RESERVOIR SOLUTIONS

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To solve well-spacing problems, Lee proposes pre-run simulations

Results more "accurate" than decline-curve analysis (DCA) and just as fast, he says

Evaluators may not have to endure the painstaking steps of history matching (HM) individual well histories to head off well-spacing problems — that is, if the right data is available, according to **John Lee**, professor at Texas A&M University.

Overly dense spacing per acre causes excessive interference between wells which eventually leads to steeper declines and deteriorating economics. In those cases, overlap of stimulated reservoir volumes (SRVs) is the root of the problem. A frac hit.

"Simulations are already available within the ranges of parameters considered important," he said. "We can fairly quickly find a simulation that's already been run and can provide a best match to available data."

In his "science-based approach" to forecasting, Lee said the evaluator creates type-well profiles (TWPs) from the simulation, which is based on input parameters — reservoir properties, completion data and pressure histories.

The science-based forecasting (SBF) process leverages stored simulation results in a system that retrieves reservoir and completion data that correspond to the best matching profiles. "It finds a best match to historical data using the parameters for the best fit," Lee said.

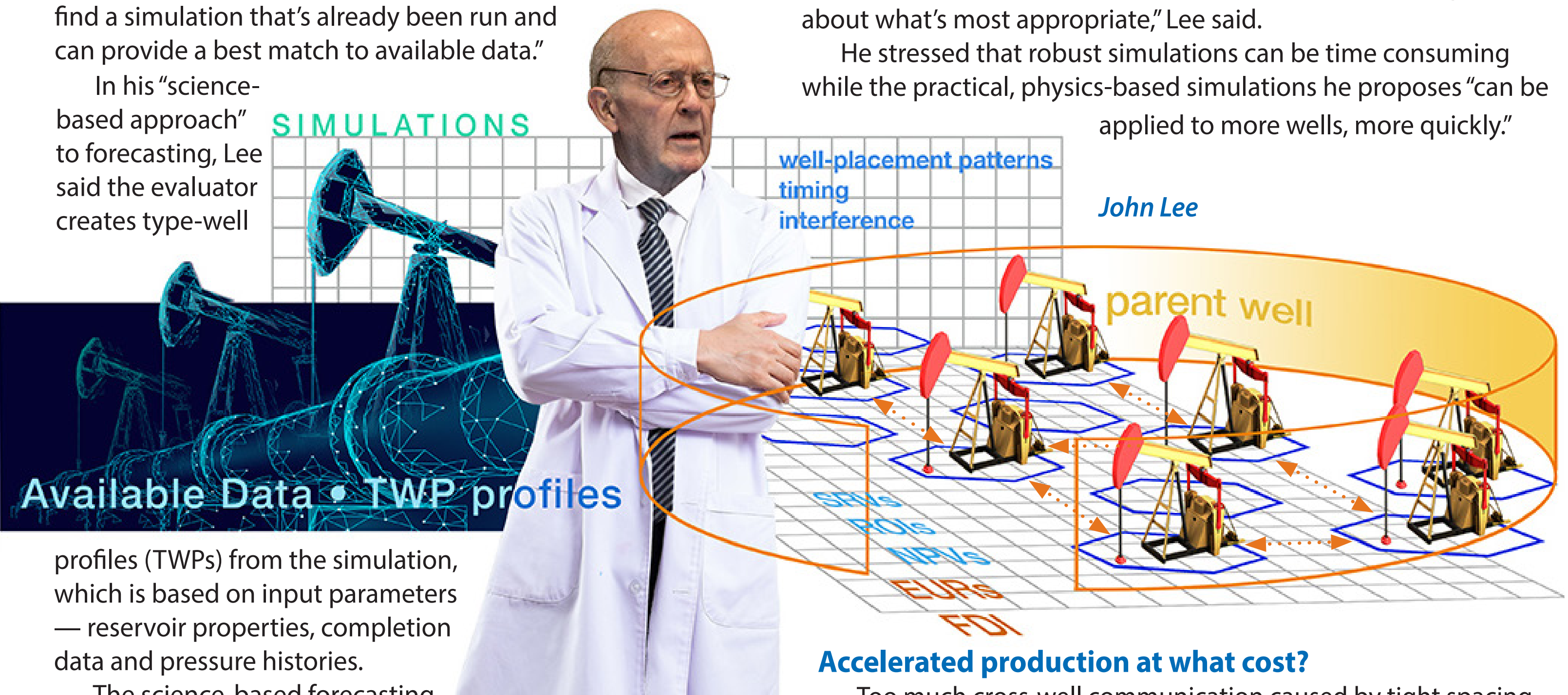
In other words, the evaluator history matches actual data from the primary (in some cases, parent) well to develop best-fit spacing and timing scenarios for the offsets. The goal is to settle on a pre-drill field development plan built around well-placement patterns, timing and interference.

