RESERVOIR SOLUTIONS

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Technology, PUD exceptions boost year-end reserves

This year, large cap oil and gas companies made numerous exceptions to the U.S. Securities and Exchange Commission time limitation for carrying proved undeveloped reserves on the books, said **Kathryn Campbell**, a partner at Sullivan & Cromwell LLP law firm. Public issuers must convert PUDs to another reserves or resources category within a five-year time frame unless valid exceptions can be made, including those based on external factors causing delays.

"Nearly all companies (from 33 surveyed) disclosed some amount of PUDs that will be developed after five years," Campbell told an audience at the United Nations Economic Commission for Europe Expert Group on Resource Classification Second Session on April 7 in Geneva.

Companies cited the following reasons for exceptions in year-end 2010 filings.

- Significant infrastructure and facilities are constructed for a large field but the drilling plan extends over the longer term.

A Swift Energy Co. field technician uses a slick line unit to finish a pressure gauge run in the AWP field in south Texas. Swift is exploiting the Eagle Ford shale formation in the field for oil. See article on Eagle Ford shale play on Page 4.

- Contractual limitations dictate production levels.
- Development schedules are constrained by physical limitations of processing facilities.
- Government imposes limitations on drilling plan.

Campbell said that a few companies provided discussion of what they considered to be reliable technologies, under the SEC definition, to support reserves additions. They included the following:

- Water flooding, steam flooding and CO2 flooding to support improved recovery.
- Wireline log and pressure data and high resolution seismic to prove reservoir continuity more than one location away from production.
- Statistical analysis of producing wells from other portions of the field to establish economic producibility. A few mention analogs.
- Pressure gradient data to extend down-dip limits of a reservoir.

Only four companies optionally disclosed probable reserves and none filed possible reserves. Three companies optionally reported reserves sensitivities based on future price scenarios not held constant.

Reasons that optional disclosures were not provided include too much time and effort, commercial sensitivity, requirements to discuss additional related uncertainty, liability concerns caused by lower confidence in probable and possible estimates and a preference to inform investors through non-SEC communications.

Presentations at the UNECE session are posted at http://www.unece.org/energy/se/docs/egrc2.html. They include "SEC Oil & Gas Reporting Rules - First Year of Compliance" by **Roger Schwall**, assistant director at the Office of Natural Resources Division of Corporation Finance at the SEC.

Inside Reservoir Solutions

ESMA proposes relaxed CPR disclosure requirements

The new European Securities and Markets Authority proposed March 23 that cash flows do not have to be included in competent persons reports on petroleum (mineral) reserves. ESMA's predecessor, the Committee of European Securities Regulators, previously required that a mineral company (including oil and gas company) without a three-year trading history publish independently audited cashflow forecasts in its prospectus. ESMA replaced CESR on Jan. 1.

ESMA said, "Estimations of cash flow are of limited value because they quickly become out of date, there are often a large number of potentially very different outcomes and outcomes tend to be highly dependent on the commodity price assumption used, which by its nature is uncertain. Estimates teamed with an accountant's report give investors a false sense of accuracy."

European Union member states will consider whether to implement the proposals next year. ESMA monitors market developments and issues guidelines and recommendations on securities law issues as CESR did, but has additional enforcement and other powers. For instance, the authority can draft technical standards that are legally binding in EU countries.

ESMA has amended Paragraphs 131-133 in CESR/05-054b and added three appendices for mineral companies, including Appendix III, "Oil and Gas Competent Persons Report – content." Last year, CESR recommended that without any requirements for the content of a CPR that it should include a geological overview, resources and reserves, valuation of reserves and other information in Appendix III.

ESMA is proposing that the detailed content in the appendix is recommended and not compulsory. The competent person will have flexibility to "adapt the (recommended) contents where appropriate for the circumstances of the issuer."

