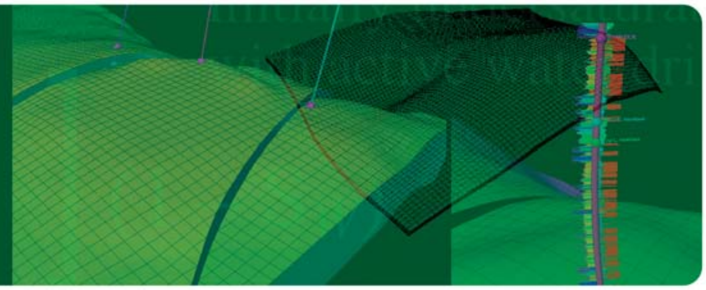
RESERVOIR SOLUTIONS



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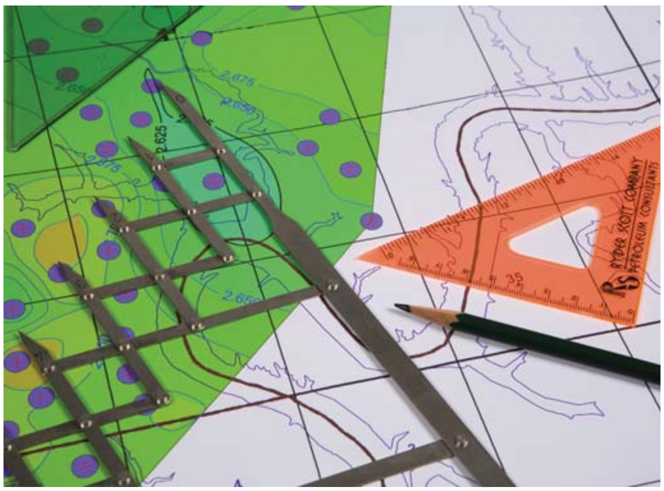
SEC comment alerts producers with horizontal wells



A recent U.S. Securities and Exchange Commission comment letter has prompted oil and gas companies with horizontal drilling operations to closely review proved undeveloped reserves booking practices. Public companies preparing year-end financials are especially concerned that if the SEC universally applies what is viewed as an arbitrary guideline on the number of proved undeveloped well offsets, the rippling effect will chip away at year-end booked asset values on horizontally drilled properties worldwide.

The SEC letter to Parallel Petroleum Corp. earlier this year stated that "areas offsetting a horizontal well that are reasonably certain of production would generally be limited to (two) direct parallel offsets to an existing horizontal well." The two-location maximum is viewed as overly restrictive by an industry that uses a combination of geological and engineering data to justify from one to eight drainage locations offsetting a proved developed producing well.

Frequently, producers use a "checkerboard" vertical-well spacing pattern to plot two horizontal and six vertical offset locations to the horizontal producer. Then they assign PUDs to offsetting locations intersected by the proposed heel-to-toe lateral, including now "suspect" vertical-well locations. The SEC is concerned that if producers book reserves for verticals when, in fact, they intend to drill horizontals, then those companies are not following their own development plans but rather attempting to put reserves on the books.

Originally, Parallel had designated 31 horizontal PUD locations as offsets in the New Mexico Wolfcamp carbonate trend, but eight of those locations fell outside of the SEC parameter. Parallel removed those locations from the PUD category and said that the resulting downward reserves revision was "immaterial" and resulted in a 2.6 percent reduction of its year-end 2006 BOEs.

The regulator's stance is that comment letters are case specific, not policy statements to be broadly interpreted and applied. However, the SEC used the term "generally" to refer to its view on horizontal offsets, which helped fuel industry concern.

North America gas producers in the Permian Basin, Barnett shale and other onshore provinces are boosting production and reserves through horizontal drilling, which accounts for 25 percent of current domestic drilling operations. International operating companies that report to U.S. markets are horizontally drilling through "continuous" reservoirs worldwide in major projects in Venezuela, Oman, United Arab Emirates, Nigeria and elsewhere.

The "balancing act" for these companies is to carry full values for proved reserves to justify horizontal drilling and completion operations while being in full compliance with regulatory interpretations.

