A Technical and Economic Study of Completion Techniques in Five Emerging US Gas Shales: A Woodford Shale Example

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Summary

With the increased demand for energy and the declining conventional hydrocarbons worldwide, energy companies are turning to unconventional resources such as shale gas. With more than 2,000 Tcf of gas in place indentified in just 5 shale gas plays in the United States, shale-gas formations are now the number one targets for exploration drilling. Furthermore, there are still many more major shale-gas plays and basins waiting to be explored, evaluated, and developed. Because of the extremely low permeability of most shale formations, it is essential to select the appropriate completion techniques for shale-gas reservoirs. There are very few papers in the petroleum literature that provide a logical method to select completion techniques for given shale-gas-reservoir conditions. There are papers discussing successful completion techniques that seem to work for a specific shale. We have used many of these SPE papers to help define "best practices" in completing shale-gas reservoirs. We then developed logic to determine the best practice in completing shale-gas reservoirs as a function of reservoir conditions. In this paper, we will specifically cover the logic we have developed for choosing completion techniques in shale-gas reservoirs.

First, we performed a literature review on the five basins as well as on all shale-gas plays in the US to determine the best practices in shale-gas completion techniques in fluctuating price environments and identify key geologic parameters that affect overall well performance. From our literature review, we identified seven pertinent geologic parameters that influence shale-gas completion practices. Next, we identified different completion trends in the industry for different geologic settings. Subsequently, we generated an economic model and performed sensitivity analysis to determine optimal completions for each gas-shale basin. On the basis of these economic models, we developed decision flow charts to select completion techniques. Finally, we programmed the flow chart, and we call this program Shale Gas Advisor. This program can be used to determine optimum completion best practices not only for the five gas-shale basins discussed, but also for gas-shale plays that have similar geologic attributes. We validated the program with published case histories in the SPE literature.

Introduction

Although gas shales are now a very important strategic play for many companies, the industry is still having difficulty determining the optimum drilling and completion techniques for wells drilled in the various shale reservoirs. The industry seems to optimize development in each different play by trial and error. Instead, the industry needs to develop predictive models to help determine the optimum drilling, completion, and stimulation options as functions of the shale-reservoir properties and economic conditions. In short, the industry needs to determine best practices for various shale scenarios.

As in most unconventional reservoirs, gas-shale characteristics can vary substantially both vertically and areally. However, despite these variations, shale reservoirs in different basins can be evaluated and compared. The best practices should be somewhat transferable. If engineers and geologists look for differences and similarities in reservoir and geologic properties, then it should be possible to use best practices to design the drilling and completion operations. Most reservoir engineers working in gas shale do not have the time to do a thorough study of industry wide activity to help determine what is working in other areas and what is not. However, if such information is made available, shale-gas development could potentially escalate worldwide.

In the petroleum literature, there are many papers discussing successful completion techniques for shale-gas reservoirs. Using this information, we can develop decision charts to allow the application of best practices in new or even existing gas-shale plays. On the basis of the decision chart, a computer program that we call Shale Gas Advisor was developed to provide best practices in the drilling and completion of shale gas. We do not advocate that Shale Gas Advisor will always provide the optimum solution. However, Shale Gas Advisor will allow the user to understand how other operators have drilled and completed wells in gas-shale formations with similar reservoir properties. In short, it helps the operator move up the learning curve more quickly in new areas.

The process of our research is described as follows. First, we performed a literature review specifically on five basins that are being drilled very actively, as well as generally on all shale-gas plays in the US to help define best practices in shale-gas drilling and completion techniques in fluctuating price environments. We wanted to identify key geologic parameters that affect overall well performance. From our literature review, we identified seven pertinent geologic parameters that influence shale-gas completion practices. Next, we identified different completion trends in the industry for different geologic settings. Subsequently, we generated an economic model and performed sensitivity analyses to determine optimal completion techniques for each gas-shale basin. On the basis of these economic models, we developed a decision flow chart to select completion techniques. We programmed the flow chart, and we call it Shale Gas Advisor. Finally, we validated the program with published case histories in the petroleum literature.

The development of Shale Gas Advisor is part of a larger research project to develop more-comprehensive software that is called the Unconventional Gas Resource (UGR) Advisor. The UGR Advisor can be used to provide basic ideas, recommendations, advice, and best practices on the development of unconventional gas reservoirs including tight gas sands, coalbed methane, and shale gas (Wei 2009; Wei and Holditch 2009; Wei et al. 2009). **Fig. 1** is a schematic of the UGR Advisor. The BASIN module is used to perform a basin analogy calculation to let the user know which one or two basins in North America are the most analogous to the target basin (Singh 2006; Singh et al. 2007; Singh et al. 2008). Also, BASIN can be used to perform a formation analogy to let the user know which one or two formations in North America are the most analogous to any specific formation in the target basin. With the known analogous basins, Petroleum Resource Investigation Summary and Evaluation can be used to estimate the technically recoverable gas volume (Old et al. 2008; Holditch and Old 2008). The D&C Advisor is used to provide advice concerning the drilling, completion, and stimulation methods being used in the UGR reservoirs. The UTILITY program is used to help the user understand the background knowledge as well as provide support

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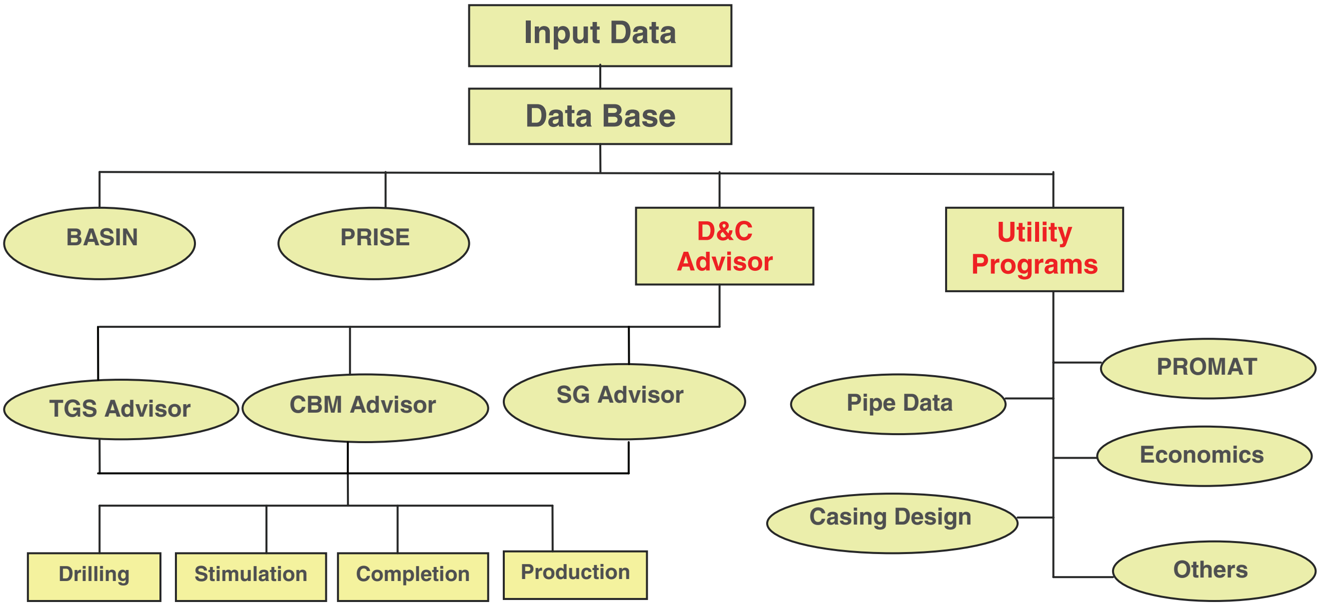

Fig. 1—A schematic of the UGR Advisor.

to the user to make a more-detailed analysis if necessary. The research team at Texas A&M University is still currently developing UGR Advisor, and the target completion date for the entire software package is the end of 2011.