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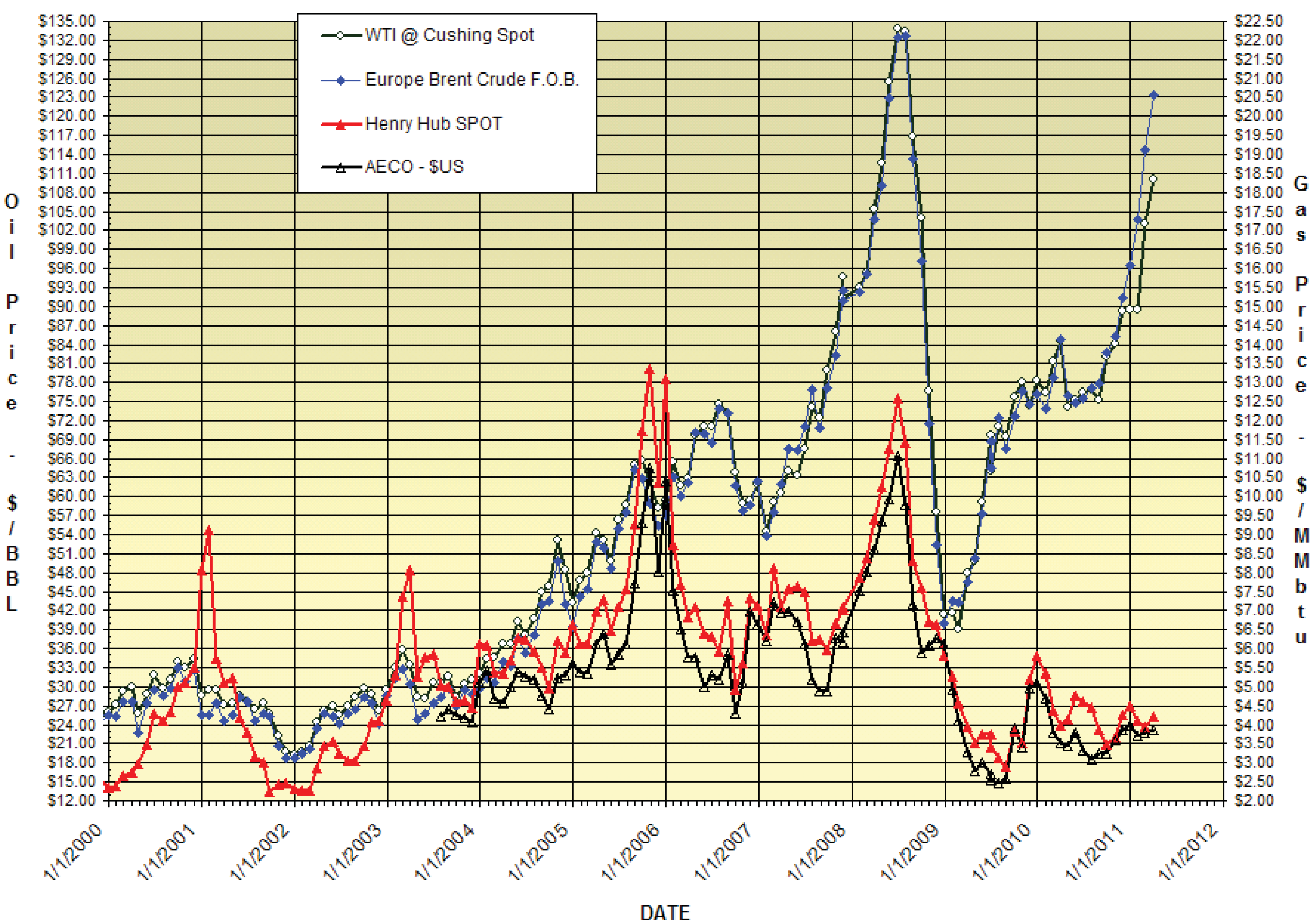
Price history of benchmark oil and gas in U.S. dollars



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

Arthur Creek in Australia: The next Bakken?

The Arthur Creek unconventional shale play in the Northern Territory of Australia is in good company. Geologically, it has been compared favorably to the prolific, widely acclaimed Bakken oil shale play in North America.

"The Lower Arthur Creek oil shales are very similar to the Bakken shale with some differences," said **Fred Dewis**, vice president of geology at Ryder Scott Canada. The Arthur Creek silty dolomites in the southern Georgina basin were formed during the Middle Cambrian Age, making them older than the Upper Devonian Bakken.

