RESERVOIR SOLUTIONS

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RS Houston Conference Recap

Alpine High overlooked until Apache discovery

Key to San Andres: Understand the reservoir

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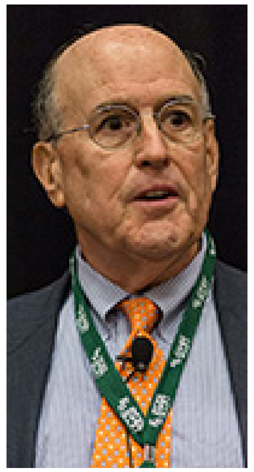
SEC seeks more details on reserves filings, issues fewer comments on development plans



Marc Folladori

The U.S. Securities and Exchange Commission dug deeper in its reviews of 2015 and 2016 year-end petroleum reserves filings, said **Marc Folladori**, senior counsel at Haynes and Boone LLP. However, compared to the previous two years, the SEC directed fewer comments to companies that repeatedly and significantly changed development plans for their PUDs (proved undeveloped reserves) over several periods.

Folladori based his remarks on an extensive survey of SEC comment letters that he conducted. "The SEC suspected that no final investment decision was made by companies changing development plans and PUD bookings," he said.

The SEC has said "mere intent to develop, without more, does not constitute adoption of a development plan. ...Adoption requires a final investment decision."

The SEC also had fewer questions on reserves impairment for companies using full-cost accounting compared to successful efforts. Folladori shared his survey results at the Ryder Scott Houston conference earlier this year. His presentation is posted at ryderscott.com/presentations.

Other findings

The SEC increased its comments to non-U.S. public issuers that file 20-Fs.

The agency asked **Statoil ASA** to disclose the likely effects of a continuation of lower prices, which the company noted in its filing on operating results, liquidity and capital resources. The SEC asked **Sasol Ltd.** to determine the economic producibility of its reserves quantities taking into account transportation-capacity-reservation costs.

The SEC is also looking for inconsistencies in press releases, earnings statements and other external communiques. The agency asked **Anadarko Petroleum Corp.** to reconcile inconsistencies between its carbon disclosure project (CDP) report on

new climate change regulations and its 2016 proxy statement. In the latter, Anadarko stated that regulatory risks around air and GHG emissions would have no significant, unmanageable impacts to its operations. That runs counter to its CDP report that stated that GHG emission regulations have a potential to increase operational costs, which will have a "high" impact on business operations.

A portion of the headline in a 2016 earnings release of **EOG Resources Inc.** stated that the company had replaced 192 percent of its total 2015 production, excluding price revisions. However, in the body of the press release, the company said that its total net proved reserves had decreased 15 percent, including price revisions. While the statements were not contradictory, the SEC suggested a more "balanced" discussion.

The SEC delved into credit agreements, debt covenants, hedging and derivative arrangements.

The SEC asked **Yuma Energy Inc.** if it had a reasonable expectation of securing a $44-million borrowing base considering current commodity prices, last year's borrowing-base redeterminations and its merger partner's senior bank credit facility cited in the filing.

The SEC took aim at PUDs associated with acreage in leases or concessions that were set to expire before the scheduled dates of initial field development. The agency asked **BP Plc** to address the approach it will use to forestall expiration of that acreage.

Eclipse Resources Corp. reported that a continuation of depressed commodity prices might result in significant downward adjustments to its reserves. That prompted the SEC to ask for information quantifying the effect of different scenarios regarding changes in commodity prices that Eclipse considered reasonably likely to occur. That request was a bit of a sticky wicket for Eclipse, as estimates of future prices are notoriously inaccurate, making it difficult to speculate on future prices with much accuracy. The SEC also asked **CNOOC Ltd.** and **Royal Dutch Shell Plc** about future price trends and their anticipated effects.

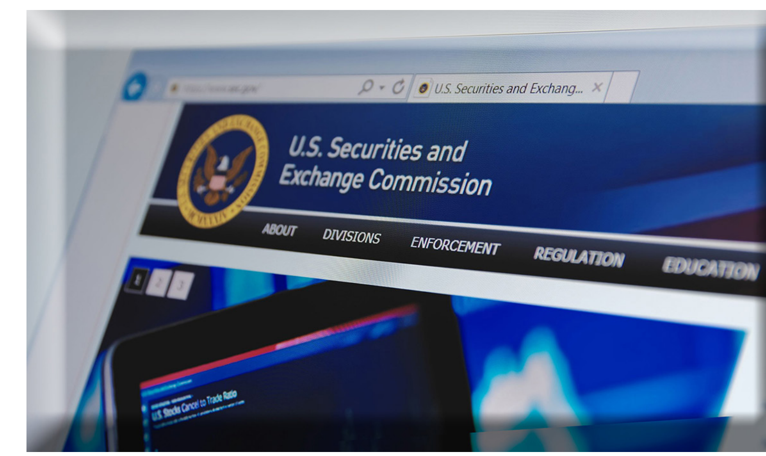
The SEC noted that **Hess Corp.** had been without a means to deliver its Libyan production to market for over two years. Therefore, the agency asked the company to support its proved reserves classification associated with such production. The SEC wanted an explanation of why Hess considered forecasted future production quantities in its standardized measure to be reasonably certain to be economically producible.

