Gas-Oil-Water Production and Water-Gas Injection Forecasts in Williston Basin

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Abstract
Production and injection forecasts are of significance in terms of constructing infrastructure to accommodate the booming of unconventional oil and gas development and production in Williston Basin in North American (United States part). Underestimate or overestimate of future production will lead to an inappropriate plan of infrastructure development in this geographic area. Insufficient infrastructure will slow down the growth of hydrocarbon development and affect the revenue from fossil energy and the United States’ (U.S.) energy security. Oversized infrastructure will result in waste of investment and leaving large footprint that impacts the environment significantly. Conventionally, production forecast is conducted at well or field level. A thoroughly literature review indicates that no study is available to predict the production of unconventional resource at basin level. To fill this gap, we propose a procedure to forecast the total production of a basin. Our study provides a guideline for forecasting production in a basin with similar geological settings.

Keywords
Bakken Oil; Production Forecast; Unconventional Oil and Gas

Introduction
Recent oil and gas-related growth in Williston Basin, North America (United States part), is affecting the ability to plan for future infrastructure development in North Dakota, Montana and South Dakota. Production and injection forecasts are important in terms of constructing infrastructure to accommodate the boom of unconventional oil and gas development and production. Underestimate or overestimate of future production will lead to inappropriate plan of infrastructure development in this geographic area. Insufficient infrastructure will slow down the growth of hydrocarbon development and affect the revenue from fossil energy and U.S. energy security. Oversized infrastructure will result in waste of investment and leaving large footprint that impacts the environment significantly.

Conventionally, production forecast is conducted at well or field level. Many studies have been focused on the production forecast. Arps (1945) proposed four types of declines: exponential, hyperbolic, harmonic, and ratio decline. Arps (1956) also estimated the primary oil reserves using decline curves and reservoir drive mechanism. Lefkovits et al. (1958) derived the exponential decline form for gravity drainage reservoirs by neglecting capillary pressure. Fetkovich (1971 and 1980) constructed type curves combining the transient rate and the pseudo-steady-state decline curves, and derived single-phase flow from material balance and Darcy law. Da Prat et al. (1981) derived single-phase oil flow for two-porosity reservoir in closed boundary systems. Doublet et al. (1994) developed the theoretical basis for combining transient and boundary dominated production behavior for the pressure transient solution to the diffusivity equation. Ling et al. (2012) proposed an economical model to optimize horizontal well producing a box-shape oil reservoir with close-boundary. His study showed exponential decline for oil flow at constant bottomhole pressure. Other investigator conducted research on production forecast. Ehlig-Economides and Ramey (1981), Chen and Poston (1989), Duong (1989), Palacio and Blasingame (1993), Rodriguez and Cinco-Ley (1993), Callard (1995), Agarwal et al. (1999) had published
papers on methods to forecast production. Ling and He (2012) indicated that Arp's empirical production declines had theoretical base. Ling et al. (2013) presented tactics and pointed out pitfalls in production forecast. A thoroughly literature review indicates that no study is available to predict the production of unconventional resource at basin level. To fill this gap, we propose a procedure to forecast the total production of a basin with similar geological setting.

**Geological Setting and Production History of Williston Basin**

The Williston Basin is a roughly oval-shaped, subsurface sedimentary basin with the deepest point near Williston, ND. The Williston Basin, an intracratonic basin, is a major structural feature of central North America that covers surface areas between 120,000 and 240,000 square miles (Landes, 1970). The basin reaches approximately 475 miles north-south from southern Saskatchewan to northern South Dakota and 300 miles east-west to western North Dakota and eastern Montana. It underlies most of North Dakota, western Montana, northwestern South Dakota, southeastern Saskatchewan and a small section of southwestern Manitoba (Fig. 1). The Williston Basin began to subside during the Ordovician Period, around 495 million years ago and underwent episodic subsidence throughout the rest of the Phanerozoic Eon. The Phanerozoic Eon extended from approximately 600 million years ago to the present. Although the Williston Basin was subsiding, marine sediments were not deposited in it continuously. The basin contains a complete rock record compared with many basins (Heck et al., 2002). All sedimentary systems from Cambrian through Quaternary are presented in the basin (Fig. 2), with a rock column more than 15,000 ft thick in the deepest section. This nearly continuous deposition of sediments shown in the geologic record makes the Williston Basin one of only a handful of basins worldwide with that distinction.

