RESERVOIR SOLUTIONS

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Bakken: Making waves from Bismarck to Brisbane

The world is watching the Bakken oil shale play. Net importers of oil—including China, France and Poland—are studying the Bakken as a model for their own countries, which contain geologically similar deposits, they say. Companies from countries as far away as Australia have Bakken interests.

The unconventional play has become a proving ground for advanced drilling-and-completions (D&C) technology, including multistage hydraulic fracturing. The Bakken is to the future of UC oil production as the 20-year-old Barnett shale play has proved to be for UC gas, industry observers say.

Barnett fracture-stimulation technology has been exported internationally for shale gas extraction for years and now the Bakken version, developed in Canada and the United States, is destined for overseas deployment. Producers are already using Bakken technology in France's Paris basin, Australia's Georgina basin and New Zealand's Taranaki basin.

Fidelity E&P Co. drilled and cased the Craft 22-15 well in the ND Bakken formation with this rig in 2009. Drilling has increased since then. In February, 171 rigs were active in the state, a record despite a severe winter that hampered oil production.

Spurring field development plans are estimated future cash flows from operations in price scenarios that are uncertain. For now, oil is king. International oil price benchmarks hovered around $90 a barrel before political turmoil in Africa and the Middle East pushed prices higher.

Epicenter of Bakken play

At the epicenter of this ripple effect is the North Dakota Bakken oil shale play. Drilling there continued unabated this year. On February 18, 171 rigs were active in the state, a record despite a severe winter that hampered oil production. About 90 percent were drilling for oil horizontally or directionally.

Early this year, a director at ND's Department of Mineral Resources said indications are that the Bakken play in the state "reasonably" contains about 11 billion barrels of oil, more than double earlier estimates of 5 billion barrels by state officials.

The United States Geological Survey published most likely estimates of 3.65 billion barrels of "technically recoverable, undiscovered oil" in the ND Bakken formation three years ago. Recently, the USGS said that it hadn't seen enough data to amend its estimate, reported *Bloomberg* news service. An estimate of technically recoverable undiscovered resources quantities is not an assessment of reserves which are calculated under economic limits imposed by price-deck scenarios and capital and operating costs.

The USGS estimate was made only a year after the industry began to fully deploy an advanced multistage frac technology in 2007. It has demonstrated a repeatable, consistent

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Inside Reservoir Solutions

Mega-database optimizes Bakken forecasting

The Ryder Scott Denver office has developed a "mega" database on the Bakken oil shale play in western North Dakota and eastern Montana to generate production forecasts with higher confidence levels. "We are mapping regional production trends to refine sweet and trouble spots in the play," said **Scott Wilson**, senior vice president in Denver.

Opinions on optimal completion techniques and ultimate recoveries vary among operators. However, as the play matures, the industry's knowledge base will grow.

"The large body of production and well data in the Ryder Scott database coupled with our experience and detailed reservoir simulation work enable our firm to forecast any type of well with a level of confidence not possible for those reviewing smaller inventories, said Wilson.

The database in Aries combines public and project information from thousands of Bakken producing wells and undeveloped locations. It contains basic information, such as well trajectories, and detailed data, such as daily production rates. Data points are spread over the entire Bakken play in the two states, a 22,000-square-mile area.

Ryder Scott generates bubble maps of oil, gas and water production trends across the basin. The Denver office also has studied how various parameters affect EUR and has history matched a 20,000-cell reservoir simulation model against daily well data to compare various completion techniques. Other evaluation methods include transient rate-time modeling and classic decline-curve analysis of essentially every well in the basin, taking into account commingled production from multiple zones.

The Denver staff has analyzed time durations for the onset of well-to-well interference relative to spacing. Ryder Scott is also reviewing the effectiveness of completions relative to the number of frac stages and proppant conductivity.

