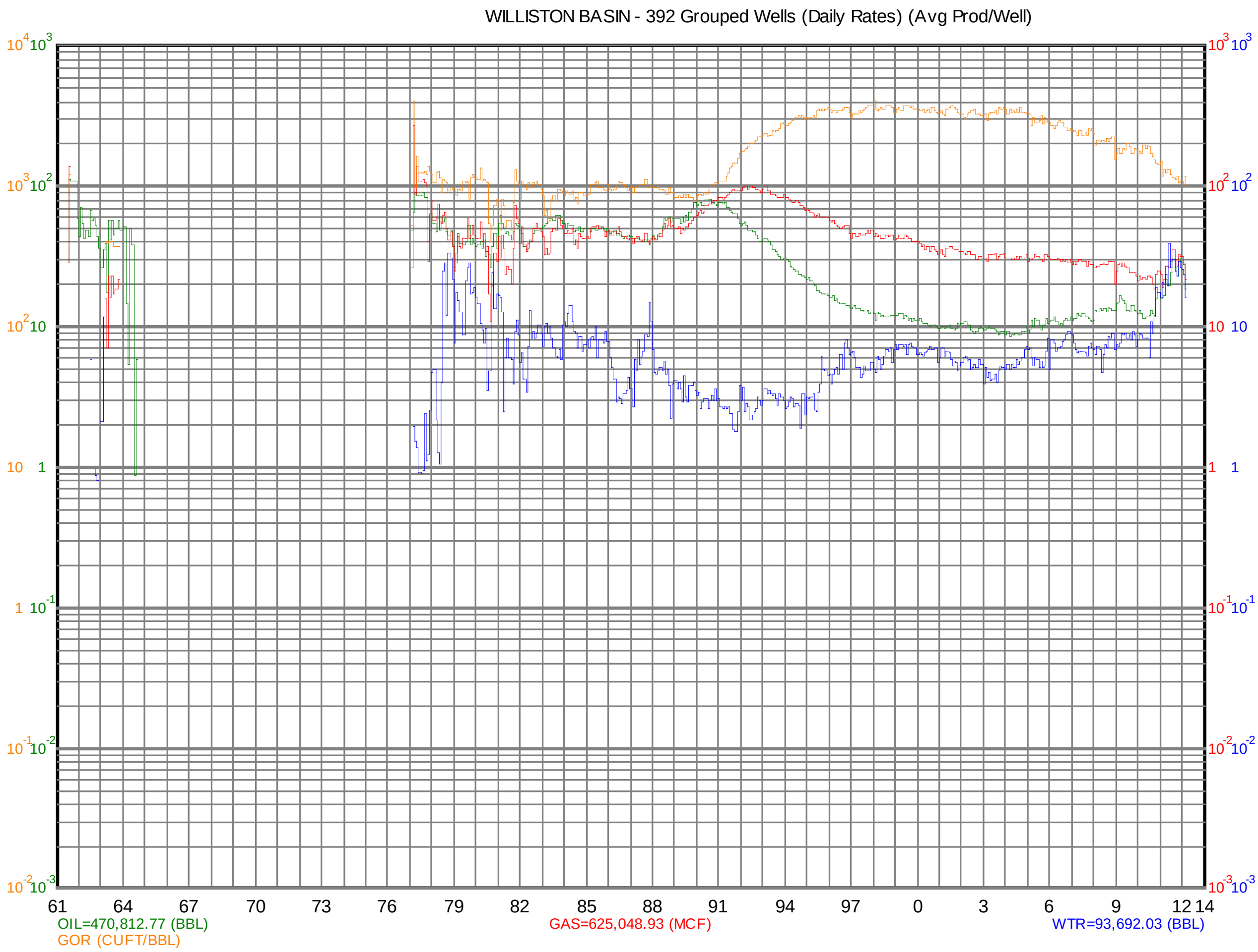
Appendix A5. Antelope Field, average production per well, daily rate.



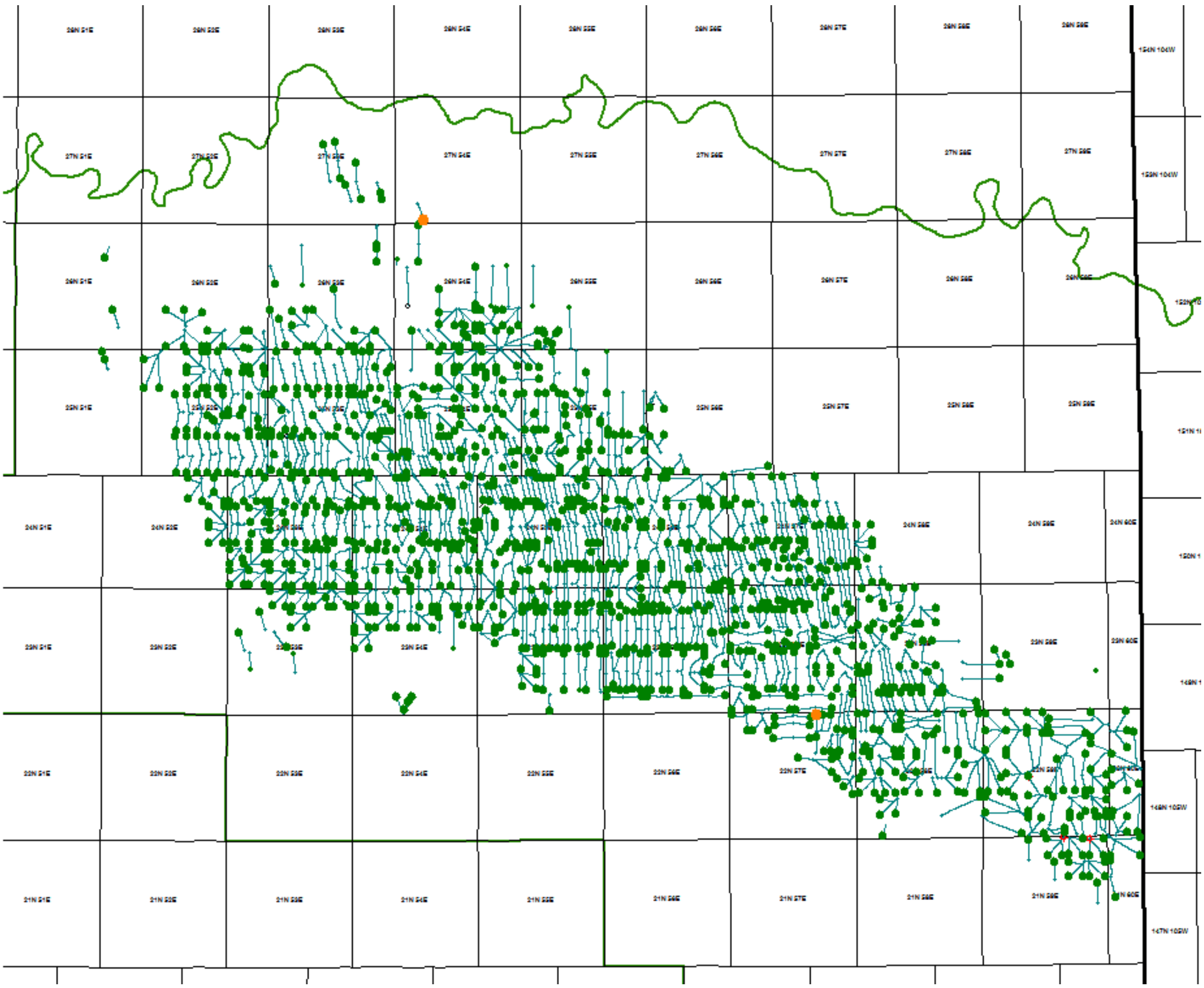
Appendix A6. Map of the Billings Nose area. Green dots are Bakken producers; orange dots are Three Forks producers.



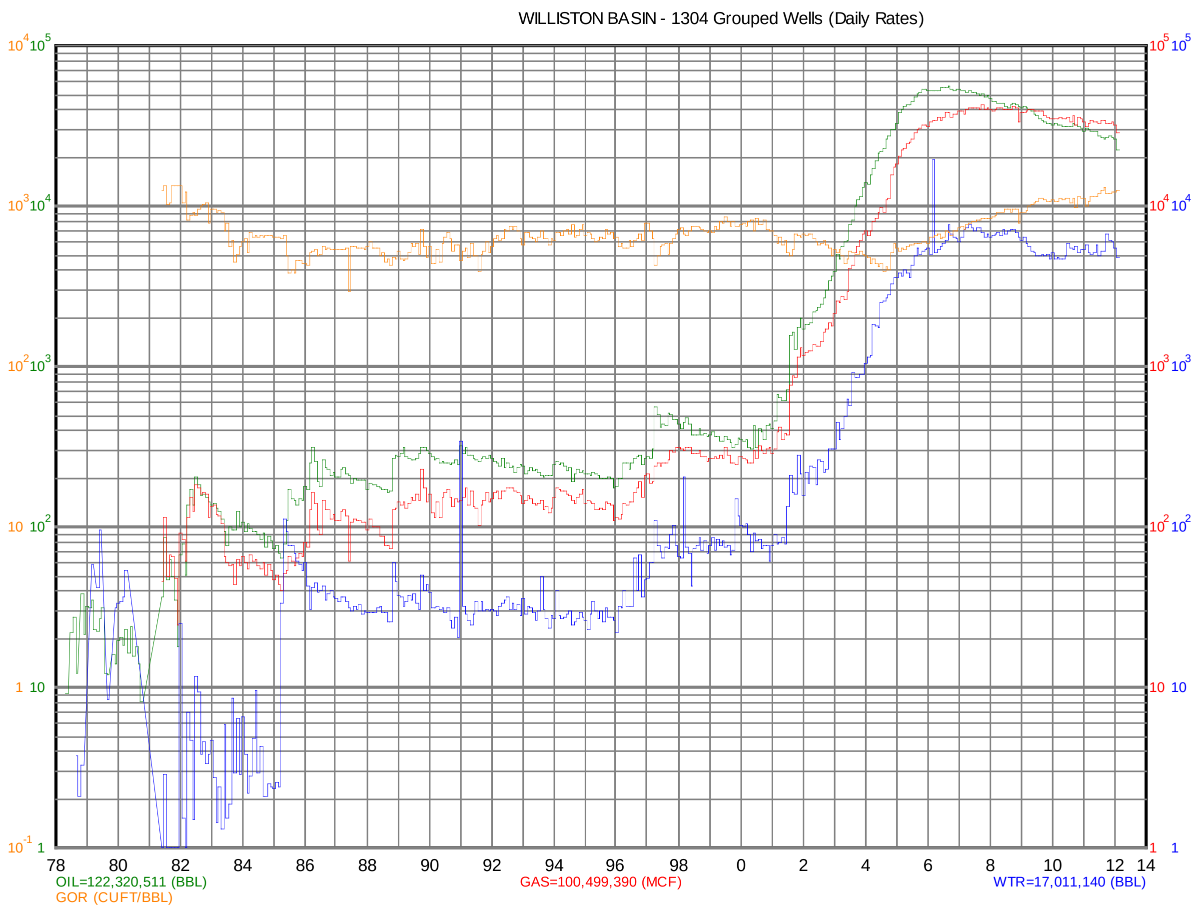
Appendix A7. Daily rate production curve for the Billings nose area (see Appendix 8). The first vertical wells were drilled in 1976. The original Shell well was completed in the Bakken in 1961; casing collapsed on this well. The first horizontal Upper Shale well was drilled in 1987. The GOR increased dramatically when drilling activity ceased in the 1990s.



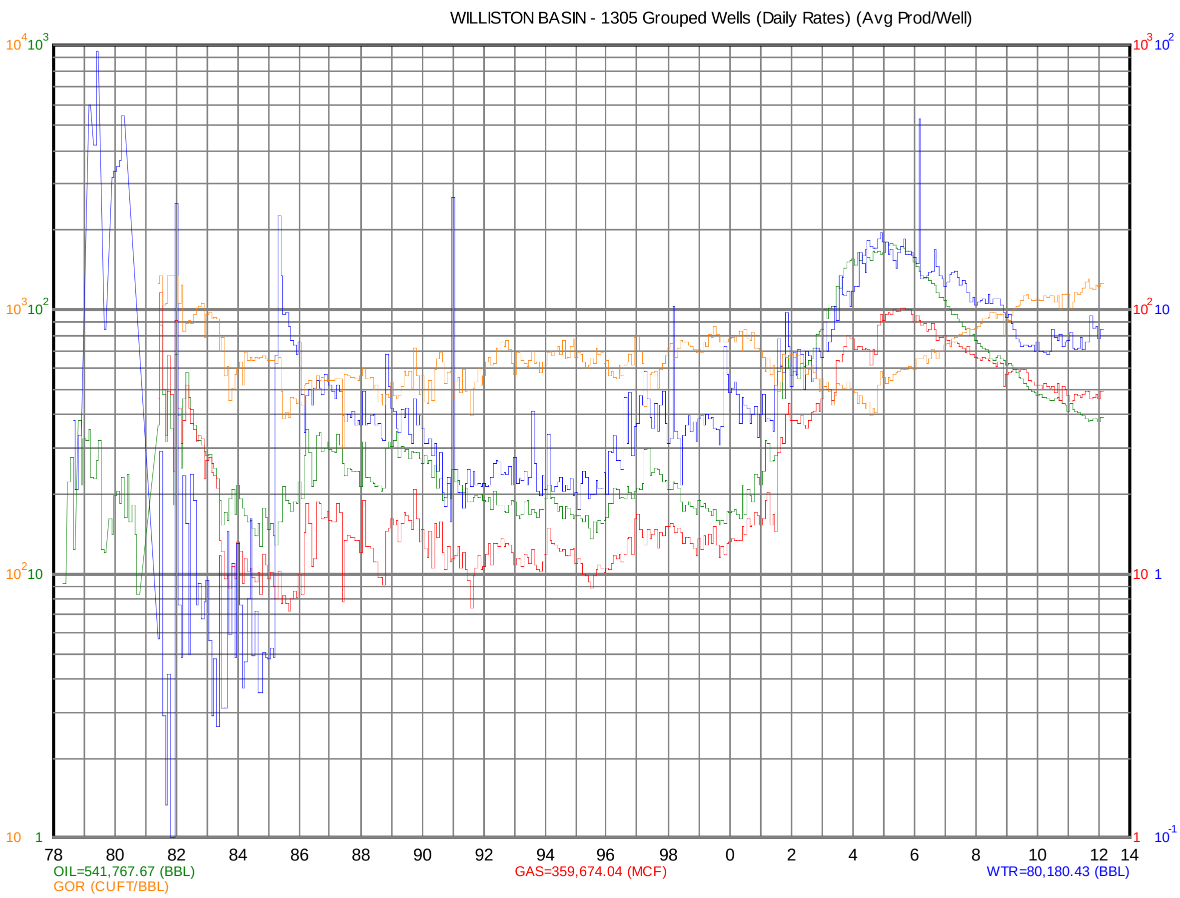
Appendix A8. Average per well production curve for the Billings Nose area.



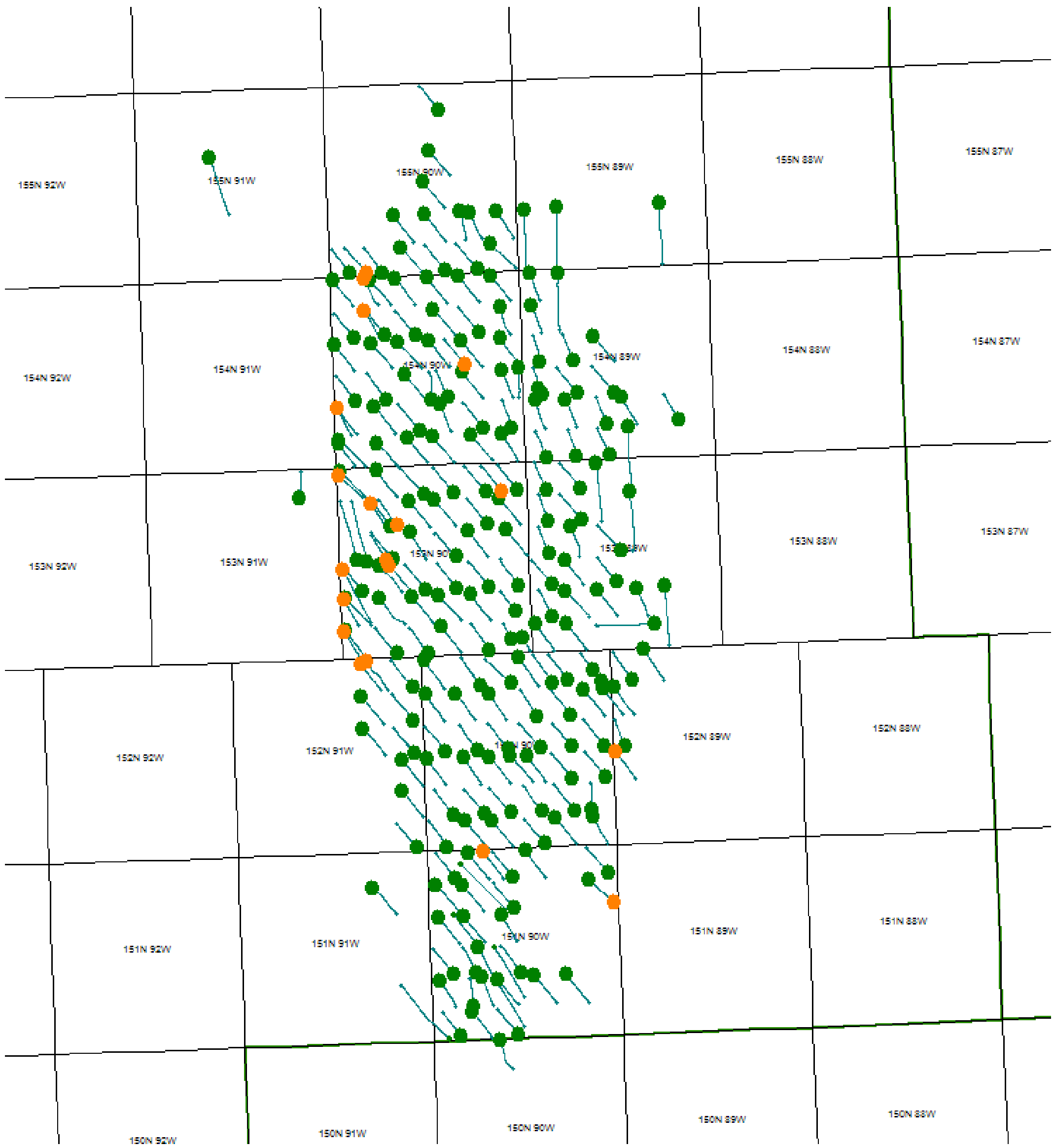
Appendix A9. Index map for the Elm Coulee Field of Richland County, Montana.



