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US Natural Gas: Lessons from BP's Tight Gas Facility in Wamsutter WY

Posted by Gail the Actuary on June 3, 2008 - 10:00am
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I recently visited BP America's tight gas facility in Wamsutter, Wyoming on a trip paid for by the American Petroleum Institute. I was the only representative of internet media on the trip. The other reporters on the trip were from AP-Cheyenne, Casper Star-Tribune, and Natural Gas Weekly. On the trip, we spent a day and a half listening to presentations and touring facilities. We also stayed overnight at the facility BP built for visiting workers.

Figure 1 - Two natural gas wells plus solar panel - Click for larger picture

In this post, I will tell a little about what I learned. I will also look at prospects for the future -- both in terms of being able to expand operations and threats to maintaining current production levels.

BP America's Wamsutter Operation - Early Years

The Wamsutter gas field is located in southwestern Wyoming. It is about 55 miles long and 35 miles wide. BP America has had operations there since the mid 1970s. BP is not the only operator in this field, but it is the largest one.

Wamsutter's gas is tight gas -- It has low permeability (.01 md) and low porosity (< 12%).

Hydraulic fracturing ("fracing") is needed to get the natural gas out. Compared to conventional gas, wells need to be spaced closer together because gas does not travel far in such a tight formation. The initial internal pressure of a well can be high, but drops off quickly. Natural gas production also start off high, but quickly drops. Wamsutter gas is sweet gas--without H_2S (hydrogen sulfide).

The produced natural gas has water with it. Once the pressure of a well declines, external energy inputs are required to separate the gas from the water. The energy source BP and other companies in the Wamsutter gas field have been using for many years is electricity from solar panels. BP is now considering adding windmills as an additional source of external energy.

The reservoir depth is about 10,000 feet. At this depth, there is a layer 500 feet thick, about 20% of which is pay. The productive portion is found in strata as thin as 10 feet thick. The productive strata (the "net pay") together add up to about 60 to 100 feet of the 500 foot layer.

In the early years, BP's approach to extracting natural gas was similar to that used for conventional gas. Individual vertical wells were drilled, with 8 wells per square mile (80 acre spacing). From the air, the arrangement looked like this:

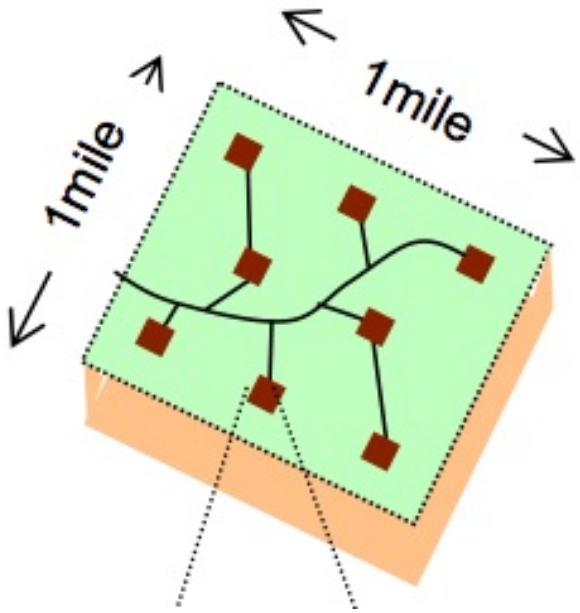

Figure 2 - Early layout of gas wells and roads

This arrangement was very costly to service and maintain, in part because BP was responsible for building the roads to the wells. In addition, service people needed to visit each well individually. Pipelines were needed to each well. Separate tanks and other infrastructure were also needed for each well.

Besides well arrangements, BP followed industry practice in other respects. When prices were relatively high, it would rent more drilling rigs and increase the number of wells drilled. When prices decreased, it would lay off workers, stop renting rigs, and let production level off or fall.

BP America's 2005 Wamsutter Investment Program

In 2005, BP made a decision to change the way it managed the Wamsutter gas field. Instead of simply following the conventional gas drilling model, it would put together its own model, one

more in line with maximizing productivity as a tight gas facility. BP announced that it was planning to invest $2.2 billion in the field, to raise production from 125 million to 250 million cubic feet a day, before 2010. Of this, $120 million was investment in improving technology.