Folladori presented several examples of the SEC probing into standardized measure calculations. He also cited several examples in which the SEC asked why recently incurred unit development costs (costs per BOE) were higher than projected costs used in the standardized measure calculation.

The SEC told **RSP Permian Inc.**, "Since proved reserves are required to be economically producible 'under existing economic conditions,' we would expect these … (unit development) costs to reflect levels you have historically incurred."

Folladori presented seven cases involving DUCs (drilled and uncompleted) wells. The SEC asked for information on proved reserves associated with suspended wells or wells awaiting completion or resumption of drilling and whether they were classified as developed or undeveloped.

The SEC doesn't accept delays caused by company internal decisions to be justification for carrying PUDs on the books past five years. The agency told **ConocoPhillips Co.** that it did not accept arguments to justify a time period longer than five



years to begin development of Eagle Ford PUDs. Those delays were caused by internal factors, i.e., decision to slow the pace of investment in the Eagle Ford drilling program, the SEC said.

Folladori said, "As is the case every year, the topic of development of PUD reserves garnered the most comments."

Overcoming challenges to make Alpine High a successful play

Apache Corp. challenged conventional thinking three years ago in validating what proved to be a highly prized unconventional play, the Alpine High. Along the way, the company dispelled early assumptions that this area of the Delaware basin was structurally complex, had poor rock properties and was an uneconomic dry gas play.

At the Ryder Scott reserves conference last September, **Kregg Olson**, executive vice president corporate reservoir engineering at Apache, told the Alpine High story through his presentation, "Alpine High Overcoming Challenges to Make a Successful Play."

"Sometimes it is hard to establish meaningful progress without challenging the conventional wisdom of the time. In our industry, many large discoveries have been associated with a unique view on old information."

At the time of the conference, Apache had drilled 56 wells with 18 more in progress. The company was running six rigs, with plans to deploy eight by 2018. In October, Apache announced it had drilled more than 70 wells on Alpine High.

"We have established commercial production rates in five separate formations, and identified thousands of drilling locations which will provide decades of drilling for the future," said Olson.

Apache started selling production from its trunkline interconnect last May. The company reported in September that it was producing more than 100 MMcf gas per day, 1,425 BOPD and 2,025 B/D NGLs.

Alpine High snubbed

Industry has been quite active in the Bone Springs and Wolfcamp plays trending along the central axis of the Delaware basin. "So why was Alpine High just sitting out there in one of the most active basins in North America," asked Olson.

He drew attention to a 2014 activity map of the Permian Basin, showing what he called a "fair amount of white space" in southwest Reeves County, just outside the major play boundaries. "That is where we found Alpine High," he said.

Before Apache's efforts, E&P companies had penetrated the area's Barnett/Woodford zones with 118 wells. Most of those were not completed, and industry failed to recognize the potential of these targets.

For Apache, finding Alpine High did not come by chance. The company had to challenge existing notions of geology and fluid characteristics of the area, said Olson. "We think of this as a major challenge but in fact, those existing notions were the primary reason we were able to put together such a major acreage position in the first place," he remarked.

In early 2014, Apache began acquiring acreage, eventually adding 320,000 net acres of leasehold. In October, Apache reported its Alpine High position had reached 366,000 net acres.

"We bought at very low prices at about $1,300-per-acre average leasehold costs with some at $700," said Olson. "We are proud of this, because Delaware basin acreage prices were trending upward from $10,000 an acre for hot plays in Wolfcamp and Bone Springs, up to as high as $40,000 during this same period. This was a coup on our side."

Overlooked play mischaracterized

Apache's primary objective was the Paleozoic interval of the Woodford and Barnett formations which are well-known source rocks in various U.S. basins.

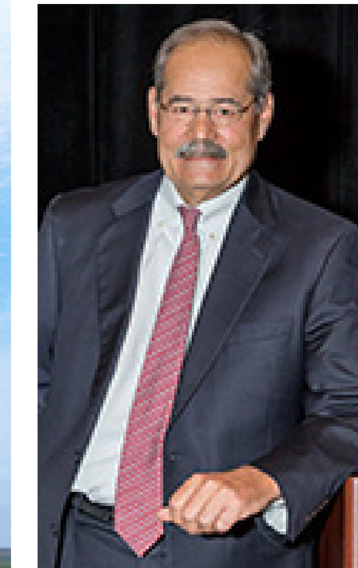
"Several wells had been drilled there, but industry did not consider those to be attractive targets," said Olson who showed a Vitrinite reflectance map presented at an American Association of Petroleum Geologists meeting this year.