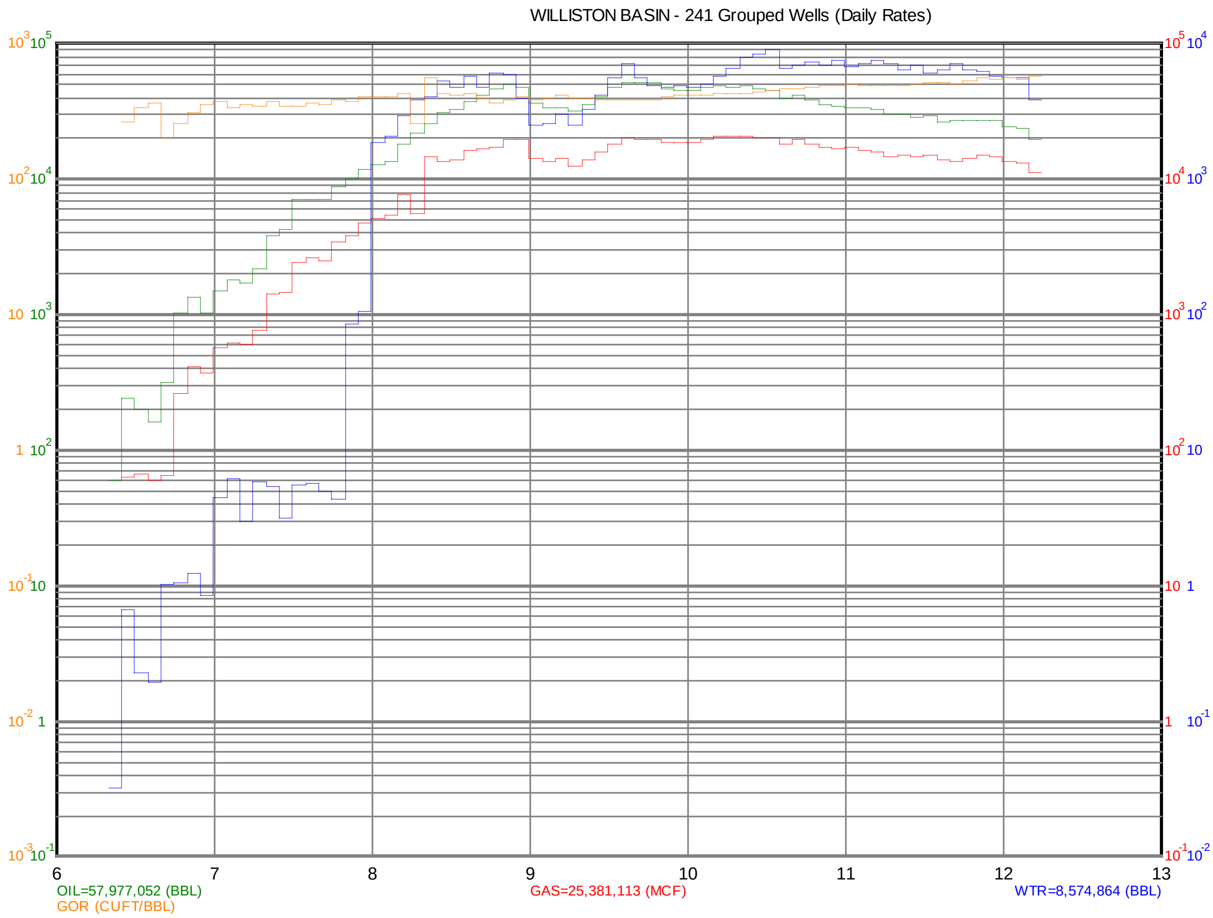
Appendix A10. Daily rate production curve for the Elm Coulee Field. The first Bakken horizontal wells were completed in 2000. As the development drilling has slowed down, the GOR is slowly rising. The current total GOR for the field is over 1000 cu ft gas per barrel oil.



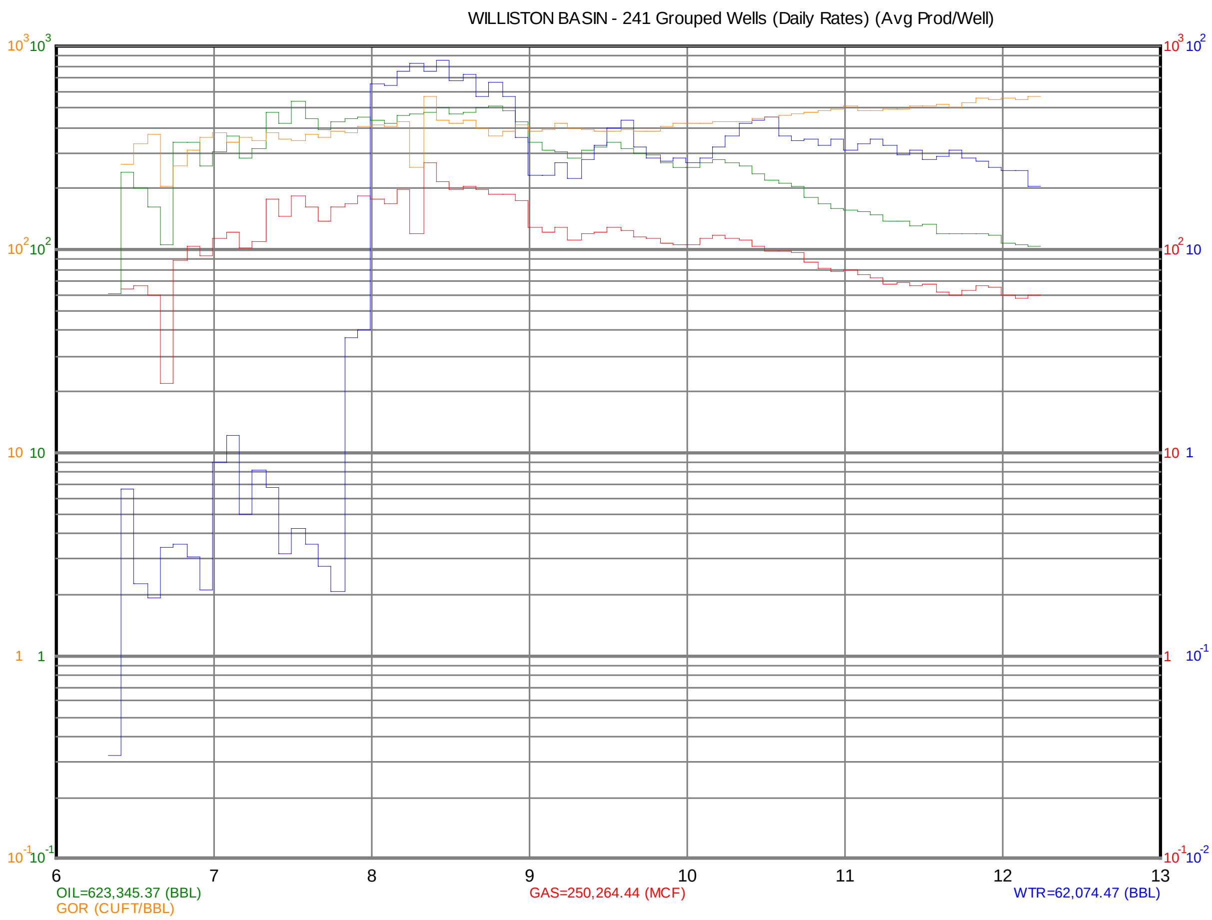
Appendix A11. Average production per well for Elm Coulee. The GOR for the field has risen steadily since 2005 from about 600 cu ft gas per barrel oil to over 1100 cu ft gas per barrel oil.



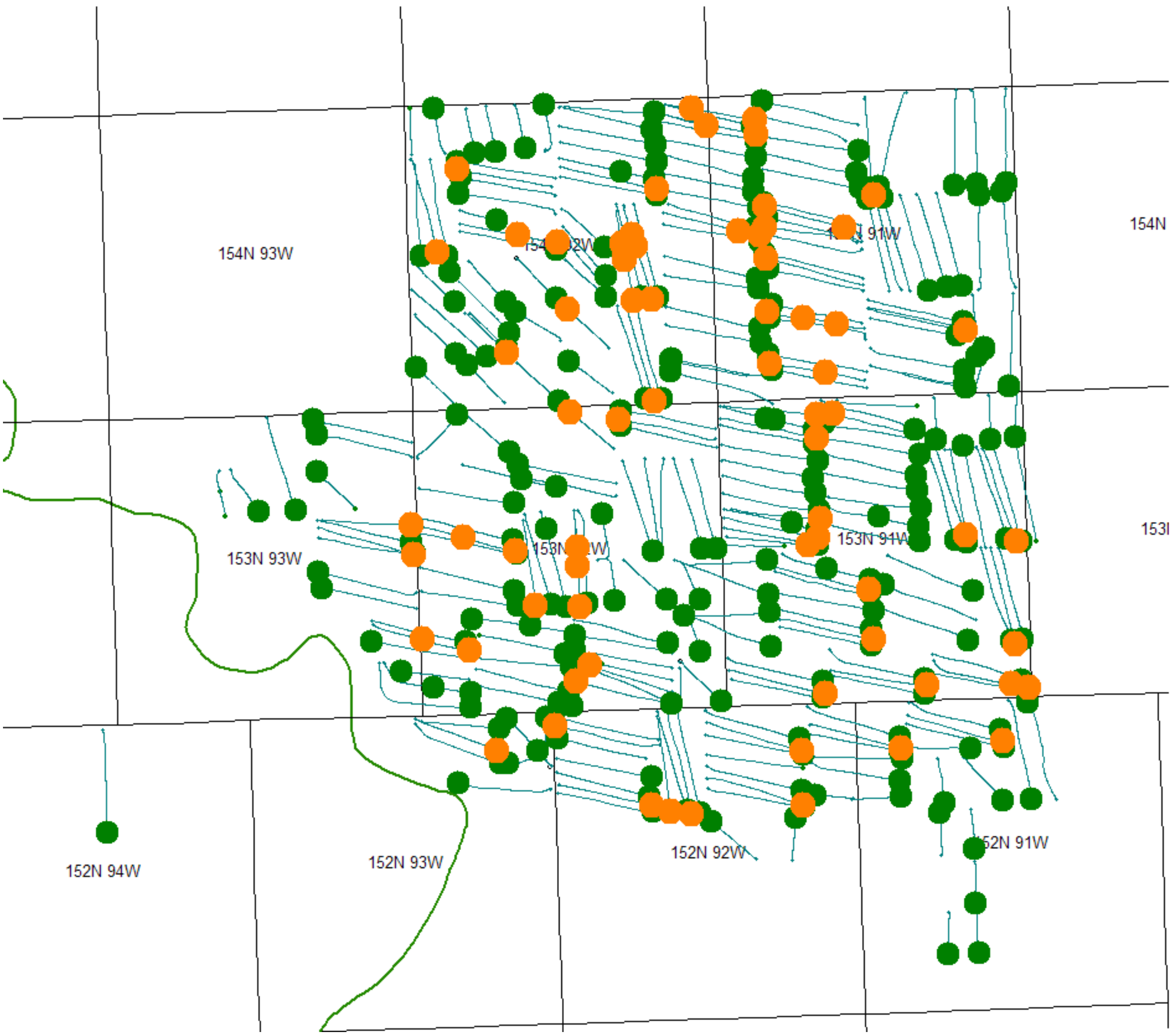
Appendix A12. Index map for Parshall Field.



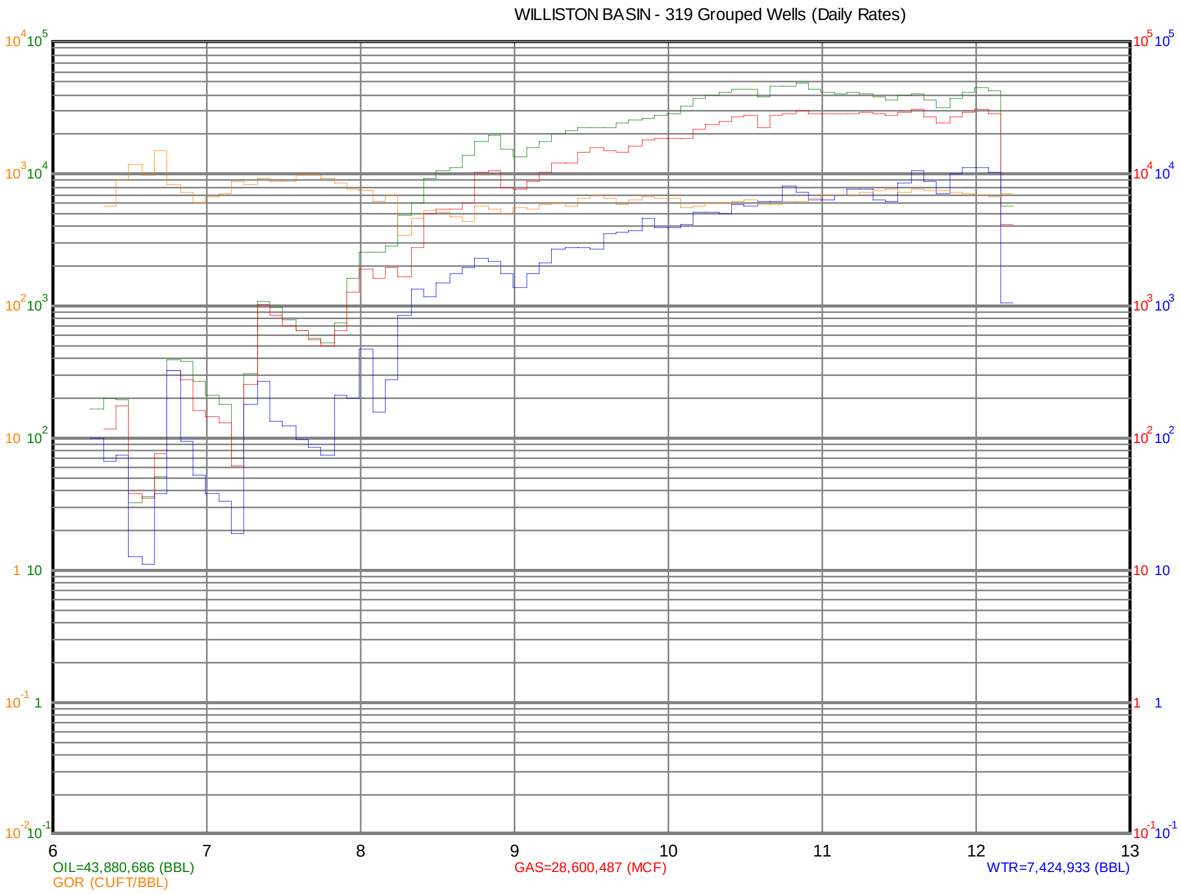
Appendix A13. Daily rate production curve for Parshall Field. Total field production is showing a slight decline and a modest increase in the GOR. The current GOR for the field is approximately 600 cu ft gas per barrel oil.



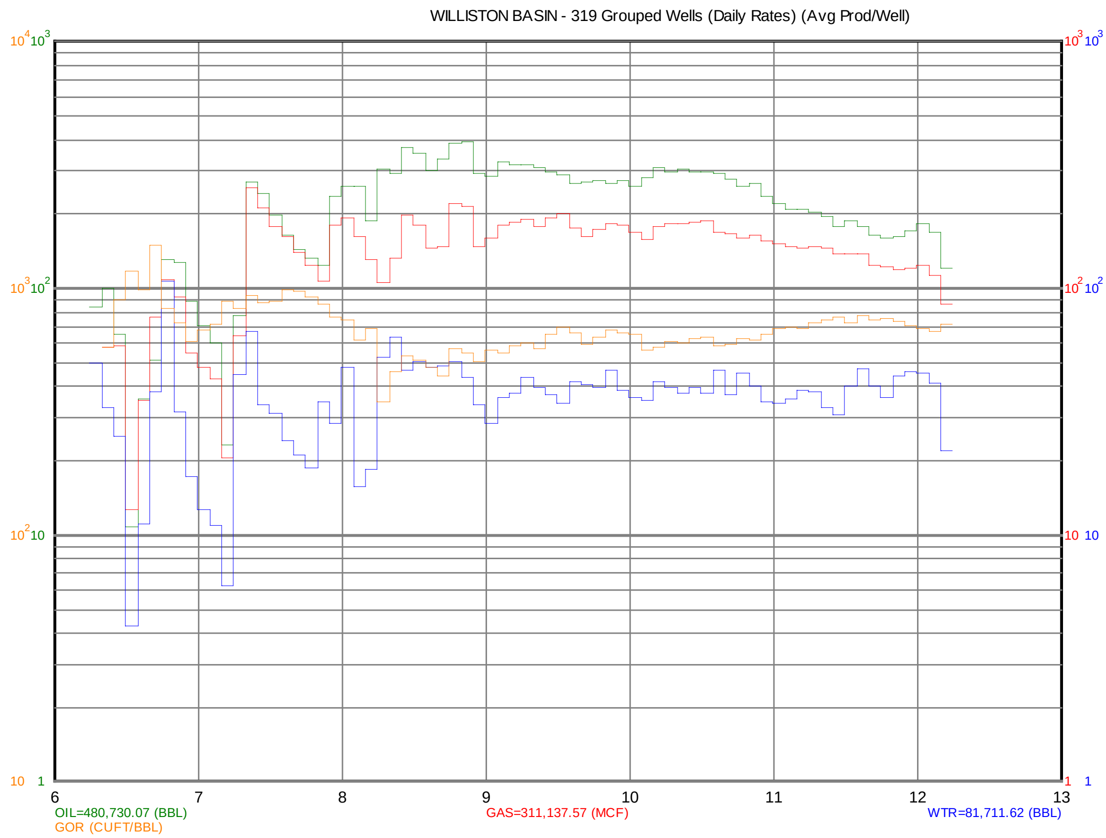
Appendix A14. Average production per well for Parshall Field.



