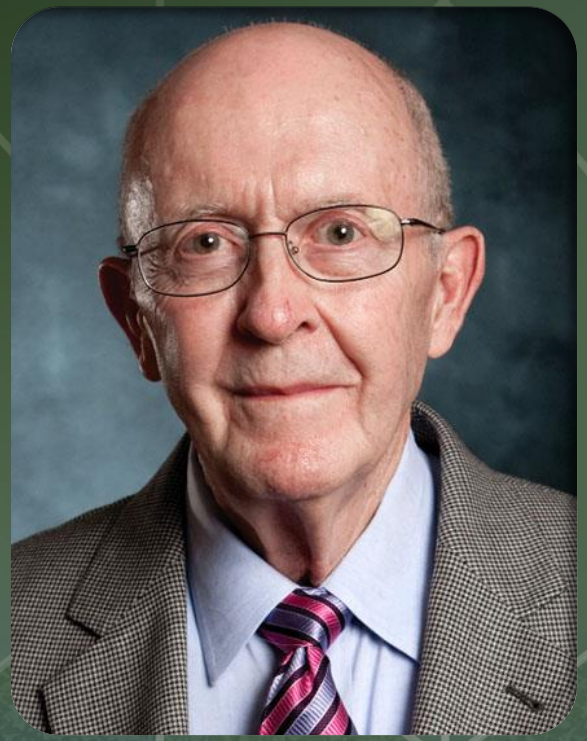
JOHN LEE



Professor of Petroleum Engineering Texas A&M University

John Lee holds the DVG Endowed Chair in Petroleum Engineering at Texas A&M University. He holds a B.S., an M.S. and a PhD degree in Chemical Engineering from Georgia Tech.

John worked for ExxonMobil early in his career and specialized in integrated reservoir studies. He has taught at Mississippi State University, the University of Houston, and Texas A&M. While at A&M, he also served as a consultant with S.A. Holditch & Associates, where he specialized in reservoir engineering aspects of unconventional gas resources. He served as an Academic Engineering Fellow with the U.S. Securities & Exchange Commission (SEC) in Washington during 2007-2008 to help modernize SEC rules for reporting oil and gas reserves.

John is the author of four textbooks published by SPE and has received numerous awards from SPE, including the Lucas Medal (the society's top technical award), the DeGolyer Distinguished Service Medal and Honorary Membership (the highest recognition awarded society members). He is a member of the U.S. National Academy of Engineering and the Russian Academy of Natural Sciences.

Contact Me

john-lee@tamu.edu

979-845-2208

3116 TAMU

College Station, TX 77843-3116

engineering.tamu.edu

Uncertainty in Type Well Construction? What Uncertainty?

John Lee, Texas A&M University

2022 Ryder Scott Reserves Conference

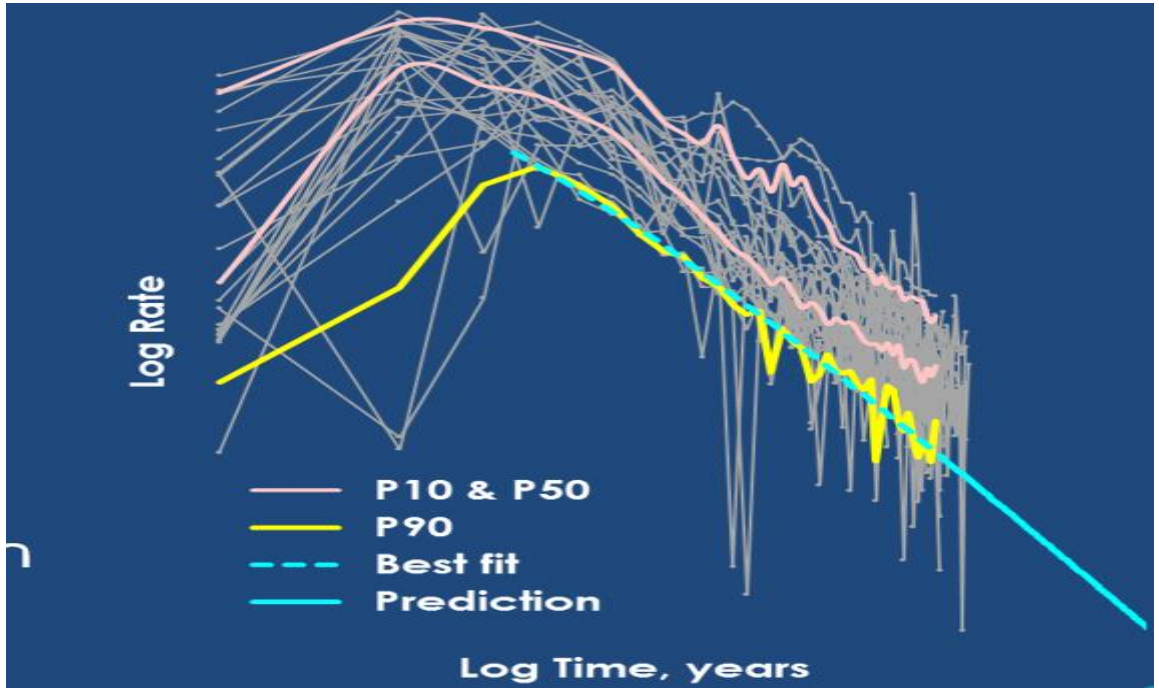
May 11, 2022

What Are Some Common Practices in Type Well Construction?

- Select a group of analog wells in area of interest
- Average production profiles in systematic way
  - Result: typical well production profile (TWP) or “type well,” aka “type curve”
- Use type well to forecast production of undrilled wells, wells with limited production history

Typical Data Available to Construct Type Well

- Production profiles for all the wells in an area of interest



R. Freeborn, SPE Distinguished Lecture 2016-2017

Characteristics of Potential Analog Wells May Vary Widely

- Lateral length
- Completion practices
  - Amount of proppant, fracture fluid
  - Fracture length
  - Fracture spacing
- Geology
  - Permeability
  - Net pay
- Operational practices
  - Drawdown
  - Choking policy

Should we just shut our eyes and average production profiles from wells with varying properties like these? Might this introduce uncertainty?

What Are Other Uncertainties in Type Well Construction and Application?

- Same degree of interference in all analog wells?
  - Well spacing, timing of infill drilling same?
- Physical parameters affecting productivity similar in analog wells?
  - Same geological characteristics in all wells?
- Is average EUR of analog wells same as average EUR of total well population?
  - Number of analog wells with similar characteristics sufficient to minimize dispersion from “true” average outcome?
  - Number of analog wells in future drilling program sufficient to minimize dispersion from “true” average outcome?

What Can We Do About It?