"This map reflects industry's longstanding perception that most of the Woodford in the Alpine High was in a dry-gas window, and that the formation was deeply buried, overcooked and subsequently uplifted to its present day structure," he said "The same conclusion was actually drawn for the Barnett, Penn and Wolfcamp formations in this area."

Industry also believed that high clay content in the Woodford and Barnett formations would cause the reservoir properties to be poor and hinder effective fracture stimulation.

"We believed that Alpine High was a stable platform with desirable rock properties in a maturity window that would produce wet gas and oil," said Olson. "Our initial exploration wells were designed to test and validate that hypothesis."

Apache's initial test well, while non-commercial, did recover small amounts of 39-gravity crude oil and demonstrated relatively low clay content in the target formations. Subsequent delineation activity validated excellent rock properties across the play and compares favorably to other established unconventional plays, said Olson.



Kregg Olson

Apache's differentiated view

"Sometimes it is hard to establish meaningful progress without challenging the conventional wisdom of the time. In our industry, many large discoveries have been associated with a unique view on old information," said Olson.

Examples cited were establishing low-resistivity pay intervals in previously bypassed zones, validating poorly understood basin-centered tight gas plays and establishing commercial production in shale plays.

"We followed a very methodical approach – the basic scientific method, taught in sixth-grade science classes," said Olson. "We used this to frame the situation and control how we gathered and analyzed data."

Based on the Apache paleo-geology study, the company developed a hypothesis and tested the concept.

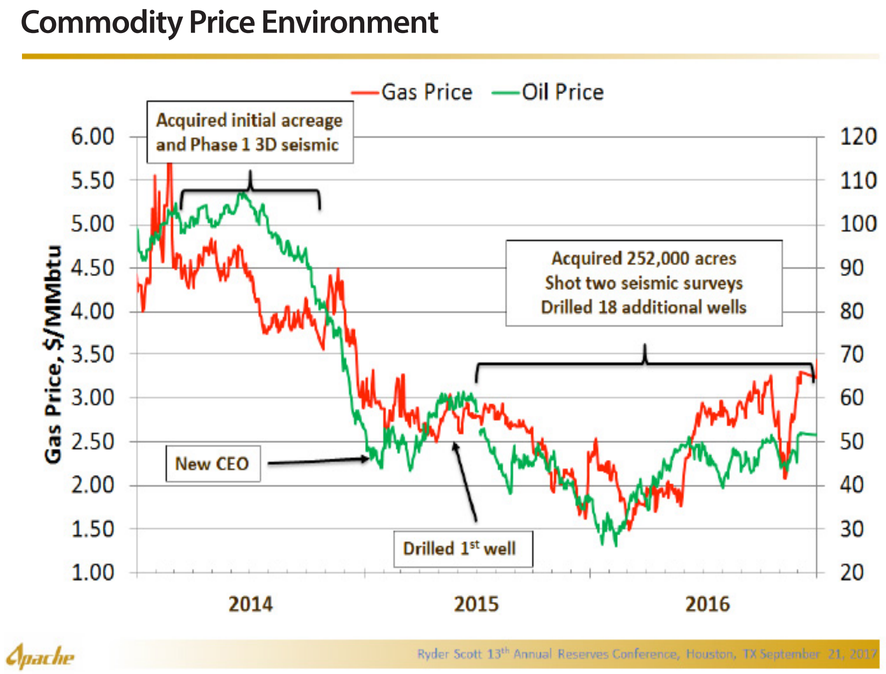
Please see, Overcoming challenges, page 6

Comparative Play Parameters
Alpine High vs. Established Resource Plays

Parameter	Alpine High *(Woodford/Barnett)*	SCOOP *(Woodford)*	Marcellus *(Wet Gas)*	Eagle Ford *(Condensate)*
TOC *(weight %)*	4%-10%	4%-10%	1%-5%	1%-7%
Primary Mineralogy	Silicate	Silicate	Silicate	Carbonate
Clay Content	10%-20%	20%-35%	20%-35%	10%-40%
Total Porosity	8%-12%	4%-10%	6%-11%	4%-11%
Pressure *(psi)*	5,000-9,000	7,700-10,500	3,500-4,200	4,875-10,000
Thickness *(ft)*	550-1,100	80-200	50-200	50-350
Depth *(ft)*	10,000-13,000	11,000-15,000	5,000-8,000	11,000-14,000

Apache — Ryder Scott 13th Annual Reserves Conference, Houston, TX September 21, 2017

Overcoming challenges – Cont. from page 5



"Apache continues to apply a similar methodical approach to testing wellbore orientation, new landing zones, well spacing and completion design," he remarked.