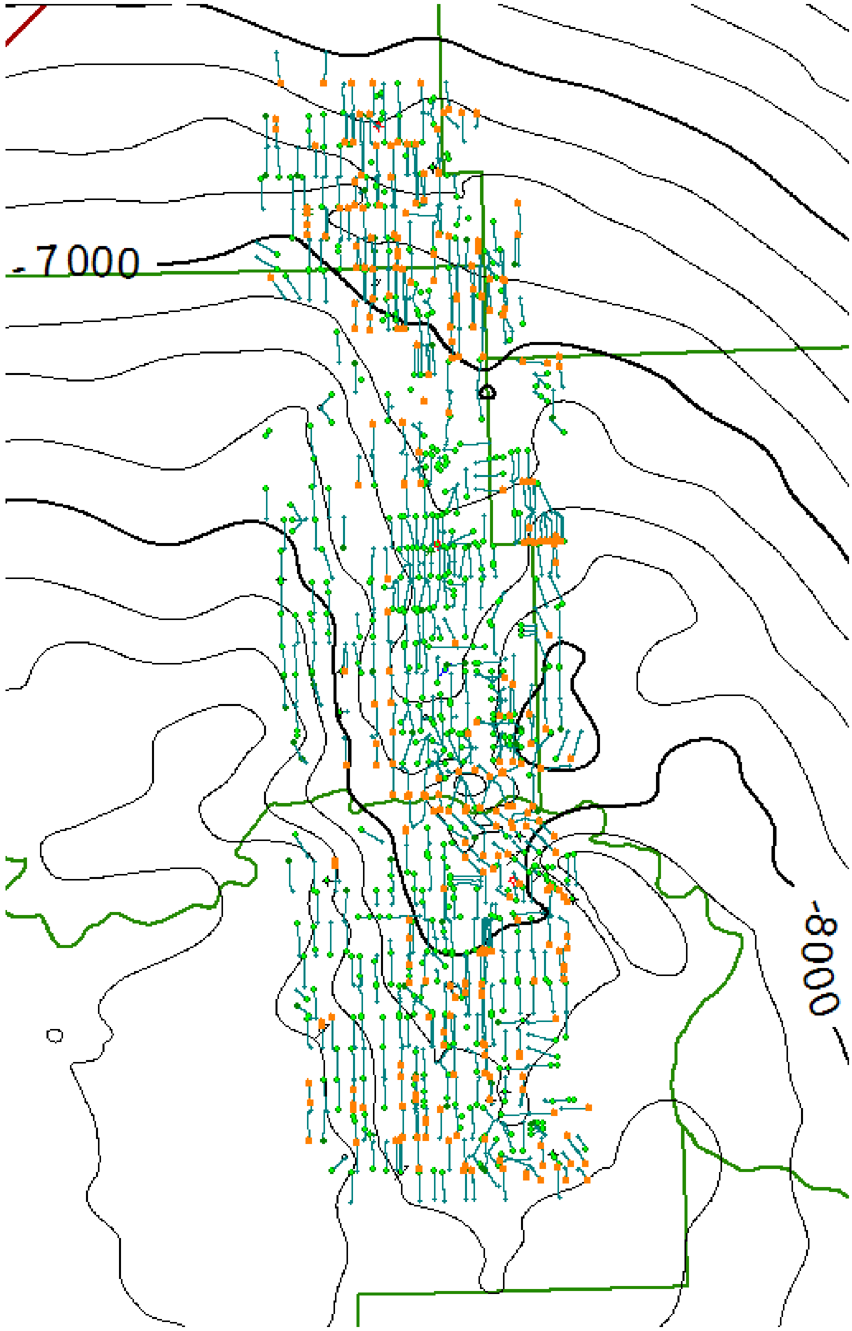
Appendix A15. Index map for Sanish Field. Refer to Figure 23 for location of study area. Green dots are Bakken producers; orange dots are Three Forks producers.



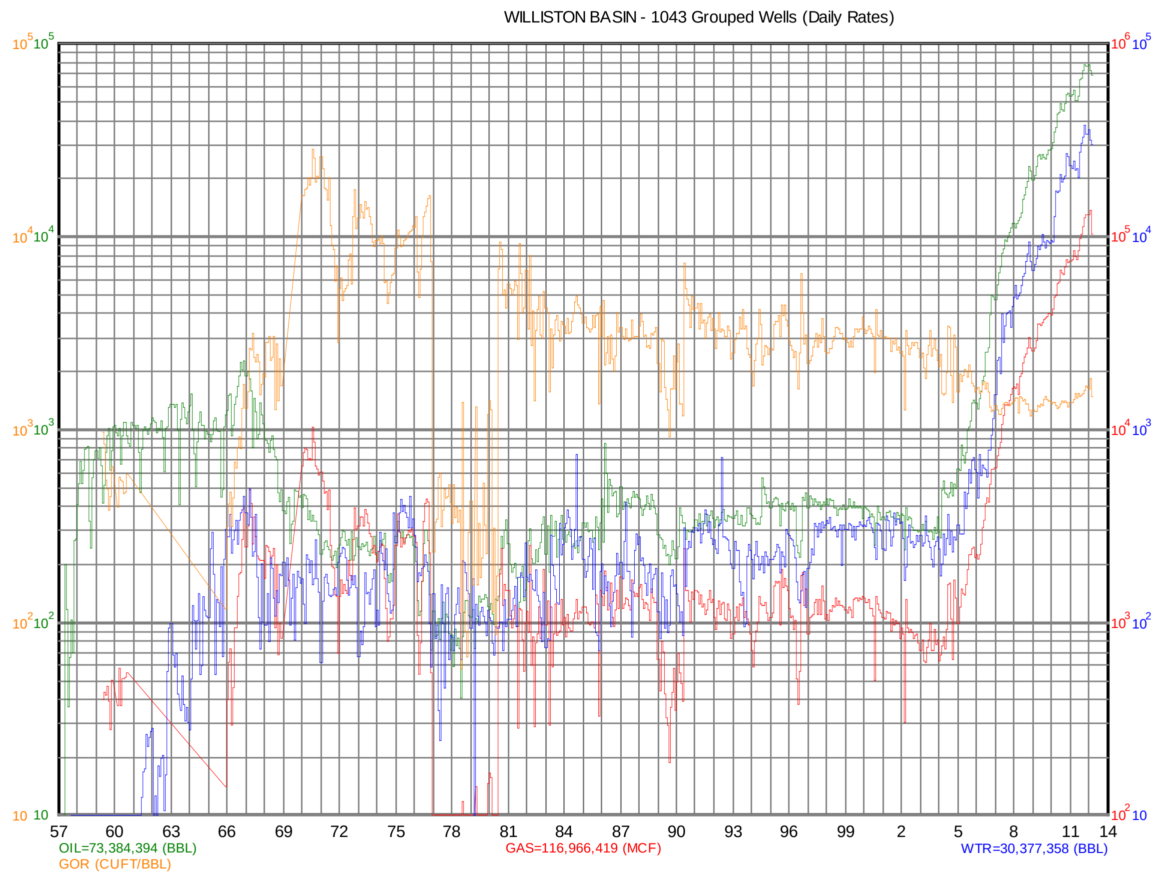
Appendix A16. Daily rate production curve for Sanish Field. Current GOR for the field is approximately 700 cu ft gas per barrel oil.



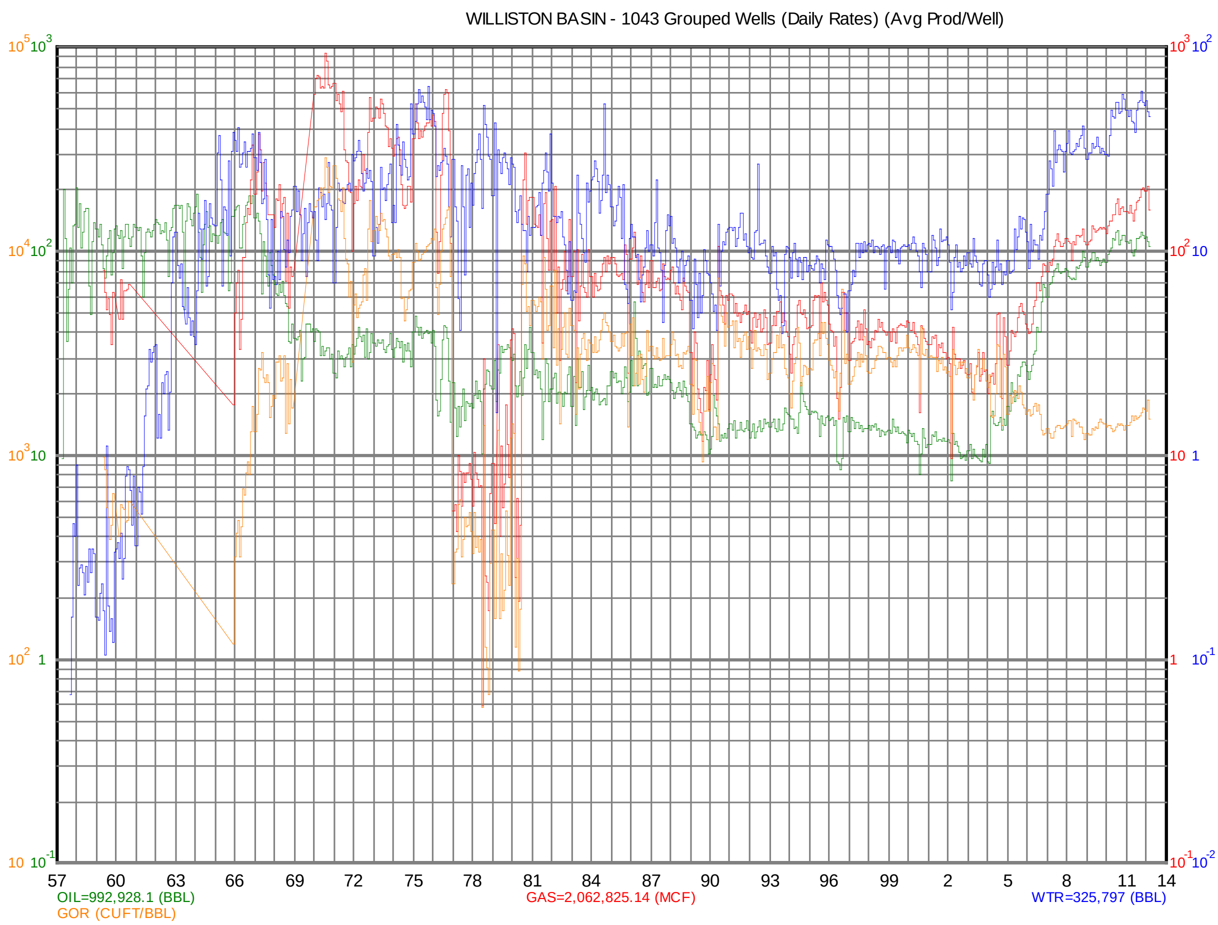
Appendix A17. Average production per well for Sanish Field. The overall GOR is approximately 800 cu ft gas per barrel oil.



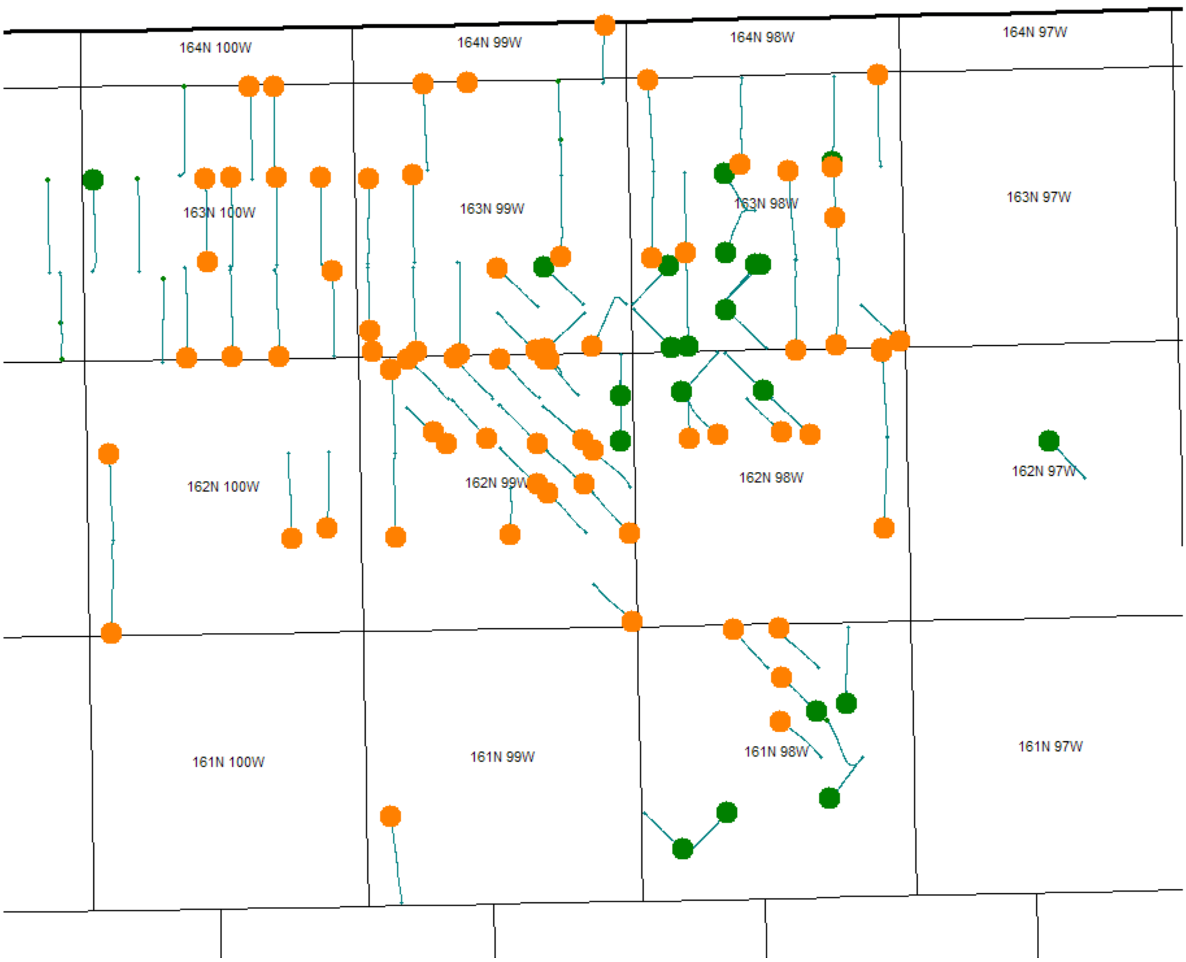
Appendix A18. Location map for wells used for the Nesson Anticline.



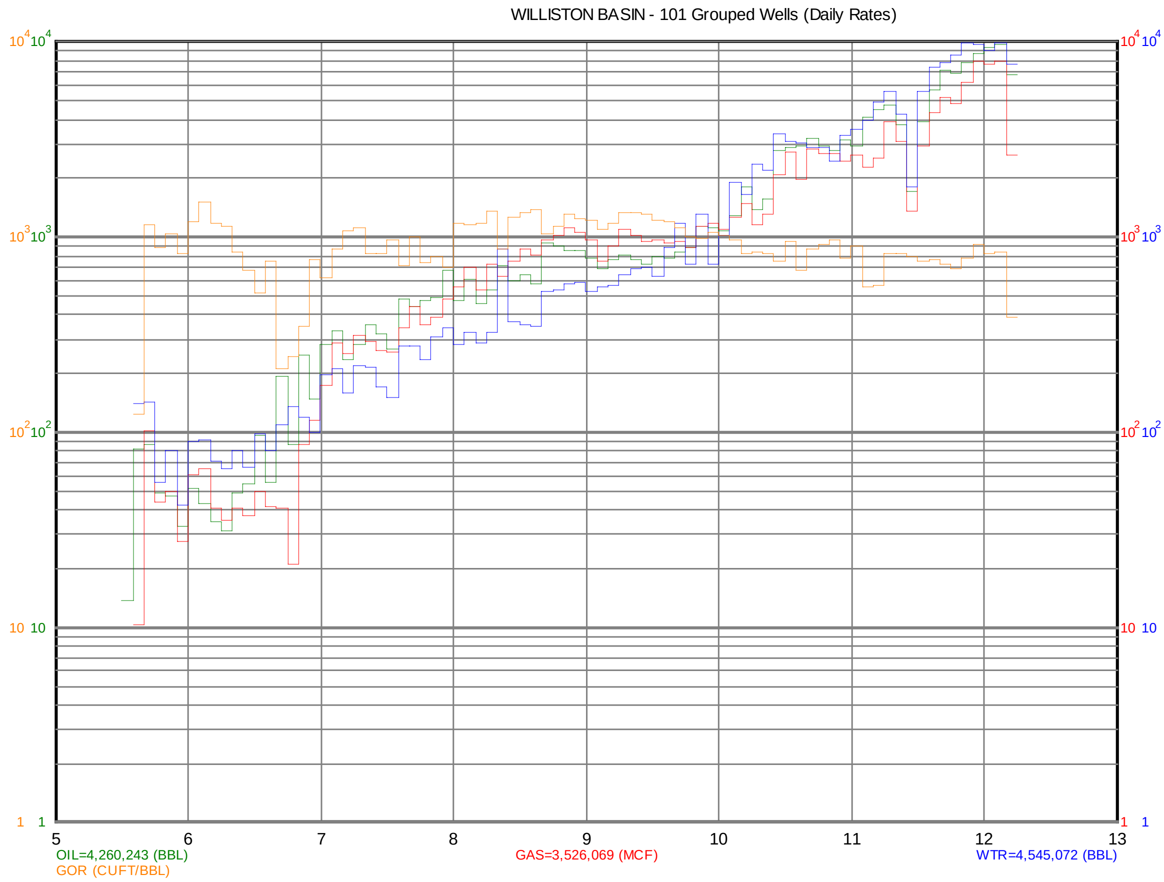
Appendix A19. Daily rate production curve for Nesson Anticline wells. The Nesson Anticline had older vertical well production from the Bakken. Prior to 2005 the GOR was approximately 3000 cu ft gas per barrel oil. The new horizontal drilling post 2005 has lowered the GOR to approximately 1500 cu ft gas per barrel oil.



