

The Evolution

of Tight and Unconventional Gas Field Development



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Ask any petroleum engineer about the science of developing tight and unconventional gas. Invariably, the answer will describe an imprecise craft, characterized by precious hard-won knowledge through generations of expensive trial and error. Most companies guard the specifics of their methods in an effort to maintain a competitive advantage. Stimulation experts who develop the right "recipe" to deliver results in a particular region and/or producing horizon become hot commodities. All of this is undoubtedly valid. In fact, many successful E&P companies have turned tight gas development and production into the Walmart of the oil and gas industry; indeed a very large scale endeavor with paper-thin margins, but highly profitable if done correctly.

Here's the problem. Most of the knowledge and technique acquired seems to be non-transferable. Companies have to (expensively) re-learn the secrets, largely by trial and error, every time they develop a new field. No one has come up with a magic formula for optimally developing a "generic" tight gas field, as it seems there are just too many variables and uncertainties in the equation. Instead, millions of dollars are often spent, following a decision of the type "Over there, they're drilling fractured horizontal wells on 40-acre spacing, so that's what we'll do over here". We're not suggesting that there is a magic formula, but what if there was a more systematic and scientific way to approach the optimum development solution?

A few years ago, we set out to try and solve this problem practically and systematically. Fast forward two years and we have F.A.S.T. Evolution™, not a magic bullet, but a practical tool that serves a specific purpose: "Identify the best development strategy using the information available". The primary value-added is that the program can narrow down a vast range of possibilities very easily and quickly, without tedious reservoir simulation or exhaustive economic runs.

The objective of F.A.S.T. Evolution™ is to answer the following questions:

1. How many wells, and of what type, are needed to optimally develop the field?
2. When and where should they be drilled?

To answer the above questions, we need to define the metrics for what is considered "optimal". All companies have different definitions for this. However, in the end, it almost always comes down to simple economics. In F.A.S.T. Evolution™, there are two main metrics that we investigate:

1. Total Field Recovery as a function of Number of Wells Drilled
2. Net Present Value as a function of Number of Wells Drilled (other net profit indicators may also be evaluated)

Over and above anything else F.A.S.T. Evolution™ is a scoping tool. The software is capable of running, comparing and testing sensitivities on a large number of simulated scenarios very quickly and efficiently. The user begins with a problem that is often vaguely defined and contains a vast number of possible solutions, and following the workflow within the software, successively narrows it down to a handful of very specific, detailed solutions.

To illustrate the software and workflow, let's consider the following example:

Operator X has acquired new acreage offsetting a large tight gas development. Infrastructure is limited, but well performance data and static reservoir data are plentiful in the offsetting regions. Operator X is not capital constrained, and is interested in finding the most profitable plan to develop the new acreage.

Area to consider – 1 section (640 acres)
Expected reservoir pressure = 5,000 psia
Volumetric parameters:
h = 25 feet
porosity = 12%
sw = 25%

Well performance analysis of 100 offsetting producers (using F.A.S.T. RTA™) suggests an average permeability of 0.01 md, with an average fracture half-length of 250 feet.

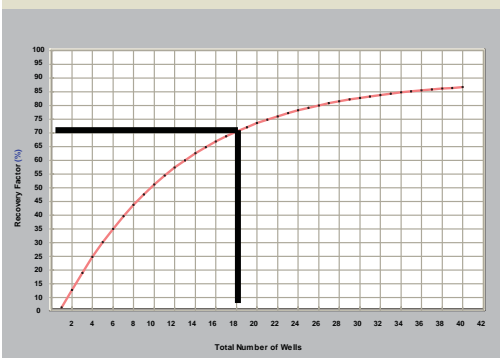
Operator X is interested in investigating the following:

1. How many wells should be drilled to achieve a total field recovery factor of at least 70 percent, over 20 years?
2. What is the most profitable well spacing scenario?
3. What is the optimum field production plateau rate, given that infrastructure will be expensive (letting all the wells flow unrestricted from day 1 is unrealistic)?
4. What is the optimum drilling schedule to achieve the desired field plateau production rate?
5. What effect does uncertainty in input parameters have on the results?

F.A.S.T. Evolution™ allows us to get a handle on these questions by investigating and comparing a large number of development scenarios very quickly.

We start by populating the analytical reservoir / well model with the known data. The program then runs multiple total field forecasts for a range of well spacing schemes, at predefined operating conditions.

Figure 1: Recovery Factor Versus Number of Wells Drilled

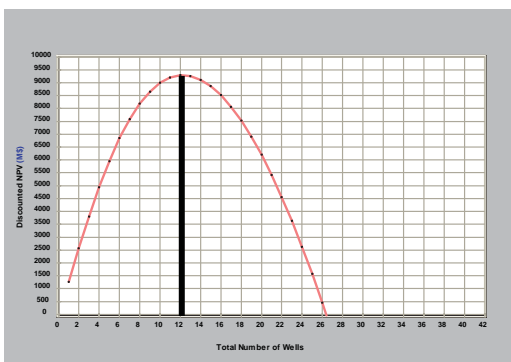


The resulting plot of Recovery Factor versus Number of Wells Drilled is shown in Figure 1.