Apache initiated exploration and development of Alpine High during an economic downturn in the industry.

"With a significant drop in commodity prices in late 2014, it required conviction and major budget concessions to execute this project and continue to move it forward," said Olson.

Early on, Apache was limited in the amount of production data it could gather to evaluate well performance in Alpine High. The discovery area had very little infrastructure, so the company had to restrict its flow tests under a temporary flaring allowance.

"In the classic chicken-and-egg scenario, we needed infrastructure to keep our wells flowing longer, but we needed to know how our wells would perform, so we could design our infrastructure efficiently," said Olson.

In addition to the Woodford and Barnett, Apache has also demonstrated productivity of the Penn, Wolfcamp and Bone Springs formations and confirmed its thermal maturity model through the entire sequence.

Apache continues to conduct geological and stratigraphic delineation of all target zones, from Bone Spring through Woodford. By September, Apache had confirmed 10 separate landing zones over 4,000 to 5,000 ft of continuous stacked pay and was gearing up for additional well spacing and pattern tests.

A major challenge to Apache is to conduct timely, extensive geographic and stratigraphic delineation of more than 1.5 billion acre-feet of prospective formations. "With 4,000 to 5,000 feet of sediment over 500 square miles to evaluate, many answers will just have to wait until we can gather enough information," said Olson.

Proving up Alpine High

What information will Apache need to justify PUD locations? What will it take to prove up the entire play? From a statistical perspective, Olson referred to the SPEE Monograph 3, which provides guidance for a probabilistic methodology and the guidelines for necessary sample size to achieve 90-percent confidence for a given geologic setting.

Apache's P10 to P90 ratio is about 4, which implies a minimum sample size of 60, said Olson.

"To achieve a statistically mature status, a geologic setting should have at least three times the sample size," he said. "Given the complexity of the Alpine High with five recognized geologic settings, five separate formations each with multiple landing zones, and with fluid composition dependent on depth and maturity, we thought it would be interesting to see how many wells would be required to statistically prove up the play."

For just the Woodford, Barnett and Penn zones, Olson calculated that it would take 2,700 wells to consider the area as statistically mature and technically and statistically proved.

"This assumes that the data supports predictable repeatability over the area," he said. "At 200 wells per year, that would take 13-½ years to assess the area."

Olson also mentioned that in the early stages of statistical maturity, PUD locations are generally limited to direct offsets to producers. The U.S. SEC limits PUD locations to those planned for development within five years of initial disclosure. Assigning two offsets per producer at a drilling pace of 200 wells per year, Apache would have to cap its proved undrilled locations at 1,000 in 2 ½ years.

"We can identify more technically proved locations, but are still limited to 1,000 PUDs, until we accelerate drilling activity," said Olson. "This is just 'fun with numbers,' but it demonstrates just how long it will take to gather enough information in a new play to define recovery potential with any amount of confidence."

Olson showed various well logs, critical play parameters, paleontological information, basin geology and trend maps, historical drilling locations, initial performance of wells and other detailed material. His presentation is posted at ryderscott.com/presentations.

Editor's Note: Please see "A five-step version of the scientific method," in Reservoir Solutions newsletter, October/December 2016, Vol. 19, No. 4, Pages 11-12.

Understanding the reservoir is key to San Andres

"The San Andres is the gift that keeps on giving. The formation has produced billions of barrels of oil over several decades and it is not finished yet."

Natalie Brown

Pump jack at the Fisher 4-4H well.

Natalie Brown, reservoir engineering manager at Forge Energy LLC, presented the company's "unconventional thinking" in developing the San Andres formation with low-risk, low-cost horizontal wells offsetting legacy vertical fields. The company has drilled some of the most productive wells in the formation, including the Fisher 9-2H well in Andrews County, TX, that initially produced 899 BOPD in 2013.

"The San Andres is the gift that keeps on giving," she said. "The formation has produced billions of barrels of oil over several decades and it is not finished yet."

In 1929, a major oil find in Andrews County caused a rush, and by the 1950s, the oil business peaked with discoveries of more than 100 fields. Drilling and production evolved through downspacing, secondary and tertiary recovery and residual-oil-zone pilots.

Some 60 years after its heyday, the San Andres has experienced redevelopment through horizontal drilling and fracing, led by Forge, a privately held independent. The company began its San Andres horizontal-drilling campaign in 2012, applying lessons learned to advance its technical approach.

Keys to success: Understanding reservoir system and completion designs

"A single recipe does not fit this play type," said Brown. "The overall principles that apply to the horizontal San Andres across the northern Permian Basin are fundamental philosophies that can apply to a multitude of formations across many basins."

