The Bakken Formation: Leading Unconventional Oil Development

name redacted
Specialist in Energy Policy

name redacted
Specialist in Energy and Defense Policy

name redacted
Specialist in Natural Resources Policy

name redacted
Specialist in Environmental Policy

May 23, 2012

Congressional Research Service
7-....
www.crs.gov
R42032

CRS Report for Congress
Prepared for Members and Committees of Congress

Summary

The Bakken Formation is a large unconventional petroleum and natural gas resource underlying parts of North Dakota, Montana, and the Canadian provinces of Saskatchewan and Manitoba. Bakken oil production is now viable because of advanced horizontal drilling and hydraulic fracturing methods. Growth in production is rapidly changing.

High oil prices and low natural gas prices have prompted shale gas producers to turn to shale oil or tight oil. The Bakken Formation has emerged as a major tight oil resource "play." The U.S. Geological Survey (USGS) estimated that the Bakken may contain 3.65 billion barrels (bbls) of undiscovered oil (or less than 3% of total U.S. estimates), 1.85 trillion cubic feet (tcf) associated/dissolved undiscovered natural gas (less than 1% of total U.S. estimates), and 148 million bbls of undiscovered natural gas liquids (NGLs) recoverable under current technology. USGS announced in July 2011 that it will reassess the Bakken resources.

Full development of this resource faces a number of hurdles. A major constraint to more vigorous development of the Bakken is the lack of pipeline capacity to move more crude oil to refineries. A proposed pipeline, the Keystone XL pipeline, would extend from Canada to Nebraska, where it would connect to another TransCanada pipeline for transport to Gulf Coast refineries, and could transport oil from the Bakken. The original proposed Keystone XL pipeline did not receive a necessary Presidential Permit; however, TransCanada, the company that proposed the pipeline resubmitted its application to the State Department on May 4, 2012, with a different configuration. Flaring of natural gas in association with Bakken oil production has also attracted a lot of interest. If producers are forced to decrease flaring it would also likely result in oil production being curtailed.

Another issue potentially affecting development of the Bakken is the need to make use of hydraulic fracturing. This technology is the subject of increasing regulatory scrutiny, along with public concern over its possible impact on water quality. The Environmental Protection Agency (EPA) is conducting a congressionally mandated study on the impact the technique may have on drinking water, and the Department of Energy (DOE) has undertaken a broader assessment of the potential environmental effects of this practice. Legislation pending in the House and the Senate would authorize EPA to regulate hydraulic fracturing used in oil and natural gas production. Currently, states broadly regulate oil and gas exploration and production on non-federal lands, and proposals to give EPA new authority in this area have been highly controversial.

A longer-term constraint may be water availability and access, as the industry's cumulative water demand for fracturing and other well development activities expands. Groundwater tables in the Bakken region have been falling as water extractions for municipal, agricultural, industrial and other purposes have exceeded aquifer recharge. The Army Corps of Engineers announced in May 2012 that it is moving forward with processing requests from oil development interests for access to a key surface water source, Lake Sakakawea on the Missouri River in North Dakota. Initially the Corps will not assess a fee for the withdrawn water, while it undertakes a pricing policy rulemaking. Uncertainty over charges related to water withdrawn from the lake has ignited concerns among those withdrawing water for other purposes (e.g., municipal and agricultural uses) and the state's authority over surface waters within its borders.

Contents

Figures

Tables

Appendixes

Contacts

Introduction

High oil prices and advances in drilling technology have allowed oil and natural gas companies to access new hydrocarbon resources that appeared uneconomic to produce only a few years ago. There has been much attention to shale gas, which has transformed the U.S. natural gas market and kept natural gas prices low. There is also growing output from shale oil or "tight" oil resources using similar technology. While tight oil and shale gas share some issues in common—both present the opportunity to significantly raise domestic hydrocarbon production and both pose certain environmental concerns—others are distinct, including the ease with which they can affect domestic energy prices. The Bakken Formation has emerged as the leading tight oil resource play.

Vocabulary: Oil Shale is not Shale Oil

Shale oil, or tight oil, which is what is contained in the Bakken formation, is petroleum that is held in shale rock. The shale has very low permeability and porosity, which does not allow the petroleum to flow to the well and be produced without modifying or "stimulating" the well to enhance permeability. Current technology is to fracture the shale surrounding the well to release the oil and allow it to flow to the well hole and be produced. The most common technique for this is hydraulic fracturing, using water, sand, and chemicals to create the fissures necessary for the oil to flow to the well. Advances in hydraulic fracturing technology coupled with improvements in directional drilling methods as well as high oil prices is what makes shale oil economic to produce. For additional information on drilling technology see **Appendix B**.[1]

Oil shale is a solid organic matter known as kerogen that is present in certain sedimentary rocks. The kerogen must be heated through various processes to convert it to a synthetic oil. Oil shale is not economic to produce at this time.

The Bakken Formation is a large unconventional petroleum and natural gas resource that is part of the Williston Basin, a historic oil-producing area underlying parts of North Dakota, Montana, and the Canadian provinces of Saskatchewan and Manitoba (see **Figure 1**).[2] Analyses dating back to 1974 recognized the Bakken as a tremendous source for the oil produced in the Williston Basin and suggested that the Bakken was capable of generating 10 billion barrels (bbls) of oil.[3]

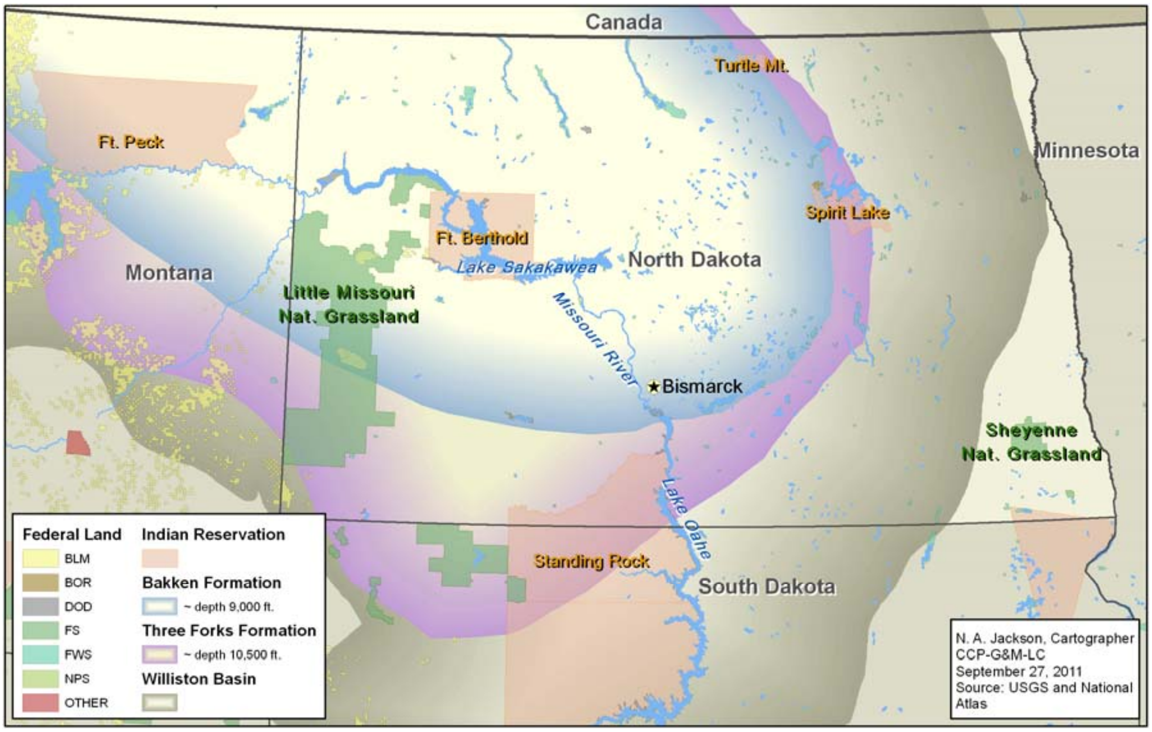
However, well drilling and completion techniques at the time made it uneconomic to develop. The key to its development lies now in technologically advanced horizontal drilling and hydraulic fracturing methods. This combination of drilling and completion technology substantially increases the production rate through a single well, and thus improves its economic rate of recovery. The use of hydraulic fracturing in tight oil development, however, faces the same environmental scrutiny that shale gas development is receiving elsewhere in the United States. (See discussion under `"Water Supply and Quality Issues" section.)

[1] For background on oil shale see CRS Report RL33359, *Oil Shale: History, Incentives, and Policy*, by (name re dacted).

[2] In conventional formations, oil or gas occurs in interconnected pore spaces that allow flow to the production well. Unconventional formations have discontinuous pores and low permeability; these formations typically must be hydraulically fractured to release the oil and gas trapped within the shale or other formation type.

[3] Julie LeFever and Lynn Helms, *Bakken Formation Reserve Estimates*, North Dakota Department of Mineral Resources, July 27, 2006, https://www.dmr.nd.gov/ ... /bakken/ ... /07272006_bakkenreserveestimates.pdf.

Figure 1. The Bakken Formation



Source: Compiled by the Library of Congress Cartography Division.

Note: The shading indicates the lateral extent of the Bakken Formation and the deeper Three Forks Formation. The Williston Basin is a large sedimentary basin spanning North Dakota, South Dakota, Montana, and part of southern Canada.

Estimates of the Bakken Formation's resource potential are a subject of debate and evolve as more information becomes available. The U.S. Geological Survey's (USGS) mean estimate for the Bakken is that it may contain 3.65 billion bbls of undiscovered oil (less than 3% of total U.S. estimates), 1.85 trillion cubic feet (tcf) associated/dissolved undiscovered natural gas (less than 1% of total U.S. estimates), and 148 million bbls of undiscovered natural gas liquids (NGLs) (there is not a comparable estimate for total U.S. NGLs) recoverable under current technology.[4] The USGS announced in July 2011 that it will reassess the resources in the Bakken by the end of 2013. As new data are acquired and analyzed and new technologies and techniques are developed the amount of resource that is recoverable changes. In the development of tight oil and shale plays, the pace of this change is rapid. The North Dakota Geologic Survey estimates place the Bakken's original oil in place (OOIP) between 200 to 300 billion bbls, with varying estimates of recovery (1.4%-3%).[5] The USGS and North Dakota Geologic Survey figures are not directly

[4] Richard M. Pollastro, Troy A. Cook, Laura N. R. Roberts, et al., U.S. Geological Survey, *Assessment of Undiscovered Oil Resources in the Devonian-Mississippian Bakken Formation, Williston Basin Province, Montana and North Dakota, 2008*, National Assessment of Oil and Gas Fact Sheet, April 2008.

[5] The OOIP is defined as the total hydrocarbon content of an oil reservoir and refers to the oil in place before the commencement of production. OOIP is measured in stock tank barrels, meaning the volume of oil is corrected for shrinkage that occurs when the oil is brought to the surface to be sold at standard pressure and temperature. OOIP must not be confused with oil reserves which are the technically and/or economically recoverable portion of the oil volume in the reservoir and is referred to in this CRS publication as estimated ultimate recovery (EUR). State of North Dakota *Bakken Formation Resources Study Project*, April 2008. Available in S. Hrg 110-769. The North Dakota Industrial Commission's Department of Mineral Resources has estimated that, based on current technologies, the recovery rate is (continued...)

comparable as the assumptions behind each differ. Additionally, the Three Forks Formation, which is at a greater depth than the Bakken, may also contain significant hydrocarbons (see **Figure 1**).

The pace of oil production now places the north central region of the United States, particularly North Dakota, among the most significant new domestic energy resources. North Dakota produced 575 thousand barrels per day (kb/d) in March, 2012, making it comparable to Alaska.

The success of the Bakken development has spurred exploration of other tight oil formations, such as the Eagle Ford Formation in Texas and the Niobrara Formation in Wyoming, as well as others. Production from these and future discoveries could continue to increase or at least hold steady U.S. oil production. Some in industry expect production from these fields to continue to increase, possibly adding as much as 4 million barrels per day of new oil production.

Market Considerations and Implications

The Bakken Formation produces both oil and natural gas, but it is the potential for oil production that has raised Bakken's profile. Bakken tight oil is notable because: (1) production from the field has contributed to reversing the annual decline in U.S. oil production over the last three years (see **Figure 2**), and (2) it is the first in a possible series of tight oil fields. Prior to 2009, U.S. oil production steadily decreased for two decades, while oil imports have increased to compensate for the production decline and meet rising consumption. Although the Bakken has been producing since 1951, it is only since 2006 that prices and technology have made it economic for industry to increase production. (See **Figure 3**.) In March 2012, Bakken production reached a new high of over 510 kb/d, the first time breaking 500 kb/d.[6]

It is unlikely that tight oil production alone will convert the United States from a net importer of oil to a net exporter. Nevertheless, any increase in domestic oil production will offset imports, improve the nation's trade balance, and enhance U.S. energy security. Continued high prices for oil would drive company interest in developing tight oil.