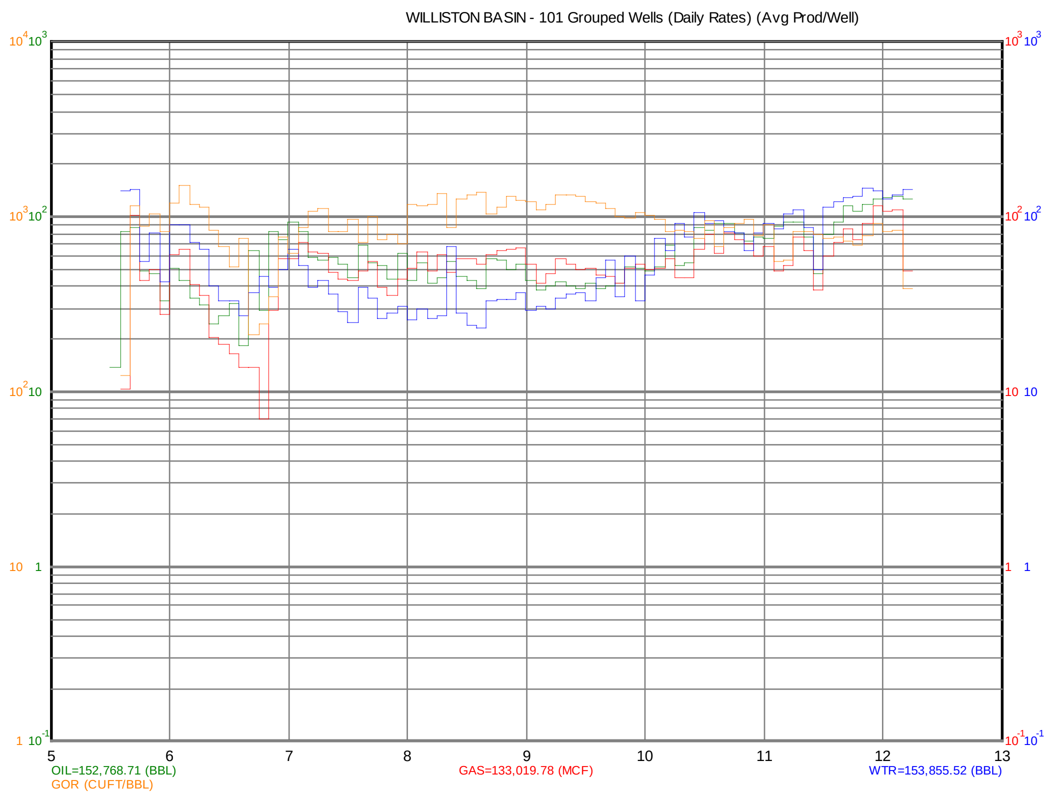
Appendix A20. Average per well production for the Nesson Anticline.



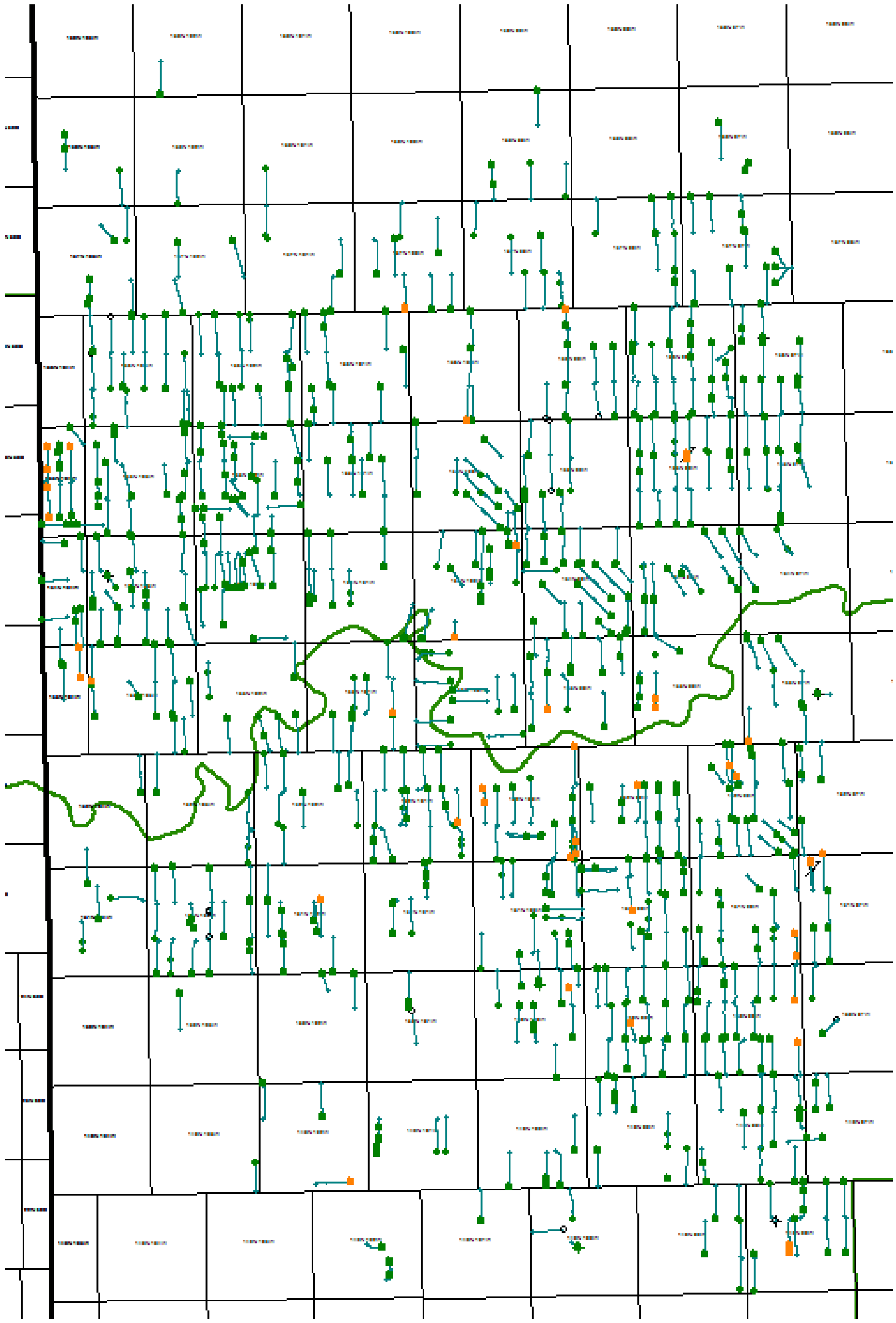
Appendix A21. Index map for Ambrose area. Refer to Figure 23 for location of study area. Green dots are Bakken producers; orange dots are Three Forks producers.



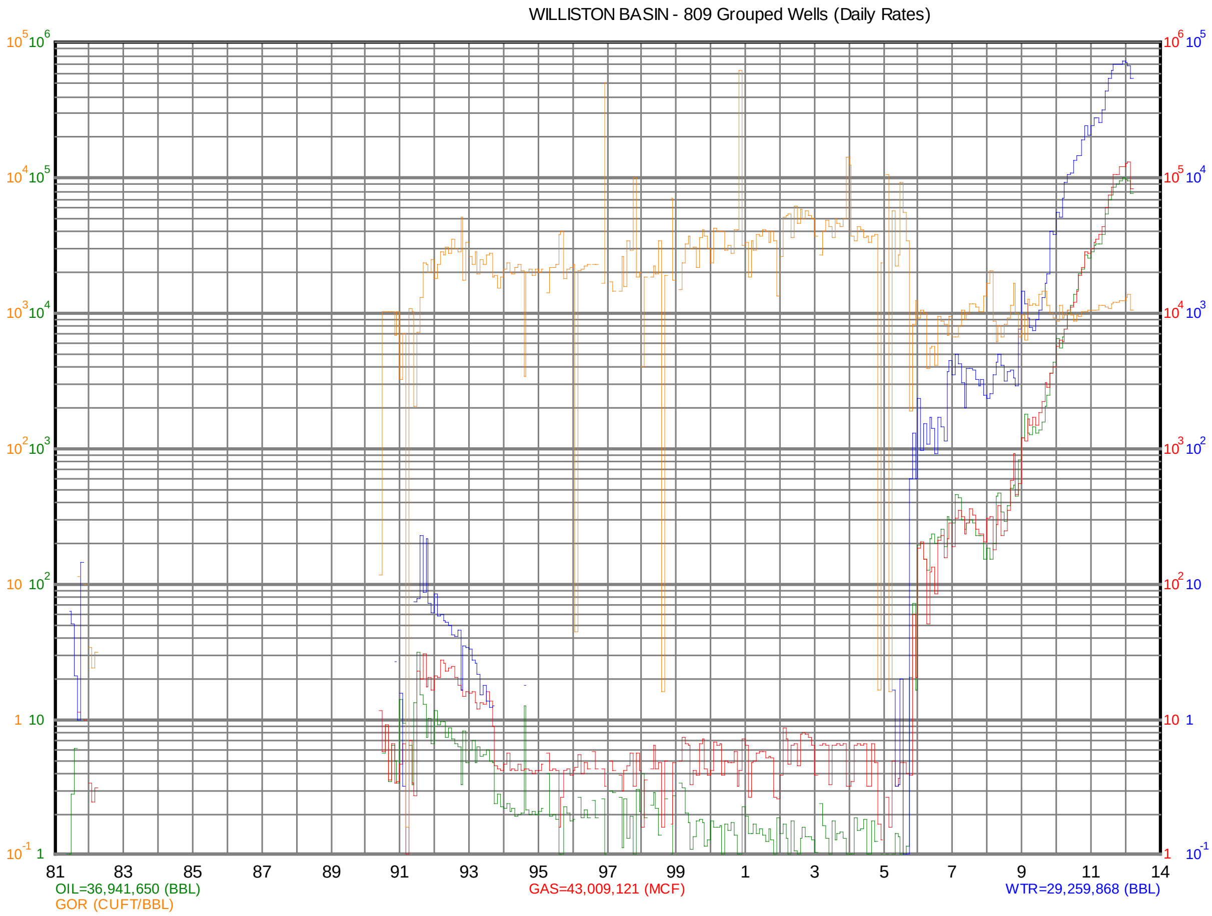
Appendix A22. Daily rate production curve for Ambrose area. Current GOR rate is approximately 900 cu ft gas per barrel oil. Majority of the production in this area is from Three Forks Formation.



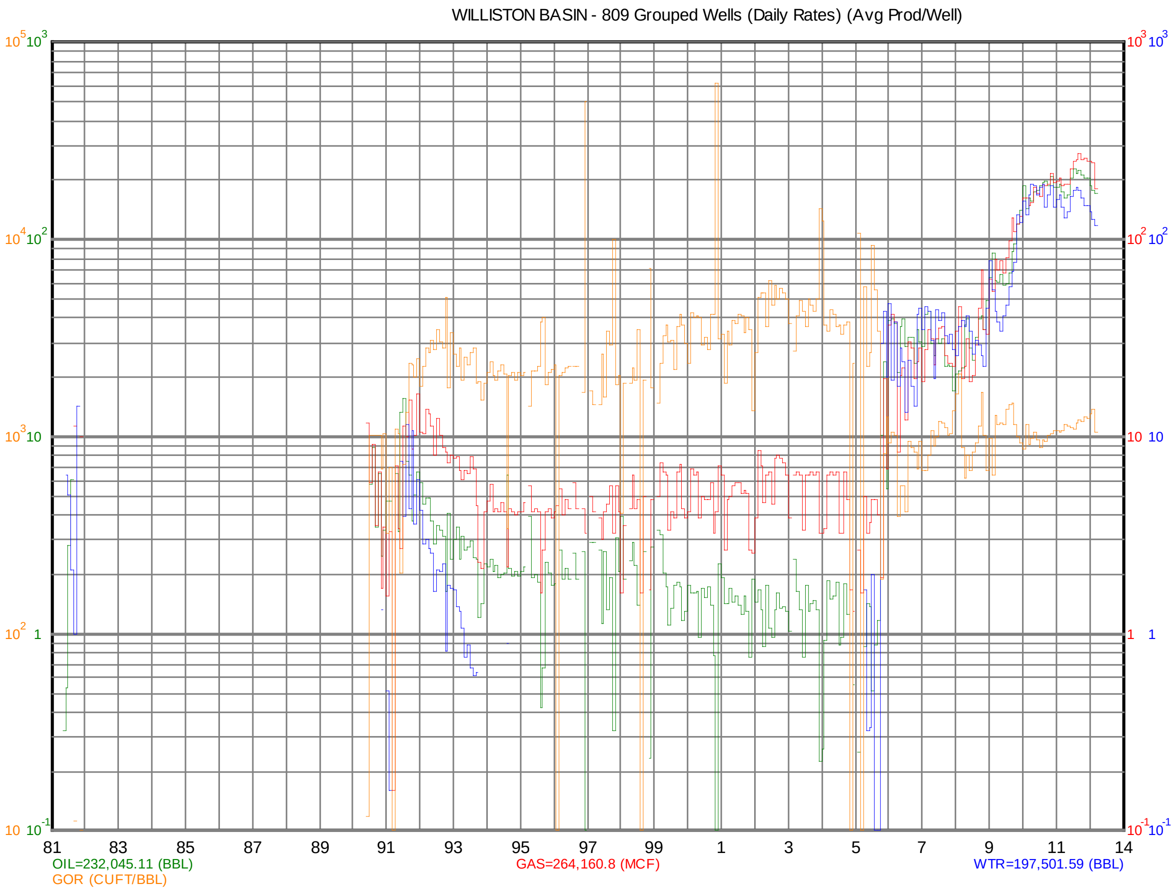
Appendix A23. Average per well production for Ambrose field area.



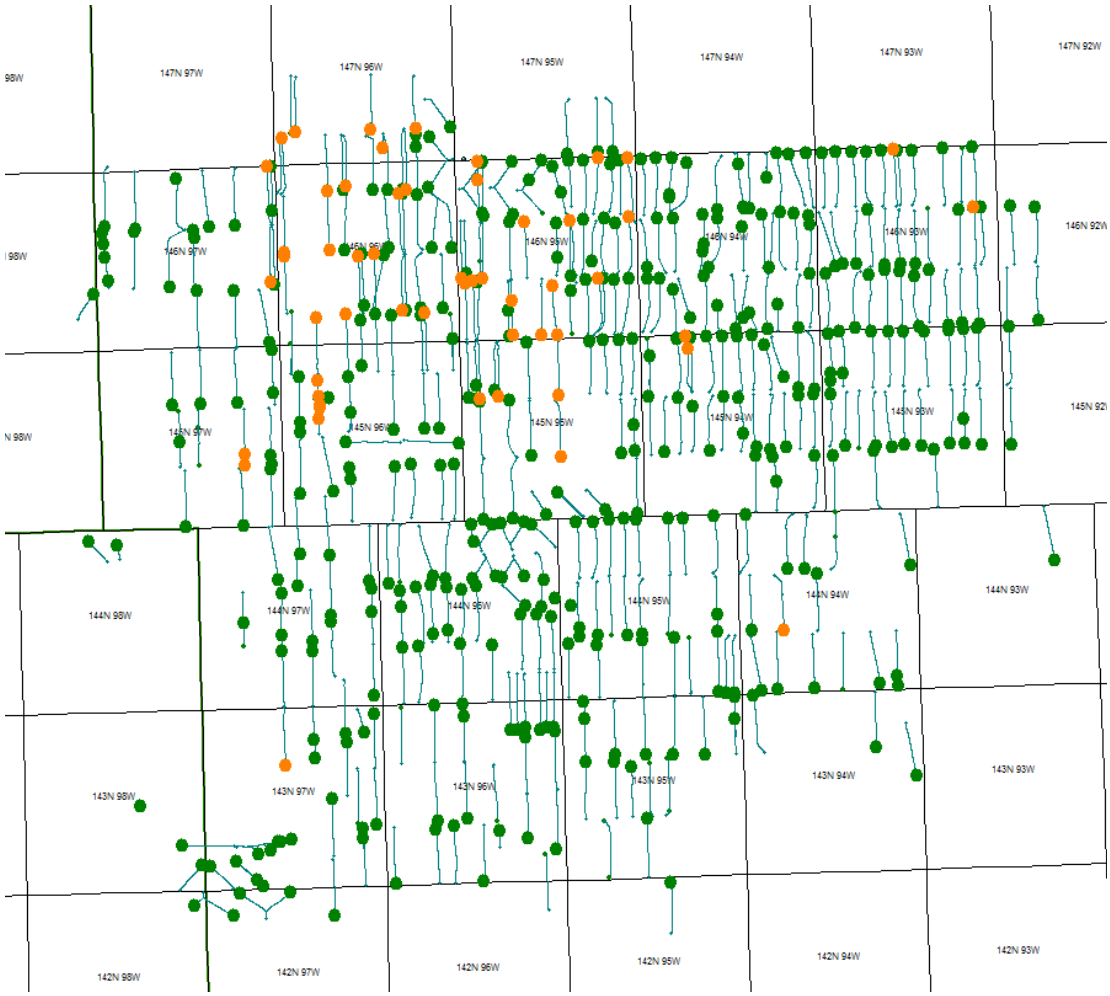
Appendix A24. Location map of West Nesson anticline area. Green dots are Bakken producers; orange dots are Three Forks producers.