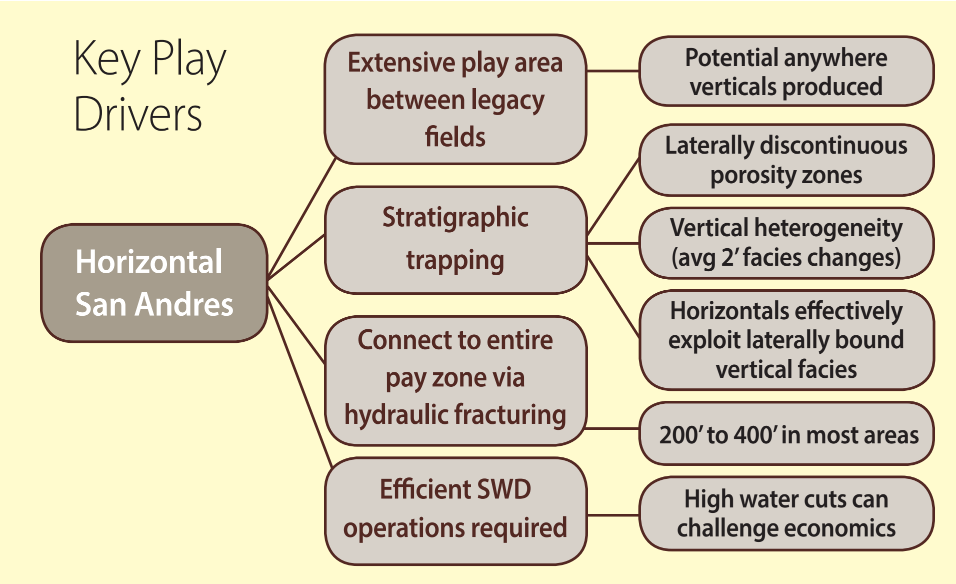
The reservoir is characterized as a heterogeneous, low permeability rock with widely pervasive stratigraphic trapping. Brown said that historically, vertical development focused on high-quality grain stone at the top of structural highs.

Often, the economic limits of these fields are reached where reservoir quality degrades and porosity becomes more dispersed throughout the formation.

"Vertical wells begin to struggle as it becomes a 'hit-or-miss' game to find good porosity units," said Brown. "Modern technology with horizontal wells and multistage completions can connect these good pockets of porosity and is more effective at stimulating the lower quality rock."

Please see, Understanding the reservoir, page 8

Understanding the reservoir – Cont. from page 7

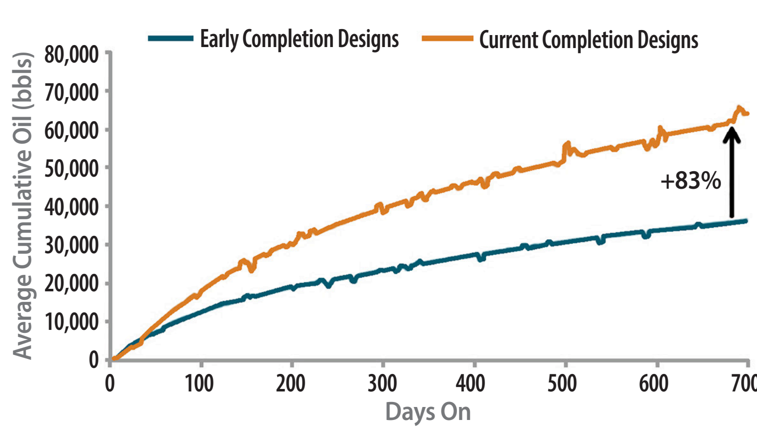


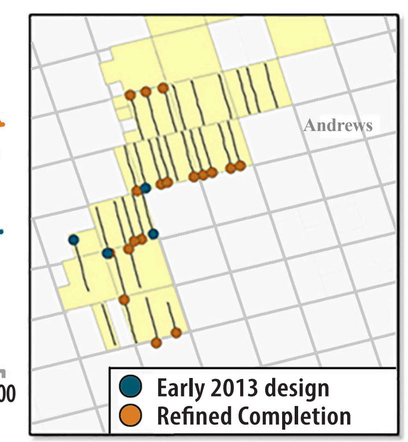
Forge has found that in any area where vertical wells have produced any measurable quantity of oil, the success of horizontal development is fairly high. Vertical production indicates moveable hydrocarbons.

"These wells are fairly shallow with small completions, particularly compared to the modern completions we see in shale plays," said Brown. "The low drilling-and-completion (D&C) cost promotes experimentation which can quickly lead to optimized results for development."