One of the major things BP decided to change was well spacing. Instead of drilling eight separate wells on individual pads within an area one mile square, it would consolidate up to eight wells onto a single pad, and arrange the pipes so they still drained the same area one mile square. This way, much less land would be disturbed and many fewer roads would be needed. Other infrastructure could also be consolidated and servicing costs would go down.

In order to make this change, BP needed drilling rigs that would drill "deviated" wells - that is, wells that angled off, then down, so that the surface portion of the wells could be placed on a single pad, while the wells themselves were spaced out, like the legs of a daddy long legs spider. The drilling rigs also needed to be capable of drilling one well, and then moving to the next, without being taken apart, transported a few feet, and put back together again. Since rigs are rented by the day, the several days that rigs are out of service during the take-down and set-up would add greatly to the cost.

In order to get rigs of the proper specifications, BP found it was necessary to work with manufacturers to produce rigs suited to its needs and then sign long-term leases on the rigs. BP decided to lease seven rigs--three from Helmerich & Payne, and four from Nabors, at rates averaging approximately $30,000 a day.

Figure 3 - One of the new drilling rigs

Besides having the proper specifications, the new drilling rigs are much more automated. The "dog houses" are air conditioned and relatively quiet. Operators need to be highly trained individuals, instead of traditional "roughnecks".

Figure 4 - Controls inside "dog house" of drilling rig - Click for larger picture

As part of the 2005 initiative, BP made a decision to staff at a fixed level--the level of operations that the seven drilling rigs on long-term contracts could support. With this approach, there would be no more lay-offs, even if the price of natural gas declined. Besides fitting with the long-term contracts on the rigs, this approach had the benefit of providing a more stable working environment for employees.

Prior to the 2005 initiative, the community of Wamsutter had a population of 261, and had few amenities. The homes were mobile homes, each with its own well. BP decided that this needed to change, if Wamsutter was to be an inviting place for educated workers to live. Starting in 2005, BP began helping Wamsutter add services. Some of the projects BP has helped fund include water and sewer systems, road improvements, a day care, and a park.

Figure 5 - Community development director at the new day care

In order to have educated workers, BP has also contributed $500,000 to Western Wyoming Community College, to enhance the college's oil and gas technology program and $5 million to University of Wyoming's School of Energy Resources.

Other Technology Enhancements

Besides shifting from individual wells to grouped wells, BP has been pursuing other types of research:

• Remote monitoring. Years back, service people needed to drive around in a truck to check each well individually. Now most of the relevant information is transmitted electronically, so that a visit is required only if there is a problem.

• Electrification of wells. Electricity is needed at the well site to separate natural gas from the water produced with it and to transmit monitoring information to the office. The original approach, used by BP and others, was to use a single solar panel and battery for each well. Now that BP is grouping wells on a pad, BP uses a larger grouping of solar panels together with several batteries, to provide longer backup. BP is considering adding a windmill to some pads, as an additional source of energy.

• Cordless seismic imaging. BP has worked with outside contractors on what it calls Firefly(R) land seismic imaging system. With the old technology, seismic imaging systems needed to be plugged into electric power at a proposed well site. This was a problem, since there are no electric power lines in most areas being tested. The new system uses battery operated units which transmit signals to the office.

• Horizontal wells. BP's current wells are basically vertical wells, adjusted for the need to have the surface units located on a single pad. BP is planning to test horizontal wells, to see how the economics of these wells compare with the current approach.

Well Productivity

The written material we were provided indicates that with BP's new technology, hydrocarbon recovery has been increased by up to 40% and drilling costs have been reduced by up to 50%. I do not know to what base this comparison is being made, but I can believe that costs have been brought down substantially.

We were not provided with an estimate of the expected recovery per well, but I tried to compute one from various information given at the presentation. I came up with a range of about 900 million to 2 billion cubic feet of natural gas per well. This seems like a fairly respectable level, compared to estimates for other natural gas producers.

One figure that is fairly easy to calculate is average annual gas production per operating well, including wells that were drilled years ago. In this calculation, only natural gas "not associated" with petroleum production is used. One can compare this statistic to statewide averages, using EIA statistics for natural gas production and number of wells.