High oil prices and low natural gas prices have encouraged oil and gas producers to shift their exploration and development activity from gas-rich areas to areas with oil and gas liquids deposits. On an energy equivalent basis oil is eight times more expensive than natural gas in the United States at March prices. Producers are applying some of the lessons learned in shale gas drilling to extraction of tight oil. As long as natural gas prices remain relatively low compared to oil prices, this trend is likely to continue.

Transportation constraints are limiting both oil and natural gas production in the Bakken (see "Transportation Constraints Limit Oil Production").[7] Pipelines that would take oil and natural gas produced from the Bakken to refineries and to markets are at full capacity. The oil sector is

---

(...continued)

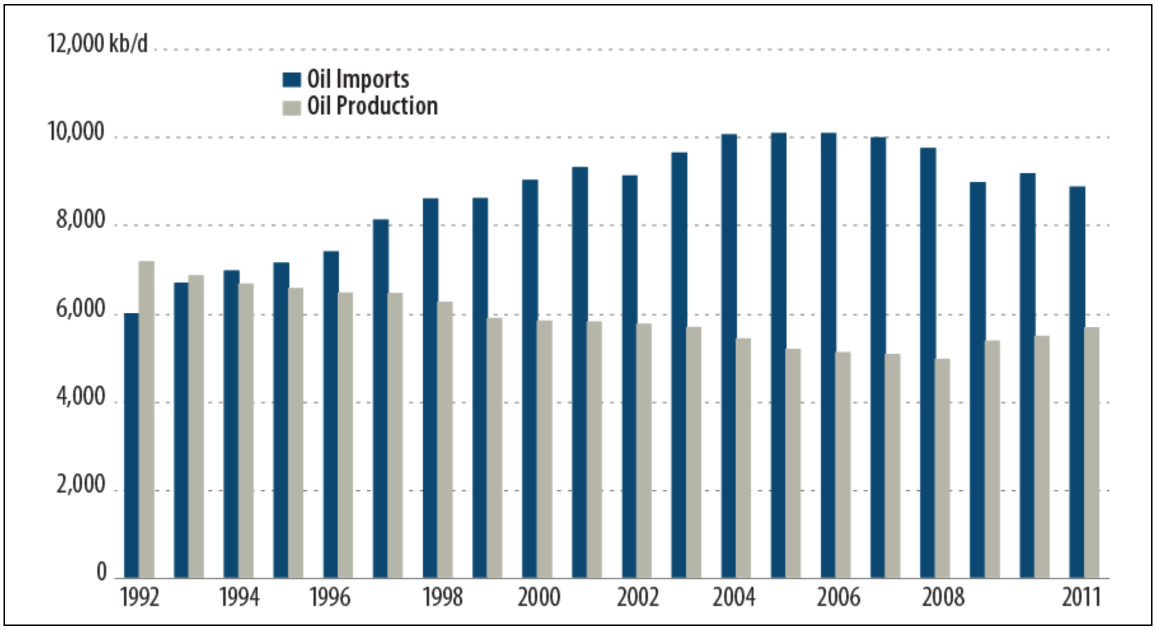
roughly 1.4% of OOIP. In contrast, more than 15% of OOIP typically can be produced from conventional oil wells.

[6] North Dakota Department of Mineral Resources, *North Dakota Monthly Oil Production Statistics*, Bismarck, ND, 2011, p. 14, https://www.dmr.nd.gov/oilgas/stats/historicaloilprodstats.pdf.

[7] Natural gas production from the Bakken is associated or linked with oil production, which is not uncommon in conventional oil production.

relying on rail and trucking to bring additional production to market, while excess natural gas is being flared or vented.

Figure 2. Annual U.S. Oil Production and Imports



Source: U.S. Energy Information Administration's Short-term Energy Outlook, http://www.eia.gov/emeu/steo/pub/cf_query/index.cfm.

Note: Units are 1,000 barrels per day (kb/d).

The Bakken in the U.S. Oil Market

Transportation infrastructure to move oil and gas produced in the Bakken is having difficulty keeping up with the rapid growth in output (see **Figure 3**). Bakken production is up approximately 1,100% between 2008 and 2012. Some industry analysts expect Bakken production to nearly triple by 2015, which would exacerbate the transportation bottleneck.[8]

Montana and North Dakota—the two states under which the Bakken Formation is located—consumed 153 kb/d or less than 1% of total U.S. consumption. As of March, Bakken production is over 510 kb/d, which is almost 8% of U.S. total oil production.[9] Rigs operating in the Bakken continue to increase: As of April, there are 196 rigs operating in North Dakota, up 25% versus a year ago, with no rigs dedicated to natural gas production. There 17 rigs operating in Montana, nearly double year-ago levels, also with no rigs for natural gas production.[10] For context, the

[8] Morgan Stanley, *Mid-Con Refining: On the Toll Road of Production*, February 3, 2011.

Oil Daily, *Bakken Fuels Rapid Growth in North Dakota Crude Oil Production*, Energy Intelligence Group, January 25, 2011.

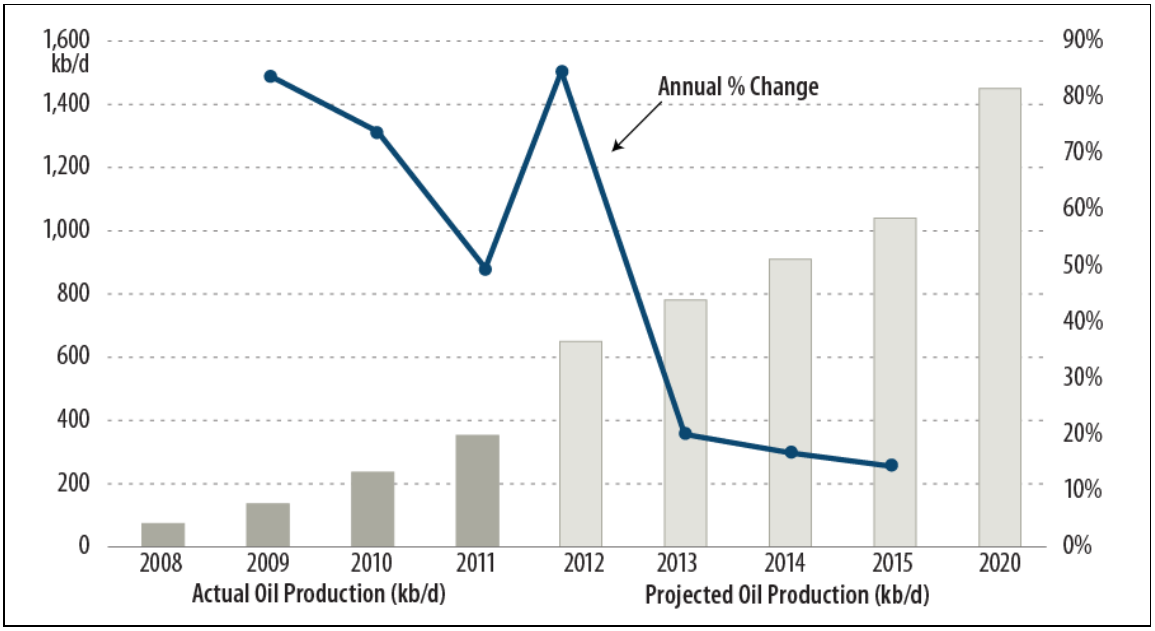
[9] The Bakken formation is not the only oil producing field in these states.

Nathan Vanderklippe, "TransCanada to move U.S. crude through Keystone," *The Globe and Mail*, January 26, 2011.

[10] LCM Commodities, "Baker Hughes Rig Count," April 27, 2012.

United States consumed approximately 18,840 kb/d of oil and petroleum products in 2011, of which about 52% came from domestic sources.[11]

Figure 3. Bakken Oil Production Through 2020



Source: Historic data is from the North Dakota Industrial Commission, Department of Mineral Resources, Oil and Gas Division, https://www.dmr.nd.gov/oilgas/stats/historicalbakkenoilstats.pdf. Projections are from Advanced Resources International, Inc. presentation at NCAC-USAEE/CSIS Tight Oil Possibilities, Challenges, and Policy Implications Conference, Washington, DC, April 3, 2012.

Note: Production units are barrels per day (b/d).

The relatively high price for oil (see **Figure 4**), particularly leading up to the 2008 economic collapse, has driven companies to find new sources of oil such as the Bakken. The breakeven price to recover about 50% of the Bakken oil is estimated at $60 per barrel not including well costs, according to an industry consultancy.[12] The price at the end of March 2012 for the U.S. benchmark crude West Texas Intermediate (WTI) was approximately $105 per barrel. Nevertheless, Bakken oil trades at a lower price than WTI and other comparable crude oils because of the high cost of transporting it to market. Bakken crude is considered a high quality crude, light and sweet, which makes it easier to refine into high value products like gasoline.[13]

[11] U.S. Energy Information Administration, Short-Term Energy Outlook and Petroleum & Other Liquids databases, http://www.eia.gov/petroleum/.

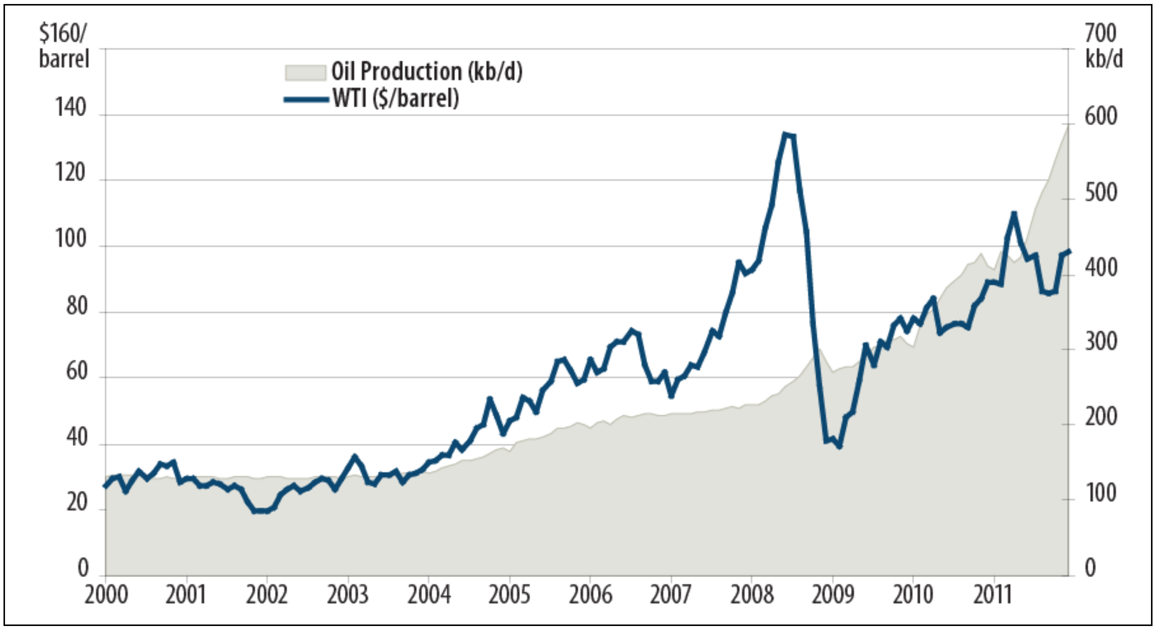
[12] Wood Mackenzie, "Tight Oil Drives L48 Investment," NCAC-USAEE/CSIS Tight Oil Possibilities, Challenges, and Policy Implications Conference, Washington, DC, April 3, 2012, p. 10.

[13] Bakken oil has an API gravity of 38 to 40 degrees with a sulfur content between 0.2% and 0.5%. LLS has an API gravity of 36 degrees and a sulfur content of 0.3%.

For additional information on the refining process see CRS Report R41478, *The U.S. Oil Refining Industry: Background in Changing Markets and Fuel Policies*, by (name redacted), (name redacted), and (name redacted).

Figure 4. Oil Production vs. Price

Montana and North Dakota Crude Oil Production vs. West Texas Intermediate Crude Oil Prices



Source: U.S. Energy Information Administration state and price databases, http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbblpd_m.htm and http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=RWTC&f=M.