"We can compare pre- and post-drill TWP profiles. Based on practical simulation, we can analyze well spacing and interference caused by overlapping SRVs," he said. "We can examine the effect of timing of infill-well drilling, and the results, and infill quickly after drilling the primary well or wait 6, 12 or 18 months."

The plan can vary depending on whether the producer wants to boost return on investment (ROI), net present values (NPVs) or estimated ultimate recoveries (EURs).

Data acquisition can be costly. "If some of the data is not available (for the model), then we have to make certain assumptions about what's most appropriate," Lee said.

He stressed that robust simulations can be time consuming while the practical, physics-based simulations he proposes "can be applied to more wells, more quickly."



John Lee

Accelerated production at what cost?

Too much cross-well communication caused by tight spacing and pad drilling is hurting production and returns on invested capital. The press has criticized some oil and gas companies in the U.S. market for overly optimistic production forecasts for child (infill) and parent wells in pressure communication.

Researchers are gathering historical data and using multivariate data analysis and other techniques to put together a clearer picture.

In the slide deck, Lee showed a Bakken modeling study that

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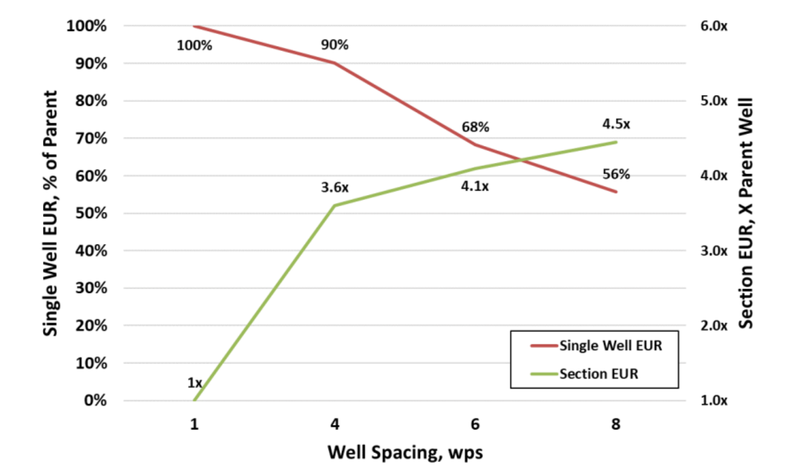
was presented at the Houston Geological Society luncheon on March 27, 2019. The study analyzed well spacing and related factors, including economics.

Lee said, "Based on actual field performance, the study shows interference occurs in the section studied."