Overview of Gas-Shale Systems

Because of the success of producing large volumes of gas from the Barnett shale and now the Haynesville shale, the petroleum industry has switched gears from looking at shales as a source rock to analyzing shales as possible gas reservoirs. Gas-shale systems are vastly different from other unconventional plays because of the nature of producing from a source rock, thus making it difficult to determine optimum drilling, completion, and stimulation methods for these reservoirs. Because these source rocks are also reservoir rocks, the environment during deposition must have been anoxic, meaning that organic-rich material could settle with minimal oxygen contact, allowing the material to later generate hydrocarbons. As shale is buried, there are two main processes that the shale undergoes to generate gas. Biogenic gas can be formed through the action of anaerobic microorganisms, and thermal gas can be formed through the thermal breakdown of kerogen. With the use of vitrinite reflectance (VR), the origin of the gas can be determined as either biogenic or thermogenic. Gas-shale rocks that are organic-rich are usually dark color (brown/black) with high total-organic-carbon (TOC) content (can be higher than 10%), and high gamma ray signatures (greater than 140 API units). The porosity and permeability of these organic shales will be a function of compaction during burial history.

Most producing gas shales will produce gas that is stored in one of two places—free gas in the pores and natural fractures or gas that has been adsorbed to the organic material in the shale. Free gas is the same as the gas that is in the pores and natural fractures found in most formations. Adsorbed gas is the gas that is attached to the surface of the organic matter and/or clay matter and is only released as the pressure in the reservoir declines below the sorption pressure. Tests must be run using cores in a laboratory to determine how much gas will be desorbed from the surface of the shale as the reservoir pressure declines. Once known, the volume of desorbed-gas production can be modeled and predicted.

The main geologic parameters we must know to determine the quality of a gas-shale reservoir are depositional environment, TOC, average gas content, shale composition, formation permeability, formation porosity, thickness, and reservoir pressure. The depositional environment is very important for determining a commercially viable shale-gas reservoir because this affects how the hydrocarbons are formed, establishes if hydrocarbons are even present, and determines what type of hydrocarbons might exist in the shale. TOC is another factor to evaluate because it is indicative of the quantity of organic material available for the formation of hydrocarbons, it can be directly proportional to the yield of gas, and it allows evaluation of organic-matter transformation.

The average gas content is important because it is indicative of what is in place and it can be used to forecast what is recoverable. Obviously, a more-porous and -permeable shale will contain more gas and will allow its production at higher gas-flow rates. Shale composition is vital to the success of any gas-shale play. If there is high clay content, the shale will be more difficult to fracture treat and it will be more difficult to keep a fracture propped open over time. If shale contains more quartz, the shale will be more brittle, it will fracture treat were readily, and it will be easier to keep a hydraulic fracture propped open.

Thickness is another parameter that is important to the commercial gas shales. It is difficult to produce from shales that are less than 50 ft thick because of the area of contact and because there might not be much gas in place. Most of the thinner shales tend to be uneconomic. Likewise, if a shale is too thick, it can become more difficult to determine the best layers to produce from, and the effectiveness of horizontal drilling is reduced in thick formations, unless large fracture treatments are pumped or multiple horizontal holes are drilled. Reservoir pressure also plays a key role in determining the gas in place and gas recovery of the gas shale. In gas shales with high pressure gradients, the shale may never have been compacted, and it is likely that the porosity and permeability of gas shales with high pressure gradients will be better than those of low-pressure gas shales, all things being equal.

The geologic parameters described have been discussed for five emerging gas-shale basins—Michigan basin (Antrim shale), the Fort Worth basin (Barnett shale), the North Louisiana Salt basin (Haynesville shale), the Appalachian basin (Marcellus shale), and the Arkoma basin (Woodford shale) in the MS thesis by Agrawal (2009). However, it is impossible to describe all of the five basins in one paper. Therefore, in this paper we describe only the Woodford shale in the Arkoma basin in detail while presenting the data for the other four gas shales only in **Table 1.** The detailed information of the other four basins can be obtained from the MS thesis by Agrawal (2009).

Evaluation of the Woodford Shale

The Woodford shale is shale deposited during the Late Devonian/Early Mississippian that is now found throughout Oklahoma and Arkansas. The Woodford shale is a producing formation in the Arkoma basin and in two other basins—the Ardmore basin and the Anadarko basin—as shown in **Fig 2.**

TABLE 1—SUMMARY OF KEY PROPERTIES FROM FIVE SHALE-GAS BASINS					
Property	Antrim Shale	Barnett Shale	Haynesville Shale	Marcellus Shale	Woodford Shale
Basin	Michigan	Fort Worth	North Louisiana Salt	Appalachian	Arkoma
Fairway depth (ft)	600 to 2,200	6,500 to 8,500	9,900 to 16,500	4,000 to 8,000	6,000 to 11,000
Thickness (ft)	120 to 200 (net 70 to 120)	200 to 300 (net 50 to 100)	270 (net 100 to 200)	40 to 900 (varies between states)	50 to 220 (net-100)
TOC (%)	up to 20	up to 12 (average 4.5)	0.5 to 4	0.3 to 11	up to 20 (average 3 to 10)
Total porosity (%)	3 to 10	3 to 8	7 to 15	9 to 13	7.5 to 14
Gas-filled porosity (%)	2 to 6	2 to 6	5 to 11	3 to 6	3 to 6.5
Gas content (scf/ton)	40 to 100	300 to 350	350 to 475	275 to 325	60 to 115
Quartz content (%)	50 to 60	40 to 45	28 to 33	18 to 24	55 to 87
Clay content (%)	20 to 35	20 to 40	25 to 33	40 to 60	8 to 34
Reservoir pressure (psi)	400	3,000 to 4,000	8,000 to 10,000	1,600 to 5,000	3,100 to 5,800
Reservoir pressure gradient (psi/ft)	0.33 to 0.38	0.42 to 0.46	0.7 to 0.92	0.4 to 0.7	0.48 to 0.55
Adsorbed gas (%)	60 to 70	15 to 30	20 to 30	20 to 40	20 to 40
Well spacing (acre as of 1/1/09)	40 to 160	80 to 160	40 to 160	40 to 80	40 to 80
Gas-In-Place (TCF as of 1/1/09)	35 to 75	25 to 30	250 to 320	1,300 to 1,650	45 to 60

Many of the operators that are producing the Woodford in the Ardmore basin are reporting oil/condensate production with minimal gas associated with the liquids. There are approximately 10 to 15 wells that have been drilled in this basin, and because it is liquid production instead of gas, most operators are shying away from it because liquids seem to lock up the system rather quickly. However, the Ardmore basin is still getting a lot of attention (Ardmore basin Woodford gas plan takes off 2008). In the Anadarko basin, most production is gas but there are limitations because of depth. Most of the Woodford shale major production comes from depths anywhere from 7,000 to 18,000 ft. Even with depth challenges, operators are slowly moving into this area. One such example is Marathon, which had a press release in January 2009 stating that their first success, Woodford Horizontal in a new area of the Anadarko basin, yielded a normalized initial production rate (IP) of approximately 5.2 MMcf/D. Even with the success in the Anadarko basin, there are only approximately 50 to 60 wells drilled there. In contrast to the Ardmore basin and the Anadarko basin, the Arkoma basin contains more than 750 wells producing from the Woodford shale at the time of this study. As mentioned, the Woodford shale is found in the Arkoma basin that covers the southeastern section of Oklahoma and western portion of Arkansas, as shown in Fig. 2.