In response to SEC comments, Parallel attempted to technically substantiate continuity of production and horizontal PUD locations based on what it said were horizontal well geometries tighter than vertical well geometries and flowback data and mudlog gas shows from 100 times more reservoir rock than typically encountered in vertical drilling.

The company also said it defined trend boundaries

Please see Horizontal Offsets on Page 8

Inside Reservoir Solutions newsletter

Canada amends reserves disclosure requirements

Canada announced that it will drop the requirement for public issuers to report petroleum reserves and future net revenue under constant prices beginning Dec. 28 of this year "provided all necessary ministerial approvals are obtained." The amendment to National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities was one of several proposed by the Canadian Securities Administrators on Oct. 12.

The CSA will continue to mandate that companies issue estimates of proved and probable reserves and related future net revenue using forecast prices and costs. However, the new change does not limit reporting to the forecast case only.

Public issuers also can report "proved reserves or its proved and probable reserves, using constant prices and costs as at the last day of the reporting issuer's most recent financial year" in a supplemental reserves information section of the filing.

Public comments on the proposed amendment included one statement that "without the constant case, it is difficult to compare issuers on a reasonably consistent and objective basis." The CSA responded, saying that "broad feedback persuades us that the mandatory use of the constant price and cost case is of little value and can be misleading." The agency added that "mandatory disclosure of price forecasts assists investors in assessing the information disclosed."

Another commenter said that the amendment was especially "relevant for heavy oil and bitumen that tend to be priced significantly below full year averages at year-end."

The CSA also issued new guidelines for disclosure of resources that cannot currently be classified as reserves. Regulators amended Section 5.3 in NI 51-101 to state that "disclosure of reserves or resources must apply the … terminology and categories set out in the COGE Handbook and must relate to the most specific category of reserves or resources …."

As an example, the agency said that "there are several subcategories of discovered resources including reserves, contingent resources and discovered unrecoverable resources. Reporting issuers must classify discovered resources into one of the subcategories…."

The CSA said that it made the changes to the reporting of resources "in anticipation of the potential adoption of the SPE/WPC definitions in the COGE Handbook."

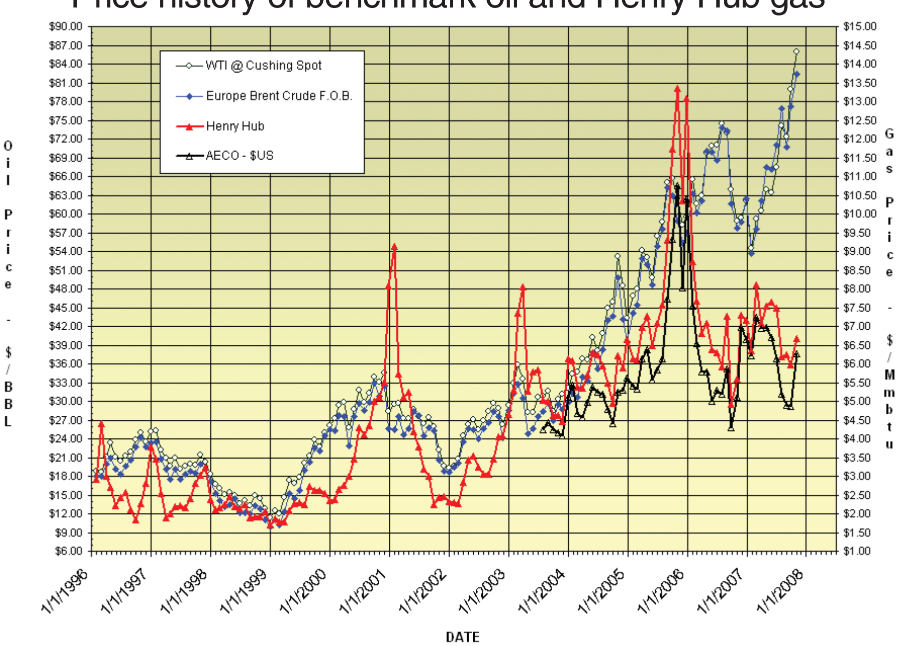
Disclosure of resources is not mandatory under NI 51-101.