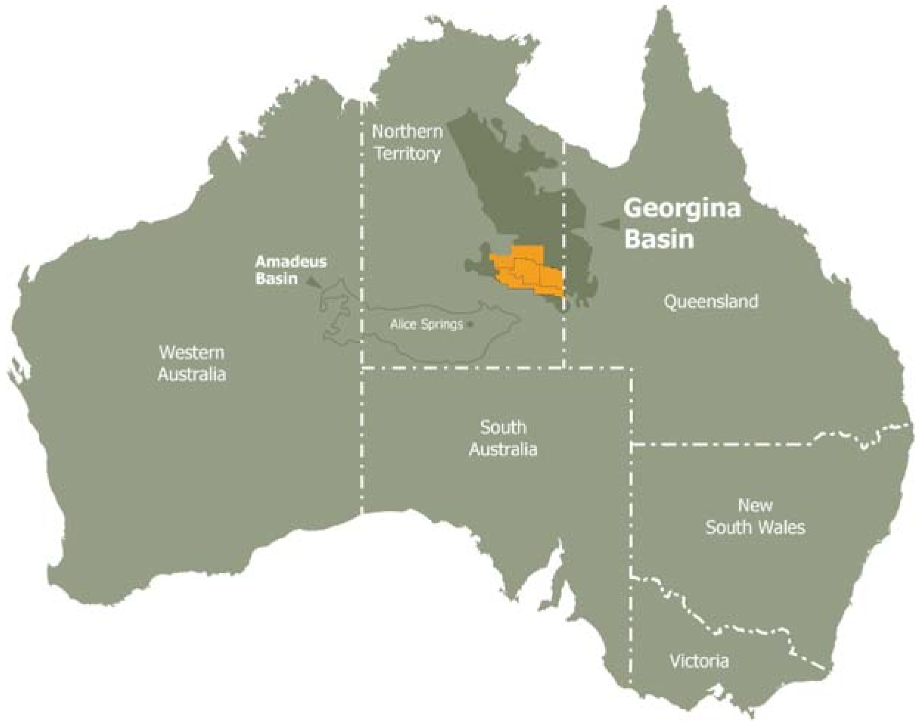
"At one time, the rocks in the Arthur Creek play were thought to be too old to be prospective. When I went to school, life started in the Cambrian Age and not enough organic material was present in Pre-Cambrian rocks to produce oil and gas," said Dewis, who graduated with a BSc degree in geology with honors from Carleton University in Ottawa in 1969.

He said that opinion changed when the industry found giant oil and gas fields with billions of barrels of oil reserves in Neoproterozoic/Cambrian rocks in Siberia and Oman. "That resulted in renewed exploration interest throughout the world in other similar-aged basins, such as the Georgina," remarked Dewis, a professional geologist for more than 40 years.

A total organic carbon (TOC) content of 2 percent is considered a sufficient screening criterion for oil shale plays. However, both the Bakken and Arthur Creek have been reported to contain much higher TOCs. Greater TOC and shale thicknesses are correlated to higher production.

The primary drilling target for unconventional oil in the southern Georgina basin is the Cambrian Arthur Creek "hot" shale. (Hot shale has a high radioactive content.) In the permitted acreage, Arthur Creek has approximately the same gross thickness at 98 ft as the 80-ft thick Bakken productive interval. (Both are actually dolomites, not shale.)

A key advantage though is the



Field development was scheduled to begin in June in PetroFrontier's four exploration blocks (in orange) in the Arthur Creek oil shale play in Australia. Arthur Creek in the southern Georgina basin has geological characteristics comparable to the prolific Bakken shale play in the United States and Canada.

low-permeability shales and siltstones of Arthur Creek are at a 2,500-ft vertical drilling depth, much shallower than the Bakken middle-dolomite member. The Bakken is 4,000 ft deep in the Canadian portion of Williston basin and drops to 10,000 ft in the United States.

Both formations are characterized by natural fractures but limited information from wells in southern Georgina suggests that the Arthur Creek shales may be more highly fractured than the Bakken and thus may require less fracture stimulation, said Dewis. The question is whether the Arthur Creek

Please see Arthur Creek on Page 7

"Familiar" rock properties are not the only drivers of well performance in shale plays

Identifying shale properties that influence hydrocarbon resources, reserves and production is difficult. Often the factors driving performance are not the rock properties that evaluators are accustomed to measuring, such as porosity, saturations, permeability and thickness.