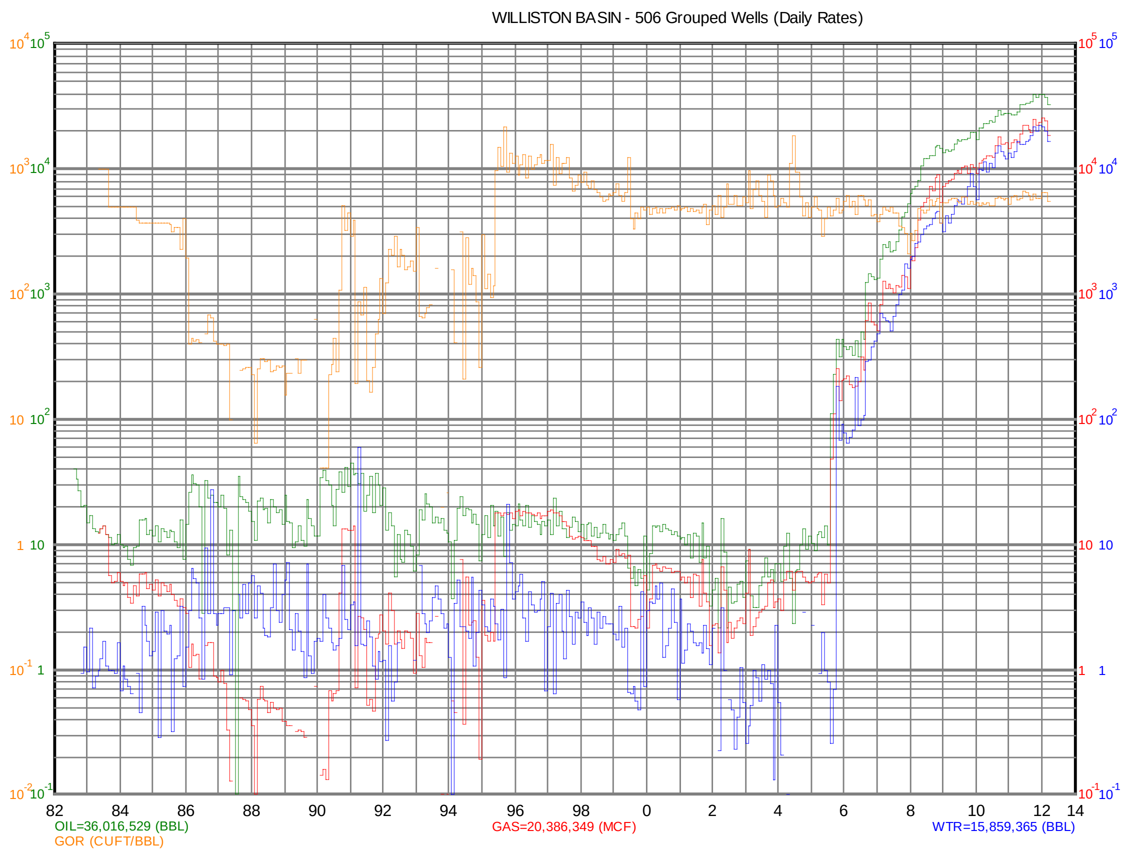
Appendix A25. Daily rate production curve for west Nesson area. The current GOR is approximately 1000 cu ft gas per barrel oil. GOR from older vertical Bakken wells was approximately 4000 cu ft gas per barrel oil.



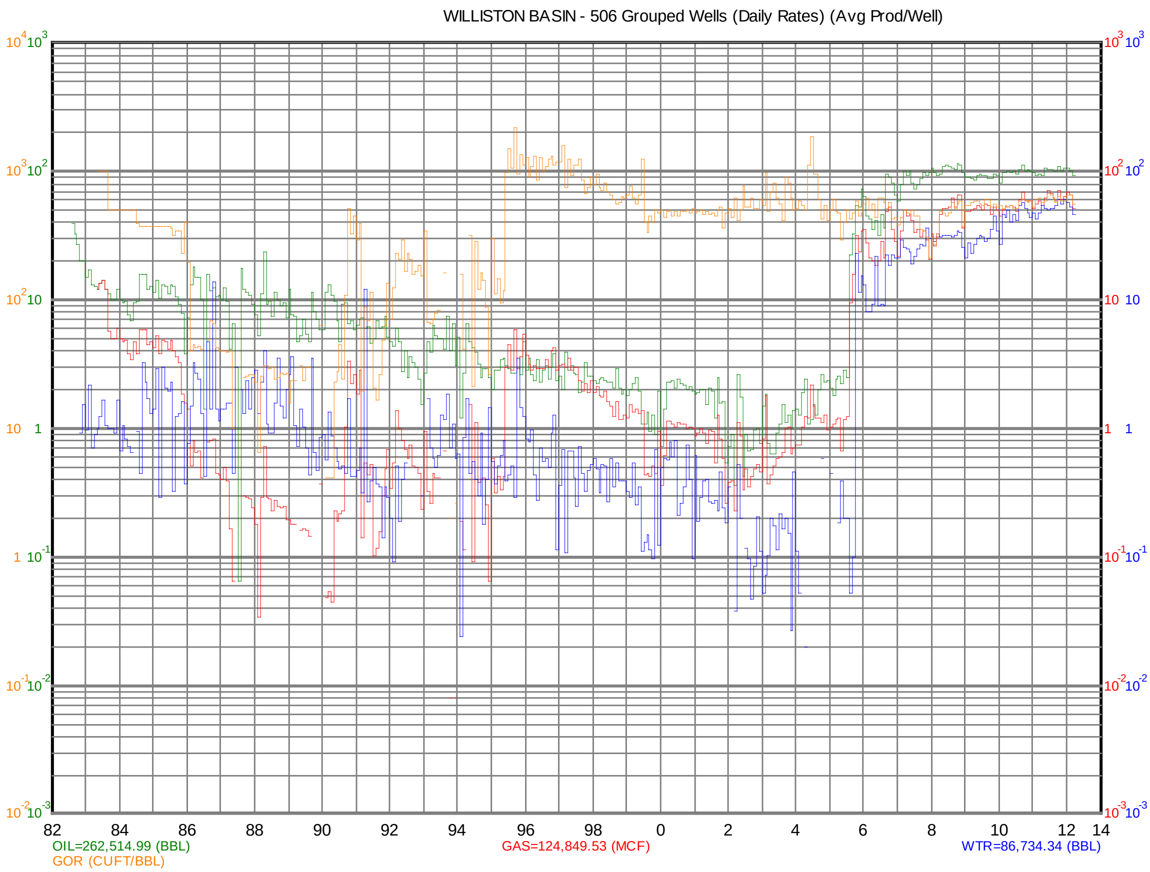
Appendix A26. Average production per well for West Nesson area.



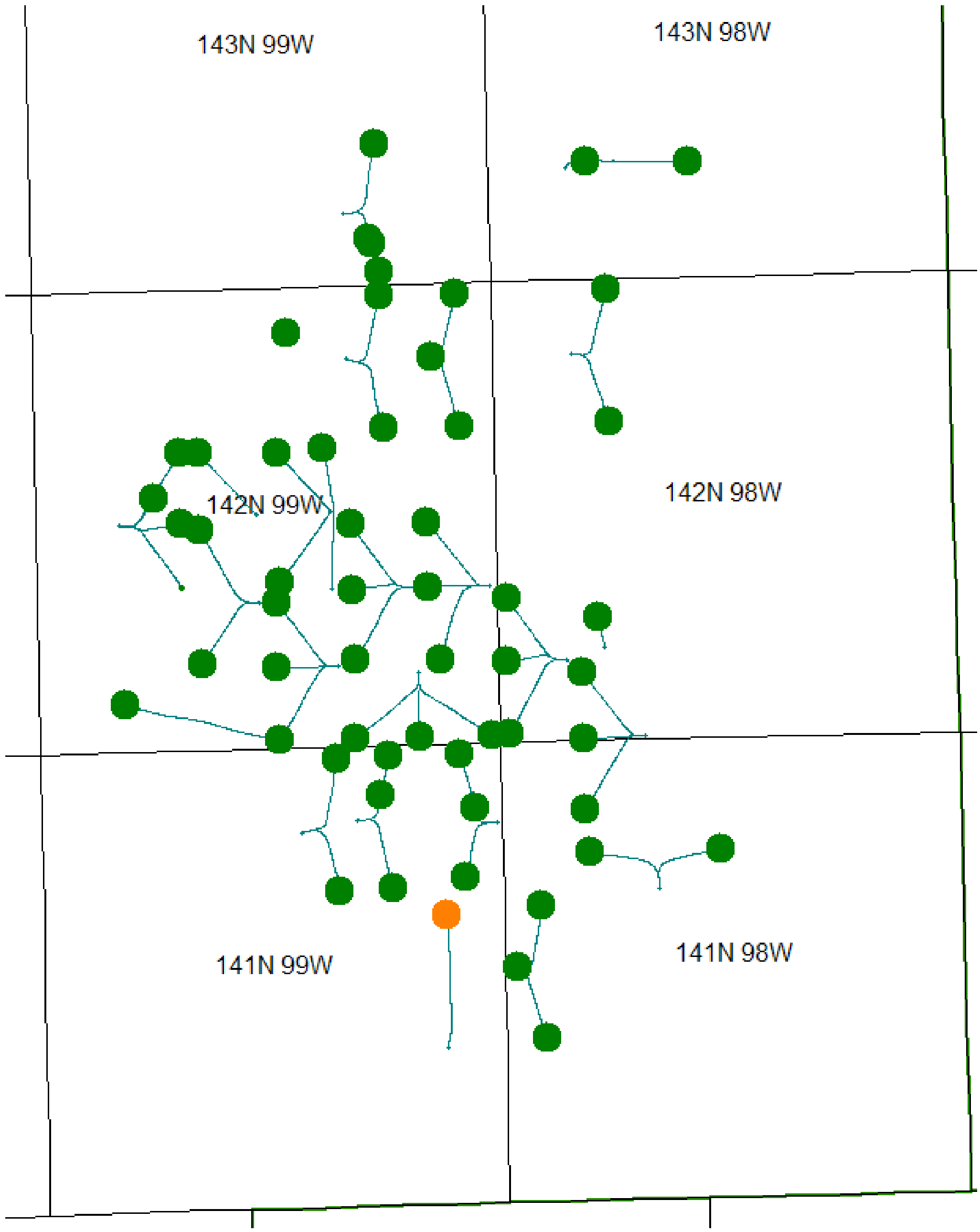
Appendix A27. Index map for Bailey area. See Figure 23 for location of study area.



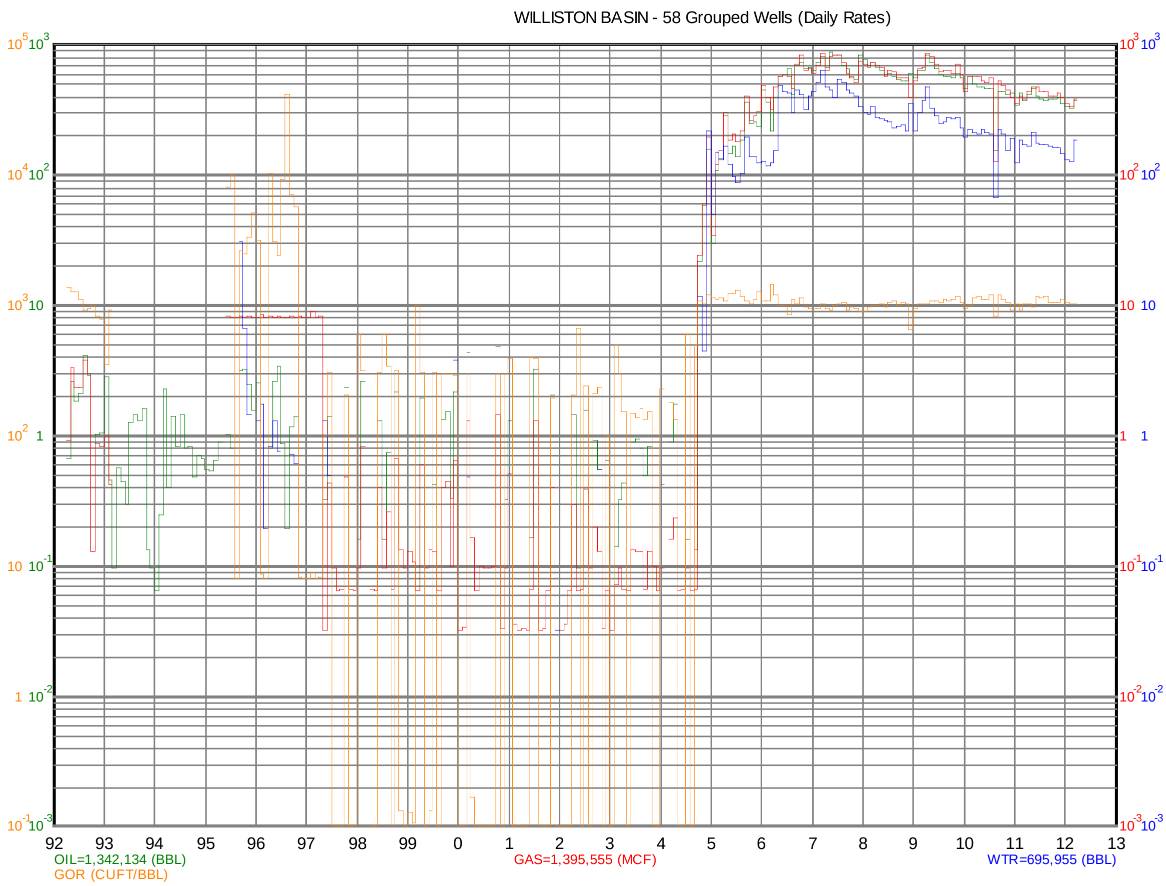
Appendix A28. Daily rate production curve for Bailey area. GOR is currently 600 cu ft gas per barrel oil.



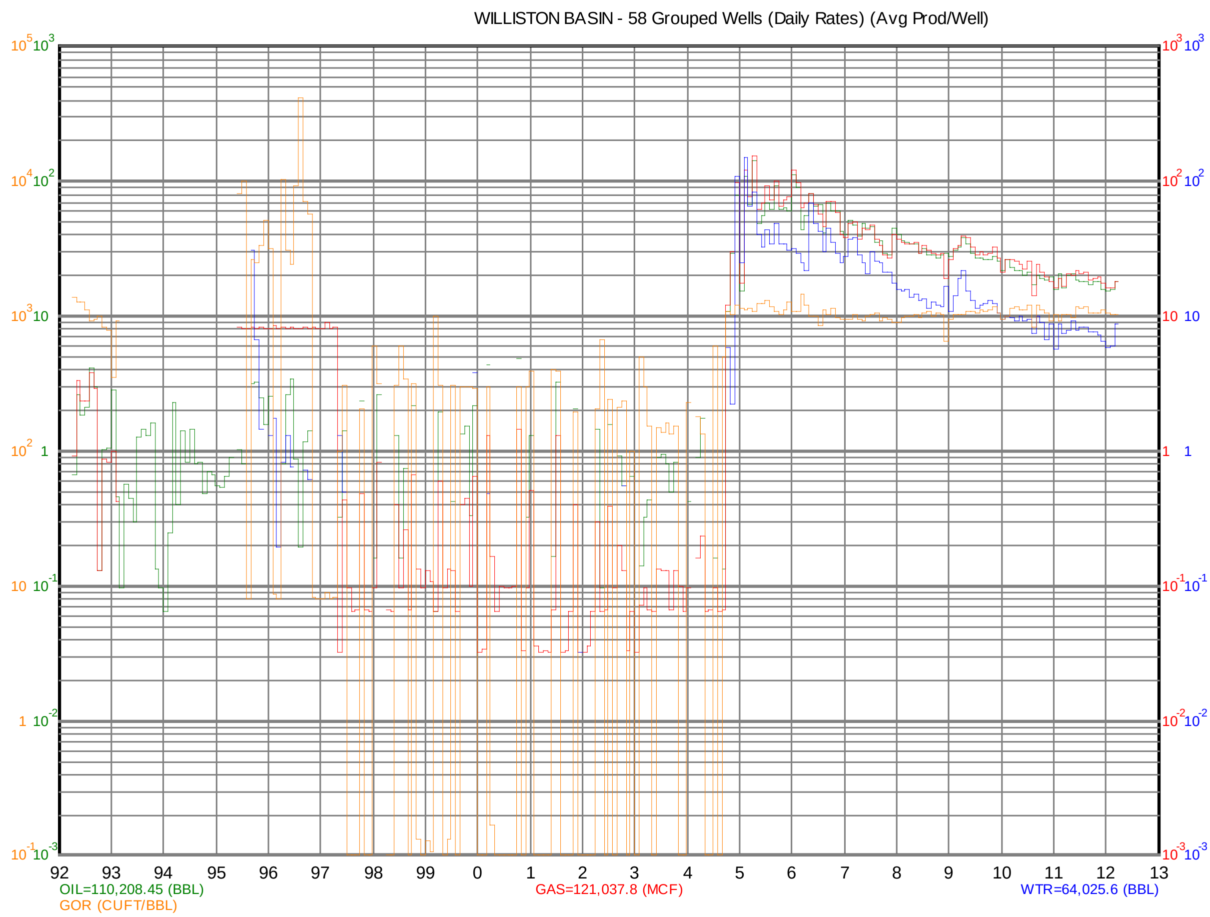
Appendix A29. Average per well production for Bailey field area.