Outside the technical realm, commercial issues are complicating the evaluation of reserves and economics in the Bakken. They include sparse completion data on non-operated wells, delayed installation of pumping units, lack of gas sales outlets and tightly stretched

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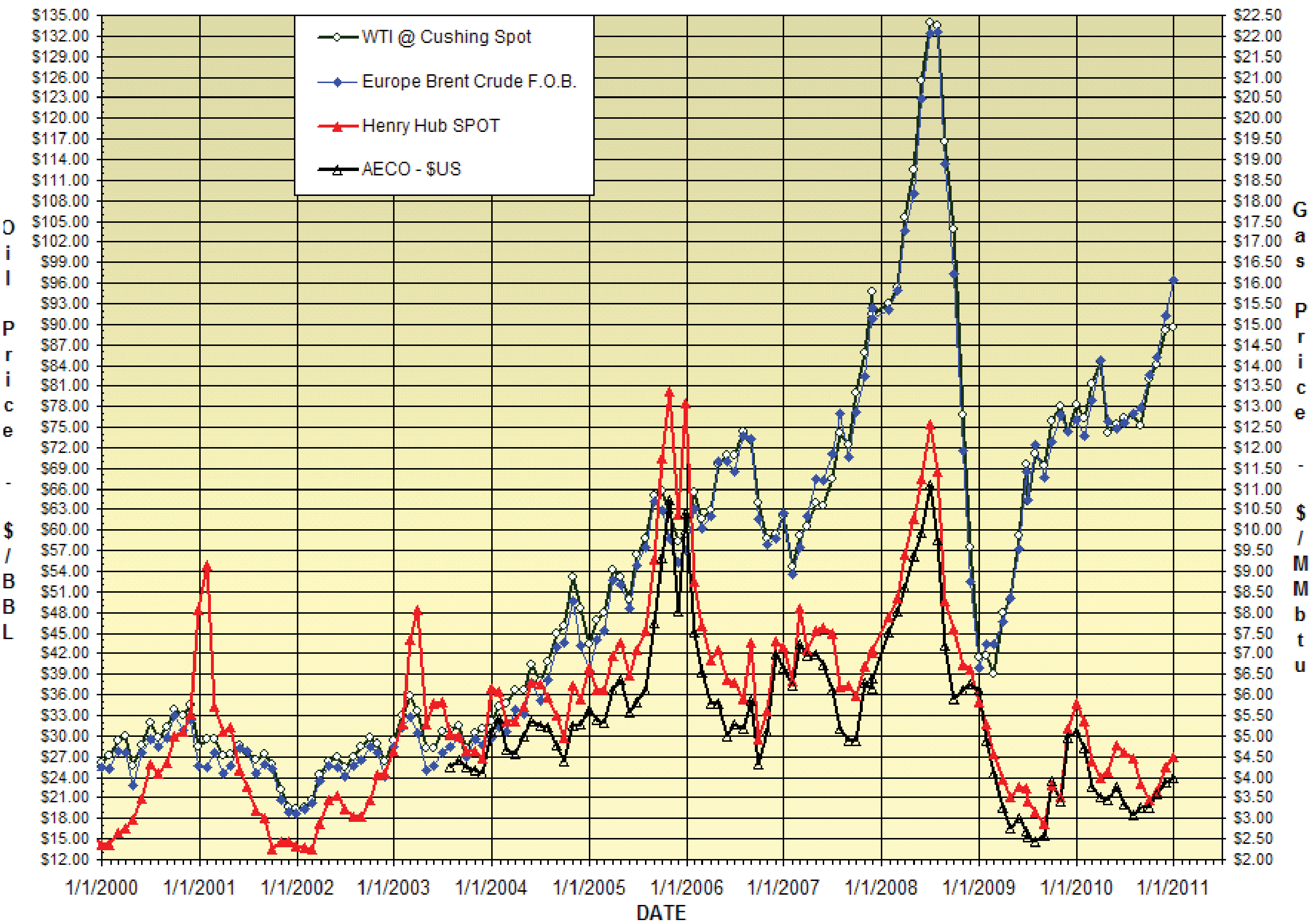
Price history of benchmark oil and gas in U.S. dollars



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

Bakken—Cont. from Page 1

track record and is in widespread use across the Bakken, allowing public companies to book proved reserves in part based on the "reliable technology" rule of the U.S. Securities and Exchange Commission.

A Marathon Oil Corp. Bakken rig overlooks a ranch in rural North Dakota. Marathon entered the play in 2006 and has lease rights in more than 350,000 acres.