Notes: Production units are 1,000 barrels per day (kb/d). West Texas Intermediate (WTI) is the primary U.S. benchmark price for crude oil. Prices are measured in nominal dollars per barrel ($/barrel).

Transportation Constraints Limit Oil Production

A shortage in pipeline transportation, which is at capacity, is constraining Bakken oil production and adding to the cost of moving the oil to refineries and large demand centers. Oil production—about 480 kb/d as of January 2012—has outpaced pipeline takeaway capacity. Oil producers have resorted to rail and truck transportation to move Bakken oil production to market.[14] Both of these methods are more costly than transit by pipeline and detract from future development. Moreover, an additional pipeline bottleneck occurs at Cushing, OK, the main interim point for Bakken oil as well as a lot of other crude oil, before being sent to refineries on the coast of the Gulf of Mexico. Additional pipeline, rail, and refining projects are under development to alleviate the Cushing bottleneck, but are not necessarily Bakken specific.

Another component of the pipeline capacity constraint is that oil production from Canada, particularly from Alberta's oil sands, has increased and created competition for pipeline space.

In response to growing output and price discounts for Bakken crude, a number of new pipeline and rail projects have been proposed (see **Table 1**). Some of these pipelines are part of larger projects that would also carry Canadian oil to U.S. refiners (see **Figure 5**).

[14] Oil Daily, *Bakken Crude Producers Use Trains to Beat Pipeline Bottlenecks*, Energy Intelligence Group, February 3, 2011.

Table 1. Oil Pipeline and Rail Projects Planned to 2013

Project	Company	Capacity (kb/d)	Start Year
Bakken North	Plains	75.0	2012
Butte Loop	True	30.0	2012
Mainline ND	Enbridge	25.0	2012
Mandan Refinery	Tesoro	10.0	2012
Additional Rail		425.0	2012
Bakken Expansion 2	Enbridge	120.0	2013
Butte Loop	True	90.0	2013
Baker to Billings	Plains	50.0	2013
Additional Rail		150.0	2013
TOTAL		1,170.5	
Existing Capacity		808.0	

Source: North Dakota Pipeline Authority, https://www.dmr.nd.gov/pipeline/.

Possible Role of the Keystone XL Pipeline

In 2008, Canadian pipeline company TransCanada filed an application with the U.S. Department of State to build the Keystone XL pipeline. The cross-border project requires a Presidential Permit, which was denied in January 2012. TransCanada has reconfigured its Keystone XL proposal and broken the project in two parts. The new Keystone XL proposal, which includes the Bakken Marketlink segment, would go from Alberta, Canada, to Steele City, NE, and the Gulf Coast Project would go from the Cushing, OK, hub to Texas.[15] TransCanada expanded its connection between Steele City and Cushing in February 2011. TransCanada had previously signed contracts with Bakken oil producers to carry 65 kb/d from the region into the Keystone XL pipeline.[16] While not the full 100 kb/d TransCanada had offered, this was enough to justify the Bakken Marketlink Project, a pipeline running from Baker, Montana to the Keystone XL pipeline, which can then carry crude to the oil hub at Cushing and on to the Gulf Coast.[17] These contracts will likely need to be amended because of the timeline and project, but would appear to still be valid. Keystone XL would also alleviate some of the oil congestion in Cushing. The Bakken Marketlink would have a 100 kb/d capacity and is estimated to cost $140 million. It could start operating in 2015 if it and the Keystone XL pipeline receive regulatory approvals.[18] These new Bakken contracts also improve the economics for Keystone XL, raising its committed capacity from 75% to near 90%.[19]

---

[15] TransCanada Corporation, "TransCanada Is Committed to the Keystone Pipeline System," company website, 2012, http://www.transcanada.com/keystone.html.

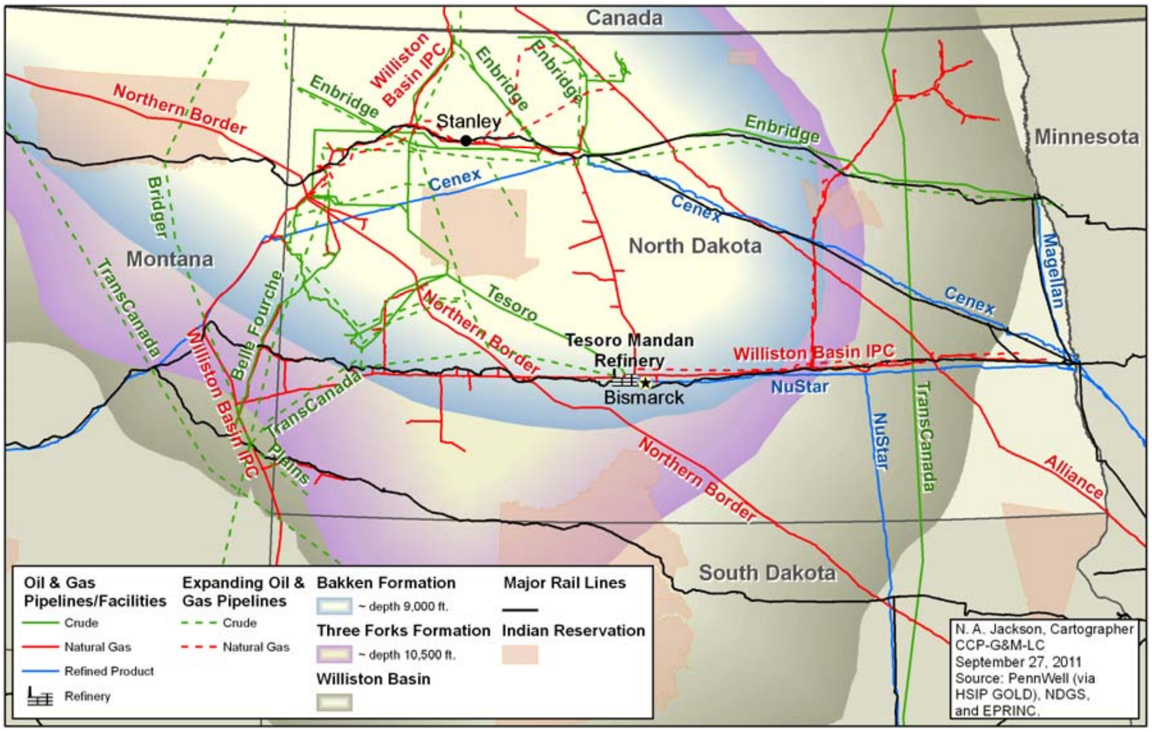
[16] For additional information on the Keystone pipeline system see CRS Report R41668, *Keystone XL Pipeline Project: Key Issues*, by (name redacted), (name redacted), and (name redacted).

[17] Jeffrey Jones, "TransCanada Plans U.S. Bakken Pipeline Link," *Reuters*, January 20, 2011.

[18] TransCanada, "TransCanada to Transport U.S. Crude Oil to Market Bakken Open Season a Success," press release, January 11, 2011, http://www.transcanada.com/5631.html.

[19] Vanderklippe, 2011.

Figure 5. Bakken Formation and Infrastructure Map



Source: Compiled by the Library of Congress Cartography Division.

Note: The shading indicates the lateral extent of the Bakken Formation and the deeper Three Forks Formation. The Williston Basin is a large sedimentary basin spanning North Dakota, South Dakota, Montana, and part of southern Canada.

The Keystone XL pipeline would lower transportation costs and provide access to new markets that may support increased investment in the Bakken. Other companies are also adding pipeline capacity; notably, Enbridge is building a 145 kb/d pipeline in the same time frame (listed in **Table 1**). According to Enbridge, sufficient pipeline capacity has been slow to emerge in the region because "they're smaller players in the Bakken. They are not able to make the 20-year commitments and it's been a lot of work to get them to commit to the level that they required to underwrite a major project out of the Bakken."[20]

Additionally, there is only one oil refinery in North Dakota, the Mandan Refinery, which has a capacity of 58 kb/d. The Tesoro Corporation, the owner of the Mandan Refinery, announced in March that it would expand the facility by 10 kb/d by 2012.[21] Montana has four refineries with a total capacity of 183 kb/d, but would require more pipeline capacity to transport the Bakken oil to those refineries and beyond. No refineries are located in South Dakota at present, but there are plans to develop one. Refining is not viewed as the primary constraint to tight oil development, however, as more refining capacity would still require more pipelines to transport the products.

[20] Lauren Krugel, "TransCanada attracts support for Montana-to-Oklahoma crude pipeline," *The Canadian Press*, January 20, 2011.

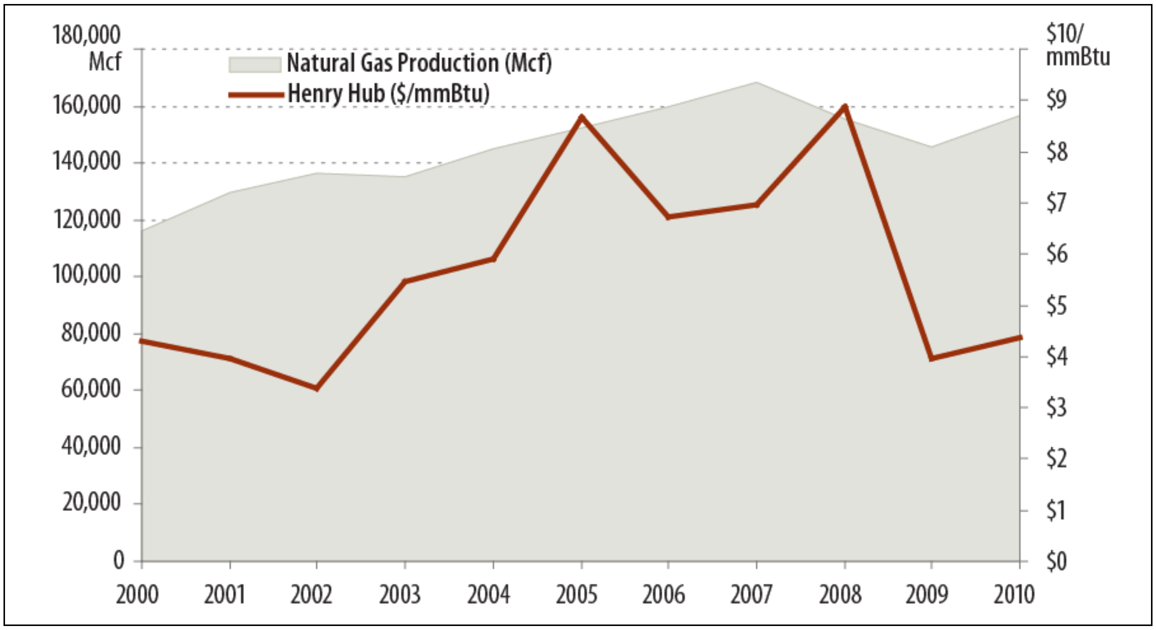
[21] Tesoro Corporation, "Tesoro Announces North Dakota Expansion," press release, March 21, 2011, http://phx.corporate-ir.net/phoenix.zhtml?c=79122&p=irol-newsArticle&ID=1541127&highlight=.

Natural Gas: A Stranded Asset

While commercial interest in the Bakken is focused primarily on the large oil deposits, some natural gas is also present and gets produced when the oil is extracted. Total natural gas production from Montana and North Dakota was less than 1% of the U.S. natural gas production of almost 24 trillion cubic feet (see **Figure 6**). Additionally, in 2010, dry natural gas production from the two states was over 10% higher than consumption. However, this does not include the amount that is vented or flared. Other states that have experienced big increases in tight oil production have also had increases in the amount of natural gas being flared.

Figure 6. Natural Gas Production vs. Price

Montana and North Dakota Natural Gas Production vs. Henry Hub Natural Gas Prices



Source: Multiple U.S. Energy Information Administration state databases.

Notes: Production units are million cubic feet (Mcf). Henry Hub is the primary U.S. benchmark price for natural gas. Prices are measured in dollars per million British thermal unit ($/mmBtu).