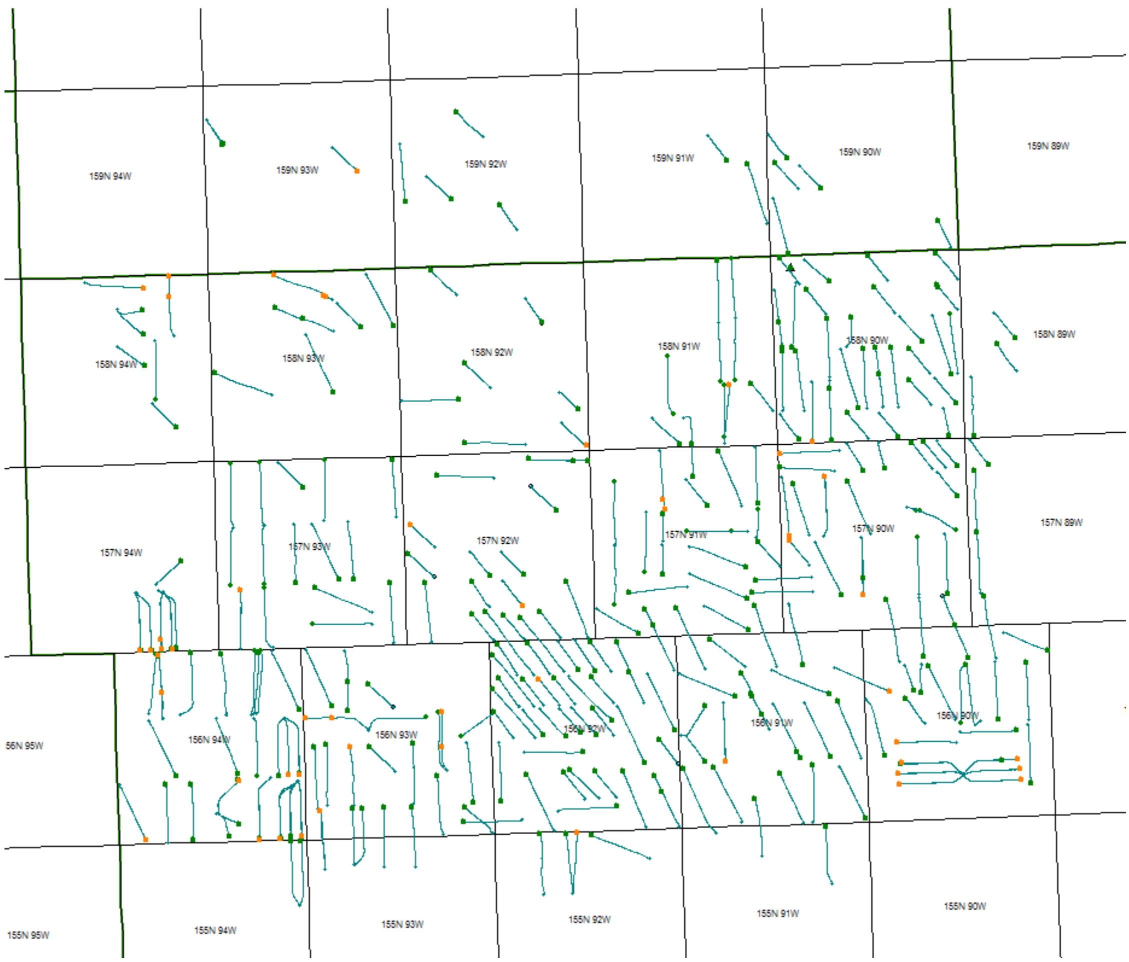
Appendix A30. Index map for St. Demetrius area. See Figure 23 for location map of study area. Green dots are Bakken producers; orange dots are Three Forks producers.



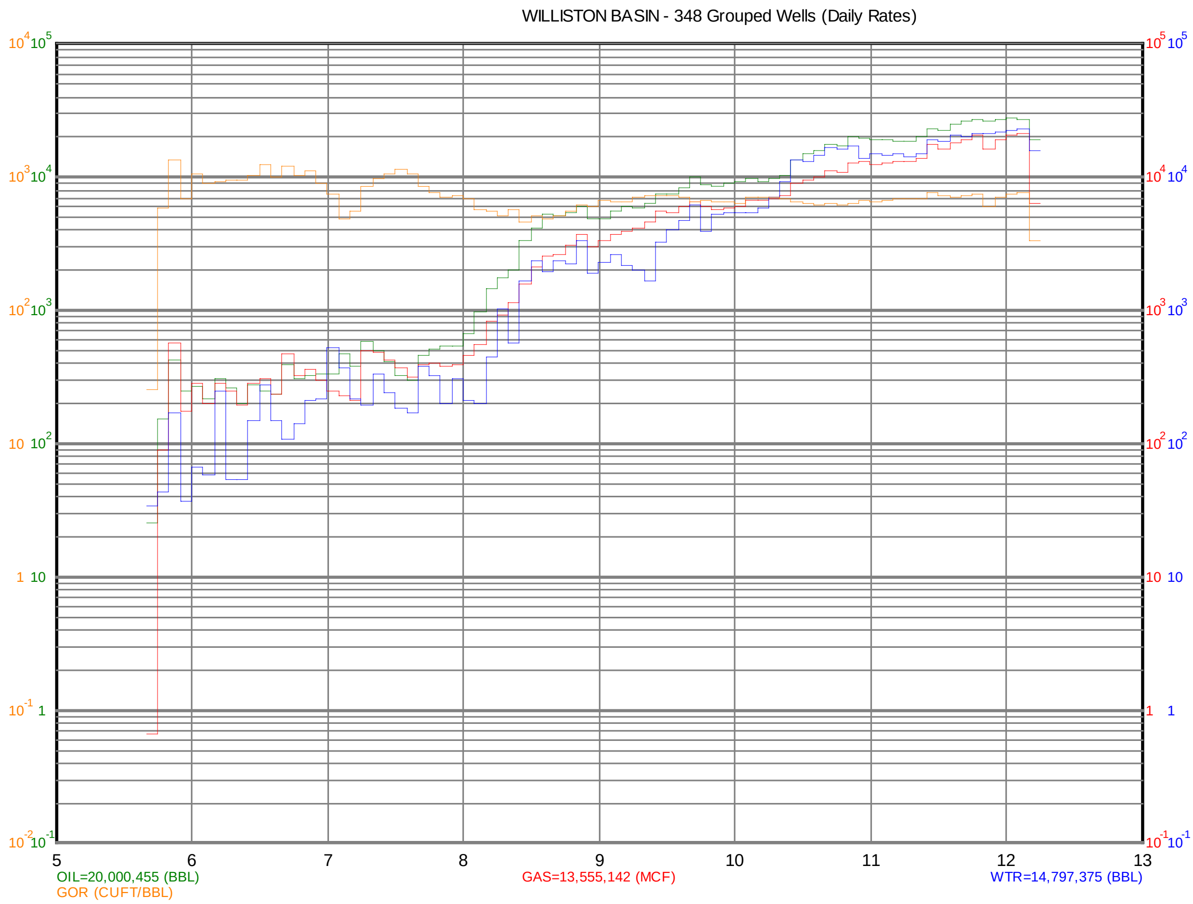
Appendix A31. Daily rate production curve for wells in St. Demetrius area. GOR is currently 1000 cu ft gas per barrel oil.



Appendix A32. Average production per well for St. Demetrius area.

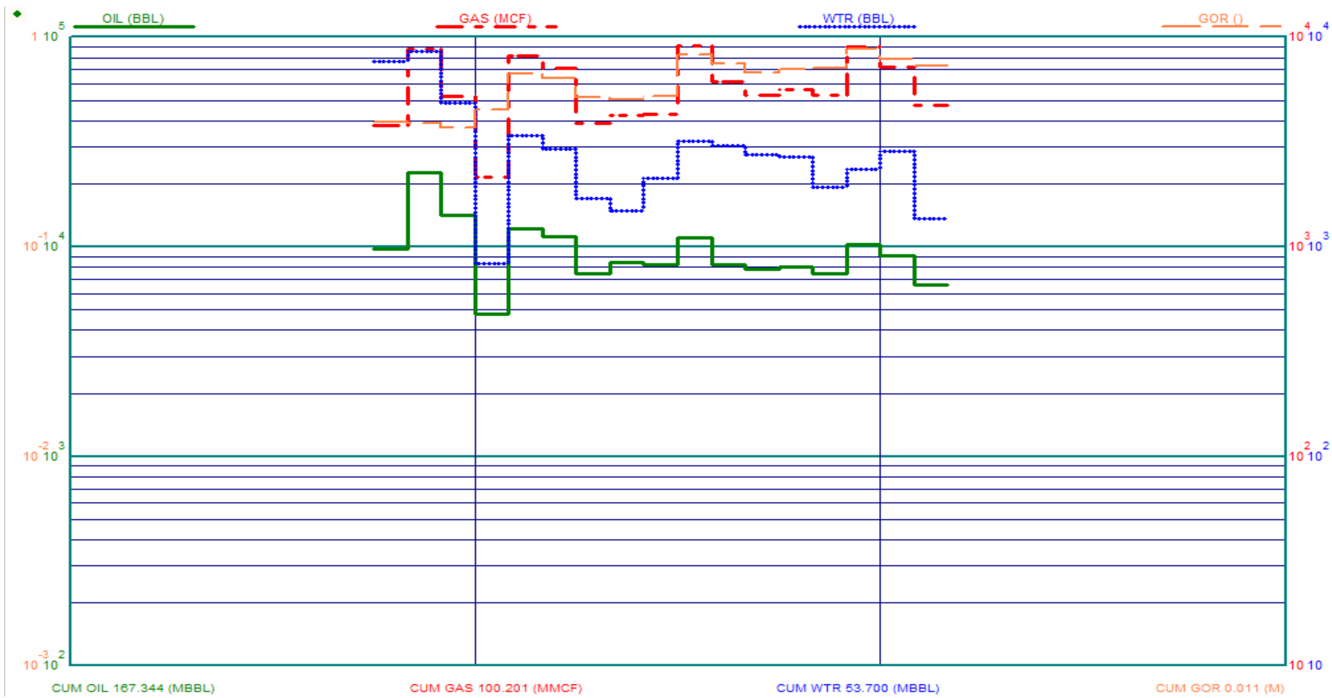


Appendix A33. Index map for Ross area. See Figure 23 for location map of study area. Green dots are Bakken producers; orange dots are Three Forks producers.

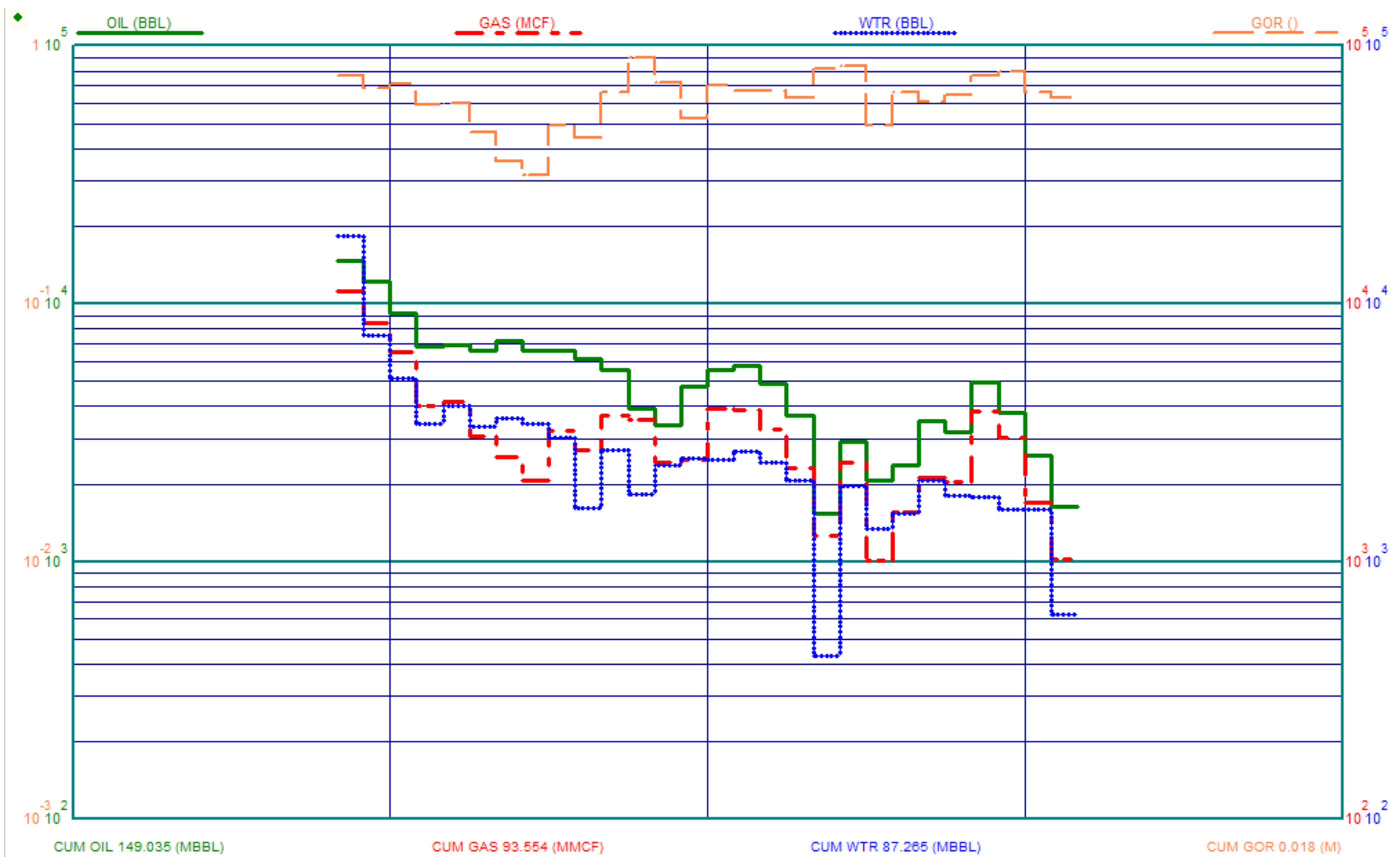


Appendix A34. Daily rate production curves for wells in the Ross area. GOR for the area is 700 top 800 cu ft gas per barrel oil. Early wells had GORs slightly higher.

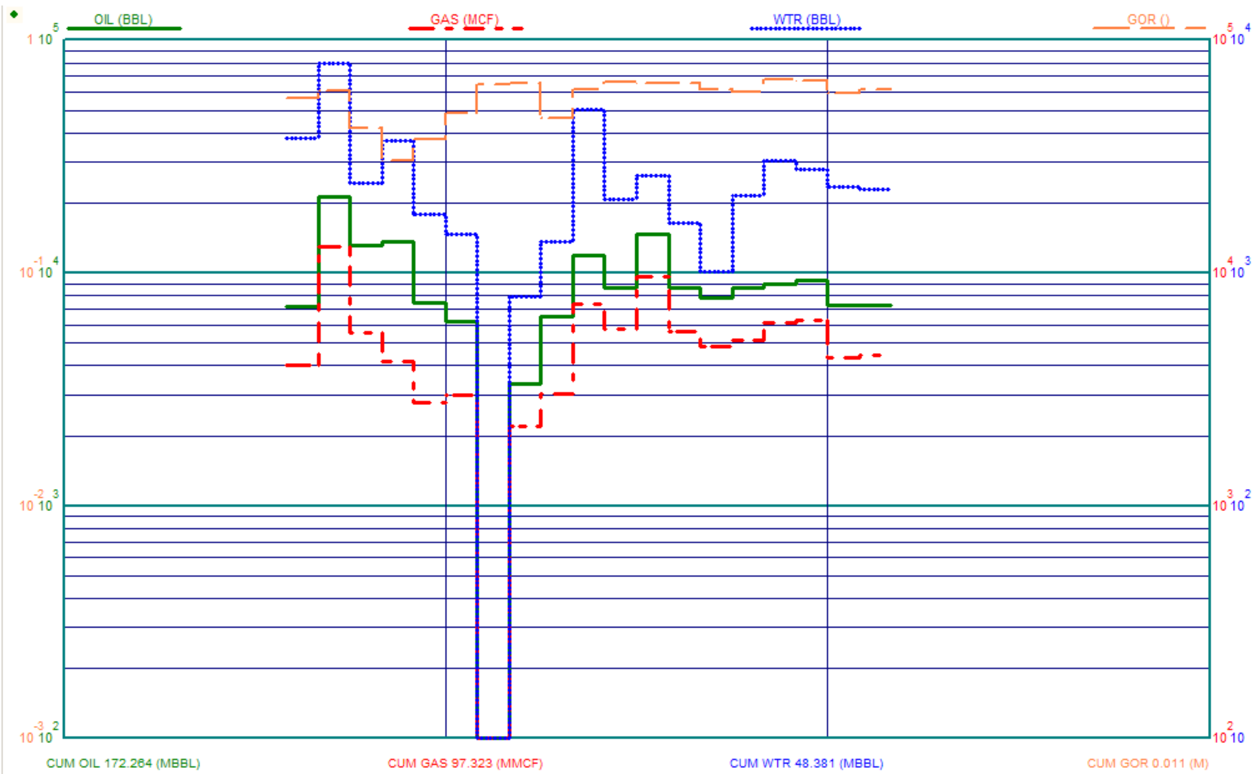
Appendix A35. Average production per well for Ross area.



Appendix A36. Area 1: Production graph for the Heiple 11-3H, sec. 3, T154N, R92W. The well had an IP of 2411 BOPD, and 1282 MCFD. Initial GOR 532 cu ft gas per barrel oil.