For BP Wamsutter, the information provided suggests the average annual production per operating well is currently about 68 million cubic feet per well ((240 million x 365 days)/1,282 wells). If wells have an average life of 30 years, and this average continues to hold, this would suggest ultimate recovery averaging just over 2.0 billion (=30 x 68 million) cubic feet per well.

One could get a similar number with a 40 year life and a lower annual average.

One thing I noticed when looking at EIA data is how much average production per well varies from state to state (Figure 6). Ohio, Pennsylvania, and West Virginia all have very low averages--about 3 or 4 million cubic feet per year. I expect this production is coal bed methane. If these wells have a 40 year life span, one might expect ultimate recovery of 140 million cubic feet per well (=40 x 3.5). I find it hard to believe that wells with this low level of productivity could be profitable. Yet developers seem to view these wells as at least marginally profitable--the number of wells in these states has been increasing in recent years.

In contrast, Figure 6 shows Wyoming's average annual production per well is above the US average (excluding these states with very low average production rates). BPs Wamsutter's average of 68 million cubic feet is in line with both the Wyoming average and the US average excluding Ohio, Pennsylvania, and West Virginia.

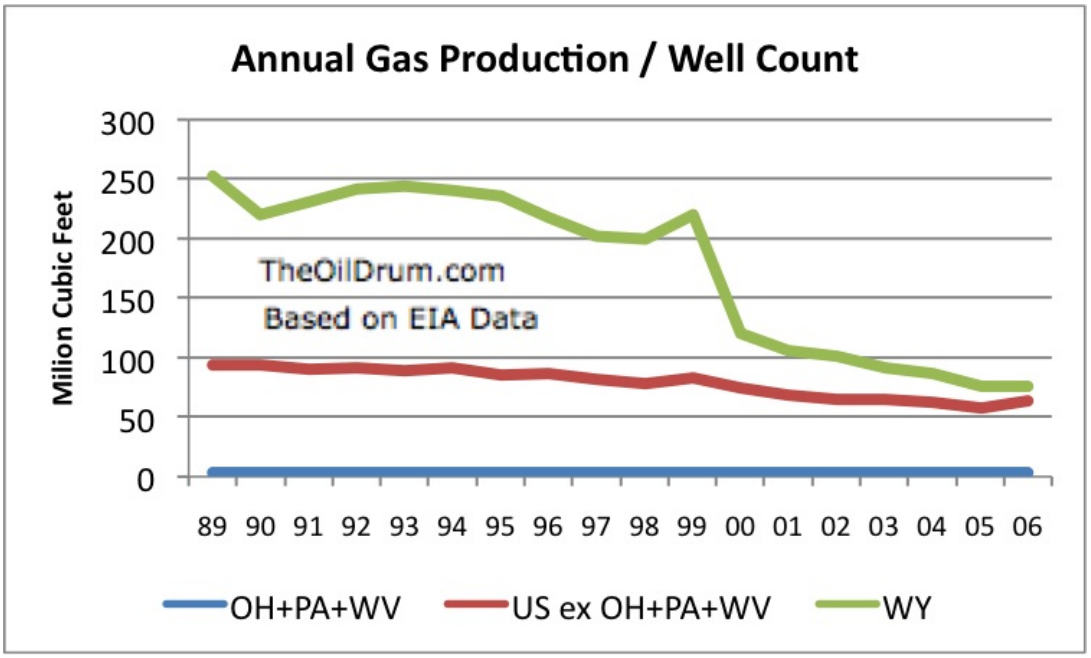

Figure 6. Average annual productivity per well for selected state groupings

Production Costs

We were not given an accounting of costs that go into producing BP's tight gas, but it appears that drilling costs are a smaller percentage of the total than for conventional gas. Items which would contribute to BPs costs include the following:

• Drilling costs. We were told that the individual wells costs in excess of $2 million. I am not certain which costs are rolled into this calculation. The seven drilling rigs are rented at rates averaging $30,000 a day, and these seven drilling rigs in total drill 150 to 170 wells a year.

• Seismic imaging. Imaging is needed at each proposed well site.

• "Fracing" of wells. BP uses two portable rigs for this operation. I would presume these rigs are considerably less expensive than the seven drilling rigs on long-term lease.

• Long term lease for the large amount of land held. Costs may be low, since the same land can be used for agricultural purposes (grazing cattle, etc.)