The lack of natural gas infrastructure means that natural gas that cannot be transported to market must be vented or flared (see **Figure 7**), which is done partially for safety reasons. As a result, 30% of gross natural gas production and almost 35% of its dry gas production in North Dakota was vented or flared in 2010.[22]

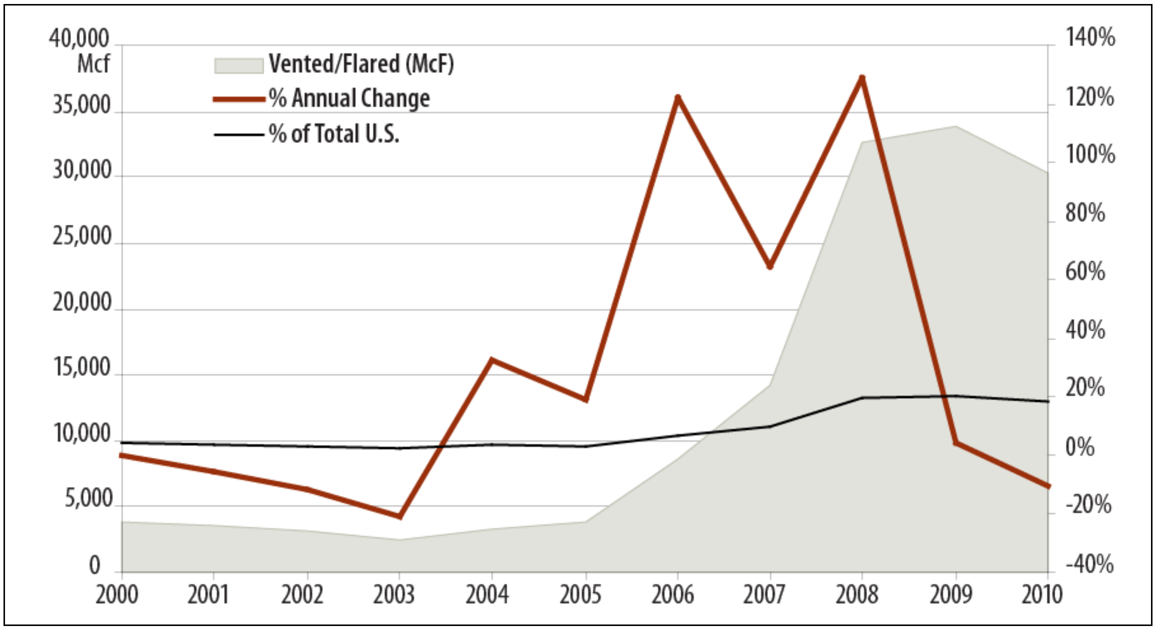
The necessary infrastructure to process natural gas, particularly gathering pipelines, has not been able to keep pace with production. Increased natural gas production will result in additional volumes being flared although the percentages may not change or even decrease. Flaring is preferred to venting, as the latter is a major environmental concern because methane, the main

[22] Energy Information Administration, *Natural Gas Gross Withdrawals and Production database*, http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_m.htm.

component of natural gas, is over 20 times more potent than carbon dioxide as a greenhouse gas.[23] However, both involve the waste of a domestic energy resource.[24]

Figure 7. Vented/Flared Natural Gas

Montana and North Dakota Vented/Flared Natural Gas Growth



Source: Multiple U.S. Energy Information Administration database databases.

Note: Production units are million cubic feet (Mcf).

Water Supply and Quality Issues

Many of the nation's conventional oil and gas fields have been depleted, and much attention has turned to oil and natural gas resources trapped in unconventional (low permeability and low

[23] When vented, natural gas (largely methane) is released directly to the air without being burned. In contrast, the main byproduct of flared (burned) natural gas is carbon dioxide.

[24] In North Dakota, the Industrial Commission (NDIC) regulates natural gas flaring. State rules generally allow gas from an oil well to be flared for one year. Thereafter, the flaring must stop and the well capped, connected to a gathering line, or equipped with an electrical generator that uses most of the gas. Violators must pay production taxes and royalties on the value of the flared gas. Exemptions may be granted under certain conditions, such as when connecting to gathering line is not economically feasible (NDCC 38-08-06.4). The NDIC also has specific rules for individual fields. An administrative order for the Banks-Bakken Pool allows wells to produce oil at a maximum efficient rate for 60 days (or 120 days if approved); after which production is limited to 150 bbd for 60 days, then 100 bbd for 60 days. These restrictions would be removed once a well is connected to a gas gathering and processing facility (Case No. 15989, Order 17944).

Montana limits the amount of gas that can be flared or otherwise wasted to an average of 100,000 cubic feet per day each month. An operator must receive approval to flare more than that amount, and the state may restrict production until the gas is marketed or otherwise beneficially used (MONT. ADMIN. R. 36.22.1220).

On April 17, 2012, the U.S. Environmental Protection Agency issued regulations to control air emissions from gas wells, including air toxics and volatile organic compounds that cause smog (including methane). EPA states that the rules do not apply to oil wells. See http://www.epa.gov/hydraulicfracture/.

porosity) formations. As with other unconventional resources, development of the Bakken formation relies on directional drilling and hydraulic fracturing to profitably produce the oil trapped within the shale, and this process requires significantly more water than traditional oil production. (See **Appendix B** for a discussion of drilling and hydraulic fracturing techniques.) While traditional wells were drilled only vertically, tight oil wells in the Bakken-Three Forks System frequently are drilled roughly two miles deep and then two miles horizontally.[25]

The North Dakota Industrial Commission projects that 28,000 new oil wells could be drilled in the state during the next 15 to 25 years, which would require more than 20 million gallons of water per day.[26] This extensive development of the Bakken (and related tight oil formations in the Williston Basin) is expected to place significant new demands on regional water resources. Consequently, tight oil production potentially could be constrained by the availability of, or access to, water supplies.

Water quality issues also have arisen with the development of unconventional oil and gas resources, including tight oil. Managing the large volumes of wastewater produced during oil production (including flowback from hydraulic fracturing and produced water that is present naturally in the rock formation) can present water treatment and disposal challenges. The geology in the Bakken region allows disposal of produced water through deep well injection. As a result, management of produced water in the Bakken has not posed the same difficulties as it has in some shale regions where the local geology limits the use of underground injection wells, creating treatment challenges and surface water quality concerns. Nonetheless, more wastewater injection wells will be needed to support the development of the Bakken tight oil, particularly because the produced water from Bakken wells is highly saline, making it technically impractical to reuse to drill the next well or otherwise recycle.

Perhaps the most controversial water quality issue—associated with unconventional oil and gas production generally—concerns the potential for hydraulic fracturing operations to contaminate drinking water supplies. Congress has asked the Environmental Protection Agency (EPA) to study this issue, and other studies are underway as well. EPA expects to publish initial research results in late 2012 and a final report in 2014.[27]

Expanding Demand for Water

In an 11-county area of North Dakota, more than 3,600 Bakken tight oil wells were developed between 2008 and 2011, and as noted above, thousands more are anticipated in the next two decades. This concentrated development, in space and time, and the water needs of the accompanying workforce is generating concerns about where the water will come from to meet the needs of the oil and natural gas industry without depleting local water resources, which are relied upon for irrigation, drinking water, and other uses.

[25] North Dakota Department of Mineral Resources and North Dakota Geological Survey,

[26] Bruce E. Hicks, Assistance Director, North Dakota Industrial Commission, Department of Mineral Resources, Oil and Gas Division, http://www.housemajority.org/seaton/pdfs/27/Hicks_presentation.pdf.

[27] For information on the EPA hydraulic fracturing study, see http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/.

Fracturing a well in the Bakken Formation in North Dakota typically can require between 0.8 million and 4.0 million gallons of water per well.[28] The amount of water used varies based on numerous factors including the length of the well, the rock formation, and the extent of fracturing. Good quality water is generally preferred for hydraulic fracturing operations in the Bakken to maintain the effectiveness of the gelled fracturing fluid used in these wells. Moreover, water with consistent characteristics (e.g., pH, mineral content) generally improves consistency in the effectiveness of fracturing. For tight oil wells, water use is most concentrated in the early stages of well development, usually in the first few months. Once the well is producing, less water is required. Refracturing four or five years after the initial fracturing to extend production can require additional water.

The oil and natural gas industry's water demand in the 11 counties in western North Dakota was estimated to reach 22 million gallons per day (24,400 acre-feet annually) in 2011, and to continue to rise if drilling and fracturing expand.[29] The industry's 2011 water use was estimated to increase the region's water use by more than 20% above the average of the previous decade.

Reuse of flowback from hydraulic fracturing and other produced water not only would help extend water supplies, but it also would reduce the volume of produced water that requires transport, treatment and/or disposal. However, as discussed below, produced water in the Bakken play currently is disposed through deep well injection and generally is not treated and reused.

Supplying Water for Energy Development

Freshwater for developing and completing Bakken tight oil wells comes from groundwater sources and surface water sources (including the mainstem of the Missouri River).[30] The recent rapid growth in groundwater use for oil development has accelerated the decline of the region's aquifers, which has been ongoing since the mid-1980s.[31] These aquifers are part of the Northern Great Plains aquifer system, which spans eastern Montana and Wyoming and extends below South Dakota, North Dakota, and Saskatchewan and Manitoba provinces in Canada.[32] This concern about depletion of limited groundwater supplies is described in an August 2010 report *Water Appropriation Requirements, Current Water Use & Water Availability for Energy Industries*

[28] An Army Corps of Engineers draft report put the lower end of water use at 0.8 million gallons, with the lower end dominated by the shorter vertical wells. U.S. Army Corps of Engineers, Omaha District, *Garrison/Lake Sakakawea Project, North Dakota, Draft Surplus Water Report*, Omaha, NE, December 2010, p 3-2, http://www.nwo.usace.army.mil/html/pd-p/review_plans.html. North Dakota State Water Commission, *Water Appropriation Requirements, Current Water Use & Water Availability for Energy Industries in North Dakota*, Water Resources Investigation No. 49, August 2010, p. 38, cites references providing the 4.0 million gallons number.

[29] Data in this paragraph are calculated from U.S. Army Corps of Engineers, Omaha District, *Garrison/Lake Sakakawea Project, North Dakota, Draft Surplus Water Report*, Omaha, NE, December 2010, p 2-21 and p 3-8.

[30] Several public water systems, including the Williston municipal water system, have made available some treated water withdrawn from Lake Sakakawea or the Missouri River.

[31] Monitoring since the 1980s reveals a groundwater decline, which already is having a negative impact on domestic and stock water wells in the western North Dakota. Robert Shaver, *Water Availability for Oil Well Development in North Dakota and Status of Water Depot Permit Applications*, Water Appropriation Division, North Dakota State Water Commission.

[32] See map at USGS, Montana Water Science Center, *Lower Tertiary and Upper Cretaceous Aquifer System Groundwater Availability Study*, http://mt.water.usgs.gov/projects/LTUC/. The Northern Great Plains aquifer system, which includes aquifers such as the Fox Hills, is significant because not only is it where Bakken oil is developed but also it spans portions of the Power River basin of Wyoming and Montana where there is extensive energy (e.g., coal bed methane and coal) and mineral (e.g., uranium) production.

in North Dakota produced by the North Dakota State Water Commission. The Commission has concluded that

> Given current estimates of oil production from the Bakken Formation over the next decade, water requirements will not be met from ground water sources and non-Missouri River surface water sources. [33]

Efforts are underway to alleviate water supply (and transport) constraints not only on energy development but also on municipal and agricultural users. Regional improvements to deliver water to the oil industry and rural communities are under development; most notably the Western Area Water Supply project, which would deliver Missouri River water to these users, obtained access in 2011 to $110 million in state loans.

Additionally, many energy industry and western North Dakota stakeholders have pushed for the federal government to allow the energy industry to directly access water stored in Lake Sakakawea behind the federal Garrison Dam on the Missouri River. In May 2012, the U.S. Army Corps of Engineers, which operates the dam, announced that it will process applications for new or increased temporary water withdrawals (i.e., five-year contracts with an option for a renewal) from surplus stored water.[34] Initially, there will be no charge associated with the contracts as the agency undertakes a rulemaking to establish a pricing policy for surplus water. This announcement follows on a December 2010 draft Corps report, *Garrison Dam/Lake Sakakawea Project, North Dakota, Draft Surplus Water Report*. In the draft report, the Corps had proposed to charge a fee commensurate with the updated construction costs for the dam for the storage space associated with the contracted water.[35] The report stirred considerable controversy because it reignited a decades-old disagreement between the Corps and North Dakota interests regarding access to Missouri River water. North Dakota interests argue that the Corps should not charge for access to what would be available water if the river were flowing freely, and that the Corps is interfering with state water rights.[36] This fee controversy is likely to continue as the rulemaking proceeds. Under the 1944 statutory authority that gives the Secretary of the Army the authority to make contracts for surplus water, the Secretary also is given discretion to set the fee "at such prices and on such terms as he may deem reasonable."[37]

Others are looking to reduce how much freshwater the energy industry needs. For most of North Dakota's Bakken wells, the majority of the fluids injected are not returned to the surface; only

---

[33] Ibid.

[34] U.S. Army Corps of Engineers, "Corps to begin finalizing surplus water applications at Lake Sakakawea," press release, May 9, 2012, http://www.nwo.usace.army.mil/pa/2012/NR20120508-LakeSakDecision.doc.pdf.

