RESERVOIR SOLUTIONS

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Promising DCA techniques emerge as widespread public debate focuses on shale gas forecasts

How E&P companies forecast future production from unconventional gas wells—an issue usually confined to the petroleum engineering realm—is in the limelight now. In August, U.S. regulators began investigating whether some publicly owned shale gas producers overestimated reported reserves in previous filings.

As part of the probe, the U.S. Securities and Exchange Commission subpoenaed company records, including those from early 2008, according to press reports. The documents reportedly include material related to the analyses of production-decline curves, historical performance of shale gas wells vs. production forecasts and appropriateness of decline-curve methods.

Observers say that the SEC acted in response to calls by politicians that regulators investigate shale gas producers after a *New York Times* article in June questioned their economic forecasts. The public is now focused on the science of how companies count cubic feet of potentially recoverable commercial shale gas.

The SEC rules, revised less than three years ago, allow for the booking of reserves based on the use of "reliable technology" including computational methods such as reservoir simulation. By definition, reliable technology has a repeatable, consistent track record and is in widespread use in a given area.

Companies have not been required to make a case for justifying the booking of reserves by proving that classic decline-curve analysis (DCA) meets SEC criteria for reliability. That engineering technique has a successful, established, 60-year-old track record.

Well performance analysis

Petroleum engineers estimate proved developed producing reserves in various regions worldwide using DCA techniques. In the hands of a skilled evaluator, DCA yields repeatable, consistent results that are scientifically valid and reliable.

Industry uses DCA along with volumetric analysis and assumed recovery factors, flowing material balance, analogy, analytical production history matching, advanced production analysis and reservoir simulation to estimate future production profiles and ultimate recoveries per well.

DCA is a simple, fast evaluation technique for estimating petroleum reserves for large populations of individual wells. Those conducting DCA use classical rate-time equations. They were empirically developed by J. J. Arps and others before 1945 to calculate declines of three observable types: exponential, hyperbolic and harmonic. Current discussion focuses on when and how quickly a shale gas well transitions from hyperbolic to exponential decline during changes in flow regimes.

Besides graphing production declines, engineers also plot cumulative production, flowing-tubing and casing-head pressures, yields (oil-gas ratio) and produced water over time. Some of these inputs are used in advanced production analysis, which combines concepts from pressure transient analysis

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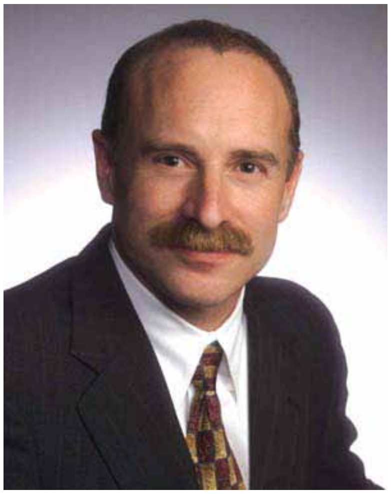


Wilson

with production data.

"Using all these curves provides additional clues to the well's personality, just like many well-log traces are used to understand reservoir properties," said **Scott Wilson**, a senior vice president and petroleum engineer.

Advanced production analysis, such as rate-transient, is an extension of DCA. It is used to evaluate shale gas but has limitations. To be useful, advanced production analysis may require additional input from other data sources. The technique also has to be done over a specific early-time production period to generate unique solutions.

