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Parent-Child, Multilateral Well and Fracture Flow Interactions

Our industry is confronting headwinds driven by uncertainty, confusion and fear, and quite likely, will be prone to act before all the facts are in. Drillers and field engineers believe that they have uncovered new physical phenomena. Rapid production declines, unlike those in past decades, certainly point to new possibilities in petrophysics – governances of Nature that we have little time to explore and tackle. The evidence is there. Just look around. The town folk are amassing. The consequences are disastrous. But big data, machine learning and artificial intelligence just might mine deeper insight. Problem solved. And the lone cowboy rides off into the sunset.

Additional questions raised. But the evidence is circumstantial. What is real are advances in hydraulic fracturing that have supported resurgences in oilfield activity. High permeability conduits created in the formation have accelerated the production of oil just about everywhere. Reserve estimates were predicted to escalate. But these increases would suddenly drop, much to the consternation of producers and bankers, destroying cash flow forecasts and independents' ability to continue loan payments. However, all of this would not be unexpected.

Unless an underground reservoir is continuously replenished by pressure drives charged by additional pools of oil (and these do, by the way, exist – e.g., see Mahfoud and Beck (1995)), any production must result from "sealed reservoirs" with initially high pressure. Thus, the amount of recoverable oil or gas is limited. Much of the reservoir is occupied by matrix rock and immovable fluids. The volume that remains is finite. Fractures remove movable fluids rapidly and leave the reservoir high and dry quickly. And so, fast declines will remain a fact of life.

In 2014, the senior author attended a meeting at a large oil service company where one of its clients was asked, "How do you determine fracture density?" This individual, a well respected industry spokesman, reluctantly admitted, "If your neighbor does 'N' number of fracs, you do '2N.'" So there was little after-thought in making operational decisions. There was neither time nor leeway to analyze. If your choice increased production, if only for a short duration, that was fine. And that's human nature, until the unavoidable reality sets in.

Problem identified. In recent years, there has been a proliferation of papers addressing the issues cited above. We will not offer any comprehensive summaries or reviews. Readers are encouraged to search for relevant case studies using keywords identified below. To highlight present industry confusion, several publications are discussed, with our comments, if only to illustrate the degree of confusion.

An interesting analysis appears in "To Solve Frac Hits, Unconventional Engineering Must Revolve Around Them," T. Jacobs, *Journal of Petroleum Technology*, April 2019, pp. 27 – 31. Noting that "the U.S. shale sector is expected to drill about 20,000 horizontal wells in 2019," the author observes that, "The impetus for an engineering overhaul is being forced by the prevalent well-to-well fracture interactions known as frac hits. These events are the subject of intensifying study by U.S. and Canadian shale producers that have attributed them to lowering oil recovery factors from new child wells by 20 - 40% while inflicting even higher losses on older, yet less productive, parent wells."

And a scientific overhaul *is* seriously needed. The senior author, an experienced reservoir engineer with major operating and oil service company experience, has never seen a comprehensive reservoir engineering assessment addressing production issues. For instance, "What well constraints were applied to parent wells, before and after, and in child wells after development? Details about drive mechanisms, well layouts, intervention activities, initial reservoir pressures?" What of supporting numerical simulations? Most computer models are difficult to use, require highly trained personnel, and unfortunately, are limited in the complexity of the physical features that can be easily described.

And catch-all terms like "frac hits" are coming under increased scrutiny. "We know they are entrenched, but honestly, they don't mean much," said George King, an industry expert, making a point that well interactions in question are not all the same. "Some are harmful, some are helpful, some are temporary, some are long-term." The paper also lists multiple strategies, e.g., "wider well spacing," "staggered wells (wine rack configuration)," "cube development," "rolling development," and "slowback," all of which should be studied using physics-based models evaluated under a wide combination of input parameters.