- Common practices
  - Normalize EUR or rates by perforated lateral length (EUR/ft)
  - Establish distinct “type well areas” based on geology
  - For other possibly important variables
    - Just ignore differences in properties and average

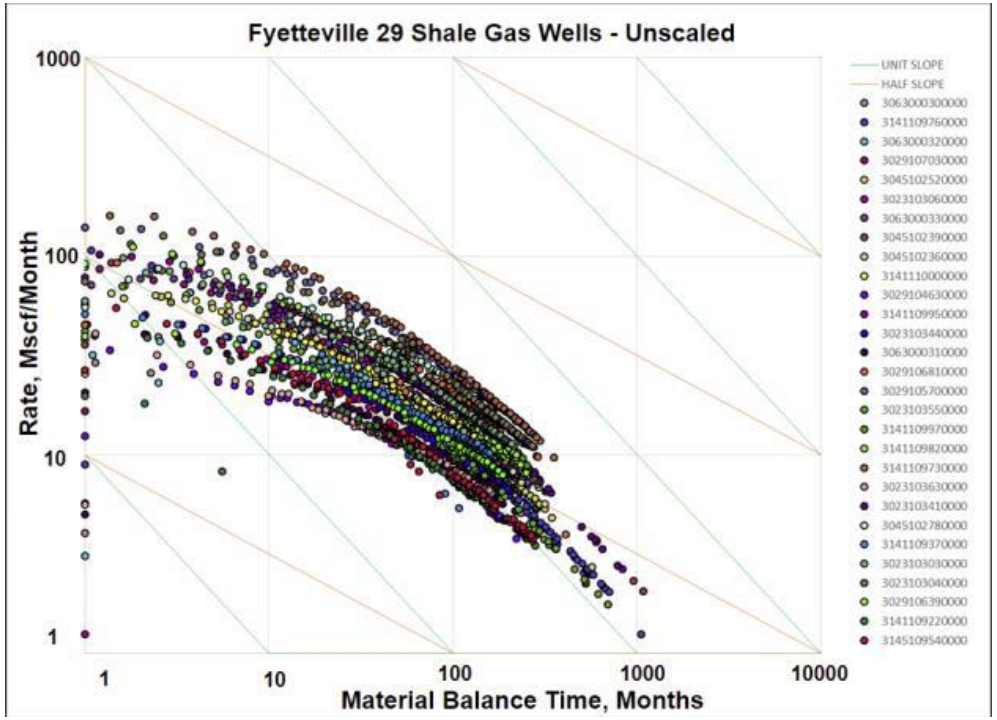
    Or

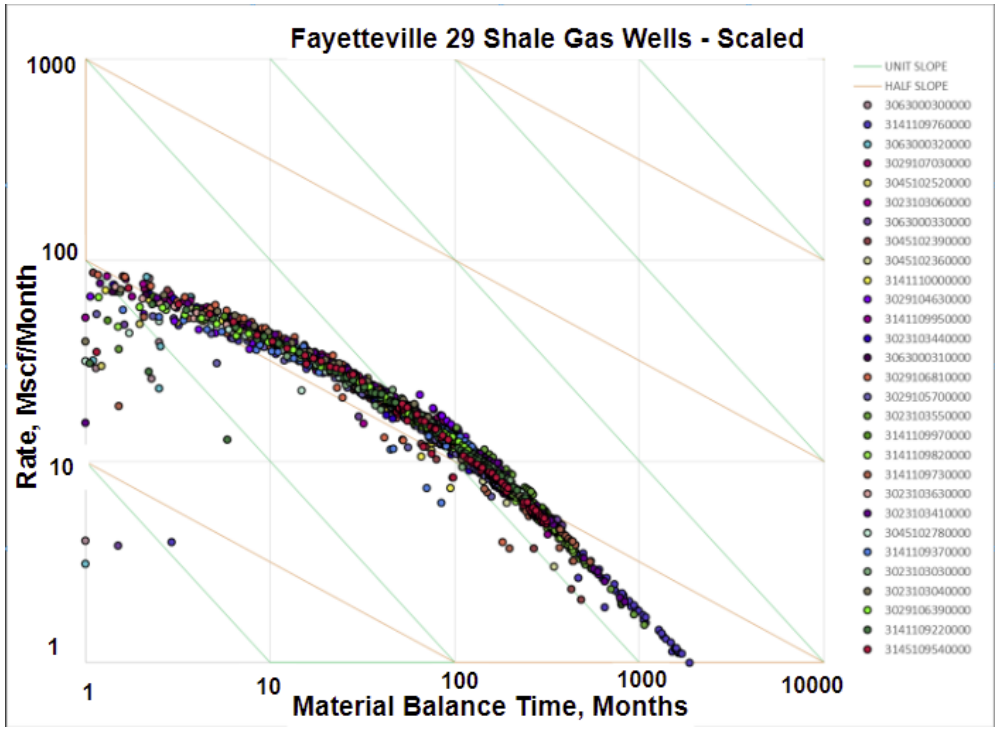
    - Create many small bins with few wells in each but with similar properties and average their production profiles

Might an Alternative Work Better?

- Yes – a systematic procedure to scale all production profiles to a *common set of reference conditions before averaging*
- Evidence suggests this approach can work
  - Production profiles in given reservoir tend to have similar shapes on log-log plots
  - Observed shapes often match Wattenbarger type curve, based on analytical solution for MFHWs in bounded reservoirs