The Woodford shale was first completed in 1939, but this play did not gain momentum until 2003 with the use of new completion techniques and the increase in gas prices. Before the boom in 2003, there were only approximately 24 wells producing in the Woodford shale throughout the entire state. Initial production rates at that time for the Woodford wells ranged up to 200 Mcf/D. After 2003, production rates increased almost exponentially, as seen in **Fig. 3.** By early 2008, there were more than 750 Woodford wells in production, with most wells being drilled in Hughes, Coal, Pittsburg, and McIntosh counties, which are located on the western side of the basin. The companies developing the Woodford include Newfield, Devon, Continental, and Chesapeake. The current estimated gas in place for the Woodford is approximately 45 to 60 Tcf. The typical depths at which the Woodford is encountered in the Arkoma basin are between 6,000 and 11,000 ft and extend areally approximately 1500 m^2.

Through the use of core analysis coupled with VR, it is known that the Woodford shale produces thermogenic methane and biogenic gas (in the cherty portion of the Woodford such as the Antrim shale). The Woodford is a brittle grey-to-black shale that is found throughout the basin. As seen in **Fig. 4,** the most distinguishing feature in the Woodford shale outcrop is three sets of natural fractures. The first set is roughly parallel to the dip direction of the bedding plane, the second set is parallel to the dip of the bedding, and the third set is oblique to the strike and fold axis of the formation.

The Woodford shale is easily recognized on well logs because of the radioactivity of the shale as well as the placement of the formation between two carbonates. The Woodford is characterized

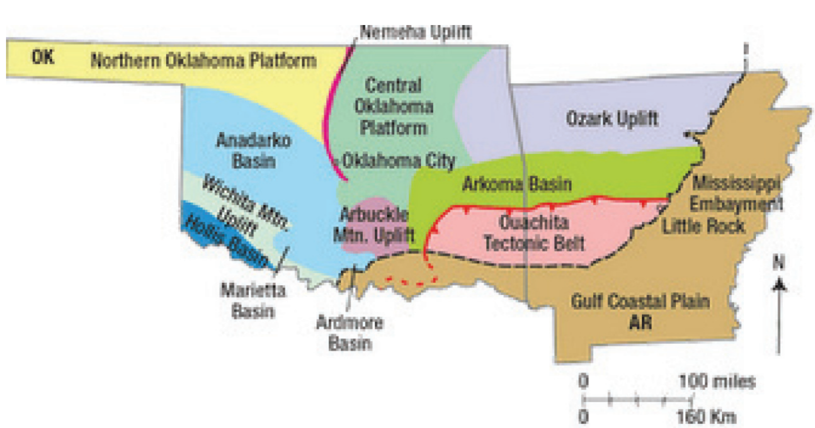

Fig. 2—Oklahoma basins (Comer 2008).

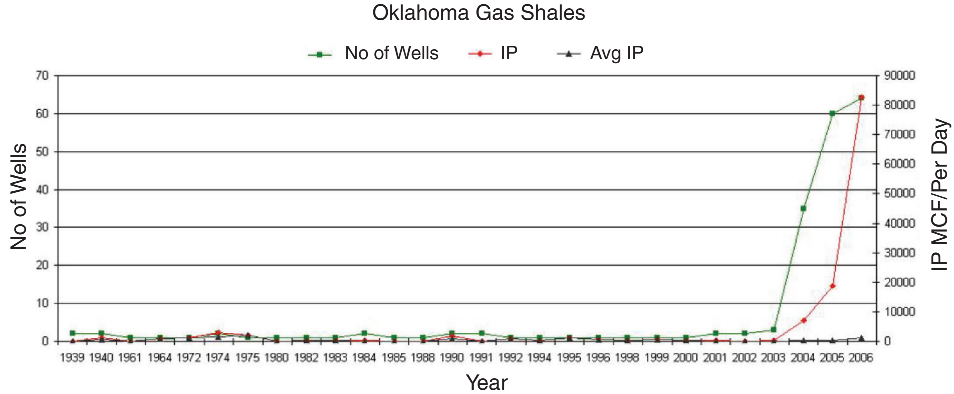

Fig. 3—Number of wells and IP rates for the Woodford shale in Oklahoma (Wickstrom 2008).

by relatively low sonic travel time, low resistivity, and neutron-induced radiation signatures, and it overlies a regional unconformity that can be observed on all well logs. The Woodford shale is divided into three units—upper, middle, and lower. The lower unit, which sits on top of the unconformity, has the lowest radioactivity and thus contains more carbonate, silt, and sand. The middle unit has the highest radioactivity; it also contains the most organic content and pyrite. The upper unit's radioactivity falls between the middle and lower unit. This unit consists of black shale with few spores and mostly parallel laminae.

Developing the Woodford does have its challenges because of several factors. The first pertinent challenge is the natural-fracture contribution. There is little knowledge on how the fracture system contributes to the overall performance of the play or the number of fractures one might encounter when drilling. One thing that is known is that the Woodford is a highly fractured reservoir that causes the rock to be very brittle in many of its layers. The next vital challenge that operators face is the vast spread of drilling depths at which the Woodford is encountered. It is much easier to develop a gas-shale play that is shallow (approximately 6,000 ft) than it is when it is deep (approximately 11,000 ft). Operators are overcoming these challenges with the development of new drilling and completion technologies that not only unlock the way to develop this reservoir but also do it economically.

Depositional Environment. As mentioned, the Woodford shale was deposited during the Late Devonian/Early Mississippian. During this time, the southern midcontinent lay along the western margin of North America in what was considered warm and dry tropics, which is confirmed by the hypersalinity found within the cracks of the present-day Woodford. The deposits that formed the Woodford shale began to be deposited into the epeiric seas when the sea level began to rise, drowning the marine embayment that was present at the time. The sea level continued to rise and cover the subaerial, eroded, and dissected terrain that consisted of Ordovician to Middle Devonian carbonate rocks.

Fig. 4—Woodford shale outcrop (Cardott 2007).

The Woodford shale is made up of three members—upper, middle, and lower units. The upper unit is chertier than the other two formations but it is not as radioactive as the middle member. On the other hand, the middle unit is more widespread than the other two regionally but it is also the one that contains the most organic content. The lower unit is known for the abundance of other lithofacies such as carbonates.