Alberta details new royalty rate structure

Alberta detailed its new proposed royalty framework for conventional petroleum and oil sands on Oct. 25. The new royalty rates are expected to go into effect Jan. 1, 2009.

For conventional oil, royalty

Please see Royalties on Page 8



The historical price chart shows published, monthly-average, cash market prices for WTI crude at Cushing (NYMEX), Brent crude and Henry Hub and AECO gas.

Publisher's Statement

Reservoir Solutions newsletter is published quarterly by Ryder Scott Company 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 115 employees, including 80 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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Russia reserves reporting to be enforced in a year

Although Russia presented its petroleum reserves classification system to the United Nations two years ago, the government will not enforce RF 2005 rules in country for another year. That's plenty of time for oil and gas companies to speculate on the ramifications of the system, especially considering Russia's recent interpretations and criticism of both publicly reported and state-submitted reserves values.

Russia will enforce the newest set of reserves guidelines starting Jan. 1, 2009. Russian classifications are based on geological certainty of in-place hydrocarbon volumes and place much greater emphasis on volumetric analysis in contrast to the Western focus on performance-based estimates.

John Ritter, chairman ex-officio of the Society of Petroleum Engineers Petroleum Oil and Gas Reserves Committee (OGRC), said that the two major changes in the new RF-2005 definitions are that reserves must have economic components, i.e., positive net present values, and reserves based on recoverable volumes must have reservoir engineering components tying to project maturity.

He added that the new RF-2005 definitions capture elements of both the 2007 SPE Petroleum Resources Management System (SPE-PRMS) and the United Nations Framework Classification (UNFC). **Yuri Podturkin**, chairman of the State Commission on Mineral Reserves of the Russian Federation, said in mid October that "there are no principle discrepancies between Russian classifications and the UNFC."

OGRC mapped differences between 1997 SPE/World Petroleum Congress and Russian guidelines in 2005. The mapping document is posted on the SPE Web site and is a reference for those wanting direct comparisons between the older systems.

SPE has not mapped in detail the 2007 SPE-PRMS to the new RF-2005. "The society is currently working with stakeholder groups to identify any potential differences," said Ritter.

In mid October, **Alexander Gert**, deputy director general at the Siberian Research Institute of Geology, Geophysics & Mineral Resources, presented the "New Russian Classification - Approximation to the International Standards" at the United Nations Economic Commission for Europe (UNECE) Ad Hoc Group of Experts on Harmonization of Fossil Energy and Mineral Resources Terminology Fourth Session, Geneva.

The presentation is posted on the UNECE Web site at www.unece.org.

Reserves data exportation becomes thorny issue in Russia

In late September, Russia accused a British oil company and its third-party consultant of exporting unlicensed geological data on petroleum reserves without approval from the Economy Ministry, reported *Bloomberg* newswire service. **Oleg Mitvol**, deputy head of Russia's Natural Resources Ministry, asked the Prosecutor General's office to investigate.

Mitvol told *Bloomberg* that "geological information on oil and natural-gas reserves must be licensed by the Economy Ministry, with the environmental inspectorate's approval, before it's shipped abroad."

The oil company denied that it exported data.

Editor's Note: Ryder Scott intentionally did not identify companies cited in the news coverage. Readers wanting more detailed information should refer to periodicals covering this story.

What is a certification of petroleum reserves?

— Fred Richoux, executive vice president

Richoux

In my nearly 30 years at Ryder Scott, I have heard the term "certification" used in many different ways. In the past, the term was more commonly used in connection with international projects. However, it is now common to hear that term used with domestic projects as well.

If a client comes to me and asks for a reserves certification, my initial assumption is that this is a request for a complete independent study. However, it is important that consultants ask exactly what their clients want because some clients consider a certification to be an audit of some sort.

While independent analysis varies by degree of rigor, I am not aware of any commonly accepted definition of "reserves certification." An independent analysis may take many forms.