Oil production surges

While debate continues about estimated ultimate recoveries (EURs) per well, there's no argument about what the Bakken is producing as a region now. In 2010, ND pumped 113 million barrels of oil from the wellhead, almost three times the state's total in 2006, with most coming from the Bakken. Drilling permit activity and rig utilization are at all-time highs in the ND Williston basin where deposits of the middle Bakken dolomite extend. (The Bakken pay interval is not shale but sandstone/siltstone/carbonate.) Oil production from the overall play will reach nearly 1.2 million B/D by 2015 or 15 percent of U.S. output, analysts at Raymond James predicted.

Bakken price sensitivities

The Bakken is a commodity play. It and other oil shale plays, such as the Eagle Ford in south Texas, will continue to draw interest with elevated oil prices and depressed gas prices. Oil-to-gas-price ratios continue to remain high. Both commodities tracked closely at year-end 2008 when oil was $34 a barrel. Since then, oil prices have pulled away from gas in spot markets. See price chart on Page 2.

Just how price sensitive is the Bakken in North Dakota? Tudor Pickering, an energy banking firm in Houston, said a year ago that the economics of the state's Bakken shale play had improved to the point where it generated returns of 10 percent at $50-a-barrel oil prices. The firm told *The Oil Daily* that "advanced well completion techniques were credited as a key factor in boosting the play's economics."

Tudor Pickering told *Reservoir Solutions* in January that the economics of the play have improved since its year-old analysis because production type curves are better while costs have stayed in line.

Skinny economics?

Are the economics in the ND Bakken "skinny" at $50 a barrel? A simple, back-of-the-envelope calculation of full-cycle costs may provide a clue.

Whole life cost analysis, which factors in sunk costs such as exploration expenditures, is outside of the forward-looking nature of petroleum reserves evaluations. (An exception is incurred exploration-and-development expenditures that are recoverable in the future as cost oil in production-sharing agreements.)

As a rule of thumb, finding-and-development (F&D) costs combined with lease operating expenses (LOEs) account for roughly 90 to 95 percent of the full-cycle costs over the life of an oil or gas asset. Reported F&D costs per barrel from the ND Bakken vary widely over four short years, have no long-running averages and are only as reliable as the reserves estimates which determine the unit costs. LOEs also are all over the board without long-term averages.

As a snapshot example, if F&D costs, reported at $10 to $20 a barrel for 1P reserves, are added to published LOEs ranging from $15 to $30 per sold BOE, then the combined full-cycle costs are $25 to $50 per proved BOE. Returns on $50-a-barrel oil are certainly cost sensitive within that range.

Working interest owners in the

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ND Bakken pay drilling-and-completion (D&C) costs, a subcategory of F&D costs, which can average $3- to $5-million a well. Capital and operational expenses include costs to prepare the drill pad for production, construction of surface treatment facilities, acquisition and deployment of pumping units, use of expendables such as drilling mud, general and administrative services and state taxes, including those on production (2 percent for qualifying Bakken wells) and corporate income (2.6 to 6.5 percent).

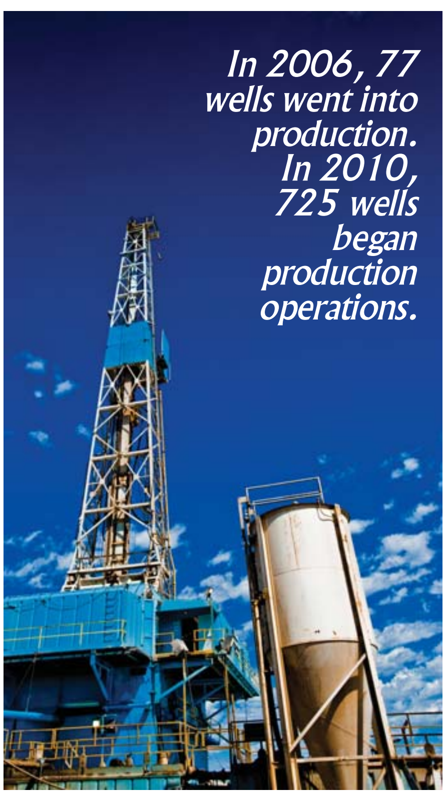
In the ND Bakken, payments of lease bonuses range up to $10,000 an acre for drilling rights. Royalty interests and overrides have been published at around 15 percent.

How the wells pay out under this cost burden depends on performance, a universal truth in E&P.

Continental Resources Inc. drilled these four wells in the greater Bakken from a single pad with an 800,000-pound rig that walks on hydraulic feet between drill sites. That eliminates dismantling time. The single pad and walking rig have reduced costs.