Instead properties like rock stress and natural fracturing, which are functions of tectonic activity, influence producibility and reserves. In many if not most cases, those properties are known only after a well is drilled. Thus predicting hydrocarbon producing rates and reserves before drilling is problematic at best.

For that reason, evaluators use statistical methods to describe the probability of various outcomes. Although evaluators cannot determine exact producing rates and reserves for a specific undrilled well, they can determine the probability the well will produce at or above a certain rate and the probability the reserves will be at or above a specified volume.

Changes in technology, supply chain and transportation to maximize production from Eagle Ford shale play

A hydraulic fracturing fleet in the Eagle Ford shale is on site for a 17-stage completion of a Swift Energy Co. well with a 6,000-ft horizontal leg. Multi-stage frac techniques are boosting recoveries from the shale play.

E&P companies are fine tuning horizontal drilling and completions technology in the promising Eagle Ford oil shale play in south Texas to boost production six-fold to an estimated 420,000 barrels per day in five years—a forecast from Bentek Energy analysts as quoted by *Reuters* in May.

Over the past two years, about 30 companies have moved into the Eagle Ford to begin field development operations to tap the liquid-rich resources. "Where wildcatters and entrepreneurs pounced on the Spindletop boom at the start of the 20th century, engineers and business analysts are leading the charge to develop reserves under 20,000 square miles of cattle land in Eagle Ford," said *Reuters*.

"The extent of the oil play is quite large," **Manuj Nikhanj**, vice president at Ross Smith Energy Group, told the *Houston Chronicle* in late May. "You could eventually see 20,000 to 30,000 wells drilled in the play. You could have more than 10 billion barrels of oil through time. And the oil economics just keep getting better, so companies want to expand in this region."

Permits in Eagle Ford jumped from 94 in 2009 to 1,010 last year and oil production increased tenfold to more than 3 million barrels during that time, said the Texas Railroad Commission.

Since the discovery in 2008, producers have used multi-stage horizontal completions with slickwater or hybrid fracture treatments to stimulate oil flow. Slickwater is a water-based, low-viscosity fluid-and-proppant combination developed in the Barnett shale play. Hybrid fracturing involves transporting the proppant into the fracture with a gelled fluid.

Now, companies, such as Petrohawk Energy Corp., are using a new method that makes use of a fiber additive to maintain the stability of flow channels in fractures to increase conductivity. In May, Petrohawk, which discovered the play, said that the completion technique was 10 percent less costly than hybrid fracking. The company also said that flow-channel fracturing required 10 percent less water and 40 percent less sand—substantial benefits from supply-chain and water-management standpoints.

Jefferies & Co. Inc., a securities and investment banking group, noted that "the jury is still out on whether the (flow-channel) technology enhances estimated ultimate recoveries or just net present values."

In May, Pioneer Natural Resources Co. said that it was testing white sand as a proppant in some shallower areas to the northwest and early results showed that the company may realize "significant savings" compared to ceramic proppants. Also, "rubblizing tech-

A new hydraulic frac truck in the Eagle Ford shale is among a fleet owned by Pioneer Natural Resources Co. Pioneer and others are acquiring their own frac fleets to cut "cost creep" for outside services and to assure availability which is tight.

niques …are now being tested," Jeffries told the *Oil & Gas Financial Journal* in April. "That technique, with more frac stages and less energy per stage, has been shown to generate higher EURs with a slight increase in costs."

Jeffries also told *OGFJ* that Goodrich Petroleum Corp. is compensating for lower initial production rates in its northern Eagle Ford acreage by applying artificial lift at earlier stages.

The cost per Eagle Ford well is $5 million to $12 million. In May, EOG Resources Inc. said "the biggest proportion of cost creep is the frac jobs" which also edged up last year as well. In response, EOG as well as Pioneer have lessened their reliance on outside fracking companies by investing in their own fracture stimulation fleets.

Petrohawk saw its spud-to-spud days decrease from 38 to 30 days the first quarter. However, the company said it has not seen a material change in overall pressure pumping costs and other related services, so it is currently not forecasting a decrease in average well cost. Goodrich is also seeing a decrease in drilling days, but with gel and sand shortages, pressure pumping costs are up.