Total Organic Content. TOC present in the Woodford shale can be as high as 20%. This is a very high TOC; in fact, it is higher than even the Barnett shale, which was the frontier play leading into the modern-day gas-shale arena. The average TOC for the Woodford in the Arkoma basin ranges from 3 to 10%. Most of the organic material found in the Woodford shale is marine in origin because the shale was deposited on an embayment. The fossils found in the Woodford shale are conodonts, ammonoids, fish debris, shark debris, and radiolarians. One of the most fascinating findings in the Woodford is that the formation is the oldest rock in Oklahoma that contains wood from the progymnosperm Archaeopteries. This wood was transported to the depositional area using rivers that were present at that time.

Gas Content. The total average porosity found throughout the Woodford shale can range from 7.5 to 14%, with an average porosity of 10%. Of that 10%, the average gas-filled porosity is anywhere from 3 to 6.5%. This range is comparable to what is seen in the Barnett and the Marcellus shales, slightly higher than the Antrim shale, and lower than what is being observed in the Haynesville shale. The Woodford shale has approximately 20 to 40% adsorbed gas. The gas content in the Woodford shale ranges from 60 to 115 scf/ton because of the depth and the thermal maturity seen in the Arkoma basin. The volume of adsorbed gas has led to much debate regarding what the correct well spacing should be for the Woodford shale in the Arkoma basin. Most companies drilled on 80-acre spacing initially; however, recently there has been indication that 40-acre spacing is possible because there has not been much depletion observed when companies have started drilling infill wells. The average recovery from these wells ranges from less than 1 Bcf to 6 Bcf, depending on whether an operator drills vertically or horizontally.

Shale Mineralogy. The major mineral found in the Woodford is quartz, which makes up anywhere from 55 to 87% of the formation. The next most abundant mineral found is illite, which can be found in quantities ranging from 8 to 34% of the mineralogy. The mineral that is next in abundance in the Woodford is kaolin, which is present at approximately 3 to 7%. Plagioclase feldspar is found in the Woodford up to 7%. Other minerals present are dolomite (0 to 3%), apatite (0 to 1%), and pyrite (0 to 1%).

Thickness and Reservoir Pressure. The Woodford shale ranges in thickness from 50 to 220 ft throughout the Arkoma basin, with an average net pay of 100 to 150 ft. **Fig. 5** depicts an isopach map of the Woodford shale found in the Arkoma basin.

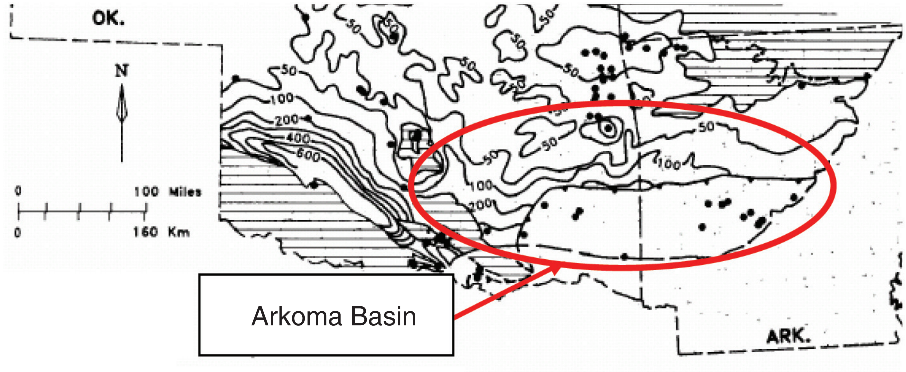

Fig. 5—Woodford shale isopach map (Cardott 2007).

The Woodford shale is the thinnest in the center of the Arkoma basin. As one moves to the outskirts of the basin, the Woodford begins to thicken. There is a also a regional thickening to the southwest of the basin. The Woodford shales just up against Ouachita Fold belt that is seen on the south of the Arkoma basin.

The average reservoir pressure that is found in the Arkoma basin for the Woodford shale varies with the depth from approximately 3,100 to 5,800 psi, yielding a pressure gradient between 0.48 to 0.55 psi/ft. As with the Haynesville shale and other gas-shale plays, the Woodford is considered an overpressured reservoir because the pressure gradient of the Woodford shale is higher than the hydrostatic gradient; therefore, it is vital to the success of this play to understand pressures and the depths at which the Woodford will be encountered to ensure successful drilling and completions.

Summary of Gas-Shale Geological Parameters

Many of the geological parameters for the five shale plays analyzed are similar. Table 1 displays the average geological parameters discussed for all five plays to help compare the plays against one another.

The information in Table 1 summarizes the results of our literature review. The data should help an operator who is looking at the viability of a new prospective gas-shale basin. In Agrawal (2009), the reader will find detailed information on all five of these shale formations. We used these data to determine how the drilling and completion methods that seem to be best practices correlate with the formation data.

Overview of Completion Techniques

For gas-shale plays, as with most plays, there is a learning curve that operators must undergo before drilling and well-completion operations can be optimized. There have been many failures and uneconomic wells drilled and completed in each of the gas-shale plays, but as technology improves and we gain more experience, the success ratio and quality of the well completions continue to improve. Failures can include anything from losing a wellbore to ending up with a subeconomical well. The objective of this work has been to review the literature to determine the best practices for drilling, completing, and stimulating wells in all of the important gas-shale plays. Using the geologic and reservoir characteristics of each gas-shale play, we have then established guidelines in the form of decision charts that help operators obtain a first estimate of how to drill, complete, and stimulate the next well in a gas-shale play. By establishing these guidelines, it will be easy to transition to how these technologies can be applied in other basins/plays that were not discussed here. These other basins/plays can be anywhere in the world where such gas shales exist.

Vertical Completions

In essentially every shale-gas play, the first wells drilled, completed, and tested were vertical wells. In the Haynesville, most vertical wells have been drilled to the Haynesville for data-acquisition purposes but never produced over the long term. In the future, we expect virtually all gas-shale plays will be developed using horizontal or even multilateral wells.

Vertical Woodford shale wells have been completed over the years, but the caveat is that these wells have been commingled with other reservoirs such as the Hunton limestone. In the late 1990s, Newfield Exploration began to drill Woodford vertical wells. From the late 1990s to 2006, approximately 100 wells have been drilled, with 60% of them drilled by Newfield. Most of these wells were completed with cemented casing and then perforated with three to four clusters throughout the interval. Some companies fracture treated all the perforations together; however, most wells were stimulated with three- to four-stage fracture treatments. The most common stimulation design used by operators drilling vertical Woodford wells has been slickwater treatment. A slickwater treatment is the lowest-cost method to complete these vertical wells. Usually approximately 100,000 gal of slickwater would be used to transport anywhere from 40,000 to 50,000 lbm of either 20/40-, 40/70-, or 100-mesh sand per stage.

In general, the average estimated ultimate recovery (EUR) has been approximately 1.35 Bcf per well. The cost of the vertical wells was approximately USD 2 million to drill and complete. **Fig. 6** compares of the average well performance of the vertical vs. horizontal wells for the Woodford shale (Andrews 2007).