[35] The current Corps procedure for determining the fee is to calculate how much of the storage space at the reservoir is being used for the surplus water to be provided and to charge an amortized updated cost of construction for that portion of the dam and for its operation and maintenance. Such payment for federal construction costs is a common feature of many large federal water projects.

[36] The report also ignited concerns that municipal users that pull water from the lake also may be charged in the future, and that irrigators withdrawing from the reservoir may face not only future fees but also access constraints because of the Corps' limited authority for supporting irrigation, which is a long-standing unresolved issue in the basin. North Dakota's opposition to the fee is tied to the history of the development of the Missouri River mainstem dams (which benefit the entire basin while the facilities and their impacts are concentrated in the upper basin) and related projects (e.g., Garrison Project for irrigation). For more on the development of the Missouri River basin, see J.E. Thorson, *River of Promise, River of Peril: The Politics of Managing the Missouri River* (Lawrence, KS: University Press of Kansas, 1994).

[37] 33 U.S.C. §708.

10% to 15% of the injected fracturing fluid is returned to the surface. This fluid, known as flowback, is typically reinjected deep underground in a permitted disposal well. Reusing flowback and other produced water is increasing in other unconventional oil and gas plays, but the cost and amount that can be reused depends on numerous factors that vary by formation and well.[38] In the Bakken region, the water produced by oil wells is highly saline and technologically difficult and costly to treat for reuse; consequently, producers currently are not recycling water from these wells. In contrast, research is indicating that the treatment of moderately saline groundwater may be a cost effective alternative to other surface water options.[39]

Water Quality Issues Associated with Bakken Development

Protecting groundwater quality during oil production is acutely important in the Bakken region, where aquifers often provide the principal source of water for domestic, agricultural, stock and municipal needs. Montana and North Dakota have a number of shallow glacial aquifers in the area that are of usable quality. Additionally, the extensive Fox Hills Sandstone formation (a bedrock aquifer) underlies a broad area (including over half of North Dakota) and forms the lowermost potable aquifer, running as deep as 2,000 feet. The top of the Bakken Formation varies in depth from 4,500 feet below the surface on the western edge in Montana and 3,100 feet on the northern edge in Canada, to more than 10,000 feet deep in some areas of western North Dakota.[40]

While the use of hydraulic fracturing and directional drilling has enabled the oil industry to greatly increase domestic oil production, concern has emerged regarding the potential impacts that this process may have on groundwater quality. During hydraulic fracturing, new fractures are induced into the shale formation, or existing fractures are lengthened. As tight oil production activities have increased, so has concern that the hydraulic fracturing process might introduce hydrocarbons, fracturing fluids, and other contaminants into aquifers. State oil and gas regulators note that the hydraulically fractured shale formations in North Dakota average 6,000 to 8,000 feet below freshwater aquifers.[41] At such depths below potable aquifers, regulators and geologists generally view as remote the possibility of creating a fracture that reaches an underground source

[38] Technologies, such as desalination and membrane treatment processes, are increasingly viewed as a means to treat water produced during energy development. In addition to reducing the quantity of flowback requiring disposal, treatment also may produce a water supply for additional energy development. For more information on these technologies, see CRS Report R40477, *Desalination and Membrane Technologies: Federal Research and Adoption Issues*, by (name redacted). Legislation has been introduced in the 112th Congress and was considered by the 111th Congress to support federal research on water use, needs, and management issues related to energy development. For example, H.R. 5827, Energy and Water Research Integration Act (112th Congress), would have required the Secretary of Energy to develop and regularly update a strategic plan within DOE research activities for research related to the energy sector's water use and efficiency, including energy-related produced water reuse. For an example of legislation specifically targeted at produced waters, H.R. 469, the Produced Water Utilization Act of 2009 (111th Congress), would have directed the Secretary of Energy to carry out a program to demonstrate technologies for environmentally sustainable use of energy-related produced waters from underground sources.

[39] Bethany Kurz, *Update on the Bakken Water Opportunities Assessment: Phase 1 and 2*, Energy & Environmental Research Center, University of North Dakota, PowerPoint presentation, January 24, 2012, p. 11, https://cms.oilresearch.nd.gov/image/cache/Beth_OGRC_Update_January_2012.pdf.

[40] Energy Information Agency, Technology Based Oil and Natural Gas Plays: Shale Shock! Could there be Billions in the Bakken?, Office of Oil and Gas, Reserves and Production Division, November 2006.

[41] Bruce E. Hicks, Assistant Director, North Dakota Industrial Commission, Department of Mineral Resources, Oil and Gas Division.

of drinking water. In Richland County, MT, where most Bakken activity has focused in that state, nearly all water wells are less than 500 feet deep.[42]

Although research is ongoing and information is incomplete, reports that hydraulic fracturing might have contaminated groundwater stem primarily from incidents involving a poorly constructed or cemented well, rather than from a fracture extending from the shale to an overlying aquifer. As with the development of other oil and gas resources, sound well construction and operation practices are essential to reducing groundwater contamination risks in the Bakken.

Another concern involves the potential contamination of usable groundwater from surface activities. Leaky surface impoundments, accidental spills, or careless surface disposal of drilling fluids at the drilling site could increase the risk of contaminating nearby water wells. The surface disposal of oil-field wastewater (including flowback from hydraulic fracturing and produced brine from the rock formations) presents a possible source of surface water and groundwater contamination.

Wastewater management issues and practices associated with development of oil and gas resources vary across different states and regions. Wastewater storage, treatment and disposal issues facing the Bakken tight oil have differed from those experienced in development of natural gas from the Marcellus Shale Formation which underlies a broad swath of Pennsylvania and New York State and portions of the mid-Atlantic region. Perhaps most notably, disposal of flowback and other wastewater produced by Bakken tight oil wells has not posed the challenge experienced in portions of the Marcellus shale region, where the geology can limit the use of underground injection wells; in such areas, wastewater disposal has posed water treatment, water quality, and regulatory problems. In contrast, the geology in the Bakken region enables disposal of produced water through deep well injection.

Water Quality Management and Protection

As with oil and gas production generally, development of the Bakken Formation on private or state land is primarily governed by state laws and regulations, including requirements addressing well construction and operation, and water quality protection. On federal lands, the Bureau of Land Management (BLM), within the Department of the Interior, administers leasing and coordinates planning and permitting with other federal agencies, as appropriate.[43] The BLM also supervises operational activities on oil and gas leases on tribal lands.[44] However, in Montana and North Dakota, operators drilling on federal lands are required to obtain a state permit as well as a federal permit and must comply with the applicable state and federal regulations.[45]

---

[42] Groundwater Information Center, Montana Bureau of Mines and Geology, County-wide Statistics, http://mbmggwic.mtech.edu/sqlserver/v11/reports/CountyStatistics.asp?MTCounty=RICHLAND.

[43] For more information, see CRS Report R40806, *Energy Projects on Federal Lands: Leasing and Authorization*, by (name redacted).

[44] Bureau of Land Management, Department of the Interior, Oil and Gas, *Oil and Gas*, http://www.blm.gov/wo/st/en/prog/energy/oil_and_gas.html.

[45] On May 4, 2012, the Bureau of Land Management proposed amendments to its oil and gas regulations for federal and Indian lands to address changes in well stimulation practices, specifically hydraulic fracturing. The proposed rule includes requirements for disclosure of chemicals used in hydraulic fracturing on public lands, new well construction requirements, and a requirement that operators develop plans for managing the fluids that flow back out of a well after hydraulic fracturing. See http://www.blm.gov/wo/st/en/info/newsroom/2012/may/NR_05_04_2012.html.

Additionally, provisions of two federal water quality laws can apply to some activities, specifically those related to flowback and produced water disposal. The Safe Drinking Water Act (SDWA) applies to the disposal of wastewater from oil and gas production by underground injection. The Clean Water Act (CWA) regulates the discharge of wastewater into surface waters through the National Pollution Discharge Elimination System (NPDES) permit program. Both of these laws typically are administered by the states.

The flowback water from hydraulic fracturing and other produced water from Bakken oil wells is being managed through injection into deep disposal wells. These wastewater disposal wells are regulated through the federal Underground Injection Control (UIC) program mandated by the federal Safe Drinking Water Act.[46] This law establishes the national regulatory program for protecting underground sources of drinking water by limiting underground injections that could contaminate aquifers. Although underground injection of wastewater produced during oil and gas development is subject to SDWA, the law specifically excludes from regulation the underground injection of fluids used in hydraulic fracturing (unless diesel fuels are used).[47]

The SDWA authorizes EPA to delegate primary enforcement authority (primacy) for UIC programs to the states, provided that the state program follows EPA regulations and prohibits underground injection that is not authorized by a state permit or rule. If a state's UIC program plan is not approved, or the state has chosen not to assume program primacy, then EPA must implement the UIC program in that state. However, in lieu of meeting the specific requirements of EPA's regulations related to the injection of brine or other fluids brought to the surface in connection with oil or gas production (Class II injection wells[48]), the statute allows a state to demonstrate that its UIC program is effective in protecting underground sources of drinking water.[49] This gives states flexibility to implement their own program requirements, rather than follow EPA regulations. Both North Dakota and Montana have attained primacy for the Class II program by making this alternative demonstration.[50]

---

[46] The Safe Drinking Water Act of 1974 (P.L. 93-523) authorized the UIC program at EPA. UIC provisions, as amended, are contained in SDWA Part C, §§1421 - 1426; 42 U.S.C. §§300h - 300h-5.

[47] The Energy Policy Act (EPAct) of 2005 (P.L. 109-58, §322), amended the SDWA to exempt from the definition of 'underground injection' the injection of fluids or propping agents (other than diesel fuel) for hydraulic fracturing purposes. EPA retained the authority to regulate the use of diesel fuel for the purpose of hydraulic fracturing. In 2010, EPA stated on its website that "any service company that performs hydraulic fracturing using diesel fuel must receive prior authorization through the applicable UIC program." On May 4, 2012, EPA issued draft UIC permitting guidance for class II wells that use diesel fuels during hydraulic fracturing. EPA developed the draft guidance "to clarify how companies can comply" with the EPAct provision. The guidance is intended for EPA UIC permit writers, but EPA notes that "[t]o the extent that states may choose to follow some aspects of EPA guidance in implementing their own programs, it may also be relevant in areas where EPA is not the permitting authority." For more information, see http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/hydraulic-fracturing.cfm. For background on the EPA underground injection control program and its role in regulating hydraulic fracturing, see CRS Report R41760, *Hydraulic Fracturing and Safe Drinking Water Act Issues*, by (name redacted) and (name redacted).

[48] For information on Class II wells, see http://water.epa.gov/type/groundwater/uic/class2/.

[49] SDWA §1425 (42 U.S.C. §300h-4). To receive approval under §1425 optional demonstration provisions, a state program must include permitting, inspection, monitoring, and record-keeping and reporting requirements.

[50] For information on EPA's UIC program and its role in oil and gas production and hydraulic fracturing, see CRS Report R41760, *Hydraulic Fracturing and Safe Drinking Water Act Issues*, by (name redacted) and (name redacted).

Most groundwater protection and other environmental regulations governing oil and gas exploration and production are the responsibility of the states, and numerous states have been revising regulations to keep pace with changes in the energy production industry.[51]

To protect ground water during well development and operation, North Dakota oil and gas regulations require that all wells must be constructed with a minimum of two steel casings and two layers of cement extending from the surface of the ground to below the deepest potable aquifer. For wells in the Bakken formation, surface casing must extend 50 feet into the Pierre Shale which underlies the lowermost underground source of drinking water (the Fox Hills Aquifer).[52] After several well integrity failures had occurred, in 2008, state regulators began requiring pressure release valves and pressure testing during hydraulic fracturing operations.[53] State regulations also prohibit the storage of flowback water in unlined pits to prevent this wastewater from seeping into shallow aquifers.[54]

In January 2012, the North Dakota Department of Mineral Resources finalized changes to the state oil and gas rules, a number of which focus on protecting water resources. The revised rules prohibit the location of well sites and related facilities "in, or hazardously near, bodies of water"; require freshwater storage pits to be lined and surface drainage to be diverted away from sites; and expand well cementing requirements.[55] New requirements that specifically address hydraulic fracture stimulation include provisions governing well construction, pressure testing, and disclosure of the chemical composition of hydraulic fracturing fluid.[56]

In Montana, the state oil and gas rules contain various provisions aimed at preventing water contamination. Of general relevance to hydraulically fractured wells, the rules include detailed requirements for blowout prevention and well control equipment, including operator training requirements.[57] Among other water protection provisions, the state allows highly saline produced

[51] For a review of state regulations and recent developments, see the Interstate Oil & Gas Compact Commission hydraulic fracturing website, http://groundwork.iogcc.org/topics-index/hydraulic-fracturing/state-progress.