Following are some examples beginning with a cursory review and moving to an in-depth study:

1. Third-party review on processes, not on quantities or economics. No opinion letter.
2. Third-party review in which the letter comments on processes only; no opinion is offered on reserves quantities or economics.
3. Third party audit involving review of new discoveries and largest revisions only; opinion letter furnished.
4. Third-party audit of new discoveries and some portion of the reserves base annually; opinion letter furnished.
5. Third-party audit of the largest producing fields comprising 80 percent of the reserves base. This is called an 80-20 audit because typically 80 percent of a company's asset value is in the top 20 percent of the fields ranked by size; opinion letter furnished
6. Full audit of all properties; opinion letter furnished. The audit letter may state that the client's reserves numbers fall within 10 percent in the aggregate of the numbers of an independent consultant.
7. In the full-scale evaluation, the consultant takes ownership of the numbers.

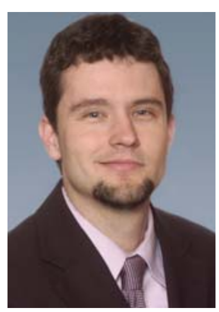
In my opinion, the first four would not qualify as a certification. Number five might qualify. Six probably would and 7 certainly would qualify. However until industry defines the ambiguous term "certification," we will have to live with it.

Editor's Note: This commentary and other comments on the term "reserves certification" were posted on the discussion forum of the Society of Petroleum Engineers Reserves and Economics technical interest group last September.

Lam

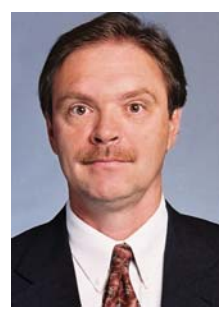
Oetama

Stotts



Wilson

Baird



Stell

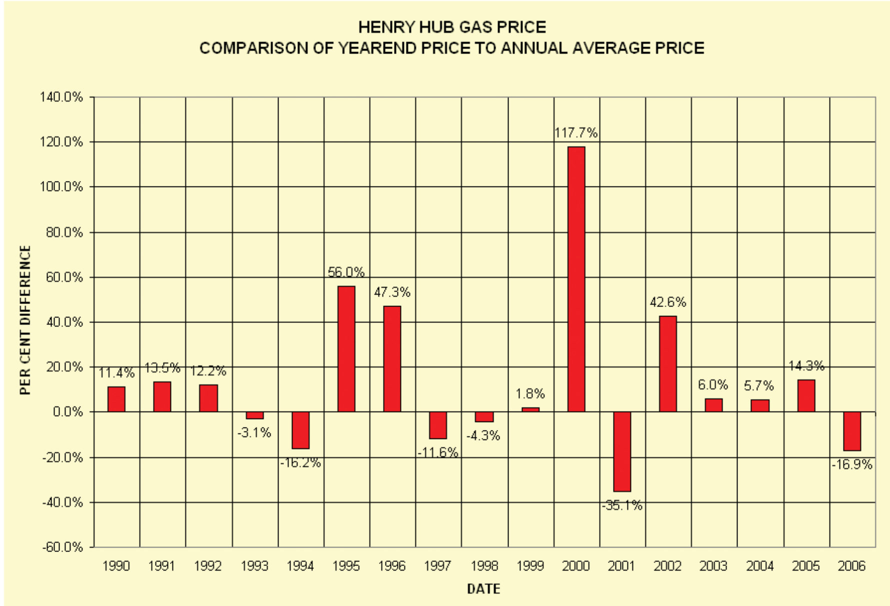
Petroleum engineers, GIT join RS, two others promoted

Michael Lam joined Ryder Scott Canada as a geologist in training. He has six years of well-site experience as a consultant in the Peace River Arch region, Red Earth area, east central Alberta and northeast British Columbia working for TIH Consulting Ltd. He performed all geological analysis for drilling, including recording and maintaining information, reading and interpreting well logs, recommending and supervising tests and measurements and analyzing subsurface strata encountered while drilling and logging. Lam has a BS degree in geology from the University of Calgary.