Bakken technology play

In the early development of the ND Bakken almost 60 years ago, D&C technology did not play the pivotal role it does now. The first oil well was spudded in the Antelope field in 1953. The conventional well pumped 280,000 barrels of oil over 4-½ years before it was plugged and abandoned because of casing problems. Vertical wells in Antelope during the 1950s and '60s produced from structurally induced fracture systems in the tight, low-permeability, low-porosity upper Bakken.



In the early 1960s, Shell Oil Co. drilled the first well that was hydraulically fractured. It was perforated and stimulated with acid and produced almost 60,000 barrels from ND's upper Bakken by 1964. In 1987, Meridian Oil Inc. drilled the first ND Bakken horizontal well—a 57-day, $2-million operation. The 2,600-ft lateral drilled through an established fracture trend in the upper Bakken that initially produced 258 BOPD. Long-term results were no better than those from vertical drilling.

In 2000, a breakthrough occurred in Montana—the first horizontal wells were drilled into the thin (as thick as 80 ft) middle dolomite sandwiched between upper and lower organic-rich shales. That resulted in the discovery of the Elm Coulee field which has EURs that range from 200 million barrels of oil to half a billion.

In the aftermath, industry focus shifted to the deeper middle member of the Bakken in Montana and then into ND where the accumulation extends into the eastern flank of the Williston basin. Early drilling results in ND were modest with the first horizontal well, a rentry completed in 2004 that penetrated lower quality middle Bakken rock.

In 2005, EOG Resources leveraged D&C technology successfully used in the Barnett shale to drill two horizontal wells with large-scale hydraulic fracture stimulation. A year later in 2006, EOG discovered the Parshall field where its horizontal drilling and open-hole multistage fracturing combination brought on wells producing 1,000 BOPD.

That triggered the current ND oil boom. Hundreds of investors and independent E&P companies flocked to the state to stake their claims and drill. In 2006, 77 wells went into production. By 2010, 725 wells began production operations.

Producers break up the dense Bakken rock using fracture treatments more intensive than those for shale gas. As a result, billions of fissures free up oil which has less mobility than methane because crude is more viscous and has larger molecules.

Operators now drill as deep as two miles underground and hydrofrac the middle Bakken in stages in a single trip with ball-and-sliding-sleeve systems tweaked over more than eight years. They push long, high-density frac liners with OH packers into the wells.

Those swell packers separate two-mile laterals—some single, some dual—into sections to be separately perforated and fraced in stages from toe to heel. The use of downhole, optimum-density proppants and chemicals boost production. Companies are increasing oil cuts, but at a D&C cost of sometimes six to seven times that of a vertical well.

Last year, Slawson Exploration Co. Inc. completed a two-mile lateral with 47 stages over two days. More fracture stages give better coverage and unlock more oil. However, the added costs for additional stages have to increase incremental production enough to pay out.

To cut costs, companies have streamlined completion project schedules through simultaneous operations and multi-well drilling pads. ND's DMR said technological improvements have cut D&C time for a well from 65 days in 2008 to 25 days in 2010. Efficiency gains, including fracing a well in several stages in a single day, have dropped D&C costs as a whole. Still, there are upward cost pressures caused by high demand for specialized equipment and services, which are in limited supply in the Bakken.

The ND Bakken and EURs

Of the 1,884 horizontal wells with first production from ND's middle Bakken over the past five full years, only 242 or 13 percent started production operations the first two years. Almost nine of 10 production histories are less than three years old, so estimating EURs through decline-curve analysis (DCA) is challenging.

Typically a Bakken well has a high initial production rate followed by a steep (hyperbolic) decline that changes to an exponential terminal decline. Industry has used Arps' hyperbolic DCA equation for almost 70 years to forecast future production and continues to use it for Bakken analysis.

"The hyperbolic exponent B in the Arps equation has been a source of much controversy through the years, with many authors condemning the use of B values greater than 1, and others freely using any B value that fits the data," stated J.P. Spivey et al in SPE paper 71038-MS, "Applications of the Transient Hyperbolic Exponent," (2001).

If matched with the Arps' equation, a hydraulically fractured well exhibits a period of linear flow that results in a B value of 2, assuming constant pressure from an infinite-acting reservoir. In low permeability formations, such as the Bakken, with long hydraulic fractures, linear flow period may last quite some time.