"Complicating the reserves analysis are bottlenecks caused by infrastructure limitations hindering the ability of operators to hook drilled wells to sales," said **Mike Stell**, a managing senior vice president at Ryder Scott who estimates reserves for numerous companies in Eagle Ford.

"To relieve a bottleneck producers say has begun to choke growth, pipeline companies in recent weeks committed more than $1 billion to add 940,000 bpd of pipeline capacity by the end of 2012," said *Reuters*. For now, tanker trucks clog farm roads and railway tank cars form long processions to markets. To help relieve crude takeaway constraints temporarily until pipeline capacity is available, EOG is building its own rail line to transport 20,000 barrels per day by year end.

Stell has evaluated about 150 wells in the core development area of the Eagle Ford which runs southwest to northeast from Webb County to Karnes County. He has also analyzed corresponding offsets

A field technician stands on drill pipe at a SM Energy Co. well site in the Eagle Ford shale. Photograph by Jim Blecha courtesy of SM Energy.

and is developing performance analogs and type curves that are rapidly changing as field development activity surges dramatically. His compilations include drilling and completion statistics, such as true vertical depth, lateral length, number of frac stages and pounds of proppant used.

Stell also has used Texas Railroad Commission information on completions, tests and other pertinent data and has created a database of active wells. Besides developing type curves, he has generated typical estimated EURs by area and depth. Stell is also collecting thermal maturity data from clients. At this early stage, acreage positions have thousands of potential well locations.

For more information, contact Stell at mike_stell@ryderscott.com.

Announcements

Ryder Scott promotions are as follows: **Allen Chen** to senior petroleum engineer; **Joe Stowers** to petroleum engineer; **Brett Gray**, **Phillip Jankowski**, **Tiffany Katerndahl** and **Michael Michaelides** to geoscientist; **Eleazar Benedetto-Padron** to senior geoscientist; **Kosta Filis** to senior engineering technician; **Jim Baird** to managing senior VP; **Frank Jeanes**, **Jim Stinson** and **Mario Ballesteros** to VP technical specialist; **Rick Robinson**, **Steve Gardner**, **Tosin Famurewa**, **Miles Palke** and **John Hanko** to VP project coordinator and **Pamela Nozza** to engineering analyst.

President **John Hodgin** will present his insights into the industry's reserves disclosures under SEC rules at a multi-society symposium July 20 in Houston. CEO **Don Roesle** is a panelist. For more information, go to www.spe.org/events/resv.

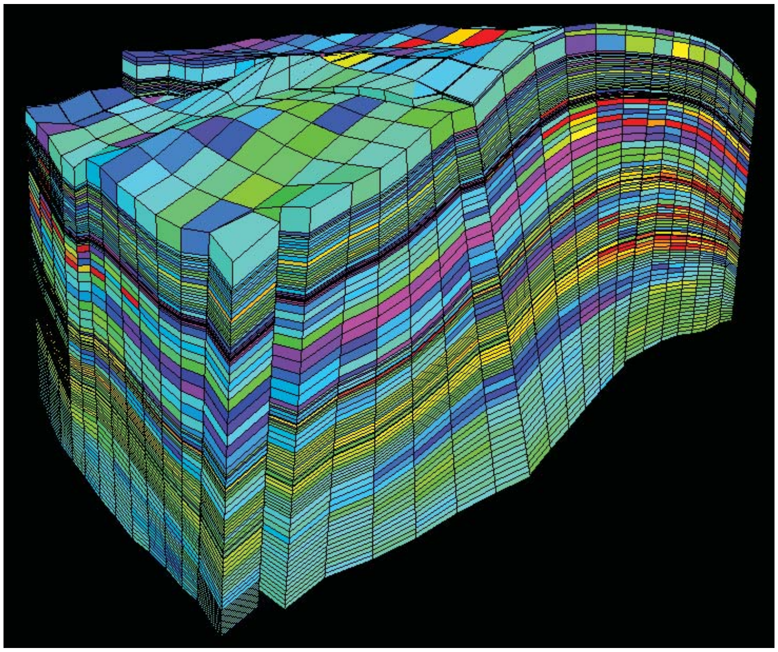
Circle the date: The 7th Annual Ryder Scott Reserves Conference will be held Friday, Sept. 16 at the Hyatt Regency Hotel in downtown Houston. Pre-registration is Aug. 1. For more information, contact **John Hodgin**, president, at john_hodgin@ryderscott.com.