From Figure 1, we can see that Operator X needs to drill at least 18 wells to recover 70% of the Original Gas-in-Place (OGIP) over 20 years.

Next, we enter some basic economic parameters, such as capital costs (well, gathering system, etc.), operating costs, gas price and discount rate. Once these have been applied to the production forecasts, F.A.S.T. Evolution™ can quantify the Net Present Value (NPV) of each scenario. The result is shown in Figure 2.

Figure 2: NPV versus Number of Wells Drilled



Unlike Figure 1, Figure 2 shows a clear maximum value, beyond which NPV declines, suggesting for the specified economic parameters, the field is most profitable with only 12 wells drilled, rather than 18.

To answer question three, we can use F.A.S.T. Evolution™ to run an alternative series of forecasts, where a pre-specified maximum field production rate is enforced. This maximum rate plateau (qmax) will restrict the total production from the field and reduce the capital cost of facilities (compression, transmission...) thus making more efficient utilization of installed facilities. F.A.S.T. Evolution™ automatically estimates the horsepower required for any qmax, and accounts for installed compression costs through a user specified dollar per horsepower amount. Figure 3 compares three different NPV curves including the unrestricted case and two different qmax cases.

Figure 3: NPV Plot Comparing Three qmax Scenarios

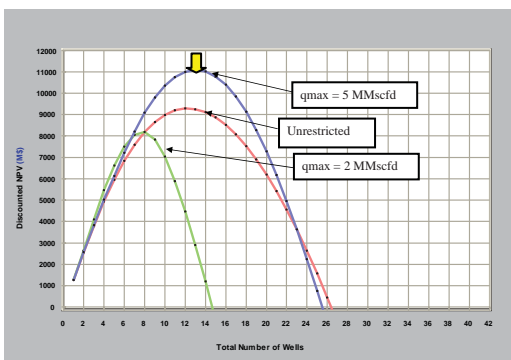
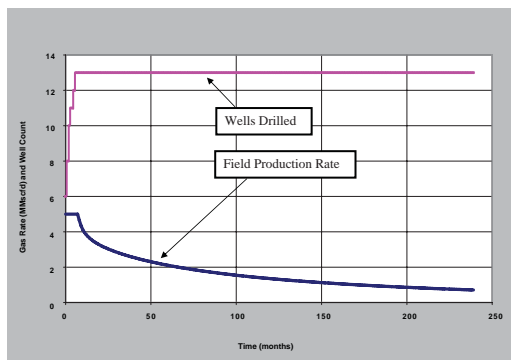


Figure 3 suggests that the optimum field development scenario consists of drilling 13 wells with a maximum rate limitation of 5 MMscfd for the field.

If the Operator decides to drill 13 wells and limit the maximum deliverability to 5 MMscfd, the obvious next question is when to drill these wells so as to maintain qmax. Clearly, there is no need to drill all 13 of them at time zero because, initially, the deliverability is being restricted to qmax. F.A.S.T. Evolution™ answers this question using a sophisticated analytical reservoir model that accounts for the interference among wells, and will also automatically determine the proper scheduling to meet the defined field rate.

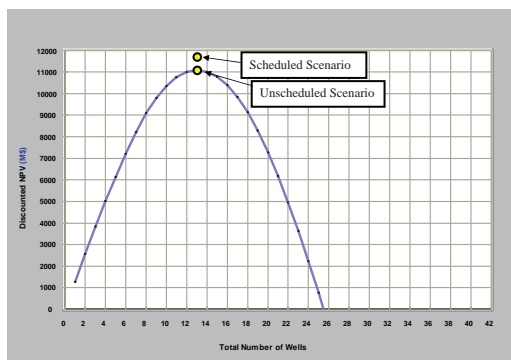
Figure 4a shows the resulting well schedule and deliverability forecast. Figure 4b shows a comparison of the NPVs for the unscheduled and scheduled scenarios.

Figure 4a: Calculated Well Schedule for qmax = 5 MMscfd



As indicated in Figure 4b, the Scheduled Scenario yields the higher NPV.

Figure 4b: Unscheduled and Scheduled Scenarios Compared on NPV Plot



Perhaps the most important thing to consider during this scoping process is the uncertainty in the input parameters. F.A.S.T. Evolution™ can evaluate this by quickly generating sensitivity scenarios for any reservoir or well parameter of interest. For example, let's say that Operator X wants to test the sensitivity of optimum well spacing to a predefined uncertainty in permeability. Figure 5 compares three NPV scenarios including the base case (k = 0.01 md), low case (k = 0.005 md) and high case (k = 0.02 md).