Several companies explored for oil starting in 1917, and although several wells hit shallow gas, it was not until 1951 that Amerada’s Clarence Iverson No. 1 well struck commercial quantities of oil south of Tioga, ND at a depth greater than 11,000 feet below the surface. This discovery led to a boom in leasing and drilling activities in the Williston Basin, especially along the prolific Nesson Anticline. The discovery well was completed in the Silurian Interlake Formation but subsequent development on the anticline focused on the Mississippian Madison Group. The basin became a major oil province in the 1950s. From 1953 to 1987, vertical wells were drilled to recover the crude oil from Bakken Formation. Successful wells were those that encountered natural fractures which displayed high production at the beginning and soon dropped rapidly to a steady, low level production rate. It has been experiencing a steady and substantial increase in oil production since 2004, when the application of horizontal drilling technologies and stage fracturing facilitated the ability to extract oil from previously unviable deposits, the Bakken shales.

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**FIG. 1. WILLISTON BASIN AND ITS MAJOR STRUCTURES (HECK ET AL., 2002).**

**FIG. 2. GENERALIZED STRATIGRAPHIC COLUMN FOR WILLISTON BASIN (HECK ET AL., 2002).**
Methodology

Recovery of hydrocarbons from an oil reservoir commonly occurs in three recovery stages, which are primary recovery, secondary recovery, and tertiary recovery or enhanced oil recovery (EOR). Primary recovery occurs in the first stage of a reservoir producing life. At this stage, pressure from the reservoir forces the hydrocarbons from the pores to the formation, moves them to the well, and up to the surface using the natural energy of the reservoir as a drive. The three principal primary recovery drive mechanisms are water drive, gas drives, and gravity drainage. In Williston Basin, all three drive mechanisms and their combinations are of importance. Secondary recovery is the second stage of hydrocarbon production during which an external fluid such as water or gas is injected into the reservoir that has fluid communication with production wells. The injection maintains reservoir pressure and displaces hydrocarbons toward the wellbore. The secondary recovery stage reaches its limit when the injected fluid is produced in considerable amounts from the production wells and the production is no longer economical. The successive use of primary recovery and secondary recovery in an oil reservoir produces about 15% to 40% of the original oil in place. Waterflooding and high-pressure air injection have been implemented in Williston Basin. The primary recovery and secondary recovery account for about 80% of total oil production in Williston Basin. The third stage is tertiary recovery or enhanced oil recovery. It covers gas injection, chemical injection, microbial injection, and thermal recovery. In Williston Basin, CO2-EOR projects have been successful in recovering huge volume of oil. Tertiary recovery accounts for about 20% of total oil production in the Basin. Oil production from a single well can be the combined result of the two or three recovery methods.

Construction of Typical Well Production Profiles

To forecast the total production of a basin, it is necessary to construct typical well production profile. Economically, a well’s life ends when revenue from production cannot cover cost. A well’s life can end due to mechanical problems, low reservoir potential, wellbore collapse, producer converted to injector, excessive water production, excessive gas production, or simply an expiration of the lease. In the study of well life, we reviewed geological and petroleum engineering data in the Williston Basin, and identified the reservoir model by integrating geological and engineering interpretations. It was determined that well lifecycles in North Dakota, Montana, and South Dakota were different. Wells in North Dakota and Montana have longer well lifecycle, 25-years, than that of wells in South Dakota, which has a 15-year lifecycle.

The estimated ultimate recovery is critical for a well. A well lifecycle alone is not enough to define the total production of a well, the annual production rate accounts for the remainder. The production rate is controlled by reservoir pressure, size of reservoir, drive mechanism, rock and fluid properties, heterogeneity of reservoir, well spacing, well geometry, recovery method and reservoir energy measurement. Oil and gas production rates decline as a function of time. Loss of reservoir pressure or the changing relative volume of produced fluids is usually the cause. For shale oil and gas, production decline has the characteristics of fast decline rate in the early stages and low decline rate in the late stages.