Production Profiles for Fayetteville Wells Similar

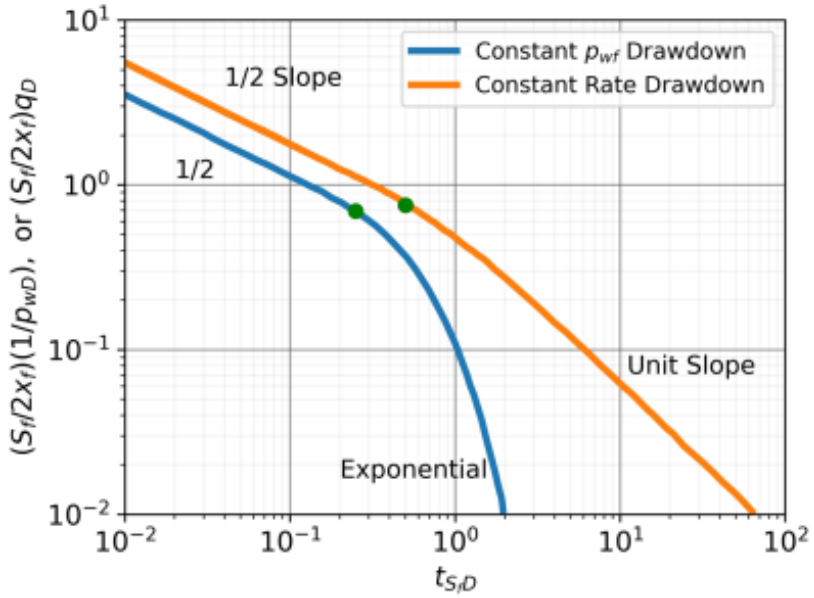




- Similar results found for Barnett, Niobrara, Bakken, Montney

Production Profiles Tend to Follow Shapes on Wattenbarger Type Curve

Wattenbarger Type Curve

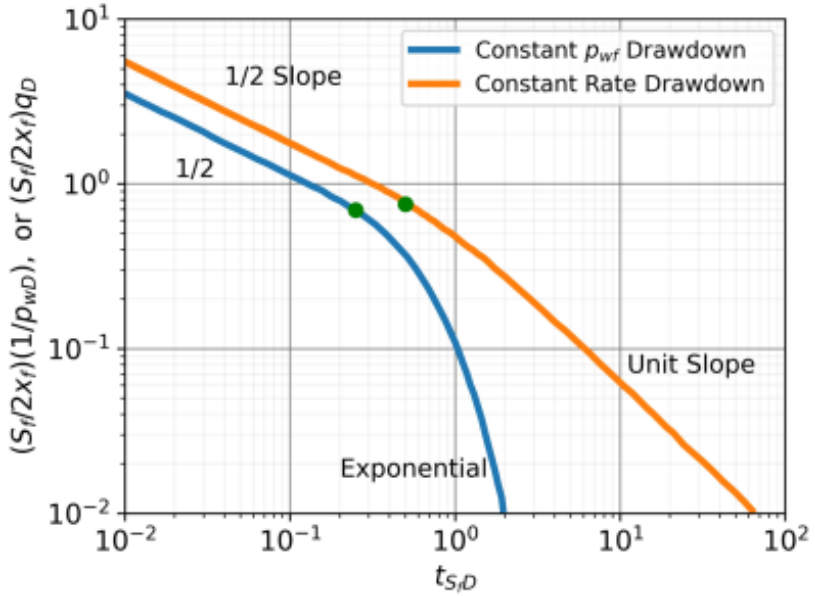


Type Curve Characteristics

- Blue curve models constant BHP production of MFHW in bounded drainage area (fixed SRV)
  - Green dot: end transient flow regime, actual time
- Gold curve models constant rate drawdown, which is same as rate vs. material balance time (N_p/q) plot
  - Green dot: end transient flow, MBT (twice actual time for linear flow)

Wattenbarger Solution Relates End of Transient Flow to Perm, Frac Length

Wattenbarger Type Curve



Perm, Frac Length Estimation

$$t_{SfD,elf} = 0.25 = \frac{0.02532kt_{elf}}{\emptyset\mu c_t S_f^2}$$

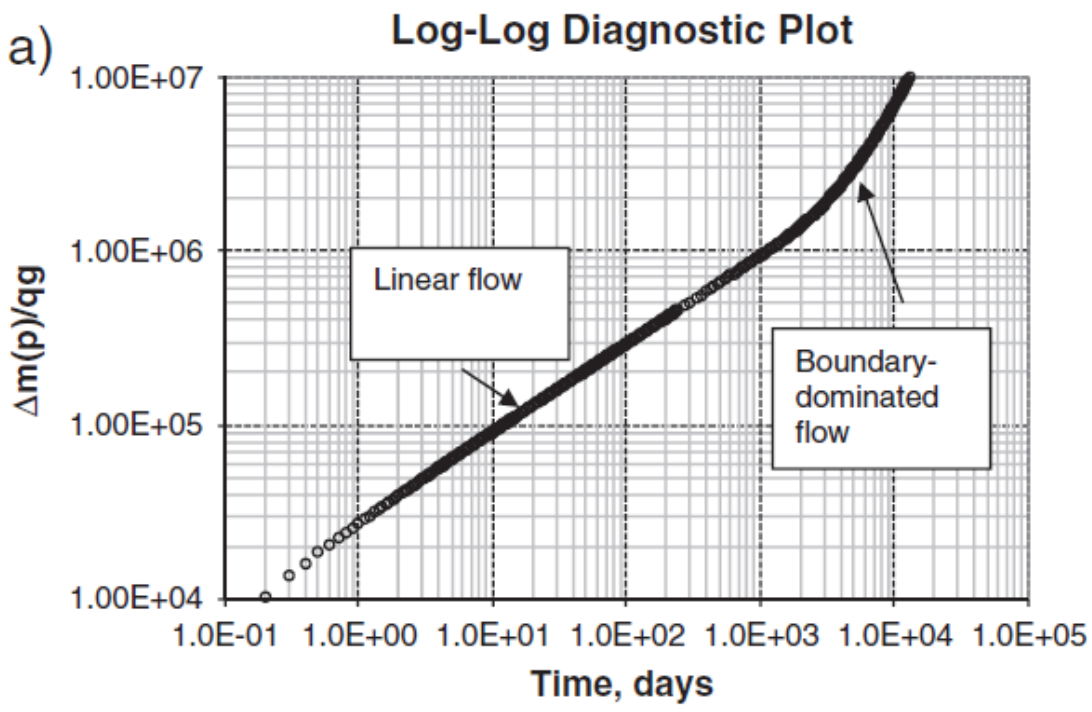
$$k = \frac{9.87\emptyset\mu c_t S_f^2}{t_{elf}}$$

$$\frac{S_f}{2x_f} q_{D,elf} = 0.694 = \frac{70.6\, q_{elf} B\mu S_f^2}{x_f khL_w\Delta p}$$