[52] The Pierre Shale is as much as 3,000 feet thick and is a major confining unit in eastern Montana and most of North Dakota. Shale oil is being developed far below this confining unit and other several additional formations. For a detailed discussion of groundwater underlying Montana and North Dakota, see *Ground Water Atlas of the United States: Montana, North Dakota, South Dakota, Wyoming,* US Geological Survey, http://pubs.usgs.gov/ha/ha730/ch_i/I-text.html.

[53] Lauren Donovan, "Killdeer Oil Spill Being Cleaned Up, Officials Investigate," *Bismarck Tribune*, September 2, 2010.

[54] The North Dakota Industrial Commission regulates the introduction of water and other substances into producing formations and the disposal of saltwater and oil field wastes (North Dakota Century Code, Control of Oil and Gas Resources, 38-08-04, Jurisdiction of Commission. September 2009.) The Commission has delegated regulation of the oil and gas drilling and production regulations to the Oil and Gas Division of the Department of Mineral Resources. Regulations are promulgated at Chapter 38-08 of the N.D. Century Code, https://www.dmr.nd.gov/oilgas.

[55] North Dakota Department of Mineral Resources, 2012 Rule Changes, General Rules and regulations, chapter 43-02-03, https://www.dmr.nd.gov/oilgas/. The revisions entered into effect April 1, 2012.

[56] Administrative Code Section 43-02-03-27.1, Hydraulic Fracture Stimulation, requires the well owner, operator, or service company to post fracturing fluid information on FracFocus, the industry and state-sponsored chemical-disclosure registry website (http://fracfocus.org).

[57] In Montana, development of shale oil is regulated by the Department of Natural Resources and Conservation, Board of Oil and Gas. Regulations are promulgated at Rule Chapter 36.22, Oil and Gas Conservation, http://www.mtrules.org/gateway/ChapterHome.asp?Chapter=36.22.

water to be stored temporarily in tanks or approved lined pits but, ultimately, the produced water must be disposed by injection into a Class II injection well and not disposed on the surface.[58]

In August 2011, the Montana Board of Oil and Gas adopted new regulations that specifically address hydraulic fracturing.[59] The new rules require, as a permit condition, detailed information on anticipated hydraulic fracturing operations, including volumes and names of chemicals to be used, expected maximum treating pressure, or written well construction specifications. After fracturing operations, operators are required to disclose more specific chemical information to state regulators and the public.[60]

Thus far in the Bakken region, underground injection is the primary disposal method for produced water and flowback. While underground injection generally is considered an environmentally sound wastewater management option, the use of disposal wells can be costly and leads to the permanent loss of water used in tight oil production. As noted, treatment and reuse of this water could reduce water acquisition, hauling, treatment and disposal costs for operators, and reduce demands on water supplies. Because of the cost and logistical challenges associated with acquisition of freshwater and treatment and disposal of wastewater, the oil and gas industry, private companies, and government agencies are pursuing research to improve technologies and practices to reduce water consumption in the oil patch.[61]

Issues for Congress

With gasoline prices in the $4 per gallon range, there have been many calls for increasing U.S. oil production. In the wake of the 2010 Deepwater Horizon oil spill, however, onshore oil production such as the Bakken play, and its constraints have grown in prominence. Increasing production from the Bakken and moving its oil to market has been an issue for previous Congresses.[62] The main focus of debate currently revolves around the possible construction of the Keystone XL pipeline from Alberta, Canada, to Steele City, Nebraska. Calgary-based TransCanada Corporation (a Canadian company) has proposed to construct an extension of the Keystone XL pipeline to the Bakken, which does not have enough pipeline capacity to move its oil to market and has to rely on rail. (See "Transportation Constraints Limit Oil Production.") The Presidential Permit for the Keystone XL project was denied on January 18, 2012; however, TransCanada resubmitted its application to the State Department on May 4, 2012, with a different configuration.[63]

---

[58] Montana Board of Oil and Gas Conservation, Title 36, Chapter 22 of the Administrative Rules of Montana, Rule 36.22.1226, Disposal of Water, http://www.mtrules.org/gateway/RuleNo.asp?RN=36%2E22%2E1226. The board may approve disposal of small amounts of produced water into pits if the operator can show that the water will not harm surface water, groundwater, or soil.

[59] Mont. Admin. R. 36.22.608. The new rule text is available at, http://bogc.dnrc.mt.gov/PDF/FinalFracRules.pdf.

[60] As with North Dakota, hydraulic fracturing information must be posted on the FracFocus website.

[61] Daniel J. Stepan, Richard E. Shockey, and Bethany A. Jurz, et al., *Bakken Water Opportunities Assessment—Phase I*, Review of Flowback Water-Recycling Technologies, p. 17.

[62] In 2008, a Senate subcommittee on Appropriations conducted a special hearing on energy supply and constraints in western North Dakota. The hearing (conducted in Bismarck, ND) focused on transportation bottlenecks that limit the takeaway capacity of pipelines and other transportation modes of moving crude oil to market. U.S. Congress, Senate Committee on Appropriations, Subcommittee on Energy and Water Development, *Energy Supply and Constraints in Western North Dakota*, 110th Cong., 2nd sess., September 2008, S. Hrg 110-869, GPO 2009.

[63] Facilities that cross the U.S. border require a Presidential Permit. Additionally, under Executive Order 13337, the Secretary of State is required to determine for liquid hydrocarbon pipeline projects whether such projects are in the (continued...)

Additionally, the Keystone XL pipeline would eventually connect to another new TransCanada pipeline, the Gulf Coast pipeline, and run to refineries on the Gulf Coast, which would help alleviate a pipeline bottleneck in oil transportation at Cushing, OK.

In addition to the above issues, development of the Bakken is facing the same environmental scrutiny as shale gas and other unconventional oil and gas resources, as they all use the controversial production technique of hydraulic fracturing. The rapid growth in the use of this technology for oil and gas production has raised public concerns, particularly over its possible impact on water resources. At issue is whether, or how, the federal government might increase its regulatory involvement in oil and gas production activities, specifically to protect the quality of ground water and drinking water sources. Various citizen and environmental groups have pressed for regulation of hydraulic fracturing under the federal Safe Drinking Water Act (SDWA) underground injection control (UIC) program.[64] In contrast, the legislatures of major oil and gas producing states, including North Dakota, have passed and sent to Congress resolutions asking Congress not to extend SDWA jurisdiction over hydraulic fracturing activities. Similarly, the Ground Water Protection Council (GWPC),[65] representing state agencies responsible for groundwater protection and implementation of the UIC program, has opposed including hydraulic fracturing under this EPA program.[66]

Congress has not authorized EPA to regulate hydraulic fracturing operations, except where diesel fuel is used.[67] In 2010, the 111th Congress directed EPA to study the potential impact that hydraulic fracturing may have on drinking water sources.[68] As part of this study, EPA has selected

(...continued)

national interest. As part of the permit review process, the Department of State determined that it should prepare an Environmental Impact Statement (EIS) under the National Environmental Policy Act. In August 2011, the Department of State issued the final EIS, which concluded that the proposed pipeline would have "no significant impact" and recommended that the project proceed. A 90-day review period began following the release of the EIS, during which the Department consulted with other agencies and took public comments. In November, 2011, the State Department announced that it would require further information on alternative pipeline routes before making a final determination as to whether the Keystone XL pipeline is in the national interest. For additional information on the Keystone project see CRS Report R41668, *Keystone XL Pipeline Project: Key Issues*, by (name redacted), (name redacted), and (name redacted).

64 As noted, the Energy Policy Act (EPAct) of 2005 (P.L. 109-58, §322), amended the SDWA to exempt from the definition of underground injection the injection of fluids or propping agents (other than diesel fuel) for hydraulic fracturing purposes. Currently, EPA is developing permitting guidance to assist states in regulating hydraulic fracturing where diesel fuel is used. For more information, see http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/wells_hydroout.cfm.

65 The GWPC has made recommendations to states to review and revise, as needed, oil and gas regulations aimed at water quality protection specifically to address hydraulic fracturing. (See http://www.gwpc.org/.) As discussed, several states, including Montana and North Dakota, have made recent revisions to their oil and gas rules.

66 Statement of Scott Kell, for the Ground Water Protection Council, House Committee on Natural Resources, Subcommittee on Energy and Mineral Resources, Oversight Hearing on "Unconventional Fuels, Part I: Shale Gas Potential," June 4, 2009.

67 EPA is developing standards for wastewater discharges produced by shale gas and coalbed methane extraction. The regulations are being developed under EPA's effluent guidelines program, which sets national regulations to control the discharge of pollutants from industry to surface waters and to municipal wastewater treatment plants. Effluent guidelines are specific to an industry and are established under the authority of CWA §304(m). For more information, see *Effluent Guidelines (Clean Water Act section 304(m)): 2010 Effluent Guidelines Program Plan*, http://water.epa.gov/lawsregs/lawsguidance/cwa/304m/. In April 2012, EPA issued regulations under the Clean Air Act that require control of air pollutants emitted from hydraulically fractured natural gas wells and related equipment. The rules do not address wells that are primarily oil wells. See http://www.epa.gov/airquality/oilandgas/actions.html.

68 P.L. 111-88, H.Rept. 111-316: "Hydraulic Fracturing Study.—The conferees urge the Agency to carry out a study on (continued...)

locations for five retrospective case studies to investigate incidents of drinking water contamination thought to be associated with hydraulic fracturing. One of these case studies involves the Bakken Shale near Killdeer, ND, where EPA will evaluate the failure of a production well during hydraulic fracturing and attempt to determine whether—and, if so, to what extent—water resources have been contaminated.[69] EPA expects to issue an initial report in 2012 and a final report to be available in 2014.

Legislation introduced in the 112th Congress would authorize EPA to regulate hydraulic fracturing—and thus, essentially all Bakken and other unconventional oil and gas production wells—under the Safe Drinking Water Act. Nearly identical bills, H.R. 1084 and S. 587, would amend the SDWA to revise the definition of underground injection to include explicitly hydraulic fracturing, and to create a new disclosure requirement for the chemicals used in hydraulic fracturing.[70] Currently, states broadly regulate oil and gas exploration and production on state and private lands (and often on federal lands within the state). In contrast, S. 2248 and H.R. 4322 would specify that a state has sole authority to regulate hydraulic fracturing on federal lands within state boundaries. This legislation was introduced as the BLM prepared to propose regulations addressing hydraulic fracturing activities on BLM-managed lands. Issued on May 4, 2012, the proposed rule includes requirements for disclosure of chemicals used in hydraulic fracturing on public lands, new well construction requirements, and a requirement that operators develop plans for managing fluids that flow back out of the well after hydraulic fracturing.[71]

Over the next decade or two, the oil industry's demand for and its impacts on local and regional freshwater supplies is an issue of concern for the industry's operations and for others dependent on the same water supplies. Current water withdrawal levels have contributed to stress on groundwater supplies and competition with existing water uses in the region. Access to a key surface water reservoir, Lake Sakakawea, would assist by relieving stress on groundwater supplies and providing a reliable water source for industry expansion. Lake Sakakawea is managed by the Army Corps of Engineers. As of May 2012, the Corps is processing oil industry applications for contracts to access to surplus water stored at the lake. Initially there is no fee associated with these surplus water contracts as the Corps completes a pricing policy rulemaking. This rulemaking will establish the process for determining future fees associated with surplus water contracts. While administering a fee would be consistent with the authority used as the basis for the surplus water contracts and Corps practices elsewhere, the Corps' potential fee for the storage of Missouri River water has frustrated North Dakota stakeholders that consider the Corps to be interfering with a state's right to allocate its water resources and being insensitive to the history of the development of the Missouri River reservoirs (e.g., flooding of a significant quantity of land in North Dakota and promised irrigation projects).

Production from the Bakken is likely to continue to expand rapidly and contribute to rising U.S. oil production. Industry interest in the formation has not waned despite the infrastructure and

---

(...continued)

the relationship between hydraulic fracturing and drinking water, using a credible approach that relies on the best available science, as well as independent sources of information.…"

[69] U.S. Environmental Protection Agency, *Case Study Locations for Hydraulic Fracturing Study*, June 2011, http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/case_studies.cfm.

[70] For a discussion of this proposal and state disclosure laws, see CRS Report R42461, *Hydraulic Fracturing: Chemical Disclosure Requirements*, by (name redacted) and (name redacted).