Horizontal Completions

Since 2000, many operators initiated new horizontal drilling and completion designs to improve the productivity of gas-shale wells. Upon reviewing the costs to drill and complete vertical wells in plays such as the Barnett shale and the Woodford shale and factoring in the EURs from most wells, the industry turned to the use of horizontal drilling technology to improve gas-flow rates and gas recovery. As is now clear, one of the greatest improvements in developing gas-shale reservoirs economically is the use of horizontal drilling. In the horizontal gas-shale wells, the biggest challenge has been to determine the best way to complete the horizontal well. There are still studies conducted throughout the industry to understand such issues as where to land the lateral in the formation and what size casing to use. As a rule of thumb, most operators will land the lateral in the middle of the formation or relatively close to the middle of the formation. For example, the Woodford, Barnett, and most of the Marcellus shale wellbores are landed in the middle, while the Haynesville is landed closer to the bottom of the formation, or approximately 55 to 60% from the top. There is not much of a difference in placement techniques, but most operators believe that the fracture stimulations grow throughout the entire interval if the horizontal hole is in the middle. With the use of microseismic technology, many operators confirmed that height growth during the fracture treatment is sufficient to connect the entire shale to the horizontal well, provided that the shale is not too thick. The optimal result that can be achieved using microseismic is to see seismic activity following the path of the perforations that the fracture treatment is trying to stimulate without too much overlap with the preceding treatment or with the one that will be pumped

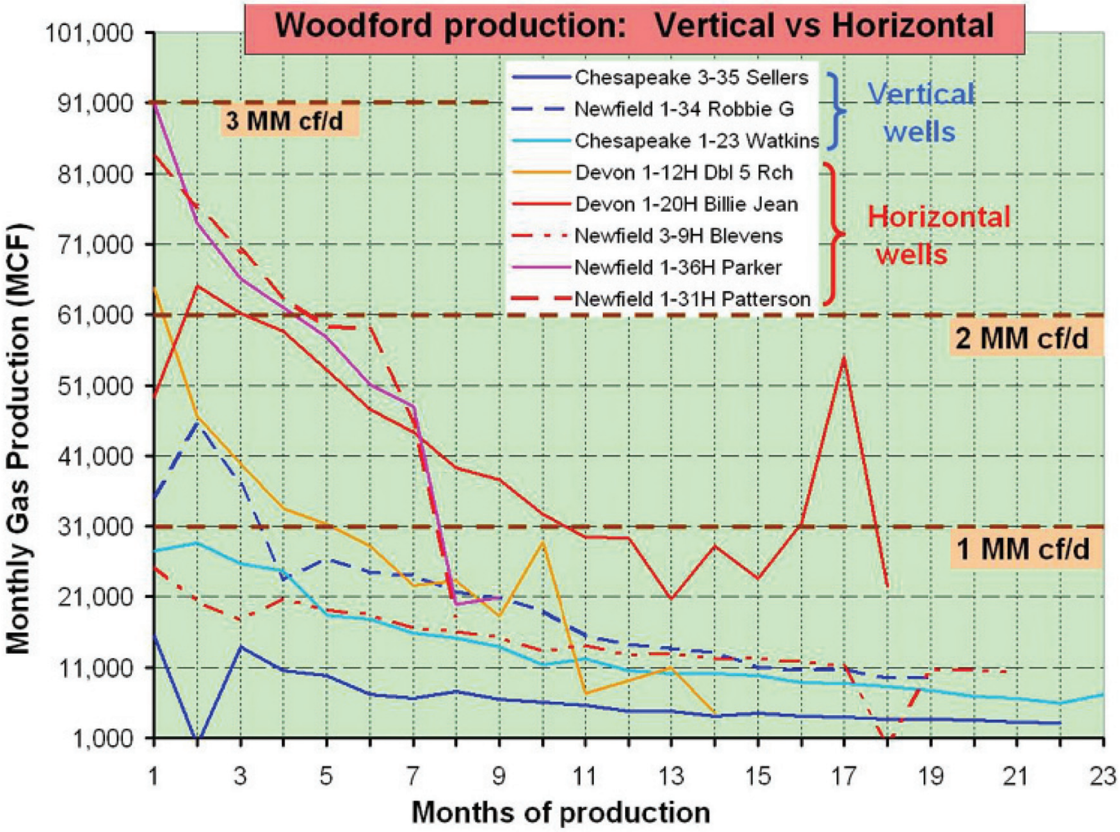

Fig. 6—Woodford shale production performance: horizontal vs. vertical (Andrews 2007).

afterwards; therefore, the entire lateral has some seismic activity without too much overlay. It is imperative to understand that if there is a significant change in the rock mechanical strengths in the reservoir, landing the lateral in the middle of the section might not be the optimal position.

According to Wickstrom (2008), in 2004 the Woodford Shale horizontal program started to take off but did not gain much momentum until 2006 when more than 130 Woodford horizontal wells were completed. As with other shale plays, there is a learning curve that leads to better completions in the Woodford shale (Coffey 2007). It is now common practice to find cased, cemented laterals in this play and the laterals range anywhere from 2,500 to 4,000 ft long. There is a difference between these two lengths in not only cost but EURs because of the number of fracs. The 2,500 ft lateral lengths tend to only allow five-stage fracs that yield an average of approximately 2.5 BCF per well that is recovered over the life of that well. In the 4,000-ft laterals, operators can execute eight- to nine-stage treatments that can yield recoveries of 6 BCF on average. From this information, many deduce that it is beneficial to drill the longer laterals, but that depends on the price environment because the shorter laterals cost approximately USD 4.75 million to drill and complete while the longer laterals cost approximately USD 7.75 million to drill and complete (Wickstrom 2008).

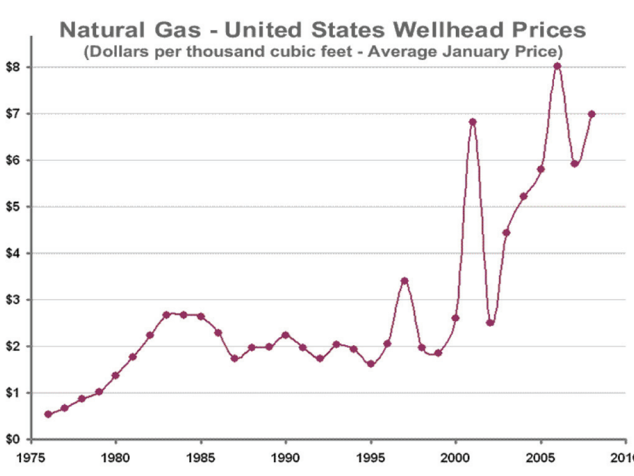

Fig. 7—Natural-gas wellhead prices (from geology.com).

Wickstrom (2008) states that a common practice in the Arkoma Woodford is to perforate 300-ft sections at a time and then acidize the perforations with 15% HCl before fracturing the formation. Each stage pumps approximately 18,000 bbl of slickwater and 200,000 lbm of sand (100 mesh, 40/70 Ottawa, or 20/40 Ottawa). Generally, a 5½-in. casing is run in hole in the lateral portion of the well so that the average pump rate is anywhere from 60 to 95 bbl/min, with an average treating pressure of approximately 5,600 to 5,800 psi. The typical performance of a 4,000-ft lateral Woodford horizontal well is seen in Fig. 6. Similar to the Barnett shale, many operators are moving to stimulation fracture treatments in the Woodford shale. Also, some operators have done zipper fracture stimulations. In a zipper fracture, two laterals are next to each other and starting from the toe of each lateral, one fracture stage is performed in Well 1 and then the same stage is performed on Well 2. Then, the operator goes up to the next stage in Well 1 and then stimulates the second stage in Well 2. The operator continues going back and forth between the two wells until both wells are stimulated from toe to heel. The reason for this is that there have been some studies conducted indicating that this method helps stimulate more of the reservoir. There is not enough data to indicate if this is true or false yet.