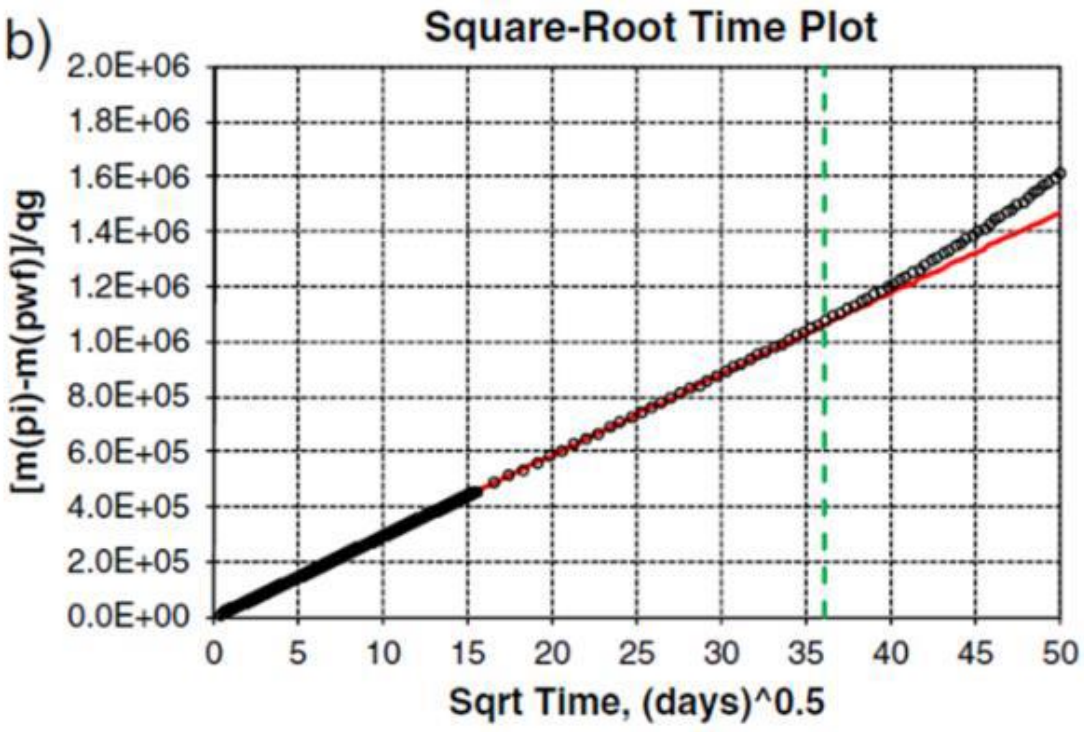
$$x_f = \frac{101.7 q_{elf} B\mu S_f^2}{khL_w\Delta p}$$

How Can We Find Time, Rate at End of Transient Flow?

Log-log Diagnostic Plot

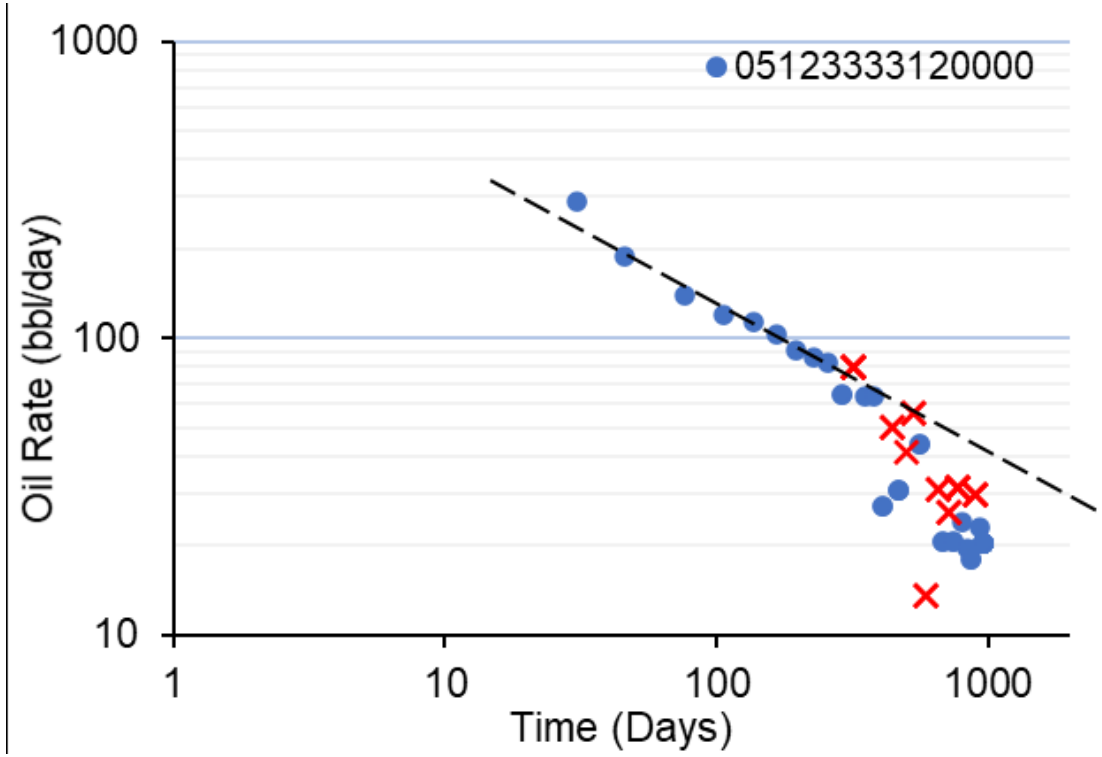


Square-Root Time Plot



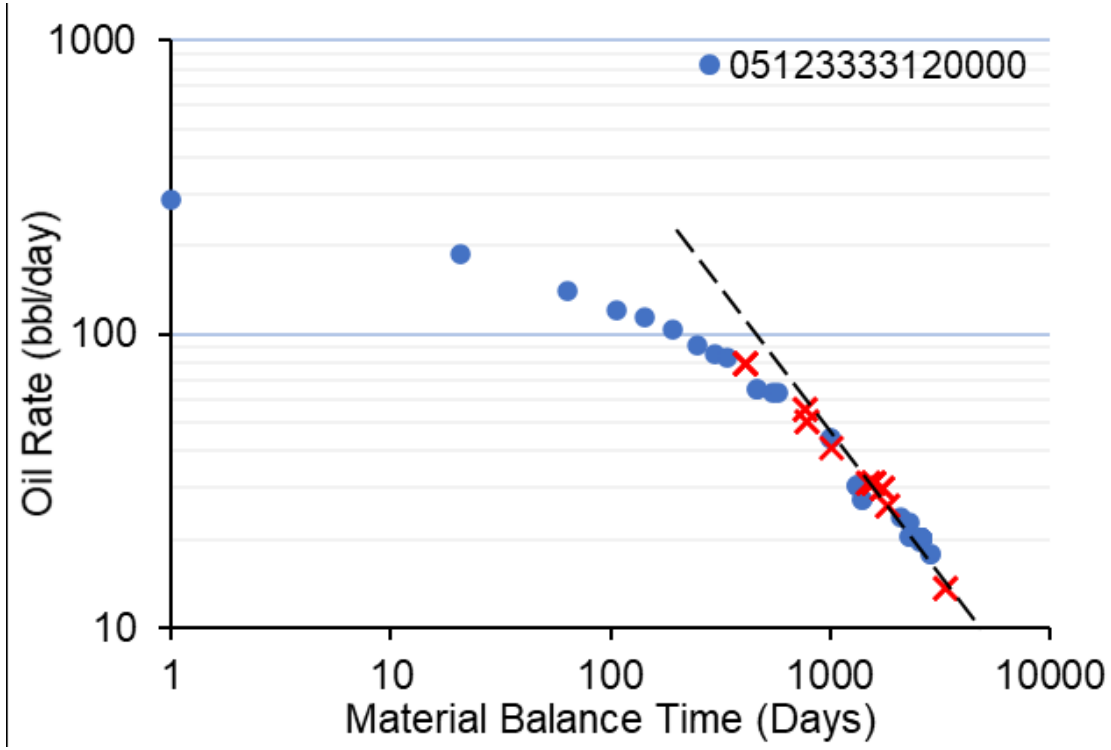
But What About Real Field Data?