[71] The BLM proposed rule and related information is available at the BLM website, http://www.blm.gov/wo/st/en/info/newsroom/2012/may/NR_05_04_2012.html.

water constraints. Companies continue to actively drill in the formation and the number of rigs operating in the field has increased almost 30% since last year.[72] Recent state regulations that impose new requirements for well construction, chemical disclosure, and water protection do not appear to have slowed oil production. Concern remains that additional hydraulic fracturing regulations or new restrictions on natural gas flaring, particularly if this becomes a national issue, could decrease oil production, at least temporarily.

[72] LCM Commodities, "Baker Hughes Rig Count," April 27, 2012.

Appendix A. Conventional vs. Unconventional Reserves and Resources

In the past, the oil and natural gas industry considered resources locked in tight, impermeable shale uneconomical to produce. However, advances in directional well drilling and reservoir stimulation have dramatically have improved the viability of these operations.

Unconventional shales are fine grained, organic rich, sedimentary rocks. The shales are both the source of and the reservoir for oil and natural gas, unlike conventional petroleum reservoirs. The Society of Petroleum Engineers describes "unconventional resources" as petroleum accumulations that are pervasive throughout a large area and that are not significantly affected by hydrodynamic influences (they are also called "continuous-type deposits" or "tight oil"). In contrast, conventional oil and natural gas occur in porous sandstone and carbonate reservoirs. Under pressure exerted by water, the hydrocarbons migrated upward from its organic source until an impermeable cap-rock (such as shale) trapped it in the reservoir rock. Though the shales may be as porous as other sedimentary reservoir rocks, their extremely small pore sizes make them relatively impermeable to hydrocarbon flow, unless natural or artificial fractures occur.

In measuring quantities of oil and natural gas, the industry has defined the terms reserves and resources, which are sometimes used incorrectly in reporting.[73] For a hydrocarbon accumulation to be considered a reserve it must be able to be produced with current technology, at existing prices of the day, and be able to reach a market. There are different levels of probability associated with reserves, distinguishing between proved (highest probability), probable, and possible (lowest) reserves. Below reserves on the likelihood of how much oil and natural gas is in a deposit is resource. Resources are not subject to the constraints of today's technology, price or marketability, and therefore tend to be a larger number than reserves. Resources do not require that evaluation wells be drilled in estimating their size and may rely on geological data and other information.

The Securities and Exchange Commission (SEC) has modified their classification of reserves to include proved reserves, probable reserves, and possible reserves as defined above. By adding this more precise language to the degree of certainty associated with a particular volume of oil or natural gas, the SEC sought to add clarity for investors. Tight oil and natural gas are not viewed differently from other oil and natural gas formation by the SEC. The SEC does not distinguish reserves by the type of accumulation.

[73] For additional information on the distinction between reserves and resources, see CRS Report R40872, *U.S. Fossil Fuel Resources: Terminology, Reporting, and Summary*, by (name redacted), (name redacted), and (name redacted).

Appendix B. Drilling and Completion Techniques

Drilling Evolution

Well drilling has progressed from an art to a science. Originally, drillers used "cable-tool" rigs and a percussion bit. The drill operator would raise the bit and release it to pulverize the sediment. From time to time, the driller would stop and "muck out" the pulverized rock cuttings to advance the well. Though time-consuming, this method was simple and required minimal labor. Some drillers still use this method for water-wells and even some shallow gas-wells. The introduction of rotary-drill rigs at the beginning of the 20th century marked a big advance in drilling, particularly with the development of the "tri-cone rotary bit."[74] This method, as the name implies, uses a weighted rotating bit to penetrate the sediment.

The key to a rotary drill's speed is the relative ease of adding new sections of drill pipe (or drill string) while the drill-bit continues turning. Circulating fluids (drilling mud) down through the center of the hollow drill pipe and up through the well bore lifts the drill cuttings to the surface. Modern drill bits studded with industrial diamonds gives them an abrasive property to grind through any rock type. However, from time to time the drill string must be removed (a process termed "tripping") to replace the dulled drill bit.

To function properly, drilling fluids must lubricate the drill bit, keep the well bore from collapsing, and remove cuttings. The weight of the mud column prevents a "blow-out" from occurring when encountering high-pressure reservoir fluids. Drillers base the mud's composition on natural bentonite clay, a "thixotropic" material that is solid when still and fluid when disturbed. This essential rheological property of the drilling fluid keeps the drill cuttings suspended in the mud. The mud's chemistry and density must be carefully monitored and adjusted as the drilling deepens (for example, adding a barium compound increases mud density). "Mud pits," excavated adjacent to the drill rig provide a reservoir for mixing and holding the mud. The mud pits also serve as settling ponds for the cuttings. At the completion of drilling, the mud may be recycled at another drilling operation, but the cuttings will be disposed of in the pit. Several environmental concerns over drilling stem from the (hazardous) composition of the drilling mud and cuttings, and the potential for mud pits overflowing and contaminating surface water.

The most recent advance in drilling is the ability to direct the drill bit beyond the region immediately beneath the drill rig. Early directional drilling involved placing a steel wedge down-hole (whipstock) that deflected the drill toward the desired target, but lacked control and consumed time. Advances such as steerable down-hole drill motors that operated on the hydraulic pressure of the circulating drilling mud offered improved directional control. However to change drilling direction the operator had to halt drill string rotation in such a position that a bend in the motor pointed in the direction of the new trajectory (referred to as the sliding mode). Newer rotary steerable systems introduced in the 1990s eliminated the need to slide a steerable down-hole motor.[75] The newer tools drill directionally while continuously being rotated from the

[74] Howard Hughes, Jr. of the Hughes Tool Company developed the modern tri-cone rotary bit. His father, Howard Robert Hughes, Sr. had invented the bit's ancestor, a two-cone rotary bit.

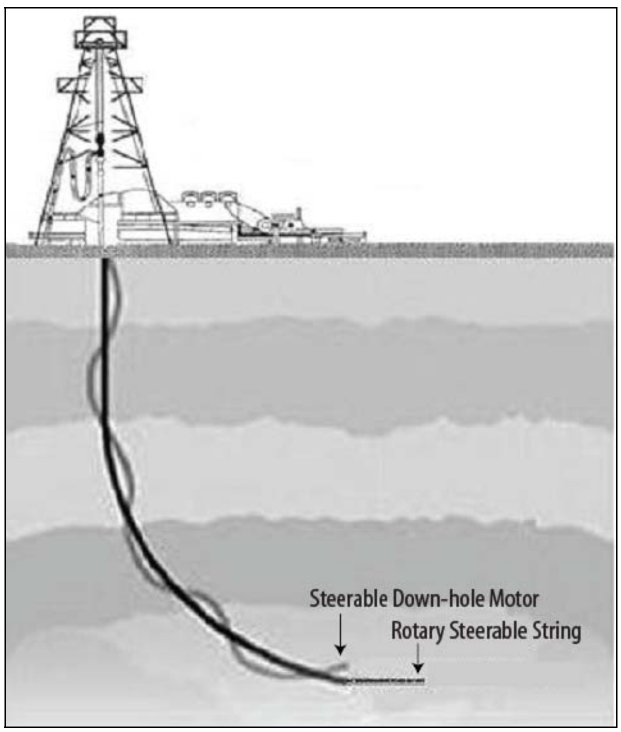
[75] Schlumberger, *Better Turns for Rotary Steerable Drilling: Overview,* http://www.slb.com/content/services/resources/oilfieldreview/ori002/01.asp?.

surface by the drilling rig. This enables a much more complex, and thus accurate, drilling trajectory. Continuous rotation also leads to faster drilling rates (penetration) and fewer incidents of the drill-string sticking. (See **Figure B-1**.)

Directional drilling offers another significant advantage in developing shales. In the case of thin or inclined shale formations, a long horizontal well increases the length of the well bore in the hydrocarbon-bearing formation and therefore increases the surface area for flow into the well. However, the increased well surface (length) is often insufficient without some means of artificially stimulating flow. In some sandstone and carbonate formations, injecting dilute acid dissolves the natural cement that binds sand grains thus increasing permeability. In tight formations like shale, inducing fractures can increase flow by orders of magnitude. However, before stimulation or for that matter production can take place, the well must be completed and cased.

Figure B-1. Directional Drilling

Steerable Down-Hole Motor vs. Rotary Steerable System



Source: Schlumberger, modified by CRS.

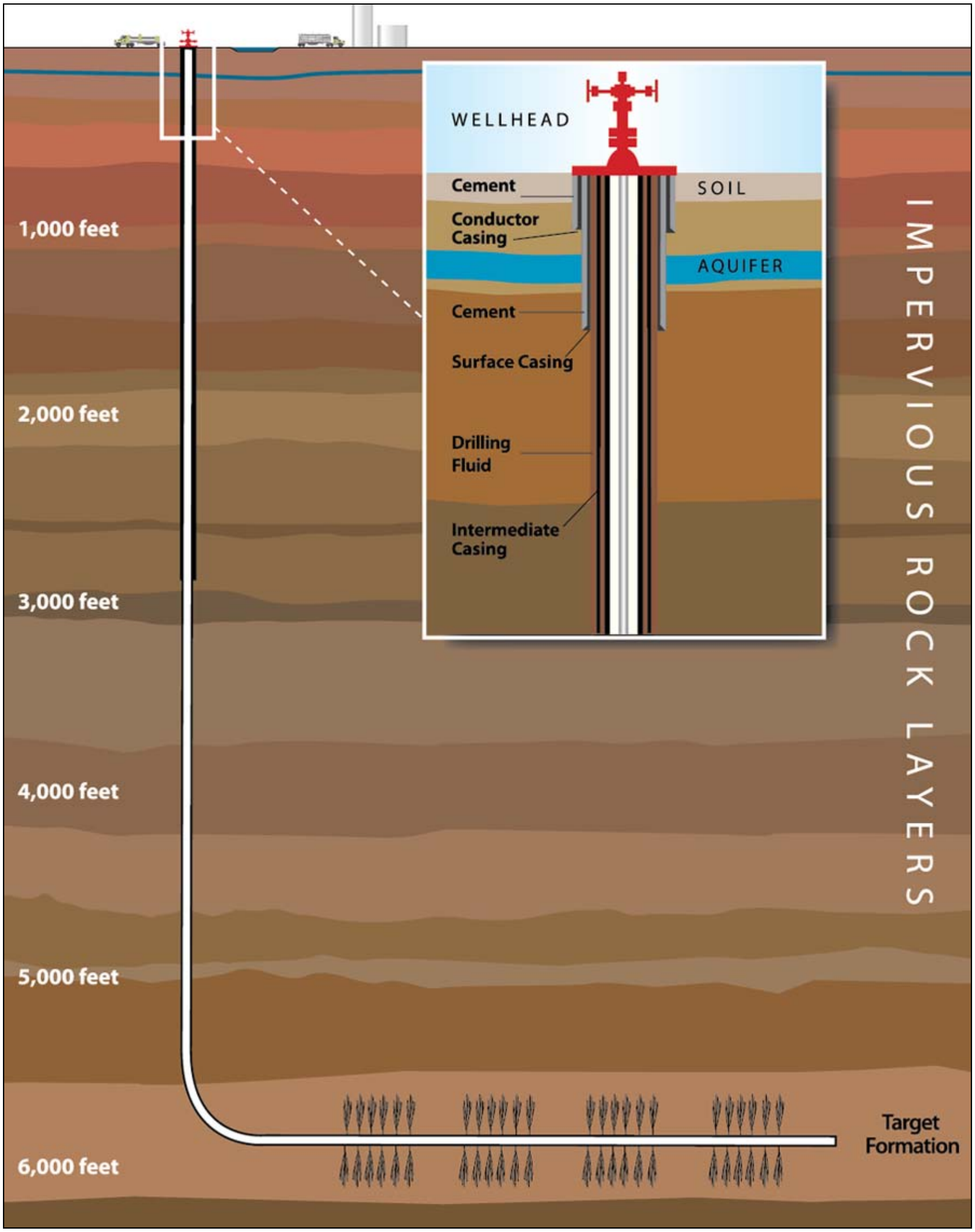
Well Construction and Casing

Commercial natural gas and oil, and municipal water-supply wells have in common a series of telescoping steel well casings that prevent well-bore collapse and water infiltration while drilling. The casing also conducts the produced reservoir fluids to the surface. A properly designed and cemented casing also prevents reservoir fluids (natural gas or oil) from infiltrating the overlying groundwater aquifers.

During the first phase of drilling, termed "spudding-in," shallow casing installed underneath the drilling platform serves to reinforce the ground surface. Drilling continues to the bottom of the water table (or the potable aquifer), at which point the drill string is "tripped" out (removed) in order to lower a second casing string, which is cemented-in and plugged at the bottom. Drillers use special oil-well cement that expands when it sets to fill the void between the casing and the wellbore.