Teddy Oetama joined Ryder Scott as a petroleum engineer. He has more than 25 years of international production and reservoir engineering experience, including production data analyses, pressure transient

Please see Oetama on Page 7

U.S. gas prices ill suited for FASB rule



Public oil and gas companies for years have critiqued the FASB 69 requirement to use single-day, year-end pricing to estimate petroleum reserves in U.S. 10-K filings. They have argued that a one-day "snap-shot" does not represent an average commodity price for the year and can mislead investors, especially if aberrant highs or lows occur at year end.

Recent annual history has shown that the variance between average and year-end prices is greater for gas than oil because of market volatility. Since 1990, the widest variance for oil occurred in 1999 when year-end prices were 33.5 percent higher than the average price that year. During that same 16-year stretch, year-end gas prices were higher than average by 117.7 percent in 2000 followed by 56 percent in 1995 and 47.3 percent in 1996. See accompanying chart.

This year, gas-price volatility in U.S. markets was never demonstrated more dramatically then when Colorado Interstate Gas Hub spot prices plunged to $1.18 per MMBTU for the Sept. 7 monthly average. A lack of pipeline capacity coupled with a surplus of gas caused unusually soft market prices. CIG rebounded with a $4.54 weekly spot price for November 20-to-26 flow dates.

Ryder Scott will post "Oil and Gas Benchmark Prices to Estimate Year-End Petroleum Reserves and Values under U.S. Securities and Exchange Commission Guidelines" at www.ryderscott.com in January.

Editor's Note: Ryder Scott posts year-end pricing data for general information purposes only. Ryder Scott makes no claims or warranties regarding the accuracy of pricing information, which is based on published benchmark prices. Users are encouraged to verify data through other sources.

Estimates of future uptime, downtime crucial in DCA

— Dan Olds, vice president

Olds

Accounting for production uptime and downtime in decline-curve analysis (DCA) is crucial in generating reliable performance-based estimates of oil and gas reserves. A familiarity with basic terms is required before addressing efficiency factors in DCA.

Most production plots are based on calendar-day (CD) production because evaluators seldom have the actual number of days or hours that the well produced. In a sense, the CD production plot is one of the few pieces of usually indisputable hard data that reservoir engineers receive.

To get CD production, the evaluator takes monthly production and divides by the number of days in the month or by the average number of days in the month, 30.4. If a well produces all day, every day, then the CD plot is the same as the production-day (PD) plot. PD production is derived by taking monthly production and dividing by the number of days and fractional days that the well actually produced.

Other terms to clarify include efficiency, uptime, downtime and availability, which are all measures of the ratio of actual to expected production from the well if it produced all day, every day, all month long.

Downtime and future production

Under normal operating conditions, routine downtime should be fairly constant on an annual basis. However, over the long term,

Please see DCA on Page 7

Production platforms, like U.K. North Sea East Brae platforms, have histories of downtime for routine maintenance reflected in calendar-day, rate/time, decline-curve analysis plots.

Simple tool reveals flawed estimates of future production

In the world of petroleum reserves validations, sometimes complex situations have simple fixes.

Wall Street analysts and hard-charging corporate managers demand growth through the drill bit. The ultimatum from "the Street"— perform as well as other companies in the peer group or the market will take its revenge.