Rate = 80 STB/D, Time = 300 days



x Outlier

Transient, BDF Observed on MBT Plot

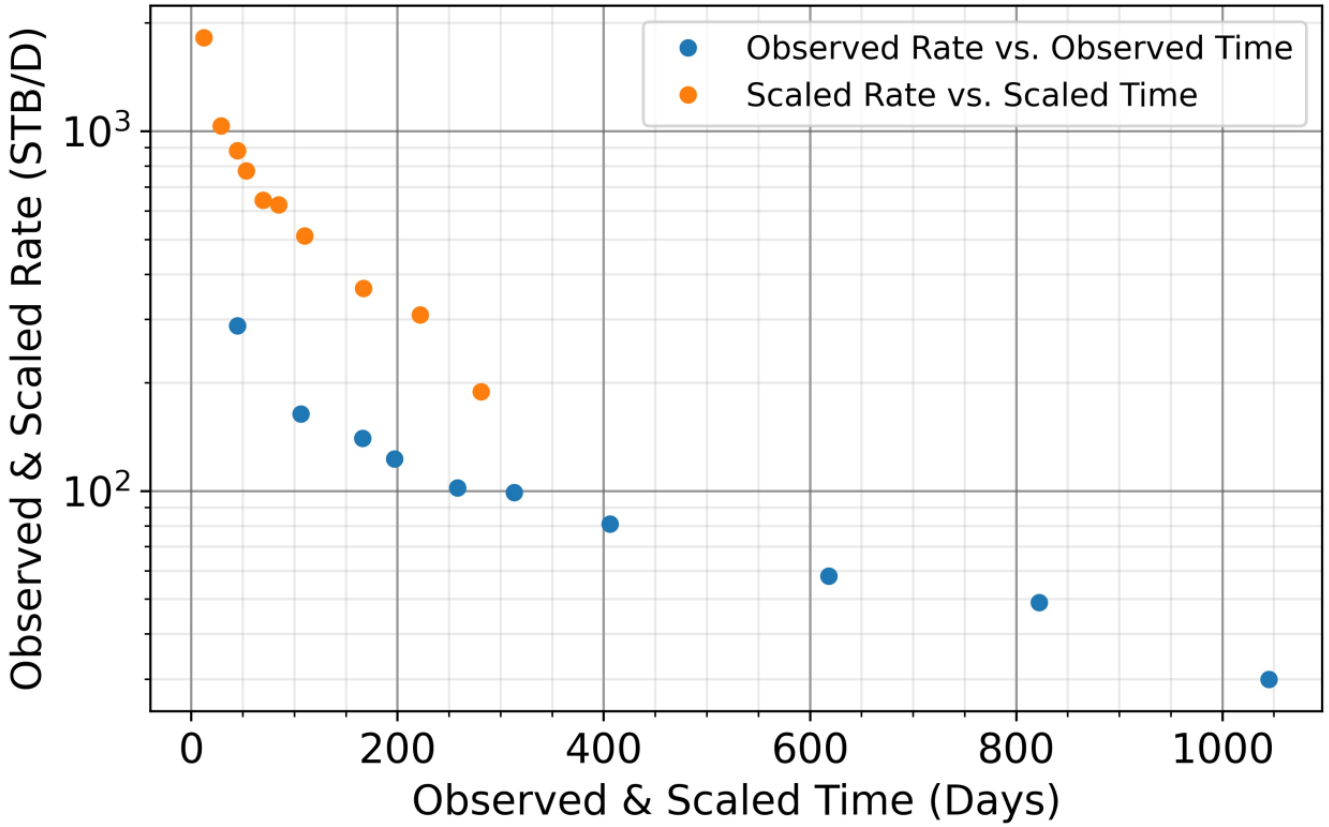


And If We Do This for All Wells in Area?

We can

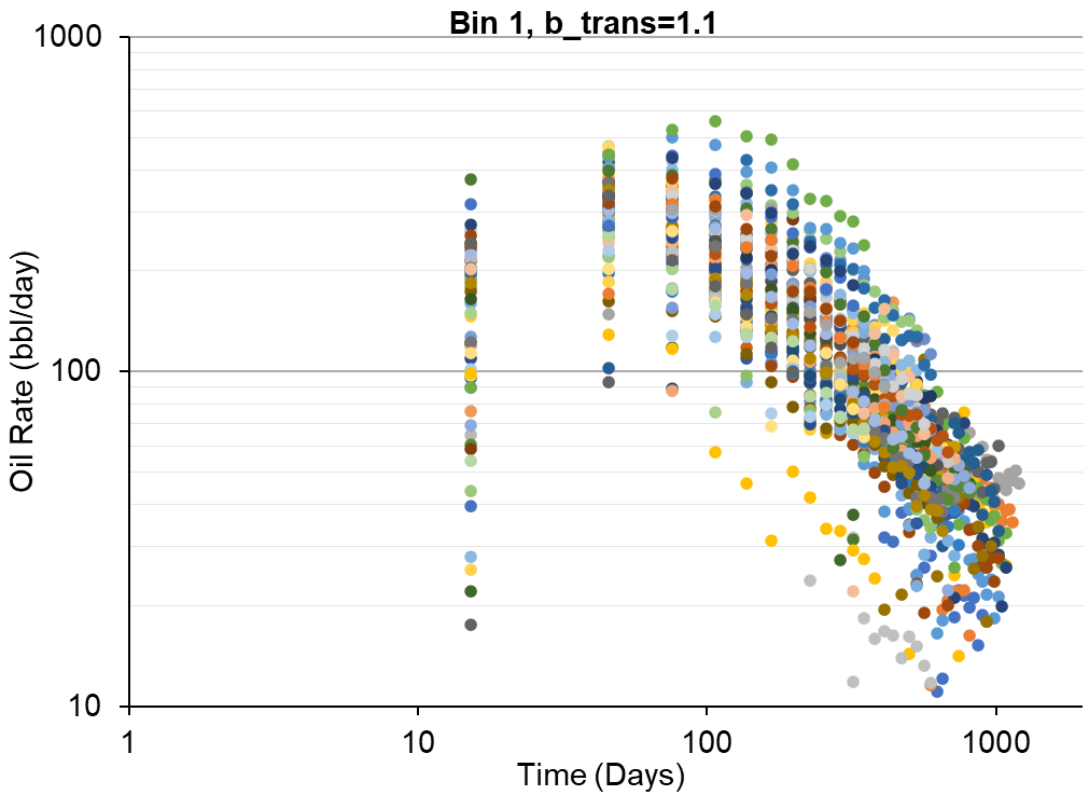
- Estimate average effective permeability for each well, perhaps map results
- Estimate average fracture length for each well, compare to completion design
- Select reference values for other parameters in dimensionless groups and scale all production profiles to reference conditions
- Average profiles with similar curve shapes
- Rescale to selected future design conditions