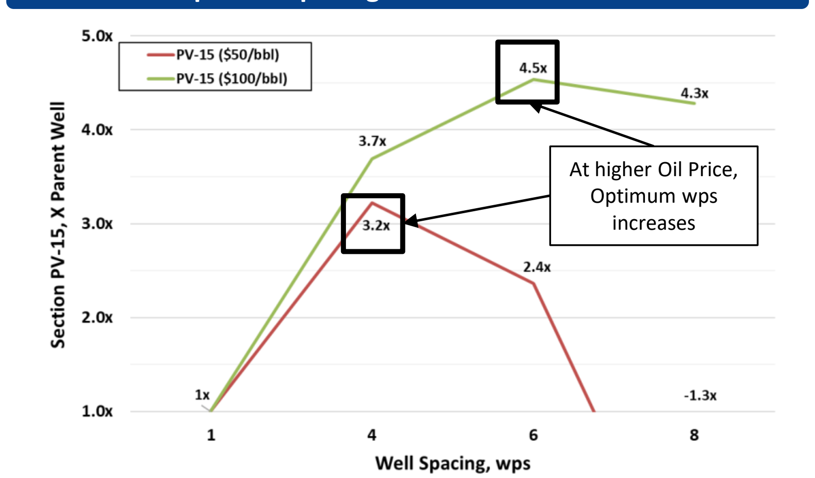
Optimal well spacing is based on the economic goals of the producer in maximizing ROI, discounted NPV or EUR. The following two charts plot well spacing and economics, respectively, in the Bakken section.

Illustrative Well Spacing and Economics
What is the Right Inter-Well Spacing?

Impact of Spacing on Section EUR



Impact of Spacing on Section Economics



The top plot on the left shows a single well EUR (red line) as a percent of the EUR from the parent well vs. the EUR from four, six or eight wells per section. With one well per section (WPS), the producer is at 100 percent of EUR. With four wells, each has, on average, about 90 percent of the EUR from the original well. For six wells, it drops to 68 percent and eight wells to 56 percent. The green line shows multiples of the single-well EUR as more wells are added. More wells increase interference and degrade well performance.

The chart on the bottom attempts to answer how spacing affects section economics. A multiple of the NPV discounted at 15 percent for the parent well is plotted against different well-spacing densities per section. The red line shows the multiples of the NPVs for the parent well, as calculated if oil is at $50 per barrel. The green line is the multiple of NPVs for $100-per-barrell oil.

"What we see is that, we can improve recovery from the section by drilling more wells, but the cost of drilling and completion is not justified by the accelerated production," said Lee. "It turned out in this study, at $50 a barrel, four WPS were optimum in this area of the Bakken, and anything more led to poor economics."

The study concluded that "drilling more wells in a higher-price environment is a rational decision while widening spacing in low-price environments also makes sense."

DCA vs. SBF

Lee compared the strengths and limitations of DCA and SBF, examining well spacing, interference and timing sensitivity results.

DCA, which is easily learned and applied, is the No. 1 choice for evaluators. On unconventional assets, they use a modified Arps equation with changing b factor and terminal decline. DCA does not model the physics of fluid flow, but with reasonable assumptions, it adequately accounts for the behavior of flow regimes.

"If we use a two-segment Arps decline model, for example, we have to select a decline rate at which we switch from a segment dominated by transient flow to one with boundary-dominated flow (BDF)," said Lee. "We also have to assume what the Arps b parameter is during BDF."

The assumptions are where a calculation can go awry. "Many assume that b will be zero, but that's not necessarily the best choice," said Lee. "In fact, my analysis indicates that a b between 0.3 and 0.5 for that final segment of boundary-dominated flow is actually a much more realistic modeling technique."

Arps defined parameters for the hyperbolic b factor to be $0<b<1$. Lee summarized the advantages of using SBF vs. DCA in the chart as follows on the next page.

Comparison of SBF and DCA-Based TWPs

SBF
- Fast, easily learned and applied
- Models well interference
- Includes multiphase flow when pressure drops below bubble point or dew point
- Allows studies of different well spacing alternatives
- Allows investigation of variable timing of infill drilling
- EUR based on rigorous modeling

DCA
- Fast, easily learned and applied
- Interference modeled only if present in well data used to construct TWP
- Includes multiphase flow only if present in data used to construct TWP
- Restricted to well spacing affecting data used to construct TWP
- Restricted to actual timing of infill wells in available data
- EUR depends on D_{min} and final *b* assumed

Lee said that he has been asked for a long time whether interference shows up in decline curves, and although he cannot generally confirm it, he cited situation-specific information that documents the phenomena. His source is "Well Spacing Optimization in Eagle Ford Shale: An Operator's Experience," SPE Paper No. 2695433-MS, **Mehdi Rafiee** et al, Equinor ASA, 2017. It is available at www.onepetro.org.