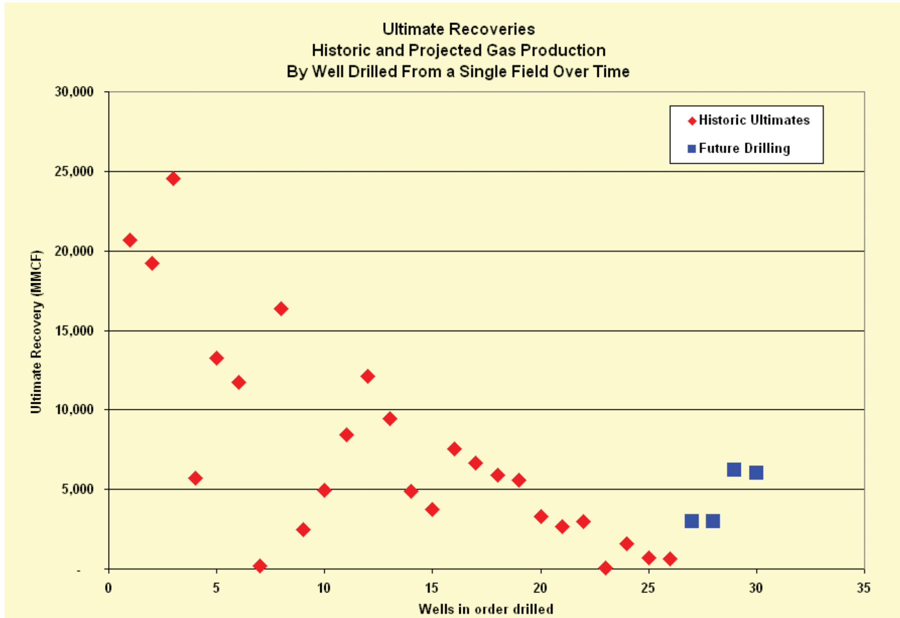
Working with mature, mostly spent fields, the company technical team masks the problem by accelerating production through infill drilling. The team books and monetizes gas reserves. In the end, though, basic field economics catches up. The company stumbles and a new CEO is hired to clean up the mess.

All could have been avoided if only management from the beginning had used a simple engineering tool– a scatter plot that provides a quick look at past performance and clues to the future.

That message and non-fictional example were included by **Don Griffin**, senior vice president at Ryder Scott, and **Ron Harrell**, chairman emeritus, in a technical paper presented at a poster session at the Society of Petroleum Engineers annual conference in November. **Scott W. Randall** co-wrote "Enterprise Risk Management in the Petroleum Industry Using Qualitative and Quantitative Techniques to Validate Information," (SPE No. 109822).

He showed how petroleum reserves evaluation techniques can be combined with operational risk-management and strategic-planning tools to support an enterprise risk management process. (Please see September 2007 *Reservoir Solutions* newsletter article, "Reserves validation techniques part of ERM system," Page 7.)

In the paper, co-authors Griffin and Harrell show examples to support steps in the secondary validation process. Randall said that an example of secondary information is the data reviewed by a stock analyst while primary information might be data gathered by a field technician.



One reserves validation technique involved the use of a scatter-plot tool to reveal overly optimistic production projections and invalid geological analysis. The other involved an abuse of variable costs in lease operating statements to accelerate cost projections, lower economic limits and extend field production life to inflate reserves.

The scatter-plot example is shown as follows.

Scatter Plot Example

A scatter plot is a visual display comparing two measured or estimated variables. Scatter plots often are used for discrete data measurements over time when performing a trend analysis. In petroleum reserves auditing, scatter plots are sometimes invaluable in spotting inconsistent data.

The reserves auditor, in this case, was examining the reserves of a publicly traded E&P company that had not delivered on its internally generated forecast of gas production over several quarters. The company's stock price had plunged in the preceding 18 months despite an aggressive infill drilling program designed to boost production.

In spite of inaccurate projections, company geologists continued to support new drilling locations with large associated reserves that they claimed were proven using their internally generated analysis.

Facing those problems head on, top management of the company asked the third-party reserves auditor to provide an independent production forecast and reserves report.

The auditor's analysis began with a review of all producing wells, past and present, and a determination of the estimated ultimate recoverable reserves (EUR) for each well. Rather than immediately examining the geology, the auditor plotted a time series of historical performance of wells drilled at a field slated for continued development drilling. The auditor then plotted the internally generated projected performance of new wells proposed by the company geologist.

A comparison of the historical vs. new projections is graphically illustrated in the scatter plot shown in the accompanying figure.

The trend of red dots, volumes actually produced, clearly shows diminishing returns over time for the drilled wells. Company geologists were unable to explain why the declining trend would be reversed with the new drilling program, shown by the blue dots. The auditor performed a similar graphical analysis on another field with more than 20 years of data and discovered the same, seemingly overly optimistic projections.

Aggravating the situation was

Please see Scatter Plot on Page 8

Oetama—Cont. from Page 4

analyses, reservoir modeling, economic analyses and fracture treatment design. His main emphasis at Ryder Scott will be in reservoir simulation studies as well as pressure transient test design and analysis.