History matching is the fundamental of production forecast. Statistical analysis and fitting a curve through performance history and assuming this same line trends similarly into the future forms the basis for the decline curve analysis concept. Historical production and injection data was analyzed to identify effects and construct three different typical well production profiles through their expected life for the three regions with a non-linear regression method. Fig. 3 shows the production profiles of typical wells in North Dakota, Montana, and South Dakota. All three declines in production follow hyperbolic decline indicating the typical reservoir performance of shale oil.

Determinations of Drilling Rig Efficiency

Advancements in technology and management optimization will increase rig efficiency, or reduce rig time for each well drilled assuming same well-geometry and reservoir properties. Total rig time, from drilling to completion, includes rig mobilization, rig-up, drilling, completion, demobilization, maintenance, and nonproductive time due to downhole problems. Well stimulation, such as fracking, is performed by a fracking rig and is not counted toward rig time. This study assumes that the average number of wells to be drilled in a single pad in the previous five years will increase as drilling multi-well pads increases. Operators have implemented a batch drilling campaign reducing moving and rig-up times in Williston Basin, however; no significant improvement in moving rigs between
wellheads in the same pad and to different pads is expected. Due to limitations such as winter weather, road weight or clearance restriction, and moving vehicle capacity, the rig-up and demobilization times cannot be substantially reduced; therefore, the percentage reduction in moving and rig-up times is expected to be less than 10 percent over the next 20 years.

Substantial technological advancements and increases in management optimization are necessary for escalating the rate of penetration, or a reduction of the completion time or non-productive time per well and are expected to follow recent historical trends. Assuming similar well geometry and reservoir properties exist throughout the region, without advancements in technology and management optimization, productive time will not substantially increase. The unconventional nature of the Bakken Formation creates a longer learning curve than a conventional reservoir, and the high uncertainty in the reservoir’s properties is an obstacle to increase drilling times.

The lateral lengths of existing horizontal wells are shown in Fig. 4 below. Lateral lengths are expected to continue to increase to retain an oil rate that economically justifies the initial costs, and some of the existing rigs in the Williston Basin will eventually need upgrading before drilling the longer lateral length wells. The rig efficiencies from 1998 to 2011 are shown in Fig. 5. The decline in wells drilled per rig, per year during 2005 to 2011 in comparison with the data from 1998 to 2004 is the result of an increase in the overall percentage of horizontal wells. The average rig efficiency during the 2005 to 2011 period was 8.8 wells drilled per rig, per year. An analysis of the aforementioned factors and information gained from stakeholder interviews resulted in a reasonable forecast of an increase from 10 wells per rig per year in 2012 to 12 wells per rig per year in 2032.

**Forecast of Drilling Activity**

Annual production volume relies on the number of existing producer and the well to be drilled. projections of future drilling activity primarily depend upon review of historical drilling activities and assessments of current and near-term drilling climate. Typical drilling plans are controlled by several factors such as the size of reservoir, utility of wellbore, well pattern, well spacing, reservoir flow capacity, recovery method, well life, production plan, drill site preparation, well numbers per drill site, well construction time, drilling rigs availability, labor, and service, drilling and completion cost and oil price. Since most wells in the Williston Base require stimulation, the availability of fracturing equipment and fracturing materials will constrain the drilling plan. Historical drilling activity helps to clarify how the aforementioned factors can affect the drilling activity.