Surface casing and casing to the bottom of the water table prevents water from flooding the well while also protecting the groundwater from contamination by drilling fluids and reservoir fluids. (The initial drilling stages may use compressed air in place of drilling fluids to avoid contaminating the potable aquifer.) Drilling and casing then continue to the "pay zone"—the formation that produces natural gas or oil. The number and length of the casings, however, depends on the depth and the properties of the geologic strata.

Figure B-2. Typical Well Casing



Source: American Petroleum Institute, http://www.api.org/policy/exploration/hydraulicfracturing/upload/HYDRAULIC_FRACT_ILLUSTRATION_121609.pdf.

Notes: Graphic is not necessarily a shale well.

After completing the well to the target depth and cementing-in the final casing, the drilling operator may hire an oil-well service company to run a "cement evaluation log." An electric probe lowered into the well, measures the cement thickness. The cement evaluation log provides the critical confirmation that the cement will function as designed—preventing well fluids from bypassing outside the casing and infiltrating overlying formations.

Absent any cement voids, the well is ready for completion. A perforating tool that uses explosive shape charges punctures the casing sidewall at the pay zone. The well may then start producing under its natural reservoir pressure or, as in the case of shales, may need stimulation treatment.

Hydraulic Fracturing

Despite their rich hydrocarbon content, most shales do not produce oil and natural gas freely. Economic production depends on some means of artificially stimulating the shale to release the oil or natural gas from its rock matrix. In the late 1940s, Oklahoma and Texas oil producers increased their well production by pumping fluids down their wells under pressures high enough to fracture (frac) the surrounding rock formation. (The practice started by attempting to use dynamite to fracture and open up the formation around well bore.) A frac job is the largest and most complex phase of drilling and well completion. The oilfield service company contracted for the work may take several weeks to stage the job, and a convoy of trucks to deliver the equipment and materials needed (tanks to hold water and mix chemicals, special tanker trailers that ship proppant, compressors, and pipe manifold to connect everything together). A single well may need multiple frac treatments to produce the target formation. A series of inflatable packers or sliding sleeves isolates each frac zone along the well, and the treatment begins from the farthest section out. The actual frac treatment takes only a day to complete.

Wells in the Bakken Formation may be spaced on intervals of 640 to 1,280 square acres (1 to 2 square miles) and completed by drilling 5,000 to 10,000 foot laterally in the formation. A lateral section may accommodate 20 fracture treatments.

Fracturing Fluids

Fracturing fluid functions in two ways: opening the fracture and transporting the "propping" agent (or proppant) the length of the fracture.[76] (See **Table B-1**.) As the term propping implies, the agent functions to prop or hold the fracture open. The fluid must have the proper viscosity and low friction pressure when pumped, it must breakdown and cleanup rapidly when treatment is over, and it must provide good fluid-loss control (not dissipate). The fluid chemistry may be water-based, oil-based or acid-based depending on the properties of the formation. Water-based fluids (sometimes referred to as slickwater) are the most widely used (especially in shale formations) because of their low cost, high performance, and ease of handling. Some fluids may also include nitrogen and carbon dioxide to help foaming. Oil-based fluids find use in hydrocarbon bearing formations susceptible to water damage, but are they expensive and difficult to use. Acid-based fluids use hydrochloric acid to dissolve the mineral matrix of carbonate formations (limestone and dolomite) and thus improve porosity; the reaction produces inert calcium chloride salt and carbon dioxide gas.

[76] "Chapter 7 - Fracturing Fluid Chemistry and Proppants," in *Reservoir Stimulation*, ed. Michael J. Economides and Kenneth G. Nolte, 3rd ed. (John Wiley & Sons, LTD, 2000).

Table B-1. Example of Hydraulic Fracturing Fluid Components

Compound	Concentration	Purpose	Common Application
Water	80.5%	Move the other materials.	Drinking.
Proppant	19.0%	Keeps fractures open to allow oil and natural gas to escape.	Drinking water filtration and play ground sand.
Acids	0.12%	Help dissolve minerals and initiate fractures in rock (pre-fracture).	Swimming pool cleaner
Petroleum Distillates	0.088%	Dissolve polymers and minimize friction.	Make-up remover, laxatives, or candy.
Isopropanol	0.081%	Increase the viscosity of the fracture fluid.	Glass cleaner, antiperspirant, or hair dye.
Potassium Chloride	0.06%	Creates a brine carrier fluid.	Low-sodium table salt substitute.
Guar Gum	0.056%	Thickens water to suspend the sand (proppant).	Cosmetics, baked goods, ice cream, toothpaste, sauces, or salad dressing.
Ethylene Glycol	0.043%	Prevents scale deposits in the pipe.	Automotive antifreeze, household cleansers, deicing, or caulk.
Sodium or Potassium Carbonate	0.011%	Improves the effectiveness of other components, such as cross-linkers.	Washing soda, detergents, soap, water softeners, or glass and ceramics.
Sodium Chloride	0.01%	Delays breakdown of the gel polymer chains.	Table salt.
Polyacrylamide	0.009%	Minimizes friction between the fluid and the pipe.	Water treatment or soil conditioner.
Ammonium Bisulfite	0.008%	Removes oxygen from the water to protect the pipe from corrosion.	Cosmetics, food and beverage processing, or water treatment.
Borate Salts	0.007%	Maintains fluid viscosity as temperature increases.	Laundry detergents, hand soaps, or cosmetics.
Citric Acid	0.004%	Prevents precipitation of metal oxides.	Food or beverage additive or lemon juice.
N, n-Dimethyl Formamide	0.002%	Prevents corrosion of the pipe.	Pharmaceuticals, acrylic fibers or plastics.
Glutaraldehyde	0.001%	Eliminates bacteria in the water.	Disinfectant or sterilizer for medical and dental equipment.

Source: Lynn Helms, North Dakota Department of Mineral Resources, Larry Dokken-Frear Consulting, and Tyler Dokken – Hess Corporation, *Bakken Basics – Drilling, Fracing, Producing (How it Works).*

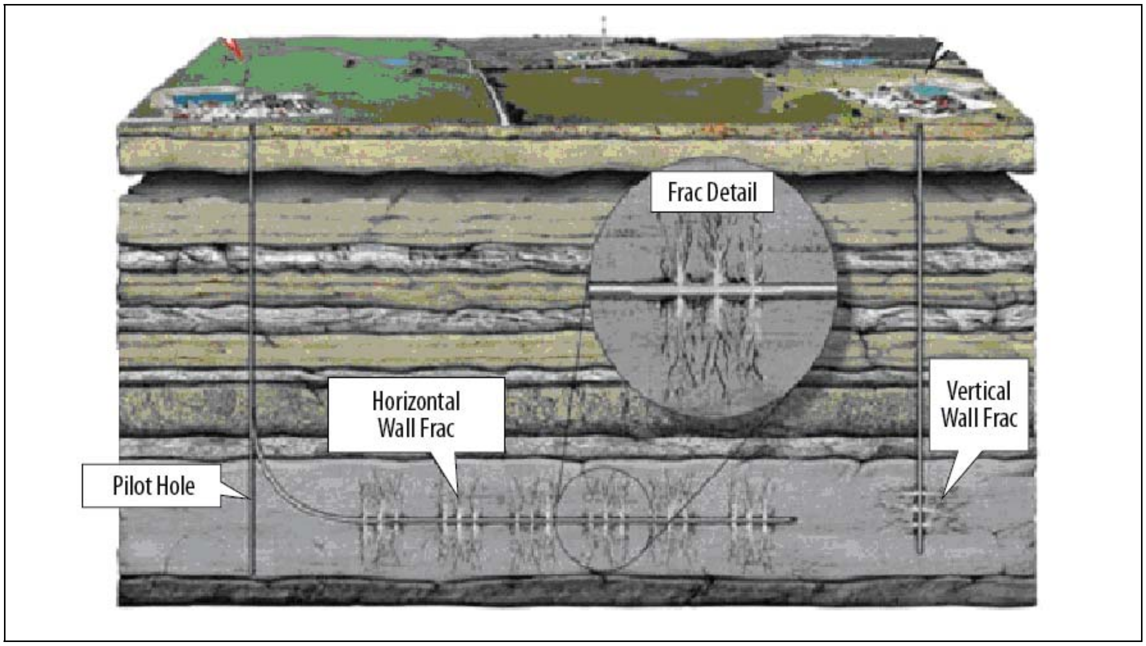
Notes: The components of hydraulic fracturing vary somewhat from each frac job.

Water-based fluids consist of roughly 99% water, with the remainder made up of additives. The initial fracturing stage may use hydrochloric acid (HCl) to cleanup the wellbore damage done during drilling and cementing. Gelling agents, based on water-soluble polymers such as vegetable-derived guar gum, adjust frac fluid viscosity. The most widely used additives for breaking down fluid viscosity after fracturing are oxidizers such as ammonium (NH^{+4}), potassium, and sodium salt of peroxydisulfate ($S_2O_8^{-2}$); enzyme breakers may be based on hemicellulase (actually a mixture of enzymes which can hydrolyze the indigestible components of plant fibers). Silica flour serves as good fluid-loss additive. Biocides added to polymer-containing fluids prevent bacterial degradation (as the polysaccharides (sugar polymer) used to thicken water are an excellent food source for bacteria). Methanol (an alcohol) and sodium thiosulfate ($Na_2S_2O_3$) are commonly used stabilizers added to prevent polysaccharide gels degrading above temperatures of 200°F.

It is important to note that the service companies adjust the proportion of frac fluid additives to the unique conditions of each well. The Occupational Safety and Health Administration (OSHA) requires that material safety data sheets (MSDS) accompany each chemical used on the drill site, but the proportion of each chemical additive may be kept proprietary.[77]

Proppants hold the fracture walls apart to create conductive paths for the oil or natural gas to reach the wellbore. Silica sands are the most commonly used proppants. Resin coating the sand grains improves their strength.

Figure B-3. Hydraulic Fracturing Example



Source: American Association of Petroleum Geologists blog, http://blog.aapg.org/learn/?p=540

Hydraulic Fracture Process

Fracture treatments are carefully controlled and monitored operations that proceed in stages. Before beginning a treatment, the service company will typically perform a series of tests on the well to determine if it is competent to hold up to the hydraulic pressures generated by the fracture pumps.

77 29 C.F.R. §§1910 Subpart Z, Toxic and hazardous substances.

In the initial stage, an HCl solution pumped down the well cleans up residue left from cementing the well casing. Each successive stage pumps discrete volumes of fluid (slickwater) and proppant down the well to open and propagate the fracture further into the formation. The treatment may last upwards of an hour or more, with the final stage designed to flush the well. Some wells may receive several or more treatments to produce multiple fractures at different depths, or further out into the formation in the case of horizontal wells.

A single fracture treatment may consume more than 500,000 gallons of water.[78] Wells subject to multiple treatments consume several million gallons of water. An Olympic-size swimming pool (164 ft x 82 ft x 6 ft deep) holds over 660,000 gallons of water, for comparison, and the average U.S. daily per capita consumption of freshwater (roughly 1,430 gallons per day) is 522,000 gallons over one year.[79]

The high injection pressure not only opens and propagates the fracture but also drives fluid into the shale's pore spaces. A high volume of fluid also remains in the fracture that will impede hydrocarbon flow to the well if not pumped out. The subsequent "flowback" treatment attempts to recover as much of the remaining fluid as possible without removing the proppants. The "flowback" water pumped out of the well may be high in dissolved salts and frac chemicals, however, making it unsuitable for beneficial use, and requiring treatment for disposal. After the well begins producing, it may also produce more flowback water. Flowback disposal presents environmental issues.

The fracture is ideally represented by a vertical plane that intersects the well casing. It does not propagate in a random direction, but opens perpendicular to the direction of least stress underground (which is nearly horizontal in orientation).

Author Contact Information

(name redacted)
Specialist in Energy Policy
[redacted]@crs.loc.gov, 7-....

(name redacted)
Specialist in Energy and Defense Policy
[redacted]@crs.loc.gov, 7-....

(name redacted)
Specialist in Natural Resources Policy
[redacted]@crs.loc.gov, 7-....

(name redacted)
Specialist in Environmental Policy
[redacted]@crs.loc.gov, 7-....

Acknowledgments

(name redacted) with CRS's Knowledge Services Group contributed greatly to the research for this report.

78 Modern Shale Gas Development in the United States: A Primer, pp. 58-59.

79 U.S. Geological Survey, *Summary of water use in the United States, 2000*, http://ga.water.usgs.gov/edu/wateruse2000.html.