Economics Model

Gas-Price Discussion. The price of natural gas is vital to the economic success of gas-shale plays in the US. From 1983 to 2000, the average annual price of natural gas was fairly steady from approximately USD 2 to 3/Mcf of gas. Since 2000, the price of natural gas has been very volatile and has varied from USD 3 to 8/Mcf of gas on average, as seen in **Fig. 7.** However, because the price declined in late 2008 to early 2009, operators have started stepping back from drilling these plays to see what the market will do.

There is a direct relationship between gas prices and the development of gas-shale plays. When the prices increase, the activity in the gas-shale basins increases. In our work, we have looked at the impact price has on the development in gas-shale basins to determine what is the best completion design to use (horizontal vs. vertical) in different price environments because this is an important analysis that needs to be performed in unconventional gas-shale basins.

Completion Cost and Variations. As gas prices and revenue decline, the cost of services such as drilling rig, mud, and stimulation services decline as well. These cost changes affect the overall economics of a project. Therefore, most operators will rerun their economics using different price and cost scenarios to determine the hurdle prices for gas required to move forward with a project. One thing to note is that service companies tend to lag behind significant increases or decreases in gas price. However, when operators began reducing drilling projects and the rig count declines, the cost of services also declines as competition increases. As such, when running economic scenarios, the gas prices and finding and development costs can usually be correlated.

Shale Economic Parameters. Economics was run on each of the five shale-gas plays described by Agrawal (2009) for two types of completions—vertical and horizontal. The reason for analyzing both vertical and horizontal wells is to observe which completion method is better under different economic environments. To determine which was the better completion design (vertical or horizonatal) for each scenario, the discounted profit to investment (DP/I) ratio was the main factor that would compare the different scenarios. To calculate DP/I, the net cash flow discounted at 10% is divided by the discounted investment; therefore, a DP/I of 1.0 is equal to the net present value of 0 at 10%, which will be indicative of a hurdle ratio.

For economics purposes, all evaluation start dates will be January 2009. Also, it is important to note that production begins 1 month after the fracture treatments are completed. These assumptions recognize the flowback period to recover load water and the time to set up facilities for each location. Also, there is always a delay of a couple of days to a week between the point when the rig moves off location and the point when stimulation begins because of two main reasons. The first reason is that the engineer and the geologist need to decide where to perforate and where to fracture stimulate the wellbore. The second is the time to design the fracture-stimulation procedure and line up the services.

For the base case, USD 7/million Btu is used because this was the typical gas price for much of 2008. The capital for each shale play and completion type will be discussed in the following sections. Because gas-shale reservoirs behave in a hyperbolic decline rate, the *b*-value for the cases will be 2.3. This is higher than 1.0, which is the typical upper limit for hyperbolic decline (harmonic), but there is evidence in the industry that a *b*-value can be higher than 1.0 and that this is indicative of wells that have multipay reservoirs, multiporosity systems, or are drilled in tight gas reservoirs. Also, the economics will be run on a 30-year life of the wellbore instead of economic limits because each operator will have a different hurdle rate than others because economic limit depends on operating expenses and lifting costs. Using a super hyperbolic decline ($b > 1$) is justified only for a well still in trainsient flow. Extending such a forecast to boundary-dominated flow would necessarily overpredict the expected ultimate recovery. It is a common industry practice, though, to fit the transient with a *b*-value greater than unity and then change it to a value between zero and unity at the estimated onset of boundary-dominated flow. In this calculation, the operating expense will be held constant at USD 5,000/well/month. Because this is a model for gas-shale plays, the working interest is 100% and the net-revenue interest is 87.5% to represent the typical ⅛ royalty.

Sensitivity-Analysis Considerations. To understand what really impacts the overall economics of the gas-shale basins studied, several components were analyzed—the operating cost, the capital cost, and the gas price. The vertical and horizontal completions for the Woodford shale economics as well as the sensitivity analysis for the three components are shown in **Figs. 8 and 9.**

In Figs. 8 and 9, the boxes that are highlighted in red are those that have a DP/I less than unity, indicating that at that particular gas price, capital-expenditure, operating expense, and EUR, the well is not economic; therefore, it is a bad investment if the well is examined individually. The boxes that are yellow represent a DP/I greater than 1.0 but less than 1.2. This yellow box indicates that the individual well will have marginal returns at those operating and price environments. The boxes that are in green are those than have a DP/I greater than 1.2 but less than 3, showing that it is a good-investment well. Last, the boxes shaded in blue are those economic environments in which the conditions are such that it is considered that any wellbore would be a sure winner to drill and complete.

Completions Decision Flow Charts. From the extensive literature review conducted on each of the five gas-shale basins discussed, a completion decision chart was created to determine the best completion method for a gas-shale play similar to these, as illustrated in **Fig. 10.**

Also, a flow chart was created in which completion fluids were chosen depending on the depth at which the reservoir was encountered and the reservoir pressure gradient, as depicted in **Fig. 11.** Although this is a simple approach to determining fluids, this is just a tool to help get a first pass or initial idea on what the fracture-stimulation size will be and what it could possibly entail.

The cutoffs for each of the different parameters were based on what was seen in the industry in terms of completions types and fluid types used in each of the different plays. With the advancement in technology, the cutoffs will change in the future, but for now these are what are seen to be realistic numbers for each of the different definitions.

From these two flow charts, coupled with the economic parameters discussed, a simple Excel program was built to help operators quickly decide if they should evaluate a potential prospect given the properties it has and to provide completion suggestions. In **Figs. 12 and 13,** the solid black arrows dictate the decisions made to arrive at the completion and fluid selection. The dotted lines indicate decisions that were not used to come to the end result.

Validation of the Decision Chart

To validate the decision chart, a well producing from the Woodford shale was looked at. The example shows the different properties necessary for the decision chart in Fig. 12. Looking at Figs. 12 and 13, one can conclude that the best way to complete this well is as a horizontal well that has multiple fracture stimulations through the lateral part of the wellbore. In addition to this, the best fluid design to use in the fracture stimulation is slickwater with sand that is anywhere from 20/40 to 100 mesh.

Conclusions

On the basis of the results of the research described, the following conclusions can be reached.