The Elm Coulee field, with a decade of production history, provides a good test case to validate early DCA on the Bakken shale. Evaluators used hyperbolic exponents greater than 3 in estimating declines and EURs of Elm Coulee and they proved to be inflated. Now evaluators are careful to use

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Continental Resources Inc. conducts a frac job on the Rhonda 1-28H well in Dunn County, North Dakota.

Technical challenges in estimating reserves Part 6: Material balance, undrilled areas, economics

Editor's Note: This is a revised excerpt from "Oil and Gas Reserves Estimates: Recurring Mistakes and Errors," (SPE Paper No. 91069). To order a copy of the full paper, go to www.onepetro.org and access the e-library.

Ryder Scott personnel see a wide variety of internally produced petroleum reserves estimates and most of them are well prepared. However, the firm has noticed common technical errors in reserves estimates.

This multipart article offers guidelines to help reduce the chance of errors in geoscientific and engineering analysis. This sixth and concluding part in the series focuses on the impact of partial waterdrive and overpressured reservoirs on gas material balance. Also examined will be undrilled fault blocks and economics projection programs.

Effect of partial waterdrive and overpressured reservoirs on gas material balance

The standard gas material balance analysis, p/z analysis, is a common tool to determine both reservoir size and recovery for a given abandonment pressure. Combined with volumetric estimates, gas material balance is an effective tool to estimate reserves, particularly in mature reservoirs.

Problems with gas material balance are typically encountered earlier in the field life when less than 25 percent of the expected volume has been produced or when reservoir pressures are still above the normal pressure gradient.

During this early period, factors that influence the reservoir pressure behavior, such as compaction and partial water drive, can be indistinguishable from a pure depletion drive (Figure 16).

Although an evaluator sometimes faces difficulties in isolating reservoir mechanisms that may affect the p/z trend, he can follow a few guidelines that will reduce the risk of overestimating gas in place and recovery early in the field life.

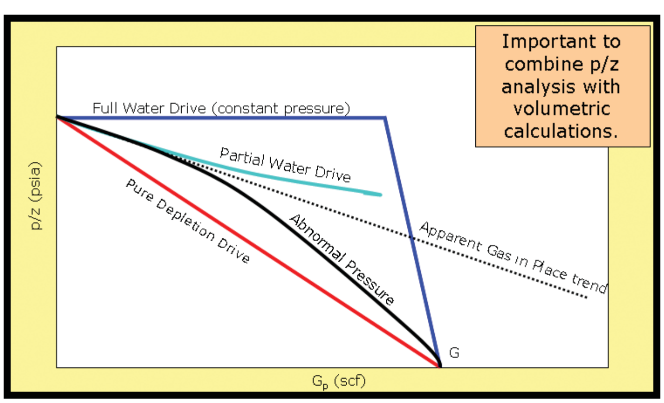
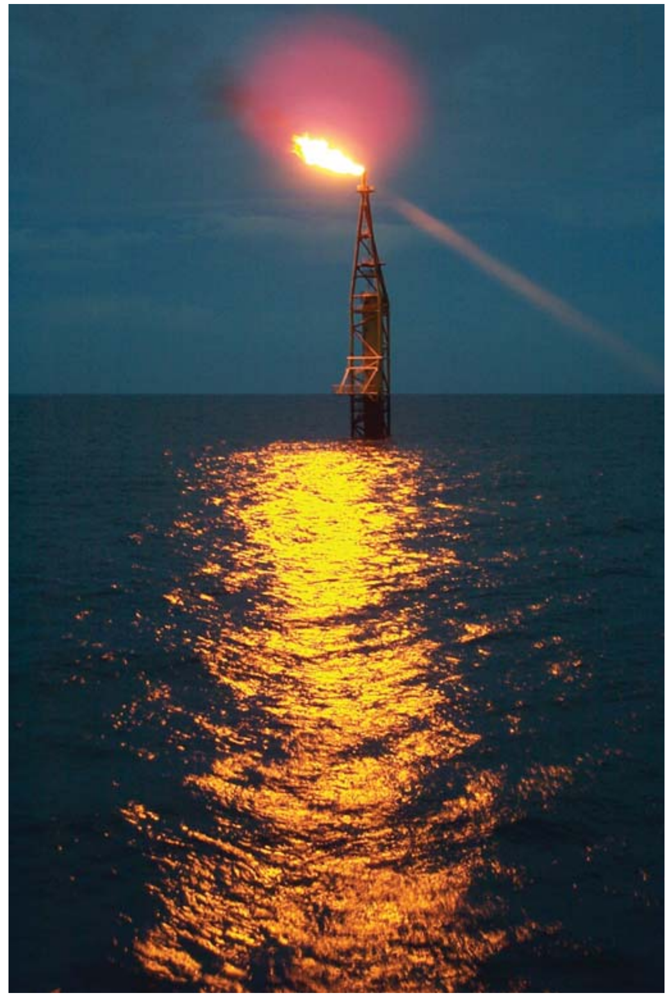