Lee said, "It's interesting that in terms of what appears to be rather conventional Arps decline curve analysis that well spacing clearly showed up in decline curves. The authors found that there's really quite a correlation between the parent Arps b factor, which fits the average of the data, and the well spacing."

The study incorporates fracture modeling, production HM and pressure communication from offset wells in the Eagle Ford shale play. Rafiee et. al conducted data analytics on almost 400 wells. The authors modeled stimulation of wells with sensitivities to fluid and proppant job sizes.

"When there is a single well, far from any others, a b factor of 1.1 was good for forecasting for longer durations up to 160 months post-completion," said Lee.

At 800 ft spacing, the b factor fit dropped to .9. then at 500 ft, dropped to 0.7, and settled at 0.5 at 250 ft. "I don't have the backup info to tell you more," said Lee.

RTA and full-scale simulation

Besides comparing SBF with DCA, Lee also cited other methods to ascertain optimum well spacing, including rate-transient analysis (RTA) and full-scale, HM reservoir simulation.

Evaluators use analytical flow models in RTA software packages to HM available transient data to solve for major unknowns, such as effective matrix permeability and fracture half-length. In the forecast, they vary the well spacing to analyze the effects of interference.

"The limitation is that analytical solutions, despite efforts to improve, ultimately depend on simplifying assumptions, such as single-phase solutions to flow equations," said Lee. "If pressure drops to bubble point or dew-point pressure in an oil or gas condensate reservoir, then multiphase solutions are needed."

He also remarked that reservoir simulation, although time consuming, solves well-spacing problems. Lee said that coupling geomechanical and flow models is an effective approach discussed in "Time Dependent Depletion of Parent Well and Impact on Well Spacing in the Wolfcamp Delaware Basin," SPE Paper No. 191799-MS, **Cyrille Defeu** et al, Schlumberger Ltd., 2018. It is available at www.onepetro.org.

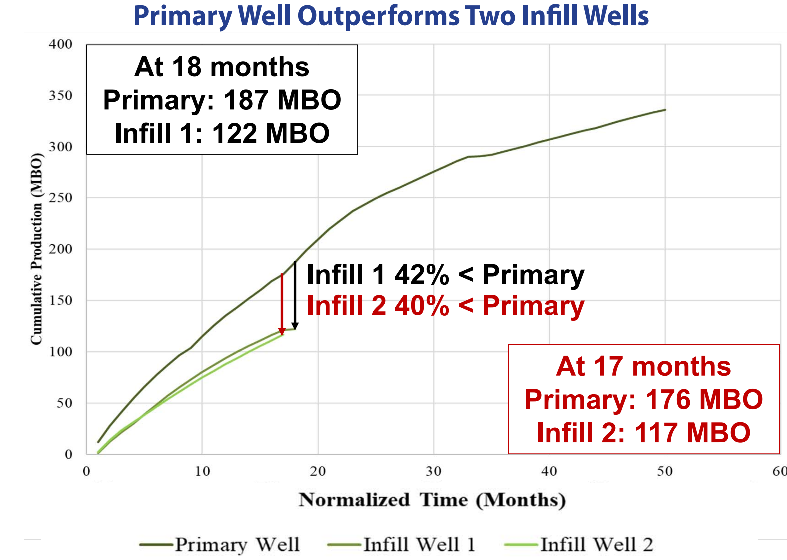
A high-resolution simulator feeds an updated pressure profile into the geomechanical simulator at selected timesteps during the production phase, the authors stated. The coupled simulators then compute the corresponding 3D change in stress, deformation and rock displacement in the reservoir and beyond in the adjacent rock formation.