Historical drilling activities are the best indicators of how the above factors affect analysis of drilling plans. In a typical wellbore scenario, well spacing and the well pattern of most reservoirs in the Williston Basin follow development of unconventional shale oilfields in other geographic regions. Reservoir flow capacity after stimulation, drive mechanism, well life, drilling
FIG. 4. PERCENT DISTRIBUTION OF DIFFERENT LATERAL LENGTHS OF EXISTING HORIZONTAL WELLS

FIG. 5. DRILLING RIG EFFICIENCIES DURING 1998-2011

FIG. 6. TOTAL RIG COUNT IN WILLISTON BASIN (UNITED STATES PART)
and completion cost and environmental relief cost are also key factors in the design of drilling plans. The total number of wells to be drilled was phased out according to production plan, the preparation of drill site, well number per drill site, well construction time, and the availability of rigs, labor and service. Effects of a reduction in well construction cost and well complexity on drilling activity were examined. It was found that the reduction of cost was a tradeoff of any increase in well complexity to maintain an economical oil rate. The majority of wells in the Williston Basin require stimulation, therefore the availability of fracturing equipment, fracturing materials and fracking crews acts as a constraint to developers drilling plans.

However, we should notice that the high uncertainty in future drilling activity in Williston Basin is due to two facts: volatile oil prices and the geological nature of the Bakken Formation. A higher than average oil price is a main driver to produce Bakken oil. The high heterogeneity of Bakken shale leads to two-year drilling plans instead of five-year plans, as is common in conventional oil and gas reservoirs. Operator plans for drilling activities beyond one to two years are highly uncertain and rely on the results of new wells in the next two years. Oil prices lower than the economic threshold will reduce or scale back many drilling plans in the Williston Basin, therefore, it is necessary to forecast low, consensus and high scenarios for drilling activity to account for oil price uncertainty and heterogeneity of Bakken shale. Drilling forecasts were estimated for the Williston Basin after studying historical drilling activity, evaluating drilling efficiency, examining the availability of rigs, and reviewing the drilling plans as shown in Fig. 6.

**Existing and Undrilled Well Production Forecast**

Given the uncertain future of petroleum development in Williston Basin, production forecast scenarios corresponding to three drilling activity scenarios are developed. These probable futures will be largely based on the rate and extent of development of the Bakken/Three Forks shale formation. They will model a robust expansion of the current Bakken/Three Forks shale play, an expected or consensus viewpoint of oilfield development and less than expected expansion of each scenario over a 20-year period.

With the typical well production profiles and future drilling activity, we forecast three production scenarios that are corresponding to the three drilling activity scenarios. Following assumptions are applied in the production forecast:

1) In case of no drilling plans provided by operator, well number/rig/year in the future will be the same as the averaged well number/rig/year in last five years.

2) There is no enough time and manpower to interview all operators in the Basin. The drilling plan from the interview of operators who contracted 80% of rig in the Basin will be extrapolated to get the total drilling activity plan.

3) The time to prepare well site, drill and complete a typical well or wells in a well site will be the same as that of last five years if no such data is available from the operator.

4) The energy required for drilling and completion for each wellsite will be the same as that of last five years.

5) The successful rates of the oil and gas producer are the same as that of last five years.

6) There are enough fracturing crews to simulate the new wells if no detail plans are provided by operator.

7) New EOR projects are forecasted only if operators have solid plans.

8) Production profiles of typical well are valid for existing and new wells.

9) Gas-oil ratio, water-oil ratio, and well-life of new well are the same as those of existing wells.

10) Performances of new injectors are the same as those of the existing wells.

11) Water injection follows the historical trend if no data is available from operators.

12) Gas injection trends become flat if no data is available from operators.

13) The energy required producing unit oil, water, or gas keeps constant.

14) The energy required injecting unit water and gas keeps constant.

The forecasts of oil, gas, and water from existing wells follow the steps below:

1) Identify reservoir fluids (gas, oil, gas with oil leg, or oil with gas cap), reservoir properties (low, moderate, or high porosity and permeability), drive mechanism in each region

2) List different regions that are corresponding to
different production profiles in Williston Basin.

3) Existing wells consist of dry holes, producers, water resource wells, gas or water injectors, water disposal wells, monitor/observation wells, and stratigraphic test wells. The percentage of producer is used as the successful rate for future wells production forecast. The study indicates that successful rates are different in three regions.

4) Existing active wells are forecasted using typical well production profile.