Figure 16. Conceptual gas material balance graph.



Conditions that should trigger caution when using gas material balance.

- Overpressured reservoirs with a gradient of 0.6 psi/ft or higher
- Small pressure change to original pressure, which may indicate water influx
- Apparent gas in place significantly larger than the volumetric estimate
- Areas prone for water influx or high pressure gradients
- Cumulative production less than 25 percent of expected ultimate based on volumetric estimate
- High withdrawal rates that may mask water influx in early life

Guidelines to reduce risk of overestimating gas in place and ultimate recovery using material balance

- Never base an early-life reserves estimate on material balance alone. Include volumetric data and performance analysis, if available.
- Review other, more mature fields in the area to

look for trends in p/z behavior and observed abandonment conditions.

- Overpressured reservoirs typically exhibit linear p/z trends until a normal pressure gradient is reached. Use caution and revert to volumetric analysis until a second trend materializes below the normal pressure gradient.
- Be cautious in assuming low abandonment pressures if water loading becomes an issue. Include nodal analysis calculations.

Assigning 1P reserves to undrilled fault blocks

Virtually all recognized proved reserves definitions refer to "known reservoirs" or "known accumulations" as a necessary qualifier to attribute proved reserves. Industry interprets the term "known" as that which is known through a well penetration. Accordingly, evaluators do not classify undrilled fault blocks or reservoir segments as "proved" reservoirs. Seismic interpretations may have advanced to the point where a 90 percent confidence factor is attributed to an undrilled reservoir. However, this is not usually adequate enough to declare an undrilled fault block as a "known reservoir."

Incomplete understanding of commercial economics projection software

R.S. Thompson and **J.D. Wright** in their 2001 paper, "A Comparative Analysis of 12 Economic Software Programs" (SPE 68588) investigated the use of economics software programs by their respective developers. They developed 30 test cases with straightforward assumptions about future oil and gas production rates, constant and variable gas-oil ratios and condensate yields and reversionary interests and overriding royalties. Assumptions further included constant and escalated prices and costs. Results were to include future net income undiscounted and discounted at several annual rates.

These cases were not unusually complex or easily misunderstood. The 12 vendors had one month to complete their forecasts. One of the simpler cases specified a drilling cost, an initial monthly oil production rate, an effective annual decline rate, exponential production decline, working and net revenue interests (constant), taxes as a percent of revenue and a beginning oil price and monthly operating cost, both escalated at 3 percent annually. The ranges in certain results are tabulated below:

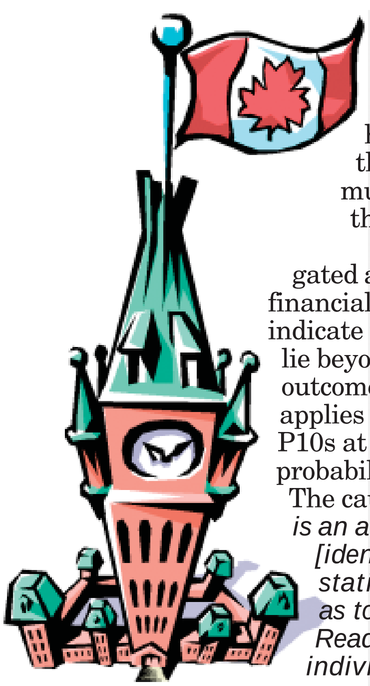
	High	Low	Expected
Undiscounted NPV	$181,000	$124,000	$160,000
NPV – 20%	$97,000	$3,000	$52,000
Rate of Return	104%	21%	34%

The expected case was prepared by the authors and was essentially hand calculated over the five-year project life. The differences reported above arose from one simple case but were magnified as example cases became more complex. How could this happen?