Entire Rate-Time Profile Scaled to Reference Conditions

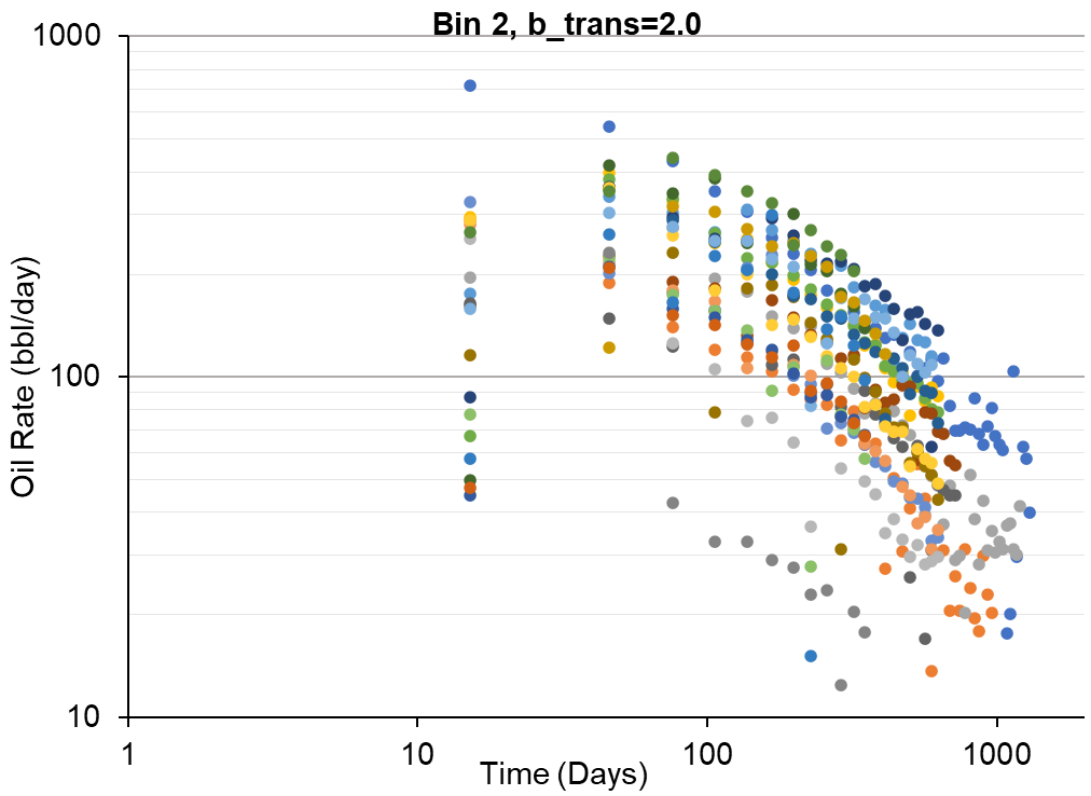


Example Production Profiles in D-J Basin Wells

Rapid early declines in some wells

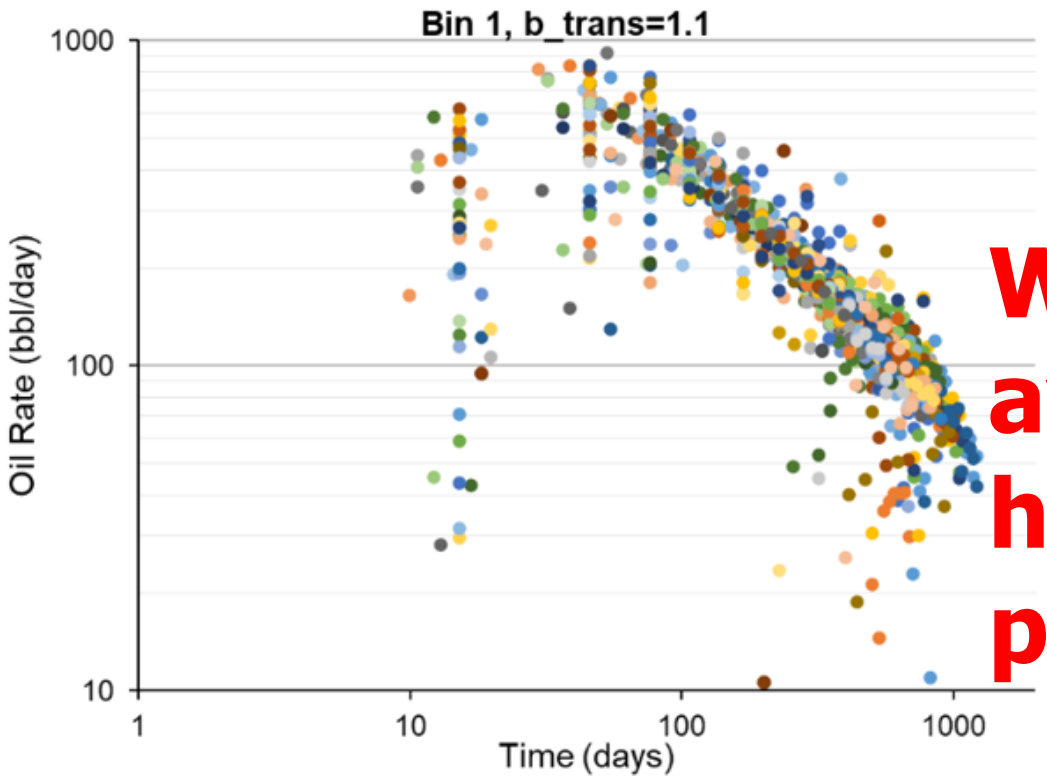


Less rapid declines in others

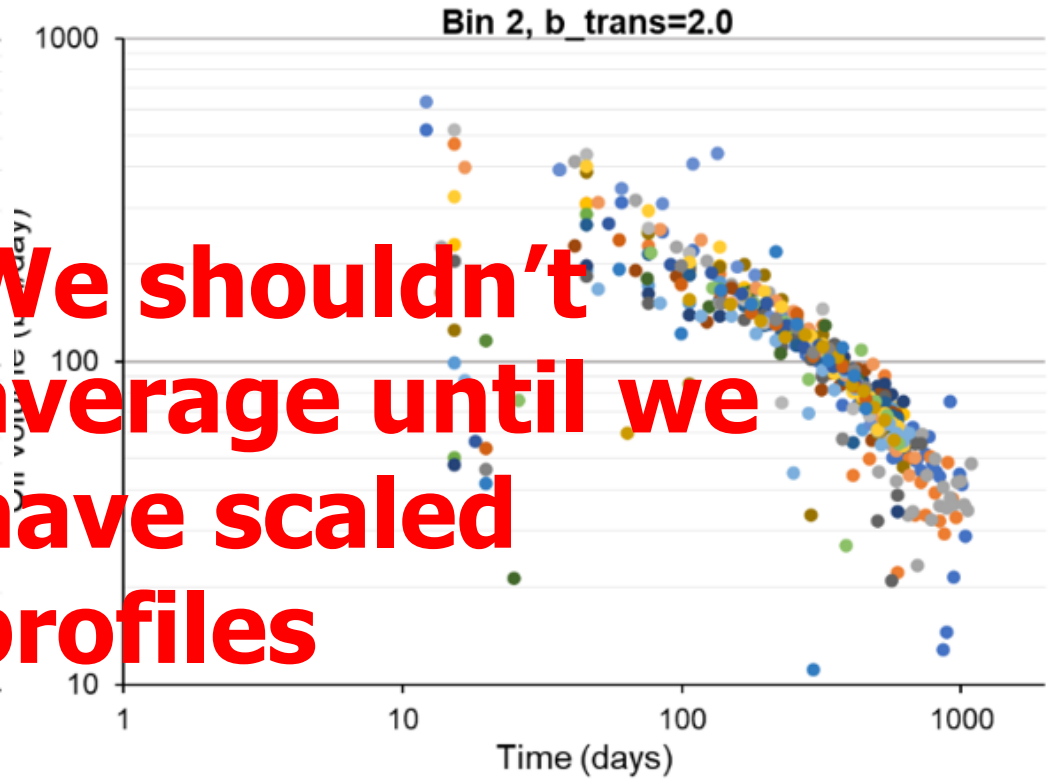


All Wells Scaled to Common Reference Conditions, Type Well Profiles Constructed

Some wells have b_{tr} near 1.1



Others have b_{tr} near 2