Palke presents reservoir simulation review practices

Petroleum engineers are frequently faced with the need to consider using reservoir simulation models that they did not create. Internal staffs at E&P companies as well as outside consultants review built-for-purpose simulation models to investigate whether they can be used for other purposes, such as reserves estimation.

Miles Palke, vice president project coordinator at Ryder Scott, discussed model reviews and pitfalls at a May meeting of the Houston chapter of the Society of Petroleum Evaluation Engineers. He outlined how to streamline the review process and cited rules of thumb based on his experience constructing and reviewing models for 15 years.

Simulation is the only single petroleum engineering technique that integrates geology, performance, production histories and other information. Palke said that the most important use of reservoir simulation is to test various field development options or the effect of uncertain reservoir parameters in what-if scenarios.



"What-if scenarios are used to evaluate the relative performance of options for field development and production planning and scheduling," he remarked. "Those options might be comparing infill Well A to infill Well B or analyzing water-injection schemes or compression packages."

Is a particular model appropriate for a purpose such as estimating reserves, making investment decisions or changing field operations? A simulation review answers that question.

Palke said that a review starts with a comparison of the original purpose of the model to its proposed use. "Sometimes a consultant is asked to review a model designed only for scoping. However, the client wants to use it for reserves and needs a final answer immediately," said Palke.

In other cases, models developed to forecast vertical well performance are used to project undeveloped horizontal well performance. "In that case, a disconnect exists between the original purpose and proposed use of the model. You have to deal with it going forward," remarked Palke.

Another reason to review a model is to investigate flexible controls used during model predictions that strongly influence outcomes. Reviews are also used to examine the model construction and history matching of simulation specialists no longer available for discussion.

Palke's tips and tricks of the trade include comparing the simulation model with traditional analytical techniques to provide a reality check. He also said always consider the following:

Model Construction—How accurate and detailed is the static model?

- Does it honor observed data from well control?
- Is the reservoir fluid characterized reasonably?
- Does the grid have sufficient resolution to address the questions asked?
- Is the initialization of the model reasonable?
- Have wells' placement and completed intervals been captured correctly?

History Match—Is the history match reasonable?

- What data was used to match history?
- How adequate is the match of the simulated values to the observed values?
- What changes were required to the description during history matching to secure the history match? Are these changes justifiable?
- How well does the model transition from history to prediction?

When considering changes made during history matching, reviewers need to be aware that in some cases, simulation software allows unreasonable changes to be made. Examples include pore volumes that exceed gross volumes, model aquifers in places where none exist, pipelines of cells connecting disconnected volumes and residual saturations of zero percent.

Another pitfall to consider is that parameters may be adjusted during history matching that modestly impact history, but significantly affect predictions. For example, a change in aquifer description in a depletion-drive reservoir may not alter the history match of initial production, but can significantly change long-term predictive results, said Palke.

In addition, history-match changes may be appropriate for certain purposes but not for others. Palke said that modifying the properties immediately around each well individually may be okay for forecasts of existing wells but probably will be inappropriate for infill wells.

"Don't be tricked by very good matches of single phases or cumulative volumes at the end of history," said Palke. Typically, a modeler fixes the dominant phase's rates so that the simulator must make those volumes. Also, a modeler might match cumulative volumes at the end of history while not accounting for trends during history, which makes predictions less useful.

Carefully review how the model transitions from simulation to prediction and review the reasonableness of the status quo case in which no operating conditions change and the well count and placement remain the same, said Palke. He also discussed the future of reservoir simulation reviews, including the development of metrics for the evaluation of simulation models—a work in progress for Palke and others at Ryder Scott.

For further information on Ryder Scott reservoir simulation capabilities, contact Palke at miles_palke@ryderscott.com or **Dean Rietz**, simulation department head, at dean_rietz@ryderscott.com.

Arthur Creek—Cont. from Page 3

interbedded shale zones will yield oil at Bakkenesque rates through horizontal wells fracked in stages—a proven drilling-and-completion technology in the Bakken to be tried for the first time in Australia.

Predicting hydrocarbon producing rates and reserves before drilling is problematic at best. See sidebar article, "'Familiar' rock properties are not the only drivers of well performance in shale plays," on Page 3.