B exponents and unconventional gas

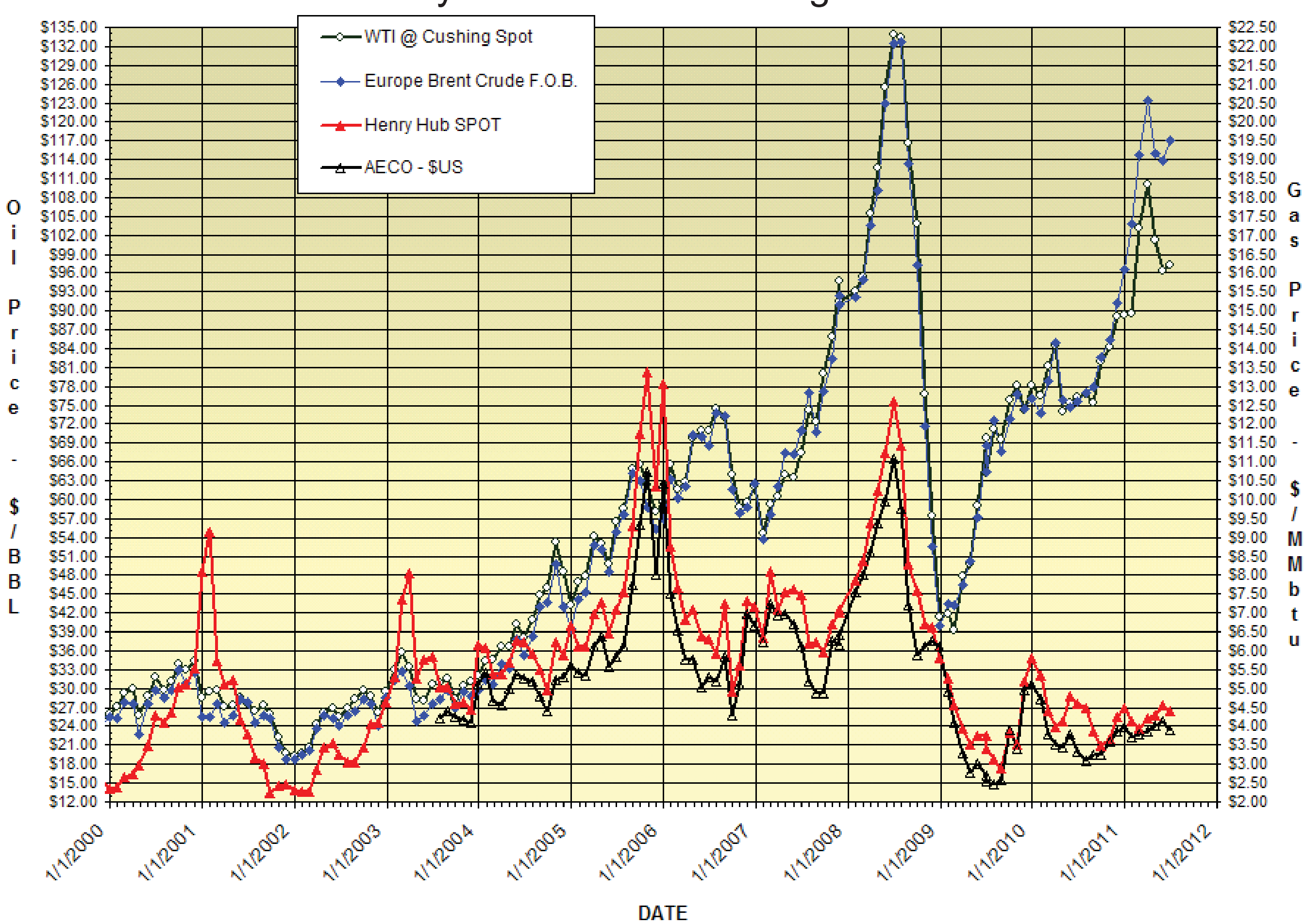
A well begins producing in early-time transient flow with possibly high bottomhole pressures (BHP) followed by boundary-dominated flow and low, constant BHP. The original Arps exponential model for the industry's decline curves was based on boundary-dominated flow which is reached in months in conventional reservoirs.

A transient-flow regime, however, can last for years as tight gas is produced through a network of fractures, tight zones or horizontal sections. So shale gas evaluators have resorted to using a hyperbolic b exponent in the Arps equation that generates the curved portion of the production decline before it straight lines into a long-tailed exponential decline.

Two schools of thought clash on how high b factors can be. Some evaluators force a $0<b<1$ limit for the hyperbolic b because they say that Arps defined those parameters for that case. They also fear that late-time volumes will be unrealistic if a minimum percentage of decline is not imposed on the tail end of production.

The assumption that b is less than one, however, does not mesh with what industry is seeing in actual wells. Hyperbolic b values approaching two, in some cases, have been shown to theoretically and in practice

Price history of benchmark oil and gas in U.S. dollars



Published, monthly-average, cash market prices for WTI crude at Cushing (NYMEX), Brent crude and Henry Hub and AECO gas.

model early shale gas production. To limit higher b values, evaluators from the "school of pragmatism" plug in a trailing exponential segment to generate rate-time plots.

DCA, type curves and analogs

Typically, a DCA exercise begins by plotting stable initial production rates in detail over one month's time for instance. At the beginning of the well's production decline trend, extrapolating forward involves a high-degree of technical uncertainty.