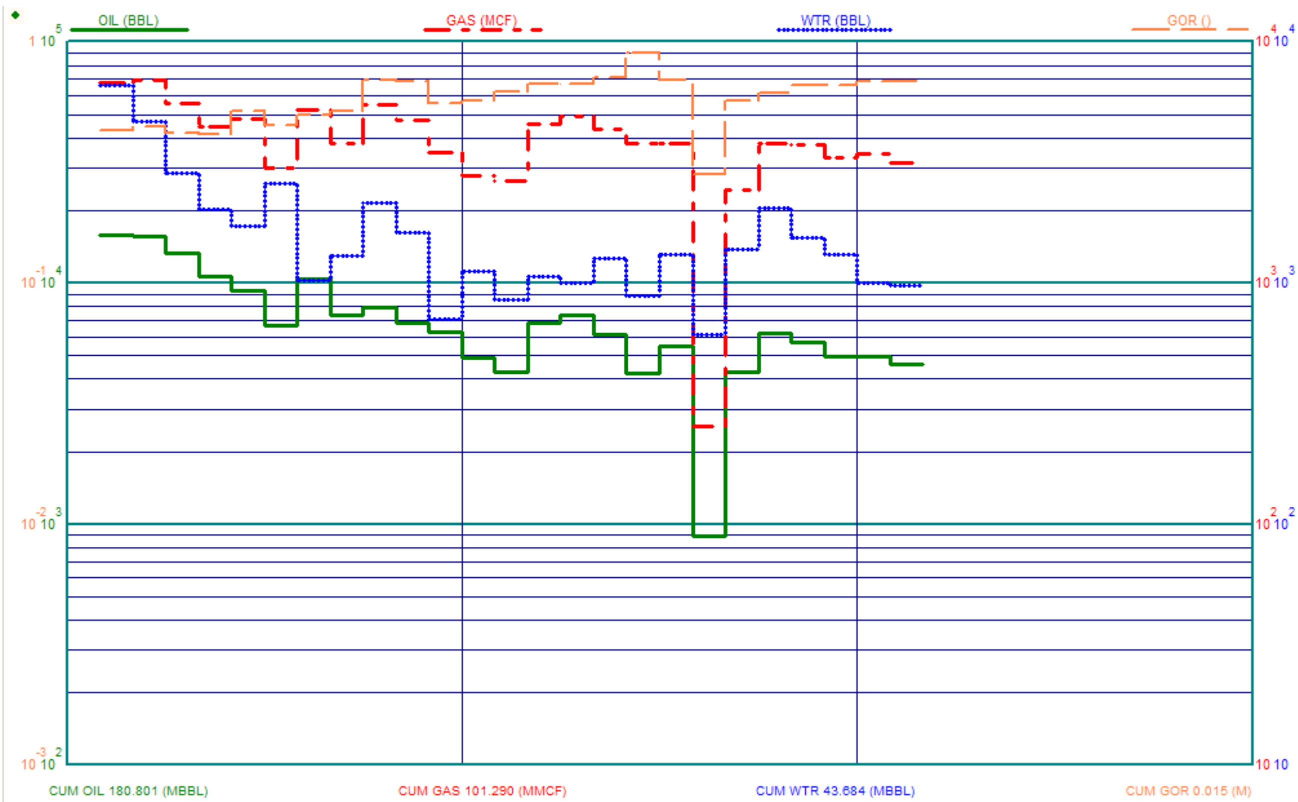


Appendix A37. Area 1: Production graph for the Odgen 11-3H, sec. 3, T154N, R92W, Nw Nw. The well had an initial IP of 1329 BOPD and 902 MCFD. Initial GOR was 678 cu ft gas per barrel of oil.

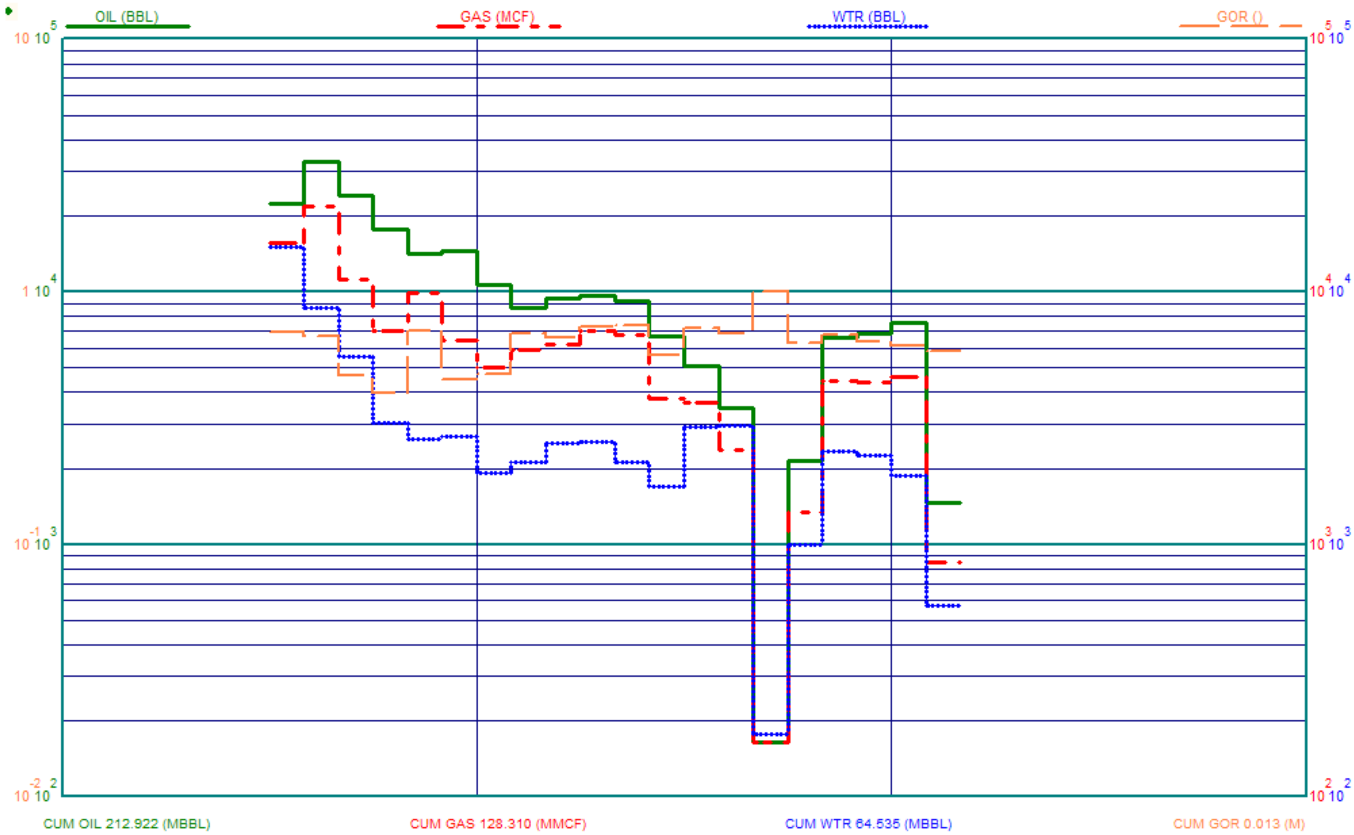


Appendix A38. Area 1: Production graph for the Odgen 12-3H, sec. 3, T154N, R92W, SW NW. The well had an initial IP of 1890 BOPD and 1479 MCFD. Initial GOR was 782 cu ft gas per barrel of oil.

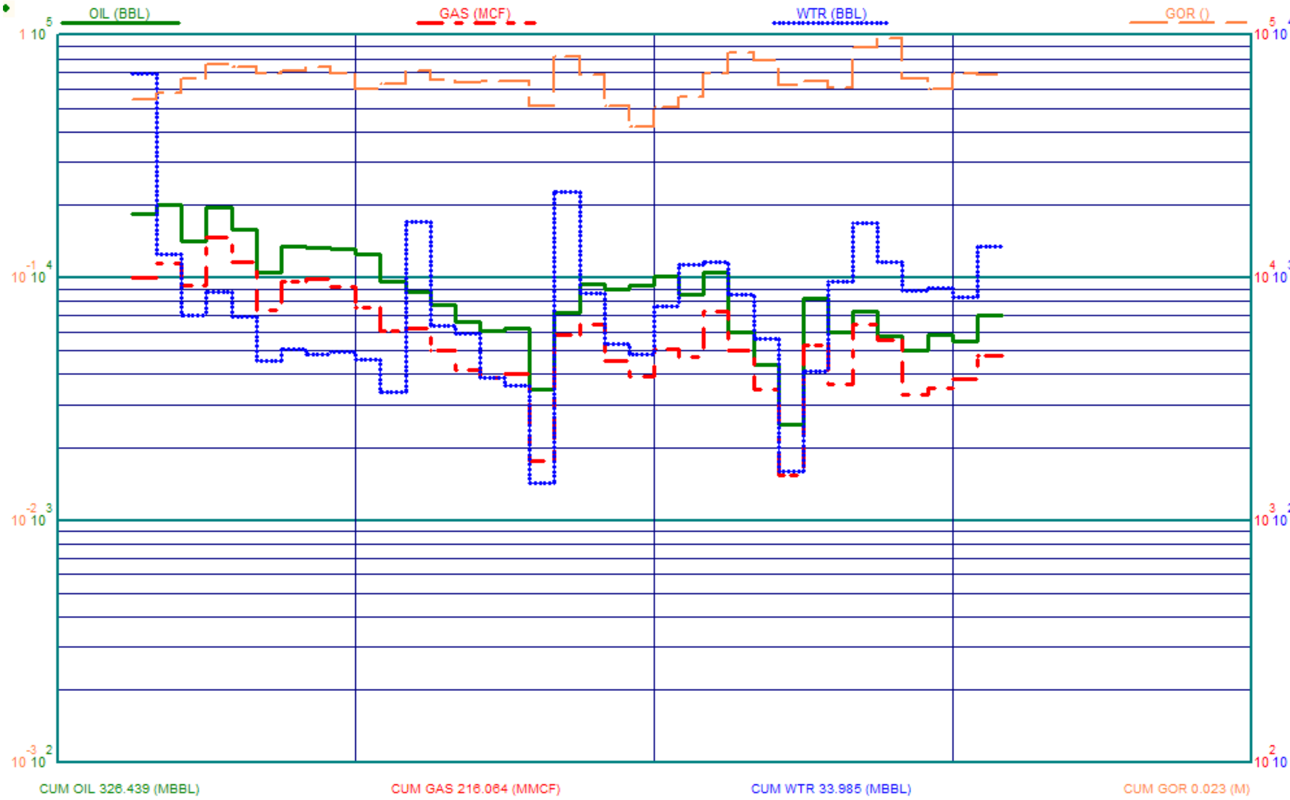
Appendix A39. Area 1: Production graph for the Heiple 14-3XH, sec. 3, T154N, R92W, SW SW. The well had an initial IP of 1870 BOPD and 1262 MCFD. Initial GOR was 674 cu ft gas per barrel oil.



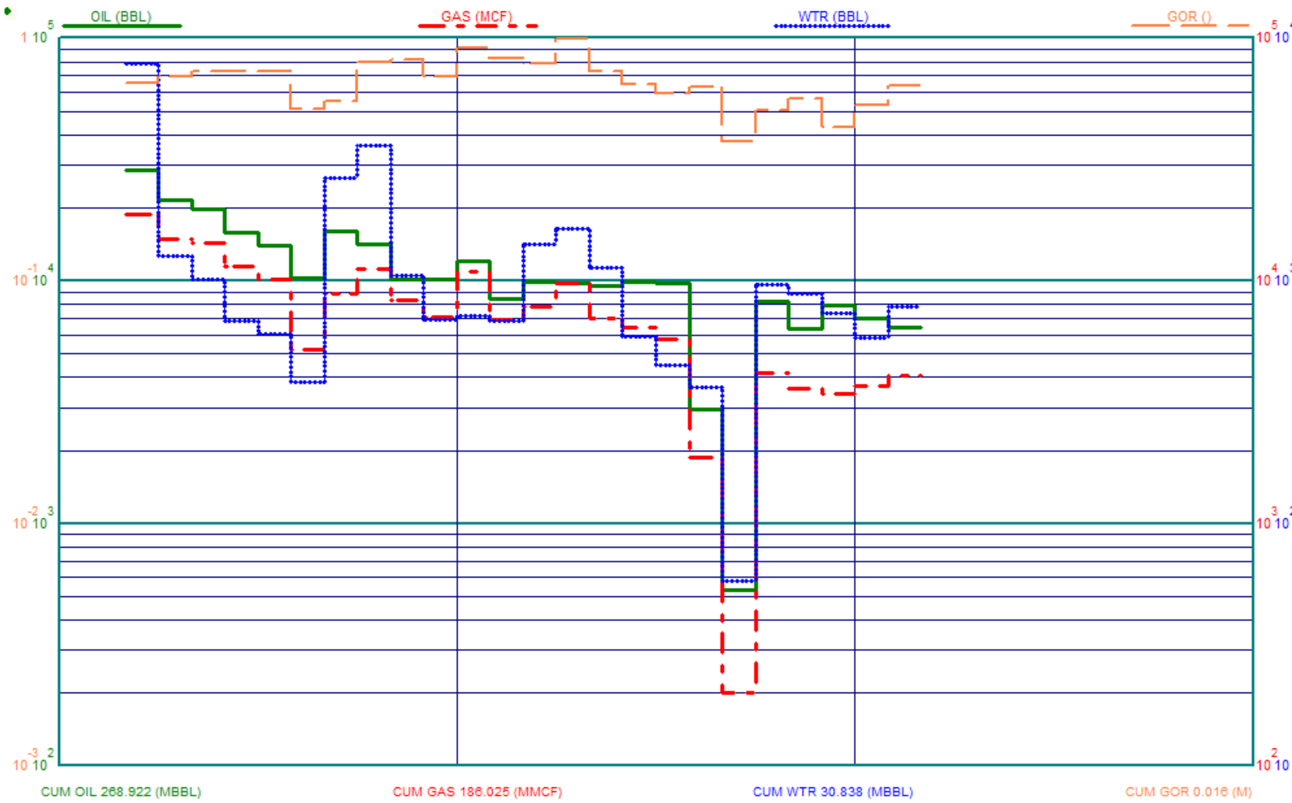
Appendix A40. Area 1:



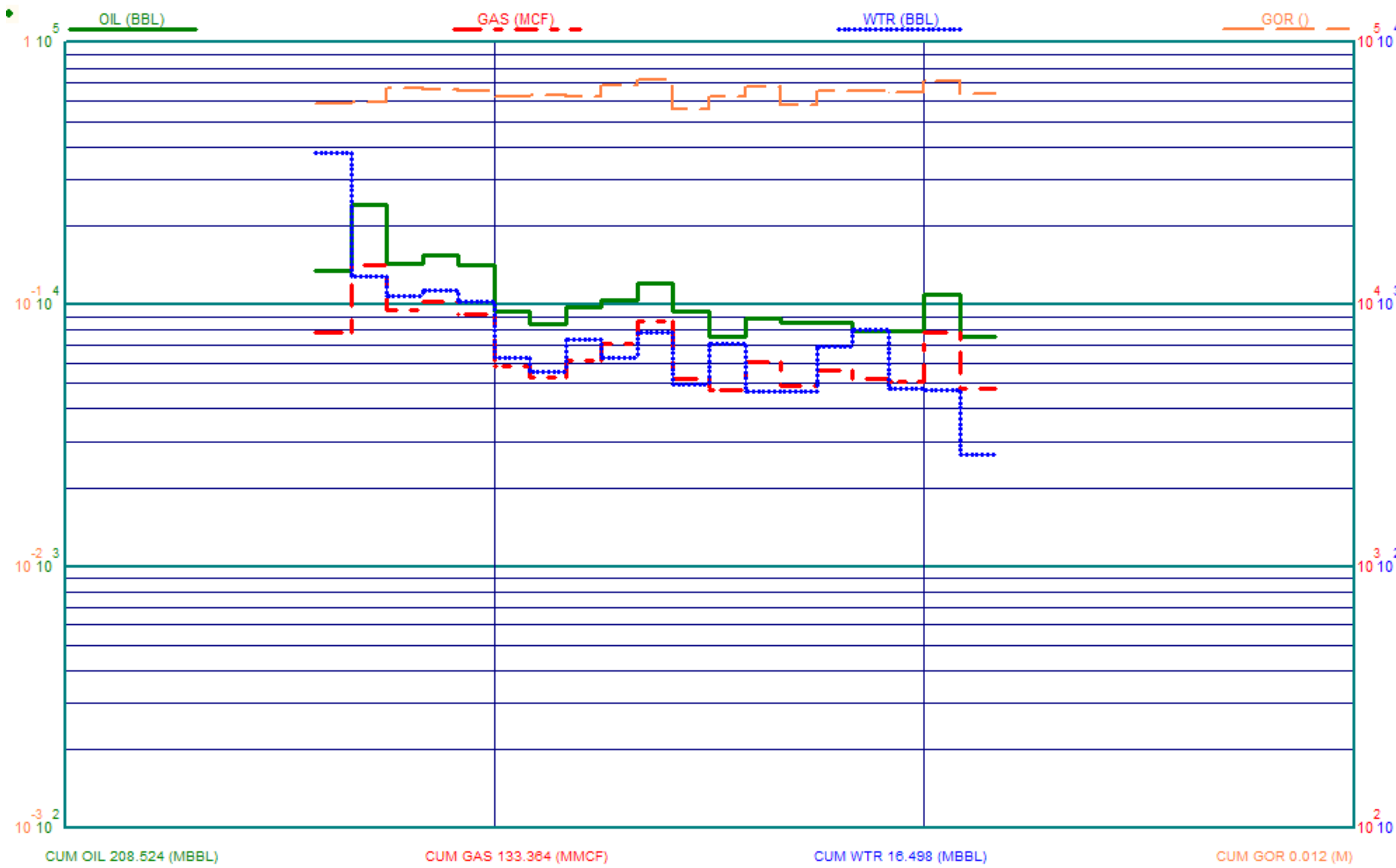
Appendix A41. Area 1: Production graph for the Fladeland 12-10H, sec. 10, T154N, R92W. The well had an initial IP of 4126 BOPD amd 1830 MCFD. Initial GOR was 357 cu ft gas per barrel oil.