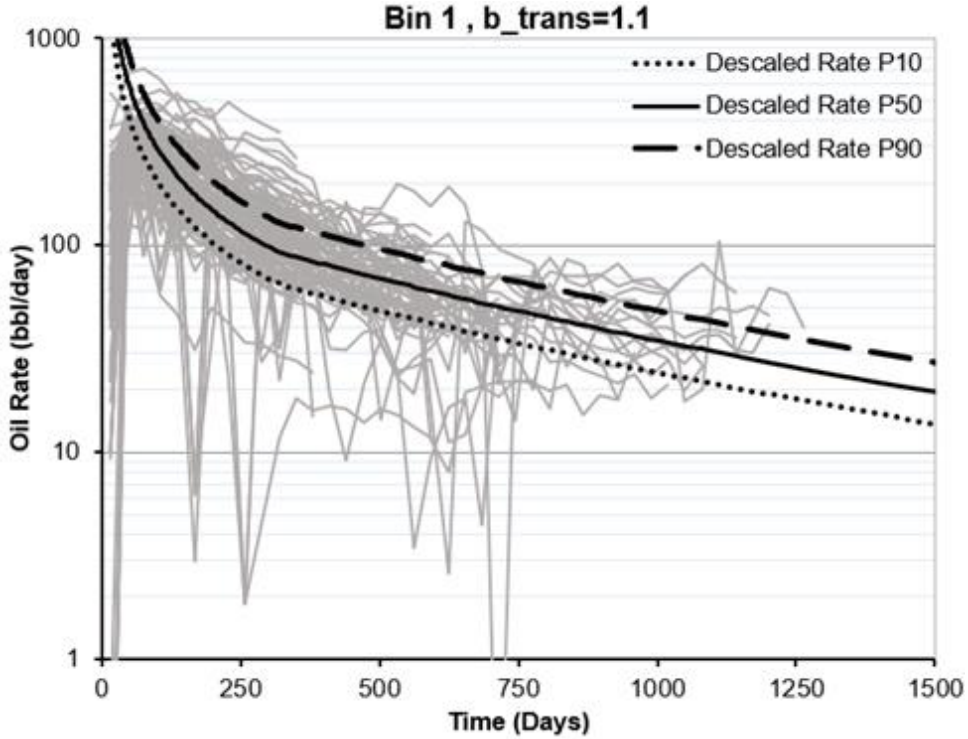


We shouldn't average until we have scaled profiles

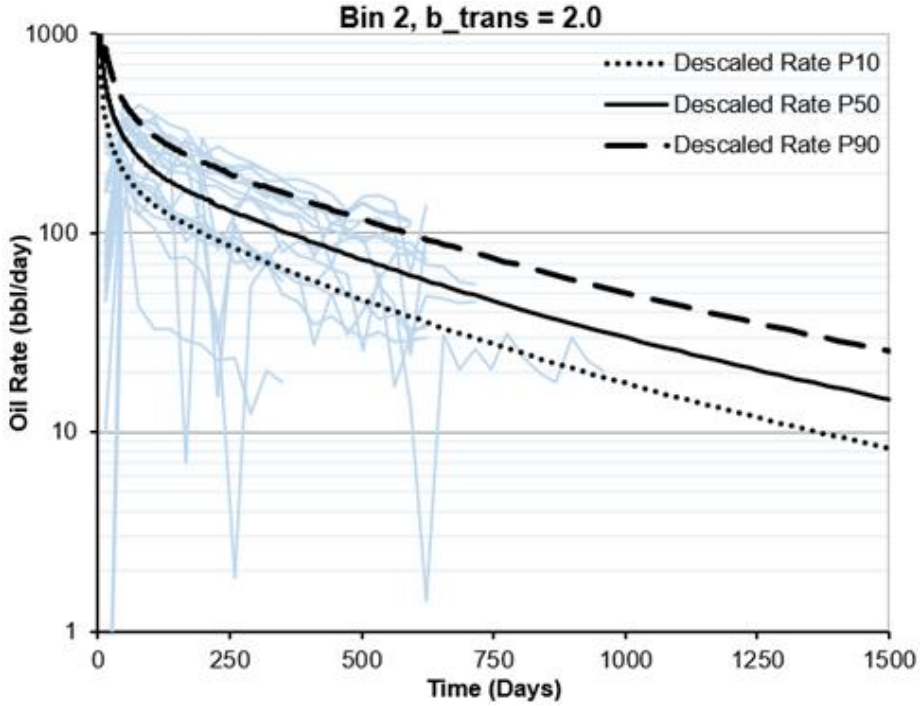
Process automated, rapid using machine learning

Production Histories, Forecasts Rescaled to Future Design Conditions, Range of Perms

Wells with more rapid early decline



Wells with less rapid early decline



Only uncertainty in k considered

How Does This Process Reduce Uncertainty in Type Well Construction?