Historical trends are frequently not sufficient to define early-time decline curves in subject wells. So evaluators look at curves from producing wells (analogs) in the same field or reservoir if available.

Evaluators type curve analogous wells to get an average production profile, which can guide forecasts for the subject immature well. Type curves are generated first by normalizing historical production from analog wells on a rate-time plot. Normalizing involves starting the plot of each of those wells at the same point in time for the sake of comparison.

Then the evaluator adds the rates of each well at incremental points in time and divides the totals by the number of wells to plot an average production curve. Type curving has limitations in shale gas evaluations because drilling-and-completions technologies change rapidly and no two wells are alike.

Hein

"Using analogs has the potential to be fairly reliable for tight/unconventional reservoirs," said **Victor Hein**, a petroleum engineer and tight-gas expert at Ryder Scott. "However an evaluator must identify appropriate analogies. The analog should be at a more advanced state of depletion than the subject well or field."

He remarked that completion methods must be similar including the frac length, sand concentration, lateral length and orientation, etc. Overall, the factors/properties controlling recovery in the analog, including effective drainage area, should be no more favorable than the considered target application.

"Analog wells should have similar completions, reservoir parameters, spacing and sufficient production history for reliable analysis," said Hein.

Without nearby analogs or a significant history on the subject well, evaluators have to conduct probabilistic analysis, a statistical approach to estimate prospective resources, a less certain category than reserves. Resources are not filed with market regulators in the United States.

Classic DCA

Evaluators use type curves from analogs and apply the b Arps hyperbolic parameter that best matches the well to forecast initial shale gas production decline. Evaluators have found that a best-fit match of the transient flow regime with the Arps hyperbolic decline gives b values greater than 1 with some approaching 2. That is a departure from the $0<b<1$ classic theory.

While shale gas evaluators may use relatively high b factors to generate hyperbolic curves, they have also observed that those b values decrease as the well transitions to boundary-dominated flow and exponential decline. So most evaluators use a minimum decline (Dmin) final segment.

Higher minimum terminal decline rates, for instance 10 percent or higher, can under-predict estimated ultimate recoveries (EURs) when used with high hyperbolic b factors. Conversely if an evaluator uses a Dmin that is too low, then the forecast will overstate reserves.

Evaluators have used the simple, yet crucial Dmin add-on for at least 25 years to account for the onset of reservoir depletion in the production tail. The Dmin also compensates for the tendency of high b-factor hyperbolics to overshoot EUR if left unconstrained.

"A higher b factor may generate higher EURs when compared to a poor fit of a hyperbolic b less than one, but the controlling factor is usually the initial rate and minimum-decline value used by the evaluator," said Wilson.

While the most frequent complaint of the Arps method is that hyperbolic b factors generate optimistic recovery values, that argument usually ignores the use of Dmin values.

"The minimum decline rate is a 'bolt-on' improvement to a method that cannot match early- or late-time behavior without using at least two segments," said Wilson, who evaluates oil and gas shale plays across the United States. "It's not technically elegant, but this combination of two segments—hyperbolic b factors and using Dmins during exponential decline—crudely honors the curvature from transient to boundary-dominated flow."

The b factor and Dmin combination for five shale plays have been calculated through a statistical analysis of historical production decline trends. Jason Baihly et al wrote SPE technical paper No. 135555 published last year with the following b and Dmin values for the following plays:

- Barnett: b=1.5933, Dmin=0.0089
- Fayetteville: b=0.6377, Dmin=0.0325
- Woodford: b=0.8436, Dmin=0.0227
- Haynesville: b=1.1852, Dmin=0.0632
- Eagle Ford: b=1.694, Dmin=0.0826

Wilson dismisses the idea that skilled evaluators will inadvertently continue to use hyperbolic b factors long past where the transient flow regime has ended. "We can tell when transient flow ends. As described by Fetkovich and others, the end of the upward curvature on a log-log plot is a simple first indicator."