Forge formed a strategy to target the mid-points of porosity distributions with strong indications of oil saturation. She added that the D&C design for each area had to evolve to account for reservoir heterogeneity. Completion optimization trials in Andrews County in 2012 indicated the following:

- Low-porosity, discrete pay lenses deliver strong production.
- Shale-style completions are not required.
- Visco-elastic surfactant frac fluid returned minimum uplift in performance.
- Smaller fracs with hybrid slickwater-cross link fluids yielded higher oil cuts while keeping costs low.
- Large fracs are necessary to contact stratified pay where porosity is less continuous.
- Five clusters per stage are effective while reducing cost.





A Forge 2013 case study indicated that increasing completion volumes 50 percent over earlier completions boosted average cumulative oil production 83 percent over 700 days of operations in Andrews County.

Brown summarized the findings of Forge in the San Andres as follows:

- Reservoir characterization relies on an understanding of depositional environments, heterogeneity and porosity/permeability distributions. They are critical in identifying target intervals and landing depths.
- Lateral landing decisions incorporate log analysis, fracture-geometry modeling and an understanding of local porosity and saturation distributions.
- Regional variations require D&C design adjustments.
- Any reduction in flowing bottomhole pressure can impact performance significantly.

"Innovative thinking is no stranger to the oil and gas industry. We've achieved so much by pushing the envelope decade after decade," said Brown. "Innovative thinking is a founding principle at Forge Energy."

Her presentation, with numerous charts and illustrations, is at ryderscott.com/presentations.

BOEM bond program to cover OCS P&A costs remains unsettled

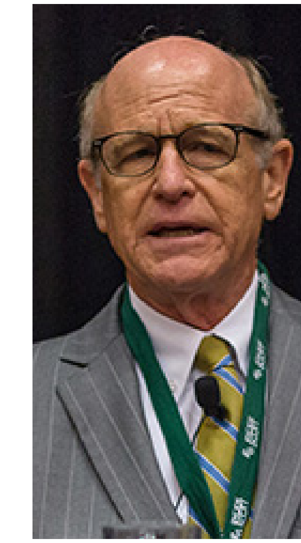
The U.S. offshore industry is waiting for further updates some four months after the Bureau of Ocean Energy Management (BOEM) indefinitely postponed implementation of a policy to increase financial assurance for decommissioning liabilities in the Gulf of Mexico.

The BOEM program requires lessees in the Outer Continental Shelf (OCS) of the gulf to post general lease surety bonds of up to $3 million and supplemental bonds for decommissioning obligations based on published criteria. The 2016 notice, NTL 2016-01, is posted at www.boem.gov/BOEM-NTL-2016-N01/.

Obligations include costs for retirement of inactive wells, plugging and abandonment of wells and dismantling and removing platforms, risers and pipelines.

Oil and gas lobbyists have argued that BOEM's policy requirements proposed in NTL 2016-01 are "… drastic changes to the financial assurances and bonding required of offshore oil and gas producers."

The bonding program comes at a time during a prolonged industry downturn, and when wells are increasingly shut in, but not decommissioned.