• Roads to service the wells. Roads are gravel and need to be regraded when affected by washing.

• Travel of service people to wells. We were told that while this amounted to 1,000,000 miles per month in the past, it has been reduced to 800,000 miles per month through greater use of long distance monitoring.

• Technology research. BP has allocated $120 million for research, over a five year period.

• Well infrastructure and replacements. Each well or group of wells contains equipment for separating the extracted material into its components, holding tanks, monitoring equipment, solar panels, and battery back-ups. If wells have a 40 year life, replacements will be needed for many reasons--corrosion, solar panel theft, battery life, etc.

• Pipelines and compressors. Pipelines are needed for natural gas transmission. Compressors use natural gas for power, since electricity is rarely available in Wyoming.

• Office. Building for people overseeing natural gas production. Also warehouse for supplies.

• Residence facility. Since nearby living facilities are very limited, BP built a residence facility for workers who desire to stay there. It provides meals, recreation and laundry for up to 200 workers. The cost is at least partly offset by charges to workers using the facility.

• Assistance to Wamsutter. BP has been active in setting up a city a water system, building a day care, and finding a person to coordinate town development. Part of this is funded by BP; part is funded by Wyoming state agencies.

• Funding for University Training Programs. Noted previously.

• Taxes. Material provided indicates that in Wyoming (not just Wamsutter), these were $60 million in 2005, plus $170 million in federal royalties.

• Cost of money. Most of the expenses are front end expenses. Either funds need to be borrowed, or there is an opportunity cost in using funds that might be invested elsewhere.

We were told that in total, there are 750 to 900 workers at the BP site in a typical month. Of these, only 150 are actually BP employees. The rest are contractors of various types.

Future Prospects for BP Wamsutter

The company generally seems to be well situated. It is taking an approach of trying to learn as it goes, and incorporating new technology to hold down costs.

The company says that it has produced about 3 trillion cubic feet of natural gas since 1977. This represents less than 20% of the resource available in BP's portion of Wamsutter field. We were told that gas wells from the 1970s are still flowing.

To date, the spacing of the wells has been one well per 80 acres. BP has filed for approval to change the spacing to one well for 40 acres, and is in the process of getting necessary approvals. With this spacing, BP can put up to 16 wells on a pad, instead on 8. It can also add infill wells to previously drilled areas. BP's research indicates that in some portions of the field, flow rates will be adequate with the closer spacing.

Based on what BP has done to date, BP seems to be in a good position to increase production in

the future, if it chooses to. For example, it could decide to increase the number of drilling rigs it operates by one or two in say, 2011. If it were to make such a decision, it would need to order new rigs sufficiently in advance, and sign additional long term leases. It might need to make increases in other areas as well--more employees, more support for the Wamsutter community, greater office space, and perhaps a larger residence for visiting workers.

I don't know whether BP would choose to make such an increase in production, however. With its current "level load" philosophy, BP could choose not to add capacity. Instead, it might extend the number of years over which it can produce gas further into the future.

I think issues which would tend to hold back BPs Wamsutter production are peak oil issues and possibility water shortages.

Wamsutter is in a remote location. At present, it has a population of about 600. It does not have a grocery store, any medical services, or a hotel. Many of the workers live as far as 70 miles away, in order to have basic services. Even those who live nearby make many long car trips to purchase necessities. All of this is very oil dependent.

BP Wamsutter's natural gas operations are also quite petroleum dependent. The service people visit the wells in trucks; the drilling rigs are powered by diesel fuel. Grading of roads requires diesel. All of the supplies are brought by truck from distant locations. Visitors generally fly into Rock Springs, a tiny airport 70 miles away. Cutbacks in the availability of oil could affect all of these oil uses.

Regarding water scarcity, Wamsutter is in the Red Desert. It gets 8 inches of rain a year. The Rock Springs newspaper was full of stories about water issues when I visited. For example, it talked about well levels for existing homeowners dropping when new wells are added. Clearly, Wamsutter cannot be self-sufficient in growing its own food. It will need to have nearly everything brought in by truck. If residents try to pump more than the aquifer can handle, there could be a serious problem. Increasing the number of resident is likely to make the water problems worse, sooner.