Wilson cited a more complicated method to discern the end of transient flow that involves plotting an

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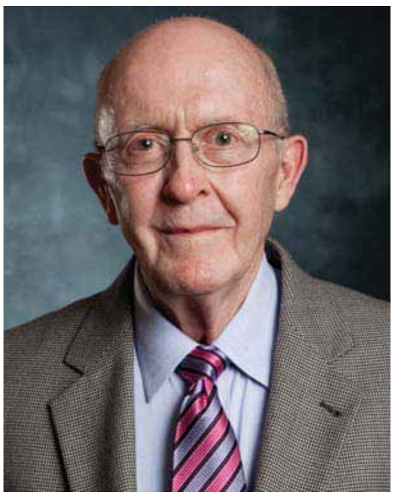
inverse of the flow rate vs. the square root of time, i.e., 1/q vs. sqrt(t). "It's somewhat more painful to use that method, but if the Y scale is inverted, it looks just like a decline curve," he remarked. "This plot identifies when a well is no longer in linear flow since the data will curve down off a straight line once the boundaries are seen."

Linear flow is seen when a well produces gas from fractures before the well begins to drain the reservoir from its boundaries in all directions in a radial pattern.

New DCA methods

Evaluators of shale gas continue to use Arps hyperbolic b factors and Dmins as a time-tested, successful estimating technique to forecast production. However, as petroleum engineers begin to understand the behavior of horizontal, fraced shale gas wells, they are developing new DCA techniques to mathematically model early-time, fracture-dominated transient flow.



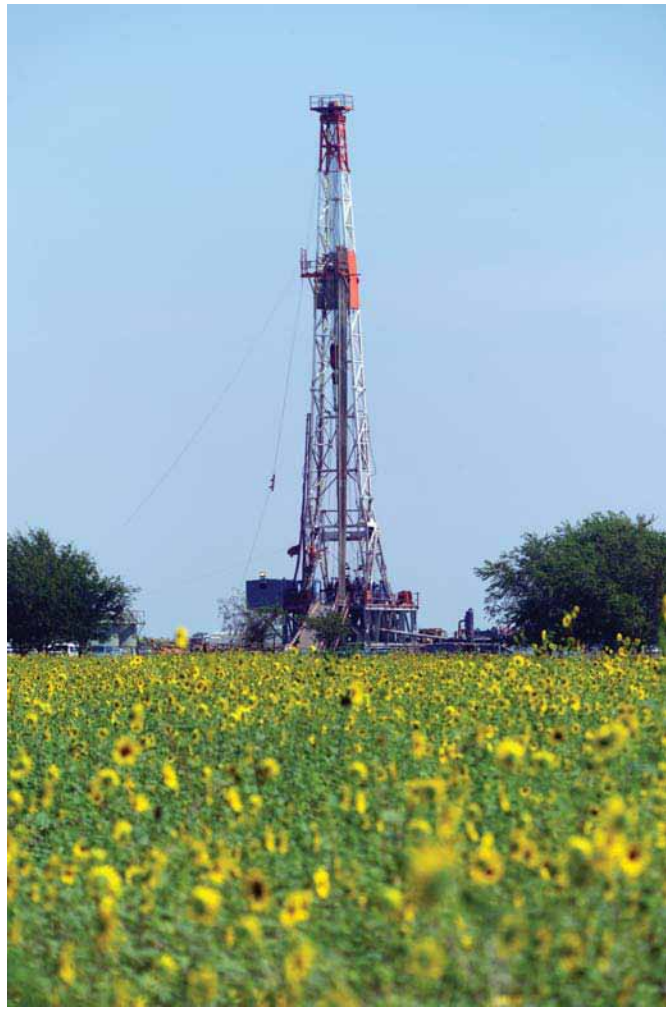
Lee

A new empirical method is catching the attention of evaluators—the stretched-exponential production decline (SEPD) model, which was introduced by **John Lee** at the Society of Petroleum Engineers annual meeting a year ago. The stretched exponential function was first introduced by physicist Rudolf Kohlrausch in 1854 to describe the discharge of a capacitor. More than 150 years later, the oil and gas industry is using the SE function to model fluid flow rather than electron flow.

Lee, a professor at the University of Houston, was an engineering fellow at the SEC during the rules-change process for reserves reporting in 2008. He is also a member of the National Academy of Engineering. The SPE technical paper on the SEPD model ("A Better Way to Forecast Production from Unconventional Gas Wells," coauthor **Peter P. Valko**, SPE No. 134231) summarizes the Lee-Valko findings.

The SEPD model has proved successful in a test case involving more than 2,800 horizontal, fractured Barnett shale gas wells. "The SEDM decline trend seems to be quite consistent at least in a completion type—most importantly for horizontal wells intersected by several propped fractures with an overall amount of sand reaching millions of pounds," said Lee.