"In this way, the spatial and temporal changes in the in-situ stress field from parent well production are computed," they stated. The paper presents an advanced modeling workflow to determine the impact of parent depletion on infill-well spacing at various periods of the parent well production.

Tit for tat: DCA and SBF

Lee said he was involved in a side-by-side study of SBF- and DCA-derived TWPs for the Delaware Basin Wolfcamp A formation. The study was based on public information. From the 44 wells, he chose a primary well that outperformed its two child wells. Both methods matched the 18-month history for Infill Well 1. They also matched the 17-month history for Infill Well 2. See the following chart.

The Fundamental Problem Illustrated:
Primary Well Outperforms Two Infill Wells



"So far, no real advantage has shown up," said Lee. "However, I'm going to claim, based on other studies, that with data to estimate bottom-hole pressure, we can match much more of the production profile. At least we can match by the time the bottom-hole pressure has settled down, and get rather close."

The chart of P50 cumulative oil results on the next page shows that with SBF, the best match for Infill 1 was 2 percent higher than the actual cum and 6 percent higher than Infill 2. With DCA, estimates were 11 and 12 percent higher for infills 1 and 2, respectively.

He remarked that DCA cannot quantify the effect, if any, of

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Summary P50 Cumulative Oil Results

Infill Well 1

Cum at 18 months	Actual C1 (MBO)	SBF P50 Cum (MBO)	DCA P50 Cum (MBO)	DCA 2018+P50 Cum (MBO)
Case 1	122	125	136	127
% Difference (wrt C1)		2%	11%	4%

Infill Well 2

Cum at 17 months	Actual C2 (MBO)	SBF P50 Cum (MBO)	DCA P50 Cum (MBO)	DCA 2018+P50 Cum (MBO)
Case 1	117	124	132	122
% Difference (wrt C1)		6%	12%	4%

- **SBF accurately approximates infill production.**
  - **I1: 2% difference in actual vs. SBF**
  - **I2: 6% difference in actual vs. SBF**
- **DCA also approximates infill production accurately.**
- **Cannot quantify effect of interference with DCA alone.**

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interference while SBF enables an evaluator to look at optional development strategies for well spacing and completion techniques.

"It's difficult to model interference with the DCA approach, unless interference effects are present in the histories and the well spacing in those histories are roughly the same for future wells," said Lee. "It's difficult to model the effects of timing infill wells and their spacing."

Conclusion

The rest of Lee's presentation covered sensitivity analyses of well spacing in the Delaware Basin, sensitivity of EURs to infill-well spacing, infills to optimize EURs and quantifying fracture interference with a fracture-driven interaction (FDI) calculation. He also discussed the effect of FDI on production forecasts and effect of fracture interference on EURs.

Lee concluded that relying solely on DCA-based TWP construction underestimates interference caused by close well spacing and long fractures in resource plays. His slide deck, which has charts and graphs, is posted at https://ryderscott.com/presentations/.

Editor's Note: Dr. John Lee is a recognized expert in petroleum reserves evaluations. Ryder Scott is grateful for his annual participation in our events as a speaker. The content of conference presentations is based on our speakers' fact finding and opinions, and are not necessarily those of Ryder Scott. Our firm's speakers also present content that does not necessarily reflect the views of Ryder Scott.

SBF promising but not the answer for every situation

— **Miles Palke**, *managing senior vice president*

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While science-based forecasting is a promising new technique, there are many situations in which a detailed, bespoke model for a particular well, reservoir or entire field is the preferred approach. Ryder Scott is in a unique position because the firm possesses high-end technical simulation expertise, combined with unmatched geoscience capability and a wealth of traditional reservoir engineering experience with every sort of reservoir imaginable. The blending of those skills enables Ryder Scott to assist clients with a wide variety of simulation-based needs. For more information, please send an email to miles_palke@ryderscott.com

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