- Identifies wells with similar shape production profiles, places them in same bin
- Scales all wells in bin to common reference conditions, so that we average wells with similar characteristics
- If we scale, bins contain more wells, reducing statistical uncertainty due to sample size
- Allows us to “rescale” to appropriate future design conditions based on known or controllable parameters

Scaling Adds Value

- If we don't scale before averaging, we get this

- But if we scale before averaging, we get this

Does Scaling Eliminate Uncertainty?

No!

- Uncontrollable, unknown parameters such as effective average permeability in undrilled wells remain uncertain
- Different degrees of interference among analog wells not accounted for
- Number of analog wells still affects statistics
- Number of wells in drilling program also affects statistics

Still, scaling reduces *some* major uncertainties – worth considering!

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Questions and Answers

Questions and Answers

- Question From Levi Briese:
  - On your Fayetteville example that you showed the shifting of production profiles can you comment on the P10/P90 ratio vs. MB time? It looks like it changed significantly between the plot of all the wells on the left and the shifted plot on the right.
- Answer:
  - If scaling worked perfectly, it would reduce the P10/P90 ratio to 1.0 – no dispersion at all. We might regard the post-scaling P10/P90 ratio as a measure of how well scaling worked in a given case. It will always reduce the ratio.

Questions and Answers

- Question From Brent Haas
  - Does the workflow need to be modified if you are in an over-pressured shale (like the Haynesville) and suspect that you have pressure dependent permeability?
- Answer:
  - I haven’t investigated this question. Intuition tells me that the post-scaling type well won’t be as accurate for forecasting in a shale with pressure-dependent permeability.

Questions and Answers

- Question From Jamir Gil
  - Thanks, Dr. Lee, for this very good presentation. Is there a paper where we can go deeper into this workflow?
- Answer:
  - The workflow that I summarized concisely at the conference is described in much greater detail in a paper to be presented at URTeC this summer, URTeC 2022-371983. The paper will be available in the SPE OnePetro after the conference. A workflow that may appeal more to those with strong spreadsheet skills in described in URTeC 2021-5030. The difference in the two papers is that the one I will present at URTeC 2022 is based on locating that single point at which data begins to deviate from the straight line characterizing transient flow, whereas the 2021 paper is based on matching the entire production profile for a well to a type curve (similar to a modified Fetkovich type curve, which will require some coding to implement) rather than identifying a single point of deviation.

Questions and Answers

- Question From John Collins
  - Great presentation, as always!
- Answer:
  - Thank you, John. We can still improve a lot, but this is a step in the right direction.

Questions and Answers

- Question From Rosa Armada
  - Thank you, Dr. Lee, for your presentation.
- Answer:
  - Rosa, thank you. We will keep trying to learn more about how to deal with other uncertainties in type well construction. We aren’t done.

Questions and Answers

- Question From Ryan Campbell
  - Are you aware if there are any plans for this approach to be added to any reserves/evaluations software packages?
- Answer:
  - I am not aware of commercial software packages that implement my ideas. I do know that some in-house software in companies that I have worked with include many of these ideas. Commercial vendors react only to strong customer demand, and that demand isn’t there yet. This implies that most people are content with the status quo.

Questions and Answers

- Question From Nassr Nassr
  - My question: Is there any effect for calculating the productivity prediction of a hydraulic fracturing well if the well is horizontal or vertical?
- Answer:
  - The techniques that I described work equally well for hydraulically fractured vertical wells and horizontal wells. However, you wouldn’t want to mix the two different types of wells: behavior after transient flow is quite different in vertical wells and horizontal wells with multiple fractures.

Questions and Answers

- Question From Kerry Kendrick
  - Is this problem a candidate for an AI or neural network solution?
- Answer:
  - This problem is a strong candidate for AI techniques, as long as they are physics based. We at A&M have made a lot of progress in doing this.

Questions and Answers

- Question From Carol Gonzalez
  - If the constant rate drawdown goes through a transition period, how do you choose “THE” point of reaching elf?
- Answer:
  - “THE” point occurs when transient flow ends – the data begin to drop off a straight-line fit. Finding that point isn’t necessarily easy, especially with noisy data. At A&M, we have developed algorithms based on statistical and machine learning techniques which smooth production profile data, identify and remove outliers, and automatically identify changes in flow regimes in well histories.

Questions and Answers

- Question From Paul Lupardus (1)
  - Dr. Lee, if the company is an SEC filer, or even if just honoring statistical aggregation, shouldn't P^ be used rather than the average for the type well?
- Answer:
  - Perhaps. P^ may be a good approximation for the P90 EUR, but I'm not sure that has been demonstrated point-by-point for the entire production profile, which would be helpful for investment decisions, given that present value calculations are strongly dependent on rates during early years rather than just on EUR.

Questions and Answers

- Question From Paul Lupardus (2)
  - Also, in my experience with various plays, I've seen scaling issues where EUR/ft changes with lateral length. You can't just scale up a longer Barnett lateral well and expect the same "Scaled" EUR of a shorter Barnett lateral.
- Answer:
  - You are absolutely on target. The dimensionless rate group used in our scaling workflow contains the perforated lateral length, L_w . Scaling would be improved if we used $(L_w)^x$ (or some other empirical modification), where "x" is a number less than one, determined from actual well performance (a non-trivial statistical exercise, which is why most people give up and say "let's just say rate is directionally proportional to perforated lateral length."

Questions and Answers

- Question From Anonymous
  - Could you elaborate more on scaling process? How you do it?
- Answer:
  - The paper I will present at URTeC 2022 this summer has numerous, easy-to-follow examples with all arithmetic included, demonstrating how we can scale. We wrote the paper with potential users like you in mind. A theory isn’t worth much if we don’t explain how to apply it.

Questions and Answers

- Question From Richard Smith
  - Have you attempted to model behavior limiting the averaging to real time, and then comparing predictive estimates to historical behavior determine the predictive capacity of the method for an area of development where wells are drilled over an extended period?
- Answer:
  - We haven’t attempted this. We need to do so in the future, because the performance of wells drilled in the future will be influenced more and more by interference. Taking that into account goes beyond simple scaling. We haven’t attempted this. We need to do so in the future, because the performance of wells drilled in the future will be influenced more and more by interference. Taking that into account goes beyond simple scaling.

Questions and Answers

- Question From Cecilia Flores
  - Thanks, Dr. Lee, for a great presentation. How can we apply the workflow on refractured wells or wells experiencing frac hits? Shall we just separate these cases on another bin?
- Answer:
  - I wouldn’t apply the workflow to refractured wells or to wells experiencing frac hits. In the case of frac hits, interference may dominate the uncertainty issue, and interference needs to be studied in different ways.