The SEPD technique models fracture-dominated flow by considering the reservoir to be heterogeneous and comprising "a great number of contributing volumes individually in exponential decay." The SEPD approach takes into account that a shale well produces from thousands of fractures.



Barnett shale gas wells, such as this one, may have long production histories, making them suitable for testing the forecasting reliability of new decline-curve methods. Photo courtesy of Oil and Gas Financial Journal.

"If a minimum ultimate decline rate is imposed, the Arps model can meet the criterion, but determining the ultimate decline rate is best found from analogous reservoirs with long histories and we don't have any in shale plays," said Lee in an interview with Hanson Wade, an events management company.

Others also see the SEPD model's so-called "bounded nature of EUR from any individual well" to be an enhancement. "The SEPD model is a modest improvement over the classic Arps hyperbolic if only because the need for a Dmin is eliminated," said Wilson.

"If you are going to forecast with Arps, you have to use a minimum decline rate from type curves of well production histories. With the SEPD model, you don't need to assume a Dmin. It's already in the formula," said **Gary Gonzenbach**, president of TRC Consultants, makers of PHDWin decline-curve/economics software.

The SEPD model is not the only one considered to be an earnest attempt to solve problems in analyzing prolonged transient flow in shale gas. This year, **Anh N. Duong** at ConocoPhillips introduced his own empirically derived decline model that is based on long-term linear flow in a large number of wells in tight and shale-gas reservoirs.

"Arps curves give more optimistic forecasts compared to the new approach," stated Duong in his SPE paper, "Rate-Decline Analysis for Fracture-Dominated Shale Reservoirs (Paper No. SPE 137748). Like Lee, Duong used Barnett shale wells to test the forecasting method.

"The method that looks best to me is not the SEPD model, but the method proposed by Duong," said Lee. "We have not found a single case with decent data in which the method failed and it works in the Bakken oil shales, Barnett gas shales and elsewhere."

Lee and others agree that all performance analysis methods used to evaluate shale gas can be reliable if done properly. Referring to Duong's method, he said, "The EURs this method predicts have been quite close to the SEPD model and Arps with a realistic Dmin."

None of the methods are as reliable during early well life. "There's nothing magical about the SEPD method. It's often very wrong, high or low, with the first year's data, but settles down and forecasts only slightly changing EURs after the first year or two," said Lee. "Also, it also has the problem that no two evaluators seem to get the same parameters in the modeling equation because they approach determining the parameters in different ways."

Despite the lack of a long track record for the non-classical methods, Lee doesn't support the use of Arps in evaluating shale gas reserves. "I can't in good conscience recommend Arps to anyone," he said. "It is technically incorrect because its use in ultra-tight reservoirs violates assumptions made in the derivation of the model. Secondly, in almost all cases, b decreases with time, meaning that the EUR estimates tend to decrease with time." Stated another way, the EUR estimates tend to be too high at early stages of production, according to Lee.

Wilson said, "Why does an evaluator use a b factor greater than one? The answer is because that's what the well is doing and there are lots of analogous wells behaving that way. If the forecast changes from b=2 to b=0 when the well leaves linear flow, is that necessarily wrong?"

Wilson said that even though he hears comments on whether the Arps hyperbolic functional form is even appropriate in the modern age, the more important consideration should be on the competence of the evaluator to use classic DCA or other newer tools to get the best answers.

"A hammer in the hands of a master carpenter can do a wonderful job. It may not do such a good job while in the hands of a two-year old trying to wake up his father," said Wilson.

As promising as they are, the new DCA approaches are relatively experimental. Production forecasts based on any widespread use of those techniques may be questioned by regulators, bankers and others for now.

Published results were based only on similarly completed Barnett shale gas wells. "We do not claim that repeating the analysis in another play will lead to similar consistency," said Lee in his paper. "Nevertheless, with some variations, the main concepts will be applicable."

Ongoing testing has further validated the new approaches. Lee said in September that his method and Duong's were used with success on significant groups of wells from unconventional resource areas other than those in the Barnett study, including the Bakken and Fayetteville shale plays.

TRC plans to program the SEPD algorithms into its release of PHDWin Version 3. Fekete Associates Inc. also said it will integrate the equations into its production analysis software.