Different program assumptions were made involving the number of days in a year, the timing of the receipt of income, timing of expenses, differing discounting and escalation calculations and the timing of payouts triggering reversionary interests.

This study supports the notion that evaluators not rely on economics software unless they have developed high-level confidence through long-term use of the program and continuous review of the results.

CSA calls for caution when aggregating high estimates



The Canadian Securities Administrators issued a staff notice Dec. 30 that calls for public issuers to use cautionary language in their filings if they aggregate high-side resources estimates. "Disclosure of the arithmetic sum of low or high estimates of multiple properties may be misleading," said the CSA.

Mean or "best" estimates may be aggregated and disclosed without misleading readers of financial information. However, statistical principles indicate that the sum of multiple high estimates will lie beyond a reasonable range of expected actual outcomes. The portfolio effect of aggregation also applies to the addition of P10 reserves. If several P10s at field levels are added together, the result is a probability of much less than 10 percent.

The cautionary language is as follows: *This volume is an arithmetic sum of multiple estimates of [identify reserves or resource classes], which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should give attention to the estimates of individual classes of [reserves or resources] and appreciate the differing probabilities of recovery associated with each class as explained [indicate where disclosed and explained].*

Reservoir Solutions

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more reasonable B values to guard against overly optimistic EURs.

Early-time estimates of exponential terminal declines are uncertain. Because terminal decline can last decades before the well becomes uneconomic, a calculation that proves to be a few percentage points off can result in significant under- or overestimations. (In a reserves report, estimated cash flow is discounted at 10 percent per annum to arrive at net present values, which somewhat mitigates the impact of terminal declines.)

DCA equations were not developed for wells in a transient-flow regime. However, horizontal wells in the ND Bakken have evolved from a transient-state flow to a steady flow stage in anywhere from six months to two years or longer after initial production.

Despite DCA limitations, evaluators plot production, well pressures and gas-oil ratios over time to gain key insights into future performance of Bakken wells.

The best approach to supplement DCA is to find and use suitable performance analogs and to account for technical uncertainty through the appropriate categorization of reserves. Also volumetric analysis of petrophysical parameters and reservoir simulation of "typical wells" lead to more reliable well-performance models in some cases.

Well densities, new rules increase PUD locations

Public companies in the ND Bakken are assigning proved undeveloped reserves to more planned well locations since the change in the SEC rules for YE 2009. The SEC allows companies to book PUD reserves from offsets more than one location from a producing well if the reasonable certainty threshold is met. Also, the SEC permits companies to assign PUDs to horizontal locations offsetting the toe of a producing well if the location is moving in the direction of other successful, analogous producing horizontal wells. Formerly, PUD locations were limited to two direct parallel offsets to an existing horizontal well.

Bakken operators are downspacing to 320 acres by drilling four wells on 1,280 acres. Increased well densities are boosting PUD locations while dragging down EURs per well. Producers are counting on incremental production from tighter densities to pay for additional D&C costs per acre and to more quickly monetize Bakken assets.

Producers will continue to optimize field development programs to find the right combination. They will experiment and innovate knowing that history, the greatest teacher of all, is measured in months or a few years in the emerging Bakken.

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service crews and equipment.

Wilson said that some press releases have published short-term production tests that are rarely seen in monthly sales data. "Being able to see through this fog to forecast long-term trends is critical to profitably operating in this basin," he remarked.

The Denver office has cost and production forecasts for almost every Bakken well in the basin and is able to quickly review virtually any owner's interests. Wilson and petroleum engineers **Jim Baird**, **Rick Marshall**, **Larry Nelms** and **Tom Venglar** in Denver have evaluated Bakken shale reserves.

Ryder Scott experts in Houston and Calgary also appraise Bakken properties in the U.S. and Canada. Ryder Scott has conducted year-end 2010 reserves evaluations of the Bakken for the largest acreage holder, Continental Resources Inc., as well as for Marathon Oil Corp., Newfield Exploration Co., SM Energy Co., QEP Resources Inc., Fidelity Exploration and Production Co., Samson Oil and Gas Ltd. and others.

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