5) Gas-oil and water-oil ratio trends in three regions: North Dakota, Montana, and South Dakota, are predicted. The gas and water rates are back-calculated using oil rate and gas-oil and water-oil ratios.

6) For the same location with different formations, a synthesized single rate will be used since wells producing single layer can be recompleted to produce multilayer thus all wells can produce layers they penetrated.

7) The typical well production profiles are applied to both primary and EOR wells.

8) We extrapolate the forecast to the three regions: North Dakota, Montana, and South Dakota, basing on typical production profile, existing well history, and total number of active wells.

9) Gas and water injection profiles follow the historical trend.

10) Sum of North Dakota, Montana, and South Dakota productions gives the total production of existing wells in Williston Basin.

The forecasts of oil, gas, and water from undrilled wells follow similar steps as existing wells. Typical well production profiles are applied to undrilled wells:

1) Classify undrilled wells basing on locations.

2) Start-ups of the undrilled wells are two months after the completion. Initial oil rate and production decline rate follow the typical well production profile derived from existing wells in the same region, historical succeed rates are multiplied to total new well number to get real producer number.

3) The production start-up date is not available in the plan, the typical time to prepare well site, drill and complete a well or wells in a well site in Williston basin will be used to estimate the start-up date.

4) Existing wells’ gas-oil and water oil ratio trends are applied to undrilled wells.

5) The undrilled well production forecasts in different regions: North Dakota, Montana, and South Dakota, are calculated.

6) Sum of North Dakota, Montana, and South Dakota productions gives the total production of undrilled wells in Williston Basin.

The total production in Williston Basin is the sum of productions of existing and undrilled wells.

Production Forecast Results

The grand total production forecasts for gas, oil, and water in Williston Basin is the sum of the productions of existing and undrilled wells. Figs. 7, 8, and 9 show the total production forecasts for oil, gas, and water, respectively.

Water and Gas Injection Forecasts

The Secondary recovery is applied in Williston Basin. Water and gas are injected into reservoirs to both maintain reservoir pressure and displace hydrocarbons toward the wellbore. Water and gas injections require the sources, transportation, injection, separation, and disposal of the injected fluids. Therefore, the implementation of water and gas injection projects depends on a mature infrastructure. The capacity of the infrastructure needs to be able to accommodate the injected fluid volume.

The water and gas injection forecasts base on the historical trends. Regulations require all produced water to meet the environmental requirement before it is disposed. Producers opt to reinject the produced oilfield water back to the aquifer or depleted zone. Some waterflood projects also inject the treated oilfield water back to reservoir to improve the oil recovery. Therefore the total injected water volume is slightly higher than the produced water. The gas injection in some enhanced oil recovery projects will continue the injection. The total water and gas injection volumes in Williston Basin are shown in Figs. 10 and 11.

Comparison of Production Forecast with Production Data

The production forecast was done in August 2012. To evaluate the accuracy of model, we compare the calculated from model with the production data from September, 2012 to September, 2013. Fig. 12 shows the comparison. It is noticed that the difference is very small.
FIG. 7. THE TOTAL OIL PRODUCTION FORECAST IN WILLISTON BASIN (UNITED STATES PART)

FIG. 8. THE TOTAL GAS PRODUCTION FORECAST IN WILLISTON BASIN (UNITED STATES PART)

FIG. 9. THE TOTAL WATER PRODUCTION FORECAST IN WILLISTON BASIN (UNITED STATES PART)
FIG. 10. THE TOTAL WATER INJECTION FORECAST IN WILLISTON BASIN (UNITED STATES PART)

FIG. 11. THE TOTAL GAS INJECTION FORECAST IN WILLISTON BASIN (UNITED STATES PART)

FIG. 12. THE COMPARISON OF PRODUCTION FORECAST WITH PRODUCTION DATA IN WILLISTON BASIN (UNITED STATES PART)
Conclusions
We have presented a method to forecast the production of unconventional resource in a basin level. The production forecast calculated from the model agrees with the production data. Our study provides a guideline for forecasting production in a basin with similar geological setting.

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