Halliburton has built scripts and incorporated the SEPD algorithms into its Aries modeler module in its economic evaluation software package. The company said in August that no clients were using the SEPD module and the only inquiries had been from consultants, not oil and gas companies.

However, as momentum picks up and if inquiries turn into sales to early adopters, the future may be bright for DCA techniques that model linear, facture-dominated flow when gas production and cashflow from unconventional wells peak.

Ahead of the curve

Ryder Scott recently compared classic DCA with the stretched exponential method and Duong's techniques on a selected well in the Haynesville shale gas play. The classic equation was a modified Arps hyperbolic with a b of 0.8 and a Dmin of 5 percent. The three forecasts under a time-limit cutoff of 4,000 days were fairly close in predicting EURs. The Duong method projected a 2.1-Bcf EUR, the highest prediction, followed by the Arps method at 1.9 Bcf and the SEDM at 1.8 Bcf. See chart.

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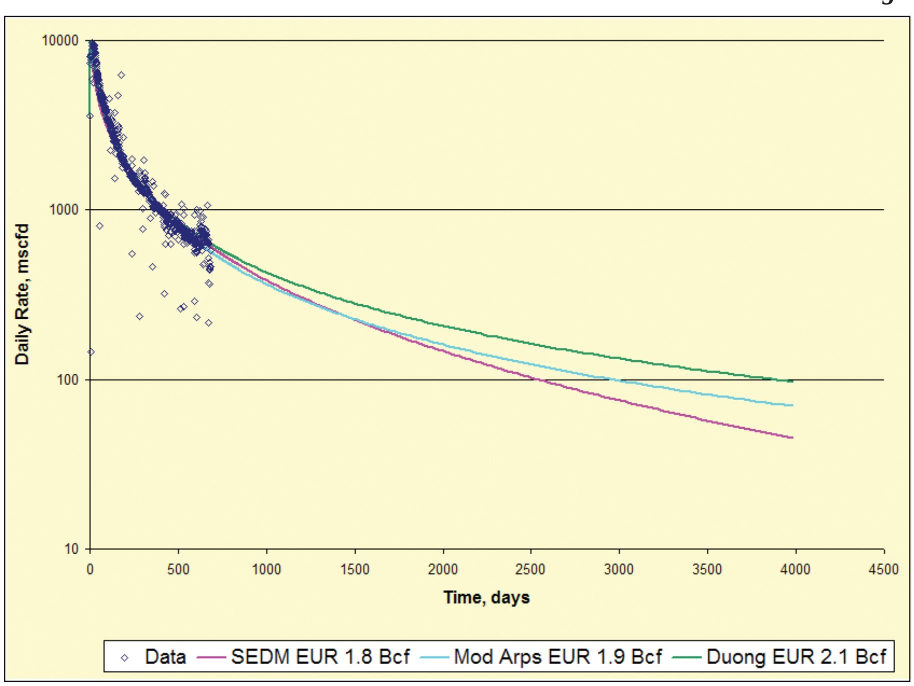

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Smith

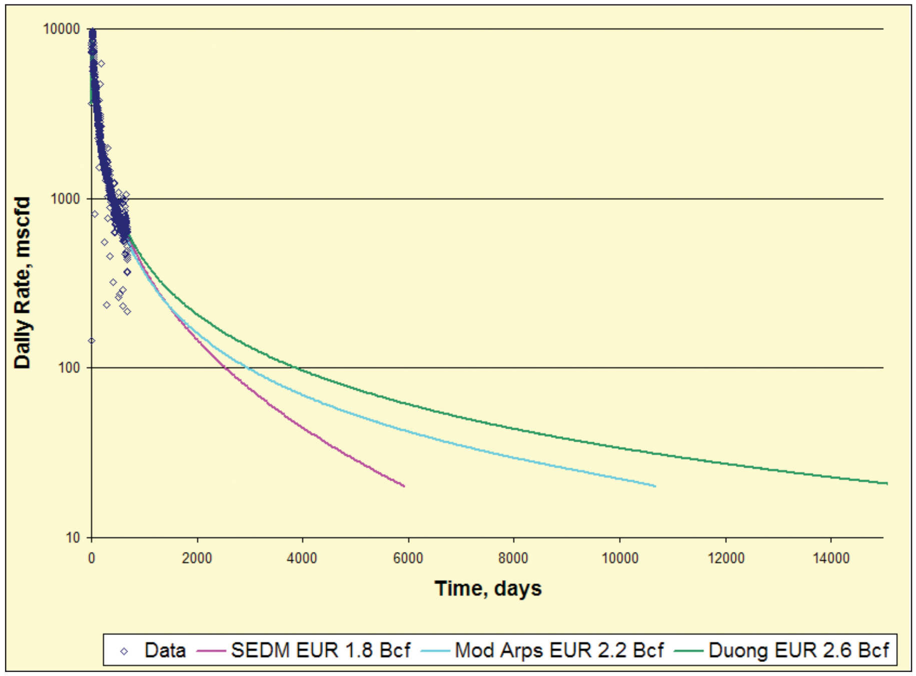
Using a production rate cutoff of 20 Mcf of gas per day, the three techniques show more divergence. See chart.