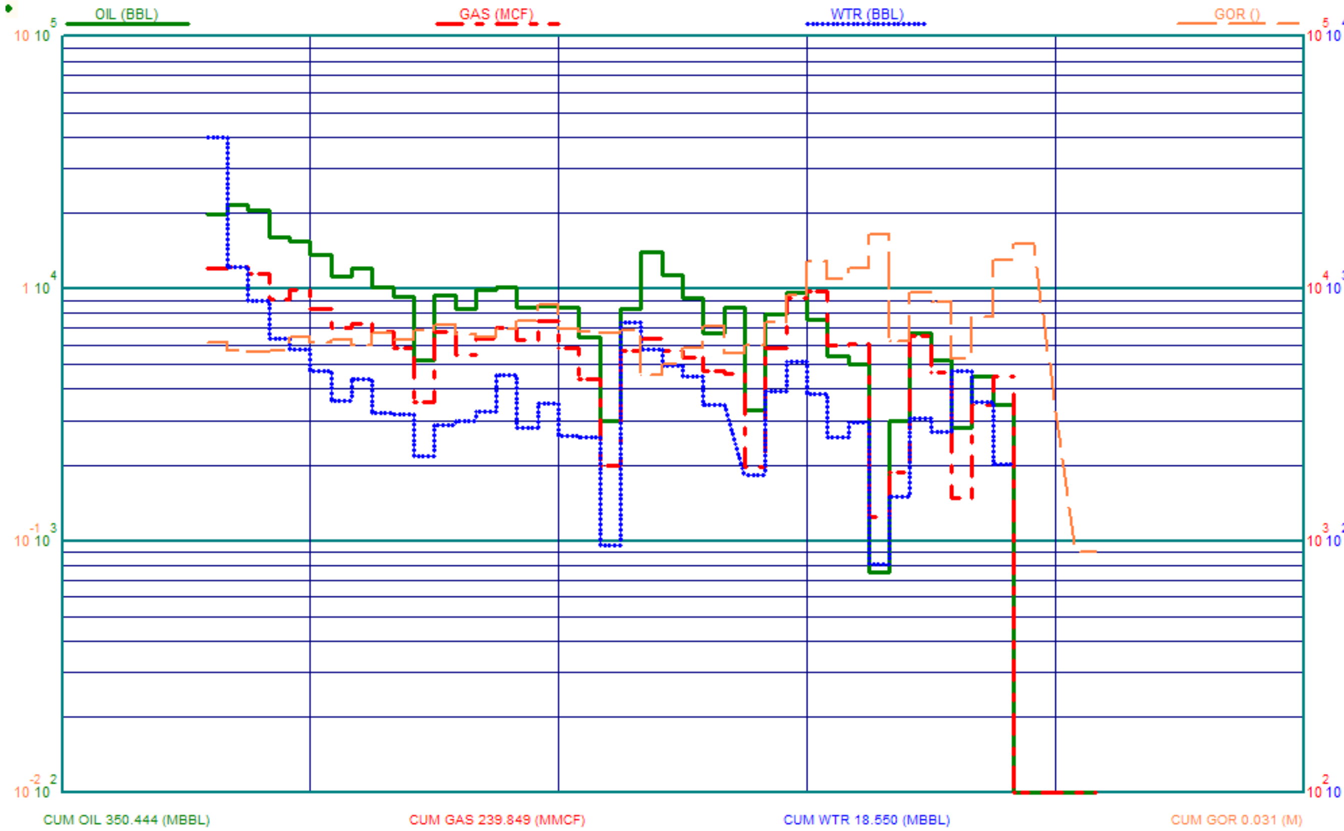
Appendix A42. Area 2: production plot for the TTT Ranch 11-6H, sec. 6, T153N, R91W, NW NW. The well had an initial IP of 2825 BOPD and 1661 MCFD. Initial GOR was 587 cu ft gas per barrel of oil.



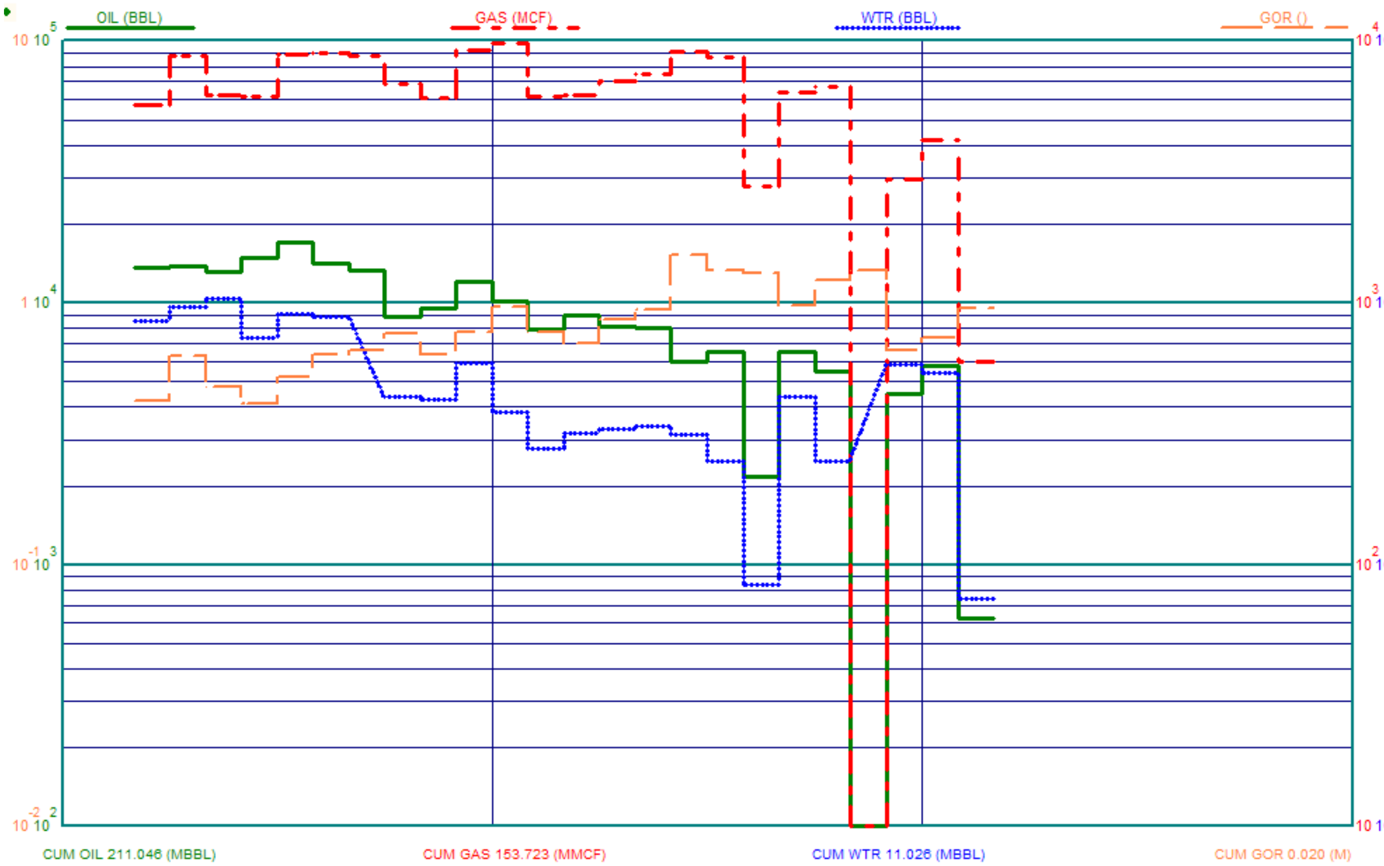
Appendix A43. Area 2: Production plot for the TTT 12-6H, Sec. 6, T153N, R91W, SW NW. The well had an initial IP of 2762 BOPD and 1349 MCFD. Initial GOR was 488 cu ft gas per barrel oil.



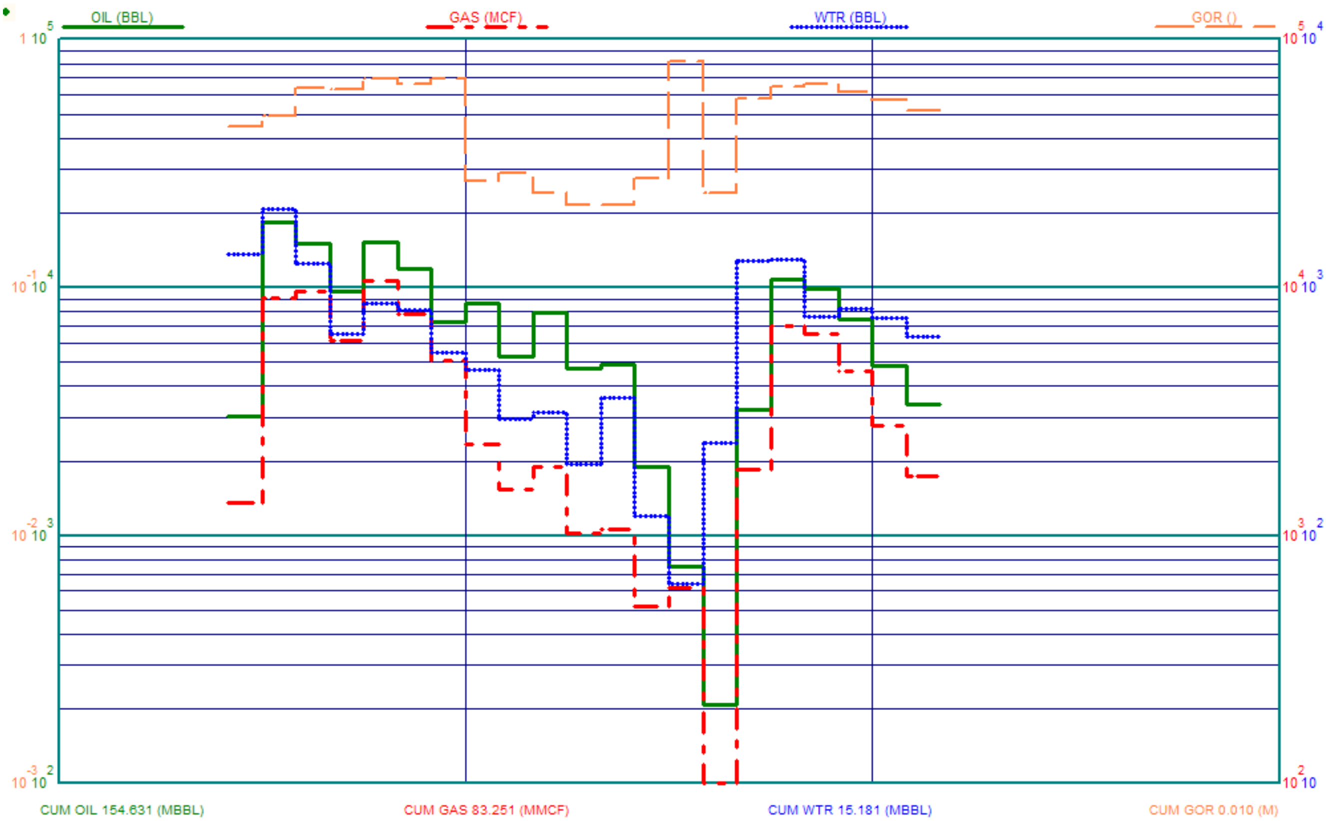
Appendix A44. Area 2: Production plot for the Rohde 14-6XH, Sec. 6, T153N, R91W, SW SW. The well had an IP of 3023 BOPD and 1620 MCFD. Initial GOR was 535 cu ft gas per barrel oil.



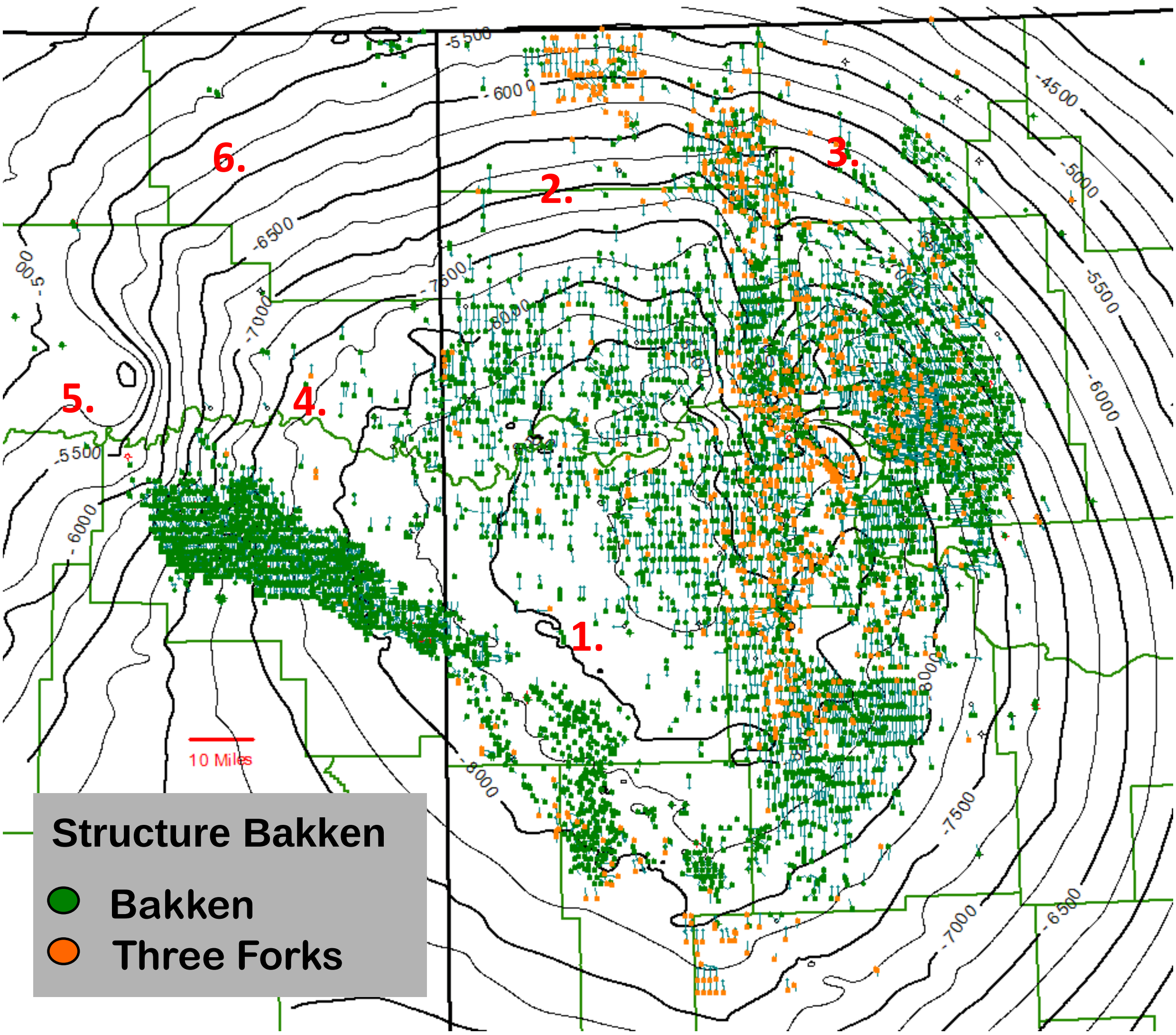
Appendix A45. Area 2: Production plot for the Smith 11-7H, sec. 7, T153N, R91W, NW NW. The well had an IP of 2012 BOPD, 1244 MCFD. Initial GOR was 623 cu ft gas per barrel oil.



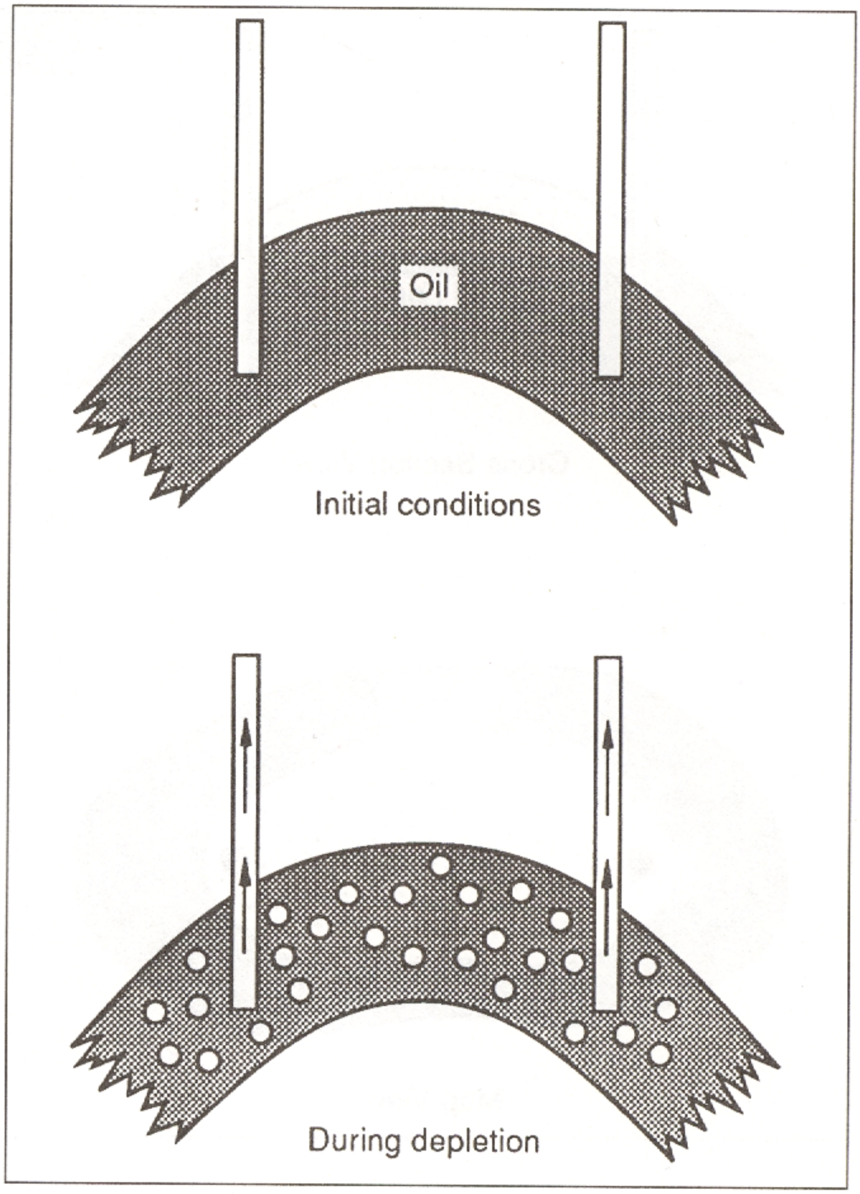
Appendix A46. Area 2: Production plot for the Smith 12-7 H, sec. 8, T153N, R91W. The well had an IP of 2530 BOPD and 1234 MCFD. Initial GOR was 487 cu ft gas per barrel oil.



Appendix A47. Area 2: Production plot for Moore 14-7XH, sec. 7, T153N, R91W, SW SW. The well had an IP of 1485 BOPD and 754 MCFD. Initial GOR for the well was 507 cu ft gas per barrel of oil.



Appendix A48. Future drilling areas, Williston Basin: 1. Area between Billings Nose and west Nesson; 2. area north of west Nesson; 3. North Ross; 4. East Roosevelt County, MT; 5. Poplar Dome area; 6. Sheridan and Daniels counties, Montana.



Appendix A49. Solution gas drive mechanism for continuous oil reservoirs.

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