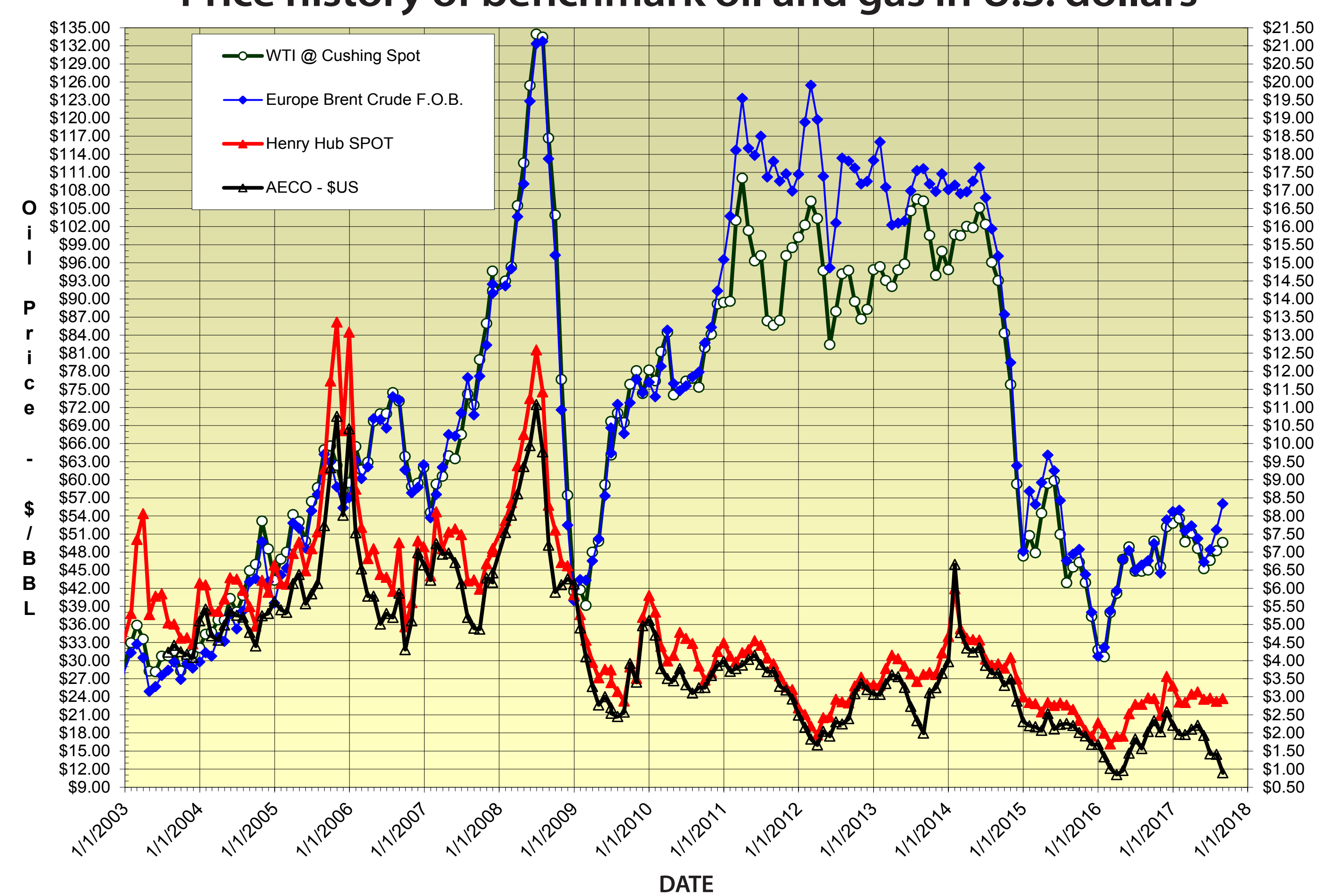
Robert P. Thibault

The BOEM is targeting lessees with sole-liability properties. The agency estimates that routine decommissioning liabilities in the OCS are about $40 billion, and sole liability represents the greatest risk to the American taxpayer.

At the Ryder Scott reserves conference in September, **Robert P. Thibault**, counsel at Haynes Boone LLP, presented, "An Update on BOEM's Financial Security Requirements for P&A and Decommissioning on OCS Leases: The 800 Pound Gorilla is Dormant . . . for Now."

Please see, BOEM bond program, page 12

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.

A Note from Dean Rietz, President at Ryder Scott

"The (Distinguished Lecturer) experience itself was daunting at the beginning, but in the end, it was very rewarding."

***Editor's Note:** Dean Rietz recently finished his one-year term as an SPE Distinguished Lecturer. Last year, a 36-member Distinguished Lecturer Committee with representatives from each SPE region selected Rietz as a reservoir simulation expert. SPE describes the selection process as "rigorous and long". Rietz delivered his presentation, "Incorporating Numerical Simulation into Your Reserves Estimation Process: A Practical Perspective," at several locations worldwide.*

It was truly an honor to be chosen as a 2016-2017 Society of Petroleum Engineers Distinguished Lecturer (DL). I began my first of four tours in October 2016, starting with a lecture in Japan. This first tour consisted of 19 stops in 18 cities and seven countries. In total, my year-long commitment consisted of 45 travel segments, with stops and overnight stays in more than 30 cities and 16 countries throughout the world. SPE and its travel partner did a phenomenal job handling the logistics, including all of the travel arrangements.

The experience itself was daunting at the beginning, but in the end, it was very rewarding. I met a lot of people of different cultures and backgrounds and visited many different regions. If you have an opportunity like this, I would encourage you to do it.

Throughout my career, my focus has been on reservoir engineering and reserves evaluations with an added interest on reservoir modeling. I have authored/coauthored several SPE papers discussing reservoir simulation and the reserves process. Concepts and ideas from these papers, as well as other experiences, were the basis of my DL presentation.

The lecture revolves around the concept that reservoir simulation is a sophisticated technique of forecasting future recoverable volumes and production rates that is becoming commonplace in the management and development of oil and gas reservoirs, small and large. Also, calculation and estimation of reserves continues to be a necessary process to properly assess value and manage the development of an oil and gas producer's assets.

These methods of analysis, while generally done for various purposes, require knowledge and expertise by the analyst (typically a reservoir engineer) to arrive at meaningful, reliable results. Increasingly, the simulation tool is being incorporated into the reserves process. However, as with any reservoir engineering technique, certain precautions must be taken when relying on reservoir simulation as the means for estimating reserves.