Another useful discussion is offered in "The Problem with Bigger Fracs in Tighter Spaces," S. Rassenfoss, *Journal of Petroleum Technology*, December 2017, pp. 28 – 31. The author identifies issues that should be addressed. "How does fracturing affect the reservoir between tightly spaced wells?" "How do we explain sudden drops in production?" "Could an existing well have produced the reserves without the infill well?" "How are surges of fluids flowing well-to-well through connected fracture systems described?" The paper also offers two self-explanatory visuals, reproduced in Figures 1.1 and 1.2. The last paragraph in Figure 1.2 is enlightening and supports the authors' contentions above, namely, that existing models are difficult to use, requiring inputs that are either difficult to obtain or simply non-existent. The present book hopes to convey two ideas – (1) the main influencers are available, and (2) simple, but rigorous, analyses *are* possible that address most physical effects, requiring minimal effort or specialized training, assuming the level of an undergraduate petroleum engineer.

The article "In the Battle Against Frac Hits, Shale Producers Go to New Extremes," T. Jacobs, *Journal of Petroleum Technology*, August 2018, pp. 35 – 38, interestingly describes one of the "new extremes" utilized in drilling practice. According to the author, "Most in the shale business know these projects as 'cube developments.' Their scope of work has moved operators away from developing wells one at a time to a half dozen or more at a time. Each cube project is done from supersized well pads that host four to six rigs, two pressure pumping fleets, and hundreds of people every day."

But just a year later, in "A Fracking Experiment Fails to Pump as Predicted," Wall Street Journal reporter Bradley Olson, on July 4, 2019, described how one company's supersized operation, one that two years earlier was thought to represent the future of the U.S. drilling boom, would lose its attractiveness. To reduce costs and avoid production problems when wells are spaced closely together, the company pioneered its "Cube Model" for reservoir development using numerous multilateral wells. Initial results were promising. However, subsequent results differed from those expected.

A more tractable idealization of this problem is presented later in Chapter 6 in which the development plan in Figure 1.3 is replaced by a nine multilateral well system with three wells residing in three separate rows. A full-field analysis is presented, requiring all but several minutes of simulation time on a Windows i5 computer – but just as important, a simpler, much less expensive drilling configuration using only two deviated wells, was identified offering the same production. Cube models do reduce drilling expenses through obvious economies of scale, but ultimately, the reservoir only contains as much oil as the volume holds. In this sense, careful cash flow management is still a must.

In the cautionary article "Factory Drilling is No Substitute for Formation Evaluation," E. Sprunt, *World Oil*, July 2014 warned, as early as five years ago, of the dangers behind methods that may not be grounded in physical principles. Ms. Sprunt, who holds a Doctorate from the Massachusetts Institute of Technology, is the president-elect of the American Geosciences Institute, and was the President of the Society of Petroleum Engineers (SPE) in 2006. In that article, she emphasizes that, "In a push to reduce costs in unconventional shale play reservoirs, some in the industry are racing to systematize development processes, even before understanding many of the aspects that play a role in shale production. This "manufacturing approach" is not a substitute for a comprehensive understanding of a formation."

The present authors agree – and, further, that "understanding of a formation" means reservoir modeling as much as it does petrophysical analysis. As emphasized earlier, a rigorous, easy-to-use Darcy flow simulator that allows rapid, convenient and rigorous model for problems containing heterogeneities, general drive models, arbitrary systems of vertical, horizontal and multilateral wells, liquids and gases, is not readily available in the industry, until now. This book, through detailed discussions in Chapters 4 – 9, will credibly fill this void.

A recent trade journal article "Physics-based or Data-Driven Models?" R. Mason, *E & P Magazine*, Hart Energy, April 2019, notes that well interference has become problematic in oil and gas. It asks, "Will data-driven analysis via artificial intelligence provide a solution?" We feel that such methods offer complementary perspectives on the general well interference problem. While many underlying flow parameters have been identified over the past decades, machine learning methods do offer the potential to identify additional causes and effects, rendering physics-based tools more useful and applicable to more applications.

Why Call Them Frac Hits?

- The word "frac hits" is the most widely used description of the phenomenon also known as "well-to-well fracture-driven incidents."
- This follows the lead of the Apache technical paper that opted for using the term frac hits, which it admits is less descriptive than "fracture-driven interaction" or "well interference" but more commonly used.
- The reality is more complex than the words frac hit imply. It is related to well-bashing, an extreme hit that can knock out production but not a good description for interwell interference. In those cases the indirect pressure of new fractures growing near old ones can cause small pressure changes that could affect a well's output over time.