Most recently Oetama worked at Gaffney, Cline & Associates, Nations Energy Co. Ltd. and Schlumberger Data & Consulting Services Group. He was an associate professor in petroleum engineering at Texas Tech University from 2002 to 2005 after working for Ryder Scott as a petroleum engineer in 2001. Previous to that, Oetama was a consultant.

He worked at S.A. Holditch & Assocs. Inc. from 1990 to 1998 where he was involved in all aspects of reservoir and production engineering, particularly, pressure transient analysis, reservoir simulation and production data analysis. Oetama has co-written nine technical papers and has MS and PhD degrees in petroleum engineering from Texas A&M University.

Garth Stotts joined Ryder Scott Canada as a petroleum engineer in training. Previously, he worked at Fekete Associates Inc. from 2005 to 2007 as a technical advisor and EIT. Stotts conducted rate transient analysis and developed RTA software.

He analyzed rate and pressure data to determine reservoir characteristics, original fluids-in-place, optimization potential, productivity issues, development plans, infill spacing and field and well recoveries.

Before that, he was a research assistant at the University of Alberta, a process engineering co-op at the Elk Valley Coal Corp. and a subsurface engineering co-op at ExxonMobil Canada West. Stotts has a BS degree in materials engineering from the University of Alberta.

Ryan Wilson joined Ryder Scott as a petroleum engineer. Before that, he worked at ExxonMobil Corp. from 2003 to 2007 as a reservoir engineer. Wilson worked on a variety of U.S. assets including tight, conventional and low-pressure gas and CO_2 and waterflood oil projects.

He was a reservoir team leader, led multi-well development drilling programs and evaluated third-party drilling opportunities. Wilson managed CO_2 flood projects, focusing on WAG, pattern analysis, workover generation and compression opportunities. He has a BS degree in chemical engineering from the University of Missouri-Rolla.

Mike Stell was promoted to managing senior vice president and group leader. **Jim Baird** in the Denver office was promoted to vice president.

DCA—Cont. from Page 5

downtime tends to increase as the well matures. Downtime can be considered as routine and non-routine or scheduled and non-scheduled.

A scheduled event might be a shut-in period for pressure buildup tests or packer integrity tests or perhaps, a periodic summer maintenance platform shutdown in the North Sea. Scheduled events should be considered in any reserves forecast. An unscheduled event might be a pipeline, compressor or rod-part failure.

As well productivity declines over time, field operations may find it necessary to shut-in the well to allow the well bore to recharge. The CD RT (rate/time) DCA plots already reflect those events and any projection based on historical data implicitly considers a continuing level of downtime.

The PD RT DCA plot represents a theoretical upper-limit case in which all production operations work optimally all the time. The plot is a useful tool to benchmark operations, but using it for forecasting purposes results in an overstatement of future production rates.

Projections based on PD DCA plots show monthly production from wells at rates higher than what is likely to occur in actual practice. In most cases, reserves will be overstated if the economic limit is not appropriately adjusted to consider the necessary difference between PD and CD.

The RC (rate/cum) DCA plots are not affected by downtime. However, if RC is used for determining reserves, it has to be converted to RT and some level of downtime should be considered. Software that automatically takes the RC projection and plots it on a RT axis makes it easy to judge whether the projection looks reasonable compared to historical trends observed on the RT plot. When using the rate/cum approach for reserves estimation, that step should always be taken.

A potential problem with using PD plots is best illustrated by intermittent producers, for example, oil wells that use beam pumps equipped with pump-off controllers or timers. In cases where the well is mature and has a low productivity index, the beam pump draws from the well bore at a faster rate than the reservoir can recharge. To remedy that, the controller cycles the beam pump on and off on a schedule that allows the well bore enough time to fill up between cycles.

"A potential problem with using PD plots is best illustrated by intermittent producers…"

If the timer is set to pump the well one hour a day, how many PDs are in a month? Is the answer calculated by multiplying 30.4 days by one hour which equals 30.4 hours per month or 1.27 days per month? Or does the evaluator use 30.4 days of normal operations?