Figure 5: Sensitivity Analysis of Optimum Well Spacing to Permeability

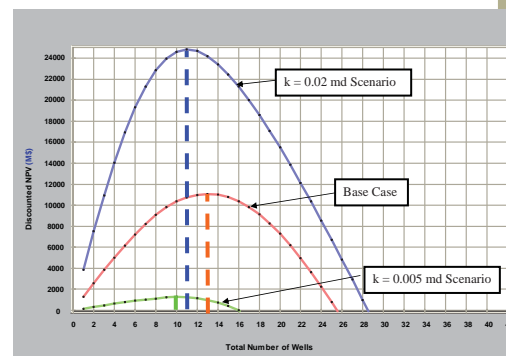


Figure 5 suggests that there is very little variation in the optimum well spacing - from 10 to 11 wells - between low and high cases, while the base case shows an optimum of 13. However, the range of permeability investigated shows a huge effect on the NPV.

In summary, we began with some basic reservoir, well and economic data, but little or no direction. Using F.A.S.T. Evolution™, we were able to quickly and systematically find an optimum development strategy for this undrilled acreage.

F.A.S.T. Evolution™ has not yet been released commercially. However, our valued customers are invited to test drive the "Beta" version of the program and provide their feedback. The program is slated for commercial release in Q4 2009.

For more information about our software contact our sales team by phone at 403.213.4200 or toll free at 1.800.625.2488, and via email at fast@fekete.com.

Well Test & Production Data Analysis



Reza Ali
Manager, Well Test & Production Data Analysis

Fekete Associates Inc. has been a leader in the petroleum industry in Pressure Transient Analysis (PTA) over the past 35 years and some 30,000 pressure transient tests have passed through our doors. We have designed, supervised and analyzed tests in every major oil and gas producing basin in the world and apply a level of detailed analysis that is unmatched in our industry. From our humble beginnings rose, arguably, the best PTA software in the world, F.A.S.T. WellTest™, that allows us to quickly load in volumes of data and then focus our efforts on interpretation.

More recently, Rate Transient Analysis (RTA) has proven itself to be invaluable to any asset team looking to better characterize a reservoir and to provide a more definitive estimate of reserves. Collectively, Fekete personnel have already conducted some 5,000 rate transient analyses in just the last few years and continue to lead in the development of this important tool.

Considering the synergies between the application and development of PTA and RTA, a natural next step to enhance consulting services to our clients, is to integrate the Well Test and Rate Transient Analysis departments into one group; Well Test and Production Data Analysis.

A well test analysis can provide the reservoir pressure, flow characteristics (permeability, skin, α), reservoir heterogeneities/boundaries and predict the near-term deliverability potential. However, we are continually under pressure to reduce flare volumes and flow times and must deal with increasingly complex reservoirs. If we hope to understand these reservoirs, we must be able to work with production data.

With good early-time production data, we can utilize RTA to estimate the flow characteristics and once boundary dominated flow is achieved during the production period, we can establish the drainage area and gas/oil-in-place. The Well Test and Production Data Analysis group can now apply both of these powerful analytical tools to provide an unparalleled opportunity to see further into the reservoir in a much shorter time frame than ever before.

For more information regarding our software you can contact our sales team by phone at 403.213.4200 or toll free at 1.800.625.2488, and via email at fast@fekete.com.

If you would like information about our Well Test and Production Data Analysis services, please contact Reza Ali at rali@fekete.com.

Fekete Announces New Partners

Over the past 35 years, we have had the privilege of working with many of you, and the projects and challenges that we have worked on together have led to tremendous growth at Fekete. We offer eight engineering services and six commercial software packages, and have more than 150 full-time staff. With new software products, practical and useful upgrades and new challenges in our engineering projects, we anticipate continued growth.

To help manage the growth of the Company, Louis Mattar (President), David Dunn (Senior Vice-President) and Ed Ferguson (Senior Vice-President) decided to enlist the help of four new partners.

Mehran Pooladi-Darvish, Ph.D., P.Eng. is Vice-President of Engineering, where he will be overseeing the simulation and integrated reservoir study projects to ensure that they meet Fekete's high standards in technical excellence. Mehran is also Fekete's expert on carbon storage, recently demonstrated in Fekete's Technical Video #15, "Geological Storage of CO₂".

Casey O'Shea, P.Eng. is Vice-President of Engineering Business Development, where he will oversee engineering project management, and staff development for engineers and geologists. Casey is developing a program to ensure new engineers and geologists are given training opportunities, both formal and on the job, to ensure continued technical excellence at Fekete for years to come.

David Anderson, P.Eng. is Vice-President of Software, and takes responsibility for the technical aspects of product development at Fekete. Dave has been outlining long term development strategies that will help Fekete's products become more integrated into the workflow of every production and reservoir engineer.

Kevin Dunn, C.E.T. is Vice-President of Software Business Development, where he ensures Fekete's software meets the needs of our clients, and leads the global sales and marketing efforts.

We look forward to working with you in the future, and growing to better meet your needs in the years to come.