Figure 1.1. List from Rassenfoss (2017).

Is a Frac Hit Model Possible?

- With growing concerns about frac hits reducing production, there is a demand for ways to model it. But the specifications for such a model set out in the technical paper by Apache could be daunting for developers.
- Models to simulate how hydraulic fracturing in one well affects others nearby are needed because the paper (SPE 187192) stated that "many prevention and remediation failures are the result of misinterpreting the cause of production loss during the frac hit."
- Getting that right will require realistic accounting for a list of geologic variables, complicated by the fact that the rock makeup varies over short distances and the properties may be interacting. "Models that predict frac hits might be possible if the rock and potential flow paths are understood, but formation heterogeneity within the shale, including the interaction of structure, rock fabric, mineralogy, in-situ stresses, and induced stresses form a very complex array of influences, with data availability and quality concerns challenging model use at present," according to the paper.
- As for using the available fracturing models, the paper noted that they "tend to yield somewhat different results." Deciding which model, or models, to use would be time-consuming and not currently worth the trouble because while they were "developed by brilliant scientists, computer programmers, and engineers" the results are questionable because "most of the time we do not have as much information as is needed to input in the models and [must] make numerous assumptions and 'best guesses.' "

Figure 1.2. Items from Rassenfoss (2017).

Thus, what we propose is tighter integration between data driven and physics-based methods – our approach is not an "either this or that" strategy, but one that combines the best of statistically driven and differential equation based techniques. Such complementary methods will support industry objectives, for instance, as expressed in "Three Unconventional Startups Offer New Clues on Shale's Biggest Well Spacing Mysteries," T. Jacobs, *Journal of Petroleum Technology*, September 2018, pp. 47 – 52, where the author observes that, "It can be fairly argued that the most important question being asked today by shale producers is this: How close can horizontal wells be placed together? The right answer is worth billions of dollars to the sector."

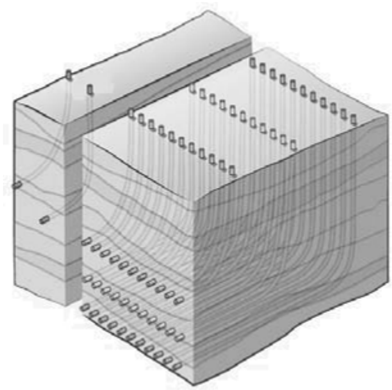

Figure 1.3. "Cube Model" for production optimization, from "A Fracking Experiment Fails to Pump as Predicted," B. Olsen, *Wall Street Journal*, July 4, 2019.

In closing, we might cite several articles that summarize what many in the industry agree to be crucial to its economic viability. Two are authored with self-explanatory titles, namely, "How Close is Too Close? Well Spacing Decisions Come With Risks," S. Rassenfoss, *Journal of Petroleum Technology*, January 2019, pp. 28 – 31, and "Fracturing Plans and Reality Often Look Really Different," S. Rassenfoss and M. Zborowski, *Journal of Petroleum Technology*, March 2018, pp. 30 – 41, which offers a good compendium of papers on different useful topics.

"What About Well Intervention?" E. Maslin, *Offshore Engineer*, July/August 2019, pp. 14 – 17, addresses how restoring shut-in wells could add production at economic rates, allowing operators to maintain production rates but with less outlay (we add that changes to well structure during production is also an option). In subsea well intervention, the author emphasizes need for increased surveillance and monitoring to bridge the hole left by a "data gap" – this, we note, is an area where "big data" and machine learning may help.

Finally, "Frac Hits Reveal Well Spacing May be Too Tight, Completion Volumes Too Large," T. Jacobs, *Journal of Petroleum Technology*, November 2017, pp. 35 – 38, notes that, "Thanks to the advent of high-speed drilling in the US shale sector, the effects of so-called frac hits on production and well economics is becoming more important than ever. It means the clock is running for shale producers to figure out how to mitigate the implications of this well-to-well interference issue before they drill too many wells too close together."

1.1 References.

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