The total life of the Duong method under the rate cutoff is 42 years—a duration too long to justify based on two years of performance. A projection over that extended time period may not produce a reliable forecast because the well is more likely to have operational, mechanical or water issues during that time. That is a special concern in a new play without established, long-life wells, such as the Haynesville.

"Price and cost forecasts that far out also become fairly uncertain, so the entire estimate may have less confidence," said **Lucas Smith**, petroleum engineer at Ryder Scott. "The production curve shape could very well be correct, but the economic and technical lives of the well are harder to predict."

For comparison purposes, it's best to pick the same ending date or the same ending rate for each case, but with a realization of the limitations of each cutoff method.

"The graph with a production-rate cutoff is interesting because it shows how each of the projection methods behave in the long term for this particular fit," said Smith. "The flattening of the Duong method for this case is much more apparent in the rate-limit graph than in the time-limit one."



While insightful, this limited test case will have to be combined with other cases to provide meaningful results before any conclusions can be made. Ryder Scott will continue to independently test and understand the newer DCA methods and other performance-based analyses on oil and gas shale wells as they are developed.

SEC compliance

The SEC concept of reasonable certainty implies that as more technical data becomes available over time, a positive or upward revision of proved reserves is much more likely than a negative or downward adjustment. Lee argues that because the b exponent tends to decrease with time in classic DCA, the method is susceptible to criticism under the reasonable certainty criterion.

Wilson said, "While it is true that hyperbolic declines over long periods of time can result in overstated reserves, it is also true that evaluators use a modified equation with a Dmin value that limits EURs to a proved-reserves basis."

Lee uses what some would call a "fudge factor" of 0.8 to incorporate conservatism in his SEPD predictions which are optimistic in 50 percent of the cases. "The requirement for a P90 demands a procedure for which 90 percent of the predictions are conservative. Therefore, we have to apply a safety factor of less than one that will bias our estimates toward the conservative side," he said.

"There are companies that have publicly stated that they use Arps with no Dmin. I believe that Arps, with or without Dmin, is subject to abuse and is, in fact, abused regularly." — Lee

Ultimately, the focus of regulatory reviews may be whether a company uses a Dmin or safety factor to reign in optimistic shale gas reserves estimates.

"There are companies that have publicly stated that they use Arps with no Dmin," said Lee. "I believe that Arps, with or without Dmin, is subject to abuse and is, in fact, abused regularly."

Editor's Note: The SPE papers cited in this article are available for purchase from SPE through the OnePetro site at www.onepetro.org.

Full array of topics featured in reserves conference

Agenda of 7th annual event includes SEC and shale gas, oil spills and ethics, nanotechnology

The 7th Annual Ryder Scott Reserves Conference was poised to draw about 200 registered guests a week before signup closed. The conference was scheduled to be held Friday, Sept. 16 at the Hyatt Regency Hotel in downtown Houston.

Ryder Scott plans to post the presentations to the website at www.ryderscott.com.

The following presenters and topics were scheduled:

- **Jeffrey Elkin**, Porter Hedges, "SEC Subpoenas to Shale Producers"
- **John Hodgin**, Ryder Scott, and **Marc Folladori**, Mayer Brown, "Observations from SEC Comment Letters Issued to Date"
- **Eric Sepolio** and **Jennifer Fitzgerald**, Ryder Scott, "Introduction to New Ryder Scott Freeware—SEC Public Data Search and Retrieval System"
- **Dr. John Lee**, University of Houston, "Exceptions to the SEC Five-Year Rule—Specific Circumstances"
- **Dr. Andrew Barron**, Rice University, "Can Nanotechnology Provide a New Approach to Oil and Gas Shale Production?"
- **Russell Hall**, Russell K. Hall & Associates, "Introduction to SPEE Monograph 3, Chapter 1—Definition of a Resource Play"
- **Martin Dobson**, Chesapeake Energy, "SPEE Monograph 3, Chapter 2—Statistics: A Brief Lesson"
- **Paul Lupardus**, Chesapeake Energy, "SPEE Monograph 3, Chapter 3—Determining Proved Areas in a Resource Play"
- **Brent Hale**, William M. Cobb & Associates, "SPEE Monograph 3, Chapter 4—Estimating Undeveloped Reserves in a Resource Play"
- **Dr. Rusty Riese**, AAPG Distinguished Ethics Lecturer, "Ethics—Oil Spills, Ethics, and Society: How Do They Intersect and Where Are the Responsibilities?"

Reservoir Solutions newsletter will recap the presentations in the upcoming December and March issues. The latest newsletter is always posted quarterly on the website and accessible from links on the home page.

The 6th Annual Ryder Scott Reserves Conference attracted about 200 guests last year, representing the largest gathering of senior reserves evaluators.

Only 16% on track to comply with 5-year PUD rule

Simplistic math allows SEC to challenge PUDs, onus on company to prove it can fulfill drilling schedule

John Hodgin, president, co-chaired a session, "Insights to the Industry's Securities and Exchange Commission Reporting and Disclosure," last July at the SPE/AAPG/SPEE Reserves and Resources Estimation and Reporting Symposium in Houston. Among several issues that he presented was how the SEC evaluates stale proved undeveloped reserves. The SEC limits PUD bookings to five years with exceptions.

Hodgin said that the agency takes the most recent 12 months of drilling activity as a percentage of the total PUDs a company has in its filing. Then the SEC uses that annual pace percentage to determine whether a company can complete the remainder of its PUDs within 5 years.

"This simplistic math allows the SEC the ability to challenge what you currently have on the books and it is up to your company to prove how your schedule can be fulfilled," he said.

Ryder Scott completed a cumulative frequency analysis on the 53 companies receiving SEC comment letters and found that 80 percent are drilling at a track record slower than required to meet the five-year rule. Only 16 percent of companies are on track to comply and 50 percent are on a 10-year track.

"The primary focus of the SEC has centered on the five-year PUD rule," said Hodgin. "Specifically, a significant portion of the SEC letters revolved around the development and the pace of a company's well portfolio."

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Engineers join Ryder Scott Houston office

Ling

Kegang Ling recently joined Ryder Scott as a petroleum engineer in the Houston office. Previously, he worked at China National Offshore Oil Co. for nine years as a reservoir engineer and geologist evaluating fields in offshore China, Indonesia, Australia and New Zealand. While there, Ling conducted reservoir simulation modeling and geological and geophysical analysis. He also interpreted 3D seismic for E&P, applied seismic to simulation modeling and diagnosed production problems.

In addition, Ling generated production profiles for undeveloped fields and supervised exploration well site mud logging. He has written several technical papers, including three on gas viscosity. Ling has a BS degree in geology from the University of Petroleum in Beijing, China. He also has MS and PHD degrees in petroleum engineering from the University of Louisiana and Texas A&M University, respectively.

Neylon

Christine Neylon was promoted to associate petroleum engineer. She worked for more than three years at Ryder Scott as an engineering technician. Neylon estimates reserves in accordance with guidelines of the U.S. Securities and Exchange Commission and the Society of Petroleum Engineers Petroleum Resources Management System (SPE-PRMS).

In addition to evaluating reserves, she performs cashflow economics and full-field analysis. Neylon has conducted project feasibility studies and technical due diligence for acquisitions and divestitures. She has a masters degree in petroleum engineering from the University of Houston. As a graduate student, her academic emphasis was on waterflood sensitivity analysis, production optimization techniques and reserves estimation.

Publisher's Statement

Reservoir Solutions newsletter is published quarterly by Ryder Scott Co. LP. Established in 1937, the reservoir evaluation consulting firm performs hundreds of studies a year. Ryder Scott multidisciplinary studies incorporate geophysics, petrophysics, geology, petroleum engineering, reservoir simulation and economics. With 130 employees, including 86 engineers and geoscientists, Ryder Scott has the capability to complete the largest, most complex reservoir-evaluation projects in a timely manner.

Reservoir Solutions

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