If the evaluator assumes 1.27 days per month, then a possible conclusion might be that the well is only producing at a capacity of 1.27 divided by 30.4 or 4 percent of its theoretical capability—obviously a significant overestimate of its actual capability. If an evaluator has good reason to believe that downtime will be materially different than history would indicate, he or she should adjust projections accordingly.

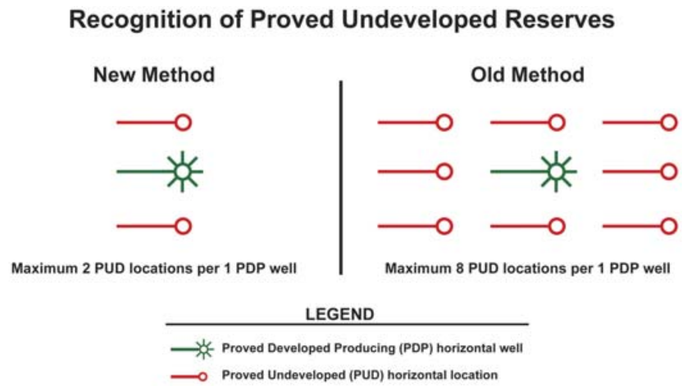
Basing projections on PD RT DCA is extra work that is likely to lead to overestimates. Using CD RT DCA is basing an estimate of what a well is expected to do in the future on what it actually did in the past, not what it might have done.

Horizontal Offsets—Cont. from Page 1

with mudlogs and openhole logs from productive vertical wells, commenting that the play is "stratigraphic in nature with little structure of significance." Parallel said that cross sections and gross pay isopach maps show the productive interval to be continuous.

The SEC countered, saying that "geological presentations of isopach maps and cross-sections are not sufficient to demonstrate continuity of production." The SEC added that for wells offsetting a productive well by more than one location away, continuity of production should be demonstrated by pressure communication.

Parallel said that some of the "decline curves validate a continuous productive interval and show no sign of reserve acceleration," adding that "actual production is a more definitive indication of continuity of production than pressure communication."



After receiving SEC comment letters earlier this year, Parallel Petroleum published this chart to show the maximum number of PUD locations offsetting a horizontal well that it would recognize.

Scatter Plot—Cont. from Page 6

pressure by Wall Street on the company to drill wells, maximize production and increase the reserves base. Consequently, the drilling program was overly aggressive, leaving little time for middle management to reflect on past results. If the managers had taken a bit more time to graphically look at the trends, then they should have been able to reign in the geologists' optimism and unrealistic expectations of upper management and investors.

The so-called vintage plot used by the auditor was just a spot check on the data. In and of itself, it did not prove very much. The plot ignored geology and production problems. It could tempt an evaluator to predict the future without regard to most of the pertinent technical data.

However, from the auditor's perspective, the scatter plot provided a simple, clear indication of the possibility that the geologic view presented to the company's upper management and to investors was unrealistic. A later analysis of the actual geologic conditions validated the auditor's suspicions.

Royalties—Cont. from Page 2

rates will range from 0 to 50 percent compared to previous maximums of 30 to 35 percent. Rate caps will jump to $120 per barrel.

For gas, royalty rates will range from 5 to 50 percent, an increase from the current 5 to 35 percent. Rate caps will increase to $16.59 per gigajoule.

For oil sands, the royalty rate for pre-payout projects will be 1 percent for oil at $55 a barrel, increasing to 9 percent for oil equal to or in excess of $120 a barrel. For post-payout projects, royalty rates will be 25 percent for oil at $55 a barrel, increasing to 40 percent for oil equal to or in excess of $120 a barrel.

Alberta anticipates that the proposed royalties, if implemented, will boost provincial government revenues from natural resources $1.4 billion in 2010, an increase of 20 percent.

Producers in Alberta are assessing the new royalty structure to determine its effect on field economics, including reserves evaluations. Software developers are incorporating new royalty formulas into their economics programs used to analyze oil and gas cash flows for year-end 2008.

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