- A systematic evaluation of completion techniques in gas-shale is important to the energy industry because gas shale plays will be an important global resource for the 21st century. With our conventional reservoirs dwindling, it is important to find new technology and techniques to economically extract oil and gas from unconventional avenues.
- Through the geologic analysis of the Antrim shale, Barnett shale, Haynesville shale, Marcellus shale, and Woodford shale, this paper looks at the similarities as well as differences in the key parameters. From the literature review, the key geologic parameters include depositional environment, depth, TOC, gas content, clay content, quartz content, shale composition, adsorbed-gas percentage, pressure gradient, and thickness.
- Because there have been numerous advances in completion techniques throughout recent years, one cannot immediately

Woodford Shale Vertical-- DP/I Per Well			
Capital Expenditure = $1,400,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	1	1.4	2
$ 3.50	0.85	1.09	1.45
$ 7.00	1.52	2.02	2.78
$ 12.00	2.48	3.34	4.69

Woodford Shale Vertical-- DP/I Per Well			
Capital Expenditure = $2,000,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	1	1.4	2
$ 3.50	0.69	0.85	1.11
$ 7.00	1.16	1.51	2.04
$ 12.00	1.83	2.43	3.37

Woodford Shale Vertical-- DP/I Per Well			
Capital Expenditure = $2,600,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	1	1.4	2
$ 3.50	0.6	0.73	0.92
$ 7.00	0.96	1.23	1.64
$ 12.00	1.48	1.95	2.67

Woodford Shale Vertical-- DP/I Per Well			
Capital Expenditure = $1,400,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	1	1.4	2
$ 3.50	0.64	0.86	1.22
$ 7.00	1.29	1.78	2.55
$ 12.00	2.25	3.11	4.46

Woodford Shale Vertical-- DP/I Per Well			
Capital Expenditure = $2,000,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	1	1.4	2
$ 3.50	0.54	0.69	0.95
$ 7.00	1	1.34	1.88
$ 12.00	1.67	2.27	3.21

Woodford Shale Vertical-- DP/I Per Well			
Capital Expenditure = $2,600,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	1	1.4	2
$ 3.50	0.49	0.61	0.8
$ 7.00	0.84	1.11	1.52
$ 12.00	1.35	1.82	2.54

Woodford Shale Vertical-- DP/I Per Well			
Capital Expenditure = $1,400,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	1	1.4	2
$ 3.50	0.56	0.76	1.1
$ 7.00	1.18	1.67	2.43
$ 12.00	2.13	3	4.34

Woodford Shale Vertical-- DP/I Per Well			
Capital Expenditure = $2,000,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	1	1.4	2
$ 3.50	0.49	0.63	0.87
$ 7.00	0.92	1.26	1.8
$ 12.00	1.59	2.19	3.13

Woodford Shale Vertical-- DP/I Per Well			
Capital Expenditure = $2,600,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	1	1.4	2
$ 3.50	0.45	0.55	0.74
$ 7.00	0.78	1.04	1.46
$ 12.00	1.29	1.76	2.48

Fig. 8—Summary of vertical completions in the Woodford shale economics.

disregard a potential shale play if several geologic parameters fall outside the ranges displayed in Table 1. Table 1 is merely a guideline for what the ranges have been for the different geologic parameters for several successful shale-gas plays.

- A decision chart was created in this paper that can help users determine completion method and fracture-fluid types needed for an effective completion as a function of geological gas-shale properties. From this decision chart, a computer program was

Woodford Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $5,425,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	3.4	4.8	6
$ 3.50	0.91	1.16	1.38
$ 7.00	1.6	2.13	2.58
$ 12.00	2.58	3.51	4.31

Woodford Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $7,750,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	3.4	4.8	6
$ 3.50	0.73	0.91	1.06
$ 7.00	1.21	1.58	1.9
$ 12.00	1.9	2.55	3.11

Woodford Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $10,075,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	3.4	4.8	6
$ 3.50	0.64	0.77	0.89
$ 7.00	1.01	1.29	1.54
$ 12.00	1.53	2.03	2.46

Woodford Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $5,425,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	3.4	4.8	6
$ 3.50	0.86	1.11	1.32
$ 7.00	1.54	2.07	2.53
$ 12.00	2.52	3.45	4.25

Woodford Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $7,750,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	3.4	4.8	6
$ 3.50	0.69	0.87	1.02
$ 7.00	1.17	1.54	1.86
$ 12.00	1.86	2.51	3.07

Woodford Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $10,075,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	3.4	4.8	6
$ 3.50	0.61	0.74	0.86
$ 7.00	0.97	1.26	1.51
$ 12.00	1.5	2	2.43

Woodford Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $5,425,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	3.4	4.8	6
$ 3.50	0.83	1.08	1.29
$ 7.00	1.51	2.04	2.5
$ 12.00	2.49	3.42	4.22

Woodford Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $7,750,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	3.4	4.8	6
$ 3.50	0.67	0.85	1
$ 7.00	1.15	1.52	1.84
$ 12.00	1.84	2.49	3.05

Woodford Shale Horizontal -- DP/I Per Well			
Capital Expenditure = $10,075,000 Operating Cost = $1,000/Well/Month			
	Estimated Ultimate Recovery (BCF)		
Gas Price ($/mcf)	3.4	4.8	6
$ 3.50	0.59	0.72	0.84
$ 7.00	0.96	1.24	1.49
$ 12.00	1.49	1.99	2.42

Fig. 9—Summary of horizontal completions in the Woodford shale economics.

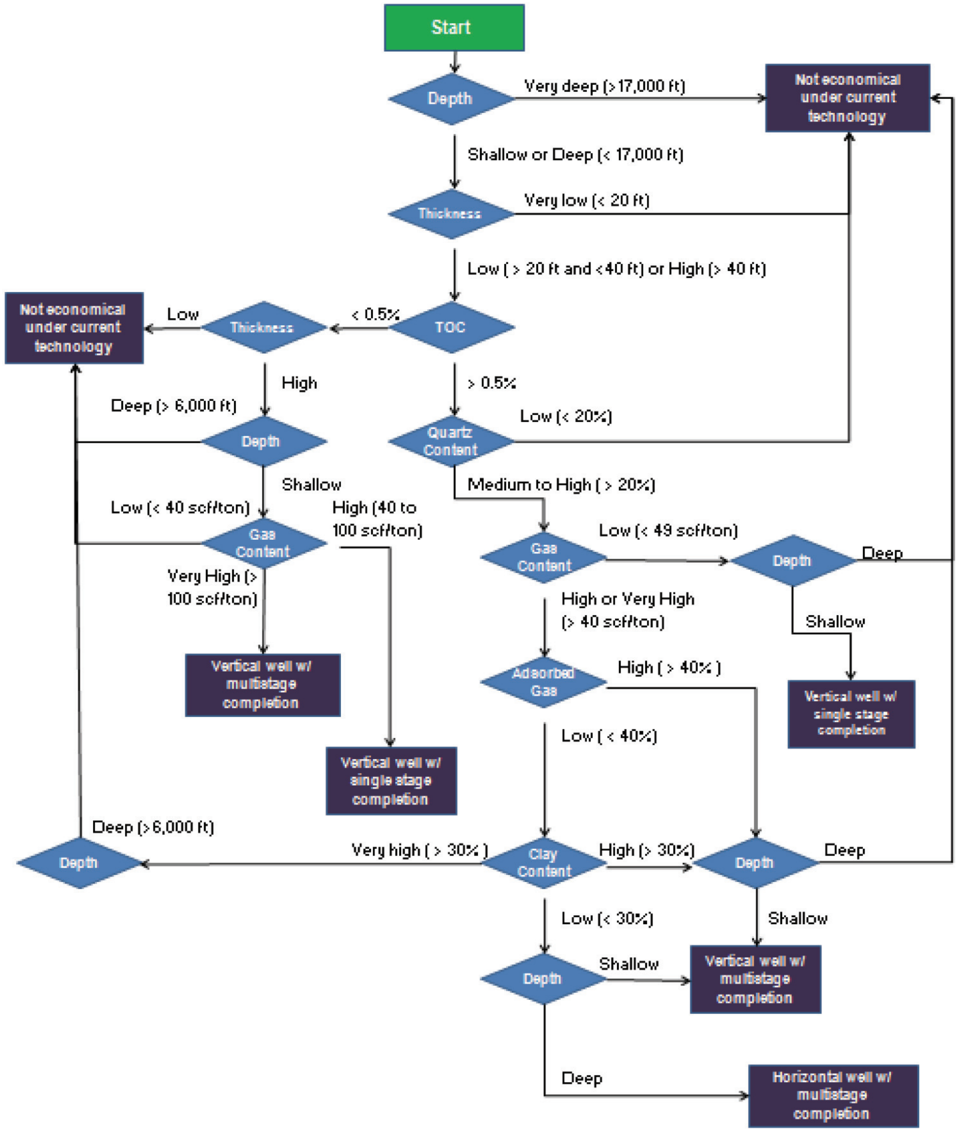

Fig. 10—Decision chart for selecting well orientation and completion type.