Possibility of Others Ramping Up Production

What is the possibility of others jumping in and ramping up production in another tight stands location?

Shale gas is different, but I don't know how different. I suspect that some of the issues might be similar with Hayneville shale, which now seems to have the possibility of increased production.

My guess would be that if anyone wants to ramp up production quickly, it will not be easy. The number of rotary drilling rigs in use for natural gas in North America has stagnated in the last year. One reason for this may be the competition from oil, since the higher price is drawing rigs toward oil. Another reason may be that the more popular rig types are already close to full utilization. If this is the case, a company wishing to ramp up production quickly might need to make do with whatever happens to be available, even if it is not optimal for the particular application.

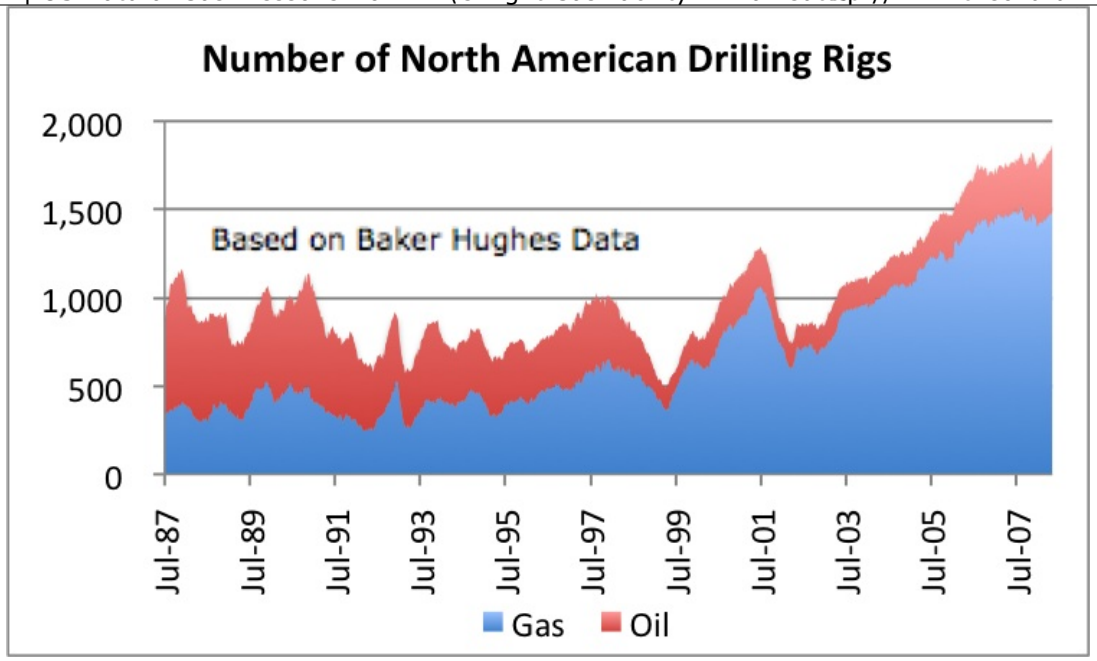

Figure 7. Number of North American leased rotary drilling rigs

Three of the rigs used by BP are manufactured by Helmerich & Payne. A check of its website indicates that in the past year, its land rigs were 97% utilized.

Clearly trained workers are another issue, especially with unconventional gas. Unconventional gas is expanding so rapidly that there are not enough workers to go around.

I have listed some other costs that BP has encountered, such as building roads, getting pipelines laid, and doing seismic testing. Depending on the location, a new company would need to deal with many of these issues. These are likely to take time and money, and may delay production.

I would expect that much of the research would be skipped, so as to start production quickly. Because of the important role technology plays, this could easily mean the difference between a profitable operation and an unprofitable one.

Putting these things together, it seems like ramping up production of tight gas will be a challenge. There is likely to be a delay of at least three years just to get all of the basics covered. Skipping research puts the new producer at risk of a much lower profitability level. And of course, the new producer will have to deal with the impacts of peak oil, just as BP will.

Previous Post

An earlier post I wrote, giving background information, can be found here:

US Natural Gas: The Role of Unconventional Gas

BP Presentation

BP provided a press version of one of the presentations that I saw. I have permission to post it:

BP Wamsutter Tight Gas Presentation