I created this presentation with reserves evaluators and simulation experts in mind – to help them have a better appreciation of the nuances of incorporating simulation in the reserves process. My presentation highlights some of the important facets that should be considered when applying numerical simulation methods to use for, or to augment, reserves estimates. Primarily focusing on SPE-PRMS and guidelines of the U.S. Securities and Exchange Commission, I discuss examples where numerical modeling is mentioned.

For example, SPE-PRMS states, "Recovery can be based on analog field or simulation studies." -- PRMS Document – SPE/WPC/AAPG/SPEE, pp.20-21. The SEC guidelines introduce the concept of "reliable technology" where computational methods, such as reservoir simulation, are considered -- Federal Register Final Rule, pp. 2190-2192.

Throughout my presentation, I focus on the observation that most simulation models are not built for reserves, but rather they are primarily built for field development and management purposes. Therefore, most models are not appropriate for reserves, particularly proved reserves, but may, in some cases, be augmented for direct use in the reserves process.

The main reason for this is that most of these "typical models" are built, based on the most likely in-place scenario, to consider the full range of development options. Therefore, these "typical models" are more akin to 2P or even 3P volumes, which would not be consistent with the limitations of a 1P-reserves scenario.

Even if the purpose of the model is for determination of 2P reserves, and the corresponding in-place volume is consistent with 2P reserves, other factors need to be considered to be in compliance with the particular reserves guidelines. One such factor might be where reasonable (parameter) assumptions are built into the model or whether the volumes are considered discovered.

Furthermore, all of the projected volumes generated by the model must pass economic and commercial producibility hurdles.

During my lecture, I provide specific examples from my personal experience where simulation was successfully used in the reserves process. I also described an acquisition evaluation for one of our clients, where I evaluated a seller-provided simulation model that was inappropriately incorporated into the reserves process. Throughout my career, I have encountered many situations in which simulation was successfully used to augment the reserves process, as well as situations where simulation results were misused.

Since the presentation, including questions and answers, was limited to about an hour, I had to conduct it at a high level, but I hope the audience walked away with an appreciation for the areas to focus on, to arrive at meaningful and defendable estimates of reserves when using reservoir models.

Reba Devi, then program chairperson of the Society of Petroleum Engineers Duliajan (India) section, presents speaker's gifts of tea and a small sculpture to Dean Rietz, SPE distinguished lecturer, last year.

Editor's Note 2

For background on the subject, Rietz and fellow staff members of Ryder Scott wrote three SPE papers devoted to this topic. They are listed as follows:

- *"The Adaptation of Reservoir Simulation Models for Use in Reserves Certification under Regulatory Guidelines or Reserves Definitions," (SPE 71430), 2001. It is intended to start a dialog.*
- *"Reservoir Simulation and Reserves Classifications-Guidelines for Reviewing Model History Matches To Help Bridge the Gap between Evaluators and Simulation Specialists" (SPE 96410), 2005*
- *"Case Studies Illustrating the Use of Reservoir Simulation Results in the Reserves Estimation Process" (SPE 110066), 2007*

To discuss this topic further, please contact Rietz at Dean_Rietz@ryderscott.com or the manager of reservoir simulation, Miles Palke at Miles_Palke@ryderscott.com.

Ryder Scott Co. LP
1100 Louisiana, Suite 4600
Houston, Texas 77002-5294
Phone: 713-651-9191; Fax: 713-651-0849
Denver, Colorado; Phone: 303-623-9147
Calgary, AB, Canada; Phone: 403-262-2799
E-mail: info@ryderscott.com
Web site: www.ryderscott.com

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BOEM bond program – Cont. from page 9

He said if the BOEM resumes implementation of the NTL 2016-01 program, creative solutions will be needed to ensure that companies are able to meet the onerous bonding requirements without tying up massive amounts of dead capital in bonds or other securities.

Thibault said some companies, however, may find the demands too burdensome and that will likely lead to the following:

- Reorganization for some companies through bankruptcy
- Consolidation of companies in the OCS
- New barriers to entry for future entrants
- Realignment, if not collapse, of the aftermarket for majors' deepwater properties and for large independents' conventional gulf properties

He also presented a more industry friendly scenario that involves phasing in any new program to lessen impact on lessee implementation and introducing an "enhanced" program before year's end.

Thibault's presentation is posted at ryderscott.com/presentations.

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 oil and gas reserves studies a year. Ryder Scott multi-disciplinary 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

Editor: Mike Wysatta
Business Development Manager

Ryder Scott Co. LP
1100 Louisiana, Suite 4600
Houston, TX 77002-5294
Phone: 713-651-9191; Fax: 713-651-0849

Denver, CO; Phone: 303-623-9147

Calgary, AB, Canada; Phone: 403-262-2799

E-mail: info@ryderscott.com

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