The executed field development plan will be the proof of concept in determining whether Arthur Creek belongs in the same company as the Bakken, Niobrara, Eagle Ford and other emerging oil shale plays. PetroFrontier Corp., a Calgary-based E&P company, has a major stake in Arthur Creek with four exploration permits—EP 103, EP 104, EP 127, EP 128—covering an area of more than 13 million acres. The operator said on May 17 that it planned to begin drilling two horizontal wells in June and will acquire an additional 1,100 miles of 2D seismic to further delineate the stratigraphy.

Dewis and **Linda Echikh**, geologist at Ryder Scott Canada, conducted a recent probabilistic analysis of the four permitted exploration areas.

Very few wells have been drilled in the entire Georgina basin. Within the four exploration permits, only 29 exploration wells have been drilled—all from 1962 to 1991. All but two were drilled off structure with no closures. All were drilled with slimhole mining rigs and a few were government stratigraphic test wells.

"The Georgina basin represents one of the few remaining virtually unexplored onshore sedimentary basins with prospective hydrocarbons," said Dewis.

Complex geology, including significant basement faulting within the area, and a lack of well control made the Ryder Scott technical analysis challenging. The Monte Carlo study generated ranges for each reservoir parameter. That included low, best and high cases for porosity, gross intervals, net-to-gross ratios for rock volumes, oil saturations and oil recovery factors.

Ryder Scott estimated about 26 billion barrels of unrisked prospective resources as a best (P50) case. See Editor's Note.

The independent study states that the Lower Arthur Creek organic rich hot shale is a potentially very large unconventional shale oil play … with world class TOC values averaging more than 5 percent in the shale intervals. The Ryder Scott third-party report is posted on the PetroFrontier website at http://www.petrofrontier.com/en/documents/pfc-2011-01-14-ryderscottreport.pdf.

Dewis and the Calgary office have prepared numerous resources reports for companies exploring in Australia. For more information, contact Dewis at fred_dewis@ryderscott.com or **Howard Lam**, manager of Ryder Scott Canada, at howard_lam@ryderscott.com.
As reported last March in Reservoir Solutions, multistage hydraulic fracturing technology used in the Bakken also has been exported to China, France and Poland.

Editor's Note: The term "unrisked" means that Ryder Scott did not incorporate geologic risk (play risk) in the hydrocarbon volume estimates. The resource plays evaluated in the Ryder Scott report are high risk. No commercial hydrocarbons have been discovered on the four exploration permits. There is no certainty that any portion of the undiscovered resources will be discovered. If discovered, the play may not be economically viable or technically feasible to produce the resources.

From left, Christine Neylon, associate petroleum engineer; Pam Wren, engineering analyst and Claudia Oramas, engineering technician. They rode in the Salt Grass Trail Ride, which promotes the annual Houston Livestock Show and Rodeo.

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ESMA—Cont. from Page 2

ESMA also has proposed that a CPR be published for all initial public offering prospectuses regardless of how long the issuer has been an oil and gas (mineral) company unless exempted under recommendation 133 (ii). If the issuer has continued to report and publish details of its resources and reserves annually in accordance with any one of the reporting standards in revised Appendix I of the prospectus directive, then it may be exempt. Ultimately that depends on whether ESMA recommendations are adopted by a given EU regulatory regime.

Appendix I standards include the Society of Petroleum Engineers Petroleum Resources Management System and the Canadian Oil and Gas Evaluation Handbook, Canada's National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities and Norwegian Petroleum Directorate classification system. The U.S. Securities and Exchange Commission oil and gas reporting disclosures are not acceptable. Feedback on the proposals was mostly in agreement with the new EU securities authority. Go to http://www.esma.europa.eu/popup2.php?id=7515 for the ESMA update.

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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.

Ron Harrell, left, chairman emeritus at Ryder Scott, receives the University of Houston's President's Medallion for his support as a donor and a founding member and chair of the UH Petroleum Engineering Advisory Board. Board members, UH administrators and others succeeded in getting an undergraduate petroleum engineering program approved by the state in December 2009. President and Chancellor Renu Khator, middle, and UH System Board of Regent member Jarvis Hollingsworth presented the medallion. Photo by Flash Photography.