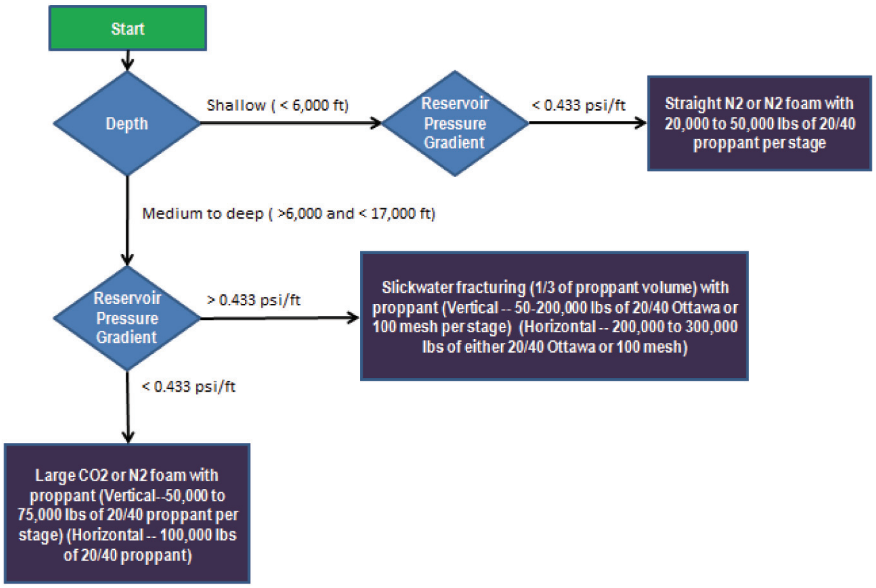

Fig. 11—Decision chart for selecting fracturing fluids.

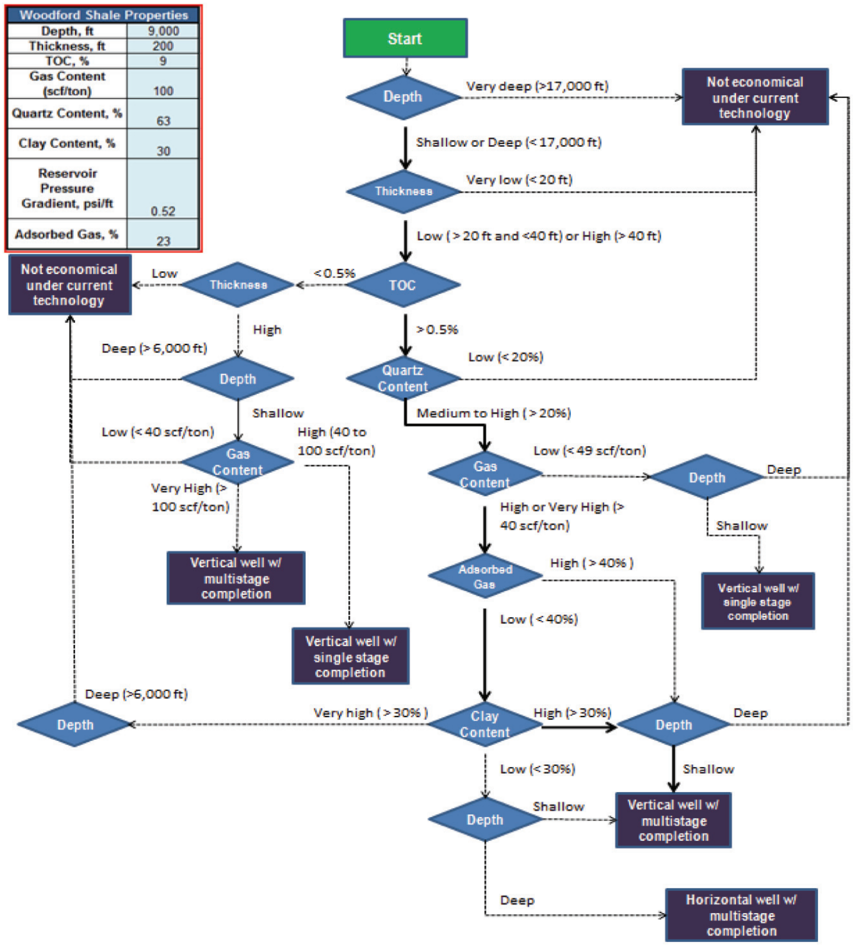

Fig. 12—Decision chart for Woodford shale example.

created for quick analysis on what is the ideal well type (vertical or horizontal) and completion fluids to use if given certain geologic parameters discussed in this paper.

- Completion is the key to the success of many of the gas-shale plays. With the development of new technology, these new gas-shale plays will take off even faster.
- Because the energy industry is volatile, economic sensitivity was conducted on the price, capital cost, and operating cost to see what effect they would have on the economic strength of these types of plays in the energy environment. Of all the observations made, it seems that horizontal drilling is economic in almost every environment except the Woodford shale, where only one scenario was not economic.

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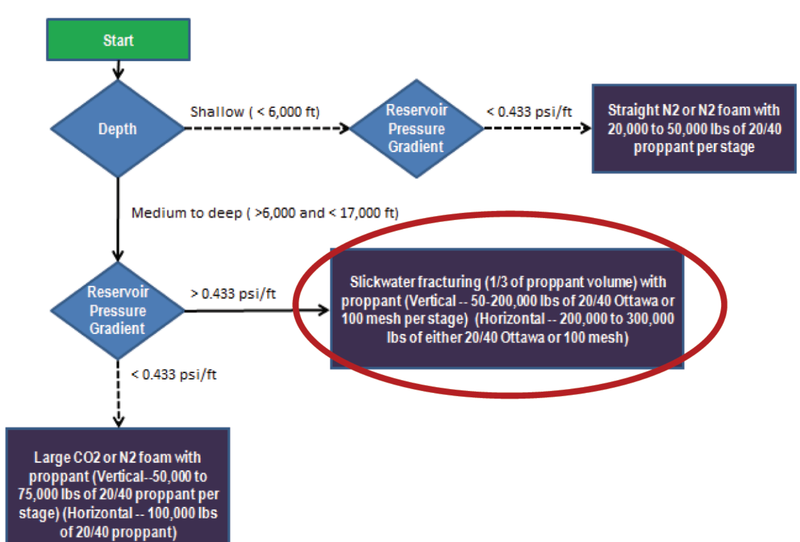

Fig. 13—Fluids decision chart for Woodford shale example.

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